CENTENNIAL

Core Oil
Delaware Basin Pure-Play

First Quarter 2019 Earnings Presentation

May 6, 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.

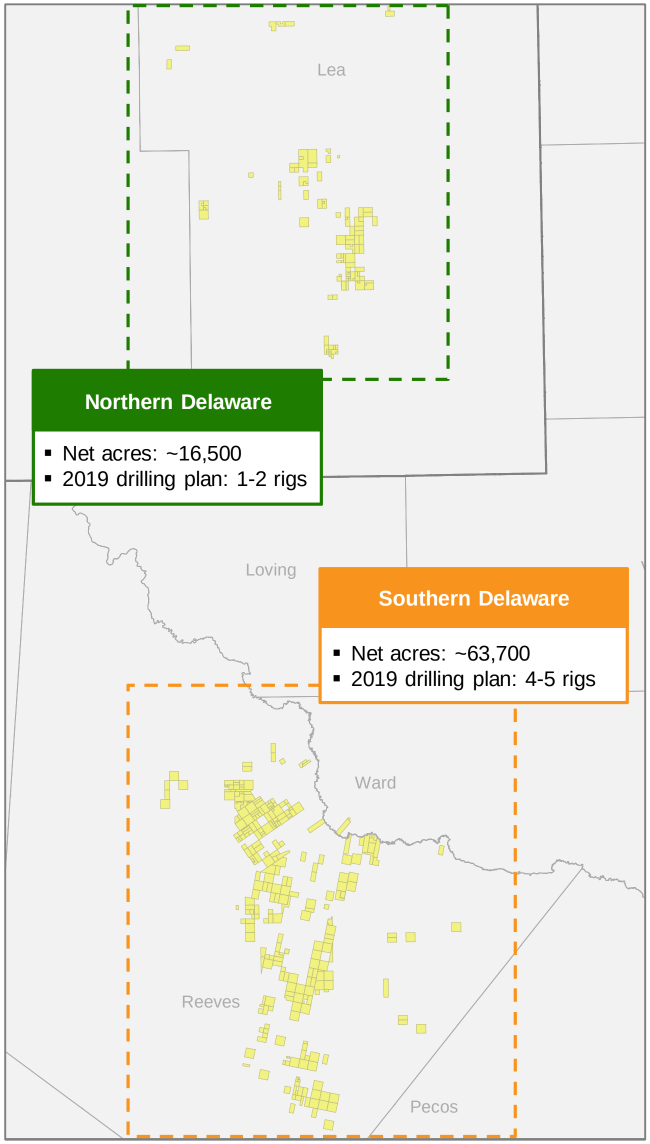
Use of Non-GAAP Financial Measures

This presentation includes the non-GAAP financial measure, Adjusted EBITDAX. Please refer to slide 17 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 on slide 17 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

Q1 2019 Financial and Operational Highlights

- **Oil-Rich Delaware Core Acreage**
  - ~80,200 net acres in core of Delaware Basin (89% operated)
- **Strong operational track record**
  - Increased daily oil and equivalent production volumes 28% and 33% year-over-year, respectively
  - Announced strong well results from multiple intervals in the Northern and Southern Delaware Basins
  - Reported successful Third Bone Spring Sand step-out in Reeves County, Texas
- **Demonstrating continued cost control**
  - Delivered total cash unit costs at the lower-half of full year guidance ranges
- **Advantaged midstream infrastructure and flow assurance**
  - Takeaway secured for the majority of crude oil and essentially all residue natural gas out of the Permian Basin
  - Experienced immaterial natural gas flaring to date
- **Maintaining conservative balance sheet and strong liquidity**
  - Borrowing base increased from $1.0bn to $1.2bn with recent redetermination
  - Elected liquidity as of 3/31/19 of ~$900mm[1]
  - Net Debt / Book Capitalization of 20%; Net Debt / LTM EBITDAX of 1.3x



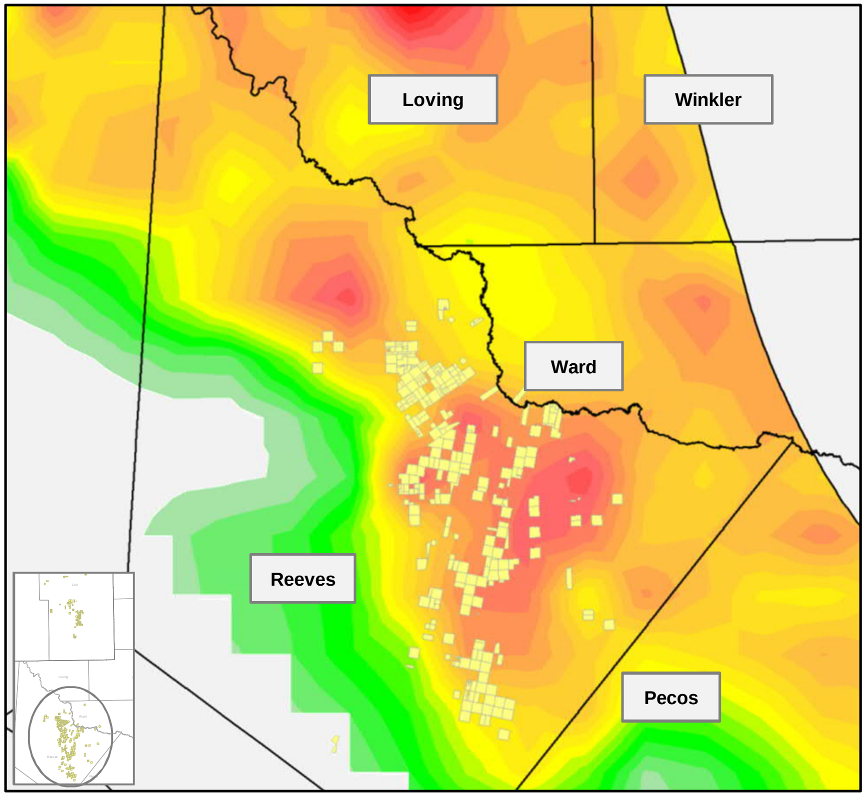
Note: Acreage figures as of December 31, 2018
(1) Liquidity based on elected commitment amount of $800mm (not full borrowing base capacity of $1.2bn)

High Quality Acreage Position in Core of the Delaware

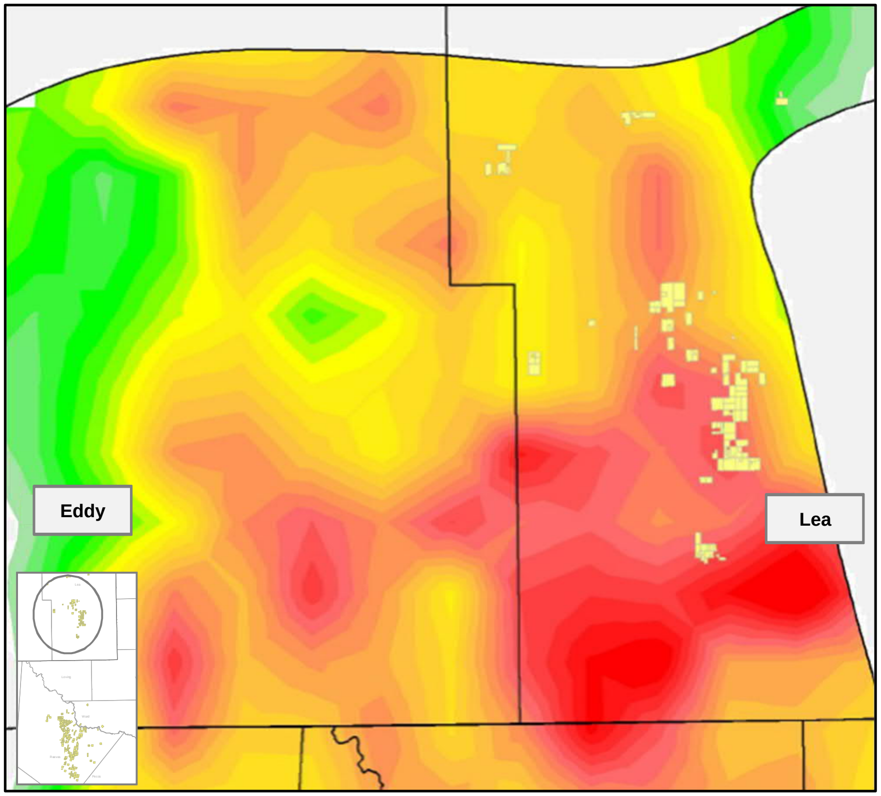
Delaware Basin Well Productivity (Peak, Normalized 90-Day Oil - Bo/d/ft.)

Scale	Maximum Oil Productivity	→	Minimum Oil Productivity

Southern Delaware Basin

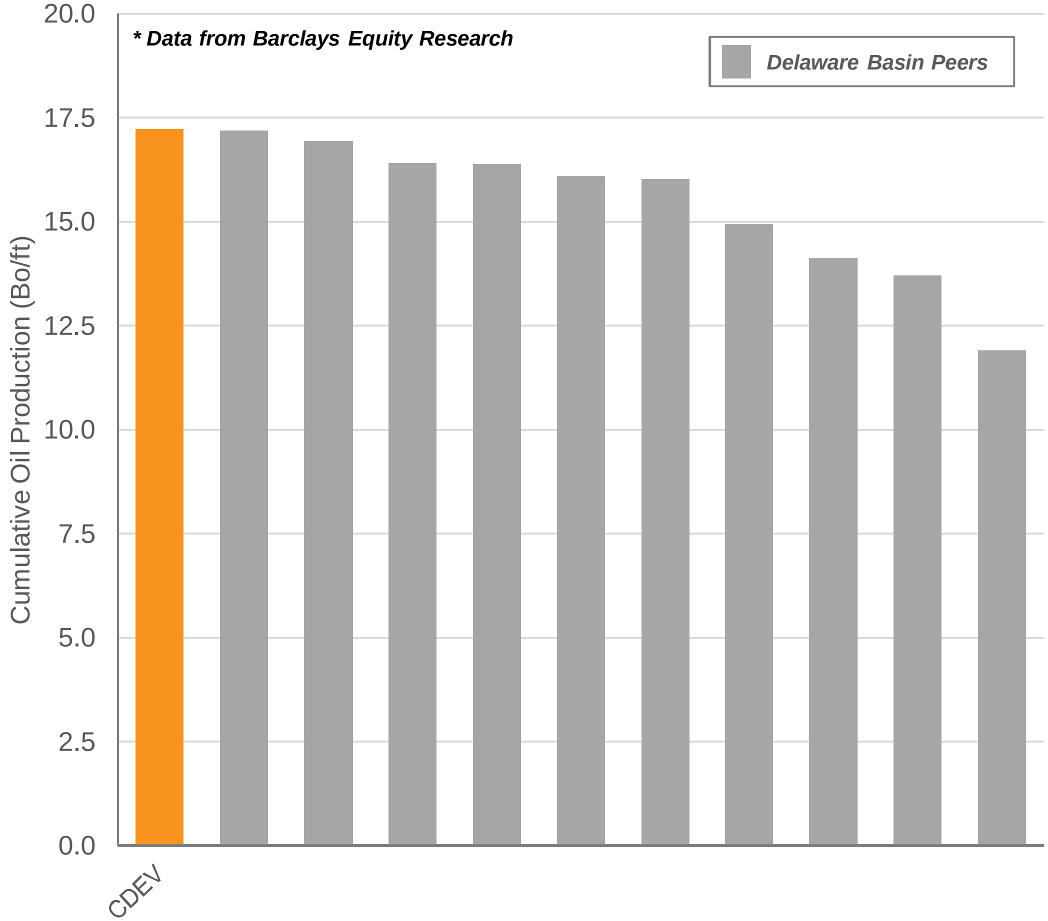


Northern Delaware Basin



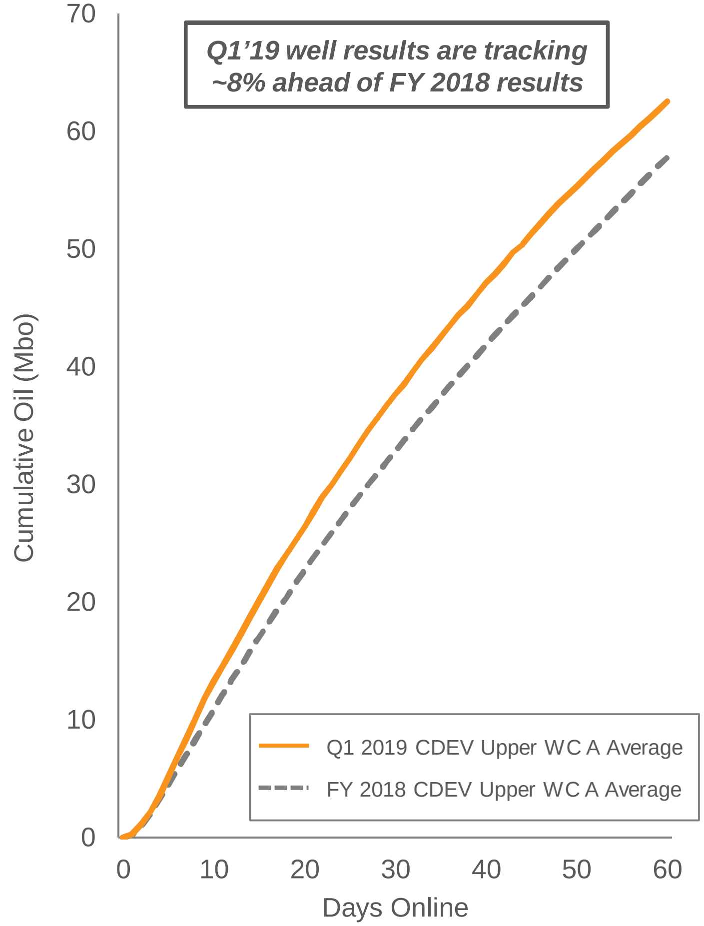
Delaware Basin Well Productivity

Mid-Cap Avg. Delaware Basin Well Performance (6-Month Oil Prod.; Bo / ft.)[1]



Consistently one of the most productive mid-cap operators in the Delaware Basin…

CDEV Q1'19 Results vs FY 2018 Avg (Upper WC A)[2]



…with continued improvements in well productivity

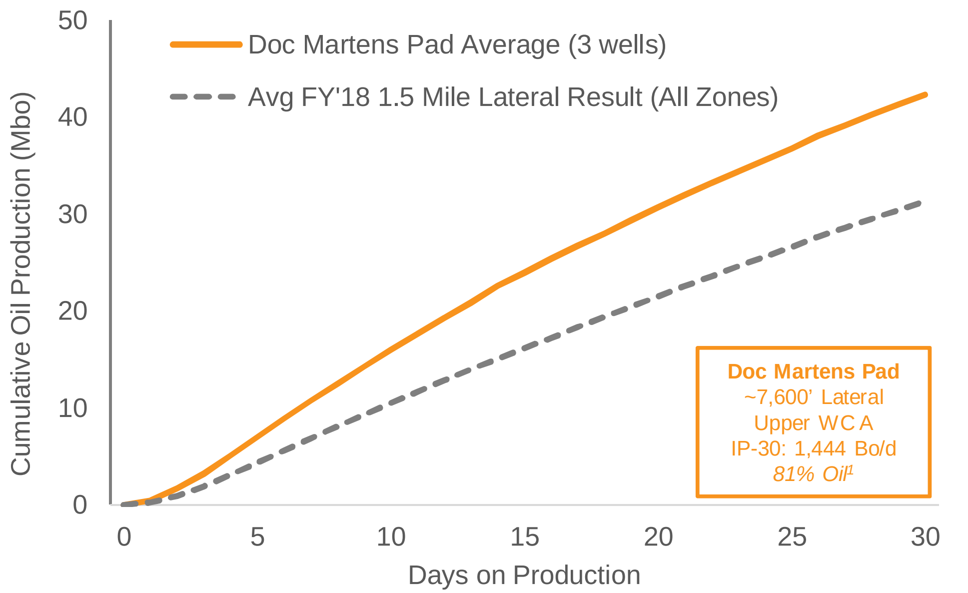
(1) Source: DrillingInfo and Barclays Equity Research; Peers include APA, CXO, DVN, EGN, FANG, MTDR, NBL, REN, WPX and XEC; Excludes companies with a market cap > $30bn; Results include wells from Reeves, Pecos, Loving, Culberson and southern half of Lea & Eddy Counties since September 2015

(2) Well results shown on a non-normalized basis; Q1 2019 average lateral length of 7,836 and FY 2018 average lateral length of 7,842

Reeves County Downspacing Test Outperforming

- Strong Upper Wolfcamp A 3-well pad from recently completed Doc Martens 3H, 9H and 16H
  - Average IP-30 of 1,775 Boe/d; oil IP-30 of 1,444 Bo/d
  - Wells successfully spaced at 660’ (8 wells / section) compared to 880’ (6 wells / section) assumed for Wolfcamp A inventory
  - Pad performance significantly exceeding legacy results and initial expectations
  - Pad directly offsetting depletion from existing producers
- Results further support Q4’18 acquisition of 2,100 net acres contiguous to the Doc Martens section

Doc Martens Pad Well Results - Cum. Oil (Mbo)

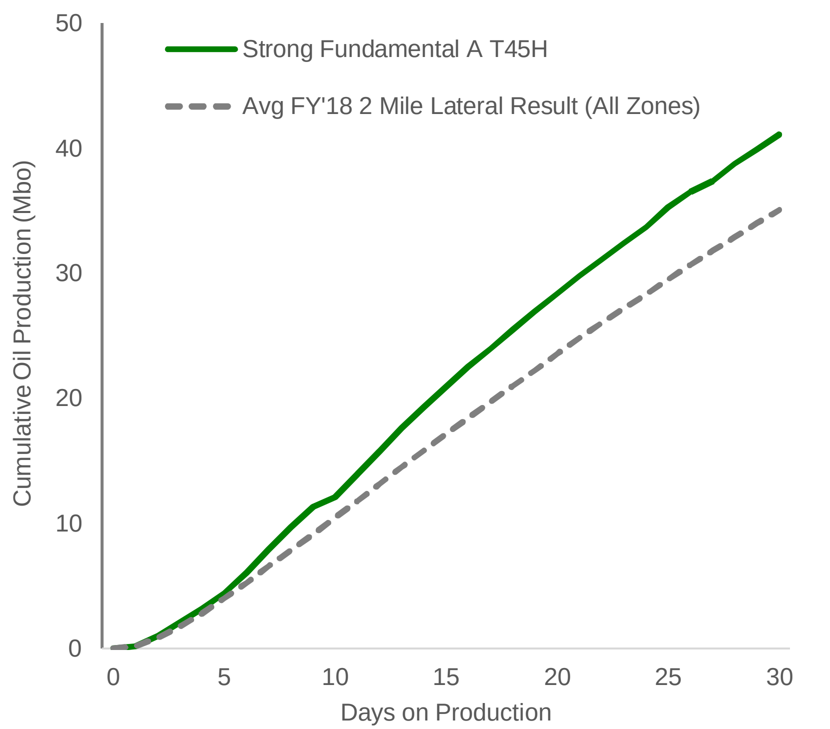


Reeves County Well Locator Map

Note: Cumulative oil production curves shown on an non-normalized basis
(1) % Oil figures shown on a 2-stream basis

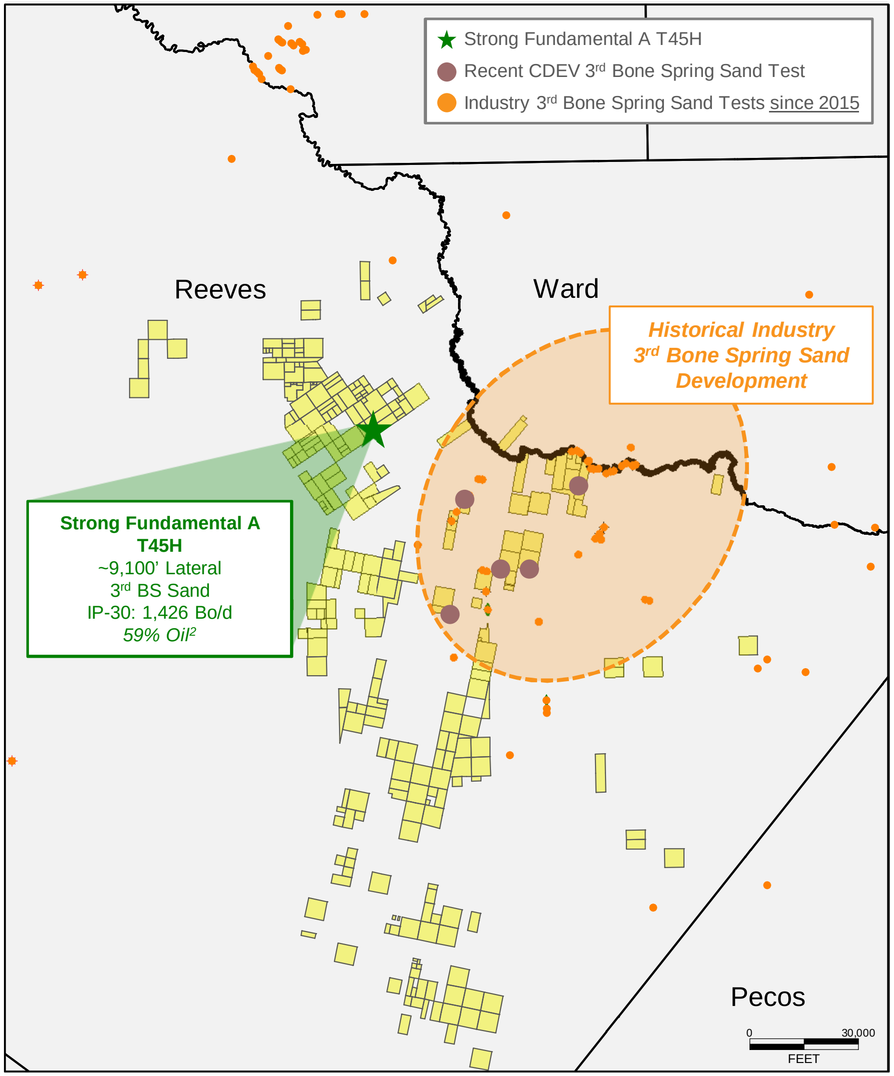
Extending the 3rd Bone Spring Boundaries

Strong Fundamental A T45H - Cum. Oil (Mbo)



- One of the strongest CDEV 3rd Bone Spring Sand wells drilled to date with an oil IP-30 of 1,426 Bo/d
- Important test to confirm 3rd Bone Spring Sand productivity on CDEV acreage outside of the traditional industry fairway
- Additional development activity planned for 2019

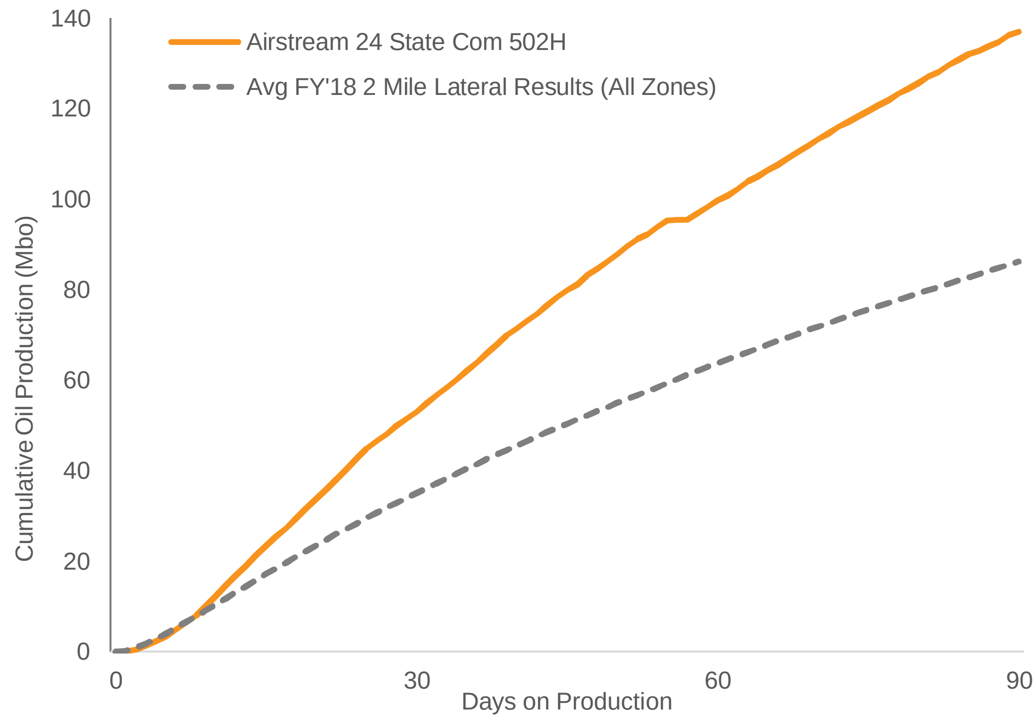
Reeves County Well Locator Map[1]



Note: Cumulative oil production curves shown on an non-normalized basis
(1) Source: IHS Petra: Geological Interpretation Software
(2) % Oil figures shown on a 2-stream basis

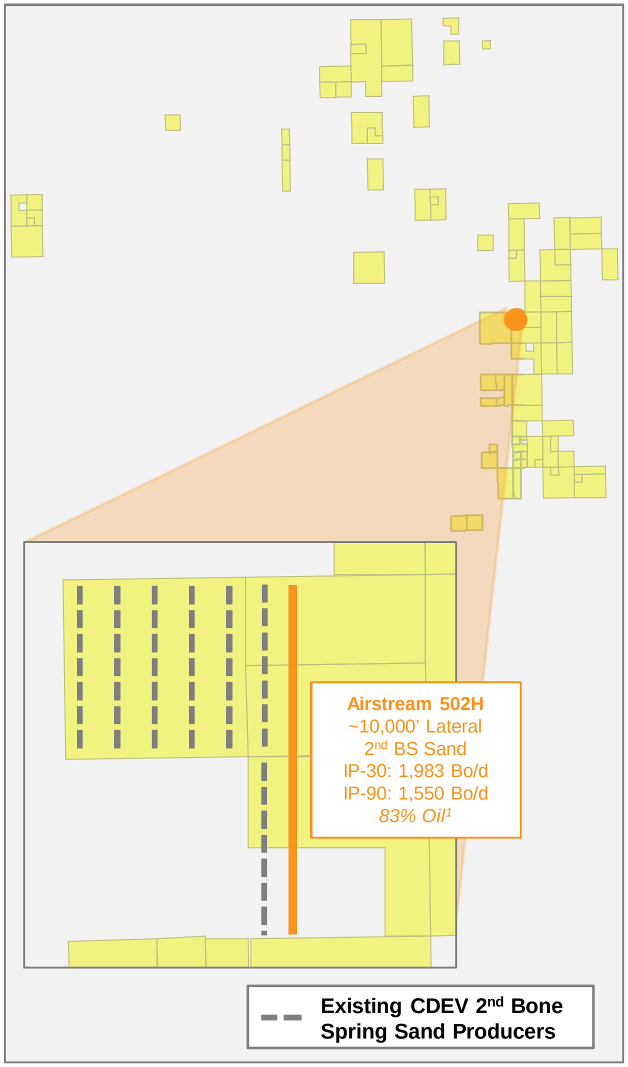
Airstream 502H Continues to Outperform

Airstream 24 State Com 502H - Cum. Oil (Mbo)



- Strongest CDEV 2nd Bone Spring Sand well drilled to date
  - One of the best 2nd Bone Spring wells drilled in the area
- First two mile 2nd Bone Spring well drilled by CDEV
- Directly offsetting producers from the same interval
- Continues to outperform average two mile well after 90 days

Lea County Well Locator Map



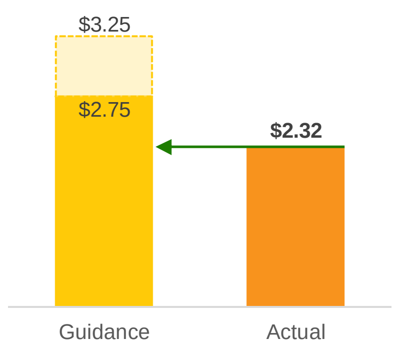
Note: Cumulative oil production curves shown on an non-normalized basis
(1) % Oil figures shown on a 2-stream basis

Delivering on Competitive Unit Costs

Q1 2019 Results vs Feb '19 Guidance

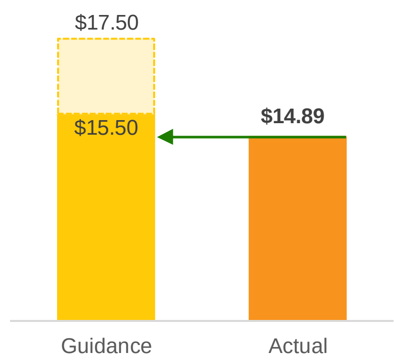
LOE ($ / Boe)

GP&T ($ / Boe)



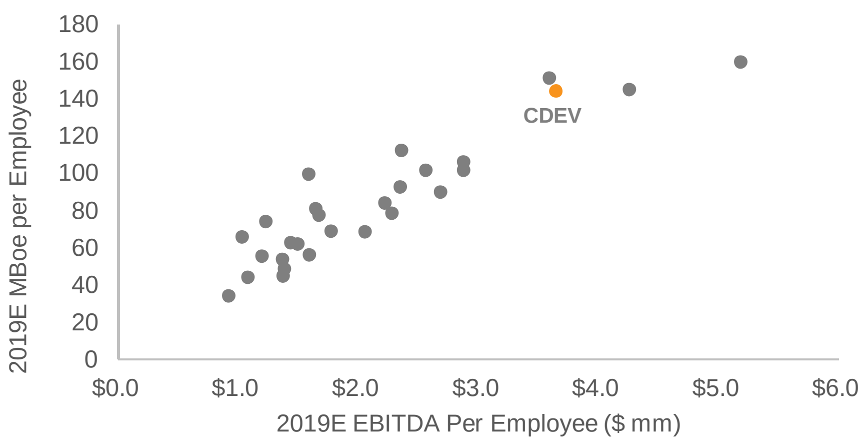
Cash G&A ($ / Boe)

DD&A ($ / Boe)

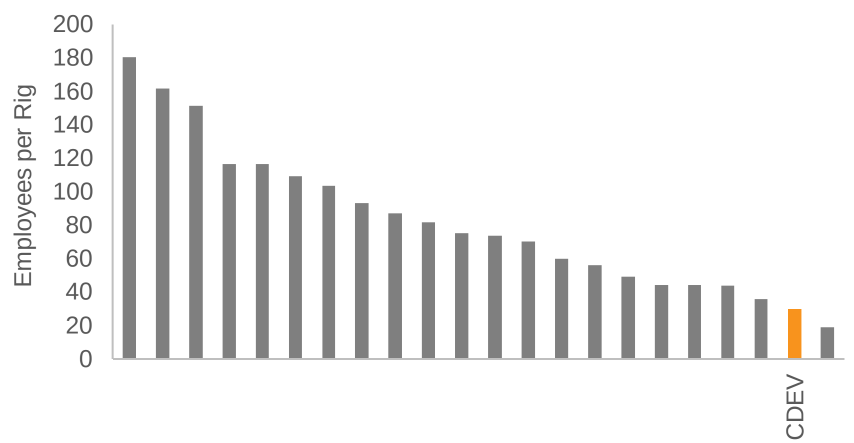


2019E G&A Benchmarking[1]

2019E MBoe per Employee vs. 2019E EBITDA per Employee[2]



2019E Employees per Rig[2]



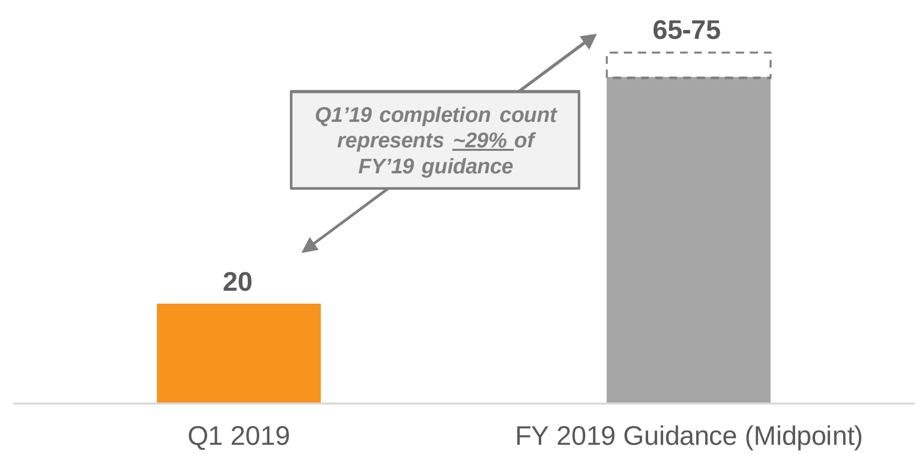
(1) Source: TPH Equity Research
(2) Peers include APA, APC, BRY, CLR, COP, CPE, CRZO, CXO, DVN, ECA, EOG, FANG, JAG, LPI, MRO, MTDR, NBL, OAS, PDCE, PE, PXD, QEP, SM, SRCI, WLL, WPX and XOG (companies with leverage to international operations removed from per rig graph)

Q1 2019 Development Activity Overview

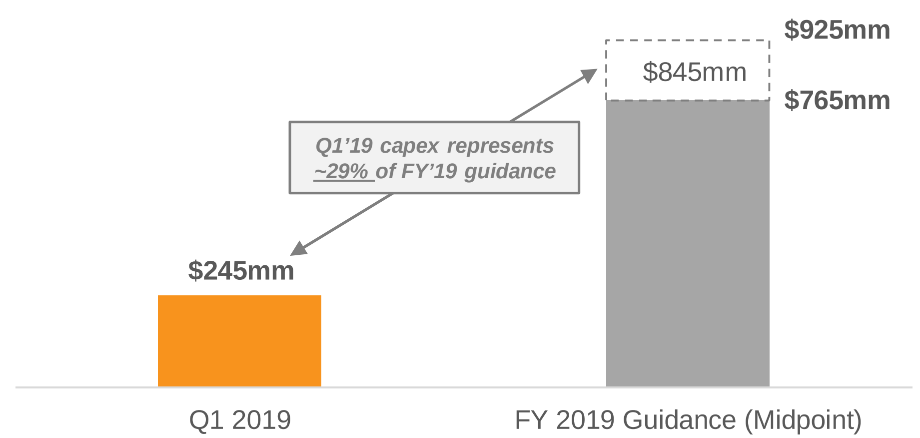
Q1 2019 Development Activity Summary

- Higher activity levels impacted by carry-over from 7 rig program in 2018 and continued operational efficiencies
- 17 gross operated wells spud
- 20 gross operated wells brought on-line, with nearly half of completions occurring in March
- Facilities constructed to support ~30 gross operated wells
- Remain on track to deliver within annual guidance

Q1'19 Gross Operated Wells Completed vs Annual Guidance



Q1'19 Total Capex vs Annual Guidance



Crude & Natural Gas Flow Assurance Summary

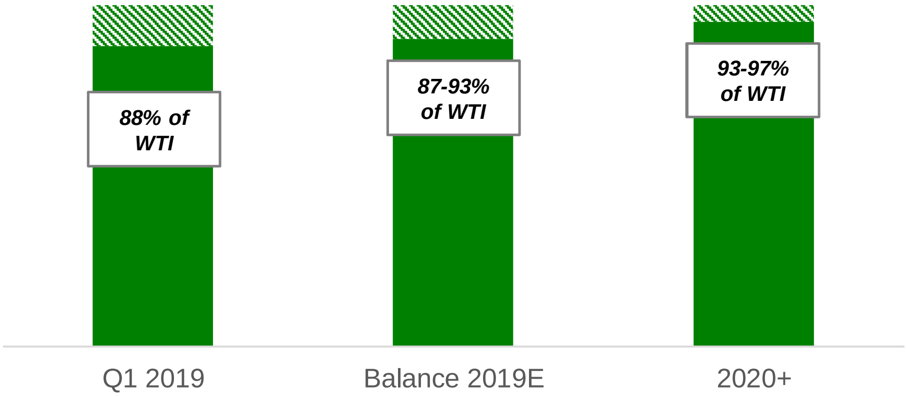
Crude Oil Flow Assurance Summary

- Crude oil basis and takeaway risk mitigated through two firm sales contracts
  - In total, secured takeaway for >50,000 Bo/d gross[1] 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
- Price Realizations
  - Expect realized pricing slightly below Midland market for the remainder of 2019
  - Realizations expected to improve meaningfully in 2020+ with exposure to a diversified mix of three price indices
- Attractive Centennial crude quality
  - Average crude oil gravity of ~43° across acreage position
  - Expect no price deducts due to crude oil quality

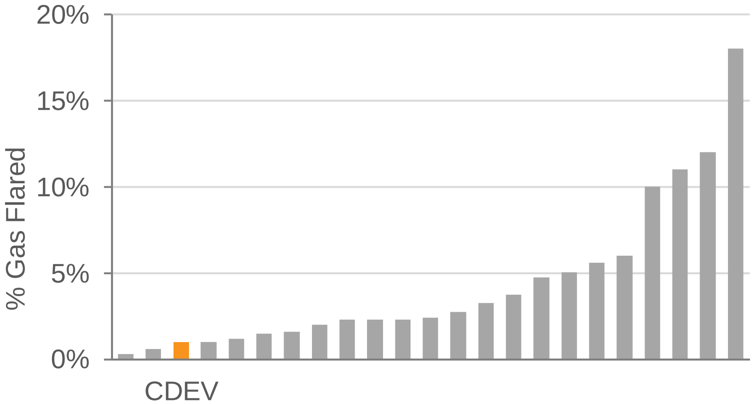
Natural Gas Flow Assurance Summary

- Natural gas basis and takeaway risk mitigated through firm transportation & firm sales contracts
  - CDEV has secured takeaway for 100%+ of forecasted 2019-2022 residue gas
  - Do not expect to flare any material amounts of gas
- Near-term Waha exposure limited due to firm transportation contracts and existing hedge profile
  - 90,000 gross MMBtu/d from Q2'19 – Q4'20 to be sold at a Mid-Continent based price, limiting Waha exposure for the majority of anticipated production over that period
  - 35,000 MMBtu/d and 15,000 MMBtu/d of Waha basis and fixed price hedges in place for remainder of 2019, respectively

Realized Oil Price Expectations (% of WTI)[2]



Average Texas Permian Gas Flaring by Operator[3]



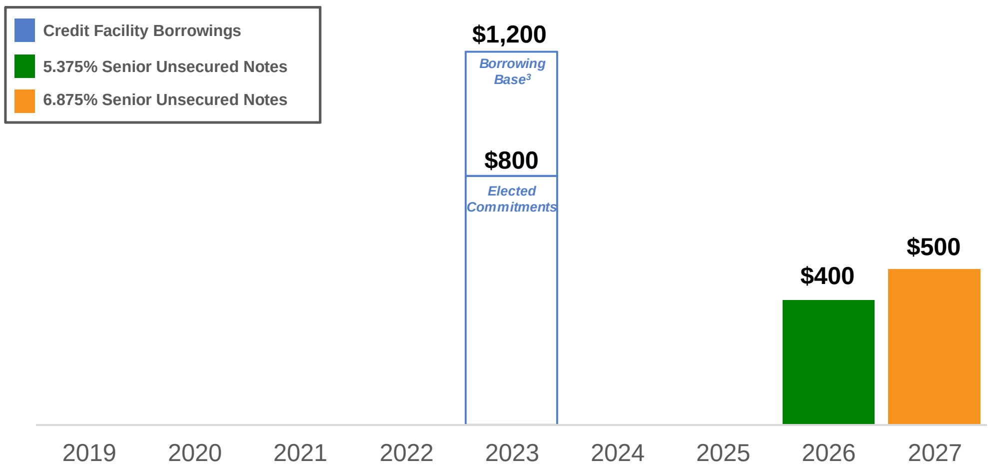
(1) Including non-operated barrels
(2) Based on current strip pricing
(3) Sources: Texas Railroad Commission and Guggenheim Securities estimates; data represents July – August 2018; Note: All volume amounts represent gross volumes; peers include: APA, APC, COP, CPE, CRZO, CVX, CXO, DVN, ECA, EGN, EOG, FANG, JAG, LPI, OAS, OXY, PE, PXD, SM, WPX, XEC and XOM

Capital Structure and Liquidity Overview

Capital structure overview

- Borrowing base increased by 20% to $1.2bn during Spring Redetermination
- Conservative leverage profile at 3/31/19
  - Net Debt / Total Book Capitalization of 20%
  - Net Debt / LTM EBITDAX of 1.3x
- ~$900 million of elected liquidity
- Credit facility matures in 2023, Senior Notes mature in 2026 and 2027

Debt maturity schedule ($ mm)



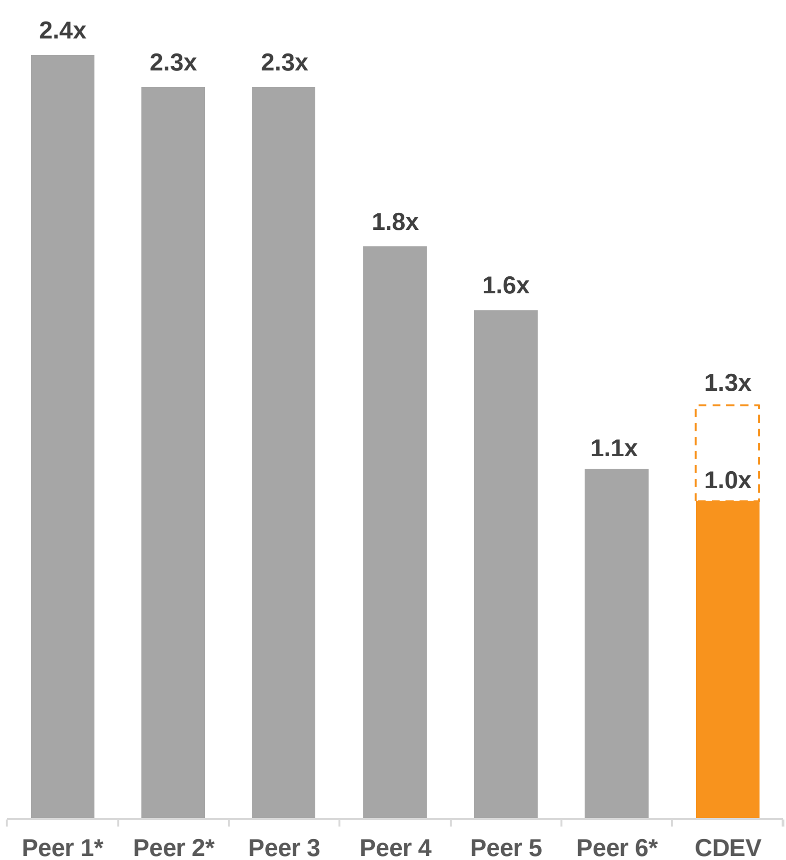
Capitalization and Liquidity ($ mm)

Capitalization	Actual (as of 3/31/19)
Cash and cash equivalents	$89
Revolving credit facility	$0
Senior Unsecured Notes [1]	$900
Total debt	$900
Book equity [2]	$3,242
Total capitalization	$4,142
Credit statistics	
Net debt / LTM EBITDAX	1.3x
Net debt / book capitalization	20%
Liquidity ($ mm)	
Borrowing base [3]	$1,200
Elected Commitment	$800
Less: Revolver borrowings	$0
Less: Letters of credit	($1)
Plus: Cash	$89
Elected liquidity [4]	$889
Borrowing base utilization	*0%*

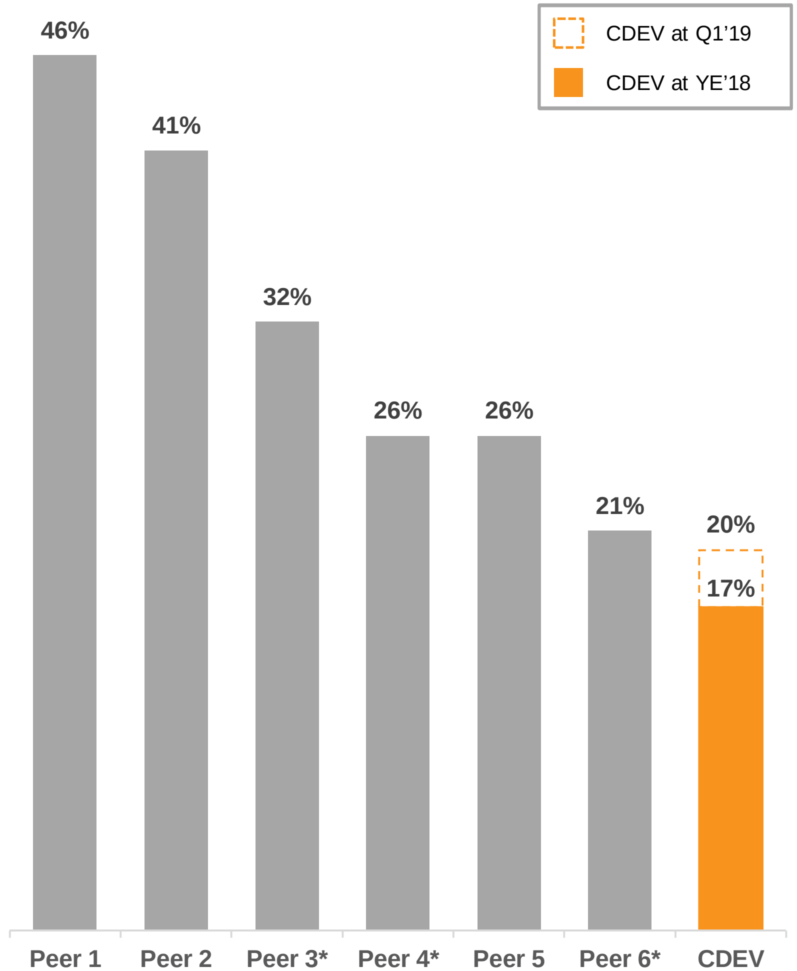
Note: Amounts may not sum due to rounding
(1) Reflects the aggregate principal amount
(2) Book equity includes non-controlling interest
(3) Borrowing base pro-forma for Spring 2019 Redetermination
(4) Total liquidity calculation based on elected commitment amount, not total borrowing base

Peer Leading Leverage & Capitalization

Net Debt / LTM EBITDAX[1]



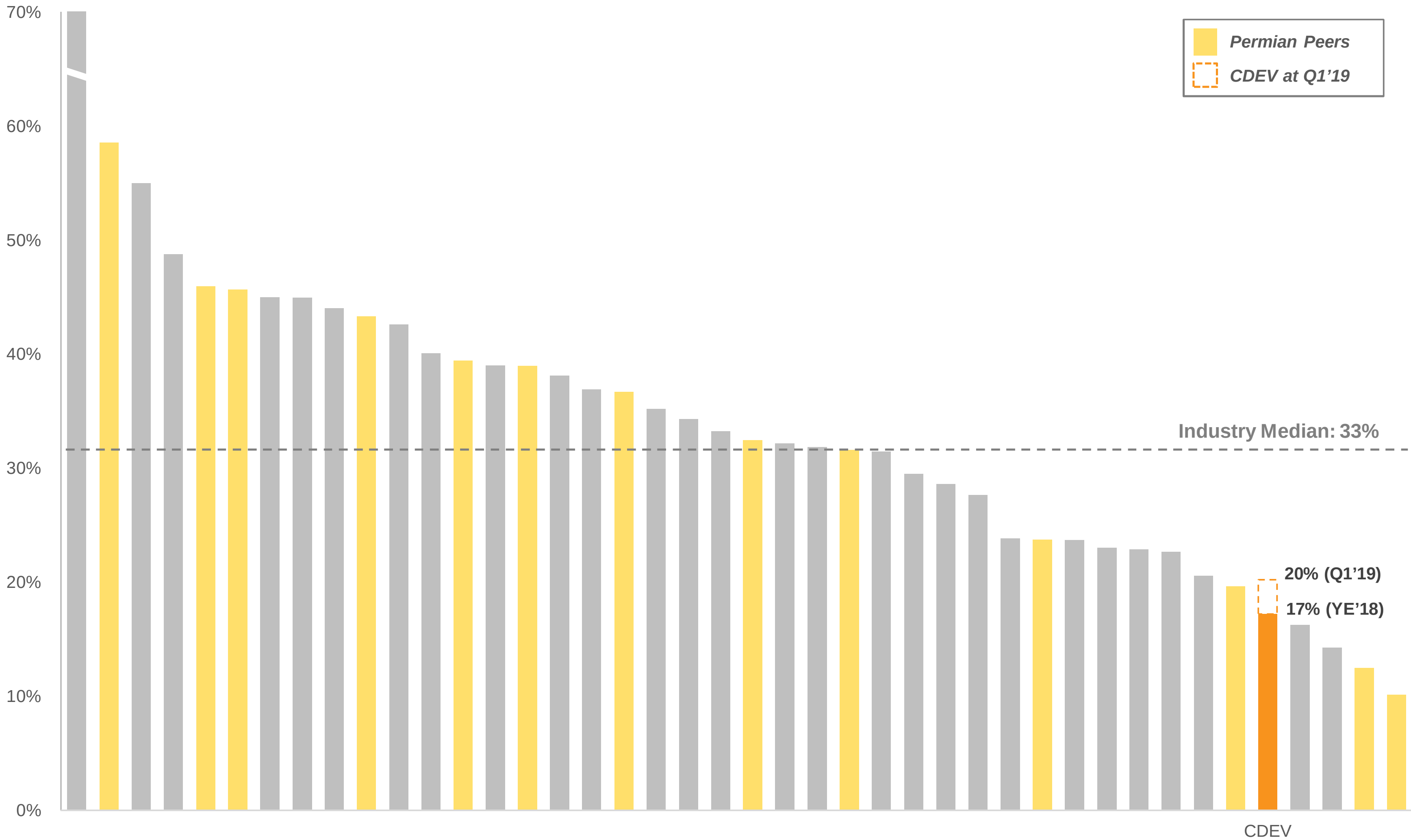
Net Debt / Total Capitalization[1]



Source: Company filings
Peer group includes CPE, FANG, JAG, LPI, MTDR and PE.
(1) LPI, MTDR and PE as of 3/31/19; CPE, FANG and JAG as of 12/31/18. Asterisk represents metric as of YE'18

Industry Benchmarking – Net Debt / Book Capitalization

Net Debt / Book Capitalization (as of YE 18)



Source: Company filings and financials
Note: Peers represent public U.S. E&P companies with market cap over $1bn; all peers shown as of 12/31/18

Q1 2019 Financial Results

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

	2018				2019
($ in millions, unless specified)	Q1	Q2	Q3	Q4	Q1
Average Daily Production (Boe/d)	54,069	57,528	62,930	69,609	72,035
Average Daily Oil Production (Bo/d)	31,573	31,271	36,027	39,978	40,508
% Oil	*58%*	*54%*	*57%*	*57%*	*56%*
Financial highlights					
Total Revenue	$215.9	$217.8	$234.9	$222.5	$214.6
Adjusted EBITDAX[2]	$161.6	$164.6	$177.9	$165.7	$141.1
Net Income (loss)[3]	$66.1	$63.5	$39.3	$31.0	($8.1)
Unit Costs ($/Boe)					
Lease Operating Expense	$3.34	$3.66	$4.09	$3.77	$4.61
Gathering, Processing & Transportation	2.84	2.92	2.78	1.94	2.32
Severance & Ad Valorem Taxes	2.91	2.71	2.49	2.14	2.49
Cash G&A	2.13	1.84	2.02	2.00	1.89
Depreciation, Depletion & Amortization	13.57	14.32	14.41	15.94	14.89
Capital Expenditures Incurred					
Drilling & Completion	$181.8	$162.7	$222.4	$199.2	$188.4
Facilities, Seismic and Other	50.2	34.3	43.5	73.1	45.6
Land and Other	6.3	6.2	7.7	9.8	11.2
Total Capital Expenditures	$238.3	$203.2	$273.6	$282.1	$245.2
Cash and Cash Equivalents	$38.2	$42.7	$58.9	$18.2	$89.5
Total Debt Outstanding	$400.0	$430.0	$540.0	$700.0	$900.0
Liquidity[4]	$637.4	$611.8	$518.0	$517.4	$888.7

(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 slide 17 for a reconciliation of Adjusted EBITDAX to net income (loss), the most comparable GAAP measure.
(3) Net income (loss) attributable to common shareholders. Figure reflects a Q1'19 impairment charge of $31.3mm
(4) Liquidity defined as cash, plus availability under the revolving credit facility

Hedge Position Overview

	FY 2019 (9 months ended 12/31/19)			
	Q2	Q3	Q4	Bal 2019
MidCush Basis Swaps				
Total Volume (Bbl)	91,000	1,380,000	920,000	2,391,000
Daily Volume (Bbl/d)	1,000	15,000	10,000	8,695
Weighted Average Price ($ / Bbl)	($10.00)	($9.03)	($4.24)	($7.22)
Henry Hub Fixed Price Swaps				
Total Volume (MMBtu)	2,730,000	2,760,000	2,760,000	8,250,000
Total Volume (MMBtu/d)	30,000	30,000	30,000	30,000
Weighted Average Price ($/MMBtu)	$2.78	$2.78	$2.78	$2.78
Waha Fixed Price Swaps				
Total Volume (MMBtu)	1,365,000	1,380,000	1,380,000	4,125,000
Daily Volume (MMBtu/d)	15,000	15,000	15,000	15,000
Weighted Average Price ($/MMBtu)	$1.61	$1.61	$1.61	$1.61
Waha Differential Basis Swaps				
Total Volume (MMBtu)	3,185,000	3,220,000	3,220,000	9,625,000
Daily Volume (MMBtu/d)	35,000	35,000	35,000	35,000
Weighted Average Price ($/MMBtu)	($1.31)	($1.31)	($1.31)	($1.31)

Note: Hedge positions as of March 31, 2019

Reconciliation of Adjusted EBITDAX to Net Income (Loss)

Adjusted EBITDAX reconciliation ($ thousands)[1]

Adjusted EBITDAX reconciliation to net income (loss):	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	2019 3 months ended March 31, 2019
Net income (loss) attributable to common shareholders	$66,090	$63,541	$39,288	$30,980	$199,899	($8,112)
Net income (loss) attributable to noncontrolling interest	4,682	3,941	2,386	1,828	$12,837	(425)
Interest expense	5,813	5,791	6,534	8,220	$26,358	10,160
Income tax expense (benefit)	19,137	19,940	11,652	8,711	$59,440	(2,263)
Depreciation, depletion and amortization	66,010	74,946	83,423	102,083	$326,462	96,558
Impairment and abandonment expenses	-	1,784	8,612	740	11,136	31,264
Non-cash portion of derivative (gain) loss	(7,482)	(11,534)	18,437	5,853	5,274	5,494
Stock-based compensation expense	3,952	4,166	4,888	5,848	18,854	5,884
Exploration expense	3,447	1,867	2,712	1,942	9,968	2,516
Transaction costs	-	-	-	-	-	-
(Gain) loss on sale of oil and natural gas properties	(15)	141	(52)	(549)	(475)	2
Adjusted EBITDAX	$161,634	$164,583	$177,880	$165,656	$669,753	$141,078

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