CALLON PETROLEUM

INVESTOR PRESENTATION

MAY 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,” “forecast” 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, 2017 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

1Q18 RESULTS

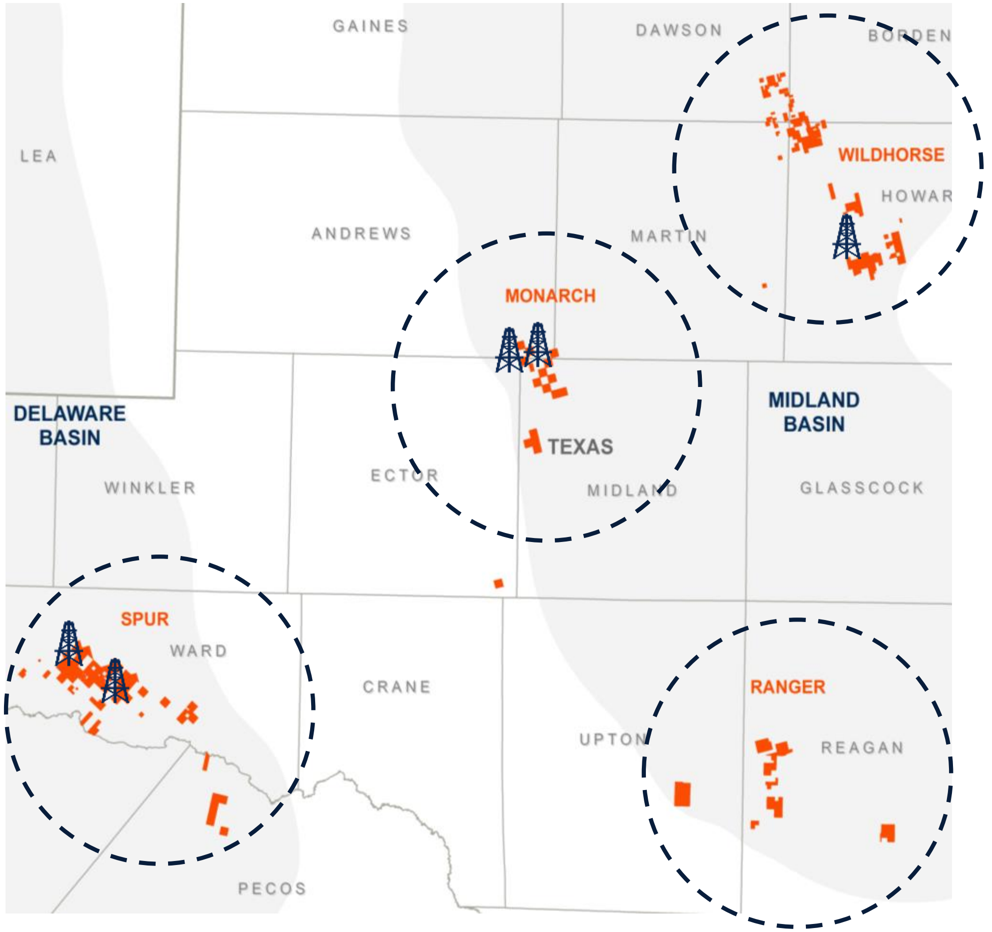
- 1Q18 production of 26.6 Mboe/d
  - Oil mix of 77%
  - YOY growth of 30%
- Operating margin of $44.31 per Boe (~83%)
- LOE per Boe $5.45 [1]
- Adjusted EBITDAX of $91.7 MM

OPERATIONAL HIGHLIGHTS

- Successful early time results from Wildhorse WC A down-spacing test
- Strong initial production from first Spur two well pad (UWC A & LWC A)
- 25%+ improvement in drilling efficiency
- Drilling of 1st "mega-pad" at Monarch underway

Key Statistics [2]	
Shares Outstanding	202 MM
Market Capitalization	$2.8 B
Net Debt	$0.7 B
Enterprise Value	$3.5 B
Net Debt/1Q18 Annualized EBITDA	1.8x

CURRENT RIG ACTIVITY

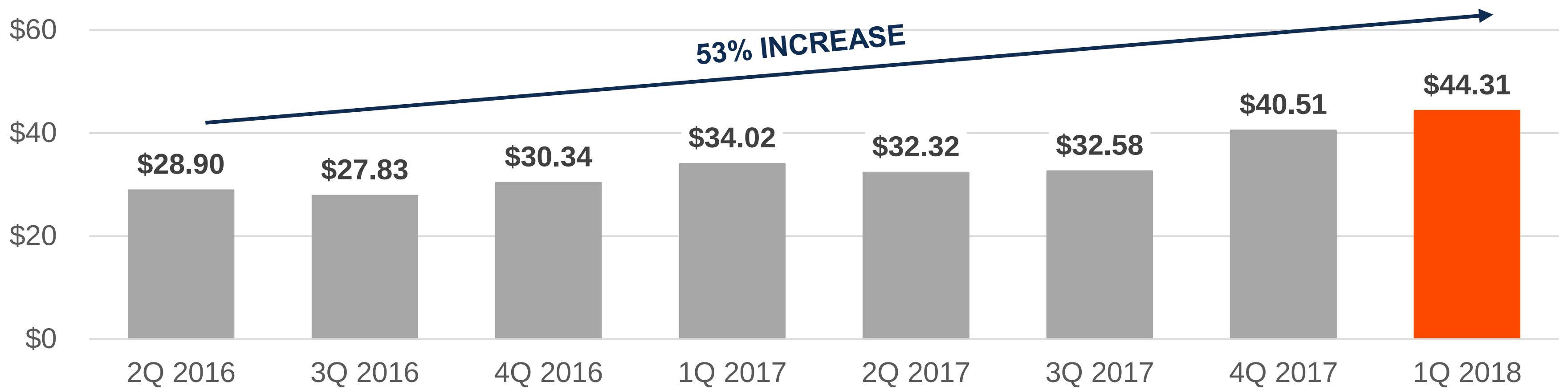


~ 60,000 NET ACRES
1,400 "DELINEATED & OPERATED" INVENTORY LOCATIONS

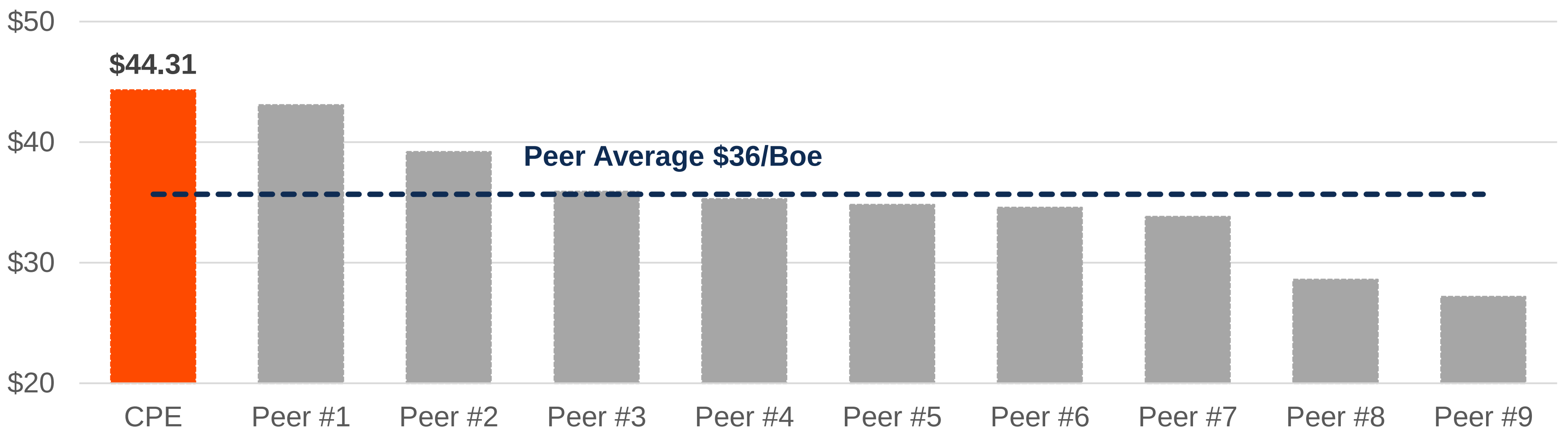
1. LOE figures are calculated on a two-stream basis.
2. Statistical measures for Market Capitalization and Enterprise Value are as of market close on April 30, 2018. Shares outstanding and net debt are represented as of March 31, 2018.

Sustained, Leading Operating Margins

OPERATING MARGIN GROWTH ($/Boe)



1Q 2018 OPERATING MARGIN PEER COMPARISON ($/Boe)



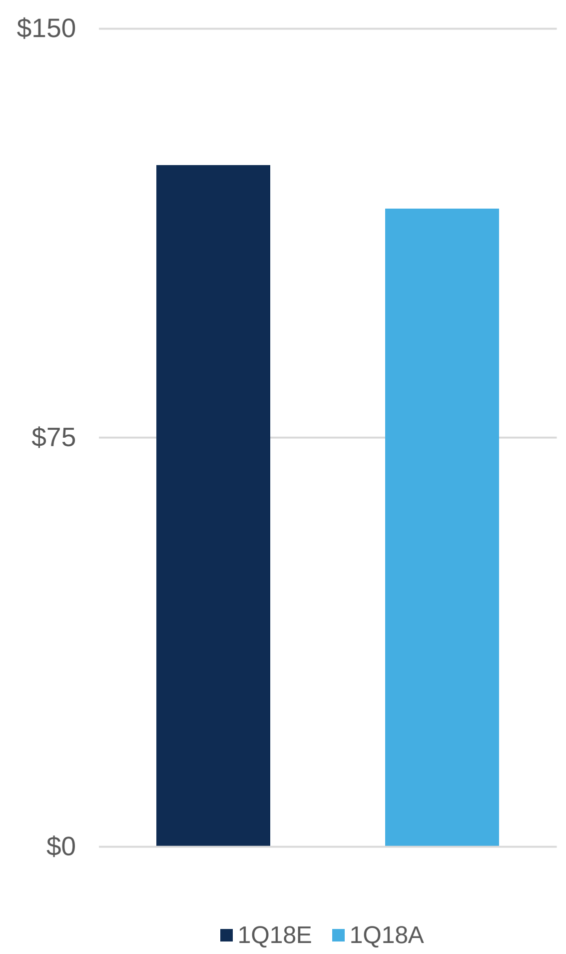
Note: Peer set includes CDEV, CXO, EGN, FANG, LPI, MTDR, PE, PXD, REN.

Operational Performance and Outlook

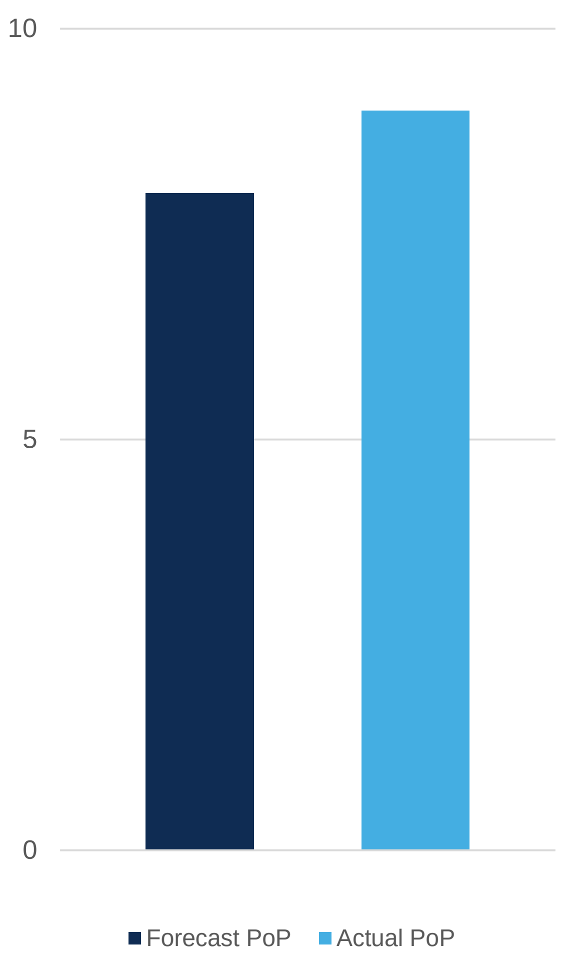
DEVELOPMENT ON TARGET

- Nine net wells placed on production during Q1
- Wells were primarily lower working interest Reagan County WC wells and shorter laterals at Monarch
- Two WC A wells at Wildhorse were PoP during the last week of the quarter
- Short pause in completions, as previously discussed, to allow for operational DUC backlog
- Both Sclumberger crews are active as of early April
- Pace of wells placed on production for 2Q18 to 4Q18 now expected to be more balanced
- Production expected to ramp fairly evenly with estimated growth of ~10% per quarter through remainder of year

1Q18 CAPITAL SPENDING ($MM)



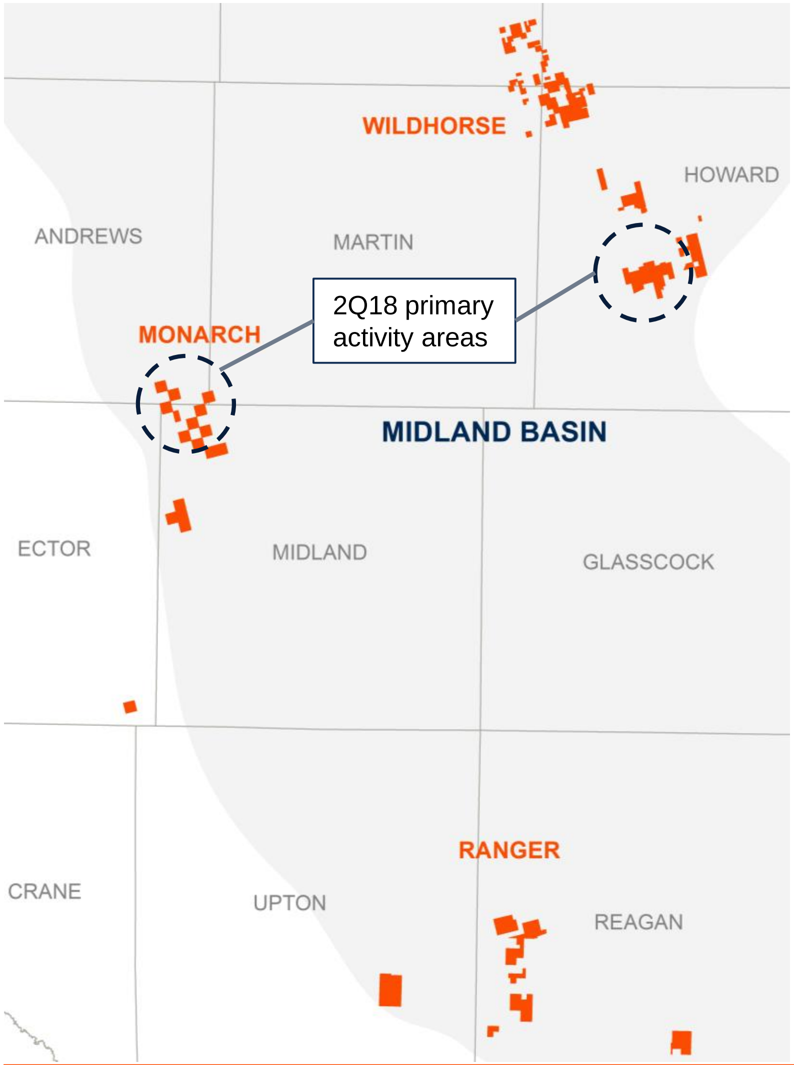
1Q18 NET WELLS PoP [1]



1. Placed on production during the quarter

Midland Basin – Operational Updates

2nd QUARTER MIDLAND ACTIVITY SHIFT



Monarch recycling program yielding benefits

- Recent wells have been able to source over 40% of frac volumes from recycling
- Model for expanded efforts across footprint

1st "mega-pad" underway at Monarch

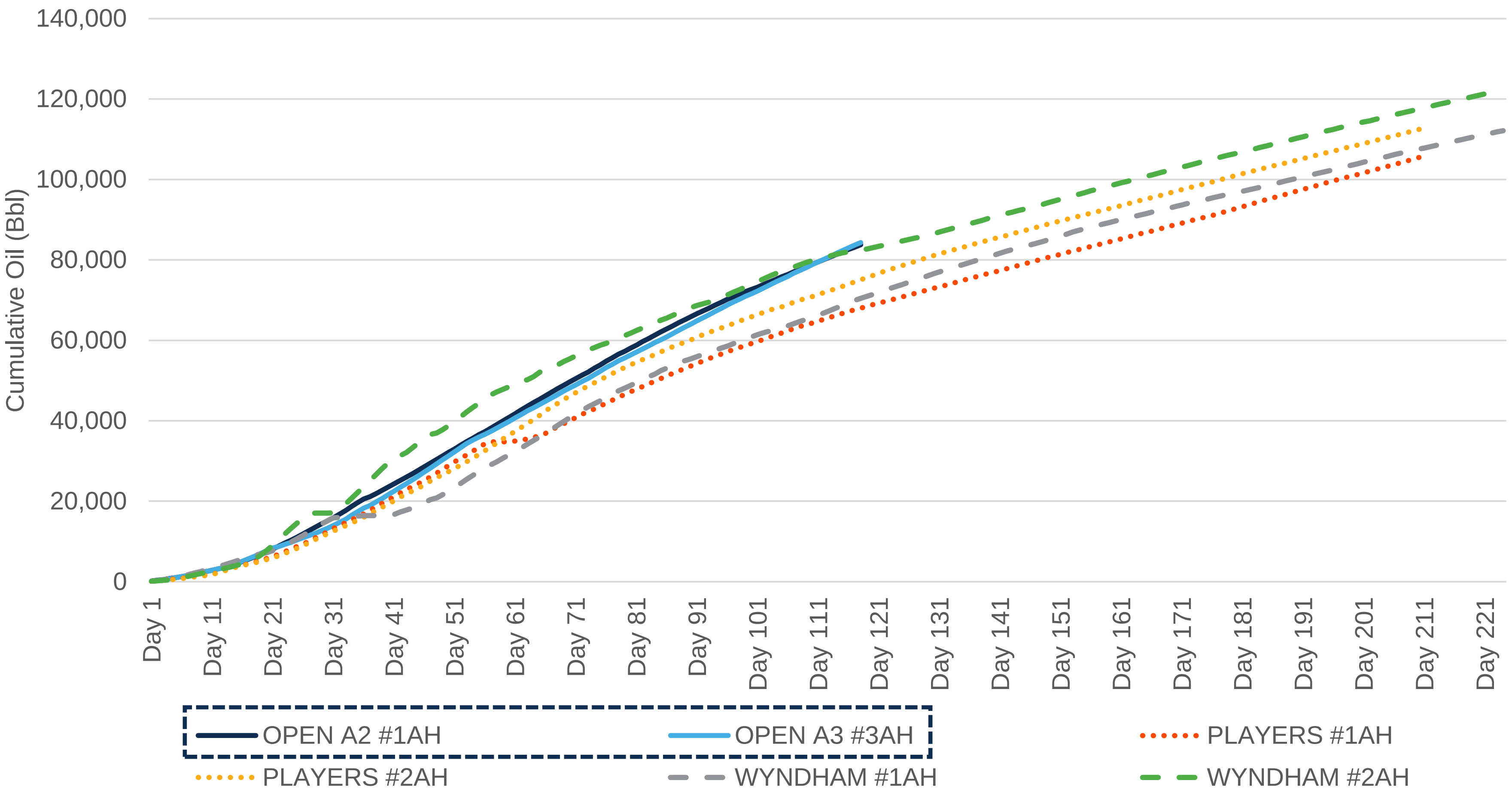
- 5 of 6 wells have been drilled with remaining underway (drilling lateral)
- Frac scheduled to begin in late 2Q (1st production expected in 3Q)

WildHorse increasing activity during 2Q

- Positive initial results from WC A down-spacing test
- Remaining 2018 scheduled activity still set for 660' spacing (monitoring down-spacing test results)
- Intra-basin sand testing underway with positive early results
- Multi-well pads in Fairway area driving operational efficiency

Wildhorse WC A Down-Spacing Test

Early results are very encouraging with ten well spacing test (Open wells) currently exceeding cumulative oil plots for comparable two well pads (eight well spacing)



Delaware Basin – Ramping Activity

SPUR AREA INTEGRATION WELL UNDERWAY

Strong initial results from Rendezvous two well pad encouraging (Upper and Lower WC A)

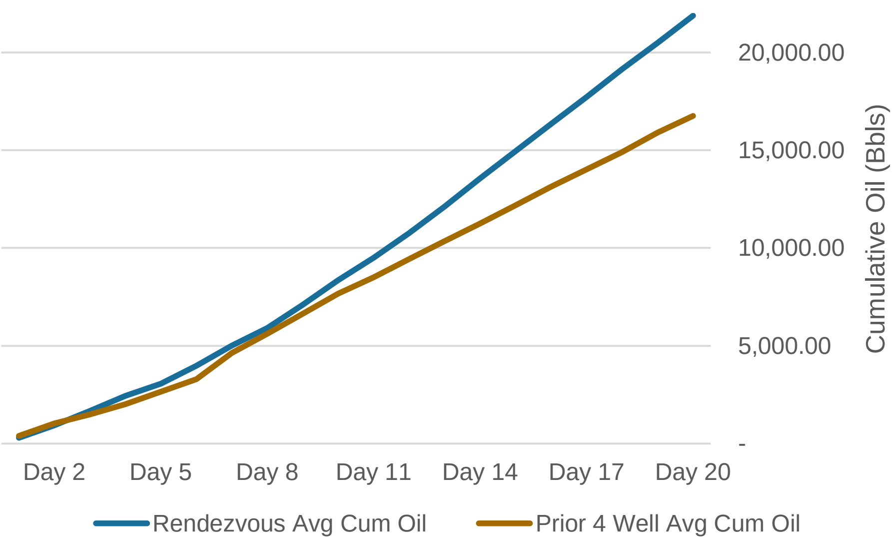
- Both wells have reached ~1,700 Boepd, (~85% oil) within first 18 days of production
- Initial average well-head pressure following drill-out of 4,000 psi with shallow pressure decline after 20 days of production

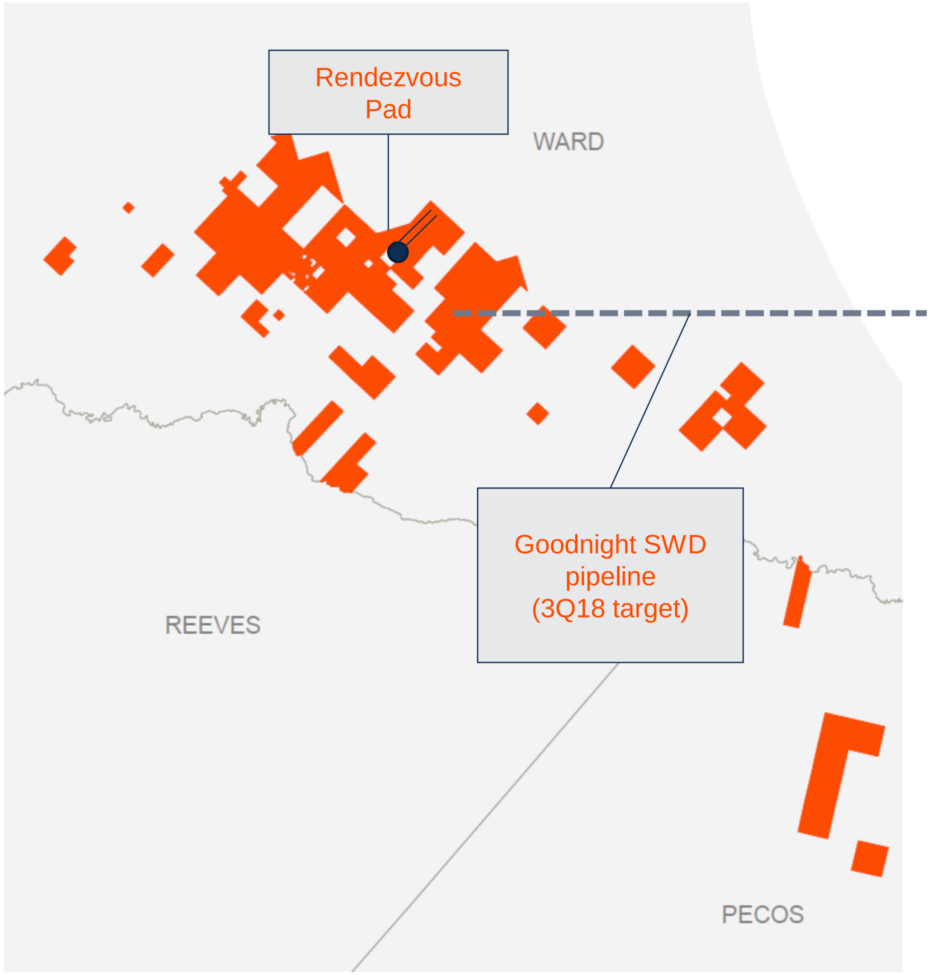
Improved efficiency in drilling as activity increases

- Production beginning to ramp and should be fairly linear from Spur going forward
- Reduction in drilling days progressing

Brazos Midstream pipeline projected online in 3Q, recycling projects moving forward

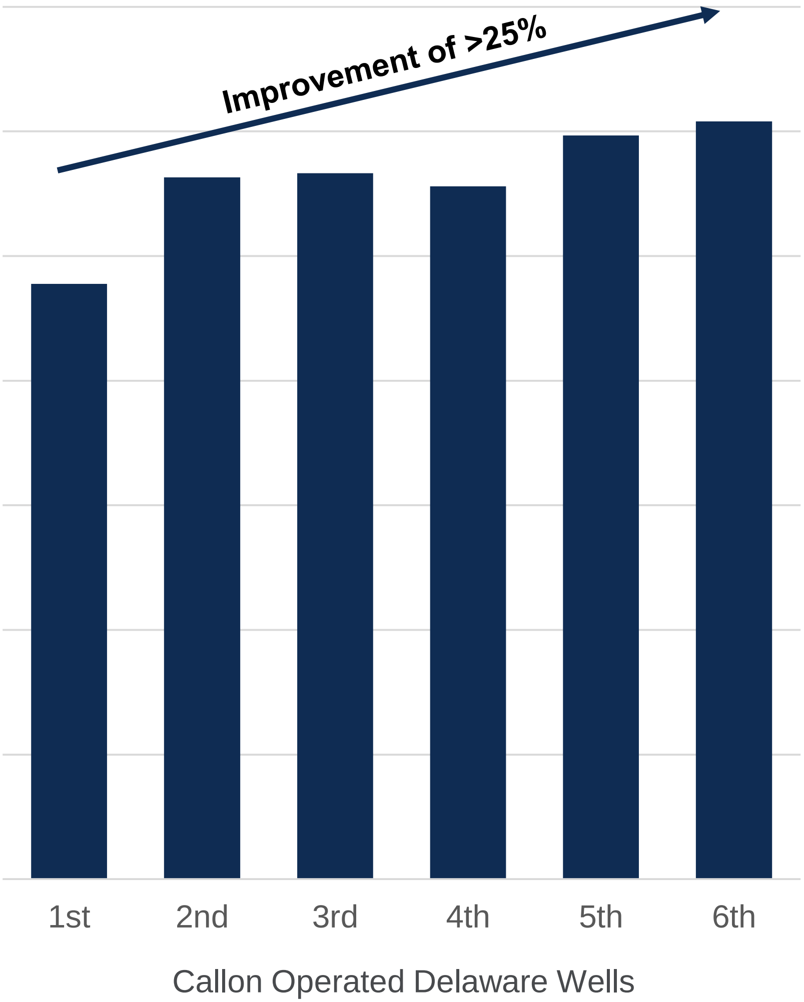
- Significant redundancy in water disposal capabilities
- Water recycling program set to ramp during 2nd half of 2018 (targeting 50% of sourced frac volumes from recycling)

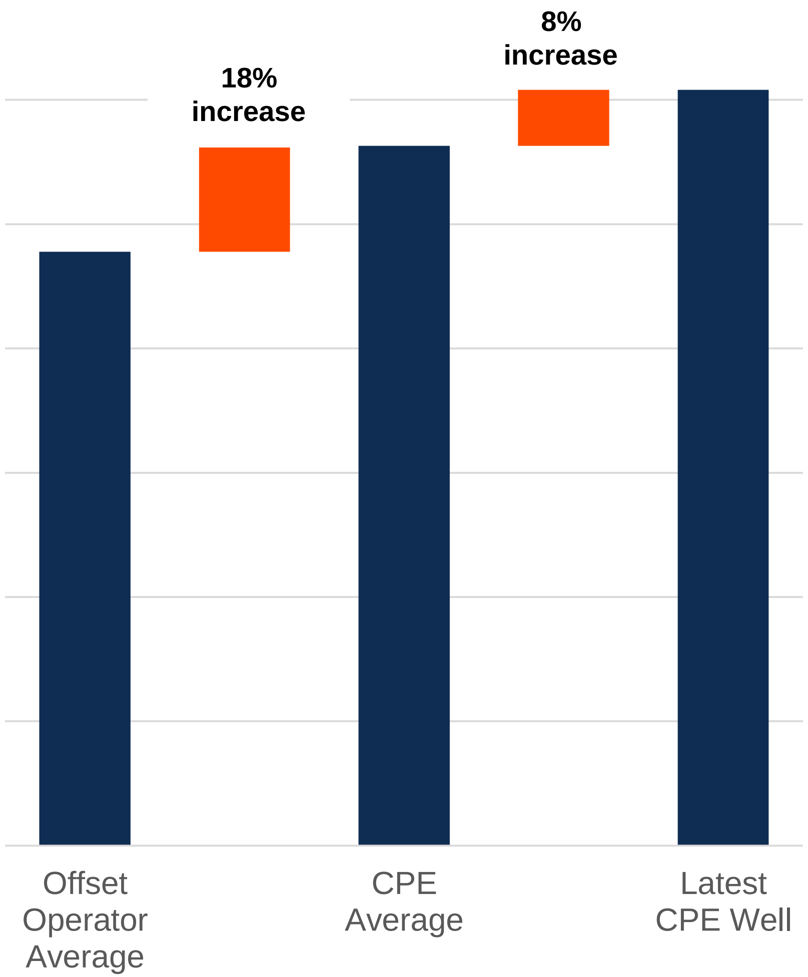




Improved Delaware Drilling Efficiency

AVERAGE DRILLING FOOTAGE PER DAY





Note: Offset Operator average is composed of 14 recent peer results in the southeast Delaware basin targeting the Wolfcamp.

2018 Delaware Infrastructure Milestones

SIGNIFICANT PROGRESS

Water Handling Upgrades

- Recycling facility completed
- 2 x 1 million bbl recycle pits completed
- SWD upgrades across footprint
- Water transfer lines underway

New Tank Batteries

Goodnight Midstream 3Q18

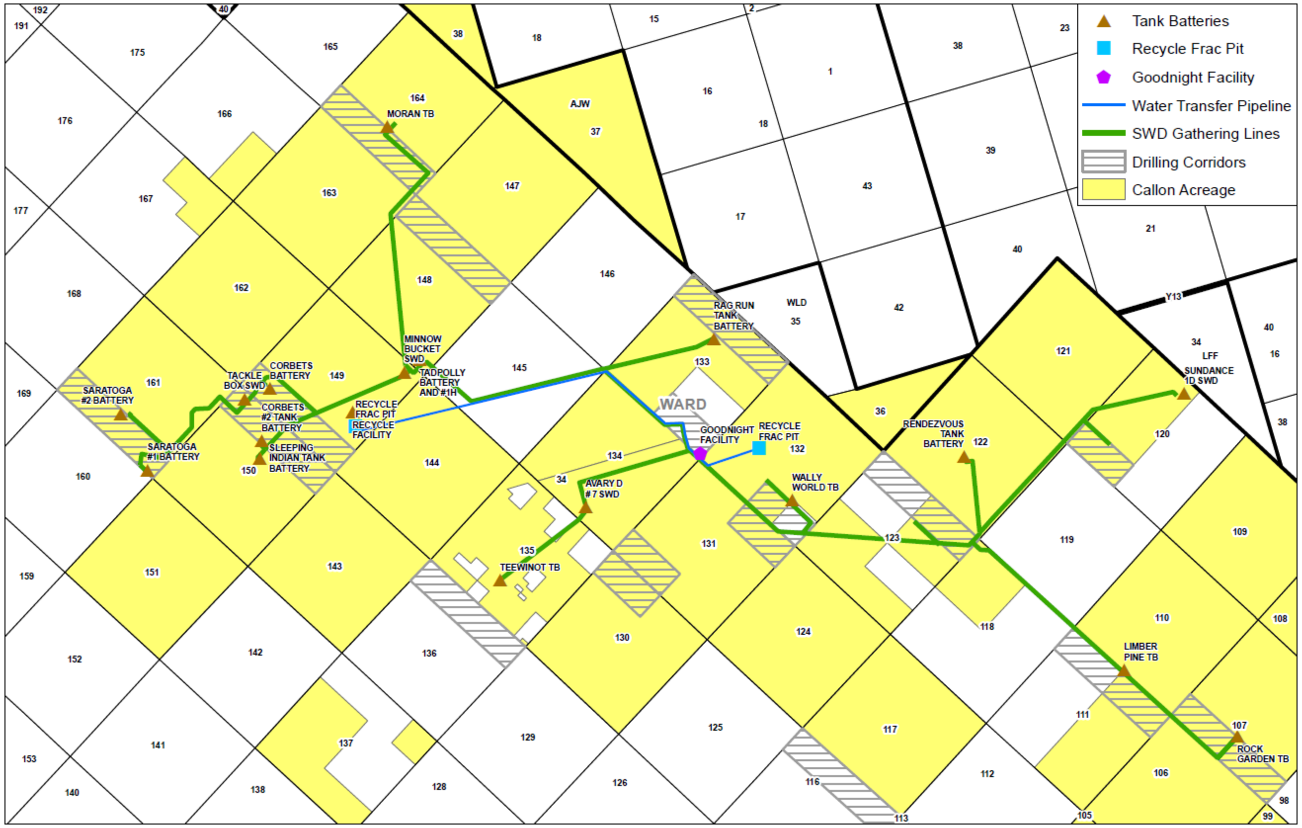
- Projected to tie into centralized water gathering facility by September
- Enhances SWD capacity to nearly 200K Bwpd

Medallion Pipeline Connection

- Will connect to new batteries during 2Q, enhancing existing oil take-away options

Designed to achieve significant LOE benefits once fully complete and operational in 3Q18

MAJOR PROJECTS



Financial Positioning

HIGHLIGHTS

Continue to maintain significant liquidity supported by recently improved revolving credit facility

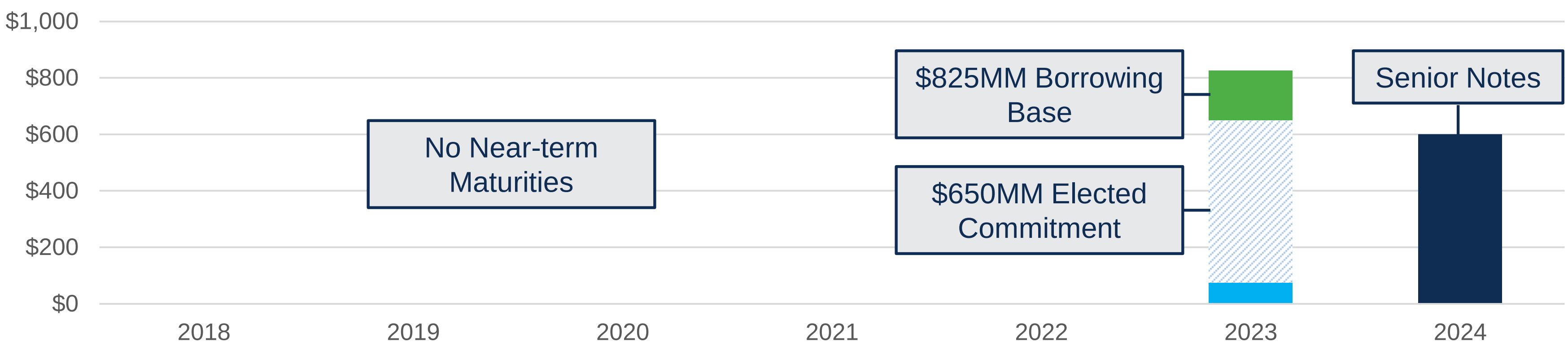
- Finalized the Spring Borrowing Base review, which included
  - Increased the Borrowing Base to $825MM (up from $700MM) with an elected commitment amount of $650MM (up from $500MM)
  - Extending the maturity to May 25, 2023 (1 year extension)
  - Reduced the pricing grid by 75 bps (L+125 - 225 bps)
- Increased 1Q18 liquidity position to $592MM as a result of the upsized revolving credit facility

Well below long-term leverage ratio threshold of < 2.5x Net Debt / Adjusted EBITDA

CAPITALIZATION ($MM) [1]

	1Q18
Cash	$18
Credit Facility	$75
Senior Notes due 2024	$600
Total Debt	$675
Stockholders' Equity	$1,911
Total Capitalization	$2,586
Total Liquidity [2]	**$592**
Net Debt to LQA Adjusted EBITDA	**1.8x**

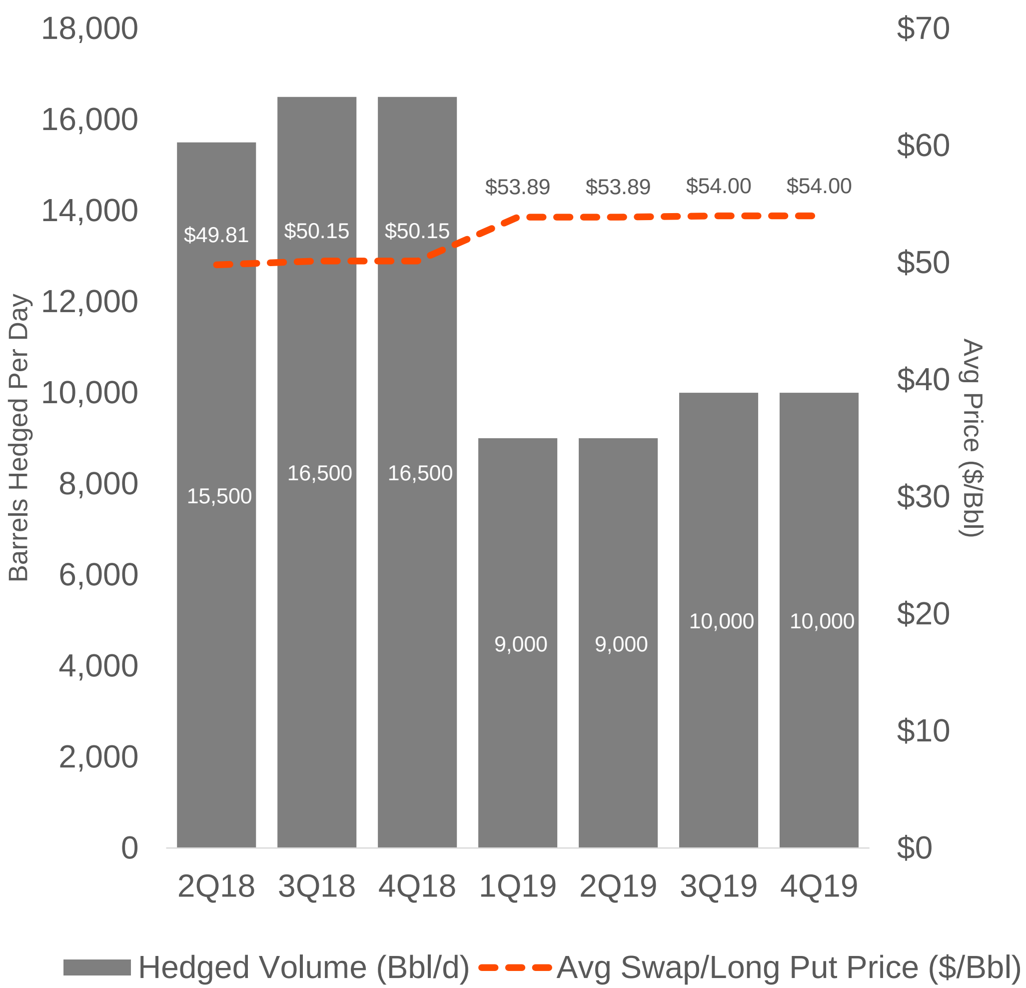
DEBT MATURITY SUMMARY ($MM)



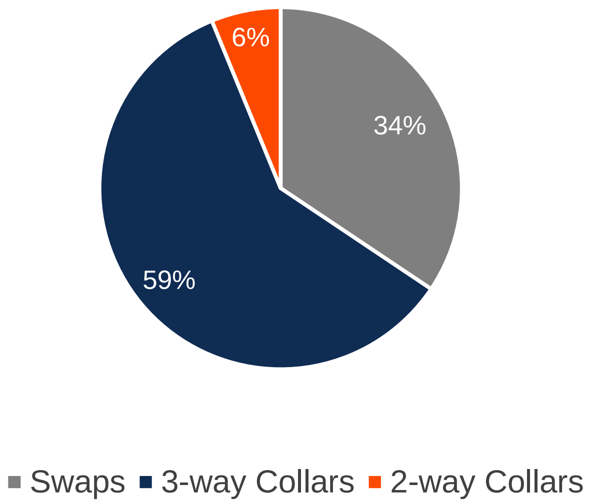
1. Assumes elected commitment amount of $650 MM.
2. Includes drawn balance and letters of credit totaling $1.25 MM

Crude Oil Hedge Contracts [1]

PRICE PROTECTION OF ~$50/BBL FOR 2018



2018 STRUCTURE BREAKDOWN



- 2018 consensus oil volumes hedged : ~65% NYMEX; ~60% Mid-Cush [2]
- 2019 forecasted oil volumes hedged: ~30% NYMEX; 0% Mid-Cush [2]
- ~65% of 2018 oil hedges are collars, allowing for meaningful participation in recent price increases

1. Hedge contracts as of April 23, 2018.
2. Percent hedged as of consensus estimates sourced from FactSet April 23, 2018.

APPENDIX

Guidance Summary

	FY18 Guidance
Total production (MBoepd)	29.5 – 32.0
Oil production	77%
Income statement expenses (per BOE)	
LOE, including workovers	$5.25 - $6.25
Production taxes, including ad valorem (% of unhedged revenues)	6%
Adjusted G&A: cash component (1)	$1.75 - $2.50
Adjusted G&A: non-cash component (2)	$0.50 - $1.00
Cash interest expense (3)	$0.00
Statutory income tax rate	22%
Capital expenditures ($MM, accrual basis)	
Total operational capital (4)	$500 - $540
Capitalized expenses	$60 - $70
Net operated horizontal wells placed on production	43 – 46

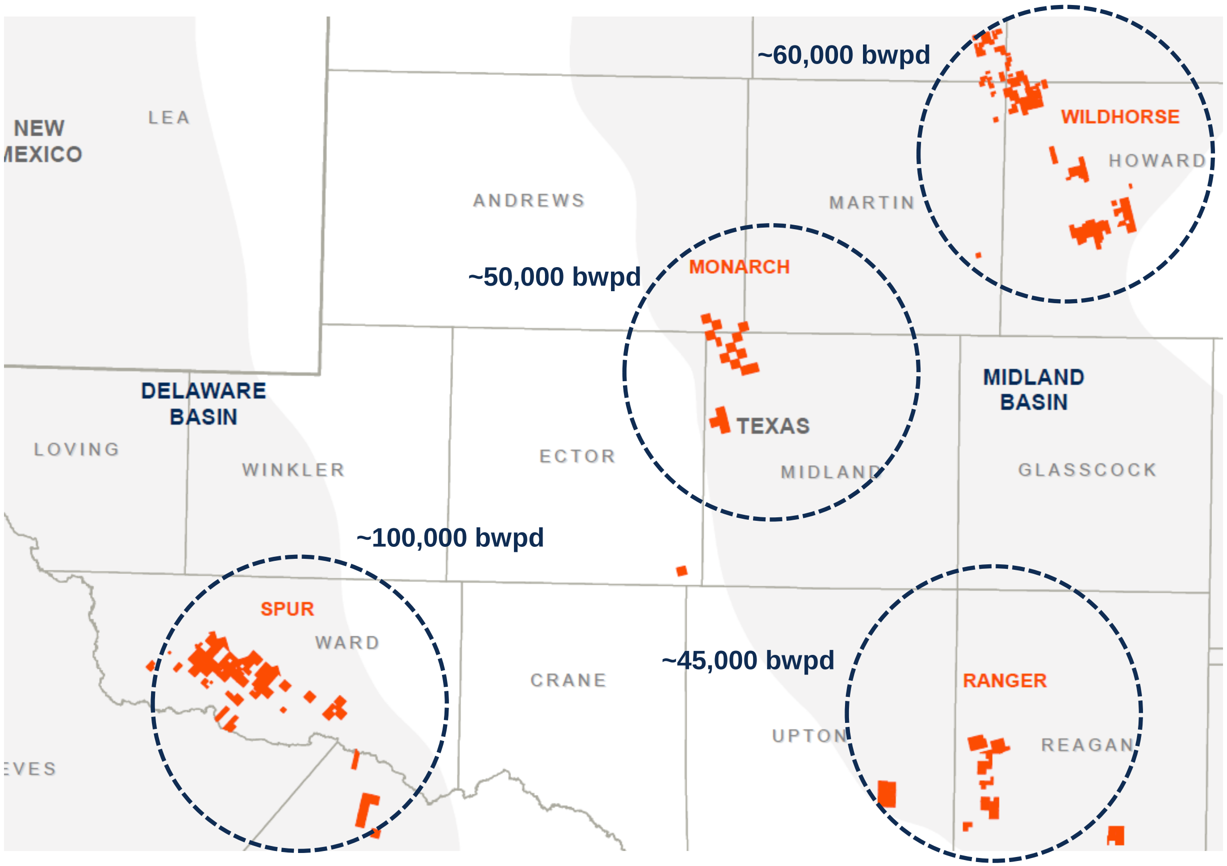
1. Excludes stock-based compensation and corporate depreciation and amortization. See the Non-GAAP related disclosures in the Appendix.
2. Excludes certain non-recurring expenses and non-cash valuation adjustments. See the non-GAAP related disclosures in the Appendix.
3. All cash interest expense anticipated to be capitalized.
4. Includes drilling, completions, facilities, seismic, land and other items. Excludes capitalized expenses. Net of infrastructure monetizations of $20 million.

Water Disposal as a Competitive Advantage

Between company owned and third party committed volumes, Callon has in excess of 400,000 bbl/d of water disposal capacity (excluding pending Goodnight project of 80,000 bbl/d)

Average CPE water disposal during February was ~90K Bwpd across the entire Permian footprint (25% of controlled capacity)

COMPANY OWNED AND OPERATED DISPOSAL CAPACITY BY AREA



WATER MANAGEMENT INITIATIVES

Strategic Water Handling Agreements

- Gravity – water sourcing (Wildhorse and Spur areas)
- Goodnight Midstream – Spur disposal pipeline to the CBP

Recycling Efforts

- Underway at Monarch, utilized on recently fracked wells **+40%** of sourced volumes
- Spur build-out progressing, goal of sourcing 50% of frac water volumes from recycling by year end

Incremental Capacity in Key Areas

- New Deep Ellenburger wells projected online at Ranger and Wildhorse during Q2 supplying significant incremental capacity

Commodity Flow Assurance Basin Wide

Multiple Deliverable Points Available

Delaware Gas Volumes

- Enters El Paso line past Waha (firm sales agreement) with back haul options to hub
- Second connection pending (mid-year) with FT to Waha via Whitewater
- February sales of less than 3 mmcf/d

Delaware Oil Volumes

- Gathered by Enterprise with additional connection to Medallion expected in May
- Reserved capacity on Medallion with ability to move to all primary delivery points (Crane, Midland, Colorado City, local refineries)

Midland Gas Volumes

- WTG, Enlink primarily (expansive delivery networks, multiple markets and plants)
- All sales are well head with NGL uplift add-back

Midland Oil Volumes

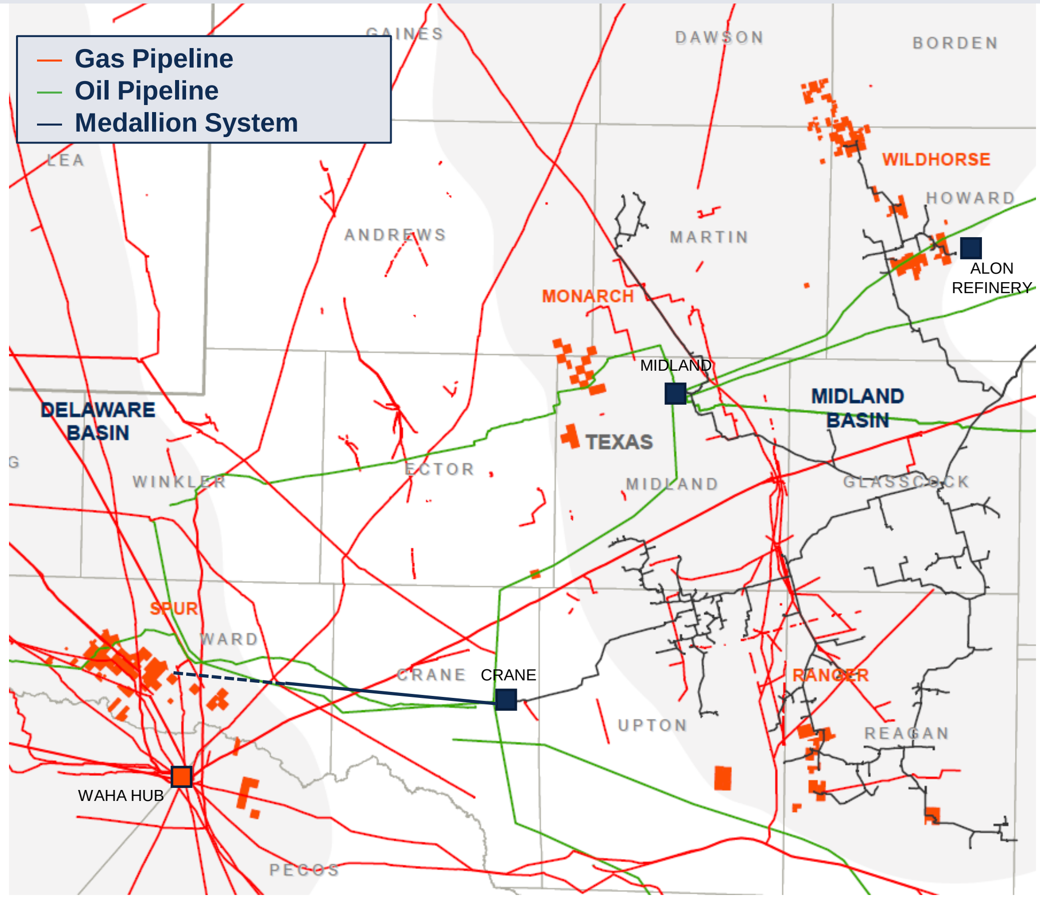
- Medallion primary gatherer with Plains, Enterprise, and Reliance as well
- Callon holds the capacity on Medallion system
- Sales are still at the wellhead

~40K Bopd gathering commitments from three primary providers (multi-year term agreements)

7 primary oil purchasers (Plains, Enterprise, Shell, BP, etc.) with 60K Bopd of volumes currently under term sales agreements

More than 90% of oil on pipe with additional tie-ins pending

Commodity Flow Options for Callon Production



Oil	▪ ~40,000 bopd of term gathering contracts on three major networks provide access to all primary delivery points ▪ Sales to seven purchasers, including in-basin refineries
Gas	▪ Firm transport to Waha and downstream point in Delaware ▪ Well established, diversified network in Midland

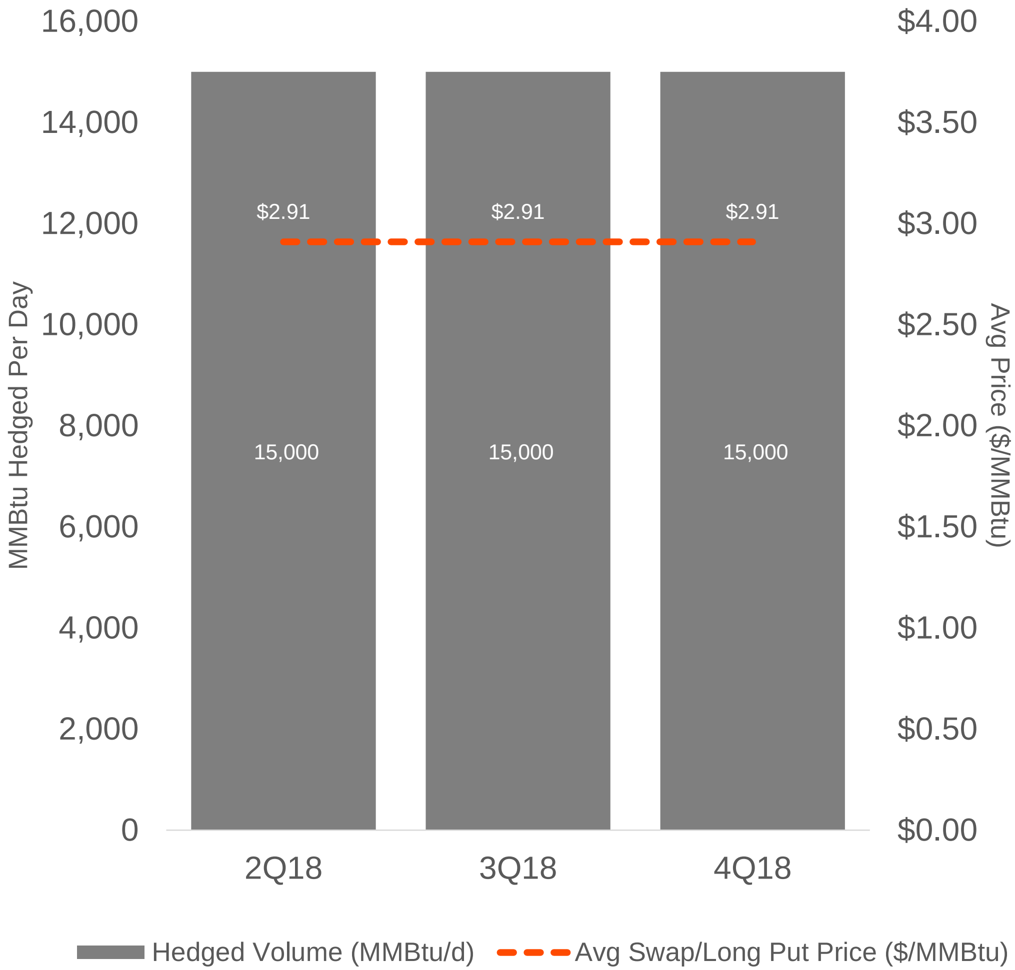
Crude Oil Hedge Contracts [1]

Crude Oil (Bbl, Wtd Avg. $/Bbl)	1Q18	2Q18	3Q18	4Q18	FY18	FY19
Swaps	450,000	455,000	552,000	552,000	2,009,000	-
Strike Price	$51.42	$51.42	$52.07	$52.07	$51.78	
Costless Collars	90,000	91,000	92,000	92,000	365,000	-
Short Call Price	$60.25	$60.25	$60.25	$60.25	$60.25	
Put Price	$50.00	$50.00	$50.00	$50.00	$50.00	
Three-way Collars	855,000	864,500	874,000	874,000	3,467,500	3,469,000
Short Call Price	$60.86	$60.86	$60.86	$60.86	$60.86	$63.71
Put Price	$48.95	$48.95	$48.95	$48.95	$48.95	$53.95
Short Put Price	$39.21	$39.21	$39.21	$39.21	$39.21	$43.95
Midland-Cushing Basis Differential	1,395,000	1,410,500	1,242,000	1,242,000	5,289,500	-
Swap Price	($0.80)	($0.80)	($0.93)	($0.93)	($0.86)	
Total NYMEX WTI Hedge Volume	1,395,000	1,410,500	1,518,000	1,518,000	5,841,500	3,469,000
Weighted Average Floor Price	$49.81	$49.81	$50.15	$50.15	$49.99	$53.95
% WTI NYMEX Hedged [2]					~65%	~30%
% Mid-Cush Basis Hedged [2]					~60%	0%

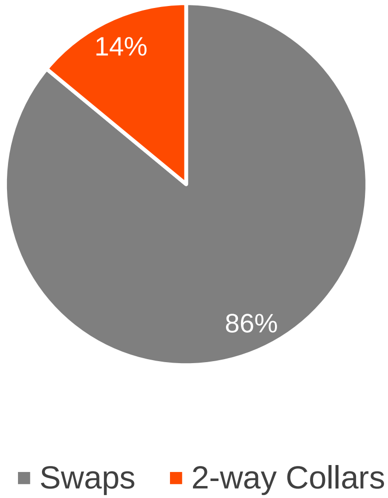
1. Hedge contracts as of April 23, 2018.
2. Percent hedged as of consensus estimates sourced from FactSet April 23, 2018.

Natural Gas Hedge Contracts [1]

PRICE PROTECTION OF ~$3/MMBTU FOR 2018



2018 STRUCTURE BREAKDOWN



- 2018 forecasted gas volumes hedged: ~25% NYMEX; 0% Waha [2]
- 2019 forecasted gas volumes hedged: 0% NYMEX; 0% Waha [2]
- 100% swaps 2Q18 to 4Q18
- Continuing to monitor Henry Hub and Waha pricing

1. Hedge contracts as of April 23, 2018.
2. Percent hedged as of consensus estimates sourced from FactSet April 23, 2018.

Natural Gas Hedge Contracts (1)

Natural Gas (MMBtu, Wtd. Avg. $/MMBtu)	1Q18	2Q18	3Q18	4Q18	FY18	FY19
Swaps Strike Price	341,000 $2.95	1,365,000 $2.91	1,380,000 $2.91	1,380,000 $2.91	4,466,000 $2.91	-
Costless Collars Short Call Price Put Price	720,000 $3.84 $3.40	-	-	-	720,000 $3.84 $3.40	-
Waha Basis Differential Swap Price	-	-	-	-	-	-
Total NYMEX Henry Hub Hedge Volume Weighted Average Floor Price	1,061,000 $3.25	1,365,000 $2.91	1,380,000 $2.91	1,380,000 $2.91	5,186,000 $2.98	-
% HH NYMEX Hedged (2)					~25%	0%
% Waha Basis Hedged (2)					0%	0%

1. Hedge contracts as of April 23, 2018.
2. Percent hedged as of consensus estimates sourced from FactSet April 23, 2018.

Quarterly Cash Flow Statement

	1Q17	2Q17	3Q17	4Q17	1Q18
Cash flows from operating activities:					
Net income	$ 47,129	$ 33,390	$ 17,081	$ 22,824	$ 55,761
Adjustments to reconcile net income to cash provided by operating activities:					
Depreciation, depletion and amortization	24,932	26,765	29,132	37,222	36,066
Accretion expense	184	208	131	154	218
Amortization of non-cash debt related items	665	589	441	455	453
Deferred income tax expense	466	323	237	247	495
(Gain) loss on derivatives, net of settlements	(17,794)	(10,761)	12,947	26,037	(3,978)
Loss on sale of other property and equipment	—	62	—	—	—
Non-cash expense related to equity share-based awards	930	4,865	1,219	1,240	1,131
Change in the fair value of liability share-based awards	(291)	1,982	732	865	1,012
Payments to settle asset retirement obligations	(765)	(816)	(250)	(216)	(366)
Changes in current assets and liabilities:					
Accounts receivable	(4,066)	(3,744)	(4,338)	(32,347)	(8,067)
Other current assets	576	(874)	(38)	444	61
Current liabilities	9,903	(4,223)	1,854	23,413	12,938
Other long-term liabilities	—	120	1	—	87
Long-term prepaid	—	—	(4,650)	—	—
Other assets, net	(523)	(247)	(606)	(152)	(507)
Payments for cash-settled restricted stock unit awards	(8,662)	(4,511)	—	—	(3,089)
Net cash provided by operating activities	52,684	43,128	53,893	80,186	92,215
Cash flows from investing activities:					
Capital expenditures	(66,154)	(79,936)	(121,128)	(152,621)	(111,330)
Acquisitions	(648,485)	(58,004)	(8,015)	(3,952)	(38,923)
Acquisition deposit	46,138	—	—	(900)	900
Proceeds from sales of mineral interests and equipment	—	—	—	20,525	—
Net cash used in investing activities	(668,501)	(137,940)	(129,143)	(136,948)	(149,353)
Cash flows from financing activities:					
Borrowings on senior secured revolving credit facility	—	—	—	25,000	80,000
Payments on senior secured revolving credit facility	—	—	—	—	(30,000)
Issuance of 6.125% senior unsecured notes due 2024	—	200,000	—	—	—
Premium on the issuance of 6.125% senior unsecured notes due 2024	—	8,250	—	—	—
Payment of preferred stock dividends	(1,824)	(1,823)	(1,824)	(1,824)	(1,824)
Payment of deferred financing costs	—	(6,765)	(401)	(28)	—
Tax withholdings related to restricted stock units	(79)	(974)	(65)	—	(560)
Net cash provided by financing activities	(1,903)	198,688	(2,290)	23,148	47,616
Net change in cash and cash equivalents	(617,720)	103,876	(77,540)	(33,614)	(9,522)
Balance, beginning of period	652,993	35,273	139,149	61,609	27,995
Balance, end of period	$ 35,273	$ 139,149	$ 61,609	$ 27,995	18,473

Non-GAAP Reconciliation (1)

	1Q17	2Q17	3Q17	4Q17	1Q18
Adjusted Income Reconciliation					
Income available to common stockholders	$ 45,305	$ 31,566	$ 15,257	$ 21,001	$ 53,937
Adjustments:					
Change in valuation allowance	(13,119)	(11,194)	(6,064)	(8,285)	(11,753)
Net (gain) loss on derivatives, net of settlements	(11,566)	(6,995)	8,416	16,924	(3,143)
Change in the fair value of share-based awards	(189)	(315)	475	562	799
Settled share-based awards	—	4,128	—	—	—
Adjusted Income	$ 20,431	$ 17,190	$ 18,084	$ 30,202	$ 39,840
Adjusted Income per fully diluted common share	$ 0.10	$ 0.09	$ 0.09	$ 0.15	$ 0.20
Adjusted EBITDA Reconciliation					
Net income	$ 47,129	$ 33,390	$ 17,081	$ 22,824	$ 55,761
Adjustments:					
Net (gain) loss on derivatives, net of settlements	(17,794)	(10,761)	12,947	26,037	(3,978)
Non-cash stock-based compensation expense	639	499	1,952	2,101	2,143
Settled share-based awards	—	6,351	—	—	—
Acquisition expense	450	2,373	205	(112)	548
Income tax expense	466	322	237	248	495
Interest expense	665	589	444	461	460
Depreciation, depletion and amortization	24,932	26,765	29,132	37,222	36,066
Accretion expense	184	208	131	154	218
Adjusted EBITDA	$ 56,671	$ 59,736	$ 62,129	$ 88,935	$ 91,713
Adjusted EBITDA inclusive of Pro forma Adjustments (2)	$ 59,329	$ 59,736	$ 62,129	$ 88,935	$ 91,713

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)

	1Q17	2Q17	3Q17	4Q17	1Q18
Adjusted G&A Reconciliation					
Total G&A expense	$ 5,206	$ 6,430	$ 7,259	$ 8,173	$ 8,769
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)	(307)	567	(731)	(844)	(991)
Adjusted G&A – total	5,513	6,472	6,528	7,329	7,778
Less: Restricted stock share-based compensation (non-cash)	(921)	(966)	(1,198)	(1,202)	(1,105)
Less: Corporate depreciation & amortization (non-cash)	(121)	(114)	(146)	(125)	(124)
Adjusted G&A – cash component	$ 4,471	$ 5,392	$ 5,184	$ 6,002	$ 6,549
Adjusted Total Revenue Reconciliation					
Oil revenue	$ 72,008	$ 72,885	$ 73,349	$ 104,132	$ 115,286
Natural gas revenue	9,355	9,398	11,265	14,081	12,154
Total revenue	81,363	82,283	84,614	118,213	127,440
Impact of cash-settled derivatives	(2,491)	(267)	(1,214)	(4,501)	(8,459)
Adjusted Total Revenue	$ 78,872	$ 82,016	$ 83,400	$ 113,712	$ 118,981
Total Production (Mboe)	1,838	2,021	2,074	2,439	2,391
Adjusted Total Revenue per Boe	$ 42.91	$ 40.58	$ 40.21	$ 46.62	$ 49.76
Discretionary Cash Flow Reconciliation					
Net cash provided by operating activities	$ 52,684	$ 43,128	$ 53,893	$ 80,186	$ 92,215
Changes in working capital	(5,890)	8,968	7,777	8,642	(4,512)
Payments to settle asset retirement obligations	765	816	250	216	366
Payments to settle vested liability share-based awards	8,662	4,511	—	—	3,089
Discretionary cash flow	$ 56,221	$ 57,423	$ 61,920	$ 89,044	$ 91,158
Discretionary cash flow per diluted share	$ 0.28	$ 0.28	$ 0.31	$ 0.44	$ 0.45

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