CALLON PETROLEUM CO
Form 10-Q
November 07, 2012

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, 2012
	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	64-0844345
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
200 North Canal Street Natchez, Mississippi	39120
(Address of principal executive offices)	(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 x 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 x

Non-accelerated filer ¨ 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 1, 2012 there were outstanding 39,799,583 shares of the Registrant’s common stock, par value $0.01 per share.

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Part I. Financial Information
Item I. Financial Statements
Callon Petroleum Company
Consolidated Balance Sheets
(in thousands, except par value per share data)

	September 30, 2012 Unaudited	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$1,485	$43,795
Accounts receivable	16,643	15,181
Fair market value of derivatives	2,013	2,499
Other current assets	1,359	1,601
Total current assets	21,500	63,076
Oil and natural gas properties, full-cost accounting method:		
Evaluated properties	1,490,862	1,421,640
Less accumulated depreciation, depletion and amortization	(1,244,329)	(1,208,331)
Net oil and natural gas properties	246,533	213,309
Unevaluated properties excluded from amortization	45,672	2,603
Total oil and natural gas properties	292,205	215,912
Other property and equipment, net	12,374	10,512
Restricted investments	3,796	3,790
Investment in Medusa Spar LLC	8,809	9,956
Deferred tax asset	64,911	65,743
Other assets, net	2,004	718
Total assets	$405,599	$369,707
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$30,988	$26,057
Asset retirement obligations	2,340	1,260
Fair market value of derivatives	224	—
Total current liabilities	33,552	27,317
13% Senior Notes:		
Principal outstanding	96,961	106,961
Deferred credit, net of accumulated amortization of $17,018 and $13,123, respectively	14,489	18,384
Total 13% Senior Notes	111,450	125,345
Senior secured revolving credit facility	40,000	—
Asset retirement obligations	11,664	12,678
Other long-term liabilities	3,471	3,165
Total liabilities	200,137	168,505
Stockholders' equity:		
Preferred Stock, $0.01 par value, 2,500 shares authorized;	—	—
Common stock, $0.01 par value, 60,000 shares authorized; 39,780 and 39,398 shares outstanding at September 30, 2012 and December 31, 2011,	398	394

respectively		
Capital in excess of par value	326,892	324,474
Other comprehensive income	279	1,624
Retained deficit	(122,107)	(125,290)
Total stockholders' equity	205,462	201,202
Total liabilities and stockholders' equity	$405,599	$369,707

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Operating revenues:				
Crude oil revenues	$24,061	$26,537	$71,883	$74,428
Natural gas revenues	3,341	7,013	10,174	21,404
Total oil and natural gas revenues	27,402	33,550	82,057	95,832
Operating expenses:				
Lease operating expenses	5,859	5,980	20,465	16,324
Depreciation, depletion and amortization	11,965	13,013	35,998	35,741
General and administrative	6,441	3,464	15,846	11,487
Accretion expense	574	569	1,709	1,767
Total operating expenses	24,839	23,026	74,018	65,319
Income from operations	2,563	10,524	8,039	30,513
Other (income) expenses:				
Interest expense	2,135	2,722	7,096	8,912
Gain on early extinguishment of debt	—	—	(1,366)	(1,942)
Gain on acquired assets	—	(46)	—	(5,025)
Unrealized loss (gain) on mark-to-market derivative instruments, net	1,598	—	(1,977)	—
Other (income) expense	237	(347)	(224)	(599)
Total other (income) expenses	3,970	2,329	3,529	1,346
Income (loss) before income taxes	(1,407)	8,195	4,510	29,167
Income tax expense (benefit)	(246)	—	1,508	(2,681)
Income (loss) before equity in earnings of Medusa Spar LLC	(1,161)	8,195	3,002	31,848
Equity in earnings of Medusa Spar LLC	56	211	180	597
Net income (loss) available to common shares	$(1,105)	$8,406	$3,182	$32,445
Net income (loss) per common share:				
Basic	$(0.03)	$0.21	$0.08	$0.87
Diluted	$(0.03)	$0.21	$0.08	$0.85
Shares used in computing net income (loss) per common share:				
Basic	39,575	39,322	39,441	37,431
Diluted	39,575	39,976	40,243	38,120

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

Callon Petroleum Company
Consolidated Statements of Comprehensive Income (Loss)
(Unaudited, in thousands)

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Net income (loss)	$(1,105)	$8,406	$3,182	$32,445
Other comprehensive (loss) income:				
Change in fair value of derivatives designated as hedges, net of tax	(1,268)	8,337	(1,345)	11,587
Total comprehensive income (loss)	$(2,373)	$16,743	$1,837	$44,032

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

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

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Cash flows from operating activities:		
Net income	$3,182	$32,445
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation, depletion and amortization	37,005	36,501
Accretion expense	1,709	1,767
Non-cash gain on acquired assets	—	(4,979)
Amortization of non-cash debt related items	293	338
Amortization of deferred credit	(2,304)	(2,361)
Non-cash gain on early extinguishment of debt	(1,366)	(1,942)
Equity in earnings of Medusa Spar LLC	(180)	(597)
Deferred income tax expense	1,508	11,987
Valuation allowance	—	(14,668)
Non-cash derivative income due to hedge ineffectiveness	(40)	(189)
Non-cash unrealized gain on mark-to-market derivative instruments, net	(1,977)	—
Non-cash charge related to compensation plans	1,901	1,122
Payments to settle asset retirement obligations	(1,136)	(2,428)
Changes in current assets and liabilities:		
Accounts receivable	(1,260)	(5,280)
Other current assets	244	37
Current liabilities	4,965	6,334
Change in natural gas balancing receivable	(96)	198
Change in natural gas balancing payable	(152)	(29)
Change in other long-term liabilities	—	100
Change in other assets, net	(911)	(427)
Cash provided by operating activities	$41,385	$57,929

Cash flows from investing activities:		
Capital expenditures	(115,401)	(74,388)
Investment in restricted assets for plugging and abandonment	—	(112)
Proceeds from sale of mineral interest and equipment	526	7,559
Distribution from Medusa Spar LLC	1,423	1,107
Cash used in investing activities	$(113,452)	$(65,834)
Cash flows from financing activities:		
Draw on senior secured credit facility	43,000	—
Payments on senior secured credit facility	(3,000)	—
Redemption of 13% senior notes	(10,225)	(35,062)
Issuance of common stock	—	73,765
Equity issued related to employee stock plans	(18)	—
Cash provided by financing activities	$29,757	$38,703
Net change in cash and cash equivalents	(42,310)	30,798
Beginning of period cash and cash equivalents	43,795	17,436
End of period cash and cash equivalents	$1,485	$48,234

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

Callon Petroleum Company
Notes to the Consolidated Financial Statements
(Unless otherwise indicated, amounts included in the footnotes to the financial statements are presented in thousands, except for per-share, per-hedge, well and acreage 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 natural 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 unle the context requires otherwise.

The Company’s properties and operations are geographically concentrated onshore in Texas and Louisiana and the offshore waters of the Gulf of Mexico.

Basis of Presentation

Unless otherwise indicated, all amounts included within the footnotes to the financial statements are presented in thousands, except for per-share, per-hedge, well and acreage data.

The interim consolidated 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 include the accounts of the Company, and its subsidiary, Callon Petroleum Operating Company (“CPOC”). CPOC also has subsidiaries, namely Callon Offshore Production, Inc. and Mississippi Marketing, Inc. CPOC also includes its former wholly owned subsidiary, Callon Entrada Company (“Callon Entrada”), which as discussed in Note 9 was reconsolidated in the Company's financial statements effective April 29, 2011.

These interim consolidated financial statements should be read in conjunction with the Company’s Annual Report on Form 10-K for the year ended December 31, 2011. The balance sheet at December 31, 2011 has been derived from the audited financial statements at that date.

Operating results for the periods presented are not necessarily indicative of the results that may be expected for the year ended December 31, 2012.

In the opinion of management, the accompanying unaudited consolidated financial statements reflect all adjustments, including normal recurring adjustments and all intercompany account and transaction eliminations, necessary to present fairly the Company's financial position, the results of its operations and its cash flows for the periods indicated. When necessary to ensure consistent presentation, certain prior year amounts may be reclassified. To the extent the amounts reclassified are material, we have either footnoted them within the Company's disclosures or have noted the items within this footnote.

Prior period correction of an immaterial error

During the second quarter of 2012, we determined that a prior reporting period had a misstatement caused by an error in adjusting the Company's deferred tax position at December 31, 2011. Management concluded that the impact of this error on the prior reporting period is immaterial. However, given that the adjustment to correct the error in 2012 would have a material impact on the 2012 financial statements, we have corrected the prior period financial statements in this current Form 10-Q in accordance with SEC guidance. The adjustment had no effect on the Company's cash flow, and the information included in this Form 10-Q sets forth the effects of this correction on the previously reported Balance Sheet and Income Statement as of December 31, 2011 as follows:

	As Reported	Adjustment	As Adjusted
Balance Sheet:			
Deferred tax asset	$63,496	$2,247	$65,743
Total assets	367,460	2,247	369,707
Retained deficit	(127,537)	2,247	(125,290)
Total stockholders' equity	198,955	2,247	201,202
Total liabilities and stockholders' equity	367,460	2,247	369,707
Income Statement:			
Income tax benefit	(67,036)	(2,247)	(69,283)
Net income available to common shares	104,149	2,247	106,396
Net income per common share - Basic	2.75	0.06	2.81
Net income per common share - Diluted	2.70	0.06	2.76

Note 2 - Property Acquisitions and Operating Leases

In February 2012, we contracted a drilling rig for a term of two years to support our horizontal drilling program in the Permian Basin. The drilling rig was delivered in April 2012, and lease costs recorded during the three and nine months ended September 30, 2012 was $2,327 and $4,283, respectively. Lease payments will approximate $6,611 in 2012 (with $2,328 remaining at September 30, 2012), $9,234 in 2013 and $2,619 in 2014. The agreement includes early termination provisions that would reduce the minimum rentals under the agreement, assuming the lessor is unable to re-charter the rig and staffing personnel to another lessee, to $4,434 in 2012 (with $1,689 remaining at September 30, 2012), $5,475 in 2013 and $1,350 in 2014.

During February 2012, the Company acquired approximately 16,020 gross (14,470 net) acres in Borden County, which is located in the northern portion of the Midland Basin. The northern portion of the Midland Basin has had limited drilling activity compared with the southern portion of the Basin (where our current production is located), increasing the risk of success for these drilling activities. The purchase price of $15,000 was funded from existing cash balances.

On June 8, 2012, the Company signed a purchase and sale agreement to acquire 2,319 gross (1,762 net) acres in southern Reagan County, Texas for a total purchase price of $12,000, which was financed with a draw on the Company's Senior Secured Credit Facility. The transaction had an effective date of May 1, 2012 and closed on July 5, 2012.

During the third quarter of 2012, we acquired an additional 8,375 gross acres (5,940, net) in the northern portion of the Midland Basin for a total consideration of $4,133. Subsequent to September 30, 2012, we acquired an additional

1,024 net acres in this area of the Midland Basin for $717.

In addition to the consideration paid for each of the above referenced leasehold additions, the Company's unevaluated property balance of $45,672 at September 30, 2012 includes the development and facility costs incurred in 2012 on these properties.

Note 3 - 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,	
	2012	2011	2012	2011
(a) Net income (loss)	$(1,105)	$8,406	$3,182	$32,445
(b) Weighted average shares outstanding	39,575	39,322	39,441	37,431
Dilutive impact of stock options	—	16	10	22
Dilutive impact of restricted stock	—	638	792	667
(c) Weighted average shares outstanding for diluted net income (loss) per share	39,575	39,976	40,243	38,120
Basic net income (loss) per share (a¸b)	$(0.03)	$0.21	$0.08	$0.87
Diluted net income (loss) per share (a¸c)	$(0.03)	$0.21	$0.08	$0.85
The following underlying shares associated with the following instruments were excluded from the diluted EPS calculation because their effect would be anti-dilutive:				
Stock options	52	67	52	82
Restricted stock	105	766	105	766

Note 4 – Borrowings

The Company’s borrowings consisted of the following at:

	September 30, 2012	December 31, 2011
Principal components:		
Credit Facility	$40,000	$—
13% Senior Notes due 2016, principal	96,961	106,961
Total principal outstanding	136,961	106,961
Non-cash components:		
13% Senior Notes due 2016 unamortized deferred credit	14,489	18,384
Total carrying value of borrowings	$151,450	$125,345

Senior Secured Revolving Credit Facility (the “Credit Facility”)

On June 20, 2012, Regions Bank increased the Company's Credit Facility to $200,000 with an associated borrowing base under the Credit Facility of $60,000 and a maturity of July 31, 2014. In October 2012, the Credit Facility was amended to increase the borrowing base to $80,000, extend the maturity to March 15, 2016 and add Citibank, NA, IberiaBank, Whitney Bank and OneWest Bank, FSB as participating lenders. Regions Bank continues to serve as Administrative Agent for the facility. Amounts borrowed under the Credit Facility may not exceed a borrowing base, which is generally reviewed on a semi-annual basis and is then eligible for re-determination. The borrowing base and scheduled maturity at year-end 2011 were $45,000 and September 25, 2012, respectively. The Credit Facility is secured by mortgages covering the Company's major producing fields.

As of September 30, 2012, the balance outstanding on the Credit Facility was $40,000 with an interest rate on the facility of 2.97%, calculated as the London Interbank Offered Rate (“LIBOR”) plus a tiered rate ranging from 2.5% to 3.0%, which is based on utilization of the facility. In addition, the Credit Facility carries a commitment fee of 0.5% per annum on the unused portion of the borrowing base, which is payable quarterly. As of November 7, 2012, the balance outstanding on the Credit Facility was $44,000 as the Company drew an additional $4,000 in support of the Company's ongoing capital development program.

Unless otherwise indicated, amounts included in the footnotes to the financial statements are presented in thousands, except for per-share, per-hedge, well and acreage data.

13% Senior Notes due 2016 (“Senior Notes”) and Deferred Credit

The Senior Notes’ 13% interest coupon is payable on the last day of each quarter. Certain of the Company’s subsidiaries guarantee the Company’s obligations under the unsecured 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. Upon issuing the Senior Notes in November 2009, the Company recorded as a deferred credit the $31,507 difference between the adjusted carrying amount of the Senior Notes that were exchanged and the principal of the Senior Notes. This deferred credit is being amortized as a reduction of 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:

Gross Carrying Amount	Accumulated Amortization at 9/30/2012	Carrying Value at 9/30/2012	Amortization Recorded during Current Year as a Reduction of Interest Expense	Estimated Amortization to be Recorded during the Remainder of the Current Year
$31,507	$17,018	$14,489	$2,304	$782

In June 2012, the Company redeemed $10,000 of its Senior Notes, which resulted in a $1,366 net gain on the early extinguishment of debt. The Notes had a carrying value of $11,591, including $1,591 of the Notes’ deferred credit. To redeem the Notes, the Company paid $10,225, comprised of the $10,000 principal of the notes and $225 of redemption expenses. The accumulated amortization reflected in the table above at September 30, 2012 includes the previously mentioned $1,591 deferred credit component, which recorded as a component of the gain on early extinguishment of debt is excluded from the amount reflected above as amortization recorded during the current year as a reduction of interest expense.

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, 2012.

Note 5 - 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 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 collar, options 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 speculative purposes.

Counterparty Risk

The use of derivative transactions exposes the Company to the risk that a counterparty will be unable to meet its commitments. To manage this risk, the Company's established counterparties for 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. Counterparty credit risk is considered when determining a derivative instruments' fair value; See Note 6 for additional information.

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 cash payment transfer or terminate the arrangement.

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Derivative positions and settlements

In the second quarter of 2012, the Company entered into fixed price natural gas swaps at $3.52 for the period October 2012 through December 2013 for 1,371 MMBtu over the 15-month period. To finance the uplift in the natural gas swap price for the period hedged, the Company sold natural gas put options at $3.00 for 1,095 MMbtu for fiscal year 2013 and sold natural gas call options at $4.75 for 456 MMbtu for fiscal year 2014.

Listed in the table below are the outstanding oil and natural gas derivative contracts as of September 30, 2012:

Commodity	Instrument	Average Notional Volumes per Month	Quantity Type	Average Floor Price per Instrument	Average Ceiling Price per Instrument	Period	Designation under ASC 815
Crude oil	Collar (1)	25	Bbls	$ 90.00	$ 122.00	Oct12 - Dec12	Designated
Crude oil	Collar (1)	25	Bbls	$ 95.00	$ 125.00	Oct12 - Dec12	Designated
Crude oil	Collar (1)	40	Bbls	$ 90.00	$ 116.00	Jan13 - Dec13	Not Designated
Natural gas	Swap (2)	91	MMbtu	$ 3.52	$ 3.52	Oct12 - Dec13	Not Designated
Natural gas	Put Option (2)	91	MMbtu	$ 3.00	n/a	Jan13-Dec13	Not Designated
Natural gas	Call Option (2)	38	MMbtu	n/a	$ 4.75	Jan14-Dec14	Not Designated

(1) A collar is a combination of a sold call option (ceiling) and a purchased put option (floor).

(2) The natural gas swap, put and call option were executed contemporaneously. The "above market" swap price the Company received was offset by the value of the two options sold by the Company. The short natural gas put option, when combined with the swap, creates the potential for a reduction in the effective swap price if NYMEX natural gas prices are below $3.00/MMbtu in 2013. The short natural gas call option, when combined with the Company's long production position, represents a "covered call," and creates a $4.75/MMbtu ceiling during the covered period.

Settlements of the Company's derivative instruments are based on the difference between the contract price or prices specified in the derivative instrument and a New York Mercantile Exchange ("NYMEX") price. The fair value of the Company's derivative instruments, depending on the type of instruments, was determined by the use of present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. See Note 6 for additional information regarding fair value.

The following table reflects the fair values of the Company's derivative instruments:

	Balance Sheet Presentation		Asset Fair Value		Liability Fair Value		Net Derivative Fair Value	
Commodity	Classification	Line Description	09/30/12	12/31/11	09/30/12	12/31/11	09/30/12	12/31/11
Derivatives designated as Hedging Instruments under ASC 815								
Natural gas	Current	Fair market value of derivatives	$—	$—	$—	$—	$—	$—
Natural gas	Non-current	Other long-term assets	—	—	—	—	—	—
Crude oil	Current		469	2,499	—	—	469	2,499

		Fair market value of derivatives						
Crude oil	Non-current	Other long-term liabilities	—	—	—	—	—	—
	Subtotals		$469	$2,499	$—	$—	$469	$2,499
Derivatives not designated as Hedging Instruments under ASC 815								
Natural gas	Current	Fair market value of derivatives	$—	$—	$(224)	$—	$(224)	$—
Natural gas	Non-current	Other long-term liabilities	—	—	(312)	—	(312)	—
Crude oil	Current	Fair market value of derivatives	1,544	—	—	—	1,544	—
Crude oil	Non-current	Other long-term assets	969	—	—	—	969	—
	Subtotals		$2,513	$—	$(536)	$—	$1,977	$—
	Totals		$2,982	$2,499	$(536)	$—	$2,446	$2,499

Unless otherwise indicated, amounts included in the footnotes to the financial statements are presented in thousands, except for per-share, per-hedge, well and acreage data.

Derivatives designated as hedging instruments

Certain of the Company’s crude oil derivative contracts in effect during 2012 are designated as cash flow hedges, and are recorded at fair market value with the effective portion of the changes in fair value recorded net of tax through other comprehensive income (loss) (“OCI”) in stockholders’ equity. The cash settlements on contracts for future production are recorded as an increase or decrease in crude oil revenues. Both changes in fair value and cash settlements of ineffective derivative contracts are recognized as derivative expense (income).

The tables below present the effect of the Company's derivative financial instruments on the consolidated statements of operations as an increase (decrease) to crude oil revenues for the effective portion and as an increase (decrease) to other (income) expense for the ineffective portion and amounts excluded from effectiveness testing:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Amount of gain (loss) reclassified from OCI into income (effective portion)	$260	$88	$772	$(361)
Amount of gain (loss) recognized in income (ineffective portion and amount excluded from effectiveness testing)	(282)	159	40	177

Derivatives not designated as hedging instruments

As discussed in the Company's Form 10-K for the year ended December 31, 2011, the Company elected not to designate any of its derivative contracts entered into subsequent to December 31, 2011 as an accounting hedge under FASB ASC 815, nor does it expect to designate future derivative contracts. Consequently, any derivative contract not designated as an accounting hedge is carried at its fair value on the balance sheet with both realized and unrealized (mark-to-market) gains or losses on these derivatives recorded on the statement of operations as a component of the Company's other income and expenses.

For the periods indicated, the Company recorded the following related to its derivative instruments that were not designated as accounting hedges:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Natural gas derivatives				
Realized gain (loss), net	$—	$—	$—	$—
Unrealized gain (loss), net	(205)	—	(536)	—
Sub-total gain (loss), net	$(205)	$—	$(536)	$—
Crude oil derivatives				
Realized gain (loss), net	$—	$—	$—	$—
Unrealized gain (loss), net	(1,393)	—	2,513	—
Sub-total gain (loss), net	$(1,393)	$—	$2,513	$—
Total gain (loss) on derivative instruments, net	$(1,598)	$—	$1,977	$—

Note 6 - 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. The carrying amounts for these instruments approximate fair value due to the short-term nature or maturity of the instruments.

Unless otherwise indicated, amounts included in the footnotes to the financial statements are presented in thousands, except for per-share, per-hedge, well and acreage data.

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, which is valued using Level 2 inputs, 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, 2012		December 31, 2011	
	Carrying Value	Fair Value	Carrying Value	Fair Value
13% Senior Notes due 2016 (1)	$111,450	$100,839	$125,345	$110,571

(1) Fair value is calculated only in relation to the $96,961 and $106,961 principal outstanding of the Senior Notes at the dates indicated above, respectively. The remaining $14,489 and $18,384, respectively, 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 4 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 the Company's Consolidated Balance Sheet. The following methods and assumptions were used to estimate the fair values:

Commodity Derivative Instruments: The Company's derivative instruments consist of financially settled commodity swap and option contracts with certain counterparties. The Company determines the value of its derivative contracts based on an income approach using a discounted cash flow model for swaps and a standard option pricing model for options. The inputs used in these models are readily available in the markets.

The Company's fair value calculations also incorporate an estimate of the counterparties' default risk for derivative assets and an estimate of the Company's default risk for derivative liabilities. A credit valuation adjustment ("CVA") is made that is based on the default probabilities by year as indicated by market quotes for the Company's or counterparties' credit default swap rates, as appropriate. If credit default rates for the Company or its counterparties are not available, market quotes of credit default rates for similar companies are used. These default probabilities have been applied to the unadjusted fair values of derivative instruments to arrive at the CVA.

The Company has consistently applied these valuation techniques in all periods presented, and believes that these inputs primarily fall within Level 2 of the fair-value hierarchy based on the wide availability of quoted market prices for similar commodity derivative contracts. See Note 5 for additional information.

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

As of 9/30/2012	Balance Sheet Presentation	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments - current	Fair market value of derivatives	$—	$2,013	$—	$2,013
Derivative financial instruments - non-current	Other long-term assets	—	969	—	969

Liabilities					
Derivative financial instruments - current	Fair market value of derivatives	$—	$224	$—	$224
Derivative financial instruments - non-current	Other long-term liabilities	—	312	—	312
Total		$—	$2,446	$—	$2,446

As of 12/31/2011	Balance Sheet Presentation	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments - current	Fair market value of derivatives	$—	$2,499	$—	$2,499
Derivative financial instruments - non-current	Other long-term assets	—	—	—	—
Total		$—	$2,499	$—	$2,499

Unless otherwise indicated, amounts included in the footnotes to the financial statements are presented in thousands, except for per-share, per-hedge, well and acreage data.

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 during the nine months ended September 30, 2012, including upward revisions of $0, were Level 3 fair value measurements. See Note 8, Asset Retirement Obligations, which provides a summary of changes in the ARO liability.

Note 7 - Income Taxes

The effective tax rate for the nine months ended September 30, 2012 and 2011 was 33% and 0%, respectively. The variance is attributable to the impact of the valuation allowance against the Company's net deferred tax asset throughout 2011 until it was reversed as of December 31, 2011. The most significant change from 2011 to 2012 other than the valuation allowance was an increase in the expected statutory depletion rate in 2012.

We have no liability for uncertain tax positions or any accrued interest or penalties as of September 30, 2012.

Note 8 - Asset Retirement Obligations

The following table summarizes the Company's asset retirement obligations activity for the nine months ended September 30, 2012:

Asset retirement obligations at January 1, 2012	$13,938	
Accretion expense	1,709	
Liabilities incurred	202	
Liabilities settled	(660	)
Revisions to estimate	(1,185	)
Asset retirement obligations at end of period	14,004	
Less: Current asset retirement obligations	2,340	
Long-term asset retirement obligations at September 30, 2012	$11,664	

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

Certain of the Company's operating agreements require that assets be restricted for future abandonment obligations. Amounts recorded on the Consolidated Balance Sheets as restricted investments were $3,796 at September 30, 2012. These investments include primarily U.S. Government securities, and are held in abandonment trusts dedicated to pay future abandonment costs for several of the Company's oil and natural gas properties.

Note 9 - Global Settlement with Joint Interest Partner

During May 2011, the Company entered into a final project wind-down agreement (the "Agreement") with CIECO. As a result of this Agreement, which included both the assignment of the rights to the Entrada assets and the proceeds from the ultimate sale of such assets, the Company gained the power to direct the activities related to the sale of the remaining assets, and therefore became the primary beneficiary of Callon Entrada. Therefore, Callon Entrada was consolidated in the Company's consolidated financial statements, effective April 29, 2011. Upon consolidating Callon Entrada, the Company estimated the fair values of the assets acquired to be $11,349 and liabilities assumed, primarily deferred tax liabilities associated with the tax basis difference in the assets, of Callon Entrada to be $2,681 as a result of this Agreement. Also in connection with this Agreement, Callon Entrada agreed to pay to CIECO approximately $438, which represented the net balance of joint interest billings due to CIECO and which had been previously accrued. The agreement also included joint releases of each party from any further liabilities or obligations to the other party in connection with the Entrada project. The adjusted fair market value of the net assets acquired of approximately $8,668 were recorded during 2011 as a $5,041 gain and $3,718 as an adjustment to the Company's full cost pool of oil and natural gas properties.

As of September 30, 2012, the remaining unsold assets had carrying values of $5,987, and are included in the Company's balance sheet as a component of Other property and equipment, net. The Company is actively marketing these assets.

Note 10 – Equity Transactions

During February 2011, the Company received $73,765 in net proceeds through the public offering of 10,100 shares of its common stock, which included the issuance of 1,100 shares pursuant to the underwriters’ over-allotment option. As discussed in Note 4, the Company used a portion of the proceeds to redeem $31,000 principal, or 22%, of its Senior Notes. The remaining proceeds were used for general corporate purposes including acreage acquisitions and the accelerated development of the Company’s Permian Basin and other onshore assets.

Special Note Regarding Forward Looking Statements

All statements, other than historical fact or present financial information, may be deemed to be 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. All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve growth and other plans and objectives for our future operations, are forward-looking statements. Although we believe the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance. We have no obligation and make no undertaking to publicly update or revise any forward-looking statements, except as may be required by law.

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Form 10-Q identified by words such as “anticipate,” “project,” “intend,” “estimate,” “expect,” “believe,” “predict,” “budget,” “projection,” “goal,” “plan,” “forecast,” “target,” "ma similar expressions.

You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect our operations, markets, products, services and prices and cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause our actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- the timing and extent of changes in market conditions and prices for commodities (including regional basis differentials);
- our ability to transport our production to the most favorable markets or at all;
- the timing and extent of our success in discovering, developing, producing and estimating reserves;
- our ability to respond to low natural gas prices;
- our ability to fund our planned capital investments;
- the impact of government regulation, including any increase in severance or similar taxes, legislation relating to hydraulic fracturing, the climate and over-the-counter derivatives;
- the costs and availability of oilfield personnel services and drilling supplies, raw materials, and equipment and services;
- our future property acquisition or divestiture activities;
- the effects of weather;
- increased competition;
- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
- conditions in capital markets, changes in interest rates and the ability of our lenders to provide us with funds as agreed;
- credit risk relating to the risk of loss as a result of non-performance by our counterparties; and
- any other factors listed in the reports we have filed and may file with the Securities and Exchange Commission (“SEC”).

We caution you that the forward-looking statements contained in this Form 10-Q are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of oil and natural gas. These risks include, but are not limited to, the risks described in Item 1A our Annual Report on Form 10-K for the year ended December 31, 2011 (the “2011 Annual Report on Form 10-K”), and all quarterly reports on Form 10-Q filed subsequently thereto ("Form 10-Qs").

Should one or more of the risks or uncertainties described above or elsewhere in our 2011 Annual Report on Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

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

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 2011 Annual Report on Form 10-K, which include additional information about our business practices, significant accounting policies, risk factors, and the transactions that underlie our financial results. When appropriate, the Company also updates 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 natural gas properties since 1950. Prior to 2009, our operations were focused on exploration and production in the Gulf of Mexico. In 2009, we began to shift our operational focus from exploration in the Gulf of Mexico to building an onshore asset portfolio in order to provide a multi-year, low-risk drilling program in both oil and natural gas basins with a particular emphasis on properties with oil-weighted drilling locations. The cash flows from our Gulf of Mexico properties have been reinvested into the Company's growing portfolio of onshore assets.

Overview and Outlook

For the three and nine months ended September 30, 2012, we reported net (loss) income and fully diluted (loss) earnings per share of $(1.1) million and $(0.03), and $3.2 million and $0.08, respectively, compared to net income and diluted earnings per share of $8.4 million and $0.21 and $32.4 million and $0.85, respectively for the same periods of 2011. These results are discussed in greater detail within the "Results of Operations" section included below.

Key accomplishments to date in 2012 include:

- We significantly expanded our acreage position in the Permian Basin with the acquisition of 24,609 gross (21,434 net) acres in the Midland Basin, prospective for both vertical and horizontal drilling of multiple zones. The total consideration paid for this expanded leasehold position was approximately $20 million, or approximately $926 per net acre.

- We commenced the horizontal development of our East Bloxom field in the southern portion of the Midland Basin, with the drilling of two horizontal wells targeting the Wolfcamp B shale. Both wells were drilled with lateral lengths of over 7,100 feet and are currently on production. The average initial (24-hour) production rate from these two wells was 804 Boe per day, with an oil composition of over 85%. The 30-day average production for these wells was 576 Boe per well per day.

- In the third quarter of 2012, we initiated the evaluation of our 14,470 contiguous net acre position in Borden County, Texas (average 90% working interest) located in the northern portion of the Midland Basin. Also in the third quarter, we began our drilling program with a vertical well followed by two horizontal wells. The first horizontal well was drilled in the Cline shale to a total measured depth of 14,300 feet, including a 6,769 foot lateral and was fracture stimulated in late October and into early November 2012. The second horizontal well is currently drilling in the Mississippian lime, and is scheduled to be fracture stimulated during the fourth quarter of 2012.

- In October, the lending group for our $200 million Credit Facility was expanded to include Citibank, NA, IberiaBank, Whitney Bank and OneWest Bank, FSB as participating lenders. Concurrently, the borrowing base was increased to $80 million from the $45 million borrowing base at December 31, 2011. Additionally, the Credit Facility's maturity was extended to March 15, 2016 from September 25, 2012 at year-end 2011.

- In June, we redeemed $10 million of our 13% Senior Notes due 2016 (the "Senior Notes") for $10.2 million. The repurchase reduced the Senior Notes balance to $97 million, and results in annualized cash interest savings of $1.3 million.

Highlights of our onshore and deepwater development program include:

- Onshore – Permian Basin

We expect that our production and reserve growth initiatives will continue to focus primarily on the Permian Basin, in which we own approximately 38,331 gross (32,649 net) acres as of November 1, 2012. In order to advance our growth plans, we are directing a significant amount of our 2012 capital budget to horizontal drilling and new acreage acquisitions in the Permian Basin. Based on completed and planned operational activity in 2012, we will drill five horizontal wells targeting three distinct intervals in the Wolfcamp B, Cline shales and the Mississippi lime.

Southern Portion: We currently own approximately 11,215 net acres in the southern portion of the Permian Basin, an increase of 18% since year-end 2011. Our current production in the southern portion of the Midland Basin (Crockett, Ector, Midland, and Upton Counties in Texas) is primarily from the Wolfberry play, which we believe to be an established, low-risk oil play that includes the Spraberry, Dean, and Wolfcamp formations. Certain of our properties also include the Atoka and Strawn formations.

During the nine months ended September 30, 2012, we drilled 15 gross vertical wells and fracture stimulated 19 gross vertical wells. We currently have four gross vertical wells awaiting fracture stimulation. In addition to our vertical drilling efforts, in the second quarter of 2012 we commenced a horizontal oil shale drilling program at our East Bloxom field in Upton County, initially targeting the Wolfcamp B formation. To date, we have drilled and completed two horizontal wells on our East Bloxom acreage in Upton County, Texas. Each well was drilled to a lateral length of over 7,100 feet, and the Company estimates it has the potential to drill a total of 24 horizontal wells at its East Bloxom field based on current assumptions of 160-acre spacing. As previously noted, the average initial (24-hour) production rate from these two wells was 804 Boe per day, with an oil composition of over 85%. The 30-day average production for these wells was 576 Boe per well per day.

In order to increase our exposure to horizontal development of the Wolfcamp B shale, we acquired 2,319 gross (1,762 net) acres in southern Reagan County, Texas, which closed on July 5, 2012. We are scheduled to drill our initial horizontal well in November 2012, which is focused on the Wolfcamp B shale.

Northern Portion: We currently own approximately 21,434 net acres in the northern portion of the Midland Basin, which includes the 14,470 net acres in Borden County, Texas that were acquired in the first quarter of 2012 and an additional 6,964 net acres acquired in and since the second quarter of 2012. We paid total consideration of $20 million for these leasehold positions. We believe this acreage is prospective for both horizontal and vertical development. Although the area has experienced a recent increase in drilling activity, the northern portion of the Midland Basin has had limited drilling activity compared with the southern portion of the Basin (where our current production is located), which significantly increases the risk associated with successful drilling activities in this area.

After completing a 3-D seismic survey on our acreage position, we commenced the drilling of an exploratory vertical well in July 2012, subsequently followed by the drilling of two horizontal wells. The first horizontal well was drilled in the Cline shale, and we began fracture stimulating the well in late October 2012. The second horizontal well is currently drilling in the Mississippian lime zone and is scheduled to be completed late in the fourth quarter of 2012.

• Onshore – Shale Gas (Haynesville Shale)

We own a 69% working interest in a 624 gross (430 net) acre unit in the Haynesville Shale play in Bossier Parish, Louisiana. Our one producing well in the Haynesville Shale was shut-in for a combined 112 days during the fourth quarter of 2011 and the first quarter of 2012 due to well interference from an offsetting well. Production was restored in mid-March 2012 following a successful remediation operation and, as of September 30, 2012, our Haynesville well was producing approximately 1,500 Mcf of natural gas per day. We currently have no drilling obligations related to this lease position.

• Offshore - Deepwater Properties

Our deepwater properties continue to play a key role in our transition to onshore operations by providing strong cash flows used to fund the expansion and development of our onshore positions. Combined production from our two deepwater properties was approximately 445 MBoe during the nine months ended September 30, 2012, equal to approximately 38% of the Company's total production for the period. Production from these properties is approximately 85% crude oil, which in the present market offers favorable pricing in relation to natural gas. Crude oil prices for production from our two deepwater fields are adjusted based upon Mars WTI differential for Medusa production and Argus Bonito WTI differential for Habanero production. These positive differentials are reflected in the realized price reconciliation table provided below within the Results of Operations discussion.

The Medusa platform was shut-in for 28 days during the second quarter of 2012 for planned construction activities on the West Delta 143 oil pipeline through which Medusa's production is transported. Production from the platform was fully restored on June 13, 2012. Due to Hurricane Isaac, the platform was once again shut-in from August 27, 2012 to September 4, 2012. As of November 1, 2012, Medusa was producing approximately 1,350 Boe per day, net. Additionally, the Medusa partner group is currently in the process of evaluating new technical data as future development plans for the field are considered.

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

The Habanero Field was shut-in on July 17, 2012 for scheduled maintenance operations on the Auger platform, which processes Habanero production volumes. Production was restored August 24, 2012 but suspended again August 27, 2012 for Hurricane Issac. Habanero was brought back on-line on September 3, 2012 and, as of November 1, 2012, was producing approximately 435 Boe per day, net. In addition, the Habanero #2 well was shut-in on June 12, 2012 due to the mechanical failure of a subsea safety valve. We have received notification from the operator of the Habanero Field that the drilling of the #2 sidetrack well targeting up-dip PUDs will commence during the fourth quarter of 2012

Liquidity and Capital Resources

Historically, our primary sources of funding have been cash flows from operations, borrowings from financial institutions and the sale of debt and equity securities. Cash and cash equivalents decreased by $42.3 million during the first nine months of 2012 to $1.5 million as compared to $43.8 million at December 31, 2011. The decrease in our cash balance is primarily attributable to capital expenditures of $115.4 million during the first nine months of 2012, representing a $41.0 million or 55% increase over the amount spent during the same period in 2011. The capital expenditures for the nine months ended September 30, 2012 include the following (in millions):

Southern Midland Basin	$57.9
Northern Midland Basin	11.1
Leasehold acquisitions	34.4
Gulf of Mexico	1.5
Capitalized general and administrative and interest expenses	10.5
Total capital expenditures	$115.4

The following table summarizes our wells drilled and completed by area during the first nine months of 2012:

	Drilling		Completion	
	Gross	Net	Gross	Net
Southern Midland Basin vertical wells	15	10.7	19	14.8
Southern Midland Basin horizontal wells	2	2.0	2	2.0
Total	17	12.7	21	16.8

	Drilling		Completion	
	Gross	Net	Gross	Net
Northern Midland Basin vertical wells	1	0.8	—	—
Northern Midland Basin horizontal wells	1	1.0	—	—
Total	2	1.8	—	—

On June 20, 2012, Regions Bank increased the Company's Credit Facility to $200 million with an associated borrowing base under the Credit Facility of $60 million and a maturity of July 31, 2014. In October 2012, the Credit Facility was amended to increase the borrowing base to $80 million, extend the maturity to March 15, 2016 and add Citibank, NA, IberiaBank, Whitney Bank and OneWest Bank, FSB as participating lenders. Regions Bank continues to serve as Administrative Agent for the facility. Amounts borrowed under the Credit Facility may not exceed a borrowing base, which is generally reviewed on a semi-annual basis and is then eligible for re-determination. The borrowing base and scheduled maturity at year-end 2011 were $45 million and September 25, 2012, respectively. The Credit Facility is secured by mortgages covering the Company's major producing fields.

As of September 30, 2012, the balance outstanding under the Credit Facility was $40 million with an interest rate on the facility of 2.97%, calculated as the London Interbank Offered Rate (“LIBOR”) plus a tiered rate ranging from 2.5% to 3.0%, which is based on utilization of the facility. In addition, the Credit Facility carries a commitment fee of 0.5% per annum on the unused portion of the borrowing base, which is payable quarterly. As of November 7, 2012, the balance outstanding on the Credit Facility was $44 million as the Company drew an additional $4 million in support of the Company's ongoing capital development program, leaving $36 million available for future draws.

At September 30, 2012, following a $10 million principal redemption in June 2012, we had approximately $97 million principal amount of 13% Senior Notes due 2016 outstanding with interest payable quarterly.

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2012 Budget and Capital Expenditures. For 2012, we designed a flexible capital spending program, which we plan to fund from cash on hand, cash flows from operations and utilization of our Credit Facility. We believe these resources will be adequate to meet our capital, interest payments, and operating requirements for 2012. Depending on commodity prices or other economic conditions we experience in 2012, and/or changes we elect to make to our capital plan based on the evaluation of our new horizontal drilling initiatives or availability of acreage acquisitions, our capital budget may be adjusted up or down.

Our revised 2012 capital budget approximates $152 million, and represents a 53% increase over 2011 actual capital expenditures. The increase in the 2012 capital budget over the previous estimate of $139 million primarily relates to the spending on additional infrastructure to support our new horizontal drilling initiatives and increased expenditures to acquire additional acreage. Of the $152 million, over 80% is allocated to onshore drilling, development and leasehold acquisition activity in the Permian Basin. Major components of this portion of the budget include:

- Drilling approximately 22 gross wells, including five horizontal wells, 16 vertical wells and one salt water disposal well
- Establishing new infrastructure and facilities to support our new horizontal drilling efforts
- Performing geologic and geophysical work in the Permian Basin
- Acquiring acreage in both the northern and southern portions of the Midland Basin

The planned Habanero #2 sidetrack well accounts for approximately 7% of the capital budget with the remainder of the capital budget allocated to planned Gulf of Mexico projects and capitalized expenses.

In addition to current cash balances of $1.1 million at November 7, 2012, we have $36 million of borrowing capacity available under our Credit Facility. We believe that this liquidity position, combined with our expected operating cash flow based on current commodity prices and forecasted production, will be adequate to meet our forecasted capital expenditures, interest payments, and operating requirements for the remainder of 2012.

Summary cash flow information is provided as follows:

Operating Activities. For the nine months ended September 30, 2012, net cash provided by operating activities decreased $16.5 million to $41.4 million, from $57.9 million for the same period in 2011. The decrease relates primarily to lower revenues due to both a 4% decrease in crude oil production, a 33% decrease in natural gas production and a 29% decrease in the average sales price realized for natural gas, all of which were partially offset by a 1% increase in the average sales price realized for crude oil. The production prices are discussed below within Results of Operations.

Investing Activities. For the nine months ended September 30, 2012, net cash used in investing activities was $113.5 million as compared to $65.8 million for the same period in 2011. The $47.6 million increase in net cash used in investing activities is primarily attributable to a $41.0 million increase in capital expenditures, which includes the acquisition of additional acreage in Borden County located in the northern portion of the Permian Basin and costs associated with the horizontal drilling activity on our East Bloxom Permian Basin acreage.

Financing Activities. For the nine months ended September 30, 2012, net cash provided by financing activities was $29.8 million compared to cash provided by financing activities of $38.7 million during the same period of 2011. Of our net $40 million draw on our Credit Facility, $30 million was used to support our Permian acreage development and $10 million was used to redeem $10 million principal value of our Senior Notes outstanding. The 2011 net cash provided by financing activities included $73.8 million of net proceeds from an equity offering offset by approximately $35.1 million used to redeem a $31 million principal portion of our outstanding Senior Notes and to pay the $4.0 million call premium and other redemption expenses.

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Results of Operations

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

	Three Months Ended September 30,			
	2012	2011	Change	% Change
Net production:				
Crude oil (MBbls)	251	270	(19)	(7)%*
Natural gas (MMcf)	890	1,284	(394)	(31)%*
Total production (MBoe)	399	484	(85)	(18)%
Average daily production (MBoe)	4.3	5.3	(1.0)	(18)%
Average realized sales price (a):				
Crude oil (Bbl)	$95.86	$98.27	$(2.41)	(2)%
Natural gas (Mcf)	$3.76	$5.46	$(1.70)	(31)%
Total on an equivalent basis (Boe)	$68.67	$69.31	$(0.64)	(1)%
Crude oil and natural gas revenues (in thousands):				
Crude oil revenue	$24,061	$26,537	$(2,476)	(9)%
Natural gas revenue	3,341	7,013	(3,672)	(52)%
Total	$27,402	$33,550	$(6,148)	(18)%
Additional per Boe data:				
Sales price	$68.67	$69.31	$(0.64)	(1)%
Lease operating expense	14.69	12.35	2.34	19 %
Operating margin	$53.98	$56.96	$(2.98)	(5)%
Other expenses per Boe:				
Depletion, depreciation and amortization	$29.99	$26.88	$3.11	12 %
General and administrative	16.14	7.16	8.98	125 %

(a) Below is a reconciliation of the average NYMEX price to the average realized sales price:

Average NYMEX price per barrel of crude oil	$92.22	$89.78	$2.44	3 %
Basis differential and quality adjustments	3.28	9.10	(5.82)	(64)%
Transportation	(0.68)	(0.94)	0.26	(28)%
Hedging	1.04	0.33	0.71	215 %
Average realized price per barrel of crude oil	$95.86	$98.27	$(2.41)	(2)%
Average NYMEX price per million British thermal units (“MMBtu”)	$2.90	$4.29	$(1.39)	(32)%
Basis differential, quality and Btu adjustments	0.86	1.17	(0.31)	(26)%
Hedging	—	—	—	— %
Average realized price per Mcf of natural gas	$3.76	$5.46	$(1.7)	(31)%

* Please refer to the Crude oil and Natural gas revenue discussions included below for an explanation of the production declines.

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	Nine Months Ended September 30,			
	2012	2011	Change	% Change
Net production:				
Crude oil (MBbls)	716	746	(30)	(4)%*
Natural gas (MMcf)	2,695	4,014	(1,319)	(33)%*
Total production (MBoe)	1,165	1,415	(250)	(18)%
Average daily production (MBoe)	4.3	5.2	(0.9)	(18)%
Average realized sales price (a):				
Crude oil (Bbl)	$100.39	$99.82	$0.57	1%
Natural gas (Mcf)	$3.77	$5.33	$(1.56)	(29)%
Total on an equivalent basis (Boe)	$70.44	$67.75	$2.69	4%
Crude oil and natural gas revenues (in thousands):				
Crude oil revenue	$71,883	$74,428	$(2,545)	(3)%
Natural gas revenue	10,174	21,404	(11,230)	(52)%
Total	$82,057	$95,832	$(13,775)	(14)%
Additional per Boe data:				
Sales price	$70.44	$67.75	$2.69	4%
Lease operating expense	17.57	11.54	6.03	52%
Operating margin	$52.87	$56.21	$(3.34)	(6)%
Other expenses per Boe:				
Depletion, depreciation and amortization	$30.90	$25.27	$5.63	22%
General and administrative	13.60	8.12	5.48	67%

(a) Below is a reconciliation of the average NYMEX price to the average realized sales price:

Average NYMEX price per barrel of crude oil	$96.21	$95.48	$0.73	1%
Basis differential and quality adjustments	3.84	5.84	(2.00)	(34)%
Transportation	(0.74)	(1.02)	0.28	(27)%
Hedging	1.08	(0.48)	1.56	(325)%
Average realized price per barrel of crude oil	$100.39	$99.82	$0.57	1%
Average NYMEX price per million British thermal units (“MMBtu”)	$2.43	$4.29	$(1.86)	(43)%
Basis differential, quality and Btu adjustments	1.34	1.04	0.30	29%
Hedging	—	—	—	—%
Average realized price per Mcf of natural gas	$3.77	$5.33	$(1.56)	(29)%

* Please refer to the Crude oil and Natural gas revenue discussions included below for an explanation of the production declines.

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

Revenues

The following table is intended to reconcile the change in crude oil, natural gas and total revenue for the respective periods presented by reflecting the effect of changes in volume, changes in the underlying commodity prices and the impact of our hedge program.

(in thousands)	Crude Oil	Natural Gas	Total
Revenues for the three-months ended September 30, 2010	$15,123	$5,362	$20,485
Volume increase	$4,448	$856	$5,304
Price increase	6,878	795	7,673
Impact of hedges increase	88	—	88
Net increase in 2011	11,414	1,651	13,065
Revenues for the three-months ended September 30, 2011	$26,537	$7,013	$33,550
Volume decrease	$(1,888)	$(2,154)	$(4,042)
Price decrease	(848)	(1,518)	(2,366)
Impact of hedges increase	260	—	260
Net decrease in 2012	(2,476)	(3,672)	(6,148)
Revenues for the three-months ended September 30, 2012	$24,061	$3,341	$27,402

(in thousands)	Crude Oil	Natural Gas	Total
Revenues for the nine-months ended September 30, 2010	$47,687	$17,752	$65,439
Volume increase	$7,327	$3,461	$10,788
Price increase	19,775	191	19,966
Impact of hedges decrease	(361)	—	(361)
Net increase in 2011	26,741	3,652	30,393
Revenues for the nine-months ended September 30, 2011	$74,428	$21,404	$95,832
Volume decrease	$(2,978)	$(7,030)	$(10,008)
Price decrease	(339)	(4,200)	(4,539)
Impact of hedges increase	772	—	772
Net decrease in 2012	(2,545)	(11,230)	(13,775)
Revenues for the nine-months ended September 30, 2012	$71,883	$10,174	$82,057

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

Crude Oil Revenue

Oil revenues decreased 9% to $24.1 million for the three months ended September 30, 2012 compared to revenues of $26.5 million for the same period of 2011. Contributing to the decrease in oil revenue was a 2% decrease in commodity prices compounded by a 7% decrease in production. The average price realized decreased to $95.86 per barrel compared to $98.27 for the same period of 2011. Production decreased to 251 thousand barrels (“MBbls”) during the third quarter of 2012 compared to production of 270 MBbls during the same period in 2011. The decrease in production was primarily attributable to approximately 47 days of down time at our Habanero field for scheduled maintenance to the Auger Facility combined with approximately 10 days of downtime at our Medusa field attributable to Hurricane Isaac. Excluding the effect of this downtime at our Habanero and Medusa fields, production in the third quarter of 2012 compared to the same quarter of 2011 would have been relatively unchanged. Further contributing to the decrease was the normal and expected declines in production from our other offshore properties. These production declines were offset by production from our Permian wells, two vertical and two horizontal, brought onto production during 2012.

Oil revenues of $71.9 million for the nine months ended September 30, 2012 decreased 3% compared to revenues of $74.4 million for the same period of 2011. While the average oil price realized increased 1%, total production decreased an offsetting 4%. The average price realized increased to $100.39 per barrel compared to $99.82 for the same period of 2011. Production decreased to 716 MBbls during the nine month period of 2012 compared to production of 746 MBbls during the same period in 2011. The decrease in production was primarily attributable to the down-time at the Habanero and Medusa fields and the normal and expected declines discussed above.

Natural Gas Revenue

Natural gas revenues of $3.3 million decreased 52% during the three months ended September 30, 2012 as compared to natural gas revenues of $7.0 million for the same period of 2011. Contributing to the decline was a 31% decrease in the average price realized, which fell to $3.76 per thousand cubic feet of natural gas ("Mcf") from $5.46 per Mcf, and a 31% decrease in natural gas production, driven primarily by down time at our East Cameron 257 well, which was suspended in the fourth quarter of 2011 due to a natural gas leak in an upstream section of the Stingray Pipeline that transports production volumes from the field. Production from our East Cameron 257 well is expected to resume once the pipeline is brought back online during the first quarter of 2013. Excluding the effect of this downtime at East Cameron 257, production decreases in the third quarter of 2012 compared to the same quarter of 2011 would have been approximately 20%. Also, as previously discussed, the down-time at our Habanero and Medusa fields combined with normal and expected declines in natural gas production from our other wells contributed to the period-to-period decline.

Natural gas revenues of $10.2 million decreased 52% during the nine months ended September 30, 2012 as compared to natural gas revenues of $21.4 million for the same period of 2011. As noted above, contributing to the decline was a 29% decrease in the average price realized, which fell to $3.77 per Mcf from $5.33 per Mcf, and a 33% decrease in natural gas production, driven primarily by down time at our Haynesville well, which was shut-in for 70 days during the first quarter of 2012 due to well interference from an offsetting well, and due to down time at our East Cameron 257 well, which was suspended in the fourth quarter of 2011 due to a natural gas leak in an upstream section of the Stingray Pipeline that transports production volumes from the field. Production from our East Cameron 257 well is expected to resume once the pipeline is brought back online during the first quarter of 2013. Also contributing to the decline was the previously discussed down time at our Habanero and Medusa fields and normal and expected declines in natural gas production from our offshore and Haynesville wells.

Our natural gas prices on an MMBtu equivalent basis exceeded the related NYMEX prices primarily due to the value of the NGLs in our natural gas stream from our Permian Basin and offshore production.

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

Operating Expenses

(in thousands except per unit data)	Three Months Ended September 30,							
					Total Change		Boe Change	
	2012	Per Boe	2011	Per Boe	$	%	$	%
Lease operating expenses	$5,859	$14.68	$5,980	$12.35	$(121)	(2)%	$2.33	19 %
Depreciation, depletion and amortization	11,965	29.98	13,013	26.88	(1,048)	(8)%	3.10	12 %
General and administrative	6,441	16.14	3,464	7.16	2,977	86 %	8.98	125 %
Accretion expense	574	1.44	569	1.18	5	1 %	0.26	22 %

(in thousands except per unit data)	Nine Months Ended September 30,							
					Total Change		Boe Change	
	2012	Per Boe	2011	Per Boe	$	%	$	%
Lease operating expenses	$20,465	$17.57	$16,324	$11.54	$4,141	25 %	$6.03	52 %
Depreciation, depletion and amortization	35,998	30.90	35,741	25.27	257	1 %	5.63	22 %
General and administrative	15,846	13.60	11,487	8.12	4,359	38 %	5.48	67 %
Accretion expense	1,709	1.47	1,767	1.25	(58)	(3)%	0.22	18 %

Lease Operating Expenses

Lease operating expenses (“LOE”) for the three months ended September 30, 2012 was relatively unchanged at $5.9 million compared to $6.0 million for the same period in 2011. The decrease was primarily due to lower deepwater property throughput charges as a result of the previously discussed reduced production volumes, partially offset by cost increases related to the significant growth in the number of wells now producing on our Permian Basin properties.

LOE increased by 25% to $20.5 million for the nine months ended September 30, 2012 compared to $16.3 million for the same period in 2011. The increase was primarily due to $3.2 million in costs related to significant growth in the number of wells now producing in our Permian Basin properties and $3.2 million associated with the remediation work on the Haynesville well. These increases were partially offset by a $2.0 million decline in LOE for our deepwater properties due to lower throughput charges as a result of reduced production volumes discussed previously.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization (“DD&A”) for the three months ended September 30, 2012 and compared to the same period of 2011 decreased 8% to $12.0 million compared to $13.0 million. The overall decrease is primarily related to the 18% drop in total production in the third quarter of 2012 compared to the same quarter of 2011. On an equivalent basis, the DD&A rate increased 12% to $29.98 per Boe from $26.88. Partially contributing to the increase per Boe is that prior period DD&A rates were effectively reduced by the impact of a $486 million 2008 impairment charge following a ceiling test writedown, which resulted in a lower, prospective DD&A rate for the then existing reserves. Subsequent increases in the rate are attributable to our planned exploration and development expenditures related to our onshore reserve development including the ongoing onshore development cost increases in the Permian Basin area.

DD&A for the nine months ended September 30, 2012 and compared to the same period of 2011 increased 1% to $36.0 million compared to $35.7 million and, on an equivalent basis, increased 22% to $30.90 per Boe from $25.27. As noted above, prior period DD&A rates were effectively reduced by the impact of a $486 million 2008 impairment. Increases in the DD&A rate subsequent to that impairment are attributable to our planned exploration and development expenditures related to our onshore reserve development discussed above. An 18% decline in total production during the first nine months of 2012 compared the same period of 2011 partially offset the overall increase in DD&A.

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

General and Administrative

General and administrative expenses, net of amounts capitalized, increased to $6.4 million for the three months ended September 30, 2012 from $3.5 million for the same period of 2011. The increases primarily includes expense of $1.6 million related to non-cash valuation adjustment to adjust to fair value a portion of our non-dilutive share-based awards that are being recognized over the service period, will be settled in cash upon vesting and are accounted for as liabilities compared to a $0.5 million reversal of expense for the same mark-to-market adjustment in the corresponding period of 2011. Additionally, we incurred $0.5 million costs related to non-recurring additional employee-related costs including early retirement and severance expense for which we had no expense during the same period of 2011. The remaining increase relates primarily to higher compensation-related expenses including the costs associated with hiring staff to support our onshore growth and 100% operated Permian production, including relocation and related costs.

Similarly, for the nine months ended September 30, 2012, general and administrative expenses, net of amounts capitalized, increased to $15.8 million from $11.5 million for the same period of 2011. The increases primarily includes expense of $1.7 million related to non-cash valuation adjustment to adjust to fair value a portion of our non-dilutive share-based awards that that are being recognized over the service period, will be settled in cash upon vesting and are accounted for as liabilities compared to a $0.2 million for the same mark-to-market adjustment in the corresponding period of 2011. Additionally, we incurred $1.1 million costs related to non-recurring additional employee-related costs including early retirement and severance expense for which we had no expense during the same period of 2011. The remaining increase relates primarily to higher compensation-related expenses including the costs associated with hiring staff to support our onshore growth and 100% operated Permian production, including relocation and related costs.

Accretion Expense

Accretion expense related to our asset retirement obligation increased 1% and decreased 3% for the three and nine months ended September 30, 2012, respectively, compared to the same periods of 2011. See Note 8 for additional information regarding the Company’s ARO.

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

Other Income and Expenses

(in thousands)	Three Months Ended September 30,			
	2012	2011	$ Change	% Change
Interest expense	$2,135	$2,722	$(587)	(22)%
Gain on acquired assets	—	(46)	46	(100)%
Unrealized loss on mark-to-market derivative instruments, net	1,598	—	1,598	100%
Other (income) expense	237	(347)	584	(168)%
Income tax expense (benefit)	(246)	—	(246)	100%
Equity in earnings of Medusa Spar LLC	56	211	(155)	(73)%
(in thousands)	Nine Months Ended September 30,			
	2012	2011	$ Change	% Change
Interest expense	$7,096	$8,912	$(1,816)	(20)%
Gain on early extinguishment of debt	(1,366)	(1,942)	576	(30)%
Gain on acquired assets	—	(5,025)	5,025	100%
Unrealized gain on mark-to-market derivative instruments, net	(1,977)	—	(1,977)	100%
Other (income) expense	(224)	(599)	375	(63)%
Income tax expense	1,508	(2,681)	4,189	(156)%
Equity in earnings of Medusa Spar LLC	180	597	(417)	(70)%

Interest Expense

Interest expense on our debt obligations decreased 22% to $2.1 million for the three months ended September 30, 2012 compared to $2.7 million for the same period of 2011. The decrease relates to the redemption of $10 million principal of Senior Notes during June 2012 in addition to a $0.5 million increase in capitalized interest compared to 2011, partially offset by interest expense related to increased borrowings under our credit facility. Interest expense on our debt obligations decreased 20% to $7.1 million for the nine months ended September 30, 2012 compared to $8.9 million for the same period of 2011. The decrease relates to the redemption of $31 million principal of Senior Notes during March 2011 and the redemption of $10 million principal of Senior Notes during June 2012 in addition to a $0.5 million increase in capitalized interest compared to 2011. This decrease is partially offset by interest expense related to increased borrowings under our credit facility.

Gain on Early Extinguishment of Debt

During June 2012, the Company redeemed $10 million of its Senior Notes with a carrying value of $11.6 million, including $1.6 million of the Notes' deferred credit, in exchange for $10.2 million, comprised of the $10 million principal of the Notes and $0.2 million of redemption expenses, which resulted in a $1.4 million net gain on the early extinguishment of debt.

During March 2011, using a portion of the proceeds from the Company's equity offering discussed in Note 10, the Company redeemed Senior Notes with a carrying value of $37 million, including $6.0 million of the Notes' deferred credit, in exchange for $35.1 million, comprised of the $31 million principal of the Notes, the $4.0 million call premium and miscellaneous redemption expenses, which resulted in a $1.9 million net gain on the early extinguishment of debt.

Gain on Acquired Assets

During the second quarter of 2011, we entered into a global settlement with a former joint interest partner through which we acquired certain assets, of which a portion was recorded as a gain. See Note 9, Global Settlement, for additional information.

Unrealized loss (gain) on mark-to-market derivative instruments

As discussed in Note 5 and beginning with derivative contracts executed in 2012, the Company elected to no longer designate its derivative contracts as accounting hedges. Unrealized losses and gains on mark-to-market derivative instruments, net for the three and nine months ended September 30, 2012 were $1.6 million loss and $2.0 million gain, respectively, compared to none in 2011 when all derivative contracts were designated as hedges for accounting purposes. See Notes 5 and 6 for disclosures related to derivative instruments including their composition and valuation.

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

Income tax expense (benefit)

Prior to 2012, we carried a full valuation allowance against our net deferred tax asset. For the three months ended September 30, 2011, a portion of the then recorded valuation allowance was utilized to offset our taxable income. For the nine months ended September 30, 2011, the income tax benefit reflected relates to the utilization of a portion of our deferred tax assets to offset the deferred tax liabilities attributable to our gain on acquired assets, discussed above, related to our global settlement with a former joint interest partner. At year-end 2011, we reversed the entire valuation allowance. Consequently, for the nine month period ended September 30, 2012 and for which we earned pre-tax income of 4.5 million, we reported income tax expense of $1.5 million. For the three months ended September 30, 2012 and for which we reported a pre-tax loss of 1.4 million, we recorded an income tax benefit of $0.2 million. See Note 7 for a discussion of our effective tax rate.

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 natural 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 natural gas price risk. The total volumes which we hedge through the use of our derivative instruments varies from period to period; however, generally our objective is to hedge approximately 50% of our anticipated internally forecasted production for the next 12 to 24 months. Our hedge policies and objectives may change significantly as commodities prices or price futures change.

As of September 30, 2012, we have commodity contracts covering approximately 53% and 28% of our internally forecasted proved developed producing crude oil and natural gas production, respectively, from October 2012 through December 2012. Our actual production will vary from the amounts estimated, perhaps materially. In addition, the Company has hedged 40 MBbls per month of crude oil and 90,000 MMBtu per month of natural gas from January 2013 to December 2013 and 38,000 MMBtu per month of natural gas from January 2014 to December 2014.

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. Swap contracts may also be enhanced by the simultaneous sale of call or put options to effectively increase the effective swap price as a result of the receipt of premiums from the option sales.

The Company may utilize price "collars" to reduce the risk of changes in oil and natural gas prices. Under these arrangements, no payments are due by either party as long as the applicable 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 natural gas prices while allowing realization of the full benefit from any increases in oil and natural 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 natural 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 5 to the Consolidated Financial Statements for a description of the Company's outstanding derivative contracts at September 30, 2012.

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, 2012.

Changes in Internal Control over Financial Reporting. There were no changes to our internal control over financial reporting during our last fiscal quarter that have materially affected, or are reasonable likely to materially affect, our internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

We are a defendant in various legal proceedings and claims, which arise in the ordinary course of our business. We do not believe the ultimate resolution of any such actions will 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 2011 Annual Report on Form 10-K.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

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)
3.4	Certificate of Amendment to the Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.4 of the Company's Annual Report on Form 10-K for the year ended December 31, 2010, 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	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)
10.	Material Contracts
10.1	Master Assignment, Agreement and Amended No.1 to the Fourth Amended and Restated Credit Agreement (incorporated by reference from Exhibit 10.1 on Form 8-K, filed October 16, 2012, File No. 001-14039)
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.
101.*	Interactive Data Files
*	Pursuant to Rule 406T of Regulation S-T, these interactive data files are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933 or Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise are not subject to liability.

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

Signature	Title	Date
/s/ Fred L. Callon Fred L. Callon	President and Chief Executive Officer	November 7, 2012
/s/ B.F. Weatherly B.F. Weatherly	Executive Vice President and Chief Financial Officer	November 7, 2012