August 2, 2017

Callon Petroleum Company Announces Second Quarter 2017 Results

NATCHEZ, Miss., Aug. 2, 2017 /PRNewswire/ -- Callon Petroleum Company (NYSE: CPE) ("Callon" or the "Company") today reported results of operations for the three months ended June 30, 2017.

Presentation slides accompanying this earnings release are available on the Company's website at www.callon.com located on the "Presentations" page within the Investors section of the site.

Financial and operational highlights for the second quarter of 2017, and other recent data points include:

- Completed delineation of Wolfcamp A zone across aerial extent of Howard County position
- Successful Lower Spraberry well density test leading to 15% uplift in Monarch inventory
- Deployed 4th rig to Delaware basin and began operated drilling program at Spur in July
- Increased production by 9% quarter over quarter, driven primarily by higher oil mix (79%)
- Reduced lease operating expense per BOE by 15% from previous quarter
- Increased borrowing base to $650 million with a company-elected commitment of $500 million
- Raised $200 million in a senior notes offering that priced at a yield-to-worst of 5.2%
- Revising guidance to lower lease operating expense per unit and increase the oil mix for fiscal year 2017

"During the quarter we delivered double-digit oil production growth coupled with a double-digit reduction in lease operating expense," commented Joe Gatto, President and Chief Executive Officer. "In addition, we made important strides in the delineation of our asset base, including the extension of our program development into the central portion of Howard County and the completion of successful Lower Spraberry density spacing tests in our Monarch area. We also recently added a dedicated rig to our Spur area in the Delaware Basin in July and are now running four rigs that will be active across all four of our operating areas during the second half of 2017. In keeping with our strategy of sustainable growth and financial discipline, we are well-positioned to add a fifth rig in early 2018 and achieve our 2018 target exit rate goal of 40,000 BOE per day."

Operations Update

At June 30, 2017, we had 205 gross (151.1 net) horizontal wells producing from seven established flow units in the Permian Basin. Net daily production for the three months ended June 30, 2017 grew approximately 65% to 22.2 thousand barrels of oil equivalent per day ("MBOE/d") (approximately 79% oil) as compared to the same period of 2016. Sequentially, we grew production by approximately 9% compared to the first quarter of 2017, with a corresponding 11% sequential increase in our oil volumes.

For the three months ended June 30, 2017, we operated three horizontal drilling rigs, drilling 14 gross (10.7 net) horizontal wells in the Monarch, Ranger and WildHorse areas. We placed a combined 14 gross (9.7 net) horizontal wells on production in the quarter in the Monarch, Spur and WildHorse areas. In July 2017, we moved from a three-rig program to a four-rig program with the arrival of our first operated rig in the Delaware basin allocated to our Spur area. In addition, we recently added a second dedicated completion crew to account for our ramp in activity during the second half of 2017.

In the Midland Basin, we completed delineation of the Wolfcamp A across our Howard County position with recent well results tracking the 1 million barrels of oil equivalent ("MMBOE") type curve. Infrastructure development in the region continues to drive down lease operating expense per BOE and is expected to enhance early time peak fluid capacity, leading to improved de-watering of the formation and early time increases in oil cuts. Recent Lower Spraberry completions in Howard County continue to produce with shallow declines and upcoming wells in the formation are expected to benefit from new completion designs that focus on high density, near-wellbore design.

Production results and pressure data from the Monarch density pilot program support the establishment of a new 13 well per section stack-and-stagger model for the Lower Spraberry. This higher density well pattern increases the Lower Spraberry inventory at Monarch by approximately 15%. The inventory for the Lower Spraberry at Monarch now equates to more than 10 years of drilling inventory for a full-time rig line.

During the second quarter, we fracture stimulated our first two Lower Wolfcamp B wells in Reagan County since 2015. These wells are currently flowing back and are expected to reach peak rate during the third quarter. Additional drilling activity is currently planned during the second half of 2017 at Ranger, inclusive of a Wolfcamp C test well.

In the Delaware basin, the two wells acquired from the previous operator are tracking the respective acquisition type curves (1.6 MMBOE for the Wolfcamp A and 900 MBOE for the Wolfcamp B, both normalized for a 7,500 foot lateral). With a full-time rig now dedicated to Spur, upcoming wells will incorporate changes to both completion design and optimized landing zone for upcoming drilling in multiple intervals within the Wolfcamp formation.

On June 5, 2017, we completed the acquisition of 7,031 gross (2,488 net) acres in the Delaware Basin, contiguous to the Spur operating area, for total cash consideration of $52.5 million, excluding customary purchase price adjustments. The purchase price was funded with available cash-on-hand and the proceeds from the recent $200 million senior notes add-on offering.

Capital Expenditures

For the three months ended June 30, 2017, we incurred $64.0 million in cash operational capital expenditures compared to $55.5 million in the first quarter of 2017. Total capital expenditures, inclusive of capitalized expenses, are detailed below on an accrual and cash basis (in thousands):

	Three Months Ended June 30, 2017				
	Operational Capital	Other [(a)]	Capitalized Interest	Capitalized G&A	Total Capital Expenditures
Cash basis [(b)]	$ 63,999	$ 1,382	$ 10,791	$ 3,764	$ 79,936
Timing adjustments [(c)]	18,082	—	(2,858)	—	15,224
Non-cash items	—	—	—	408	408
Accrual (GAAP) basis	$ 82,081	$ 1,382	$ 7,933	$ 4,172	$ 95,568

(a) Includes seismic, land and other items.
(b) Cash basis is a non-GAAP measure that we believe helps users of the financial information reconcile amounts to the cash flow statement and to account for timing related operational changes such as our development pace and rig count.
(c) Includes timing adjustments related to cash disbursements in the current period for capital expenditures incurred in the prior period.

Operating and Financial Results

The following table presents summary information for the periods indicated:

	Three Months Ended		
	June 30, 2017	March 31, 2017	June 30, 2016
Net production:			
Oil (MBbls)	1,596	1,434	948
Natural gas (MMcf)	2,550	2,422	1,658
Total production (MBOE)	2,021	1,838	1,224
Average daily production (BOE/d)	22,209	20,422	13,451
% oil (BOE basis)	79 %	78 %	77 %
Oil and natural gas revenues (in thousands):			
Oil revenue	$ 72,885	$ 72,008	$ 40,555
Natural gas revenue	9,398	9,355	4,590
Total revenue	82,283	81,363	45,145
Impact of cash-settled derivatives	(267)	(2,491)	4,017
Adjusted Total Revenue [(i)]	$ 82,016	$ 78,872	$ 49,162
Average realized sales price:			
Oil (Bbl) (excluding impact of cash settled derivatives)	$ 45.67	$ 50.21	$ 42.78
Oil (Bbl) (including impact of cash settled derivatives)	45.47	48.45	46.69
Natural gas (Mcf) (excluding impact of cash settled derivatives)	$ 3.69	$ 3.86	$ 2.77
Natural gas (Mcf) (including impact of cash settled derivatives)	3.70	3.88	2.96
Total (BOE) (excluding impact of cash settled derivatives)	$ 40.71	$ 44.27	$ 36.88
Total (BOE) (including impact of cash settled derivatives)	40.58	42.91	40.17
Additional per BOE data:			
Sales price (excluding impact of cash settled derivatives)	$ 40.71	$ 44.27	$ 36.88
Lease operating expense (excluding gathering and treating expense)	5.56	6.61	5.70
Gathering and treating expense	0.45	0.43	0.27
Production taxes	2.38	3.21	2.01
Operating margin	$ 32.32	$ 34.02	$ 28.90
Depletion, depreciation and amortization	$ 12.97	$ 13.29	$ 13.31
Adjusted G&A [(a)]			
Cash component [(b)]	$ 2.67	$ 2.43	$ 2.92
Non-cash component	0.53	0.57	0.63

(a) Excludes certain non-recurring expenses and non-cash valuation adjustments. See the reconciliation provided within this press release for a reconciliation of G&A expense on a GAAP basis to Adjusted G&A expense.
(b) Excludes the amortization of equity-settled share-based incentive awards and corporate depreciation and amortization.

Total Revenue. For the quarter ended June 30, 2017, Callon reported total revenue of $82.3 million and total revenue including cash-settled derivatives ("Adjusted Total Revenue," a non-GAAP financial measure[(i)]) of $82.0 million, including the impact of a $0.3 million loss from the settlement of derivative contracts. The table above reconciles Adjusted Total

Revenue to the related GAAP measure of the Company's revenue. Average daily production for the quarter was 22.2 MBOE/d compared to average daily production of 20.4 MBOE/d in the first quarter of 2017. Average realized prices, including and excluding the effects of hedging, are detailed below.

Hedging impacts. For the quarter ended June 30, 2017, Callon recognized the following hedging-related items (in thousands, except per unit data):

	In Thousands	Per Unit
Oil derivatives		
Net gain (loss) on settlements	$ (315)	$ (0.20)
Net gain (loss) on fair value adjustments	10,128	
Total gain (loss) on oil derivatives	$ 9,813	
Natural gas derivatives		
Net gain on settlements	$ 48	$ 0.01
Net gain (loss) on fair value adjustments	633	
Total gain (loss) on natural gas derivatives	$ 681	
Total oil & natural gas derivatives		
Net loss on settlements	$ (267)	$ (0.13)
Net gain on fair value adjustments	10,761	
Total gain on total oil & natural gas derivatives	$ 10,494	

Lease Operating Expenses, including workover and gathering expense ("LOE"). LOE per BOE for the three months ended June 30, 2017 was $6.01 per BOE, compared to LOE of $7.04 per BOE in the first quarter of 2017. The decrease in this metric was related to early-day benefits from infrastructure projects materializing throughout the quarter as well as an increase in production volumes.

Production Taxes, including ad valorem taxes. Production taxes were $2.38 per BOE for the three months ended June 30, 2017, representing approximately 5.9% of total revenue before the impact of derivative settlements.

Depreciation, Depletion and Amortization ("DD&A"). DD&A for the three months ended June 30, 2017 was $12.97 per BOE compared to $13.29 per BOE in the first quarter of 2017. The decrease on a per unit basis was primarily attributable to greater increases in the estimated total proved reserve base as compared to the increases in our depreciable asset base and assumed future development costs related to undeveloped proved reserves.

General and Administrative ("G&A"). G&A, excluding certain non-cash incentive share-based compensation valuation adjustments, ("Adjusted G&A", a non-GAAP measure[i]) was $6.5 million, or $3.20 per BOE, for the three months ended June 30, 2017 compared to $5.5 million, or $3.00 per BOE, for the first quarter of 2017. The cash component of Adjusted G&A was $5.4 million, or $2.67 per BOE, for the three months ended June 30, 2017 compared to $4.5 million, or $2.43 per BOE, for the first quarter of 2017.

For the three months ended June 30, 2017, G&A and Adjusted G&A, which excludes the amortization of equity-settled, share-based incentive awards and corporate depreciation and amortization, are calculated as follows (in thousands):

	Three Months Ended June 30, 2017	
Total G&A expense	$	6,430
Less: Early retirement expenses		(444)
Less: Early retirement expenses related to share-based compensation		(81)
Less: Change in the fair value of liability share-based awards (non-cash)		567
Adjusted G&A – total		6,472
Less: Restricted stock share-based compensation (non-cash)		(966)
Less: Corporate depreciation & amortization (non-cash)		(114)
Adjusted G&A – cash component	$	5,392

Settled share-based awards. In June 2017, the Company settled the outstanding share-based award agreements of its former Chief Executive Officer, resulting in a payment of $6.4 million.

Income tax expense. Callon typically provides for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, which primarily relate to non-deductible executive compensation expenses and state income taxes. We recorded an income tax expense of $0.3 million for the three months ended June 30, 2017. At June 30, 2017 we had a valuation allowance of $115.9 million. Adjusted Income per fully diluted common share, a non-GAAP financial measure[i], adjusts our income (loss) available to common stockholders to reflect our theoretical tax provision of $11.2 million (or $0.06 per diluted share) for the quarter as if the valuation allowance did not exist.

2017 Guidance Update

	Third Quarter 2017 Guidance	Full Year 2017 Guidance
Total production (BOE/d)	23,000 - 25,000	22,500 - 25,500
% oil	77 %	78 %
Income Statement Expenses (per BOE)		
LOE, including workovers	$6.00 - $6.50	$5.75 - $6.25
Gathering and treating	$0.40 - $0.50	$0.40 - $0.50
Production taxes, including ad valorem (% unhedged revenue)	7%	7%
Adjusted G&A: cash component [a]	$2.25 - $2.50	$2.00 - $2.50
Adjusted G&A: non-cash component [b]	$0.50 - $0.75	$0.50 - $1.00
Interest expense [c]	$0.00	$0.00
Effective income tax rate	0%	0%
Capital expenditures ($MM, accrual basis)		
Operational [d]	$110 - $130	$350
Capitalized expenses (cash component)	$12 - $17	$40 - $45
Net operated horizontal well completions		
Midland Basin	~10	~39
Delaware Basin	~1	~3

(a) Excludes stock-based compensation and corporate depreciation and amortization. See the Non-GAAP related disclosures referenced in the footnote (b) below.

(b) Excludes certain non-recurring expenses and non-cash valuation adjustments. The reconciliation above provides a reconciliation of second quarter 2017 G&A expense on a GAAP basis to Adjusted G&A expense, a non-GAAP measure. The Company is unable to present a quantitative reconciliation of this forward-looking non-GAAP financial measure without unreasonable effort because of the number of estimated variables that could affect the final value. Accordingly, investors are cautioned not to place undue reliance on this information.

(c) All interest expense anticipated to be capitalized.

(d) Includes seismic, land and other items. Excludes capitalized expenses.

Hedge Portfolio Summary

The following tables summarize our open derivative positions for the periods indicated:

Oil contracts (WTI)	For the Remainder of 2017	For the Full Year of 2018
Swap contracts combined with short puts (enhanced swaps)		
Total volume (MBbls)	368	—
Weighted average price per Bbl		
Swap	$ 44.50	$ —
Short put option	$ 30.00	$ —
Swap contracts		
Total volume (MBbls)	368	730
Weighted average price per Bbl	$ 45.74	$ 50.03
Deferred premium put spread option		
Total volume (MBbls)	506	—
Premium per Bbl	$ 2.45	$ —
Weighted average price per Bbl		
Long put option	$ 50.00	$ —
Short put option	$ 40.00	$ —
Collar contracts (two-way collars)		
Total volume (MBbls)	681	—
Weighted average price per Bbl		
Ceiling (short call)	$ 58.19	$ —
Floor (long put)	$ 47.50	$ —
Call option contracts		
Total volume (MBbls)	338	—
Premium per Bbl	$ 1.82	$ —
Weighted average price per Bbl		
Short call strike price [(a)]	$ 50.00	$ —
Long call strike price [(a)]	$ 50.00	$ —
Collar contracts combined with short puts (three-way collars)		
Total volume (MBbls)	—	3,468
Weighted average price per Bbl		
Ceiling (short call option)	$ —	$ 60.86
Floor (long put option)	$ —	$ 48.95
Short put option	$ —	$ 39.21

(a) Offsetting contracts.

Oil contracts (Midland basis differential)	For the Remainder of 2017	For the Full Year of 2018
Swap contracts		
Volume (MBbls)	1,104	2,738
Weighted average price per Bbl	$ (0.52)	$ (1.03)

Natural gas contracts (Henry Hub)	For the Remainder of 2017	For the Full Year of 2018
Collar contracts combined with short puts (three-way collars)		
Total volume (BBtu)	736	—
Weighted average price per MMBtu		
Ceiling (short call option)	$ 3.71	$ —
Floor (long put option)	$ 3.00	$ —
Short put option	$ 2.50	$ —
Collar contracts (two-way collars)		
Total volume (BBtu)	1,224	720
Weighted average price per MMBtu		
Ceiling (short call option)	$ 3.74	$ 3.84
Floor (long put option)	$ 3.16	$ 3.40
Swap contracts		
Total volume (BBtu)	492	—
Weighted average price per MMBtu	$ 3.39	$ —

Income (Loss) Available to Common Shareholders. The Company reported net income available to common shareholders of $31.6 million for the three months ended June 30, 2017 and Adjusted Income available to common shareholders of $17.2 million, or $0.09 per diluted share. Adjusted Income per fully diluted common share, a non-GAAP financial measure(i), adjusts our income (loss) available to common stockholders to reflect our theoretical tax provision for the quarter as if the valuation allowance did not exist. The following tables reconcile to the related GAAP measure the Company's income (loss) available to common stockholders to Adjusted Income and the Company's net income (loss) to Adjusted EBITDA (in thousands):

	Three Months Ended		
	June 30, 2017	**March 31, 2017**	**June 30, 2016**
Income (loss) available to common stockholders	$ 31,566	$ 45,305	$ (71,920)
Change in valuation allowance	(11,194)	(13,119)	24,409
Write-down of oil and natural gas properties	—	—	39,658
Net (gain) loss on derivatives, net of settlements	(6,995)	(11,566)	12,676
Change in the fair value of share-based awards	(315)	(189)	1,277
Settled share-based awards	4,128	—	—
Withdrawn proxy contest expenses	—	—	2
Adjusted Income	$ 17,190	$ 20,431	$ 6,102
Adjusted Income per fully diluted common share	$ 0.09	$ 0.10	$ 0.05

	Three Months Ended		
	June 30, 2017	**March 31, 2017**	**June 30, 2016**
Net income (loss)	$ 33,390	$ 47,129	$ (70,097)
Write-down of oil and natural gas properties	—	—	61,012
Net (gain) loss on derivatives, net of settlements	(10,761)	(17,794)	19,501
Non-cash stock-based compensation expense	499	639	2,628
Settled share-based awards	6,351	—	—
Withdrawn proxy contest expenses	—	—	3
Acquisition expense	2,373	450	1,906
Income tax expense	322	466	—
Interest expense	589	665	4,180
Depreciation, depletion and amortization	26,765	24,932	16,698
Accretion expense	208	184	395
Adjusted EBITDA	$ 59,736	$ 56,671	$ 36,226

Discretionary Cash Flow. Discretionary cash flow, a non-GAAP measure(i), for the three months ended June 30, 2017 was $57.4 million and is reconciled to operating cash flow in the following table (in thousands):

	Three Months Ended		
	June 30, 2017	**March 31, 2017**	**June 30, 2016**
Cash flows from operating activities:			
Net income (loss)	$ 33,390	$ 47,129	$ (70,097)
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depreciation, depletion and amortization	26,765	24,932	16,698
Write-down of oil and natural gas properties	—	—	61,012
Accretion expense	208	184	395
Amortization of non-cash debt related items	589	665	780
Deferred income tax expense	323	466	—
Net (gain) loss on derivatives, net of settlements	(10,761)	(17,794)	19,501
Loss on sale of other property and equipment	62	—	—
Non-cash expense related to equity share-based awards	4,865	930	(1,253)
Change in the fair value of liability share-based awards	1,982	(291)	1,965
Discretionary cash flow	$ 57,423	$ 56,221	$ 29,001
Changes in working capital	$ (8,968)	$ 5,890	$ (6,974)
Payments to settle asset retirement obligations	(816)	(765)	(158)
Payments to settle vested liability share-based awards	(4,511)	(8,662)	(493)
Net cash provided by operating activities	$ 43,128	$ 52,684	$ 21,376

Callon Petroleum Company
Consolidated Balance Sheets

(in thousands, except par and per share values and share data)

	June 30, 2017 Unaudited	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 139,149	$ 652,993
Accounts receivable	77,635	69,783
Fair value of derivatives	9,241	103
Other current assets	2,545	2,247
Total current assets	228,570	725,126
Oil and natural gas properties, full cost accounting method:		
Evaluated properties	3,125,238	2,754,353
Less accumulated depreciation, depletion, amortization and impairment	(1,998,294)	(1,947,673)
Net evaluated oil and natural gas properties	1,126,944	806,680
Unevaluated properties	1,194,999	668,721
Total oil and natural gas properties	2,321,943	1,475,401
Other property and equipment, net	18,071	14,114
Restricted investments	3,348	3,332
Deferred financing costs	5,273	3,092
Fair value of derivatives	3,804	—
Acquisition deposit	—	46,138
Other assets, net	655	384
Total assets	$ 2,581,664	$ 2,267,587
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 144,958	$ 95,577
Accrued interest	9,256	6,057
Cash-settleable restricted stock unit awards	3,650	8,919
Asset retirement obligations	1,767	2,729
Fair value of derivatives	2,243	18,268
Total current liabilities	161,874	131,550
Senior secured revolving credit facility	—	—
6.125% senior unsecured notes due 2024, net of unamortized deferred financing costs	595,138	390,219
Asset retirement obligations	5,031	3,932
Cash-settleable restricted stock unit awards	1,957	8,071
Deferred tax liability	921	90
Fair value of derivatives	441	28
Other long-term liabilities	405	295
Total liabilities	765,767	534,185
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 and 1,458,948 shares outstanding, respectively	15	15
Common stock, $0.01 par value, 300,000,000 and 300,000,000 shares authorized; 201,806,900 and 201,041,320 shares outstanding, respectively	2,018	2,010
Capital in excess of par value	2,177,547	2,171,514
Accumulated deficit	(363,683)	(440,137)
Total stockholders' equity	1,815,897	1,733,402
Total liabilities and stockholders' equity	$ 2,581,664	$ 2,267,587

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016

Operating revenues:				
Oil sales	$ 72,885	$ 40,555	$ 144,893	$ 67,998
Natural gas sales	9,398	4,590	18,754	7,845
Total operating revenues	82,283	45,145	163,647	75,843
Operating expenses:				
Lease operating expenses	12,145	7,311	25,084	14,268
Production taxes	4,820	2,455	10,723	4,675
Depreciation, depletion and amortization	26,213	16,293	50,646	32,015
General and administrative	6,430	6,302	11,636	11,864
Settled share-based awards	6,351	—	6,351	—
Accretion expense	208	395	392	575
Write-down of oil and natural gas properties	—	61,012	—	95,788
Acquisition expense	2,373	1,906	2,822	1,954
Total operating expenses	58,540	95,674	107,654	161,139
Income (loss) from operations	23,743	(50,529)	55,993	(85,296)
Other (income) expenses:				
Interest expense, net of capitalized amounts	589	4,180	1,254	9,671
(Gain) loss on derivative contracts	(10,494)	15,484	(25,797)	16,416
Other income	(64)	(96)	(772)	(177)
Total other (income) expense	(9,969)	19,568	(25,315)	25,910
Income (loss) before income taxes	33,712	(70,097)	81,308	(111,206)
Income tax expense	322	—	789	—
Net income (loss)	33,390	(70,097)	80,519	(111,206)
Preferred stock dividends	(1,824)	(1,823)	(3,647)	(3,647)
Income (loss) available to common stockholders	$ 31,566	$ (71,920)	$ 76,872	$ (114,853)
Income (loss) per common share:				
Basic	$ 0.16	$ (0.61)	$ 0.38	$ (1.14)
Diluted	$ 0.16	$ (0.61)	$ 0.38	$ (1.14)
Shares used in computing income (loss) per common share:				
Basic	201,386	118,209	201,220	100,895
Diluted	201,905	118,209	201,823	100,895

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	**2016**	**2017**	**2016**
Cash flows from operating activities:				
Net income (loss)	$ 33,390	$ (70,097)	$ 80,519	$ (111,206)
Adjustments to reconcile net income to cash provided by operating activities:				
Depreciation, depletion and amortization	26,765	16,698	51,697	32,827
Write-down of oil and natural gas properties	—	61,012	—	95,788
Accretion expense	208	395	392	575
Amortization of non-cash debt related items	589	780	1,254	1,561
Deferred income tax expense	323	—	789	—
Net (gain) loss on derivatives, net of settlements	(10,761)	19,501	(28,555)	28,149
Loss on sale of other property and equipment	62	—	62	—
Non-cash expense related to equity share-based awards	4,865	665	5,795	1,177
Change in the fair value of liability share-based awards	1,982	1,965	1,691	2,674
Payments to settle asset retirement obligations	(816)	(158)	(1,581)	(319)
Changes in current assets and liabilities:				
Accounts receivable	(3,744)	(10,777)	(7,810)	(4,836)
Other current assets	(874)	(885)	(298)	(305)
Current liabilities	(4,223)	4,830	5,680	4,113
Change in other long-term liabilities	120	75	120	86
Change in other assets, net	(247)	(217)	(770)	(450)
Payments to settle vested liability share-based awards	(4,511)	(493)	(13,173)	(10,300)
Net cash provided by operating activities	43,128	23,294	95,812	39,534
Cash flows from investing activities:				
Capital expenditures	(79,936)	(24,505)	(146,090)	(75,280)
Acquisitions	(58,004)	(273,841)	(706,489)	(284,024)
Acquisition deposit	—	—	46,138	—
Proceeds from sales of mineral interests and equipment	—	23,631	—	23,631
Net cash used in investing activities	(137,940)	(274,715)	(806,441)	(335,673)
Cash flows from financing activities:				
Borrowings on senior secured revolving credit facility	—	98,000	—	143,000
Payments on senior secured revolving credit facility	—	(58,000)	—	(143,000)
Issuance of 6.125% senior unsecured notes due 2024	200,000	—	200,000	—
Premium on the issuance of 6.125% senior unsecured notes due 2024	8,250	—	8,250	—

Issuance of common stock	—	205,858	—	300,807
Payment of preferred stock dividends	(1,823)	(1,823)	(3,647)	(3,647)
Payment of deferred financing costs	(6,765)	—	(6,765)	—
Tax withholdings related to restricted stock units	(974)	(1,918)	(1,053)	(2,038)
Net cash provided by financing activities	198,688	242,117	196,785	295,122
Net change in cash and cash equivalents	103,876	(9,304)	(513,844)	(1,017)
Balance, beginning of period	35,273	9,511	652,993	1,224
Balance, end of period	$ 139,149	$ 207	$ 139,149	$ 207

Non-GAAP Financial Measures and Reconciliations

This news release refers to non-GAAP financial measures such as "Discretionary Cash Flow," "Adjusted G&A," "Adjusted Income," "Adjusted EBITDA," and "Adjusted Total Revenue." These measures, detailed below, are provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our SEC filings and posted on our website.

- Callon believes that the non-GAAP measure of discretionary cash flow is useful as an indicator of an oil and natural gas exploration and production company's ability to internally fund exploration and development activities and to service or incur additional debt. The Company also has included this information because changes in operating assets and liabilities relate to the timing of cash receipts and disbursements which the company may not control and may not relate to the period in which the operating activities occurred. Discretionary cash flow is calculated using net income (loss) adjusted for certain items including depreciation, depletion and amortization, the impact of financial derivatives (including the mark-to-market effects, net of cash settlements and premiums paid or received related to our financial derivatives), remaining asset retirement obligations related to our divested offshore properties, restructuring and other non-recurring costs, deferred income taxes and other non-cash income items.
- Callon believes that the non-GAAP measure of Adjusted G&A is useful to investors because it provides readers with a meaningful measure of our recurring G&A expense and provides for greater comparability period-over-period. The table above details all adjustments to G&A on a GAAP basis to arrive at Adjusted G&A.
- We believe that the non-GAAP measure of Adjusted Income available to common shareholders ("Adjusted Income") and Adjusted Income per diluted share are useful to investors because they provide readers with a meaningful measure of our profitability before recording certain items whose timing or amount cannot be reasonably determined. These measures exclude the net of tax effects of certain non-recurring items and non-cash valuation adjustments, which are detailed in the reconciliation provided below. Prior to being tax-effected and excluded, the amounts reflected in the determination of Adjusted Income and Adjusted Income per diluted share above were computed in accordance with GAAP.
- We calculate Adjusted Earnings before Interest, Income Taxes, Depreciation, Depletion and Amortization ("Adjusted EBITDA") as Adjusted Income plus interest expense, income tax expense (benefit) and depreciation, depletion and amortization expense. Adjusted EBITDA is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income (loss), operating income (loss), cash flow provided by operating activities or other income or cash flow data prepared in accordance with GAAP. However, we believe that Adjusted EBITDA provides additional information with respect to our performance or ability to meet its

future debt service, capital expenditures and working capital requirements. Because Adjusted EBITDA excludes some, but not all, items that affect net income (loss) and may vary among companies, the Adjusted EBITDA we present may not be comparable to similarly titled measures of other companies.

- We believe that the non-GAAP measure of Adjusted Total Revenue is useful to investors because it provides readers with a revenue value more comparable to other companies who account for derivative contracts and hedges and include their effects in revenue. We believe Adjusted Total Revenue is also useful to investors as a measure of the actual cash inflows generated during the period.

Earnings Call Information

The Company will host a conference call on Thursday, August 3, 2017, to discuss second quarter 2017 financial and operating results.

Please join Callon Petroleum Company via the Internet for a webcast of the conference call:

Date/Time:	Thursday, August 3, 2017, at 9:00 a.m. Central Time (10:00 a.m. Eastern Time)
Webcast:	Live webcast will be available at www.callon.com in the "Investors" section of the website
Presentation Slides:	Available at http://ir.callon.com/presentations in the "Investors" section of the website

Alternatively, you may join by telephone using the following numbers:

Toll Free:	1-888-317-6003
Canada Toll Free:	1-866-284-3684
International:	1-412-317-6061
Access code:	5792667

An archive of the conference call webcast will also be available at www.callon.com in the "Investors" section of the website.

About Callon Petroleum

Callon Petroleum Company is an independent energy company focused on the acquisition, development, exploration, and operation of oil and natural gas properties in the Permian Basin in West Texas.

This news release is posted on the Company's website at www.callon.com and will be archived there for subsequent review under the "News" link on the top of the homepage.

Cautionary Statement Regarding Forward Looking Statements

This news release contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements include all statements regarding wells anticipated to be drilled and placed on production; future levels of drilling activity and associated production and cash flow expectations; the Company's 2017 guidance and capital expenditure forecast; estimated reserve quantities and the present value thereof; and the implementation of the Company's business plans and strategy, as well as statements including the words "believe," "expect," "plans" and words of similar meaning. These statements reflect the Company's current views with respect to future events and financial performance. No assurances can be given, however, that these events will occur or that these projections will be achieved, and actual results could differ materially from those projected as a result of certain factors. Some of the factors which could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements include the volatility of oil and natural gas prices, ability to drill and complete wells, operational, regulatory and environment risks, our ability to finance our activities and other risks more fully discussed in our filings with the Securities and Exchange Commission, including our Annual Reports on Form 10-K and Quarterly Reports on Form 10-Q, available on our website or the SEC's website at www.sec.gov.

For further information contact:
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i) See "Non-GAAP Financial Measures and Reconciliations" included within this release for related disclosures and calculations