CALLON PETROLEUM CO
Form 10-Q
November 02, 2011

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

FORM 10-Q

x Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended September 30, 2011
or
.. Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from__________ to__________

Commission File Number 001-14039

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes x No ¨

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

Large accelerated filer ¨ Accelerated filer x

Non-accelerated filer ¨ Smaller reporting company ¨

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

Yes ¨ No x

As of November 1, 2011 there were outstanding 39,397,451 shares of the Registrant's common stock, par value $0.01 per share.

Table of Contents

Table of Contents

Part 1. Financial Information
Item 1. Financial Statements

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

	September 30, 2011 (Unaudited)	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 48,234	$ 17,436
Accounts receivable	15,786	10,728
Fair market value of derivatives	8,338	-
Other current assets	1,744	2,180
Total current assets	74,102	30,344
Oil and gas properties, full-cost accounting method:		
Evaluated properties	1,388,501	1,316,677
Less accumulated depreciation, depletion and amortization	(1,195,371)	(1,155,915)
Net oil and gas properties	193,130	160,762
Unevaluated properties excluded from amortization	7,811	8,106
Total oil and gas properties	200,941	168,868
Other property and equipment, net	10,716	3,370
Restricted investments	3,750	4,044
Investment in Medusa Spar LLC	9,914	10,424
Other assets, net	3,395	1,276
Total assets	$ 302,818	$ 218,326
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 24,335	$ 17,702
Asset retirement obligations	1,372	2,822
Fair market value of derivatives	-	937
Total current liabilities	25,707	21,461
13% Senior Notes due 2016		
Principal outstanding	106,961	137,961
Deferred credit, net of accumulated amortization of $12,329 and $3,964, respectively	19,178	27,543
Total 13% Senior Notes	126,139	165,504
Asset retirement obligations	12,565	13,103
Other long-term liabilities	2,910	2,448
Total liabilities	167,321	202,516
Stockholders' equity:		
Preferred Stock, $.01 par value, 2,500,000 shares authorized;	-	-

Common Stock, $.01 par value, 60,000,000 shares authorized; 39,381,693 and 28,984,125 shares outstanding at September 30, 2011 and December 31, 2010, respectively		394		290
Capital in excess of par value		323,693		248,160
Other comprehensive income (loss)		3,027		(8,560)
Retained earnings (deficit)		(191,617)		(224,080)
Total stockholders' equity		135,497		15,810
Total liabilities and stockholders' equity	$	302,818	$	218,326

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

Table of Contents

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

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Operating revenues:				
Oil sales	$26,537	$15,123	$74,428	$47,687
Gas sales	7,013	5,362	21,404	17,752
Total operating revenues	33,550	20,485	95,832	65,439
Operating expenses:				
Lease operating expenses	5,980	4,327	16,324	13,006
Depreciation, depletion and amortization	13,013	7,392	35,741	21,247
General and administrative	3,464	3,371	11,487	12,086
Accretion expense	569	601	1,767	1,803
Acquisition expense	-	139	-	139
Total operating expenses	23,026	15,830	65,319	48,281
Income from operations	10,524	4,655	30,513	17,158
Other (income) expenses:				
Interest expense	2,722	3,133	8,912	9,925
(Gain) loss on early extinguishment of debt	-	-	(1,942)	339
Gain on acquired assets (See Note 10)	-	-	(3,688)	-
Gain on sale of acquired assets	(217)	-	(217)	-
Loss on impairment of acquired assets	171	-	171	-
Other (income) expense	(347)	63	(599)	(409)
Total other (income) expenses	2,329	3,196	2,637	9,855
Income before income taxes	8,195	1,459	27,876	7,303
Income tax benefit	-	-	(3,972)	-
Income before equity in earnings of Medusa Spar LLC	8,195	1,459	31,848	7,303
Equity in earnings of Medusa Spar LLC	211	143	597	352
Net income available to common shares	$8,406	$1,602	$32,445	$7,655
Net income per common share:				
Basic	$0.21	$0.06	$0.87	$0.27
Diluted	$0.21	$0.05	$0.85	$0.26
Shares used in computing net income per common share:				
Basic	39,322	28,815	37,431	28,769
Diluted	39,976	29,491	38,120	29,431

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

Table of Contents

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

	Nine Months Ended September 30, 2011	2010
Cash flows from operating activities:		
Net income	$32,445	$7,655
Adjustments to reconcile net income to		
cash provided by operating activities:		
Depreciation, depletion and amortization	36,501	21,860
Accretion expense	1,767	1,803
Gain on acquired assets	(3,688)	-
Amortization of non-cash debt related items	338	305
Amortization of deferred credit	(2,361)	(2,723)
Non-cash (gain) loss on early extinguishment of debt	(1,942)	179
Equity in earnings of Medusa Spar LLC	(597)	(352)
Deferred income tax expense	10,696	2,455
Deferred income tax asset valuation allowance	(14,668)	(2,455)
Non-cash derivative income due to hedge ineffectiveness	(189)	-
Non-cash charge related to compensation plans	1,122	2,356
Payments to settle asset retirement obligations	(2,428)	(1,211)
Changes in current assets and liabilities		
Accounts receivable	(5,280)	54,593
Other current assets	37	(1,462)
Current liabilities	6,334	(134)
Change in gas balancing receivable	198	370
Change in gas balancing payable	(29)	(292)
Change in other long-term liabilities	100	(115)
Change in other assets, net	(427)	(588)
Cash provided by operating activities	57,929	82,244
Cash flows from investing activities:		
Capital expenditures	(74,388)	(39,617)
Acquisition expenditures	-	(995)
Investment in restricted assets for plugging and abandonment	(112)	(337)
Proceeds from sale of mineral interest and equipment	7,559	-
Distribution from Medusa Spar LLC	1,107	1,224
Cash used in investing activities	(65,834)	(39,725)
Cash flows from financing activities:		
Payments on senior secured credit facility	-	(10,000)
Redemption of remaining 9.75% senior notes	-	(16,052)
Redemption of 13% senior notes	(35,062)	-
Proceeds from exercise of employee stock options	-	(41)
Issuance of common stock	73,765	-
Cash provided by (used in) financing activities	38,703	(26,093)

Net change in cash and cash equivalents	30,798	16,426
Cash and cash equivalents:		
Balance, beginning of period	17,436	3,635
Less: Cash held by subsidiary deconsolidated at January 1, 2010	-	(311)
Balance, end of period	$48,234	$19,750

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

5

Table of Contents

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

INDEX TO THE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 - Description of Business and Basis of Presentation

Description of Business

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

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

Basis of Presentation

These interim financial statements of the Company have been prepared in accordance with (1) accounting principles generally accepted in the United States (“US GAAP”), (2) the Securities and Exchange Commission’s instructions to Quarterly Report on Form 10-Q and (3) Rule 10-01 of Regulation S-X, and should be read in conjunction with the Company’s Annual Report on Form 10-K for the year ended December 31, 2010. The balance sheet at December 31, 2010 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) necessary to present fairly the Company's financial position, the results of its operations and its cash flows for the periods indicated. Operating results for the periods presented are not necessarily indicative of the results that may be expected for the year ended December 31, 2011.

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

Table of Contents

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

Note 2 - Earnings Per Share

The following table sets forth the computation of basic and diluted earnings per share (“EPS”):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
(a) Net income	$8,406	$1,602	$32,445	$7,655
(b) Weighted average shares outstanding	39,322	28,815	37,431	28,769
Dilutive impact of stock options	16	147	22	127
Dilutive impact of restricted stock	638	529	667	535
(c) Weighted average shares outstanding for diluted net income per share	39,976	29,491	38,120	29,431
Basic net income per share (a/b)	$0.21	$0.06	$0.87	$0.27
Diluted net income per share (a/c)	$0.21	$0.05	$0.85	$0.26
The following were excluded from the diluted EPS calculation because their effect would be anti-dilutive:				
Stock options	82	122	67	122
Warrants	-	365	-	365
Restricted stock	766	36	766	36

Note 3 - Comprehensive Income

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Net income	$8,406	$1,602	$32,445	$7,655
Other comprehensive income:				
Change in fair value of derivatives	8,337	(860)	11,587	591
Total comprehensive income	$16,743	$742	$44,032	$8,246

Table of Contents

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

Note 4 – Borrowings

The Company’s borrowings consisted of the following at:

	September 30, 2011	December 31, 2010
Principal components:		
Credit Facility	$ -	$ -
13% Senior Notes due 2016, principal	106,961	137,961
Total principal outstanding	106,961	137,961
Non-cash components:		
13% Senior Notes due 2016 unamortized deferred credit	19,178	27,543
Total carrying value	$ 126,139	$ 165,504

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. Amounts borrowed under the Credit Facility may not exceed a borrowing base which is reviewed and re-determined on a semi-annual basis using second and fourth quarter financial results and reserve information available at the time of the redetermination. During the second quarter of 2011, the lender completed their borrowing base redetermination, which resulted in a 50% increase in the borrowing base from $30,000 at December 31, 2010 to $45,000 at September 30, 2011. As of September 30, 2011, the interest rate on the facility was 3%, defined in the amended agreement 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 carries a commitment fee of 0.5% per annum on the unused portion of the borrowing base, which is payable quarterly.

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

During the fourth quarter of 2009, the Company exchanged approximately 92% of the principal amount, or $183,948, of the Company’s 9.75% Senior Notes (“Old Notes”) for $137,961 of Senior Notes. The exchange resulted in a 25% reduction in the principal amount of the Old Notes, and included a 3.25% increase in the coupon rate from 9.75% to 13%. In addition, holders of the tendered notes received an aggregate of 3,794 shares of common stock and 311 shares of Convertible Preferred Stock which was valued on November 24, 2009 in the amount of $11,527 and recorded as an increase to stockholders’ equity. On December 31, 2009, each share of the convertible preferred stock was automatically converted into 10 shares of common stock. 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.

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

Upon issuing the Senior Notes in 2009, the Company reduced the carrying amount of the Old Notes by the fair value of the common and preferred stock issued in the amount of $11,527. The $31,507 difference between the adjusted carrying amount of the Old Notes and the principal of the Senior Notes was recorded as a deferred credit, which 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 September 30, 2011(1)	Carrying Value at September 30, 2011	Amortization Recorded during 2011 as a Reduction of Interest Expense(1)	Estimated Amortization Expected to be Recorded during the Remainder of 2011
$31,507	$ 12,329	$19,178	$ 2,361	$ 794

(1) Amortization recorded during 2011 excludes $6,004 of accelerated amortization related to the March 2011 early redemption of $31,000 principal of notes discussed below, which is recorded in the Statement of Operations as a component of the "Gain on early extinguishment of debt." Accumulated Amortization at September 30, 2011 includes the $6,004 of accelerated amortization.

On March 19, 2011, using a portion of the proceeds from the Company's February 2011 equity offering discussed in Note 7, the Company redeemed an aggregate principal amount of $31,000 of its Senior Notes with a carrying value of $37,004 including $6,004 of the Notes' deferred credit, in exchange for $35,062. The amount paid included the $31,000 principal of the notes, the $4,030 call premium and $32 of redemption expenses, which resulted in a $1,942 net gain on the early extinguishment of debt.

Restrictive Covenants

Both the indenture governing our Senior Notes and the Company's Credit Facility contain various covenants including restrictions on additional indebtedness and payment of cash dividends. In addition, Callon's Credit Facility contains covenants for maintenance of certain financial ratios. The Company was in compliance with these covenants at September 30, 2011.

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 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 terminate the arrangement or demand the posting of collateral, which may involve cash, letters of credit or property.

Table of Contents

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

Settlements and Financial Statement Presentation

Settlements of the Company's oil and gas collar derivative contracts 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 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."

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

Listed in the table below are the outstanding oil and gas derivative contracts as of September 30, 2011:

Product	Product Type	Volumes per Month	Quantity Type	Average Floor Price per Hedge	Average Ceiling Price per Hedge	Period
Oil	Collar	10	Bbls	$75.00	$101.85	Oct11 - Dec11
Oil	Collar	5	Bbls	80.00	102.00	Oct11 - Dec11
Oil	Collar	10	Bbls	75.00	94.50	Oct11 - Dec11
Oil	Collar	15	Bbls	90.00	122.00	Oct11 - Dec11
Oil	Collar	25	Bbls	90.00	122.00	Jan12 - Dec12
Oil	Collar	25	Bbls	95.00	125.00	Jan12 - Dec12

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Amount of gain (loss) reclassified from OCI into income (effective portion)	$88	$124	$(361)	$364
Amount of gain recognized in income (ineffective portion and amount excluded from effectiveness testing)	159	-	177	-

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 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.

Table of Contents

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

	September 30, 2011		December 31, 2010	
	Carrying Value	Fair Value	Carrying Value	Fair Value
13% Senior Notes due 2016 (1)	$126,139	$110,170	$165,504	$140,030

(1) Fair value is calculated only in relation to the $106,961 and $137,961 principal outstanding of the 13% Senior Notes at the dates indicated above, respectively. The remaining $19,178 and $27,543, 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 Sheets. 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 September 30, 2011	Balance Sheet Presentation	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments - current	Fair market value of derivatives	$-	$8,338	$-	$8,338
Derivative financial instruments - non-current	Other assets, net	-	2,500	-	2,500
Liabilities					
Derivative financial instruments - current	Fair market value of derivatives	$-	$-	$-	$-
Derivative financial instruments - non-current	Other long-term liabilities	-	-	-	-
Total		$-	$10,838	$-	$10,838

As of December 31, 2010	Balance Sheet Presentation	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments - current	Fair market value of derivatives	$-	$-	$-	$-
Derivative financial instruments - non-current	Other assets, net	-	-	-	-
Liabilities					
Derivative financial instruments - current	Fair market value of derivatives	$-	$937	$-	$937
Derivative financial instruments - non-current	Other long-term liabilities	-	-	-	-
Total		$-	$(937)	$-	$(937)

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.

Callon Petroleum Company
Notes to the Consolidated Financial Statements
(all amounts in thousands, except per-share and per-hedge 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 ("AROs") 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 and nine-month periods ended September 30, 2011, including upward revisions of $186 and $405, respectively, were Level 3 fair value measurements. See Note 9, "Asset Retirement Obligations," which provides a summary of changes in the ARO liability.

Other Property and Equipment. During the quarter ended September 30, 2011, the Company determined that certain unsold surplus Entrada equipment with carrying values of $690 had become impaired due to the limited market for these assets and based on discussions with potential buyers. Consequently, the Company reduced these assets' carrying value to $348, which represents a Level 3 fair value measurement. See Note 10 for additional information regarding this equipment.

Note 7 – 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 partial exercise of the underwriters' over-allotment option. As discussed in Note 4, the Company used a portion of the proceeds to redeem $31,000 principal amount, or 22% of its outstanding Senior Notes. The remaining proceeds are intended for general corporate purposes including the accelerated development of the Company's Permian Basin properties and for potential acquisitions.

Note 8 - Income Taxes

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

	September 30, 2011	December 31, 2010
Deferred tax asset:		
Federal net operating loss carryforward	$ 77,432	$ 79,680
Statutory depletion carryforward	7,392	6,140
Alternative minimum tax credit carryforward	209	208
Asset retirement obligations	3,565	4,018
Other	11,078	16,807
Deferred tax asset before valuation allowance	99,676	106,853
Less: Valuation allowance	(68,151)	(85,222)
Total deferred tax asset	31,525	21,631
Deferred tax liability:		
Oil and gas properties	31,525	21,631
Total deferred tax liability	31,525	21,631

Net deferred tax asset	$ -	$ -

In assessing the realizability of deferred tax assets, the Company considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. The Company considers the scheduled expiration of deferred tax assets, projected future taxable income and tax planning strategies in making this assessment. Following an impairment of oil and gas properties recorded during the fourth quarter of 2008, the Company remains in a three-year cumulative loss position as of September 30, 2011. Accordingly, the Company continues to carry a full valuation allowance against its net deferred tax assets, which will affect the Company's effective tax rate in future periods to the extent these deferred tax assets are recognized.

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

Note 9 - Asset Retirement Obligations

The following table summarizes the Company's asset retirement obligations year-to-date activity:

Asset retirement obligations at January 1, 2011	$15,925
Accretion expense	1,767
Liabilities incurred	29
Liabilities settled	(3,109)
Revisions to estimate	(675)
Asset retirement obligations at end of period	13,937
Less: current asset retirement obligations	(1,372)
Long-term asset retirement obligations at September 30, 2011	$12,565

Liabilities settled relate to properties sold during the period for which the related asset retirement obligations were assumed by the purchaser, and also includes individual 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 long-term restricted investments were $3,750 at September 30, 2011. 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 gas properties.

Note 10 – Entrada Project Wind-Down

Effective January 1, 2010, Callon Entrada Company ("CEC"), a variable interest entity, was deconsolidated from the Company's consolidated financial statements because the Company no longer had the power to direct the activities that most significantly affected CEC's economic performance, which was the liquidation of the surplus equipment related to the Entrada project. During May 2011, the Company entered into a final project wind-down agreement (the "Agreement") with CIECO Energy LLC ("CIECO"), its former joint interest partner in the Entrada deepwater project. The Agreement, effective as of April 29, 2011, provided for the extinguishment of all existing agreements and commitments between the parties as it related to the past development of the Entrada project. The Agreement included a formal extinguishment of the non-recourse credit agreement between CEC and CIECO and the assignment to CEC of CIECO's 50% rights to the remaining assets including primarily the unsold, residual equipment and all engineering data related to the Entrada project. When combined with CEC's existing 50% ownership of these assets, this Agreement results in CEC's full ownership of all remaining assets. Also, 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 CEC. Therefore, as Callon became its primary beneficiary, CEC was consolidated in the Company's consolidated financial statements, effective April 29, 2011.

At June 30, 2011, the Company estimated the fair values of the assets acquired to be $11,349 and liabilities assumed of CEC to be $3,972 as a result of this Agreement. The assets acquired consisted primarily of the Entrada surplus equipment and the liabilities assumed consisted of deferred tax liabilities associated with the basis difference of the equipment. The total net assets acquired of approximately $7,377 were recorded at June 30, 2011 as a $3,688 gain and $3,689 as an adjustment to the Company's full cost pool of oil and gas properties. The gain recognition was required as a result of the Company acquiring CIECO's former 50% share of the assets and the full cost pool adjustment was required to reflect the Company's 50% share of the assets held by the Company prior to the deconsolidation of the CEC subsidiary in 2010. The gain of $3,688 increased the Company's fully diluted earnings per share by $0.09 and $0.10, respectively, for the three and six months ended June 30, 2011.

With respect to the deferred tax liability, the Company utilized a portion of its deferred tax asset and recognized an income tax benefit equal to $3,972. During the period from the acquisition date through June 30, 2011, the Company sold certain of the acquired assets for $3,658. The remaining unsold assets were recorded on the Company's balance sheet at June 30, 2011 as $296 in Other current assets and $7,395 included in Other property and equipment, net. The Company is actively marketing these assets. Also in connection with this Agreement, CEC 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.

During the quarter ended September 30, 2011, the Company sold Entrada surplus equipment with carrying values of $778 for $1,211. As discussed above, 50% of the proceeds received in excess of the carrying value of the assets, or $217, were recorded as a gain on sale of assets, while the remaining 50% was recorded as an adjustment to the full cost pool. Also during the current quarter, the Company determined that certain unsold equipment with carrying values of $690 had become impaired due to the limited market for these assets, and consequently the Company reduced these assets' carrying value to $348. The $342 reduction in carrying value was recorded as a $171 loss with the remaining as an adjustment to the Company's full cost pool. As of September 30, 2011, the remaining unsold assets had carrying values of $6,570 and are included in the Company's balance sheet as a component of Other property and equipment, net.

Table of Contents

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

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,” “r 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 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, 2010 (the "2010 Annual Report on Form 10-K"), and all quarterly reports on Form 10-Q filed subsequently thereto ("Form 10-Qs").

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reservoir engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil and natural gas that are ultimately recovered.

Should one or more of the risks or uncertainties occur as described above or elsewhere in our 2010 Annual Report on Form 10-K or in our 2011 Quarterly Reports on Form 10-Q, 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.

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 2010 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 gas properties since 1950. In late 2008, our management shifted 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. The transition from offshore to onshore has been and is expected to continue to be primarily funded by reinvesting onshore the cash flows from our legacy Gulf of Mexico properties.

Overview and Outlook

For the nine months ended September 30, 2011, we reported net income and fully diluted earnings per share of $32.4 million and $0.85, respectively, compared to net income and diluted earnings per share of $7.7 million and $0.26, respectively for the same period of 2010. These results are discussed in greater detail within the "Results of Operations" section included below. Key accomplishments to date in 2011 include:

- Successfully completed a public offering of 10.1 million shares during February 2011 for which the Company received $73.8 million in net proceeds. While approximately 47% of the proceeds were used to reduce the Company's debt outstanding, the remaining proceeds will be used for general corporate purposes, to fund the Company's development of its Permian Basin and other properties and would be available should the Company identify an attractive acquisition opportunity.

- Redeemed during March 2011 $31 million aggregate principal amount of our Senior Notes resulting in a net gain on the early extinguishment of debt of approximately $2.0 million. This redemption reduced the principal of the Company's debt outstanding by approximately 22% to $107 million, and will reduce future interest expense by approximately $3.2 million during 2011 and by $4.0 million for each full year through the Senior Notes' maturity in 2016.

- Increased Credit Facility borrowing base to $45 million, representing a $15 million or 50% increase over the previously approved $30 million borrowing base and simultaneously received a reduction in the Credit Facility's interest rate from a minimum of 6% to 3%.

- Increased production from our Permian Basin properties. Production has increased approximately 135% since December 31, 2010 to approximately 1,300 net barrels of oil equivalent per day ("Boe/d") from 550 Boe/d.

- Executed an Agreement with our former joint interest partner to complete the wind-down of the Company's previously abandoned deepwater Entrada Project. Through the Agreement, the Company acquired rights to the remaining, unsold assets from the project. Upon recording these assets in the Company's consolidated financial statements, we recognized a gain of $3.7 million and a related income tax benefit of $4.0 million.

Our success in these areas allows us to continue executing on our strategy to shift our operational focus from the offshore Gulf of Mexico to developing longer life, lower risk onshore properties. Our onshore properties along with the cash flows from our Gulf of Mexico operations have re-shaped our portfolio and outlook, and we believe we are positioned to continue diversifying our portfolio by building profitable growth opportunities onshore. At December 31, 2010, our onshore properties represented 50% of our proved reserves, and we expect to increase this percentage throughout the remainder of 2011 as we further develop our onshore assets. Highlights of our onshore and deepwater development program include:

Onshore – Permian Basin

We currently own approximately 9,300 net acres in the Permian Basin, of which approximately 80% is prospective for the Wolfberry play. We operate substantially all of the production and development of these Permian assets, which are located in Crockett, Ector, Midland and Upton Counties, Texas. As of December 31, 2010, the properties included an estimated 4.5 million barrels of oil equivalent ("MMBoe") of proved reserves. As of September 30, 2011 and compared to December 31, 2010, production from these properties has increased over 135% to approximately 1,300 net Boe/d from 59 gross wells compared to production of 550 net Boe/d from 33 gross wells. As of September 30, 2011, the acreage has the remaining potential for an approximate 127 additional net wells based on 40-acre spacing.

During the first nine months of 2011, we fracture stimulated and placed on production 29 wells and have 8 wells awaiting fracture stimulation services. We also drilled 25 wells during the first nine months of 2011 at a total cost, including fracture stimulation, other completion and facility costs, of approximately $61.8 million. While the majority of these costs were included in our 2011 capital expenditures budget, certain costs have exceeded our expectations by approximately $6 million during the first nine months of 2011 and include items such as drilling a portion of our wells deeper to the Atoka and Strawn formations. While production results achieved from the Atoka completion declined to the point that we are no longer drilling through this formation, we are encouraged with the early results from the Strawn such that most completions now include a fracture stimulation in the Strawn. Also exceeding our original development cost expectations are higher costs related to increased demand for materials and services in the basin, the costs associated with various down-hole drilling difficulties and other similar development costs. For example, drilling rig rates have increased 34% due to increased labor costs to maintain crew continuity, and fracture stimulation services and associated wireline services have increased approximately 13% over the first nine months of 2011. We continue to monitor these trends and, to the extent possible, negotiate favorable pricing based on any leverage we possess, such as negotiating volume discounts. We also continue to monitor drilling rig operator efficiency, and have replaced one operator with another that we believe will improve drilling efficiency.
We now expect to drill approximately 36 total gross wells in 2011, down from 41 previously estimated wells due primarily to drilling wells deeper through the Atoka to define deeper potential within the Wolfberry interval and increasing costs pressures. We expect to fracture stimulate approximately an additional 11 wells during the fourth quarter of 2011 under our fracture stimulation service agreement.

Onshore – Haynesville Shale

We own a 69% working interest in a 624-acre unit in the heart of the Haynesville Shale play in Bossier Parish, Louisiana. Our multi-year development plan for this property includes drilling and operating a total of seven horizontal wells, the first of which was placed on production in September 2010. As of September 30, 2011, this well was producing 3,400 thousand cubic feet of natural gas equivalent per day. We have no drilling obligations in our Haynesville Shale position, and currently plan to mobilize a rig to the area once natural gas prices warrant continued development of the remaining six planned gross horizontal wells.

Deepwater – Mississippi Canyon Blocks 538/582 ("Medusa") and Garden Banks Block 341 ("Habanero")

Our deepwater, legacy 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 have produced approximately 645 MBoe equal to nearly 50% of the Company's total year-to-date production in 2011. Most of our Medusa's eight wells continue to produce from their initial completions and, as of December 31, 2010, had 2.4 MMBoe of proved developed non-producing reserves that will be accessed by recompletions in the existing wells. Another 1.2 MMBoe of proved undeveloped reserves will be developed by side tracking an existing well. On March 29, 2011, the operator of our Medusa property successfully recompleted at a net cost to Callon of $0.2 million the A6 well from the T4-C zone to the T4-B zone, which increased production net to Callon from approximately 80 Boe/day to approximately 850 Boe/day. As of September 30, 2011, production from the A6 well was approximately 500 Boe/day, net. Production from our deepwater properties is approximately 85% oil, which in the present market offers favorable pricing in relation to gas.

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.

Table of Contents

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations (continued)
Liquidity and Capital Resources

Historically, our primary sources of capital have been cash flows from operations, borrowings from financial institutions and the sale of debt and equity securities. Cash and cash equivalents increased by approximately $30.8 million during the nine month period ended September 30, 2011 to $48.2 million compared to $17.4 million at December 31, 2010. The increase in liquidity is primarily attributable to higher commodity oil prices, increased production levels and the receipt of $73.8 million from the previously discussed equity offering of 10.1 million shares of common stock offset by approximately $35 million used to repurchase $31 million principal amount of our outstanding Senior Notes and by the use of cash for ongoing operations, including capital expenditures.

In January 2010, we amended our senior secured credit agreement to include Regions Bank as the sole arranger and administrative agent. The Third Amended and Restated Senior Secured Credit Agreement ("the Credit Facility") matures on September 25, 2012, and provides for a $100 million facility with a current borrowing base of $45 million as approved by Regions Bank in May 2011. The current borrowing base represents a $15 million, or 50%, increase over the previous $30 million borrowing base as of December 31, 2010. Simultaneous with the May 2011 increase in the borrowing base, Regions Bank also approved a reduction in the interest rate on the facility from the previous floor of 6% to 3%. The rate is calculated as 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, which continues to carry a commitment fee of 0.5% per annum on the unused portion of the borrowing base, is payable quarterly. As of September 30, 2011, the interest rate on the facility was 3%, though no amounts were outstanding under the amended facility as of September 30, 2011. We are in discussions with Regions Bank to syndicate this facility, which is expected to include an extension of the maturity beyond the September 25, 2012 date noted above. Similarly, we expect that reserves growth related to our accelerated development of our Permian Basin properties could result in an additional increase in the borrowing base at syndication.

At September 30, 2011, we had approximately $107.0 million principal amount of 13% Senior Notes due 2016 outstanding with interest payable quarterly, a $31 million decrease from amounts outstanding at December 31, 2010 following the partial redemption previously discussed. The principal reduction in our Senior Notes will reduce 2011 cash interest paid by approximately $3.2 million and each full-year thereafter by approximately $4.0 million.

2011 Budget and Capital Expenditures. For 2011, we designed a flexible capital expenditures spending program that can be funded from cash on hand, inclusive of the proceeds received from the previously discussed equity offering, and cash flows from operations. This budget projects approximately $107 million of capital expenditures and is primarily focused on the accelerated development of our Permian Basin oil properties including completion costs and the drilling of an estimated 36 wells. Despite the previously discussed $6 million increase in Permian related capital expenditures, the overall budget is expected to remain at the current projected level or slightly under. This budget also includes all anticipated plugging and abandonment, capitalized interest and certain overhead costs related to acquiring, exploring and developing oil and gas properties.

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. We believe that our cash on hand and operating cash flows along with our Credit Facility, if needed, will be adequate to meet our capital, interest payments, and operating requirements for 2011.

Table of Contents

Summary cash flow information is provided as follows:

Operating Activities. For the nine-months ended September 30, 2011, net cash provided by operating activities was \$57.9 million, compared to \$82.2 million for the same period in 2010. Cash flows from operations in the first nine months of 2010 included a \$44.8 million recoupment of royalties paid to the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE"; formerly the Minerals Management Service), and related interest of \$7.9 million. Excluding this \$52.7 million related to the BOEMRE royalty recoupment, cash flow provided by operating activities increased period-over-period by approximately 96% or \$28.4 million primarily as a result of a 25% increase in the average realized sales price on an equivalent basis and a 17% increase in total production on an equivalent basis.

Investing Activities. For the nine months ended September 30, 2011, net cash used in investing activities was \$65.8 million as compared to \$39.7 million for the same period in 2010. The \$26.1 million increase in net cash used in investing activities is primarily attributable to an increase in capital expenditure spending, and relates to drilling activity on our Permian Basin acreage, which was partially offset by \$7.6 million in proceeds received for the sale of certain mineral interests and assets acquired as part of the Entrada project wind-down agreement discussed below and in Note 10 of Part 1, Item 1 of this report.

Financing Activities. For the nine months ended September 30, 2011, net cash provided by financing activities was \$38.7 million compared to cash used by financing activities of \$26.1 million during the same period of 2010. 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 \$31.0 million principal portion of our outstanding Senior Notes and to pay the \$4.0 million call premium and other redemption expenses. The 2010 expenditures related to the \$10.0 million repayment of outstanding borrowings under the Credit Facility and the \$16.0 million redemption of the Company's remaining outstanding 9.75% Senior Notes.

Income Taxes

As a result of the impairment of oil and gas properties recorded in the fourth quarter of 2008, we incurred losses on an aggregate basis for the three-year period ended December 31, 2008. At the time of this impairment, we also established a full valuation allowance against our deferred tax asset at the end of that year because, based on the relevant accounting rules, it was more likely than not that we would be unable to utilize our deferred tax assets. During the current quarter, and consistent with previous profitable periods, we recognized no income tax expense by applying a portion of our net operating losses against current income, and simultaneously reversed a portion of the deferred tax valuation allowance equal to this benefit. As a result, we recognized no income tax expense in the income statement for the past two years as we continue to utilize our deferred tax assets to offset taxable income. We have reported earnings in 2009, 2010 and expect to have earnings for the full year of 2011. Based on our recent profitable operations, we have evaluated whether it is more likely than not that we will be able to utilize our deferred tax assets and, as of September 30, 2011, we concluded that we should not reverse all or a portion of our valuation allowance. At September 30, 2011, our net deferred tax asset was \$68.2 million. We will continue to evaluate this conclusion as of December 31, 2011 when we have our year-end reserve report and have finalized our projections for 2012 and beyond.

Entrada Project Wind-down Agreement

Effective January 1, 2010, Callon Entrada Company ("CEC"), a variable interest entity, was deconsolidated from our consolidated financial statements because we no longer had the power to direct the activities that most significantly affected CEC's economic performance, which was the liquidation of the surplus equipment related to the Entrada project. During the second quarter of 2011, we entered into a final project wind-down agreement (the Agreement) with CIECO Energy LLC ("CIECO"), our former joint interest partner in the Entrada deepwater project. The Agreement provides for the extinguishment of all existing agreements and commitments between the parties as it relates to the past development of the Entrada project. The Agreement included a formal extinguishment of the non-recourse credit agreement between CEC and CIECO and the assignment to CEC of CIECO's 50% rights to the remaining assets including primarily the unsold, residual equipment and all engineering data related to the Entrada project. When combined with CEC's existing 50% ownership of these assets, this Agreement results in CEC's full ownership of all remaining assets. Also, 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, we gained the power to direct the activities related to the sale of the remaining assets, and therefore became the primary beneficiary of CEC. Therefore, as we became its primary beneficiary, CEC was included in our consolidated financial statements, effective April 29, 2011.

As discussed in Note 6, at June 30, 2011, we estimated the fair values of the assets acquired to be $11.4 million and liabilities assumed of CEC to be $4.0 million as a result of this Agreement. The assets acquired consisted primarily of the Entrada surplus equipment and the liabilities assumed consisted of deferred tax liabilities associated with the basis difference of the equipment. The total net assets acquired of approximately $7.4 million were recorded at June 30, 2011 as a $3.7 million gain and $3.7 million as an adjustment to our full cost pool of oil and gas properties. The gain recognition was required as a result of our acquiring CIECO's former 50% share of the assets, and the full cost pool adjustment was required to reflect the 50% share of the assets we held prior to the deconsolidation of the CEC subsidiary in 2010. The gain of $3.7 million increased our fully diluted earnings per share by $0.09 and $0.10, respectively for the three and six months ended June 30, 2011.

With respect to the deferred tax liability, we utilized a portion of our deferred tax asset and recognized an income tax benefit equal to $4.0 million. During the period from the acquisition date through June 30, 2011, we sold certain of the acquired assets for $3.7 million. The remaining unsold assets are recorded on our balance sheet as $0.3 million in Other current assets and $7.7 million included in Other property and equipment, net. We are actively marketing these assets. Also in connection with this Agreement, CEC agreed to pay to CIECO approximately $0.4 million, 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.

During the quarter ended September 30, 2011, the Company sold Entrada surplus equipment with carrying values of $0.8 million for $1.2 million. As discussed above, 50% of the proceeds received in excess of the carrying value of the assets, or $0.2 million, were recorded as a gain on sale of assets, while the remaining 50% was recorded as an adjustment to the full cost pool. Also during the current quarter, the Company determined that certain unsold equipment with carrying values of $0.7 million had become impaired due to the limited market for these assets, and consequently the Company reduced these assets' carrying value to $0.4 million. The $0.3 million reduction in carrying value was recorded as a $0.2 million loss with the remaining as an adjustment to the Company's full cost pool. As of September 30, 2011, the remaining unsold assets had carrying values of $6.6 million and are included in the Company's balance sheet as a component of Other property and equipment, net.

Table of Contents

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

Results of Operations

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

	Three Months Ended September 30,			
	2011	2010	Change	% Change
Net production:				
Oil (MBbls)	270	209	61	29 %
Gas (MMcf)	1,284	1,107	177	16 %
Total production (Mboe)	484	393	91	23 %
Average daily production (Boe)	5,261	4,274	987	23 %
Average realized sales price (a):				
Oil (Bbl)	$98.27	$72.47	$25.80	36 %
Gas (Mcf)	5.46	4.84	0.62	13 %
Total (Boe)	69.31	52.10	17.21	33 %
Oil and gas revenues (in thousands):				
Oil revenue	$26,537	$15,123	$11,414	76 %
Gas revenue	7,013	5,362	1,651	31 %
Total	$33,550	$20,485	$13,065	64 %
Additional per Boe data:				
Sales price	$69.31	$52.10	$17.21	33 %
Lease operating expense	(12.35)	(11.00)	(1.35)	(12)%
Operating margin	$56.96	$41.10	$15.86	39 %
Other expenses per Boe:				
Depletion, depreciation and amortization	$26.88	$18.80	$8.08	43 %
General and administrative	$7.16	$8.57	$(1.41)	(16)%

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

	2011	2010	Change	% Change
Average NYMEX price per barrel of oil	$89.78	$76.23	$13.55	18 %
Basis differential and quality adjustments	9.10	(2.62)	11.72	nm
Transportation	(0.94)	(1.14)	0.20	(18)%
Hedging	0.33	-	0.33	100 %
Average realized price per barrel of oil	$98.27	$72.47	$25.80	36 %
Average NYMEX price per Mcf of natural gas	$4.29	$4.24	0.05	1 %
Basis differential and quality adjustments	1.17	0.49	0.68	139 %
Hedging	-	0.11	(0.11)	100 %
Average realized price per Mcf of natural gas	$5.46	$4.84	$0.62	13 %

nm – Not Meaningful

20

Table of Contents

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

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

	Nine Months Ended September 30,			
	2011	2010	Change	% Change
Net production:				
Oil (MBbls)	746	646	100	15 %
Gas (MMcf)	4,014	3,359	655	19 %
Total production (Mboe)	1,415	1,206	209	17 %
Average daily production (Boe)	5,182	4,417	765	17 %
Average realized sales price (a):				
Oil (Bbl)	$ 99.82	$ 73.78	$ 26.04	35 %
Gas (Mcf)	5.33	5.29	0.04	1 %
Total (Boe)	67.75	54.27	13.48	25 %
Oil and gas revenues (in thousands):				
Oil revenue	$ 74,428	$ 47,687	$ 26,741	56 %
Gas revenue	21,404	17,752	3,652	21 %
Total	$ 95,832	$ 65,439	$ 30,393	46 %
Additional per Boe data:				
Sales price	$ 67.75	$ 54.27	$ 13.48	25 %
Lease operating expense	(11.54)	(10.79)	(0.75)	(7) %
Operating margin	$ 56.21	$ 43.48	$ 12.73	29 %
Other expenses per Boe:				
Depletion, depreciation and amortization	$ 25.27	$ 17.62	$ 7.65	43 %
General and administrative	$ 8.12	$ 10.02	$ (1.90)	(19)%

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

	2011	2010	Change	% Change
Average NYMEX price per barrel of oil	$ 95.48	$ 77.65	$ 17.83	23 %
Basis differential and quality adjustments	5.84	(2.70)	8.54	nm
Transportation	(1.02)	(1.18)	0.16	(14)%
Hedging	(0.48)	0.01	(0.49)	nm
Average realized price per barrel of oil	$ 99.82	$ 73.78	$ 26.04	35 %
Average NYMEX price per Mcf of natural gas	$ 4.29	$ 4.54	$ (0.25)	(6)%
Basis differential and quality adjustments	1.04	0.64	0.40	63 %
Hedging	-	0.11	(0.11)	(100)%
	$ 5.33	$ 5.29	$ 0.04	1 %

Average realized price per Mcf of natural gas

nm – Not Meaningful

21

Table of Contents

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

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.

Changes in Oil and Gas Production Revenues

	Crude Oil	Natural Gas	Total
Revenues for the three months ended September 30, 2009	$16,451	$4,869	$21,320
Volume increase (decrease)	947	(833)	114
Price increase (decrease)	(2,275)	1,202	(1,073)
Impact of hedges increase	-	124	124
Net increase (decrease) in 2010	(1,328)	493	(835)
Revenues for the three months ended September 30, 2010	$15,123	$5,362	$20,485
Volume increase	4,448	856	5,304
Price increase	6,878	795	7,673
Impact of hedges increase	88	-	88
Net increase in 2011	11,414	1,651	13,065
Revenues for the three months ended September 30, 2011	$26,537	$7,013	$33,550

Changes in Oil and Gas Production Revenues

	Crude Oil	Natural Gas	Total
Revenues for the nine months ended September 30, 2009	$ 51,374	$ 19,786	$ 71,160
Volume increase (decrease)	(5,465)	(4,023)	(9,488)
Price increase (decrease)	1,769	1,634	3,403
Impact of hedges increase	9	355	364
Net increase (decrease) in 2010	(3,687)	(2,034)	(5,721)
Revenues for the nine months ended September 30, 2010	$ 47,687	$ 17,752	$ 65,439
Volume increase (decrease)	7,327	3,461	10,788
Price increase (decrease)	19,775	191	19,966
Impact of hedges increase (decrease)	(361)	-	(361)
Net increase (decrease) in 2011	26,741	3,652	30,393
Revenues for the nine months ended September 30, 2011	$ 74,428	$ 21,404	$ 95,832

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

Total Revenue

Total oil and gas revenues of $33.6 million for the three months ended September 30, 2011 increased approximately $13.1 million or 64% from $20.5 million during the same period of 2010 principally driven by an increase in pricing on an equivalent unit basis combined with an increase in overall production. Compared to the third quarter of 2010, and on an equivalent basis, the average price realized by the Company increased 33%, while overall production on an equivalent basis increased by 23%. Production increases were primarily attributable to the Company's accelerated development program in its Permian Basin properties, the addition of the Company's Haynesville Shale gas well which began producing late in the third quarter of 2010 and due to a well recompletion at its Medusa offshore property. While year-over-year production increased 23%, production during the current quarter was negatively affected by the shut-in of our Medusa and Habanero wells due to Tropical Storm Lee and due to other required maintenance work on the facilities. Combined, these events reduced current period production by approximately 25 MBoe. Also offsetting the increases in production discussed above are the normal and expected declines in other legacy properties.

For the nine months ended September 30, 2011, total oil and gas revenues of $95.8 million increased approximately $30.4 million or 46% from $65.4 million for the same period of 2010. Compared to the first nine months of 2010 and despite the shut-in of our Medusa and Habanero wells discussed above, total production on an equivalent basis increased by 17%, for the same reasons cited above, while the average realized price per Boe also increased by 25%.

Oil Revenue

Oil revenues increased $11.4 million or 76% to $26.5 million for the three months ended September 30, 2011 compared to revenues of $15.1 million for the same period of 2010. As noted above in conjunction with the overall increase in total revenue, both an increase in commodity prices and production resulted in the increase in oil revenue. The average price realized increased 36% to $98.27 per barrel compared to $72.47 for the same period of 2010. Similarly, production levels, for the reasons previously discussed, increased 29% to 270 thousand barrels ("MBbls") compared to 209 MBbls during the same period in 2010.

For the nine months ended September 30, 2011, oil revenues increased $26.7 million or 56% to $74.4 million compared to revenues of $47.7 million for the same period of 2010. As previously mentioned, increases in both commodity prices and production contributed to the increase in revenue. The average price realized increased 35% to $99.82 per barrel compared to $73.78 for the same period of 2010. Similarly, production increased 15% to 746 MBbls compared to 646 MBbls during the same period in 2010.

Gas Revenue

Gas revenues of $7.0 million for the three months ended September 30, 2011 increased 31% or $1.6 million compared to gas revenues of $5.4 million for the same period of 2010. Gas production increased 16% period-over-period, primarily driven by production from our Haynesville Shale gas well, which was placed on production during September 2010, and due to the production from East Cameron #2 well, which was shut-in during the first quarter of 2010 for repairs to the host facility and did not return to production until December 2010. In addition to production increases, the average realized price increased 13% to $5.46 per thousand cubic feet of natural gas ("Mcf") compared to an average realized price of $4.84 per Mcf for the corresponding period in 2010.

For the nine months ended September 30, 2011, gas revenues of $21.4 million increased 21% or $3.7 million when compared to gas revenues of $17.8 million for the same period of 2010. The largest contributor to the period-over-period increase was a 19% increase in production, the drivers of which are discussed above and a 1% period-over-period increase in the average realized gas sales price.

Table of Contents

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

Expenses

	Three Months Ended September 30,							
	2011	Per Boe	2010	Per Boe	Year $ Change	Year % Change	Boe $ Change	Boe % Change
Lease operating expenses	$5,980	$12.35	$4,327	$11.00	$1,653	38 %	$1.35	12 %
Depreciation, depletion and amortization	13,013	26.88	7,392	18.80	5,621	76 %	8.08	43 %
General and administrative	3,464	7.16	3,371	8.57	93	3 %	(1.41)	(16)%
Accretion expense	569	1.18	601	1.53	(32)	(5)%	(0.35)	(23)%

	Nine Months Ended September 30,							
	2011	Per Boe	2010	Per Boe	Year $ Change	Year % Change	Boe $ Change	Boe % Change
Lease operating expenses	$16,324	$11.54	$13,006	$10.79	$3,318	26 %	$0.75	7 %
Depreciation, depletion and amortization	35,741	25.27	21,247	17.62	14,494	68 %	7.65	43 %
General and administrative	11,487	8.12	12,086	10.02	(599)	(5)%	(1.90)	(19)%
Accretion expense	1,767	1.25	1,803	1.50	(36)	(2)%	(0.25)	(17)%

Lease Operating Expenses

For the three months ended September 30, 2011, lease operating expenses ("LOE") of $6.0 million increased by 38% or $1.7 million compared to $4.3 million for the same period in 2010. The significant growth in the number of wells now producing in our Permian Basin properties and the Haynesville Shale well that was placed on production in September of 2010 together increased LOE approximately $1.2 million compared to the corresponding period of 2010. Additionally, LOE increased approximately $0.3 million related to both increased production from our Medusa A6 well following the previously discussed well recompletion and due to LOE at our East Cameron #2 well, which was shut-in for repairs on the host facility during the first quarter of 2010 and returned to production during December 2010. The remaining $0.2 million increase in LOE is attributable to higher severance taxes partially offset by a mix of lower LOE related primarily to our shelf properties.

For the nine months ended September 30, 2011, LOE of $16.3 million increased by 26% or $3.3 million compared to $13.0 million for the same period in 2010. As discussed above, the significant growth in the number of wells now producing in our Permian Basin properties and our Haynesville Shale well increased LOE approximately $2.9 million compared to the corresponding period of 2010. Additionally, LOE increased approximately $0.5 million related to platform maintenance work at Medusa and the increased production from the Medusa A6 well following the previously discussed well recompletion, and also increased $0.4 million due to LOE at our East Cameron #2 well discussed above. Offsetting these increases was a mix of lower LOE related primarily to our shelf properties.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization ("DD&A") for the three months ended September 30, 2011 increased 43% per Boe to $26.88 per Boe compared to $18.80 per Boe for the same period of 2010. Similarly, DD&A for the nine months ended September 30, 2011 increased 43% per Boe to $25.27 per Boe compared to $17.62 per Boe for the same period of 2010. As we began developing our onshore properties and in-line with our expectations, our per-unit DD&A rate began to normalize itself and increase in comparison to prior period DD&A rates, which were effectively reduced by the impact of a $486 million 2008 impairment charge following the then annual ceiling test. This significant oil and gas property impairment charge resulted in a lower, prospective DD&A rate for the then existing reserves. Also contributing to the current rate increase, and as previously discussed above related to the development of our Permian basin properties, onshore development cost pressures have exceeded our original estimates.

General and Administrative

For the three months ended September 30, 2011, general and administrative ("G&A") expenses of $3.5 million, net of amounts capitalized, was relatively flat compared to $3.4 million for the same period of 2010. For the nine months ended September 30, 2011, G&A expenses of $11.5 million, net of amounts capitalized, decreased 5% or $0.6 million compared to $12.1 million for the same period of 2010. Reduced legal expenses and lower employee-related costs were the primary drivers of the decrease.

Accretion Expense

Accretion expense related to our asset retirement obligation decreased 5% and 2% for the three and nine months ended September 30, 2011, respectively, compared to the same periods of 2010. Accretion expense correlates directionally with the Company's asset retirement obligation ("ARO"). At September 30, 2011, our asset retirement obligation of $13.9 million was lower than the $14.9 million ARO at September 30, 2010. See Note 9 for additional information regarding the Company's ARO.

Table of Contents

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

Other Income and Expenses

	Three Months Ended September 30,			
	2011	2010	$ Change	% Change
Interest expense	$2,722	$3,133	$(411)	(13)%
Gain on acquired assets	(46)	-	(46)	100%
Other (income) expense	(347)	63	(410)	nm

	Nine Months Ended September 30,			
	2011	2010	$ Change	% Change
Interest expense	$8,912	$9,925	$(1,013)	(10)%
Gain on early extinguishment of debt	(1,942)	-	(1,942)	100%
Gain on acquired assets	(3,734)	339	(4,073)	nm
Other (income) expense	(599)	(409)	(190)	46%
Income tax benefit	(3,972)	-	(3,972)	100%

nm – Not Meaningful

Interest Expense

Interest expense on Callon's debt obligations decreased 13% to $2.7 million for the three months ended September 30, 2011 compared to $3.1 million for the same period of 2010. Similarly, for the nine months ended September 30, 2010 interest expense decreased 10% to $8.9 million compared to $9.9 million. The decrease in both the three and nine-month periods relate primarily to the redemption of $31 million principal of 13% Senior Notes during March 2011. This early redemption reduced interest expense by approximately $1.0 million and $2.1 million for the three and nine-month periods, respectively, compared to the same periods of 2010. Additionally, 2010 interest expense for the nine-month period ended September 30, 2010 included approximately $0.5 million related to the remaining outstanding $16.1 million of old 9.75% Senior Notes, which were redeemed on April 30, 2010 and were therefore not included in 2011 interest expense. Offsetting these declines in interest expense is a $0.4 million and $1.2 million decline in capitalized interest for the three and nine-month periods ended September 30, 2011, respectively. The reduction in capitalized interest relates to a lower balance year-over-year in average unevaluated oil and gas properties following the write-off earlier in 2011 of certain leases, primarily offshore, that the Company elected not to renew. Further offsetting the declines discussed above are slight decreases in the deferred credit amortization recorded for the three and nine-month periods ended September 30 2011, respectively compared to the same period of 2010.

Gain on Early Extinguishment of Debt

During March 2011, using a portion of the proceeds from the Company's February 2011 equity offering discussed in Note 7, 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 & Income Tax Benefit

For information concerning the gain on acquired assets and the related income tax benefit, please refer to the discussions included in "Entrada Project Wind-down Agreement" and in Note 10 included in Part I, Item 1 of this report.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

The Company's revenues are derived from the sale of its crude oil and natural gas production. The prices for oil and gas remain extremely volatile and sometimes experience large fluctuations as a result of relatively small changes in supply, weather conditions, economic conditions and government actions. From time to time, the Company enters into derivative financial instruments to manage oil and gas price risk. The 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 proven production for the next 12 to 24 months. Our hedge policies and objectives may change significantly as commodities prices or price futures change.

As of September 30, 2011, we have commodity contracts covering approximately 55% of our internally estimated net proved oil production from October 2011 through December 2012. 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 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 gas prices while allowing realization of the full benefit from any increases in oil and gas prices. If the price falls below the floor, the counter-party pays the difference to the Company.

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

See Note 5 to the Consolidated Financial Statements for a description of the Company's outstanding derivative contracts at the most recent reporting date.

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 (the "Exchange Act"), 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. During the second quarter of 2011, the Company implemented a new financial system that encompasses financial reporting, the general ledger, land management, and other similar and related processes. The new financial system was implemented to enhance the Company's business and financial reporting processes. 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 Exchange Act) were effective as of September 30, 2011.

26

Table of Contents

Part II. Other Information

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

There have been no material changes with respect to the risk factors disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2010 except as described below:

Weather, unexpected subsurface conditions, and other unforeseen operating hazards may adversely impact our ability to conduct business.

There are many operating hazards in exploring for and producing oil and gas, including:

- our drilling operations may encounter unexpected formations or pressures, which could cause damage to equipment or personal injury;
- we may experience equipment failures which curtail or stop production;
- we could experience blowouts or other damages to the productive formations that may require a well to be re-drilled or other corrective action to be taken;
- hurricanes, storms and other weather conditions could cause damages to our production facilities or wells; and
- because of these or other events, we could experience environmental hazards, including release of oil and gas from spills, gas leaks, accidental leakage of toxic or hazardous materials, such as petroleum liquids or drilling fluids, into the environment, and ruptures.

If we experience any of these problems, it could affect well bores, platforms, gathering systems and processing facilities, which could adversely affect our ability to conduct operations. We could also incur substantial losses in excess of our insurance coverage as a result of:

- injury or loss of life;
- severe damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of our operations; and
- repairs to resume operations.

Offshore operations are also subject to a variety of additional operating risks peculiar to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce or eliminate the funds available for development or leasehold acquisitions, or result in loss of equipment and properties.

We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with many of the wells for which we are the operator. Contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under federal and state laws. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury. In March 2010, the EPA announced that it would conduct a wide-ranging study on the effects of hydraulic fracturing on drinking water resources. Interim results of the study are expected in 2012, with final results expected in 2014. The agency also announced that one of its enforcement initiatives for 2011 to 2013 would be to focus on environmental compliance by the energy extraction sector. This study and enforcement initiative could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

We cannot assure you that we will be able to maintain adequate insurance at rates we consider reasonable to cover our possible losses from operating hazards. The occurrence of a significant event not fully insured or indemnified against could materially and adversely affect our financial condition and results of operations.

The unavailability or high cost of drilling rigs, pressure pumping equipment and crews, other equipment, supplies, water, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies, water or qualified personnel. There is currently a shortage of pressure pumping equipment and crews in all of our areas of operation. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. Increasing levels of exploration and production may increase the demand for oilfield services and equipment, and the costs of these services and equipment may increase, while the quality of these services and equipment may suffer. The unavailability or high cost of drilling rigs, pressure pumping equipment, supplies or qualified personnel can materially and adversely affect our operations and profitability.

Table of Contents

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. [Removed and Reserved]

Item 5. Other Information

None.

Item 6. Exhibits

Index of Exhibits

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

Exhibit Number	Description
10	Material Contracts
10.1	Severance Compensation Agreement, dated as of September 21, 2011, by and between Gary A. Newberry and Callon Petroleum Company (incorporated by reference from Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 21, 2011).
+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.

+ Filed herewith.

++ 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.

Table of Contents

SIGNATURES

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

Callon Petroleum Company

Signature	Title	Date
/s/ Fred L. Callon Fred L. Callon	President and Chief Executive Officer	November 2, 2011
/s/ B.F. Weatherly B.F. Weatherly	Executive Vice President and Chief Financial Officer	November 2, 2011