Exhibit 99.1

Callon Petroleum Company Announces First Quarter 2017 Results

Natchez, MS (May 2, 2017) - Callon Petroleum Company (NYSE: CPE) ("Callon" or the "Company") today reported results of operations for the three months ended March 31, 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 first quarter of 2017, and other recent data points include:

- Daily production of 20.4 MBOE/d (78% oil), a sequential quarterly increase of 11% in total daily production and 14% increase in daily oil production
- Lease operating expense, including workovers, of $6.61 per BOE, a sequential quarterly decrease of 17%
- Two Wolfcamp A wells in Howard County (WildHorse area) reached average 30-day peak production rates of 237 BOE/d per 1,000 feet of completed lateral (91% oil) with a third continuing to build to peak production rates
- Increase in northern Howard County Wolfcamp A type curve (7,500' drilled lateral) to 1.3 MMBOE (85% oil)
- Closed the Ameredev transaction in mid-February and subsequently signed purchase and sale agreements for the acquisition of an additional 2,626 net acres in Ward County (Spur area) for $54.3 million, establishing a position of over 19,300 net surface acres in the Delaware Basin

"We are off to a strong start in 2017 with the increasing impact of our WildHorse area that is now in program development mode," commented Fred Callon, Chairman and Chief Executive Officer. "Our activity in this core area has initially focused on northern Howard County where we have demonstrated the repeatability of exceptional Wolfcamp A results from larger completion designs. Our efforts in WildHorse will now move toward the central part of Howard County, focusing on three development zones, and we will be active with two rigs across our entire Howard County position throughout 2017. In parallel, we have been executing our plans to initiate program development in our recently acquired Delaware Basin acreage position which will begin with the arrival of our fourth horizontal drilling rig in July. As we approach this date, we have been refining our completion designs and landing zone concepts based on analysis of core data from our Lower Wolfcamp A well that was placed on production in January 2017 and upgrading the existing infrastructure to support a two rig development program in the future. We have also been successful in expanding our footprint in this core area, increasing our Delaware Basin position by approximately 15% since we closed our initial acquisition in February and, importantly, enhancing our opportunity set with the extension of existing laterals and the addition of additional locations at attractive valuations."

Operations Update

At March 31, 2017, we had 191 gross (142.4 net) horizontal wells producing from six established flow units in the Permian Basin. Net daily production for the three months ended March 31, 2017 grew approximately 64% to 20.4 MBOE/d ("MBOE/d") (approximately 78% oil) as compared to the same period of 2016. Sequentially, we grew production by approximately 11% compared to the fourth quarter of 2016 with a corresponding 14% sequential increase in our oil volumes.

For the three months ended March 31, 2017, we operated three horizontal drilling rigs, drilling nine gross (7.8 net) horizontal wells in both the Monarch and WildHorse areas. We placed a combined nine gross (6.6 net) horizontal wells on production in the quarter in these two areas.

WildHorse

During the first quarter, we completed six wells including three Wolfcamp A wells and three Lower Spraberry wells. Based on production data from our Wolfcamp A wells in the Sidewinder field that were completed with larger proppant loadings (including extended time performance from the Silver City 01AH) and offsetting well results in the area, we are increasing our Wolfcamp A type curve (7,500' drilled lateral) in northern Howard County to 1.3 MMBOE (85% oil), an increase of 85% over the 700 MBOE type curve originally assumed at the time of the Big Star acquisition in April 2016. In addition, following the recent completion of our Garrett-Reed 37-48 #8AH well in the Maverick field and upcoming Wolfcamp A completions in the Fairway field, we will be re-evaluating our current type curve assumptions in central Howard County in the coming months.

i. See "Non-GAAP Financial Measures and Reconciliations" included within this release for related disclosures and calculations

The following table highlights the three Wolfcamp A wells in Howard County that achieved peak rates since the beginning of the year, expressed in absolute barrels of oil equivalent per day ("BOE/d") and production rates per 1,000 feet of completed lateral:

				24-Hour Peak IP (BOE/d; Two-stream) [a]			30-Day Average Peak IP (BOE/d; Two-stream)		
24-Hour IP Date	Well	Area (Field / Zone)	Completed Lateral (ft)	Peak 24-Hour IP	Production (% oil)	Per 1,000' Lateral Feet	Peak 30-Day IP	Production (% oil)	Per 1,000' Lateral Feet
03/16/2017	Wright-Adams 31-42 #5AH	WildHorse (Sidewinder/WCA)	6,832	2,333	90%	341	1,976	91%	289
Pending	Cheek 28-21 #1AH	WildHorse (Sidewinder/WCA)	9,720		Flowing back			Flowing back	
03/02/2017	Garrett-Reed 37-48 #8AH	WildHorse (Maverick/WCA)	6,560	1,530	92%	233	1,211	90%	184

(a) 24-Hour Peak IPs correspond to the rates filed with the Railroad Commission of Texas and are captured using well tests on the specified date, which may result in an understated rate as the production typically varies more widely during the early days of production. The 30-Day Average Peak IP is calculated using well tests on dates taken and allocated production for all other dates.

These wells were completed in individual two-well pads that also included Lower Spraberry wells. The Lower Spraberry wells employed larger completion designs than legacy wells in the area and are in the process of dewatering as they build to peak production rates.

Monarch

During the first quarter, three Lower Spraberry wells were placed on production in two flow units within the zone. In addition, we are in the process of completing a three well pad including two Lower Spraberry wells and one Wolfcamp A well that will be our third test of increased density development in the Lower Spraberry.

Spur

In our newest core operating area, we are in the final stages of preparation for program development. As part of our execution plan, we have been upgrading facilities as well as incorporating the analysis of core data from the Corbets 34-149 02A into the refinement of our completion designs and target landing zones from those utilized by the prior operator in two recent wells that we acquired with our recent transaction. The first of these wells, the Corbets 34-149 02A, targeted the Lower Wolfcamp A and has been flowing under natural pressure since being placed on production in late January. The well has produced in excess of 100 MBOE (90% oil) in the first 90 days since first production and continues to flow under a pressure management program. The second well, the Saratoga 34-161 01WB, was landed in the Wolfcamp B zone and recently placed on production.

Ward County Acquisitions

Since the closing of our Spur acquisition on February 13, 2017, we have signed agreements to acquire 2,626 net acres for $54.3 million, equating to an average purchase price of approximately $20,700 per net surface acre. In total, these acquisitions will: (i) increase our working interest in a meaningful portion of our existing gross operated inventory; (ii) extend the lateral length of 93 gross existing Wolfcamp A and B locations from a prior blended average of 5,000' to a new blended average of approximately 9,200'; and (iii) add an estimated 41 net new Wolfcamp A and B locations (over 90% operated) with an average lateral length of roughly 7,500'. The combined acquisition impact of these three factors is the addition of an estimated equivalent 67 net Wolfcamp locations with an average lateral length of over 8,000' at a purchase price of approximately $800 thousand per location. These acquisitions are expected to be funded with existing cash balances and credit facility borrowings.

i. See "Non-GAAP Financial Measures and Reconciliations" included within this release for related disclosures and calculations

Capital Expenditures

For the three months ended March 31, 2017, we incurred $55.5 million in cash operational capital expenditures compared to $53.4 million in the fourth quarter of 2016. Total capital expenditures, inclusive of capitalized expenses, are detailed below on an accrual and cash basis (in thousands):

	Three Months Ended March 31, 2017				
	Operational Capital	Other [(a)]	Capitalized Interest	Capitalized G&A	Total Capital Expenditures
Cash basis [(b)]	$ 55,503	$ 6,230	$ 487	$ 3,934	$ 66,154
Timing adjustments [(c)]	26,011	—	6,057	—	32,068
Non-cash items	—	—	—	572	572
Accrual (GAAP) basis	$ 81,514	$ 6,230	$ 6,544	$ 4,506	$ 98,794

(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		
	March 31, 2017	December 31, 2016	March 31, 2016
Net production:			
Oil (MBbls)	1,434	1,287	892
Natural gas (MMcf)	2,422	2,413	1,443
Total production (MBOE)	1,838	1,689	1,132
Average daily production (BOE/d)	20,422	18,359	12,440
% oil (BOE basis)	78%	76%	79%
Oil and natural gas revenues (in thousands):			
Oil revenue	$ 72,008	$ 60,559	$ 27,443
Natural gas revenue	9,355	8,522	3,255
Total revenue	$ 81,363	$ 69,081	$ 30,698
Impact of cash-settled derivatives	(2,491)	2,079	7,716
Adjusted Total Revenue [(i)]	$ 78,872	$ 71,160	$ 38,414

Total Revenue. For the quarter ended March 31, 2017, Callon reported total revenues of $81.4 million and total revenues including cash-settled derivatives ("Adjusted Total Revenue," a non-GAAP financial measure[(i)]) of $78.9 million, including the negative $2.5 million impact of settled 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 20,422 BOE/d compared to average daily production of 18,359 BOE/d in the fourth quarter of 2016. Average realized prices, including and excluding the effects of hedging, are detailed below.

i. See "Non-GAAP Financial Measures and Reconciliations" included within this release for related disclosures and calculations

Hedging impacts. For the quarter ended March 31, 2017, Callon recognized the following hedging-related items (in thousands, except per unit data):

	In Thousands	Per Unit
Oil derivatives		
Net loss on settlements	$ (2,524)	$ (1.76)
Net gain on fair value adjustments	17,266	
Total gain on oil derivatives	$ 14,742	
Natural gas derivatives		
Net gain on settlements	$ 33	$ 0.02
Net gain on fair value adjustments	528	
Total gain on natural gas derivatives	$ 561	
Total oil & natural gas derivatives		
Net loss on settlements	$ (2,491)	$ (1.36)
Net gain on fair value adjustments	17,794	
Total gain on total oil & natural gas derivatives	$ 15,303	

Average realized prices, including and excluding the impact of cash settled derivatives during the first quarter, were as follows:

	Three Months Ended March 31, 2017
Average realized sales price	
Oil (per Bbl) (excluding impact of cash-settled derivatives)	$ 50.21
Impact of cash-settled derivatives	(1.76)
Oil (per Bbl) (including impact of cash-settled derivatives)	$ 48.45
Natural gas (per Mcf) (excluding impact of cash-settled derivatives)	$ 3.86
Impact of cash-settled derivatives	0.02
Natural gas (per Mcf) (including impact of cash-settled derivatives)	$ 3.88
Total (per BOE) (excluding impact of cash-settled derivatives)	$ 44.27
Impact of cash-settled derivatives	(1.36)
Total (per BOE) (including impact of cash-settled derivatives)	$ 42.91

	Three Months Ended		
	March 31, 2017	December 31, 2016	March 31, 2016
Additional per BOE data:			
Sales price, excluding impact of cash-settled derivatives	$ 44.27	$ 40.90	$ 27.12
Sales price, including impact of cash-settled derivatives	42.91	42.13	33.93
Lease operating expense (excluding gathering and treating expense)	$ 6.61	$ 7.96	$ 5.97
Gathering and treating expense	0.43	0.40	0.18
Production taxes	3.21	2.20	1.96
Depletion, depreciation and amortization	13.29	13.06	13.89
Adjusted G&A [(a)]			
Cash component [(b)]	2.43	2.84	3.55
Non-cash component	0.57	0.54	0.55

(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.

Lease Operating Expenses, including workover and gathering expense ("LOE"). LOE per BOE for the three months ended March 31, 2017 was $7.04 per BOE, compared to LOE of $8.36 per BOE in the fourth quarter of 2016. The decrease in this metric was primarily related to a decrease in the number of workover activities in the quarter and an increase in production volumes.

Production Taxes, including ad valorem taxes. Production taxes were $3.21 per BOE in the first quarter of 2017, representing approximately 7.3% of total revenue before the impact of derivative settlements.

i. See "Non-GAAP Financial Measures and Reconciliations" included within this release for related disclosures and calculations

Depreciation, Depletion and Amortization ("DD&A"). DD&A for the three months ended March 31, 2017 was $13.29 per BOE compared to $13.06 per BOE in the fourth quarter of 2016, attributable to increases in our depreciable asset base and assumed future development costs related to undeveloped proved reserves relative to the increase in proved reserves as a result of additions made through our horizontal drilling efforts and acquisitions made during the quarter.

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 $5.5 million, or $3.00 per BOE, for the first quarter of 2017 compared to $5.7 million, or $3.38 per BOE, for the fourth quarter of 2016. The cash component of Adjusted G&A was $4.5 million, or $2.43 per BOE, for the first quarter of 2017 compared to $4.8 million, or $2.84 per BOE, for the fourth quarter of 2016.

For the first quarter of 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):

		For the Three Months March 31, 2017
Total G&A expense		5,206
Less: Change in the fair value of liability share-based awards (non-cash)	$	307
Adjusted G&A – total		5,513
Restricted stock share-based compensation (non-cash)		(921)
Corporate depreciation & amortization (non-cash)		(121)
Adjusted G&A – cash component	$	4,471

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 $0.5 million for the three months ended March 31, 2017. At March 31, 2017 we had a valuation allowance of $127.1 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 for the quarter as if the valuation allowance did not exist.

2017 Guidance Update

	Second Quarter 2017 Guidance	Full Year 2017 Guidance
Total production (BOE/d)	21,500 - 23,500	22,500 - 25,500
% oil	76% - 78%	76% - 78%
Income Statement Expenses (per BOE)		
LOE, including workovers	$6.25 - $7.00	$6.00 - $6.50
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 - $2.75
Adjusted G&A: non-cash component [b]	$0.50 - $0.75	$0.50 - $0.75
Interest expense [c]	$0.00 - $0.00	$0.00 - $0.00
Effective income tax rate	0%	0%
Capital expenditures ($MM, accrual basis)		
Drilling and completion	$55 - $60	$240 - $255
Facilities and other [d]	$35 - $40	$85 - $95
Capitalized expenses (cash component)	$10 - $12	$40 - $45
Net operated horizontal well completions		
Midland Basin	9 - 11	30 - 32
Delaware Basin	1	3 - 4

(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 first 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.

i. See "Non-GAAP Financial Measures and Reconciliations" included within this release for related disclosures and calculations

Hedge Portfolio Summary

The following table summarizes our open derivative positions for the periods indicated:

Oil contracts	For the Remainder of 2017	For the Full Year of 2018
Swap contracts combined with short puts (WTI, enhanced swaps)		
Total volume (MBbls)	550	—
Weighted average price per Bbl		
Swap	$ 44.50	$ —
Short put option	$ 30.00	$ —
Deferred premium put option		
Total volume (MBbls)	250	—
Premium per Bbl	$ 2.05	$ —
Weighted average price per Bbl		
Long put option	$ 50.00	$ —
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 (WTI, two-way collars)		
Total volume (MBbls)	1,018	—
Weighted average price per Bbl		
Ceiling (short call)	$ 58.19	$ —
Floor (long put)	$ 47.50	$ —
Call option contracts (short position)		
Total volume (MBbls)	505	—
Weighted average price per Bbl		
Call strike price	$ 50.00	$ —
Swap contracts (Midland basis differential)		
Volume (MBbls)	1,650	2,008
Weighted average price per Bbl	$ (0.52)	$ (1.02)
Collar contracts combined with short puts (WTI, three-way collars)		
Total volume (MBbls)	—	2,738
Weighted average price per Bbl		
Ceiling (short call option)	$ —	$ 62.84
Floor (long put option)	$ —	$ 50.00
Short put option	$ —	$ 40.00

Natural gas contracts	For the Remainder of 2017	For the Full Year of 2018
Collar contracts combined with short puts (Henry Hub, three-way collars)		
Total volume (BBtu)	1,100	—
Weighted average price per MMBtu		
Ceiling (short call option)	$ 3.71	$ —
Floor (long put option)	$ 3.00	$ —
Short put option	$ 2.50	$ —
Collar contracts (Henry Hub, two-way collars)		
Total volume (BBtu)	1,588	720
Weighted average price per MMBtu		
Ceiling (short call option)	$ 3.72	$ 3.84
Floor (long put option)	$ 3.10	$ 3.40
Swap contracts		
Total volume (BBtu)	736	—
Weighted average price per MMBtu	$ 3.39	$ —

i. See “Non-GAAP Financial Measures and Reconciliations” included within this release for related disclosures and calculations

Income (Loss) Available to Common Shareholders. The Company reported net income available to common shareholders of $45.3 million in the first quarter of 2017 and Adjusted Income available to common shareholders of $20.4 million, or $0.10 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		
	March 31, 2017	**December 31, 2016**	**March 31, 2016**
Income (loss) available to common stockholders	$ 45,305	$ (3,570)	$ (42,933)
Change in valuation allowance	(13,119)	559	14,288
Write-down of oil and natural gas properties	—	—	22,604
Net (gain) loss on derivatives, net of settlements	(11,566)	7,170	5,621
Change in the fair value of share-based awards	(189)	590	461
Withdrawn proxy contest expenses	—	—	144
Loss on early extinguishment of debt	—	8,374	—
Adjusted Income	$ 20,431	$ 13,123	$ 185
Adjusted Income per fully diluted common share	$ 0.10	$ 0.08	$ 0.00

	Three Months Ended		
	March 31, 2017	**December 31, 2016**	**March 31, 2016**
Net income (loss)	$ 47,129	$ (1,746)	$ (41,109)
Write-down of oil and natural gas properties	—	—	34,776
Net (gain) loss on derivatives, net of settlements	(17,794)	11,030	8,648
Non-cash stock-based compensation expense	639	1,718	1,225
Loss on early extinguishment of debt	—	12,883	—
Withdrawn proxy contest expenses	—	—	221
Acquisition expense	450	1,263	48
Income tax (benefit) expense	466	48	—
Interest expense	665	1,369	5,491
Depreciation, depletion and amortization	24,932	22,512	16,129
Accretion expense	184	196	180
Adjusted EBITDA	$ 56,671	$ 49,273	$ 25,609

Discretionary Cash Flow. Discretionary cash flow, a non-GAAP measure[(i)], for the first quarter of 2017 was $56.2 million and is reconciled to operating cash flow in the following table (in thousands):

	Three Months Ended		
	March 31, 2017	**December 31, 2016**	**March 31, 2016**
Cash flows from operating activities:			
Net income (loss)	**$** 47,129	$ (1,746)	$ (41,109)
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depreciation, depletion and amortization	24,932	22,512	16,129
Write-down of oil and natural gas properties	—	—	34,776
Accretion expense	184	196	180
Amortization of non-cash debt related items	665	744	781
Deferred income tax expense	466	48	—
Net (gain) loss on derivatives, net of settlements	(17,794)	11,030	8,648
Loss on early extinguishment of debt	—	9,883	—
Non-cash expense related to equity share-based awards	930	811	516
Change in the fair value of liability share-based awards	(291)	908	709
Discretionary cash flow	$ 56,221	$ 44,386	$ 20,630
Changes in working capital	5,890	(7,832)	5,582
Payments to settle asset retirement obligations	(765)	(576)	(161)
Payments to settle vested liability share-based awards	(8,662)	—	(9,807)
Net cash provided by operating activities	$ 52,684	$ 35,978	$ 16,244

i. See "Non-GAAP Financial Measures and Reconciliations" included within this release for related disclosures and calculations

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

	March 31, 2017 Unaudited	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 35,273	$ 652,993
Accounts receivable	75,959	69,783
Fair value of derivatives	3,093	103
Other current assets	1,671	2,247
Total current assets	115,996	725,126
Oil and natural gas properties, full cost accounting method:		
Evaluated properties	3,009,059	2,754,353
Less accumulated depreciation, depletion, amortization and impairment	(1,972,091)	(1,947,673)
Net evaluated oil and natural gas properties	1,036,968	806,680
Unevaluated properties	1,154,850	668,721
Total oil and natural gas properties	2,191,818	1,475,401
Other property and equipment, net	18,067	14,114
Restricted investments	3,339	3,332
Deferred financing costs related to the senior secured revolving credit facility	2,744	3,092
Fair value of derivatives	2,939	—
Acquisition deposit	—	46,138
Other assets, net	676	384
Total assets	$ 2,335,579	$ 2,267,587
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 131,252	$ 95,577
Accrued interest	12,114	6,057
Cash-settleable restricted stock unit awards	4,025	8,919
Asset retirement obligations	1,588	2,729
Fair value of derivatives	6,430	18,268
Total current liabilities	155,409	131,550
Senior secured revolving credit facility	—	—
6.125% senior unsecured notes due 2024, net of unamortized deferred financing costs	390,536	390,219
Asset retirement obligations	4,652	3,932
Cash-settleable restricted stock unit awards	4,108	8,071
Deferred tax liability	556	90
Fair value of derivatives	—	28
Other long-term liabilities	285	295
Total liabilities	555,546	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; 201,054,884 and 201,041,320 shares outstanding, respectively	2,011	2,010
Capital in excess of par value	2,173,243	2,171,514
Accumulated deficit	(395,236)	(440,137)
Total stockholders' equity	1,780,033	1,733,402
Total liabilities and stockholders' equity	$ 2,335,579	$ 2,267,587

i. See "Non-GAAP Financial Measures and Reconciliations" included within this release for related disclosures and calculations

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

	Three Months Ended March 31,	
	2017	**2016**
Operating revenues:		
Oil sales	$ 72,008	$ 27,443
Natural gas sales	9,355	3,255
Total operating revenues	81,363	30,698
Operating expenses:		
Lease operating expenses	12,937	6,957
Production taxes	5,904	2,220
Depreciation, depletion and amortization	24,433	15,722
General and administrative	5,206	5,562
Accretion expense	184	180
Write-down of oil and natural gas properties	—	34,776
Acquisition expense	450	48
Total operating expenses	49,114	65,465
Income (loss) from operations	32,249	(34,767)
Other (income) expenses:		
Interest expense, net of capitalized amounts	665	5,491
(Gain) loss on derivative contracts	(15,303)	932
Other income	(708)	(81)
Total other (income) expense	(15,346)	6,342
Income (loss) before income taxes	47,595	(41,109)
Income tax expense	466	—
Net income (loss)	47,129	(41,109)
Preferred stock dividends	(1,824)	(1,824)
Income (loss) available to common stockholders	$ 45,305	$ (42,933)
Income (loss) per common share:		
Basic	$ 0.23	$ (0.51)
Diluted	$ 0.22	$ (0.51)
Shares used in computing income (loss) per common share:		
Basic	201,054	83,582
Diluted	201,740	83,582

i. See "Non-GAAP Financial Measures and Reconciliations" included within this release for related disclosures and calculations

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

	Three Months Ended March 31,	
	2017	**2016**
Cash flows from operating activities:		
Net income (loss)	$ 47,129	$ (41,109)
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation, depletion and amortization	24,932	16,129
Write-down of oil and natural gas properties	—	34,776
Accretion expense	184	180
Amortization of non-cash debt related items	665	781
Deferred income tax expense	466	—
Net (gain) loss on derivatives, net of settlements	(17,794)	8,648
Non-cash expense related to equity share-based awards	930	516
Change in the fair value of liability share-based awards	(291)	709
Payments to settle asset retirement obligations	(765)	(161)
Changes in current assets and liabilities:		
Accounts receivable	(4,066)	5,941
Other current assets	576	580
Current liabilities	9,903	(717)
Change in other long-term liabilities	—	11
Change in other assets, net	(523)	(233)
Payments to settle vested liability share-based awards	(8,662)	(9,807)
Net cash provided by operating activities	52,684	16,244
Cash flows from investing activities:		
Capital expenditures	(66,154)	(50,775)
Acquisitions	(648,485)	(10,183)
Acquisition deposit	46,138	—
Net cash used in investing activities	(668,501)	(60,958)
Cash flows from financing activities:		
Borrowings on senior secured revolving credit facility	—	45,000
Payments on senior secured revolving credit facility	—	(85,000)
Issuance of common stock	—	94,949
Payment of preferred stock dividends	(1,824)	(1,824)
Tax withholdings related to restricted stock units	(79)	(124)
Net cash provided by (used in) financing activities	(1,903)	53,001
Net change in cash and cash equivalents	(617,720)	8,287
Balance, beginning of period	652,993	1,224
Balance, end of period	$ 35,273	$ 9,511

i. See “Non-GAAP Financial Measures and Reconciliations” included within this release for related disclosures and calculations

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 (Loss),” “Adjusted EBITDA,” and “Adjusted Total Revenues.” 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 and discretionary cash flow per diluted share are 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 Revenues 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 Wednesday, May 3, 2017, to discuss first quarter 2017 financial and operating results.

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

Date/Time:	Wednesday, May 3, 2017, at 8:00 a.m. Central Time (9:00 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:	5057175

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:
Eric Williams
Manager, Investor Relations
1-800-451-1294