CENTENNIAL

Core Oil
Delaware Basin Pure-Play

Fiscal Year 2017 Earnings Presentation

February 26, 2018

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" 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 22 for a reconciliation of Adjusted EBITDAX to net (loss) 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 slide 22 from net (loss) income 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.

Recent Financial and Operational highlights

- Increased fourth quarter daily oil production 30% versus Q3
- Grew 2017 oil and equivalent production volumes 233% and 278% year-over-year, respectively
- Raised the Company's 2020 oil production target to 65,000 Bo/d from 60,000 Bo/d
  - No change to previously anticipated rig cadence
- Successfully completed wells in the 3rd Bone Spring Sand and 3rd Bone Spring Carbonate
- Delivered strong well results from the Northern and Southern Delaware Basins
  - Included successful Avalon Shale well and 660' Wolfcamp A density test
- Increased 2017 total proved reserves 125%
  - Achieved 2017 drill-bit F&D costs of $5.47 / Boe[1], proved developed F&D of $10.62 / Boe[2] and organic reserves replacement ratio of over 950%[3]
- Acquired ~4,000 net acres in Lea County, New Mexico adjacent to the Company's existing position, increasing the Northern Delaware footprint by ~30%
- Announced the pending sale of ~8,600 non-operated net acres in Reeves County, TX

(1) Calculation defined as total 2017 exploration and developments costs of $607.4mm divided by the sum of total 2017 reserve extensions, discoveries and revisions (technical and pricing) of 111.0 MMBoe
(2) Calculation defined as total 2017 exploration and developments costs of $607.4mm divided by the sum of total proved developed reserve extensions and discoveries, transfers from proved undeveloped reserves at year-end 2016, and proved developed reserve revisions (technical and pricing), totaling 57.2 MMBoe
(3) Calculation defined as the sum of total 2017 reserve extensions, discoveries and revisions (technical and pricing) of 111.0 MMBoe, divided by total 2017 production of 11.6 MMBoe

Centennial Resource Development Overview

Industry-leading production growth

- Increased Q4 2017 average daily oil production volumes by 30% compared to Q3 2017
- Realized over 230% oil production growth from 2016 to 2017
- 2018E oil production guidance implies ~85% year-over-year growth from 2017

Delaware Basin pure-play operator

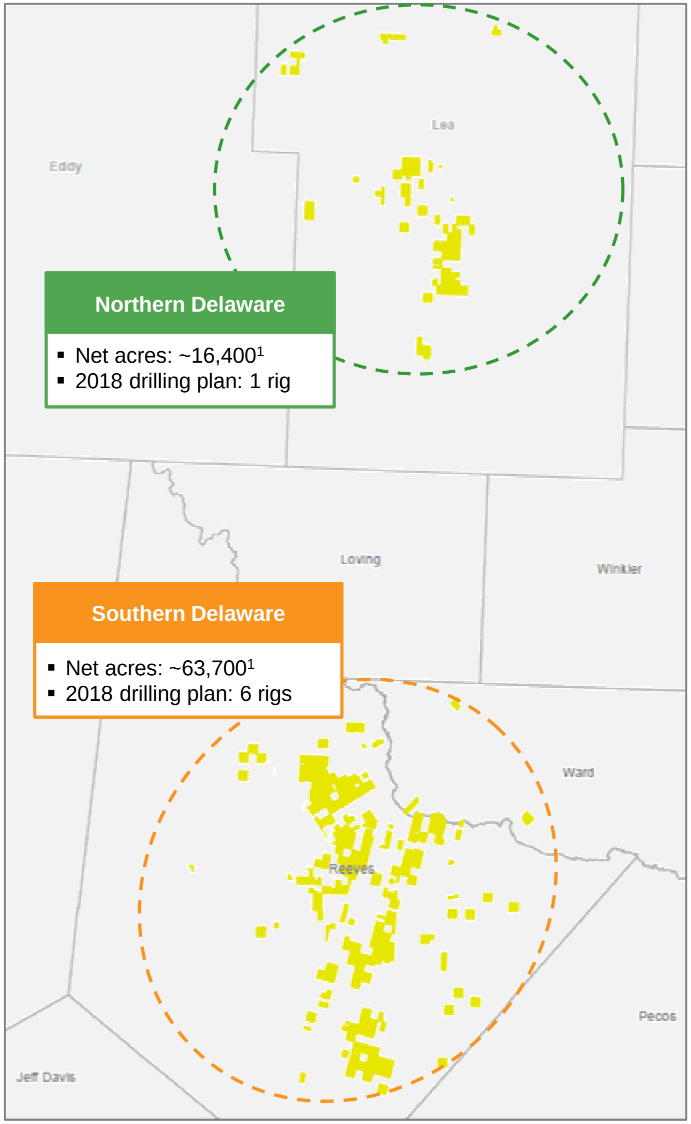
- ~80,100 net acres located primarily in Reeves County, TX and Lea County, NM[1]
- Over 90% of acreage is operated

Financial flexibility - strong balance sheet and liquidity position

- Net Debt / Q4 Annualized EBITDA of 0.6x; Net Debt / Total Capitalization of 8%
- Total liquidity of $591mm as of 12/31/17

Summary operational statistics

Operational overview	Q4 2017	FY 2017
Total production (Boe/d)	44,304	31,864
Oil production (Bo/d)	27,402	19,161
% oil	*62%*	*60%*
2018E production guidance (midpoint)		
2018E production (Boe/d)		59,250
2018E oil production (Bo/d)		35,500
Implied oil production growth		*85%*
Current operated rigs running		*7*
Acreage		
Total net acreage (as of 12/31/17)		~84,700
% Operated		*91%*
Pro forma net acreage[1]		~80,100
Drilling inventory[2]		
Gross horizontal drilling locations		~2,400
Gross operated horizontal drilling locations		~1,400
Proved reserves		
Total proved reserves at 12/31/17 (MBoe)		186,454



Note: Acreage map highlights current acreage position (shown pro forma for YTD closed/pending A&D activity)

(1) Pro forma net acreage figure, adjusted for closed ~4,000 net acre Northern Delaware acquisition and pending ~8,600 net acre Southern Delaware divestiture

(2) Represents gross horizontal drilling locations; for Southern Delaware assumes credit for the Upper and Lower Wolfcamp A, Wolfcamp B, Wolfcamp C and 3rd Bone Spring Sand; for Northern Delaware assumes credit for the Avalon Shale, 1st Bone Spring Sand, 2nd Bone Spring Sand, 3rd Bone Spring Sand and Wolfcamp A

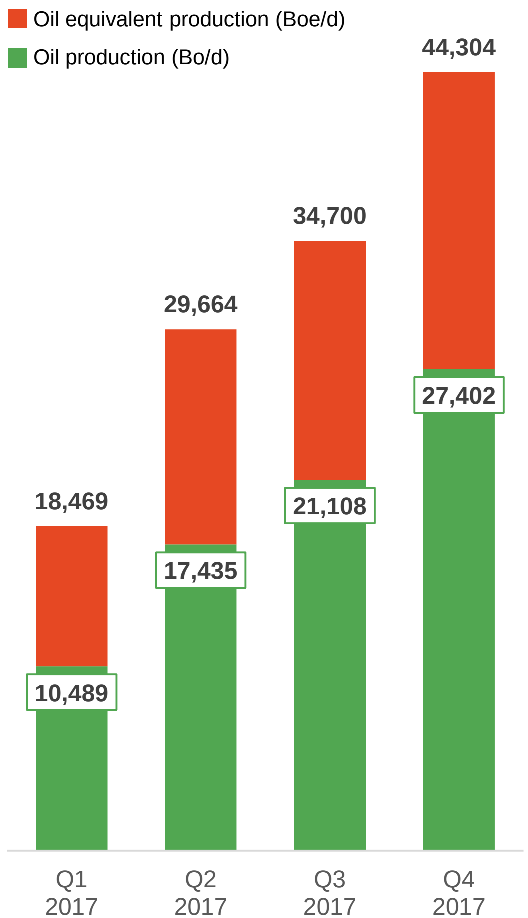
2017 Game Plan Review

Delivering on our goals

- **Grow net oil production ~215% to 18,200 Bo/d in 2017** ✓
  - *Exceeded high-end of oil production target (Actual: 19,161 Bo/d; 230%+ growth)*
- **Become mid-cap technical leader in G&G and well completion technology** ✓
  - *Comparative well results indicate this goal has been achieved*
- **Focus on GAAP returns and link employee compensation to returns of capital program** ✓
  - *Majority of compensation linked to reinvestment ROR on the capital program, including indirect costs*
- **Grow net oil production from ~5,700 Bo/d in 2016 to 60,000 by 2020** ✓
  - *Raised 2020 oil target to 65,000 Bo/d*
- **Evaluate Bone Spring Shale prospectivity across acreage** ✓
  - *Completed two successful tests in the 3rd Bone Spring Sand and 3rd Bone Spring Carbonate*
- **Maintain one of the lowest net debt positions of all U.S. E&P companies** ✓
  - *8% Net Debt / Total Capitalization*
- **Maintain clear, easy to understand financials** ✓
  - *Extinguished public warrants and converted preferred shares*
- **Target $50-$70 million per year spend for acreage acquisitions** ✓
  - *Organically leased high-quality acreage in and around our position for ~$55 million*
- **Achieve lowest unit costs among peers by 2018 – LOE and G&A**
  - *Ongoing; cash G&A per Boe expected to decrease ~25% in 2018*

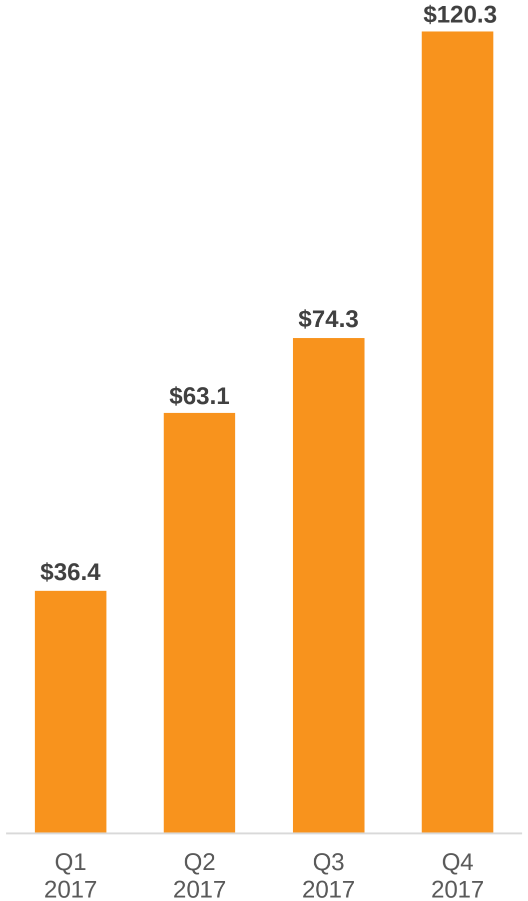
FY 2017 Quarterly Results

Production (Bo/d and Boe/d)



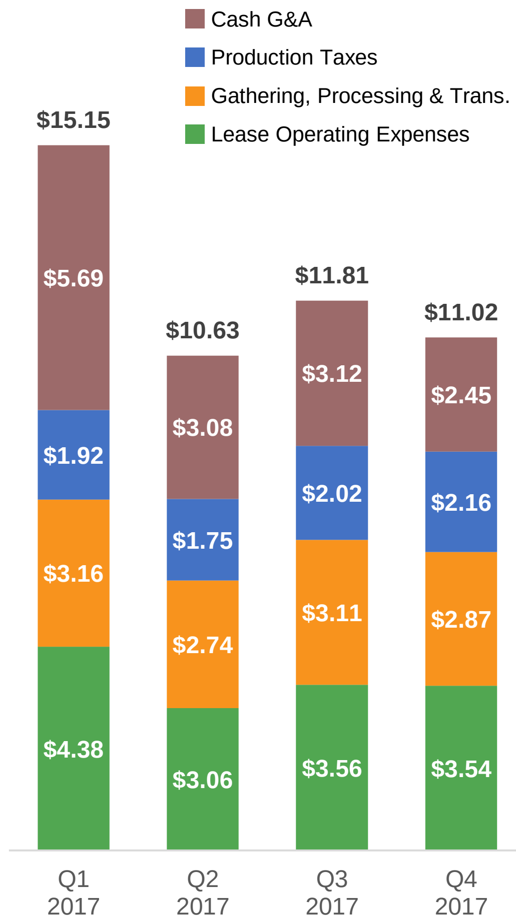
% oil			
57%	*59%*	*61%*	*62%*

Adjusted EBITDAX[1] ($ mm)



~230% EBITDAX growth (Q1 – Q4 2017)

Cash operating costs[2] ($ / Boe)



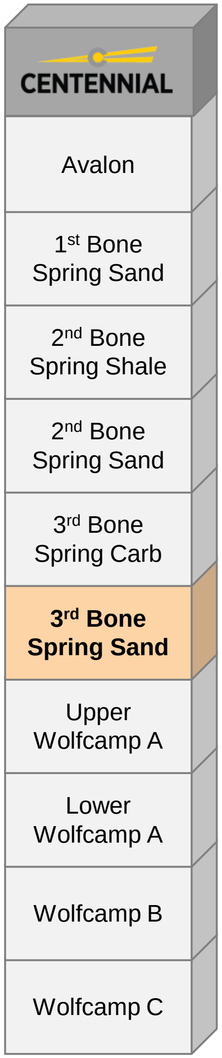
27% cash operating cost reduction (Q1 – Q4 2017)

(1) Adjusted EBITDAX is not presented in accordance with generally accepted accounting principles in the United States. Please refer to slide 22 for a reconciliation of Adjusted EBITDAX to net (loss) income, the most comparable GAAP measure.

(2) Q1 2017 G&A / Boe metric includes ~$1.8mm in one-time / non-recurring charges, which contributes $0.15/Boe to FY 2017 G&A / Boe

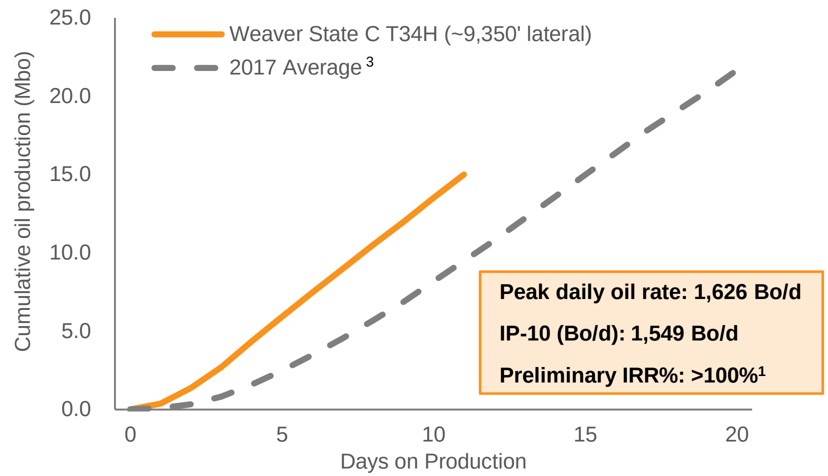
Initial 3rd Bone Spring Sand Result Outperforming

Weaver State C T34H overview

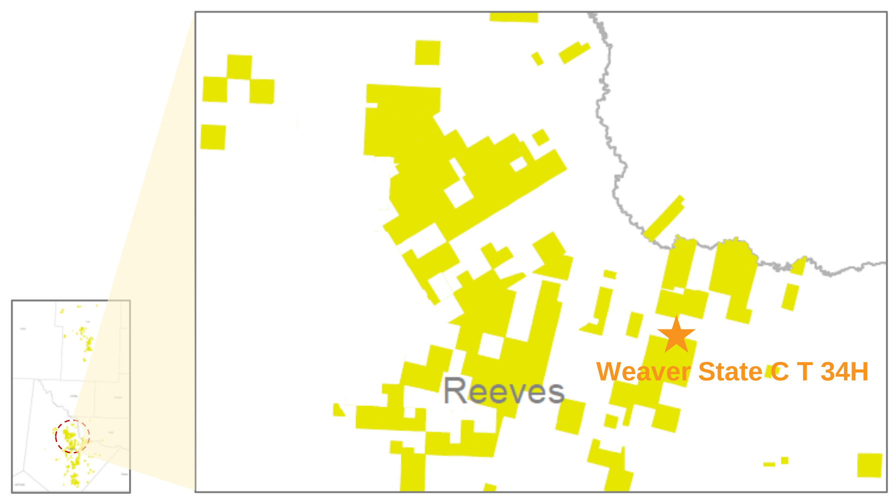


- Weaver State C T34H: Centennial's first 3rd Bone Spring Sand well utilizing latest completion technology in the Southern Delaware Basin
- Preliminary analysis indicates a pre-tax IRR of over 100%, assuming a flat $60 / Bbl oil price[1]
- Initial flowback results outperforming 2017 extended lateral average by >50%
- 3rd Bone Spring Sand extends over a significant portion of CDEV Reeves County acreage position
- Plan to drill and complete a confirmation test later in 2018
  - If successful, will initiate a full-scale development program

Weaver State C T34H performance vs. 2017 average[2]



Well Locator Map



(1) Preliminary economics assume pre-tax IRR calculated using illustrative $11mm well cost (inclusive of well-level facilities); $60 / Bbl flat oil price and $2.75 / MMBtu flat gas price
(2) Cumulative well performance from Weaver State C T 34H shown on an unnormalized basis
(3) 2017 average only includes production from two section laterals, normalized to 9,500'

Initial 3rd Bone Spring Carbonate Results

Big House C-3H overview

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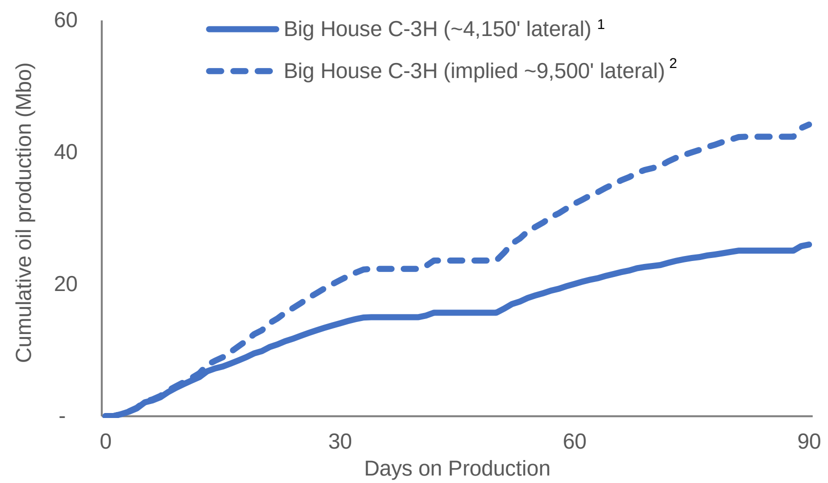
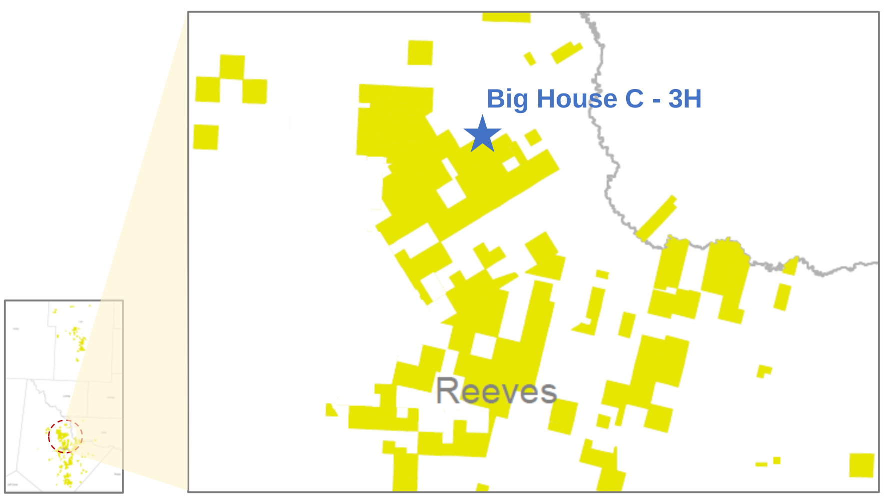
- Avalon
- 1st Bone Spring Sand
- 2nd Bone Spring Shale
- 2nd Bone Spring Sand
- **3rd Bone Spring Carb**
- 3rd Bone Spring Sand
- Upper Wolfcamp A
- Lower Wolfcamp A
- Wolfcamp B
- Wolfcamp C

- Big House C–3H is one of the first 3rd Bone Spring Carbonate wells tested in Reeves County
- Single-well economics (at a 4,150' lateral length) are not competitive with the current portfolio
- Adjusted for implied 2-section lateral performance upgrade, this zone will likely compete for future development capital
- Preliminary analysis indicates that a 2 section lateral would generate a pre-tax IRR of ~45%[3]
- Plan further target optimization and extended lateral test later in 2018

Big House C-3H actual performance vs. extended lateral



Well Locator Map



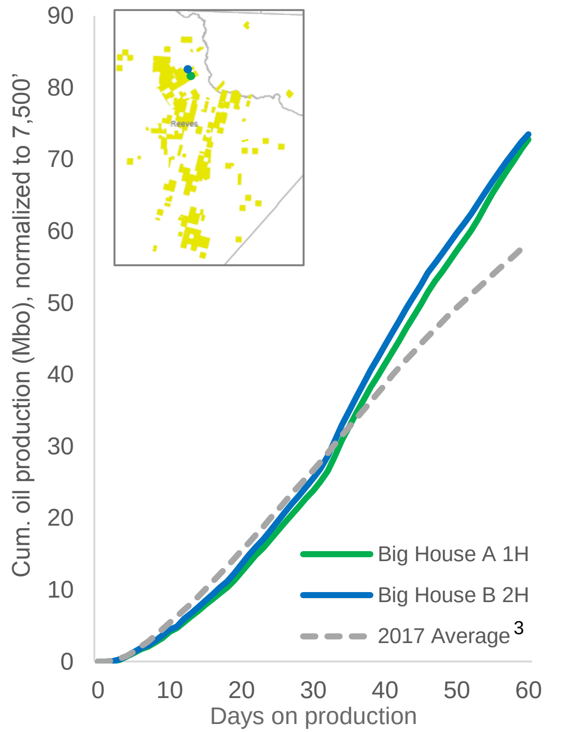
(1) Cumulative well performance from Big House C-3H shown on an unnormalized basis
(2) Implied 9,500' lateral calculated based on historical average relative performance between 1 and 2 sectional laterals
(3) Pre-tax IRR assumes flat $65 oil price deck and illustrative D&C costs of $11.0mm (inclusive of well-level infrastructure and facilities costs)

Q4 2017 Well Result Highlights

Reeves County

Big House A 4 57-60 1H / B 4 57-60 2H[1]

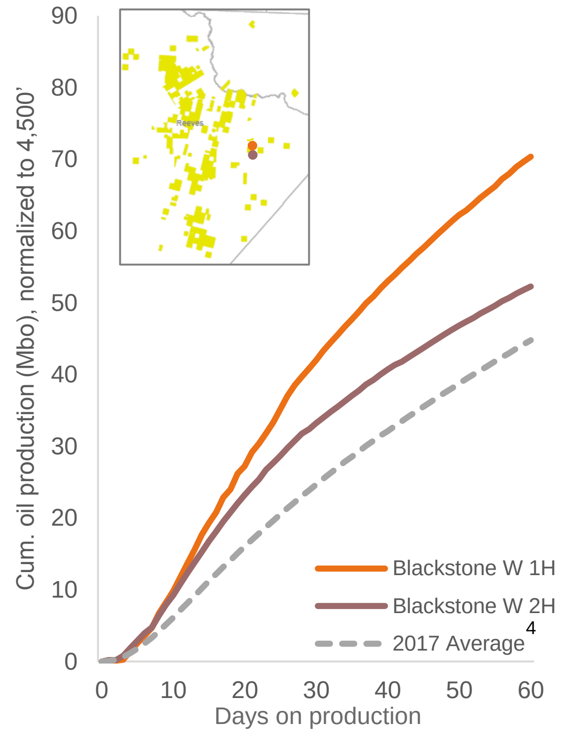
Strong result from 660' downspacing test, peak rates over 2,000 Bo/d per well



Well Statistics	Big House A 1H	Big House B 2H
First production date	12/11/17	12/11/17
Target formation	WC UA	WC UA
Lateral length (ft.)	7,040	7,040
IP-30 (Bo/d)	1,409	1,447
IP-30 / 1,000 (Bo/d)	200	206
Cluster / stage	18	17
Proppant (lbs. / ft)	2,750	2,220

Blackstone West 1H / 2H[2]

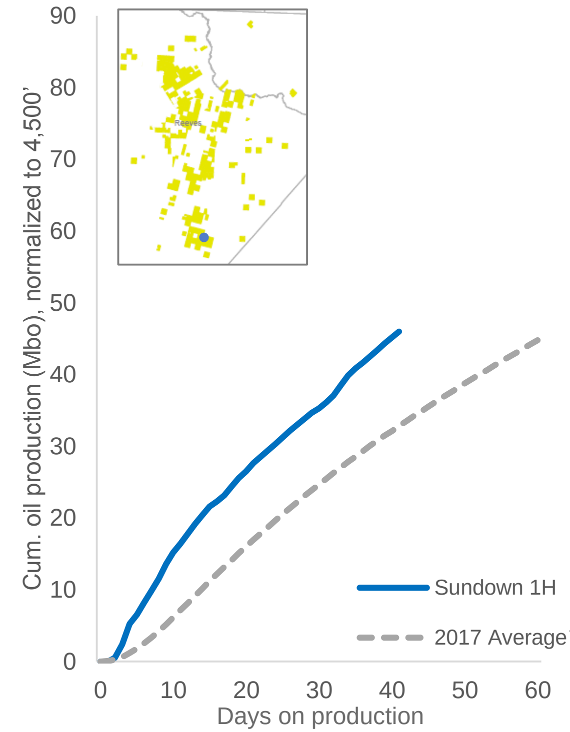
Two well pad averaging over 1,200 Bo/d IP-30 per well



Well Statistics	Blackstone W 1H	Blackstone W 2H
First production date	11/14/17	11/14/17
Target formation	WC UA	WC UA
Lateral length (ft.)	4,120	4,110
IP-30 (Bo/d)	1,409	1,081
IP-30 / 1,000 (Bo/d)	342	263
Cluster / stage	18	15
Proppant (lbs. / ft)	2,490	2,500

Sundown 1H[2]

Strong Lower Wolfcamp A result in Big Chief



Well Statistics	Sundown 1H
First production date	12/21/17
Target formation	WC LA
Lateral length (ft.)	4,150
IP-30 (Bo/d)	1,113
IP-30 / 1,000 (Bo/d)	268
Cluster / stage	12
Proppant (lbs. / ft)	1,130

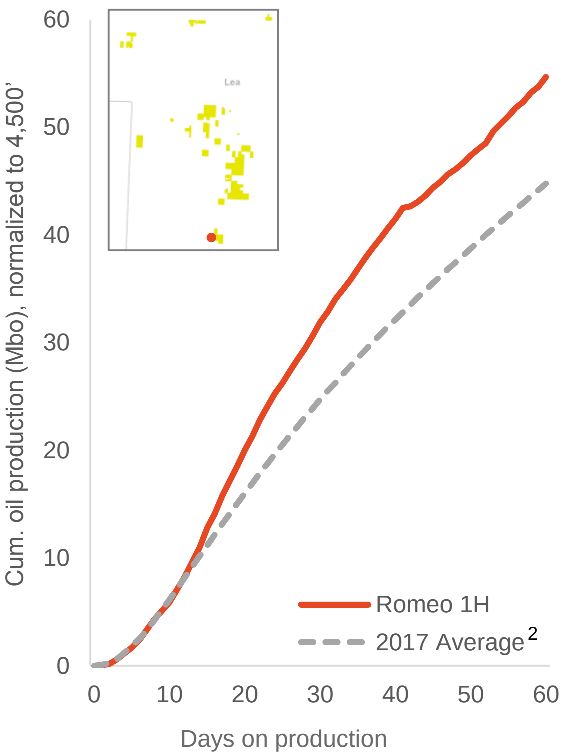
(1) Cumulative oil production for the Big House A 4 57-60 1H and Big House 4 57-60 2H normalized to 7,500'
(2) Cumulative oil production for the Blackstone West 1H, Blackstone West 2H and Sundown 1H normalized to 4,500'
(3) 2017 average only includes production from 1.5 section laterals, normalized to 7,500' (includes all formations across TX and NM)
(4) 2017 average only includes production from single section laterals, normalized to 4,500' (includes all formations across TX and NM)

Q4 2017 Well Result Highlights

Lea County

Romeo 1H[1]

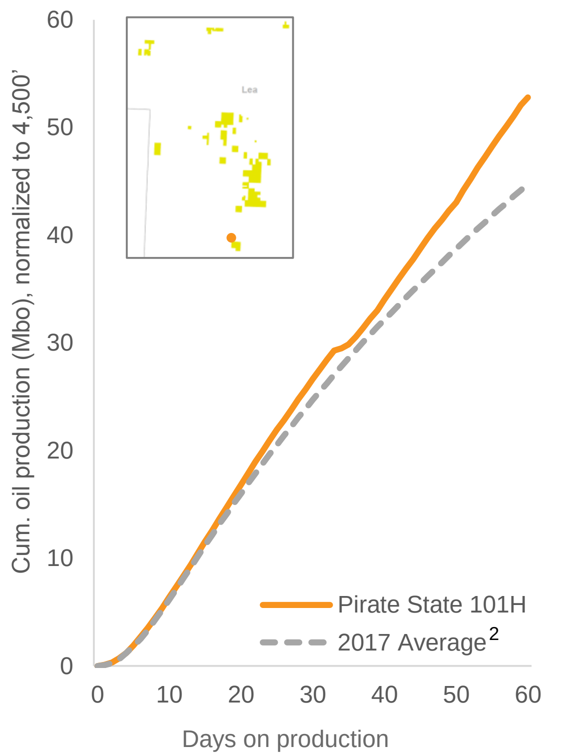
Initial Lea County well outperforming 2017 average



Well Statistics	Romeo 1H
First production date	7/30/17
Target formation	2nd BS
Lateral length (ft.)	4,200
IP-30 (Bo/d)	1,105
IP-30 / 1,000 (Bo/d)	263
Cluster / stage	15
Proppant (lbs. / ft)	3,000

Pirate State 101H[1]

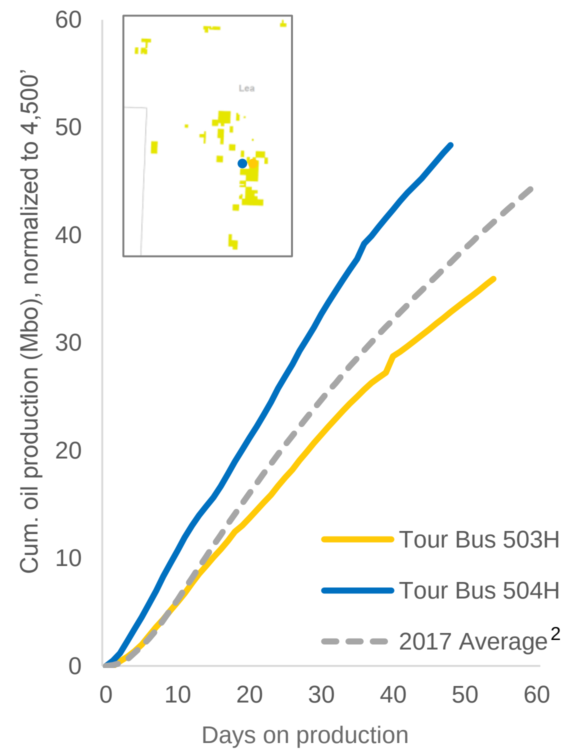
Positive initial Avalon well



Well Statistics	Pirate State 101H
First production date	10/27/17
Target formation	Avalon
Lateral length (ft.)	4,190
IP-30 (Bo/d)	883
IP-30 / 1,000 (Bo/d)	211
Cluster / stage	18
Proppant (lbs. / ft)	2,810

Tour Bus 23 State 503H & 504H[1]

Encouraging results from 2nd Bone Spring in Pryor area of New Mexico



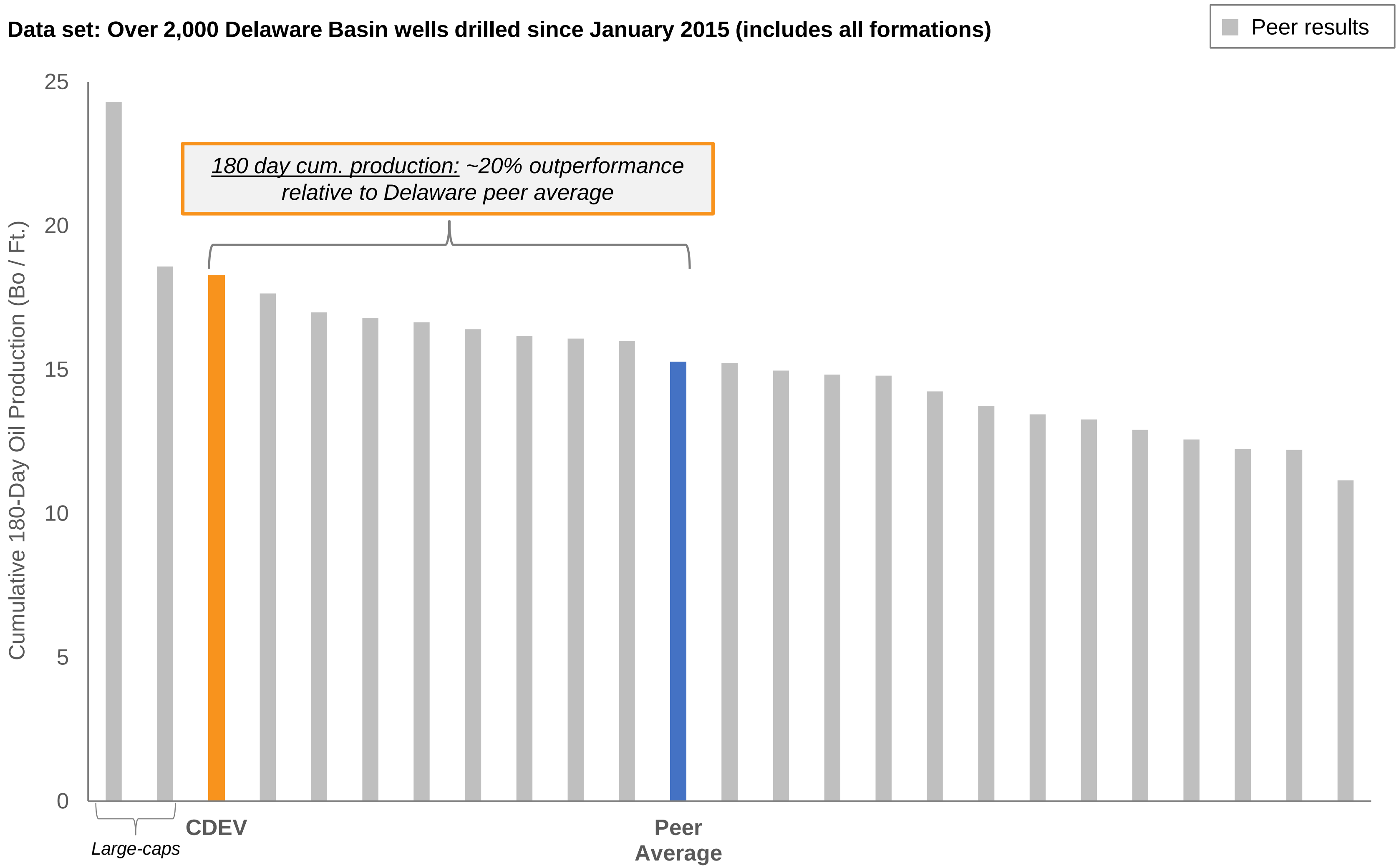
Well Statistics	Tour Bus 503H	Tour Bus 504H
First production date	12/19/17	12/23/17
Target formation	2nd BS	2nd BS
Lateral length (ft.)	4,120	3,960
IP-30 (Bo/d)	706	989
IP-30 / 1,000 (Bo/d)	171	250
Cluster / stage	18	18
Proppant (lbs. / ft)	3,030	2,990

(1) Cumulative oil production for the Romeo 1H, Pirate State 101H, Tour Bus 23 State 503H and Tour Bus 23 State 504H normalized to 4,500'
(2) 2017 average only includes production from single section laterals, normalized to 4,500' (includes all formations across TX and NM)

Overall Delaware Basin Completion Benchmarking

Delaware Basin Oil Well Performance (180-Day Cumulative Production; Bo / ft.)

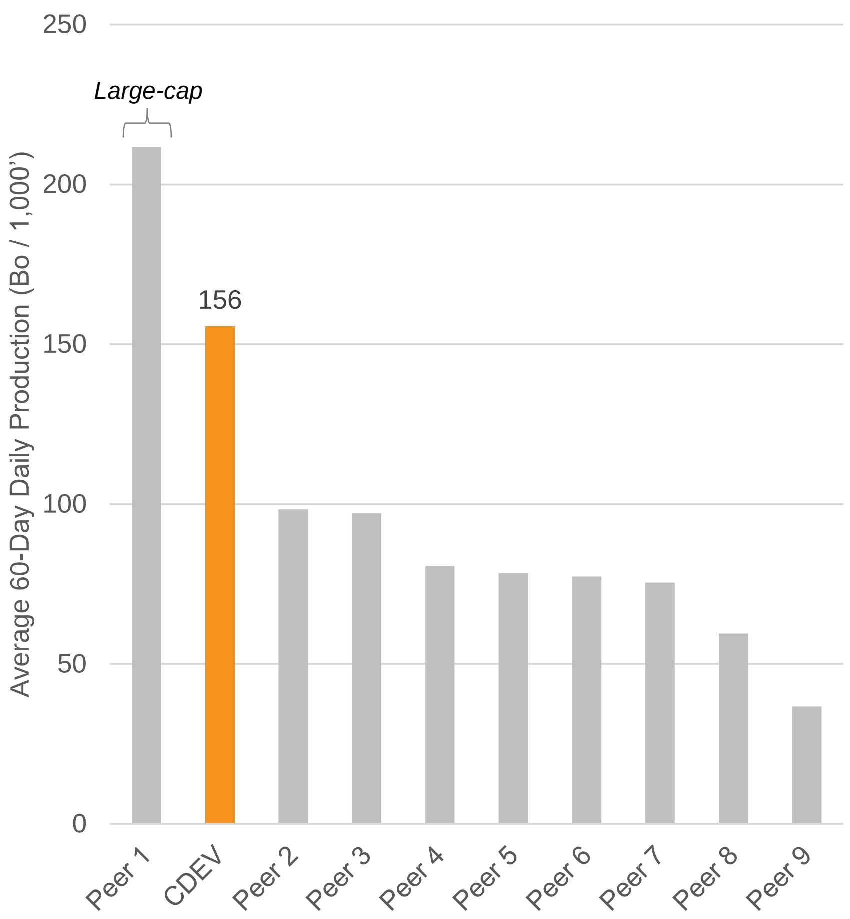
Data set: Over 2,000 Delaware Basin wells drilled since January 2015 (includes all formations)



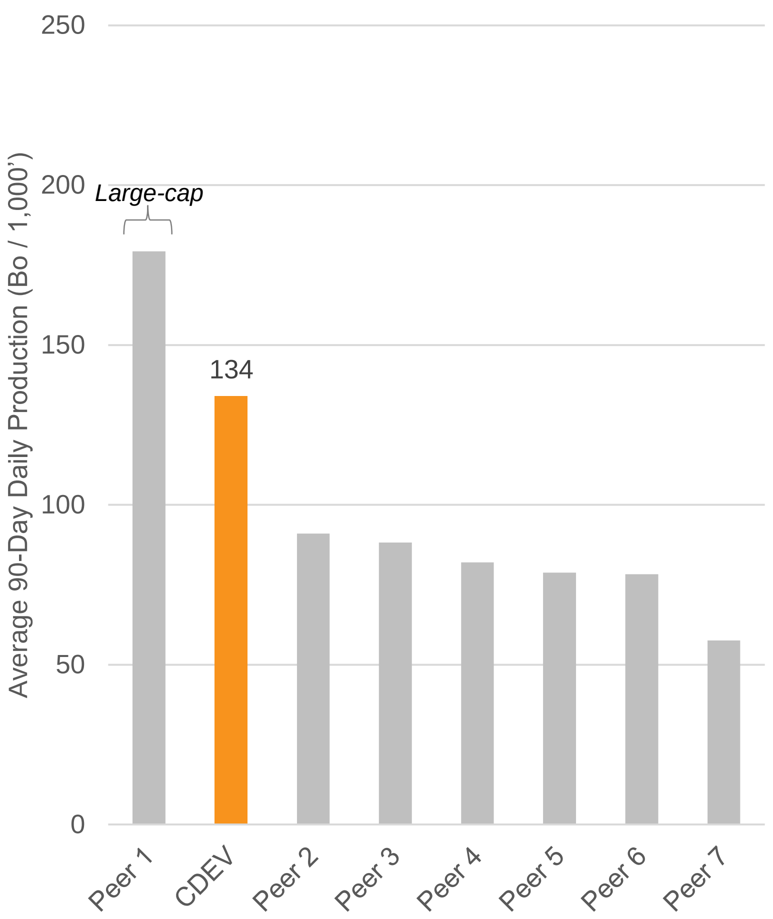
Southern Delaware – 2017 Wolfcamp Completions

2017 Texas Wolfcamp Completions (Daily Average; Bo / 1,000')

60-Day Average



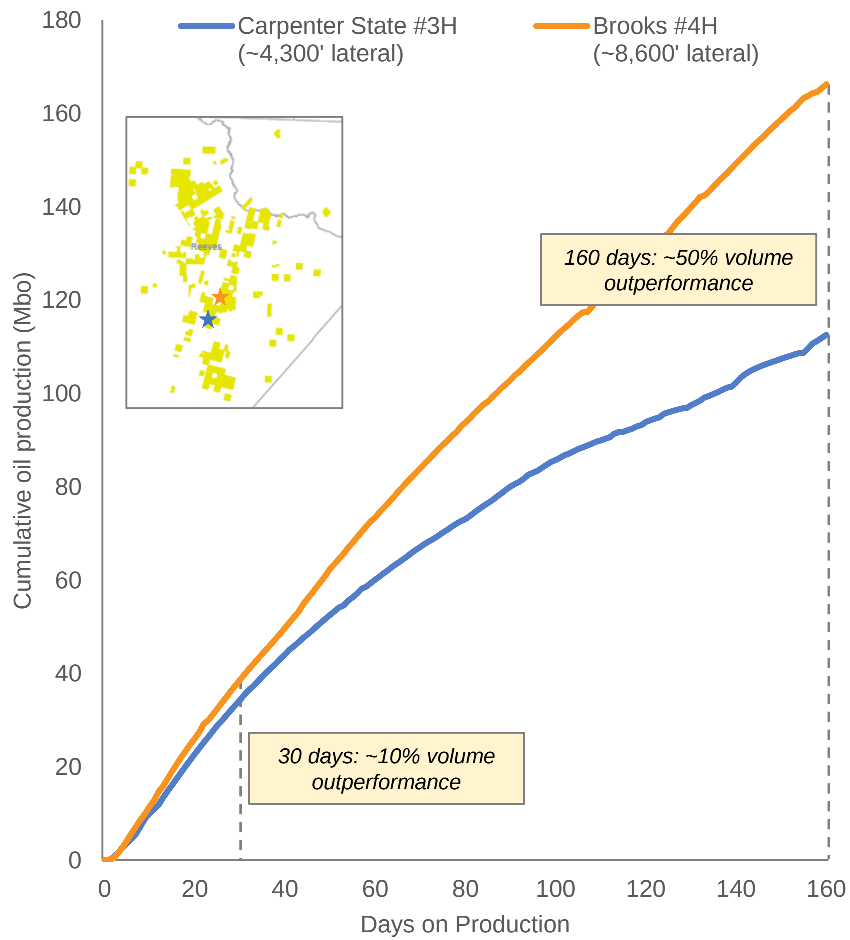
90-Day Average



Source: Stifel Equity Research, DrillingInfo, Stifel Estimates
Note: Peer data represents weighted average results; peers include APC, CXO, EOG, FANG, HK, JAG, OXY, PDCE, PE, XEC – only includes peers with at least 10 data points

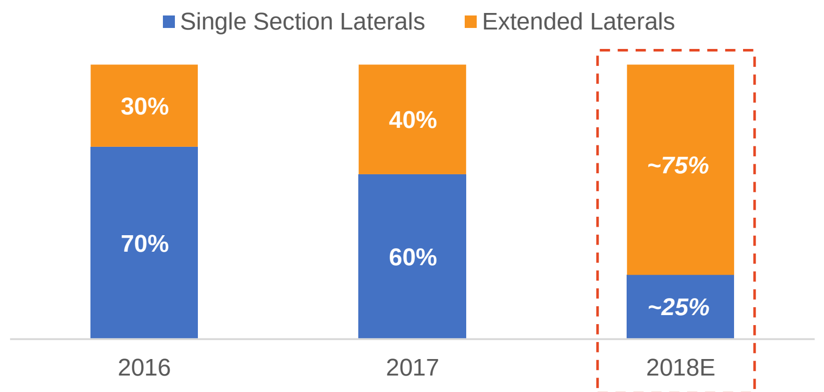
2018 Portfolio Shift to Extended Lateral Development

Oil Volume Comparison (Cumulative MBo)[1]

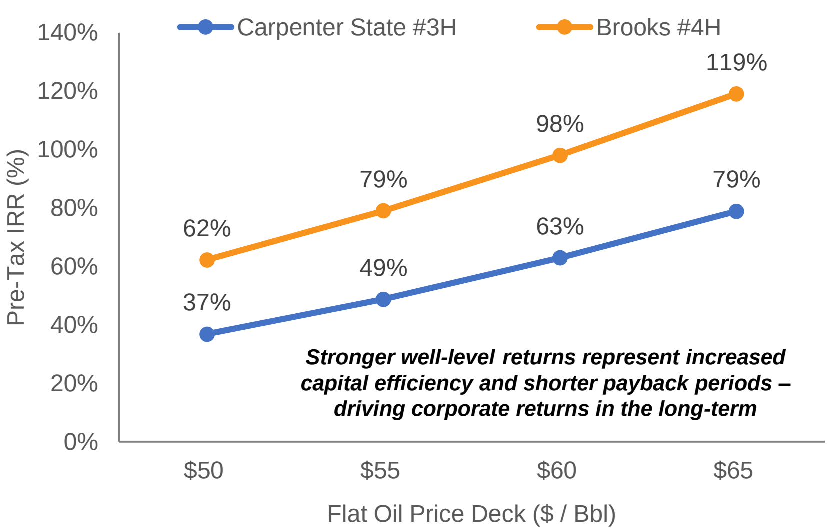


Volume differentiation improves with time

Portfolio weighting (based on wells brought on line)



Economic Comparison (Pre-Tax IRR -%)[2]



Stronger well-level returns represent increased capital efficiency and shorter payback periods – driving corporate returns in the long-term

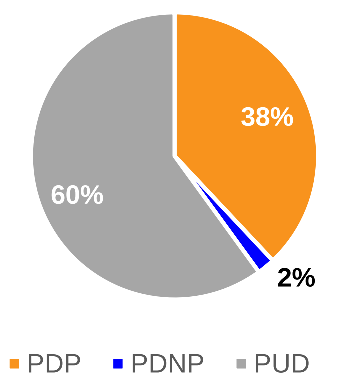
Note: Cumulative oil production curve excludes downtime
(1) Cumulative oil production shown on an unnormalized basis
(2) Economics assume flat oil price decks as labeled and gas price of $2.75/MMBtu; Illustrative D&C costs utilized of $7.5mm for the Carpenter State #3H and $11mm for the Brooks #4H (inclusive of well-level infrastructure and facilities costs)

YE 2017 Proved Reserves Summary

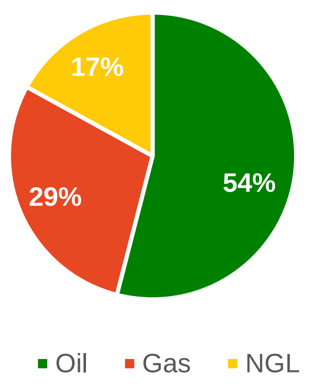
Reserve statistics

Drill-bit F&D costs[1]	$5.47 / Boe
Proved developed F&D costs[2]	$10.62 / Boe
Organic reserves replacement ratio[3]	> 950%
Reserves growth (YE 2016 – YE 2017)	125%

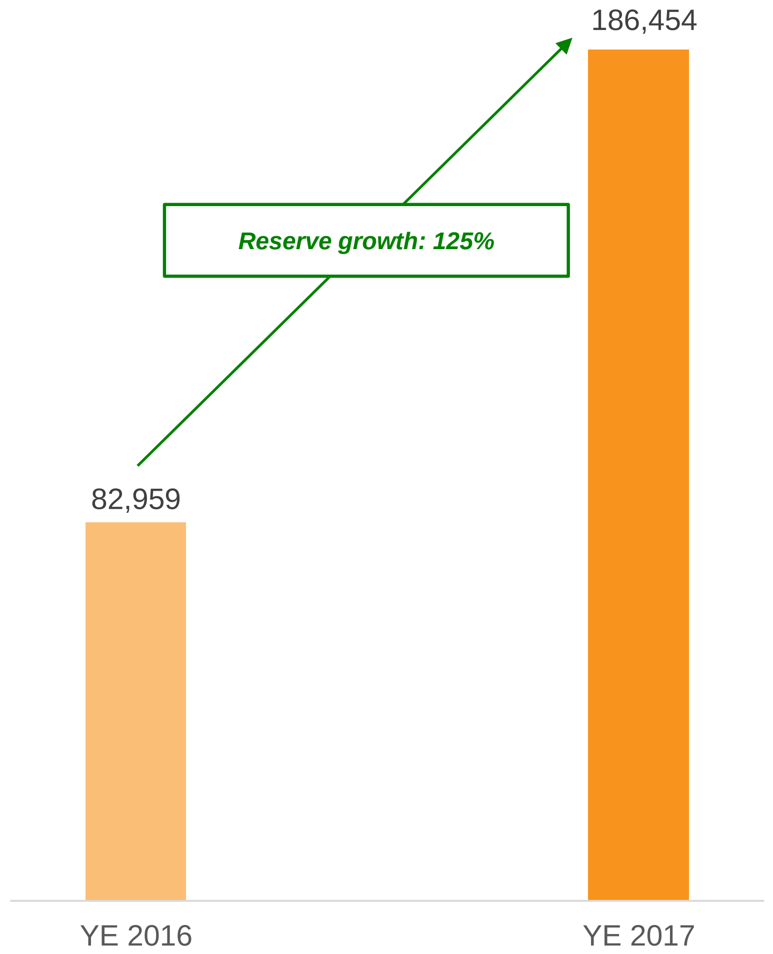
Reserves by category



Reserves by commodity



Proved Reserves (Mboe)



Source: NSAI prepared reserve report as of 12/31/17

(1) Calculation defined as total 2017 exploration and developments costs of $607.4mm divided by the sum of total 2017 reserve extensions, discoveries and revisions (technical and pricing) of 111.0 MMBoe

(2) Calculation defined as total 2017 exploration and developments costs of $607.4mm divided by the sum of total proved developed reserve extensions and discoveries, transfers from proved undeveloped reserves at year-end 2016, and proved developed reserve revisions (technical and pricing), totaling 57.2 MMBoe

(3) Calculation defined as the sum of total 2017 reserve extensions, discoveries and revisions (technical and pricing) of 111.0 MMBoe, divided by total 2017 production of 11.6 MMBoe

Active Portfolio Management

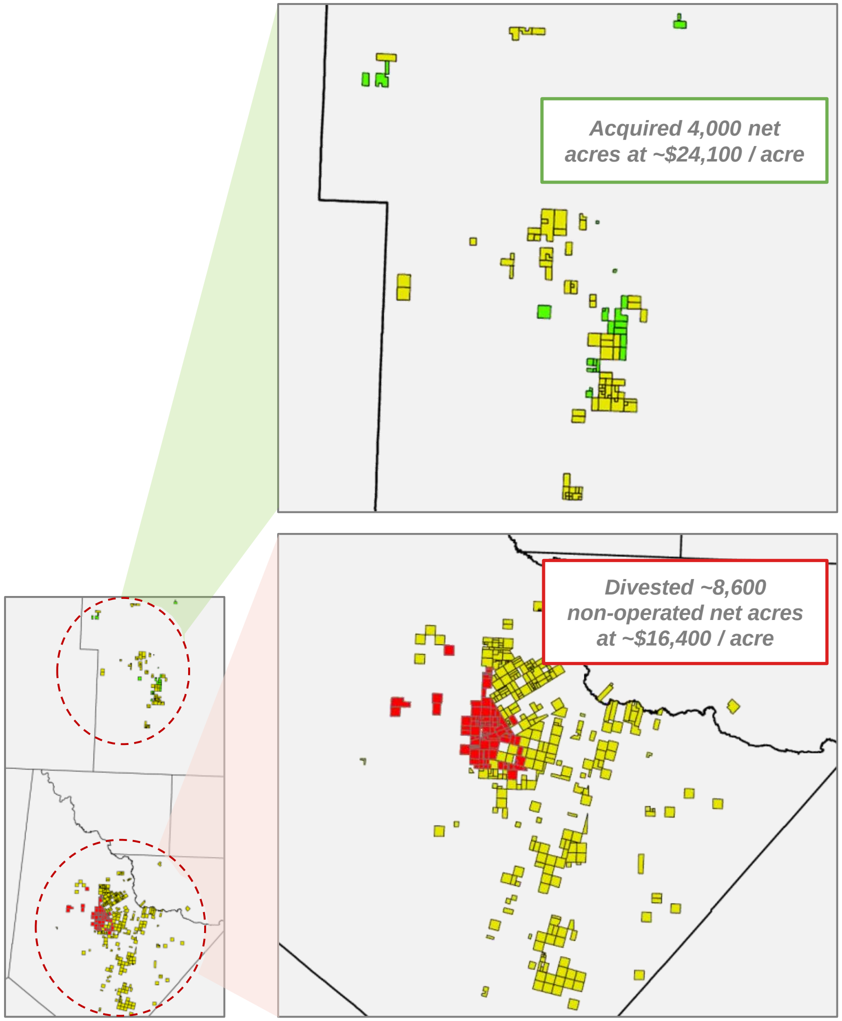
Transaction overview

	N. Delaware acquisition	S. Delaware divestiture
Closing date:	Feb-18	Mar-18[1]
Transaction value ($ mm)	$94.7	$140.7
Net acreage	~4,000	~8,600
Working interest %	*95%*	*32%*
Valuation ($ / acre)[2]	$24,100	$16,400

Portfolio Management rationale

- Divest non-operated acreage and acquire operated acreage in core area; enhance operational control
- Expand contiguous acreage footprint in New Mexico
  - ~30% increase in Lea County net acres
- Transactions generate net cash to CDEV, to be deployed into drilling program and/or other bolt-on opportunities
- Acquisition and divestiture transacted at valuations in line with other recent Delaware deals

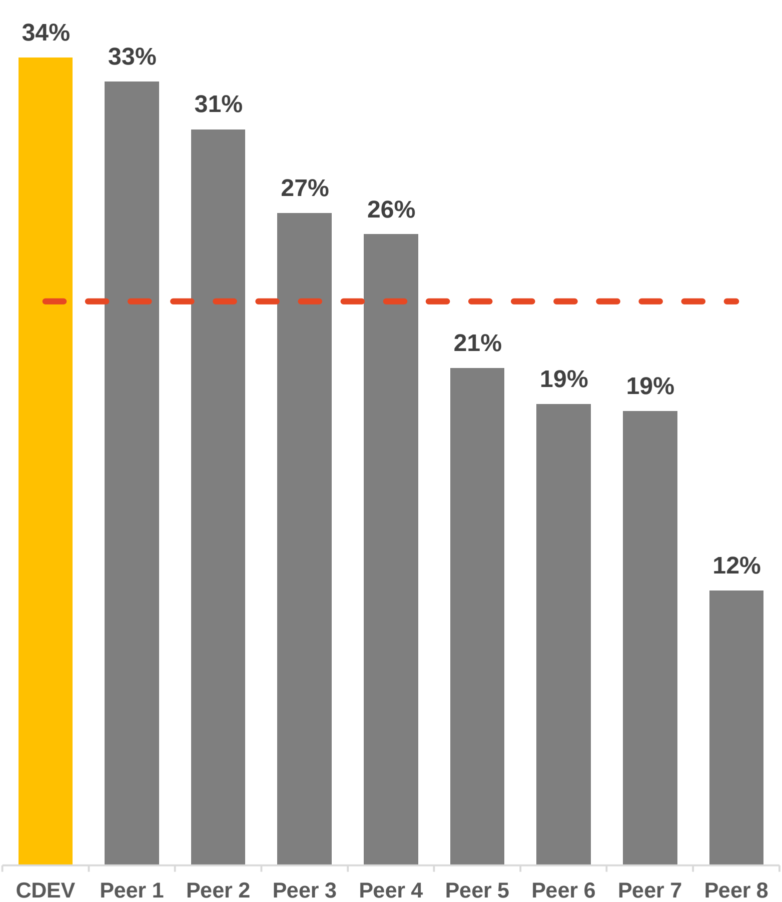
Asset map



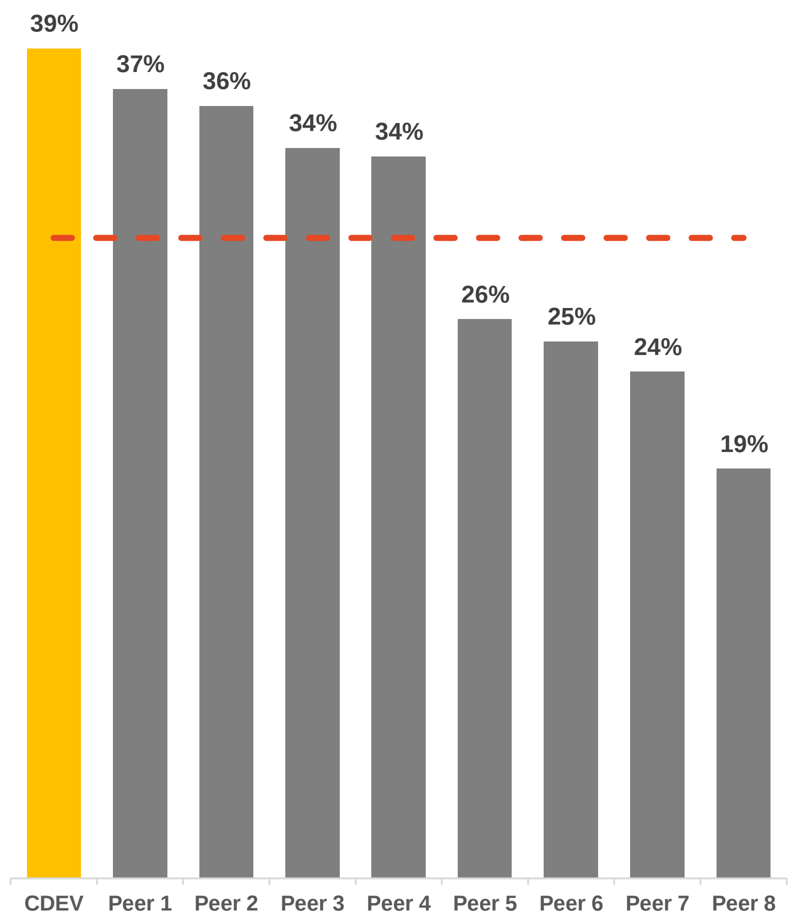
(1) Transaction expected to close in early March 2018, PSA executed in February 2018
(2) Valuation based on total purchase price divided by total net acreage; unadjusted for PDP production

Centennial provides investors with peer-leading growth

Production Per Debt-Adj. Share Growth (2017-22E CAGR)



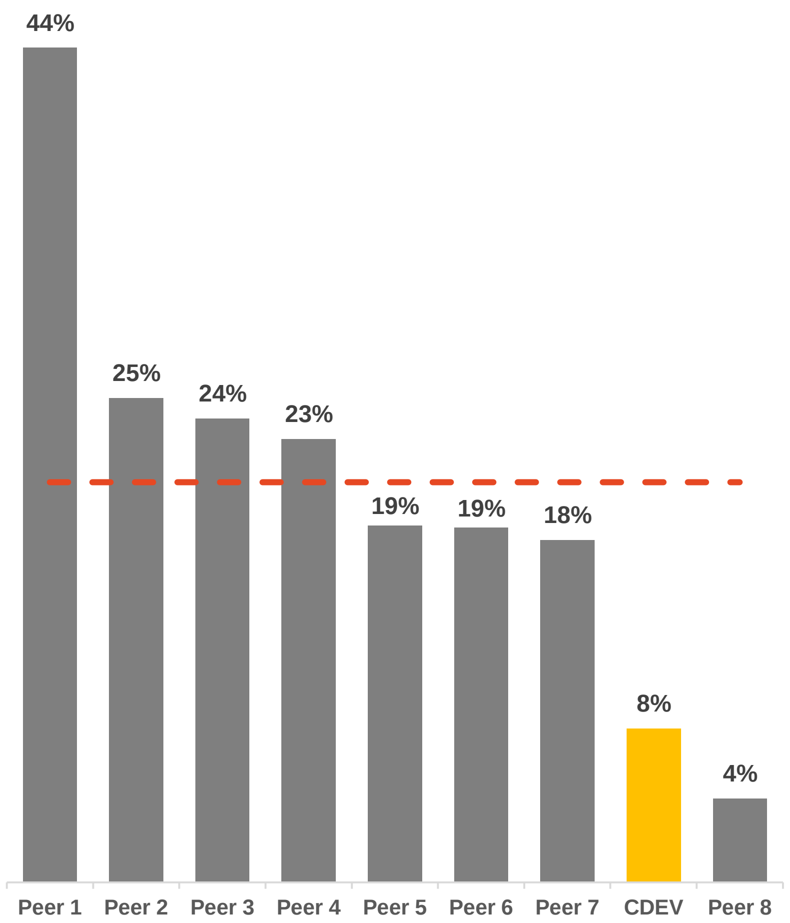
Cash Flow Per Debt-Adj. Share Growth (2017-22E CAGR)



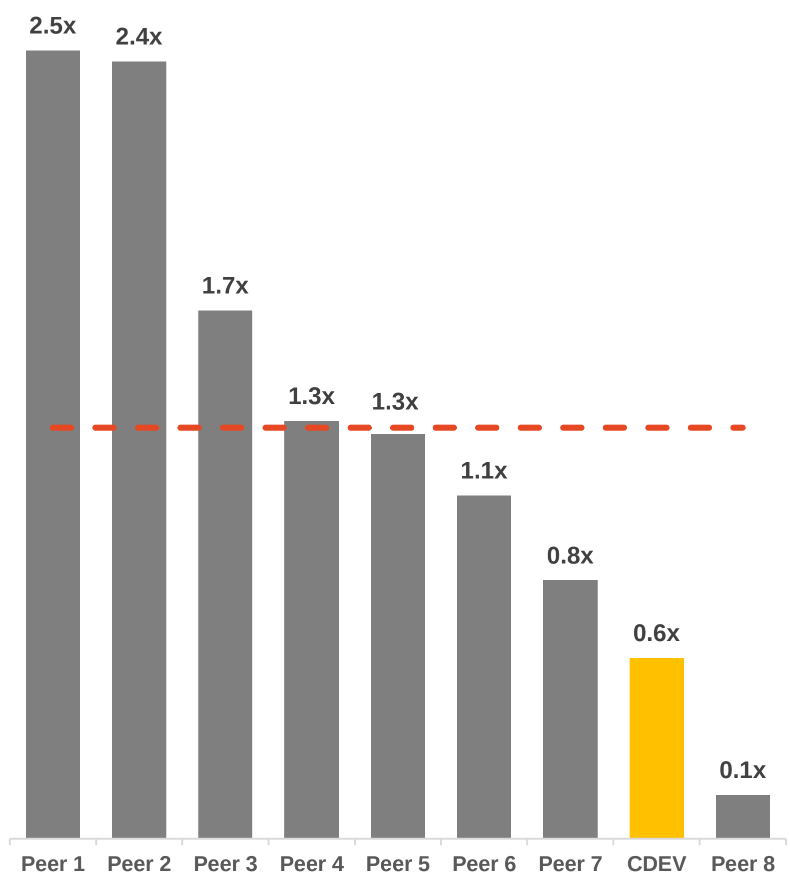
Source: Credit Suisse Equity Research
Note: Peer group includes: CPE, CXO, EGN, FANG, JAG, LPI, PE, and RSPP; dotted line represents median and excludes CDEV

Low leverage profile

Net Debt / Total Capitalization[1]



Net Debt / LQA EBITDAX[1]



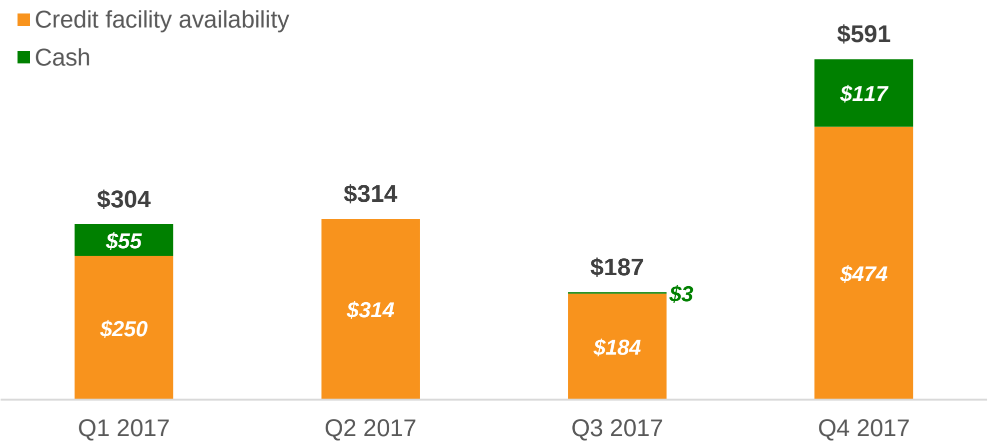
Source: Company filings and consensus estimates
Note: Peer group includes: CPE, CXO, EGN, FANG, JAG, LPI, PE, and RSPP; dotted line represents median and excludes CDEV
(1) LQA represents last quarter annualized; CDEV, CXO, EGN, FANG, LPI and PE as of 12/31/17; remaining companies as of 9/30/17; pro forma for capital markets and A&D activity

Capital structure and liquidity overview

Capital structure overview

- Ongoing commitment to conservative leverage profile
  - Net Debt / Q4 annualized EBITDAX of 0.6x
  - Net Debt / Total Capitalization of 8%
- Senior Unsecured Notes offering in November 2017 bolstered liquidity profile and extended maturities (8.2 year note)
  - Issuer Credit Rating: B2 (Moody's), B+ (S&P)
  - Voluntarily reduced elected commitment amount to $475mm from $575mm in connection with the offering
  - Undrawn credit facility as of 12/31/17

FY 2017 liquidity profile[1,4] ($ mm)



Capitalization ($ mm)[1]

	As of 12/31/2017
Capitalization summary	
Cash and cash equivalents	$117
Revolving credit facility	$--
5.375% Senior Notes Due 2026	400
Total debt outstanding	$400
Total shareholders' equity[2]	$3,004
Net Debt / Q4 annualized EBITDAX	0.6x
Net Debt / LTM EBITDAX	1.0x
Net Debt / Total Capitalization	8%
Liquidity summary	
Cash and cash equivalents	$117
Credit facility availability[3]	474
Liquidity	$591

(1) Amounts may not sum due to rounding
(2) Total shareholders' equity includes non-controlling interest
(3) Elected commitment amount under the revolving credit facility was reduced to $475mm in connection with the November 2017 Senior Unsecured Notes offering
(4) Liquidity defined as cash, plus availability under the revolving credit facility; Note: Q4 2017 liquidity based on $475mm elected commitment amount

Centennial 2018 Game Plan

- Grow net oil production 85% to 35,500 Bo/d
- Grow net oil production from ~19,200 Bo/d in 2017 to 65,000 Bo/d in 2020
- Maintain mid-cap industry leadership position regarding oil shale G&G and well completion technology
- By YE18 determine extent of Bone Spring prospectivity on Reeves County acreage
- By YE18 generate top tier Lea County well results
- Maintain one of the lowest net debt positions of all U.S. E&P companies
- Target up to $70mm for organic acreage acquisitions
- Generate competitive GAAP ROE’s and ROCE’s

2018 Guidance Summary

Guidance summary

- CDEV is currently running 7 rigs with no additional rigs expected throughout 2018
- Production guidance points to Centennial's robust near-term growth profile
  - Midpoint of average daily production guidance represents annual production growth of ~85% for both oil and oil equivalents during 2017
- Capital program assumes gross horizontal well costs[1] of $7.0 - $8.0mm for a single section lateral, $9.0 - $10.0mm for a 1.5 section lateral and $10.0 - $12.0mm for a 2 section lateral
  - Average completed lateral length for 2018 expected to be ~7,500' with extended laterals comprising ~75% of operated completions[2]
  - Average working interest for operated completions of 85% - 90%
  - ~10% of estimated D&C costs will be associated with non-operated activity

FY 2018 Guidance Summary

	FY 2018 Guidance		
Production			
Net Average Daily Production (Boe/d)	55,000	-	63,500
Net Average Daily Oil Production (Bo/d)	33,500	-	37,500
Production Costs ($ / Boe)			
Lease Operating Expense	$3.60	-	$4.20
Gathering, Processing & Transportation	$3.20	-	$3.80
Depreciation, Depletion, Amortization	$14.00	-	$16.00
Cash General and Administrative	$2.20	-	$2.70
Non-cash Stock-based Compensation	$0.90	-	$1.20
Severance and Ad Valorem Taxes (% of revenue)	6.0%	-	8.0%
Capital Expenditure Program ($MM)			
Drilling & Completions	$710	-	$820
Facilities, Infrastructure and Other	$125	-	$160
Land	$50	-	$70
Total Capital Expenditures	$885	-	$1,050
Operated Drilling Program			
Wells Spud (Gross)	80	-	95
Wells Completed (Gross)	75	-	85

(1) Gross well costs inclusive of well level facilities costs
(2) Average lateral length calculation assumes 4,500' for a single section lateral, 6,700' for a 1.5 section lateral and 9,500' for a 2 section lateral

Q4 2017 Financial Results

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

($ in millions, unless specified)	Q1 2017	Q2 2017	Q3 2017	Q4 2017	FY 2017
Average Daily Production (Boe/d)	18,469	29,664	34,700	44,304	31,864
Average Daily Oil Production (Bo/d)	10,489	17,435	21,108	27,402	19,161
% Oil	*57%*	*59%*	*61%*	*62%*	*60%*
Financial highlights					
Total Revenue	$ 61.1	$ 91.1	$ 111.6	$ 166.1	$ 429.9
Adjusted EBITDAX[2]	$ 36.4	$ 63.1	$ 74.3	$ 120.3	$ 294.2
Net Income[3]	$ 9.8	$ 20.8	$ 14.4	$ 30.5	$ 75.6
Unit Costs ($/Boe)					
Lease Operating Expense	$ 4.38	$ 3.06	$ 3.56	$ 3.54	$ 3.55
Gathering, Processing & Transportation	$ 3.16	$ 2.74	$ 3.11	$ 2.87	$ 2.95
Severance & Ad Valorem Taxes	$ 1.92	$ 1.75	$ 2.02	$ 2.16	$ 1.99
Cash G&A	$ 5.69	$ 3.08	$ 3.12	$ 2.45	$ 3.24
Depreciation, Depletion & Amortization	$ 15.74	$ 12.70	$ 13.28	$ 14.42	$ 13.90
Capital Expenditures Incurred					
Drilling & Completion	$ 89.4	$ 145.7	$ 163.3	$ 225.7	$ 624.1
Land and Other	9.2	17.1	14.2	14.6	55.1
Facilities, Seismic and Other	2.2	6.8	2.3	5.9	17.2
Total Capital Expenditures	$ 100.8	$ 169.6	$ 179.8	$ 246.2	$ 696.4
Total Debt Outstanding	$ -	$35.0	$165.0	$400.0	$400.0
Cash and Cash Equivalents	54.9	-	2.6	117.3	117.3
Liquidity[4]	$304.4	$ 314.1	$ 186.7	$ 591.5	$ 591.5

(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 22 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; Note: Q4 2017 liquidity based on $475mm elected commitment amount

Reconciliation of Adjusted EBITDAX to Net Income

Adjusted EBITDAX reconciliation ($ thousands)[1]

Adjusted EBITDAX reconciliation to net income:	Q1 2017 3 months ended March 31, 2017	Q2 2017 3 months ended June 30, 2017	Q3 2017 3 months ended Sept. 30, 2017	Q4 2017 3 months ended Dec. 31, 2017	2017 12 months ended Dec. 31, 2017
Net income (loss) attributable to common shareholders	$9,823	$20,762	$14,447	$30,536	$75,568
Net income attributable to noncontrolling interest	884	2,436	1,813	2,854	$7,987
Interest expense	410	707	1,015	3,597	$5,729
Income tax expense (benefit)	-	9,069	8,233	12,628	$29,930
Depreciation, depletion and amortization	26,160	34,300	42,387	58,781	$161,628
Impairment and abandonment expenses	(29)	-	-	-	(29)
Non-cash portion of derivative (gain) loss	(4,156)	(2,256)	1,286	(679)	(5,805)
Stock-based compensation expense	2,610	2,318	3,360	3,862	12,150
Exploration expense	-	2,470	1,622	10,281	14,373
Transaction costs	887	457	42	68	1,454
(Gain) loss on sale of oil and natural gas properties	(166)	(7,191)	141	(1,580)	(8,796)
Adjusted EBITDAX	$36,423	$63,072	$74,346	$120,348	$294,189

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