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

Corporate Presentation
June 2018

LAREDO PETROLEUM

Forward-Looking / Cautionary Statements

This presentation, including any oral statements made regarding the contents of this presentation, contains forward-looking statements within the meaning of 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 fact, included in this presentation that address activities, events or developments that Laredo Petroleum, Inc. (together with its subsidiaries, the “Company”, “Laredo” or “LPI”) assumes, plans, expects, believes or anticipates will or may occur in the future are forward-looking statements. The words “believe,” “expect,” “may,” “estimates,” “will,” “anticipate,” “plan,” “project,” “intend,” “indicator,” “foresee,” “forecast,” “guidance,” “should,” “would,” “could,” “goal,” “target,” “suggest” or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature and are not guarantees of future performance. However, the absence of these words does not mean that the statements are not forward-looking. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include the expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including the Company’s drilling program, production, hedging activities, capital expenditure levels, possible impacts of pending or potential litigation and other guidance included in this presentation. These statements are based on certain assumptions made by the Company based on management’s expectations and perception of historical trends, current conditions, anticipated future developments and rate of return and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include risks relating to financial performance and results, current economic conditions and resulting capital restraints, prices and demand for oil and natural gas and the related impact to financial statements as a result of asset impairments and revisions to reserve estimates, availability and cost of drilling equipment and personnel, availability of sufficient capital to execute the Company’s business plan, impact of compliance with legislation and regulations, impacts of pending or potential litigation, impacts relating to the Company’s share repurchase program (which may be suspended or discontinued by the Company at any time without notice), successful results from the Company’s identified drilling locations, the Company’s ability to replace reserves and efficiently develop and exploit its current reserves and other important factors that could cause actual results to differ materially from those projected as described in the Company’s Annual Report on Form 10-K for the year ended December 31, 2017 and other reports filed with the Securities and Exchange Commission (“SEC”).

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 to disclose proved reserves in filings made with the SEC, 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 “unproved reserves,” “resource potential,” “estimated ultimate recovery,” “EUR,” “development ready,” “type curve” or other descriptions of potential reserves or volumes of reserves which the SEC guidelines restrict from being included in filings with the SEC without strict compliance with SEC definitions. “Unproved reserves” refers to the Company’s internal estimates of 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. The Company does not choose to include unproved reserve estimates in its filings with the SEC. “Estimated ultimate recovery”, or “EUR”, refers to the Company’s internal estimates of per-well hydrocarbon quantities that may be potentially recovered from a hypothetical and/or actual well completed in the area. Actual quantities that may be ultimately recovered from the Company’s interests are unknown. Factors affecting ultimate recovery include the scope of the Company’s ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability and cost of drilling services and equipment, lease expirations, transportation constraints, regulatory approvals and other factors, as well as actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of ultimate recovery from reserves may change significantly as development of the Company’s core assets provide additional data. “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.

This presentation includes financial measures that are not in accordance with generally accepted accounting principles (“GAAP”), including Adjusted EBITDA and Proved F&D Cost. 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 and Proved F&D Cost to the nearest comparable measure in accordance with GAAP, please see the Appendix.

2018 Highlights




>12% Anticipated FY-18E BOE production growth

>10% Anticipated FY-18E oil production growth

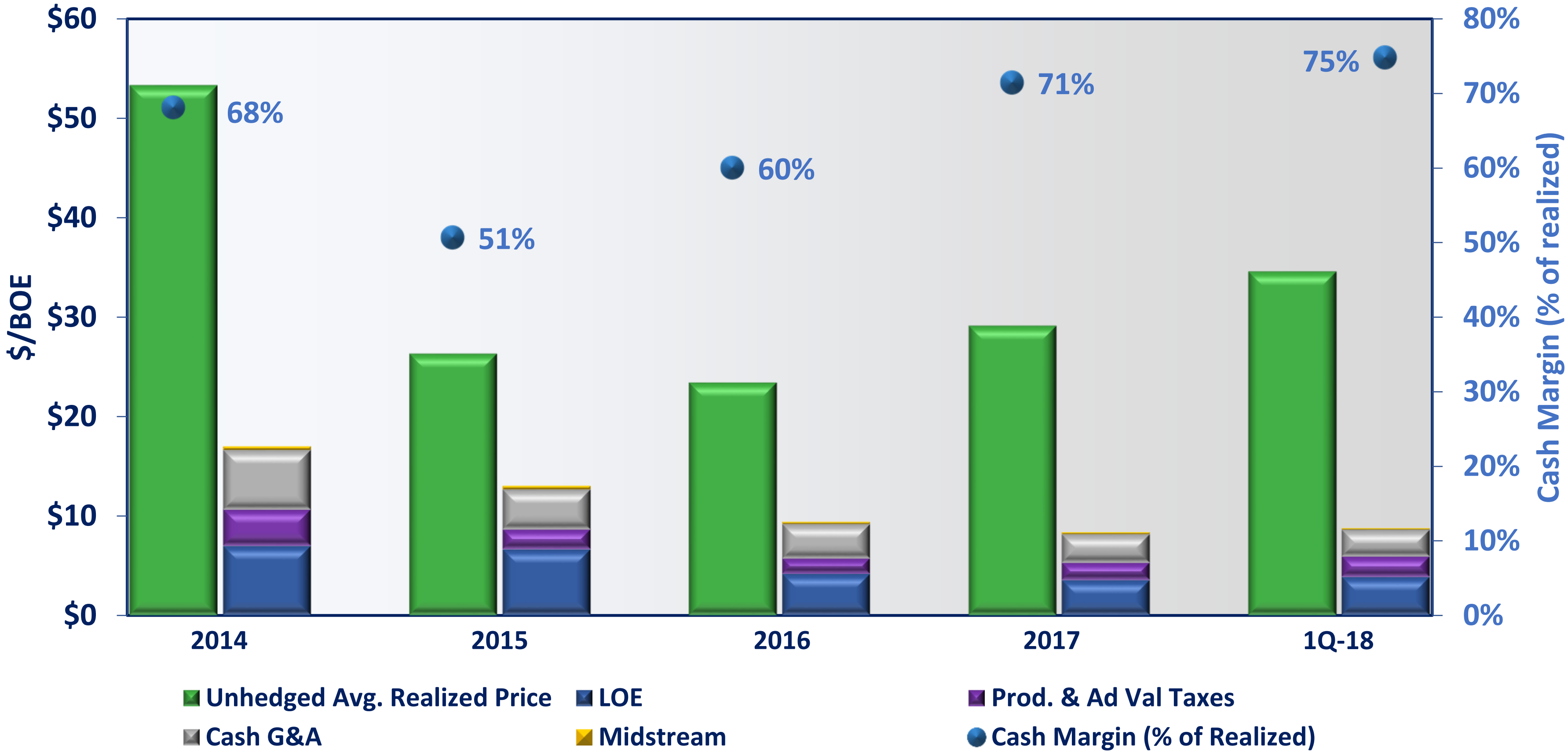
~70% FY-18E oil volumes protected from Midland pricing

~1.4x Net debt to Adjusted EBITDA[1]

$58.5 MM of $200 MM stock repurchase program utilized in 1Q-18

[1] Net debt to Adjusted EBITDA includes net debt as of 3/31/18 and 1Q-18 annualized Adjusted EBITDA. Net debt as of 3/31/18 is calculated as the face value of long-term debt of $855 MM, reduced by cash on hand of $56 MM. See Appendix for a reconciliation of Net Income to Adjusted EBITDA

Cash Margin Improved By Controlling Cash Costs



75% Current cash margin % exceeds pre-price decline cash margin[1]

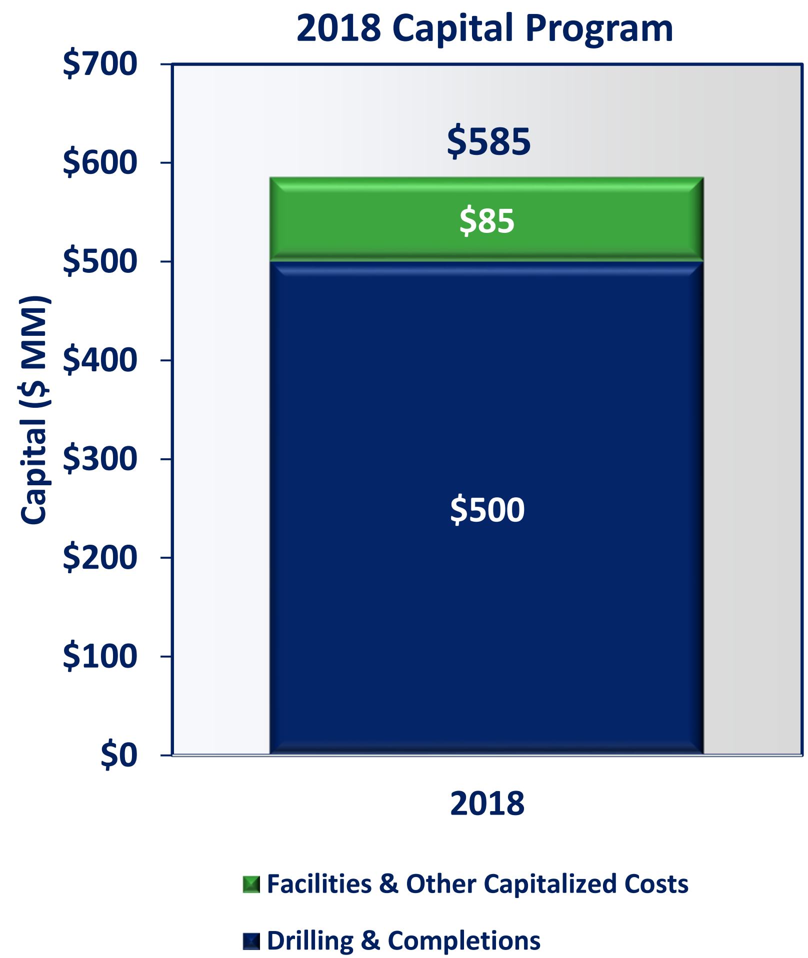
[1] Current cash margin as a percent of unhedged average realized price

Note: 2014 cash margin has been converted to 3-stream using actual gas plant economics

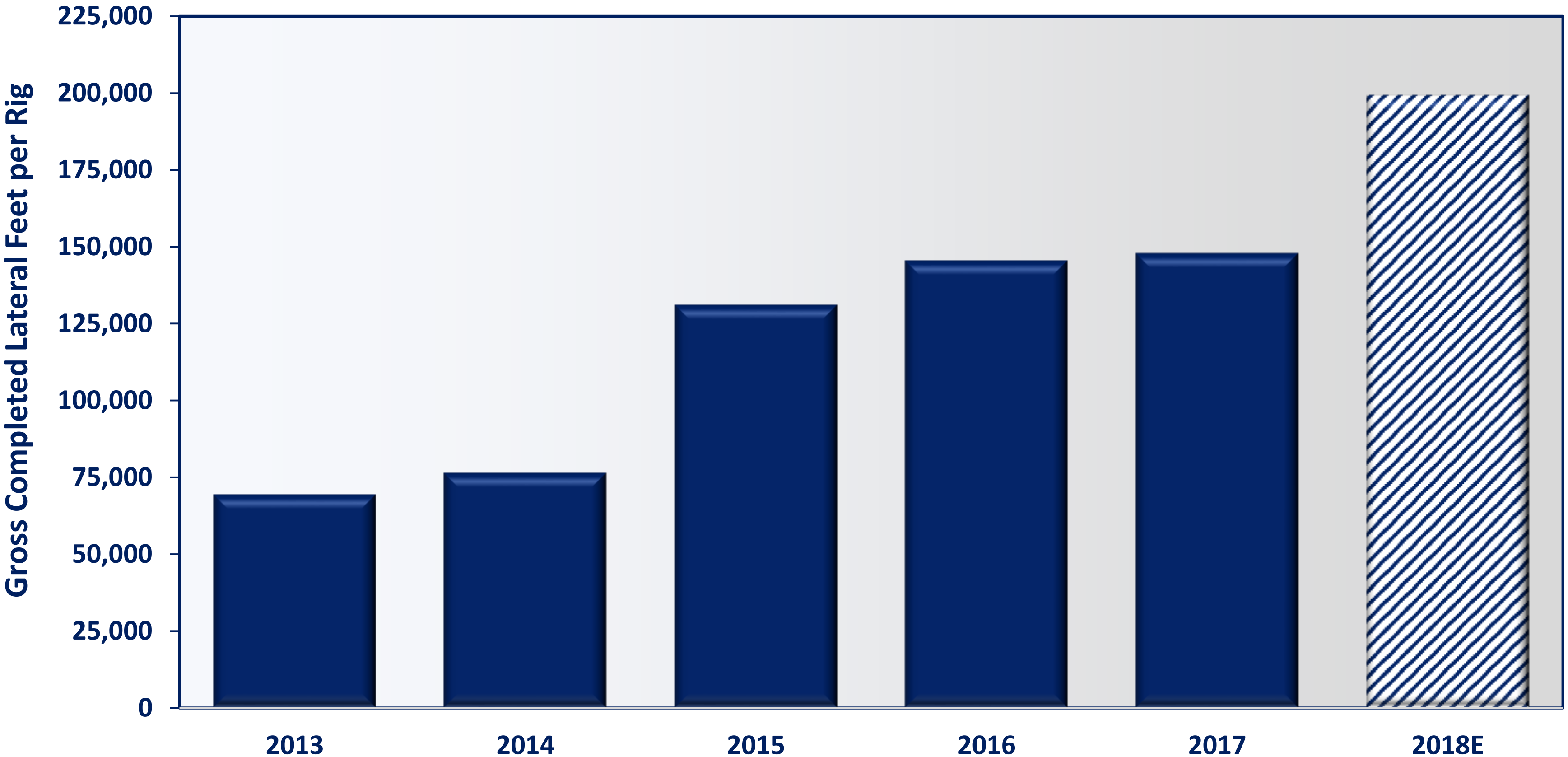
2018 Capital Program

2018 Drilling & Completions Plan

- Completing 60 - 65 net wells
- ~10,600' avg. Hz lateral length
- ~95% avg. working interest
- Adding 4th Hz rig in 3Q-18



Operational Efficiencies Enable Us To Do More With Less



35% YoY increase in gross completed lateral feet per rig

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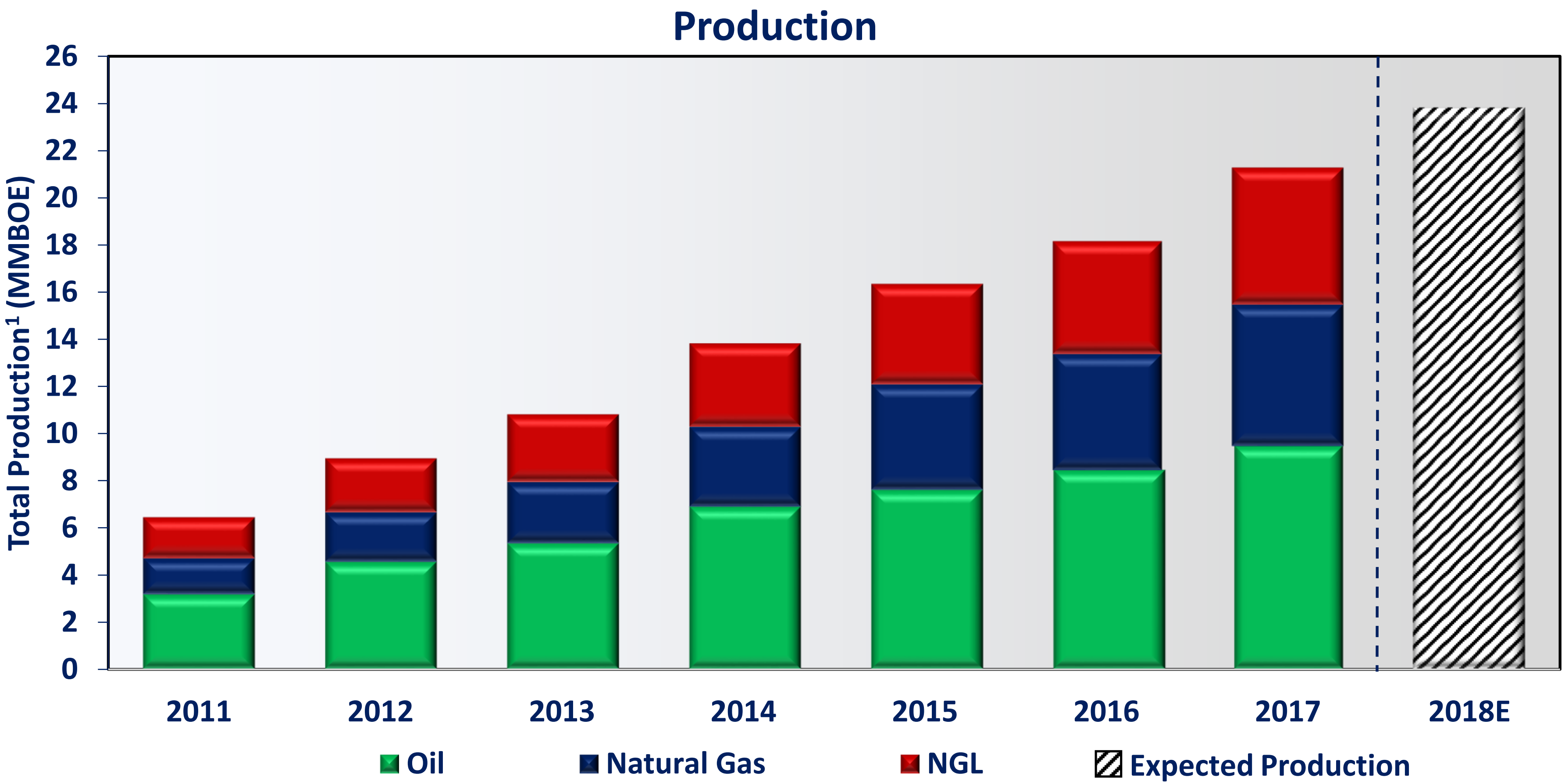
Consistent Production Growth



>10% FY-18E YoY oil production growth

FY-18E YoY BOE production growth >12%

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[1] 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 August 1, 2013

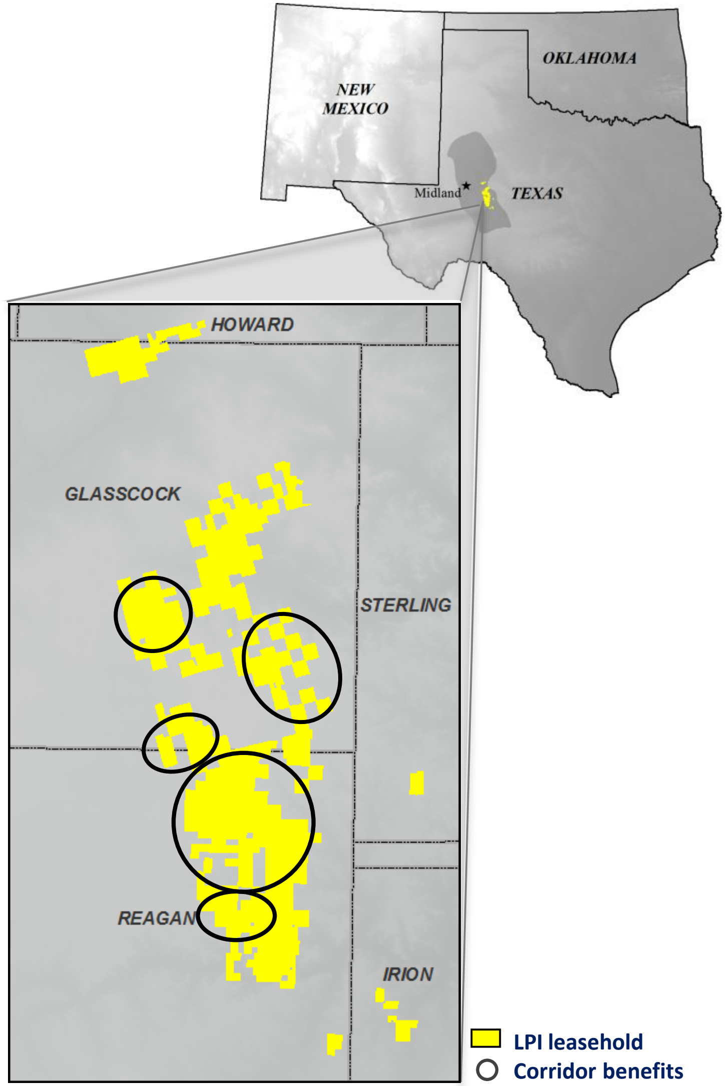
Capitalizing On Our Contiguous Acreage Position

- **Longer laterals enhance returns**
  - **>500 land-ready UWC/MWC locations of at least 15,000’**
- **Centralized infrastructure enables increased capital and operational efficiencies**
  - **Five active production corridors**
  - **Seven consecutive quarters of unit LOE below $4.00 per BOE**
- **Divested of ~2,600 net acres not serviced by a production corridor**

~86%

HBP acreage, enabling a concentrated development plan along production corridors

138,791 gross/122,061 net acres



Note: Maps, acreage counts and statistics as of 5/15/18

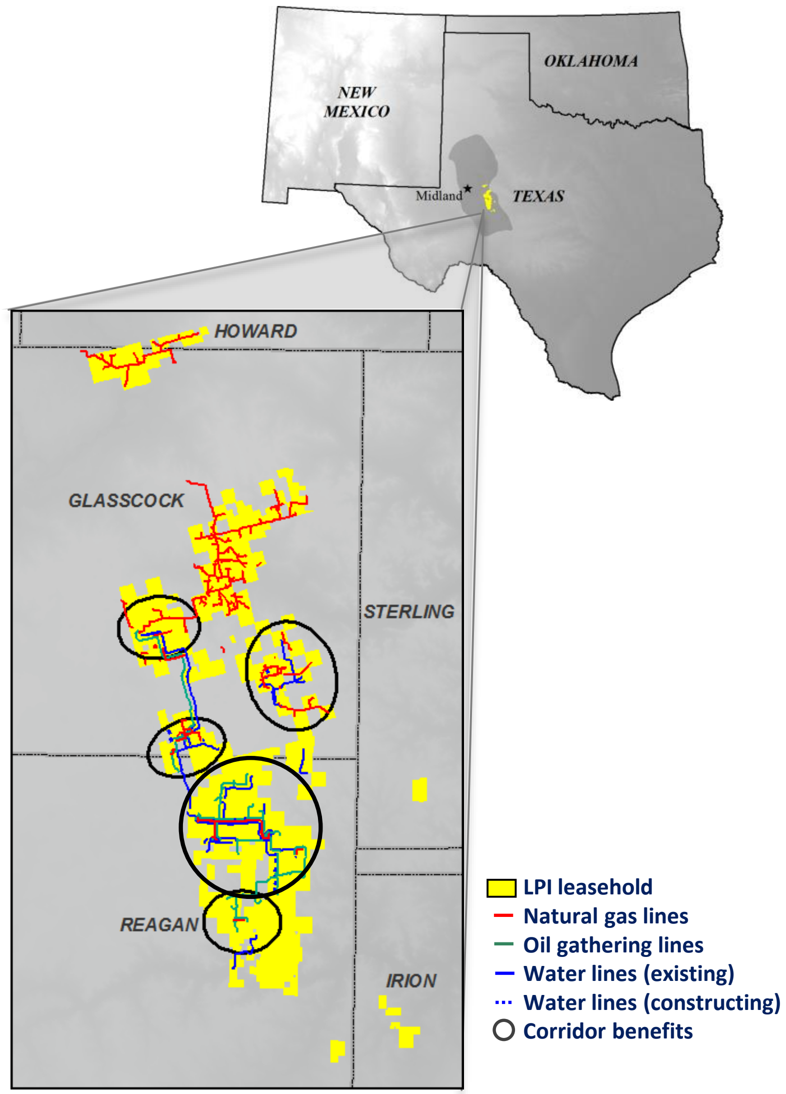
Contiguous Acreage Facilitates Robust Infrastructure Investments

Pipeline Infrastructure

- ~60 miles crude gathering
- ~100 miles water gathering/recycled distribution
- ~190 miles natural gas gathering & distribution
- ~50,000 1Q-18 truckloads removed due to LMS infrastructure

~$30 MM

2018E net benefits from strategic infrastructure investments



Note: Maps, acreage counts and statistics as of 5/15/18
Benefits defined as capital savings, LOE savings, price uplift and LMS net operating income

Crude Value Maximized Via Physical & Financial Contracts

Gulf Coast Access

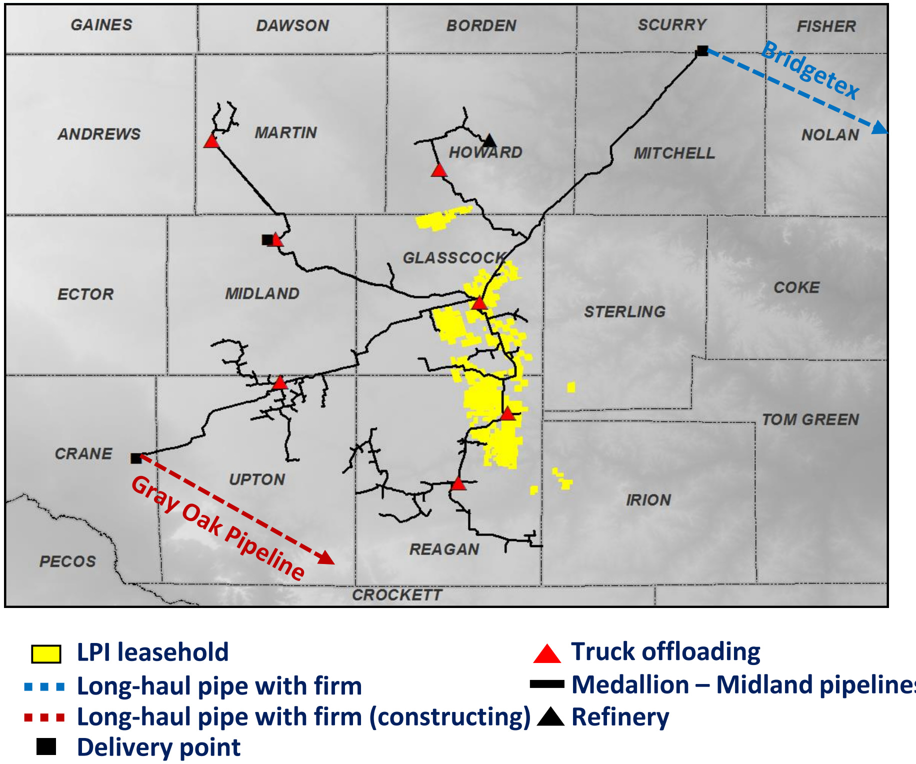
- 10,000 BOPD gross firm transportation on Bridgetex through 1Q-25
- Contracted firm transportation on Gray Oak through 4Q-26E
  - Year 1: 25,000 BOPD gross firm
  - Years 2 - 7: 35,000 BOPD gross firm

Operational Assurance

- LMS-owned gathering minimizes trucking
- 30,000 BOPD gross firm transportation on Medallion provides access to long-haul pipes exiting the basin

Financial Stability

- Protected from Midland pricing via:
  - U.S. Gulf Coast pricing on 10,000 BOPD via Jun-18 - Jun-19 Mid/Hou basis swaps, $7.30/Bbl wtd-avg price
  - 10,000 BOPD via 2Q-18 - 4Q-18 Mid/Cush basis swaps, -$0.56/Bbl wtd-avg price



~70% FY-18E volumes protected from Midland pricing

Note: Hedge percentage assumes reiterated previously-issued guidance of 10% YoY oil volume growth from FY-17

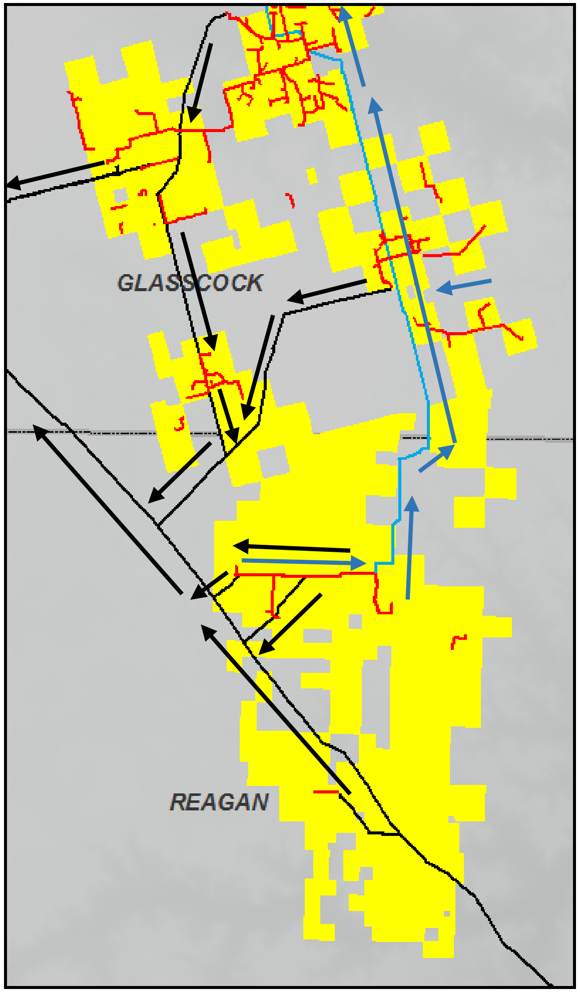
Natural Gas Value Maximized Via Physical & Financial Contracts

Operational Assurance

- Data from purchasers supports that they have sufficient firm transportation, and it is believed they can accommodate LPI's natural gas volumes
- LMS assets provide field-level optionality to move production between two purchasers

Financial Stability

- ~75% of FY-18E natural gas is protected from a widening Waha basis via Waha puts & collars & Waha/HH basis swaps
  - ~55% of FY-18E volumes protected with a $2.50/MMBtu Waha wtd-avg floor price[1]
  - Add'l ~20% of FY-18E volumes protected by Waha/HH basis swaps, -$0.62/MMBtu wtd-avg price



LPI leasehold
LMS natural gas lines
Primary 3rd-party takeaway lines
Secondary 3rd-party takeaway lines

[1]As of 6/1/18, Waha pricing $1.90/MMBtu

Note: Hedge percentages assume updated guidance of >12% YoY total BOE volume growth from FY-17

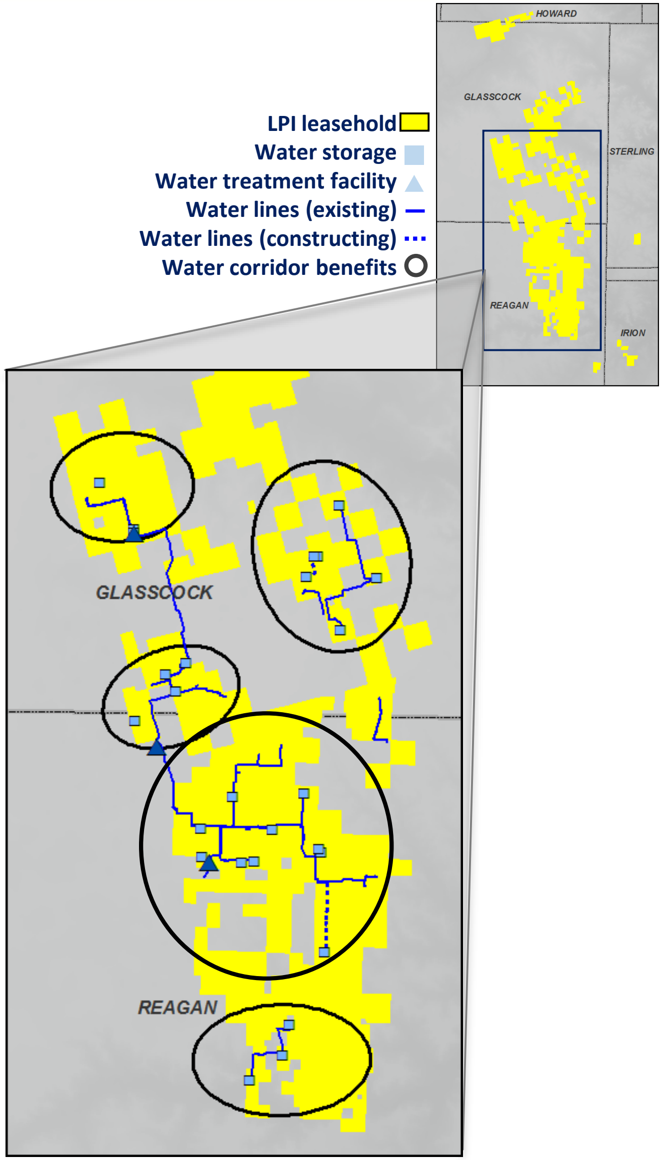
Significant Benefits Through Water Infrastructure Investments

~$10.3 MM

FY-18E LOE reduction generated by LMS water infrastructure investments[1]

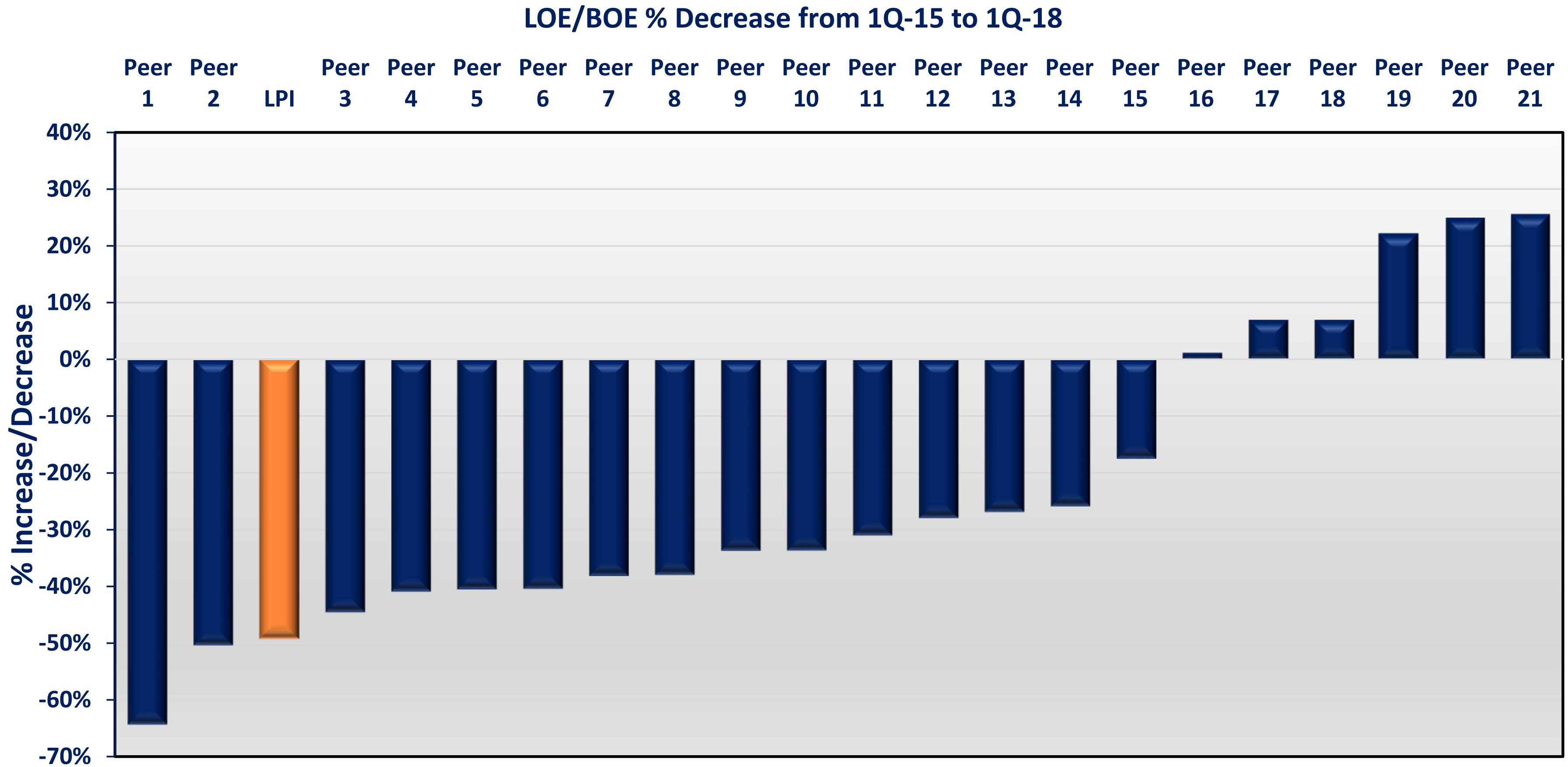
LMS Corridor Benefit	LPI Benefit	FY-18E (% of Total Activity)
Produced Water Gathered on Pipe	Capital & LOE savings	81%
Produced Water Recycled	Capital & LOE savings	42%
Completions Utilizing Recycled Water	Capital savings	23%
Completions Utilizing LPI Fresh Water Wells	Capital savings	14%

- 54 MBWPD recycling processing capacity
- 22.5 MMBW owned or contracted storage capacity



[1]Calculated utilizing a 95% WI & 72% NRI
Note: Statistics, estimates and maps as of 5/15/18

Infrastructure Investments Facilitate Lower Unit LOE



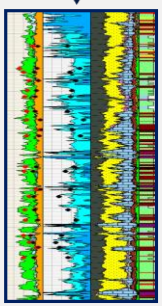
$0.51 Per BOE savings on unit LOE in 1Q-18 due to infrastructure benefits

Peers include: CLR, CPE, CRZO, CXO, DVN, EGN, EOG, EPE, FANG, MTDR, NFX, OAS, PDCE, PE, PXD, QEP, RSPP, SM, WLL, WPX, and XEC
Those that report two stream have been converted to three stream

Advanced Subsurface Characterization Drives Optimized Development

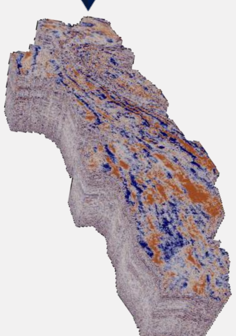
Physics-Based Workflows

Acquire Subsurface data

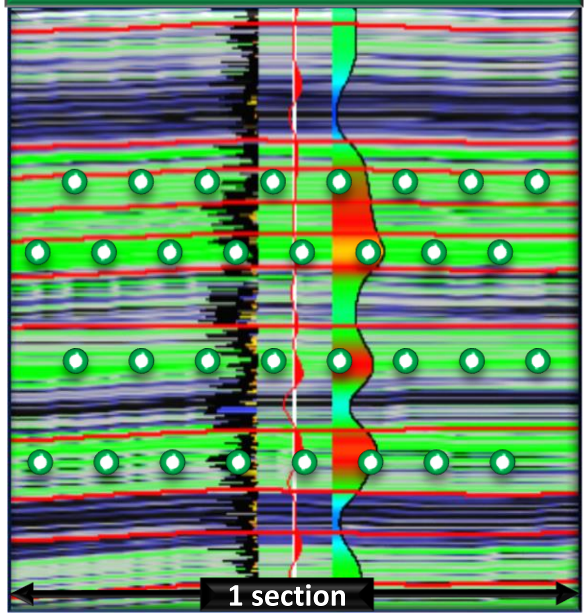


Calibrate Petrophysical model

Integrate spatial data



High-Resolution 3D Reservoir Geomodels

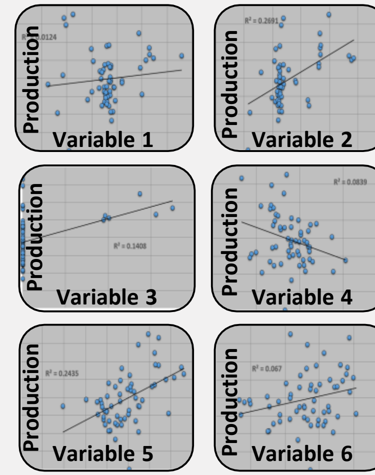


Increased NAV

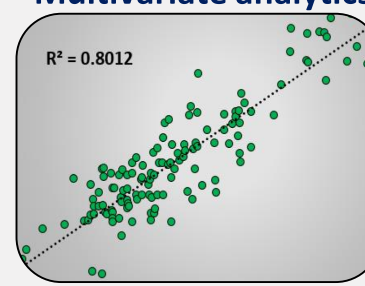
driven by high-density development

Improved Analytics

Bivariate analytics



Multivariate analytics



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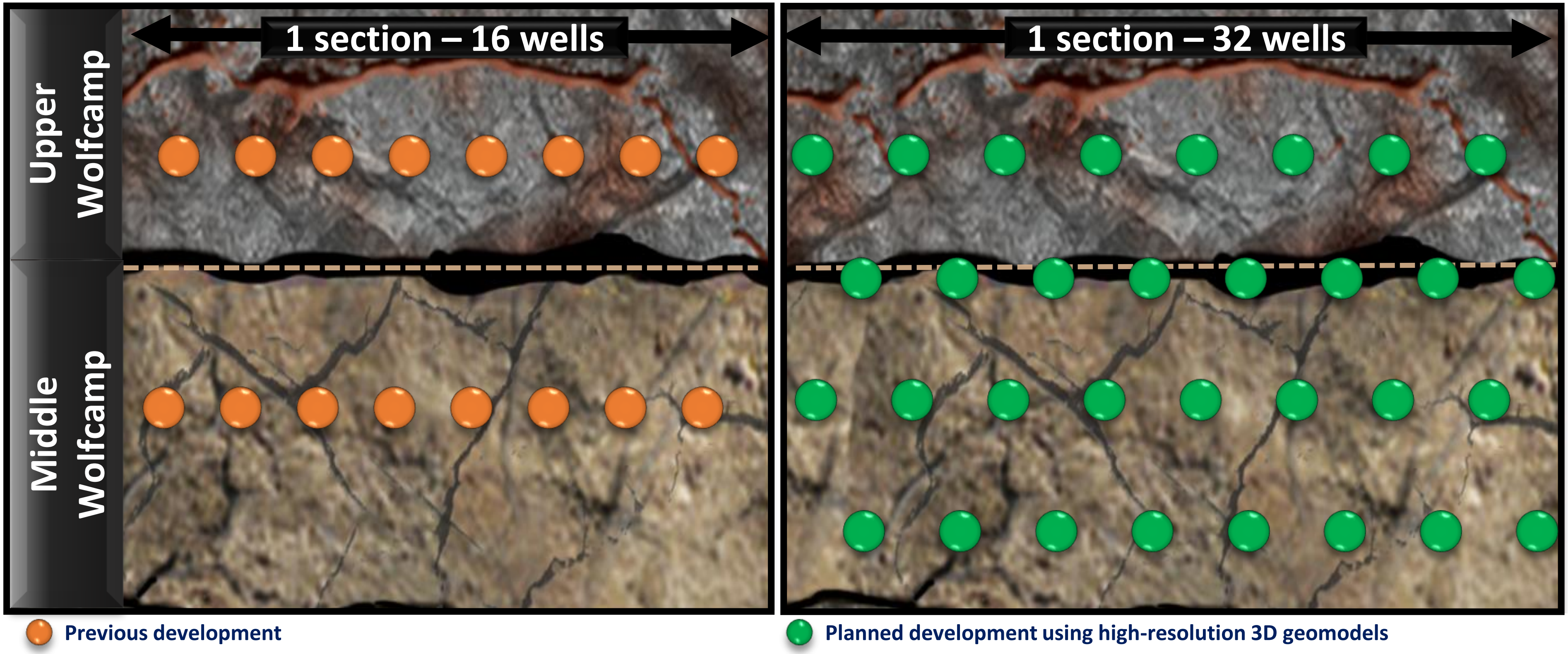
Note: Diagrams are not to scale

Transitioning To Higher-Density Development



32 locations per section

Results of 2017 spacing tests suggest development possibility of up to 32 UWC/MWC locations per spacing unit

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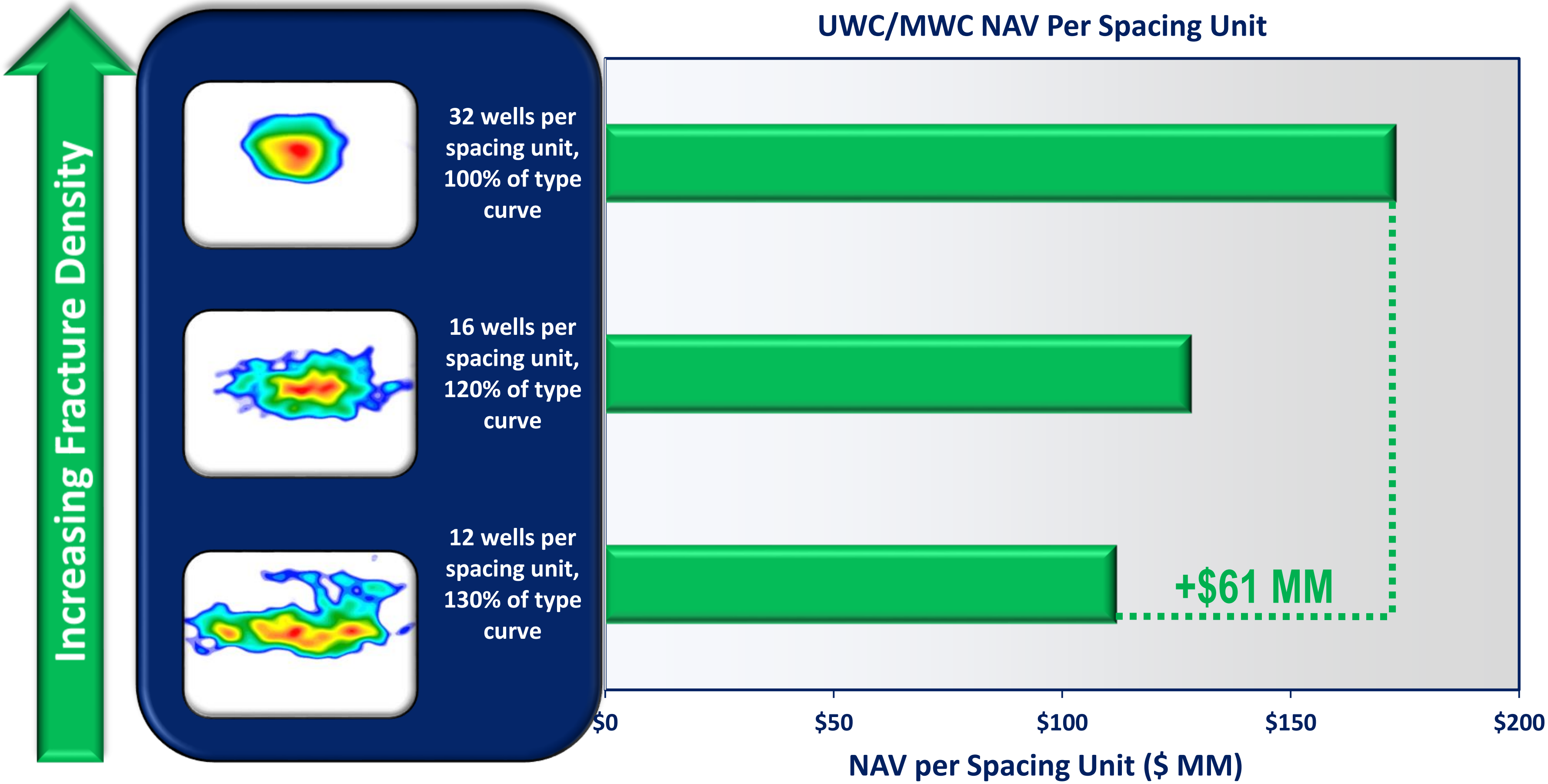
Note: Diagrams are not to scale
Spacing unit comprised of two sections to accommodate 10,000’ laterals

Tighter Cluster Spacing Facilitates Higher-Density Development

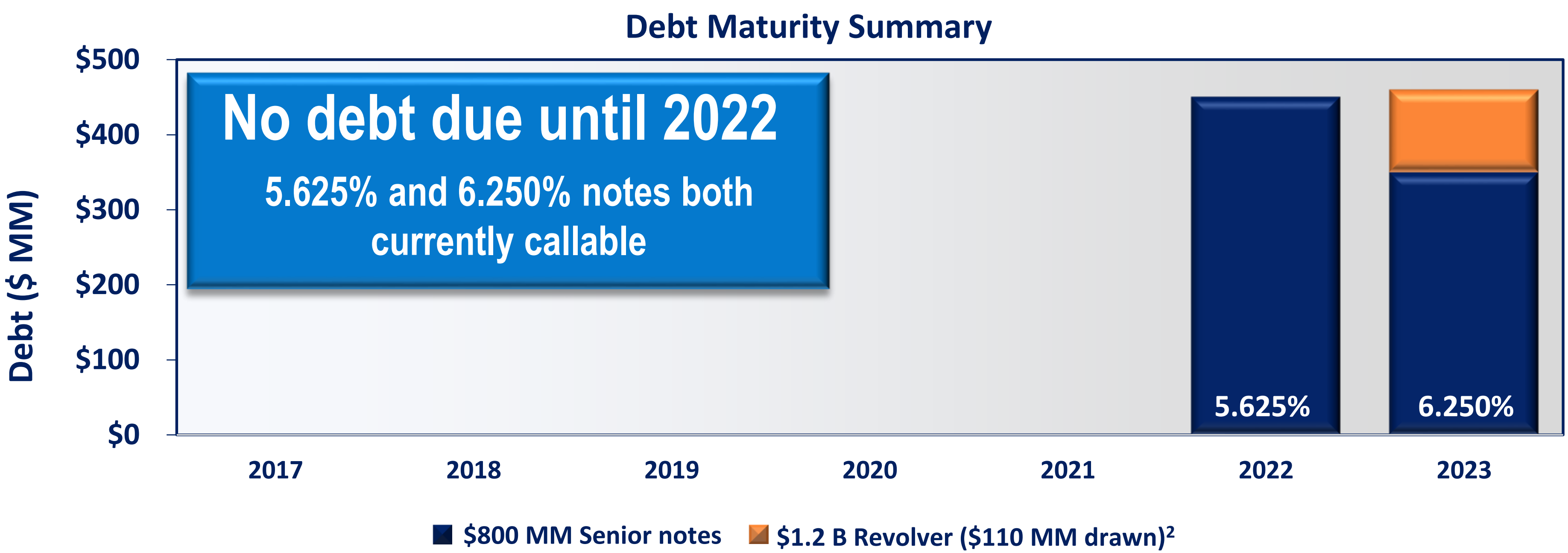


Increase in wells drives higher potential value per spacing unit

Note: NAV calculation pricing reflective of $55/Bbl WTI benchmark, utilizing $3/Mcf flat HH benchmark and $7.1 MM D&C well cost
Spacing unit comprised of two sections to accommodate 10,000' laterals

Maintaining A Strong Balance Sheet

~1.4x net debt to Adjusted EBITDA[1]



Increased borrowing base elected commitment from $1 B to $1.2 B

[1] Net debt to Adjusted EBITDA includes net debt as of 3/31/18 and 1Q-18 annualized Adjusted EBITDA. Net debt is calculated as the face value of long-term debt of $855 MM, reduced by cash on hand of $56 MM. See Appendix for a reconciliation of Net Income to Adjusted EBITDA

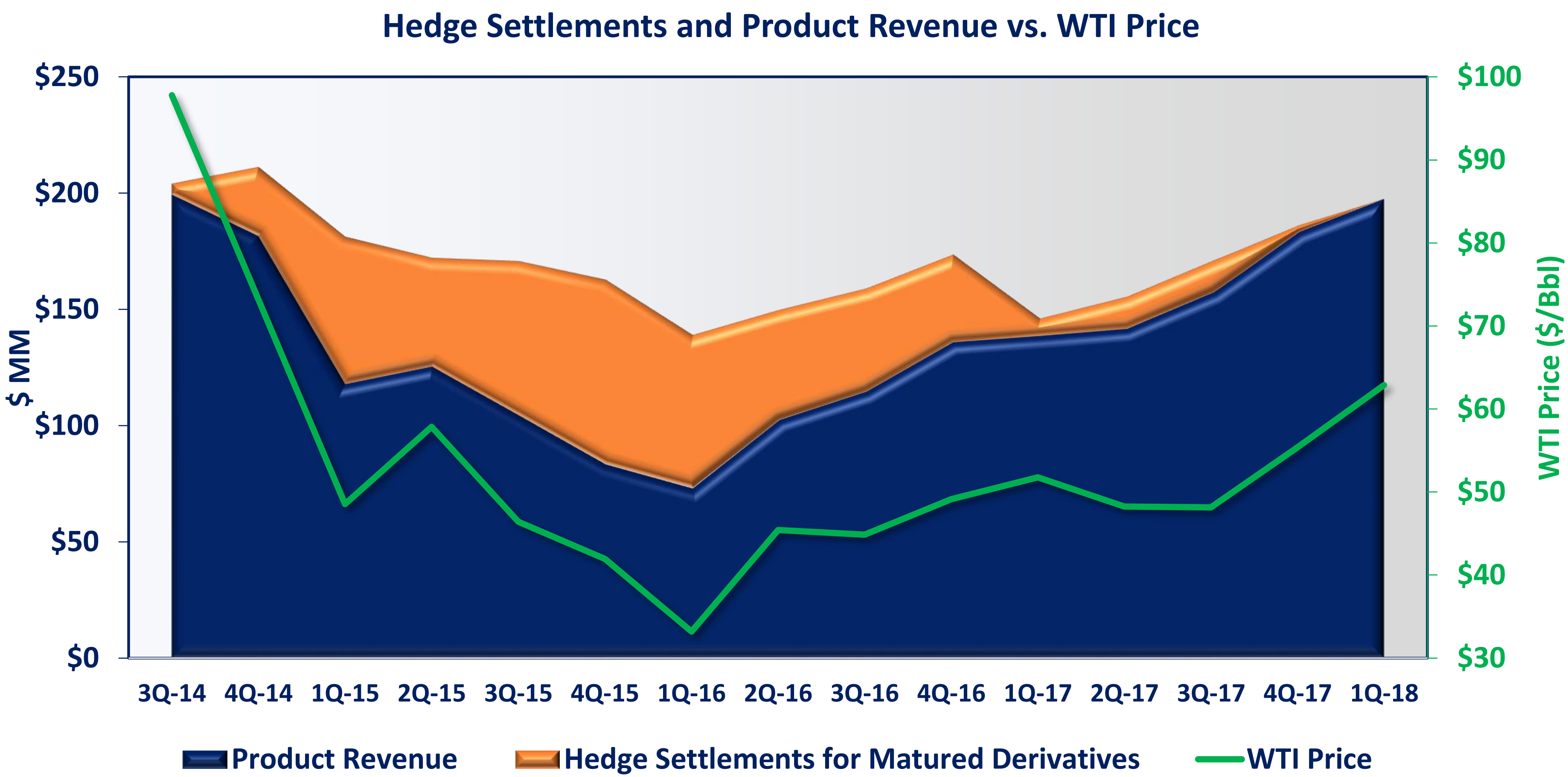
[2] As of 5/1/18, with $1.3 B borrowing base and $1.2 B aggregate elected commitment in place under Fifth Amended and Restated Senior Secured Credit Facility

Stock Repurchase Program

- **Approved by Board of Directors in 1Q-18**
- **Allows stock repurchases of up to $200 MM**
- **Program authorized for two years**
- **6,727,901 shares of common stock repurchased in 1Q-18 at a weighted-average price of $8.69/share for a total of $58.5 MM**

1Q-18 stock repurchases represented a highly accretive use of capital

Disciplined Risk Management Philosophy Protects Long-Term Value



Hedges provide cash flow stability during volatile pricing

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Oil, Natural Gas & Natural Gas Liquids Hedges

Hedge Product Summary	2Q-18 - 4Q-18	FY-19	FY-20
Oil total floor volume (Bbl)	7,168,750	6,606,500	1,061,400
Oil wtd-avg floor price ($/Bbl)	$47.42	$48.82	$49.70
Nat gas total floor volume (MMBtu)	17,907,500		
Nat gas wtd-avg floor price ($/MMBtu)	$2.50		
NGL total floor volume (Bbl)	1,182,500		

Oil	2Q-18 - 4Q-18	FY-19	FY-20
Puts			
Hedged volume (Bbl)	4,088,750	5,949,500	366,000
Wtd-avg floor price ($/Bbl)	$51.93	$48.31	$45.00
Swaps			
Hedged volume (Bbl)		657,000	695,400
Wtd-avg price ($/Bbl)		$53.45	$52.18
Collars			
Hedged volume (Bbl)	3,080,000		
Wtd-avg floor price ($/Bbl)	$41.43		
Wtd-avg ceiling price ($/Bbl)	$60.00		

Note: Oil derivatives are settled based on the month's average daily NYMEX index price for the first nearby month of the WTI Light Sweet Crude Oil futures contract

Basis Swaps	2Q-18 - 4Q-18	FY-19	FY-20
Mid/Cush			
Hedged volume (Bbl)	2,750,000		
Wtd-avg price ($/Bbl)	-$0.56		
Mid/Hou			
Hedged volume (Bbl)	2,140,000	1,810,000	
Wtd-avg price ($/Bbl)	$7.30	$7.30	
HH/Waha			
Hedged volume (MMBtu)	6,875,000	20,075,000	25,254,000
Wtd-avg price ($/MMBtu)	-$0.62	-$1.05	-$0.76

Note: Mid/Cush oil basis swaps are settled based on the West Texas Intermediate Midland weighted average price published in Argus Americas Crude and the West Texas Intermediate Cushing Formula Basis price published in Argus Americas Crude. Mid/Hou oil basis swaps are settled based on the price for a pricing date, published under the headings “US Gulf Coast and Midcontinent: WTI: WTI Houston: Weighted Average” and “US Gulf Coast and Midcontinent” for “WTI Midland” under the column “Weighted Average” for the prompt month in the issue of Argus Crude that reports prices effective as of the pricing date. HH/Waha natural gas basis swaps are settled based on the inside FERC index price for West Texas WAHA and NYMEX Henry Hub

Natural Gas Liquids	2Q-18 - 4Q-18	FY-19	FY-20
Swaps - Ethane			
Hedged volume (Bbl)	467,500		
Wtd-avg price ($/Bbl)	$11.66		
Swaps - Propane			
Hedged volume (Bbl)	385,000		
Wtd-avg price ($/Bbl)	$33.92		
Swaps – Normal Butane			
Hedged volume (Bbl)	137,500		
Wtd-avg price ($/Bbl)	$38.22		
Swaps - Isobutane			
Hedged volume (Bbl)	55,000		
Wtd-avg price ($/Bbl)	$38.33		
Swaps - Natural Gasoline			
Hedged volume (Bbl)	137,500		
Wtd-avg price ($/Bbl)	$57.02		

Note: Natural gas liquids derivatives are settled based on the month’s average daily OPIS index price for Mt. Belvieu Purity Ethane and Non-TET: Propane, Normal Butane, Isobutane and natural gasoline

Natural Gas - WAHA	2Q-18 - 4Q-18	FY-19	FY-20
Puts			
Hedged volume (MMBtu)	6,165,000		
Wtd-avg floor price ($/MMBtu)	$2.50		
Collars			
Hedged volume (MMBtu)	11,742,500		
Wtd-avg floor price ($/MMBtu)	$2.50		
Wtd-avg ceiling price ($/MMBtu)	$3.35		

Note: Natural gas derivatives are settled based on Inside FERC index price for West Texas WAHA for the calculation period

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Note: Positions as of 6/1/18

2Q-18E Guidance

	2Q-18E
Production (MBOE/d)…………	64.0
Crude oil production (MBbl/d)…………	27.4
Price Realizations (pre-hedge):	
Crude oil (% of WTI)…………	91%
Natural gas liquids (% of WTI)…………	28%
Natural gas (% of Henry Hub)…………	36%
Operating Costs & Expenses:	
Lease operating expenses ($/BOE)…………	$3.70
Midstream expenses ($/BOE)…………	$0.15
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)….	6.25%
General and administrative expenses:	
Cash ($/BOE)…………	$2.70
Non-cash stock-based compensation ($/BOE)…………	$1.85
Depletion, depreciation and amortization ($/BOE)…………	$8.00

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Positioned For The Future

Operational Efficiencies
facilitated by contiguous acreage

High-Density Development
enhancing shareholder value

Production Corridors
reducing costs & enabling large well packages

Consistent Growth
underpinned by strong balance sheet

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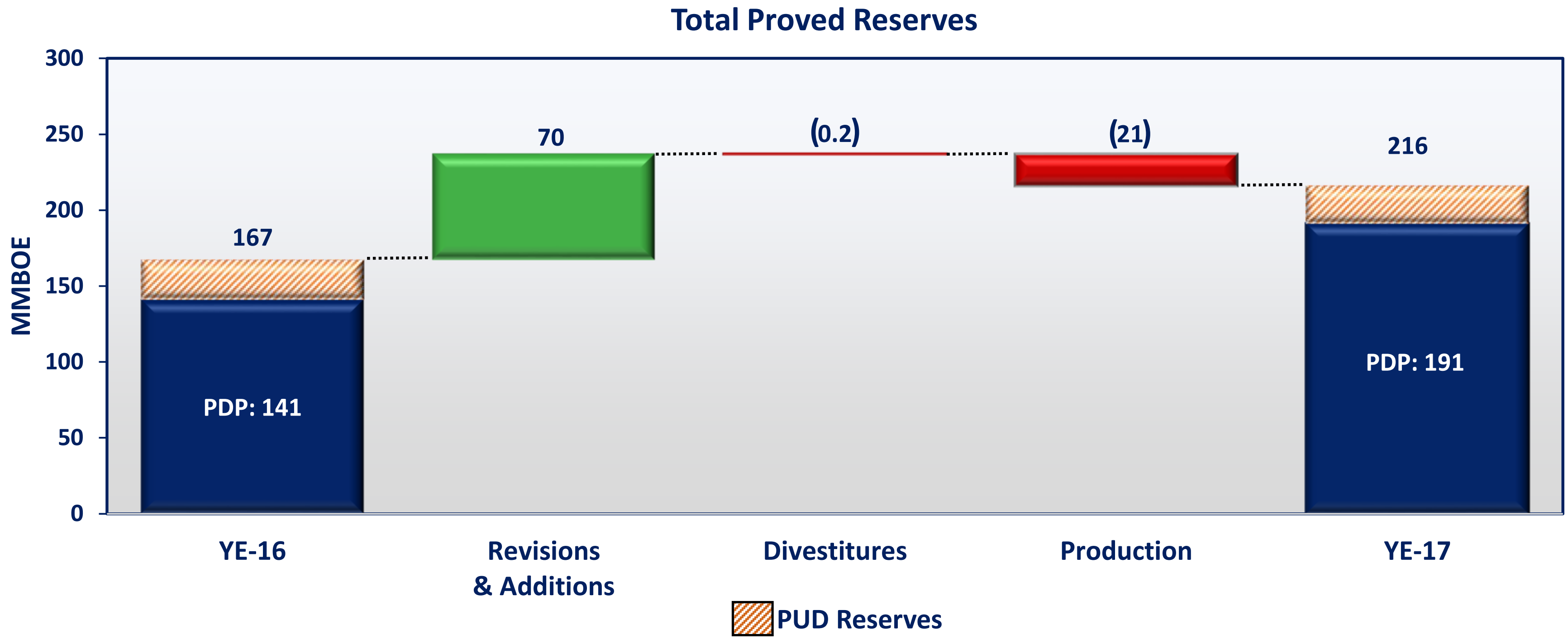
APPENDIX

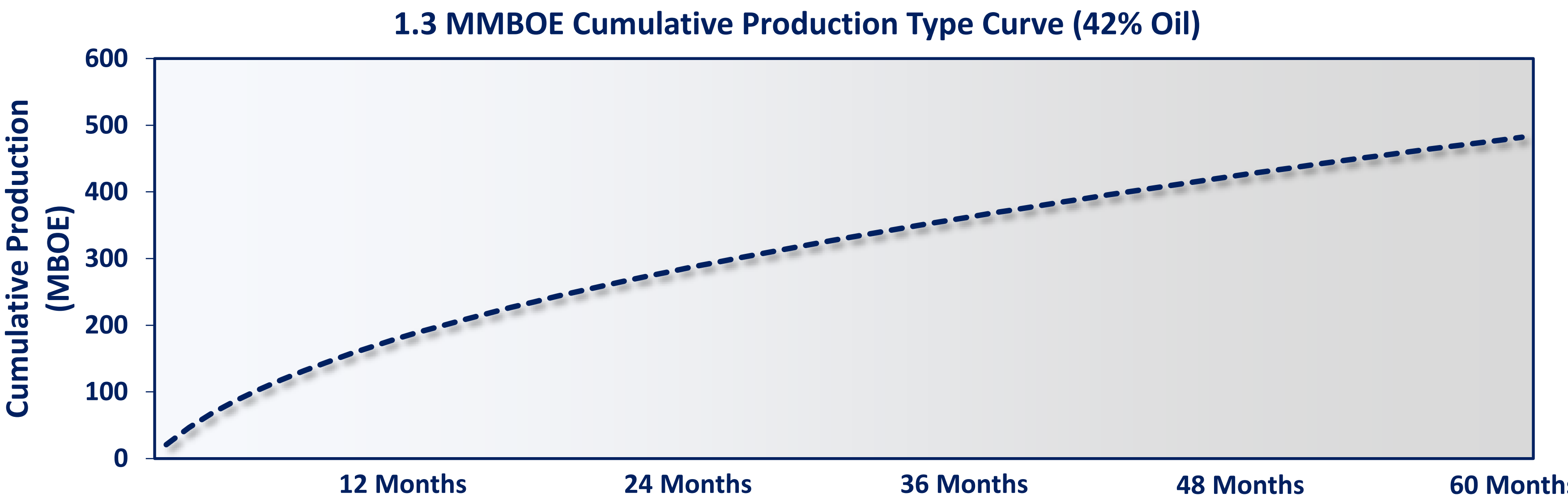
Low-Cost Proved Reserves Growth



36% Organic growth in proved developed reserves at a proved developed F&D cost of $7.90/BOE

Note: Proved Developed F&D Cost is a non-GAAP financial measure. See the Appendix for information on this calculation

UWC & MWC 1.3 MMBOE Cumulative Production Type Curve



Months	Cumulative Production (MBOE)	Cumulative % Oil
12	189	60%
24	288	56%
36	363	54%
48	426	52%
60	482	51%

45%

Total oil recovered in the first five years

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Note: 10,000' lateral length with 1,800 pounds of sand per foot completions at 54' perf cluster spacing

2017 & 2018 Actuals

		1Q-17	2Q-17	3Q-17	4Q-17	FY-17	1Q-18
Sales Volumes	3-Stream Sales Volumes						
	MBOE	4,716	5,336	5,521	5,697	21,270	5,698
	BOE/d	52,405	58,632	60,011	61,922	58,273	63,314
	% oil	45%	47%	44%	43%	45%	43%
Pricing	3-Stream Realized Prices						
	Oil ($/Bbl)	$46.91	$42.00	$45.44	$53.57	$46.97	$61.87
	NGL ($/Bbl)	$16.49	$13.82	$18.58	$20.53	$17.49	$18.14
	Gas ($/Mcf)	$2.31	$2.09	$2.04	$1.95	$2.09	$1.79
	Avg. price ($/BOE)	$29.42	$26.58	$28.54	$32.19	$29.22	$34.65
Unit Cost Metrics	3-Stream Unit Cost Metrics ($/BOE)						
	Lease operating expenses	$3.60	$3.77	$3.55	$3.22	$3.53	$3.85
	Midstream	$0.19	$0.17	$0.21	$0.20	$0.19	$0.12
	Production & ad val taxes	$1.86	$1.59	$1.73	$1.93	$1.78	$2.07
	General & administrative						
	Cash	$3.47	$2.50	$2.90	$2.61	$2.85	$2.70
	Non-cash stock-based compensation	$1.96	$1.63	$1.62	$1.55	$1.68	$1.64
	DD&A	$7.23	$7.12	$7.46	$7.91	$7.45	$7.99

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2015 & 2016 Actuals

		1Q-15	2Q-15	3Q-15	4Q-15	FY-15	1Q-16	2Q-16	3Q-16	4Q-16	FY-16
Sales Volumes	**3-Stream Sales Volumes**										
	MBOE	4,274	4,234	4,124	3,714	16,346	4,204	4,338	4,718	4,889	18,149
	BOE/d	47,487	46,532	44,820	40,368	44,782	46,202	47,667	51,276	53,141	49,586
	% oil	51%	46%	45%	45%	47%	48%	46%	46%	46%	47%
Pricing	**3-Stream Realized Prices**										
	Oil ($/Bbl)	$41.73	$50.77	$42.88	$36.97	$43.27	$27.51	$39.37	$39.10	$43.98	$37.73
	NGL ($/Bbl)	$13.34	$12.85	$10.36	$11.06	$11.86	$8.50	$12.24	$11.54	$14.79	$11.91
	Gas ($/Mcf)	$2.14	$1.82	$2.01	$1.76	$1.93	$1.31	$1.31	$2.07	$2.13	$1.73
	Avg. price ($/BOE)	$27.64	$29.65	$25.37	$22.47	$26.41	$17.40	$23.64	$24.34	$27.82	$23.50
Unit Cost Metrics	**3-Stream Unit Cost Metrics ($/BOE)**										
	Lease operating expenses	$7.58	$6.90	$6.09	$5.83	$6.63	$4.88	$4.43	$3.85	$3.56	$4.15
	Midstream	$0.37	$0.38	$0.26	$0.43	$0.36	$0.14	$0.27	$0.22	$0.26	$0.22
	Production & ad val taxes	$2.13	$2.24	$1.91	$1.73	$2.01	$1.53	$1.84	$1.50	$1.45	$1.58
	General & administrative										
	Cash	$3.99	$4.00	$3.89	$4.27	$4.03	$3.72	$3.33	$3.49	$3.28	$3.45
	Non-cash stock-based compensation	$1.12	$1.48	$1.67	$1.77	$1.50	$0.91	$1.40	$2.05	$1.98	$1.61
	DD&A	$16.83	$17.03	$16.19	$18.01	$16.99	$9.87	$7.88	$7.45	$7.68	$8.17

2014 Actuals: Two-Stream To Three-Stream Conversions

		1Q-14	2Q-14	3Q-14	4Q-14	FY-14
Sales Volumes	2-Stream Sales Volumes					
	MBOE	2,434	2,607	3,033	3,654	11,729
	BOE/d	27,041	28,653	32,970	39,722	32,134
	% oil	58%	58%	59%	60%	59%
	3-Stream Sales Volumes					
	MBOE	2,912	3,078	3,569	4,267	13,827
	BOE/d	32,358	33,829	38,798	46,379	37,882
	% oil	49%	49%	50%	51%	50%
Pricing	2-Stream Realized Prices					
	Oil ($/Bbl)	$91.78	$94.47	$87.65	$65.05	$82.83
	Gas ($/Mcf)	$7.04	$6.08	$5.80	$4.46	$5.72
	Avg. Price ($/BOE)	$71.17	$70.13	$65.77	$49.70	$62.86
	3-Stream Realized Prices					
	Oil ($/Bbl)	$91.78	$94.47	$87.65	$65.05	$82.83
	NGL ($/Bbl)	$32.88	$28.79	$29.21	$19.65	$27.00
	Gas ($/Mcf)	$4.00	$3.73	$3.25	$3.00	$3.45
	Avg. Price ($/BOE)	$59.48	$59.40	$55.89	$42.57	$53.32
Unit Cost Metrics	2-Stream Unit Cost Metrics ($/BOE)					
	Lease operating expenses	$8.95	$7.74	$8.30	$8.04	$8.23
	Midstream	$0.35	$0.59	$0.40	$0.50	$0.46
	Production & ad valorem taxes	$5.12	$5.05	$4.14	$3.33	$4.29
	General & administrative					
	Cash	$9.58	$8.88	$6.89	$4.27	$7.07
	Non-cash stock-based compensation	$1.78	$2.45	$2.04	$1.69	$1.97
	DD&A	$20.38	$20.35	$21.08	$21.85	$21.01
	3-Stream Unit Cost Metrics ($/BOE)					
	Lease operating expenses	$7.48	$6.55	$7.05	$6.88	$6.98
	Midstream	$0.29	$0.50	$0.34	$0.43	$0.39
	Production & ad valorem taxes	$4.28	$4.27	$3.52	$2.85	$3.64
	General & Administrative					
	Cash	$8.01	$7.52	$5.85	$3.66	$6.00
	Non-cash stock-based compensation	$1.49	$2.08	$1.74	$1.44	$1.67
	DD&A	$17.03	$17.23	$17.91	$18.72	$17.83

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Note: 2014 2-stream to 3-stream conversion based on actual gas plant economics

Supplemental Non-GAAP Financial Measure

Proved Developed Finding and Development Cost (Unaudited)

Proved developed finding and development ("F&D") cost per BOE is calculated by dividing (x) development costs for the period, by (y) proved developed reserve additions for the period, defined as the change in proved developed reserves, less purchased reserves, plus sold reserves and plus sales volumes during the period. The method we use to calculate our proved developed F&D cost may differ significantly from methods used by other companies to compute similar measures. As a result, our proved developed F&D cost may not be comparable to similar measures provided by other companies. We believe that providing the measure of proved development F&D cost is useful in evaluating the cost, on a per BOE basis, to added proved developed reserves.

However, this measure is provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP. Due to various factors, including timing differences in the addition of proved reserves and the related costs to develop those reserves, proved developed F&D cost does not necessarily reflect precisely the costs associated with particular proved reserves. As a result of various factors that could materially affect the timing and amounts of future increases in proved reserves and the timing and amounts of future costs, we cannot assure you that our future proved developed F&D cost will not differ materially from those presented.

($ MM, except per BOE amount, reserves and sales volumes in MMBOE)	Proved Developed F&D
Development costs (x)	$561
Proved developed reserves:	
As of December 31, 2017	191
As of December 31, 2016	(141)
Change in proved developed reserves	50
Plus sales of proved developed reserves during 2017	-
Plus 2017 sales volumes	21
Proved developed reserve additions (y)	71
Proved developed F&D cost per BOE	$7.90

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Supplemental Non-GAAP Financial Measure

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for 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 presents a reconciliation of net income (GAAP) to Adjusted EBITDA (non-GAAP):

(in thousands)		1Q-18
Net income	$	86,520
Plus:		
Depletion, depreciation and amortization		45,553
Non-cash stock-based compensation, net of amounts capitalized		9,339
Accretion expense		1,106
Mark-to-market on derivatives:		
Gain on derivatives, net		(9,010)
Settlements paid for matured derivatives, net		(2,236)
Premiums paid for derivatives		(4,024)
Interest expense		13,518
Loss on disposal of assets, net		2,617
Adjusted EBITDA	$	143,383

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