February 27, 2018

CALLON PETROLEUM

Callon Petroleum Company Announces Fourth Quarter 2017 Results

NATCHEZ, Miss., Feb. 27, 2018 /PRNewswire/ -- Callon Petroleum Company (NYSE: CPE) ("Callon" or the "Company") today reported results of operations for the three months and full-year ended December 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 fourth quarter of 2017, and other recent data points, include:

- Full-year 2017 production of 22.9 MBOE/d (78% oil), an increase of 50% over 2016 volumes
- Fourth quarter 2017 production of 26.5 MBOE/d (79% oil), a sequential quarterly increase of 18%
- Year-end proved reserves of 137.0 MMBOE (78% oil), a year-over-year increase of 50%
- Organic reserve replacement[i] of 566% of 2017 production at a "Drill-Bit" finding and development cost concept[i] of $8.21 per BOE on a two-stream basis
- Reduced lease operating expense to $4.84 per BOE in the fourth quarter of 2017, a sequential quarterly decrease of 5%, contributing to a total reduction of 27% since the first quarter of 2017
- Generated a fourth quarter operating margin of $40.51 per BOE
- Currently operating five horizontal rigs and two dedicated completion crews

Joe Gatto, President and Chief Executive Officer commented, "Our full year results for 2017 highlight solid execution by our team, resulting in annual production growth of more than 50% and a greater than 25% reduction in lease operating expense over the course of the year. Our operating margins improved 30% over 2016 and our oil content remained just below 80%, contributing to strong internal cash flow generation. Importantly, these top tier cash margins, coupled with drill-bit finding and development cost below $10 per BOE, are a fundamental driver of corporate level returns that continue to improve in parallel with our growth in producing assets. We have recently increased our operating activity to five drilling rigs and plan to remain at this pace for the balance of 2018 as we incorporate larger pad development concepts into our program and drive steady improvement in our net cash flow profile over the course of the year."

Operations Update

At December 31, 2017, we had 232 gross (171.8 net) horizontal wells producing from eight established flow units in the Permian Basin. Net daily production for the three months ended December 31, 2017 grew approximately 44% to 26.5 thousand barrels of oil equivalent per day (approximately 79% oil) as compared to the same period of 2016. Full year production for 2017 averaged 22,940 barrels of oil equivalent per day (approximately 78% oil) reflecting growth of 50% over 2016 volumes.

Midland Basin

During the fourth quarter, over 50% of the wells placed on production were from our WildHorse area with an average completed lateral length of approximately 7,300 feet. This area continues to be a key area of production growth for the company and is projected to comprise in excess of 30% of our total gross drilling activity in 2018. Completed lateral lengths are projected to average over 8,000 feet and the majority of activity will continue to focus predominantly on the development of the Wolfcamp A.

In our Monarch area, we placed six wells on production during the quarter. Activity in this area continues to focus on the Lower Spraberry which has consistently generated some of the highest returns in our portfolio. The three-well Kendra pad, with average completed lateral lengths of approximately 10,350, has produced over 236,000 BOE (87% oil) over the first 90 days online. Additionally, we commenced production of our first multi-well pad that utilized recycled flowback water volumes and plan to increase recycling activity in Monarch with upcoming wells. Our 2018 activity plan for Monarch will feature two separate "mega-pad" concepts incorporating simultaneous development of two contiguous three-well pads. Each pad will be drilled concurrently by dedicated rigs and all six wells placed on production at the same time. We expect these larger pads to be placed on production during the second half of the year.

In Reagan County at the Ranger area, our first Wolfcamp C well, together with two Lower Wolfcamp B wells, was completed during the fourth quarter and began flowback in January. The Wolfcamp C well continues to produce under natural flowing pressure with recent production rates in excess of 1,000 BOE/d (85% - 90% oil) and is still in the process of establishing a peak rate. We anticipate drilling four (gross) additional Wolfcamp C wells in Ranger during the course of 2018 with an average working interest of approximately 55%.

Delaware Basin

We recently completed drilling of our first two-well pad in the area and also added a second rig to our Spur development program in February. As part of this increased activity, we plan to enhance our existing saltwater disposal capacity of over 100,000 barrels per day with the connection to a pipeline system operated by Goodnight Midstream that will move water disposal volumes outside of our operating area. In addition, we are in the final stages of establishing a recycling program in this area and targeting usage of up to 50% recycled volumes for completion operations by year end 2018. During the fourth quarter, the Saratoga 7LA well came online and has produced at an average daily rate of approximately 1,015 BOE/d (83% oil) during its first 56 days of production.

Capital Expenditures

For the three months ended December 31, 2017, we incurred $115.8 million in accrued operational capital expenditures (excluding other items) compared to $113.4 million in the third quarter of 2017. Total capital expenditures, inclusive of capitalized expenses, are detailed below on an accrual and cash basis (in thousands):

	Three Months Ended December 31, 2017				
	Operational Capital	Other [a]	Capitalized Interest	Capitalized G&A	Total Capital Expenditures
Cash basis [b]	$ 123,664	$ 5,006	$ 18,848	$ 5,103	$ 152,621
Timing adjustments [c]	(7,910)	—	(9,140)	—	(17,050)
Non-cash items	—	—	—	1,173	1,173
Accrual (GAAP) basis	$ 115,754	$ 5,006	$ 9,708	$ 6,276	$ 136,744

(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.

We also divested certain infrastructure during the fourth quarter for proceeds of just over $20 million. We anticipate Callon will have additional opportunities to selectively monetize other infrastructure and facilities investments as we leverage strategic partnerships and increasingly transition to the use of recycled water volumes in our completion operations.

Operating and Financial Results

The following table presents summary information for the periods indicated:

	Three Months Ended		
	December 31, 2017	September 30, 2017	December 31, 2016
Net production			
Oil (MBbls)	1,936	1,591	1,287
Natural gas (MMcf)	3,018	2,900	2,412
Total (MBOE)	2,439	2,074	1,689
Average daily production (BOE/d)	26,511	22,543	18,359
% oil (BOE basis)	79 %	77 %	76 %
Oil and natural gas revenues (in thousands)			
Oil revenue	$ 104,132	$ 73,349	$ 60,559
Natural gas revenue	14,081	11,265	8,522
Total	118,213	84,614	69,081
Impact of cash-settled derivatives	(4,501)	(1,214)	2,079
Adjusted Total Revenue [i]	$ 113,712	$ 83,400	$ 71,160
Average realized sales price (excluding impact of cash settled derivatives)			
Oil (Bbl)	$ 53.79	$ 46.10	$ 47.05

Natural gas (Mcf)	4.67	3.88	3.53
Total (BOE)	48.47	40.80	40.90
Average realized sales price (including impact of cash settled derivatives)			
Oil (Bbl)	$ 51.28	$ 45.24	$ 48.87
Natural gas (Mcf)	4.78	3.94	3.43
Total (BOE)	46.62	40.21	42.13
Additional per BOE data			
Sales price [(a)]	$ 48.47	$ 40.80	$ 40.90
Lease operating expense [(b)]	4.84	5.08	7.96
Gathering and treating expense	0.57	0.52	0.40
Production taxes	2.55	2.62	2.20
Operating margin	$ 40.51	$ 32.58	$ 30.34
Depletion, depreciation and amortization	$ 14.98	$ 13.75	$ 13.06
Adjusted G&A [(c)]			
Cash component [(d)]	$ 2.46	$ 2.50	$ 2.84
Non-cash component	0.54	0.65	0.54

(a) Excludes the impact of cash settled derivatives.
(b) Excludes gathering and treating expense.
(c) 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.
(d) Excludes the amortization of equity-settled share-based incentive awards and corporate depreciation and amortization.

Total Revenue. For the quarter ended December 31, 2017, Callon reported total revenue of $118.2 million and total revenue including cash-settled derivatives ("Adjusted Total Revenue," a non-GAAP financial measure[(i)]) of $113.7 million, including the impact of a $4.5 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 26.5 MBOE/d compared to average daily production of 22.5 MBOE/d in the third quarter of 2017. Average realized prices, including and excluding the effects of hedging, are detailed below.

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

	Three Months Ended December 31, 2017	
	In Thousands	Per Unit
Oil derivatives		
Net loss on settlements	$ (4,854)	$ (2.51)
Net loss on fair value adjustments	(26,010)	
Total loss on oil derivatives	$ (30,864)	
Natural gas derivatives		
Net gain on settlements	$ 353	$ 0.11
Net loss on fair value adjustments	(26)	
Total gain on natural gas derivatives	$ 327	
Total oil & natural gas derivatives		
Net loss on settlements	$ (4,501)	$ (1.85)
Net loss on fair value adjustments	(26,036)	
Total loss on total oil & natural gas derivatives	$ (30,537)	

Lease Operating Expenses, including workover and gathering expense ("LOE"). LOE per BOE for the three months ended December 31, 2017 was $5.41 per BOE, compared to LOE of $5.60 per BOE in the third quarter of 2017. The decrease in this metric resulted primarily from an increase in production period over period.

Production Taxes, including ad valorem taxes. Production taxes were $2.55 per BOE for the three months ended December 31, 2017, representing approximately 5.3% of total revenue before the impact of derivative settlements.

Depreciation, Depletion and Amortization ("DD&A"). DD&A for the three months ended December 31, 2017 was $14.98 per BOE compared to $13.75 per BOE in the third quarter of 2017. The increase on a per unit basis was primarily attributable to greater increases in our depreciable asset base and assumed future development costs related to undeveloped proved reserves as compared to the estimated total proved reserve base.

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 $7.3 million, or $3.00 per BOE, for the three months ended December 31, 2017 compared to $6.5 million, or $3.15 per BOE, for the third quarter of 2017. The cash component of Adjusted G&A was $6.0 million, or $2.46 per BOE, for the three months ended December 31, 2017 compared to $5.2 million, or $2.50 per BOE, for the third quarter of 2017.

For the three months ended December 31, 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 December 31, 2017
Total G&A expense	$ 8,173
Less: Change in the fair value of liability share-based awards (non-cash)	(844)
Adjusted G&A – total	7,329
Less: Restricted stock share-based compensation (non-cash)	(1,202)
Less: Corporate depreciation & amortization (non-cash)	(125)
Adjusted G&A – cash component	$ 6,002

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 $0.2 million for the three months ended December 31, 2017 which relates to deferred State of Texas gross margin tax. At December 31, 2017 we had a valuation allowance of $60.9 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 $8.3 million (or $0.04 per diluted share) for the quarter as if the valuation allowance did not exist.

Proved Reserves

The Company recently completed the reserve audit for the year ended December 31, 2017 with its independent reserve auditor, DeGolyer and MacNaughton. As of December 31, 2017, Callon's estimated total proved reserves were 137.0 MMBOE, a 50% increase over the previous year-end. The proved reserves estimate is comprised of 78% oil of which our total proved developed estimated volumes are comprised of 75% oil.

The following table presents the progression of our estimated net proved oil and natural gas reserves from December 31, 2016 to 2017, and in each case, prepared in accordance with the rules and regulations of the SEC.

Proved developed and undeveloped reserves	Oil (MBbls)	Natural Gas (MMcf)	Total (MBOE)
As of December 31, 2016	71,145	122,611	91,580
Revisions to previous estimates	(5,171)	6,336	(4,115)
Extensions and discoveries	39,267	48,648	47,375
Purchases, net of sales, of reserves in place	8,388	12,711	10,507
Production	(6,557)	(10,896)	(8,373)
As of December 31, 2017	107,072	179,410	136,974

Callon added a total of 47.4 MMBOE in 2017 from horizontal development of our properties, replacing 566% of 2017 production as calculated by the sum of reserve extensions and discoveries, divided by annual production ("Organic reserve replacement"). The Company's finding and development costs from extensions and discoveries ("Drill-Bit F&D costs") were $8.21 per BOE calculated as accrual costs incurred for exploration and development divided by the reserves (in barrels of oil equivalent) added from extensions and discoveries. See "Non-GAAP Financial Measures and Reconciliations" included within this release for related disclosures and calculations.

Guidance Update

As a result of the Tax Cuts and Jobs Act, signed into law in December 2017 and effective January 1, 2018, the new federal statutory income tax rate was reduced to 21% from 35%. In addition, the Company adopted the *Revenue from Contracts with Customers* accounting standard on January 1, 2018. Starting with the first quarter of 2018, certain natural gas gathering and treating expenses will be accounted for as a reduction to revenue.

	2017 Actual	2018 Forecast
Total production (MBOE/d)	22.9	29.5 - 32.0
% oil	78%	77%
Income statement expenses (per BOE)		
LOE, including workovers	$5.46	$5.25 - $6.25

Production taxes, including ad valorem (% unhedged revenue)	6%	6%
Adjusted G&A: cash component [(a)]	$2.51	$1.75 - $2.50
Adjusted G&A: non-cash component [(b)]	$0.57	$0.50 - $1.00
Interest expense [(c)]	$0.00	$0.00
Statutory income tax rate	36%	22%
Capital expenditures ($MM, accrual basis)		
Operational (net of monetizations) [(d)]	$389	$500 - $540
Capitalized expenses	$48	$60 - $70
Net operated horizontal wells placed on production	37	43 - 46

(a) Excludes stock-based compensation and corporate depreciation and amortization.
(b) Excludes certain non-recurring expenses and non-cash valuation adjustments.
(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 Full Year of 2018**	**For the Full Year of 2019**
Swap contracts		
Total volume (MBbls)	2,009	—
Weighted average price per Bbl	$ 51.78	$ —
Collar contracts (two-way collars)		
Total volume (MBbls)	365	—
Weighted average price per Bbl		
Ceiling (short call)	$ 60.50	$ —
Floor (long put)	$ 50.00	$ —
Collar contracts combined with short puts (three-way collars)		
Total volume (MBbls)	3,468	1,825
Weighted average price per Bbl		
Ceiling (short call option)	$ 60.86	$ 62.40
Floor (long put option)	$ 48.95	$ 53.00
Short put option	$ 39.21	$ 43.00

Oil contracts (Midland basis differential)	**For the Full Year of 2018**	**For the Full Year of 2019**
Swap contracts		
Volume (MBbls)	5,289	—
Weighted average price per Bbl	$ (0.86)	$ —

Natural gas contracts	**For the Full Year of 2018**	**For the Full Year of 2019**
Collar contracts (Henry Hub, two-way collars)		
Total volume (BBtu)	720	—
Weighted average price per MMBtu		
Ceiling (short call option)	$ 3.84	$ —
Floor (long put option)	$ 3.40	$ —
Swap contracts (Henry Hub)		

Total volume (BBtu)	3,366	—
Weighted average price per MMBtu	$ 2.95	$ —

Income (Loss) Available to Common Shareholders. The Company reported net income available to common shareholders of $21.0 million for the three months ended December 31, 2017 and Adjusted Income available to common shareholders of $30.2 million, or $0.15 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		
	December 31, 2017	**September 30, 2017**	**December 31, 2016**
Income (loss) available to common stockholders	$ 21,001	$ 15,257	$ (3,570)
Change in valuation allowance	(8,285)	(6,064)	559
Net loss on derivatives, net of settlements	16,924	8,416	7,170
Change in the fair value of share-based awards	562	475	590
Loss on early extinguishment of debt	—	—	8,374
Adjusted Income	$ 30,202	$ 18,084	$ 13,123
Adjusted Income per fully diluted common share	$ 0.15	$ 0.09	$ 0.08

	Three Months Ended		
	December 31, 2017	**September 30, 2017**	**December 31, 2016**
Net income (loss)	$ 22,824	$ 17,081	$ (1,746)
Net loss on derivatives, net of settlements	26,037	12,947	11,030
Non-cash stock-based compensation expense	2,101	1,952	1,718
Loss on early extinguishment of debt	—	—	12,883
Acquisition expense	(112)	205	1,263
Income tax expense	248	237	48
Interest expense	461	444	1,369
Depreciation, depletion and amortization	37,222	29,132	22,512
Accretion expense	154	131	196
Adjusted EBITDA	$ 88,935	$ 62,129	$ 49,273

Discretionary Cash Flow. Discretionary cash flow, a non-GAAP measure(i), for the three months ended December 31, 2017 was $89.0 million and is reconciled to operating cash flow in the following table (in thousands):

	Three Months Ended		
	December 31, 2017	**September 30, 2017**	**December 31, 2016**
Cash flows from operating activities:			
Net income (loss)	$ 22,824	$ 17,081	$ (1,746)
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depreciation, depletion and amortization	37,222	29,132	22,512
Accretion expense	154	131	196
Amortization of non-cash debt related items	455	441	744
Deferred income tax expense	247	237	48
Net loss on derivatives, net of settlements	26,037	12,947	11,030
Loss on early extinguishment of debt	—	—	9,883
Non-cash expense related to equity share-based awards	1,240	1,219	811
Change in the fair value of liability share-based awards	865	732	908
Discretionary cash flow	$ 89,044	$ 61,920	$ 44,386
Changes in working capital	(8,642)	(7,777)	$ (7,832)
Payments to settle asset retirement obligations	(216)	(250)	(576)
Net cash provided by operating activities	$ 80,186	$ 53,893	$ 35,978

F&D and Reserve Replacement

	Calculation Parameters	2017 Metrics
Production (MBOE)	(A)	8,373
Proved reserve data		
Proved reserves (MBOE)		
Total (MBOE) extensions and discoveries	(B)	47,375
PUD additions	(C)	24,322
PUDs transferred to PDP	(D)	8,281
Total annual reserve additions, net of revisions	(E)	53,767
Capital costs (in thousands)		
Property acquisition costs		
Exploration costs		$ 239,453
Development costs		279,424
Unevaluated properties		
Exploration costs	(F)	6,374
Transfers to evaluated properties		(131,170)
Leasehold and seismic		5,006
Total capital costs incurred	(G)	$ 389,075
Drill-Bit F&D costs per BOE (two-stream)	(G) / (B)	$ 8.21
PD F&D per BOE (two-stream)	(G - F) / (B - C + D)	$ 12.21
Organic reserve replacement ratio	(B) / (A)	566 %
All-sources reserve replacement ratio	(E) / (A)	642 %

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

	December 31, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 27,995	$ 652,993
Accounts receivable	114,320	69,783
Fair value of derivatives	406	103
Other current assets	2,139	2,247
Total current assets	144,860	725,126
Oil and natural gas properties, full cost accounting method:		
Evaluated properties	3,429,570	2,754,353
Less accumulated depreciation, depletion, amortization and impairment	(2,084,095)	(1,947,673)
Net evaluated oil and natural gas properties	1,345,475	806,680
Unevaluated properties	1,168,016	668,721
Total oil and natural gas properties, net	2,513,491	1,475,401
Other property and equipment, net	20,361	14,114
Restricted investments	3,372	3,332
Deferred tax asset	52	—
Deferred financing costs	4,863	3,092
Acquisition deposit	900	46,138
Other assets, net	5,397	384
Total assets	$ 2,693,296	$ 2,267,587
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 162,878	$ 95,577
Accrued interest	9,235	6,057
Cash-settleable restricted stock unit awards	4,621	8,919

Asset retirement obligations	1,295	2,729
Fair value of derivatives	27,744	18,268
Total current liabilities	205,773	131,550
Senior secured revolving credit facility	25,000	—
6.125% senior unsecured notes due 2024, net of unamortized deferred financing costs	595,196	390,219
Asset retirement obligations	4,725	3,932
Cash-settleable restricted stock unit awards	3,490	8,071
Deferred tax liability	1,457	90
Fair value of derivatives	1,284	28
Other long-term liabilities	405	295
Total liabilities	837,330	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 shares outstanding	15	15
Common stock, $0.01 par value, 300,000,000 shares authorized; 201,836,172 and 201,041,320 shares outstanding, respectively	2,018	2,010
Capital in excess of par value	2,181,359	2,171,514
Accumulated deficit	(327,426)	(440,137)
Total stockholders' equity	1,855,966	1,733,402
Total liabilities and stockholders' equity	$ 2,693,296	$ 2,267,587

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

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2017	2016	2017	2016
Operating revenues:				
Oil sales	$ 104,132	$ 60,559	$ 322,374	$ 177,652
Natural gas sales	14,082	8,522	44,100	23,199
Total operating revenues	118,214	69,081	366,474	200,851
Operating expenses:				
Lease operating expenses	13,201	14,124	49,907	38,353
Production taxes	6,228	3,717	22,396	11,870
Depreciation, depletion and amortization	36,543	22,051	115,714	71,369
General and administrative	8,172	6,562	27,067	26,317
Settled share-based awards	—	—	6,351	—
Accretion expense	154	196	677	958
Write-down of oil and natural gas properties	—	—	—	95,788
Acquisition expense	(112)	1,263	2,916	3,673
Total operating expenses	64,186	47,913	225,028	248,328
Income (loss) from operations	54,028	21,168	141,446	(47,477)
Other (income) expenses:				
Interest expense, net of capitalized amounts	461	1,369	2,159	11,871
Loss on early extinguishment of debt	—	12,883	—	12,883
Loss on derivative contracts	30,536	8,952	18,901	20,233
Other income	(41)	(338)	(1,311)	(637)
Total other (income) expense	30,956	22,866	19,749	44,350
Income (loss) before income taxes	23,072	(1,698)	121,697	(91,827)
Income tax (benefit) expense	248	48	1,273	(14)
Net income (loss)	22,824	(1,746)	120,424	(91,813)
Preferred stock dividends	(1,823)	(1,824)	(7,295)	(7,295)
Income (loss) available to common stockholders	$ 21,001	$ (3,570)	$ 113,129	$ (99,108)
Income (loss) per common share:				

Basic	$ 0.10	$ (0.02)	$ 0.56	$ (0.78)
Diluted	$ 0.10	$ (0.02)	$ 0.56	$ (0.78)
Shares used in computing income (loss) per common share:				
Basic	201,835	166,258	201,526	126,258
Diluted	202,426	166,258	202,102	126,258

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

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2017	**2016**	**2017**	**2016**
Cash flows from operating activities:				
Net income (loss)	$ 22,824	$ (1,746)	$ 120,424	$ (91,813)
Adjustments to reconcile net income to cash provided by operating activities:				
Depreciation, depletion and amortization	37,222	22,512	118,051	73,072
Write-down of oil and natural gas properties	—	—	—	95,788
Accretion expense	154	196	677	958
Amortization of non-cash debt related items	455	744	2,150	3,115
Deferred income tax (benefit) expense	247	48	1,273	(14)
Loss on derivatives, net of settlements	26,037	11,030	10,429	38,135
Loss on sale of other property and equipment	—	—	62	—
Non-cash loss on early extinguishment of debt	—	9,883	—	9,883
Non-cash expense related to equity share-based awards	1,240	811	8,254	2,765
Change in the fair value of liability share-based awards	865	908	3,288	6,953
Payments to settle asset retirement obligations	(216)	(576)	(2,047)	(1,471)
Changes in current assets and liabilities:				
Accounts receivable	(32,347)	(13,611)	(44,495)	(30,055)
Other current assets	444	(535)	108	(786)
Current liabilities	23,413	5,473	30,947	25,288
Other long-term liabilities	—	10	121	96
Long-term prepaid	—	—	(4,650)	—
Other assets, net	(152)	831	(1,528)	(840)
Payments for cash-settled restricted stock unit awards	—	—	(13,173)	(10,300)
Net cash provided by operating activities	80,186	35,978	229,891	120,774
Cash flows from investing activities:				
Capital expenditures	(152,621)	(67,334)	(419,839)	(190,032)
Acquisitions	(3,952)	(352,622)	(718,456)	(654,679)
Acquisition deposit	(900)	(13,438)	45,238	(46,138)
Proceeds from sales of mineral interest and equipment	20,525	1,639	20,525	24,562
Net cash used in investing activities	(136,948)	(431,755)	(1,072,532)	(866,287)
Cash flows from financing activities:				
Borrowings on senior secured revolving credit facility	25,000	—	25,000	217,000
Payments on senior secured revolving credit facility	—	—	—	(257,000)
Payments on term loans	—	(300,000)	—	(300,000)
Issuance of 6.125% senior unsecured notes due 2024	—	400,000	200,000	400,000
Premium on the issuance of 6.125% senior unsecured notes due 2024	—	—	8,250	—
Payment of deferred financing costs	(28)	(10,153)	(7,194)	(10,793)
Issuance of common stock	—	634,862	—	1,357,577
Payment of preferred stock dividends	(1,824)	(1,824)	(7,295)	(7,295)
Tax withholdings related to restricted stock units	—	—	(1,118)	(2,207)
Net cash provided by financing activities	23,148	722,885	217,643	1,397,282
Net change in cash and cash equivalents	(33,614)	327,108	(624,998)	651,769
Balance, beginning of period	61,609	325,885	652,993	1,224
Balance, end of period	$ 27,995	$ 652,993	$ 27,995	$ 652,993

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," "Adjusted Total Revenue," "Drill-Bit F&D costs," "PD F&D costs" and

"Organic reserve replacement." 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), accretion expense, 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 above. 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 our 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.
- We believe "Drill-Bit F&D costs," "PD F&D costs" and "Organic reserve replacement" ratios are non-GAAP metrics commonly used by Callon and other companies in our industry, as well as analysts and investors, to measure and evaluate the cost of replenishing annual production and adding proved reserves. The Company's definitions of "Drill-Bit F&A costs," "PD F&D costs" and "Organic reserve replacement" may differ significantly from definitions used by other companies to compute similar measures and as a result may not be comparable to similar measures provided by other companies. Consequently, we provided the detail of our calculation within the included tables.

Earnings Call Information

The Company will host a conference call on Wednesday, February 28, 2018, to discuss fourth quarter and full-year 2017 financial and operating results.

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

Date/Time:	Wednesday, February 28, 2018, at 8:00 a.m. Central Time (9:00 a.m. Eastern Time)
Webcast:	Select "IR Calendar" under the "Investors" section of the Company's website: www.callon.com.
Presentation Slides:	Select "Presentations" under the "Investors" section of the Company's website: www.callon.com.

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

Domestic:	1-888-317-6003
Canada:	1-866-284-3684
International:	1-412-317-6061
Access code:	2180929

An archive of the conference call webcast will also be available atwww.callon.com under 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 atwww.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 2018 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.

Contact information:

Mark Brewer
Director of Investor Relations
Callon Petroleum Company
ir@callon.com
1-281-589-5279

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