L A R E D O   P E T R O L E U M

# Corporate Presentation
## September 2019

# Forward-Looking / Cautionary Statements

This presentation, including any oral statements made regarding the contents of this presentation, contains forward-looking statements as defined under Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, that address activities that Laredo Petroleum, Inc. (together with its subsidiaries, the "Company", "Laredo" or "LPI") assumes, plans, expects, believes, intends, projects, estimates or anticipates (and other similar expressions) will, should or may occur in the future, including, but not limited to, the share repurchase program, which may be suspended or discontinued by the Company at any time, are forward-looking statements. The forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events.

General risks relating to Laredo include, but are not limited to, the decline in prices of oil, natural gas liquids and natural gas and the related impact to financial statements as a result of asset impairments and revisions to reserve estimates, long-term performance of wells, drilling and operating risks, the increase in service costs, hedging activities, possible impacts of potential litigation and other factors, including those and other risks described in its Annual Report on Form 10-K for the year ended December 31, 2018, and those set forth from time to time in other filings with the Securities Exchange Commission ("SEC"). These documents are available through Laredo's website at www.laredopetro.com under the tab "Investor Relations" or through the SEC's Electronic Data Gathering and Analysis Retrieval System at www.sec.gov. Any of these factors could cause Laredo's actual results and plans to differ materially from those in the forward-looking statements. Therefore, Laredo can give no assurance that its future results will be as estimated. Laredo does not intend to, and disclaims any obligation to, update or revise any forward-looking statement.

Any forward-looking statement speaks only as of the date on 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.

The SEC generally permits oil and natural gas companies, in filings made with the SEC, to disclose proved reserves, which are reserve estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions and certain probable and possible reserves that meet the SEC's definitions for such terms. In this presentation, the Company may use the terms "resource potential," "estimated ultimate recovery" ("EURs") or "type curve," each of which the SEC guidelines restrict from being included in filings with the SEC without strict compliance with SEC definitions. These terms refer to the Company's internal estimates of unbooked hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. "Resource potential" is used by the Company to refer to the estimated quantities of hydrocarbons that may be added to proved reserves, largely from a specified resource play potentially supporting numerous drilling locations. A "resource play" is a term used by the Company to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section potentially supporting numerous drilling locations, which, when compared to a conventional play, typically has a lower geological and/or commercial development risk. EURs are based on the Company's previous operating experience in a given area and publicly available information relating to the operations of producers who are conducting operations in these areas. Unbooked resource potential or EURs do not constitute reserves within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System or SEC rules and do not include any proved reserves. Actual quantities of reserves that may be ultimately recovered from the Company's interests may differ substantially from those presented herein. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, decreases in oil, natural gas liquids and natural gas prices, well spacing, drilling costs and production costs, availability and costs of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals, negative revisions to reserve estimates and other factors as well as actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of EURs may change significantly as development of the Company's core assets provides additional data. In addition, our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases. "Type curve" refers to a production profile of a well, or a particular category of wells, for a specific play and/or area. In addition, the Company's production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases. The "standardized measure" of discounted future new cash flows is calculated in accordance with SEC regulations and a discount rate of 10%. The actual results may vary considerably and should not be considered to represent the fair market value of the Company's proved reserves.

This presentation includes financial measures that are not in accordance with generally accepted accounting principles ("GAAP"), including Adjusted EBITDA, cash flow and free cash flow. While management believes that such measures are useful for investors, they should not be used as a replacement for financial measures that are in accordance with GAAP. For a reconciliation of Adjusted EBITDA, cash flow and free cash flow to the nearest comparable measure in accordance with GAAP, please see the Appendix.

All amounts, dollars and percentages presented in this presentation are rounded and therefore approximate.

# Laredo Petroleum Overview

## Laredo Petroleum (LPI)

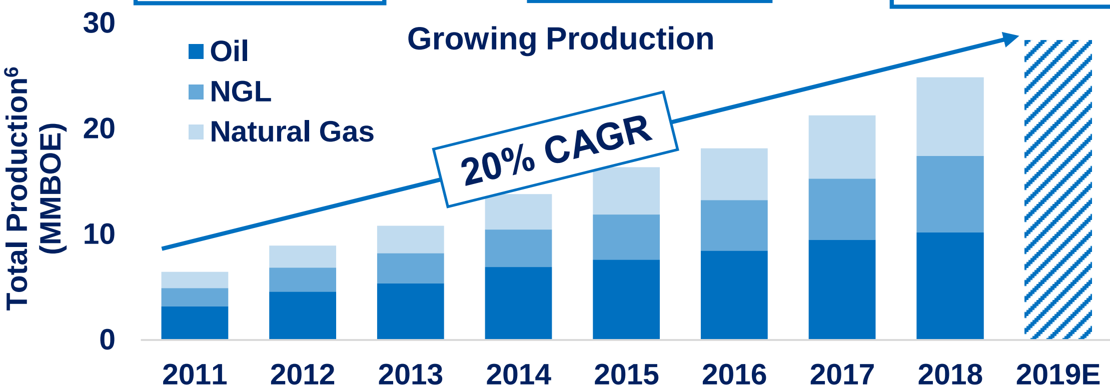
**Market Cap[1]: $589 MM; Enterprise Value[2]: $1,568 MM**

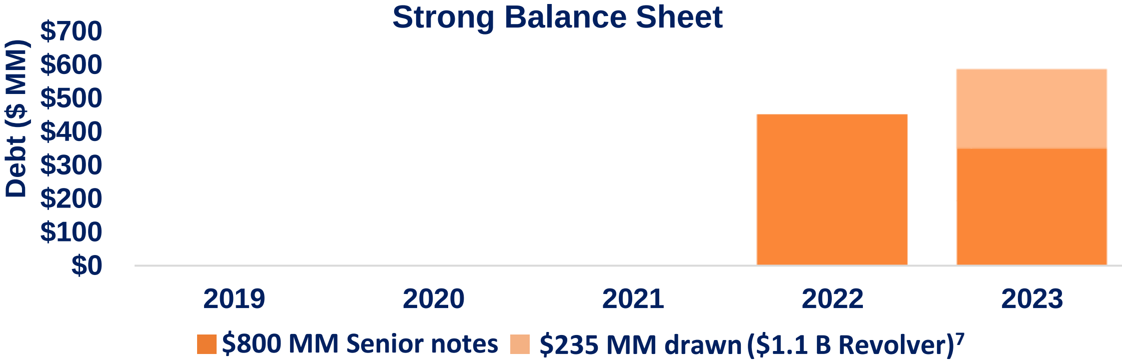
**Operations: Permian Basin (TX), Headquarters: Tulsa, OK**

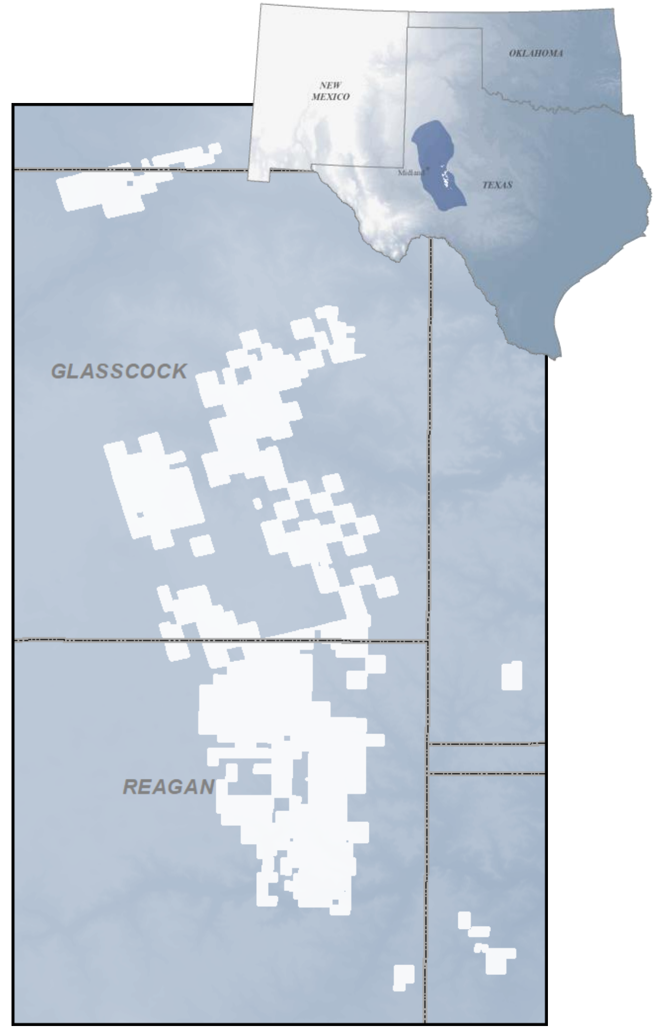
**55.9** MMBO PDP oil reserves[3]

**30.4** MBOPD oil production[4]

**1.7x** Net Debt to Adj. EBITDA[5]




137,831 gross/ 122,787 net acres[4]

[1]As of 8/30/19; [2] Market cap as of 8/30/19; net debt as of 6/30/19; [3]As of 12/31/18; [4]As of 6/30/19; [5]See Appendix for the calculation of net debt to Adjusted EBITDA and a reconciliation of Net Income to Adjusted EBITDA; [6]2011-2014 results have been converted to 3-stream using actual gas plant economics; 2011-2013 results have been adjusted for Granite Wash divestiture, closed 8/1/13; [7]As of 6/30/19, per the 4/30/19 semi-annual redetermination of $1.1 B aggregate elected commitment in place under Fifth Amended and Restated Senior Secured Credit Facility

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# 2019: A Transformational Year

- Optimized operations
- Aligned personnel costs with activity
- Reconstructed Senior Management Team

- Moved to wider-spaced development
- $30 MM/year annualized cash & non-cash expenses & capital savings expected
- New President, COO, CFO & GC

**Execution of strategic initiatives are driving free cash flow generation in 2019E**

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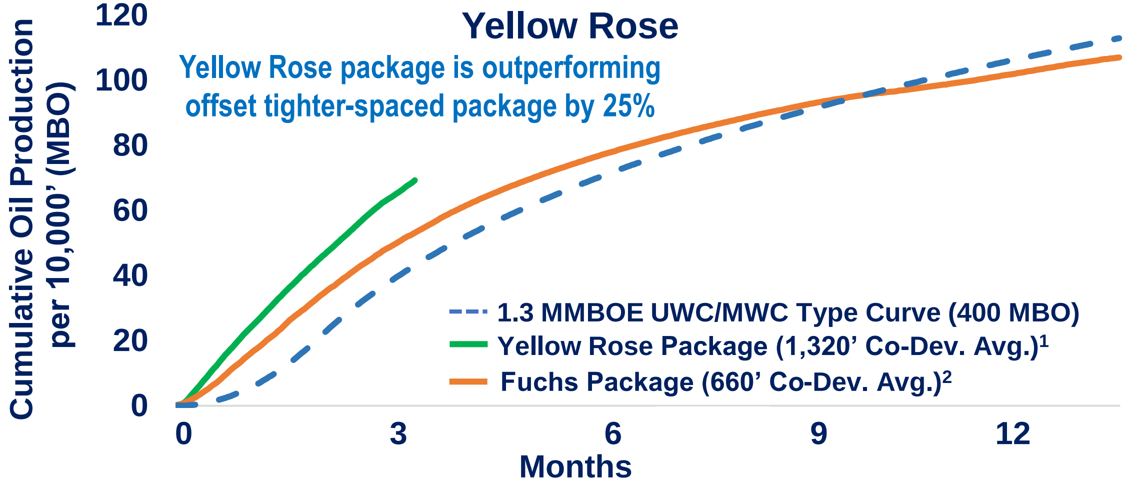
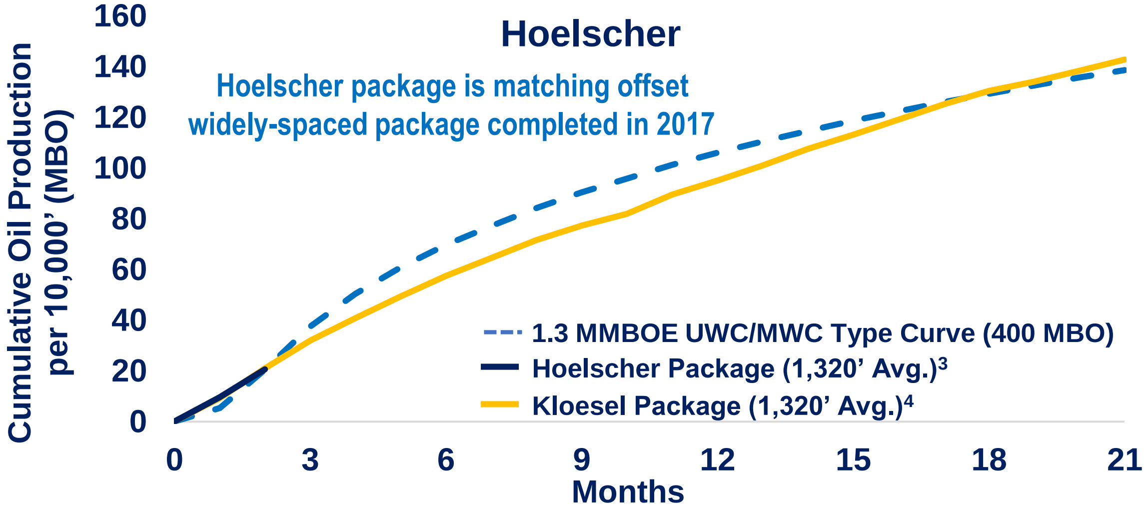
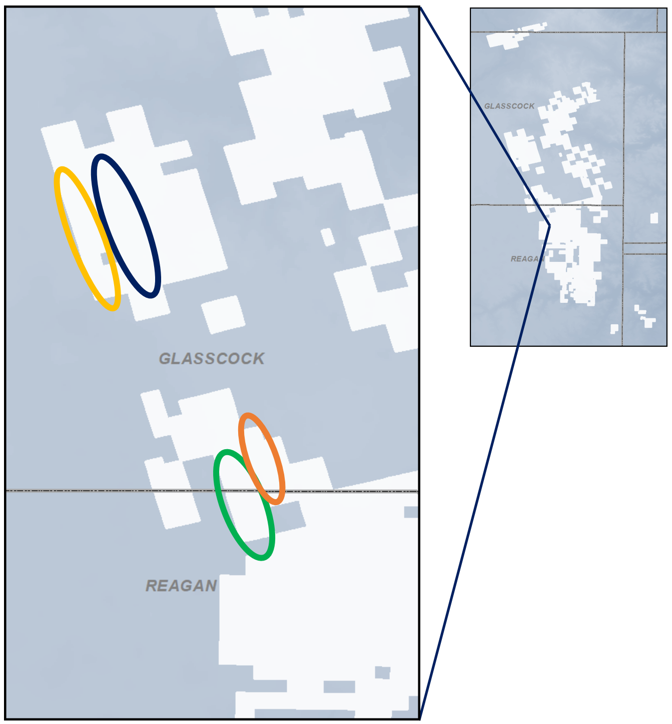
# Wider Spacing Improves Oil Productivity



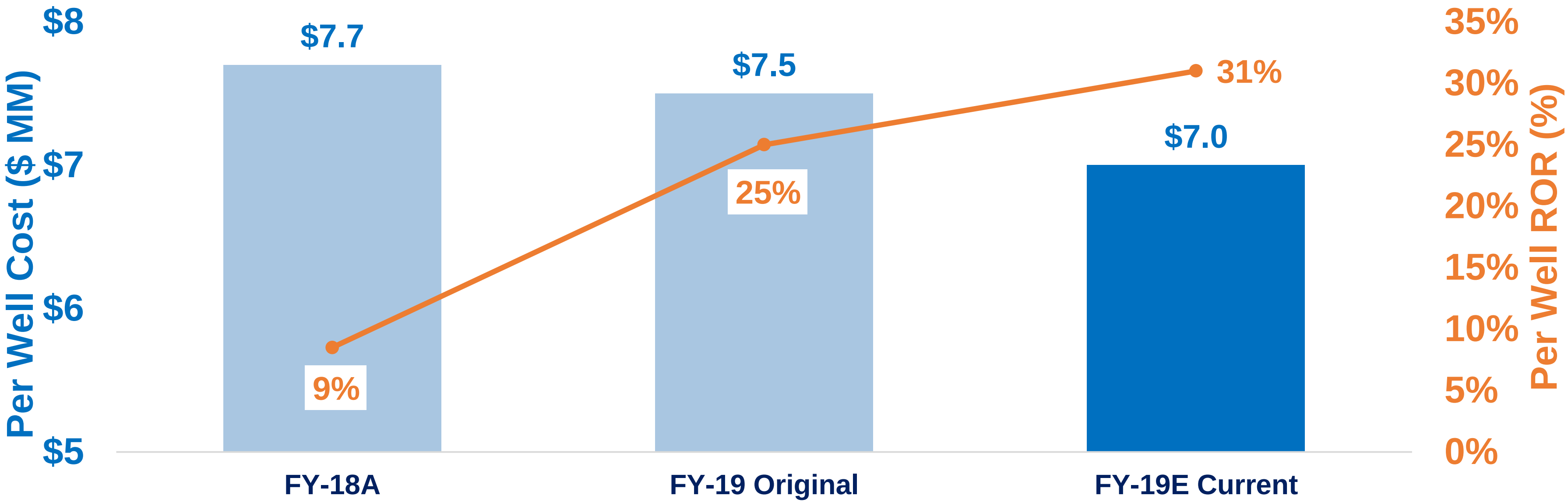

**Initial widely-spaced packages confirm improved oil productivity assumptions and Company's UWC/MWC type curve**

[1]Includes an average of the Yellow Rose package (8 wells); [2]Includes an average of the Fuchs package (11 wells); [3]Includes an average of the Hoelscher package (4 wells); [4]Includes an average of the Kloesel package (3 wells); All wells show cumulative oil production, normalized to a 10,000' lateral

Note: UWC/MWC 1.3 MMBOE type curve (400 MBO) representative of a 10,000' well, utilizing a 1.2 b-factor

# Wider Spacing & Reduced Well Costs Improve IRR

## Per Well Costs & ROR




| | FY-18A | FY-19 Original | FY-19E Current |
|---|---|---|---|
| LPI Well Type | Tightly-Spaced | 1.3 MMBOE Type Curve | 1.3 MMBOE Type Curve |
| Well Cost[1] ($ MM) | $7.7 | $7.5 | $7.0 |
| WTI Price ($/BO) | $65 | $54 | $56 |
| Well Spacing | 660’ | 1,320’ | 1,320’ |

**Strategic improvements versus 2018 development plan are driving higher returns**

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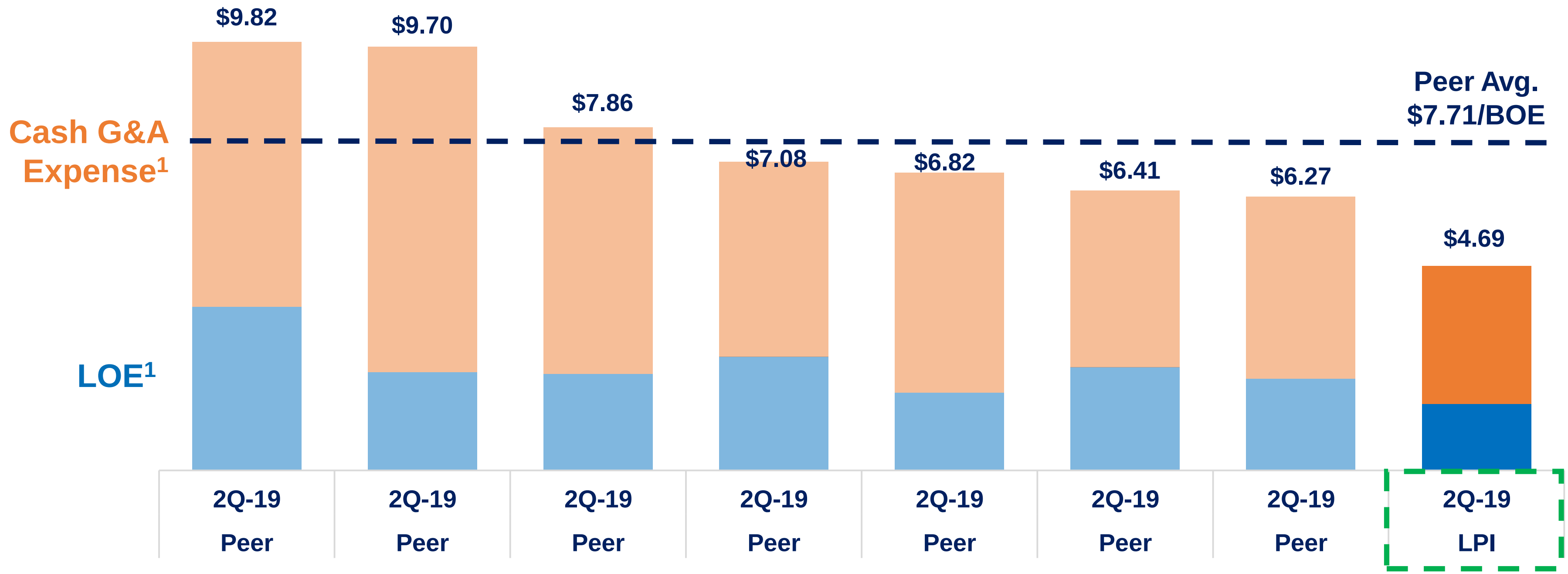
[1]Well costs indicative of a 10,000’ UWC/MWC utilizing a 2-well pad

# Lowest Cash Costs Among Permian Peers

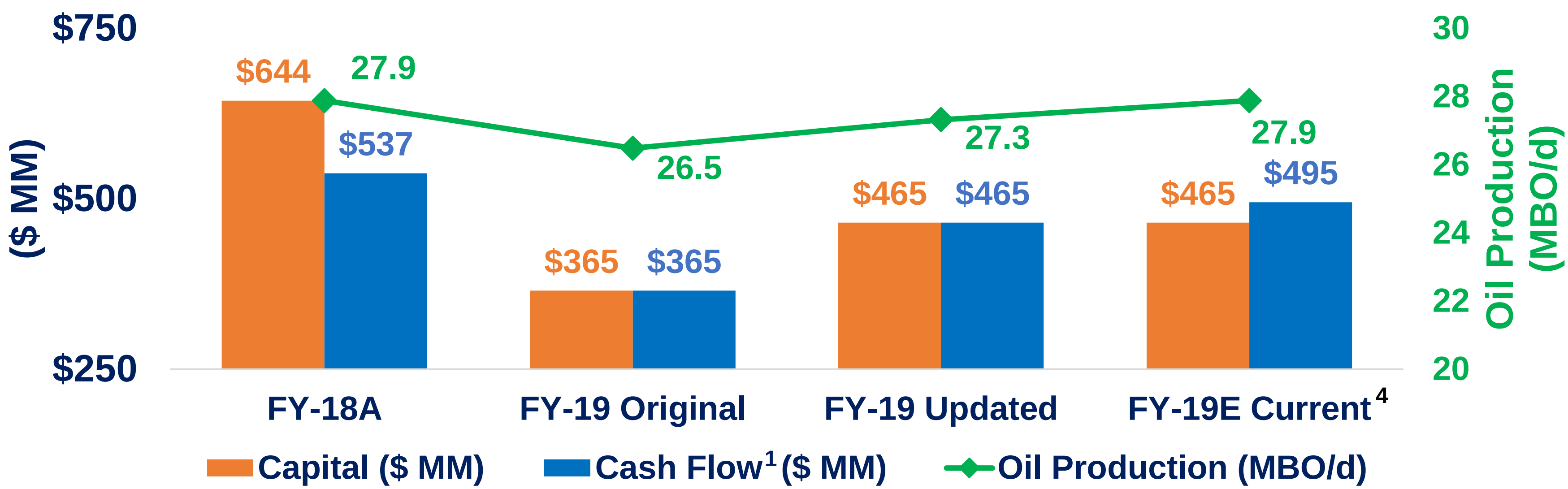



## 40% lower 2Q-19A controllable cash costs versus 2Q-19A peer average

[1]Representative of unit expenses

Note: Peers include - CDEV, CPE, CRZO, JAG, MTDR, QEP, SM

# Higher FY-19 Oil Guidance, Maintaining Capex & Generating Free Cash




| | FY-18A | FY-19 Original | FY-19 Updated | FY-19E Current[4] |
|---|---|---|---|---|
| LPI Well Type | Tightly-Spaced | 1.3 MMBOE UWC/MWC Type Curve | 1.3 MMBOE UWC/MWC Type Curve | 1.3 MMBOE UWC/MWC Type Curve |
| Well Cost[2] ($ MM) | $7.7 | $7.5 | $7.0 | $7.0 |
| WTI Price ($/BO) | $65 | $54 | $58 | $56 |
| Hedged Price[3] ($/BO) | $47.42 | $47.91 | $60.42 | $60.42 |
| Well Spacing | 660’ | 1,320’ | 1,320’ | 1,320' |

## Expect to generate $30 MM of free cash flow[1] in 2019

[1]See Appendix for a reconciliation of net cash provided by operating activities to cash flow and free cash flow
[2]Well costs indicative of a 10,000’ UWC/MWC utilizing a 2-well pad
[3]Reflective of the weighted-average WTI floor price in place for the period
[4]Updated as of 8/1/19
Note: Capital excludes non-budgeted acquisitions & includes cash & non-cash capital

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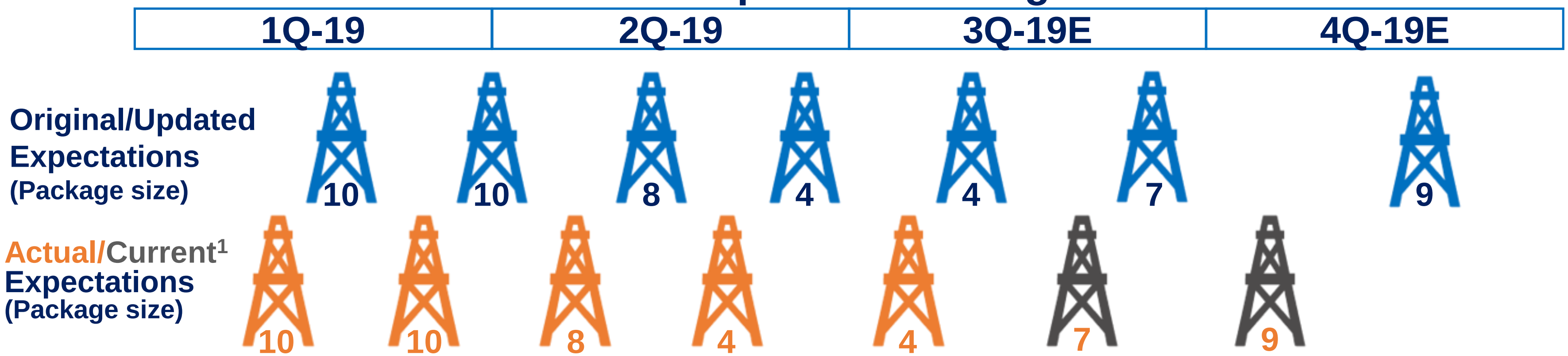
# Operational Efficiencies Pulling Activity Forward

## Operating Activity by Quarter

| Actual/Future Activity | 1Q-19A | 2Q-19A | 3Q-19E | 4Q-19E |
|---|---|---|---|---|
| Drilling Rigs | 3.0 | 2.6 | 2.0 | 2.0 |
| Spuds | 14 | 14 | 12 | 10 |
| Completion Crews | 2.0 | 1.2 | 1.0 | 0.3 |
| Completions | 20 | 12 | 11 | 9 |

## 2019 Completions Timing




**Reduced cycle time increased new-drill production days by 8% in 1H-19**

[1] Updated as of 8/1/19

# High-Grading Inventory To Reduce Risk & Maximize Returns

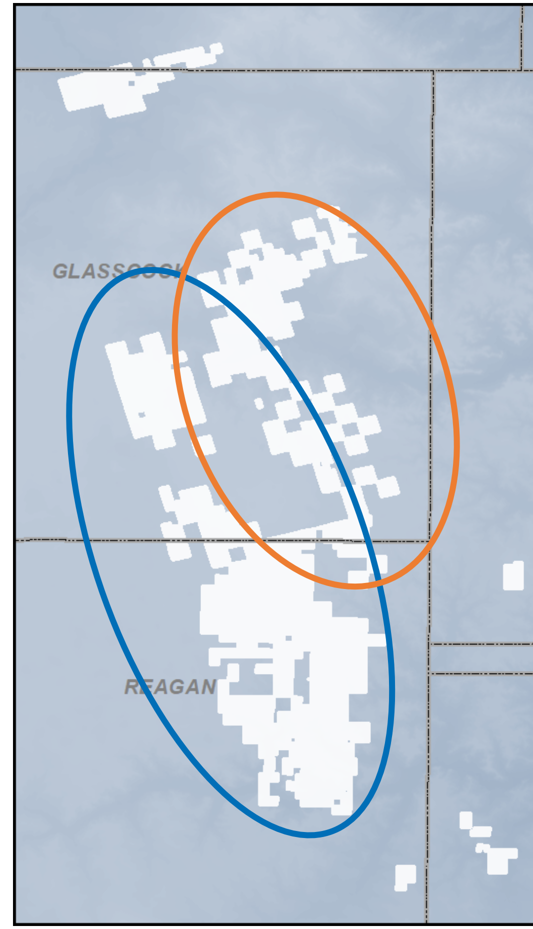

**UWC/MWC Combined**

| Wells per DSU | Drill Pattern | Inventory[1] |
|---|---|---|
| 8 - 12 | ● ● ● ●<br>● ● ● ● (green)<br>● ● ● ● | 350 - 500 |

**Regional Cline**

| Wells per DSU | Drill Pattern | Inventory[1] |
|---|---|---|
| 4 | ● ● ● ● | 140 - 160 |

● 1,320' single zone development
● 1,320' co-development




UWC/MWC Inventory
Regional Cline Inventory

**Continually optimizing inventory to incorporate current spacing and cost assumptions**

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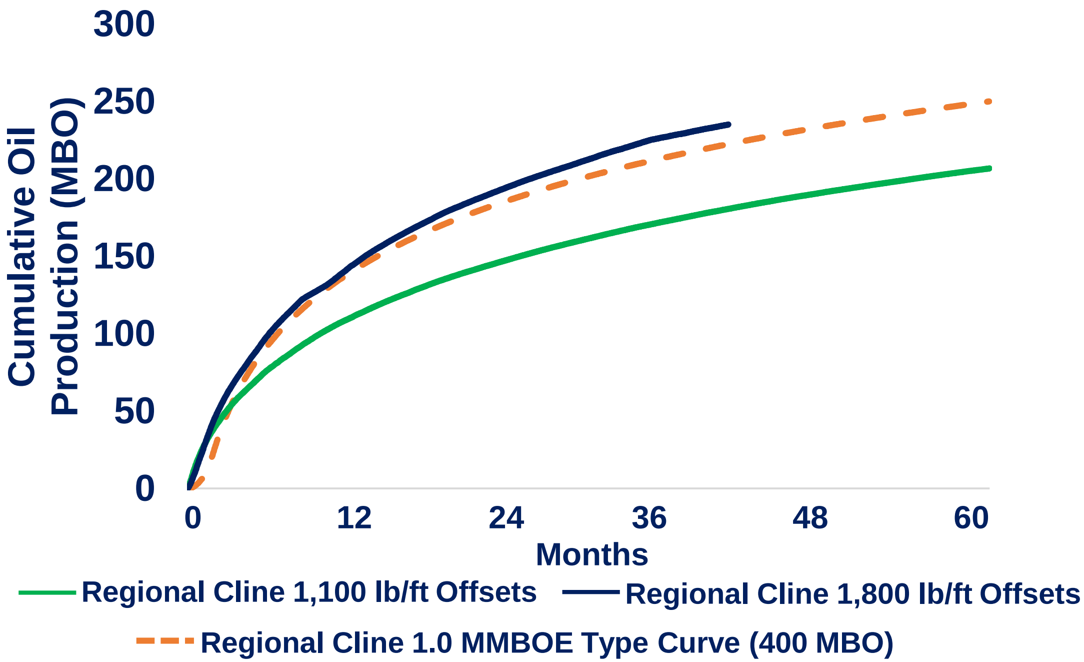
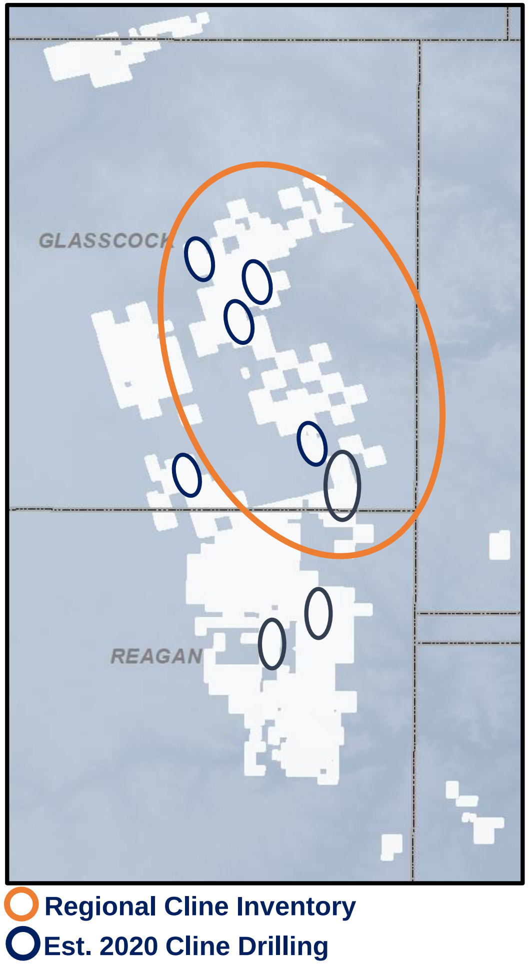
[1]Inventory expected to average oil type curve productivity
Note: Drilling spacing unit (DSU)

# Cline Reintroduced As Primary Target




- Completions optimization increased well productivity 30%
- Expected decrease in Cline well costs from $8.9 MM to $8.2 MM based on current service costs

**Combination of lower costs and increased productivity drives expected Cline ROR from 20%[1] to 35%[2]**

[1]Indicative of 10,000' lateral utilizing 1,100 lb/ft productivity assumptions and assumed well cost of $7.6 MM based on $56/BO WTI
[2]Indicative of 10,000' lateral utilizing 1,800 lb/ft productivity assumptions and assumed well cost of $8.2 MM based on $56/BO WTI
Note: Data from 32 regional Cline wells to develop a region-specific curve
Regional Cline 1.0 MMBOE type curve (400 MBO) representative of a 10,000' well, utilizing a 1.0 b-factor

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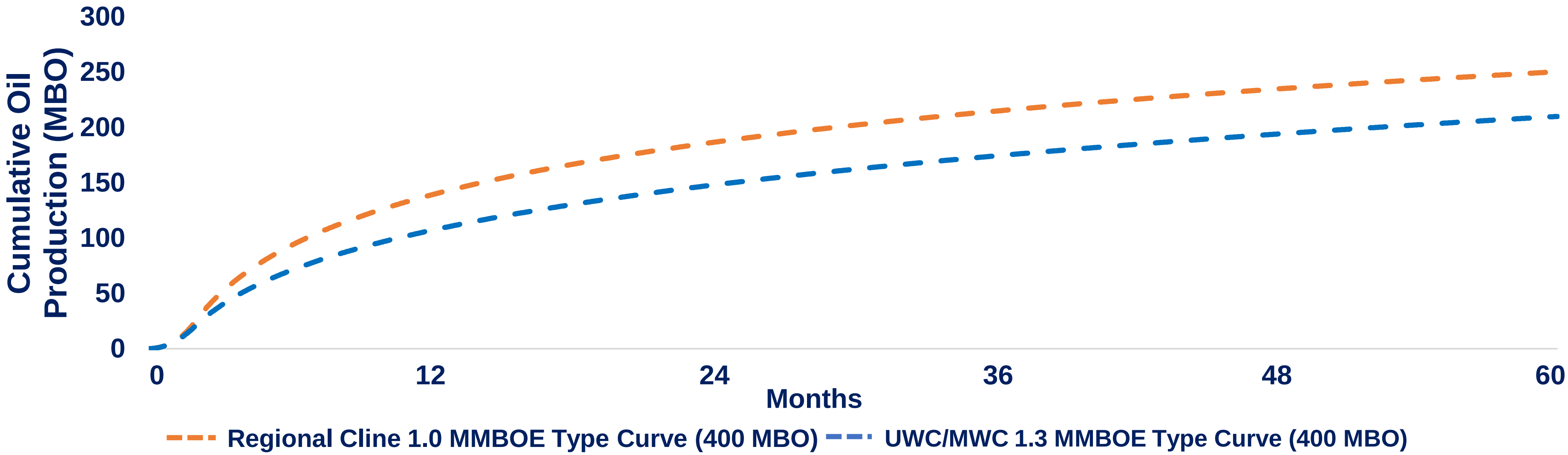
# Regional Cline Returns Compete With UWC/MWC




| | UWC/MWC 1.3 MMBOE Type Curve (400 MBO) | | | Regional Cline 1.0 MMBOE Type Curve (400 MBO) | | |
|---|---|---|---|---|---|---|
| Year | Oil (MBO) | Total (MBOE) | Oil Cut (%) | Oil (MBO) | Total (MBOE) | Oil Cut (%) |
| 1 | 107 | 213 | 50% | 139 | 295 | 47% |
| 2 | 41 | 130 | 32% | 48 | 128 | 37% |
| 3 | 26 | 84 | 31% | 28 | 76 | 37% |
| 4 | 20 | 64 | 31% | 20 | 55 | 37% |
| 5 | 16 | 53 | 30% | 16 | 43 | 37% |
| 5-Year Cum. Prod. | 210 | 544 | 39% | 250 | 596 | 42% |
| Life of Well | 400 | 1,300 | 30% | 400 | 1,000 | 40% |

## Regional Cline wells exceed near-term UWC/MWC oil productivity

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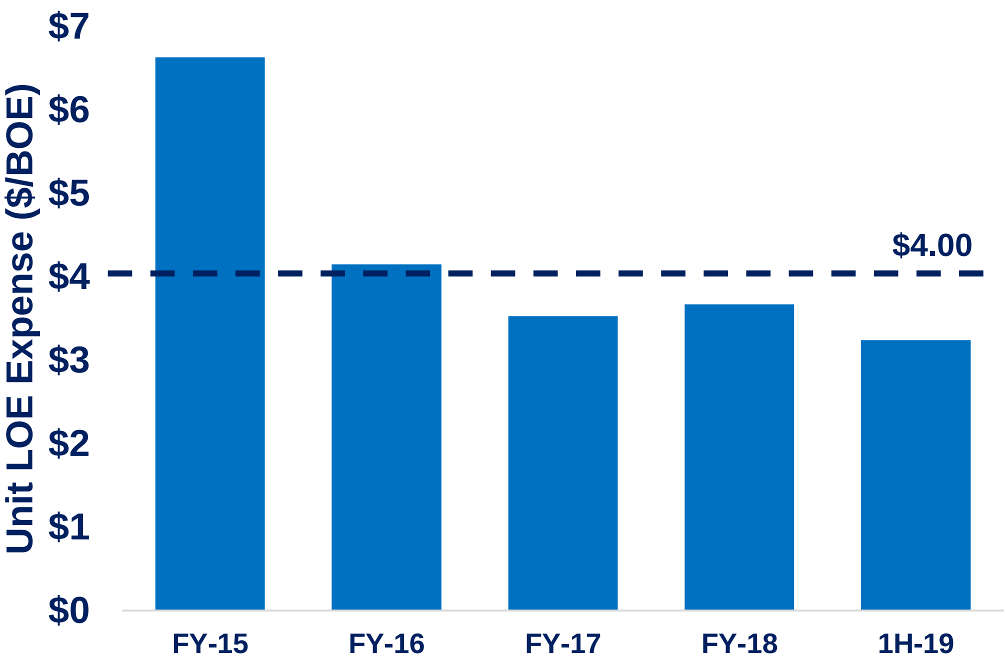
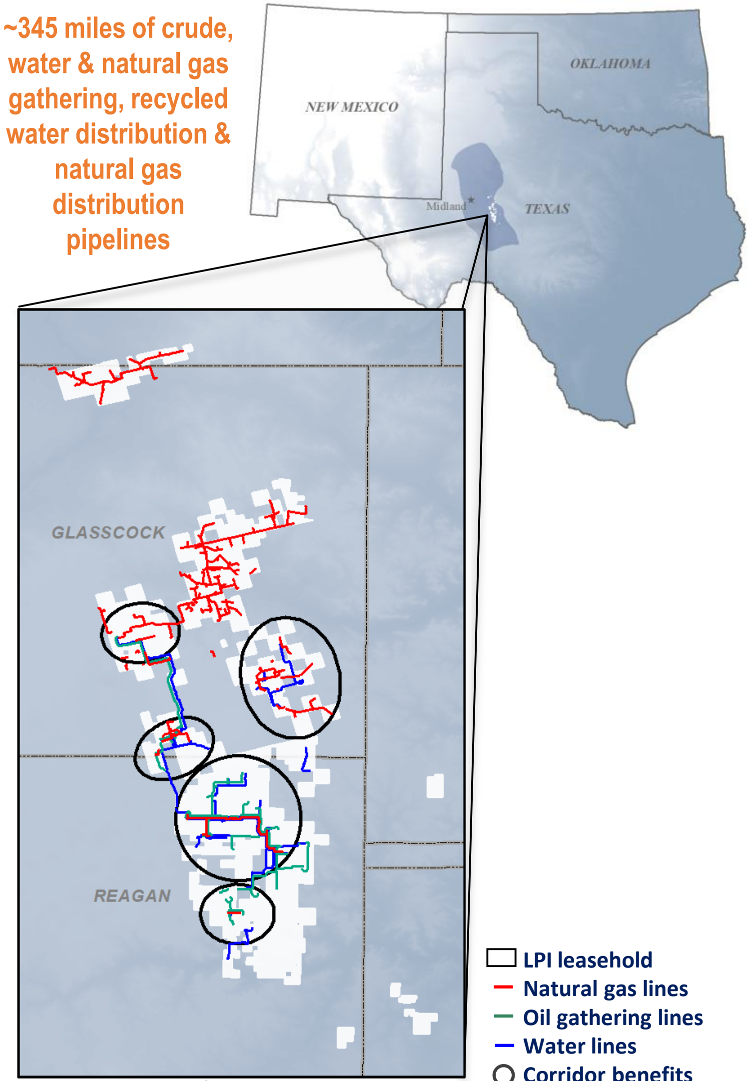
Note: Table may not foot due to rounding
Regional Cline 1.0 MMBOE type curve (400 MBO) representative of a 10,000' well, utilizing a 1.0 b-factor; assumed well cost of $8.2 MM; UWC/MWC 1.3 MMBOE type curve (400 MBO) representative of a 10,000' well, utilizing a 1.2 b-factor; assumed well cost of $7.0 MM

# Existing Infrastructure Reduces Operating Costs

## 12 consecutive quarters with unit LOE less than $4.00/BOE




~345 miles of crude, water & natural gas gathering, recycled water distribution & natural gas distribution pipelines




137,831 gross/ 122,787 net acres

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Note: Map, acreage count and statistics as of 6/30/19

# Infrastructure Protects The Environment & Enhances Economics

## LPI In-Place Infrastructure

**60 Miles**
Crude oil gathering pipelines

**170 miles**
Natural gas gathering pipelines

**110 Miles**
Water gathering & distribution pipelines

**54 MBWPD**
Produced water recycling capacity

## Environmental Impact

**Truckloads eliminated from the field**
**>220,000**

**Barrels of water recycled**
**>8,500,000**

**Additional gas sold vs. vented/flared**
**>3.2 Bcf**

## Shareholder Value

**$0.51/BOE**
Reduction in unit LOE, helping to control operating costs

**$110,000**
Per well reduction in capital due to in-place water infrastructure

**$10.4 MM**
Revenue from natural gas sold versus vented/flared

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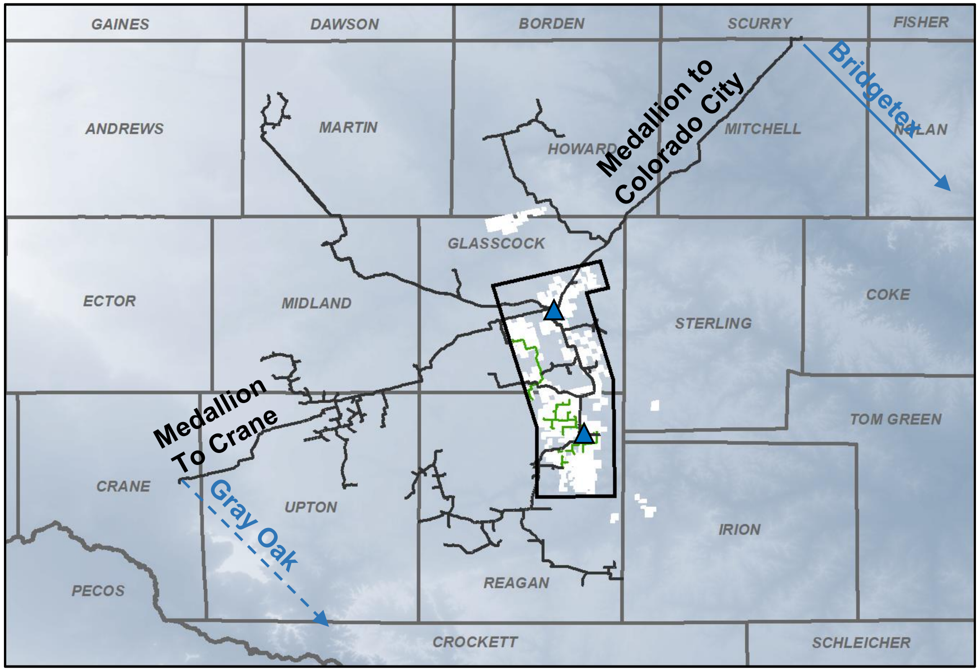
Note: Existing infrastructure as of 7/17/19
Environmental impact and shareholder value based on FY-18

# Oil Value Enhanced Via Gulf Coast Access

**Gross Physical Transportation Contracts:**

- **Medallion firm transportation secured for all crude oil produced within dedication area**
- **10 MBOPD firm transportation on Bridgetex through 1Q-22, with option to extend through 1Q-26 (USGC pricing)**
- **Firm transportation on Gray Oak through 4Q-26E upon startup (Brent-related pricing):**
  - **Year 1: 25 MBOPD**
  - **Years 2 - 7: 35 MBOPD**




LPI leasehold
LMS truck stations
LMS oil gathering pipelines
Medallion-dedicated LPI acreage
Medallion intra-basin pipelines
Long-haul pipelines
Long-haul transport (constructing)

**Firm transportation to the US Gulf Coast provides exposure to Brent-based pricing for majority of crude oil production**

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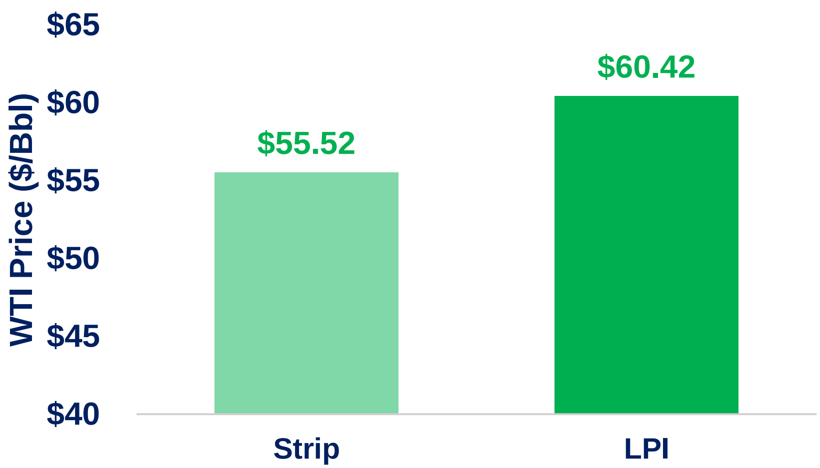
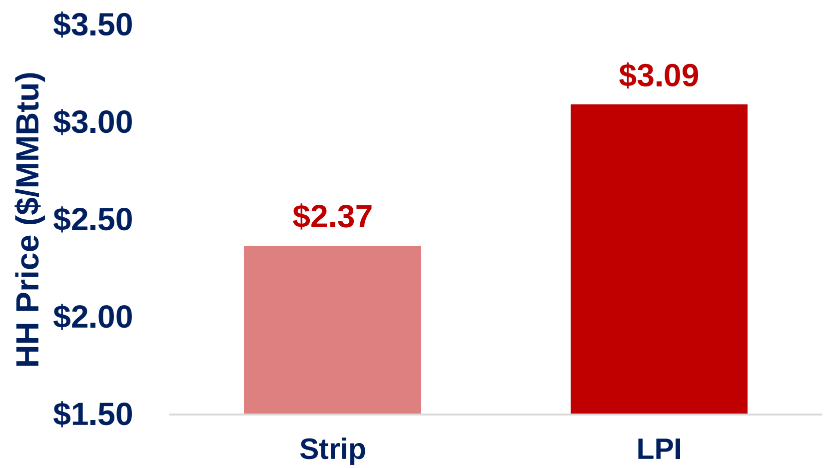
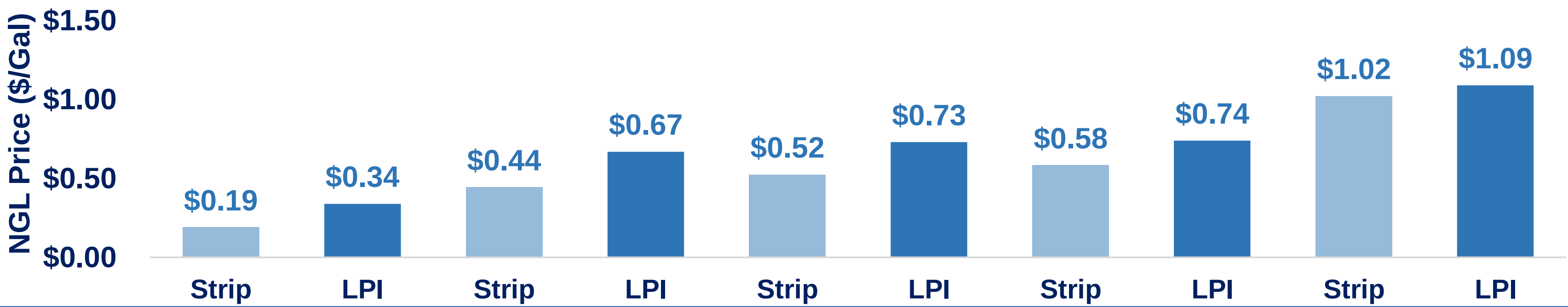
Note: Map as of 6/30/19

# 2019 Product Hedges Protect Cash Flow




% Hedged[1] Oil: 95% Natural Gas: 70%




% Hedged[1] Ethane: 65% Propane: 65% N. Butane: 70% I. Butane: 70% N. Gasoline: 65%

**Hedges in place significantly reduce the impact of commodity price fluctuations and help ensure cash flow projections**

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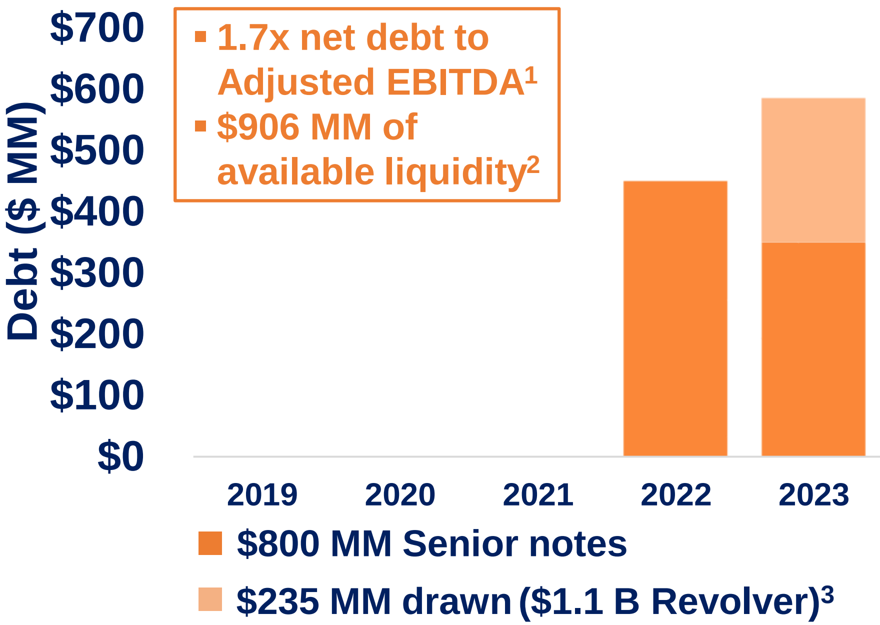
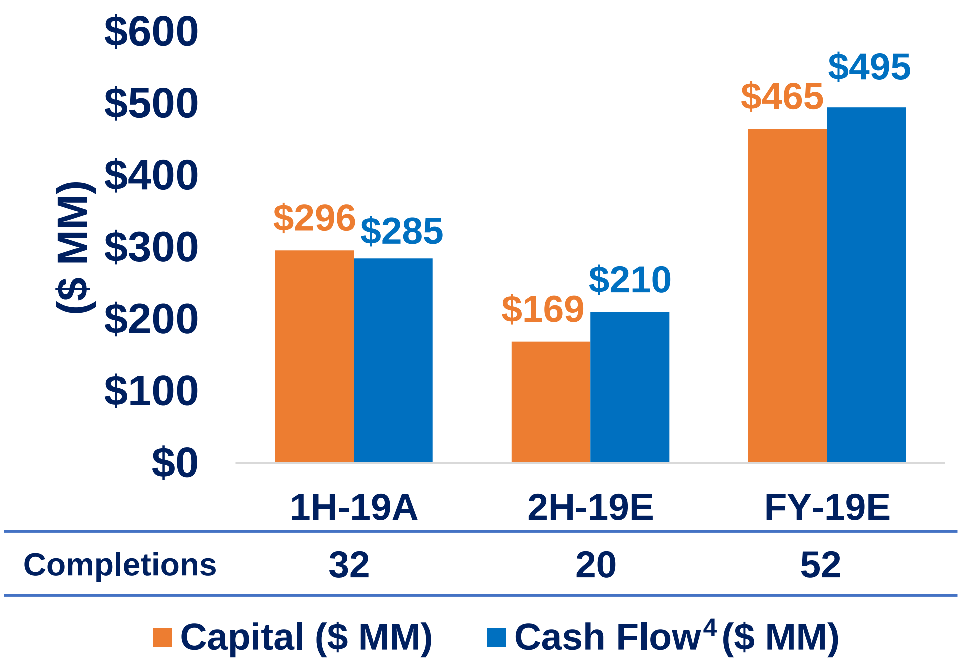
[1]Percentages reflective of hedged volumes as a percent of forecasted production; strip as of 8/30/19; LPI is representative of LPI's 2H-19 weighted-average floor price

# Stronger Than Expected Cash Flow Generation Used To Pay Down Debt




## Utilized $35 MM of free cash flow[4] in 2Q-19 to reduce outstanding borrowings on the revolver

[1]As of 2Q-19. See Appendix for the calculation of net debt to Adjusted EBITDA and a reconciliation of Net Income to Adjusted EBITDA
[2]As of 2Q-19. See Appendix for the calculation of liquidity
[3]As of 6/30/19, per the 4/30/19 semi-annual redetermination of $1.1 B aggregate elected commitment in place under Fifth Amended and Restated Senior Secured Credit Facility
[4]See Appendix for a reconciliation of net cash provided by operating activities to cash flow and free cash flow
Note: Capital excludes non-budgeted acquisitions & includes cash & non-cash capital; FY-19E based on $56/BO WTI & $2.60/MMBtu HH

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# Redefined Development Strategy Drives Free Cash Flow Generation

- High-Grading Inventory
- Optimizing Spacing
- Controlling Costs
- Driving Operational Efficiencies
- Ongoing Financial Risk Management

- Free Cash Flow
- Improved Returns
- Measured Oil Growth

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# APPENDIX

# 3Q-19 Guidance

| Production | |
|---|---|
| Total production (MBOE/d) | 79.0 |
| Oil production (MBbl/d) | 27.3 |

| Average sales price realizations: *(excluding derivatives)* | |
|---|---|
| Oil (% of WTI) | 97% |
| NGL (% of WTI) | 15% |
| Natural gas (% of Henry Hub) | 20% |

| Operating costs & expenses ($/BOE): | |
|---|---|
| Lease operating expenses | $3.35 |
| Production and ad valorem taxes *(% of oil, NGL and natural gas revenues)* | 6.50% |
| Transportation and marketing expenses | $0.70 |
| Midstream service expenses | $0.15 |
| General and administrative expenses: | |
| Cash | $1.70 |
| Non-cash stock-based compensation, net | $0.65 |
| Depletion, depreciation and amortization | $9.00 |

# Oil, Natural Gas & Natural Gas Liquids Hedges

| Hedge Product Summary | 3Q-19 - 4Q-19 | FY-20 | FY-21 |
|---|---|---|---|
| Oil total floor volume (Bbl) | 4,600,000 | 7,539,600 | 912,500 |
| Oil wtd-avg floor price ($/Bbl) | $60.42 | $58.79 | $45.00 |
| *Oil total floor volume w. deferred premium (Bbl)* | *644,000* | | |
| *Oil wtd-avg deferred premium price ($/Bbl)* | *$4.39* | | |
| Nat gas total floor volume (MMBtu) | 19,688,000 | 23,790,000 | 14,052,500 |
| Nat gas wtd-avg floor price ($/MMBtu) | $3.09 | $2.72 | $2.63 |
| NGL total floor volume (Bbl) | 2,925,600 | 2,562,000 | 2,202,775 |

| Oil | 3Q-19 - 4Q-19 | FY-20 | FY-21 |
|---|---|---|---|
| Puts | | | |
| Hedged volume (Bbl) | 644,000 | 366,000 | |
| Wtd-avg floor price ($/Bbl) | $55.00 | $45.00 | |
| *Hedged Volume w. Deferred Premium (Bbl)* | *644,000* | | |
| *Wtd-avg deferred premium price ($/Bbl)* | *$4.39* | | |
| Swaps | | | |
| Hedged volume (Bbl) | 3,956,000 | 7,173,600 | |
| Wtd-avg price ($/Bbl) | $61.31 | $59.50 | |
| Collars | | | |
| Hedged volume (Bbl) | | | 912,500 |
| Wtd-avg floor price ($/Bbl) | | | $45.00 |
| Wtd-avg ceiling price ($/Bbl) | | | $71.00 |

| Natural Gas - HH | 3Q-19 - 4Q-19 | FY-20 | FY-21 |
|---|---|---|---|
| Swaps | | | |
| Hedged volume (MMBtu) | 19,688,000 | 23,790,000 | 14,052,500 |
| Wtd-avg price ($/MMBtu) | $3.09 | $2.72 | $2.63 |

| Natural Gas Liquids | 3Q-19 - 4Q-19 | FY-20 | FY-21 |
|---|---|---|---|
| Swaps - Ethane | | | |
| Hedged volume (Bbl) | 1,196,000 | 366,000 | 912,500 |
| Wtd-avg price ($/Bbl) | $14.22 | $13.60 | $12.01 |
| Swaps - Propane | | | |
| Hedged volume (Bbl) | 956,800 | 1,244,400 | 730,000 |
| Wtd-avg price ($/Bbl) | $27.97 | $26.58 | $25.52 |
| Swaps – Normal Butane | | | |
| Hedged volume (Bbl) | 368,000 | 439,200 | 255,500 |
| Wtd-avg price ($/Bbl) | $30.73 | $28.69 | $27.72 |
| Swaps - Isobutane | | | |
| Hedged volume (Bbl) | 92,000 | 109,800 | 67,525 |
| Wtd-avg price ($/Bbl) | $31.08 | $29.99 | $28.79 |
| Swaps - Natural Gasoline | | | |
| Hedged volume (Bbl) | 312,800 | 402,600 | 237,250 |
| Wtd-avg price ($/Bbl) | $45.80 | $45.15 | $44.31 |

| Basis Swaps | 3Q-19 - 4Q-19 | FY-20 | FY-21 |
|---|---|---|---|
| Mid/Cush | | | |
| Hedged volume (Bbl) | 2,392,000 | | |
| Wtd-avg price ($/Bbl) | -$3.23 | | |
| Waha/HH | | | |
| Hedged volume (MMBtu) | 19,688,000 | 32,574,000 | 23,360,000 |
| Wtd-avg price ($/MMBtu) | -$1.51 | -$0.76 | -$0.47 |

LAREDO PETROLEUM

Note: Open positions as of 6/30/19, hedges executed through 8/30/19
Hedged volumes with deferred premiums outlined above are included in provided totals and are therefore not additive

# Supplemental Financial Calculations

***Net debt to Adjusted EBITDA***

**Net debt to Adjusted EBITDA is calculated as net debt as of June 30, 2019 divided by trailing twelve-month Adjusted EBITDA ending June 30, 2019 of $569 million. Net debt as of June 30, 2019 was $979 million, calculated as the face value of debt of $1.035 billion reduced by cash and cash equivalents of $56 million.**

**See next slide for a reconciliation of Net Income to Adjusted EBITDA.**

***Liquidity***

**At June 30, 2019, the Company had outstanding borrowings of $235 million on its $1.1 billion senior secured credit facility, resulting in available capacity, after reductions for outstanding letters of credit, of $850 million. Including cash and cash equivalents of $56 million, total liquidity was $906 million.**

# Supplemental Non-GAAP Financial Measure

***Adjusted EBITDA (Unaudited)***

**Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for income taxes, depletion, depreciation and amortization, non-cash stock-based compensation, net, accretion expense, mark-to-market on derivatives, premiums paid for derivatives, interest expense, gains or losses on disposal of assets and other non-recurring income and expenses. Adjusted EBITDA provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, working capital movement or tax position. Adjusted EBITDA does not represent funds available for discretionary use because those funds are required for debt service, capital expenditures, working capital, income taxes, franchise taxes and other commitments and obligations. However, our management believes Adjusted EBITDA is useful to an investor in evaluating our operating performance because this measure:**

- **is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods, the book value of assets, capital structure and the method by which assets were acquired, among other factors;**
- **helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and**
- **is used by our management for various purposes, including as a measure of operating performance, in presentations to our board of directors and as a basis for strategic planning and forecasting. There are significant limitations to the use of Adjusted EBITDA as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations to different companies and the different methods of calculating Adjusted EBITDA reported by different companies. Our measurements of Adjusted EBITDA for financial reporting as compared to compliance under our debt agreements differ.**

**The following table presents a reconciliation of net income (GAAP) to Adjusted EBITDA (non-GAAP):**

| *(in thousands, unaudited)* | 3Q-18 | 4Q-18 | 1Q-19 | 2Q-19 |
|---|---|---|---|---|
| Net income (loss) | $55,050 | $149,573 | $(9,491) | $173,382 |
| Plus: | | | | |
| Income tax expense (benefit) | 1,387 | 2,862 | (96) | 1,751 |
| Depletion, depreciation and amortization | 55,963 | 60,399 | 63,098 | 65,703 |
| Non-cash stock-based compensation, net | 8,733 | 7,648 | 7,406 | (423) |
| Restructuring expense | - | - | - | 10,406 |
| Accretion expense | 1,114 | 1,131 | 1,052 | 1,020 |
| Mark-to-market on derivatives: | | | | |
| (Gain) loss on derivatives, net | 32,245 | (112,195) | 48,365 | (88,394) |
| Settlements received (paid) for matured derivatives, net | (3,888) | 12,033 | 102 | 23,480 |
| Settlements paid for early termination of derivatives, net | - | - | - | (5,409) |
| Premiums paid for derivatives | (5,455) | (5,405) | (4,016) | (2,233) |
| Interest expense | 14,845 | 15,117 | 15,547 | 15,765 |
| Litigation settlement | - | - | - | (42,500) |
| Loss on disposal of assets, net | 616 | 1,207 | 939 | 670 |
| Adjusted EBITDA | $160,610 | $132,370 | $122,906 | $153,218 |

# Cash Flow & Free Cash Flow

## *Free Cash Flow*

Historic Free Cash Flow is calculated as estimated cash flows from operating activities before changes in assets and liabilities, less cash and non-cash capital investments made during the period, excluding non-budgeted acquisitions. Management believes this is useful to investors in evaluating the operating trends in its business due to production, commodity prices, operating costs and other related factors.
The following table presents a reconciliation of net cash provided by operating activities (GAAP) to cash flow (non-GAAP) and free cash flow (non-GAAP):

| *(in thousands, unaudited)* | FY-18 | 1Q-19 | 2Q-19 |
|---|---|---|---|
| Net cash provided by operating activities | $537,804 | $77,458 | $183,811 |
| Less: | | | |
| Changes in working capital | 427 | (35,686) | 11,541 |
| Adjusted cash flows from operating activities ("Cash flow") | 537,377 | 113,144 | 172,270 |
| Less: | | | |
| Costs incurred, including LMS investments ("Capital") | 644,000 | 164,000 | 132,000 |
| Free cash flow | ($106,623) | ($50,856) | $40,270 |

Future Free Cash Flow is calculated as estimated future cash flows from operating activities before changes in assets and liabilities, less cash and non-cash capital investments expected to be made during the period, excluding non-budgeted acquisitions.