CALLON PETROLEUM CO
Form 10-Q
November 15, 2010

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

x Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended September 30, 2010
or
.. 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 001-14039

CALLON PETROLEUM COMPANY
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	64-0844345 (I.R.S. Employer Identification No.)
200 North Canal Street Natchez, Mississippi (Address of principal executive offices)	39120 (Zip Code)

601-442-1601
(Registrant's telephone number, including area code)

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 x No ¨

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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes ¨ No ¨

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

Large accelerated filer ¨ Accelerated filer ¨

Non-accelerated filer x	Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ¨	No x

As of November 9, 2010 there were outstanding 28,947,800 shares of the Registrant’s common stock, par value $0.01 per share.

Table of Contents

Table of Contents

Part 1. Financial Information

Item 1. Financial Statements

Callon Petroleum Company
Consolidated Balance Sheets
(in thousands, except share data)

	September 30, 2010 (Unaudited)	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 19,750	$ 3,635
Accounts receivable	15,239	20,798
Accounts receivable - BOEMRE royalty recoupment	-	51,534
Fair market value of derivatives	646	145
Other current assets	3,432	1,572
Total current assets	39,067	77,684
Oil and gas properties, full-cost accounting method:		
Evaluated properties	1,280,714	1,593,884
Less accumulated depreciation, depletion and amortization	(1,145,363)	(1,488,718)
Net oil and gas properties	135,351	105,166
Unevaluated properties excluded from amortization	20,038	25,442
Total oil and gas properties	155,389	130,608
Other property and equipment, net	3,353	2,508
Restricted investments	4,005	4,065
Investment in Medusa Spar LLC	10,665	11,537
Other assets, net	1,341	1,589
Total assets	$ 213,820	$ 227,991
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)		
Current liabilities:		
Accounts payable and accrued liabilities	$ 14,619	$ 12,887
Asset retirement obligations	1,778	4,002
9.75% Senior Notes, net of $0 and $232 discount, respectively	-	15,820
Subtotal	16,397	32,709
Callon Entrada non-recourse credit facility (See Note 1)	-	84,847
Total current liabilities	16,397	117,556
13% Senior Notes (See Note 6)		
Principal outstanding	137,961	137,961
Deferred credit, net of accumulated amortization of $3,017 and $294, respectively	28,490	31,213
Total 13% Senior Notes	166,451	169,174
Senior secured revolving credit facility	-	10,000
Asset retirement obligations	13,158	10,648

Other long-term liabilities		1,931			1,467	
Total liabilities		197,937			308,845	
Stockholders' equity (deficit):						
Preferred Stock, $.01 par value, 2,500,000 shares authorized;		-			-	
Common Stock, $.01 par value, 60,000,000 shares authorized; 28,965,421 and 28,742,926 shares outstanding at September 30, 2010 and December 31, 2009, respectively		290			287	
Capital in excess of par value		247,291			243,898	
Other comprehensive loss		(6,887	)		(7,478	)
Retained earnings (deficit)		(224,811	)		(317,561	)
Total stockholders' equity (deficit)		15,883			(80,854	)
Total liabilities and stockholders' equity (deficit)	$	213,820		$	227,991	

The accompanying notes are an integral part of these consolidated financial statements.

Table of Contents

Callon Petroleum Company
Consolidated Statements of Operations (Unaudited)
(in thousands, except per share data)

	Three-Months Ended September 30, 2010	Three-Months Ended September 30, 2009	Nine-Months Ended September 30, 2010	Nine-Months Ended September 30, 2009
Operating revenues:				
Oil sales	$ 15,123	$ 16,451	$ 47,687	$ 51,374
Gas sales	5,362	4,869	17,752	19,786
Total operating revenues	20,485	21,320	65,439	71,160
Operating expenses:				
Lease operating expenses	4,327	4,962	13,006	13,657
Depreciation, depletion and amortization	7,392	6,861	21,247	24,726
General and administrative	3,371	3,000	12,086	10,210
Accretion expense	601	698	1,803	2,531
Acquisition expense	139	-	139	-
Total operating expenses	15,830	15,521	48,281	51,124
Income from operations	4,655	5,799	17,158	20,036
Other (income) expenses:				
Interest expense	3,133	4,919	9,925	14,555
Callon Entrada non-recourse credit facility interest expense (See Note 2)	-	1,882	-	5,373
Loss on early extinguishment of debt	-	-	339	-
Other (income) expense	63	110	(409)	76
Total other expenses	3,196	6,911	9,855	20,004
Income (loss) before income taxes	1,459	(1,112)	7,303	32
Income tax expense	-	-	-	-
Income (loss) before equity in earnings of Medusa Spar LLC	1,459	(1,112)	7,303	32
Equity in earnings of Medusa Spar LLC	143	157	352	492
Net income (loss) available to common shares	$ 1,602	$ (955)	$ 7,655	$ 524
Net income (loss) per common share:				
Basic	$ 0.06	$ (0.04)	$ 0.27	$ 0.02
Diluted	$ 0.05	$ (0.04)	$ 0.26	$ 0.02
Shares used in computing net income per common share:				
Basic	28,815	21,705	28,769	21,631
Diluted	29,491	21,705	29,431	21,665

The accompanying notes are an integral part of these consolidated financial statements.

Table of Contents

Callon Petroleum Company
Consolidated Statements of Cash Flows (Unaudited)
(in thousands)

	Nine-Months Ended September 30, 2010	2009
Cash flows from operating activities:		
Net income	$ 7,655	$ 524
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation, depletion and amortization	21,860	25,359
Accretion expense	1,803	2,531
Amortization of non-cash debt related items	305	2,251
Callon Entrada non-recourse credit facility interest expense	-	3,296
Amortization of deferred credit	(2,723)	-
Equity in earnings of Medusa Spar LLC	(352)	(492)
Non-cash charge for early debt extinguishment	179	-
Non-cash charge related to compensation plans	2,356	1,947
Payments to settle asset retirement obligations	(1,211)	(5,412)
Changes in current assets and liabilities:		
Accounts receivable	54,593	8,355
Other current assets	(1,462)	(841)
Current liabilities	(134)	(25,709)
Change in gas balancing receivable	370	454
Change in gas balancing payable	(292)	(201)
Change in other long-term liabilities	(115)	54
Change in other assets, net	(588)	(531)
Cash provided by operating activities	82,244	11,585
Cash flows from investing activities:		
Capital expenditures	(39,617)	(29,030)
Acquisition expenditures	(995)	-
Investment in restricted assets related to plugging and abandonment	(337)	-
Distribution from Medusa Spar LLC	1,224	1,381
Cash used in investing activities	(39,725)	(27,649)
Cash flows from financing activities:		
Borrowings from senior secured credit facility	-	9,337
Payments on senior secured credit facility	(10,000)	(9,337)
Redemption of remaining 9.75% senior notes	(16,052)	-
Proceeds from exercise of employee stock options	(41)	-
Cash used in financing activities	(26,093)	-
Net change in cash and cash equivalents	16,426	(16,064)
Cash and cash equivalents:		
Balance, beginning of period	3,635	17,126
Less: Cash held by subsidiary deconsolidated at January 1, 2010	(311)	-

Balance, end of period	$ 19,750	$ 1,062

The accompanying notes are an integral part of these consolidated financial statements.

Callon Petroleum Company
Notes to the Consolidated Financial Statements
(all amounts in thousands, except per-share and per-hedge data)

INDEX TO THE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 - Description of Business and Basis of Presentation

Description of Business

Callon Petroleum Company has been engaged in the exploration, development, acquisition and production of oil and gas properties since 1950. The Company was incorporated under the laws of the state of Delaware in 1994 and succeeded to the business of a publicly traded limited partnership, a joint venture with a consortium of European investors and an independent energy company partially owned by a member of current management. As used herein, the “Company,” “Callon,” “we,” “us,” and “our” refer to Callon Petroleum Company and its predecessors and subsidiaries unl the context requires otherwise.

Callon is engaged in the acquisition, development, exploration and operation of oil and gas properties. The Company’s properties and operations are geographically concentrated onshore in Louisiana and Texas and the offshore waters of the Gulf of Mexico.

Basis of Presentation

These interim financial statements of the Company have been prepared in accordance with (1) accounting principles generally accepted in the United States (“US GAAP”), (2) the Securities and Exchange Commission’s instructions to Quarterly Report on Form 10-Q and (3) Rule 10-01 of Regulation S-X, and should be read in conjunction with the Company’s Annual Report on Form 10-K for the year ended December 31, 2009.

In the opinion of management, the accompanying unaudited consolidated financial statements reflect all adjustments (including normal recurring adjustments) necessary to present fairly the Company's financial position, the results of its operations and its cash flows for the periods indicated. Operating results for the periods presented are not necessarily indicative of the results that may be expected for the year ended December 31, 2010.

Unless otherwise indicated, all amounts contained in the notes to the consolidated financial statements are presented in thousands, with the exception of years, per-share and per-hedge amounts.

Callon Petroleum Company
Notes to the Consolidated Financial Statements
(all amounts in thousands, except per-share and per-hedge data)

Note 2 - Deconsolidation of Callon Entrada

In April 2008, Callon completed the sale of a 50% working interest in the Entrada Field to CIECO Energy (US) Limited ("CIECO") effective January 1, 2008. At closing, CIECO paid Callon $155,000, and reimbursed the Company $12,600 for 50% of Entrada capital expenditures incurred prior to the closing date. In addition, as part of the purchase and sale agreement, CIECO agreed to loan Callon Entrada, a wholly owned subsidiary of the Company, up to $150,000 plus interest expense incurred up to $12,000, for its share of the development costs for the Entrada project. Based on the terms of the credit agreement with CIECO Energy (Entrada) LLC ("CIECO Entrada"), the debt was to be repaid solely from assets, primarily production, from the Entrada field. All assets of Callon Entrada, and its stock, are pledged to CIECO Entrada under the Callon Entrada credit agreement, and neither Callon nor its subsidiaries (other than Callon Entrada) guaranteed the Callon Entrada credit facility.

Prior to January 1, 2010, the Company was required to consolidate the financial statements and results of operations of Callon Entrada, and as such, Callon Entrada's non-recourse principal and interest due under the credit facility was reflected in a separate line item in Callon's 2009 consolidated financial statements.

In June 2009, the Financial Accounting Standards Board ("FASB") issued an accounting standard which became effective for the first annual reporting period that begins after November 15, 2009 (with early adoption prohibited), and which amended US GAAP as follows:

- to require an enterprise to perform an analysis to determine whether the enterprise's variable interest or interests give it a controlling financial interest in a Variable Interest Entity ("VIE"), identifying the primary beneficiary of a VIE;
- to require ongoing reassessment of whether an enterprise is the primary beneficiary of a VIE, rather than only when specific events occur;
- to eliminate the quantitative approach previously required for determining the primary beneficiary of a VIE;
- to amend certain guidance for determining whether an entity is a VIE;
- to add an additional reconsideration event when changes in facts and circumstances pertinent to a VIE occur;
- to eliminate the exception for troubled debt restructuring regarding VIE reconsideration; and
- to require advanced disclosures that will provide users of financial statements with more transparent information about an enterprise's involvement in a VIE.

The Company adopted the pronouncement for consolidation of variable interest entities on January 1, 2010. Upon adoption, the Company reevaluated its interest in its subsidiary, Callon Entrada. Based on the evaluation performed, which is detailed below, the Company concluded that a VIE reconsideration event had taken place resulting in the determination that Callon Entrada is a VIE, for which the Company is not the primary beneficiary and, as a result, Callon Entrada is deconsolidated from the Company's consolidated financial statements as of January 1, 2010. The Company included additional disclosures related to the deconsolidation of Callon Entrada in its Form 10-K for the year-ended December 31, 2009. Key events considered in this analysis include the following:

Default on non-recourse debt and CIECO's acceleration rights exercised: As a result of abandoning the Entrada project in November 2008, prior to completion, Callon Entrada's only source of payment is the proceeds from the sale of equipment purchased but not used for the Entrada project. On April 2, 2009, Callon Entrada received a notice from CIECO Entrada advising Callon Entrada that certain alleged events of default occurred under the credit agreement relating to failure to pay interest when due and the breach of various other covenants related to the decision to abandon the Entrada project. The notice of default received from CIECO Entrada invoked CIECO Entrada's rights under the Callon Entrada credit agreement to accelerate payment of the principal and interest due, and to invoke its rights to the surplus equipment related to the Entrada project, including the proceeds from the sale of the equipment and the ability to control the decisions related to the sale of the equipment. Based on the advice of legal counsel, Callon believes that it and its other subsidiaries are not otherwise obligated to repay the principal, accrued interest or any other amounts which may become due under the Callon Entrada credit facility.

Table of Contents

Callon Petroleum Company
Notes to the Consolidated Financial Statements
(all amounts in thousands, except per-share and per-hedge data)

Abandonment obligations satisfied: Callon guaranteed Callon Entrada's payment of all amounts to plug and abandon the wells and related facilities and for a breach of law, rule or regulation (including environmental laws) and for any losses of CIECO Entrada attributable to gross negligence of Callon Entrada. The well for which Callon Entrada was responsible was plugged and abandoned in the fourth of quarter of 2008, and the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE," formerly the Minerals Management Service) confirmed to Callon during September 2009 that Callon had satisfied all if its abandonment obligations related to this project.

No ability to control future actions of Callon Entrada: As of December 31, 2009, the wind down of the Entrada project was complete, all of the costs related to the Entrada project were paid, and subsequent to the lease expiration June 1, 2009, control of the property reverted to the BOEMRE. The sale of remaining equipment purchased for the Entrada project remains ongoing, and the Company believes that the amount of future operating costs of Callon Entrada, for which the Company would be responsible for, is insignificant and is limited to minimal storage fees for the surplus equipment while the equipment is being liquidated.

As a result of the events described above, the Company lost its power to direct the only remaining activities that affect Callon Entrada's future economic performance. Below is a condensed balance sheet of Callon presented to demonstrate the effect of deconsolidation on the financial statements at January 1, 2010:

	Callon Consolidated at 12/31/09	Callon Entrada Deconsolidated	Callon Consolidated at 1/1/2010
Total current assets	$ 77,684	$ (1,767)	$ 75,917
Total oil and gas properties	130,608	-	130,608
Other property and equipment	2,508	-	2,508
Other assets	17,191	-	17,191
Total assets	$ 227,991	$ (1,767)	$ 226,224
Other current liabilities	$ 16,889	$ (2,015)	$ 14,874
9.75% Senior Notes, due December 2010	15,820	-	15,820
Callon Entrada non-recourse credit facility	84,847	(84,847)	-
Total current liabilities	117,556	(86,862)	30,694
Total long-term debt	179,174	-	179,174
Total other long-term liabilities	12,115	-	12,115
Total stockholders' equity (deficit)	(80,854)	85,095	4,241
Total liabilities and stockholders' equity (deficit)	$ 227,991	$ (1,767)	$ 226,224

Callon Petroleum Company
Notes to the Consolidated Financial Statements
(all amounts in thousands, except per-share and per-hedge data)

Note 3 – Bureau of Ocean Energy Management, Regulation and Enforcement (“BOEMRE”) Royalty Recoupment

During 2009, we recorded a receivable attributable to a recoupment of royalty payments we previously made to the BOEMRE on our deepwater property, Medusa. Following the decisions resulting from several court cases brought by another oil and gas company, the court ruled that the BOEMRE was not entitled to receive these royalty payments. Accordingly, in November 2009 the Company filed for a recoupment of royalties paid to the BOEMRE in the amount of $44,787 from inception-to-date production at the Company’s Medusa field. At December 31, 2009, Callon accrued the royalty recoupment of $44,787 and estimated interest of $7,681. The Company received the recoupment of principal in January 2010, and received $7,927 of interest during the second quarter of 2010, which included additional accrued interest through the repayment date. In addition, the Company is no longer required to make any future royalty payments to the BOEMRE related to its Medusa production.

Note 4 - Earnings per Share

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

	Three-Months Ended September 30,		Nine-Months Ended September 30,	
	2010	2009	2010	2009
(a) Net income (loss)	$1,602	$(955)	$7,655	$524
(b) Weighted average shares outstanding	28,815	21,705	28,769	21,631
Dilutive impact of stock options	147	-	127	-
Dilutive impact of restricted stock	529	-	535	34
(c) Weighted average shares outstanding for diluted net income per share	29,491	21,705	29,431	21,665
Basic net income per share (a/b)	$0.06	$(0.04)	$0.27	$0.02
Diluted net income per share (a/c)	$0.05	$(0.04)	$0.26	$0.02
The following were excluded from the diluted EPS calculation because their effect would be anti-dilutive:				
Stock options	122	978	122	978
Warrants	365	365	365	365
Restricted stock	36	1,041	36	488

Note 5 - Comprehensive Income (Loss)

The components of comprehensive income (loss), net of related taxes, are as follows:

	Three-Months Ended September 30,		Nine-Months Ended September 30,	
	2010	2009	2010	2009

Net income (loss)	$1,602	$(955)	$7,655	$524
Other comprehensive income:				
Change in fair value of derivatives	(860)	(3,475)	591	(18,213)
Total comprehensive income (loss)	$742	$(4,430)	$8,246	$(17,689)

Table of Contents

Callon Petroleum Company
Notes to the Consolidated Financial Statements
(all amounts in thousands, except per-share and per-hedge data)

Note 6 – Borrowings

The Company's borrowings consisted of the following at:

	September 30, 2010	December 31, 2009
Principal components:		
Senior secured revolving credit facility	$ -	$ 10,000
9.75% Senior Notes due 2010, principal	-	16,052
13% Senior Notes due 2016, principal	137,961	137,961
Callon Entrada non-recourse credit facility (1)	-	84,847
Total principal outstanding	137,961	248,860
Non-cash components:		
9.75% Senior Notes, due 2010 unamortized discount	-	(232)
13% Senior Notes due 2016 unamortized deferred credit	28,490	31,213
Total carrying value	$ 166,451	$ 279,841

(1) Liability was removed as part of the deconsolidation of Callon Entrada. See Note 2 for additional information.

Senior Secured Revolving Credit Facility (the "Credit Facility")

In January 2010, the Company amended its Credit Facility agreement to include Regions Bank as the sole arranger and administrative agent. The third amended and restated Credit Facility, which matures on September 25, 2012, provides for a $100,000 facility and had an initial borrowing base of $20,000, which is reviewed and re-determined on a semi-annual basis during the second and fourth quarters. The Credit Facility bears interest at 4% above a defined base rate, and in no event will the interest rate be less than 6%. As of September 30, 2010, the interest rate on the facility was 6%. In addition, a commitment fee of 0.5% per annum on the unused portion of the borrowing base, is payable quarterly. During October 2010, Regions Bank approved a $30,000 borrowing base, which represents a $10,000 or 50% increase over the Company's previous $20,000 borrowing base with Regions Bank. The next borrowing base review is scheduled for the second quarter of 2011.

Simultaneously with the January 2010 execution of the third amended and restated Credit Facility, the Company repaid the $10,000 outstanding draw under the second amended and restated Credit Facility, which was outstanding as of December 31, 2009.

9.75% Senior Notes ("Old Notes") (Due December 2010)

During the fourth quarter of 2009, Callon commenced an exchange offer for any and all of its outstanding Old Notes. Holders of approximately 92% of the Old Notes tendered their Notes in the exchange offer. During March 2010, the Company announced its intention to redeem all remaining Old Notes by April 30, 2010 (the "Redemption Date") at a redemption price of 101% of their principal amount, plus accrued and unpaid interest to the Redemption Date. Pursuant to the terms of the debt agreement, the Company mailed a notice of redemption to all registered holders of the remaining Old Notes, and posted the notice with the responsible transfer agent.

On April 30, 2010, the Company completed its publically announced plans to redeem for 101% of the par value the remaining $16,052 outstanding Old Notes for $16,343, which included the 1% call premium and $130 of accrued interest through the repurchase date. The Company also recognized $179 of additional interest expense related to the accelerated amortization of the Old Notes' remaining discount and debt issuance costs, which when added to the $160 call premium resulted in a $339 loss on early extinguishment of this debt. Since the April 30, 2010 redemption date, no Old Notes remain outstanding.

Table of Contents

Callon Petroleum Company
Notes to the Consolidated Financial Statements
(all amounts in thousands, except per-share and per-hedge data)

13% Senior Notes due 2016 ("Senior Notes") and Deferred Credit

As described above, during the fourth quarter of 2009, the Company exchanged approximately 92% of the principal amount, or $183,948, of the Old Notes for $137,961 of Senior Notes. The exchange resulted in a 25% reduction in the principal amount of the Old Notes tendered, and included a 3.25% increase in the coupon rate from 9.75% to 13%. In addition, holders of the tendered notes received 3,794 shares of common stock and 311 shares of Convertible Preferred Stock which was valued on November 24, 2009 in the amount of $11,527 and recorded as an increase to stockholders' equity. On December 31, 2009, each share of the Convertible Preferred Stock was automatically converted by the Company into 10 shares of common stock following shareholder approval and the filing of an amendment to the Company's charter increasing the number of authorized shares of common stock as necessary to accommodate such conversion. The Senior Notes' 13% interest coupon is payable on the last day of each quarter.

Upon issuing the Senior Notes during November 2009, the Company reduced the carrying amount of the Old Notes by the fair value of the common and preferred stock issued in the amount of $11,527. The difference between the adjusted carrying amount of the Old Notes and the face value of the Senior Notes was recorded as a deferred credit, which is being amortized as a credit to interest expense over the life of the Senior Notes at an 8.5% effective interest rate. The following table summarizes the Company's deferred credit balance at September 30, 2010:

Gross Carrying Amount	Accumulated Amortization at September 30, 2010	Carrying Value at September 30, 2010	Amortization Recorded during 2010 as a Reduction of Interest Expense	Estimated Amortization Expected to be Recorded for the Remainder of 2010
$31,507	$ 3,017	$28,490	$ 2,723	$ 872

Certain of the Company's subsidiaries guarantee the Company's obligations under the Senior Notes. The subsidiary guarantors are 100% owned, all of the guarantees are full and unconditional and joint and several, the parent company has no independent assets or operations and any subsidiaries of the parent company other than the subsidiary guarantors are minor.

Restrictive Covenants

The Indenture governing our Senior Notes and the Company's Credit Facility contains various covenants including restrictions on additional indebtedness and payment of cash dividends. In addition, Callon's Credit Facility contains covenants for maintenance of certain financial ratios. The Company was in compliance with these covenants at September 30, 2010.

Note 7 - Derivative Instruments and Hedging Activities

Objectives and Strategies for Using Derivative Instruments

The Company is exposed to fluctuations in crude oil and natural gas prices on the majority of its production. Consequently, the Company believes it is prudent to manage the variability in cash flows on a portion of its crude oil and natural gas production. The Company utilizes primarily collars and swap derivative financial instruments to manage fluctuations in cash flows resulting from changes in commodity prices. The Company does not use these instruments for trading purposes.

Counterparty Risk

The use of derivative transactions exposes the Company to counterparty credit risk, or the risk that a counterparty will be unable to meet its commitments. To reduce the Company's risk in this area, counterparties to the Company's commodity derivative instruments include a large, well-known financial institution and a large, well-known oil and gas company. The Company monitors counterparty creditworthiness on an ongoing basis; however, it cannot predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, the Company may be limited in its ability to mitigate an increase in counterparty credit risk. Should one of these counterparties not perform, the Company may not realize the benefit of some of its derivative instruments under lower commodity prices.

Table of Contents

Callon Petroleum Company
Notes to the Consolidated Financial Statements
(all amounts in thousands, except per-share and per-hedge data)

The Company executes commodity derivative transactions under master agreements that have netting provisions that provide for offsetting payables against receivables. In general, if a party to a derivative transaction incurs an event of default, as defined in the applicable agreement, the other party will have the right to demand the posting of collateral, demand a transfer or terminate the arrangement.

Settlements and Financial Statement Presentation

Settlements of oil and gas derivative contracts are generally based on the difference between the contract price or prices specified in the derivative instrument and a New York Mercantile Exchange ("NYMEX") price or other cash or futures index price. The current and non-current portion of derivative contracts are carried at fair value in the consolidated balance sheet under the caption "Fair Market Value of Derivatives" and "Other Assets, net / Other long-term liabilities" respectively. The oil and gas derivative contracts are settled based upon reported prices on NYMEX. The estimated fair value of these contracts is based upon closing exchange prices on NYMEX and in the case of collars and floors, the time value of options. See Note 8, "Fair Value Measurements."

The Company's derivative contracts are designated as cash flow hedges, and are recorded at fair market value with the changes in fair value recorded net of tax through other comprehensive income (loss) ("OCI") in stockholders' equity (deficit). The cash settlements on contracts for future production are recorded as an increase or decrease in oil and gas sales. Both changes in fair value and cash settlements of ineffective derivative contracts are recognized as derivative expense (income).

Listed in the table below are the outstanding oil and gas derivative contracts, consisting entirely of collars, as of September 30, 2010:

Product	Volumes per Month	Quantity Type	Average Floor Price per Hedge	Average Ceiling Price per Hedge	Period
Natural Gas	75	MMbtu	$5.00	$8.30	Oct10 - Dec10
Oil	20	Bbls	$70.00	$91.50	Oct10 - Dec10
Oil	10	Bbls	75.00	101.50	Oct10 - Dec10
Oil	10	Bbls	75.00	101.85	Jan11 - Dec11
Oil	5	Bbls	80.00	102.00	Jan11 - Dec11
Oil	10	Bbls	75.00	94.50	Jan11 - Dec11

The tables below present the effect of the Company's derivative financial instruments on the consolidated statements of operations as an increase (decrease) to oil and gas sales:

	Three-Months ended September 30,		Nine-Months ended September 30,	
	2010	2009	2010	2009

Amount of gain reclassified from OCI into income (effective portion)	$124	$3,753	$364	$16,145
Amount of gain (loss) recognized in income (ineffective portion and amount excluded from effectiveness testing)	-	-	-	-

12

Table of Contents

Callon Petroleum Company
Notes to the Consolidated Financial Statements
(all amounts in thousands, except per-share and per-hedge data)

Note 8 - Fair Value Measurements

The fair value hierarchy outlined in the relevant accounting guidance gives the highest priority to Level 1 inputs, which consist of unadjusted quoted prices for identical instruments in active markets. Level 2 inputs consist of quoted prices for similar instruments. Level 3 valuations are derived from inputs that are significant and unobservable, and these valuations have the lowest priority.

Fair Value of Financial Instruments

Cash, Cash Equivalents, Short-Term Investments, Accounts Receivable and Accounts Payable. The carrying amounts for these instruments approximate fair value due to the short-term nature or maturity of the instruments.

Debt. The Company's debt is recorded at the carrying amount on its Consolidated Balance Sheet. The fair value of Callon's fixed-rate debt is based upon estimates provided by an independent investment banking firm. The carrying amount of floating-rate debt approximates fair value because the interest rates are variable and reflective of market rates.

The following table summarizes the respective carrying and fair values at:

	September 30, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Credit Facility	$-	$-	$10,000	$10,000
9.75% Senior Notes due 2010, net of unamortized discount	-	-	15,820	15,249
13% Senior Notes due 2016 (1)	166,451	139,341	169,174	103,471
Callon Entrada Credit Facility; non-recourse	-	-	84,847	-
Total	$166,451	$139,341	$279,841	$128,720

(1) 2010 Fair value is calculated only in relation to the $137,961 par value outstanding of the 13% Senior Notes. The remaining $28,490, which the Company has recorded as a deferred credit, is excluded from the fair value calculation, and will be recognized in earnings as a reduction of interest expense over the remaining amortization period. See Note 6 for additional information.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are reported at fair value on a recurring basis (unless otherwise noted below) in Callon's Consolidated Balance Sheet. The following methods and assumptions were used to estimate the fair values:

Commodity Derivative Instruments. Callon's derivative policy allows for commodity derivative instruments to consist of collars and natural gas and crude oil basis swaps, though at September 30, 2010 the Company's portfolio included only collars. The fair values of the Company's derivative instruments are not actively quoted in the open market and are valued using forward commodity price curves. Consequently, the Company estimates the fair values of derivative instruments using internal discounted cash flow calculations based upon forward commodity price curves, which are corroborated by quotes obtained from counterparties to the agreements. These valuations include primarily Level 3 inputs. For additional information, see Note 7, Derivative Instruments and Hedging Activities, of this Form 10-Q.

Callon Petroleum Company
Notes to the Consolidated Financial Statements
(all amounts in thousands, except per-share and per-hedge data)

The following tables present the Company's assets and liabilities measured at fair value on a recurring basis for each hierarchy level:

As of September 30, 2010	Level 1	Level 2	Level 3	Total
Assets				
Derivative financial instruments	$-	$-	$736	$736
Liabilities				
Derivative financial instruments	-	-	-	-
Total	$-	$-	$736	$736

As of December 31, 2009	Level 1	Level 2	Level 3	Total
Assets				
Derivative financial instruments	$-	$-	$145	$145
Liabilities				
Derivative financial instruments	-	-	-	-
Total	$-	$-	$145	$145

The derivative fair values above are based on analysis of each contract. Derivative assets and liabilities with the same counterparty are presented here on a gross basis, even where the legal right of offset exists. Additionally, $646 of the derivative assets is reflected as a current asset on the Company's Consolidated Balance Sheet at September 30, 2010, and as such is expected to settle within the next twelve months. See Note 7, Derivative Instruments and Hedging Activities, of this Form 10-Q for a discussion of net amounts recorded in the Consolidated Balance Sheet at September 30, 2010.

The following table presents the Company's assets and liabilities measured at fair value on a recurring basis using significant, unobservable inputs (Level 3):

	Derivatives
Balance at January 1, 2010	$145
Total gains or losses (realized or unrealized):	
Included in earnings	364
Included in other comprehensive (income) loss	591
Purchases, issuances and settlements	(364)
Balance at September 30, 2010	$736
Change in unrealized gains (losses) included in earnings relating to derivatives still held as of September 30, 2010	$-

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis in Callon's Consolidated Balance Sheet. The following methods and assumptions were used to estimate the fair values:

Asset Retirement Obligations Incurred in Current Period. Callon estimates the fair value of AROs based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as (1) the existence of a legal obligation for an ARO, (2) amounts and timing of settlements, (3) the credit-adjusted risk-free rate to be used and (4) inflation rates. AROs incurred through September 30, 2010, including upward revisions to ARO liabilities of $1,590, were Level 3 fair value measurements. See Note 10, Asset Retirement Obligations, which provides a summary of changes in the ARO liability.

Table of Contents

Callon Petroleum Company
Notes to the Consolidated Financial Statements
(all amounts in thousands, except per-share and per-hedge data)

Note 9 - Income Taxes

The following table presents Callon's net unrecognized tax benefits relating to its reported net losses and other temporary differences from operations:

	September 30, 2010	December 31, 2009
Deferred tax asset:		
Federal net operating loss carryforward	$ 83,685	$ 94,125
Statutory depletion carryforward	5,475	4,895
Alternative minimum tax credit carryforward	383	383
Asset retirement obligations	3,826	3,704
Other	939	34,170
Deferred tax asset before valuation allowance	94,308	137,277
Less: Valuation allowance	(79,947)	(116,676)
Total deferred tax asset	14,361	20,601
Deferred tax liability:		
Oil and gas properties	14,361	9,555
Other	-	11,046
Total deferred tax liability	14,361	20,601
Net deferred tax asset	$ -	$ -

As of January 1, 2010 and as previously disclosed in Note 2, Callon Entrada has been deconsolidated from the Company's consolidated financial statements, resulting in a $30,330 decrease in deferred tax assets and a corresponding reduction in the valuation allowance.

As previously disclosed in Note 6 of the Company's 2009 Form 10-K, the Company recorded a full valuation allowance against its net deferred tax assets. Consequently, the Company's effective tax rate will be affected in future periods to the extent these deferred tax assets are recognized. The Company continues to assess whether or not deferred tax assets can be recognized based on current and expected future operating results and other factors.

Note 10 - Asset Retirement Obligations

The following table summarizes the Company's asset retirement obligations activity for the nine-months ended September 30, 2010:

Asset retirement obligations at January 1, 2010	$14,650
Accretion expense	1,803
Liabilities incurred	590
Liabilities settled	(3,133)
Revisions to estimate	1,026
Asset retirement obligations at end of period	14,936
Less: current asset retirement obligations	(1,778)
Long-term asset retirement obligations at end of period	$13,158

Liabilities settled primarily relate to individual properties, primarily located in the Gulf of Mexico, plugged and abandoned during the period.

Restricted assets, primarily U.S. Government securities, of approximately $4,403 at September 30, 2010, are recorded as restricted investments. These assets are held in abandonment trusts dedicated to pay future abandonment costs for several of the Company's oil and gas properties.

Note 11 – Supplemental Oil and Gas Reserve Data

On September 22, 2010 the Company announced that its proved reserves as of September 1, 2010 had increased to 13 million barrels of oil equivalent, a 34% increase as compared to proved reserves as of December 31, 2009. The increase in reserves is attributable to its development activities in the Wolfberry and Haynesville Shale plays. These amounts are based on internal estimates, and have not yet been subject to the Company's annual independent reserve engineer's review. The reserves quantities were prepared in accordance with guidelines established by the SEC, and accordingly are based upon existing operating conditions. There are numerous uncertainties inherent in establishing quantities of proved reserves. The following reserve data represents estimates only and should not be construed as being exact.

Table of Contents

Management’s Discussion and Analysis of Financial Condition and Results of Operations

Forward-Looking Statements

Certain statements in this Current Report on Form 10-Q (or otherwise made by or on the behalf of Callon Petroleum) contain various forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”) and the Private Securities Litigation Reform Act of 1995. Such statements represent management's beliefs and assumptions concerning future events. When used in this document and in documents incorporated by reference, forward-looking statements include, without limitation, statements regarding financial forecasts or projections, our expectations, beliefs, intentions or future strategies that are signified by the words "expects," "anticipates," "intends," "believes" or similar language. These forward-looking statements are subject to risks, uncertainties and assumptions that could cause our actual results and the timing of certain events to differ materially from those expressed in the forward-looking statements. All forward-looking statements included in this Report are based on information available to us on the date of this Report. It is routine for our internal projections and expectations to change as the year or each quarter in the year progress, and therefore it should be clearly understood that the internal projections, beliefs and assumptions upon which we base our expectations may change prior to the end of each quarter or the year. Although these expectations may change, we may not inform you if they do. Our policy is generally to provide our expectations only once per quarter, and not to update that information until the next quarter.

Many important factors, in addition to those discussed in this Report, could cause our results to differ materially from those expressed in the forward-looking statements. Some of the potential factors that could affect our results are described below within Management’s Discussion and Analysis of Financial Condition and Results of Operations. In light of these risks and uncertainties, and others not described in this Report, the forward-looking events discussed in this Report might not occur, might occur at a different time, or might cause effects of a different magnitude or direction than presently anticipated.

General

The following management’s discussion and analysis describes the principal factors affecting the Company’s results of operations, liquidity, capital resources and contractual cash obligations. This discussion should be read in conjunction with the accompanying unaudited consolidated financial statements and our Annual Report on Form 10-K for the year ended December 31, 2009 (“Annual Report”), which include additional information about our business practices, significant accounting policies, risk factors, and the transactions that underlie our financial results. The Company also updates, as necessary, its risk factors in Part II, Item 1A of this filing.

Our website address is www.callon.com. All of our filings with the SEC are available free of charge through our website as soon as reasonably practicable after we file them with, or furnish them to, the SEC. Information on our website does not form part of this report on Form 10-Q.

We have been engaged in the exploration, development, acquisition and production of oil and gas properties since 1950. Prior to 2009, our operations were focused on exploration and production in the Gulf of Mexico. During 2009, we took steps to change our operational focus to lower risk, onshore exploration and development activities.

16

Table of Contents

Management's Discussion and Analysis of Financial Condition and Results of Operations

Overview and Outlook

During the third quarter of 2010, we continued to show improving quarter-over-quarter results of operations with net income and fully diluted earnings per share of $1.6 million and $0.05, respectively, compared to a net loss of $1.0 million and diluted loss per share of $0.04, respectively for the same three-month period of 2009. Further, our year-to-date net income and fully diluted earnings per share of $7.7 million and $0.26, respectively, represent a $7.1 million and $0.24 increase, respectively, over the same nine-month period of 2009. These results are discussed in greater detail within the "Results of Operations" section included below.

In an effort to position ourselves for future growth, we remain focused on strengthening our balance sheet by improving our liquidity. We made significant progress during the first nine months of 2010:

- Including principal and interest, we received $52.7 million for recoupment of deepwater royalty payments made to the BOEMRE.
- The borrowing base of our Credit Facility was amended to provide for a $30 million borrowing base, representing a $10 million or 50% increase over the originally approved borrowing base. The underwriting bank approved the increase following its most recent borrowing base review based on the growth of the Company's proved reserves, the collateral for the facility.
- After successfully restructuring during fourth quarter 2009 our 9.75% Senior Notes due December 2010 (the "Old Notes") through an exchange offer, we completed on April 30, 2010 the redemption of the remaining $16.1 million outstanding of Old Notes held by those note holders who did not participate in the exchange. The restructuring reduced by 25% the principal balance of the notes and extended the restructured notes' maturity from 2010 to 2016 in exchange for a 3.25% increase in the coupon rate and equity consideration. Principal outstanding under the 13% Senior Notes due 2016 is approximately $137.9 million, a significant decrease from the $200 principal formerly outstanding under the Old Notes.

Our success in these areas allows us to continue executing on our strategy to shift our operational focus from the offshore Gulf of Mexico to developing longer life, lower risk onshore properties. Our new onshore properties along with the cash flow from our Gulf of Mexico operations have already begun to re-shape our portfolio and outlook, and we believe that we are well positioned to continue diversifying our portfolio by building profitable growth opportunities onshore. During 2010, we began to develop the properties we acquired during late 2009:

- Onshore – Permian Basin

During the fourth quarter of 2009, we acquired interests in properties producing from the Permian Basin's Wolfberry formation in Crockett, Ector, Midland and Upton Counties, Texas. The acquisition included year-end proven reserves of 1.6 MMBoe, 22 existing wells producing 350 Boe per day and upside from a multi-year inventory of drilling opportunities. We operate substantially all of the production and development of these properties.

During the first nine months of 2010, we drilled and placed on production nine wells at a total cost of approximately $14.7 million, which was included in our 2010 capital expenditures budget. Additionally, as of October 1, 2010 we are in the process of completing one well, drilling two wells and have five wells awaiting fracture stimulation. We plan to drill up to an additional six wells during the fourth quarter, thereby increasing to 23 total net wells our full-year 2010 development in the Permian Basin.

As a result of our development drilling activity, our net production has increased from 350 net Boe/d to 500 net Boe/d as of September 30, 2010. Based on the current pace of our development program, we expect to exit the year at approximately 750 net Boe/d, somewhat lower than our original expectations of 1,000 net Boe/d. The downward revision in our plan relates primarily to delays in receiving fracture stimulation services for which there is increased demand in the area at the present time. As of November 15, 2010, we had six wells awaiting fracture stimulation with the expectation that we will continue to build an inventory of wells waiting on fracture stimulation through the end of the year until the service organization builds additional capacity to handle industry requirements. We expect to fracture stimulate three additional wells prior to year-end, and expect that our remaining inventory of wells awaiting stimulation will be serviced by the second quarter of 2011.

In addition, we have increased our interest in the East Bloxom Development Area, located in Upton County, from an average 47% working interest to 100% working interest through a number of small acquisitions and farm-ins. As a result, we now control the activity in three development areas encompassing 11 sections.

- Onshore – Shale Gas (Haynesville Shale)

Also during the fourth quarter of 2009, we acquired a 70% working interest in a 577-acre unit in the heart of the Haynesville Shale play in Bossier Parish, Louisiana. Our multi-year development plan for this property includes drilling and operating a total of seven horizontal wells. The first of these wells was spud during June 2010 and completed and placed on production in September 2010. The well cost approximately $8.4 million net to Callon, which was also included in our 2010 capital expenditure budget. We have no remaining drilling obligations in our Haynesville Shale position, and currently plan to mobilize a rig to the area once natural gas prices warrant continued development of the remaining six planned horizontal wells.

Also highlighting the continued successful execution of our long-term strategy and as a result of an increase in our market capitalization to an amount above the minimum required threshold, on April 23, 2010 the New York Stock Exchange ("NYSE") removed Callon from its "Watch List" and affirmed that we are now considered a "company back in compliance" with the NYSE's quantitative continued listing standards.

In our effort to continue to conduct safe operations, and in an effort to evaluate any potential affect on planned production, Callon closely monitored response activities related to the oil spill that occurred off the Louisiana coast. Callon experienced no safety concerns for those operating on our offshore facilities, nor impacts to our production operations. In response to the recent oil spill in the Gulf of Mexico, the United States Congress is considering a number of legislative proposals relating to the upstream oil and gas industry both onshore and offshore that could result in significant additional laws or regulations governing our operations in the United States, including a proposal to raise or eliminate the cap on liability for oil spill cleanups under the Oil Pollution Act of 1990. We continue to monitor ongoing discussions regarding new regulations, though at present we do not believe it will affect our planned drilling program related to developing future reserves.

We also continue to monitor the changing regulatory environment, particularly the passing of the recent Dodd-Frank Wall Street Reform and Consumer Protection act (the "Bill") of 2010, including its section 1504 that is applicable to "resource extraction issuers" (i.e. oil and gas companies). Among a broad spectrum of the Bill's provisions aimed at reforming the United States' financial system in an effort to reduce systemic risk, the Bill contains various corporate governance and disclosure provisions. While it is too soon to fully analyze the impact the new legislation will have on our operations and profitability, we do not currently believe that its Section 1504 will materially affect our operations or profitability. We will continue to monitor the regulatory environment in our effort to proactively respond the relevant changes.

Deconsolidation of Callon Entrada

As more fully discussed in Note 2, Deconsolidation of Callon Entrada, included in Item I, Part I of this filing, in September 2009, the FASB issued an accounting standard which became effective for the first annual reporting period that begins after November 15, 2009 (with early adoption prohibited), and which amended US GAAP in several ways, which are disclosed in Note 2 included in Part I, Item 1 of this filing. We adopted this pronouncement on January 1, 2010.

Upon adoption and as a result of the amendments described above, we reevaluated our interest in Callon Entrada, and based on the evaluation performed, we concluded that a VIE reconsideration event had taken place. Our reconsideration analysis resulted in the determination that Callon Entrada is a VIE for which we are not the primary beneficiary. Consequently, effective January 1, 2010, Callon Entrada was deconsolidated from our consolidated financial statements.

The deconsolidation of Callon Entrada resulted in the removal of approximately $1.8 million of current assets, $2.0 million of current liabilities, $30.3 million of deferred tax assets, $30.3 million of tax valuation allowance and approximately $84.8 million of non-recourse debt and the related obligation for the cumulative amount of interest. Retained earnings increased by $85.1 million as a cumulative effect of change related to this accounting standard. No gain was recognized in the statement of operations. See Note 2 of Part I, Item I – Consolidated Financial Statements.

Table of Contents

Liquidity and Capital Resources

Historically, our primary sources of capital have been cash flows from operations, borrowings from financial institutions and the sale of debt and equity securities. Cash and cash equivalents increased by $16.2 million during the nine month period ending September 30, 2010 to $19.8 million compared to $3.6 million at December 31, 2009. Cash provided from operating activities during the first nine months of 2010 totaled $82.2 million, an increase of $70.6 million compared to the same period of 2009. The increase in liquidity is primarily attributable to receipt of the $44.8 million BOEMRE royalty recoupment and related interest of $7.9 million, production from our newly acquired properties and higher realized, average commodity prices on an equivalent basis, partially offset by production declines on some legacy properties.

During 2009, we recorded a receivable attributable to a recoupment of royalty payments we previously made to the BOEMRE on our deep water property, Medusa. Following the decisions resulting from several court cases brought by another oil and gas company, the court ruled that the BOEMRE was not entitled to receive these royalty payments. Accordingly the BOEMRE refunded the payments previously made. We received the principal payment of $44.8 million in January 2010, and received approximately $7.9 million during the second quarter of 2010 representing interest on the amounts previously withheld.

In January 2010, we amended our Senior Secured Credit Agreement to include Regions Bank as the sole arranger and administrative agent. The third amended and restated senior secured credit agreement ("the Credit Facility"), which matures on September 25, 2012, provides for a $100 million facility with a current borrowing base of $30 million, which represents a $10 million or 50% increase over the original $20 million borrowing base. Regions Bank approved the increase following its fourth quarter redetermination review. The bank performs its redetermination reviews on a semi-annual basis. The Credit Facility bears interest at 4% above a defined base rate and in no event will the interest rate be less than 6%. As of September 30, 2010, the interest rate on the facility was 6%. In addition, a commitment fee of 0.5% per annum on the unused portion of the borrowing base, is payable quarterly. Simultaneously with the execution of the third amended and restated senior secured credit agreement, we repaid the $10 million outstanding on the borrowing base under the second amended and restated senior secured credit agreement, which was outstanding as of December 31, 2009. No amounts were outstanding under the amended facility as of September 30, 2010.

During the fourth quarter of 2009, we completed an exchange offer for our $200 million of outstanding 9.75% Senior Notes due December 2010 ("Old Notes"). Holders of approximately 92% of the 9.75% Old Notes tendered their notes in the exchange offer, and received in their place 13% Senior Notes due 2016 ("Senior Notes"). The exchange offer included a 25% decrease in the principal amount exchanged, increased the coupon rate to 13% and included equity consideration. In addition, holders who tendered Old Notes consented to amend the indenture governing the Old Notes, eliminating substantially all of the indenture's restrictive covenants. On April 30, 2010, as previously discussed, we used a portion of the proceeds received from the BOEMRE recoupment to retire the remaining $16.1 million of Old Notes, which did not exchange, for 101% of par plus accrued interest not yet paid. At September 30, 2010, $137.9 million of the 13% Senior Notes were outstanding with interest payable quarterly, a $62.1 million decrease from amounts outstanding under the Old Notes at December 31, 2009.

2010 Budget and Capital Expenditures. For 2010, we designed a flexible capital spending program that can be funded from cash on hand and cash flows from operations. Our preliminary base capital program includes an accelerated development program of our Permian Basin crude oil assets as well as exploiting our Haynesville Shale gas play.

- Our 2010 capital budget approximates $65 million and includes plugging and abandonment, capitalized interest and certain overhead costs related to acquiring, exploring and developing our oil and gas properties.

- Planned capital expenditures for 2010 include, in addition to other less significant items, drilling and completing up to 23 wells in the Permian Basin and drilling and completing one well in the Haynesville Shale gas play. In the Permian Basin, as previously discussed, as of September 30, 2010 nine wells were complete and producing while eight additional wells were in various stages of the development progress. In the Haynesville Shale, the planned well was completed and placed on production during September 2010.

- We believe that our cash on hand and operating cash flow along with our Credit Facility, if needed, will be adequate to meet our capital, interest payments, and operating requirements for 2010.

Summary cash flow information is provided as follows:

Operating Activities. For the nine-months ended September 30, 2010, net cash provided by operating activities was $82.2 million, a $70.6 million increase from net cash provided by operating activities of $11.6 million for the same period in 2009. The increase in net cash provided by operating activities was primarily attributable to receipt of the $44.8 million BOEMRE royalty recoupment plus interest, production from our newly acquired properties and higher commodity prices on an equivalent basis, partially offset by production declines on some legacy properties.

Investing Activities. For the nine-months ended September 30, 2010, net cash used in investing activities was $39.7 million as compared to $27.6 million for the same period in 2009. The $12.1 million increase in net cash used in investing activities, primarily attributable to an increase in capital expenditure spending, relates to new drilling activity as we develop our Permian Basin and Haynesville Shale properties. These increases were partially offset by the wind-down costs paid in 2009 for Callon Entrada with no similar costs paid during 2010.

Financing Activities. For the nine-months ended September 30, 2010, net cash used in financing activities was $26.1 million compared to no financing activity cash flows for the same period in 2009. The 2010 expenditures related to the redemption of the $16.1 million remaining 9.75% Old Notes and to the repayment of $10 million outstanding borrowings under the Credit Facility simultaneous with the amendment to include Regions Bank as the sole arranger and administrative agent.

Table of Contents

Management's Discussion and Analysis of Financial Condition and Results of Operations

Results of Operations

The following table sets forth certain unaudited operating information with respect to the Company's oil and gas operations for the periods indicated:

	Three-Months Ended September 30,			
	2010	2009	Change	% Change
Net production:				
Oil (MBbls)	209	197	12	6 %
Gas (MMcf)	1,107	1,336	(229)	(17)%
Total production (MMcfe)	2,359	2,520	(161)	(6)%
Average daily production (MMcfe)	25.6	27.4	(1.8)	(7)%
Average realized sales price (a):				
Oil (Bbl)	$72.47	$83.38	$(10.91)	(13)%
Gas (Mcf)	4.84	3.64	1.20	33 %
Total (Mcfe)	8.68	8.46	0.22	3 %
Oil and gas revenues (in thousands):				
Oil revenue	$15,123	$16,451	$(1,328)	(8)%
Gas revenue	5,362	4,869	493	10 %
Total	$20,485	$21,320	$(835)	(4)%
Additional per Mcfe data:				
Sales price	$8.68	$8.46	$0.22	3 %
Lease operating expense	(1.83)	(1.97)	0.14	(7)%
Operating margin	$6.85	$6.49	$0.36	6 %
Other expenses on a per Mcfe basis:				
Depletion, depreciation and amortization	$3.13	$2.72	$0.41	15 %
General and administrative (net of capitalized amounts)	$1.43	$1.19	$0.24	20 %

(a) Below is a reconciliation of the average NYMEX price to the average realized sales price per barrel of oil / Mcf of gas:

	2010	2009	Change	% Change
Average NYMEX oil price	$76.23	$68.27	$7.96	12 %
Basis differential and quality adjustments	(2.62)	(2.60)	(0.02)	1 %
Transportation	(1.14)	(1.32)	0.18	(14)%
Hedging	-	19.03	(19.03)	(100)%
Average realized oil price	$72.47	$83.38	$(10.91)	(13)%
Average NYMEX gas price	$4.24	$3.46	$0.78	23 %
Natural gas liquid content and volume conversion adjustments	0.49	0.18	0.31	172 %
Hedging	0.11	-	0.11	100 %
Average realized gas price	$4.84	$3.64	$1.20	33 %

21

Table of Contents

Management's Discussion and Analysis of Financial Condition and Results of Operations

The following table sets forth certain unaudited operating information with respect to the Company's oil and gas operations for the periods indicated:

	Nine-Months Ended September 30,			
	2010	2009	Change	% Change
Net production:				
Oil (MBbls)	646	723	(77)	(11)%
Gas (MMcf)	3,359	4,216	(857)	(20)%
Total production (MMcfe)	7,237	8,556	(1,319)	(15)%
Average daily production (MMcfe)	26.5	31.3	(4.8)	(15)%
Average realized sales price (a):				
Oil (Bbl)	$73.78	$71.03	$2.75	4%
Gas (Mcf)	5.29	4.69	0.60	13%
Total (Mcfe)	9.04	8.32	0.72	9%
Oil and gas revenues (in thousands):				
Oil revenue	$47,687	$51,374	$(3,687)	(7)%
Gas revenue	17,752	19,786	(2,034)	(10)%
Total	$65,439	$71,160	$(5,721)	(8)%
Additional per Mcfe data:				
Sales price	$9.04	$8.32	$0.72	9%
Lease operating expense	(1.80)	(1.60)	(0.20)	13%
Operating margin	$7.24	$6.72	$0.52	8%
Other expenses on a per Mcfe basis:				
Depletion, depreciation and amortization	$2.94	$2.89	$0.05	2%
General and administrative (net of capitalized amounts)	$1.67	$1.19	$0.48	40%

(a) Below is a reconciliation of the average NYMEX price to the average realized sales price per barrel of oil / Mcf of gas:

	2010	2009	Change	% Change
Average NYMEX oil price	$77.65	$56.99	$20.66	36%
Basis differential and quality adjustments	(2.70)	(4.40)	1.70	(39)%
Transportation	(1.18)	(1.35)	0.17	(13)%
Hedging	0.01	19.79	(19.78)	(100)%
Average realized oil price	$73.78	$71.03	$2.75	4%
Average NYMEX gas price	$4.54	$3.92	$0.62	16%
Natural gas liquid content and volume conversion adjustments	0.64	0.33	0.31	94%
Hedging	0.11	0.44	(0.33)	(75)%
Average realized gas price	$5.29	$4.69	$0.60	13%

Table of Contents

Management's Discussion and Analysis of Financial Condition and Results of Operations

Revenues

The following tables are intended to reconcile the change in crude oil, natural gas and total revenue by reflecting the effect of changes in volume, changes in the underlying commodity prices and the impact of our hedge program.

Changes in Oil and Gas Production Revenues – Three-Months

	Crude Oil	Natural Gas	Total
Revenues for the three-months ended September 30, 2008	$20,366	$12,417	$32,783
Volume increase (decrease)	(753)	1,967	1,214
Price increase (decrease)	(6,915)	(9,515)	(16,430)
Impact of hedges increase	3,753	-	3,753
Net increase (decrease) in 2009	(3,915)	(7,548)	(11,463)
Revenues for the three-months ended September 30, 2009	$16,451	$4,869	$21,320
Volume increase (decrease)	947	(833)	114
Price increase (decrease)	(2,275)	1,202	(1,073)
Impact of hedges increase	-	124	124
Net increase (decrease) in 2010	(1,328)	493	(835)
Revenues for the three-months ended September 30, 2010	$15,123	$5,362	$20,485

Changes in Oil and Gas Production Revenues – Nine-Months

	Crude Oil	Natural Gas	Total
Revenues for the nine-months ended September 30, 2008	$74,016	$51,756	$125,772
Volume increase (decrease)	(5,394)	(7,339)	(12,733)
Price increase (decrease)	(31,558)	(26,466)	(58,024)
Impact of hedges increase	14,310	1,835	16,145
Net increase (decrease) in 2009	(22,642)	(31,970)	(54,612)
Revenues for the nine-months ended September 30, 2009	$51,374	$19,786	$71,160
Volume increase (decrease)	(5,465)	(4,023)	(9,488)
Price increase (decrease)	1,769	1,634	3,403
Impact of hedges increase	9	355	364
Net increase (decrease) in 2010	(3,687)	(2,034)	(5,721)
Revenues for the nine-months ended September 30, 2010	$47,687	$17,752	$65,439

23

Table of Contents

Management's Discussion and Analysis of Financial Condition and Results of Operations

Total Revenue

For the three-months ended September 30, 2010, total oil and gas revenues of $20.5 million decreased approximately $0.8 million or 4% from $21.3 million for the same period of 2009. Compared to the third quarter of 2009, total production on an equivalent basis decreased by 6% during the third quarter of 2010. Production decreases from our legacy offshore fields continue to be offset by new production from our Permian Basin and Haynesville Shale properties. While total production on an equivalent basis fell slightly and average realized oil sales prices dropped 13%, the decline in revenue was reduced by a 33% increase in the average realized gas price after accounting for the impact of hedging. Consequently, on an equivalent basis, average realized prices increased by 3%.

For the nine-months ended September 30, 2010, total oil and gas revenues of $65.4 million decreased approximately $5.7 million or 8% from $71.2 million for the same period of 2009. Compared to the first nine months of 2009, total production on an equivalent basis decreased by 15% during the same period of 2010. As discussed above, production from our Permian Basin and Haynesville Shale properties offset production declines from our legacy offshore fields. This decline in 2010 production was partially offset by an increase in the average realized sales price of both oil and gas of 4% and 13%, respectively or 9% on an equivalent basis.

Oil Revenue

For the three-months ended September 30, 2010, oil revenues of $15.1 million decreased $1.3 million or 8% from the same period of 2009. The largest contributor to the decline was a 13% decrease in the average realized oil price after accounting for the impact of hedging, but was partially offset by a 6% increase in production. The increase in production is largely attributable to production from our newly drilled and completed wells on the Permian Basin properties that we acquired during the fourth quarter of 2009.

For the nine-months ended September 30, 2010, oil revenues of $47.7 million decreased $3.7 million or 7% compared to revenues of $51.4 million for the same period of 2009. The largest contributor to the decline was an 11% decrease in production, partially offset by a 4% increase in the average realized oil price after accounting for the impact of hedging. In addition to normal and expected production declines, volumes declined primarily due to our working interest in Habanero #1 decreasing from 25% to 11.25% in June 2009 following the payout of a sidetrack on this well. The payout was associated with a third quarter 2007 sidetrack of the #1 well for which the operator elected to non-consent. These declines were partially offset by production from our newly drilled and completed wells on the Permian Basin properties that we acquired during the fourth quarter of 2009.

Gas Revenue

For the three-months ended September 30, 2010, gas revenues of $5.4 million increased by 10% when compared to gas revenues of $4.9 million for the same period of 2009. The largest contributor to the increase was a 33% increase in the average realized sale price, offset by a 17% decline in production. The most significant production decreases in third quarter 2010 production relate to lower production from our East Cameron #2 facility and from our Mobile Block 864 property. The host facility for East Cameron #2 was shut-in during January 2010 due to damage resulting from a fire, though production is expected to be restored in the fourth quarter of 2010 following the completion of the necessary repairs and BOEMRE inspections. The Mobile Block 864 production was suspended during much of the current quarter awaiting BOEMRE approval of a recompletion. The property returned to production in late August 2010. Other less significant declines included a mix of both normal and expected declines from our legacy properties and due to the Habanero #1 well reversionary interest discussed above in the oil revenue analysis. Offsetting these declines are increases from our Haynesville and Permian properties, the largest of which was our new Haynesville well at Swan Lake, which came online in early September 2010.

For the nine-months ended September 30, 2010, gas revenues of $17.8 million declined by 10% when compared to gas revenues of $19.8 million for the same period of 2009. The largest contributor to the decline was a 20% decrease in production, partially offset by a 13% increase in the average realized sales price of gas. As mentioned above, the largest contributor to the decline in production is the shut-in of the East Cameron #2 well. Production for the East Cameron #2 well is expected to be restored in the fourth quarter of 2010. The remaining decrease in production was due to normal and expected declines from our legacy properties and due to the Habanero #1 well reversionary interest discussed above in the oil revenue analysis. Offsetting these declines are increases from our Haynesville and Permian properties discussed above.

Table of Contents

Management's Discussion and Analysis of Financial Condition and Results of Operations

Operating Expenses

	Three-Months ended September 30,					
	2010	Per Mcfe	2009	Per Mcfe	Year $ Change	Year % Change
Lease operating expenses	$4,327	$1.83	$4,962	$1.97	$(635)	(13)%
Depreciation, depletion and amortization	7,392	3.13	6,861	2.72	531	8 %
General and administrative, net	3,371	1.43	3,000	1.19	371	12 %
Accretion expense	601	0.25	698	0.28	(97)	(14)%
Acquisition expense	139	0.06	-	-	139	100 %

	Nine-Months ended September 30,					
	2010	Per Mcfe	2009	Per Mcfe	Year $ Change	Year % Change
Lease operating expenses	$13,006	$1.80	$13,657	$1.60	$(651)	(5)%
Depreciation, depletion and amortization	21,247	2.94	24,726	2.89	(3,479)	(14)%
General and administrative, net	12,086	1.67	10,210	1.19	1,876	18 %
Accretion expense	1,803	0.25	2,531	0.30	(728)	(29)%
Acquisition expense	139	0.02	-	-	139	100 %

Lease Operating Expenses

For the three-month period ended September 30, 2010, lease operating expenses ("LOE") decreased 13% to $4.3 million compared to $5.0 million for the same period in 2009. The primary contributor to the reduction in LOE was normal and expected declines in production in addition to, as previously discussed above in the oil revenue comparative analysis, the reduction in our working interest in Habanero #1 well following the payout of a sidetrack on this well. Partially offsetting these decreases, LOE increased related to our acquisition of the Permian Basin properties and a modest increase in insurance rates due to adding additional coverage to our program designed to better protect the Company from damage caused by severe weather.

For the nine-month period ended September 30, 2010, LOE decreased 5% to $13.0 million compared to $13.7 million for the same period in 2009. While normal and expected declines in production in addition to the reduction in our Habanero #1 well working interest discussed above resulted in lower LOE, we experienced an offsetting increase in LOE related to our acquisition of the Permian Basin properties and a modest increase in insurance rates due to adding additional coverage to our program discussed above.

Depreciation, Depletion and Amortization

For the three-month period ended September 30, 2010, depreciation, depletion and amortization ("DD&A") increased approximately $0.5 million or 8% to $7.4 million compared to $6.9 million for the same period of 2009. The slight increase is due to a higher DD&A rate partially offset by production declines.

For the nine-month period ended September 30, 2010, DD&A decreased approximately $3.5 million or 14% to $21.2 million compared to $24.7 million for the same period of 2009. Production declines account for nearly all of the decrease, while a slight rate increase partially offset the production volume decreases.

General and Administrative

For the three-month period ended September 30, 2010, general and administrative (“G&A”) expenses, net of amounts capitalized, increased approximately $0.4 million or 12% to $3.4 million from $3.0 million for the same period of 2009. The primary contributor to the three-month period-over-period increase was the adjustment required to mark to their fair values a portion of our share-based compensation awards.

For the nine-month period ended September 30, 2010, G&A expenses, net of amounts capitalized, increased $1.9 million or 18% to $12.1 million from $10.2 million for the same period of 2009. Our performance-based incentive program runs from April to March, and adjustments to our accruals are recorded during the first quarter of the year subsequent to the issuance of final year-end financials. During the first quarter of 2009, we recorded a 75% reduction in incentive-based compensation related to our actual 2008 results. These results, which were negatively affected by the decline in oil and gas prices, the abandonment of the Entrada project and worsening broader economic conditions, were lower than the performance goals set for fiscal year 2008. Conversely, the increase experienced year-to-date in 2010 relates primarily to a 21% increase in incentive-based compensation related to exceeding performance goals set for fiscal year 2009. Also contributing to the increase is (1) a valuation adjustment to mark to fair value a portion of our share-based awards that will vest in the future which are accounted for as a liability, (2) additional employee-related costs, including non-recurring early retirement expenses, and (3) costs associated with adding new employees, including relocation and similar costs. Partially offsetting the increases is a $2.2 million expenses related to staff reductions incurred during the second quarter of 2009 for which no similar charge was recorded during 2010.

Accretion Expense

For the three-month period ended September 30, 2010, accretion expense related to our asset retirement obligations (“ARO”) decreased 14% to $0.6 million from $0.7 million incurred during the same period of 2009. Similarly, for the nine-month period ended September 30, 2010, accretion expense decreased 29% to $1.8 million from $2.5 million incurred during the same period of 2009. As the Company’s ARO decreases, so to does the related accretion expense. As of September 30, 2010, our average ARO liability for 2010 of $14.6 million was significantly lower than our average ARO liability of $31.2 million for the same period in 2009. Additionally, as we plug and abandon shelf wells, we are replacing those properties with on-shore wells. Our on-shore properties, in addition to typically having lower plugging and abandoning costs, tend to have longer lives, which therefore extends the accretion period and results in lower period expense. For additional information regarding the company’s ARO, see Note 10 included within the Consolidated Financial Statements found in Item 1, Part I of this filing.

Acquisition Expenses

For the three-month period ended September 30, 2010, acquisition expenses increased $0.1 million or 100% compared to 2009, during which we incurred no similar costs. During the current quarter, we increased our interest in the East Bloxom Development Area, located in Upton County, from an average 47% working interest to 100% working interest through a number of small acquisitions and farm-ins. As a result, we now control the activity in three development areas encompassing 11 sections (6,656 net acres).

Other

	Three-Months ended September 30,			
	2010	2009	$ Change	% Change
Interest expense	$3,133	$4,919	$(1,786)	(36)%
Callon Entrada non-recourse credit facility interest expense (1)	-	1,882	(1,882)	(100)%
Other (income) expense	63	110	(47)	(43)%
Income tax expense	-	-	-	-

	Nine-Months ended September 30,			
	2010	2009	$ Change	% Change
Interest expense	$9,925	$14,555	$(4,630)	(32)%
Callon Entrada non-recourse credit facility interest expense (1)	-	5,373	(5,373)	(100)%
Loss on early extinguishment of debt	339	-	339	100%
Other (income) expense	(409)	76	(485)	(638)%
Income tax expense	-	-	-	-

(1) See Note 2 included in the Notes to the Consolidated Financial Statements

Interest Expense

For the three-month period ended September 30, 2010, interest expense decreased $1.8 million or 36% to $3.1 million compared to $4.9 million for the same period of 2009. For the nine-month period ended September 30, 2010, interest expense decreased $4.6 million or 32% to $9.9 million compared to $14.6 million for the same period of 2009. The decrease was primarily due to $0.9 million and $2.7 million amortization of our deferred credit related to the Senior Notes, for the three and nine month periods, respectively, which is recorded as a decrease to interest expense. Also reducing interest expense was a decrease in 2010 in the amount of discount amortization recognized related to our 9.75% Old Notes, 92% of which were exchanged during 2009, in addition to a reduced amount of interest capitalized during the current periods compared to the same periods of 2009. Further, the remaining $16.1 million of outstanding Old Notes were redeemed on April 30, 2010 resulting in $0.3 million and $0.6 million of interest expense savings for the three and nine month periods of 2010 as compared to the same periods of 2009.

Loss on Early Extinguishment of Debt

For the nine-month period ended September 30, 2010, the loss on early extinguishment of debt was $0.34 million, though no similar expense was incurred during 2009. The $0.3 million related to the 1% call premium, equal to $0.16 million, paid to redeem the remaining $16.1 million of Old Notes not exchanged during the restructuring of the Old Notes, plus $0.18 million for the accelerated amortization of the Old Notes' remaining discount and debt issuance costs.

Other (Income) Expense

For the three-month period ended September 30, 2010, other expense remained flat compared to the same period of the prior year and amounted to less than $0.1 million. However, for the nine-month period ended September 30, 2010, other income increased $0.5 million to $0.4 million compared to other expenses of $0.1 million for the same period of the prior year. The increase was primarily related to interest income received from the BOEMRE related to the royalty recoupment previously discussed and due to income earned on a higher average balance of cash and cash equivalents held during the period. Cash and cash equivalents increased due to the receipt of the BOEMRE royalty recoupment.

Income Tax Expense

For the three-month and nine-month periods ended September 30, 2010 and 2009, income tax expense was negligible despite a period-over-period increase in pre-tax income of approximate $2.6 million and $7.1 million, respectively. Income tax expense remained immaterial due to adjustments made to our deferred tax asset valuation allowance. While we established a full valuation allowance at December 31, 2008, we adjust the valuation allowance each subsequent quarter to utilize our deferred tax asset to offset current period estimated taxable income.

Table of Contents

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

The Company's revenues are derived from the sale of its crude oil and natural gas production. The prices for oil and gas remain extremely volatile and sometimes experience large fluctuations as a result of relatively small changes in supply, weather conditions, economic conditions and government actions. From time to time, the Company enters into derivative financial instruments to manage oil and gas price risk.

The Company may utilize fixed price “swaps,” which reduce the Company's exposure to decreases in commodity prices and limit the benefit the Company might otherwise have received from any increases in commodity prices.

The Company may utilize price "collars" to reduce the risk of changes in oil and gas prices. Under these arrangements, no payments are due by either party as long as the market price is above the floor price and below the ceiling price set in the collar. If the price falls below the floor, the counter-party to the collar pays the difference to the Company, and if the price rises above the ceiling, the counter-party receives the difference from the Company.

Callon may purchase “puts” which reduce the Company’s exposure to decreases in oil and gas prices while allowing realization of the full benefit from any increases in oil and gas prices. If the price falls below the floor, the counter-party pays the difference to the Company.

The Company enters into these various agreements from time to time to reduce the effects of volatile oil and gas prices and does not enter into derivative transactions for speculative purposes. However, under certain circumstances some of the Company’s derivative positions may not be designated as hedges for accounting purposes.

See Note 7 to the Consolidated Financial Statements for a description of the Company's outstanding derivative contracts at September 30, 2010.

Item 4. Controls and Procedures

Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to the issuer’s management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. The Company’s principal executive and principal financial officers have concluded that the Company’s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the “Exchange Act”)) were effective as of September 30, 2010.

There were no changes in the Company’s internal control over financial reporting that occurred during the Company’s last fiscal quarter that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

Callon Petroleum Company is involved in various lawsuits incidental to our business. While the outcome of these lawsuits and proceedings cannot be predicted with certainty, it is the opinion of our management, based on current information and legal advice, that the ultimate disposition of these suits will not have a material effect on our financial position or results of operations.

Item 1A. Risk Factors

There have been no material changes with respect to the risk factors disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2009 except for the updates described below:

The following risk factor in our Form 10-K for the year ending December 31, 2009, is revised as follows to include a description of action taken by the Environmental Protection Agency on March 23, 2010.

Climate change legislation or regulations restricting emissions of "greenhouse gasses" could result in increased operating costs and reduced demand for the oil and gas we produce.

On December 15, 2009, the U.S. Environmental Protection Agency ("EPA") officially published its findings that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Accordingly, the EPA has proposed two sets of regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and could trigger permit review for greenhouse gas emissions from certain stationary sources.

In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. On March 23, 2010, the EPA announced that it will be proposing a rule to extend this reporting obligation to oil and gas facilities, including onshore and offshore oil and gas production facilities.

Also, on June 26, 2009, the U.S. House of Representatives passed the "American Clean Energy and Security Act of 2009," or "ACESA," which would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. ACESA would require a 17% reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80% reduction of such emissions by 2050. Under this legislation, the EPA would issue a capped and steadily declining number of tradable emissions allowances authorizing emissions of greenhouse gases into the atmosphere. These reductions would be expected to cause the cost of allowances to escalate significantly over time. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas.

The U.S. Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions, and the Obama Administration has indicated its support for legislation to reduce greenhouse emissions through an emission allowance system. At the state level, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to accumulate the required data and/or reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the oil and natural gas that we produce.

The adoption of derivatives legislation and regulations related to derivative contracts could have an adverse impact on our ability to hedge risks associated with our business.

The President recently signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act. Among other things, the act requires the Commodity Futures Trading Commission and the SEC to enact regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility. We cannot predict the content of these regulations or the effect that these regulations will have on our hedging activities. Of particular concern, the act does not explicitly exempt end users (such as us) from the requirements to post margin in connection with hedging activities. While several Senators have indicated that it was not the intent of the act to require margin from end users, the exemption is not in the act. If the regulations ultimately adopted were to require that we post margin for our hedging activities, our hedging would become more expensive. Additionally, it is possible that regulations, when finally adopted, in addition to increasing the expenses related to our hedging program may cause us to alter our hedging strategy.

Our operations could be adversely impacted by the recent drilling rig accident and resulting discharge of oil and gas in the Gulf of Mexico.

On April 22, 2010, a deepwater Gulf of Mexico drilling rig, Deepwater Horizon, sank after an apparent blowout and fire. Although we are shifting the focus of our operations onshore, we have ongoing operations in the Gulf of Mexico that could be negatively affected by the consequences of this accident.

As a result of the incident and spill, there may be changes in laws and regulations, increases in insurance costs or decreases in insurance availability, as well as delays in, or suspension of, our offshore development and production activities in the Gulf of Mexico. For example, the Minerals Management Service (now known as the Bureau of Ocean Energy Management, Regulation and Enforcement) of the U.S. Department of the Interior issued a notice on July 12, 2010 implementing a moratorium originally scheduled to stand through November 30, 2010 on certain drilling activities in the U.S. Gulf of Mexico. The moratorium was lifted during October 2010, and while the moratorium had no affect on our current drilling program, we have no assurance that a future moratorium, if enacted, would not hinder our development plans. To date, the incident has not had an impact on our Gulf of Mexico operations or production, but we cannot predict the full impact of the incident and resulting spill on these operations. In addition, we cannot predict how government or regulatory agencies will respond to the incident or whether changes in laws and regulations concerning operations in the Gulf of Mexico, or more generally throughout the U.S., will be enacted. Significant changes in regulations regarding future development and production activities in the Gulf of Mexico or other government or regulatory actions could reduce drilling and production activity, which could have a material adverse impact on our business and financing condition.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Removed and Reserved

Item 5. Other Information

None.

Table of Contents

Item 6. Exhibits

Index of Exhibits

The following exhibits are filed as part of this Form 10-Q.

Exhibit Number	Description
3.	Articles of Incorporation and By-Laws
3.1	Certificate of Incorporation of the Company, as amended (incorporated by reference from Exhibit 3.1 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003 filed March 15, 2004, File No. 001-14039)
3.2	Bylaws of the Company (incorporated by reference from Exhibit 3.2 of the Company's Registration Statement on Form S-4, filed August 4, 1994, Reg. No. 33-82408)
3.3	Certificate of Amendment to Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.3 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)
4.	Instruments defining the rights of security holders, including indentures
4.1	Specimen Common Stock Certificate (incorporated by reference from Exhibit 4.1 of the Company's Registration Statement on Form S-4, filed August 4, 1994, Reg. No. 33-82408)
4.2	Form of Warrants dated December 8, 2003 and December 29, 2003 entitling lenders under the Company's $185 million amended and restated Senior Unsecured Credit Agreement, dated December 23, 2003, to purchase common stock from the Company (incorporated by reference to Exhibit 4.14 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)
4.3	Indenture for the Company's 13.00% Senior Notes due 2016, dated November 24, 2009, between Callon Petroleum Company, the subsidiary guarantors described therein, Regions Bank and American Stock Transfer & Trust Company (incorporated by reference to Exhibit T3C to the Company's Form T3, filed November 19, 2009, File No. 022-28916)
31.	Certifications
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.	Section 1350 Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

30

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.

		Callon Petroleum Company
	By:	/s/ Fred L. Callon Fred L. Callon
Date: November 15, 2010		President and Chief Executive Officer
	By:	/s/ B.F. Weatherly B.F, Weatherly
Date: November 15, 2010		Executive Vice President and Chief Financial Officer