CALLON PETROLEUM COMPANY

IPAA Conference: Houston, TX

April 21, 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.

This presentation includes certain estimates based on production, reserve and other data regarding the Big Star and AMI properties. The production, reserve and other data included have not been reviewed by our reserve engineer, DeGolyer and MacNaughton, and may vary from what is presented here. We cannot assure you that these estimates are accurate.

ADDITIONAL DISCLOSURES

SUPPLEMENTAL NON-GAAP FINANCIAL MEASURES

This presentation includes non-GAAP measures, such as Adjusted EBITDA. 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.

For a reconciliation of non-GAAP measures to their most directly comparable GAAP measure, please see the Appendix.

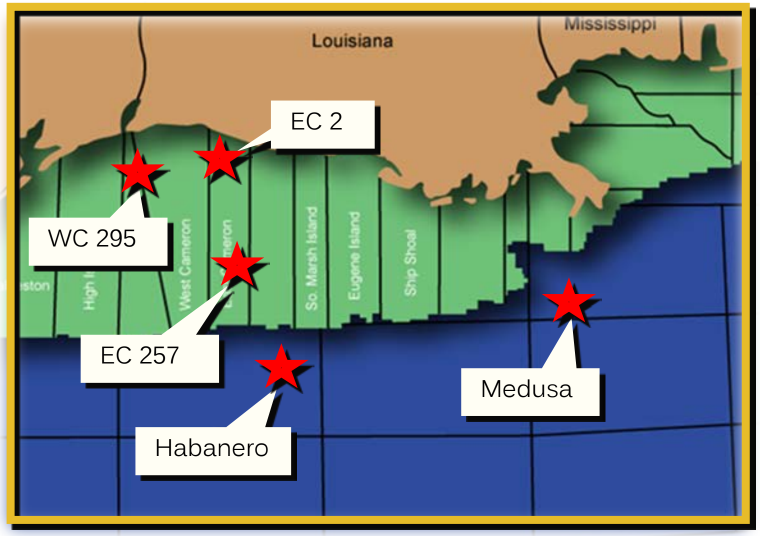
METRIC CALCULATION METHODOLOGIES

$/Adjusted Acre: This calculation aims to normalize transaction purchase prices for the value of the production acquired to arrive at an implied "adjusted" valuation for the undeveloped acreage acquired. The "adjustment" value for the acquired production is determined by applying what management believes is a reasonable valuation multiple for the present value of a flowing equivalent barrel of production—based on prevailing NYMEX strip pricing at the time of the acquisition—to reported sustained production rates at the time of the acquisition. This "adjusted" undeveloped valuation is then divided by the net surface acreage acquired to yield a best-efforts, "apples-to-apples" transaction metric to use as a rough guide for relative valuation purposes.

$/"Delineated" Horizontal Location: This calculation aims to normalize transaction purchase prices for the value of the production acquired to arrive at an implied "adjusted" valuation for the inventory of undeveloped horizontal locations (net to the acquired interest), in zones, which management believes to have been sufficiently "delineated" by operated and/or offsetting industry activity to date. The "adjustment" value for the acquired production is determined by applying what management believes is a reasonable valuation multiple for the present value of a flowing equivalent barrel of production—based on prevailing NYMEX strip pricing at the time of the acquisition—to reported sustained production rates at the time of the acquisition. This "adjusted" undeveloped valuation is then divided by the previously described net identified horizontal locations acquired to yield a best-efforts, "apples-to-apples" transaction metric to use as a rough guide for relative valuation purposes.

CALLON PETROLEUM COMPANY - 2009

Field	WI%	Gross Production Oil (BOPD)	 Gas (MMcf/d)
Medusa Field (MC Blocks 538/582)	15%	12,600	11.5
Habanero Field (GB Block 241)	25% / 11.25%	5,700	8.6
West Cameron Block 295	20.5%	120	19.0
East Cameron Block 2 (N. Pronghorn)	42.5%	100	7.0
East Cameron 257	50%	-	5.0
TOTAL NET PRODUCTION		**31 MMcf/d (51% Gas)**	



Production Profile:

- 100% Offshore
- >50% Gas

2009 STRATEGIC OBJECTIVES

Callon Petroleum Company

- Lower the risk profile of the company
- Increase the % of oil assets
- Lengthen the reserve life
- Build a portfolio of lower risk repeatable drilling opportunities
- Strengthen the balance sheet **(including the need to address a 2010 debt maturity of ~$200MM)**

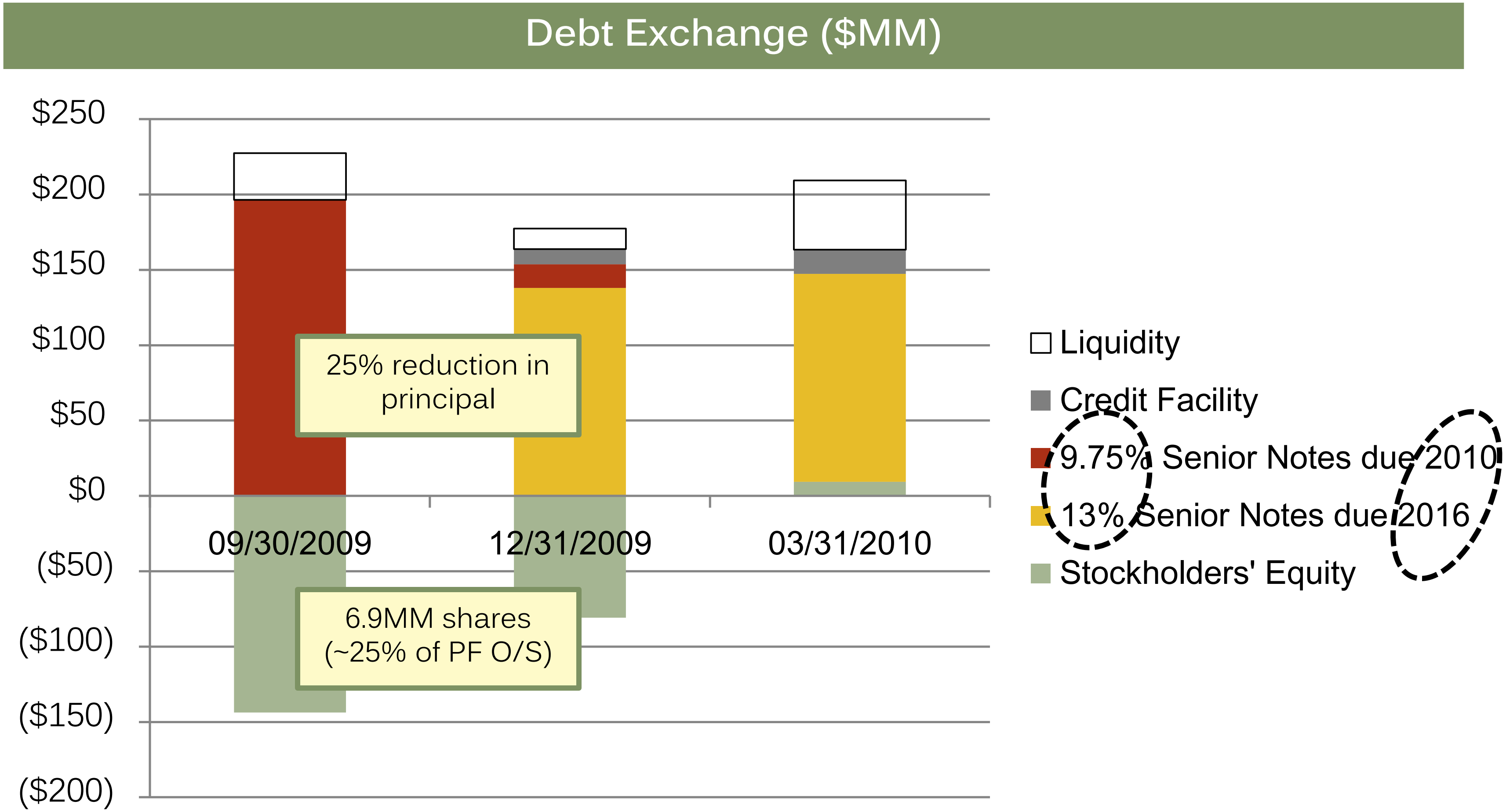
RESTRUCTURING OVERVIEW

Callon Petroleum Company

- Limited alternatives
  - Public capital markets not available
  - Primarily non-operated asset base
    - Constraints on structured alternatives
    - Lack of asset sales options
  - Debt restructuring path most actionable
- No traditional advisory firms involved
- Premised on strong relationship with anchor holder
  - Detailed strategic plan and financial roadmap for recovery of principal
  - Foundation of trust built from initial issuance in 2003

MECHANICS

Callon Petroleum Company



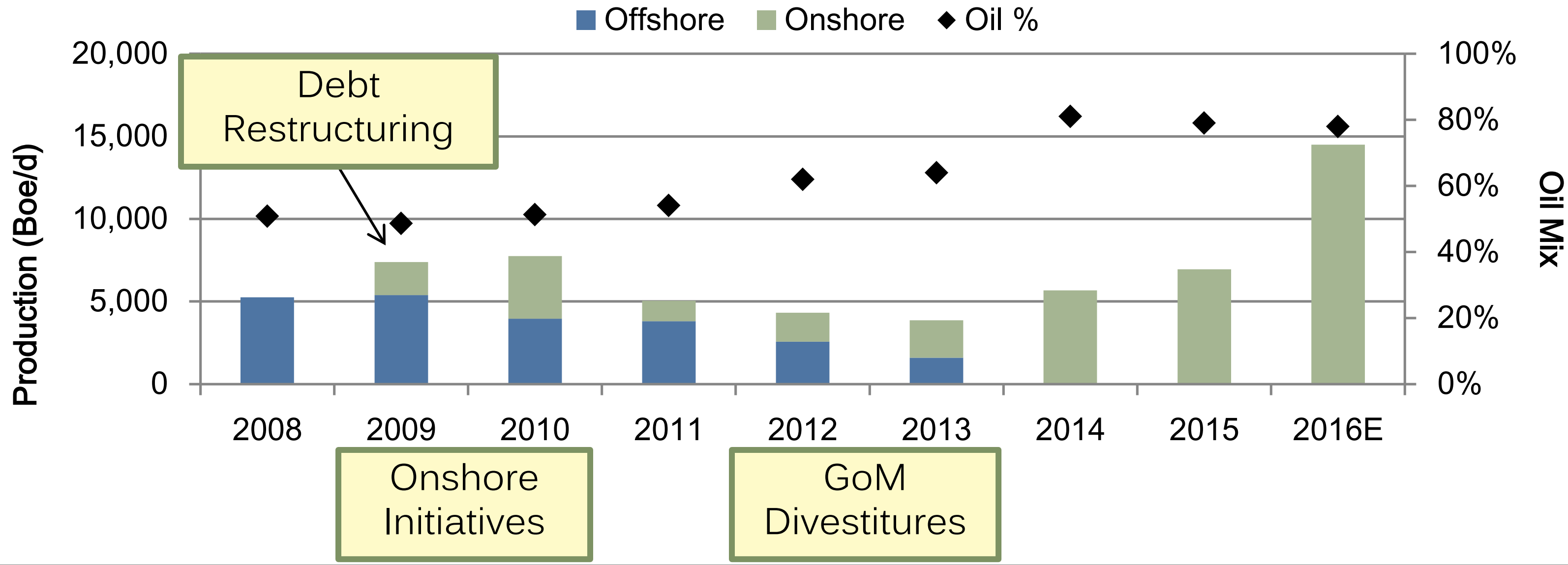
- Parameters
  - Maintain absolute cash coupon for income fund
  - Principal recovered at $6.67 per share ($1.70 average in 4Q 2009)
  - Extend maturity past bank facility

ASSET TRANSFORMATION

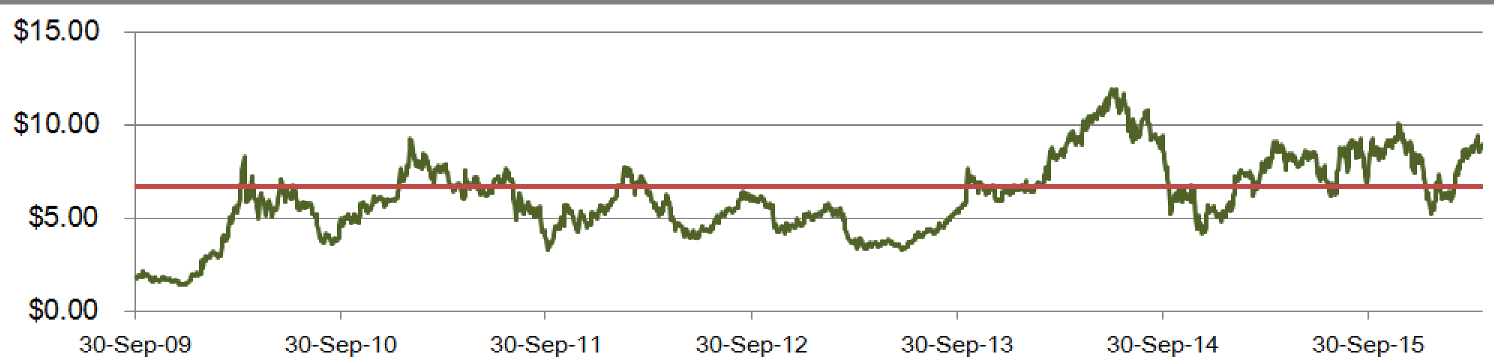
Callon Petroleum Company

Deepwater to "Boots on the Ground"

Average Daily Production for CPE by Play Type



Stock Price Performance



Note: 2016 based on midpoint of current guidance.

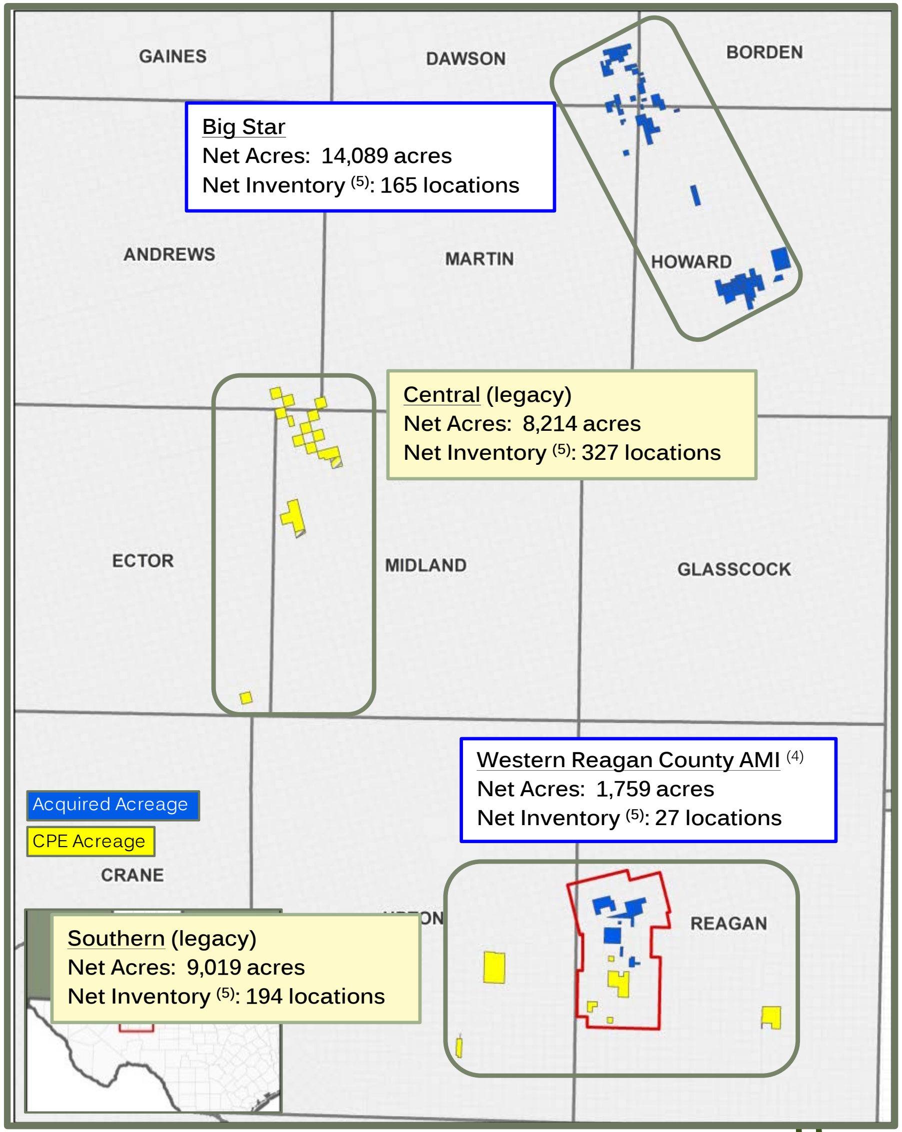
PRO FORMA CALLON

Callon Petroleum Company

- 34,000 net surface acres in Midland Basin
- Over 100,000 net "effective" acres in delineated zones
- Estimated 2016 production of 14,000 – 15,000 Boepd
- Commitment to equity content (over 30 million common shares)

"All-in" Acquisition Metrics	
Total Consideration (3)	$334 MM
Total Net Surface Acreage Acquired	15,848 acres
Net Production (1)	2,884 Boe/d
% Oil (1)	78%
Net "Delineated" Horizontal Locations (5)	192, net
$/Adjusted Acre (3)	$15,630/acre
$/"Delineated" Hz Location (3)	$1.29mm

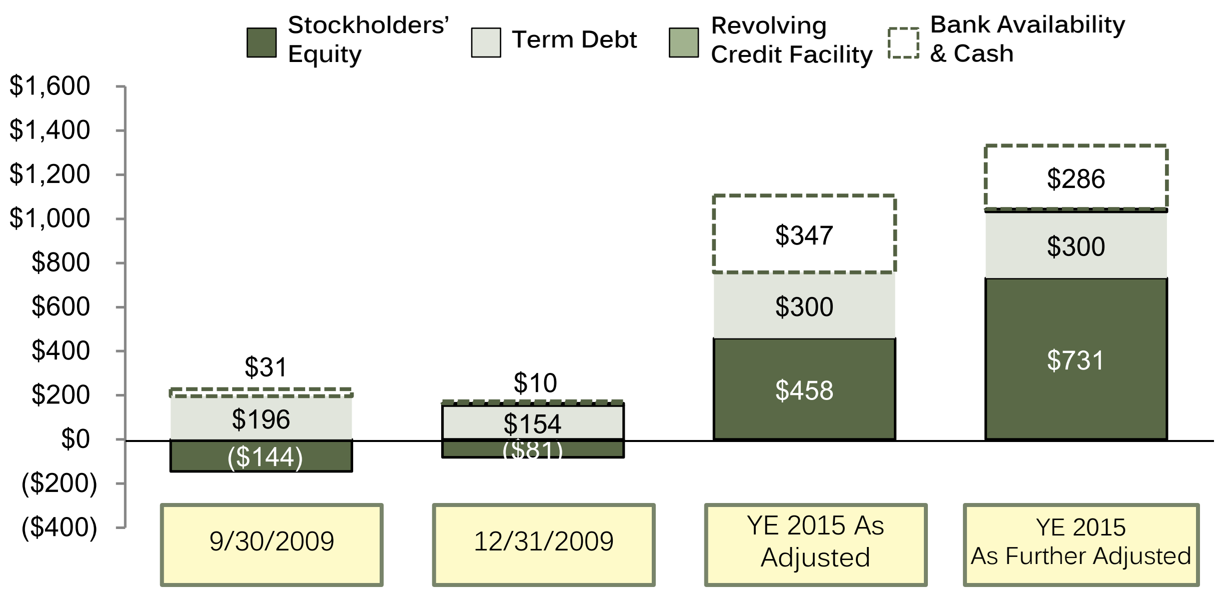
	Callon	Big Star	Reagan AMI (4)
Net Acres	17,233	14,089	1,759
Production (1)	12,400 Boe/d (79% oil)	1,931 Boe/d (82% oil)	953 Boe/d (68% oil)
"Delineated" Inventory(5) *(Gross/Net)*	648 / 521	178 / 165	83 / 27



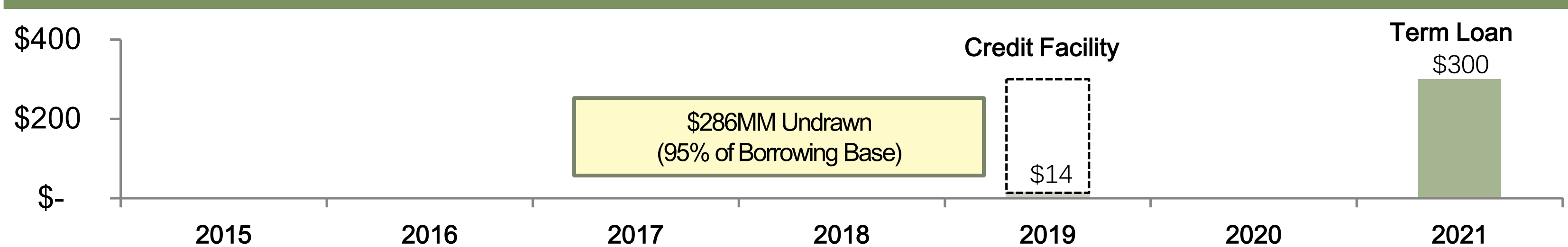
1) Production figures are estimated 1Q16 average volumes.
2) Based on CPE closing price of $8.73 per share as of April 18, 2016.
3) Assumes $30,000 per flowing Boe to value PDP. Please refer to "Metric Calculation Methodologies" on Slide 3, for further clarity.
4) Reagan AMI metrics reflect the net impact of the acquisition of 55% of incremental western Reagan County assets and 27.5% selldown of legacy Garrison Draw working interests.
5) "Delineated" inventory includes: a) currently producing zones for Callon legacy acreage; b) Lower Spraberry, Wolfcamp A and B on Big Star acreage; c) Wolfcamp A, Upper/Lower Wolfcamp B on AMI.

FINANCIAL PROFILE

Capitalization ($MM) (1)



Debt Maturity Summary ($MM) (4)



1) "As Adjusted" capitalization statistics are YE15 balances pro forma for estimated net proceeds $95 million from the March 9, 2016 equity offering and for January 2016 CaBo working interest acquisition ($9 million). :As Further Adjusted" figures are also pro forma for the proposed equity offering of $192 million, the issuance of 9.3 million shares ($81 million, assuming CPE's closing price on April 18th, 2016 of $8.73/share) to the sellers, and for April 2016 acquisitions of Big Star assets ($301 million),and Western Reagan County AMI assets ($33 million),
2) Reserves data as of December 31, 2015.
3) See reconciliation of Adjusted EBITDA, a Non-GAAP measure, included in the Appendix. Includes the impact of cash settled derivatives.
4) Debt balances are pro forma for estimated net proceeds from the proposed equity offering of $192 million and $95 million from the March 9, 2016 equity offering, the issuance of 9.3 million shares ($81 million, assuming CPE's closing price on April 18th, 2016 of $8.73/share) to the sellers, and for April 2016 acquisitions of Big Star assets ($301 million),and Western Reagan County AMI assets ($33 million), and for January 2016 CaBo working interest acquisition ($9 million).