February 27, 2017

Callon Petroleum Company Announces Fourth Quarter 2016 Results

NATCHEZ, Miss., Feb. 27, 2017 /PRNewswire/ --

Click here for a PDF version of this release.

Callon Petroleum Company (NYSE: CPE) ("Callon" or the "Company") today reported results of operations for the three months and full-year ended December 31, 2016.

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 full-year and fourth quarter 2016, and other recent data points include:

- Full-year 2016 production of 15.2 MBOE/d (77% oil), an increase of 59% over 2015 volumes
- Fourth quarter 2016 production of 18.4 MBOE/d (76% oil), a sequential quarterly increase of 11%
- Year-end proved reserves of 91.6 MMBOE (78% oil), a yearly increase of 69%
- Organic reserve replacement[i] of 311% of 2016 production at a "Drill-Bit" finding and development cost concept[i] of $8.77 per BOE on a two-stream basis
- GAAP loss per diluted common share of $0.02 and Adjusted Income per fully diluted common share, a non-GAAP financial measure[i], of $0.08
- Entered into agreements for multiple acquisitions during 2016, forming two new core operating areas and increasing our total acreage footprint by approximately 41,000 net acres
- Currently operating three horizontal rigs, including two in WildHorse and one in Monarch
- Increased full-year 2017 production guidance to a range of 22.5 – 25.5 MBOE/d, an increase of approximately 60% over 2016 based on the midpoint of guidance

"Callon delivered exceptional growth in our producing assets in 2016, with a nearly 60% increase in daily production and 70% increase in proved reserves," commented Fred Callon, Chairman and Chief Executive Officer. "The strength of a capital efficient operational base, combined with our solid financial position, allowed us to stay on our front foot throughout the year and ultimately enter into acquisition agreements that tripled our acreage position in the Permian Basin on an accretive basis. We are now entering a period that will be characterized by drill-bit growth, planning to increase our horizontal development program to five rigs in both the Midland and Delaware Basins by early 2018. Our 2017 drilling program will be active in all four of our core operating areas as we prioritize top-tier cash returns in our portfolio, without the need to manage onerous drilling obligations. In the near-term, we are on the cusp of unlocking the value of our newly acquired WildHorse position after investing in facilities for efficient development and adding a second rig to this position last month. We look forward to accelerating the value proposition in a similar manner in the Spur area with a rig starting by mid-year. Overall, we currently expect our operations to produce another year of production growth approaching 60% in 2017 while maintaining the financial strength required to navigate any potential headwinds in 2017 and beyond. With our existing portfolio of delineated locations in core, unconventional shale plays, Callon is well-positioned to deliver leading production and cash flow growth per share, as well as additional upside in emerging zones across the entire Permian Basin."

Operations Update

At December 31, 2016, we had 148 gross (112.5 net) horizontal wells producing from six established flow units in the Midland Basin. Net daily production for the three months ended December 31, 2016 grew approximately 73% to 18.4 thousand barrels of oil equivalent per day ("MBOE/d") (approximately 76% oil) as compared to the same period of 2015. Sequentially, we grew production by approximately 11% compared to the third quarter of 2016.

For the three months ended December 31, 2016, we operated two horizontal drilling rigs, drilling 10 gross (7.4 net) horizontal wells in both the Monarch and WildHorse areas. We placed 10 gross (6.9 net) horizontal wells on production in the quarter, all of which were located in our Monarch area.

Well Activity Summary

The following table details well-related activity for the quarter by operating area:

	For the Three Months Ended December 31, 2016					
	Drilled		Completed/ On Production[a]		Awaiting Completion	
	Gross	Net	Gross	Net	Gross	Net
Monarch horizontal wells	5	2.9	10	6.9	3	1.4
WildHorse horizontal wells	5	4.5	—	—	3	2.8
Total Midland Basin wells	10	7.4	10	6.9	6	4.2

(a) Wells turned to production batteries. Includes wells drilled prior to the fourth quarter of 2016.

During the fourth quarter, we continued to focus on the development of two flow units within the Lower Spraberry in the Monarch area, and also expanded our development to include the Wolfcamp A zone which was placed on production in early October 2016. The following table highlights wells that achieved peak rates during the period, expressed in absolute barrels of oil equivalent per day ("BOE/d") and production rates per 1,000 feet of completed lateral:

24-Hour IP Date	Well	Focus Area (Zone)	Completed Lateral (ft)	24-Hour Peak IP (BOE/d; Two-stream) [a] Peak 24-Hour IP	Production (% oil)	Per 1,000' Lateral Feet	30-Day Average Peak IP (BOE/d; Two-stream) Peak 30-Day IP	Production (% oil)	Pe 1,0 Late Fe
11/20/2016	Casselman 40-6LL	Monarch (LLS)	4,473	987	76%	221	760	78%	17
11/20/2016	Casselman 40-8LL	Monarch (LLS)	4,623	968	78%	209	760	82%	16
11/22/2016	Pecan Acres 23 PSA 2 09SH	Monarch (LLS)	9,206	1,411	88%	153	1,142	86%	12
12/01/2016	Casselman 40 07UL	Monarch (ULS)	4,473	1,030	86%	230	883	86%	19
12/05/2016	Pecan Acres 23 PSA 2 16AH	Monarch (WCA)	9,234	1,440	89%	156	1,352	89%	14
12/06/2016	Kendra-Kristen 4 24SH	Monarch (LLS)	9,642	1,797	93%	186	1,255	92%	13
12/16/2016	Kendra-Kristen 3 23SH	Monarch (ULS)	9,678	1,296	93%	134	1,101	92%	11
12/25/2016	Kendra-Kristen 5 25SH	Monarch (ULS)	9,402	1,500	93%	160	1,167	92%	12
01/05/2017	Kendra PSA 1 216LL	Monarch (LLS)	10,061	1,747	90%	174	1,381	90%	13
01/05/2017	Kendra PSA 1 218LL	Monarch (LLS)	10,343	1,517	89%	147	1,289	90%	12

(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 allocated production, and is occasionally greater than the reported 24-Hour Peak IP if the well test on that date captured a lower rate than the average for the period.

We are encouraged with the performance of the first Wolfcamp A well in the Monarch focus area. The Pecan Acres PSA 2 16AH was drilled from a stacked two-well pad with a ULS well and achieved a Peak 30-Day IP of over 1,350 BOE/d (89% oil), further demonstrating the high quality of targeted flow units for multi-zone development in the future. This well represents our fifth producing flow unit in the Monarch area, inclusive of the Upper and Lower benches of the Lower Spraberry (the "ULS" and "LLS", respectively), the Middle Spraberry and the Wolfcamp B. Additionally, we drilled and completed our longest laterals to date in our Carpe Diem field targeting the LLS with drilled laterals averaging nearly 11,500 ft. and average Peak 30-Day IPs of approximately 1,350 BOE (90% oil).

We also drilled five gross wells in WildHorse in the fourth quarter as we commenced our program development of this new core operating unit. We recently completed our first four wells during January 2017, including a two-well, staggered Wolfcamp A and Lower Spraberry pad in the Sidewinder field in northwest Howard County, and a stacked Wolfcamp A and Lower Spraberry pad located approximately 10 miles south of Sidewinder in the Maverick field. These four wells are in various stages of flowback and continue to climb towards peak rates.

Callon is currently operating three horizontal rigs, two of which are running in the WildHorse area. We initiated our pad development program in this area in late 2016 and recently accelerated our activity with the addition of a second rig in January 2017 after making substantial progress on our infrastructure investment plan. Both rigs are currently drilling in the Fairway field located in central Howard County. The rig on the western side of Fairway is drilling a three-well, stacked pad targeting the Lower Spraberry, Wolfcamp A and Wolfcamp B zones, which we expect to complete in March 2017. The rig on the eastern side of Fairway is drilling a two-well pad targeting the Wolfcamp A, which we expect to complete in April 2017. Our third horizontal rig continues to be focused in Monarch before moving to Reagan County in the Ranger unit in the second quarter.

We are also progressing our plans for program development in our recently acquired acreage in the Delaware Basin, which has been named the Spur operating area. We are currently flowing back a recently completed 10,000' lateral well targeting the Lower Wolfcamp A, the Corbets 34-149 2WA, and early time performance is in-line with our type curve expectations. We are also preparing to complete a 10,000' lateral well targeting the Wolfcamp B in an offsetting drilling unit. Following the completion of upgrades to existing infrastructure, we plan to add a dedicated horizontal drilling rig to the Spur operating area by mid-year 2017, with the potential for incremental drilling activity in the Delaware Basin in 2018.

Capital Expenditures

For the three months ended December 31, 2016, we accrued $43.3 million in operational capital expenditures, including facilities expenditures of $11.4 million, equal to $43.3 million accrued in the third quarter of 2016. Total capital expenditures, inclusive of capitalized expenses, are detailed below on an accrual and cash basis (in thousands):

	Three Months Ended December 31, 2016				
	Operational Capital Expenditures	**Seismic & Other**	**Capitalized Interest**	**Capitalized G&A**	**Total Capital Expenditures**
Cash basis [a]	$ 53,358	$ 3,625	$ 6,699	$ 3,652	$ 67,334
Timing adjustments [b]	(10,030)	754	1	—	(9,275)
Non-cash items	—	—	—	1,352	1,352
Accrual (GAAP) basis	$ 43,328	$ 4,379	$ 6,700	$ 5,004	$ 59,411

(a) 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.

(b) 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		
	December 31, 2016	**September 30, 2016**	**December 31, 2015**
Net production			

Oil (MBbls)	1,287	1,153	777
Natural gas (MMcf)	2,413	2,244	1,188
Total production (MBOE)	1,689	1,527	975
Average daily production (BOE/d)	18,359	16,598	10,598
% oil (BOE basis)	76%	76%	80%
Oil and natural gas revenues (in thousands)			
Oil revenue	$ 60,559	$ 49,095	$ 30,582
Natural gas revenue	8,522	6,832	2,981
Total revenue	$ 69,081	$ 55,927	$ 33,563
Impact of cash-settled derivatives	2,079	4,091	9,918
Adjusted Total Revenue (i)	$ 71,160	$ 60,018	$ 43,481

Total Revenue. For the quarter ended December 31, 2016, Callon reported total revenues of $69.1 million and total revenues including cash-settled derivatives ("Adjusted Total Revenue," a non-GAAP financial measure(i)) of $71.2 million, including the $2.1 million impact of settled derivative contracts. The table above reconciles to the related GAAP measure of the Company's revenue to Adjusted Total Revenue. Average daily production for the quarter was 18,359 BOE/d compared to average daily production of 16,598 BOE/d in the third quarter of 2016. Average realized prices, including and excluding the effects of hedging, are detailed below.

Hedging impacts. For the quarter ended December 31, 2016, Callon recognized the following hedging-related items (in thousands, except per unit data):

	In Thousands	Per Unit
Oil derivatives contracts		
Net gain on settlements	$ 2,334	$ 1.82
Net loss on fair value adjustments	(10,639)	
Total net loss on oil derivatives contracts	$ (8,305)	
Natural gas derivatives contracts		
Net loss on settlements	$ (255)	$ (0.10)
Net loss on fair value adjustments	(392)	
Total net loss on natural gas derivatives contracts	$ (647)	
Total derivatives contracts		
Net gain on settlements	$ 2,079	$ 1.23
Net loss on fair value adjustments	(11,031)	
Total net loss on total derivatives contracts	$ (8,952)	

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

Three Months Ended

Average realized sales price	December 31, 2016
Oil (per Bbl) (excluding impact of cash-settled derivatives)	$ 47.05
Impact of cash-settled derivatives	1.82
Oil (per Bbl) (including impact of cash-settled derivatives)	$ 48.87
Natural gas (per Mcf) (excluding impact of cash-settled derivatives)	$ 3.53
Impact of cash-settled derivatives	(0.10)
Natural gas (per Mcf) (including impact of cash-settled derivatives)	$ 3.43
Total (per BOE) (excluding impact of cash-settled derivatives)	$ 40.90
Impact of cash-settled derivatives	1.23
Total (per BOE) (including impact of cash-settled derivatives)	$ 42.13

	Three Months Ended		
Additional per BOE data	December 31, 2016	September 30, 2016	December 31, 2015
Sales price, excluding impact of cash-settled derivatives	$ 40.90	$ 36.63	$ 34.42
Sales price, including impact of cash-settled derivatives	42.13	39.30	44.60
Lease operating expense, including workover and gathering	$ 8.36	$ 6.52	$ 6.47
Production taxes	2.20	2.28	2.04
Depletion, depreciation and amortization	13.06	11.33	17.29
Adjusted G&A[(a)]			
Cash component	2.84	2.38	3.80
Non-cash component	0.54	0.58	0.65

(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 December 31, 2016 was $8.36 per BOE, compared to LOE of $6.52 per BOE in the third quarter of 2016. The increase in this metric was primarily related to an increase in the number of workover activities in the quarter and higher fuel and power expenses related to assets acquired during 2016. We continue to make investments in infrastructure in these new operating areas to support our planned increases in drilling activity and expect these investments to reduce our LOE in these areas over time.

Production Taxes, including ad valorem taxes. Production taxes were $2.20 per BOE in the fourth quarter of 2016, representing approximately 5.4% of total revenue before the impact of derivative settlements.

Depreciation, Depletion and Amortization ("DD&A"). DD&A for the three months ended December 31, 2016 was $13.06 per BOE compared to $11.33 per BOE in the third 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.

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 $5.7 million, or $3.38 per BOE, for the fourth quarter of 2016 compared to $4.5 million, or $2.96 per BOE, for the third quarter of 2016. The cash component of Adjusted G&A was $4.8 million, or $2.84 per BOE, for the fourth quarter of 2016 compared to $3.6 million, or $2.38 per BOE, for the third quarter of 2016.

For the fourth quarter of 2016, 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):

	Recurring		
	Cash	**Non-Cash**	**Total**
G&A expenses			
Cash G&A	$ 4,800	$ —	$ 4,800
Restricted stock share-based compensation	—	801	801
Change in the fair value of liability share-based awards	—	857	857
Corporate depreciation & amortization	—	104	104
Total G&A expense:	$ 4,800	$ 1,762	$ 6,562
Adjusted G&A			
Less: Change in the fair value of liability share-based awards			$ (857)
Adjusted G&A – total			5,705
Restricted stock share-based compensation (non-cash)			(801)
Corporate depreciation & amortization (non-cash)			(104)
Adjusted G&A – cash component			$ 4,800

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 benefit of less than $0.1 million for the three months ended December 31, 2016.

At December 31, 2016 we had a valuation allowance of $140.2 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.

A breakdown of the Company's actual 2016 capital expenditures and anticipated 2017 operational plan and associated expenditures is presented below on an accrual, or GAAP, basis:

	2016 Actual	2017 Forecast
Net operated horizontal well completions		
Midland Basin	23.7	30 - 32
Delaware Basin	—	3 - 4
Average lateral length	6,510	~7,500
Average working interest	~74%	~75%
Gross horizontal well costs ($MM)		
Midland Basin (7,500' drilled lateral)		$ 5.0 - 5.5
Delaware Basin (10,000' drilled lateral)		$ 8.5 - 9.5
Non-operated horizontal activity ($MM)		$ 7.5 - 10.0
Capital expenditures ($MM, accrual basis)		
Drilling and completion	$ 117.4	$ 240 - 255
Facilities and other	38.9	85 - 95
Total operational capital expenditures	$ 156.3	$ 325 - 350

Proved Reserves

The Company recently completed the reserve audit for the year ended December 31, 2016 with its independent reserve auditor, DeGolyer and MacNaughton. As of December 31, 2016, Callon's estimated total proved reserves were 91.6 million BOE, a 69% 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 76% oil. Included in total proved reserve estimates are 105 (gross) horizontal proved undeveloped locations. These estimates do not include the impact of our recently completed acquisition in the Delaware Basin.

The following table presents the progression of our estimated net proved oil and natural gas reserves from December 31, 2015 to 2016, 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, 2015	43,348	65,537	54,271
Revisions to previous estimates	(5,738)	13,929	(3,417)
Extensions and discoveries	14,479	17,194	17,345
Purchases, net of sales, of reserves in place	23,336	33,709	28,954

Production	(4,280)	(7,758)	(5,573)
As of December 31, 2016	71,145	122,611	91,580

Callon added a total of 17.3 MMBOE in 2016 from horizontal development of a portion of our properties, replacing 311% of 2016 production as calculated by the sum of reserve extensions, discoveries and revisions (including all price-related revisions), divided by annual production ("Organic reserve replacement"). The Company's finding and development from extensions and discoveries "Drill-Bit F&D costs" were $8.77 per BOE calculated as cash costs incurred for exploration and development divided by the sum of extensions and discoveries. See "Non-GAAP Financial Measures and Reconciliations" included within this release for related disclosures and calculations.

2017 Guidance Update

	First Quarter 2017	Annual 2017
Total production (BOE/d)	19,500 - 21,000	22,500 - 25,500
% oil	75% - 77%	75% - 77%
Income Statement Expenses (per BOE)		
LOE, including workovers	$6.75 - $7.50	$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)	$2.50 - $3.00	$2.00 - $2.50
Adjusted G&A: non-cash component (b)	$0.75 - $1.25	$0.50 - $1.00
Interest expense (c)	$0.00 - $0.00	$0.00 - $0.00
Effective income tax rate	0.0%	0.0%
Capital expenditures ($MM, accrual basis)		
Total operational capital expenditures (d)	$70 - $75	$325 - $350
Capitalized expenses (cash component)	$10 - $12	$40 - $45

(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 fourth quarter 2016 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 table summarizes our open derivative positions as of February 27, 2017:

Oil contracts	For the Full Year of 2017	For the Full Year of 2018
Swap contracts combined with short puts (WTI, enhanced swaps)		
Total volume (MBbls)	730	—
Weighted average price per Bbl		
Swap	$ 44.50	$ —

Short put option	$ 30.00	$ —
Deferred premium put option		
Total volume (MBbls)	498	—
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)	1,351	—
Weighted average price per Bbl		
Ceiling (short call)	$ 58.19	$ —
Floor (long put)	$ 47.50	$ —
Call option contracts (short position)		
Total volume (MBbls)	670	—
Weighted average price per Bbl		
Call strike price	$ 50.00	$ —
Swap contracts (Midland basis differential)		
Volume (MBbls)	2,004	1,825
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		
Collar contracts combined with short puts (Henry Hub, three-way collars)		
Total volume (BBtu)	1,460	—
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)	1,460	—
Weighted average price per MMBtu		
Ceiling (short call option)	$ 3.68	$ —
Floor (long put option)	$ 3.00	$ —

Income (Loss) Available to Common Shareholders. The Company reported a net loss available to common shareholders of $3.6 million in the fourth quarter of 2016 and Adjusted Income available to common shareholders of $13.1 million, or $0.08 per diluted share. 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):

	For the Three Months Ended		
	December 31, 2016	**September 30, 2016**	**December 31, 2015**
Income (loss) available to common stockholders	$ (3,570)	$ 19,315	$ (115,144)
Change in valuation allowance	559	(7,907)	40,025
Write-down of oil and natural gas properties	—	—	78,737
Net loss (gain) on derivatives, net of settlements	7,170	(679)	(635)
Rig termination fee	—	—	(368)
Change in the fair value of share-based awards	590	2,192	1,197
Loss on early extinguishment of debt	8,374	—	—
Adjusted Income	$ 13,123	$ 12,921	$ 3,812
Adjusted Income per fully diluted common share	$ 0.08	$ 0.09	$ 0.05

	For the Three Months Ended		
	December 31, 2016	**September 30, 2016**	**December 31, 2015**
Net income (loss)	$ (1,746)	$ 21,139	$ (113,170)
Write-down of oil and natural gas properties	—	—	121,134
Net loss (gain) on derivatives, net of settlements	11,030	(1,044)	(977)
Change in the fair value of share-based awards	1,718	4,150	2,354
Rig termination fee	—	—	(566)

	12,883	—	—
Loss on early extinguishment of debt			
Acquisition expense	1,263	456	27
Income tax (benefit) expense	48	(62)	—
Interest expense	1,369	831	5,544
Depreciation, depletion and amortization	22,512	17,733	17,308
Accretion expense	196	187	175
Adjusted EBITDA	$ 49,273	$ 43,390	$ 31,829

Discretionary Cash Flow. Discretionary cash flow, a non-GAAP measure[i], for the fourth quarter of 2016 was $44.4 million and is reconciled to operating cash flow in the following table (in thousands):

	Three Months Ended		
	December 31, 2016	September 30, 2016	December 31, 2015
Cash flows from operating activities:			
Net income (loss)	$ (1,746)	$ 21,139	$ (113,170)
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depreciation, depletion and amortization	22,512	17,733	17,308
Write-down of oil and natural gas properties	—	—	121,134
Accretion expense	196	187	175
Amortization of non-cash debt related items	744	810	781
Deferred income tax (benefit) expense	48	(62)	—
Net (gain) loss on derivatives, net of settlements	11,030	(1,044)	(977)
Loss on early extinguishment of debt	9,883	—	—
Rig termination fee	—	—	(566)
Non-cash expense related to equity share-based awards	811	608	521
Change in the fair value of liability share-based awards	908	3,371	1,853
Discretionary cash flow	$ 44,386	$ 42,742	$ 27,059
Changes in working capital	(7,832)	2,927	4,475
Payments to settle asset retirement obligations	(576)	(576)	(211)

Net cash provided by operating activities	$ 35,978	$ 45,093	$ 31,323

F&D and Reserve Replacement:

	Calculation Parameters	2016 Metrics
Production (MBOE)	(A)	5,573
Proved Reserve Data		
Proved reserves (MBOE)		
Total (MBOE) extensions and discoveries	(B)	17,345
PUD additions	(C)	12,035
PUDs transferred to PDP	(D)	6,823
Total annual reserve additions, net of revisions	(E)	42,882
Capital Costs (in thousands)		
Property acquisition costs		
Exploration costs		$ 38,612
Development costs		151,735
Unevaluated properties		
Exploration costs	(F)	8,631
Transfers to evaluated properties		(40,621)
Leasehold and seismic		(6,220)
Total capital costs incurred	(G)	$ 152,137
Drill-Bit F&D costs per BOE (two-stream)	(G) / (B)	$ 8.77
PD F&D per BOE (two-stream)	(G - F) / (B - C + D)	$ 11.83
Organic reserve replacement ratio	(B) / (A)	$ 311%
All-sources reserve replacement ratio	(E) / (A)	$ 769%

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

	December 31, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 652,993	$ 1,224
Accounts receivable	69,783	39,624

Fair value of derivatives	103	19,943
Other current assets	2,247	1,461
Total current assets	725,126	62,252
Oil and natural gas properties, full cost accounting method:		
Evaluated properties	2,754,353	2,335,223
Less accumulated depreciation, depletion, amortization and impairment	(1,947,673)	(1,756,018)
Net evaluated oil and natural gas properties	806,680	579,205
Unevaluated properties	668,721	132,181
Total oil and natural gas properties	1,475,401	711,386
Other property and equipment, net	14,114	7,700
Restricted investments	3,332	3,309
Deferred financing costs related to the senior secured revolving credit facility	3,092	3,642
Acquisition deposit	46,138	—
Other assets, net	384	305
Total assets	$ 2,267,587	$ 788,594
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 95,577	$ 70,970
Accrued interest	6,057	5,989
Cash-settleable restricted stock unit awards	8,919	10,128
Asset retirement obligations	2,729	790
Fair value of derivatives	18,268	—
Total current liabilities	131,550	87,877
Senior secured revolving credit facility	—	40,000
Secured second lien term loan, net of unamortized deferred financing costs	—	288,565
6.125% senior unsecured notes due 2024, net of unamortized deferred financing costs	390,219	—
Asset retirement obligations	3,932	4,317
Cash-settleable restricted stock unit awards	8,071	4,877
Deferred tax liability	90	—

Fair value of derivatives	28	—
Other long-term liabilities	295	200
Total liabilities	534,185	425,836
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 1,578,948 shares outstanding, respectively	15	16
Common stock, $0.01 par value, 300,000,000 and 150,000,000 shares authorized; 201,041,320 and 80,087,148 shares outstanding, respectively	2,010	801
Capital in excess of par value	2,171,514	702,970
Accumulated deficit	(440,137)	(341,029)
Total stockholders' equity	1,733,402	362,758
Total liabilities and stockholders' equity	$ 2,267,587	$ 788,594

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

	Three Months Ended December 31,		Year Ended December 31,	
	2016	**2015**	**2016**	**2015**
Operating revenues:				
Oil sales	$ 60,559	$ 30,582	$ 177,652	$ 125,166
Natural gas sales	8,522	2,981	23,199	12,346
Total operating revenues	69,081	33,563	200,851	137,512
Operating expenses:				
Lease operating expenses	14,124	6,308	38,353	27,036
Production taxes	3,717	1,993	11,870	9,793
Depreciation, depletion and amortization	22,051	16,854	71,369	69,249
General and administrative	6,562	6,180	26,317	28,347
Accretion expense	196	175	958	660
Write-down of oil and natural gas properties	—	121,134	95,788	208,435
Rig termination fee	—	(566)	—	3,075
Acquisition expense	1,263	27	3,673	27
Total operating expenses	47,913	152,105	248,328	346,622

Income (loss) from operations	21,168	(118,542)	(47,477)	(209,110)
Other (income) expenses:				
Interest expense, net of capitalized amounts	1,369	5,544	11,871	21,111
Loss on early extinguishment of debt	12,883	—	12,883	—
(Gain) loss on derivative contracts	8,952	(10,895)	20,233	(28,358)
Other income	(338)	(21)	(637)	(198)
Total other (income) expense	22,866	(5,372)	44,350	(7,445)
Loss before income taxes	(1,698)	(113,170)	(91,827)	(201,665)
Income tax (benefit) expense	48	—	(14)	38,474
Net loss	(1,746)	(113,170)	(91,813)	(240,139)
Preferred stock dividends	(1,824)	(1,974)	(7,295)	(7,895)
Loss available to common stockholders	$ (3,570)	$ (115,144)	$ (99,108)	$ (248,034)
Loss per common share:				
Basic	$ (0.02)	$ (1.58)	$ (0.78)	$ (3.77)
Diluted	$ (0.02)	$ (1.58)	$ (0.78)	$ (3.77)
Shares used in computing loss per common share:				
Basic	166,258	73,036	126,258	65,708
Diluted	166,258	73,036	126,258	65,708

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

	Three Months Ended December 31,		For the Year Ended December 31,	
	2016	**2015**	**2016**	**2015**
Cash flows from operating activities:				
Net income (loss)	$ (1,746)	$ (113,170)	$ (91,813)	$ (240,139)
Adjustments to reconcile net income to cash provided by operating activities:				
Depreciation, depletion and amortization	22,512	17,308	73,072	69,891
Write-down of oil and natural gas properties	—	121,134	95,788	208,435
Accretion expense	196	175	958	660
Amortization of non-cash debt related items	744	781	3,115	3,123
Deferred income tax expense	48	—	(14)	38,474
Net loss (gain) on derivatives, net of settlements	11,030	(977)	38,135	6,658
Non-cash loss on early extinguishment of debt	9,883	—	9,883	—
Non-cash expense related to equity share-based awards	811	521	558	221

	908	1,853	6,953	6,612
Change in the fair value of liability share-based awards				
Payments to settle asset retirement obligations	(576)	(211)	(1,471)	(3,258)
Changes in current assets and liabilities:				
Accounts receivable	(13,611)	2,517	(30,055)	(4,761)
Other current assets	(535)	(51)	(786)	(20)
Current liabilities	5,473	1,546	25,288	8,001
Change in other long-term liabilities	10	(20)	96	80
Change in other assets, net	831	(83)	(840)	338
Payments to settle vested liability share-based awards related to early retirements	—	—	—	(3,538)
Payments to settle vested liability share-based awards	—	—	(10,300)	(3,925)
Net cash provided by operating activities	35,978	31,323	118,567	86,852
Cash flows from investing activities:				
Capital expenditures	(67,334)	(51,593)	(190,032)	(227,292)
Acquisitions	(352,622)	(29,396)	(654,679)	(32,245)
Acquisition deposit	(13,438)	—	(46,138)	—
Proceeds from sales of mineral interest and equipment	1,639	29	24,562	377
Net cash used in investing activities	(431,755)	(80,960)	(866,287)	(259,160)
Cash flows from financing activities:				
Borrowings on senior secured revolving credit facility	—	51,000	217,000	181,000
Payments on senior secured revolving credit facility	—	(110,000)	(257,000)	(176,000)
Payments on term loans	(300,000)	—	(300,000)	—
Issuance of 6.125% senior unsecured notes due 2024	400,000	—	400,000	—
Payment of deferred financing costs	(10,153)	—	(10,793)	—
Issuance of common stock	634,862	109,913	1,357,577	175,459
Payment of preferred stock dividends	(1,824)	(1,974)	(7,295)	(7,895)
Net cash provided by financing activities	722,885	48,939	1,399,489	172,564
Net change in cash and cash equivalents	327,108	(698)	651,769	256
Balance, beginning of period	325,885	1,922	1,224	968
Balance, end of period	$ 652,993	$ 1,224	$ 652,993	$ 1,224

Non-GAAP Financial Measures and Reconciliations

This news release refers to non-GAAP financial measures such as "Discretionary Cash

Flow," "Adjusted Income (Loss)," "Adjusted G&A" and "Adjusted EBITDA," "Adjusted Total Revenues", "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 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.
- 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&D 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 Tuesday, February 28, 2017, to discuss fourth quarter 2016 financial and operating results.

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

Date/Time:	Tuesday, February 28, 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:	1-855-284-3684
International:	1-412-317-6061
Access code:	1632538

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

---

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

To view the original version on PR Newswire, visit:http://www.prnewswire.com/news-releases/callon-petroleum-company-announces-fourth-quarter-2016-results-300414305.html

SOURCE Callon Petroleum Company