MERIDIAN RESOURCE CORP
Form 10-Q
May 24, 2010

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

(Mark One)

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

For the quarterly period ended: March 31, 2010

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 or other jurisdiction of incorporation or organization)	(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**

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 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 is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition 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

Number of shares of common stock outstanding at May 24, 2010: 0

Prior to the Company s merger with Alta Mesa Acquisition Sub, LLC on May 13, 2010, the Company had 92,475,527 shares outstanding. Following the merger, shares of the Company ceased to be publicly traded. All of its membership interests are owned by Alta Mesa Holdings, LP.

THE MERIDIAN RESOURCE CORPORATION
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PART I FINANCIAL INFORMATION

ITEM 1. Financial Statements

THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(thousands of dollars, except per share information)
(unaudited)

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
REVENUES:		
Oil and natural gas	$ 20,976	$ 22,109
Price risk management activities		2
Interest and other	71	21
	21,047	22,132
OPERATING COSTS AND EXPENSES:		
Oil and natural gas operating	3,066	4,629
Severance and ad valorem taxes	1,772	1,635
Depletion and depreciation	7,397	11,763
General and administrative	4,517	3,369
Rig operations, net	1,442	
Accretion expense	546	523
Impairment of long-lived assets		59,539
	18,740	81,458
EARNINGS (LOSS) BEFORE OTHER EXPENSE & INCOME TAXES	2,307	(59,326)
OTHER EXPENSE:		
Interest expense	1,966	1,634
EARNINGS (LOSS) BEFORE INCOME TAXES	341	(60,960)
INCOME TAXES:		
Current	1	1
Deferred		
	1	1
NET EARNINGS (LOSS)	$ 340	$ (60,961)
NET EARNINGS (LOSS) PER SHARE:		

Basic	$	$ (0.66)
Diluted	$	$ (0.66)
WEIGHTED AVERAGE NUMBER OF COMMON SHARES:		
Basic	92,476	92,451
Diluted	93,678	92,451

See notes to consolidated financial statements.

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

	March 31, 2010 (unaudited)	December 31, 2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 7,851	$ 5,273
Restricted cash	35	35
Accounts receivable, less allowance for doubtful accounts of $110 [2010 and 2009]	11,028	12,185
Prepaid expenses and other	1,381	2,195
Total current assets	20,295	19,688
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, full cost method (including $1,567 [2010]and $1,647 [2009] not subject to depletion)	1,891,818	1,890,079
Equipment and other	20,467	20,469
	1,912,285	1,910,548
Less accumulated depletion and depreciation	1,754,669	1,747,274
Total property and equipment, net	157,616	163,274
OTHER ASSETS:		
Other	106	168
Total other assets	106	168
TOTAL ASSETS	$ 178,017	$ 183,130

See notes to consolidated financial statements.

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

	March 31, 2010 (unaudited)	December 31, 2009
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 7,241	$ 6,136
Revenues and royalties payable	5,095	4,890
Due to affiliates	243	542
Accrued liabilities	8,877	10,109
Asset retirement obligations	5,626	4,570
Current maturities of long-term debt	88,512	93,666
Total current liabilities	115,594	119,913
LONG-TERM DEBT		
OTHER:		
Asset retirement obligations	18,880	19,253
Other	2,453	3,220
	21,333	22,473
COMMITMENTS AND CONTINGENCIES (Note 8)		
STOCKHOLDERS EQUITY:		
Common stock, $0.01 par value (200,000,000 shares authorized, 92,475,527 [2010 and 2009] issued)	925	925
Additional paid-in capital	535,449	535,443
Accumulated deficit	(495,284)	(495,624)
Total stockholders equity	41,090	40,744
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 178,017	$ 183,130

See notes to consolidated financial statements.

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

	Three Months Ended March 31,	
	2010	**2009**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net earnings (loss)	$ 340	$ (60,961)
Adjustments to reconcile net earnings (loss) to net cash provided by operating activities:		
Depletion and depreciation	7,397	11,763
Impairment of long-lived assets		59,539
Amortization of other assets	61	304
Non-cash compensation	6	53
Non-cash gain on change in fair value of outstanding warrants		(641)
Non-cash price risk management activities		(2)
Accretion expense	546	523
Changes in assets and liabilities:		
Restricted cash		4
Accounts receivable	1,157	3,927
Prepaid expenses and other	814	2,429
Due to/from affiliates	(299)	89
Accounts payable	1,278	(3,448)
Advances from non-operators	1	(3,376)
Revenues and royalties payable	205	(951)
Asset retirement obligations	(140)	
Other assets and liabilities	(1,869)	(497)
Net cash provided by operating activities	9,497	8,755
CASH FLOWS USED IN INVESTING ACTIVITIES:		
Additions to property and equipment	(1,765)	(15,009)
Net cash used in investing activities	(1,765)	(15,009)
CASH FLOWS USED IN FINANCING ACTIVITIES:		
Reductions to long-term debt	(5,154)	(445)
Reductions in notes payable		(1,573)
Net cash used in financing activities	(5,154)	(2,018)
NET CHANGE IN CASH AND CASH EQUIVALENTS	2,578	(8,272)
Cash and cash equivalents at beginning of period	5,273	13,354
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 7,851	$ 5,082

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION				
Increase (decrease) of Non-cash Activities:				
Accrual of capital expenditures	$	(303)	$	(2,826)
ARO liability changes in estimates	$	277	$	522

See notes to consolidated financial statements.

THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
Three Months Ended March 31, 2010 and 2009
(in thousands)
(unaudited)

	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, 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)
Stock-based compensation	25		53					53
Accumulated other comprehensive income					227			227
Net loss				(60,961)				(60,961)
Balance, March 31, 2009	93,070	$ 948	$ 538,614	$ (483,949)	$ 8,356	1,712	$ (3,099)	$ 60,870
Balance, December 31, 2009	92,475	$ 925	$ 535,443	$ (495,624)	$		$	$ 40,744
Stock-based compensation			6					6
Net income				340				340
Balance, March 31, 2010	92,475	$ 925	$ 535,449	$ (495,284)	$		$	$ 41,090

See notes to consolidated financial statements.

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

	Three Months Ended March 31,	
	2010	**2009**
Net earnings (loss) applicable to common stockholders	$ 340	$ (60,961)
Other comprehensive income (loss), net of tax, for unrealized gains (losses) from hedging activities:		
Unrealized holding gains (losses) arising during period (1)		3,798
Reclassification adjustments on settlement of contracts (2)		(3,571)
		227
Total comprehensive income (loss)	$ 340	$ (60,734)
(1) Net income tax (expense) benefit	$	$
(2) Net income tax (expense) benefit	$	$

See notes to consolidated financial statements.

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THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

1. BASIS OF PRESENTATION, AND GOING CONCERN

The consolidated financial statements reflect the accounts of The Meridian Resource Corporation and its subsidiaries (the Company or Meridian) after elimination of all significant intercompany transactions and balances. The financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Company s Annual Report on Form 10-K for the year ended December 31, 2009, as filed with the Securities and Exchange Commission (SEC).

The financial statements included herein as of March 31, 2010, and for the three month periods ended March 31, 2010 and 2009, are unaudited, and in the opinion of management, the information furnished reflects all material adjustments, consisting of normal recurring adjustments, necessary for a fair presentation of financial position and of the results of operations for the interim periods presented. Certain minor reclassifications of prior period financial statements have been made to conform to current reporting practices. The results of operations for interim periods are not necessarily indicative of results to be expected for a full year.

Merger. 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 would receive $0.33 per share of common stock, to be paid in cash, and Alta Mesa would assume the Company s debts and obligations. The Company would be merged into Merger Sub with Merger Sub as the surviving entity. The merger was subject to approval by holders of two thirds of the Company s outstanding shares of common stock. 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. At a shareholder meeting held on May 10, 2010 where a vote was taken, the merger was approved. The transaction was closed on May 13, 2010, at which time the Company s stock ceased to be publicly traded and the Company was merged with and into Merger Sub, assuming the name Alta Mesa Acquisition Sub, LLC. The Company s shareholders immediately prior to the merger ceased to have any rights as shareholders of the Company, and no longer have an interest in the Company s future earnings or growth (other than the right to receive consideration for their shares under the Merger Agreement, or the right to an appraisal of their shares under Texas law.) The debt under the Company s credit facility, $82 million at the time, was extinguished, and all other liabilities, including a $5.3 million term note, were assumed by Merger Sub as of the closing date. The Company has filed the appropriate forms with the SEC to discontinue its reporting obligations, and the stock has been delisted from the New York Stock Exchange. As of May 13, 2010, Meridian is no longer a separate and independent going concern. 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. No adjustments related to the subsequent merger have been made.

2. SIGNIFICANT ACCOUNTING POLICIES

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 was subsequently 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.

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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.

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. Any such 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 the three months ended March 31, 2010 was $145,000. For the three months ended March 31, 2009, although the Company was unable to fully utilize the two rigs, rig operations were estimated to have resulted in no profit or loss. Therefore no related expense was recognized. The dayrate contract for the Company-owned rig expired March 31, 2010; the dayrate contract for the other rig continues to February 2011.

Depreciation of the owned rig was $221,000 for each of the three month periods ended March 31, 2010 and 2009, respectively. In the first quarter of 2009, $90,000 was capitalized to the full cost pool, and the remainder was included in depletion and depreciation expense on the consolidated statements of operations. In the first quarter of 2010, the entire amount was included in depletion and depreciation expense.

See Note 8 for additional information on the Company s plans for potential disposition of the Company-owned rig and the obligation under the remaining drilling contract and the lease of the Company-owned rig.

Property and Equipment

The Company uses the full cost method of accounting for its investments in oil and natural gas properties. Capitalized costs of proved oil and natural gas properties are depleted on a units of production method using proved oil and natural gas reserves. Costs depleted include net capitalized costs subject to depletion and estimated future dismantlement, restoration, and abandonment costs. 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 were zero and $2.6 million for the three month periods ended March 31, 2010 and March 31, 2009, respectively.

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.

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Fair Value of Financial Instruments

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 March 31, 2010 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. However, the merger transaction which closed in May 2010, under which Merger Sub assumed all the liabilities and paid off the $82 million outstanding balance under the credit facility, in addition to a cash purchase of all of the outstanding shares of the Company, indicates the underlying collateral, the Company s oil and natural gas reserves, was supportive of the full balance of the debt, and the carrying value and fair value were similar. The carrying value of the debt was $83 million at March 31, 2010. See Note 6 for further details on the credit facility. The Company also has a financing agreement with a fixed rate, the rig note. The fair value of the rig note at March 31, 2010 is estimated as approximately $4 million; the corresponding carrying value of the debt is $5.5 million. The fair value was estimated based on the fair value of the underlying collateral. The collateral is a drilling rig owned by the Company; see Note 4 for further information on how fair value for the rig was estimated. Our oil and gas price risk hedging contracts are also financial instruments, recorded at fair value; see Note 11.

Recent Accounting Pronouncements

A standard to improve disclosures about fair value measurements was issued by the Financial Accounting Standards Board (the FASB) in January 2010. The additional disclosures required include: (1) the different classes of assets and liabilities measured at fair value, (2) the significant inputs and techniques used to measure Level 2 and Level 3 assets and liabilities for both recurring and nonrecurring fair value measurements, (3) the gross presentation of purchases, sales, issuance and settlements for the rollforward of Level 3 activity and (4) the transfers in and out of Levels 1 and 2. The Company adopted the new disclosures in the first quarter of 2010.

3. IMPAIRMENT OF LONG-LIVED ASSETS

At the end of each quarter, the unamortized cost of oil and natural gas properties, net of related deferred income taxes, is limited to the sum of the estimated future after-tax net revenues from proved properties using period-end prices, after giving effect to cash flow hedging positions, discounted at 10%, and the lower of cost or fair value of unproved properties adjusted for related income tax effects. This is known as the ceiling test.

Accordingly, based on March 31, 2009 pricing of $3.76 per Mmbtu of natural gas and $49.66 per barrel of oil, the Company recognized a non-cash impairment of $59.5 million of the Company s oil and natural gas properties under the full cost method of accounting during the first quarter of 2009. Prices used in the ceiling test in the first quarter of 2010 were $3.99 per Mmbtu of natural gas and $69.64 per barrel of oil. No impairment was required in the first quarter of 2010.

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.

Based on March 31, 2010 prices for oil and natural gas, the Company had an excess of the ceiling over our capitalized costs of $17.4 million (pretax and aftertax). See Note 8 for further information regarding the sensitivity of the ceiling to changes in the prices of oil and natural gas.

The Company performs impairment testing of its drilling rig each quarter. At March 31, 2010, the carrying value of the rig exceeded its estimated fair value (based on discounted cash flows) by approximately $0.7 million. 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.

4. FAIR VALUE MEASUREMENT

The Company follows the FASB guidance 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.

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 Note 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 in the current period. 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 utilized 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 classified the fair values of all its derivative contracts as Level 2. There are currently no derivative contracts outstanding.

The fair value of the Company s General Partner Warrants (see Note 9) was calculated using the Black-Scholes option pricing model.

Assets and liabilities measured at fair value on a recurring basis

Description	March 31, 2010	Fair Value Measurements at March 31, 2010 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)
General Partner Warrants [(1)]	$ 412		$ 412	

(1) General Partner Warrants are more fully described in Note 9.

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 no additions to asset retirement obligations measured at fair value during the three months ended March 31, 2010.

The Company estimates the fair value of its drilling rig quarterly (see Note 3), 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.

5. ACCRUED LIABILITIES

Below is the detail of accrued liabilities on the Company s balance sheets as of March 31, 2010 and December 31, 2009 (thousands of dollars):

	March 31, 2010	**December 31, 2009**
Capital expenditures	$ 703	$ 830
Operating expenses/taxes	3,182	4,072
Compensation	419	918
Interest and accrued bank fees	268	353
General partner warrants	412	412
Shell settlement (current portion)	1,878	1,003
Other	2,015	2,521
Total	$ 8,877	$ 10,109

6. DEBT

***Credit Facility*.** The Company had 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 was subject to borrowing base redeterminations and bore 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 were 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 were 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 contained 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 required 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 March 31, 2010. The Company was 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 $87.5 million at December 31, 2009 and $83.0 million at March 31, 2010 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 covered in excess of 95% of the present value of proved oil and natural gas properties.

The Credit Facility was 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 was 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 could redetermine the borrowing base to a lower level if they determined that the Company s oil and natural gas reserves, at the time of redetermination, were inadequate to support the borrowing base then in effect. In the event the redetermined borrowing base was less than outstanding borrowings under the Credit Facility, the Credit Facility required 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 (a $500,000 principal payment had been made in June 2009). 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 had 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.

The Bank Forbearance Agreement also modified the schedule of borrowing base redeterminations from semi-annually to quarterly. However, a subsequent amendment to the Bank Forbearance Agreement provided a limited waiver postponing the next borrowing base redetermination to the end of the forbearance period.

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 was based on the prime interest rate, 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 through April 2010. The additional default interest was 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 were in arrears at either March 31, 2010 or December 31, 2009.

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; as of March 31, 2010, the balance was reduced to $83.0 million, and as of May 4, 2010 the balance was $82.0 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 during 2009.

On December 22, 2009, the Company entered into the Merger Agreement with 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 and required the Company to repay $1 million in principal to the Lenders per month. On April 15, 2010, the Company entered the Twelfth Amendment to Forbearance and Amendment Agreement, which extended the deadline for shareholder vote to May 7, 2010 and included an amendment fee of $208,000; on May 7, 2010, the Company entered the Thirteenth Amendment to Forbearance and Amendment Agreement which extended the deadline for consummation of the transaction to May 14, 2010 (or to no later than May 31, 2010 upon consent by the Lenders, based on necessity for additional time to obtain shareholder or other approvals); this final extension included an amendment fee of $82,000. Total forbearance fees in the first quarter of 2010 were zero; forbearance fees of $290,000 will be recorded in the second quarter of 2010.

On May 10, 2010, the merger proposal was approved by the shareholders and the merger transaction was closed on May 13, 2010. On that date, all debts under the Credit Facility, including accrued interest and forbearance fees, were extinguished.

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 was collateralized by the drilling rig, as well as general corporate credit. The term of the loan was 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 triggered a cross-default under the rig note. The remedies available to CIT in the event of default included acceleration of all principal and interest payments. Accordingly, all indebtedness under the rig note, $6.2 million at December 31, 2009 and $5.5 million at March 31, 2010, has been classified as current in the accompanying consolidated balance sheets.

On September 3, 2009, the Company entered into a forbearance agreement with CIT (CIT Forbearance Agreement.) The forbearance period under the CIT Forbearance Agreement was extended several times, most recently by the Fourth Amendment to Forbearance and Amendment Agreement (4th Amendment). The forbearance period would end 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 provided CIT s consent to the merger with Alta Mesa.

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 of 2009, a forbearance fee of approximately $50,000.

On May 13, 2010, the merger transaction with Alta Mesa was closed, and the forbearance period ended. The note continued with TMRD, and both Merger Sub and Alta Mesa Holdings, LP became guarantors of the note.

7. INCOME TAXES

The Company s effective income tax rate is near zero in the first quarters of both 2009 and 2010. 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 realize its deferred tax assets, and therefore recorded a valuation allowance in the fourth quarter of 2008 to the full extent of all net deferred tax assets. The allowance has subsequently been adjusted each quarter, including the first quarters of 2009 and 2010, to maintain this complete offset of all deferred tax assets. Thus, the tax expense or benefit related to net income or loss recognized in the first quarter of each of 2010 and 2009 was zero, and the effective tax rate for those periods is 0%. There is no tax expense related to net income for the first quarter of 2010, as tax loss carryforwards are sufficient to absorb the income.

8. COMMITMENTS AND CONTINGENCIES

Default under Credit Agreement

As described in Note 6, the Company has been in default under the terms of the Credit Facility and the rig note since December 31, 2008. As of December 31, 2009, and continuing at March 31, 2010, the Company had obtained forbearance from these Lenders under short-term agreements. The credit defaults have subsequently been resolved by the closing of the merger transaction on May 13, 2010. Consistent with prior periods, the Company has not provided for this matter in its financial statements at March 31, 2010 and December 31, 2009, other than to reclassify all outstanding debt as current at those dates.

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 March 31, 2010.

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, which was amended on April 15, 2010. Under the terms of the settlement as amended, 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, which has now occurred), 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 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. The settlement becomes binding upon the first payment of $1 million, which occurred in conjunction with the closing of the merger transaction on May 13, 2010, and the transfer of the land and overriding royalty interest. Merger Sub has assumed all of the remaining obligations to Shell under the settlement agreement.

Other than 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 March 31, 2010.

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 March 31, 2010.

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. Effective on March 23, 2010, the parties executed a Memorandum of Understanding (MOU) reflecting their agreement in principle to settle the now-consolidated *Leider* action. The MOU provides that the defendants deny all liability. The proposed settlement was conditioned on, among other things, approval of the merger by Meridian s shareholders, which has now occurred. Under the terms of the proposed settlement, and upon approval by the Court, all claims relating to the Merger Agreement as amended, the merger, and disclosures related to 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 parties have agreed to stay the litigation while the settlement process is ongoing. The proposed settlement did 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 as amended. The terms of the MOU have been described in previous SEC filings. Expenses of the proposed settlement were recorded in the first quarter of 2010.

Other contingencies

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 March 31, 2010, 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 March 31, 2009, 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. No impairment was recorded in the first quarter of 2010.

At March 31, 2010, we had a cushion (i.e., the excess of the ceiling over capitalized costs) of approximately $17.4 million (pretax and after-tax). A 10% increase in prices would have increased the cushion by approximately $27.9 million. A 10% decrease in prices would have eliminated the cushion and resulted in an impairment write down of approximately $10 million. Decreases in prices affecting the end of subsequent accounting periods, net of the effect of any hedging positions the Company may have at the time, 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.

Drilling rigs. As described in Note 2, Rig Operations , the Company continues to have a significant contractual obligation for the use of a drilling rig. The Company s capital expenditure plans no longer include full use of this rig; however, the Company is obligated for the dayrate regardless of whether the rig is working or idle. The operator, Orion, has sought other parties to use the rig and agreed to credit the Company s obligation, based on revenues from third parties who utilize the rig when the Company is unable to. Management cannot predict whether utilization of the rig by third parties will be consistent, nor to what extent it may offset obligations under the dayrate contract. The Company has not provided any amount for any future losses on this drilling contract in its financial statements at March 31, 2010. The drilling contract will terminate in February 2011.

The Company entered into a forbearance agreement with Orion which may grant title to a company-owned rig to Orion, the operator under the dayrate contract, in exchange for release of all accrued and future liabilities under the rig contract and under a similar rig contract now expired. 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 Company-owned 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.

At March 31, 2010, the rig is included in equipment at a net book value of $4.4 million, and accounts payable includes a total of $5.5 million in accrued unpaid invoices from Orion for underutilization of both rigs, which is net of a reduction of $1.2 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 3.

9. STOCKHOLDER S EQUITY

Merger

Subsequent to March 31, 2010, as described in Note 1, the Company merged with and into Merger Sub, with Merger Sub as the surviving entity as of May 13, 2010. In connection with the consummation of the merger, each share of the Company s common stock outstanding immediately prior to the merger was converted into the right to receive $0.33 per share in cash. Shares of the Company have ceased to be publicly traded. The Company s shareholders immediately prior to the merger ceased to have any rights as shareholders of the Company and no longer have an interest in the Company s future earnings and growth (other than the right to receive consideration for their shares under the Merger Agreement, or the right to an appraisal of their shares under Texas law.)

Subsequent to March 31, 2010, certain outstanding warrants (see below, Warrants) were 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 Facility 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 March 31, 2010, the Company had repurchased 535,416 common shares at a cost of $1,234,000, of which 501,300 shares were reissued for 401(k) contributions, for contract services and for compensation, and 34,116 were retired. The Bank Forbearance Agreement prohibited any further repurchase of Company stock; none was repurchased in either 2009 or in 2010.

General Partner Warrants

As of March 31, 2010, 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. The number of shares of common stock purchasable upon the exercise of each warrant and its corresponding exercise price are subject to various anti-dilution adjustments. Messrs. Reeves and Mayell, respectively, are the former Chief Executive Officer and former Chief Operating Officer of the Company. 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

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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 are made each quarter, beginning in 2009. For the three month periods ended March 31, 2010 and 2009, the Company recorded a gain (loss) on the valuation of the warrants of zero and $641,000, respectively. The gain in 2009 is included in General and Administrative Expense.

There were 1,872,998 General Partner Warrants outstanding at March 31, 2010, included in accrued liabilities at a total fair value of $412,000. Fair value is based on the Black-Scholes model for option pricing.

At the closing of the merger transaction, the warrants were canceled and the holders of the warrants received approximately $431,000 in total.

10. EARNINGS PER SHARE

The following table sets forth the computation of basic and diluted net earnings (loss) per share (in thousands, except per share):

	Three Months Ended March 31,	
	2010	**2009**
Numerator:		
Net earnings (loss)	$ 340	$ (60,961)
Denominator:		
Denominator for basic earnings per share weighted-average shares outstanding	92,476	92,451
Effect of potentially dilutive common shares:		
Warrants and stock rights (a)	1,202	NA
Employee and director stock options (a)	NA	NA
Denominator for diluted earnings per share - weighted-average shares outstanding and assumed conversions	93,678	92,451
Basic earnings (loss) per share	$	$ (0.66)
Diluted earnings (loss) per share	$	$ (0.66)

(a) The number of warrants excluded for the three months ended March 31, 2009 totaled approximately 3.3 million. The number of options excluded for that period totaled approximately

700,000. A total of 404,000 options were excluded for the three months ended March 31, 2010, because the options exercise price was greater than the average market price of the common shares, which made them anti-dilutive.

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. All potentially dilutive shares, whether from options or warrants, are excluded when there is an operating loss, because inclusion of such shares would be anti-dilutive.

11. RISK MANAGEMENT ACTIVITIES

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Management of Financial Risk

The Company s operating environment included 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 impacted revenue, and the risk of interest rate movements, which impacted interest expense from floating rate debt. The Company has not historically utilized derivative contracts or any other form of hedging against interest rate risk. The Company utilized 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 were entered into for trading purposes, and the Company generally holds each instrument to maturity. The Company s commodity derivative contracts were considered cash flow hedges under generally accepted accounting principles.

Oil and Natural Gas Hedging Contracts

The Company has historically utilized derivative contracts to hedge the sale of a portion of its future production. The Company s objective was 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 considered some exposure to market pricing to be desirable, due to the potential for favorable price movements, but preferred 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 were executed by affiliates of the Lenders under the Credit Facility and were collateralized by the security interest the Lenders had in the oil and natural gas assets of the Company. Due to the default under the Credit Facility, the Lenders did not allow the Company to enter into any additional hedging agreements. As a result, the Company s oil and natural gas sales for the first quarter of 2010 were unhedged, and there are no assets or liabilities from price risk management as of March 31, 2010.

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 were designated as cash-flow hedges and were stated at fair value on the Consolidated Balance Sheets. See Note 4, Fair Value Measurements for further information on how fair values of derivative instruments are determined. Changes in fair value, which occur due to commodity price movements, were offset in Accumulated Other Comprehensive Income. When the derivative contract or a portion of it matured, the gain or loss was settled in cash and reclassified from Accumulated Other Comprehensive Income to Revenues from Oil and Natural Gas. Net settlements under hedging agreements increased oil and natural gas revenues by zero and $3,571,000 for the three months ended March 31, 2010 and 2009, 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 by ASC 815, or if the forecasted transaction is no longer expected to occur. Although the Company periodically recorded gains or losses from hedge ineffectiveness, there were no losses recorded due to cancellations or changes in expectations regarding occurrence of the hedged transactions. The following table provides information regarding gains and losses related to derivative contracts, and where these amounts are reflected within the Company s financial statements (in thousands):

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Effect of Derivative Contracts on the Consolidated Statements of Operations

Description	Location of Gain (Loss) within Financial Statements	For the three months ended March 31, 2010	March 31, 2009
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		3,798
Gain (loss) on derivative contracts reclassified from OCI to earnings			
Commodities Contracts	Oil and Natural Gas Revenues		3,571
Gain (loss) due to hedging ineffectiveness reported in earnings			
Commodities Contracts	Revenues from Price Risk Management Activities		2
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

As of March 31, 2010, the Company had no unrealized gains or losses deferred in Accumulated Other Comprehensive Income.

12. SHARE-BASED COMPENSATION

Stock Options

The Company records share-based compensation expense based on the fair value of the share-based award determined at grant date and recognized over the service period, which is generally the vesting period of the award. Share-based compensation expense of approximately $6,000 and $53,000 was recorded in the three month periods ended March 31, 2010 and 2009, respectively. Compensation paid in share-based awards included stock options and non-vested shares granted to our employees and directors.

13. 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.

The following table describes the change in the Company s asset retirement obligations for the three months ended March 31, 2010 (thousands of dollars):

Asset retirement obligation at December 31, 2009	$ 23,823
Additional retirement obligations recorded in 2010	
Settlements during 2010	(140)
Revisions to estimates and other changes during 2010	277
Accretion expense for 2010	546
Asset retirement obligation at March 31, 2010	24,506
Less: current portion	5,626
Asset retirement, long-term, at March 31, 2010	$ 18,880

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

14. SUBSEQUENT EVENT

Merger. On May 10, 2010, the Company held a shareholder meeting and vote at which the merger with Alta Mesa was approved. The transaction was closed on May 13, 2010 and the Company was merged with and into Merger Sub, with Merger Sub as the surviving entity. In connection with the consummation of the merger, each share of the Company s common stock outstanding immediately prior to the merger was converted into the right to receive $0.33 per share in cash. Shares of the Company have ceased to be publicly traded. The Company s shareholders immediately prior to the merger ceased to have any rights

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as shareholders of the Company and no longer have an interest in the Company s future earnings and growth (other than the right to receive consideration for their shares under the Merger Agreement, or the right to an appraisal of their shares under Texas law.) The debt under the Company s credit facility, $82 million at the time, was extinguished, and all other liabilities, including a $5.3 million term note, were assumed by Merger Sub.

The Company has filed the appropriate forms with the SEC to discontinue its reporting obligations, and the stock has been delisted from the New York Stock Exchange.

ITEM 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

Operations Update

Production volumes for the first quarter of 2010 totaled 2.6 billion cubic feet of gas equivalent (Bcfe), or an average of 29.0 million cubic feet of natural gas equivalent per day (Mmcfe/d) compared to 3.3 Bcfe or 37.1 Mmcfe per day for the first quarter of 2009. The variance in production volumes between the two periods is due to natural production declines. Sequentially, production is comparable to the average daily production of 30.0 Mmcfe/d in the fourth quarter of 2009. The Company is experiencing a gradual decline in daily production levels as a result of the reduction in capital spending in the past year. Currently production ranges between approximately 27 and 28 Mmcfe per day.

During the first quarter of 2010, we performed one well recompletion in our Turtle Bayou field. We participated as an overriding royalty owner (2%) in a well drilled in Karnes County, Texas, the Drees A-179 #1. This well was drilled to a total measured depth of approximately 17,340 feet (true vertical depth of approximately 11,900). The well had a 30-day production average of 1,264 barrels of oil and 1.1 million cubic feet of gas per day. The well will be completed as a producing oil well in the Eagle Ford Shale formation.

Merger. Subsequent to March 31, 2010, as described in Notes 1 and 9 to the accompanying Notes to Consolidated Financial Statements, the Company merged with and into Alta Mesa Acquisition Sub, LLC (Merger Sub) with Merger Sub as the surviving entity. Merger Sub is a wholly owned subsidiary of Alta Mesa Holdings, LP (Alta Mesa). The merger was the result of management s efforts over the past year to complete a corporate transaction sufficient to resolve the default under our primary credit facility and to allow the Company to resume its exploration and development activities. The merger was approved by shareholders on May 10, 2010, and the merger transaction was completed on May 13, 2010. In connection with the consummation of the merger, each share of the Company s common stock outstanding immediately prior to the merger was converted into the right to receive $0.33 per share in cash. Shares of the Company have ceased to be publicly traded and have been delisted from the New York Stock Exchange. The Company s shareholders immediately prior to the merger ceased to have any rights as shareholders of the Company and no longer have an interest in the Company s future earnings and growth (other than the right to receive consideration for their shares under the Merger Agreement, or the right to an appraisal of their shares under Texas law.) All liabilities under the credit facility were extinguished in the closing of the merger transaction on May 13, 2010 and all other liabilities were assumed by Merger Sub. The completion of this transaction will provide the Company with the capital to resume exploration and development of its properties.

Other Conditions

Industry and Economic Conditions. Revenues, profitability and future growth rates of Meridian are substantially dependent upon prevailing prices for oil and natural gas. Oil and natural gas prices have been extremely volatile in recent years and are affected by many factors outside of our control. Our average oil price for the three months ended March 31, 2010, was $72.99 per barrel compared to $45.62 per barrel for the three months ended March 31, 2009. Our average natural gas price (after adjustments for hedging activities) for the three months ended March 31, 2010, was $5.28 per Mcf compared to $6.07 per Mcf for the three months ended March 31, 2009. Fluctuations in prevailing prices for oil and natural gas have several important consequences to us, including affecting the level of cash flow received from our producing properties. Pricing also significantly impacts our future net revenue from oil and natural gas, which impacts the ceiling test and related impairment expense. Refer to Item 3, Quantitative and Qualitative Disclosures about Market Risk, for information regarding commodity price risk management activities utilized to mitigate a portion of the near term effects of this exposure to price volatility.

Global capital markets have experienced significant disruptions in the past eighteen months, 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. In addition, the market value of the Company s reserves decreased, both in the fourth quarter of 2008 and in the first quarter of 2009, though a partial recovery of prices occurred subsequently, due primarily to energy price fluctuations. Our access to credit significantly declined.

The decrease in oil and natural gas prices has also caused operating cash flows to decline across the industry and at Meridian.

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 and adopted in the United States. 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. See the Company s Annual Report on Form 10-K for the year ended December 31, 2009, for further discussion.

The Company adopted new authoritative guidance from the Financial Accounting Standards Board (FASB) effective January 1, 2009. The adoption requires us to value certain outstanding warrants for our common stock, known as the General Partner Warrants, at fair value at each reporting date. As the fair value changes, the difference from period to period is recognized in the consolidated statement of operations. The fair value is based on the Black-Scholes model for option pricing, and varies from period to period primarily due to fluctuation in the market price of our common stock. Upon adoption, we recorded a charge of $960,000 to retained earnings to reflect the cumulative effect of recording the 1.9 million warrants at fair value on January 1, 2009, with an offsetting entry to accrued liabilities. For the three month period ended March 31, 2010 there was no change in the value of the warrants and no related gain or loss. For the three month period ended March 31, 2009, we recorded a reduction of general and administrative expense of $641,000 due to the change in fair value of the warrants. The factors that determine the fair value are not in our control.

Results of Operations

Three Months Ended March 31, 2010 Compared to Three Months Ended March 31, 2009

Operating Revenues. First quarter 2010 oil and natural gas revenues decreased $1.1 million (5%) as compared to first quarter 2009 revenues due to a 22% decrease in production volumes partially offset by a 21% increase in average commodity prices on a natural gas equivalent basis. Oil and natural gas production volumes totaled 2,613 Mmcfe for the first quarter of 2010 compared to 3,340 Mmcfe for the

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comparable period of 2009. Our average daily production decreased from 37 Mmcfe during the first quarter of 2009 to 29 Mmcfe for the first quarter of 2010. First quarter 2010 production was generally lower due to natural production declines.

The following table summarizes the Company s operating revenues, production volumes and average sales prices for the three months ended March 31, 2010 and 2009:

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009	Increase (Decrease)
Production Volumes:			
Oil (Mbbl)	174	199	(13%)
Natural gas (MMcf)	1,569	2,147	(27%)
Mmcfe	2,613	3,340	(22%)
Average Sales Prices:			
Oil (per Bbl)	$ 72.99	$ 45.62	60%
Natural gas (per Mcf)	$ 5.28	$ 6.07	(13%)
Mmcfe	$ 8.03	$ 6.62	21%
Operating Revenues (000 s):			
Oil	$ 12,691	$ 9,071	40%
Natural gas	$ 8,285	$ 13,038	(36%)
Total Operating Revenues	$ 20,976	$ 22,109	(5%)

Operating Expenses. Oil and natural gas operating expenses on an aggregate basis decreased $1.5 million (34%) to $3.1 million during the first quarter of 2010, compared to $4.6 million in the first quarter of 2009. On a unit basis, lease operating expenses decreased $0.22 per Mcfe to $1.17 per Mcfe for the first quarter of 2010 from $1.39 per Mcfe for the first quarter of 2009. Oil and natural gas operating expenses decreased primarily due to reduced labor costs, salt water disposal fees, fuel and compression charges, platform facilities charges, and lower workover expenses.

Severance and Ad Valorem Taxes. Severance and ad valorem taxes increased $0.2 million (8%) to $1.8 million for the first quarter of 2010, compared to $1.6 million during the same period in 2009 primarily because of the increase in oil prices and an increase in the tax rate for natural gas, partially offset by production declines. The Company s production is primarily in Louisiana, where the severance tax for oil is 12.5% of revenue, and thus tracks increases in oil revenues. Louisiana severance tax for natural gas is computed using a rate per mcf. The rate used in the first quarter of 2010 increased 15% as compared to the rate used in the comparable period in 2009 (to $0.331 per mcf from $0.288). On an equivalent unit of production basis, severance and ad valorem taxes increased to $0.68 per Mcfe from $0.49 per Mcfe for the comparable three-month period. This unit increase is primarily related to the factors described above.

Depletion and Depreciation. Depletion and depreciation expense decreased $4.4 million (37%) during the first quarter of 2010 to $7.4 million, from $11.8 million for the same period of 2009. This was the result of lower depreciation expense per unit, combined with a decrease in oil and natural gas production. On a unit basis, depletion and depreciation expense decreased by $0.69 per Mcfe, to $2.83 per Mcfe for the three months ended March 31, 2010, compared to $3.52 per Mcfe for the same period in 2009. The reduction in expense per unit is due to the decrease in the carrying value of oil and gas properties which resulted from the significant impairment write-down to the properties recorded in March 2009.

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Impairment of Long-Lived Assets. A decline in oil and natural gas prices as of March 31, 2009, resulted in the Company recognizing a non-cash impairment totaling $59.5 million of its oil and natural gas properties under the full cost method of accounting. There was no impairment in the three months ended March 31, 2010.

General and Administrative Expense. General and administrative expense was $4.5 million in the first quarter of 2010 compared to $3.4 million in the first quarter of 2009. After the first quarter of 2009 the Company discontinued capitalizing general and administrative expenses to the full cost pool, based on reduced exploration and development activity. Gross general and administrative expenses, irrespective of any capitalization of expense, decreased from $6.0 million in the first quarter of 2009 to $4.5 million in the first quarter of 2010, or 25%. This $1.5 million decrease resulted from the Company s efforts to reduce headcount and other successful cost cutting measures in 2009, the impact of which primarily occurred after the first quarter of that year. These expense reductions were partially offset, however, by higher legal fees associated with the Company s pending merger and shareholder vote (now completed), and continuing activities with regard to the forbearance agreements with the lenders under our primary credit agreement in the first quarter of 2010. Legal expenses increased approximately $700,000 between the two periods. On an equivalent unit of production basis, gross general and administrative expenses before the capitalization of $2.6 million in the first quarter of 2009 decreased $0.05/Mcfe to $1.73/Mcfe for the first quarter of 2010 compared to $1.78/Mcfe for the comparable 2009 period. The expense per Mcfe was impacted by the decrease in production between the two periods.

Rig Operations, Net. Rig operations, net is the expense related to underutilized contracted drilling rigs. The Company had drilling contracts covering two rigs which it was unable to utilize for drilling, beginning in the first quarter of 2009 for one rig and in the second quarter of 2009 for the other. Under these drilling contracts the Company is obligated for the daily rate of the rigs regardless of the Company s actual use of the rigs; in practice, the rigs have been utilized by third parties and the Company has recorded a liability for the difference between its contracted dayrate and that collected by the drilling operator from the third party. See further information in Note 2 of Notes to Consolidated Financial Statements. Total net expense related to this underutilization of contracted rigs was $1.4 million in the first quarter of 2010; although there was some underutilization in the first quarter of 2009, rig operations were estimated to have resulted in no profit or loss and there is no expense for that period.

Interest Expense. Interest expense increased $0.4 million (20%), to $2.0 million for the first quarter of 2010 in comparison to $1.6 million for the first quarter of 2009. The increase is primarily a result of the incurrence of higher default interest rates under our primary credit facility and our fixed term rig note, partially offset by lower average debt balances.

Taxes on Income. Income tax expense for the first quarter of 2010 and 2009 was zero. The Company has a substantial tax carryforward position, which is utilized to offset all tax expense for the first quarter of 2010. The deferred tax asset related to the tax carryfoward is fully reserved by a valuation allowance. Management believes, given our overall financial position, that there are significant uncertainties regarding our ability to generate net profits in the near term; thus a tax asset valuation allowance sufficient to offset all deferred tax assets has been continuously maintained since December 2008. This prevents recognition of tax benefit during periods of additional losses, such as the first quarter of 2009.

Liquidity and Capital Resources

Cash Flows. Net cash provided by operating activities was $9.5 million for the three months ended March 31, 2010, as compared to $8.8 million for the same period in 2009. Cash-based revenues and expenses provided fewer cash flows, due primarily to a $1.1 million decrease in revenues, and to a net aggregate increase of $1.2 million in total cash-based expenses, which include lease operating expense, severance and ad valorem taxes, general and administrative expense, and the net expense of rig operations. The expense of rig operations accounts for $1.4 million of this total increase. Offsetting the effect of these cash-based revenues and expenses was increased cash flow from changes in working capital accounts, which provided positive cash flow of $1.1 million in the first quarter of 2010, as opposed to negative cash flow of $1.8 million from changes in working capital accounts in the corresponding period in 2009. The cash outflow from these working capital accounts in 2009 primarily reflected the paydown of obligations to vendors and joint interest partners as we decreased our drilling and other capital expenditures, establishing a lower base of payables related to operations. By the first quarter of 2010, this adjustment had been completed and movement in those accounts provided positive cash flow.

Net cash used in investing activities was $1.8 million during the three months ended March 31, 2010, versus $15.0 million in the first three months of 2009, due to decreased capital expenditures. In the first quarter of 2009, we participated in drilling two wells, whereas in the first quarter of 2010 we have confined our activities primarily to recompletions and required abandonment of existing wells and facilities.

Cash flows used in financing activities during the first quarter of 2010 were $5.2 million, compared to $2.0 million during the first quarter of 2009 primarily due to the repayments of amounts borrowed under the Credit Facility as required by the Bank Forbearance Agreement, as amended.

Continuing Obligations. In addition to the amounts due under our Credit Facility and rig note, the Company has continuing obligations under various contracts, the most significant of which is the remaining unexpired drilling contract described in Notes 2 and 8 of the accompanying Notes to Consolidated Financial Statements. Under this contract, we will continue to be obligated to pay daily rig rates for a drilling rig regardless of whether we are able to use the rig or it is idle. This obligation has, for the past twelve months, been mitigated by third party use of the rigs, but as of April 2010 we remained liable to the rig operator for any shortfall in rig rate from our contracted rate. Net expense related to underutilization of the rig and an additional rig for which the dayrate contract expired on March 31, 2010, was $1.4 million for the first quarter of 2010. The remaining contract terminates in February 2011. The Company entered into a forbearance agreement on September 3, 2009 with the rig operator, under which cash payment for the shortfall in rig rates is deferred, as described in Note 8.

For a more complete list of contractual obligations, refer to our 2009 Form 10-K, Item 7, Liquidity and Capital Resources, Cash Obligations.

Working Capital. During the first quarter of 2010, Meridian s capital expenditures were internally financed with cash flow from operations and cash on hand. As of March 31, 2010, the Company had a cash balance of $7.9 million and a working capital deficit of $95.3 million.

Credit Facility. The Company had 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 was subject to borrowing base redeterminations and bore 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 were 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 were 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 contained 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 required 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 March 31, 2010. The Company was 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 $87.5 million at December 31, 2009 and $83.0 million at March 31, 2010 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 covered in excess of 95% of the present value of proved oil and natural gas properties.

The Credit Facility was 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 was 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 could redetermine the borrowing base to a lower level if they determined that the Company s oil and natural gas reserves, at the time of redetermination, were inadequate to support the borrowing base then in effect. In the event the redetermined borrowing base was less than outstanding borrowings under the Credit Facility, the Credit Facility required 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 (a $500,000 principal payment had been made in June 2009). 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 had 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.

The Bank Forbearance Agreement also modified the schedule of borrowing base redeterminations from semi-annually to quarterly. However, a subsequent amendment to the Bank Forbearance Agreement provided a limited waiver postponing the next borrowing base redetermination to the end of the forbearance period.

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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 was based on the prime interest rate, 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 through April 2010. The additional default interest was 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 were in arrears at either March 31, 2010 or December 31, 2009.

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; as of March 31, 2010, the balance was reduced to $83.0 million, and as of May 4, 2010 the balance was $82.0 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 during 2009.

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 and required the Company to repay $1 million in principal to the Lenders per month. On April 15, 2010, the Company entered the Twelfth Amendment to Forbearance and Amendment Agreement, which extended the deadline for shareholder vote to May 7, 2010 and included an amendment fee of $208,000; on May 7, 2010, the Company entered the Thirteenth Amendment to Forbearance and Amendment Agreement which extended the deadline for consummation of the transaction to May 14, 2010 (or to no later than May 31, 2010 upon consent by the Lenders, based on necessity for additional time to obtain shareholder or other approvals); this final extension included an amendment fee of $82,000. Total forbearance fees in the first quarter of 2010 were zero; forbearance fees of $290,000 will be recorded in the second quarter of 2010.

On May 10, 2010, the merger proposal was approved and the merger transaction was closed on May 13, 2010. On that date, all debts under the Credit Facility, including accrued interest and forbearance fees, were extinguished.

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 was collateralized by the drilling rig, as well as general corporate credit. The term of the loan was 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 triggered a cross-default under the rig note. The remedies available to CIT in the event of default included acceleration of all principal and interest payments. Accordingly, all indebtedness under the rig note, $6.2 million at December 31, 2009 and $5.5 million at March 31, 2010, has been classified as current in the accompanying consolidated balance sheets.

On September 3, 2009, the Company entered into a forbearance agreement with CIT (CIT Forbearance

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Agreement.) The forbearance period under the CIT Forbearance Agreement was extended several times, most recently by the Fourth Amendment to Forbearance and Amendment Agreement (4th Amendment). The forbearance period would end 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 provided CIT s consent to the merger with Alta Mesa.

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 of 2009, a forbearance fee of approximately $50,000.

On May 13, 2010, the merger transaction with Alta Mesa was closed, and the forbearance period ended. The note continued with TMRD, and both Merger Sub and Alta Mesa Holdings, LP became guarantors of the note.

Dividends. It has been our policy to retain existing cash for reinvestment in our business. In addition, the terms of the bank forbearance agreement prohibited payment of dividends.

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 and plans to sell properties, anticipated results from third party disputes and litigation, expectations regarding future financing and compliance with our credit facility, the anticipated results of wells based on logging data and production tests, future sales of production, earnings, margins, production levels and costs, market trends in the oil and natural gas industry and the exploration and development sector thereof, environmental and other expenditures and various business trends. Forward-looking statements may be made by management orally or in writing including, but not limited to, the Management s Discussion and Analysis of Financial Condition and Results of Operations section and other sections of our filings with the Securities and Exchange Commission under the Securities Act of 1933, as amended, and the Securities Exchange Act of 1934, as amended.

Actual results and trends in the future may differ materially depending on a variety of factors including, but not limited to the following:

Changes in the price of oil and natural gas. The prices we receive for our oil and natural gas production and the level of such production are subject to wide fluctuations and depend on numerous factors that we do not control, including seasonality, worldwide economic conditions, the condition of the United States economy (particularly the manufacturing sector), foreign imports, political conditions in other oil-producing countries, the actions of the Organization of Petroleum Exporting Countries and domestic government regulation, legislation and policies. Material declines in the prices received for oil and natural gas could make the actual results differ from those reflected in our forward-looking statements.

Operating Risks. The occurrence of a significant event against which we are not fully insured could have a material adverse effect on our financial position and results of operations. Our operations are subject to all of the risks normally incident to the exploration for and the production of oil and natural gas, including uncontrollable flows of oil, natural gas, brine or well fluids into the environment (including groundwater and shoreline contamination), blowouts, cratering, mechanical difficulties, fires, explosions, unusual or unexpected formation pressures, pollution and environmental hazards, each of which could result in damage to or destruction of oil and natural gas wells, production facilities or other property, or injury to persons. In addition, we are subject to other operating and production risks such as title problems, weather conditions, compliance with government permitting requirements, shortages of or delays in obtaining equipment, reductions in product prices, limitations in the market for products, litigation and disputes in the ordinary course of business. Although we maintain insurance coverage considered to be customary in the industry, we are not fully insured against certain of these risks either because such insurance is not available or because of high premium costs. We cannot predict if or when any such risks could affect our operations. The occurrence of a significant event for which we are not adequately insured could cause our actual results to differ from those reflected in our forward-looking statements.

Drilling Risks. Our decision to purchase, explore, develop or otherwise exploit a prospect or property will depend in part on the evaluation of data obtained through geophysical and geological analysis, production data and engineering studies, which are inherently imprecise. Therefore, we cannot assure you that all of our drilling activities will be successful or that we will not drill uneconomical wells. The occurrence of unexpected drilling results could cause the actual results to differ from those reflected in our forward-looking statements.

Uncertainties in Estimating Reserves and Future Net Cash Flows. Reserve engineering is a subjective process of estimating the recovery from underground accumulations of oil and natural gas we cannot measure in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Reserve estimates may be imprecise and may be expected to change as additional information becomes available. There are numerous uncertainties inherent in estimating quantities and values of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. The quantities of oil and natural gas that we ultimately recover, production and operating costs, the amount and timing of future development expenditures and future oil and natural gas sales prices may differ from those assumed in these estimates. Significant downward revisions to our existing reserve estimates could cause the actual results to differ from those reflected in our forward-looking statements.

Full-Cost Ceiling Test. At the end of each quarter, the unamortized cost of oil and natural gas properties, net of related deferred income taxes, is limited to the sum of the estimated future after-tax net revenues from proved properties using period-end prices, after giving effect to cash flow hedge positions, discounted at 10%, and the lower of cost or fair value of unproved properties adjusted for related income tax effects.

The calculation of the ceiling test and the 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.

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 March 31, 2010, we had a cushion (i.e., the excess of the ceiling over capitalized costs) of approximately $17.4 million (pretax and after-tax). A 10% increase in prices would have increased the cushion by approximately $27.9 million. A 10% decrease in prices would have eliminated the cushion and resulted in an impairment write down of approximately $10 million. Decreases in prices affecting the end of subsequent accounting periods, net of the effect of any hedging positions the Company may have at the time, 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.

ITEM 3. Quantitative and Qualitative Disclosures about Market Risk

The Company is currently exposed to market risk from hedging contracts changes and changes in interest rates. A discussion of the market risk exposure in financial instruments follows.

Interest Rates

Through May 13, 2010, the Company was subject to interest rate risk on our long-term fixed interest rate debt and variable interest rate borrowings. Our long-term borrowings primarily consisted of borrowings under the Credit Facility. Interest charged on borrowings under the Credit Facility floated with prevailing interest rates. However, at closing of the merger, all debt under the Credit Facility was subsequently extinguished and responsibility for the fixed rate debt, the rig note, was assumed by Alta Mesa as purchaser of the subsidiary that held that note.

Hedging Contracts

Management of Financial Risk. The Company s operating environment includes one primary financial risk which could be addressed through derivatives and similar financial instruments: the risk of movement in oil and natural gas commodity prices, which impacts revenue.

The Company historically utilized 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 held each instrument to maturity. However, as a result of our default under the Credit Facility the Company was not able to enter into new hedging contracts during the latter part of 2009, and all of our previous hedging contracts expired on or before December 31, 2009. Thus the Company s oil and natural gas revenues have been unhedged throughout the first quarter of 2010.

Oil and Natural Gas Hedging Contracts. 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 considered some exposure to market pricing to be desirable, due to the potential for favorable price movements, but preferred to achieve a measure of stability and predictability over revenues and cash flows by hedging some portion of production. As noted above, the Company s future production is currently unhedged.

ITEM 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

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We conducted an evaluation under the supervision of 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 first quarter of 2010. 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.

During the three month period ended March 31, 2010, there were no changes in the Company s internal control over financial reporting that have materially affected or are reasonably likely to materially affect such internal control over financial reporting.

PART II OTHER INFORMATION

ITEM 1. Legal Proceedings.

Default under Credit Agreement

As described in Note 6, the Company has been in default under the terms of the Credit Facility and the rig note since December 31, 2008. As of December 31, 2009, and continuing at March 31, 2010, the Company had obtained forbearance from these Lenders under short-term agreements. The credit defaults have subsequently been resolved by the closing of the merger transaction on May 13, 2010. Consistent with prior periods, the Company has not provided for this matter in its financial statements at March 31, 2010 and December 31, 2009, other than to reclassify all outstanding debt as current at those dates.

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 March 31, 2010.

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, which was amended on April 15, 2010. Under the terms of the settlement as amended, 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, which has now occurred), 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 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. The settlement becomes binding upon the first payment of $1 million, which occurred in conjunction with the closing of the merger transaction on May 13, 2010, and the transfer of the land and overriding royalty interest. Merger Sub has assumed all of the remaining obligations to Shell under the settlement agreement.

Other than 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 March 31, 2010.

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

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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 March 31, 2010.

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. Effective on March 23, 2010, the parties executed a Memorandum of Understanding (MOU) reflecting their agreement in principle to settle the now-consolidated *Leider* action. The MOU provides that the defendants deny all liability. The proposed settlement was conditioned on, among other things, approval of the merger by Meridian s shareholders, which has now occurred. Under the terms of the proposed settlement, and upon approval by the court, all claims relating to the Merger Agreement as amended, the merger, and disclosures related to 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 parties have agreed to stay the litigation while the settlement process is ongoing. The proposed settlement did 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 as amended. The terms of the MOU have been described in previous Securities and Exchange Commission filings. Expenses of the proposed settlement were recorded in the first quarter of 2010.

ITEM 1A. Risk Factors.

For a discussion of the Company s risk factors, see Item 1A, Risk Factors , in the Company s Form 10-K for the year ended December 31, 2009. There have been no changes to these risk factors during the quarter ended March 31, 2010.

ITEM 6. Exhibits.

* 3.1 Certificate of Formation of Alta Mesa Acquisition Sub, LLC, a Texas limited liability company, dated November 9, 2009

* 3.2 Company agreement of Alta Mesa Acquisition Sub, LLC, a Texas limited liability company, dated November 9, 2009

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*10.1 Thirteenth Amendment to Forbearance and Amendment Agreement, dated as of May 7, 2010, 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
* 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.
* filed herewith

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SIGNATURES

Pursuant to the requirements 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 AND SUBSIDIARIES
(Registrant)

Date: May 24, 2010	By: /s/ Harlan H. Chappelle Harlan H. Chappelle President and Chief Executive Officer
	By: /s/ LLOYD V. DELANO Lloyd V. DeLano, Chief Accounting Officer, Senior Vice President