Second-Quarter 2020 Earnings Presentation

Forward-Looking / Cautionary Statements

This presentation, including any oral statements made regarding the contents of this presentation, including in the conference call referenced herein, 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, indicates, enables, transforms, estimates or anticipates (and other similar expressions) will, should or may occur in the future 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, oil production quotas or other actions that might be imposed by the Organization of Petroleum Exporting Countries and other producing countries (“OPEC+”), the outbreak of disease, such as the coronavirus (“COVID-19”) pandemic, and any related government policies and actions, changes in domestic and global production, supply and demand for commodities, including as a result of the COVID-19 pandemic and actions by OPEC+, long-term performance of wells, drilling and operating risks, the increase in service and supply costs, tariffs on steel, pipeline transportation and storage constraints in the Permian Basin, the possibility of production curtailment, hedging activities, possible impacts of litigation and regulations, the impact of repurchases, if any, of securities from time to time, and other factors, including those and other risks described in its Annual Report on Form 10-K for the year ended December 31, 2019, Amendment No. 1 to its Quarterly Report on Form 10-Q for the quarter ended March 31, 2020, its Quarterly Report on Form 10-Q for the quarter ended June 30, 2020 and those set forth from time to time in other filings with the Securities and 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.

Any forward-looking statement speaks only as of the date on which such statement is made. Laredo does not intend to, and disclaims any obligation to, correct, update or revise 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 press release and the conference call, the Company may use the terms “resource potential,” “resource play,” “estimated ultimate recovery,” or “EURs,” and “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 and production costs, availability and cost 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. EURs from reserves 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%. 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.

Unless otherwise specified, references to “average sales price” refer to average sales price excluding the effects of our derivative transactions. All amounts, dollars and percentages presented in this presentation are rounded and therefore approximate.

Successfully Operating in a Turbulent Macro Environment

2Q-20 Select Results vs Guidance[1]

Production

Oil Production
31.2 MBO/d
2% beat vs guidance

Total Production
94.1 MBOE/d
10% beat vs guidance

Controllable Cash Costs

Lease Operating Expense
$2.40/BOE
16% beat vs guidance

G&A (Excluding LTIP)
$1.02/BOE
27% beat vs guidance

Financial & Operational Highlights

- Maintained drilling efficiencies during transition to Howard County
- Realized $87 MM in matured commodity derivative settlements
- Reduced flared / vented gas to only 1.1% of total natural gas production
- Increased FY-21 oil hedges to 70% of expected production[2]

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[1]Utilizes high end of guidance where applicable
[2]Hedges executed through 8-4-20

Strategy to Increase Stakeholder Value

Foundation

Manage Financial Risk

Optimize Existing Assets

Expand High-Margin Inventory

Consolidate to Increase Scale

Objectives

Improve oil cut

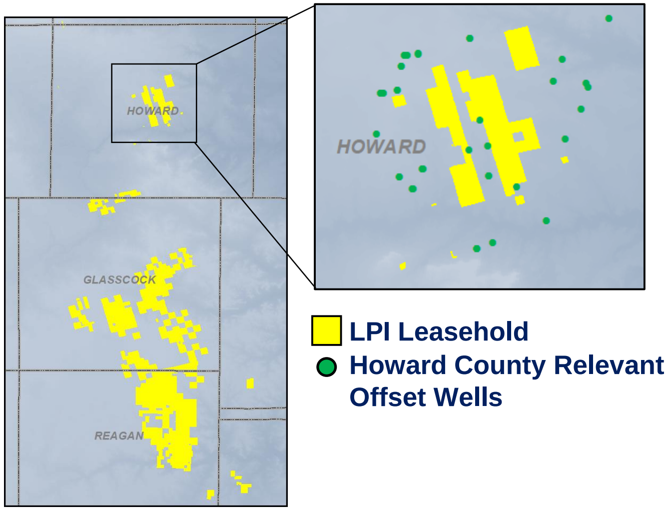
Reduce leverage

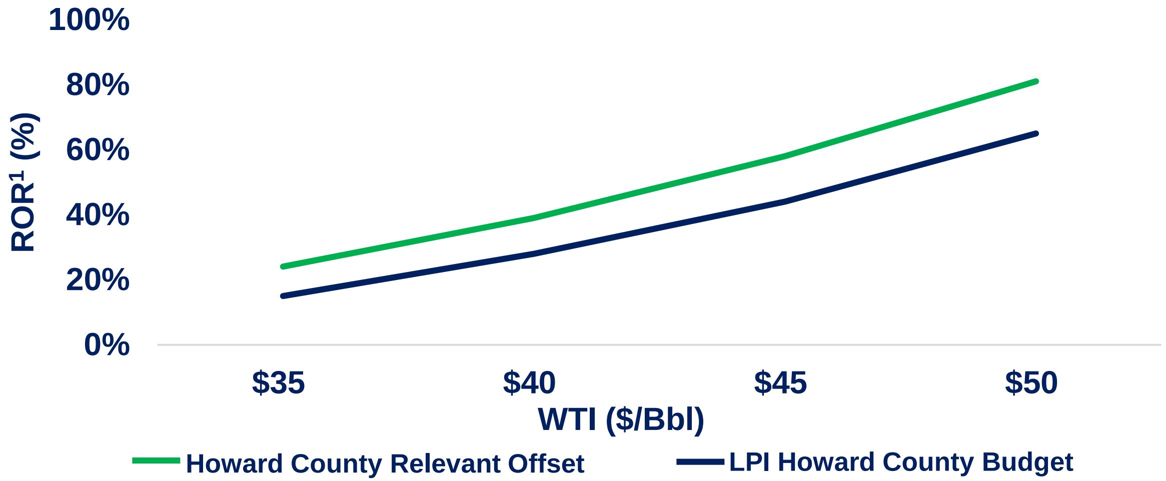
Expand margins

Target Free Cash Flow[1]

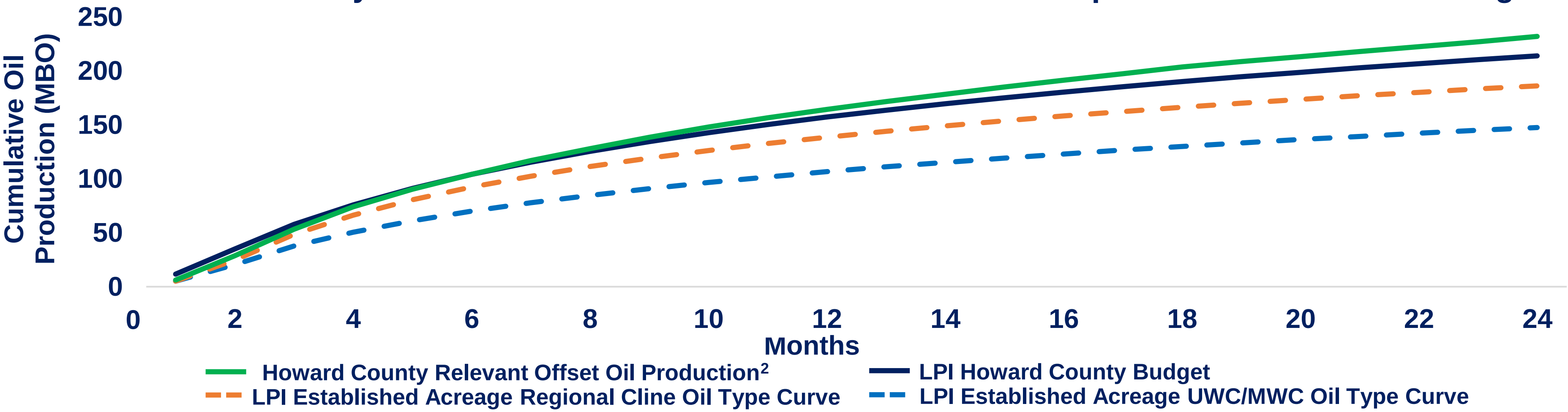
[1]See Appendix for reconciliations of non-GAAP measures

Howard County Oil Productivity Drives Returns





Howard County Relevant Offset Cumulative Oil Production Compared to Established Acreage



Expect to complete first 15-well package in Howard County during 4Q-20

[1]Returns are based on $5.5 MM well costs; applicable natural gas strip pricing details can be found in the Appendix
[2]Howard County Relevant Offset cumulative oil production normalized to time 0 start and 10,000’, courtesy of Enverus (as of 10-28-19)
Note: Map as of 06-30-20

Increased Activity Accelerates Development of Howard County DUCs

	1Q-20A	2Q-20A	3Q-20E	4Q-20E	FY-20E
Drilling Rigs	4.0	2.4	1.0	1.0	2.1
Spuds	25	17	7	6	55

Accelerated Activity

	1Q-20A	2Q-20A	3Q-20E	4Q-20E	FY-20E
Completion Crews	1.7	0.3	0.3	1.0	0.8
Completions	28	5	0	15	48
Total Capital	$155	$78	$105 - $115		$340 - $350
Avg. Working Interest					98%
Avg. Lateral Length					9,000

Cash Flow[1] from additional activity is secured with additional 2021 hedges

[1]See Appendix for reconciliations of non-GAAP measures

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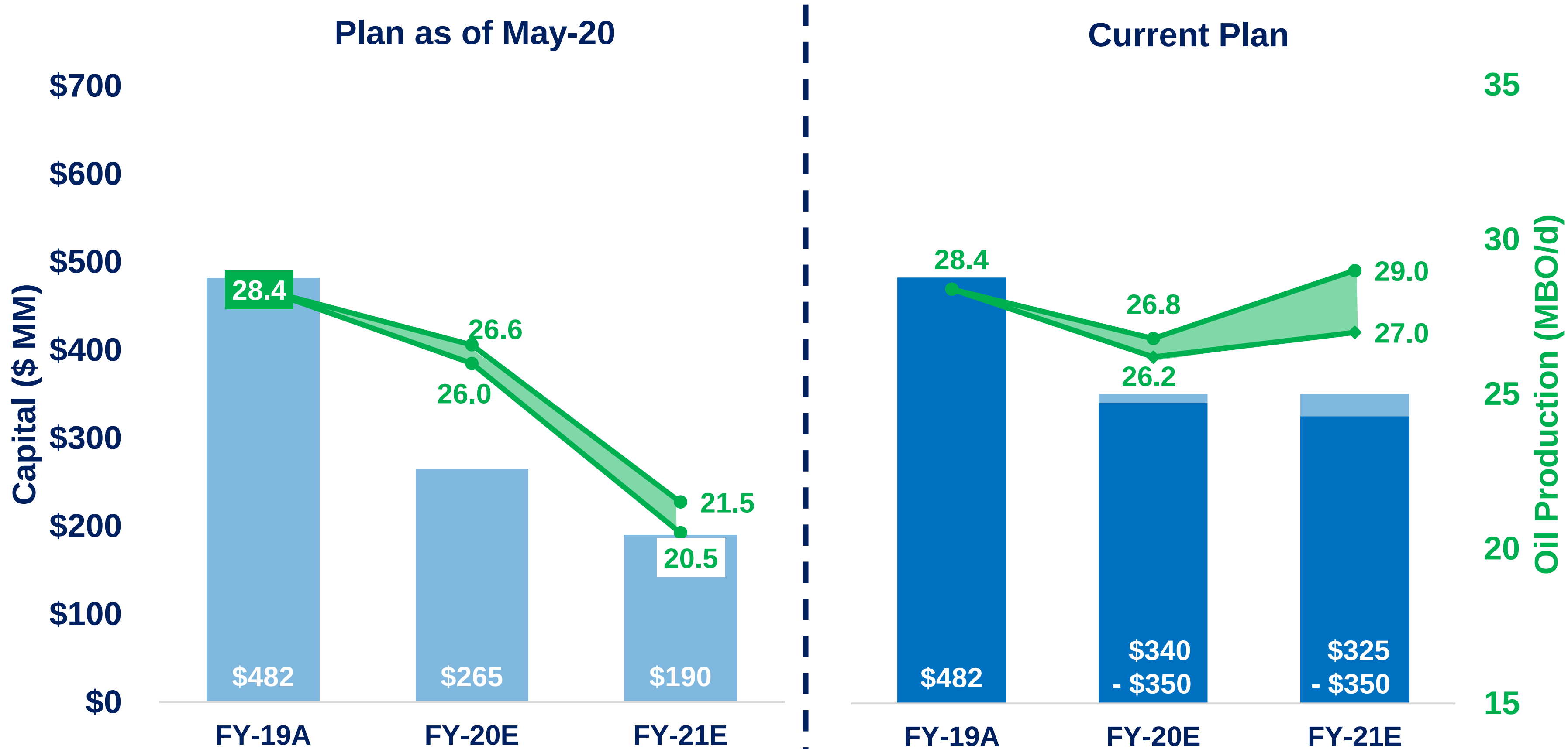
Howard County Development Drives Capital Efficiency



$/Bbl	2020	2021
Hedged Oil Price[1]	$57.20	$45.25

Capital[2] ($ MM) Oil Production (MBO/d)

2020 & 2021 normalized development plans focus on production and Cash Flow[3] stability

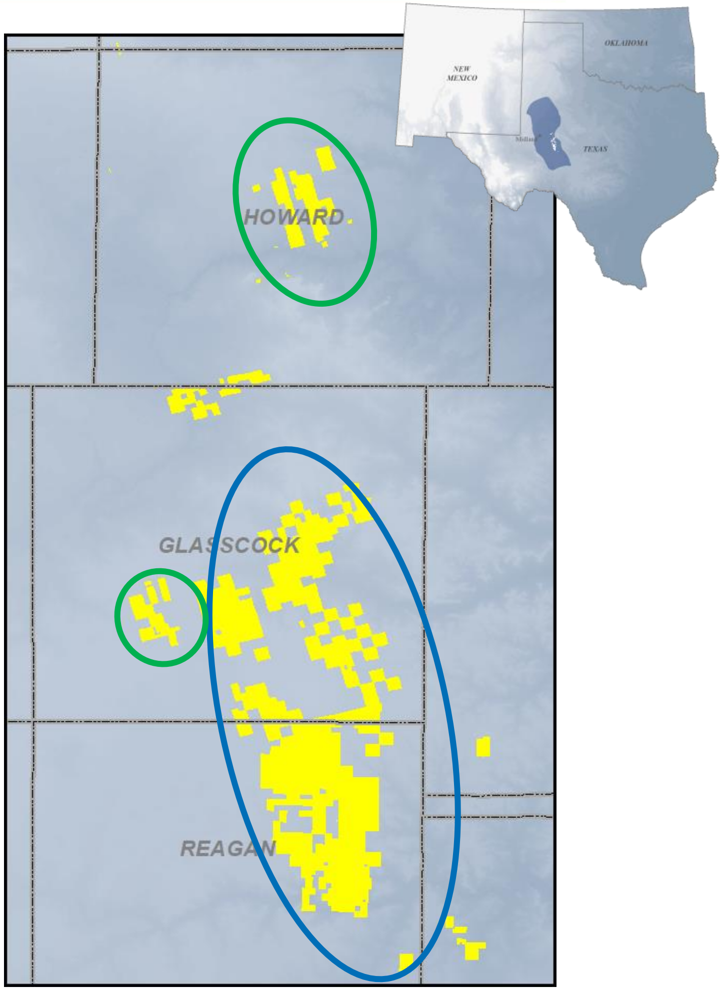
[1]Reflects an average of realized hedged pricing, when applicable, strip pricing and hedges in place as of 8-4-20. Strip pricing details can be found in the Appendix; [2]Capital expectations exclude non-budgeted acquisitions; [3]See Appendix for reconciliations of non-GAAP measures

Acquisitions Added Oily, High-Margin Inventory

Returns on acquired inventory locations place them at the front of the development schedule

- **High-margin (50+% oil), higher-return inventory**
- **Contiguous Midland Basin acreage positioned to benefit from LPI's peer-leading operational costs and efficiencies**
- **Target long-term, consistent Free Cash Flow[1] generation and leverage ratio reduction**

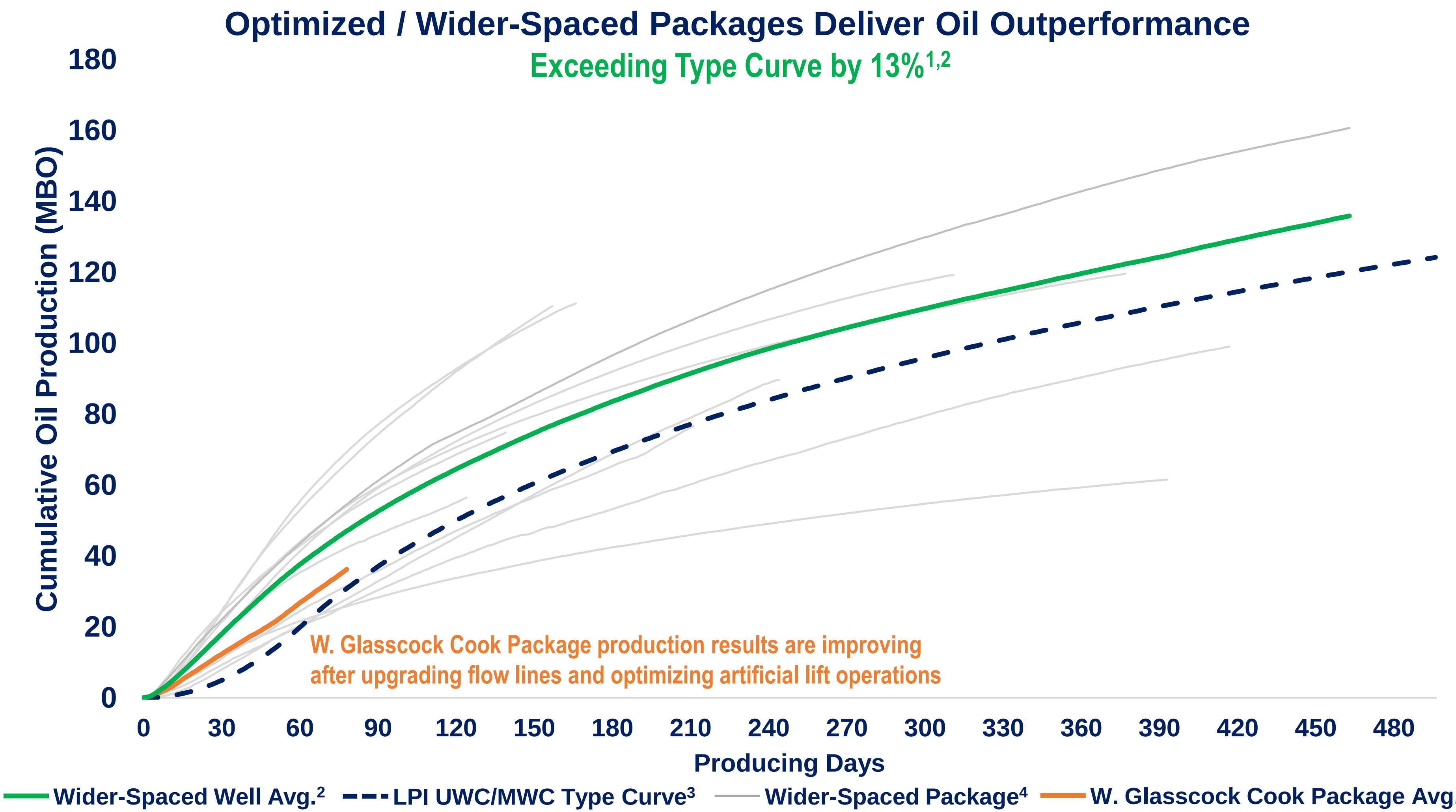
Acquired Inventory	Inventory
Lower Spraberry / UWC/MWC	175
Established Inventory	**Inventory**
UWC/MWC	300 - 450
Cline	140 - 160
Total Inventory	**Inventory**
Acquired & Established	615 - 785



148,712 gross / 130,993 net acres
LPI Leasehold
Acquired Inventory Established Inventory

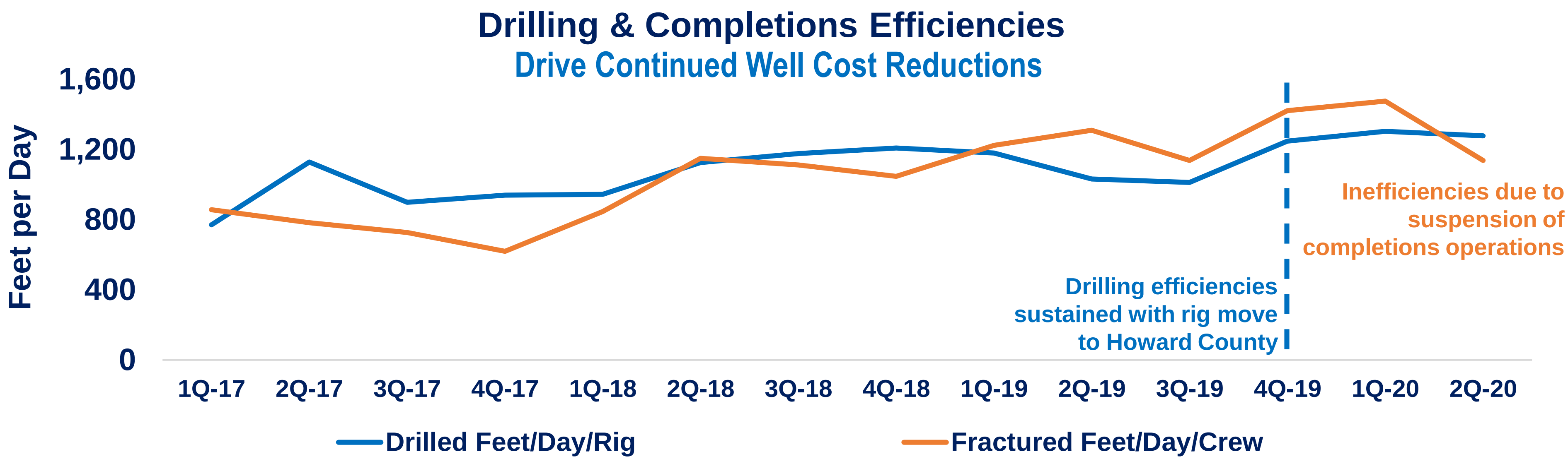
[1]See Appendix for reconciliations of non-GAAP measures
Note: Inventory expected to average oil type curve productivity on Established Inventory and budget expectations on Acquired Inventory
Map as of 06-30-20

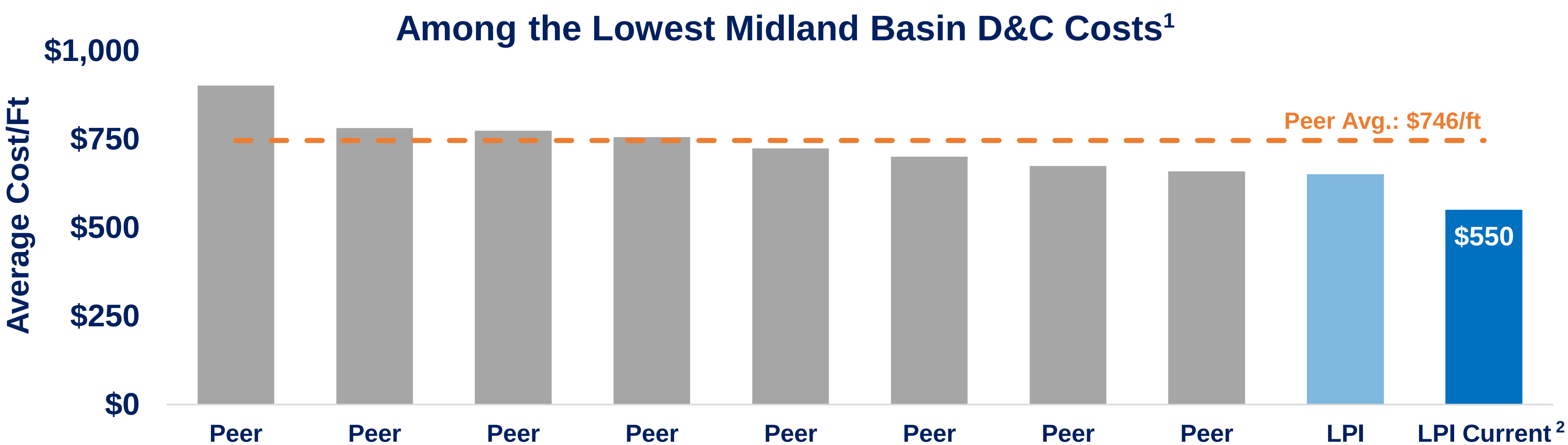
Optimized Development Supports Consistent Oil Outperformance



[1]Wider-Spaced Well Average vs LPI UWC/MWC Type Curve; [2]The Wider-Spaced Well Average includes packages developed on LPI's Established Acreage using optimized completions. It excludes the W. Glasscock Cook Package Average (5 wells), which was developed on LPI's Western Glasscock Acreage using optimized completions; [3]UWC/MWC 1.3 MMBOE type curve (400 MBO) representative of a 10,000' well, utilizing a 1.2 b-factor; [4]Includes an average of the Yellow Rose (8 wells), Hoelscher (4 wells), Frysak/Halfmann (4 wells), Sugg-B (7 wells), Von Gonten (9 wells), Driver-Agnell (6 wells), Lynda (6 wells), Lacy Creek (2 wells), Mize (7 wells), Sugg B Sugg D (8 wells) & Sugg B 137 (4 wells); Chart lines show cumulative oil production for all named wells, normalized to a 10,000' lateral, as of 7-30-2020

Maintaining Operational & Cost Advantages in Move to Howard County

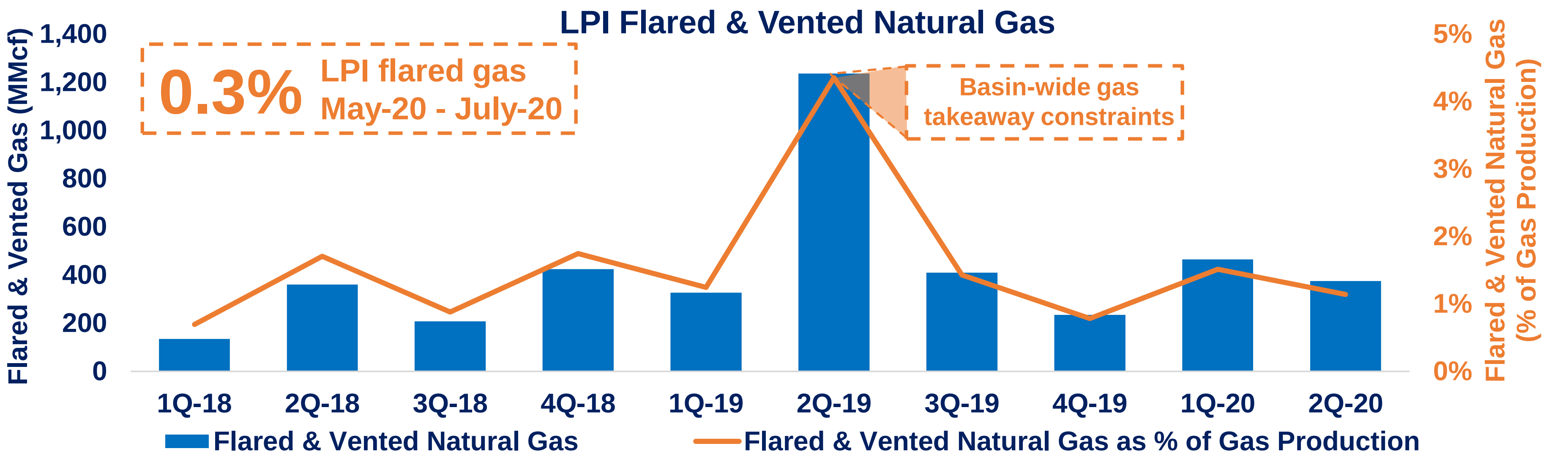


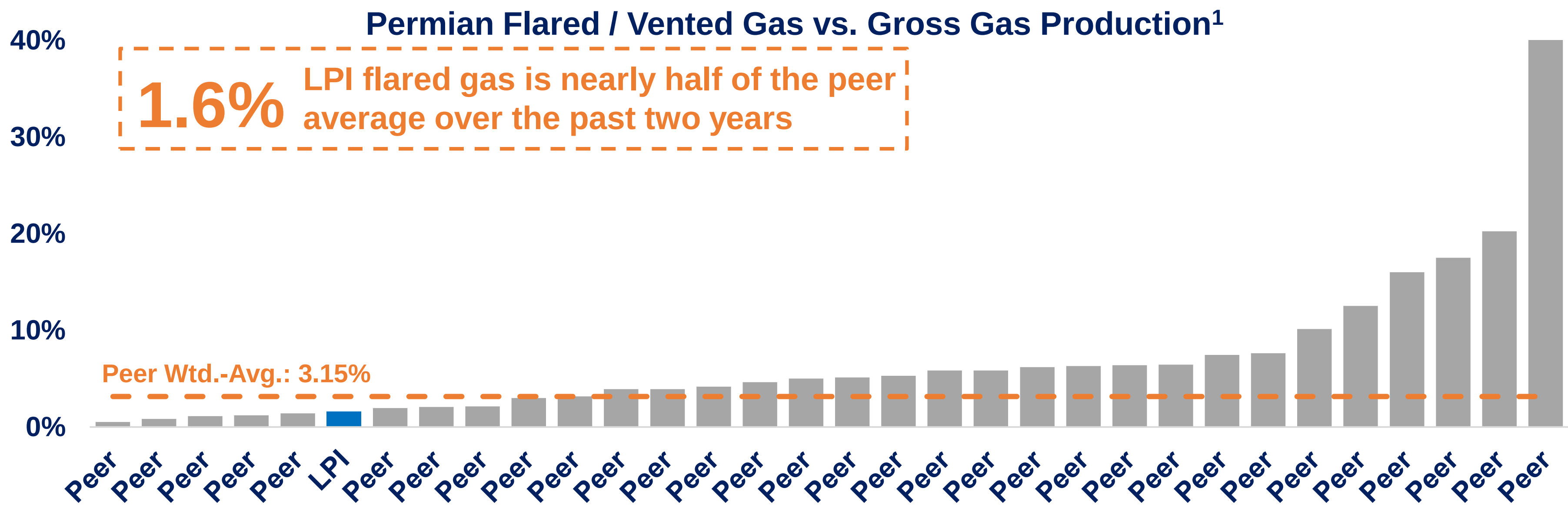


[1]Source: RSEG 7-27-2020 2019 & 2020 quarterly weighted average lateral cost per foot. Peers include: CPE, CXO, FANG, OVV, PE, PXD, QEP, and SM

[2]Based on internal estimates

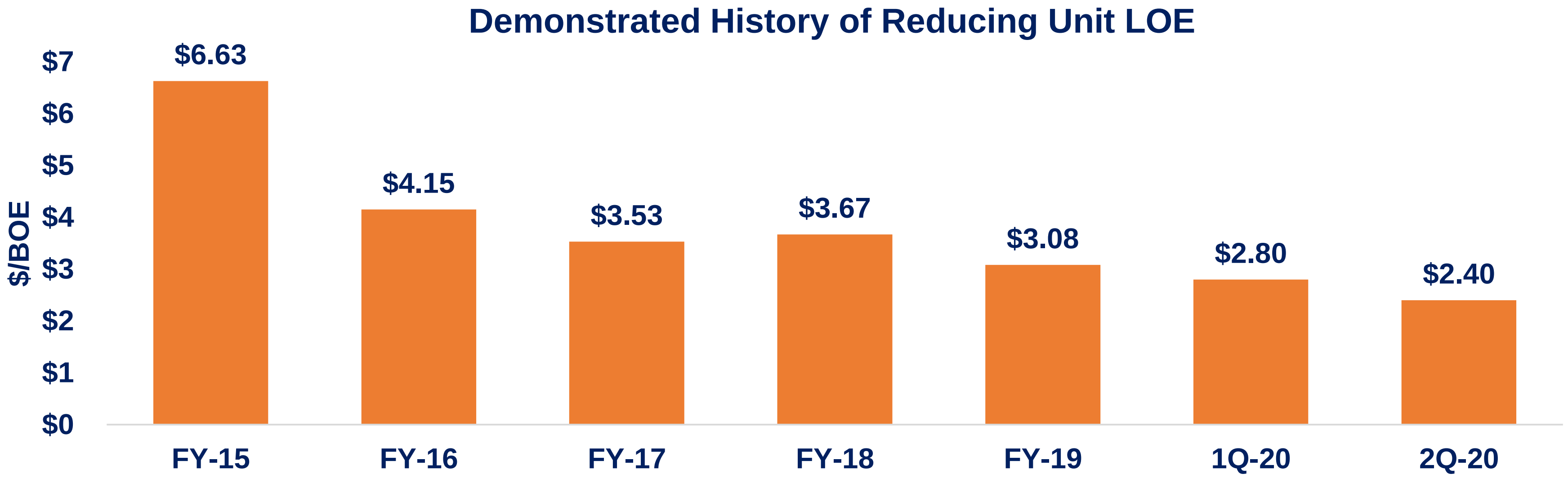
Long-Term Focus on Minimizing Flaring Protects the Environment

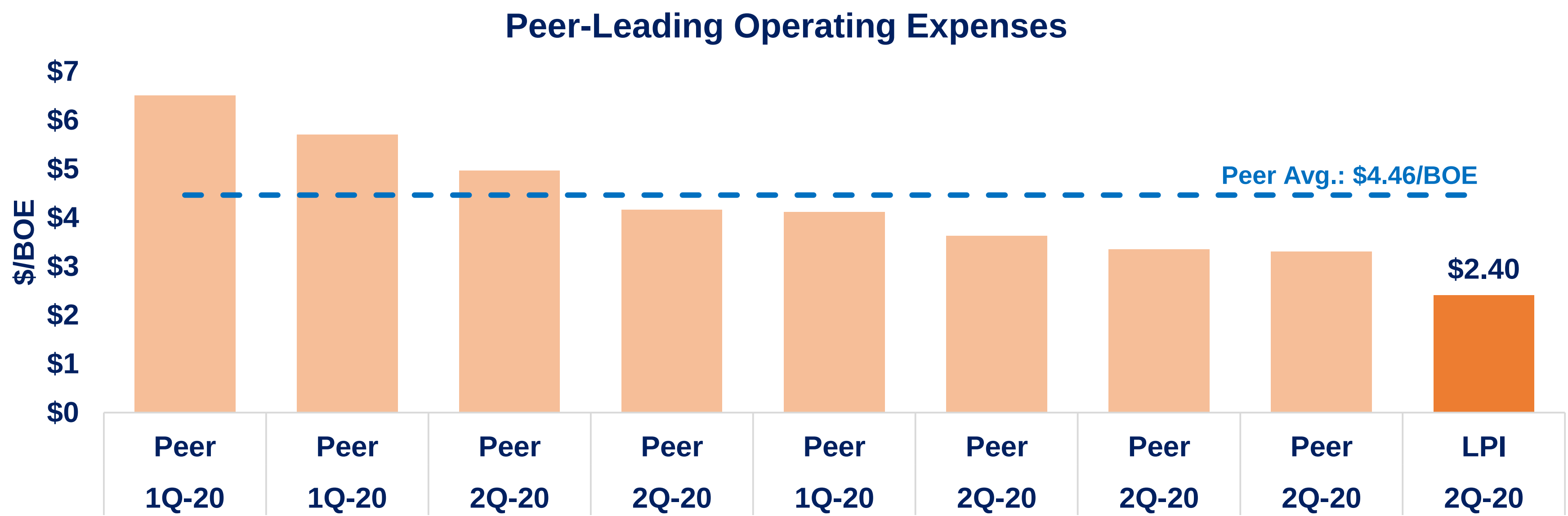




[1]Source: Rystad Energy as of 7-21-20, with data beginning as of January 2018; Peers include: APA, AXAS, BATL, BP, CDEV, COP, CPE, CVX, CXO, DVN, EOG, EPEGQ, FANG, LLEX, MRO, MTDR, NBL, OAS, OVV, OXY, PDCE, PE, PXD, QEP, REI, ROSE, RYDAF, SM, WPX, XEC and XOM

Expect to Maintain Peer-Leading LOE





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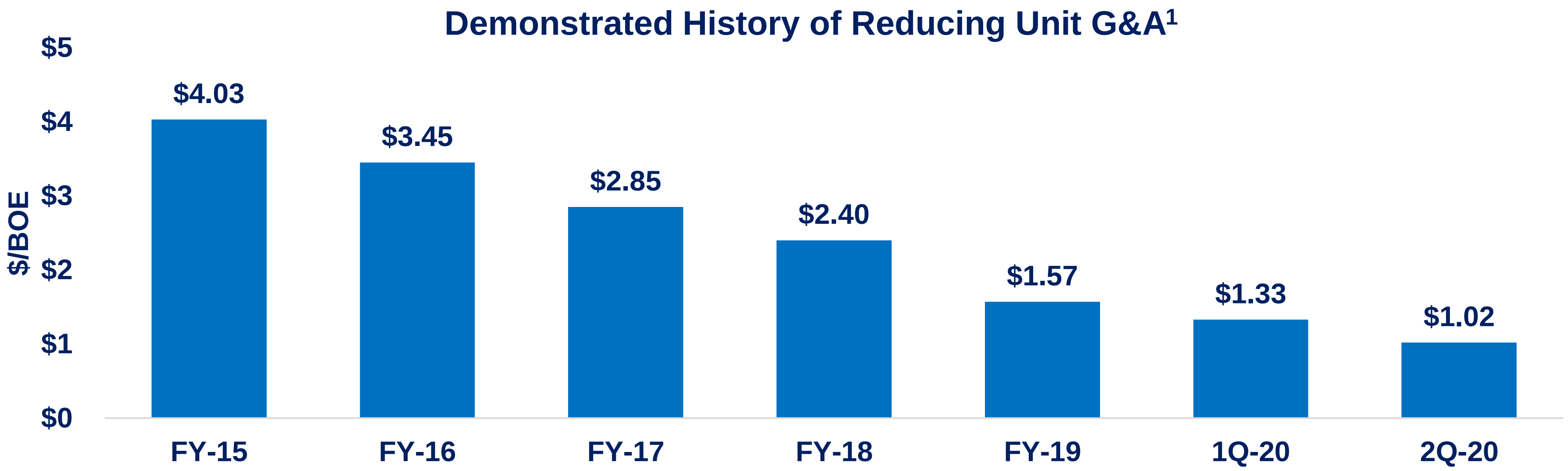
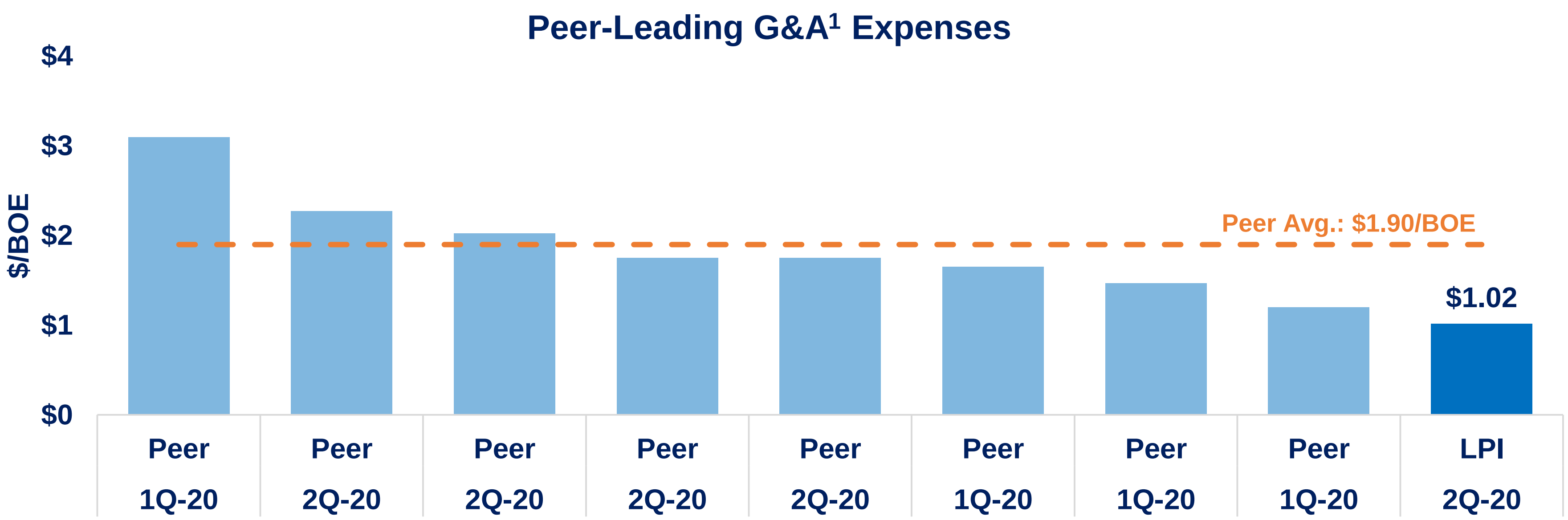
Note: Peer results are based on most recent public filing and include: CDEV, CPE, ESTE, MTDR, PE, QEP, SM and WPX

Cost-Control Focus Drives Competitive G&A Expenses

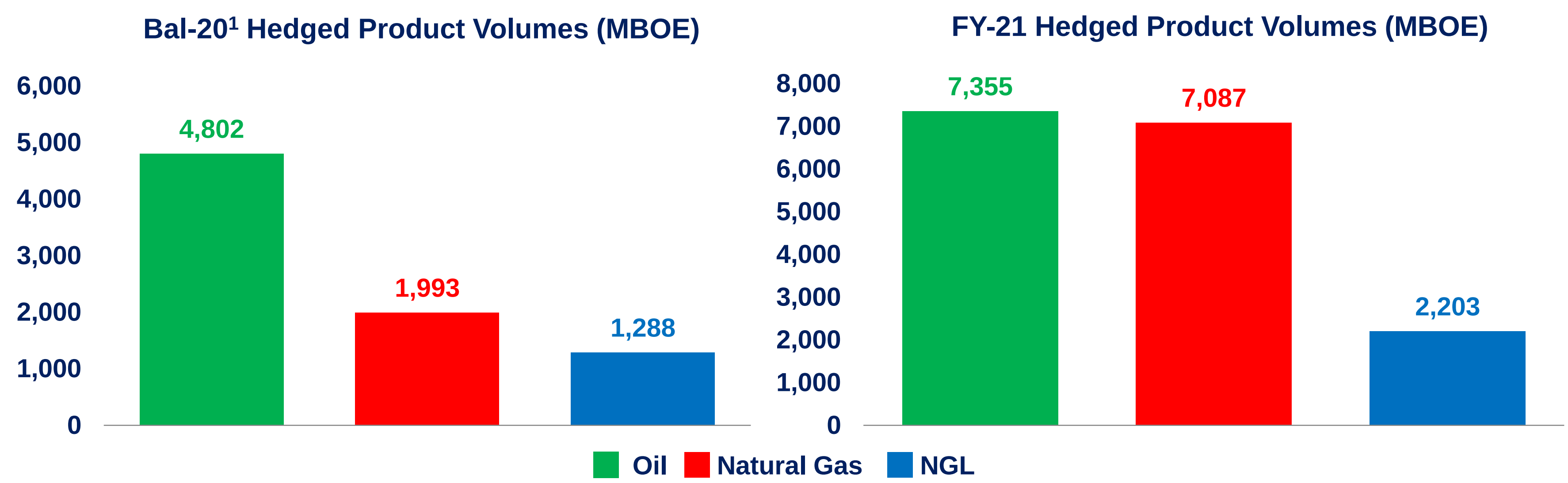


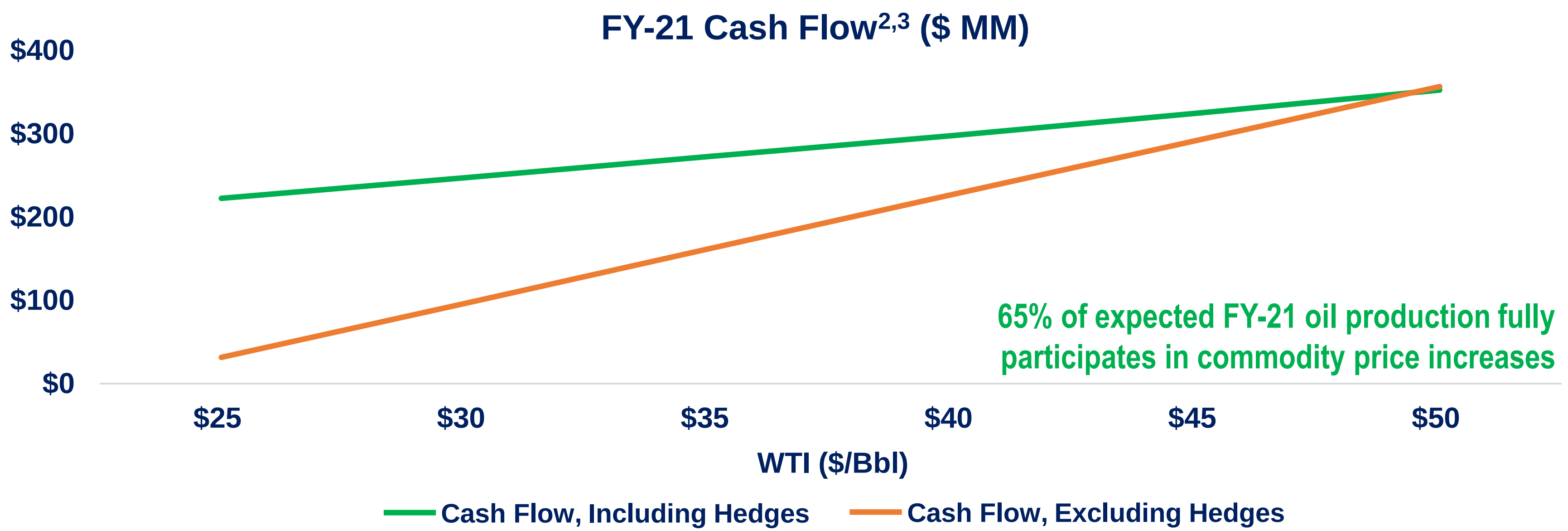


[1]Excludes long-term cash & non-cash compensation expenses

Note: Peer results are based on most recent public filing and include: CDEV, CPE, ESTE, MTDR, PE, QEP, SM and WPX

Active Derivatives Strategy Manages Price Risk and Supports Cash Flow





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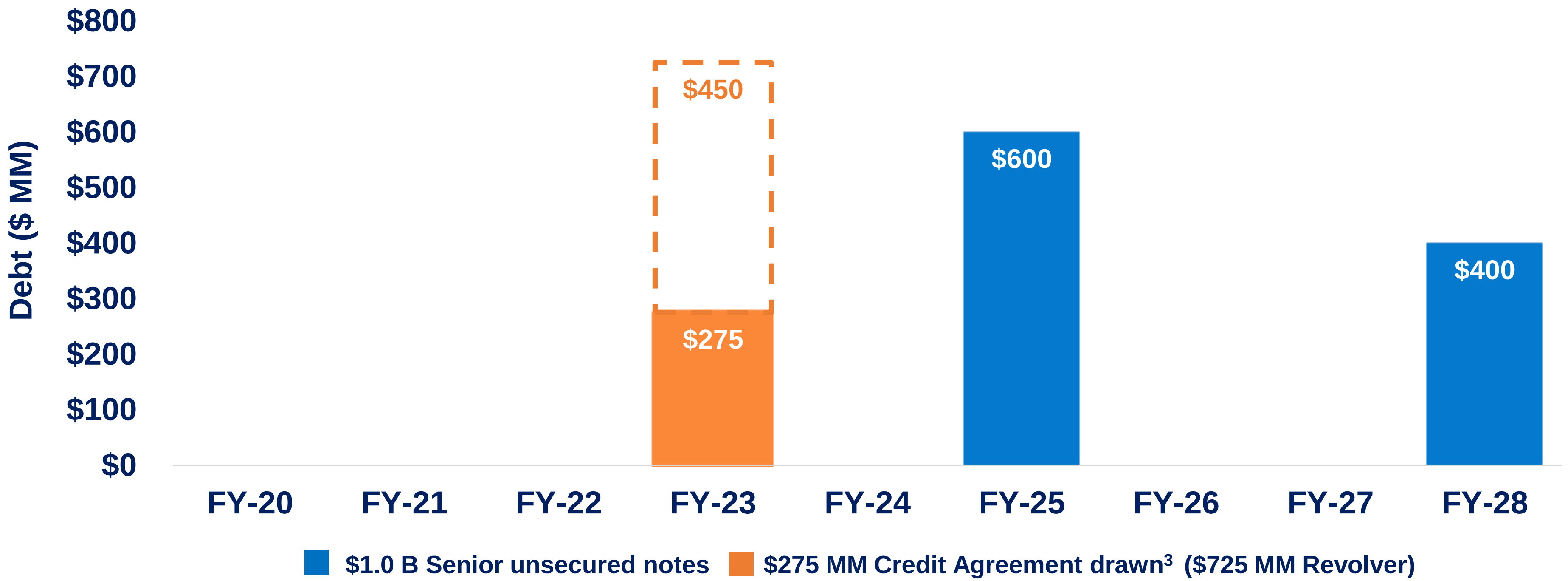
[1]Open positions as of 6-30-20; [2]See Appendix for reconciliations of non-GAAP measures; [3]Applicable natural gas strip pricing details can be found in the Appendix; Note: Hedges executed through 8-4-20

Actively Managing our Balance Sheet and Debt Ratios

2.4x Net Debt to Adj. EBITDA[1,2] (as reported)
2.6x Net Debt to Consolidated EBITDAX[1] (Credit Agreement calculation)



Expect to reduce net borrowings with Free Cash Flow[1] in 2H-20

[1]See Appendix for reconciliations of non-GAAP measures
[2]Includes TTM Adjusted EBITDA and net debt as of 6-30-20
[3]Amount drawn as of 6-30-20

APPENDIX

Guidance

Production:	3Q-20	4Q-20	FY-20
Total production (MBOE/d)	83.5 - 85.5	78.0 - 80.0	85.5 - 86.5
Oil production (MBO/d)	24.2 - 25.2	20.5 - 21.5	26.2 - 26.8

Average sales price realizations: *(excluding derivatives)*	3Q-20
Oil (% of WTI)	96%
NGL (% of WTI)	21%
Natural gas (% of Henry Hub)	54%

Other ($ MM):	3Q-20
Net income / (expense) of purchased oil	($4.5)
Net midstream income / (expense)	$1.2

Operating costs & expenses ($/BOE):	3Q-20
Lease operating expenses	$2.75
Production and ad valorem taxes *(% of oil, NGL and natural gas revenues)*	7.25%
Transportation and marketing expenses	$1.40
General and administrative expenses (excluding LTIP)	$1.40
General and administrative expenses (LTIP cash & non-cash)	$0.45
Depletion, depreciation and amortization	$6.50

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Commodity Prices Used for 3Q-20 Realization Guidance

Oil:

	WTI NYMEX ($/Bbl)	Brent ICE ($/Bbl)
Jul-20	$40.77	$43.24
Aug-20	$41.42	$44.15
Sep-20	$41.79	$44.53
3Q-20 Average	$41.32	$43.96

Natural Gas Liquids:

	C2 ($/Bbl)	C3 ($/Bbl)	IC4 ($/Bbl)	NC4 ($/Bbl)	C5+ ($/Bbl)	Composite ($/Bbl)
Jul-20	$9.07	$20.76	$24.56	$22.21	$28.69	$17.13
Aug-20	$9.03	$22.05	$29.40	$22.31	$33.92	$18.27
Sep-20	$9.16	$21.45	$30.08	$22.37	$34.18	$18.18
3Q-20 Average	$9.09	$21.42	$27.99	$22.29	$32.24	$17.86

Natural Gas:

	HH ($/MMBtu)	Waha ($/MMBtu)
Jul-20	$1.50	$1.33
Aug-20	$1.85	$1.30
Sep-20	$2.10	$1.55
3Q-20 Average	$1.81	$1.39

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Note: Pricing assumptions as of 8-3-20

Strip Pricing

	WTI ($/Bbl)	Brent ($/Bbl)	HH ($/MMBtu)
Bal-20	$41.45	$44.60	$2.45
FY-21	$43.40	$46.90	$2.75
FY-22	$44.80	$48.85	$2.55

Note: Utilizing 8-3-20 strip pricing

Oil, Natural Gas & Natural Gas Liquids Hedges

Hedge Product Summary	Bal-20	FY-21	FY-22
Oil total volume (Bbl)	4,802,400	7,354,750	2,920,000
Oil wtd-avg price ($/Bbl) - WTI	$59.50		
Oil wtd-avg price ($/Bbl) - Brent	$63.07	$51.11	$46.40
Nat gas total volume (MMBtu)	11,960,000	42,522,500	
Nat gas wtd-avg price ($/MMBtu) - HH	$2.72	$2.59	
NGL total volume (Bbl)	1,288,000	2,202,775	

Oil	Bal-20	FY-21	FY-22
WTI Swaps			
Volume (Bbl)	3,606,400		
Wtd-avg price ($/Bbl)	$59.50		
Brent Swaps			
Volume (Bbl)	1,196,000	4,307,000	2,920,000
Wtd-avg price ($/Bbl)	$63.07	$49.71	$46.40
Brent Puts			
Volume (Bbl)		2,463,750	
Wtd-avg floor price ($/Bbl)		$55.00	
Brent Collars			
Volume (Bbl)		584,000	
Wtd-avg floor price ($/Bbl)		$45.00	
Wtd-avg celing price ($/Bbl)		$59.50	

Oil Basis Swaps	Bal-20	FY-21	FY-21
Brent/WTI			
Volume (Bbl)	1,803,200		
Wtd-avg price ($/Bbl)	$5.09		

Natural Gas Swaps	Bal-20	FY-21	FY-21
HH			
Volume (MMBtu)	11,960,000	42,522,500	
Wtd-avg price ($/MMBtu)	$2.72	$2.59	

Natural Gas Liquids Swaps	Bal-20	FY-21	FY-22
Ethane			
Volume (Bbl)	184,000	912,500	
Wtd-avg price ($/Bbl)	$13.60	$12.01	
Propane			
Volume (Bbl)	625,600	730,000	
Wtd-avg price ($/Bbl)	$26.58	$25.52	
Normal Butane			
Volume (Bbl)	220,800	255,500	
Wtd-avg price ($/Bbl)	$28.69	$27.72	
Isobutane			
Volume (Bbl)	55,200	67,525	
Wtd-avg price ($/Bbl)	$29.99	$28.79	
Natural Gasoline			
Volume (Bbl)	202,400	237,250	
Wtd-avg price ($/Bbl)	$45.15	$44.31	

Basis Swaps	Bal-20	FY-21	FY-22
Waha/HH			
Volume (MMBtu)	21,160,000	41,610,000	7,300,000
Wtd-avg price ($/MMBtu)	($0.82)	($0.55)	($0.53)

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Note: Open positions as of 6-30-20, hedges executed through 8-4-20
Natural gas liquids consist of Mt. Belvieu purity ethane and Mt. Belvieu non-TET propane, normal butane, isobutane, and natural gasoline

Supplemental Non-GAAP Financial Measures

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for share-settled equity-based compensation, depletion, depreciation and amortization, impairment expense, mark-to-market on derivatives, premiums paid for commodity derivatives that matured during the period, accretion expense, gains or losses on disposal of assets, interest expense, income taxes 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 future discretionary use because it excludes funds 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 that 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 and the lack of comparability of results of operations to different companies due to 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 (loss) (GAAP) to Adjusted EBITDA (non-GAAP):

	Three months ended,			
(in thousands, unaudited)	9/30/19	12/31/19	3/31/20[1]	6/30/20
Net income (loss)	($264,629)	($241,721)	$74,646	($545,455)
Plus:				
Share-settled equity-based compensation, net	—	—	2,376	1,694
Non-cash stock-based compensation, net	(1,739)	3,046	—	
Depletion, depreciation and amortization	69,099	67,846	61,302	66,574
Impairment expense	397,890	222,999	186,699	406,448
Organizational restructuring expense	5,965	—	—	4,200
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	(96,684)	57,562	(297,836)	90,537
Settlements received (paid) for matured derivatives, net	25,245	14,394	47,723	86,872
Settlements paid for early terminations of derivatives, net	—	—	—	—
Premiums paid for derivatives	(1,415)	(1,399)	(477)	—
Accretion expense	1,005	1,041	1,106	1,117
(Gain) loss on disposal of assets, net	(1,294)	(67)	602	(152)
Interest expense	15,191	15,044	24,970	27,072
Litigation settlement	—	—	—	—
Loss on extinguishment of debt	—	—	13,320	—
Write-off of debt issuance costs	—	935	—	1,103
Income tax (benefit) expense	(2,467)	(1,776)	2,417	(7,173)
Adjusted EBITDA	$146,167	$137,904	$116,848	$132,837

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[1]Reflects revised and restated figures in 1Q-20 10-Q/A

Supplemental Non-GAAP Financial Measure

Consolidated EBITDAX (Credit Agreement Calculation)

"Consolidated EBITDAX" means, for any Person for any period, the Consolidated Net Income of such Person for such period, plus each of the following, to the extent deducted in determining Consolidated Net Income without duplication, determined for such Person and its Consolidated Subsidiaries on a consolidated basis for such period: any provision for (or less any benefit from) income or franchise Taxes; interest expense (as determined under GAAP as in effect as of December 31, 2016), depreciation, depletion and amortization expense; exploration expenses; and other non-cash charges to the extent not already included in the foregoing clauses (ii), (iii) or (iv), plus the aggregate Specified EBITDAX Adjustments during such period; *provided* that the aggregate Specified EBITDAX Adjustments shall not exceed fifteen percent (15%) of the Consolidated EBITDAX for such period prior to giving effect to any Specified EBITDAX Adjustments for such period, and minus all non-cash income to the extent included in determining Consolidated Net Income. For the purposes of calculating Consolidated EBITDAX for any Rolling Period in connection with any determination of the financial ratio contained in Section 10.1(b), if during such Rolling Period, Borrower or any Consolidated Restricted Subsidiary shall have made a Material Disposition or Material Acquisition, the Consolidated EBITDAX for such Rolling Period shall be calculated after giving pro forma effect thereto as if such Material Disposition or Material Acquisition, as applicable, occurred on the first day of such Rolling Period.

For additional information, please see the Company's Fifth Amended and Restated Credit Agreement, as amended, dated May 2, 2017 as filed with Securities and Exchange Commission.

The following table presents a reconciliation of net income (loss) (GAAP) to Consolidated EBITDA (Credit Agreement Calculation; non-GAAP):

	Three months ended,			
(in thousands, unaudited)	9/30/2019	12/31/2019	3/31/20[1]	6/30/2020
Net income (loss)	($264,629)	($241,721)	$74,646	($545,455)
Organizational restructuring expenses	5,965	-	-	4,200
Loss on early redemption of debt	-	-	13,320	-
(Gain) loss on disposal of assets, net	(1,294)	(67)	602	(152)
Consolidated Net Income (Loss)	(259,958)	(241,788)	88,568	(541,407)
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	(96,684)	57,562	(297,836)	90,537
Settlements received (paid) for matured commodity derivatives, net	25,245	14,394	47,723	86,872
Settlements received (paid) for early terminations of commodity derivatives, net	-	-	-	-
Mark-to-market (gain) loss on derivatives, net	(71,439)	71,956	(250,113)	177,409
Non-Cash Charges/Income:				
Deferred income tax expense (benefit)	(2,467)	(1,776)	2,417	(7,173)
Depletion, depreciation and amortization	69,099	67,846	61,302	66,574
Premiums paid for commodity derivatives	(1,415)	(1,399)	(477)	(50,593)
Share-settled equity-based compensation, net	(1,739)	3,046	2,376	1,694
Accretion expense	1,005	1,041	1,106	1,117
Impairment expense	397,890	222,999	186,699	406,448
Write-off of debt issuance costs	-	935	-	1,103
Interest Expense	15,191	15,044	24,970	27,072
Consolidated EBITDAX after EBITDAX Adjustments (limited to 15%)	$146,167	$137,904	$116,848	$82,244

LAREDO PETROLEUM

[1]Reflects revised and restated figures in 1Q-20 10-Q/A

Supplemental Non-GAAP Financial Measure

Net debt to TTM Adjusted EBITDA

Net Debt to TTM Adjusted EBITDA is calculated as net debt divided by trailing twelve-month Adjusted EBITDA. Net debt is calculated as the face value of debt, reduced by cash and cash equivalents.

Net Debt to Adjusted EBITDA 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.

See Appendix slides for a definition of Adjusted EBITDA and for a reconciliation of Net Income to Adjusted EBITDA.

Net debt to TTM Consolidated EBITDAX (Credit Agreement Calculation)

Net Debt to TTM Consolidated EBITDAX is calculated as net debt divided by trailing twelve-month Consolidated EBITDAX. Net debt is calculated as the face value of debt, reduced by cash and cash equivalents.

Net Debt to Consolidated EBITDAX is used by the banks in our Senior Secured Credit Agreement as a measure of indebtedness and as a calculation to measure compliance with the Company's leverage covenant.

See Appendix slides for a definition of Consolidated EBITDAX and for a reconciliation of Net Income to Consolidated EBITDAX.

Liquidity

Calculated as the Company's outstanding borrowings on its Senior Secured Credit Agreement, less outstanding letters of credit, plus cash and cash equivalents.

Free Cash Flow

Free Cash Flow, a non-GAAP financial measure, does not represent funds available for future discretionary use because it excludes funds required for future debt service, capital expenditures, acquisitions, working capital, income taxes, franchise taxes and other commitments and obligations. However, our management believes Free Cash Flow is useful to management and investors in evaluating operating trends in our business that are affected by production, commodity prices, operating costs and other related factors. There are significant limitations to the use of Free Cash Flow as a measure of performance, including the lack of comparability due to the different methods of calculating Free Cash Flow reported by different companies.