BHP BILLITON PLC
Form 6-K
June 01, 2005

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 6-K

REPORT OF FOREIGN ISSUER

PURSUANT TO RULE 13a-16 OR 15d-16 OF

THE SECURITIES EXCHANGE ACT OF 1934

For the Date of 27 May 2005

BHP Billiton Plc

Registration Number 3196209

Neathouse Place

London SW1V 1BH

United Kingdom

Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20-F or Form 40-F.

Form 20-F X Form 40-F

Indicate by check mark whether the registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934

Yes No X

If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b):

SCHEDULE 10
NOTIFICATION OF MAJOR INTERESTS IN SHARES
All relevant boxes should be completed in block capital letters.

1. Name of company

2. Name of shareholder having a major interest

BHP BILLITON PLC	THE CAPITAL GROUP COMPANIES, INC.
3. Please state whether notification indicates that it is in respect of holding of the shareholder named in 2 above or in respect of a non-beneficial interest or in the case of an individual holder if it is a holding of that person's spouse or children under the age of 18	4. Name of the registered holder(s) and, if more than one holder, the number of sharesheld by each of them
NOTIFICATION BY THE CAPITAL GROUP COMPANIES, INC. ON BEHALF OF ITS AFFILIATES	SEE SCHEDULE B ANNEXED HERETO

5. Number of shares/amount of stock acquired	6. Percentage of issued class	7. Number of shares/ amount of stock disposed	8. Percentage of issued class
		21,439,413	0.869%

9. Class of security	10. Date of transaction	11. Date company informed
ORDINARY US$0.50	24 MAY 2005	26 MARCH 2005

12. Total holding following this notification	13. Total percentage holding of issued class following this notification
74,026,297	2.999%

14. Any additional information	15. Name of contact and telephone number for queries
ANNOUNCEMENT TRIGGERED BY THE CAPITAL GROUP COMPANIES, INC CEASING TO HOLD A NOTIFIABLE INTEREST (SEE SCHEDULE A ANNEXED HERETO)	INES WATSON +44 (0)20 7802 4176

16. Name and signature of authorised company official responsible for making this notification

INES WATSON, ASSISTANT SECRETARY, BHP BILLITON PLC

Date of notification 27 MAY 2005

Schedule of holdings in BHP Billiton Plc as of 24 May 2005

BHP Billiton Plc

Schedule A

	Number of Shares	Percent of Outstanding
The Capital Group Companies, Inc. ("CG") holdings	74,026,297	2.999%
Holdings by CG Management Companies and Funds:		
- Capital Guardian Trust Company	17,736,265	0.719%
- Capital International Limited	30,707,406	1.244%
- Capital International S.A.	5,992,953	0.243%
- Capital International, Inc.	8,124,655	0.329%
- Capital Research and Management Company	11,465,018	0.465%

Schedule of holdings in BHP Billiton Plc as of 24 May 2005

BHP Billiton Plc

Schedule B

Capital Guardian Trust Company

Registered Name	Local Shares
State Street Nominees Limited Canary Wharf 27th Floor, 1 Canada Square London E14 5AF	2,080,892
Bank of New York Nominees Bank of New York 3 Birchin Lane London EC3V 9BY	444,598
Northern Trust C/o NorTrust Nominees Limited 155 Bishopsgate London EC2M 3XS	75,298
Chase Nominees Limited	7,627,812

Woolgate House Coleman Street London EC2P 2HD	
BT Globenet Nominees Ltd 1 Appold Street Broadgate London EC2A 2HE	153,085
Midland Bank plc 5 Laurence Poutney Hill London EC4R OE	3,287,191
Bankers Trust 59 1/2 Southmark Street 2nd Floor London SE1 OHH	462,351
Registered Name Local Shares	
Barclays Bank Barclays Global Securities Services 8 Angel Court London EC2R 7HT	265,459
Citibank London 11 Old Jewry London EC2R 8D8	5,802
Royal Trust	10,600
Brown Bros One Mellon Bank Center Pittsburgh, PA 15258	8,700
Nortrust Nominees 155 Bishopsgate London EC2M 3XS	1,844,380
Royal Bank of Scotland Regents House, 42 Islington High St London N1 8XL	28,305
MSS Nominees Limited Midland Bank plc Mariner House, Pepys London EC3N 4DA	12,810
State Street Bank & Trust Co	92,838
Citibank	10,200
HSBC Bank plc Securities Services, Mariner House Pepys Street London EC3N 4DA	7,272
Mellon Bank N.A. London Branch London	50,700
ROY Nominees Limited	11,496

71N Queen Victoria Street London EC4V 4DE	
Mellon Nominees (UK) Limited 150 Buchanan Street Glasgow G1 2DY	623,755
JP Morgan Chase Bank	632,721
Total	17,736,265

Schedule of holdings in BHP Billiton Plc as of 24 May 2005

Capital International Limited

Registered Name	Local Shares
State Street Nominees Limited Canary Wharf 27th Floor, 1 Canada Square London E14 5AF	767,667
Bank of New York Nominees Bank of New York 3 Birchin Lane London EC3V 9BY	8,580,963
Northern Trust C/o NorTrust Nominees Limited 155 Bishopsgate London EC2M 3XS	2,119,429
Chase Nominees Limited Woolgate House Coleman Street London EC2P 2HD	4,467,252
Midland Bank plc 5 Laurence Poutney Hill London EC4R OE	180,559
Bankers Trust 59 1 / 2 Southmark Street 2nd Floor London SE1 OHH	238,463
Barclays Bank Barclays Global Securities Services 8 Angel Court London EC2R 7HT	360,879
Citibank London 11 Old Jewry London EC2R 8D8	314,129

Registered Name Local Shares	
Morgan Guaranty 83 Pall Mall London SW1Y 5ES	239,032
Nortrust Nominees 155 Bishopsgate London EC2M 3XS	4,539,719
Royal Bank of Scotland Regents House, 42 Islington High Street London N1 8XL	1,529,069
MSS Nominees Limited Midland Bank plc Mariner House, Pepys London EC3N 4DA	64,200
State Street Bank & Trust Co	2,625,368
National Westminster Bank	372,722
Lloyds Bank Central Settlement Section Branches Stock Office 34 Threadneedle Street	98,912
Citibank NA Toronto	79,294

Registered Name Local Shares	
Deutsche Bank AG 23 Great Winchester Street London EC2P 2AX	1,240,756
State Street Australia Limited Australia	11,300
HSBC Bank plc Securities Services, Mariner House Pepys Street London EC3N 4DA	936,817
Mellon Bank N.A. London Branch London	370,039
Northern Trust AVFC South Africa	289,432
KAS UK Kass Associate P.O. Box 178 1000 AD Amsterdam	78,500
Mellon Nominees (UK) Limited 150 Buchanan Street Glasgow G1 2DY	317,589
Bank One London	333,473

Clydesdale Bank plc	238,243
JP Morgan Chase Bank	313,600
Total	30,707,406

Schedule of holdings in BHP Billiton Plc as of 24 May 2005

Capital International S.A.

Registered Name	Local Shares
State Street Nominees Limited Canary Wharf 27th Floor, 1 Canada Square London E14 5AF	18,565
Bank of New York Nominees Bank of New York 3 Birchin Lane London EC3V 9BY	24,400
Chase Nominees Limited Woolgate House Coleman Street London EC2P 2HD	1,250,140
Credit Suisse London Branch 24 Bishopsgate London EC2N 4BQ	102,755
Midland Bank plc 5 Laurence Poutney Hill EC4R OE	454,211
Barclays Bank Barclays Global Securities Services 8 Angel Court London EC2R 7HT	273,647
Pictet & Cie, Geneva	45,300
Citibank London 11 Old Jewry London EC2R 8D8	59,324
Brown Bros One Mellon Bank Center Pittsburgh, PA 15258	51,196
Nortrust Nominees 155 Bishopsgate London EC2M 3XS	37,286
Morgan Stanley	34,105

Royal Bank of Scotland Regents House, 42 Islington High Street London N1 8XL	71,326
J.P. Morgan	2,845,627
National Westminster Bank	78,800
Lloyds Bank Central Settlement Section Branches Stock Office 34 Threadneedle Street	7,000
RBSTB Nominees Ltd 67 Lombard Street London EC3 3DL UK	144,200
Citibank NA Toronto	28,033
Deutsche Bank AG 23 Great Winchester Street London EC2P 2AX	264,832
HSBC Bank plc Securities Services, Mariner House Pepys Street London EC3N 4DA	202,206
Total	5,992,953

Schedule of holdings in BHP Billiton Plc as of 24 May 2005

Capital International, Inc.

Registered Name	Local Shares
State Street Nominees Limited Canary Wharf 27th Floor, 1 Canada Square London E14 5AF	3,183,692
Bank of New York Nominees Bank of New York 3 Birchin Lane London EC3V 9BY	626,099
Northern Trust C/o NorTrust Nominees Limited 155 Bishopsgate London EC2M 3XS	49,889
Chase Nominees Limited Woolgate House Coleman Street	2,213,410

London EC2P 2HD	
Midland Bank plc 5 Laurence Poutney Hill London EC4R OE	211,214
Bankers Trust 59 1/2 Southmark Street 2nd Floor London SE1 OHH	22,991
Citibank London 11 Old Jewry London EC2R 8D8	45,200
Brown Bros One Mellon Bank Center Pittsburgh, PA 15258	147,502
Nortrust Nominees 155 Bishopsgate London EC2M 3XS	217,650
Royal Bank of Scotland Regents House, 42 Islington High Street London N1 8XL	149,169
State Street Bank & Trust Co.	195,753
Sumitomo Trust & Banking Fiduciary & Securities Business Dept. 1-5 Nihonbashi - Honcho 4-chome Cho-ku, Tokyo 103	55,300
Citibank	32,147
RBSTB Nominees Ltd 67 Lombard Street London EC3 3DL UK	32,995
Citibank NA Toronto	413,644
State Street Australia Limited Australia	43,200
HSBC Bank plc Securities Services, Mariner House Pepys Street London EC3N 4DA	106,800
JP Morgan Chase Bank	378,000
Total	8,124,655

Schedule of holdings in BHP Billiton Plc as of 24 May 2005

Capital Research and Management Company

Registered Name		Local Shares
State Street Nominees Limited Canary Wharf 27th Floor, 1 Canada Square London E14 5AF		1,500,000
Chase Nominees Limited Woolgate House Coleman Street London EC2P 2HD		9,965,018
	Total	11,465,018

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.

BHP BILLITON Plc
/s/ KAREN WOOD

Karen Wood
Title: Company Secretary
Date: 27 May 2005

style="font-family:inherit;font-size:10pt;">Production taxes

10,263

5,444

26,265

16,168

Depreciation, depletion and amortization
48,257

28,525

122,407

79,172

General and administrative
9,721

7,259

26,779

18,894

Settled share-based awards
—

—

—

6,351

Accretion expense
202

131

626

523

Acquisition expense
1,435

205

3,750

3,027

Total operating expenses
88,403

53,188

224,532

160,843

Income from operations
72,811

31,426

201,197

87,418

Other (income) expenses:

Interest expense, net of capitalized amounts
711

444

1,765

1,698

(Gain) loss on derivative contracts

34,339

14,162

55,374

(11,636
)
Other income
(1,657
)

(498
)

(2,571
)

(1,270
)
Total other (income) expense
33,393

14,108

54,568

(11,208
)
Income before income taxes
39,418

17,318

146,629

98,626

Income tax expense
1,487

237

2,463

1,026

Net income
37,931

17,081

144,166

97,600

Preferred stock dividends
(1,823
)

(1,824
)

(5,471
)

(5,471
)
Income available to common stockholders
$
36,108

$
15,257

$
138,695

$
92,129

Income per common share:

Basic
$
0.16

$
0.08

$
0.65

$
0.46

Diluted
$
0.16

$
0.08

$
0.65

$
0.46

Shares used in computing income per common share:

Basic
227,564

201,827

213,409

201,422

Diluted
228,140

202,337

214,079

201,995

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)

	Nine Months Ended September 30,	
	2018	2017
Cash flows from operating activities:		
Net income	$144,166	$97,600
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation, depletion and amortization	124,430	80,829
Accretion expense	626	523
Amortization of non-cash debt related items	1,749	1,695
Deferred income tax expense	2,463	1,026
Net (gain) loss on derivatives, net of settlements	29,696	(15,608)
(Gain) loss on sale of other property and equipment	(80)	62
Non-cash expense related to equity share-based awards	4,466	7,014
Change in the fair value of liability share-based awards	1,428	2,423
Payments to settle asset retirement obligations	(1,080)	(1,831)
Changes in current assets and liabilities:		
Accounts receivable	(54,384)	(12,148)
Other current assets	(1,665)	(336)
Current liabilities	64,801	7,534
Other long-term liabilities	5,787	121
Long-term prepaid	—	(4,650)
Other assets, net	(1,398)	(1,376)
Payments to settle vested liability share-based awards	(4,990)	(13,173)
Net cash provided by operating activities	316,015	149,705
Cash flows from investing activities:		
Capital expenditures	(455,352)	(267,218)
Acquisitions	(595,984)	(714,504)
Acquisition deposit	—	46,138
Proceeds from sale of assets	8,326	—
Net cash used in investing activities	(1,043,010)	(935,584)
Cash flows from financing activities:		
Borrowings on senior secured revolving credit facility	270,000	—
Payments on senior secured revolving credit facility	(230,000)	—
Issuance of 6.125% senior unsecured notes due 2024	—	200,000
Premium on the issuance of 6.125% senior unsecured notes due 2024	—	8,250
Issuance of 6.375% senior unsecured notes due 2026	400,000	—
Issuance of common stock	288,364	—
Payment of preferred stock dividends	(5,471)	(5,471)
Payment of deferred financing costs	(9,960)	(7,166)
Tax withholdings related to restricted stock units	(1,804)	(1,118)
Net cash provided by financing activities	711,129	194,495
Net change in cash and cash equivalents	(15,866)	(591,384)
Balance, beginning of period	27,995	652,993
Balance, end of period	$12,129	$61,609

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.

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.

Callon Petroleum Company Notes to the Consolidated Financial Statements (All dollar amounts in thousands, except per share and per unit data) Table of Contents

Prior to the adoption of ASC 606, gathering and treating fees associated with our gas processing agreements have historically been presented within lease operating expenses in the statement of operations. The current period presentation reports these fees as a reduction to natural gas revenues. See Note 2 for additional information on revenue recognition.

The Company adopted the new standard on January 1, 2018 using the modified retrospective method at the date of adoption and the impact of adoption on the current period statement of operations is as follows:

	Three Months Ended September 30, 2018		
	As reported	Adjustments	Presentation without adoption of ASC Topic 606
Operating revenues:			
Natural gas sales	$18,613	$ 2,209	$ 20,822
Total operating revenues	161,214	2,209	163,423
Operating expenses:			
Lease operating expenses	$18,525	$ 2,209	$ 20,734
Total operating expenses	88,403	2,209	90,612

	Nine Months Ended September 30, 2018		
	As reported	Adjustments	Presentation without adoption of ASC Topic 606
Operating revenues:			
Natural gas sales	$45,229	$ 5,413	$ 50,642
Total operating revenues	425,729	5,413	431,142
Operating expenses:			
Lease operating expenses	$44,705	$ 5,413	$ 50,118
Total operating expenses	224,532	5,413	229,945

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. 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 - Leases

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842): Amendments to the FASB Accounting Standards Codification ("ASU 2016-02"). In January 2018, the FASB issued ASU No. 2018-01, Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842 ("ASU 2018-01"). In July 2018, the FASB issued ASU No. 2018-11, Leases (Topic 842): Targeted Improvements ("ASU 2018-11"). Together these related amendments to GAAP represent ASC Topic 842, Leases ("ASC Topic 842").

ASC Topic 842 requires lessees to recognize lease assets and liabilities (with terms in excess of 12 months) on the balance sheet, disclose key quantitative and qualitative information about leasing arrangements, and permits an entity not to evaluate existing or expired land easements that were not previously assessed under Topic 840. The Company has engaged a third party consultant to assist with its current process of assessing existing contracts, as well as future potential contracts, and to determine the impact of applying Topic 842 on its consolidated financial statements and related disclosures. The contract evaluation process includes review of drilling rig contracts, field vehicles and equipment, office facility leases, compressors, general corporate leased equipment, and other existing arrangements that may contain a lease component. The Company will adopt this guidance as of January 1, 2019, the transition date, using a modified retrospective method with use of the transition option, in which a cumulative-effect adjustment will be recognized in the opening balance of retained earnings in the period of adoption. The Company expects the adoption of ASC Topic 842 to primarily impact the asset and liability balances on the balance sheet and will result in changes to the timing and presentation of certain operating expenses on its consolidated statement of operations.

Recently issued ASUs - Other

In June 2018, the FASB issued ASU No. 2018-07, Compensation - Stock Compensation (Topic 718): Improvements to Nonemployee Share-Based Payment Accounting ("ASU 2018-07"). The standard is intended to simplify several aspects of the accounting for nonemployee share-based payment transactions for acquiring goods and services from nonemployees, including the timing and measurement of nonemployee awards. The guidance in ASU 2018-06 is effective for public entities for annual reporting periods beginning after December 15, 2018, including interim periods therein. Early adoption is permitted, but no earlier than an entity's adoption date of Topic 606. The Company does not expect a material impact on its consolidated financial statements upon adoption of this guidance.

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 and nine months ended September 30, 2018, $2,209 and $5,413 of gathering and treating fees were recognized and recorded as a reduction to natural gas revenues in the consolidated statement of operations, respectively. For the three and nine months ended September 30, 2017, $909 and $2,393 of gathering and treating fees were recognized and recorded as part of lease operating expense in the consolidated statement of operations, respectively.

Callon Petroleum Company Notes to the Consolidated Financial Statements (All dollar amounts in thousands, except per share and per unit data) Table of Contents

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 first quarter of 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.

On August 31, 2018, the Company completed the acquisition of approximately 28,000 net surface acres in the Spur operating area, located in the Delaware Basin, from Cimarex Energy Company, for $539,519, including customary purchase price adjustments (the "Cimarex Asset Acquisition"). The Company issued debt and equity to fund, in part, the Cimarex Asset Acquisition. See Notes 5 and 10 for additional information regarding the Company's debt obligations and equity offerings. The following table summarizes the estimated acquisition date fair values of the acquisition:

Evaluated oil and natural gas properties	$253,089
Unevaluated oil and natural gas properties	287,000
Asset retirement obligations	(570)
Net assets acquired	$539,519

The preliminary purchase price allocations are subject to change based on numerous factors, including the final adjusted purchase price and the final estimated fair value of the assets acquired and liabilities assumed. Any such adjustments to the preliminary estimates of fair value could be material.

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 $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.

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 $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 Cimarex Asset Acquisition and Ameredev Transaction had occurred as presented, or to project the Company's results of operations for any future periods:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018 [(a)]	2017 [(a)]	2018 [(a)]	2017 [(a)]
Revenues	$181,880	$107,966	$506,864	$326,357
Income from operations	82,057	42,556	238,776	124,005
Income available to common stockholders	44,703	26,387	175,623	128,716
Net income per common share:				
Basic	$0.20	$0.13	$0.82	$0.64
Diluted	$0.20	$0.13	$0.82	$0.64

(a) The pro forma financial information was prepared assuming the Cimarex Asset Acquisition and the Ameredev Transaction occurred as of January 1, 2017.

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 Cimarex Asset Acquisition and 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 September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Net income	$37,931	$17,081	$144,166	$97,600

Preferred stock dividends	(1,823)	(1,824)	(5,471)	(5,471)
Income available to common stockholders	$36,108	$15,257	$138,695	$92,129
Weighted average shares outstanding	227,564	201,827	213,409	201,422
Dilutive impact of restricted stock	576	510	670	573
Weighted average shares outstanding for diluted income per share	228,140	202,337	214,079	201,995
Basic income per share	$0.16	$0.08	$0.65	$0.46
Diluted income per share	$0.16	$0.08	$0.65	$0.46
Restricted stock [(a)]	154	51	154	51

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

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Note 5 - Borrowings

The Company's borrowings consisted of the following at:

	September 30, 2018	December 31, 2017
Principal components:		
Senior secured revolving credit facility	$ 65,000	$ 25,000
6.125% senior unsecured notes due 2024	600,000	600,000
6.375% senior unsecured notes due 2026	400,000	—
Total principal outstanding	1,065,000	625,000
Premium on 6.125% senior unsecured notes due 2024, net of accumulated amortization	6,750	7,594
Unamortized deferred financing costs	(18,222)	(12,398)
Total carrying value of borrowings	$ 1,053,528	$ 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.

Effective 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.

Effective September 27, 2018, the Company entered into the second amendment to the Sixth Amended and Restated Credit Agreement to the Credit Facility, which (1) increased the borrowing base to $1,100,000, (2) increase the elected commitment amount to $850,000, and (3) amended various covenants and terms to reflect current market trends. As of September 30, 2018, the Credit Facility's borrowing base remained at $1,100,000 with an elected commitment amount of $850,000.

As of September 30, 2018, there was $65,000 principal and $17,675 in letters of credit outstanding under the Credit Facility. For the quarter ended September 30, 2018, the Credit Facility had a weighted-average interest rate of 3.29%, calculated as the LIBOR plus a tiered rate ranging from 1.25% to 2.25%, 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.

6.375% senior unsecured notes due 2026 ("6.375% Senior Notes")

On June 7, 2018, the Company issued $400,000 aggregate principal amount of 6.375% Senior Notes with a maturity date of July 1, 2026 and interest payable semi-annually beginning on January 1, 2019. The net proceeds of the offering, after deducting initial purchasers' discounts and estimated offering expenses, were approximately $394,000. The 6.375% 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.

The Company may redeem the 6.375% Senior Notes in accordance with the following terms: (1) prior to July 1, 2021, 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 106.375% 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 July 1, 2021, 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 103.188% of principal if the redemption occurs on or after July 1, 2021, but before July 1, 2022, and (ii) of 102.125% of principal if the redemption occurs on or after July 1, 2022, but before July 1, 2023, and (iii) of 101.063% of principal if the redemption occurs on or after July 1, 2023, but before July 1, 2024, and (iv) of 100% of principal if the redemption occurs on or after July 1, 2024.

Following a change of control, each holder of the 6.375% Senior Notes may require the Company to repurchase all or a portion of the 6.375% 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.

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 indentures governing its 6.125% and 6.375% 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 September 30, 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.

Callon Petroleum Company Notes to the Consolidated Financial Statements (All dollar amounts in thousands, except per share and per unit data) Table of Contents

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. 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	9/30/2018	12/31/2017	9/30/2018	12/31/2017	9/30/2018	12/31/2017
Natural gas	Current	Fair value of derivatives	$750	$ 406	$(21)	$—	$729	$406
Natural gas	Non-current	Fair value of derivatives	—	—	(1,299)	—	(1,299)	—
Oil	Current	Fair value of derivatives	3,539	—	(47,146)	(27,744)	(43,607)	(27,744)
Oil	Non-current	Fair value of derivatives	—	—	(14,141)	(1,284)	(14,141)	(1,284)
Totals			$4,289	$ 406	$(62,607)	$(29,028)	$(58,318)	$(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:

	September 30, 2018		
	Presented without Effects of Netting	Effects of Netting	As Presented with Effects of Netting
Current assets: Fair value of derivatives	$16,157	$(11,868)	$4,289
Long-term assets: Fair value of derivatives	2,786	(2,786)	—

Current liabilities: Fair value of derivatives	$(59,035)	$11,868	$(47,167)
Long-term liabilities: Fair value of derivatives	(18,226)	2,786	(15,440)

	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)

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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 September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Oil derivatives				
Net loss on settlements	$(9,306)	$(1,373)	$(26,353)	$(4,213)
Net gain (loss) on fair value adjustments	(24,476)	(12,811)	(28,720)	14,584
Total gain (loss) on oil derivatives	$(33,782)	$(14,184)	$(55,073)	$10,371
Natural gas derivatives				
Net gain on settlements	$67	$159	$675	$241
Net gain (loss) on fair value adjustments	(624)	(137)	(976)	1,024
Total gain (loss) on natural gas derivatives	$(557)	$22	$(301)	$1,265
Total gain (loss) on oil & natural gas derivatives	$(34,339)	$(14,162)	$(55,374)	$11,636

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Derivative positions

Listed in the tables below are the outstanding oil and natural gas derivative contracts as of September 30, 2018:

Oil contracts (WTI)	For the Remainder of 2018	For the Full Year of 2019	For the Full Year of 2020
Swap contracts			
Total volume (Bbls)	552,000	—	—
Weighted average price per Bbl	$ 52.07	$ —	$ —
Collar contracts (two-way collars)			
Total volume (Bbls)	92,000	1,095,000	—
Weighted average price per Bbl			
Ceiling (short call)	$ 60.50	$ 80.00	$ —
Floor (long put)	$ 50.00	$ 65.00	$ —
Collar contracts combined with short puts (three-way collars)			
Total volume (Bbls)	874,000	3,469,000	—
Weighted average price per Bbl			
Ceiling (short call option)	$ 60.86	$ 63.71	$ —
Floor (long put option)	$ 48.95	$ 53.95	$ —
Short put option	$ 39.21	$ 43.95	$ —
Puts			
Total volume (Bbls)	276,000	1,825,000	—
Weighted average price per Bbl	$ 65.00	$ 65.00	$ —
Oil contracts (Midland basis differential)			
Swap contracts			
Total volume (Bbls)	1,518,000	4,746,500	4,024,000
Weighted average price per Bbl	$ (5.30)	$ (4.72)	$ (1.51)
Natural gas contracts (Henry Hub)			
Swap contracts			
Total volume (MMBtu)	1,380,000	—	—
Weighted average price per MMBtu	$ 2.91	$ —	$ —
Collar contracts (two-way collars)			
Total volume (MMBtu)	552,000	2,372,500	—
Weighted average price per MMBtu			
Ceiling (short call)	$ 3.19	$ 2.95	$ —
Floor (long put)	$ 2.75	$ 2.65	$ —
Natural gas contracts (Waha basis differential)			
Swap contracts			
Total volume (MMBtu)	552,000	5,840,000	2,196,000
Weighted average price per MMBtu	$ (1.14)	$ (1.21)	$ (1.14)

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Subsequent Event

The following derivative contracts were executed subsequent to September 30, 2018:

	For the Remainder of 2018	For the Full Year of 2019	For the Full Year of 2020
Natural gas contracts (Henry Hub)			
Collar contracts (two-way collars)			
Total volume (MMBtu)	—	1,355,000	—
Weighted average price per MMBtu			
Ceiling (short call)	—	$ 3.45	—
Floor (long put)	—	$ 2.83	—
Natural gas contracts (Waha basis differential)			
Swap contracts			
Total volume (MMBtu)	—	3,650,000	—
Weighted average price per MMBtu	—	$ (1.30)	—

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.

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.

	September 30, 2018		December 31, 2017	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Credit Facility [(a)]	$65,000	$—	$25,000	$—
6.125% Senior Notes [(b)]	595,729	610,500	595,196	618,000
6.375% Senior Notes [(b)]	392,799	409,000	—	—
Total	$1,053,528	$1,019,500	$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% and 6.375% 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.

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

September 30, 2018	Classification	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments	Fair value of derivatives	$ —	$4,289	$ —	$4,289
Liabilities					
Derivative financial instruments	Fair value of derivatives	—	(62,607)	—	(62,607)
Total net liabilities		$ —	$(58,318)	$ —	$(58,318)

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 are 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 primarily relates to deferred State of Texas gross margin tax. The valuation allowance was $30,281 as of September 30, 2018.

Note 9 - Asset Retirement Obligations

The table below summarizes the activity for the Company's ARO:

	Nine Months Ended

	September 30, 2018
Asset retirement obligations at January 1, 2018	$ 6,020
Accretion expense	626
Liabilities incurred	729
Liabilities settled	(989)
Sales	(612)
Revisions to estimate [a]	4,118
Asset retirement obligations at end of period	9,892
Less: Current asset retirement obligations	(4,464)
Long-term asset retirement obligations at September 30, 2018	$ 5,428

(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 September 30, 2018 as long-term restricted investments were $3,413. 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 $1,823 and $1,824 for the three months ended September 30, 2018 and 2017, respectively. Preferred Stock dividends of $5,471 for the nine months ended September 30, 2018 remained consistent compared to the same period of 2017.

The Preferred Stock has no stated maturity and is not subject to any sinking fund or other mandatory redemption. The Company may, at its option, redeem the Preferred Stock, in whole or in part, at any time on or after May 30, 2018, 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 September 30, 2018, and the Company did not exercise its right to redeem the Preferred Stock, using the closing price of $11.99 as the value of a share of common stock, each share of Preferred Stock would be convertible into approximately 4.2 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 May 30, 2018, the Company completed an underwritten public offering of 25,300,000 shares of its common stock for total estimated net proceeds (after the underwriter’s discounts and estimated offering costs) of approximately $288,364. The Company used proceeds from the offering to partially fund the Cimarex Asset Acquisition completed in the third quarter, described in Note 3.

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 September 30, 2018 the Company had contracts for five horizontal drilling rigs. The contract terms, as amended effective as of July 9, 2018, will end on various dates between July 2019 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 November 6, 2018, the Company would owe a maximum of $26,696 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 was effective on April 16, 2018 for a two-year period. The agreement was amended effective October 16, 2018 to reflect updated market conditions and to extend the contract expiration date to December 31, 2021.

In August 2018, the Company executed a firm transportation agreement for dedicated capacity on a new pipeline system that will connect with a regional gathering system which currently transports oil volumes under long-term agreements from our properties in Howard,

Ward, Reagan and Upton counties to multiple marketing points in the Permian Basin. Subject to completion of the new pipeline system, which will have delivery points in several locations along the Gulf Coast, we will have a long-term commitment that will apply applicable tariff rates to our 15,000 Bbls per day commitment for the term of the agreement. Barrels may be transported to multiple delivery points along the Gulf Coast and may include volumes produced by us and other third-party working, royalty, and overriding royalty interest owners whose volumes we market on their behalf.

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 consummate and 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;
- risks associated with acquisitions, including liabilities associated with acquired properties or businesses and the ability to realize expected benefits;
- 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, including the potential for capacity constraints in pipeline systems;
- 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, 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 nine months ended September 30, 2018. On September 30, 2018, our net acreage position in the Permian Basin was approximately 87,000 net acres.

Acquisition Highlights

On August 31, 2018, the Company completed the acquisition of approximately 28,000 net surface acres in the Spur operating area, located in the Delaware Basin, from Cimarex Energy Company, for $539.5 million, including customary purchase price adjustments (the "Cimarex Asset Acquisition"). The Company issued debt and equity to fund, in part, the Cimarex Asset Acquisition. See Notes 3, 5, and 10 in the Footnotes to the Financial Statements for additional information regarding the Company's acquisitions, debt obligations, and equity offerings.

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 55% and 39% for the three and nine months ended September 30, 2018, compared to the same periods of 2017, respectively. Production increased to 3,212 MBOE for the three months ended September 30, 2018 from 2,074 MBOE for the three months ended September 30, 2017 and increased to 8,238 MBOE for the nine months ended September 30, 2018 from 5,934 MBOE for the nine months ended September 30, 2017.

For the three months ended September 30, 2018, we drilled 19 gross (15.2 net) horizontal wells and completed 19 gross (14.6 net) horizontal wells. For the nine months ended September 30, 2018, we drilled 53 gross (42.2 net) horizontal wells and completed 46 gross (36.3 net) horizontal wells. As of September 30, 2018, we had 12 gross (10.0 net) horizontal wells awaiting completion.

As of September 30, 2018, we had 846 gross (641.6 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 non-core 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 September 30, 2018, we had $65 million principal outstanding on our Credit Facility, which had a borrowing base of $1.1 billion with an elected commitment of $850 million. At period ended September 30, 2018, we held cash and cash equivalents of $12.1 million as compared to $28.0 million at year ended December 31, 2017.

Liquidity and cash flow

	Nine Months Ended September 30,	
(in thousands)	2018	2017
Net cash provided by operating activities	$316,015	$149,705
Net cash used in investing activities	(1,043,010)	(935,584)
Net cash provided by financing activities	711,129	194,495
Net change in cash and cash equivalents	$(15,866)	$(591,384)

Operating activities. For the nine months ended September 30, 2018, net cash provided by operating activities was $316.0 million compared to net cash provided by operating activities of $149.7 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 nine months ended September 30, 2018, net cash used in investing activities was $1.0 billion compared to $935.6 million for the same period in 2017. The change was predominantly attributable to the following:

- A $178.9 million increase in operational expenditures due to the transition from a three-rig program in the second quarter 2017 to a five-rig program commencing February 2018; and
- An $80.7 million decrease in acquisition activity, net of proceeds from sale of assets. 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):

	Nine Months Ended September 30,		
	2018	2017	$ Change
Operational expenditures	$411,109	$232,169	$178,940
Seismic, leasehold and other	7,137	11,379	(4,242)
Capitalized general and administrative costs	16,544	11,913	4,631
Capitalized interest	20,562	11,757	8,805
Total capital expenditures[(a)]	455,352	267,218	188,134
Acquisitions	595,984	714,504	(118,520)
Acquisition deposits	—	(46,138)	46,138
Proceeds from sale of assets	(8,326)	—	(8,326)
Total investing activities	$1,043,010	$935,584	$107,426

(a)

On an accrual (GAAP) basis, which is the methodology used for establishing our annual capital budget, operational expenditures for the nine months ended September 30, 2018 were $435.1 million. Inclusive of seismic, leasehold and other, capitalized general and administrative, and capitalized interest costs, total capital expenditures for the nine months ended September 30, 2018 were $500.7 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 nine months ended September 30, 2018, net cash provided by financing activities was $711.1 million compared to net cash provided by financing activities of $194.5 million for the same period of 2017. The change was predominantly attributable to the following:

- An increase in proceeds from a common stock offering in 2018 that raised $288.4 million as compared to no offerings in 2017;

- A $200.0 million increase in net borrowings on fixed-rate debt, resulting from the issuances of $400 million of 6.375% Senior Notes in 2018 as compared to $200 million of 6.125% Senior Notes in 2017; and
- A $40.0 million increase in net borrowings on our Credit Facility in 2018.

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

	Nine Months Ended September 30, 2018		
	2018	2017	$ Change
Net borrowings on senior secured revolving credit facility	$40,000	$—	$40,000
Issuance of 6.125% senior unsecured notes due 2024	—	200,000	(200,000)
Premium on the issuance of 6.125% senior unsecured notes due 2024	—	8,250	(8,250)
Issuance of 6.375% senior unsecured notes due 2026	400,000	—	400,000
Issuance of common stock	288,364	—	288,364
Payment of preferred stock dividends	(5,471)	(5,471)	—
Payment of deferred financing costs	(9,960)	(7,166)	(2,794)
Tax withholdings related to restricted stock units	(1,804)	(1,118)	(686)
Net cash provided by financing activities	$711,129	$194,495	$516,634

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

Capital Plan and Year to Date 2018 Summary

Operational capital expenditures, including other items, on an accrual basis were $442.2 million for the nine months ended September 30, 2018. In addition to the operational capital expenditures, $19.9 million of capitalized general and administrative and $38.7 million of capitalized interest expenses were accrued in the nine months ended September 30, 2018. As of September 30, 2018, we have placed 48 gross (36.5 net) horizontal wells on production. Our operational capital budget for 2018 was revised to approximately $560 million.

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 September 30,			
	2018	2017	Change	% Change
Net production				
Oil (MBbls)	2,521	1,591	930	58 %
Natural gas (MMcf)	4,144	2,900	1,244	43 %
Total (MBOE)	3,212	2,074	1,138	55 %
Average daily production (BOE/d)	34,913	22,543	12,370	55 %
% oil (BOE basis)	78 %	77 %		
Average realized sales price (excluding impact of settled derivatives):				
Oil (Bbl)	$56.57	$46.10	$10.47	23 %
Natural gas (Mcf)	4.49	3.88	0.61	16 %
Total (BOE)	50.19	40.80	9.39	23 %
Average realized sales price (including impact of settled derivatives):				
Oil (Bbl)	$52.87	$45.24	$7.63	17 %
Natural gas (Mcf)	4.51	3.94	0.57	14 %
Total (BOE)	47.31	40.21	7.10	18 %
Oil and natural gas revenues (in thousands)				
Oil revenue	$142,601	$73,349	$69,252	94 %
Natural gas revenue	18,613	11,265	7,348	65 %
Total	$161,214	$84,614	$76,600	91 %
Additional per BOE data				
Sales price [(a)]	$50.19	$40.80	$9.39	23 %
Lease operating expense [(b)]	5.77	5.08	0.69	14 %
Gathering and treating expense [(c)]	—	0.52	(0.52)	(100)%
Production taxes	3.20	2.62	0.58	22 %
Operating margin	$41.22	$32.58	$8.64	27 %

(a) Excludes the impact of 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 September 30, 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.

	Nine Months Ended September 30,			
	2018	2017	Change	% Change
Net production				
Oil (MBbls)	6,368	4,621	1,747	38 %
Natural gas (MMcf)	11,222	7,878	3,344	42 %
Total (MBOE)	8,238	5,934	2,304	39 %
Average daily production (BOE/d)	30,176	21,736	8,440	39 %
% oil (BOE basis)	77 %	78 %		
Average realized sales price (excluding impact of settled derivatives)				
Oil (Bbl)	$59.75	$47.23	$12.52	27 %
Natural gas (Mcf)	4.03	3.81	0.22	6 %
Total (BOE)	51.68	41.84	9.84	24 %
Average realized sales price (including impact of settled derivatives)				
Oil (Bbl)	$55.61	$46.32	$9.29	20 %
Natural gas (Mcf)	4.09	3.84	0.25	7 %
Total (BOE)	48.56	41.17	7.39	18 %
Oil and natural gas revenues (in thousands)				
Oil revenue	$380,500	$218,242	$162,258	74 %
Natural gas revenue	45,229	30,019	15,210	51 %
Total	$425,729	$248,261	$177,468	71 %
Additional per BOE data				
Sales price [(a)]	$51.68	$41.84	$9.84	24 %
Lease operating expense [(b)]	5.43	5.72	(0.29)	(5)%
Gathering and treating expense [(c)]	—	0.47	(0.47)	(100)%
Production taxes	3.19	2.72	0.47	17 %
Operating margin	$43.06	$32.93	$10.13	31 %

(a) Excludes the impact of 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 nine months ended September 30, 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 tables reconcile the change in oil, natural gas and total revenue for the respective periods presented by reflecting the effect of changes in volume and in the underlying commodity prices.

(in thousands)	Oil	Natural Gas	Total
Revenues for the three months ended September 30, 2017	$73,349	$11,265	$84,614
Volume increase	42,873	4,827	47,700
Price increase	26,379	2,521	28,900
Net increase	69,252	7,348	76,600
Revenues for the three months ended September 30, 2018	$142,601	$18,613	$161,214

(in thousands)	Oil	Natural Gas	Total
Revenues for the nine months ended September 30, 2017	$218,242	$30,019	$248,261
Volume increase	82,511	12,741	95,252
Price increase	79,747	2,469	82,216
Net increase	162,258	15,210	177,468
Revenues for the nine months ended September 30, 2018	$380,500	$45,229	$425,729

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 and nine months ended September 30, 2018, the average NYMEX price for a barrel of oil was $69.43 and $66.77 per Bbl compared to $48.20 and $49.36 per Bbl for the same period of 2017. The NYMEX price for a barrel of oil for the three and nine months ended September 30, 2018 ranged from a low of $65.01 per Bbl to a high of $74.14 per Bbl and a low of $59.19 per Bbl to a high of $74.15 per Bbl, respectively.

For the three and nine months ended September 30, 2018, the average NYMEX price for natural gas was $2.87 and $2.85 per MMBtu compared to $2.95 and $3.05 per MMBtu for the same periods of 2017. The NYMEX price for natural gas for the three and nine months ended September 30, 2018 ranged from a low of $2.72 per MMBtu to a high of $3.08 per MMBtu and a low of $2.55 per MMBtu to a high of $3.63 per MMBtu, respectively.

Oil revenue

For the three months ended September 30, 2018, oil revenues of $142.6 million increased $69.3 million, or 94%, compared to revenues of $73.3 million for the same period of 2017. The increase in oil revenue was primarily attributable to a 58% increase in production and a 23% increase in the average realized sales price, which rose to $56.57 per Bbl from $46.10 per Bbl. The production increase of 930 MBbls was a result of new wells placed on production from our horizontal drilling program, as well as volumes contributed by newly acquired properties. Offsetting these increases were normal and expected declines from our existing wells.

For the nine months ended September 30, 2018, oil revenues of $380.5 million increased $162.3 million, or 74%, compared to revenues of $218.2 million for the same period of 2017. The increase in oil revenue was primarily attributable to a 38% increase in production and a 27% increase in the average realized sales price, which rose to $59.75 per Bbl from $47.23 per Bbl. The production increase of 2,774 MBbls was a result of new wells placed on production from our horizontal drilling program, as well as volumes contributed by newly 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 September 30, 2018, natural gas revenues of $18.6 million increased $7.3 million, or 65%, compared to $11.3 million for the same period of 2017. The increase primarily relates to a 43% increase in natural gas volumes and a 16% increase in the average realized sales price, which rose to $4.49 per Mcf from $3.88 per Mcf, reflecting both natural gas and natural gas liquids prices. The production increase of 1,244 MMcf was a result of new wells placed on production from our horizontal drilling program, as well as volumes contributed by newly acquired properties. Offsetting these increases were normal and expected declines from our existing wells. Natural gas revenues for the three months ended September 30, 2018, include a reduction of $2.2 million of gathering and treating expense.

For the nine months ended September 30, 2018, natural gas revenues of $45.2 million increased $15.2 million, or 51%, compared to $30.0 million for the same period of 2017. The increase primarily relates to a 42% increase in natural gas volumes. The production increase of 3,344 MMcf was a result of new wells placed on production from our horizontal drilling program, as well as volumes contributed by newly acquired properties. The average realized sales price of $4.03 per Mcf, reflecting both natural gas and natural gas liquids prices, was consistent with prices for the same period of 2017. Offsetting these increases were normal and expected declines from our existing wells. Natural gas revenues for the nine months ended September 30, 2018, include a reduction of $5.4 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

	Three Months Ended September 30,							
		Per		Per	Total Change		BOE Change	
(in thousands, except per unit amounts)	2018	BOE	2017	BOE	$	%	$	%
Lease operating expenses [(a)]	$18,525	$5.77	$11,624	$5.60	$6,901	59 %	$0.17	3 %
Production taxes	10,263	3.20	5,444	2.62	4,819	89 %	0.58	22 %
Depreciation, depletion and amortization	48,257	15.02	28,525	13.75	19,732	69 %	1.27	9 %
General and administrative	9,721	3.03	7,259	3.50	2,462	34 %	(0.47)	(13)%
Accretion expense	202	0.06	131	0.06	71	54 %	—	— %
Acquisition expense	1,435	0.45	205	0.10	1,230	600%	0.35	350 %

	Nine Months Ended September 30,							
		Per		Per	Total Change		BOE Change	
(in thousands, except per unit amounts)	2018	BOE	2017	BOE	$	%	$	%
Lease operating expenses [(a)]	$44,705	$5.43	$36,708	$6.19	$7,997	22 %	$(0.76)	(12)%
Production taxes	26,265	3.19	16,168	2.72	10,097	62 %	0.47	17 %
Depreciation, depletion and amortization	122,407	14.86	79,172	13.34	43,235	55 %	1.52	11 %
General and administrative	26,779	3.25	18,894	3.18	7,885	42 %	0.07	2 %
Settled share-based awards	—	—	6,351	1.07	(6,351)	(100)%	(1.07)	(100)%
Accretion expense	626	0.08	523	0.09	103	20 %	(0.01)	(11)%
Acquisition expense	3,750	0.46	3,027	0.51	723	24 %	(0.05)	(10)%

(a) On January 1, 2018, the Company adopted the revenue recognition accounting standard. Consequently, natural gas gathering and treating expenses for the three and nine months ended September 30, 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 September 30, 2018, LOE increased by 59% to $18.5 million compared to $11.6 million for the same period of 2017. For the three months ended September 30, 2018, LOE per BOE increased to $5.77 per BOE, excluding gathering and treating expense, compared to $5.60 per BOE, including $0.52 per BOE of gathering and treating expense, for the same period of 2017, which was primarily attributable to an increase in costs from workover activity on our properties offset by higher production volumes. The increase in production was primarily attributable to 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.

For the nine months ended September 30, 2018, LOE increased by 22% to $44.7 million compared to $36.7 million for the same period of 2017. For the nine months ended September 30, 2018, LOE per BOE decreased to $5.43 per BOE, excluding gathering and treating expense, compared to $6.19 per BOE, including $0.47 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 September 30, 2018 increased by 89% to $10.3 million compared to $5.4 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. On a per BOE basis, production taxes for the three months ended September 30, 2018 increased by 22% compared to the same period of 2017.

Production taxes for the nine months ended September 30, 2018 increased by 62% to $26.3 million compared to $16.2 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, and acquisitions as discussed above. On a per BOE basis, production taxes for the nine months ended September 30, 2018 increased by 17% 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 September 30, 2018, DD&A increased 69% to $48.3 million compared to $28.5 million for the same period of 2017. The increase is primarily attributable to a 55% increase in production and a 9% increase in our per BOE DD&A rate. For the three months ended September 30, 2018, DD&A on a per unit basis increased to $15.02 per BOE compared to $13.75 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.

For the nine months ended September 30, 2018, DD&A increased 55% to $122.4 million compared to $79.2 million for the same period of 2017. The increase is primarily attributable to a 39% increase in production and an 11% increase in our per BOE DD&A rate. For the nine months ended September 30, 2018, DD&A on a per unit basis increased to $14.86 per BOE compared to $13.34 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 September 30, 2018 increased to $9.7 million compared to $7.3 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 September 30,			
	2018	2017	$ Change	% Change
Recurring expenses				
G&A	$7,070	$5,330	$ 1,740	33 %

Share-based compensation	1,730	1,198	532	44	%
Fair value adjustments of cash-settled RSU awards	921	731	190	26	%
Total G&A expenses	$9,721	$7,259	$ 2,462	34	%

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G&A for the nine months ended September 30, 2018 increased to $26.8 million compared to $18.9 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):

	Nine Months Ended September 30,			
	2018	2017	$ Change	% Change
Recurring expenses				
G&A	$20,929	$15,428	$5,501	36 %
Share-based compensation	4,422	3,084	1,338	43 %
Fair value adjustments of cash-settled RSU awards	1,428	(143)	1,571	(1,099)%
Non-recurring expenses				
Early retirement expenses	—	444	(444)	(100)%
Early retirement expenses related to share-based compensation	—	81	(81)	(100)%
Total G&A expenses	$26,779	$18,894	$7,885	42 %

Settled share-based awards. In June 2017, the Company settled the outstanding share-based award agreements of its former Chief Executive Officer, resulting in $6.4 million recorded on the Consolidated Statements of Operations as Settled share-based awards.

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 for the three and nine months ended September 30, 2018, increased 54% and 20%, compared to the same periods of 2017, respectively. Accretion expense generally correlates with the Company's ARO, which was $9.9 million at September 30, 2018 as compared to $5.0 million at September 30, 2017. See Note 9 in the Footnotes to the Financial Statements for additional information regarding the Company's ARO.

Acquisition expense. Acquisition expense increased $1.2 million and $0.7 million for the three and nine months ended September 30, 2018, compared to the same periods 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

	Three Months Ended September 30,			
(in thousands)	2018	2017	$ Change	% Change
Interest expense, net of capitalized amounts	$711	$444	$267	60 %
Loss on derivative contracts	34,339	14,162	20,177	142 %
Other income	(1,657)	(498)	(1,159)	233 %
Total other (income) expense	$33,393	$14,108		
Income tax expense	$1,487	$237	$1,250	527 %
Preferred stock dividends	(1,823)	(1,824)	1	— %

	Nine Months Ended September 30,			
(in thousands)	2018	2017	$ Change	% Change
Interest expense, net of capitalized amounts	$1,765	$1,698	$67	4 %
(Gain) loss on derivative contracts	55,374	(11,636)	67,010	(576)%
Other income	(2,571)	(1,270)	(1,301)	102 %
Total other (income) expense	$54,568	$(11,208)		
Income tax expense	$2,463	$1,026	$1,437	140 %
Preferred stock dividends	(5,471)	(5,471)	—	— %

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, of $0.7 million and $1.8 million incurred during the three and nine months ended September 30, 2018, remained consistent compared to the same periods of 2017.

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 September 30, 2018, we recorded a net loss on derivative contracts of $34.3 million as compared to a net loss of $14.2 million 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 September 30,	
	2018	2017
Oil derivatives		
Net loss on settlements	$(9,306)	$(1,373)
Net loss on fair value adjustments	(24,476)	(12,811)
Total loss on oil derivatives	$(33,782)	$(14,184)
Natural gas derivatives		
Net gain on settlements	$67	$159

Net loss on fair value adjustments	(624)	(137)
Total gain (loss) on natural gas derivatives	$(557)	$22
Total loss on oil & natural gas derivatives	$(34,339)	$(14,162)

For the nine months ended September 30, 2018, we recorded a net loss on derivative contracts of $55.4 million compared to a net gain of $11.6 million for the same period of 2017. The net gain (loss) on derivative instruments for the periods indicated includes the following (in thousands):

	Nine Months Ended September 30,	
	2018	2017
Oil derivatives		
Net loss on settlements	$(26,353)	$(4,213)
Net gain (loss) on fair value adjustments	(28,720)	14,584
Total gain (loss) on oil derivatives	$(55,073)	$10,371
Natural gas derivatives		
Net gain on settlements	$675	$241
Net gain (loss) on fair value adjustments	(976)	1,024
Total gain (loss) on natural gas derivatives	$(301)	$1,265
Total gain (loss) on oil & natural gas derivatives	$(55,374)	$11,636

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 $1.5 million and $2.5 million for the three and nine months ended September 30, 2018, compared to income tax expense of $0.2 million and $1.0 million for the same periods of 2017. The change in income tax expense is primarily related to deferred state of Texas gross margin tax. The Company had a valuation allowance of $30.3 million as of September 30, 2018. See Note 8 in the Footnotes to the Financial Statements for additional information.

Preferred Stock dividends. Preferred Stock dividends of $1.8 million and $5.5 million for the three and nine months ended September 30, 2018 were consistent with dividends for the same periods 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, demand, regional market conditions, 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, subject to market conditions, 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 1,794,000 Bbls and 1,932,000 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 and Waha basis differentials covering approximately 1,518,000 Bbls and 552,000 MMBtu of our expected oil and natural gas production, respectively, 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 September 30, 2018, and any 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 September 30, 2018, the Company had $65.0 million principal outstanding under the Credit Facility with a weighted average interest rate of 3.29%. 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 $0.7 million, based on the balance outstanding at September 30, 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 September 30, 2018 our total receivables from the sale of our oil and natural gas production were approximately $107.3 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 September 30, 2018 our joint interest receivables were approximately $59.5 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 September 30, 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 reasonably 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

In addition to the other information set forth in this Quarterly Report, you should carefully consider the risk factors and other cautionary statements described under the heading "Item 1A. Risk Factors" included in our Annual Report on Form 10-K for the year ended December 31, 2017, and the risk factors and other cautionary statements contained in our other SEC filings, including our Quarterly Report on Form 10-Q for the period ended June 30, 2018, which could materially affect our business, financial condition or future results. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results. There have been no material changes in our risk factors from those described in our Annual Report or our other SEC filings.

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
2.		Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession
2.1		Purchase and Sale Agreement, dated May 23, 2018, between Cimarex Energy Co, Prize Energy Resources, Inc., and Magnum Hunter Production, Inc. and Callon Petroleum Operating Company (incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K, filed on May 24, 2018)
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, 2016, 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		Indenture of 6.375% Senior Notes Due 2026, dated as of June 7, 2018, 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 June 7, 2018)
4.6		Registration Rights Agreement of 6.375% Senior Notes Due 2026, dated June 7, 2018, 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 4.2 of the Company's Current Report on Form 8-K, filed on June 7, 2018)
10.		Material contracts
10.1		Amendment No. 2 to the Sixth Amended and Restated Credit Agreement, dated September 27, 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 September 28, 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.

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SIGNATURES

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

Callon Petroleum Company

Signature	Title	Date
/s/ Joseph C. Gatto, Jr. Joseph C. Gatto, Jr.	President and Chief Executive Officer	November 6, 2018
/s/ James P. Ulm, II James P. Ulm, II	Senior Vice President and Chief Financial Officer	November 6, 2018