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): May 2, 2018

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 May 2, 2018, Laredo Petroleum, Inc. (the "Company") announced its financial and operating results for the quarter ended March 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 May 3, 2018 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 3698623. A replay of the call will be available through Thursday, May 10, 2018, by dialing 1-855-859-2056, and using conference code 3698623. 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 May 2, 2018, 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 May 2, 2018, 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 May 2, 2018 announcing financial and operating results.
99.2	Presentation dated May 2, 2018.

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: May 2, 2018	By:	/s/ Richard C. Buterbaugh
		Richard C. Buterbaugh
		Executive Vice President & Chief Financial Officer

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Laredo Petroleum Announces 2018 First-Quarter Financial and Operating Results

TULSA, OK - May 2, 2018 - Laredo Petroleum, Inc. (NYSE: LPI) ("Laredo" or "the Company") today announced its 2018 first-quarter results, reporting net income attributable to common stockholders of $86.5 million, or $0.36 per diluted share. Adjusted Net Income, a non-GAAP financial measure, for the first quarter of 2018 was $57.6 million, or $0.24 per diluted share. Adjusted EBITDA, a non-GAAP financial measure, for the first quarter of 2018 was $143.4 million. Please see supplemental financial information at the end of this news release for reconciliations of non-GAAP financial measures.

2018 First-Quarter Highlights

- Produced a Company record 63,314 barrels of oil equivalent ("BOE") per day and increased anticipated production growth for full-year 2018 to greater than 12%
- Reduced unit cash costs to $8.74 per BOE, a decrease of approximately 4% from the first quarter of 2017
- Increased Adjusted EBITDA to $143.4 million, up 33% from the first quarter of 2017
- Repurchased 6,727,901 shares of common stock at a weighted-average price of $8.69 per share for $58.5 million under the Company's share repurchase program

"Operational results in the first quarter were in-line with expectations as we overcame delays from adverse weather at the beginning of the quarter," stated Randy A. Foutch, Chairman and Chief Executive Officer. "We completed four more wells than projected, driven by efficiency gains in our completions operations that pulled wells forward from the second quarter. The results our drilling and completions teams were able to accomplish to shorten cycle times significantly improved efficiency during the quarter."

"We are increasing our production expectations for 2018 as our work to optimize contract areas on our contiguous acreage is increasing both the working interest and lateral lengths of our wells. Additionally, the longer-term results from well packages designed to test tighter spacing are encouraging. We are aggressively moving forward with our development utilizing 32 Upper/Middle Wolfcamp wells per drilling spacing unit which, coupled with shorter cycle times and an accelerated pace of drilling, is expected to drive improved capital efficiency. We now anticipate adding a fifth horizontal drilling rig around the end of 2018 or beginning of 2019."

E&P Update

In the first quarter of 2018, Laredo produced a Company record 63,314 BOE per day, completing 20 gross (20 net) horizontal wells with an average completed lateral length of approximately 9,700 feet. The number of completions in first-quarter 2018 was positively impacted by shortened cycle times, reflecting efficiency improvements related to contracting a second dedicated completions crew and completion design modifications.

Laredo continued to utilize various completion designs during the first quarter with the goal of improving productivity, reducing capital costs and driving improved capital efficiency. Design refinements included lengthening stages, reducing fluid concentrations and utilizing PerfExtra, the Gas Technology Institutes' patented hydraulic fracturing technology. These completion designs were planned as parts of larger well packages wherein the remaining wells were completed with the Company's standard design in order to obtain a direct comparison of the wells' productivity. Well productivity is balanced with the capital savings to assess the value of the completion design modifications. Lengthening stages and reducing fluid concentrations both contributed to cycle time and capital costs reductions. The initial productivity of the wells with reduced fluid concentration has been below expectations, although additional production data will be needed to determine the impact on longer-term capital efficiency. The Company does expect to continue to phase in longer stage lengths and PerfExtra on wells throughout the year, as they are positive for capital efficiency.

Unit lease operating expenses ("LOE") were $3.85 per BOE in the first quarter of 2018, the seventh consecutive quarter of unit LOE less than $4.00 per BOE. Cost pressure and non-recurring well work contributed to the increase from fourth-quarter 2017. The Company's guidance for second-quarter 2018 unit LOE of $3.70 per BOE is expected to be more reflective of unit LOE for the remainder of 2018.

Laredo expects to complete 17 gross horizontal wells (16.5 net) in the second quarter of 2018 with an average completed lateral length of approximately 10,800 feet. Eleven of these wells are being developed as a package and are not expected to begin flowback until the end of second-quarter 2018. The Company is currently operating three horizontal drilling rigs and is in the process of adding a fourth rig at the beginning of the third quarter. Laredo also expects to add a fifth horizontal rig around the end of 2018 or beginning of 2019 as completion efficiency gains and the current commodity price environment drive increasing operating cash flow.

The Company expects average completed lateral length to increase throughout 2018. Laredo's first three 15,000-foot horizontal wells have continued to improve since they were completed in the third quarter of 2017 and their average cumulative production is now performing in-line with the Company's Upper/Middle Wolfcamp type curve, adjusted for their lateral length. Laredo's contiguous acreage currently supports more than 500 land-ready Upper/Middle Wolfcamp locations of at least 15,000 feet.

Positive results from previously drilled co-developed packages support Laredo's transition to a 32 Upper/Middle Wolfcamp wells per drilling spacing unit ("DSU") development plan. The Sugg-A 157/158 five-well package, developed on 32 Upper/Middle Wolfcamp wells per DSU spacing and completed in the second and third quarters of 2017, is performing above type curve after approximately nine months. The nine-well Lane Trust package, developed on 24 Upper/Middle Wolfcamp wells per DSU spacing and completed in the fourth quarter of 2017, is also performing above type curve. Throughout the remainder of 2018, Laredo expects approximately 20 to 25 of its remaining completions in 2018 to be developed on 32 Upper/Middle Wolfcamp wells per DSU spacing.

The Company is increasing its anticipated full-year 2018 total production growth guidance to greater than 12% and reiterating previously-issued oil production growth guidance of greater than 10% as compared to 2017. Quarterly production growth is expected to be uneven as three packages of at least eight wells are scheduled to be brought on production throughout the last seven months of 2018.

Crude Marketing

Laredo crude marketing has focused on achieving the ability to sell crude in multiple markets and protecting the Company's oil pricing from basin differentials. The Company entered into a crude oil purchase agreement with Shell Trading (US) Company ("Shell") effective October 1, 2016 through June 30, 2020 ("the Contract"), for this purpose. The Contract provided a menu of pricing alternatives that enabled Laredo, at the Company's option, to take advantage of Midland market pricing as well as U.S. Gulf Coast market pricing.

As previously reported, on May 3, 2017, Shell sued Laredo, alleging that the Contract did not accurately reflect the compensation to be paid to Shell under one of the pricing options due to a drafting mistake, despite clear language in the Contract to the contrary. Laredo does not believe that there was a drafting mistake. Although the Contract is still the subject of litigation regarding the alleged mistake and other related claims asserted by Shell, as of May 1, 2018, Shell has terminated the Contract and informed Laredo that it will no longer continue to purchase crude oil from Laredo, as well as sell crude oil to Laredo, as it is required to do under the Contract. Laredo believes the termination was improper and the Company intends to vigorously pursue its rights under the terminated Contract and seek all appropriate damages from Shell. The Company continues to believe that Shell's claims are without merit.

Although not reflective of the total damages caused by Shell's wrongful termination, the estimated current net impact to Laredo's crude oil price realization as a result of the Shell breach is the reduction of aggregate second-quarter 2018 forecasted crude oil price realizations from 95% of West Texas Intermediate ("WTI") to 91% of WTI. The Company estimates that approximately 70% of its anticipated crude oil production for the remainder of 2018 is still protected from the Midland basis differential through a combination of 10,000 barrels of oil per day ("BOPD") of Midland-Cushing basis swaps and 10,000 BOPD of Laredo's firm capacity on the Bridgetex pipeline, hedged with Midland-Houston basis swaps, providing Laredo exposure to pricing at the U.S. Gulf Coast market.

Further discussion regarding the litigation will be included in the Company's Quarterly Report on Form 10-Q.

Natural Gas Marketing

The Company, through Laredo Midstream Services, LLC ("LMS"), a wholly-owned subsidiary of Laredo, owns approximately 170 miles of natural gas gathering pipelines. By owning the pipelines that deliver natural gas to processors' systems instead of utilizing gathering infrastructure owned by a processor, Laredo is better able to manage the delivery of its gas for sales. Should a processor be unable to accept the Company's natural gas production due to curtailments, Laredo's owned natural gas gathering system has the ability to shift production to another processor for continued natural gas sales.

In addition to the Company's focus on field-level flow assurance, Laredo makes substantial efforts to protect anticipated cash flows generated from the sales of the Company's produced natural gas. For 2018, the Company has hedged approximately 75% of anticipated natural gas production to protect from a widening Waha basis. For the second quarter of 2018, resulting from a severe widening of the Waha basis, Laredo anticipates the Company's realized price for natural gas will be approximately 36% of Henry Hub. If the Company's natural gas hedges and basis swaps were included in realized pricing, the anticipated realized price would rise to 62% of Henry Hub.

2018 Capital Program

During the first quarter of 2018, Laredo invested approximately $140 million in drilling and completion activities. Other expenditures incurred during the quarter included approximately $3 million in bolt-on land acquisitions, lease extensions and data, approximately $8 million in infrastructure, including LMS investments, and approximately $10 million in other capitalized costs.

The Company's expected working interest and lateral length for wells completed in 2018 has increased from original budget expectations to approximately 95% and 10,600 feet, respectively. Additionally, delayed implementation of in-basin sand is impacting well costs. Including these new expectations, drilling and completion capital for 2018 is expected to increase $30 million to $500 million. Other capital expenditures are expected to remain unchanged at $85 million, bringing total annual capital expenditures to $585 million.

Liquidity

At March 31, 2018, the Company had cash and cash equivalents of approximately $56 million and undrawn capacity under the senior secured credit facility of $945 million, resulting in total liquidity of approximately $1.0 billion.

On April 19, 2018, in connection with the semi-annual redetermination of the Company's senior secured credit facility, lenders increased the Company's borrowing base to $1.3 billion and Laredo increased its elected commitment to $1.2 billion. The pricing grid for the facility was reduced by 75 basis points for drawn amounts at all utilization breakpoints.

At May 1, 2018, the Company had cash and equivalents of approximately $81 million and available capacity under the senior secured credit facility of $1.09 billion, resulting in total available liquidity of approximately $1.17 billion.

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 contracts 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 2018 and has oil hedges through 2020. Laredo has also entered into NGL and natural gas hedges through 2018 and basis hedges through 2020. 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 is increasing its anticipated full-year 2018 total production growth guidance to greater than 12% and reiterating previously issued oil production growth guidance of greater than 10% as compared to 2017. The table below reflects the Company's guidance for the second quarter of 2018.

	2Q-2018E
Total production (MBOE/d)	64.0
Oil production (MBO/d)	27.4
Price Realizations (pre-hedge):	
Crude oil (% of WTI)	91%
Natural gas liquids (% of WTI)	28%
Natural gas (% of Henry Hub)	36%
Operating Costs & Expenses:	
Lease operating expenses ($/BOE)	$3.70
Midstream expenses ($/BOE)	$0.15
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)	6.25%
General and administrative expenses:	
Cash ($/BOE)	$2.70
Non-cash stock-based compensation ($/BOE)	$1.85
Depletion, depreciation and amortization ($/BOE)	$8.00

Conference Call Details

On Thursday, May 3, 2018, at 7:30 a.m. CT, Laredo will host a conference call to discuss its first-quarter 2018 financial and operating results and management’s outlook, the content of which is not part of this earnings release. A slide presentation providing summary financial and statistical information that will be discussed on the call will be posted to the Company’s website and available for review. The Company invites interested parties to listen to the call via the Company’s website at www.laredopetro.com, under the tab for "Investor Relations." Portfolio managers and analysts who would like to participate on the call should dial 877.930.8286, using conference code 3698623, approximately 10 minutes prior to the scheduled conference time. International participants should dial 253.336.8309, also using conference code 3698623. A telephonic replay will be available approximately two hours after the call on May 3, 2018 through Thursday, May 10, 2018. Participants may access this replay by dialing 855.859.2056, using conference code 3698623.

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 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, the suspension or discontinuance of share repurchases at any time 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 and Exchange Commission ("SEC"). These documents are available through Laredo's website at www.laredopetro.com under the tab "Investor Relations" or through the SEC's Electronic Data Gathering and Analysis Retrieval System at www.sec.gov. Any of these factors could cause Laredo's actual results and plans to differ materially from those in the forward-looking statements. Therefore, Laredo can give no assurance that its future results will be as estimated. Laredo does not intend to, and disclaims any obligation to, update or revise any forward-looking statement.

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," 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 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 reserves may change significantly as development of the Company's core assets provides additional data. In addition, our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

Laredo Petroleum, Inc.
Condensed consolidated statements of operations

(in thousands, except per share data)	Three months ended March 31, 2018	2017
	(unaudited)	
Revenues:		
Oil, NGL and natural gas sales	$ 197,434	$ 138,736
Midstream service revenues	2,359	2,999
Sales of purchased oil	59,903	47,271
Total revenues	259,696	189,006
Costs and expenses:		
Lease operating expenses	21,951	16,992
Production and ad valorem taxes	11,812	8,781
Midstream service expenses	693	916
Costs of purchased oil	60,664	50,256
General and administrative	24,725	25,597
Depletion, depreciation and amortization	45,553	34,112
Other operating expenses	1,106	1,026
Total costs and expenses	166,504	137,680
Operating income	93,192	51,326
Non-operating income (expense):		
Gain on derivatives, net	9,010	36,671
Income from equity method investee[(1)]	—	3,068
Interest expense	(13,518)	(22,720)
Other, net	(2,164)	(69)
Non-operating income (expense), net	(6,672)	16,950
Income before income taxes	86,520	68,276
Income tax:		
Deferred	—	—
Total income tax	—	—
Net income	$ 86,520	$ 68,276
Net income per common share:		
Basic	$ 0.36	$ 0.29
Diluted	$ 0.36	$ 0.28
Weighted-average common shares outstanding:		
Basic	238,228	238,505
Diluted	239,319	244,379

(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 balance sheets

(in thousands)	March 31, 2018	December 31, 2017
	(unaudited)	
Assets:		
Current assets	$ 185,193	$ 235,382
Property and equipment, net	1,882,249	1,768,385
Noncurrent assets	20,089	19,522
Total assets	$ 2,087,531	$ 2,023,289
Liabilities and stockholders' equity:		
Current liabilities	$ 239,666	$ 277,419
Long-term debt, net	847,300	791,855
Noncurrent liabilities	58,735	188,436
Stockholders' equity	941,830	765,579
Total liabilities and stockholders' equity	$ 2,087,531	$ 2,023,289

Laredo Petroleum, Inc.
Condensed consolidated statements of cash flows

(in thousands)	Three months ended March 31, 2018	Three months ended March 31, 2017
	(unaudited)	
Cash flows from operating activities:		
Net income	$ 86,520	$ 68,276
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation and amortization	45,553	34,112
Non-cash stock-based compensation, net	9,339	9,224
Mark-to-market on derivatives:		
Gain on derivatives, net	(9,010)	(36,671)
Settlements (paid) received for matured derivatives, net	(2,236)	7,451
Premiums paid for derivatives	(4,024)	(2,107)
Other, net[1]	5,308	(762)
Cash flows from operations before changes in assets and liabilities	131,450	79,523
Decrease (increase) in current assets and liabilities, net	15,495	(15,695)
Increase in other noncurrent assets and liabilities, net	(474)	(44)
Net cash provided by operating activities	146,471	63,784
Cash flows from investing activities:		
Capital expenditures:		
Oil and natural gas properties	(195,025)	(110,542)
Midstream service assets	(3,362)	(1,731)
Other fixed assets	(3,963)	(1,203)
Proceeds from disposition of equity method investee, net of selling costs[1]	1,655	—
Proceeds from dispositions of capital assets, net of selling costs	1,021	59,515
Net cash used in investing activities	(199,674)	(53,961)
Cash flows from financing activities:		
Borrowings on Senior Secured Credit Facility	55,000	50,000
Payments on Senior Secured Credit Facility	—	(55,000)
Share repurchases	(53,714)	—
Other, net	(4,353)	(7,143)
Net cash used in financing activities	(3,067)	(12,143)
Net decrease in cash and cash equivalents	(56,270)	(2,320)
Cash and cash equivalents, beginning of period	112,159	32,672
Cash and cash equivalents, end of period	$ 55,889	$ 30,352

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

Laredo Petroleum, Inc.
Selected operating data

	Three months ended March 31,	
	2018	2017
	(unaudited)	
Sales volumes:		
Oil (MBbl)	2,439	2,120
NGL (MBbl)	1,563	1,263
Natural gas (MMcf)	10,173	8,000
Oil equivalents (MBOE)[1][2]	5,698	4,716
Average daily sales volumes (BOE/D)[2]	63,314	52,405
% Oil[2]	43%	45%
Average sales prices[2]:		
Oil, realized ($/Bbl)[3]	$ 61.87	$ 46.91
NGL, realized ($/Bbl)[3]	$ 18.14	$ 16.49
Natural gas, realized ($/Mcf)[3]	$ 1.79	$ 2.31
Average price, realized ($/BOE)[3]	$ 34.65	$ 29.42
Oil, hedged ($/Bbl)[4]	$ 58.53	$ 49.70
NGL, hedged ($/Bbl)[4]	$ 18.11	$ 16.04
Natural gas, hedged ($/Mcf)[4]	$ 1.85	$ 2.31
Average price, hedged ($/BOE)[4]	$ 33.34	$ 30.55
Average costs per BOE sold[2]:		
Lease operating expenses	$ 3.85	$ 3.60
Production and ad valorem taxes	2.07	1.86
Midstream service expenses	0.12	0.19
General and administrative:		
Cash	2.70	3.47
Non-cash stock-based compensation, net	1.64	1.96
Depletion, depreciation and amortization	7.99	7.23
Total costs and expenses	$ 18.37	$ 18.31
Cash margins per BOE sold[2]:		
Realized	$ 25.91	$ 20.30
Hedged	$ 24.60	$ 21.43

(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 realized at the wellhead adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

(4) Hedged prices reflect the after-effects of our hedging transactions on our average sales prices. Our calculation of such after-effects includes current period settlements of matured derivatives in accordance with GAAP and an adjustment to reflect premiums incurred previously or upon settlement that are attributable to instruments that settled in the period.

Laredo Petroleum, Inc.
Costs incurred

The following table presents costs incurred in the acquisition, exploration and development of oil and natural gas properties:

	Three months ended March 31,	
(in thousands)	**2018**	**2017**
	(unaudited)	
Property acquisition costs:		
Evaluated	$ —	$ —
Unevaluated	—	—
Exploration costs	6,137	15,543
Development costs	149,038	111,158
Total costs incurred	$ 155,175	$ 126,701

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 and Adjusted EBITDA should not be considered in isolation or as a substitute for GAAP measures, such as net income or loss, operating income or loss or any other GAAP measure of liquidity or financial performance.

Adjusted Net Income

Adjusted Net Income is a non-GAAP financial measure we use to evaluate performance, prior to income tax expense or benefit, 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 March 31,	
(in thousands, except per share data)	2018	2017
	(unaudited)	
Income before income taxes	$ 86,520	$ 68,276
Plus:		
Mark-to-market on derivatives:		
Gain on derivatives, net	(9,010)	(36,671)
Settlements (paid) received for matured derivatives, net	(2,236)	7,451
Premiums paid for derivatives	(4,024)	(2,107)
Loss on disposal of assets, net	2,617	214
Adjusted income before adjusted income tax expense	73,867	37,163
Adjusted income tax expense[1]	(16,251)	(13,379)
Adjusted Net Income	$ 57,616	$ 23,784
Net income per common share:		
Basic	$ 0.36	$ 0.29
Diluted	$ 0.36	$ 0.28
Adjusted Net Income per common share:		
Basic	$ 0.24	$ 0.10
Diluted	$ 0.24	$ 0.10
Weighted-average common shares outstanding:		
Basic	238,228	238,505
Diluted	239,319	244,379

(1) Adjusted income tax expense is calculated by applying a statutory tax rate of 22% for the three months ended March 31, 2018, in response to recent changes in the tax code, and 36% for the three months ended March 31, 2017.

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, income or loss from equity method investee, proportionate Adjusted EBITDA of 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):

	Three months ended March 31,	
(in thousands)	2018	2017
	(unaudited)	
Net income	$ 86,520	$ 68,276
Plus:		
Depletion, depreciation and amortization	45,553	34,112
Non-cash stock-based compensation, net	9,339	9,224
Accretion expense	1,106	928
Mark-to-market on derivatives:		
Gain on derivatives, net	(9,010)	(36,671)
Settlements (paid) received for matured derivatives, net	(2,236)	7,451
Premiums paid for derivatives	(4,024)	(2,107)
Interest expense	13,518	22,720
Loss on disposal of assets, net	2,617	214
Income from equity method investee[1]	—	(3,068)
Proportionate Adjusted EBITDA of equity method investee[1][2]	—	6,365
Adjusted EBITDA	$ 143,383	$ 107,444

____

(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:

	Three months ended March 31,	
(in thousands)	2018	2017
	(unaudited)	
Income from equity method investee	$ —	$ 3,068
Adjusted for proportionate share of depreciation and amortization	—	3,297
Proportionate Adjusted EBITDA of equity method investee	$ —	$ 6,365

# # #

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18-6

EXHIBIT 99.2

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

Corporate Presentation
May 2018

LAREDO
PETROLEUM

Forward-Looking / Cautionary Statements

This presentation, including any oral statements made regarding the contents of this presentation, contains 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. All statements, other than statements of historical fact, included in this presentation that address activities, events or developments that Laredo Petroleum, Inc. (together with its subsidiaries, the "Company", "Laredo" or "LPI") assumes, plans, expects, believes or anticipates will or may occur in the future are forward-looking statements. The words "believe," "expect," "may," "estimates," "will," "anticipate," "plan," "project," "intend," "indicator," "foresee," "forecast," "guidance," "should," "would," "could," "goal," "target," "suggest" or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature and are not guarantees of future performance. However, the absence of these words does not mean that the statements are not forward-looking. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include the expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including the Company's drilling program, production, hedging activities, capital expenditure levels, possible impacts of pending or potential litigation and other guidance included in this presentation. These statements are based on certain assumptions made by the Company based on management's expectations and perception of historical trends, current conditions, anticipated future developments and rate of return and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include risks relating to financial performance and results, current economic conditions and resulting capital restraints, prices and demand for oil and natural gas and the related impact to financial statements as a result of asset impairments and revisions to reserve estimates, availability and cost of drilling equipment and personnel, availability of sufficient capital to execute the Company's business plan, impact of compliance with legislation and regulations, impacts of pending or potential litigation, impacts relating to the Company's share repurchase program (which may be suspended or discontinued by the Company at any time without notice), successful results from the Company's identified drilling locations, the Company's ability to replace reserves and efficiently develop and exploit its current reserves and other important factors that could cause actual results to differ materially from those projected as described in the Company's Annual Report on Form 10-K for the year ended December 31, 2017 and other reports filed with the Securities and Exchange Commission ("SEC").

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 to disclose proved reserves in filings made with the SEC, 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 "unproved reserves," "resource potential," "estimated ultimate recovery," "EUR," "development ready," "type curve" or other descriptions of potential reserves or volumes of reserves which the SEC guidelines restrict from being included in filings with the SEC without strict compliance with SEC definitions. "Unproved reserves" refers to the Company's internal estimates of 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. The Company does not choose to include unproved reserve estimates in its filings with the SEC. "Estimated ultimate recovery", or "EUR", refers to the Company's internal estimates of per-well hydrocarbon quantities that may be potentially recovered from a hypothetical and/or actual well completed in the area. Actual quantities that may be ultimately recovered from the Company's interests are unknown. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability and cost of drilling services and equipment, lease expirations, transportation constraints, regulatory approvals and other factors, as well as actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of ultimate recovery from reserves may change significantly as development of the Company's core assets provide additional data. "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 and Proved F&D Cost. 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 and Proved F&D Cost to the nearest comparable measure in accordance with GAAP, please see the Appendix.

1Q-18 Highlights & FY-18 Expectations

~21% Production growth YoY from 1Q-17

>12% Increased anticipated FY-18E BOE production growth

$25.91 1Q-18 cash margin per BOE

~1.4x Net debt to Adjusted EBITDA[1]

$58.5 MM utilized to repurchase 6.7 MM shares

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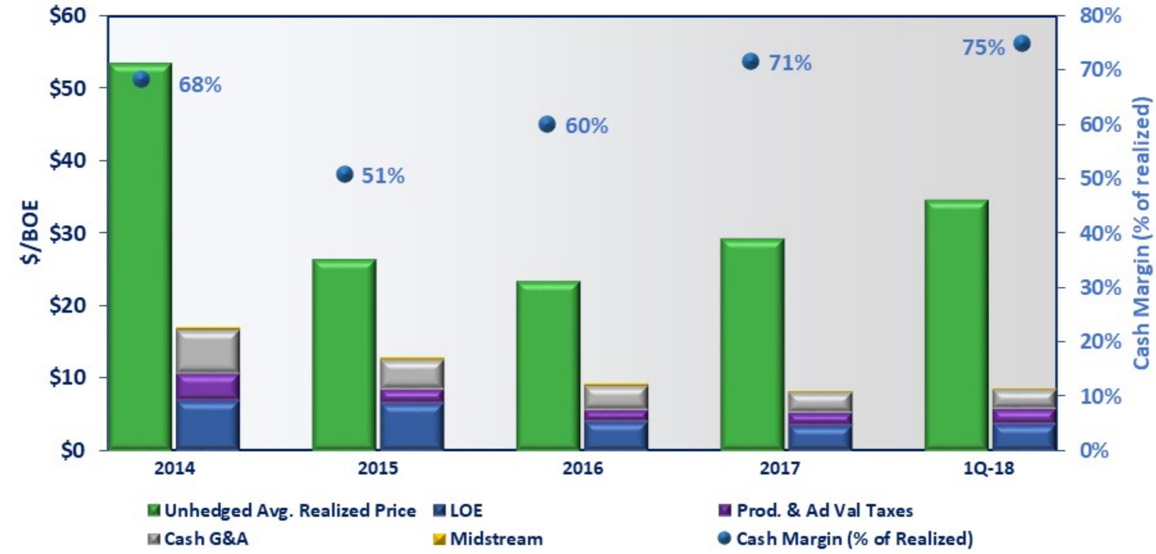
[1] Net debt to Adjusted EBITDA includes net debt as of 3/31/18 and 1Q-18 annualized Adjusted EBITDA. Net debt as of 3/31/18 is calculated as the face value of long-term debt of $855 MM, reduced by cash on hand of $56 MM. See Appendix for a reconciliation of Net Income to Adjusted EBITDA

Cash Margin Improved By Controlling Cash Costs



75% **Current cash margin % exceeds pre-price decline cash margin[1]**

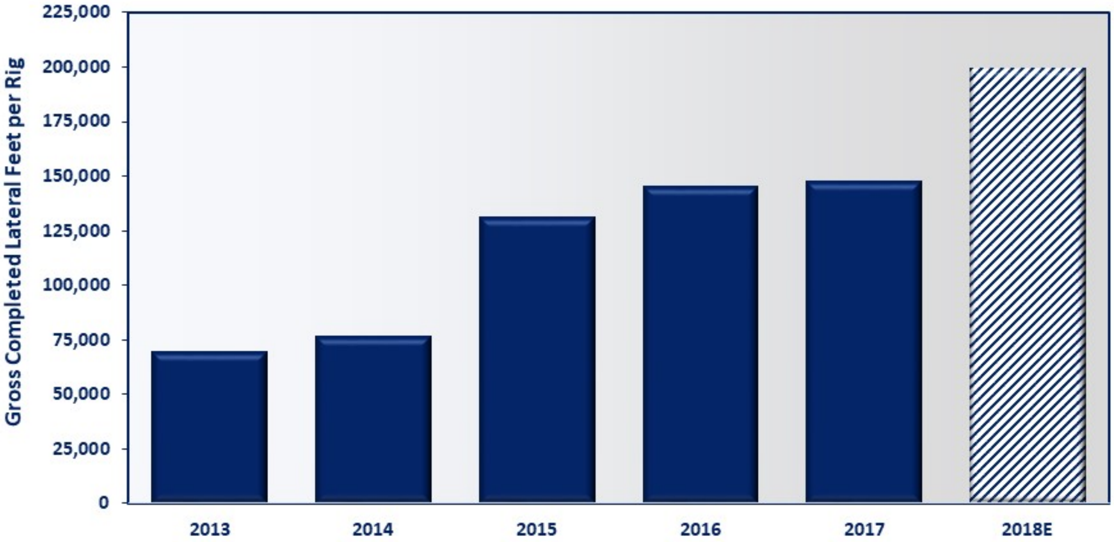
[1] Current cash margin as a percent of unhedged average realized price

Note: 2014 cash margin has been converted to 3-stream using actual gas plant economics

2018 Drilling & Completions Plan

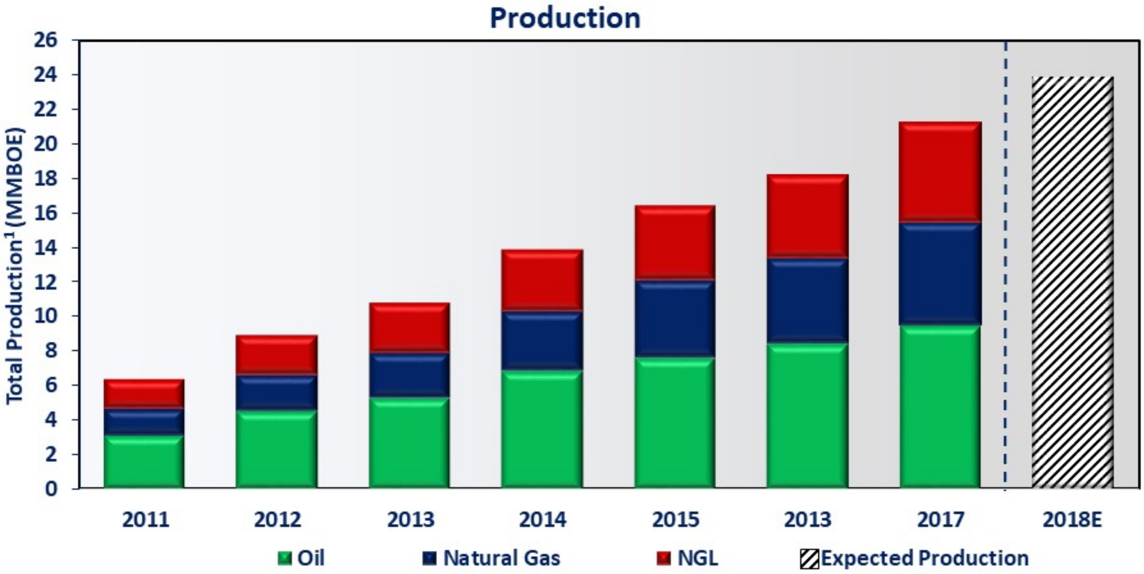
- Completing 60 - 65 net wells
- ~10,600' avg. Hz lateral length
- ~95% avg. working interest
- Actively accelerating:
  - Currently running 3 Hz rigs
  - Adding 4th Hz rig at beginning of 3Q-18
  - Anticipate adding 5th Hz rig at end of '18 or beginning of '19

Operational Efficiencies Enable Us To Do More With Less



35% YoY increase in gross completed lateral feet per rig

Consistent Production Growth



>12% FY-18E YoY BOE Production Growth

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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

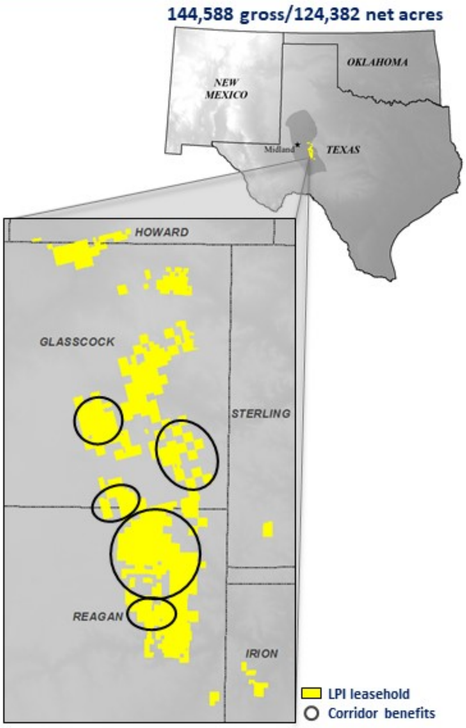
Capitalizing On Our Contiguous Acreage Position

- **Longer laterals enhance returns**
  - **>500 land-ready UWC/MWC locations of at least 15,000'**

- **Centralized infrastructure enables increased capital and operational efficiencies**
  - **Five active production corridors**
  - **Seven consecutive quarters of unit LOE below $4.00 per BOE**

~87%

HBP acreage, enabling a concentrated development plan along production corridors



Note: Maps, acreage counts and statistics as of 3/31/18

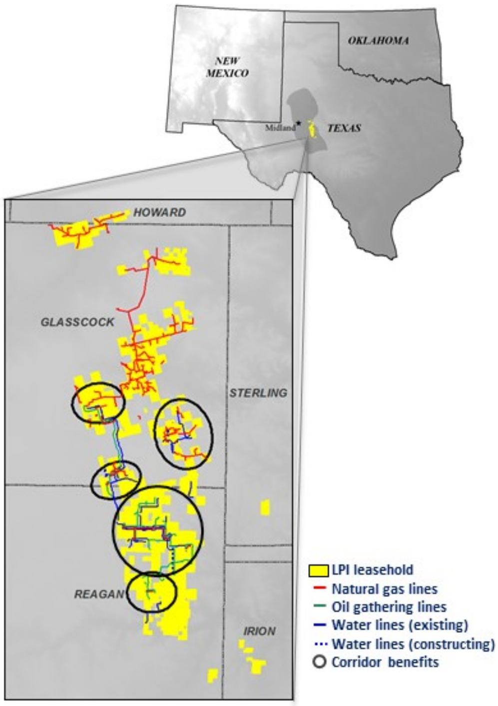
Contiguous Acreage Facilitates Robust Infrastructure Investments

Pipeline Infrastructure

- ~60 miles crude gathering
- ~100 miles water gathering/recycled distribution
- ~190 miles natural gas gathering & distribution
- ~50,000 1Q-18 truckloads removed due to LMS infrastructure

~$30 MM

2018E net benefits from strategic infrastructure investments

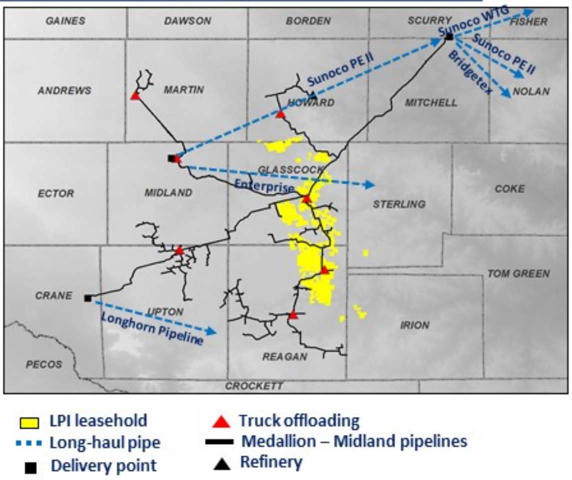


Note: Maps, acreage counts and statistics as of 3/31/18
Benefits defined as capital savings, LOE savings, price uplift and LMS net operating income

Crude Value Maximized Via Physical & Financial Contracts

Physical Firm Transport

- LMS-owned gathering minimizes trucking
- Medallion contract provides intra-basin transport
  - 30,000 BOPD gross firm transport provides access to long-haul pipes exiting the basin
  - Substantially all acreage dedicated to pipeline system
- 10,000 BOPD gross firm transportation on Bridgetex through 1Q-25



Financial Stability

- Protected from Midland pricing via:
  - U.S. Gulf Coast pricing on 10,000 BOPD via Jun-18 - Jun-19 Mid/Hou basis swaps, $7.30/Bbl wtd-avg price
  - 10,000 BOPD via 2Q-18 - 4Q-18 Mid/Cush basis swaps, -$0.56/Bbl wtd-avg price

~70% FY-18E volumes protected from Midland pricing

Note: Hedge percentage assumes reiterated previously-issued guidance of 10% YoY oil volume growth from FY-17

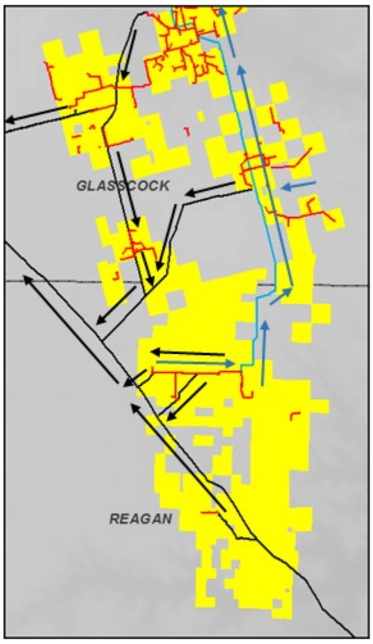
Natural Gas Value Maximized Via Physical & Financial Contracts

Operational Assurance

- Data from purchasers supports that they have sufficient firm transportation, and it is believed they can accommodate LPI's natural gas volumes
- LMS assets provide field-level optionality to move production between two purchasers

Financial Stability

- ~75% of FY-18E natural gas is protected from a widening Waha basis via Waha puts & collars & Waha/HH basis swaps
  - ~55% of FY-18E volumes protected with a $2.50/MMBtu Waha wtd-avg floor price[1]
  - Add'l ~20% of FY-18E volumes protected by Waha/HH basis swaps, -$0.62/MMBtu wtd-avg price



LPI leasehold
LMS natural gas lines
Primary 3rd-party takeaway lines
Secondary 3rd-party takeaway lines

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[1] As of 5/1/18, Waha pricing $1.41/MMBtu
Note: Hedge percentages assume updated guidance of >12% YoY total BOE volume growth from FY-17

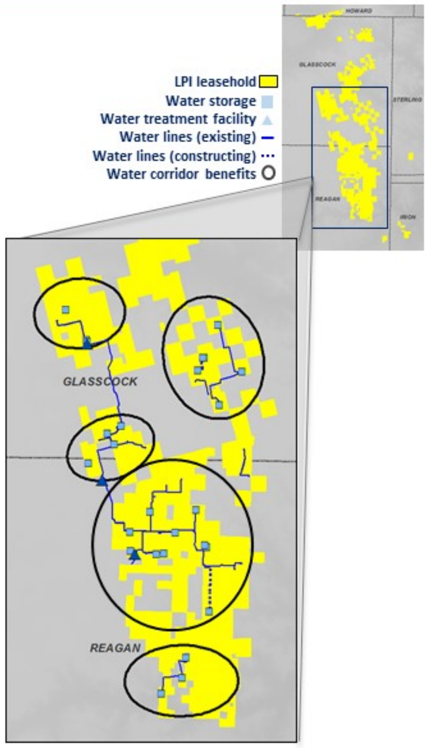
Significant Benefits Through Water Infrastructure Investments

~$10.3 MM

FY-18E LOE reduction generated by LMS water infrastructure investments[1]

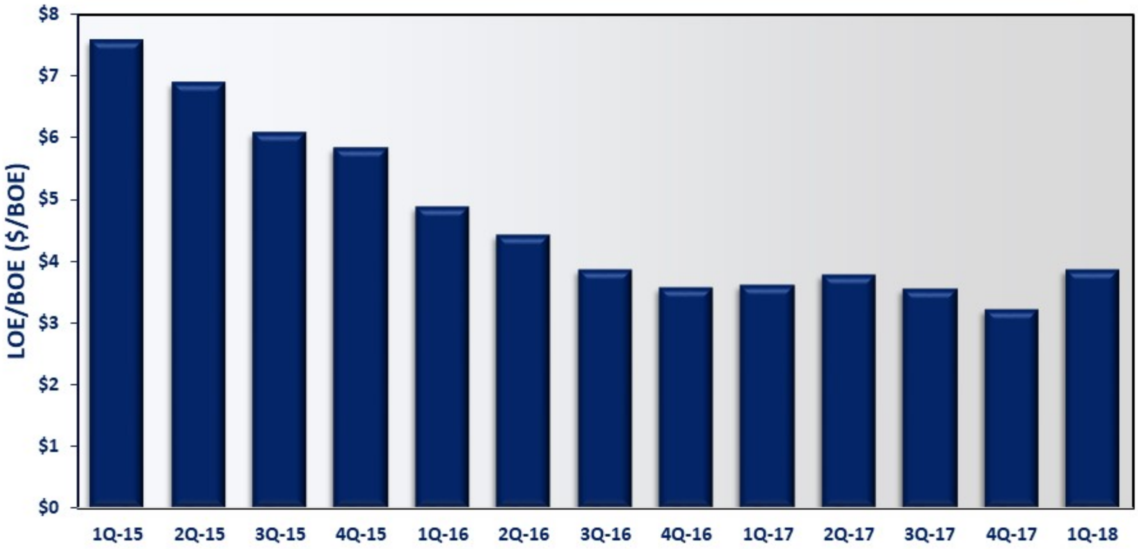
LMS Corridor Benefit	LPI Benefit	FY-18E (% of Total Activity)
Produced Water Gathered on Pipe	Capital & LOE savings	81%
Produced Water Recycled	Capital & LOE savings	42%
Completions Utilizing Recycled Water	Capital savings	23%
Completions Utilizing LPI Fresh Water Wells	Capital savings	14%

- 54 MBWPD recycling processing capacity
- 22.5 MMBW owned or contracted storage capacity



[1] Calculated utilizing a 95% WI & 72% NRI
Note: Statistics, estimates and maps as of 3/31/18

Infrastructure Investments Facilitate Lower Unit LOE



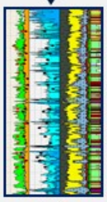
$0.51 Per BOE savings on unit LOE in 1Q-18 due to infrastructure benefits

Advanced Subsurface Characterization Drives Optimized Development

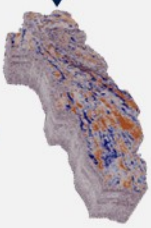
Physics-Based Workflows

Acquire Subsurface data

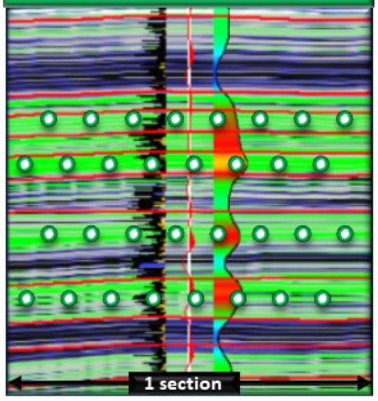
Calibrate Petrophysical model



Integrate spatial data



High-Resolution 3D Reservoir Geomodels

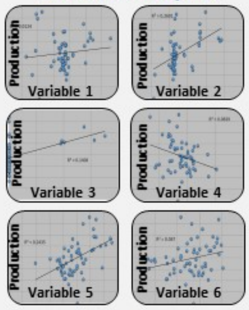


Increased NAV

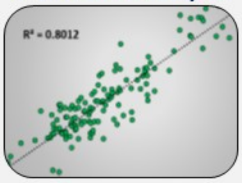
driven by high-density development

Improved Analytics

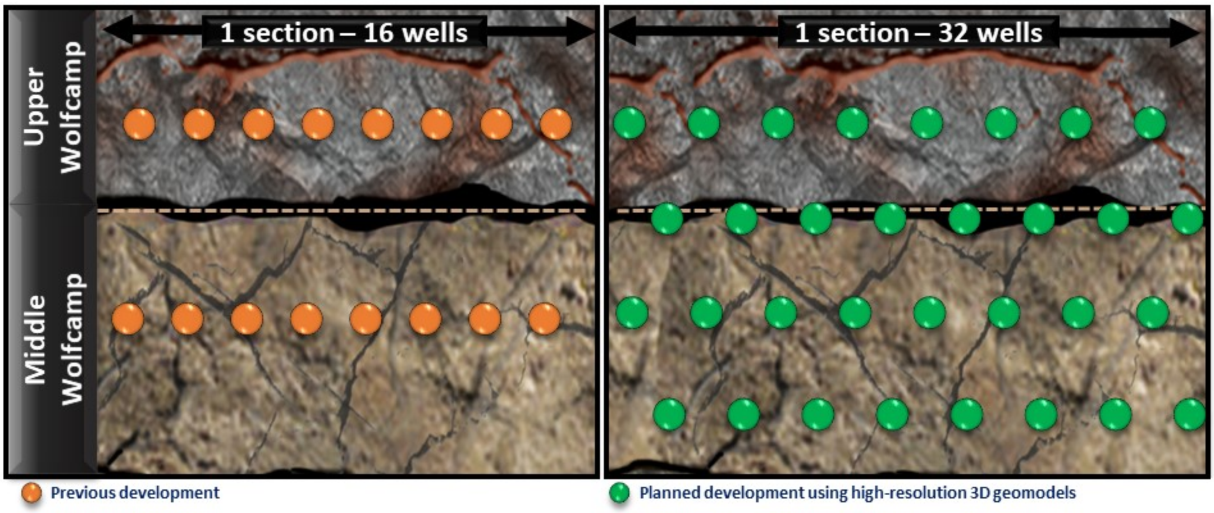
Bivariate analytics



Multivariate analytics



Transitioning To Higher-Density Development

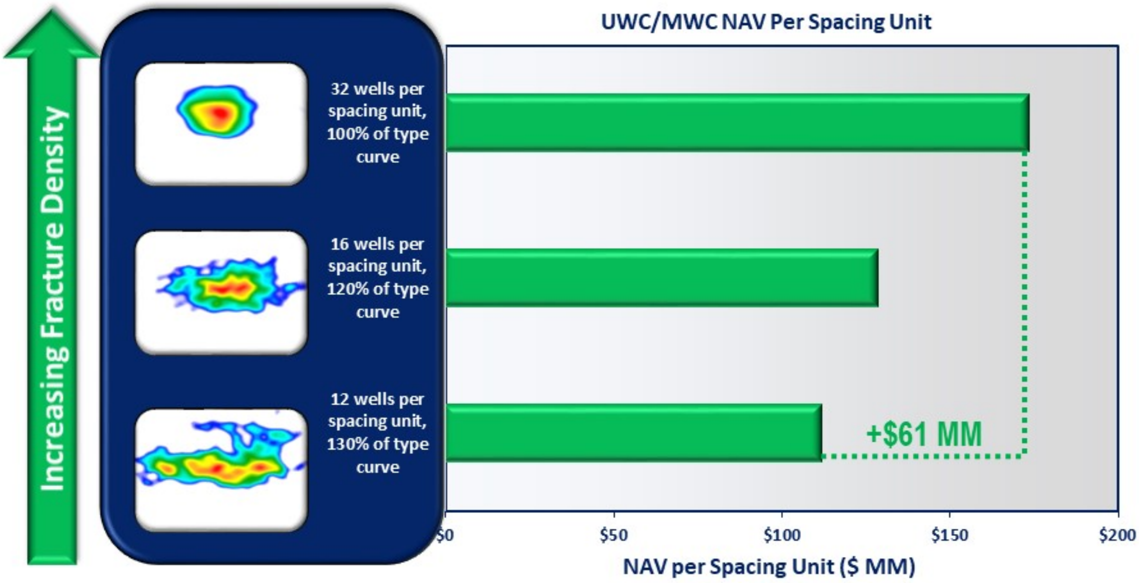


32 locations per section

Results of 2017 spacing tests suggest development possibility of up to 32 UWC/MWC locations per spacing unit

Note: Diagrams are not to scale
Spacing unit comprised of two sections to accommodate 10,000' laterals

Tighter Cluster Spacing Facilitates Higher-Density Development



Increase in wells drives higher potential value per spacing unit

Note: NAV calculation pricing reflective of $55/Bbl WTI benchmark, utilizing $3/Mcf flat HH benchmark and $7.1 MM D&C well cost
Spacing unit comprised of two sections to accommodate 10,000' laterals

Maintaining A Strong Balance Sheet

~1.4x net debt to Adjusted EBITDA[1]

Increased borrowing base elected commitment from $1 B to $1.2 B

[1] Net debt to Adjusted EBITDA includes net debt as of 3/31/18 and 1Q-18 annualized Adjusted EBITDA. Net debt is calculated as the face value of long-term debt of $855 MM, reduced by cash on hand of $56 MM. See Appendix for a reconciliation of Net Income to Adjusted EBITDA

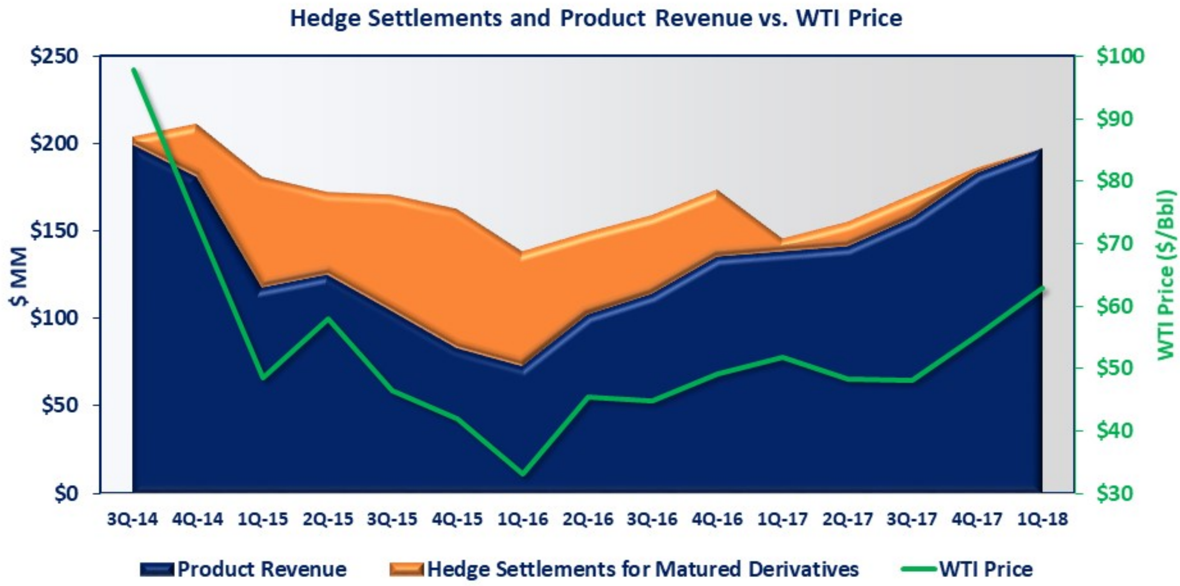
[2] As of 5/1/18, with $1.3 B borrowing base and $1.2 B aggregate elected commitment in place under Fifth Amended and Restated Senior Secured Credit Facility

Stock Repurchase Program

- Approved by Board of Directors in 1Q-18
- Allows stock repurchases of up to $200 MM
- Program authorized for two years
- 6,727,901 shares of common stock repurchased in 1Q-18 at a weighted-average price of $8.69/share for a total of $58.5 MM

1Q-18 stock repurchases represented a highly accretive use of capital

Disciplined Risk Management Philosophy Protects Long-Term Value



Hedges provide cash flow stability during volatile pricing

Oil, Natural Gas & Natural Gas Liquids Hedges

Hedge Product Summary	2Q-18 - 4Q-18	FY-19	FY-20
Oil total floor volume (Bbl)	7,168,750	6,606,500	1,061,400
Oil wtd-avg floor price ($/Bbl)	$47.42	$48.82	$49.70
Nat gas total floor volume (MMBtu)	17,907,500		
Nat gas wtd-avg floor price ($/MMBtu)	$2.50		
NGL total floor volume (Bbl)	1,182,500		

Oil	2Q-18 - 4Q-18	FY-19	FY-20
Puts			
Hedged volume (Bbl)	4,088,750	5,949,500	366,000
Wtd-avg floor price ($/Bbl)	$51.93	$48.31	$45.00
Swaps			
Hedged volume (Bbl)		657,000	695,400
Wtd-avg price ($/Bbl)		$53.45	$52.18
Collars			
Hedged volume (Bbl)	3,080,000		
Wtd-avg floor price ($/Bbl)	$41.43		
Wtd-avg ceiling price ($/Bbl)	$60.00		

Note: Oil derivatives are settled based on the month's average daily NYMEX index price for the first nearby month of the WTI Light Sweet Crude Oil futures contract

Basis Swaps	2Q-18 - 4Q-18	FY-19	FY-20
Mid/Cush			
Hedged volume (Bbl)	2,750,000		
Wtd-avg price ($/Bbl)	-$0.56		
Mid/Hou			
Hedged volume (Bbl)	2,140,000	1,810,000	
Wtd-avg price ($/Bbl)	$7.30	$7.30	
HH/Waha			
Hedged volume (MMBtu)	6,875,000	20,075,000	25,254,000
Wtd-avg price ($/MMBtu)	-$0.62	-$1.05	-$0.76

Note: Mid/Cush oil basis swaps are settled based on the West Texas Intermediate Midland weighted average price published in Argus Americas Crude and the West Texas Intermediate Cushing Formula Basis price published in Argus Americas Crude. Mid/Hou oil basis swaps are settled based on the price for a pricing date, published under the headings "US Gulf Coast and Midcontinent: WTI: WTI Houston: Weighted Average" and "US Gulf Coast and Midcontinent" for "WTI Midland" under the column "Weighted Average" for the prompt month in the issue of Argus Crude that reports prices effective as of the pricing date. HH/Waha natural gas basis swaps are settled based on the inside FERC index price for West Texas WAHA and NYMEX Henry Hub

Natural Gas Liquids	2Q-18 - 4Q-18	FY-19	FY-20
Swaps - Ethane			
Hedged volume (Bbl)	467,500		
Wtd-avg price ($/Bbl)	$11.66		
Swaps - Propane			
Hedged volume (Bbl)	385,000		
Wtd-avg price ($/Bbl)	$33.92		
Swaps – Normal Butane			
Hedged volume (Bbl)	137,500		
Wtd-avg price ($/Bbl)	$38.22		
Swaps - Isobutane			
Hedged volume (Bbl)	55,000		
Wtd-avg price ($/Bbl)	$38.33		
Swaps - Natural Gasoline			
Hedged volume (Bbl)	137,500		
Wtd-avg price ($/Bbl)	$57.02		

Note: Natural gas liquids derivatives are settled based on the month's average daily OPIS index price for Mt. Belvieu Purity Ethane and Non-TET: Propane, Normal Butane, Isobutane and natural gasoline

Natural Gas - WAHA	2Q-18 - 4Q-18	FY-19	FY-20
Puts			
Hedged volume (MMBtu)	6,165,000		
Wtd-avg floor price ($/MMBtu)	$2.50		
Collars			
Hedged volume (MMBtu)	11,742,500		
Wtd-avg floor price ($/MMBtu)	$2.50		
Wtd-avg ceiling price ($/MMBtu)	$3.35		

Note: Natural gas derivatives are settled based on Inside FERC index price for West Texas WAHA for the calculation period

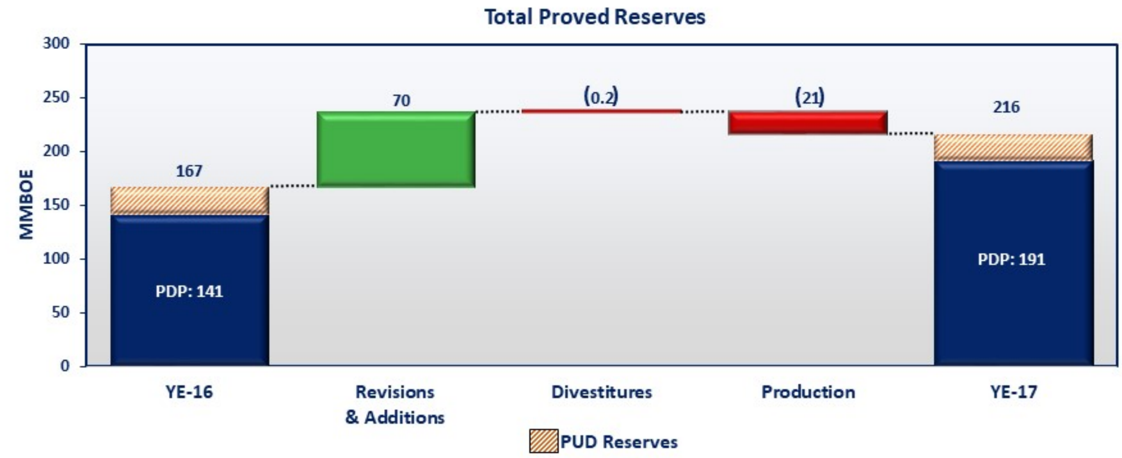
2Q-18E Guidance

	2Q-18E
Production (MBOE/d)........	64.0
Crude oil production (MBbl/d)........	27.4
Price Realizations (pre-hedge):	
Crude oil (% of WTI)........	91%
Natural gas liquids (% of WTI)........	28%
Natural gas (% of Henry Hub)........	36%
Operating Costs & Expenses:	
Lease operating expenses ($/BOE)........	$3.70
Midstream expenses ($/BOE)........	$0.15
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)....	6.25%
General and administrative expenses:	
Cash ($/BOE)........	$2.70
Non-cash stock-based compensation ($/BOE)........	$1.85
Depletion, depreciation and amortization ($/BOE)........	$8.00

Positioned For The Future

APPENDIX

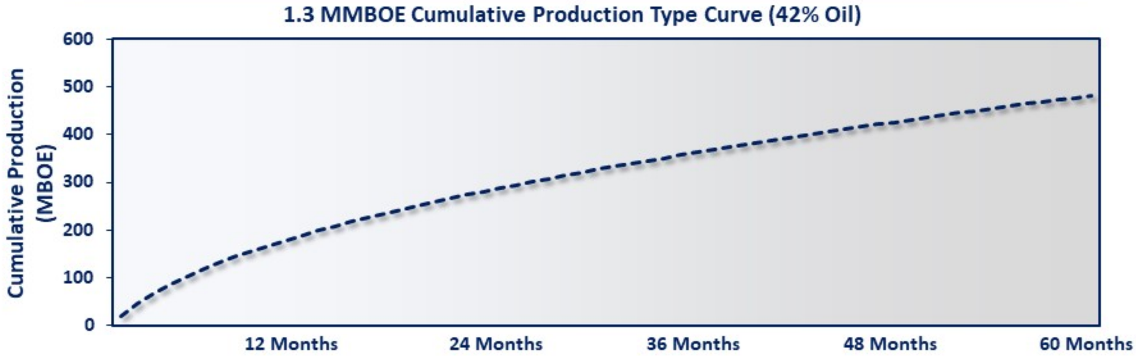
Low-Cost Proved Reserves Growth



36% Organic growth in proved developed reserves at a proved developed F&D cost of $7.90/BOE

Note: Proved Developed F&D Cost is a non-GAAP financial measure. See the Appendix for information on this calculation

UWC & MWC 1.3 MMBOE Cumulative Production Type Curve



Months	Cumulative Production (MBOE)	Cumulative % Oil
12	189	60%
24	288	56%
36	363	54%
48	426	52%
60	482	51%

45%

Total oil recovered in the first five years

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Note: 10,000' lateral length with 1,800 pounds of sand per foot completions at 54' perf cluster spacing

2017 & 2018 Actuals

		1Q-17	2Q-17	3Q-17	4Q-17	FY-17	1Q-18
Sales Volumes	3-Stream Sales Volumes						
	MBOE	4,716	5,336	5,521	5,697	21,270	5,698
	BOE/d	52,405	58,632	60,011	61,922	58,273	63,314
	% oil	45%	47%	44%	43%	45%	43%
Pricing	3-Stream Realized Prices						
	Oil ($/Bbl)	$46.91	$42.00	$45.44	$53.57	$46.97	$61.87
	NGL ($/Bbl)	$16.49	$13.82	$18.58	$20.53	$17.49	$18.14
	Gas ($/Mcf)	$2.31	$2.09	$2.04	$1.95	$2.09	$1.79
	Avg. price ($/BOE)	$29.42	$26.58	$28.54	$32.19	$29.22	$34.65
Unit Cost Metrics	3-Stream Unit Cost Metrics ($/BOE)						
	Lease operating expenses	$3.60	$3.77	$3.55	$3.22	$3.53	$3.85
	Midstream	$0.19	$0.17	$0.21	$0.20	$0.19	$0.12
	Production & ad val taxes	$1.86	$1.59	$1.73	$1.93	$1.78	$2.07
	General & administrative						
	Cash	$3.47	$2.50	$2.90	$2.61	$2.85	$2.70
	Non-cash stock-based compensation	$1.96	$1.63	$1.62	$1.55	$1.68	$1.64
	DD&A	$7.23	$7.12	$7.46	$7.91	$7.45	$7.99

2015 & 2016 Actuals

		1Q-15	2Q-15	3Q-15	4Q-15	FY-15	1Q-16	2Q-16	3Q-16	4Q-16	FY-16
Sales Volumes	3-Stream Sales Volumes										
	MBOE	4,274	4,234	4,124	3,714	16,346	4,204	4,338	4,718	4,889	18,149
	BOE/d	47,487	46,532	44,820	40,368	44,782	46,202	47,667	51,276	53,141	49,586
	% oil	51%	46%	45%	45%	47%	48%	46%	46%	46%	47%
Pricing	3-Stream Realized Prices										
	Oil ($/Bbl)	$41.73	$50.77	$42.88	$36.97	$43.27	$27.51	$39.37	$39.10	$43.98	$37.73
	NGL ($/Bbl)	$13.34	$12.85	$10.36	$11.06	$11.86	$8.50	$12.24	$11.54	$14.79	$11.91
	Gas ($/Mcf)	$2.14	$1.82	$2.01	$1.76	$1.93	$1.31	$1.31	$2.07	$2.13	$1.73
	Avg. price ($/BOE)	$27.64	$29.65	$25.37	$22.47	$26.41	$17.40	$23.64	$24.34	$27.82	$23.50
Unit Cost Metrics	3-Stream Unit Cost Metrics ($/BOE)										
	Lease operating expenses	$7.58	$6.90	$6.09	$5.83	$6.63	$4.88	$4.43	$3.85	$3.56	$4.15
	Midstream	$0.37	$0.38	$0.26	$0.43	$0.36	$0.14	$0.27	$0.22	$0.26	$0.22
	Production & ad val taxes	$2.13	$2.24	$1.91	$1.73	$2.01	$1.53	$1.84	$1.50	$1.45	$1.58
	General & administrative										
	Cash	$3.99	$4.00	$3.89	$4.27	$4.03	$3.72	$3.33	$3.49	$3.28	$3.45
	Non-cash stock-based compensation	$1.12	$1.48	$1.67	$1.77	$1.50	$0.91	$1.40	$2.05	$1.98	$1.61
	DD&A	$16.83	$17.03	$16.19	$18.01	$16.99	$9.87	$7.88	$7.45	$7.68	$8.17

2014 Actuals: Two-Stream To Three-Stream Conversions

		1Q-14	2Q-14	3Q-14	4Q-14	FY-14
Sales Volumes	2-Stream Sales Volumes					
	MBOE	2,434	2,607	3,033	3,654	11,729
	BOE/d	27,041	28,653	32,970	39,722	32,134
	% oil	58%	58%	59%	60%	59%
	3-Stream Sales Volumes					
	MBOE	2,912	3,078	3,569	4,267	13,827
	BOE/d	32,358	33,829	38,798	46,379	37,882
	% oil	49%	49%	50%	51%	50%
Pricing	2-Stream Realized Prices					
	Oil ($/Bbl)	$91.78	$94.47	$87.65	$65.05	$82.83
	Gas ($/Mcf)	$7.04	$6.08	$5.80	$4.46	$5.72
	Avg. Price ($/BOE)	$71.17	$70.13	$65.77	$49.70	$62.86
	3-Stream Realized Prices					
	Oil ($/Bbl)	$91.78	$94.47	$87.65	$65.05	$82.83
	NGL ($/Bbl)	$32.88	$28.79	$29.21	$19.65	$27.00
	Gas ($/Mcf)	$4.00	$3.73	$3.25	$3.00	$3.45
	Avg. Price ($/BOE)	$59.48	$59.40	$55.89	$42.57	$53.32
Unit Cost Metrics	2-Stream Unit Cost Metrics ($/BOE)					
	Lease operating expenses	$8.95	$7.74	$8.30	$8.04	$8.23
	Midstream	$0.35	$0.59	$0.40	$0.50	$0.46
	Production & ad valorem taxes	$5.12	$5.05	$4.14	$3.33	$4.29
	General & administrative					
	Cash	$9.58	$8.88	$6.89	$4.27	$7.07
	Non-cash stock-based compensation	$1.78	$2.45	$2.04	$1.69	$1.97
	DD&A	$20.38	$20.35	$21.08	$21.85	$21.01
	3-Stream Unit Cost Metrics ($/BOE)					
	Lease operating expenses	$7.48	$6.55	$7.05	$6.88	$6.98
	Midstream	$0.29	$0.50	$0.34	$0.43	$0.39
	Production & ad valorem taxes	$4.28	$4.27	$3.52	$2.85	$3.64
	General & Administrative					
	Cash	$8.01	$7.52	$5.85	$3.66	$6.00
	Non-cash stock-based compensation	$1.49	$2.08	$1.74	$1.44	$1.67
	DD&A	$17.03	$17.23	$17.91	$18.72	$17.83

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Note: 2014 2-stream to 3-stream conversion based on actual gas plant economics

Supplemental Non-GAAP Financial Measure

Proved Developed Finding and Development Cost (Unaudited)

Proved developed finding and development ("F&D") cost per BOE is calculated by dividing (x) development costs for the period, by (y) proved developed reserve additions for the period, defined as the change in proved developed reserves, less purchased reserves, plus sold reserves and plus sales volumes during the period. The method we use to calculate our proved developed F&D cost may differ significantly from methods used by other companies to compute similar measures. As a result, our proved developed F&D cost may not be comparable to similar measures provided by other companies. We believe that providing the measure of proved development F&D cost is useful in evaluating the cost, on a per BOE basis, to added proved developed reserves.

However, this measure is provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP. Due to various factors, including timing differences in the addition of proved reserves and the related costs to develop those reserves, proved developed F&D cost does not necessarily reflect precisely the costs associated with particular proved reserves. As a result of various factors that could materially affect the timing and amounts of future increases in proved reserves and the timing and amounts of future costs, we cannot assure you that our future proved developed F&D cost will not differ materially from those presented.

($ MM, except per BOE amount, reserves and sales volumes in MMBOE)	Proved Developed F&D
Development costs (x)	$561
Proved developed reserves:	
As of December 31, 2017	191
As of December 31, 2016	(141)
Change in proved developed reserves	50
Plus sales of proved developed reserves during 2017	-
Plus 2017 sales volumes	21
Proved developed reserve additions (y)	71
Proved developed F&D cost per BOE	$7.90

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.

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

(in thousands)		1Q-18
Net income	$	86,520
Plus:		
Depletion, depreciation and amortization		45,553
Non-cash stock-based compensation, net of amounts capitalized		9,339
Accretion expense		1,106
Mark-to-market on derivatives:		
Gain on derivatives, net		(9,010)
Settlements paid for matured derivatives, net		(2,236)
Premiums paid for derivatives		(4,024)
Interest expense		13,518
Loss on disposal of assets, net		2,617
Adjusted EBITDA	$	143,383

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