CALLON
PETROLEUM

# FEBRUARY PRESENTATION

FEBRUARY 2019

# IMPORTANT DISCLOSURES

## FORWARD LOOKING STATEMENTS

This presentation contains 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. Forward-looking statements include all statements regarding wells anticipated to be drilled and placed on production; future levels of drilling activity and associated production and cash flow expectations; the Company's 2019 production guidance and capital expenditure forecast; estimated reserve quantities and the present value thereof; anticipated returns and financial position; and the implementation of the Company's business plans and strategy, as well as statements including the words "believe," "expect," “may,” “will,” "forecast," “outlook,” "plans" and words of similar meaning. These statements reflect the Company's current views with respect to future events and financial performance based on management’s experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. 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. Any forward-looking statement speaks only as of the date of which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law. Some of the factors which could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements include the volatility of oil and natural gas prices, ability to drill and complete wells, operational, regulatory and environment risks, cost and availability of equipment and labor, our ability to finance our activities and other risks more fully discussed in our filings with the Securities and Exchange Commission, including our Annual Reports on Form 10-K and Quarterly Reports on Form 10-Q, available on our website or the SEC's website at www.sec.gov.

## 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, PV-10 and other measures identified as non-GAAP. Management also uses EBITDAX, which reflects EBITDA plus exploration and abandonment 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, asset retirement obligation accretion expense, exploration expense, (gains) losses on derivative instruments excluding net settled derivative instruments, impairment of oil and natural gas properties, non-cash equity based compensation, other income, gains and losses from the sale of assets and other non-cash operating items. 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.

Year-end pre-tax PV-10 value is a non-GAAP financial measure as defined by the SEC. Callon believes that the presentation of pre-tax PV-10 value is relevant and useful to its investors because it presents the discounted future net cash flows attributable to reserves prior to taking into account future corporate income taxes and the Company’s current tax structure. The Company further believes investors and creditors use pre-tax PV-10 values as a basis for comparison of the relative size and value of its reserves as compared with other companies.

The GAAP financial measure most directly comparable to pre-tax PV-10 is the standardized measure of discounted future net cash flows (“Standardized Measure”). Pre-tax PV-10 is calculated using the Standardized Measure before deducting future income taxes, discounted at 10 percent. The Company expects to include a full reconciliation of pre-tax PV-10 to the GAAP financial measure of Standardized Measure in its Earnings Press Release on Form 8-K for the fourth quarter 2018 financial and operating results, which it intends to file with the SEC on February 26, 2019.

# EXECUTION REMAINS PRIORITY ONE

**THE EVOLUTION FROM CORE ASSETS TO A SUSTAINABLE OPERATING BUSINESS MODEL**

## Core Permian Footprint Established

**2014 - 2018**

- Increased Permian position from ~19,000 to ~85,000 net acres in core areas
- Ramped activity from 2 to 5 rigs and increased net lateral footage drilled
- Built out robust infrastructure network (>$200 mm invested)
- Increased credit facility from $250 million to $1.1 billion
- Expanded Callon skill sets with significant investments in employee base
- Added cash flow per debt-adjusted share to compensation metrics

## Evolving to Full Field Development

**2019**

- Harvest asset value through increasing pad development and cycle time reductions
- Optimize margins and increase operational flexibility
- Thoughtful capital allocation to minimize outspend while growing at a measured rate to augment sustainable corporate return model
- Balance longer term reinvestment opportunities with near-term return profile
- Selective activity to "block up" acreage, extend laterals, and increase working and mineral interests

## Sustainable Growth and FCF Generation

**2020 +**

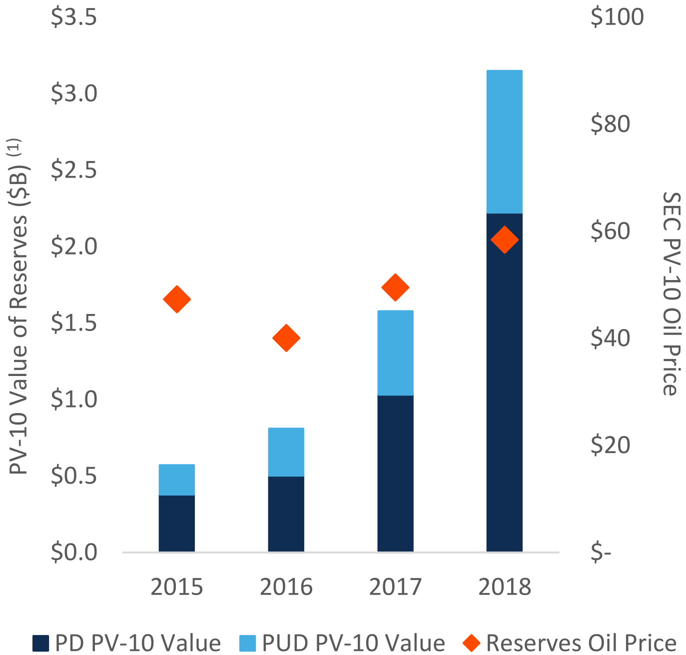
- Sustainable double-digit organic growth funded with internally generated cash flow
- Large pad development, benefiting resource optimization and long-term corporate level returns
- Leading cash margin preservation through cost management and leveraging of existing infrastructure
- Select asset rationalization opportunities to enhance returns on capital
- Accelerate capital efficiency with balanced growth and maturing decline profile

# SOLID FOUNDATION OF PROVED RESERVE VALUE

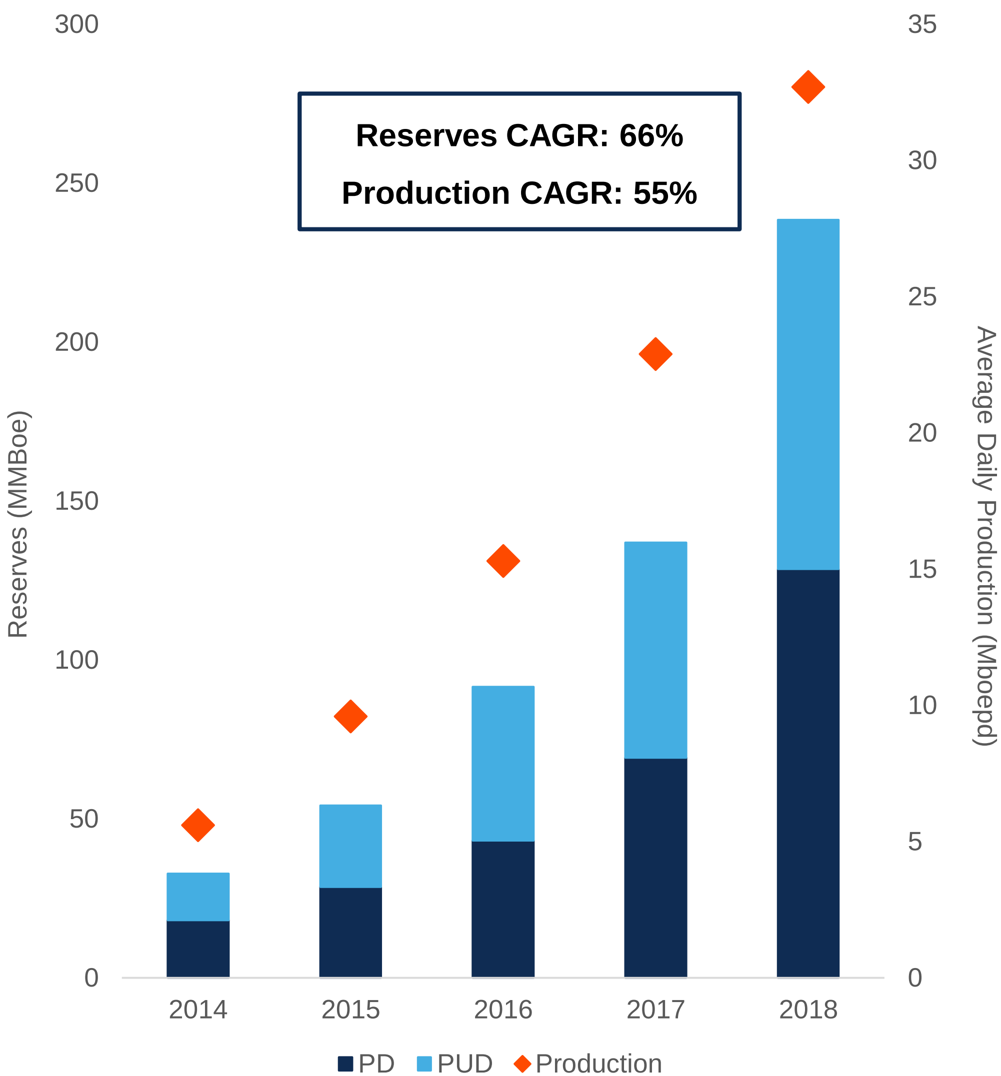
## CONSERVATIVE AND CONSISTENT GROWTH

- Total Proved PV-10 [(1)] value of $3.1 billion
- PD PV-10 [(1)] value of $2.2 billion
- Oil accounts for > 75% of proved reserves
- PUD bookings consist of just over 200 locations
- PD accounts for 54% of reserve volumes and 71% of PV-10 [(1)] value

## PD GROWTH DRIVING RESERVE VALUE



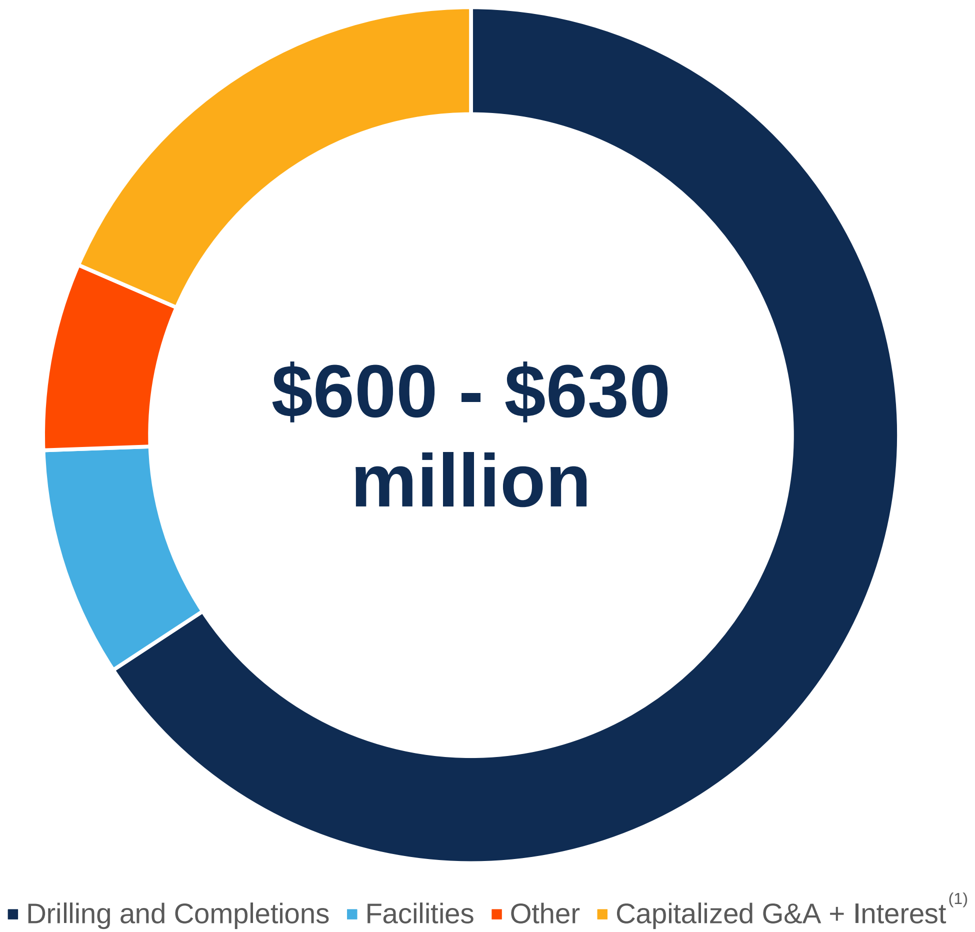

## TOP TIER RESERVE AND PRODUCTION GROWTH [(2)]




1. A non-GAAP financial measure: The 12-month average benchmark pricing used to estimate proved reserves in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission ("SEC") and pre-tax PV-10 value for crude oil and natural gas was $65.56 per Bbl of WTI crude oil and $3.10 per MMBtu of natural gas at Henry Hub before differential adjustments. After differential adjustments, the Company's SEC pricing realizations for year-end 2018 were $58.40 per Bbl of oil and $3.64 per Mcf of natural gas. Please refer to the Non-GAAP Disclosure at the beginning of this release for information regarding pre-tax PV-10.
2. 4Q18 production based on current (2/7/19) "street" consensus.

# 2019 CAPITAL BUDGET GUIDANCE

## ANNUAL EXPENDITURE BUDGET ($MM)




## PRIMARY COMPONENTS

- Budget based upon $50 oil / $2.75 natural gas with strip differentials from early January
- Operational capital budget (D&C, facilities, & other) range between $500 - $525 million
- Weighting is roughly 60% Delaware / 40% Midland inclusive of facilities capital
- Operational capital deployment is projected to be relatively balanced between 1H19 and 2H19
- Potential “bolt-on” acquisitions to be funded with non-core divestitures

## 2019 ACTIVITY LEVELS

- Currently 6 rigs declining to 4 rigs at mid-year before entering 2020 with 5 rigs
- Currently 1 completion crew with intermittent addition of an additional crew for larger pad concepts
- Estimated 47 to 49 net wells POP
  - Lower YoY net wells, but average net lateral length per net well increases by ~15%
  - Small DUC build for larger pad development
  - 1H19 Midland focus transitions to Delaware in 2H19
- Sequential 1Q19 production decline followed by gradual increase to over 42.5 Mboepd in 4Q19

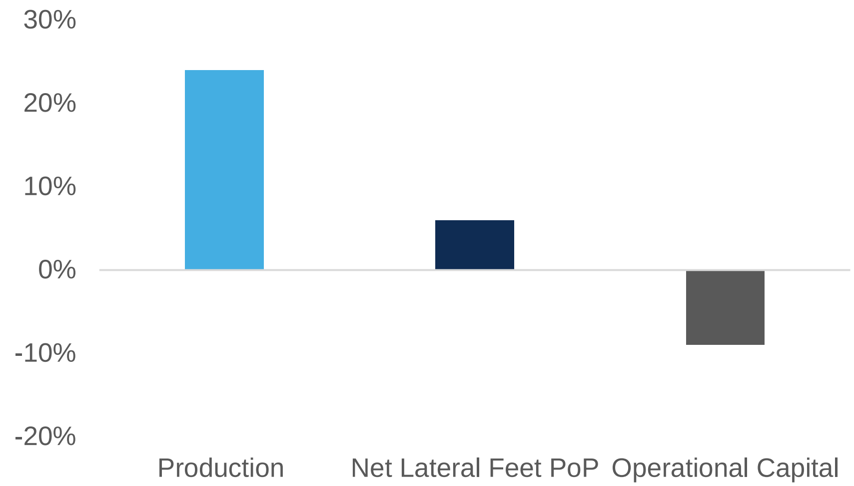
1. Assumes $50/Bbl WTI benchmark (flat).

# 2019 CAPITAL PROGRAM: SUSTAINABLE VALUE CREATION

## MANAGE CASH CONVERSION OF QUALITY INVENTORY

- Capital expenditures actively managed across the organization to optimize both well-level and corporate-level targets
- Development planning and well selection
  - Prioritize multi-well pad development vs single-well pads
  - Establish DSUs which allow longer laterals and higher NRI to efficiently access more acreage
  - Target multi-interval development for long-term returns
  - Leverage utilization of existing facilities
- Active supplier negotiations and D&C cost saving initiatives
  - Completions contract in place for 2019
  - Increase use of local sand
  - Integrate supply chain to reduce costs
  - Increase water recycling and non-potable water sourcing
  - Reduce drilling days
- Application of technology for long-term continuous improvement and NPV accretion
  - Completion and well spacing optimization
  - Enhanced subsurface knowledge and reservoir characterization

## HIGHIGHTING CAPITAL EFFICIENCY (YoY vs 2018) [1]




## OPTIMIZE GROSS CAPITAL PER OPERATED LATERAL FT

| | Midland | Delaware |
|---|---|---|
| 2018 Gross D&C/1,000’ | $1.1MM | $1.4MM |
| 2019E Gross D&C/1,000’ | $0.9MM | $1.2MM |
| 2018 Avg Net Lateral | 6,500’ | 7,400’ |
| 2019E Avg Net Lateral | 7,700’ | 8,400’ |

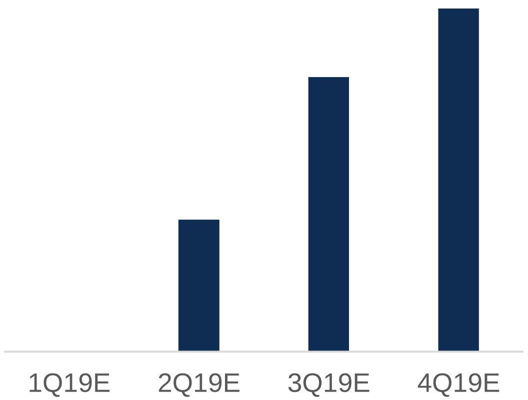
1. 2018 reference points based on current (2/7/19) “street” consensus. 2019 reference points based on midpoint of guidance.

# DELAWARE: SUSTAINABLE INVESTMENT AND RETURN

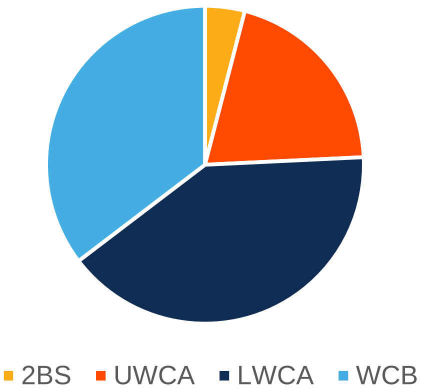
## OPTIMAL DEVELOPMENT GOALS

- Transition from single-well, HBP-driven activity to multi-pad concepts
- Define well spacing assumptions early in single-interval and multi-interval inventory development
- Benefit from existing infrastructure
- Selectively test new intervals

## NET WELLS PoP BUILD INTO YE19

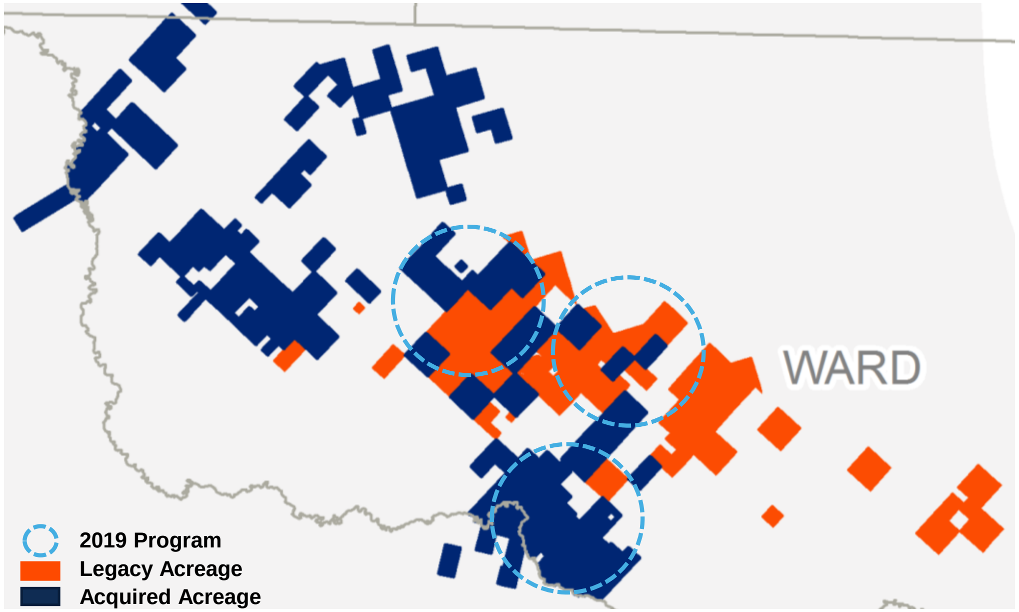



## NET WELLS BY ZONE




## SPUR OPERATING AREA

- Larger pad concepts with multi-interval development of upper WCA, lower WCA, and WCB objectives
- 2nd Bone Shale upside evaluation
- Offset development of existing lower WCA well development
- Continue co-development of the upper and lower WCA in mega-pad concept
- Expand water recycling to eventually eliminate potable water sourcing
- Field optimization projects underway to enhance operational reliability and safety

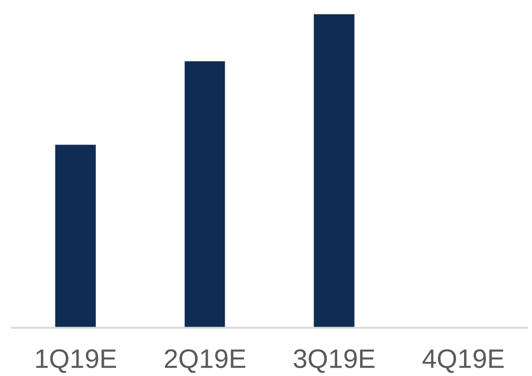


# MIDLAND: BALANCED MULTI-INTERVAL DEVELOPMENT

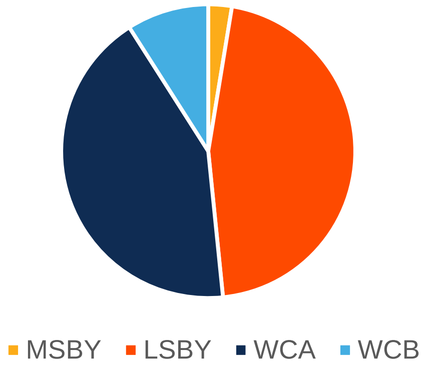
## OPTIMAL DEVELOPMENT GOALS

- Leverage operational flexibility embedded in program given infrastructure investments and inventory depth
- Advance multi-interval development concepts across areas
- Increase average pad size for scalability and mitigation of timing effects

## NET WELLS PoP FOCUSED IN 2Q/3Q

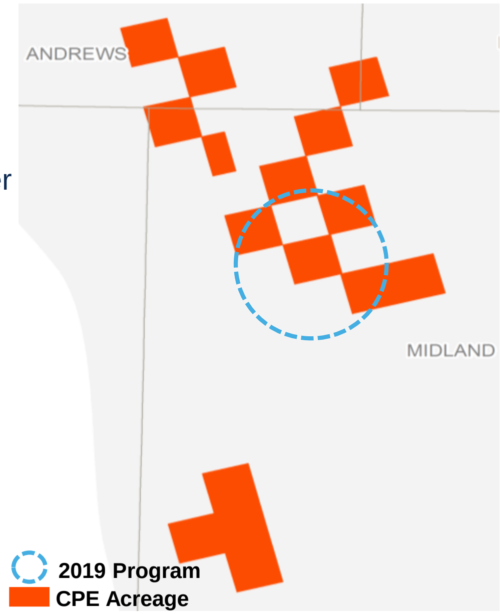



## NET WELLS BY ZONE




## MONARCH OPERATING AREA

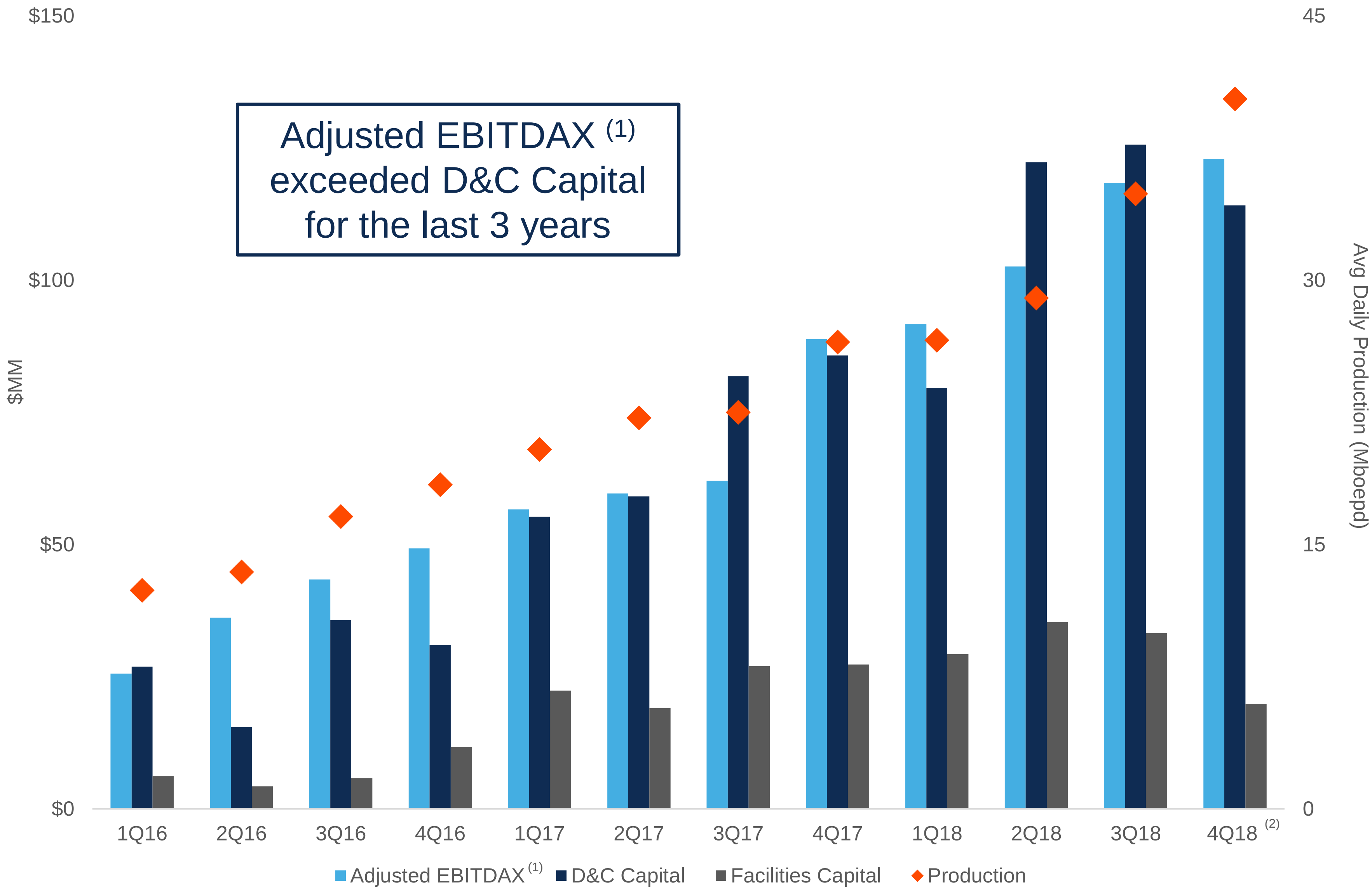
- Co-development of WCA/WCB
- Continued program development of upper/lower LSBY
- Test MSBY upside interval for future large pad drilling
- Increase water recycling efforts to reduce potable water sourcing




## WILDHORSE OPERATING AREA

- Focus on combined WCA/LSBY pads
- Selective integration of WCB in larger scale co-development pads
- Increase average net pad size
- Leverage SWD network to third-parties for further cost reductions

# DEVELOPMENT CAPITAL ALIGNED WITH CASH FLOW

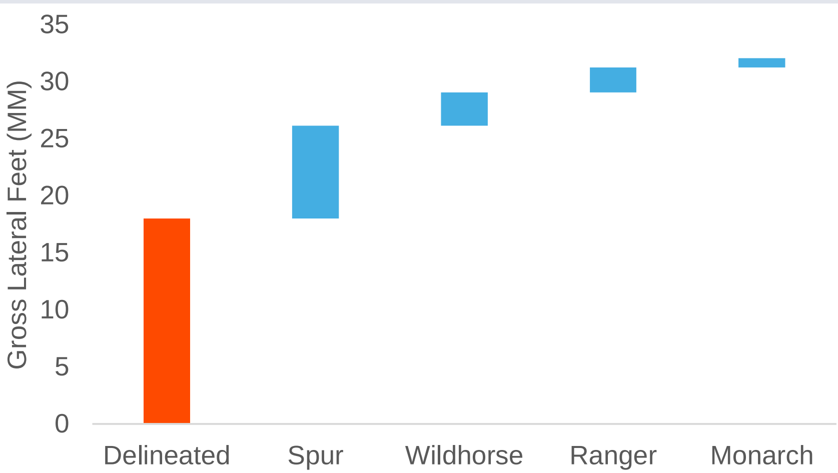


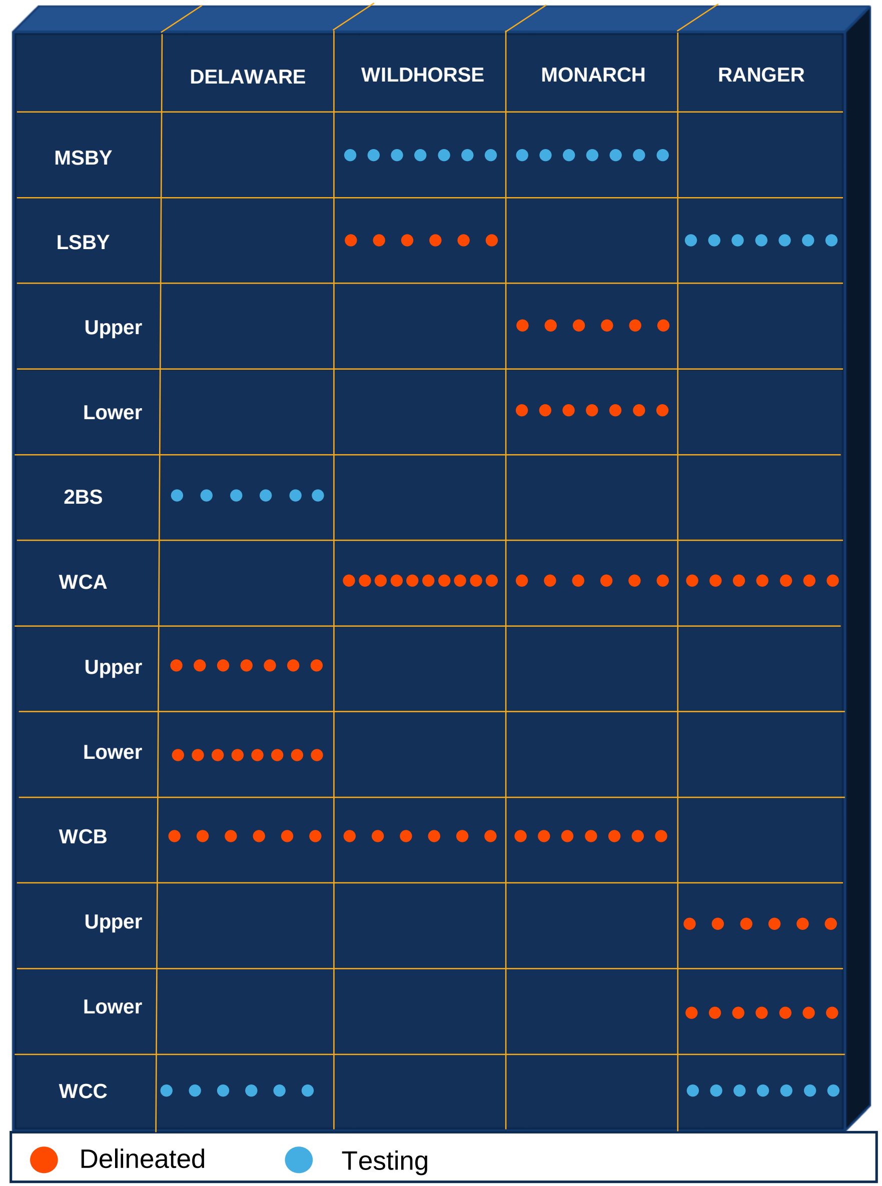

1. 1Q16-3Q18 based on CPE calculated Adjusted EBITDA(X), a non-GAAP financial measure. Please see the Appendix for additional reconciliation.
2. 4Q18 EBITDA, D&C capital, and production are based on Bloomberg consensus estimates as of 2/7/19.

# QUALITY INVENTORY SCALABLE FOR LARGER PADS

| | MIDLAND | DELAWARE |
|---|---|---|
| Net Acres | ~ 39,500 | ~ 45,200 |
| Producing Flow Units | 7 | 4 |
| Gross Delineated Locations | 940 | 1,210 |
| Operated | 820 | 580 |
| Non-Operated | 120 | 630 |
| Wtd. Avg. Lateral Length | 8,100’ | 8,600’ |
| Operated | 7,800’ | 8,900’ |
| Non-Operated | 9,600’ | 8,400’ |
| Delineated Lateral Feet (Gross Operated) | ~ 18 Million | |

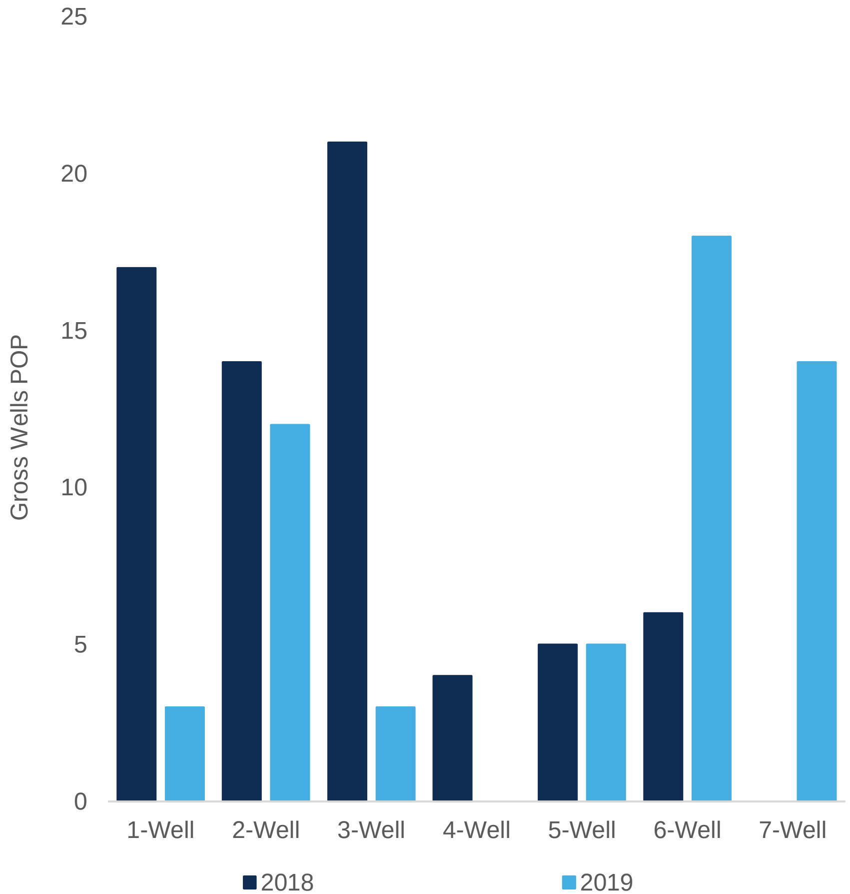
**32 MM GROSS LATERAL FEET OF POTENTIAL RESOURCE**



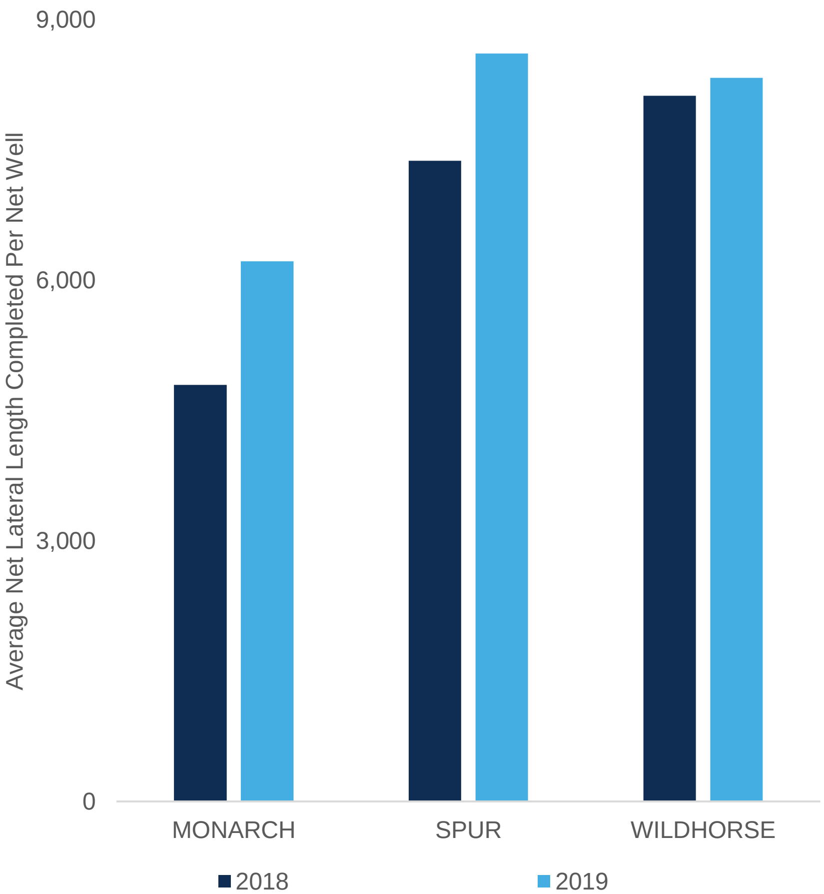
# INCREMENTAL CAPITAL EFFICIENCY

## MULTI-WELL PROJECT DEVELOPMENT ACCELERATES




**2019 Average Project Size Increases 75%**

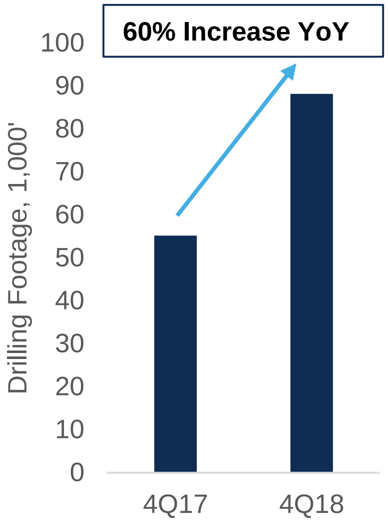
## INCREASING NET LATERAL LENGTH PER WELL

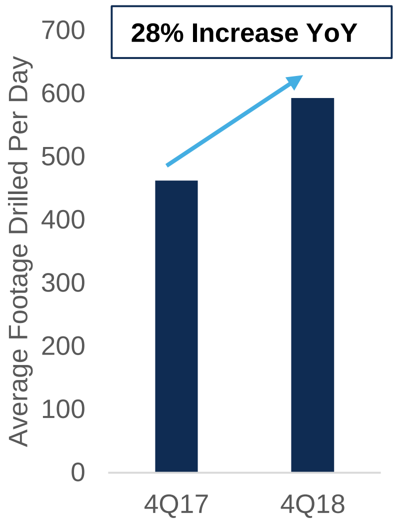



**2019 Average Net Lateral Feet Increases + 15%**

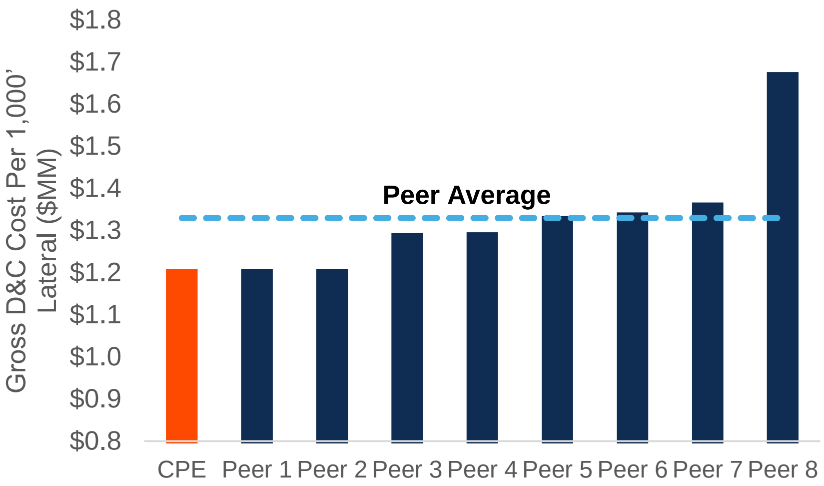
# COST LEADERSHIP IN SOUTHERN DELAWARE

## DRILLING SCALE AND EFFICIENCY GAINS

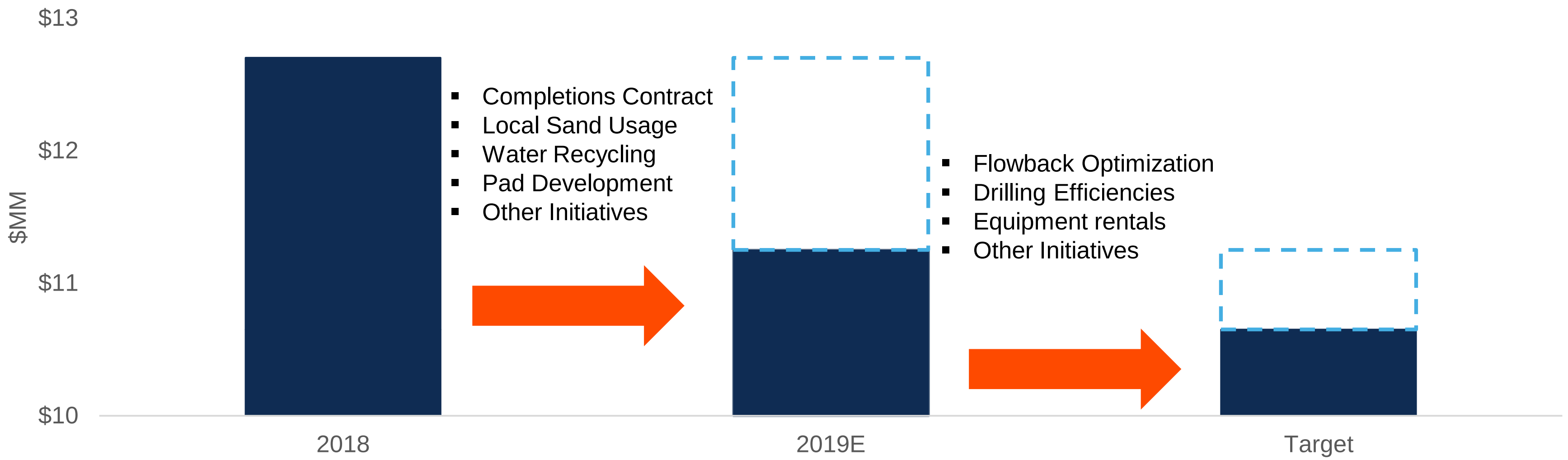



## LEADER IN SOUTHERN DELAWARE WELL COSTS [1]




## INCREMENTAL COST SAVINGS TARGETED FROM AVERAGE 2018 WCA AFE (10,000' LATERAL)



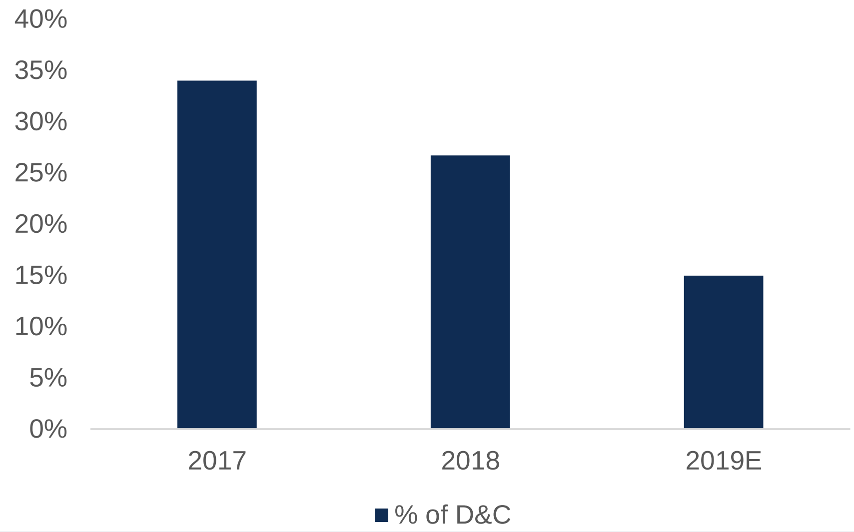

1. Based on JPM estimates. Peers include CRZO, CDEV, CXO, HK, JAG, OAS, PE, PDCE.

# INFRASTRUCTURE ALLOWS OPERATIONAL FLEXIBILITY

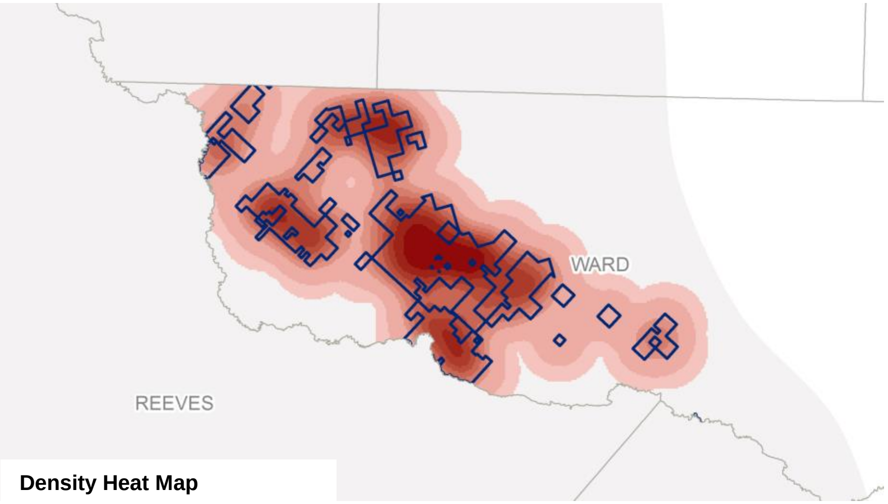
## OPERATIONAL FLEXIBILITY FROM PRIOR INVESTMENTS

- Leveraging existing facilities in 2019 development schedule
  - Over 80% of wells drilled in 2019 utilize existing facilities
  - 4 new production facilities and 12 production facility upgrade projects across the assets
- Significant increase of recycling capabilities with addition of incremental 30K BPD capacity
- Sustainable investments in the Delaware account for more than 2/3rds of 2019 facilities spend
- Monetization opportunities available if accretive to long-term corporate-level return profile without reducing operational reliability

## 2019: FACILITIES CAPEX DECLINES BY 50% YoY

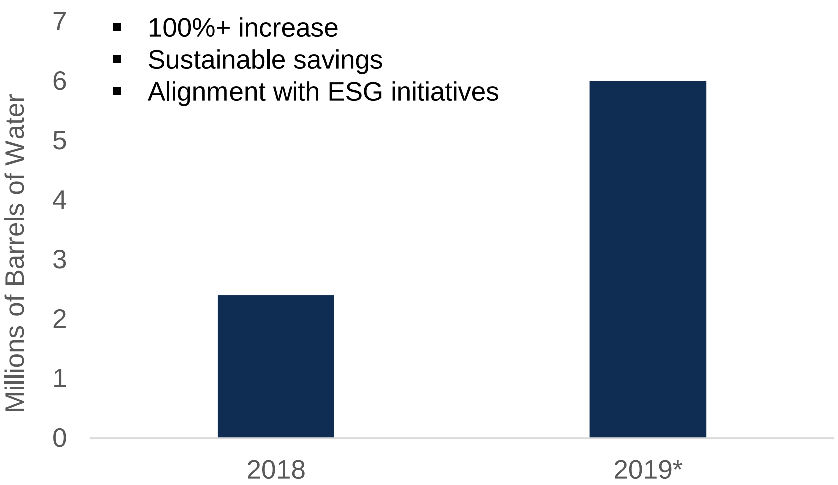



## SCALABILITY UPSIDE FROM CONTIGUOUS ACREAGE




Density Heat Map

## DELAWARE WATER RECYCLING GROWTH [1]



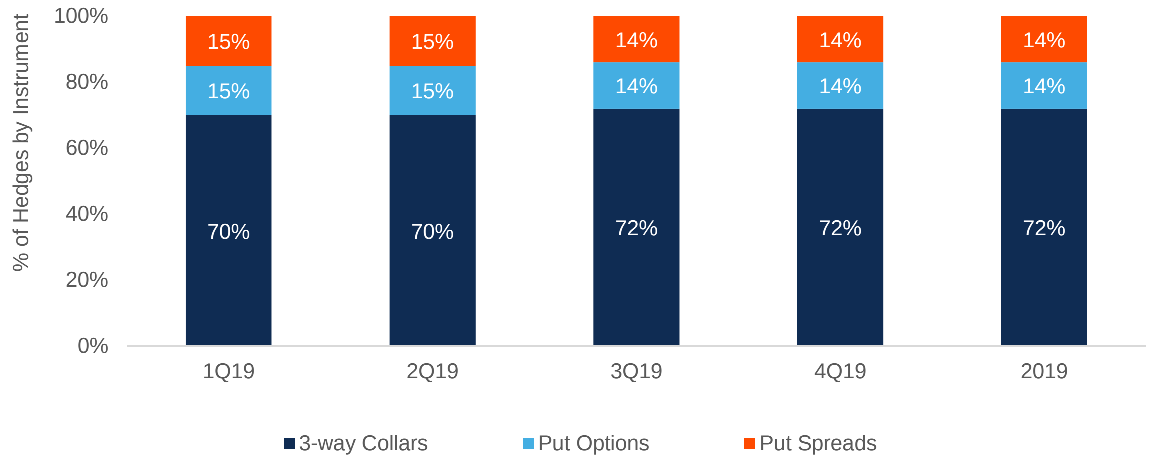

1. 2019 Delaware recycling volumes based on projected targets for announced capital program.

# RISK MANAGEMENT [1]

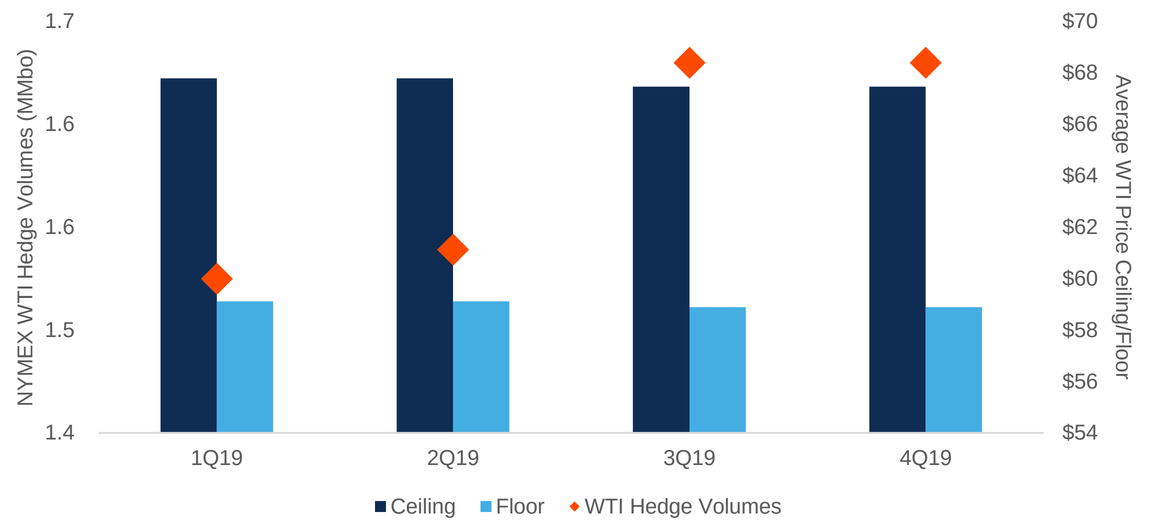
## STRATEGY

- Portfolio approach with focus on total realized price
- Protect WTI downside at ~$59 and allow for upside price participation in a volatile market
- Lock in WTI protection to support cash flow with FY19E ~ 55% hedged [2]
- Monitor market dynamics between WTI, MEH and Brent in anticipation of volumes being sold outside the basin expected by late 2019
  - 4Q19+ Gray Oak: ~ 15 Mb/d gross FT
  - 2019 Mid-Cush basis swaps: ~ 19 Mb/d hedged at an average swap price of ($4.34)
  - 2020 Mid-Cush basis swaps: ~13 Mb/d hedged at an average swap price of ($1.29)
- Mitigate WaHa price volatility through basis swaps with ~ 55% of FY19E gas volumes exposed to basis swap protection [2]
- Evaluate a variety of physical and financial risk mitigation alternatives

## WTI INSTRUMENT BREAKOUT




## WTI HEDGE VOLUME WITH WEIGHTED AVERAGE CEILING AND FLOOR PRICE




1. Hedge contracts as of 2/7/19.
2. Percentages based on the mid-point of 2019 guidance.

# OUTLOOK

**RESPONSIBILITY: EXECUTION AND SAFETY**

**OPTIMIZE HIGH-QUALITY PERMIAN INVENTORY**

**DRIVE CORPORATE LEVEL RETURNS WITH PEER LEADING CASH MARGINS**

**EFFICIENT CAPITAL CONVERSION WITHIN CASH FLOWS GENERATES DOUBLE DIGIT PRODUCTION GROWTH**

**DELINEATE AND RATIONALIZE RESOURCE BASE**

**INTEGRATE SUSTAINABLE INVESTMENTS TO DRIVE FUTURE COST SAVINGS AND LONG-TERM EFFICIENCY GAINS**

# APPENDIX

# OIL AND GAS HEDGE PORTFOLIO (1)

| | 1Q19 | 2Q19 | 3Q19 | 4Q19 | 1H19 | 2H19 | 2019 | 1Q20 | 2Q20 | 3Q20 | 4Q20 | 1H20 | 2H20 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **NYMEX WTI (Bbl, $/Bbl)** | | | | | | | | | | | | | | |
| **Three-way Collars** | | | | | | | | | | | | | | |
| Total Volumes | 1,080,000 | 1,092,000 | 1,196,000 | 1,196,000 | 2,172,000 | 2,392,000 | 4,564,000 | - | - | - | - | - | - | - |
| Total Daily Volumes | 12,000 | 12,000 | 13,000 | 13,000 | 12,000 | 13,000 | 12,504 | - | - | - | - | - | - | - |
| Avg. Short Call Price | $67.78 | $67.78 | $67.46 | $67.46 | $67.78 | $67.46 | $67.62 | - | - | - | - | - | - | - |
| Avg. Long Put Price | $56.67 | $56.67 | $56.54 | $56.54 | $56.67 | $56.54 | $56.60 | - | - | - | - | - | - | - |
| Avg. Short Put Price | $43.54 | $43.54 | $43.65 | $43.65 | $43.54 | $43.65 | $43.60 | - | - | - | - | - | - | - |
| Avg. Premium Price | ($0.10) | ($0.10) | ($0.09) | ($0.09) | ($0.10) | ($0.09) | ($0.09) | - | - | - | - | - | - | - |
| **Put Options** | | | | | | | | | | | | | | |
| Total Volumes | 225,000 | 227,500 | 230,000 | 230,000 | 452,500 | 460,000 | 912,500 | - | - | - | - | - | - | - |
| Total Daily Volumes | 2,500 | 2,500 | 2,500 | 2,500 | 2,500 | 2,500 | 2,500 | - | - | - | - | - | - | - |
| Avg. Long Put Price | $65.00 | $65.00 | $65.00 | $65.00 | $65.00 | $65.00 | $65.00 | - | - | - | - | - | - | - |
| Avg. Premium Price | $6.44 | $6.44 | $6.44 | $6.44 | $6.44 | $6.44 | $6.44 | - | - | - | - | - | - | - |
| **Put Spreads** | | | | | | | | | | | | | | |
| Total Volumes | 225,000 | 227,500 | 230,000 | 230,000 | 452,500 | 460,000 | 912,500 | - | - | - | - | - | - | - |
| Total Daily Volumes | 2,500 | 2,500 | 2,500 | 2,500 | 2,500 | 2,500 | 2,500 | - | - | - | - | - | - | - |
| Avg. Long Put Price | $65.00 | $65.00 | $65.00 | $65.00 | $65.00 | $65.00 | $65.00 | - | - | - | - | - | - | - |
| Avg. Short Put Price | $42.50 | $42.50 | $42.50 | $42.50 | $42.50 | $42.50 | $42.50 | - | - | - | - | - | - | - |
| Avg. Premium Price | $4.39 | $4.39 | $4.39 | $4.39 | $4.39 | $4.39 | $4.39 | - | - | - | - | - | - | - |
| Total Volume Hedged (Bbl) | 1,530,000 | 1,547,000 | 1,656,000 | 1,656,000 | 3,077,000 | 3,312,000 | 6,389,000 | - | - | - | - | - | - | - |
| Average Ceiling Price ($/Bbl) | $67.78 | $67.78 | $67.46 | $67.46 | $67.78 | $67.46 | $67.62 | - | - | - | - | - | - | - |
| Average Floor Price ($/Bbl) | $59.12 | $59.12 | $58.89 | $58.89 | $59.12 | $58.89 | $59.00 | - | - | - | - | - | - | - |
| **MIDLAND-CUSHING DIFFERENTIAL (Bbls/$/Bbl)** | | | | | | | | | | | | | | |
| **Swaps** | | | | | | | | | | | | | | |
| Total Volumes | 1,634,000 | 1,683,500 | 1,748,000 | 1,670,500 | 3,317,500 | 3,418,500 | 6,736,000 | 1,092,000 | 1,092,000 | 1,196,000 | 1,196,000 | 2,184,000 | 2,392,000 | 4,576,000 |
| Total Daily Volumes | 18,156 | 18,500 | 19,000 | 18,158 | 18,329 | 18,579 | 18,455 | 12,000 | 12,000 | 13,000 | 13,000 | 12,000 | 13,000 | 12,503 |
| Avg. Swap Price | ($5.59) | ($5.51) | ($3.13) | ($3.22) | ($5.55) | ($3.18) | ($4.34) | ($1.73) | ($1.73) | ($0.89) | ($0.89) | ($1.73) | ($0.89) | ($1.29) |
| **NYMEX Henry Hub (MMBtu, $/MMBtu)** | | | | | | | | | | | | | | |
| **Swaps** | | | | | | | | | | | | | | |
| Total Volumes | - | 455,000 | 1,242,000 | 155,000 | 455,000 | 1,397,000 | 1,852,000 | - | - | - | - | - | - | - |
| Total Daily Volumes | - | 5,000 | 13,500 | 1,685 | 2,514 | 7,592 | 5,074 | - | - | - | - | - | - | - |
| Avg. Swap Price | - | $2.87 | $2.89 | $2.87 | $2.87 | $2.89 | $2.88 | - | - | - | - | - | - | - |
| **Two-way Collars** | | | | | | | | | | | | | | |
| Total Volumes | 2,525,000 | 1,501,500 | 598,000 | 598,000 | 4,026,500 | 1,196,000 | 5,222,500 | - | - | - | - | - | - | - |
| Total Daily Volumes | 28,056 | 16,500 | 6,500 | 6,500 | 22,246 | 6,500 | 14,308 | - | - | - | - | - | - | - |
| Avg. Short Call Price | $3.63 | $3.82 | $3.50 | $3.50 | $3.70 | $3.50 | $3.65 | - | - | - | - | - | - | - |
| Avg. Put Price | $2.97 | $3.06 | $3.13 | $3.13 | $3.00 | $3.13 | $3.03 | - | - | - | - | - | - | - |
| Total Volume Hedged (MMBtu) | 2,525,000 | 1,956,500 | 1,840,000 | 753,000 | 4,481,500 | 2,593,000 | 7,074,500 | - | - | - | - | - | - | - |
| Average Ceiling Price ($/MMBtu) | $3.63 | $3.60 | $3.09 | $3.37 | $3.62 | $3.17 | $3.45 | - | - | - | - | - | - | - |
| Average Floor Price ($/MMBtu) | $2.97 | $3.02 | $2.97 | $3.07 | $2.99 | $3.00 | $2.99 | - | - | - | - | - | - | - |
| **WAHA DIFFERENTIAL (MMBtu, $/MMBtu)** | | | | | | | | | | | | | | |
| **Swaps** | | | | | | | | | | | | | | |
| Total Volumes | 2,610,000 | 2,639,000 | 3,036,000 | 3,036,000 | 5,249,000 | 6,072,000 | 11,321,000 | 1,183,000 | 1,183,000 | 1,196,000 | 1,196,000 | 2,366,000 | 2,392,000 | 4,758,000 |
| Total Daily Volumes | 29,000 | 29,000 | 33,000 | 33,000 | 29,000 | 33,000 | 31,016 | 13,000 | 13,000 | 13,000 | 13,000 | 13,000 | 13,000 | 13,000 |
| Avg. Swap Price | ($1.25) | ($1.25) | ($1.22) | ($1.22) | ($1.25) | ($1.22) | ($1.23) | ($1.12) | ($1.12) | ($1.12) | ($1.12) | ($1.12) | ($1.12) | ($1.12) |

1. Hedge contracts as of 2/7/19.

# NON-GAAP RECONCILIATION [1]

| | 3Q17 | 4Q17 | 1Q18 | 2Q18 | 3Q18 |
|---|---|---|---|---|---|
| **Adjusted Income Reconciliation** | | | | | |
| Income available to common stockholders | $ 15,257 | $ 21,001 | $ 53,937 | $ 48,650 | $ 36,108 |
| Adjustments: | | | | | |
| Net (gain) loss on derivatives, net of settlements | 12,947 | 26,037 | (3,978) | 8,572 | 25,100 |
| Change in the fair value of share-based awards | 732 | 865 | 1,012 | (463) | 879 |
| Tax effect on adjustments above | (4,788) | (9,416) | 622 | (1,703) | (5,456) |
| Change in valuation allowance | (6,064) | (8,285) | (11,753) | (10,562) | (8,323) |
| Adjusted Income | $ 18,084 | $ 30,202 | $ 39,840 | $ 44,494 | $ 48,308 |
| Adjusted Income per fully diluted common share | $ 0.09 | $ 0.15 | $ 0.20 | $ 0.21 | $ 0.21 |
| | | | | | |
| **Adjusted EBITDA Reconciliation** | | | | | |
| Net income | $ 17,081 | $ 22,824 | $ 55,761 | $ 50,474 | $ 37,931 |
| Adjustments: | | | | | |
| Net (gain) loss on derivatives, net of settlements | 12,947 | 26,037 | (3,978) | 8,572 | 25,100 |
| Non-cash stock-based compensation expense | 1,952 | 2,101 | 2,143 | 1,164 | 2,587 |
| Acquisition expense | 205 | (112) | 548 | 1,767 | 1,435 |
| Income tax expense | 237 | 248 | 495 | 481 | 1,487 |
| Interest expense | 444 | 461 | 460 | 594 | 711 |
| Depreciation, depletion and amortization | 29,132 | 37,222 | 36,066 | 39,387 | 48,977 |
| Accretion expense | 131 | 154 | 218 | 206 | 202 |
| Adjusted EBITDA | $ 62,129 | $ 88,935 | $ 91,713 | $ 102,645 | $ 118,430 |

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