CALLON PETROLEUM CO
Form 10-Q
May 03, 2018
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 March 31, 2018
OR
Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from ____________ to ____________
Commission File Number 001-14039

Callon Petroleum Company
(Exact Name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	64-0844345 (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, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth 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	Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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 201,958,575 shares of common stock outstanding as of April 27, 2018.

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Glossary of Certain Terms

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.
- ASU: accounting standards update.
- 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.
- BLM: Bureau of Land Management.
- 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.
- Completion: The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.
- Cushing: An oil delivery point that serves as the benchmark oil price for West Texas Intermediate.
- DOI: Department of Interior.
- EPA: Environmental Protection Agency.
- FASB: Financial Accounting Standards Board.
- 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.
- Horizontal drilling: A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.
- GHG: greenhouse gases.
- LIBOR: London Interbank Offered Rate.
- LOE: lease operating expense.
- MBbls: thousand barrels of oil.
- MBOE: thousand BOE.
- Mcf: thousand cubic feet of natural gas.
- MMBOE: million BOE.
- 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.
- OPEC: Organization of Petroleum Exporting Countries.
- PDPs: proved developed producing reserves.
- PDNPs: proved developed non-producing reserves.
- PUDs: proved undeveloped reserves.
- Realized price: The cash market price less all expected quality, transportation and demand adjustments.
- Royalty interest: An interest that gives an owner the right to receive a portion of the resources or revenues without having to carry any costs of development.
- RSU: restricted stock units.

- SEC: United States Securities and Exchange Commission.
- Working interest: An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.
- 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 data)

	March 31, 2018 Unaudited	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$18,473	$27,995
Accounts receivable	122,411	114,320
Fair value of derivatives	4,210	406
Other current assets	2,078	2,139
Total current assets	147,172	144,860
Oil and natural gas properties, full cost accounting method:		
Evaluated properties	3,598,868	3,429,570
Less accumulated depreciation, depletion, amortization and impairment	(2,119,599)	(2,084,095)
Net evaluated oil and natural gas properties	1,479,269	1,345,475
Unevaluated properties	1,174,385	1,168,016
Total oil and natural gas properties	2,653,654	2,513,491
Other property and equipment, net	21,173	20,361
Restricted investments	3,382	3,372
Deferred tax asset	26	52
Deferred financing costs	4,588	4,863
Acquisition deposit	—	900
Other assets, net	5,524	5,397
Total assets	$2,835,519	$2,693,296
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$187,267	$162,878
Accrued interest	18,491	9,235
Cash-settleable restricted stock unit awards	4,081	4,621
Asset retirement obligations	2,784	1,295
Fair value of derivatives	25,912	27,744
Total current liabilities	238,535	205,773
Senior secured revolving credit facility	75,000	25,000
6.125% senior unsecured notes due 2024, net of unamortized deferred financing costs	595,374	595,196
Asset retirement obligations	7,717	4,725
Cash-settleable restricted stock unit awards	2,392	3,490
Deferred tax liability	1,950	1,457
Fair value of derivatives	2,942	1,284
Other long-term liabilities	465	405
Total liabilities	924,375	837,330
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, series A cumulative, $0.01 par value and $50.00 liquidation preference, 2,500,000 shares authorized; 1,458,948 shares outstanding	15	15
Common stock, $0.01 par value, 300,000,000 shares authorized; 201,947,883 and 201,836,172 shares outstanding, respectively	2,019	2,018

Capital in excess of par value	2,182,599	2,181,359
Accumulated deficit	(273,489)	(327,426)
Total stockholders’ equity	1,911,144	1,855,966
Total liabilities and stockholders’ equity	$2,835,519	$2,693,296

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 March 31,	
	2018	2017
Operating revenues:		
Oil sales	$115,286	$72,008
Natural gas sales	12,154	9,355
Total operating revenues	127,440	81,363
Operating expenses:		
Lease operating expenses	13,039	12,937
Production taxes	8,463	5,904
Depreciation, depletion and amortization	35,417	24,433
General and administrative	8,769	5,206
Accretion expense	218	184
Acquisition expense	548	450
Total operating expenses	66,454	49,114
Income from operations	60,986	32,249
Other (income) expenses:		
Interest expense, net of capitalized amounts	460	665
(Gain) loss on derivative contracts	4,481	(15,303)
Other income	(211)	(708)
Total other (income) expense	4,730	(15,346)
Income before income taxes	56,256	47,595
Income tax expense	495	466
Net income	55,761	47,129
Preferred stock dividends	(1,824)	(1,824)
Income available to common stockholders	$53,937	$45,305
Income per common share:		
Basic	$0.27	$0.23
Diluted	$0.27	$0.22
Shares used in computing income per common share:		
Basic	201,921	201,054
Diluted	202,588	201,740

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)

	Three Months Ended March 31, 2018	2017
Cash flows from operating activities:		
Net income	$55,761	$47,129
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation, depletion and amortization	36,066	24,932
Accretion expense	218	184
Amortization of non-cash debt related items	453	665
Deferred income tax expense	495	466
Net gain on derivatives, net of settlements	(3,978)	(17,794)
Non-cash expense related to equity share-based awards	1,131	930
Change in the fair value of liability share-based awards	1,012	(291)
Payments to settle asset retirement obligations	(366)	(765)
Changes in current assets and liabilities:		
Accounts receivable	(8,067)	(4,066)
Other current assets	61	576
Current liabilities	12,938	9,903
Other long-term liabilities	87	—
Other assets, net	(507)	(523)
Payments to settle vested liability share-based awards	(3,089)	(8,662)
Net cash provided by operating activities	92,215	52,684
Cash flows from investing activities:		
Capital expenditures	(111,330)	(66,154)
Acquisitions	(38,923)	(648,485)
Acquisition deposit	900	46,138
Net cash used in investing activities	(149,353)	(668,501)
Cash flows from financing activities:		
Borrowings on senior secured revolving credit facility	80,000	—
Payments on senior secured revolving credit facility	(30,000)	—
Payment of preferred stock dividends	(1,824)	(1,824)
Tax withholdings related to restricted stock units	(560)	(79)
Net cash provided by (used in) financing activities	47,616	(1,903)
Net change in cash and cash equivalents	(9,522)	(617,720)
Balance, beginning of period	27,995	652,993
Balance, end of period	$18,473	$35,273

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

Index to the Notes to the 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. 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. The Company’s operations to date have been predominantly focused on the horizontal development of several prospective intervals, including multiple levels of the Wolfcamp formation and the Lower Spraberry shales. 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 its existing acreage and acquisition of additional locations through working interest acquisitions, leasing programs, 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, 2017. The balance sheet at December 31, 2017 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, 2018.

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.

Accounting Standards Updates (“ASUs”)

Recently Adopted ASUs - Revenue Recognition

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (“ASU 2014-09”). The standard requires an entity to recognize revenue in a manner that depicts the transfer of goods or services to customers at an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 replaced most of the existing revenue recognition requirements in GAAP. The standard can be applied using either the full retrospective approach or a modified retrospective approach at the date of adoption.

Throughout 2015 and 2016, the FASB issued several updates to the revenue recognition guidance in Accounting Standards Codification Topic 606 (“ASC 606”). In August 2015, the FASB issued ASU No. 2015-14, deferring the effective date of ASU 2014-09 by one year. In March 2016, the FASB issued ASU No. 2016-08, Revenue from Contracts with Customers - Principal versus Agent Considerations (Reporting Revenue Gross versus Net). Under this update, an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In April 2016, the FASB issued ASU No. 2016-10, Revenue from Contracts with Customers - Identifying Performance Obligations and Licensing. This update clarifies two principles of ASC 606: identifying performance obligations and the licensing implementation guidance. In May 2016, the FASB issued ASU No. 2016-12, Revenue from Contracts with Customers - Narrow-Scope Improvements and Practical Expedients. This update applies only to the following areas from ASC 606: assessing the collectability criterion and accounting for contracts that do not meet the criteria for step 1, presentation of sales taxes and other similar taxes collected from customers, non-cash consideration, contract modification at transition, completed contracts at transition and technical correction.

The Company adopted the new standard on January 1, 2018 using the modified retrospective method at the date of adoption. See Note 2 for additional information on Revenue Recognition.

Recently adopted ASUs - Other

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments (“ASU 2016-15”). The objective of the standard is to reduce the existing diversity in practice of several cash flow issues, including debt prepayment or debt extinguishment costs, settlement of zero-coupon debt instruments or other debt instruments with coupon rates that are insignificant in relation to the effective interest rate of the borrowing, contingent consideration payment made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies, including bank-owned life insurance policies, distributions received from equity method investees, beneficial interests in securitization transactions, and separately identifiable cash flows and application of the predominance principle. The guidance in ASU 2016-15 is effective for public entities for annual reporting periods beginning after December 15, 2017, including interim periods therein. Early adoption is permitted and is to be applied on retrospective basis. The Company adopted this update on January 1, 2018 and it did not have a material impact on its consolidated financial statements.

In January 2017, the FASB issued ASU No. 2017-01, Business Combinations-Clarifying the Definition of a Business (“ASU 2017-01”). The guidance in ASU 2017-01 clarifies the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions or disposals of assets or businesses. The guidance provides a screen to determine when a set of assets and activities is not a business. The screen requires that when substantially all of the fair value of the gross assets acquired or disposed of is concentrated in a single identifiable asset or a group of similar identifiable assets, the set is not a business. The guidance in ASU 2017-01 is effective for annual reporting periods beginning after December 15, 2017, including interim periods therein. The Company adopted this update effective January 1, 2018. The adoption of this update did not have a material impact on its consolidated financial statements.

Recently issued ASUs

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) (“ASU 2016-02”). The standard requires all lease transactions (with terms in excess of 12 months) to be recognized on the balance sheet as lease assets and lease liabilities. Public entities are required to apply ASU 2016-02 for annual and interim reporting periods beginning after December 15, 2018 with early adoption permitted. In January 2018, the FASB issued ASU No. 2018-01, Leases (Topic 842) (“ASU 2018-01”). The standard provides an optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the current leases guidance in Topic 840. Public entities are required to apply ASU 2016-02 for annual and interim reporting periods beginning after December 15, 2018 with early adoption permitted. The Company is currently evaluating the impact of its pending adoption of this guidance on its consolidated financial statements.

Note 2 - Revenue Recognition

Revenue from contracts with customers

Oil sales

Under the Company's oil sales contracts it sells oil production at the point of delivery and collects an agreed upon index price, net of pricing differentials. The Company recognizes revenue when control transfers to the purchaser at the point of delivery at the net price received.

Natural gas sales

Under the Company's natural gas sales processing contracts, it delivers natural gas to a midstream processing entity. The midstream processing entity gathers and processes the natural gas and remits proceeds to the Company for the resulting sale of natural gas. The revenue received from the sale of NGLs is included in the natural gas sales. Under these processing agreements, when control of the natural gas changes at the point of delivery, the treatment of gathering and treating fees are recorded net of revenues. Gathering and treating fees have historically been recorded as an expense in lease operating expense in the statement of operations. The Company has modified the presentation of revenues and expenses to include these fees net of revenues. For the three months ended March 31, 2018, $1,252 of gathering and treating fees were recognized and recorded as a reduction to natural gas revenues in the consolidated statement of operations. For the three months ended March 31, 2017, $723 of gathering and treating fees were recognized and recorded as part of lease operating expense in the consolidated statement of operations.

Production imbalances

Previously, the Company elected to utilize the entitlements method to account for natural gas production imbalances, which is no longer applicable. In conjunction with the Company's adoption of the new revenue recognition accounting standards, there was no material impact to the financial statements due to this change in accounting for its production imbalances.

Transaction price allocated to remaining performance obligations

For the Company's product sales that have a contract term greater than one year, it has utilized the practical expedient in Accounting Standards Codification 606-10-50-14, which states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Prior period performance obligations

The Company records revenue in the month production is delivered to the purchaser. However, settlement statements for sales may not be received for 30 to 90 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. The Company records the differences between estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. The Company has existing internal controls for its revenue estimation process and related accruals, and any identified differences between its revenue estimates and actual revenue received historically have not been significant.

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.

2018 Acquisitions

During the three months ended March 31, 2018, the Company completed acquisitions of additional working interests and acreage in the Company's existing core operating areas of Monarch and Wildhorse, located in the Permian Basin, for an aggregate total purchase price of approximately $35,900 excluding customary purchase price adjustments.

2017 Acquisitions

On February 13, 2017, the Company completed the acquisition of 29,175 gross (16,688 net) acres in the Delaware Basin, primarily located in Ward and Pecos Counties, Texas from American Resource Development, LLC, for total cash consideration of $646,559 excluding customary purchase price adjustments (the “Ameredev Transaction”). The Company funded the cash purchase price with the net proceeds of an equity offering (see Note 10 for additional information regarding the equity offering). The Company obtained an 82% average working interest (75% average net revenue interest) in the properties acquired in the Ameredev Transaction. In December 2016, in connection with the execution of the purchase and sale agreement for the Ameredev Transaction, the Company paid a deposit in the amount of $46,138 to a third party escrow agent, which was recorded as Acquisition deposit on the balance sheet as of December 31, 2016. The following table summarizes the estimated acquisition date fair values of the acquisition:

Evaluated oil and natural gas properties	$137,368
Unevaluated oil and natural gas properties	509,359
Asset retirement obligations	(168)
Net assets acquired	$646,559

On June 5, 2017, the Company completed the acquisition of 7,031 gross (2,488 net) acres in the Delaware Basin, located near the acreage acquired in the Ameredev Transaction discussed above, for total cash consideration of $52,500 excluding customary purchase price adjustments. The Company funded the cash purchase price with its available cash and proceeds from the issuance of an additional $200,000 of its 6.125% senior notes due 2024 (see Note 5 for additional information regarding the Company's debt obligations).

Unaudited pro forma financial statements

The following unaudited summary pro forma financial information for the periods presented is for illustrative purposes only and does not purport to represent what the Company's results of operations would have been if the Ameredev Transaction had occurred as presented, or to project the Company's results of operations for any future periods:

	Three Months Ended March 31, 2017 [(a)]
Revenues	$84,416
Income from operations	34,907
Income available to common stockholders	47,963
Net income per common share:	
Basic	$0.24
Diluted	$0.24

(a) The pro forma financial information was prepared assuming the Ameredev Transaction occurred as of January 1, 2016.

The pro forma adjustments are based on available information and certain assumptions that management believes are reasonable, including revenue, lease operating expenses, production taxes, depreciation, depletion and amortization expense, accretion expense, interest expense and capitalized interest.

The properties associated with the Ameredev Transaction have been commingled with the Company's existing properties and it is impractical to provide the stand-alone operational results related to these properties.

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 March 31,	
	2018	2017
Net income	$55,761	$47,129
Preferred stock dividends	(1,824)	(1,824)
Income available to common stockholders	$53,937	$45,305
Weighted average shares outstanding	201,921	201,054
Dilutive impact of restricted stock	667	686
Weighted average shares outstanding for diluted income per share	202,588	201,740

Basic income per share	$0.27	$0.23
Diluted income per share	$0.27	$0.22
Stock options [(a)]	—	15
Restricted stock [(a)]	3	—

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

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

Note 5 - Borrowings

The Company's borrowings consisted of the following at:

	March 31, 2018	December 31, 2017
Principal components:		
Senior secured revolving credit facility	$75,000	$ 25,000
6.125% senior unsecured notes due 2024	600,000	600,000
Total principal outstanding	675,000	625,000
Premium on 6.125% senior unsecured notes due 2024, net of accumulated amortization	7,312	7,594
Unamortized deferred financing costs	(11,938)	(12,398)
Total carrying value of borrowings	$670,374	$ 620,196

Senior secured revolving credit facility (the "Credit Facility")

On May 25, 2017, the Company entered into the Sixth Amended and Restated Credit Agreement to the Credit Facility with a maturity date of May 25, 2022. JPMorgan Chase Bank, N.A. is Administrative Agent, and participants include 17 institutional lenders. The total notional amount available under the Credit Facility is $2,000,000. Amounts borrowed under the Credit Facility may not exceed the borrowing base, which is generally reviewed on a semi-annual basis. The Credit Facility is secured by first preferred mortgages covering the Company's major producing properties. As of March 31, 2018, the Credit Facility's borrowing base was $700,000 with an elected commitment amount of $500,000.

As of March 31, 2018, there were $75,000 of principal and $1,250 in letters of credit outstanding under the Credit Facility. For the quarter ended March 31, 2018, the Credit Facility had a weighted-average interest rate of 3.75%, calculated as the LIBOR plus a tiered rate ranging from 2.00% to 3.00%, which is determined based on utilization of the facility. In addition, the Credit Facility carried a commitment fee of 0.375% per annum, payable quarterly, on the unused portion of the borrowing base.

On April 5, 2018, the Company entered into the first amendment to the Sixth Amended and Restated Credit Agreement to the Credit Facility, which (1) increased the borrowing base to $825,000, (2) increased the elected commitment amount to $650,000, (3) decreased the applicable margins for interest rates, based on utilization, to a range of 1.25% to 2.25%, and (4) extended the maturity date to May 25, 2023.

6.125% senior unsecured notes due 2024 ("6.125% Senior Notes")

On October 3, 2016, the Company issued $400,000 aggregate principal amount of 6.125% Senior Notes with a maturity date of October 1, 2024 and interest payable semi-annually beginning on April 1, 2017. The net proceeds of the offering, after deducting initial purchasers' discounts and estimated offering expenses, were approximately $391,270. The 6.125% Senior Notes are guaranteed on a senior unsecured basis by the Company's wholly-owned subsidiary, Callon Petroleum Operating Company, and may be guaranteed by certain future subsidiaries. The subsidiary guarantor is 100% owned, all of the guarantees are full and unconditional and joint and several, the parent company has no independent assets or operations and any subsidiaries of the parent company other than the subsidiary guarantor are minor.

On May 19, 2017, the Company issued an additional $200,000 aggregate principal amount of its 6.125% Senior Notes which with the existing $400,000 aggregate principal amount of 6.125% Senior Notes are treated as a single class of notes under the indenture. The net proceeds of the offering, including a premium issue price of 104.125% and after deducting initial purchasers' discounts and estimated offering expenses, were approximately $206,139. The Company used the proceeds, in part, to fund an acquisition completed on June 5, 2017 (discussed further in Note 3) and for general corporate purposes.

The Company may redeem the 6.125% Senior Notes in accordance with the following terms: (1) prior to October 1, 2019, a redemption of up to 35% of the principal in an amount not greater than the net proceeds from certain equity offerings, and within 180 days of the closing date of such equity offerings, at a redemption price of 106.125% of principal, plus accrued and unpaid interest, if any, to the date of the redemption, if at least 65% of the principal will remain outstanding after such redemption; (2) prior to October 1, 2019, a redemption of all or part of the principal at a price of 100% of principal of the amount redeemed, plus an applicable make-whole premium and accrued and unpaid interest, if any, to the date of the redemption; and (3) a redemption, in whole or in part, at a redemption price, plus accrued and unpaid interest, if any, to the date of the redemption, (i) of 104.594% of principal if the redemption occurs on or after October 1, 2019, but before October 1, 2020, and (ii) of 103.063% of principal if the redemption occurs on or after October 1, 2020, but before October 1, 2021, and (iii) of 101.531% of principal if the redemption occurs on or after October 1, 2021, but before October 1, 2022, and (iv) of 100% of principal if the redemption occurs on or after October 1, 2022.

Following a change of control, each holder of the 6.125% Senior Notes may require the Company to repurchase all or a portion of the 6.125% Senior Notes at a price of 101% of principal of the amount repurchased, plus accrued and unpaid interest, if any, to the date of repurchase.

Restrictive covenants

The Company's Credit Facility and the indenture governing its 6.125% Senior Notes 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 March 31, 2018.

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, put and call options 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.

The Company executes commodity derivative contracts under master agreements with 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 a 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	3/31/2018	12/31/2017	3/31/2018	12/31/2017	3/31/2018	12/31/2017
Natural gas	Current	Fair value of derivatives	$317	$ 406	$—	$—	$317	$406
Oil	Current	Fair value of derivatives	3,893	—	(25,912)	(27,744)	(22,019)	(27,744)
Oil	Non-current	Fair value of derivatives	—	—	(2,942)	(1,284)	(2,942)	(1,284)
Totals			$4,210	$ 406	$(28,854)	$(29,028)	$(24,644)	$(28,622)

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:

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	March 31, 2018		
	Presented without Effects of Netting	Effects of Netting	As Presented with Effects of Netting
Current assets: Fair value of derivatives	$10,638	$(6,428)	$4,210
Current liabilities: Fair value of derivatives	$(32,340)	$6,428	$(25,912)
Long-term liabilities: Fair value of derivatives	(2,942)	—	(2,942)

	December 31, 2017		
	Presented without Effects of Netting	Effects of Netting	As Presented with Effects of Netting
Current assets: Fair value of derivatives	$406	$ —	$406
Current liabilities: Fair value of derivatives	$(27,744)	$ —	$(27,744)
Long-term liabilities: Fair value of derivatives	(1,284)	—	(1,284)

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 March 31,	
	2018	2017
Oil derivatives		
Net loss on settlements	$(8,916)	$(2,524)
Net gain on fair value adjustments	4,067	17,266
Total gain (loss) on oil derivatives	$(4,849)	$14,742
Natural gas derivatives		
Net gain on settlements	$457	$33
Net gain (loss) on fair value adjustments	(89)	528
Total gain on natural gas derivatives	$368	$561
Total gain (loss) on oil & natural gas derivatives	$(4,481)	$15,303

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Derivative positions

Listed in the tables below are the outstanding oil and natural gas derivative contracts as of March 31, 2018:

Oil contracts (WTI)	For the Remainder of 2018	For the Full Year of 2019
Swap contracts		
Total volume (MBbls)	1,559	—
Weighted average price per Bbl	$ 51.88	$—
Collar contracts (two-way collars)		
Total volume (MBbls)	275	—
Weighted average price per Bbl		
Ceiling (short call)	$ 60.50	$—
Floor (long put)	$ 50.00	$—
Collar contracts combined with short puts (three-way collars)		
Total volume (MBbls)	2,612	2,739
Weighted average price per Bbl		
Ceiling (short call option)	$ 60.86	$62.96
Floor (long put option)	$ 48.95	$53.67
Short put option	$ 39.21	$43.67

Oil contracts (Midland basis differential)	For the Remainder of 2018	For the Full Year of 2019
Swap contracts		
Volume (MBbls)	3,895	—
Weighted average price per Bbl	$ (0.86)	$ —

Natural gas contracts (Henry Hub)	For the Remainder of 2018	For the Full Year of 2019
Swap contracts		
Total volume (BBtu)	4,125	—
Weighted average price per MMBtu	$ 2.91	—

Subsequent Event

The following derivative contract was executed subsequent to March 31, 2018:

For the Remainder	For the Full

Oil contracts (WTI)	of 2018	Year of 2019
Collar contracts combined with short puts (three-way collars)		
Volume (MBbls)	—	730
Weighted average price per Bbl		
Ceiling (short call option)	$ —	$66.53
Floor (long put option)	$ —	$55.00
Short put option	$ —	$45.00

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 approximated fair value due to the short-term nature or maturity of the instruments.

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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.

	March 31, 2018		December 31, 2017	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Credit Facility [(a)]	$75,000	$—	$25,000	$—
6.125% Senior Notes [(b)]	595,374	613,680	595,196	618,000
Total	$670,374	$613,680	$620,196	$618,000

(a) Floating-rate debt.
(b) The fair value was based upon Level 2 inputs. See Note 5 for additional information about the Company's 6.125% Senior Notes.

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:

March 31, 2018	Classification	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments	Fair value of derivatives	$ —	$4,210	$ —	$4,210
Liabilities					
Derivative financial instruments	Fair value of derivatives	—	(28,854)	—	(28,854)
Total net liabilities		$ —	$(24,644)	$ —	$(24,644)

December 31, 2017	Classification	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments	Fair value of derivatives	$ —	$406	$ —	$406
Liabilities					
Derivative financial instruments	Fair value of derivatives	—	(29,028)	—	(29,028)
Total net liabilities		$ —	$(28,622)	$ —	$(28,622)

Assets and liabilities measured at fair value on a nonrecurring basis

Acquisitions. The Company determines the fair value of the assets acquired and liabilities assumed using the income approach based on expected discounted future cash flows from estimated reserve quantities, costs to produce and develop reserves, and oil and natural gas forward prices. The future net revenues are discounted using a weighted average cost of capital. The discounted future net revenues of proved undeveloped and probable reserves are reduced by an additional reserve adjustment factor to compensate for the inherent risk of estimating the value of unevaluated properties. The fair value measurements were based on Level 2 and Level 3 inputs.

Note 8 - Income Taxes

The Company provides for income taxes at the statutory rate of 21%. The statutory rate is adjusted for permanent differences expected to be realized, which primarily relate to non-deductible executive compensation expenses, restricted stock windfalls and shortfalls, and state income taxes.

As a result of the write-down of oil and natural gas properties in the latter part of 2015 and the first half of 2016, 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 full valuation allowance for the net U.S. federal deferred tax asset in 2015. In subsequent periods where the Company has recorded pre-tax income, it has reversed a portion of the U.S. federal valuation allowance, net of discrete items, to the extent necessary to offset U.S. federal income tax expense on pre-tax income recorded for the period. Income tax expense recorded in this period relates to deferred State of Texas gross margin tax. The valuation allowance was $49,166 as of March 31, 2018.

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Note 9 - Asset Retirement Obligations

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

	Three Months Ended March 31, 2018
Asset retirement obligations at January 1, 2018	$6,020
Accretion expense	218
Liabilities incurred	44
Liabilities settled	(95)
Revisions to estimate [a]	4,314
Asset retirement obligations at end of period	10,501
Less: Current asset retirement obligations	(2,784)
Long-term asset retirement obligations at March 31, 2018	$7,717

(a) Revisions to estimated ARO obligations can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment.

Certain of the Company's operating agreements require that assets be restricted for abandonment obligations. Amounts recorded in the consolidated balance sheet at March 31, 2018 as long-term restricted investments were $3,382. These assets, which primarily include short-term U.S. Government securities, are held in abandonment trusts dedicated to pay future abandonment costs for several of the Company's oil and natural gas properties.

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 the Company's 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 the Company's Board of Directors. Preferred Stock dividends were $1,824 for the three months ended March 31, 2018 and 2017, 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, 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 March 31, 2018, and the Company did not exercise its right to redeem the Preferred Stock, using the closing price of $13.24 as the value of a share of common stock, each share of Preferred Stock would be convertible into approximately 3.8 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.

Common stock

On December 19, 2016, the Company completed an underwritten public offering of 40,000,000 shares of its common stock for total estimated net proceeds (after the underwriter's discounts and estimated offering expenses) of approximately $634,934. Proceeds from the offering were used to substantially fund the Ameredev Transaction, described in Note 3.

Note 11 - Other

Operating leases

As of March 31, 2018 the Company had contracts for five horizontal drilling rigs. The contract terms, as amended through March 31, 2018, will end on various dates between July 2018 and February 2021. All of the drilling rig contracts provide for early termination, with penalties calculated at a reduced daily rate. In the event that Callon terminated all five drilling contracts as of May 2, 2018, the Company would owe a maximum of $23,682 over the remaining terms of the respective contracts, offset by any revenues earned for replacement work subsequently secured by the contractor. Management does not currently anticipate the early termination of any drilling rig contracts.

Other commitments

In March 2018, the Company entered into a contract for dedicated fracturing and pump down perforating crews, which will be effective on April 16, 2018. The term of the agreement is for two years from the effective date.

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 efficiently integrate recent acquisitions;
- prospect development and property acquisitions; and
- the expected impact of the Tax Cuts and Jobs Act of 2017.

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;
- impairments;
- the impact of competition;
- the availability and cost of seismic, drilling and other equipment, water, and personnel;
- 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 hydraulic fracturing and water disposal wells;
- any increase in severance or similar taxes;
- 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;
- cyberattacks on the Company or on systems and infrastructure used by the oil and gas industry;
- 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 in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2017 (the "2017 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 2017 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 2017 Annual Report on Form 10-K, which include additional information about our business practices, significant accounting policies, risk factors, and the transactions that underlie our financial results. Our website address is www.callon.com. All of our filings with the SEC are available free of charge through our website as soon as reasonably practicable after we file them with, or furnish them to, the SEC. Information on our website does not form part of this report on Form 10-Q.

We are an independent oil and natural gas company established in 1950. We are focused on the acquisition, development, exploration and exploitation of unconventional, onshore, oil and natural gas reserves in the Permian Basin. The Permian Basin is located in West Texas and southeastern New Mexico and is comprised of three primary sub-basins: the Midland Basin, the Delaware Basin, and the Central Basin Platform. We have historically been focused on the Midland Basin and more recently entered the Delaware Basin through an acquisition completed in February 2017. Our operating culture is centered on responsible development of hydrocarbon resources, with a particular focus on safety and the environment, which we believe strengthens our operational performance. Our operational performance is enhanced by the empowerment of our employees. Our drilling activity is predominantly focused on the horizontal development of several prospective intervals, including multiple levels of the Wolfcamp formation and the Lower Spraberry shales. 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, leasing programs, acreage purchases, joint ventures and asset swaps. Our production was approximately 77% oil and 23% natural gas for the three months ended March 31, 2018. On March 31, 2018, our net acreage position in the Permian Basin was approximately 56,929 net acres.

Operational Highlights

All of our producing properties are located in the Permian Basin. As a result of our acquisitions and horizontal development efforts, our production grew 30% for the three months ended March 31, 2018, compared to the same period of 2017, increasing to 2,391 MBOE from 1,838 MBOE.

For the three months ended March 31, 2018, we drilled 16 gross (13.2 net) horizontal wells and completed 8 gross (4.4 net) horizontal wells and had 12 gross (10.8 net) horizontal wells awaiting completion.

As of March 31, 2018, we had 553 gross (443.2 net) working interest oil wells, three 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. We continue to evaluate other sources of capital to complement our cash flow from operations and as we pursue our long-term growth plans.

As of March 31, 2018, we had $75.0 million outstanding on our Credit Facility, which had a borrowing base of $700 million with an elected commitment of $500 million. Effective April 5, 2018, the borrowing base was increased to $825 million with an elected commitment of $650 million. For the three months ended March 31, 2018, cash and cash equivalents decreased $16.8 million to $18.5 million compared to $35.3 million at March 31, 2017.

Liquidity and cash flow

	Three Months Ended March 31,	
(in thousands)	2018	2017
Net cash provided by operating activities	$92,215	$52,684
Net cash used in investing activities	(149,353)	(668,501)
Net cash provided by (used in) financing activities	47,616	(1,903)
Net change in cash and cash equivalents	$(9,522)	$(617,720)

Operating activities. For the three months ended March 31, 2018, net cash provided by operating activities was $92.2 million compared to net cash provided by operating activities of $52.7 million for the same period in 2017. The change was predominantly attributable to the following:

- An increase in revenue;
- A decrease on settlements of derivative contracts;
- An increase in certain operating expenses related to acquired properties;
- An decrease in payments in cash-settled restricted stock unit ("RSU") awards; 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 three months ended March 31, 2018, net cash used in investing activities was $149.4 million compared to $668.5 million for the same period in 2017. The change was predominantly attributable to the following:

- A $43.3 million increase in operational expenditures due to the transition from a three-rig program in the first quarter 2017 to a five-rig program commencing February 2018; and
- A $564.3 million decrease in acquisition activity. 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 thousands):

	Three Months Ended March 31,		
	2018	2017	$ Change
Operational expenditures	$98,849	$55,503	$43,346
Seismic, leasehold and other	6,481	6,230	251
Capitalized general and administrative costs	5,187	3,934	1,253
Capitalized interest	813	487	326
Total capital expenditures[(a)]	111,330	66,154	45,176
Acquisitions	38,923	648,485	(609,562)
Acquisition deposits	(900)	(46,138)	45,238
Proceeds from the sale of mineral interest and equipment	—	—	—
Total investing activities	$149,353	$668,501	$(519,148)

(a) On an accrual (GAAP) basis, which is the methodology used for establishing our annual capital budget, operational expenditures for the three months ended March 31, 2018 were $110.3 million. Inclusive of capitalized general and administrative and capitalized interest costs, total capital expenditures for the three months ended March 31, 2018 were $133.2 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 three months ended March 31, 2018, net cash provided by financing activities was $47.6 million compared to net cash used in financing activities of $1.9 million for the same period of 2017. The change was predominantly attributable to the following:

• A $50.0 million increase in net borrowings on our Credit Facility.

Net cash provided by (used in) financing activities includes the following for the periods indicated (in thousands):

	Three Months Ended March 31, 2018		
	2018	2017	$ Change
Net borrowings on senior secured revolving credit facility	$50,000	$—	$50,000
Payment of preferred stock dividends	(1,824)	(1,824)	—
Tax withholdings related to restricted stock units	(560)	(79)	(481)
Net cash provided by (used in) financing activities	$47,616	$(1,903)	$49,519

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

Capital Plan and Year to Date 2018 Summary

Our operational capital budget for 2018 was established in the range of $500 to $540 million on an accrual, or GAAP, basis, inclusive of a transition from a four-rig program that commenced in July 2017 to a five-rig program by mid-February 2018.

As part of our 2018 operated horizontal drilling program, we expect to place 43 to 46 net horizontal wells on production with lateral lengths ranging from 5,000' to 10,000'.

In addition to the operational capital expenditures budget, which includes well costs, facilities and infrastructure capital, and surface land purchases, we budgeted an estimated $23 to $28 million for capitalized general and administrative expenses on an accrual, or GAAP, basis.

Operational capital expenditures on an accrual basis were $110.3 million for the three months ended March 31, 2018. In addition to the operational capital expenditures, $6.3 million of capitalized general and administrative and $10.1 million of capitalized interest expenses were accrued in the three months ended March 31, 2018.

Our revenues, earnings, liquidity and ability to grow are substantially dependent on the prices we receive for, and our ability to develop our reserves of oil and natural gas. We believe the long-term outlook for our business is favorable due to our resource base, low cost structure, financial strength, risk management, including commodity hedging strategy, and disciplined investment of capital. We monitor current and expected market conditions, including the commodity price environment, and our liquidity needs and may adjust our capital investment plan accordingly.

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 March 31,			
	2018	2017	Change	% Change
Net production				
Oil (MBbls)	1,851	1,434	417	29 %
Natural gas (MMcf)	3,240	2,422	818	34 %
Total (MBOE)	2,391	1,838	553	30 %
Average daily production (BOE/d)	26,567	20,422	6,145	30 %
% oil (BOE basis)	77 %	78 %		
Average realized sales price (excluding impact of cash settled derivatives):				
Oil (Bbl)	$62.28	$50.21	$12.07	24 %
Natural gas (Mcf)	3.75	3.86	(0.11)	(3)%
Total (BOE)	53.30	44.27	9.03	20 %
Average realized sales price (including impact of cash settled derivatives):				
Oil (Bbl)	$57.47	$48.45	$9.02	19 %
Natural gas (Mcf)	3.89	3.88	0.01	— %
Total (BOE)	49.76	42.91	6.85	16 %
Oil and natural gas revenues (in thousands)				
Oil revenue	$115,286	$72,008	$43,278	60 %
Natural gas revenue	12,154	9,355	2,799	30 %
Total	$127,440	$81,363	$46,077	57 %
Additional per BOE data				
Sales price [(a)]	$53.30	$44.27	$9.03	20 %
Lease operating expense [(b)]	5.45	6.61	(1.16)	(18)%
Gathering and treating expense [(c)]	—	0.43	(0.43)	(100)%
Production taxes	3.54	3.21	0.33	10 %
Operating margin	$44.31	$34.02	$10.29	30 %

(a) Excludes the impact of cash settled derivatives.

(b) Excludes gathering and treating expense.

(c) On January 1, 2018, the Company adopted the revenue recognition accounting standard. Consequently, natural gas gathering and treating expenses for the three months ended March 31, 2018 were accounted for as a reduction to revenue. See Notes 1 and 2 in the Footnotes to the Financial Statements for additional information regarding revenue recognition and the treatment of gathering and treating expense.

Revenues

The following table reconciles the change in oil, natural gas and total revenue for the respective periods presented by reflecting the effect of changes in volume and in the underlying commodity prices.

(in thousands)	Oil	Natural Gas	Total
Revenues for the three months ended March 31, 2017	$72,008	$9,355	$81,363
Volume increase	20,938	3,157	24,095
Price increase (decrease)	22,340	(358)	21,982
Net increase	43,278	2,799	46,077
Revenues for the three months ended March 31, 2018	$115,286	$12,154	$127,440

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 Credit Facility; and
- the value of our oil and natural gas properties.

For the three months ended March 31, 2018, the average NYMEX price for a barrel of oil was $62.88 per Bbl compared to $51.78 per Bbl for the same period of 2017. The NYMEX price for a barrel of oil for the three months ended March 31, 2018 ranged from a low of $59.19 per Bbl to a high of $66.14 per Bbl.

For the three months ended March 31, 2018, the average NYMEX price for natural gas was $2.84 per MMBtu compared to $3.06 per MMBtu for the same period of 2017. The NYMEX price for natural gas for the three months ended March 31, 2018 ranged from a low of $2.55 per MMBtu to a high of $3.63 per MMBtu.

Oil revenue

For the three months ended March 31, 2018, oil revenues of $115.3 million increased $43.3 million, or 60%, compared to revenues of $72.0 million for the same period of 2017. The increase in oil revenue was primarily attributable to a 29% increase in production and a 24% increase in the average realized sales price, which rose to $62.28 per Bbl from $50.21 per Bbl. The increase in production was comprised of 956 MBbls attributable to wells placed on production as a result of our horizontal drilling program and 10 MBbls from producing wells added from our acquired properties. Offsetting these increases were normal and expected declines from our existing wells.

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

Natural gas revenue (including NGLs)

For the three months ended March 31, 2018, natural gas revenues of $12.2 million increased $2.8 million, or 30%, compared to $9.4 million for the same period of 2017. The increase primarily relates to a 34% increase in natural gas volumes and a 3% increase in the average realized sales price, which rose to $3.75 per Mcf from $3.86 per Mcf, reflecting both natural gas and natural gas liquids prices. The increase in production was comprised of 1,055 MMcf attributable to wells placed on production as a result of our horizontal drilling program and 25 MMcf from producing wells added from our acquired properties. Offsetting these increases were normal and expected declines from our existing wells. Natural gas revenues for the three months ended March 31, 2018, include a reduction of $1.3 million of gathering and treating expense.

See Notes 1, 2 and 3 in the Footnotes to the Financial Statements for additional information regarding revenue recognition and the treatment of gathering and treating expense and the Company’s acquisitions, respectively.

Operating Expenses

(in thousands, except per unit amounts)	Three Months Ended March 31,							
		Per		Per	Total Change		BOE Change	
	2018	BOE	2017	BOE	$	%	$	%
Lease operating expenses [(a)]	$13,039	$5.45	$12,937	$7.04	$102	1 %	$(1.59)	(23)%
Production taxes	8,463	3.54	5,904	3.21	2,559	43%	0.33	10 %
Depreciation, depletion and amortization	35,417	14.81	24,433	13.29	10,984	45%	1.52	11 %
General and administrative	8,769	3.67	5,206	2.83	3,563	68%	0.84	30 %
Accretion expense	218	0.09	184	0.10	34	18%	(0.01)	(10)%
Acquisition expense	548	0.23	450	0.24	98	22%	(0.01)	(4)%

(a) On January 1, 2018, the Company adopted the revenue recognition accounting standard. Consequently, natural gas gathering and treating expenses for the three months ended March 31, 2018 were accounted for as a reduction to revenue. See Notes 1 and 2 in the Footnotes to the Financial Statements for additional information regarding revenue recognition and the treatment of gathering and treating expense.

Lease operating expenses (“LOE”). These are daily costs incurred to extract oil and natural gas and maintain our producing properties. Such costs also include maintenance, repairs, salt water disposal, insurance and workover expenses related to our oil and natural gas properties.

For the three months ended March 31, 2018, LOE increased by 1% to $13.0 million compared to $12.9 million for the same period of 2017. For the three months ended March 31, 2018, LOE per BOE decreased to $5.45 per BOE, excluding gathering and treating expense, compared to $7.04 per BOE, including $0.43 per BOE of gathering and treating expense, for the same period of 2017, which was primarily attributable to higher production volumes from an increased number of producing wells from our horizontal drilling program and acquisitions as discussed above. See Notes 1 and 2 in the Footnotes to the Financial Statements for additional information regarding revenue recognition and the treatment of gathering and treating expense.

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 March 31, 2018 increased by 43% to $8.5 million compared to $5.9 million for the same period of 2017. The increase was primarily due to an increase in severance taxes, which was attributable to the increase in revenue. Also contributing to the increase was an increase in ad valorem taxes, which was attributable to an increase in the valuation of our oil and gas properties by taxing jurisdictions as a result of an increased number of producing wells from our horizontal drilling program, acquisitions as discussed above, and an increase in commodity prices year over year. On a per BOE basis, production taxes for the three months ended March 31, 2018 increased by 10% compared to the same period of 2017.

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 March 31, 2018, DD&A increased 45% to $35.4 million compared to $24.4 million for the same period of 2017. The increase is primarily attributable to a 30% increase in production and an 11% increase in our per BOE DD&A rate. For the three months ended March 31, 2018, DD&A on a per unit basis increased to $14.81 per BOE compared to $13.29 per BOE for the same period of 2017. The increase is attributable to greater increases in our depreciable base and assumed future development costs to undeveloped proved reserves relative to the increase in our estimated proved reserve base. The increases in our depreciable base, assumed future development costs and estimated proved reserve base are a result of additions made through our horizontal drilling efforts and acquisitions.

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 offices, 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 March 31, 2018 increased to $8.8 million compared to $5.2 million for the same period of 2017. The increase is primarily attributable to non-cash compensation and the corresponding rise in personnel costs due to the growth in our operating activities. G&A expenses for the periods indicated include the following (in thousands):

	Three Months Ended March 31,			
	2018	2017	$ Change	% Change
Recurring expenses				
G&A	$6,673	$4,592	$2,081	45 %
Share-based compensation	1,105	921	184	20 %
Fair value adjustments of cash-settled RSU awards	991	(307)	1,298	(423)%
Total G&A expenses	$8,769	$5,206	$3,563	68 %

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 18% for the three months ended March 31, 2018, compared to the same period of 2017. Accretion expense generally correlates with the Company's ARO, which was $10.5 million at March 31, 2018 as compared to $6.2 million at March 31, 2017. See Note 9 in the Footnotes to the Financial Statements for additional information regarding the Company's ARO.

Acquisition expense. Acquisition expense increased $0.1 million for the three months ended March 31, 2018, compared to the same period of 2017. Acquisition expense for all periods was 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.

Other Income and Expenses and Preferred Stock Dividends

(in thousands)	Three Months Ended March 31,			
	2018	2017	$ Change	% Change
Interest expense, net of capitalized amounts	$460	$665	$(205)	(31)%
(Gain) loss on derivative contracts	4,481	(15,303)	19,784	(129)%
Other income	(211)	(708)	497	(70)%
Total other (income) expense	$4,730	$(15,346)		
Income tax expense	$495	$466	$29	6 %
Preferred stock dividends	(1,824)	(1,824)	—	— %

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 March 31, 2018 decreased $0.2 million compared to the same period of 2017. The decrease is primarily attributable to a $3.5 million increase in capitalized interest compared to the 2017 period, resulting from a higher average unevaluated property balance for the three months ended March 31, 2018 as compared to the same period of 2017. The increase in unevaluated property was primarily due to acquired properties. Offsetting the decrease was a $3.3 million increase in interest expense on our Credit Facility and term debt.

See Notes 3 and 5 in the Footnotes to the Financial Statements for additional information on our acquisitions and debt.

Gain (loss) on derivative instruments. 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 March 31, 2018, the net loss on derivative contracts was $4.5 million compared to a $15.3 million net gain for the same period of 2017. The net gain (loss) on derivative instruments for the periods indicated includes the following (in thousands):

	Three Months Ended March 31,	
	2018	2017
Oil derivatives		
Net loss on settlements	$(8,916)	$(2,524)
Net gain on fair value adjustments	4,067	17,266
Total gain (loss) on oil derivatives	$(4,849)	$14,742
Natural gas derivatives		
Net gain on settlements	$457	$33
Net gain (loss) on fair value adjustments	(89)	528
Total gain on natural gas derivatives	$368	$561
Total gain (loss) on oil & natural gas derivatives	$(4,481)	$15,303

See Notes 6 and 7 in the Footnotes to the Financial Statements for additional information on the Company's derivative contracts and disclosures related to derivative instruments.

Income tax expense. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period the rate change is enacted. When appropriate, based on our analysis, we record a valuation allowance for deferred tax assets when it is more likely than not that the deferred tax assets will not be realized.

The Company had income tax expense of $0.5 million for the three months ended March 31, 2018, compared to income tax expense of $0.5 million for the same period of 2017. The change in income tax expense is primarily related to deferred state income tax expense. The Company had a valuation allowance of $49.2 million as of March 31, 2018. See Note 8 in the Footnotes to the Financial Statements for additional information.

Preferred Stock dividends. Preferred Stock dividends of $1.8 million for the three months ended March 31, 2018 were consistent with dividends for the same period of 2017. 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 mitigate 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 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 40% to 60% 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 4,446 MBbls and 4,125 MMBtu of our expected oil and natural gas production, respectively, for the remainder of 2018. We also have commodity hedging contracts linked to Midland WTI basis differentials relative to Cushing covering approximately 3,895 MBbls of our expected oil production for the remainder of 2018. See Note 6 in the Footnotes to the Financial Statements for a description of the Company’s outstanding derivative contracts at March 31, 2018, 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 and call 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 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

The Company is subject to market risk exposure related to changes in interest rates on our indebtedness under our Credit Facility. As of March 31, 2018, the Company had $75.0 million outstanding under the Credit Facility with a weighted average interest rate of 3.75%. An increase or decrease of 1.00% in the interest rate would have a corresponding increase or decrease in our annual net income of approximately $0.8 million based on the balance outstanding at March 31, 2018. See Note 5 in the Footnotes to the Financial Statements for more information on the Company's interest rates on its Credit Facility.

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. The inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. At March 31, 2018 our total receivables from the sale of our oil and natural gas production were approximately $75.2 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 March 31, 2018 our joint interest receivables were approximately $45.4 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 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. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), is accumulated and communicated to the issuer's management, including its principal executive and financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. 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 March 31, 2018.

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

There have been no material changes with respect to the risk factors disclosed in our 2017 Annual Report on Form 10-K.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

Item 6. Exhibits

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

Exhibit Number		Description
3.		Articles of Incorporation and By-Laws
3.1		Certificate of Incorporation of the Company, as amended through May 12, 2016 (incorporated by reference to Exhibit 3.1 of the Company's Quarterly Report on Form 10-Q, filed on November 3, 2016)
3.2		Certificate of Designation of Rights and Preferences of 10.00% 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 to Exhibit 3.3 of the Company's Form 10-K, filed on February 28, 2018)
4.		Instruments defining the rights of security holders, including indentures
4.1		Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 of the Company's Form 10-K, filed on February 28, 2018)
4.2		Certificate for the Company's 10.00% Series A Cumulative Preferred Stock (incorporated by reference to Exhibit 4.1 of the Company's Form 8-A, filed on May 23, 2013)
4.3		Registration Rights Agreement, dated May 26, 206, among Callon Petroleum Company and each of the Persons set forth on Schedule A therein (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on May 31, 2016)
4.4		Indenture of 6.125% Senior Notes Due 2024, dated as of October 3, 2016, among Callon Petroleum Company, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed on October 4, 2016)
4.5		Registration Rights Agreement of 6.125% Senior Notes Due 2024, dated May 24, 2017, among Callon Petroleum Company, Callon Petroleum Operating Company and J.P. Morgan Securities LLC, as representative of the Initial Purchasers named on Annex E thereto (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed on May 24, 2017)
10.		Material contracts
10.1		Callon Petroleum Company 2018 Omnibus Incentive Plan (incorporated by reference to Exhibit A of the Company's Definitive Proxy Statement on Schedule 14A, filed on March 23, 2018)
10.2		Amendment No. 1 to the Sixth Amended and Restated Credit Agreement, dated April 5, 2018, among Callon Petroleum Company, JPMorgan Chase Bank, National Association, as administrative agent and the Lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on April 6, 2018)
31.		Section 13a-14 Certifications
31.1	(a)	Certification of Chief Executive Officer pursuant to Rule 13(a)-14(a)
31.2	(a)	Certification of Chief Financial Officer pursuant to Rule 13(a)-14(a)
32.	(b)	Section 1350 Certifications of Chief Executive and Financial Officers pursuant to Rule 13(a)-14(b)
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/ Joseph C. Gatto, Jr. Joseph C. Gatto, Jr.	President and Chief Executive Officer	May 2, 2018
/s/ James P. Ulm, II James P. Ulm, II	Senior Vice President and Chief Financial Officer	May 2, 2018