CENTENNIAL

Core Oil
Delaware Basin Pure-Play

Fourth Quarter 2018 Earnings Presentation

February 25, 2019

Important Information

Forward-Looking Statements

The information in this presentation includes “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, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this presentation, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “project,” “goal,” “plan,” “target” and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on management’s current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the development, production, gathering and sale of oil and natural gas. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures and the other risks described in our filings with the Securities and Exchange Commission. Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this presentation.

Use of Non-GAAP Financial Measures

This presentation includes the non-GAAP financial measure, Adjusted EBITDAX. Please refer to slides 17 and 18 for a reconciliation of Adjusted EBITDAX to net income, the most comparable GAAP measure. We believe Adjusted EBITDAX is useful as it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period and against our peers without regard to financing methods or capital structure. We exclude the items listed in slides 17 and 18 from net income (loss) in arriving at Adjusted EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company’s financial performance, such as a company’s cost of capital and tax structure, as well as the historic cost of depreciable assets, none of which are components of Adjusted EBITDAX. Our presentation of Adjusted EBITDAX should not be construed as an inference that our results will be unaffected by unusual or non-recurring items. Our computations of Adjusted EBITDAX may not be comparable to other similarly titled measures of other companies.

Centennial Resource Development Overview

FY 2018 Financial & Operational Highlights

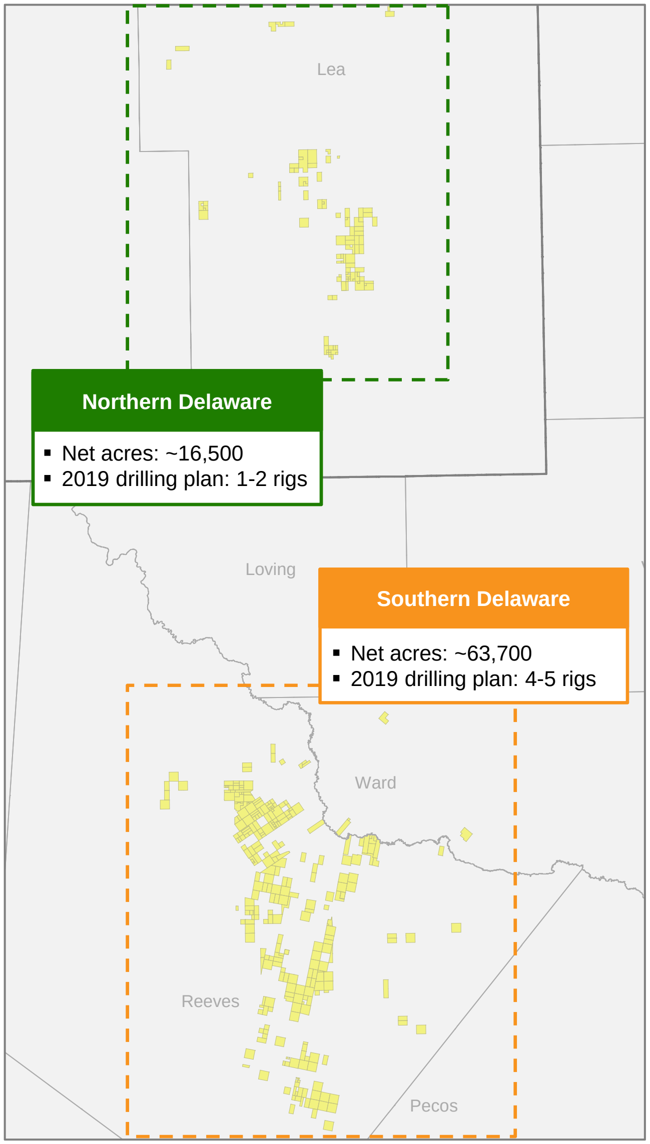
- Increased 2018 daily oil and equivalent production volumes 81% and 92% year-over-year, respectively
- Announced solid well results in the Northern and Southern Delaware Basins, including successful delineation tests and Centennial's best New Mexico well to date
- Reported full year D&C capital expenditures at the mid-point of original guidance range and delivered unit costs at or below low-end of full year guidance ranges
- Net Debt / 2018 EBITDAX of 1.0x and Net Debt / Total Capitalization of 17%

2019 Financial & Operational Plan

- Announced full year 2019 total capital budget of $845 million, a decrease of 15% compared to 2018
- Expect to run 6 rigs flat and grow 2019 crude oil production ~12% year-over-year
- Plan to maintain a flexible approach to operational activity depending on future commodity prices
- Maintain focus on conservative balance sheet and strong liquidity

Summary operational statistics

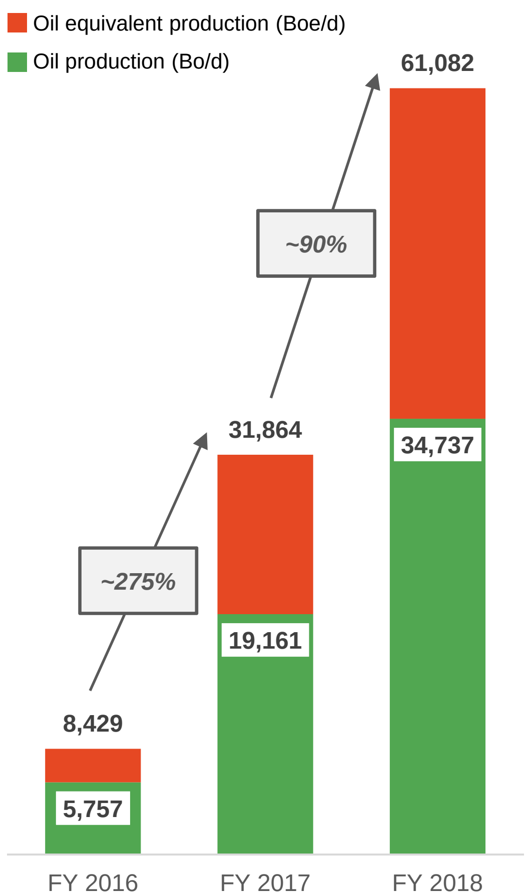
Operational overview			
Production	**FY 2017**	**Q4 2018**	**FY 2018**
Total production (Boe/d)	31,864	69,609	61,082
Oil production (Bbls/d)	19,161	39,978	34,737
% oil	*60%*	*57%*	*57%*
Acreage & Inventory			
Total net acreage (as of 12/31)[1]	~80,100	--	~80,200
% CDEV Operated	*91%*	--	*89%*
% Held by production	*64%*	--	*76%*
Proved reserves			
Total proved reserves (MBoe)	186,454	--	261,826
% growth (y-o-y)	*125%*	--	*40%*
Proved Reserves PV-10 ($ mm)	$1,748	--	$2,979
% growth (y-o-y)	*309%*	--	*70%*



Note: Acreage map highlights current acreage position
(1) FY 2017 acreage number shown pro forma for early 2018 A&D activity in accordance with Q4 2017 presentation

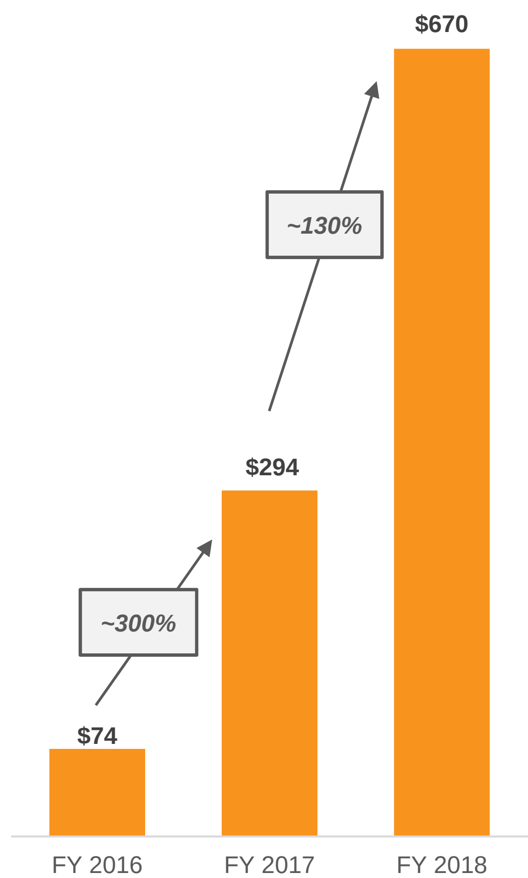
FY 2018 Annual Results Review

Production (Bo/d and Boe/d)



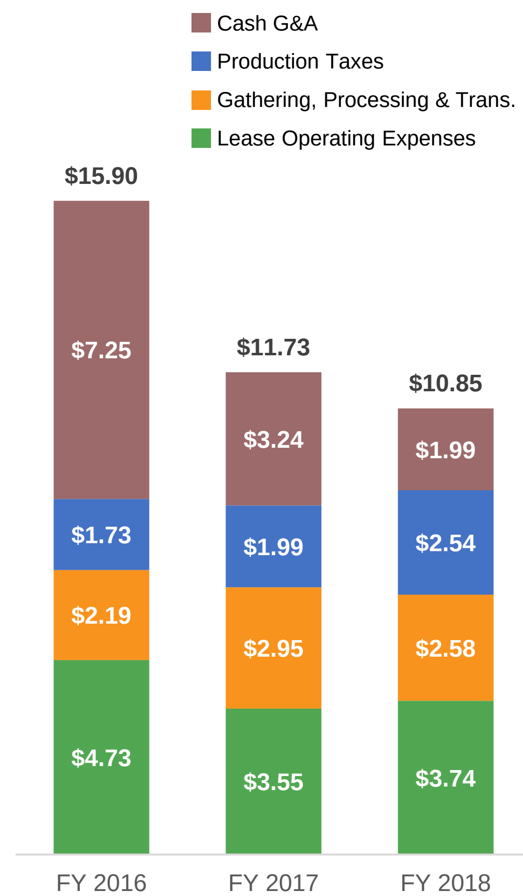
Oil Growth (%)		
--	*~230%*	*~80%*

Adjusted EBITDAX[1] ($ mm)



Realized Oil Price ($ / Bbl)[2]		
$39.91	*$48.17*	*$55.98*

Cash operating costs ($ / Boe)[3]



Low cost operator

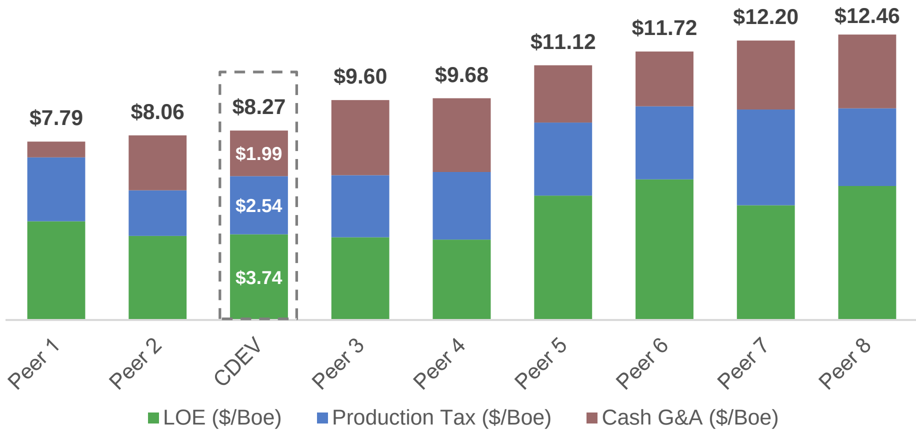
Note: FY 2016 represents a combination of Predecessor (January 1, 2016 – October 10, 2016) and Successor (October 11, 2016 – December 31, 2016) periods
(1) Adjusted EBITDAX is not presented in accordance with generally accepted accounting principles in the United States. Please refer to slides 17 and 18 for a reconciliation of Adjusted EBITDAX to net (loss) income, the most comparable GAAP measure. 2016 EBITDAX represents a combination of Predecessor and Successor periods of $58.7mm and $15.7mm, respectively
(2) Realized oil price shown without the effect of derivative settlements
(3) FY 2016 Cash G&A adjusted to remove $14.0mm in non-cash transaction costs incurred during the year

FY 2018 Review: Delivering on Goals

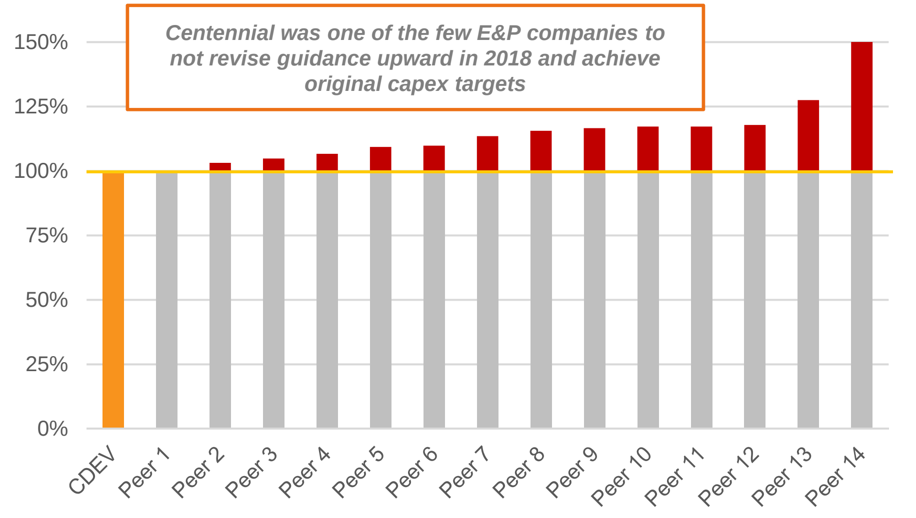
FY 2018 Guidance vs. Actuals

	2018 Guidance	2018 Actuals
Net Average Daily Production (Boe/d)	**55,750 - 64,250**	**61,082**
Oil Net Average Daily Production (Bo/d)	33,500 - 37,500	34,737
Production Costs ($ / Boe)		
Lease Operating Expense	$3.50 - $4.10	$3.74
Gathering, Processing & Transportation	$2.85 - $3.45	$2.58
Depreciation, Depletion, Amortization	$14.00 - $15.50	$14.64
Cash General and Administrative[1]	$2.00 - $2.40	$1.99
Stock-based Compensation	$0.90 - $1.20	$0.85
Severance & Ad Val. Taxes (% of revenue)	6.0% - 8.0%	6.3%
Capital Expenditure Program ($MM)	**$885 - $1,050**	**$997**
D&C Capital Expenditure	$710 - $820	$766
Facilities, Infrastructure and Other	$125 - $160	$201
Land	$50 - $70	$30
Operated Drilling Program		
Wells Spud (Gross)	80 - 95	82
Wells Completed (Gross)	75 - 85	80

FY 2018 Unit Cost Benchmarking[2]



2018 Capital Guidance Revisions (% of original guidance)[3]



(1) Represents G&A expenses less stock-based compensation expense
(2) Peer group includes CPE, CXO, EGN, FANG, JAG, LPI, MTDR, PE and WPX; benchmarking does not include GP&T due to disparate accounting methodologies. JAG, CPE and MTDR estimates as of Q3'18
(3) Peer group includes CPE, CRZO, CXO, FANG, HK, JAG, LPI, MTDR, PE, PDCE, PXD, SM, WPX and XEC

Q4 2018 Well Result Review

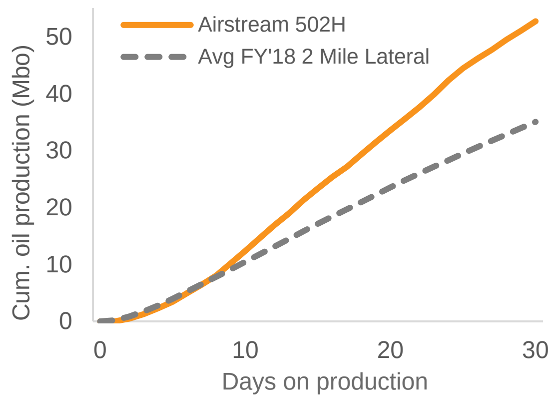
Recent New Mexico Success

Well Highlights

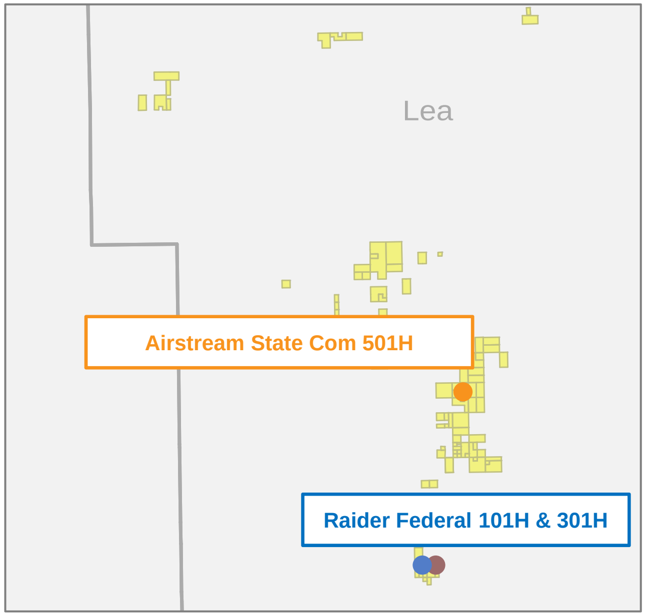
- Airstream 502H performance represents CDEV's strongest New Mexico well to-date
- Raider Federal 101 / 301 pad replicated prior success of 1st Bone Spring Sand and Avalon co-development
  - Raider 301 outperforming the Pirate State 301, (CDEV Q3'18 well) previously considered to be the best 1st Bone Spring Sand well ever drilled in NM

Airstream 24 State Com 502H

Strongest NM well drilled by CDEV to date



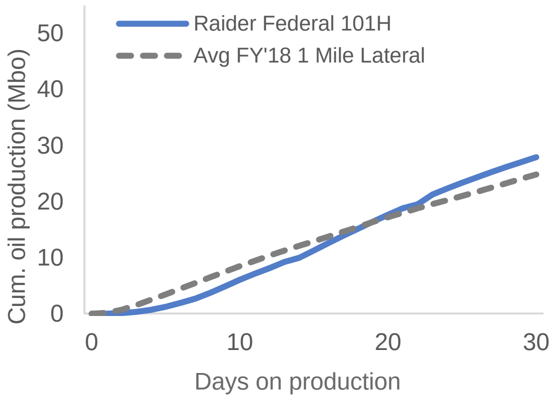
Well Locator Map



	Raider Federal 101H	Raider Federal 301H	Airstream 502H
Lateral length (ft.)	4,200	4,300	10,000
Targeted zone	Avalon	1st BS Sand	2nd BS Sand
IP30 (Bo/d)	956	1,447	1,983
IP30 (Boe/d)	1,260	1,729	2,385
% oil	*76%*	*84%*	*83%*
IP30 / 1,000' (Bo/d)	228	337	198
IP30 / 1,000' (Boe/d)	300	402	238

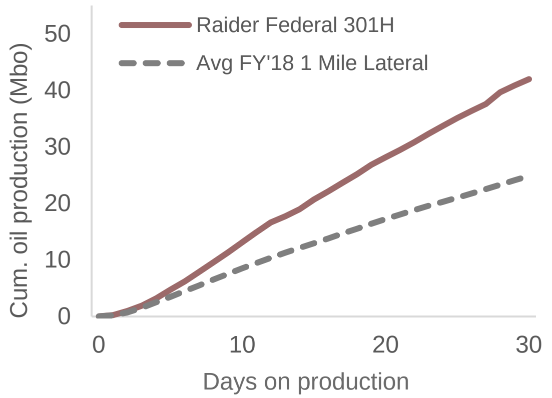
Raider Federal 101H

Avalon shale pilot in-line with expectations



Raider Federal 301H

Strong 1st Bone Spring Sand test



Note: Cumulative oil production curves shown on an non-normalized basis

Q4 2018 Well Result Review

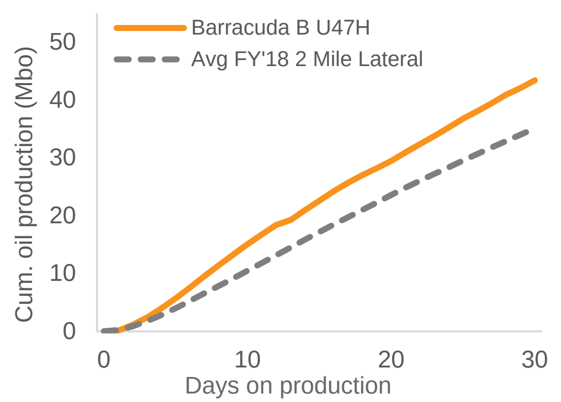
Recent Reeves County Delineation and Development

Well Highlights

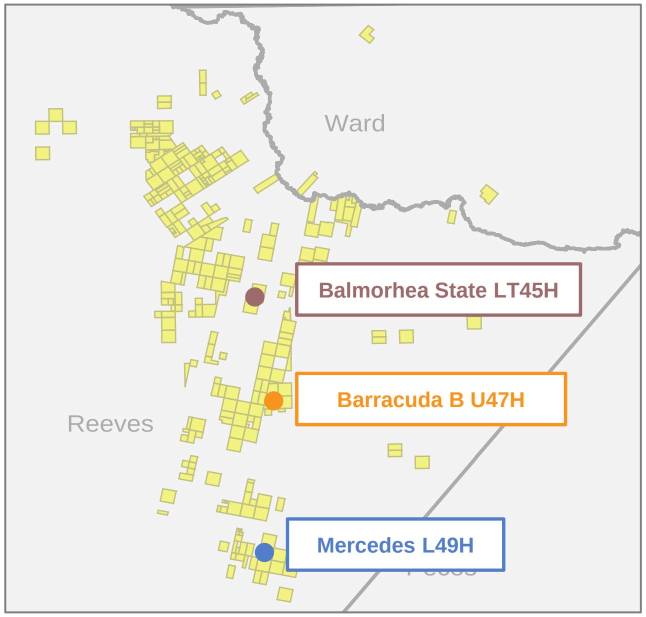
- Continued development across entirety of acreage position and across multiple horizons
  - Highlighting strong wells in the Upper Wolfcamp A, Wolfcamp B and 3rd Bone Spring Sand
- Balmorhea State well in 3rd Bone Spring Sand continues to support confidence in development across acreage position
- Mercedes Wolfcamp B well in southernmost acreage is encouraging result to support further development of deeper Wolfcamp targets

Barracuda B U47H

Continued execution in the Upper WC A



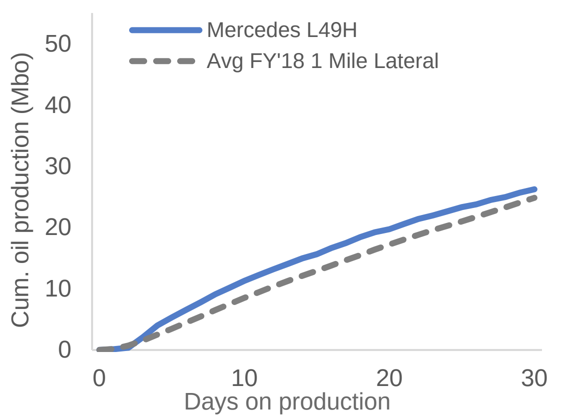
Well Locator Map



	Balmorhea LT45H	Barracuda B U47H	Mercedes L49H
Lateral length (ft.)	6,200	9,800	4,800
Targeted zone	3rd BS Sand	U WC A	WC B
IP30 (Bo/d)	983	1,495	901
IP30 (Boe/d)	1,246	1,807	1,058
% oil	*79%*	*83%*	*85%*
IP30 / 1,000' (Bo/d)	158	153	188
IP30 / 1,000' (Boe/d)	201	184	220

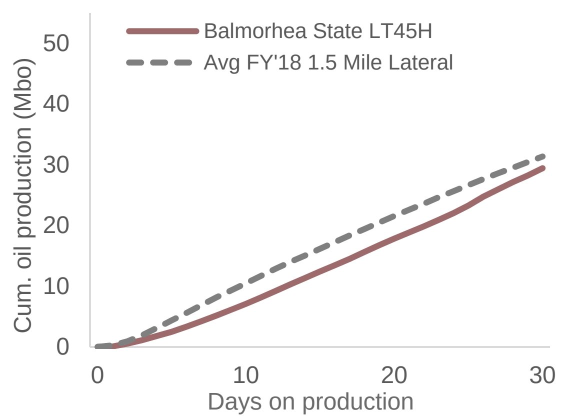
Mercedes L49H

Strong Wolfcamp B delineation well



Balmorhea State LT45H

Pushing the 3rd Bone Spring Sand further west



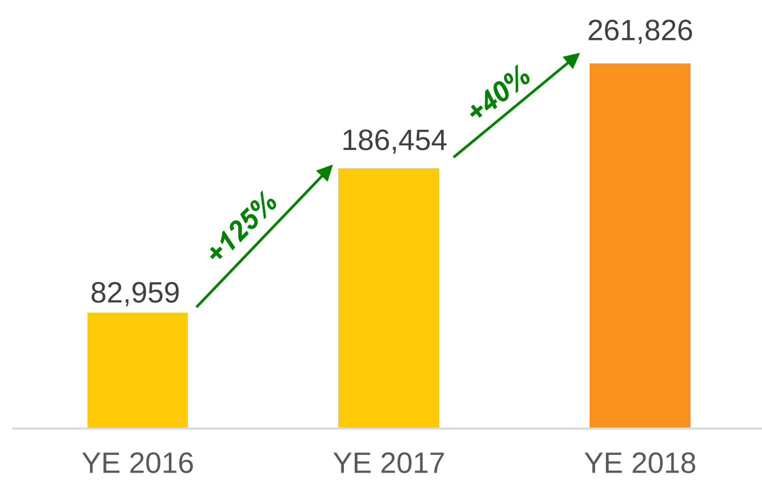
Note: Cumulative oil production curves shown on an non-normalized basis, with the exception of the Balmorhea State L T45H due to lateral length variance (normalized to 7,500')

YE 2018 Proved Reserves Summary

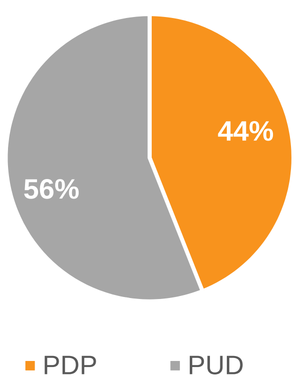
FY 2018 Reserve statistics

Reserves growth *(FY 2017 – FY 2018)*	40%
PV-10 growth *(FY 2017 – FY 2018)*	70%
Organic reserves replacement ratio[1]	~420%
Drill-bit F&D costs[2]	$10.06
Proved developed F&D costs[3]	$14.65

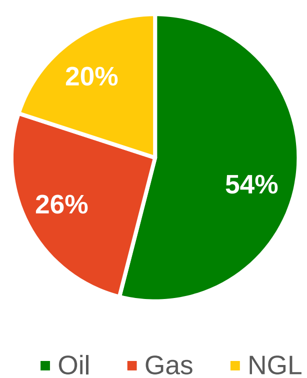
Proved Reserves (Mboe)



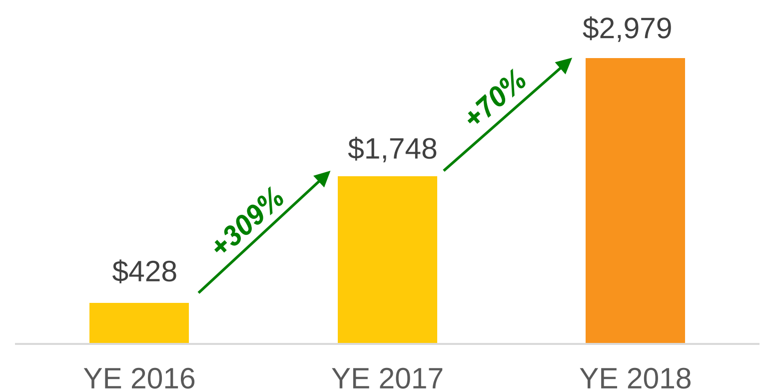
Reserves by category



Reserves by commodity



Proved Reserves PV-10 ($ mm)



Source: NSAI prepared reserve report as of 12/31/18

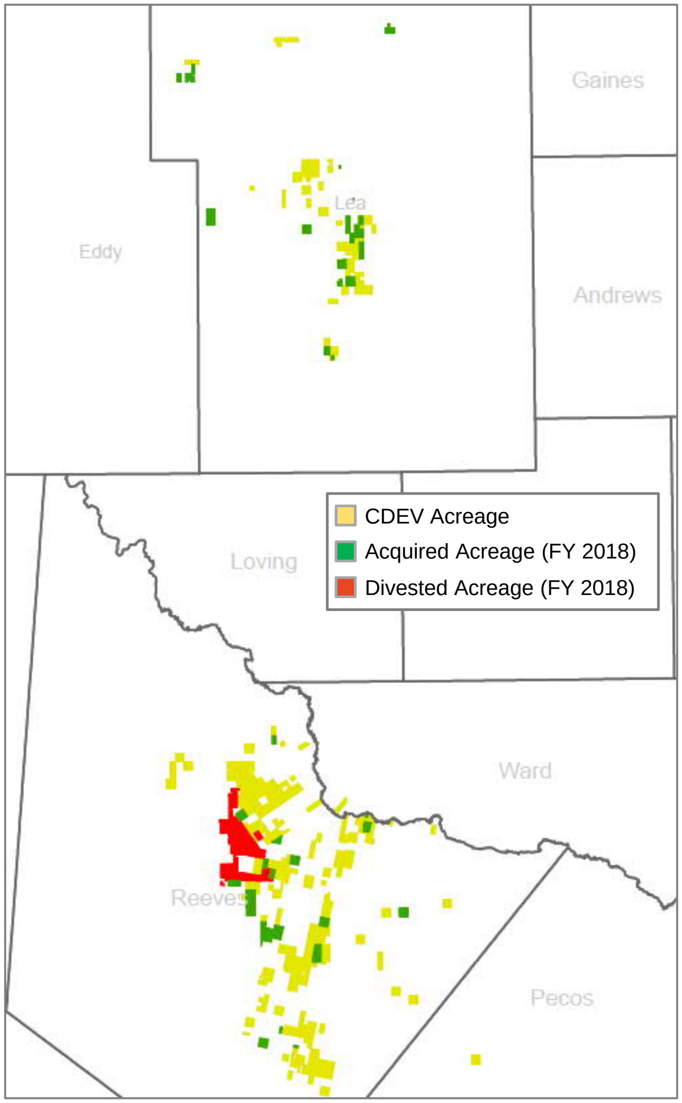
(1) Calculated as the sum of total 2018 reserve extensions, discoveries and revisions (technical and pricing) of 93.8 MMBoe, divided by total 2018 production of 22.3 MMBoe

(2) Calculated as total 2018 exploration and developments costs of $943.6mm divided by the sum of total 2018 reserve extensions, discoveries and revisions (technical and pricing) of 93.8 MMBoe

(3) Calculated as total 2018 exploration and developments costs of $943.6mm divided by the sum of total proved developed reserve extensions and discoveries, transfers from proved undeveloped reserves at year-end 2017, and proved developed reserve revisions (technical and pricing), totaling 64.4 MMBoe

A&D and Inventory Replacement

- **Centennial Inventory Replacement Strategy in Action:**
  - Acquired ~9,000 net acres and ~100 gross operated locations through acquisitions and organic leasing for ~$22,500 / undeveloped acre adjusted for production
  - Acquisitions predominately funded through sale of ~8,600 non-operated, non-core net acres for ~$140mm
  - Added incremental ~200+ gross operated locations through continued exploration efforts in the 3rd Bone Spring Sand
  - Total inventory additions represent approximately 4x the 2018 gross drilled locations
- **2019 and Beyond:**
  - Selectively pursue tactical bolt-on acquisitions at reasonable valuations, supported by strong offset well results
  - Continue to explore the additional horizons across our existing acreage position
  - Primary focus to replace annual drilled inventory and retain significant runway for future development



Flow Assurance Summary

Flow Assurance Strategy

- ✓ Prevent shut-in of any Centennial operated well due to takeaway constraints or gas flaring limitations
- ✓ Enhance realized oil pricing through exposure to a diverse set of pricing indices

Crude and Natural Gas Summary

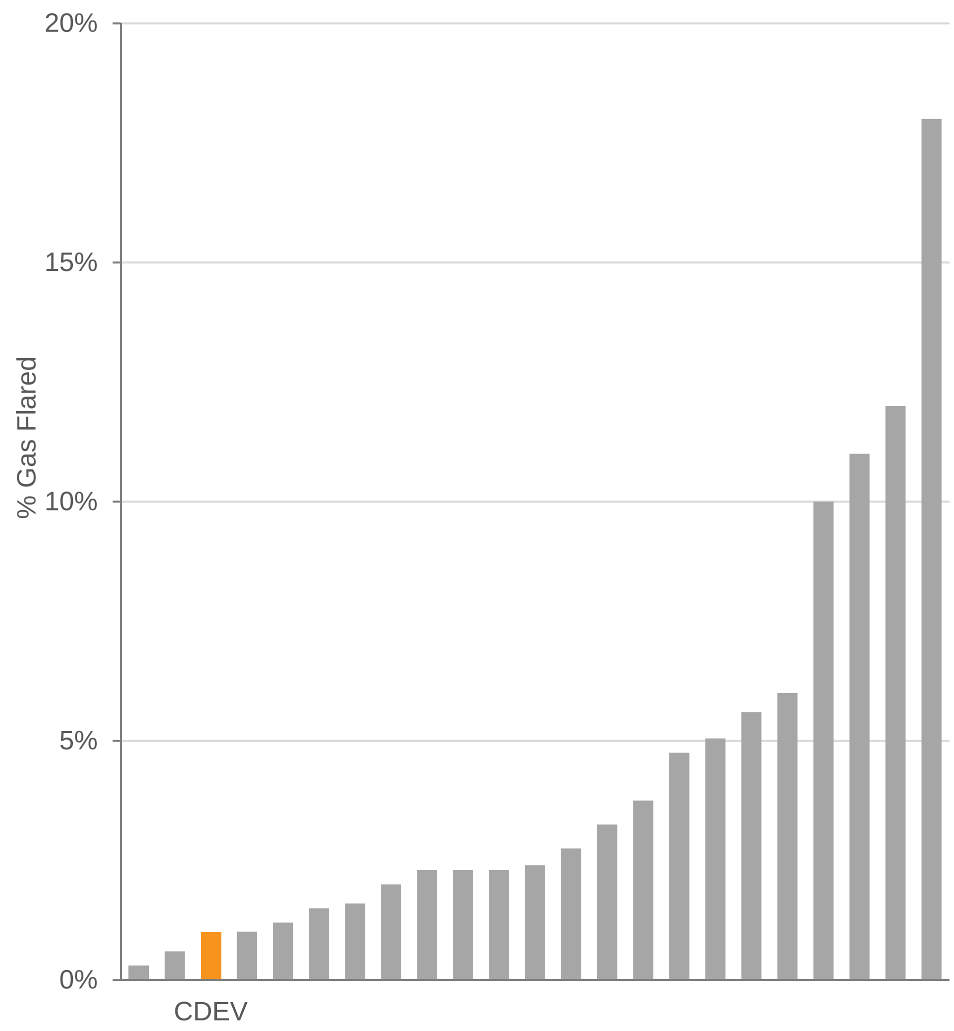
Crude Oil

- Basis and takeaway risk mitigated through two firm sales contracts
- In total, secured takeaway for >50,000 Bo/d in 2019 through firm sales agreements with major, integrated oil companies
- Contract structures allow for full development plan flexibility with low risk of financial penalty

Natural Gas

- ~100% of expected residue gas under firm transportation or firm sales agreements to Waha and out of the Basin through 2022
- Do not expect to flare any material amounts of gas for the foreseeable future

Average Texas Permian Gas Flaring by Operator[1]



Note: All volume amounts represent gross volumes; peers include: APA, APC, COP, CPE, CRZO, CVX, CXO, DVN, ECA, EGN, EOG, FANG, JAG, LPI, OAS, OXY, PE, PXD, SM, WPX, XEC and XOM

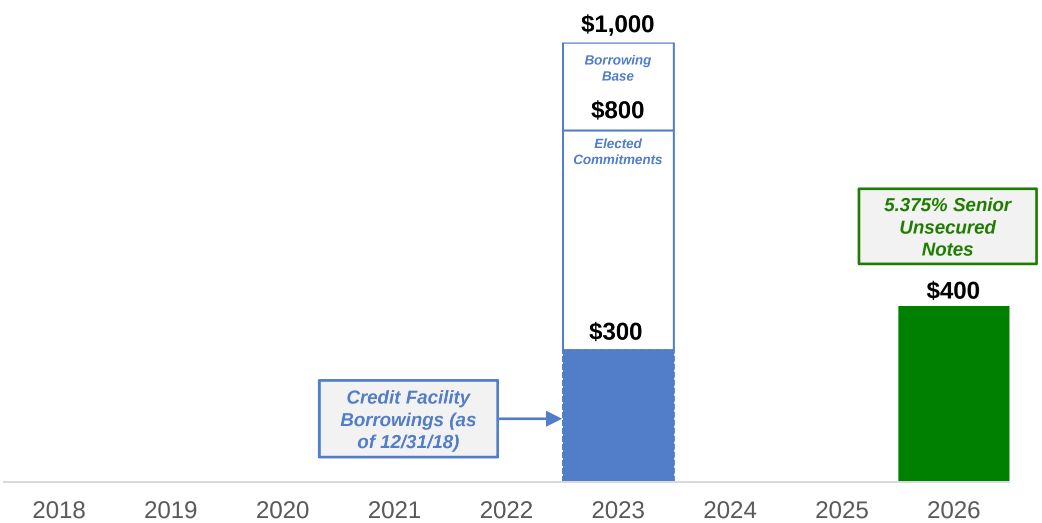
(1) Sources: Texas Railroad Commission and Guggenheim Securities estimates; data represents July – August 2018

Capital Structure and Liquidity Overview

Capital structure overview

- Conservative leverage profile at 12/31/18
  - Net Debt / Total Book Capitalization of 17%
  - Net Debt / FY 2018 EBITDAX of 1.0x
- Liquidity of $517mm
- Credit facility matures in 2023, senior notes mature in 2026

Debt maturity schedule ($ mm)



Capitalization and Liquidity ($ mm)[1]

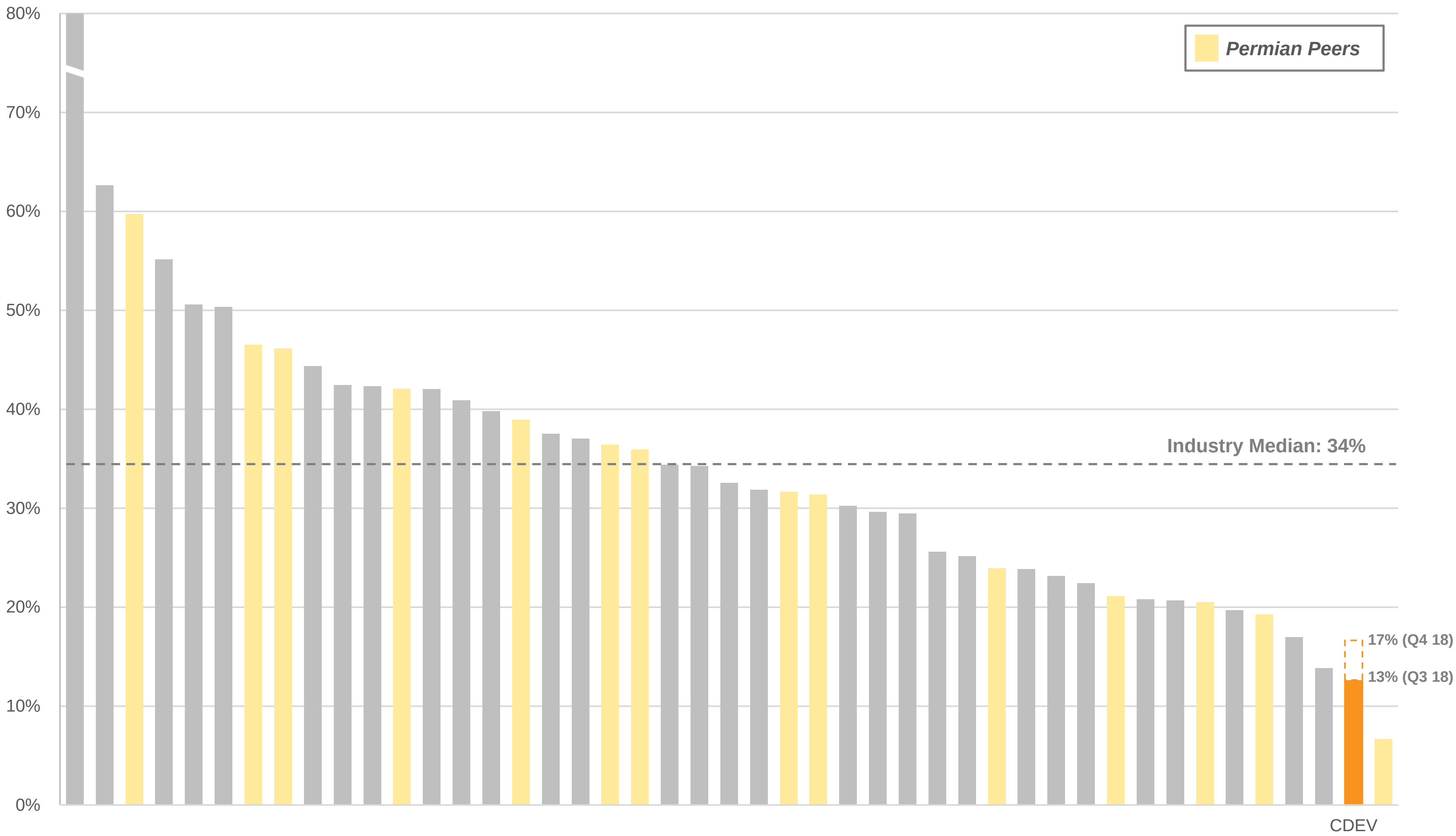
Capitalization summary	As of 12/31/2018
Cash and cash equivalents	$18
Revolving credit facility	$300
5.375% Senior Notes Due 2026	400
Total debt outstanding	$700
Total shareholders' equity[2]	$3,244
Net Debt / Q4 annualized EBITDAX	1.0x
Net Debt / LTM EBITDAX	1.0x
Net Debt / Total Book Capitalization	17%

Liquidity summary	As of 12/31/2018
Cash and cash equivalents	$18
Credit facility availability[3]	499
Liquidity[4]	$517

(1) Amounts may not sum due to rounding
(2) Total shareholders' equity includes non-controlling interest
(3) Credit facility availability as of 12/31/18; net of $0.8mm in letters of credit
(4) Liquidity defined as cash, plus availability under the revolving credit facility

Centennial enters 2019 as one of the best capitalized E&P companies in the industry

Net Debt / Book Capitalization (as of 9/30/18)



Source: Company filings and financials
Note: Peers represent public U.S. E&P companies with market cap over $1bn

FY 2019 Guidance Summary

Guidance summary

- Announced 6 rig program and will maintain flexible approach to activity
- Production guidance will provide 12% mid-point oil production growth year-over-year
- Total capital guidance represents a 15% reduction from 2018 levels
- Average completed lateral length for 2019 expected to be ~7,500' with extended laterals comprising ~80% of operated completions[1]
- Average working interest for operated completions of ~85%

FY 2019 Guidance Summary

	FY 2019 Guidance		
Production			
Net Average Daily Production (Boe/d)	61,500	-	70,500
Net Average Daily Oil Production (Bo/d)	36,500	-	41,500
Production Costs ($ / Boe)			
Lease Operating Expense	$4.35	-	$4.95
Gathering, Processing & Transportation	$2.75	-	$3.25
Depreciation, Depletion, Amortization	$15.50	-	$17.50
Cash General and Administrative	$2.25	-	$2.75
Stock-based Compensation	$1.00	-	$1.20
Severance and Ad Valorem Taxes (% of revenue)	5.5%	-	7.5%
Capital Expenditure Program ($MM)			
Drilling & Completions	$625	-	$725
Facilities, Infrastructure and Other	$120	-	$160
Land	$20	-	$40
Total Capital Expenditures	$765	-	$925
Operated Drilling Program			
Wells Spud (Gross)	70	-	80
Wells Completed (Gross)	65	-	75

(1) Average lateral length calculation assumes 4,500' for a single section lateral, 6,800' for a 1.5 section lateral and 9,500' for a 2 section lateral

Centennial 2019 Game Plan

- Prioritize balance sheet protection by moderating production growth
- Maintain operational and financial flexibility
- Retain high-quality inventory, maximizing rate of return by deferring development to a more constructive commodity price environment
- Replenish anticipated 2019 drilling activity through exploration and organic leasing efforts
- Plan flexible approach to activity depending on commodity prices

Q4 2018 Financial Results

Financial summary ($mm, unless otherwise noted)[1]

($ in millions, unless specified)	FY 2017	Q1 2018	Q2 2018	Q3 2018	Q4 2018	FY 2018
Average Daily Production (Boe/d)	31,864	54,069	57,528	62,930	69,609	61,082
Average Daily Oil Production (Bo/d)	19,161	31,573	31,271	36,027	39,978	34,737
% Oil	*60%*	*58%*	*54%*	*57%*	*57%*	*57%*
Financial highlights						
Total Revenue	$ 429.9	$ 215.9	$ 217.8	$ 234.9	$ 222.5	$ 891.0
Adjusted EBITDAX[2]	$ 294.2	$ 161.6	$ 164.6	$ 177.9	$ 165.7	$ 669.8
Net Income[3]	$ 75.6	$ 66.1	$ 63.5	$ 39.3	$ 31.0	$ 199.9
Unit Costs ($/Boe)						
Lease Operating Expense	$ 3.55	$ 3.34	$ 3.66	$ 4.09	$ 3.77	$ 3.74
Gathering, Processing & Transportation	$ 2.95	$ 2.84	$ 2.92	$ 2.78	$ 1.94	$ 2.58
Severance & Ad Valorem Taxes	$ 1.99	$ 2.91	$ 2.71	$ 2.49	$ 2.14	$ 2.54
Cash G&A	$ 3.24	$ 2.13	$ 1.84	$ 2.02	$ 2.00	$ 1.99
Depreciation, Depletion & Amortization	$ 13.90	$ 13.57	$ 14.32	$ 14.41	$ 15.94	$ 14.64
Capital Expenditures Incurred						
Drilling & Completion	$ 624.1	$ 181.8	$ 162.7	$ 222.4	$ 199.2	$ 766.1
Facilities, Seismic and Other	17.2	50.2	34.3	43.5	73.1	$ 201.1
Land and Other	55.1	6.3	6.2	7.7	9.8	$ 30.0
Total Capital Expenditures	$ 696.4	$ 238.3	$ 203.2	$ 273.6	$ 282.1	$ 997.2
Total Debt Outstanding	$ 400.0	$ 400.0	$430.0	$540.0	$700.0	$700.0
Cash and Cash Equivalents	117.3	38.2	42.7	58.9	18.2	18.2
Liquidity[4]	$591.5	$637.4	$ 611.8	$ 518.0	$ 517.4	$ 517.4

(1) Amounts may not sum due to rounding
(2) Adjusted EBITDAX is not presented in accordance with generally accepted accounting principles in the United States. Please refer to slides 17 and 18 for a reconciliation of Adjusted EBITDAX to net (loss) income, the most comparable GAAP measure.
(3) Net income attributable to common shareholders
(4) Liquidity defined as cash, plus availability under the revolving credit facility

Hedge Position Overview

	FY 2019				
	Q1	Q2	Q3	Q4	FY 2019
MidCush Basis Swaps					
Total Volume (Bbl)	540,000	91,000	1,380,000	920,000	2,931,000
Daily Volume (Bbl/d)	6,000	1,000	15,000	10,000	8,030
Weighted Average Price ($ / Bbl)	($5.34)	($10.00)	($9.03)	($4.24)	($6.88)
Henry Hub Fixed Price Swaps					
Total Volume (MMBtu)	2,700,000	2,730,000	2,760,000	2,760,000	10,950,000
Total Volume (MMBtu/d)	30,000	30,000	30,000	30,000	30,000
Weighted Average Price ($/MMBtu)	$2.78	$2.78	$2.78	$2.78	$2.78
Waha Fixed Price Swaps					
Total Volume (MMBtu)	1,350,000	1,365,000	1,380,000	1,380,000	5,475,000
Daily Volume (MMBtu/d)	15,000	15,000	15,000	15,000	15,000
Weighted Average Price ($/MMBtu)	$1.61	$1.61	$1.61	$1.61	$1.61
Waha Differential Basis Swaps					
Total Volume (MMBtu)	3,150,000	3,185,000	3,220,000	3,220,000	12,775,000
Daily Volume (MMBtu/d)	35,000	35,000	35,000	35,000	35,000
Weighted Average Price ($/MMBtu)	($1.31)	($1.31)	($1.31)	($1.31)	($1.31)

Note: Hedge positions as of December 31, 2018

Reconciliation of Adjusted EBITDAX to Net Income

Adjusted EBITDAX reconciliation ($ thousands)[1]

Adjusted EBITDAX reconciliation to net income:	Q1 2018 3 months ended March 31, 2018	Q2 2018 3 months ended June 30, 2018	Q3 2018 3 months ended Sept. 30, 2018	Q4 2018 3 months ended Dec. 31, 2018	2018 12 months ended Dec. 31, 2018
Net income (loss) attributable to common shareholders	$66,090	$63,541	$39,288	$30,980	$199,899
Net income attributable to noncontrolling interest	4,682	3,941	2,386	1,828	$12,837
Interest expense	5,813	5,791	6,534	8,220	$26,358
Income tax expense (benefit)	19,137	19,940	11,652	8,711	$59,440
Depreciation, depletion and amortization	66,010	74,946	83,423	102,083	$326,462
Impairment and abandonment expenses	-	1,784	8,612	740	11,136
Non-cash portion of derivative (gain) loss	(7,482)	(11,534)	18,437	5,853	5,274
Stock-based compensation expense	3,952	4,166	4,888	5,848	18,854
Exploration expense	3,447	1,867	2,712	1,942	9,968
Transaction costs	-	-	-	-	-
(Gain) loss on sale of oil and natural gas properties	(15)	141	(52)	(549)	(475)
Adjusted EBITDAX	$161,634	$164,583	$177,880	$165,656	$669,753

(1) Adjusted EBITDAX is not presented in accordance with generally accepted accounting principles in the United States

Reconciliation of Adjusted EBITDAX to Net Income

Adjusted EBITDAX reconciliation ($ thousands)[1]

Adjusted EBITDAX reconciliation to net income:	Predecessor Jan. 1, 2016 through Oct. 10, 2016	Successor Oct. 11, 2016 through Dec. 31, 2016	2016 12 months ended Dec. 31, 2016	2017 12 months ended Dec. 31, 2017	2018 12 months ended Dec. 31, 2018
Net income (loss) attributable to common shareholders	($218,724)	($8,081)	($226,805)	$75,568	$199,899
Net income attributable to noncontrolling interest	-	(904)	(904)	7,987	12,837
Interest expense	5,626	378	6,004	5,729	26,358
Income tax expense (benefit)	(406)	-	(406)	29,930	59,440
Depreciation, depletion and amortization	62,964	14,877	77,841	161,628	326,462
Impairment and abandonment expenses	2,545	-	2,545	(29)	11,136
Non-cash portion of derivative (gain) loss	23,461	2,602	26,063	(5,805)	5,274
Stock-based compensation expense	-	1,333	1,333	12,150	18,854
Incentive unit compensation	165,394	-	165,394	-	-
Exploration expense	920	1,468	2,388	14,373	9,968
Transaction costs	15,792	4,097	19,889	1,454	-
Write-off of deferred offering costs	1,181	-	1,181	-	-
(Gain) loss on sale of oil and natural gas properties	(11)	(24)	(35)	(8,796)	(475)
Adjusted EBITDAX	$58,742	$15,746	$74,488	$294,189	$669,753

Note: 2016 EBIITDAX represents a combination of Predecessor and Successor periods

(1) Adjusted EBITDAX is not presented in accordance with generally accepted accounting principles in the United States