MERIDIAN RESOURCE CORP
Form 10-Q
November 09, 2009

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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: September 30, 2009

OR

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

For the transition period from __________________ to _________________

Commission file number: 1-10671

THE MERIDIAN RESOURCE CORPORATION

(Exact name of registrant as specified in its charter)

Texas	**76-0319553**
(State 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 þ	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

Number of shares of common stock outstanding at November 2, 2009: 92,475,527

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 September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
REVENUES:				
Oil and natural gas	$ 21,950	$ 36,806	$ 66,769	$ 121,788
Price risk management activities	(2)	3	(5)	(27)
Interest and other	8	174	13	406
	21,956	36,983	66,777	122,167
OPERATING COSTS AND EXPENSES:				
Oil and natural gas operating	3,637	5,927	12,883	19,151
Severance and ad valorem taxes	1,914	2,551	5,538	8,125
Depletion and depreciation	8,088	15,870	29,222	51,498
General and administrative	4,519	5,944	12,175	15,234
Rig operations, net	1,189		3,028	
Contract settlement				9,894
Impairment of long-lived assets			59,539	
Accretion expense	496	482	1,573	1,580
Hurricane damage repairs		1,462		1,462
	19,843	32,236	123,958	106,944
EARNINGS (LOSS) BEFORE INTEREST AND INCOME TAXES	2,113	4,747	(57,181)	15,223
OTHER EXPENSE:				
Interest expense	2,881	1,399	6,010	3,922
EARNINGS (LOSS) BEFORE INCOME TAXES	(768)	3,348	(63,191)	11,301
INCOME TAXES:				
Current		23		34
Deferred		2,626		6,166
		2,649		6,200
NET EARNINGS (LOSS)	$ (768)	$ 699	$ (63,191)	$ 5,101

NET EARNINGS (LOSS) PER SHARE:				
Basic	$ (0.01)	$ 0.01	$ (0.68)	$ 0.06
Diluted	$ (0.01)	$ 0.01	$ (0.68)	$ 0.05
WEIGHTED AVERAGE NUMBER OF COMMON SHARES:				
Basic	92,472	92,349	92,461	91,035
Diluted	92,472	94,143	92,461	94,653

See notes to consolidated financial statements.

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

	September 30, 2009 (unaudited)	December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 1,940	$ 13,354
Restricted cash	36	9,971
Accounts receivable, less allowance for doubtful accounts of $210 [2009 and 2008]	10,828	16,980
Due from affiliates	1,094	
Prepaid expenses and other	2,356	3,292
Assets from price risk management activities	1,836	8,447
Total current assets	18,090	52,044
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, full cost method (including $10,072 [2009] and $39,927 [2008] not subject to depletion)	1,886,911	1,877,925
Land	91	48
Equipment and other	20,464	21,371
	1,907,466	1,899,344
Less accumulated depletion and depreciation	1,735,456	1,647,496
Total property and equipment, net	172,010	251,848
OTHER ASSETS:		
Other	239	683
Total other assets	239	683
TOTAL ASSETS	$ 190,339	$ 304,575

See notes to consolidated financial statements.

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

	September 30, 2009 (unaudited)	December 31, 2008
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 4,998	$ 15,097
Advances from non-operators	283	5,517
Revenues and royalties payable	4,630	6,267
Due to affiliates		8,145
Notes payable	645	1,775
Accrued liabilities	9,368	18,831
Liabilities from price risk management activities	3	311
Asset retirement obligations	3,719	1,457
Current income taxes payable		47
Current maturities of long-term debt	96,988	103,849
Total current liabilities	120,634	161,296
LONG-TERM DEBT		
OTHER:		
Asset retirement obligations	17,736	20,768
COMMITMENTS AND CONTINGENCIES (Note 8)		
STOCKHOLDERS EQUITY:		
Common stock, $0.01 par value (200,000,000 shares authorized, 92,459,654 [2009] and 93,045,592 [2008] issued)	925	948
Additional paid-in capital	535,415	538,561
Accumulated deficit	(486,179)	(422,028)
Accumulated other comprehensive income	1,808	8,129
	51,969	125,610
Less treasury stock, at cost -0- [2009] and 1,712,114 [2008]shares		3,099
Total stockholders equity	51,969	122,511
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 190,339	$ 304,575

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)

	Nine Months Ended Sept 30,	
	2009	**2008**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net earnings (loss)	$ (63,191)	$ 5,101
Adjustments to reconcile net earnings (loss) to net cash provided by operating activities:		
Depletion and depreciation	29,222	51,498
Impairment of long-lived assets	59,539	
Amortization of other assets	444	154
Non-cash compensation	126	1,505
Non-cash gain on change in fair value of outstanding warrants	(306)	
Non-cash price risk management activities	5	27
Accretion expense	1,573	1,580
Deferred income taxes		6,166
Changes in assets and liabilities:		
Restricted cash	9,935	(9,931)
Accounts receivable	5,400	(3,937)
Prepaid expenses and other	936	(63)
Due to/from affiliates	(9,239)	12,628
Accounts payable	(4,269)	680
Advances from non-operators	(5,234)	(3,839)
Revenues and royalties payable	(1,637)	1,006
Asset retirement obligations	(2,079)	(587)
Other assets and liabilities	(4,284)	10,888
Net cash provided by operating activities	16,941	72,876
CASH FLOWS USED IN INVESTING ACTIVITIES:		
Additions to property and equipment	(22,588)	(100,620)
Proceeds from sale of property	2,419	7,161
Net cash used in investing activities	(20,169)	(93,459)
CASH FLOWS PROVIDED BY (USED IN) FINANCING ACTIVITIES:		
Proceeds from long-term debt		40,000
Reductions to long-term debt	(6,861)	(18,713)
Proceeds from notes payable	2,232	5,684
Reductions in notes payable	(3,362)	(5,017)
Repurchase of common stock		(75)
Payment of taxes due on vested stock	(195)	(3,035)
Additions to deferred loan costs		(904)

Net cash provided by (used in) financing activities	(8,186)	17,940
NET CHANGE IN CASH AND CASH EQUIVALENTS	(11,414)	(2,643)
Cash and cash equivalents at beginning of period	13,354	13,526
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 1,940	$ 10,883

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SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION	Nine Months Ended Sept 30, 2009	2008
Increase (decrease) of Non-cash Activities:		
Accrual of capital expenditures	$(10,981)	$(6,342)
ARO liability additions to liabilities	$ 47	$ 176
ARO liability changes in estimates	$ (311)	$(4,754)
Rig depreciation capitalized to oil and natural gas properties	$ 91	$ 978

See notes to consolidated financial statements.

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THE MERIDIAN RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
Nine Months Ended September 30, 2009 and 2008
(in thousands)
(unaudited)

	Common Stock Shares	Common Stock Par Value	Additional Paid-In Capital	Accumulated Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss)	Treasury Stock Shares	Treasury Stock Cost	Total
Balance, December 31, 2007	89,450	$ 936	$ 537,145	$ (212,142)	$ (221)	159	$ (288)	$ 325,430
Issuance of rights to common stock		4	(4)					
Issuance of shares for rights to common stock	1,803							
Shares withheld for payment of taxes due on vested stock		(10)	(3,025)					(3,035)
Company s 401(k) plan contributions	22		92			(99)	181	273
Stock-based compensation FAS123R			130					130
Compensation expense			968					968
Accum. other comprehensive income activity					346			346
Issuance of shares for contract services			26			(60)	107	133
Shares repurchased and retired	(34)		(75)					(75)
Net earnings				5,101				5,101
Balance, September 30, 2008	91,241	$ 930	$ 535,257	$ (207,041)	$ 125		$	$ 329,271
	93,045	$ 948	$ 538,561	$ (422,028)	$ 8,129	1,712	$ (3,099)	$ 122,511

Balance, December 31, 2008								
Effect of adoption of EITF Issue 07-05 (to record outstanding warrants at fair value)				(960)				(960)
Distribution of shares from Rabbi Trust:								
From treasury shares		(17)	(3,082)			(1,712)	3,099	
Repurchased in exchange for payment of withholding tax on vested stock						610	(195)	(195)
Retired	(610)	(6)	(189)			(610)	195	
Stock-based compensation	25		125					125
Accumulated other comprehensive income activity					(6,321)			(6,321)
Net loss				(63,191)				(63,191)
Balance, September 30, 2009	92,460	$ 925	$ 535,415	$ (486,179)	$ 1,808		$	$ 51,969

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 September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Net earnings (Loss)	$ (768)	$ 699	$ (63,191)	$ 5,101
Other comprehensive income (loss), net of tax, for unrealized gains (losses) from hedging activities:				
Unrealized holding gains (losses) arising during period (1)	304	12,479	3,460	(3,396)
Reclassification adjustments on settlement of contracts (2)	(2,758)	1,585	(9,781)	3,742
	(2,454)	14,064	(6,321)	346
Total comprehensive income (loss)	$ (3,222)	$ 14,763	$ (69,512)	$ 5,447
(1) net income tax (expense) benefit	$	$ (6,720)	$	$ 1,829
(2) net income tax (expense) benefit	$	$ (853)	$	$ (2,015)

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, 2008, as filed with the Securities and Exchange Commission (SEC).

The financial statements included herein as of September 30, 2009, and for the three month and nine month periods ended September 30, 2009 and 2008, 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.

As a result of the default under the Company s credit facility, under which borrowings were $90.5 million at September 30, 2009 and $89.5 million on November 9, 2009, and related cross defaults which arose under the Company s $6.5 million term loan and its master derivative agreements, the Company faces substantial economic difficulties. Although operating cash flow has been positive and capital expenditures have been very significantly reduced, the Company continues to be obligated for the expense of drilling rigs it cannot fully utilize and to be impacted by prices for oil and natural gas which have exhibited extreme volatility in the recent past.. The Company s default under the debt agreements, which has been mitigated in the short term by certain forbearance agreements, negatively impacts future cash flow and the Company s access to credit or other forms of capital. If the Company is unable to comply with the terms of the forbearance agreements, it will continue to be in default under the credit facility, the term loan, and the hedge agreements and will be subject to the exercise of remedies by third parties on account of such defaults. The exercise of such remedies, which include acceleration of all principal and interest payments, could potentially result in the Company seeking protection under federal bankruptcy laws. Such relief could materially and adversely affect the Company and its shareholders. Therefore, there is substantial doubt as to the Company s ability to continue as a going concern for a period longer than the next twelve months.

For further information regarding bank debt, master derivative agreements, and forbearance agreements, see Note 6. For further information regarding the Company s drilling rig contracts, and a forbearance agreement with the rig operator, see Note 8.

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.

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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 contracted to a third party during the second and third quarters 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.

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. All TMRD profits or losses related to lease of the rig, including any incidental profits related to the share of drilling costs borne by joint interest partners, are offset against the full cost pool. From April through December of 2008, the rig was utilized almost continuously on Company wells and its profits were accordingly capitalized. For the three and nine month periods ending September 30, 2008, the rig profits capitalized to the full cost pool were $397,000 and $545,000. For the three and nine month periods ending September 30, 2009, the rig profits capitalized to the full cost pool were zero and $180,000.

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 the nine months ended September 30, 2009, the rig worked on third party wells. The Company is obligated for the difference in dayrates if the rig is utilized by a third party at a lesser dayrate, which has occurred during 2009. This loss on a contractual obligation is included in Rig Operations, net in the consolidated statements of operations. The Company s share of profits on the lease of the rig to Orion partially offsets the loss on the drilling contract and is included in Rig operations, net on the consolidated statements of operations. The total lease revenue included in Rig operations, net for the three and nine month periods ended September 30, 2009 was $3,000 and $648,000, respectively.

In addition, depreciation expense on the owned rig of $221,000 and $663,000 for the three and nine month periods ended September 30, 2009, respectively, was included in depletion and depreciation expense on the consolidated statements of operation.

See Notes 1 and 8 for additional information on the Company s plans for potential disposition of the rig and the obligations under the drilling contracts.

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 and nine month periods ended September 30, 2009, and $4.9 million and $13.2 million for the three and nine month periods ended September 30, 2008.

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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.

Restricted Cash, Rabbi Trust, and Treasury Stock

The Company classifies cash balances as restricted when cash is restricted as to withdrawal or usage. The restricted cash balance at December 31, 2008, was $9,971,000 and at September 30, 2009, was $36,000. Restricted cash increased by $9,894,000 in May 2008, when contractual obligations to two former executive officers were funded by cash placed in a Rabbi Trust account. Additional restricted cash relates to a contractual royalties payable obligation. The obligations to the former executive officers included an obligation to pay them a total of $9.9 million in cash and 1.7 million shares of common stock of the Company, based on agreements effective in April 2008, which terminated their employment agreements and certain other compensation-related agreements. Pursuant to the contractual terms, both the shares and the cash from the trust were distributed to the former officers upon dissolution of the trust during the second quarter of 2009. The shares in the trust were accounted for as treasury shares so long as they remained in the trust. Until distribution, the assets of the trust belonged to the Company, but were effectively restricted due to the obligation to the former officers.

As of September 30, 2009, the Company had no remaining shares in treasury.

Fair Value of Financial Instruments

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and bank borrowings. The carrying amounts of cash and cash equivalents, accounts receivable, accounts payable, and accrued liabilities approximate fair value due to the highly liquid nature of these short-term instruments. As of September 30, 2009 the Company believes it is not practicable to estimate the fair value of its outstanding debt under its credit facility in light of the payment default. The reduction in credit standing from this default would certainly tend to reduce the fair value of the debt, but it is not practicable to estimate the amount of such reduction. The carrying value of that debt is $90.5 million at September 30, 2009. 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 September 30, 2009 is estimated as approximately $4 million; the corresponding carrying value is $6.5 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 6 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 12.

Subsequent Events

The Company reviews events occurring after the balance sheet date which could affect the financial position and / or results of operations for the period. The Company continues to review and evaluate events through the date on which the financial statements are issued, which, for the three month and nine month periods ending September 30, 2009, is November 9, 2009.

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Recent Accounting Pronouncements

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

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

In June 2009, the Financial Accounting Standards Board (FASB) issued revised authoritative guidance regarding consolidation of variable interest entities (VIE s), which amends existing consolidation guidance for variable interest entities. Variable interest entities generally are thinly-capitalized entities which under previous guidance may not have been consolidated. The revised guidance requires a company to perform a qualitative analysis to determine whether to consolidate a VIE, which includes consideration of control issues other than the primarily quantitative considerations utilized prior to this revision. In addition, the revised guidance requires ongoing assessments of whether to consolidate VIE s, rather than only when specific events occur. The revised guidance also requires additional disclosures about consolidated and unconsolidated VIE s, including their impact on the company s risk exposure and its financial statements. The revised guidance will be effective for financial statements for annual and interim periods beginning after November 15, 2009. The Company has not yet determined the impact of adoption on its financial position or results of operations.

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

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 hedge positions, discounted at 10% (the ceiling), and the lower of cost or fair value of unproved properties adjusted for related income tax effects.

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Accordingly, based on March 31, 2009 pricing of $3.76 per Mcfe 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.

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 September 30, 2009 prices for oil and natural gas, the Company had an excess of the ceiling over our capitalized costs of $84.6 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 September 30, 2009, the carrying value of the rig exceeded its estimated fair value (based on discounted cash flows) by approximately $0.9 million. However, no impairment was necessary at that date as the undiscounted cash flows exceeded the carrying value. Authoritative accounting guidance provides for impairment only when undiscounted cash flows exceed carrying value.

4. FAIR VALUE MEASUREMENT

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

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

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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

		Fair Value Measurements at September 30, 2009 Using (thousands of dollars)		
Description	September 30, 2009	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)
Assets from price risk management activities (1)	$ 1,836		$ 1,836	
Liabilities from price risk management activities (1)	$ 3		$ 3	
General partner warrants (2)	$ 655		$ 655	

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

(2) 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 $47,000 in additions to asset retirement obligations measured at fair value during the three and nine months ended September 30, 2009.

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.

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5. ACCRUED LIABILITIES

Below is the detail of accrued liabilities on the Company s balance sheets as of September 30, 2009 and December 31, 2008 (thousands of dollars):

	September 30, 2009		December 31, 2008	
Capital expenditures	$	2,322	$	8,227
Operating expenses/taxes		4,152		4,452
Hurricane damage repairs				1,555
Compensation		457		2,478
Interest and accrued bank fees		513		261
General partner warrants		655		
Other		1,269		1,858
Total	$	9,368	$	18,831

6. DEBT

Credit Facility. The Company has a $200 million credit facility with a group of banks (collectively, the Lenders,) with a maturity date of February 21, 2012 (the Credit Facility.) The Credit Facility is subject to borrowing base redeterminations and bears a floating interest rate based on LIBOR or the prime rate of Fortis Capital Corp., the administrative agent of the Lenders. The borrowing base and the interest formula have been redetermined or amended multiple times. As of December 31, 2008, the borrowing base was $95 million and was fully drawn. The interest rate formula in effect at that date was LIBOR plus 3.25% or prime plus 2.5%.

Obligations under the Credit Facility are to be secured by pledges of outstanding capital stock of the Company s subsidiaries and by a first priority lien on not less than 75% (95% in the case of an event of default) of its present value of proved oil and natural gas properties. The Credit Facility also contains other restrictive covenants, including, among other items, maintenance of certain financial ratios, restrictions on cash dividends on common stock and under certain circumstances preferred stock, limitations on the redemption of preferred stock, limitations on repurchases of common stock, restrictions on incurrence of additional debt, and an unqualified audit report on the Company s consolidated financial statements.

As of December 31, 2008, the Company was in default of two of the covenants under the agreement, including one that requires that the Company maintain a current ratio (as defined in the Credit Facility) of one to one. The current ratio, as defined, was less than the required one to one at December 31, 2008, March 31, 2009, June 30, 2009, and September 30, 2009. The Company is also in default of the requirement that the Company s auditors opinion for the current financial statements be without modification. The Company s 2008 audit report from its independent registered accounting firm included a going concern explanatory paragraph that expressed substantial doubt about the Company s ability to continue as a going concern. As a result of the defaults, the outstanding Credit Facility balances of $95 million at December 31, 2008 and $90.5 million at September 30, 2009 have been classified as current in the accompanying consolidated balance sheets. Also in response to the defaults, the Company provided additional security to the Lenders, such that first priority liens cover in excess of 95% of the present value of proved oil and natural gas properties.

The Credit Facility has been subject to semi-annual borrowing base redeterminations effective on April 30 and October 31 of each year, with limited additional unscheduled redeterminations also available to the Lenders or the Company. The determination of the borrowing base is subject to a number of factors, including quantities of proved oil and natural gas reserves, the banks price assumptions related to the price of oil and natural gas and other various factors unique to each member bank. The Lenders can redetermine the borrowing base to a lower level than the current borrowing base if they determine that the Company s oil and natural gas reserves, at the time of redetermination, are inadequate to support the borrowing base then in effect. In the event the redetermined borrowing base is less than outstanding borrowings under the Credit Facility, the Credit Facility requires repayment of the deficit within a specified period of time.

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

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

On September 3, 2009, the Company entered into a forbearance agreement with the Lenders under the Credit Facility (Bank Forbearance Agreement). The Bank Forbearance Agreement provided that the Lenders would forbear from exercising any right or remedy arising as a result of certain existing events of default under the Credit Facility until the earlier of December 3, 2009 or the date that any default occurred under the Bank Forbearance Agreement. This date has subsequently been extended to December 19, 2009 or the date that any default occurs under the Bank Forbearance Agreement.

As required by the Bank Forbearance Agreement, on September 3, 2009 the Company paid the Lenders $2.0 million of principal owed under the Credit Facility. The agreement required additional monthly principal payments of the greater of excess cash flow, as defined in the agreement, or $1.0 million for each of the months September through December 2009. Accordingly, the Company paid the Lenders $1.0 million on each of September 10, September 30, and October 30, 2009, bringing the current balance to $89.5 million as of November 9, 2009. An additional $1.0 million payment is scheduled for December 10, 2009 under the terms of the Bank Forbearance Agreement (or a greater amount if excess cash flow is greater than $1.0 million). The Company also agreed to pay a forbearance fee of $945,000, one-fourth of which was paid on each of September 3, September 30, and October 30, 2009, and one-fourth of which remains to be paid on December 2, 2009. The entire fee was charged to interest expense in the third quarter of 2009. In addition, the Company incurred approximately $800,000 in legal and consulting fees to originate the Bank Forbearance Agreement and other related agreements. Upon execution of the Third Amendment to Forbearance and Amendment Agreement on October 20, 2009, the Company agreed to pay an additional $226,000 in forbearance fees to the Lenders for an extension of time to comply with certain terms of the Bank Forbearance Agreement, which will be payable on November 15, 2009. This will be charged to interest expense in the fourth quarter of 2009.

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

The agreement provided for early termination of the forbearance period in case of certain events. As of September 30, 2009, the Company failed to enter into a sale or merger, capital infusion, or purchase and sale agreement sufficient to provide the funds to repay the borrowing base deficiency. This had been a condition to continuation of forbearance. This date was subsequently extended to November 15, 2009.

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The terms of the extension also require that some form of transaction be completed by November 15, 2009. The Company will not be able to enter into and complete such a transaction by that date.

Under the terms of the Bank Forbearance Agreement, as amended, the Credit Facility is amended such that scheduled borrowing base redeterminations will occur quarterly rather than semi-annually, to be effective January 31, April 30, July 31, and October 31 of each year. Any incremental borrowing base deficiency not covered by the Bank Forbearance Agreement must be repaid according to certain defined terms, or the forbearance period ends. The deficiency could be paid in three equal installments over a maximum period of 90 days, or alternatively, the Company could provide additional sufficient collateral to cover the deficiency. However, as the Company has already pledged in excess of 95% of the value of all proved oil and natural gas reserves as security, such an alternative could apply only to a small borrowing base deficiency. The Lenders have informed the Company that the borrowing base will be redetermined effective November 20, 2009. No assurance can be given that further deficiencies will not be incurred. No assurance can be given that the forbearance period will provide the Company with sufficient time to resolve the deficiencies and forestall further default.

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

***Rig Note*.** On May 2, 2008, the Company, through its wholly owned subsidiary TMRD, entered into a financing agreement (rig note) with The CIT Group / Equipment Financing, Inc. (CIT). Under the terms of the agreement, TMRD borrowed $10.0 million, at a fixed interest rate of 6.625%, which increases in an event of default. The loan is collateralized by the drilling rig, as well as general corporate credit. The term of the loan is five years, expiring on May 2, 2013.

Effective as of December 31, 2008, the Company is in default under the rig note. Under the terms of the rig note, a default under the Credit Facility triggers a cross-default under the rig note. The remedies available to CIT in the event of default include acceleration of all principal and interest payments. Accordingly, all indebtedness under the rig note, $8.8 million at December 31, 2008 and $6.5 million at September 30, 2009, has been classified as current in the accompanying consolidated balance sheets.

On September 3, 2009, the Company also entered into a forbearance agreement with CIT (CIT Forbearance Agreement.) The forbearance period under the CIT Forbearance Agreement expires December 3, 2009, or earlier if there is any default under either it or the Bank Forbearance Agreement. 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 interest expense in the third quarter, a forbearance fee of approximately $50,000. There can be no assurance that the forbearance period under the CIT Forbearance Agreement will provide sufficient time to resolve the cross-default under the rig note.

7. INCOME TAXES

The Company s effective income tax rate has varied significantly in recent periods. In the first nine months of 2008, the effective income tax rate was 55%, which is higher than the corporate income tax rate of 35% primarily due to state taxes and permanent differences, in addition to a $1.2 million write-down of a deferred tax asset in the third quarter of 2008, related to shares issued from the deferred compensation plan (see Note 10 below). In the fourth quarter of 2008 and the first quarter of 2009, the Company recorded significant non-cash impairment losses (see Note 3). The Company does not expect to realize its deferred tax assets, and therefore recorded a valuation allowance as of December 31, 2008 to the full extent of all net deferred tax assets. The allowance was adjusted in the first nine months of 2009 to maintain this complete offset of all deferred tax assets. Thus, the tax benefit related to net losses recognized in the first, second and third quarters of 2009 was zero, and the effective tax rate for the first nine months is 0%.

8. COMMITMENTS AND CONTINGENCIES

Litigation

H. L. Hawkins litigation. In December 2004, the estate of H.L. Hawkins filed a claim against Meridian for damages estimated to exceed several million dollars for Meridian s alleged gross negligence, willful misconduct and breach of fiduciary duty under certain agreements concerning certain wells and property in the S.W. Holmwood and E. Lake Charles Prospects in Calcasieu Parish in Louisiana, as a result of Meridian s 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 September 30, 2009.

Parsons Exploration litigation. On May 3, 2007, Parsons Exploration Company, LLC (Parsons) filed a claim against Meridian for damages and specific performance requiring Meridian to assign Parsons an overriding royalty interest in certain wells the Company has drilled in east Texas. The complaint alleged that the Company breached its contractual and fiduciary obligations to Parsons under an Exploration and Prospect Origination Agreement between the parties dated April 22, 2003. The complaint also alleged that the Company engaged in a civil conspiracy to breach its contractual and fiduciary obligations to Parsons and tortiously interfered with existing and prospective business relationships/contracts of Parsons. The Company recognized an estimated settlement for this matter in the amount of $2.1 million in the first quarter of 2009, which was charged to the full cost pool. The parties reached a final settlement agreement in the second quarter of 2009.

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. Shell has not to date produced all of the supporting documentation for its claim. 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. An arbitration panel has been selected and an initial conference was held with the panel on July 31, 2009. The two companies have entered into settlement discussions. Meridian denies that it owes any indemnity under either of the two acquisition agreements; however, the amounts claimed are substantial in nature and if adversely determined, would have a material adverse effect on the Company. The Company is unable to express an opinion with respect to the likelihood of an unfavorable outcome of these matters or to estimate the amount or range of potential loss should any outcome be unfavorable. Therefore, the Company has not provided any amount for these matters in its financial statements at September 30, 2009.

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 September 30, 2009. The Company has not provided any amount for this matter in its financial statements at September 30, 2009.

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

Litigation involving insurable issues. There are no material legal proceedings involving insurable issues which exceed insurance limits to which Meridian or any of its subsidiaries is a party or to which any of its property is subject, other than ordinary and routine litigation incidental to the business of producing and exploring for crude oil and natural gas.

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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 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. This is known as the ceiling test. The Company recorded significant impairment charges against oil and gas properties based on the results of the ceiling test in the fourth quarter of 2008 and again in the first quarter of 2009.

At September 30, 2009, the Company had a cushion (i.e., the excess of the ceiling over capitalized costs) of approximately $84.6 million (pretax and after-tax). A 10% increase in prices would have increased the cushion by approximately 43%. A 10% decrease in prices would have decreased the cushion by approximately 43%. Decreases in prices affecting the end of subsequent accounting periods, net of the effect of the Company s hedging positions, may necessitate additional impairment charges. Any future impairment would be impacted by changes in the accumulated costs of oil and natural gas properties, which may in turn be affected by sales or acquisitions of properties and additional capital expenditures. Future impairment would also be impacted by changes in estimated future net revenues, which are impacted by additions and revisions to oil and natural gas reserves, as well as by sales and acquisitions of properties.

Due to the redetermination of the borrowing base under the Credit Facility, the Company is considering sales of assets to generate cash for repayment of debt. Sales of significant assets would impact future ceiling tests, as their estimated future after-tax net revenues would be removed from the calculation. Proceeds from sales of properties are generally credited to the full cost pool, reducing the carrying value of oil and gas properties subject to the ceiling test. The Company cannot predict whether significant property sales will cause additional ceiling test impairments, but it is possible that they will.

In addition, the new guidance provided by the SEC s Final Rule, Modernization of Oil and Gas Reporting will change how the Company computes the value of oil and natural gas reserves when it becomes effective for reporting at December 31, 2009. The Company will use average prices for the most recent twelve months to value reserves, whereas it currently uses period-end prices. This change will impact the ceiling test and any related cushion.

Drilling rigs. As described in Note 2, the Company has significant contractual obligations for the use of two drilling rigs. The Company s capital expenditure plans no longer include full use of these rigs; however, the Company is obligated for the dayrate regardless of whether the rigs are working or idle. The operator, Orion, has sought other parties to use the rigs and agreed to credit the Company s obligation, based on revenues from third parties who utilize the rig(s) when the Company is unable to. Management cannot predict whether utilization of the rigs by third parties will be consistent, nor to what extent it may offset obligations under the dayrate contracts. The Company has not provided any amount for any future losses on these drilling contracts in its financial statements at September 30, 2009. The two drilling contracts will terminate in February 2011 (as to the rig not owned by the Company) and March 2010 (as to the rig owned by the Company and operated by Orion).

The Company entered into a forbearance agreement with Orion which may grant title to the company-owned rig to Orion, the operator under both the dayrate contracts, in exchange for release of all accrued and future liabilities under the rig contracts. This would occur at termination and final payment of the related rig note held by CIT, which is scheduled for 2013, if the Company continues to perform its obligations under the rig note and the rig is free of any security interest at title transfer. Both the rig value and the net payable to Orion would be written off at the time of such title transfer, if it were to occur. Alternatively, the terms of the forbearance agreement allow the Company an option to settle all claims with Orion in cash at the end of the term of the rig note, and retain title to the rig. There can be no assurance that the forbearance period under the CIT Forbearance Agreement will provide sufficient time to cure the cross-default under the rig note with CIT and ensure performance under the Orion forbearance agreement. All accrued unpaid liabilities for rig expense are classified in the accompanying consolidated balance sheet as current. At September 30, 2009, the rig is included in equipment at a net book value of $4.9 million, and accounts payable includes a total of $3.0 million in accrued unpaid invoices from Orion for underutilization of the rig, which is net of a reduction of $648,000 estimated as the Company s share of profits on the rig. The Company performs impairment testing of the rig each quarter; see Note 3.

9. STOCKHOLDER S EQUITY

Common Stock

In March 2007, the Company s Board of Directors authorized a share repurchase program; an amendment to the credit agreement at that time increased the available limit for the Company s repurchase of its common stock from $1.0 million to $5.0 million annually, so long as the Company was in compliance with certain provisions of the Credit Facility. From March 2007, the inception of the share repurchase program, through September 30, 2009, the Company had repurchased 535,416 common shares at a cost of $1,234,000, of which 501,300 shares have been reissued for 401(k) contributions, for contract services and for compensation, and 34,116 have been retired. The Bank Forbearance Agreement prohibits any further repurchase of Company stock. The Company did not repurchase any shares during the nine months ended September 30, 2009 and does not expect to make share repurchases in the foreseeable future.

General Partner Warrants

As of December 31, 2008, the Company had outstanding warrants (the General Partner Warrants) that entitle Joseph A. Reeves, Jr. and Michael J. Mayell to purchase an aggregate of 1,884,544 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 retained earnings to reflect the cumulative effect of recording the 1,884,544 warrants at fair value, with an offsetting entry to accrued liabilities. Adjustments to fair value have been made on a prospective basis, beginning in 2009. For the nine months and three months ended September 30, 2009, the Company recorded a gain (loss) on the valuation of the warrants of $306,000 and ($94,000), respectively, which is included in General and Administrative Expense.

At September 30, 2009, 1,872,998 General Partner Warrants were outstanding and included in accrued liabilities at a total fair value of $655,000. Fair value is based on the Black-Scholes model for option pricing.

Other

Other significant changes in stockholders equity include the distribution of shares from treasury in the second quarter of 2009, as described in Note 10.

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10. CONTRACT SETTLEMENTS AND RABBI TRUST

In April 2008 the Company made significant changes in the structure of the compensation of two executives, Mr. Joseph A. Reeves and Mr. Michael J. Mayell, former Chief Executive Officer and former Chief Operating Officer. Effective April 29, 2008, the employment contracts for Messrs. Reeves and Mayell were replaced with new agreements. In addition, certain other agreements that governed other elements of their compensation packages were also settled. As a result of the agreements, the Company recorded $9.9 million in contract settlement expense in the second quarter of 2008, and placed that amount of cash in a Rabbi Trust for the former officers. In June 2009, pursuant to the contractual terms, the cash was distributed from the trust to the former officers.

In addition, the Company discontinued the deferred compensation plan provided to these officers, which resulted in the issuance of a total of 1,803,291 shares of new common stock for Messrs. Reeves and Mayell (combined) on July 2, 2008. The shares issued were net of a reduction of 1,001,511 shares withheld from issuance in lieu of the former executives personal withholding tax. An additional 1,712,114 new shares (856,057 shares to each of the two former officers) were placed in the Rabbi Trust in the third quarter of 2008, and distributed to the former officers in June 2009. The shares were again issued net of shares withheld for personal withholding tax (a total of 610,938 shares were withheld from distribution and retired). Substantially all of the compensation expense related to these shares was recognized historically, when the rights to such future shares were granted.

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

11. EARNINGS (LOSS) 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 September 30,	
	2009	**2008**
Numerator:		
Net earnings (loss)	$ (768)	$ 699
Denominator:		
Denominator for basic earnings per share weighted-average shares outstanding	92,472	92,349
Effect of potentially dilutive common shares:		
Warrants and stock rights (a)	NA	1,775
Employee and director stock options (a)	NA	19
Denominator for diluted earnings per share weighted-average shares outstanding and assumed conversions	92,472	94,143
Basic earnings (loss) per share	$ (0.01)	$ 0.01
Diluted earnings (loss) per share	$ (0.01)	$ 0.01

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	Nine Months Ended September 30,			
	2009		2008	
Numerator:				
Net earnings (loss)	$	(63,191)	$	5,101
Denominator:				
Denominator for basic earnings per share weighted-average shares outstanding		92,461		91,035
Effect of potentially dilutive common shares:				
Warrants and stock rights (a) (b)		NA		3,606
Employee and director stock options (a) (b)		NA		12
Denominator for diluted earnings per share weighted-average shares outstanding and assumed conversions		92,461		94,653
Basic earnings (loss) per share	$	(0.68)	$	0.06
Diluted earnings (loss) per share	$	(0.68)	$	0.05

(a) The number of warrants excluded for the three months and nine months ended September 30, 2009 totaled approximately 3.3 million. The number of options excluded for those periods totaled approximately 0.7 million. All outstanding warrants and options were excluded, as all would be anti-dilutive to the net losses for those periods.

(b) The number of warrants excluded for the three months and nine months ended September 30, 2008 totaled approximately 1.4 million, because their exercise price was anti-dilutive. A weighted average total of 2.2 million and 3.0 million options were excluded for the three months and nine months ended September 30, 2008, respectively, because their exercise prices were 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. Stock rights issued under our deferred compensation plan had no exercise price and are included in diluted earnings per share for the nine months ended September 30, 2008. The plan was discontinued in the second quarter of 2008 and the rights were subsequently converted to shares. All potentially dilutive shares, whether from options, warrants, or rights, are excluded when there is an operating loss, because inclusion of such shares would be anti-dilutive.

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12. RISK MANAGEMENT ACTIVITIES

Management of Financial Risk

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

Oil and Natural Gas Hedging Contracts

The Company has historically utilized derivative contracts to hedge the sale of a portion of its future production. The Company s objective is to reduce the impact of commodity price fluctuations on both income and cash flow, as well as to protect future revenues from adverse price movements. Management considers some exposure to market pricing to be desirable, due to the potential for favorable price movements, but prefers to achieve a measure of stability and predictability over revenues and cash flows by hedging some portion of production. The Company s commodity derivative positions as of September 30, 2009 hedge approximately 33% of proved developed natural gas production and 13% of proved developed oil production during the remaining terms of all derivative agreements in the aggregate. All the Company s hedging agreements expire in December 2009. All of the Company s hedging agreements are executed by affiliates of the Lenders under the Credit Facility and are collateralized by the security interest the Lenders have in the oil and natural gas assets of the Company. Due to the previously discussed defaults under the Credit Facility, the Lenders have not allowed the Company to enter into any additional hedging agreements. As a result, the Company s oil and natural gas sales for periods beyond December 2009 will more closely resemble prevailing market prices.
The Company s current derivative contracts are primarily floor contracts. These agreements ensure the Company receives a minimum (floor) price for the commodity. The Company holds a single collar contract which also contains a ceiling, or maximum price the Company may receive. Typically, the contracts specify monthly hedged volumes subject to the floor and ceiling prices over a period of 6 to 18 months. The contracts are settled monthly based on the NYMEX futures contract. The following table lists all of the Company s commodity derivative contracts as of September 30, 2009:

	Type	Notional Amount	Floor Price ($ per unit)	Ceiling Price ($ per unit)	Estimated Fair Value Asset (Liability) September 30, 2009 (in thousands)
Natural Gas (mmbtu)					
Oct 2009 Dec 2009	Floor	250,000	$ 7.50		$ 705
Oct2009 Dec 2009	Floor	160,000	$ 8.00		522
Oct 2009 Dec 2009	Floor	110,000	$ 8.00		361
Total Natural Gas					1,588

Crude Oil (bbls)									
Oct 2009	Dec 2009	Collar	5,000	$	70.00	$	93.55		18
Oct 2009	Dec 2009	Floor	7,000	$	80.00				77
Oct 2009	Dec 2009	Floor	10,000	$	85.00				150
Total Crude Oil									245
								$	1,833

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Accounting and financial statement presentation for derivatives

The Company accounts for its derivative contracts under the provisions of ASC 815, Derivatives and Hedging. Under ASC 815, the Company s commodity derivatives are designated as cash-flow hedges and are stated at fair value on the Consolidated Balance Sheets. See Note 4, Fair Value Measurements for further information on how fair values of derivative instruments are determined. Changes in the fair value of the contracts, which occur due to commodity price movements, are offset in Accumulated Other Comprehensive Income. When the derivative contract or a portion of it matures, the gain or loss is settled in cash and reclassified from Accumulated Other Comprehensive Income to Revenues from Oil and Natural Gas. Net settlements under hedging agreements increased (decreased) oil and natural gas revenues by $2.8 million and ($2.4 million) for the three months ended September 30, 2009 and 2008, respectively and $9.8 million and ($5.8 million) for the nine months ended September 30, 2009 and 2008, respectively. A gain or loss may be recorded to earnings prior to contract maturity if a portion of the cash flow hedge becomes ineffective under the guidelines provided under generally accepted accounting principles, or if the forecasted transaction is no longer expected to occur. Although the Company periodically records gains or losses from hedge ineffectiveness, there have been no losses recorded due to changes in expectations regarding occurrence of the hedged transactions. The following two tables provide information regarding assets, liabilities, gains, and losses related to derivative contracts, and where these amounts are reflected within the Company s financial statements (in thousands):

	Fair Values of Derivative Contracts at	
Description and location within Consolidated Balance Sheet	September 30, 2009	December 31, 2008
Derivative contracts designated as hedging instruments		
Commodities Contracts		
Current assets from price risk management activities	$ 1,836	$ 8,447
Non-current assets from price risk management activities		
Current liabilities from price risk management activities	$ 3	$ 311
Non-current liabilities from price risk management activities		
Derivative contracts not designated as hedging instruments	NONE	NONE

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

Description	Location of Gain (Loss) within Financial Statements	For the three months ended September 30, 2009	For the three months ended September 30, 2008	For the nine months ended September 30, 2009	For the nine months ended September 30, 2008
Derivative contracts designated as cash flow hedging instruments:					
Gain (loss) on derivative contracts recognized in Other Comprehensive Income (OCI)					
Commodities Contracts	Accumulated Other Comprehensive Income	304	12,479	3,460	(3,396)
Gain (loss) on derivative contracts reclassified from OCI to earnings					
Commodities Contracts	Oil and Natural Gas Revenues	2,758	(2,438)	9,781	(5,757)
Gain (loss) due to hedging ineffectiveness reported in earnings					
Commodities Contracts	Revenues from Price Risk Management Activities	(2)	3	(5)	(27)
Fair value of derivative contracts designated as cash flow hedging instruments, excluded from effectiveness assessments		NONE	NONE	NONE	NONE
Derivative contracts not designated as hedging instruments		NONE	NONE	NONE	NONE

As of September 30, 2009, the Company had an unrealized gain of $1.8 million (pre-tax and net of tax) deferred in Accumulated Other Comprehensive Income. Based upon oil and natural gas commodity prices at September 30, 2009, all of the unrealized gain deferred in Accumulated Other Comprehensive Income could potentially increase gross revenues in the next three months. These derivative agreements expire December 31, 2009.

Special terms in derivative contracts

Although the Company s counterparties provide no collateral, the master derivative agreements with each counterparty effectively allow the Company, at its option, so long as it is not a defaulting party, after a default or the occurrence of a termination event, to set-off an unpaid hedging agreement receivable against the interest of the counterparty in any outstanding balance under the Credit Facility. In practice, no such set-off has been made, and all settlements have been made in cash. As of December 31, 2008, the Company was in default, and continuing at September 30, 2009, the Company is in default under the Credit Facility, the breach of which is also a cross-default under the master derivative agreements. Although the Company s hedge counterparties have continued to make contract payments subsequent to the default, they are not obligated to make payments to the Company under the hedging agreements while the Company s default is continuing. The Company s set-off rights under the master derivative agreements cannot be exercised due to such default. The Company s hedging counterparties may exercise their remedies under the hedging agreements, and potentially under the Credit Facility, on account of the Company s default, which includes a right to terminate the agreements and set-off any settlement amount due to the Company against amounts owed under the Credit Facility. The settlement amount would be based on the estimated value of the remaining forward portion of the contracts based on market values at settlement. However, the Company reached a forbearance agreement with the counterparty which holds a significant majority of these contracts. So long as the hedge forbearance agreement is in place, no remedies will be undertaken by that counter-party. The hedge forbearance agreement expires November 30, 2009, or sooner if the Company has any event of default under the Bank Forbearance Agreement.

If a counterparty were to default in payment of an obligation under the master derivative agreements, the Company would be exposed to commodity price fluctuations, and the protection intended by the hedge would be lost. The value of assets from price risk management would be impacted. In addition, as expected cash flows from hedging contracts are included in computing future net revenues, the ceiling test could be impacted, which could result in a non-cash write-down of oil and natural gas properties.

13. 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 $29,000 and $126,000 was recorded for the three months and nine months ended September 30, 2009, respectively, and $180,000 and $1,505,000 was recorded for the three months and nine months ended September 30, 2008, respectively. Compensation paid in share-based awards included stock options and non-vested shares granted to our employees and directors and stock rights awarded under our deferred compensation plan for certain executives, which was discontinued after April 2008.

14. 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 nine months ended September 30, 2009 (thousands of dollars):

Asset retirement obligation at December 31, 2008	$ 22,225
Additional retirement obligations recorded in 2009	47
Settlements during 2009	(2,079)
Revisions to estimates and other changes during 2009	(311)
Accretion expense for 2009	1,573
Asset retirement obligation at September 30, 2009	21,455
Less: current portion	3,719
Asset retirement, long-term, at September 30, 2009	$ 17,736

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.

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

Operations Update

Production volumes for the third quarter of 2009 totaled 3.0 billion cubic feet of gas equivalent (Bcfe), or an average of 33 million cubic feet of natural gas equivalent per day (Mmcfe/d) compared to 3.1 Bcfe or 33 Mmcfe per day for the third quarter of 2008. Sequentially, production is down compared to the average daily production of 38 Mmcfe/d in the second quarter of 2009. Although the Company has been able to maintain a relatively even level of production for the past several quarters, we are now seeing a gradual decline in daily production levels as a result of the reduction in capital spending in the past two quarters. Currently production is approximately 31.5 Mmcfe per day.

Capital Expenditure Plans for 2009

The Company anticipates the remaining 2009 capital spending budget will be primarily used for required abandonment of existing wells and facilities. We anticipate that the budget will be significantly lower than in past years, reflecting our expectations of reduced cash flows due to commodity price declines and the loss of availability of funds under our credit facility (Credit Facility), as well as various spending restrictions imposed by the terms of the forbearance agreements. These factors will significantly impact funds available for capital spending. We currently anticipate funding capital expenditures for the remainder of 2009 by utilizing cash flow from operations and cash on hand.

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 (after adjustments for hedging activities) for the three months ended September 30, 2009, was $65.06 per barrel compared to $99.42 per barrel for the three months ended September 30, 2008, and $55.09 per barrel for the three months ended June 30, 2009. Our average natural gas price (after adjustments for hedging activities) for the three months ended September 30, 2009, was $4.68 per Mcf compared to $9.67 per Mcf for the three months ended September 30, 2008, and $4.85 per Mcf for the three months ended June 30, 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 year, resulting in the closing or restructuring of numerous large financial institutions. Extreme uncertainty about creditworthiness, liquidity and interest rates, as well as the global economic recession, continue to limit credit availability. In addition, the market value of the Company s reserves has decreased, both in the fourth quarter of 2008 and in the first quarter of 2009, though a partial recovery of prices occurred in the second and third quarters of 2009, due primarily to energy price fluctuations. Our access to credit has 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, 2008, 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 nine months ended September 30, 2009, we recorded a reduction of general and administrative expense of $306,000 due to the change in fair value of the warrants; for the three months ended September 30, 2009 the revaluation of the warrants increased expense by $94,000. The factors that determine the fair value are not in our control and may potentially produce a more material impact on future consolidated statements of operations.

Results of Operations

Three Months Ended September 30, 2009 Compared to Three Months Ended September 30, 2008

Operating Revenues. Third quarter 2009 oil and natural gas revenues, which include oil and natural gas hedging activities (see Note 12 of Notes to Consolidated Financial Statements), decreased $14.9 million (40%) as compared to third quarter 2008 revenues due to a 2% decrease in production volumes and a 39% decrease in average commodity prices on a natural gas equivalent basis. Oil and natural gas production

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volumes totaled 3,008 Mmcfe for the third quarter of 2009 compared to 3,060 Mmcfe for the comparable period of 2008. Our average daily production decreased slightly from 33.3 Mmcfe during the third quarter of 2008 to 32.7 Mmcfe for the third quarter of 2009. Third quarter 2009 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 September 30, 2009 and 2008:

	Three Months Ended September 30,		Increase
	2009	2008	(Decrease)
Production Volumes:			
Oil (Mbbl)	213	174	22%
Natural gas (MMcf)	1,731	2,017	(14%)
Mmcfe	3,008	3,060	(2%)
Average Sales Prices:			
Oil (per Bbl)	$ 65.06	$ 99.42	(35%)
Natural gas (per Mcf)	4.68	9.67	(52%)
Mmcfe	7.30	12.03	(39%)
Operating Revenues (000 s):			
Oil	$ 13,848	$ 17,299	(20%)
Natural gas	8,102	19,507	(58%)
Total Operating Revenues	$ 21,950	$ 36,806	(40%)

Operating Expenses. Oil and natural gas operating expenses on an aggregate basis decreased $2.3 million (39%) to $3.6 million during the third quarter of 2009, compared to $5.9 million in the third quarter of 2008. On a unit basis, lease operating expenses decreased $0.73 per Mcfe to $1.21 per Mcfe for the third quarter of 2009 from $1.94 per Mcfe for the third quarter of 2008. Oil and natural gas operating expenses decreased primarily due to reduced labor costs, decreased compressor, salt water disposal, and fuel costs, lower insurance costs, and lower platform and facility charges.

Severance and Ad Valorem Taxes. Severance and ad valorem taxes decreased $0.6 million (25%) to $1.9 million for the third quarter of 2009, compared to $2.6 million during the same period in 2008 primarily due to a decrease in taxes per Mcfe. On an equivalent unit of production basis, severance and ad valorem taxes decreased to $0.64 per Mcfe from $0.83 per Mcfe for the comparable three-month period. This unit decrease is primarily related to the decrease in oil and natural gas prices.

Depletion and Depreciation. Depletion and depreciation expense decreased $7.8 million (49%) during the third quarter of 2009 to $8.1 million, from $15.9 million for the same period of 2008. This was primarily the result of the decline in the depletion rate as compared to the 2008 period. The reduction in the rate is due to the decrease in the carrying value of oil and natural gas properties which resulted from the significant impairment write-downs to the properties recorded in December 2008 and March 2009. On a unit basis, depletion and depreciation expense decreased by $2.50 per Mcfe, to $2.69 per Mcfe for the three months ended September 30, 2009, compared to $5.19 per Mcfe for the same period in 2008.

General and Administrative Expense. General and administrative expense was $4.5 million in the third quarter of 2009 compared to $5.9 million in the third quarter of 2008. The $1.4 million decrease was primarily due to reductions in staff and associated costs, partially offset by approximately $800,000 in legal and consulting fees incurred in the third quarter of 2009 to originate certain forbearance agreements described below. On an equivalent unit of production basis, general and administrative expenses decreased $0.44 per Mcfe to $1.50 per Mcfe for the third quarter of 2009 compared to $1.94 per Mcfe for the comparable 2008 period primarily due to the Company s staff reductions.

Rig Operations, Net. Rig operations, net is the expense related to underutilized contracted drilling rigs. The Company has 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 $1.2 million in the third quarter of 2009; there was no corresponding expense in the third quarter of 2008.

Interest Expense. Interest expense increased $1.5 million (106%), to $2.9 million for the third quarter of 2009 in comparison to $1.4 million for the third quarter of 2008. Interest expense for the third quarter of 2009 includes a charge of $1.0 million in forbearance fees, paid to originate the forbearance agreements described below. The increase is also the result of higher average debt balances and the implementation of higher interest rates applicable when the loans are in default. See Liquidity and Capital Resources, below, for further information.

Taxes on Income. Income tax expense for the third quarter of 2009 was zero, compared to $2.6 million in the third quarter of 2008. The elimination of tax benefit from losses originated in the fourth quarter of 2008 as a result of the Company s deferred tax asset valuation allowance. Management believes, given the Company s overall current financial position, that there are significant uncertainties regarding its 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.

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008

Operating Revenues. Oil and natural gas revenues during the nine months ended September 30, 2009, which include oil and natural gas hedging activities (see Note 12 of Notes to Consolidated Financial Statements) decreased $55.0 million (45%) as compared to first nine months of 2008 revenues due to a 42% decrease in average sale prices on a natural gas equivalent basis, as well as a 6% decrease in production volumes. Our average daily production decreased from 38.1 Mmcfe during the first nine months of 2008 to 35.9 Mmcfe for the first nine months of 2009. Oil and natural gas production volume totaled 9,792 Mmcfe for the first nine months of 2009, compared to 10,436 Mmcfe for the comparable period of 2008. The variance in production volumes between the two periods is primarily due to natural production declines.

The following table summarizes the Company s operating revenues, production volumes and average sales prices for the nine months ended September 30, 2009 and 2008:

	Nine Months Ended September 30, 2009	2008	Increase (Decrease)
Production Volumes:			
Oil (Mbbl)	643	546	18%
Natural gas (MMcf)	5,936	7,159	(17%)
Mmcfe	9,792	10,436	(6%)
Average Sales Prices:			
Oil (per Bbl)	$ 55.46	$ 95.10	(42%)
Natural gas (per Mcf)	5.24	9.76	(46%)
Mmcfe	6.82	11.67	(42%)
Operating Revenues (000 s):			
Oil	$ 35,642	$ 51,927	(31%)
Natural gas	31,127	69,861	(55%)
Total Operating Revenues	$ 66,769	$ 121,788	(45%)

Operating Expenses. Oil and natural gas operating expenses on an aggregate basis decreased $6.3 million (33%) to $12.9 million during the first nine months of 2009, compared to $19.2 million in 2008. Expenses decreased primarily due to reduced labor costs, saltwater disposal fees, fuel and compression charges, platform and facility charges and lower insurance costs. On a unit basis, lease operating expenses decreased $0.52 per Mcfe to $1.32 per Mcfe for the first nine months of 2009 from $1.84 per Mcfe for the first nine months of 2008. The decrease in the per Mcfe rate is due to the reduction in expenses.

Severance and Ad Valorem Taxes. Severance and ad valorem taxes decreased $2.6 million (32%), to $5.5 million for the first nine months of 2009 in comparison to the same period in 2008, primarily because of the decrease in prices. On an equivalent unit of production basis, severance and ad valorem taxes decreased $0.21 to $.57 per Mcfe for the first nine months of 2009 from $0.78 per Mcfe for the comparable nine month period.

Depletion and Depreciation. Depletion and depreciation expense decreased $22.3 million (43%) during the first nine months of 2009 to $29.2 million, from $51.5 million for the same period of 2008. This was primarily the result of the decline in the depletion rate as compared to the 2008 period. The reduction in the rate is due to the decrease in the carrying value of oil and natural gas properties which resulted from the significant impairment write-downs to the properties recorded in December 2008 and March 2009. On a unit basis, depletion and depreciation expense decreased by $1.95 per Mcfe, to $2.98 per Mcfe for the nine months ended September 30, 2009, compared to $4.93 per Mcfe for the same period in 2008.

General and Administrative Expense. General and administrative expense was $12.2 million for the first nine months of 2009 and for the same period in 2008 was $15.2 million. This decrease was primarily due to reductions in staff and associated costs, partially offset by approximately $800,000 in legal and consulting fees incurred in the third quarter of 2009 to originate certain forbearance agreements described below. On an equivalent unit of production basis, general and administrative expenses decreased $0.22 per Mcfe to $1.24 per Mcfe for the first nine months of 2009 compared to $1.46 per Mcfe for the comparable 2008 period.

Rig Operations, Net. Rig operations, net is the expense related to underutilized contracted drilling rigs. The Company has 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 $3.0 million in the first nine months of 2009; there was no corresponding expense in the first nine months of 2008.

Contract Settlement Expense. Contract settlement expense of $9.9 million was recorded in the second quarter of 2008 when the employment contracts of certain executive officers were renegotiated. See further information in Note 10 of Notes to Consolidated Financial Statements. Restricted cash decreased $9.9 million in June 2009 when the obligation was discharged by distributing funds from a rabbi trust account. There is no comparable expense in 2009.

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 in the first nine months of 2009. There was no corresponding item in the first nine months of 2008.

Interest Expense. Interest expense increased $2.1 million (53%), to $6.0 million for the first nine months of 2009 in comparison to the first nine months of 2008. Interest expense for the third quarter of 2009 includes a charge of $1.0 million in forbearance fees, paid to originate the forbearance agreements described below. The increase is also the result of higher average debt balances and the implementation of higher interest rates applicable when the loans are in default. See Liquidity and Capital Resources, below, for further information.

Liquidity and Capital Resources

Cash Flows. Net cash provided by operating activities was $16.9 million for the nine months ended September 30, 2009, as compared to $72.9 million for the same period in 2008. The decrease of $56 million was primarily due to lower crude oil and natural gas prices, and to a lesser extent, lower natural gas production volumes, which reduced revenues by $55.0 million. The impact of the revenue decrease was mitigated by a total of $13.4 million in reduced expenses for lease operations, severance and ad valorem taxes, general and administrative, and hurricane-related expenses. Partially offsetting these improvements was an increase in interest expense totaling $2.1 million. The remainder of the decrease in cash flow from operations is due to changes in working capital account balances. The cash outflow from these working capital accounts primarily reflects the paydown in 2009 of obligations to vendors and joint interest partners as we decreased our drilling and other capital expenditures, establishing a lower base of payables related to operations. Other working capital changes included paydown of our retention bonus obligation to our employees (a non-recurring item), which was $2.0 million at the beginning of the year, and a reduction in payables to royalty owners of $1.6 million due to declines in commodities prices. Our trade receivables provided $5.4 million in funds, as that balance also moved to a lower base due to decreased revenues, whereas during the first nine months of 2008, it increased $3.9 million, a use of funds. We anticipate that our cash from operations will continue to be impacted by volatility in the prices of crude oil and natural gas.

Net cash used in investing activities was $20.2 million during the nine months ended September 30, 2009, versus $93.4 million in the first nine months of 2008 due to decreased capital expenditures. In the first nine months of 2009, we participated in drilling only two wells, after which we have confined our activities to required abandonment of existing wells and facilities. We expect to continue with the approach of reduced capital expenditures, funded by cash from operations, for the remainder of 2009.

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This is necessitated by the loss of availability of credit and amounts currently owed under our Credit Facility.

Cash flows used in financing activities during the first nine months of 2009 were $8.2 million, compared to cash provided by financing activities of $17.9 million during the first nine months of 2008 primarily due to the net drawdown on the Credit Facility of $12 million in the first nine months of 2008, plus the additional debt incurred under the rig note in the second quarter of 2008. In contrast, repayments of amounts borrowed under the Credit Facility and the Company s rig note were $4.5 million and $2.4 million, respectively, in the first nine months of 2009.

Outlook. As further described below under Credit Facility, the Company s borrowing base was reduced significantly by our bank group earlier this year. The borrowing base was lowered due primarily to the reduction in borrowing capacity attributable to the value of Meridian s oil and natural gas properties as a result of precipitous declines in commodity prices. As of July 29, 2009, the Company was in payment default of the Credit Facility, in addition to its already-existing covenant default, for failure to pay a borrowing base deficiency of $34.5 million. At November 9, 2009, the current borrowing base is $60 million, and the deficiency is $29.5 million, after giving effect to certain principal payments made in the third and fourth quarters of 2009. The amount outstanding under the Credit Facility is $90.5 million at September 30, 2009 and $89.5 million at November 9, 2009. The Company does not currently have sufficient cash available to repay the deficiency. The Company has entered into a short-term forbearance agreement with the lenders under the Credit Facility, which is currently set to expire December 19, 2009, unless terminated earlier due to the Company s failure to enter into and complete by November 15, 2009 a sale or merger, capital infusion, or purchase and sale agreement sufficient to provide the funds to repay the borrowing base deficiency.

In addition, our default under the Credit Facility resulted in a cross-default under our $6.5 million loan secured in 2008 for the purchase of a drilling rig (see further information below under Rig Note). Default remedies available to the lender include acceleration of all payment of principal and interest. We obtained a forbearance agreement in regard to this cross-default which expires December 3, 2009, or earlier if there is any default under either it or the bank forbearance agreement.

No assurance can be provided that the Company will be able to comply with the terms of the bank forbearance agreement, which includes completion of a significant transaction which would ease our financial position, such as a significant sale of assets, a corporate sale or merger, or a capital infusion. Each of these alternatives is particularly challenging in the current economic environment. The deadline for the completion of such a transaction is currently November 15, 2009, based on the bank forbearance agreement, as amended. The Company will not be able to enter into and complete such a transaction by that date. If the deadline is not met, the bank forbearance period ends, and the forbearance agreement relating to the rig note ends also. Although the lenders have already extended the deadline for the transaction several times, no assurance can be given that any further extensions will be granted, nor that the Company will be able to meet any new deadlines established.

We are seeking to accomplish a significant transaction as prescribed by the bank forbearance agreement, which includes a significant sale of assets, a corporate sale or merger, or a significant capital infusion. However, due to the default under the Credit Facility, we have increased the amount of our oil and natural gas properties provided as security under that agreement to in excess of 95% of the value of these assets. We may not be able to sell assets on terms that we consider advantageous to us and our shareholders, and capital on acceptable terms may not be available from other sources. If we are unable to comply with the terms of the forbearance agreements, the forbearance agreements will terminate, and we would be subject to the exercise of remedies by the parties to those agreements on account of such defaults. The exercise of

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such remedies could potentially result in us seeking protection under federal bankruptcy laws. Such relief could materially and adversely affect the Company and its shareholders.

In addition to uncertainty regarding the current deficiency, the intervals at which the borrowing base will be redetermined recently increased from semi-annually to quarterly. The next redetermined borrowing base will be effective November 20, 2009. The lenders may again choose to reduce the base and thereby increase any deficiency which may exist at that time.

Because of the defaults under the Credit Facility and the rig note, all balances owing under those agreements have been classified as current liabilities in the accompanying balance sheet as of September 30, 2009, resulting in a working capital deficit of $102.5 million. Excluding acceleration of the long-term portion of the two loans, working capital is negative $7.5 million.

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 are the two drilling contracts described in Notes 2 and 8 of the accompanying Notes to Consolidated Financial Statements. Under these contracts, we will continue to be obligated to pay daily rig rates for two drilling rigs regardless of whether we are able to use the rigs or they are idle. This obligation has, in the first nine months of 2009, been mitigated by third party use of the rigs, but we remain liable to the rig operator for any shortfall in rig rate from our contracted rate. Net expense related to underutilization of the rigs was $3.0 million for the first nine months of 2009. The contracts terminate in February 2011 and March 2010. The Company also entered into a forbearance agreement on September 3, 2009 with the rig operator, which runs in tandem with the forbearance agreement related to the rig note.

For a more complete list of contractual obligations, refer to our 2008 Form 10-K, Item 7, Liquidity and Capital Resources, Cash Obligations.

Credit Facility. The Company has a $200 million Credit Facility with a group of banks (collectively, the Lenders,) with a maturity date of February 21, 2012. The Credit Facility is subject to borrowing base redeterminations and bears a floating interest rate based on LIBOR or the prime rate of Fortis Capital Corp., the administrative agent of the Lenders. The borrowing base and the interest formula have been redetermined or amended multiple times. As of December 31, 2008, the borrowing base was $95 million and was fully drawn. The interest rate formula in effect at that date was LIBOR plus 3.25% or prime plus 2.5%.

Obligations under the Credit Facility are to be secured by pledges of outstanding capital stock of the Company s subsidiaries and by a first priority lien on not less than 75% (95% in the case of an event of default) of its present value of proved oil and natural gas properties. The Credit Facility also contains other restrictive covenants, including, among other items, maintenance of certain financial ratios, restrictions on cash dividends on common stock and under certain circumstances preferred stock, limitations on the redemption of preferred stock, limitations on repurchases of common stock, restrictions on incurrence of additional debt, and an unqualified audit report on the Company s consolidated financial statements.

As of December 31, 2008, the Company was in default of two of the covenants under the agreement, including one that requires that the Company maintain a current ratio (as defined in the Credit Facility) of one to one. The current ratio, as defined, was less than the required one to one at December 31, 2008, March 31, 2009, June 30, 2009, and September 30, 2009. The Company is also in default of the requirement that the Company s auditors opinion for the current financial statements be without modification. The Company s 2008 audit report from its independent registered accounting firm included a going concern explanatory paragraph that expressed substantial doubt about the Company s ability to continue as a going concern. As a result of the defaults, the outstanding Credit Facility balances of $95 million at December 31, 2008 and $90.5 million at September 30, 2009 have been classified as current in the accompanying consolidated balance sheets. Also in response to the defaults, the Company provided additional security to the Lenders, such that first priority liens cover in excess of 95% of the present value of proved oil and natural gas properties.

The Credit Facility has been subject to semi-annual borrowing base redeterminations effective on April 30 and October 31 of each year, with limited additional unscheduled redeterminations also available to the Lenders or the Company. The determination of the borrowing base is subject to a number of factors, including quantities of proved oil and natural gas reserves, the banks price assumptions related to the price of oil and natural gas and other various factors unique to each member bank. The Lenders can redetermine the borrowing base to a lower level than the current borrowing base if they determine that the Company s oil and natural gas reserves, at the time of redetermination, are inadequate to support the borrowing base then in effect. In the event the redetermined borrowing base is less than outstanding borrowings under the Credit Facility, the Credit Facility requires repayment of the deficit within a specified period of time.

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

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

On September 3, 2009, the Company entered into a forbearance agreement with the Lenders under the Credit Facility (Bank Forbearance Agreement). The Bank Forbearance Agreement provided that the Lenders would forbear from exercising any right or remedy arising as a result of certain existing events of default under the Credit Facility until the earlier of December 3, 2009 or the date that any default occurred under the Bank Forbearance Agreement. This date has subsequently been extended to December 19, 2009 or the date that any default occurs under the Bank Forbearance Agreement.

As required by the Bank Forbearance Agreement, on September 3, 2009 the Company paid the Lenders $2.0 million of principal owed under the Credit Facility. The agreement required additional monthly principal payments of the greater of excess cash flow, as defined in the agreement, or $1.0 million for each of the months September through December 2009. Accordingly, the Company paid the Lenders $1.0 million on each of September 10, September 30, and October 30, 2009, bringing the current balance to $89.5 million as of November 9, 2009. An additional $1.0 million payment is scheduled for December 10, 2009 under the terms of the Bank Forbearance Agreement (or a greater amount if excess cash flow is greater than $1.0 million). The Company also agreed to pay a forbearance fee of $945,000, one-fourth of which was paid on each of September 3, September 30, and October 30, 2009, and one-fourth of which remains to be paid on December 2, 2009. The entire fee was charged to interest expense in the third quarter of 2009. In addition, the Company incurred approximately $800,000 in legal and consulting fees to originate the Bank Forbearance Agreement and other related agreements. Upon execution of the Third Amendment to Forbearance and Amendment Agreement on October 20, 2009, the Company agreed to pay an additional $226,000 in forbearance fees to the Lenders for an extension of time to comply with certain terms of the Bank Forbearance Agreement, which will be payable on November 15, 2009. This will be charged to interest expense in the fourth quarter of 2009.

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

The agreement provided for early termination of the forbearance period in case of certain events. As of September 30, 2009, the Company failed to enter into a sale or merger, capital infusion, or purchase and sale agreement sufficient to provide the funds to repay the borrowing base deficiency. This had been a condition to continuation of forbearance. This date was subsequently extended to November 15, 2009. The terms of the extension also require that some form of transaction be completed by November 15, 2009. The Company will not be able to enter into and complete such a transaction by that date.

Under the terms of the Bank Forbearance Agreement, as amended, the Credit Facility is amended such that scheduled borrowing base redeterminations will occur quarterly rather than semi-annually, to be effective January 31, April 30, July 31, and October 31 of each year. Any incremental borrowing base deficiency not covered by the Bank Forbearance Agreement must be repaid according to certain defined terms, or the forbearance period ends. The deficiency could be paid in three equal installments over a maximum period of 90 days, or alternatively, the Company could provide additional sufficient collateral to cover the deficiency. However, as the Company has already pledged in excess of 95% of the value of all proved oil and natural gas reserves as security, such an alternative could apply only to a small borrowing base deficiency. The Lenders have informed the Company that the borrowing base will be redetermined effective November 20, 2009. No assurance can be given that further deficiencies will not be incurred. No assurance can be given that the forbearance period will provide the Company with sufficient time to resolve the deficiencies and forestall further default.

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

***Rig Note*.** On May 2, 2008, the Company, through its wholly owned subsidiary TMRD, entered into a financing agreement (rig note) with The CIT Group / Equipment Financing, Inc. (CIT). Under the terms of the agreement, TMRD borrowed $10.0 million, at a fixed interest rate of 6.625%, which increases in an event of default. The loan is collateralized by the drilling rig, as well as general corporate credit. The term of the loan is five years, expiring on May 2, 2013.

Effective as of December 31, 2008, the Company is in default under the rig note. Under the terms of the rig note, a default under the Credit Facility triggers a cross-default under the rig note. The remedies available to CIT in the event of default include acceleration of all principal and interest payments. Accordingly, all indebtedness under the rig note, $8.8 million at December 31, 2008 and $6.5 million at September 30, 2009, has been classified as current in the accompanying consolidated balance sheets.

On September 3, 2009, the Company also entered into a forbearance agreement with CIT (CIT Forbearance Agreement.) The forbearance period under the CIT Forbearance Agreement expires December 3, 2009, or earlier if there is any default under either it or the Bank Forbearance Agreement. 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 interest expense in the third

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quarter, a forbearance fee of approximately $50,000. There can be no assurance that the forbearance period under the CIT Forbearance Agreement will provide sufficient time to resolve the cross-default under the rig note.

Capital Expenditures. Total capital expenditures for the first nine months of 2009 were approximately $11.6 million. Drilling in the first quarter included two wells, both spudded near the end of the fourth quarter of 2008 in the Austin Chalk play, one operated and one non-operated. There were no wells spudded during the second or third quarters of 2009. Capital expenditures for subsequent quarters will depend on the availability of capital.

The Company anticipates that remaining 2009 capital spending will be primarily used for abandonment of certain existing wells and facilities. Expenditures will be significantly lower than in past years, reflecting reduced cash flows due to commodity price declines and the loss of availability of funds under the Credit Facility. These factors will continue to significantly impact funds available for capital spending. We currently anticipate funding the remainder of 2009 capital expenditures by utilizing cash flow from operations and cash on hand.

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

At March 31, 2009, the unamortized cost of our oil and natural gas properties, net of related deferred income taxes, exceeded the ceiling under the full cost method of accounting for oil and natural gas properties. Accordingly, based on March 31, 2009 pricing of $3.76 per Mcf of natural gas and $49.66 per barrel of oil, in the first quarter of 2009, 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. A non-cash impairment of $216.8 million ($203.2 million after tax) was recognized in the fourth quarter of 2008, based on prices prevailing at the time.

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

At September 30, 2009, the Company had a cushion (i.e., the excess of the ceiling over capitalized costs) of approximately $84.6 million (pretax and after-tax). A 10% increase in prices would have increased the cushion by approximately 43%. A 10% decrease in prices would have decreased the cushion by approximately 43%. Decreases in prices affecting the end of subsequent accounting periods, net of the effect of the Company s hedging positions, may necessitate additional impairment charges. Any future impairment would be impacted by changes in the accumulated costs of oil and natural gas properties, which may in turn be affected by sales or acquisitions of properties and additional capital expenditures. Future impairment would also be impacted by changes in estimated future net revenues, which are impacted by additions and revisions to oil and natural gas reserves, as well as by sales and acquisitions of properties.

In addition, the new guidance provided by the Securities and Exchange Commission s Final Rule, Modernization of Oil and Gas Reporting will change how the Company computes the value of oil and natural gas reserves when it becomes effective for reporting at December 31, 2009. The Company will use average prices for the most recent twelve months to value reserves, whereas it currently uses period-end prices. This change will impact the ceiling test and any related cushion.

Borrowing base for the Credit Facility. The Credit Facility with Fortis Capital Corp. as administrative agent, is presently scheduled for borrowing base redetermination dates on a quarterly basis with the next such redetermination scheduled for November 20, 2009. The borrowing base is redetermined based on numerous factors including current reserve estimates, reserves that have recently been added, current commodity prices, current production rates and estimated future net cash flows. These factors have associated risks with each of them. Significant reductions or increases in the borrowing base will be determined by these factors, which, to a significant extent, are not under the Company s control.

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

We are subject to interest rate risk on our long-term variable interest rate and fixed interest rate borrowings. Our long-term borrowings primarily consist of borrowings under the Credit Facility, which bears a floating interest rate. Changes in interest rates will change the cost of borrowing. Our default under the Credit Facility poses a more significant interest rate risk, as we may not be able to continue to borrow at the rates currently in place. Further, we are currently in payment default with respect to $29.5 million of the outstanding borrowings under the Credit Facility. There can be no assurance that the Company will be able to maintain borrowings at these rates under the Credit Facility or execute other alternatives to replace this borrowed capital at the current rates. In addition, we have already incurred approximately $1.0 million in forbearance fees in connection with the default, recorded as interest expense in the third quarter of 2009. We incurred an additional $226,000 in such fees in October 2009, which will be recorded as interest expense in the fourth quarter of 2009.

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Assuming $89.5 million remains borrowed under the amended Credit Facility or a successor debt agreement, we estimate our annual interest expense will change by $0.9 million for each 100 basis point change in the applicable interest rates.

Hedging Contracts

Management of Financial Risk. The Company s operating environment includes two primary financial risks which could be addressed through derivatives and similar financial instruments: the risk of movement in oil and natural gas commodity prices, which impacts revenue, and the risk of interest rate movements, which impacts interest expense from floating rate debt.

The Company currently does not utilize derivative contracts or any other form of hedging against interest rate risk.

The Company utilizes derivative contracts to address the risk of adverse oil and natural gas commodity price fluctuations. While the use of derivative contracts limits the downside risk of adverse price movements, it may also limit future gains from favorable movements. No derivative contracts have been entered into for trading purposes, and the Company has the intent to hold each instrument to maturity. The Company s commodity derivative contracts are considered cash flow hedges under generally accepted accounting principles. All of the Company s hedging agreements are executed by affiliates of the Lenders under the Credit Facility and are collateralized by the security interest the Lenders have in the oil and natural gas assets of the Company. Due to the previously discussed defaults under the Credit Facility, the Lenders have not allowed the Company to enter into any additional hedging agreements. As a result, the Company s oil and natural gas sales for periods beyond December 2009 will more closely resemble prevailing market prices.

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. The Company s commodity derivative positions as of September 30, 2009 hedge approximately 33% of proved developed natural gas production and 13% of proved developed oil production during the remaining terms of all derivative agreements in the aggregate. All the Company s hedging agreements expire in December 2009.

The Company s current derivative contracts are primarily floor contracts. These agreements ensured the Company would receive a minimum (floor) price for the commodity. The Company holds a single collar contract which also contains a ceiling, or maximum price the Company may receive. Typically, the contracts specify monthly hedged volumes subject to the floor and ceiling prices over a period of 6 to 18 months. The contracts are settled monthly based on the NYMEX futures contract. The following table lists all of the Company s commodity derivative contracts as of September 30, 2009:

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		Type	Notional Amount	Floor Price ($ per unit)	Ceiling Price ($ per unit)	Estimated Fair Value Asset (Liability) September 30, 2009 (in thousands)
Natural Gas (mmbtu)						
Oct 2009	Dec 2009	Floor	250,000	$ 7.50		$ 705
Oct 2009	Dec 2009	Floor	160,000	$ 8.00		522
Oct 2009	Dec 2009	Floor	110,000	$ 8.00		361
					Total Natural Gas	1,588
Crude Oil (bbls)						
Oct 2009	Dec 2009	Collar	5,000	$ 70.00	$ 93.55	18
Oct 2009	Dec 2009	Floor	7,000	$ 80.00		77
Oct 2009	Dec 2009	Floor	10,000	$ 85.00		150
					Total Crude Oil	245
						$ 1,833

Special terms in derivative contracts. Although the Company s counterparties provide no collateral, the master derivative agreements with each counterparty effectively allow the Company, at its option, so long as it is not a defaulting party, after a default or the occurrence of a termination event, to set-off an unpaid hedging agreement receivable against the interest of the counterparty in any outstanding balance under the Credit Facility. In practice, no such set-off has been made, and all settlements have been made in cash. As of December 31, 2008, however, the Company is in default under the Credit Facility, the breach of which is also a default under the master derivative agreements. Although the Company s hedge counterparties have continued to make contract payments subsequent to its default, they are not obligated to make payments to the Company under the hedging agreements while the Company s default is continuing. The Company s set-off rights under the master derivative agreements cannot be exercised due to such default. The Company s hedging counterparties may exercise their remedies under the hedging agreements, and potentially under the Credit Facility, on account of the Company s default, which includes a right to terminate the agreements and set-off any settlement amount due to the Company against amounts owed under the Credit Facility. The settlement amount would be based on the estimated value of the remaining forward portion of the contracts based on market values at settlement. However, the Company reached a forbearance agreement with the counter-party which holds a significant majority of these contracts. So long as the hedge forbearance agreement is in place, no remedies will be undertaken by that counter-party. The hedge forbearance agreement expires November 30, 2009, or sooner if the Company has any event of default under the Bank Forbearance Agreement.

If a counterparty were to default in payment of an obligation under the master derivative agreements, the Company would be exposed to commodity price fluctuations, and the protection intended by the hedge would be lost. The value of assets from price risk management would be impacted. In addition, as expected cash flows from hedging contracts are included in computing future net revenues, the ceiling test could be impacted, which could result in a non-cash write-down of oil and natural gas properties.

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ITEM 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

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 third quarter of 2009. Based upon that evaluation, our Chief Executive Officer and Chief Accounting Officer concluded that the design and operation of our disclosure controls and procedures are effective. There have been no significant changes in our internal controls or in other factors during the first nine months of 2009 that could significantly affect these controls.

Changes in Internal Controls

During the three month period ended September 30, 2009, 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 above under Management s Discussion and Analysis of Financial Condition and Result of Operations-Liquidity and Capital Resources-Credit Facility and- Rig Note, and Quantitative and Qualitative Disclosures about Market Risk-Hedging Contracts Special terms in derivative contracts, the Company is in default under the terms of the Credit Facility, the master derivative agreements, and the rig note. Default under the Credit Facility is based on a payment deficiency of $30.5 million as of September 30, 2009 ($29.5 million as of November 9, 2009) as well as defaults under certain covenants. Default under the master derivative agreements and the rig note are not due to payment deficiency, but to cross-default clauses related to the Credit Facility. The Company currently has in place short-term forbearance agreements for each of these agreements in default and does not have sufficient cash available to repay the shortfall under the Credit Facility. Should the forbearance periods expire without extension or resolution of the deficiency and covenant defaults, the remedies available to lenders under each of these agreements include acceleration of all principal and interest payments. Accordingly, all debts noted above, including the rig note, have been classified as current in the Consolidated Balance Sheets as of December 31, 2008 and September 30, 2009. The Company is currently unable to predict what further actions the Lenders may pursue; therefore, the Company has not provided for this matter in its financial statements at September 30, 2009, other than to reclassify all outstanding debt as current.

Litigation

H. L. Hawkins litigation. In December 2004, the estate of H.L. Hawkins filed a claim against Meridian for damages estimated to exceed several million dollars for Meridian s alleged gross negligence, willful misconduct and breach of fiduciary duty under certain agreements concerning certain wells and property in the S.W. Holmwood and E. Lake Charles Prospects in Calcasieu Parish in Louisiana, as a result of

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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 September 30, 2009.

Parsons Exploration litigation. On May 3, 2007, Parsons Exploration Company, LLC (Parsons) filed a claim against Meridian for damages and specific performance requiring Meridian to assign Parsons an overriding royalty interest in certain wells the Company has drilled in east Texas. The complaint alleged that the Company breached its contractual and fiduciary obligations to Parsons under an Exploration and Prospect Origination Agreement between the parties dated April 22, 2003. The complaint also alleged that the Company engaged in a civil conspiracy to breach its contractual and fiduciary obligations to Parsons and tortiously interfered with existing and prospective business relationships/contracts of Parsons. The Company recognized an estimated settlement for this matter in the amount of $2.1 million in the first quarter of 2009, which was charged to the full cost pool. The parties reached a final settlement agreement in the second quarter of 2009.

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. Shell has not to date produced all of the supporting documentation for its claim. 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. An arbitration panel has been selected and an initial conference was held with the panel on July 31, 2009. The two companies have entered into settlement discussions. Meridian denies that it owes any indemnity under either of the two acquisition agreements; however, the amounts claimed are substantial in nature

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and if adversely determined, would have a material adverse effect on the Company. The Company is unable to express an opinion with respect to the likelihood of an unfavorable outcome of these matters or to estimate the amount or range of potential loss should any outcome be unfavorable. Therefore, the Company has not provided any amount for these matters in its financial statements at September 30, 2009.

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 September 30, 2009. The Company has not provided any amount for this matter in its financial statements at September 30, 2009.

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

Litigation involving insurable issues. There are no material legal proceedings involving insurable issues which exceed insurance limits to which Meridian or any of its subsidiaries is a party or to which any of its property is subject, other than ordinary and routine litigation incidental to the business of producing and exploring for crude oil and natural gas.

ITEM 1A. Risk Factors.

The following are updates to certain of the risk factors that appear in our annual report on Form 10-K for the year ended December 31, 2008. Each of the following risk factors could adversely affect our business, operating results and financial condition. It is not possible to foresee or identify all such factors. Investors should not consider this list or the list of risk factors contained in our most recent Form 10-K an exhaustive statement of all risks and uncertainties. This report and our most recent Form 10-K also contain forward-looking statements that involve risks and uncertainties. Our actual results may differ from those anticipated in these forward-looking statements as a result of both the risks described below and factors described elsewhere in this report and in our most recent Form 10-K. You should read the sections in our most recent Form 10-K entitled Risk Factors and Forward-Looking Statements for further discussion of these matters.

We are currently in payment default under our Credit Facility and in covenant default under certain of the covenants in our Credit Facility. Such covenant and payment defaults under the Credit Facility have resulted in defaults under hedging agreements we have entered into with certain affiliates of Fortis Capital Corp. and Scotia Bank due to cross default provisions therein. Furthermore, as a result of such defaults under the Credit Facility, we are also in default under our drilling rig financing with CIT Group/Equipment Financing, Inc. due to cross default provisions

therein. We will have difficulty returning to compliance with the Credit Facility, the hedging agreements and the drilling rig financing, and if we are unable to return to compliance, our Lenders may exercise remedies that would have a material adverse effect on us and our shareholders.

Under our Credit Facility, our borrowing base was redetermined effective April 30, 2009, at which time the borrowing base was reduced to $60 million from $95 million. As of November 9, 2009, we have outstanding indebtedness of $89.5 million under the Credit Facility, and a borrowing base payment deficiency of $29.5 million. We do not currently have sufficient cash available to repay the borrowing base deficiency.

In addition to such default for failure to pay the borrowing base deficiency, there are other covenant defaults existing under the Credit Facility. Such covenant and payment defaults under the Credit Facility have resulted in defaults under hedging agreements we have entered into with certain affiliates of Fortis Capital Corp. and Scotia Bank due to cross default provisions therein.

As a result of the payment default for the borrowing base deficiency and financial covenant defaults under the Credit Facility, we are also in default under our drilling rig financing with CIT Group/Equipment Financing, Inc. due to cross default provisions therein. We currently owe approximately $6.5 million to CIT under the drilling rig financing, and we have additional substantial financial obligations under related drilling rig contracts.

Under each of the two debt agreements, remedies available to the creditors include acceleration of all principal and interest payments. Default remedies available under the hedging agreements include unwinding and settlement of all contracts prior to expiration. Although we have obtained short-term forbearance agreements for each of these agreements in default, we may not be able to comply with the conditions and covenants set forth in those forbearance agreements. There can be no assurance that these forbearance agreements provide us the time to resolve the deficiencies and forestall further default.

We are seeking to accomplish a significant transaction as prescribed by the forbearance agreement with the Lenders, which includes a significant sale of assets, a corporate sale or merger, or a significant capital infusion. We may not be able to sell assets on terms that we consider advantageous to us and our shareholders, and capital on acceptable terms may not be available from other sources. We may be unable to find an acceptable candidate for a corporate merger or sale. If we are unable to comply with the terms of the forbearance agreements, we will be in default under the Credit Facility, the CIT financing and the hedge agreements and we will be subject to the exercise of remedies by such parties on account of such defaults. The exercise of such remedies could potentially result in us seeking protection under federal bankruptcy laws. Such relief could materially and adversely affect the Company and its shareholders.

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

There can be no assurance that we will be able to further extend the terms of the Bank Forbearance Agreement, the CIT Forbearance Agreement, and other related agreements. There can be no assurance that we will be able to comply with the terms of those agreements. If we are unable to comply, and no further extensions are granted, the forbearance period ends. Our creditors would then have various remedies available to them under the terms of our debt agreements, including acceleration of all principal and interest. The exercise of such remedies could potentially result in us seeking protection under the Bankruptcy Code. Even under a proposed corporate transaction such as a merger or sale of the Company, we may still be required to seek protection under the Bankruptcy Code to consummate such a transaction.

Under the priority scheme established by the Bankruptcy Code, pre-petition and post-petition liabilities (including certain fees and interest) must be satisfied in full before stockholders are entitled to receive any distribution or retain any property under a plan of reorganization. Amounts that would need to be satisfied in full before any recovery by our stockholders would include, among other things, $89.5 million in principal plus any accrued interest which is owed under our Credit Facility and approximately $6.5 million owed under the rig note. In addition, as of September 30, 2009, we have a working capital deficit of $5.6 million in addition to amounts owed under the two credit agreements, which represents amounts owed to vendors and others which exceed amounts collectible from customers and others. The total amount of this liquidation preference is approximately $101.6 million and any recovery for our common stockholders would only be available if the value available in any Bankruptcy Code proceeding exceeded the amount required to repay all of our outstanding indebtedness and other obligations (including trade payables and other unsecured claims). The ultimate recovery to creditors and/or stockholders, if any, would not be determined until the confirmation of any plan of reorganization. No assurance can be given as to what values, if any, would be ascribed in any potential Chapter 11 filing to each of these constituencies or what types or amounts of distributions, if any, they would receive. If certain requirements of the Bankruptcy Code are met, a plan of reorganization can be confirmed notwithstanding its rejection by equity holders and notwithstanding the fact that equity holders do not receive or retain any property under the plan of reorganization. Unless there is significant improvement in market conditions, we believe it is very unlikely that our common stockholders would receive any recovery in a Chapter 11 proceeding.

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

On December 4, 2008, we received notification from the New York Stock Exchange (NYSE) that the Company had fallen below certain continued listing criteria that require a minimum average closing price of $1.00 per share over 30 consecutive trading days. The NYSE temporarily suspended the minimum average closing price requirement during part of the first half of 2009. We received notification from the NYSE that our common stock would potentially be delisted if we were not in compliance with that requirement by November 9, 2009. However, we have subsequently corresponded with the NYSE such that delisting is not eminent on November 9, 2009. We are continuing to address the issue with the NYSE through continuing correspondence and discussion.

In addition, we are currently monitoring the Company s compliance with another listing criterion. This criterion requires that average market capital over 30 consecutive trading days must be at least $15 million. Based on shares outstanding at November 2, 2009, the Company s average market capital decreases below this level when the stock price drops below approximately $0.16 per share. Some closing prices in the first half of 2009 have been below this price. If the Company becomes non-compliant with this criterion, our common stock would be subject to the NYSE s delisting procedures.

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

In our communications with the NYSE they noted that we have not held a shareholders meeting in more than twelve months, since August 6, 2008. The NYSE has advised the Company that such a meeting must be held prior to December 31, 2009, or the Company will again be added to its list of issuers non-compliant with corporate governance listing standards. We are also in discussions with the NYSE about this matter.

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

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

ITEM 6. Exhibits.

10.1	Forbearance and Amendment Agreement, dated as of September 3, 2009, among The Meridian Resource Corporation, certain of its subsidiaries, Fortis Capital Corp., as administrative agent, and the several banks, financial institutions and other entities from time to time parties to the Amended and Restated Credit Agreement, dated as of December 23, 2004, as amended, among The Meridian Resource Corporation, Fortis Capital Corp., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Registrant s Current Report on Form 8-K filed with the SEC on September 10, 2009).
10.2*	First Amendment to Forbearance and Amendment Agreement, dated as of September 30, 2009, among The Meridian Resource Corporation, certain of its subsidiaries, Fortis Capital Corp., as administrative agent, and the several banks, financial institutions and other entities from time to time parties to the Amended and Restated Credit Agreement, dated as of December 23, 2004, as amended, among The Meridian Resource Corporation, Fortis Capital Corp., as administrative agent, and the lenders party thereto.
10.3*	Second Amendment to Forbearance and Amendment Agreement, dated as of October 2, 2009, among The Meridian Resource Corporation, certain of its subsidiaries, Fortis Capital Corp., as administrative agent, and the several banks, financial institutions and other entities from time to time parties to the Amended and Restated Credit Agreement, dated as of December 23, 2004, as amended, among The Meridian Resource Corporation, Fortis Capital Corp., as administrative agent, and the lenders party thereto.
10.4	Third Amendment to Forbearance and Amendment Agreement, dated as of October 20, 2009, among The Meridian Resource Corporation, certain of its subsidiaries, Fortis Capital Corp., as administrative agent, and the several banks, financial institutions and other entities from time to time parties to the Amended and Restated Credit Agreement, dated as of December 23, 2004, as amended, among The Meridian

Resource Corporation, Fortis Capital Corp., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Registrant s Current Report on Form 8-K filed with the SEC on October 22, 2009).

10.5 Forbearance Agreement, dated September 3, 2009, by and among Fortis Capital Corp., Fortis Energy Marketing & Trading GP and The Meridian Resource Corporation (incorporated by reference to Exhibit 10.2 to the Registrant s Current Report on Form 8-K filed with the SEC on September 10, 2009).

10.6 Forbearance and Amendment Agreement, dated September 3, 2009, by and among TMR Drilling Corporation, The Meridian Resource Corporation, The Meridian Resource & Exploration LLC and The CIT Group/Equipment Financing, Inc, as administrative agent and lender (incorporated by reference to Exhibit 10.3 to the Registrant s Current Report on Form 8-K filed with the SEC on September 10, 2009).

10.7 Forbearance and Amendment Agreement, dated September 3, 2009, by and among The Meridian Resource Corporation, The Meridian Resource & Exploration LLC, TMR Drilling Corporation and Orion Drilling Company LLC (incorporated by reference to Exhibit 10.4 to the Registrant s Current Report on Form 8-K filed with the SEC on September 10, 2009).

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 Rule15d- 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

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: November 9, 2009	By: /s/ LLOYD V. DELANO Lloyd V. DeLano Chief Accounting Officer, Senior Vice President and Secretary

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