UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE

SECURITIES EXCHANGE ACT OF 1934

Date of report (Date of earliest event reported): February 13, 2019

LAREDO PETROLEUM, INC.

(Exact name of registrant as specified in charter)

Delaware	**001-35380**	**45-3007926**
(State or other jurisdiction of incorporation or organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

15 W. Sixth Street, Suite 900, Tulsa, Oklahoma	**74119**
(Address of principal executive offices)	(Zip code)

Registrant's telephone number, including area code: **(918) 513-4570**

Not Applicable

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging Growth Company o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o

Item 2.02. Results of Operations and Financial Condition.

On February 13, 2019, Laredo Petroleum, Inc. (the "Company") announced its financial and operating results for the quarter and year ended December 31, 2018. Copies of the Company's press release and Presentation (as defined below) are furnished as Exhibit 99.1 and 99.2, respectively, to this Current Report on Form 8-K and are incorporated herein by reference. The Company plans to host a teleconference and webcast on February 14, 2019 at 7:30 am Central Time to discuss these results. To access the call, please dial 1-877-930-8286 or 1-253-336-8309 for international callers, and use conference code 9775779. A replay of the call will be available through Thursday, February 21, 2019, by dialing 1-855-859-2056, and using conference code 9775779. The webcast may be accessed at the Company's website, www.laredopetro.com, under the tab "Investor Relations."

In accordance with General Instruction B.2 of Form 8-K, the information furnished under this Item 2.02 of this Current Report on Form 8-K and the exhibits attached hereto are deemed to be "furnished" and shall not be deemed "filed" for the purpose of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section, nor shall such information and exhibits be deemed incorporated by reference in any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended.

Item 7.01. Regulation FD Disclosure.

On February 13, 2019, the Company furnished the press release described above in Item 2.02 of this Current Report on Form 8-K. A copy of the press release is attached hereto as Exhibit 99.1 and incorporated into this Item 7.01 by reference.

On February 13, 2019, the Company also posted to its website a Corporate Presentation (the "Presentation"). The Presentation is available on the Company's website, www.laredopetro.com, and is attached hereto as Exhibit 99.2 and incorporated into this Item 7.01 by reference.

All statements in the press release, teleconference and the Presentation, other than historical financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Although the Company believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance, and actual results or developments may differ materially from those in the forward-looking statements. The Company disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

In accordance with General Instruction B.2 of Form 8-K, the information furnished under Item 7.01 of this Current Report on Form 8-K and the exhibits attached hereto are deemed to be "furnished" and shall not be deemed "filed" for the purpose of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section, nor shall such information and exhibits be deemed incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended.

Item 9.01. Financial Statements and Exhibits.

(d) *Exhibits*.

Exhibit Number	Description
99.1	Press Release dated February 13, 2019 announcing financial and operating results.
99.2	Presentation dated February 13, 2019.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

LAREDO PETROLEUM, INC.

Dated: February 13, 2019	By:	/s/ Richard C. Buterbaugh
		Richard C. Buterbaugh
		Executive Vice President & Chief Financial Officer

EXHIBIT 99.1

LAREDO PETROLEUM, INC.

15 West 6th Street, Suite 900 · Tulsa, Oklahoma 74119 · (918) 513-4570 · Fax: (918) 513-4571
www.laredopetro.com

Laredo Petroleum Announces 2018 Fourth-Quarter and Full-Year Financial and Operating Results

TULSA, OK - February 13, 2019 - Laredo Petroleum, Inc. (NYSE: LPI) ("Laredo" or the "Company") today announced its 2018 fourth-quarter and full-year results. For the fourth quarter of 2018, the Company reported net income attributable to common stockholders of $149.6 million, or $0.65 per diluted share. Adjusted Net Income, a non-GAAP financial measure, for the fourth quarter of 2018 was $37.5 million, or $0.16 per adjusted diluted share. Adjusted EBITDA, a non-GAAP financial measure, for the fourth quarter of 2018, was $132.4 million.

For the year ended December 31, 2018, the Company reported net income attributable to common stockholders of $324.6 million, or $1.39 per diluted share. Adjusted Net Income for the year ended December 31, 2018 was $216.4 million, or $0.93 per adjusted diluted share, and Adjusted EBITDA was $588.9 million. Please see supplemental financial information at the end of this news release for reconciliation of the non-GAAP financial measures.

2018 Highlights

- Produced a Company record average of 68,168 barrels of oil equivalent ("BOE") per day in full-year 2018, resulting in production growth of approximately 17% from full-year 2017
- Grew the value of the Company's proved reserves by 19% from year-end 2017
- Increased cash margin per BOE, a non-GAAP financial measure, to $23.85 in full-year 2018, an increase of 14% from full-year 2017
- Reduced unit cash general and administrative ("G&A") expense by approximately 16% in full-year 2018
- Recognized approximately $31.9 million of net cash benefits from Laredo Midstream Services, LLC ("LMS") field infrastructure investments through reduced capital and operating costs and increased revenue

"The Company's 2018 drilling program generated significant data on well spacing, furthering our subsurface understanding and driving a key strategic shift in our development plan," stated Randy A. Foutch, Chairman and Chief Executive Officer. "The resulting 2019 capital program is expected to produce a returns and capital efficiency inflection point for the Company, while also generating high-single digit production growth within operating cash flow. We have already begun to pivot our development plan to emphasize returns by moving to wider well spacing and expect a commensurate long-term improvement in well productivity. This strategic transition, coupled with our focus on controlling cash costs, is expected to position Laredo to take advantage of numerous opportunities to enhance value for our shareholders."

E&P Update

During the fourth quarter of 2018, Laredo continued the superior operational efficiency performance demonstrated in the previous three quarters of 2018. The Company completed 18 gross horizontal wells with an average completed lateral length of approximately 10,100 feet. Laredo continued to set Company records for drilling efficiency, averaging 8.3 drilling days per 10,000 feet from rig accept to rig release for wells drilled in fourth-quarter 2018. The combined benefit of these continued efficiency improvements resulted in Laredo completing 74 gross (71.2 net) horizontal wells in full-year 2018, exceeding the originally budgeted well completions expectations by approximately 14%.

Total production in fourth-quarter 2018 averaged 70,653 BOE per day, an increase of approximately 14% from the fourth quarter of 2017. Fourth-quarter 2018 oil production increased by approximately 5% from the fourth quarter of 2017. Full-year 2018 total production averaged a Company record 68,168 BOE per day, an increase of approximately 17% from full-year 2017 and exceeding initial 2018 guidance of total production growth of at least 10%. Oil production increased approximately 7% from full-year 2017, less than original 2018 oil production growth guidance of greater than 10%.

Laredo has taken action to address the reduced oil productivity experienced in 2018 that we believe was impacted by the tighter spacing of some wells drilled in 2017 and 2018. Responding to these results, the Company began widening spacing on wells spud in the first quarter of 2019. Laredo expects this shift in development strategy to drive higher returns and increased capital efficiency versus 2018 as widening spacing is anticipated to address one of the causes of higher oil decline rates.

In the first quarter of 2019, the Company expects to complete 15 gross (14.8 net) horizontal wells with an average completed lateral length of approximately 11,300 feet, all developed with Laredo's previous tight-spacing plan. The five remaining tightly-spaced wells are expected to be completed early in the second quarter of 2019. In the later part of the second quarter of 2019, the Company expects to begin completing wells that were developed on Laredo's wider-spaced development strategy that is expected to result in improved returns and capital efficiency versus 2018.

Throughout 2018, the Company maintained a strong focus on controllable cash costs, reducing combined unit lease operating expenses ("LOE") and unit cash G&A expense approximately 5% to $6.07 per BOE for full-year 2018 versus $6.38 per BOE for full-year 2017. Laredo's prior strategic investments in field infrastructure continue to drive unit operational costs that are among the lowest in the Midland Basin, reducing unit LOE by an estimated $0.55 per BOE in the fourth quarter of 2018 to $3.51 per BOE. Additionally, Laredo's management team held the line on total G&A expense, reducing total cash G&A by approximately 1% compared to 2017.

2018 Capital Program

During the fourth quarter of 2018, the Company invested approximately $132 million in exploration and development activities. Other expenditures incurred during the quarter included approximately $2 million in bolt-on leasing, lease extensions and data, approximately $5 million in infrastructure, including LMS investments, and approximately $9 million in other capitalized costs. Additionally, the Company completed property acquisitions of approximately $1 million that were not previously budgeted.

For full-year 2018, Laredo invested approximately $575 million in exploration and development activities. Other expenditures incurred during the year included approximately $12 million in bolt-on leasing, lease extensions and data, approximately $23 million in infrastructure, including LMS investments, and approximately $34 million in other capitalized costs. Additionally, the Company completed property acquisitions of approximately $17 million that were not previously budgeted.

2019 Capital Program

Laredo expects 2019 to be a transitional year as the Company tailors operational cadence and corporate cost structure, including G&A expense, to balance capital expenditures and cash flow from operations. The evolution of Laredo's development plan to focus on more widely spaced wells is expected to drive long-term capital efficiency improvements and higher returns versus 2018 results, enabling Laredo to hold oil production relatively flat within cash flow in 2020 compared to 2019's exit rate.

Responding to the current commodity price environment of WTI strip pricing of approximately $54 per barrel, Laredo expects to invest approximately $365 million in 2019, excluding non-budgeted acquisitions. This budget includes approximately $300 million for drilling and completion activities and approximately $65 million for production facilities, land and other capitalized costs. Laredo anticipates adjusting capital spending levels to match operating cash flow if operating cash flow does not meet budgeted expectations. Should operating cash flow exceed budget expectations, free cash flow could be used to complete additional wells, repurchase stock or pay down debt.

By the third quarter of 2019, enabled by the Company's operational flexibility, Laredo anticipates reducing activity from the current three horizontal rigs and two completion crews to operating one horizontal rig and utilizing a single completion crew, as needed. The front-loaded completion schedule and disciplined reduction in activity should drive free cash flow generation in the second half of 2019 that is expected to balance capital expenditures with cash flow from operations for full-year 2019.

The Company's 2019 budget is underpinned by a robust hedge position. Approximately 90% of 2019 forecasted oil production is hedged with a combination of puts and swaps at a weighted-average floor price of approximately $48 per barrel. Importantly, Laredo retains unlimited upside to oil prices on almost all of the Company's oil hedges since puts have no price ceiling.

Total production for 2019 is expected to grow approximately 9% versus full-year 2018 and oil production is expected to decline approximately 5% versus 2018. The Company expects to replace both total and oil production organically through development drilling in 2019. Under current conditions, beyond 2019, Laredo expects to hold annual oil production relatively flat within cash flow, compared to a fourth-quarter 2019 exit rate of approximately 23.0 MBOPD. Additionally, the Company's future corporate oil decline rates are expected to be lower, commensurate with reduced activity levels and wider well spacing, improving future capital efficiency.

Reserves

Beginning with the first horizontal well Laredo drilled in the Midland Basin in 2008, the Company's primary goal has been the execution of the most efficient and value-enhancing development program for its acreage position. Laredo fully embraced the challenge of replicating stand-alone well performance in tighter-spaced, full-field development, minimizing parent-child performance degradation and maximizing premium well inventory. Utilizing extensive pre-drill forward modeling that integrated Laredo's broad dataset and third-party technologies, the Company began drilling a majority of its wells in dense, multi-zone packages in mid-2017.

In general, production performance for tighter-spaced packages was very encouraging for the first year, but subsequent data began to exhibit more rapid oil decline rates than anticipated, leading to longer-term results that underperformed expectations, primarily related to the tighter spacing. Additionally, as wells were more tightly spaced in 2018, oil declines became evident earlier in the wells' life than more widely spaced wells.

For the Company's year-end 2018 reserves estimation, Laredo incorporated additional production data to reflect the higher natural gas content and steeper oil declines on its historical wells and the related negative impact on oil production from tighter well spacing during the last two years. These process enhancements have led to more specific forecasts for estimated reserves as the Company takes into account well spacing's impact on estimated oil reserves.

The value of Laredo's proved reserves increased to approximately $2.1 billion at year-end 2018, an increase of approximately 19% from year-end 2017. Total proved reserve volumes increased by approximately 10% to 238 MMBOE, including an approximately 13% increase in proved developed reserves to 217 MMBOE and increasing proved developed reserves to 91% of total proved reserves. Proved oil reserves decreased by approximately 22%, driven primarily by longer-term performance revisions associated with tighter well spacing.

Changes in total proved reserves for 2018 are summarized in the following table:

	Year ended December 31, 2018			
	Oil (MMBbl)	NGL (MMBbl)	Natural gas (Bcf)	Oil equivalents[(1)] (MMBOE)
Beginning of year	79.4	67.4	414.6	215.9
Revisions of previous estimates	(20.9)	11.1	72.0	2.2
Extensions, discoveries and other additions	13.3	15.1	93.8	44.1
Acquisitions and divestitures of reserves, net	0.2	0.3	2.1	0.9
Production	(10.2)	(7.3)	(44.7)	(24.9)
End of year[(1)]	61.9	86.6	537.8	238.2
Standardized measure of discounted future net cash flows, end of year - ($ millions)				$ 2,114

(1) Figures may not add due to rounding.

The most recent results from tighter well spacing have been incorporated into year-end 2018 proved reserves and Laredo believes that the shift in future development to wider spacing will mitigate the negative impact to oil production seen in tightly spaced wells. Expectations for future drilling, which take into account all landing points and both horizontal and vertical spacing and the related interference, are reflected in Laredo's updated type curve for Upper/Middle Wolfcamp 10,000-foot lateral horizontal wells. Total production expectations for the updated type curve are 1.3 MMBOE for the life of the well, comprised of approximately 31% oil, with more than 50% of expected oil production recovered in the first five years of production.

Rate of return expectations for the Company's updated type curve are commensurate with those for the previous type curve. Increased expectations for natural gas and natural gas liquids recoveries early in the life of well offset reduced expectations for oil recoveries late in the life of the well. Further, estimated ultimate recovery for oil reflected in the Company's updated type curve is approximately 55% higher than current expectations for tightly spaced wells drilled in 2017 and 2018.

Liquidity

At December 31, 2018, the Company had cash and cash equivalents of approximately $45 million and available capacity under the senior secured credit facility of $995 million. At February 12, 2019, the Company had cash and cash equivalents of approximately $30 million and available capacity under the senior secured credit facility of $945 million, resulting in total liquidity of approximately $975 million.

Commodity Derivatives

Laredo maintains a disciplined hedging program to reduce the variability in its anticipated cash flow due to fluctuations in commodity prices. The Company utilizes a combination of puts, swaps and collars, entering into hedges solely with banks that are part of its senior secured credit facility. Laredo currently has hedges in place for approximately 90% of anticipated oil production in 2019 and has oil hedges in place through 2021. The Company has also entered into NGL hedges through 2021, natural gas hedges through 2019 and various product basis hedges through 2021. Details of the Company's hedge positions are included in the current Corporate Presentation available on the Company's website at www.laredopetro.com.

Guidance

The Company anticipates total production growth of approximately 9% and an oil production decline of approximately 5% for full-year 2019 as compared to full-year 2018. The table below reflects the Company's guidance for the first quarter of 2019.

	1Q-2019E
Total production (MBOE/d)	74.0
Oil production (MBO/d)	27.5
Average sales price realizations (without derivatives):	
Oil (% of WTI)	90%
NGL (% of WTI)	24%
Natural gas (% of Henry Hub)	34%
Operating costs & expenses:	
Lease operating expenses ($/BOE)	$3.50
Production and ad valorem taxes (% of oil, NGL and natural gas revenues)	6.50%
Transportation and marketing expenses ($/BOE)	$0.80
Midstream service expenses ($/BOE)	$0.15
General and administrative:	
Cash ($/BOE)	$2.25
Non-cash stock-based compensation, net ($/BOE)	$1.25
Depletion, depreciation and amortization ($/BOE)	$9.30

Fourth-Quarter and Full-Year 2018 Earnings Conference Call

Laredo will host a conference call on Thursday, February 14, 2019 at 7:30 a.m. CT (8:30 a.m. ET) to discuss its fourth-quarter and full-year 2018 financial and operating results and management's outlook. Individuals who would like to participate on the call should dial 877.930.8286 (international dial-in 253.336.8309), using conference code 9775779 or listen to the call via the Company's website at www.laredopetro.com, under the tab for "Investor Relations." A telephonic replay will be available approximately two hours after the call on February 14, 2019 through Thursday, February 21, 2019. Participants may access this replay by dialing 855.859.2056, using conference code 9775779.

About Laredo

Laredo Petroleum, Inc. is an independent energy company with headquarters in Tulsa, Oklahoma. Laredo's business strategy is focused on the acquisition, exploration and development of oil and natural gas properties, and midstream and marketing services, primarily in the Permian Basin of West Texas.

Additional information about Laredo may be found on its website at www.laredopetro.com.

Forward-Looking Statements

This press release and any oral statements made regarding the subject of this release, including in the conference call referenced herein, contain 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 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, 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, the increase in service costs, hedging activities, possible impacts of pending or 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, 2017, and those set forth from time to time in other filings with the Securities Exchange Commission ("SEC") including, but not limited to, its Annual Report on Form 10-K for the year ended December 31, 2018, to be filed with the 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.*

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 added to proved reserves, largely from a specified resource play. 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, drilling costs and production costs, availability 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 unproved resources 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.

Laredo Petroleum, Inc.
Condensed consolidated statements of operations

(in thousands, except per share data)	Three months ended December 31, 2018	Three months ended December 31, 2017	Year ended December 31, 2018	Year ended December 31, 2017
	(unaudited)		(unaudited)	
Revenues:				
Oil, NGL and natural gas sales	$ 176,671	$ 183,376	$ 808,530	$ 621,507
Midstream service revenues	2,397	2,369	8,987	10,517
Sales of purchased oil	36,219	54,592	288,258	190,138
Total revenues	215,287	240,337	1,105,775	822,162
Costs and expenses:				
Lease operating expenses	22,823	18,359	91,289	75,049
Production and ad valorem taxes	11,225	10,991	49,457	37,802
Transportation and marketing expenses	5,134	—	11,704	—
Midstream service expenses	1,048	1,113	2,872	4,099
Costs of purchased oil	36,222	54,247	288,674	195,908
General and administrative	21,182	23,707	96,138	96,312
Depletion, depreciation and amortization	60,399	45,062	212,677	158,389
Other operating expenses	1,131	1,025	4,472	4,931
Total costs and expenses	159,164	154,504	757,283	572,490
Operating income	56,123	85,833	348,492	249,672
Non-operating income (expense):				
Gain (loss) on derivatives, net	112,195	(37,777)	42,984	350
Interest expense	(15,117)	(19,787)	(57,904)	(89,377)
Income from equity method investee[(1)]	—	575	—	8,485
Gain on sale of investment in equity method investee[(1)]	—	405,906	—	405,906
Loss on early redemption of debt	—	(23,761)	—	(23,761)
Other, net	(766)	(628)	(4,728)	(501)
Non-operating income (expense), net	96,312	324,528	(19,648)	301,102
Income before income taxes	152,435	410,361	328,844	550,774
Income tax benefit (expense):				
Current	426	(1,800)	807	(1,800)
Deferred	(3,288)	—	(5,056)	—
Total income tax expense	(2,862)	(1,800)	(4,249)	(1,800)
Net income	$ 149,573	$ 408,561	$ 324,595	$ 548,974
Net income per common share:				
Basic	$ 0.65	$ 1.71	$ 1.40	$ 2.30
Diluted	$ 0.65	$ 1.70	$ 1.39	$ 2.29
Weighted-average common shares outstanding:				
Basic	229,700	239,332	232,339	239,096
Diluted	230,190	240,289	233,172	240,122

(1) On October 30, 2017, LMS, together with Medallion Midstream Holdings, LLC, which is owned and controlled by an affiliate of the third-party interest holder, The Energy & Minerals Group, completed the sale of 100% of the ownership interests in Medallion Gathering & Processing, LLC, a Texas limited liability company formed on October 12, 2012, which, together with its wholly-owned subsidiaries (collectively, "Medallion"), to an affiliate of Global Infrastructure Partners ("GIP"), for cash consideration of $1.825 billion (the "Medallion Sale"). LMS' net cash proceeds for its 49% ownership interest in Medallion in 2017 were $829.6 million, before post-closing adjustments and taxes, but after deduction of its proportionate share of fees and other expenses associated with the Medallion Sale. On February 1, 2018, closing adjustments were finalized and LMS received additional net cash of $1.7 million for total net cash proceeds before taxes of $831.3 million. The Medallion Sale closed pursuant to the membership interest purchase and sale agreement, which provides for potential post-closing additional cash consideration that is structured based on GIP's realized profit at exit. There can be no assurance as to when and whether the additional consideration will be paid.

Laredo Petroleum, Inc.
Condensed consolidated statements of cash flows

(in thousands)	Three months ended December 31, 2018	Three months ended December 31, 2017	Year ended December 31, 2018	Year ended December 31, 2017
	(unaudited)		(unaudited)	
Cash flows from operating activities:				
Net income	$ 149,573	$ 408,561	$ 324,595	$ 548,974
Adjustments to reconcile net income to net cash provided by operating activities:				
Deferred income tax expense	3,288	—	5,056	—
Depletion, depreciation and amortization	60,399	45,062	212,677	158,389
Gain on sale of investment in equity method investee(1)	—	(405,906)	—	(405,906)
Loss on early redemption of debt	—	23,761	—	23,761
Non-cash stock-based compensation, net	7,648	8,857	36,396	35,734
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	(112,195)	37,777	(42,984)	(350)
Settlements received for matured derivatives, net	12,033	2,792	6,090	37,583
Settlements received for early terminations of derivatives, net	—	—	—	4,234
Premiums paid for derivatives	(5,405)	(12,311)	(20,335)	(25,853)
Other, net(1)	3,544	3,196	15,882	2,062
Cash flows from operations before changes in assets and liabilities	118,885	111,789	537,377	378,628
Decrease (increase) in current assets and liabilities, net	10,842	(3,340)	1,157	2,239
(Increase) decrease in noncurrent assets and liabilities, net	(451)	4,414	(730)	4,047
Net cash provided by operating activities	129,276	112,863	537,804	384,914
Cash flows from investing activities:				
Deposit utilized for sale of oil and natural gas properties	—	(3,000)	—	(3,000)
Acquisitions of oil and natural gas properties	(1,198)	—	(17,538)	—
Capital expenditures:				
Oil and natural gas properties	(151,114)	(156,957)	(673,584)	(538,122)
Midstream service assets	(1,020)	(9,207)	(6,784)	(20,887)
Other fixed assets	(1,363)	(1,301)	(7,308)	(4,905)
Investment in equity method investee(1)	—	(7,236)	—	(31,808)
Proceeds from disposition of equity method investee, net of selling costs(1)	—	829,615	1,655	829,615
Proceeds from dispositions of capital assets, net of selling costs	170	29	12,603	64,157
Net cash (used in) provided by investing activities	(154,525)	651,943	(690,956)	295,050
Cash flows from financing activities:				
Borrowings on Senior Secured Credit Facility	20,000	35,000	210,000	190,000
Payments on Senior Secured Credit Facility	—	(190,000)	(20,000)	(260,000)
Early redemption of debt	—	(518,480)	—	(518,480)
Share repurchases	—	—	(97,055)	—
Other, net	(7)	15	(6,801)	(11,997)
Net cash provided (used in) by financing activities	19,993	(673,465)	86,144	(600,477)
Net (decrease) increase in cash and cash equivalents	(5,256)	91,341	(67,008)	79,487
Cash and cash equivalents, beginning of period	50,407	20,818	112,159	32,672
Cash and cash equivalents, end of period	$ 45,151	$ 112,159	$ 45,151	$ 112,159

(1) See footnote 1 to the condensed consolidated statements of operations.

Laredo Petroleum, Inc.
Selected operating data

	Three months ended December 31,		Year ended December 31,	
	2018	2017	2018	2017
	(unaudited)		(unaudited)	
Sales volumes:				
Oil (MBbl)	2,571	2,448	10,175	9,475
NGL (MBbl)	1,931	1,613	7,259	5,800
Natural gas (MMcf)	11,983	9,818	44,680	35,972
Oil equivalents (MBOE)[1][2]	6,500	5,697	24,881	21,270
Average daily sales volumes (BOE/D)[2]	70,653	61,922	68,168	58,273
% Oil[2]	40%	43%	41%	45%
Average sales Realized Prices[2]:				
Oil, without derivatives ($/Bbl)[3]	$ 52.59	$ 53.57	$ 59.48	$ 46.97
NGL, without derivatives ($/Bbl)[3]	$ 17.53	$ 20.53	$ 20.64	$ 17.49
Natural gas, without derivatives ($/Mcf)[3]	$ 0.63	$ 1.95	$ 1.20	$ 2.09
Average price, without derivatives ($/BOE)[3]	$ 27.18	$ 32.19	$ 32.50	$ 29.22
Oil, with derivatives ($/Bbl)[4]	$ 49.55	$ 54.38	$ 55.49	$ 50.45
NGL, with derivatives ($/Bbl)[4]	$ 17.47	$ 19.53	$ 20.03	$ 16.91
Natural gas, with derivatives ($/Mcf)[4]	$ 1.74	$ 2.08	$ 1.77	$ 2.15
Average price, with derivatives ($/BOE)[4]	$ 28.01	$ 32.48	$ 31.72	$ 30.71
Average costs and expenses per BOE sold[2]:				
Lease operating expenses	$ 3.51	$ 3.22	$ 3.67	$ 3.53
Production and ad valorem taxes	1.73	1.93	1.99	1.78
Transportation and marketing expenses	0.79	—	0.47	—
Midstream service expenses	0.16	0.20	0.12	0.19
General and administrative:				
Cash	2.08	2.61	2.40	2.85
Non-cash stock-based compensation, net	1.18	1.55	1.46	1.68
Depletion, depreciation and amortization	9.29	7.91	8.55	7.45
Total costs and expenses	$ 18.74	$ 17.42	$ 18.66	$ 17.48
Cash margins per BOE[2][5]:				
Realized	$ 18.91	$ 24.23	$ 23.85	$ 20.87
Hedged	$ 19.74	$ 24.52	$ 23.07	$ 22.36

(1) BOE is calculated using a conversion rate of six Mcf per one Bbl.

(2) The numbers presented are based on actual results and are not calculated using the rounded numbers presented in the table above.

(3) Realized oil, NGL and natural gas prices are the actual prices received when control passes to the purchaser/customer adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

(4) Price reflects the after-effects of our derivative transactions on our average sales Realized Prices. Our calculation of such after-effects includes settlements of matured derivatives during the respective periods in accordance with GAAP and an adjustment to reflect premiums incurred previously or upon settlement that are attributable to derivatives that settled during the respective periods.

(5) On a per BOE basis, cash margins are calculated as average price less, (i) lease operating expenses, (ii) production and ad valorem taxes, (iii) transportation and marketing expenses, (iv) midstream service expenses and (v) cash general and administrative.

Laredo Petroleum, Inc.
Costs incurred

The following table presents costs incurred in the acquisition, exploration and development of oil and natural gas properties, with asset retirement obligations included in evaluated property acquisition costs and development costs, for the periods presented:

	Three months ended December 31,		Year ended December 31,	
(in thousands)	**2018**	**2017**	**2018**	**2017**
	(unaudited)		(unaudited)	
Property acquisition costs:				
Evaluated	$ 1,225	$ —	$ 15,072	$ —
Unevaluated	—	—	2,790	—
Exploration costs	5,137	7,920	23,884	36,257
Development costs	140,208	163,664	607,790	560,919
Total costs incurred	$ 146,570	$ 171,584	$ 649,536	$ 597,176

Laredo Petroleum, Inc.
Supplemental reconciliations of GAAP to non-GAAP financial measures

Non-GAAP financial measures

The non-GAAP financial measures of Adjusted Net Income and Adjusted EBITDA, as defined by us, may not be comparable to similarly titled measures used by other companies. Therefore, these non-GAAP measures should be considered in conjunction with net income or loss and other performance measures prepared in accordance with GAAP, such as operating income or loss or cash flows from operating activities. Adjusted Net Income, Adjusted EBITDA and proved developed Finding and Development Cost should not be considered in isolation or as a substitute for GAAP measures, such as net income or loss, operating income or loss, standardized measure of discounted future net cash flows or any other GAAP measure of liquidity or financial performance.

Adjusted Net Income (Unaudited)

Adjusted Net Income is a non-GAAP financial measure we use to evaluate performance, prior to income tax taxes, mark-to-market on derivatives, premiums paid for derivatives, gains or losses on disposal of assets and other non-recurring income and expenses and after applying adjusted income tax expense. We believe Adjusted Net Income helps investors in the oil and natural gas industry to measure and compare our performance to other oil and natural gas companies by excluding from the calculation items that can vary significantly from company to company depending upon accounting methods, the book value of assets and other non-operational factors.

The following table presents a reconciliation of income before income taxes (GAAP) to Adjusted Net Income (non-GAAP):

	Three months ended December 31,		Year ended December 31,	
(in thousands, except for per share data, unaudited)	**2018**	**2017**	**2018**	**2017**
Income before income taxes	$ 152,435	$ 410,361	$ 328,844	$ 550,774
Plus:				
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	(112,195)	37,777	(42,984)	(350)
Settlements received for matured derivatives, net	12,033	2,792	6,090	37,583
Settlements received for early terminations of derivatives, net	—	—	—	4,234
Premiums paid for derivatives	(5,405)	(12,311)	(20,335)	(25,853)
Gain on sale of investment in equity method investee[(1)]	—	(405,906)	—	(405,906)
Loss on disposal of assets, net	1,207	906	5,798	1,306
Loss on early redemption of debt	—	23,761	—	23,761
Adjusted net income before adjusted income tax expense	48,075	57,380	277,413	185,549
Adjusted income tax expense[(2)]	(10,577)	(12,624)	(61,031)	(40,821)
Adjusted Net Income	$ 37,498	$ 44,756	$ 216,382	$ 144,728
Net income per common share:				
Basic	$ 0.65	$ 1.71	$ 1.40	$ 2.30
Diluted	$ 0.65	$ 1.70	$ 1.39	$ 2.29
Adjusted Net Income per common share:				
Basic	$ 0.16	$ 0.19	$ 0.93	$ 0.61
Diluted	$ 0.16	$ 0.19	$ 0.93	$ 0.60
Weighted-average common shares outstanding:				
Basic	229,700	239,332	232,339	239,096
Diluted	230,190	240,289	233,172	240,122

(1) See footnote 1 to the condensed consolidated statements of operations.

(2) Adjusted income tax expense is calculated by applying a statutory tax rate of 22% for the each of the periods ended December 31, 2018 and 2017.

Adjusted EBITDA (Unaudited)

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for income tax expense or benefit, depletion, depreciation and amortization, non-cash stock-based compensation, net, accretion expense, mark-to-market on derivatives, premiums paid for derivatives, interest expense, gains or losses on disposal of assets, income or loss from equity method investee, proportionate Adjusted EBITDA of our equity method investee and other non-recurring income and expenses. Adjusted EBITDA provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, working capital movement or tax position. Adjusted EBITDA does not represent funds available for discretionary use because those funds are required for debt service, capital expenditures, working capital, income taxes, franchise taxes and other commitments and obligations. However, our management believes Adjusted EBITDA is useful to an investor in evaluating our operating performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods, the book value of assets, capital structure and the method by which assets were acquired, among other factors;

- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and

- is used by our management for various purposes, including as a measure of operating performance, in presentations to our board of directors and as a basis for strategic planning and forecasting.

There are significant limitations to the use of Adjusted EBITDA as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations to different companies and the different methods of calculating Adjusted EBITDA reported by different companies. Our measurements of Adjusted EBITDA for financial reporting as compared to compliance under our debt agreements differ.

The following table presents a reconciliation of net income (GAAP) to Adjusted EBITDA (non-GAAP):

(in thousands, unaudited)	Three months ended December 31, 2018	Three months ended December 31, 2017	Year ended December 31, 2018	Year ended December 31, 2017
Net income	$ 149,573	$ 408,561	$ 324,595	$ 548,974
Plus:				
Income tax expense	2,862	1,800	4,249	1,800
Depletion, depreciation and amortization	60,399	45,062	212,677	158,389
Non-cash stock-based compensation, net	7,648	8,857	36,396	35,734
Accretion expense	1,131	969	4,472	3,791
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	(112,195)	37,777	(42,984)	(350)
Settlements received for matured derivatives, net	12,033	2,792	6,090	37,583
Settlements received for early terminations of derivatives, net	—	—	—	4,234
Premiums paid for derivatives	(5,405)	(12,311)	(20,335)	(25,853)
Interest expense	15,117	19,787	57,904	89,377
Gain on sale of investment in equity method investee[1]	—	(405,906)	—	(405,906)
Loss on disposal of assets, net	1,207	906	5,798	1,306
Loss on early redemption of debt	—	23,761	—	23,761
Income from equity method investee[1]	—	(575)	—	(8,485)
Proportionate Adjusted EBITDA of equity method investee[1][2]	—	2,326	—	22,081
Adjusted EBITDA	$ 132,370	$ 133,806	$ 588,862	$ 486,436

(1) See footnote 1 to the condensed consolidated statements of operations.

(2) Proportionate Adjusted EBITDA of Medallion, our equity method investee until its sale on October 30, 2017, is calculated as follows:

(in thousands, unaudited)	Three months ended December 31, 2018	Three months ended December 31, 2017	Year ended December 31, 2018	Year ended December 31, 2017
Income from equity method investee	$ —	$ 575	$ —	$ 8,485
Adjusted for proportionate share of depreciation and amortization	—	1,751	—	13,596
Proportionate Adjusted EBITDA of equity method investee	$ —	$ 2,326	$ —	$ 22,081

# # #

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EXHIBIT 99.2

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

Fourth-Quarter & Full-Year 2018
Earnings Presentation

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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, 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, the increase in service costs, hedging activities, possible impacts of pending or 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, 2017, and those set forth from time to time in other filings with the Securities Exchange Commission ("SEC") including, but not limited to, its Annual Report on Form 10-K for the year ended December 31, 2018, to be filed with the 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. "Estimated ultimate recovery," or "EURs," are based on the Company's previous operating experience in a given area and publicly available information relating o 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.

This presentation includes financial measures that are not in accordance with generally accepted accounting principles ("GAAP"), including Adjusted EBITDA. 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 to the nearest comparable measure in accordance with GAAP, please see the Appendix.

FY-18 Highlights

~17% BOE YoY production growth

~19% Proved reserves YoY value increase to $2.1 B

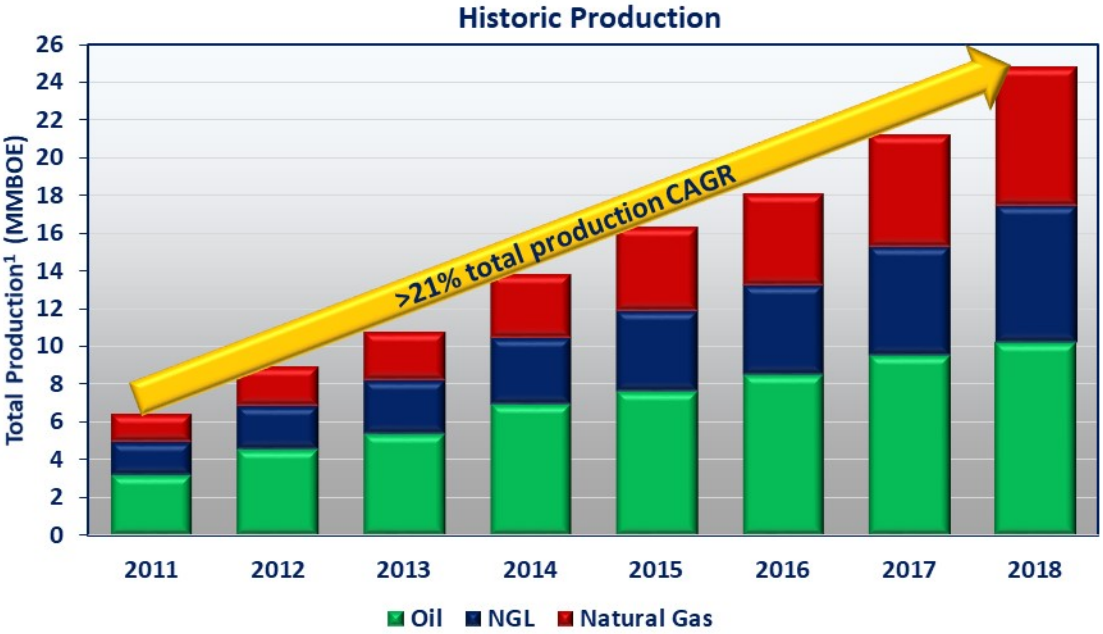
~13% Organic proved developed reserves YoY volume growth

~14% Cash margin per BOE increase YoY[1]

~1.6x Net debt to Adjusted EBITDA[2]

[1]See Appendix for an explanation of Cash Margin per BOE
[2]Net debt to Adjusted EBITDA is calculated as net debt as of 12/31/18 divided by FY-18 Adjusted EBITDA. Net debt as of 12/31/18 is calculated as the face value of long-term debt of $990 MM, reduced by cash on hand of $45 MM. See Appendix for a reconciliation of Net Income to Adjusted EBITDA

History of Consistent Production Growth



~17% YoY growth in FY-18 total production

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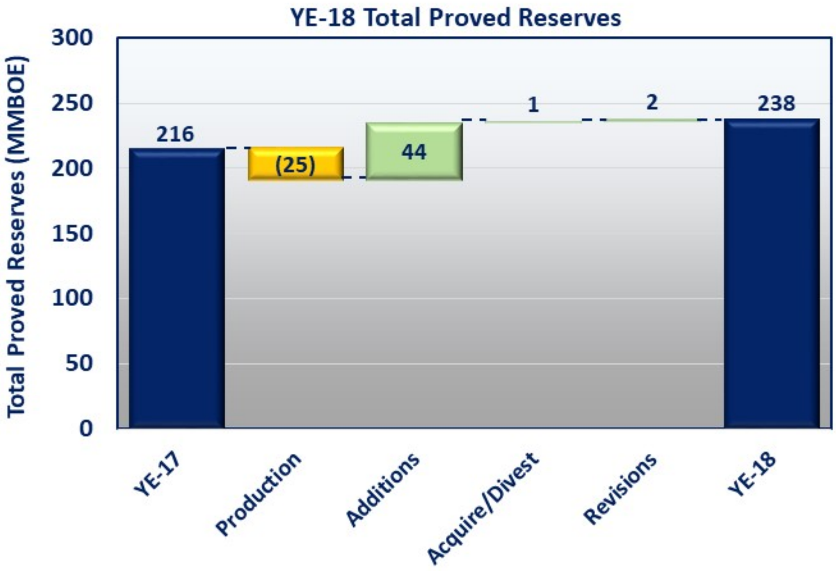
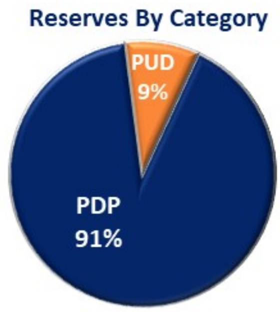
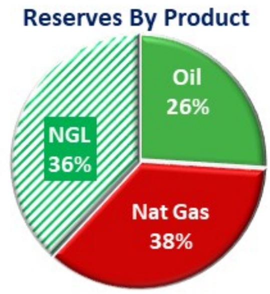
[1] 2011 - 2014 results have been converted to 3-stream using actual gas plant economics. 2011 - 2013 results have been adjusted for Granite Wash divestiture, closed August 1, 2013

Organically Grew Total Proved Reserves In 2018



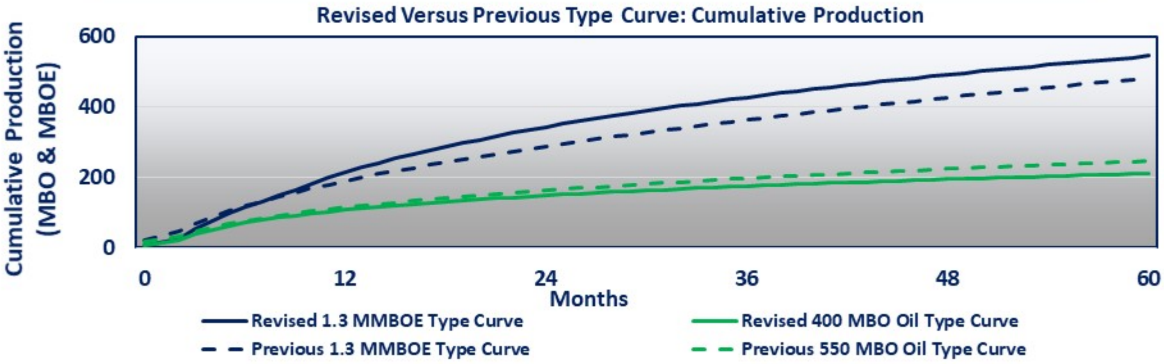




~19% YoY increase in total proved reserves value

Note: Based on YE-18 3-stream proved reserves, prepared by Ryder Scott. Reserves have been rounded to the nearest 1 MMBOE

Revised Type Curve Expected to Yield Similar Returns as Previous



Revised Type Curve: Production By Year			
Year	Oil (MBO)	Total (MBOE)	Oil Cut (%)
1	107	213	50%
2	41	130	32%
3	26	84	31%
4	20	64	31%
5	16	53	30%
5-Year Cumulative	210	544	39%

Previous Type Curve: Production By Year			
Year	Oil (MBO)	Total (MBOE)	Oil Cut (%)
1	114	189	60%
2	49	98	49%
3	34	75	46%
4	27	64	43%
5	23	55	41%
5-Year Cumulative	246	481	51%

Similar returns driven by accelerated natural gas & NGL recoveries

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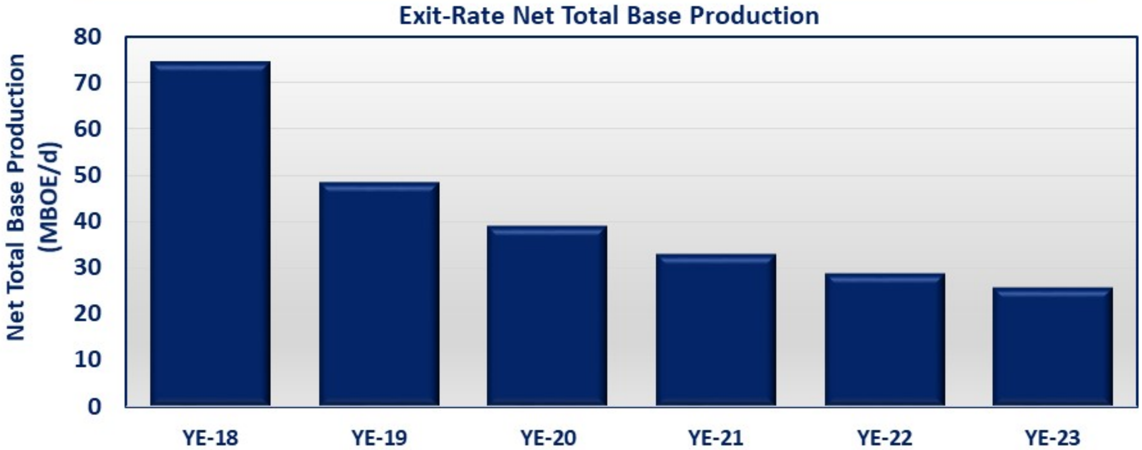
Note: Previous 1.3 MMBOE type curve included a 1.45 b-factor
Revised 1.3 MMBOE type curve includes a 1.20 b-factor
Table may not foot due to rounding

YE-18 Total PDP Reserves 5-Year Decline



	Year 1	Year 2	Year 3	Year 4	Year 5
Decline Rate	-35%	-20%	-15%	-13%	-11%

Natural gas and NGLs are exhibiting flatter declines, yielding shallower total decline rates than oil

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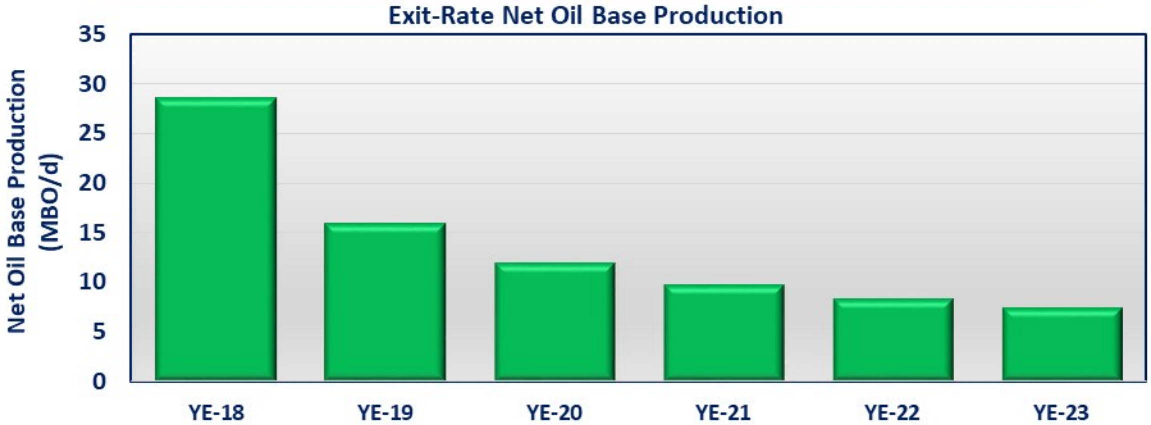
Note: Based on YE-18 3-stream proved reserves, prepared by Ryder Scott

YE-18 Oil PDP Reserves 5-Year Decline



	Year 1	Year 2	Year 3	Year 4	Year 5
Decline Rate	-44%	-25%	-18%	-14%	-12%

Future oil decline rates expected to moderate with wider-spacing development strategy

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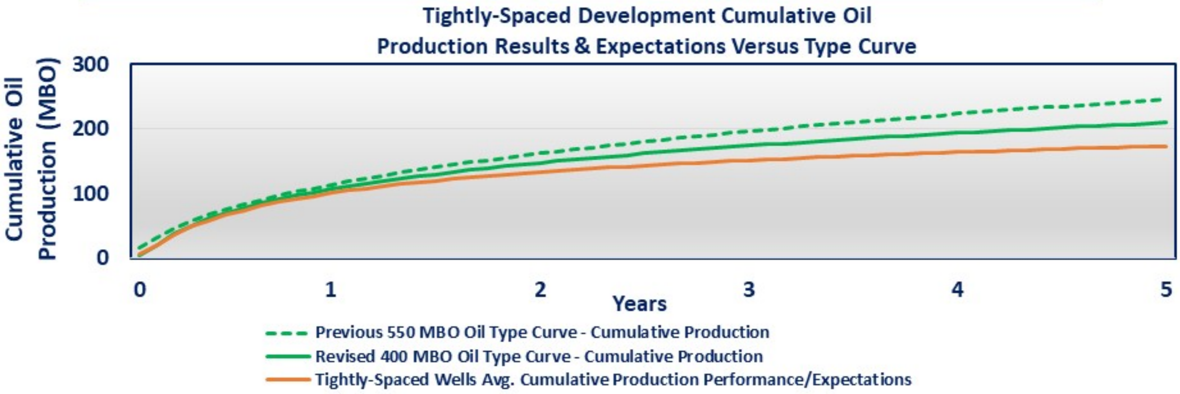
Note: Based on YE-18 3-stream proved reserves, prepared by Ryder Scott

Revised Type Curve Improves Productivity Versus Tighter Wells



Revised Type Curve: Production By Year			
Year	Oil (MBO)	Total (MBOE)	Oil Cut (%)
1	107	213	50%
2	41	130	32%
3	26	84	31%
4	20	64	31%
5	16	53	30%
5-Year Cumulative	210	544	39%

47 Tightly-Spaced Wells: Avg. Production By Year			
Year	Oil (BO)	Total (BOE)	Oil Cut (%)
1	101	198	51%
2	33	116	28%
3	18	84	22%
4	13	62	20%
5	9	49	19%
5-Year Cumulative	174	509	34%

Note: Includes the tightly-spaced 47 UWC/MWC development wells from the Sugg A 157/158, Lane Trust, Fuchs & Sugg D 104, Barbee-B and Sugg A 141/140 packages as of 2/10/2019, normalized to 10,000'
Table may not foot due to rounding

Development Strategy Focused on Wider Spacing

Formation	Development Zone	Wells per DSU: NAV/ Tight Spacing	Wells per DSU: ROR/ Wide Spacing
UWC	UW-AB UW-CD UWE-MWA	12 - 16 Wells	4 - 8 Wells
MWC	MW-B MW-C MW-D	12 - 16 Wells	4 - 8 Wells
LWC	LW-AB LW-C	6 - 8 Wells	4 Wells
Cline	CLINE-AB CLINE-CD	6 - 8 Wells	4 Wells
Total Well Count per DSU		36 - 48 Wells	16 - 24 Wells

Transitioning to wider-spacing development with 1Q-19 spuds, driving expected future improvements in capital efficiency and returns vs 2018

Note: Excludes ABW, Canyon and Spraberry formations
Drilling spacing unit (DSU)

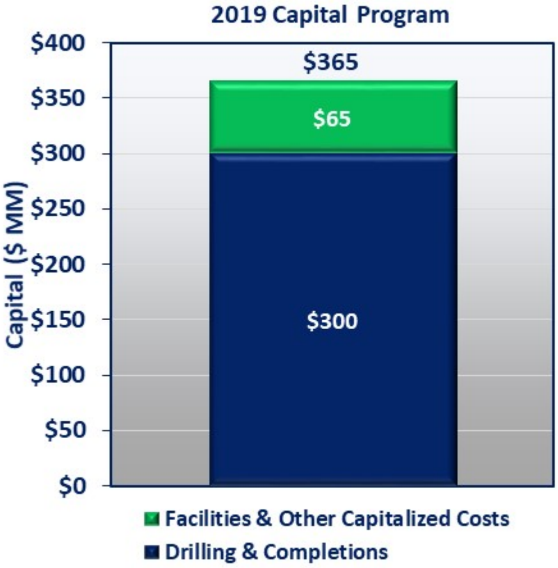
Transitional Year With a Commitment to Cash Flow Neutrality

Expected Activity	1Q-19	2Q-19	3Q-19	4Q-19
Continuous Drilling Activity	~ 3 rigs	~2 rigs	~1 rig	~1 rig
~28 gross well Completions <$54/BO WTI	~2.0 crews	~1.5 crews	0 crews	0 crews
~36 gross well Completions at $54/BO WTI	~2.0 crews	~1.5 crews	~0.5 crew	0 crews
Min. 36 gross well Completions >$54/BO WTI	~2.0 crews	~1.5 crews	Min. 0.5 crew & add'l as needed	

Strategic shift of varying operational cadence to match annual capital with operating cash flow

Any excess free cash flow could be utilized to complete additional wells, repurchase stock or reduce debt

2019 Capital Program Demonstrates Flexibility & Discipline



- **YoY production expectations:**
  - **~9% total production growth**
  - **~5% oil decline**
- **Completing ~34 net wells**
- **~11,400' avg. Hz lateral length**
- **~95% avg. working interest**

Expect to operate within cash flow, driven by front-loaded completions and a measured reduction in activity

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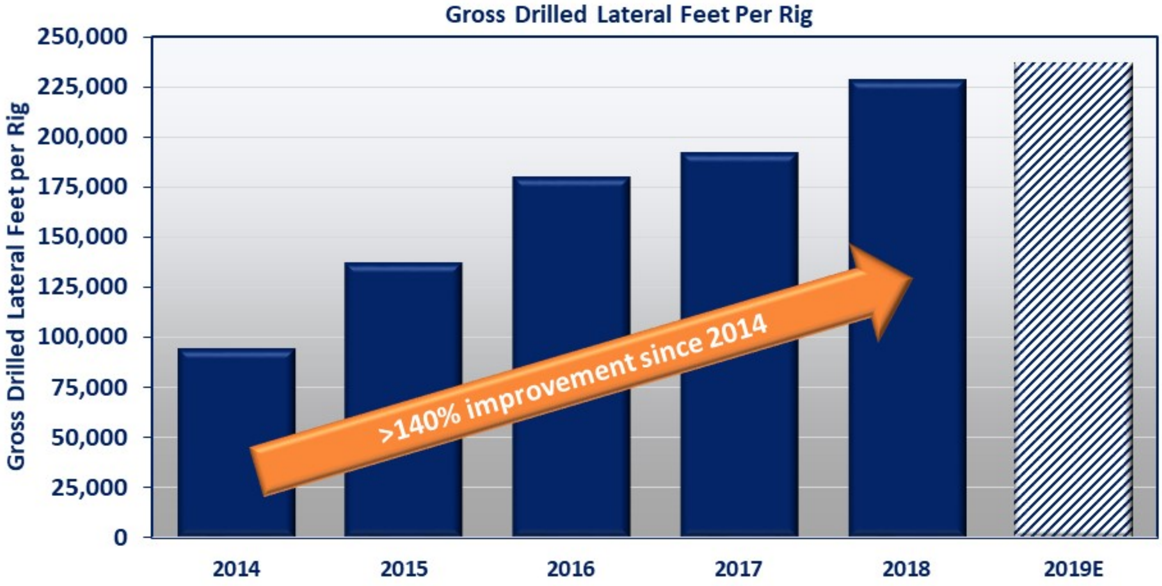
Note: Excludes non-budgeted acquisitions
Capital program based on $54/BO WTI & $2.90/MMBtu HH

History of Improving Drilling Efficiencies



Continuous improvements are enabling us to do more with less

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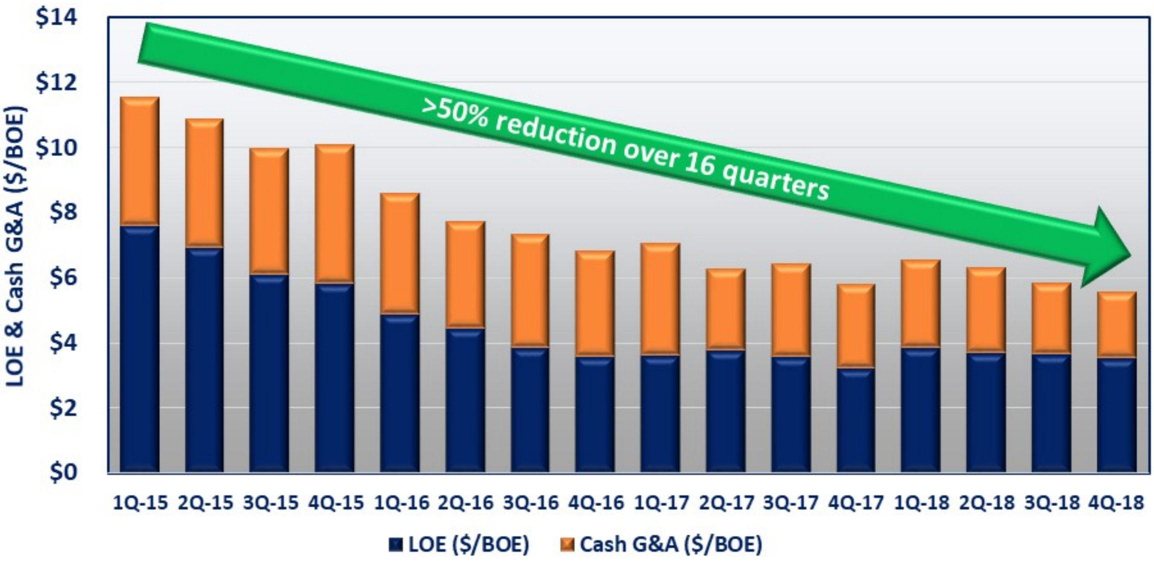
Note: 2019E as of 2/13/2019

Substantial Reduction in Controllable Cash Costs



Striving for further improvements in 2019

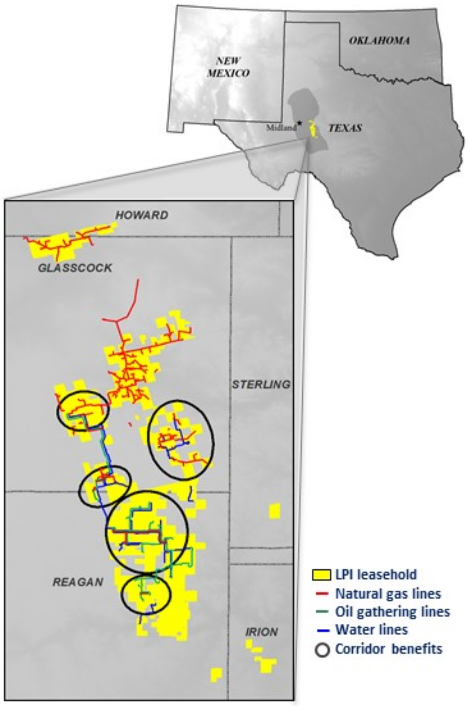
Prior Infrastructure Investments Helping to Reduce Operating Costs

Pipeline Infrastructure

- ~60 miles crude gathering
- ~110 miles water gathering/recycled distribution
- ~180 miles natural gas gathering & distribution
- >220,000 truckloads removed due to LMS infrastructure FY-18

~$32 MM

2018 net benefits from strategic infrastructure investments



Note: Maps, acreage counts and statistics as of 12/31/18
Benefits defined as capital savings, LOE savings, price uplift and LMS net operating income

Redefined Development Strategy Translates to Increased Value

Development Strategy

wider-spacing development + measured growth

- Reduced future oil decline rates
- Cash flow neutrality
- Increased ROR vs. tighter-spaced development
- Improved long-term capital efficiency

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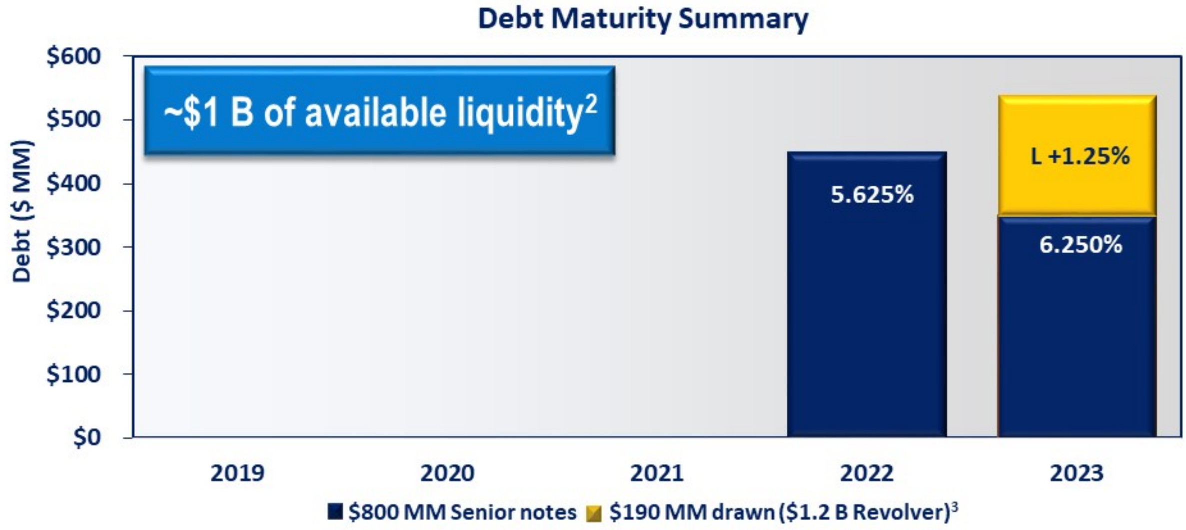
APPENDIX

1Q-19 Guidance

	1Q-19E
Production (MBOE/d)........	74.0
Crude oil production (MBbl/d)........	27.5
Price Realizations (pre-hedge):	
Crude oil (% of WTI)........	~90%
Natural gas liquids (% of WTI)........	~24%
Natural gas (% of Henry Hub)........	~34%
Operating Costs & Expenses:	
Lease operating expenses ($/BOE)........	$3.50
Midstream service expenses ($/BOE)........	$0.15
Transportation and marketing expenses ($/BOE)........	$0.80
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)........	6.50%
General and administrative expenses:	
Cash ($/BOE)........	$2.25
Non-cash stock-based compensation ($/BOE)........	$1.25
Depletion, depreciation and amortization ($/BOE)........	$9.30

Maintaining A Strong Balance Sheet

~1.6x net debt to Adjusted EBITDA[1]



[1]Net debt to Adjusted EBITDA is calculated as net debt as of 12/31/18 divided by FY-18 Adjusted EBITDA. Net debt as of 12/31/18 is calculated as the face value of debt of $990 MM, reduced by cash on hand of $45 MM. See Appendix for a reconciliation of Net Income to Adjusted EBITDA
[2]As of 12/31/18, with $1.2 B aggregate elected commitment in place under Fifth Amended and Restated Senior Secured Credit Facility, decreased by the $190 MM outstanding on the Revolver, increased by cash on hand of $45 MM and reduced by ~$14.7 MM outstanding letter of credit
[3]As of 12/31/18, with $1.2 B aggregate elected commitment in place under Fifth Amended and Restated Senior Secured Credit Facility

Significant Benefits Through Water Infrastructure Investments

Water Infrastructure

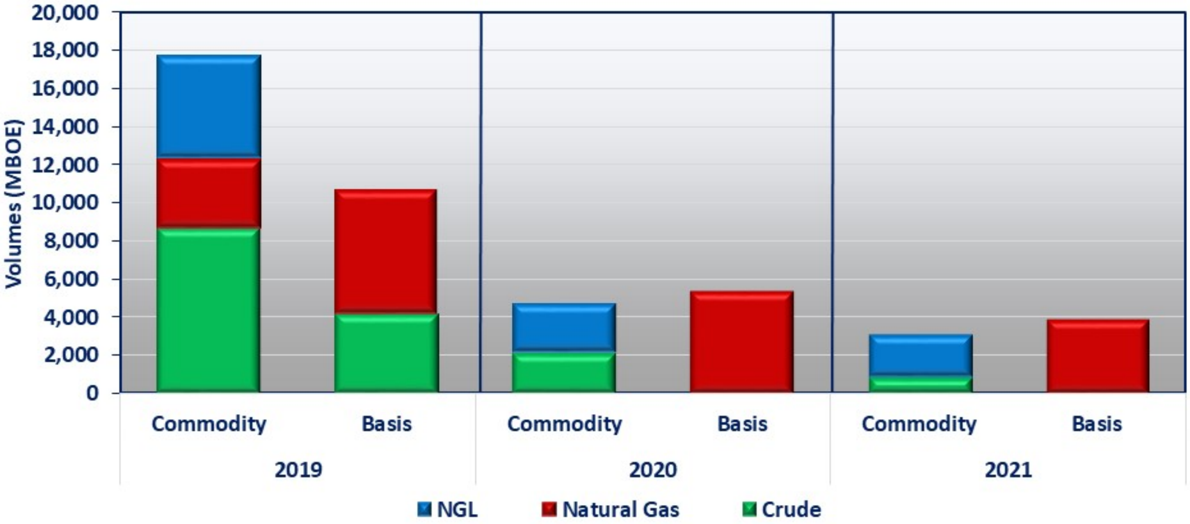
- ~110 miles of water gathering & distribution pipelines
- ~71% of produced water gathered by pipe and ~31% of produced water recycled in 2018
- 54 MBWPD recycling processing capacity
- 22.5 MMBW owned or contracted storage capacity

~$20 MM

FY-18 net savings generated by LMS water infrastructure investments[1]

[1]Calculated utilizing a 95% WI & 74% NRI
Note: Statistics, estimates and maps as of 12/31/18

Consistent Financial Hedging Program



>90% **Cal-19 oil hedges are puts that retain unlimited upside to higher oil prices**

Oil, Natural Gas & Natural Gas Liquids Hedges

Hedge Product Summary	FY-19	FY-20	FY-21
Oil total floor volume (Bbl)	8,687,000	2,196,000	912,500
Oil wtd-avg floor price ($/Bbl)	$47.91	$47.27	$45.00
Oil total floor volume w. deferred premium (Bbl)	*4,745,000*		
Oil wtd-avg deferred premium price ($/Bbl)	*$3.21*		
Nat gas total floor volume (MMBtu)	21,900,000		
Nat gas wtd-avg floor price ($/MMBtu)	$3.23		
NGL total floor volume (Bbl)	5,388,100	2,562,000	2,202,775

Oil	FY-19	FY-20	FY-21
Puts			
Hedged volume (Bbl)	8,030,000	366,000	
Wtd-avg floor price ($/Bbl)	$47.45	$45.00	
Hedged Volume w. Deferred Premium (Bbl)	*4,745,000*		
Wtd-avg deferred premium price ($/Bbl)	*$3.21*		
Swaps			
Hedged volume (Bbl)	657,000	695,400	
Wtd-avg price ($/Bbl)	$53.45	$52.18	
Collars			
Hedged volume (Bbl)		1,134,600	912,500
Wtd-avg floor price ($/Bbl)		$45.00	$45.00
Wtd-avg ceiling price ($/Bbl)		$76.13	$71.00

Natural Gas - HH	FY-19	FY-20	FY-21
Swaps			
Hedged volume (MMBtu)	21,900,000		
Wtd-avg price ($/MMBtu)	$3.23		

Natural Gas Liquids	FY-19	FY-20	FY-21
Swaps - Ethane			
Hedged volume (Bbl)	2,233,000	366,000	912,500
Wtd-avg price ($/Bbl)	$14.21	$13.60	$12.01
Swaps - Propane			
Hedged volume (Bbl)	1,736,800	1,244,400	730,000
Wtd-avg price ($/Bbl)	$27.97	$26.58	$25.52
Swaps – Normal Butane			
Hedged volume (Bbl)	668,000	439,200	255,500
Wtd-avg price ($/Bbl)	$30.73	$28.69	$27.72
Swaps - Isobutane			
Hedged volume (Bbl)	167,000	109,800	67,525
Wtd-avg price ($/Bbl)	$31.08	$29.99	$28.79
Swaps - Natural Gasoline			
Hedged volume (Bbl)	583,300	402,600	237,250
Wtd-avg price ($/Bbl)	$45.83	$45.15	$44.31

Basis Swaps	FY-19	FY-20	FY-21
Mid/Cush			
Hedged volume (Bbl)	2,392,000		
Wtd-avg price ($/Bbl)	-$3.23		
Hou/Mid			
Hedged volume (Bbl)	1,810,000		
Wtd-avg price ($/Bbl)	$7.30		
Waha/HH			
Hedged volume (MMBtu)	39,055,000	32,574,000	23,360,000
Wtd-avg price ($/MMBtu)	-$1.51	-$0.76	-$0.47

Note: Open positions as of 12/31/2018, hedges executed through 2/13/19
See slide 23 for settlement details
Hedged volumes with deferred premiums outlined above are included in provided totals and are therefore not additive

Hedge Settlement Details

Other than the oil basis swaps, the Company's oil derivatives are settled based on the month's arithmetic average of the daily settlement prices for the NYMEX index price for the first nearby month of the West Texas Intermediate Light Sweet Crude Oil Futures Contract.

The oil basis swaps are settled based on the differential between the basis swaps' fixed differential price as compared to the differential between the arithmetic average of each day's index prices for the first nearby month on the pricing dates in each calculation period with the index prices being either (i) the Argus Americas Crude's West Texas Intermediate ("WTI") Midland-weighted average and the Cushing-based NYMEX West Texas Intermediate Light Sweet Crude Oil Futures Contract, (ii) the Argus Americas Crude's WTI Midland-weighted average and the WTI formula basis or (iii) the Argus Americas Crude's WTI Houston-weighted average and the WTI Midland-weighted average.

The Company's NGL derivatives are settled based on the month's arithmetic average of the daily average of the high and low OPIS index prices for Mont Belvieu Purity Ethane, TET and Non-TET Propane, Non-TET Normal Butane, Non-TET Isobutane and Non-TET Natural Gasoline.

Other than the natural gas basis swaps, the Company's natural gas derivatives are settled based on the Inside FERC index price for West Texas WAHA or the NYMEX index price for Henry Hub for the calculation period. The natural gas basis swaps are settled based on the differential between the basis swaps' fixed differential price as compared to the differential between the Inside FERC index price for West Texas WAHA and the NYMEX index price for Henry Hub for the calculation period.

Supplemental Non-GAAP Financial Measure

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for depletion, depreciation and amortization, non-cash stock-based compensation, net, accretion expense, mark-to-market on derivatives, premiums paid for derivatives, interest expense, gains or losses on disposal of assets and other non-recurring income and expenses. Adjusted EBITDA provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, working capital movement or tax position. Adjusted EBITDA does not represent funds available for discretionary use because those funds are required for debt service, capital expenditures, working capital, income taxes, franchise taxes and other commitments and obligations. However, our management believes Adjusted EBITDA is useful to an investor in evaluating our operating performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods, the book value of assets, capital structure and the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and
- is used by our management for various purposes, including as a measure of operating performance, in presentations to our board of directors and as a basis for strategic planning and forecasting.

There are significant limitations to the use of Adjusted EBITDA as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations to different companies and the different methods of calculating Adjusted EBITDA reported by different companies. Our measurements of Adjusted EBITDA for financial reporting as compared to compliance under our debt agreements differ.

(in thousands, unaudited)	FY-18
Net income	$324,595
Plus:	
Income tax expense	4,249
Depletion, depreciation and amortization	212,677
Non-cash stock-based compensation, net	36,396
Accretion expense	4,472
Mark-to-market on derivatives:	
(Gain) loss on derivatives, net	(42,984)
Settlements received for matured derivatives, net	6,090
Premiums paid for derivatives	(20,335)
Interest expense	57,904
Loss on disposal of assets, net	5,798
Adjusted EBITDA	$588,862

Cash Margin Per BOE

($/BOE)[1]	2018	2017
Average sales price without derivatives[2]	$32.50	$29.22
Minus:		
Lease operating expenses	$3.67	$3.53
Production and ad valorem taxes	$1.99	$1.78
Transportation and marketing expenses	$0.47	---
Midstream service expenses	$0.12	$0.19
General and administrative – cash	$2.40	$2.85
Cash Margin	$23.85	$20.87

[1] The numbers presented above are based on actual results and are not calculated using rounded numbers
[2] Realized oil, NGL and natural gas prices are the actual prices received when control passes to the purchaser/customer adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.