CALLON
PETROLEUM

October Investor Presentation

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

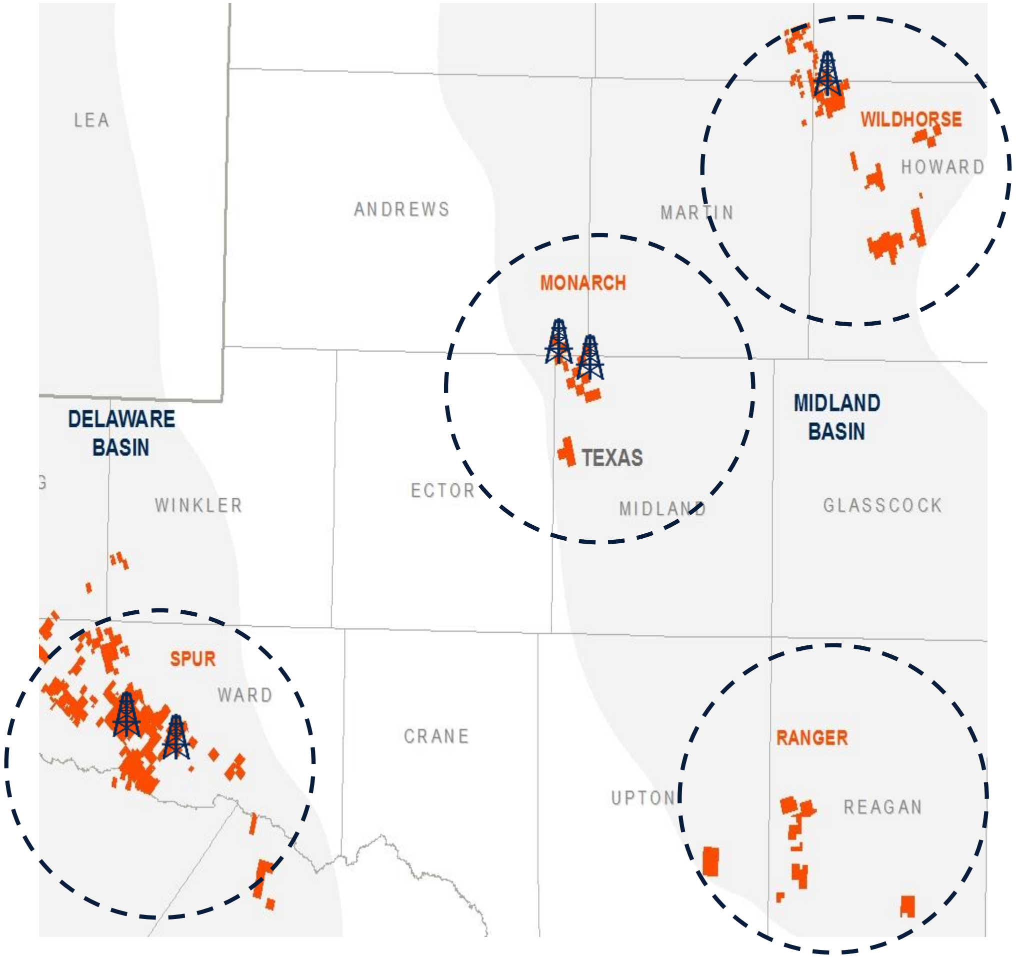
RECENT HIGHLIGHTS

- Closed acquisition of significant bolt-on acreage in Delaware Basin with meaningful near-term value contribution
- Operational efficiencies driving higher FY'18 guidance for wells PoP while maintaining disciplined capital strategy
- Evolving to larger scale development with first "mega-pad"
- Spur D&C efficiencies continue to improve

PORTFOLIO FOR OPERATED INVESTMENT

- Over 1,500 operated locations in *only currently producing zones* (11.7mm lateral feet)
- Total EUR of 1.4 Billion Boe (77% oil) based on current type curves
- Avg. Spur lateral increased to ~8,200' post transaction
- Weighted average IRR of 40%+ [2]

CURRENT RIG ACTIVITY



~ 86,000+ PRO FORMA NET ACRES

1. LOE figures are calculated on a two-stream basis.
2. Assumes NYMEX benchmark prices of $60/Bbl and $2.75/MMBtu.

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

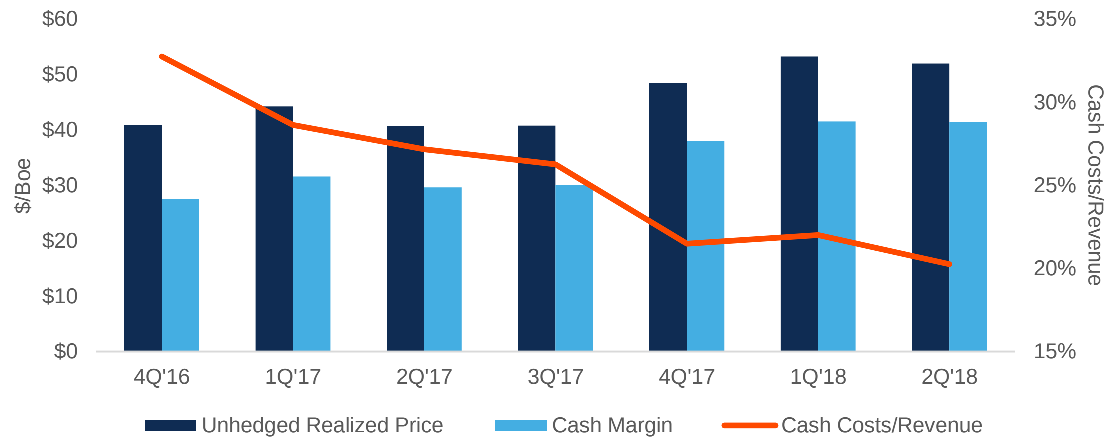
Industry leading operating margins

- During 1H'18, CPE achieved the highest Bloomberg standardized Adj. EBITDAX/Boe operating margin across publicly traded E&Ps [2]
- 2Q'18 Adj. EBITDA(X)/Boe expanded to $38.95/Boe[3], representing 17% margin CAGR over the last 2 years

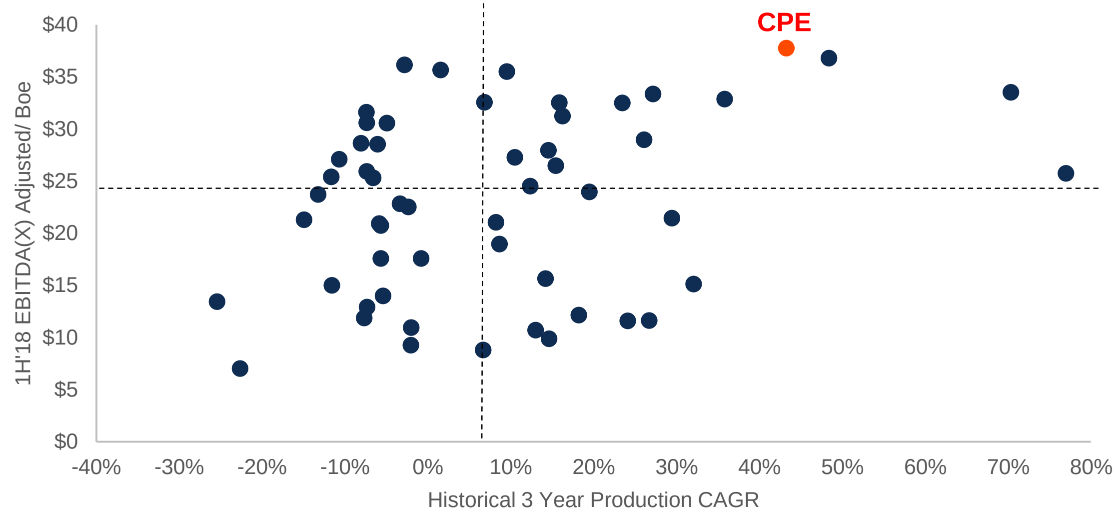
Future outlook

- Strategic infrastructure investment preserves margin strength
- Ongoing water recycling and power supply initiatives, combined with increased scale, expected to benefit improved capital efficiencies

COST IMPROVEMENTS DRIVING OPERATING RETURNS



CAPITAL EFFICIENT PRODUCTION GROWTH WITH SUPERIOR MARGINS [2]



1. Cash operating costs include Lease Operating Expenses, Production Taxes, and Cash G&A.
2. Based on standardized Bloomberg calculations for Adjusted EBITDA(X) for over 55 publicly traded E&Ps.
3. Based on CPE calculated Adjusted EBITDA(X).

Spur Bolt-On Acquisition

Unique Investment Opportunity	▪ Bolsters position in oil rich, over-pressured core of Southern Delaware Basin ▪ “Hand-in-glove” land position for extended laterals and increased working interest ▪ Leverage combined infrastructure
Compelling Corporate Value Proposition	▪ Purchase price underpinned by substantial PDP value ▪ Established production base provides current returns and contributes to accretion in CF per DAS ▪ Organic upside from emerging target zones
Near-Term Contribution	▪ 1Q18 production of 6,831 Boepd (73% oil) on 3-stream basis with a mature decline profile ▪ Currently completing an inherited DUC ▪ Immediately incorporating D&C activities into a combined Spur operating program

2018 Guidance Update

	1H 2018 ACTUALS	PRIOR FY18 GUIDANCE	UPDATED FY18 GUIDANCE
Total production (MBoepd)	27.8	29.5 – 32.0	**31.5 – 33.0**
Oil production	77%	77%	**76%**
Income statement expenses (per BOE)			
LOE, including workovers	$5.21	$5.25 - $6.25	**$5.00 - $6.00**
Production taxes, including ad valorem (% of unhedged revenues)	6%	6%	**7%**
Adjusted G&A: cash component [1]	$2.71	$1.75 - $2.50	**$1.75 - $2.50**
Adjusted G&A: non-cash component [2]	$0.58	$0.50 - $1.00	**$0.50 - $1.00**
Cash interest expense [3]	$0.00	$0.00	**$0.00**
Statutory income tax rate	22%	22%	**22%**
Capital expenditures ($MM, accrual basis)			
Total operational capital [4]	$283	$500 - $540	**$530 - $560**
Capitalized expenses	$33	$60 - $70	**$75 - $85**
Net operated horizontal wells placed on production	23	43 – 46	**47 - 50**

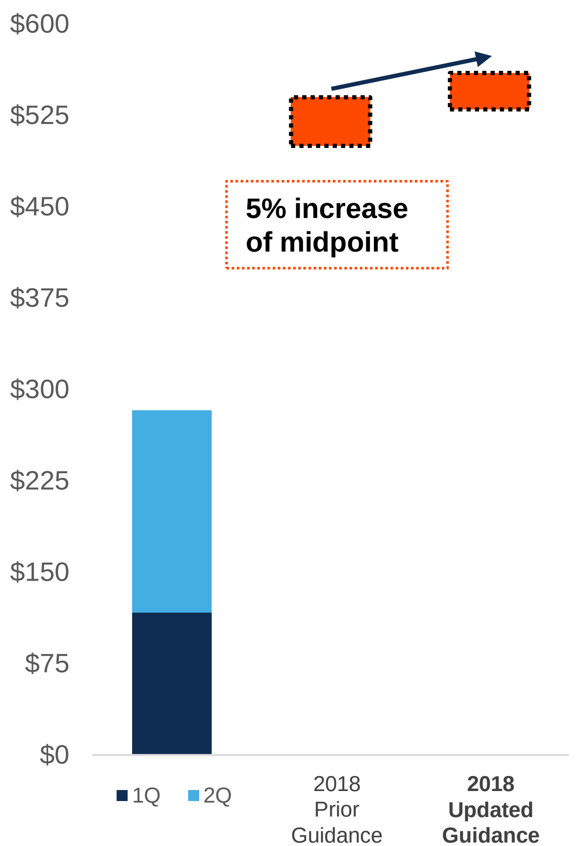
1. Excludes stock-based compensation and corporate depreciation and amortization. See the Non-GAAP related disclosures in the Appendix.
2. Excludes certain non-recurring expenses and non-cash valuation adjustments. See the non-GAAP related disclosures in the Appendix.
3. All cash interest expense anticipated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

Operational Efficiencies Guidance Update

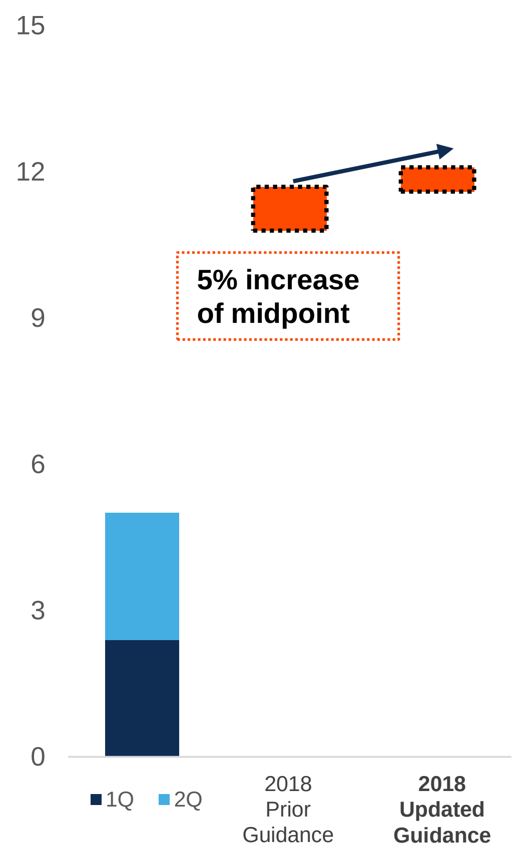
DEVELOPMENT ON TARGET

- 1H18 capital expenditures tracked on budget with additional 2H18 benefits expected from: increased local sand usage, ramped up recycling efforts, various supply chain initiatives, and reduced infrastructure spending in 3Q and 4Q
- Forecasted increase in FY18 operational capital driven by: ~10% increase in PoP from acquisition and D&C efficiencies, continued increase in non-op activity, and activity associated with acquired acreage

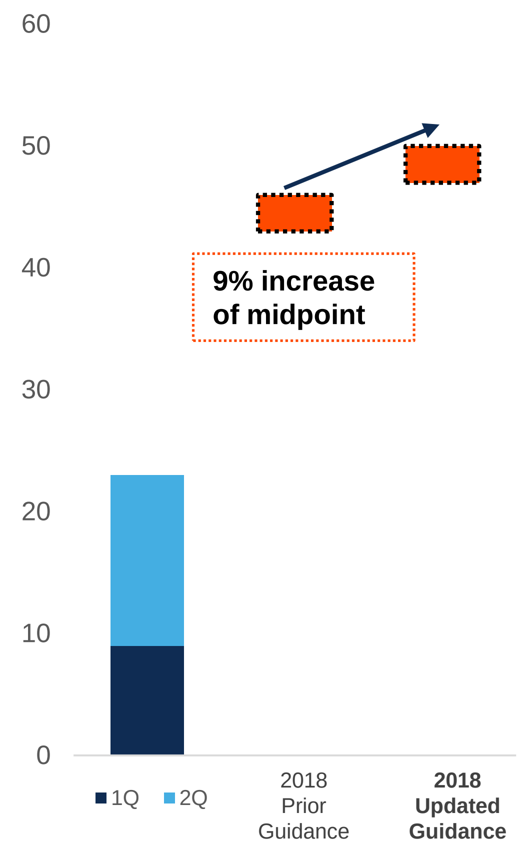
OPERATIONAL CAPITAL ($MM)



NET PRODUCTION (MMBoe)



NET WELLS PoP [1]



1. Placed on Production.

Production Growth Drivers

HIGHLIGHTS

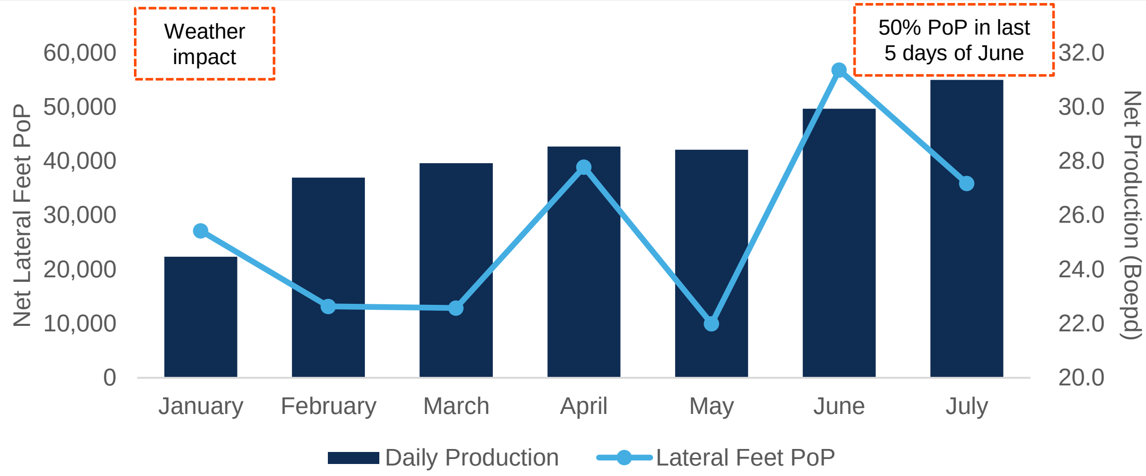
Evolution to larger pad concepts

- 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)

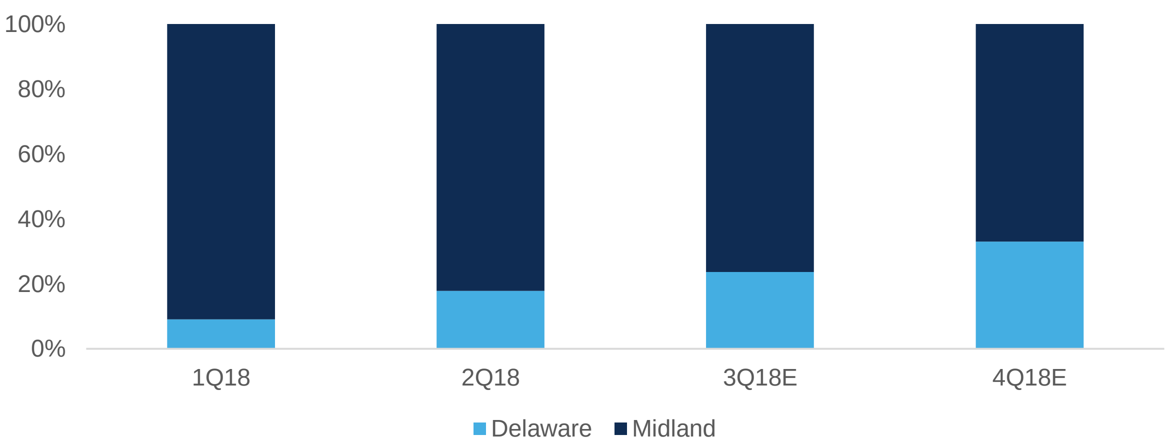
Delaware Basin underpins robust production growth outlook

- 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
- Acquisition impact bolsters future production profile

INCREASED PAD DEVELOPMENT [1]



RAPIDLY EMERGING DELAWARE PRODUCTION CONTRIBUTION



1. Placed on production for the quarter.

Cash Flow Alignment with Improving Capital Efficiency

FOCUSED ON GROWTH AND RETURNS

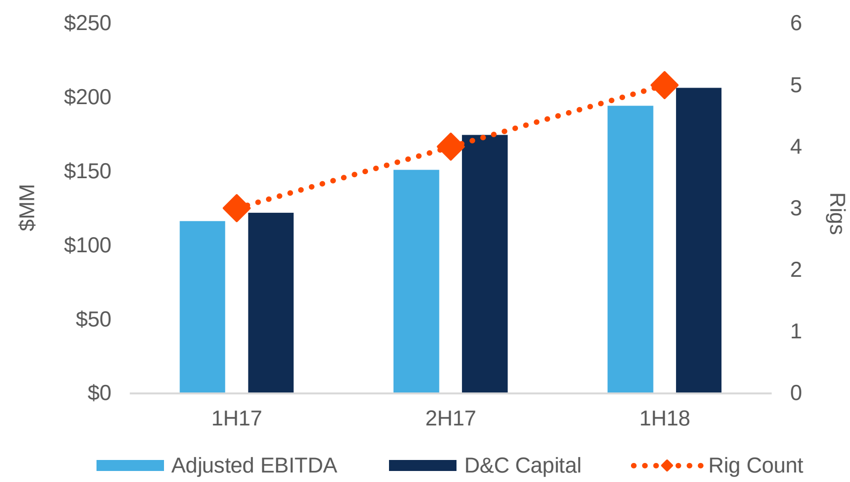
Company remains focused on growing responsibly

- 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

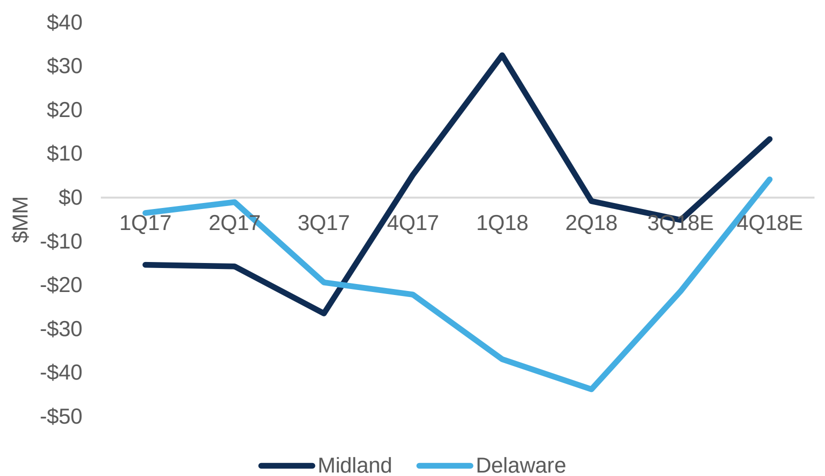
Returns driven capital allocation

- 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

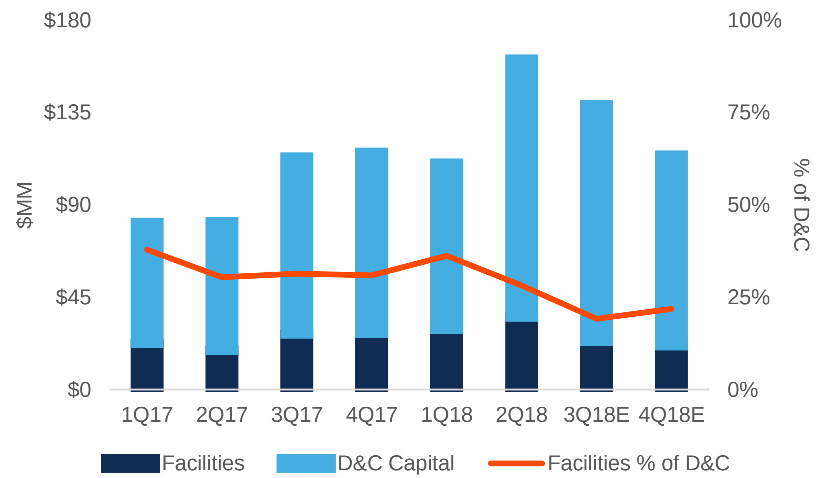
ADJ. EBITDA GROWTH TRACKING D&C SPENDING



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 8/23/2018.
2. 3Q'18 and 4Q'18 estimates reflect incorporation of XEC acquisition and updated guidance.

Mega-Pads at Monarch

SIMULTANEOUS RIG OPERATIONS CREATING LARGER PROJECTS WITH SHORTER CYCLE TIMES

1st Monarch "Mega-Pad" online

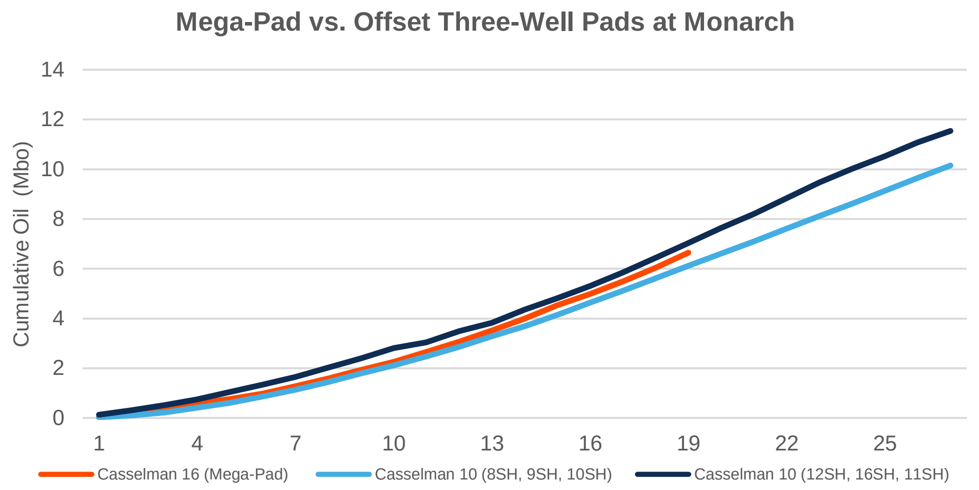
- Placed on production in July
- Average production exceeding 162 Bopd (185 Boepd) per 1,000 feet of lateral
- Average completed lateral length of 4,234 feet

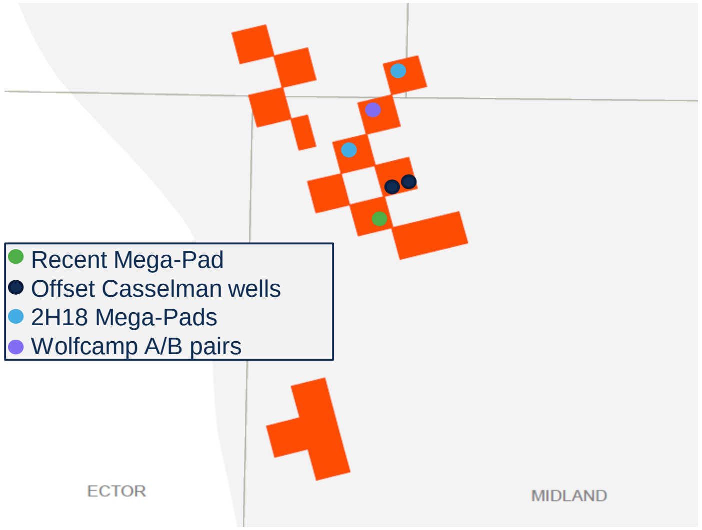
Additional development planned for 2H18

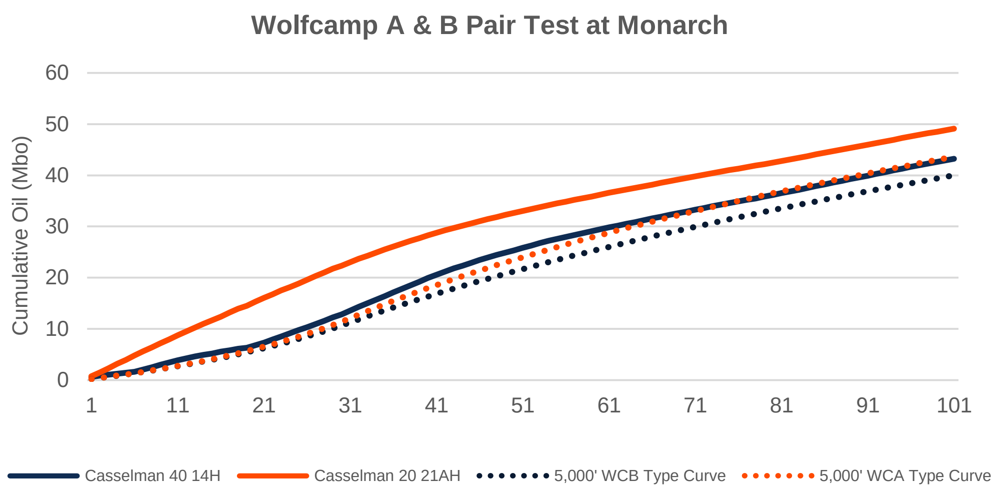
- 2nd location expected to be POP during Q4
- 3rd pad projected to spud near YE18

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



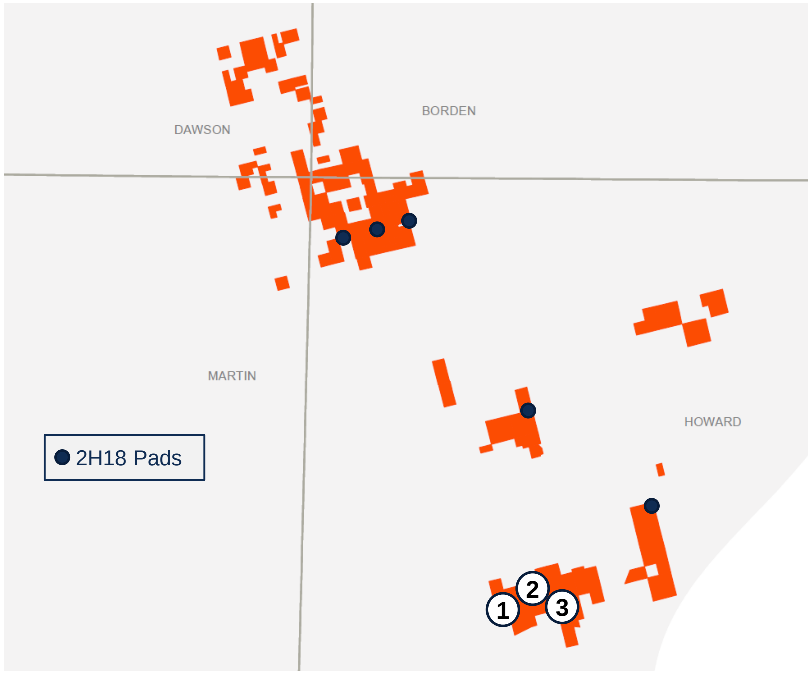




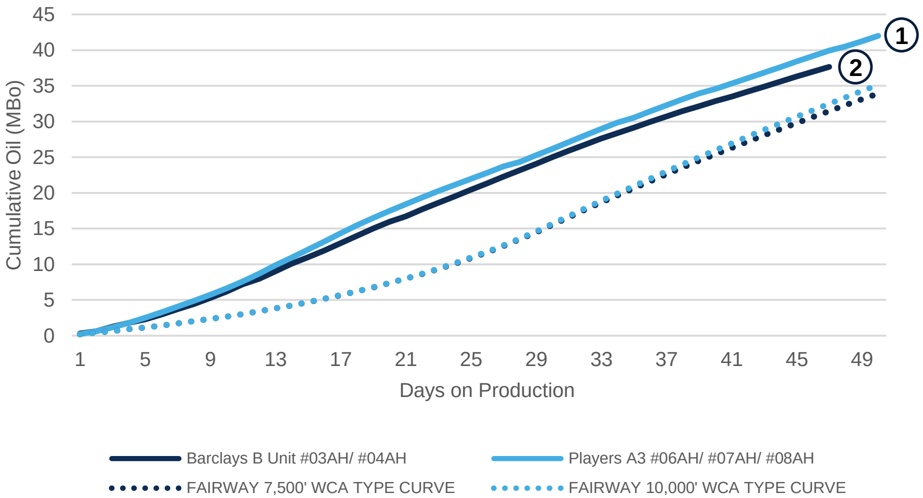
Robust Activity at Wildhorse

HOWARD COUNTY ACTIVITY RAMPING IN 2H18

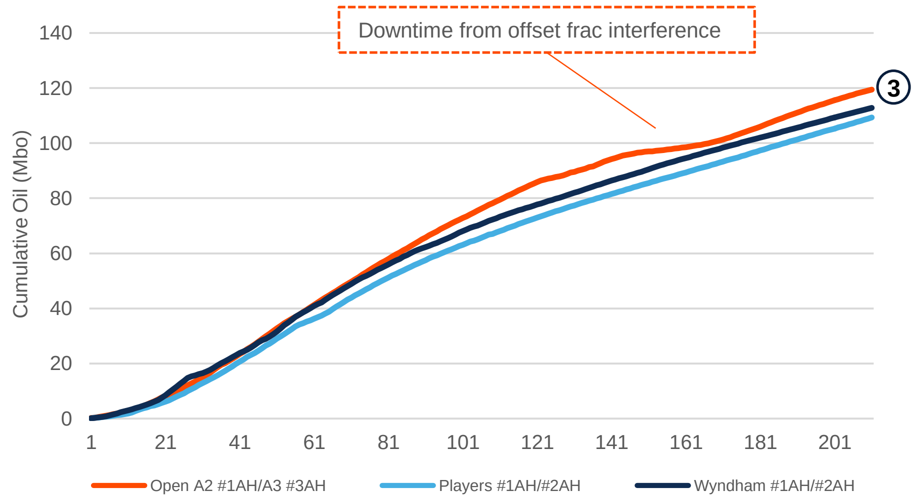
- Barclays and Players wells exceeding oil type curves early time by roughly 29% and 33% respectively
- Optimized frac loadings achieving 3-5% cost savings per well
- 10 well downspacing test continues to exceed offsets
- Majority of activity focused on multi-well pads with ~10 gross wells expected to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



STRONG EARLY RATES FROM RECENT FAIRWAY WELLS



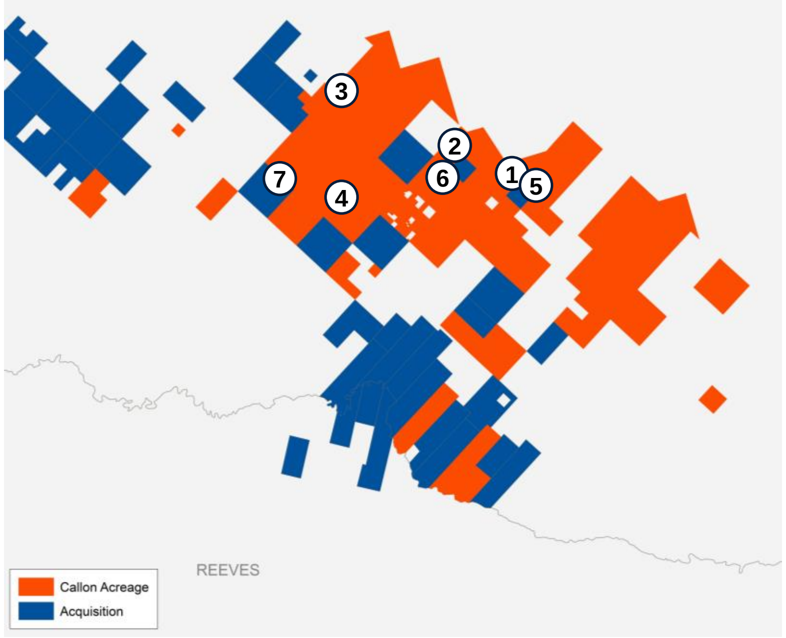
DOWN SPACING TESTS CONTINUE TO OUTPERFORM

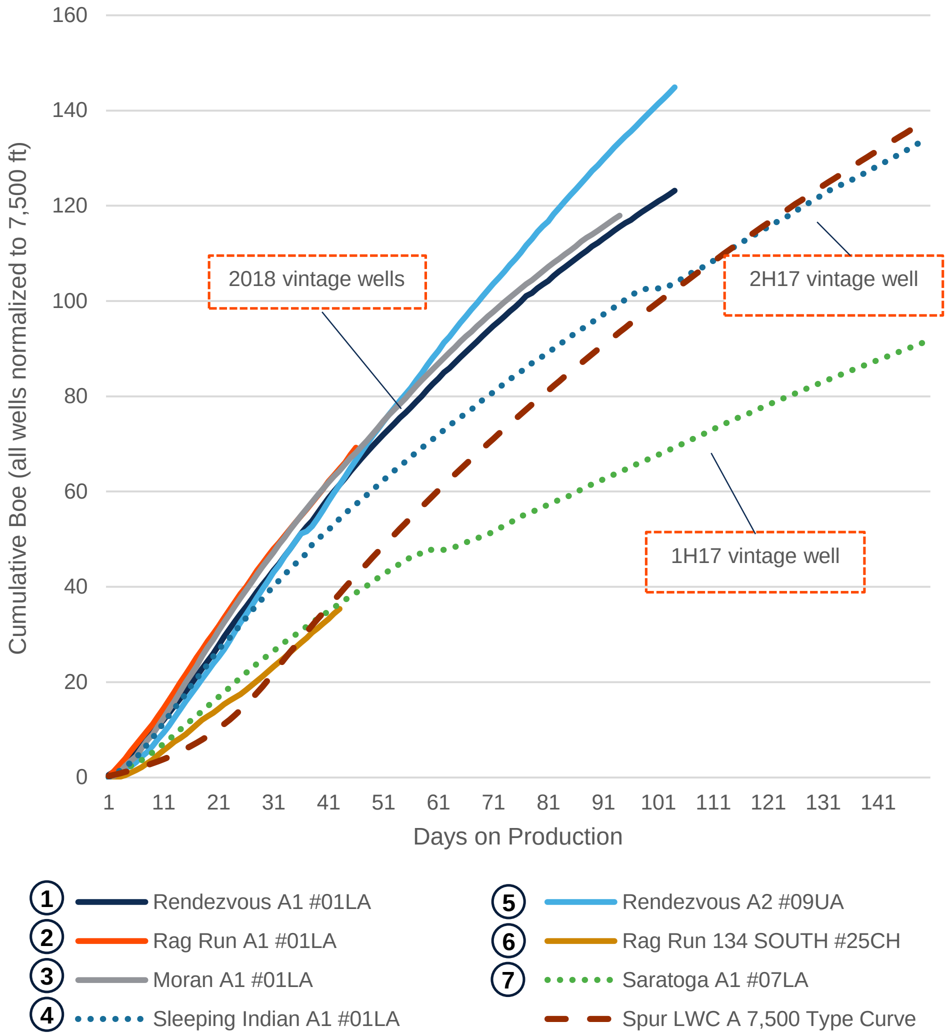


Delaware Basin – Impressive Well Results

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





Financial Positioning

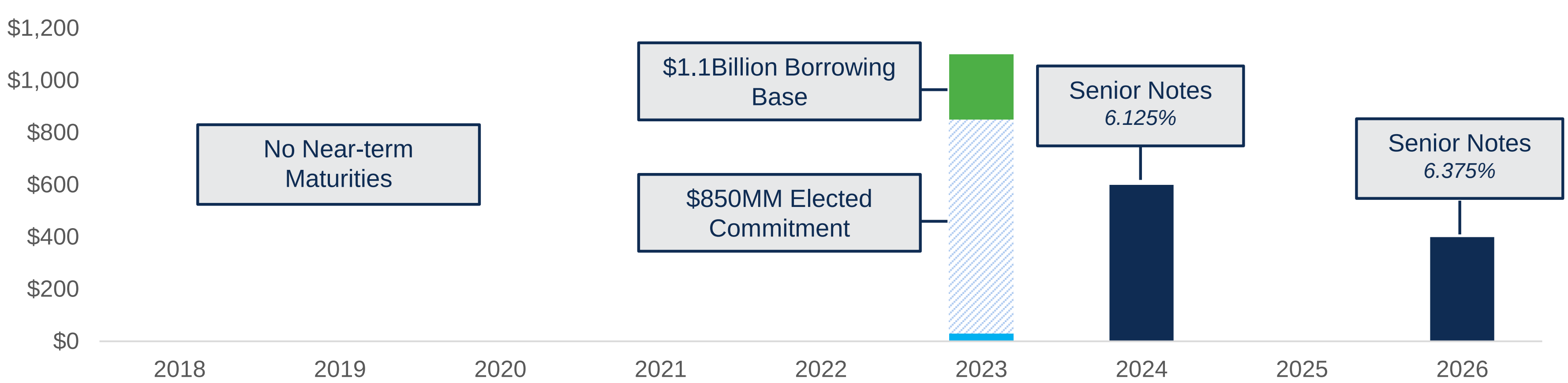
HIGHLIGHTS

- Borrowing base
- Solid balance sheet with strong liquidity and credit metrics
- Significant PDP base from pending acquisition expected to provide material cash flow and capital flexibility
- Expect material increase to liquidity position with the upcoming fall borrowing base redetermination
- Visible path to cash flow neutrality driven by focus on strong cash flow per debt-adjusted share growth

UPDATED CAPITALIZATION ($MM)

	2Q18	Adj. (1)	Pro Forma (2)
Cash	$509	($480)	$29
Credit facility	0	$30	$30
Senior notes	$1,000	0	$1,000
Total debt	**$1,000**	$30	**$1,030**
Stockholders' equity	2,290		2,290
Total capitalization	**$3,290**		**$3,320**
Credit statistics			
PF Net debt / LQA Adj. EBITDA(3)	- / -		2.0x
Liquidity			
Commitment amount	$650		$850
Less: drawn	0	($30)	($30)
Plus: cash	$509	($480)	$29
Total liquidity	**$1,159**	**($510)**	**$849**

DEBT MATURITY SUMMARY ($MM)



1. $510mm represents all in cash costs at closing; a $28.5mm deposit was also paid at signing.
2. Pro Forma figures reflect the recent (September 28, 2018) adjustment to the borrowing base in both the overall commitment amount elected by CPE and the resulting total liquidity
3. Acquired Adjusted EBITDA estimates based on most recent lease operating statements. For a reconciliation of Callon's Net Income (Loss) to Adjusted EBITDA see the Appendix.

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

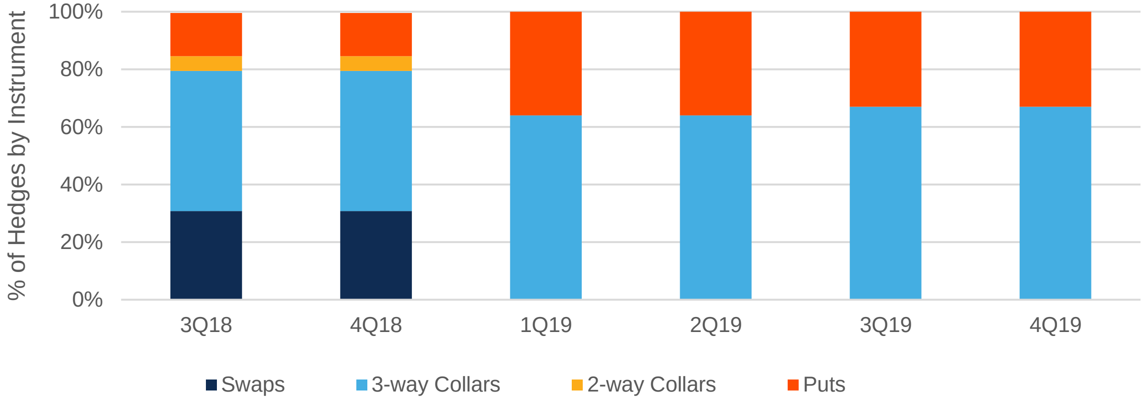
- **2H18:** ~50% hedged at an average swap price of ($4.61)
- **2019:** ~40% hedged at an average swap price of ($4.69)
- **2020:** ~25% hedged at an average swap price of ($1.53)

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

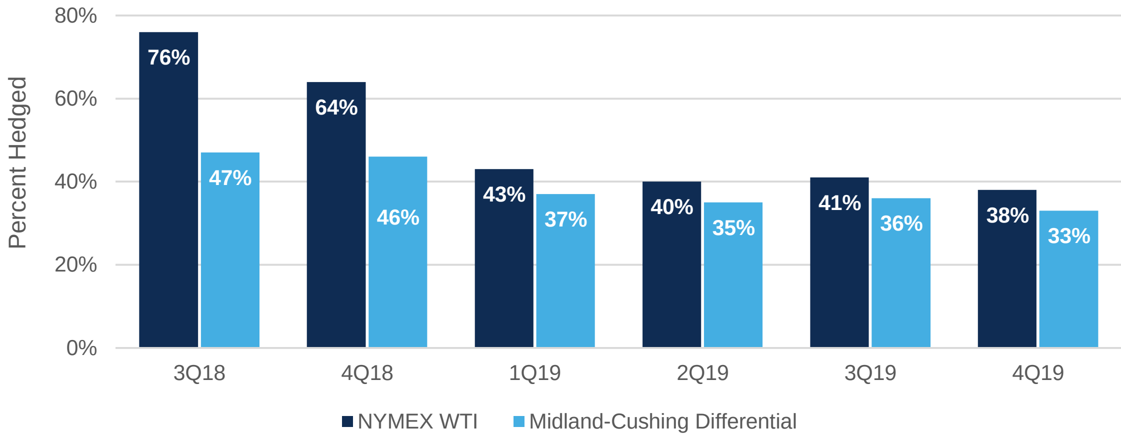
Continuing to evaluate a variety of physical (firm pipeline capacity out of Permian) and financial risk mitigation alternatives

- 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 8/30/18. Volumes hedged as a percentage of Consensus estimates sourced from FactSet 8/30/18.

Expanding Sales and Transport Options

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

Firm Transport capacity to Gulf Coast markets

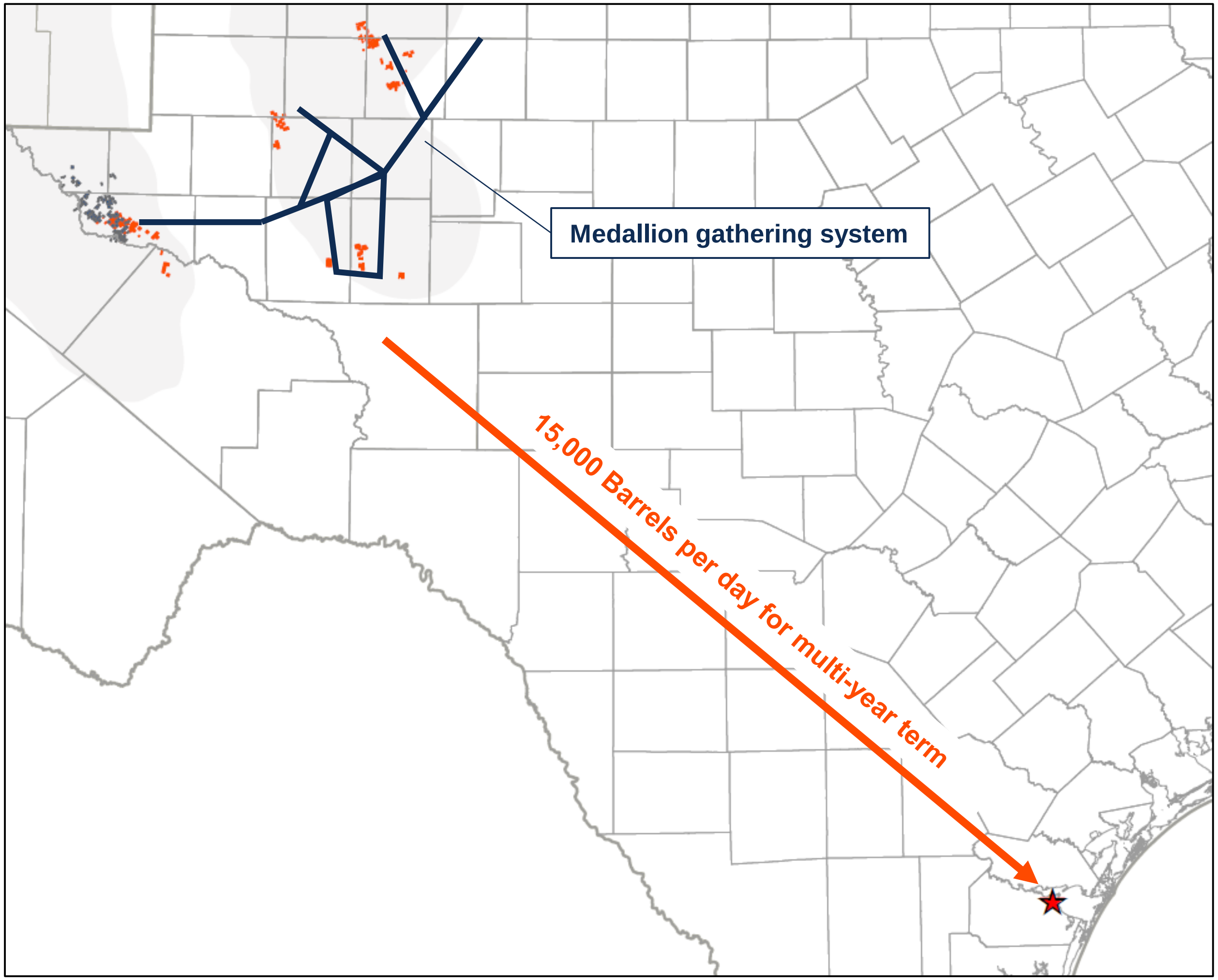
- Securing FT capacity for 15,000 barrels per day
- Multi-year term with attractive transport rates
- Interconnect with Medallion system (40MBopd of firm gathering transport)
- Availability expected in late 2019

Gulf Coast and International pricing benchmarks

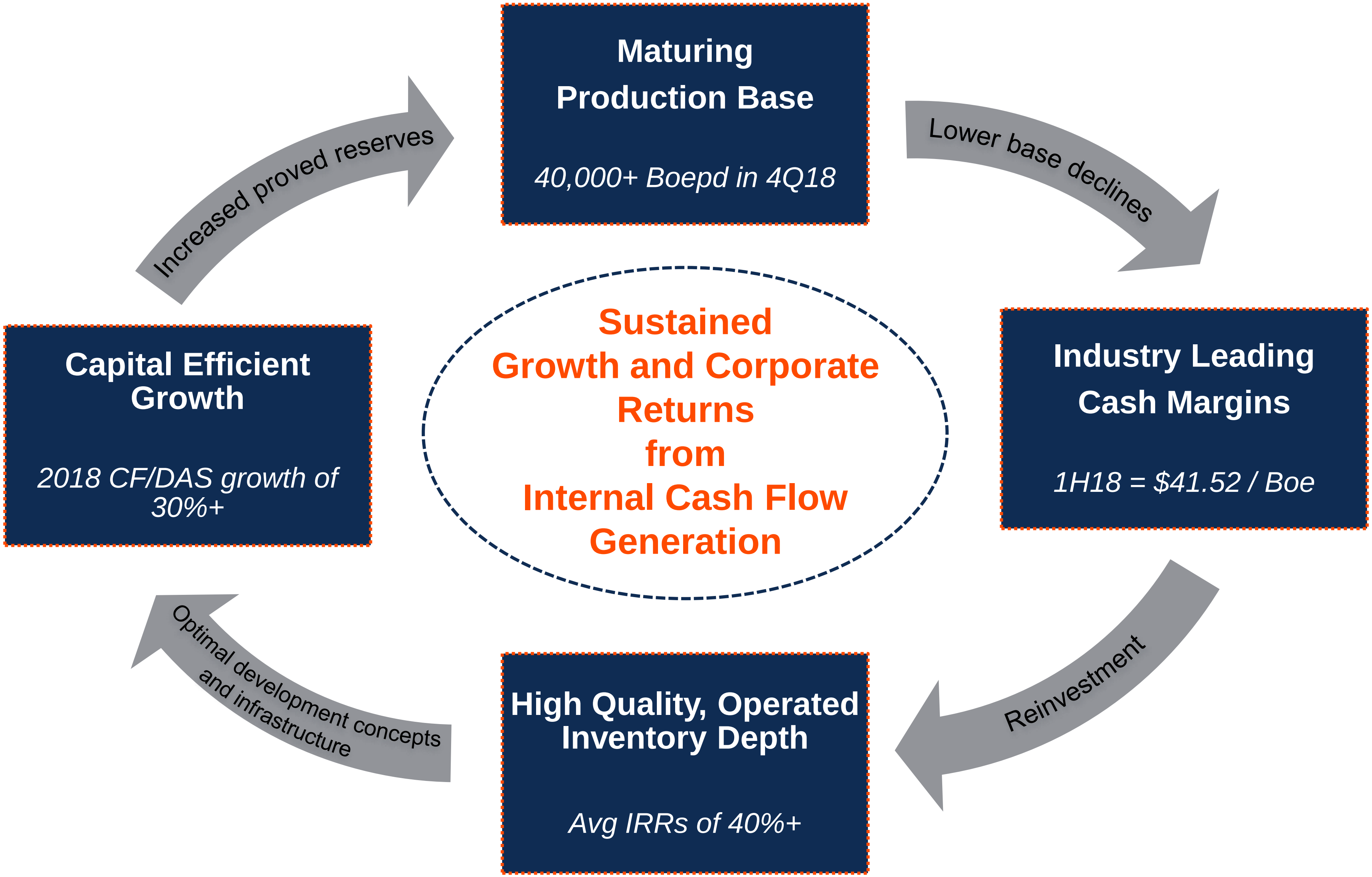
- Multi-year term sales agreements matching transport commitment
- Not linked to export terminal development
- Opportunity to hedge liquid pricing benchmarks

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



The Path Forward



APPENDIX

Pad Development Across The Asset Base

PAD DEVELOPMENT INCREASING

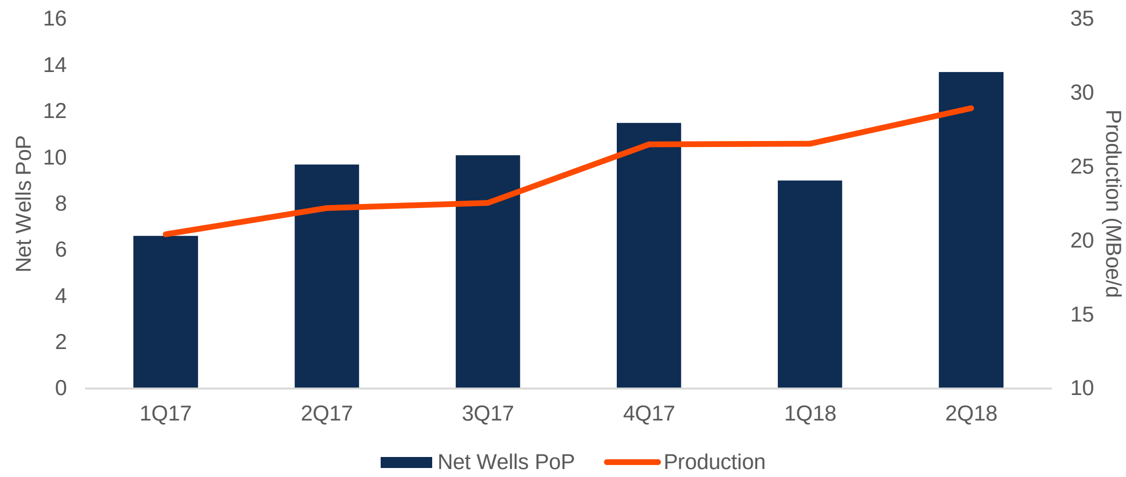
Consistent movement towards larger, multi-well pads over time

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

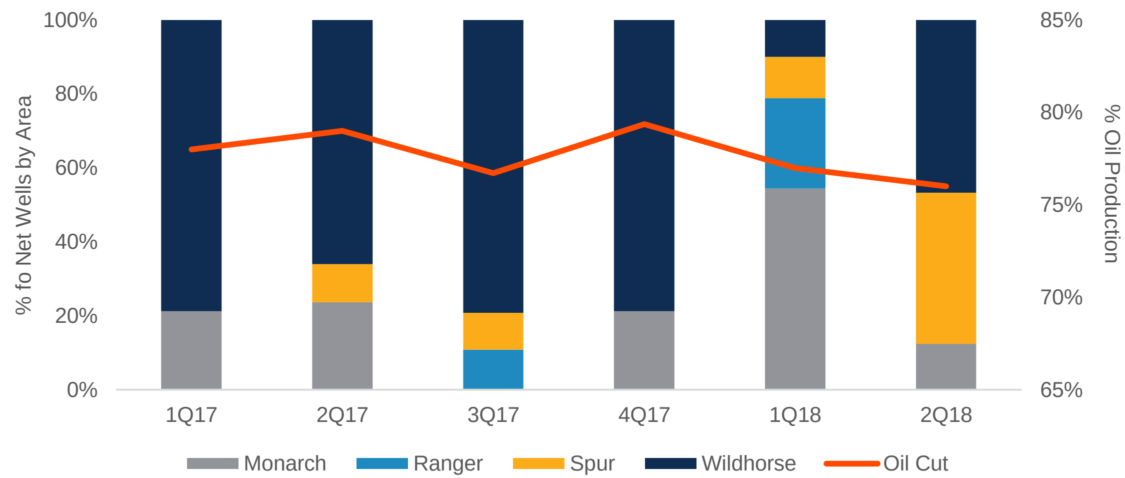
Change in asset base and drilling areas over time affect product mix

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)]

	3Q18	4Q18	2H18	1Q19	2Q19	3Q19	4Q19	2020
NYMEX WTI (Bbls, $/Bbl)								
Swaps								
Total Volumes	552,000	552,000	1,104,000	-	-	-	-	-
Daily Volumes	6,000	6,000	6,000	-	-	-	-	-
Avg. Swap	$52.07	$52.07	$52.07	-	-	-	-	-
Three-way Collars								
Total Volumes	874,000	874,000	1,748,000	810,000	819,000	920,000	920,000	-
Daily Volumes	9,500	9,500	9,500	9,000	9,000	10,000	10,000	-
Avg. Short Call	$60.86	$60.86	$60.86	$63.71	$63.71	$63.70	$63.70	-
Avg. Long Put	$48.95	$48.95	$48.95	$53.89	$53.89	$54.00	$54.00	-
Avg. Short Put	$39.21	$39.21	$39.21	$43.89	$43.89	$44.00	$44.00	-
Two-way Collars								
Total Volumes	92,000	92,000	184,000	-	-	-	-	-
Daily Volumes	1,000	1,000	1,000	-	-	-	-	-
Avg. Short Call	$60.50	$60.50	$60.50	-	-	-	-	-
Avg. Put	$50.00	$50.00	$50.00	-	-	-	-	-
Deferred Premium Put Options								
Total Volumes	276,000	276,000	552,000	450,000	455,000	460,000	460,000	-
Daily Volumes	3,000	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	$65.00	-
Total Volume Hedged	1,794,000	1,794,000	3,588,000	1,260,000	1,274,000	1,380,000	1,380,000	-
MIDLAND-CUSHING DIFFERENTIAL (Bbls/$/Bbl)								
Swaps								
Total Volumes	1,104,000	1,288,000	2,392,000	1,080,000	1,092,000	1,196,000	1,196,000	3,842,000
Daily Volumes	12,000	14,000	13,000	12,000	12,000	13,000	13,000	10,497
Avg. Swap Price	($4.18)	($4.98)	($4.61)	($5.76)	($5.76)	($3.72)	($3.72)	($1.53)

1. Hedge contracts as of 8/30/18.

Gas Hedge Portfolio (1)

	3Q18	4Q18	2H18	1Q19	2Q19	3Q19	4Q19	2020
NYMEX Henry Hub (MMBtu, $/MMBtu)								
Swaps								
Total Volumes	1,380,000	1,380,000	2,760,000	-	-	-	-	-
Daily Volumes	15,000	15,000	15,000	-	-	-	-	-
Avg. Swap	$2.91	$2.91	$2.91	-	-	-	-	-
Two-way Collars								
Total Volumes	552,000	552,000	1,104,000	585,000	591,500	598,000	598,000	-
Daily Volumes	6,000	6,000	6,000	6,500	6,500	6,500	6,500	-
Avg. Short Call	$3.19	$3.19	$3.19	$2.95	$2.95	$2.95	$2.95	-
Avg. Put	$2.75	$2.75	$2.75	$2.65	$2.65	$2.65	$2.65	-
Total Volume Hedged	1,932,000	1,932,000	3,864,000	585,000	591,500	598,000	598,000	-
Average Ceiling Price	$2.99	$2.99	$2.99	$2.95	$2.95	$2.95	$2.95	-
Average Floor Price	$2.86	$2.86	$2.86	$2.65	$2.65	$2.65	$2.65	-
WAHA DIFFERENTIAL (MMBtu, $/MMBtu)								
Swaps								
Total Volumes	552,000	552,000	1,104,000	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	6,000
Avg. Swap	($1.14)	($1.14)	($1.14)	($1.14)	($1.14)	($1.14)	($1.14)	($1.14)

1. Hedge contracts as of 8/30/18.

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	$ 139,149	$ 61,609	$ 27,995	$ 18,473	$ 509,146

Non-GAAP Reconciliation [1]

	2Q17	3Q17	4Q17	1Q18	2Q18
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	$ 17,190	$ 18,084	$ 30,202	$ 39,840	$ 44,494
Adjusted Income per fully diluted common share	$ 0.09	$ 0.09	$ 0.15	$ 0.20	$ 0.21
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	$ 59,736	$ 62,129	$ 88,935	$ 91,713	$ 102,645

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	$ 5,392	$ 5,184	$ 6,002	$ 6,549	$ 7,077
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	$ 82,016	$ 83,400	$ 113,712	$ 118,981	$ 129,095
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	$ 57,423	$ 61,920	$ 89,044	$ 91,158	$ 100,894
Discretionary cash flow per diluted share	$ 0.28	$ 0.31	$ 0.44	$ 0.45	$ 0.48

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