CALLON PETROLEUM

Investor Presentation

FEBRUARY 2018

Important Disclosures

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. Words such as “estimate,” “project,” “will,” “may,” “anticipate,” “plan,” “intend,” “believe,” “expect,” “outlook,” “guidance,” “target,” “objective” or similar expressions that convey the prospective nature of events or outcomes generally indicate forward-looking statements. 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, 2016 filed with the Securities and Exchange Commission (the “SEC”). Unless legally required, Callon does not undertake any obligation to update forward looking statements as a result of new information, future events or otherwise

SUPPLEMENTAL NON-GAAP FINANCIAL MEASURES

This presentation includes non-GAAP measures, such as Adjusted EBITDA, Adjusted Income, Adjusted Income per diluted share, Adjusted G&A and other measures identified as non-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.

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 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 Appendix table details all adjustments to G&A on a GAAP basis to arrive at Adjusted G&A.

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

Callon Petroleum

4Q17 RESULTS

4Q17 production of ~26.5 Mboe/d

- Oil mix of ~79%
- Sequential oil growth of ~20%
- >50% annual production growth

FY18 HIGHLIGHTS

Operational capex of $500 to $540 mm

- D&C accounts for ~80% of spending

Production growth of 30% to 40%

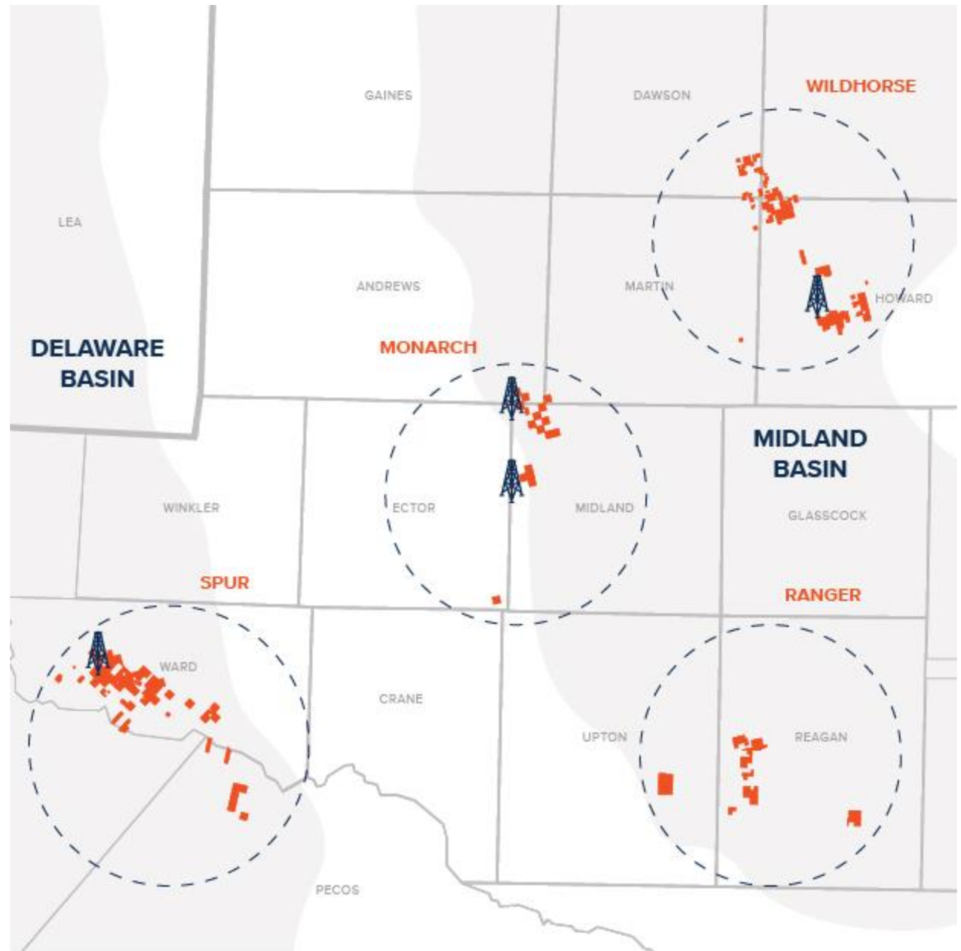
Development focused activity across all 4 core areas

- Delineation and downspacing opportunities in both basins

Cost reduction initiatives for capex and LOE with long-term benefits

- Increased pad development driving capital efficiency
- Improved water handling, including ramp in recycling
- Testing of intra-basin sand
- Infrastructure upgrades reduce long-term costs and clear path for development

CURRENT RIG ACTIVITY



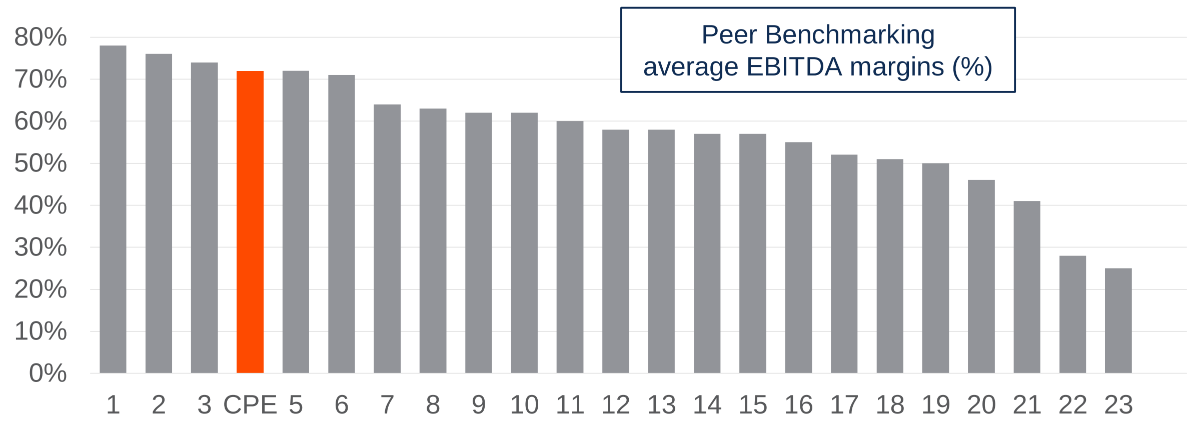
~ 60,000 NET ACRES

Focused on Corporate Level Returns

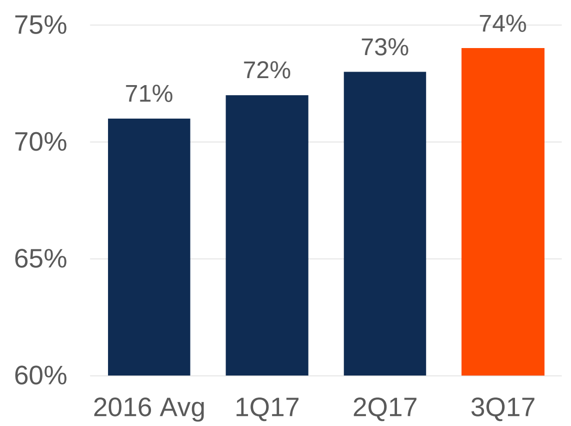
WHAT CREATES VALUE?

- Constant re-evaluation of best capital allocation decisions on a full-cycle basis
- Long-term view of priority projects to clear the development runway for capital efficient growth
- Redeployment of strong cash margins to pull forward well-level returns on a measured basis
- Visible path to near-term cash flow neutrality, balanced with operational flexibility to react to market conditions
- Consistent, manageable growth within conservative leverage and liquidity parameters

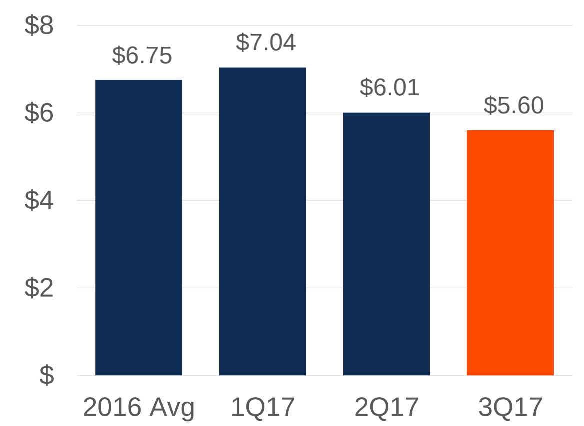
EBITDA MARGINS DRIVE RE-INVESTMENT VALUE [1]



ADJUSTED EBITDA MARGINS [2]



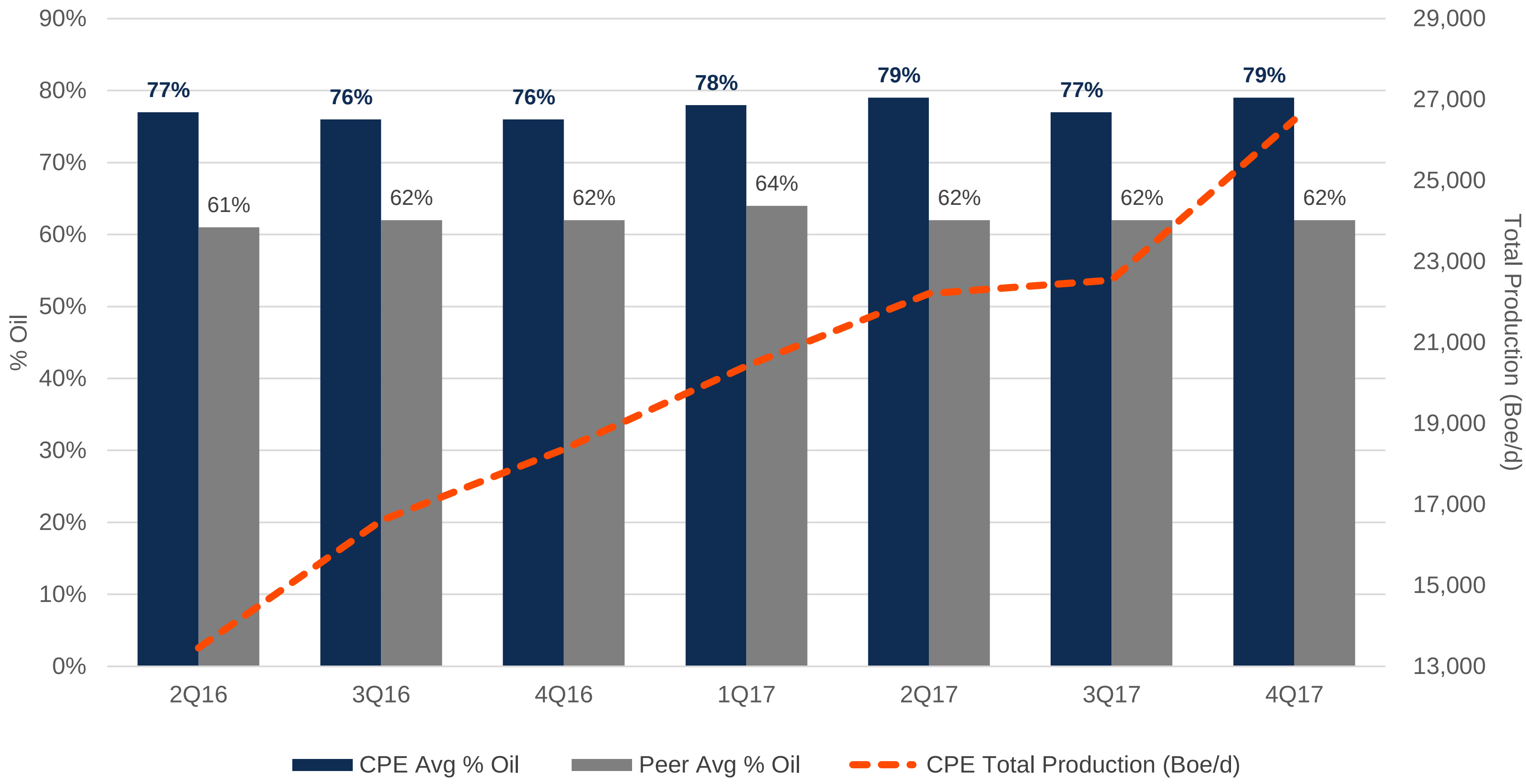
TOTAL LOE ($/BOE)



1. Average adjusted EBITDA margins 4Q16 to 2Q17. Peers include: APA, AREX, CDEV, CXO, DVN, EGN, EPE, FANG, JAG, LPI, MRO, MTDR, NFX, OAS, PE, PXD, QEP, REN, RSPP, SM, WPX, and XEC. Source: FactSet.
2. Adjusted EBITDA margins by quarter based on internal calculations. See Appendix for reconciliation.

Quarterly Production

Callon has delivered sustained, sequential production growth while consistently outpacing peers on oil content (1)



1. Sources: FactSet and company filings. 4Q17 data based on consensus estimates or actuals if available. Peers include CXO, FANG, RSPP, MTDR, EGN, LPI, and PE.

Capital Deployment Across The Entire Portfolio

2018 DEVELOPMENT PLAN

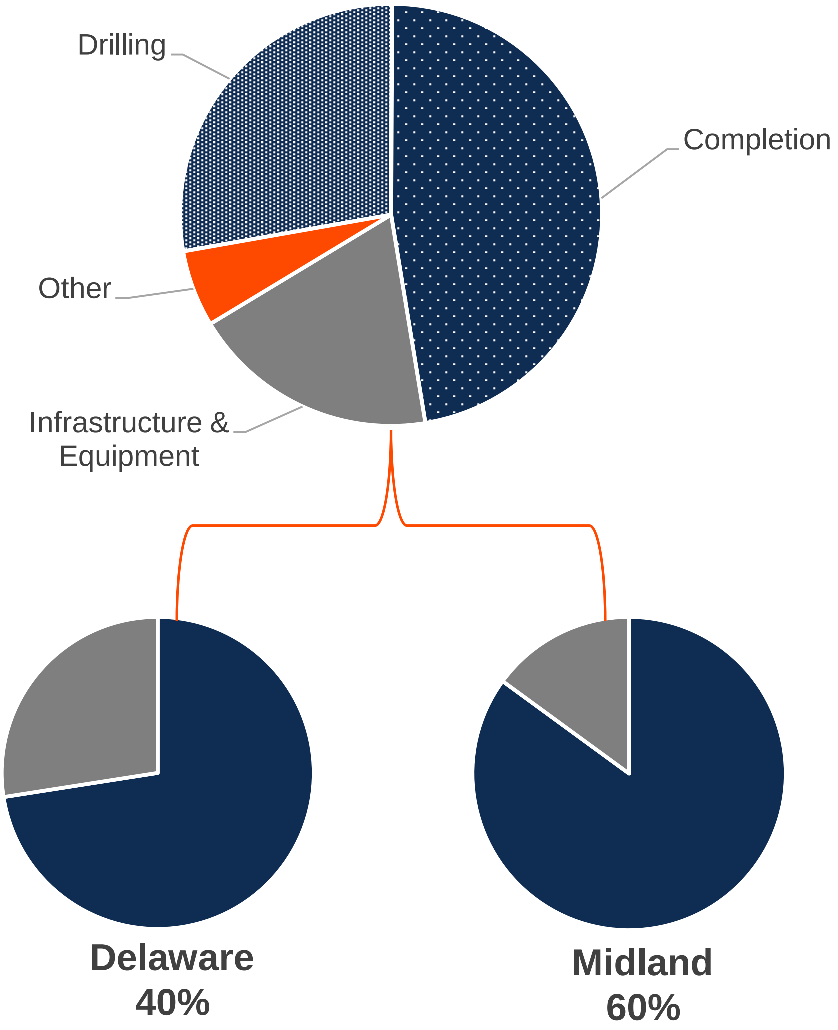
Operating plan is focused on increasing capital efficiency with a focus on development activity

- Increasing to 5 rigs with incremental Delaware activity / no change to 2 dedicated completion crews
- Drilling focused on primary targets in each area
- Progression of larger pad development concepts
- Select delineation and down-spacing opportunities offer organic inventory growth without acquisition costs

Infrastructure and equipment investment continues to lower operating expenses and pave path for development

- Ahead of the curve on water sourcing and disposal issues
- Recycling program focus on Spur after Monarch success

OPERATIONAL CAPEX BUDGET OF $500 TO $540 MILLION



2018 Infrastructure Projects

2018 DEVELOPMENT

2018 infrastructure focus primarily at Spur with increasing activity

- Tank batteries in new drilling units
- Water system connectivity

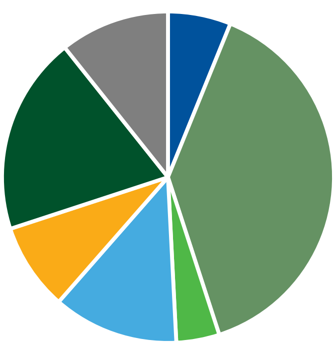
Leverage partnership structures to reduce capital investment

Past Midland Basin investment provides control of development pace

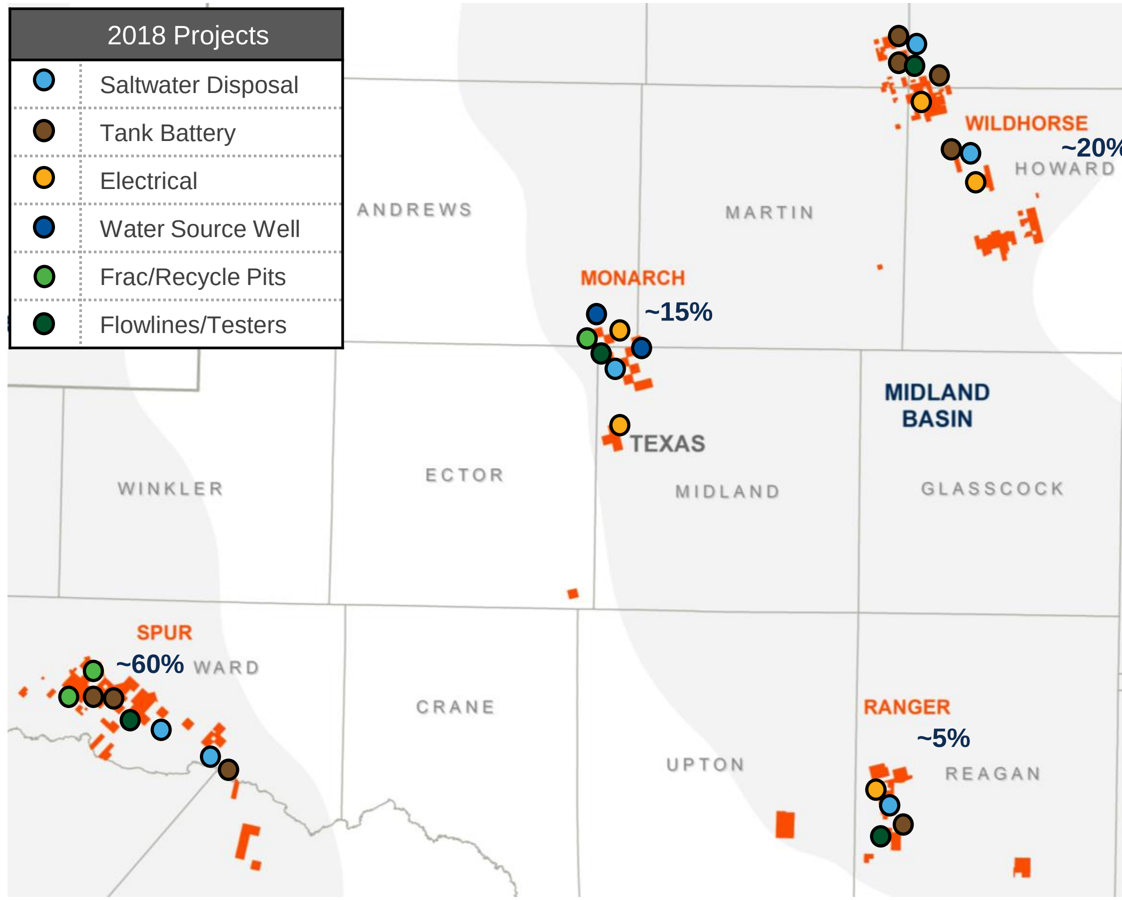
- Significant water infrastructure
- Nearly 100% of oil on pipe
- Larger tank batteries accommodate pad development

LOE benefits being realized

INFRASTRUCTURE BY CATEGORY [(1)]



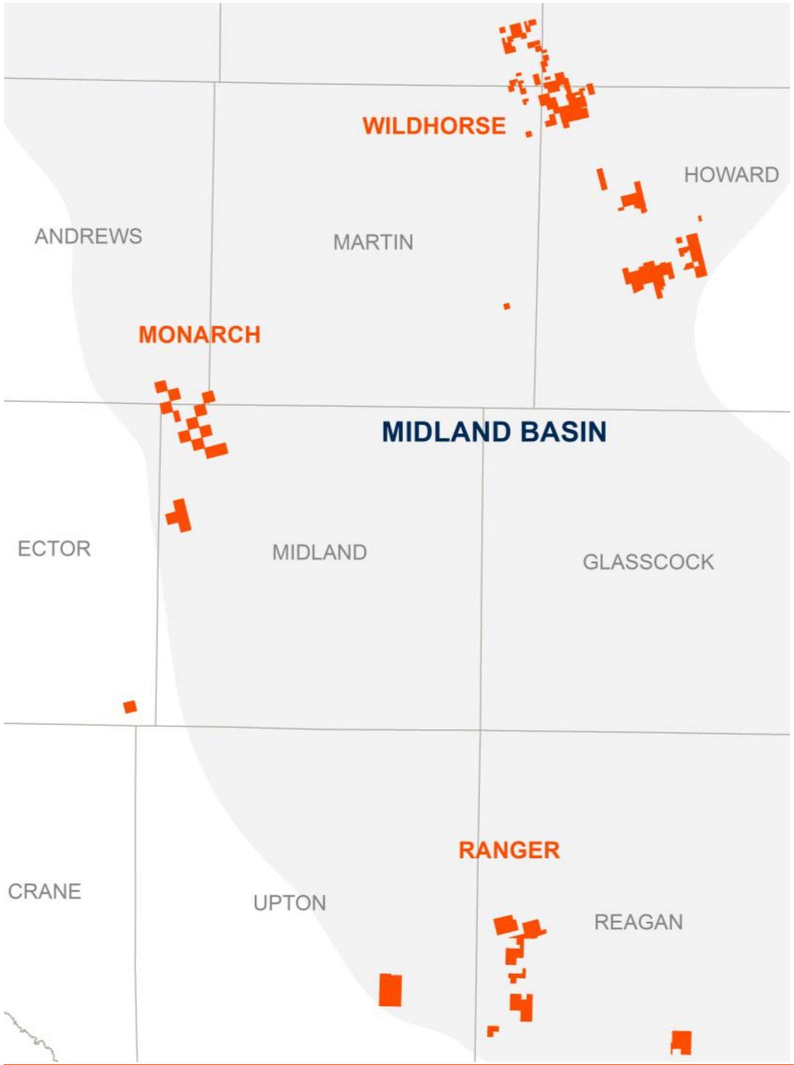
MAJOR INFRASTRUCTURE PROJECTS



1. "Other" includes Land, ESP, rod pump installation, and plug and abandonment.

Midland Basin – Delineation and Development

MAJOR 2018 INITIATIVES IN THE MIDLAND



Focused on High Return/Potential Projects

- LSBY at Monarch
- WC A at WildHorse
- WC C at Ranger

WildHorse: Expanded drilling of WC A pads

- Testing down-spacing concept at roughly 460’ spacing (2 well pad), success could lead to 25% uplift in inventory
- Intra-basin sand testing during 1H18

Monarch: Continued focus on LSBY development

- Testing pad concept (6 wells, single zone) planned for 2018, with mid-year 1st production
- Established infrastructure allows recycling ramp in 2018, targeting capacity of 30k bwpd by year end

Ranger: Optimizing LWC B / Testing the Wolfcamp C

- Recent results by offset operators confirm broader productivity within WC C
- First Callon WC C on flowback along with 2 additional LWC B tests utilizing new generation completions
- Level of additional capital allocation dependent on well results

Delaware Basin – Increasing Activity

MAJOR 2018 INITIATIVES IN THE DELAWARE

2018 activity will focus primarily on WC A drilling with tests of WC C and 2nd BS Shale planned

- Activity level increase with entry of 2nd rig in mid-Q1
- Majority of production ramp in middle to 2nd half of year

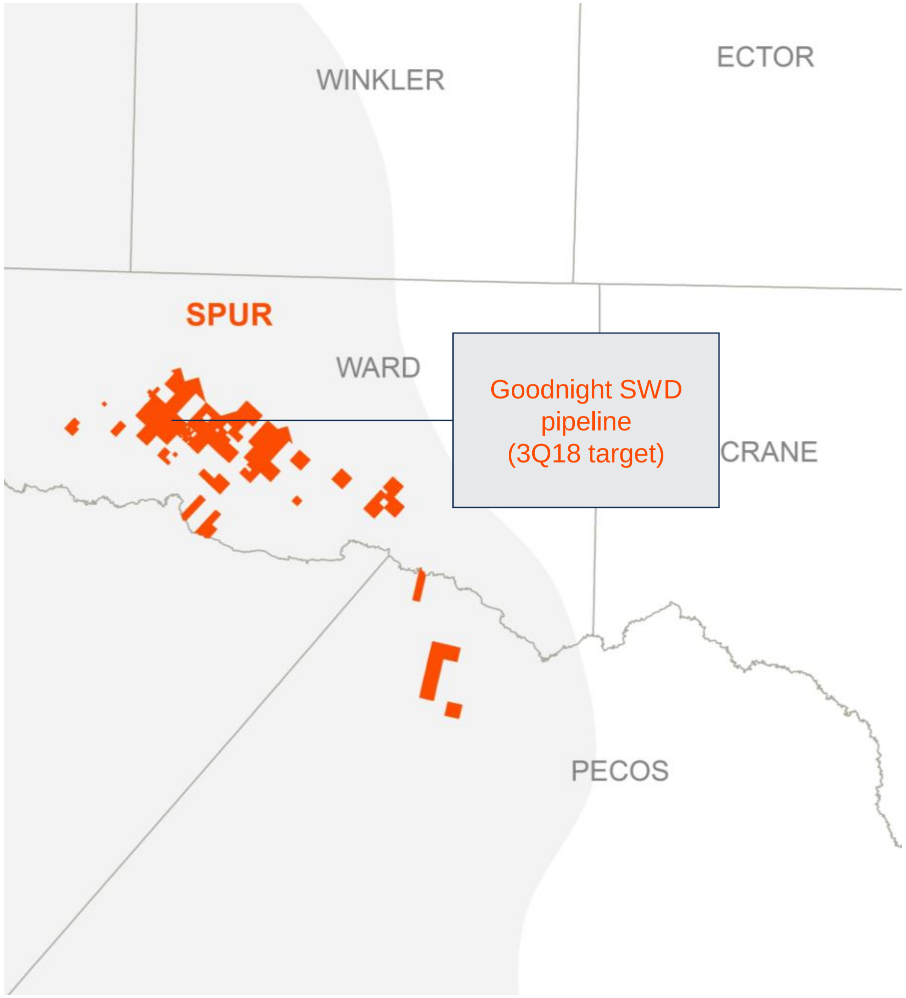
Majority of infrastructure investment to be completed by YE18

- Establish tank battery footprint
- Centralized water gathering system

Recent transactions (Brazos Midstream, Goodnight, Gravity) help to clear the path for efficient future development

- Sourcing (Gravity) and disposal (Goodnight) deals ensure resource capacity for ramp in activity
- Water recycling program set to ramp during 2nd half of 2018 creating meaningful cost savings opportunities

Offset results surrounding Spur footprint have pointed to incremental opportunities in additional zones



Financial Positioning

HIGHLIGHTS

Significant liquidity supported by a largely unfunded revolving credit facility

- Current borrowing base of $700MM with an elected commitment of $500MM
- $562MM [3] of liquidity as of September 30th

Target a long-term leverage ratio of <2.5x Net Debt / Adjusted EBITDA

Continued to strategically enter into additional 2018 hedges (benchmark and basis) [4]

- Approximately 16,000 Bbl/d
- Cash flow protection as progress to cash flow neutrality

CAPITALIZATION ($MM) [1]

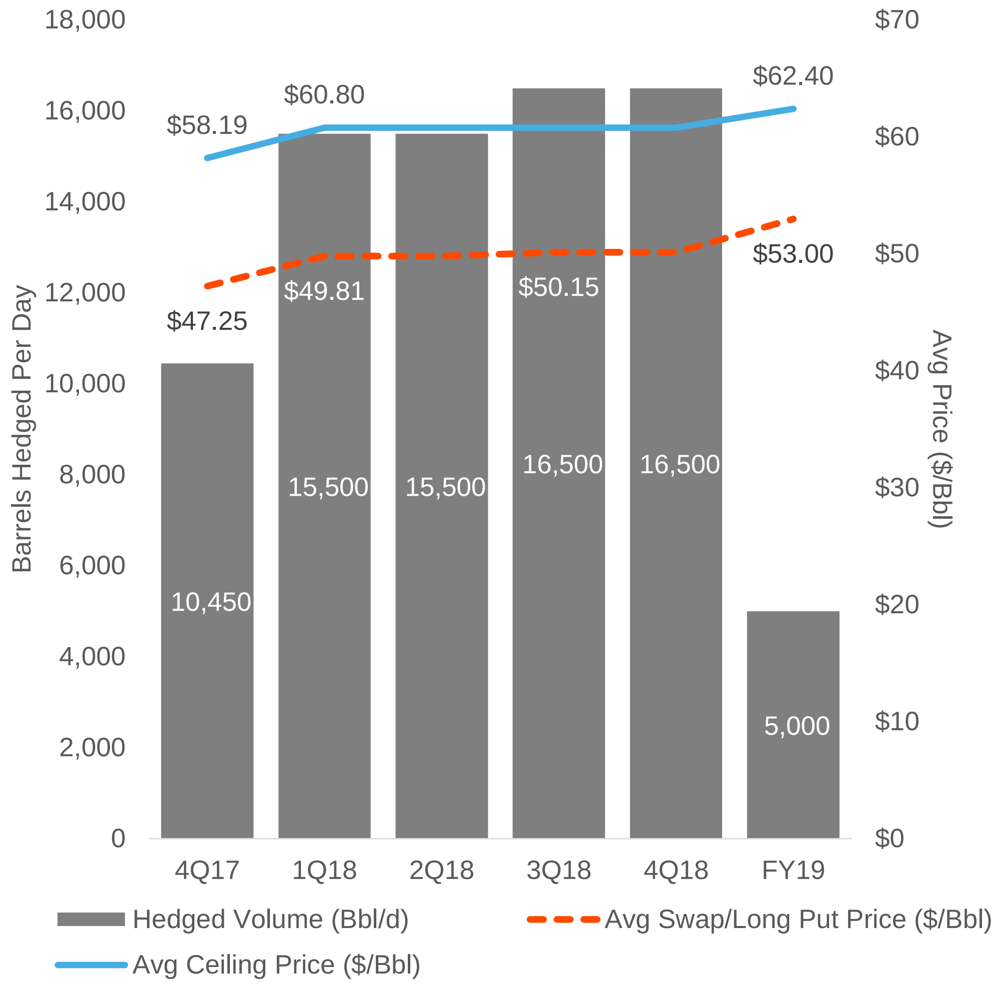
	Sept 30, 2017
Cash	$62
Credit Facility [2]	$1
Senior Notes due 2024	$600
Total Debt	$601
Stockholders' Equity	$1,833
Total Capitalization	$2,434
Total Liquidity [3]	**$562**
Net Debt to LQA Adj EBITDA [1]	**2.2x**

DEBT MATURITY SUMMARY ($MM)

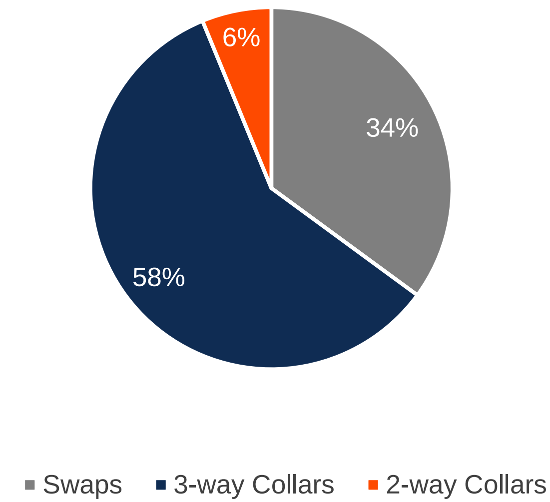
1. See the non-GAAP related disclosures in the Appendix.
2. $1.25 MM Letters of Credit outstanding.
3. Assumes elected commitment amount of $500 MM.
4. See Appendix.

Crude Oil Hedge Contracts [1]

PRICE PROTECTION OF ~$50/BBL FOR 2018



2018 STRUCTURE BREAKDOWN

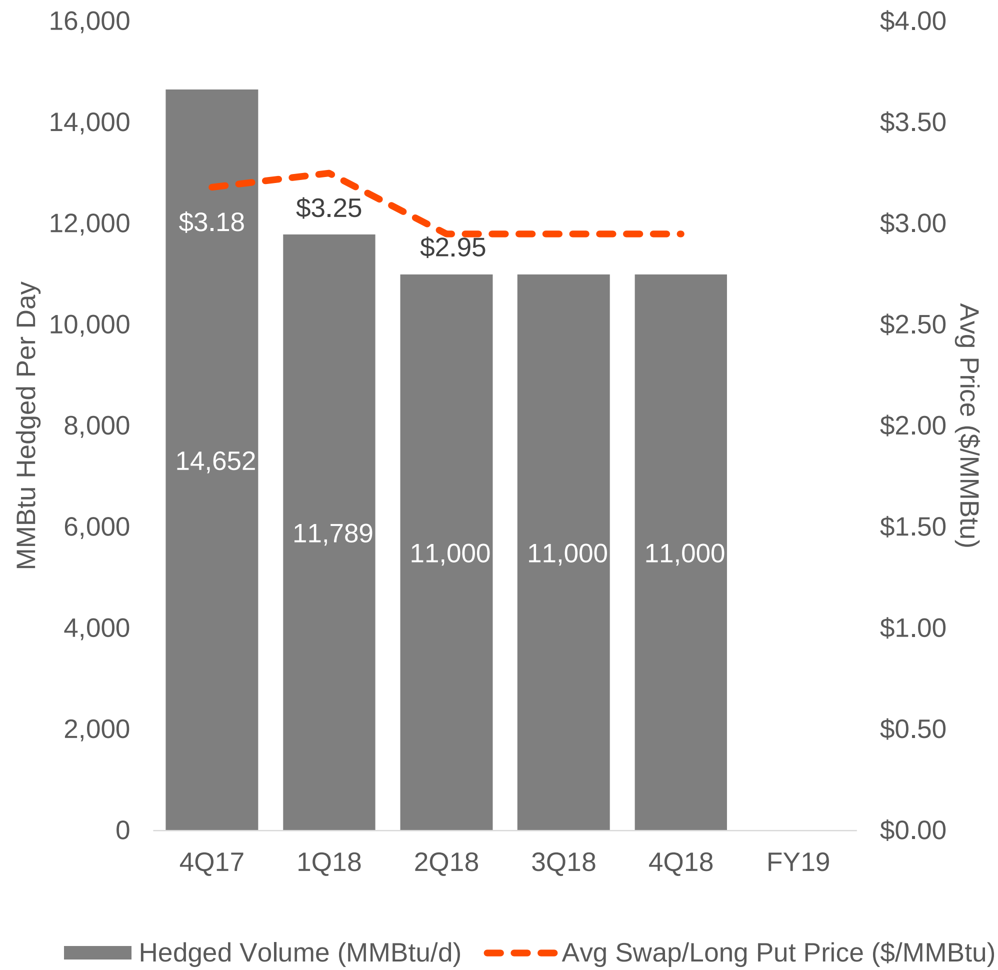


- ~60% of 2018 Consensus oil volumes hedged [2]
- ~15% of 2019 Consensus oil volumes hedged [2]
- ~65% of 2018 oil hedges are Collars, allowing for meaningful participation in recent price increases

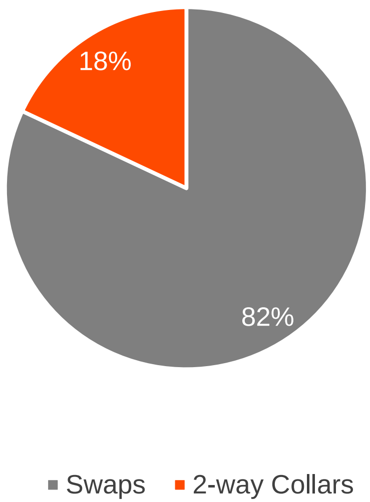
1. Hedge contracts as of February 1, 2018.
2. FactSet as of January 29, 2018.

Natural Gas Hedge Contracts [1]

PRICE PROTECTION OF ~$3/MMBTU FOR 2018



2018 STRUCTURE BREAKDOWN



- ~20% of 2018 consensus volumes hedged [2]
- Weighted average ceiling price of $3.84 for 1Q18
- Continuing to monitor Henry Hub and Waha pricing

1. Hedge contracts as of February 1, 2018.
2. FactSet as of January 29, 2018.

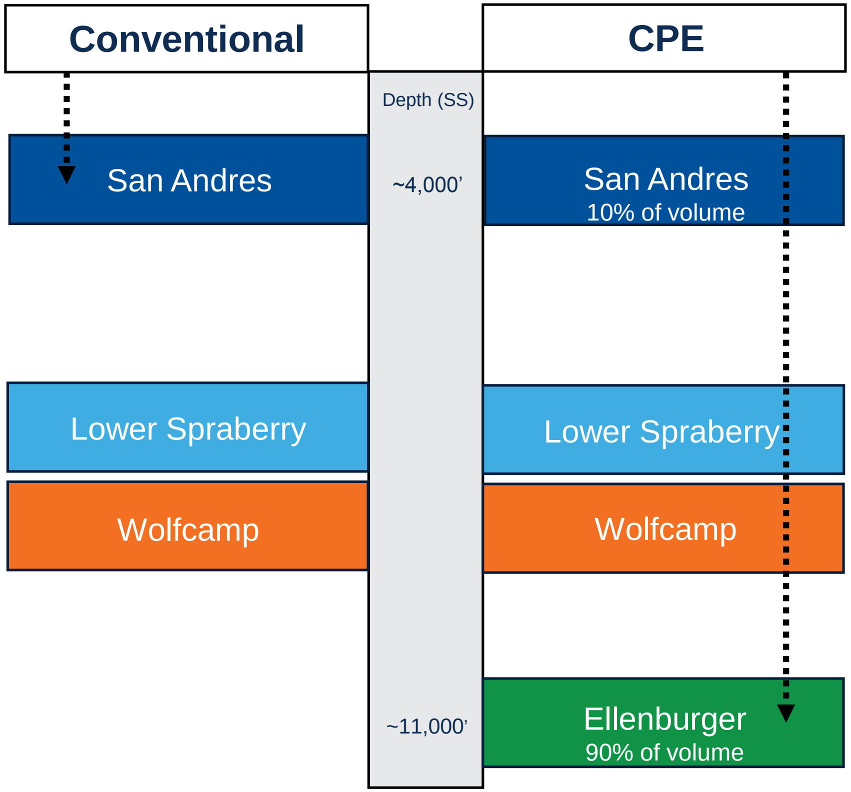
Guidance Summary

	4Q17 Guidance	FY17 Guidance
Total production (MBoepd)	24.0 – 25.5	22.0 – 23.0
Oil production	77%	78%
Income Statement Expenses (per BOE)		
LOE, including workovers	$5.75 - $6.25	$5.75 - $6.25
Gathering and treating	$0.55 - $0.65	$0.40 - $0.50
Production taxes, including ad valorem (% of unhedged revenues)	7%	7%
Adjusted G&A: cash component [1]	$2.25 - $2.50	$2.00 - $2.50
Adjusted G&A: non-cash component [2]	$0.55 - $0.65	$0.50 - $1.00
Cash interest expense [3]	$0.00	$0.00
Capital expenditures ($MM, accrual basis)		
Total operational/Net of monetization [4]	$108 - $112/ $88 - $92	$350
Capitalized expenses (cash component)	$13 - $17	$40 - $45

1. Excludes stock-based compensation and corporate depreciation and amortization. See the Non-GAAP related disclosures in the Appendix.
2. Excludes certain non-recurring expenses and non-cash valuation adjustments. See the non-GAAP related disclosures in the Appendix.
3. All cash interest expense anticipated to be capitalized.
4. Includes drilling, completions, facilities, seismic, land and other items. Excludes capitalized expenses.

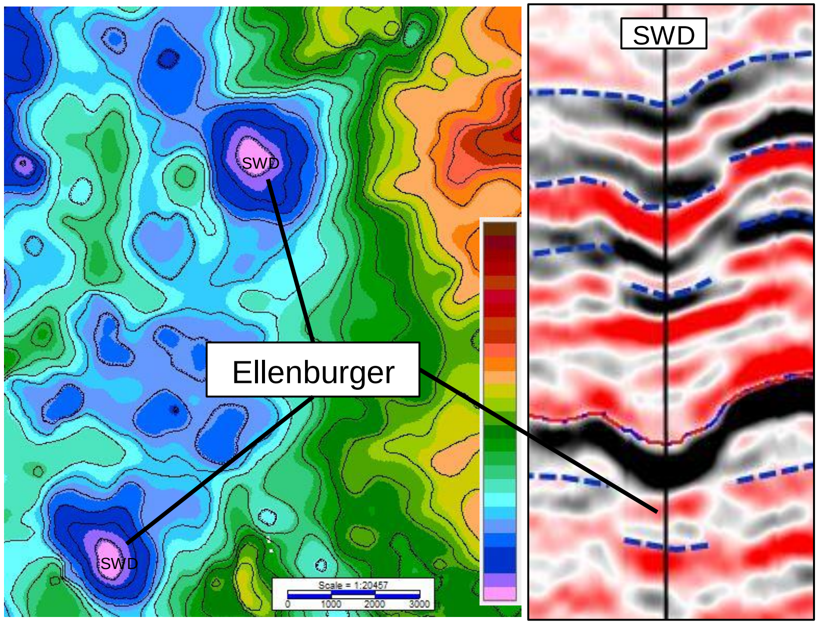
Continued Focus on Responsible Water Management

DISPOSAL DEPTH COMPARISON [1]



Conventional San Andres SWD		CPE Ellenburger SWD
~$2.4 MM	Absolute Cost	~$3.5 MM
~15 MBwpd	Avg. Capacity	~30 MBwpd
~$160/Bwpd	Per Unit Cost	~$117/Bwpd

IDENTIFYING SWD LOCATIONS WITH SEISMIC [2]



- Utilizing seismic technology to improve deep SWD well location success
- Investing in long-term water disposal solution that doesn’t over pressure development formations
- Long-term planning: partnering with 3rd party SWD providers moves entire industry to a better water management solution
- Recycle/reuse reduces disposal requirements

1. Zone thickness not to scale.
2. Seismic cross-section source: CGG.

Salt Water Disposal – Leading the Way in the Delaware

KEY PARTNERSHIP DETAILS

New agreement with 3rd party operator (Goodnight) to dispose up to 80% of produced volumes at Spur

Disposal volumes piped to CBP, 15+ miles away from current Spur footprint

In-service date of 3Q18

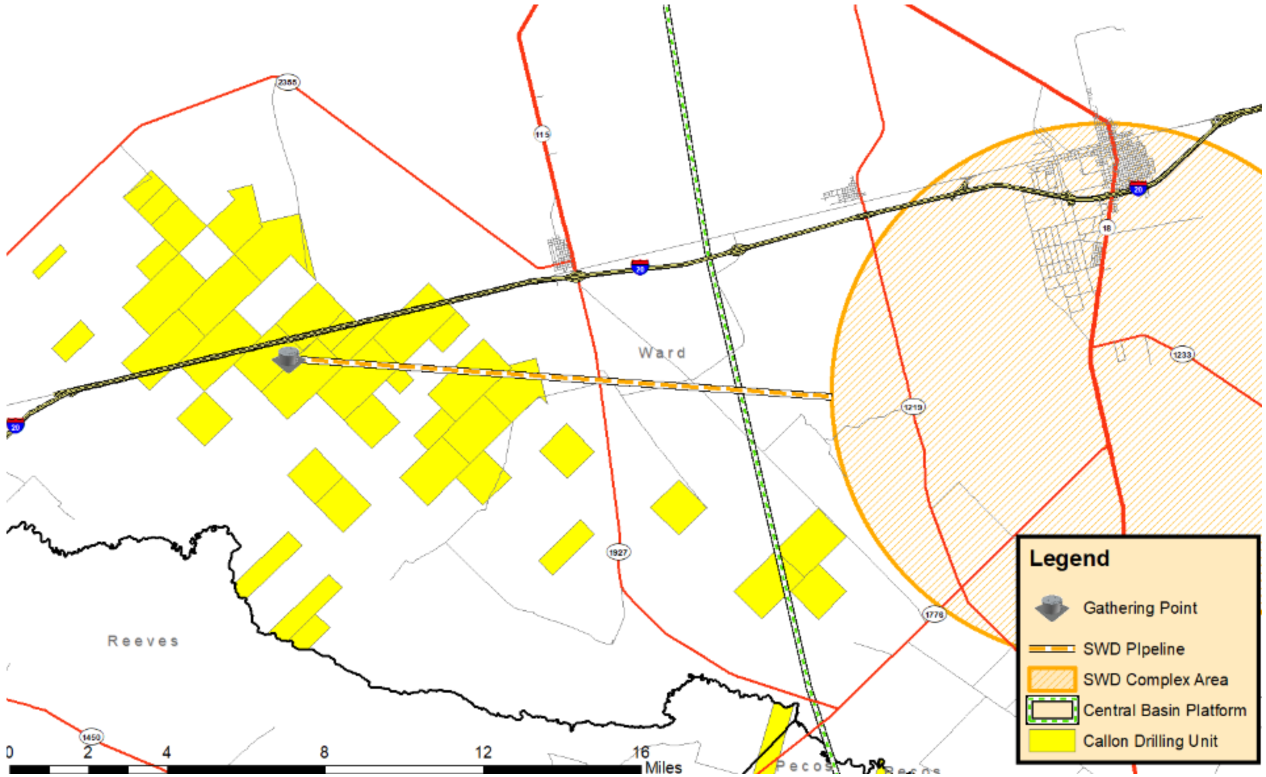
Positive NPV impact versus Callon-standalone SWD infrastructure

- Substantial capital reduction for Callon beginning in 2H18
- Disposal rates roughly inline with royalty-burdened, operated SWD wells

Optionality to divert disposal volumes for recycle and re-use in fracs with no penalty

Accelerating remaining planned operated SWD wells to 2H17 to bridge activity ramp for 2nd rig until Goodnight system online

SOUTH CENTRAL BASIN DISPOSAL SYSTEM (“SCBDS”)



Crude Oil Hedge Contracts (1)

Crude Oil (Bbl, $/Bbl)	4Q17	1Q18	2Q18	3Q18	4Q18	FY18	FY19
Swaps Strike Price	184,000 $45.74	450,000 $51.42	455,000 $51.42	552,000 $52.07	552,000 $52.07	2,009,000 $51.78	-
Costless Collars Ceiling Floor	340,400 $58.19 $47.50	90,000 $60.25 $50.00	91,000 $60.25 $50.00	92,000 $60.25 $50.00	92,000 $60.25 $50.00	365,000 $60.25 $50.00	-
Three-way Collars Ceiling Floor Short Put	-	855,000 $60.86 $48.95 $39.21	864,500 $60.86 $48.95 $39.21	874,000 $60.86 $48.95 $39.21	874,000 $60.86 $48.95 $39.21	3,467,500 $60.86 $48.95 $39.21	1,825,000 $62.40 $53.00 $43.00
Swaps combined with Short Puts Swap Price Short Put	184,000 $44.50 $30.00	-	-	-	-	-	-
Deferred Premium Put Spreads Premium Long Put Short Put	253,000 $2.45 $50.00 $40.00	-	-	-	-	-	-
Midland-Cushing Basis Differential Swap Price	552,000 ($0.52)	1,395,000 ($0.80)	1,410,500 ($0.80)	1,242,000 ($0.93)	1,242,000 ($0.93)	5,289,500 ($0.86)	-
Total NYMEX WTI Hedge Volume Weighted Average Floor Price	961,400 $47.25	1,395,000 $49.81	1,410,500 $49.81	1,518,000 $50.15	1,518,000 $50.15	5,841,500 $49.99	1,825,000 $53.00

1. Hedge contracts as of February 1, 2018.

Natural Gas Hedge Contracts (1)

Natural Gas (MMBtu, $/MMBtu)	4Q17	1Q18	2Q18	3Q18	4Q18	FY18	FY19
Swaps Strike Price	124,000 $3.39	341,000 $2.95	1,001,000 $2.95	1,012,000 $2.95	1,012,000 $2.95	3,366,000 $2.95	-
Costless Collars Ceiling Floor	856,000 $3.23	720,000 $3.40	-	-	-	720,000 $3.40	-
Three-way Collars Ceiling Floor Short Put	368,000 $3.71 $3.00 $2.50	-	-	-	-	-	-
Waha Basis Differential Swap Price	-	-	-	-	-	-	-
Total NYMEX Henry Hub Hedge Volume Weighted Average Floor Price	1,348,00 0 $3.18	1,061,000 $3.25	1,001,000 $2.95	1,012,000 $2.95	1,012,000 $2.95	4,086,000 $3.03	-

1. Hedge contracts as of February 1, 2018.

Quarterly Cash Flow Statement

	3Q16	4Q16	1Q17	2Q17	3Q17
Cash flows from operating activities:					
Net income (loss)	$ 21,139	$ (1,746)	$ 47,129	$ 33,390	$ 17,081
Adjustments to reconcile net income (loss) to cash provided by operating activities:					
Depreciation, depletion and amortization	17,733	22,512	24,932	26,765	29,132
Accretion expense	187	196	184	208	131
Amortization of non-cash debt related items	810	744	665	589	441
Deferred income tax (benefit) expense	(62)	48	466	323	237
Net (gain) loss on derivatives, net of settlements	(1,044)	11,030	(17,794)	(10,761)	12,947
Loss on sale of other property and equipment	—	—	—	62	—
Non-cash gain for early debt extinguishment	—	9,883	—	—	—
Non-cash expense related to equity share-based awards	778	811	930	4,865	1,219
Change in the fair value of liability share-based awards	3,371	908	(291)	1,982	732
Payments to settle asset retirement obligations	(576)	(576)	(765)	(816)	(250)
Changes in current assets and liabilities:					
Accounts receivable	(11,608)	(13,611)	(4,066)	(3,744)	(4,338)
Other current assets	54	(535)	576	(874)	(38)
Current liabilities	15,702	5,473	9,903	(4,223)	1,854
Change in other long-term liabilities	—	10	—	120	1
Change in long-term prepaid	—	—	—	—	(4,650)
Change in other assets, net	(1,221)	831	(523)	(247)	(606)
Payments to settle vested liability share-based awards	—	—	(8,662)	(4,511)	—
Net cash provided by operating activities	45,263	35,978	52,684	43,128	53,893
Cash flows from investing activities:					
Capital expenditures	(47,418)	(67,334)	(66,154)	(79,936)	(121,128)
Acquisitions	(18,033)	(352,622)	(648,485)	(58,004)	(8,015)
Acquisition deposit	(32,700)	(13,438)	46,138	—	—
Proceeds from sales of mineral interests and equipment	(708)	1,639	—	—	—
Net cash used in investing activities	(98,859)	(431,755)	(668,501)	(137,940)	(129,143)
Cash flows from financing activities:					
Borrowings on senior secured revolving credit facility	74,000	—	—	—	—
Payments on senior secured revolving credit facility	(114,000)	—	—	—	—
Payments on term loan	—	(300,000)	—	—	—
Issuance of 6.125% senior unsecured notes due 2024	—	400,000	—	200,000	—
Premium on the issuance of 6.125% senior unsecured notes due 2024	—	—	—	8,250	—
Issuance of common stock	421,908	634,862	—	—	—
Payment of preferred stock dividends	(1,824)	(1,824)	(1,824)	(1,823)	(1,824)
Payment of deferred financing costs	(640)	(10,153)	—	(6,765)	(401)
Tax withholdings related to restricted stock units	(170)	—	(79)	(974)	(65)
Net cash provided by financing activities	379,274	722,885	(1,903)	198,688	(2,290)
Net change in cash and cash equivalents	325,678	327,108	(617,720)	103,876	(77,540)
Balance, beginning of period	207	325,885	652,993	35,273	139,149
Balance, end of period	$ 325,885	$ 652,993	$ 35,273	$ 139,149	$ 61,609

Non-GAAP Reconciliation [1]

	3Q16	4Q16	1Q17	2Q17	3Q17
Adjusted Income Reconciliation					
Income (loss) available to common stockholders	$ 19,315	$ (3,570)	$ 45,305	$ 31,566	$ 15,257
Adjustments:					
Change in valuation allowance	(7,907)	559	(13,119)	(11,194)	(6,064)
Net (gain) loss on derivatives, net of settlements	(679)	7,170	(11,566)	(6,995)	8,416
Change in the fair value of share-based awards	2,192	590	(189)	(315)	475
Settled share-based awards	—	—	—	4,128	—
Loss on early redemption of debt	—	8,374	—	—	—
Adjusted Income	$ 12,921	$ 13,123	$ 20,431	$ 17,190	$ 18,084
Adjusted Income per fully diluted common share	$ 0.09	$ 0.08	$ 0.10	$ 0.09	$ 0.09
Adjusted EBITDA Reconciliation					
Net income (loss)	$ 21,139	$ (1,746)	$ 47,129	$ 33,390	$ 17,081
Adjustments:					
Net (gain) loss on derivatives, net of settlements	(1,044)	11,030	(17,794)	(10,761)	12,947
Non-cash stock-based compensation expense	4,150	1,718	639	499	1,952
Settled share-based awards	—	—	—	6,351	—
Loss on early redemption of debt	—	12,883	—	—	—
Acquisition expense	456	1,263	450	2,373	205
Income tax (benefit) expense	(62)	48	466	322	237
Interest expense	831	1,369	665	589	444
Depreciation, depletion and amortization	17,733	22,512	24,932	26,765	29,132
Accretion expense	187	196	184	208	131
Adjusted EBITDA	$ 43,390	$ 49,273	$ 56,671	$ 59,736	$ 62,129
Adjusted EBITDA inclusive of Pro forma Adjustments [2]	$ 52,876	$ 54,030	$ 59,329	$ 59,736	$ 62,129

1. See "Important Disclosure" slides for disclosures related to Supplemental Non-GAAP Financial Measures.
2. Adjusted EBITDA inclusive of Pro forma Adjustments is used primarily for the purpose of calculating compliance with covenants, such as Debt/EBITDA calculations, and includes the impact of acquisitions closed during prior periods as if they were completed at the beginning of the reporting period.

Non-GAAP Reconciliation (1)

	3Q16	4Q16	1Q17	2Q17	3Q17
Adjusted G&A Reconciliation					
Total G&A expense	$ 7,891	$ 6,562	$ 5,206	$ 6,430	$ 7,259
Adjustments:					
Less: Early retirement expenses	—	—	—	(444)	—
Less: Early retirement expenses related to share-based compensation	—	—	—	(81)	—
Less: Change in the fair value of liability share-based awards (non-cash)	(3,372)	(857)	(307)	567	(731)
Adjusted G&A – total	4,519	5,705	5,513	6,472	6,528
Less: Restricted stock share-based compensation (non-cash)	(768)	(801)	(921)	(966)	(1,198)
Less: Corporate depreciation & amortization (non-cash)	(114)	(104)	(121)	(114)	(146)
Adjusted G&A – cash component	$ 3,637	$ 4,800	$ 4,471	$ 5,392	$ 5,184
Adjusted Total Revenue Reconciliation					
Oil revenue	$ 49,095	$ 60,559	$ 72,008	$ 72,885	$ 73,349
Natural gas revenue	6,832	8,522	9,355	9,398	11,265
Total revenue	55,927	69,081	81,363	82,283	84,614
Impact of cash-settled derivatives	4,091	2,079	(2,491)	(267)	(1,214)
Adjusted Total Revenue	$ 60,018	$ 71,160	$ 78,872	$ 82,016	$ 83,400
Total Production (Mboe)	1,527	1,689	1,838	2,021	2,074
Adjusted Total Revenue per Boe	$ 39.30	$ 42.13	$ 42.91	$ 40.58	$ 40.21
Discretionary Cash Flow Reconciliation					
Net cash provided by operating activities	$ 45,263	$ 35,978	$ 52,684	$ 43,128	$ 53,893
Changes in working capital	(2,927)	7,832	(5,890)	8,968	7,777
Payments to settle asset retirement obligations	576	576	765	816	250
Payments to settle vested liability share-based awards	—	—	8,662	4,511	—
Discretionary cash flow	$ 42,912	$ 44,386	$ 56,221	$ 57,423	$ 61,920
Discretionary cash flow per diluted share	$ 0.31	$ 0.27	$ 0.28	$ 0.28	$ 0.31

1. See “Important Disclosure” slides for disclosures related to Supplemental Non-GAAP Financial Measures.