CALLON PETROLEUM CO
Form 10-Q
May 08, 2014

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM
10-Q

QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For The Quarterly Period Ended March 31, 2014

OR

TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF SECURITIES EXCHANGE ACT OF 1934

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	(IRS Employer

Incorporation or Organization)	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 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 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 (232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).Yes No

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

Large accelerated filer	Accelerated filer
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

As of May 2, 2014, 40,449,884 shares of the Registrant's common stock, par value $0.01 per share, were outstanding.

Table of Contents

Table of Contents

DEFINITIONS

All defined terms under Rule 4-10(a) of Regulation S-X shall have their statutorily prescribed meanings when used in this report. As used in this document:

- ARO: Asset Retirement Obligation.
- Bbl or Bbls: barrel or barrels of oil or natural gas liquids.
- Bcf: billion cubic feet.
- BOE: barrel of oil equivalent, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of gas. The ratio of one barrel of oil or NGL to six Mcf of natural gas is commonly used in the industry and represents the approximate energy equivalence of oil or NGLs to natural gas, and does not represent the economic equivalency of oil and NGLs to natural gas. The sales price of a barrel of oil or NGLs is considerably higher than the sales price of six Mcf of natural gas.
- BOE/d: BOE per day.
- Btu: a British thermal unit, which is a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.
- LIBOR: London Interbank Offered Rate.
- LOE: lease operating expense.
- MBbls: thousand barrels of oil.
- MBOE: thousand boe.
- MBOE/d: Mboe per day.
- Mcf: thousand cubic feet of natural gas.
- Mcfe: thousand cubic feet of natural gas equivalents.
- Mcf/d: Mcf per day.
- MMBbls: million barrels of oil.
- MMBOE: million BOE.
- MMBtu: million Btu.
- MMcf: million cubic feet of natural gas.
- MMcf/d: MMcf per day.
- NGL or NGLs: natural gas liquids, such as ethane, propane, butanes and natural gasoline that are extracted from natural gas production streams.
- NYMEX: New York Mercantile Exchange.
- Oil: includes crude oil and condensate.
- SEC: United States Securities and Exchange Commission.
- GAAP: Generally Accepted Accounting Principles in the United States

With respect to information relating to our working interest in wells or acreage, “net” oil and gas wells or acreage is determined by multiplying gross wells or acreage by our working interest therein. Unless otherwise specified, all references to wells and acres are gross.

Table of Contents

Part I. Financial Information

Item I. Financial Statements

Callon Petroleum Company

Consolidated Balance Sheets

(in thousands, except par and per share values and share data)

	March 31, 2014	December 31, 2013
ASSETS	Unaudited	
Current assets:		
Cash and cash equivalents	$ 1,742	$ 3,012
Accounts receivable	23,237	20,586
Fair market value of derivatives	—	60
Deferred tax asset, current	6,320	3,843
Other current assets	1,356	2,063
Total current assets	32,655	29,564
Oil and natural gas properties, full-cost accounting method:		
Evaluated properties	1,783,598	1,701,577
Less accumulated depreciation, depletion and amortization	(1,432,213)	(1,420,612)
Net oil and natural gas properties	351,385	280,965
Unevaluated properties excluded from amortization	36,772	43,222
Total oil and natural gas properties	388,157	324,187
Other property and equipment, net	7,413	7,255
Restricted investments	3,806	3,806
Deferred tax asset	54,047	57,765
Other assets, net	3,168	1,376
Total assets	$ 489,246	$ 423,953
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 71,293	$ 57,637
Asset retirement obligations	4,483	4,120
Fair market value of derivatives	2,645	1,036
Total current liabilities	78,421	62,793
13% Senior Notes:		
Principal outstanding	48,481	48,481
Deferred credit, net of accumulated amortization of $26,673 and $26,239, respectively	4,834	5,267
Total 13% Senior Notes	53,315	53,748
Senior secured revolving credit facility	68,000	22,000
Asset retirement obligations	2,767	2,612
Other long-term liabilities	6,163	3,706
Total liabilities	208,666	144,859
Stockholders' equity:		
	16	16

Preferred stock, series A cumulative, $0.01 par value and $50.00 liquidation preference, 2,500,000 shares authorized: 1,578,948 and 1,578,948 shares outstanding, respectively		
Common stock, $0.01 par value, 110,000,000 and 60,000,000 shares authorized; 40,365,710 and 40,345,456 shares outstanding, respectively	405	404
Capital in excess of par value	403,136	401,540
Accumulated deficit	(122,977)	(122,866)
Total stockholders' equity	280,580	279,094
Total liabilities and stockholders' equity	$ 489,246	$ 423,953

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 March 31,	
	2014	2013
Operating revenues:		
Oil sales	$ 30,909	$ 19,540
Natural gas sales	2,376	3,001
Total operating revenues	33,285	22,541
Operating expenses:		
Lease operating expenses	4,230	5,576
Production taxes	1,917	721
Depreciation, depletion and amortization	10,538	11,042
General and administrative	10,807	3,739
Accretion expense	228	565
Gain on sale of other property and equipment	(1,080)	—
Total operating expenses	26,640	21,643
Income from operations	6,645	898
Other (income) expenses:		
Interest expense	977	1,515
Loss on derivative contracts	2,513	418
Other (income) expense	(49)	(45)
Total other expenses	3,441	1,888
Income (loss) before income taxes	3,204	(990)
Income tax expense (benefit)	1,341	(169)
Income (loss) before equity in earnings of Medusa Spar LLC	1,863	(821)
Equity in earnings of Medusa Spar LLC	—	21
Net income (loss)	1,863	(800)
Preferred stock dividends	(1,974)	—
Loss available to common stockholders	$ (111)	$ (800)
Loss per common share:		
Basic	$ (0.00)	$ (0.02)
Diluted	$ (0.00)	$ (0.02)
Shares used in computing loss per common share:		
Basic	40,328	39,793
Diluted	40,328	39,793

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)

	Three Months Ended March 31	
	2014	2013
Cash flows from operating activities:		
Net income	$ 1,863	$ (800)
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation, depletion and amortization	10,598	11,393
Accretion expense	228	565
Amortization of non-cash debt related items	119	111
Amortization of deferred credit	(433)	(799)
Equity in earnings of Medusa Spar LLC	—	(21)
Deferred income tax expense	1,341	(169)
Net loss (gain) on derivatives, net of settlements	1,639	1,039
Gain on sale of other property and equipment	(1,080)	—
Non-cash expense related to equity share-based awards	996	580
Change in the fair value of liability share-based awards	3,483	(195)
Payments to settle asset retirement obligations	(26)	(396)
Changes in current assets and liabilities:		
Accounts receivable	(2,928)	1,333
Other current assets	707	857
Current liabilities	5,155	158
Payments to settle vested liability share-based awards	(1,669)	—
Change in other long-term liabilities	—	(206)
Change in other assets, net	(26)	(575)
Net cash provided by operating activities	19,967	12,875
Cash flows from investing activities:		
Capital expenditures	(65,760)	(30,089)
Proceeds from sales of mineral interest and equipment	2,226	114
Distribution from Medusa Spar LLC	—	340
Net cash used in investing activities	(63,534)	(29,635)
Cash flows from financing activities:		
Borrowings on credit facility	46,000	17,000
Payment of deferred financing costs	(1,729)	—
Payment of preferred stock dividends	(1,974)	—
Net cash provided by financing activities	42,297	17,000
Net change in cash and cash equivalents	(1,270)	240
Balance, beginning of period	3,012	1,139
Balance, end of period	$ 1,742	$ 1,379

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

Table of Contents

Callon Petroleum Company

Notes to the Consolidated Financial Statements

(Unless otherwise indicated, dollar amounts included in the footnotes to the financial

statements are presented in thousands, except for per share and per unit data)

INDEX TO THE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 - Description of Business and Basis of Presentation

Description of business

Callon Petroleum Company is an independent oil and natural gas company established in 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 unless the context requires otherwise.

Callon is focused on the acquisition, development, exploration and exploitation of unconventional oil and natural gas reserves in the Permian Basin in West Texas. In late 2013, with the sale of its remaining offshore assets in the Gulf of Mexico, the Company completed the onshore strategic repositioning it initiated in 2009.

Basis of presentation

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

The interim consolidated financial statements of the Company have been prepared in accordance with (1) accounting principles generally accepted in the United States ("US GAAP"), (2) the Securities and Exchange Commission's instructions to Quarterly Report on Form 10-Q and (3) Rule 10-01 of Regulation S-X, and include the accounts of the Company, and its subsidiary, Callon Petroleum Operating Company ("CPOC"). CPOC also has subsidiaries, namely Callon Offshore Production, Inc., and Mississippi Marketing, Inc.

These interim consolidated financial statements should be read in conjunction with the Company's Annual Report on Form 10-K for the year ended December 31, 2013. The balance sheet at December 31, 2013 has been derived from the audited financial statements at that date.

Operating results for the periods presented are not necessarily indicative of the results that may be expected for the year ended December 31, 2014.

In the opinion of management, the accompanying unaudited consolidated financial statements reflect all adjustments, including normal recurring adjustments and all intercompany account and transaction eliminations, necessary to present fairly the Company's financial position, the results of its operations and its cash flows for the periods indicated. When necessary to ensure consistent presentation, certain prior year amounts may be reclassified. Certain prior year amounts have been reclassified to conform to current year presentation.

Note 2 – Oil and Natural Gas Properties

Acquisitions

In the first quarter of 2014, the Company acquired 1,527 net acres in Upton and Reagan Counties, Texas, which are located in the southern portion of the Midland Basin near our existing core development fields, for an aggregate cash purchase price of $8,200. The properties bear a working interest of 100% and an average net revenue interest of 78%.

Acreage Expiration

During the first quarter of 2014, the Company transferred $9,855 from unevaluated properties to the full cost pool related to 5,924 net acres in the Northern Midland Basin that expired or are scheduled to expire in the near future and are no longer included in the Company’s exploration and development plans. The Company continues to narrow its focus acreage for continued exploration and delineation efforts, which remains focused on horizontal development drilling in the Southern and Central portions of the Midland Basin. As of March 31, 2014, Callon has a remaining net acreage position in the Northern Midland Basin of 11,857 acres for which the Company is still evaluating potential future exploration activities.

Note 3 - Earnings Per Share

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

(share amounts in thousands)	Three Months Ended March 31,

		2014		2013
Net income (loss)	$	1,863	$	(800)
Preferred stock dividends		(1,974)		—
Loss available to common stockholders	$	(111)	$	(800)
Weighted average shares outstanding		40,328		39,793
Weighted average shares outstanding for diluted net loss per share		40,328		39,793
Basic loss per share	$	(0.00)	$	(0.02)
Diluted loss per share	$	(0.00)	$	(0.02)
The following were excluded from the diluted earnings per share calculation because their effect would be anti-dilutive:				
Stock options		40		67
Restricted stock		—		40

Note 4 – Borrowings

The Company’s borrowings consisted of the following at:

	March 31, 2014	December 31, 2013
Principal components:		
Credit Facility	$ 68,000	$ 22,000
13% Senior Notes, principal	48,481	48,481
Total principal outstanding	116,481	70,481
13% Senior Notes unamortized deferred credit	4,834	5,267
Total carrying value of borrowings	$ 121,315	$ 75,748

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

On March 11, 2014, the Company entered into the Fifth Amended and Restated Credit Agreement to the Credit Facility. The total amount available under the Credit Facility is $500,000, with an initial associated borrowing base of $95,000 and a maturity of March 11, 2019. JPMorgan Chase Bank, N.A. is Administrative Agent, and participating lenders include Regions Bank, Citibank, N.A., Capital One, N.A., KeyBank, N.A., Whitney Bank, IberiaBank, N.A., OneWest Bank, N.A., SunTrust Bank and Royal Bank of Canada. Amounts borrowed under the Credit Facility may not exceed the borrowing base, which is

8

generally reviewed on a semi-annual basis. The first redetermination is scheduled with an effective date of May 30, 2014, with subsequent redeterminations occurring every six months beginning on September 1, 2014. The Credit Facility is secured by first preferred mortgages covering the Company's major producing properties.

As of March 31, 2014, the balance outstanding on the Credit Facility was $68,000 with a weighted interest rate of 2.41%, calculated as the London Interbank Offered Rate ("LIBOR") plus a tiered rate ranging from 1.75% to 2.75%, which is determined based on utilization of the facility. In addition, the Credit Facility carries a commitment fee of 0.5% per annum, payable quarterly, on the unused portion of the borrowing base.

Second Lien Term Loan Facility (the "Second Lien Facility")

The Company also entered into the Second Lien Facility in an aggregate amount of up to $125,000, including initial commitments of $100,000 and additional availability of $25,000 subject to the consent of two-thirds of the lenders and compliance with financial covenants after giving effect to such increase. The Second Lien Facility, matures on September 11, 2019, and is not subject to mandatory prepayments unless new debt is issued. The Second Lien Facility may be prepaid at our option if we pay a prepayment premium. The prepayment premium is (i) 102% if the prepayment event occurs prior to March 11, 2015, and (ii) 101% if the prepayment event occurs on or after March 15, 2015 but before March 15, 2016, and (iii) 100% for prepayments made on or after March 15, 2016. The Second Lien Facility is secured by junior liens on properties mortgaged under the Credit Facility, subject to an intercreditor agreement.

There were no outstanding balances on the Second Lien Facility as of March 31, 2014. The initial draw amount of $62,500 was made on April 10, 2014 with an original issue discount of 1.0%. Subsequent draws, allowable during the first year, are subject to the same 1.0% original issue discount on the drawn amount, applied on the date such draw is funded. Beginning on April 10, 2014, the interest rate is 8.75%, calculated at a rate of LIBOR (subject to a floor rate of 1.0%) plus 7.75% per annum. In addition, the Second Lien Facility carries a commitment fee of 0.5% per annum, payable quarterly, on the unused portion of the initial commitment amount until March 11, 2015.

13% Senior Notes due 2016 ("Senior Notes") and Deferred Credit

On April 11, 2014, the Company completed a full redemption of the remaining $48,481 principal amount of outstanding Senior Notes using proceeds from the Second Lien Facility. The redemption, which will be accounted for in the quarter ending June 30, 2014, will result in a net $3,204 gain on the early extinguishment of debt (including $4,780 of accelerated deferred credit amortization). The gain represents the difference between the $50,047 paid for the redemption of the Senior Notes ($1,576 of redemption costs, primarily the call premium) and the carrying value of the remaining Senior Notes of $53,261 (inclusive of $4,780 of deferred credit). The Company also paid $193 for accrued interest through the redemption date. Upon the redemption, the indenture governing the Senior Notes was discharged in accordance with its terms.

Interest on the Senior Notes was payable on the last day of each quarter. Certain of the Company's subsidiaries guaranteed the Company's obligations under the Senior Notes. The subsidiary guarantors were 100% owned, all of the guarantees were full and unconditional and joint and several, the parent company had no independent assets or operations, and any subsidiaries of the parent company other than the subsidiary guarantors were minor. Upon issuing the Senior Notes in November 2009, the Company recorded as a deferred credit the $31,507 difference between the adjusted carrying amount of the previous Senior Notes that were exchanged and the principal of the new Senior Notes. This deferred credit was being amortized as a reduction of interest expense over the life of the Senior Notes at an 8.5% effective interest rate.

As of March 31, 2014, the deferred credit balance was $4,834, net of $26,673 of amortization through that date. Amortization recorded as a reduction of interest expense for the quarter ended March 31, 2014 was $433.

Restrictive Covenants

The indentures governing the Senior Notes, Credit Facility and Second Lien Facility contain various covenants including restrictions on additional indebtedness and payment of cash dividends. In addition, the Credit Facility and Second Lien Facility contain covenants for maintenance of certain financial ratios. The Company was in compliance with these covenants at March 31, 2014.

Note 5 - Derivative Instruments and Hedging Activities

Objectives and strategies for using derivative instruments

The Company is exposed to fluctuations in oil and natural gas prices received for its production. Consequently, the Company believes it is prudent to manage the variability in cash flows on a portion of its oil and natural gas production. The Company utilizes a mix of collar, swap, put, call and similar derivative financial instruments to manage fluctuations in cash flows resulting from changes in commodity prices. The Company does not use these instruments for speculative or trading purposes.

Counterparty risk and offsetting

The use of derivative transactions exposes the Company to the risk that a counterparty will be unable to meet its commitments. While the Company monitors counterparty creditworthiness on an ongoing basis, 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 while continuing to be obligated under higher commodity price contracts subject to any right of offset under the agreements. Counterparty credit risk is considered when determining a derivative instruments' fair value; see Note 6 for additional information regarding fair value.

The Company executes commodity derivative transactions under master agreements that have netting provisions that provide for offsetting payables against receivables. In general, if a party to a derivative transaction incurs an event of default, as defined in the applicable agreement, the other party will have the right to demand the posting of collateral, demand a cash payment transfer or terminate the arrangement.

Financial statement presentation and settlements

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

Derivatives not designated as hedging instruments

The Company has elected not to designate its derivative contracts as accounting hedges under Accounting Standards Codification 815. Consequently, the Company records its derivative contracts at their fair values on the balance sheet and marks-to-market these contracts at the end of each period. The Company records changes in fair values as a gain or loss on the statement of operations as a component of gain (loss) on derivative contracts. The gain (loss) on derivative contracts in the statement of operations includes the mark-to-market adjustments on outstanding contracts and the impact of cash settlements.

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

	Balance Sheet Presentation		Asset Fair Value		Liability Fair Value		Net Derivative Fair Value	
Commodity	Classification	Line Description	03/31/2014	12/31/2013	03/31/2014	12/31/2013	03/31/2014	12/31/2013
Natural gas	Current	Fair market value of derivatives	$ —	$ 60	$ (160)	$ —	$ (160)	$ 60
Natural gas	Non-current	Other long-term liabilities	—	—	(41)	(72)	(41)	(72)
Oil	Current	Fair market value of derivatives	—	—	(2,485)	(1,036)	(2,485)	(1,036)
	Totals		$ —	$ 60	$ (2,686)	$ (1,108)	$ (2,686)	$ (1,048)

10

(Unless otherwise indicated, dollar amounts included in the footnotes to the financial
statements are presented in thousands, except for per share and per unit data)

As previously discussed, the Company's derivative contracts are subject to master netting arrangements. The Company's policy is to present the fair value of derivative contracts on a net basis based on the underlying commodity being hedged. The following presents the impact of this presentation to the Company's recognized assets and liabilities at March 31, 2014:

	Presented without Effects of Netting	Effects of Netting	As Presented with Effects of Netting
Current assets: Fair value of hedging contracts	$ 59	$ (59)	$ —
Current liabilities: Fair market value of derivatives	(2,704)	59	(2,645)
Long-term liabilities: Fair market value of derivatives	(41)	—	(41)

For the periods indicated, the Company recorded the following related to its derivatives in the statement of operations as gain or loss on derivative contracts:

	Three Months Ended March 31	
	2014	2013
Natural gas derivatives		
Net gain (loss) on settlements	$ (102)	$ 49
Net gain (loss) on mark-to-market adjustments	(190)	(388)
Total loss	$ (292)	$ (339)
Oil derivatives		
Net gain (loss) on settlements	$ (773)	$ 573
Net gain (loss) on mark-to-market adjustments	(1,448)	(652)
Total loss	$ (2,221)	$ (79)
Total loss on derivative instruments	$ (2,513)	$ (418)

Derivative positions

Listed in the table below are the outstanding oil and natural gas derivative contracts as of March 31, 2014 (volumes in thousands):

Commodity	Instrument	Average Notional Volumes per Month (000s)	Quantity Type	Strike Price	Swap Price	Period
Natural gas	Swap	61	MMBtu	n/a	$ 4.25	Apr14 - Dec14
Natural gas	Call Option (sold)	37	MMBtu	$ 5.00	n/a	Jan15 - Dec15
Oil	Swap	30	Bbls	n/a	$ 93.35	Apr14 - Dec14
Oil	Put Option (sold)	30	Bbls	$ 70.00	n/a	Apr14 - Dec14
Oil	Swap	9	Bbls	n/a	$ 94.58	Apr14 - Dec14
Oil	Swap	15	Bbls	n/a	$ 92.80	Apr14 - Jun14
Oil	Swap	15	Bbls	n/a	$ 90.40	Jul14 - Sep14
Oil	Swap	15	Bbls	n/a	$ 88.35	Oct14 - Dec14

Excluded from the table above are offsetting natural gas long and short call options of 38,000 MMBtu per month for the period Apr14 – Dec14, each at a strike price of $4.75 per MMBtu.

The following derivative contracts were executed subsequent to March 31, 2014 (volumes in thousands):

Commodity	Instrument	Average Notional Volumes per Month (000s)	Quantity Type	Strike Price	Swap Price	Period
Oil	Swap	31	Bbls	n/a	$ 99.87	Jul14 - Sep14
Oil	Swap	21	Bbls	n/a	$ 96.92	Oct14 - Dec14

(Unless otherwise indicated, dollar amounts included in the footnotes to the financial
statements are presented in thousands, except for per share and per unit data)

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

Debt. The Company's debt is recorded at the carrying amount on its Consolidated Balance Sheet. The fair value of Callon's fixed-rate debt, which is valued using Level 2 inputs, is based upon estimates provided by an independent investment banking firm. The carrying amount of floating-rate debt approximates fair value because the interest rates are variable and reflective of market rates.

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

`

	March 31, 2014		December 31, 2013	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Credit Facility	$ 68,000	$ 68,000	$ 22,000	$ 22,000
13% Senior Notes due 2016 (a)	53,315	50,420	53,748	50,299
Total	$ 121,315	$ 118,420	$ 75,748	$ 72,299

(a) Fair value is calculated only in relation to the $48,481 and $48,481 principal outstanding of the Senior Notes at the dates indicated above, respectively. The remaining $4,834 and $5,267, respectively, which the Company has recorded as a deferred credit, is excluded from the fair value calculation, and will be recognized in earnings as a reduction of interest expense over the remaining amortization period. See Note 4 for additional information.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are reported at fair value on a recurring basis (unless otherwise noted below) in Callon's consolidated balance sheet. The following methods and assumptions were used to estimate the fair values:

Commodity Derivative Instruments. The fair value of commodity derivative instruments is derived 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 the majority of the inputs used to calculate the commodity derivative instruments fall within Level 2 of the fair-value hierarchy based on the wide availability of quoted market prices for similar commodity derivative contracts. See Note 5 for additional information regarding the Company's derivative instruments.

Footnotes to the Financial Statements (continued)

Table of Contents

(Unless otherwise indicated, dollar amounts included in the footnotes to the financial statements are presented in thousands, except for per share and per unit data)

The following tables present the Company's assets and liabilities measured at fair value on a recurring basis:

March 31, 2014	Balance Sheet Presentation	Level 1	Level 2	Level 3	Total
Liabilities					
Derivative financial instruments (current)	Fair market value of derivatives	$ —	$ 2,645	$ —	$ 2,645
Derivative financial instruments (non-current)	Other long-term liabilities	—	41	—	41
Total net liability		$ —	$ (2,686)	$ —	$ (2,686)

December 31, 2013	Balance Sheet Presentation	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments (current)	Fair market value of derivatives	$ —	$ 60	$ —	$ 60
Sub-total assets		—	60	—	60
Liabilities					
Derivative financial instruments (current)	Fair market value of derivatives	$ —	$ 1,036	$ —	$ 1,036
Derivative financial instruments (non-current)	Other long-term liabilities	—	72	—	72
Sub-total liabilities		$ —	$ 1,108	$ —	$ 1,108
Total net liability		$ —	$ (1,048)	$ —	$ (1,048)

The derivative fair values above are based on analysis of each contract. Derivative assets and liabilities with the same counterparty are presented here on a gross basis, even where the legal right of offset exists. See Note 5 for a discussion of net amounts recorded in the consolidated balance sheet at March 31, 2014.

Note 7 - Income Taxes

The Company provides for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, which primarily relate to statutory depletion, non-deductible executive compensation expenses and state income taxes. The effective tax rate for the three months ended March 31, 2014 and 2013 was 42% and 17%, respectively.

Note 8 - Asset Retirement Obligations

The table below summarizes the Company’s asset retirement obligations activity for the three months ended March 31, 2014:

Asset retirement obligations at January 1, 2014	$ 6,732
Accretion expense	228
Liabilities incurred	272
Revisions to estimate	18
Asset retirement obligations at end of period	7,250
Less: Current asset retirement obligations	4,483
Long-term asset retirement obligations at March 31, 2014	$ 2,767

Certain of the Company’s operating agreements require that assets be restricted for abandonment obligations. Amounts recorded on the consolidated balance sheets as restricted investments were $3,806 at March 31, 2014 and December 31, 2013. These investments include primarily U.S. Government securities, and are held in abandonment trusts dedicated to pay future abandonment costs for several of the Company’s oil and natural gas properties.

Note 9 – Preferred Stock

Holders of the Company’s Preferred Stock are entitled to receive, when, as and if declared by our Board of Directors, out of funds legally available for the payment of dividends, cumulative cash dividends at a rate of 10.0% per annum of the $50.00 liquidation preference per share (equivalent to $5.00 per annum per share). Dividends are payable quarterly in arrears on the last day of each March, June, September and December when, as and if declared by our Board of Directors. For the quarter ended March 31, 2014, the Board declared a dividend of $1.25 per share, or a total of $1,974, on the Company’s Preferred Stock.

As defined in a provision of the Preferred Stock prospectus, the common shares reserved for issuance vary based on the number of authorized common shares. In January 2014, following a majority shareholder vote, the number of authorized shares of common stock was increased from 60,000,000 to 110,000,000 with a corresponding increase in the number of common shares reserved for a potential conversion to a maximum of 42,200,000 shares. Based on the Company's closing common stock price of $8.37 per share on March 31, 2014, the Company reserved 9,432,186 shares to satisfy the potential conversion.

Note 10 – Other

Operating Leases

In April 2012, the Company contracted a drilling rig (the "Cactus 1 Rig") for a term of two years, which it subsequently renewed in March 2014 for an additional two year term ending April 2016. In April 2014, the Company contracted an additional horizontal drilling rig (the "Cactus 2 Rig") for a term of two years ending April 2016. The Cactus 2 Rig replaced a previously contracted horizontal drilling rig, which was cancelled in March 2014. The Cactus 1 and Cactus 2 Rig lease agreements include early termination provisions that would reduce the minimum rentals under the agreement, and also include early termination payments that would be reduced assuming the lessor is able to re-charter the rig and staffing personnel to another lessee. Lease payments in 2014, 2015 and 2016 are expected to approximate $18,015 (with $13,758 remaining at March 31, 2014), $18,250 and $4,795, respectively.

Other Property and Equipment

As disclosed in the Company's Annual Report on Form 10-K for the year ended December 31, 2013, the Company made a decision to abandon certain specialized deep water property and equipment received as part of a prior settlement agreement related to various disputes with a previous joint interest partner as a result of the unsuccessful marketing of such assets. Accordingly, the Company recognized an impairment charge of $1,707 related to such property and equipment in the year ended December 31, 2013. Subsequent to the filing of the Annual Report on Form 10-K, the Company entered into an agreement to sell the property and equipment to a third party. While the third party had previously performed some initial inspection and evaluation of the equipment, based on the amount of time the equipment had been unsuccessfully marketed and the feedback from potential buyers, management concluded the likelihood of completing a sale of the equipment was low, resulting in the decision to abandon the equipment and recognize an impairment charge in 2013. As a result of the subsequent sale of the property and equipment, the Company recognized a gain of $1,080 in the first quarter 2014.

Table of Contents

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 quantities, present value and 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.

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” or si

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 oil, natural gas and NGLs (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.

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 of our Annual Report on Form 10-K for the year ended December 31, 2013 (the 2013 Annual Report on Form 10-K"), and all quarterly reports on Form 10-Q filed subsequently thereto ("Form 10-Qs").

Should one or more of the risks or uncertainties described above or in our 2013 Annual Report on Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

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

Table of Contents

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

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 2013 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. 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 are an independent oil and natural gas company established in 1950. We are focused on the acquisition, development, exploration and exploitation of unconventional, onshore, oil and natural gas reserves in the Permian Basin in West Texas, and more specifically, the Midland Basin. Our operations are predominantly focused on horizontal drilling of several prospective intervals, including multiple levels of the Wolfcamp formation. We have assembled a multi-year inventory of potential horizontal well locations and intend to add to this inventory through delineation drilling of emerging zones on our existing acreage and acquisition of additional locations through acreage purchases, joint ventures and asset swaps. Our production was approximately 85% oil and 15% natural gas for the three months ended March 31, 2014. On March 31, 2014, our net acreage position in the Permian Basin was approximately 25,481 net acres.

Recent Developments

- Acquired 1,527 net acres in Upton and Reagan Counties, in close proximity to our existing East Bloxom and Garrison Draw fields for a combined purchase price of $8.2 million
- Established production from two Wolfcamp B horizontal wells in the Carpe Diem field, increasing our core horizontal development areas to four fields
- Closed a $500 million revolving credit facility with a present borrowing base of $95 million and a $125 million second lien term loan facility with initial availability of $100 million
- Completed the full redemption of our Senior Notes due 2016 in April 2014

Operational Highlights

Following the sale of our remaining offshore and Haynesville properties in the fourth quarter of 2013, all of our producing properties are located in the Permian Basin. Our Permian production grew 176% in the first quarter of 2014 compared to the same period of 2013, increasing to 392 MBOE from 142 MBOE, respectively.

	Net Production (MBOE) Three Months Ended March 31			
	2014	2013	Change	% Change
Onshore:				
Southern Midland Basin	315	93	222	239%
Central Midland Basin	71	49	22	46%
Northern Midland Basin	6	—	6	—
Total Permian	392	142	250	176%
Offshore and other (a)	—	195	(186)	(95)%
Total	392	328	64	20%

(a) In late 2013, we sold the remaining interest in our offshore fields and Haynesville shale.

Table of Contents

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

The following table sets forth productive wells as of March 31, 2014:

	Oil Wells		Natural Gas Wells	
	Gross	Net	Gross	Net
Working interest	133	112.4	—	—
Royalty interest	3	0.0	—	—
Total	136	112.4	—	—

A well is categorized as an oil well or a natural gas well based upon the ratio of oil to natural gas reserves on a Mcfe basis. However, most of our wells produce both oil and natural gas.

The following table summarizes the Company's drilling progress in the Permian Basin for the three months ended March 31, 2014:

	Drilled		Completed (a)		Awaiting Completion	
	Gross	Net	Gross	Net	Gross	Net
Southern Midland Basin						
Vertical wells	1	1.0	1	1.0	—	—
Horizontal wells	8	7.3	5	5.0	3	2.3
Total	9	8.3	6	6.0	3	2.3
Central Midland Basin						
Vertical wells	1	0.4	—	—	1	0.4
Horizontal wells	1	0.8	2	1.7	1	0.8
Total	2	1.3	2	1.7	2	1.3
Northern Midland Basin						
Vertical wells	2	1.5	1	0.8	—	—
Total	2	1.5	1	0.8	—	—
Total vertical wells	4	2.9	2	1.8	1	0.4
Total horizontal wells	9	8.1	7	6.7	4	3.1
Total	13	11.0	9	8.4	5	3.5

(a) Completions include wells drilled prior to 2014.

Liquidity and Capital Resources

Historically, our primary sources of capital have been cash flows from operations, borrowings from financial institutions, the sale of debt and equity securities and asset dispositions. Our primary uses of capital have been for the acquisition, development, exploration and exploitation of oil and natural gas properties.

Based upon current commodity price expectations for 2014, we believe that our cash flow from operations and borrowings under our Credit Facility and Second Lien Facility will be sufficient to fund our operations for 2014, including any deficiencies in the Company’s current net working capital. However, future cash flows are subject to a number of variables, including forecasted production volumes and commodity prices. Our 2014 capital program is 100% operated and, as a result, the amount and timing of a large portion of our planned capital expenditures are largely discretionary in the event we needed to curtail drilling and completion operations due to capital constraints.

We recently entered into an amended Credit Facility and Second Lien Facility to support the funding of our ongoing operations and acquisition initiatives, which are discussed in greater detail in Note 4 to the Consolidated Financial Statements. In addition, we regularly evaluate other sources of capital, including debt and equity securities, to complement our cash flow from operations and other sources of capital as we pursue our long-term growth plans in the Permian Basin.

Table of Contents

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

Cash and cash equivalents decreased $1.3 million in the first quarter of 2014 to $1.7 million compared to $3.0 million at December 31, 2013. At March 31, 2014, our available liquidity, inclusive of undrawn amounts on our Credit Facility ($27.0 million) and Second Lien Facility ($100.0 million), increased to $128.7 million, a $64.7 million increase over year-end 2013.

Liquidity and Cash Flow

	For the Quarter Ended March 31	
	2014	2013
Net cash provided by operating activities	$ 20.0	$ 12.9
Net cash used in investing activities	(63.5)	(29.6)
Net cash provided by (used in) financing activities	42.3	17.0
Net change in cash	$ (1.3)	$ 0.2

Operating Activities. For the three months ended March 31, 2014, net cash provided by operating activities was $20.0 million, compared to $12.9 million for the same period in 2013. The increase was primarily due to an increase in oil sales and a reduction in lease operating expense, partially offset by losses on derivatives, settled and an increase in production taxes. Production and realized prices are discussed below in Results of Operations. See Notes 5 and 6 for a reconciliation of the components of the Company's derivative contracts and disclosures related to derivative instruments including their composition and valuation.

Investing Activities. For the three months ended March 31, 2014, net cash used in investing activities was $63.5 million as compared to $29.6 million for the same period in 2013. The $36.1 million increase in cash used in investing activities was primarily attributable to a $25.0 million increase in drilling and completion activities in the Permian Basin driven by the addition of a second horizontal drilling rig in August 2013. In addition, the Company completed $8.2 million of acquisitions in the first three months of 2014, with no acquisition completed in the comparable 2013 period.

Capital expenditures for the three months ended March 31, 2014 include the following (in millions):

Southern Midland Basin	$ 37
Central Midland Basin	14
Northern Midland Basin	2

Total operational expenditures	53
Capitalized general and administrative costs allocated directly to exploration and development projects	4
Capitalized interest	1
Total capitalized expenses	5
Total operational expenditures inclusive of capitalized amounts	58
Acquisitions	8
Total capital expenditures	$ 66

Financing Activities. For the three months ended March 31, 2014, net cash provided by financing activities was $42.3 million compared to cash provided by financing activities of $17.0 million during the same period of 2013. Net cash provided by financing activities during the three months ended March 31, 2014 included a net $46 million of borrowings on our Credit Facility offset by approximately $2.0 million in preferred stock dividends.

2014 Capital Expenditures

Our 2014 operational capital budget approximates $185 million, excluding $8 million of acquisitions completed in 2014 (see Note 2). This budgeted amount includes plans to drill up to 27 horizontal and nine vertical wells, while completing 26 horizontal and eight vertical wells. In the first quarter of 2014, we began testing larger horizontal well completion designs in an effort to improve production rates and the amount of recoverable resources. Based on satisfactory drilling, completion and well performance to date, we believe that these enhanced completion designs create the potential for increased total returns on

Table of Contents

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

capital after adjusting for incremental costs of approximately $0.5 million to $0.8 million per completion depending on the depth of the well. Consequently, we are in the process of evaluating our 2014 operational capital budget in anticipation of modifying our completion plans for future horizontal wells in selected areas. We are also forming our development plans related to recently acquired acreage in Upton and Reagan Counties. We expect to finalize our 2014 operational plan and any related increase in our current operational capital budget during the second quarter of 2014.

Results of Operations

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

	Three Months Ended March 31,			
	2014	2013	Change	% Change
Net production:				
Oil (MBbls)	332	206	126	61%
Natural gas (MMcf)	363	738	(375)	(51)%
Total production (MBOE)	392	328	64	20%
Average daily production (BOE/d)	4,355	3,644	711	20%
% Oil (MBOE basis)	85%	63%	—	—
Average realized sales price:				
Oil (Bbl)	$ 93.12	$ 94.85	$ (1.73)	(2)%
Natural gas (Mcf) (includes NGLs)	6.54	4.07	2.47	61%
Total (BOE)	84.82	68.72	16.10	23%
Oil and natural gas revenues (in thousands):				
Oil revenue	$ 30,909	$ 19,540	$ 11,369	58%
Gas revenue	2,376	3,001	(625)	(21)%
Total	$ 33,285	$ 22,541	$ 10,744	48%
Additional per BOE data:				
Sales price	$ 84.82	$ 68.72	$ 16.10	23%
Lease operating expense	10.78	17.00	(6.22)	(37)%
Production taxes	4.88	2.20	2.68	122%
Operating margin	$ 69.15	$ 49.52	$ 19.63	40%

Table of Contents

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

Revenues

The following tables are intended to reconcile the change in oil, natural gas and total revenue for the respective periods presented by reflecting the effect of changes in volume and in the underlying commodity prices.

(in thousands)	Oil	Natural Gas	Total
Revenues for the three-months ended March 31, 2012	$ 25,749	$ 3,545	$ 29,294
Volume increase (decrease)	(3,739)	(651)	(4,390)
Price increase (decrease)	(2,470)	107	(2,363)
Net increase (decrease) in 2013	(6,209)	(544)	(6,753)
Revenues for the three-months ended March 31, 2013	$ 19,540	$ 3,001	$ 22,541
Volume increase (decrease)	12,015	(1,524)	10,491
Price increase (decrease)	(646)	899	253
Net increase (decrease) in 2014	11,369	(625)	10,744
Revenues for the three-months ended March 31, 2014	$ 30,909	$ 2,376	$ 33,285

Oil Revenue

For the quarter ended March 31, 2014, oil revenues of $30.9 million increased $11.4 million, or 58%, compared to revenues of $19.5 million for the same period of 2013. Contributing to the increase in oil revenue was a 61% increase in production partially offset by a 2% decrease in the average realized sales price. The increase in production was primarily attributable to a 221 MBbls increase in production from our Permian properties, partially offset by a 92 MBbls decline in production due to the sale of our deepwater Medusa field in the fourth quarter of 2013 as well as normal and expected declines from our existing wells.

Natural Gas Revenue (including NGLs)

Natural gas revenues of $2.4 million decreased $0.6 million, or 21%, during the three months ended months ended March 31, 2014 as compared to $3.0 million for the same period of 2013. The decrease primarily relates to a 51% decrease in natural gas volumes partially offset by a 61% increase in the average price realized, which rose to $6.54 per Mcf from $4.07 per Mcf. Our natural gas prices on an MMBtu equivalent basis exceeded the related NYMEX prices primarily due to the value of the NGLs in our natural gas stream from our Permian Basin and offshore production. The production declines were primarily attributable to the sale of our offshore fields and our Haynesville well in the fourth quarter of 2013 as well as normal and expected declines from our existing wells. Offsetting these declines was a 156 million cubic feet increase in horizontal well production from our Permian properties.

Operating Expenses

Principal components of our cost structure

Lease operating expenses. These are daily costs incurred to bring oil and natural gas out of the ground and to the market, together with the daily costs incurred to maintain our producing properties. Such costs also include maintenance, repairs and workover expenses related to our oil and natural gas properties.

Production taxes. Production taxes include severance and ad valorem taxes. Severance taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at fixed rates established by federal, state or local taxing authorities. Where available, we benefit from tax credits and exemptions in our various taxing jurisdictions. We are also subject

Table of Contents

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

to ad valorem taxes in the counties where our production is located. Ad valorem taxes are generally based on the valuation of our oil and gas properties.

Depreciation, depletion and amortization. Under the full cost accounting method, we capitalize costs within a cost center and then systematically expense those costs on a units-of-production basis based on proved oil and natural gas reserve quantities. We calculate depletion on the following types of costs: (i) all capitalized costs, other than the cost of investments in unproved properties and major development projects for which proved reserves cannot yet be assigned, less accumulated amortization; (ii) the estimated future expenditures to be incurred in developing proved reserves; and (iii) the estimated dismantlement and abandonment costs, net of estimated salvage values. Depreciation of other property and equipment is computed using the straight line method over their estimated useful lives, which range from three to fifteen years.

General and administrative. These are costs incurred for overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, public company costs, vesting of equity and liability awards under share-based compensation plans, fees for audit and other professional services and legal compliance.

Accretion expense. The Company is required to record the estimated fair value of liabilities for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. Interest is accreted on the present value of the asset retirement obligations and reported as accretion expense within operating expenses in the consolidated statements of operations.

(in thousands, except per unit amounts)	Three Months Ended March 31,							
		Per		Per	Total Change		BOE Change	
	2014	BOE	2013	BOE	$	%	$	%
Lease operating expenses	$ 4,230	$ 10.78	$ 5,576	$ 17.00	(1,346)	(24)%	(6.22)	(37)%
Production taxes	1,917	4.88	721	2.20	1,196	166%	2.68	122%
Depreciation, depletion and amortization	10,538	26.88	11,042	33.66	(504)	(5)%	(6.78)	(20)%
General and administrative	10,807	27.55	3,739	11.40	7,068	189%	16.15	142%
Accretion expense	228	0.58	565	1.72	(337)	(60)%	(1.14)	(66)%
Gain on sale of other property and equipment	(1,080)	nm	—	nm	(1,080)	—	nm	nm

*nm = not meaningful

Lease Operating Expenses (“LOE”)

LOE for the three months ended March 31, 2014 decreased by 24% to $4.2 million compared to $5.6 million for the same period of 2013 was primarily due to an estimated decrease of $2.3 million of LOE resulting from the previously discussed sale of our interests in Medusa, the Medusa Spar LLC, our Haynesville property and substantially all our remaining shelf properties. These decreases were partially offset by $1.0 million in LOE costs related to the growth in Permian production and operations, including an increase in workover expenses associated with accelerated horizontal well activity.

Production Taxes

For the three months ended March 31, 2014, production taxes increased 166%, or $1.2 million, to $1.9 million compared to $0.7 million for the same period of 2013. The increase was predominantly attributable to an increase of onshore production subject to these taxes accompanied by a decline in offshore production, resulting from the sale of our Gulf of Mexico position in 2013, which was exempt from production taxes.

Depreciation, Depletion and Amortization (“DD&A”)

DD&A for the three months ended March 31, 2014 decreased 20% per BOE to $26.88 per BOE compared to $33.66 per BOE for the same period of 2013 attributable to our increasing estimated proved reserves relative to our depreciable asset base (the full cost pool).

Table of Contents

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

General and Administrative, net of amounts capitalized (“G&A”)

G&A for the three months ended March 31, 2014 increased to $10.8 million compared to $3.7 million for the same period of 2013. Total G&A for the first quarter of 2014 also included $6.3 million of expense related to the following items:

- $1.2 million in non-recurring, cash expense related to a threatened proxy contest
- $2.5 million in non-recurring, expenses (both non-cash and cash components) primarily related to the accelerated vesting of outstanding equity awards for early retirement of employees
- $2.7 million in non-cash expense related to the mark-to-market adjustment of performance-based phantom stock incentive awards

Accretion Expense

Accretion expense related to our ARO decreased 60% for the three months ended March 31, 2014 compared to the same period of 2013. Accretion expense correlates directionally with the Company’s ARO which was $7.3 million at March 31, 2014 versus $14.3 million at March 31, 2013. The reduction in ARO was primarily a result of our property divestiture in the fourth quarter of 2013. See Note 8 for additional information regarding the Company’s ARO.

Gain on sale of other property and equipment

See Note 10 for a discussion of the gain on the sale of equipment.

Other Income and Expenses

(in thousands)	Three Months Ended March 31,			
	2014	2013	$ Change	% Change
Interest expense	$ 977	$ 1,515	$ (538)	(36)%

Loss on derivative contracts	2,513	418	2,095	501%
Other (income) expense, net	(49)	(45)	(4)	9%
Income tax expense (benefit)	1,341	(169)	1,510	(893)%
Equity in earnings of Medusa Spar LLC	—	21	(21)	(100)%
Preferred stock dividends	(1,974)	—	(1,974)	100%

Interest Expense

Interest expense incurred during the three months ended March 31, 2014 decreased $0.5 million compared to the same period of 2013 and is primarily related to $1.4 million lower interest expense related to our Senior Notes following a $48.5 million principal redemption during the fourth quarter of 2013. Offsetting the decrease is a $0.5 million decline in capitalized interest for the comparative three month period, resulting from a lower average unevaluated property balance period over period, and an additional $0.4 million interest expense related to additional draws on our Credit Facility in 2014 compared to the corresponding period of the prior year.

Loss (Gain) on Derivative Contracts

See Notes 5 and 6 for a reconciliation of the components of the Company’s derivative contracts and disclosures related to derivative instruments including their composition and valuation.

Income Tax Expense

Please see Note 7 for a discussion of our effective tax rates for the periods presented above.

Table of Contents

Preferred Stock Dividends

Preferred Stock dividends for the three months ended March 31, 2014 increased $2.0 million compared to the same period of 2013 in which we had no dividend expense. The expense of $2.0 million for the three-month period is consistent with its 10% dividend rate and $75 million face value.

Table of Contents

Item 3. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to a variety of market risks including commodity price risk, interest rate risk and counterparty and customer risk. We address these risks through a program of risk management including the use of derivative instruments.

Commodity price risk

The Company's revenues are derived from the sale of its oil and natural gas production. The prices for oil and natural gas remain extremely volatile and sometimes experience large fluctuations as a result of relatively small changes in supply, weather conditions, economic conditions and government actions. From time to time, the Company enters into derivative financial instruments to manage oil and natural gas price risk. The total volumes which we hedge through the use of our derivative instruments varies from period to period; however, generally our objective is to hedge approximately 50% to 75% of our anticipated internally forecasted production for the next 12 to 24 months. Our hedge policies and objectives may change significantly as commodities prices or price futures change.

As of March 31, 2014, we had commodity contracts covering approximately 52% and 33% of our expected oil and natural gas production for the remaining nine months of 2014, respectively, based on the midpoint of publicly disclosed guidance as of May 8, 2014 and including the impact of derivative contracts established after March 31, 2014. Our actual production will vary from the amounts estimated, perhaps materially. See Note 5 to the Consolidated Financial Statements for a description of the Company's outstanding derivative contracts at March 31, 2014 and derivative contracts established subsequent to that date.

The Company may utilize fixed price swaps, which reduce the Company's exposure to decreases in commodity prices and limit the benefit the Company might otherwise have received from any increases in commodity prices. Swap contracts may also be enhanced by the simultaneous sale of call or put options to effectively increase the effective swap price as a result of the receipt of premiums from the option sales. Additionally, the Company may sell put options or call options in conjunction with a swap and use the proceeds to increase the fixed price received.

The Company may utilize price collars to reduce the risk of changes in oil and natural gas prices. Under these arrangements, no payments are due by either party as long as the applicable market price is above the floor price (purchased put option) and below the ceiling price (sold call option) 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 counterparty receives the difference from the Company. Additionally, the Company may sell put options at a price lower than the floor price in conjunction with a collar and use the proceeds to increase either or both the floor or ceiling prices.

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

The Company enters into these various agreements from time to time to reduce the effects of volatile oil and natural gas prices and does not enter into derivative transactions for speculative purposes. Presently, none of the Company’s derivative positions are designated as hedges for accounting purposes.

Interest rate risk

On March 31, 2014, the majority of the Company’s debt consisted of its fixed-rate 13% Senior Notes. However, we are subject to market risk exposure related to changes in interest rates on our indebtedness under our Credit Facility and Second Lien Facility into which we entered during March 2014. As of March 31, 2014, the weighted average interest rate on our Credit Facility borrowings was 2.41%. An increase or decrease of 1% in the interest rate would have a corresponding increase or decrease in our net income of approximately $0.4 million based on the $68 million outstanding in the aggregate under our Credit Facility on March 31, 2014.

Table of Contents

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from derivatives financial contracts, joint interest receivables and the receivables from the sale of our oil and natural gas production, which we market to energy marketing companies.

Our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. The counterparties on our derivative instruments currently in place are lenders under our Credit Facility. We are likely to enter into additional derivative instruments with these or other lenders under our Credit Facility, representing institutions with an investment grade ratings. We have existing International Swap Dealers Association Master Agreements (“ISDA Agreements”) with our derivative counterparties. The terms of the ISDA Agreements provide us and the counterparties with rights of set off upon the occurrence of defined acts of default by either us or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party.

Joint interest receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we intend to drill. We have little ability to control whether these entities will participate in our wells. At March 31, 2014 our joint interest receivables were approximately $4.0 million.

We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. We do not require any of our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. At March 31, 2014 our receivables from the sale of our oil and natural gas production were approximately $16.5 million in total.

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 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 Exchange Act) were effective as of March 31, 2014.

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

Table of Contents

Part II. Other Information

Item 1. Legal Proceedings

We are a defendant in various legal proceedings and claims, which arise in the ordinary course of our business. We do not believe the ultimate resolution of any such actions will have a material effect on our financial position or results of operations.

Item 1A. Risk Factors

There have been no material changes with respect to the risk factors disclosed in our 2013 Annual Report on Form 10-K.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

Table of Contents

Item 6. Exhibits

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

Exhibit Number	Description
3.	Articles of Incorporation and By-Laws
3.1	Certificate of Incorporation of the Company, as amended (incorporated by reference from Exhibit 3.1 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003 filed March 15, 2004, File No. 001-14039)
3.2	Bylaws of the Company (incorporated by reference from Exhibit 3.2 of the Company's Registration Statement on Form S-4, filed August 4, 1994, Reg. No. 33-82408)
3.3	Certificate of Amendment to Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.3 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)
3.4	Certificate of Amendment to the Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.4 of the Company's Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-14039)
3.5	Certificate of Designation of Rights and Preferences of 10.0% Series A Cumulative Preferred Stock (incorporated by reference to Exhibit 3.5 of the Company's Form 8-A filed on May 23, 2013)
4.	Instruments defining the rights of security holders, including indentures
4.1	Specimen Common Stock Certificate (incorporated by reference from Exhibit 4.1 of the Company's Registration Statement on Form S-4, filed August 4, 1994, Reg. No. 33-82408)
4.2	Indenture for the Company's 13.00% Senior Notes due 2016, dated November 24, 2009, between Callon Petroleum Company, the subsidiary guarantors described therein, Regions Bank and American Stock Transfer & Trust Company (incorporated by reference to Exhibit T3C to the Company's Form T3, filed November 19, 2009, File No. 022-28916)

4.3 Form of Certificate representing the 10.0% Series A Cumulative Preferred Stock (incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-A filed on May 23, 2013)

10.Material Contracts

10.1 $500 million Amended and Restated Credit Facility, dated March 11, 2014

10.2 $125 million Second Lien Term Loan Facility, dated March 11, 2014

10.3 Inter Creditor Agreement, dated March 11, 2014

10.4 Settlement Agreement, dated March 9, 2014, with Lone Star Value Investors, L.P. and other persons (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed by the Company on March 10, 2014)

31. Certifications

31.1 Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32 Section 1350 Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

101.* Interactive Data Files

* Pursuant to Rule 406T of Regulation S-T, these interactive data files are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933 or Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise are not subject to liability.

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.

May 8, 2014

Callon Petroleum Company

Signature	Title	Date
/s/ Fred L. Callon Fred L. Callon	President and Chief Executive Officer	May 8, 2014
/s/ Joseph C. Gatto, Jr. Joseph C. Gatto, Jr.	Senior Vice President, Chief Financial Officer and Treasurer	May 8, 2014