CALLON PETROLEUM COMPANY

1Q 2016 Earnings Presentation

May 4, 2016

IMPORTANT DISCLOSURES

Callon Petroleum Company

FORWARD-LOOKING STATEMENTS

This presentation contains projections and other 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. These projections and statements reflect the Company's current views with respect to future events and financial performance as of this date. 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. For a summary of events that may affect the accuracy of these projections and forward-looking statements, see "Risk Factors" in our Form 10-K for the year ended December 31, 2015 filed with the Securities and Exchange Commission (the "SEC").

RESERVE-RELATED DISCLOSURES

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves that meet the SEC's definitions for such terms, and price and cost sensitivities for such reserves, and prohibits disclosure of resources that do not constitute such reserves. The Company uses the terms "estimated ultimate recovery" (or "EUR") that the SEC's rules may prohibit the Company from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved, probable and possible reserves, and accordingly are subject to substantially greater risk of being realized by the Company.

EUR estimates and potential horizontal well locations have not been risked by the Company. Actual locations drilled and quantities that may be ultimately recovered from the Company's interest may differ substantially from the Company's estimates. There is no commitment by the Company to drill all of the potential horizontal drilling locations. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability of drilling and completion services and equipment, drilling results, commodity price levels, lease expirations, regulatory approval and actual drilling results, as well as geological and mechanical factors. Estimates of type/decline curves and per-well EURs may change significantly as development of the Company's oil and gas assets provides additional data.

Type/decline curves, estimated EURs, recovery factors and well costs represent Company estimates based on evaluation of petrophysical analysis, core data and well logs, well performance from existing drilling and recompletion results and seismic data, and have not been reviewed by independent engineers. These are presented as hypothetical recoveries if assumptions and estimates regarding recoverable hydrocarbons, recovery factors and costs prove correct. As a result, such estimates may change significantly as results from more wells are evaluated. Estimates of EURs do not constitute reserves, but constitute estimates of contingent resources that the SEC has determined are too speculative to include in SEC filings. Unless otherwise noted, Internal Rate of Return (or "IRR") and Net Present Value (or "NPV") estimates are before taxes and assume Company-generated EUR and decline curve estimates based on Company drilling and completion cost estimates that do not include land, seismic, G&A or other corporate level costs.

Investors are urged to consider closely the disclosure in our Form 10-K and other reports filed with the SEC, available on our website or by request by contacting Investor Relations: Callon Petroleum Company, 1401 Enclave Parkway, Suite 600, Houston, TX 77077. You may also email the Company at ir@callon.com.

You can also obtain our Form 10-K and other reports filed with the SEC by contacting the SEC directly at 1-800-SEC-0330 or by downloading it from the SEC's web site http://www.sec.gov.

1Q16/RECENT HIGHLIGHTS

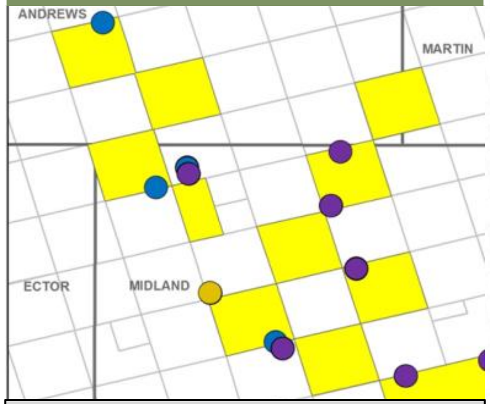
Callon Petroleum Company

Production	▪ Record daily volumes of 12,440 Boe/d (79% oil); up 17% sequentially ▪ Full-year guidance, w/ pending acquisitions, raised to 14,500 Boe/d midpoint
Pricing	▪ 74% of 1Q16 oil production on pipe contributing to improved transportation differentials and operational reliability; Remaining legacy production on pipe by 2H16 ▪ Combined with tightened regional basis, yields oil realizations at 92% of NYMEX
OPEX	▪ Two-stream per unit operating costs of $6.15/Boe; down 5% sequentially
Well Cost	▪ Realized leading edge well costs of $4.9MM ($5.1MM incl. facilities) ▪ Continuing to make incremental progress including lower frac costs
Activity	▪ Placed-on-Production 8 gross (6.1 net) horizontal wells in 1Q16 targeting the lower level of the Lower Spraberry zone within our CaBo field ▪ Drilling a 3-well, chevron-pattern pad targeting the LS at Carpe Diem to further test incremental well density potential
Financial	▪ Expect to achieve cash flow neutrality during 2Q16 ▪ Borrowing Base reaffirmed at $300MM with no changes to terms ▪ Exited 1Q16 with Debt/LTM Adjusted EBITDA of ~2.4x and $310MM of liquidity ▪ Successfully defending Adjusted EBITDA margins of ~70% despite a ~40% decrease in average realized pricing since 1Q15 ▪ Raised over $300MM of net equity proceeds YTD 2016 to finance pending and completed acquisitions and bolster balance sheet
Acquisitions	▪ Announced pending Big Star and AMI transactions, significantly adding to our inventory of economic drilling locations ▪ Pro forma Midland Basin position of ~35,000 net acres

OPERATIONS UPDATE

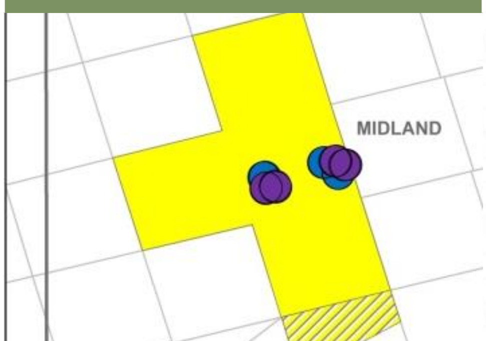
Callon Petroleum Company

CaBo



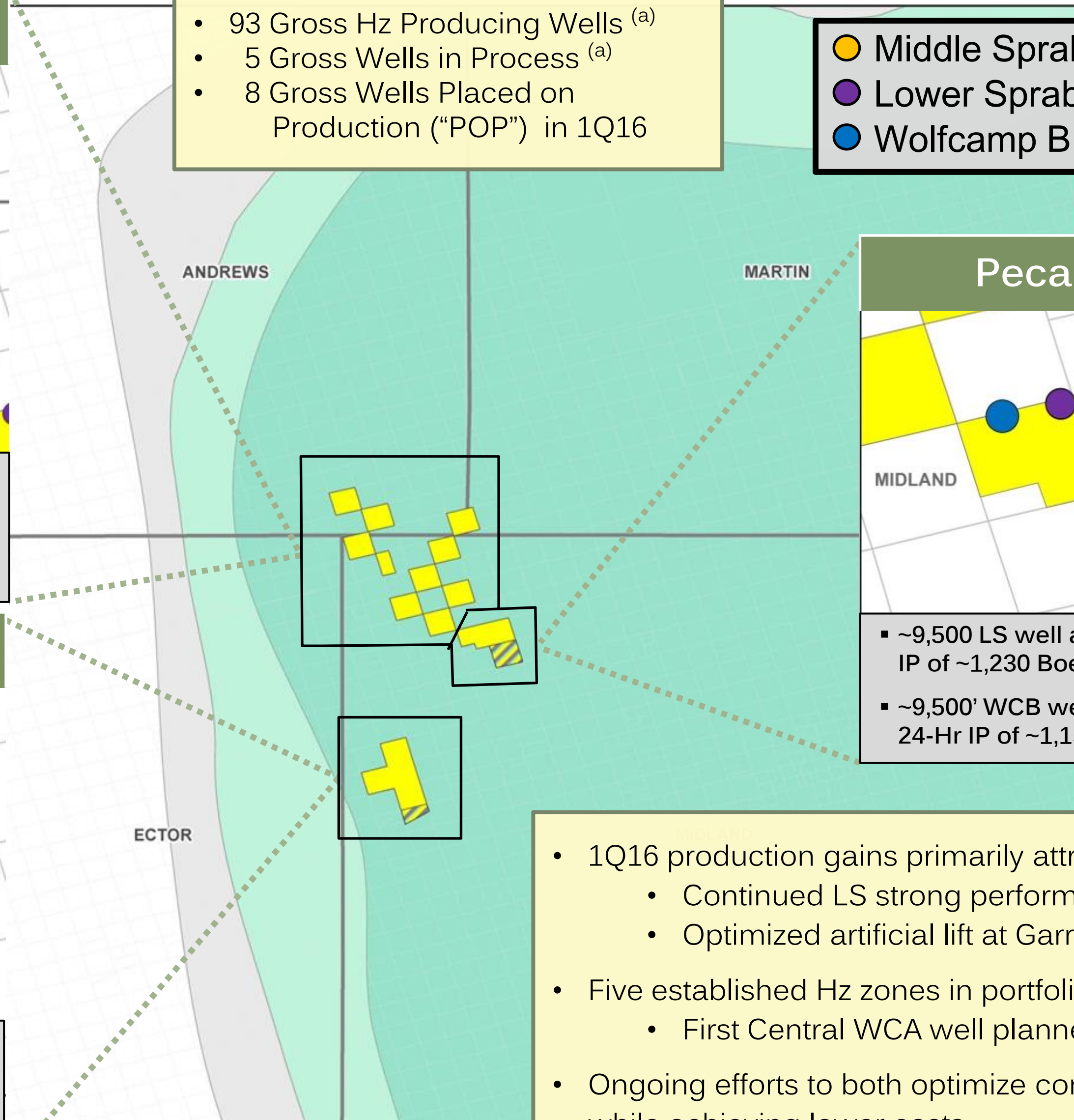
- Eight LS wells placed on production
- Four ~5,000' LS wells averaged 24-HR IPs of 930 Boe/d (87% Oil)
- Optimizing water infrastructure

Carpe Diem

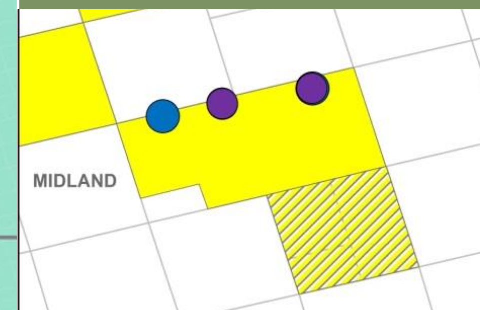


- Two ~8,000' LS wells achieved peak 24-Hr IP of ~1,100 Boe/d (91% Oil)
- Drilling 3-well pad jointly with RSPP in a chevron pattern at 12 WPS

- 93 Gross Hz Producing Wells (a)
- 5 Gross Wells in Process (a)
- 8 Gross Wells Placed on Production ("POP") in 1Q16



Pecan Acres



- ~9,500 LS well achieved peak 24-Hr IP of ~1,230 Boe/d (90% Oil)
- ~9,500' WCB well achieved peak 24-Hr IP of ~1,150 Boe/d (86% Oil)

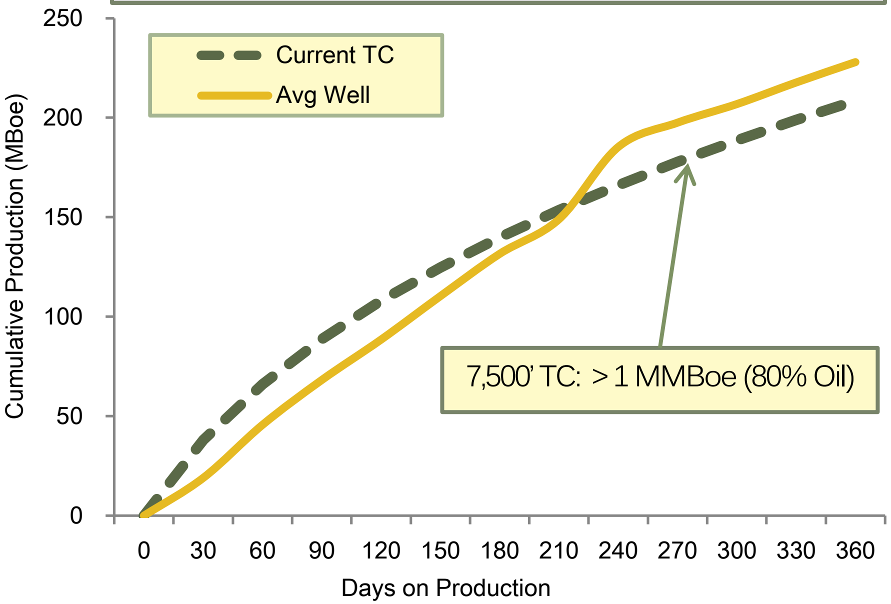
- 1Q16 production gains primarily attributed to:
  - Continued LS strong performance
  - Optimized artificial lift at Garrison Draw
- Five established Hz zones in portfolio
  - First Central WCA well planned 3Q16
- Ongoing efforts to both optimize completion designs while achieving lower costs

a) As of May 3, 2016. We had 89 wells producing as of March 31, 2016.

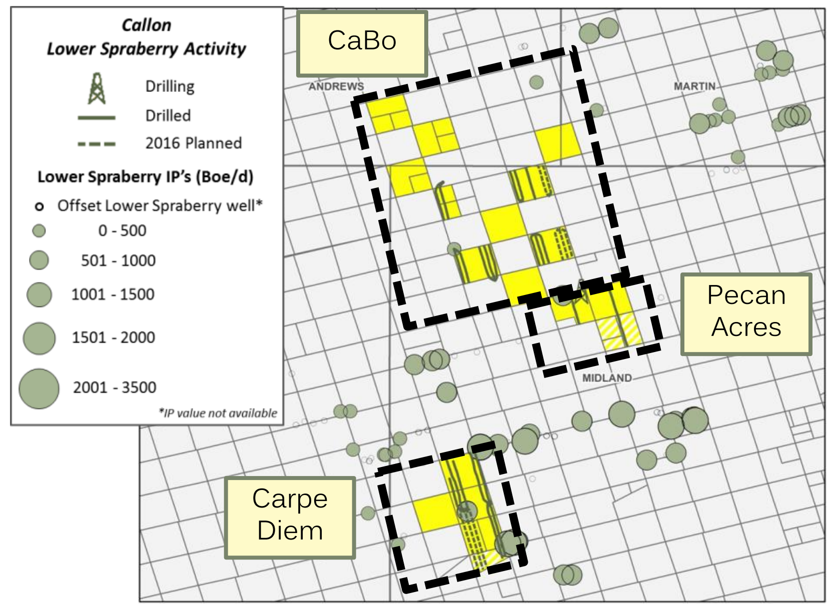
LOWER SPRABERRY FOCUS

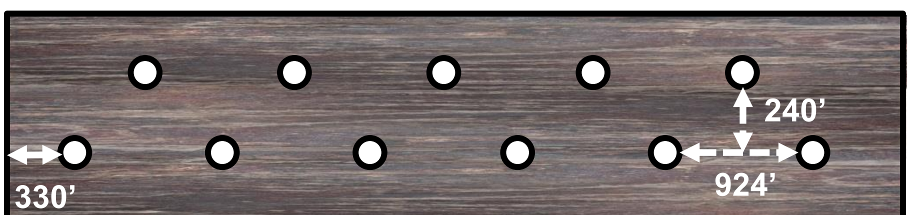
Production Performance Drives Lower Spraberry Type Curve Increase

Increased CMB LS Type Curve (7,500') [a]



CMB LS Activity – Operated vs. Offset





Proof of concept on 11 wells/section ("WPS") in a chevron pattern, with industry continuing to highlight additional well density potential (16+ WPS).

Down-Spacing Initiatives Continue

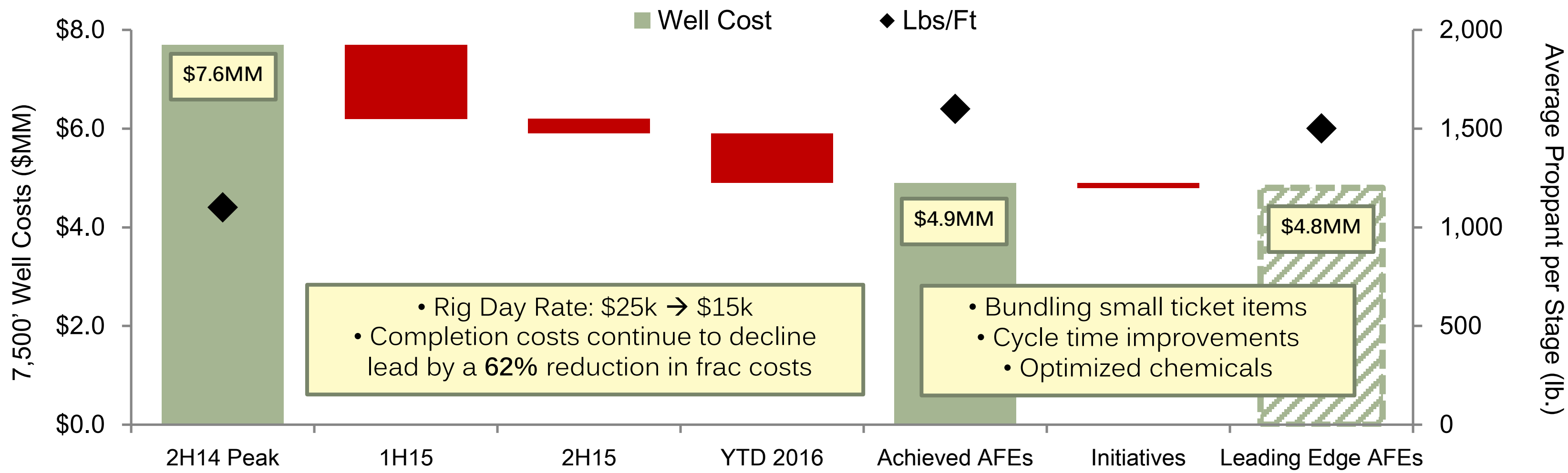
- Drilling a 12 WPS density test in 2Q16 and a 13 WPS in 2H16 as we evaluate potential upside as high as 16 WPS
- Inventory upside of ~45% at 16 WPS
- Continuing to monitor offset activity, share data with peer operators and perform joint testing (i.e., RSPP JV wells)

a) Production normalized to 7,500'.

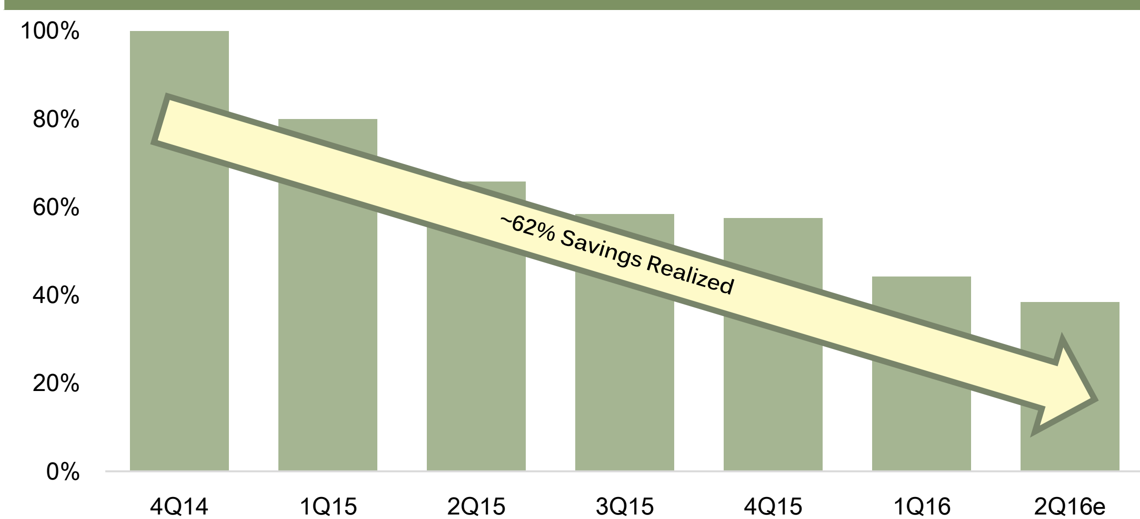
CURRENT SNAPSHOT: WELL COSTS

Callon Petroleum Company

Continuing to Deliver CWC Reductions Period-over-Period (a)



Hydraulic Fracturing Cost Progression Continue to Improve



- Increasing proppant volumes including larger grain size
- Streamlining communication with all service providers; Emphasis on building strong relationships
- Optimizing chemical program; Adjusting levels based on real-time frac data
- Rigorous, real-time bacteria monitoring and treating system on frac and drill-out operations

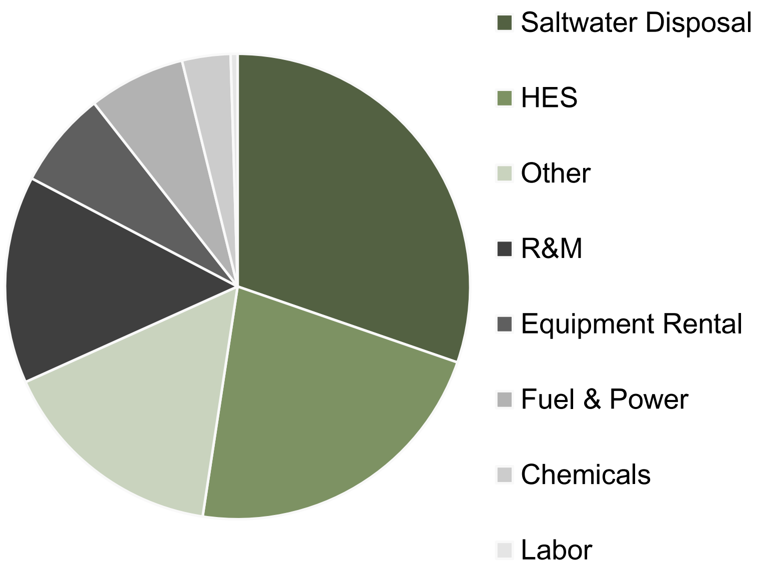
a) Excludes approximately $150K of well-level facilities

CURRENT SNAPSHOT: OPEX

Callon Petroleum Company

Substantial Progress Made in Lowering OpEx versus Both Historicals and Peer Group

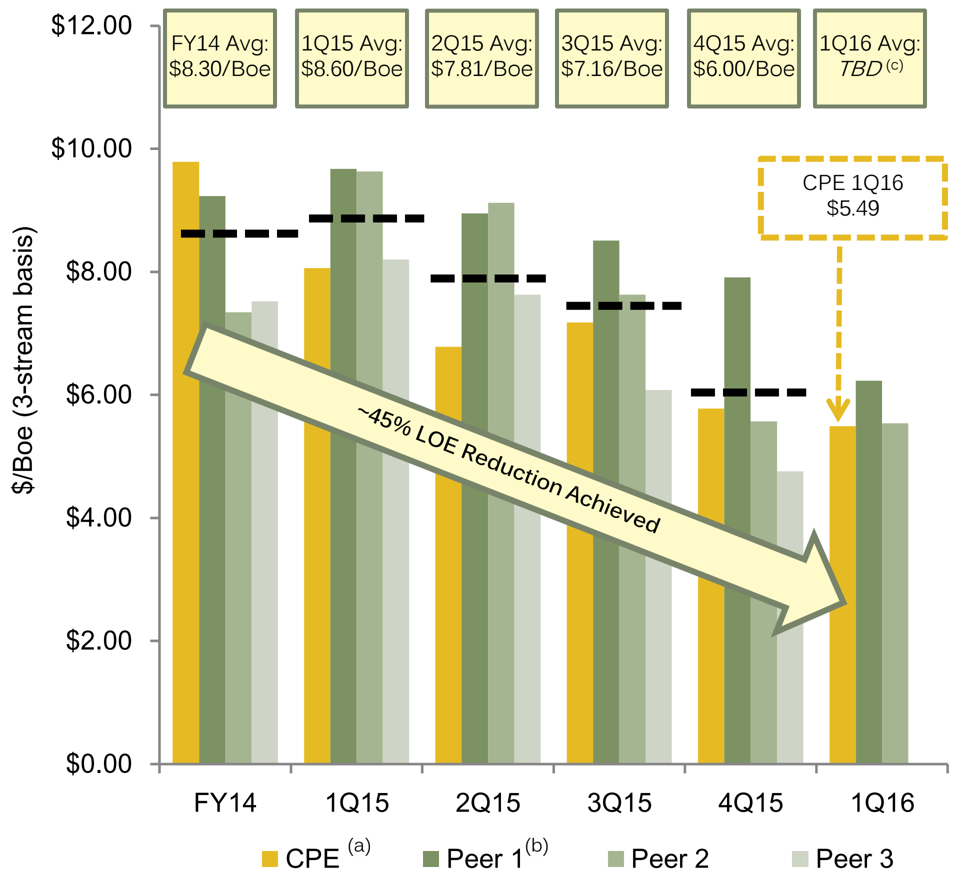
Non-Workover Savings Breakdown



Key 2016 OPEX initiatives:

- Focused on achieving incremental savings across entire spectrum of OPEX components
- Saltwater Disposal and Chemicals have greatest potential for meaningful 1H16 savings

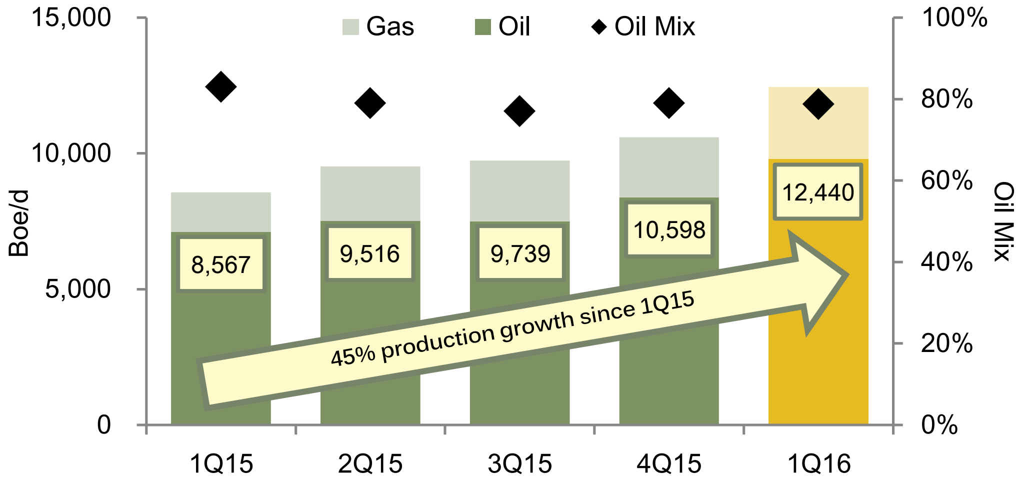
Midland Basin Peers *3-Stream* LOE



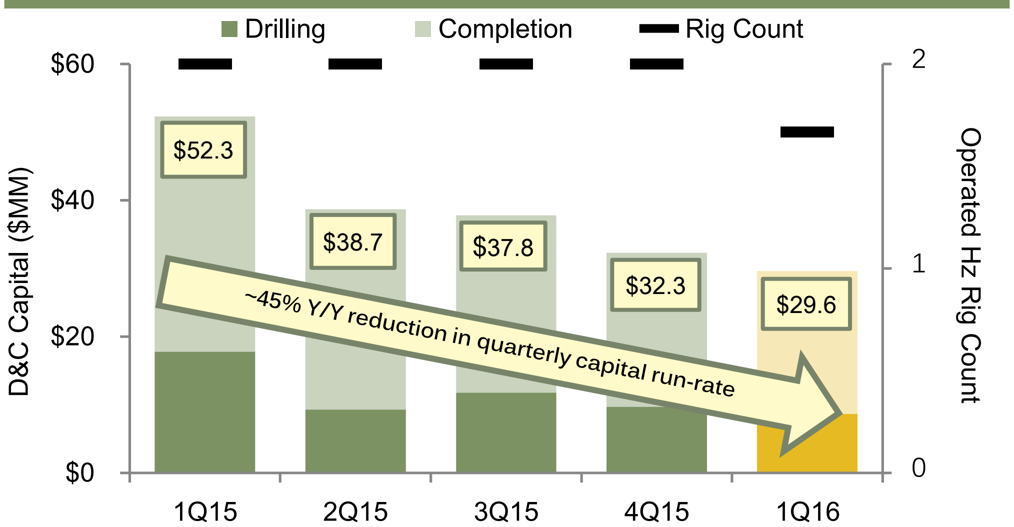
a) CPE converted to 3-stream for comparison purposes by assuming a ~12% volumetric uplift from capturing NGL volumes.
b) Peer 1 LOE per unit nets out production attributed to non-cost bearing minerals interest.
c) Peer 3 LOE for 1Q16 not available prior to publish.

OPERATIONAL DRIVERS

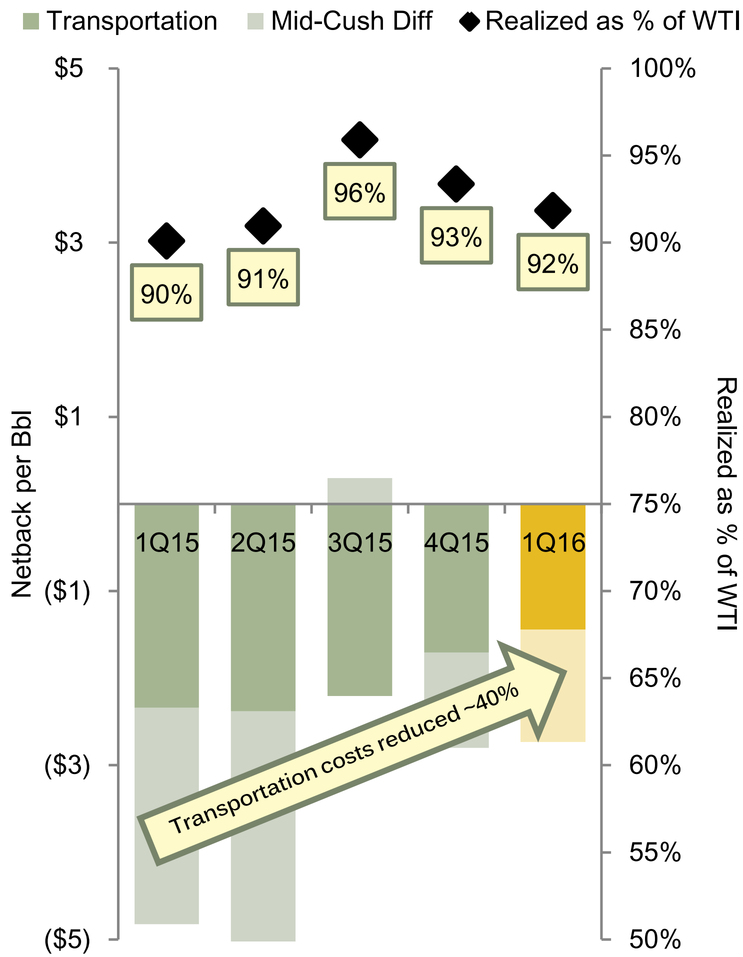
Strong Production Growth Momentum



Consistent Reduction in Capital



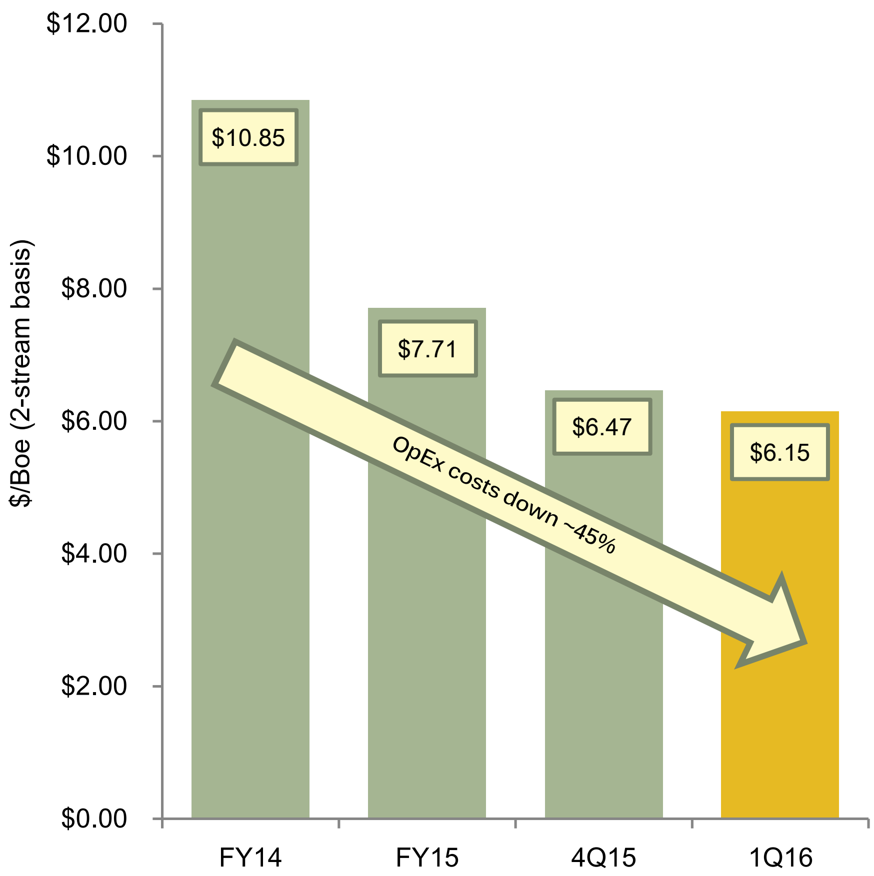
Realized Oil Prices ($/Bbl)



Realized benefits from increasing gathering system offtake

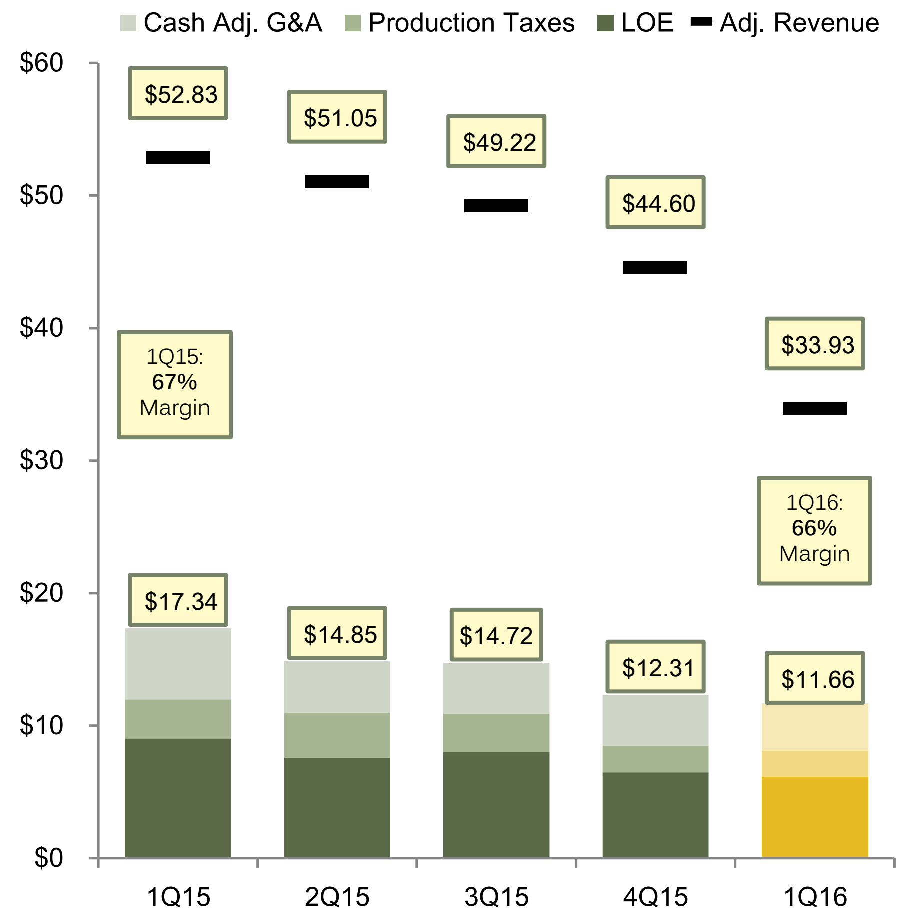
OPEX & MARGINS

OPEX Savings Easing Margin Pressure



OpEx ($/Boe) is down ~45% since 2014 peak

Adjusted EBITDA Margins ($/Boe)[(a)]

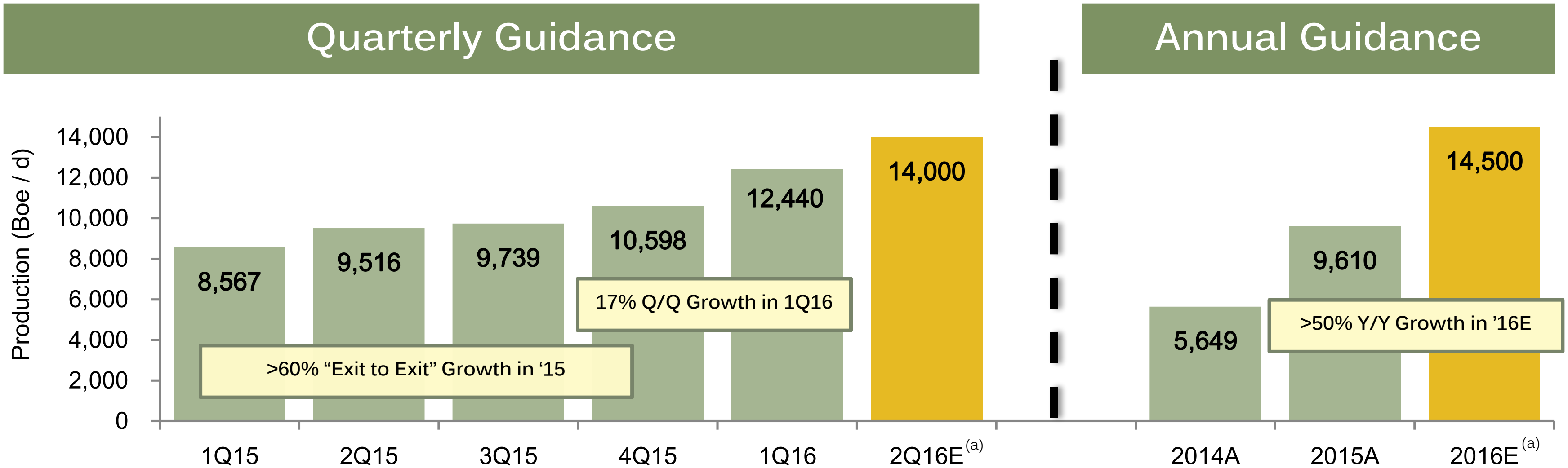


Managing volatility with resilient cash flow margins

a) See definition of Cash Adjusted EBITDA and Adjusted Revenues, Non-GAAP measures, included in the Appendix. Adjusted Revenues include the impact of cash settled derivatives.

PRO FORMA 2016 GUIDANCE

Callon Petroleum Company



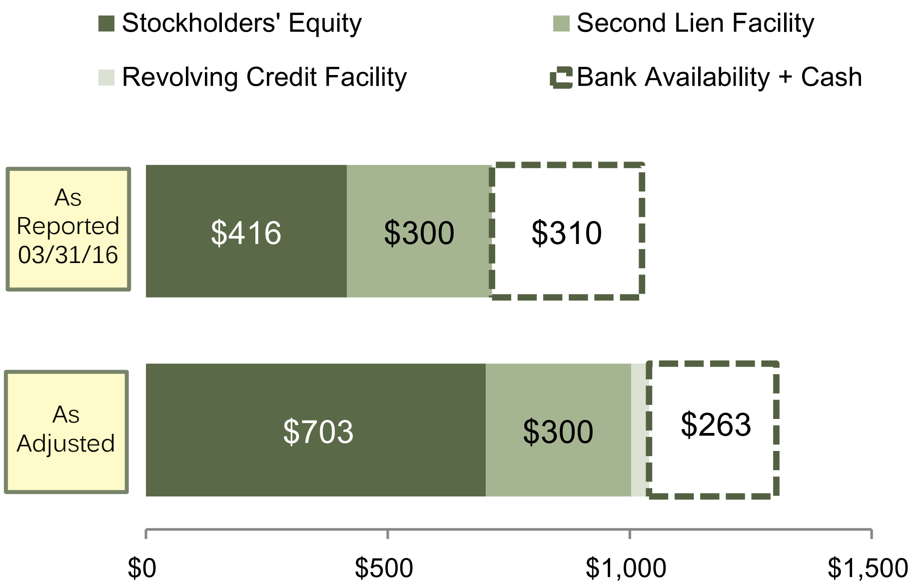
	2Q16 Guidance	FY16 Guidance
Total Production (Boe/d)	13,500 - 14,500	14,000 - 15,000
% oil	76% - 78%	76% - 80%
% oil hedged[(a)]	56%	52%
Average swap/long-put price	$49.97	$50.44
Expenses (per Boe)		
LOE, including workovers	$6.00 - $6.50	$6.75 - $7.25
Production and ad valorem taxes	$2.25 - $2.50	$2.00 - $2.50
Adjusted G&A[(b)]	$3.75 - $4.25	$3.30 - $3.80
Recurring cash component[(c)]	$3.00 - $3.50	$2.90 - $3.40
Operational Capital Expenditures		
Accrual basis ($MM)	$15 - $25	$95 - $105

a) Based on the midpoint of guidance.
b) Excludes certain non-recurring expenses and non-cash valuation adjustments related to incentive compensation plans. See Non-GAAP disclosures included in the Appendix.
c) Excludes stock-based compensation and corporate depreciation and amortization.

PRO FORMA FINANCIAL PROFILE

Callon Petroleum Company

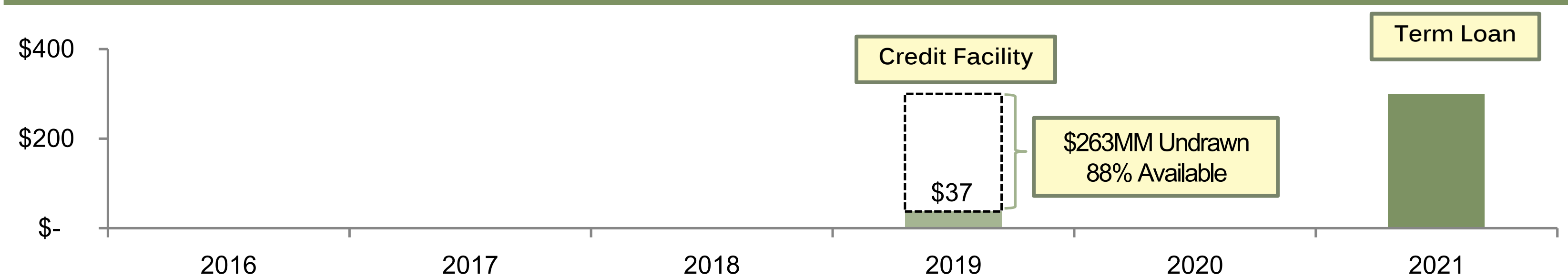
1Q16 & Pro Forma Capitalization ($MM) (a)



Borrowing Base reaffirmed at $300MM in April 2016

- Unanimous approval from all 10 participating banks
- No changes to any other terms in the facility
- Increased 20% in Fall 2015 redetermination ($250MM → $300MM)
- Excludes any potential increase related to the Big Star and AMI transactions

Debt Maturity Summary ($MM) (a)

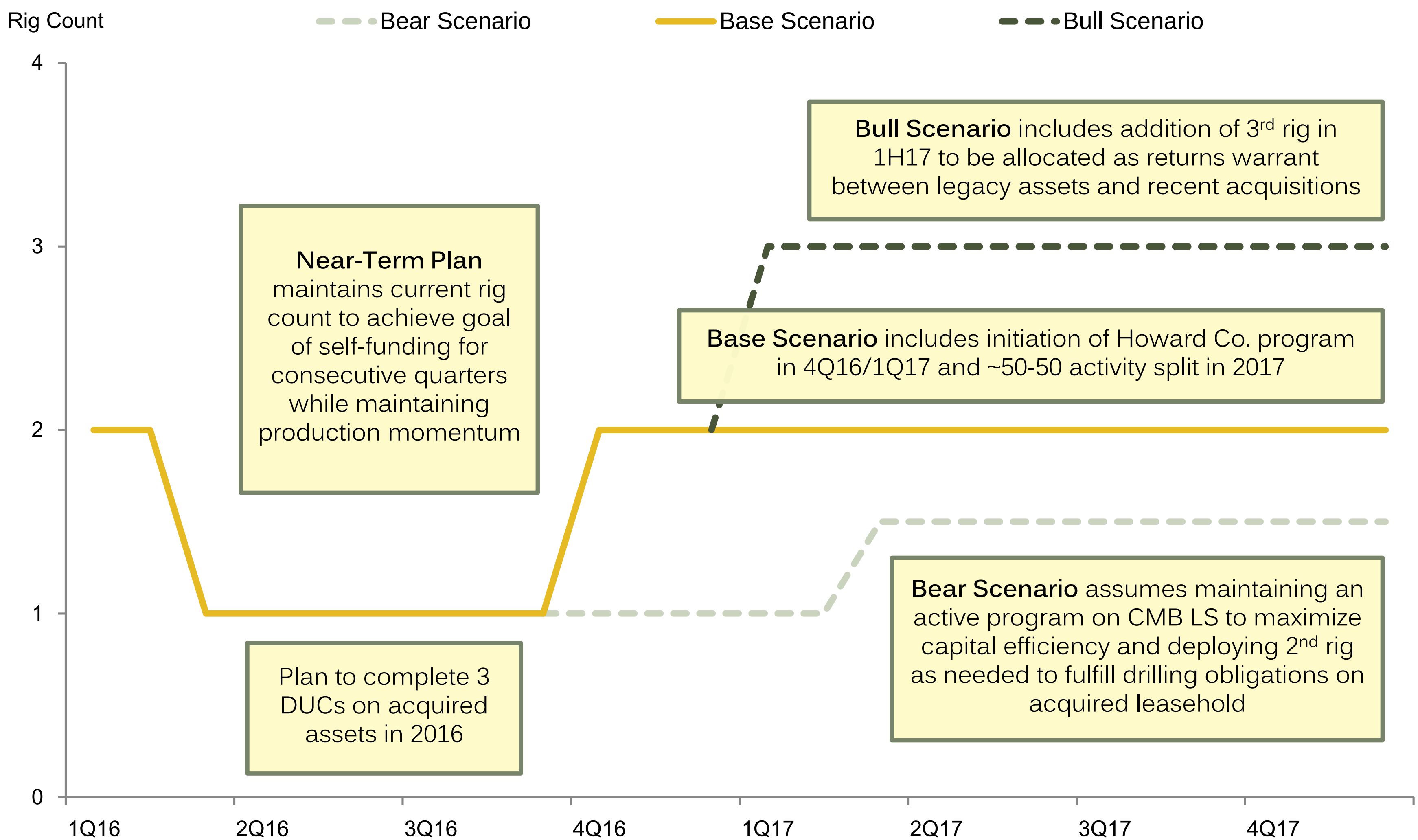


a) "As Adjusted" capitalization and the debt maturity summary are presented pro forma for (i) the April equity offering proceeds of ~$206 million, including overallotment; (ii) the issuance of 9.3 million shares to the sellers of Big Star assets ($81 million or $8.50 per share as of 4/18/16); (iii) the cash portion paid to the sellers of the Big Star assets ($220 million); (iv) and western Reagan County AMI transaction ($33 million, net).

DEVELOPMENT OUTLOOK

Callon Petroleum Company

Illustrative Pro Forma Program



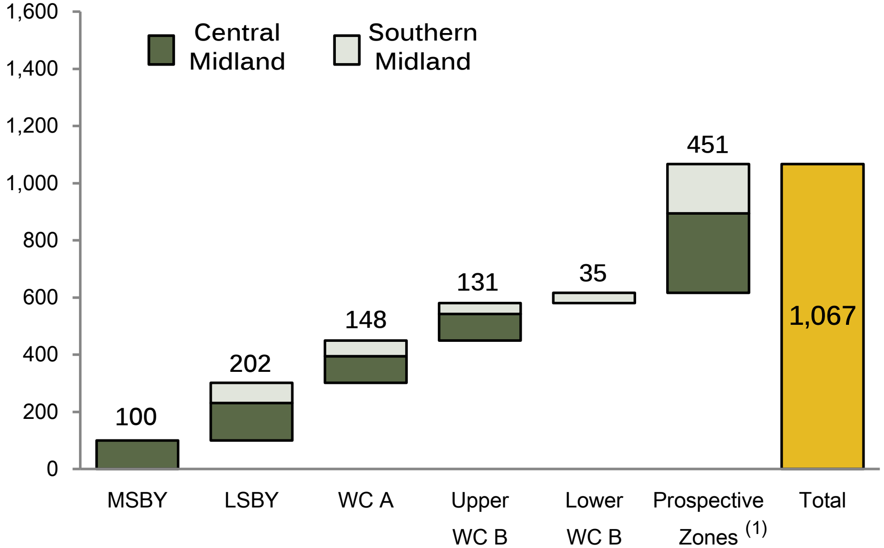
APPENDIX

Callon Petroleum Company

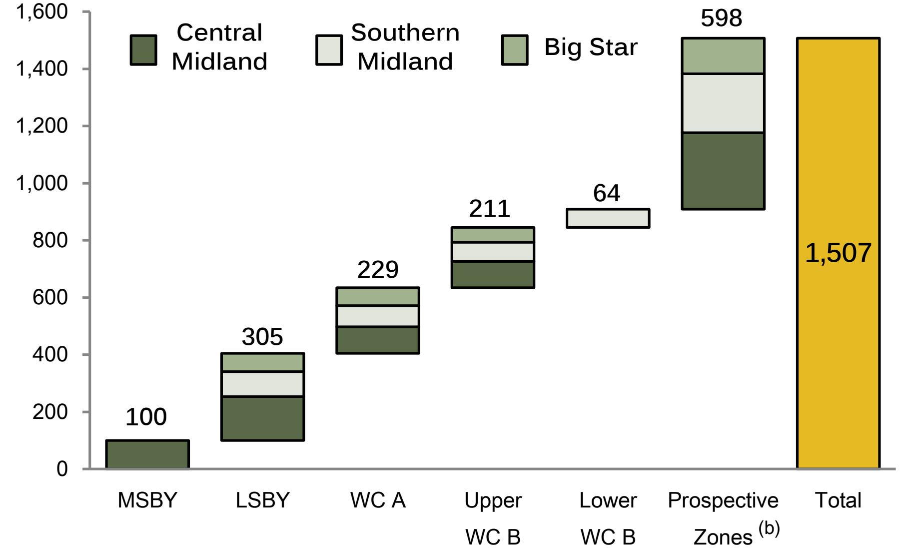
INVENTORY OVERVIEW

Potential Gross Horizontal Locations

Legacy Callon



Pro Forma Pending Acquisitions [a]



Pro Forma Effective Acreage Breakdown (Grand Total: 152,430 net)

Operated Producing Zones

	Gross	Net
Middle Spraberry	17,369	14,382
Lower Spraberry	28,125	23,190
Wolfcamp A	35,141	27,177
Upper Wolfcamp B	33,861	25,800
Lower Wolfcamp B	15,852	10,778
Total	130,349	101,327

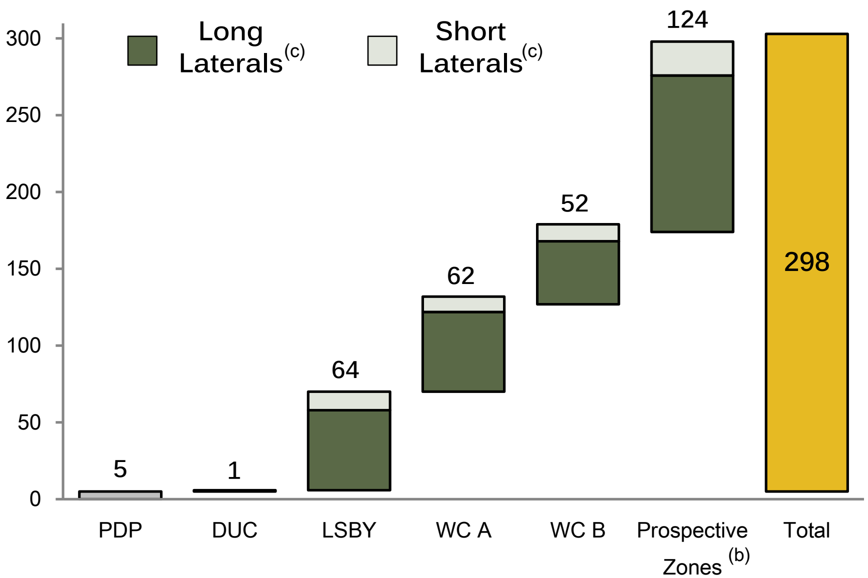
Prospective Zones

	Gross	Net
Clearfork	6,238	4,450
Jo Mill	19,367	15,292
Wolfcamp C	15,062	10,328
Wolfcamp D/Cline	28,674	21,033
Total	69,341	51,103

a) Pending acquisitions include the Big Star and AMI acquisitions announced on April 19, 2016
b) Prospective zones include: Jo Mill, Wolfcamp C, Wolfcamp D/Cline for legacy Callon properties, Middle Spraberry and Wolfcamp D/Cline for Big Star acreage and Wolfcamp C and Wolfcamp D/Cline for western Reagan AMI.

BIG STAR INVENTORY OVERVIEW [(a)]

Gross Horizontal Location Inventory

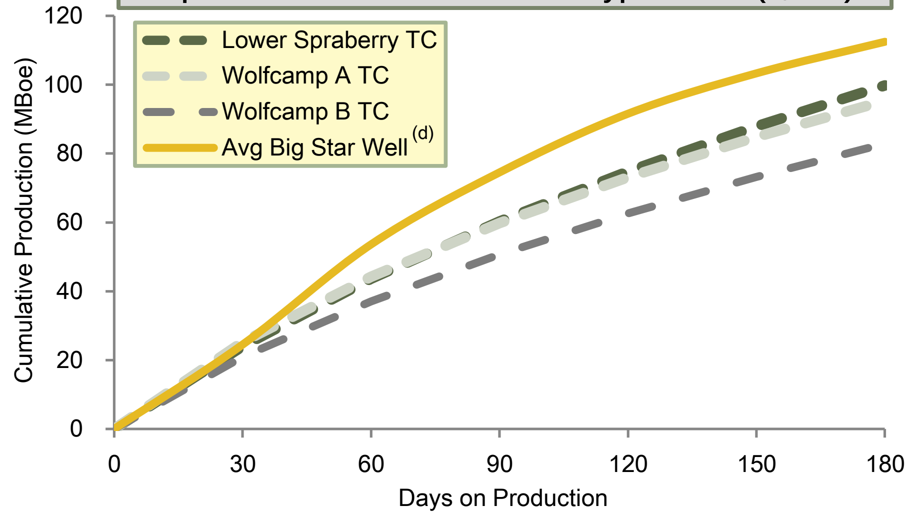


Lateral Length Breakdown

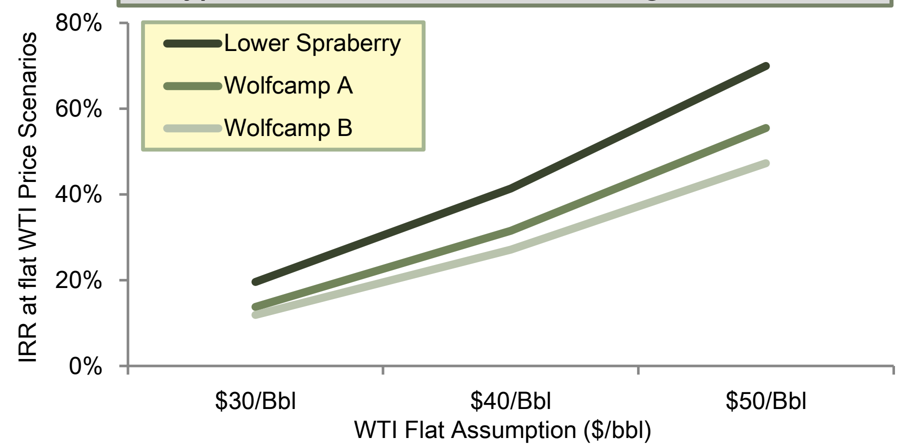
	>7,500'	7,500'	<7,500'	Avg.
Lower Spraberry	40	12	12	8,286'
Wolfcamp A	41	11	10	8,481'
Wolfcamp B	32	9	11	8,240'
Prospective Zones (b)	79	23	22	8,341'
TOTAL	192	55	55	8,341'

Big Star Type Curves

Operated Hz Performance vs. Type Curve (7,500')



Type Curve IRRs at WTI Flat Pricing Scenarios (e)

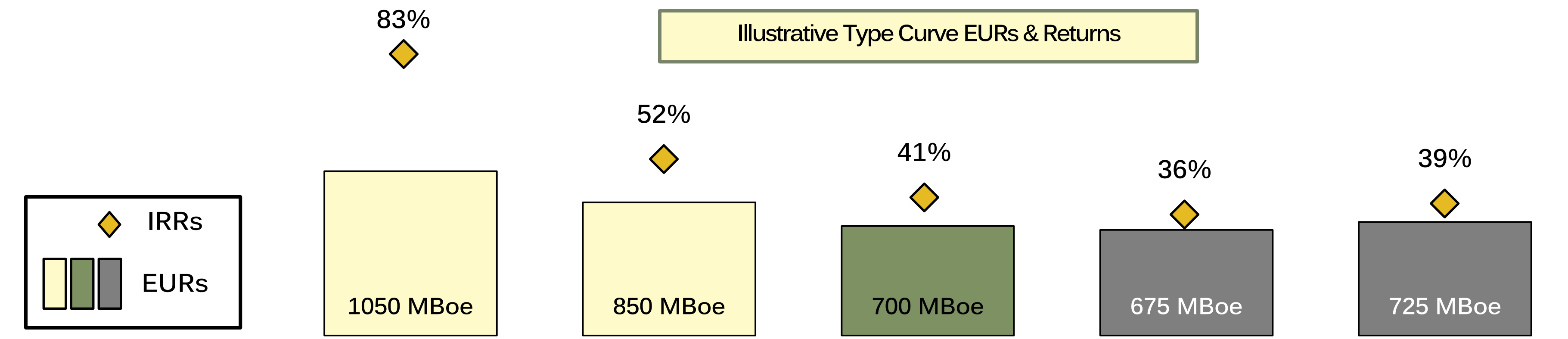


a) Pending acquisition announced on April 19, 2016.
b) Prospective zones for Big Star acreage include Middle Spraberry and Wolfcamp D/Cline.
c) Long Laterals include gross laterals that are projected to be drilled to 7,500' or more. Short Laterals include those projected to be drilled to less than 7,500'.
d) "Avg Big Star Well" reflects the actual average daily production volumes from five operated Big Star horizontals, normalized for lateral length (7,500') and downtime.
e) Assumes flat $2.50/MMBtu NYMEX natural gas prices.

DEEP HIGH-RETURN INVENTORY

Callon Petroleum Company

Acquired Properties' Returns Are Competitive with Top-Tier Legacy Portfolio



	Legacy Central	Big Star			AMI/Legacy South
	Lower Spraberry	Lower Spraberry	Wolfcamp A	Wolfcamp B	Lower Wolfcamp B
Wellhead EUR	1,050	850	700	675	725
Oil Mix	83%	87%	88%	87%	76%
D&C Cost ($M)	$5,050	$5,050	$5,050	$5,050	$5,050
Lateral Length (Ft)	7,500'	7,500'	7,500'	7,500'	7,500'
Single Well IRR [a]	83%	52%	41%	36%	39%
ROI [a]	5.4x	4.5x	3.7x	3.6x	3.5x
NPV ($MM) [a]	$8.3 MM	$6.1 MM	$4.5 MM	$4.1 MM	$4.1 MM
Gross / Net Locations	131 / 96	64 / 59	62 / 58	52 / 48	66 / 46
Spacing Assumption [b]	11 wells / section	8 wells / section	7 wells / section	6 wells / section	7 wells / section
"Full-Cycle" Returns [c]					
Single Well IRR [a]	n/a	31%	24%	21%	36%
NPV ($MM) [a]	n/a	$4.6 MM	$3.0 MM	$2.6 MM	$3.9 MM

a) Assumes NYMEX pricing as of April 8, 2016. NPV calculations assume a 10% discount rate.
b) Spacing Assumptions are based on geological and petrophysical surveys of the respective areas and through analogy to comparable producing zones/acreage.
c) "Full-cycle" IRRs and NPVs calculated by adding ~$1.47mm/"delineated" Hz Location for Big Star acquisition (slide 7) and ~$0.16mm/"delineated" Hz Location for Western Reagan Co. AMI acquisition.

METRICS & COMPARABLES

Callon Petroleum Company

Recent Howard Co. Transactions [a]

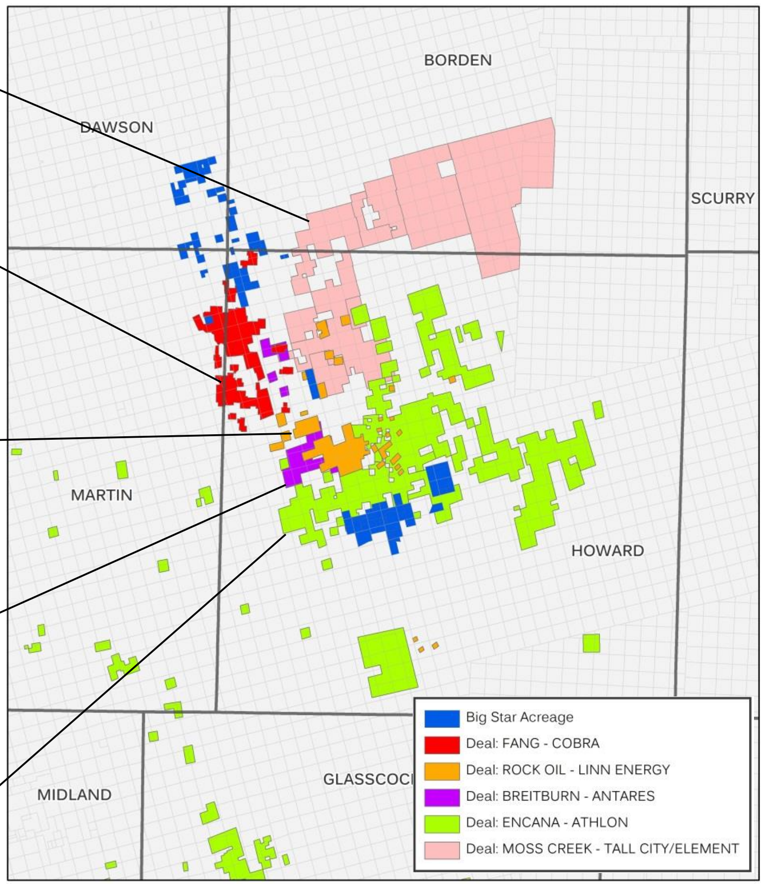
Moss Creek Acquisition of Tall City/Element
10/23/15
Purchase Price: ~$1,084mm
Production, net: ~6,000 Boe/d
Acreage, net: ~78,000 acres

Diamondback Acquisition of Cobra Oil & Gas, etc.
5/6/15
Purchase Price: ~$438mm
Production, net: ~2,500 Boe/d
Acreage, net: ~11,948 acres

Rock Oil Acquisition of Linn Energy Assets
7/2/15
Purchase Price: ~$281mm
Production, net: ~2,000 Boe/d
Acreage, net: ~6,400 acres

Breitburn Acquisition of Antares Energy
10/24/14
Purchase Price: ~$123mm
Production, net: ~600 Boe/d
Acreage, net: ~3,700 acres

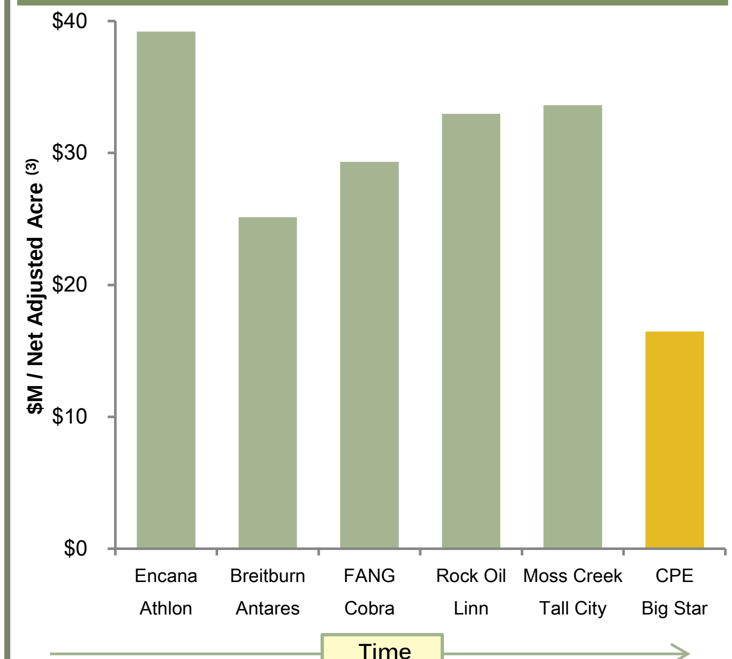
Encana Acquisition of Athlon Energy
9/27/14
Purchase Price: ~$6,989mm
Production, net: ~30,000 Boe/d
Acreage, net: ~140,000 acres



Big Star Metrics

Total Consideration [b]	$301 MM
Net Surface Acreage Acquired	14,089 acres
1Q16e Net Production (% oil) [c]	1,931 Boe/d (82% oil)
"Delineated" Horizontal Locations	165, net
$/Adjusted Acre [d]	$17,270/acre
$/"Delineated" Hz Location [d]	$1.47 mm

Recent Howard Co. A&D Metrics [a]



a) Sources: 1Derrick, third-party press releases and investor presentations. Transactions include deals >$100mm occurring in Howard Co. since 2H14. Purchase price metrics reflect figures from transaction announcements, before giving effect to closing adjustments.
b) Based on CPE closing price of $8.73 per share as of April 18, 2016.
c) Production figures are estimated 1Q16 average volumes.
d) Production valued at the following "per flowing Boe" assumptions for transactions in a given year: $50,000 for 2014, $35,000 for 2015 and $30,000 for 2016. Please refer to "Metric Calculation Methodologies" on Slide 3, for further clarity.

HEDGE PORTFOLIO

	2016 Average Daily Volumes				2017 Average Daily Volumes			
	1Q16	2Q16	3Q16	4Q16	1Q17	2Q17	3Q17	4Q17
Crude Oil								
Swap contracts								
Volume (Bbl per day)	2,000	2,670	3,000	2,000	2,000	2,000	2,000	2,000
Average NYMEX swap price	$ 58.23	$ 58.07	$ 58.02	$ 58.23	$44.50	$44.50	$44.50	$44.50
Put contracts								
Volume (Bbl per day)					2,000	2,000	2,000	2,000
Average NYMEX swap price					30.00	30.00	30.00	30.00
Collar contracts with short puts ("three-way" collar)								
Volume (BBl per day)	2,000	1,330	1,000	2,000				
Average NYMEX price:								
Ceiling	$ 65.00	$ 62.48	$ 60.00	$ 65.00				
Floor	$ 55.00	$ 52.48	$ 50.00	$ 55.00				
Short put	$ 40.33	$ 39.97	$ 35.65	$ 40.33				
Two-way collar contracts [(a)]								
Volume (BBl per day)	1,319	2,000	2,000	2,000	1,836	1,836	1,836	1,836
Average NYMEX price:								
Ceiling	$ 46.50	$ 46.50	$ 46.50	$ 46.50				
Floor	$ 37.50	$ 37.50	$ 37.50	$ 37.50				
Call					$50.00	$50.00	$50.00	$50.00
Midland Basin Oil Differential								
Volume (Bbl per day)	4,000	4,000	4,000	4,000				
Swap price spread to NYMEX	$ 0.17	$ 0.17	$ 0.17	$ 0.17				
Natural Gas								
Swap contracts								
Volume (MMBtu per day)	6,000	6,000	6,000	6,000				
Average NYMEX swap price	$ 2.52	$ 2.52	$ 2.52	$ 2.52				

Callon Petroleum Company

QUARTERLY CASH FLOW STATEMENT

Callon Petroleum Company

	1Q-2015	2Q-2015	3Q-2015	4Q-2015	1Q-2016
Cash flows from operating activities:					
Net loss	$ (10,197)	$ (4,967)	$ (111,805)	$ (113,170)	$ (41,109)
Adjustments to reconcile net loss to cash provided by operating activities:					
Depreciation, depletion and amortization	18,546	18,011	16,026	17,308	16,129
Write-down of oil and natural gas properties	-	-	87,301	121,134	34,776
Accretion expense	209	134	142	175	180
Amortization of non-cash debt related items	781	780	781	781	781
Deferred income tax (benefit) expense	(5,077)	(2,116)	45,667	-	-
Net loss on derivatives, net of settlements	7,914	13,214	(13,495)	(977)	8,648
Non-cash expense related to equity share-based awards	86	(754)	368	521	392
Change in the fair value of liability share-based awards	3,088	1,607	64	1,853	709
Payments to settle asset retirement obligations	258	(2,163)	(1,142)	(211)	(161)
Changes in current assets and liabilities:					
Accounts receivable	(2,125)	(4,821)	(332)	2,517	5,941
Other current assets	452	(536)	117	(51)	580
Current liabilities	(355)	5,904	906	1,546	(717)
Change in other long-term liabilities	-	100	-	(20)	11
Change in other assets, net	(319)	(209)	949	(83)	(233)
Payments to settle vested liability share-based awards related to early retirements	(3,538)	-	-	-	-
Payments to settle vested liability share-based awards	(3,599)	(326)	-	-	(9,807)
Net cash provided by operating activities	6,124	23,858	25,547	31,323	16,120
Cash flows from investing activities:					
Capital expenditures	(70,780)	(60,067)	(47,701)	(48,744)	(50,775)
Acquisitions	-	-	-	(32,245)	(10,183)
Proceeds from sales of mineral interest and equipment	272	54	22	29	-
Net cash used in investing activities	(70,508)	(60,013)	(47,679)	(80,960)	(60,958)
Cash flows from financing activities:					
Borrowings on credit facility	60,000	43,000	27,000	51,000	45,000
Payments on credit facility	(58,000)	(5,000)	(3,000)	(110,000)	(85,000)
Payment of deferred financing costs	(12)	12	-	-	-
Issuance of common stock	65,546	-	-	109,913	94,949
Payment of preferred stock dividends	(1,974)	(1,973)	(1,974)	(1,974)	(1,824)
Net cash provided by financing activities	65,560	36,039	22,026	48,939	53,125
Net change in cash and cash equivalents	1,176	(116)	(106)	(698)	8,287
Balance, beginning of period	968	2,144	2,028	1,922	1,224
Balance, end of period	$ 2,144	$ 2,028	$ 1,922	$ 1,224	$ 9,511

NON-GAAP RECONCILIATION[a]

Callon Petroleum Company

	1Q-2015	2Q-2015	3Q-2015	4Q-2015	1Q-2016
Loss available to common stockholders	$ (12,171)	$ (6,940)	$ (113,779)	$ (115,144)	$ (42,933)
Adjustments:					
Valuation allowance	-	-	68,818	40,025	14,288
Net loss (gain) on derivatives, net of settlements	5,144	8,589	(8,771)	(635)	5,621
Write-down of oil and natural gas properties	-	-	56,746	78,737	22,604
Rig termination fee	2,367	-	-	(368)	-
Change in the fair value of share-based awards	1,676	1,045	37	1,197	461
Early retirement expenses	3,034	-	-	-	-
Withdrawn proxy contest expenses	72	150	65	-	144
Adjusted Income	$ 122	$ 2,844	$ 3,116	$ 3,812	$ 185
Net loss	$ (10,197)	$ (4,967)	$ (111,805)	$ (113,170)	$ (41,109)
Adjustments:					
Write-down of oil and natural gas properties	-	-	87,301	121,134	34,776
Net loss (gain) on derivatives, net of settlements	7,914	13,214	(13,494)	(977)	8,648
Change in the fair value of share-based awards	3,057	2,086	655	2,354	1,225
Early retirement expenses	4,668	-	-	-	-
Rig termination fee	3,641	-	-	(566)	-
Withdrawn proxy contest expenses	111	230	100	-	221
Acquisition expense	3	-	(3)	27	48
Income tax benefit	(5,077)	(2,116)	45,667	-	-
Interest expense	4,858	5,106	5,603	5,544	5,491
Depreciation, depletion and amortization	18,546	18,011	16,026	17,308	16,129
Accretion expense	209	134	142	175	180
Adjusted EBITDA	$ 27,733	$ 31,698	$ 30,192	$ 31,829	$ 25,609

a) See "Additional Disclosure" slides for disclosures related to Supplemental Non-GAAP Financial Measures.

NON-GAAP RECONCILIATION[a]

	1Q-2015	2Q-2015	3Q-2015	4Q-2015	1Q-2016
Total G&A expense	$ 12,102	$ 5,763	$ 4,302	$ 6,180	$ 5,562
Adjustments:					
Change in the fair value of liability share-based awards	(2,578)	(1,607)	(57)	(1,842)	(698)
Early retirement expenses	(4,668)	-	-	-	-
Threatened proxy contest	(111)	(230)	(100)	-	(221)
Adjusted G&A - Total	4,745	3,926	4,145	4,338	4,643
Restricted stock share-based compensation	(479)	(479)	(598)	(512)	(511)
Corporate depreciation & amortization	(129)	(115)	(133)	(117)	(113)
Adjusted G&A - Cash	$ 4,137	$ 3,332	$ 3,414	$ 3,709	$ 4,019
Oil Revenue	$ 27,909	$ 36,093	$ 30,582	$ 30,582	$ 27,443
Natural gas revenue	2,482	3,149	3,734	2,981	3,255
Total revenue	30,391	39,242	34,316	33,563	30,698
Impact of cash-settled derivatives	10,343	4,965	9,789	9,918	7,716
Adjusted Total Revenue	$ 40,734	$ 44,207	$ 44,105	$ 43,481	$ 38,414
Total Production (MBOE)	771	866	896	975	1,132
Adjusted Total Revenue per BOE	$ 52.83	$ 51.05	$ 49.22	$ 44.60	$ 33.93

a) See "Additional Disclosure" slides for disclosures related to Supplemental Non-GAAP Financial Measures.

ADDITIONAL DISCLOSURE

Supplemental Non-GAAP Financial Measures

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 below were computed in accordance with GAAP.

Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDA as net income (loss) before interest expense, income taxes, depreciation, depletion and amortization, exploration expense, (gains) losses on derivative instruments excluding net cash receipts (payments) on settled derivative instruments and premiums paid for put options that settled during the period, impairment of oil and natural gas properties, non-cash equity based compensation, asset retirement obligation accretion expense, other income, gains and losses from the sale of assets and other non-cash operating items. Adjusted EBITDA is not a measure of net income as determined by United States generally accepted accounting principles ("GAAP").

Management believes Adjusted EBITDA is useful because it allows it to more effectively evaluate our operating performance and compare the results of our operations from period to period and against our peers without regard to our financing methods or capital structure. We exclude the items listed above from net income in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDA. Our presentation of Adjusted EBITDA should not be construed as an inference that our results will be unaffected by unusual or non-recurring items..

Adjusted general and administrative expense ("Adjusted G&A") is a supplemental non-GAAP financial measure that excludes certain non-recurring expenses and non-cash valuation adjustments related to incentive compensation plans. We believe 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 below 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 below were computed in accordance with GAAP.

Certain Reserve Information

Cautionary Note to U.S. Investors: The Securities and Exchange Commission ("SEC") prohibits oil and gas companies, in their filings with the SEC, from disclosing estimates of oil or gas resources other than "reserves," as that term is defined by the SEC. This presentation discloses estimates of quantities of oil and gas using certain terms, such as "resource potential," "net recoverable resource potential," "resource base," "estimated ultimate recovery," "EUR" or other descriptions of volumes of reserves, which terms include quantities of oil and gas that may not meet the SEC's definitions of proved, probable and possible reserves, and which the SEC's guidelines strictly prohibit the Company from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being recovered by the Company. U.S. investors are urged to consider closely the disclosures in the Company's periodic filings with the SEC. Such filings are available from the Company at 1401 Enclave Pkwy, Ste 600, Houston, TX 77077, Attention: Investor Relations, and the Company's website at www.callon.com. These filings also can be obtained from the SEC by calling 1-800-SEC-0330.