MERIDIAN RESOURCE CORP
Form 10-K
April 15, 2010

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, 2009

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

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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No o

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 o	Non-accelerated filer þ (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, 2009: $31,337,635

Number of shares of common stock outstanding at March 31, 2010: 92,475,527

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 Form 10-K/A to be filed on or before April 30, 2010.

THE MERIDIAN RESOURCE CORPORATION
INDEX TO FORM 10-K

Table of Contents

PART I

Item 1. Business

General

The Meridian Resource Corporation (Meridian, the Company, us, our, or we) is an independent oil and natural g company that explores for, acquires and develops oil and natural gas properties. 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, 2009, we had proved reserves of 75 Bcfe with a present value of future net cash flows of approximately $139 million. Seventy percent (70%) of our proved reserves were natural gas and approximately 64% were classified as proved developed. We own interests in 20 fields and 76 producing wells, and operated approximately 89% of our total production in 2009.

Recent developments, 2008-2009

The Company has historically been highly focused on exploration and reserve replacement. We relied 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, gradually increasing the amount outstanding under the facility. Typically, until late 2008, we had not always fully utilized the borrowing base. However, in the second half of 2008, global economic events occurred which significantly impacted our industry and company. Prices for oil and natural gas, which had recently reached historic highs, dropped precipitously. This was related to the onset of a global recession, marked by extreme disruption in the credit markets which persisted throughout 2009.

In December 2008, two events marked a significant change in our financial position, both related to the Credit Facility. On December 19, 2008, our lenders under the facility (Lenders) reduced the borrowing base to $95 million, the amount which was outstanding at that time, thus eliminating our access to additional capital from that source. In addition, as of December 31, 2008, we experienced a covenant default under the Credit Facility, based on a failure to meet a financial ratio test. A test of the ratio of our current assets to current liabilities, as defined in the Credit Facility, resulted in a value less than the required one to one ratio. As a result of the default, and a cross-default which then occurred under our other principal debt arrangement, a fixed term financing arrangement (the rig note), our ability to continue as a going concern was in doubt. Accordingly, in our annual financial report on Form 10-K for 2008, our independent registered public accounting firm included a going concern explanatory paragraph that expressed substantial doubt as to the Company s ability to continue as a going concern. The firm has also included a going concern explanatory paragraph in this report for 2009.

The Company s credit situation was exacerbated in April, 2009, when the Lenders reduced the borrowing base under the Credit Facility from $95 million to $60 million. As a result, a $34.5 million payment to the Lenders for the borrowing base deficiency was due July 29, 2009, based on the borrowings outstanding on that date. The Company did not have sufficient cash available to repay the deficiency and, consequently, failed to pay such amount when due. Prior to July 29, 2009, the Company was in covenant default under the terms of the Credit Facility; on and after that date it was in covenant default and payment default as well.

Table of Contents

We responded to these events by pursuing several courses of action beginning in late 2008. The capital expenditures budget for 2009 was severely reduced to include drilling only two wells during the first quarter, which had already been committed. In January 2009, the Company reduced its workforce significantly in the Houston office and in the field. Further headcount reductions were undertaken in 2009. Our operations group re-examined all field level expenses and initiated cost reductions in the field. As a result, gross general and administrative expenses before capitalization of a portion of those costs to the full cost pool, decreased $15.8 million, or 43% from 2008 to 2009; year over year operating expenses decreased $6.7 million, or 28%; and capital expenditures on an accrual basis decreased $105 million, or 89%. However, these savings were offset by decreases in revenue of $59.4 million, or 40%, caused primarily by further decreases in the price of natural gas, augmented by a decline in natural gas production. The decrease in oil and natural gas prices also caused us to record significant non-cash impairments, or ceiling test write-downs, to our oil and natural gas properties of $63.5 million in 2009, and $216.8 million in 2008.

We also worked to resolve the credit situation by soliciting offers from potential strategic partners for a possible capital infusion, merger or sale of properties. Ultimately, we agreed to the merger with Alta Mesa described below under -Proposed Merger .

As work continued through the year on a potential strategic transaction, our finance department worked with our lenders with regard to the Credit Facility and the rig note. As a result, in September 2009, we entered into forbearance agreements with both those parties, which would allow us time to pursue an appropriate strategic transaction and ultimately provide the funds to repay our borrowing base deficit. The forbearance period under these agreements has been extended several times, and currently will terminate at the latest on May 31, 2010. The forbearance agreements included requirements that the Company pay a total of $1.5 million in forbearance fees, primarily to the Lenders under the Credit Facility, with a minor amount related to the rig note. The forbearance agreements also increased our interest rates for default interest, and cost approximately $2.3 million in legal and professional fees to originate and amend the various agreements. In addition, certain paydowns of principal under the Credit Facility were required, and are continuing at approximately $1 million per month. Through April 12, 2010, the Company has paid $11.5 million pursuant to the terms of the Credit Facility forbearance agreement, and an additional $1 million was paid on the rig note when we entered into that forbearance agreement.

We also worked to resolve two major obligations which encumbered our efforts to find a suitable strategic partner for the Company. First, we entered into a forbearance agreement with a major vendor, our drilling contractor, Orion Drilling Company, LLC (Orion). The Company has two long-term drilling contracts with Orion at dayrates which exceed the current market, and we have been unable to utilize the rigs since early 2009 when we significantly reduced our capital expenditures. The forbearance agreement defers payment of the accrued shortfall in dayrate payments (we receive credit against our obligation when third parties utilize the rigs) in exchange for the possibility of transfer of title to our Company-owned drilling rig to Orion, prospectively in 2013. The Company also has the option to retain title to the rig, however, and pay the obligation in cash at that time.

The other obligation we addressed was an outstanding arbitration action from Shell Oil Company and one of its subsidiaries (Shell) against the Company, regarding certain environmental claims on properties we purchased from Shell in 1998. The amount claimed by Shell was substantial and created significant uncertainty for potential buyers or partners of the Company. The action was settled by an agreement in January 2010, under which the Company will pay Shell $5 million over a five year term, beginning in 2010. The Shell agreement terminates and becomes void if the first annual payment of $1 million is not made by May 1, 2010, unless extended at Shell s discretion.

All of these forbearance and settlement agreements are interdependent, and have been constructed such that they all may fail if the forbearance period under the Credit Facility forbearance agreement terminates without payment of the borrowing base deficit. Several of the agreements have already been extended, but no assurance can be provided that the

Table of Contents

parties will continue to extend their forbearance. Each of the Company s counterparties under these various agreements is individually motivated and although they have extended forbearance in tandem thus far, they may not continue to do so.

Our creditors under the Credit Facility and the rig note have available to them various remedies if they choose to terminate forbearance, including acceleration of payment of all principal and interest and foreclosing on substantially all of our assets. In that event, we may be forced to liquidate or to otherwise seek protection under federal bankruptcy laws, and there is no assurance that in a bankruptcy proceeding the Meridian shareholders would receive any value for their shares.

Proposed Merger

As a result of our continued efforts to find a strategic partner for the Company, on December 22, 2009, the Company entered into an Agreement and Plan of Merger (Merger Agreement) with Alta Mesa Holdings, LP (Alta Mesa) and Alta Mesa Acquisition Sub, LLC, a direct wholly owned subsidiary of Alta Mesa (Merger Sub). Under the terms of the Merger Agreement, as amended, shareholders will receive $0.33 per share of common stock, to be paid in cash, and Alta Mesa will assume the Company s debts and obligations. The Company would be merged into Alta Mesa Acquisition Sub, LLC with the Merger Sub as the surviving entity. The Company s stock would cease to be publicly traded. The merger is subject to approval by holders of two thirds of the Company s outstanding shares of common stock; a shareholder meeting and vote are currently scheduled for April 28, 2010. The Company filed a proxy statement regarding the proposed merger on February 8, 2010, in which the Company s board recommended that shareholders vote in favor of the merger. For further information on the proposed merger, refer to the proxy statement. The Company s various forbearance agreements have been extended to allow for completion of the merger, assuming shareholder approval is obtained. However, the most recent amendment to the Credit Facility forbearance agreement also allows the Lenders to terminate the forbearance period on or after February 28, 2010, without cause, so long as the decision to terminate is unanimous among the Lenders.

There can be no assurance that the proposed merger will be completed. Approval by the shareholders is not assured. Litigation was filed by a group of shareholders claiming the Company s directors breached their fiduciary duties in approving the merger. To avoid the risk of the litigation delaying or adversely affecting the merger and to minimize the expense of defending the Company against the lawsuit, in March 2010 management agreed to a proposed settlement of the litigation (see Note 7 of the accompanying Notes to Consolidated Financial Statements for further information). There can be no assurance the bank forbearance period will not be terminated by the Lenders before the proposed merger can be completed. If the merger is not completed, we may be forced to liquidate or to otherwise seek protection under federal bankruptcy laws.

The Merger Agreement with Alta Mesa includes a reimbursement clause under which the Company will pay Alta Mesa s reasonable costs of the merger, not to exceed $1 million, in case of termination of the agreement under various circumstances, including expiration of the term on May 31, 2010 without consummation of the merger, and also including termination of the Merger Agreement due to non-approval in the shareholder vote. In addition to reimbursement of Alta Mesa s costs, the Company would pay Alta Mesa a $3 million termination fee if, among other reasons, the Company terminates the Alta Mesa agreement and accepts another offer for the Company, so long as the definitive agreement related to the other offer is entered into within nine months after termination of the Merger Agreement with Alta Mesa. The termination fee would be payable no later than two business days after consummation of the transaction which triggered the fee.

Alta Mesa has the right to terminate the Merger Agreement at any time, whether before or after approval by the Company s shareholders, upon payment of a termination fee of $3 million to the Company. The terms of the Company s

Credit Facility forbearance agreement require any such termination payment received by Meridian to be used to repay any outstanding balance under the Credit Facility.

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, until 2009 we had 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.

After thorough testing and analysis, some of our new exploration areas showed only limited promise and were 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 14 producing wells in this area. We have pursued our historical strategy of limiting participations with partners; we operate many of our more recent discoveries as well as our older properties.

Our properties in onshore Louisiana continue to be our most valuable assets, comprising the majority of our reserve base and current cash flow. These mature fields represent 78% of our proved reserves, and 80% of our estimated future net revenues. Although these fields are mature, we continue to review them for any opportunities for increased or prolonged production.

In addition to these areas of interest, we acquired a number of acres of exploratory leases in Karnes and Lavaca Counties of South Texas. The objective of these leases was the Austin Chalk formation, as well as the Eagle Ford Shale, where others have had successful drilling. In 2009, we sold our acreage in Lavaca County, retaining an overriding royalty interest, and sold down our position in Karnes County. This augmented our cash flow while retaining for the Company the opportunity to participate in Karnes County wells at up to a 25% working interest, plus an overriding royalty, or receive an overriding royalty interest only, if we choose not to participate. The Karnes County leases are currently beginning to be explored by an outside operator. See Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations, Operations Overview for further information on exploration in Karnes County.

We have sought to create a competitive advantage for the Company in the areas where we operate through acquiring a large inventory of lease acreage and related seismic data, and by retaining experienced geotechnical, land and operational staff. Although some of these advantages have been eroded by the events of the past year, including the sale of some acreage and reductions in staff, we believe we are still positioned to exploit the opportunities offered by our portfolio. 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, depends upon having access to additional capital to resume exploration and development activities, and we do not currently have capital available for those activities.

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, 2009. The reserve volumes were prepared by T. J. Smith & Company, Inc., independent reservoir engineers.

Table of Contents

	Louisiana	Texas	Gulf of Mexico	Total
Production for the year ended December 31, 2009				
Oil (MBbls)	613	184	37	834
Natural Gas (MMcf)	6,567	690	292	7,549
Reserves as of December 31, 2009				
Oil (MBbls)	2,336	1,309	123	3,768
Natural Gas (MMcf)	44,616	6,363	1,384	52,363
Estimated future net cash flows ($000)(1)				$ 189,163
Standardized measure of discounted future net cash flows ($000)(2)				$ 138,955

(1) Estimated Future Net Cash Flows represent the net undiscounted future revenues to be generated from the production of proved reserves, net of estimated production and future development costs, using expected realized prices based on the average prices for the most recent twelve months at December 31, 2009. Over the estimated life of the properties, the prices average $59.94 per Bbl of oil and $3.97 per Mcf of natural gas.

(2) 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 estimated future taxable income.

Productive Wells

At December 31, 2009, 2008 and 2007, we held interests in the following productive wells:

	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Oil Wells	27	16	34	20	33	19
Natural Gas Wells	49	24	66	37	88	43
Total	76	40	100	57	121	62

As of December 31, 2009, we own interests in 15 gross (3 net) wells in the Gulf of Mexico which are outside operated and net to 2 oil wells and 1 natural gas well. In addition, of the total well count for 2009, 1 well (1 net) is a multiple completion.

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, 2009. 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 prepared by T. J. Smith & Company, Inc., independent reservoir engineers. Mr. T. J. Smith is the person primarily responsible for overseeing the preparation of our annual reserve estimates. Mr. Smith is a graduate of Mississippi State University with a Bachelor of Science degree in Petroleum Engineering. He has over 40 years experience with approximately 35 years focused on reserve evaluation. He is a member of the Society of Petroleum Engineers and is a Registered Professional Engineer in the states of Texas and Louisiana. Under new rules issued by the SEC, our estimated proved oil and natural gas reserves as of December 31, 2009, were valued using average prices for the most recent twelve months. The average is calculated using the first day of the month price for each of the twelve months that make up the reporting period. As of December 31, 2008 and 2007, previous rules required that we value our estimated proved oil and natural gas reserves using period end prices.

The reserve estimates for producing properties are based on production trends, material balance calculations, analogy to comparable properties, or volumetric analysis. Performance methods are preferred. Reserve estimates for developed non-producing properties and for undeveloped properties are based primarily on volumetric analysis or analogy to offset production in the same field. Much of the data utilized by Mr. Smith in preparing these reserve estimates is provided by the engineering department of the Company, although it may be originally obtained from other departments. The individual responsible for this process and for other aspects of reserve estimation is a member of the Society of Petroleum Engineers with 10 years experience in reservoir engineering. Various procedures are used to ensure the accuracy of the data provided to Mr. Smith, including review processes. Changes in reserves are closely monitored from quarter to quarter, as well as from year to year at the close of the fiscal year. Mr. Smith prepares our annual reserves estimates, whereas quarterly estimates are internally prepared. The reconciliation of reserves from the previous quarter to the current, which includes an explanation of all significant changes, is reviewed by both the engineering department and upper management, including our CEO. The relatively smaller size of the Company allows us to perform this analysis at the well level.

	Proved Reserves at December 31, 2009			
	Developed Producing	**Developed Non-Producing**	**Undeveloped**	**Total**
	(dollars in thousands)			
Net Proved Reserves:				
Oil (MBbls)	1,432	1,139	1,197	3,768
Natural Gas (MMcf)	18,058	14,502	19,803	52,363
Natural Gas Equivalent (MMcfe)	26,650	21,336	26,985	74,971
Estimated Future Net Cash Flows(1)				$ 189,163
Standardized Measure of Discounted Future Net Cash Flows(2)				$ 138,955

(1) Estimated Future Net Cash Flows represent the net undiscounted future revenues to be generated from the production of proved reserves, net of estimated production and future development costs, using expected realized prices based on the most recent twelve months

at December 31, 2009. Over the estimated life of the properties, the prices average $59.94 per Bbl of oil and $3.97 per Mcf of natural gas.

(2) 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.

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 as of December 31, 2009 are based on average prices for oil and natural gas for the most recent twelve months, unless such prices or costs are contractually determined at the date of the report. As of December 31, 2008 and 2007, the estimated discounted future net revenues from estimated proved reserves are based on period-end prices, unless such prices are contractually determined at the date of the report. Future operating and capital costs are based on current levels as of the date of the report. 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.

Proved Undeveloped Reserves

The total of the Company s proved undeveloped reserves (PUD s) is 27 Bcfe, or approximately 36% of total proved reserves at December 31, 2009. The undeveloped properties are primarily in our East Texas area and in two of our mature fields in Louisiana and are the same or similar properties to those reported in 2008, which totaled 29 Bcfe. Reductions in PUD s from the prior year include a decrease of 5.6 Bcfe at the outside-operated East Cameron 331/332 field offshore. We have eliminated these non-operated reserves as there is substantial uncertainty as to their development as the field has undergone numerous operator changes (again in 2009) and we have no firm plans to develop them at this time. Other changes in PUD s include a reduction of 3.7 Bcfe for several oil wells that had been candidates for updip oil development; however, there is no certainty that these updip locations will be oil. We have, for reserve purposes, estimated that the section will be natural gas, and hence, the reserves are uneconomic and have been eliminated.

Increases to PUD s were due primarily to upward revisions of estimates and the addition of several new locations in East Texas totaling 5.8 Bcfe, based on new drilling and production information for that area. Progress toward development of our portfolio of PUD s was necessarily minimal during 2009, as we minimized capital spending due to our Credit Facility defaults.

Approximately 11.5 Bcfe of our PUD s at December 31, 2009 originated more than five years ago. Certain PUD s in our mature fields in Louisiana have been included for more than five years, because they have been planned as sidetracks and cannot be developed until the current producing well bores have been depleted and abandoned. We have been exploring and developing our East Texas acreage since 2005, and now have a total of 14 producing wells in that area.

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 2009, 2008 and 2007.

Table of Contents

	Gross Wells			Net Wells		
	Productive	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Exploratory Wells						
Year ended December 31, 2009	1		1	0.2		0.2
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
Development Wells						
Year ended December 31, 2009	1		1	0.7		0.7
Year ended December 31, 2008	7	4	11	5.0	3.2	8.2
Year ended December 31, 2007						

Meridian had no wells in progress at December 31, 2009. In addition to the wells noted above, we participated in two successful recompletion operations in 2009 and one sidetrack.

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 2009, 2008 and 2007.

	Year Ended December 31,		
	2009	**2008**	**2007**
Production:			
Oil (MBbls)	834	765	838
Natural gas (MMcf)	7,549	9,369	13,239
Natural gas equivalent (MMcfe)	12,551	13,958	18,269
Average Prices:			
Oil ($/Bbl)	$ 59.02	$ 83.18	$ 64.70
Natural gas ($/Mcf)	$ 5.30	$ 9.07	$ 7.29
Natural gas equivalent ($/Mcfe)	$ 7.11	$ 10.65	$ 8.25
Production Expenses:			
Lease operating expenses ($/Mcfe)	$ 1.40	$ 1.74	$ 1.55
Severance and ad valorem taxes ($/Mcfe)	$ 0.53	$ 0.70	$ 0.52

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, 2009. 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.

Table of Contents

	December 31, 2009			
	Developed		Undeveloped	
Region	**Gross**	**Net**	**Gross**	**Net**
Louisiana	27,828	19,447	13,763	11,942
Oklahoma	1,809	699		
Kentucky			27,094	22,615
Texas	14,805	8,593	73,222	33,032
Gulf of Mexico	28,759	5,613	5,000	765
Total	73,201	34,352	119,079	68,354

Our undeveloped net acreage, including optioned acreage, expires during the next three years at the rate of 10,400 acres in 2010, 45,400 acres in 2011, and 10,400 acres in 2012.

Employees

Meridian employs 45 full-time non-union employees and one part-time employee. We use contract employees to a limited extent on an as-needed basis.

Marketing of Production

We market our production to third parties in a manner consistent with industry practices. Typically, the oil production is sold at the wellhead at prices listed in industry publications, less applicable transportation deductions, and the natural gas is sold at published indices, less applicable transportation 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 2009, 2008 and 2007.

	Year Ended December 31,		
Customer	**2009**	**2008**	**2007**
Shell Trading (U.S.)	28%	21%	14%
Stone Energy Corporation	17%	8%	8%
Superior Natural Gas	11%	17%	23%
Crosstex Gulfcoast Marketing	10%	14%	16%

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, 2009, was $7.11 per Mcfe compared to $10.65 per Mcfe (each net of commodity hedge gains/losses) during the year ended December 31, 2008. The volatile nature of energy

Table of Contents

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

Table of Contents

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

Table of Contents

financial responsibility in the amount of $35 million ($10 million if the offshore facility is located landward of the seaward boundary of a state) to cover liabilities related to a crude oil spill for which such person is statutorily responsible. The amount of required financial responsibility may be increased above the minimum amounts to an amount not exceeding $150 million depending on the risk represented by the quantity or quality of crude oil that is handled by the facility. The MMS has promulgated regulations that implement the financial responsibility requirements of the OPA. Under the MMS regulations, the amount of financial responsibility required for an offshore facility is increased above the minimum amount if the worst case oil spill volume calculated for the facility exceeds certain limits established in the regulations.

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

CERCLA. The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as the Superfund law, and comparable state statutes impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to have contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances. Under CERCLA, persons or companies that are statutorily liable for a release could be subject to joint-and-several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Except as described in Item 3. Legal Proceedings, we are not aware of any hazardous substance contamination for which we may be liable.

Clean Water Act. The Federal Water Pollution Control Act of 1972, as amended (the Clean Water Act), imposes restrictions and controls on the discharge of produced waters and other oil and natural gas wastes into navigable waters. These controls have become more stringent over the years, and it is possible that additional restrictions will be imposed in the future. Permits must be obtained to discharge pollutants into state and federal waters. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore water. The Clean Water Act provides for civil, criminal and administrative penalties for unauthorized discharges of oil and other hazardous substances and imposes liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. Comparable state statutes impose liability and authorize penalties in the case of an unauthorized discharge of petroleum or its derivatives, or other hazardous substances, into state waters. Except as described in Item 3, Legal Proceedings, we believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

Resource Conservation and Recovery Act. The Resource Conservation and Recovery Act (RCRA) is the principal federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements, and liability for failure to meet such requirements, on a person who is either a generator or transporter of hazardous waste or an owner or operator of a hazardous waste treatment, storage or disposal facility. At present, RCRA includes a statutory exemption that allows most crude oil and natural gas exploration and production waste to be classified as nonhazardous waste. A similar exemption is contained in many of the state counterparts to RCRA. As a result, we are not required to comply with a substantial portion of RCRA s requirements because our operations generate minimal quantities of hazardous wastes. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes crude oil and natural gas exploration and production wastes from regulation as

hazardous waste. Repeal or modification of the exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and could cause us to incur increased operating expenses.

Title to Properties

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

We believe that we have good title to our oil and natural gas properties, some of which are subject to immaterial encumbrances, easements and restrictions. Under the terms of our Credit Facility, we may not grant liens on various properties and must grant to our Lenders a mortgage on our oil and natural gas properties of at least 75% of our present value of proved properties (such requirements increased to 95% as a result of our defaults under the Credit Facility). 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 have 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.

We are currently in payment default under our Credit Facility and in covenant default under certain of the covenants in our Credit Facility. As a result of such defaults under the Credit Facility, we are also in default under our drilling rig financing with CIT Group/Equipment Financing, Inc. due to cross default provisions therein. It is unlikely that we will be able to return to compliance with the Credit Facility and the drilling rig financing, and if we are unable to return to compliance, our Lenders may exercise remedies that would have a material adverse effect on us and our shareholders.

Under our Credit Facility, our borrowing base was redetermined effective April 30, 2009, at which time the borrowing base was reduced to $60 million from $95 million. As of March 31, 2010, we have outstanding indebtedness of $83 million under the Credit Facility, and a borrowing base payment deficiency of $23 million. We do not currently have sufficient cash available to repay the borrowing base deficiency.

As a result of the payment default for the borrowing base deficiency and financial covenant defaults under the Credit Facility, we are also in default under our drilling rig financing with CIT Group/Equipment Financing, Inc. (CIT) due to cross default provisions therein. We currently owe approximately $6.2 million to CIT under the drilling rig financing, and we have additional substantial financial obligations under related drilling rig contracts.

Under each of the Credit Facility and the rig note, remedies available to the creditors include acceleration of all principal and interest payments. Although we have obtained short-term forbearance agreements for each of these agreements in default, we may not be able to comply with the conditions and covenants set forth in those forbearance agreements. There can be no assurance that these forbearance agreements provide us the time to resolve the deficiencies and forestall further default.

Our proposed merger with Alta Mesa may not be completed due to lack of shareholder approval or other circumstances. We may not be able to sell assets on terms that we consider advantageous to us and our shareholders, and capital on acceptable terms may not be available from other sources. We may be unable to find an acceptable alternate candidate for a corporate merger or sale. If we are unable to comply with the terms of the forbearance agreements, we will be in default under the Credit Facility and the CIT financing, and we will be subject to the exercise of remedies by such parties on account of such defaults. The exercise of such remedies may force us to liquidate or to otherwise seek protection under federal bankruptcy laws. Such relief would materially and adversely affect the Company and its shareholders.

As a result of our current lack of financial liquidity, we have received a going concern modification to our independent registered public accounting firm 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, 2009 consolidated financial statements regarding their substantial doubt as to our ability to continue as a going concern. Our lack of sufficient liquidity makes 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.

If the merger with Alta Mesa is not completed, we may be forced to liquidate or to otherwise seek protection under federal bankruptcy laws.

If the merger is not consummated for any reason, our shareholders will not receive the merger consideration and our current management under the direction of our board of directors will continue to manage us as a stand-alone, independent business and the value of shares of our common stock will continue to be subject to the risks and uncertainties identified herein and any updates to those risks and uncertainties set forth in our subsequent filings. In addition, if the merger is not completed, the forbearance agreements with our creditors and certain others would terminate, allowing them to take action to enforce their rights with respect to the outstanding obligations. Because substantially all of our assets are pledged as collateral under our Credit Facility, if our Lenders declare an event of default, they would be entitled to foreclose on and take possession of our assets, including our cash balances. In such an event, we may be forced to liquidate or to otherwise seek protection under federal bankruptcy laws, and we can give you no assurance that in a bankruptcy proceeding you would receive any value for your shares.

Our efforts to cure the deficiency under the Credit Facility may not be successful and we may be required to seek bankruptcy protection under Chapter 11 of Title 11 of the United States Code (the Bankruptcy Code). Even if our efforts are successful, we may still be required to seek protection under the Bankruptcy Code to consummate a corporate transaction such as a merger or sale of the Company.

There can be no assurance that we will be able to further extend the terms of the forbearance agreements with the Lenders under the Credit Facility and CIT, nor the terms of other related agreements. There can be no assurance that we will be able to comply with the terms of those agreements. If we are unable to comply, and no further extensions are granted, the forbearance periods end. Our creditors would then have various remedies available to them under the terms of our debt agreements, including acceleration of all principal and interest. The exercise of such remedies could potentially result in us seeking protection under the Bankruptcy Code. Even under a proposed corporate transaction such as a merger or sale of the Company, we may still be required to seek protection under the Bankruptcy Code to consummate such a transaction.

Table of Contents

Under the priority scheme established by the Bankruptcy Code, pre-petition and post-petition liabilities (including certain fees and interest) must be satisfied in full before stockholders are entitled to receive any distribution or retain any property under a plan of reorganization. Amounts that would need to be satisfied in full before any recovery by our stockholders would include, among other things, $83 million currently owed in principal plus any accrued interest which is owed under our Credit Facility and approximately $6.2 million owed under the rig note. In addition, as of December 31, 2009, we have a working capital deficit of $6.6 million in addition to amounts owed under the Credit Facility and the rig note, which generally represents amounts owed to vendors and others which exceed cash and amounts collectible from customers and others. The total amount of this liquidation preference is approximately $95.8 million and any recovery for our common stockholders would only be available if the value available in any Bankruptcy Code proceeding exceeded the amount required to repay all of our outstanding indebtedness and other obligations (including trade payables and other unsecured claims). The ultimate recovery to creditors and/or stockholders, if any, would not be determined until the confirmation of any plan of reorganization. No assurance can be given as to what values, if any, would be ascribed in any potential Chapter 11 filing to each of these constituencies or what types or amounts of distributions, if any, they would receive. If certain requirements of the Bankruptcy Code are met, a plan of reorganization can be confirmed notwithstanding its rejection by equity holders and notwithstanding the fact that equity holders do not receive or retain any property under the plan of reorganization. If Meridian is forced to liquidate or to otherwise seek protection under federal bankruptcy laws, there is no assurance that in a bankruptcy proceeding the Meridian shareholders would receive any value for their shares.

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

On December 4, 2008, we received notification from the New York Stock Exchange (NYSE) 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. The NYSE temporarily suspended the minimum average closing price requirement during part of the first half of 2009. We received notification from the NYSE that our common stock would potentially be delisted if we were not in compliance with that requirement by November 9, 2009. To date we have not been delisted from the NYSE.

In addition, we are currently monitoring the Company s compliance with another listing criterion. This criterion requires that average market capital over 30 consecutive trading days must be at least $15 million. Based on shares outstanding at March 31, 2010, 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 half of 2009 have been below this price. If the Company becomes non-compliant with this criterion, our common stock would be subject to the NYSE s delisting procedures.

During 2008 and part of 2009, the Company was also non-compliant with an NYSE listing criterion which requires that a majority of our directors be independent. However, after the voluntary resignations of three non-independent directors effective October 13, 2009, the Company is now in compliance with this listing criterion, and has been removed from the NYSE s list of issuers non-compliant with corporate governance listing standards on www.nyse.com. The resignations were not the result of any disagreement with the Company on any matter relating to the Company s operations, policies or practices. Rather, the resigning directors agreed to resign to facilitate compliance with NYSE rules for listed companies. The Company currently has seven directors, of which four are independent.

In our communication with the NYSE they noted that we have not held a shareholders meeting in more than 12 months, since August 6, 2008, and we are not in compliance with NYSE rules in that respect.

Finally, the NYSE also noted that it can take accelerated listing action in the event that our common stock trades at levels viewed to be abnormally low over a sustained period of time, and that it is continuing to evaluate the trading levels of our stock, including the price per share.

Table of Contents

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 in the event we are delisted from the NYSE. 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.

Our Credit Facility has substantial restrictions and financial covenants. We are currently in default under, and it is unlikely that we will be able to return 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 unlikely. 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. This pledge of collateral to our Credit Facility Lenders would 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, 2009 is $6.2 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. Although these defaults have been mitigated with short term forbearance agreements, the terms of forbearance under the Credit Facility include the Lenders right to terminate forbearance without cause at any time after February 28, 2010. We cannot predict what action they may take. Furthermore, forbearance under the CIT agreement is tied to forbearance under the Credit Facility, such that if forbearance under the Credit Facility is early terminated, then forbearance under the CIT agreement will also terminate.

Our Credit Facility has periodic borrowing base redeterminations and we will have difficulty maintaining our total borrowing base at the current level of $60 million at future redeterminations, or maintaining or obtaining additional credit at similar terms, which could adversely affect our operations.

As of December 31, 2009, we had outstanding indebtedness of $87.5 million ($ 83 million as of March 31, 2010) under our Credit Facility, which exceeded 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. We have exceeded that amount and are currently in a deficit as to the borrowing base. The borrowing base will be redetermined quarterly, 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 100 days, either in prescribed installments beginning 40 days after the incurrence of a borrowing base deficit, or all at once. This term has been mitigated with a short-term forbearance agreement, which is subject to termination by the Lenders without cause after February 28, 2010. Further redeterminations of the borrowing base have been postponed until termination of the forbearance period. We may not have the financial resources in the future to make any mandatory principal repayments required under the Credit Facility.

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 poor 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.

In order to explore for and develop our oil and natural gas properties, we would need substantial capital. Historically, we have relied heavily on our credit facilities for our capital needs. Due to our default, the Credit Facility is not currently a source of funds for the Company. If we were 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. We are currently unable to fully execute our growth strategy, or take advantage of business opportunities, and we may be unable to 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. Our net working capital position at December 31, 2009, is a deficit of $100.2 million, which includes $91.7 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 through 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.

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

In 2009 and 2008, we recorded significant non-cash impairments, or ceiling test write-downs, to our oil and natural gas properties of $63.5 million and $216.8 million, respectively. 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 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, as adjusted for the Company s cash flow hedge positions, and on current costs, plus the lower of cost or estimated fair value of unproved properties, adjusted for related income tax effects. Under new rules issued by the SEC, the estimated future net cash flows as of December 31, 2009, were determined using average prices for the most recent twelve months. The average is calculated using the first day of the month price for each of the twelve months that make up the reporting period. As of December 31, 2008 and 2007, previous rules required that estimated future net cash flows from proved reserves be based on period end prices.

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 in 2008. 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.

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.

Table of Contents

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. Due to our default, the Lenders have not allowed us to execute any new hedging agreements, and all our previous hedging contracts have now expired.
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. Our interim Chief Executive Officer, Paul D. Ching, is only contractually committed to serve us on a month-to-month basis. 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 property 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.

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.

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.

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 2009, 11% of our production and 13% of our reserves were outside operated. The operators of those properties may 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, which 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

Table of Contents

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.

Our inability to develop new exploration prospects will inhibit our growth.

From time to time, our business strategy has included acquisition and development of new exploration prospects that complement or expand our prospect inventory. We may not be able to identify attractive prospect opportunities. Even if we do identify attractive opportunities, we may not have the capital to be able to complete the acquisition of the prospect or to do so on commercially acceptable terms. If we do acquire additional prospects, we may not realize the anticipated benefits of any such acquisition, due to lack of available capital.

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

Table of Contents

Operations section and other sections of this report and our other filings with the Securities and Exchange Commission under the Securities Act of 1933, as amended, and the Securities Exchange Act of 1934, as amended.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties

Producing Properties

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

Item 3. Legal Proceedings

Default under Credit Agreement. As described below under Management s Discussion and Analysis of Financial Condition and Result of Operations-Liquidity and Capital Resources-Credit Facility and- Rig Note, the Company is in default under the terms of the Credit Facility and the rig note. Defaults under the Credit Facility include a borrowing base deficiency, which was $27.5 million as of December 31, 2009 ($23 million as of March 31, 2010) as well as defaults under certain covenants. Default under the rig note is not due to payment deficiency, but to a cross-default resulting from the defaults under the Credit Facility. The Company currently has in place short-term forbearance agreements for each of these agreements in default and does not have sufficient cash available to repay the shortfall under the Credit Facility. Should the forbearance periods expire without extension or resolution of the deficiency and covenant defaults, the remedies available to lenders under each of these agreements include acceleration of all principal and interest payments. Accordingly, all debts noted above, including the rig note, have been classified as current in the Consolidated Balance Sheets as of December 31, 2008 and 2009. The Company is currently unable to predict what further actions the Lenders may pursue; therefore, the Company has not provided for this matter in its financial statements at December 31, 2009, other than to reclassify all outstanding debt as current.

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 ended with Mr. Hawkins, Jr., and his companies, 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 filed a motion with Judge Bates asking that the ruling be made a final judgment which would give Meridian the right to appeal immediately; however, the Judge declined to grant the motion, allowing the case to proceed to trial. 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, 2009.

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 two 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 fields 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 and making claims of amounts which were substantial in nature and if adversely determined, would have a material adverse effect on the Company. Shell initiated formal arbitration proceedings on May 11, 2009, seeking relief only for the claimed costs and expenses arising from one of the two acquisition agreements between Shell and Meridian. Meridian denies that it owes any indemnity under either of the two acquisition agreements; however, the Company and Shell entered into a settlement agreement on January 11, 2010. Under the terms of the settlement, the Company will pay Shell $5 million in five equal annual payments beginning in 2010 upon the closing of a sale of the assets or equity interest in the Company to a third party (such as the merger with Alta Mesa), or at an earlier date should Meridian be able. Meridian will also transfer title to certain land the Company owns in Louisiana and an overriding royalty interest of minor value. In return, Shell will release Meridian from any indemnity claim arising from any current or historical claim against Shell, and will release Meridian s indemnity obligation with respect to any future claim on all but a small subset of the properties acquired pursuant to the acquisition agreements related to the fields. The settlement agreement will terminate on May 1, 2010 if the first payment and the land and overriding royalty interest transfer have not been made, or unless extended at the discretion of Shell. The Company recorded $4.2 million in expense in the fourth quarter of 2009 to recognize the estimated value of the proposed settlement, including the historical cost of the land and discounting the cash payments to present value.

Other than with regard to the Shell matter, the Company is unable to express an opinion with respect to the likelihood of an unfavorable outcome of the various environmental claims or to estimate the amount or range of potential loss should the outcome be unfavorable. Therefore, the Company has not provided any amount for these claims in its financial statements at December 31, 2009.

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.

Property tax litigation. In August, 2009, Gene P. Bonvillain, the tax assessor for Terrebonne Parish, Louisiana, filed a lawsuit against the Company, alleging under-reporting and underpayment of parish property taxes for the years 1998-2008. The claims, which are very similar to thirty other cases filed by Bonvillain against other oil and natural gas companies, allege that certain facilities or other property of the Company were improperly omitted from annual self-reporting tax forms submitted to the parish for the years 1998-2008, and that the properties Meridian did report on such forms were improperly undervalued and mischaracterized. The claims include recovery of delinquent taxes in the amount

Table of Contents

of $3.5 million, which the claimant advises may be revised upward, and general fraud charges against the Company. All thirty-one similar cases have been consolidated in U. S. District Court for the Eastern District of Louisiana. Meridian denies the claims and expects to file a motion to dismiss the case, which it considers to be without merit. Meridian asserts that Mr. Bonvillain has no legal basis for filing litigation to collect what are, in essence, additional taxes based on reassessed property values. Furthermore, Meridian asserts that the fraud element of the case is insufficiently supported. Meridian intends to vigorously defend this action. 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, 2009.

Shareholder litigation. On January 8, 2010 Mr. Eliezer Leider, a purported Company shareholder, filed a derivative lawsuit filed on behalf of the Company, *Leider, derivatively on behalf of The Meridian Resource Corporation v. Ching, et al.* in Harris County District Court. Defendants were the Company s directors, Alta Mesa Holdings, LP, and Alta Mesa Acquisition Sub, LLC. Leider alleged that the Company s directors breached their fiduciary duties in approving the merger transaction with Alta Mesa and he requested, but was denied, a temporary restraining order against the Company. This lawsuit was consolidated with another, similar one from Mr. Jeremy Rausch, which was a class action lawsuit. Counsel for Leider was appointed lead counsel. On March 23, 2010, the parties agreed in principle to settle the now-consolidated *Leider* action. The settlement is conditioned on, among other things, approval of the merger by Meridian s shareholders. Under the terms of the proposed settlement, all claims relating to the Merger Agreement and the merger will be dismissed on behalf of Meridian s stockholders. As part of the proposed settlement, the defendants have agreed not to oppose plaintiff s counsel s request to the court to be paid up to $164,000 for their fees and expenses and up to $1,000 as an incentive award for plaintiff Leider. Any payment of fees, expenses, and incentives is subject to final approval of the settlement and such fees, expenses, and incentives by the court. The proposed settlement will not affect the amount of merger consideration to be paid to Meridian s shareholders in the merger or change any other terms of the merger or Merger Agreement. Expenses of the proposed settlement are expected to be recorded in the first quarter of 2010.

Item 4. [Reserved]

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
2009:		
First quarter	$ 0.70	$ 0.13
Second quarter	0.67	0.20
Third quarter	0.57	0.26
Fourth quarter	0.43	0.18
2008:		
First quarter	$ 1.88	$ 1.32
Second quarter	3.30	1.45
Third quarter	3.29	1.66
Fourth quarter	1.90	.55

The closing sale price of the common stock on April 12, 2010, as reported on the New York Stock Exchange Composite Tape, was $0.3075. As of April 12, 2010, we had approximately 679 shareholders of record.

On December 4, 2008, we received notification from the New York Stock Exchange (NYSE) 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. The NYSE temporarily suspended the minimum average closing price requirement during part of the first half of 2009. We received notification from the NYSE that our common stock would potentially be delisted if we were not in compliance with that requirement by November 9, 2009. To date, we have not been delisted from the NYSE.

In addition, we are currently monitoring the Company s compliance with another listing criterion. This criterion requires that average market capital over 30 consecutive trading days must be at least $15 million. Based on shares outstanding at March 31, 2010, 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 half of 2009 have been below this price. If the Company becomes non-compliant with this criterion, our common stock would be subject to the NYSE s delisting procedures.

The Company was also non-compliant with an NYSE listing criterion which requires that a majority of our directors be independent. However, after the voluntary resignations of three non-independent directors effective October 13, 2009, the Company is now in compliance with this listing criterion, and the Company has been removed from the NYSE s list of issuers non-compliant with corporate governance listing standards on www.nyse.com. The resignations were not the result of any disagreement with the Company on any matter relating to the Company s operations, policies or practices. Rather, the resigning directors agreed to resign to facilitate compliance with NYSE rules for listed companies. The Company currently has seven directors, of which four are independent.

In our communication with the NYSE they noted that we have not held a shareholders meeting in more than 12 months, since August 6, 2008, and we are not in compliance with the NYSE rules in that respect.

Finally, the NYSE also noted that it can take accelerated listing action in the event that our common stock trades at levels viewed to be abnormally low over a sustained period of time, and that it is continuing to evaluate the trading levels of our stock, including the price per share.

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 in the event we are delisted from the NYSE. 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.

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 repayment of debt. We also are currently restricted under our Credit Facility from paying any cash dividends on common stock, and from the purchase of shares of common stock. See Item 7. Management s Discussion and Analysis of Financial Condition and Results Operations Liquidity and Capital Resources.

Table of Contents

The following stock price performance graph is intended to allow review of stockholder returns, expressed in terms of the appreciation of the Company s common stock relative to two comparison stock performance indices. The graph compares the yearly percentage change in the cumulative total stockholder return on the Company s common stock with the cumulative total return of the NYSE Composite Index and a peer group index from December 31, 2004 through December 31, 2009.

COMPARISON OF 5-YEAR CUMULATIVE TOTAL RETURN AMONG THE MERIDIAN RESOURCE CORPORATION, NYSE COMPOSITE INDEX AND PEER GROUP INDEX

ASSUMES $100 INVESTED ON DEC. 31, 2004
ASSUMES DIVIDEND REINVESTED
FISCAL YEAR ENDING DEC. 31, 2009

	Fiscal Year Ending December 31,					
Company/Index/Market	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Meridian Resource Corporation	$ 100.00	$ 69.42	$ 51.07	$ 29.92	$ 9.42	$ 4.38
NYSE Composite Index	$ 100.00	$ 109.36	$ 131.75	$ 143.43	$ 87.12	$ 111.76
Peer Group Index	$ 100.00	$ 143.85	$ 160.16	$ 214.41	$ 110.43	$ 152.74

The Peer Group Index consists of the common stocks of the following companies:

Cabot Oil & Gas Corporation, Chesapeake Corporation, Comstock Resources, Inc., Denbury Resources, Inc., Energy Partners, Ltd., Petroquest Energy, Inc., St. Mary Land & Exploration Company, Stone Energy Corporation, and Swift Energy Company.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth information as of December 31, 2009, with respect to our compensation plans (including individual compensation arrangements) under which equity securities are authorized for issuance:

Plan Category	**(a)** Number of securities to be issued upon exercise of outstanding options, warrants and rights	**(b)** Weighted-average exercise price of outstanding options, warrants and rights	**(c)** Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	2,276,998	$ 0.36	4,140,000
Equity compensation plans not approved by security holders			
Total	2,276,998	$ 0.36	4,140,000

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,				
	2009	**2008**	**2007**	**2006**	**2005**
	(In thousands, except prices and per share information)				
A. Summary of Operating Data					
Production:					
Oil (MBbls)	834	765	838	859	882
Natural gas (MMcf)	7,549	9,369	13,239	18,170	20,490
Natural gas equivalent (MMcfe)	12,551	13,958	18,269	23,323	25,781
Average prices:					
Oil ($/Bbl)	$ 59.02	$ 83.18	$ 64.70	$ 55.73	$ 39.29
Natural gas ($/Mcf)	5.30	9.07	7.29	7.77	7.84
Natural gas equivalent ($/Mcfe)	7.11	10.65	8.25	8.11	7.57
B. Summary of Operations					
Total revenues	$ 89,254	$ 149,165	$ 152,178	$ 190,957	$ 195,696
Depletion and depreciation	37,102	72,072	77,076	106,067	97,354
Net earnings (loss)(1)(2)	(72,636)	(209,886)	7,137	(73,884)	27,849
Net earnings (loss) per share:(1)(2)					
Basic	$ (0.79)	$ (2.30)	$ 0.08	$ (0.84)	$ 0.33

Diluted	(0.79)	(2.30)	0.08	(0.84)	0.31
Dividends per:					
Common share	$	$	$	$	$
Redeemable preferred share					2.60
Weighted average common shares outstanding basic	92,465	91,382	89,307	87,670	84,527
C. Summary Balance Sheet Data					
Total assets	$ 183,130	$ 304,575	$ 483,775	$ 467,895	$ 555,802
Long-term obligations, inclusive of current maturities	93,666	103,849	75,000	75,000	75,000
Stockholders equity	40,744	122,511	325,430	320,797	377,565

(1) Applicable to common stockholders.

(2) Includes the impact (before tax) of impairments of long-lived assets of $63.5 million, $223.5 million and $134.9 million, in 2009, 2008, and 2006 respectively.

30

Table of Contents

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. 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 of exploration.

However, economic developments in 2008 and 2009, most importantly the precipitous decrease in the prices of oil and natural gas in the second half of 2008, significantly impacted the Company s financial position. At December 31, 2008, our current ratio failed to meet a covenant contained in our Credit Facility, resulting in covenant default. In April 2009, our Lenders under the Credit Facility reduced our borrowing base from $95 million, which was fully drawn at the time, to $60 million. As a result, after a 90 day period, the Company was unable to pay the $35 million deficit and has been in payment default under the Credit Facility since July 29, 2009. The default under the Credit Facility resulted in a cross-default under our other primary lending arrangement, the fixed term rig note.

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 a review of our liquidity.

Industry and economic conditions. The oil and gas industry has experienced significant volatility in the past two years. 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 2008; 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. In 2009, prices have experienced some strengthening, but are still extremely volatile. Oil prices ranged from a low of $34 to a high of $81 for West Texas Intermediate during the year. Gas futures prices ranged from $2.51 to $6.07 during 2009.

Global capital markets have experienced significant disruptions in 2008 and continuing in 2009, 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, Meridian s cash resources have been extremely stressed.

Credit agreements. As noted above, since December 2008 we have been in default under both our primary lending arrangements, the Credit Facility and the rig note. During 2009, management was strongly focused on resolving these defaults. In September 2009, the Company successfully negotiated forbearance agreements under each of the two debt agreements. The forbearance period has been extended to May 31, 2010 to provide time to complete the merger with Alta Mesa. Under the terms of the forbearance agreement, the Lenders have the right to terminate the agreement without cause at any time after February 28, 2010, provided that all parties in the lending group unanimously agree. As of December 31, 2009, our net working capital reflects a deficit of approximately $100.2 million, which includes $91.7 million of amounts due under these two debt agreements which have been reclassified as current as a result of the defaults noted above. The outstanding balances under these debt agreements at December 31, 2009 are $87.5 million for the credit facility, and $6.2 million for the rig note.

Proposed merger. As described in Item 1 Business Proposed Merger, the board of directors has approved a Merger Agreement, as amended, with Alta Mesa, under which shareholders will receive $0.33 per share of common stock in cash and Alta Mesa will assume the liabilities of the Company, including outstanding amounts under the debt agreements in default. The merger is subject to approval by holders of two-thirds of our outstanding shares; a shareholder meeting and vote are currently scheduled for April 28, 2010. The board of directors has recommended that shareholders vote in favor of the merger. There can be no assurance that the shareholders will approve the transaction. Some shareholders, in fact, filed litigation alleging that the Company s directors breached their fiduciary duties in approving the merger. To avoid the risk of the litigation delaying or adversely affecting the merger and to minimize the expense of defending the Company against the lawsuit, in March 2010 management agreed to a proposed settlement of the litigation (see Note 7 of the accompanying Notes to Consolidated Financial Statements for further information). The offer from Alta Mesa was the result of many months of effort to find an appropriate and sufficiently funded buyer or partner for the Company, and a transaction which would allow the shareholders to receive some value for their shares, in spite of the extreme difficulties posed by our credit defaults, borrowing base deficiency, the tight credit market, and continuing low prices for oil and natural gas.

Management believes the Alta Mesa merger is in the best interests of the Company and its shareholders. Should that transaction fail, either due to shareholder vote or some other circumstance, there can be no assurance the Company will be able to continue as a going concern. Furthermore, under the terms of the bank forbearance agreement, the Lenders under the Credit Facility have the right to terminate the forbearance period without cause on or after February 28, 2010, provided that all parties in the lending group unanimously agree. If the currently proposed merger fails, the Lenders may choose to halt forbearance and accelerate all principal and interest payments and we may be forced to liquidate or otherwise seek protection under federal bankruptcy laws.

The Merger Agreement with Alta Mesa includes a reimbursement clause under which the Company will pay Alta Mesa s reasonable costs of the merger, not to exceed $1 million, in case of termination of the agreement under various circumstances, including expiration of the term on May 31, 2010 without consummation of the merger, and also including termination of the Merger Agreement due to non-approval in the shareholder vote. In addition to reimbursement of Alta Mesa s costs, the Company would pay Alta Mesa a $3 million termination fee if, among other reasons, the Company terminates the Alta Mesa agreement and accepts another offer for the Company, so long as the definitive agreement related to the other offer is entered into within nine months after termination of the Merger Agreement with Alta Mesa. The termination fee would be payable no later than two business days after consummation of the transaction which triggered the fee.

Alta Mesa has the right to terminate the Merger Agreement at any time, whether before or after approval by the Company s shareholders, upon payment of a termination fee of $3 million to the Company. The terms of the Company s Credit Facility forbearance agreement require any such termination payment received by Meridian to be used to repay any outstanding balance under the Credit Facility.

Reserves. Our management focuses 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 prices based on the average of the prices for the twelve most recent months. During 2009, our total proved reserves decreased 5.3 Bcfe, due to production which exceeded total reserves added through discoveries, extensions, and positive revisions. We limited our drilling efforts in 2009 to two wells in the East Texas Austin Chalk gas play in the first quarter, after which we ceased all but the most essential capital expenditures and management concentrated on production and ongoing operations. The opportunities for increases in reserves were accordingly reduced, and this is reflected in our decreased reserves.

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 reserves, impacting the economic viability of reserves which are yet to be developed.

While we received historically high average prices for oil and natural gas in 2008, by year-end 2008 our oil price had decreased approximately 52% from the average received in 2008. The natural gas price we received in December 2008 was approximately 27% less than the average received in 2008. In 2009, energy prices continued to be extremely volatile, showing generally further declines for natural gas and an increase for oil. Meridian s reserves are approximately 70% gas.

Our estimated present value of future net revenues (before tax) from oil and natural gas at December 31, 2009 is $139 million, a decrease of $40.5 million, or 23%, from the value one year earlier. The decrease is due to both the 5.3 Bcfe decrease in reserves explained above, and the decrease in prices used to compute the value of our reserves. At December 31, 2008, the price per Mcfe used in computing future net revenues, over the life of the reserves, was $6.11. This price reflects application of previous SEC rules requiring us to value our estimated proved oil and natural gas using period end prices. At December 31, 2009 the future price used was $5.52 per Mcfe, or 10% lower. This price reflects application of new SEC rules requiring us to value our estimated proved oil and natural gas using average prices for the most recent twelve months.

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 for natural gas during 2009, as well as to the decrease in our reserves, we recorded significant non-cash impairments, or ceiling test write-downs, to our oil and natural gas properties in the first and fourth quarters, totaling $63.5 million.

Based on the continued volatility of energy prices, Meridian may incur additional non-cash impairments in the future.

Production. Management closely monitors production. Results for 2009 reflect a decline in production of 10% overall, consisting of a 19% decrease in natural gas production, partially offset by a 9% increase in oil production. This is the result of natural production declines in our mature south Louisiana properties.

Non-routine contract settlement expense. On January 10, 2010, we entered into a settlement agreement with Shell Oil Company and one of its subsidiaries (Shell). The settlement covered indemnification for environmental claims related to oil and natural gas properties purchased from Shell in 1998. The dispute had been submitted to arbitration prior to settlement, and Shell s claims against the Company were substantial in nature. We vigorously defended our position and worked to resolve the matter for many months, as the uncertainty attached to this dispute encumbered management s efforts to find a suitable capital partner for the Company. Entry into the settlement agreement was required under the terms of the Merger Agreement with Alta Mesa. We recorded $4.2 million as indemnification settlement expense in the fourth quarter of 2009 for the estimated present value of cash payments totaling $5 million which the Company will make to Shell over a five year period; we will also transfer certain land and an overriding royalty interest of minor value to

Shell, under the terms of the settlement. The settlement becomes binding when Meridian makes the first annual payment of $1 million and executes the land and overriding royalty transfer, which is due by May 1, 2010, unless extended at Shell s discretion. The settlement agreement will terminate if the initial payment and land and royalty transfers are not made.

Expenses. We took steps in 2009 to reduce our annual expenses, both in the field and in the office. We reduced our staff significantly. A portion of the severance expense for the employees was recorded in the first quarter of 2009, although a majority of it had been previously accrued in 2008. The reduction was primarily in our Houston office. The decrease in general and administrative expenses was substantial; in 2008, general and administrative expenses were $36.5 million gross (before a portion of those expenses were capitalized to the full cost pool); in 2009, gross general and administrative expenses were $20.7 million, a decrease of 43%. Although expenses were decreased in nearly all categories, the majority of the decrease was in payroll and related expenses. The decrease in net general and administrative expenses (after capitalization of a portion to the full cost pool) is less dramatic, as we ceased capitalization of these expenses after the first quarter of 2009, which resulted in 100% of such expenses flowing to the statement of operations. However, the strong reduction in cash expenditures was the objective achieved by management.

We also made changes to certain field operations to reduce costs. As a result, operating expenses for 2009 decreased 28%, from $24.3 million to $17.6 million.

Drilling rig obligations. Costs related to drilling obligations have continued to be significant in 2009. 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.

We do not operate the rig; we lease the rig to Orion Drilling Company, LLC (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 was originally 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 credited our obligation when appropriate, 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, but beginning in the first quarter of 2009 it has been subleased to others, 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 used this rig continuously in our East Texas drilling program through the end of the first quarter of 2009; since then, it has been subleased to others at a rate which is less than the dayrate under our contract. The total expense we recorded in 2009 as a result of underutilization of the two rigs, and net of rental revenues from Orion for the rig owned by the Company, was $4.3 million. No similar expenses were recorded in 2008 or 2007, as there was no underutilization of rigs during those periods.

We have continued to accrue this cost and have not yet expended cash to settle it. In September 2009, we entered into a forbearance agreement with Orion which may grant title to the company-owned rig to Orion in exchange for release of all accrued and future liabilities under the rig contracts. This would occur at termination and final payment of the related rig note, which is scheduled for 2013, if the Company continues to perform its obligations under the rig note and the rig is free of any security interest at title transfer. Both the rig value and the net payable to Orion would be written off at the time of such title transfer, if it were to occur. At December 31, 2009, the rig is included in equipment at a net book value of $4.6 million. The forbearance agreement also extends the term of the rig lease to Orion (but not the dayrate contract) to March 31, 2013. Alternatively, the terms of the forbearance agreement allow the Company an option to settle all claims with Orion in cash at the end of the term of the rig note, and retain title to the rig. So long as the forbearance agreement is not early terminated, the Company may continue to accrue the liability for under-utilization of the two rigs, rather than settling in cash.

We cannot predict to what extent, if any, our obligation will continue to be mitigated by utilization of the rigs by third parties, nor can we give assurance that the forbearance period with Orion will not be early terminated. The forbearance agreement references termination of the forbearance agreement provided to us by the creditor under the rig note, which is in turn dependent on our forbearance agreement related to the Credit Facility.

The rig owned by the Company is subject to assessment for impairment on a quarterly basis. In 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. In 2009 there were no impairments of this asset; however, we cannot be assured that the market for such rigs and for drilling services will not further soften, which may necessitate additional write-downs in the future.

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. However, beginning in 2008, due to the uncertainties regarding our ability to generate net profits in the near term, we have maintained a valuation allowance equal to the value of our net deferred tax assets. This resulted in zero tax benefit recorded against our book net losses. Future effective tax rates may be reduced by the exhaustion of the valuation allowance over time. The total valuation allowance is $93.7 million.

Operations Overview

Production volumes for 2009 totaled 12.6 billion cubic feet of gas equivalent (Bcfe), or an average of 34.4 million cubic feet of natural gas equivalent per day (Mmcfe/d) compared to 14.0 Bcfe or 38.1 Mmcfe per day for 2008. The reduction in production volumes between the two periods is due to natural production declines. Currently, the overall average daily production for the Company ranges between 27 and 29 Mmcfe per day.

During the first quarter, Meridian completed the Goodrich-Cocke No. 7 sidetrack and the Myles Salt No. 27 recompletion, both in Weeks Island. The previously announced Weeks Bay No. 15 began producing in the second quarter. In late April 2009, the outside operated Davis A-39 in East Texas was completed as a producing well. We also completed the Company-operated Black Stone Minerals No. A-278 well in East Texas.

As discussed elsewhere, we restricted our capital expenditures to only the most necessary activities after the first quarter. We concentrated on reducing costs in the field, with significant success; operating expenses decreased 28% from 2008 levels. Several marginal wells were shut in, reducing our active well count, while also decreasing our expenses.

We carefully considered the elements of our lease portfolio and made the decision to monetize a portion of our leasehold position in South Texas. These leases were recently acquired with the aim of exploring the Austin Chalk and the Eagle Ford Shale formations. In 2009, we sold all of our working interest in leases covering approximately 19,000 acres in Lavaca County, retaining an overriding royalty interest. Also in 2009, we reduced our ownership in approximately 13,000 acres of Karnes County leases by selling down our interest to a working interest participation option, which may range from 17% to 25%, depending on the participation elections of others. We also retained an overriding royalty interest, which is effective regardless of any election we may make regarding our working interest participation. The first well in this area was recently drilled by the outside operator to a total measured depth of approximately 17,340 feet (true vertical depth of approximately 11,900) and is currently being tested. The operator has obtained permission from the regulatory agency for an extended test. Preliminary test results indicate it will be completed as a producing oil well in the Eagle Ford

Table of Contents

Shale formation. Our interest in this unit is a 2% overriding royalty interest. There can be no assurance that we will have sufficient liquidity to drill or participate as a working interest owner in future wells in this area should they arise.

Results of Operations

Year Ended December 31, 2009, Compared to Year Ended December 31, 2008

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, 2009, decreased $59.4 million (40%) to $89.2 million, as compared to 2008 revenues of $148.6 million, due to a 10% decrease in production volumes primarily from natural production declines, and by a 33% decrease in average commodity prices on a natural gas equivalent basis. Our average daily production decreased to 34.4 MMcfe for 2009 from 38.1 MMcfe during 2008. Oil and natural gas production volume totaled 12,551 MMcfe for 2009, compared to 13,958 MMcfe for 2008. During 2009, the Company s drilling activity was limited to two wells in the East Texas project area, one exploratory and one developmental, and both were completed as producing wells. The following table summarizes Meridian s operating revenues, production volumes and average sales prices for the years ended December 31, 2009 and 2008.

	Year Ended December 31,		Increase
	2009	2008	(Decrease)
Production:			
Oil (MBbls)	834	765	9%
Natural gas (MMcf)	7,549	9,369	(19%)
Natural gas equivalent (MMcfe)	12,551	13,958	(10%)
Average Sales Price:			
Oil (per Bbl)	$ 59.02	$ 83.18	(29%)
Natural gas (per Mcf)	5.30	9.07	(42%)
Natural gas equivalent (per Mcfe)	7.11	10.65	(33%)
Operating Revenues (000 s):			
Oil	$ 49,222	$ 63,636	(23%)
Natural gas	40,023	84,998	(53%)
Total	$ 89,245	$ 148,634	(40%)

Operating Expenses.

Oil and natural gas operating expenses on an aggregate basis decreased $6.7 million (28%) to $17.6 million in 2009, compared to $24.3 million in 2008. On a unit basis, lease operating expenses decreased $0.34 per Mcfe to $1.40 per Mcfe for the year 2009 from $1.74 per Mcfe for the year 2008. Oil and natural gas operating expenses decreased between the periods primarily due to reduced labor costs, salt water disposal fees, fuel and compression charges, platform facilities charges and lower insurance costs. The decrease in the per Mcfe rate was attributable to the reduced expenses partially offset by lower production in 2009.

Severance and Ad Valorem Taxes.

Severance and ad valorem taxes decreased $3.0 million (31%) to $6.7 million in 2009, compared to $9.7 million in 2008, because of a decrease in the average price of oil as well as lower gas production. Meridian s oil and natural gas production is primarily from Louisiana and is therefore subject to Louisiana severance tax. The severance tax rates for Louisiana are 12.5% of gross oil revenues and $0.331 per Mcf (effective July 1, 2009) for natural gas. Generally in 2009, although overall production was down, oil production was up slightly, and for this product, severance taxes are computed on a percentage basis. Therefore the year to year reduction in oil prices strongly impacted total severance taxes. Natural gas taxes in Louisiana are based on a per mcf rate which increased slightly (from $0.288 to $0.331 per mcf). On an equivalent unit of production basis, severance and ad valorem taxes decreased $0.17 to $0.53 per Mcfe for 2009 from $0.70 per Mcfe for 2008. This was primarily the result of the decrease in oil prices. The per-unit flat tax for gas results in a severance tax rate that fluctuates as prices change, with the downward trend in prices we experienced in 2009 producing a higher effective tax rate. In addition, the unit tax itself increased in 2009. All these factors tended to increase taxes on a unit basis, offsetting the decrease caused by the oil price decrease, and resulting in a decrease in severance tax expense which is disproportionate to the decrease in revenues.

Depletion and Depreciation.

Depletion and depreciation expense decreased $35.0 million (49%) during 2009 to $37.1 million compared to $72.1 million for 2008. The reduction is primarily due to a decrease in the rate per unit produced, and secondarily to a 10% decrease in production volumes in 2009 compared to 2008. This decrease in rate was caused by the reduction in the carrying value of oil and natural gas properties which resulted from the significant impairment write-downs to oil and natural gas properties recorded in December 2008 and March 2009. On a unit basis, depletion and depreciation expenses decreased to $2.96 per Mcfe for 2009, compared to $5.16 per Mcfe for 2008.

Impairment of Long-Lived Assets.

In the first quarter of 2009, the Company recognized a non-cash impairment of $59.5 million to oil and natural gas properties, based on March 31, 2009 pricing of $3.76 per Mcf of natural gas and $49.66 per barrel of oil. In the fourth quarter of 2009, the Company recognized a non-cash impairment of $4.0 million to oil and natural gas properties, based on December 31, 2009 pricing of $3.87 per Mcf of natural gas and $61.18 per barrel of oil. The total impairment recorded in 2009 to oil and natural gas properties was $63.5 million.

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, based on December 31, 2008 pricing of $5.79 per Mcf of natural gas and $44.04 per barrel of oil. 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 Notes 2 and 19 of Notes to Consolidated Financial Statements included elsewhere herein), decreased $0.9 million (5%) to $18.1 million in 2009 compared to $19.1 million for the year 2008. Although the Company reduced headcount in the office and undertook other successful cost cutting measures, the savings gained were offset in part by increased legal and professional fees, primarily related to the negotiation of forbearance agreements with various creditors, and to management s ongoing efforts to locate a suitable candidate for a strategic transaction such as the proposed merger with Alta Mesa.

However, overall general and administrative expense was also impacted by the decision to cease capitalizing such expenses to the full cost pool after the first quarter of 2009, based on reduced exploration and development activity. Excluding capitalized amounts, gross general and administrative expenses decreased from $36.5 million in 2008 to $20.7 million in 2009, or 43%.

Table of Contents

On an equivalent unit of production basis, general and administrative expenses increased $0.07 per Mcfe to $1.44 per Mcfe for 2009 compared to $1.37 per Mcfe for 2008.

Contract and Indemnification Settlement Expenses.

In 2008, contract settlement expense of $9.9 million was recorded in the second quarter when the employment contracts of certain executive officers were replaced and certain other agreements governing other elements of their compensation packages were settled. See further information in Note 12 of Notes to Consolidated Financial Statements.

Indemnification settlement expense of $4.2 million was recorded in the fourth quarter of 2009, based on a settlement with Shell and its subsidiary, to resolve a dispute regarding responsibility for environmental claims on oil and gas properties the Company purchased from Shell in 1998. See further information in Note 7 of Notes to Consolidated Financial Statements.

Accretion Expense.

The Company records long-term liabilities representing the discounted present value of its 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 $2.1 million in 2009 and 2008, respectively.

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 2009.

Interest Expense.

Interest expense increased $3.1 million (57%) to $8.5 million in 2009 compared to $5.4 million for 2008. The increase was a result of $1.4 million in forbearance fees included in the expense in 2009, and increased interest rates during 2009. Interest rates on both the Credit Facility debt and the rig note increased under the terms of those agreements, which allow such increases when the Company is in default. The increase in rates was partially offset by lower debt balances.

Taxes on Income.

Income tax benefit for 2009 was $120,000 as compared to a benefit of $8.5 million for 2008. Income tax (benefit) is generally provided on book income (loss) after taking into account permanent differences between book and taxable income (loss). 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 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 both 2008 and 2009. The tax benefit recognized in 2009 relates to a tax refund.

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

Revenue.

Table of Contents

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 $148.6 million, as compared to 2007 revenues of $150.7 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,		Increase
	2008	2007	(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%
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 Notes 2 and 19 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 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.

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.

The Company records long-term liabilities representing the discounted present value of its 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 benefit for 2008 was $8.5 million as compared to a provision of $5.7 million for 2007. Income tax (benefit) is generally provided on book income (loss) after taking into account permanent differences between book and taxable income (loss). 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.

Liquidity and Capital Resources

Cash Flows. Net cash flow provided by operating activities was $27.0 million for the year ended December 31, 2009, as compared to $92.8 million for the year ended December 31, 2008, a decrease of $65.8 million or 71%. The decrease was primarily due to lower crude oil and natural gas prices, and lower natural gas production volumes, which reduced oil and natural gas revenues by a combined $59.4 million. Interest expense increased $3.1 million. These reductions in cash flow were partially offset by reduced cash-based operating expenses, severance taxes, general and administrative expenses, and hurricane damage repair expense, totaling approximately $12.1 million; in addition, 2008 included the funding of $9.9 million of contract settlement expenses for certain Company officers. The remainder of the decrease in cash flow from operations is due to changes in working capital account balances. The cash outflow from these working capital accounts primarily reflects the paydown in 2009 of obligations to vendors and joint interest partners as we decreased our drilling and other capital expenditures and established a lower base of payables related to operations.

Net cash flows used in investing activities were $22.9 million for the year ended December 31, 2009, as compared to $116.9 million for the year ended December 31, 2008. This decrease was due to the Company s steep reduction in exploration and development activities after the first quarter of 2009, as management sought to address the credit default.

Net cash flows used by financing activities were $12.2 million for the year ended December 31, 2009, as compared to net cash flows provided by financing activities of $23.9 million for 2008. Historically, the trend of our financing activities had been toward increasing use of our Credit Facility and other new debt, until 2009 when credit under that facility became unavailable and we began working to reduce the amount outstanding (in thousands):

	2009	2008	2007
Cash provided by			
Operating activities	$ 27,017	$ 92,767	$ 96,991
Net drawdown under credit facility		20,000	
New debt for drilling rig		10,000	
Sales of property	2,432	7,171	3,060
	29,449	129,938	100,051
Cash utilized in			
Additions to property and equipment	25,377	124,059	116,696
Repurchase of common stock		75	1,158
Net payments of credit facility debt	7,500		
Reductions of drilling rig debt	2,683	1,150	
	35,560	125,284	117,854

Other uses, net	(1,970)	(4,826)	(95)
Net decrease in cash	$ (8,081)	$ (172)	$ (17,898)

Table of Contents

As noted above, we are in default under the terms of our Credit Facility, and our borrowing base is limited to $60 million, which is less than the amount outstanding at December 31, 2009 of $87.5 million. The default under the Credit Facility has also triggered an event of default under our rig note. Under both these debt agreements, the creditors may accelerate all payments of principal and interest in response to an event of default, although the Company has obtained short-term forbearance agreements for each. 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 are our primary source of cash.

We anticipate reduced cash from operations in 2010, due to expected natural production declines, somewhat mitigated by the full-year impact of reductions in office and field expenses initiated in 2009. As described earlier, we have obligations under two long-term drilling contracts which may significantly impact operational cash flows, but are also currently mitigated by a forbearance agreement with the drilling contractor. If we are unable to effectively sublease the two rigs continuously, or if the terms of any subleasing agreements do not completely cover the commitment under our drilling contracts, we will continue to incur obligations under those contracts. Management does not anticipate that any further significant reductions in expenses can be achieved. As described above, management hopes to complete a merger of the Company with Alta Mesa, which would provide a new foundation for financial position, but we can give no assurance that the merger will be completed. Should the merger fail, and the forbearance period under either of the two lending agreements and/or the drilling contracts end without repayment, the Company would be exposed to the action of remedies available to its creditors, which includes acceleration of all interest and principal. We would not have sufficient cash to meet those obligations and in that event we may be forced to seek protection under federal bankruptcy laws.

Cash Obligations. The following summarizes the Company s contractual obligations at December 31, 2009, 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
Debt	$ 93,666	$	$	$ 93,666
Interest (5)	3,379			3,379
Drilling rigs (1) (2)	12,385	899		13,284
Exploration contract settlement (3)	360			360
Settlement obligations (4)	2,383	3,200	1,000	6,583
Non-cancelable operating leases	2,099	1,601		3,700
Total contractual cash obligations	$ 114,272	$ 5,700	$ 1,000	$ 120,972

In addition to the obligations described above, the Company has a contingent obligation related to the merger with Alta Mesa. The Merger Agreement with Alta Mesa includes a reimbursement clause under which the Company will pay Alta Mesa s reasonable costs of the merger, not to exceed $1 million, in case of termination of the agreement under various circumstances, including expiration of the term on May 31, 2010 without consummation of the merger, and also including termination of the Merger Agreement due to non-approval in the shareholder vote. In addition to reimbursement of Alta Mesa s costs, the Company would pay Alta Mesa a $3 million termination fee if, among other reasons, the Company terminates the Alta Mesa agreement and accepts another offer for the Company, so long as the definitive agreement related to the other offer is entered into within nine months after termination of the Merger Agreement with Alta Mesa.

Table of Contents

The termination fee would be payable no later than two business days after consummation of the transaction which triggered the fee.

(1) Commitments for drilling rigs include $1.8 million 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 2009 was $1.1 million. We have a dayrate contract for an additional rig which we do not own; the obligation under that dayrate contract is $10.6 million and $0.9 million in each of the years 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 credited our obligation to some extent, based on revenues from other parties who utilize the rig when the Company is unable to. During 2009, both rigs have been effectively subleased to others under short-term contracts. No such reduction

in our net obligation has been included in the table above.

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

(4) This obligation primarily relates to settlement of an indemnification dispute between the Company and Shell Oil Company and one of its subsidiaries (Shell), relating to properties the Company acquired from Shell some years ago. The settlement contract will become binding when the first payment of $1.0 million is made; this payment is due by May 1, 2010, unless extended at Shell s discretion. Subsequent payments, should the contract become binding, are

required on January 4th of each succeeding year (2011 through 2014), for a total of $5.0 million. Although contingent, the obligation is included in the table above.

Also included in the first and second year projections are obligations for payments totaling $1,481,000 and $200,000, respectively, under various settlement contracts.

(5) Interest has been computed through the end of the forbearance period for both the debt under the Company s Credit Facility and the rig note. The forbearance period is anticipated to terminate May 31, 2010; see below for further details.

Credit Facility. The Company has a credit facility with a group of banks (collectively, the Lenders,) with a maturity date of February 21, 2012 (the Credit Facility.) The Credit Facility is subject to borrowing base redeterminations and bears a floating interest rate based on LIBOR or the prime rate of Fortis Capital Corp., the administrative agent of the Lenders. The borrowing base and the interest formula have been redetermined or amended multiple times. As of December 31, 2008, the borrowing base was $95 million and was fully drawn. The interest rate formula in effect at that date was LIBOR plus 3.25% or prime plus 2.5%.

Obligations under the Credit Facility are to be 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. 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 of December 31, 2008, the Company was in default of two of the covenants under the agreement, including one that requires that the Company maintain a current ratio (as defined in the Credit Facility) of one to one. The current ratio, as defined, was less than the required one to one at December 31, 2008 and continued to be, through December 31, 2009. The Company is also in default of the requirement that the Company s auditors opinion for the current financial statements be without modification. Both the Company s 2008 and 2009 audit reports from its independent registered public accounting firm included a going concern explanatory paragraph that expressed substantial doubt about the Company s ability to continue as a going concern. As a result of the defaults, the outstanding Credit Facility balances of $95 million at December 31, 2008 and $87.5 million at December 31, 2009 have been classified as current in the accompanying consolidated balance sheets. Also in response to the defaults, the Company provided additional security to the Lenders, such that first priority liens cover in excess of 95% of the present value of proved oil and natural gas properties.

The Credit Facility has been subject to semi-annual borrowing base redeterminations effective on April 30 and October 31 of each year, with limited additional unscheduled redeterminations also available to the Lenders or the Company. 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 related to the price of oil and natural gas 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 the Company s 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 outstanding borrowings under the Credit Facility, the Credit Facility requires repayment of the deficit within a specified period of time.

On April 13, 2009, the Lenders notified the Company that, effective April 30, 2009, the borrowing base was reduced from its then-current and fully drawn $95 million to $60 million. As a result, a $34.5 million payment to the Lenders for the borrowing base deficiency was due July 29, 2009, based on the borrowings outstanding on that date. The Company did not have sufficient cash available to repay the deficiency and, consequently, failed to pay such amount when due. Prior to July 29, 2009, the Company was in covenant default under the terms of the Credit Facility; on and after that date it was in covenant default and payment default as well.

Under the terms of the Credit Facility, the Lenders have various remedies available in the event of a default, including acceleration of payment of all principal and interest.

On September 3, 2009, the Company entered into a forbearance agreement with the Lenders under the Credit Facility (Bank Forbearance Agreement). The Bank Forbearance Agreement provided that the Lenders would forbear from exercising any right or remedy arising as a result of certain existing events of default under the Credit Facility until the earlier of December 3, 2009 or the date that any default occurred under the Bank Forbearance Agreement. The terms of the Bank Forbearance Agreement required the Company to consummate a capital transaction such as a capital infusion or a sale or merger of the Company, before October 30, 2009. The deadlines for the capital transaction and the forbearance period were extended several times by amendments to the Bank Forbearance Agreement.

At origination of the Bank Forbearance Agreement, the Company paid the Lenders $2.0 million of principal owed under the Credit Facility. Under the terms of the agreement the Company made a total of $5.0 million in further principal payments through December 31, 2009, bringing the balance at that date to $87.5 million. The Company also paid forbearance fees to the Lenders of $945,000, charged to interest expense in the third quarter of 2009, and accrued an additional $476,000 in forbearance fees, charged to interest expense in the fourth quarter of 2009. In addition, the Company incurred approximately $2.3 million in legal and consulting fees recorded in general and administrative expense, to originate and amend the Bank Forbearance Agreement and other related agreements.

Table of Contents

On December 22, 2009, the Company entered into an Agreement and Plan of Merger (the Merger Agreement) with Alta Mesa Holdings, LP (Alta Mesa) and Alta Mesa Acquisition Sub, LLC, a direct wholly owned subsidiary of Alta Mesa. The Eleventh Amendment to Forbearance and Amendment Agreement (11th Amendment) provided the Lenders consent to the Merger Agreement and extended the date for consummation of a capital transaction, such as the Alta Mesa merger, and the forbearance period, to the earlier of the consummation of the merger with Alta Mesa, the termination of the Merger Agreement, or May 31, 2010. However, the 11th Amendment also allows the Lenders to terminate the forbearance period on or after February 28, 2010, without cause, so long as the decision to terminate is unanimous among the Lenders. The 11th Amendment also requires the Company to repay $1 million in principal to the Lenders per month. As of March 31, 2010, the outstanding balance under the Credit Facility is $83 million.

In accordance with the 11th Amendment, the Company has filed its shareholder proxy statement regarding the merger and called a shareholder meeting currently scheduled for April 28, 2010 to approve the transaction. There can be no assurance that shareholders will approve the transaction or that the merger will be consummated within the time constraints specified in the 11th Amendment. Should the forbearance period terminate, the Company will be in default, unprotected from the action of remedies available to the Lenders, which cannot be predicted. Such remedies include acceleration of all outstanding principal and interest.

The Bank Forbearance Agreement placed other restrictions on the Company with respect to capital expenditures, sales of assets, and incurrence and prepayments of other indebtedness and amended the Credit Facility in certain respects. It contains covenants regarding the frequency of reporting of financial and cash flow information to the Lenders, as well as cash account control agreements which provide a secured lien over substantially all of the Company s cash accounts.

Under the terms of the Bank Forbearance Agreement, as amended, the Credit Facility is amended such that scheduled borrowing base redeterminations will occur quarterly rather than semi-annually, to be effective January 31, April 30, July 31, and October 31 of each year. Outstanding amounts in excess of the borrowing base must be repaid according to certain defined terms. The deficiency could be paid in three equal installments over a maximum period of 100 days after the incurrence of a borrowing base deficiency, or alternatively, the Company could provide additional sufficient collateral to cover the deficiency. However, as the Company has already pledged in excess of 95% of the value of all proved oil and natural gas reserves as security, such an alternative could apply only to a small borrowing base deficiency. The Lenders have provided the Company with a limited waiver postponing the next borrowing base redetermination to the end of the forbearance period. No assurance can be given that further deficiencies will not be incurred at the next redetermination.

The Lenders exercised their right to increase the interest rate on outstanding borrowings by 2% (default interest, under the terms of the Credit Facility) as of July 30, 2009. The floating interest rate is based on the prime interest rate, currently 3.25%, plus 2.5%, plus the default increment of 2%, resulting in a total rate of 7.75% at December 31, 2009 and continuing at that rate currently. The additional default interest has been effective as to all outstanding borrowings under the Credit Facility since the July 29, 2009 payment default, and the LIBOR alternative was also eliminated. No interest payments are in arrears.

Rig Note. On May 2, 2008, the Company, through its wholly owned subsidiary TMRD, entered into a financing agreement (rig note) 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%, which increases in an event of default. The loan is collateralized by the drilling rig, as well as general corporate credit. The term of the loan is five years, expiring on May 2, 2013.

Effective as of December 31, 2008, the Company was in default under the rig note. Under the terms of the rig note, a default under the Credit Facility triggers a cross-default under the rig note. 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 at December 31, 2008 and $6.2 million at December 31, 2009, has been classified as current in the accompanying consolidated balance sheets.

On September 3, 2009, the Company also entered into a forbearance agreement with CIT (CIT Forbearance Agreement.) The forbearance period under the CIT Forbearance Agreement has been extended several times, most recently by the Fourth Amendment to Forbearance and Amendment Agreement (4th Amendment). The forbearance period ends the earlier of the consummation of the merger with Alta Mesa, the termination of the Merger Agreement, May 31, 2010, or the date of any default under either the CIT Forbearance Agreement or the Bank Forbearance Agreement. The 4th Amendment also provides CIT s consent to the merger with Alta Mesa. CIT retains the right to terminate the forbearance period if, in its sole determination, Alta Mesa experiences changes to its financial condition that would adversely affect its ability to complete the merger with the Company.

At origination of the CIT Forbearance Agreement, the Company prepaid, without penalty, $1.0 million of principal on the rig note and began to pay default interest of an additional 4% effective August 1, 2009, as allowed to CIT under the terms of the rig note, bringing the total monthly payment to approximately $220,000. The Company also paid, and recorded in general and administrative expense in the third quarter, a forbearance fee of approximately $50,000. There can be no assurance that the forbearance period under the CIT Forbearance Agreement will provide sufficient time to resolve the cross-default under the rig note.

Capital Expenditures. Capital expenditures in 2009 consisted of $12.8 million (on an accrual basis) for property and equipment additions related to exploration and development, including drilling and workover activities, commitments under leases, and work on production facilities.

The Company anticipates the 2010 capital spending budget will be primarily used for any major lease maintenance costs. We anticipate that the budget will be significantly lower than in past years, including 2009, which included the drilling of two wells in the first quarter. We currently anticipate funding the 2010 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.

Off-Balance Sheet Arrangements. None.

Share Repurchase Program. In March 2007, the Company s Board of Directors authorized a share repurchase program; an amendment to the credit agreement at that time increased the available limit for the Company s repurchase of its common stock from $1.0 million to $5.0 million annually, so long as the Company was in compliance with certain provisions of the Credit Facility. From March 2007, the inception of the share repurchase program, through December 31, 2009, 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. The Bank Forbearance Agreement prohibits any further repurchase of Company stock. The Company did not repurchase any shares during 2009 and does not expect to make share repurchases in the foreseeable future.

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 2009, 2008, and 2007, capitalized general and administrative costs totaled $2.6 million, $17.4 million, and $16.5 million, respectively. General and administrative costs related to production and general overhead are expensed as incurred. The Company discontinued capitalization of general and administrative costs after the first quarter of 2009, based on its curtailment of exploration and development activities; the Company will resume such capitalization if circumstances in the future warrant.

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 and reduced by estimated salvage values, 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.

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, 2009, we had $1.6 million allocated to unevaluated oil and natural gas properties. A 10% decrease in the unevaluated oil and natural gas properties balance would have increased our 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, 2009.

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, 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. This limitation is known as the ceiling test, and is based on SEC rules for the full cost oil and gas accounting method. Prior to December 31, 2009, SEC rules prescribed that future revenues from estimated reserves be calculated using period end prices. This method was used in 2007 and 2008 to compute future revenues used in the ceiling test. As of December 31, 2009, the SEC requires that future revenues utilize prices based on the average of the most recent twelve months. The average is calculated using the first day of the month price for each of the twelve months making up the reporting period. This change in the method for estimating future revenues from oil and natural gas reserves impacted the ceiling test in the fourth quarter of 2009. In that quarter, we recorded a ceiling test write-down of $4.0 million; had we used the previous pricing methodology, there would not have been a write-down.

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 March 31, 2009, and again at December 31, 2009, 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. In the first quarter of 2009, the Company recognized a non-cash impairment of $59.5 million to oil and natural gas properties, based on March 31, 2009 pricing of $3.76 per Mcf of natural gas and $49.66 per barrel of oil. In the fourth quarter of 2009, the Company recognized a non-cash impairment of $4.0 million to oil and natural gas properties, based on December 31, 2009 pricing of $3.87 per Mcf of natural gas and $61.18 per barrel of oil. The total impairment recorded in 2009 to oil and natural gas properties was $63.5 million (before and after tax). A non-cash impairment of $216.8 million ($203.2 million after tax) was recognized in the fourth quarter of 2008, based on prices prevailing at that time.

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, 2009, 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 fourth quarter 2009 non-cash impairment expense by approximately $28 million; a 10% increase in prices would have eliminated the need for a write-off.

Price Risk Management Activities. The Company follows the guidance of Accounting Standards Codification (ASC) Topic 815, Derivatives and Hedging (ASC 815) 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, in the past, entered into various derivative contracts. These contracts allowed 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 historical derivative instruments were found 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 ASC 815 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 losses of $6,000 and $18,000 during the years ended December 31, 2009 and 2008, respectively, and a gain of $21,000 during the year ended December 31, 2007.

As of December 31, 2009 and 2008, the Company had unrealized gains of zero and $8.1 million (pre-tax and net of tax) deferred in Accumulated Other Comprehensive Income, respectively. All of the Company s derivative agreements expired December 31, 2009.

Net settlements under these contract agreements increased (decreased) oil and natural gas revenues by $11,745,000, ($4,663,000), and $3,252,000 for the years ended December 31, 2009, 2008, and 2007, 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. As of December 31, 2009 the Company believes it is not practicable to estimate the fair value of its outstanding debt under its Credit Facility in light of the payment default. The reduction in credit standing from this default would certainly tend to reduce the fair value of the debt, but it is not practicable to estimate the amount of such reduction. The carrying value of that debt is $87.5 million at December 31, 2009. See Liquidity and Capital Resources Current Credit Facility for further details on the Credit Facility. The Company also has a smaller bank debt with a fixed rate, the rig note. The fair value of the rig note at December 31, 2009 is estimated as approximately $4 million; the corresponding carrying value is $6.2 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 Notes 4 and 9 of the accompanying notes to consolidated financial statements for further information on how fair value for the rig was estimated. The Company s oil and gas price risk hedging contracts are also financial instruments, recorded at fair value; see Note 13 of the accompanying notes to consolidated financial statements.

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 and 2009 we recorded a valuation allowance against deferred tax assets equal to the full amount of those assets.

Table of Contents

Rig Operations. The Company has long-term drilling contracts for two rigs, both of which it has been unable to utilize since early 2009. Although the drilling contractor has been able sublease the rigs during the time Meridian is not utilizing them, the Company is obligated for the difference if the third party sub-lessor s dayrate is less than that provided under the Company s drilling contract, and for the full dayrate if the rig is idle. This cost related to the rigs when they are not providing services to the Company have been included in the consolidated statements of operations as Rig operations, net. The expense was $4.3 million in 2009 and zero in 2008.

The Company owns one of the two rigs, and leases it to the drilling contractor; rentals are based on a percentage of the operating profits of the rig. The lease revenues for the period in which the rigs have not been utilized by Meridian have been included in Rig operations, net, effectively offsetting a portion of the expense of underutilization of that rig. Rig operations expense for the year 2009 includes $1.1 million in lease revenue.

When the owned rig performs services for Meridian, the dayrate costs are capitalized to the full cost pool, and any rental profits after ownership costs (primarily, depreciation and property taxes) are also capitalized to the full cost pool. For the years ended 2009 and 2008, total rig profits capitalized to the full cost pool were $180,000 and $1.1 million, respectively.

New Accounting Pronouncements. In July 2009, the Financial Accounting Standards Board (FASB) issued revised authoritative guidance regarding the hierarchy of generally accepted accounting principles. Under this revised guidance, the FASB Accounting Standards Codification (Codification), the FASB s new web-based codification of accounting and reporting guidance, along with guidance provided by the SEC, are the only authoritative sources of such guidance. All guidance not contained in the Codification, other than SEC guidance, will be considered non-authoritative. The Codification is designed to incorporate previously issued guidance from sources such as the FASB, the American Institute of Certified Public Accountants, and the Public Company Accounting Oversight Board, and is not intended to change GAAP for non-governmental entities. The revised guidance on the hierarchy provides additional guidance on the selection, interpretation, and application of accounting principles from the Codification and from non-authoritative sources when necessary. The guidance is effective for financial statements issued for interim and annual periods ending after September 15, 2009. The Company adopted the revised guidance effective July 1, 2009; the adoption did not have a material impact on financial position or results of operations.

In September 2006, the FASB issued Statement of Financial Accounting Standard (SFAS) No. 157, Fair Value Measurements, codified in Accounting Standards Codification (ASC) Topic 820 (ASC 820). ASC 820 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosure about fair value measurements. In accordance with the effective dates provided in the guidance, the Company adopted the guidance for measurements of the fair values of financial instruments and recurring fair value measurements of non-financial assets and liabilities on January 1, 2008. Effective January 1, 2009, the Company began applying the new guidance to non-recurring measurements of the fair values 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 adoptions had no material impact on financial position or results of operations.

In January 2010, the FASB updated Topic 820 with Accounting Standards Update (ASU) 2010-06, Fair Value Measurements and Disclosures (Topic 820) Improving Disclosures about Fair Value Measurements. This ASU requires new disclosures and clarifies certain existing disclosure requirements about fair value measurements. ASU 2010-06 requires a reporting entity to disclose significant transfers in and out of Level 1 and Level 2 fair value measurements, to describe the reasons for the transfers, and to present separately information about purchases, sales, issuances and settlements for fair value measurements using significant unobservable inputs. ASU 2010-06 is effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances and settlements in the roll forward of activity in Level 3 fair value measurements, which is effective for interim and annual reporting periods beginning after December 15, 2010; early adoption is permitted. The Company does not expect that the adoption of ASU 2010-06 will have a material impact on financial position, results of operations or cash flows.

Table of Contents

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations, codified in ASC Topic 805 (ASC 805). ASC 805 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. ASC 805 was effective on a prospective basis for all business combinations completed on or after January 1, 2009. The Company adopted the revised guidance effective January 1, 2009; the adoption did not have a material impact on financial position or results of operations.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities, codified in ASC Topic 815-10-50 (ASC 815-10-50). ASC 815-10-50 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. The Company adopted the revised guidance effective January 1, 2009; the adoption did not have a material impact on financial position or results of operations. The additional disclosures are included in Note 13 of the accompanying notes to consolidated financial statements.

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 codified as ASC Topic 815-40-15 (ASC 815-40-15). ASC 815-40-15 clarifies the determination of equity instruments which may qualify for an exemption from the other provisions of ASC 815, Derivatives and Hedging. Generally, equity instruments which qualify under the guidelines of ASC 815-40-15 may be accounted for in equity accounts; those which do not qualify are subject to derivative accounting. The Company adopted the guidance of ASC 815-40-15 on January 1, 2009. The effects of the adoption included a revision in the carrying value of certain outstanding warrants, and recognition of a related liability of $960,000 on January 1, 2009, as well as recognition of an unrealized gain of $548,000 due to the change in fair value of those warrants during 2009, which is included in general and administrative expense. See Note 10 in the accompanying notes to consolidated financial statements, under the subheading Warrants, for further information.

In December 2008, the SEC 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 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 affects impairment and depletion calculations. The new rule became effective for reserve reports as of December 31, 2009; the FASB incorporated the new guidance into the Codification as Accounting Standards Update 2010-03, effective also on December 31, 2009, ASC Topic 932, Extractive Activities Oil and Gas.

The Company adopted the new guidance effective December 31, 2009; information about the company s reserves has been prepared in accordance with the new guidance and is included in Note 19 of the accompanying notes to consolidated financial statements; management has chosen not to provide information on probable and possible reserves. The Company s reserves were affected primarily by the use of the average price rather than the year-end price required under the prior rules. As a result of adopting the new guidance, we estimate that Meridian s December 31, 2009 proven reserves decreased approximately 1.4 Bcfe and prices used in the calculation decreased approximately 30%. These changes in turn affected the results of the Company s ceiling test for the fourth quarter, which was a write-down of $4.0 million. Had the new rule using average pricing not been implemented, the write-down in the fourth quarter of 2009 would not have been necessary. The change in total reserves had only a negligible effect on depletion expense in the fourth quarter of 2009, as total proved reserves are the basis of depletion calculations.

In December 2009, the FASB issued revised authoritative guidance regarding consolidation of variable interest entities (VIE s) in ASU 2009-17, Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities, codified as ASC 810-10-05-08. The ASU (originally issued as SFAS No. 167 in June 2009) amends existing consolidation guidance for variable interest entities. Variable interest entities generally are thinly-capitalized entities which under previous guidance may not have been consolidated. The revised guidance requires a company to perform a qualitative analysis to determine whether to consolidate a VIE, which includes consideration of control issues other than the primarily quantitative considerations utilized prior to this revision. In addition, the revised guidance requires ongoing assessments of whether to consolidate VIE s, rather than only when specific events occur. The revised guidance also requires additional disclosures about consolidated and unconsolidated VIE s, including their impact on the company s risk exposure and its financial statements. The revised guidance will be effective for financial statements for annual and interim periods beginning after November 15, 2009. The Company has not yet determined the impact of adoption on its financial position or results of operations.

In April 2009, the FASB issued new authoritative guidance regarding interim disclosures about the fair value of financial instruments, which enhances consistency in financial reporting by increasing the frequency of fair value disclosures. The guidance is effective for interim and annual periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. The Company adopted the new guidance effective April 1, 2009. The adoption did not have a material impact on financial position or results of operations of the Company. The disclosures are included in Note 2 of the accompanying notes to consolidated financial statements, under the subheading Fair Value of Financial Instruments.

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 $87.5 million remains borrowed under the Credit Facility, we estimate our annual interest expense will change by $0.88 million for each 100 basis point change in the applicable interest rates utilized under the Credit Facility.

Hedging Contracts

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 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, 2009, however, the all of the Company s derivative contracts have expired.

Due to our default under the Credit Facility, the Lenders have not allowed the Company to enter into any additional hedging agreements. As a result, our oil and natural gas sales for periods beyond December 2009 will more closely resemble prevailing market prices.

GLOSSARY OF CERTAIN OIL AND NATURAL GAS TERMS

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

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

Bbl/d One barrel per day.

Bcf Billion cubic feet.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Mcf One thousand cubic feet.

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

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

MD Measured depth.

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

MMbtu One million Btus.

MMMbtu One billion Btus.

MMcf One million cubic feet.

MMcf/d One million cubic feet per day.

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

Net acres or net wells The sum of the fractional working interests owned in gross acres or gross wells.

Net revenue interest An interest in the production and revenues created from the working interest which is generally calculated net or after deducting any royalty interests.

NYMEX New York Mercantile Exchange.

OCS Outer Continental Shelf in the Gulf of Mexico.

Oil Crude oil and condensate

Present value or PV10 or SEC PV-10 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 based on an average of the most recent twelve months 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 analysis of geoscience 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.

Table of Contents

Item 8. Financial Statements and Supplementary Data

Index to Financial Statements

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

CONSOLIDATED FINANCIAL STATEMENT SCHEDULES

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of The Meridian Resource Corporation as of December 31, 2009 and 2008 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, 2009. 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, 2009 and 2008, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2009 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, 2009, 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.

As discussed in Note 2 to the consolidated financial statements, effective December 31, 2009, the Company changed its reserve estimates and related disclosures as a result of adopting new oil and natural gas reserve estimation and disclosure requirements.

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, 2009, 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 April 15, 2010 expressed an unqualified opinion thereon.

/s/ BDO Seidman, LLP
Houston, Texas
April 15, 2010

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

	Year Ended December 31,		
	2009	**2008**	**2007**
REVENUES:			
Oil and natural gas	$ 89,245	$ 148,634	$ 150,709
Price risk management activities	(6)	(18)	21
Interest and other	15	549	1,448
	89,254	149,165	152,178
OPERATING COSTS AND EXPENSES:			
Oil and natural gas operating	17,550	24,280	28,338
Severance and ad valorem taxes	6,696	9,727	9,409
Depletion and depreciation	37,102	72,072	77,076
General and administrative	18,121	19,063	16,221
Rig operations, net	4,254		
Contract settlement		9,894	
Indemnification settlement	4,223		
Accretion expense	2,083	2,064	2,230
Impairment of long-lived assets	63,495	223,543	
Hurricane damage repairs		1,462	
	153,524	362,105	133,274
EARNINGS (LOSS) BEFORE OTHER EXPENSES & INCOME TAXES	(64,270)	(212,940)	18,904
OTHER EXPENSES:			
Interest expense	8,486	5,408	6,090
EARNINGS (LOSS) BEFORE INCOME TAXES	(72,756)	(218,348)	12,814
INCOME TAX EXPENSE (BENEFIT):			
Current	(120)	(269)	650
Deferred		(8,193)	5,027
	(120)	(8,462)	5,677
NET EARNINGS (LOSS)	(72,636)	(209,886)	7,137
NET EARNINGS (LOSS) APPLICABLE TO COMMON STOCKHOLDERS	$ (72,636)	$ (209,886)	$ 7,137
NET EARNINGS (LOSS) PER SHARE:			
Basic	$ (0.79)	$ (2.30)	$ 0.08
Diluted	$ (0.79)	$ (2.30)	$ 0.08
WEIGHTED AVERAGE NUMBER OF COMMON SHARES:			

Basic	92,465	91,382	89,307
Diluted	92,465	91,382	94,944

See notes to consolidated financial statements.

Table of Contents

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

	December 31,	
	2009	**2008**
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 5,273	$ 13,354
Restricted cash	35	9,971
Accounts receivable, less allowance for doubtful accounts of $110 [2009] and $210 [2008]	12,185	16,980
Prepaid expenses and other	2,195	3,292
Assets from price risk management activities		8,447
Total current assets	19,688	52,044
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, full cost method (including $1,647 [2009] and $39,927 [2008] not subject to depletion)	1,890,079	1,877,925
Land		48
Equipment and other	20,469	21,371
	1,910,548	1,899,344
Less accumulated depletion and depreciation	1,747,274	1,647,496
Total property and equipment, net	163,274	251,848
OTHER ASSETS:		
Other	168	683
Total other assets	168	683
TOTAL ASSETS	$ 183,130	$ 304,575

See notes to consolidated financial statements.

Table of Contents

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

	December 31, 2009	December 31, 2008
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 6,133	$ 15,097
Advances from non-operators	3	5,517
Revenues and royalties payable	4,890	6,267
Due to affiliates	542	8,145
Notes payable		1,775
Accrued liabilities	10,109	18,831
Liabilities from price risk management activities		311
Asset retirement obligations	4,570	1,457
Current income taxes payable		47
Current maturities of long-term debt	93,666	103,849
Total current liabilities	119,913	161,296
LONG-TERM DEBT		
OTHER:		
Asset retirement obligations	19,253	20,768
Other	3,220	
	22,473	20,768
COMMITMENTS AND CONTINGENCIES (Notes 5, 6, 7, 11, and 12)		
STOCKHOLDERS EQUITY:		
Common stock, $0.01 par value (200,000,000 shares authorized, 92,475,527 [2009] and 93,045,592 [2008] shares issued)	925	948
Additional paid-in capital	535,443	538,561
Accumulated deficit	(495,624)	(422,028)
Accumulated other comprehensive income		8,129
	40,744	125,610
Less treasury stock, at cost, -0- [2009] and 1,712,114 [2008] shares		3,099
Total stockholders equity	40,744	122,511
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 183,130	$ 304,575

See notes to consolidated financial statements.

62

Table of Contents

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

	Year Ended December 31,		
	2009	**2008**	**2007**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net earnings (loss)	$ (72,636)	$ (209,886)	$ 7,137
Adjustments to reconcile net earnings (loss) to net cash provided by operating activities:			
Depletion and depreciation	37,102	72,072	77,076
Impairment of long-lived assets	63,495	223,543	
Amortization of other assets	516	224	436
Non-cash compensation	153	1,728	2,549
Non-cash gain on change in fair value of outstanding warrants	(549)		
Non-cash price risk management activities	6	18	(21)
Accretion expense	2,083	2,064	2,230
Deferred income taxes		(8,193)	5,027
Changes in assets and liabilities:			
Restricted cash	9,936	(9,941)	1,252
Accounts receivable	4,044	3,645	4,411
Prepaid expenses and other	1,191	1,246	(1,081)
Accounts payable	(3,022)	4,629	(946)
Advances from non-operators	(5,514)	(1,480)	3,945
Due to (from) affiliates	(7,603)	10,725	(1,910)
Revenues and royalties payable	(1,377)	(325)	(1,341)
Asset retirement obligations	(2,243)	(613)	(2,055)
Other assets and liabilities	1,435	3,311	282
Net cash provided by operating activities	27,017	92,767	96,991
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to property and equipment	(25,377)	(124,059)	(116,696)
Proceeds from sale of property	2,432	7,171	3,060
Net cash used in investing activities	(22,945)	(116,888)	(113,636)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term debt		48,000	3,000
Reductions in long-term debt	(10,183)	(19,150)	(3,000)
Proceeds Notes payable	2,232	5,684	9,540
Reductions Notes payable	(4,007)	(6,571)	(9,632)
Repurchase of common stock		(75)	(1,158)
Payment of taxes due on vested stock	(195)	(3,035)	
Additions to deferred loan costs		(904)	(3)
Net cash provided by (used in) financing activities	(12,153)	23,949	(1,253)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(8,081)	(172)	(17,898)

Cash and cash equivalents at beginning of year	13,354	13,526	31,424
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 5,273	$ 13,354	$ 13,526
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Non-cash activities:			
Issuance of shares for contract services	$	$ 144	$ (1,033)
Capital expenditures	$ (12,585)	$ (6,460)	$ 4,799
Rig depreciation capitalized to oil and natural gas properties	$ 91	$ 1,538	$
ARO Liability new wells drilled	$ 47	$ 451	$ 476
ARO Liability changes in estimates	$ 1,711	$ (3,160)	$ 24

See notes to consolidated financial statements.

Table of Contents

THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
Years Ended December 31, 2007, 2008 and 2009 (in thousands)

	Common Stock		Additional Paid-In	Accumulated Earnings	Accumulated Other Comprehensive Income	Treasury Stock		
	Shares	Par Value	Capital	(Deficit)	(Loss)	Shares	Cost	Total
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 activity					(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 contribution	103	1	240			(99)	181	422
			193					193

Share-based compensation								
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
Effect of adoption of EITF Issue 07-05 (to record outstanding warrants at fair value)				(960)				(960)
Distribution of shares from Rabbi Trust:								
From treasury shares		(17)	(3,082)			(1,712)	3,099	
Repurchased in exchange for payment of withholding tax on vested stock						610	(195)	(195)
Retired	(610)	(6)	(189)			(610)	195	
Share-based compensation	40		153					153
Accum. other comprehensive income activity					(8,129)			(8,129)
Net loss				(72,636)				(72,636)
Balance, December 31, 2009	92,475	$ 925	$ 535,443	$ (495,624)	$		$	$ 40,744

64

Table of Contents

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

	Year Ended December 31,		
	2009	2008	2007
Net earnings (loss) applicable to common stockholders	$ (72,636)	$ (209,886)	$ 7,137
Other comprehensive income (loss), net of tax, for unrealized gains (losses) from hedging activities:			
Unrealized holding gains (losses) arising during period (1)	3,616	3,806	(2,814)
Reclassification adjustments on settlement of contracts (2)	(11,745)	4,544	(2,114)
	(8,129)	8,350	(4,928)
Total comprehensive income (loss)	$ (80,765)	$ (201,536)	$ 2,209

(1)	Net income tax (expense) benefit	$	$	$ 1,515
(2)	Net income tax (expense) benefit	$	$ (119)	$ 1,138

See notes to consolidated financial statements.

65

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.

Since December 31, 2008, the Company has been in default of its credit facility, under which borrowings were $87.5 million at December 31, 2009. The credit facility default gave rise to a cross default under the Company s $6.2 million term loan (rig note). As a result, the Company faces substantial economic difficulties. Although operating cash flow has been positive and capital expenditures have been very significantly reduced, the Company continues to be obligated for the expense of drilling rigs it cannot fully utilize and continues to be impacted by prices for oil and natural gas which have exhibited extreme volatility in the recent past. The Company s default under the debt agreements, which has been mitigated in the short term by certain forbearance agreements, negatively impacts future cash flow and the Company s access to credit or other forms of capital. If the Company is unable to comply with the terms of the forbearance agreements, it will continue to be in default under the credit facility and the rig note and will be subject to the exercise of remedies by third parties on account of such defaults. The exercise of such remedies, which include acceleration of all principal and interest payments, could potentially result in the Company seeking protection under federal bankruptcy laws. Such relief could materially and adversely affect the Company and its shareholders. Therefore, there is substantial doubt as to the Company s ability to continue as a going concern for a period longer than the next twelve months. In addition, the accompanying report of the Company s independent registered public accounting firm includes a going concern explanatory paragraph that expresses substantial doubt as to the Company s ability to continue as a going concern.

For further information regarding bank debt and forbearance agreements, see Note 5. For further information regarding the Company s drilling rig contracts, and a forbearance agreement with the rig operator, see Note 7.

Proposed Merger. Management has actively pursued many avenues to strengthen the financial position of the Company over the past year. As a result, on December 22, 2009, the Company entered into an Agreement and Plan of Merger (Merger Agreement) with Alta Mesa Holdings, LP (Alta Mesa) and Alta Mesa Acquisition Sub, LLC, a direct wholly owned subsidiary of Alta Mesa (Merger Sub). Under the terms of the Merger Agreement, as amended, shareholders will receive $0.33 per share of common stock, to be paid in cash, and Alta Mesa will assume the Company s debts and obligations. The Company would be merged into Alta Mesa Acquisition Sub, LLC with the Merger Sub as the surviving entity. The Company s stock would cease to be publicly traded. The merger is subject to approval by holders of two thirds of the Company s outstanding shares of common stock; a shareholder meeting and vote are currently scheduled for April 28, 2010. The Company filed a proxy statement regarding the proposed merger on February 8, 2010, in which the Company s board recommended that shareholders vote in favor of the merger. For further information on the proposed merger, refer to the proxy statement.

The Company s various forbearance agreements have been extended to allow for completion of the merger, assuming shareholder approval is obtained. However, the most recent amendment to the bank forbearance agreement also allows the lenders to terminate the forbearance period on or after February 28, 2010, without cause, so long as the decision to terminate is unanimous among the lenders.

Table of Contents

The Merger Agreement may be terminated under various conditions, including the occurrence of an event with a material adverse effect on Meridian (Material Adverse Event, as defined in the Merger Agreement). Both Meridian and Alta Mesa must adhere to certain customary representations and covenants contained in the Merger Agreement, including those that restrict Meridian s conduct of business primarily to current operations, and restrict Meridian from soliciting other offers for the Company, although Meridian is entitled to consider any superior proposal, as defined in the Merger Agreement. As a condition of the merger, Meridian was required to enter into a settlement regarding certain indemnification claims, which it has done (see Note 7, Environmental litigation, for further information).
The Merger Agreement with Alta Mesa includes a reimbursement clause under which the Company will pay Alta Mesa s reasonable costs of the merger, not to exceed $1 million, in case of termination of the agreement under various circumstances, including expiration of the term on May 31, 2010 without consummation of the merger, and also including termination of the Merger Agreement due to non-approval in the shareholder vote. In addition to reimbursement of Alta Mesa s costs, the Company would pay Alta Mesa a $3 million termination fee if, among other reasons, the Company terminates the Alta Mesa agreement and accepts another offer for the Company, so long as the definitive agreement related to the other offer is entered into within nine months after termination of the Merger Agreement with Alta Mesa. The termination fee would be payable no later than two business days after consummation of the transaction which triggered the fee.
Alta Mesa has the right to terminate the Merger Agreement at any time, whether before or after approval by the Company s shareholders, upon payment of a termination fee of $3 million to the Company. The terms of the Company s Credit Facility forbearance agreement require any such termination payment received by Meridian to be used to repay any outstanding balance under the Credit Facility.
There can be no assurance that the proposed merger will be completed. Approval by the shareholders is not assured. Litigation was filed by some shareholders claiming the Company s directors breached their fiduciary duties in approving the merger. To avoid the risk of the litigation delaying or adversely affecting the merger and to minimize the expense of defending the Company against the lawsuit, in March 2010 management agreed to a proposed settlement of the litigation (see Note 7). There can be no assurance the bank forbearance period will not be terminated by the lenders before the proposed merger can be completed. 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 accompanying consolidated financial statements have been prepared in accordance with generally accepted accounting principles applicable to a going concern, which implies that the Company will continue to meet its obligations and continue its operations for the next twelve months. No adjustments relating to the recoverability or classification of recorded amounts have been made, other than to classify all bank debt as current.

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, 2009, was $35,000 and at December 31, 2008, was $9,971,000. 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. The funds from the trust were disbursed in 2009. Remaining restricted cash is related to a contractual obligation with respect to royalties payable.

Table of Contents

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. Through March 2009, capitalized costs included general and administrative costs directly related to acquisition, exploration and development activities. Subsequent to that date, no general and administrative costs have been capitalized, as such activities have significantly decreased. The Company may capitalize general and administrative costs in the future, when costs related directly to the acquisition, exploration, and development of oil and natural gas properties are incurred. Total general and administrative costs capitalized for the years 2009 and 2008 were $2.6 million and $17.4 million, respectively. 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, as adjusted for the Company s cash flow hedge positions, and on current costs, plus the lower of cost or estimated fair value of unproved properties adjusted for related income tax effects. Under new rules issued by the SEC, the estimated future net cash flows as of December 31, 2009, were determined using average prices for the most recent twelve months. The average is calculated using the first day of the month price for each of the twelve months that make up the reporting period. As of December 31, 2008 and 2007, previous rules required that estimated future net cash flows from proved reserves be based on period end prices. 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 subject to depletion include net capitalized costs, and estimated future dismantlement, restoration, and abandonment costs and are reduced by estimated salvage values. 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. Capitalized costs related to unproved oil and natural gas properties are excluded from the full cost pool until proven or impaired in the judgment of management; such costs total $1.6 million and $39.9 million as of December 31, 2009 and 2008, respectively. At December 31, 2009, excluded costs include no exploratory well costs.

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. In 2009, gross asset retirements included $940,000 for furniture and equipment retired, with related accumulated depreciation of $911,000. Repairs and maintenance are charged to expense as incurred.

Rig Operations

The Company has a long-term dayrate contract to utilize a drilling rig from an unaffiliated service company, Orion Drilling Company, LLC, (Orion). Although capital expenditure plans no longer accommodate full use of this rig, the Company is obligated for the dayrate regardless of whether the rig is working or idle. When the contracted rig is not in use on Meridian-operated wells, Orion may contract it to third parties, or the rig may be idled. The Company is obligated for the difference in dayrates if it is utilized by a third party at a lesser dayrate. The contracted rig was utilized drilling a Meridian-operated well through the end of the first quarter of 2009, and has subsequently been contracted to a third party at a lesser dayrate than the Company s contracted dayrate. The costs of the rig when it is not providing services to the Company have been included in the consolidated statements of operations as Rig operations, net.

Table of Contents

TMR Drilling Corporation (TMRD), a wholly owned subsidiary of the Company, owns a rig which was also intended primarily to drill wells operated by the Company. In April 2008, Orion began leasing the rig from TMRD, and operating it under a dayrate contract with the Company. When the rig drills Company wells, drilling expenditures under the dayrate contract are capitalized as exploration costs and all TMRD profits or losses related to lease of the rig, including any incidental profits related to the share of drilling costs borne by joint interest partners, are offset against the full cost pool. From April through December of 2008, the rig was utilized almost continuously on Company wells and its profits were accordingly capitalized. For the years ended 2009 and 2008, the rig profits capitalized to the full cost pool were $180,000 and $1.1 million, respectively.

When the rig is used by Orion for work on third party wells in which the Company has no economic or management interest, TMRD s profit or loss related to the lease of the rig is reflected in the consolidated statements of operations. During 2009, the rig worked on third party wells. The Company is obligated for the difference in dayrates if the rig is utilized by a third party at a lesser dayrate, which has occurred during 2009. This loss on a contractual obligation is included in Rig Operations, net in the consolidated statements of operations. The Company s share of profits on the lease of the rig to Orion partially offsets the loss on the drilling contract and is included in Rig operations, net on the consolidated statements of operations. The total lease revenue included in Rig operations, net for 2009 was $1.1 million.

Depreciation of the owned rig was $0.9 million and $1.5 million for 2009 and 2008, respectively, of which $0.8 million and zero was included in depletion and depreciation expense on the consolidated statements of operations, and the remainder was capitalized to the full cost pool. In addition, impairment expense includes $6.7 million in 2008 for impairment of the value of the rig.

See Note 7 for additional information on the Company s plans for potential disposition of the rig and the obligations under the drilling contracts.

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 $7.9 million, $5.6 million, and $6.0 million in 2009, 2008 and 2007, respectively. Such payments include $1.2 million in forbearance fees in 2009, which have been included in interest expense. Cash payments (refunds) for income taxes (federal and state, net of receipts) were $(505,000), $385,000, and $61,000 for 2009, 2008, and 2007, respectively.

Concentrations of Credit Risk

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

The Company maintains its cash in bank deposit accounts which, at times, may exceed federally insured limits. Accounts are guaranteed by the Federal Deposit Insurance Corporation (FDIC) up to $250,000 as of December 31, 2009. As of December 31, 2008, the FDIC also provides an unlimited guarantee for balances in non-interest bearing transactional accounts. At December 31, 2009, and December 31, 2008, the Company had approximately $35,000 and $20,696,000, 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

Table of Contents

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 $10.1 million and $10.2 million as of December 31, 2009 and 2008, respectively.

Accounts receivable includes $1.1 million and $1.6 million in amounts due from joint interest owners as of December 31, 2009 and 2008, respectively. As of December 31, 2008, accounts receivable included $2.4 million for insurance proceeds related to hurricane damage.

The Company maintains an allowance for doubtful accounts for 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 expense of $1.5 million in 2008 is related to damages incurred from hurricanes Ike and Gustav and is primarily related to the Company s insurance deductible.

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 the Company s drilling rig. The Company s oil and natural gas properties did not include any individual investments considered significant enough to qualify for interest capitalization under our internal policies. Interest is capitalized using a weighted average interest rate based on the Company s outstanding borrowings. No interest was capitalized in 2009.

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, have been included in the computation of basic and diluted earnings per share, as all conditions precedent to their issue, other than passage of time, had been satisfied prior to distribution of the shares in 2009.

Stock Options

The Company follows the guidance in Accounting Standards Codification Topic 718 (ASC 718) to account for share-based payment transactions in which the Company receives services in exchange for equity instruments of the Company.

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

Table of Contents

The Company s 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. As of December 31, 2009 the Company believes it is not practicable to estimate the fair value of its outstanding debt under its credit facility in light of the payment default. The reduction in credit standing from this default would certainly tend to reduce the fair value of the debt, but it is not practicable to estimate the amount of such reduction. The carrying value of that debt is $87.5 million at December 31, 2009. See Note 5 for further details on the credit facility. The Company also has a smaller bank debt with a fixed rate. The fair value of the rig note at December 31, 2009 is estimated as approximately $4 million; the corresponding carrying value is $6.2 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 9 for further information on how fair value for the rig was estimated. The Company s oil and gas price risk hedging contracts are also financial instruments, recorded at fair value; see Note 13.

Notes Payable

Notes payable are related to the financing of the Company s insurance program. The weighted average interest rate on the notes payable was 4.69%, as of December 31, 2008. There were no outstanding notes payable as of December 31, 2009.

Lease Accounting

The Company amortizes the cost of leasehold improvements over the shorter of the life of the asset or 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 guidance of Accounting Standards Codification Topic 815, Derivatives and Hedging (ASC 815). 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 typically 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. Derivatives are noted as Assets (or Liabilities) from price risk management activities and are classified on the Consolidated Balance Sheets as long-term or short-term based on the maturity date of the derivative agreement. 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, whereupon they are recognized in oil or natural gas revenues. The Company recognized a loss of $6,000, a loss of $18,000, and a gain of $21,000 related to hedge ineffectiveness during the years ended December 31, 2009, 2008, and 2007, respectively. Gains and losses from hedge ineffectiveness are presented as Price risk management activities in the Consolidated Statements of Operations.

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

When cash flow hedge accounting is discontinued because it is probable that a forecasted transaction will not occur, the Company continues to carry the derivative on the balance sheet at its fair value with subsequent changes in fair value included in earnings, and gains and losses that were accumulated in other comprehensive income are immediately recognized in earnings. In all other situations in which hedge accounting is discontinued, the Company continues to carry the derivative at its fair value on the balance sheet and recognizes any subsequent changes in its fair value in earnings. Gains or losses accumulated in other comprehensive income at the time the hedge relationship is terminated are 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 both 2008 and 2009 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 Consolidated Statements 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 2009, the Financial Accounting Standards Board (FASB) issued revised authoritative guidance regarding the hierarchy of generally accepted accounting principles. Under this revised guidance, the FASB Accounting Standards Codification (Codification), the FASB s new web-based codification of accounting and reporting guidance, along with guidance provided by the SEC, are the only authoritative sources of such guidance. All guidance not contained in the Codification, other than SEC guidance, will be considered non-authoritative. The Codification is designed to incorporate previously issued guidance from sources such as the FASB, the American Institute of Certified Public Accountants, and the Public Company Accounting Oversight Board, and is not intended to change GAAP for non-governmental entities. The revised guidance on the hierarchy provides additional guidance on the selection, interpretation, and application of accounting principles from the Codification and from non-authoritative sources when necessary. The guidance is effective for financial statements issued for interim and annual periods ending after September 15, 2009. The Company adopted the revised guidance effective July 1, 2009; the adoption did not have a material impact on financial position or results of operations.

In September 2006, the FASB issued Statement of Financial Accounting Standard (SFAS) No. 157, Fair Value Measurements, codified in Accounting Standards Codification (ASC) Topic 820 (ASC 820). ASC 820 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosure about fair value measurements. In accordance with the effective dates provided in the guidance, the Company adopted the guidance for measurements of the fair values of financial instruments and recurring fair value measurements of non-financial assets and liabilities on January 1, 2008. Effective January 1, 2009, the Company began applying the new guidance to non-recurring measurements of the fair values 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 adoptions had no material impact on financial position or results of operations.

In January 2010, the FASB updated Topic 820 with Accounting Standards Update (ASU) 2010-06, Fair Value Measurements and Disclosures (Topic 820) Improving Disclosures about Fair Value Measurements. This ASU requires new disclosures and clarifies certain existing disclosure requirements about fair value measurements. ASU 2010-06 requires a reporting entity to disclose significant transfers in and out of Level 1 and Level 2 fair value measurements, to describe the reasons for the transfers and to present separately information about purchases, sales, issuances and settlements for fair value measurements using significant unobservable inputs. ASU 2010-06 is effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances and settlements in the roll forward of activity in Level 3 fair value measurements, which is effective for interim and annual reporting periods beginning after December 15, 2010; early adoption is permitted. The Company does not expect that the adoption of ASU 2010-06 will have a material impact on financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations, codified in ASC Topic 805 (ASC 805). ASC 805 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, ASC 805 is effective on a prospective basis for all business combinations completed on or after January 1, 2009. The Company adopted the revised guidance effective January 1, 2009; the adoption did not have a material impact on financial position or results of operations.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities, codified in ASC Topic 815-10-50 (ASC 815-10-50). ASC 815-10-50 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. The Company adopted the revised guidance effective

January 1, 2009; the adoption did not have a material impact on financial position or results of operations. The additional disclosures are included in Note 13.

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 codified as ASC Topic 815-40-15 (ASC 815-40-15). ASC 815-40-15 clarifies the determination of equity instruments which may qualify for an exemption from the other provisions of ASC 815, Derivatives and Hedging. Generally, equity instruments which qualify under the guidelines of ASC 815-40-15 may be accounted for in equity accounts; those which do not qualify are subject to derivative accounting. The Company adopted the guidance of ASC 815-40-15 on January 1, 2009. The effects of the adoption included a revision in the carrying value of certain outstanding warrants, and recognition of a related liability of $960,000 on January 1, 2009, as well as recognition of an unrealized gain of $548,000 included in general and administrative expense, due to the change in fair value of those warrants during 2009. See Note 10, Warrants, for further information.

In December 2008, the SEC 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 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 affects impairment and depletion calculations. The new rule became effective for reserve reports as of December 31, 2009; the FASB incorporated the new guidance into the Codification as Accounting Standards Update 2010-03, effective also on December 31, 2009, ASC Topic 932, Extractive Activities Oil and Gas.

The Company adopted the new guidance effective December 31, 2009; information about the company s reserves has been prepared in accordance with the new guidance and is included in Note 19; management has chosen not to provide information on probable and possible reserves. The Company s reserves were affected primarily by the use of the average prices rather than the period-end prices required under the prior rules. As a result of adopting the new guidance, we estimate that Meridian s December 31, 2009 proven reserves decreased approximately 1.4 Bcfe and prices used in the calculation decreased approximately 30%. This change in turn affected the results of the Company s ceiling test for the fourth quarter of 2009, which was a write-down of $4.0 million. Had the new rule using average pricing not been implemented, the write down in the fourth quarter of 2009 would not have been necessary. The change in total reserves using the new rules had a negligible effect on depletion expense in the fourth quarter of 2009, as total proved reserves are the basis of depletion calculations.

In December 2009, the FASB issued revised authoritative guidance regarding consolidation of variable interest entities (VIE s) in ASU 2009-17, Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities, codified as ASC 810-10-05-08. The ASU (originally issued as SFAS No. 167 in June 2009) amends existing consolidation guidance for variable interest entities. Variable interest entities generally are thinly-capitalized entities which under previous guidance may not have been consolidated. The revised guidance requires a company to perform a qualitative analysis to determine whether to consolidate a VIE, which includes consideration of control issues other than the primarily quantitative considerations utilized prior to this revision. In addition, the revised guidance requires ongoing assessments of whether to consolidate VIE s, rather than only when specific events occur. The revised guidance also requires additional disclosures about consolidated and unconsolidated VIE s, including their impact on the company s risk exposure and its financial statements. The revised guidance will be effective for financial statements for annual and interim periods beginning after November 15, 2009. The Company has not yet determined the impact of adoption on its financial position or results of operations.

Table of Contents

In April 2009, the FASB issued new authoritative guidance regarding interim disclosures about the fair value of financial instruments, which enhances consistency in financial reporting by increasing the frequency of fair value disclosures. The guidance is effective for interim and annual periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. The Company adopted the new guidance effective April 1, 2009. The adoption did not have a material impact on financial position or results of operations of the Company. The disclosures are included above, Fair Value of Financial Instruments.

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 estimates the present value of future costs of dismantlement and abandonment of its wells, facilities, and other tangible long-lived assets, recording them as liabilities in the period incurred. Asset retirement obligations are calculated using an expected present value technique. Salvage values are excluded from the estimation.

When the liability is initially recorded, the entity increases the carrying amount of the related long-lived asset. 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, the Company incurs a gain or loss based upon the difference between the estimated and final liability amounts. The Company records gains or losses from settlements as adjustments to the full cost pool.

Accretion expenses were $2.1 million, $2.1 million and $2.2 million in 2009, 2008 and 2007, respectively.

The following table describes the change in the Company s asset retirement obligations for the years ended December 31, 2009 and 2008 (thousands of dollars):

	2009	**2008**
Asset retirement obligation at beginning of year	$ 22,225	$ 23,483
Additional retirement obligations incurred	47	451
Settlements	(2,243)	(613)
Revisions to estimates and other changes	1,711	(3,160)
Accretion expense	2,083	2,064
Asset retirement obligation at end of year	23,823	22,225
Less: current portion	4,570	1,457
Asset retirement obligation, long-term	$ 19,253	$ 20,768

Table of Contents

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 present value (10% discount rate) of the estimated future after-tax net revenues from proved properties after giving effect to cash flow hedge positions, and the lower of cost or fair value of unproved properties adjusted for related income tax effects. Under new rules issued by the SEC, the estimated future net cash flows as of December 31, 2009, were determined using average prices for the most recent twelve months. The average is calculated using the first day of the month price for each of the twelve months that make up the reporting period. As of December 31, 2008 and 2007, previous SEC rules required that estimated future net cash flows from proved reserves be based on period end prices.

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.

In the first quarter of 2009, the Company recognized a non-cash impairment of $59.5 million to oil and natural gas properties, based on March 31, 2009 pricing of $3.76 per Mcf of natural gas and $49.66 per barrel of oil. In the fourth quarter of 2009, the Company recognized a non-cash impairment of $4.0 million to oil and natural gas properties, based on December 31, 2009 pricing of $3.87 per Mcf of natural gas and $61.18 per barrel of oil. The total impairment recorded in 2009 to oil and natural gas properties was $63.5 million.

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, based on December 31, 2008 pricing of $5.79 per Mcf of natural gas and $44.04 per barrel of oil.

The Company also recorded a non-cash impairment of the value of its drilling rig in 2008, due to uncertainties regarding utilization and dayrates for similar rigs, which decreased significantly after the second quarter of 2008. The value of the rig was based on the present value of estimated cash flows from the asset, using management s best estimates of utilization and dayrates. The estimated value was $5.5 million as of December 31, 2008. Accordingly, the Company recorded non-cash impairment expense of $6.7 million to write down the net book value of the rig to $5.5 million. Management performs impairment testing of the drilling rig each quarter. No further impairment has been recorded for the rig. At December 31, 2009, the carrying value of the rig exceeded its estimated fair value (based on discounted cash flows) by approximately $0.9 million. However, no impairment was necessary at that date as the undiscounted cash flows exceeded the carrying value. Authoritative accounting guidance provides for impairment only when carrying value exceeds undiscounted cash flows.

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

***Credit Facility*.** The Company has a credit facility with a group of banks (collectively, the Lenders,) with a maturity date of February 21, 2012 (the Credit Facility.) The Credit Facility is subject to borrowing base redeterminations and bears a floating interest rate based on LIBOR or the prime rate of Fortis Capital Corp., the administrative agent of the Lenders. The borrowing base and the interest formula have been redetermined or amended multiple times. As of December 31, 2008, the borrowing base was $95 million and was fully drawn. The interest rate formula in effect at that date was LIBOR plus 3.25% or prime plus 2.5%.

Obligations under the Credit Facility are to be 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. 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 of December 31, 2008, the Company was in default of two of the covenants under the agreement, including one that requires that the Company maintain a current ratio (as defined in the Credit Facility) of one to one. The current ratio, as defined, was less than the required one to one at December 31, 2008 and continued to be, through December 31, 2009. The Company is also in default of the requirement that the Company s auditors opinion for the current financial statements be without modification. Both the Company s 2008 and 2009 audit reports from its independent registered public accounting firm included a going concern explanatory paragraph that expressed substantial doubt about the Company s ability to continue as a going concern. As a result of the defaults, the outstanding Credit Facility balances of $95 million at December 31, 2008 and $87.5 million at December 31, 2009 have been classified as current in the accompanying consolidated balance sheets. Also in response to the defaults, the Company provided additional security to the Lenders, such that first priority liens cover in excess of 95% of the present value of proved oil and natural gas properties.

The Credit Facility has been subject to semi-annual borrowing base redeterminations effective on April 30 and October 31 of each year, with limited additional unscheduled redeterminations also available to the Lenders or the Company. 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 related to the price of oil and natural gas 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 the Company s 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 outstanding borrowings under the Credit Facility, the Credit Facility requires repayment of the deficit within a specified period of time.

On April 13, 2009, the Lenders notified the Company that, effective April 30, 2009, the borrowing base was reduced from its then-current and fully drawn $95 million to $60 million. As a result, a $34.5 million payment to the Lenders for the borrowing base deficiency was due July 29, 2009, based on the borrowings outstanding on that date. The Company did not have sufficient cash available to repay the deficiency and, consequently, failed to pay such amount when due. Prior to July 29, 2009, the Company was in covenant default under the terms of the Credit Facility; on and after that date it was in covenant default and payment default as well.

Under the terms of the Credit Facility, the Lenders have various remedies available in the event of a default, including acceleration of payment of all principal and interest.

On September 3, 2009, the Company entered into a forbearance agreement with the Lenders under the Credit Facility (Bank Forbearance Agreement). The Bank Forbearance Agreement provided that the Lenders would forbear from exercising any right or remedy arising as a result of certain existing events of default under the Credit Facility until the earlier of December 3, 2009 or the date that any default occurred under the Bank Forbearance Agreement. The terms of the Bank Forbearance Agreement required the Company to consummate a capital transaction such as a capital infusion or a sale or merger of the Company, before October 30, 2009. The deadlines for the capital transaction and the forbearance period were extended several times by amendments to the Bank Forbearance Agreement.

At origination of the Bank Forbearance Agreement, the Company paid the Lenders $2.0 million of principal owed under the Credit Facility. Under the terms of the agreement the Company made a total of $5.0 million in further principal payments through December 31, 2009, bringing the balance at that date to $87.5 million. The Company also paid forbearance fees to the Lenders of $945,000, charged to interest expense in the third quarter of 2009, and incurred an additional $476,000 in forbearance fees, charged to interest expense in the fourth quarter of 2009. In addition, the Company incurred approximately $2.3 million in legal and consulting fees, recorded in general and administrative expense, to originate and amend the Bank Forbearance Agreement and other related agreements.

On December 22, 2009, the Company entered into an Agreement and Plan of Merger (the Merger Agreement) with Alta Mesa Holdings, LP (Alta Mesa) and Alta Mesa Acquisition Sub, LLC, a direct wholly owned subsidiary of Alta Mesa. The Eleventh Amendment to Forbearance and Amendment Agreement (11^{th} Amendment) provided the Lenders consent to the Merger Agreement and extended the date for consummation of a capital transaction, such as the Alta Mesa merger, and the forbearance period, to the earlier of the consummation of the merger with Alta Mesa, the termination of the Merger Agreement, or May 31, 2010. However, the 11^{th} Amendment also allows the Lenders to terminate the forbearance period on or after February 28, 2010, without cause, so long as the decision to terminate is unanimous among the Lenders. The 11^{th} Amendment also requires the Company to repay $1 million in principal to the Lenders per month. As of March 31, 2010, the outstanding balance under the Credit Facility is $83 million.

In accordance with the 11th Amendment, the Company has filed its shareholder proxy statement regarding the merger and called a shareholder meeting currently scheduled for April 28, 2010 to approve the transaction. There can be no assurance that shareholders will approve the transaction or that the merger will be consummated within the time constraints specified in the11th Amendment. Should the forbearance period terminate, the Company will be in default, unprotected from the action of remedies available to the Lenders, which cannot be predicted. Such remedies include acceleration of all outstanding principal and interest.

The Bank Forbearance Agreement placed other restrictions on the Company with respect to capital expenditures, sales of assets, and incurrence and prepayments of other indebtedness and amended the Credit Facility in certain respects. It contains covenants regarding the frequency of reporting of financial and cash flow information to the Lenders, as well as cash account control agreements which provide a secured lien over substantially all of the Company s cash accounts.

Under the terms of the Bank Forbearance Agreement, as amended, the Credit Facility is amended such that scheduled borrowing base redeterminations will occur quarterly rather than semi-annually, to be effective January 31, April 30, July 31, and October 31 of each year. Outstanding amounts in excess of the borrowing base must be repaid according to certain defined terms. The deficiency could be paid in three equal installments over a maximum period of 100 days after the incurrence of a borrowing base deficiency, or alternatively, the Company could provide additional sufficient collateral to cover the deficiency. However, as the Company has already pledged in excess of 95% of the value of all proved oil and natural gas reserves as security, such an alternative could apply only to a small borrowing base deficiency. The Lenders have provided the Company with a limited waiver postponing the next borrowing base redetermination to the end of the forbearance period. No assurance can be given that further deficiencies will not be incurred at the next redetermination.

Table of Contents

The Lenders exercised their right to increase the interest rate on outstanding borrowings by 2% (default interest, under the terms of the Credit Facility) as of July 30, 2009. The floating interest rate is based on the prime interest rate, currently 3.25%, plus 2.5%, plus the default increment of 2%, resulting in a total rate of 7.75% at December 31, 2009 and continuing at that rate currently. The additional default interest has been effective as to all outstanding borrowings under the Credit Facility since the July 29, 2009 payment default, and the LIBOR alternative was also eliminated. No interest payments are in arrears.

Rig Note. On May 2, 2008, the Company, through its wholly owned subsidiary TMRD, entered into a financing agreement (rig note) 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%, which increases in an event of default. The loan is collateralized by the drilling rig, as well as general corporate credit. The term of the loan is five years, expiring on May 2, 2013.

Effective as of December 31, 2008, the Company was in default under the rig note. Under the terms of the rig note, a default under the Credit Facility triggers a cross-default under the rig note. 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 at December 31, 2008 and $6.2 million at December 31, 2009, has been classified as current in the accompanying consolidated balance sheets.

On September 3, 2009, the Company also entered into a forbearance agreement with CIT (CIT Forbearance Agreement.) The forbearance period under the CIT Forbearance Agreement has been extended several times, most recently by the Fourth Amendment to Forbearance and Amendment Agreement (4th Amendment). The forbearance period ends the earlier of the consummation of the merger with Alta Mesa, the termination of the Merger Agreement, May 31, 2010, or the date of any default under either the CIT Forbearance Agreement or the Bank Forbearance Agreement. The 4th Amendment also provides CIT s consent to the merger with Alta Mesa. CIT retains the right to terminate the forbearance period if, in its sole determination, Alta Mesa experiences changes to its financial condition that would adversely affect its ability to complete the merger with the Company.

At origination of the CIT Forbearance Agreement, the Company prepaid, without penalty, $1.0 million of principal on the rig note and began to pay default interest of an additional 4% effective August 1, 2009, as allowed to CIT under the terms of the rig note, bringing the total monthly payment to approximately $220,000. The Company also paid, and recorded in general and administrative expense in the third quarter, a forbearance fee of approximately $50,000. There can be no assurance that the forbearance period under the CIT Forbearance Agreement will provide sufficient time to resolve the cross-default under the rig note.

Current Debt Maturities

Scheduled debt maturities for the next five years and thereafter, as of December 31, 2009, including notes payable, are as follows: $93.7 million in 2010 and none thereafter. Absent the assumed acceleration of principal under the Credit Facility and the rig note, scheduled maturities would be: $29.5 million in 2010, $2.2 million in 2011, $62.0 million in 2012, and none thereafter.

6. CONTRACTUAL OBLIGATIONS

In April 2006, the Company negotiated an amendment to its office building lease agreement that extended the Company s office lease until September 30, 2011. As of December 31, 2009, the remaining base rental payments will be $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 $1.8 million, $2.0 million, and $2.1 million in 2009, 2008, and 2007, respectively. Future minimum lease payments under all non-cancelable operating leases having initial terms of one year or more are $2.1 million for 2010, $1.6 million for 2011, and none thereafter. In addition, over the next two years, the Company has contractual obligations for the use of two drilling rigs. These obligations are $12.4 million in 2010 and $0.9 million in 2011. See Note 7 for further information.

Additional contractual obligations include: $1 million in 2010 to Shell Oil Company under the settlement contract described in Note 7 below, if the contract is not terminated; and $1.5 million in 2010 and $0.2 million in 2011 to be paid under various settlement contracts. The Shell Oil Company obligation continues through 2014, with a payment of $1 million due each calendar year, for a total of $5 million.

In addition to the obligations described above, the Company has a contingent obligation related to the merger with Alta Mesa. The Merger Agreement with Alta Mesa includes a reimbursement clause under which the Company will pay Alta Mesa s reasonable costs of the merger, not to exceed $1 million, in case of termination of the agreement under various circumstances, including expiration of the term on May 31, 2010 without consummation of the merger, and also including termination of the Merger Agreement due to non-approval in the shareholder vote. In addition to reimbursement of Alta Mesa s costs, the Company would pay Alta Mesa a $3 million termination fee if, among other reasons, the Company terminates the Alta Mesa agreement and accepts another offer for the Company, so long as the definitive agreement related to the other offer is entered into within nine months after termination of the Merger Agreement with Alta Mesa. The termination fee would be payable no later than two business days after consummation of the transaction which triggered the fee.

7. COMMITMENTS AND CONTINGENCIES

Default under Credit Agreement

As described in Notes 1 and 5, the Company has been in default under the terms of the Credit Facility and the rig note since December 31, 2008. Although forbearance has been provided by these Lenders under short-term agreements, there can be no assurance that the Company will be able to comply with the terms of the agreements. Among the default remedies available to the 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, 2009 and 2008. The Company can give no assurance that the transactions contemplated by the Merger Agreement will be completed (see Note 1) and failure to complete the merger will significantly impact the credit defaults as well as the Company s ability to continue as a going concern; therefore, the Company has not provided for this matter as of December 31, 2009, in its financial statements at December 31, 2009, other than to reclassify all outstanding debt as current at that date and at December 31, 2008.

Proposed Merger Termination Fee

As described in Note 1, the Company s board of directors has approved an offer of merger with Alta Mesa, pending a shareholder vote. If the Merger Agreement is terminated by Meridian under various scenarios, including lack of shareholder approval, the Company will be required to reimburse Alta Mesa for their expenses of the merger, not to exceed $1 million. Acceptance of an alternative offer for the Company and consummation of that transaction under certain circumstances could obligate the Company to pay Alta Mesa a termination fee of $3 million (see Note 6 above).

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 ended with Mr. Hawkins, Jr., and his companies, 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 filed a motion with Judge Bates asking that the ruling be made a final judgment which would give Meridian the right to appeal immediately; however, the Judge declined to grant the motion, allowing the case to proceed to trial. 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, 2009.

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 two 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 and making claims of amounts which were substantial in nature and if adversely determined, would have a material adverse effect on the Company. Shell initiated formal arbitration proceedings on May 11, 2009, seeking relief only for the claimed costs and expenses arising from one of the two acquisition agreements between Shell and Meridian. Meridian denies that it owes any indemnity under either of the two acquisition agreements; however, the Company and Shell entered into a settlement agreement on January 11, 2010. Under the terms of the settlement, the Company will pay Shell $5 million in five equal annual payments beginning in 2010 upon the closing of a sale of the assets or equity interest in the Company to a third party (such as the merger with Alta Mesa described in Note 1), or at an earlier date should Meridian be able. Meridian will also transfer title to certain land the Company owns in Louisiana and an overriding royalty interest of minor value. In return, Shell will release Meridian from any indemnity claim arising from any current or historical claim against Shell, and will release Meridian s indemnity obligation with respect to any future claim on all but a small subset of the properties acquired pursuant to the acquisition agreements related to the fields. The settlement agreement will terminate on May 1, 2010 if the first payment and the land and overriding royalty interest transfer have not been made, or unless extended at the discretion of Shell. The Company recorded $4.2 million in expense in the fourth quarter of 2009 to recognize the estimated value of the proposed settlement, including the historical cost of the land and discounting the cash payments to present value.

Other than the with regard to the Shell matter, the Company is unable to express an opinion with respect to the likelihood of an unfavorable outcome of the various environmental claims or to estimate the amount or range of potential loss should the outcome be unfavorable. Therefore, the Company has not provided any amount for these claims in its financial statements at December 31, 2009.

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.

Property tax litigation. In August, 2009, Gene P. Bonvillain, the tax assessor for Terrebonne Parish, Louisiana, filed a lawsuit against the Company, alleging under-reporting and underpayment of parish property taxes for the years 1998-2008. The claims, which are very similar to thirty other cases filed by Bonvillain against other oil and natural gas companies, allege that certain facilities or other property of the Company were improperly omitted from annual self-reporting tax forms submitted to the parish for the years 1998-2008, and that the properties Meridian did report on such forms were improperly undervalued and mischaracterized. The claims include recovery of delinquent taxes in the amount of $3.5 million, which the claimant advises may be revised upward, and general fraud charges against the Company. All thirty-one similar cases have been consolidated in U. S. District Court for the Eastern District of Louisiana.

Meridian denies the claims and expects to file a motion to dismiss the case, which it considers to be without merit. Meridian asserts that Mr. Bonvillain has no legal basis for filing litigation to collect what are, in essence, additional taxes based on reassessed property values. Furthermore, Meridian asserts that the fraud element of the case is insufficiently supported. Meridian intends to vigorously defend this action. 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, 2009.

Shareholder litigation. On January 8, 2010 Mr. Eliezer Leider, a purported Company shareholder, filed a derivative lawsuit filed on behalf of the Company, *Leider, derivatively on behalf of The Meridian Resource Corporation v. Ching, et al.* in Harris County District Court. Defendants were the Company s directors, Alta Mesa Holdings, LP, and Alta Mesa Acquisition Sub, LLC. Leider alleged that the Company s directors breached their fiduciary duties in approving the merger transaction with Alta Mesa and he requested, but was denied, a temporary restraining order against the Company. This lawsuit was consolidated with another, similar one from Mr. Jeremy Rausch, which was a class action lawsuit. Counsel for Leider was appointed lead counsel. On March 23, 2010, the parties agreed in principle to settle the now-consolidated *Leider* action. The settlement proposed is conditioned on, among other things, approval of the merger by Meridian s shareholders. Under the terms of the proposed settlement, all claims relating to the Merger Agreement and the merger will be dismissed on behalf of Meridian s stockholders. As part of the settlement, the defendants have agreed not to oppose plaintiff s counsel s request to the court to be paid up to $164,000 for their fees and expenses and up to $1,000 as an incentive award for plaintiff Leider. Any payment of fees, expenses, and incentives is subject to final approval of the settlement and such fees, expenses, and incentives by the court. The proposed settlement will not affect the amount of merger consideration to be paid to Meridian s shareholders in the merger or change any other terms of the merger or Merger Agreement. Expenses of the proposed settlement are expected to be recorded in the first quarter of 2010.

Other contingencies

Table of Contents

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, 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. This limitation is known as the ceiling test. Under new rules issued by the SEC, the estimated future net cash flows as of December 31, 2009, were determined using average prices for the most recent twelve months. The average is calculated using the first day of the month price for each of the twelve months that make up the reporting period. As of December 31, 2008 and 2007, previous rules required that estimated future net cash flows from proved reserves be based on period end prices. The Company recorded impairment charges against oil and natural gas properties based on the results of the ceiling test in the fourth quarter of 2008 and again in the first and fourth quarters of 2009.

At December 31, 2009, the Company had no cushion (i.e., the excess of the ceiling over capitalized costs). Thus, any future decrease in the average price to be used for the ceiling test, net of the effect of any hedging positions the Company may have, may necessitate 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, as well as by sales and acquisitions of properties. A 10% decrease in prices would have increased our fourth quarter 2009 non-cash impairment expense by approximately $28 million; a 10% increase in prices would have eliminated the need for a write-off.

Due to the its default under lending agreements, should the proposed merger with Alta Mesa (see Note 1) not be completed, the Company would be forced to consider sales of assets to generate cash for repayment of debt. Sales of significant assets would impact future ceiling tests, as their estimated future after-tax net revenues would be removed from the calculation. Proceeds from sales of properties are generally credited to the full cost pool, reducing the carrying value of oil and gas properties subject to the ceiling test. The Company cannot predict whether significant property sales will cause additional ceiling test impairments, but it is possible that they will.

Drilling rigs. As described in Note 2, Rig Operations , 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. The operator, Orion, has sought other parties to use the rigs and agreed to credit the Company s obligation, based on revenues from third parties who utilize the rig(s) when the Company is unable to. Management cannot predict whether utilization of the rigs by third parties will be consistent, nor to what extent it may offset obligations under the dayrate contracts. The Company has not provided any amount for any future losses on these drilling contracts in its financial statements at December 31, 2009. The two drilling contracts will terminate in February 2011 (as to the rig not owned by the Company) and March 2010 (as to the rig owned by the Company and operated by Orion).

The Company entered into a forbearance agreement with Orion which may grant title to the company-owned rig to Orion, the operator under both the dayrate contracts, in exchange for release of all accrued and future liabilities under the rig contracts. This would occur at termination and final payment of the related rig note held by CIT, which is scheduled for 2013, if the Company continues to perform its obligations under the rig note and the rig is free of any significant security interest at title transfer. Both the rig value and the net payable to Orion would be written off at the time of such title transfer, if it were to occur. Alternatively, the terms of the forbearance agreement allow the Company an option to settle all claims with Orion in cash at the end of the term of the rig note, and retain title to the rig. There can be no assurance that the forbearance period under the CIT Forbearance Agreement will provide sufficient time to cure the default under the rig note and ensure performance under the Orion forbearance agreement. All accrued unpaid liabilities for rig expense through December 31, 2009 are classified in the accompanying consolidated balance sheet as current.

Table of Contents

At December 31, 2009, the rig is included in equipment at a net book value of $4.6 million, and accounts payable includes a total of $4.3 million in accrued unpaid invoices from Orion for underutilization of both rigs, which is net of a reduction of $1.1 million estimated as the Company s share of profits on the rig it owns. The Company performs impairment testing of the rig each quarter; see Note 4.

8. TAXES ON INCOME

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

	Year Ended December 31,		
	2009	2008	2007
Current:			
Federal	$ (96)	$ (304)	$ 560
State	(24)	35	90
Deferred:			
Federal		(7,984)	4,470
State		(209)	557
Income tax expense (benefit)	$ (120)	$ (8,462)	$ 5,677

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

	Year Ended December 31,		
	2009	2008	2007
Income tax provision (benefit) computed at statutory rate	$ (25,465)	$ (76,422)	$ 4,485
Nondeductible costs	2,005	1,956	577
State income tax, net of federal tax benefit	(2,864)	(1,475)	615
Tax on other comprehensive income	(2,846)	2,846	
Change in valuation allowance	29,050	64,633	
Income tax expense (benefit)	$ (120)	$ (8,462)	$ 5,677

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,	
	2009	2008
Deferred tax assets:		
Net operating tax loss carryforward	$ 57,674	$ 32,745
Statutory depletion carryforward	950	950
Tax credits	1,805	1,901
Deferred compensation		5,474
Tax basis in excess of book basis in property and equipment	31,717	25,655
Valuation allowance	(93,683)	(64,633)
Other	1,537	754
Total deferred tax assets		2,846

Deferred tax liabilities:		
Unrealized hedge gain		2,846
Total deferred tax liabilities		2,846
Net deferred tax liability	$	$

Table of Contents

As of December 31, 2009, the Company had approximately $164.8 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 whether 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, 2009, the Company had net operating loss carryforwards for regular tax and alternative 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	$ 10,549	$ 13,820
2019	47,730	48,630
2020	31	31
2021	36	36
2022	3,719	6,232
2023	36,376	44,516
2025	42	11
2026	52	
2027	77	1,369
2028	6,596	8,062
2029	59,574	61,896
Total	$ 164,782	$ 184,603

As of December 31, 2009, the Company had approximately $1.8 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 and 2009 to the full extent of all net deferred tax assets.

9. FAIR VALUE MEASUREMENT

Effective January 1, 2008, the Company adopted new authoritative guidance from the FASB regarding fair value, contained in Accounting Standards Codification Topic 820 (ASC 820). ASC 820 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 defined levels, which are based on the reliability of the evidence used to determine fair value, with Level 1 being the most reliable and Level 3 the least. Level 1 evidence consists of observable inputs, such as quoted prices in an active market. Level 2 inputs typically correlate the fair value of the asset or liability to a similar, but not identical item which is actively traded. Level 3 inputs include at least some unobservable inputs, such as valuation models developed using the best information available in the circumstances.

Table of Contents

The Company adopted the provisions of ASC 820 as it applies to assets and liabilities measured at fair value on a recurring basis on January 1, 2008. This included oil and natural gas derivatives contracts, and as of January 1, 2009, certain outstanding warrants known as the General Partner Warrants (see Notes 2 and 9).

In accordance with the deferred effective date provided by the FASB, on January 1, 2009, the Company adopted the provisions of ASC 820 for non-financial assets and liabilities which are measured at fair value on a non-recurring basis. This includes new additions to asset retirement obligations, and any long-lived assets, other than oil and natural gas properties, for which an impairment write-down is recorded during the period. There have been no such impairments of long-lived assets since adoption. ASC 820 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.

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.

The fair value of the Company s general partner warrants (see Notes 2 and 10) was calculated using the Black-Scholes option pricing model.

Assets and liabilities measured at fair value on a recurring basis

		Fair Value Measurements at December 31, 2009 Using (thousands of dollars)		
Description	December 31, 2009	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]	$		$	
Liabilities from price risk management activities [1]	$		$	
General partner warrants [2]	$ 412 86		$ 412	

Table of Contents

Description	December 31, 2008	Fair Value Measurements at December 31, 2008 Using (thousands of dollars) 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	
Liabilities from price risk management activities [1]	$ 311		$ 311	
General partner warrants [2]	$		$	

(1) Assets and liabilities from price risk management activities are oil and natural gas derivative contracts, primarily in the form of floor contracts to sell oil and natural gas within specific future time periods. These contracts are more fully described in Note 12. As of December 31, 2009, all of the Company s oil and natural gas derivative contracts had expired.

(2) General partner warrants are more fully

described in Note 10. The warrants were carried at historical cost at December 31, 2008; historical cost was replaced with fair value upon adoption of new accounting guidance on January 1, 2009 (see Note 2).

As noted above, ASC 820 also applies to new additions to asset retirement obligations, which must be estimated at fair value when added. New additions result from estimations for new obligations for new properties, and fair values for them are categorized as Level 3. Such estimations are based on present value techniques which utilize company-specific information. The Company recorded $47,000 in additions to asset retirement obligations measured at fair value during the year ended December 31, 2009.

The Company estimates the fair value of its drilling rig quarterly (see Note 4), based on the present value of estimated cash flows from the rig, using management s best estimates of utilization and dayrates. This is considered a Level 3 fair value.

10. STOCKHOLDERS EQUITY

Proposed Merger

As described in Note 1, the Company has proposed that it be merged with Alta Mesa, and the board of directors has recommended that shareholders vote in favor of the merger, with the vote currently scheduled for April 28, 2010. Under the terms of the Merger Agreement, as amended, shareholders will receive $0.33 per share of common stock, to be paid in cash, and shares of the Company would cease to be publicly traded. The Company would be merged into Alta Mesa Acquisition Sub, LLC with the Merger Sub as the surviving entity.

Table of Contents

Under the terms of the Merger Agreement, all the Company s outstanding stock options will become vested and exercisable. As all such options bear exercise prices in excess of the price of $0.33 per share to be received in the merger, the Company expects no additional consideration for the options. Certain outstanding warrants (see below, Warrants) are expected to be settled for a total of approximately $431,000 with two members of the Company s Board of Directors, who are also former officers.

Common Stock

In March 2007, the Company s Board of Directors authorized a share repurchase program; an amendment to the credit agreement at that time increased the available limit for the Company s repurchase of its common stock from $1.0 million to $5.0 million annually, so long as the Company was in compliance with certain provisions of the Credit Facility. From March 2007, the inception of the share repurchase program, through December 31, 2009, 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. The Bank Forbearance Agreement prohibits any further repurchase of Company stock. The Company did not repurchase any shares during 2009 and does not expect to make share repurchases in the foreseeable future.

In 2008, the Company issued shares to certain former executives upon the discontinuation of its deferred compensation plan (see Note 12). Shares sufficient to cover the value of these former executives withholding taxes were withheld from issuance, and the Company made a cash payment for the withholding tax. The total number of shares withheld was 1,001,511, at a value of approximately $3,035,000. In 2009, the Company again withheld shares from a distribution in order to cover the recipients personal withholding tax, which was paid in cash by the Company. The total shares withheld in the 2009 transaction were 610,938 shares at a total cost of $195,000. These transactions are considered an indirect repurchase and have been presented in the Consolidated Statements of Cash Flows as a financing item.

Warrants

As of December 31, 2009, the Company had outstanding warrants (the General Partner Warrants) that entitle Joseph A. Reeves, Jr. and Michael J. Mayell to purchase an aggregate of 1,872,998 shares of common stock at an exercise price of $0.10 per share through December 31, 2015. 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.

The number of shares of common stock purchasable upon the exercise of the warrants and its corresponding exercise price are subject to customary anti-dilution adjustments. In addition to such customary adjustments, the number of shares of common stock and exercise price per share of the General Partner Warrants are subject to adjustment for any issuance of common stock by the Company such that each warrant will permit the holder to purchase at the same aggregate exercise price, a number of shares of common stock equal to the percentage of outstanding shares of the common stock that the holder could purchase before the issuance. Currently each of these 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 the General Partner Warrants in cash.

The Company adopted new authoritative guidance from the FASB with regard to these warrants on January 1, 2009. The provisions of the new guidance, which relate to equity securities indexed to the price of a company s own stock, were considered in regard to the General Partner Warrants and it was determined that they were not indexed to the price of the Company s own stock and should therefore be subject to fair value accounting. Accordingly, a charge of $960,000 was recorded on January 1, 2009 to retained earnings to reflect the cumulative effect of recording the 1,884,544 warrants outstanding at that date at fair value, with an offsetting entry to accrued liabilities. Adjustments to fair value have been made on a prospective basis, beginning in 2009. For the year ended December 31, 2009, the Company recorded a gain on the valuation of the warrants of $548,000, which is included in general and administrative expense.

At December 31, 2009, 1,872,998 General Partner Warrants were outstanding and included in accrued liabilities at a total fair value of $412,000. Fair value is based on the Black-Scholes model for option pricing.

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 $153,000, $193,000, and $294,000 was recorded in the years ended December 31, 2009, 2008, and 2007, 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 zero, $144,000, and $1,144,000, for each of the years ended December 31, 2009, 2008, and 2007, respectively. No portion of this expense has been capitalized. At December 31, 2009, 2008, and 2007, 4,140,000, 3,970,000, and 3,850,000 shares, respectively, were available for grant under the plans. Summaries of share-based awards transactions follow:

	Number of Share Options		**Weighted Average Exercise Price**
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	115,000		2.34
Exercised			
Canceled or Expired	(3,053,188)		3.37
Outstanding at December 31, 2008	461,500	$	4.41
Granted	250,000	$	0.58
Exercised			
Canceled or Expired	(307,500)	$	5.01
Outstanding at December 31, 2009	404,000	$	1.59

Share options exercisable:			
December 31, 2007	3,252,001	$	3.57
December 31, 2008	265,875	$	5.74
December 31, 2009	226,500	$	1.90

Table of Contents

	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
Granted		
Vested	(40,873)	$ 2.32
Forfeited		
Outstanding non-vested at December 31, 2009		

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, 2009, 2008 and 2007, respectively: risk-free interest rates of 1.5%, 3.0% and 4.54%; dividend yield of 0%; volatility factors of the expected market price of the Company s common stock of 0.58, 0.59, and 0.59; and weighted-average expected lives of three years, four years, and five years. These assumptions resulted in weighted average grant date fair values of $0.25, $1.14 and $1.36 for options granted in 2009, 2008, and 2007, respectively.

The aggregate intrinsic value of share options exercised was zero in each of the years ended December 31, 2009, 2008, and 2007, as no options were exercised. The aggregate intrinsic value of non-vested shares which vested was $14,000, zero, and zero, for each of the years 2009, 2008, and 2007, respectively. No shares vested during 2008 and 2007.

Range of Exercisable Prices		Options Outstanding: Outstanding at December 31, 2009	Options Outstanding: Weighted Average Exercise Price	Options Exercisable: Exercisable at December 31, 2009	Options Exercisable: Weighted Average Exercise Price
$0.58	$1.93	267,500	0.66	129,375	.62
$2.31	$3.99	114,000	3.06	74,625	3.16
$4.42	$5.32	22,500	5.11	22,500	5.11
		404,000	1.59	226,500	1.90

The weighted average remaining contractual life of options outstanding at December 31, 2009, was approximately four years.

The aggregate intrinsic value for all options outstanding and for all exercisable options at December 31, 2009 was zero. 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 2009 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, 2009. The amount of aggregate intrinsic value will change based on the fair market value of the Company s common stock.

As of December 31, 2009, there was approximately $30,000 of total unrecognized compensation expense related to stock-based compensation plans. This compensation expense is expected to be recognized 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 Chief Operating Officer, 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 and $400,000 for 2007. 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 and $1,598,000 for 2008 and 2007, respectively. The costs are reflected in general and administrative expense and in oil and natural gas properties for the years ended December 31, 2008 and 2007, respectively as follows: $484,000 and $799,000 in general and administrative expense, and $484,000 and $799,000 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 to the trust was approximately $3.1 million at $1.81 per share. The shares were distributed upon dissolution of the trust on June 26, 2009. The distribution was again issued net of a reduction of shares withheld in lieu of personal withholding tax; the number of shares withheld totaled 610,938. The intrinsic value of the 1,101,176 shares distributed and the 610,938 shares withheld was $352,000 and $195,000, respectively, at $0.32. See Note 12 for further information.

Table of Contents

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

	Number of Share Rights*	Weighted Average Grant Date Fair Value
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 2007 and early 2008) have been treated as common stock equivalents in computing earnings per share.

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 $382,000, $531,000, and $545,000, in 2009, 2008, and 2007, 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, together with the Trust 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 $2.3 million, $5.0 million, and $4.7 million, in 2009, 2008, and 2007, respectively. A portion of these amounts was 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

Table of Contents

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 will be subject to the general credit of the Company. For certain employees covered under the Management Well Bonus Plan 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, 2009, 2008, and 2007, compensation expense in the amounts of zero, $137,350, and $78,054 were recorded for each Messrs. Reeves and Mayell. Grants made in 2009 were negligible. 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 as to new properties, but continues to apply to all properties on which the Company had expended funds prior to discontinuation. See Note 12 for further information.

12. CONTRACT SETTLEMENTS, RABBI TRUST, EMPLOYEE RETENTION, AND INDEMNIFICATION SETTLEMENT

In April 2008 the Company made significant changes in the structure of the compensation of two executives, Mr. Joseph A. Reeves and Mr. Michael J. Mayell, former Chief Executive Officer and former Chief Operating Officer. 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. As a result of the agreements, the Company recorded $9.9 million in contract settlement expense in the second quarter of 2008, and placed that amount of cash in a Rabbi Trust for the former officers. In June 2009, pursuant to the contractual terms, the cash was distributed from the trust to the former officers. Also 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 was 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.

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 from issuance in lieu of the former executives personal withholding tax. An additional 1,712,114 new shares (856,057 shares to each of the two former officers) were

Table of Contents

placed in the Rabbi Trust in the third quarter of 2008, and distributed to the former officers in June 2009. The shares were again issued net of shares withheld for personal withholding tax (a total of 610,938 shares were withheld from distribution and retired). The total net shares distributed to the two officers was 1,101,176 (550,588 each). Substantially all of the compensation expense related to these shares had been recognized historically, when the rights to such future shares were granted.

Prior to distribution, the cash in the Rabbi Trust was included on the Consolidated Balance Sheets under Restricted Cash, and the shares in the trust were accounted for as treasury shares, assigned a value based on the closing market price on the date they were issued, October 2, 2008. Until distribution, the assets of the trust belonged to the Company, but were effectively restricted due to the obligation to the former officers.

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 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 had been very strong for some time when the plan was initiated. Management s intention for the incentive program was to help equalize its employees compensation with current market conditions and motivate them to continue their careers with Meridian. The terms of the plan included a second, final bonus to those employees who continued their employment with the Company through March 31, 2009. The second payment, issued April 3, 2009, totaled approximately $2.9 million; the expense was accrued ratably over the time period July 2008 through March 2009. The Company recognized $1.7 million in general and administrative expense, net of capitalization of a portion to the full cost pool, through December 31, 2008, and approximately $0.5 million in general and administrative expense for the retention bonus plan in 2009, net of capitalization.

As described in Note 7, in the fourth quarter of 2009 the Company recorded $4.2 million in expense for a settlement with Shell regarding indemnification of environmental claims.

13. RISK MANAGEMENT ACTIVITIES

Management of Financial Risk

The Company s operating environment includes two primary financial risks which could be addressed through derivatives and similar financial instruments: the risk of movement in oil and natural gas commodity prices, which impacts revenue, and the risk of interest rate movements, which impacts interest expense from floating rate debt. The Company currently does not utilize derivative contracts or any other form of hedging against interest rate risk. The Company utilizes derivative contracts to address the risk of adverse oil and natural gas commodity price fluctuations. While the use of derivative contracts limits the downside risk of adverse price movements, it may also limit future gains from favorable movements. No derivative contracts have been entered into for trading purposes, and the Company generally holds each remaining instrument to maturity. The Company s commodity derivative contracts are considered cash flow hedges under generally accepted accounting principles.

Oil and Natural Gas Hedging Contracts

Table of Contents

The Company has historically utilized derivative contracts to hedge the sale of a portion of its future production. The Company s objective is to reduce the impact of commodity price fluctuations on both income and cash flow, as well as to protect future revenues from adverse price movements. Management considers some exposure to market pricing to be desirable, due to the potential for favorable price movements, but prefers to achieve a measure of stability and predictability over revenues and cash flows by hedging some portion of production. All the Company s hedging agreements expired in December 2009. All of the Company s hedging agreements are executed by affiliates of the Lenders under the Credit Facility and are collateralized by the security interest the Lenders have in the oil and natural gas assets of the Company. Due to the default under the Credit Facility, the Lenders have not allowed the Company to enter into any additional hedging agreements. As a result, the Company s oil and natural gas sales for periods beyond December 2009 will more closely resemble prevailing market prices.

Accounting and financial statement presentation for derivatives

The Company accounts for its derivative contracts under the provisions of ASC 815, Derivatives and Hedging. Under ASC 815, the Company s commodity derivatives are designated as cash-flow hedges and are stated at fair value on the Consolidated Balance Sheets. See Note 9, Fair Value Measurements for further information on how fair values of derivative instruments are determined. Changes in the fair value of the contracts, which occur due to commodity price movements, are offset in Accumulated Other Comprehensive Income. When the derivative contract or a portion of it matures, the gain or loss is settled in cash and reclassified from Accumulated Other Comprehensive Income to Revenues from Oil and Natural Gas. Net settlements under hedging agreements increased (decreased) oil and natural gas revenues by $11.7 million, ($4.7 million) and $3.3 million for the years ended December 31, 2009, 2008 and 2007, respectively. A gain or loss may be recorded to earnings prior to contract maturity if a portion of the cash flow hedge becomes ineffective under the guidelines provided under generally accepted accounting principles, or if the forecasted transaction is no longer expected to occur. Although the Company periodically records gains or losses from hedge ineffectiveness, there have been no losses recorded due to changes in expectations regarding occurrence of the hedged transactions. The following two tables provide information regarding assets, liabilities, gains, and losses related to derivative contracts, and where these amounts are reflected within the Company s financial statements (in thousands):

Description and location within Consolidated Balance Sheet	Fair Values of Derivative Contracts at December 31, 2009	December 31, 2008
Derivative contracts designated as hedging instruments		
Commodities Contracts		
Current assets from price risk management activities		$ 8,447
Non-current assets from price risk management activities		
Current liabilities from price risk management activities		$ 311
Non-current liabilities from price risk management activities		
Derivative contracts not designated as hedging instruments	NONE	NONE

95

Table of Contents

Effect of Derivative Contracts on the
Consolidated Balance Sheets and the Consolidated Statements of Operations

Description	Location of Gain (Loss) within Financial Statements	For the year ended December 31, 2009	December 31, 2008
Derivative contracts designated as cash flow hedging instruments:			
Gain (loss) on derivative contracts recognized in Other Comprehensive Income (OCI)			
Commodities Contracts	Accumulated Other Comprehensive Income	3,616	3,806
Gain (loss) on derivative contracts reclassified from OCI to earnings			
Commodities Contracts	Oil and Natural Gas Revenues	11,745	(4,663)
Gain (loss) due to hedging ineffectiveness reported in earnings			
Commodities Contracts	Revenues from Price Risk Management Activities	(6)	(18)
Fair value of derivative contracts designated as cash flow hedging instruments, excluded from effectiveness assessments		NONE	NONE
Derivative contracts not designated as hedging instruments		NONE	NONE

Table of Contents

As of December 31, 2009 and 2008, the Company had unrealized gains of zero and $8.1 million (pre-tax and net of tax) deferred in Accumulated Other Comprehensive Income, respectively. All of the Company s derivative agreements expired December 31, 2009.

14. MAJOR CUSTOMERS

Major customers for the years ended December 31, 2009, 2008, and 2007, were as follows (based on sales exceeding 10% of total oil and natural gas revenues):

	Year Ended December 31,		
Customer	2009	2008	2007
Shell Trading (U.S.)	28%	21%	14%
Stone Energy Corporation	17%	8%	8%
Superior Natural Gas	11%	17%	23%
Crosstex Gulfcoast Marketing	10%	14%	16%

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, where applicable, at a 1.5% to 4% working interest basis. The maximum total percentage at which either officer was allowed to participate in any prospect was a 4% working interest. The right to participate in new oil and gas projects was terminated as of December 29, 2008, under the settlement agreements with Messrs. Reeves and Mayell described immediately below and in Note 12. On a collective basis, TODD, JAR and Sydson invested $997,000, $4,321,000, and $9,871,000, for the years ended December 31, 2009, 2008, and 2007, respectively, in oil and natural gas drilling activities. The former officers continued to be offered participation in new wells in 2009, from prospects initiated prior to December 29, 2008. Net amounts due to (from) TODD, JAR, Matrix Petroleum LLC (see below) and Mr. Reeves were approximately $76,000 and ($1,981,000) as of December 31, 2009 and 2008, respectively. Net amounts due to Sydson and Mr. Mayell were approximately $466,000 and $232,000 as of December 31, 2009 and 2008, respectively.

Messrs. Reeves and Mayell each entered into consulting agreements with the Company, commencing December 30, 2008. Each provided professional services to the Company for a monthly fee; the agreements terminated on April 30, 2009, with a total of $217,000 paid to or on behalf of each of the two former officers during 2009. During 2008, the Company settled certain compensation-related contracts with Messrs. Reeves and Mayell, accruing a total of $9,894,000 for obligations under the settlements, included in Due to affiliates in the accompanying Consolidated Balance Sheet for December 31, 2008. See Note 12 for further details. As a result of this settlement, during the second quarter of 2009, the Company paid $4,954,000 and $4,940,000 to Messrs. Reeves and Mayell, respectively. Funds for the payments were provided from those previously set aside in the related Rabbi Trust. In addition to the cash payment, each of the former officers received 550,588 shares of Company stock distributed from the Rabbi Trust. Under the terms of other employment contracts entered into in 2008, Messrs. Reeves and Mayell also continued to receive such employee benefits as medical insurance throughout 2009, as well as other fringe benefits, primarily the maintenance of certain club memberships on their behalf. The Company is obligated to continue these benefits to each of these two former officers through October 2010.

Also under the terms of the 2008 settlement with Messrs. Reeves and Mayell, in 2009 the Company transferred to them the furniture, equipment, and artwork from their Meridian executive offices.

During 2009, Matrix Petroleum LLC (Matrix), an entity controlled by Mr. Reeves, entered into a lease of office space from Meridian. The Company has invoiced Matrix a total of $77,000 for rent and minor charges for use of Meridian office support staff.

As described in Note 11, Messrs. Reeves and Mayell are entitled to certain grants of net profits interests in properties initiated for development during their term of employment. As properties develop from geological studies to executed mineral leases, Messrs. Reeves and Mayell receive interests in the mineral leases. Such grants were valued by third party appraisal at $137,350 and $78,054 for the years 2008 and 2007, respectively. Grants made in 2009 were negligible.

In December 2009, the Company reached a settlement agreement with Mr. Reeves, TODD, and JAR (collectively, the Reeves Parties) regarding amounts the Reeves Parties claimed were owed to them by the Company under various agreements, all of which involve the Company s and the Reeves Parties ownership interests in various oil and natural gas properties. In settlement of these claims: 1) the Company agreed to credit by $600,000 the balance owed by the Reeves Parties to the Company as joint interest partners; 2) the Reeves Parties paid the Company $400,000 against their joint interest accounts in December 2009 and agreed to bring their account balances current by May 2010; 3) the Company indemnified the Reeves Parties against claims arising prior to the settlement date of December 22, 2009 in regard to the properties in which the Reeves Parties share an interest with the Company; and 4) the Reeves Parties ownership in each property was clarified and listed, including those potential properties included in areas of study performed during Mr. Reeves tenure as an officer. Together with credits for the Reeves Parties share of fourth quarter revenues on the properties, these transactions brought the balance between the Company and Reeves Parties to the amount cited above, $76,000 owed by the Company to Reeves.

The Company also entered a settlement contract with Mr. Mayell and Sydson (together, Mayell Parties) on December 17, 2009, clarifying and listing the Mayell Parties ownership in each oil and natural gas property, including those potential properties included in areas of study performed during Mr. Mayell s tenure as an officer. The Company provided the Mayell Parties with indemnifications as to claims arising before the date of settlement, with regard to the properties in which the Mayell Parties share an interest with the Company.

Mr. Joe Kares, a former 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, 2009, 2008, and 2007 and received fees of approximately $150,000, $216,000, and $231,000, 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 $101,000 during 2009, $335,000 during 2008, and $275,000 during 2007. Mr. Kares resigned from the Board of Directors effective October 13, 2009.

Table of Contents

Mr. Gary A. Messersmith, a former 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, 2009, 2008, and 2007, and received fees of approximately $137,000, $118,000, and $73,000, respectively. In addition, during 2007, 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 $159,000 during 2009, $527,000 during 2008, and $441,000 during 2007. Mr. Messersmith resigned from the Board of Directors effective October 13, 2009.

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 former Director of Meridian, is a petroleum industry consultant that provided the Company with services for the years ended December 31, 2009, 2008, and 2007, and received consulting fees of approximately $44,000, $210,000, and $223,000, respectively. Mr. Larberg resigned from the Board of Directors effective October 13, 2009.

Mr. J. Drew Reeves, the son of Mr. Joseph A. Reeves, Jr., is a staff member in the Land Department. Mr. Drew Reeves was paid $218,000, $227,000, and $168,000, for the years 2009, 2008, and 2007, 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 $198,000, $193,000, and $164,000, for the years 2009, 2008, and 2007, 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 $63,000 in 2009, $197,000 in 2008, and $371,000 in 2007. 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 $174,000, $169,000, and $129,000 for the years 2009, 2008, and 2007, 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 for the year 2007.

Earnings during 2008 and 2009 noted above 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:

	Year Ended December 31,		
	2009	**2008**	**2007**
	(in thousands, except per share)		
Numerator:			
Net earnings (loss) applicable to common stockholders	$ (72,636)	$ (209,886)	$ 7,137
Denominator:			
Denominator for basic earnings (loss) per share weighted-average shares outstanding	92,465	91,382	89,307
Effect of potentially dilutive common shares:			
Warrants and rights (a)	NA	NA	5,637
Employee and director stock options (b)	NA	NA	
Denominator for diluted earnings (loss) per share weighted-average shares outstanding and assumed conversions	92,465	91,382	94,944
Basic earnings (loss) per share	$ (0.79)	$ (2.30)	$ 0.08

Diluted earnings (loss) per share	$ (0.79)	$ (2.30)	$ 0.08

Table of Contents

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 the Company s deferred compensation plan, which was discontinued in 2008, 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 1.9 million, 3.3 million, and 1.4 million, in 2009, 2008, and 2007, respectively.

(b) The number of stock options excluded totaled approximately 0.4 million, 0.5 million, and 3.6 million, in 2009, 2008, and 2007, respectively.

17. ACCRUED LIABILITIES AND OTHER LIABILITIES

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

	2009	2008
Capital expenditures	$ 830	$ 8,227
Operating expenses/taxes	4,072	4,452
Hurricane damage repairs		1,555
Compensation	918	2,478
Interest and accrued bank fees	353	261
General partner warrants	412	
Shell settlement	1,003	
Other	2,521	1,858
Total	$ 10,109	$ 18,831

The total Shell settlement obligation is $4,223,000, of which $3,220,000 is classified as Other Liabilities in the long-term section of the accompanying Consolidated Balance Sheets at December 31, 2009. See Note 7 for further information. The balance is to be paid over a five year period.

18. QUARTERLY RESULTS OF OPERATIONS (Unaudited)

Results of operations by quarter for the year ended December 31, 2009 were (thousands of dollars, except per share):

	Quarter Ended			
2009	**March 31**	**June 30**	**Sept. 30**	**Dec. 31**
Revenues	$ 22,109	$ 22,710	$ 21,950	$ 22,476
Results of operations from exploration and production activities(1) (2)	(55,672)	4,550	6,923	(851)
Net (loss)	$ (60,961)	$ (1,462)	$ (768)	$ (9,445)
Net (loss) per share:				
Basic	$ (0.66)	$ (0.02)	$ (0.01)	$ (0.10)
Diluted	$ (0.66)	$ (0.02)	$ (0.01)	$ (0.10)

Table of Contents

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

2008	Quarter Ended 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) (3)	11,586	18,136	10,595	(224,406)
Net earnings (loss)	$ 3,563	$ 839	$ 699	$ (214,987)
Net earnings (loss) per share:				
Basic	$ 0.04	$ 0.01	$ 0.01	$ (2.33)
Diluted	$ 0.04	$ 0.01	$ 0.01	$ (2.33)

(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 impairments of long-lived assets of $59.5 million and $4.0 million in the first and fourth quarters, respectively.

(3) Includes impairment of long-lived assets of $223.5 million in the fourth

quarter.

19. SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES (Unaudited)

In December 2008, the SEC 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 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 affects impairment and depletion calculations. The new rule became effective for reserve reports as of December 31, 2009; the FASB incorporated the new guidance into the Codification as Accounting Standards Update 2010-03, effective also on December 31, 2009, ASC Topic 932, Extractive Activities Oil and Gas.

The Company adopted the new guidance effective December 31, 2009; information about the Company s reserves has been prepared in accordance with the new guidance; management has chosen not to provide information on probable and possible reserves. The Company s reserves were affected primarily by the use of the average price rather than the year-end price required under the prior rules. Under the new rules issued by the SEC, the estimated future net cash flows as of December 31, 2009, were determined using average prices for the most recent twelve months. The average is calculated using the first day of the month price for each of the twelve months that make up the reporting period. As of December 31, 2008 and 2007, previous rules required that estimated future net cash flows from proved reserves be based on period end prices. As a result of adopting the new guidance, we estimate that Meridian s December 31, 2009 proven reserves decreased approximately 1.4 Bcfe and prices used in the calculation decreased approximately 30%. These changes in turn affected the results of the Company s ceiling test for the fourth quarter, which was a write-down of $4.0 million. Had the new rule using average pricing not been implemented, the write-down in the fourth quarter of 2009 would not have been necessary. The change in total reserves had only a negligible effect on depletion expense in the fourth quarter of 2009; total proved reserves are the basis of depletion calculations.

The reserve volumes and associated cash flows were prepared by T. J. Smith & Company, Inc., independent reservoir engineers. For further information on Mr. Smith s qualifications and on the methods and controls used in the process of estimating reserves, please see Part I, Item 1, Business, Oil and Natural Gas Reserves.

The reserve information presented below is provided as supplemental information in accordance with the provisions of ASC Topic 932-235.

Costs Incurred in Oil and Natural Gas Acquisition, Exploration and Development Activities
(thousands of dollars)

	Year Ended December 31,		
	2009	**2008**	**2007**
Costs incurred during the year:(1)(2)			
Property acquisition costs Unproved (3)	$ (2,136)	$ 21,879	$ 9,589
Proved			
Exploration	5,838	51,752	92,320
Development	10,765	38,159	9,026
	$ 14,467	$ 111,790	$ 110,935

(1) Costs incurred during the years ended December 31, 2009, 2008 and 2007 include general and administrative costs related to acquisition, exploration and development of oil and natural gas properties, net of third party reimbursements, of $2,567,000, $17,390,000, and $16,492,000, respectively.

(2) Costs incurred during the years ended December 31, 2009 and 2008 include $180,000 and $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. Profits from the rig reduce the costs incurred.

(3) Property acquisition costs for unproved properties reflect a negative value for 2009, due to the reimbursement of costs upon the partial sale of interests in various unproven leaseholds. The Company retained an interest in the properties.

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

	December 31,	
	2009	**2008**
Capitalized costs	$ 1,890,079	$ 1,877,925
Accumulated depletion	1,732,112	1,632,622

Net capitalized costs	$ 157,967	$ 245,303

At December 31, 2009 and 2008, unevaluated costs of $1,647,000 and $39,927,000, respectively, were excluded from the depletion base. The costs excluded in 2009 are expected to be evaluated within the next three years. These costs consist primarily of acreage acquisition costs at December 31, 2009, and acreage acquisition costs and related geological and geophysical costs at December 31, 2008.

Table of Contents

Costs Not Being Amortized

The following table sets forth a summary of oil and natural gas property costs not being amortized at December 31, 2009, by the year in which such costs were incurred. All the costs not being amortized relate to one property, a group of leaseholds in south Texas under exploration with another operator, and include no exploratory well costs.

(thousands of dollars)

	Total	2009	2008	2007 & Prior
Leasehold acquisition costs	$ 1,440	$ 46	$ 1,394	$
Capitalized general and administrative costs	207		207	
Total	$ 1,647	$ 46	$ 1,601	$

Results of Operations from Oil and Natural Gas Producing Activities

(thousands of dollars)

	Year Ended December 31, 2009	2008	2007
Operating Revenues:			
Oil	$ 49,222	$ 63,636	$ 54,218
Natural Gas	40,023	84,998	96,491
	89,245	148,634	150,709
Less:			
Oil and natural gas operating costs	17,550	24,280	28,338
Severance and ad valorem taxes	6,696	9,727	9,409
Depletion	35,994	71,647	76,660
Accretion expense	2,083	2,064	2,230
Impairment of long-lived assets (1)	63,495	223,543	
Hurricane damage repairs		1,462	
Rig operations, net	4,254		
Indemnification settlement	4,223		
Income tax expense (benefit)	(120)	(8,462)	14,992
	134,175	324,261	131,629
Results of operations from oil and natural gas producing activities	(44,930)	(175,627)	$ 19,080
Depletion expense per Mcfe	$ 2.87	$ 5.13	$ 4.20

(1) For 2008, includes impairment of oil and natural gas properties of $216.8 million and impairment

of drilling rig of $6.7 million; for 2009, all impairments are to oil and natural gas properties.

Estimated Quantities of Proved Reserves

The following table sets forth the net proved reserves of the Company as of December 31, 2009, 2008, and 2007, 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 prepared by T. J. Smith & Company, Inc., independent reservoir engineers, for 2009, 2008, and 2007. Mr. T. J. Smith is the person primarily responsible for overseeing the preparation of our annual reserve estimates. Mr. Smith is a graduate of Mississippi State University with a Bachelor of

Table of Contents

Science degree in Petroleum Engineering. He has over 40 years experience with approximately 35 years focused on reserve evaluation. He is a member of the Society of Petroleum Engineers and is a Registered Professional Engineer in the states of Texas and Louisiana. 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, 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
Production during 2009	(834)	(7,549)
Sale of reserves in-place		
Discoveries and extensions	516	3,666
Revisions of previous quantity estimates and other	(817)	5,350
Balance at December 31, 2009	3,768	52,363
Proved Developed Reserves:		
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
Balance at December 31, 2009	2,571	32,560

Proved Undeveloped Reserves

The total of the Company s proved undeveloped reserves (PUD s) is 27 Bcfe, or approximately 36% of total proved reserves at December 31, 2009. The undeveloped properties are primarily in our East Texas area and in two of our mature fields in Louisiana and are the same or similar properties to those reported in 2008, which totaled 29 Bcfe. Reductions in PUD s from the prior year include a decrease of 5.6 Bcfe at the outside operated East Cameron 331/332 field offshore. We have eliminated these non-operated reserves as there is substantial uncertainty as to their development as the field has undergone numerous operator changes (again in 2009) and we have no firm plans to develop them at this time. Other changes in PUD s include a reduction of 3.7 Bcfe for several oil wells that had been candidates for updip oil development; however, there is no certainty that these updip locations will be oil. We have, for reserve purposes, estimated that the section will be natural gas, and hence, the reserves are uneconomic and have been eliminated.

Increases to PUD s were due primarily to upward revisions of estimates and the addition of several new locations in East Texas totaling 5.8 Bcfe, based on new drilling and production information for that area. Progress toward development of our portfolio of proved undeveloped reserves was necessarily minimal during 2009, as we minimized capital spending due to our Credit Facility defaults.

Table of Contents

Approximately 11.5 Bcfe of our PUD s at December 31, 2009 originated more than five years ago. Certain PUD s in our mature fields in Louisiana have been included for more than five years, because they have been planned as sidetracks and cannot be developed until the current producing well bores have been depleted and abandoned. We have been exploring and developing our East Texas acreage since 2005, and now have a total of 14 producing wells in that area.

Standardized Measure of Discounted Future Net Cash Flows

The information that follows has been developed pursuant to ASC 932-235 and utilizes reserve and production data prepared 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 historical prices and costs as of the date of the estimate unless such prices or costs are contractually determined at such date. Actual future prices and costs may be materially higher or lower. Actual future net revenues also will be affected by factors such as actual production, supply and demand for oil and natural gas, curtailments or increases in consumption by natural gas purchasers, changes in governmental regulations or taxation and the impact of inflation on costs. Future income tax expense has been reduced for the effect of available net operating loss carryforwards.

The following table sets forth the components of the standardized measure of discounted future net cash flows for the years ended December 31, 2009, 2008, and 2007 (thousands of dollars):

	At December 31,		
	2009	**2008**	**2007**
Future cash flows	$ 414,043	$ 490,602	$ 842,986
Future production costs	(138,982)	(168,160)	(185,768)
Future development costs	(85,898)	(82,866)	(80,656)
Future taxes on income			(80,029)
Future net cash flows	189,163	239,576	496,533
Discount to present value at 10 percent per annum	(50,208)	(60,139)	(105,069)
Standardized measure of discounted future net cash flows	$ 138,955	$ 179,437	$ 391,464

The average expected realized price for natural gas in the above computations was $3.97, $5.79, and $6.66 per Mcf at December 31, 2009, 2008, and 2007, respectively. The average expected realized price used for crude oil in the above computations was $59.94, $44.04, and $95.54, per Bbl at December 31, 2009, 2008, and 2007, respectively. No consideration was been given to the Company s hedged transactions.

Changes in Standardized Measure of Discounted Future Net Cash Flows

The following table sets forth the changes in standardized measure of discounted future net cash flows for the years ended December 31, 2009, 2008, and 2007 (thousands of dollars):

	Year Ended December 31,		
	2009	**2008**	**2007**
Balance at Beginning of Period	$ 179,437	$ 391,464	$ 327,899
Sales of oil and natural gas, net of production costs	(65,000)	(114,626)	(112,962)
Changes in sales & transfer prices, net of production costs	(12,019)	(165,125)	125,623
Revisions of previous quantity estimates	1,192	(32,842)	25,751
Purchase of reserves-in-place			
Sale of reserves in-place		177	(2,233)
Current year discoveries, extensions and improved recovery	7,407	44,112	32,939
Changes in estimated future development costs	8,778	(1,417)	(7,917)

Development costs incurred during the period	979	8,298	8,526
Accretion of discount	17,944	39,146	32,790
Net change in income taxes		23,453	(14,451)
Change in production rates (timing) and other	237	(13,203)	(24,501)
Net change	(40,482)	(212,027)	63,565
Balance at End of Period	$ 138,955	$ 179,437	$ 391,464

Table of Contents

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 2009. 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 2009 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, 2009. 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, 2009, 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

Table of Contents

The Meridian Resource Corporation
Houston, Texas

We have audited The Meridian Resource Corporation s internal control over financial reporting as of December 31, 2009, 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.

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, 2009, 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, 2009 and 2008, 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, 2009 and our report dated April 15, 2010 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
April 15, 2010

Item 9B. Other Information.

Table of Contents

None.

PART III

The information required in Items 10, 11, 12, 13 and 14 is incorporated by reference to the Company s Form 10-K/A to be filed with the SEC on or before April 30, 2010.

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, 2009
   - (iii) Consolidated Balance Sheets as of December 31, 2009 and 2008
   - (iv) Consolidated Statements of Cash Flows for each of the three years in the period ended December 31, 2009
   - (v) Consolidated Statements of Changes in Stockholders Equity for each of the three years in the period ended December 31, 2009
   - (vi) Consolidated Statements of Comprehensive Income (Loss) for each of the three years in the period ended December 31, 2009
   - (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:

2.1 Agreement and Plan of Merger, dated December 22, 2009, by and among Alta Mesa Holdings, LP, a Texas limited partnership, Alta Mesa Acquisition Sub, LLC, a Texas limited liability company, and The Meridian Resource Corporation, a Texas corporation (incorporated by reference to Exhibit 2.1 of the Company s Current Report on Form 8-K filed December 29, 2009).

2.2 First Amendment to Agreement and Plan of Merger, dated April 7, 2010, by and among Alta Mesa Holdings, LP, a Texas limited partnership, Alta Mesa Acquisition Sub, LLC, a Texas limited liability company, and The Meridian

Table of Contents

Resource Corporation, a Texas corporation (incorporated by reference to Exhibit 2.1 of the Company s Current Report on Form 8-K filed April 12, 2010).

3.1 Third Amended and Restated Articles of Incorporation of the Company (incorporated by reference to Exhibit 3.1 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 Exhibit 3.2 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).

3.5 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 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).

*4.6 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).

10.1 See exhibits 4.2 through 4.6 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).

Table of Contents

*10.3 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).
*10.4 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).
*10.5 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).
*10.6 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).
*10.7 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).
*10.8 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).
*10.9 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).
*10.10 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).
*10.11 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).
*10.12 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).
*10.13 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).
*10.14 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).
*10.15 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).
*10.16 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).

Table of Contents

*10.17 The Meridian Resource & Exploration LLC Change in Control and Severance Plan (incorporated by reference to Exhibit 10.1 to Amendment No. 1 to the Company s Annual Report on Form 10-K/A for the year ended December 31, 2008).
*10.18 Employment Agreement, dated effective as of December 30, 2008, by and between The Company and Paul D. Ching (incorporated by reference to Exhibit 10.31 of the Company s Report on Form 10-K for the year ended December 31, 2008).
*10.19 Amendment to Employment Agreement, dated June 4, 2009, between The Meridian Resource Corporation and Paul D. Ching. (incorporated by reference to Exhibit 10.1 of the Company s Report on Form 8-K filed June 5, 2009).
*10.20 Amendment No. 2 to Employment Agreement, dated February 22, 2010, between The Meridian Resource Corporation and Paul D. Ching (incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K filed February 26, 2010).
*10.21 Employment Agreement, dated effective as of December 17, 2008, by and between The Company and Lloyd V. DeLano (incorporated by reference to Exhibit 10.32 of the Company s Report on Form 10-K for the year ended December 31, 2008).
*10.22 Employment Agreement, dated effective as of December 17, 2008, by and between The Company and Stephen G. Ives (incorporated by reference to Exhibit 10.33 of the Company s Report on Form 10-K for the year ended December 31, 2008).
*10.23 Employment Agreement, dated effective as of December 17, 2008, by and between The Company and Allen D. Breaux (incorporated by reference to Exhibit 10.34 of the Company s Report on Form 10-K for the year ended December 31, 2008).
*10.24 Employment Agreement, dated effective as of December 17, 2008, by and between The Company and Alan S. Pennington (incorporated by reference to Exhibit 10.35 of the Company s Report on Form 10-K for the year ended December 31, 2008).
10.25 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 to Exhibit 10.1 of the Company s Current Report on Form 8-K dated December 23, 2004).
10.26 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 to Exhibit 10.21 of the Company s Annual Report on Form 10-K for the year ended December 31, 2007).
10.27 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).

Table of Contents

10.28 Forbearance and Amendment Agreement, dated as of September 3, 2009, among The Meridian Resource Corporation, certain of its subsidiaries, Fortis Capital Corp., as administrative agent, and the several banks, financial institutions and other entities from time to time parties to Amended and Restated Credit Agreement, dated as of December 23, 2004, as amended, among The Meridian Resource Corporation, Fortis Capital Corp., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K filed September 10, 2009).
10.29 First Amendment to Forbearance and Amendment Agreement, dated as of September 30, 2009, among The Meridian Resource Corporation, certain of its subsidiaries, Fortis Capital Corp., as administrative agent, and the several banks, financial institutions and other entities from time to time parties to the Amended and Restated Credit Agreement, dated as of December 23, 2004, as amended, among The Meridian Resource Corporation, Fortis Capital Corp., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 of the Company s Quarterly Report on Form 10-Q for the three months ended September 30, 2009).
10.30 Second Amendment to Forbearance and Amendment Agreement, dated as of October 2, 2009, among The Meridian Resource Corporation, certain of its subsidiaries, Fortis Capital Corp., as administrative agent, and the several banks, financial institutions and other entities from time to time parties to the Amended and Restated Credit Agreement, dated as of December 23, 2004, as amended, among The Meridian Resource Corporation, Fortis Capital Corp., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.3 of the Company s Quarterly Report on Form 10-Q for the three months ended September 30, 2009).
10.31 Third Amendment to Forbearance and Amendment Agreement, dated as of October 20, 2009, among The Meridian Resource Corporation, certain of its subsidiaries, Fortis Capital Corp., as administrative agent, and the several banks, financial institutions and other entities from time to time parties to the Amended and Restated Credit Agreement, dated as of December 23, 2004, as amended, among The Meridian Resource Corporation, Fortis Capital Corp., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Registrant s Current Report on Form 8-K filed with the SEC on October 22, 2009).
10.32 Fourth Amendment to Forbearance and Amendment Agreement, dated as of November 13, 2009, among The Meridian Resource Corporation, certain of its subsidiaries, Fortis Capital Corp., as administrative agent, and the several banks, financial institutions and other entities from time to time parties to the Amended and Restated Credit Agreement, dated as of December 23, 2004, as amended, among The Meridian Resource Corporation, Fortis Capital Corp., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K filed November 19, 2009).
10.33 Fifth Amendment to Forbearance and Amendment Agreement, dated as of November 20, 2009, among The Meridian Resource Corporation, certain of its subsidiaries, Fortis Capital Corp., as administrative agent, and the several banks, financial institutions and other entities from time to time parties to the Amended and Restated Credit Agreement, dated as of December 23, 2004, as amended, among The Meridian Resource Corporation, Fortis Capital Corp., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K filed November 25, 2009).
10.34 Sixth Amendment to Forbearance and Amendment Agreement, dated as of November 30, 2009, among The Meridian Resource Corporation, certain of its subsidiaries, Fortis Capital Corp., as administrative agent, and the several banks, financial institutions and other entities from time to time parties to the Amended and Restated Credit Agreement, dated as of December 23, 2004, as amended, among The Meridian Resource Corporation, Fortis Capital Corp., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K filed December 2, 2009).

10.35 Seventh Amendment to Forbearance and Amendment Agreement, dated as of December 2, 2009, among The Meridian Resource Corporation, certain of its subsidiaries, Fortis Capital Corp., as administrative agent, and the several banks, financial institutions and other entities from time to time parties to the Amended and Restated Credit Agreement, dated as of December 23, 2004, as amended, among The Meridian Resource Corporation, Fortis Capital Corp., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K filed December 8, 2009).
10.36 Eighth Amendment to Forbearance and Amendment Agreement, dated as of December 4, 2009, among The Meridian Resource Corporation, certain of its subsidiaries, Fortis Capital Corp., as administrative agent, and the several banks, financial institutions and other entities from time to time parties to the Amended and Restated Credit Agreement, dated as of December 23, 2004, as amended, among The Meridian Resource Corporation, Fortis Capital Corp., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 of the Company s Current Report on Form 8-K filed December 8, 2009).
10.37 Ninth Amendment to Forbearance and Amendment Agreement, dated as of December 14, 2009, among The Meridian Resource Corporation, certain of its subsidiaries, Fortis Capital Corp., as administrative agent, and the several banks, financial institutions and other entities from time to time parties to the Amended and Restated Credit Agreement, dated as of December 23, 2004, as amended, among The Meridian Resource Corporation, Fortis Capital Corp., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K filed December 17, 2009).
10.38 Tenth Amendment to Forbearance and Amendment Agreement, dated as of December 21, 2009, among The Meridian Resource Corporation, certain of its subsidiaries, Fortis Capital Corp., as administrative agent, and the several banks, financial institutions and other entities from time to time parties to the Amended and Restated Credit Agreement, dated as of December 23, 2004, as amended, among The Meridian Resource Corporation, Fortis Capital Corp., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 of the Company s Current Report on Form 8-K filed December 29, 2009).
10.39 Eleventh Amendment to Forbearance and Amendment Agreement, dated as of December 22, 2009, among The Meridian Resource Corporation, certain of its subsidiaries, Fortis Capital Corp., as administrative agent, and the several banks, financial institutions and other entities from time to time parties to the Amended and Restated Credit Agreement, dated as of December 23, 2004, as amended, among The Meridian Resource Corporation, Fortis Capital Corp., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K filed December 29, 2009).
10.40 Forbearance Agreement, dated as of September 3, 2009, by and among Fortis Capital Corp., Fortis Energy Marketing & Trading GP and The Meridian Resource Corporation (incorporated by reference to Exhibit 10.2 of the Company s Current Report on Form 8-K filed September 10, 2009).
10.41 First Amendment to Forbearance Agreement, dated as of December 4, 2009, among The Meridian Resource Corporation, certain of its subsidiaries, Fortis Capital Corp. and Fortis Energy Marketing & Trading GP (incorporated by reference to Exhibit 10.3 of the Company s Current Report on Form 8-K filed December 8, 2009).
10.42 Second Amendment to Forbearance Agreement, dated as of December 14, 2009, among The Meridian Resource Corporation, certain of its subsidiaries, Fortis Capital Corp. and Fortis Energy Marketing & Trading GP (incorporated by reference to Exhibit 10.2 of the Company s Current Report on Form 8-K filed December 17, 2009).

10.43 Third Amendment to Forbearance Agreement, dated as of December 16, 2009, among The Meridian Resource Corporation, certain of its subsidiaries, Fortis Capital Corp. and Fortis Energy Marketing & Trading GP (incorporated by reference to Exhibit 10.3 of the Company s Current Report on Form 8-K filed December 29, 2009).
10.44 Forbearance and Amendment Agreement, dated as of September 3, 2009, by and among TMR Drilling Corporation, The Meridian Resource Corporation, The Meridian Resource & Exploration LLC and The CIT Group/Equipment Financing, Inc, as administrative agent and lender (incorporated by reference to Exhibit 10.3 of the Company s Current Report on Form 8-K filed September 10, 2009).
10.45 First Amendment to Forbearance and Amendment Agreement, dated as of December 4, 2009, among The Meridian Resource Corporation, certain of its subsidiaries and The CIT Group/Equipment Financing, Inc. (incorporated by reference to Exhibit 10.4 of the Company s Current Report on Form 8-K filed December 8, 2009).
10.46 Second Amendment to Forbearance and Amendment Agreement, dated as of December 14, 2009, among The Meridian Resource Corporation, certain of its subsidiaries and The CIT Group/Equipment Financing, Inc. (incorporated by reference to Exhibit 10.3 of the Company s Current Report on Form 8-K filed December 17, 2009).
10.47 Third Amendment to Forbearance and Amendment Agreement, dated as of December 21, 2009, among The Meridian Resource Corporation, certain of its subsidiaries and The CIT Group/Equipment Financing, Inc. (incorporated by reference to Exhibit 10.5 of the Company s Current Report on Form 8-K filed December 29, 2009).
10.48 Fourth Amendment to Forbearance and Amendment Agreement, dated as of December 22, 2009, among The Meridian Resource Corporation, certain of its subsidiaries and The CIT Group/Equipment Financing, Inc. (incorporated by reference to Exhibit 10.4 of the Company s Current Report on Form 8-K filed December 29, 2009).
10.49 Forbearance and Amendment Agreement, dated as of September 3, 2009, by and among The Meridian Resource Corporation, The Meridian Resource & Exploration LLC, TMR Drilling Corporation and Orion Drilling Company LLC (incorporated by reference to Exhibit 10.4 of the Company s Current Report on Form 8-K filed September 10, 2009).
*10.50 Omnibus Agreement Relating to Assigned Interests, dated December 22, 2009, by and among Joseph A. Reeves, Jr., Texas Oil Distribution & Development, Inc., JAR Resource Holdings, LLP, The Meridian Resource Corporation, The Meridian Resource & Exploration LLC, Louisiana Onshore Properties LLC, and Cairn Energy USA, Inc. (incorporated by reference to Exhibit 10.6 of the Company s Current Report on Form 8-K filed December 29, 2009).
*10.51 Settlement and Release Agreement, dated December 22, 2009, by and among Joseph A. Reeves, Jr., Texas Oil Distribution & Development, Inc., JAR Resource Holdings, LLP, and The Meridian Resource Corporation (incorporated by reference to Exhibit 10.7 of the Company s Current Report on Form 8-K filed December 29, 2009).
*10.52 Agreement with Cross-Release, dated December 17, 2009, by and among Michael J. Mayell, Sydson Energy, Inc., The Meridian Resource Corporation, The Meridian Resource & Exploration LLC, Louisiana Onshore Properties LLC, and Cairn Energy USA, Inc. (incorporated by reference to Exhibit 10.8 of the Company s Current Report on Form 8-K filed December 29, 2009).
**10.53 Compromise and Settlement Agreement, dated January 11, 2010, among The Meridian Resource Corporation, Shell Oil Company and SWEPI, LP.
**10.54 Amendment to Compromise and Settlement Agreement, dated March 30, 2010, among The Meridian Resource Corporation, Shell Oil Company and SWEPI, LP.

Table of Contents

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.
**23.3 Report 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 compensatory plan.

** Filed herewith.

Table of Contents

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: April 15, 2010

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	Chief Executive Officer	April 15, 2010
Paul D. Ching	(Principal Executive Officer) President Director and Chairman of the Board	
BY: /s/ LLOYD V. DELANO	Senior Vice President	April 15, 2010
Lloyd V. DeLano	(Chief Accounting Officer)	
BY: /s/ E. L. HENRY	Director	April 15, 2010
E. L. Henry		
BY: /s/ MICHAEL J. MAYELL	Director	April 15, 2010
Michael J. Mayell		
BY: /s/ C. MARK PEARSON	Director	April 15, 2010
C. Mark Pearson		
BY: /s/ JOSEPH A. REEVES, JR.	Director	April 15, 2010
Joseph A. Reeves, Jr.		
BY: /s/ JOHN B. SIMMONS	Director	April 15, 2010
John B. Simmons		

BY: /s/ FENNER R. WELLER, JR.	Director	April 15, 2010
Fenner R. Weller, Jr.		