MERIDIAN RESOURCE CORP
Form 10-K
March 17, 2008

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
FORM 10-K

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

For the fiscal year ended December 31, 2007

OR

o **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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No þ

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 o No þ

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. Yesþ No o

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. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer o	Accelerated filer þ	Non-accelerated filer o	Smaller reporting company o
		(Do not check if a smaller reporting company)	

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

Aggregate market value of shares of common stock held by non-affiliates of the Registrant at June 30, 2007	$266,718,455
Number of shares of common stock outstanding at March 3, 2008:	89,363,795

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 April 29, 2008.

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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 the latest in completion and 3-D seismic technology. Our operations have historically focused on the onshore oil and natural gas regions in south Louisiana, Texas and offshore in the Gulf of Mexico. Beginning in 2005, the Company diversified its exploration and development portfolio to include unconventional styled reserve properties, first with the addition of its east Texas Austin Chalk play, and continuing in areas such as north-central Oklahoma and Kentucky exploration and development opportunities. Successful wells in these areas generally exhibit lower initial production rates than the Company s traditional styled exploration and development, yet increase the overall reserve life of the Company. As of December 31, 2007, we had proved reserves of 90 Bcfe with a present value of future net cash flows before income taxes of approximately $415 million ($391 million after tax). Sixty-eight percent (68%) of our proved reserves were natural gas and approximately sixty-six percent (66%) were classified as proved developed. We own interests in 26 fields and 121 producing wells, and operate approximately 81% 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 processing and interpretive technology and have participated in the discovery of more than 900 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, cash flows, strategic acreage positions and large database of 2-D and 3-D seismic data provide us with a significant presence in our 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 the distribution of its current capital expenditures such that it can add reserves and production from longer-lived reserves to equate to 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 historical 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.

As of December 31, 2007, we had interests in leases and options to lease acreage in approximately 363,000 gross acres in Louisiana, Texas, Oklahoma, Kentucky and the Gulf of Mexico, including approximately 100,000 net acres located in unconventional gas regions. We also have rights or access to approximately 8,600 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.

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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 processing and 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 development of a balanced exploration inventory, geologically and geographically, including deeper higher-risk, 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. To maintain our competitive advantage and protect our exploration opportunities, we will typically operate our plays, acquire large acreage positions, and focus on reducing our costs of operations. We believe that our 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 natural 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, as well as with respect to analysis, evaluation and completions.

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Oil and Natural 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, 2007. The reserve volumes were reviewed by T. J. Smith & Company, Inc., independent reservoir engineers.

	Louisiana	Texas	Gulf of Mexico	Total
Production for the year ended December 31, 2007				
Oil (MBbls)	645	124	69	838
Natural Gas (MMcf)	11,468	1,095	676	13,239
Reserves as of December 31, 2007				
Oil (MBbls)	3,198	724	934	4,856
Natural Gas (MMcf)	48,221	6,922	6,186	61,329
Estimated future net cash flows ($000)[(1)]				$576,562
Present value of future net cash flows before income taxes ($000)[(2)]				$414,918
Standardized measure of discounted future net cash flows ($000)[(3)]				$391,464

(1) Estimated Future Net Cash Flows represent the net undiscounted future revenues to be generated from the production of proved reserves, net of estimated production and future development costs, using expected realized prices at December 31, 2007, which averaged $95.54 per Bbl of oil and $6.66 per Mcf of natural gas over the estimated life of the properties and do not reflect the impact of

hedges.

(2) The Present Value of Future Net Cash Flows Before Taxes represents Estimated Future Net Cash Flows discounted to present value using an annual discount rate of 10%.

(3) The Standardized Measure of Discounted Future Net Cash Flows represents the Present Value of Future Net Cash Flows after income taxes of $23.4 million.

Productive Wells

At December 31, 2007, 2006 and 2005, we held interests in the following productive wells. As of December 31, 2007, we own interests in 26 gross (4.5 net) wells in the Gulf of Mexico which are outside operated and net to 2.1 oil wells and 2.4 natural gas wells. In addition, of the total well count for 2007, 7 wells (2.9 net) are multiple completions.

	2007		2006		2005	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil Wells	33	19	44	28	35	24
Natural Gas Wells	88	43	77	43	69	39
Total	121	62	121	71	104	63

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, 2007. Information set forth in the following table is based on reserve reports prepared in accordance with the rules and regulations of the SEC. The reserves and associated cash flows were reviewed by T. J. Smith & Company, Inc., independent reservoir engineers.

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	Proved Reserves at December 31, 2007			
	Developed Producing	Developed Non-Producing	Undeveloped	Total
	(dollars in thousands)			
Net Proved Reserves:				
Oil (MBbls)	1,502	1,390	1,964	4,856
Natural Gas (MMcf)	24,182	18,373	18,774	61,329
Natural Gas Equivalent (MMcfe)	33,194	26,711	30,559	90,464
Estimated Future Net Cash Flows[1]				$576,562
Present Value of Future Net Cash Flows (before income taxes)[2]				$414,918
Standardized Measure of Discounted Future Net Cash Flows[3]				$391,464

(1) Estimated Future Net Cash Flows represent the net undiscounted future revenues to be generated from the production of proved reserves, net of estimated production and future development costs, using expected realized prices at December 31, 2007, which averaged $95.54 per Bbl of oil and $6.66 per Mcf of natural gas over the estimated life of the properties and do not reflect the impact of hedges.

(2) The Present Value of Future Net Cash Flows

Before Taxes represents Estimated Future Net Cash Flows discounted to present value using an annual discount rate of 10%.

(3) The Standardized Measure of Discounted Future Net Cash Flows represents the Present Value of Future Net Cash Flows after income taxes of $23.4 million.

You can read additional reserve information in our Consolidated Financial Statements and the Supplemental Oil and Natural Gas Disclosures (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 2007, 2006 and 2005.

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	Gross Wells			Net Wells		
	Productive	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Exploratory Wells						
Year ended December 31, 2007	13	12	25	4.2	6.6	10.8
Year ended December 31, 2006	7	7	14	4.1	5.4	9.5
Year ended December 31, 2005	10	13	23	8.0	10.8	18.8
Development Wells						
Year ended December 31, 2007						
Year ended December 31, 2006	1		1	0.7		0.7
Year ended December 31, 2005	1		1	0.3		0.3

Meridian had 9 gross (5.9 net) wells in progress at December 31, 2007.

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 (net of commodity hedge gains/losses), from all properties in which Meridian held an interest during 2007, 2006 and 2005.

	Year Ended December 31,		
	2007	**2006**	**2005**
Production:			
Oil (MBbls)	838	859	882
Natural gas (MMcf)	13,239	18,170	20,490
Natural gas equivalent (MMcfe)	18,269	23,323	25,781
Average Prices:			
Oil ($/Bbl)	$ 64.70	$ 55.73	$ 39.29
Natural gas ($/Mcf)	$ 7.29	$ 7.77	$ 7.84
Natural gas equivalent ($/Mcfe)	$ 8.25	$ 8.11	$ 7.57
Production Expenses:			
Lease operating expenses ($/Mcfe)	$ 1.55	$ 0.97	$ 0.61
Severance and ad valorem taxes ($/Mcfe)	$ 0.52	$ 0.48	$ 0.34

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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, 2007. 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, 2007			
	Developed		Undeveloped	
Region	Gross	Net	Gross	Net
Louisiana	29,826	20,950	11,576	9,059
Oklahoma	2,958	1,397	32,473	25,206
Kentucky			46,676	35,280
Texas	7,044	4,278	183,382	93,510
Gulf of Mexico	33,759	5,988	14,908	10,673
Total	73,587	32,613	289,015	173,728

In addition to the above acreage, we currently have options or farm-ins to acquire leases on approximately 4,702 gross (3,634 net) acres of undeveloped land located in Louisiana. 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 18,800 acres in 2008, 46,000 acres in 2009, and 34,600 acres in 2010.

Geologic/Land and Operations Geophysical Expertise

Meridian employs approximately 91 full-time non-union employees and 13 contract employees. This staff includes geologists, geophysicists, land and engineering staff with over 620 combined years of experience in generating and developing onshore and offshore prospects in the regions in which we operate. 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 2007, 2006 and 2005.

	Year Ended December 31,		
Customer	**2007**	**2006**	**2005**
Superior Natural Gas	23%	35%	46%
Crosstex/Louisiana Intrastate Gas	16%	21%	19%
Shell Trading (U.S.)	14%		

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 approximately $110.00 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, 2007, was $8.25 per Mcfe compared to $8.11 per Mcfe (each net of commodity hedge gains/losses) during the year ended December 31, 2006. 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 natural gas. Individual states also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural 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. It is not possible to predict what, if any, effect the FERC s future policies will have on us. 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 natural 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

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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 natural 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 natural 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 are in material compliance 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 waters of the United States. 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. Except as described in Item 3. Legal Proceedings, we are not aware of any hazardous substance contamination for which we may be liable.

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 natural 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 natural gas industry into certain coastal and offshore water. The Clean Water Act provides for civil, criminal and administrative penalties for unauthorized discharges of 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. Except as described in Item 3. Legal Proceedings, 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 natural 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

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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, 2007, we had long-term indebtedness of $75.0 million compared to approximately $325.4 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, 2007, we had outstanding indebtedness of $75.0 million under our revolving credit facility, which was $40 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 natural 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 natural 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 natural 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

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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, natural 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 natural disasters, 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:

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- 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. 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.

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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. In 2007, 19% of our production and 21% of our reserves were outside operated. 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 may 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. Some working interest owners 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 exploratory drilling projects are based in part on seismic data, which is costly and cannot ensure the commercial success of the project.

Our decisions to purchase, explore, develop and exploit prospects or properties depend in part on data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often uncertain. Even when used and properly interpreted, 3-D seismic data and visualization techniques only assist geoscientists and geologists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know conclusively if hydrocarbons are present or producible economically. In addition, the use of 3-D seismic and other advanced technologies require greater predrilling expenditures than traditional drilling strategies, resulting in higher finding costs. Because of these factors, we could incur losses as a result of exploratory drilling expenditures. Poor results from exploration activities could have a material adverse effect on our future cash flows, ability to replace reserves and results of operations.

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, willful misconduct and breach of fiduciary duty 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. Mr. James Bond had been added as a defendant by Hawkins claiming Mr. Bond, when he was General Manager of Hawkins, did not have the right to consent, could not consent or breached his fiduciary duty to Hawkins if he did consent to all actions taken by Meridian. Mr. James T. Bond was employed by H.L. Hawkins Jr. and his companies as General Manager until 2002. He served on the Board of Directors of the Company from March 1997 to August 2004. After Mr. Bond s employment with Mr. Hawkins, Jr., and his companies ended, Mr. Bond was engaged by The Meridian Resource & Exploration LLC as a consultant. This relationship continued until his death. Mr. Bond was also the father-in-law of Michael J. Mayell, the President of the Company. Management continues to vigorously defend this action on the basis that Mr. Hawkins individually and through his agent, Mr. Bond, agreed to the course of action adopted by Meridian and further that Meridian s actions were not grossly negligent, but were within the business judgment rule. Since Mr. Bond s death, a pleading has recently been filed substituting the proper party for Mr. Bond. The Company is unable to express an opinion with respect to the likelihood of an unfavorable outcome of this matter or to estimate the amount or range of potential loss should the outcome be unfavorable. Therefore, the Company has not provided any amount for this matter in its financial statements at December 31, 2007.

Title/lease disputes. Title and lease disputes may arise in the normal course of the Company s operations. These disputes are usually small but could result in an increase or decrease in reserves once a final resolution to the title dispute is made.

Environmental litigation. Various landowners have sued Meridian (along with numerous other oil companies) in 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 Company s oil and natural gas operations. In some of the lawsuits, Shell Oil Company and SWEPI LP have demanded contractual indemnity and defense from Meridian based upon the terms of the purchase and sale agreement related to the fields, and in another lawsuit, Exxon Mobil Corporation has demanded contractual indemnity and defense from Meridian on the basis of a purchase and sale agreement related to the field(s) referenced in the lawsuit; Meridian has challenged such demands. In some cases, Meridian has also demanded defense and indemnity from their subsequent purchasers of the fields. The Company is unable to express an opinion with respect to the likelihood of an unfavorable outcome of these matters or to estimate the amount or range of potential loss should any outcome be unfavorable. Therefore, the Company has not provided any amount for these matters in its financial statements at December 31, 2007.

Consent Decree. During the fourth quarter of 2007 the Company entered into a Consent Decree with the United States Environmental Protection Agency (EPA) in settlement of alleged violations of the Clean Water Act, as amended by the Oil Pollution Act of 1990. Under the Consent Decree, the Company paid $504,000 in civil penalties for alleged discharges of crude oil into navigable waters or adjoining shorelines from the Company s operations at the Weeks Island field in Iberia Parish, Louisiana. The Company will also be subject to certain injunctive relief, requiring the Company to enhance certain pipeline survey, monitoring and reporting activities. Under the Consent Decree, the Company does not admit any liability arising out of the occurrences described in the Consent Decree or the related Complaint. The Company recorded an expense for the above amount in oil and natural gas operating expenses.

Litigation involving insurable issues. There are no material legal proceedings involving insurable issues which exceed 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.

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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 2007.

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PART II

Item 5. Market for Registrant s Common Equity, Related Stockholder Matters, and Issuer Purchases of Equity Securities

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
2007:		
First quarter	$3.01	$2.28
Second quarter	3.38	2.31
Third quarter	3.08	2.24
Fourth quarter	2.58	1.63
2006:		
First quarter	$5.09	$3.75
Second quarter	4.22	3.04
Third quarter	3.55	3.04
Fourth quarter	3.70	2.91

The closing sale price of the common stock on March 3, 2008, as reported on the New York Stock Exchange Composite Tape, was $1.57. As of March 1, 2008, we had approximately 768 shareholders of record.

Meridian has not paid cash dividends on its common stock and does not intend to pay cash dividends on its 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, and for amounts we may spend for purchase of shares of common stock over $5 million per year, without the prior consent of the lenders. See Item 7. Management s Discussion and Analysis of Financial Condition and Results Operations Liquidity and Capital Resources.

Repurchase of Common Stock

Following is a summary of our repurchase activity for the three-month period ending December 31, 2007:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of a Publicly Announced Plan (a)	Approximate Dollar Value of Shares That May Be Purchased Under the Plan During 2008
October 2007				
November 2007				
December 2007	142,000	$ 1.76	142,000	$ 5,000,000
Total	142,000	$ 1.76	142,000	$ 5,000,000

(a) In March 2007, our Board of

Directors authorized the repurchase in the open market or through privately negotiated transactions of up to $5 million worth of common shares per year over three years. The timing, volume, and nature of share repurchases will be at the discretion of management, depending on market conditions, applicable securities laws, and other factors. As of December 31, 2007, the Company had repurchased 501,300 common shares in the open market at an aggregate cost of $1,158,000 of which 342,617 shares have been issued for 401(k) contributions, for contract services and for compensation. Such shares are reflected in the accompanying Consolidated Balance Sheet as treasury stock. See Note 10 of the Notes to Consolidated Financial Statements. It is our intent to continue this program through this and future years subject to certain limitations within our Credit Facility.

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Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth information as of December 31, 2007, 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 (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)(1)) (c)
Equity compensation plans approved by security holders	6,636,204	$ 3.11	3,850,000
Equity compensation plans not approved by security holders			
Total	6,636,204	$ 3.11	3,850,000

(1) Does not include 4,650,000 shares which have been reserved for issuance in lieu of cash compensation under the Company s deferred compensation plan, which plan was approved by security holders.

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Item 6. Selected Financial Data

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

	Year Ended December 31,				
	2007	2006	2005	2004	2003
	(In thousands, except prices and per share information)				
A. Summary of Operating Data					
Production:					
Oil (MBbls)	838	859	882	1,270	1,403
Natural gas (MMcf)	13,239	18,170	20,490	27,839	20,142
Natural gas equivalent (MMcfe)	18,269	23,323	25,781	35,457	28,563
Average prices:					
Oil ($/Bbl)	$ 64.70	$ 55.73	$ 39.29	$ 28.40	$ 24.97
Natural gas ($/Mcf)	7.29	7.77	7.84	5.98	5.07
Natural gas equivalent ($/Mcfe)	8.25	8.11	7.57	5.71	4.80
B. Summary of Operations					
Total revenues	$152,178	$190,957	$195,696	$203,118	$137,479
Depletion and depreciation	77,076	106,067	97,354	102,915	75,441
Net earnings (loss)[(1)]	7,137	(73,884)	27,849	29,248	7,246
Net earnings (loss) per share:[(1)]					
Basic	$ 0.08	$ (0.84)	$ 0.33	$ 0.41	$ 0.14
Diluted	0.08	(0.84)	0.31	0.37	0.13
Dividends per:					
Common share	$	$	$	$	$
Redeemable preferred share			2.60	8.50	8.50
Preferred share					
Weighted average common shares outstanding basic	89,307	87,670	84,527	72,084	53,325
C. Summary Balance Sheet Data					
Total assets	$483,775	$467,895	$555,802	$513,274	$448,400
Long-term obligations, inclusive of current maturities	75,000	75,000	75,000	75,129	152,320
Redeemable preferred stock				31,589	60,446
Stockholders equity	325,430	320,797	377,565	316,041	184,335

(1) Applicable to common stockholders.

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

General

Meridian is an independent oil and natural gas company that explores for, acquires and develops oil and natural gas properties utilizing 3-D seismic technology. Our operations have historically been focused on the onshore oil and natural gas regions in south Louisiana, the Texas Gulf Coast and offshore in the Gulf of Mexico. Beginning in 2005, the Company continued to diversify its oil and natural gas exploration and development portfolio to include unconventional-styled reserve properties with the addition of its east Texas Austin Chalk play, and continuing in areas such as north-central Oklahoma and Kentucky exploration and development opportunities. 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 south Louisiana still contains both tremendous attributes high producing rates, high cash flows and returns, plus lower lifting 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 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.

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Operations Overview

Our four primary regions where the capital budget will be spent, and where we are currently active are: (1) East Texas, (2) South Louisiana, (3) North Louisiana, and (4) South Texas.

East Texas Austin Chalk

Meridian is on track with its plans to develop this growing core area. The Company originally acquired an interest in this play as a 50% working interest owner in approximately 7,600 acres during mid-year 2005. The original plan was to develop the Woodbine sand section offsetting the prolific Double A Wells field. Additional objectives were the Austin Chalk and Buda formations. Meridian was granted operatorship of the play and has since developed a current gross acreage position of approximately 83,000 contiguous acres in this play area. This will provide enough acreage for a drilling inventory of up to 80 possible dual lateral well locations. Since initial drilling starting in 2006, the Company has drilled or participated in the drilling of eight Austin Chalk wells (six are producing, one is drilling, one is currently completing and about to be tested). The aggregate gross proved reserves discovered as a result of the completed wells, including PUD locations, equal over 50 Bcfe (12 Bcfe net to Meridian). Average wells in the area reportedly recover approximately 3.8 Bcfe, with the best wells recovering as much as 15 Bcfe. This play s contribution to the Company s net proven reserve base has grown from 0% to approximately 11% over the course of the past 18 months and is projected to be one of the top four cash flow producing fields in the Company. Scheduled wells for 2008 are in the thicker, shallower chalk areas that are expected to produce higher oil ratios than the Company s initial wells that were primarily focused on the original Woodbine test locations.

As stated above, two wells are currently being drilled and completed in this area. The BSM No. 5 well (65% WI), has drilled two horizontal laterals with approximate lengths of 5,000 and 5,500 feet measured depth (MD), respectively. Currently a liner is being run in the second lateral and is expected to be completed and tested in the coming weeks. The Freeman No. 1 well (84% WI) has completed its first lateral at approximately 5,000 feet MD. The second lateral is currently at a length of approximately 1,400 feet MD, going to a targeted 6,000 feet MD in length. The vertical depth of the Austin Chalk formation in this area is approximately 13,500 feet. Additionally, Meridian participated in the outside operated BSM A-917 No. 1H, which was a single lateral well that reached a total depth of 18,800 MD. The well was recently tested at 2.8 Mmcf/d with 700 barrels of oil per day. Meridian holds approximately 9% working interest in this well.

The key to this project is management of the cost of drilling and completing dual laterals within estimated cost levels and leveraging the large acreage position to increase production and reserves with continual drilling. We have achieved these goals in a relatively short cycle and, in doing so, believe that with the addition of our recently acquired and constructed new drilling rig, we will be able to maintain a continuous drilling program within this region.

Levering off the knowledge and experience of the Company in this play, the Company has expanded beyond its currently established boundaries to explore and test acreage located in two separate south-central Texas areas. Meridian is building leasehold positions and has budgeted four test wells in these areas for calendar year 2008. It is anticipated that in these areas, the production will have a higher liquid (oil) content than its current production in the initial wells in east Texas. The expanded play areas are unproven and in the early stage, therefore, as they are tested, the Company will release additional details on these opportunities as they develop.

South Louisiana

South Louisiana remains a core area for near term and long term upside for Meridian. Weeks Island field continues to be the Company s largest oil field and render additional opportunities from new well locations, sidetracks and development drilling. The Company is currently reprocessing its 3-D seismic data over Weeks Island and regions in its south Louisiana play area, the expectations being that the re-processed and newly acquired 3-D data will enhance the Company s generation of lower to moderate risk new projects in this core area where it is already active and has operations and production facilities in place.

Currently, in the Weeks Island field, work is being done on the Myles Salt No. 27 development well located in Iberia Parish. The well was re-entered and is being sidetracked to approximately 11,400 feet MD. Currently the well is drilling at approximately 10,900 feet MD. The targeted sands for this re-entry are the O, P and Q sands. These are primarily oil based sands in the Miocene formation. Meridian owns a 72% working interest and is the operator of the well.

Recently in the Weeks Island field, the Goodrich Cocke No. 7 well was recompleted in the BF4 sand in the Miocene formation. Average daily production from the well is approximately 650 barrels of oil (equivalent). Flowing tubing pressure was measured at approximately 1,100 psi through a 13/64th-inch choke. The Company is the operator and owns a 69% working interest in the well.

North Louisiana

The Company is in the early stages of establishing foothold lease positions in two different repeatable project opportunities in north Louisiana. Meridian will release additional details on these opportunities as the plays develop.

New Albany Shale Play

In the New Albany Shale Play in the Illinois Basin, two wells were drilled and tested during the fourth quarter of 2007. The first well, the Farms of Meadow Hills No. 1 well was drilled to 4,600 feet, targeting the Devonian New Albany Shale formation. A second well, the Keach No. 1, was drilled to approximately the same depth, also targeting the New Albany Shale formation. Both wells were fracture stimulated and allowed to flow back the water used in the frac. Subsequent pumping of the load water off the formation resulted in the production of minor amounts of natural gas from each well. The results of the completion process have not been economic to date, and the Company is currently reviewing its options for this area for an additional test of its southern acreage position.

Oklahoma

In the Mid-Continent area, the Company tested the Hunton De-watering play and concluded that it did not fit the criteria of the Company for near or long term economic growth. The underlying assumptions as presented in this play were not achieved and therefore the Company took advantage of the opportunity to sell the remainder of its acreage position in the area recouping relatively all of its costs for the leasehold position in this area for approximately $5 million, the proceeds of which were received in 2008. Although the last well drilled, the Benkendorf No. 21-1 well appeared to be economic based on initial data points, the Company concluded that the risk of development beyond this limited acreage to other positions in the area constituted too high of a risk and that it was more prudent to deploy the capital into other areas with less risk and better economics.

Rig Status

The Company s new rig, the Triton, is anticipated to be delivered by the end of March 2008 to either the next well in the Company s East Texas Austin Chalk play, or one of the previously referenced wells in the south Texas area. Orion Drilling Company, LP will be operating, maintaining and crewing two rigs used by Meridian. One of the rigs will be owned by Meridian and one will be on a long term contract. It is anticipated that Orion s management and operations of the rigs will improve drilling efficiencies and costs for the wells it drills.

Capital Expenditure Plans for 2008. The Company anticipates a 2008 capital spending budget of approximately $74.3 million for new prospect opportunities, ranging in depths from shallow to deep. Based on current projections, these expenditures are within the Company s expected operating cash flows (including cash on hand) and allow the Company the flexibility to take on additional prospects, acquisitions or joint ventures as the opportunities are presented or developed throughout the year.

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, 2007 was $8.25 per Mcfe compared to $8.11 per Mcfe during the year ended December 31, 2006. 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 7A, Quantitative and Qualitative Disclosures about Market Risk, for a discussion of commodity price risk management activities utilized to mitigate a portion of the near term effects of this exposure to price volatility.

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Results of Operations

Year Ended December 31, 2007, Compared to Year Ended December 31, 2006

Oil and natural gas revenues, which include oil and natural gas hedging activities (see Note 12 of Notes to Consolidated Financial Statements included elsewhere herein), during the twelve months ended December 31, 2007, decreased $38.3 million (20%) as compared to 2006 revenues due to a 22% decrease in production volumes primarily from natural production declines, partially offset by a 2% increase in average commodity prices on a natural gas equivalent basis and new discoveries brought on between the comparable periods. Our average daily production decreased from 63.9 MMcfe during 2006 to 50.1 MMcfe for 2007. Oil and natural gas production volume totaled 18,269 MMcfe for 2007, compared to 23,323 MMcfe for 2006. During 2007, the Company s drilling activity was primarily focused in the East Texas project area, the Oklahoma project area and the Terrebonne Parish area of South Louisiana. During 2007, the Company drilled or participated in the drilling of 25 wells of which 13 wells were completed, representing a 52% success rate. The following table summarizes Meridian s operating revenues, production volumes and average sales prices for the years ended December 31, 2007 and 2006.

	Year Ended December 31, 2007	Year Ended December 31, 2006	Increase (Decrease)
Production:			
Oil (MBbls)	838	859	(2%)
Natural gas (MMcf)	13,239	18,170	(27%)
Natural gas equivalent (MMcfe)	18,269	23,323	(22%)
Average Sales Price:			
Oil (per Bbl)	$ 64.70	$ 55.73	16%
Natural gas (per Mcf)	7.29	7.77	(6%)
Natural gas equivalent (per Mcfe)	8.25	8.11	2%
Operating Revenues (000 s):			
Oil	$ 54,218	$ 47,859	13%
Natural gas	96,491	141,182	(32%)
Total	$ 150,709	$ 189,041	(20%)

Operating Expenses.

Oil and natural gas operating expenses on an aggregate basis increased $5.7 million (25%) to $28.3 million in 2007, compared to $22.6 million in 2006. On a unit basis, lease operating expenses increased $0.58 per Mcfe to $1.55 per Mcfe for the year 2007 from $0.97 per Mcfe for the year 2006. Oil and natural gas operating expenses increased between the periods primarily due to significantly higher insurance costs, industry wide increases in service costs and increased maintenance-related activities. For the policy year beginning in May 2006 through April 2007, insurance premiums increased over 450% from the prior policy year. During 2007, insurance premiums increased by $2.2 million and represented 39% of the difference in lease operating expenses between the periods. During the second quarter of 2007 approximately $0.5 million was expensed due to a civil penalty arising from environmental litigation (see Note 7 to Consolidated Financial Statements). The remaining $3.0 million increase in operating expenses was associated with the addition and acquisition of producing wells and additional costs related to Biloxi Marshlands area production and facilities including compression, storage, and repairs. Although the Company s insurance costs rose for the period from May 2006 through April 2007, the premium for the policy for May 2007 through April 2008 has decreased by approximately 30%. We continue to insure our assets with improved coverage as a safeguard against losses for the Company in the event of another hurricane. The increase in the per Mcfe rate was additionally attributable to the lower production between the two corresponding periods.

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Severance and Ad Valorem Taxes.
Severance and ad valorem taxes decreased $1.9 million (16%) to $9.4 million in 2007, compared to $11.3 million in 2006, primarily because of a decrease in oil and natural gas production partially offset by a higher average 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 $0.269 per Mcf (effective July 1, 2007) for natural gas. For the first six months of 2007, and the last six months of 2006, the rate was $0.373 per Mcf for natural gas, an increase from $0.252 per Mcf for the first half of 2006. On an equivalent unit of production basis, severance and ad valorem taxes increased to $0.52 per Mcfe for 2007 from $0.48 per Mcfe for 2006.
Depletion and Depreciation.
Depletion and depreciation expense decreased $29.0 million (27%) during 2007 to $77.1 million compared to $106.1 million for 2006. This was primarily the result of a decrease in the depletion rate as compared to the 2006 period and the 22% decrease in production volumes in 2007 from 2006 levels. On a unit basis, depletion and depreciation expenses decreased to $4.22 per Mcfe for 2007, compared to $4.55 per Mcfe for 2006. Depletion and depreciation expense on a per Mcfe basis decreased primarily due to the impact of the impairment of long-lived assets during 2006 as referenced below.
Impairment of Long-Lived Assets.
A decline in oil and natural gas prices as of September 30, 2006, resulted in the Company recognizing a non-cash impairment totaling $134.9 million ($87.7 million after tax) of its oil and natural gas properties under the full cost method of accounting. Additionally, the effect of this write-down resulted in a decrease in the Company s depletion rate for 2007. See Note 4 of Notes to Consolidated Financial Statements included elsewhere herein, for additional information.
General and Administrative Expense.
General and administrative expenses, which are net of costs capitalized in our oil and natural gas properties (see Note 19 of Notes to Consolidated Financial Statements included elsewhere herein), decreased $0.5 million (3%) to $16.2 million in 2007 compared to $16.7 million for the year 2006, primarily due to a decrease in professional services. On an equivalent unit of production basis, general and administrative expenses increased $0.18 per Mcfe to $0.89 per Mcfe for 2007 compared to $0.71 per Mcfe for 2006.
Accretion Expense.
In accordance with the Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations, (SFAS 143) the Company records long-term liabilities representing the discounted present value of the estimated asset retirement obligations with offsetting increases in capitalized oil and natural gas properties. This liability will continue to be accreted to its future value in subsequent reporting periods. The Company has charged approximately $2.2 million and $1.6 million to earnings as accretion expense during 2007 and 2006, respectively. The increase in 2007 levels in comparison to 2006 is primarily the result of additional wells drilled and placed on production during the year and revisions to estimated abandonment costs in the industry.
Hurricane Damage Repairs.
There were no hurricane damage repairs recorded in 2007, as compared to $4.3 million in 2006 related to damages incurred from the 2005 hurricanes Katrina and Rita, primarily related to the Company s insurance deductible and repair costs in excess of insured values. Due to the extensive damage throughout the area and the limited resources available for repairs, significant cost increases were experienced by the industry. The

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actual repair costs were higher than originally estimated and exceeded our claim limits and therefore resulted in increased expense.

Interest Expense.

Interest expense increased $0.1 million (2%) to $6.1 million in 2007 compared to $6.0 million for 2006. The increase was primarily a result of increased interest rates during 2007.

Taxes on Income.

The provision for income tax expense (benefit) for 2007 was $5.7 million as compared to ($38.5 million) for 2006. Income taxes were provided on book income after taking into account permanent differences between book income and taxable income. The benefit for 2006 was primarily the result of the impairment of long-lived assets recognized during the third quarter of 2006.

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Year Ended December 31, 2006, Compared to Year Ended December 31, 2005

Oil and natural gas revenues, which include oil and natural gas hedging activities (see Note 12 of Notes to Consolidated Financial Statements included elsewhere herein), during the twelve months ended December 31, 2006, decreased $6.2 million (3%) as compared to 2005 revenues due to a 10% decrease in production volumes primarily from natural production declines, partially offset by a 7% increase in average commodity prices on a natural gas equivalent basis and new discoveries brought on between the comparable periods. Our average daily production decreased from 70.6 MMcfe during 2005 to 63.9 MMcfe for 2006. Oil and natural gas production volume totaled 23,323 MMcfe for 2006, compared to 25,781 MMcfe for 2005. During 2006, the Company s drilling activity was primarily focused in the East Texas project area, the Biloxi Marshlands project area and the Terrebonne Parish area of South Louisiana. During 2006, the Company drilled or participated in the drilling of 15 wells of which 8 wells were completed, representing a 53% success rate. The following table summarizes Meridian s operating revenues, production volumes and average sales prices for the years ended December 31, 2006 and 2005.

	Year Ended December 31, 2006	Year Ended December 31, 2005	Increase (Decrease)
Production:			
Oil (MBbls)	859	882	(3%)
Natural gas (MMcf)	18,170	20,490	(11%)
Natural gas equivalent (MMcfe)	23,323	25,781	(10%)
Average Sales Price:			
Oil (per Bbl)	$ 55.73	$ 39.29	42%
Natural gas (per Mcf)	7.77	7.84	(1%)
Natural gas equivalent (per Mcfe)	8.11	7.57	7%
Operating Revenues (000 s):			
Oil	$ 47,859	$ 34,647	38%
Natural gas	141,182	160,608	(12%)
Total	$ 189,041	$ 195,255	(3%)

Operating Expenses.

Oil and natural gas operating expenses on an aggregate basis increased $6.7 million (43%) to $22.6 million in 2006, compared to $15.9 million in 2005. On a unit basis, lease operating expenses increased $0.35 per Mcfe to $0.97 per Mcfe for the year 2006 from $0.62 per Mcfe for the year 2005. Oil and natural gas operating expenses increased primarily due to additional properties acquired and wells drilled since the previous year, industry wide increases in service costs and significantly higher insurance costs resulting from the previous year s hurricane season. The Company s insurance rates increased by more than three times the previous year s annual premiums and represented $3.0 million of the increase for the comparable periods.

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Severance and Ad Valorem Taxes.

Severance and ad valorem taxes increased $2.5 million (28%) to $11.3 million in 2006, compared to $8.8 million in 2005, primarily because of an increase in oil prices and a higher natural gas tax rate, partially offset by a decrease in oil and natural gas production. 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 $0.373 per Mcf (effective July 1, 2006) for natural gas. For the first six months of 2006, and the last six months of 2005, the rate was $0.252 per Mcf for natural gas, an increase from $0.208 per Mcf for the first half of 2005. On an equivalent unit of production basis, severance and ad valorem taxes increased to $0.48 per Mcfe for 2006 from $0.34 per Mcfe for 2005.

Depletion and Depreciation.

Depletion and depreciation expense increased $8.7 million (9%) during 2006 to $106.1 million compared to $97.4 million for 2005. This was primarily the result of an increase in the depletion rate as compared to the 2005 period, partially offset by the 10% decrease in production volumes in 2006 from 2005 levels. On a unit basis, depletion and depreciation expenses increased to $4.55 per Mcfe for 2006, compared to $3.78 per Mcfe for 2005. 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.

Impairment of Long-Lived Assets.

A decline in oil and natural gas prices as of September 30, 2006, resulted in the Company recognizing a non-cash impairment totaling $134.9 million ($87.7 million after tax) of its oil and natural gas properties under the full cost method of accounting. See Note 4 of Notes to Consolidated Financial Statements included elsewhere herein, for additional information.

General and Administrative Expense.

General and administrative expenses, which are net of costs capitalized in our oil and natural gas properties (see Note 19 of notes to consolidated financial statements included elsewhere herein), decreased $1.3 million (7%) to $16.7 million in 2006 compared to $18.0 million for the year 2005, primarily due to a decrease in professional services, partially offset by an increase in employee compensation associated with the higher industry-wide demand for experienced personnel. On an equivalent unit of production basis, general and administrative expenses increased $0.01 per Mcfe to $0.71 per Mcfe for 2006 compared to $0.70 per Mcfe for 2005.

Accretion Expense.

In accordance with the Statement SFAS 143, the Company records long-term liabilities representing the discounted present value of the estimated asset retirement obligations with offsetting increases in capitalized oil and natural gas properties. This liability will continue to be accreted to its future value in subsequent reporting periods. The Company has charged approximately $1.6 million and $1.1 million to earnings as accretion expense during 2006 and 2005, respectively. The increase in 2006 levels in comparison to 2005 is primarily the result of a property acquisition in 2006, the additional wells drilled and placed on production during the year, revisions to estimated abandonment costs in the industry, and the acquisition of properties during 2006.

Hurricane Damage Repairs.

This expense of $4.3 million in 2006 and $3.1 million in 2005 is related to damages incurred from hurricanes Katrina and Rita, primarily related to the Company s insurance deductible and repair costs in excess of insured values. Due to the extensive damage throughout the area and the limited resources available for

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repairs, significant cost increases were experienced by the industry. The actual repair costs were higher than originally estimated and exceeded our claim limits and therefore resulted in increased expense. Additionally, a portion of the 2006 expenses resulted from changes in damage classifications with different insurance coverage. The final claim settlement negotiations were concluded in February 2007.

Interest Expense.

Interest expense increased $1.3 million (27%) to $6.0 million in 2006 compared to $4.7 million for 2005. The increase was primarily a result of the increased interest rates during 2006.

Taxes on Income.

The provision for income tax expense (benefit) for 2006 was ($38.5 million) as compared to $18.0 million for 2005. Income taxes were provided on book income after taking into account permanent differences between book income and taxable income. The benefit for 2006 was primarily the result of the impairment of long-lived assets recognized during the third quarter of 2006.

Liquidity and Capital Resources

Cash Flows. Net cash flows provided by operating activities was $97.0 million for the year ended December 31, 2007, as compared to $137.3 million for the year ended December 31, 2006, a decrease of $40.3 million or 29%, primarily due to the decrease in revenues and production volumes and the increase in operating expenses. Changes in assets and liabilities was $2.6 million primarily attributable to the reduction in accounts receivable and an increase in advances from non-operators.

Net cash flows used in investing activities were $113.6 million for the year ended December 31, 2007, as compared to $130.8 million for the year ended December 31, 2006. This decrease was due to lower expenditures for property and equipment in 2007.

Net cash flows used in financing activities were $1.3 million for the year ended December 31, 2007, as compared to net cash flows provided by financing activities of $1.7 million for 2006 primarily from the repurchase of common stock and a decrease in notes payable.

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, collectively the Lenders. The initial borrowing base under the Credit Facility was $130 million. The borrowing base under the Credit Facility was redetermined by the syndication group to be $115 million effective October 31, 2007. As of December 31, 2007, 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 natural gas reserves, the banks 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 natural 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 natural 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 natural 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, limitations on repurchases of common stock, and an unqualified audit report on the Company s consolidated financial statements, with, all of which, the Company is in compliance.

Under the Credit Facility, the Company may secure either (i) (a) an alternative base rate loan that bears interest at a rate per annum equal to the greater of the administrative agent s prime rate; or (b) federal funds-based rate plus 1/2 of 1%, plus an additional 0.5% to 1.25% depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base or; (ii) a Eurodollar base rate loan that bears interest, generally, at a rate per annum equal to the London interbank offered rate (LIBOR) plus 1.5% to 2.25%, depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base. At December 31, 2007, the three-month LIBOR interest rate was 4.70%.

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.

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On February 21, 2008, the Company amended this credit facility (Amended Credit Facility). The lending institutions under the Amended Credit Facility include Fortis Capital Corp. as administrative agent, co-lead arranger and bookrunner; The Bank of Nova Scotia, as co-lead arranger and syndication agent; Comerica Bank, US Bank NA and Allied Irish Bank plc each in their respective capacities as lenders. The borrowing base under the Amended Credit Facility is $110 million. The maturity date was extended to February 21, 2012.

Under the Amended 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 0.75% to 1.75% 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 LIBOR plus 1.5% to 2.5%, depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base. The Amended Credit Facility continues to provide 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 agreements. As of March 14, 2008, outstanding borrowing under the Amended Credit Facility totaled $80 million.

Capital Expenditures. Capital expenditures in 2007 consisted of $121.5 million for property and equipment additions related to exploration and development of various prospects, including leases, seismic data acquisitions, production facilities, and related drilling and workover activities and property acquisitions. 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 2008 capital expenditures plan is currently forecast at approximately $74.3 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 2008 plan utilizing cash flow from operations and cash on hand. When appropriate, excess cash flow from operations beyond that needed for the 2008 capital expenditures plan may be used to reduce debt or to repurchase common stock.

Cash Obligations. The following summarizes the Company s contractual obligations at December 31, 2007, including adjustments for the Amended Credit Facility, 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	$ 2,662	$	$ 75,000	$ 77,662
Interest	5,223	10,400	5,994	21,617
Drilling rigs	16,400	11,975		28,375
Non-cancelable operating leases	1,990	4,060	1,580	7,630
Total contractual cash obligations	$ 26,275	$ 26,435	$ 82,574	$ 135,284

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.

Off-Balance Sheet Arrangements. None.

Share Repurchase Program. In March 2007, the Company s Board of Directors authorized a share repurchase program. Under the program, the Company may repurchase in the open market or through privately negotiated transactions up to $5 million worth of common shares per year over three years. The timing, volume, and nature of share repurchases will be at the discretion of management, depending on market conditions, applicable securities laws, and other factors.

Prior to implementing this program, the Company was required to seek approval of the repurchase program from the Lenders under the Credit Facility. The repurchase program was approved by the Lenders, subject to certain restrictive covenants. During February 2007, the Lenders in the Credit Facility unanimously approved an amendment increasing the available limit for the Company s repurchase of its common stock from $1.0 million to $5.0 million annually. The amendment contained restrictive covenants on the Company s ability to repurchase its common stock including (i) the Company cannot utilize funds under the Credit Facility to fund any stock repurchases and (ii) immediately prior to any repurchase, availability under the Credit Facility must be equal to at least 20% of the then effective borrowing base.

As of December 31, 2007, the Company had repurchased 501,300 common shares at a cost of $1,158,000, of which 342,617 shares have been issued for 401(k) contributions for contract services and for compensation. The program does not require the Company to repurchase any specific number of shares and may be modified, suspended or terminated at any time without prior notice. The Company expects repurchases to be funded by available cash. It is the intent of the Company to continue this program through this and future years.

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 2 of the notes to the consolidated financial statements included herein.

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. Reserve estimates significantly impact depletion and potential impairments of oil and natural gas properties. The Company analyzes its estimates, including those related to oil and natural gas revenues, bad debts, oil and natural gas properties, derivative contracts, 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. 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 2007, 2006, and 2005, such capitalized costs totaled $16.5 million, $15.4 million, and $13.8 million, respectively. General and administrative costs related to production and general overhead are expensed as incurred.

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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 10.5%; however, a 10% increase in our reserves would have decreased our provision for the year by approximately 8.7%.
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 natural 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, 2007, we had $53.6 million allocated to unevaluated oil and natural gas properties. A 10% decrease in the unevaluated oil and natural gas properties balance would have increased our provision for depletion and amortization of oil and natural gas properties by approximately 1.1% and a 10% increase would have decreased our provision by approximately 1.3% for the year ended December 31, 2007.
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 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.
Accordingly, based on September 30, 2006, pricing of $4.17 per Mcf of natural gas and $63.37 per barrel of oil, the Company recognized in the third quarter of 2006 a non-cash impairment of $134.9 million ($87.7 million after tax) of the Company s oil and natural gas properties under the full cost method of accounting.
Due to the imprecision in estimating oil and natural gas revenues as well as the potential volatility in oil and natural gas prices and their effect on the carrying value of our proved oil and natural 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

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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, 2007, we had a cushion (i.e. the excess of the ceiling over our capitalized costs) of $62.2 million (before tax). A 10% increase in prices would have increased our cushion by approximately 32%. A 10% decrease in prices would have decreased our cushion by approximately 34%. Our hedging program would reduce some of the impact of a price decline.

Price Risk Management Activities. The Company follows SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS 133) 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.

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 SFAS 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 $21,000 during the year ended December 31, 2007, a gain of $128,000 during the year ended December 31, 2006, and a loss of $251,000 during the year ended December 31, 2005.

As of December 31, 2007, the estimated fair value of the Company s oil and natural gas contracts was an unrealized loss of $0.3 million ($0.2 million net of tax) which is recognized in other comprehensive income. Based upon December 31, 2007, oil and natural gas commodity prices, approximately $0.3 million of the loss deferred in other comprehensive income could potentially decrease gross revenues in 2008. The contract agreements expire at various dates through December 31, 2009.

Net settlements under these contract agreements increased (decreased) oil and natural gas revenues by $3,252,000, $3,821,000 and ($20,578,000) for the years ended December 31, 2007, 2006, and 2005, respectively.

See Item 7A, 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, 2007 and 2006, and were determined based upon variable interest rates currently available to us for borrowings with similar terms.

New Accounting Pronouncements. In July 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes and Interpretation of SFAS No. 109 (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The Company adopted the provisions of FIN 48 on January 1, 2007, and the adoption had no material impact on the Company s results of operations and financial position.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115 (SFAS 159). SFAS 159 permits entities to choose to measure eligible financial assets and liabilities at fair value. Unrealized gains and loses on items for which the fair value option has been elected are reported in earnings. SFAS 159 is effective for years beginning after November 15, 2007. We adopted SFAS 159 on January 1, 2008 and did not elect to apply the fair value method to any eligible assets or liabilities at that time.

In September 2006, the SEC issued Staff Accounting Bulletin No. 108 (SAB 108). Due to diversity in practice among registrants, SAB 108 expresses SEC staff views regarding the process by which misstatements in financial statements are evaluated for purposes of determining whether financial statement restatement is necessary. The Company adopted the provisions of SAB 108 on January 1, 2007, and the adoption did not have a material impact on our financial position or results of operations.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS 157). SFAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosure about fair value measurements. The standard applies prospectively to new fair value measurements performed after the required effective dates, which are as follows: on January 1, 2008, the standard became applicable to measurements of the fair values of financial instruments and recurring fair value measurements of non-financial assets and liabilities; on January 1, 2009, the standard will apply to all remaining fair value measurements, including non-recurring measurements of non-financial assets and liabilities, such as asset retirement obligations and impairments of long-lived assets. The Company adopted the effective portion of SFAS 157 on January 1, 2008; we do not expect the adoption to have a material impact on our financial position or results of operations.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations. SFAS 141(R) replaces SFAS No. 141, Business Combinations. SFAS 141(R) retains the purchase method of accounting for acquisitions, but requires a number of changes, including changes in the way assets and liabilities are recognized in purchase accounting. It also changes the recognition of assets acquired and liabilities assumed arising from contingencies and requires the expensing of acquisition-related costs as incurred. Generally, SFAS 141(R) is effective on a prospective basis for all business combinations completed on or after January 1, 2009. We do not expect the adoption of SFAS 141(R) to have a material impact on our financial position or results of operations, provided we do not undertake a significant acquisition or business combination.

ITEM 7A. 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.

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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 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. 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 35% of our proved developed natural gas production and 26% 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 NYMEX future prices for the applicable trading months. The fair values of our hedging agreements are recorded on our consolidated balance sheet as assets or liabilities. The estimated fair value of our hedging agreements as of December 31, 2007, is provided below (see the Company s website at www.tmrc.com for a quarterly breakdown of the Company s hedge position for 2007 and beyond):

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	Type	Notional Amount	Floor Price ($ per unit)	Ceiling Price ($ per unit)	Estimated Fair Value Asset (Liability) December 31, 2007 (in thousands)
Natural Gas (mmbtu)					
Jan 2008 - Dec 2008	Collar	2,230,000	$ 7.00	$ 12.15	$ 606
Jan 2008 - Dec 2008	Collar	1,010,000	$ 7.50	$ 11.50	479
Jan 2008 - Dec 2008	Collar	1,830,000	$ 7.50	$ 10.10	655
Jan 2009 - Dec 2009	Collar	1,230,000	$ 7.50	$ 10.45	108
Total Natural Gas					1,848
Crude Oil (bbls)					
Jan 2008 - Dec 2008	Collar	40,000	$ 55.00	$ 83.00	(492)
Jan 2008 - Dec 2008	Collar	20,000	$ 65.00	$ 80.60	(280)
Jan 2008 - Dec 2008	Collar	30,000	$ 65.00	$ 85.00	(319)
Jan 2008 - April 2008	Collar	24,000	$ 60.00	$ 82.00	(341)
May 2008 - July 2008	Collar	15,000	$ 60.00	$ 82.00	(198)
Jan 2008 - July 2008	Collar	28,000	$ 65.00	$ 93.15	(183)
Jan 2008 - July 2008	Collar	21,000	$ 70.00	$ 87.40	(204)
Jan 2008 - Dec 2008	Collar	19,000	$ 75.00	$ 102.50	(42)
Jan 2009 - Dec 2009	Collar	23,000	$ 70.00	$ 93.55	(104)
Total Crude Oil					(2,163)
					$ (315)

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GLOSSARY OF CERTAIN OIL AND NATURAL GAS TERMS

The definitions set forth below apply to the indicated terms as used in this Annual Report on Form 10-K. All volumes of natural gas referred to are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit and in most instances are rounded to the nearest major multiple.

Bbl One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to crude oil or other liquid hydrocarbons.

Bbl/d One barrel per day.

Bcf Billion cubic feet.

Bcfe Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Btu British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Completion The installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Developed acreage The number of acres allocated or assignable to producing wells or wells capable of production.

Developed well A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole or well A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

Equivalents When we refer to equivalents, we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one barrel of oil is equal to six thousand cubic feet of natural gas.

Exploratory well A well drilled to find and produce oil or natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

Farm-in or farm-out An agreement where the owner of a working interest in a natural gas and oil lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a farm-in while the interest transferred by the assignor is a farm-out.

Field An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

Gross acres or gross wells The total acres or wells, as the case may be, in which a working interest is owned.

Intangible Drilling and Development Costs Expenditures made by an operator for wages, fuel, repairs, hauling, supplies, surveying, geological works, etc., incident to and necessary for the preparing for and drilling of wells and the construction of production facilities and pipelines.

Lease Operating Expense Recurring expenses incurred to operate wells and equipment on a producing lease. Examples include pumping and gauging, chemicals, compression, fuel and water, insurance and property taxes.

MBbls One thousand barrels of crude oil or other liquid hydrocarbons.

Mcf One thousand cubic feet.

Mcfe One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Mcfe/d One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids, per day.

MD Measured depth.

MMBls One million barrels of crude oil or other liquid hydrocarbons.

MMbtu One million Btus.

MMMbtu One billion Btus.
MMcf One million cubic feet.
MMcf/d One million cubic feet per day.
MMcfe One million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.
Net acres or net wells The sum of the fractional working interests owned in gross acres or gross wells.
Net revenue interest An interest in the production and revenues created from the working interest which is generally calculated net or after deducting any royalty interests.
NYMEX New York Mercantile Exchange.
OCS Outer Continental Shelf in the Gulf of Mexico.
Oil Crude oil and condensate
Present value or PV10 When used with respect to natural gas and oil reserves, the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date indicated, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%.
Productive well A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.
Proved developed nonproducing reserves Proved developed reserves expected to be recovered from zones behind casing in existing wells.
Proved developed producing reserves Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and able to produce to market.
Proved reserves The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. In addition, please refer to the definitions of proved oil and natural gas reserves as provided in Rule 4-10(a)(2)(3)(4) of Regulation S-X of the federal securities laws.
Proved undeveloped location A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.
Proved undeveloped reserves Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.
Recompletion The completion for production of an existing well bore to another formation from that in which the well has been previously completed.
Reservoir A porous and permeable underground formation containing a natural accumulation of producible oil or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.
Royalty interest An interest in a natural gas and oil property entitling the owner to a share of natural gas or oil production free of costs of production.
Tangible Drilling and Development Costs The costs of physical lease and well equipment and structures and the costs of assets that themselves have a salvage value.
TVD Total vertical depth.
Undeveloped acreage Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil, regardless of whether the acreage contains proved reserves.
WI Working interest.
Working interest The operating interest which gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.
Workover Operations on a producing well to restore or increase production.

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.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors
The Meridian Resource Corporation
Houston, Texas

We have audited the accompanying consolidated balance sheets of The Meridian Resource Corporation and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of operations, stockholders equity, cash flows, and comprehensive income (loss) for each of the three years in the period ended December 31, 2007. 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.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards No. 123(R), Share-Based Payment.

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, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, 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, 2007, 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 14, 2008, expressed an unqualified opinion thereon.

BDO SEIDMAN, LLP
Houston, Texas
March 14, 2008

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

	Year Ended December 31,		
	2007	**2006**	**2005**
REVENUES:			
Oil and natural gas	$ 150,709	$ 189,041	$ 195,255
Price risk management activities	21	128	(251)
Interest and other	1,448	1,788	692
	152,178	190,957	195,696
OPERATING COSTS AND EXPENSES:			
Oil and natural gas operating	28,338	22,614	15,860
Severance and ad valorem taxes	9,409	11,259	8,811
Depletion and depreciation	77,076	106,067	97,354
General and administrative	16,221	16,674	18,010
Accretion expense	2,230	1,588	1,120
Impairment of long-lived assets		134,865	
Hurricane damage repairs		4,314	3,066
	133,274	297,381	144,221
EARNINGS (LOSS) BEFORE OTHER EXPENSES & INCOME TAXES	18,904	(106,424)	51,475
OTHER EXPENSES:			
Interest expense	6,090	5,982	4,724
EARNINGS (LOSS) BEFORE INCOME TAXES	12,814	(112,406)	46,751
INCOME TAXES:			
Current	650	369	(568)
Deferred	5,027	(38,891)	18,568
	5,677	(38,522)	18,000
NET EARNINGS (LOSS)	7,137	(73,884)	28,751
Dividends on preferred stock			902
NET EARNINGS (LOSS) APPLICABLE TO COMMON STOCKHOLDERS	$ 7,137	$ (73,884)	$ 27,849

NET EARNINGS (LOSS) PER SHARE:						
Basic	$	0.08	$	(0.84)	$	0.33
Diluted	$	0.08	$	(0.84)	$	0.31
WEIGHTED AVERAGE NUMBER OF COMMON SHARES:						
Basic		89,307		87,670		84,527
Diluted		94,944		87,670		90,090

See notes to consolidated financial statements.

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

	December 31, 2007	December 31, 2006
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 13,526	$ 31,424
Restricted cash	30	1,282
Accounts receivable, less allowance for doubtful accounts of $210 [2007] and $232 [2006]	19,874	24,285
Due from affiliates	2,580	670
Prepaid expenses and other	4,538	3,457
Assets from price risk management activities	2,453	7,968
Deferred tax asset	164	
Total current assets	43,165	69,086
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, full cost method (including $53,645 [2007] and $54,356 [2006] not subject to depletion)	1,771,768	1,663,865
Land	48	48
Equipment and other	18,503	7,492
	1,790,319	1,671,405
Less accumulated depletion and depreciation	1,350,577	1,273,522
Total property and equipment, net	439,742	397,883
OTHER ASSETS:		
Assets from price risk management activities	865	490
Other	3	436
Total other assets	868	926
TOTAL ASSETS	$ 483,775	$ 467,895

See notes to consolidated financial statements.

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

	December 31, 2007	December 31, 2006
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 9,583	$ 6,700
Advances from non-operators	6,996	3,051
Revenues and royalties payable	6,592	7,933
Notes payable	2,662	2,754
Accrued liabilities	22,011	21,938
Liabilities from price risk management activities	2,772	1,024
Asset retirement obligations	3,365	4,803
Deferred income taxes payable		2,336
Current income taxes payable	147	
Total current liabilities	54,128	50,539
LONG-TERM DEBT	75,000	75,000
OTHER:		
Deferred income taxes	8,238	3,364
Liabilities from price risk management activities	861	190
Asset retirement obligations	20,118	18,005
	29,217	21,559
COMMITMENTS AND CONTINGENCIES (Notes 6, 7, and 11)		
STOCKHOLDERS EQUITY:		
Common stock, $0.01 par value (200,000,000 shares authorized, 89,450,466 [2007] and 89,139,600 [2006] shares issued)	936	928
Additional paid-in capital	537,145	534,441
Accumulated deficit	(212,142)	(219,279)
Accumulated other comprehensive income (loss)	(221)	4,707
	325,718	320,797
Less treasury stock, at cost 158,683 [2007] shares	288	
Total stockholders equity	325,430	320,797

TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 483,775	$ 467,895

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2007	2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net earnings (loss)	$ 7,137	$ (73,884)	$ 28,751
Adjustments to reconcile net earnings (loss) to net cash provided by operating activities:			
Depletion and depreciation	77,076	106,067	97,354
Impairment of long-lived assets		134,865	
Amortization of other assets	436	443	446
Non-cash compensation	2,549	2,300	1,845
Non-cash price risk management activities	(21)	(128)	251
Accretion expense	2,230	1,588	1,120
Deferred income taxes	5,027	(38,891)	18,568
Changes in assets and liabilities:			
Restricted cash	1,252	(48)	(343)
Accounts receivable	4,411	16,903	(13,425)
Prepaid expenses and other	(1,081)	(2,163)	969
Accounts payable	(946)	362	(118)
Advances from non-operators	3,945	3,051	
Due to (from) affiliates	(1,910)	(5,308)	772
Revenues and royalties payable	(1,341)	(1,216)	1,032
Asset retirement obligations	(2,055)	(6,026)	(469)
Other assets and liabilities	282	(643)	3,936
Net cash provided by operating activities	96,991	137,272	140,689
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to property and equipment	(116,696)	(130,062)	(139,522)
Acquisition of properties		(11,734)	
Proceeds from (settlements on) sale of property	3,060	11,032	(51)
Net cash used in investing activities	(113,636)	(130,764)	(139,573)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term debt	3,000	10,000	10,000
Reductions in long-term debt	(3,000)	(10,000)	(10,129)
Proceeds Notes payable	9,540	9,248	3,142
Reductions Notes payable	(9,632)	(7,597)	(2,909)
Repurchase of common stock	(1,158)		
Issuance of stock/exercise of stock options			13
Preferred dividends			(2,166)
Additions to deferred loan costs	(3)		(99)
Net cash provided by (used in) financing activities	(1,253)	1,651	(2,148)

NET CHANGE IN CASH AND CASH EQUIVALENTS	(17,898)	8,159	(1,032)
Cash and cash equivalents at beginning of year	31,424	23,265	24,297
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 13,526	$ 31,424	$ 23,265
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Non-cash activities:			
Conversion of preferred stock	$	$	$ (30,625)
Issuance of shares for contract services	$ (1,033)	$ (795)	$ (1,932)
Issuance of shares for acquisition of properties	$	$ (7,000)	$
Accrual of capital expenditures	$ 4,799	$ (259)	$ (7,079)
ARO Liability new wells drilled	$ 476	$ 4,559	$ 883
ARO Liability changes in estimates	$ 24	$ 10,723	$ 806

See notes to consolidated financial statements.

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THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
Years Ended December 31, 2005, 2006 and 2007 (in thousands)

	Common Stock		Additional Paid-In	Accumulated Earnings	Accumulated Other Comprehensive Income	Unamortized Deferred	Treasury Stock		
	Shares	Par Value	Capital	(Deficit)	(Loss)	Compensation	Shares	Cost	Total
Balance, December 31, 2004	79,215	$ 821	$ 490,351	$ (173,244)	$ (1,574)	$ (313)		$	$ 316,041
Issuance of rights to common stock		3	1,597			(1,600)			
Company s 401(k) plan contribution	53		250						250
Exercise of stock options	49		163						163
Compensation expense						1,595			1,595
Accum. other comprehensive income					(740)				(740)
Issuance for conversion of pref stock	7,099	71	30,554						30,625
Issuance cost 2004 stock offering			(150)						(150)
Issuance of shares for contract services	402	5	1,927						1,932
Preferred dividends				(902)					(902)
Net earnings				28,751					28,751
Balance, December 31, 2005	86,818	$ 900	$ 524,692	$ (145,395)	$ (2,314)	$ (318)		$	$ 377,565
Effect of adoption of SFAS 123(R)			(318)			318			
Issuance of rights to common stock		5	(5)						
	92	1	335						336

Company s 401(k) plan contribution									
Stock-based compensation			372						372
Compensation expense			1,592						1,592
Accum. other comprehensive income					7,021				7,021
Issuance of shares for contract services	224	2	793						795
Issuance of shares Vintage acq.	2,006	20	6,980						7,000
Net loss				(73,884)					(73,884)
Balance, December 31, 2006	89,140	$ 928	$ 534,441	$ (219,279)	$ 4,707	$		$	$ 320,797
Shares repurchased							501	(1,158)	(1,158)
Issuance of rights to common stock		5	(5)						
Company s 401(k) plan contribution	42	1	155				(157)	390	546
Stock-based compensation			294						294
Compensation expense			1,598						1,598
Accum. other comprehensive income					(4,928)				(4,928)
Issuance of shares for contract services	237	2	584				(175)	447	1,033
Issuance of shares as compensation	31		78				(10)	33	111
Net earnings				7,137					7,137
Balance, December 31, 2007	89,450	$ 936	$ 537,145	$ (212,142)	$ (221)	$	159	$ (288)	$ 325,430

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2007	**2006**	**2005**
Net earnings (loss) applicable to common stockholders	$ 7,137	$ (73,884)	$ 27,849
Other comprehensive income (loss), net of tax, for unrealized gains (losses) from hedging activities:			
Unrealized holding gains (losses) arising during period (1)	(2,814)	9,505	(14,116)
Reclassification adjustments on settlement of contracts (2)	(2,114)	(2,484)	13,376
	(4,928)	7,021	(740)
Total comprehensive income (loss)	$ 2,209	$ (66,863)	$ 27,109
(1) Net income tax (expense) benefit	$ 1,515	$ (5,118)	$ 7,601
(2) Net income tax (expense) benefit	$ 1,138	$ 1,337	$ (7,202)

See notes to consolidated financial statements.

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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, Texas 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, 2007, was $30,000, and at December 31, 2006, was $1,282,000. 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 a drilling rig, computer equipment, computer 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.

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Statement of Cash Flows

For purposes of the statements of cash flows, cash equivalents include time deposits, certificates of deposit and all highly liquid instruments with original maturities of three months or less. The Company made cash payments for interest of $6.0 million, $5.5 million, and $3.9 million in 2007, 2006 and 2005, respectively. Cash payments (refunds) for income taxes (federal and state, net of receipts) were $61,000 for 2007, ($322,000) for 2006 and $1,285,000 for 2005.

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, 2007, and December 31, 2006, the Company had approximately $13,318,000 and $32,475,000, respectively, in excess of FDIC insured limits. The Company has not experienced any losses in such accounts.

Revenue Recognition and Accounts Receivable

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. Accounts receivable includes accrued oil and natural gas revenue receivables of approximately $16.6 million and $18.3 million as of December 31, 2007 and 2006, respectively.

The Company maintains an allowance for doubtful accounts on trade receivables equal to amounts estimated to be uncollectible. This estimate is based upon historical collection experience, combined with a specific review of each customer s outstanding trade receivable balance. Management believes that the allowance for doubtful accounts is adequate, however, actual write-offs may exceed the recorded allowance.

Hurricane Damage Repairs

This expense of $4.3 million in 2006 and $3.1 million in 2005 is related to damages incurred from hurricanes Katrina and Rita, primarily related to the Company s insurance deductible and repair costs in excess of insured values. Due to the extensive damage throughout the area and the limited resources available for repairs, significant cost increases were experienced by the industry. The actual repair costs were higher than originally estimated and exceeded our claim limits and therefore resulted in increased expense. Additionally, a portion of the 2006 expenses resulted from changes in damage classifications with different insurance coverage. The final claim settlement negotiations were concluded in February 2007.

Capitalized Interest

Interest cost is capitalized as part of the historical cost of assets. During 2007, interest of approximately $323,000 was capitalized on the construction of our drilling rig purchase. Our oil and natural gas properties not being amortized, did not include significant investments qualifying for capitalized interest. Interest is capitalized using a weighted average interest rate based on our outstanding borrowings.

Earnings Per Share

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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

Effective January 1, 2006, the Company adopted the provisions of SFAS No. 123R, Shared-Based Payment, (SFAS 123R) using the modified prospective method. SFAS 123R replaces SFAS No. 123, Accounting for Stock-Based Compensation and amends SFAS No. 95, Statement of Cash Flows. SFAS 123R addresses the accounting for share-based payment transactions in which an enterprise received 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. SFAS 123R eliminates the ability to account for share-based compensation transactions using Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees, (APB 25) and generally requires instead that such transactions be accounted for using the fair-value based method. Prior to adoption of SFAS 123R, the Company followed the intrinsic value method in accordance with APB 25 to account for stock options. Prior period financial statements have not been restated. Compensation expense is recorded for stock option awards over the requisite vesting periods based upon the market value on the date of the grant. Stock-based compensation expense related to SFAS123R of approximately $294,000 and $372,000 was recorded in the years ended December 31, 2007 and 2006, respectively. No stock-based compensation expense related to SFAS 123R was recorded in the year ended December 31, 2005.

The following is a pro-forma reconciliation of reported earnings and earnings per share for the year ended December 31, 2005, as if the Company used the fair value method of accounting for stock-based compensation (thousands of dollars, except per share information):

	2005
Net earnings applicable to common stockholders as reported	$ 27,849
Stock-based compensation expense determined under fair method for all awards, net of tax	(237)
Net earnings applicable to common stockholders (pro forma)	$ 27,612
Basic earnings per share:	
As reported	$ 0.33
Pro forma	$ 0.33
Diluted earnings per share:	
As reported	$ 0.31
Pro forma	$ 0.31

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 4.54%, 4.97%, and 3.97%; dividend yield of 0%; volatility factors of the expected market price of the Company s common stock of 0.59, 0.80 and 0.92 for 2007, 2006 and 2005, respectively; and a weighted-average expected life of five years. These assumptions resulted in a weighted average grant date fair value of $1.36, $2.33 and $3.43 for options granted in 2007,

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2006 and 2005, 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, accounts payable, and accrued liabilities 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, 2007 and 2006, and were determined based upon variable interest rates currently available to us for borrowings with similar terms.

Notes Payable.

Notes payable are related to the financing of the Company s insurance program. The weighted average interest rates on the notes payable were 6.76% and 6.86%, as of December 31, 2007 and 2006, respectively.

Lease Accounting.

The Company amortizes the cost of leasehold improvements over the term of the lease. Rent incentives, such as holidays, are also amortized over the life of the lease.

Derivative Financial Instruments

The Company follows the provisions of SFAS No. 133, Accounting for Derivative Instruments and Certain Hedging Activities (SFAS 133). The Company enters into derivative contracts to hedge the price risks associated with a portion of anticipated future oil and natural 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 gains of $21,000 and $128,000 related to hedge ineffectiveness during the years ended December 31, 2007 and 2006, respectively, 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 are 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.

Income Taxes

The Company accounts for federal income taxes using the liability method. Under the liability method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. Under the liability method, the effect on previously recorded deferred tax assets and liabilities resulting from a change in tax rates is recognized in earnings in the period in which the change is enacted.

The Company may from time to time be assessed interest or penalties by major tax jurisdictions, although any such assessments historically have been minimal and immaterial to our financial results. Should the Company determine that any of its tax positions are uncertain, it may record related interest and penalties that may be assessed. Interest recorded, if any, will be charged to interest expense and penalties recorded will be charged to operating expenses in the Company s statement of operations.

Environmental Expenditures

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a noncapital nature are recorded when environmental assessment and or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally not estimable unless the timing of cash payments for the liability or component are fixed or reliably determinable.

New Accounting Pronouncements

In July 2006, the Financial Accounting Standard Board (FASB) issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes and interpretation of SFAS No. 109 (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on recognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. The Company adopted the provisions of FIN 48 on January 1, 2007, and the adoption had no material impact on the Company s results of operations and financial position.

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In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115 (SFAS 159). SFAS 159 permits entities to choose to measure eligible financial assets and liabilities at fair value. Unrealized gains and loses on items for which the fair value option has been elected are reported in earnings. SFAS 159 is effective for years beginning after November 15, 2007. We adopted SFAS 159 on January 1, 2008 and did not elect to apply the fair value method to any eligible assets or liabilities at that time.

In September 2006, the SEC issued Staff Accounting Bulletin No. 108 (SAB 108). Due to diversity in practice among registrants, SAB 108 expresses SEC staff views regarding the process by which misstatements in financial statements are evaluated for purposes of determining whether financial statement restatement is necessary. The Company adopted the provisions of SAB 108 on January 1, 2007, and the adoption did not have a material impact on our financial position or results of operations.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS 157). SFAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosure about fair value measurements. The standard applies prospectively to new fair value measurements performed after the required effective dates, which are as follows: on January 1, 2008, the standard became applicable to measurements of the fair values of financial instruments and recurring fair value measurements of non-financial assets and liabilities; on January 1, 2009, the standard will apply to all remaining fair value measurements, including non-recurring measurements of non-financial assets and liabilities, such as asset retirement obligations and impairments of long-lived assets. The Company adopted the effective portion of SFAS 157 on January 1, 2008; we do not expect the adoption to have a material impact on our financial position or results of operations.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations. SFAS 141(R) replaces SFAS No. 141, Business Combinations. SFAS 141(R) retains the purchase method of accounting for acquisitions, but requires a number of changes, including changes in the way assets and liabilities are recognized in purchase accounting. It also changes the recognition of assets acquired and liabilities assumed arising from contingencies and requires the expensing of acquisition-related costs as incurred. Generally, SFAS 141(R) is effective on a prospective basis for all business combinations completed on or after January 1, 2009. We do not expect the adoption of SFAS 141(R) to have a material impact on our financial position or results of operations, provided we do not undertake a significant acquisition or business combination.

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. Reserve estimates significantly impact depreciation and depletion expense and potential impairments of oil and natural gas properties. The Company analyzes its estimates, including those related to oil and natural gas revenues, bad debts, oil and natural gas properties, derivative contracts, 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.

Reclassification of Prior Period Statements

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

3. ASSET RETIREMENT OBLIGATIONS

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The Company follows SFAS No. 143, Accounting for Asset Retirement Obligations, which 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.

Accretion expenses were $2.2 million, $1.6 million and $1.1 million in 2007, 2006 and 2005, respectively.

The following table describes the change in the Company s asset retirement obligations for the years ended December 31, 2007 and 2006 (thousands of dollars):

Asset retirement obligation at December 31, 2005	$ 11,964
Additional retirement obligations recorded in 2006	4,559
Settlements during 2006	(6,026)
Revisions to estimates and other changes during 2006	10,723
Accretion expense for 2006	1,588
Asset retirement obligation at December 31, 2006	22,808
Additional retirement obligations recorded in 2007	476
Settlements during 2007	(2,055)
Revisions to estimates and other changes during 2007	24
Accretion expense for 2007	2,230
Asset retirement obligation at December 31, 2007	$ 23,483

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 the costs to do so.

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4. IMPAIRMENT OF LONG-LIVED ASSETS

At the end of each quarter, the unamortized cost of oil and natural gas properties, net of related deferred income taxes, is limited to the sum of the estimated future net revenues from proved properties using 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.

Accordingly, based on September 30, 2006, pricing of $4.17 per Mcf of natural gas and $63.37 per barrel of oil, the Company recognized in the third quarter of 2006 a non-cash impairment of $134.9 million ($87.7 million after tax) of the Company s oil and natural gas properties under the full cost method of accounting.

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

5. DEBT

Current Revolving Credit Agreement

On December 23, 2004, the Company amended its 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, collectively the Lenders. The initial borrowing base under the Credit Facility was $130 million. The borrowing base under the Credit Facility was redetermined by the syndication group to be $115 million, effective October 31, 2007. As of December 31, 2007, 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 natural 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 natural 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 natural 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 natural 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, limitations on repurchases of common stock, and an unqualified audit report on the Company s consolidated financial statements, with, all of which, the Company is in compliance.

Under the Credit Facility, the Company may secure either (i) (a) an alternative base rate loan that bears interest at a rate per annum equal to the greater of the administrative agent s prime rate; or (b) federal funds-based rate plus 1/2 of 1%, plus an additional 0.5% to 1.25% depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base or; (ii) a Eurodollar base rate loan that bears interest, generally, at a rate per annum equal to the London interbank offered rate (LIBOR) plus 1.5% to 2.25%, depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base. At December 31, 2007, the three-month LIBOR interest rate was 4.70%. 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.

On February 21, 2008, the Company amended this credit facility (Amended Credit Facility). The lending institutions under the Amended Credit Facility include Fortis Capital Corp. as administrative agent, co-lead arranger and bookrunner; The Bank of Nova Scotia, as co-lead arranger and syndication agent; Comerica Bank, US Bank NA and Allied Irish Bank plc each in their respective capacities as lenders. The borrowing base under the Amended Credit Facility is $110 million. The maturity date was extended to February 21, 2012.

Under the Amended 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 0.75% to 1.75% 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 LIBOR plus 1.5% to 2.5%, depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base. The Amended Credit Facility continues to provide 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 agreements. As of March 14, 2008, outstanding borrowing under the Amended Credit Facility totaled $80 million.

Current Debt Maturities

Scheduled debt maturities for the next five years and thereafter, as of December 31, 2007, are as follows: none in 2008 through 2011, $75 million in 2012, and none thereafter.

6. CONTRACTUAL OBLIGATIONS

In April 2006, the Company negotiated an amendment to its office building lease agreement that extended the Company s office lease until September 30, 2011. As of December 31, 2007, the remaining base rental payments will be $1.7 million in 2008, $1.8 million in 2009, $2.0 million in 2010 and $1.6 million in 2011. The Company also has operating leases for equipment with various terms, none exceeding three years. Rental expense amounted to approximately $2.0 million, $2.5 million and $2.5 million in 2007, 2006 and 2005, respectively. Future minimum lease payments under all non-cancelable operating leases having initial terms of one year or more are $2.0 million for each of 2008, 2009 and 2010, $1.6 million for 2011, and none thereafter. In addition, over the next three years, the Company has contractual obligations for the use of drilling rigs. These obligations are $16.4 million in 2008, $10.1 million in 2009, and $1.9 million in 2010.

7. 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, willful misconduct and breach of fiduciary duty 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

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satisfying a prior adverse judgment in favor of Amoco Production Company. Mr. James Bond had been added as a defendant by Hawkins claiming Mr. Bond, when he was General Manager of Hawkins, did not have the right to consent, could not consent or breached his fiduciary duty to Hawkins if he did consent to all actions taken by Meridian. Mr. James T. Bond was employed by H.L. Hawkins Jr. and his companies as General Manager until 2002. He served on the Board of Directors of the Company from March 1997 to August 2004. After Mr. Bond s employment with Mr. Hawkins, Jr., and his companies ended, Mr. Bond was engaged by The Meridian Resource & Exploration LLC as a consultant. This relationship continued until his death. Mr. Bond was also the father-in-law of Michael J. Mayell, the President of the Company. Management continues to vigorously defend this action on the basis that Mr. Hawkins individually and through his agent, Mr. Bond, agreed to the course of action adopted by Meridian and further that Meridian s actions were not grossly negligent, but were within the business judgment rule. Since Mr. Bond s death, a pleading has recently been filed substituting the proper party for Mr. Bond. The Company is unable to express an opinion with respect to the likelihood of an unfavorable outcome of this matter or to estimate the amount or range of potential loss should the outcome be unfavorable. Therefore, the Company has not provided any amount for this matter in its financial statements at December 31, 2007.

Title/lease disputes. Title and lease disputes may arise in the normal course of the Company s operations. These disputes are usually small but could result in an increase or decrease in reserves once a final resolution to the title dispute is made.

Environmental litigation. Various landowners have sued Meridian (along with numerous other oil companies) in 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 Company s oil and natural gas operations. In some of the lawsuits, Shell Oil Company and SWEPI LP have demanded contractual indemnity and defense from Meridian based upon the terms of the purchase and sale agreement related to the fields, and in another lawsuit, Exxon Mobil Corporation has demanded contractual indemnity and defense from Meridian on the basis of a purchase and sale agreement related to the field(s) referenced in the lawsuit; Meridian has challenged such demands. In some cases, Meridian has also demanded defense and indemnity from their subsequent purchasers of the fields. The Company is unable to express an opinion with respect to the likelihood of an unfavorable outcome of these matters or to estimate the amount or range of potential loss should any outcome be unfavorable. Therefore, the Company has not provided any amount for these matters in its financial statements at December 31, 2007.

Consent Decree. During the fourth quarter of 2007 the Company entered into a Consent Decree with the United States Environmental Protection Agency (EPA) in settlement of alleged violations of the Clean Water Act, as amended by the Oil Pollution Act of 1990. Under the Consent Decree, the Company paid $504,000 in civil penalties for alleged discharges of crude oil into navigable waters or adjoining shorelines from the Company s operations at the Weeks Island field in Iberia Parish, Louisiana. The Company will also be subject to certain injunctive relief, requiring the Company to enhance certain pipeline survey, monitoring and reporting activities. Under the Consent Decree, the Company does not admit any liability arising out of the occurrences described in the Consent Decree or the related Complaint. During 2007, the Company recorded an expense for the above amount in oil and natural gas operating expenses.

Litigation involving insurable issues. There are no material legal proceedings involving insurable issues which exceed 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.

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8. TAXES ON INCOME

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

	Year Ended December 31,		
	2007	**2006**	**2005**
Current:			
Federal	$ 560	$ 334	$ (676)
State	90	35	108
Deferred:			
Federal	4,470	(39,108)	17,480
State	557	217	1,088
Income tax expense (benefit)	$ 5,677	$ (38,522)	$ 18,000

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

	Year Ended December 31,		
	2007	**2006**	**2005**
Income tax provision (benefit) computed at statutory rate	$ 4,485	$ (39,342)	$ 16,363
Nondeductible costs	577	415	479
State income tax, net of federal tax benefit	615	240	1,158
Decrease in net operating loss carryover due to expiration		165	
Income tax expense (benefit)	$ 5,677	$ (38,522)	$ 18,000

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,	
	2007	**2006**
Deferred tax assets:		
Net operating tax loss carryforward	$ 27,391	$ 40,085
Statutory depletion carryforward	950	950
Tax credits	2,205	1,644
Unrealized hedge loss	119	
Deferred compensation	6,232	5,673
Other	44	187
Total deferred tax assets	36,941	48,539
Deferred tax liabilities:		
Book basis in excess of tax basis in oil and natural gas properties	45,015	51,705
Unrealized hedge gain		2,534
Total deferred tax liabilities	45,015	54,239

Net deferred tax liability	$ (8,074)	$ (5,700)

As of December 31, 2007, the Company had approximately $78.3 million of tax net operating loss carryforwards. The net operating loss carryforwards assume that certain items, primarily intangible drilling

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costs, have been capitalized and are being amortized 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 2019 and extend through 2026. A portion of the net operating loss carryforwards is subject to change in ownership limitations that could restrict the Company s ability to utilize such losses in the future.

As of December 31, 2007, 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**
2019	$ 20,379	$ 44,170
2020	30	30
2021	36	36
2022	13,053	6,502
2023	44,669	44,516
2025	42	54
2026	52	
Total	$ 78,261	$ 95,308

As of December 31, 2007, the Company had approximately $2.2 million of AMT tax credit carryforwards that do 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 2007.

9. REDEEMABLE CONVERTIBLE PREFERRED STOCK

During the first six months of 2005, the Company completed the conversion of all of the remaining outstanding shares of its 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. In 2005, the Company paid $2.2 million of preferred dividends, which included $1.3 million accumulated from the prior year.

10. STOCKHOLDERS EQUITY

Common Stock

In March 2007, the Company s Board of Directors authorized a share repurchase program. Under the program, the Company may repurchase in the open market or through privately negotiated transactions up to $5 million worth of common shares per year over three years. The timing, volume, and nature of share repurchases will be at the discretion of management, depending on market conditions, applicable securities laws, and other factors. Prior to implementing this program, the Company was required to seek approval of the repurchase program from the Lenders under the Credit Facility. The repurchase program was approved by the Lenders, subject to certain restrictive covenants. During February 2007, the lenders in the Credit Facility unanimously approved an amendment increasing the available limit for the Company s repurchase of its common stock from $1.0 million to $5.0 million annually. The amendment contained restrictive covenants on the Company s ability to repurchase its common stock including (i) the Company cannot utilize funds under the Credit Facility to fund any stock repurchases and (ii) immediately prior to any repurchase, availability under the Credit Facility must be equal to at least 20% of the then effective borrowing base. As of December 31, 2007, the Company had repurchased 501,300 common shares at a cost of $1,158,000, of which 342,617 shares have been reissued for 401(k) contributions, for contract services and for compensation. The program does not require the Company to repurchase any specific number of shares and may be modified, suspended, or terminated at any time without prior notice. The Company expects repurchases to be funded by available cash. It is the intent of the Company to continue this program through this and future years.

Warrants

The Company had the following warrants outstanding at December 31, 2007:

Warrants	Number of Shares	Exercise Price	Expiration Date
Executive Officers	1,428,000	$ 5.85	*
General Partner	1,808,516	$ 0.10	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, 2007, 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 1,808,516 shares of common stock at an exercise price of $0.10 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 in cash 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.

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Stock Options

Options to purchase the Company s common stock have been granted to officers, employees, nonemployee directors and certain key individuals, under various stock option plans. Options generally become exercisable in 25% cumulative annual increments beginning with the date of grant and expire at the end of ten years. At December 31, 2007, 2006 and 2005, 3,850,000, 1,785,310, and 2,162,478 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, 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
Granted	109,668		3.40
Exercised			
Canceled	(245,750)		7.72
Outstanding at December 31, 2006	3,458,968	$	3.84
Granted	115,000		2.69
Exercised			
Canceled	(174,280)		8.80
Outstanding at December 31, 2007	3,399,688	$	3.55
Shares exercisable:			
December 31, 2005	3,430,050	$	3.97
December 31, 2006	3,285,465	$	3.76
December 31, 2007	3,252,001	$	3.57

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Range of Exercisable Prices	Options Outstanding: Outstanding at December 31, 2007		Weighted Average Exercise Price	Options Exercisable: Exercisable at December 31, 2007		Weighted Average Exercise Price
$1.79 - $2.71	55,000	$	2.34	17,083	$	2.36
$3.00 - $3.99	3,173,947		3.37	3,076,048		3.37
$4.01 - 8.42	170,741		7.36	158,870		7.54
	3,399,688	$	3.55	3,252,001	$	3.57

The weighted average remaining contractual life of options outstanding at December 31, 2007, was approximately two years.

The aggregate intrinsic value of options outstanding and exercisable at December 31, 2007, was de minimis. The aggregate intrinsic value represents the total pre-tax value (the difference between the Company s closing stock price on the last trading day of 2007 and the exercise price, multiplied by the number of in-the-money options) that would have been received by the option holders had all option holders exercised their options on December 31, 2007. The amount of aggregate intrinsic value will change based on the fair market value of the Company s common stock.

As of December 31, 2007, there was approximately $175.4 thousand of total unrecognized compensation expense related to unvested stock-based compensation plans. This compensation expense is expected to be recognized, net of forfeitures, on a straight-line basis over the remaining vesting period of approximately 2.5 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 an electable portion of their cash compensation rights to common stock pursuant to the Company s Long Term Incentive Plan. Under the terms of this deferred compensation plan, Messrs., Reeves and Mayell each elected to defer $400,000 for 2007, $400,000 for 2006 and $400,000 for 2005. 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 the amount deferred, which is subject to a one-year vesting period. Under the terms of the deferred compensation plan, the employee and matching deferrals are allocated to a notional common stock account in which notional shares of common stock are credited to the accounts of the officers 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, 2007, the plan had reserved 5,650,000 shares of common stock for future issuance and 4,163,332 notional shares had been granted. No actual shares of common stock have been issued and the officers have 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 and matching grants 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 these deferred portions of their base salaries during these periods, the compensation expense required to be reported by the Company for these equity grants was $1,598,000

$1,593,000, and $1,595,000 for 2007, 2006 and 2005 periods, respectively, and is reflected in general and administrative expense and in oil and natural gas properties for the years ended December 31, 2007, 2006 and 2005, respectively.

Stockholder Rights Plan

On May 5, 1999, the Company s Board of Directors declared a dividend distribution of one Right for each then-current and future outstanding share of common stock. Each Right entitles the registered holder to purchase one one-thousandth percent interest in a share of the Company s Series B Junior Participating preferred stock with a par value of $.01 per share and an exercise price of $30. Unless earlier redeemed by the Company at a price of $.01 each, the Rights become exercisable only in certain circumstances constituting a potential change in control of the Company and will expire on May 5, 2009.

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

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

11. PROFIT SHARING AND SAVINGS PLAN

The Company has a 401(k) profit sharing and savings plan (the Plan) that covers substantially all employees and entitles them to contribute up to 15% of their annual compensation, subject to maximum limitations imposed by the Internal Revenue Code. The Company matches 100% of each employee s contribution up to 6.5% of annual compensation subject to certain limitations as outlined in the Plan. In addition, the Company may make discretionary contributions which are allocable to participants in accordance with the Plan. Total expense related to the Company s 401(k) plan was $545,000, $381,000, and $300,000 in 2007, 2006, and 2005, 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 was $4.7 million, $6.7 million and $6.4 million in 2007, 2006 and 2005, 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

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additional future wells would be placed into the Geoscientist Plan. During 2002, the Executive Committee decided to modify this position and for certain key geoscientists the Geoscientist 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. For the years ended December 31, 2007, 2006 and 2005, compensation expense in the amounts of $78,054, $137,624, and $120,161 were recorded for each individual. The net profit interests represent real property rights that are not subject to vesting or continued employment with the Company. Messrs. Reeves and Mayell will not participate in the Well Bonus Plans for any particular property to the extent the original net profit interest grants covers such property.

12. OIL AND NATURAL GAS HEDGING ACTIVITIES

The Company may address market risk by selecting instruments whose value fluctuations correlate strongly with the underlying commodity being hedged. 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 SFAS 133 and any changes in fair value are recorded in

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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 gains of $21,000 and $128,000 during the years ended December 31, 2007 and 2006, respectively, and a loss of $251,000 during the year ended December 31, 2005 due to hedge ineffectiveness.

As of December 31, 2007, the estimated fair value of the Company s oil and natural gas contracts was an unrealized loss of $0.3 million ($0.2 million net of tax) which is recognized in other comprehensive income. Based upon oil and natural gas commodity prices at December 31, 2007, approximately $0.3 million of the loss deferred in other comprehensive income could potentially decrease gross revenues in 2008. These derivative agreements expire at various dates through December 31, 2009.

Net settlements under these contracts increased (decreased) oil and natural gas revenues by $3,252,000, $3,821,000, and ($20,578,000) for the years ended December 31, 2007, 2006, and 2005 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 35% of proved developed natural gas production and 26% 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.

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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, 2007, is provided below:

	Type	Notional Amount	Floor Price ($ per unit)	Ceiling Price ($ per unit)	Estimated Fair Value Asset (Liability) December 31, 2007 (in thousands)
Natural Gas (mmbtu)					
Jan 2008 - Dec 2008	Collar	2,230,000	$ 7.00	$ 12.15	$ 606
Jan 2008 - Dec 2008	Collar	1,010,000	$ 7.50	$ 11.50	479
Jan 2008 - Dec 2008	Collar	1,830,000	$ 7.50	$ 10.10	655
Jan 2009 - Dec 2009	Collar	1,230,000	$ 7.50	$ 10.45	108
Total Natural Gas					1,848
Crude Oil (bbls)					
Jan 2008 - Dec 2008	Collar	40,000	$ 55.00	$ 83.00	(492)
Jan 2008 - Dec 2008	Collar	20,000	$ 65.00	$ 80.60	(280)
Jan 2008 - Dec 2008	Collar	30,000	$ 65.00	$ 85.00	(319)
Jan 2008 - April 2008	Collar	24,000	$ 60.00	$ 82.00	(341)
May 2008 - July 2008	Collar	15,000	$ 60.00	$ 82.00	(198)
Jan 2008 - July 2008	Collar	28,000	$ 65.00	$ 93.15	(183)
Jan 2008 - July 2008	Collar	21,000	$ 70.00	$ 87.40	(204)
Jan 2008 - Dec 2008	Collar	19,000	$ 75.00	$ 102.50	(42)
Jan 2009 - Dec 2009	Collar	23,000	$ 70.00	$ 93.55	(104)
Total Crude Oil					(2,163)
					$ (315)

13. MAJOR CUSTOMERS

Major customers for the years ended December 31, 2007, 2006 and 2005, were as follows (based on sales exceeding 10% of total oil and natural gas revenues):

	Year Ended December 31,		
Customer	**2007**	**2006**	**2005**
Superior Natural Gas	23%	35%	46%
Crosstex/Louisiana Intrastate Gas	16%	21%	19%
Shell Trading (U.S.)	14%		

14. RELATED PARTY TRANSACTIONS

Historically since 1994, affiliates of Meridian have been permitted to hold interests in projects of the Company. With the approval of the Board of Directors, Texas Oil Distribution and Development, Inc. (TODD), JAR Resources LLC (JAR) and Sydson Energy, Inc. (Sydson), entities controlled by Joseph A. Reeves, Jr. and Michael J. Mayell, 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 $9,871,000, $7,743,000, and $9,997,000 for the years ended December 31, 2007, 2006 and 2005, respectively, in oil and natural gas drilling activities. Net amounts due from TODD, JAR and Mr. Reeves were approximately $1,753,000 and $337,000 as of December 31, 2007 and 2006, respectively. Net amounts due from Sydson and Mr. Mayell were approximately $827,000 and $333,000 as of December 31, 2007 and 2006, 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, 2007, 2006 and 2005 and received fees of approximately $231,000, $227,000, and $320,000 respectively. Such fees exceeded 5% of the gross revenues of Kares & Cihlar for those respective years. Mr. Kares also participated in the Management Plan described in Note 11 above, pursuant to which he was paid approximately $275,000 during 2007, $438,000 during 2006, and $464,000 during 2005.

Mr. Gary A. Messersmith, a Director of Meridian, is currently a member of the law firm of Looper, Reed & McGraw P.C. in Houston, Texas, which provided legal services for the Company for the years ended December 31, 2007, 2006 and 2005, and received fees of approximately $73,000, $26,000, and $19,000, respectively. In addition, the Company pays Gary A. Messersmith, P.C. $8,333 per month relating to his services provided to the Company. Mr. Messersmith also participated in the Management Plan described in Note 11 above, pursuant to which he was paid approximately $441,000 during 2007, $751,000 during 2006, and $702,000 during 2005.

Mr. G. M. Larberg, a recently added Director of Meridian, is a petroleum industry consultant that provided the Company with services for the years ended December 31, 2007 and 2006, and received consulting fees of approximately $223,000 and $21,000, respectively.

Mr. J. Drew Reeves, the son of Mr. Joseph A. Reeves, Jr., is a staff member in the Land Department. Mr. Drew Reeves was paid $168,000, $146,000, and $100,000 for the years 2007, 2006 and 2005, respectively. Mr. 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 $164,000, $150,000, and $111,000 for the years 2007, 2006 and 2005, respectively. Mr. 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 year ended December 31, 2005 and received fees of approximately $32,000. 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 $371,000 in 2007, $337,000 in 2006 and $100,000 in 2005. Such fees exceeded 5% of the gross revenues for these firms for those respective years.

Mr. Michael W. Mayell, the son of Mr. Michael J. Mayell, an officer and Director of Meridian, is a staff member in the Production Department, and was paid $129,000, $114,000, and $79,000 for the years 2007, 2006 and 2005, respectively. Mr. James T. Bond, former Director of Meridian, was the father-in-law of Mr. Michael J. Mayell, and was providing consultant services to the Company and received fees in the amount of $48,000, $155,000, and $175,000, for the years 2007, 2006 and 2005, respectively.

15. EARNINGS PER SHARE

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

	(in thousands, except per share)		
	Year Ended December 31,		
	2007	**2006**	**2005**
Numerator:			
Net earnings (loss) applicable to common stockholders	$ 7,137	$ (73,884)	$ 27,849
Plus income impact of assumed conversions:			
Preferred stock dividends (c)			
Net earnings (loss) applicable to common stockholders plus assumed conversions	$ 7,137	$ (73,884)	$ 27,849
Denominator:			
Denominator for basic earnings (loss) per share weighted-average shares outstanding	89,307	87,670	84,527
Effect of potentially dilutive common shares:			
Warrants and rights (a)	5,637	N/A	4,755
Employee and director stock options (b)		N/A	808
Redeemable preferred stock (c)			
Denominator for diluted earnings (loss) per share weighted-average shares outstanding and assumed conversions	94,944	87,670	90,090
Basic earnings (loss) per share	$ 0.08	$ (0.84)	$ 0.33
Diluted earnings (loss) per share	$ 0.08	$ (0.84)	$ 0.31

Warrants and stock options for which the exercise prices were greater than the average market price of the Company s common stock are excluded from the computation of diluted earnings per share. Stock rights issued under our deferred compensation plan have no exercise price and are included in diluted earnings per share in all years, unless there is a loss. Redeemable preferred stock, outstanding only in 2005, is considered for inclusion based on the if converted method. Under this method, the shares are assumed converted, and any related preferred dividends earned are added to income. The result may be dilutive to earnings per share, in which case the shares are included in our computation of diluted earnings per share, or it may be anti-dilutive, in which case the shares are excluded. All potentially dilutive shares, whether from options, warrants, rights, or redeemable preferred stock, are excluded when there is an operating loss, because inclusion of such shares would be anti-dilutive.

(a) The number of warrants excluded totaled approximately 1.4 million, 3.2 million, and 1.4 million in 2007, 2006 and 2005, respectively.

The number of stock rights excluded totaled approximately 3.6 million in 2006.

(b) The number of stock options excluded totaled approximately 3.6 million, 3.7 million, and 0.5 million in 2007, 2006 and 2005, respectively.

(c) A weighted average of approximately 2.1 million redeemable preferred shares were excluded in 2005.

16. ACCRUED LIABILITIES

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

	2007	2006
Capital expenditures	$ 14,821	$ 13,851
Operating expenses/Taxes	3,881	4,024
Hurricane damage repairs		71
Compensation	853	1,197
Interest	460	506
Other	1,996	2,289
Total	$ 22,011	$ 21,938

17. SUBSEQUENT EVENTS

During February 2008, the Company entered into a series of hedging contracts to hedge a portion of its crude oil and natural gas production for the period from March 2008 through December 2009. The hedge contracts were completed 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 will be settled monthly based on the NYMEX futures contract of oil and natural gas during each respective month. These hedge contracts, combined with those discussed in Note 12, effectively hedge approximately 41% of the estimated proved developed natural gas production, and 38% of the estimated proved developed oil production during the respective terms of the hedging agreements. The following table summarizes the contracted volumes and prices for the costless collars.

	Notional Amount	Floor Price ($ per unit)	Ceiling Price ($ per unit)
Natural Gas (mmbtu)			
Mar 2008 - Dec 2008	200,000	$ 8.00	$ 10.50
Jan 2009 - Dec 2009	760,000	$ 8.00	$ 10.30
Crude Oil (bbls)			
Mar 2008 - Dec 2008	66,000	$85.00	$111.40
Jan 2009 - Dec 2009	43,000	$80.00	$111.00

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18. QUARTERLY RESULTS OF OPERATIONS (Unaudited)

Results of operations by quarter for the year ended December 31, 2007 were (thousands of dollars, except per share):

2007	Quarter Ended March 31	June 30	Sept. 30	Dec. 31
Revenues	$40,143	$39,716	$33,709	$37,141
Results of operations from exploration and production activities(1)	8,107	10,033	6,557	9,375
Net earnings (2)	$ 1,668	$ 2,705	$ 750	$ 2,014
Net earnings per share:(2)				
Basic	$ 0.02	$ 0.03	$ 0.01	$ 0.02
Diluted	$ 0.02	$ 0.03	$ 0.01	$ 0.02

Results of operations by quarter for the year ended December 31, 2006 were (thousands of dollars, except per share):

2006	Quarter Ended March 31	June 30	Sept. 30	Dec. 31
Revenues	$57,506	$46,540	$ 46,059	$40,852
Results of operations from exploration and production activities(1)	18,973	9,320	(127,773)	8,671
Net earnings (loss) (2) (3)(4)	$ 7,331	$ 2,843	$ (86,879)	$ 2,821
Net earnings (loss) per share:(2) (3)(4)				
Basic	$ 0.08	$ 0.03	$ (0.99)	$ 0.03
Diluted	$ 0.08	$ 0.03	$ (0.99)	$ 0.03

(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, impairment of long-lived assets, accretion and hurricane damage repairs.

(2) Applicable to common stockholders.

(3) Adopted SFAS 123(R) effective January 1, 2006.

(4) Includes impairment of long-lived assets of $134.9 million in the third quarter.

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19. SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES (Unaudited)

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

Costs Incurred in Oil and Natural Gas Acquisition, Exploration and Development Activities

(thousands of dollars)

	Year Ended December 31, 2007	2006	2005
Costs incurred during the year:[1]			
Property acquisition costs			
Unproved	$ 9,589	$ 35,728	$ 7,097
Proved		8,239	
Exploration	92,320	95,486	110,669
Development	9,026	23,405	16,136
	$ 110,935	$ 162,858	$ 133,902

(1) Costs incurred during the years ended December 31, 2007, 2006 and 2005 include general and administrative costs related to acquisition, exploration and development of oil and natural gas properties, net of third party reimbursements, of $16,492,000, $15,375,000, and $13,814,000 respectively.

Capitalized Costs Relating to Oil and Natural Gas Producing Activities

(thousands of dollars)

	December 31, 2007	2006
Capitalized costs	$ 1,771,768	$ 1,663,865
Accumulated depletion	1,344,164	1,267,504
Net capitalized costs	$ 427,604	$ 396,361

At December 31, 2007 and 2006, unevaluated costs of $53,645,000 and $54,356,000, 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.

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Costs Not Being Amortized
(thousands of dollars)
The following table sets forth a summary of oil and natural gas property costs not being amortized at December 31, 2007, by the year in which such costs were incurred. There are no individually significant properties or significant development projects included in costs not being amortized.

	Total	2007	2006	2005	2004&Prior
Leasehold and Geological & Geophysical	$ 39,478	$ 21,443	$ 16,621	$ 1,409	$ 5
Exploration Drilling	14,167	13,693	272	202	
Total	$ 53,645	$ 35,136	$ 16,893	$ 1,611	$ 5

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Results of Operations from Oil and Natural Gas Producing Activities
(thousands of dollars)

	Year Ended December 31,		
	2007	2006	2005
Operating Revenues:			
Oil	$ 54,218	$ 47,859	$ 34,647
Natural Gas	96,491	141,182	160,608
	150,709	189,041	195,255
Less:			
Oil and natural gas operating costs	28,338	22,614	15,860
Severance and ad valorem taxes	9,409	11,259	8,811
Depletion	76,660	105,210	96,396
Accretion expense	2,230	1,588	1,120
Impairment of long-lived assets		134,865	
Hurricane damage repairs		4,314	3,066
Income tax expense (benefit)	14,992	(31,783)	24,501
	131,629	248,067	149,754
Results of operations from oil and natural gas producing activities	$ 19,080	$ (59,026)	$ 45,501
Depletion expense per Mcfe	$ 4.20	$ 4.51	$ 3.74

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Estimated Quantities of Proved Reserves

The following table sets forth the net proved reserves of the Company as of December 31, 2007, 2006 and 2005, and the changes therein during the years then ended. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. The reserve information was reviewed by T. J. Smith & Company, Inc., independent reservoir engineers, for 2007, 2006 and 2005. 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, 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
Production during 2006	(859)	(18,170)
Purchase of reserves in-place	24	1,390
Discoveries and extensions	270	7,138
Revisions of previous quantity estimates and other	124	(3,460)
Balance at December 31, 2006	4,736	66,815
Production during 2007	(838)	(13,239)
Sale of reserves in-place	(3)	(413)
Discoveries and extensions	634	5,465
Revisions of previous quantity estimates and other	327	2,701
Balance at December 31, 2007	4,856	61,329
Proved Developed Reserves:		
Balance at December 31, 2004	4,716	85,507
Balance at December 31, 2005	3,492	62,524
Balance at December 31, 2006	3,151	49,253
Balance at December 31, 2007	2,892	42,555

Standardized Measure of Discounted Future Net Cash Flows

The information that follows has been developed pursuant to SFAS 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.

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The following table sets forth the components of the standardized measure of discounted future net cash flows for the years ended December 31, 2007, 2006 and 2005 (thousands of dollars):

	At December 31,		
	2007	**2006**	**2005**
Future cash flows	$ 842,986	$ 657,584	$ 1,122,282
Future production costs	(185,768)	(150,462)	(163,804)
Future development costs	(80,656)	(64,417)	(55,212)
Future taxes on income	(80,029)	(46,034)	(201,582)
Future net cash flows	496,533	396,671	701,684
Discount to present value at 10 percent per annum	(105,069)	(68,772)	(144,481)
Standardized measure of discounted future net cash flows	$ 391,464	$ 327,899	$ 557,203

The average expected realized price for natural gas in the above computations was $6.66, $5.69, and $10.40 per Mcf at December 31, 2007, 2006, and 2005, respectively. The average expected realized price used for crude oil in the above computations was $95.54, $63.32, and $59.37 per Bbl at December 31, 2007, 2006, and 2005, 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, 2007, 2006 and 2005 (thousands of dollars):

	Year Ended December 31,		
	2007	**2006**	**2005**
Balance at Beginning of Period	$ 327,899	$ 557,203	$ 470,357
Sales of oil and natural gas, net of production costs	(112,962)	(155,167)	(170,584)
Changes in sales & transfer prices, net of production costs	125,623	(243,150)	293,294
Revisions of previous quantity estimates	25,751	(11,022)	(130,813)
Purchase of reserves-in-place		2,393	
Sale of reserves in-place	(2,233)		
Current year discoveries, extensions and improved recovery	32,939	30,710	107,393
Changes in estimated future development costs	(7,917)	(13,016)	(16,764)
Development costs incurred during the period	8,526	18,051	10,654
Accretion of discount	32,790	55,720	47,036
Net change in income taxes	(14,451)	114,782	(49,453)
Change in production rates (timing) and other	(24,501)	(28,605)	(3,917)
Net change	63,565	(229,304)	86,846
Balance at End of Period	$ 391,464	$ 327,899	$ 557,203

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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-15(e) under the Securities Exchange Act of 1934) as of the end of the fourth quarter of 2007. 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 2007 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, 2007. 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, 2007, the Company s system of internal control over financial reporting was effective.

The Company s independent registered public accounting firm has issued a report on the effectiveness 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

Board of Directors and Shareholders
The Meridian Resource Corporation
Houston, Texas

We have audited The Meridian Resource Corporation s internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Meridian Resource Corporation 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, included in the accompanying Item 9A, Management s Annual Report on Internal Control Over Financial Reporting . Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

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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, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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, The Meridian Resource Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, 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 Meridian Resource Corporation and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of operations, stockholders equity, cash flows, and comprehensive income (loss) for each of the three years in the period ended December 31, 2007, and our report dated March 14, 2008 expressed an unqualified opinion thereon.

BDO Seidman, LLP
Houston, Texas
March 14, 2008

Item 9B. Other Information.

None.

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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 April 29, 2008.

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 Firm s Report
   - (ii) Consolidated Statements of Operations for each of the three years in the period ended December 31, 2007
   - (iii) Consolidated Balance Sheets as of December 31, 2007 and 2006
   - (iv) Consolidated Statements of Cash Flows for each of the three years in the period ended December 31, 2007
   - (v) Consolidated Statements of Changes in Stockholders Equity for each of the three years in the period ended December 31, 2007
   - (vi) Consolidated Statements of Comprehensive Income (Loss) for each of the three years in the period ended December 31, 2007
   - (vii) Notes to Consolidated Financial Statements
   - (viii) Supplemental Oil and Natural 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 Amendment No. 1 to Amended and Restated Bylaws (incorporated by reference to Exhibit 3.1 of the Company s Report on Form 8-K dated May 5, 1999).

   3.4 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)).

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*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).
4.8	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	The Meridian Resource Corporation 2006 Non-Employee Directors Incentive Plan (incorporated by reference to Exhibit A of the Company s Proxy Statement on Schedule 14A filed May 19, 2006).
4.10	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 4.10 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).
**10.21	First Amendment to Credit Agreement, dated February 21, 2008, among The Meridian Resource Corporation, Fortis Capital Corp., as administrative agent, co-lead arranger and bookrunner; The Bank of Nova Scotia, as co-lead arranger and syndication agent; Comerica Bank, US Bank NA, and Allied Irish Bank plc each in their respective capacities as lenders.
**21.1	Subsidiaries of the Company
**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.

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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 14, 2008

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 14, 2008
BY: /s/ MICHAEL J. MAYELL Michael J. Mayell	President and Director	March 14, 2008
BY: /s/ LLOYD V. DELANO Lloyd V. DeLano	Chief Accounting Officer	March 14, 2008
BY: E. L. Henry	Director	March 14, 2008
BY: /s/ JOE E. KARES Joe E. Kares	Director	March 14, 2008
BY: /s/ GARY A. MESSERSMITH Gary A. Messersmith	Director	March 14, 2008
BY: /s/ DAVID W. TAUBER David W. Tauber	Director	March 14, 2008
BY: /s/ JOHN B. SIMMONS John B. Simmons	Director	March 14, 2008

BY:	Director	March 14, 2008
Fenner R. Weller, Jr.		
BY:	Director	March 14, 2008
C. Mark Pearson		

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Name	Title	Date
BY: /s/ PAUL D. CHING	Director	March 14, 2008
Paul D. Ching		
BY: /s/ G.M. LARBERG	Director	March 14, 2008
G.M. Larberg		

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Exhibit Index

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	Amendment No. 1 to Amended and Restated Bylaws (incorporated by reference to Exhibit 3.1 of the Company s Report on Form 8-K dated May 5, 1999).
3.4	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	The Meridian Resource Corporation 2006 Non-Employee Directors Incentive Plan (incorporated by reference to Exhibit A of the Company s Proxy Statement on Schedule 14A filed May 19, 2006).
4.10	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 4.10 for additional material contracts.
*10.2	The Meridian Resource Corporation 1990 Stock Option Plan (incorporated by reference to Exhibit 10.6 of the Company s Annual Report on Form 10-K for the year ended December 31, 1991, as amended by the Company s Form 8 filed March 4, 1993).
*10.3	Employment Agreement dated August 18, 1993, between the Company and Joseph A. Reeves, Jr. (incorporated by reference from the Company s Annual Report on Form 10-K for the year ended December 31, 1995).

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*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

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	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).
**10.21	Amended and Restated Credit Agreement, dated February 21, 2008, among The Meridian Resource Corporation, Fortis Capital Corp., as administrative agent, co-lead arranger and bookrunner; The Bank of Nova Scotia, as co-lead arranger and syndication agent; Comerica Bank, US Bank NA, and Allied Irish Bank plc each in their respective capacities as lenders.
**21.1	Subsidiaries of the Company
**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.