CALLON PETROLEUM CO
Form 10-Q
November 06, 2007

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

FORM 10-Q
QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the Quarterly Period Ended September 30, 2007
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 þ No o

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

Large accelerated filer o Accelerated filer þ Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2). Yes o No þ

As of November 1, 2007, there were 20,883,149 shares of the Registrant s Common Stock, par value $0.01 per share, outstanding.

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

	September 30, 2007 (Unaudited)	December 31, 2006 (Note 1)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 3,175	$ 1,896
Accounts receivable	21,664	32,166
Restricted investments	604	4,306
Fair market value of derivatives	2,185	13,311
Other current assets	6,385	5,973
Total current assets	34,013	57,652
Oil and gas properties, full-cost accounting method:		
Evaluated properties	1,313,382	1,096,907
Less accumulated depreciation, depletion and amortization	(661,279)	(604,682)
	652,103	492,225
Unevaluated properties excluded from amortization	67,394	54,802
Total oil and gas properties	719,497	547,027
Other property and equipment, net	2,014	1,996
Restricted investments	3,959	1,935
Investment in Medusa Spar LLC	12,641	12,580
Other assets, net	8,289	4,337
Total assets	$ 780,413	$ 625,527
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 27,035	$ 46,611
Asset retirement obligations	7,175	14,355
Current maturities of long-term debt		213
Total current liabilities	34,210	61,179
Long-term debt	391,451	225,521
Asset retirement obligations	25,286	26,824

Deferred tax liability	32,330	30,054
Accrued liabilities to be refinanced	10,000	
Other long-term liabilities	1,265	586
Total liabilities	494,542	344,164
Stockholders equity:		
Preferred Stock, $.01 par value, 2,500,000 shares authorized;		
Common Stock, $.01 par value, 30,000,000 shares authorized; 20,879,220 and 20,747,773 shares outstanding at September 30, 2007 and December 31, 2006, respectively	209	207
Capital in excess of par value	222,448	220,785
Other comprehensive income	843	8,652
Retained earnings	62,371	51,719
Total stockholders equity	285,871	281,363
Total liabilities and stockholders equity	$ 780,413	$ 625,527

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

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Callon Petroleum Company
Consolidated Statements of Operations
(In thousands, except per share amounts) (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Operating revenues:				
Oil sales	$ 15,912	$ 23,754	$ 48,058	$ 78,133
Gas sales	21,957	21,124	78,769	59,383
Total operating revenues	37,869	44,878	126,827	137,516
Operating expenses:				
Lease operating expenses	5,338	8,070	20,550	21,340
Depreciation, depletion and amortization	15,931	14,973	56,597	43,600
General and administrative	2,606	2,908	7,098	6,558
Accretion expense	904	1,082	2,959	3,832
Derivative expense		30		150
Total operating expenses	24,779	27,063	87,204	75,480
Income from operations	13,090	17,815	39,623	62,036
Other (income) expenses:				
Interest expense	10,148	4,027	23,905	12,303
Other (income)	(387)	(354)	(814)	(1,354)
Total other (income) expenses	9,761	3,673	23,091	10,949
Income before income taxes	3,329	14,142	16,532	51,087
Income tax expense	1,165	4,856	6,283	17,700
Income before Medusa Spar LLC	2,164	9,286	10,249	33,387
Income from Medusa Spar LLC net of tax	104	344	403	1,313
Net income	$ 2,268	$ 9,630	$ 10,652	$ 34,700
Net income per share:				
Basic	$ 0.11	$ 0.47	$ 0.51	$ 1.74
Diluted	$ 0.11	$ 0.45	$ 0.50	$ 1.64

Shares used in computing net income per share:				
Basic	20,800	20,650	20,728	19,919
Diluted	21,230	21,326	21,220	21,154

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

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

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Cash flows from operating activities:		
Net income	$ 10,652	$ 34,700
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation, depletion and amortization	57,270	44,105
Accretion expense	2,959	3,832
Amortization of deferred financing costs	2,153	1,667
Non-cash derivative expense		150
Equity in earnings of Medusa Spar LLC	(403)	(1,313)
Deferred income tax expense	6,283	17,700
Non-cash charge related to compensation plans	490	718
Excess tax benefits from share-based payment arrangements		(1,449)
Changes in current assets and liabilities:		
Accounts receivable	7,891	4,569
Other current assets	(413)	(687)
Current liabilities	896	5,404
Change in gas balancing receivable	(160)	(131)
Change in gas balancing payable	564	149
Change in other long-term liabilities	(7)	1
Change in other assets, net	1,745	(2,692)
Cash provided by operating activities	89,920	106,723
Cash flows from investing activities:		
Capital expenditures	(106,899)	(122,002)
Entrada acquisition	(150,000)	
Distribution from Medusa Spar LLC	559	849
Cash used by investing activities	(256,340)	(121,153)
Cash flows from financing activities:		
Change in accrued liabilities to be refinanced	10,000	2,000
Increases in debt	213,000	63,000
Payments on debt	(48,000)	(51,000)
Deferred financing costs	(6,429)	
Equity issued related to employee stock plans		(438)
Excess tax benefits from share-based payment arrangements		1,449
Capital leases	(872)	(200)
Cash provided by financing activities	167,699	14,811
Net increase in cash and cash equivalents	1,279	381

Cash and cash equivalents:				
Balance, beginning of period		1,896		2,565
Balance, end of period	$	3,175	$	2,946

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

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CALLON PETROLEUM COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
September 30, 2007

1. General

The financial information presented as of any date other than December 31, 2006 has been prepared from the books and records of Callon Petroleum Company (the Company or Callon) without audit. Financial information as of December 31, 2006 has been derived from the audited financial statements of the Company, but does not include all disclosures required by U.S. generally accepted accounting principles. In the opinion of management, all adjustments, consisting only of normal recurring adjustments, necessary for the fair presentation of the financial information for the periods indicated, have been included. For further information regarding the Company s accounting policies, refer to the Consolidated Financial Statements and related notes for the year ended December 31, 2006 included in the Company s Annual Report on Form 10-K filed March 16, 2007. The results of operations for the three-month and nine-month periods ended September 30, 2007 are not necessarily indicative of future financial results.

2. Net Income Per Share

Basic net income per share was computed by dividing net income by the weighted average number of shares of common stock outstanding during the period. Diluted net income per share was determined on a weighted average basis using common shares issued and outstanding adjusted for the effect of common stock equivalents computed using the treasury stock method.

A reconciliation of the basic and diluted net income per share computation is as follows (in thousands, except per share amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
(a) Net income	$ 2,268	$ 9,630	$ 10,652	$ 34,700
(b) Weighted average shares outstanding	20,800	20,650	20,728	19,919
Dilutive impact of stock options	136	193	142	258
Dilutive impact of warrants	292	443	308	894
Dilutive impact of restricted stock	2	40	42	83
(c) Weighted average shares outstanding for diluted net income per share	21,230	21,326	21,220	21,154
Basic net income per share (a¸b)	$ 0.11	$ 0.47	$ 0.51	$ 1.74
Diluted net income per share (a¸c)	$ 0.11	$ 0.45	$ 0.50	$ 1.64
Stock options and warrants excluded due to the exercise price being greater than the average stock price	104	30	92	27

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3. Derivatives

The Company periodically uses derivative financial instruments to manage oil and gas price risk on a limited amount of its future production and does not use these instruments for trading purposes. Settlements of oil and gas derivative contracts are generally based on the difference between the contract price or prices specified in the derivative instrument and a NYMEX price or other cash or futures index price. Such derivative contracts are accounted for under Statement of Financial Accounting Standards No. 133. Accounting for Derivative Instruments and Hedging Activities, (SFAS No. 133), as amended.

In September 2007, the Company entered into a six-month interest rate swap with Union Bank of California (UBOC), N.A. Callon will pay UBOC a fixed interest rate of 5.43% on a notional amount of $25,000,000 and receive the floating LIBOR rate. The objective of the interest rate swap is to minimize the impact of variable interest rates by locking into a fixed rate on a portion of the borrowings of the Merrill Lynch Senior Secured Credit Agreement dated April 18, 2007. The fair value of this interest rate swap as of September 30, 2007 was immaterial.

The Company s derivative contracts that are accounted for as cash flow hedges under SFAS 133 are recorded at fair market value and the changes in fair value are recorded through other comprehensive income (loss), net of tax, in stockholders equity. The cash settlements on contracts for future production are recorded as an increase or decrease in oil and gas sales. The cash settlements for interest rate contacts are recorded as an increase or decrease to interest expense. The changes in fair value related to ineffective derivative contracts are recognized as derivative expense (income). The cash settlements on these contracts are also recorded within derivative expense (income).

Cash settlements on effective oil and gas cash flow hedges during the three-month periods ended September 30, 2007 and 2006 resulted in an increase in oil and gas sales of $3.4 million and $3.2 million, respectively. Cash settlements on effective oil and gas cash flow hedges during the nine-month periods ended September 30, 2007 and 2006 resulted in an increase in oil and gas sales of $7.0 million and $5.7 million, respectively.

Derivative expense of $30,000 and $150,000 for three-month and the nine-month periods ended September 30, 2006, respectively, represents the amortization of derivative contract premiums.

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Listed in the table below are the outstanding oil and gas derivative contracts as of September 30, 2007:

Collars

Product	Volumes per Month	Quantity Type	Average Floor Price	Average Ceiling Price	Period
Oil	25,000	Bbls	$ 65.00	$ 83.30	10/07-12/07
Oil	25,000	Bbls	$ 65.00	$ 94.20	10/07-12/07
Oil	30,000	Bbls	$ 65.00	$ 81.50	01/08-12/08
Natural Gas	600,000	MMBtu	$ 8.00	$ 12.70	10/07-12/07

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4. Long-Term Debt

Long-term debt consisted of the following at:

	September 30, 2007	December 31, 2006
	(In thousands)	
Senior Secured Credit Facility (matures July 31, 2010)	$	$ 35,000
9.75% Senior Notes (due 2010), net of discount	191,451	189,862
Senior Revolving Credit Facility (due 2014)	200,000	
Capital lease		872
Total debt	391,451	225,734
Less current portion:		
Capital lease		213
Long-term debt	$ 391,451	$ 225,521

On August 30, 2006, the Company closed on a four-year amended and restated senior secured credit facility with UBOC. The borrowing base, which is reviewed and redetermined semi-annually, was $50 million at September 30, 2007. Borrowings under the credit facility are secured by mortgages covering the Company s major fields excluding Entrada. As of September 30, 2007, there were no borrowings under the facility.

On April 18, 2007, Callon closed the Entrada acquisition contemporaneous with a seven-year $200 million senior revolving credit facility arranged by Merrill Lynch Capital Corporation, which is secured by a lien on the Entrada properties. Borrowings outstanding under the facility bear interest at a rate of LIBOR plus 7%. The Company borrowed the full commitment amount under the facility at closing to cover the required $150 million payment to BP Exploration and Production Company (BP) and expenses and fees related to the transaction and the balance was used to pay down the Company s UBOC senior secured credit facility. Callon s UBOC senior secured credit facility was amended to allow for this transaction. The amendment included a provision which reduced the borrowing base under the UBOC facility to $50 million until the next borrowing base redetermination date. See Note 7 for more discussion on the Entrada acquisition.

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5. Comprehensive Income

A summary of the Company s comprehensive income is detailed below (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Net income	$ 2,268	$ 9,630	$ 10,652	$ 34,700
Other comprehensive income (loss):				
Change in fair value of derivatives	(1,968)	8,472	(7,809)	10,766
Total comprehensive income	$ 300	$ 18,102	$ 2,843	$ 45,466

6. Asset Retirement Obligations

The following table summarizes the activity for the Company s asset retirement obligations:

	Nine Months Ended September 30, 2007
Asset retirement obligation at beginning of period	$ 41,179
Accretion expense	2,959
Liabilities incurred	1,509
Liabilities settled	(16,868)
Revisions to estimate	3,682
Asset retirement obligation at end of period	32,461
Less: current asset retirement obligation	(7,175)
Long-term asset retirement obligation	$ 25,286

Assets, primarily U.S. Government securities, of approximately $4.6 million at September 30, 2007, are recorded as restricted investments. These assets are held in abandonment trusts dedicated to pay future abandonment costs for several of the Company s oil and gas properties.

7. Entrada Acquisition and Development

On April 18, 2007, the Company completed an acquisition of BP s 80% working interest in the Entrada Field for a purchase price of $190 million. The purchase price included $150 million payable at closing and an additional $40 million payable after the achievement of certain production milestones. The purchased interests included five federal offshore blocks at Garden Banks Blocks 738, 782, 785, 826 and 827, subject to certain depth limitations. As a result of the acquisition, Callon owns a 100% working interest in the Entrada Field and is operator. The acquisition added 150 billion cubic feet of natural gas equivalent (Bcfe) to Callon s proved undeveloped reserves.

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The acquisition was recorded at fair value based on the initial purchase price of $150 million. The Company may record the additional $40 million as additional purchase price in the future when the production milestones are achieved, in accordance with the terms of the agreement.

To finance the initial $150 million payment of the purchase price, Callon closed on a seven-year $200 million senior revolving credit facility arranged by Merrill Lynch Capital Corporation contemporaneous with the closing of the acquisition. The facility is secured by a lien on the Entrada properties. The Company borrowed the full commitment amount under the facility at closing to cover the required $150 million payment to BP and expenses and fees related to the transaction and the balance was used to pay down our UBOC senior secured credit facility.

In August 2007, Callon entered into a production handling agreement (PHA) with ConocoPhillips and Devon Energy Corporation. The PHA provides for production from the Entrada Field to be processed through the Magnolia production platform, which is owned by ConocoPhillips and Devon.

Callon is in the process of identifying a partner to participate in the Entrada Field development and has retained Merrill Lynch Petrie Divestiture Advisors to assist with this search.

8. Accounting for Uncertainty in Income Taxes

Callon adopted Financial Accounting Standards Board (FASB) Interpretation No. 48 Accounting for Uncertainty in Income Taxes (FIN 48), effective January 1, 2007. FIN 48 clarifies the accounting for income taxes by prescribing the minimum recognition threshold a tax position is required to meet before being recognized in the financial statements. FIN 48 also provides guidance on derecognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure and transition. The Company had no significant unrecognized tax benefits at the date of adoption or at September 30, 2007. Accordingly, the Company does not have any interest or penalties related to uncertain tax positions. However, if interest or penalties were to be incurred related to uncertain tax positions, such amounts would be recognized in income tax expense. Tax periods for all years after 1978 remain open to examination by the federal and state taxing jurisdictions to which the Company is subject.

9. Accrued Liabilities to be Refinanced

Amounts included in accrued liabilities to be refinanced at September 30, 2007 represent capital expenditures that were refinanced with the availability under the Company s senior secured credit facility subsequent to September 30, 2007.

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10. Accounting Pronouncements

In September 2006, the FASB issued Statement of Financial Accounting Standard No. 157, (SFAS 157), Fair Value Measurements. SFAS 157 defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures about fair value measurements. SFAS 157 is effective for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. The Company is currently reviewing the provisions of SFAS 157 and has not yet determined the impact of adoption.

In February 2007, the FASB issued Statement of Financial Accounting Standard No. 159 The Fair Value Option for Financial Assets and Liabilities Including an amendment of FASB No. 115 (SFAS 159). SFAS 159 permits entities to choose to measure many financial instruments and certain other items at fair value. This statement is effective for fiscal years beginning after November 15, 2007, with early adoption allowed. The Company has not yet determined the impact, if any, the adoption of this standard may have on its financial condition or results of operations.

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Item 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Forward-Looking Statements

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical facts included in this report, including statements regarding our financial position, adequacy of resources, estimated reserve quantities, business strategies, plans, objectives and expectations for future operations and covenant compliance, are forward-looking statements. We can give no assurances that the assumptions upon which such forward-looking statements are based will prove to have been correct. Important factors that could cause actual results to differ materially from our expectations (Cautionary Statements) are disclosed in the section entitled Risk Factors included in our Annual Report on Form 10-K for our most recent fiscal year, elsewhere in this report and from time to time in other filings made by us with the Securities and Exchange Commission. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified by the Cautionary Statements.

General

Our revenues, profitability, future growth and the carrying value of our oil and gas properties are substantially dependent on prevailing prices of oil and gas, our ability to find, develop and acquire additional oil and gas reserves that are economically recoverable and our ability to develop existing proved undeveloped reserves. Our ability to maintain or increase our borrowing capacity and to obtain additional capital on attractive terms is also influenced by oil and gas prices. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond our control. These factors include weather conditions in the United States, the condition of the United States economy, the actions of the Organization of Petroleum Exporting Countries, governmental regulations, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, the price of foreign imports and the availability of alternate fuel sources. Any substantial and extended decline in the price of oil or gas would have an adverse effect on the carrying value of our proved reserves, borrowing capacity, revenues, profitability and cash flows from operations. We use derivative financial instruments for price protection purposes on a limited amount of our future production, but do not use derivative financial instruments for trading purposes.

The following discussion is intended to assist in an understanding of our historical financial position and results of operations. Our historical financial statements and notes thereto included elsewhere in this quarterly report contain detailed information that should be referred to in conjunction with the following discussion.

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Liquidity and Capital Resources

Our primary sources of capital are cash flows from operations, borrowings from financial institutions and the sale of debt and equity securities. On September 30, 2007, we had cash and cash equivalents of $3.2 million and $50 million of availability under our UBOC senior secured credit facility. Cash provided from operating activities during the nine-month period ended September 30, 2007 totaled $89.9 million, a 16% decrease when compared to 2006. The decrease was primarily attributable to an increase in interest expense resulting from the seven-year $200 million senior revolving credit facility discussed below and a reduction in revenues primarily due to lower oil production.

Our capital expenditure budget for 2007, including capitalized interest and general and administrative expenses, will require approximately $125 million of funding. We expect that available cash and cash flows generated from operations during 2007 along with current availability under our UBOC senior secured credit facility will provide the capital necessary to fund these capital expenditures as well as our asset retirement obligations which are expected to be approximately $2 million. See the Capital Expenditures section below for a more detailed discussion of our anticipated capital expenditures for 2007.

On April 18, 2007, we closed the Entrada acquisition contemporaneous with a seven-year $200 million senior revolving credit facility arranged by Merrill Lynch Capital Corporation. This facility is secured by a lien on the Entrada properties. We borrowed the full commitment amount under the facility at closing to cover the required $150 million payment to BP and expenses and fees related to the transaction, and the balance was used to pay down our UBOC senior secured credit facility.

On August 30, 2006, we closed on a four-year amended and restated senior secured credit facility with UBOC. The borrowing base, which is reviewed and redetermined semi-annually, was $50 million at September 30, 2007. Borrowings under the UBOC senior secured credit facility are secured by mortgages covering our major fields excluding Entrada. Our UBOC senior secured credit facility was amended to allow for the financing arranged to acquire BP s interest in the Entrada Field. See Entrada Acquisition and Development below for further discussion about the acquisition.

The Indenture governing our 9.75% Senior Notes due 2010, the seven-year $200 million senior revolving credit facility and our senior secured credit facility with UBOC contain various covenants, including restrictions on additional indebtedness and payment of cash dividends. In addition, our senior secured credit facility contains covenants for maintenance of certain financial ratios. We were in compliance with these covenants at September 30, 2007. See Note 7 of the Consolidated Financial Statements for the year ended December 31, 2006 included in our Annual Report on Form 10-K filed March 16, 2007 for a more detailed discussion of long-term debt.

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The following table describes our outstanding contractual obligations (in thousands) as of September 30, 2007:

Contractual Obligations	**Total**	**Less Than One Year**	**One-Three Years**	**Four-Five Years**	**After-Five Years**
Senior Secured Credit Facility	$	$	$	$	$
9.75% Senior Notes	200,000			200,000	
Senior Revolving Credit Facility	200,000				200,000
Throughput Commitments:					
Medusa Spar LLC	6,412	2,580	3,832		
Medusa Oil Pipeline	322	87	118	71	46
	$ 406,734	$ 2,667	$ 3,950	$ 200,071	$ 200,046

Capital Expenditures

Capital expenditures on an accrual basis, excluding the Entrada acquisition, were $88 million for the nine-months ended September 30, 2007. Included in the $88 million were $33 million of costs incurred in the Gulf of Mexico Shelf Area for drilling costs associated with five wells, completion costs for three successful wells and completion and development costs related to 2006 discoveries. In addition, we incurred $29 million of costs in the Gulf of Mexico Deepwater Area for development drilling cost at our Habanero Field, exploratory drilling cost for Bob North and long-lead items and engineering for the development of Entrada. Interest of approximately $5 million and general and administrative costs allocable directly to exploration and development projects of approximately $8 million were capitalized for the first nine months of 2007. The remainder of the capital expended primarily includes the acquisition of seismic and leases.

Capital expenditures for the remainder of 2007 are projected to be approximately $36 million and include:

- development wells and discretionary drilling of exploratory wells;
- Entrada development costs;
- the acquisition of seismic and leases; and
- capitalized interest and general and administrative costs.

In addition, we are projecting to spend $700,000 for the remainder of 2007 for asset retirement obligations.

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Entrada Acquisition and Development

On April 18, 2007, we completed an acquisition with BP to purchase its 80% working interest in the Entrada Field for a purchase price of $190 million. The purchase price included $150 million payable at closing and an additional $40 million payable after the achievement of certain production milestones. The purchased interests included five federal offshore blocks at Garden Banks Blocks 738, 782, 785, 826 and 827, subject to certain depth limitations. As a result of the acquisition, we own a 100% working interest in the Entrada Field and became operator. The acquisition added 150 Bcfe to our proved undeveloped reserves.

The acquisition was recorded at fair value based on the initial purchase price of $150 million. We may record the additional $40 million as additional purchase price in the future when the production milestones are achieved, in accordance with the terms of the agreement.

To finance the initial $150 million payment of the purchase price, we closed on a seven-year $200 million senior revolving credit facility arranged by Merrill Lynch Capital Corporation contemporaneous with the closing of the acquisition. The facility is secured by a lien on the Entrada properties. We borrowed the full commitment amount under the facility at closing to cover the required $150 million payment to BP and expenses and fees related to the transaction, and the balance was used to pay down our UBOC senior secured credit facility.

Our UBOC senior secured credit facility was amended to allow for the Merrill Lynch Capital Corporation financing. The amendment included a provision which reduced the borrowing base under the UBOC facility to $50 million until the next borrowing base redetermination date.

In August 2007, we entered into a production handling agreement (PHA) with ConocoPhillips and Devon Energy Corporation. The PHA provides for production from the Entrada Field to be processed through the Magnolia production platform, which is owned by ConocoPhillips and Devon. We currently expect first production to commence in the first half of 2009.

We are now in the process of identifying a partner to participate in the Entrada Field development and have retained Merrill Lynch Petrie Divestiture Advisors to assist with this search.

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Off-Balance Sheet Arrangements

We have a 10% ownership interest in Medusa Spar LLC (LLC), which is a limited liability company that owns a 75% undivided ownership interest in the deepwater Spar production facilities on our Medusa Field in the Gulf of Mexico. We contributed a 15% undivided ownership interest in the production facility to the LLC in return for approximately $25 million in cash and a 10% ownership interest in the LLC. The LLC will earn a tariff based upon production volume throughput from the Medusa area. We are obligated to process our share of production from the Medusa Field and any future discoveries in the area through the Spar production facilities. This arrangement allows us to defer the cost of the Spar production facility over the life of the Medusa Field. Our cash proceeds were used to reduce the balance outstanding under our senior secured credit facility. The LLC used $83.7 million of cash proceeds from non-recourse financing and a cash contribution by one of the LLC owners to acquire its 75% interest in the Spar. The balance of Medusa Spar LLC is owned by Oceaneering International, Inc. and Murphy Oil Corporation. We are accounting for our 10% ownership interest in the LLC under the equity method.

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Results of Operations

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Net production :				
Oil (MBbls)	223	381	774	1,340
Gas (MMcf)	2,840	2,710	9,883	7,241
Total production (MMcfe)	4,179	4,998	14,527	15,278
Average daily production (MMcfe)	45.4	54.3	53.2	56.0
Average sales price:				
Oil (Bbls) (a)	$ 71.29	$ 62.31	$ 62.09	$ 58.33
Gas (Mcf)	7.73	7.79	7.97	8.20
Total (Mcfe)	9.06	8.98	8.73	9.00
Oil and gas revenues:				
Oil revenue	$ 15,912	$ 23,754	$ 48,058	$ 78,133
Gas revenue	21,957	21,124	78,769	59,383
Total	$ 37,869	$ 44,878	$ 126,827	$ 137,516
Oil and gas production costs:				
Lease operating expenses	$ 5,338	$ 8,070	$ 20,550	$ 21,340
Additional per Mcfe data:				
Sales price	$ 9.06	$ 8.98	$ 8.73	$ 9.00
Lease operating expense	1.28	1.61	1.41	1.40
Operating margin	$ 7.78	$ 7.37	$ 7.32	$ 7.60
Depletion, depreciation and amortization	$ 3.81	$ 3.00	$ 3.90	$ 2.85
General and administrative (net of management fees)	$ 0.62	$ 0.58	$ 0.49	$ 0.43

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

Average NYMEX oil price	$ 75.37	$ 70.51	$ 66.21	$ 68.23
Basis differential and quality adjustments	(2.96)	(6.91)	(4.45)	(7.81)
Transportation	(1.12)	(1.29)	(1.13)	(1.28)
Hedging			1.46	(0.81)
Average realized oil price	$ 71.29	$ 62.31	$ 62.09	$ 58.33

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Comparison of Results of Operations for the Three Months Ended September 30, 2007 and the Three Months Ended September 30, 2006.

Oil and Gas Production and Revenues

Total oil and gas revenues decreased to $37.9 million in the third quarter of 2007 compared to $44.9 million in the third quarter of 2006. Total production on an equivalent basis for the third quarter of 2007 decreased by 16% compared to the third quarter of 2006.

Gas production during the third quarter of 2007 totaled 2.8 billion cubic feet of gas (Bcf) and generated $22 million in revenues compared to 2.7 Bcf and $21.1 million in revenues during the same period in 2006. The average gas price after hedging impact for the third quarter of 2007 was $7.73 per thousand cubic feet of natural gas (Mcf) compared to $7.79 per Mcf for the same period last year. The 5% increase in 2007 production was primarily attributable to new discoveries being brought online. The increase was partially offset by the sale of our Mobile Bay 952,953,955 Field, early water production from our High Island Block 73 and North Padre Island Block 913 fields and normal and expected declines in production from our High Island Block 119 and Mobile Bay 864 fields and older properties. In addition, remedial work with wireline and coil tubing was performed to correct mechanical problems on the A-1 well at Medusa in the fourth quarter of 2006 that resulted in production being restored at a lower rate.

Oil production during the third quarter of 2007 totaled 223,000 barrels and generated $15.9 million in revenues compared to 381,000 barrels and $23.8 million in revenues for the same period in 2006. The average oil price received after hedging impact in the third quarter of 2007 was $71.29 per barrel compared to $62.31 per barrel in the third quarter of 2006. The 41% decrease in production was primarily due to the A-1 well at Medusa having mechanical problems which required remedial work and resulted in production being restored at a lower rate. In addition, the #1 well at Habanero became uneconomic as expected in the third quarter of 2007 and was sidetracked and completed as planned in an updip location in the reservoir. Production at this well commenced in October 2007.

Lease Operating Expenses

Lease operating expenses were $5.3 million for the three-month period ended September 30, 2007, a 34% decrease when compared to the same period in 2006. The decrease was primarily due to the sale of the Mobile Bay 952,953,955 Field effective May 1, 2007 and the shut-in of our South Marsh Island 261 Field, which is scheduled to be plugged and abandoned. The decrease was partially offset by additional operating costs associated with new discoveries.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for the three months ended September 30, 2007 and 2006 was $15.9 million and $15.0 million, respectively. The 6% increase was due to a higher depletion rate resulting from higher costs associated with our exploration and development activities in the Gulf of Mexico.

Accretion Expense

Accretion expense for the three-month periods ended September 30, 2007 and 2006 of $904,000 and $1.1 million, respectively, represents accretion of our asset retirement obligations. See Note 6 to the Consolidated Financial Statements.

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General and Administrative

General and administrative expenses, net of amounts capitalized, were $2.6 million and $2.9 million for the three-month periods ended September 30, 2007 and 2006, respectively. The 10% decrease was primarily the result of the non-cash charge that was recognized in the third quarter of 2006 for the vesting of 20% of restricted shares issued as part of the 2006 restricted stock award.

Interest Expense

Interest expense increased to $10.1 million during the three months ended September 30, 2007 compared to $4.0 million during the three months ended September 30, 2006. This increase was due to the new debt associated with the Entrada acquisition. See Note 4 and 7 for more details.

Income Taxes

Income tax expense was $1.2 million and $4.9 million for the three-month periods ended September 30, 2007 and 2006, respectively. The decrease was due to a decrease in income before income taxes.

Comparison of Results of Operations for the Nine Months Ended September 30, 2007 and the Nine Months Ended September 30, 2006.

Oil and Gas Production and Revenues

Total oil and gas revenues decreased to $126.8 million in the first nine months of 2007 compared to $137.5 million in the same period in 2006. Total production on an equivalent basis during nine-month period ended September 30, 2007 decreased by 5% compared to the nine-month period ended September 30, 2006.

Gas production during the first nine months of 2007 totaled 9.9 Bcf and generated $78.8 million in revenues compared to 7.2 Bcf and $59.4 million in revenues during the same period in 2006. The average gas price after hedging impact for the nine months ended September 30, 2007 was $7.97 per Mcf compared to $8.20 per Mcf for the same period in 2006. The 36% increase in 2007 production was primarily attributable to new discoveries being brought online. The increase was partially offset by the sale of the Mobile Bay 952,953,955 Field in the second quarter of 2007, early water production from East Cameron Block 90, High Island Block 73 and North Padre Island Block 913 and normal and expected declines in production from our High Island Block 119 and Mobile Bay area fields and older properties. In addition, remedial work with wireline and coil tubing was performed to correct mechanical problems on the A-1 well at Medusa in the fourth quarter of 2006 that resulted in production being restored at a lower rate.

Oil production during the nine months ended September 30, 2007 totaled 774,000 barrels and generated $48.1 million in revenues compared to 1,340,000 barrels and $78.1 million in revenues for the same period in 2006. The average oil price received after hedging impact for the nine-month period ended September 30, 2007 was $62.09 per barrel compared to $58.33 per barrel during the same period in 2006. The 42% decrease in production was primarily due to the A-1 well at Medusa having mechanical problems which required remedial work and resulted in production being restored at a lower rate. In addition, the #1 well at Habanero became uneconomic as expected in the third quarter of 2007 and was sidetracked and completed as planned in an updip location in the reservoir. Production at this well commenced in October 2007.

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Lease Operating Expenses

Lease operating expenses were $20.6 million for the nine-month period ended September 30, 2007, a 4% decrease when compared to the same period in 2006. The decrease was primarily due to the sale of the Mobile Bay 952,953,955 Field effective May 1, 2007, lower throughput charges at Habanero and the shut-in of our South Marsh Island 261 Field, which is scheduled to be plugged and abandoned. The decrease was partially offset by additional operating costs associated with our new discoveries.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for the nine months ended September 30, 2007 and 2006 was $56.6 million and $43.6 million, respectively. The 30% increase was due to a higher depletion rate resulting from higher costs associated with our exploration and development activities in the Gulf of Mexico.

Accretion Expense

Accretion expense for the nine-month periods ended September 30, 2007 and 2006 of $3.0 million and $3.8 million, respectively, represents accretion of our asset retirement obligations. See Note 6 to the Consolidated Financial Statements.

General and Administrative

General and administrative expenses, net of amounts capitalized, were $7.1 million and $6.6 million for the nine-month periods ended September 30, 2007 and 2006, respectively. The 8% increase was a result of additions to our staff and higher compensation costs.

Interest Expense

Interest expense increased to $23.9 million during the nine months ended September 30, 2007 compared to $12.3 million during the nine months ended September 30, 2006. The increase was due to the new debt associated with the Entrada acquisition. See note 4 and 7 for more details.

Income Taxes

Income tax expense was $6.3 million and $17.7 million for the nine-month periods ended September 30, 2007 and 2006, respectively. The decrease was primarily due to a decrease in income before income taxes.

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Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

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

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

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

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

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

See Note 3 to the Consolidated Financial Statements for a description of the Company s outstanding derivative contracts at September 30, 2007.

Interest Rate Risk

The Company s $200 million senior revolving credit facility arranged by Merrill Lynch Capital Corporation bears interest at a variable LIBOR-based rate. As a result, an increase in LIBOR would increase the interest cost associated with this facility and would have a negative impact on the Company s results of operations and cash flows. As of September 30, 2007, the Company had $200 million of borrowings outstanding under the facility and had an interest rate swap in place to reduce its risk associated with changes in interest rates on $25 million of this variable rate debt for a six-month period. See Note 3 to the Consolidated Financial Statements for a description of the interest rate hedge and Note 4 for the Company s outstanding debt at September 30, 2007.

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Item 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to the issuer s management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. The Company s principal executive and principal financial officers have concluded that the Company s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)) were effective as of September 30, 2007.

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

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CALLON PETROLEUM COMPANY
PART II. OTHER INFORMATION

Item 6. EXHIBITS

Exhibits

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)
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 Rights Agreement between Callon Petroleum Company and American Stock Transfer & Trust Company, Rights Agent, dated March 30, 2000 (incorporated by reference from Exhibit 99.1 of the Company s Registration Statement on Form 8-A, filed April 6, 2000, File No. 001- 14039)
   - 4.3 Form of Warrant entitling certain holders of the Company s 10.125% Senior Subordinated Notes due 2002 to purchase common stock from the Company (incorporated by reference to Exhibit 4.13 of the Company s Form 10-Q for the period ended June 30, 2002, File No. 001-14039)

4.4 Form of Warrants dated December 8, 2003 and December 29, 2003 entitling lenders under the Company s $185 million amended and restated Senior Unsecured Credit Agreement, dated December 23, 2003, to purchase common stock from the Company (incorporated by reference to Exhibit 4.14 of the Company s Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)

4.5 Indenture for the Company s 9.75% Senior Notes due 2010, dated March 15, 2004, between Callon Petroleum Company and American Stock Transfer & Trust Company (incorporated by reference to Exhibit 4.16 of the Company s Quarterly Report on Form 10-Q for the period ended March 31, 2004, File No. 001-14039)

10. Material Contracts

10.1 Deepwater Production Handling and Operating Services Agreement for Garden Banks Blocks 738, 782, 785, 826 and 827 Production Handling at the Garden Banks Block 783 Magnolia TLP, dated as of August 31, 2007, by and between ConocoPhillips Company and Devon Energy Production Company, L.P. and Callon Petroleum Operating Company

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 Certifications

32.1 Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

32.2 Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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SIGNATURES

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

	CALLON PETROLEUM COMPANY
Date: November 5, 2007	By: /s/ B.F. Weatherly
	B.F. Weatherly, Executive Vice-President and Chief Financial Officer

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