



2nd QUARTER 2018 EARNINGS

AUGUST 6, 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, investment plans 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”) and other filings with 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. Management also uses EBITDAX, which reflects EBITDA plus exploration and abandonments expense.

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

2Q18 RESULTS

2Q18 production of 29.0 Mboe/d

- Oil mix of 76%
- YoY growth of 30% / sequential growth of 9%

Operating margin of \$44.17 per Boe (~85%)

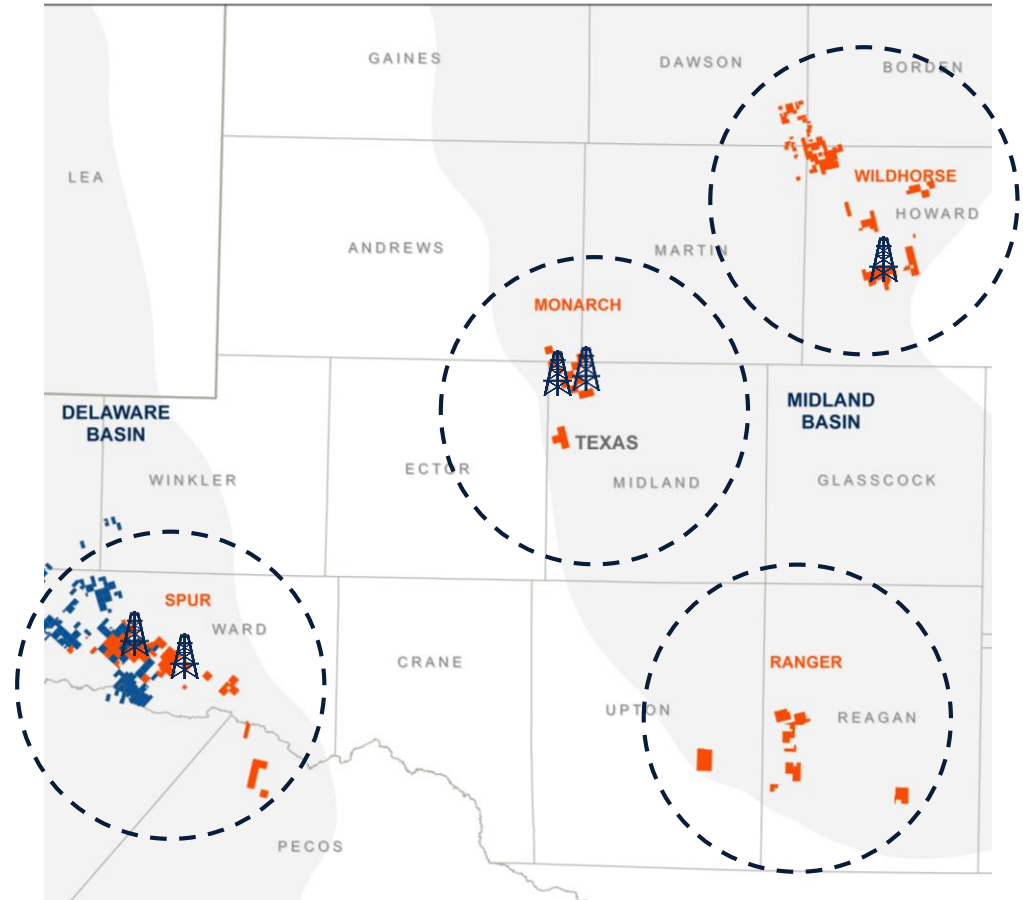
LOE per Boe \$4.99 ⁽¹⁾

Adjusted EBITDA of \$102.6 MM

QUARTERLY HIGHLIGHTS

- Announced acquisition of significant bolt-on acreage in Delaware Basin with meaningful near-term value contribution
- 8% sequential reduction in LOE
- Operational efficiencies driving more wells PoP during Q2 with operational capex lower than estimated
- 1st Mega-pad online with wells performing favorably against offset three-well pads
- Multiple new Wolfcamp wells online at Spur, including first WC C test well
- Recent Fairway wells outperforming type curves early time
- Executed Firm Transportation agreement to move 15,000 barrels per day to Gulf Coast

CURRENT RIG ACTIVITY



85,000+ PRO FORMA NET ACRES



1. LOE figures are calculated on a two-stream basis.

CPE Industry Leading Margins Continue to Improve

MARGIN EXPANSION

Cash margin growth illustrates operational efficiencies

- Per unit cash operating costs⁽¹⁾ declined 10% sequentially
- Overall cash operating costs as a percent of unhedged revenue declined to 20% in 2Q'18 from 33% in 4Q'16

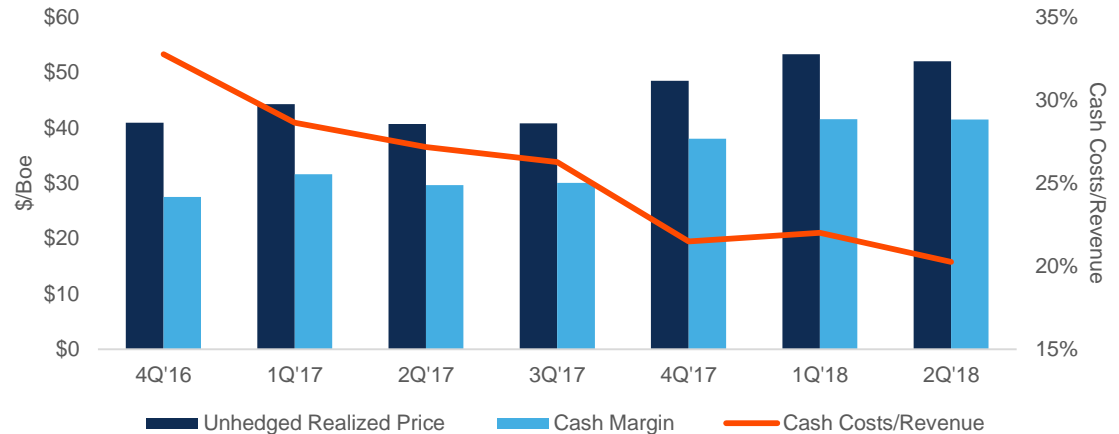
Industry leading operating margins

- 2Q'18 Adj. EBITDA(X)/Boe expanded to \$38.95/Boe⁽²⁾, representing 17% margin CAGR over the last 2 years
- CPE continues to exhibit one of the highest cash operating margins across 60+ E&Ps

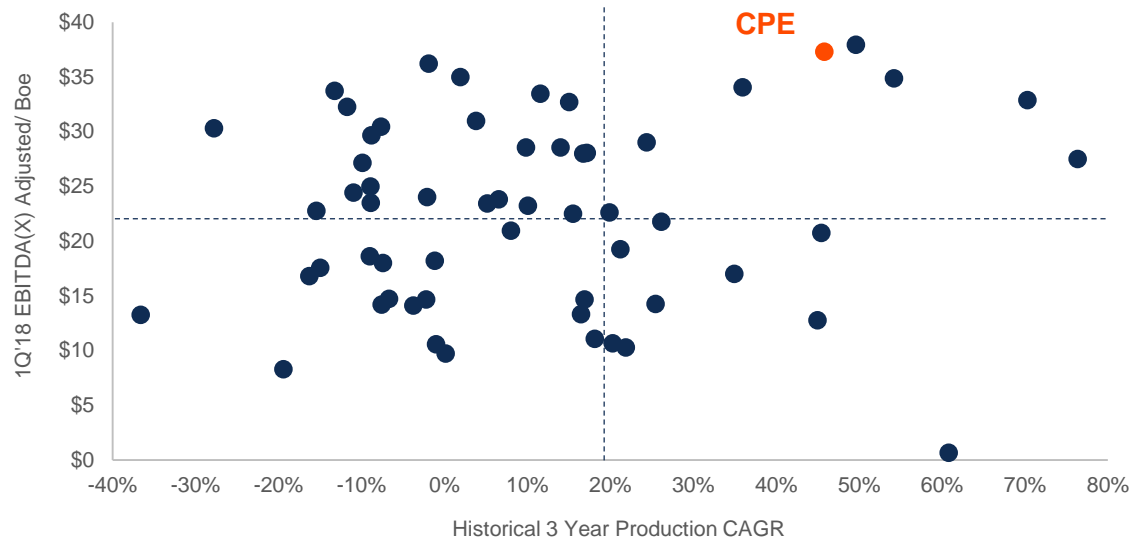
Integration of XEC assets will further margin expansion trajectory

- Immediate low cost cash flow stream from producing wells
- Improved scalability enhances optionality for multi-well pad development
- Accelerates timing of FCF

COST IMPROVEMENTS DRIVING OPERATING RETURNS



CAPITAL EFFICIENT PRODUCTION GROWTH WITH SUPERIOR MARGINS ⁽³⁾



1. Cash operating costs include Lease Operating Expenses, Production Taxes, and Cash G&A.
 2. Based on CPE calculated Adjusted EBITDA(X).
 3. Based on standardized Bloomberg calculations for Adjusted EBITDA(X).

Operational Execution

DEVELOPMENT ON TARGET

14 net wells placed on production during Q2, bringing 1H18 total to 23

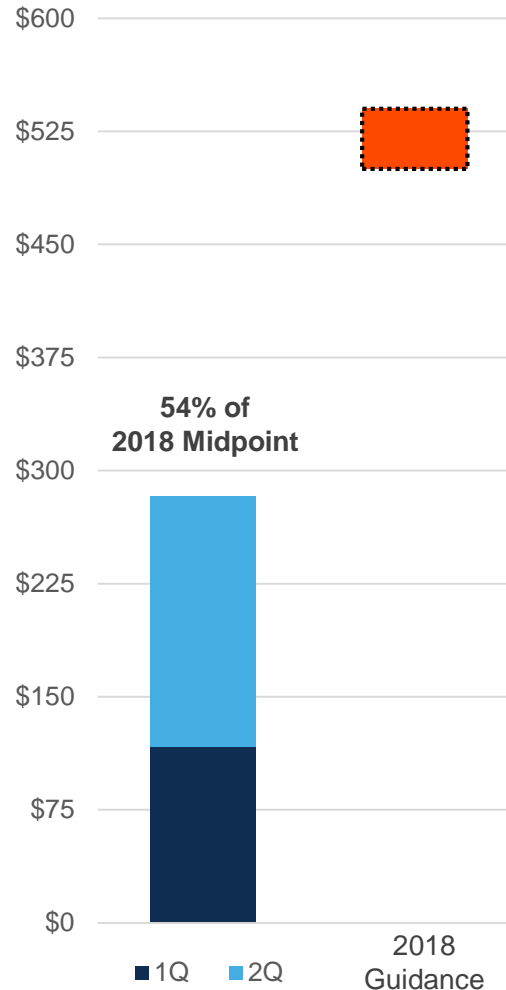
8 net wells PoP in June, combined with Monarch area mega-pad in July, provide strong momentum into Q3

Capital expenditures tracking on budget with additional 2H18 benefits expected from:

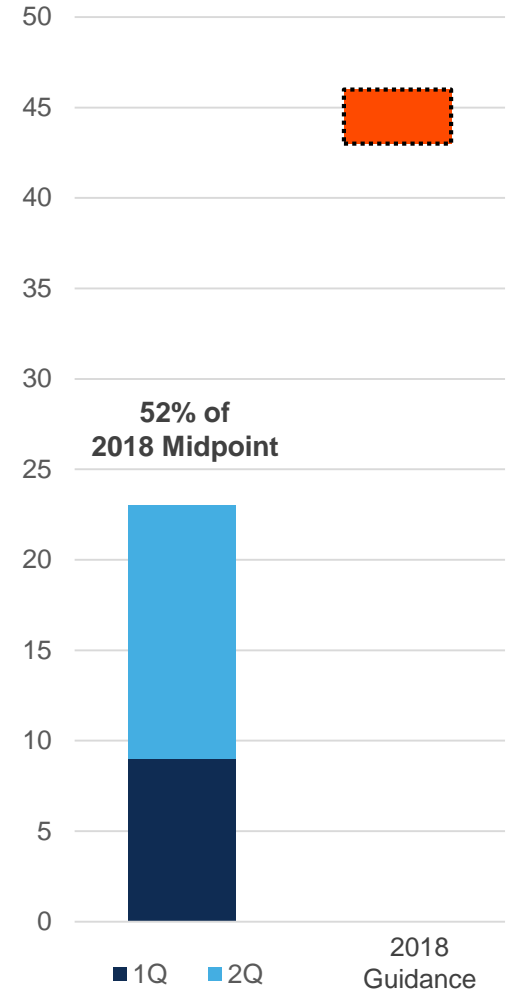
- Increased local sand usage
- Ramp-up of recycling efforts
- Supply chain initiatives
- Reduced infrastructure spending in Q3 and Q4

To date in the reporting cycle, oil-levered E&P 2Q capital expenditures have been 12% above consensus estimates on average ⁽²⁾

1H18 OPERATIONAL CAPITAL (\$MM)



1H18 NET WELLS PoP ⁽¹⁾



1. Placed on production during the quarter.
 2. Based on Bloomberg consensus estimates vs. reported capital expenditures from property additions.

Production Growth Drivers

HIGHLIGHTS

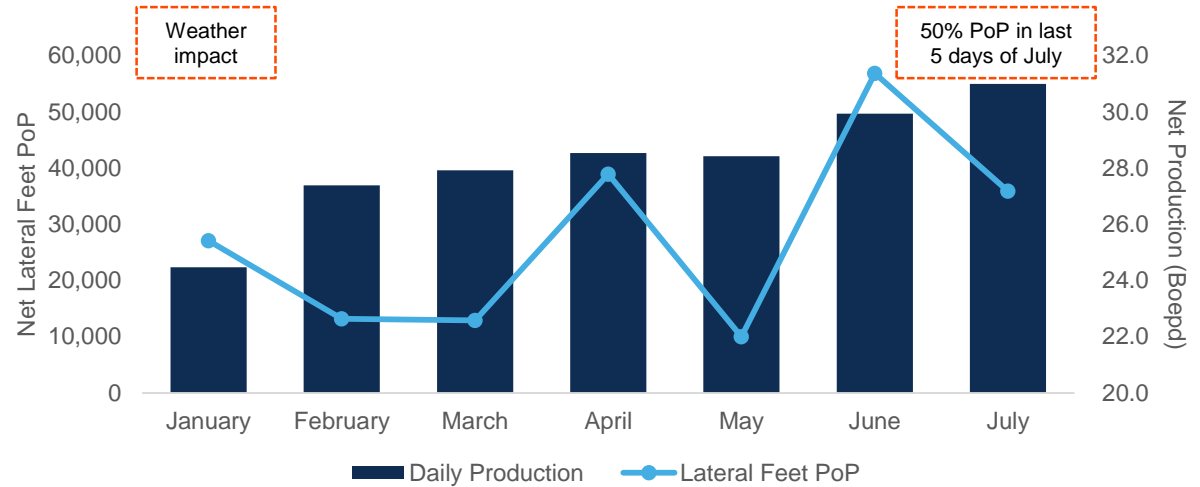
Evolution to larger pad concepts

- Mitigate offset frac impacts
- Multi-zone development where lack of natural barriers
- Simultaneous operation of two drilling rigs followed by two completion crews preserves short cycle times
- ~160,000 net lateral feet PoP in 1H18 (~60K in June alone)

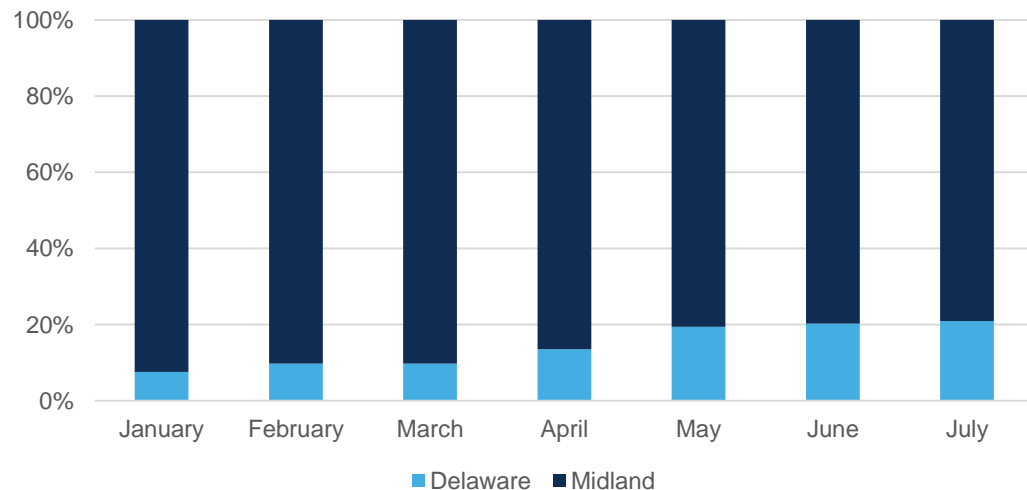
Delaware Basin underpins robust production growth outlook

- Prolific well results with improvements over initial vintages
- Reduced cycle times and move to multi-well pad development breed cost savings
- Infrastructure build-out removes impediments to growth
- Pending acquisition impact bolsters future production profile

INCREASED PAD DEVELOPMENT (1)



RAPIDLY EMERGING DELAWARE PRODUCTION CONTRIBUTION



1. Placed on production during the quarter.

Cash Flow Alignment with Improving Capital Efficiency

FOCUSED ON GROWTH AND RETURNS

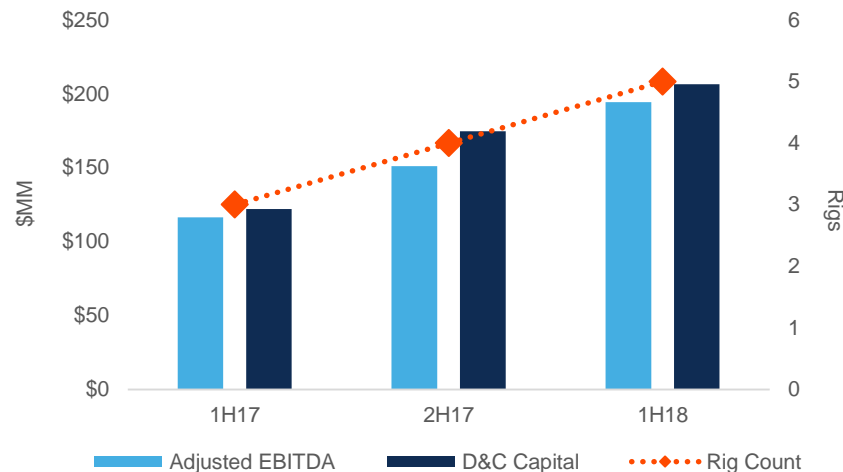
Company remains focused on growing responsibly

- Rig deployment and spending guided by path to cash flow neutrality
- Infrastructure investments in new areas dropping while D&C dollars growing
- Forward looking capital efficiency metrics expected to reap significant benefits

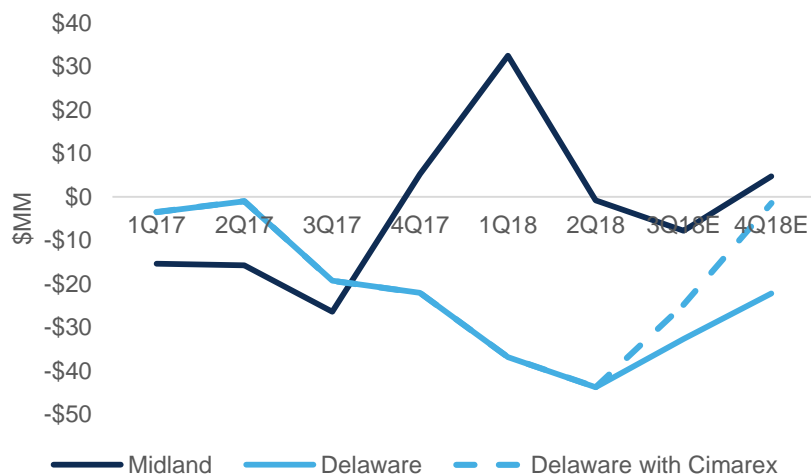
Returns driven capital allocation

- SIMOPS style pad development tailored to reduce cycle times
- As areas of focus mature, cash flow trajectory improves
- Operational efficiency will help drive returns on capital

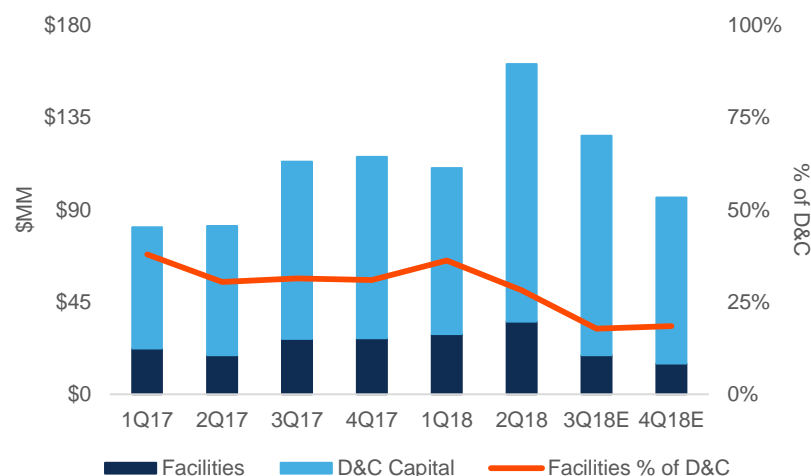
ADJ. EBITDA GROWTH TRACKING D&C SPENDING



FIELD LEVEL CASH FLOW ON THE RISE (1)



CAPITAL SPENDING INCREASINGLY FOCUSED ON D&C (2)



1. Pricing is forward strip for all commodities (including WaHa and Midland Basis differentials) as of 7/16/2018.
 2. 3Q'18 and 4Q'18 estimates reflect previous guidance and do not incorporate pending acquisition.

Mega-Pads at Monarch

SIMULTANEOUS RIG OPERATIONS CREATING LARGER PROJECTS WITH SHORTER CYCLE TIMES

1st Monarch “Mega-Pad” online

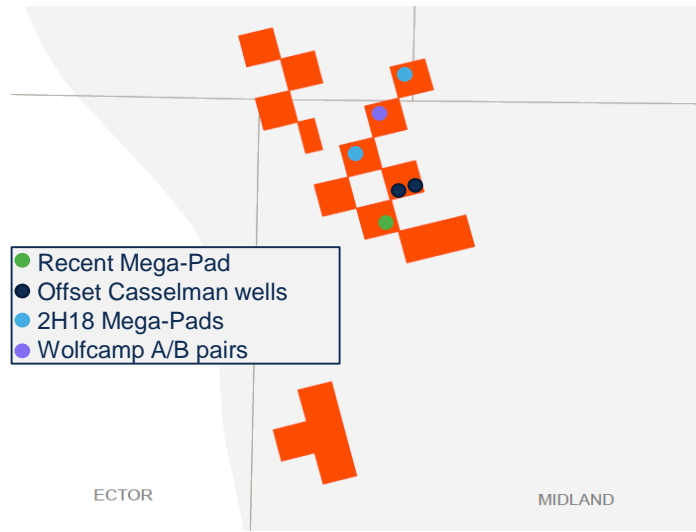
- Placed on production in July
- Average production exceeding 162 Bopd (185 Boepd) per 1,000 feet of lateral
- Average completed lateral length of 4,234 feet

Additional development planned for 2H18

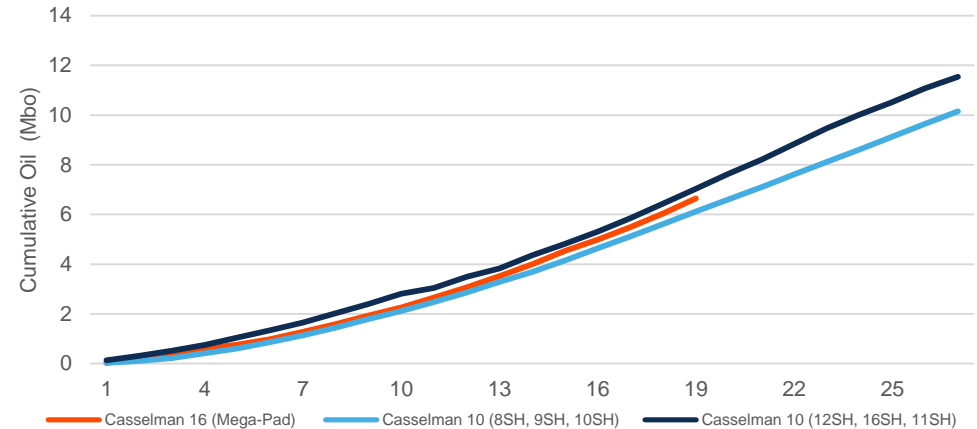
- 2nd location expected to be POP during Q4
- 3rd pad projected to spud near YE18

Wolfcamp A/B pair test expands opportunity

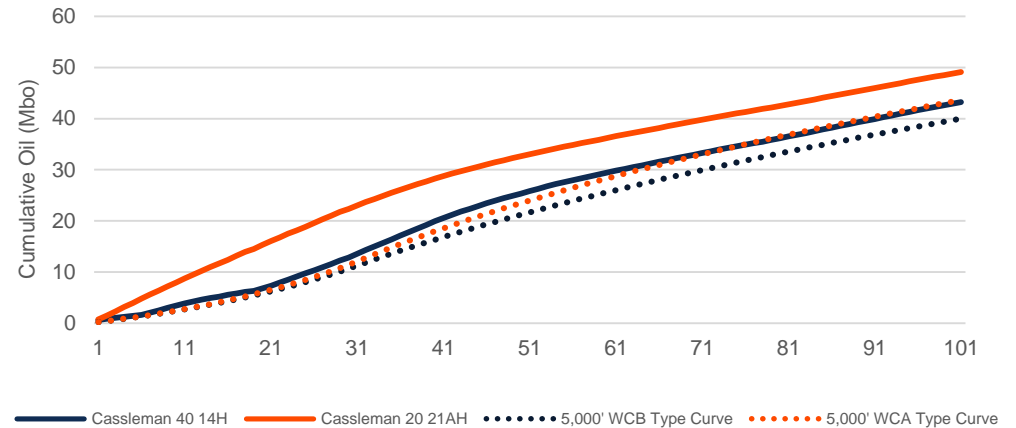
- Both wells outperforming oil type curves through 100 days
- Low cost, short cycle time option for additional “Mega-Pad” style development at Monarch



Mega-Pad vs. Offset Three-Well Pads at Monarch



Wolfcamp A & B Pair Test at Monarch

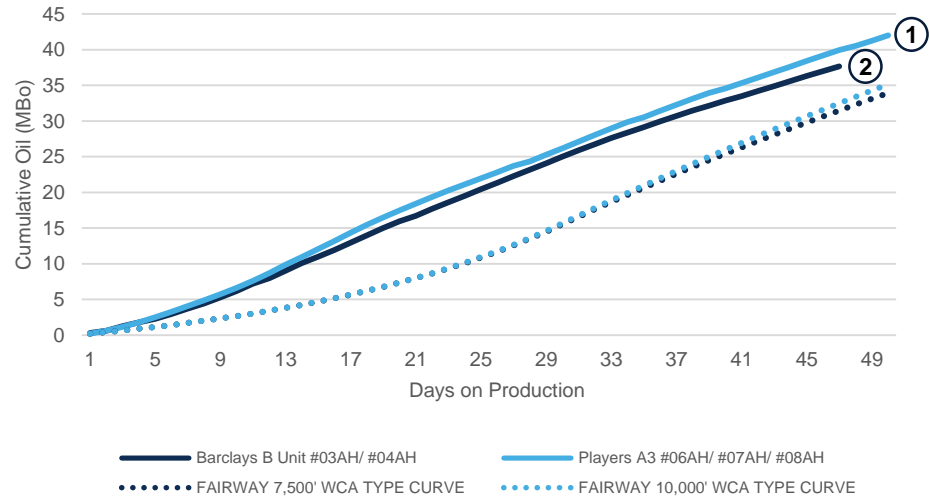


Robust Activity at Wildhorse

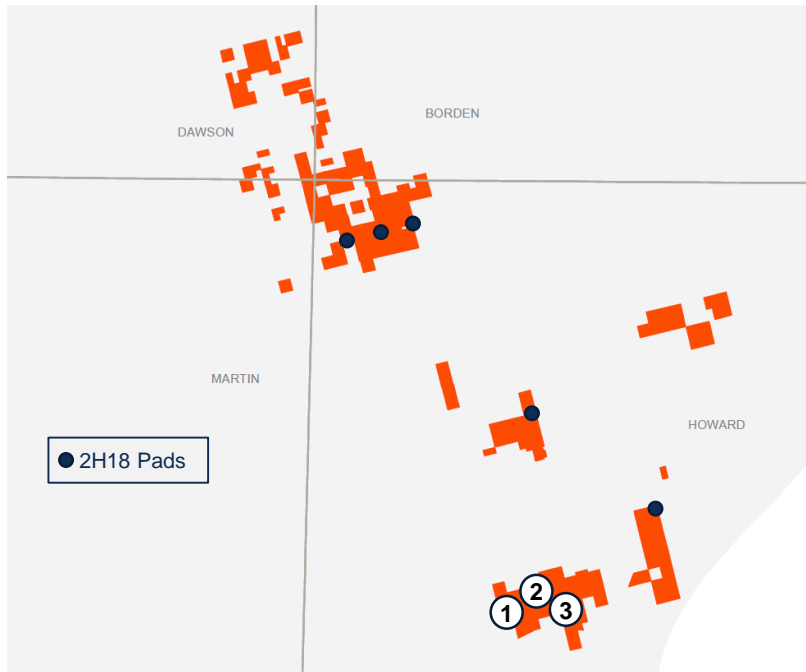
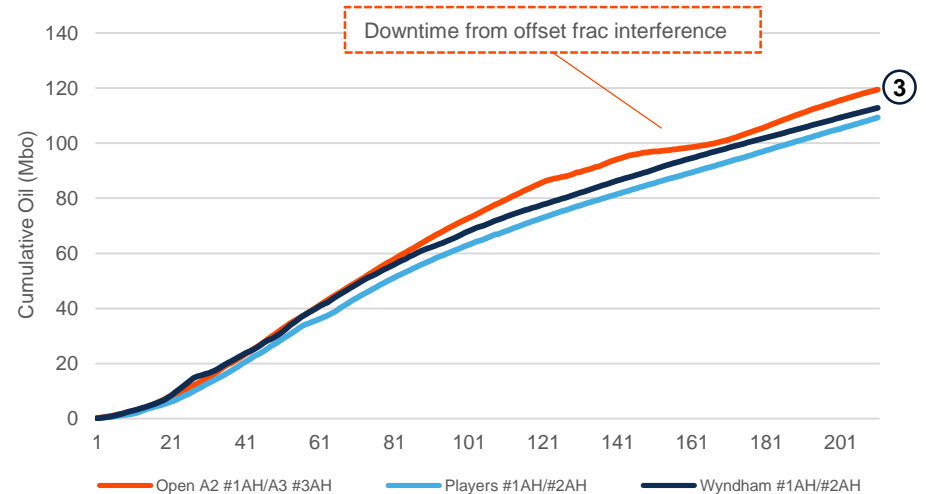
HOWARD COUNTY ACTIVITY RAMPING IN 2H18

- Barclays and Players wells exceeding oil type curves early time by roughly 29% and 33% respectively
- Optimized frac loadings achieving 3-5% cost savings per well
- 10 well downspacing test continues to exceed offsets
- Majority of activity focused on multi-well pads with ~10 gross wells expected to be POP in 2H18
- 2H18 Wildhorse wells expected to average ~8,500 lateral feet

STRONG EARLY RATES FROM RECENT FAIRWAY WELLS



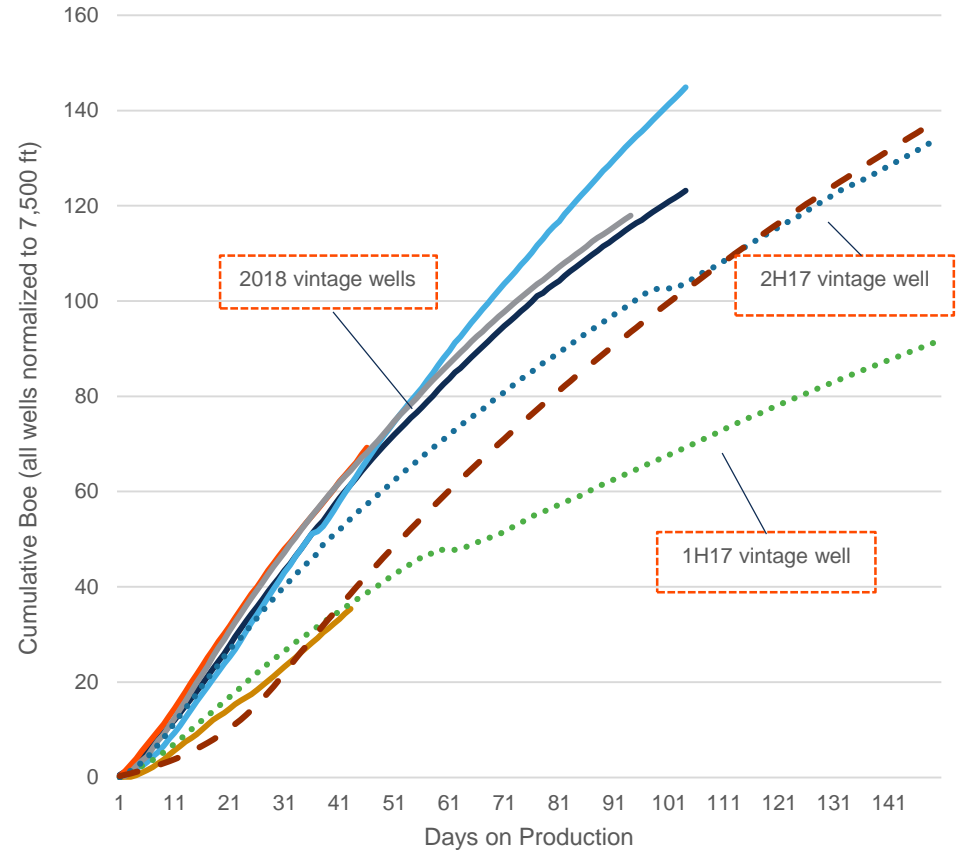
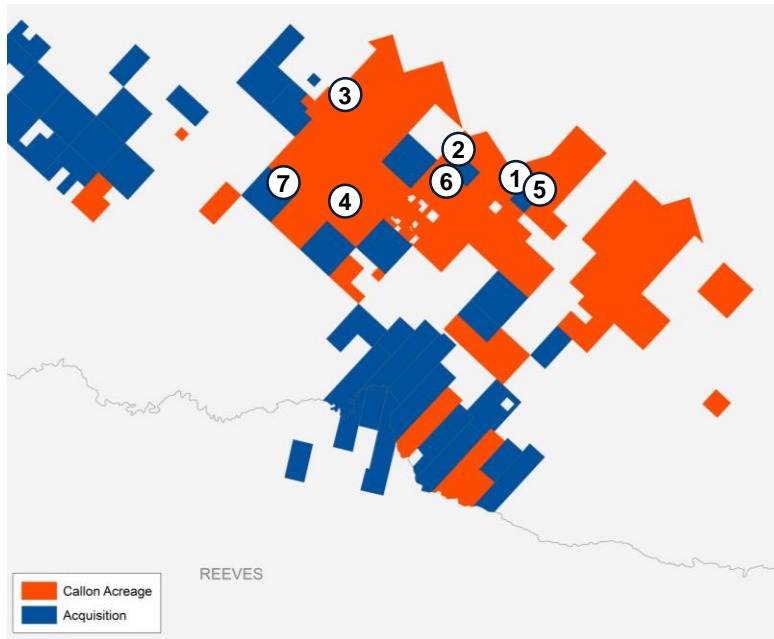
DOWN SPACING TESTS CONTINUE TO OUTPERFORM



Delaware Basin – Impressive Well Results

SPUR PROGRAM DEVELOPMENT FIRING ON ALL CYLINDERS

- Recent vintage wells showing significant improvement in early time production
- Currently producing from five flow units (Upper & Lower WCA, WC B, WC C and 3rd BS)
- Infrastructure investments paying off as recycling program ramps
- Recent WC C well, Rag Run 134 South #25CH (4,800' lateral), has produced ~23,000 Boe (80% oil) through first 43 days online and continues to clean up



- | | | | |
|---|----------------------------|---|-------------------------------|
| ① | — Rendezvous A1 #01LA | ⑤ | — Rendezvous A2 #09UA |
| ② | — Rag Run A1 #01LA | ⑥ | — Rag Run 134 SOUTH #25CH |
| ③ | — Moran A1 #01LA | ⑦ | — Saratoga A1 #07LA |
| ④ | — Sleeping Indian A1 #01LA | | — Spur LWC A 7,500 Type Curve |

Expanding Sales and Transport Options

SECURING LONG HAUL TRANSPORTATION TO GULF COAST FOR LONG-TERM GROWTH

Firm Transport capacity to Gulf Coast markets

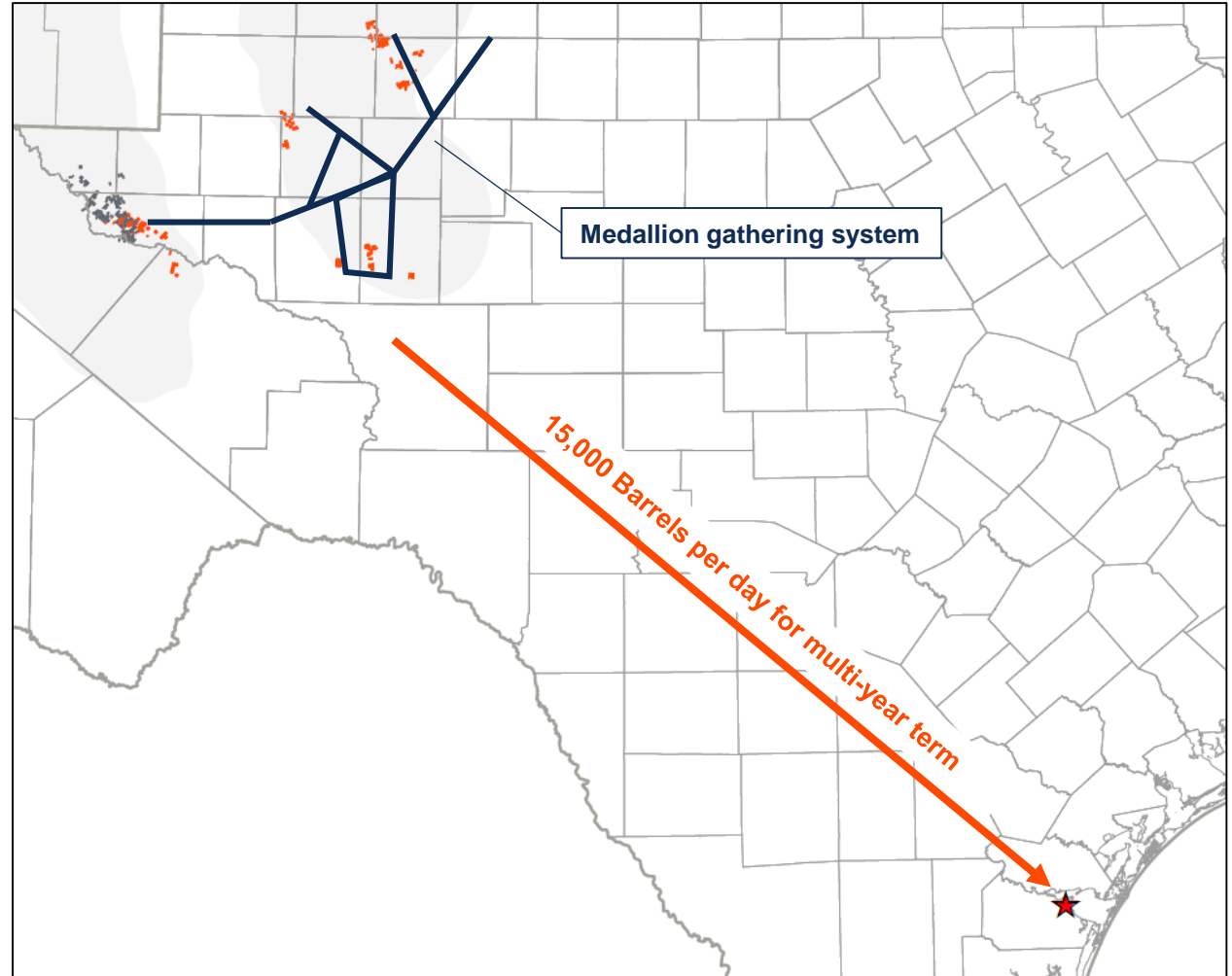
- Securing FT capacity for 15,000 barrels per day
- Multi-year term with attractive transport rates
- Interconnect with Medallion system (40MBopd of firm gathering transport)
- Availability expected in late 2019

Gulf Coast and International pricing benchmarks

- Multi-year term sales agreements matching transport commitment
- Not linked to export terminal development
- Opportunity to hedge liquid pricing benchmarks

Provides optionality and diversified pricing as part of portfolio management

- Increased diversification of buyers and markets
- Plan to further reduce Midland-based pricing exposure over time



Financial Positioning

HIGHLIGHTS

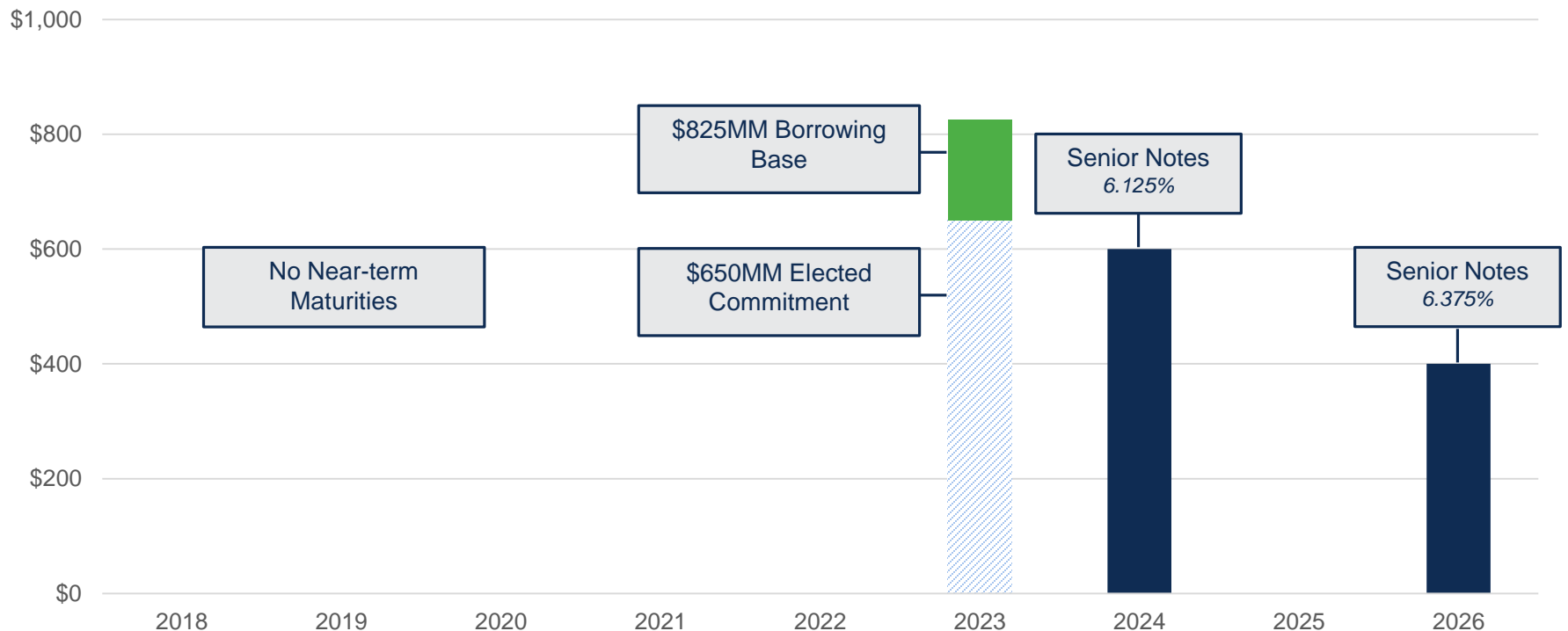
Continue to maintain solid balance sheet with strong liquidity and credit metrics

Significant PDP base from pending acquisition expected to provide material cash flow and capital flexibility

Enhanced liquidity position projected following pro forma borrowing base redetermination

Visible path to cash flow neutrality driven by focus on strong cash flow per debt-adjusted share growth

DEBT MATURITY SUMMARY (\$MM)



Risk Management

HEDGING STRATEGY (1)

Portfolio approach with focus on total realized price versus basis differential in isolation

Allow for upside pricing participation in a volatile market

Locking in WTI protection to support cash flow

- 2H18: ~70% hedged
- 2019: ~40% hedged

Methodically layering in Midland-Cushing basis differential protection to mitigate financial risk

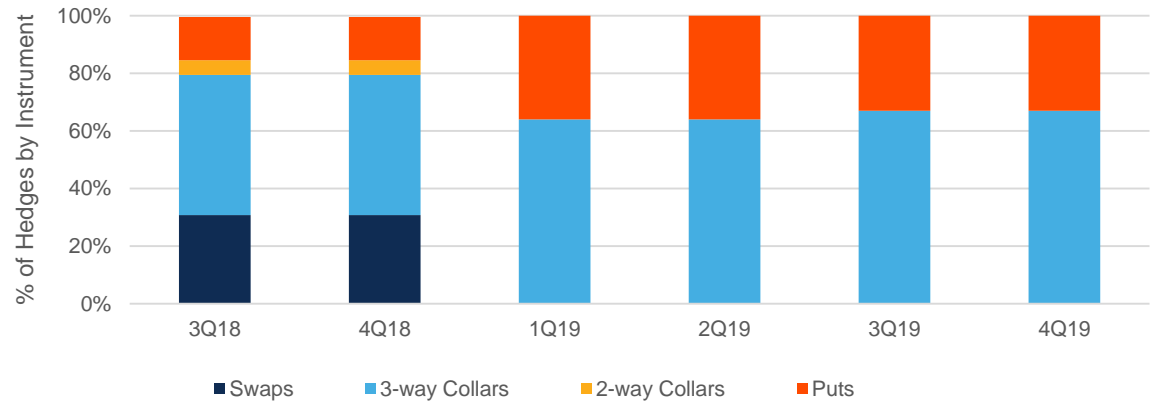
- 2H18: ~45% hedged at an average swap price of (\$4.26)
- 2019: ~40% hedged at an average swap price of (\$4.77)
- 2020: ~20% hedged at an average swap price of (\$1.47)

Establishing long-term gathering and sales contracts within the Permian Basin for incremental production

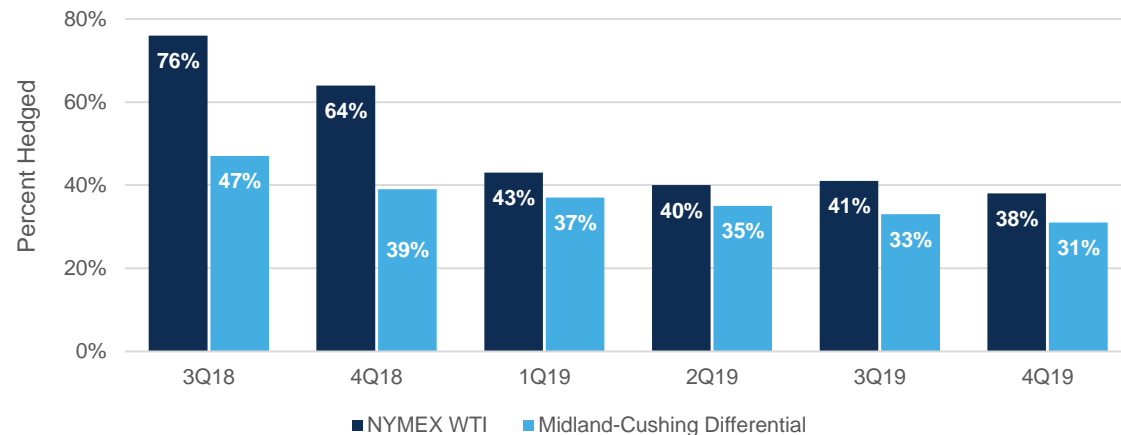
Continuing to evaluate a variety of physical (firm pipeline capacity out of Permian) and financial risk mitigation alternatives

- Match long-term growth trajectory
- Flow assurance
- Economic/realized price benefits

WTI INSTRUMENT BREAKOUT



CRUDE OIL HEDGE POSITION BY QUARTER (1)



1. Hedge contracts as of 7/31/18. Volumes hedged as a percentage of Consensus estimates sourced from FactSet 7/31/18.



Performance Relative to 2018 Guidance

	1H 2018 ACTUALS	STAND ALONE FY18 GUIDANCE
Total production (MBoepd)	27.8	29.5 – 32.0
Oil production	77%	77%
Income statement expenses (per BOE)		
LOE, including workovers	\$5.21	\$5.25 - \$6.25
Production taxes, including ad valorem (% of unhedged revenues)	6%	6%
Adjusted G&A: cash component ⁽¹⁾	\$2.71	\$1.75 - \$2.50
Adjusted G&A: non-cash component ⁽²⁾	\$0.58	\$0.50 - \$1.00
Cash interest expense ⁽³⁾	\$0.00	\$0.00
Statutory income tax rate	22%	22%
Capital expenditures (\$MM, accrual basis)		
Total operational capital ⁽⁴⁾	\$283	\$500 - \$540
Capitalized expenses	\$33	\$60 - \$70
Net operated horizontal wells placed on production	23	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.

APPENDIX

Pad Development Across The Asset Base

PAD DEVELOPMENT INCREASING

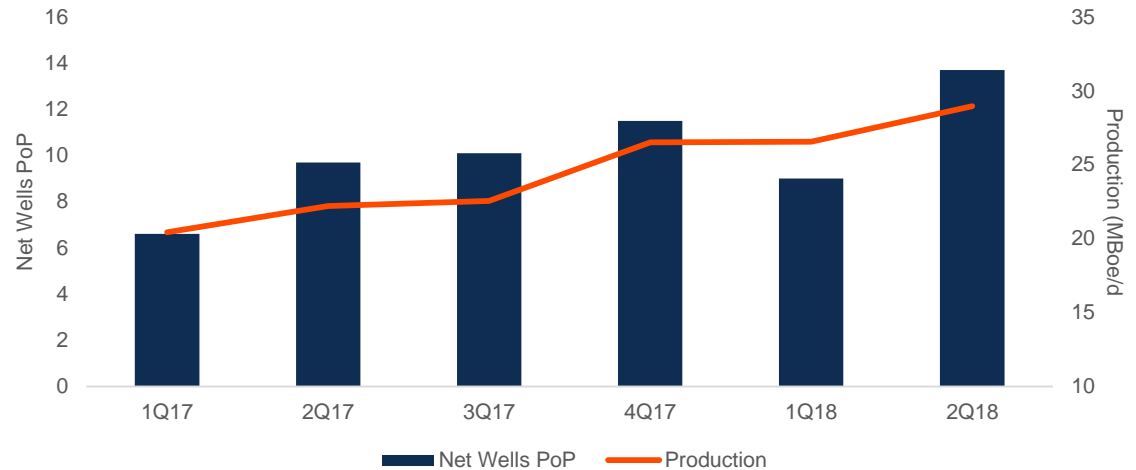
Consistent movement towards larger, multi-well pads over time

Operational efficiencies improve, but timing of production adds less consistent

Production ramp is affected by multiple factors:

- Intra-quarter timing of wells PoP
- Development area and net lateral length
- Impact to offset production

TIMING OF WELLS PoP CREATES LUMPINESS IN PRODUCTION GROWTH



PRODUCT MIX VARIES BY QUARTER

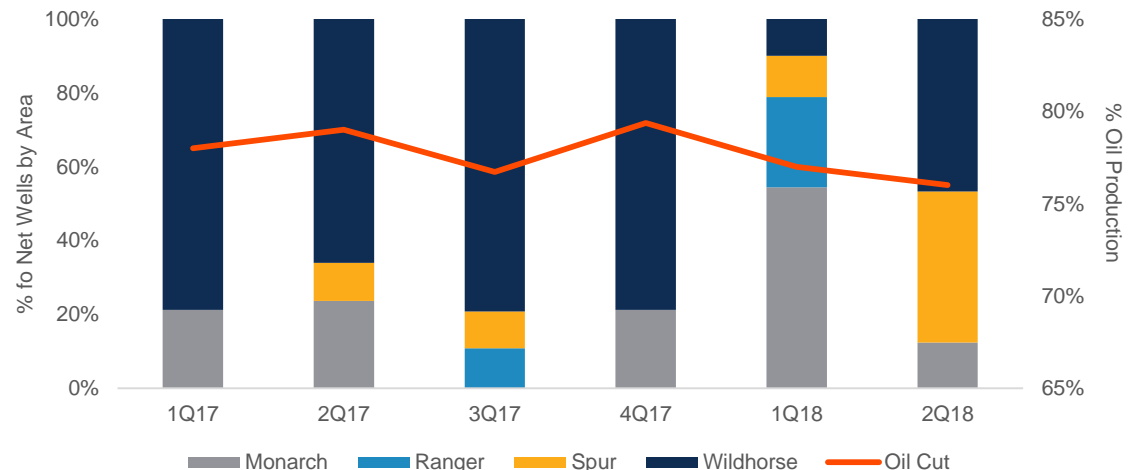
Change in asset base and drilling areas over time affect product mix

Oil production has ranged over past six quarters between 76% and 79%

Periods with activity at Ranger tend to pull down the mix temporarily

- 2Q18 Ranger oil mix: 55%
- 2Q18 Wildhorse oil mix: 84%
- 2Q18 Monarch oil mix: 76%
- 2Q18 Spur oil mix: 82%

WELLS PoP IN A QUARTER DRIVE MIX



Oil Hedge Portfolio (1)

	<u>1Q18</u>	<u>2Q18</u>	<u>3Q18</u>	<u>4Q18</u>	<u>1Q19</u>	<u>2Q19</u>	<u>3Q19</u>	<u>4Q19</u>	<u>FY2020</u>
NYMEX WTI (Bbls, \$/Bbl)									
Swaps									
Total Quarterly Volumes	450,000	455,000	552,000	552,000	-	-	-	-	-
Daily Volumes	5,000	5,000	6,000	6,000	-	-	-	-	-
Avg. Swap Price	\$51.42	\$51.42	\$52.07	\$52.07	-	-	-	-	-
Three-way Collars									
Total Quarterly Volumes	855,000	864,500	874,000	874,000	810,000	819,000	920,000	920,000	-
Daily Volumes	9,500	9,500	9,500	9,500	9,000	9,000	10,000	10,000	-
Avg. Short Call	\$60.86	\$60.86	\$60.86	\$60.86	\$63.71	\$63.71	\$63.70	\$63.70	-
Avg. Long Put	\$48.95	\$48.95	\$48.95	\$48.95	\$53.89	\$53.89	\$54.00	\$54.00	-
Avg. Short Put	\$39.21	\$39.21	\$39.21	\$39.21	\$43.89	\$43.89	\$44.00	\$44.00	-
Two-way Collars									
Total Quarterly Volumes	90,000	91,000	92,000	92,000	-	-	-	-	-
Daily Volumes	1,000	1,000	1,000	1,000	-	-	-	-	-
Avg. Short Call	\$60.50	\$60.50	\$60.50	\$60.50	-	-	-	-	-
Avg. Put	\$50.00	\$50.00	\$50.00	\$50.00	-	-	-	-	-
Deferred Premium Put Option									
Total Quarterly Volumes	-	-	276,000	276,000	450,000	455,000	460,000	460,000	-
Daily Volumes	-	-	3,000	3,000	5,000	5,000	5,000	5,000	-
Avg. Long Put	-	-	\$65.00	\$65.00	\$65.00	\$65.00	\$65.00	\$65.00	-
Total Volume Hedged	1,395,000	1,410,500	1,794,000	1,794,000	1,260,000	1,274,000	1,380,000	1,380,000	-
MIDLAND-CUSHING DIFFERENTIAL									
Swaps									
Total Quarterly Volumes	1,395,000	1,410,500	1,104,000	1,104,000	1,080,000	1,092,000	1,104,000	1,104,000	3,660,000
Daily Volumes	15,500	15,500	12,000	12,000	12,000	12,000	12,000	12,000	10,000
Avg. Swap Price	(\$0.80)	(\$0.80)	(\$4.18)	(\$4.33)	(\$5.76)	(\$5.76)	(\$3.81)	(\$3.81)	(\$1.47)

1. Hedge contracts as of 7/31/18.



Gas Hedge Portfolio (1)

	<u>1Q18</u>	<u>2Q18</u>	<u>3Q18</u>	<u>4Q18</u>	<u>1Q19</u>	<u>2Q19</u>	<u>3Q19</u>	<u>4Q19</u>	<u>FY2020</u>
NYMEX Henry Hub (MMBtu, \$/MMBtu)									
Swaps									
Total Quarterly Volumes	341,000	1,365,000	1,380,000	1,380,000	-	-	-	-	-
Daily Volumes	3,667	15,000	15,000	15,000	-	-	-	-	-
Avg Swap Price	\$2.95	\$2.91	\$2.91	\$2.91	-	-	-	-	-
Two-way Collars									
Total Quarterly Volumes	720,000	-	552,000	552,000	585,000	591,500	598,000	598,000	-
Daily Volumes	8,000	-	6,000	6,000	6,500	6,500	6,500	6,500	-
Avg Ceiling	\$3.84	-	\$3.19	\$3.19	\$2.95	\$2.95	\$2.95	\$2.95	-
Avg Floor	\$3.40	-	\$2.75	\$2.75	\$2.65	\$2.65	\$2.65	\$2.65	-
Total Volume Hedged	1,061,000	1,365,000	1,932,000	1,932,000	585,000	591,500	598,000	598,000	-
Average Ceiling Price	\$3.84	-	\$3.19	\$3.19	\$2.95	\$2.95	\$2.95	\$2.95	-
Average Floor Price	\$3.25	\$2.91	\$2.86	\$2.86	\$2.65	\$2.65	\$2.65	\$2.65	-
WAHA DIFFERENTIAL									
Swaps									
Total Quarterly Volumes	-	-	552,000	552,000	540,000	546,000	552,000	552,000	2,196,000
Daily Volumes	-	-	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Avg Swap Price	-	-	(\$1.14)	(\$1.14)	(\$1.14)	(\$1.14)	(\$1.14)	(\$1.14)	(\$1.14)

1. Hedge contracts as of 7/31/18.



Quarterly Cash Flow Statement

	2Q17	3Q17	4Q17	1Q18	2Q18
Cash flows from operating activities:					
Net income	\$ 33,390	\$ 17,081	\$ 22,824	\$ 55,761	\$ 50,474
Adjustments to reconcile net income to cash provided by operating activities:					
Depreciation, depletion and amortization	26,765	29,132	37,222	36,066	39,387
Accretion expense	208	131	154	218	206
Amortization of non-cash debt related items	589	441	455	453	588
Deferred income tax expense	323	237	247	495	481
(Gain) loss on derivatives, net of settlements	(10,761)	12,947	26,037	(3,978)	8,572
Loss on sale of other property and equipment	62	—	—	—	22
Non-cash expense related to equity share-based awards	4,865	1,219	1,240	1,131	1,627
Change in the fair value of liability share-based awards	1,982	732	865	1,012	(463)
Payments to settle asset retirement obligations	(816)	(250)	(216)	(366)	(207)
Changes in current assets and liabilities:					
Accounts receivable	(3,744)	(4,338)	(32,347)	(8,067)	10,447
Other current assets	(874)	(38)	444	61	(5,611)
Current liabilities	(4,223)	1,854	23,413	12,938	4,123
Other long-term liabilities	120	1	—	87	200
Long-term prepaid	—	(4,650)	—	—	—
Other assets, net	(247)	(606)	(152)	(507)	(181)
Payments to settle vested liability share-based awards	(4,511)	—	—	(3,089)	(1,901)
Net cash provided by operating activities	43,128	53,893	80,186	92,215	107,764
Cash flows from investing activities:					
Capital expenditures	(79,936)	(121,128)	(152,621)	(111,330)	(187,040)
Acquisitions	(58,004)	(8,015)	(3,952)	(38,923)	(6,469)
Acquisition deposit	—	—	(900)	900	(28,500)
Proceeds from sales of mineral interests and equipment	—	—	20,525	—	3,077
Net cash used in investing activities	(137,940)	(129,143)	(136,948)	(149,353)	(218,932)
Cash flows from financing activities:					
Borrowings on senior secured revolving credit facility	—	—	25,000	80,000	85,000
Payments on senior secured revolving credit facility	—	—	—	(30,000)	(160,000)
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	—	—	—	—
Issuance of 6.375% senior unsecured notes due 2026	—	—	—	—	400,000
Issuance of common stock	—	—	—	—	288,357
Payment of preferred stock dividends	(1,823)	(1,824)	(1,824)	(1,824)	(1,824)
Payment of deferred financing costs	(6,765)	(401)	(28)	—	(8,664)
Tax withholdings related to restricted stock units	(974)	(65)	—	(560)	(1,028)
Net cash provided by (used in) financing activities	198,688	(2,290)	23,148	47,616	601,841
Net change in cash and cash equivalents	103,876	(77,540)	(33,614)	(9,522)	490,673
Balance, beginning of period	35,273	139,149	61,609	27,995	18,473
Balance, end of period	<u>\$ 139,149</u>	<u>\$ 61,609</u>	<u>\$ 27,995</u>	<u>\$ 18,473</u>	<u>\$ 509,146</u>



Non-GAAP Reconciliation ⁽¹⁾

	<u>2Q17</u>	<u>3Q17</u>	<u>4Q17</u>	<u>1Q18</u>	<u>2Q18</u>
Adjusted Income Reconciliation					
Income available to common stockholders	\$ 31,566	\$ 15,257	\$ 21,001	\$ 53,937	\$ 48,650
Adjustments:					
Change in valuation allowance	(11,194)	(6,064)	(8,285)	(11,753)	(10,562)
Net (gain) loss on derivatives, net of settlements	(6,995)	8,416	16,924	(3,143)	6,772
Change in the fair value of share-based awards	(315)	475	562	799	(366)
Settled share-based awards	4,128	—	—	—	—
Adjusted Income	<u>\$ 17,190</u>	<u>\$ 18,084</u>	<u>\$ 30,202</u>	<u>\$ 39,840</u>	<u>\$ 44,494</u>
Adjusted Income per fully diluted common share	<u>\$ 0.09</u>	<u>\$ 0.09</u>	<u>\$ 0.15</u>	<u>\$ 0.20</u>	<u>\$ 0.21</u>
Adjusted EBITDA Reconciliation					
Net income	\$ 33,390	\$ 17,081	\$ 22,824	\$ 55,761	\$ 50,474
Adjustments:					
Net (gain) loss on derivatives, net of settlements	(10,761)	12,947	26,037	(3,978)	8,572
Non-cash stock-based compensation expense	499	1,952	2,101	2,143	1,164
Settled share-based awards	6,351	—	—	—	—
Acquisition expense	2,373	205	(112)	548	1,767
Income tax expense	322	237	248	495	481
Interest expense	589	444	461	460	594
Depreciation, depletion and amortization	26,765	29,132	37,222	36,066	39,387
Accretion expense	208	131	154	218	206
Adjusted EBITDA	<u>\$ 59,736</u>	<u>\$ 62,129</u>	<u>\$ 88,935</u>	<u>\$ 91,713</u>	<u>\$ 102,645</u>



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

Non-GAAP Reconciliation ⁽¹⁾

	2Q17	3Q17	4Q17	1Q18	2Q18
Adjusted G&A Reconciliation					
Total G&A expense	\$ 6,430	\$ 7,259	\$ 8,173	\$ 8,769	\$ 8,289
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)	567	(731)	(844)	(991)	484
Adjusted G&A – total	6,472	6,528	7,329	7,778	8,773
Less: Restricted stock share-based compensation (non-cash)	(966)	(1,198)	(1,202)	(1,105)	(1,587)
Less: Corporate depreciation & amortization (non-cash)	(114)	(146)	(125)	(124)	(109)
Adjusted G&A – cash component	<u>\$ 5,392</u>	<u>\$ 5,184</u>	<u>\$ 6,002</u>	<u>\$ 6,549</u>	<u>\$ 7,077</u>
Adjusted Total Revenue Reconciliation					
Oil revenue	\$ 72,885	\$ 73,349	\$ 104,132	\$ 115,286	\$ 122,613
Natural gas revenue	9,398	11,265	14,081	12,154	14,462
Total revenue	82,283	84,614	118,213	127,440	137,075
Impact of cash-settled derivatives	(267)	(1,214)	(4,501)	(8,459)	(7,980)
Adjusted Total Revenue	<u>\$ 82,016</u>	<u>\$ 83,400</u>	<u>\$ 113,712</u>	<u>\$ 118,981</u>	<u>\$ 129,095</u>
Total Production (Mboe)	2,021	2,074	2,439	2,391	2,635
Adjusted Total Revenue per Boe	\$ 40.58	\$ 40.21	\$ 46.62	\$ 49.76	\$ 48.99
Discretionary Cash Flow Reconciliation					
Net cash provided by operating activities	\$ 43,128	\$ 53,893	\$ 80,186	\$ 92,215	\$ 107,764
Changes in working capital	8,968	7,777	8,642	(4,512)	(8,978)
Payments to settle asset retirement obligations	816	250	216	366	207
Payments to settle vested liability share-based awards	4,511	—	—	3,089	1,901
Discretionary cash flow	<u>\$ 57,423</u>	<u>\$ 61,920</u>	<u>\$ 89,044</u>	<u>\$ 91,158</u>	<u>\$ 100,894</u>
Discretionary cash flow per diluted share	<u>\$ 0.28</u>	<u>\$ 0.31</u>	<u>\$ 0.44</u>	<u>\$ 0.45</u>	<u>\$ 0.48</u>

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

