LAREDO PETROLEUM

February 2020 Corporate Presentation

Forward-Looking / Cautionary Statements

This presentation, including any oral statements made regarding the contents of this presentation, contains forward-looking statements as defined under Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, that address activities that Laredo Petroleum, Inc. (together with its subsidiaries, the “Company”, “Laredo” or “LPI”) assumes, plans, expects, believes, intends, projects, 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, long-term performance of wells, drilling and operating risks, the increase in service and supply costs, tariffs on steel, pipeline transportation constraints in the Permian Basin, 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 presentation, the Company may use the terms “resource potential,” “estimated ultimate recovery” (“EURs”) or “type curve,” each of which the SEC guidelines restrict from being included in filings with the SEC without strict compliance with SEC definitions. These terms refer to the Company’s internal estimates of unbooked hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. “Resource potential” is used by the Company to refer to the estimated quantities of hydrocarbons that may be added to proved reserves, largely from a specified resource play potentially supporting numerous drilling locations. A “resource play” is a term used by the Company to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section potentially supporting numerous drilling locations, which, when compared to a conventional play, typically has a lower geological and/or commercial development risk. EURs are based on the Company’s previous operating experience in a given area and publicly available information relating to the operations of producers who are conducting operations in these areas. Unbooked resource potential or EURs do not constitute reserves within the meaning of the Society of Petroleum Engineer’s Petroleum Resource Management System or SEC rules and do not include any proved reserves. Actual quantities of reserves that may be ultimately recovered from the Company’s interests may differ substantially from those presented herein. Factors affecting ultimate recovery include the scope of the Company’s ongoing drilling program, which will be directly affected by the availability of capital, decreases in oil, natural gas liquids and natural gas prices, well spacing, drilling costs and production costs, availability and costs of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals, negative revisions to reserve estimates and other factors as well as actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of EURs may change significantly as development of the Company’s core assets provides additional data. In addition, our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases. “Type curve” refers to a production profile of a well, or a particular category of wells, for a specific play and/or area. In addition, the Company’s production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases. The “standardized measure” of discounted future new cash flows is calculated in accordance with SEC regulations and a discount rate of 10%. The actual results may vary considerably and should not be considered to represent the fair market value of the Company’s proved reserves.

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

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.

Pivoted Strategy Transforming Laredo

Delivering sustainable oil production growth and Free Cash Flow[1]

Surpassed Expectations in 2019

- Generated $60 MM in Free Cash Flow[1] vs initial expectation of Cash Flow[1] neutrality
- Grew oil production 2% YoY vs original expectation of a 5% decrease

Acquisitions Expected to Increase Returns

- Added 175 gross tier-one locations, driving expected corporate oil mix to 40% by YE-21
- Improved capital efficiency enables anticipated mid-single digit annual oil production growth in 2021 & 2022 with 15% to 20% less capital vs 2020

Low-Cost Operations Improve Margins

- LOE/BOE 39% below Permian peers[2]
- Operational efficiencies drive D&C costs among the lowest in the Midland Basin[3]

Actively Manage Financial Risk

- Extended high-yield debt maturities to 2025
- FY-20 derivatives position value of $150+ MM at $50/Bbl WTI

[1]See Appendix for reconciliations of non-GAAP measures
[2]Peer data as of most recent SEC filing (3Q-19 or 4Q-19) and includes: CDEV, CPE, MTDR, QEP, SM
[3]Source: RSEG 1-21-20 2019 average lateral cost per foot. Peers include: APA, CPE, CVX, CXO, ECA, ESTE, FANG, OXY, PE, PXD, QEP, SM and XOM

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Pivoted Strategy to Increase 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

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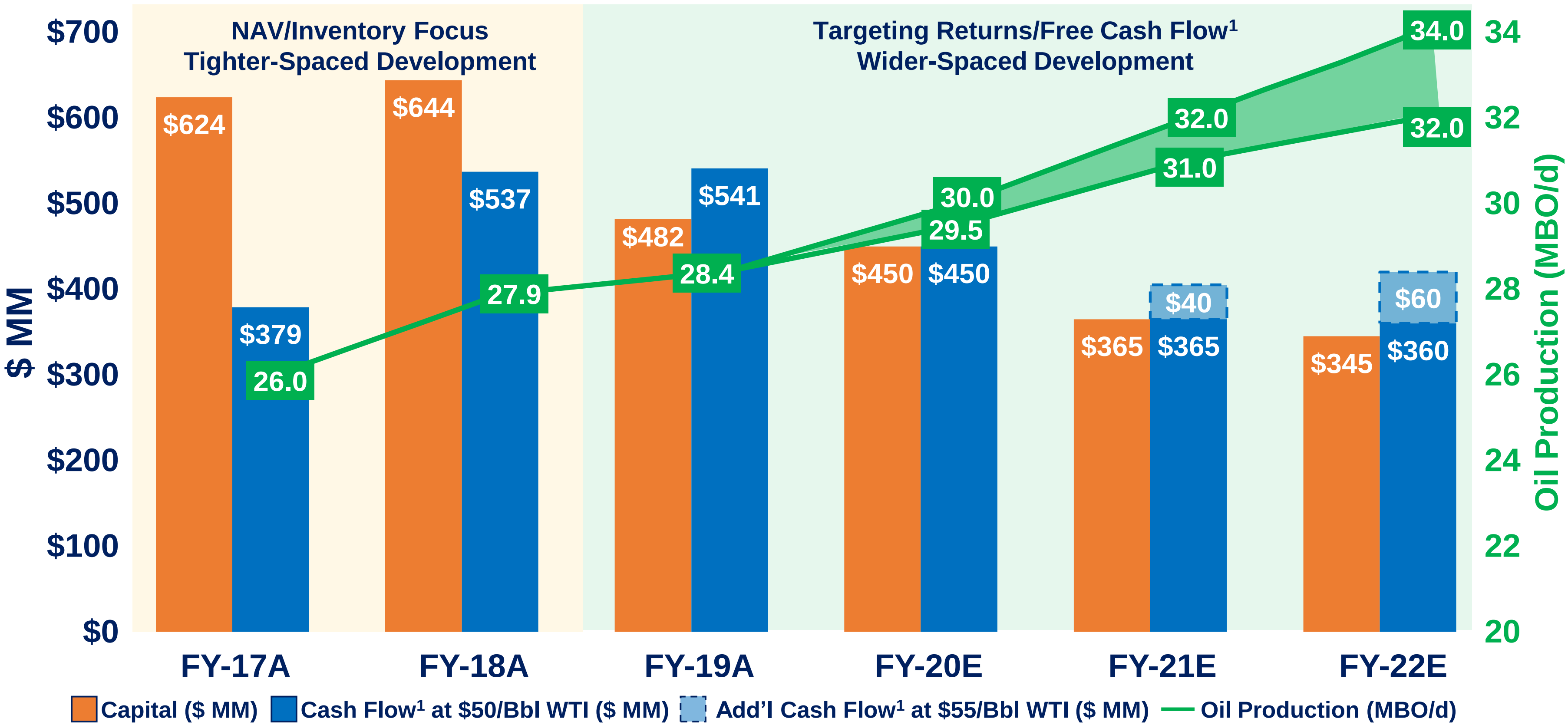
[1]See Appendix for reconciliations of non-GAAP measures

Delivering on Returns-Focused Strategy

- Mid-single digit annual oil growth expected for FY-20E - FY-22E
- 40% oil mix anticipated by YE-21
- Free Cash Flow[1] earmarked for debt repayment



Tier-one inventory acquisitions position Company for oil growth & Free Cash Flow[1] generation

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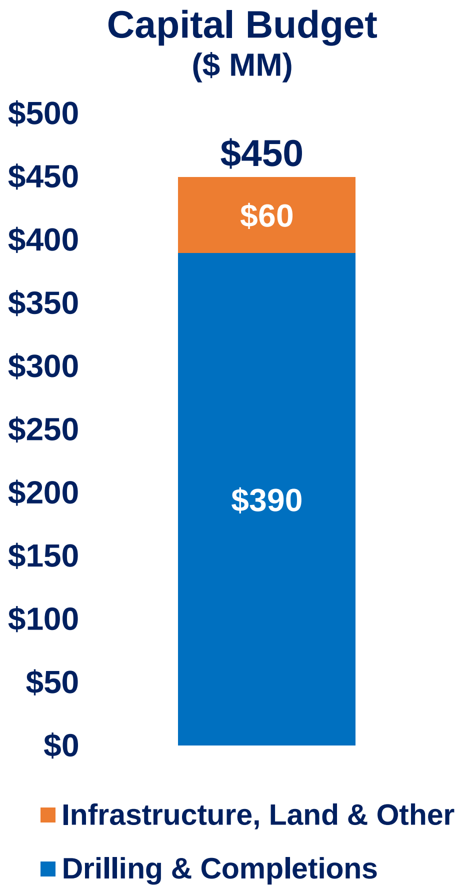
[1]See Appendix for reconciliations of non-GAAP measures; Cash flow estimates assume WTI as described, $2.25/MMBtu HH and excludes non-budgeted acquisitions

2020 Capital Budget Expectations

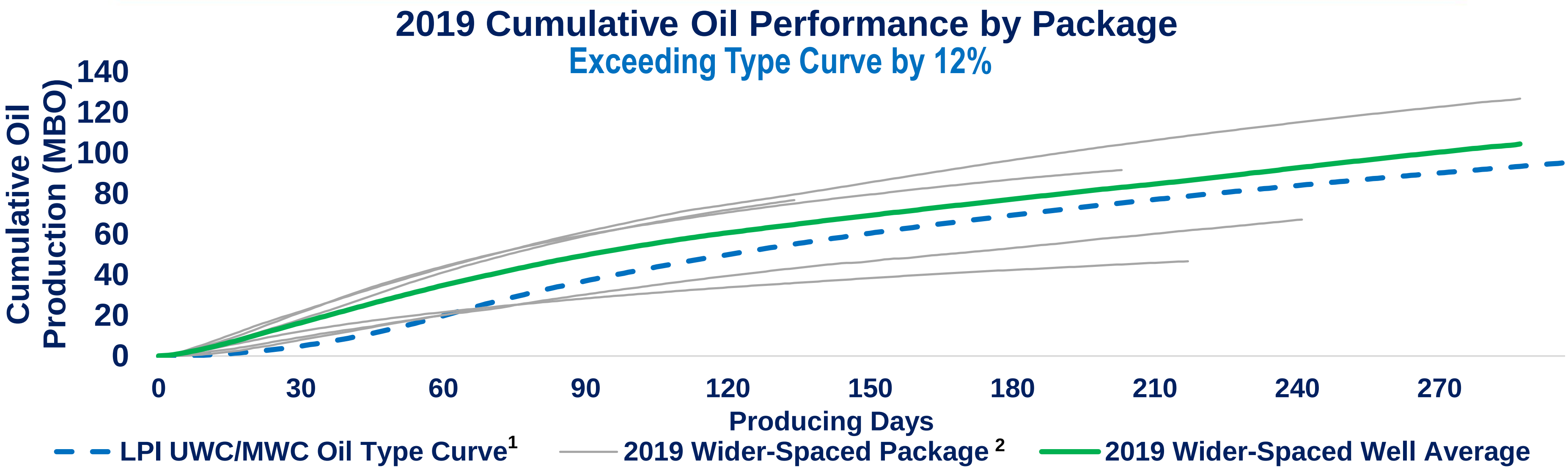


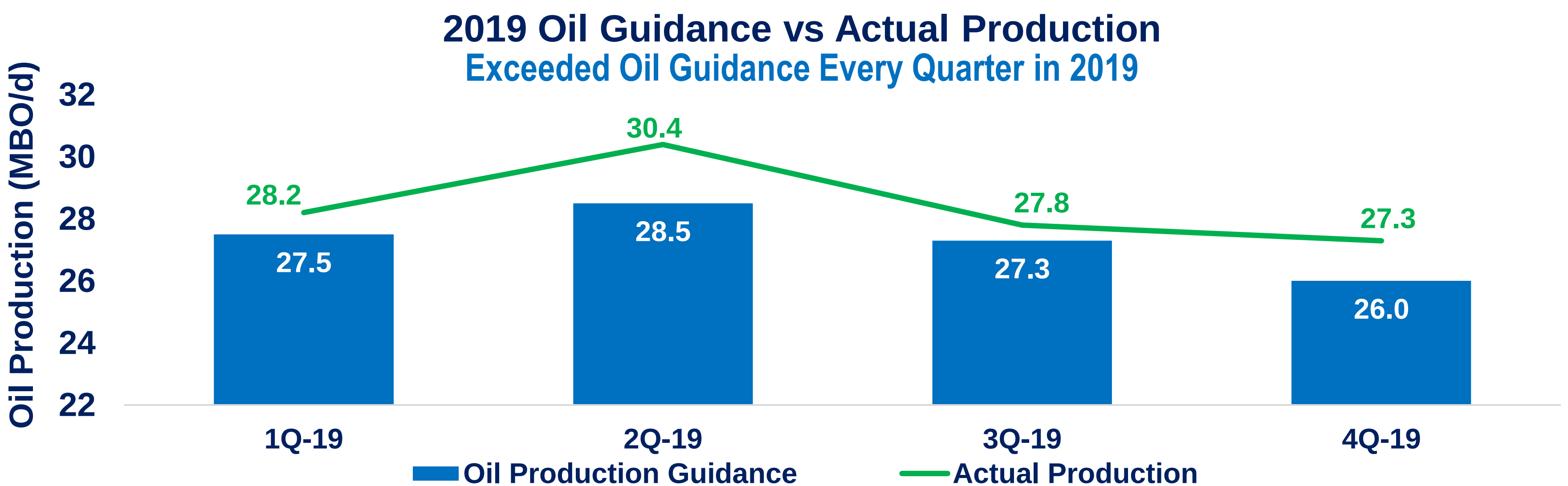
	1Q-20E	2Q-20E	3Q-20E	4Q-20E	FY-20E
Drilling Rigs	3.9	3.2	2.0	2.0	2.8
Spuds	26	21	14	13	74
% Howard County	*50%*	*100%*	*100%*	*100%*	*82%*
Completion Crews	1.8	1.0	1.0	0.6	1.1
Completions	28	11	10	15	64
% Howard County	*0%*	*55%*	*100%*	*100%*	*48%*
Total Capital	$175	$120	$90	$65	$450
Working Interest					99%
Lateral Length					9,000’

Plan to adjust activity to balance Cash Flow[1] and capital expenditures

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

Wider-Spaced Packages Support Consistent Oil Outperformance

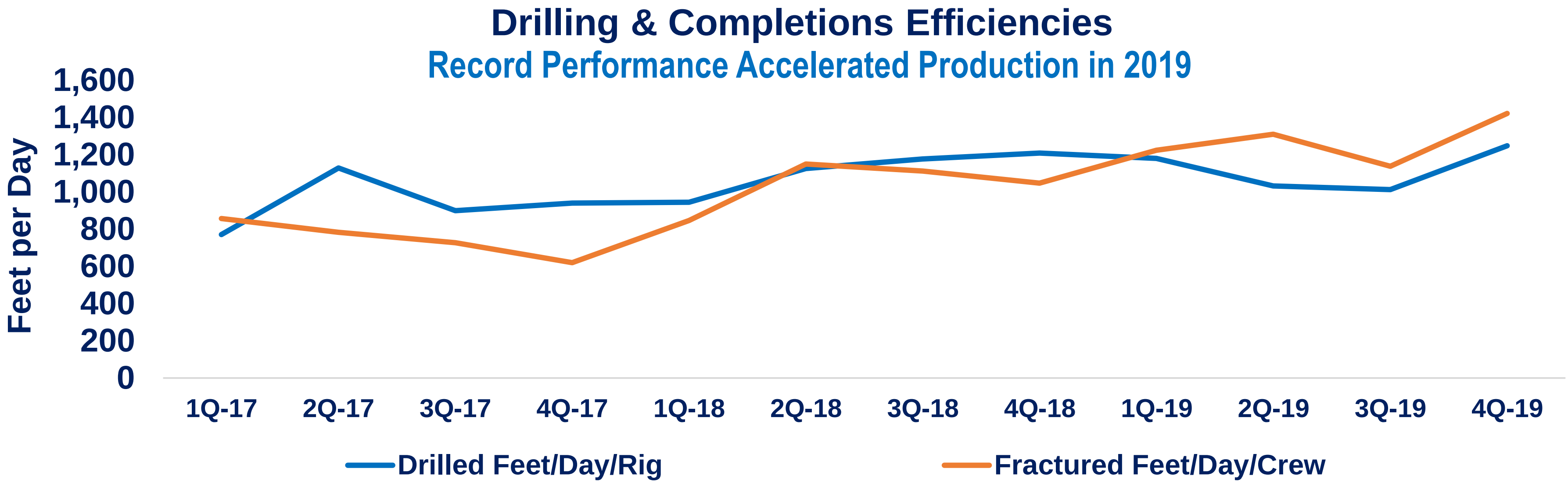


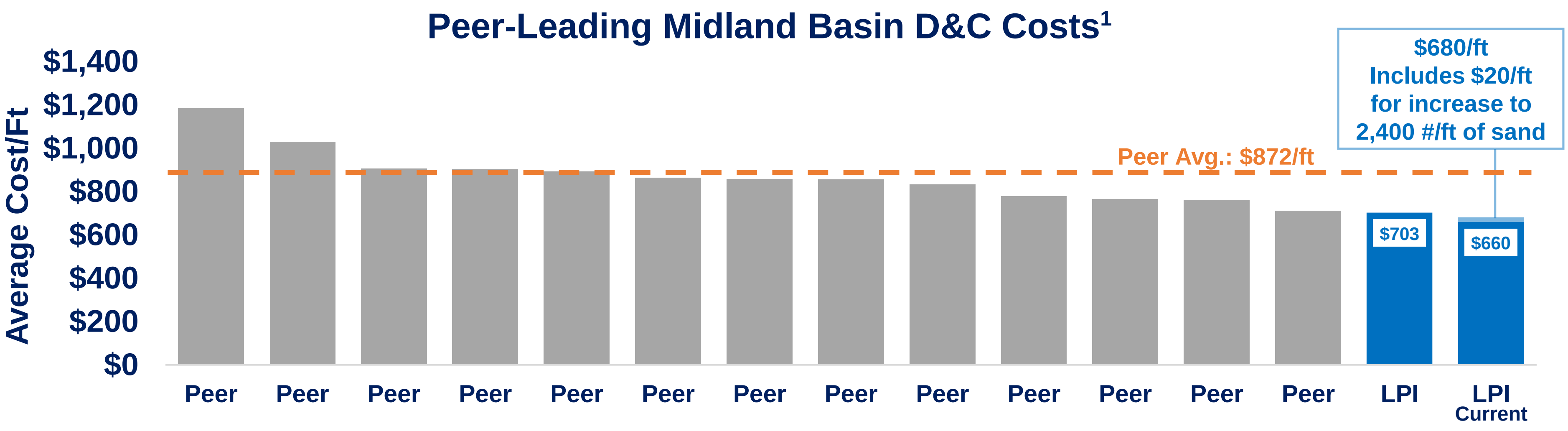


[1]UWC/MWC 1.3 MMBOE type curve (400 MBO) representative of a 10,000' well, utilizing a 1.2 b-factor

[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); All wells show cumulative oil production, normalized to a 10,000' lateral, as of 2-6-20

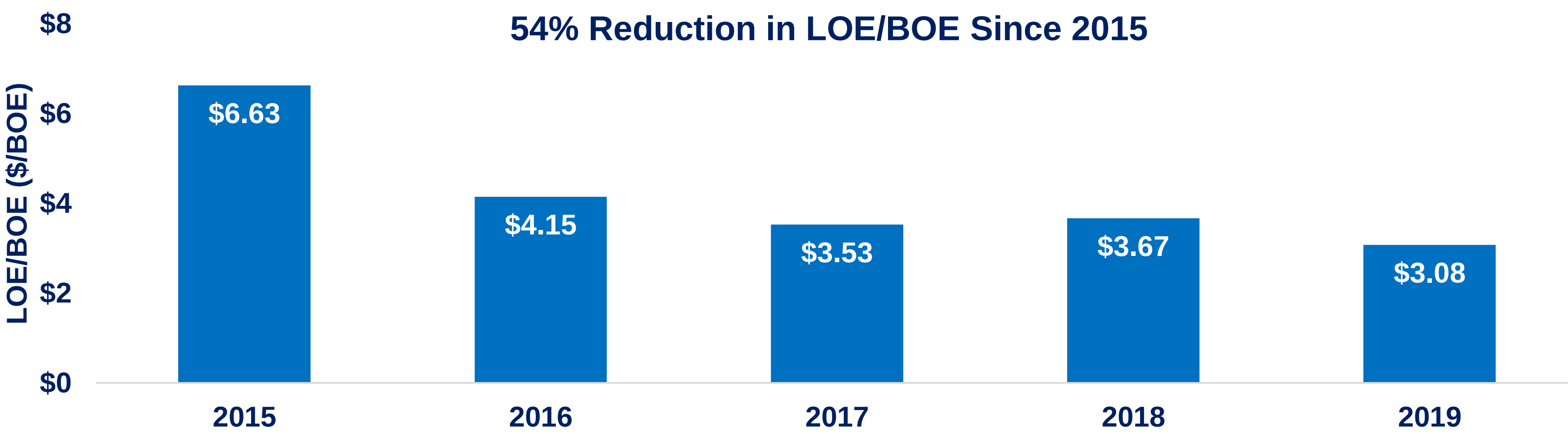
Operational Efficiencies Drive Peer-Leading Capital Costs



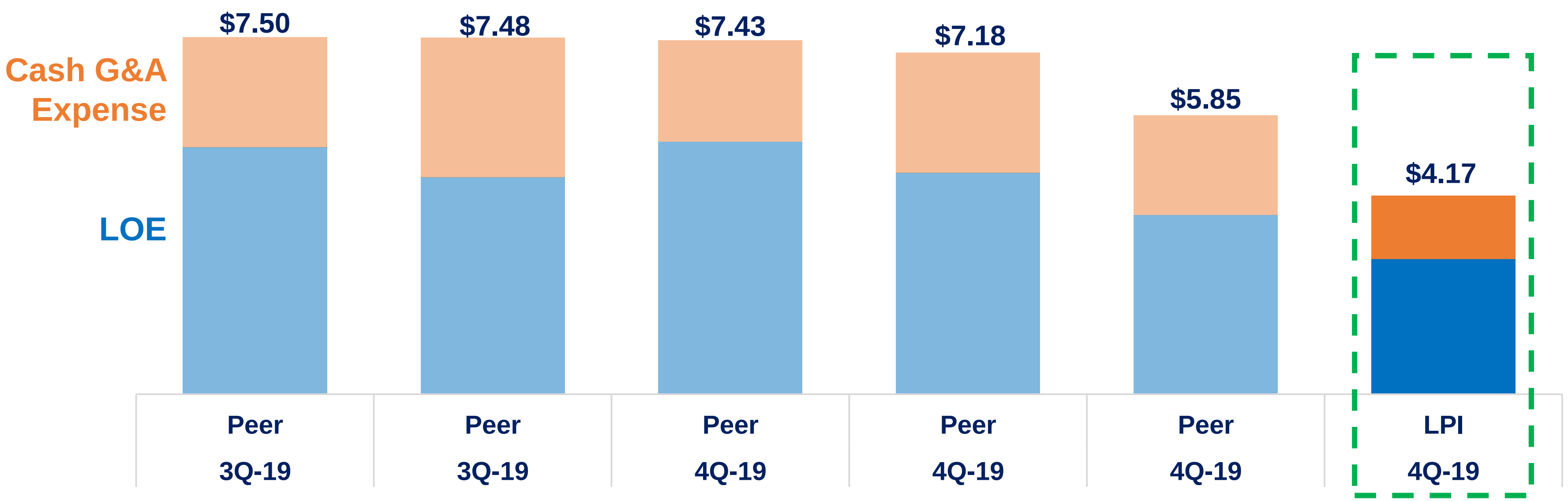


[1]Source: RSEG 1-21-2020 2019 average lateral cost per foot. Peers include: APA, CPE, CVX, CXO, ECA, ESTE, FANG, OXY, PE, PXD, QEP, SM and XOM; LPI Current per internal data

Demonstrated Management of Controllable Cash Costs



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



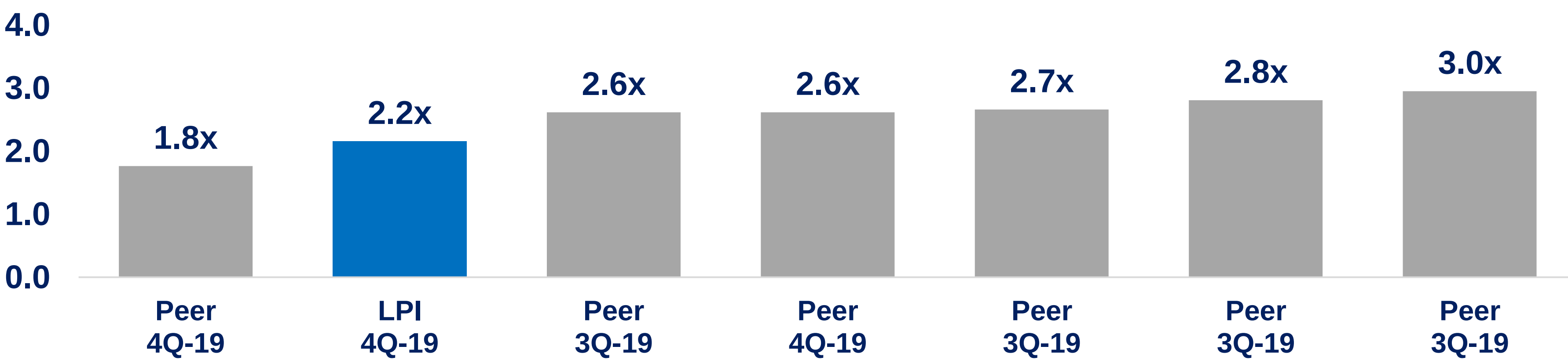
[1]Peer data as of most recent SEC filing (3Q-19 or 4Q-19) and includes: CDEV, CPE, MTDR, QEP, SM

Disciplined Acquisition Strategy, Committed to a Strong Balance Sheet

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

- **High-margin, higher-return (50+% oil) 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 to a level at or below pre-acquisitions level**

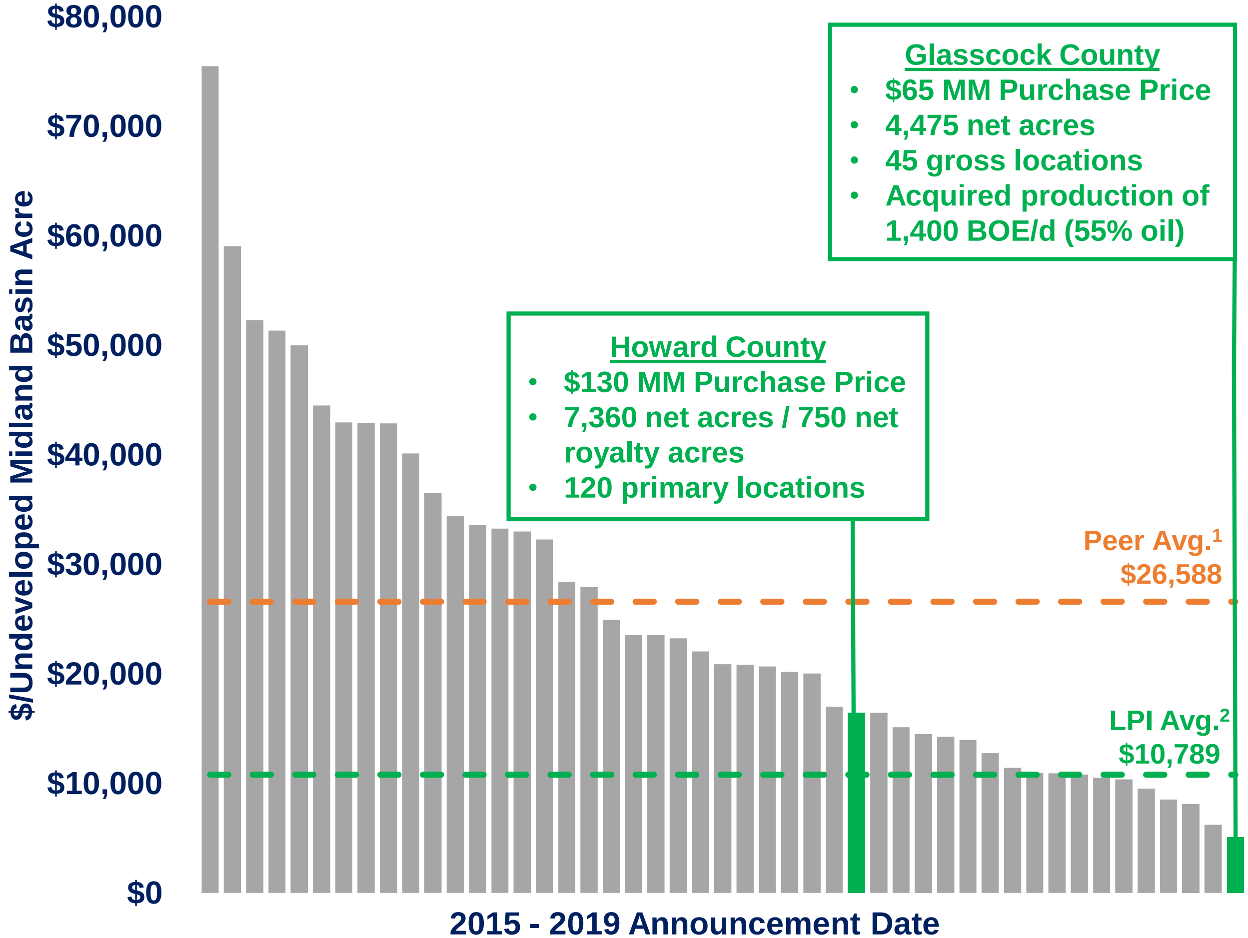
Net Debt to TTM Adjusted EBITDA[2]

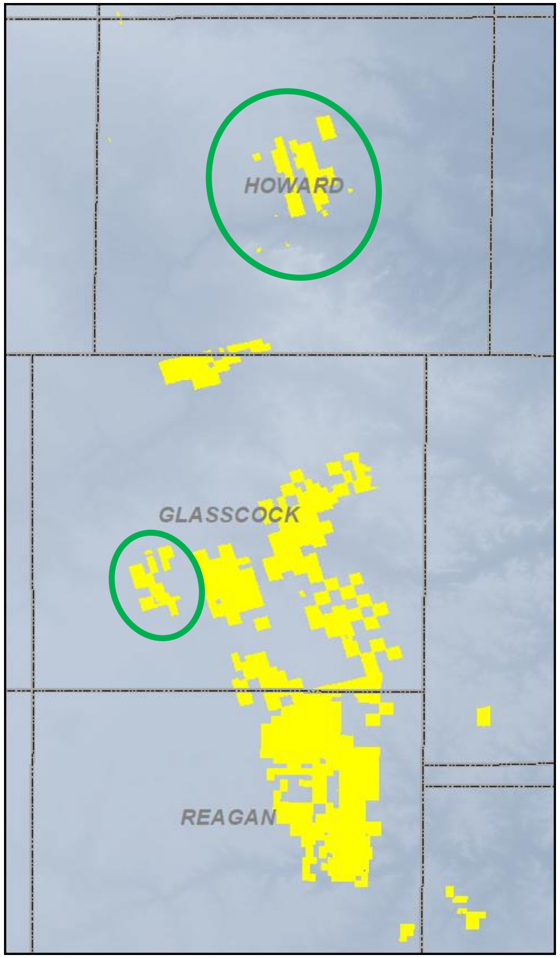


[1]See Appendix for reconciliations of non-GAAP measures; [2]Peers are as of most recent SEC filing (3Q-19 or 4Q-19), and include CDEV, CPE PF (pro forma for the CRZO acquisition), MTDR, OAS, QEP, and SM. Peer company Net Debt is calculated using each peer company's cash, total debt and preferred equity as they appear in such peer company's most recent SEC filing (note: CPE is presented pro forma for the CRZO acquisition). Peer company TTM Adjusted EBITDA is as presented in each company's most recent SEC filing. Net Debt and Adjusted EBITDA are non-GAAP financial measures, and each company's calculation of Adjusted EBITDA may therefore not be directly comparable to that of another company's. LPI includes FY-19 TTM Adjusted EBITDA and net debt as of 2-11-20

Laredo's Recent Acquisitions at Discount to Precedent Transactions

Focused on employing a disciplined approach to acquisition economic evaluation





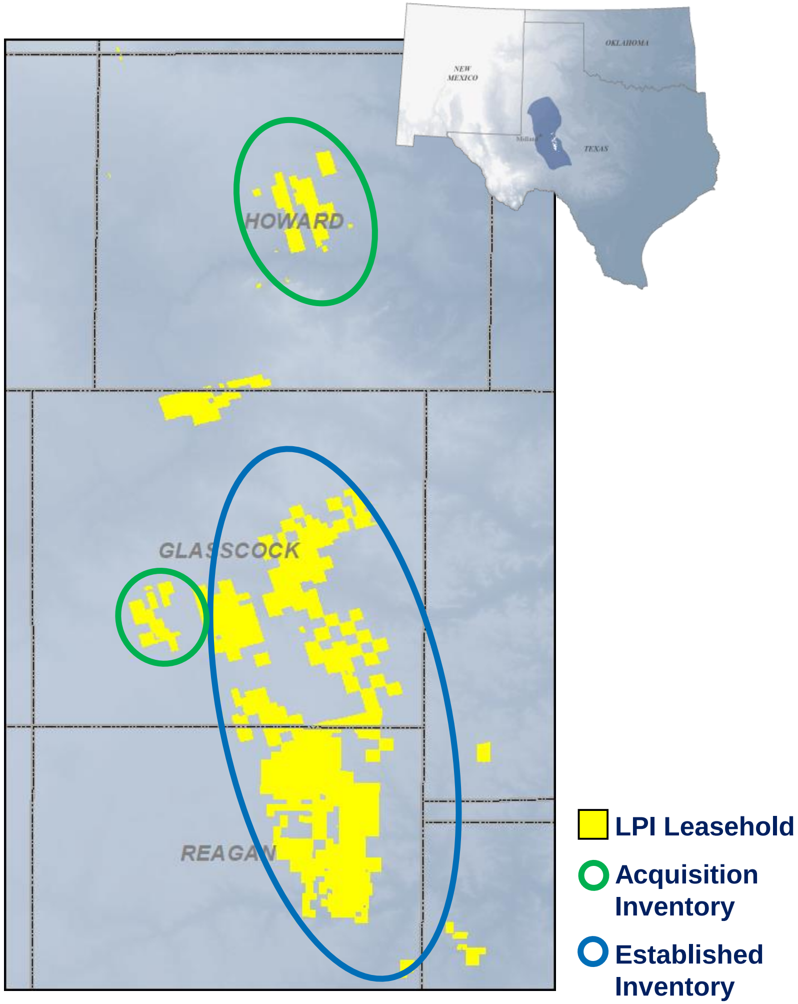
Note: Data from company disclosures and Enverus as of 12-11-19
[1]Includes all Midland basin transactions >$50 MM since 1-1-15
[2]Average of recently announced Glasscock and Howard acquisitions

Acquisitions Add Oily, High-Margin Inventory

Total Inventory (Acquired + Established)	
Inventory	Inventory Years
655 - 825	12.5

Acquired Inventory Lower Spraberry/UWC/MWC	
Inventory	Inventory Years
175	3

Established Inventory UWC/MWC	
Inventory	Inventory Years
350 - 500	7
Cline	
Inventory	Inventory Years
140 - 160	2.5



153,300 gross / 134,621 net acres

Acquired locations move to front of drill schedule

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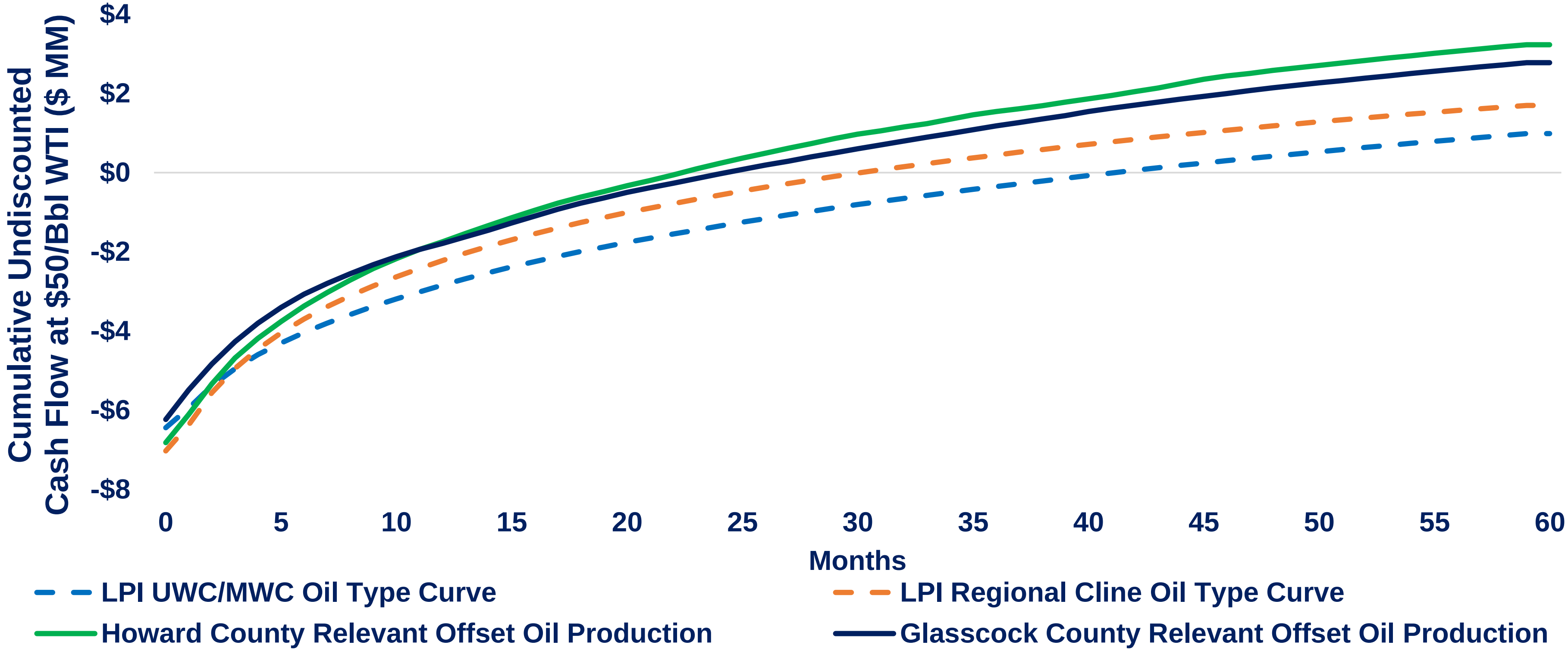
Note: Inventory expected to average oil type curve productivity
Inventory Years assumes 60 wells per year

Acquisitions Support Oil Growth & Free Cash Flow[1] Generation



	Established UWC/MWC Oil Type Curve		Established Cline Oil Type Curve		Glasscock County Acquisition Relevant Offset Oil Production		Howard County Acquisition Relevant Offset Oil Production	
WTI ($/Bbl)	$50	$55	$50	$55	$50	$55	$50	$55
24 Mo. Cumulative Oil (MBO)	148	148	186	186	202	202	232	232
ROR (%)	20%	28%	25%	36%	37%	51%	39%	54%
Payback Period (Months)	43	33	32	24	26	20	24	19

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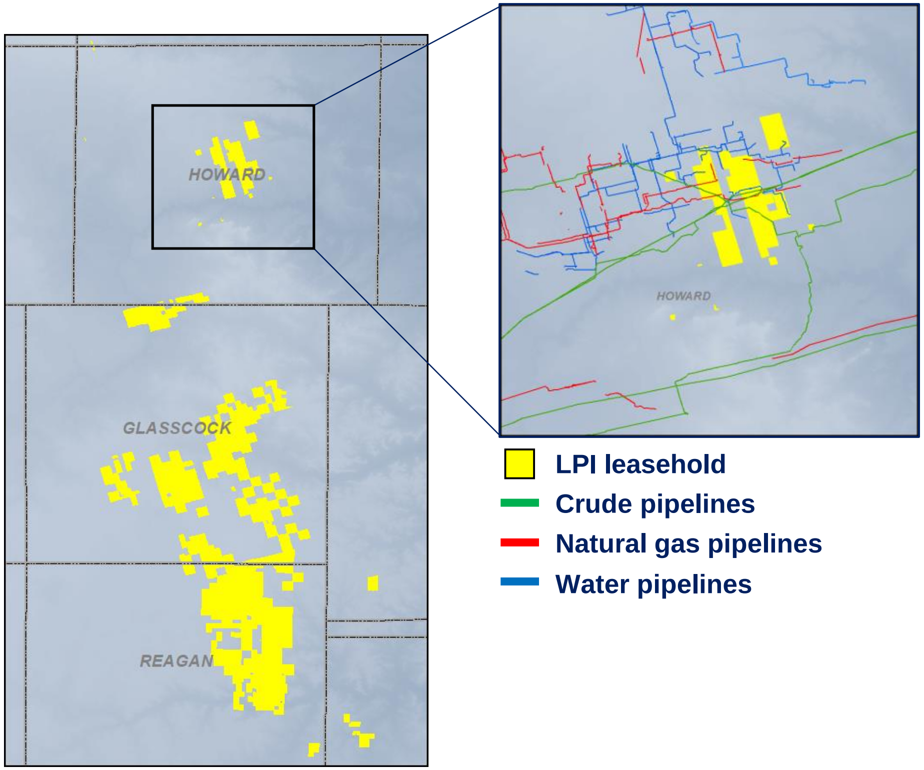
[1]See Appendix for reconciliations of non-GAAP measures
Note: Utilizes $2.25/MMBtu HH and standard completions design

Successfully Transitioning to Howard County



- **Operations transition is currently under way:**
  - **Three of four drilling rigs in Howard County, with fourth expected in Apr-20**
  - **First well of 15-well package has been drilled, completions beginning in 2Q-20E**
- **Current negotiations with multiple third-party service infrastructure providers indicate service costs similar to the established acreage**

Howard County Acquisitions	#1	#2	Current 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	

Acquisition prices are well below historic Howard County averages, with potential for additional bolt-on acquisitions

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

LPI Infrastructure Protects the Environment & Enhances Economics

Oil & Natural Gas Infrastructure

60 Miles
Crude oil gathering pipelines

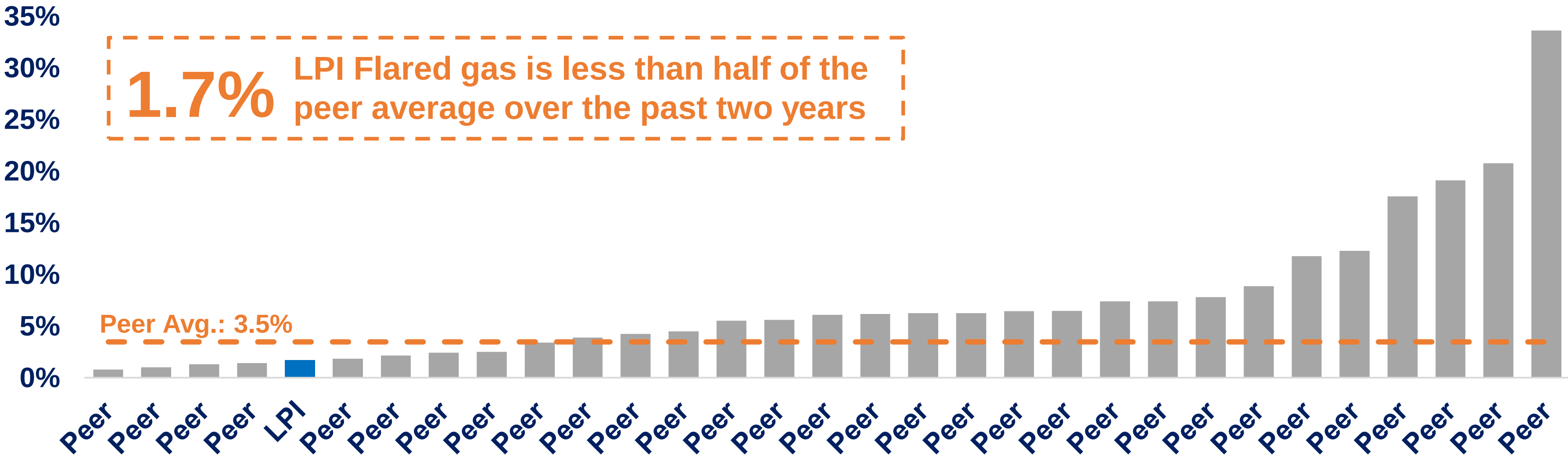
170 miles
Natural gas gathering and distribution pipelines

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 2-10-20, with data beginning as of January 2018; Peers include: APA, AXAS, BP, CDEV, COP, CPE, CVX, CXO, DVN, EOG, FANG, HALC, LLEX, MRO, MTDR, NBL, OAS, OVV, OXY, PDCE, PE, PXD, QEP, REI, ROSE, RYDAF, SM, WPX, XEC and XOM

Note: Existing infrastructure as of 1-1-20 and impact as of FY-19

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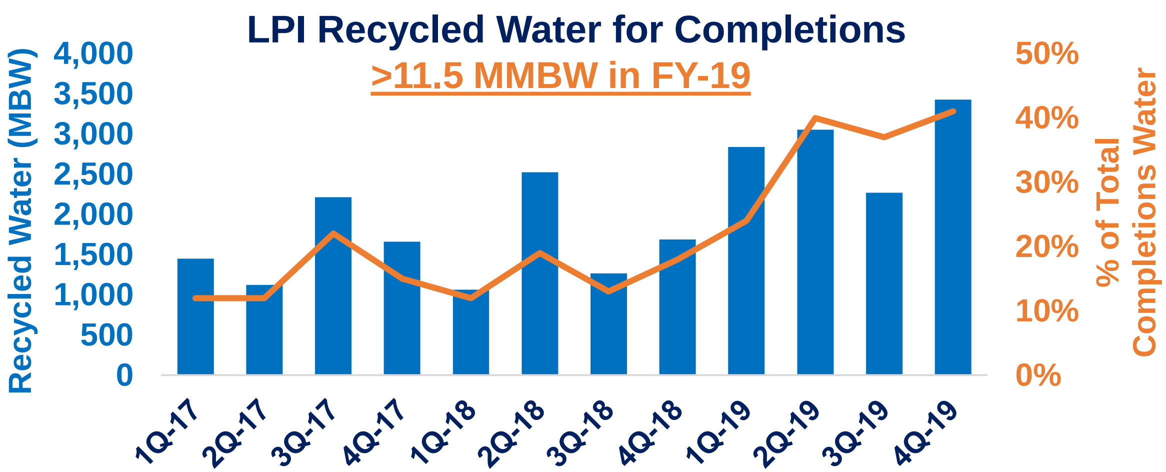
Significant Benefits through Water Infrastructure Investments

110 Miles
Water gathering & distribution pipelines

54 MBW/d
Produced water recycling capacity

22.5 MMBW
Owned or contracted storage capacity

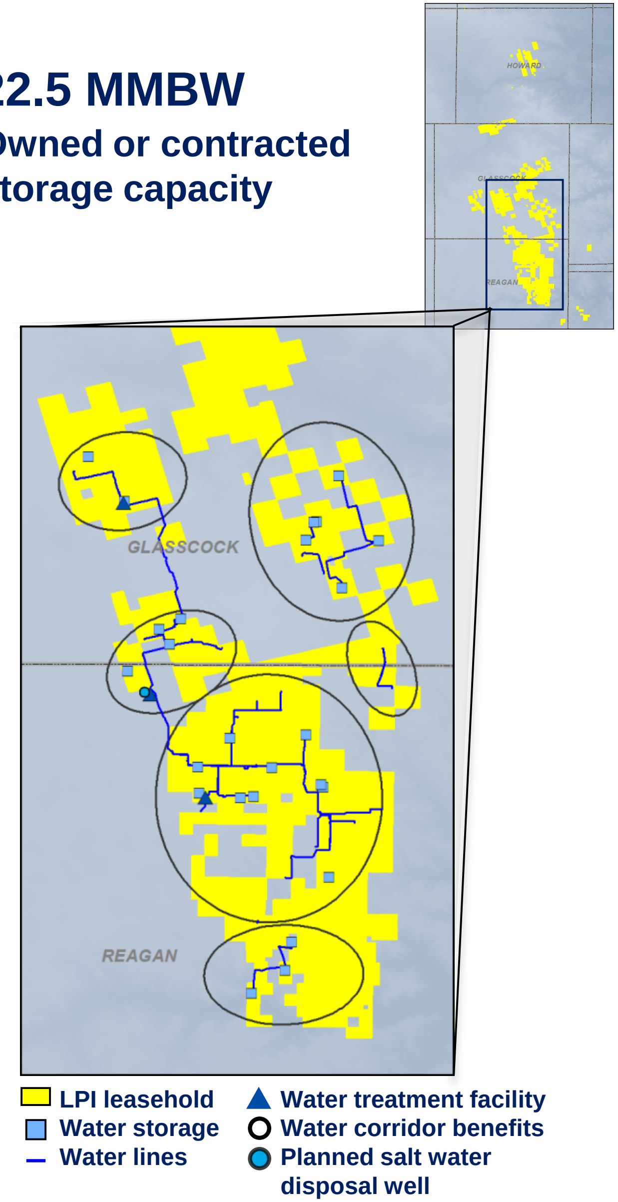


79% **23.5 MMBW**
Produced water gathered by pipe

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



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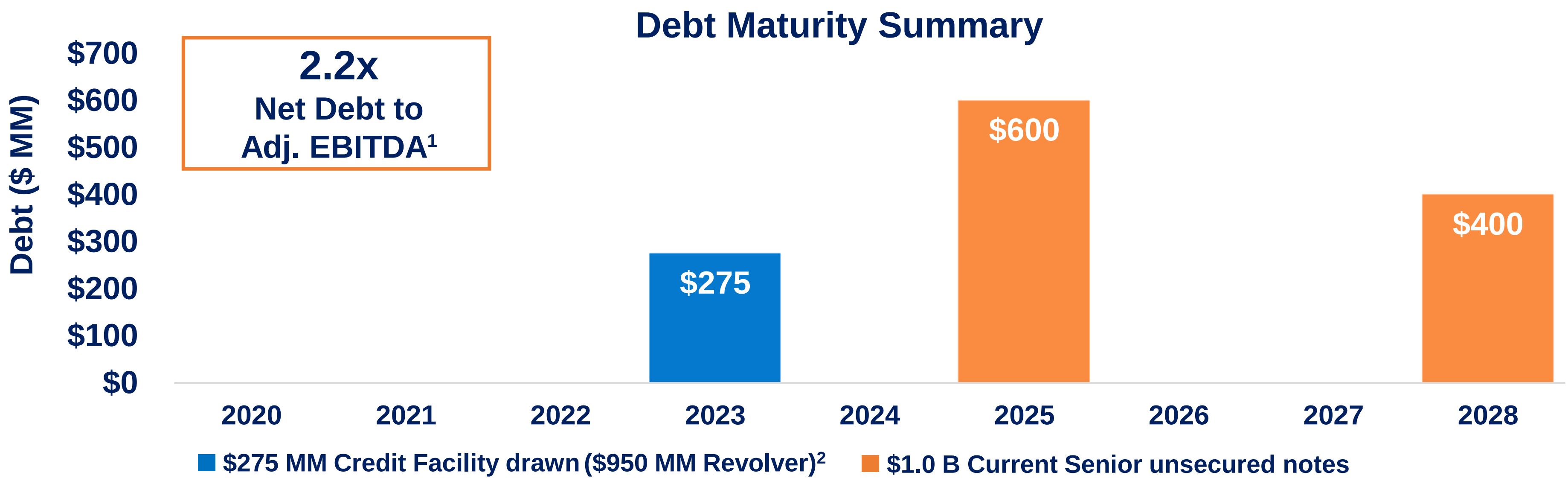
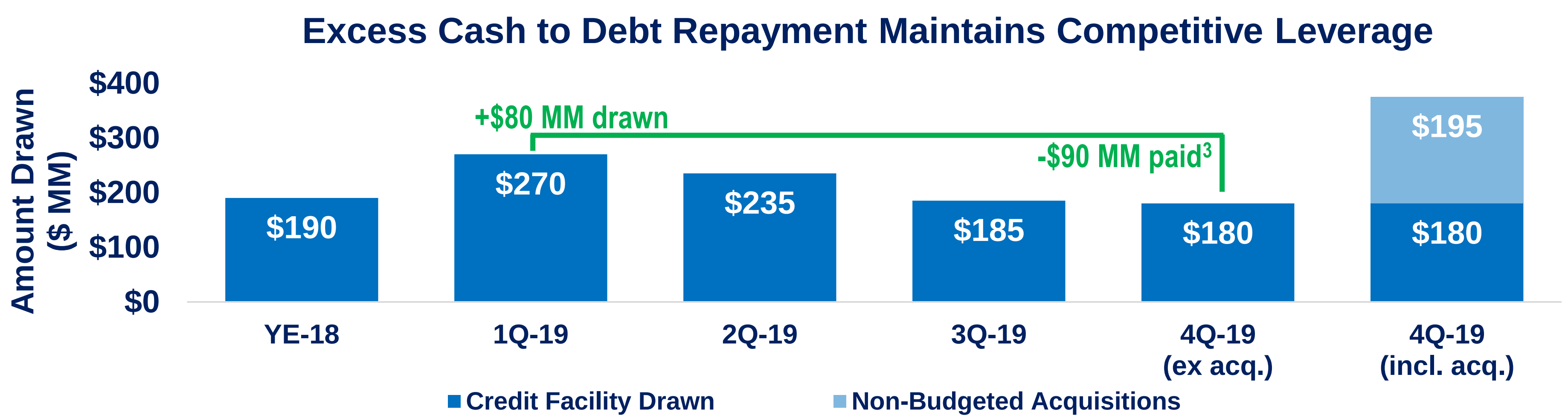
Note: Infrastructure statistics as of 1-1-20, infrastructure and financial impacts as of FY-19 and map as of 2-13-20
Financial benefits calculated utilizing a 95% WI & 72% NRI

Demonstrated Discipline Preserves Competitive Leverage





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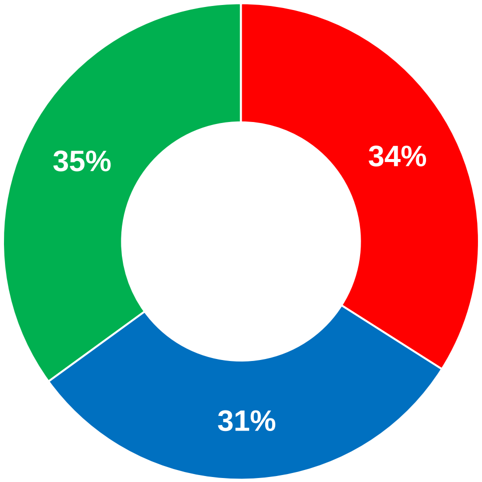
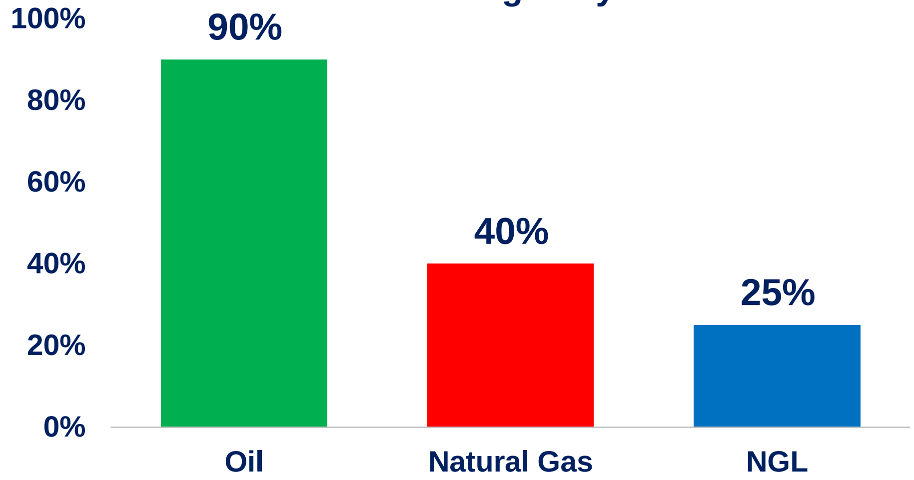
[1]See Appendix for reconciliations of non-GAAP measures; Includes TTM Adjusted EBITDA as of 12-31-19 and net debt as of 2-11-20; [2]LPI issued $1 B of new senior unsecured notes in Jan-20, with the net proceeds to be used to redeem its previously-existing $800 MM of outstanding senior unsecured notes and to partially repay its senior unsecured credit facility. In conjunction with the closing of the notes issuance, LPI's borrowing base in place under its Fifth Amended and Restated Senior Secured Credit Facility was reduced to ~$950 MM; Amount drawn is as of 2-11-20; [3]Excluding non-budgeted acquisitions

Derivatives Position Underpins 2020 Cash Flow[1]

FY-20E Product Mix

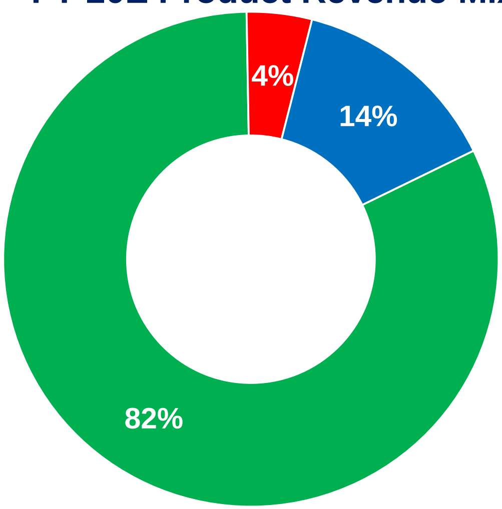


FY-20E % Hedged by Product

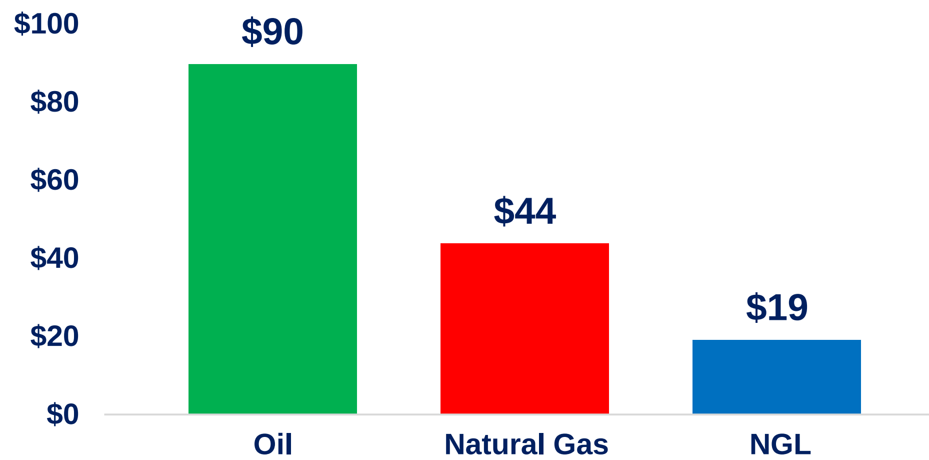


Oil
Natural Gas
NGLs

FY-20E Product Revenue Mix



Value of 2020 Derivatives Contracts at $50/Bbl WTI & $2.25/MMBtu HH



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

APPENDIX

Guidance

Production:	1Q-20	FY-20
Total production (MBOE/d)	81.2 - 81.7	85.5 - 87.0
Oil production (MBbl/d)	26.8 - 27.3	29.5 - 30.0
Average sales price realizations: *(excluding derivatives)*		
Oil (% of WTI)	100%	
NGL (% of WTI)	14%	
Natural gas (% of Henry Hub)	13%	
Other ($ MM):		
Net income / (expense) of purchased crude oil	($4.0)	
Net midstream income / (expense)	$1.5	
Operating costs & expenses ($/BOE):		
Lease operating expenses	$3.00	
Production and ad valorem taxes *(% of oil, NGL and natural gas revenues)*	6.50%	
Transportation and marketing expenses	$2.15	
General and administrative expenses:		
Cash	$1.60	
Non-cash stock-based compensation, net	$0.55	
Depletion, depreciation and amortization	$9.00	

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Oil, Natural Gas & Natural Gas Liquids Hedges

Hedge Product Summary	FY-20	FY-21
Oil total volume (Bbl)	9,552,600	1,460,000
Oil wtd-avg price ($/Bbl) - WTI	$59.50	
Oil wtd-avg price ($/Bbl) - Brent	$63.07	$60.16
Nat gas total volume (MMBtu)	23,790,000	14,052,500
Nat gas wtd-avg price ($/MMBtu) - HH	$2.72	$2.63
NGL total volume (Bbl)	2,562,000	2,202,775

Oil Swaps	FY-20	FY-21
WTI		
Volume (Bbl)	7,173,600	
Wtd-avg price ($/Bbl)	$59.50	
Brent		
Volume (Bbl)	2,379,000	1,460,000
Wtd-avg price ($/Bbl)	$63.07	$60.16

Natural Gas Swaps	FY-20	FY-21
HH		
Volume (MMBtu)	23,790,000	14,052,500
Wtd-avg price ($/MMBtu)	$2.72	$2.63

Basis Swaps	FY-20	FY-21
Waha/HH		
Volume (MMBtu)	32,574,000	23,360,000
Wtd-avg price ($/MMBtu)	-$0.76	-$0.47

Natural Gas Liquids Swaps	FY-20	FY-21
Ethane		
Volume (Bbl)	366,000	912,500
Wtd-avg price ($/Bbl)	$13.60	$12.01
Propane		
Volume (Bbl)	1,244,400	730,000
Wtd-avg price ($/Bbl)	$26.58	$25.52
Normal Butane		
Volume (Bbl)	439,200	255,500
Wtd-avg price ($/Bbl)	$28.69	$27.72
Isobutane		
Volume (Bbl)	109,800	67,525
Wtd-avg price ($/Bbl)	$29.99	$28.79
Natural Gasoline		
Volume (Bbl)	402,600	237,250
Wtd-avg price ($/Bbl)	$45.15	$44.31

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Note: Open positions as of 1-1-20, hedges executed through 2-11-20
Natural gas liquids consist of Mt. Belvieu purity ethane and Mt. Belvieu non-TET propane, normal butane, isobutane, and natural gasoline

Budget Pricing

	WTI ($/Bbl) Base	WTI ($/Bbl) Upside	HH ($/MMBtu)
FY-20	$50.00	$50.00	$2.25
FY-21	$50.00	$55.00	$2.25
FY-22+	$50.00	$55.00	$2.25

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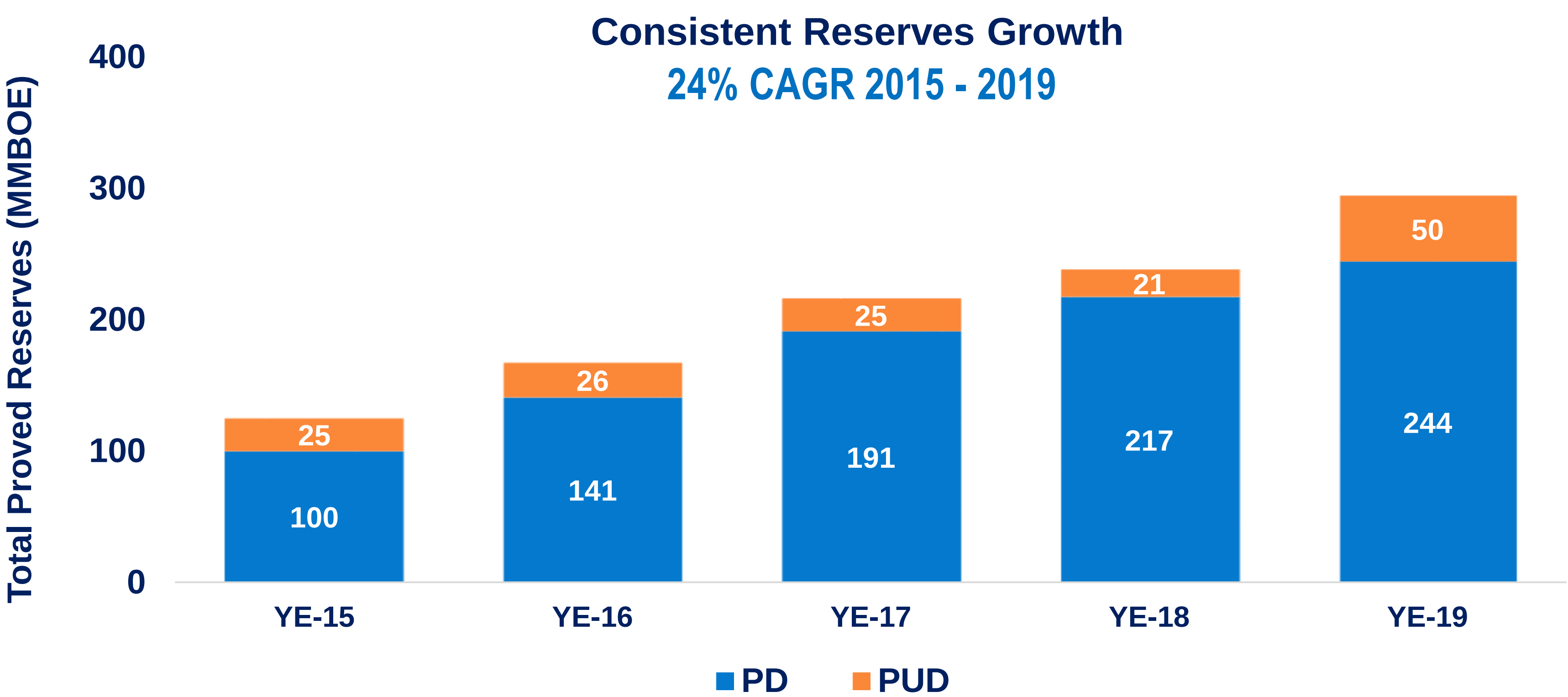
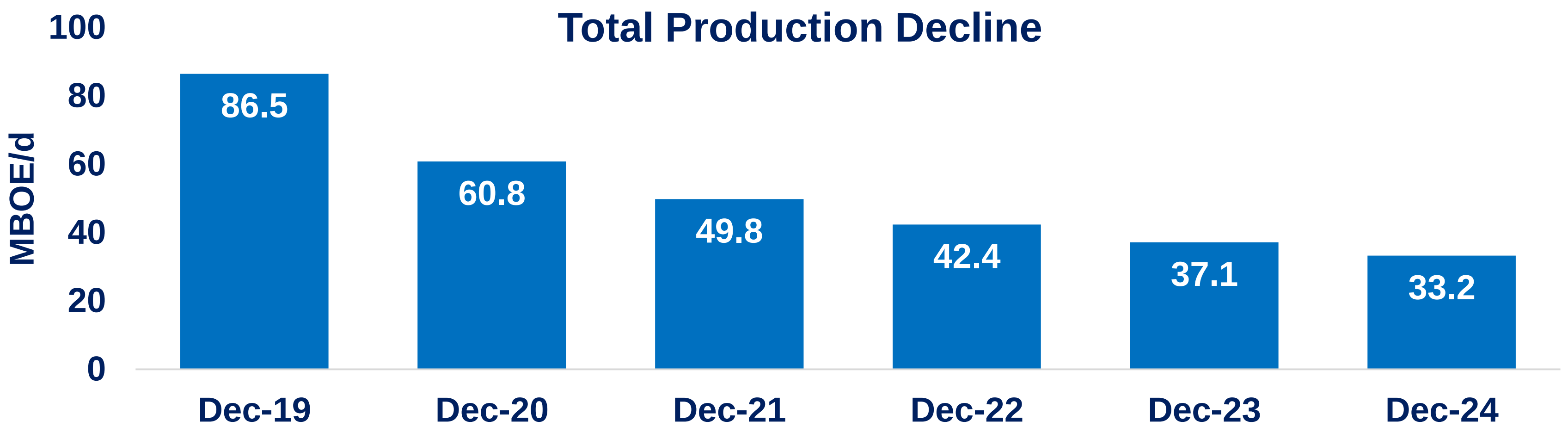
23% YoY Total Proved Reserves Growth in 2019

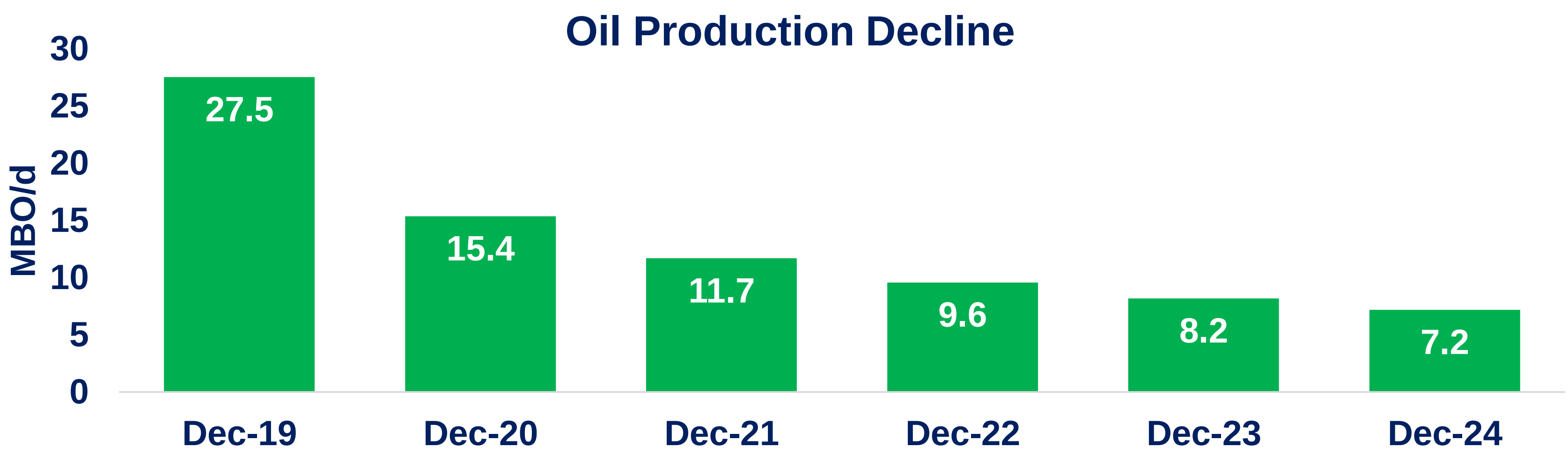


70% of YE-19 PUD locations booked in Howard County

Note: YE-15 to YE-19 3-stream Reserves prepared by Ryder Scott

YE-19 Base Production Decline Expectations





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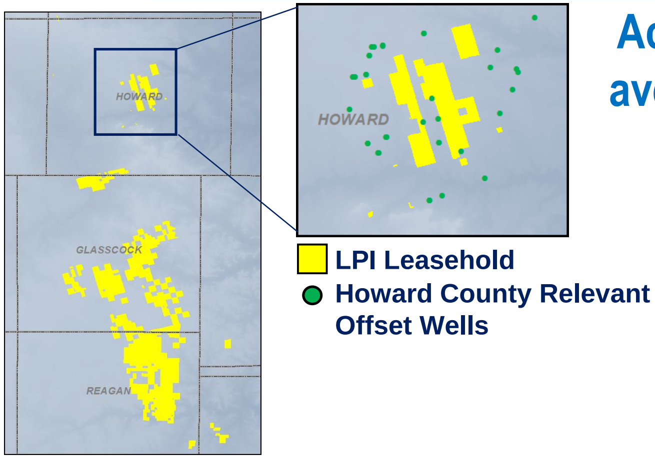
Howard County Tier-One Acquisitions Deliver Higher-Margin Production

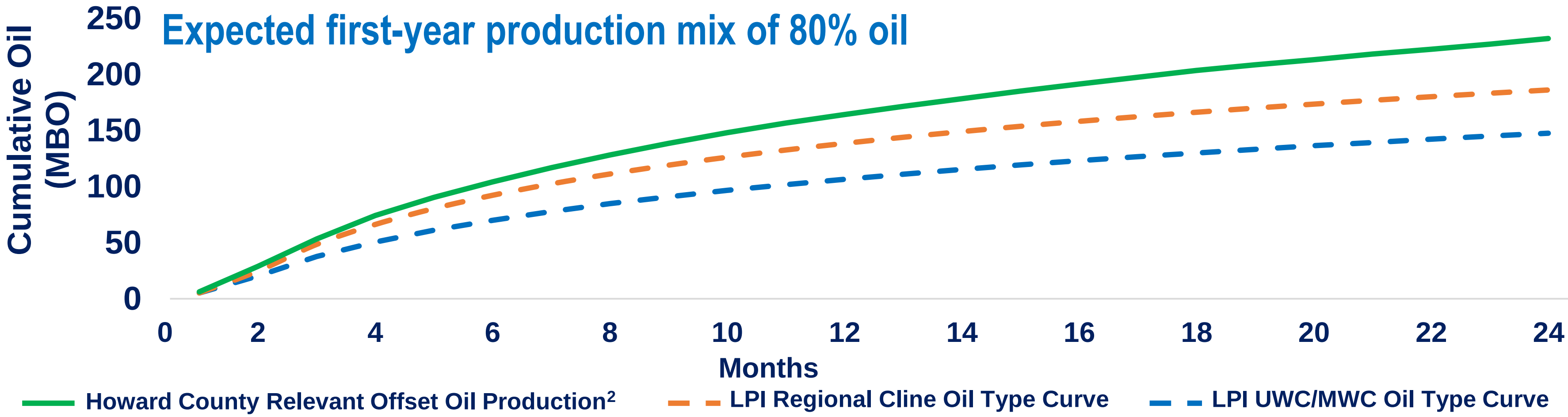


Acquisition prices are well below historic Howard County averages, with potential for additional bolt-on acquisitions

Howard County Acquisitions	#1	#2	Current 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	

Acquired Howard County Acreage Transforms Near-Term Drilling Plans

- Co-developing primarily as 16-well packages (4 LS & 12 UWC/MWC)
- Drilling began in early 1Q-20, with the first package completed in 3Q-20E



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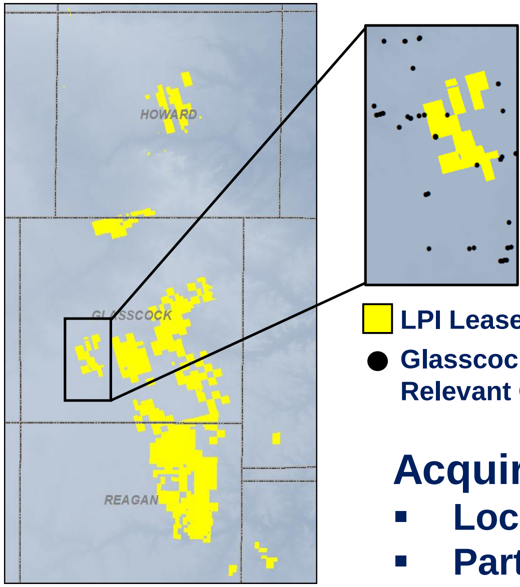
[1]Pursuant to the terms of the purchase agreement, if the average WTI crude price exceeds $60/BO for the year ending 12-31-20, the Company is obligated to pay the seller $20 MM

[2]Howard County Relevant Offset cumulative oil production normalized to time 0 start and 10,000', courtesy of Enverus (as of 10-28-19)

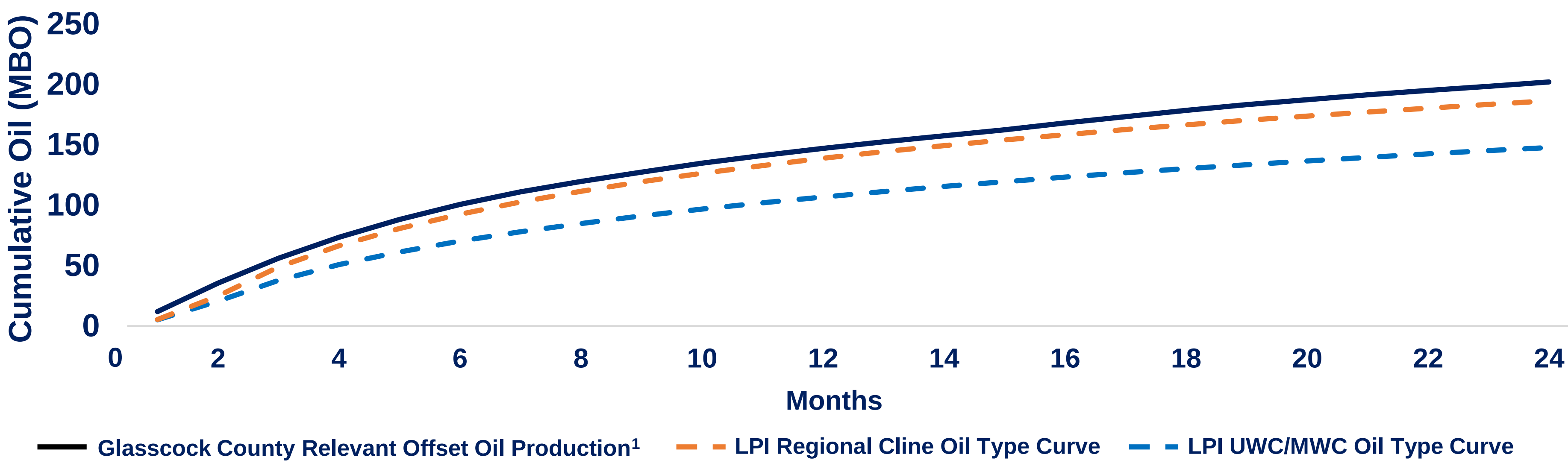
Bolt-On Glasscock County Acquisition Adds High-Return Inventory



W. Glasscock County Acquisition	Current 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

Acquired Western Glasscock Acreage Bolsters High-Margin Inventory

- Locations across LS & UWC/MWC formations
- Partial drilling expected in 2020 & 2021, with primary development in 2022



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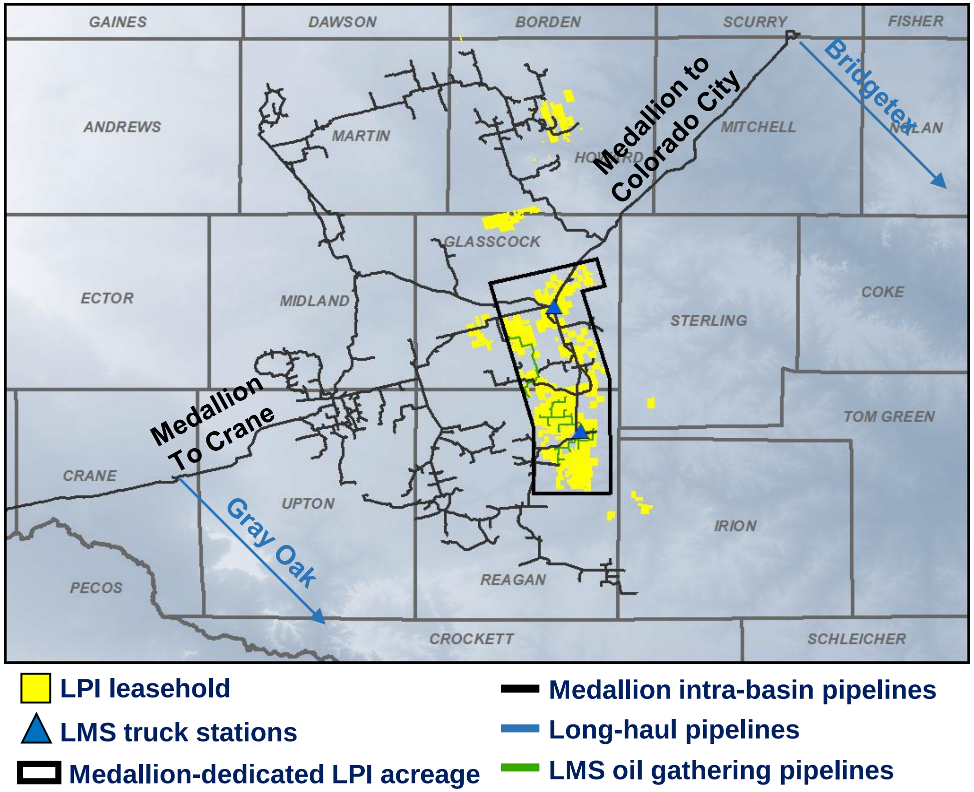
[1]Glasscock County Relevant Offset cumulative oil production normalized to time 0 start and 10,000', courtesy of Enverus and internal data (as of 10-28-19)

Oil Value Enhanced Via Gulf Coast Access

Gross Physical Transportation Contracts:

- **Medallion firm transportation secured for all crude oil produced within dedication area**
- **10 MBOPD firm transportation on Bridgetex through 1Q-22, with option to extend through 1Q-26 (USGC pricing)**
- **Firm transportation on Gray Oak upon full-service startup in 1Q-20E (Brent-related pricing):**
  - **Year 1: 25 MBOPD**
  - **Years 2 - 7: 35 MBOPD**



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

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 December 31,		Twelve months ended December 31,	
(in thousands, unaudited)	2019	2018	2019	2018
Net income (loss)	($241,721)	$149,573	($342,459)	$324,595
Plus:				
Non-cash stock based compensation, net	3,046	7,648	8,290	36,396
Depletion, depreciation and amortization	67,846	60,399	265,746	212,677
Impairment expense	222,999	-	620,889	-
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	57,562	(112,195)	(79,151)	(42,984)
Settlements received for matured derivatives, net	14,394	12,033	63,221	6,090
Settlements paid for early termination of commodity derivatives, net	-	-	(5,409)	-
Premiums paid for derivatives	(1,399)	(5,405)	(9,063)	(20,335)
Accretion expense	1,041	1,131	4,118	4,472
(Gain) Loss on disposal of assets, net	(67)	1,207	248	5,798
Write-off of debt issuance costs	935	-	935	-
Interest expense	15,044	15,117	61,547	57,904
Organizational restructuring expenses	-	-	16,371	-
Litigation settlement	-	-	(42,500)	-
Income tax (benefit) expense	(1,776)	2,862	(2,588)	4,249
Adjusted EBITDA	$137,904	$132,370	$560,195	$588,862

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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 includes TTM Adjusted EBITDA ending 12-31-19 of $560 million and net debt as of 2-11-20. Net Debt as of 2-11-20 is calculated as the face value of debt of $1.275 billion, reduced by cash and cash equivalents of $67 million, which is net of expected cash to be used to redeem the remaining March 2023 Notes.

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.

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

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.

The following table presents a reconciliation of net cash provided by operating activities (GAAP) to cash flows from operating activities before changes in assets and liabilities, net (non-GAAP), less costs incurred, excluding non-budgeted acquisition costs, for the calculation of Free Cash Flow (non-GAAP):

	Three months ended December 31,		Twelve months ended December 31,	
(in thousands, unaudited)	2019	2018	2019	2018
Net cash provided by operating activities	$108,206	$129,276	$475,074	$537,804
Less:				
Increase in current assets and liabilities, net	(15,818)	10,842	(64,123)	1,157
(Increase) decrease in noncurrent assets and liabilities, net	(3,923)	(451)	(2,070)	(730)
Cash flows from operating activities before changes in assets and liabilities, net ('Cash Flow')	127,947	118,885	541,267	537,377
Less costs incurred, excluding non-budgeted acquisition costs				
Oil and natural gas properties	104,616	145,345	470,455	631,674
Midstream service assets	1,071	970	8,655	4,618
Other fixed assets	504	1,124	2,470	7,322
Total costs incurred, excluding non-budgeted acquisition costs	106,191	147,439	481,580	643,614
Free Cash Flow (Deficit)	$21,756	($28,554)	$59,687	($106,237)