

CALLON PETROLEUM CO
Form 10-Q
August 06, 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 June 30, 2014

OR

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

For the transition period _____ to: _____

Commission File Number 001-14039

Callon Petroleum Company

(Exact Name of Registrant as Specified in Its Charter)

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Delaware
64-0844345
(State or Other
Jurisdiction of (IRS
Employer
Incorporation
or Identification
Organization) No.)

200 North
Canal Street

Natchez,
Mississippi

(Address of
Principal 39120
Executive
Offices) (Zip Code)

601-442-1601

(Registrant's Telephone Number, Including Area Code)

Not Applicable

(Former Name, Former Address and Former Fiscal Year, If Changed Since Last Report)

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):

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Large accelerated filer

Accelerated filer

Non-accelerated filer (Do not check if smaller reporting company) 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 August 1, 2014, 40,843,827 shares of the Registrant's common stock, par value \$0.01 per share, were outstanding.

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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.
- BBtu: billion Btu
- 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.

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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)

	June 30, 2014	December 31, 2013
	Unaudited	
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 1,172	\$ 3,012
Accounts receivable	26,951	20,586
Deferred tax asset	5,846	3,843
Other current assets	1,798	2,123
Total current assets	35,767	29,564
Oil and natural gas properties, full cost accounting method:		
Evaluated properties	1,844,691	1,701,577
Less accumulated depreciation, depletion and amortization	(1,444,169)	(1,420,612)
Net oil and natural gas properties	400,522	280,965
Unevaluated properties	36,957	43,222
Total oil and natural gas properties	437,479	324,187
Other property and equipment, net	7,388	7,255
Restricted investments	3,806	3,806
Deferred tax asset	50,421	57,765
Other assets, net	5,057	1,376
Total assets	\$ 539,918	\$ 423,953
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	\$ 61,028	\$ 53,464
Market-based restricted stock unit awards	6,683	4,173
Asset retirement obligations	2,846	4,120
Fair value of derivatives	5,306	1,036
Total current liabilities	75,863	62,793
13% senior notes:		
Principal outstanding	—	48,481
Deferred credit, net of accumulated amortization of \$0 and \$26,239, respectively	—	5,267
Total 13% senior notes	—	53,748
Senior secured revolving credit facility	84,000	22,000
Second lien term loan facility	82,500	—
Asset retirement obligations	2,752	2,612
Market-based restricted stock unit awards	10,717	3,409

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Other long-term liabilities	1,497	297
Total liabilities	257,329	144,859
Stockholders' equity:		
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	16	16
Common stock, \$0.01 par value, 110,000,000 and 60,000,000 shares authorized; 40,785,751 and 40,345,456 shares outstanding, respectively	408	404
Capital in excess of par value	402,375	401,540
Accumulated deficit	(120,210)	(122,866)
Total stockholders' equity	282,589	279,094
Total liabilities and stockholders' equity	\$ 539,918	\$ 423,953

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

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Callon Petroleum Company

Consolidated Statements of Operations

(Unaudited; in thousands, except per share data)

	Three Months Ended		Six Months Ended	
	June 30,	2013	June 30,	2013
	2014		2014	
Operating revenues:				
Oil sales	\$ 37,710	\$ 19,061	\$ 68,619	\$ 38,601
Natural gas sales	2,792	3,699	5,168	6,700
Total operating revenues	40,502	22,760	73,787	45,301
Operating expenses:				
Lease operating expenses	4,363	5,259	8,593	10,836
Production taxes	2,265	812	4,182	1,532
Depreciation, depletion and amortization	11,982	10,654	22,520	21,696
General and administrative	9,639	4,545	20,446	8,284
Accretion expense	173	533	401	1,098
Gain on sale of other property and equipment	—	—	(1,080)	—
Total operating expenses	28,422	21,803	55,062	43,446
Income from operations	12,080	957	18,725	1,855
Other (income) expenses:				
Interest expense	1,825	1,537	2,802	3,052
Gain on early extinguishment of debt	(3,205)	—	(3,205)	—
Loss (gain) on derivative contracts	4,685	(1,981)	7,198	(1,563)
Other (income) expense	(93)	(44)	(142)	(89)
Total other expenses	3,212	(488)	6,653	1,400
Income before income taxes	8,868	1,445	12,072	455
Income tax expense	4,128	663	5,469	494
Income (loss) before equity in earnings of Medusa Spar LLC	4,740	782	6,603	(39)
Loss from Medusa Spar LLC	—	(24)	—	(3)
Net income (loss)	4,740	758	6,603	(42)
Preferred stock dividends	(1,973)	(680)	(3,947)	(680)
Income (loss) available to common stockholders	\$ 2,767	\$ 78	\$ 2,656	\$ (722)
Income (loss) per common share:				
Basic	\$ 0.07	\$ 0.00	\$ 0.07	\$ (0.02)
Diluted	\$ 0.07	\$ 0.00	\$ 0.06	\$ (0.02)
Shares used in computing income (loss) per common share:				
Basic	40,606	40,089	40,467	39,941
Diluted	41,605	40,323	41,652	39,941

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

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Callon Petroleum Company

Consolidated Statements of Cash Flows

(Unaudited; in thousands)

	Six Months Ended June	
	30,	
	2014	2013
Cash flows from operating activities:		
Net income	\$ 6,603	\$ (42)
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation, depletion and amortization	22,976	22,405
Accretion expense	401	1,098
Amortization of non-cash debt related items	298	228
Amortization of deferred credit	(433)	(1,615)
Equity in earnings of Medusa Spar LLC	—	3
Deferred income tax expense	5,469	494
Net loss (gain) on derivatives, net of settlements	4,677	(249)
Gain on sale of other property and equipment	(1,080)	—
Non-cash gain for early debt extinguishment	(3,205)	—
Non-cash expense related to equity share-based awards	(36)	734
Change in the fair value of liability share-based awards	8,070	(852)
Payments to settle asset retirement obligations	(1,469)	(615)
Changes in current assets and liabilities:		
Accounts receivable	(5,268)	789
Other current assets	265	598
Current liabilities	2,014	(324)
Payments to settle vested liability share-based awards	(3,469)	(239)
Change in other long-term liabilities	—	(386)
Change in other assets, net	(216)	(1,790)
Net cash provided by operating activities	35,597	20,237
Cash flows from investing activities:		
Capital expenditures	(127,219)	(58,385)
Acquisition	—	(11,000)
Proceeds from sales of mineral interest and equipment	2,267	1,389
Distribution from Medusa Spar LLC	—	616
Net cash used in investing activities	(124,952)	(67,380)
Cash flows from financing activities:		
Borrowings on debt	150,000	31,000
Payment of deferred financing costs	(2,928)	—
Payments on debt	(55,610)	(41,000)
Issuance of preferred stock	—	70,090
Payment of preferred stock dividends	(3,947)	(680)

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Net cash provided by financing activities	87,515	59,410
Net change in cash and cash equivalents	(1,840)	12,267
Balance, beginning of period	3,012	1,139
Balance, end of period	\$ 1,172	\$ 13,406

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

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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)

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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) GAAP, (2) the SEC'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 to conform to presentation in the current period. Certain prior year amounts have been reclassified to conform to current year presentation.

Footnotes to the Financial Statements (continued)

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(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)

Recently issued accounting policies

In May 2014, the Financial Accounting Standards Board issued accounting standards update (“ASU”) No. 2014-09, Revenue from Contracts with Customers. The standard requires an entity to recognize revenue in a manner that depicts the transfer of goods or services to customers at an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU No. 2014-09 will replace most of the existing revenue recognition requirements in GAAP when it becomes effective. The guidance in ASU No. 2014-09 is effective for public entities for annual reporting periods beginning after December 15, 2016, including interim periods therein. Early adoption is not permitted. The Company is currently evaluating the method of adoption and impact this standard will have on its financial statements and related disclosures.

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 six months ended June 30, 2014, the Company transferred \$12,940 from unevaluated properties to the full cost pool related to 8,028 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. As of June 30, 2014, net of these expirations, Callon had a remaining net acreage position in the Northern Midland Basin of 9,480 acres which the Company is still evaluating for 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		Six Months Ended	
	June 30, 2014	2013	June 30, 2014	2013
Net income (loss)	\$ 4,740	\$ 758	\$ 6,603	\$ (42)
Preferred stock dividends	(1,973)	(680)	(3,947)	(680)
Income (loss) available to common stockholders	\$ 2,767	\$ 78	\$ 2,656	\$ (722)
Weighted average shares outstanding	40,606	40,089	40,467	39,941
Dilutive impact of restricted stock	999	234	1,185	—
Weighted average shares outstanding for diluted income (loss) per share	41,605	40,323	41,652	39,941
Basic income (loss) per share	\$ 0.07	\$ 0.00	\$ 0.07	\$ (0.02)
Diluted income (loss) per share	\$ 0.07	\$ 0.00	\$ 0.06	\$ (0.02)

The following were excluded from the diluted earnings per share calculation because their effect would be anti-dilutive:

Stock options	30	52	30	52
Restricted stock	—	267	—	267

Footnotes to the Financial Statements (continued)

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(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 4 – Borrowings

The Company's borrowings consisted of the following at:

	June 30, 2014	December 31, 2013
Principal components:		
Senior secured revolving credit facility	\$ 84,000	\$ 22,000
Second lien term loan facility	82,500	—
13% Senior Notes, principal	—	48,481
Total principal outstanding	166,500	70,481
13% Senior Notes unamortized deferred credit	—	5,267
Total carrying value of borrowings	\$ 166,500	\$ 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 with a maturity date 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. The total notional amount available under the Credit Facility is \$500,000. Amounts borrowed under the Credit Facility may not exceed the borrowing base, which is generally reviewed on a semi-annual basis. In June 2014, the Credit Facility's borrowing base was increased to \$155,000 following a redetermination based upon a May 1, 2014 internally estimated reserve report. Subsequent redeterminations are scheduled to occur at six month intervals beginning on September 1, 2014. The Credit Facility is secured by first preferred mortgages covering the Company's major producing properties.

As of June 30, 2014, the balance outstanding on the Credit Facility was \$84,000 with a weighted-average interest rate of 2.43%, calculated as the 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”)

In connection with the Credit 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 or preferred stock is issued. The Second Lien Facility may be prepaid at the Company’s option, subject to a prepayment premium. The prepayment amount 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.

On April 10, 2014, the Company drew an initial amount of \$62,500 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. 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. As of June 30, 2014, the balance outstanding on the Second Lien Facility was \$82,500 with an interest rate of 8.75%, calculated at a rate of LIBOR (subject to a floor rate of 1.0%) plus 7.75% per annum.

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 resulted in a net \$3,205 gain on the early extinguishment of debt (including \$4,780 of accelerated deferred credit amortization). The gain represents the difference between the \$50,057 paid for the redemption of the Senior Notes (\$1,576 of redemption costs, primarily the call premium) and the carrying value of the remaining

Footnotes to the Financial Statements (continued)

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(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)

Senior Notes of \$53,261 (inclusive of \$4,780 of deferred credit). The Company also paid \$193 in accrued interest through the redemption date. Upon the redemption, the indenture governing the Senior Notes was discharged in accordance with its terms.

Restrictive covenants

The Company's Credit Facility and Second Lien Facility contain various covenants including restrictions on additional indebtedness, payment of cash dividends and maintenance of certain financial ratios. The Company was in compliance with these covenants at June 30, 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 collars, swaps, puts, calls 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 instruments 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 contracts 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 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 elected not to designate its derivative contracts as accounting hedges under Accounting Standards Codification 815. Consequently, the Company records its derivative contracts at fair value in the consolidated balance sheet and records changes in fair value as a gain or loss on derivative contracts in the consolidated statement of operations. Cash settlements are also recorded as gain or loss on derivative contracts in the consolidated statement of operations.

Footnotes to the Financial Statements (continued)

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(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 table reflects the fair value of the Company's derivative instruments for the periods presented:

Commodity	Balance Sheet Presentation		Asset Fair Value		Liability Fair Value		Net Derivative Fair Value	
	Classification	Line Description	06/30/14	12/31/2013	06/30/2014	12/31/2013	06/30/2014	12/31/2013
Natural gas	Current	Fair value of derivatives	\$ —	\$ —	\$ (114)	\$ —	\$ (114)	\$ —
Natural gas	Current	Other current assets	—	60	—	—	—	60
Natural gas	Non-current	Other long-term liabilities	—	—	(29)	(72)	(29)	(72)
Oil	Current	Fair value of derivatives	—	—	(5,192)	(1,036)	(5,192)	(1,036)
Oil	Non-current	Other long-term assets	851	—	—	—	851	—
Oil	Non-current	Other long-term liabilities	—	—	(1,242)	—	(1,242)	—
	Totals		\$ 851	\$ 60	\$ (6,577)	\$ (1,108)	\$ (5,726)	\$ (1,048)

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 in the consolidated balance sheet. The following presents the impact of this presentation to the Company's recognized assets and liabilities at June 30, 2014:

	Presented without	Effects of	As Presented with
	Effects of	Netting	Effects of
	Netting	of	Netting
	Netting	Netting	Netting
Current assets: Fair value of derivatives	\$ 26	\$ (26)	\$ —
Long-term assets: Fair value of derivatives	851	—	851
Current liabilities: Fair value of derivatives	(5,332)	26	(5,306)
Long-term liabilities: Fair value of derivatives	\$ (1,271)	\$ —	\$ (1,271)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Natural gas derivatives				
Net loss on settlements	\$ (77)	\$ (156)	\$ (179)	\$ (107)
Net gain (loss) on fair value adjustments	58	485	(132)	97
Total gain (loss)	\$ (19)	\$ 329	\$ (311)	\$ (10)
 Oil derivatives				
Net gain (loss) on settlements	\$ (1,569)	\$ 849	\$ (2,341)	\$ 1,422
Net gain (loss) on fair value adjustments	(3,097)	803	(4,546)	151
Total gain (loss)	\$ (4,666)	\$ 1,652	\$ (6,887)	\$ 1,573
 Total gain (loss) on derivative instruments	\$ (4,685)	\$ 1,981	\$ (7,198)	\$ 1,563

Footnotes to the Financial Statements (continued)

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(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)

Derivative positions

Listed in the tables below are the outstanding oil and natural gas derivative contracts as of June 30, 2014:

	For the Six Months Ending December 31, 2014	For the Year Ending December 31, 2015
Oil contracts		
Collar contracts combined with short puts (three-way collar):		
Volume (MBbls)	—	317
Price per Bbl		
Ceiling (short call)	—	\$ 99.10
Floor (long put)	—	\$ 90.00
Short put	—	\$ 75.00
Swap contracts:		
Total volume (MBbls)	304	—
Weighted average price per Bbl	\$ 95.10	—
Put spreads:		
Volume (MBbls)	—	276
Long put price per Bbl	—	\$ 90.00
Short put price per Bbl	—	\$ 75.00
Swap contracts combined with short put:		
Volume (MBbls)	184	—
Swap price per Bbl	\$ 93.35	—
Short put price per Bbl	\$ 70.00	—
	For the Six Months Ending December 31, 2014	For the Year Ending December 31, 2015
Natural gas contracts		

Call contracts:

Volume (MMBtu)	230	—
Short call price per MMBtu (a)	\$ 4.75	—
Long call price per MMBtu (a)	\$ 4.75	—

Swap contracts combined with short calls:

Swap volume (MMBtu)	368	—
Swap price per MMBtu	\$ 4.25	—
Short call volume (MMBtu)	—	438
Short call price per MMBtu	—	\$ 5.00

(a) Offsetting contracts.

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 in the consolidated balance sheet. The carrying amount of floating-rate debt approximated fair value because the interest rates were variable and reflective of market rates.

Footnotes to the Financial Statements (continued)

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(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 table summarizes the respective carrying and fair values at:

	June 30, 2014		December 31, 2013	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Credit Facility	\$ 84,000	\$ 84,000	\$ 22,000	\$ 22,000
Second Lien Facility	82,500	82,500	—	—
13% Senior Notes due 2016 (a)	—	—	53,748	50,299
Total	\$ 166,500	\$ 166,500	\$ 75,748	\$ 72,299

(a) Fair value is calculated only in relation to the \$48,481 principal outstanding of the Senior Notes at December 31, 2013 and excludes the remaining \$5,267 deferred credit. The fair value of the Senior Notes, which is valued using Level 2 inputs, is based upon estimates provided by an independent investment banking firm. 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 in the consolidated balance sheet. The following methods and assumptions were used to estimate fair value:

Commodity derivative instruments. The fair value of commodity derivative instruments is derived using an income approach 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.

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

June 30, 2014	Balance Sheet Presentation	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments (non-current)	Other long-term assets	\$ —	\$ 851	\$ —	\$ 851
Sub-total assets		\$ —	\$ 851	\$ —	\$ 851
Liabilities					
Derivative financial instruments (current)	Fair value of derivatives	\$ —	\$ (5,306)	\$ —	\$ (5,306)
Derivative financial instruments (non-current)	Other long-term liabilities	—	(1,271)	—	(1,271)
Sub-total liabilities		\$ —	\$ (6,577)	\$ —	\$ (6,577)
Total net assets (liabilities)		\$ —	\$ (5,726)	\$ —	\$ (5,726)
December 31, 2013					
Assets					
Derivative financial instruments (current)	Other current assets	\$ —	\$ 60	\$ —	\$ 60
Sub-total assets		\$ —	\$ 60	\$ —	\$ 60
Liabilities					
Derivative financial instruments (current)	Fair 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 assets (liabilities)		\$ —	\$ (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 June 30, 2014.

Footnotes to the Financial Statements (continued)

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(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 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 non-deductible executive compensation expenses and state income taxes. The effective tax rate for the six months ended June 30, 2014 and 2013 was 45% and 109%, respectively.

Note 8 - Asset Retirement Obligations

The table below summarizes the Company's asset retirement obligations activity for the six months ended June 30, 2014:

Asset retirement obligations at January 1, 2014	\$ 6,732
Accretion expense	401
Liabilities incurred	404
Liabilities settled	(1,747)
Revisions to estimate	(192)
Asset retirement obligations at end of period	5,598
Less: Current asset retirement obligations	2,846
Long-term asset retirement obligations at June 30, 2014	\$ 2,752

Certain of the Company's operating agreements require that assets be restricted for abandonment obligations. Amounts recorded in the consolidated balance sheets as restricted investments were \$3,806 at June 30, 2014. 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 June 30, 2014, the Board declared a dividend of \$1.25 per share, or a total of \$1,973, on the Company's Preferred Stock. Dividends for the six months ended June 30, 2014 were \$3,947.

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 \$11.65 per share on June 30, 2014, the Company has reserved 6,776,601 shares of its total authorized shares to satisfy a potential conversion that would be subject to the satisfaction of several conditions, including a change of control as defined in description of Preferred Stock.

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 in April 2016. In April 2014, the Company contracted an additional horizontal drilling rig (the "Cactus 2 Rig") for a term of two years ending in 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 \$18,111 (with \$9,200 remaining at June 30, 2014), \$18,250 and \$4,795, respectively.

Footnotes to the Financial Statements (continued)

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(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)

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.

Subsequent Events

In August 2014, the Company signed a one-year contract for a vertical drilling rig to be used as part of our horizontal drilling program, drilling the vertical component of horizontal wells. Lease payments in 2014 and 2015 are expected to approximate \$1,656 and \$4,914, respectively, subject to customary termination provisions.

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

Special Note Regarding Forward Looking Statements

All statements, other than statements of historical fact, 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 similar words.

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 regulation of endangered species, 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.

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.

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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 to date have been 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 84% oil and 16% natural gas for the six months ended June 30, 2014. On June 30, 2014, our net acreage position in the Permian Basin was approximately 25,208 net acres, including 9,480 exploratory net acres in the Northern Midland Basin.

Recent Developments

Redemption of Senior Notes

On April 11, 2014, the Company redeemed the remaining \$48.5 million aggregate principal amount of its outstanding Senior Notes at a redemption price of 103.25% plus accrued and unpaid interest (approximately \$50.3 million, including \$0.2 million in accrued interest).

Acceleration of Horizontal Development Program

The Company recently entered into a one-year contract for a vertical drilling rig that will be used to drill the vertical sections of horizontal wells and facilitate the acceleration of its horizontal development program. The Company will take delivery of the rig in October 2014.

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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 182% and 178% for the three and six months ended June 30, 2014, respectively, compared to the same periods of 2013 increasing to 480 MBOE from 170 MBOE and 873 MBOE from 314 MBOE for the comparative three and six months periods, respectively.

	Net Production (MBOE)			
	Three Months Ended June 30,			
	2014	2013	Change	% Change
Onshore:				
Southern Midland Basin	372	122	250	205%
Central Midland Basin	103	48	55	114%
Northern Midland Basin	5	—	5	100%
Total Permian	480	170	310	182%
Offshore and other (a)	—	159	(159)	(100)%
Total	480	329	151	46%

	Net Production (MBOE)			
	Six Months Ended June 30,			
	2014	2013	Change	% Change
Onshore:				
Southern Midland Basin	688	216	472	218%
Central Midland Basin	174	98	76	78%
Northern Midland Basin	11	—	11	100%
Total Permian	873	314	559	178%
Offshore and other (a)	—	344	(344)	(100)%
Total	873	658	215	33%

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

The following table sets forth productive wells as of June 30, 2014:

	Oil Wells		Natural Gas Wells	
	Gross	Net	Gross	Net
Working interest	146	123.8	—	—
Royalty interest	3	0.0	—	—
Total	149	123.8	—	—

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.

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The following table summarizes the Company's drilling progress in the Permian Basin for the six months ended June 30, 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	13	12.1	12	11.3	4	3.8
Total	14	13.1	13	12.3	4	3.8
Central Midland Basin						
Vertical wells	2	0.8	1	0.4	1	0.4
Horizontal wells	2	1.7	4	3.4	—	—
Total	4	2.5	5	3.8	1	0.4
Northern Midland Basin						
Vertical wells	2	1.5	1	0.8	—	—
Total	2	1.5	1	0.8	—	—
Total vertical wells	5	3.3	3	2.2	1	0.4
Total horizontal wells	15	13.7	16	14.6	4	3.8
Total	20	17.1	19	16.8	5	4.2

(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.

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.

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 forecast production volumes and commodity prices. Over 95% of our current 2014 capital program is allocated to properties we operate and, as a result, the amount and timing of a substantial portion of our planned capital expenditures is largely discretionary in the event we determine it prudent to curtail drilling and completion operations due to capital constraints.

Cash and cash equivalents decreased \$1.8 million in the six months ended June 30, 2014 to \$1.2 million compared to \$3.0 million at December 31, 2013. At June 30, 2014, our available liquidity, inclusive of undrawn amounts on our Credit Facility (\$71.0 million) and Second Lien Facility (\$17.5 million), increased to \$89.7 million, a \$25.7 million increase over year-end 2013. This liquidity amount excludes \$25 million of availability under the Second Lien Facility, which is subject to lender consent and compliance with a maximum financial leverage covenant.

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Liquidity and cash flow

	Six Months Ended	
	June 30,	
	2014	2013
Net cash provided by operating activities	\$ 35.6	\$ 20.2
Net cash used in investing activities	(125.0)	(67.4)
Net cash provided by financing activities	87.5	59.4
Net change in cash	\$ (1.9)	\$ 12.3

Operating activities. For the six months ended June 30, 2014, net cash provided by operating activities was \$35.6 million, compared to \$20.2 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 the settlement of derivative contracts, 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 six months ended June 30, 2014, net cash used in investing activities was \$125.0 million compared to \$67.4 million for the same period in 2013. The \$57.6 million increase in cash used in investing activities was primarily attributable to a \$68.8 million increase in drilling and completion activities in the Permian Basin driven by the addition of a second horizontal drilling rig in August 2013 and acreage acquisitions. Offsetting these increases was an \$11.0 million acquisition completed in the 2013 period.

Capital expenditures for the six months ended June 30, 2014 include the following (in millions):

Southern Midland Basin	\$ 84
Central Midland Basin	27
Total operational expenditures	111
Capitalized general and administrative costs allocated directly to exploration and development projects	6
Capitalized interest	1
Total capitalized expenses	7
Total operational expenditures inclusive of capitalized amounts	118
Acquisitions	9
Total capital expenditures	\$ 127

Financing activities. For the six months ended June 30, 2014, net cash provided by financing activities was \$87.5 million compared to cash provided by financing activities of \$59.4 million during the same period of 2013. Net cash provided by financing activities during the six months ended June 30, 2014 included a net \$139.9 million of borrowings on our Credit Facility and Second Lien Facility offset by a \$50.1 million redemption of our Senior Notes. In addition the Company paid approximately \$3.9 million in preferred stock dividends.

2014 capital expenditures

Our 2014 operational capital budget approximates \$215 million, excluding acquisitions completed in 2014 (see Note 2) and capitalized expenses. This budgeted amount includes plans to drill up to 30 gross (25.3 net) horizontal and seven gross (4.7 net) vertical wells, while completing 31 gross (26.7 net) horizontal and five gross (3.3 net) vertical wells. Our initial operational capital budget was established at \$185 million, and has been subsequently adjusted for the items below.

In the first half 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 our enhanced completion designs create the potential for increased total returns on capital after adjusting for incremental costs of approximately \$0.5 million to \$0.8 million per completion depending on the depth of the well. While we continue to monitor the effectiveness of our enhanced completion designs, we increased our 2014 operational budget to include the incremental change in costs for the completion designs by approximately \$10 million for this initiative.

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We also recently commenced drilling a horizontal well in partnership with a large public company at our recently acquired acreage in Upton County. This non-operated well, of which we own a 57% working interest, is estimated to cost approximately \$5.5 million on a net basis.

As described in Subsequent Events, we signed an agreement for a drilling rig to be used in our horizontal development program. We currently forecast that this initiative will add approximately \$9 million to our original operational capital budget.

The remaining difference, approximately \$5.5 million, is primarily due to a higher number of scheduled completions resulting from modifications to our original drilling schedule. We currently intend to complete 26.7 net horizontal wells relative to 24.7 net wells in our previous forecast.

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Results of Operations

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

	Three Months Ended June 30,			
	2014	2013	Change	% Change
Net production:				
Oil (MBbls)				