CALLON PETROLEUM CO
Form 10-Q
May 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: March 31, 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 May 4, 2012 there were outstanding 39,444,301 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 share data)

	March 31, 2012 Unaudited	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$9,926	$43,795
Accounts receivable	18,536	15,181
Fair market value of derivatives	467	2,499
Other current assets	527	1,601
Total current assets	29,456	63,076
Oil and natural gas properties, full-cost accounting method:		
Evaluated properties	1,446,890	1,421,640
Less accumulated depreciation, depletion and amortization	(1,220,520)	(1,208,331)
Net oil and natural gas properties	226,370	213,309
Unevaluated properties excluded from amortization	18,433	2,603
Total oil and natural gas properties	244,803	215,912
Other property and equipment, net	12,646	10,512
Restricted investments	3,792	3,790
Investment in Medusa Spar LLC	9,361	9,956
Deferred tax asset	64,097	63,496
Other assets, net	824	718
Total assets	$364,979	$367,460
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$25,148	$26,057
Asset retirement obligations	1,170	1,260
Fair market value of derivatives	82	—
Total current liabilities	26,400	27,317
13% Senior Notes:		
Principal outstanding	106,961	106,961
Deferred credit, net of accumulated amortization of $13,934 and $13,123, respectively	17,573	18,384
Total 13% Senior Notes	124,534	125,345
Senior secured revolving credit facility	—	—
Asset retirement obligations	12,900	12,678
Other long-term liabilities	2,394	3,165
Total liabilities	166,228	168,505
Stockholders' equity:		
Preferred Stock, $.01 par value, 2,500,000 shares authorized;	—	—
Common Stock, $.01 par value, 60,000,000 shares authorized; 39,412,238 and 39,398,416 shares outstanding at March 31, 2012 and December 31, 2011,	394	394

respectively		
Capital in excess of par value	325,252	324,474
Other comprehensive income	154	1,624
Retained deficit	(127,049)	(127,537)
Total stockholders' equity	198,751	198,955
Total liabilities and stockholders' equity	$364,979	$367,460

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 March 31, 2012	2011
Operating revenues:		
Oil	$25,749	$18,804
Natural gas	3,545	6,645
Total oil and natural gas revenues	29,294	25,449
Operating expenses:		
Lease operating expenses	8,784	5,045
Depreciation, depletion and amortization	12,189	9,776
General and administrative	5,031	4,224
Accretion expense	574	615
Total operating expenses	26,578	19,660
Income from operations	2,716	5,789
Other (income) expenses:		
Interest expense	2,577	3,492
Gain on early extinguishment of debt, net	—	(1,942)
Unrealized gain on mark-to-market derivative instruments, net (See Note 5)	(70)	—
Other (income) expense	(305)	172
Total other expenses	2,202	1,722
Income before income taxes	514	4,067
Income tax expense	144	—
Income before equity in earnings of Medusa Spar LLC	370	4,067
Equity in earnings of Medusa Spar LLC	118	97
Net income available to common shares	$488	$4,164
Net income per common share:		
Basic	$0.01	$0.12
Diluted	$0.01	$0.12
Shares used in computing net income per common share:		
Basic	39,351	33,744
Diluted	40,254	34,539

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 March 31,	
	2012	2011
Net income	$488	$4,164
Other comprehensive (loss) income:		
Change in fair value of derivatives, net of tax	(1,470)	(1,959)
Total comprehensive (loss) income	$(982)	$2,205

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

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

	Three-Months Ended March 31,	
	2012	2011
Cash flows from operating activities:		
Net income	$488	$4,164
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation, depletion and amortization	12,486	10,001
Accretion expense	574	615
Amortization of non-cash debt related items	122	104
Amortization of deferred credit	(811)	(822)
Gain on early extinguishment of debt	—	(1,942)
Equity in earnings of Medusa Spar LLC	(118)	(97)
Deferred income tax expense	144	1,982
Valuation allowance	—	(1,982)
Non-cash derivative (income) expense due to hedge ineffectiveness	(229)	41
Non-cash derivative (income) due to mark-to-market adjustment for derivatives not designated as accounting hedges	(70)	—
Non-cash charge related to compensation plans	1,349	776
Payments to settle asset retirement obligations	(630)	(71)
Changes in current assets and liabilities:		
Accounts receivable	(3,177)	(110)
Other current assets	1,075	933
Current liabilities	(730)	(256)
Change in natural gas balancing receivable	1	182
Change in natural gas balancing payable	50	69
Change in other assets, net	(174)	(130)
Cash provided by operating activities	$10,350	$13,457
Cash flows from investing activities:		
Capital expenditures	(45,481)	(18,170)
Investment in restricted assets for plugging and abandonment	—	(38)
Proceeds from sale of mineral interest and equipment	506	2,787
Distribution from Medusa Spar LLC	758	307
Cash used in investing activities	$(44,217)	$(15,114)
Cash flows from financing activities:		
Redemption of 13% senior notes	—	(35,062)
Issuance of common stock	—	73,765
Equity issued related to employee stock plans	(2)	—
Cash (used in) provided by financing activities	$(2)	$38,703
Net change in cash and cash equivalents	(33,869)	37,046
Beginning of period cash and cash equivalents	43,795	17,436
End of period cash and cash equivalents	$9,926	$54,482

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

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

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

INDEX TO THE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 - Description of Business and Basis of Presentation

Description of Business

Callon Petroleum Company has been engaged in the exploration, development, acquisition and production of oil and 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 Louisiana and Texas and the offshore waters of the Gulf of Mexico.

Basis of Presentation

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 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 statement 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.

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.

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

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Note 2 - Property Acquisition and Operating Leases

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. This acquisition significantly expanded Callon's Permian Basin acreage position by 152% to approximately 24,010 net acres from the approximately 9,540 net acres at year-end 2011. The purchase price was funded from existing cash balances. 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), making drilling activities in this area much more high risk. The Company has an average 90% working interest across the contiguous acreage positions and is the operator, and has initiated a 3-D seismic survey in the second quarter of 2012. The Company currently expects to commence exploratory drilling on the acreage in the third quarter of 2012.

During 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 no lease expense was recorded during the three months ended March 31, 2012. Lease payments will approximate $6,957 in 2012, $9,234 in 2013 and $2,277 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.

Note 3 - Earnings per Share

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

	Three-Months Ended March 31,	
	2012	2011
(a) Net income	$488	$4,164
(b) Weighted average shares outstanding	39,351	33,744
Dilutive impact of stock options	20	28
Dilutive impact of restricted stock	883	767
(c) Weighted average shares outstanding for diluted net income per share	40,254	34,539
Basic net income per share (a/b)	$0.01	$0.12
Diluted net income per share (a/c)	$0.01	$0.12
The following were excluded from the diluted EPS calculation because their effect would be anti-dilutive:		
Stock options	67	92

Note 4 – Borrowings

The Company’s borrowings consisted of the following at:

	March 31, 2012	December 31, 2011
Principal components:		
Credit Facility	$—	$—
13% Senior Notes due 2016, principal	106,961	106,961
Total principal outstanding	106,961	106,961
Non-cash components:		
13% Senior Notes due 2016 unamortized deferred credit	17,573	18,384

Total carrying value of borrowings	$124,534	$125,345

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

In January 2010, the Company amended its Credit Facility agreement to include Regions Bank as the sole arranger and administrative agent. The third amended and restated Credit Facility, which matures on September 25, 2012, provides for a $100,000 facility secured by mortgages covering the Company's major oil fields. 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

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borrowing base was $45,000 at December 31, 2011. In May 2012, the Company received a commitment letter from Regions Bank to increase the Credit Facility to $200,000 with a revised borrowing base under the facility of $60,000, representing a 33% increase over the previous $45,000 borrowing base. Additionally, the maturity of the Credit Facility will be extended to July 31, 2014 from the previous maturity date of September 25, 2012. The amended Credit Facility is subject to customary closing conditions. As of March 31, 2012, the interest rate on the facility was 3%, which is calculated as the London Interbank Offered Rate ("LIBOR"), with a minimum of 0.5%, 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.

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 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 March 31, 2012	Carrying Value at March 31, 2012	Amortization Recorded during 2012 as a Reduction of Interest Expense	Estimated Amortization Expected to be Recorded during the Remainder of 2012
$31,507	$13,934	$17,573	$811	$2,539

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 March 31, 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 collars and swap derivative financial instruments to manage fluctuations in cash flows resulting from changes in commodity prices. The Company does not use these instruments for 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 transfer or terminate the arrangement.

Settlements and Financial Statement Presentation

Settlements of the Company's oil and natural gas collar derivative contracts are based on the difference between the contract price

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or prices specified in the derivative instrument and a New York Mercantile Exchange ("NYMEX") price. The estimated fair value of these collar contracts is based upon closing exchange prices on NYMEX and the time value of options. See Note 6, "Fair Value Measurements."

Listed in the table below are the outstanding oil and natural gas derivative contracts as of March 31, 2012:

Product	Product Type	Volumes per Month	Quantity Type	Average Floor Price per Hedge	Average Ceiling Price per Hedge	Period
Oil	Collar	25	Bbls	$90.00	$122.00	Apr12 - Dec12
Oil	Collar	25	Bbls	$95.00	$125.00	Apr12 - Dec12
Oil	Collar	40	Bbls	$90.00	$116.00	Jan13 - Dec13

Derivatives designated as hedging instruments

The Company's 2012 derivative contracts are designated as cash flow hedges, and are recorded at fair market value with the changes in fair value recorded net of tax through other comprehensive income (loss) ("OCI") in stockholders' equity. The cash settlements on contracts for future production are recorded as an increase or decrease in oil and natural gas sales. 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 oil and natural gas sales 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 March 31,	
	2012	2011
Amount of gain (loss) reclassified from OCI into income (effective portion)	$—	$(101)
Amount of gain (loss) recognized in income (ineffective portion and amount excluded from effectiveness testing)	230	(41)

Derivatives not designated as hedging instruments

As discussed in the Company's Form 10-K for the year ended December 31, 2011, in February 2012 the Company elected not to designate its 2013 derivative contract, nor does it expect to designate future derivative contracts, as an accounting hedge under FASB ASC 815-20-25. 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 March 31,	
	2012	2011
Realized gain (loss), net	$—	$—
Unrealized gain (loss), net	70	—
Total gain (loss) on derivative instruments, net	$70	$—

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.

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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:

	March 31, 2012		December 31, 2011	
	Carrying Value	Fair Value	Carrying Value	Fair Value
13% Senior Notes due 2016 (1)	$124,534	$114,983	$125,345	$110,571

(1) Fair value is calculated only in relation to the $106,961 principal outstanding of the 13% Senior Notes at the dates indicated above, respectively. The remaining $17,573 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 Callon's Consolidated Balance Sheet. The following methods and assumptions were used to estimate the fair values:

Commodity Derivative Instruments. Callon's derivative policy allows for commodity derivative instruments to consist of collars and natural gas and crude oil basis swaps. As disclosed in Note 5, the Company's hedge portfolio includes only collar contracts. The fair value of these derivatives is calculated using a valuation model that utilizes market-corroborated inputs that are observable over the term of the derivative contract, and the values are corroborated by quotes obtained from counterparties to the agreements. 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. The Company 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. For additional information, see Note 5.

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

As of March 31, 2012	Balance Sheet Presentation	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments - current	Fair market value of derivatives	$—	$467	$—	$467
Derivative financial instruments - non-current	Other long-term assets	—	152	—	152
Liabilities					
Derivative financial instruments - current	Fair market value of derivatives	$—	$82	$—	$82
Derivative financial instruments - non-current	Other long-term liabilities	—	—	—	—

Total		$—	$537	$—	$537

As of December 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 liabilities	—	—	—	—
Total		$—	$2,499	$—	$2,499

The derivative fair values above are based on analysis of each contract. Derivative liabilities with the same counterparty are presented here on a gross basis, even where the legal right of offset exists. Derivative contracts designated as accounting hedges are reflected above as current assets of $467. Derivative contracts not designated as accounting hedges are reflected in the table above as non-current assets of $152 and current liabilities of $82.

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

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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 three-month period ended March 31, 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:

	March 31, 2012	December 31, 2011
Deferred tax asset:		
Federal net operating loss carryforward	$86,572	$86,551
Statutory depletion carryforward	7,354	7,032
Alternative minimum tax credit carryforward	208	208
Asset retirement obligations	3,597	3,552
Other	7,362	6,935
Deferred tax asset before valuation allowance	105,093	104,278
Less: Valuation allowance	—	—
Total deferred tax asset	105,093	104,278
Deferred tax liability:		
Oil and natural gas properties	40,996	40,782
Total deferred tax liability	40,996	40,782
Net deferred tax asset	$64,097	$63,496

The effective tax rate for the three-month period ended March 31, 2012 was 28% compared to 0% for the period ended March 31, 2011. The variance is attributable to the impact of the valuation allowance against net deferred tax assets throughout 2011 until it was reversed as of December 31, 2011. The rate for 2011 would have been 33% excluding the impact of the valuation allowance. The most significant change from 2011 to 2012 other than the valuation allowance was the impact of statutory depletion rate of 2.45% in the first quarter of 2011 vs. 12.14% in the first quarter of 2012.

We believe our recorded assets and liabilities are reasonable; however, tax laws and regulations are subject to interpretation and tax litigation is inherently uncertain, and therefore our assessments can involve a series of complex judgments about future events and rely heavily on estimates and assumptions. We do not have a liability for uncertain tax positions or any accrued interest or penalties as of March 31, 2012.

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Note 8 - Asset Retirement Obligations

The following table summarizes the Company's asset retirement obligations activity for the three-months ended March 31, 2012:

Asset retirement obligations at January 1, 2012	$13,938
Accretion expense	574
Liabilities incurred	3
Liabilities settled	(255)
Revisions to estimate	(190)
Asset retirement obligations at end of period	14,070
Less: current asset retirement obligations	1,170
Long-term asset retirement obligations at March 31, 2012	$12,900

Liabilities settled primarily relate to properties primarily 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 March 31, 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 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 March 31, 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 are intended 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. This onshore transition has been, and is expected to continue to be, primarily funded by reinvesting the cash flows from our Gulf of Mexico properties.

Overview and Outlook

For the three months ended March 31, 2012, we reported net income and fully diluted earnings per share of $0.5 million and $0.01, respectively, compared to net income and diluted earnings per share of $4.2 million and $0.12, respectively for the same period 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 16,020 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 vertical drilling of multiple intervals. The acquisition increased our leasehold position by more than 150% to just over 24,000 net acres. We have an average 90% working interest across the contiguous acreage positions, and we are the operator. 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 drilling activities in this area.

- We initiated a Permian Basin horizontal drilling program targeting the Wolfcamp B shale on our East Bloxom acreage and the Cline shale on our newly acquired acreage in Borden County. To support this program, we accepted delivery in April 2012 a fit-for-purpose drilling rig under a two-year contract.

- In May 2012, we obtained from Regions Bank a commitment letter to increase 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. As part of the commitment, the bank is proposing an extension of the Credit Facility's maturity to July 31, 2014 from September 25, 2012. The execution of an amended facility in conjunction with this commitment is subject to customary closing conditions.

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 order to advance our growth plans, we will be 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 primary target in the southern portion of the Midland Basin is 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 Sprayberry, Dean, and Wolfcamp formations. Certain of our properties also include the Atoka and Strawn formations. As of March 31, 2012, we owned approximately 9,540 net acres in the southern portion of the Permian Basin.

During the three-month period March 31, 2012, we drilled eight of 28 planned gross wells for 2012, fracture stimulated 12 wells, placed 13 wells on production and have seven wells awaiting fracture stimulation services. Included in the 12 wells that

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

were fracture stimulated during the first quarter of 2012 are four wells in our Pecan Acre field, which have had initial production rates approximating 200 Boe per day.

In April 2012, we initiated drilling the first of four planned horizontal wells for 2012 on our East Bloxom acreage in Upton County, Texas. Based on our ongoing evaluation of our acreage and recent industry drilling results in the area, we have identified up to 24 horizontal drilling locations based on 160 acre spacing on our East Bloxom acreage. To support our horizontal drilling program, and as discussed in Note 2, we contracted a new-generation drilling rig for a term of two years at a cost of approximately $9.2 million per year.

Northern Portion: With respect to our recently acquired acreage in Borden County, which increased the Company's total acreage within the Permian Basin to approximately 24,010 net acres, we initiated a 3-D seismic survey in the second quarter of 2012 and currently expect to commence exploratory drilling in the third quarter of 2012. Based on technical analysis to date, our drilling plans include three horizontal exploration wells and one vertical exploration well.

• 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 March 31, 2012, our Haynesville well was producing 1,550 Mcf of natural gas equivalent per day. 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 178 MBoe equal to approximately 45% of the Company's total production during the three-month period ending March 31, 2012. Production from our deepwater properties is approximately 84% oil, which in the present market offers favorable pricing in relation to natural gas. 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 favorable differentials are reflected in the realized price reconciliation table provided below within the Results of Operations discussion.

We have confirmed with the operator that the Medusa platform will be shut-in approximately 28 days during the second quarter of 2012 due to planned construction activities on the West Delta 143 oil pipeline, through which Medusa's production is transported. In addition, the operator recently restricted the production rate from the A-1 well due to some indications of solids being produced. During the scheduled downtime on the Medusa platform referenced above, the operator plans to use coiled tubing to clean out the well and reset the isolation plug in an attempt to restore production to previous levels.

We also 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. Additionally, we have been notified that the Habanero Field will be shut-in 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 second and third quarters 2012.

While we are proud of the portfolio of assets we have built, we remain committed to strategic, onshore growth through attractive property acquisitions. To this end, we have been actively evaluating various opportunities.

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 $33.9 million during the first quarter of 2012 to $9.9 million compared to $43.8 million at December 31, 2011. The decrease in our cash balance is primarily attributable to capital expenditures of $45.5 million during the first quarter of 2012, representing a $27.3 million or 150% increase over the amount spent during the first quarter of 2011. The 2012 capital expenditures include approximately $15 million for the previously discussed acreage acquisition in Borden County, $22.3 million of costs related to drilling and completing eight gross vertical wells on our other Permian Basin acreage and costs associated with other wells in progress. These expenditures were partially offset by cash receipts from higher revenues stemming from higher oil prices.

In January 2010, the Company amended its Credit Facility agreement to include Regions Bank as the sole arranger and

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

administrative agent. The third amended and restated Credit Facility, which matures on September 25, 2012, provides for a $100 million facility secured by mortgages covering the Company's major oil fields. 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-determined. The borrowing base was $45 million at March 31, 2012. In May 2012, we obtained from Regions Bank a commitment letter to increase 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. Simultaneously, the bank proposed an extension of the Credit Facility's maturity to July 31, 2014 from September 25, 2012. We expect to execute this amendment to the Credit Facility during the second quarter of 2012, subject to customary closing conditions. As of March 31, 2012, the interest rate on the facility was 3%, which is calculated as the London Interbank Offered Rate (“LIBOR”), with a minimum of 0.5%, 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.

At March 31, 2012, we had approximately $107 million principal amount of 13% Senior Notes due 2016 outstanding with interest payable quarterly.

2012 Budget and Capital Expenditures. For 2012, we designed a flexible capital spending program, which we plan to fund from cash on hand and cash flows from operations. We believe these resources along with borrowings under our Credit Facility, if needed, 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 current 2012 capital budget totals approximately $139 million, representing a 32% increase over 2011 actual capital expenditures. Of the $139 million, 79% is allocated to onshore activity in the Permian Basin. Specifically, we expect to drill approximately 28 gross wells including seven horizontal wells and 21 vertical wells and perform geologic and geophysical work in the Permian Basin and have also included an allocation to acquire new acreage positions, including the recently acquired package in Borden County, TX. As previously discussed, we expect to drill four of the planned horizontal wells as development wells on our East Bloxom property. The remaining three horizontal wells, which will be exploration wells, are planned for our newly acquired Borden County acreage. We expect to drill 20 vertical wells on our southern Permian Basin properties, of which eight were drilled as of March 31, 2012 for a total cost (including completion costs) of $22.3 million, and one vertical exploration well on our newly acquired Borden County acreage. The remainder of the capital budget is primarily allocated to the planned Habanero #2 sidetrack well and capitalized expenses.

In addition to cash on hand, should we identify an attractive strategic opportunity or acquisition, we currently have $45 million of borrowing capacity available under our Credit Facility, with a commitment letter from Regions Bank to increase the borrowing base to $60 million. We believe that our cash on hand and operating cash flow along with our Credit Facility, if needed, will be adequate to meet our capital, interest payments, and operating requirements for the remainder of 2012.

Cost Pressures. While on a consolidated basis, inflation has not had a material impact on us, we have experienced increasing inflationary pressure in our Permian Basin operations, and we believe this cost trend may affect future development costs at our Medusa and Habanero fields. With respect to the Permian, increased demand for materials and services, including the costs associated with various down-hole drilling difficulties and other similar development costs.

Summary cash flow information is provided as follows:

Operating Activities. For the three-months ended March 31, 2012, net cash provided by operating activities decreased $3.1 million to $10.4 million, from $13.5 million for the same period in 2011. The decrease relates primarily to higher operating expenses, including the repairs at our Haynesville natural gas well.

Investing Activities. For the three-months ended March 31, 2012, net cash used in investing activities was $44.2 million as compared to $15.1 million for the same period in 2011. The $29.1 million increase in net cash used in investing activities is primarily attributable to a $27.3 million increase in capital expenditure spending, and relates to the acquisition of additional acreage in Borden County located in the northern portion of the Permian Basin and to drilling activity on our other Permian Basin acreage.

Financing Activities. For the three-months ended March 31, 2012, net cash used in financing activities was $0 million compared to cash provided by financing activities of $38.7 million during the same period of 2011. 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.

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

Results of Operations

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

	Three-Months Ended March 31,			
	2012	2011	Change	% Change
Net production:				
Oil (MBbls)	241	201	40	20 %
Natural gas (MMcf)	904	1,342	(438)	(33)%
Total production (Mboe)	392	424	(32)	(8)%
Average daily production (Boe)	4.3	4.7	(0.4)	(7)%
Average realized sales price (a):				
Oil (Bbl)	$106.84	$93.78	$13.06	14 %
Natural gas (Mcf)	$3.92	$4.95	$(1.03)	(21)%
Total on an equivalent basis (Boe)	$74.73	$59.99	$14.74	25 %
Oil and natural gas revenues (in thousands):				
Oil revenue	$25,749	$18,804	$6,945	37 %
Natural gas revenue	3,545	6,645	(3,100)	(47)%
Total	$29,294	$25,449	$3,845	15 %
Additional per Boe data:				
Sales price	$74.73	$59.99	$14.74	25 %
Lease operating expense	22.41	11.89	10.52	88 %
Operating margin	$52.32	$48.10	$4.22	9 %
Other expenses per Boe:				
Depletion, depreciation and amortization	$31.09	$23.05	$8.04	35 %
General and administrative	12.83	9.96	2.87	29 %

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

	2012	2011	Change	% Change
Average NYMEX price per barrel of oil	$102.93	$94.11	$8.82	9 %
Basis differential and quality adjustments	4.78	1.28	3.50	273 %
Transportation	(0.87)	(1.11)	0.24	(22)%
Hedging	—	(0.50)	0.50	(100)%
Average realized price per barrel of oil	$106.84	$93.78	$13.06	14 %
Average NYMEX price per million British thermal units (“MMBtu”)	$2.51	$4.20	$(1.69)	(40)%
Basis differential, quality and Btu adjustments	1.41	0.75	0.66	88 %
Hedging	—	—	—	— %
Average realized price per Mcf of natural gas	$3.92	$4.95	$(1.03)	(21)%

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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 three-month periods presented by reflecting the effect of changes in volume, changes in the underlying commodity prices and the impact of our hedge program.

	Crude Oil	Natural Gas	Total
Revenues for the three-months ended March 31, 2010	$16,663	$6,722	$23,385
Volume increase (decrease)	$(1,670)	$1,014	$(656)
Price increase (decrease)	3,912	(1,108)	2,804
Impact of hedges increase	(101)	17	(84)
Net increase (decrease) in 2011	2,141	(77)	2,064
Revenues for the three-months ended March 31, 2011	$18,804	$6,645	$25,449
Volume increase (decrease)	$3,841	$(2,170)	$1,671
Price increase (decrease)	3,104	(930)	2,174
Impact of hedges increase (decrease)	—	—	—
Net increase (decrease) in 2012	6,945	(3,100)	3,845
Revenues for the three-months ended March 31, 2012	$25,749	$3,545	$29,294

Total Revenue

Total oil and natural gas revenues of $29.3 million for the three-months ended March 31, 2012 increased $3.8 million or 15% from the same period of 2011 principally driven by a 14% increase in average realized oil prices. For additional information, please refer to the "Oil Revenue" and "Natural Gas Revenue" discussions included below.

Oil Revenue

Oil revenues increased 37% to $25.7 million for the three-months ended March 31, 2012 compared to revenues of $18.8 million for the same period of 2011. Contributing to the increase in oil revenue was an increase in commodity prices compounded by an increase in production. The average price realized increased 14% to $106.84 per barrel compared to $93.78 for the same period of 2011. Similarly, production increased 20% to 241 thousand barrels (“MBbls”) during the first quarter of 2012 compared to production of 201 MBbls during the same period in 2011. The increase in production was attributable to increasing production from our Permian Basin properties partially offset by normal and expected declines in production from our offshore properties.

Natural Gas Revenue

Natural gas revenues of $3.5 million decreased 47% during the three-months ended March 31, 2012 as compared to natural gas revenues of $6.6 million for the same period of 2011. Contributing to the decline was a 21% decrease in the average price realized, which fell to $3.92 per thousand cubic feet of natural gas ("Mcf") from $4.95 per Mcf, and a 33% 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 Singray 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. 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

	Three-months ended March 31,								
					Total Change			Boe Change	
	2012	Per Boe	2011	Per Boe	$	%		$	%
Lease operating expenses	$8,784	$22.41	$5,045	$11.90	$3,739	74	%	$10.51	88 %
Depreciation, depletion and amortization	12,189	31.09	9,776	23.06	2,413	25	%	8.03	35 %
General and administrative	5,031	12.83	4,224	9.96	807	19	%	2.87	29 %
Accretion expense	574	1.46	615	1.45	(41)	(7	)%	0.01	1 %

Lease Operating Expenses

Lease operating expenses (“LOE”) increased by 74% to $8.8 million for the three-month period ended March 31, 2012 compared to $5.0 million for the same period in 2011. The increase was primarily due to $1.5 million in costs related to significant growth in the number of wells now producing in our Permian Basin properties and $2.9 million associated with the workover on the Haynesville well. These increases were partially offset by a $0.6 million decline in LOE for our deepwater properties.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization (“DD&A”) for the three-months ended March 31, 2012 and compared to the same period of 2011 increased 25% to $12.2 million compared to $9.8 million and, on an equivalent basis, 35% to $31.09 per Boe from $23.06. The 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. With each successive period, the rate continues to normalize itself. Additionally contributing to the rate increase are the ongoing onshore development cost increases in the Permian Basin area.

General and Administrative

General and administrative expenses, net of amounts capitalized, increased to $5.0 million for the three-months ended March 31, 2012 from $4.2 million for the same period of 2011. The increase relates primarily to (1) higher compensation-related expenses as we add staff to support our onshore growth and 100% operated Permian production, (2) the non-cash accrual of a mark-to-market adjustment of certain liability-based incentive compensation instruments and (3) higher consulting expenses for various services.

Accretion Expense

Accretion expense related to our asset retirement obligation decreased 7% for the three-months ended March 31, 2012 compared to the same period 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

	For the quarter ended March 31,			
	2012	2011	$ Change	% Change
Interest expense	$2,577	$3,492	$(915)	(26)%
Gain on early extinguishment of debt	—	(1,942)	1,942	(100)%
Unrealized gain on mark-to-market derivative instruments, net	(70)	—	(70)	100%
Other (income) expense	(305)	172	(477)	(277)%
Income tax expense	144	—	144	100%
Equity in earnings of Medusa Spar LLC	118	97	21	22%

Interest Expense

Interest expense on Callon's debt obligations decreased 26% to $2.6 million for the three-months ended March 31, 2012 compared to $3.5 million for the same period of 2011. The decrease relates to the redemption of $31 million principal of Senior Notes during March 2011.

Gain on 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.

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. Consequently, the $0.1 million unrealized, mark-to-market gain relates to recording our undesignated 2013 oil collar contract at its net fair value.

Income tax expense

Prior to 2012, we carried a full valuation allowance against our net deferred tax assets. A portion of this valuation allowance was reversed each period to offset taxable income, which resulted in $0 income tax expense during the first quarter of 2011. At year-end 2011, we reversed the entire valuation allowance. Consequently, during the three month period ended March 31, 2012, we reported $0.1 million income tax expense. 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 March 31, 2012, we have commodity contracts covering approximately 53% of our internally forecasted oil production from April 2012 through December 2012 and 40 Mboe per month of our internally forecasted oil production from January 2013 to December 2013. Our actual production will vary from the amounts estimated, perhaps materially.

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

The Company may utilize price "collars" to reduce the risk of changes in oil and 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 and as was the case with the Company's 2013 collar contracts, 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 March 31, 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 March 31, 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. However, as a result of the matter that led to the restatement and the related assessment of internal control over financial reporting discussed in our 2011 Annual Report on Form 10-K, the Company implemented remediation steps to address the material weakness discussed therein and to improve its internal controls over financial reporting. Specifically, the Company will routinely evaluate the necessity for third party specialists' advice or assistance and utilize such advice or assistance as deemed appropriate when dealing with material and complex tax accounting matters in the preparation of its financial statements.

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)
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	May 7, 2012
/s/ B.F. Weatherly B.F. Weatherly	Executive Vice President and Chief Financial Officer	May 7, 2012