CALLON PETROLEUM CO
Form 10-Q
August 08, 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: June 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 August 3, 2012 there were outstanding 39,487,033 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)

	June 30, 2012 Unaudited	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$113	$43,795
Accounts receivable	17,247	15,181
Fair market value of derivatives	4,645	2,499
Other current assets	1,538	1,601
Total current assets	23,543	63,076
Oil and natural gas properties, full-cost accounting method:		
Evaluated properties	1,472,497	1,421,640
Less accumulated depreciation, depletion and amortization	(1,232,364)	(1,208,331)
Net oil and natural gas properties	240,133	213,309
Unevaluated properties excluded from amortization	22,451	2,603
Total oil and natural gas properties	262,584	215,912
Other property and equipment, net	12,506	10,512
Restricted investments	3,792	3,790
Investment in Medusa Spar LLC	9,027	9,956
Deferred tax asset	63,965	65,743
Other assets, net	3,195	718
Total assets	$378,612	$369,707
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$32,997	$26,057
Asset retirement obligations	997	1,260
Total current liabilities	33,994	27,317
13% Senior Notes:		
Principal outstanding	96,961	106,961
Deferred credit, net of accumulated amortization of $16,253 and $13,123, respectively	15,254	18,384
Total 13% Senior Notes	112,215	125,345
Senior secured revolving credit facility	10,000	—
Asset retirement obligations	12,784	12,678
Other long-term liabilities	2,397	3,165
Total liabilities	171,390	168,505
Stockholders' equity:		
Preferred Stock, $0.01 par value, 2,500 shares authorized;	—	—
Common stock, $0.01 par value, 60,000 shares authorized; 39,472 and 39,398 shares outstanding at June 30, 2012 and December 31, 2011, respectively	395	394
Capital in excess of par value	326,281	324,474

Other comprehensive income	1,547	1,624
Retained deficit	(121,001)	(125,290)
Total stockholders' equity	207,222	201,202
Total liabilities and stockholders' equity	$378,612	$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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Operating revenues:				
Crude oil revenues	$22,073	$29,087	$47,822	$47,891
Natural gas revenues	3,287	7,747	6,833	14,392
Total oil and natural gas revenues	25,360	36,834	54,655	62,283
Operating expenses:				
Lease operating expenses	5,821	5,299	14,606	10,344
Depreciation, depletion and amortization	11,844	12,952	24,033	22,728
General and administrative	4,374	3,799	9,405	8,023
Accretion expense	562	583	1,135	1,198
Total operating expenses	22,601	22,633	49,179	42,293
Income from operations	2,759	14,201	5,476	19,990
Other (income) expenses:				
Interest expense	2,384	2,698	4,961	6,190
Gain on early extinguishment of debt	(1,366)	—	(1,366)	(1,942)
Gain on acquired assets	—	(4,979)	—	(4,979)
Unrealized gain on mark-to-market derivative instruments, net	(3,505)	—	(3,575)	—
Other income	(157)	(425)	(461)	(253)
Total other (income) expenses	(2,644)	(2,706)	(441)	(984)
Income before income taxes	5,403	16,907	5,917	20,974
Income tax expense (benefit)	1,610	(2,681)	1,754	(2,681)
Income before equity in earnings of Medusa Spar LLC	3,793	19,588	4,163	23,655
Equity in earnings of Medusa Spar LLC	6	289	124	386
Net income available to common shares	$3,799	$19,877	$4,287	$24,041
Net income per common share:				
Basic	$0.10	$0.51	$0.11	$0.66
Diluted	$0.09	$0.50	$0.11	$0.65
Shares used in computing net income per common share:				
Basic	39,399	39,225	39,375	36,485
Diluted	40,155	39,844	40,204	37,191

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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Net income	$3,799	$19,877	$4,287	$24,041
Other comprehensive (loss) income:				
Change in fair value of derivatives designated as hedges, net of tax	1,393	5,209	(77)	3,250
Total comprehensive income	$5,192	$25,086	$4,210	$27,291

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

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

	Six Months Ended June 30, 2012	2011
Cash flows from operating activities:		
Net income	$4,287	$24,041
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation, depletion and amortization	24,676	23,203
Accretion expense	1,135	1,198
Non-cash gain on acquired assets	—	(3,688)
Amortization of non-cash debt related items	225	218
Amortization of deferred credit	(1,538)	(1,583)
Non-cash gain on early extinguishment of debt	(1,366)	(1,942)
Equity in earnings of Medusa Spar LLC	(124)	(386)
Deferred income tax expense	1,754	8,186
Valuation allowance	—	(12,158)
Non-cash derivative income due to hedge ineffectiveness	(322)	(33)
Non-cash unrealized gain on mark-to-market derivative instruments, net	(3,575)	—
Non-cash charge related to compensation plans	1,512	1,239
Payments to settle asset retirement obligations	(1,029)	(1,288)
Changes in current assets and liabilities:		
Accounts receivable	(2,036)	(7,909)
Other current assets	63	572
Current liabilities	4,756	1,353
Change in natural gas balancing receivable	(95)	187
Change in natural gas balancing payable	(17)	(52)
Change in other long-term liabilities	—	100
Change in other assets, net	(865)	(300)
Cash provided by operating activities	$27,441	$30,958
Cash flows from investing activities:		
Capital expenditures	(72,538)	(42,018)
Investment in restricted assets for plugging and abandonment	—	(75)
Proceeds from sale of mineral interest and equipment	522	6,417
Distribution from Medusa Spar LLC	1,120	597
Cash used in investing activities	$(70,896)	$(35,079)
Cash flows from financing activities:		
Draw on senior secured credit facility	10,000	—
Redemption of 13% senior notes	(10,225)	(35,062)
Issuance of common stock	—	73,765
Equity issued related to employee stock plans	(2)	—
Cash (used in) provided by financing activities	$(227)	$38,703
Net change in cash and cash equivalents	(43,682)	34,582
Beginning of period cash and cash equivalents	43,795	17,436
End of period cash and cash equivalents	$113	$52,018

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

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.

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

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. The transaction had an effective date of May 1, 2012 and closed on July 5, 2012. The Company intends to initiate a horizontal drilling program focused on the Wolfcamp B shale, and currently estimates that the leasehold acquisition will add 19 horizontal Wolfcamp B drilling locations. The acquisition also includes seven vertical Spraberry wells, five of which were producing with the remaining two awaiting completion. In connection with the acquisition, the Company paid a $1,200 deposit prior to closing, which is included in unevaluated property at June 30, 2012.

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. The Company has an average 90% working interest across the contiguous acreage positions and is the operator. After completing in the second quarter a 3-D seismic survey on our acreage position, we commenced the drilling of an exploratory vertical well in July 2012.

Subsequent to June 30, 2012, we acquired an additional 3,586 gross acres (2,732, net) in the northern portion of the Midland Basin for a total consideration of $1,770.

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 six months ended June 30, 2012 was $1,956. Lease payments will approximate $6,611 in 2012, $9,234 in 2013 and $2,606 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, $5,475 in 2013 and $1,350 in 2014.

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Note 3 - Earnings per Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
(a) Net income	$3,799	$19,877	$4,287	$24,041
(b) Weighted average shares outstanding	39,399	39,225	39,375	36,485
Dilutive impact of stock options	7	22	14	24
Dilutive impact of restricted stock	749	597	815	682
(c) Weighted average shares outstanding for diluted net income per share	40,155	39,844	40,204	37,191
Basic net income per share (a/b)	$0.10	$0.51	$0.11	$0.66
Diluted net income per share (a/c)	$0.09	$0.50	$0.11	$0.65
The following were excluded from the diluted EPS calculation because their effect would be anti-dilutive:				
Stock options	67	67	52	67
Restricted stock	1,013	675	1,013	675

Note 4 – Borrowings

The Company’s borrowings consisted of the following at:

	June 30, 2012	December 31, 2011
Principal components:		
Credit Facility	$10,000	$—
13% Senior Notes due 2016, principal	96,961	106,961
Total principal outstanding	106,961	106,961
Non-cash components:		
13% Senior Notes due 2016 unamortized deferred credit	15,254	18,384
Total carrying value of borrowings	$122,215	$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 a revised borrowing base under the Credit Facility of $60,000. The Credit Facility maturity was also extended to July 31, 2014 from September 25, 2012. 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 was $45,000 at December 31, 2011, and increased to $60,000 with the fourth amendment. As of June 30, 2012, the balance outstanding on the Credit Facility was $10,000 with an interest rate on the facility of 2.75%, calculated as the London Interbank Offered Rate (“LIBOR”) plus a tiered rate ranging from 2.5% to 3.0%, which is based on the amount drawn on the facility. In addition, the Credit Facility continues to carry a commitment fee of 0.5% per annum on the unused portion of the borrowing base, which is payable quarterly. As of August 8, 2012, the balance outstanding on the Credit Facility was $28,000 as the Company drew an additional $18,000 subsequent to June 30, 2012 to fund the previously discussed Reagan County Permian acreage acquisitions and to support the Company's ongoing capital development program following the Company's opportunistic repurchase of $10,000 principal value of Senior Notes discussed below. The

Credit Facility is secured by mortgages covering the Company's major producing fields.

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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 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 6/30/2012	Carrying Value at 6/30/2012	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	$16,253	$15,254	$1,539	$1,548

In June 2012, the Company redeemed $10,000 of its Senior Notes with a carrying value of $11,591, including $1,591 of the Notes' deferred credit, in exchange for $10,225, comprised of the $10,000 principal of the notes and $225 of redemption expenses. The transaction resulted in a $1,366 net gain on the early extinguishment of debt. The accumulated amortization at June 30, 2012 includes the pro-rata $1,591 of accelerated amortization related to this principal redemption, which 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 June 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 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/or 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.

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. Counterparty credit risk is considered when determining a derivative instruments' fair value; See Note 6 for additional information.

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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 for fiscal year 2013 natural gas put options at $3.00 for 1,095 MMbtu and for fiscal year 2014 sold natural gas call options at $4.75 for 456 MMbtu.

Listed in the table below are the outstanding oil and natural gas derivative contracts as of June 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	Jul12 - Dec12	Designated
Crude oil	Collar (1)	25	Bbls	$ 95.00	$ 125.00	Jul12 - 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	06/30/12	12/31/11	06/30/12	12/31/11	06/30/12	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	Fair market value of derivatives	2,702	2,499	—	—	2,702	2,499
Crude oil	Non-current		—	—	—	—	—	—

		Other long-term liabilities						
	Subtotals		$2,702	$2,499	$—	$—	$2,702	$2,499
Derivatives not designated as Hedging Instruments under ASC 815								
Natural gas	Current	Fair market value of derivatives	$19	$—	$—	$—	$19	$—
Natural gas	Non-current	Other long-term liabilities	—	—	(350)	—	(350)	—
Crude oil	Current	Fair market value of derivatives	1,924	—	—	—	1,924	—
Crude oil	Non-current	Other long-term assets	1,982	—	—	—	1,982	—
	Subtotals		$3,925	$—	$(350)	$—	$3,575	$—
	Totals		$6,627	$2,499	$(350)	$—	$6,277	$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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Amount of gain (loss) reclassified from OCI into income (effective portion)	$512	$(350)	$512	$(449)
Amount of gain (loss) recognized in income (ineffective portion and amount excluded from effectiveness testing)	92	59	322	18

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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Natural gas derivatives				
Realized gain (loss), net	$—	$—	$—	$—
Unrealized gain (loss), net	(331)	—	(331)	—
Sub-total gain (loss), net	$(331)	$—	$(331)	$—
Crude oil derivatives				
Realized gain (loss), net	$—	$—	$—	$—
Unrealized gain (loss), net	3,836	—	3,906	—
Sub-total gain (loss), net	$3,836	$—	$3,906	$—
Total gain (loss) on derivative instruments, net	$3,505	$—	$3,575	$—

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.

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.

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.

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

	June 30, 2012		December 31, 2011	
	Carrying Value	Fair Value	Carrying Value	Fair Value
13% Senior Notes due 2016 (1)	$112,215	$99,385	$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 $15,254 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 6/30/2012	Balance Sheet Presentation	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments - current	Fair market value of derivatives	$—	$4,645	$—	$4,645
Derivative financial instruments - non-current	Other long-term assets	—	1,982	—	1,982
Liabilities					
Derivative financial instruments - current	Fair market value of derivatives	$—	$—	$—	$—
	Other long-term liabilities	—	350	—	350

Derivative financial instruments - non-current					
Total		$—	$6,277	$—	$6,277

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

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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 six months ended June 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 following table presents Callon's net unrecognized tax benefits relating to its reported net losses and other temporary differences from operations, and as discussed in Note 1, amounts presented for December 31, 2011 have been adjusted:

	June 30, 2012	December 31, 2011
Deferred tax asset:		
Federal net operating loss carryforward	$88,987	$86,551
Statutory depletion carryforward	7,600	7,032
Alternative minimum tax credit carryforward	208	208
Asset retirement obligations	3,496	3,552
Other	7,064	9,182
Deferred tax asset before valuation allowance	107,355	106,525
Less: Valuation allowance	—	—
Total deferred tax asset	107,355	106,525
Deferred tax liability:		
Crude oil and natural gas properties	41,325	38,534
Acquired assets (see Note 9)	2,065	2,248
Total deferred tax liability	43,390	40,782
Net deferred tax asset	$63,965	$65,743

The effective tax rate for the six months ended June 30, 2012 and 2011 was 30% 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 do not have a liability for uncertain tax positions or any accrued interest or penalties as of June 30, 2012.

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.

Note 8 - Asset Retirement Obligations

The following table summarizes the Company’s asset retirement obligations activity for the six months ended June 30, 2012:

Asset retirement obligations at January 1, 2012	$13,938
Accretion expense	1,135
Liabilities incurred	4
Liabilities settled	(512)
Revisions to estimate	(784)
Asset retirement obligations at end of period	13,781
Less: Current asset retirement obligations	997
Long-term asset retirement obligations at June 30, 2012	$12,784

Liabilities settled primarily relate to properties located in the Gulf of Mexico, 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 $3,792 at June 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 June 30, 2012, the remaining unsold assets had carrying values of $6,008, 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 six months ended June 30, 2012, we reported net income and fully diluted earnings per share of $3.8 million and $0.09, and $4.3 million and $0.11, respectively, compared to net income and diluted earnings per share of $19.9 million and $0.50 and $24.0 million and $0.65, 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:

- In February, we significantly expanded our Permian Basin acreage position with the acquisition of approximately 16,233 gross (14,470 net) acres in the northern portion of the Midland basin in Borden County. We believe the newly acquired Permian acreage is prospective for horizontal drilling of the Cline shale and Mississippian lime zones, and vertical drilling of multiple intervals. We have an average 90% working interest across the contiguous acreage positions, and we are the operator. In the third quarter of 2012, we began our drilling program with a vertical well after which we will drill two horizontal wells during 2012. 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.

- In the second quarter of 2012, we initiated a Permian Basin horizontal drilling program targeting the Wolfcamp B shale on our East Bloxom acreage. The first well was drilled to a total measured depth of 16,101 feet, including a 7,430 foot lateral, and produced at initial (24-hour) production rate of 827 Bbls of oil equivalent on July 16, 2012. A second horizontal well has been drilled and is expected to be fracture stimulated in August.

- In June, we 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 million. The transaction closed on July 5, 2012. We intend to initiate a horizontal drilling program focused on the Wolfcamp B shale in late 2012, and currently estimate that the leasehold acquisition will add 19 horizontal Wolfcamp B drilling locations.

- 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 annual cash interest savings of $1.3

million. Over the past 18 months, we have reduced the carrying value and principal value of our Senior Notes balance by $53.3 million and $41.0 million, or approximately 30%, respectively, through repurchases of the Senior Notes, decreasing fixed-rate interest expense and demonstrating our continued focus on lowering financing costs.

- On June 20th, Regions Bank increased our Senior Secured Credit Facility to $200 million with a revised borrowing base under the Credit Facility of $60 million, representing a $15 million or 33% increase over the previously approved $45 million borrowing base. The Credit Facility's maturity was extended to July 31, 2014 from September 25, 2012.

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

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 33,542 gross (28,416 net) acres as of August 3, 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 initiatives in the Permian Basin. We believe the potential for increased production rates and improved capital efficiency from our horizontal drilling initiatives will enhance the quality of our asset base as this program evolves over time.

Southern Portion: Our current production in the southern portion of the Midland Basin is primarily from the Wolfberry play, which is located on our properties in Crockett, Ector, Midland, and Upton counties, Texas, and which we believe to be a proven, low-risk oil play that includes the Spraberry, Dean, and Wolfcamp formations. Certain of our properties also include the Atoka and Strawn formations. As of June 30, 2012 and August 3, 2012, we owned approximately 9,452 and 11,214 net acres, respectively, in the southern portion of the Permian Basin, an increase of 18% since year-end 2011.

During the six months ended June 30, 2012, we drilled 12 gross vertical wells and fracture stimulated 17 gross vertical wells. We currently have five gross vertical wells awaiting fracture stimulation services. In addition to our vertical drilling efforts, we recently 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 two horizontal wells on our East Bloxom acreage in Upton County, Texas, with the first on production and the second well awaiting completion scheduled in August 2012. Each well was drilled to a lateral length of over 7,000 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.

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 intend to initiate a horizontal drilling program focused on the Wolfcamp B shale in late 2012 with two horizontal wells, and we currently estimate that the leasehold acquisition will add 19 horizontal Wolfcamp B drilling locations.

Northern Portion: We acquired 14,470 net acres in Borden County, TX in the first quarter of 2012 in an area we believe is prospective for both horizontal and vertical development. After completing a 3-D seismic survey on our acreage position, we commenced the drilling of a vertical well on July 16, 2012. We plan to drill two horizontal exploration wells in the second half of 2012 to evaluate the potential of the Cline shale and Mississippian lime zones.

Subsequent to June 30, 2012, we have acquired an additional 3,586 gross acres (2,732, net) in the northern portion of the Midland Basin for a total consideration of $1,770. These acquisitions increase our net total acreage in the northern portion of the Midland Basin to 17,202 acres as of August 3, 2012.

• Onshore – Shale Gas (Haynesville Shale)

We own a 69% working interest in a 624-acre (430 net) 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 June 30, 2012, our Haynesville well was producing approximately 1,275 Mcf of natural gas per day. Following the remediation, the rate has continued to increase, and was approximately 1,800 Mcf on August 2, 2012. We currently have no drilling obligations in our

Haynesville Shale 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 development of our onshore properties. Together, our two deepwater properties produced approximately 307 MBoe during the six months ended June 30, 2012, equal to approximately 40% of the Company's total production for the period. Production from our deepwater 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

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June 13, 2012, and as of August 3, 2012 was producing approximately 1,400 Boe/d, net. Additionally, the Medusa partner group is currently in the process of evaluating new technical data as future drilling plans are considered. The Habanero Field was shut-in July 17, 2012 for scheduled maintenance operations on the Auger platform, which processes Habanero production volumes. As a result, the operator of the Habanero Field expects production to be offline for a total of approximately 60 days during the third quarter of 2012. In addition, the Habanero #2 well was shut-in on June 12, 2012 resulting from the mechanical failure of a subsea safety valve. We have received confirmation from the operator of the Habanero Field that 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 capital have been cash flows from operations, borrowings from financial institutions and the sale of debt and equity securities. Cash and cash equivalents decreased by $43.7 million during the first six months of 2012 to $0.1 million as compared to $43.8 million at December 31, 2011. The decrease in our cash balance is primarily attributable to capital expenditures of $72.5 million during the six months of 2012, representing a $30.5 million or 73% increase over the amount spent during the same period in 2011. The capital expenditures for the six months ended June 30, 2012 include the following (in millions):

Southern Midland Basin	$46.6
Northern Midland Basin	1.7
Leasehold acquisitions	17.0
Gulf of Mexico	0.7
Capitalized general and administrative and interest expenses	6.5
Total capital expenditures	$72.5

The following table summarizes by area our drilled and completed wells through June 30, 2012:

	Drilling		Completion	
	Gross	Net	Gross	Net
Southern Midland Basin vertical wells	12	9	17	13.8
Southern Midland Basin horizontal wells	1	0.8	1	0.8
Total	13	9.8	18	14.6

On June 20, 2012, Regions Bank increased our Credit Facility to $200 million with a revised borrowing base under the Credit Facility of $60 million. The Credit Facilities maturity was extended to July 31, 2014 from September 25, 2012. 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. As of June 30, 2012, the balance outstanding on the Credit Facility was $10 million with an interest rate on the facility of 2.75%, calculated as the London Interbank Offered Rate (“LIBOR”) plus a tiered rate ranging from 2.5% to 3.0%, which is based on the amount drawn on the facility. In addition, the Credit Facility continues to carry a commitment fee of 0.5% per annum on the unused portion of the borrowing base, is payable quarterly. As of August 8, 2012, the balance outstanding on the Credit Facility was $28 million leaving $32 million available for future draws.

At June 30, 2012, following the previously mentioned $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 draws on 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, 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 related to spending on additional infrastructure to support our new horizontal drilling initiatives and increased expenditures to acquire additional acreage.

Of the $152 million, 57% is allocated to onshore drilling and development activity in the Permian Basin. Major components of this portion of the budget include:

- drilling approximately 24 gross wells, including six horizontal wells, 17 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.

The capital budget also includes an allocation of approximately 23% to acquire new acreage positions, including the recently acquired packages in Borden and the Reagan Counties in Texas. The planned Habanero #2 sidetrack well accounts for approximately 10% 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 $1.2 at August 8, 2012, we have $32 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 capital expenditure, interest payments, and operating requirements for the remainder of 2012. To the extent these cash requirements exceed our current sources of liquidity, we will be required to address our cash requirements through other means, including unsecured debt and equity financings, asset monetizations and joint ventures, and a reduction in our capital expenditures. In addition, we will continue to evaluate alternatives to increase our existing liquidity position as we establish our horizontal drilling and acreage plans in the Permian Basin in future years.

Summary cash flow information is provided as follows:

Operating Activities. For the six months ended June 30, 2012, net cash provided by operating activities decreased $3.5 million to $27.4 million, from $31.0 million for the same period in 2011. The decrease relates primarily to reduced revenues due to both an 18% decrease on total production and a 28%% decrease in the average natural gas sales price realized, partially offset by a 2% increase in the average crude oil sales price realized.

Investing Activities. For the six months ended June 30, 2012, net cash used in investing activities was $70.9 million as compared to $35.1 million for the same period in 2011. The $35.8 million increase in net cash used in investing activities is primarily attributable to a $30.5 million increase in capital expenditure spending, 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 six months ended June 30, 2012, net cash used in financing activities was $0.2 million compared to cash provided by financing activities of $38.7 million during the same period of 2011. Our redemption of $10 million principal value of our Senior Notes outstanding was offset by a $10 million draw on our Credit Facility. 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 June 30,			
	2012	2011	Change	% Change
Net production:				
Crude oil (MBbls)	223	275	(52)	(19)%*
Natural gas (MMcf)	902	1,388	(486)	(35)%*
Total production (Mboe)	374	506	(132)	(26)%
Average daily production (MBoe)	4.1	5.6	(1.5)	(26)%
Average realized sales price (a):				
Crude oil (Bbl)	$98.78	$105.75	$(6.97)	(7)%
Natural gas (Mcf)	$3.65	$5.58	$(1.93)	(35)%
Total on an equivalent basis (Boe)	$67.85	$72.75	$(4.90)	(7)%
Crude oil and natural gas revenues (in thousands):				
Crude oil revenue	$22,073	$29,087	$(7,014)	(24)%
Natural gas revenue	3,287	7,747	(4,460)	(58)%
Total	$25,360	$36,834	$(11,473)	(31)%
Additional per Boe data:				
Sales price	$67.85	$72.75	$(4.90)	(7)%
Lease operating expense	15.57	10.47	5.10	49%
Operating margin	$52.28	$62.28	$(10.00)	(16)%
Other expenses per Boe:				
Depletion, depreciation and amortization	$31.69	$25.58	$6.11	24%
General and administrative	11.70	7.50	4.20	56%

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

Average NYMEX price per barrel of crude oil	$93.49	$102.56	$(9.07)	(9)%
Basis differential and quality adjustments	3.68	5.50	(1.82)	(33)%
Transportation	(0.68)	(1.04)	0.36	(35)%
Hedging	2.29	(1.27)	3.56	(280)%
Average realized price per barrel of crude oil	$98.78	$105.75	$(6.97)	(7)%
Average NYMEX price per million British thermal units ("MMBtu")	$2.35	$4.37	$(2.02)	(46)%
Basis differential, quality and Btu adjustments	1.30	1.21	0.09	7%
Hedging	—	—	—	—%
Average realized price per Mcf of natural gas	$3.65	$5.58	$(1.93)	(35)%

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

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	Six Months Ended June 30,			
	2012	2011	Change	% Change
Net production:				
Crude oil (MBbls)	465	476	(11)	(2)%
Natural gas (MMcf)	1,806	2,730	(924)	(34)%
Total production (Mboe)	766	931	(165)	(18)%
Average daily production (MBoe)	4.2	5.1	(0.9)	(18)%
Average realized sales price (a):				
Crude oil (Bbl)	$102.86	$100.71	$2.15	2%
Natural gas (Mcf)	$3.78	$5.27	$(1.49)	(28)%
Total on an equivalent basis (Boe)	$71.36	$66.93	$4.43	7%
Crude oil and natural gas revenues (in thousands):				
Crude oil revenue	$47,822	$47,891	$(69)	—%
Natural gas revenue	6,833	14,392	(7,559)	(53)%
Total	$54,655	$62,283	$(7,628)	(12)%
Additional per Boe data:				
Sales price	$71.36	$66.93	$4.43	7%
Lease operating expense	19.07	11.12	7.95	71%
Operating margin	$52.29	$55.81	$(3.52)	(6)%
Other expenses per Boe:				
Depletion, depreciation and amortization	$31.38	$24.43	$6.95	28%
General and administrative	12.28	8.62	3.66	42%

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

Average NYMEX price per barrel of crude oil	$98.21	$98.34	$(0.13)	—%
Basis differential and quality adjustments	4.33	4.48	(0.15)	(3)%
Transportation	(0.78)	(1.17)	0.39	(33)%
Hedging	1.10	(0.94)	2.04	(217)%
Average realized price per barrel of crude oil	$102.86	$100.71	$2.15	2%
Average NYMEX price per million British thermal units (“MMBtu”)	$2.43	$4.29	$(1.86)	(43)%
Basis differential, quality and Btu adjustments	1.35	0.98	0.37	38%
Hedging	—	—	—	—%
Average realized price per Mcf of natural gas	$3.78	$5.27	$(1.49)	(28)%

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 June 30, 2010	$15,901	$5,668	$21,569
Volume increase	$4,460	$1,579	$6,039
Price increase	9,076	500	9,576
Impact of hedges decrease	(350)	—	(350)
Net increase in 2011	13,186	2,079	15,265
Revenues for the three-months ended June 30, 2011	$29,087	$7,747	$36,834
Volume decrease	$(5,455)	$(2,713)	$(8,168)
Price decrease	(2,071)	(1,747)	(3,818)
Impact of hedges increase	512	—	512
Net decrease in 2012	(7,014)	(4,460)	(11,474)
Revenues for the three-months ended June 30, 2012	$22,073	$3,287	$25,360

(in thousands)	Crude Oil	Natural Gas	Total
Revenues for the six-months ended June 30, 2010	$32,564	$12,390	$44,954
Volume increase	$2,822	$2,631	$5,453
Price increase (decrease)	12,954	(629)	12,325
Impact of hedges decrease	(449)	—	(449)
Net increase (decrease) in 2011	15,327	2,002	17,329
Revenues for the six-months ended June 30, 2011	$47,891	$14,392	$62,283
Volume decrease	$(1,070)	$(4,872)	$(5,942)
Price increase (decrease)	489	(2,687)	(2,198)
Impact of hedges increase	512	—	512
Net decrease in 2012	(69)	(7,559)	(7,628)
Revenues for the six-months ended June 30, 2012	$47,822	$6,833	$54,655

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

Total Revenue

Total oil and natural gas revenues of $25.4 million for the three months ended June 30, 2012 decreased $11.5 million or 31% from the same period of 2011 principally driven by a 26% decrease in total production and a 7% decrease in average realized prices on an equivalent basis. For additional information, please refer to the "Oil Revenue" and "Natural Gas Revenue" discussions included below.

Total oil and natural gas revenues of $54.7 million for the six months ended June 30, 2012 decreased $7.6 million or 12% from the same period of 2011 principally driven by a 18% decrease in production partially offset by a 7% increase in averaged realized prices on an equivalent basis. For additional information, please refer to the "Oil Revenue" and "Natural Gas Revenue" discussions included below.

Crude Oil Revenue

Oil revenues decreased 24% to $22.1 million for the three months ended June 30, 2012 compared to revenues of $29.1 million for the same period of 2011. Contributing to the decrease in oil revenue was a 7% decrease in commodity prices compounded by a 19% decrease in production. The average price realized decreased to $98.78 per barrel compared to $105.75 for the same period of 2011. Similarly, production decreased to 223 thousand barrels (“MBbls”) during the second quarter of 2012 compared to production of 275 MBbls during the same period in 2011. The decrease in production was primarily attributable to approximately 28 days of down time at our Medusa field for scheduled third-party pipeline maintenance, which reduced second quarter 2012 production by an estimated 35 MBoe. Excluding the one-time effect of this downtime at Medusa, production decreases in the second quarter of 2012 compared to the same quarter of 2011 would have been approximately 6%. Further contributing to the decrease was the normal and expected declines in production from our offshore properties. These production declines were partially offset by production from Permian wells brought onto production during the second quarter of 2012.

Oil revenues of $47.8 million for the six months ended June 30, 2012 were flat compared to revenues of $47.9 million for the same period of 2011. While the average oil price realized increased 2%, total production decreased an offsetting 2%. The average price realized increased to $102.86 per barrel compared to $100.71 for the same period of 2011. Production decreased to 465 MBbls during the six month period of 2012 compared to production of 476 MBbls during the same period in 2011. The decrease in production was primarily attributable to the down time at the Medusa field and the normal and expected declines, which were previously discussed above.

Natural Gas Revenue

Natural gas revenues of $3.3 million decreased 58% during the three months ended June 30, 2012 as compared to natural gas revenues of $7.7 million for the same period of 2011. Contributing to the decline was a 35% decrease in the average price realized, which fell to $3.65 per thousand cubic feet of natural gas ("Mcf") from $5.58 per Mcf, and a 35% 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 fourth quarter of 2012. Excluding the effect of this downtime at East Cameron 257, production decreases in the second quarter of 2012 compared to the same quarter of 2011 would have been approximately 11%. Also contributing to the decline was reduced volumes from our Haynesville well, which was continuing to return to normal production following well remediation work performed in the first quarter of 2012. While the well was producing approximately 1,275 MMcf/day at June 30, 2012, the rate had increased 41% to approximately 1,800 as of August 3, 2012. Finally, and as previously discussed, the 28 day period of down time at our Medusa field 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 $6.8 million decreased 53% during the six months ended June 30, 2012 as compared to natural gas revenues of $14.4 million for the same period of 2011. As noted above, contributing to the decline was a 28% decrease in the average price realized, which fell to $3.78 per Mcf from $5.27 per Mcf, and a 34% decrease in natural gas production, driven primarily by down time at our Haynesville well, which was the 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 fourth quarter of 2012. Also contributing to the decline was the previously discussed 28 day period of down time at our Medusa field 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.

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 June 30,							
					Total Change		Boe Change	
	2012	Per Boe	2011	Per Boe	$	%	$	%
Lease operating expenses	$5,821	$15.57	$5,299	$10.47	$522	10 %	$5.10	49 %
Depreciation, depletion and amortization	11,844	31.69	12,952	25.58	(1,108)	(9)%	6.11	24 %
General and administrative	4,374	11.70	3,799	7.50	575	15 %	4.20	56 %
Accretion expense	562	1.50	583	1.15	(22)	(4)%	0.35	30 %

(in thousands except per unit data)	Six Months Ended June 30,							
					Total Change		Boe Change	
	2012	Per Boe	2011	Per Boe	$	%	$	%
Lease operating expenses	$14,606	$19.07	$10,344	$11.12	$4,262	41 %	$7.95	71 %
Depreciation, depletion and amortization	24,033	31.38	22,728	24.43	1,305	6 %	6.95	28 %
General and administrative	9,405	12.28	8,023	8.62	1,382	17 %	3.66	42 %
Accretion expense	1,135	1.48	1,198	1.29	(63)	(5)%	0.19	15 %

Lease Operating Expenses

Lease operating expenses (“LOE”) increased by 10% to $5.8 million for the three months ended June 30, 2012 compared to $5.3 million for the same period in 2011. The increase was primarily due to $1.0 million in costs related to significant growth in the number of wells now producing in our Permian Basin properties and $0.3 million associated with the remediation work on the Haynesville well. These increases were partially offset by a $0.8 million decline in LOE for our deepwater properties due to lower throughput charges as a result of reduced production volumes discussed previously.

LOE increased by 41% to $14.6 million for the six months ended June 30, 2012 compared to $10.3 million for the same period in 2011. The increase was primarily due to $2.5 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 $1.4 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 June 30, 2012 and compared to the same period of 2011 decreased 9% to $11.8 million compared to $13.0 million and, on an equivalent basis, increased 24% to $31.69 per Boe from $25.58. The overall decrease is primarily related to the 26% drop in total production in the second quarter of 2012 compared the same quarter of 2011. Partially offsetting this overall decrease 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 six months ended June 30, 2012 and compared to the same period of 2011 increased 6% to $24.0 million compared to $22.7 million and, on an equivalent basis, increased 28% to $31.38 per Boe from $24.43. As noted above, prior period DD&A rates were effectively reduced by the impact of a $486 million 2008 impairment.

Subsequent increases in the rate 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 the first six 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 $4.4 million for the three months ended June 30, 2012 from $3.8 million for the same period of 2011. Similarly, for the six months ended June 30, 2012, general and administrative expenses, net of amounts capitalized, increased to $9.4 million from $8.0 million for the same period of 2011. The increases relates primarily to higher compensation-related expenses as we add staff to support our onshore growth and 100% operated Permian production and higher consulting expenses for various services primarily related to the previously discussed property acquisitions.

Accretion Expense

Accretion expense related to our asset retirement obligation decreased 4% and 5% for the three and six months ended June 30, 2012, respectively, compared to the same periods of 2011. See Note 8 for additional information regarding the Company's ARO.

Other Income and Expenses

(in thousands)	Three Months Ended June 30,			
	2012	2011	$ Change	% Change
Interest expense	$2,384	$2,698	$(314)	(12)%
Gain on early extinguishment of debt	(1,366)	—	(1,366)	100 %
Gain on acquired assets	—	(4,979)	4,979	(100)%
Unrealized gain on mark-to-market derivative instruments, net	(3,505)	—	(3,505)	(100)%
Other (income) expense	(157)	(425)	268	(63)%
Income tax expense (benefit)	1,610	(2,681)	4,291	(160)%
Equity in earnings of Medusa Spar LLC	6	289	(283)	(98)%
(in thousands)	Six Months Ended June 30,			
	2012	2011	$ Change	% Change
Interest expense	$4,961	$6,190	$(1,229)	(20)%
Gain on early extinguishment of debt	(1,366)	(1,942)	575	(30)%
Gain on acquired assets	—	(4,979)	4,979	100 %
Unrealized gain on mark-to-market derivative instruments, net	(3,575)	—	(3,575)	100 %
Other (income) expense	(461)	(253)	(209)	82 %
Income tax expense	1,754	(2,681)	4,435	(165)%
Equity in earnings of Medusa Spar LLC	124	386	(262)	(68)%

Interest Expense

Interest expense on Callon's debt obligations decreased 12% to $2.4 million for the three months ended June 30, 2012 compared to $2.7 million for the same period of 2011. Interest expense on Callon's debt obligations decreased 20% to $5.0 million for the six months ended June 30, 2012 compared to $6.2 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 $0.2 million increase in capitalized interest compared to 2011.

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

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 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 gains on mark-to-market derivative instruments, net for the three and six months ended June 30, 2012 were $3.5 million and $3.6 million, 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.

Income tax expense (benefit)

Prior to 2012, we carried a full valuation allowance against our net deferred tax assets. The income tax benefit reflected for the three and six month periods ended June 30, 2011 relate to the utilization of a portion of our deferred tax assets to offset the gain on acquired assets, discussed above, related to our global settlement with a former joint interest partner. A portion of this valuation allowance was utilized to offset this gain and our taxable income. At year-end 2011, we reversed the entire valuation allowance. Consequently, during the three and six month periods ended June 30, 2012, we reported income tax expense of $1.6 million and $1.8 million, respectively. 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 June 30, 2012, we have commodity contracts covering approximately 52% and 13% of our internally forecasted proved developed producing crude oil and natural gas production, respectively, from June 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 June 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 June 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	Fourth Amended and Restated Credit Agreement dated as of June 20, 2012, by and among the Company, the "Lenders" described therein, and Regions Bank as the sole arranger and administrative agent (incorporated by reference from Exhibit 10.1 on Form 8-K, filed June 25, 2012, File No. 001-14039)
10.2	Fourth Amended and Restated Revolving Promissory Note dated June 20, 2012 (incorporated by reference from Exhibit 10.1 on Form 8-K, filed June 25, 2012, File No. 001-14039)
10.3	Fourth Amended and Restated Guaranty Agreement dated June 20, 2012 (incorporated by reference from Exhibit 10.1 on Form 8-K, filed June 25, 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.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	Callon Petroleum Company	
Signature	Title	Date
/s/ Fred L. Callon Fred L. Callon	President and Chief Executive Officer	August 8, 2012
/s/ B.F. Weatherly B.F. Weatherly	Executive Vice President and Chief Financial Officer	August 8, 2012

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