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

Corporate Presentation

December 2019

Forward-Looking / Cautionary Statements

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

General risks relating to Laredo include, but are not limited to, the decline in prices of oil, natural gas liquids and natural gas and the related impact to financial statements as a result of asset impairments and revisions to reserve estimates, long-term performance of wells, drilling and operating risks, the increase in service costs, hedging activities, possible impacts of potential litigation and other factors, including those and other risks described in its Annual Report on Form 10-K for the year ended December 31, 2018, its Quarterly Report on Form 10-Q for the quarter ended September 30, 2019 and those set forth from time to time in other filings with the Securities Exchange Commission ("SEC"). These documents are available through Laredo's website at www.laredopetro.com under the tab "Investor Relations" or through the SEC's Electronic Data Gathering and Analysis Retrieval System at www.sec.gov. Any of these factors could cause Laredo's actual results and plans to differ materially from those in the forward-looking statements. Therefore, Laredo can give no assurance that its future results will be as estimated. Laredo does not intend to, and disclaims any obligation to, update or revise any forward-looking statement.

Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

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

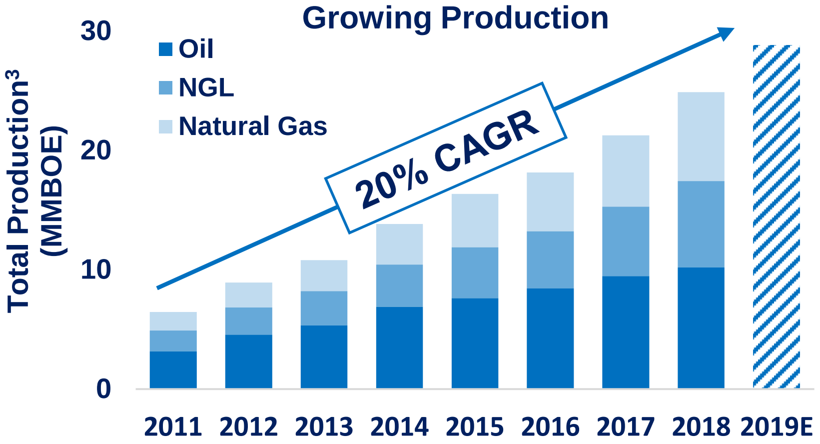
This presentation includes financial measures that are not in accordance with generally accepted accounting principles ("GAAP"), including Adjusted EBITDA, cash flow and Free Cash Flow. While management believes that such measures are useful for investors, they should not be used as a replacement for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

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

Laredo Petroleum Overview

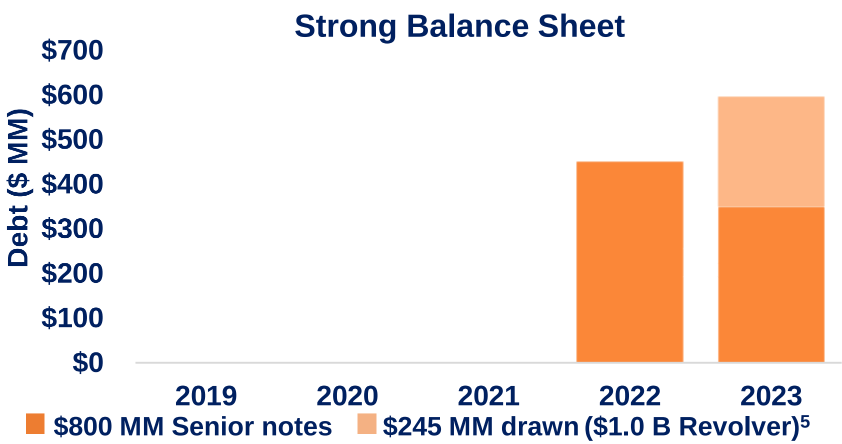
Laredo Petroleum (LPI)

Market Cap[1]: $595 MM; Enterprise Value[2]: $1,550 MM
Operations: Permian Basin (TX), Headquarters: Tulsa, OK



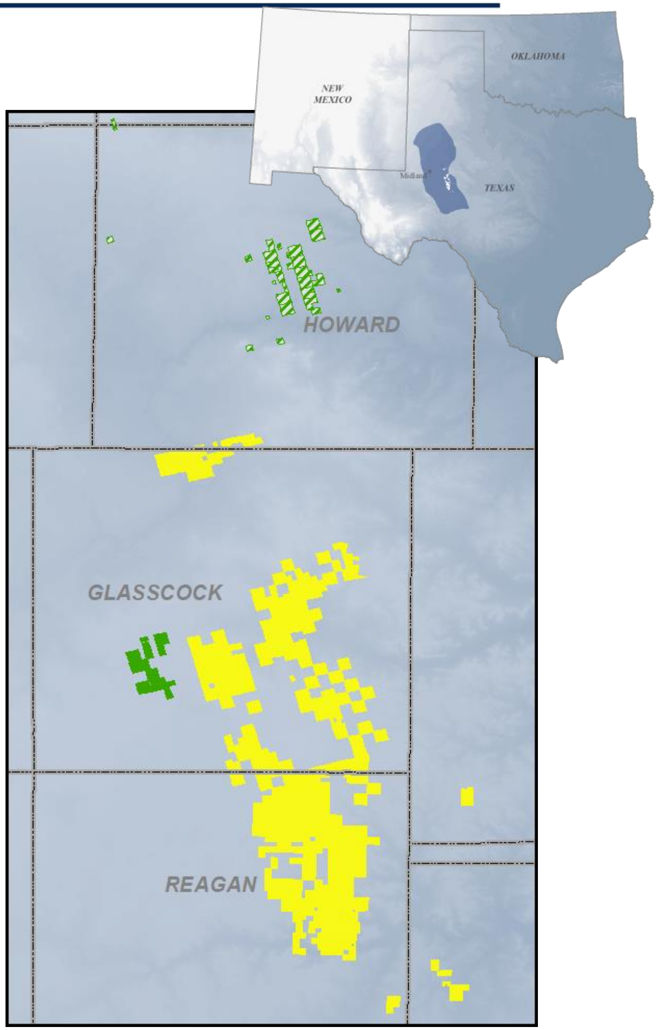
81.9 MBOEPD
3Q-19 total production

16%
Estimated total production growth in 2019



1.8x
Net Debt to Adj. EBITDA[4]

>$40 MM
Estimated FCF[4] generation in 2019



LPI - 137,312 gross/ 122,398 net acres
Acquisition – 5,750 gross/ 4,475 net
Pending Acquisition - 10,407 gross/ 7,364 net acres

[1]As of 11/6/19; [2] Market cap as of 11/6/19; net debt as of 9/30/19; [3]2011-2014 results have been converted to 3-stream using actual gas plant economics; 2011-2013 results have been adjusted for Granite Wash divestiture, closed 8/1/13; [4]See Appendix for reconciliations of non-GAAP measures and the calculations of Net Debt to Adjusted EBITDA and Free Cash Flow excluding pending acquisition; [5]As of 12/6/2019, per the semi-annual redetermination of $1.0 B aggregate elected commitment in place under Fifth Amended and Restated Senior Secured Credit Facility
Note: Map and acreage as of 12/6/2019

Pivoting Strategy to Increase Stakeholder Value

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

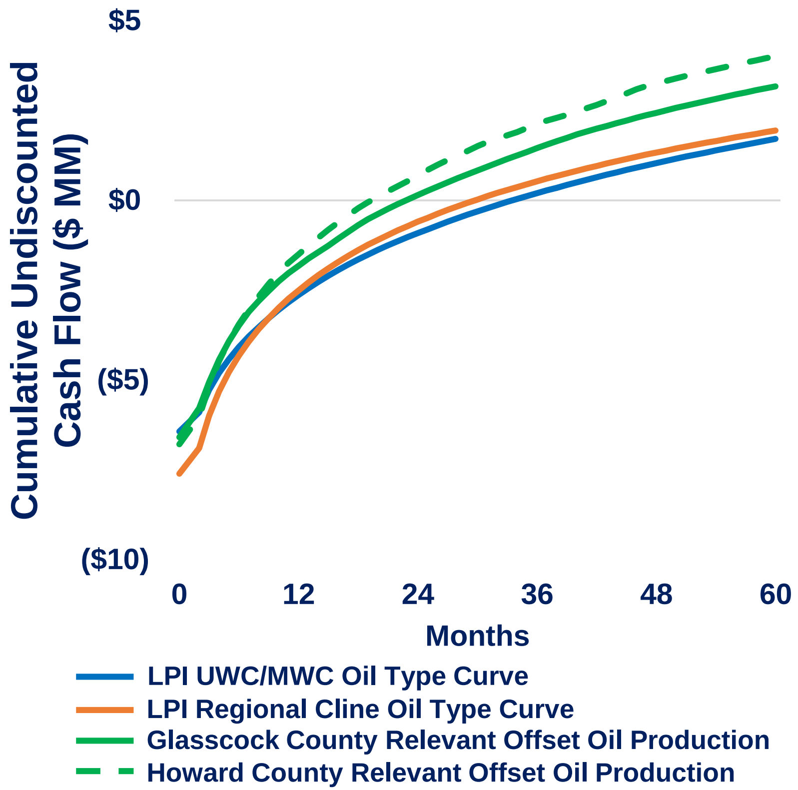
Continuous	In Process	Opportunistic
Optimize existing acreage	**Improve corporate returns through accretive acquisitions**	**Increase scale through consolidation**
High-grade development to maximize oil productivity	Opportunistically target high-margin inventory	Combine operations to eliminate redundancies
+	+	+
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 & oil growth	Delivers increased return of cash to stakeholders

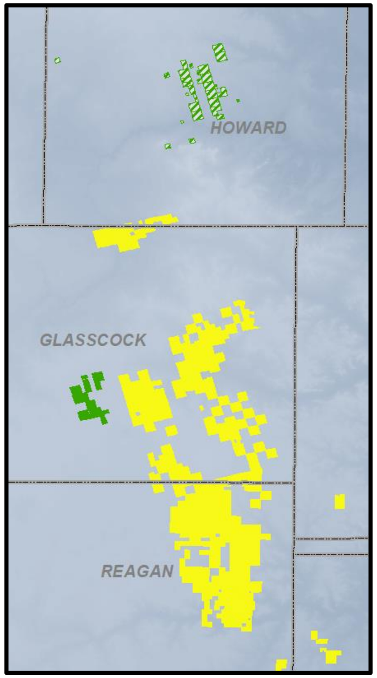
[1]See Appendix for reconciliations of non-GAAP measures and the calculation of Free Cash Flow

Acquisition Strategy Supports Oil Growth & Free Cash Flow Generation

FY-20 & FY-21 Expectations:

- Mid-to-high single digit annual oil growth
- 40% oil mix by YE-21
- $100 MM Free Cash Flow[1] generation in FY-20E & FY-21E combined, at strip prices





Established Leasehold
Acquired Leasehold
Pending Acquisition Leasehold

	Established UWC/MWC Oil Type Curve	Established Cline Oil Type Curve	Glasscock County Acq. Relevant Offset Oil Production	Pending Howard County Acq. Relevant Offset Oil Production
24 Mo. Cumulative Oil (MBO)	148	186	202	232
ROR (%)	26%	27%	41%	49%
Payback Period (Months)	34	30	23	20

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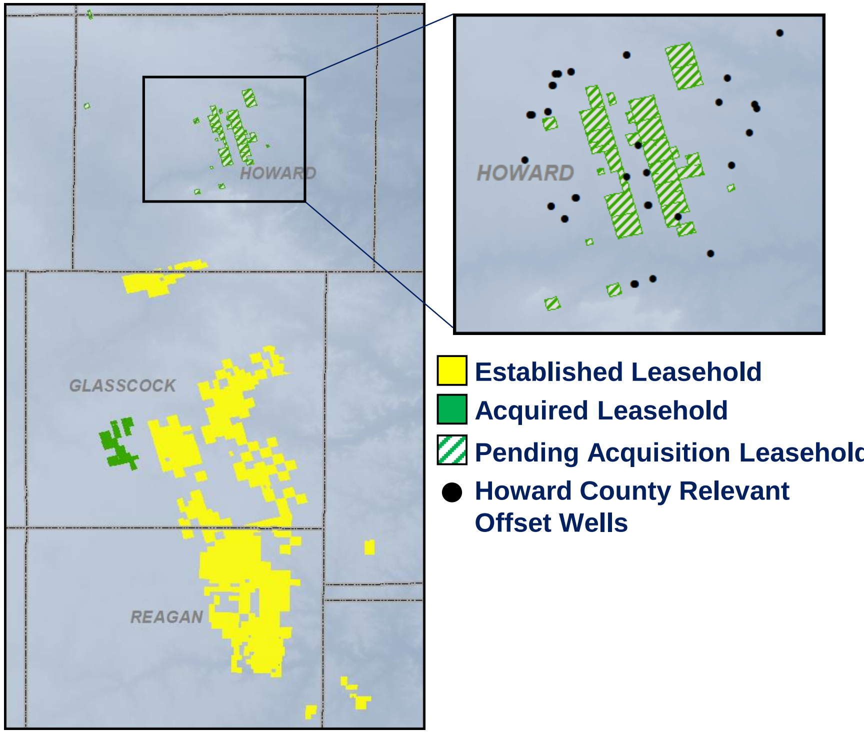
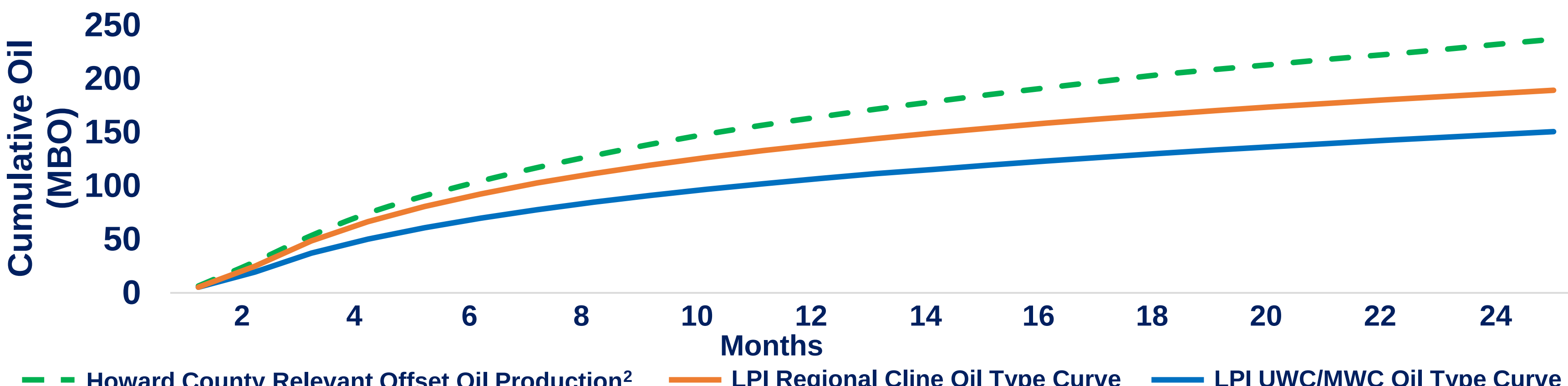
[1]See Appendix for reconciliations of non-GAAP measures and the calculation of Free Cash Flow
Note: Pricing utilizes strip as of 10/22/19

Howard County Tier-One Acquisition Delivers Higher-Margin Production



- **$130 MM acquisition price[1], well below historic Howard County averages**
- **High-margin, tier-one acreage**
  - **7,360 net acres / 750 net royalty acres**
  - **Expected first-year production mix of 80% oil**
- **Transforms near-term drilling plan**
  - **120 primary locations expected in Lower Spraberry (LS) and UWC/MWC**
  - **Plan to co-develop primarily as 16-well packages (4 LS & 12 UWC/MWC)**
  - **Drilling begins in 1Q-20E, with the first package completed in 3Q-20E**



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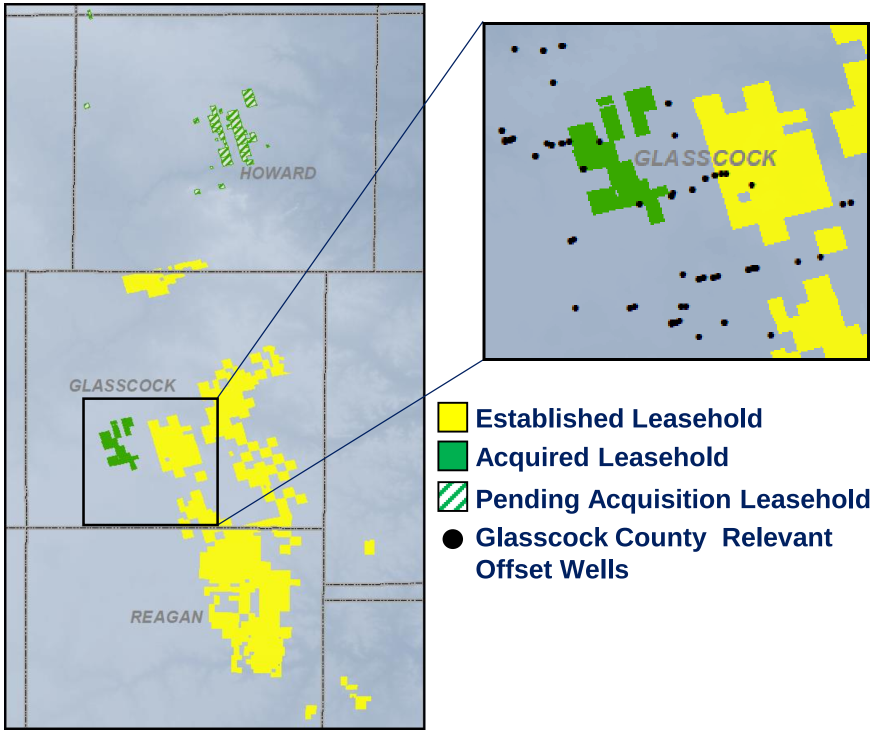
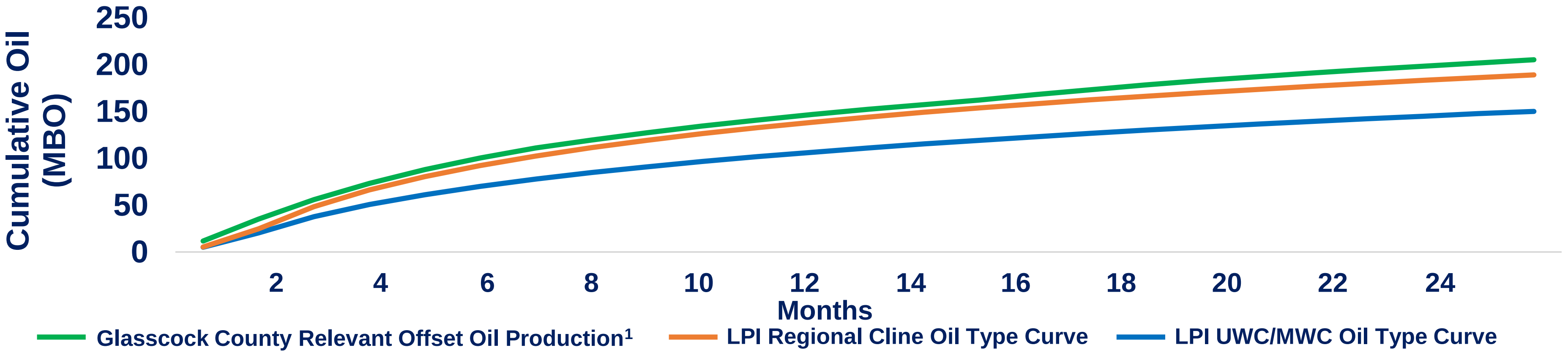
[1]Subject to standard purchase price adjustments; expected to close late in 4Q-19; see Form 8-K filed on 11/05/19 for additional information regarding the transaction

[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



- **$65 MM purchase price**
  - **4,475 net acres**
  - **1,400 BOE/d (55% oil) current net production**
  - **45 total gross expected locations across LS & UWC/MWC formations**
- **Acquisition closed 12/6/2019**



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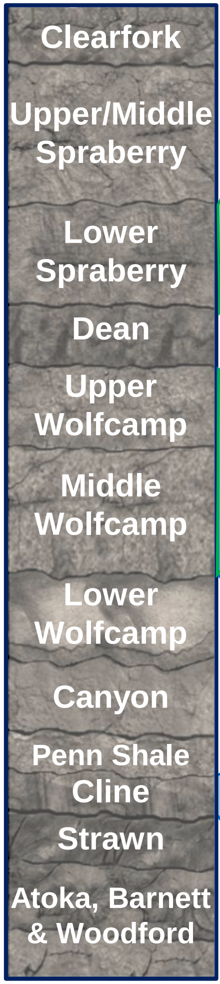
[1]Glasscock County Relevant Offset cumulative oil production normalized to time 0 start and 10,000', courtesy of Enverus and internal data (as of 10/28/19)

Acquisitions Add Oily, High-Margin Inventory

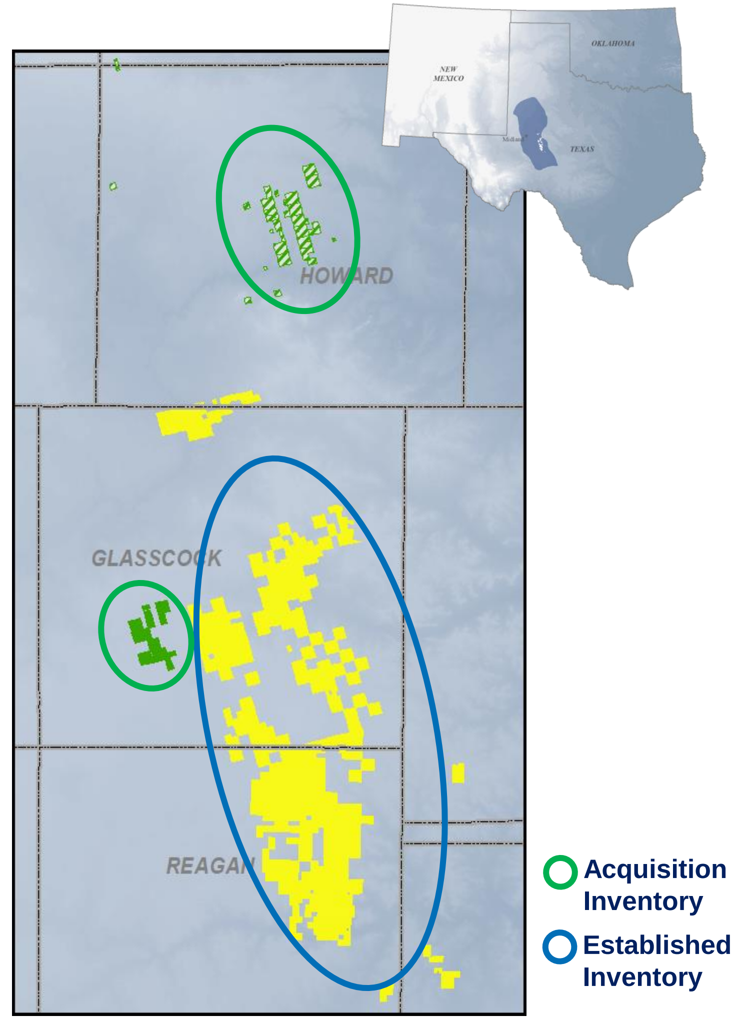


Acquisition - L. Spraberry	
Wells per DSU	Inventory
4	45

Acquisition - UWC/MWC	
Wells per DSU	Inventory
8 - 12	120

Established - UWC/MWC	
Wells per DSU	Inventory[1]
8 - 12	350 - 500

Established - Cline	
Wells per DSU	Inventory[1]
4	140 - 160



Acquired locations move to front of drill schedule

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

Surpassing Guidance on Production & Expenses

3Q-19 Select Results

Production

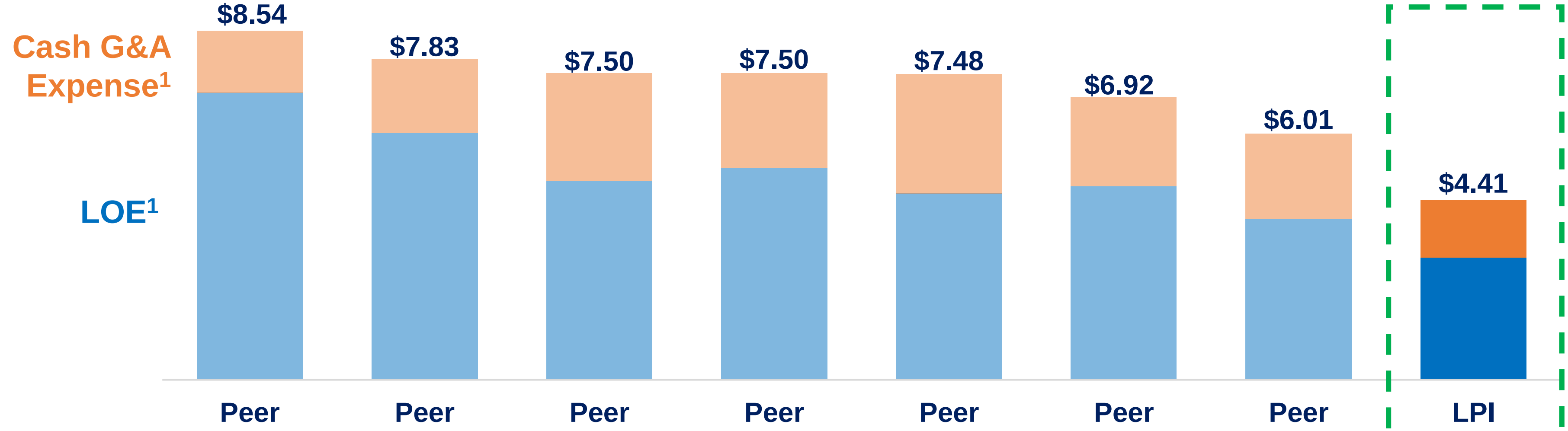
Oil Production
27.8 MBO/d
2% beat vs guidance

Total Production
81.9 MBOE/d
4% beat vs guidance

Controllable Cash Costs

Lease Operating Expense
$3.00/BOE
10% beat vs guidance

G&A Cash Expense
$1.41/BOE
17% beat vs guidance



Generated $49 MM of Free Cash Flow[2], reduced outstanding borrowings by $50 MM and maintained Net Debt to Adjusted EBITDA[2] at 1.7x

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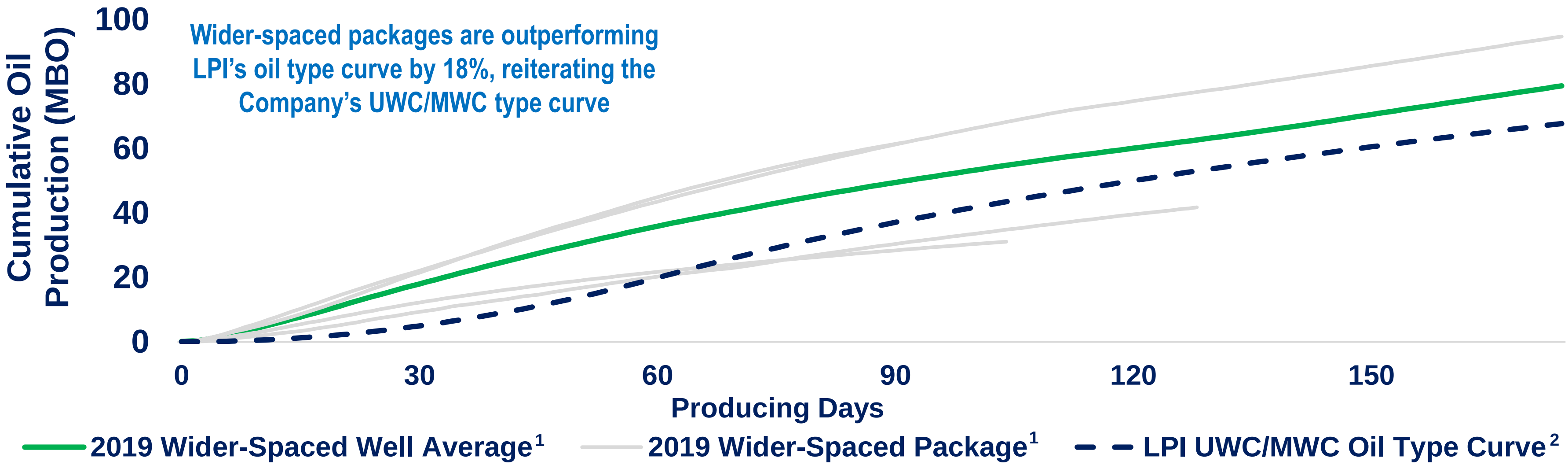
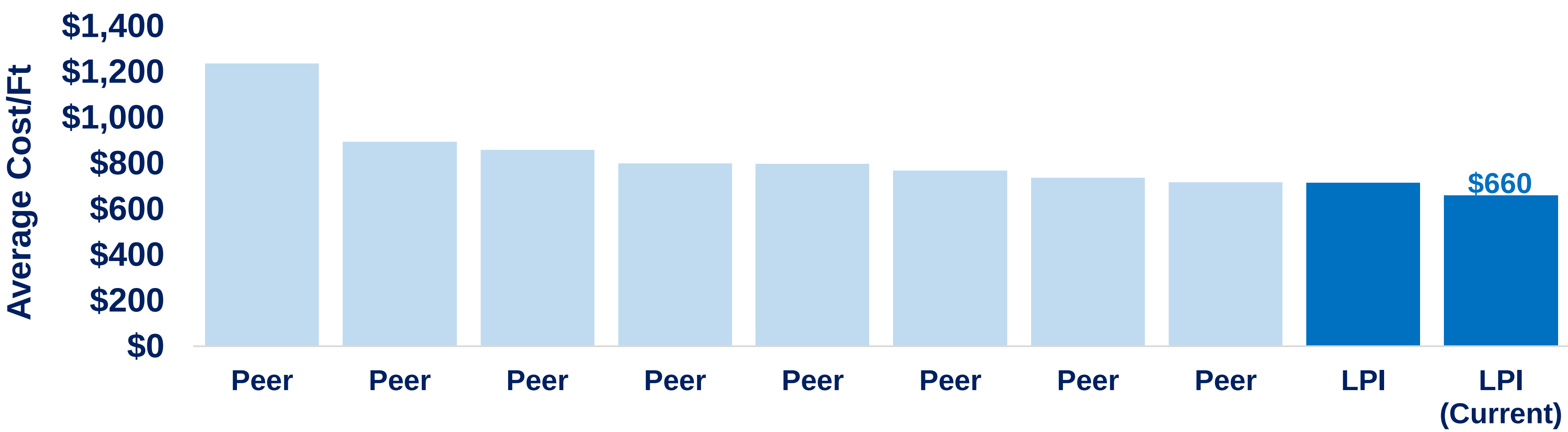
[1]Representative of unit expenses; Peers include - CDEV, CPE, CRZO, JAG, MTDR, QEP, SM
[2]See Appendix for reconciliations of non-GAAP measures and the calculations of Free Cash Flow and Net Debt to Adjusted EBITDA

Optimizing Well Productivity and Costs on Existing Acreage

2019 Wider-Spaced Well Results



Peer-Leading D&C Costs[3]

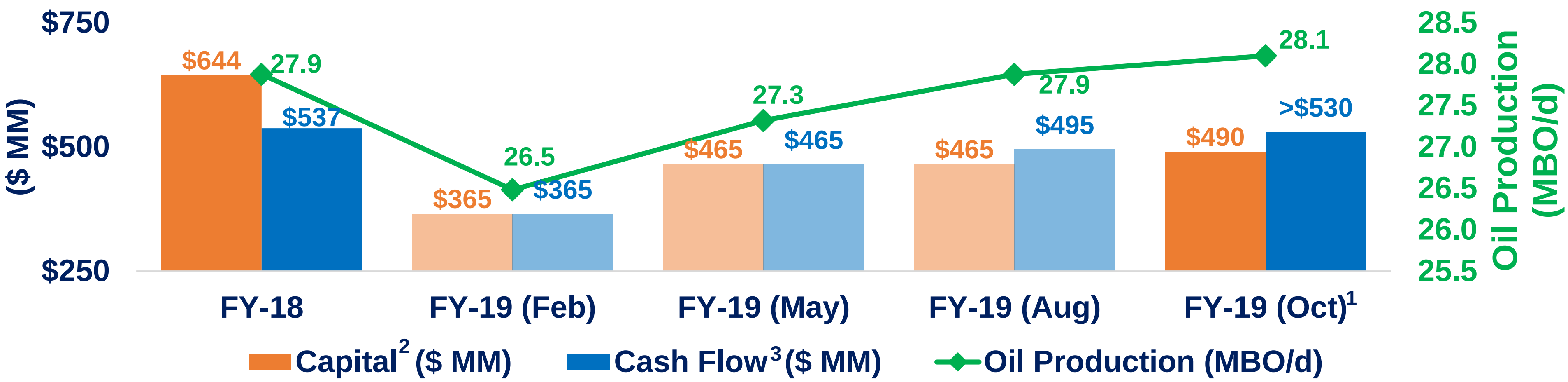


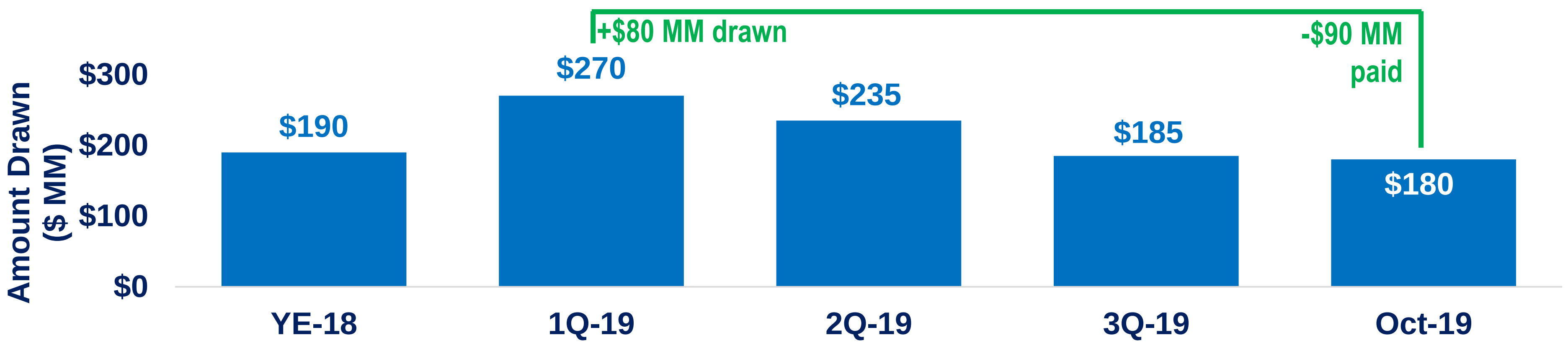
[1]Includes an average of the Yellow Rose package (8 wells), Hoelscher package (4 wells), Frysak/Halfmann (4 wells) and Sugg-B (7 wells); All wells show cumulative oil production, normalized to a 10,000' lateral

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

[3]Source: RSEG YTD-19 average lateral cost per foot. Peers include: CPE, CXO, ECA, FANG, PE, PXD, QEP and SM; LPI (Current) per internal data

Demonstrated Discipline and Continuous Improvement Drive Cash Flow

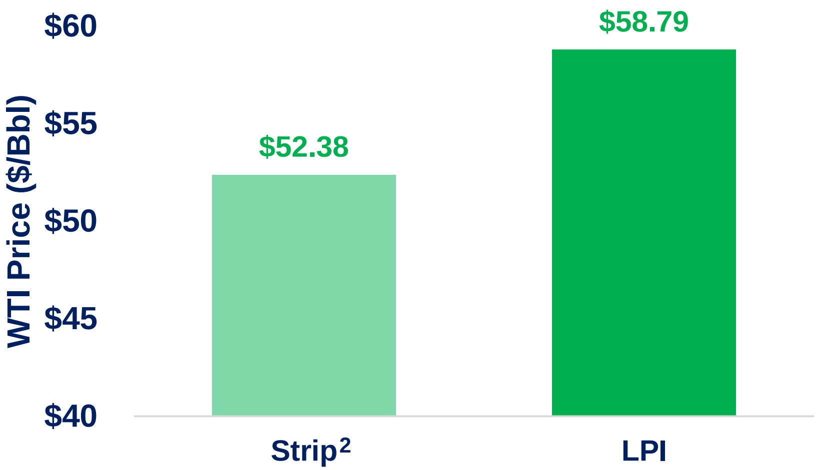


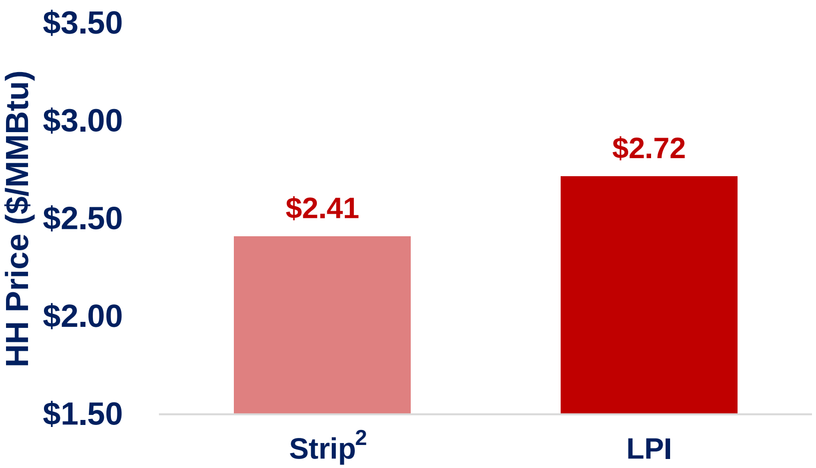


Delivered on commitment to pay down the $80 MM drawn on revolver in first-quarter 2019

[1]FY-19E (Oct) WTI price of $55.20/BO and HH price of $2.55/MMBtu include 1Q-19 - 3Q-19 actuals and 4Q-19E strip as of 10-22-19
[2]Estimated costs incurred, including LMS investments, excluding future non-budgeted acquisitions and the pending Howard County transaction that is expected to close late in 4Q-19 (see Form 8-K filed on 11/05/19 for additional information regarding the transaction)
[3]See Appendix for reconciliations of non-GAAP measures and the calculation of Projected Free Cash Flow

Hedging Strategy Reduces Impact of Commodity Price Fluctuations





2020 Vol Hedged[1] **Oil: 7,539,600 BO** **Natural Gas: 23,790,000 MMBtu**

	2020 Volume Hedged[1] (gal)	Strip[2] ($/gal)	LPI ($/gal)
Ethane	15,372,000	$0.19	$0.32
Propane	52,264,800	$0.46	$0.63
Normal Butane	18,446,400	$0.54	$0.68
Iso Butane	4,611,600	$0.59	$0.71
Natural Gasoline	16,909,200	$1.02	$1.08

Robust hedges in place for FY-20 help ensure cash flow projections

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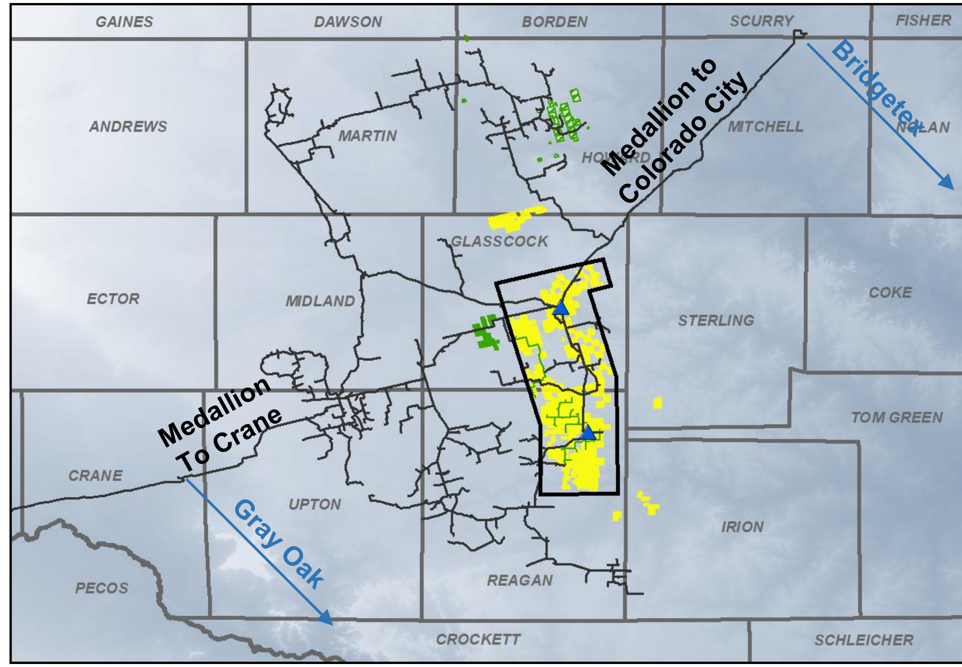
[1]2020 volume hedged as of 12/6/19
[2]Strip as of 10/22/19
Note: LPI representative of weighted-average floor price for the period presented

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



- Established leasehold
- Acquired Leasehold
- Pending Acquisition Leasehold
- LMS truck stations
- Medallion intra-basin pipelines
- Long-haul pipelines
- LMS oil gathering pipelines
- Medallion-dedicated LPI acreage

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

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Note: Map as of 12/6/19

Infrastructure Protects The Environment & Enhances Economics

LPI In-Place Infrastructure

60 Miles
Crude oil gathering pipelines

170 miles
Natural gas gathering pipelines

110 Miles
Water gathering & distribution pipelines

54 MBWPD
Produced water recycling capacity

Environmental Impact

Truckloads eliminated from the field
>220,000

Barrels of water recycled
>8,500,000

Additional gas sold vs. vented/flared
>3.2 Bcf

Shareholder Value

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

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

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

Note: Existing infrastructure as of 9/30/19
Environmental impact and shareholder value based on FY-18

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APPENDIX

4Q-19 Guidance

Production:	
Total production (MBOE/d)	76.5
Oil production (MBbl/d)	26.0

Average sales price realizations: *(excluding derivatives)*	
Oil (% of WTI)	99%
NGL (% of WTI)	20%
Natural gas (% of Henry Hub)	29%

Operating costs & expenses ($/BOE):	
Lease operating expenses	$3.20
Production and ad valorem taxes *(% of oil, NGL and natural gas revenues)*	6.50%
Transportation and marketing expenses	$1.75
Midstream service expenses	$0.15
General and administrative expenses:	
Cash	$1.60
Non-cash stock-based compensation, net	$0.50
Depletion, depreciation and amortization	$8.75

Oil, Natural Gas & Natural Gas Liquids Hedges

Hedge Product Summary	4Q-19	FY-20	FY-21
Oil total floor volume (Bbl)	2,300,000	7,539,600	912,500
Oil wtd-avg floor price ($/Bbl)	$60.42	$58.79	$45.00
Oil total floor volume w. deferred premium (Bbl)	*322,000*		
Oil wtd-avg deferred premium price ($/Bbl)	*$4.39*		
Nat gas total floor volume (MMBtu)	9,844,000	23,790,000	14,052,500
Nat gas wtd-avg floor price ($/MMBtu)	$3.09	$2.72	$2.63
NGL total floor volume (Bbl)	1,462,800	2,562,000	2,202,775

Oil	4Q-19	FY-20	FY-21
Puts - WTI			
Volume (Bbl)	322,000	366,000	
Wtd-avg floor price ($/Bbl)	$55.00	$45.00	
Volume w. Deferred Premium (Bbl)	*322,000*		
Wtd-avg deferred premium price ($/Bbl)	*$4.39*		
Swaps - WTI			
Volume (Bbl)	1,978,000	7,173,600	
Wtd-avg price ($/Bbl)	$61.31	$59.50	
Collars - WTI			
Volume (Bbl)			912,500
Wtd-avg floor price ($/Bbl)			$45.00
Wtd-avg ceiling price ($/Bbl)			$71.00

Natural Gas Liquids	4Q-19	FY-20	FY-21
Swaps - Ethane			
Volume (Bbl)	598,000	366,000	912,500
Wtd-avg price ($/Bbl)	$14.22	$13.60	$12.01
Swaps – Propane			
Volume (Bbl)	478,400	1,244,400	730,000
Wtd-avg price ($/Bbl)	$27.97	$26.58	$25.52
Swaps – Normal Butane			
Volume (Bbl)	184,000	439,200	255,500
Wtd-avg price ($/Bbl)	$30.73	$28.69	$27.72
Swaps – Isobutane			
Volume (Bbl)	46,000	109,800	67,525
Wtd-avg price ($/Bbl)	$31.08	$29.99	$28.79
Swaps - Natural Gasoline			
Volume (Bbl)	156,400	402,600	237,250
Wtd-avg price ($/Bbl)	$45.80	$45.15	$44.31

Natural Gas	4Q-19	FY-20	FY-21
Swaps - HH			
Volume (MMBtu)	9,844,000	23,790,000	14,052,500
Wtd-avg price ($/MMBtu)	$3.09	$2.72	$2.63

Basis Swaps	4Q-19	FY-20	FY-21
Mid/WTI			
Volume (Bbl)	1,104,000		
Wtd-avg price ($/Bbl)	-$3.08		
Waha/HH			
Volume (MMBtu)	9,844,000	32,574,000	23,360,000
Wtd-avg price ($/MMBtu)	-$1.51	-$0.76	-$0.47

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Note: Open positions as of 9/30/19, hedges executed through 12/6/19
Volumes with deferred premiums outlined above are included in provided totals and are therefore not additive
Natural gas liquids consist of Mt. Belvieu purity ethane and Mt. Belvieu non-TET propane, normal butane, isobutane, and natural gasoline

Supplemental Financial Calculations

Net debt to Adjusted EBITDA

Net Debt to Adjusted EBITDA is calculated as net debt as of September 30, 2019 divided by trailing twelve-month Adjusted EBITDA ending September 30, 2019 of $555 million. Net debt as of September 30, 2019 was $953 million, calculated as the face value of debt of $985 million reduced by cash and cash equivalents of $32 million. Pro forma for the Glasscock acreage acquisition as of December 6, 2019, net debt was $1,018 million. 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 above for a definition of Adjusted EBITDA.

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

Liquidity

At September 30, 2019, the Company had outstanding borrowings of $185 million on its $1.1 billion senior secured credit facility, resulting in available capacity, after the reduction for outstanding letters of credit, of $900 million. Including cash and cash equivalents of $32 million, total liquidity was $932 million.

Pro forma for the Glasscock acreage acquisition, as of December 6, 2019, outstanding borrowings were $245 million.

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 September 30,		Nine months ended September 30,	
(in thousands, unaudited)	2019	2018	2019	2018
Net income (loss)	($264,629)	$55,050	($100,738)	$175,022
Plus:				
Income tax (benefit) expense	(2,467)	1,387	(812)	1,387
Depletion, depreciation and amortization	69,099	55,963	197,900	152,278
Impairment expense	397,890	-	397,890	-
Non-cash stock-based compensation, net	(1,739)	8,733	5,244	28,748
Restructuring expenses	5,965	-	16,371	-
Accretion expense	1,005	1,114	3,077	3,341
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	(96,684)	32,245	(136,713)	69,211
Settlements received (paid) for matured derivatives, net	25,245	(3,888)	48,827	(5,943)
Settlements paid for early termination of derivatives, net	-	-	(5,409)	-
Premiums paid for derivatives	(1,415)	(5,455)	(7,664)	(14,930)
Interest expense	15,191	14,845	46,503	42,787
Litigation settlement	-	-	(42,500)	-
(Gain) Loss on disposal of assets, net	(1,294)	616	315	4,591
Adjusted EBITDA	$146,167	$160,610	$422,291	$456,492

Free Cash Flow and Projected Free Cash Flow

Free Cash Flow 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 September 30,		Nine months ended September 30,	
(in thousands, unaudited)	2019	2018	2019	2018
Net cash provided by operating activities	$105,599	$145,927	$366,868	$408,528
Less:				
Increase in current assets and liabilities, net	(21,183)	(313)	(48,305)	(9,685)
(Increase) decrease in noncurrent assets and liabilities, net	(1,124)	(1,570)	1,853	(279)
Cash flows from operating activities before changes in assets and liabilities, net	127,906	147,810	413,320	418,492
Less costs incurred, excluding non-budgeted acquisition costs				
Oil and natural gas properties	76,837	147,250	365,839	486,329
Midstream service assets	1,147	383	7,584	3,649
Other fixed assets	999	1,255	1,966	6,197
Total costs incurred, excluding non-budgeted acquisition costs	78,983	148,888	375,389	496,175
Free Cash Flow	$48,923	($1,078)	$37,931	($77,683)

Projected Free Cash Flow is calculated as estimated cash flows from operating activities before changes in assets and liabilities, less estimated costs incurred, excluding non-budgeted acquisition costs, made during the period. Management believes this 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.