MERIDIAN RESOURCE CORP
Form 10-K
March 16, 2009

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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, 2008

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. Yes þ 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 (Do not check if a smaller reporting company)	Smaller reporting company o

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, 2008 $260,739,160
Number of shares of common stock outstanding at March 4, 2009: 93,070,592

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 30, 2009.

THE MERIDIAN RESOURCE CORPORATION
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PART I

Item 1. Business

General

The Meridian Resource Corporation (Meridian, the Company, us, our, or we) 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. The Company 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.

Through our wholly-owned subsidiaries, we hold interests primarily in the onshore oil and natural gas regions of south Louisiana and Texas and offshore in the Gulf of Mexico. We treat all operations as one line of business.

As of December 31, 2008, we had proved reserves of 80 Bcfe with a present value of future net cash flows of approximately $179 million. Sixty-three percent (63%) of our proved reserves were natural gas and approximately sixty-four percent (64%) were classified as proved developed. We own interests in 19 fields and 100 producing wells, and operated approximately 96% of our total production in 2008.

Recent developments

We rely on our Amended and Restated Credit Agreement (as amended, the Credit Facility) for funds during times of increased capital expenditures or decreased cash flow from operations. Recently, our access to capital was restricted by a reduction in the borrowing base under our Credit Facility, and our ability to fund capital expenditures has significantly decreased. In December 2008, our lenders reduced the borrowing base to equal the amount already outstanding under the Credit Facility ($95 million), leaving no additional credit available. With the precipitous decrease in the price of oil and natural gas in the second half of 2008, we are experiencing decreased cash flow from operations. The reduction in available credit under these conditions creates significant uncertainties for the Company.

Our Credit Facility contains a number of positive and negative covenants with which we must comply. As of December 31, 2008, we are in default of one such covenant, the test of our current ratio. The current ratio is defined under the Credit Facility as current assets divided by current liabilities, but excluding current assets or liabilities from commodity price hedging agreements, excluding amounts payable under the Credit Facility itself, and excluding current asset retirement obligations. Unused available funds under the Credit Facility are added to current assets in computing the ratio. The required ratio is one to one or higher; our actual ratio, as defined, at December 31, 2008 is 0.76, absent certain adjustments to current liabilities for potential acceleration of payment due to default of covenants.

We are also in default of a covenant in the Credit Facility that requires us to deliver to our lenders audited financial statements for each fiscal year that do not have a going concern or like modification. As a result of our current lack of financial liquidity, our independent registered public accounting firm has included such a modification in its report on our consolidated financial statements. See Note 1 of the Notes to Consolidated Financial Statements included herein.

Presently, our lenders have been informed of our default under these covenants, and have not responded with a notice of any exercise of remedies.

Our lenders have available to them various remedies if they choose to declare an event of default, including

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acceleration of payment of all principal and interest. Although they have not demanded any accelerated payments, they may. If they were to make such demands, the Company would likely be forced to sell assets to make any such payments. To mitigate such circumstance to the extent feasible, we are currently pursuing a number of actions to reduce expenses and conserve cash; see Current Plans, below.

In addition to the circumstance of default, the borrowing base is scheduled for redetermination as of April 30, 2009. The borrowing base is determined at the discretion of the lenders, based primarily on the value of our proved reserves. We believe it is likely that the lenders will set the base at a level below outstanding borrowings. In that case, the Company would be required to repay the deficit within 90 days. We may not have enough cash available to repay any of our outstanding borrowings nor can we predict the actions of the lenders. As noted above, to mitigate the effects of these circumstances, we are currently pursuing a number of actions to reduce expenses and conserve cash; see Current Plans, below.

Our financial position includes one other debt obligation, a five year note for the purchase of a drilling rig (the rig note). The rig note is payable in monthly installments, with a total outstanding balance of $8.8 million as of December 31, 2008. Any non-compliance or default under the terms of the Credit Facility triggers a default under the terms of the rig note, as well. The remedies available to the lender under the rig note also include acceleration of all principal and interest payments. The lenders under the rig note have been timely advised of the default under the covenants of the Credit Facility. The lenders may accelerate all payments of principal and interest in response to an event of default, or they may elect to take other action. We may not have enough cash available to repay the rig note, nor can we predict the actions of the lenders under the rig note.

As of December 31, 2008, our net working capital reflects a deficit of approximately $109.3 million, which includes $103.8 million of amounts due under these two debt agreements which have been reclassified to current as a result of the defaults noted above.

Management is currently pursuing discussions with the lenders to obtain waivers. In addition, management is exploring a number of options to conserve or increase cash. These actions include a significant reduction of capital spending, renegotiation of drilling rig contracts, cost reductions through headcount reductions as well as reductions of field operating expenses, and sales of assets.

There can be no assurance that cash flow from operations and other sources of liquidity, including asset sales, will be sufficient to meet contractual, operating and capital obligations. The financial statements have been adjusted to reclassify to current liabilities debts which, absent the default and resulting potential for acceleration of payment by the lenders, would have been classified as long-term. The financial statements do not include any other adjustments that might result from the outcome of uncertainty regarding the Company s ability to raise additional capital, sell assets, or otherwise obtain sufficient funds to meet its obligations. See further information under Current Plans and Management s Discussion and Analysis of Financial Condition and Results of Operation Liquidity and Capital Resources Cash Obligations, below.

In addition, due to the decrease in oil and natural gas prices at year-end, as well as to the decrease in our reserves, in December 2008 we recorded a significant non-cash impairment, or ceiling test write-down, to our oil and natural gas properties of $216.8 million. We also recorded a $6.7 million non-cash impairment of our drilling rig, due to decreases in utilization and dayrates for similar rigs. See Management s Discussion and Analysis of Financial Condition and Results of Operations Reserves , - Prices, - Ceiling Test, and - Drilling Rig Obligation.

Development of our oil and natural gas properties.

Our operations have historically focused on the onshore oil and natural gas regions in south Louisiana and offshore in the Gulf of Mexico. While maintaining and exploiting our older properties, in recent years we have expanded exploration into new areas. Our objective was to replace our reserves, and to strengthen our reserve base with longer lived properties from unconventional gas plays in various regions of Texas, Oklahoma, and Kentucky. We also invested in conventional horizontal gas plays in Texas.

In exploring these new areas, we invested in seismic data, geological research, acreage, and drilling. Our strategy included building a large inventory of lease acreage to provide ourselves a wide range of opportunities and ensure that new discoveries were highly repeatable.

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After thorough testing and analysis, some of our new exploration areas showed only limited promise and have been dropped or sold. The most significant success has been in the East Texas Austin Chalk formation, where our acreage is primarily in Polk County. We have drilled 12 wells in East Texas and 11 of them have been completed as producers. We pursued our historical strategy of limiting participations with partners; we operate many of our new discoveries as well as our older properties and are positioned to operate our undrilled leases.

As a result of pursuing our expanded exploration strategy in prior years, we have accumulated the following significant assets:

- 11 producing natural gas wells in East Texas with significant leaseholds available for development;
- Geologic information to assist us in locating and defining the higher yielding areas within our East Texas Austin Chalk holdings;
- Experience that has improved efficiencies in drilling and operating in the Austin Chalk, which we have used to reduce costs;
- An additional portfolio of approximately 30,000 net acres in Karnes and Lavaca Counties of South Central Texas covering the Austin Chalk, as well as the Eagle Ford Shale where others have had successful drilling; and
- A significant library of 3-D and 2-D seismic data, much of which as been reprocessed and utilized for the identification and development of new prospects.

In addition, our historically acquired properties in onshore and offshore Louisiana are valuable assets comprising the majority of our reserve base and current cash flow. Although these fields are mature, we continue to review them for any opportunities for increased or prolonged production.

We 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. We also believe that our operational control over most of our properties adds to our competitive advantage, through greater flexibility and control of costs. Our ability to exploit these advantages, however, will be limited by our current lack of liquidity to fund the necessary capital expenditures.

Current Plans.

Results of our exploratory drilling efforts have been intermittent and while more recent wells have improved both as to drilling costs and productive results, reaching this point has absorbed significant cash flow as well as significant utilization of the borrowing base under our Credit Facility. In the second half of 2008, as our returns on drilling expenditures in the Austin Chalk began to improve, energy prices dropped precipitously. This impacted the borrowing base under our Credit Facility, which is based on the value of our proved reserves and is subject to redetermination at least semi-annually. We have lower expectations of cash flow for the near future, and availability of additional funds under our Credit Facility has been reduced to zero.

Our most basic mission is unchanged. We intend to preserve and exploit the Company s best assets and continue to produce oil and natural gas. We will continue to make environmental and operational safety in the field our first priority.

However, economic circumstances have necessitated that we revise our short term objectives. We are currently focused primarily on our cash position and our standing with our lenders. Thus cash preservation and strict management of cash flow are currently our highest priorities.

We have identified multiple action areas to achieve our short-term cash-focused objectives, including:

- Reducing capital expenditures by shifting away from exploratory efforts on new wells to recompletions and workovers of existing wells based on strict economic analysis focused on increased production and cash flow;
- Renegotiation of drilling-related contractual commitments;

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- Cost reductions in the office, based on headcount reductions and close examination of all other general and administrative expenses;

- Cost reductions in the field through close review of lease operating expenses and implementation of more strict efficiency measures;

- Sale of non-strategic assets, including both developed and undeveloped properties; and

- Partial sale of our key exploratory and development assets in the East Texas Austin Chalk, in order to raise cash and reduce risk through a reduced working interest.

Strategy for preservation and exploitation of our assets.

Our operational objectives for the near term are focused on maintaining current production levels, in spite of the natural declines we will continue to experience from our mature properties. To achieve this objective, we are reviewing our properties for recompletion and other reconditioning opportunities. Each of these is being subjected to rigorous cost analysis, to ensure that the project has economic value at current prices. Pursuit of these opportunities, however, is dependent on the availability of funds, which we cannot presently predict; we expect such availability to be very limited.

Our exploration strategy is necessarily curtailed by the limited resources available to us for capital expenditures. We believe that our best approach for the near term is to minimize drilling expense, maximize cash flow, and maintain or increase the future value of the assets we hold. To achieve that objective we are taking the following steps:

- We will cease drilling activities after completion of the two wells in which we are currently participating (one operated and one non-operated);

- We are seeking partners to assist us in developing our holdings in East Texas, with the goal of reducing our working interests into the range of 25-35% for new wells;

- We have directed our staff to continue to analyze geological and seismic data, which we believe enhances the value of our assets, as well as identifying the best opportunities for capital expenditures under a limited resource scenario;

- We have taken steps to reduce or offset our cash obligations under drilling contracts;

- We are monitoring the exploration results of others, particularly in the Eagle Ford trend in South Texas; although we cannot allocate funds to these areas currently, we intend to test them when the opportunity arises; and

- Although staff reductions have been necessary, we have retained a well-qualified team of exploratory and operational personnel.

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, 2008. 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, 2008				
Oil (MBbls)	567	154	44	765
Natural Gas (MMcf)	8,173	842	354	9,369
Reserves as of December 31, 2008				

Oil (MBbls) [1]	3,580	795	528	4,903
Natural Gas (MMcf) [1]	42,367	3,406	5,122	50,895

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Estimated future net cash flows ($000)[(2)]	$239,576
Present value of future net cash flows before income taxes ($000)[(3)]	$179,437
Standardized measure of discounted future net cash flows ($000)[(4)]	$179,437

(1) Includes 83 MBbls of oil and 226 MMcf of gas (724 MMcfe) in proved developed shut-in reserves (PDSI); these reserves are for wells which have been shut-in primarily due to hurricane damage, which we expect to repair.

(2) 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, 2008, which averaged $44.04 per Bbl of oil and $5.79 per Mcf of natural gas over the estimated life of

the properties and do not reflect the impact of hedges.

(3) 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%.

(4) The Standardized Measure of Discounted Future Net Cash Flows represents the Present Value of Future Net Cash Flows after income taxes of zero. Income taxes are zero because the tax basis of oil and natural gas properties exceeds the book basis.

Productive Wells

At December 31, 2008, 2007 and 2006, we held interests in the following productive wells. As of December 31, 2008, we own interests in 20 gross (4 net) wells in the Gulf of Mexico which are outside operated and net to 2 oil wells and 2 natural gas wells and 1 gross (1 net) operated offshore oil well. In addition, of the total well count for 2008, 1 well (1 net) are multiple completions.

	2008		2007		2006	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil Wells	34	20	33	19	44	28
Natural Gas Wells	66	37	88	43	77	43
Total	100	57	121	62	121	71

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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, 2008. 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.

	Proved Reserves at December 31, 2008			
	Developed Producing (1)	Developed Non-Producing	Undeveloped	Total
	(dollars in thousands)			
Net Proved Reserves:				
Oil (MBbls)	1,431	1,301	2,171	4,903
Natural Gas (MMcf)	19,239	15,815	15,842	50,896
Natural Gas Equivalent (MMcfe)	27,825	23,619	28,869	80,313
Estimated Future Net Cash Flows(2)				$239,576
Present Value of Future Net Cash Flows (before income taxes)(3)				$179,437
Standardized Measure of Discounted Future Net Cash Flows(4)				$179,437

(1) Includes 83 MBbls of oil and 226 MMcf of gas (724 MMcfe) in proved developed shut-in reserves (PDSI); these reserves are for wells which have been shut-in primarily due to hurricane damage, which we expect to repair.

(2) 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, 2008, which averaged $44.04 per Bbl of oil and $5.79 per Mcf of natural gas over the estimated life of the properties and do not reflect the impact of hedges.

(3) 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%.

(4) The Standardized Measure of Discounted Future Net Cash Flows represents the Present Value of Future Net Cash Flows after income taxes of zero. Income taxes are zero because we have estimated that we will not

be in a tax paying position based on the low commodity prices used in the computation.

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 2008, 2007 and 2006.

	Gross Wells			Net Wells		
	Productive	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Exploratory Wells						
Year ended December 31, 2008	6	4	10	2.7	3.1	5.8
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
Development Wells						
Year ended December 31, 2008	7	4	11	5.0	3.2	8.2
Year ended December 31, 2007						
Year ended December 31, 2006	1		1	0.7		0.7

Meridian had two gross (0.8 net) wells in progress at December 31, 2008. In addition, Meridian participated in four successful recompletion operations in 2008.

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 2008, 2007 and 2006.

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	Year Ended December 31,		
	2008	2007	2006
Production:			
Oil (MBbls)	765	838	859
Natural gas (MMcf)	9,369	13,239	18,170
Natural gas equivalent (MMcfe)	13,958	18,269	23,323
Average Prices:			
Oil ($/Bbl)	$ 83.13	$ 64.70	$ 55.73
Natural gas ($/Mcf)	$ 9.07	$ 7.29	$ 7.77
Natural gas equivalent ($/Mcfe)	$ 10.65	$ 8.25	$ 8.11
Production Expenses:			
Lease operating expenses ($/Mcfe)	$ 1.74	$ 1.55	$ 0.97
Severance and ad valorem taxes ($/Mcfe)	$ 0.70	$ 0.52	$ 0.48

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, 2008. 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, 2008			
	Developed		Undeveloped	
Region	**Gross**	**Net**	**Gross**	**Net**
Louisiana	30,082	21,002	16,142	14,299
Oklahoma	1,809	699		
Kentucky			28,750	24,236
Texas	10,842	6,551	139,991	91,442
Gulf of Mexico	28,759	5,613	11,440	3,976
Total	71,492	33,865	196,323	133,953

In addition to the above acreage, we currently have options or farm-ins to acquire leases on approximately 2,183 gross (2,183 net) acres of undeveloped land located in Louisiana. Our undeveloped net acreage, including optioned acreage, expires during the next three years at the rate of 33,600 acres in 2009, 15,200 acres in 2010, and 65,300 acres in 2011.

Geologic/Land and Operations Geophysical Expertise

Meridian employs approximately 67 full-time non-union employees and 11 contract employees. Our office staff includes geologists, geophysicists, land and engineering staff with many 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.

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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 2008, 2007 and 2006.

	Year Ended December 31,		
Customer	**2008**	**2007**	**2006**
Shell Trading (U.S.)	21%	14%	
Superior Natural Gas	17%	23%	35%
Crosstex Gulfcoast Marketing	14%	16%	21%

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 $145.00 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, 2008, was $10.65 per Mcfe compared to $8.25 per Mcfe (each net of commodity hedge gains/losses) during the year ended December 31, 2007. 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 risk.

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 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

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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 non-cost-bearing interests customary in the industry.

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

Item 1A. Risk Factors

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

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As a result of our current lack of financial liquidity, we have received a going concern modification to our independent accountant s opinion on our consolidated financial statements.

Our independent registered public accounting firm has included an explanatory paragraph in their report on our December 31, 2008 consolidated financial statements regarding their substantial doubt as to our ability to continue as a going concern. Our lack of sufficient liquidity could make it more difficult for us to secure additional financing or enter into strategic relationships on terms acceptable to us, if at all, and may materially and adversely affect the terms of any financing that we may obtain and our public stock price generally.

Our Credit Facility has substantial restrictions and financial covenants. We are currently in default under, and may have difficulty returning to compliance with, certain of the covenants in our Credit Facility, including our covenant to maintain a ratio of current assets to current liabilities of not less than 1.0 to 1.0, and our covenant to deliver to our lenders audited financial statements for each fiscal year that do not have a going concern or like qualification or exception.

Our current Credit Facility contains restrictive covenants that 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 downturns in our business or in the general economy or to otherwise conduct necessary corporate activities. We are also required to comply with certain financial covenants and ratios. We are currently in default under certain of those covenants. Our ability to return to compliance and maintain compliance in the future is uncertain. Our ability to comply with these covenants and restrictions will be affected by the levels of cash flow from our operations and events or circumstances beyond our control, including events and circumstances that may stem from the condition of financial markets and commodity price levels.

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. We are in material default of our obligations under the Credit Facility, and 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, or at all.

Our failure to comply with any of the restrictions and covenants under our Credit Facility results in an event of default under the facility, which results in an event of default on our rig note as well. The total balance outstanding under the rig note at December 31, 2008 is $8.8 million. The remedies available to the lender under the rig note include acceleration of all principal and interest payments. 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.

Presently, our lenders have been informed of our default under these covenants, and have not responded with a notice of any exercise of remedies. We cannot predict what action they may take.

Our Credit Facility has periodic borrowing base redeterminations and we may have difficulty maintaining our total borrowing base at the current level of $95 million at future redeterminations, or maintaining or obtaining additional credit at similar terms, which could adversely affect our operations.

As of December 31, 2008, we had outstanding indebtedness of $95.0 million under our Credit Facility, which equaled the current limit to our borrowings under that facility. The Credit Facility limits the amounts we can borrow to the borrowing base amount, determined by the lenders in their sole discretion. The borrowing base will be redetermined semi-annually, and may be redetermined at our request more frequently and by the lenders in their sole discretion based on reserve reports prepared by reserve engineers, together with, among other things, the oil and natural gas prices existing at the time. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the Credit Facility. Any increase in the borrowing base requires the consent of all the lenders. Outstanding borrowings in excess of the borrowing base must be repaid within 90 days, and we may not have the financial resources in the future to make any mandatory principal repayments required under the Credit Facility.

The borrowing base is scheduled for redetermination as of April 30, 2009. We believe it is likely that the lenders will set the base at a level below outstanding borrowings. We may not have enough cash available to repay any of our outstanding borrowings.

Because of the recent deterioration of the credit and capital markets, we may be unable to obtain financing from sources other than our Credit Facility on acceptable terms or at all.

Global market and economic conditions have been, and continue to be, disruptive and volatile. The debt and equity capital markets have been adversely affected by significant write-offs in the financial services sector relating to subprime mortgages, and the re-pricing of credit risk in the broadly syndicated market, among other things. These events have led to worsening general economic conditions.

In particular, the cost of capital in the debt and equity capital markets has increased substantially, while the availability of funds from those markets has diminished significantly. Also, concerns about the stability of financial markets generally and the solvency of counterparties specifically have led to increases in the cost of obtaining money from the credit markets as many lenders and institutional investors have increased interest rates, enacted tighter lending standards and reduced funding and, in some cases, ceased to provide funding to borrowers.

We have substantial anticipated capital requirements. Our ongoing capital requirements consist primarily of the need to fund our capital budget and the exploitation, development, production and abandonment of oil and natural gas reserves. Historically, we have relied heavily on our credit facilities for our capital needs. As of December 31, 2008, we had outstanding indebtedness of $95.0 million under our Credit Facility, which equaled the current limit to our borrowings under that facility. If we need to raise capital from a source other than our Credit Facility, it is unlikely that additional capital will be available to the extent required and on acceptable terms. If capital on acceptable terms is not available, we may be unable to fully execute our growth strategy, otherwise take advantage of business opportunities, or respond to competitive pressures, any of which could have a material adverse effect on our results of operations and financial condition. We may be forced to sell a significant portion of our assets in order to meet near-term contractual requirements. We may not be able to sell assets on terms that we consider advantageous to the Company and our stockholders.

We have significant near-term contractual obligations, which we may not be able to meet; our working capital is currently a net deficit.

We have significant near-term contractual obligations, including, but not limited to, two drilling contracts, certain obligations to employees for compensation, and certain oil and natural gas property investment commitments. Our net working capital position at December 31, 2008, is a deficit of $109.3 million, which includes $103.8 million of amounts due under the Credit Facility and the rig note which have been reclassified as current as a result of the defaults noted elsewhere herein. Our cash flow and working capital have been significantly impacted by the precipitous decrease in the prices we received for oil and natural gas in the second half of 2008, and continuing into 2009. If we are not able to increase cash flow, our ability to meet these obligations may be impacted, which could have a material adverse effect on our results of operations and financial condition.

Our common stock could be delisted from the New York Stock Exchange.

As of December 4, 2008, we received notification from the New York Stock Exchange that the Company had fallen below certain continued listing criteria, that require a minimum average closing price of $1.00 per share over 30 consecutive trading days. In addition, we are currently monitoring the Company s compliance with another listing criteria. This criteria requires that average market capital over 30 consecutive trading days must be at least $15 million. Based on shares currently outstanding, the Company s average market capital decreases below this level when the stock price drops below approximately $0.16 per share. Some closing prices in the first quarter of 2009 have been below this price. If the Company becomes non-compliant with this criteria, our common stock will be immediately subject to the NYSE s delisting procedures.

There can be no assurance that the stock of the Company will continue to be listed on the NYSE; there can be no assurance that we will obtain listing on an alternate stock exchange or automated quotation service. A delisting of our common stock could materially and adversely affect, among other things, the liquidity and market price of our common stock; the number of investors willing to hold or acquire our common stock; and our access to capital markets to raise capital in the future.

If oil or natural gas prices decrease or exploration and development efforts are unsuccessful, we may be required to take further write-downs.

In 2008, we recorded a significant non-cash impairment, or ceiling test write-down, to our oil and natural gas properties of $216.8 million. There is a risk that we will be required to take additional write-downs in the future, which would reduce our earnings and shareholders equity. A write-down could occur when oil and natural gas prices are low or if we have substantial downward adjustments to our estimated proved reserves, increases in our estimates of development costs or deterioration in our exploration and development results. Downward adjustments to proved reserves may result from decreasing prices of oil and natural gas, as expected development reserves become uneconomic under revised conditions.

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 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, less related deferred taxes, is limited to the sum of the present value (10% discount rate) of the estimated future after-tax 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 value of unproved properties adjusted for related income tax effects.

We review our oil and natural gas properties for impairment quarterly or whenever events and circumstances indicate that the carrying value may not be recoverable. Once incurred, a writedown of oil and natural gas properties is not reversible at a later date even if natural gas or oil prices increase. Given the complexities associated with oil and natural gas reserve estimates and the history of price volatility in the oil and natural gas markets, events may arise that would require us to record additional impairments of the recorded carrying values associated with our oil and natural gas properties.

In addition, our undeveloped leases are subject to expiration and forfeiture if not drilled. Our drilling plans for these areas are subject to the availability of funds for exploration, which is in turn affected by the risk factors described above. The leases may also be sold or assigned, but the oil and natural gas industry is currently undergoing significant market disruptions, which may make it difficult for us to extract value from these assets before expiration. Such circumstances increase the risk of the transfer of unevaluated oil and natural gas properties to the full cost pool where they would be subject to amortization or impairment.

In addition to the impairment of our oil and natural gas properties, we recorded a $6.7 million non-cash impairment of our drilling rig. The rig was purchased in 2007, with the intention of securing access to an appropriate rig and crew for our exploration efforts. Although we utilized the rig for our own drilling during 2008, it has been utilized by others since then based on short-term arrangements. Due to the continued volatility in the prices of oil and natural gas, and its negative effect on the drilling industry, we will continue to review this asset for additional impairment. We cannot predict whether additional impairment will be necessary.

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Our indebtedness may adversely affect operations and limit our growth.

As of December 31, 2008, we had total indebtedness under credit agreements and a short term note of $105.6 million compared to approximately $122.5 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.

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 Credit Facility requires that only lenders under that agreement may act as counterparties under our hedging agreements; our hedging contracts are not collateralized. Recent uncertainty in financial markets could impact the ability of our counterparties under hedging agreements to pay, which could reduce the value of our proved reserves, our hedge-related assets and liabilities, and our expected cash flow.

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. Moreover, our future profitability will depend on our ability to attract and retain qualified personnel. During 2008, our former Chief Executive Officer, Mr. Joseph A. Reeves, and our former Chief Operating Officer and President, Mr. Michael J. Mayell, both of whom had been with the Company since inception, ceased their full-time employment with the Company. Our interim Chief Executive Officer, Paul D. Ching, is contractually committed to serve through June 30, 2009. There can be no assurance that we will be able to attract a qualified individual to succeed him.

We compete against significant players in the oil and natural gas industry, and our failure in the long-term to complete future acquisitions successfully and generate commercial exploration and development drilling opportunities could reduce our earnings and cause revenues to decline.

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

The oil and natural gas markets are heavily regulated.

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

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

The nature of our operations exposes us to environmental liabilities.

Our operations create the risk of environmental liabilities. We may incur liability to governments or to third parties for any unlawful discharge of oil, 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.

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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.

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.

In addition, disruptions in financial markets have affected the credit standing of various insurance companies. Our ability to collect on our current or future claims and to obtain insurance at a price acceptable to us may be adversely affected by such general financial conditions, which are beyond our control.

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.

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We may not be able to effectively market our oil and natural gas production.
We may encounter difficulties in the marketing of our oil and natural gas production. Effective marketing depends on factors such as the existing market supply and demand for oil and natural gas and the limitations imposed by governmental regulations. The proximity of our reserves to pipelines and the available capacity of such pipelines and other transportation, processing and refining facilities also affect our marketing efforts. Even if we discover hydrocarbons in commercial quantities, a substantial period of time may elapse before we begin commercial production. If pipeline facilities in an area are insufficient, we may have to wait for the construction or expansion of pipeline capacity before we can market production from that area. Another risk lies in our ability to negotiate commercially satisfactory arrangements with the owners and operators of production platforms in close proximity to our wells. Also, natural gas wells may be shut in for lack of market demand or because of the inadequate capacity or unavailability of natural gas pipelines or gathering systems.

We are dependent on other operators who influence our productivity.
We have limited influence over the nature and timing of exploration and development on oil and natural gas properties we do not operate, including limited control over the maintenance of both safety and environmental standards. In 2008, 4% of our production and 17% 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 remain at present levels or decline further, 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 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.

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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

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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 Chief Operating Officer of the Company at the time. A hearing was held before Judge Kay Bates on April 14, 2008. Judge Bates granted Hawkins Motion finding that Meridian was estopped from arguing that it did not breach its contract with Hawkins as a result of the United States Fifth Circuit s decision in the *Amoco* litigation. Meridian disagrees with Judge Bates ruling but the Louisiana First Court of Appeal declined to hear Meridian s writ requesting the court overturn Judge Bates ruling. Meridian has filed a motion with Judge Bates asking that she make her ruling a final judgement which would give Meridian the right to appeal now. The Hawkins interests have opposed this motion. 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 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, 2008.

Parsons Exploration litigation. On May 3, 2007, Parsons Exploration Company, LLC (Parsons) filed a claim against Meridian for damages and specific performance requiring Meridian to assign Parsons an overriding royalty interest in certain wells the Company has drilled in east Texas. The complaint alleges that the Company breached its contractual and fiduciary obligations to Parsons under an Exploration and Prospect Origination Agreement between the parties dated April 22, 2003. The complaint also alleges that the Company engaged in a civil conspiracy to breach its contractual and fiduciary obligations to Parsons and tortiously interfered with existing and prospective business relationships/contracts of Parsons. The Company has been served notice of the lawsuit and discovery has commenced. The Company intends to vigorously defend this matter. 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, 2008.

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 (together, Shell) have demanded contractual indemnity and defense from Meridian based upon the terms of the acquisition agreements 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

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some cases, Meridian has also demanded defense and indemnity from their subsequent purchasers of the fields. On December 9, 2008 Shell sent Meridian a letter reiterating its demand for indemnity. Shell has not to date produced supporting documentation for its claim. Meridian denies that it owes any indemnity under the acquisition agreements; however, the amounts claimed are substantial in nature and if adversely determined, would have a material adverse effect on the Company. 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, 2008.

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.

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 2008.

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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
2008:		
First quarter	$1.86	$1.36
Second quarter	3.09	1.49
Third quarter	3.21	1.82
Fourth quarter	1.81	.56
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

The closing sale price of the common stock on March 3, 2009, as reported on the New York Stock Exchange Composite Tape, was $0.15. As of March 4, 2009, we had approximately 712 shareholders of record.

On December 4, 2008, the Company received notification from the New York Stock Exchange that the Company had fallen below the continued listing criteria which requires a minimum average closing price of $1.00 per share over 30 consecutive trading days. The NYSE has suspended the minimum price requirement on a temporary basis, initially through June 30, 2009. The Company s business operations, credit agreements, other debt obligations and Securities and Exchange Commission reporting requirements, are unaffected by this notification. The Company s common stock remains listed on the NYSE under the symbol TMR, but the NYSE has assigned a .BC indicator to the symbol to denote that the company is below compliance for continued listing requirements.

In addition to the Company s non-compliance with the listing criteria related to minimum average closing price, the Company is currently monitoring its compliance with another listing criteria. This criteria requires that average market capital over 30 consecutive trading days must be at least $15 million. Based on shares currently outstanding, the Company s average market capital decreases below this level when the stock price drops below approximately $0.16 per share. Some closing prices in the first quarter of 2009 have been below this price.

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.

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Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth information as of December 31, 2008, 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)) (c)
Equity compensation plans approved by security holders	4,024,044	$ 2.66	3,970,000
Equity compensation plans not approved by security holders			
Total	4,024,044	$ 2.66	3,970,000

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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,				
	2008	2007	2006	2005	2004
	(In thousands, except prices and per share information)				
A. Summary of Operating Data					
Production:					
Oil (MBbls)	765	838	859	882	1,270
Natural gas (MMcf)	9,369	13,239	18,170	20,490	27,839
Natural gas equivalent (MMcfe)	13,958	18,269	23,323	25,781	35,457
Average prices:					
Oil ($/Bbl)	$ 83.18	$ 64.70	$ 55.73	$ 39.29	$ 28.40
Natural gas ($/Mcf)	9.07	7.29	7.77	7.84	5.98
Natural gas equivalent ($/Mcfe)	10.65	8.25	8.11	7.57	5.71
B. Summary of Operations					
Total revenues	$ 149,165	$152,178	$190,957	$195,696	$203,118
Depletion and depreciation	72,072	77,076	106,067	97,354	102,915
Net earnings (loss)(1)	(209,886)	7,137	(73,884)	27,849	29,248
Net earnings (loss) per share:(1)					
Basic	$ (2.30)	$ 0.08	$ (0.84)	$ 0.33	$ 0.41
Diluted	(2.30)	0.08	(0.84)	0.31	0.37
Dividends per:					
Common share	$	$	$	$	$
Redeemable preferred share				2.60	8.50
Preferred share					
Weighted average common shares outstanding basic	91,382	89,307	87,670	84,527	72,084
C. Summary Balance Sheet Data					
Total assets	$ 304,575	$483,775	$467,895	$555,802	$513,274
Long-term obligations, inclusive of current maturities	103,849	75,000	75,000	75,000	75,129
Redeemable preferred stock					31,589
Stockholders equity	122,511	325,430	320,797	377,565	316,041

(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. In recent years, the Company s goal has been to replace our reserves, and to strengthen our reserve base with longer lived properties from our new areas for exploration. Increases in the prices of oil and natural gas over the past several years have favorably impacted our earnings from operations and enabled us to increase exploration efforts, and our capital spending has increased.

However, recent economic developments, most importantly the precipitous decrease in the prices of oil and natural gas in the second half of 2008, have necessitated that we reduce capital investment and revise our short term focus. While our long-term objective has not changed, our short term goals currently focus on maintaining and improving production, increasing working capital through property sales, and conserving cash through cost saving measures.

The following discussion points are organized around the issues upon which our management is most highly focused, as well as the industry conditions that most influence our performance; the discussion contains information relating to the past year s performance as well as to our present circumstances and expectations for the coming fiscal year. Following that discussion, we provide the customary year to year analysis of our results of operations, and an expanded review of our liquidity.

Industry and economic conditions. The oil and gas industry has experienced significant volatility in the past year. After several years of rising demand, costs of exploration and development had risen in tandem with the prices for energy products. These economic trends encouraged exploration in more marginal areas at higher costs. However, in the second half of 2008, energy prices dropped precipitously. West Texas Intermediate traded on the spot market at approximately $145 per Bbl in July; by December 31, 2008, the price was approximately $40 per Bbl. Natural gas similarly reached a spot market high in July 2008 of over $13 per mmbtu, but by year-end was trading at approximately $6 per mmbtu.

Global capital markets have experienced significant disruptions in the past year, resulting in the closing or restructuring of numerous large financial institutions. Extreme uncertainty about creditworthiness, liquidity and interest rates, as well as the global economic recession, continue to limit credit availability. Typically, as is the case with Meridian, exploration and production companies borrow against the value of their proved reserves. When the market value of those reserves decreases due to energy price fluctuations, their ability to borrow declines; coupled with the recently tightened credit environment, exploration and production companies are experiencing a significant loss of credit availability, and Meridian is no exception.

The decrease in oil and natural gas prices has also caused operating cash flows to decline across the industry and at Meridian; coupled with the loss of credit access, companies cash resources may be extremely stressed.

Credit agreements. Commodity prices are a significant factor in the determination of the borrowing base available to the Company under our Credit Facility. Recently, the Company s access to capital was restricted by a reduction in the borrowing base, and our ability to fund capital expenditures has significantly decreased. In December 2008, the borrowing base was reduced to equal the amount already outstanding, leaving no additional credit available. This impacts the Company s capital spending plans and our ability to replace reserves.

As explained under Item I, General Recent Developments, we are in default under certain covenants under the terms of our Credit Facility, and although our lenders have not responded with a notice of exercise of remedies, they may. Similarly, we are also in default under the terms of our rig note, which may also be declared in default by the lenders. Under each of these debt agreements, the lenders may accelerate all interest and principal payments in the event of default. Accordingly, we have classified the $95 million of debt outstanding under the credit facility at December 31, 2008, as well as the $8.8 million rig note, as current in the accompanying consolidated balance sheet as of December 31, 2008.

In addition, the borrowing base under our Credit Facility is scheduled for the next redetermination as of April 30, 2009. The lenders may set the base at a level below outstanding borrowings. In that case, the Company would be required to repay the deficit within 90 days.

As of December 31, 2008, our net working capital reflects a deficit of approximately $109.3 million, which includes $103.8 million of amounts due under these two debt agreements which have been reclassified as current as a result of the defaults noted above.

Cash preservation and strict management of cash flow are currently our highest priorities. We are currently pursuing a number of options to raise cash by selling non-strategic properties on reasonable terms, as well as reducing our ownership in some of our core properties. Our intent is to maintain ownership in our core production areas of south Louisiana and East Texas. See Item 1, General Current Plans for more detailed information on our current plans.

Reserves. Our management has always focused on our reserve base, both the volume of proved reserves and the value of our future net revenues, which we calculate following SEC rules using the prices prevailing at the end of the period. During 2008, our total proved reserves decreased 10.2 Bcfe, due to production and because downward revisions exceeded total reserves added through discoveries, extensions, and positive revisions. We concentrated drilling efforts in 2008 on the East Texas Austin Chalk gas play. Although results there were generally encouraging, with seven new producing wells in 2008, performance of wells drilled in the Chalk in 2007 failed to reach expectations and some of our plans for development are considered uneconomic at current prices. These factors affected reserves by contributing negative revisions and decreasing the contribution of economic reserves from new discoveries.

Prices for oil and natural gas. Our revenues, operating profits, property impairment expense, and access to credit are all significantly impacted by the price of oil and natural gas. Prices also strongly influence our drilling programs, impacting the economic projections for proposed exploration and development activity.

While we received historically high average prices for oil and natural gas in 2008, by year-end our expected oil price, as utilized in our reserve estimates, had decreased approximately 47% from the average received in 2008. Similarly, our expected natural gas price decreased approximately 36% from the average received in 2008. The prices used in our reserve report are based on the prices prevailing at December 31, 2008; since that date, energy prices have continued to be extremely volatile, showing generally further declines.

Our estimated present value of future net revenues (before tax) from oil and natural gas at December 31, 2008 is $179.4 million, a decrease of $235.5 million, or 57%, from the value one year earlier. The decrease is due to both the 10.2 Bcfe decrease in reserves explained above, and the decrease in prices used to compute the value of our reserves. At December 31, 2007, the price per Mcfe used in computing future net revenues was $9.32; at December 31, 2008 it was $6.11 per Mcfe, or 34% lower.

Ceiling test. The carrying value of our oil and natural gas properties are limited according to SEC full cost accounting rules to the present value of our future net revenues from oil and natural gas (the ceiling test). Due to the decrease in prices at year-end, as well as to the decrease in our reserves, we recorded a significant non-cash impairment, or ceiling test write-down, to our oil and natural gas properties of $216.8 million. The impairment was also necessitated by the changed economics of our drilling program; a majority of our exploration efforts in the East Texas Austin Chalk were predicated on an expectation of higher natural gas prices than those we now expect to receive, and many of our newer wells were drilled when drilling costs had increased in tandem with increases in energy prices. We have curtailed our exploration and development plans for these economic reasons, as well as due to cash constraints, and the future value of our reserves accordingly reflects the reduction in the volume of undeveloped reserves. However, the most significant

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factors necessitating the ceiling test write-down were the decreases in prices and reserves, which directly decrease the ceiling.

Based on the continued volatility of energy prices since December 31, 2008, and the trend toward price decreases, Meridian may have an additional non-cash impairment in the first quarter of 2009.

Production. Management closely monitors production. Results for 2008 reflect a decline in production of 24% overall, primarily in the production of gas. This is the result of natural production declines in our mature south Louisiana properties.

Management team and non-routine contract settlement expenses.. During 2008, we settled the compensation contracts for our former Chief Executive Officer, Mr. Joseph A. Reeves, and our former Chief Operating Officer and President, Mr. Michael J. Mayell. The settlement resulted in a significant cash charge of $9.9 million to general and administrative expense, terminating all obligations under these contracts. In addition, we terminated the deferred compensation plan under which Messrs. Reeves and Mayell had received stock rights in lieu of cash compensation for many years. The termination resulted in issuance of approximately 3.5 million new shares of common stock, and a cash payment of approximately $3.0 million in lieu of stock for personal withholding taxes related to the stock issuance. Messrs. Reeves and Mayell remain on our Board of Directors, and will provide professional services to the Company under short-term consulting contracts that terminate on April 30, 2009.

Expenses. In addition to the non-routine contract settlement expense in 2008, we recorded approximately $1.7 million in compensation expense, net of capitalization, for employee retention bonuses. See Note 12 of Notes to Consolidated Financial Statements included herein for further information about this incentive plan for non-executive employees. This non-routine item has increased our expenses in 2008, but will have a lesser expense impact in 2009 (approximately $0.5 million expected in the first quarter of 2009); however, the cash impact will be greater in 2009 due to the second payment of approximately $2.9 million due March 31, 2009.

We have taken steps in early 2009 to reduce our annual expenses, both in the field and in the office. We reduced our staff by approximately 25 people, or 27%. The severance expense for the employees will be recorded in the first quarter of 2009, and will eliminate the retention incentive bonus they would otherwise have received (and is included in the $0.5 million expected expense mentioned above). The majority of the reduction was in our Houston office. We also have made changes to certain field operations that are also expected to yield cost savings. We will continue to review all expenses for additional opportunities for savings.

Drilling rig obligations. Although baseline field expenses are expected to decline during 2009, potential cash expenditures related to drilling obligations are expected to continue to be significant. During 2007, in order to ensure access to a drilling rig with the technical specifications appropriate to our drilling program, we committed to purchase a drilling rig. At the time, such rigs were in high demand, and as a result of this demand, our drilling program was faced with delays and increased costs. The purchased rig was largely constructed in 2007, and was placed in service near the end of the first quarter of 2008, at a total cost of $13.7 million.

We do not operate the rig; we lease the rig to Orion Drilling Company, LP (Orion). Orion pays us a monthly rental fee based on 50% of the monthly net profits of rig operation. The lease of the rig to Orion runs concurrently with a dayrate contract we have entered, under which Orion operates the rig. Each agreement is for twenty-four months terminating in March, 2010. Pursuant to our dayrate contract with Orion, we are obligated to pay the dayrate regardless of any inability to use the rig which may arise. When the rig is not in use on our wells, Orion may contract it to third parties, or the rig may be idled. Orion has been cooperative in actively seeking other parties to use the rig, and in agreeing to credit our obligation to some extent, based on revenues from other parties who utilize the rig when the Company is unable to. The rig was used continuously during 2008 in our East Texas drilling efforts; during the first quarter of 2009, the rig has been effectively subleased to others, but for short duration, at rates which are less than the dayrate under our contract. We are obligated for the difference in dayrates. We cannot predict whether such use by third parties will be consistent, nor to what extent it may offset our obligations under the dayrate contract.

We have an additional drilling rig commitment with Orion for a second rig, which we do not own; this is also a dayrate contract, which will terminate in February, 2011. We have used this rig continuously in our east Texas drilling program, and it is currently drilling one well which was in progress at December 31, 2008. We have no firm plans to utilize the rig once this well is complete, and have requested that Orion assist us in reducing our obligation under the same understanding as the owned rig described above. That is, we have requested that Orion utilize the rig on other projects and credit our contractual obligation based on this third party usage.

These obligations impact our drilling plans as well as critical cash flow projections for the coming months. If the rigs are idled, or if Orion is unable to fully credit the commitment under our dayrate drilling contracts when the rigs are utilized by third parties, we will incur losses which cannot be capitalized as part of the cost of oil and natural gas properties.

The market for drilling rigs deteriorated in the second half of 2008 in tandem with prices for oil and natural gas. Our rig, which includes a top-drive, is a well-equipped, long-lived asset and nearly new. While we believe it retains value, utilization in the short-term is uncertain, and dayrates have decreased. Based on the economic information available to us, and using conservative estimates of utilization and dayrates, we estimated the present value of the rig at $5.5 million as of December 31, 2008. Accordingly, in the fourth quarter of 2008, we recorded a non-cash impairment expense of $6.7 million to write down the net book value of the rig to $5.5 million. Due to the continued volatility in the prices of oil and natural gas, and its negative effect on the drilling industry, we will continue to review this asset for additional impairment. We cannot predict whether additional impairment will be necessary.

Exploration commitment. The Company has an exploration commitment under a contract regarding exploration in an area which management no longer believes has potential. The commitment totals $2.7 million and is due in the third quarter of 2009. It was recorded as a current liability and included in our full cost pool before impairment.

Tax Rate. Our effective income tax rate has varied significantly in the past several years. During periods of profitability, the effective rate was approximately 38-44%, which is greater than the corporate income tax rate of 35% primarily due to state taxes and other permanent differences. In 2008, we recorded a significant loss due to the non-cash impairment expense described above; the tax benefit to the Consolidated Statement of Operations resulting from the loss was limited to $8.4 million, which is the amount of our deferred tax liabilities at December 31, 2007. We limited the tax benefit by recording a valuation allowance against the deferred tax assets resulting from the 2008 net loss because management believes, given our overall current financial position, that there are significant uncertainties regarding our ability to generate net profits in the near term.

Thus the 4% effective income tax rate for 2008 is anomalous. Future effective tax rates will be reduced by the exhaustion of the valuation allowance over time. The total valuation allowance is $64.6 million.

Tax audit. In the fourth quarter of 2008, we were notified by the Internal Revenue Service that Meridian would be audited for fiscal years 2006 and 2007. We have engaged tax consultants to assist us in cooperating with the audit, which has progressed satisfactorily, although we cannot predict the outcome of the audit.

Operations Overview

During 2008, we achieved several goals in the areas of drilling success, production rates, favorable hedges, drilling cost reductions and prospect development.

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Meridian participated in, drilled or recompleted 18 successful wells, eight in East Texas Austin Chalk, nine in South Louisiana, and one in Texas offshore. We managed to maintain roughly flat production levels by offsetting our fields 20-30% decline rates, and to enhance our 2008 and 2009 cash flow with favorable hedges. Drilling cost for wells in East Texas were reduced by approximately 20% compared to wells drilled in 2007. We moved out of some uneconomic areas (New Albany Shale, Palo Duro Basin, Oklahoma and Delaware Basin) and have generated several promising prospects in the Atchafalaya Bay and Barataria Bay areas by optimizing our well developed in-house seismic databases and technical team. Like many of our peers, Meridian was also forced to deal with several challenges. Those challenges included production interruptions from two hurricanes and severe commodity price swings that required us to report a non-cash ceiling test impairment as well as negative revisions to proved reserves. The two areas in which Meridian was most active in 2008 were East Texas and South Louisiana.

East Texas Austin Chalk

During 2008 Meridian participated in nine wells in the East Texas Austin Chalk area, including seven successful completions, and two wells still drilling or under evaluation as of December 31, 2008. The successful wells include:

Blackstone Minerals A-917 No. 1H tested at gross daily flow rates of up to 7.0 Mmcfe/d
Black Stone Minerals No. 5 tested at gross daily flow rates of up to 18.1 Mmcfe/d
Freeman No. 1 tested at gross daily flow rates of up to 16.7 Mmcfe/d
Blackstone Minerals A-507 No. 1 tested at gross daily flow rates of up to 57 Mmcfe/d
Davis A-388 No. 1 tested at gross daily flow rates of up to 38 Mmcfe/d
Blackstone Minerals A-507 No. 2 tested at gross daily flow rates of up to 27.3 Mmcfe/d
Sutton A-574 No. 1 tested at gross daily flow rates of up to 35.4 Mmcfe/d.

The key to being successful in this area is our focus on strict management of drilling and completion costs and leveraging our large acreage position through development drilling.

South Louisiana

During 2008 Meridian recompleted or drilled nine wells in the Company s legacy asset areas of South Louisiana. The successful wells include:

Goodrich Cocke No. 7 gross daily flow rate of 650 Bopd
Avoca 8 No.1 gross daily flow rate of 2.6 Mmcfe/d
Myles Salt No. 27 gross daily flow rate of 2.1 Mmcfe/d
CL&F B1 gross daily flow rate of 700 Mcfe/d
CL&F C1 gross daily flow rate of 900 Mcfe/d
Goodrich-Cocke No. 6 ST gross daily flow rate of 2500 Bopd
Myles Salt No. 31 gross daily flow rates of 300 Bopd
Myles Salt No. 46 gross daily flow rate of 330 Bopd
Weeks Bay No. 15 tested at a gross daily flow rate of 685 Bopd

South Louisiana remains a core area for near term and long term upside for Meridian. Weeks Island field is the Company s largest oil field and continues to provide us additional opportunities from new well locations, sidetracks and development drilling. We are evaluating our reprocessed 3-D seismic data over Weeks Island

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and other regions of South Louisiana. The re-processed and newly acquired 3-D data has enhanced our generation of lower to moderate risk new projects in this core area where we are already active and have operations and production facilities in place. We anticipate drilling and recompletion activity in this area during 2009, primarily in the Weeks Island and Biloxi Marshland areas.

South Texas

Levering off the knowledge and experience gained in the East Texas Austin Chalk, we expanded beyond its currently established boundaries to potentially explore and test acreage located in the south-central Texas counties of Karnes and Lavaca. Last year, Meridian built a 30,000 acre leasehold position where we anticipate that potential production will have a higher oil content than our current production in the initial wells in East Texas. Our leases are still in their primary term; due to constraints on our capital budget, management plans to observe the exploration results of other operators during 2009, in order to gain additional geological and operational information about this play.

Capital Expenditure Plans for 2009. The Company anticipates the 2009 capital spending budget will be primarily used for recompletions and similar work on existing properties, and for lease maintenance costs. We anticipate that the budget will be significantly lower than in past years, reflecting our expectations of reduced cash flows due to commodity price declines and the loss of availability of funds under the Credit Facility. These factors will significantly impact funds available for capital spending. We currently anticipate funding the 2009 plan utilizing cash flow from operations and cash on hand, augmented by proceeds from sales of assets as possible.

Results of Operations

Year Ended December 31, 2008, Compared to Year Ended December 31, 2007

Revenue.

Oil and natural gas revenues, which include oil and natural gas hedging activities (see Note 13 of Notes to Consolidated Financial Statements included elsewhere herein), during the twelve months ended December 31, 2008, decreased $2.1 million (1%) to $149.2 million, as compared to 2007 revenues of $152.2 million, due to a 24% decrease in production volumes primarily from natural production declines, partially offset by a 29% 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 to 38.1 MMcfe for 2008 from 50.1 MMcfe during 2007. Oil and natural gas production volume totaled 13,958 MMcfe for 2008, compared to 18,269 MMcfe for 2007. During 2008, the Company s drilling activity was primarily focused in the East Texas project area and the Terrebonne Parish area of South Louisiana. During 2008, the Company drilled or participated in the drilling of 22 wells of which 14 wells were completed, representing a 64% success rate. The following table summarizes Meridian s operating revenues, production volumes and average sales prices for the years ended December 31, 2008 and 2007.

	Year Ended December 31, 2008	Year Ended December 31, 2007	Increase (Decrease)
Production:			
Oil (MBbls)	765	838	(9%)
Natural gas (MMcf)	9,369	13,239	(29%)
Natural gas equivalent (MMcfe)	13,958	18,269	(24%)
Average Sales Price:			
Oil (per Bbl)	$ 83.18	$ 64.70	29%
Natural gas (per Mcf)	9.07	7.29	24%

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	Year Ended December 31, 2008	Year Ended December 31, 2007	Increase (Decrease)
Natural gas equivalent (per Mcfe)	10.65	8.25	29%
Operating Revenues (000 s):			
Oil	$ 63,636	$ 54,218	17%
Natural gas	84,998	96,491	(12%)
Total	$ 148,634	$ 150,709	(1%)

Operating Expenses.
Oil and natural gas operating expenses on an aggregate basis decreased $4.1 million (14%) to $24.3 million in 2008, compared to $28.3 million in 2007. On a unit basis, lease operating expenses increased $0.19 per Mcfe to $1.74 per Mcfe for the year 2008 from $1.55 per Mcfe for the year 2007. Oil and natural gas operating expenses decreased between the periods primarily due to lower insurance and workover costs; in addition, some fields were shut-in during the third and fourth quarters of 2008 due to hurricane damage. The increase in the per Mcfe rate was attributable to the lower production between the two corresponding periods.
Severance and Ad Valorem Taxes.
Severance and ad valorem taxes increased $0.3 million (3%) to $9.7 million in 2008, compared to $9.4 million in 2007, primarily because of an increase in the average price of oil. 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 $0.288 per Mcf (effective July 1, 2008) for natural gas. Generally in 2008, although total revenue was flat, a larger proportion was generated from oil, for which severance taxes are computed on a percentage basis. Natural gas taxes are based on a per mcf rate which on average did not significantly change. On an equivalent unit of production basis, severance and ad valorem taxes increased to $0.70 per Mcfe for 2008 from $0.52 per Mcfe for 2007. The effective severance tax rate for oil is significantly higher than that for natural gas, particularly when natural gas prices are trending higher, as they were throughout a good portion of 2008; thus the change in the mix of revenues and volumes toward more oil increased the effective tax rate, which is reflected in the per unit costs.
Depletion and Depreciation.
Depletion and depreciation expense decreased $5.0 million (6%) during 2008 to $72.1 million compared to $77.1 million for 2007. This was primarily the result of a 24% decrease in production volumes in 2008 compared to 2007, partially offset by an increase in the depletion rate compared to 2007. On a unit basis, depletion and depreciation expenses increased to $5.16 per Mcfe for 2008, compared to $4.22 per Mcfe for 2007. Depletion and depreciation expense on a per Mcfe basis increased primarily due to capital costs.
Impairment of Long-Lived Assets.
A decline in oil and natural gas prices as of December 31, 2008, resulted in the Company recognizing a non-cash impairment totaling $216.8 million of its oil and natural gas properties under the full cost method of accounting. In addition, we recorded impairment expense of $6.7 million on our drilling rig. 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 20 of Notes to Consolidated Financial Statements included elsewhere herein), increased $2.8 million (17%) to $19.1 million in 2008 compared to $16.2 million for the year 2007, primarily due to the cost of a retention bonus program for non-executive employees, and to a contract settlement with a former employee. (See Note 12 of Notes to Consolidated Financial Statements). On an equivalent unit of production basis, general and administrative expenses increased $0.47 per Mcfe to $1.36 per Mcfe for 2008 compared to $0.89 per Mcfe for 2007.

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Contract Settlement Expense.

Contract settlement expense of $9.9 million was recorded in the second quarter of 2008 when the employment contracts of certain executive officers were replaced and certain other agreements governing other elements of their compensation packages were settled. There was no contract settlement expense recorded in 2007. See further information in Note 12 of Notes to Consolidated Financial Statements.

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 recorded accretion expense of $2.1 million and $2.2 million in 2008 and 2007, respectively. The slight decrease in 2008 levels in comparison to 2007 is primarily the result of revisions to estimated abandonment costs and actual abandonments, offset by additional wells drilled and placed on production during the year.

Hurricane Damage Repairs.

Hurricane damage repairs of $1.5 million were recorded in 2008 for hurricanes Ike and Gustav, primarily related to the Company s insurance deductibles for each storm. There were no hurricane damage repairs recorded in 2007.

Interest Expense.

Interest expense decreased $0.7 million (11%) to $5.4 million in 2008 compared to $6.1 million for 2007. The decrease was primarily a result of decreased interest rates during 2008, partially offset by higher debt balances.

Taxes on Income.

Income tax expense for 2008 was a benefit of $8.5 million as compared to a provision of $5.7 million for 2007. Income taxes are generally provided on book income after taking into account permanent differences between book income and taxable income. The benefit for 2008 was primarily the result of the impairment of long-lived assets recognized during the fourth quarter of 2008. The effective tax rate of 44% in 2007 is typical of the rate experienced by the Company in a year without unusual items. The 2007 rate differs from the statutory corporate tax rate of 35% due to state income taxes, non-deductible expenses related to the basis of certain oil and natural gas properties acquired in years past, and non-deductible expenses. The effective tax rate of 4% in 2008 is the result of recording the impairment loss and the deferred tax asset valuation allowance. When there is uncertainty as to the ability to recover a deferred tax asset through future taxable income, no benefit can be recognized, and this was the case in 2008.

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 13 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, but the rate increased in 2008 due to capital costs. 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 20 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.

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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 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 (benefit) for income tax expense for 2007 was $5.7 million as compared to ($38.5 million) for 2006. Income taxes are generally 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. The effective tax rate of 44% in 2007 is typical of the rate experienced by the Company in a year without unusual items. The 2007 rate differs from the statutory corporate tax rate of 35% due to state income taxes, non-deductible expenses related to the basis of certain oil and natural gas properties acquired in years past, and non-deductible expenses. The effective tax rate of 35% for the net loss in 2006 is the result of the impairment loss recorded that year at a 35% benefit.

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Liquidity and Capital Resources

Cash Flows. Net cash flow provided by operating activities was $92.8 million for the year ended December 31, 2008, as compared to $97.0 million for the year ended December 31, 2007, a decrease of $4.2 million or 4%, primarily due to funding $9.9 million of contract settlement expenses in 2008 for certain officers (see Note 12 of Notes to Consolidated Financial Statements included elsewhere herein) and lower oil and natural gas revenues primarily due to lower production, partially offset by changes in working capital accounts.

Net cash flows used in investing activities were $116.9 million for the year ended December 31, 2008, as compared to $113.6 million for the year ended December 31, 2007. This increase was due to higher expenditures for property and equipment in 2008.

Net cash flows provided by financing activities were $23.9 million for the year ended December 31, 2008, as compared to net cash flows used in financing activities of $1.3 million for 2007. Historically, the trend of our cash provision has been toward increasing use of our Credit Facility and other new debt (in thousands):

	2008	2007	2006
Cash provided by			
Operating activities	$ 92,767	$ 96,991	$ 137,272
Net drawdown under credit facility	20,000		
New debt for drilling rig	10,000		
Sales of property	7,171	3,060	11,032
	129,938	100,051	148,304
Cash utilized in			
Additions to property and equipment	124,059	116,696	141,796
Repurchase of common stock	75	1,158	
Reductions of drilling rig debt	1,150		
	125,284	117,854	141,796
Other source (uses), net	(4,826)	(95)	1,651
Net increase (decrease) in cash	$ (172)	$ (17,898)	$ 8,159

As noted above, we are in default under the terms of our Credit Facility, and our borrowing base is limited to the $95.0 million currently borrowed. This has also triggered an event of default under our rig note. The lenders under the rig note have been timely advised of the default under the Credit Facility and may respond with a declaration of default under the rig note. Under both these debt agreements, the creditors may accelerate all payments of principle and interest in response to an event of default, or they may elect to take other action. Thus far, neither lender has responded with a notice of any exercise of remedies. With credit markets extremely tight and the decrease in value of our proved reserves due to decreased energy prices, it is unlikely that supplemental credit sources will be available to us in the near term. In addition, the terms of our Credit Facility restrict our ability to engage in other borrowing transactions. At present, cash flows from operations and sales of property are our primary sources of cash.

We anticipate reduced cash from operations in 2009, due to the significant reduction in prices for oil and natural gas, and due to expected natural production declines, although we expect some offsets due to reduced general and administrative and field operations expenses. However, as described earlier, we have obligations under two long-term drilling contracts which may significantly impact operational cash flows. If we are unable to effectively sublease the two rigs continuously, or if the terms of agreements do not completely cover the commitment under our drilling contracts, we will incur negative cash flow under those contracts. We hope to limit such losses by utilizing the rigs in our own drilling as intended, but significant uncertainty exists regarding our capital expenditures for 2009 and forward. Reduction in capital spending is our first alternative after expense reductions to improve cash flow.

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Cash Obligations. The following summarizes the Company s contractual obligations at December 31, 2008, 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	$ 105,624	$	$	$ 105,624
Interest (6)	261			261
Drilling rigs (1) (2)	19,586	13,734		33,320
Drilling obligation (3)	2,666			2,666
Contract settlement obligation (4)	9,894			9,894
Retention incentive compensation plan (5)	2,946			2,946
Non-cancelable operating leases	2,170	3,700		5,870
Total contractual cash obligations	$ 143,147	$ 17,434	$	$ 160,581

(1) Commitments for drilling rigs include $11.4 million ($9.1 million and $2.3 million in 2009 and 2010, respectively) for a dayrate contract for operation of a rig owned by Meridian. The rig is leased to the operator with whom we have the dayrate contract. Offsetting this obligation for the dayrate contract, but not included above, are the payments we receive from the operator for his lease of the rig, which are based on a percentage of the monthly net profits of rig operation. The total rental income related to the rig in 2008, for nine months of rig operation, was $2,621,000. We have a dayrate contract for an additional rig which we

do not own; the obligation under that dayrate contract is $10.5 million, $10.6 million, and $0.9 million in each of the years 2009, 2010, and 2011, respectively.

(2) Actual net cash outflow for rig obligations will be impacted by the outcome of events which are currently uncertain. Under each of these contracts, when the rig is drilling for the Company, the entire dayrate is payable, but can be expected to be partially recovered if other working interest owners share costs of the well. When the Company is unable to utilize the rig, the Company is liable for the entire dayrate. However, the operator has been willing to credit our obligation to some extent, based on revenues from other parties who utilize the rig when the Company is unable to. During the first quarter of 2009, one rig has been effectively subleased to others, but for short duration; the resulting reduction in our net obligation has not been included in the table above. The other rig was utilized in the first quarter of 2009 drilling a Meridian-operated well in which the Company s working

interest is approximately 60%; the resulting reduction in our net obligation has not been included in the table above.

(3) This obligation relates to an exploration commitment under a contract regarding exploration in an area which management no longer believes has potential.

(4) This compensation-related obligation is to certain executives and is expected to be paid in June 2009 with funds currently set aside in a Rabbi Trust account. See Note 12 of the Notes to Consolidated Financial Statements included herein for further details. Until distribution, the assets of the trust belong to the Company, but are effectively restricted due to the obligation to the officers.

(5) These contractually-obligated retention payments are to be paid to our non-executive employees who continue their employment with the Company through March 31, 2009. See Note 12 of the Notes to Consolidated Financial Statements included herein for further details. Payment is

expected to be made in the first quarter of 2009 using general funds. As of December 31, 2008, we had accrued $2.0 million of this liability.

***Current Credit Facility*.** On December 23, 2004, the Company amended the Credit Facility to provide for a four-year $200 million senior secured credit facility (the Credit Facility) with Fortis Capital Corp., as administrative agent, sole lead arranger and bookrunner; Comerica Bank as syndication agent; and Union Bank of California as documentation agent. Bank of Nova Scotia, Allied Irish Banks PLC, RZB Finance LLC and Standards Bank PLC completed the syndication group. The initial borrowing base under the Credit

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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.

The terms of the Credit Facility contain numerous covenants and restrictions. Currently, we are in default of a covenant which requires that we maintain a current ratio (as defined in the Credit Facility) of one to one. Our current ratio, as defined, is 0.76 at December 31, 2008. Presently, our lenders have been informed of our default under these covenants, and have not responded with a notice of any exercise of remedies. Among the remedies available to the lenders upon an event of default is acceleration of all principal and interest payments. Accordingly, we have classified all indebtedness under the Credit Facility, $95.0 million, in current liabilities on the accompanying Consolidated Balance Sheets. We cannot predict what action our lenders may take.

On February 21, 2008, the Company amended the 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 (collectively, the Lenders.) The maturity date was extended to February 21, 2012, and the borrowing base was redetermined to be $110 million. Interest rates were slightly increased by increasing the range of the add-on to the prime base rate by 250 basis points on the lower end of the range and by 500 basis points on the higher end of the range; the range of the add-on to the alternative base rate was increased by 250 basis points on the higher end of the range.

On December 19, 2008, the Company entered into the Second Amendment to Credit Agreement to the Credit Facility (Second Amendment). The Second Amendment redetermined the borrowing base at $95 million, limiting borrowing to the amount outstanding at December 31, 2008. In addition, interest rates were increased by increasing the range of the add-on to the prime base rate by 500 basis points on the lower end of the range and by 750 basis points on the higher end of the range; the range of the add-on to the alternative base rate was increased by the same amounts.

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. In the event our then-redetermined borrowing base is less than our outstanding borrowings under the Credit Facility, we will be required to repay the deficit within a 90-day period.

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, restrictions on incurrence of additional debt, and an unqualified audit report on the Company s consolidated financial statements. The Company is in compliance with each of these covenants, with the exception of the requirement that we maintain a current ratio (as defined in the Credit Facility) of 1.0, and the requirement that we deliver an unqualified audit report on our consolidated financial statements. As of December 31, 2008, our current ratio, as defined, was 0.76. As a result of our current lack of financial liquidity, our independent registered public accounting firm has included a modification in its report on our consolidated financial statements included herein.

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 1.25% to 2.50% 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 2.0% to 3.25%, depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base. At December 31, 2008, the three-month LIBOR interest rate was 1.425%. The 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 13, 2009, outstanding borrowing under the Credit Facility totaled $95.0 million.

Rig Note. On May 2, 2008, the Company, through its wholly owned subsidiary TMR Drilling Corporation (TMRD), entered into a financing agreement with The CIT Group Equipment Financing, Inc. (CIT). Under the terms of the agreement, TMRD borrowed $10.0 million, at a fixed interest rate of 6.625%, in order to refinance the purchase of a land-based drilling rig to be used in Company operations. The rig had been purchased using cash on hand and funds available to the Company under the Credit Facility. Funds from the new agreement were used to reduce borrowing under the Credit Facility. The loan is collateralized by the drilling rig, as well as general corporate credit. The term of the loan is five years; monthly payments of $196,248 for interest and principal are to be made until the loan is completely repaid at termination of the agreement on May 2, 2013.

Our failure to comply with any of the restrictions and covenants under our Credit Facility results in a default under the facility, which results in an event of default under our rig note. The total balance outstanding under the rig note at December 31, 2008 is $8.8 million. The remedies available to CIT under the rig note include acceleration of all principal and interest payments. Accordingly, we have classified all indebtedness under the rig note, $8.8 million, in current liabilities on the accompanying Consolidated Balance Sheets at December 31, 2008.

Presently, CIT has been informed of our default under the covenants of the Credit Facility, and has not responded with a notice of any exercise of remedies. We cannot predict what action they may take.

Capital Expenditures. Capital expenditures in 2008 consisted of $117.6 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.

The Company anticipates the 2009 capital spending budget will be primarily used for recompletions and similar work on existing properties, and for lease maintenance costs. We anticipate that the budget will be significantly lower than in past years, reflecting our expectations of reduced cash flows due to commodity price declines and the loss of availability of funds under the Credit Facility. These factors will significantly impact funds available for capital spending. We currently anticipate funding the 2009 plan utilizing cash flow from operations and cash on hand, augmented by proceeds from sales of assets as possible.

Dividends. It is our policy to retain existing cash for reinvestment in our business, and therefore, we do not anticipate that dividends will be paid with respect to the common stock in the foreseeable future.

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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, 2008, availability under the Credit Facility was less than the required 20%, and repurchases have been suspended.

As of December 31, 2008, the Company had repurchased 535,416 common shares at a cost of $1,234,000, of which 501,300 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 does not expect to make share repurchases in the near term.

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 2008, 2007, and 2006, such capitalized costs totaled $17.4 million, $16.5 million, and $15.4 million, respectively. General and administrative costs related to production and general overhead are expensed as incurred.

Proceeds from the sale of oil and natural gas properties are credited to the full cost pool, except in transactions involving a significant quantity of reserves or where the proceeds received from the sale would significantly alter the relationship between capitalized costs and proved reserves, in which case a gain or loss would be recognized.
Future development, site restoration, and dismantlement and abandonment costs, are estimated property by property based upon current economic conditions and are included in 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), 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 expense of depletion and amortization of oil and natural gas properties. A 10% decrease in reserves would have increased our expense for the year by approximately 3%; however, a 10% increase in our reserves would have decreased our expense for the year by approximately 3%.
The cost of unevaluated oil and natural gas properties not subject to depletion 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, available geological and geophysical information, and actual exploration and development plans. Any impairment assessed is added to the cost of proved properties being amortized.
At December 31, 2008, we had $39.9 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 expense of depletion and amortization of oil and natural gas properties by less than 1% and a 10% increase would have decreased our provision by less than 1% for the year ended December 31, 2008.
Full-Cost Ceiling Test. At the end of each quarter, the unamortized cost of oil and natural gas properties, net of related deferred income taxes, is limited to the sum of the estimated future after-tax 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 depletion expense 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.
At December 31, 2008, the unamortized cost of our oil and natural gas properties, net of related deferred income taxes, exceeded the ceiling under the full cost method of accounting for our oil and natural gas properties. Accordingly, based on December 31, 2008 pricing of $5.79 per Mcf of natural gas and $44.04 per barrel of oil, in the fourth quarter of 2008, the Company recognized a non-cash impairment of $216.8 million ($203.2 million after tax) of the Company s oil and natural gas properties under the full cost method of accounting. A non-cash impairment of $134.9 million ($87.7 million after tax) was recognized in the third quarter of 2006, based on prices prevailing at that time.

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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 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, 2008, we had no cushion (i.e., the excess of the ceiling over our capitalized costs). Thus, any decrease in prices affecting the end of subsequent accounting periods, net of the effect of our hedging positions, may require us to record additional impairment charges. Any future impairment would be impacted by changes in the accumulated costs of oil and natural gas properties, which may in turn be affected by sales or acquisitions of properties and additional capital expenditures. Future impairment would also be impacted by changes in estimated future net revenues, which are impacted by additions and revisions to oil and natural gas reserves. A 10% decrease in prices would have increased our 2008 non-cash impairment expense by approximately $31.3 million, or 15%.

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 loss of $18,000 during the year ended December 31, 2008, a gain of $21,000 during the year ended December 31, 2007, and a gain of $128,000 during the year ended December 31, 2006.

As of December 31, 2008, the estimated fair value of the Company s oil and natural gas agreements was an unrealized gain of $8.1 million ($8.1 million net of tax) which is recognized in Accumulated Other Comprehensive Income (Loss). Based upon oil and natural gas commodity prices at December 31, 2008, all of the unrealized gain deferred in Accumulated Other Comprehensive Income (Loss) could potentially increase gross revenues in 2009. The derivative agreements expire at various dates through December 31, 2009.

Net settlements under these contract agreements increased oil and natural gas revenues by $4,663,000, $3,252,000 and $3,821,000 for the years ended December 31, 2008, 2007, and 2006, 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 value of bank borrowings under the Credit Facility approximate the carrying amounts as of December 31, 2008 and 2007. The rate is variable and had been recently renegotiated on December 19, 2008; in addition, the value of the underlying collateral is in excess of the outstanding amount. The Company also has a smaller bank debt with a fixed rate (the rig note). The fair value of the rig note, computed for disclosure purposes only, is estimated as $5.5 million; the carrying value of the debt is $8.8 million. The fair value was estimated based on the fair value of the underlying collateral, which is a drilling rig owned by the Company. See Note 4 of Notes to Consolidated Financial Statements included herein for further information on how fair value for the rig was estimated; see Note 5 for further information on the Credit Facility and the rig note.

Deferred Tax Asset Valuation Allowance. Under the liability method, deferred tax assets and liabilities are recognized for the estimated future tax effects attributable to temporary differences and carryforwards. Ultimately, realization of a deferred tax benefit depends on the existence of sufficient taxable income within the carryback/carryforward period to absorb future deductible temporary differences or a carryforward. In assessing the realizability of deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized, including such evidence as the scheduled reversal of deferred tax liabilities and projected future taxable income. As a result of the current assessment, in 2008 we recorded a valuation allowance against deferred tax assets equal to the full amount of those assets.

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. 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 other than oil and natural gas properties. The Company adopted the effective portion of SFAS 157 on January 1, 2008; the adoption did not have a material impact on our financial position or results of operations. We do not expect the adoption in 2009 of application of the new standard to non-financial assets and liabilities 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.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities (SFAS 161), which amends FASB Statement No. 133. SFAS 161 provides guidance for additional disclosures regarding derivative contracts, including expanded discussions of risk and hedging strategy, as well as new tabular presentations of accounting data related to derivative instruments. SFAS 161 will be effective for fiscal years and interim periods beginning after November 15, 2008 with early application encouraged. We do not expect the adoption of SFAS 161 to have a material impact on our reported statements of financial position or results of operations.

In May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles (SFAS 162), which identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America (the GAAP hierarchy). This Statement became effective November 15, 2008. The adoption of SFAS 162 had no material effect on our financial statements or related disclosures.

In June 2008 the FASB Emerging Task Force issued EITF Abstract Issue No. 07-05, Determining Whether an Instrument (or Embedded Feature) Is Indexed to an Entity s Own Stock (EITF 07-05). The issue clarifies the determination of equity instruments which may qualify for an exemption from SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. Generally, equity instruments which qualify under the guidelines of EITF 07-05 may be accounted for in equity accounts; those which do not qualify are subject to derivative accounting. The guidance will be effective for fiscal years and interim periods beginning after December 15, 2008. We are evaluating the effect of EITF 07-05 on our financial statements; we expect that certain of our outstanding warrants will be subject to derivative accounting, and we cannot predict the effect on our results of operations, as it is dependent on our stock price.

In December 2008, the Securities and Exchange Commission published a Final Rule, *Modernization of Oil and Gas Reporting* . The new rule permits the use of new technologies to determine proved reserves if those technologies have been demonstrated to lead to reliable conclusions about reserves volumes. The new requirements also will allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (*a*) report the independence and qualifications of its reserves preparer or auditor; (*b*) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit; and (*c*) report oil and gas reserves using an average price based upon the prior 12-month period rather than year-end prices. The use of average prices will affect future impairment and depletion calculations.

The new disclosure requirements are effective for annual reports on Forms 10-K for fiscal years ending on or after December 31, 2009. A company may not apply the new rules to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required. The Company has not yet determined the impact of this Final Rule, which will vary depending on changes in commodity prices on its disclosures financial position or results of operations.

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 $95 million remains borrowed under the Credit Facility, we estimate our annual interest expense will change by $0.95 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 agreements 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. The Company s Credit Facility (Note 5) requires that counterparties in derivative transactions be limited to the Lenders, including affiliates of the Lenders. The Company does not obtain collateral from the Company s counterparties to support counterparty obligations under the agreements. The master derivative contracts with each counterparty allow the Company, so long as it is not a defaulting party, after a default or the occurrence of a termination event, to set-off against the interest of the counterparty in any outstanding balance under the Credit Facility. In practice, no such set-off has been made, and all settlements have been made in cash. As of December 31, 2008, however, the Company is in default of two covenants contained in the Credit Facility, the breach of which is also a default under the master derivative agreements. The Company s hedge counterparties are not obligated to make payments to the Company under the hedging agreements while the Company s default is continuing. The Company s set-off rights under the master derivative agreements cannot be exercised due to such default. The Company s hedging counterparties may exercise their remedies under the hedging agreements, and potentially under the Credit Facility, on account of the Company s default. If a counterparty were to default in payment of an obligation, the Company would be exposed to commodity price fluctuations, and the protection intended by the hedge would be lost. The value of assets from hedging activities would be impacted. In addition, as expected cash flows from hedging contracts are included in computing future net revenues, the ceiling test could be impacted, which could result in a non-cash write-down of oil and natural gas properties. Balances owed by the Company under derivative agreements are collateralized by the security interests supporting the Credit Facility. The agreements also contain provisions permitting netting of multiple unrelated transactions that settle on the same day and in the same currency.

All of the Company s current hedging agreements 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 34% of our proved developed natural gas production and 19% 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, 2008, is provided below (see the Company s website at www.tmrc.com for a quarterly breakdown of the Company s hedge position for 2008 and beyond):

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	Type	Notional Amount	Floor Price ($ per unit)	Ceiling Price ($ per unit)	Estimated Fair Value Asset (Liability) December 31, 2008 (in thousands)
Natural Gas (mmbtu)					
Jan 2009 - Dec 2009	Collar	1,230,000	$ 7.50	$ 10.45	$ 2,070
Jan 2009 - Dec 2009	Collar	760,000	$ 8.00	$ 10.30	1,592
Jan 2009 - Dec 2009	Collar	540,000	$ 8.00	$ 13.35	1,166
Total Natural Gas					$ 4,828
Crude Oil (bbls)					
Jan 2009 - Dec 2009	Collar	23,000	$ 70.00	$ 93.55	$ 434
Jan 2009 - Dec 2009	Collar	43,000	$ 80.00	$ 111.00	1,236
Jan 2009 - Dec 2009	Collar	49,000	$ 85.00	$ 128.50	1,638
Total Crude Oil					3,308
					$ 8,136

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.

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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.

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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.

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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 as of December 31, 2008 and 2007 and the related consolidated statements of operations, comprehensive income (loss), stockholders equity and cash flows for each of the three years in the period ended December 31, 2008. 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 of America). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of The Meridian Resource Corporation at December 31, 2008 and 2007, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 to the consolidated financial statements, at December 31, 2008, the Company was in violation of certain debt covenants resulting in the default on its revolving credit and other debt agreements, which raise substantial doubt about the Company s ability to continue as a going concern. Management s plans in regard to these matters are also described in Note 1. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), The Meridian Resource Corporation s internal control over financial reporting as of December 31, 2008, 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 16, 2009 expressed an unqualified opinion thereon.

/s/ BDO Seidman, LLP

Houston, Texas
March 16, 2009

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

	Year Ended December 31,		
	2008	**2007**	**2006**
REVENUES:			
Oil and natural gas	$ 148,634	$ 150,709	$ 189,041
Price risk management activities	(18)	21	128
Interest and other	549	1,448	1,788
	149,165	152,178	190,957
OPERATING COSTS AND EXPENSES:			
Oil and natural gas operating	24,280	28,338	22,614
Severance and ad valorem taxes	9,727	9,409	11,259
Depletion and depreciation	72,072	77,076	106,067
General and administrative	19,063	16,221	16,674
Contract settlement	9,894		
Accretion expense	2,064	2,230	1,588
Impairment of long-lived assets	223,543		134,865
Hurricane damage repairs	1,462		4,314
	362,105	133,274	297,381
EARNINGS (LOSS) BEFORE OTHER EXPENSES & INCOME TAXES	(212,940)	18,904	(106,424)
OTHER EXPENSES:			
Interest expense	5,408	6,090	5,982
EARNINGS (LOSS) BEFORE INCOME TAXES	(218,348)	12,814	(112,406)
INCOME TAXES:			
Current	(269)	650	369
Deferred	(8,193)	5,027	(38,891)
	(8,462)	5,677	(38,522)
NET EARNINGS (LOSS)	(209,886)	7,137	(73,884)
NET EARNINGS (LOSS) APPLICABLE TO COMMON STOCKHOLDERS	$ (209,886)	$ 7,137	$ (73,884)
NET EARNINGS (LOSS) PER SHARE:			

Basic	$ (2.30)	$ 0.08	$ (0.84)
Diluted	$ (2.30)	$ 0.08	$ (0.84)
WEIGHTED AVERAGE NUMBER OF COMMON SHARES:			
Basic	91,382	89,307	87,670
Diluted	91,382	94,944	87,670

See notes to consolidated financial statements.

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

	December 31, 2008	December 31, 2007
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 13,354	$ 13,526
Restricted cash	9,971	30
Accounts receivable, less allowance for doubtful accounts of $210 [2008] and $210 [2007]	16,980	19,874
Due from affiliates		2,580
Prepaid expenses and other	3,292	4,538
Assets from price risk management activities	8,447	2,453
Deferred tax asset		164
Total current assets	52,044	43,165
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, full cost method (including $39,927 [2008] and $53,645 [2007] not subject to depletion)	1,877,925	1,771,768
Land	48	48
Equipment and other	21,371	18,503
	1,899,344	1,790,319
Less accumulated depletion and depreciation	1,647,496	1,350,577
Total property and equipment, net	251,848	439,742
OTHER ASSETS:		
Assets from price risk management activities		865
Other	683	3
Total other assets	683	868
TOTAL ASSETS	$ 304,575	$ 483,775

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, 2008	December 31, 2007
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 15,097	$ 9,583
Advances from non-operators	5,517	6,996
Revenues and royalties payable	6,267	6,592
Due to affiliates	8,145	
Notes payable	1,775	2,662
Accrued liabilities	18,831	22,011
Liabilities from price risk management activities	311	2,772
Asset retirement obligations	1,457	3,365
Current income taxes payable	47	147
Current maturities of long-term debt	103,849	
Total current liabilities	161,296	54,128
LONG-TERM DEBT		75,000
OTHER:		
Deferred income taxes		8,238
Liabilities from price risk management activities		861
Asset retirement obligations	20,768	20,118
	20,768	29,217
COMMITMENTS AND CONTINGENCIES (Notes 6, 7, 11, and 12)		
STOCKHOLDERS EQUITY:		
Common stock, $0.01 par value (200,000,000 shares authorized, 93,045,592 [2008] and 89,450,466 [2007] shares issued) 07] and 89,139,600 [2006] issued)	948	936
Additional paid-in capital	538,561	537,145
Accumulated deficit	(422,028)	(212,142)
Accumulated other comprehensive income (loss)	8,129	(221)
	125,610	325,718
Less treasury stock, at cost, 1,712,114 [2008] and 158,683 [2007] shares	3,099	288
Total stockholders equity	122,511	325,430
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 304,575	$ 483,775

See notes to consolidated financial statements.

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

	Year Ended December 31, 2008	2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net earnings (loss)	$ (209,886)	$ 7,137	$ (73,884)
Adjustments to reconcile net earnings (loss) to net cash provided by operating activities:			
Depletion and depreciation	72,072	77,076	106,067
Impairment of long-lived assets	223,543		134,865
Amortization of other assets	224	436	443
Non-cash compensation	1,728	2,549	2,300
Non-cash price risk management activities	18	(21)	(128)
Accretion expense	2,064	2,230	1,588
Deferred income taxes	(8,193)	5,027	(38,891)
Changes in assets and liabilities:			
Restricted cash	(9,941)	1,252	(48)
Accounts receivable	3,645	4,411	16,903
Prepaid expenses and other	1,246	(1,081)	(2,163)
Accounts payable	4,629	(946)	362
Advances from non-operators	(1,480)	3,945	3,051
Due to (from) affiliates	10,725	(1,910)	(5,308)
Revenues and royalties payable	(325)	(1,341)	(1,216)
Asset retirement obligations	(613)	(2,055)	(6,026)
Other assets and liabilities	3,311	282	(643)
Net cash provided by operating activities	92,767	96,991	137,272
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to property and equipment	(124,059)	(116,696)	(130,062)
Acquisition of properties			(11,734)
Proceeds from (settlements on) sale of property	7,171	3,060	11,032
Net cash used in investing activities	(116,888)	(113,636)	(130,764)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term debt	48,000	3,000	10,000
Reductions in long-term debt	(19,150)	(3,000)	(10,000)
Proceeds Notes payable	5,684	9,540	9,248
Reductions Notes payable	(6,571)	(9,632)	(7,597)
Repurchase of common stock	(75)	(1,158)	
Payment of taxes due on vested stock	(3,035)		
Additions to deferred loan costs	(904)	(3)	
Net cash provided by (used in) financing activities	23,949	(1,253)	1,651
NET CHANGE IN CASH AND CASH EQUIVALENTS	(172)	(17,898)	8,159

Cash and cash equivalents at beginning of year		13,526		31,424		23,265
CASH AND CASH EQUIVALENTS AT END OF YEAR	$	13,354	$	13,526	$	31,424
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION						
Non-cash activities:						
Issuance of shares for contract services	$	144	$	(1,033)	$	(795)
Issuance of shares for acquisition of properties	$		$		$	(7,000)
Accrual of capital expenditures	$	(6,460)	$	4,799	$	(259)
Rig depreciation capitalized to oil and natural gas properties	$	1,538	$		$	
ARO Liability new wells drilled	$	451	$	476	$	4,559
ARO Liability changes in estimates	$	(3,160)	$	24	$	10,723

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, 2006, 2007 and 2008 (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, 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)						
Company s 401(k) plan contribution	92	1	335						336
Share-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

Share-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
Issuance of rights to common stock		4	(4)					
Compensation expense stock rights			968					968
Issuance of shares for rights to common stock	3,515	17	3,082			(1,712)	(3,099)	
Reductions of rights to common stock		(10)	(3,025)					(3,035)
Company s 401(k) plan contributions	103	1	240			(99)	181	422
Share-based compensation			193					193
Accum. other comprehensive income activity					8,350			8,350
Issuance of shares for contract services	11		37			(60)	107	144
Shares repurchased and retired	(34)		(75)					(75)
Net loss				(209,886)				(209,886)
Balance, December 31, 2008	93,045	948	538,561	(422,028)	8,129	$ (1,712)	(3,099)	122,511

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,		
	2008	**2007**	**2006**
Net earnings (loss) applicable to common stockholders	$ (209,886)	$ 7,137	$ (73,884)
Other comprehensive income (loss), net of tax, for unrealized gains (losses) from hedging activities:			
Unrealized holding gains (losses) arising during period (1)	3,806	(2,814)	9,505
Reclassification adjustments on settlement of contracts (2)	4,544	(2,114)	(2,484)
	8,350	(4,928)	7,021
Total comprehensive income (loss)	$ (201,536)	$ 2,209	$ (66,863)
(1) Net income tax (expense) benefit	$ 0	$ 1,515	$ (5,118)
(2) Net income tax (expense) benefit	$ (119)	$ 1,138	$ 1,337

See notes to consolidated financial statements.

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THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION, BASIS OF PRESENTATION AND GOING CONCERN

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.

The accompanying financial statements have been prepared assuming the Company will continue as a going concern. As shown in the accompanying financial statements, the Company experienced a net loss of $209.9 million for the year ended December 31, 2008, has a working capital deficiency of $109.3 million, including $95.0 million outstanding under its credit facility and $8.8 million in additional bank debt, and is facing immediate and long-term obligations in excess of its existing sources of liquidity, which raise substantial doubt about the Company s ability to continue as a going concern.

The Company is in default of two covenants under its revolving credit facility (Credit Facility) at December 31, 2008. The Company s current ratio, as defined in the Credit Facility, is below the required 1.0 ratio. In addition, the Company is not in compliance with a covenant requiring that the Company s auditors opinion of its current financial statements be without, modification. The accompanying report of independent registered accounting firm includes a going concern explanatory paragraph that expresses substantial doubt about the Company s ability to continue as a going concern.

Under the terms of the Credit Facility, the lenders have various remedies available if they choose to declare a default, including acceleration of payment of all principal and interest. Although they have not demanded any accelerated payments, they may. In addition, the borrowing base under the Credit Facility, which is scheduled for redetermination effective April 30, 2009, is determined at the discretion of the lenders, based primarily on the value of the Company s proved reserves. The value of proved reserves has been significantly reduced during the second half of 2008 due to the precipitous decrease in the prices of oil and natural gas. The lenders may set the borrowing base at a level below the outstanding borrowings of $95.0 million. In that case, the Company would be required to repay the deficit within 90 days.

The Company is also in default of its other bank debt, a five-year $8.8 million loan, payable in monthly installments of approximately $196,000, which was used to purchase a drilling rig (rig note.) Under the terms of the rig note, any non-compliance or default under the terms of the Credit Facility triggers a default under the terms of the rig note, as well. The remedies available to the lender under the rig note also include acceleration of all principal and interest payments. The lenders under the rig note have been timely advised of the default under the covenants of the Credit Facility and may respond with a declaration of default under the rig note. The lenders may accelerate all payments of principle and interest in response to an event of default, or they may elect to take other action.

If either or both of these lenders were to make demands for repayment either due to the default of covenants or in reference to a reduction in the borrowing base, the Company would likely be forced to sell assets to make any such payments.

In addition to liquidity issues related to bank debt and working capital, the Company has significant obligations under two long term dayrate drilling rig contracts. These obligations, described more fully in Notes 6 and 7, place a significant burden on cash flow in the immediate future.

Management is currently pursuing discussions with the lenders to obtain waivers. In addition, management is exploring a number of options to conserve or increase cash. These actions include a significant reduction of capital spending, renegotiation of drilling rig contracts, cost reductions through headcount reductions as well as reductions of field operating expenses, and sales of assets.

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There can be no assurance that cash flow from operations and other sources of liquidity, including asset sales, will be sufficient to meet contractual, operating and capital obligations. The financial statements have been adjusted to reclassify to current liabilities debts which, absent the default and resulting potential for acceleration of payment by the lenders, would have been classified as long-term. The financial statements do not include any other adjustments that might result from the outcome of uncertainty regarding the Company s ability to raise additional capital, sell assets, or otherwise obtain sufficient funds to meet its obligations.

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, 2008, was $9,971,000 and at December 31, 2007, was $30,000. Restricted cash was increased by $9,894,000 in May 2008, when contractual obligations to certain executives were funded by cash placed in a Rabbi Trust account. The obligations and trust are more fully described in Note 12. Additional 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, less related deferred taxes, is limited to the sum of the present value (10% discount rate) of the estimated future net after-tax 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 value of unproved properties adjusted for related income tax effects. See Note 4.

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, and wells and related structures.

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.

Drilling Rig

TMR Drilling Corporation (TMRD), a wholly owned subsidiary of the Company, owns a rig which is used primarily to drill wells operated by the Company. In April 2008, an unaffiliated service company, Orion Drilling, Ltd, began leasing the rig from TMRD, and operating it under a dayrate contract with the Company. The Company records drilling expenditures under the dayrate contract as capitalized exploration costs. All TMRD profits or losses related to lease of the rig, including any incidental profits or losses related to the share of drilling costs borne by our joint interest partners, are offset against the full cost pool. SEC guidelines for full cost accounting require this method in cases where services are performed by a company on properties that it owns and/or manages. A total of $1.1 million in profit was transferred to the full cost pool during 2008, representing all profits on the lease, including those related to services performed on behalf of our joint interest partners.

In the future the rig may be used by the service company for work on third party wells in which the Company has no economic or management interest. In that case, a proportional amount of TMRD s profit or loss related to the lease of the rig will be reflected in the statement of operations.

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 $5.6 million, $6.0 million, and $5.5 million in 2008, 2007 and 2006, respectively. Cash payments (refunds) for income taxes (federal and state, net of receipts) were $385,000 for 2008, $61,000 for 2007 and ($322,000) for 2006.

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.

Receivables related to oil and natural gas hedging contracts are not collateralized but are supported by rights of offset against the Company s credit facility, so long as our compliance with all the terms of that facility is complete. However,we are not in compliance with certain financial covenants as of December 31, 2008. See Notes 5 and 13 for further information.

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 $250,000 as of December 31, 2008 ($100,000 as of December 31, 2007). As of December 31, 2008, the FDIC also provides an unlimited guarantee for balances in non-interest bearing transactional accounts. At December 31, 2008, and December 31, 2007, the Company had approximately $20,696,000 and $13,318,000, respectively, in excess of FDIC insured limits, including cash in restricted cash accounts. 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 $10.2 million and $16.6 million as of December 31, 2008 and 2007, 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

The expenses of $1.5 million in 2008 and $4.3 million in 2006 are related to damages incurred from hurricanes Ike and Gustav in 2008, and hurricanes Katrina and Rita in 2005. Damages are primarily related to the Company s insurance deductible; in 2005 damages also included repair costs in excess of insured values. The final claim settlement negotiations for the 2005 hurricanes were concluded in February 2007; settlements with insurers for damages incurred in 2008 are currently in process.

Capitalized Interest

Interest cost is capitalized as part of the historical cost of assets. During 2008 and 2007, respectively, interest of approximately $191,000 and $323,000 was capitalized on the construction of our drilling rig purchase. Our unevaluated oil and natural gas properties did not include any individual investments which we consider significant enough to qualify for interest capitalization under our internal policies. Interest is capitalized using a weighted average interest rate based on our outstanding borrowings.

Earnings Per Share

Basic earnings per share amounts are calculated based on the weighted average number of shares of common stock outstanding during each period. Diluted earnings per share is based on the weighted average number of shares of common stock outstanding for the periods, including the dilutive effects of stock options, warrants, and share rights granted. Dilutive options, warrants, and share rights 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. Shares of Company stock held by the trustee of the Rabbi Trust, although treated as treasury stock for presentation on the Consolidated Balance Sheets, are included in computation of basic and diluted earnings per share, as all conditions precedent to their issue, other than passage of time, have been satisfied.

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 addresses the accounting for share-based payment transactions in which an enterprise received 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.

Compensation expense is recorded for stock options and other equity awards over the requisite vesting periods based upon the fair value on the date of the grant.

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 value of bank borrowings under our Credit Facility, which constitute the majority of bank debt, approximates the carrying amounts as of December 31, 2008 and 2007. The rate is variable and had been recently renegotiated on December 19, 2008. See Note 5 for further details on the Credit Facility. The Company also has a

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smaller bank debt with a fixed rate. The fair value for that debt, computed for disclosure purposes only, is estimated as $5.5 million; the carrying value of the debt is $8.8 million. The fair value was estimated based on the fair value of the underlying collateral. The collateral is a drilling rig owned by the Company; see Note 4 for further information on how fair value for the rig was estimated.

Our oil and gas price risk hedging contracts are also financial instruments, recorded at fair value; see Note 9.

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 4.69% and 6.76%, as of December 31, 2008 and 2007, respectively.

Lease Accounting.

The Company amortizes the cost of leasehold improvements over the term of the lease. Rent incentives, such as rent 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 a loss of $18,000, and gains of $21,000, and $128,000 related to hedge ineffectiveness during the years ended December 31, 2008, 2007, and 2006, respectively.

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

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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 reclassified into operations in the month in which the related derivative contracts settle.

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, deferred tax assets and liabilities are recognized for the estimated future tax effects attributable to temporary differences and carryforwards. Ultimately, realization of a deferred tax benefit depends on the existence of sufficient taxable income within the carryback/carryforward period to absorb future deductible temporary differences or a carryforward. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized, including such evidence as the scheduled reversal of deferred tax liabilities and projected future taxable income. As a result of the current assessment, in 2008 the Company recorded a valuation allowance equal to the net deferred tax assets.

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.

Recent 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 other than oil and natural gas properties. The Company adopted the effective portion of SFAS 157 on January 1, 2008; the adoption did not have a material impact on our financial position or results of operations. We do not expect the adoption in 2009 of application of the new standard to non-financial assets and liabilities 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.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities (SFAS 161), which amends FASB Statement No. 133. SFAS 161 provides guidance for additional disclosures regarding derivative contracts, including expanded discussions of risk and hedging strategy, as well as new tabular presentations of accounting data related to derivative instruments. SFAS 161 will be effective for fiscal years and interim periods beginning after November 15, 2008 with early application encouraged. We do not expect the adoption of SFAS 161 to have a material impact on our reported statements of financial position or results of operations.

In May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles (SFAS 162), which identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America (the GAAP hierarchy). This Statement became effective November 15, 2008. The adoption of SFAS 162 had no material effect on our financial statements or related disclosures.

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In June 2008, the FASB Emerging Task Force issued EITF Abstract Issue No. 07-05, Determining Whether an Instrument (or Embedded Feature) Is Indexed to an Entity s Own Stock (EITF 07-05). The issue clarifies the determination of equity instruments which may qualify for an exemption from SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. Generally, equity instruments which qualify under the guidelines of EITF 07-05 may be accounted for in equity accounts; those which do not qualify are subject to derivative accounting. The guidance will be effective for fiscal years and interim periods beginning after December 15, 2008. We are evaluating the effect of EITF 07-05 on our financial statements; we expect that certain of our outstanding warrants will be subject to derivative accounting, and we cannot predict the effect on our results of operations, as it is dependent on our stock price.

In December 2008, the Securities and Exchange Commission published a Final Rule, *Modernization of Oil and Gas Reporting* . The new rule permits the use of new technologies to determine proved reserves if those technologies have been demonstrated to lead to reliable conclusions about reserves volumes. The new requirements also will allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (*a*) report the independence and qualifications of its reserves preparer or auditor; (*b*) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit; and (*c*) report oil and gas reserves using an average price based upon the prior 12-month period rather than year-end prices. The use of average prices will affect future impairment and depletion calculations.

The new disclosure requirements are effective for annual reports on Forms 10-K for fiscal years ending on or after December 31, 2009. A company may not apply the new rules to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required. The Company has not yet determined the impact of this Final Rule, which will vary depending on changes in commodity prices on its disclosures financial position or results of operations.

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

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. 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 $2.1 million, $2.2 million and $1.6 million in 2008, 2007 and 2006, respectively.

The following table describes the change in the Company s asset retirement obligations for the years ended December 31, 2008 and 2007 (thousands of dollars):

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
Additional retirement obligations recorded in 2008	451
Settlements during 2008	(613)
Revisions to estimates and other changes during 2008	(3,160)
Accretion expense for 2008	2,064
Asset retirement obligation at December 31, 2008	$ 22,225

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.

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 after-tax 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 cost of unevaluated oil and natural gas properties not subject to depletion is also 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, available geological and geophysical information, and actual exploration and development plans. Any impairment assessed is added to the cost of proved properties being amortized.

At December 31, 2008, the unamortized cost of our oil and natural gas properties, net of related deferred income taxes, exceeded the ceiling under the full cost method of accounting for our oil and natural gas properties. Accordingly, based on December 31, 2008 pricing of $5.79 per Mcf of natural gas and $44.04 per barrel of oil, in the fourth quarter of 2008 the Company recognized non-cash impairment expense of $216.8 million ($203.2 million after tax) to the Company s oil and natural gas properties under the full cost method of accounting. A non-cash impairment of $134.9 million ($87.7 million after tax) was recognized in the third quarter of 2006, based on prices prevailing at that time.

The Company also recorded a non-cash impairment of the value of its drilling rig, due to uncertainties regarding utilization and dayrates for similar rigs, which have decreased significantly since the second quarter of 2008. Based on the economic information available to us, and using conservative estimates of utilization and dayrates, we estimated the present value of the rig at $5.5 million as of December 31, 2008. Accordingly, we recorded non-cash impairment expense of $6.7 million to write down the net book value of the rig to $5.5 million in the fourth quarter.

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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. Furthermore, due to the related impact of volatile energy prices on the drilling industry, there can be no assurance that future write-downs will not be required for the drilling rig as well.

5. DEBT

Revolving Credit Agreement

On December 23, 2004, the Company amended its credit facility to provide for a four-year $200 million senior secured credit facility (the Credit Facility) with Fortis Capital Corp., as administrative agent, sole lead arranger and bookrunner; Comerica Bank as syndication agent; and Union Bank of California as documentation agent. Bank of Nova Scotia, Allied Irish Banks PLC, RZB Finance LLC and Standards Bank PLC completed the syndication group. The initial borrowing base under the Credit Facility was $130 million. The borrowing base under the Credit Facility was redetermined by the syndication group to be $115 million effective October 31, 2007.

The terms of the Credit Facility contain numerous covenants and restrictions. Currently, the Company is in default of a covenant which requires that it maintain a current ratio (as defined in the Credit Facility) of one to one. The current ratio, as defined, is 0.76 at December 31, 2008, exclusive of amounts which would not be currently payable, except for the circumstances of potential acceleration of payment. The Company is also in default of the requirement that the Company s auditors opinion for the current financial statements be without modification. The accompanying report of independent registered accounting firm includes a going concern explanatory paragraph expressing substantial doubt about the Company s ability to continue as a going concern.

Presently, the lenders have been informed of the default under these covenants, and have not responded with a notice of any remedies they may choose to pursue. Among the remedies available to the lenders upon an event of default is acceleration of all principal and interest payments. Accordingly, all indebtedness under the Credit Facility at December 31, 2008, $95.0 million, has been classified in current liabilities on the accompanying Consolidated Balance Sheets.

On February 21, 2008, the Company amended the 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 (collectively, the Lenders.) The maturity date was extended to February 21, 2012, and the borrowing base was redetermined to be $110 million. Interest rates were slightly increased by increasing the range of the add-on to the prime base rate by 250 basis points on the lower end of the range and by 500 basis points on the higher end of the range; the range of the add-on to the alternative base rate was increased by 250 basis points on the higher end of the range.

On December 19, 2008, the Company entered into the Second Amendment to Credit Agreement to the Credit Facility (Second Amendment). The Second Amendment redetermined the borrowing base at $95 million, limiting borrowing to the amount outstanding at December 31, 2008. In addition, interest rates were increased by increasing the range of the add-on to the prime base rate by 500 basis points on the lower end of the range and by 750 basis points on the higher end of the range; the range of the add-on to the alternative base rate was increased by the same amounts.

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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 the 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. The 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 the redetermined borrowing base is less than our outstanding borrowings under the Credit Facility, the Company will be required to repay the deficit within a 90-day period.

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, restrictions on incurrence of additional debt, and an unqualified audit report on the Company s consolidated financial statements. As noted above, at December 31, 2008, the Company is in default of two of these covenants.

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 1.25% to 2.50% 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 2.0% to 3.25%, depending on the ratio of the aggregate outstanding loans and letters of credit to the borrowing base. At December 31, 2008, the three-month LIBOR interest rate was 1.425%. The 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 13, 2009, outstanding borrowing under the Credit Facility totaled $95.0 million.

Rig Note. On May 2, 2008, the Company, through its wholly owned subsidiary TMR Drilling Corporation (TMRD), entered into a financing agreement with The CIT Group Equipment Financing, Inc. (CIT). Under the terms of the agreement, TMRD borrowed $10.0 million, at a fixed interest rate of 6.625%, in order to refinance the purchase of a land-based drilling rig to be used in Company operations. The rig had been purchased using cash on hand and funds available to the Company under the Credit Facility. Funds from the new agreement were used to reduce borrowing under the Credit Facility. The loan is collateralized by the drilling rig, as well as general corporate credit. The term of the loan is five years; monthly payments of $196,248 for interest and principal are to be made until the loan is completely repaid at termination of the agreement on May 2, 2013.

The Company s default under the Credit Facility also resulted in an event of default under our rig note. The total balance outstanding under the rig note at December 31, 2008 is $8.8 million. The remedies available to CIT in the event of default include acceleration of all principal and interest payments. Accordingly, all indebtedness under the rig note, $8.8 million, has been classified in current liabilities on the accompanying Consolidated Balance Sheets as of December 31, 2008.

Presently, CIT has been informed of the Company s default under the covenants of the Credit Facility, and has not responded with a notice of any remedies it may choose to pursue.

Current Debt Maturities

Scheduled debt maturities for the next five years and thereafter, as of December 31, 2008, including notes payable, are as follows: $105,624,000 in 2009 and none thereafter. Absent the assumed acceleration of principal under the Credit Facility and the rig note, scheduled maturities would be: $3,598,000 in 2009, $1,948,000 in 2010, $2,081,000 in 2011, $97,223,000 in 2012, $774,000 in 2013, 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, 2008, the remaining base rental payments will be $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, $2.1 million and $2.6 million in 2008, 2007 and 2006, respectively. Future minimum lease payments under all non-cancelable operating leases having initial terms of one year or more are $2.2 million for 2009, $2.1 million for 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 two drilling rigs. These obligations are $19.6 million in 2009, $12.8 million in 2010, and $0.9 million in 2011.

Additional contractual obligations in 2009 include: $9.9 million to be paid to former executives under a settlement of various compensatory agreements (see Note 12 for further information); $2.9 million payable to non-executive employees under a retention incentive plan (see Note 12 for further information); and $2.7 million payable under a commitment for exploratory activity.

7. COMMITMENTS AND CONTINGENCIES

Default under Credit Agreement

As described in Notes 1 and 5, the Company is in default under the terms of the Credit Facility and the Rig note. It may also be declared in default, at the discretion of CIT, under the terms of the rig note. The lead or administrative lenders under each of these agreements have been informed of the circumstances of default under the Credit Facility. Neither lender has advised the Company of an event of default, nor the action they intend to take in response. Among the remedies available to lenders under each of these debt agreements is acceleration of all principal and interest payments. Accordingly, all such debt has been classified as current in the Consolidated Balance Sheets as of December 31, 2008. The Company is currently unable to predict what actions the lenders may pursue; therefore, the Company has not provided for this matter as of December 31, 2008, in its financial statements at December 31, 2008, other than to reclassify all outstanding debt as current.

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 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 Chief Operating Officer of the Company at the time. A hearing was held before Judge Kay Bates on April 14, 2008. Judge Bates granted Hawkins Motion finding that Meridian was estopped from arguing that it did not breach its contract with Hawkins as a result of the United States Fifth Circuit s decision in the *Amoco* litigation. Meridian disagrees with Judge Bates ruling but the Louisiana First Court of Appeal declined to hear Meridian s writ requesting the court overturn Judge Bates ruling. Meridian has filed a motion with Judge Bates asking that she make her ruling a final judgement which would give Meridian the right to appeal now. The Hawkins interests have opposed this motion. 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 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, 2008.

Parsons Exploration litigation. On May 3, 2007, Parsons Exploration Company, LLC (Parsons) filed a claim against Meridian for damages and specific performance requiring Meridian to assign Parsons an overriding royalty interest in certain wells the Company has drilled in east Texas. The complaint alleges that the Company breached its contractual and fiduciary obligations to Parsons under an Exploration and Prospect Origination Agreement between the parties dated April 22, 2003. The complaint also alleges that the Company engaged in a civil conspiracy to breach its contractual and fiduciary obligations to Parsons and tortiously interfered with existing and prospective business relationships/contracts of Parsons. The Company has been served notice of the lawsuit and discovery has commenced. The Company intends to vigorously defend this matter. 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, 2008.

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 (together, Shell) have demanded contractual indemnity and defense from Meridian based upon the terms of the acquisition agreements 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. On December 9, 2008 Shell sent Meridian a letter reiterating its demand for indemnity. Shell has not to date produced supporting documentation for its claim. Meridian denies that it owes any indemnity under the acquisition agreements; however, the amounts claimed are substantial in nature and if adversely determined, would have a material adverse effect on the Company. 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, 2008.

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.

Hurricane damages. Certain oil and natural gas properties sustained physical damage during two hurricanes in the third quarter of 2008, hurricane Gustav and hurricane Ike. The Company has recorded $1.5 million in expense for repairs, and a $2.4 million insurance receivable at December 31, 2008, based on the most current information available. Damage estimates for non-operated properties are preliminary and subject to revision. Also, additional information regarding non-operated properties may be obtained which bears on the applicability of insurance deductibles, and may also require revision to loss estimates.

Tax audit. In the fourth quarter of 2008, we were notified by the Internal Revenue Service that Meridian would be audited for fiscal years 2006 and 2007. We have engaged tax consultants to assist us in cooperating with the audit, which has progressed satisfactorily, although we cannot predict the outcome of the audit.

Drilling rigs. As described in Note 6, over the next three years, the Company has significant contractual obligations for the use of two drilling rigs. The Company s capital expenditure plans no longer include full use of these rigs; however, the Company is obligated for the dayrate regardless of whether the rigs are working or idle. When either rig is not in use on Meridian-operated wells, the operator may contract it to third parties, or the rig may be idled. The operator has been cooperative in actively seeking other parties to use the rigs, and in agreeing to credit the Company s obligation to some extent, based on revenues from other parties who utilize the rig(s) when the Company is unable to. The rigs were used continuously by the Company through approximately the end of 2008. During the first quarter of 2009, one rig has been effectively subleased to others, but for short duration, at rates less than the dayrate under the Company s contract. The Company is obligated for the difference in dayrates. The other rig has continued to be utilized drilling a Meridian-operated well. Management cannot predict whether such use by third parties will be consistent, nor to what extent it may offset obligations under the dayrate contract. The Company has not provided any amount for these matters in its financial statements at December 31, 2008. Expenditures in 2009 and forward for the rigs when they are not drilling for the Company are expected to be expensed.

Exploration commitment. The Company has an exploration commitment under a contract regarding exploration in an area which management no longer believes has potential. The commitment totals $2.7 million and is due in the third quarter of 2009. It was recorded as a current liability and included in the full cost pool before impairment.

8. TAXES ON INCOME

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

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	Year Ended December 31,		
	2008	2007	2006
Current:			
Federal	$ (304)	$ 560	$ 334
State	35	90	35
Deferred:			
Federal	(7,984)	4,470	(39,108)
State	(209)	557	217
Income tax expense (benefit)	$ (8,462)	$ 5,677	$ (38,522)

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

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	Year Ended December 31,		
	2008	**2007**	**2006**
Income tax provision (benefit) computed at statutory rate	$ (76,422)	$ 4,485	$ (39,342)
Nondeductible costs	1,956	577	415
State income tax, net of federal tax benefit	(1,475)	615	240
Decrease in net operating loss carryover due to expiration			165
Tax on other comprehensive income	2,846		
Change in valuation allowance	64,633		
Income tax expense (benefit)	$ (8,462)	$ 5,677	$ (38,522)

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,	
	2008	**2007**
Deferred tax assets:		
Net operating tax loss carryforward	$ 32,745	$ 27,391
Statutory depletion carryforward	950	950
Tax credits	1,901	2,205
Unrealized hedge loss		119
Deferred compensation	5,474	6,232
Tax basis in excess of book basis in property and equipment	25,655	
Valuation allowance	(64,633)	
Other	754	44
Total deferred tax assets	2,846	36,941
Deferred tax liabilities:		
Book basis in excess of tax basis in oil and natural gas properties		45,015
Unrealized hedge gain	2,846	
Total deferred tax liabilities	2,846	45,015
Net deferred tax liability	$	$ (8,074)

As of December 31, 2008, the Company had approximately $93.6 million of tax net operating loss carryforwards. The net operating loss carryforwards assume that certain items, primarily intangible drilling 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.

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, 2008, the Company had net operating loss carryforwards for regular tax and alternative

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minimum tax (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
2018	$ 5,493	$ 9,416
2019	47,730	48,630
2020	31	31
2021	36	36
2022	3,719	6,189
2023	36,376	44,516
2025	42	12
2026	52	42
2027	77	
2028		369
Total	$ 93,556	$ 109,241

As of December 31, 2008, the Company had approximately $1.9 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 does not expect to fully realize its deferred tax assets, and therefore recorded a valuation allowance in 2008 to the full extent of all net deferred tax assets.

As described above in Note 7, we are undergoing an audit by the Internal Revenue Service covering the tax years 2006 and 2007.

9. FAIR VALUE MEASUREMENT

The Company adopted the provisions of SFAS 157, effective January 1, 2008. SFAS 157 does not expand the use of fair value measurements, but rather, provides a framework for consistent measurement of fair value for those assets and liabilities already measured at fair value under other accounting pronouncements. Certain specific fair value measurements, such as those related to share-based compensation, are not included in the scope of SFAS 157. Primarily, SFAS 157 is applicable to assets and liabilities related to financial instruments, to some long-term investments and liabilities, to initial valuations of assets and liabilities acquired in a business combination, and to long-lived assets carried at fair value subsequent to an impairment write-down. It does not apply to oil and natural gas properties accounted for under the full cost method, which are subject to impairment based on SEC rules. SFAS 157 applies to assets and liabilities carried at fair value on the consolidated balance sheet, as well as to supplemental fair value information about financial instruments not carried at fair value, which the Company provides annually under the provisions of SFAS 107, Disclosures about Fair Value of Financial Instruments.

Certain provisions of SFAS 157 have been deferred by the FASB. Accordingly, the Company has not applied the provisions of SFAS 157 to those non-financial assets and liabilities which are measured at fair value on a non-recurring basis. This includes asset retirement obligations, and any assets other than oil and natural gas properties, for which an impairment write-down is recorded during the period. There have been no such asset impairments in the current period.

The Company has applied the provisions of SFAS 157 to assets and liabilities measured at fair value on a recurring basis. This includes oil and natural gas derivatives contracts.

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SFAS 157 provides a definition of fair value and a framework for measuring fair value, as well as expanding disclosures regarding fair value measurements. The framework requires fair value measurement techniques to include all significant assumptions that would be made by willing participants in a market transaction. These assumptions include certain factors not consistently provided for previously by those companies utilizing fair value measurement; examples of such factors would include the company s own credit standing (when valuing liabilities) and the buyer s risk premium. In adopting SFAS 157, the Company determined that the impact of these additional assumptions on fair value measurements did not have a material effect on financial position or results of operations. The Company is still assessing the potential impact of implementation in 2009 of those portions of the guidance for which the effective date has been deferred by the FASB.

SFAS 157 provides a hierarchy of fair value measurements, based on the inputs to the fair value estimation process. It requires disclosure of fair values classified according to the levels described below. The hierarchy is based on the reliability of the inputs used in estimating fair value. The framework for fair value measurement assumes that transparent observable (Level 1) inputs generally provide the most reliable evidence of fair value and should be used to measure fair value whenever available. The classification of a fair value measurement is determined based on the lowest level (with Level 3 as lowest) of significant input to the fair value estimation process.

> Level 1 fair values are based on observable inputs. Observable inputs are quoted active market prices for assets and liabilities identical to those being valued.
>
> Level 2 fair values are based on observable inputs for similar assets and liabilities to those being valued. Level 2 fair values often rely on valuation models for which the significant inputs are observable Level 1 inputs or inputs which can be derived from Level 1 inputs through correlation.
>
> Level 3 fair values are based on at least one significant unobservable input, and may also utilize observable inputs. Unobservable inputs must be utilized when the asset or liability being valued is not actively traded. Level 3 fair values rely on valuation models that may utilize company-specific information or other unobservable inputs, developed based on the best information available in the circumstances.

The Company utilizes the modified Black-Scholes option pricing model to estimate the fair value of oil and natural gas derivative contracts. Inputs to this model include observable inputs from the New York Mercantile Exchange (NYMEX) for futures contracts, and inputs derived from NYMEX observable inputs, such as implied volatility of oil and gas prices. The Company has classified the fair values of all its derivative contracts as Level 2.

Assets and liabilities measured at fair value on a recurring basis

		Fair Value Measurements at December 31, 2008 Using		
Description	December 31, 2008	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)
Assets from price risk management activities [1]	$ 8,447		$ 8,447	

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		Fair Value Measurements at December 31, 2008 Using		
Description	December 31, 2008	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)
Liabilities from price risk management activities[(1)]	$ 311		$ 311	

(1) Assets and liabilities from price risk management activities are oil and natural gas derivative contracts, in the form of costless collars to sell oil and natural gas within specific future time periods. These contracts are more fully described in Note 13.

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, 2008, availability under the Amended Credit Facility was less than the required 20%, and repurchases have been suspended.

From March 2007, the inception of the share repurchase program, through December 31, 2008, the Company had repurchased 535,416 common shares at a cost of $1,234,000, of which 501,300 shares have been reissued for 401(k) contributions, for contract services and for compensation, and 34,116 have been retired. In addition, the Company issued shares to certain executives during the third quarter upon the discontinuation of its deferred compensation plan (see Note 12). Shares sufficient to cover the value of these employees withholding taxes were withheld from issuance, and the Company made a cash payment for the withholding tax. This transaction may be considered an indirect repurchase and has been presented on the Consolidated Statements of Cash Flows as a financing item. The total number of shares withheld was 1,001,511, at a value of approximately $3,035,000. 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 does not expect to make share repurchases in the near term.

Warrants

The Company had the following warrants outstanding at December 31, 2008:

Warrants	Number of Shares	Exercise Price	Expiration Date
Executive Officers	1,428,000	$5.85	December 29, 2009
General Partner	1,884,544	$0.10	December 31, 2015

As of December 31, 2008, 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 1,884,544 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). Messrs. Reeves and Mayell, respectively, were the Chief Executive Officer and Chief Operating Officer of the Company for many years. Messrs. Reeves and Mayell both ceased to be employees of the Company on December 29, 2008, and the Executive Officer Warrants will expire on December 29, 2009.

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

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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 two warrant arrangements 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.

Share-based Compensation

Options to purchase the Company s common stock have been granted to officers, employees, nonemployee directors and certain key individuals, under various stock incentive plans. Options generally become exercisable in 25% cumulative annual increments beginning with the date of grant and expire at the end of ten years. The Company has also made grants of stock shares which vest over time (typically, three years). The Company has also issued rights to shares of common stock under its deferred compensation plan (see additional information for that plan below, Deferred Compensation.) The Company typically utilizes newly issued stock shares when options are exercised or shares vest.

Compensation expense is recorded for share-based awards over the requisite vesting periods based upon the fair value of the award on the date of the grant. Share-based compensation expense for grants of options and non-vested shares of approximately $193,000, $294,000 and $372,000 was recorded in the years ended December 31, 2008, 2007, and 2006, respectively and is included in general and administrative expense. In addition, general and administrative expense related to issuance of shares in lieu of cash for services was $144,000, $1,144,000, and $795,000 for each of the years ended December 31, 2008, 2007, and 2006, respectively. No portion of this expense has been capitalized. At December 31, 2008, 2007 and 2006, 3,970,000, 3,850,000, and 1,785,310 shares, respectively, were available for grant under the plans. Summaries of share-based awards transactions follow:

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	Number of Share Options		Weighted Average Exercise Price
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
Granted	365,000		1.12
Exercised			
Canceled or Expired	(3,053,188)		3.37
Outstanding at December 31, 2008	711,500	$	3.06
Share options exercisable:			
December 31, 2006	3,285,465	$	3.76
December 31, 2007	3,252,001	$	3.57
December 31, 2008	265,875	$	5.74

	Number of Non-Vested Shares		Weighted Average Grant Date Fair Value
Outstanding non-vested at December 31, 2007		$	
Granted	40,873		2.32
Vested			
Forfeited			
Outstanding non-vested at December 31, 2008	40,873	$	2.32

Fair value of share options was estimated at the date of grant using the Black-Scholes option pricing model. Certain assumptions were used in determining the fair value of share options using this model. The Company calculated the estimated volatility of its stock by averaging the historical daily price intervals for closing prices of the common stock. The risk-free interest rate is based on observed U.S. Treasury rates at date of grant, appropriate for the expected lives of the options. The expected life of options was determined based on the method provided in Staff Accounting Bulletin 107, as we do not have an adequate exercise history to determine the average life for the options with the characteristics of those granted.

Weighted averages of the assumptions used in the Black-Scholes option pricing model were as follows for grants of options in the years ended December 31, 2008, 2007, and 2006, respectively: risk-free interest rates of 2.0%, 4.54%, and 4.97%; dividend yield of 0%; volatility factors of the expected market price of the Company s common stock of 0.58, 0.59, and 0.80; and weighted-average expected lives of four years, five years, and five years. These assumptions resulted in weighted average grant date fair values of $0.52, $1.36, and $2.33 for options granted in 2008, 2007 and 2006, respectively.

The aggregate intrinsic value of share options exercised was zero in each of the years ended December 31, 2008, 2007, and 2006, as no options were exercised. The aggregate intrinsic value of non-vested shares which vested during each of the years was zero, as no shares vested during that time.

Range of Exercisable Prices	Options Outstanding: Outstanding at December 31, 2008	Options Outstanding: Weighted Average Exercise Price	Options Exercisable: Exercisable at December 31, 2008	Options Exercisable: Weighted Average Exercise Price
$0.56 $1.93	295,000	0.75	3,334	1.79
$2.27 $3.99	249,500	2.86	96,166	2.92
$4.125 8.42	167,000	7.44	166,375	7.45
	711,500	3.06	265,875	5.74

The weighted average remaining contractual life of options outstanding at December 31, 2008, was approximately four years.

The aggregate intrinsic values of all options outstanding and of all exercisable options at December 31, 2008, was minimal. 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 2008 and the exercise price, multiplied by the number of in-the-money options) that would have been received by the option holders had they exercised their options on December 31, 2008. The amount of aggregate intrinsic value will change based on the fair market value of the Company s common stock.

As of December 31, 2008, there was approximately $349,000 of total unrecognized compensation expense related to 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 years.

Deferred Compensation

In July 1996, the Company through the Compensation Committee of the Board of Directors offered to Messrs. Reeves and Mayell (at the time, 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 deferred $160,000 for 2008, $400,000 for 2007, and $400,000 for 2006. 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, subject to a one-year vesting period. Under the terms of the deferred compensation plan, the employee and matching deferrals were allocated to a notional common stock account in which notional shares of common stock were 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 with the deferred and matched funds. 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. Compensation costs related to the amounts deferred by the officers and matched by the Company for these equity grants were $968,000 $1,598,000, and $1,593,000 for 2008, 2007 and 2006 , respectively. The costs are reflected in general and administrative expense and in oil and natural gas properties for the years ended December 31, 2008, 2007 and 2006, respectively as follows: $484,000, $799,000, and $797,000 in general and administrative expense and $484,000, $799,000, and $797,000 capitalized to oil and natural gas properties.

The Company discontinued the deferred compensation plan provided to these officers, which resulted in the issuance of a total of 1,803,291 shares of new common stock for Messrs. Reeves and Mayell (combined) on July 2, 2008. The shares issued were net of a reduction of 1,001,511 shares withheld in lieu of the executives personal withholding tax. The intrinsic value of all these shares on date of issuance, including those withheld, was approximately $8.5 million at $3.03 per share. Also due to termination of the plan, 1,712,114 new shares (856,057 shares for each of the two officers) were issued and placed into a Rabbi Trust on October 2, 2008. The intrinsic value of these shares on date of issuance was approximately $3.1 million at $1.81per share. The shares are expected to be distributed upon dissolution of the trust, which is anticipated for the second quarter of 2009. See Note 12 for further information.

Activity in the notional accounts for the years ended December 31, 2008, 2007, and 2006 is as follows:

	Number of Share Rights*	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2005	3,225,988	4.63
Granted	414,200	3.86
Outstanding at December 31, 2006	3,640,188	4.54
Granted	523,144	3.06
Outstanding at December 31, 2007	4,163,332	4.36
Granted	353,584	1.81
Converted to shares of common stock	(4,516,916)	4.16
Outstanding at December 31, 2008		

* For simplicity, share rights vesting on a routine schedule are not separately shown; only the original granting of the share rights is presented, and outstanding year-end balances include both vested and unvested shares. As the

Company matching portion of share rights vested monthly over a one year period, each year s activity actually included vesting of approximately one-half of the prior year s matching rights, and non-vesting of approximately one-half of the current year s matching rights. When the plan was discontinued in 2008, all remaining unvested rights (approximately 180,478 rights) were vested on an accelerated basis, then all rights were converted to shares of common stock. As of December 31, 2008, there were no rights remaining in the notional accounts and no cost related to any rights granted which had not yet been recognized.

The shares of common stock which would have been issuable upon distribution of deferrals and matching grants during the time the plan was active (including 2006, 2007, and early 2008) have been treated as common stock equivalents in computing earnings per share.

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 $531,000, $545,000, and $381,000, in 2008, 2007, and 2006, 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 $5.0 million, $4.7 million, and $6.7 million in 2008, 2007 and 2006, 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 was 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 participated in the Management Plan. The participants in the Trust Plan generally will be employees of the Company that do not participate in one of the other Well Bonus Plans. Effective March 2001, the participants in the Geoscientist Plan were notified that no additional future wells would be placed into the Geoscientist Plan. During 2002, the Executive Committee decided to modify this position and for certain key geoscientists the Geoscientist Plan will include 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 0.1% to 0.5%, depending on the level of the employee. It is intended that these well bonuses function similar to 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. For certain employees covered under the Management Well Bonus Plana and the Geoscientist Well Bonus Plan, 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 is 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 practice, most payments have been made in cash, with some payments to ex-employees made in common stock.

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 expended 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, 2008, 2007 and 2006, compensation expense in the amounts of $137,350, $78,054, and $137,624 were recorded for each individual. The net profit interests represent real property rights not subject to vesting or continued employment with the Company. Messrs. Reeves and Mayell did not participate in the Well Bonus Plans. The net profits interest plan for Messrs. Reeves and Mayell was discontinued in April, 2008. See Note 12 for further information.

12. CONTRACT SETTLEMENTS, RABBI TRUST, AND EMPLOYEE RETENTION

In April 2008 the Company made significant changes in the structure of the compensation of its top two executives, Messrs. Reeves and Mayell, who were the Chief Executive Officer and Chief Operating Officer of the Company through December 29, 2008. Effective April 29, 2008, the employment contracts for Messrs. Reeves and Mayell were replaced with new agreements. In addition, certain other agreements that governed other elements of their compensation packages were also settled. Messrs. Reeves and Mayell agreed to these changes under the terms of the settlement agreements executed by each of them effective April 29, 2008. The agreements provided for cash payments totaling approximately $4.9 million to each of Messrs. Reeves and Mayell, for a total of $9.9 million. The cash payments to Messrs. Reeves and Mayell were placed in a Rabbi Trust, which is included on the Consolidated Balance Sheets under Restricted Cash as of December 31, 2008.

In addition, the Company discontinued the deferred compensation plan provided to these officers, which resulted in the issuance of a total of 1,803,291 shares of new common stock for Messrs. Reeves and Mayell (combined) on July 2, 2008. The shares issued were net of a reduction of 1,001,511 shares withheld in lieu of the executives personal withholding tax. An additional 1,712,114 new shares (856,057 shares to each of the two officers) were issued and placed in a Rabbi Trust on October 2, 2008. Substantially all of the compensation expense related to these shares was recognized historically, when the rights to such future shares were granted. The discontinuation of the plan required conversion of the rights into shares of common stock. See further information regarding the deferred compensation plan in Note 10.

A total of $9.9 million was recorded as contract settlement expense in the second quarter of 2008 for the cash portion of the settlement. In the third quarter of 2008, the Company recorded a $1.2 million non-cash expense due to write-down of the deferred tax asset related to the stock rights; the write-down is the result of the difference between the market value of the stock when the rights were issued and expensed, and the market value at conversion of the rights into shares.

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Both the shares and the cash from the trust will be distributed to the officers upon dissolution of the trust, anticipated for the second quarter of 2009. Until distribution, the assets of the trust belong to the Company, but are effectively restricted due to the obligation to the officers. The shares in the trust will be accounted for as treasury shares so long as they remain in the trust.

On July 29, 2008, the Company reached an agreement with a former employee to terminate a compensation agreement. Under the terms of the termination agreement, the Company paid the former employee $825,000 and repurchased from him, 34,116 shares of Company stock, which had been issued to him in lieu of cash compensation. The total cost of repurchasing the shares was approximately $75,000. The Company has no further obligation to this former employee. The termination payment was recorded as general and administrative expense in the third quarter of 2008.

On July 3, 2008, the Company initiated the Meridian Resource & Exploration LLC Retention Incentive Compensation Plan, and under the terms of the plan, distributed a total of $1.6 million in bonuses to its non-executive employees. The purpose of the plan was to encourage the retention of valued employees for the immediate term. The employment market for experienced personnel in the oil and gas industry has been very strong in recent years. The Company believes the incentive program will help to equalize its employees compensation with current market conditions and motivate them to continue their careers with Meridian. The terms of the plan include a second, final bonus to those employees who continue their employment with the Company through March 31, 2009. The second payment, due March 31, 2009, is expected to total approximately $2.9 million; the expense is being accrued ratably over the time period July 2008 through March 2009. A portion of the bonus expense is capitalized to the full cost pool in accordance with Company practice for internal expenses related to exploration and development of oil and natural gas properties. The Company recognized $1.7 million in expense, net of capitalization, through December 31, 2008 and expects to recognize approximately $0.5 million in retention bonus expense in the next quarter (first quarter of 2009).

13. OIL AND NATURAL GAS HEDGING ACTIVITIES

The Company may address market risk by selecting instruments whose value fluctuations correlate strongly with the underlying commodity being hedged. From time to time, we enter into derivative agreements 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. The Company s Amended Credit Facility (Note 5) requires that counterparties in derivative transactions be limited to the Lenders, including affiliates of the Lenders. There is no collateral securing counterparty obligations owed to the Company under the agreements. Balances owed by the Company under derivative agreements are collateralized by the liens and security interests supporting the Amended Credit Facility. The master derivative agreements also contain provisions permitting netting of multiple unrelated transactions that settle on the same day and in the same currency.

Although the Company s counterparties provide no collateral, the master derivative agreements with each counterparty effectively allow the Company, at its option, so long as it is not a defaulting party, after a default or the occurrence of a termination event, to set-off an unpaid hedging agreement receivable against the interest of the counterparty in any outstanding balance under the Credit Facility. In practice, no such set-off has been made, and all settlements have been made in cash. As of December 31, 2008, however, the Company is in default of two covenants contained in the Credit Facility, the breach of which is also a default under the master derivative agreements. The Company s hedge counterparties are not obligated to make payments to the Company under the hedging agreements while the Company s default is continuing. The Company s set-off rights under the master derivative agreements cannot be exercised due to such default. The Company s hedging counterparties may exercise their remedies under the hedging agreements, and potentially under the Credit Facility, on account of the Company s default. If a counterparty were to default in payment of an obligation under the master derivative agreements, the Company would be exposed to commodity price fluctuations, and the protection intended by the hedge would be lost. The value of assets from price risk management would be impacted. In addition, as expected cash flows from hedging contracts are included in computing future net revenues, the ceiling test could be impacted, which could result in a non-cash write-down of oil and gas properties.

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 agreements 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 loss of $18,000 during the year ended December 31, 2008, and gains of $21,000 and $128,000 during the years ended December 31, 2007 and 2006, respectively, due to hedge ineffectiveness.

As of December 31, 2008, the estimated fair value of the Company s oil and natural gas hedging agreements was an unrealized gain of $8.1 million ($8.1 million net of tax) which is recognized in Accumulated Other Comprehensive Income (Loss). Based upon oil and natural gas commodity prices at December 31, 2008, all of the unrealized gain deferred in Accumulated Other Comprehensive Income (Loss) could potentially increase gross revenues in 2009. These derivative agreements expire at various dates through December 31, 2009.

Net settlements under hedging agreements increased oil and natural gas revenues by $4,663,000, $3,252,000, and $3,821,000 for the years ended December 31, 2008, 2007, and 2006 respectively.

All of the Company s current hedging agreements 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 34% of proved developed natural gas production and 19% 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 values of hedging agreements are recorded on the consolidated balance sheet as assets or liabilities. The estimated fair value of hedging agreements as of December 31, 2008, is provided below:

	Type	Notional Amount	Floor Price ($ per unit)	Ceiling Price ($ per unit)	Estimated Fair Value Asset (Liability) December 31, 2008 (in thousands)
Natural Gas (mmbtu)					
Jan 2009 - Dec 2009	Collar	1,230,000	$ 7.50	$ 10.45	$ 2,070
Jan 2009 - Dec 2009	Collar	760,000	$ 8.00	$ 10.30	1,592
Jan 2009 - Dec 2009	Collar	540,000	$ 8.00	$ 13.35	1,166
Total Natural Gas					$ 4,828
Crude Oil (bbls)					
Jan 2009 - Dec 2009	Collar	23,000	$ 70.00	$ 93.55	$ 434
Jan 2009 - Dec 2009	Collar	43,000	$ 80.00	$ 111.00	1,236
Jan 2009 - Dec 2009	Collar	49,000	$ 85.00	$ 128.50	1,638
Total Crude Oil					3,308
					$ 8,136

14. MAJOR CUSTOMERS

Major customers for the years ended December 31, 2008, 2007 and 2006, were as follows (based on sales exceeding 10% of total oil and natural gas revenues):

	Year Ended December 31,		
Customer	**2008**	**2007**	**2006**
Shell Trading (U.S.)	21%	14%	
Superior Natural Gas	17%	23%	35%
Crosstex Gulfcoast Marketing	14%	16%	21%

15. RELATED PARTY TRANSACTIONS

Messrs. Joseph A. Reeves, Jr. and Michael J. Mayell, each of whom was an officer of the Company until December 29, 2008 and is a current Director of Meridian, are working interest partners of the Company. Historically since 1994, affiliates of Meridian have been permitted to hold interests in projects of the Company. With the approval of the Board of Directors, Texas Oil Distribution and Development, Inc. (TODD) and JAR Resources LLC (JAR), entities controlled by Joseph A. Reeves, Jr and Sydson Energy, Inc. (Sydson), an entity controlled by Michael J. Mayell, have each invested in Meridian drilling locations on a promoted basis, where applicable, at a 1.5% to 4% working interest basis. The maximum total percentage that either officer may elect to participate in any prospect is a 4% working interest. On a collective basis, TODD, JAR and Sydson invested $4,321,000, $9,871,000, and $7,743,000 for the years ended December 31, 2008, 2007 and 2006, respectively, in oil and natural gas drilling activities. Net amounts due from TODD, JAR and Mr. Reeves were approximately $1,968,000 and $1,753,000 as of December 31, 2008 and 2007, respectively. Net amounts due (to) from Sydson and Mr. Mayell were approximately ($244,000) and $827,000 as of December 31, 2008 and 2007, respectively.

Messrs. Reeves and Mayell each entered into consulting agreements with the Company, commencing December 30, 2008. Each will provide professional services to the Company for a monthly fee of $50,000; the agreements terminate on April 30, 2009.

During 2008, the Company settled certain compensation-related contracts with Messrs. Reeves and Mayell. See Note 12 for further details. As a result of this settlement, the Company has recorded a liability to Mr. Reeves of $4,954,000 and to Mr. Mayell of $4,940,000. These liabilities are included in Due to affiliates in the accompanying Consolidated Balance Sheet for December 31, 2008. They are expected to be paid in the second quarter of 2009 with funds from the related Rabbi Trust.

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, 2008, 2007 and 2006 and received fees of approximately $216,000, $231,000, and $227,000 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 $335,000 during 2008, $275,000 during 2007, and $438,000 during 2006.

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, 2008, 2007 and 2006, and received fees of approximately $118,000, $73,000, and $26,000, respectively. In addition, during 2007 and 2006, the Company paid Gary A. Messersmith, P.C. $8,333 per month relating to his services provided to the Company. The retainer was paid through March, 2008, then discontinued. Mr. Messersmith also participated in the Management Plan described in Note 11 above, pursuant to which he was paid approximately $527,000 during 2008, $441,000 during 2007, and $751,000 during 2006.

During 2008, both Mr. Kares and Mr. Messersmith requested the Company discontinue their participation in the Management Well Bonus Plan as to new wells drilled after mid-April 2008. Their participation as to wells previously drilled is unchanged.

Mr. G. M. Larberg, a Director of Meridian, is a petroleum industry consultant that provided the Company with services for the years ended December 31, 2008, 2007 and 2006, and received consulting fees of approximately $210,000, $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.

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Drew Reeves was paid $227,000, $168,000, and $146,000 for the years 2008, 2007 and 2006, 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 $193,000, $164,000, and $150,000 for the years 2008, 2007 and 2006, respectively. Mr. J. Todd Reeves, the son of Joseph A. Reeves, Jr., is a partner in the law firm of J. Todd Reeves and Associates, which provides legal services to the Company and received fees of approximately $197,000 in 2008, $371,000 in 2007, and $337,000 in 2006. Such fees exceeded 5% of the gross revenues for the firm for those respective years.

Mr. Michael W. Mayell, the son of Mr. Michael J. Mayell, an officer until December 29, 2008 and a current Director of Meridian, is a staff member in the Production Department, and was paid $169,000, $129,000, and $114,000 for the years 2008, 2007 and 2006, respectively. Mr. James T. Bond, former Director of Meridian, was the father-in-law of Mr. Michael J. Mayell; he provided consulting services to the Company and received fees in the amount of $48,000 and $155,000 for the years 2007 and 2006, respectively.

Earnings for 2008 for related party employees include the impact of the Retention Incentive Compensation Plan described in Note 12.

16. 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,		
	2008	**2007**	**2006**
Numerator:			
Net earnings (loss) applicable to common stockholders	$ (209,886)	$ 7,137	$ (73,884)
Denominator:			
Denominator for basic earnings (loss) per share weighted-average shares outstanding	91,382	89,307	87,670
Effect of potentially dilutive common shares:			
Warrants and rights (a)	NA	5,637	NA
Employee and director stock options (b)	NA		NA
Denominator for diluted earnings (loss) per share weighted-average shares outstanding and assumed conversions	91,382	94,944	87,670
Basic earnings (loss) per share	$ (2.30)	$ 0.08	$ (0.84)
Diluted earnings (loss) per share	$ (2.30)	$ 0.08	$ (0.84)

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 had no exercise price and are included in diluted earnings per share in all years during which they were outstanding, unless there is a loss. All potentially dilutive shares, whether from options, warrants, or rights, 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 3.3 million, 1.4 million, and 3.2 million, in

2008, 2007 and 2006, respectively. The number of stock rights excluded totaled approximately 3.6 million in 2006.

(b) The number of stock options excluded totaled approximately 0.7 million, 3.6 million, and 3.7 million, in 2008, 2007 and 2006, respectively.

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17. ACCRUED LIABILITIES

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

	2008	2007
Capital expenditures	$ 8,227	$ 14,821
Operating expenses/Taxes	4,452	3,881
Hurricane damage repairs	1,555	
Compensation	2,478	853
Interest	261	460
Other	1,858	1,996
Total	$ 18,831	$ 22,011

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18. QUARTERLY RESULTS OF OPERATIONS (Unaudited)

Results of operations by quarter for the year ended December 31, 2008 were (thousands of dollars, except per share):

	Quarter Ended			
2008	**March 31**	**June 30**	**Sept. 30**	**Dec. 31**
Revenues	$38,448	$46,534	$36,806	$ 26,846
Results of operations from exploration and production activities[(1) (2)]	11,586	18,136	10,595	(224,406)
Net earnings	$ 3,563	$ 839	$ 699	$(214,987)
Net earnings per share:				
Basic	$ 0.04	$ 0.01	$ 0.01	$ (2.33)
Diluted	$ 0.04	$ 0.01	$ 0.01	$ (2.33)

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

	Quarter Ended			
2007	**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	$ 1,668	$ 2,705	$ 750	$ 2,014
Net earnings per share:				
Basic	$ 0.02	$ 0.03	$ 0.01	$ 0.02
Diluted	$ 0.02	$ 0.03	$ 0.01	$ 0.02

(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) Includes impairment of

long-lived assets of $223.5 million in the fourth 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,		
	2008	**2007**	**2006**
Costs incurred during the year:(1)(2)			
Property acquisition costs			
Unproved	$ 21,879	$ 9,589	$ 35,728
Proved			8,239
Exploration	51,752	92,320	95,486
Development	38,159	9,026	23,405
	$ 111,790	$ 110,935	$ 162,858

(1) Costs incurred during the years ended December 31, 2008, 2007 and 2006 include general and administrative costs related to acquisition, exploration and development of oil and natural gas properties, net of third party reimbursements, of $17,390,000, $16,492,000, and $15,375,000, respectively.

(2) Costs incurred during the year ended December 31, 2008 include $1.1 million in net profit (loss) related to the lease of a drilling rig by

TMRD. The rig was used to drill wells which the Company owns and operates. The amount transferred to the full cost pool represents the portion of profits (losses) on the lease related to services performed on behalf of others, primarily our joint interest partners.

Capitalized Costs Relating to Oil and Natural Gas Producing Activities
(thousands of dollars)

	December 31, 2008	December 31, 2007
Capitalized costs	$ 1,877,925	$ 1,771,768
Accumulated depletion	1,632,622	1,344,164
Net capitalized costs	$ 245,303	$ 427,604

At December 31, 2008 and 2007, unevaluated costs of $39,927,000 and $53,645,000, 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.

Costs Not Being Amortized

The following table sets forth a summary of oil and natural gas property costs not being amortized at December 31, 2008, 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.
(thousands of dollars)

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	Total	**2008**	**2007**	**2006**	**2005 & Prior**
Leasehold and Geological & Geophysical	$30,964	$16,604	$11,388	$2,942	$ 30
Exploration Drilling	8,963	8,319	564	80	
Total	$39,927	$24,923	$11,952	$3,022	$ 30

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

	Year Ended December 31,		
	2008	**2007**	**2006**
Operating Revenues:			
Oil	$ 63,636	$ 54,218	$ 47,859
Natural Gas	84,998	96,491	141,182
	148,634	150,709	189,041
Less:			
Oil and natural gas operating costs	24,280	28,338	22,614
Severance and ad valorem taxes	9,727	9,409	11,259
Depletion	71,647	76,660	105,210
Accretion expense	2,064	2,230	1,588
Impairment of long-lived assets (1)	223,543		134,865
Hurricane damage repairs	1,462		4,314
Income tax expense (benefit)	(8,462)	14,992	(31,783)
	324,261	131,629	248,067
Results of operations from oil and natural gas producing activities	(175,627)	$ 19,080	$ (59,026)
Depletion expense per Mcfe	$ 5.13	$ 4.20	$ 4.51

(1) For 2008, includes impairment of oil and natural gas properties of $216,811,000 million and impairment of drilling rig of $6,732,000; for 2006, all impairments are to

oil and natural gas
properties.

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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, 2008, 2007 and 2006, 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 2008, 2007 and 2006. 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, 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
Production during 2008	(765)	(9,369)
Sale of reserves in-place	(3)	(170)
Discoveries and extensions	1,934	3,817
Revisions of previous quantity estimates and other	(1,119)	(4,711)
Balance at December 31, 2008	4,903	50,896
Proved Developed Reserves:		
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
Balance at December 31, 2008	2,732	35,054

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

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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.

The following table sets forth the components of the standardized measure of discounted future net cash flows for the years ended December 31, 2008, 2007 and 2006 (thousands of dollars):

	At December 31,		
	2008	**2007**	**2006**
Future cash flows	$ 490,602	$ 842,986	$ 657,584
Future production costs	(168,160)	(185,768)	(150,462)
Future development costs	(82,866)	(80,656)	(64,417)
Future taxes on income		(80,029)	(46,034)
Future net cash flows	239,576	496,533	396,671
Discount to present value at 10 percent per annum	(60,139)	(105,069)	(68,772)
Standardized measure of discounted future net cash flows	$ 179,437	$ 391,464	$ 327,899

The average expected realized price for natural gas in the above computations was $5.79, $6.66, and $5.69, per Mcf at December 31, 2008, 2007, and 2006, respectively. The average expected realized price used for crude oil in the above computations was $44.04, $95.54, and $63.32 per Bbl at December 31, 2008, 2007, and 2006, respectively. No consideration has been given to the Company s hedged transactions.

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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, 2008, 2007 and 2006 (thousands of dollars):

	Year Ended December 31,		
	2008	**2007**	**2006**
Balance at Beginning of Period	$ 391,464	$ 327,899	$ 557,203
Sales of oil and natural gas, net of production costs	(114,626)	(112,962)	(155,167)
Changes in sales & transfer prices, net of production costs	(165,125)	125,623	(243,150)
Revisions of previous quantity estimates	(32,842)	25,751	(11,022)
Purchase of reserves-in-place			2,393
Sale of reserves in-place	177	(2,233)	
Current year discoveries, extensions and improved recovery	44,112	32,939	30,710
Changes in estimated future development costs	(1,417)	(7,917)	(13,016)
Development costs incurred during the period	8,298	8,526	18,051
Accretion of discount	39,146	32,790	55,720
Net change in income taxes	23,453	(14,451)	114,782
Change in production rates (timing) and other	(13,203)	(24,501)	(28,605)
Net change	(212,027)	63,565	(229,304)
Balance at End of Period	$ 179,437	$ 391,464	$ 327,899

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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 2008. 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 2008 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, 2008. 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, 2008, 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, 2008, 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, 2008, 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 as of December 31, 2008 and 2007, and the related consolidated statements of operations, comprehensive income (loss), stockholders equity and cash flows for each of the three years in the period ended December 31, 2008 and our report dated March 16, 2009 included an explanatory paragraph that expressed substantial doubt about the Company s ability to continue as a going concern.

/s/ BDO Seidman, LLP

Houston, Texas
March 16, 2009

Item 9B. Other Information.

None.

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 30, 2009.

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, 2008
   - (iii) Consolidated Balance Sheets as of December 31, 2008 and 2007
   - (iv) Consolidated Statements of Cash Flows for each of the three years in the period ended December 31, 2008
   - (v) Consolidated Statements of Changes in Stockholders Equity for each of the three years in the period ended December 31, 2008
   - (vi) Consolidated Statements of Comprehensive Income (Loss) for each of the three years in the period ended December 31, 2008
   - (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).
   - 3.5 Amendment No. 2 to Amended and Restated Bylaws of The Meridian Resource Corporation, adopted April 29, 2008 (incorporated by reference to Exhibit 3.1 of the

Company s Current Report on Form 8-K filed May 2, 2008).

3.6 Amendment No. 3 to Amended and Restated Bylaws of The Meridian Resource Corporation, adopted December 22, 2008 (incorporated by reference to Exhibit 3.1 of the Company s Current Report on Form 8-K filed December 29, 2008).

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).

4.8 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 (incorporated by reference from the Company s Annual Report on Form 10-K for the year ended December 31, 2007).

10.22 Second Amendment to Credit Agreement, dated as of December 19, 2008, among the Company, the several banks, financial institutions and other entities from time to time parties to the Credit Agreement (collectively, the Lenders), and Fortis Capital Corp., as administrative agent for the Lenders (incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K filed December 29, 2008).

*10.23 Employment Agreement, dated April 29, 2008, by and between The Meridian Resources Corporation and Joseph A. Reeves, Jr. (incorporated by reference to Exhibit 10.1 to the Company s Annual Report on Form 10-K/A for the year ended December 31, 2007).

*10.24 Employment Agreement, dated April 29, 2008, by and between The Meridian Resources Corporation and Michael J. Mayell (incorporated by reference to Exhibit 10.2 to the Company s Annual Report on Form 10-K/A for the year ended December 31, 2007).

*10.25 Termination Agreement, dated April 29, 2008, by and between The Meridian Resources Corporation and Joseph A. Reeves, Jr. (incorporated by reference to Exhibit 10.3 to the Company s Annual Report on Form 10-K/A for the year ended December 31, 2007).

*10.26 Termination Agreement, dated April 29, 2008, by and between The Meridian Resources Corporation and Michael J. Mayell (incorporated by reference to Exhibit 10.4 to the Company s Annual Report on Form 10-K/A for the year ended December 31, 2007).

*10.27 Agreement (regarding Net Profits Interests), effective January 1, 1994, between Joseph A. Reeves, Jr. and Texas Meridian Resources Corporation (n/k/a The Meridian Resource Corporation), incorporated by reference to Exhibit 10.5 to the Company s Annual Report on Form 10-K/A for the year ended December 31, 2007.

*10.28 Agreement (regarding Net Profits Interests), effective January 1, 1994, between Michael J. Mayell and Texas Meridian Resources Corporation (n/k/a The Meridian Resource Corporation), incorporated by reference to Exhibit 10.6 to the Company s Annual Report on Form 10-K/A for the year ended December 31, 2007.

*10.29 Consulting Agreement, dated effective as of December 30, 2008, between the Company and Joseph A. Reeves, Jr. (incorporated by reference to Exhibit 10.2 of the Company s Current Report on Form 8-K filed December 29, 2008).

*10.30 Consulting Agreement, dated effective as of December 30, 2008, between the Company and Michael J. Mayell (incorporated by reference to Exhibit 10.3 of the Company s Current Report on Form 8-K filed

December 29, 2008).

*,**10.31	Employment Agreement, dated effective as of December 30, 2008, by and between The Company and Paul D. Ching.
*,**10.32	Employment Agreement, dated effective as of December 17, 2008, by and between The Company and Lloyd V. DeLano.
*,**10.33	Employment Agreement, dated effective as of December 17, 2008, by and between The Company and Stephen G. Ives.
*,**10.34	Employment Agreement, dated effective as of December 17, 2008, by and between The Company and Allen D. Breaux.
*,**10.35	Employment Agreement, dated effective as of December 17, 2008, by and between The Company and Alan S. Pennington.
21.1	Subsidiaries of the Company (incorporated by reference to Exhibit 2.1 of the Company s annual report on Form 10-K for the year ended December 31, 2007).
**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 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 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/ PAUL D. CHING
Chief Executive Officer
(Principal Executive Officer)
President Director and Chairman of the Board

Date: March 16, 2009

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/ PAUL D. CHING Paul D. Ching	Chief Executive Officer (Principal Executive Officer) President Director and Chairman of the Board	March 16, 2009
BY: /s/ LLOYD V. DELANO Lloyd V. DeLano	Senior Vice President (Chief Accounting Officer)	March 16, 2009
BY: /s/ E. L. HENRY E. L. Henry	Director	March 16, 2009
BY: /s/ JOE E. KARES Joe E. Kares	Director	March 16, 2009
BY: /s/ G.M. LARBERG G.M. Larberg	Director	March 16, 2009
BY: /s/ MICHAEL J. MAYELL Michael J. Mayell	Director	March 16, 2009
BY: /s/ GARY A. MESSERSMITH Gary A. Messersmith	Director	March 16, 2009

BY: /s/ C. MARK PEARSON	Director	March 16, 2009
C. Mark Pearson		
BY: /s/ JOSEPH A. REEVES, JR.	Director	March 16, 2009
Joseph A. Reeves, Jr.		
BY: /s/ DAVID W. TAUBER	Director	March 16, 2009
David W. Tauber		
BY: /s/ JOHN B. SIMMONS	Director	March 16, 2009
John B. Simmons		
BY: /s/ FENNER R. WELLER, JR.	Director	March 16, 2009
Fenner R. Weller, Jr.		