CALLON PETROLEUM CO
Form 10-Q
August 08, 2016

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM
10-Q

Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For The Quarterly Period Ended June 30, 2016

OR

Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from ____________ to ____________

Commission File Number 001-14039

Callon Petroleum Company

(Exact Name of Registrant as Specified in Its Charter)

Delaware	64-0844345
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification No.)
200 North Canal Street	
Natchez, Mississippi	
(Address of Principal Executive Offices)	39120 (Zip Code)

601-442-1601

(Registrant's Telephone Number, Including Area Code)

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 the definitions 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	(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

The Registrant had 131,136,233 shares of common stock outstanding as of August 1, 2016.

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DEFINITIONS

All defined terms under Rule 4-10(a) of Regulation S-X shall have their 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.
- 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.
- BBtu: billion Btu.
- 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.
- GAAP: Generally Accepted Accounting Principles in the United States.
- Henry Hub: A natural gas pipeline delivery point that serves as the benchmark natural gas price underlying NYMEX natural gas futures contracts.
- LIBOR: London Interbank Offered Rate.
- LOE: lease operating expense.
- MBbls: thousand barrels of oil.
- MBOE: thousand BOE.
- Mcf: thousand cubic feet of natural gas.
- MMBtu: million Btu.
- MMcf: million cubic feet of natural gas.
- 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.
- WTI: West Texas Intermediate grade crude oil, used as a pricing benchmark for sales contracts and NYMEX oil futures contracts.

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, 2016 Unaudited	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 207	$ 1,224
Accounts receivable	44,460	39,624
Fair value of derivatives	5,537	19,943
Other current assets	1,766	1,461
Total current assets	51,970	62,252
Oil and natural gas properties, full cost accounting method:		
Evaluated properties	2,530,978	2,335,223
Less accumulated depreciation, depletion, amortization and impairment	(1,883,806)	(1,756,018)
Net oil and natural gas properties	647,172	579,205
Unevaluated properties	379,605	132,181
Total oil and natural gas properties	1,026,777	711,386
Other property and equipment, net	9,971	7,700
Restricted investments	3,323	3,309
Deferred financing costs	3,076	3,642
Fair value of derivatives	60	—
Other assets, net	413	305
Total assets	$ 1,095,590	$ 788,594
LIABILITIES AND STOCKHOLDERS’ EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 71,960	$ 70,970
Accrued interest	6,258	5,989
Cash-settleable restricted stock unit awards	5,168	10,128
Asset retirement obligations	3,933	790
Fair value of derivatives	7,491	—
Total current liabilities	94,810	87,877
Senior secured revolving credit facility	40,000	40,000
Secured second lien term loan, net of unamortized deferred financing costs	289,559	288,565
Asset retirement obligations	2,164	4,317
Cash-settleable restricted stock unit awards	4,141	4,877
Fair value of derivatives	6,313	—
Other long-term liabilities	286	200

Total liabilities	437,273	425,836
Stockholders’ equity:		
Preferred stock, series A cumulative, $0.01 par value and $50.00 liquidation preference, 2,500,000 shares authorized: 1,458,948 and 1,578,948 shares outstanding, respectively	15	16
Common stock, $0.01 par value, 300,000,000 and 150,000,000 shares authorized, respectively; 131,090,644 and 80,087,148 shares outstanding, respectively	1,311	801
Capital in excess of par value	1,112,873	702,970
Accumulated deficit	(455,882)	(341,029)
Total stockholders’ equity	658,317	362,758
Total liabilities and stockholders’ equity	$ 1,095,590	$ 788,594

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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Operating revenues:				
Oil sales	$ 40,555	$ 36,093	$ 67,998	$ 64,002
Natural gas sales	4,590	3,149	7,845	5,631
Total operating revenues	45,145	39,242	75,843	69,633
Operating expenses:				
Lease operating expenses	7,311	6,575	14,268	13,534
Production taxes	2,455	2,952	4,675	5,217
Depreciation, depletion and amortization	16,293	17,587	32,015	35,691
General and administrative	6,302	5,763	11,864	17,865
Accretion expense	395	134	575	343
Write-down of oil and natural gas properties	61,012	—	95,788	—
Rig termination fee	—	—	—	3,641
Acquisition expense	1,906	—	1,954	—
Total operating expenses	95,674	33,011	161,139	76,291
Income (loss) from operations	(50,529)	6,231	(85,296)	(6,658)
Other (income) expense:				
Interest expense, net of capitalized amounts	4,180	5,106	9,671	9,964
Loss on derivative contracts	15,484	8,249	16,416	5,820
Other income, net	(96)	(41)	(177)	(85)
Total other expense	19,568	13,314	25,910	15,699
Loss before income taxes	(70,097)	(7,083)	(111,206)	(22,357)
Income tax benefit	—	(2,116)	—	(7,193)
Net loss	(70,097)	(4,967)	(111,206)	(15,164)
Preferred stock dividends	(1,823)	(1,973)	(3,647)	(3,947)
Loss available to common stockholders	$ (71,920)	$ (6,940)	$ (114,853)	$ (19,111)
Loss per common share:				
Basic	$ (0.61)	$ (0.11)	$ (1.14)	$ (0.31)
Diluted	$ (0.61)	$ (0.11)	$ (1.14)	$ (0.31)
Shares used in computing loss per common share:				
Basic	118,209	66,038	100,895	61,759

Diluted	118,209	66,038	100,895	61,759

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,	
	2016	2015
Cash flows from operating activities:		
Net loss	$ (111,206)	$ (15,164)
Adjustments to reconcile net loss to cash provided by operating activities:		
Depreciation, depletion and amortization	32,827	36,557
Write-down of oil and natural gas properties	95,788	—
Accretion expense	575	343
Amortization of non-cash debt related items	1,561	1,561
Deferred income tax benefit	—	(7,193)
Net loss on derivatives, net of settlements	28,149	21,129
Non-cash expense related to equity share-based awards	(861)	(668)
Change in the fair value of liability share-based awards	2,674	4,695
Payments to settle asset retirement obligations	(319)	(1,905)
Changes in operating assets and liabilities:		
Accounts receivable	(4,836)	(6,946)
Other current assets	(305)	(85)
Current liabilities	4,113	5,549
Change in other long-term liabilities	86	100
Change in other assets, net	(450)	(528)
Payments to settle vested liability share-based awards related to early retirements	—	(3,538)
Payments to settle vested liability share-based awards	(10,300)	(3,925)
Net cash provided by operating activities	37,496	29,982
Cash flows from investing activities:		
Capital expenditures	(75,280)	(129,050)
Acquisitions	(284,024)	(1,797)
Proceeds from sales of mineral interests and equipment	23,631	326
Net cash used in investing activities	(335,673)	(130,521)
Cash flows from financing activities:		
Borrowings on senior secured revolving credit facility	143,000	103,000
Payments on senior secured revolving credit facility	(143,000)	(63,000)
Issuance of common stock, net	300,807	65,546
Payment of preferred stock dividends	(3,647)	(3,947)
Net cash provided by financing activities	297,160	101,599
Net change in cash and cash equivalents	(1,017)	1,060
Balance, beginning of period	1,224	968
Balance, end of period	$ 207	$ 2,028

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

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 onshore, oil and natural gas reserves in the Permian Basin in West Texas. The Company’s operations to date have been predominantly focused on horizontal drilling of several prospective intervals, including multiple levels of the Wolfcamp formation and, more recently, the Lower Spraberry shale in the Midland Basin. Callon has assembled a multi-year inventory of potential horizontal well locations and intends to add to this inventory through delineation drilling of emerging zones on our existing acreage and acquisition of additional locations through working interest acquisitions, acreage purchases, joint ventures and asset swaps.

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 Callon Petroleum 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, 2015. The balance sheet at December 31, 2015 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, 2016.

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. Certain prior year amounts may have been reclassified to conform to current year presentation.

Recently issued accounting policies

In March 2016, the Financial Accounting Standards Board issued accounting standards update No. 2016-09, Compensation – Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting ("ASU 2016-09"). The standard is intended to simplify several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows, and will allow companies to estimate the number of stock awards expected to vest. The guidance in ASU 2016-09 is effective for public entities for annual reporting periods beginning after December 15, 2016, including interim periods therein. Early adoption is permitted and is to be applied on retrospective basis. The Company is currently evaluating the method of adoption and impact this standard may have on its financial statements and related disclosures.

Recently adopted accounting policies

In November 2015, the FASB issued ASU No. 2015-17, Balance Sheet Classification of Deferred Taxes ("ASU 2015-17"), which eliminates the current requirement to present deferred tax liabilities and assets as current and noncurrent amounts on the balance sheet. Instead, entities will be required to classify all deferred tax assets and liabilities as noncurrent on the balance sheet. The guidance in ASU 2015-17 is effective for public entities for annual reporting periods beginning after December 15, 2016, and interim periods within those annual periods. Early application is permitted. As of June 30, 2016, the Company adopted this ASU, which does not have a material impact on its financial statements.

Note 2 – Oil and Natural Gas Properties

The Company uses the full cost method of accounting for its exploration and development activities. Under this method of accounting, the cost of both successful and unsuccessful exploration and development activities are capitalized as oil and gas properties. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals, interest capitalized on unevaluated leases, other costs related to exploration and development activities, and site restoration, dismantlement and abandonment costs capitalized in accordance with asset retirement obligation accounting guidance. Costs capitalized also include any internal costs that are directly related to exploration and development activities, including salaries and benefits, but do not include any costs related to production, general corporate overhead or similar activities.

Under full cost accounting rules, the Company reviews the carrying value of its proved oil and natural gas properties each quarter. Under these rules, capitalized costs of oil and natural gas properties, net of accumulated depreciation, depletion and amortization and deferred income taxes, may not exceed the present value of estimated future net cash flows from proved oil and natural gas reserves, discounted at 10%, plus the lower of cost or fair value of unevaluated properties, net of related tax effects (the full cost ceiling). These rules require pricing based on the preceding 12-months' average oil and natural gas prices based on closing prices on the first day of each month and require a write-down if the net capitalized costs of proved oil and natural gas properties exceeds the full cost ceiling. At June 30, 2016, the prices used in determining the estimated future net cash flows from proved reserves were $40.62 per barrel of oil and $2.46 per Mcf of natural gas. For the three and six months ended June 30, 2016, the Company recognized write-downs of oil and natural gas properties of $61,012 and $95,788, respectively, as a result of the ceiling test limitation.

Note 3 - Acquisitions

Acquisitions were accounted for under the acquisition method of accounting, which involves determining the fair value of the assets acquired and liabilities assumed under the income approach.

2016 acquisitions

On May 26, 2016, the Company completed the acquisition of 17,298 gross (14,089 net) acres primarily located in Howard County, Texas from BSM Energy LP, Crux Energy LP and Zaniah Energy LP, for total cash consideration of $220,000 and 9,333,333 shares of common stock for a total purchase price of $329,573, excluding customary purchase price adjustments (the "Big Star Transaction"). The Company acquired an 81% average working interest (61% average net revenue interest) in the properties acquired in the Big Star Transaction.

The preliminary purchase price allocation is subject to change based on numerous factors, including the final adjusted purchase price and the final estimated fair value of the assets acquired and liabilities assumed. Any such adjustments to the preliminary estimates of fair value could be material. The following table summarizes the estimated acquisition date fair values of the net assets to be acquired in the acquisition (in thousands):

Oil and natural gas properties	$ 96,194
Unevaluated oil and natural gas properties	233,387
Asset retirement obligations	(8)
Net assets acquired	$ 329,573

The following unaudited summary pro forma financial information for the three and six months ended June 30, 2016 has been presented for illustrative purposes only and does not purport to represent what the Company's results of operations would have been if the Big Star Transaction had occurred as presented, or to project the Company's results of operations for any future periods. The pro forma financial information was prepared assuming the Big Star Transaction occurred as of January 1, 2015. The pro forma adjustments are based on available information and certain assumptions that management believes are reasonable, including those pertaining to revenue, lease operating expenses, production taxes, depreciation, depletion and amortization expense, accretion expense, interest expense and capitalized interest.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Revenues	$ 48,937	$ 45,047	$ 85,010	$ 78,060
Income from operations	(50,004)	6,179	(85,405)	(7,695)
Income available to common stockholders	(68,452)	(3,011)	(108,202)	(12,176)
Net income per common share:				
Basic	$ (0.58)	$ (0.03)	$ (1.07)	$ (0.13)
Diluted	$ (0.58)	$ (0.03)	$ (1.07)	$ (0.13)

From the date of the acquisition through the period ended June 30, 2016, the properties associated with the Big Star Transaction have been comingled with our existing properties and it is impractical to provide the stand-alone operational results related to these properties.

On May 16, 2016, the Company completed the following transactions (collectively, the "AMI Transaction") for an aggregate cash purchase price of $33,012, excluding customary purchase price adjustments. Key elements of the AMI Transaction include:

- Formation of an area of mutual interest with TRP Energy, LLC ("TRP") in western Reagan County, Texas, through the joint acquisition from a private party of 4,745 net acres (with a 55% share to Callon) north of the Garrison Draw field; and
- Callon's simultaneous sale of a 27.5% interest in the Garrison Draw field to TRP.

The following table summarizes the acquisition date fair values of the net assets acquired, including customary purchase price adjustments:

Oil and natural gas properties	$ 15,951
Unevaluated oil and natural gas properties	17,069
Asset retirement obligations	(8)
Net assets acquired	$ 33,012

On January 18, 2016, the Company completed the acquisition of an additional 4.9% working interest (3.7% net revenue interest) in the Casselman-Bohannon fields for an aggregate cash purchase price of $10,183, including customary purchase price adjustments. Following the completion of this acquisition the Company owned 71.3% working interest (53.5% net revenue interest) in the Casselman-Bohannon fields. The following table summarizes the acquisition date fair values of the net assets acquired, including customary purchase price adjustments:

Oil and natural gas properties	$ 5,527
Unevaluated oil and natural gas properties	4,656
Net assets acquired	$ 10,183

Subsequent event

On August 3, 2016, the Company entered into a definitive purchase and sale agreement for the acquisition of an additional 4.0% working interest (3.0% net revenue interest) in the Casselman-Bohannon fields for total cash consideration of $13,000, excluding customary purchase price adjustments, with an effective date of August 1, 2016. Following the completion of this acquisition the Company will own approximately 75.3% working interest (58.5% net revenue interest) in the Casselman-Bohannon fields.

Note 4 - Earnings Per Share

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

(share amounts in thousands)	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015

Net loss	$ (70,097)	$ (4,967)	$ (111,206)	$ (15,164)
Preferred stock dividends	(1,823)	(1,973)	(3,647)	(3,947)
Loss available to common stockholders	$ (71,920)	$ (6,940)	$ (114,853)	$ (19,111)
Weighted average shares outstanding	118,209	66,038	100,895	61,759
Dilutive impact of restricted stock	—	—	—	—
Weighted average shares outstanding for diluted loss per share	118,209	66,038	100,895	61,759
Basic loss per share	$ (0.61)	$ (0.11)	$ (1.14)	$ (0.31)
Diluted loss per share	$ (0.61)	$ (0.11)	$ (1.14)	$ (0.31)
Stock options (a)	15	15	15	15
Restricted stock (a)	36	284	36	284

(a) Shares excluded from the diluted earnings per share calculation because their effect would be anti-dilutive.

Note 5 - Borrowings

The Company’s borrowings consisted of the following at:

	June 30, 2016	December 31, 2015
Principal components		
Senior secured revolving credit facility	$ 40,000	$ 40,000
Secured second lien term loan	300,000	300,000
Total principal outstanding	340,000	340,000
Secured second lien term loan, unamortized deferred financing costs	(10,441)	(11,435)
Total carrying value of borrowings	$ 329,559	$ 328,565

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 participants include several institutional lenders. 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. As of June 30, 2016, the Credit Facility's borrowing base was $300,000. The Credit Facility is secured by first preferred mortgages covering the Company's major producing properties.

As of June 30, 2016, there was a $40,000 balance outstanding on the Credit Facility. For the quarter ended June 30, 2016, the Credit Facility had a weighted-average interest rate of 2.21%, 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.

Effective July 13, 2016, the Credit Facility's borrowing base was increased to $385,000 and the Company's capacity to hedge oil and natural gas volumes was effectively increased with a change in the capacity calculation to a percentage of total proved reserves from proved producing reserves. In addition, the interest rate for borrowings under the Credit Facility was increased 0.25% across all tiers of the pricing grid, resulting in a range of interest costs equal to LIBOR plus 2.00% to 3.00%. There were no modifications to other terms or covenants of the Credit Facility.

Secured second lien term loan (the "Term Loan")

On October 8, 2014, the Company entered into the Term Loan with an aggregate amount of up to $300,000 and a maturity date of October 8, 2021. The Royal Bank of Canada is Administrative Agent, and participants include several institutional lenders. The Term Loan may be prepaid at the Company's option, subject to a prepayment premium. The prepayment amount (i) is 102% if the prepayment event occurs prior to October 8, 2016, (ii) 101% if the prepayment event occurs on or after October 8, 2016 but before October 8, 2017, and (iii) is 100% for prepayments made on or after October 8, 2017. The Term Loan is secured by junior liens on properties mortgaged under the Credit Facility, subject to an intercreditor agreement.

As of June 30, 2016, the balance outstanding on the Term Loan was $300,000 with an interest rate of 8.5%, calculated at a rate of LIBOR (subject to a floor rate of 1.0%) plus 7.5% per annum. The Company can elect a LIBOR rate based on various tenors, and is currently incurring interest based on an underlying three-month LIBOR rate, which was last elected in July 2016.

Restrictive covenants

The Company's Credit Facility and Term Loan 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, 2016.

Note 6 - 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 the fair value of a derivative instrument; see Note 7 for additional information regarding fair value.

(All dollar amounts in thousands, except per share and per unit data)

The Company executes commodity derivative contracts under master agreements that have netting provisions that provide for offsetting assets against liabilities. 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, the Company utilizes present value methods that include assumptions about commodity prices based on those observed in underlying markets. See Note 7 for additional information regarding fair value.

Derivatives not designated as hedging instruments

The Company records its derivative contracts at fair value in the consolidated balance sheets and records changes in fair value as a gain or loss on derivative contracts in the consolidated statements of operations. Cash settlements are also recorded as gain or loss on derivative contracts in the consolidated statements of operations.

The following table reflects the fair value 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	06/30/2016	12/31/2015	06/30/2016	12/31/2015	06/30/2016	12/31/2015
Natural gas	Current	Fair value of derivatives	$ —	$ —	$ (545)	$ —	$ (545)	$ —
Oil	Current	Fair value of derivatives	5,537	19,943	(6,946)	—	(1,409)	19,943
Oil	Non-current	Fair value of derivatives	60	—	(6,313)	—	(6,253)	—
	Totals		$ 5,597	$ 19,943	$ (13,804)	$ —	$ (8,207)	$ 19,943

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 for the periods indicated:

	June 30, 2016		
	Presented without Effects of Netting	Effects of Netting	As Presented with Effects of Netting
Current assets: Fair value of derivatives	$ 5,655	$ (118)	$ 5,537
Long-term assets: Fair value of derivatives	60	—	60
Current liabilities: Fair value of derivatives	(7,609)	118	(7,491)
Long-term liabilities: Fair value of derivatives	$ (6,313)	$ —	$ (6,313)

	December 31, 2015		
	Presented without Effects of Netting	Effects of Netting	As Presented with Effects of Netting
Current assets: Fair value of derivatives	$ 19,943	$ —	$ 19,943

(All dollar amounts in thousands, except per share and per unit data)

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,	
	2016	2015	2016	2015
Oil derivatives				
Net gain on settlements	$ 3,707	$ 4,511	$ 11,214	$ 14,464
Net loss on fair value adjustments	(18,466)	(12,755)	(27,604)	(20,544)
Total loss	$ (14,759)	$ (8,244)	$ (16,390)	$ (6,080)
Natural gas derivatives				
Net gain on settlements	$ 310	$ 454	$ 519	$ 845
Net loss on fair value adjustments	(1,035)	(459)	(545)	(585)
Total gain (loss)	$ (725)	$ (5)	$ (26)	$ 260
Total loss on derivative contracts	$ (15,484)	$ (8,249)	$ (16,416)	$ (5,820)

Derivative positions

Listed in the tables below are the outstanding oil and natural gas derivative contracts as of June 30, 2016:

Oil contracts	For the Remainder of 2016	For the Full Year of 2017
Swap contracts (WTI)		
Total volume (MBbls)	460	—
Weighted average price per Bbl	$ 58.10	$ —
Swap contracts combined with short puts (WTI, enhanced swaps)		
Total volume (MBbls)		730
Weighted average price per Bbl		
Swap	$ —	$ 44.50
Short put option	$ —	$ 30.00
Collar contracts combined with short puts (WTI, three-way collars)		
Volume (MBbls)	276	—
Weighted average price per Bbl		
Ceiling (short call option)	$ 63.33	$ —

Floor (long put option)	$ 53.33	$ —
Short put option	$ 38.77	$ —
Collar contracts (WTI, two-way collars)		
Total volume (MBbls)	368	438
Weighted average price per Bbl		
Ceiling (short call)	$ 46.50	$ 59.05
Floor (long put)	$ 37.50	$ 47.50
Call option contracts (short position)		
Total volume (MBbls)	—	670
Weighted average price per Bbl		
Call strike price	$ —	$ 50.00
Swap contracts (Midland basis differentials)		
Volume (MBbls)	736	—
Weighted average price per Bbl	$ 0.17	$ —
Natural gas contracts		
Swap contracts (Henry Hub)		
Total volume (BBtu)	1,104	—
Weighted average price per MMBtu	$ 2.52	$ —

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Subsequent event

The following derivative contract was executed subsequent to June 30, 2016:

Natural gas contracts	For the Remainder of 2016	For the Remainder of 2017
Collar contracts combined with short puts (Henry Hub, three-way collars)		
Total volume (BBtu)	—	1,460
Weighted average price per MMBtu		
Ceiling (short call option)	$ —	$ 3.71
Floor (long put option)	$ —	$ 3.00
Short put option	$ —	$ 2.50

Note 7 - Fair Value Measurements

The fair value hierarchy included in GAAP 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, and restricted investments. The carrying amounts for these instruments approximate fair value due to the short-term nature or maturity of the instruments.

Debt. The carrying amount of the Company's floating-rate debt approximated fair value because the interest rates were variable and reflective of market rates.

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. 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 6 for additional information regarding the Company's derivative instruments.

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

June 30, 2016	Classification	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments	Fair value of derivatives	$ —	$ 5,597	$ —	$ 5,597
Liabilities					
Derivative financial instruments	Fair value of derivatives	—	(13,804)	—	(13,804)
Total net assets		$ —	$ (8,207)	$ —	$ (8,207)

December 31, 2015	Classification	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments	Fair value of derivatives	$ —	$ 19,943	$ —	$ 19,943
Liabilities					
Derivative financial instruments	Fair value of derivatives	—	—	—	—
Total net assets		$ —	$ 19,943	$ —	$ 19,943

(All dollar amounts in thousands, except per share and per unit data)

Assets and liabilities measured at fair value on a nonrecurring basis

Acquisitions. As discussed in Note 3, the Company completed three acquisitions during the six months ended June 30, 2016. The Company determined the fair value of the assets acquired using the income approach based on expected future cash flows from estimated reserve quantities, costs to produce and develop reserves, and oil and gas forward prices. The fair value measurements were based on level 2 and level 3 inputs.

Note 8 - Income Taxes

The Company typically 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. As a result of the write-down of oil and natural gas properties in the latter part of 2015 the Company incurred a cumulative three year loss. Because of the impact the cumulative loss has on the determination of the recoverability of deferred tax assets through future earnings, the Company assessed the ability to realize its deferred tax assets based on the future reversals of existing deferred tax liabilities. Accordingly, the Company established a valuation allowance for a portion of the deferred tax asset. The valuation allowance was $147,540 as of June 30, 2016.

Note 9 - Asset Retirement Obligations

The table below summarizes the Company’s asset retirement obligations activity for the six months ended June 30, 2016:

Asset retirement obligations at January 1, 2016	$	5,107
Accretion expense		575
Liabilities incurred		7
Liabilities settled		(459)
Revisions to estimate		867
Asset retirement obligations at end of period		6,097
Less: Current asset retirement obligations		(3,933)
Long-term asset retirement obligations at June 30, 2016	$	2,164

Certain of the Company's operating agreements require that assets be restricted for abandonment obligations. Amounts recorded in the consolidated balance sheet at June 30, 2016 as long-term restricted investments were $3,323. These assets, which primarily include short-term U.S. Government securities, are held in abandonment trusts dedicated to pay future abandonment costs.

Note 10 - Equity Transactions

10% Series A Cumulative Preferred Stock ("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. Preferred Stock dividends were $1,823 and $1,973 for the three months ended June 30, 2016 and 2015, respectively, and $3,647 and $3,947 for the six months ended June 30, 2016 and 2015, respectively.

The Preferred Stock has no stated maturity and is not subject to any sinking fund or other mandatory redemption. On or after May 30, 2018, the Company may, at its option, redeem the Preferred Stock, in whole or in part, by paying $50.00 per share in cash, plus any accrued and unpaid dividends to the redemption date.

Following a change of control in which the Company or the acquirer no longer have a class of common securities listed on a national exchange, the Company will have the option to redeem the Preferred Stock, in whole but not in part for $50.00 per share in cash, plus accrued and unpaid dividends (whether or not declared), to the redemption date. If the Company does not exercise its option to redeem the Preferred Stock upon such change of control, the holders of the Preferred Stock have the option to convert the Preferred Stock into a number of shares of the Company's common stock based on the value of the common stock on the date of the change of control as determined under the certificate of designations for the Preferred Stock. If the change of control occurred on June 30, 2016, and the Company did not exercise its right to redeem the Preferred Stock, using the closing price of $11.23 as the value of a share of common stock, each share of Preferred Stock would be convertible into approximately 4.5 shares of common stock. If the Company exercises its redemption rights relating to shares of Preferred Stock, the holders of Preferred Stock will not have the conversion right described above.

On February 4, 2016, the Company exchanged a total of 120,000 shares of Preferred Stock for 719,000 shares of common stock. As of June 30, 2016, the Company had 1,458,948 shares of its Preferred Stock issued and outstanding.

Common stock

On March 9, 2016, the Company completed an underwritten public offering of 15,250,000 shares of its common stock for total net proceeds (after the underwriting discounts and estimated offering costs) of approximately $94,973.

On April 25, 2016, the Company completed an underwritten public offering of 25,300,000 shares of its common stock for total estimated net proceeds (after the underwriter's discounts and commissions and estimated offering expenses) of approximately $205,874. Proceeds from the offering were used to fund the May 2016 acquisitions described in Note 3.

On May 26, 2016, the Company issued 9,333,333 shares of common stock to partially fund the Big Star Transaction, described in Note 3, at an assumed offering price of $11.74 per share, which is the last reported sale price of our common stock on the New York Stock Exchange on that date.

Note 11 - Other

Operating leases

As of June 30, 2016, the Company had contracts for two horizontal drilling rigs (the “Cactus 1 Rig” and “Cactus 2 Rig”). The contract terms of the Cactus 1 Rig and Cactus 2 Rig will end in July 2018 and August 2018, respectively. The rig lease agreements include early termination provisions that obligate the Company to pay reduced minimum rentals for the remaining term of the agreement. These payments would be reduced assuming the lessor is able to re-charter the rig and staffing personnel to another lessee. In January 2016, the Company decided to place its Cactus 1 Rig on standby and is required to pay a “standby” day rate of $15,000 per day, pursuant to the terms of the agreement, allowing the Company to retain the option to return the rig to service under the contract terms.

Special Note Regarding Forward Looking Statements

This report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 (the "Securities Act"), as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These statements involve known and unknown risks, uncertainties and other factors that may 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 some cases, you can identify forward-looking statements in this Form 10-Q by words such as "anticipate," "project," "intend," "estimate," "expect," "believe," "predict," "budget," "pro "goal," "plan," "forecast," "target" or similar expressions.

All statements, other than statements of historical facts, included in this report that address activities, events or developments that we expect or anticipate will or may occur in the future are forward-looking statements, including such things as:

- our oil and gas reserve quantities, and the discounted present value of these reserves;
- the amount and nature of our capital expenditures;
- our future drilling and development plans and our potential drilling locations;
- the timing and amount of future production and operating costs;
- commodity price risk management activities and the impact on our average realized prices;
- business strategies and plans of management;
- our ability to close pending transactions, the anticipated timing and terms of pending transactions, our ability to realize the anticipated benefits of pending transactions, and our ability to manage the risks of pending transactions; and
- prospect development and property acquisitions.

Some of the risks, which could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements, include:

- general economic conditions including the availability of credit and access to existing lines of credit;
- the volatility of oil and natural gas prices;
- the uncertainty of estimates of oil and natural gas reserves;
- the impact of competition;
- the availability and cost of seismic, drilling and other equipment;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- difficulties encountered during the exploration for and production of oil and natural gas;
- difficulties encountered in delivering oil and natural gas to commercial markets;
- changes in customer demand and producers' supply;

- the uncertainty of our ability to attract capital and obtain financing on favorable terms;
- compliance with, or the effect of changes in, the extensive governmental regulations regarding the oil and natural gas business including those related to climate change and greenhouse gases;
- the impact of government regulation, including regulation of endangered species, any increase in severance or similar taxes;
- litigation relating to hydraulic fracturing, the climate and over-the-counter derivatives;
- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
- credit risk relating to the risk of loss as a result of non-performance by our counterparties;
- weather conditions; and
- any other factors listed in the reports we have filed and may file with the SEC.

We caution you that the forward-looking statements contained in this Form 10-Q are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of oil and natural gas. These risks include, but are not limited to, the risks described herein and in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2015 (the "2015 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 herein or in our 2015 Annual Report on Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

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

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

General

The following management's discussion and analysis describes the principal factors affecting the Company's results of operations, liquidity, capital resources and contractual cash obligations. This discussion should be read in conjunction with the accompanying unaudited consolidated financial statements and our 2015 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 Web site address is www.callon.com. All of our filings with the SEC are available free of charge through our Web site as soon as reasonably practicable after we file them with, or furnish them to, the SEC. Information on our Web site 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 operating culture is centered on responsible development of hydrocarbon resources, safety and the environment, which we believe strengthens our operational performance. Our drilling activity is predominantly focused on the horizontal development of several prospective intervals, including multiple levels of the Wolfcamp formation and, more recently, the Lower Spraberry shale. 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 working interest acquisitions, acreage purchases, joint ventures and asset swaps. Our production was approximately 78% oil and 22% natural gas for the six months ended June 30, 2016. On June 30, 2016, our net acreage position in the Permian Basin was approximately 33,734 net acres.

Commodity Prices

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 actions by the Organization of Petroleum Exporting Countries and other countries and government actions. Prices of oil and natural gas will affect the following aspects of our business:

- our revenues, cash flows and earnings;
- the amount of oil and natural gas that we are economically able to produce;
- our ability to attract capital to finance our operations and cost of the capital;
- the amount we are allowed to borrow under our senior secured revolving credit facility; and
- the value of our oil and natural gas properties.

Beginning in the second half of 2014, the NYMEX price for a barrel of oil declined from $105.37 on June 30, 2014 to $40.06 on August 1, 2016. For the three months ended June 30, 2016, the average NYMEX price for a barrel of oil was $45.59 per Bbl compared to $57.95 per Bbl for the same period of 2015. The NYMEX price for a barrel of oil ranged from a low of $35.70 per Bbl to a high of $51.23 per Bbl for the three months ended June 30, 2016.

For the three months ended June 30, 2016, the average NYMEX price for natural gas was $1.95 per MMBtu compared to $2.64 per MMBtu for the same period in 2015. The NYMEX price for natural gas ranged from a low of $1.90 per MMBtu to a high of $2.92 per MMBtu for the three months ended June 30, 2016.

The Company uses the full cost method of accounting for its exploration and development activities. Under full cost accounting rules, the Company reviews the carrying value of its proved oil and natural gas properties each quarter. Under these rules, capitalized costs of oil and natural gas properties, net of accumulated depreciation, depletion and amortization and deferred income taxes, may not exceed the present value of estimated future net cash flows from proved oil and natural gas reserves, discounted at 10%, plus the lower of cost or fair value of unevaluated properties, net of related tax effects (the full cost ceiling). These rules generally require pricing based on the preceding 12-months' average oil and natural gas prices based on closing prices on the first day of each month and require a write-down if the net capitalized costs of proved oil and natural gas properties exceeds the full cost ceiling. At June 30, 2016, the realized prices used in determining the estimated future net cash flows from proved reserves were $40.62 per barrel of oil and $2.46 per Mcf of natural gas (including the value of NGLs in the natural gas stream). For the three and six months ended June 30, 2016, the Company recognized a write-downs of oil and natural gas properties of $61 million and $95.8 million, respectively, as a result of the ceiling test limitation. Based on prevailing commodity prices in the current environment, we expect to incur additional ceiling test write-downs in the future. However, we do not expect such prevailing commodity prices to have significant adverse effects on our proved oil and gas reserves. See Note 2 in the Footnotes to the Financial Statements for more information.

The table below presents the cumulative results of the full cost ceiling test for 2016 as of June 30, 2016, along with various pricing scenarios to demonstrate the sensitivity of our full cost ceiling to changes in 12-month average oil and natural gas prices. This sensitivity analysis is as of June 30, 2016, and accordingly, does not consider drilling results, production, changes in oil and natural gas prices, and changes in future development and operating costs subsequent to June 30, 2016 that may require revisions to our proved reserve estimates and resulting estimated future net cash flows used in the full cost ceiling test.

	12-Month Average Realized Prices		Excess (Deficit) of full cost ceiling over net capitalized costs	(Increase) Decrease in excess of full cost ceiling over net capitalized costs
Pricing Scenarios	Oil ($/Bbl)	Natural gas ($/Mcf)	(in thousands)	
June 30, 2016 Actual	$ 40.62	$ 2.46	$ (95,788)	
Combined price sensitivity				
Oil and natural gas +10%	$ 44.69	$ 2.70	$ (33,871)	$ 61,917
Oil and natural gas -10%	36.56	2.21	(157,706)	(61,918)
Oil price sensitivity				
Oil +10%	$ 44.69	$ 2.46	$ (39,289)	$ 56,499
Oil -10%	36.56	2.46	(152,287)	(56,499)
Natural gas sensitivity				
Natural gas +10%	$ 40.62	$ 2.70	$ (90,370)	$ 5,418
Natural gas -10%	40.62	2.21	(101,207)	(5,419)

Operational Highlights

Our production grew 41% and 44% for the three and six months ended June 30, 2016, respectively, compared to the same periods of 2015, increasing to 1,224 MBOE from 866 MBOE and 2,357 MBOE from 1,637 MBOE for the comparative three and six months periods, respectively.

For the three months ended June 30, 2016, we drilled 6 gross (3.7 net) horizontal wells and completed 5 gross (3.4 net) horizontal wells. For the six months ended June 30, 2016, we drilled 11 gross (8.0 net) horizontal wells and completed 14 gross (10.5 net) horizontal wells. As of June 30, 2016, we had 6 gross (4.2 net) horizontal wells awaiting completion, including 2 gross drilled, uncompleted wells recently acquired.

As of June 30, 2016, we had 413 gross (323.5 net) working interest oil wells, 3 gross (0.1 net) royalty interest oil wells and no natural gas wells. 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 BOE basis. However, most of our wells produce both oil and natural gas.

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, in addition to refinancing of debt instruments.

During 2016, we completed two public common stock offerings to raise additional capital, and we continue to evaluate other sources of capital to complement our cash flows from operations as we pursue our long-term growth plan in the Permian Basin. As of June 30, 2016, there was a $40 million balance outstanding on the Credit Facility, and the borrowing base was increased to $385 million on July 13, 2016.

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For the six months ended June 30, 2016, cash and cash equivalents decreased $1.0 million to $0.2 million compared to $1.2 million at June 30, 2015.

Liquidity and cash flow

	For the Six Months Ended June 30,	
(dollars in millions)	2016	2015
Net cash provided by operating activities	$ 37.5	$ 30.0
Net cash used in investing activities	(335.7)	(130.5)
Net cash provided by financing activities	297.2	101.6
Net change in cash	$ (1.0)	$ 1.1

Operating activities. For the six months ended June 30, 2016, net cash provided by operating activities was $37.5 million compared to net cash provided by operating activities of $30.0 million for the same period in 2015. The change was predominantly attributable to the following:

- A 15% increase in revenue offset by a loss on settlement of derivative contracts;
- An increase in payments on cash-settled restricted stock unit ("RSU") awards;
- A decrease in payments related to nonrecurring early retirement expenses that were incurred in 2015; and
- A change related to the timing of working capital payments and receipts.

Production, realized prices, and operating expenses are discussed below in Results of Operations. See Notes 6 and 7 in the Footnotes to the Financial Statements 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, 2016, net cash used in investing activities was $335.7 million compared to $130.5 million for the same period in 2015. The $205.2 million increase in cash used in investing activities was primarily attributable to the following:

- A $54.9 million decrease in operational expenditures due to the transition from a two-rig to a one-rig program in January 2016, offset in part by the release of a vertical rig in April 2015; and
- A $258.9 million increase driven by various acquisitions, net of proceeds from the sale of mineral interest and equipment, during the six months ended months June 30, 2016. The acquisitions were funded with cash and common stock.

See Note 3 in the Footnotes to the Financial Statements for additional information on the Company's acquisitions.

Our investing activities, on a cash basis, include the following for the periods indicated (in millions):

	For the Six Months Ended June 30,		
	2016	2015	$ Change
Operational expenditures	$ 63.1	$ 118.0	$ (54.9)
Capitalized general and administrative costs allocated directly to exploration and development projects	6.2	5.3	0.9
Capitalized interest	6.0	5.7	0.3
Total capital expenditures (a)	75.3	129.0	(53.7)
Acquisitions	284.0	1.8	282.2
Proceeds from the sale of mineral interest and equipment	(23.6)	(0.3)	(23.3)
Total investing activities	$ 335.7	$ 130.5	$ 205.2

(a) On an accrual (GAAP) basis, which is the methodology used for establishing our annual capital budget, operational expenditures for the six months ended June 30, 2016 were $56.2 million. Inclusive of capitalized general and administrative and interest costs, total capital expenditures were $71.1 million.

General and administrative expenses and capitalized interest are discussed below in Results of Operations. See Note 3 in the Footnotes to the Financial Statements for additional information on acquisitions.

Financing activities. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our Credit Facility, term debt and equity offerings. For the six months ended June 30, 2016, net cash provided by financing activities was $297.2 million compared to cash provided by financing activities of $101.6 million during the same period of 2015. The change in net cash provided by financing activities was primarily attributable to the following:

- Payments, net of borrowings, on our Credit Facility netted to zero, $40 million less than the same period of 2015; and
- A $235.3 million increase in proceeds resulting from common stock offerings in March and April 2016 as compared to proceeds resulting from a common stock offering in March 2015.

See Notes 5 and 10 in the Footnotes to the Financial Statements for additional information on our debt and equity offerings.

Operational Capital Budget and Second Quarter Summary

Subsequent to the acquisitions made during the second quarter 2016 (see Note 3 in the Footnotes to the Financial Statements), our operational capital guidance was updated from $75 to $80 million to $95 to $105 million, which reflects an increase in expenditures related to incremental completions and infrastructure investments for future development of the acquired properties. In early August 2016, we announced an increase of our operational capital guidance to $140 million. The increased guidance reflects expenditures related to the reactivation of our idled second drilling rig that will be primarily in the WildHorse operating area, and increased infrastructure investments to accommodate development in this area.

Operational capital expenditures on an accrual basis were $21.3 million for the six months ended June 30, 2016. In addition to the operational capital expenditures, $14.9 million of capitalized general and administrative and capitalized interest expenses were accrued in the six months ended June 30, 2016.

Based upon current commodity price expectations for 2016, we believe that our cash flow from operations and available borrowings under our Credit Facility will be sufficient to fund our remaining 2016 capital program, including working capital requirements.

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,			
	2016	2015	Change	% Change
Net production:				
Oil (MBbls)	948	685	263	38%
Natural gas (MMcf)	1,658	1,084	574	53%
Total (MBOE)	1,224	866	358	41%
Average daily production (BOE/d)	13,451	9,516	3,935	41%
% oil (BOE basis)	77%	79%		
Average realized sales price:				
Oil (Bbl) (excluding impact of cash settled derivatives)	$ 42.78	$ 52.69	$ (9.91)	(19)%
Oil (Bbl) (including impact of cash settled derivatives)	46.69	59.28	(12.59)	(21)%
Natural gas (Mcf) (excluding impact of cash settled derivatives)	$ 2.77	$ 2.90	$ (0.13)	(4)%
Natural gas (Mcf) (including impact of cash settled derivatives)	2.96	3.32	(0.36)	(11)%
Total (BOE) (excluding impact of cash settled derivatives)	$ 36.88	$ 45.31	$ (8.43)	(19)%
Total (BOE) (including impact of cash settled derivatives)	40.17	51.05	(10.88)	(21)%
Oil and natural gas revenues (in thousands):				
Oil revenue	$ 40,555	$ 36,093	$ 4,462	12%
Natural gas revenue	4,590	3,149	1,441	46%
Total	$ 45,145	$ 39,242	$ 5,903	15%
Additional per BOE data:				
Sales price (excluding impact of cash settled derivatives)	$ 36.88	$ 45.31	$ (8.43)	(19)%
Lease operating expense	5.97	7.59	(1.62)	(21)%
Production taxes	2.01	3.41	(1.40)	(41)%
Operating margin	$ 28.90	$ 34.31	$ (5.41)	(16)%

	Six Months Ended June 30,			
	2016	2015	Change	% Change
Net production:				
Oil (MBbls)	1,840	1,323	517	39%

Natural gas (MMcf)	3,101	1,885	1,216	65%
Total (MBOE)	2,357	1,637	720	44%
Average daily production (BOE/d)	12,951	9,044	3,907	43%
% oil (BOE basis)	78%	81%		
Average realized sales price:				
Oil (Bbl) (excluding impact of cash settled derivatives)	$ 36.96	$ 48.38	$ (11.42)	(24)%
Oil (Bbl) (including impact of cash settled derivatives)	43.05	59.31	(16.26)	(27)%
Natural gas (Mcf) (excluding impact of cash settled derivatives)	$ 2.53	$ 2.99	$ (0.46)	(15)%
Natural gas (Mcf) (including impact of cash settled derivatives)	2.70	3.44	(0.74)	(22)%
Total (BOE) (excluding impact of cash settled derivatives)	$ 32.18	$ 42.54	$ (10.36)	(24)%
Total (BOE) (including impact of cash settled derivatives)	37.16	51.89	(14.73)	(28)%
Oil and natural gas revenues (in thousands):				
Oil revenue	$ 67,998	$ 64,002	$ 3,996	6%
Natural gas revenue	7,845	5,631	2,214	39%
Total	$ 75,843	$ 69,633	$ 6,210	9%
Additional per BOE data:				
Sales price (excluding impact of cash settled derivatives)	$ 32.18	$ 42.54	$ (10.36)	(24)%
Lease operating expense	6.05	8.27	(2.22)	(27)%
Production taxes	1.98	3.19	(1.21)	(38)%
Operating margin	$ 24.15	$ 31.08	$ (6.93)	(22)%

Revenues

The following table is 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 the underlying commodity prices.

(in thousands)	Oil	Natural Gas	Total
Revenues for the three months ended June 30, 2015	$ 36,093	$ 3,149	$ 39,242
Volume increase	13,818	1,670	15,488
Price decrease	(9,356)	(229)	(9,585)
Net increase	4,462	1,441	5,903
Revenues for the three months ended June 30, 2016	$ 40,555	$ 4,590	$ 45,145

(in thousands)	Oil	Natural Gas	Total
Revenues for the six months ended June 30, 2015	$ 64,002	$ 5,631	$ 69,633
Volume increase	24,985	3,631	28,616
Price decrease	(20,989)	(1,417)	(22,406)
Net increase	3,996	2,214	6,210
Revenues for the six months ended June 30, 2016	$ 67,998	$ 7,845	$ 75,843

Oil revenue

For the quarter ended June 30, 2016, oil revenues of $40.6 million increased $4.5 million, or 12%, compared to revenues of $36.1 million for the same period of 2015. The increase in oil revenue was primarily attributable to a 38% increase in production offset by a 19% decrease in the average realized sales price, which fell to $42.78 per Bbl from $52.69 per Bbl. The increase in production was primarily attributable to an increased number of producing wells from our horizontal drilling program and acquisitions, offset by normal and expected declines from our existing wells.

For the six months ended June 30, 2016, oil revenues of $68.0 million increased $4.0 million, or 6%, compared to revenues of $64.0 million for the same period of 2015. The increase in oil revenue was primarily attributable to a 39% increase in production, and was predominantly offset by a 24% decrease in the average realized sales price, which fell to $36.96 per Bbl from $48.38 per Bbl. The increase in production was primarily attributable to an increased number of producing wells from our horizontal drilling program and acquisitions, offset by normal and expected declines from our existing wells.

Natural gas revenue (including NGLs)

Natural gas revenues of $4.6 million increased $1.4 million, or 46%, during the three months ended June 30, 2016, compared to $3.1 million for the same period of 2015. The increase primarily relates to a 53% increase in natural gas volumes and was predominantly offset by a 4% decrease in the average price realized, which fell to $2.77 per Mcf from $2.90 per Mcf, reflecting decreases in both natural gas and natural gas liquids prices. The increase in natural gas production was primarily attributable to an increased number of producing wells as mentioned above, offset by normal and expected declines from our existing wells.

Natural gas revenues of $7.8 million increased $2.2 million, or 39%, during the six months ended, June 30, 2016, compared to $5.6 million for the same period of 2015. The increase primarily relates to a 65% increase in natural gas volumes and was predominantly offset by an 15% decrease in the average price realized, which fell to $2.53 per Mcf from $2.99 per Mcf, reflecting decreases in both natural gas and natural gas liquids prices. The increase in natural gas production was primarily attributable to an increased number of producing wells as mentioned above, offset by normal and expected declines from our existing wells.

Operating Expenses

(in thousands, except per unit amounts)	Three Months Ended June 30,							
		Per		Per	Total Change		BOE Change	
	2016	BOE	2015	BOE	$	%	$	%
Lease operating expenses	$ 7,311	$ 5.97	$ 6,575	$ 7.59	$ 736	11%	$ (1.62)	(21)%
Production taxes	2,455	2.01	2,952	3.41	(497)	(17)%	(1.40)	(41)%
Depreciation, depletion and amortization	16,293	13.31	17,587	20.31	(1,294)	(7)%	(7.00)	(34)%
General and administrative	6,302	5.15	5,763	6.65	539	9%	(1.50)	(23)%
Accretion expense	395	0.32	134	0.15	261	195%	0.17	113%
Acquisition expense	1,906	nm	—	—	1,906	nm	nm	nm
Write-down of oil and natural gas properties	61,012	nm	—	—	61,012	nm	nm	nm

	Six Months Ended June 30,							
		Per		Per	Total Change		BOE Change	
	2016	BOE	2015	BOE	$	%	$	%
Lease operating expenses	$ 14,268	$ 6.05	$ 13,534	$ 8.27	$ 734	5%	$ (2.22)	(27)%
Production taxes	4,675	1.98	5,217	3.19	(542)	(10)%	(1.21)	(38)%
Depreciation, depletion and amortization	32,015	13.58	35,691	21.80	(3,676)	(10)%	(8.22)	(38)%
General and administrative	11,864	5.03	17,865	10.91	(6,001)	(34)%	(5.88)	(54)%
Accretion expense	575	0.24	343	0.21	232	68%	0.03	14%
Write-down of oil and natural gas properties	95,788	nm	—	—	95,788	nm	nm	nm
Rig termination fee	—	—	3,641	nm	(3,641)	nm	nm	nm
Acquisition expense	1,954	nm	—	—	1,954	nm	nm	nm

*nm = not meaningful

Lease operating expenses. These are daily costs incurred to extract oil and natural gas out of the ground, 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.

For the three months ended June 30, 2016, LOE increased by 11% to $7.3 million compared to $6.6 million for the same period of 2015. For the three months ended June 30, 2016, LOE per BOE decreased to $5.97 per BOE compared to $7.59 per BOE for the same period of 2015, which was primarily attributable to improving operational efficiency, reductions in workovers of vertical wells and working with our service partners to achieve cost reductions. Higher production volumes also contributed to the 21% per BOE decrease for the three months ended June 30, 2016. The increase in production was primarily attributable to an increased number of producing wells as discussed above.

For the six months ended, June 30, 2016, LOE increased by 5% to $14.3 million compared to $13.5 million for the same period of 2015. For the six months ended, June 30, 2016, LOE per BOE decreased to $6.05 per BOE compared to $8.27 per BOE for the same period of 2015, which was primarily attributable to improving operational efficiency and reduced vertical workovers, and other cost reductions as mentioned above. Higher production volumes also contributed to the 27% per BOE decrease for the six months ended, June 30, 2016. The increase in production was primarily attributable to an increased number of producing wells as discussed above.

Production taxes. Production taxes include severance and ad valorem taxes. In general, production taxes are directly related to commodity price changes; however, severance taxes are based upon current year commodity prices, whereas ad valorem taxes are based upon prior year commodity prices. 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. In the counties where our production is located, we are also subject to ad valorem taxes, which are generally based on the taxing jurisdictions' valuation of our oil and gas properties.

Production taxes for the three months ended June 30, 2016 decreased by 17% to $2.5 million compared to $3.0 million for the same period of 2015. The decrease was primarily due to a decrease in ad valorem taxes attributable to a lower valuation of our oil and gas properties by the taxing jurisdictions. The decrease was offset by an increase in severance taxes, which was attributable to an increase in revenue. On a per BOE basis, production taxes for the three months ended June 30, 2016 decreased by 41% compared to the same period of 2015.

Production taxes for the six months ended June 30, 2016 decreased by 10% to $4.7 million compared to $5.2 million for the same period of 2015. The decrease was primarily due to a decrease in ad valorem taxes attributable to a lower valuation of our oil and gas properties by the taxing jurisdictions. The decrease was offset by an increase in severance taxes, which was attributable to an increase in revenue. On a per BOE basis, production taxes for the six months ended June 30, 2016 decreased by 38% compared to the same period of 2015.

Depreciation, depletion and amortization ("DD&A"). 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 unevaluated properties, 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.

For the three months ended June 30, 2016, DD&A decreased 7% to $16.3 million compared to $17.6 million for the same period of 2015. For the three months ended June 30, 2016, DD&A decreased 34% per BOE to $13.31 per BOE compared to $20.31 per BOE for the same period of 2015. The decrease is attributable to our increased estimated proved reserves relative to our depreciable asset base and assumed future development costs related to undeveloped proved reserves. The decrease in our depreciable base was primarily related to the write-down of oil and natural gas properties during 2015 and the first quarter of 2016.

For the six months ended June 30, 2016, DD&A decreased 10% to $32.0 million compared to $35.7 million for the same period of 2015. For the six months ended June 30, 2016, DD&A decreased 38% per BOE to $13.58 per BOE compared to $21.80 per BOE for the same period of 2015. The decrease is attributable to our increased estimated proved reserves relative to our depreciable asset base and assumed future development costs related to undeveloped proved reserves. The decrease in our depreciable base was primarily related to the write-down of oil and natural gas properties during 2015 and the first quarter of 2016.

General and administrative, net of amounts capitalized (“G&A”). These are costs incurred for overhead, including payroll and benefits for our corporate staff, severance and early retirement expenses, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, depreciation of corporate level assets, public company costs, vesting of equity and liability awards under share-based compensation plans and related mark-to-market valuation adjustments over time, fees for audit and other professional services, and legal compliance.

G&A for the three months ended June 30, 2016 increased to $6.3 million compared to $5.8 million for the same period of 2015. G&A expenses for the periods indicated include the following (in millions):

	For the Three Months Ended June 30,			
	2016	2015	$ Change	% Change
Recurring expenses				
G&A	$ 3.7	$ 3.5	$ 0.2	6%
Share-based compensation	0.6	0.5	0.1	20%
Fair value adjustments of cash-settled RSU awards	2.0	1.6	0.4	(25)%
Non-recurring expenses				
Expense related to a threatened proxy contest	—	0.2	(0.2)	(100)%
Total G&A expenses	$ 6.3	$ 5.8	$ 0.5	9%

G&A for the six months ended June 30, 2016 decreased to $11.9 million compared to $17.9 million for the same period of 2015. G&A expenses for the periods indicated include the following (in millions):

	For the Six Months Ended June 30,			
	2016	2015	$ Change	% Change
Recurring expenses				
G&A	$ 7.8	$ 7.7	$ 0.1	1%
Share-based compensation	1.2	1.0	0.2	20%
Fair value adjustments of cash-settled RSU awards	2.7	4.2	(1.5)	(36)%
Non-recurring expenses				
Early retirement expenses	—	3.6	(3.6)	(100)%
Early retirement expenses related to share-based compensation	—	1.1	(1.1)	(100)%
Expense related to a threatened proxy contest	0.2	0.3	(0.1)	(33)%
Total G&A expenses	$ 11.9	$ 17.9	$ (6.0)	(34)%

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 ARO costs. Interest is accreted on the present value of the ARO and reported as accretion expense within operating expenses in the consolidated statements of operations.

Accretion expense related to our ARO increased 195% and 68% for the three and six months ended June 30, 2016, respectively, compared to the same periods of 2015. Accretion expense generally correlates with the Company's ARO, which was $6.1 million at June 30, 2016 as compared to $4.1 million at June 30, 2015. See Note 9 in the Footnotes to the Financial Statements for additional information regarding the Company's ARO.

Rig termination fee. During the first quarter of 2015, the Company recognized $3.1 million in expense related to the early termination of the contract for its vertical rig. In March 2015, the Company decided to terminate its one-year contract for a vertical rig (effective April 2015). The Company paid approximately $3.1 million in reduced rental payments over the remainder of the lease term, which ended November 2015.

Acquisition expense. Acquisition expense for the three and six months ended June 30, 2016 were related to costs with respect to our acquisition efforts in the Permian Basin. See Note 3 in the Footnotes to the Financial Statements for additional information regarding the Company’s acquisitions.

Write-down of oil and natural gas properties. Under full cost accounting rules, the Company reviews the carrying value of its proved oil and natural gas properties each quarter. Under these rules, capitalized costs of oil and natural gas properties, net of accumulated depreciation, depletion and amortization and deferred income taxes, may not exceed the present value of estimated future net cash flows from proved oil and natural gas reserves, discounted at 10%, plus the lower of cost or fair value of unevaluated properties, net of related tax effects (the full cost ceiling amount). These rules require pricing based on the preceding 12-months’ average oil and natural gas prices based on closing prices on the first day of each month and require a write-down if the net capitalized costs of proved oil and natural gas properties exceeds the full cost ceiling.

For the three and six months ended June 30, 2016, the Company recognized write-downs of oil and natural gas properties of $61 million and $95.8 million, respectively, as a result of the ceiling test limitation. No write-down was recognized during the same periods of 2015. See Note 2 in the Footnotes to the Financial Statements for additional information. Based on prevailing commodity prices in the current environment, we could incur additional ceiling test write-downs in the future.

Other Income and Expenses and Preferred Stock Dividends

	Three Months Ended June 30,			
(in thousands)	2016	2015	$ Change	% Change
Interest expense, net of capitalized amounts	$ 4,180	$ 5,106	$ (926)	(18)%
Loss on derivative contracts	15,484	8,249	7,235	88%
Other income, net	(96)	(41)	(55)	134%
Total	$ 19,568	$ 13,314		
Income tax benefit	$ —	$ (2,116)	$ 2,116	(100)%
Preferred stock dividends	(1,823)	(1,973)	150	(8)%

	Six Months Ended June 30,			
(in thousands)	2016	2015	$ Change	% Change
Interest expense, net of capitalized amounts	$ 9,671	$ 9,964	$ (293)	(3)%
Loss on derivative contracts	16,416	5,820	10,596	182%
Other income, net	(177)	(85)	(92)	108%
Total	$ 25,910	$ 15,699		
Income tax benefit	$ —	$ (7,193)	$ 7,193	(100)%
Preferred stock dividends	(3,647)	(3,947)	300	(8)%

Interest expense, net of capitalized amounts. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our Credit Facility or with term debt. We incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to our lender in interest expense, net of capitalized amounts. In addition, we include the amortization of deferred financing costs (including origination and amendment fees), commitment fees and annual agency fees in interest expense.

Interest expense, net of capitalized amounts, incurred during the three months ended June 30, 2016 decreased $0.9 million compared to the same period of 2015. The decrease is primarily attributable to a $0.8 million increase in capitalized interest compared to the 2015 period, resulting from a higher average unevaluated property balance for the three months ended June 30, 2016 as compared to the same period of 2015. The increase in unevaluated property was primarily due to acquisitions costs. Also contributing to the decrease was a $0.1 million decrease in interest expense related to our debt.

Interest expense, net of capitalized amounts, incurred during the six months ended June 30, 2016 decreased $0.3 million compared to the same period of 2015. The decrease is primarily attributable to a $0.4 million increase in capitalized interest compared to the 2015 period, resulting from a higher average unevaluated property balance for the six months ended June 30, 2016 as compared to the same period of 2015. The increase in unevaluated property was primarily due to acquisitions costs. Offsetting the decrease was a $0.1 million increase in interest expense related to our debt.

See Note 5 in the Footnotes to the Financial Statements for additional information on our debt.

(Gain) loss on derivative contracts. We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in commodity prices. This amount represents the (i) (gain) loss related to fair value adjustments on our open derivative contracts and (ii) (gains) losses on settlements of derivative contracts for positions that have settled within the period.

For the three months ended June 30, 2016, the net loss on derivative contracts was $15.5 million compared to an $8.2 million net loss for the same period of 2015. The net gain (loss) on derivative instruments for the periods indicated includes the following (in millions):

	For the Three Months Ended March 31,		
	2016	2015	$ Change
Oil derivatives			
Net gain on settlements	$ 3.7	$ 4.5	$ (0.8)
Net loss on fair value adjustments	(18.5)	(12.7)	(5.8)
Total loss	$ (14.8)	$ (8.2)	$ (6.6)
Natural gas derivatives			
Net gain on settlements	$ 0.3	$ 0.5	$ (0.2)
Net loss on fair value adjustments	(1.0)	(0.5)	(0.5)
Total loss	$ (0.7)	$ —	$ (0.7)
Total loss on derivative contracts	$ (15.5)	$ (8.2)	$ (7.2)

For the six months ended June 30, 2016, the net loss on derivative contracts was $16.4 million compared to a $5.8 million net loss for the same period of 2015. The net gain (loss) on derivative instruments for the periods indicated includes the following (in millions):

	For the Six Months Ended June 30,		
	2016	2015	$ Change
Oil derivatives			
Net gain on settlements	$ 11.2	$ 14.5	$ (3.3)
Net loss on fair value adjustments	(27.6)	(20.5)	(7.1)
Total loss	$ (16.4)	$ (6.0)	$ (10.4)
Natural gas derivatives			
Net gain on settlements	$ 0.5	$ 0.8	$ (0.3)
Net loss on fair value adjustments	(0.5)	(0.6)	0.1

Total gain (loss)	$ —	$ 0.2	$ (0.2)
Total loss on derivative contracts	$ (16.4)	$ (5.8)	$ (10.6)

See Notes 6 and 7 in the Footnotes to the Financial Statements 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. The Company had no income tax expense for the three and six months ended June 30, 2016 compared to an income tax benefit of $2.1 million and $7.2 million for the same periods of 2015. The change in income tax expense is primarily related to recording a valuation allowance of $147.5 million at June 30, 2016 and the difference in the amount of income (loss) before income taxes between periods. See Note 8 in the Footnotes to the Financial Statements for additional information.

Preferred Stock dividends. Preferred Stock dividends for the three and six months ended June 30, 2016 were $1.8 million and $3.6 million, respectively, as compared to $2.0 million and $3.9 million for the same periods of 2015, respectively. The decrease was due to a decrease in the number of preferred shares outstanding attributable to a partial share conversion in February 2016 in which the Company exchanged a total of 120,000 shares of Preferred Stock for 719,000 shares of common stock. Dividends reflect a 10% dividend rate. See Note 10 in the Footnotes to the Financial Statements for additional information.

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, related both to NYMEX benchmark prices and regional basis differentials. The total volumes which we hedge through 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 forecast production for the next 12 to 24 months, subject to the covenants under our Credit Facility. Our hedge policies and objectives may change significantly with movements in commodities prices or futures prices, in addition to modification of our capital spending plans related to operational activities and acquisitions.

The Company’s hedging portfolio, linked to NYMEX benchmark pricing, covers approximately 48% and 25% of our expected oil and natural gas production, respectively, for the remaining six months of 2016, based on the midpoint of publicly disclosed guidance as of August 8, 2016, including the impact of pending transactions. We also have commodity hedging contracts linked to Midland WTI basis differentials relative to Cushing covering approximately 32% of our expected oil production for the remaining six months of 2016, based on the midpoint of publicly disclosed oil production guidance as of August 8, 2016, including the impact of pending transactions. Our actual production may vary from the amounts estimated, perhaps materially. See Note 6 in the Footnotes to the Financial Statements for a description of the Company’s outstanding derivative contracts at June 30, 2016 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.

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 (or call) options at a price lower than the floor price (or higher than the ceiling price) in conjunction with a collar (three-way collar) and use the proceeds to increase either or both the floor or ceiling prices. In a three-way collar, to the extent that realized prices are below the floor price of the sold put option (or above the ceiling price of the sold call option), the Company's net realized benefit from the three-way collar will be reduced on a dollar-for-dollar basis.

The Company 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 counterparty 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 June 30, 2016, the Company's debt consisted of $300 million of outstanding principal related to its Term Loan and $40 million outstanding balance on our Credit Facility. The Company is subject to market risk exposure related to changes in interest rates on our indebtedness under the Term Loan and Credit Facility. As of June 30, 2016, the interest rate on our Term Loan borrowings was 8.50%. An increase or decrease of 1% in the interest rate would have a corresponding increase or decrease in our annual net income of approximately $3.4 million based on the $340 million outstanding in the aggregate under the Term Loan on June 30, 2016. The Company is also subject to market risk exposure related to changes in the underlying LIBOR-based interest rate used for the Term Loan to the extent that available LIBOR election options exceed the 1.0% floor rate. See Note 5 to the Consolidated Financial Statements for more information on the Company's interest rates on debt.

Counterparty and customer credit risk

The Company's principal exposures to credit risk are through receivables from the sale of our oil and natural gas production, joint interest receivables and receivables resulting from derivative financial contracts.

The Company markets its oil and natural gas production to energy marketing companies. 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 June 30, 2016 our total receivables from the sale of our oil and natural gas production were approximately $30.6 million.

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 have or intend to drill. We have little ability to control whether these entities will participate in our wells. At June 30, 2016 our joint interest receivables were approximately $12.4 million.

Our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. Most of 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 offset upon the occurrence of defined acts of default by either us or a counterparty to a derivative, whereby the party not in default may offset all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party.

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 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. Our Chief Executive Officer and Chief Financial Officer performed an evaluation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). Based on this evaluation, our principal executive and principal financial officers have concluded that the Company's disclosure controls and procedures were effective as of June 30, 2016.

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.

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

Other than as set forth below, there have been no material changes with respect to the risk factors disclosed in our 2015 Annual Report on Form 10-K and our Quarterly Report on Form 10-Q for the three months ended March 31, 2016.

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

On May 26, 2016, to partially fund the Big Star Transaction described in Note 3 in the Footnotes to the Financial Statements, the Company issued 9,333,333 shares of common stock to the sellers of the properties at an assumed offering price of $11.74 per share, which is the latest reported sale price of our common stock on the New York Stock Exchange on that date. The shares were issued in reliance on Section 4(2) of the Securities Act.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

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	(a)	Certificate of Incorporation of the Company, as amended through May 1, 2016
3.2		Certificate of Designation of Rights and Preferences of 10% Series A Cumulative Preferred Stock (incorporated by reference to Exhibit 3.5 of the Company’s Form 8-A, filed on May 23, 2013)
3.3		Bylaws of the Company (incorporated by reference from Exhibit 3.2 of the Company’s Registration Statement on Form S-4, filed on August 4, 1994, Reg. No. 33-82408)
4.		Instruments defining the rights of security holders, including indentures
4.1		Specimen Common Stock Certificate (incorporated by reference from Exhibit 4.1 of the Company’s Registration Statement on Form S-4, filed on August 4, 1994, Reg. No. 33-82408)
4.2		Certificate for the Company’s 10% Cumulative Preferred Stock (incorporated by reference to Exhibit 4.1 of the Company’s Form 8-A, filed on May 23, 2013)
10.		Material Contracts
10.1		Purchase and Sale Agreement among BSM Energy LP, Crux Energy, LP and Zaniah Energy, LP, as Sellers and CPOC, as Purchaser and Callon, as Purchaser Parent, dated April 19, 2016 (incorporated by reference to Exhibit 2.1 of the Company's Form 8-K, filed on April 19, 2016)
10.2		Underwriting Agreement dated as of April 19, 2016 between Callon Petroleum Company and Credit Suisse Securities (USA) LLC (incorporated by reference to Exhibit 1.1 of the Company's Form 8-K, filed on April 21, 2016)
10.3		Registration Rights Agreement among Callon Petroleum Company and each of the persons set forth on Schedule A therein, dated May 26, 2016 (incorporated by reference to Exhibit 10.1 of the Company's Form 8-K, filed on May 31, 2016)
10.4	(a)	Amendment No. 3 to the Fifth Amended and Restated Credit Agreement among Callon Petroleum Company, JPMorgan Chase Bank, National Association, as administrative agent and the Lenders and parties named therein dated July 13, 2016
31.		Section 13a-14 Certifications
31.1	(a)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	(a)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.		Section 1350 Certifications
32.1	(b)	Section 1350 Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.	(c)	Interactive Data Files

(a) Filed herewith.

(b) Furnished herewith. Pursuant to SEC Release No. 33-8212, this certification will be treated as “accompanying” this report and not “filed” as part of such report for purposes of Section 18 of the Exchange Act or otherwise subject to the liability of Section 18 of the Exchange Act, and this certification will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, except to the extent that the registrant specifically incorporates it by reference.

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

SIGNATURES

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

Callon Petroleum Company

Signature	Title	Date
/s/ Fred L. Callon Fred L. Callon	President and Chief Executive Officer	August 8, 2016
/s/ Joseph C. Gatto, Jr. Joseph C. Gatto, Jr.	Senior Vice President, Chief Financial Officer and Treasurer	August 8, 2016