CENTENNIAL

Core Oil
Delaware Basin Pure-Play

Second Quarter 2019 Earnings Presentation

August 5, 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 16 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 16 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.

Q2 2019 Highlights

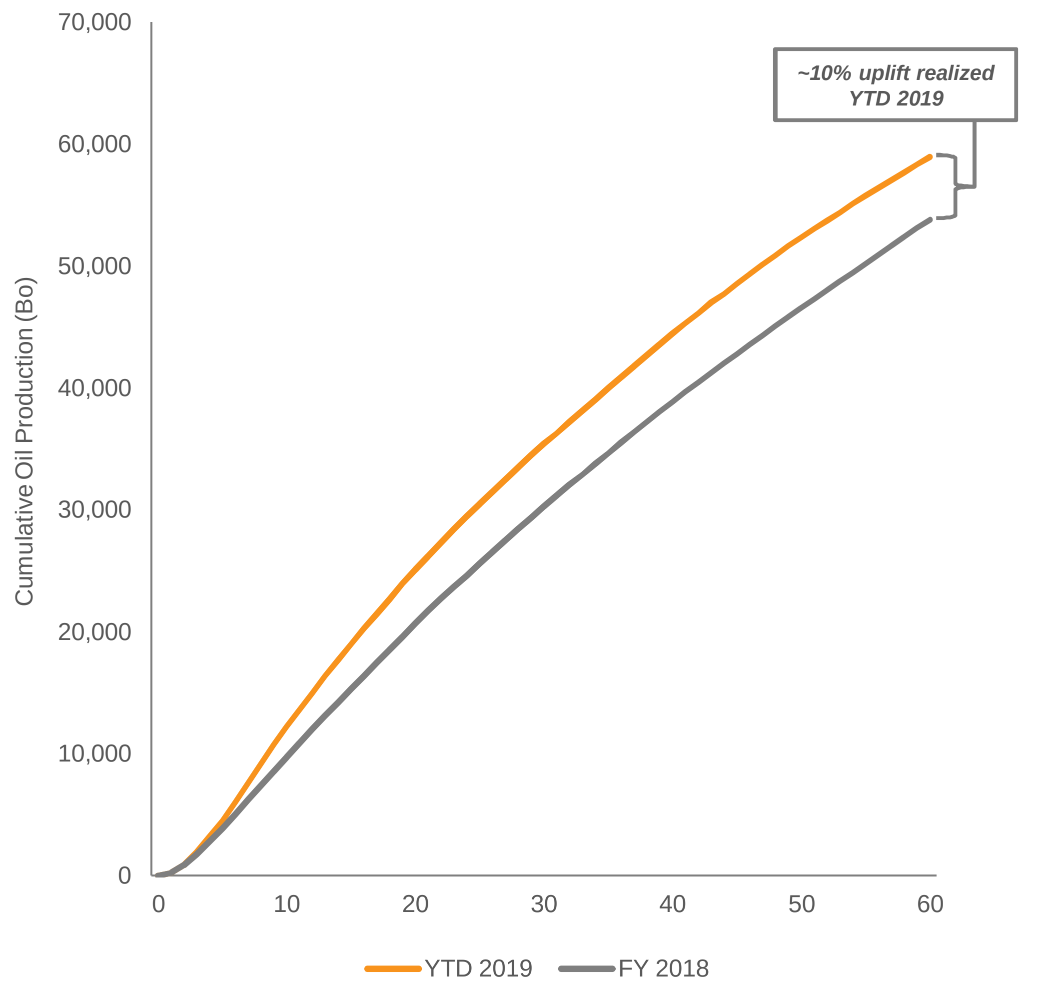
- Increased daily oil production volumes 38% from Q2 2018 and 6% from Q1 2019
- Increased full-year 2019 oil and oil equivalents production guidance by 5% and 8%, respectively, while maintaining full-year capex guidance
- Reported four of the top five wells in Company history
- Reducing operated rig count from six to five rigs in early September 2019 as a result of operational efficiencies and commitment to original capital guidance
- Lowered full-year 2019 unit cost guidance for G&A, GP&T and DD&A
- Conservative well spacing: ~880' spacing across Texas position
- Maintained conservative balance sheet and strong liquidity
  - Net Debt / Book Capitalization of 21%; Net Debt / LTM EBITDAX of 1.3x

Drilling Program Results: YTD 2019 vs. 2018

2019 Development Overview

- Diversified development across stacked pay in the Northern and Southern Delaware
  - Sending a second rig to New Mexico in Q3, supported by recent well results and continued infrastructure build-out
- Drilling program focused on co-development of multiple zones
  - Co-developing 3rd Bone Spring Sand and Upper Wolfcamp A in Texas
  - Focused across Bone Spring Sand formations in New Mexico
- Primarily developing 2-3 well pads
  - Driving operational efficiencies while minimizing downtime and interference

Average Cumulative Oil Production (Bo) – YTD 2019 vs. FY 2018 (All Wells)



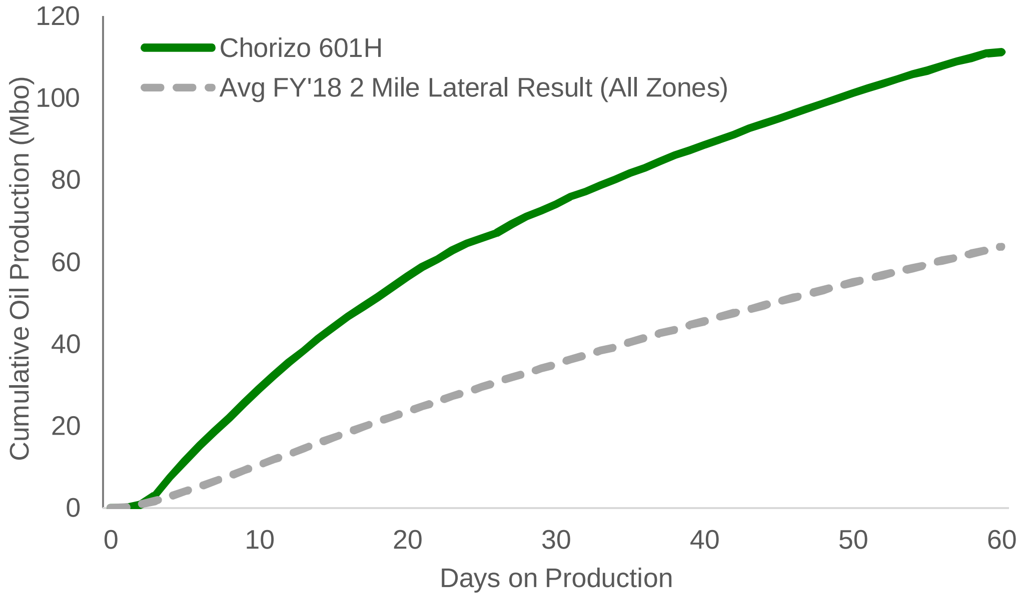
Note: Average cumulative production data shown on a non-normalized basis; YTD 2019 average lateral length of ~7,900', FY 2018 average lateral length of ~7,400'

Chorizo 601H – Best CDEV Well Drilled To-Date

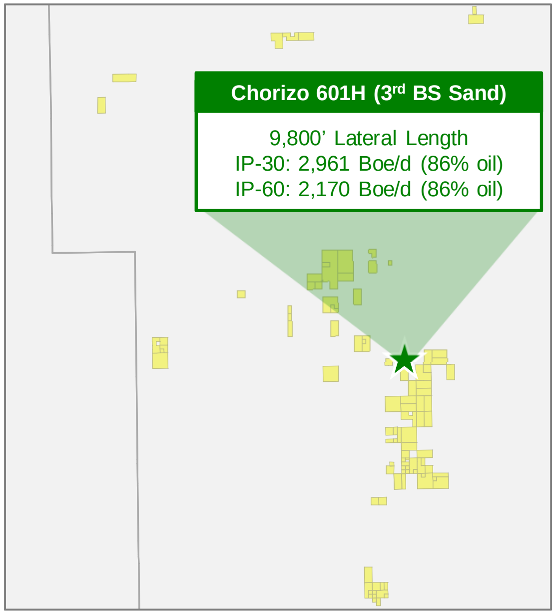
Chorizo 601H Overview

- Best CDEV well drilled to-date
  - Four of the top five wells in CDEV history drilled in Q2 2019 (Chorizo 601H, Duck Hunt 501H, Red Rock T34H and Red Rock U30H)
- 3rd Bone Spring Sand well drilled with a 2-mile lateral (~9,800' lateral length)
  - IP-30 of 2,961 Boe/d (86% oil) and IP-60 of 2,170 Boe/d (86% oil)
- Further supports productivity of the northern edge of the eastern NM acreage

Chorizo 601H Cumulative Oil Production

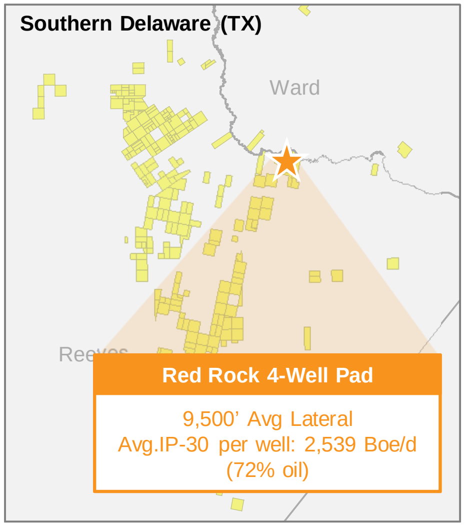


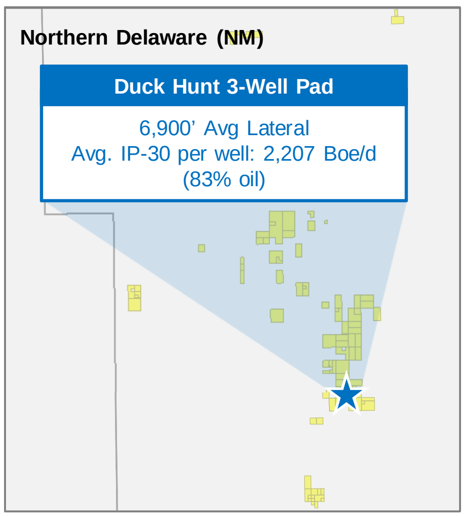
Well Locator Map



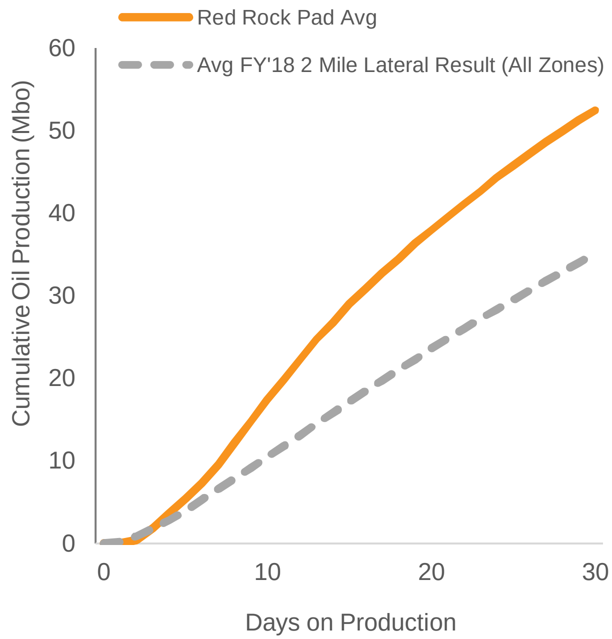
Recent Co-Development Results Outperforming

Asset map

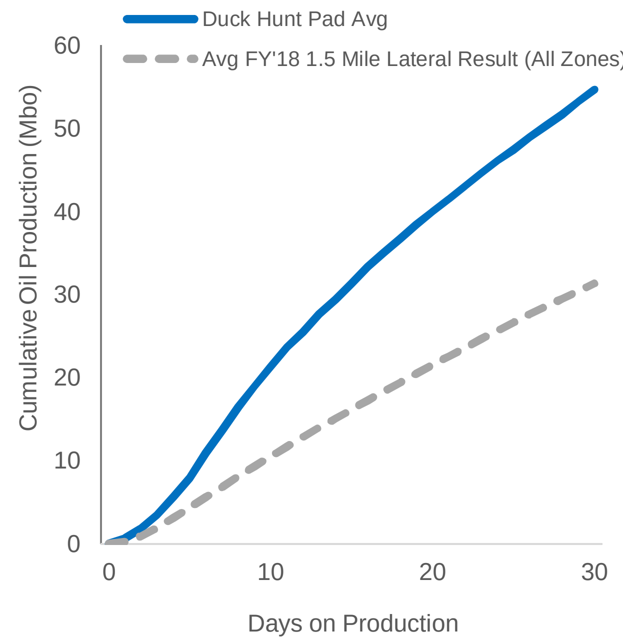


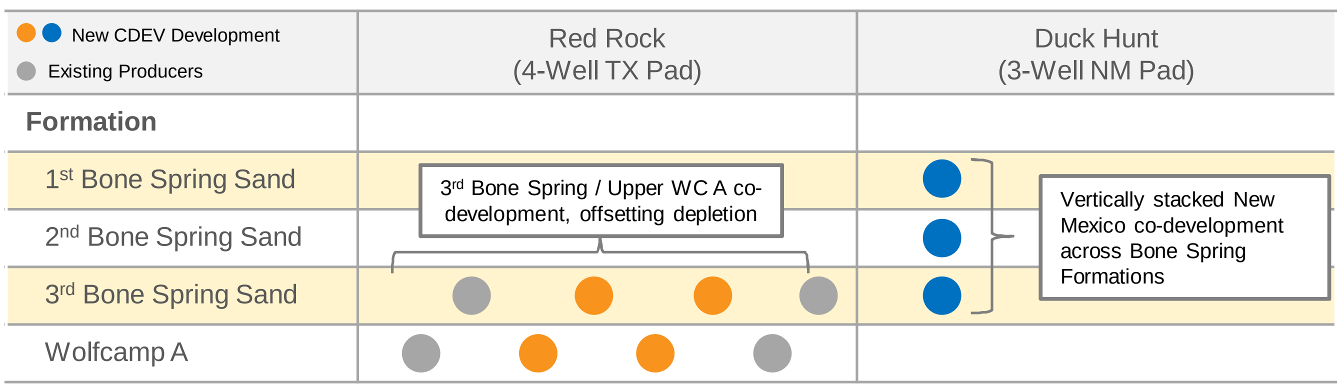


Red Rock 4-Well Pad (TX)



Duck Hunt 3-Well Pad (NM)

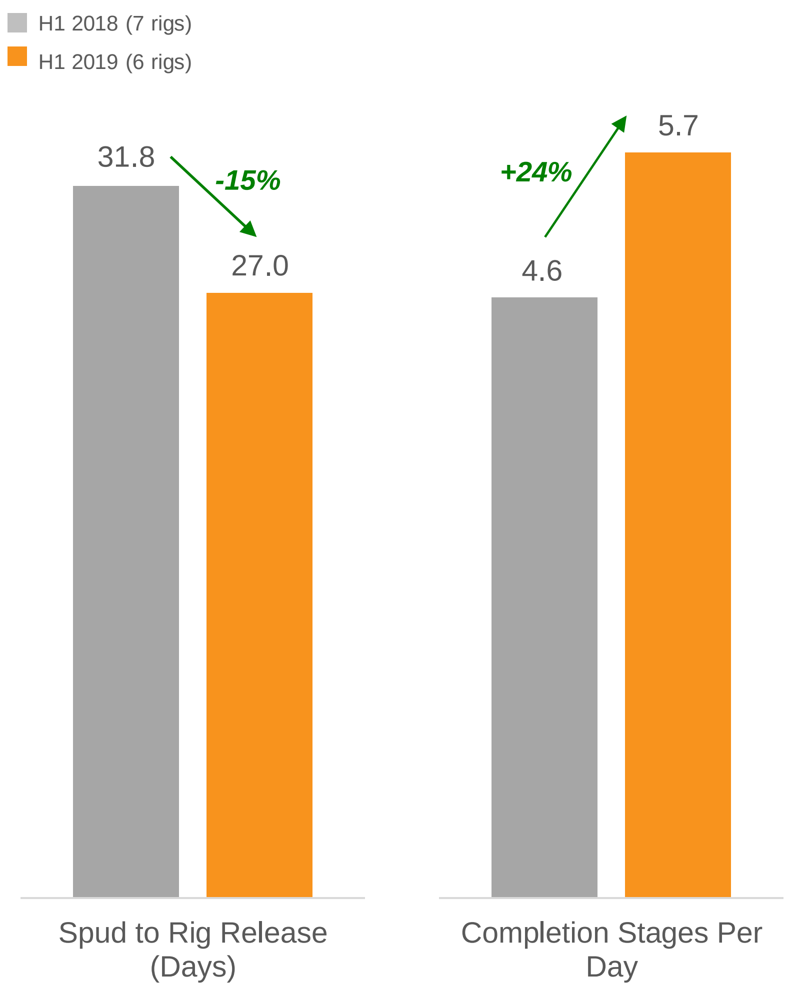




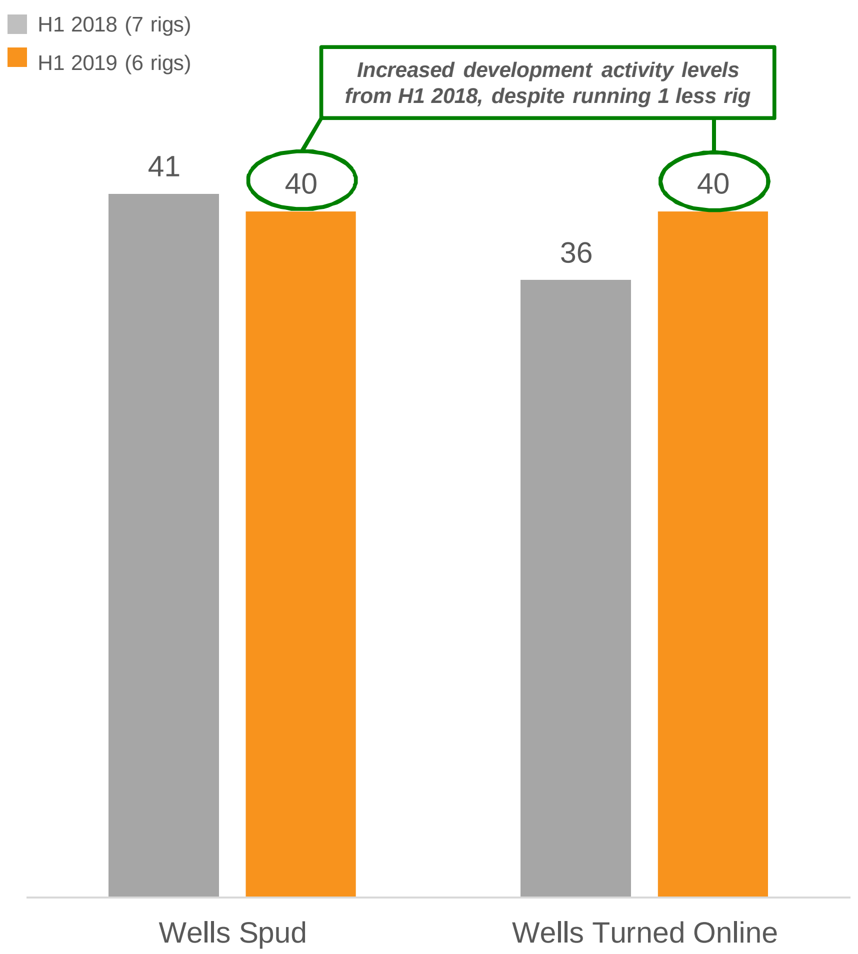
Note: Cumulative oil production curves shown on an non-normalized basis; % oil shown on a 2-stream basis

Significant Operational Efficiencies Realized in 2019

Cycle Time Improvements



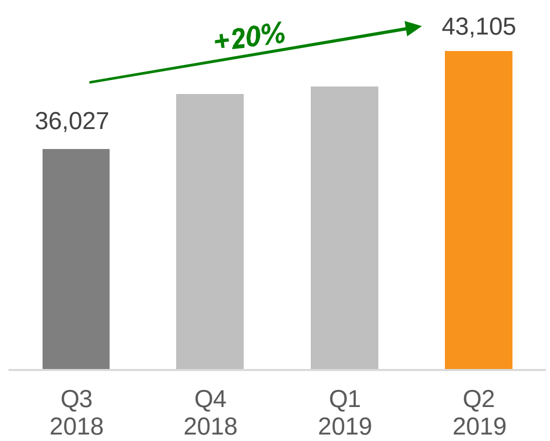
Development Activity



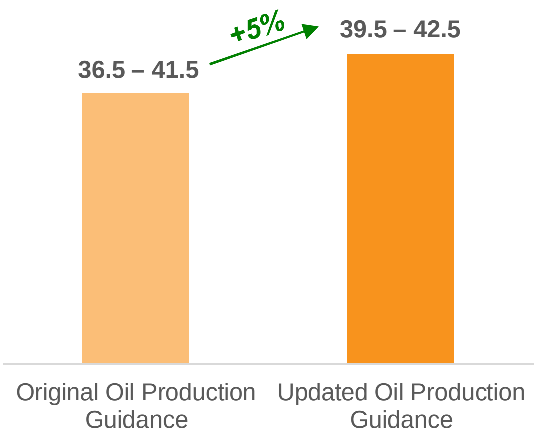
Raising Production Guidance While Reducing Rigs

- Realization of drilling and completion efficiencies outpacing original expectations, driving increased development activity
- Dropping from 6 to 5 rigs in early September as a result of efficiencies and commitment to original capital guidance
  - Activity level with 5 rigs expected to be in-line with original expectations for 6 rigs
- Increasing oil and oil equivalent production guidance as a result of outperformance and efficiencies

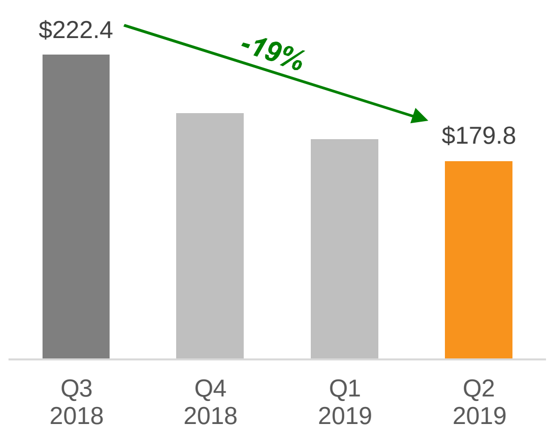
LTM Oil Production (Bo/d)



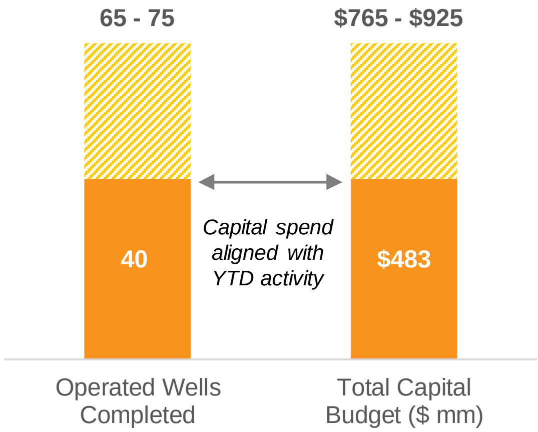
FY 2019 Oil Production Guidance (Mbo/d)



LTM D&C Capex ($ mm)



FY 2019 Capital & Activity Guidance



CDEV Marketing Summary

Marketing & Flow Assurance Summary

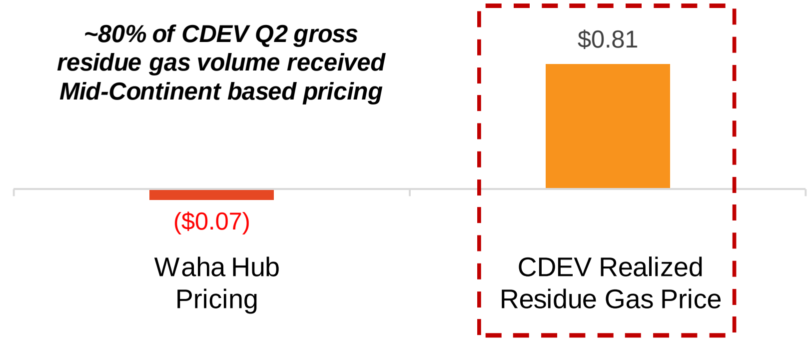
Crude Oil Overview

- Crude oil basis and takeaway risk mitigated through two firm sales contracts
- Average crude quality of ~43° API significantly reduces risk of incremental price deducts

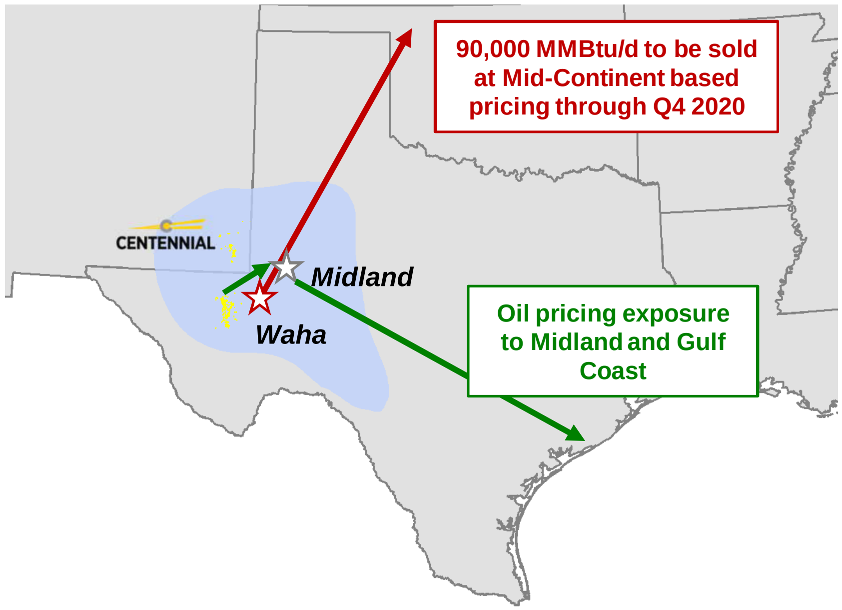
Natural Gas Overview

- Natural gas basis and takeaway risk mitigated through firm transportation & firm sales contracts
  - 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
  - Contracts in place to limit Waha exposure for the majority of anticipated residue gas production through Q4 2020
  - Henry Hub, Waha basis and Waha fixed price hedges in place for remainder of 2019

Q2 2019 Residue Gas Pricing Overview[1]



Market Exposure Overview

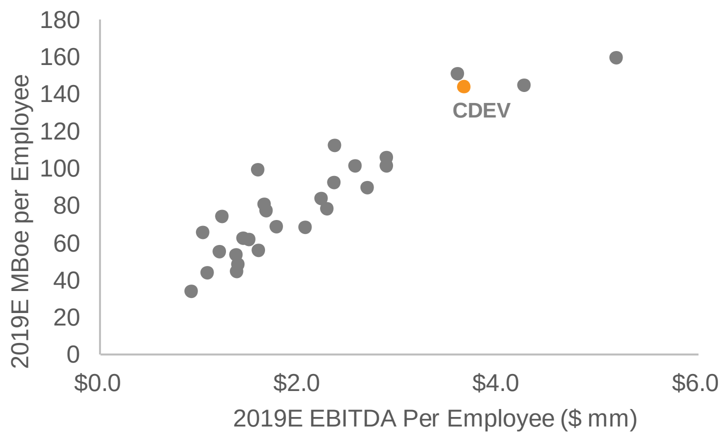


(1) Waha Hub pricing shown as $/MMBtu, CDEV realized price shown as $ / Mcf

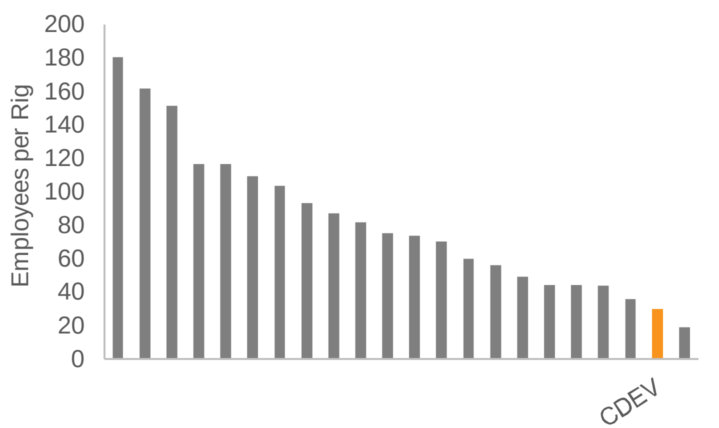
Low G&A Costs Relative to Peers

2019E G&A Benchmarking[1]

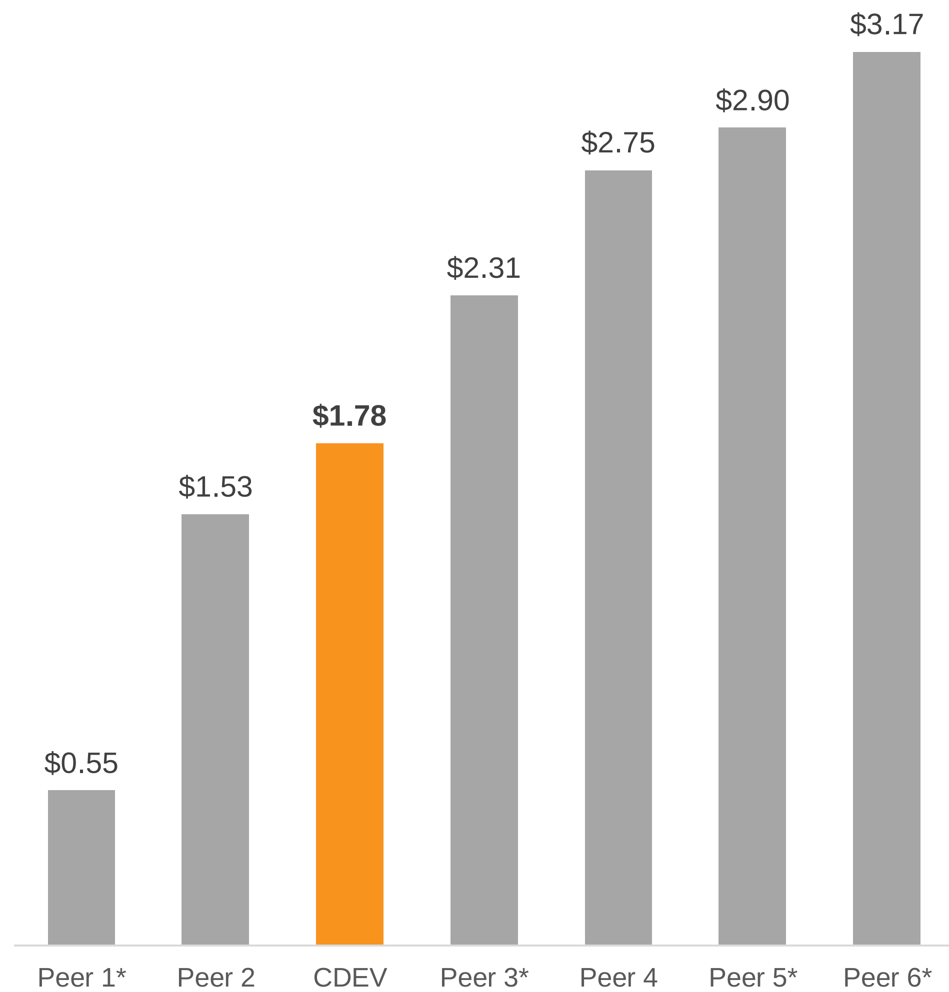
2019E MBoe per Employee vs. 2019E EBITDA per Employee[2]



2019E Employees per Rig[2]



Permian Peers - Cash G&A ($ / Boe)[3]



(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)
(3) Peer group includes CPE, FANG, JAG, LPI, MTDR and PE; MTDR and LPI as of 6/30/19; CPE, FANG, PE and JAG as of 3/31/19. Asterisk represents metric as of Q1'19

Updated FY 2019 Guidance Summary

Guidance summary

- Maintaining original capital budget guidance
  - Reducing operated rig count from six to five rigs in early September as result of efficiencies seen year-to-date
- Increased 2019 total company and oil production guidance by 8% and 5%, respectively
  - Represents oil growth of 18% year-over-year at the midpoint
- Lowered full-year unit cost guidance as a result of lower G&A, GP&T and DD&A expenses

Updated FY 2019 Guidance Summary

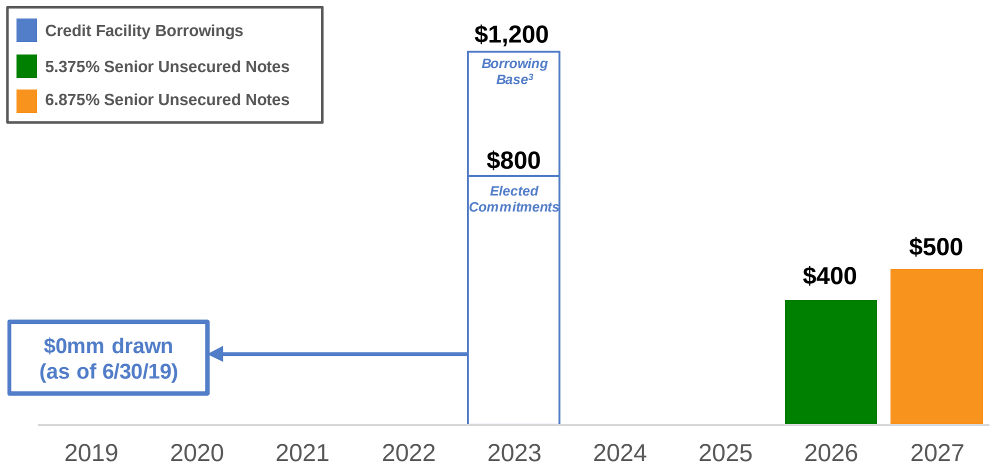
	Initial FY 2019 Guidance			Updated FY 2019 Guidance			%Chg.
Production							
Net Average Daily Production (Boe/d)	61,500	-	70,500	68,000	-	75,000	*8%*
Net Average Daily Oil Production (Bo/d)	36,500	-	41,500	39,500	-	42,500	*5%*
Production Costs ($ / Boe)							
Lease Operating Expense	$4.35	-	$4.95	$4.35	-	$4.95	--
Gathering, Processing & Transportation	$2.75	-	$3.25	$2.50	-	$2.80	*(12%)*
Depreciation, Depletion, Amortization	$15.50	-	$17.50	$15.25	-	$17.25	*(2%)*
Cash General and Administrative	$2.25	-	$2.75	$1.90	-	$2.30	*(16%)*
Stock-based Compensation	$1.00	-	$1.20	$0.90	-	$1.10	*(9%)*
Severance and Ad Valorem Taxes (% of revenue)	5.5%	-	7.5%	5.5%	-	7.5%	--
Capital Expenditure Program ($MM)							
Drilling & Completions	$625	-	$725	$625	-	$725	--
Facilities, Infrastructure and Other	$120	-	$160	$120	-	$160	--
Land	$20	-	$40	$20	-	$40	--
Total Capital Expenditures	$765	-	$925	$765	-	$925	--
Operated Drilling Program							
Wells Spud (Gross)	70	-	80	70	-	80	--
Wells Completed (Gross)	65	-	75	65	-	75	--

Capital Structure and Liquidity Overview

Capital structure overview

- Conservative leverage profile at 6/30/19
  - Net Debt / Total Book Capitalization of 21%
  - Net Debt / LTM EBITDAX of 1.3x
- Undrawn Credit Facility as of 6/30/19
- No bond maturities until 2026
- ~$830 million of elected liquidity

Debt maturity schedule ($ mm)



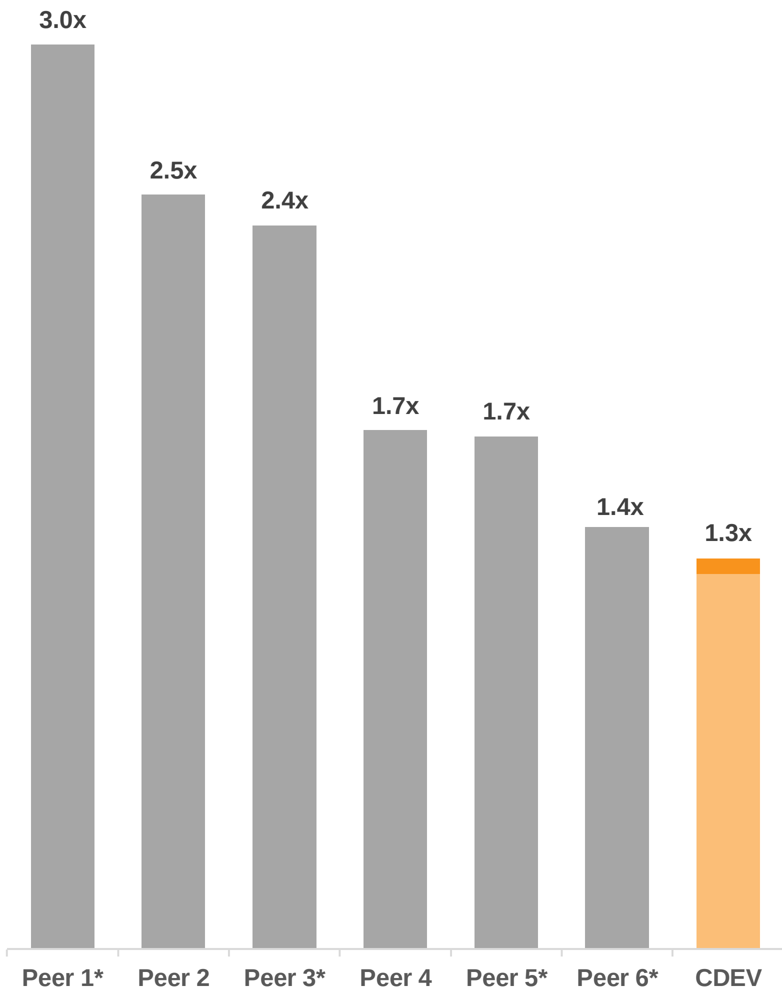
Capitalization and Liquidity ($ mm)

Capitalization	Actual (as of 6/30/19)
Cash and cash equivalents	$28
Revolving credit facility	$0
Senior Unsecured Notes [1]	$900
Total debt	$900
Book equity [2]	$3,267
Total capitalization	$4,167
Credit statistics	
Net debt / LTM EBITDAX	1.3x
Net debt / book capitalization	21%
Liquidity ($ mm)	
Borrowing base [3]	$1,200
Elected Commitment	$800
Less: Revolver borrowings	$0
Less: Letters of credit	($1)
Plus: Cash	$28
Elected liquidity [4]	$828
Borrowing base utilization	*0%*

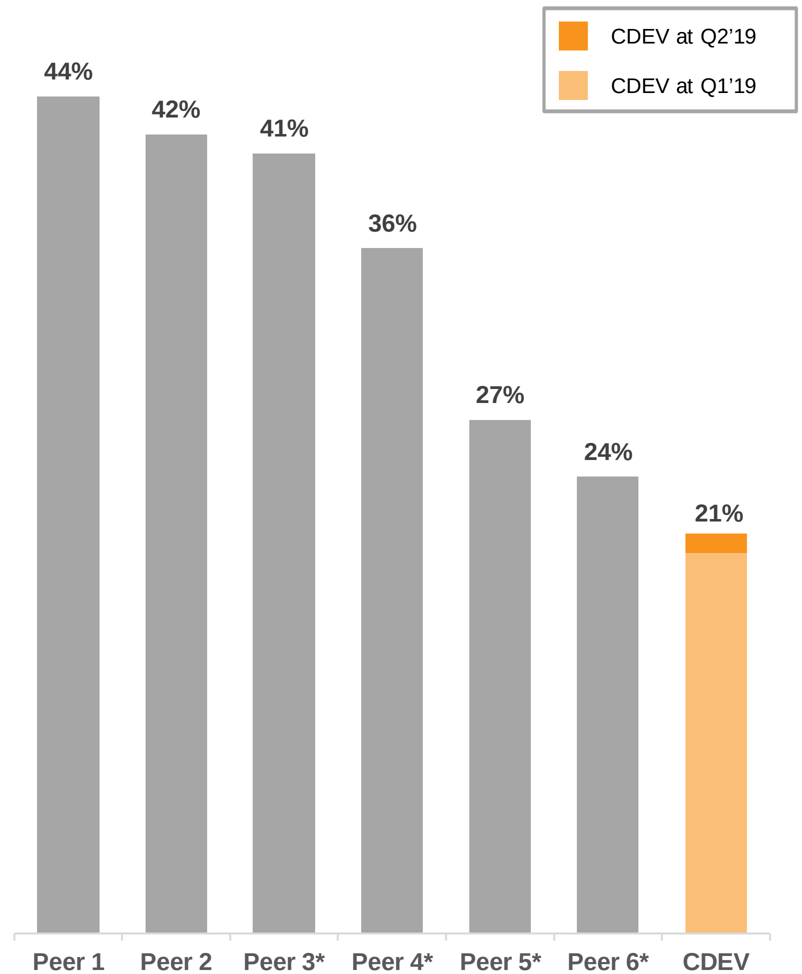
Note: Amounts may not sum due to rounding
(1) Reflects the aggregate principal amount
(2) Book equity includes non-controlling interest
(3) Borrowing base as of Spring 2019 Redetermination
(4) Total liquidity calculation based on elected commitment amount, not total borrowing base

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) MTDR and LPI as of 6/30/19; CPE, PE, FANG and JAG as of 3/31/19. Asterisk represents metric as of Q1'19

Quarterly Financial Results

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

	2018				2019	
($ in millions, unless specified)	Q1	Q2	Q3	Q4	Q1	Q2
Average Daily Production (Boe/d)	54,069	57,528	62,930	69,609	72,035	76,122
Average Daily Oil Production (Bo/d)	31,573	31,271	36,027	39,978	40,508	43,105
% Oil	*58%*	*54%*	*57%*	*57%*	*56%*	*57%*
Financial highlights						
Total Revenue	$215.9	$217.8	$234.9	$222.5	$214.6	$244.2
Adjusted EBITDAX[2]	$161.6	$164.6	$177.9	$165.7	$141.1	$170.1
Net Income (loss)[3]	$66.1	$63.5	$39.3	$31.0	($8.1)	$17.9
Unit Costs ($/Boe)						
Lease Operating Expense	$3.34	$3.66	$4.09	$3.77	$4.61	$5.04
Gathering, Processing & Transportation	2.84	2.92	2.78	1.94	2.32	2.34
Severance & Ad Valorem Taxes	2.91	2.71	2.49	2.14	2.49	2.48
Cash G&A	2.13	1.84	2.02	2.00	1.89	1.78
Depreciation, Depletion & Amortization	13.57	14.32	14.41	15.94	14.89	16.18
Capital Expenditures Incurred						
Drilling & Completion	$181.8	$162.7	$222.4	$199.2	$188.4	$179.8
Facilities, Seismic and Other	50.2	34.3	43.5	73.1	45.6	44.6
Land and Other	6.3	6.2	7.7	9.8	11.2	13.0
Total Capital Expenditures	$238.3	$203.2	$273.6	$282.1	$245.2	$237.4
Cash and Cash Equivalents	$38.2	$42.7	$58.9	$18.2	$89.5	$28.4
Total Debt Outstanding	$400.0	$430.0	$540.0	$700.0	$900.0	$900.0
Liquidity[4]	$637.4	$611.8	$518.0	$517.4	$888.7	$827.6

(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 16 for a reconciliation of Adjusted EBITDAX to net income (loss), the most comparable GAAP measure
(3) Net income (loss) attributable to common shareholders
(4) Liquidity defined as cash, plus availability under the revolving credit facility elected commitment amount

Hedge Position Overview

	H2 2019 (6 months ended 12/31/19)		
	Q3	Q4	H2 2019
MidCush Basis Swaps			
Total Volume (Bbl)	1,380,000	920,000	2,300,000
Daily Volume (Bbl/d)	15,000	10,000	12,500
Weighted Average Price ($ / Bbl)	($9.03)	($4.24)	($7.11)
Henry Hub Fixed Price Swaps			
Total Volume (MMBtu)	2,760,000	2,760,000	5,520,000
Total Volume (MMBtu/d)	30,000	30,000	30,000
Weighted Average Price ($/MMBtu)	$2.78	$2.78	$2.78
Waha Fixed Price Swaps			
Total Volume (MMBtu)	1,380,000	1,380,000	2,760,000
Daily Volume (MMBtu/d)	15,000	15,000	15,000
Weighted Average Price ($/MMBtu)	$1.61	$1.61	$1.61
Waha Differential Basis Swaps			
Total Volume (MMBtu)	3,220,000	3,220,000	6,440,000
Daily Volume (MMBtu/d)	35,000	35,000	35,000
Weighted Average Price ($/MMBtu)	($1.31)	($1.31)	($1.31)

Note: Hedge positions as of June 30, 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	Q1 2019 3 months ended March 31, 2019	Q2 2019 3 months ended June 30, 2019
Net income (loss) attributable to common shareholders	$66,090	$63,541	$39,288	$30,980	$199,899	($8,112)	$17,877
Net income (loss) attributable to noncontrolling interest	4,682	3,941	2,386	1,828	$12,837	(425)	1,125
Interest expense	5,813	5,791	6,534	8,220	$26,358	10,160	14,437
Income tax expense (benefit)	19,137	19,940	11,652	8,711	$59,440	(2,263)	5,928
Depreciation, depletion and amortization	66,010	74,946	83,423	102,083	$326,462	96,558	112,114
Impairment and abandonment expenses	-	1,784	8,612	740	11,136	31,264	4,418
Non-cash portion of derivative loss (gain)	(7,482)	(11,534)	18,437	5,853	5,274	5,494	4,260
Stock-based compensation expense	3,952	4,166	4,888	5,848	18,854	5,884	6,076
Exploration expense	3,447	1,867	2,712	1,942	9,968	2,516	3,861
(Gain) loss on sale of long-lived assets	(15)	141	(52)	(549)	(475)	2	(9)
Adjusted EBITDAX	$161,634	$164,583	$177,880	$165,656	$669,753	$141,078	$170,087

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