LAREDO PETROLEUM

First-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 state regulators to enact production curtailment, hedging activities, possible impacts of litigation and regulations, and other factors, including those and other risks described in its Annual Report on Form 10-K for the year ended December 31, 2019 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. 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 press release and the conference call, the Company may use the terms “resource potential” and “estimated ultimate recovery,” “type curve” or “EURs,” 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%. 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.

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.

Strategy Increases Stakeholder Value

Target consistent Free Cash Flow[1] generation and oil growth per net debt-adjusted share

Continuous	In Process	Opportunistic
Optimize existing acreage	**Improve corporate returns through accretive acquisitions**	**Increase scale through consolidation**
High-grade development to maximize oil productivity	Opportunistically target high-margin inventory	Combine operations to eliminate redundancies
+	+	+
Maintain capital and operational cost advantages	Utilize Free Cash Flow[1] to maintain a competitive leverage profile	Leverage basin-leading low cost structure to achieve synergies
=	=	=
Improves capital efficiency on existing acreage	Accelerates Cash Flow[1] & oil growth	Delivers increased return of cash to stakeholders

LAREDO PETROLEUM

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

Surpassing Guidance on Production & Expenses

1Q-20 Select Results vs Guidance[1]

Production

Oil Production
29.2 MBO/d
7% beat vs guidance

Total Production
86.5 MBOE/d
6% beat vs guidance

Controllable Cash Costs

Lease Operating Expense
$2.80/BOE
7% beat vs guidance

G&A (Excluding LTIP)
$1.33/BOE
17% beat vs guidance

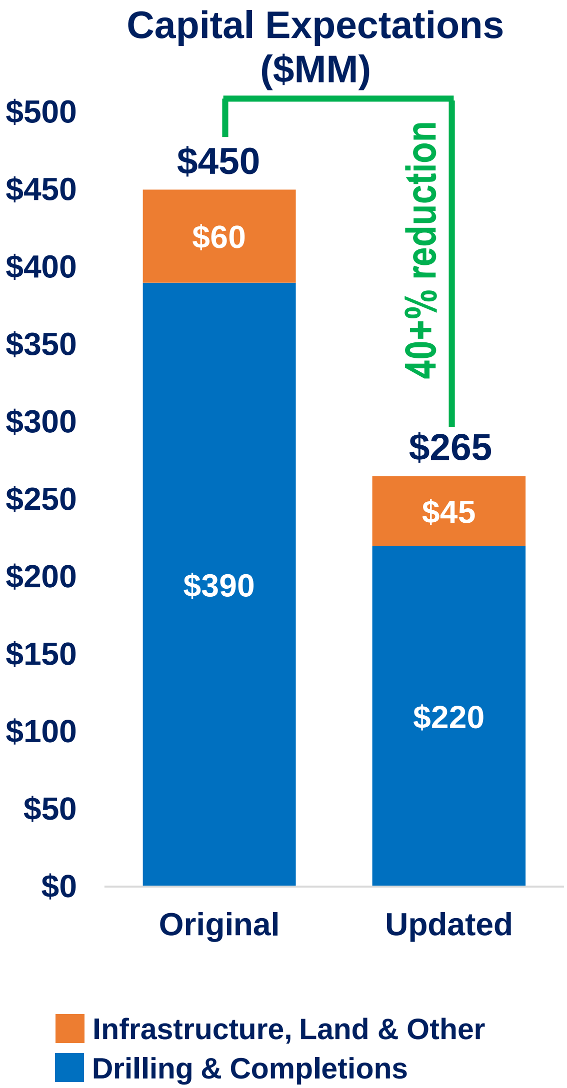
Financial & Operational Highlights

- Extended senior unsecured debt maturities to 2025 & 2028
- 34% higher average sales price due to realized derivatives
- 11% below capital expenditures expectations
- 7% reduction in well costs to $630 per lateral foot

LAREDO PETROLEUM

[1]Utilizes high end of 1Q-20 guidance where applicable, provided on 02-12-20

Significantly Reduced Activity in Response to Oil Price Decline



	1Q-20A	2Q-20E	3Q-20E	4Q-20E	FY-20E
Drilling Rigs	4.0	2.4	1.0	1.0	2.1
Spuds	25	17	6	7	55
Completion Crews	1.7	0.3	0.0	0.0	0.5
Completions	28	5	0	0	33
Total Capital	$155	$65	$20	$25	$265
Avg. Working Interest					98%
Avg. Lateral Length					8,550

Adjusted capital expectations demonstrate Free Cash Flow[1], balance sheet and returns focus

[1]See Appendix for reconciliations of non-GAAP measures
Note: Capital Expectations exclude non-budgeted acquisitions

Acquisitions Added Oily, High-Margin Inventory

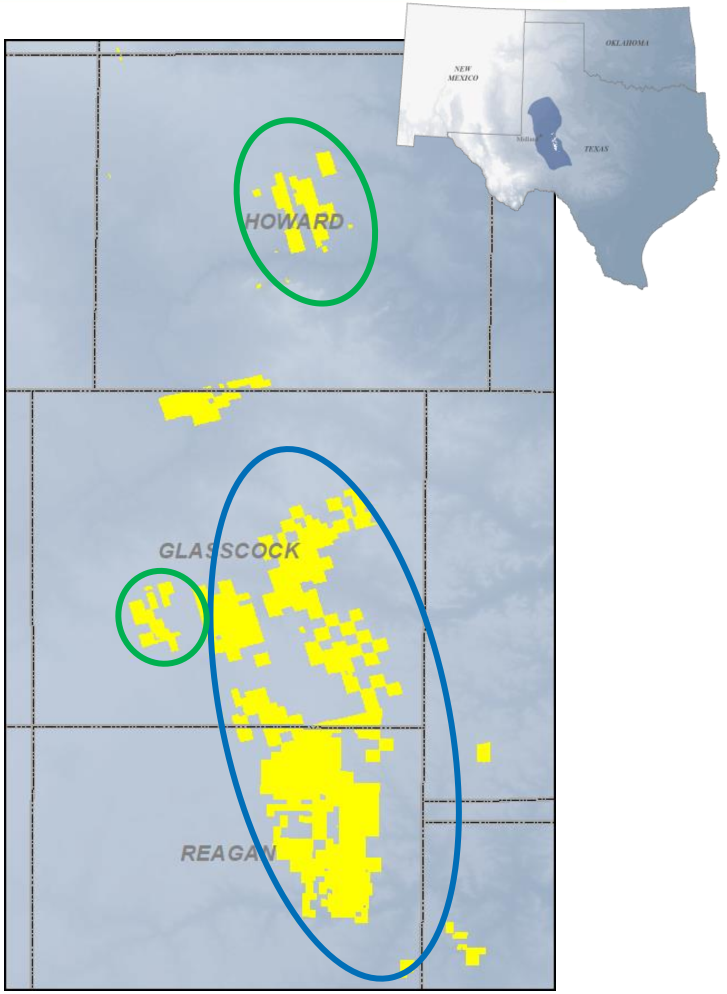
Target consistent Free Cash Flow[1] generation and oil growth per net debt-adjusted share

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

Acquired Inventory	Inventory	Inventory Years[2]
Lower Spraberry / UWC/MWC	175	6

Established Inventory	Inventory	Inventory Years[2]
UWC/MWC	300 - 450	12
Cline	140 - 160	5

Total Inventory	Inventory	Inventory Years[2]
Acquired & Established	615 - 785	23



152,750 gross / 134,614 net acres

LPI Leasehold
Acquired Inventory Established Inventory

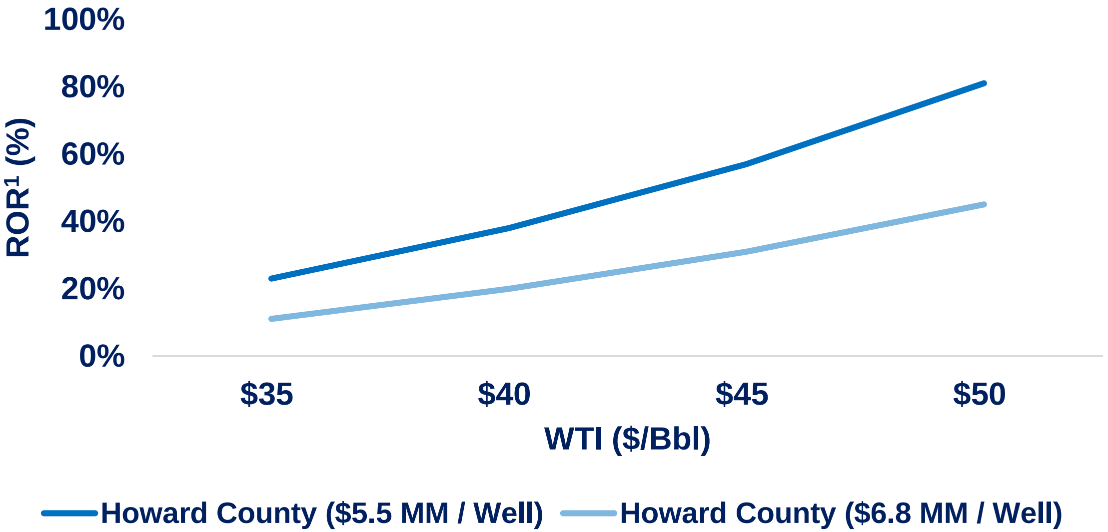
LAREDO PETROLEUM

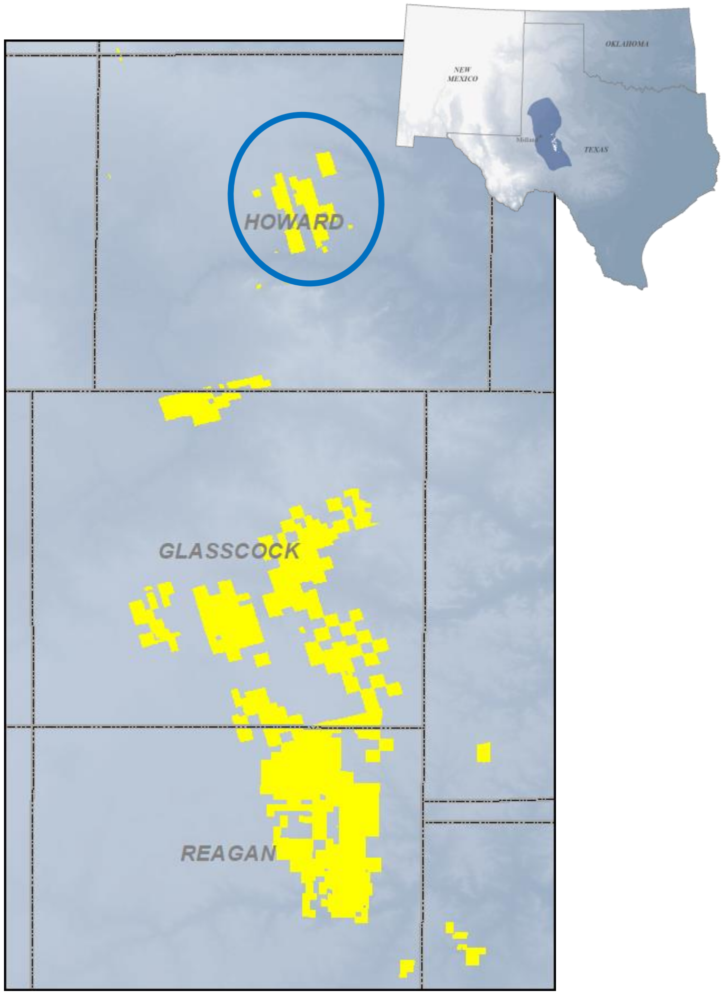
[1]See Appendix for reconciliations of non-GAAP measures
[2]Inventory Years assumes 30 wells per year
Note: Inventory expected to average oil type curve productivity

Howard County Position Increases Leverage to Oil Prices

Anticipated returns double with a 20% decrease in well costs

- **Forecasted first-year production mix of 80% oil drives exposure to an oil price recovery**
- **40 DUCs at YE-20E sets up capital-efficient development**





152,750 gross / 134,614 net acres

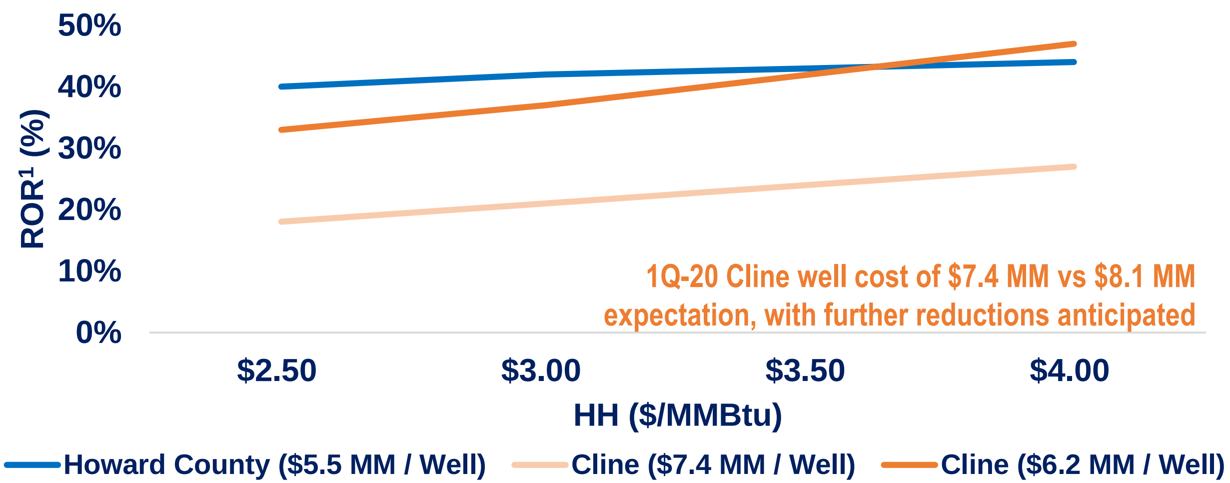
LPI Leasehold

[1]Rates of return utilize $2/MMBtu HH
Laredo's current well cost estimate

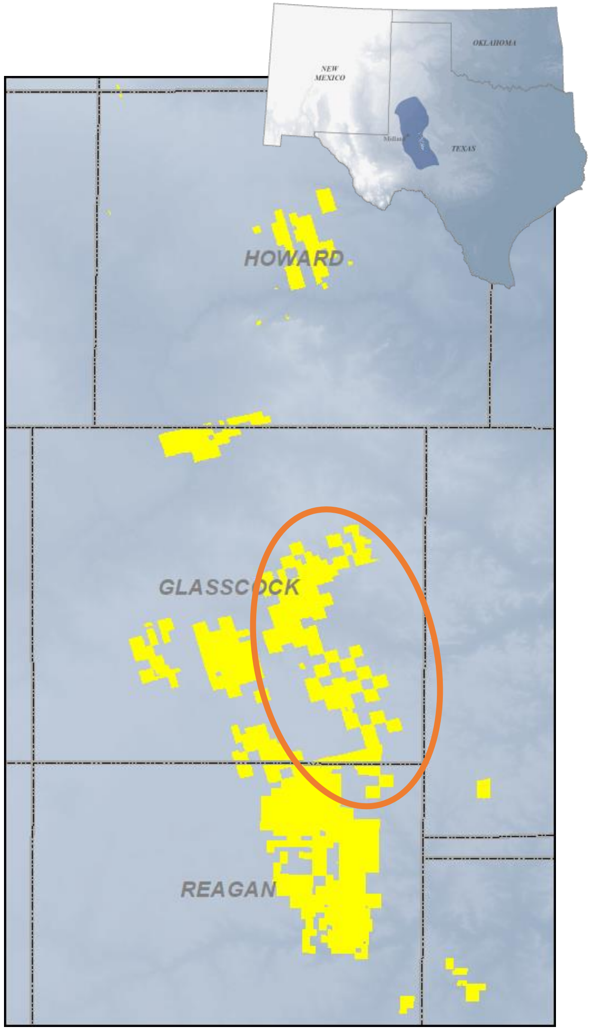
LAREDO PETROLEUM

Established Cline Inventory Provides Leverage to Natural Gas Prices

Cline returns are forecasted to be on par with Howard County when pairing higher natural gas prices with a 15% decrease in well costs



Regional Cline 1.0 MMBOE Type Curve (400 MBO)					
Year	Oil (MBO)	Total (MBOE)	Oil Mix (%)	Natural Gas Mix (%)	Natural Gas Liquids Mix (%)
1	139	295	47%	28%	25%
2	48	128	38%	33%	30%
3	28	76	37%	33%	30%
4	20	55	37%	33%	30%
5	16	43	37%	33%	30%
5-Year Cum. Prod.	250	596	42%	30%	28%
Life of Well	400	1,000	39%	32%	29%



152,750 gross / 134,614 net acres

LPI Leasehold

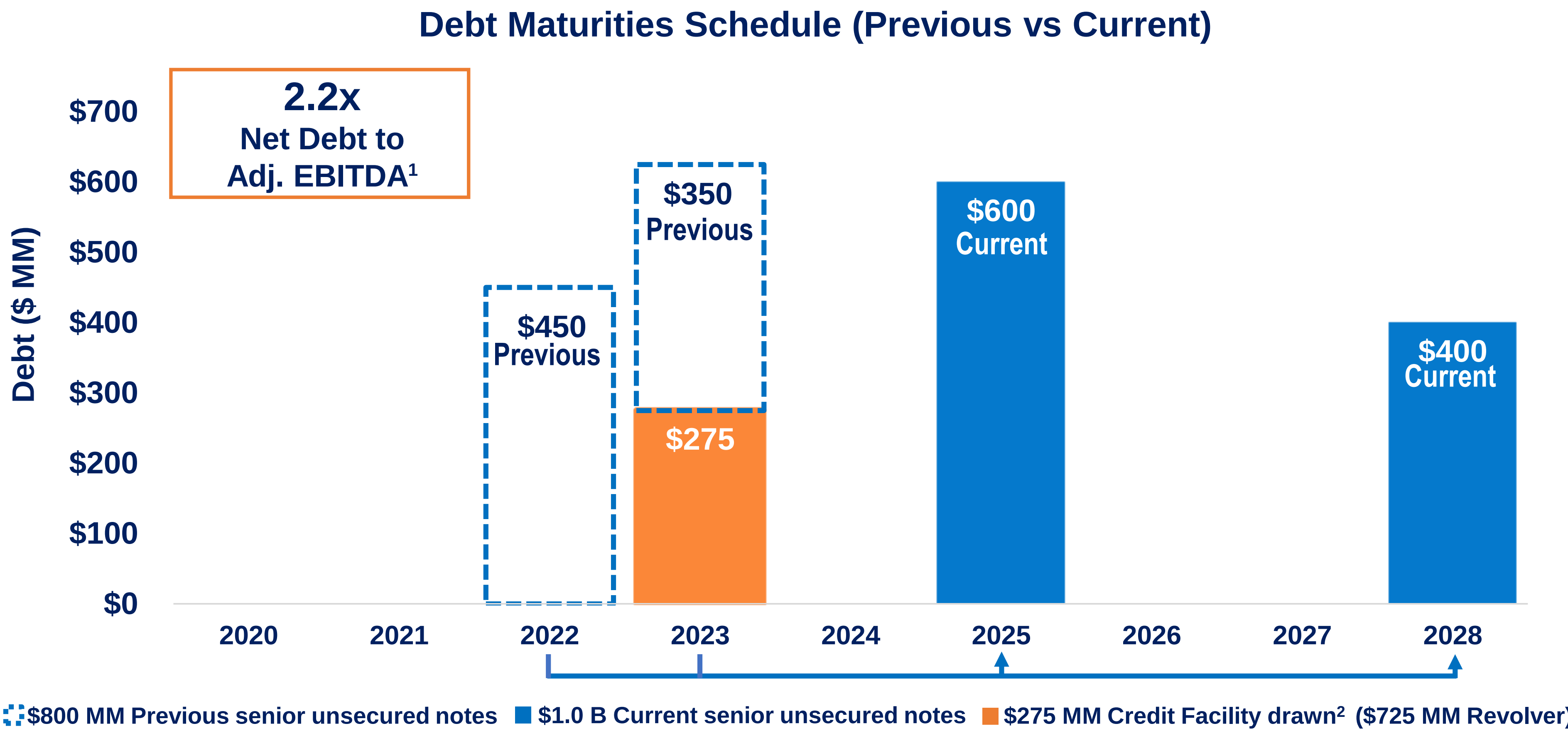
Regional Cline Inventory

[1]Rates of return utilize $40/Bbl WTI

Note: Numbers may not foot due to rounding

LAREDO PETROLEUM

Successfully Extended Sr. Unsecured Notes Maturities to 2025 & 2028



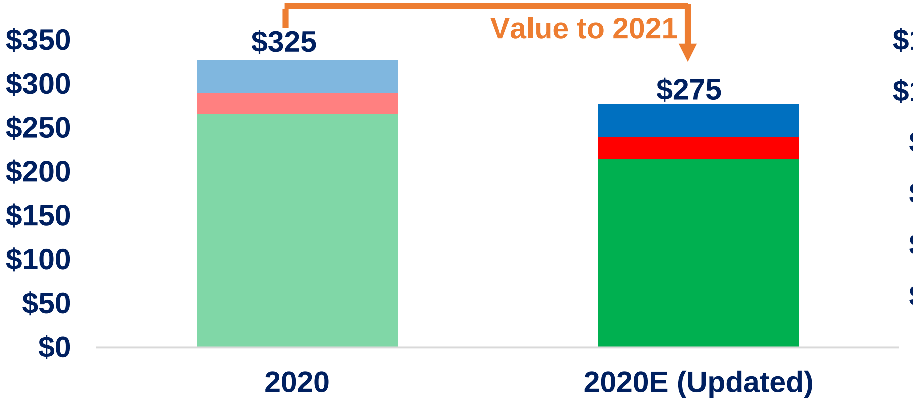
Expect to reduce net borrowings by $120 MM from 1Q-20 to YE-20E

[1]See Appendix for reconciliations of non-GAAP measures; Includes TTM Adjusted EBITDA and net debt as of 3-31-20
[2]Amount drawn as of 3-31-20

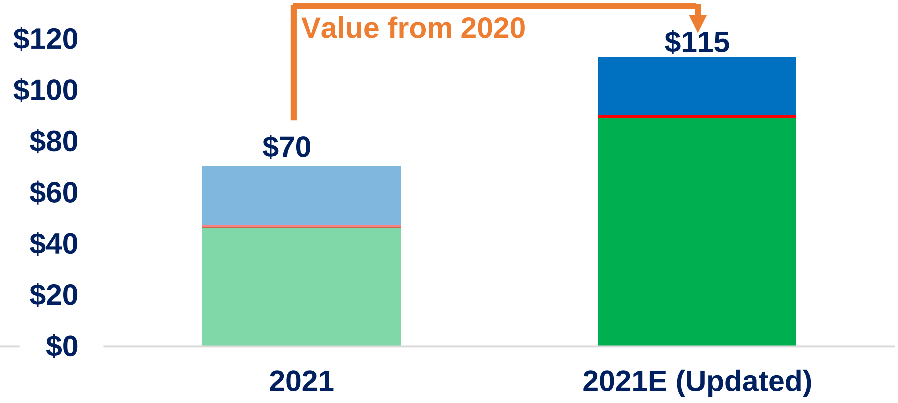
Strategic Derivatives Protect 2020 & 2021 Cash Flow[1]

$50 MM of FY-20E Free Cash Flow[1] redeployed into FY-21 Brent hedges to strategically manage commodity price risk and cash flow generation in 2021

2020 Net Cash Expected from Commodity Derivatives[2] at Strip Pricing[3] ($ MM)

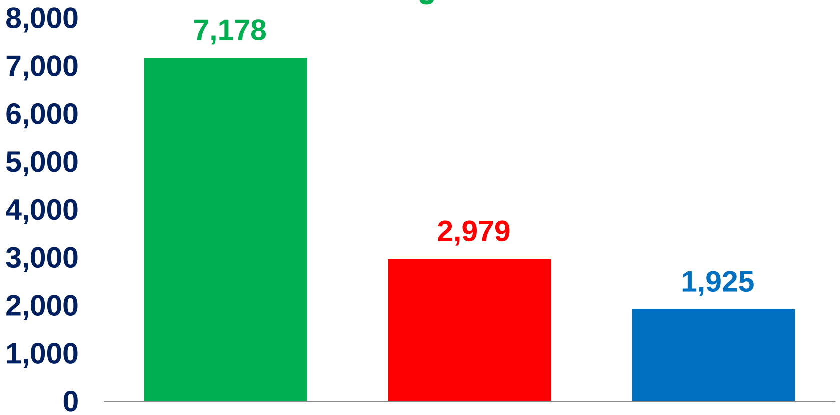


2021 Net Cash Expected from Commodity Derivatives[2] at Strip Pricing[3] ($ MM)

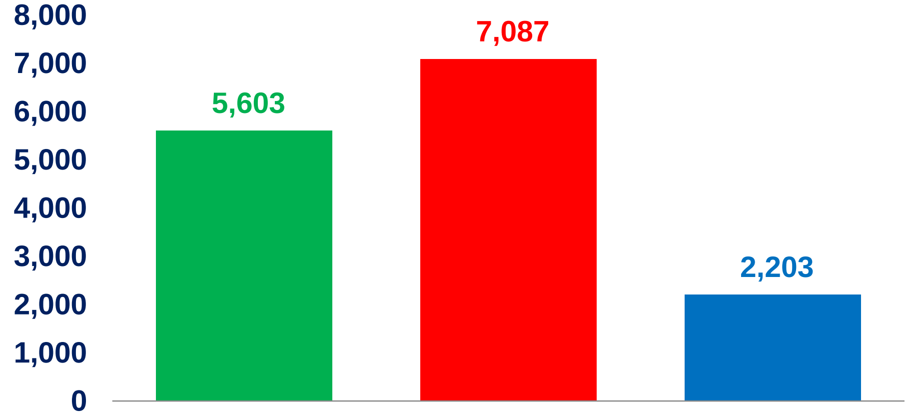


Bal-20 Hedged Product Volumes (MBOE)

100% hedged on oil for Bal-20



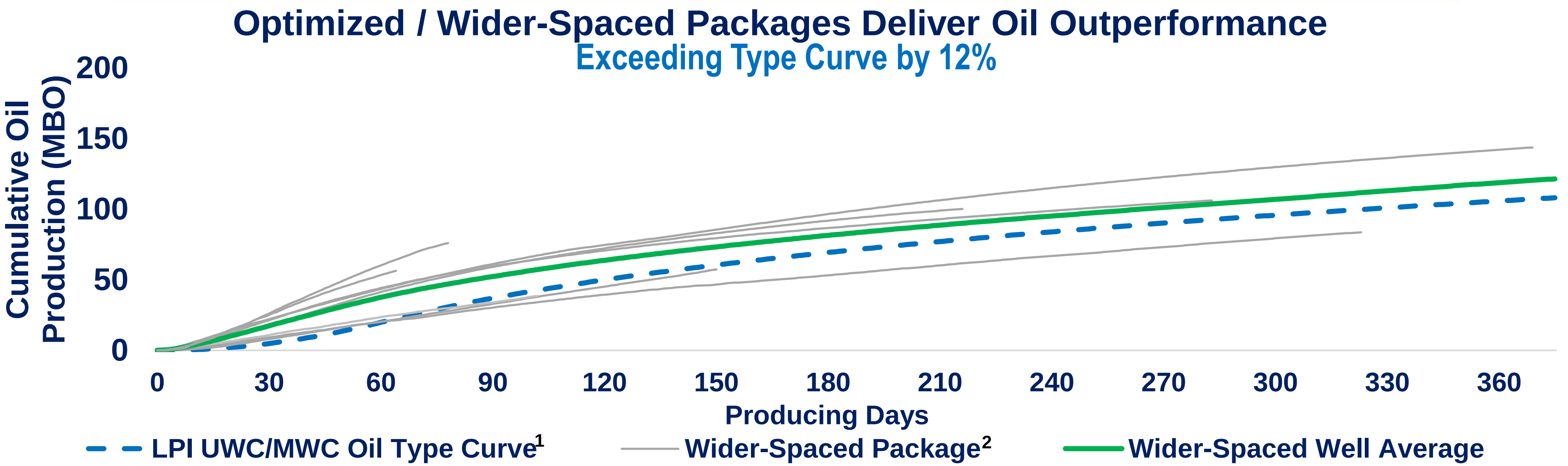
2021 Hedged Product Volumes (MBOE)

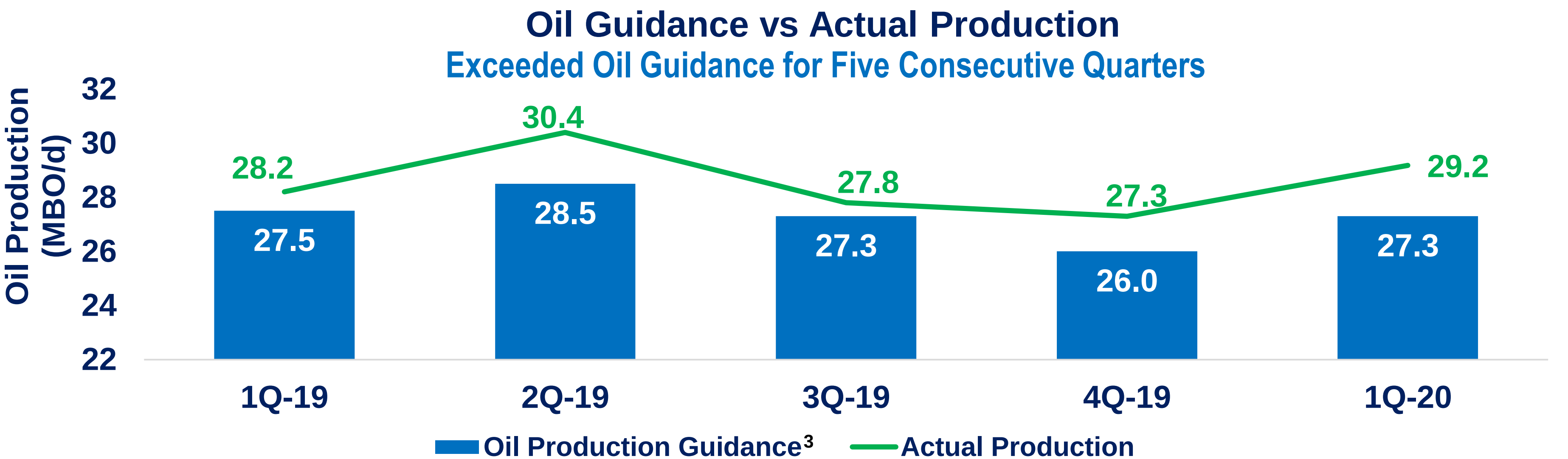


Oil Natural Gas NGL

[1]See Appendix for reconciliations of non-GAAP measures; [2]Net of premiums paid at contract execution; [3]Strip pricing details can be found in the Appendix

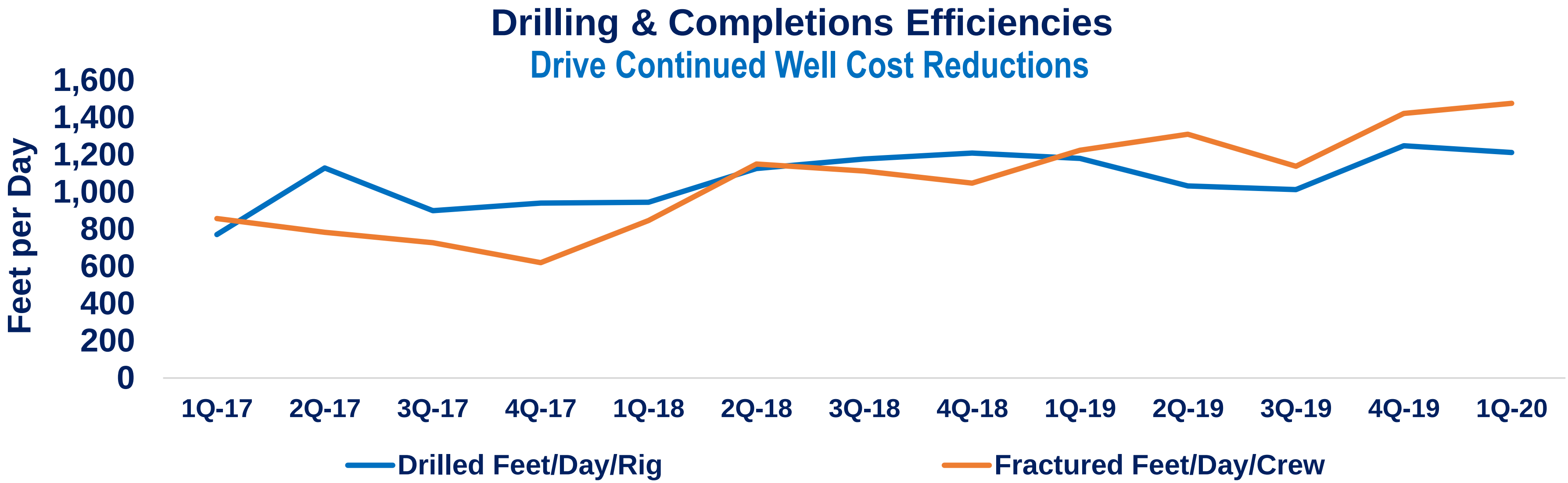
Optimized Development Supports Consistent Oil Outperformance

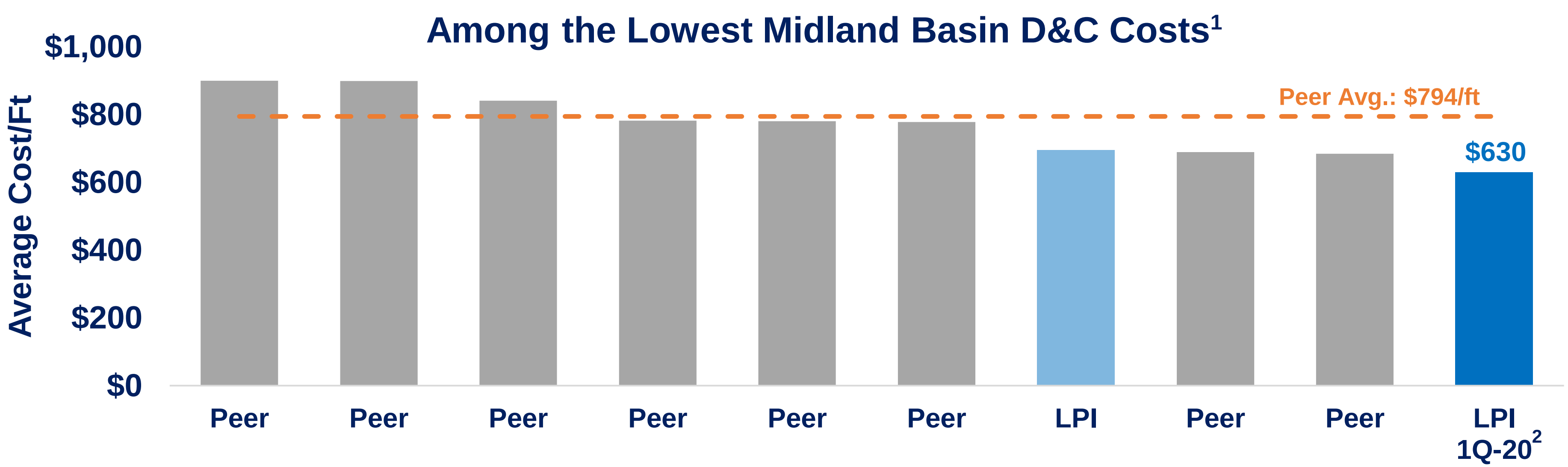




[1]UWC/MWC 1.3 MMBOE type curve (400 MBO) representative of a 10,000' well, utilizing a 1.2 b-factor
[2]Includes an average of the Yellow Rose package (8 wells), Hoelscher package (4 wells), Frysak/Halfmann package (4 wells), Sugg-B package (7 wells), Von Gonten package (9 wells), Driver-Agnell package (6 wells), Lynda (6 wells), Lacy Creek (2 wells) & Mize (7 wells); Chart lines show cumulative oil production for all named wells, normalized to a 10,000' lateral, as of 5-2-20
[3]Utilizes high end of guidance where applicable

Operational Efficiencies Drive Lower Capital Costs

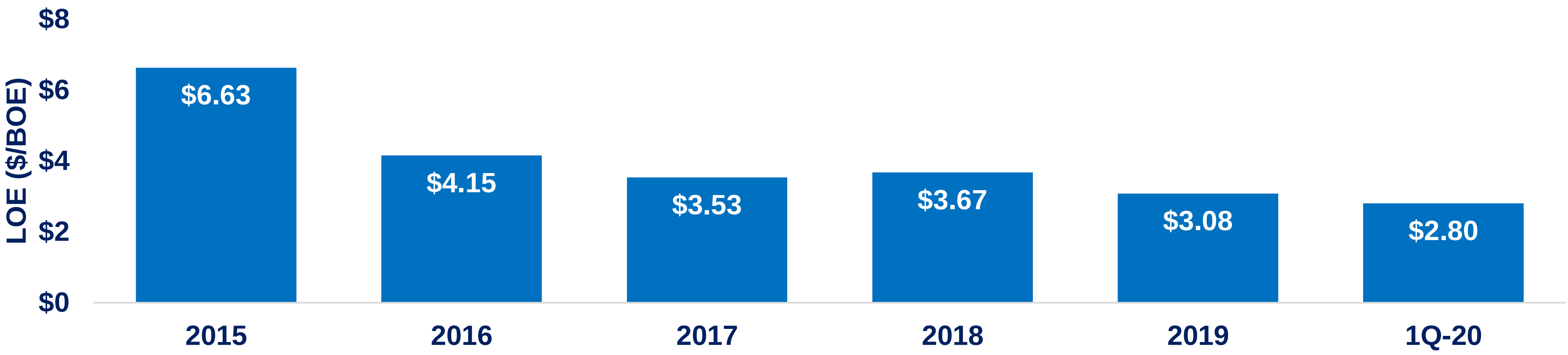




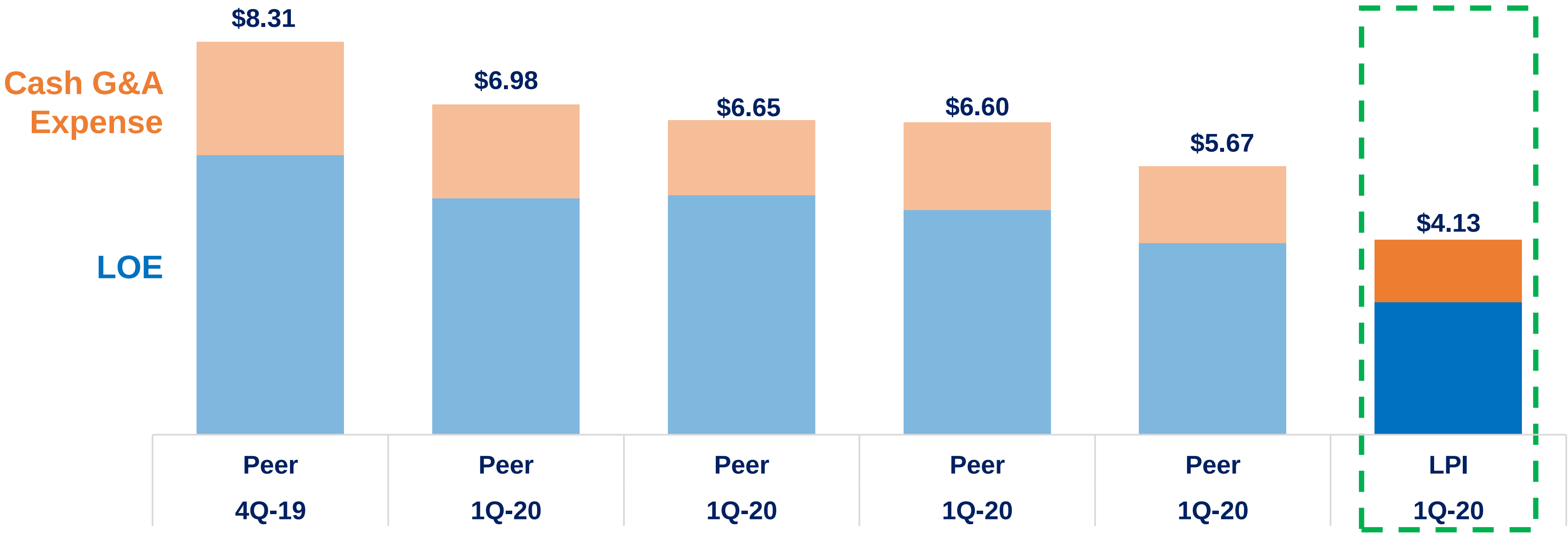
[1]Source: RSEG 5-1-2020 2019 & 2020 quarterly weighted average lateral cost per foot. Peers include: CPE, CXO, FANG, OVV, PE, PXD, QEP, and SM; LPI Current per internal data
[2]Includes +$20/ft for increase to 2,400 #/ft of sand

Demonstrated Management of Controllable Cash Costs

58% Reduction in LOE/BOE Since 2015



Peer-Leading Controllable Cash Costs ($/BOE)[1]



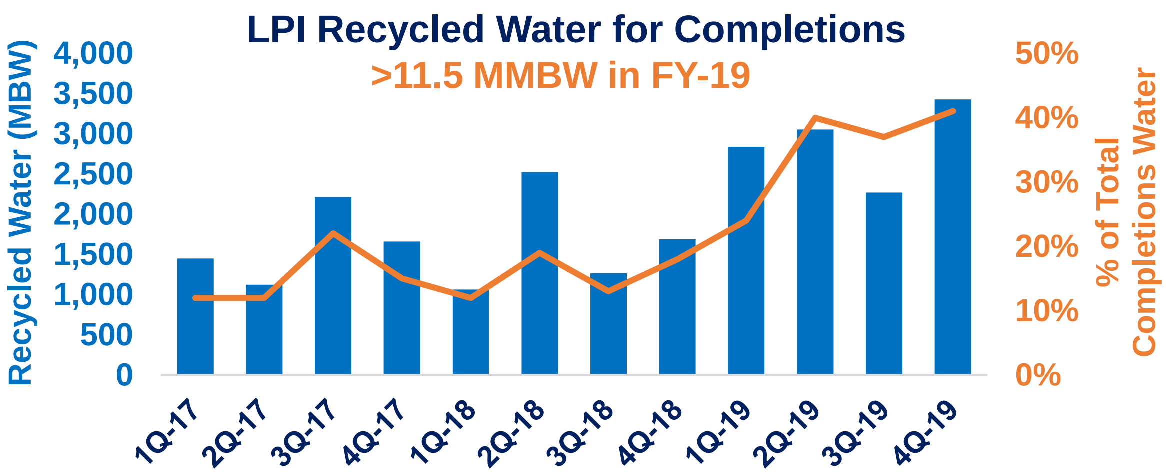
[1]Peer data as of most recent SEC filing and includes: CDEV, CPE, MTDR, QEP, SM

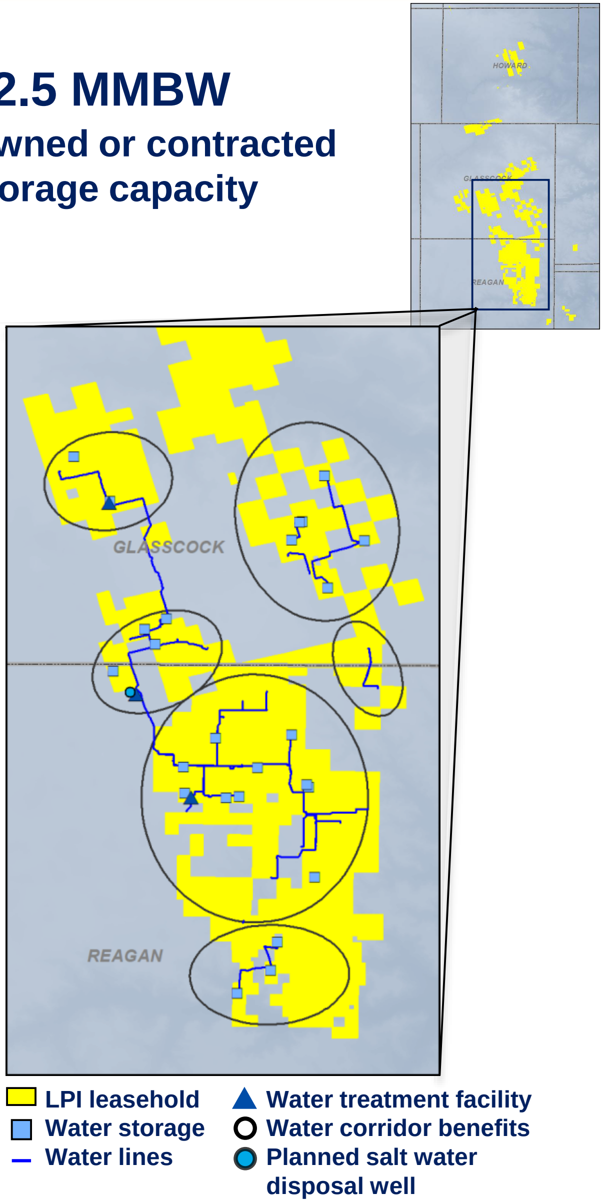
Significant Benefits through Water Infrastructure Investments

110 Miles
Water gathering & distribution pipelines

54 MBW/d
Produced water recycling capacity

22.5 MMBW
Owned or contracted storage capacity





79% — **23.5 MMBW**
Produced water gathered by pipe

34% — **10.1 MMBW**
Produced water recycled

$0.56/BOE
Reduction in unit LOE from water infrastructure

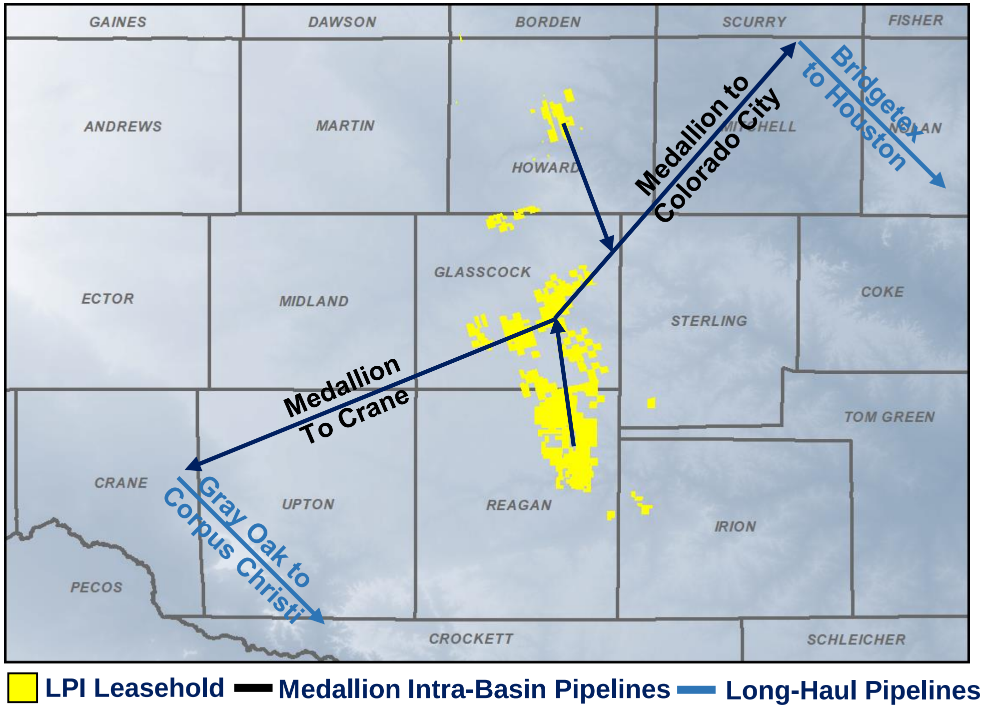
$174,000/well
Reduction in capital due to in-place water infrastructure

LAREDO PETROLEUM

Note: Infrastructure statistics and map as of 3-31-20; infrastructure and financial impacts for FY-19
Financial benefits calculated utilizing a 95% WI & 72% NRI

Crude Contracts Maximize Deliverability and Sales Point Performance

- Long-term firm-transportation contracts secure delivery of oil production to the Gulf Coast
- Receive WTI-Houston-based and Brent-based pricing through large, international logistics providers that redeliver purchased crude to multiple domestic & international buyers
- WTI-Houston and Brent have historically received a premium to Midland and WTI-Cushing pricing



Physical Transportation Contracts:

- Firm transportation on Gray Oak
  - Year 1: 25 MBOPD; Years 2 - 7: 35 MBOPD
  - Brent-based pricing
- 10 MBOPD firm transportation on Bridgetex
  - Through 1Q-22, option to extend contract through 1Q-26
  - WTI-Houston-based pricing

Firm transportation and firm-sales arrangements maximize access to global markets and waterborne pricing

LPI Infrastructure Protects the Environment & Enhances Economics

Oil & Natural Gas Infrastructure

60 Miles
Crude oil gathering pipelines

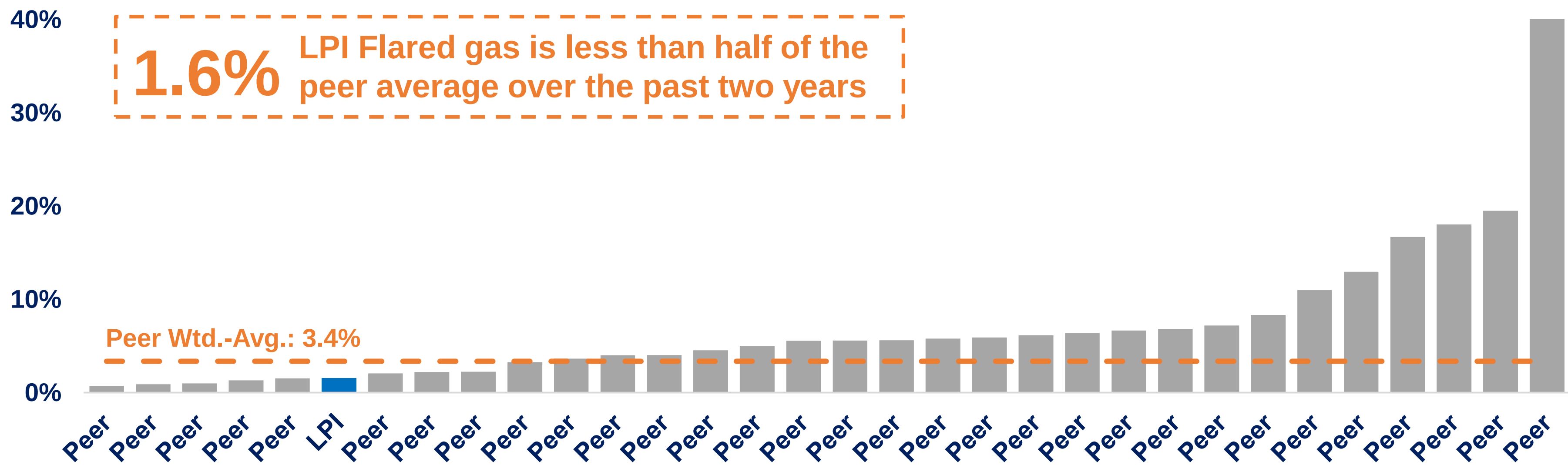
170 miles
Natural gas gathering and distribution pipelines

Infrastructure Impact

>250,000
Truckloads eliminated from the field

>2.4 Bcf
Additional gas sold vs. vented/flared

Permian Flared / Vented Gas vs. Gross Gas Production[1]



[1]Source: Rystad Energy as of 4-27-20, 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
Note: Existing infrastructure as of 3-31-20 and impact as of FY-19

LAREDO PETROLEUM

APPENDIX

Guidance

Production:	2Q-20	3Q-20	4Q-20	FY-20
Total production (MBOE/d)	84.8 - 85.8	78.8 - 80.8	72.5 - 74.5	80.6 - 81.9
Oil production (MBO/d)	30.0 - 30.5	24.2 - 25.2	20.5 - 21.5	26.0 - 26.6

Average sales price realizations: *(excluding derivatives)*	2Q-20
Oil (% of WTI)	82%
NGL (% of WTI)	4%
Natural gas (% of Henry Hub)	29%

Other ($ MM):	2Q-20
Net income / (expense) of purchased oil	($1.5)
Net midstream income / (expense)	$1.5

Operating costs & expenses ($/BOE):	2Q-20
Lease operating expenses	$2.85
Production and ad valorem taxes *(% of oil, NGL and natural gas revenues)*	7.00%
Transportation and marketing expenses	$1.70
General and administrative expenses (excluding LTIP)	$1.40
General and administrative expenses (LTIP cash & non-cash)	$0.45
Depletion, depreciation and amortization	$8.00

LAREDO PETROLEUM

Oil, Natural Gas & Natural Gas Liquids Hedges

Hedge Product Summary	Bal-20	FY-21	FY-22
Oil total volume (Bbl)	7,177,500	5,602,750	
Oil wtd-avg price ($/Bbl) - WTI	$59.50		
Oil wtd-avg price ($/Bbl) - Brent	$63.07	$53.13	
Nat gas total volume (MMBtu)	17,875,000	42,522,500	
Nat gas wtd-avg price ($/MMBtu) - HH	$2.72	$2.59	
NGL total volume (Bbl)	1,925,000	2,202,775	

Oil	Bal-20	FY-21	FY-22
WTI Swaps			
Volume (Bbl)	5,390,000		
Wtd-avg price ($/Bbl)	$59.50		
Brent Swaps			
Volume (Bbl)	1,787,500	2,555,000	
Wtd-avg price ($/Bbl)	$63.07	$53.19	
Brent Puts			
Volume (Bbl)		2,463,750	
Wtd-avg floor price ($/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-22
Brent/WTI			
Volume (Bbl)	2,695,000		
Wtd-avg price ($/Bbl)	$5.09		

Natural Gas Swaps	Bal-20	FY-21	FY-22
HH			
Volume (MMBtu)	17,875,000	42,522,500	
Wtd-avg price ($/MMBtu)	$2.72	$2.59	

Natural Gas Liquids Swaps	Bal-20	FY-21	FY-22
Ethane			
Volume (Bbl)	275,000	912,500	
Wtd-avg price ($/Bbl)	$13.60	$12.01	
Propane			
Volume (Bbl)	935,000	730,000	
Wtd-avg price ($/Bbl)	$26.58	$25.52	
Normal Butane			
Volume (Bbl)	330,000	255,500	
Wtd-avg price ($/Bbl)	$28.69	$27.72	
Isobutane			
Volume (Bbl)	82,500	67,525	
Wtd-avg price ($/Bbl)	$29.99	$28.79	
Natural Gasoline			
Volume (Bbl)	302,500	237,250	
Wtd-avg price ($/Bbl)	$45.15	$44.31	

Basis Swaps	Bal-20	FY-21	FY-22
Waha/HH			
Volume (MMBtu)	31,625,000	41,610,000	7,300,000
Wtd-avg price ($/MMBtu)	($0.82)	($0.55)	($0.53)

LAREDO PETROLEUM

Note: Open positions as of 3-31-20, hedges executed through 5-1-20
Natural gas liquids consist of Mt. Belvieu purity ethane and Mt. Belvieu non-TET propane, normal butane, isobutane, and natural gasoline

Strip Pricing

	WTI ($/Bbl)	Brent ($/Bbl)	HH ($/MMBtu)
Bal-20	$26.85	$31.20	$2.40
FY-21	$33.30	$37.15	$2.70

Note: Utilizing 4-23-20 strip pricing

Commodity Prices Used for 2Q-20 Realization Estimates

Oil:

	WTI NYMEX ($/Bbl)	Brent ICE ($/Bbl)
Apr-20	$16.70	$26.69
May-20	$20.62	$27.22
Jun-20	$22.93	$28.78
2Q-20 Average	$20.09	$27.56

Natural Gas Liquids:

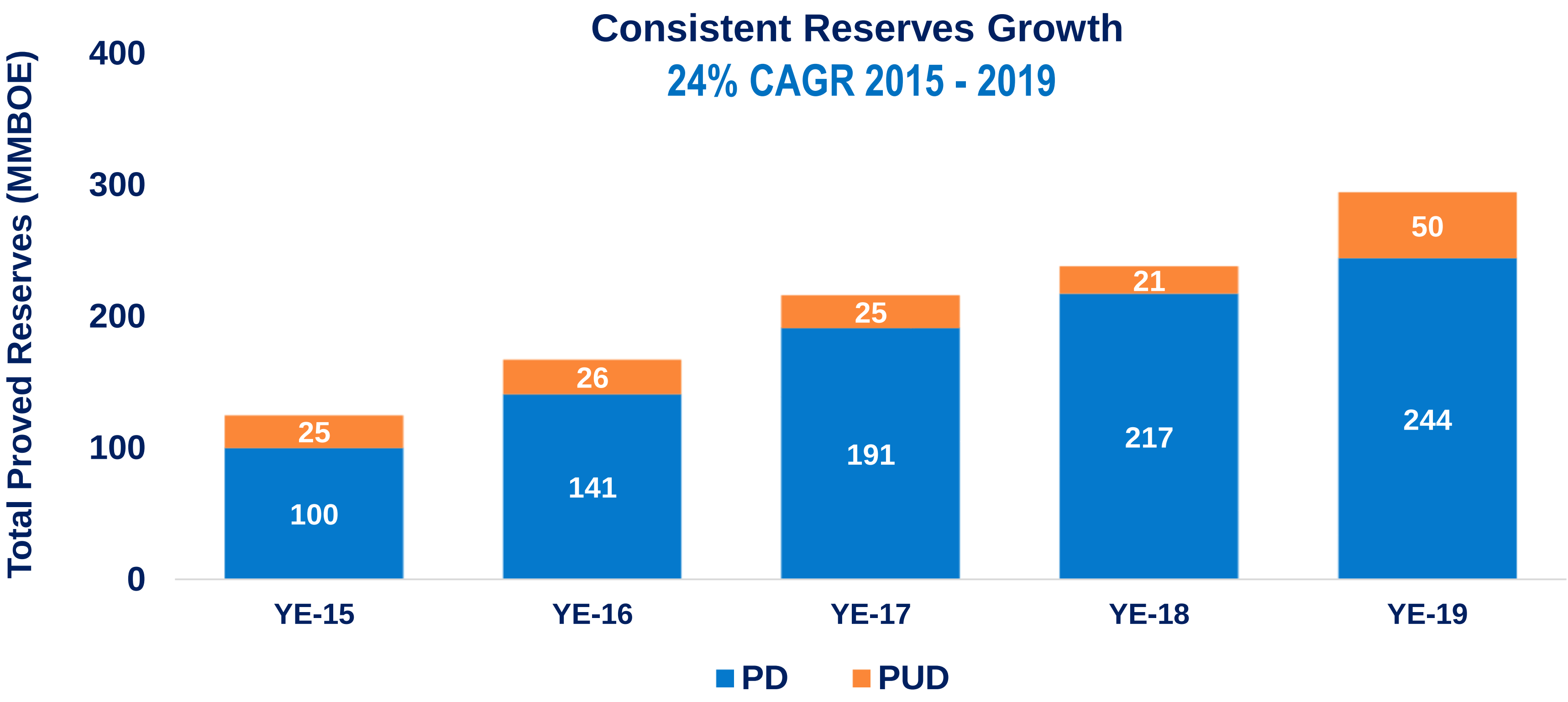
	C2 ($/Bbl)	C3 ($/Bbl)	IC4 ($/Bbl)	NC4 ($/Bbl)	C5+ ($/Bbl)	Composite ($/Bbl)
20-Apr	$5.45	$13.54	$13.95	$14.59	$14.54	$10.47
20-May	$6.96	$14.07	$13.68	$13.73	$15.80	$11.29
20-Jun	$6.93	$14.23	$13.55	$13.52	$15.59	$11.28
2Q-20 Average	$6.45	$13.95	$13.72	$13.94	$15.32	$11.02

Natural Gas:

	HH ($/MMBtu)	Waha ($/MMBtu)
Apr-20	$1.63	$0.21
May-20	$1.79	$1.20
Jun-20	$1.89	$1.56
2Q-20 Average	$1.77	$0.99

Note: Pricing assumptions as of 5-4-20

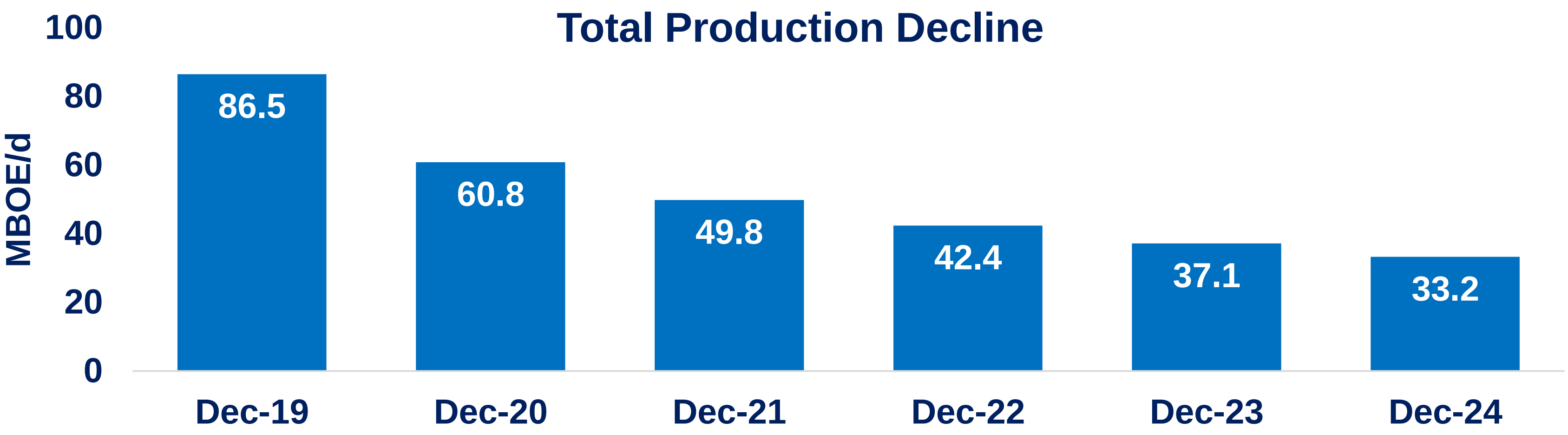
23% YoY Total Proved Reserves Growth in 2019

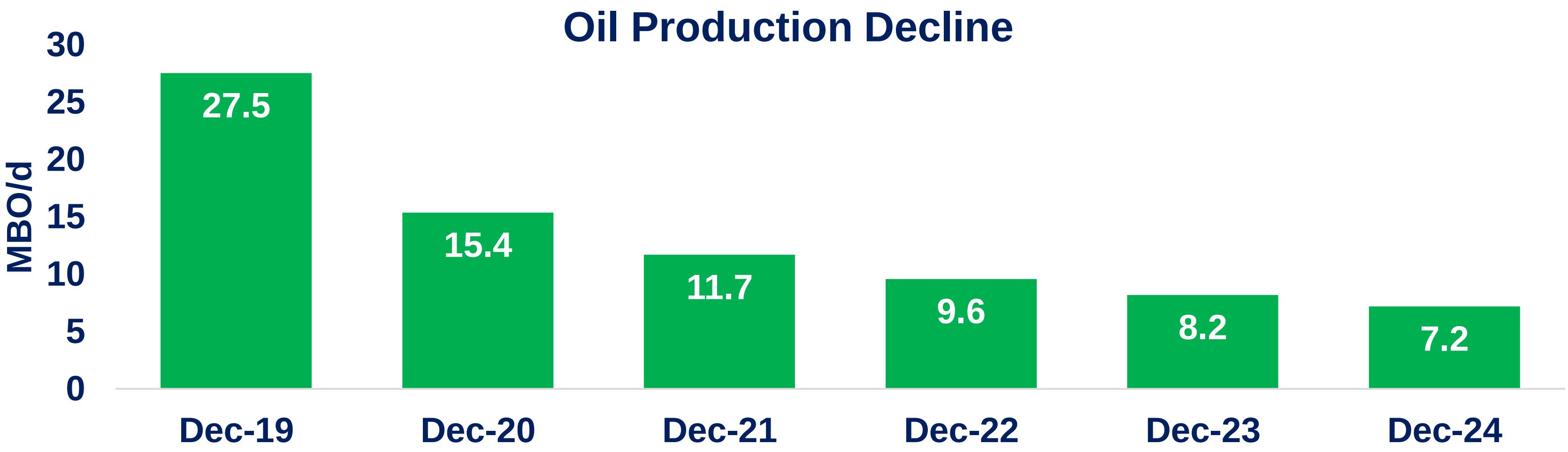


70% of YE-19 PUD locations booked in Howard County

Note: YE-15 to YE-19 3-stream Reserves prepared by Ryder Scott
See SEC form 10-K for the year ended 12-31-19 for a description of the Company's PUD booking methodology

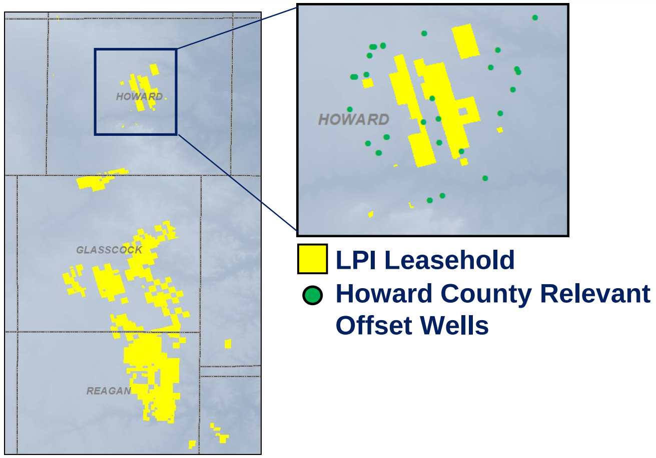
YE-19 Base Production Decline Expectations





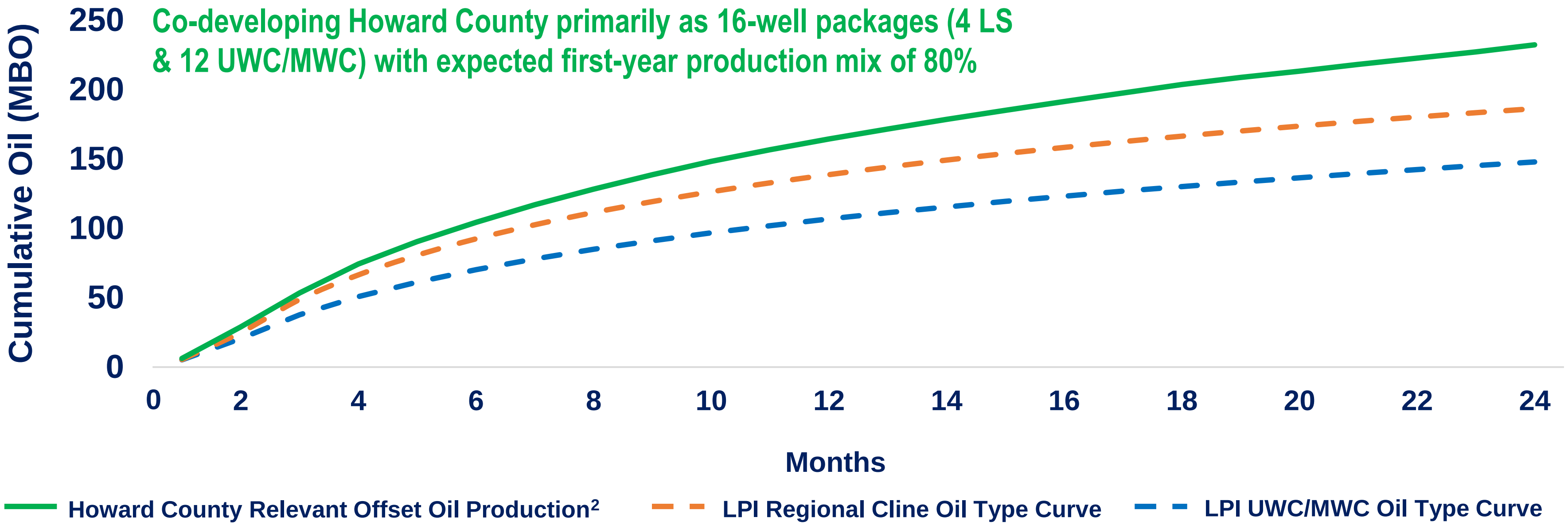
LAREDO PETROLEUM

Tier-One Howard County Acquisitions



Howard County Acquisitions	#1	#2	Total
Purchase Price ($ MM)	$130[1]	$22.5	$155.5
Net Acres	7,360	1,100	8,380
Net Royalty Acres	750	0	750
Gross Locations	120	10	130
Net Locations	100	24	124
Closing Date	Dec-19	Feb-20	

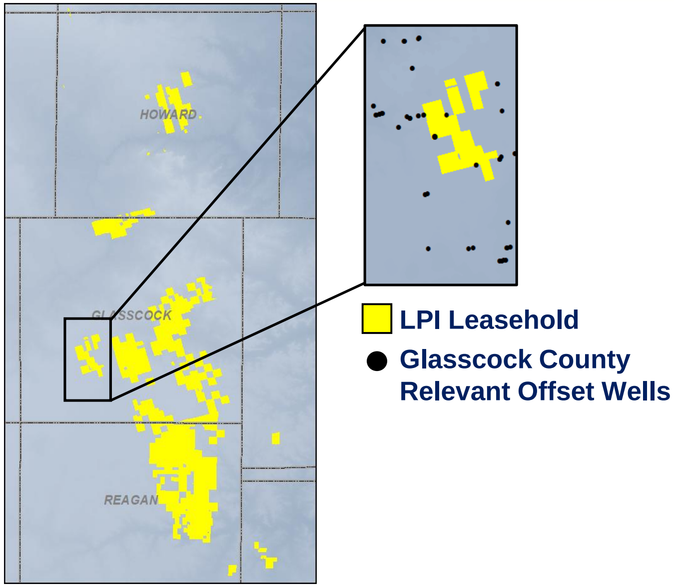
Howard County Relevant Offset Cumulative Oil Production Compared to Established Acreage



[1]Pursuant to the terms of the purchase agreement, if the average WTI crude price exceeds $60/BO for the year ending 12-31-20, the Company is obligated to pay the seller $20 MM
[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: As of 03-31-20

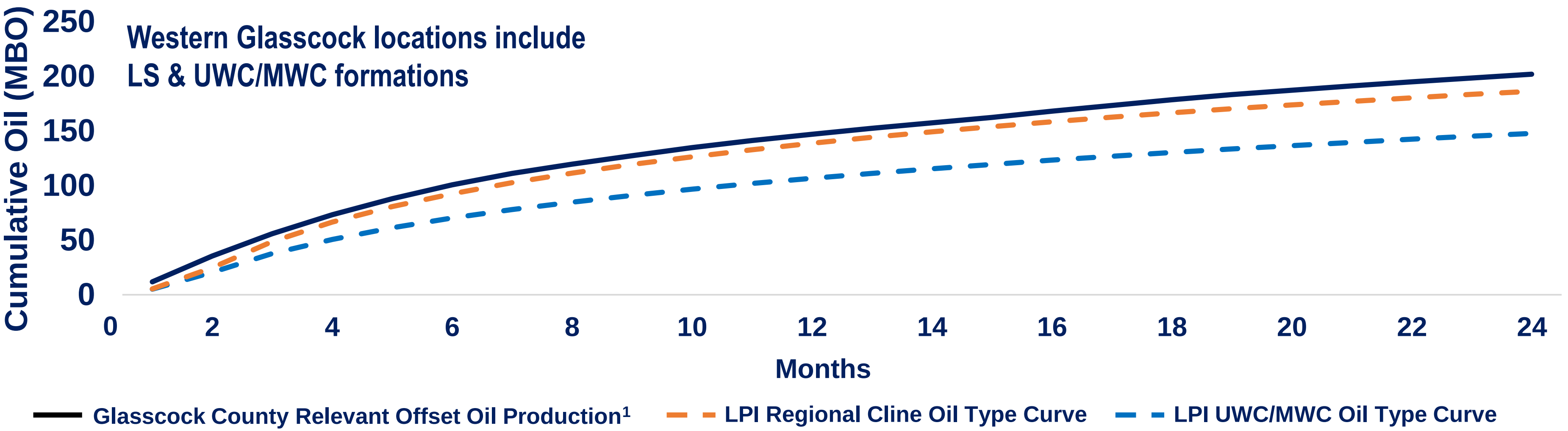
LAREDO PETROLEUM

Bolt-On Glasscock County Acquisition



W. Glasscock County Acquisition	Total
Purchase Price ($ MM)	$65
Net Acres	4,475
Net Production, BOE/d (% oil)	1,400 (55%)
Gross Locations	45
Net Locations	36
Closing Date	Dec-19

W. Glasscock Relevant Offset Cumulative Oil Production Compared to Established Acreage



[1]Glasscock County Relevant Offset cumulative oil production normalized to time 0 start and 10,000', courtesy of Enverus and internal data (as of 10-28-19)
Note: As of 03-31-20

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 income taxes, depletion, depreciation and amortization, impairment expense, 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 future discretionary use because those funds are required for future 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 (loss) (GAAP) to Adjusted EBITDA (non-GAAP):

	Three months ended,			
(in thousands, unaudited)	6/30/19	9/30/19	12/31/19	3/31/20
Net income (loss)	$173,382	($264,629)	($241,721)	$235,095
Plus:				
Share-settled equity-based compensation, net	—	—	—	2,376
Non-cash stock-based compensation, net	(423)	(1,739)	3,046	—
Depletion, depreciation and amortization	65,703	69,099	67,846	61,302
Restructuring expense	10,406	5,965	—	—
Impairment expense	—	397,890	222,999	26,250
Mark-to-market on derivatives:				—
(Gain) loss on derivatives, net	(88,394)	(96,684)	57,562	(297,836)
Settlements received (paid) for matured derivatives, net	23,480	25,245	14,394	47,723
Settlements paid for early terminations of derivatives, net	(5,409)	—	—	—
Premiums paid for derivatives	(2,233)	(1,415)	(1,399)	(477)
Accretion expense	1,020	1,005	1,041	1,106
(Gain) loss on disposal of assets, net	670	(1,294)	(67)	602
Interest expense	15,765	15,191	15,044	24,970
Litigation settlement	(42,500)	—	—	—
Loss on extinguisment of debt	—	—	—	13,320
Deferrred income tax expense	1,751	—	—	—
Write-off of debt issuance costs	—	—	935	—
Income tax (benefit) expense	—	(2,467)	(1,776)	2,417
Adjusted EBITDA	$153,218	$146,167	$137,904	$116,848

LAREDO PETROLEUM

Supplemental Financial Calculations

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 previous slide for a definition of Adjusted EBITDA and for a reconciliation of Net Income to Adjusted EBITDA. Our measurements of Adjusted EBITDA for financial reporting as compared to compliance under our debt agreements differ.

Liquidity

Calculated as the Company's outstanding borrowings on its senior secured credit facility, less outstanding letters of credit, plus cash and cash equivalents.

Free Cash Flow

Calculated as the Company's outstanding borrowings on its senior secured credit facility, less outstanding letters of credit, plus cash and cash equivalents.

Free Cash Flow is a non-GAAP financial measure that does not represent funds available for future discretionary use because those funds are required for future debt service, capital expenditures, 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 the operating trends in its business due to 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 different methods of calculating Free Cash Flow reported by different companies.