UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

☒**QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For The Quarterly Period Ended June 30, 2019

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ____________ to ____________

Commission File Number 001-14039

Callon Petroleum Company

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**64-0844345**
State or Other Jurisdiction of Incorporation or Organization	I.R.S. Employer Identification No.
One Briarlake Plaza **2000 W. Sam Houston Parkway S., Suite 2000** **Houston, Texas**	**77042**
Address of Principal Executive Offices	Zip Code

(281) 589-5200

Registrant's Telephone Number, Including Area Code

1401 Enclave Pkwy, Suite 600, Houston, TX 77077

Former Name, Former Address and Former Fiscal Year, if Changed Since Last Report

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Stock, $0.01 par value	CPE	New York Stock Exchange
10.0% Series A Cumulative Preferred Stock	CPE.A	New York Stock Exchange

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The Registrant had 228,304,366 shares of common stock outstanding as of July 31, 2019.

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GLOSSARY OF CERTAIN TERMS

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

- **ARO**: asset retirement obligation.
- **ASU**: accounting standards update.
- **Bbl** or **Bbls**: barrel or barrels of oil or natural gas liquids.
- **BOE**: barrel of oil equivalent, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of gas. The ratio of one barrel of oil or NGL to six Mcf of natural gas is commonly used in the industry and represents the approximate energy equivalence of oil or NGLs to natural gas, and does not represent the economic equivalency of oil and NGLs to natural gas. The sales price of a barrel of oil or NGLs is considerably higher than the sales price of six Mcf of natural gas.
- **BOE/d**: BOE per day.
- **Btu**: a British thermal unit, which is a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.
- **Completion**: The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.
- **Cushing**: An oil delivery point that serves as the benchmark oil price for West Texas Intermediate.
- **FASB**: Financial Accounting Standards Board.
- **GAAP**: Generally Accepted Accounting Principles in the United States.
- **Henry Hub**: A natural gas pipeline delivery point that serves as the benchmark natural gas price underlying NYMEX natural gas futures contracts.
- **Horizontal drilling**: A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.
- **LIBOR**: London Interbank Offered Rate.
- **LOE**: lease operating expense.
- **MBbls**: thousand barrels of oil.
- **MBOE**: thousand BOE.
- **Mcf**: thousand cubic feet of natural gas.
- **MEH**: Magellan East Houston, a delivery point in Houston, Texas that serves as a benchmark for crude oil.
- **MMBtu**: million Btu.
- **MMcf**: million cubic feet of natural gas.
- **NGL or NGLs**: natural gas liquids, such as ethane, propane, butanes and natural gasoline that are extracted from natural gas production streams.
- **NYMEX**: New York Mercantile Exchange.
- **Oil**: includes crude oil and condensate.
- **PUDs**: proved undeveloped reserves.
- **Realized price**: The cash market price less all expected quality, transportation and demand adjustments.
- **Royalty interest**: An interest that gives an owner the right to receive a portion of the resources or revenues without having to carry any costs of development.
- **RSU**: restricted stock units.
- **SEC**: United States Securities and Exchange Commission.
- **Waha**: A delivery point in West Texas that serves as the benchmark for natural gas.
- **Working interest**: An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.
- **WTI**: West Texas Intermediate grade crude oil, used as a pricing benchmark for sales contracts and NYMEX oil futures contracts.

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

Part I. Financial Information
Item 1. Financial Statements

Callon Petroleum Company
Consolidated Balance Sheets
(in thousands, except par and share data)

	June 30, 2019	December 31, 2018
ASSETS	**Unaudited**	
Current assets:		
Cash and cash equivalents	$ 16,052	$ 16,051
Accounts receivable	93,039	131,720
Fair value of derivatives	13,164	65,114
Other current assets	15,841	9,740
Total current assets	138,096	222,625
Oil and natural gas properties, full cost accounting method:		
Evaluated properties	4,665,761	4,585,020
Less accumulated depreciation, depletion, amortization and impairment	(2,399,886)	(2,270,675)
Evaluated oil and natural gas properties, net	2,265,875	2,314,345
Unevaluated properties	1,429,624	1,404,513
Total oil and natural gas properties, net	3,695,499	3,718,858
Operating lease right-of-use assets	31,904	—
Other property and equipment, net	23,363	21,901
Restricted investments	3,468	3,424
Deferred financing costs	5,427	6,087
Fair value of derivatives	11,679	—
Other assets, net	6,061	6,278
Total assets	$ 3,915,497	$ 3,979,173
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 221,452	$ 261,184
Operating lease liabilities	24,141	—
Accrued interest	22,695	24,665
Cash-settleable restricted stock unit awards	819	1,390
Asset retirement obligations	3,103	3,887
Fair value of derivatives	17,251	10,480
Other current liabilities	2,472	13,310
Total current liabilities	291,933	314,916
Senior secured revolving credit facility	105,000	200,000
6.125% senior unsecured notes due 2024	596,154	595,788
6.375% senior unsecured notes due 2026	394,106	393,685
Operating lease liabilities	7,680	—
Asset retirement obligations	9,315	10,405
Cash-settleable restricted stock unit awards	2,568	2,067
Deferred tax liability	21,106	9,564
Fair value of derivatives	3,663	7,440
Other long-term liabilities	100	100
Total liabilities	1,431,625	1,533,965
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, series A cumulative, $0.01 par value and $50.00 liquidation preference, 2,500,000 shares authorized; 1,458,948 shares outstanding	15	15
Common stock, $0.01 par value, 300,000,000 shares authorized; 228,263,955 and 227,582,575 shares outstanding, respectively	2,283	2,276
Capital in excess of par value	2,483,945	2,477,278
Accumulated deficit	(2,371)	(34,361)
Total stockholders' equity	2,483,872	2,445,208
Total liabilities and stockholders' equity	$ 3,915,497	$ 3,979,173

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

Callon Petroleum Company
Consolidated Statements of Operations
(Unaudited; in thousands, except per share data)

	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
Operating revenues:				
Oil sales	$ 160,728	$ 122,613	$ 301,826	$ 237,898
Natural gas sales	6,324	14,462	18,273	26,617
Total operating revenues	167,052	137,075	320,099	264,515
Operating expenses:				
Lease operating expenses	22,776	13,141	46,843	26,179
Production taxes	11,131	7,539	21,944	16,002
Depreciation, depletion and amortization	62,921	38,733	122,688	74,151
General and administrative	10,564	8,289	22,317	17,057
Settled share-based awards	—	—	3,024	—
Accretion expense	216	206	457	424
Other operating expense	935	1,767	1,092	2,315
Total operating expenses	108,543	69,675	218,365	136,128
Income from operations	58,509	67,400	101,734	128,387
Other (income) expenses:				
Interest expense, net of capitalized amounts	741	594	1,479	1,053
(Gain) loss on derivative contracts	(14,036)	16,554	53,224	21,036
Other income	(67)	(703)	(148)	(914)
Total other (income) expense	(13,362)	16,445	54,555	21,175
Income (loss) before income taxes	71,871	50,955	47,179	107,212
Income tax (benefit) expense	16,691	481	11,542	976
Net income (loss)	55,180	50,474	35,637	106,236
Preferred stock dividends	(1,823)	(1,824)	(3,647)	(3,647)
Income (loss) available to common stockholders	$ 53,357	$ 48,650	$ 31,990	$ 102,589
Income (loss) per common share:				
Basic	$ 0.23	$ 0.23	$ 0.14	$ 0.50
Diluted	$ 0.23	$ 0.23	$ 0.14	$ 0.50
Weighted average common shares outstanding:				
Basic	228,051	210,698	227,917	206,309
Diluted	228,411	211,465	228,599	207,027

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

Callon Petroleum Company
Consolidated Statements of Cash Flows
(Unaudited; in thousands)

	Six Months Ended June 30,	
Cash flows from operating activities:	**2019**	**2018**
Net income (loss)	$ 35,637	$ 106,236
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation, depletion and amortization	125,046	75,453
Accretion expense	457	424
Amortization of non-cash debt related items	1,479	1,041
Deferred income tax (benefit) expense	11,542	976
(Gain) loss on derivatives, net of settlements	51,777	4,594
Loss on sale of other property and equipment	49	22
Non-cash expense related to equity share-based awards	6,299	2,758
Change in the fair value of liability share-based awards	1,031	549
Payments to settle asset retirement obligations	(771)	(573)
Payments for cash-settled restricted stock unit awards	(1,425)	(4,990)
Changes in current assets and liabilities:		
Accounts receivable	38,681	2,380
Other current assets	(6,101)	(5,550)
Current liabilities	(36,254)	17,061
Other	(2,401)	(402)
Net cash provided by operating activities	225,046	199,979
Cash flows from investing activities:		
Capital expenditures	(359,430)	(298,370)
Acquisitions	(39,370)	(45,392)
Acquisition deposit	—	(27,600)
Proceeds from sale of assets	274,296	3,077
Net cash used in investing activities	(124,504)	(368,285)
Cash flows from financing activities:		
Borrowings on senior secured revolving credit facility	360,000	165,000
Payments on senior secured revolving credit facility	(455,000)	(190,000)
Issuance of 6.375% senior unsecured notes due 2026	—	400,000
Issuance of common stock	—	288,357
Payment of preferred stock dividends	(3,647)	(3,647)
Payment of deferred financing costs	(31)	(8,664)
Tax withholdings related to restricted stock units	(1,858)	(1,589)
Other financing activities	(5)	—
Net cash provided by (used in) financing activities	(100,541)	649,457
Net change in cash and cash equivalents	1	481,151
Balance, beginning of period	16,051	27,995
Balance, end of period	$ 16,052	$ 509,146

Supplemental cash flow information:		
Interest paid, net of capitalized amounts	$ —	$ —
Income taxes paid	—	—
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	1,293	—
Investing cash flows from operating leases	17,865	—
Non-cash investing and financing activities:		
Change in accrued capital expenditures	$ (16,286)	$ 16,088
Change in asset retirement costs	—	4,440
Right-of-use assets obtained in exchange for operating lease liabilities	2,462	—
Contingent consideration arrangement	8,512	—

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

Callon Petroleum Company
Consolidated Statements of Stockholders' Equity
(Unaudited; in thousands)

	Preferred Stock		Common Stock		Capital in Excess of Par	Accumulated Deficit	Total Stockholders' Equity
	Shares	$	Shares	$			
Balance at 12/31/2018	1,459	$ 15	227,583	$ 2,276	$ 2,477,278	$ (34,361)	$ 2,445,208
Net income (loss)	—	—	—	—	—	(19,543)	(19,543)
Shares issued pursuant to employee benefit plans	—	—	24	—	154	—	154
Restricted stock	—	—	277	3	4,447	—	4,450
Preferred stock dividend ($1.25 per share)	—	—	—	—	—	(1,824)	(1,824)
Balance at 03/31/2019	1,459	$ 15	227,884	$ 2,279	$ 2,481,879	$ (55,728)	$ 2,428,445
Net income (loss)	—	—	—	—	—	55,180	55,180
Restricted stock	—	—	380	4	2,071	—	2,075
Preferred stock dividend ($1.25 per share)	—	—	—	—	—	(1,823)	(1,823)
Preferred stock redemption costs	—	—	—	—	(5)	—	(5)
Balance at 06/30/2019	1,459	$ 15	228,264	$ 2,283	$ 2,483,945	$ (2,371)	$ 2,483,872

	Preferred Stock		Common Stock		Capital in Excess of Par	Accumulated Deficit	Total Stockholders' Equity
	Shares	$	Shares	$			
Balance at 12/31/2017	1,459	$ 15	201,836	$ 2,018	$ 2,181,359	$ (327,426)	$ 1,855,966
Net income (loss)	—	—	—	—	—	55,761	55,761
Shares issued pursuant to employee benefit plans	—	—	7	—	88	—	88
Restricted stock	—	—	105	1	1,152	—	1,153
Preferred stock dividend ($1.25 per share)	—	—	—	—	—	(1,824)	(1,824)
Balance at 03/31/2018	1,459	$ 15	201,948	$ 2,019	$ 2,182,599	$ (273,489)	$ 1,911,144
Net income (loss)	—	—	—	—	—	50,474	50,474
Shares issued pursuant to employee benefit plans	—	—	11	—	141	—	141
Restricted stock	—	—	248	3	1,312	—	1,315
Common stock issued	—	—	25,300	253	288,103	—	288,356
Preferred stock dividend ($1.25 per share)	—	—	—	—	—	(1,824)	(1,824)
Balance at 06/30/2018	1,459	$ 15	227,507	$ 2,275	$ 2,472,155	$ (224,837)	$ 2,249,608

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 has been engaged in the development, acquisition and production of oil and natural gas properties since 1950. 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. We were incorporated in the state of Delaware in 1994.

Callon is focused on the acquisition and development 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. Since our entry into the Permian Basin in late 2009, we have been focused on the Midland Basin and entered the Delaware Basin through an acquisition completed in February 2017. The Company further expanded its presence in the Delaware Basin through acquisitions in 2018.

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 a subsidiary, namely Mississippi Marketing, Inc. Effective February 28, 2019, Callon Offshore Production, Inc. was merged with and into Callon Petroleum Operating Company.

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, 2018. The balance sheet at December 31, 2018 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, 2019.

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, results of operations and cash flows for the periods indicated. Certain prior year amounts have been reclassified to conform to current year presentation.

Accounting Standards Updates ("ASUs")

Recently adopted 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"). In March 2019, the FASB issued ASU No. 2019-01, Leases (Topic 842): Codification Improvements ("ASU 2019-01"). Together these related amendments to GAAP represent ASC Topic 842, Leases ("ASC Topic 842").

ASU 2016-02 requires lessees to recognize lease assets and liabilities (with terms in excess of 12 months) on the balance sheet and disclose key quantitative and qualitative information about leasing arrangements. The Company engaged a third-party consultant to assist with assessing its existing contracts, as well as future potential contracts, and to determine the impact of its application on its consolidated financial statements and related disclosures. The contract evaluation process includes review of drilling rig contracts, office facility leases, compressors, field vehicles and equipment, general corporate leased equipment, and other existing arrangements to support its operations that may contain a lease component.

The new standard was effective for us in the first quarter of 2019, and we adopted the new standard using a modified retrospective approach, with the date of initial application on January 1, 2019. Consequently, upon transition, we recognized the cumulative effect of adoption in retained earnings as of January 1, 2019. We further utilized the package of practical expedients at transition to not reassess the following:

- Whether any expired or existing contracts were or contained leases;
- The lease classification for any expired or existing leases; and
- Initial direct costs for any existing leases.

Additionally, we elected the practical expedient under ASU 2018-01, which did not require us to evaluate existing or expired land easements not previously accounted for as leases prior to the effective date. We also chose not to separate lease and non-lease components for the various classes of underlying assets. In addition, for all of our asset classes, we have made an accounting policy election not to apply the lease recognition requirements to our short-term leases. Accordingly, we recognize lease payments related to our short-term leases in profit or loss on a straight-line basis over the lease term.

Through our implementation process, we evaluated each of our lease arrangements and enhanced our systems to track and calculate additional information required upon adoption of this standard. The standard had an impact on our consolidated balance sheets at March 31, 2019 and June 30, 2019, resulting from the recognition of right-of-use assets and lease liabilities for operating leases. We have no leases that meet the criteria for classification as a finance lease. We lease certain office space, office equipment, production facilities, compressors, drilling rigs, vehicles and other ancillary drilling equipment under cancelable and non-cancelable leases to support our operations. See Note 10 for additional information regarding the impact of adoption of the new leases standard on our current period results.

Adoption of the new leases standard did not impact our consolidated statement of operations or cash provided from or used in operating, investing or financing in our consolidated statement of cash flows.

We note that the standard does not apply to leases to explore for or use minerals, oil or natural gas resources, including the right to explore for those natural resources and rights to use the land in which those natural resources are contained.

Recently adopted 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 Company adopted this update on January 1, 2019 and it did not have 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 Company’s share of 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 operating revenues. For the three and six months ended June 30, 2019, $2,805 and $5,213 of gathering and treating fees were recognized and recorded as a reduction to natural gas sales in the consolidated statement of operations, respectively. For the three and six months ended June 30, 2018, $1,952 and $3,204 of gathering and treating fees were recognized and recorded as a reduction to natural gas sales in the consolidated statement of operations, respectively.

Accounts receivable from revenues from contracts with customers

Net accounts receivable include amounts billed and currently due from revenues from contracts with customers of our oil and natural gas production, which had a balance at June 30, 2019 and December 31, 2018 of $67,891 and $87,061, respectively, and does not currently include an allowance for doubtful accounts. Accounts receivable, net, from the sale of oil and natural gas are included in accounts receivable on the consolidated balance sheets.

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 and Dispositions

2019 Acquisitions and Dispositions

On June 12, 2019, the Company completed its divestiture of certain non-core assets in the southern Midland Basin (the "Ranger Asset Divestiture") for net cash proceeds received at closing of $244,935, including customary purchase price adjustments. The transaction also provides for potential contingent consideration in payments of up to $60,000 based on West Texas Intermediate average annual pricing over a three-year period (see Notes 6 and 7 for additional information regarding the contingent consideration payments). The divestiture encompasses the Ranger operating area in the southern Midland Basin which includes approximately 9,850 net Wolfcamp acres with an average 66% working interest. The divestiture did not significantly alter the relationship between capitalized costs and proved reserves, and as such, net cash proceeds and contingent consideration were recorded as adjustments to our full cost pool with no gain or loss recognized.

In the first quarter of 2019, the Company completed various acquisitions and dispositions of additional working interests and acreage located in our existing core operating areas within the Permian Basin. The Company purchased mineral rights for $21,407 in the Spur operating area and received proceeds of $14,084, including customary purchase price adjustments, for certain leasehold interests in our WildHorse acreage. In the second quarter of 2019, the Company completed various acreage swaps in the Permian Basin and received proceeds of $19,108, including customary purchase price adjustments, for certain working interests in our Spur acreage.

2018 Acquisitions

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 "Delaware Asset Acquisition"). The Company issued debt and equity to fund, in part, the Delaware Asset Acquisition. See Notes 5 and 9 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

In addition, the Company completed various acquisitions of additional working interests and mineral rights, and associated production volumes, in the Company's existing core operating areas within the Permian Basin. In the first quarter of 2018, the Company completed acquisitions within Monarch and WildHorse operating areas for $37,770, including customary purchase price adjustments. In the fourth quarter of 2018, the Company completed acquisitions of leasehold interests and mineral rights within its WildHorse and Spur operating areas for $87,865, including customary purchase price adjustments.

Note 4 - Earnings Per Share

Basic earnings (loss) per share is computed by dividing income (loss) available to common stockholders by the weighted average number of shares outstanding for the periods presented. The calculation of diluted earnings (loss) per share includes the potential dilutive impact of non-vested restricted shares outstanding during the periods presented, as calculated using the treasury stock method, unless their effect is anti-dilutive. The following table sets forth the computation of basic and diluted earnings per share:

(amounts in thousands)	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
Net income (loss)	$ 55,180	$ 50,474	$ 35,637	$ 106,236
Preferred stock dividends	(1,823)	(1,824)	(3,647)	(3,647)
Income (loss) available to common stockholders	$ 53,357	$ 48,650	$ 31,990	$ 102,589
Weighted average common shares outstanding	228,051	210,698	227,917	206,309
Dilutive impact of restricted stock	360	767	682	718
Weighted average common shares outstanding for diluted income (loss) per share	228,411	211,465	228,599	207,027
Basic income (loss) per share	$ 0.23	$ 0.23	$ 0.14	$ 0.50
Diluted income (loss) per share	$ 0.23	$ 0.23	$ 0.14	$ 0.50
Restricted stock [(a)]	641	—	498	—

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

Note 5 - Borrowings

The Company's borrowings consisted of the following:

	As of	
Principal components:	**June 30, 2019**	**December 31, 2018**
Senior secured revolving credit facility	$ 105,000	$ 200,000
6.125% senior unsecured notes due 2024	600,000	600,000
6.375% senior unsecured notes due 2026	400,000	400,000
Total principal outstanding	1,105,000	1,200,000
Premium on 6.125% senior unsecured notes due 2024, net of accumulated amortization	5,906	6,469
Unamortized deferred financing costs	(15,646)	(16,996)
Total carrying value of borrowings [(a)]	$ 1,095,260	$ 1,189,473

(a) Excludes unamortized deferred financing costs related to the Company's senior secured revolving credit facility of $5,427 and $6,087 as of June 30, 2019 and December 31, 2018, respectively.

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. 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. The maturity date of the Credit Facility is May 25, 2023.

Effective May 1, 2019, the Company entered into the third amendment (the "Third Amendment") to the Sixth Amended and Restated Credit Agreement to the Credit Facility to, among other things: (i) reaffirm the borrowing base at $1,100,000, excluding the Ranger assets sold; and (ii) amend various covenants and terms to reflect current market trends. As of June 30, 2019, the Credit Facility's borrowing base remained at $1,100,000 with an elected commitment amount of $850,000.

As of June 30, 2019, there was $105,000 principal and $17,675 in letters of credit outstanding under the Credit Facility. For the period ended June 30, 2019, the Credit Facility had a weighted-average interest rate of 3.65%, 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 carries a current commitment fee of 0.375% per annum, payable quarterly, on the unused portion of the borrowing base.

Restrictive covenants

The Company's Credit Facility and the indentures governing its 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 June 30, 2019.

Note 6 - Derivative Instruments and Hedging Activities

Objectives and strategies for using commodity 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 and put and call options to manage fluctuations in cash flows resulting from changes in commodity prices. The Company does not use these instruments for speculative or trading purposes.

Counterparty risk and offsetting

The use of derivative instruments exposes the Company to the risk that a counterparty will be unable to meet its commitments. While the Company monitors counterparty creditworthiness on an ongoing basis, it cannot predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, the Company may be limited in its ability to mitigate an increase in counterparty credit risk. Should one of these counterparties not perform, the Company may not realize the benefit of some of its derivative instruments under lower commodity prices while continuing to be obligated under higher commodity price contracts subject to any right of offset under the agreements. Counterparty credit risk is considered when determining the fair value of a derivative instrument; see Note 7 for additional information regarding fair value.

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

Financial statement presentation and settlements

Settlements of the Company's commodity 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.

Contingent consideration arrangement

Our Ranger Asset Divestiture in June of 2019 provides for potential contingent consideration to be received by the Company if commodity prices exceed specific thresholds in each of the next several years. On the disposition date, we recognized a derivative asset of $8,512 based on the initial fair value measurement. See Note 7 for additional information regarding fair value measurement. These contingent payments are summarized in the tables below (in thousands):

Year of Potential Settlement	Threshold [(a)]	Contingent Payment Amount	Threshold [(a)]	Contingent Payment Amount	Fair Value as of June 30, 2019 [(b)]	Aggregate Settlements Limit[(c)]
						$ 60,000
2019	Greater than $60/bbl, less than $65/bbl	$9,000	Equal to or greater than $65/bbl	$20,833	$2,485	
2020	Greater than $60/bbl, less than $65/bbl	$9,000	Equal to or greater than $65/bbl	$20,833	$5,085	
2021	Greater than $60/bbl, less than $65/bbl	$9,000	Equal to or greater than $65/bbl	$20,833 (c)	$4,255	

(a) The price used to determine whether the specified thresholds have been met is the average of the final monthly settlements for each month during each annual period end for NYMEX Light Sweet Crude Oil Futures, as reported by the CME Group Inc.
(b) Contingent consideration to be received will be classified as cash flows from financing activities up to the initial recognition fair value of $8,512; amounts in excess of the initial recognition fair value will be classified as cash flows from operating activities.
(c) In the event that the 2019 and 2020 prices exceed the $65/bbl threshold, the aggregate amount of contingent consideration is limited to $60,000, resulting in the potential reduction in settlement for 2021 to $18,334.

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:

As of June 30, 2019				
Derivative Instrument	**Balance Sheet Presentation**	**Asset**	**Liability**	**Net Asset (Liability)**
Commodity - Oil	Fair value of derivatives - Current	$ 8,671	$ (17,251)	$ (8,580)
Commodity - Natural gas	Fair value of derivatives - Current	2,008	—	2,008
Contingent consideration arrangement	Fair value of derivatives - Current	2,485	—	2,485
Commodity - Oil	Fair value of derivatives - Non-current	2,335	(3,327)	(992)
Commodity - Natural gas	Fair value of derivatives - Non-current	4	(336)	(332)
Contingent consideration arrangement	Fair value of derivatives - Non-current	9,340	—	9,340
Totals		$ 24,843	$ (20,914)	$ 3,929

As of December 31, 2018				
Derivative Instrument	**Balance Sheet Presentation**	**Asset**	**Liability**	**Net Asset (Liability)**
Commodity - Oil	Fair value of derivatives - Current	$ 60,097	$ (10,480)	$ 49,617
Commodity - Natural gas	Fair value of derivatives - Current	5,017	—	5,017
Commodity - Oil	Fair value of derivatives - Non-current	—	(5,672)	(5,672)
Commodity - Natural gas	Fair value of derivatives - Non-current	—	(1,768)	(1,768)
Totals		$ 65,114	$ (17,920)	$ 47,194

As previously discussed, the Company's commodity derivative contracts are subject to master netting arrangements. The Company's policy is to present the fair value of commodity 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:

	As of June 30, 2019		
	Presented without Effects of Netting	**Effects of Netting**	**As Presented with Effects of Netting**
Current assets: Fair value of commodity derivatives	$ 20,044	$ (9,365)	$ 10,679
Long-term assets: Fair value of commodity derivatives	4,420	(2,081)	2,339
Current liabilities: Fair value of commodity derivatives	$ (26,616)	$ 9,365	$ (17,251)
Long-term liabilities: Fair value of commodity derivatives	(5,744)	2,081	(3,663)

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

	As of December 31, 2018		
	Presented without Effects of Netting	Effects of Netting	As Presented with Effects of Netting
Current assets: Fair value of commodity derivatives	$ 78,091	$ (12,977)	$ 65,114
Current liabilities: Fair value of commodity derivatives	$ (23,457)	$ 12,977	$ (10,480)
Long-term liabilities: Fair value of commodity derivatives	(7,440)	—	(7,440)

For the periods indicated, the Company recorded the following in the consolidated statements of operations as a gain or loss on derivative contracts:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
Oil derivatives				
Net gain (loss) on settlements	$ (4,461)	$ (8,131)	$ (6,003)	$ (17,049)
Net gain (loss) on fair value adjustments	13,310	(8,311)	(53,517)	(4,243)
Total gain (loss) on oil derivatives	8,849	(16,442)	(59,520)	(21,292)
Natural gas derivatives				
Net gain (loss) on settlements	3,304	151	4,556	607
Net gain (loss) on fair value adjustments	(1,430)	(263)	(1,573)	(351)
Total gain (loss) on natural gas derivatives	1,874	(112)	2,983	256
Contingent consideration arrangement				
Net gain (loss) on fair value adjustments	3,313	—	3,313	—
Total gain (loss) on derivatives	$ 14,036	$ (16,554)	$ (53,224)	$ (21,036)

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

Derivative positions

Listed in the tables below are the outstanding oil and natural gas derivative contracts as ofJune 30, 2019:

Oil contracts (WTI)	For the Remainder of 2019	For the Full Year of 2020	For the Full Year of 2021
Puts			
Total volume (Bbls)	460,000	—	—
Weighted average price per Bbl	$ 65.00	$ —	$ —
Put spreads			
Total volume (Bbls)	460,000	—	—
Weighted average price per Bbl			
Floor (long put)	$ 65.00	$ —	$ —
Floor (short put)	$ 42.50	$ —	$ —
Collar contracts with short puts (three-way collars)			
Total volume (Bbls)	2,392,000	3,294,000	—
Weighted average price per Bbl			
Ceiling (short call)	$ 67.46	$ 65.72	$ —
Floor (long put)	$ 56.54	$ 55.69	$ —
Floor (short put)	$ 43.65	$ 44.47	$ —
Oil contracts (Midland basis differential)			
Swap contracts			
Total volume (Bbls)	4,137,500	4,576,000	1,095,000
Weighted average price per Bbl	$ (2.64)	$ (1.29)	$ 1.00
Oil contracts (Argus Houston MEH basis differential)			
Swap contracts			
Total volume (Bbls)	—	552,000	—
Weighted average price per Bbl	$ —	$ 3.30	$ —
Natural gas contracts (Henry Hub)			
Collar contracts (two-way collars)			
Total volume (MMBtu)	1,196,000	—	—
Weighted average price per MMBtu			
Ceiling (short call)	$ 3.50	$ —	$ —
Floor (long put)	$ 3.13	$ —	$ —
Swap contracts			
Total volume (MMBtu)	1,397,000	—	—
Weighted average price per MMBtu	$ 2.89	$ —	$ —
Natural gas contracts (Waha basis differential)			
Swap contracts			
Total volume (MMBtu)	4,232,000	4,758,000	—
Weighted average price per MMBtu	$ (1.18)	$ (1.12)	$ —

Note 7 - Fair Value Measurements

The fair value hierarchy 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.

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

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.

	June 30, 2019		December 31, 2018	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Credit Facility [(a)]	$ 105,000	$ 105,000	$ 200,000	$ 200,000
6.125% Senior Notes [(b)]	596,154	609,048	595,788	558,000
6.375% Senior Notes [(b)]	394,106	403,988	393,685	372,000
Total	$ 1,095,260	$ 1,118,036	$ 1,189,473	$ 1,130,000

(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.

Contingent consideration arrangement - embedded derivative financial instrument. The embedded option within the contingent consideration arrangement is considered a financial instrument under ASC 815. The Company engages a third-party valuation specialist using an option pricing model approach to measure the fair value of the embedded option on a recurring basis. The valuation includes significant inputs such as forward oil price curves, time to expiration, and implied volatility. The model provides for the probability that the specified pricing thresholds would be met for each settlement period, estimates an undiscounted payout, and risk adjusts for the discount rates inclusive of adjustments for the counterparty's credit quality. As these inputs are substantially observable for the full term of the contingent consideration arrangement, the inputs are considered Level 2 inputs within the fair value hierarchy. See Note 6 for additional information regarding the Company's contingent consideration arrangement.

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

June 30, 2019	Classification	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments	Fair value of derivatives	$ —	$ 24,843	$ —	$ 24,843
Liabilities					
Derivative financial instruments	Fair value of derivatives	—	(20,914)	—	(20,914)
Total net assets (liabilities)		$ —	$ 3,929	$ —	$ 3,929

December 31, 2018	Classification	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments	Fair value of derivatives	$ —	$ 65,114	$ —	$ 65,114
Liabilities					
Derivative financial instruments	Fair value of derivatives	—	(17,920)	—	(17,920)
Total net assets		$ —	$ 47,194	$ —	$ 47,194

Assets and liabilities measured at fair value on a nonrecurring basis

Acquisitions. The Company determines the fair value of the assets acquired and liabilities assumed using the income approach based on expected discounted future cash flows from estimated reserve quantities, costs to produce and develop reserves, and oil and natural gas forward prices. The future net revenues are discounted using a weighted average cost of capital. The discounted future net revenues of proved undeveloped and probable reserves are reduced by an additional reserve adjustment factor to compensate for the inherent risk of estimating the value of unevaluated properties. The fair value measurements were based on Level 1, Level 2 and Level 3 inputs.

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

Note 8 - Income Taxes

The Company provides for income taxes at the statutory rate of21% adjusted for permanent differences expected to be realized, which primarily relate to non-deductible executive compensation expenses, restricted stock windfalls, and state income taxes. The following table presents a reconciliation of the reported amount of income tax expense to the amount of income tax expense that would result from applying domestic federal statutory tax rates to pretax income from continuing operations:

	Three Months Ended June 30,		Six Months Ended June 30,	
Components of income tax rate reconciliation	2019	2018	2019	2018
Income tax expense computed at the statutory federal income tax rate	21%	21 %	21%	21 %
State taxes net of federal expense	1%	1 %	1%	1 %
Section 162(m)	—%	1 %	—%	— %
Valuation allowance	—%	(21)%	—%	(21)%
Effective income tax rate, before discrete items	22%	2 %	22%	1 %
Discrete items (a)	1%	(1)%	2%	— %
Effective income tax rate, after discrete items	23%	1 %	24%	1 %

(a) Accounts for the potential impact of periodic volatility of stock-based compensation tax deductions on future effective tax rates.

Note 9 - Equity Transactions

10% Series A Cumulative Preferred Stock ("Preferred Stock")

Holders of the Company's 10.00% Series A Cumulative Preferred Stock were 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 were 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 of $1,823 and $3,647 for the three and six months endedJune 30, 2019 remained consistent compared to the same periods of2018, respectively.

On June 18, 2019, the Company announced it had given notice for the redemption (the "Redemption") of all outstanding shares of the Preferred Stock. The redemption date of the Preferred Stock was July 18, 2019 (the "Redemption Date"). The Preferred Stock were redeemed at the redemption price equal to $50.00 per share, plus an amount equal to all accrued and unpaid dividends in an amount equal to $0.24 per share, for a total redemption price of$50.24 per share (the "Redemption Price"). After the Redemption Date, the Preferred Stock were no longer deemed outstanding, dividends on the Preferred Stock ceased to accrue, and all rights of the holders with respect to such Preferred Stock were terminated, except the right of the holders to receive the Redemption Price, without interest. Regular dividends on the Preferred Stock for the second quarter of 2019 were paid prior to the end of the period.

Common stock

On May 30, 2018, the Company completed an underwritten public offering of25.3 million shares of its common stock for total estimated net proceeds (after the underwriter's discounts and estimated offering costs) of approximately $287,988. The Company used proceeds from the offering to partially fund the Delaware Asset Acquisition completed in the third quarter of 2018, described in Note 3.

Note 10 - Leases

Leases

We determine if an arrangement is a lease at inception of the arrangement. To the extent that we determine an arrangement represents a lease, we classify that lease as an operating lease or a finance lease. Based on our evaluation of leases for the three months ended March 31, 2019, we have no leases that meet the criteria for classification as a finance lease. We capitalize operating leases on our consolidated balance sheets through a right-of-use ("ROU") asset and a corresponding lease liability. ROU assets represent our right to use an underlying asset for the lease term, and lease liabilities represent our obligation to make lease payments arising from the lease.

Operating leases are included in operating lease ROU assets, current operating lease liabilities, and long-term operating lease liabilities in our consolidated balance sheets. Operating lease ROU assets and liabilities are recognized at the commencement date of an arrangement based on the present value of lease payments over the lease term. The operating lease ROU asset also includes any lease payments made to the lessor prior to lease commencement, less any lease incentives, and initial direct costs incurred. Lease expense for operating lease payments is recognized on a straight-line basis over the lease term.

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

Nature of leases

In support of our operations, we lease certain drilling rigs, office space, office equipment, production facilities, compressors, vehicles and other ancillary drilling equipment under cancelable and non-cancelable contracts. A more detailed description of our material lease types is included below.

Drilling rigs

The Company enters into daywork and long-term contracts for drilling rigs with third party service contractors to support the development of undeveloped reserves. Our daywork drilling rig arrangements are typically structured with a term that is in effect until drilling operations are completed on a contractually specified well or well pad. Upon mutual agreement with the contractor, we typically have the option to extend the contract term for additional wells, well pads or contractually stated extension terms by providing 30 days' notice prior to the end of the original contract term.

The Company's long-term drilling contracts are generally structured with an initial non-cancelable term of one totwo years. We have concluded that our long-term drilling rig arrangements represent operating leases with a lease term greater than twelve months. Additionally, we have concluded that our daywork drilling rig arrangements represent short-term operating leases with a lease term that equals the period of time required to complete drilling operations on the contractually specified well or well pad (that is, generally one to a few months from commencement of drilling).

We do not include the option to extend the drilling rig contract in the lease term due to the continuously evolving nature of our drilling schedules, which requires significant flexibility in the structure of the term of these arrangements, and the potential volatility in commodity prices in an annual period. We have further elected to apply the practical expedient for short-term leases to our daywork drilling rig leases. Accordingly, we do not apply the lease recognition requirements to our daywork drilling rig contracts, and we recognize lease payments related to these arrangements in profit or loss on a straight-line basis over the lease term.

Corporate and field offices

We enter into long-term contracts to lease corporate and field office space in support of company operations. These contracts are generally structured with an initial non-cancelable term of two to five years. To the extent that our corporate and field office contracts include renewal options, we evaluate whether we are reasonably certain to exercise those options on a contract by contract basis based on expected future office space needs, market rental rates, drilling plans and other factors. We have further determined that our current corporate and field office leases represent operating leases.

Transportation, gathering and processing arrangements

We engage in various types of transactions in which midstream entities transport, gather and/or process our product leveraging integrated systems and facilities wholly-owned and operated by the midstream counterparty. Under most of these arrangements, we do not utilize substantially all of the underlying pipeline, gathering system or processing facilities, and thus, we have concluded that those underlying assets do not meet the definition of an identified asset.

The following tables reflect the current period impact of our adoption of the new leases standard. As we have no leases that meet the criteria for classification as a finance lease, all information contained herein represents our operating leases.

The components of our total lease cost were as follows:

	Three Months Ended June 30, 2019	Six Months Ended June 30, 2019
Operating lease cost	$ 9,591	$ 19,156
Short-term lease cost [(a)]	1,849	3,347

[(a)] Short-term lease cost excludes expenses related to leases with a contract term of one month or less.

As of June 30, 2019, our weighted average remaining lease term and our weighted average discount rate for our operating leases were1.45 years and 4.02%, respectively.

Our operating lease liabilities with enforceable contract terms that are greater than one year mature as follows:

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

		As of June 30, 2019
Remainder of 2019	$	15,937
2020		13,847
2021		1,576
2022		534
2023		517
Thereafter		431
Total lease payments		32,842
Less imputed interest		1,022
Total	$	31,820

Note 11 - Asset Retirement Obligations

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

		Six Months Ended June 30, 2019
Asset retirement obligations at January 1, 2019	$	14,292
Accretion expense		457
Liabilities incurred		199
Liabilities settled		(630)
Dispositions		(1,701)
Revisions to estimate		(199)
Asset retirement obligations at end of period		12,418
Less: Current asset retirement obligations		(3,103)
Long-term asset retirement obligations at June 30, 2019	$	9,315

- *Liabilities incurred* include additions from acquisitions, asset swaps, and new wells drilled during the year.
- *Liabilities settled* include the retirement of 20 wells during the year.
- *Dispositions* are primarily attributable to the Ranger Asset Divestiture in the second quarter of 2019. See Note 3 for details about the Ranger Asset Divestiture.
- *Revisions to estimates* were due to changes in plugging cost estimates, timing of abandonment activities, and changes in working interest of producing wells.

Certain of the Company's operating agreements require that assets be restricted for abandonment obligations. Amounts recorded in the consolidated balance sheet at June 30, 2019 as long-term restricted investments were $3,468. 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 12 - Other

Other commitments

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 and Ward 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.

In January 2019, the Company executed a crude oil sales contract that provides further dedicated capacity on several pipeline systems that will connect with a regional gathering system which currently transports oil volumes under long-term agreements from our properties in Howard and Ward counties and will have delivery points in several locations along the Gulf Coast, providing the Company with the potential benefit of access to an international weighted average sales price. We will have a long-term 10,000 Bbls per day commitment for the term of the agreement, 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.

In June 2019, the Company executed a firm transportation agreement for dedicated capacity on a new pipeline system that originates in Midland, Texas and terminates in Houston, Texas. 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 quantities committed that average 10,000 Bbls per day 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.

In July 2019, the Company executed a crude oil sales contact that provides dedicated capacity on a new pipeline system that originates in Midland County and will have delivery points in several locations along the Gulf Coast. We will have a long-term 5,000 Bbls per day commitment for the term of the agreement and will apply applicable tariff rates to those quantities. Barrels may include volumes produced by us and other third-party working, royalty, and overriding royalty interest owners whose volumes we market on their behalf.

Note 13 - Carrizo Acquisition

On July 14, 2019, Callon and Carrizo Oil & Gas, Inc. ("Carrizo") entered into an Agreement and Plan of Merger (the "Merger Agreement"), pursuant to which, upon the terms and subject to the conditions set forth therein, Carrizo will merge with and into Callon, with Callon as the surviving corporation (the "Merger" or the "Carrizo Acquisition"). The combination will result in a portfolio of core oil-weighted assets in both the Permian Basin and Eagle Ford Shale.

Subject to the terms and conditions of the Merger Agreement, at the effective time of the Merger (the "Effective Time"), each outstanding share of Carrizo Common Stock, will be converted into the right to receive 2.05 shares of Callon Common Stock. Following the closing of the Merger, Callon's existing shareholders and Carrizo's existing shareholders will own approximately 54% and 46%, respectively, of the outstanding shares of the combined company.

The Merger Agreement provides that, upon consummation of the Merger, the board of directors of Callon will consist of the eight members of the board of directors of Callon immediately prior to the Effective Time and three members of the board of directors of Carrizo, two of such directors to be chosen by Carrizo and one such director to be chosen by Callon. Additionally, the Merger Agreement provides that, upon consummation of the Merger, the officers of Callon immediately prior to the Effective Time shall be the officers of the combined company. Callon will continue to be headquartered in Houston, Texas, where both companies are currently based. Callon expects that the acquisition will close during the fourth quarter of 2019, subject to the approval of both shareholder bases, the satisfaction of certain regulatory approvals and other closing conditions.

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,” “projection,” “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:

- matters relating to the Carrizo Acquisition;
- our oil and natural 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 capital and operating costs;
- production decline rates from our wells being greater than expected;
- 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; and
- prospect development and property acquisitions.

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

- general economic conditions including the availability of credit and access to existing lines of credit;
- the volatility of oil and natural gas prices;
- the uncertainty of estimates of oil and natural gas reserves;
- impairments;
- the impact of competition;
- the availability and cost of seismic, drilling and other equipment, waste and water disposal infrastructure, 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;
- the potential impact of future drilling on production from existing wells;
- difficulties encountered in delivering oil and natural gas to commercial markets;
- changes in customer demand and producers’ supply;
- the uncertainty of our ability to attract capital and obtain financing on favorable terms;
- compliance with, or the effect of changes in, the extensive governmental regulations regarding the oil and natural gas business including those related to climate change and greenhouse gases;
- the impact of government regulation, including regulation of hydraulic fracturing and water disposal wells;
- any increase in severance or similar taxes;
- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
- credit risk relating to the risk of loss as a result of non-performance by our counterparties;
- cyberattacks on the Company or on systems and infrastructure used by the oil and gas industry;
- weather conditions;
- risks associated with acquisitions, including the Carrizo Acquisition;
- failure to consummate the Carrizo Acquisition in a timely manner, or at all, and failure to realize the expected benefits thereof; 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, 2018 (the “2018 Annual Report on Form 10-K”), and all quarterly reports on Form 10-Q filed subsequently thereto.

Should one or more of the risks or uncertainties described above or in our2018 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. Any forward-looking statement speaks only as of the date of which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except required by applicable law.

Except as required by applicable law, all forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

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 2018 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 Quarterly Report on Form 10-Q.

We are an independent oil and natural gas company incorporated in the State of Delaware in 1994, but our roots go back nearly 70 years to our Company's establishment in 1950. We are focused on the acquisition and development 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. Since our entry into the Permian Basin in late 2009, we have historically been focused on the Midland Basin and more recently entered the Delaware Basin through an acquisition completed in February 2017. We further expanded our presence in the Delaware Basin through our acquisitions in 2018. Our operating culture is centered on responsible development of hydrocarbon resources, safety and the environment, which we believe strengthens our operational performance. Our drilling activity is 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 78% oil and 22% natural gas for the six months ended June 30, 2019.

Recent Developments

On June 12, 2019, we completed the Ranger Asset Divestiture for net cash proceeds received at closing of $245 million, including customary purchase price adjustments.

On July 18, 2019, we redeemed all outstanding shares of the Preferred Stock at a Redemption Price of $50.24 per share for a total redemption of $73 million. After the Redemption Date, the Preferred Stock were no longer deemed outstanding, dividends on the Preferred Stock ceased to accrue, and all rights of the holders with respect to such Preferred Stock were terminated, except the right of the holders to receive the Redemption Price, without interest.

In July 2019, Callon and Carrizo entered into the Merger Agreement, pursuant to which, upon the terms and subject to the conditions set forth therein, Carrizo will merge with and into Callon, with Callon as the surviving corporation. The combination will result in a portfolio of core oil-weighted assets in both the Permian Basin and Eagle Ford Shale. The Company expects that the acquisition will close during the fourth quarter of 2019. See Note 13 for additional information regarding the Carrizo Acquisition.

Operational Highlights

All of our producing properties are located in the Permian Basin. As a result of our horizontal development and acquisition efforts, our production grew 40% and 46% for the three and six months ended June 30, 2019, compared to the same periods of 2018, respectively. Production increased to 3,687 MBOE for the three months ended June 30, 2019 from 2,635 MBOE for the same period of 2018, and increased to 7,314 MBOE for the six months ended June 30, 2019 from 5,026 MBOE for the same period of 2018. As of June 30, 2019, we had 798 gross (600.3 net) working interest oil wells and two gross (0.02 net) royalty interest natural gas wells.

For the three months ended June 30, 2019, we drilled 15 gross (14.3 net) horizontal wells and completed 14 gross (12.4 net) horizontal wells. For the six months ended June 30, 2019, we drilled 36 gross (30.7 net) horizontal wells and completed 25 gross (22.5 net) horizontal wells. As of June 30, 2019, we had 22 gross (17.6 net) horizontal wells awaiting completion.

Results of Operations

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

	Three Months Ended June 30,			
	2019	**2018**	**Change**	**% Change**
Net production				
Oil (MBbls)	2,848	1,995	853	43 %
Natural gas (MMcf)	5,031	3,839	1,192	31 %
Total (MBOE)	3,687	2,635	1,052	40 %
Average daily production (BOE/d)	40,516	28,954	11,562	40 %
% oil (BOE basis)	77%	76%		
Average realized sales price (excluding impact of settled derivatives)				
Oil (per Bbl)	$ 56.44	$ 61.46	$ (5.02)	(8)%
Natural gas (per Mcf)	1.26	3.77	(2.51)	(67)%
Total (per BOE)	45.31	52.02	(6.71)	(13)%
Average realized sales price (including impact of settled derivatives)				
Oil (per Bbl)	$ 54.87	$ 57.38	$ (2.51)	(4)%
Natural gas (per Mcf)	1.91	3.81	(1.90)	(50)%
Total (per BOE)	44.99	48.99	(4.00)	(8)%
Oil and natural gas revenues (in thousands)				
Oil revenue	$ 160,728	$ 122,613	$ 38,115	31 %
Natural gas revenue	6,324	14,462	(8,138)	(56)%
Total	$ 167,052	$ 137,075	$ 29,977	22 %
Additional per BOE data				
Sales price [(a)]	$ 45.31	$ 52.02	$ (6.71)	(13)%
Lease operating expense [(b)]	6.18	4.99	1.19	24 %
Production taxes	3.02	2.86	0.16	6 %
Operating margin	$ 36.11	$ 44.17	$ (8.06)	(18)%
Benchmark prices				
WTI (per Bbl)	$ 59.88	$ 68.07	$ (8.19)	(12)%
Henry Hub (per Mmbtu)	2.57	2.85	(0.28)	(10)%

(a) Excludes the impact of settled derivatives.
(b) Excludes gathering and treating expense.

	Six Months Ended June 30,			
	2019	2018	Change	% Change
Net production				
Oil (MBbls)	5,706	3,846	1,860	48 %
Natural gas (MMcf)	9,650	7,078	2,572	36 %
Total (MBOE)	7,314	5,026	2,288	46 %
Average daily production (BOE/d)	40,409	27,766	12,643	46 %
% oil (BOE basis)	78%	77%		
Average realized sales price (excluding impact of settled derivatives)				
Oil (per Bbl)	$ 52.90	$ 61.86	$ (8.96)	(14)%
Natural gas (per Mcf)	1.89	3.76	(1.87)	(50)%
Total (per BOE)	43.77	52.63	(8.86)	(17)%
Average realized sales price (including impact of settled derivatives)				
Oil (per Bbl)	$ 51.84	$ 57.42	$ (5.58)	(10)%
Natural gas (per Mcf)	2.37	3.85	(1.48)	(38)%
Total (per BOE)	43.57	49.36	(5.79)	(12)%
Oil and natural gas revenues (in thousands)				
Oil revenue	$ 301,826	$ 237,898	$ 63,928	27 %
Natural gas revenue	18,273	26,617	(8,344)	(31)%
Total	$ 320,099	$ 264,515	$ 55,584	21 %
Additional per BOE data				
Sales price [(a)]	$ 43.77	$ 52.63	$ (8.86)	(17)%
Lease operating expense [(b)]	6.40	5.21	1.19	23 %
Production taxes	3.00	3.18	(0.18)	(6)%
Operating margin	$ 34.37	$ 44.24	$ (9.87)	(22)%
Benchmark prices				
WTI (per Bbl)	$ 57.39	$ 65.55	$ (8.16)	(12)%
Henry Hub (per Mmbtu)	2.74	2.96	(0.22)	(7)%

(a) Excludes the impact of settled derivatives.
(b) Excludes gathering and treating expense.

Revenues

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

(in thousands)	Oil	Natural Gas	Total
Revenues for the three months ended June 30, 2018	$ 122,613	$ 14,462	$ 137,075
Volume increase (decrease)	52,425	4,494	56,919
Price increase (decrease)	(14,310)	(12,632)	(26,942)
Net increase (decrease)	38,115	(8,138)	29,977
Revenues for the three months ended June 30, 2019	$ 160,728	$ 6,324	$ 167,052

(in thousands)	Oil	Natural Gas	Total
Revenues for the six months ended June 30, 2018	$ 237,898	$ 26,617	$ 264,515
Volume increase (decrease)	115,060	9,671	124,731
Price increase (decrease)	(51,132)	(18,015)	(69,147)
Net increase (decrease)	63,928	(8,344)	55,584
Revenues for the six months ended June 30, 2019	$ 301,826	$ 18,273	$ 320,099

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.

Oil revenue

For the three months ended June 30, 2019, oil revenues of $160.7 million increased $38.1 million, or 31%, compared to revenues of $122.6 million for the same period of 2018. The increase was primarily attributable to a 43% increase in production from our acquisition and development efforts, offset by an 8% decrease in the average realized sales price, which fell to $56.44 per Bbl from $61.46 per Bbl.

For the six months ended June 30, 2019, oil revenues of $301.8 million increased $63.9 million, or 27%, compared to revenues of $237.9 million for the same period of 2018. The increase was primarily attributable to a 48% increase in production from our acquisition and development efforts, offset by a 14% decrease in the average realized sales price, which fell to $52.90 per Bbl from $61.86 per Bbl.

Natural gas revenue (including NGLs)

For the three months ended June 30, 2019, natural gas revenues of $6.3 million decreased $8.1 million, or 56%, compared to $14.5 million for the same period of 2018. The decrease was primarily attributable to a 67% decrease in the average realized sales price, which fell to $1.26 per Mcf from $3.77 per Mcf. The decrease in realized natural gas pricing was partially offset by a 31% increase in natural gas volumes.

For the six months ended June 30, 2019, natural gas revenues of $18.3 million decreased $8.3 million, or 31%, compared to $26.6 million for the same period of 2018. The decrease was primarily attributable to a 50% decrease in the average realized sales price, which fell to $1.89 per Mcf from $3.76 per Mcf. The decrease in realized natural gas pricing was partially offset by a 36% increase in natural gas volumes.

Operating Expenses

	Three Months Ended June 30,							
		Per		Per	Total Change		BOE Change	
(in thousands, except per unit amounts)	2019	BOE	2018	BOE	$	%	$	%
Lease operating expenses	$ 22,776	$ 6.18	$ 13,141	$ 4.99	$ 9,635	73 %	$ 1.19	24 %
Production taxes	11,131	3.02	7,539	2.86	3,592	48 %	0.16	6 %
Depreciation, depletion and amortization	62,921	17.07	38,733	14.70	24,188	62 %	2.37	16 %
General and administrative	10,564	2.87	8,289	3.15	2,275	27 %	(0.28)	(9)%
Accretion expense	216	0.06	206	0.08	10	5 %	(0.02)	(25)%
Other operating expense	935	0.25	1,767	0.67	(832)	(47)%	(0.42)	(63)%

	Six Months Ended June 30,							
		Per		Per	Total Change		BOE Change	
(in thousands, except per unit amounts)	2019	BOE	2018	BOE	$	%	$	%
Lease operating expenses	$ 46,843	$ 6.40	$ 26,179	$ 5.21	$ 20,664	79 %	$ 1.19	23 %
Production taxes	21,944	3.00	16,002	3.18	5,942	37 %	(0.18)	(6)%
Depreciation, depletion and amortization	122,688	16.77	74,151	14.75	48,537	65 %	2.02	14 %
General and administrative	22,317	3.05	17,057	3.39	5,260	31 %	(0.34)	(10)%
Settled share-based awards	3,024	0.41	—	—	3,024	100 %	0.41	100 %
Accretion expense	457	0.06	424	0.08	33	8 %	(0.02)	(25)%
Other operating expense	1,092	0.15	2,315	0.46	(1,223)	(53)%	(0.31)	(67)%

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.

LOE for the three months ended June 30, 2019 increased to $22.8 million compared to $13.1 million for the same period of 2018. The increase in LOE primarily related to a higher well count due to our successful drilling activity and a net increase in wells from acquisitions and divestitures. We had 798 gross working interest wells as of June 30, 2019 as compared to 563 gross working interest wells as of the same period of 2018. Additionally, workover expense increased $2.4 million between periods as a result of the increased well count and higher workover activity.

LOE on a per unit basis increased when comparing the second quarter of 2019 to the same period in 2018. LOE per BOE increased to $6.18 for the second quarter of 2019, which represents an increase of $1.19 per BOE from the second quarter of 2018. This rate increase was primarily related to increased workover activity and the acquisition of certain assets with higher historical operating costs.

LOE for the six months ended June 30, 2019 increased to $46.8 million compared to $26.2 million for the same period of 2018. The increase in LOE primarily related to our higher well count discussed above. Additionally, workover activity increased $4.4 million between periods.

For the six months ended June 30, 2019, LOE on a per unit basis increased to $6.40 per BOE compared to $5.21 per BOE for the same period of 2018 primarily due to increased workover activity and the acquisition of certain assets with higher historical operating costs.

Production taxes. Production taxes include severance and ad valorem taxes. In general, production taxes are directly related to commodity price changes; however, severance taxes are based upon current year commodity prices, whereas ad valorem taxes are based upon prior year commodity prices. Severance taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at fixed rates established by federal, state or local taxing authorities. Where available, we benefit from tax credits and exemptions in our various taxing jurisdictions. In the counties where our production is located, we are also subject to ad valorem taxes, which are generally based on the taxing jurisdictions' valuation of our oil and gas properties.

Production taxes for the three months ended June 30, 2019 increased 48% to $11.1 million compared to $7.5 million for the same period of 2018. On a per BOE basis, production taxes for the three months ended June 30, 2019 increased by 6% compared to the same period of 2018. The increase in production taxes is partially due to higher severance taxes as a result of higher revenues. Severance taxes as a percentage of total revenue were consistent across the comparable periods at approximately 5%. Additionally, ad valorem taxes increased $2.4 million over the comparative periods due to a higher valuation of our oil and gas properties by the taxing jurisdictions resulting from an increased number of producing wells in the current period, as a result of our horizontal drilling program and acquisition efforts.

Production taxes for the six months ended June 30, 2019 increased 37% to $21.9 million compared to $16.0 million for the same period of 2018. On a per BOE basis, production taxes for the three months ended June 30, 2019 decreased by 6% compared to the same period of 2018. The increase in production taxes is partially due to higher severance taxes as a result of higher revenues. Severance taxes as a percentage of total revenue were relatively unchanged across the comparable periods at approximately 5%. Additionally, ad valorem taxes increased $3.6 million over the comparative periods due to a higher valuation of our oil and gas properties by the taxing jurisdictions resulting from an increased number of producing wells in the current period, as a result of our horizontal drilling program and acquisition efforts.

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.

DD&A rates fluctuate as a result of changes in finding and development costs, acquisitions, impairments, and changes in proved reserves. For the three months ended June 30, 2019, DD&A expense was $62.9 million compared to $38.7 million for the same period of 2018. The additional DD&A was related to a 40% increase in production volumes combined with higher DD&A rates between the periods, which resulted in $9.3 million and $15.5 million, respectively, of incremental DD&A expense being incurred during the second quarter of 2019.

For the three months ended June 30, 2019, DD&A on a per unit basis increased to $17.07 per BOE compared to $14.70 per BOE for the same period of 2018. The primary factors contributing to the increased DD&A rate were higher drilling and completion costs for new wells placed on production over the past 12 months, higher estimated future development costs for PUD locations added, and the cost of our recent acquisitions relative to our historical rate. Additionally, the rate increase can be partially attributed to recent dispositions with a lower relative cost per BOE.

For the six months ended June 30, 2019, DD&A expense was $122.7 million compared to $74.2 million for the same period of 2018. The additional DD&A was related to a 46% increase in production volumes combined with higher DD&A rates between the periods, which resulted in $33.7 million and $15.4 million, respectively, of incremental DD&A expense being incurred during the six months ended June 30, 2019.

On a per unit basis DD&A increased to $16.77 per BOE compared to $14.75 per BOE for the same period of 2018. As discussed above, the increased DD&A rate is a function of recent drilling and completion costs incurred over the past 12 months, higher estimated future development cost for PUD locations, and the cost of our recent acquisitions relative to our historical rate. Additionally, the rate increase can be partially attributed to recent dispositions with a lower relative cost per BOE.

General and administrative, net of amounts capitalized ("G&A"). G&A for the three months ended June 30, 2019 increased to $10.6 million compared to $8.3 million for the same period of 2018. The increase is primarily attributable to a rise in personnel costs resulting from the growth in our operating activities. On a per unit basis, G&A decreased 9% to $2.87 per BOE for the three months ended June 30, 2019 compared to $3.15 per BOE for the same period in 2018. G&A expenses for the periods indicated include the following (in thousands):

	Three Months Ended June 30,			
	2019	**2018**	**$ Change**	**% Change**
G&A	$ 9,736	$ 7,186	$ 2,550	35%
Share-based compensation	1,687	1,587	100	6%
Fair value adjustments of cash-settled RSU awards	(859)	(484)	(375)	77%
Total G&A expenses	$ 10,564	$ 8,289	$ 2,275	27%

G&A for the six months ended June 30, 2019 increased to $22.3 million compared to $17.1 million for the same period of 2018. The increase is primarily attributable to a rise in personnel costs resulting from the growth in our operating activities. On a per unit basis, G&A decreased 10% to $3.05 per BOE for the six months ended June 30, 2019 compared to $3.39 per BOE for the same period in 2018. G&A expenses for the periods indicated include the following (in thousands):

	Six Months Ended June 30,			
	2019	**2018**	**$ Change**	**% Change**
G&A	$ 18,100	$ 13,858	$ 4,242	31%
Share-based compensation	3,187	2,692	495	18%
Fair value adjustments of cash-settled RSU awards	1,030	507	523	103%
Total G&A expenses	$ 22,317	$ 17,057	$ 5,260	31%

Settled share-based awards. During the first quarter of 2019, the Company settled certain of the outstanding share-based award agreements of two former officers of the Company, resulting in the $3.0 million recorded on the consolidated statements of operations as settled share-based awards.

Other Income and Expenses and Preferred Stock Dividends

	Three Months Ended June 30,			
(in thousands)	2019	2018	$ Change	% Change
Interest expense	$ 19,478	$ 12,644	$ 6,834	54 %
Capitalized interest	(18,737)	(12,050)	(6,687)	55 %
Interest expense, net of capitalized amounts	741	594	147	25 %
(Gain) loss on derivative contracts	(14,036)	16,554	(30,590)	(185)%
Other income	(67)	(703)	636	(90)%
Total other (income) expense	$ (13,362)	$ 16,445	$ (29,807)	(181)%
Income tax (benefit) expense	$ 16,691	$ 481	$ 16,210	3,370 %
Preferred stock dividends	(1,823)	(1,824)	1	— %

	Six Months Ended June 30,			
(in thousands)	2019	2018	$ Change	% Change
Interest expense	$ 40,059	$ 23,171	$ 16,888	73 %
Capitalized interest	(38,580)	(22,118)	(16,462)	74 %
Interest expense, net of capitalized amounts	1,479	1,053	426	40 %
(Gain) loss on derivative contracts	53,224	21,036	32,188	153 %
Other income	(148)	(914)	766	(84)%
Total other (income) expense	$ 54,555	$ 21,175	$ 33,380	158 %
Income tax (benefit) expense	$ 11,542	$ 976	$ 10,566	1,083 %
Preferred stock dividends	(3,647)	(3,647)	—	— %

Interest expense, net of capitalized amounts. We finance a portion of our capital expenditures, acquisitions and working capital requirements with borrowings under our Credit Facility or with term debt. We incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to our lender in interest expense, net of capitalized amounts. In addition, we include the amortization of deferred financing costs (including origination and amendment fees), commitment fees and annual agency fees in interest expense. Interest expense, net of capitalized amounts, incurred during the three months ended June 30, 2019 increased $0.1 million to $0.7 million compared to $0.6 million for the same period of 2018. Interest expense, net of capitalized amounts, incurred during the six months ended June 30, 2019 increased $0.4 million to $1.5 million compared to $1.1 million for the same period of 2018.

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. The net gain (loss) on derivative instruments for the periods indicated includes the following (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
Oil derivatives				
Net gain (loss) on settlements	$ (4,461)	$ (8,131)	$ (6,003)	$ (17,049)
Net gain (loss) on fair value adjustments	13,310	(8,311)	(53,517)	(4,243)
Total gain (loss) on oil derivatives	8,849	(16,442)	(59,520)	(21,292)
Natural gas derivatives				
Net gain (loss) on settlements	3,304	151	4,556	607
Net gain (loss) on fair value adjustments	(1,430)	(263)	(1,573)	(351)
Total gain (loss) on natural gas derivatives	1,874	(112)	2,983	256
Contingent consideration arrangement				
Net gain (loss) on fair value adjustments	3,313	—	3,313	—
Total gain (loss) on derivatives	$ 14,036	$ (16,554)	$ (53,224)	$ (21,036)

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 $16.7 million for the three months ended June 30, 2019, compared to income tax expense of $0.5 million for the same period of 2018. The Company had income tax expense of $11.5 million for the six months ended June 30, 2019, compared to income tax expense of $1.0 million for the same period of 2018. The change in income tax is primarily related to the change in our tax position in the current period, for which there is no longer a cumulative three year loss trend and booking of a valuation allowance for deferred tax benefits as compared to the prior period. See Note 8 in the Footnotes to the Financial Statements for additional information on income tax.

Preferred Stock dividends. Preferred Stock dividends of $1.8 million and $3.6 million for the three and six months ended June 30, 2019, respectively, were consistent with dividends for the same periods of 2018. Dividends reflect a 10% dividend yield. On July 18, 2019, we redeemed all outstanding shares of the Preferred Stock, after which, the Preferred Stock were no longer deemed outstanding and dividends on the Preferred Stock ceased to accrue. See Note 9 in the Footnotes to the Financial Statements for additional information.

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 and development 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 June 30, 2019, we had $105 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 June 30, 2019 and at year ended December 31, 2018, we held cash and cash equivalents of $16.1 million.

	Six Months Ended June 30,	
(in thousands)	2019	2018
Net cash provided by operating activities	$ 225,046	$ 199,979
Net cash used in investing activities	(124,504)	(368,285)
Net cash provided by (used in) financing activities	(100,541)	649,457
Net change in cash and cash equivalents	$ 1	$ 481,151

Operating activities. For the six months ended June 30, 2019, net cash provided by operating activities was $225.0 million compared to net cash provided by operating activities of $200.0 million for the same period in 2018. The change was predominantly attributable to the following:

- An increase in revenues from an increase in production volumes, offset by a decrease in realized pricing, and
- Changes related to the timing of working capital payments and receipts.

Production, realized prices, and operating expenses are discussed in Results of Operations. SeeNotes 6 and 7 in the Footnotes to the Financial Statements for a reconciliation of the components of the Company’s derivative contracts and disclosures related to derivative instruments including their composition and valuation.

Investing activities. For the six months ended June 30, 2019, net cash used in investing activities was $124.5 million compared to $368.3 million for the same period in 2018. The change was predominantly attributable to the following:

- A $33.5 million net increase in operational capital expenditures including seismic, leasehold, and other, due to increased activity and additional net wells drilled.
- Acquisitions and divestiture activity, resulting in an increase to net cash provided of $304.8 million, primarily provided by our Ranger Asset Divestiture completed in June 2019.

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

	Six Months Ended June 30,		
	2019	2018	$ Change
Operational expenditures	$ 298,348	$ 257,331	$ 41,017
Seismic, leasehold and other	3,947	11,461	(7,514)
Capitalized general and administrative costs	16,584	9,576	7,008
Capitalized interest	40,551	20,002	20,549
Total capital expenditures[(a)]	359,430	298,370	61,060
Acquisitions	39,370	45,392	(6,022)
Acquisition deposits	—	27,600	(27,600)
Proceeds from sale of assets	(274,296)	(3,077)	(271,219)
Total investing activities	$ 124,504	$ 368,285	$ (243,781)

(a) On an accrual basis, which is the methodology used for establishing our annual capital budget, operational expenditures for the six months ended June 30, 2019 were $284.7 million. Inclusive of seismic, leasehold and other, capitalized general and administrative, and capitalized interest costs, total capital expenditures for the six months ended June 30, 2019 were $346.4 million.

See Note 3 in the Footnotes to the Financial Statements for additional information on acquisitions and dispositions.

Financing activities. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our Credit Facility, term debt and equity offerings. For the six months ended June 30, 2019, net cash used in financing activities was $100.5 million compared to net cash provided by financing activities of $649.5 million for the same period of 2018. The change was predominantly attributable to 2018 financing activity used for funding our Delaware Asset Acquisition completed in the third quarter of 2018.

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

	Six Months Ended June 30,		
	2019	2018	$ Change
Net repayments on Credit Facility	$ (95,000)	$ (25,000)	$ (70,000)
Issuance of 6.375% senior unsecured notes due 2026	—	400,000	(400,000)
Issuance of common stock	—	288,357	(288,357)
Payment of preferred stock dividends	(3,647)	(3,647)	—
Payment of deferred financing costs	(31)	(8,664)	8,633
Tax withholdings related to restricted stock units	(1,858)	(1,589)	(269)
Other financing activities	(5)	—	(5)
Net cash provided by financing activities	$ (100,541)	$ 649,457	$ (749,998)

See Notes 5 and 9 in the Footnotes to the Financial Statements for additional information on our debt and equity transactions.

Capital Plan and Year to Date 2019 Summary

Our original operational capital budget for2019 was established in the range of $500 to $525 million on an accrual, or GAAP, basis, running an average of five drilling rigs to support larger, and more efficient, multi-well pad development. Of this range, approximately 15% is comprised of infrastructure and facilities capital. In addition to the operational capital expenditures budget, which includes well costs, facilities and infrastructure capital, and surface land purchases, we budgeted an estimated $100 to $105 million for capitalized interest and general and administrative expenses. In June 2019, we updated our annual operational capital budget to a range of $495 to $520 million, lowering our estimates to reflect realized efficiencies and cost reductions.

Operational capital expenditures, including other items, on an accrual basis were$288.6 million for the six months ended June 30, 2019. During the six months ended June 30, 2019, we placed 31 gross (27.1 net) horizontal wells on production. As of June 30, 2019, we have built a drilled, uncompleted inventory of 22 gross (17.6 net) wells to support a transition to larger pad development. In addition to the operational capital expenditures, $19.1 million of capitalized general and administrative and $38.6 million of capitalized interest expenses were accrued in the six months ended June 30, 2019.

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, 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.

Contractual Obligations

We had no material changes in our contractual obligations from amounts listed under "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Contractual Obligations" in our Annual Report on Form 10-K for the year ended December 31, 2018.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

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

Commodity price risk

The Company's revenues are derived from the sale of its oil and natural gas production. The prices for oil and natural gas remain volatile and sometimes experience large fluctuations as a result of relatively small changes in supply, weather conditions, economic conditions and government actions. From time to time, the Company enters into derivative financial instruments to manage oil and natural gas price risk, related both to NYMEX benchmark prices and regional basis differentials. The total volumes which we hedge through use of our derivative instruments varies from period to period; however, generally our objective is to hedge approximately 40% to 60% of our anticipated internally forecast production for the next 12 to 24 months, subject to the covenants under our Credit Facility. Our hedge policies and objectives may change significantly with movements in commodities prices or futures prices.

The Company's hedging portfolio as of June 30, 2019, indexed to NYMEX benchmark pricing, covers approximately 3,312,000 Bbls and 2,593,000 MMBtu of our expected oil and natural gas production, respectively, for the remainder of 2019. We also have commodity hedging contracts indexed to Midland WTI oil basis differentials relative to Cushing and Waha natural gas basis differentials covering approximately 4,137,500 Bbls and 4,232,000 MMBtu, respectively, of our expected oil and natural gas production for the remainder of 2019. As of June 30, 2019, we had outstanding oil and natural gas derivative contracts with a net liability position of $7.9 million. The following table provides a sensitivity analysis of the projected incremental effect on income (loss) before income taxes of a hypothetical 10% change in NYMEX WTI, Henry Hub, Midland WTI, Waha, and Houston MEH prices on our open commodity derivative instruments as of June 30, 2019 (in thousands):

	Hypothetical Price Increase of 10%	Hypothetical Price Decrease of 10%
Oil derivatives	$ (22,486)	$ 22,162
Natural gas derivatives	406	(398)
Total	$ (22,080)	$ 21,764

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 counterparty 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 from time to time to reduce the effects of volatile oil and natural gas prices and does not enter into derivative transactions for speculative purposes. Presently, none of the Company's derivative positions are designated as hedges for accounting purposes. See Note 6 in the Footnotes to the Financial Statements for a description of the Company's outstanding derivative contracts at June 30, 2019.

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 ofJune 30, 2019, the Company had $105.0 million outstanding under the Credit Facility with a weighted average interest rate of3.65%. 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 $1.1 million, based on the balance outstanding at June 30, 2019. 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. In order to mitigate potential exposure to credit risk, we may require from time to time for our customers to provide financial security. At June 30, 2019 our total receivables from the sale of our oil and natural gas production were approximately $67.9 million.

Joint interest receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we have or intend to drill. We have little ability to control whether these entities will participate in our wells. At June 30, 2019 our joint interest receivables were approximately $22.3 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.

The fair value of our contingent consideration arrangement was determined by a third-party valuation specialist using an option pricing model and includes significant inputs such as forward oil price curves, time to expiration, and implied volatility. See Note 7 in the Footnotes to the Financial Statements for more information on the fair value of the contingent consideration arrangement. The following table provides a sensitivity analysis of the projected incremental effect on income (loss) before income taxes based on a hypothetical 10% change in the underlying forward oil price curve as of June 30, 2019 (in thousands):

	Hypothetical Price Increase of 10%	Hypothetical Price Decrease of 10%
Contingent consideration arrangement	$ 8,196	$ (6,234)

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 June 30, 2019.

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 believe the ultimate resolution of any such actions will not 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 2018 Annual Report on Form 10-K and the risk factors and other cautionary statements contained in our other SEC filings, 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 2018 Annual Report on Form 10-K, other than the risk factors set forth below, which relate to the Carrizo Acquisition.

The transactions contemplated by the Merger Agreement are subject to conditions, including certain conditions that may not be satisfied or completed on a timely basis or at all. Failure to complete the transactions contemplated by the Merger Agreement, including the Carrizo Acquisition, could have material and adverse effects on us.

Completion of the Carrizo Acquisition is subject to a number of conditions, including, among other things, (i) the approval by our shareholders of the issuance of our common stock in the Carrizo Acquisition and of amendments to our certificate of incorporation to increase the authorized number of shares of our common stock, (ii) the adoption of the Merger Agreement and the Carrizo Acquisition by our common shareholders, (iii) the approval by the holders of Carrizo's common stock of the Merger Agreement, (iv) either (a) the approval by the holders of Carrizo's preferred stock of the Merger Agreement or (b) the Preferred Deposit (as defined in the Merger Agreement) having been deposited and the Preferred Redemption (as defined in the Merger Agreement) having occurred, (v) the absence of any law or order prohibiting the consummation of the Carrizo Acquisition, (vi) the effectiveness of the registration statement on Form S-4 pursuant to which the shares of our common stock issuable in the Carrizo Acquisition are registered with the SEC, (vii) the authorization for listing of the shares of our common stock issuable in the Carrizo Acquisition on the New York Stock Exchange, (viii) the expiration or termination of the applicable waiting periods under the Hart-Scott-Rodino Act, and (ix) delivery of opinions of counsel to us and to Carrizo to the effect that the Carrizo Acquisition will qualify as a reorganization within the meaning of Section 368(a) of the Internal Revenue Code of 1986, as amended. Such conditions, some of which are beyond our control, may not be satisfied or waived in a timely manner or at all and therefore make the completion and timing of the completion of the Carrizo Acquisition uncertain. In addition, the Merger Agreement contains certain termination rights for both Carrizo and us, which if exercised, will also result in the Carrizo Acquisition not being consummated. Furthermore, the governmental authorities from which the regulatory approvals are required may impose conditions on the completion of the Carrizo Acquisition or require changes to the terms of the Carrizo Acquisition or Merger Agreement.

If the transactions contemplated by the Merger Agreement are not completed, our ongoing business may be adversely affected and, without realizing any of the benefits of having completed the Carrizo Acquisition, we will be subject to a number of risks, including the following: we will be required to pay our costs relating to the Carrizo Acquisition, such as legal, accounting, financial advisory and printing fees, whether or not the Carrizo Acquisition is completed; time and resources committed by our management to matters relating to the Carrizo Acquisition could otherwise have been devoted to pursuing other beneficial opportunities; and the market price of our common stock could be impacted to the extent that the current market price reflects a market assumption that the Carrizo Acquisition will be completed. In addition to the above risks, if the Merger Agreement is terminated and our Board of Directors seeks another acquisition, our shareholders cannot be certain that we will be able to find a party willing to enter into a transaction as attractive to us as the Carrizo Acquisition.

We will be subject to business uncertainties while the Carrizo Acquisition is pending, which could adversely affect our business.

It is possible that certain persons with whom we have a business relationship may delay certain business decisions relating to us in connection with the pendency of the Carrizo Acquisition or they might decide to seek to terminate, change or renegotiate their relationships with us as a result of the Carrizo Acquisition, which could negatively affect our revenues, earnings and cash flows, as well as the market price of our common stock, regardless of whether the Carrizo Acquisition is completed. Also, our ability to attract, retain and motivate employees may be impaired until the Carrizo Acquisition is completed and for a period of time thereafter as current and prospective employees may experience uncertainty about their roles within the combined company following the Carrizo Acquisition.

In addition, under the terms of the Merger Agreement, we are subject to certain restrictions on the conduct of our business prior to the completion of the Carrizo Acquisition, which may adversely affect our ability to execute certain of our business strategies, including the ability in certain cases to modify or enter into certain contracts, acquire or dispose of certain assets or incur or pre-pay certain indebtedness, incur encumbrances, make capital expenditures, issue shares, or settle claims. Such limitations could negatively affect our business and operations prior to the completion of the Carrizo Acquisition.

Our shareholders will have a reduced ownership in the combined company after the Carrizo Acquisition and will exercise less influence over the policies of the combined company.

Based on the number of issued and outstanding shares of Carrizo common stock as of July 11, 2019 and the number of outstanding Carrizo equity awards currently estimated to be payable in shares of our common stock in connection with the Carrizo Acquisition, we anticipate issuing up to approximately 197.1 million shares of our common stock pursuant to the Merger Agreement. The actual number of shares of our common stock to be issued pursuant to the Merger Agreement will be determined at the completion of the Carrizo Acquisition based on the number of shares of Carrizo common stock outstanding at such time. The issuance of these new shares could have the effect of depressing the market price of our common stock, through dilution of earnings per share or otherwise. Any dilution of, or delay of any accretion to, our earnings per share could cause the price of our common stock to decline or increase at a reduced rate.

The Carrizo Acquisition will also dilute the current ownership position and voting interest of our shareholders. Immediately after the completion of the Carrizo Acquisition, it is expected that current Callon shareholders will own approximately 54%, and Carrizo shareholders will own approximately 46%, of the combined company's outstanding common stock. As a result, our current shareholders will have less influence on the policies of the combined company than they currently have.

The market price of shares of our common stock may decline in the future as a result of the sale of shares of our common stock held by former Carrizo shareholders or our current shareholders.

Following their receipt of shares of our common stock as consideration in the Carrizo Acquisition, former Carrizo shareholders may seek to sell the shares of our common stock delivered to them, and the Merger Agreement contains no restriction on the ability of former Carrizo shareholders to sell such shares of our common stock following completion of the Carrizo Acquisition. Other shareholders may also seek to sell shares of our common stock held by them following, or in anticipation of, completion of the Carrizo Acquisition. These sales (or the perception that these sales may occur), coupled with the increase in the outstanding number of shares of our common stock, may affect the market for, and the market price of, our common stock in an adverse manner.

The Merger Agreement limits our ability to pursue alternatives to the Carrizo Acquisition.

The Merger Agreement contains certain provisions that restrict our ability to solicit, initiate or knowingly encourage or facilitate, among other things, any inquiries, proposals, offers or requests for information regarding, or the making of a competing proposal, engage in any discussions or negotiations with respect to a competing proposal or furnish any non-public information to any person in connection with a competing proposal. In addition, if the Merger Agreement is terminated under certain specified circumstances, including the following, we would be required to pay Carrizo a termination fee of $57.0 million: (i) our Board of Directors changes its recommendation with respect to the Carrizo Acquisition, or if we willfully breach the covenant not to solicit alternative business combination proposals from third parties, or (ii) we enter into or consummate an alternative transaction within 12 months of termination of the Merger Agreement and prior to that either (a) our shareholders did not approve the Carrizo Acquisition, (b) we breached or failed to perform any of our representations, warranties or covenants in the Merger Agreement that could not be or was not cured in accordance with the terms of the Merger Agreement and such breach or failure to perform would cause applicable closing conditions not to be satisfied, or (c) the Carrizo Acquisition was not consummated by February 14, 2020 (with a possible extension to April 14, 2020 if all of the conditions to closing other than certain specified conditions have been satisfied). See our Current Report on Form 8-K filed with the SEC on July 15, 2019 for a more detailed discussion of the termination provisions in the Merger Agreement.

Even if the Carrizo Acquisition is completed, we may not achieve the anticipated benefits and the Carrizo Acquisition may disrupt our current plans or operations.

The success of the Carrizo Acquisition will depend, in part, on our ability to realize the anticipated benefits and cost savings from combining our and Carrizo's businesses, and there can be no assurance that we will be able to successfully integrate Carrizo or otherwise realize the anticipated benefits of the Carrizo Acquisition. Difficulties in integrating Carrizo into our company may result in the combined company performing differently than expected, in operational challenges or in the failure to realize anticipated expense-related efficiencies. Potential difficulties that may be encountered in the integration process include, among others:

- the inability to successfully integrate Carrizo into our company in a manner that permits us to achieve the full revenue and cost savings anticipated from the Carrizo Acquisition;
- complexities associated with managing a larger, more complex, integrated business;
- not realizing anticipated operating synergies;
- integrating personnel from the two companies and the loss of key employees;

- potential unknown liabilities and unforeseen expenses, delays or regulatory conditions associated with the Carrizo Acquisition and following completion of the Carrizo Acquisition;
- integrating relationships with customers, vendors and business partners;
- performance shortfalls as a result of the diversion of management's attention caused by completing the Carrizo Acquisition and integrating Carrizo's operations into our company; and
- the disruption of, or the loss of momentum in, each company's ongoing business or inconsistencies in standards, controls, procedures and policies.

We are expected to incur significant transaction costs in connection with the Carrizo Acquisition, which may be in excess of those anticipated by us.

We have incurred and are expected to continue to incur a number of non-recurring costs associated with negotiating and completing the Carrizo Acquisition, combining the operations of the two companies and achieving desired synergies. These fees and costs have been, and will continue to be, substantial and, in many cases, will be borne by us whether or not the Carrizo Acquisition is completed. A substantial majority of our non-recurring expenses will consist of transaction costs related to the Carrizo Acquisition and include, among others, fees paid to financial, legal, accounting and other advisors, and filing fees. We will also incur transaction costs related to formulating and implementing integration plans, including facilities and systems consolidation costs and other employment-related costs. We will continue to assess the magnitude of these costs, and additional unanticipated costs may be incurred in connection with the Carrizo Acquisition and the integration of the two companies' businesses. The elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the businesses, may not offset integration-related costs and achieve a net benefit in the near term, or at all. The costs described above and any unanticipated costs and expenses, many of which will be borne by us even if the Carrizo Acquisition is not completed, could have an adverse effect on our financial condition and operating results following the completion of the transaction.

We may be a target of securities class action and derivative lawsuits, which could result in substantial costs and may delay or prevent the Carrizo Acquisition from being completed.

Securities class action lawsuits and derivative lawsuits are often brought against public companies that have entered into acquisition or merger agreements. Even if the lawsuits are without merit, defending against these claims can result in substantial costs and divert management time and resources. An adverse judgment could result in monetary damages, which could have a negative impact on our liquidity and financial condition. Additionally, if a plaintiff is successful in obtaining an injunction prohibiting completion of the Carrizo Acquisition, that injunction may delay or prevent the Carrizo Acquisition from being completed, which may adversely affect our business, financial position and results of operations.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

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

Exhibit Number		Description	Incorporated by reference (File No. 001-14039, unless otherwise indicated) Form	Exhibit	Filing Date
3.1		Certificate of Incorporation of the Company, as amended through May 12, 2016	10-Q	3.1	11/03/2016
3.2		Amended and Restated Bylaws of the Company	10-K	3.2	02/27/2019
10.1		Purchase and Sale Agreement between Callon Petroleum Operating Company and Sequitur Permian, LLC dated April 8, 2019	8-K	2.1	06/13/2019
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)			
32.1	(b)	Section 1350 Certifications of Chief Executive and Financial Officers pursuant to Rule 13(a)-14(b)			
101.INS	(a)	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.			
101.SCH	(a)	Inline XBRL Taxonomy Extension Schema Document			
101.CAL	(a)	Inline XBRL Taxonomy Extension Calculation Linkbase Document.			
101.DEF	(a)	Inline XBRL Taxonomy Extension Definition Linkbase Document.			
101.LAB	(a)	Inline XBRL Taxonomy Extension Label Linkbase Document.			
101.PRE	(a)	Inline XBRL Taxonomy Extension Presentation Linkbase Document.			

(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.

† Indicates management compensatory plan, contract, or arrangement.

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	August 6, 2019
/s/ James P. Ulm, II James P. Ulm, II	Senior Vice President and Chief Financial Officer	August 6, 2019

Exhibit 31.1

CERTIFICATIONS

I, Joseph C. Gatto, Jr., certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Callon Petroleum Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 6, 2019

/s/ Joseph C. Gatto, Jr.
Joseph C. Gatto, Jr.
President and Chief Executive Officer
(Principal executive officer)

Exhibit 31.2

CERTIFICATIONS

I, James P. Ulm, II, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Callon Petroleum Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 6, 2019

/s/ James P. Ulm, II

James P. Ulm, II

Senior Vice President and Chief Financial Officer

(Principal financial officer)

Exhibit 32.1

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the Quarterly Report on Form 10-Q of Callon Petroleum Company for the quarterly period ended June 30, 2019, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, in the capacities and on the dates indicated below, each hereby certify pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Report fully complies with requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: August 6, 2019

/s/ Joseph C. Gatto, Jr.
Joseph C. Gatto, Jr.
(Principal executive officer)

Date: August 6, 2019

/s/ James P. Ulm, II
James P. Ulm, II
(Principal financial officer)

The foregoing certification is being furnished as an exhibit to the Report pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, is not being filed as part of the Report for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.