Antero Resources

Credit Suisse 23rd Annual Energy Summit

FEBRUARY 13, 2018

Cautionary Statement

This presentation includes "forward-looking statements". Such forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond AR's control. All statements, except for statements of historical fact, made in this release regarding activities, events or developments AR expects, believes or anticipates will or may occur in the future, such as those regarding future commodity prices, future production targets, completion of natural gas or natural gas liquids transportation projects, future earnings, Consolidated Adjusted EBITDAX, Stand-Alone E&P Adjusted EBITDAX, Consolidated Adjusted Operating Cash Flow, Stand-Alone Adjusted Operating Cash Flow, Free Cash Flow, future capital spending plans, improved and/or increasing capital efficiency, continued utilization of existing infrastructure, gas marketability, estimated realized natural gas, natural gas liquids and oil prices, acreage quality, access to multiple gas markets, expected drilling and development plans (including the number, type, lateral length and location of wells to be drilled, the number and type of drilling rigs and the number of wells per pad), projected well costs, future financial position, future technical improvements and future marketing opportunities, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All forward-looking statements speak only as of the date of this release. Although Antero believes that the plans, intentions and expectations reflected in or suggested by the forward-looking statements are reasonable, there is no assurance that these plans, intentions or expectations will be achieved. Therefore, actual outcomes and results could materially differ from what is expressed, implied or forecast in such statements.

AR cautions 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 the AR's control, incident to the exploration for and development, production, gathering and sale of natural gas, NGLs and oil. 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 natural gas and oil reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures, and the other risks described under the heading "Item 1A. Risk Factors" in AR's Annual Report on Form 10-K for the year ended December 31, 2016.

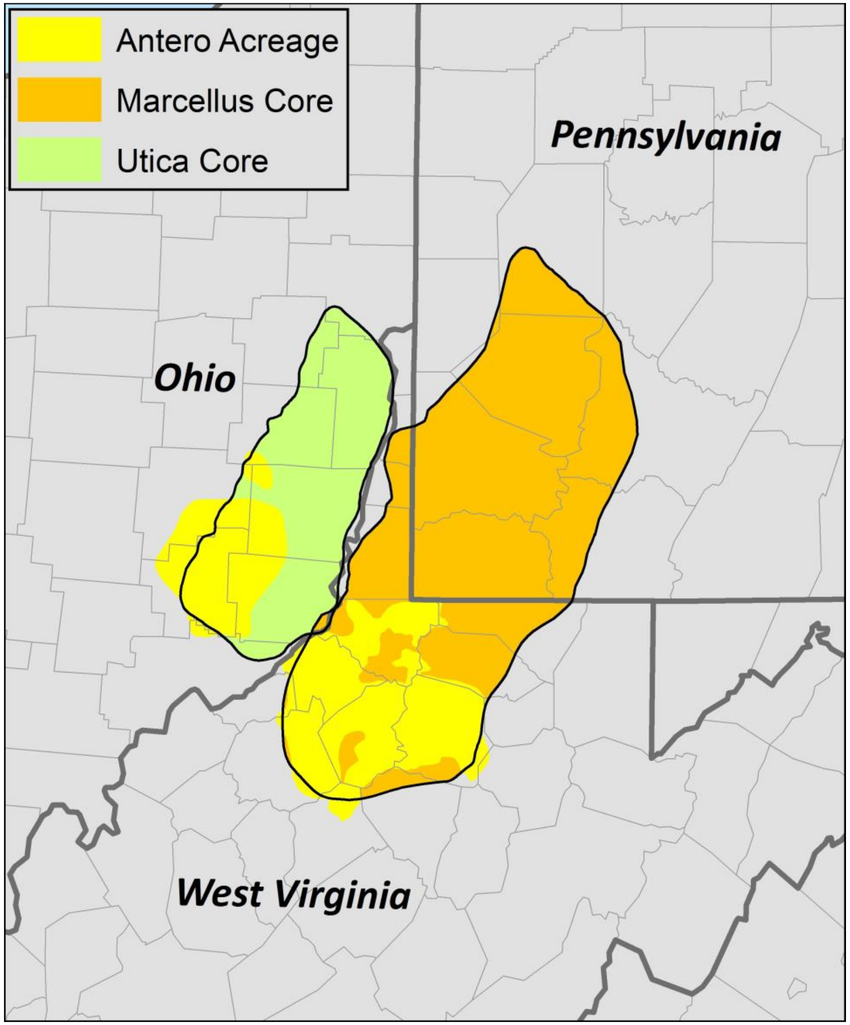
Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

This presentation includes certain financial measures that are not calculated in accordance with U.S. generally accepted accounting principles ("GAAP"). These measures include (i) Consolidated Adjusted EBITDAX, (ii) Stand-Alone E&P Adjusted EBITDAX, (iii) Consolidated Adjusted Operating Cash Flow, (iv) Stand-Alone E&P Adjusted Operating Cash Flow, (v) Free Cash Flow. Please see "Antero Definitions" and "Antero Non-GAAP Measures" for the definition of each of these measures as well as certain additional information regarding these measures, including the most comparable financial measures calculated in accordance with GAAP.

Antero Resources Corporation is denoted as "AR" in the presentation, Antero Midstream Partners LP is denoted as "AM" and Antero Midstream GP LP is denoted as "AMGP", which are their respective New York Stock Exchange ticker symbols.

Market Cap………………......	$5.4B
Consolidated Enterprise Value	$10.7B
Corporate Debt Ratings……	Ba2 / BB+ / BBB-
Stand-Alone Leverage…….	2.6x
Net Production (4Q 2017)…	2,347 MMcfe/d
Liquids............................	107,000 Bbl/d
3P Reserves………..….......	53.0 Tcfe
Net Acres………………..……	630,000
Hedge Mark to Market……..	$1.3B
AR Midstream Ownership (53%)	$2.7B

AR LISTED NYSE



Note: Equity market data as of 2/9/18. Balance sheet data as of 9/30/17 and hedge mark to market as of 12/31/17. Reserve data as of mid-year 2017.

Reaching an Inflection Point

Announced New Long Lateral Development Plan Averaging 11,500’

Step Change in Capital Efficiency Reduces 5-Year D&C Capex by $2.9B

Highest Leverage to NGL Prices as Largest NGL Producer

The Size & Scale to Capitalize on Resource

Sustainable Cash Flow Growth

Generating 5-Year Free Cash Flow of $1.6B at YE Strip & $2.8B at $60 Oil

Disciplined Returns Focus

→ 28% Full Cycle Returns
→ 23% 5-Year Debt-Adjusted Production CAGR per share
→ 22% 5-Year Cash Flow CAGR per share

Joining an Elite Group With:

Scale

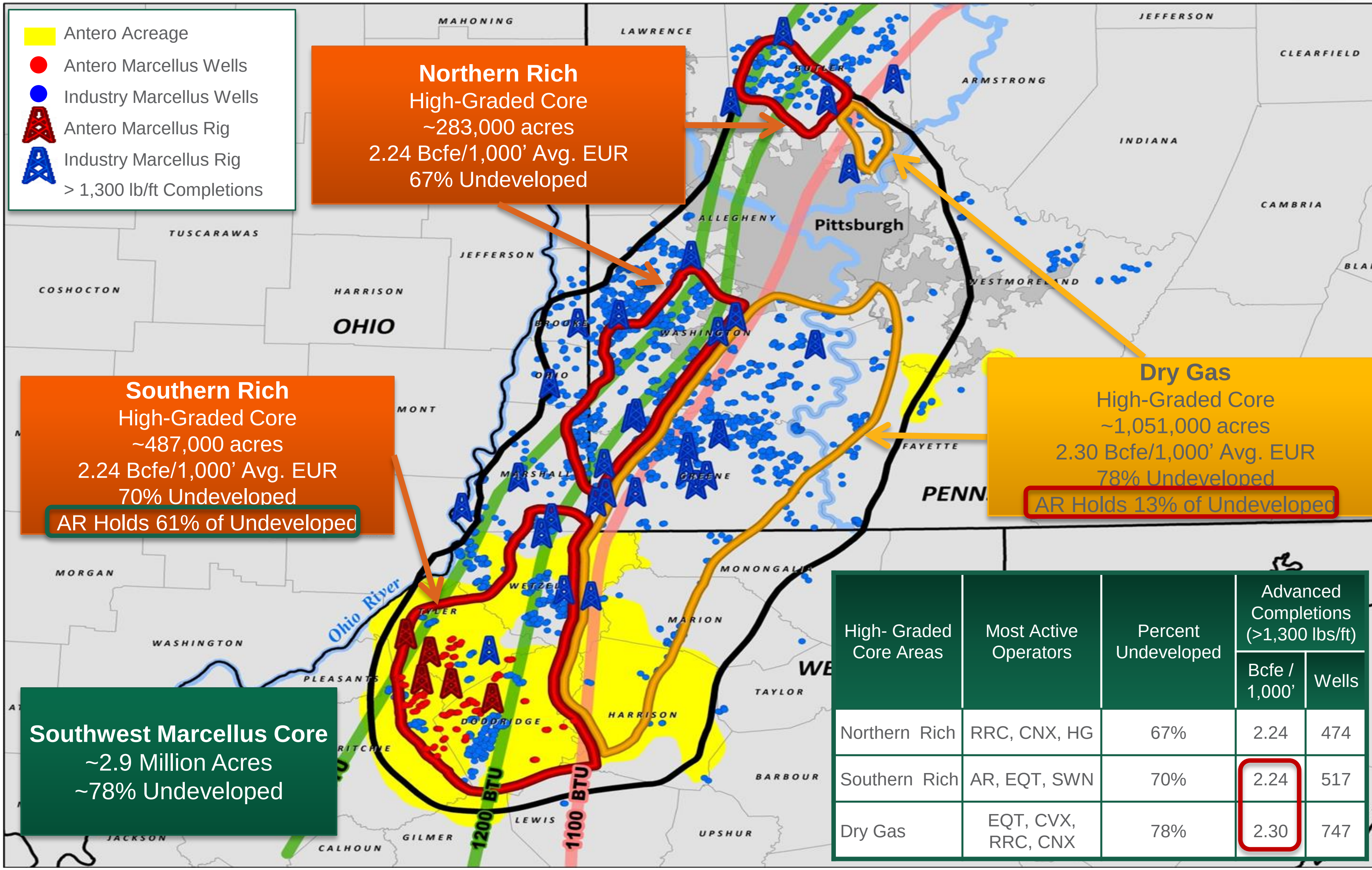
Double Digit Growth

Low Leverage

Free Cash Flow

Note: See definitions for free cash flow and assumptions behind long-term targets in Appendix; free cash flow definition includes maintenance land spending, but excludes growth land spending.

Positioned in the Core of the Core



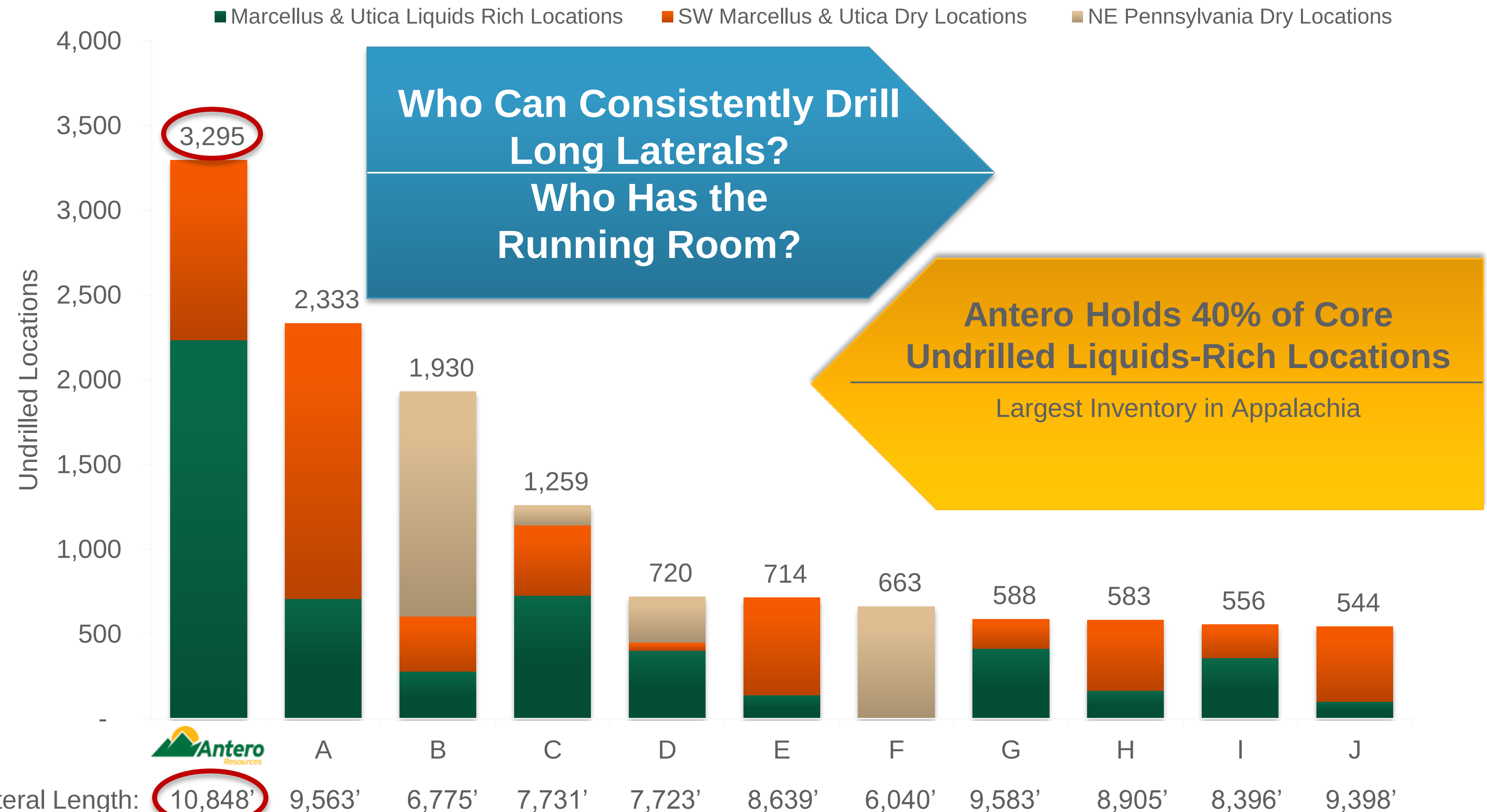
High- Graded Core Areas	Most Active Operators	Percent Undeveloped	Advanced Completions (>1,300 lbs/ft) Bcfe / 1,000'	Advanced Completions (>1,300 lbs/ft) Wells
Northern Rich	RRC, CNX, HG	67%	2.24	474
Southern Rich	AR, EQT, SWN	70%	2.24	517
Dry Gas	EQT, CVX, RRC, CNX	78%	2.30	747

Antero is Very Well Positioned in the Core of the Core

Note: Excludes 600,000 urban acres. EURs assume full ethane rejection. Based on Antero reserve engineering of most recent state and internal production data.

Largest Core Drilling Inventory

Undrilled Core Marcellus & Utica Locations[1]



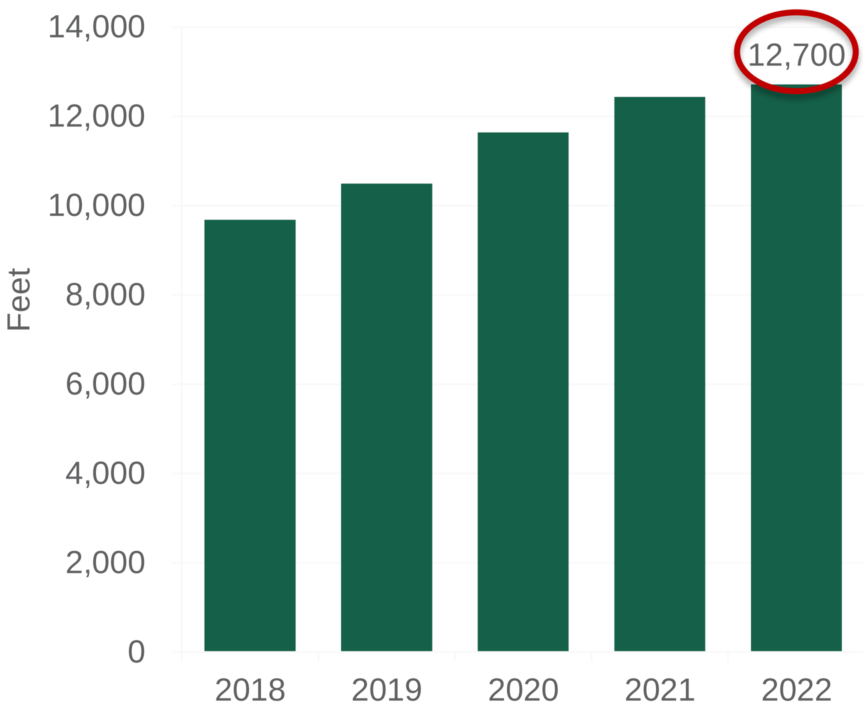
(1) Peers include Ascent, CHK, CNX, COG, CVX, EQT, GPOR, HG, RRC and SWN. Based on Antero analysis of undeveloped acreage in the core of the Marcellus and Utica plays.

New Long Lateral Development Plan

5-Year Plan Averages 11,500'

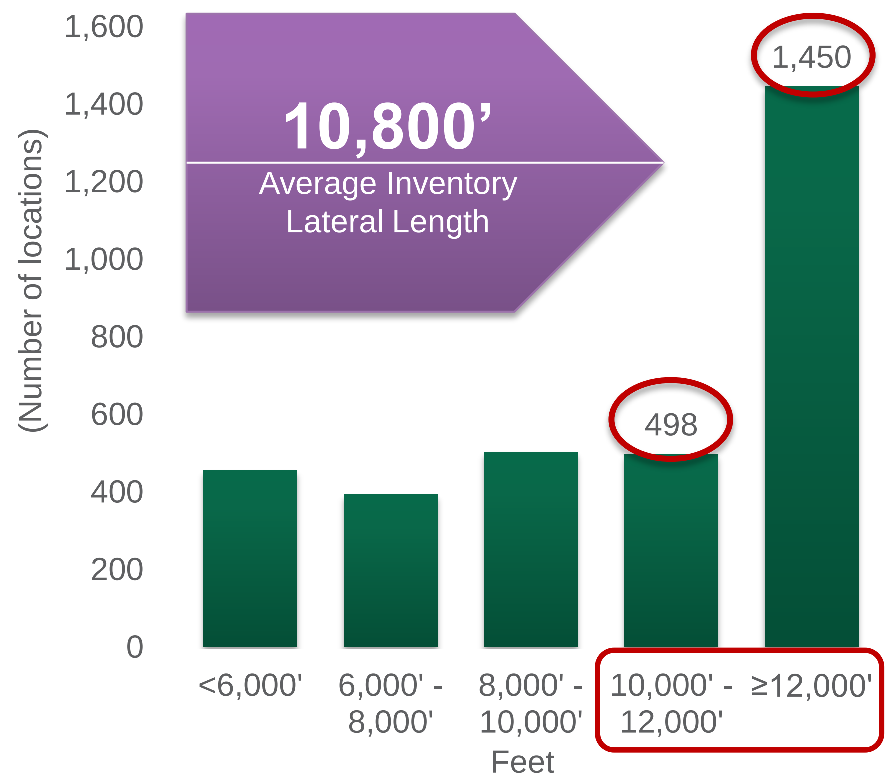
59% of Inventory Now ≥ 10,000' Lateral Length

Average Lateral Length per Completed Well



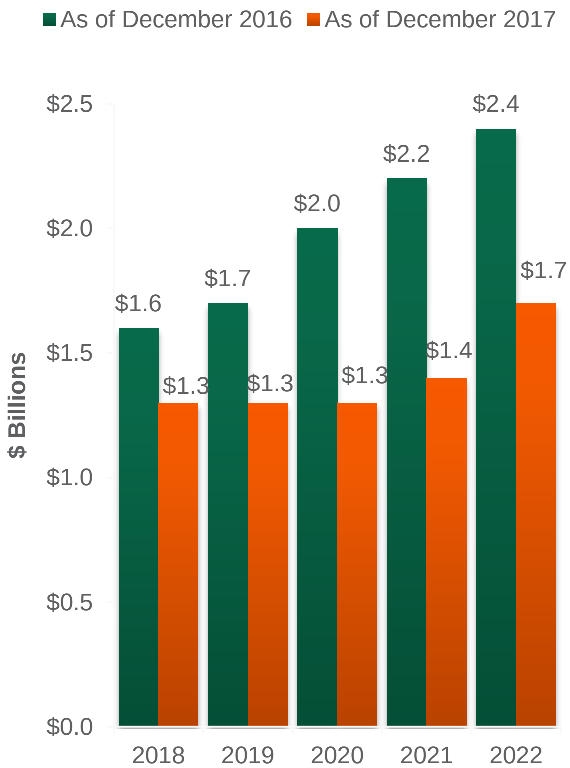
Wells Completed[1]	145	155	160	165	165

Core Inventory by Lateral Length



1) Wells completed reflects midpoint of targeted completions per year.

Consolidated Drilling & Completion Capital Expenditures



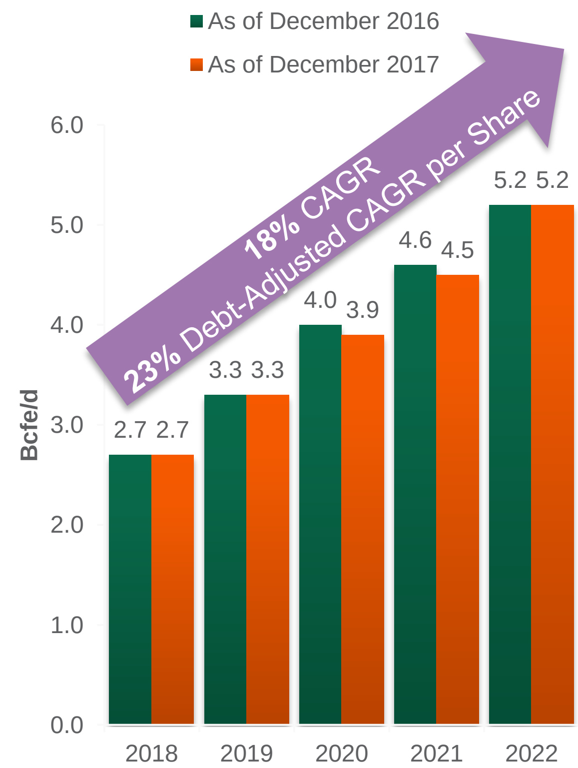
$2.9B Capex Reduction

Cumulative Reduction in Drilling & Completion Capital

Same Production Targets

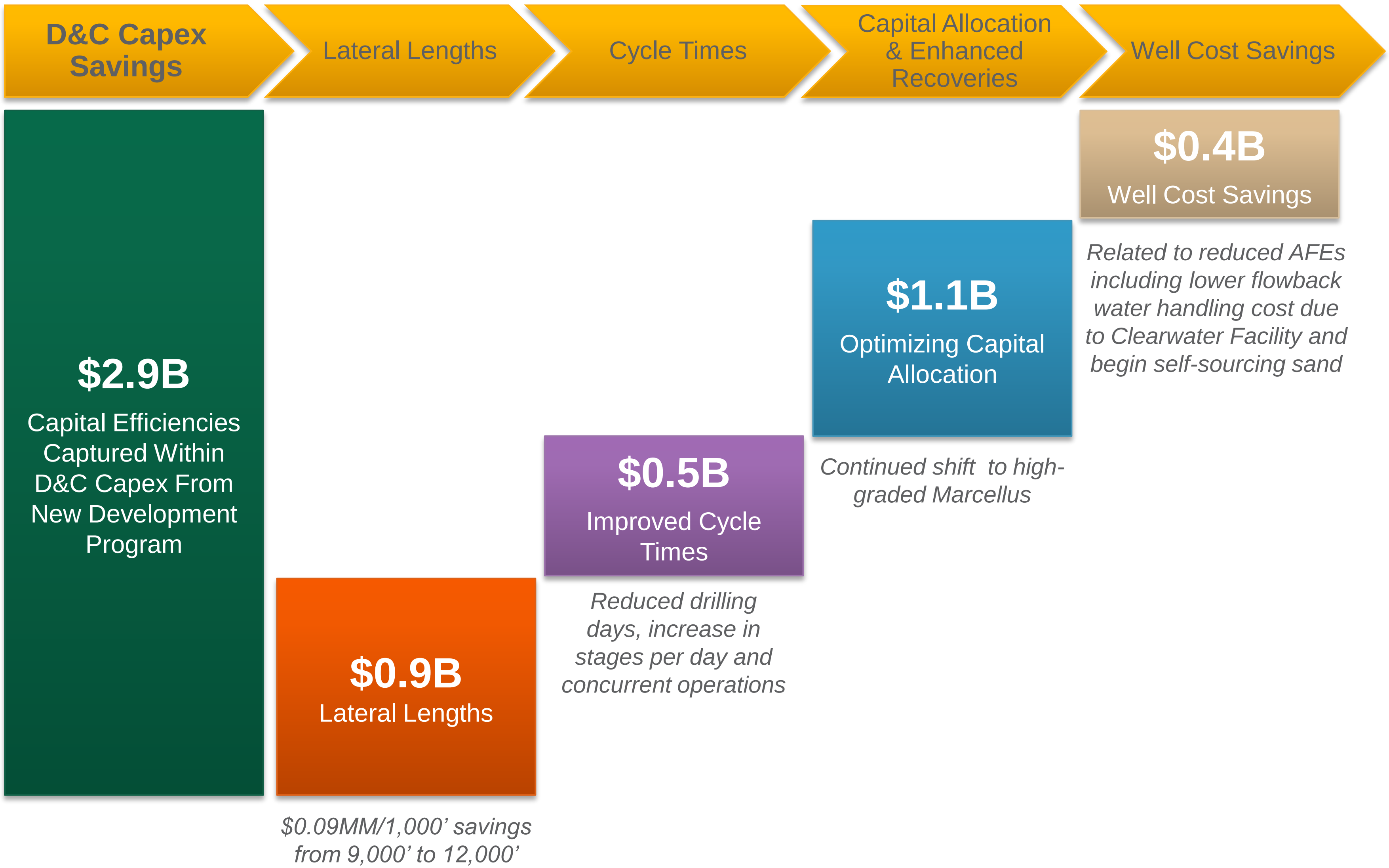
20% Production CAGR 2018-2020
15% Production CAGR 2021-2022

Production Targets



Same Production Growth With Much Less Capital Spending

Breakdown of D&C Capex Savings



Note: See appendix for further detail on D&C capital.

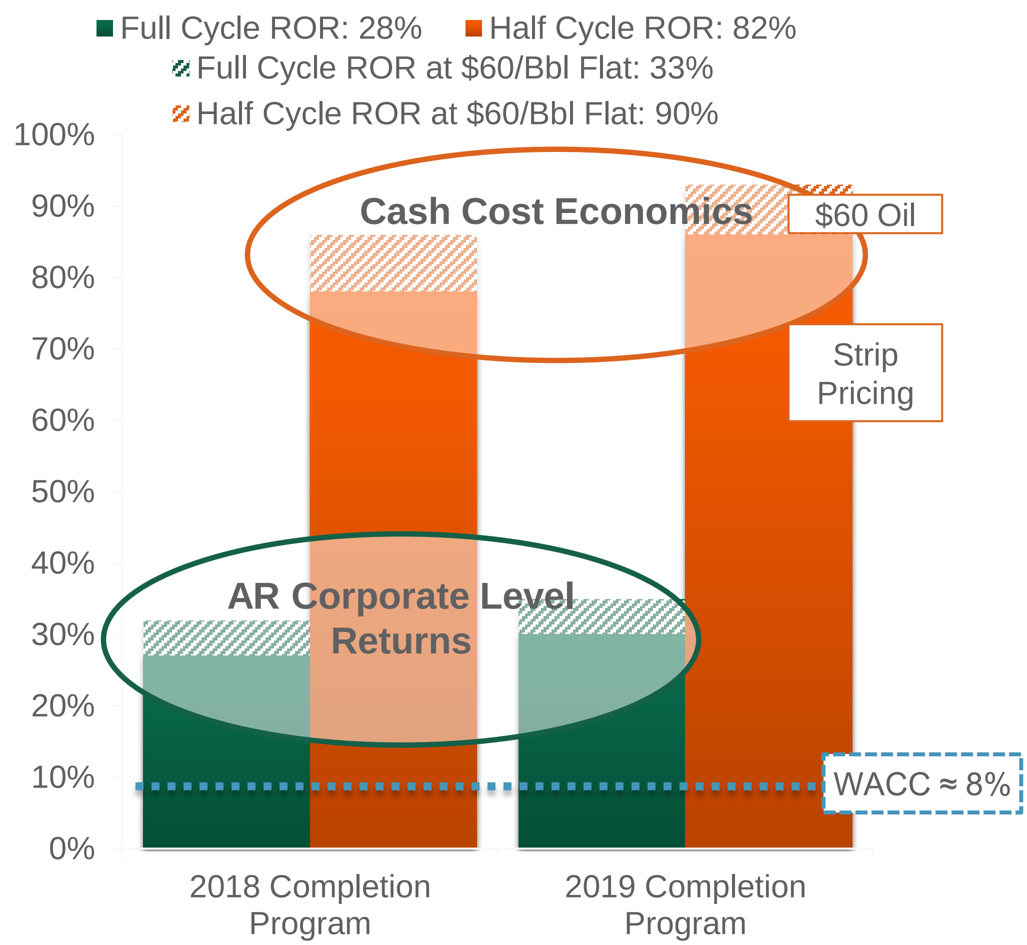
Well Economics Support Investment

ROR Well in Excess of Cost of Capital

28% Corporate Level ROR

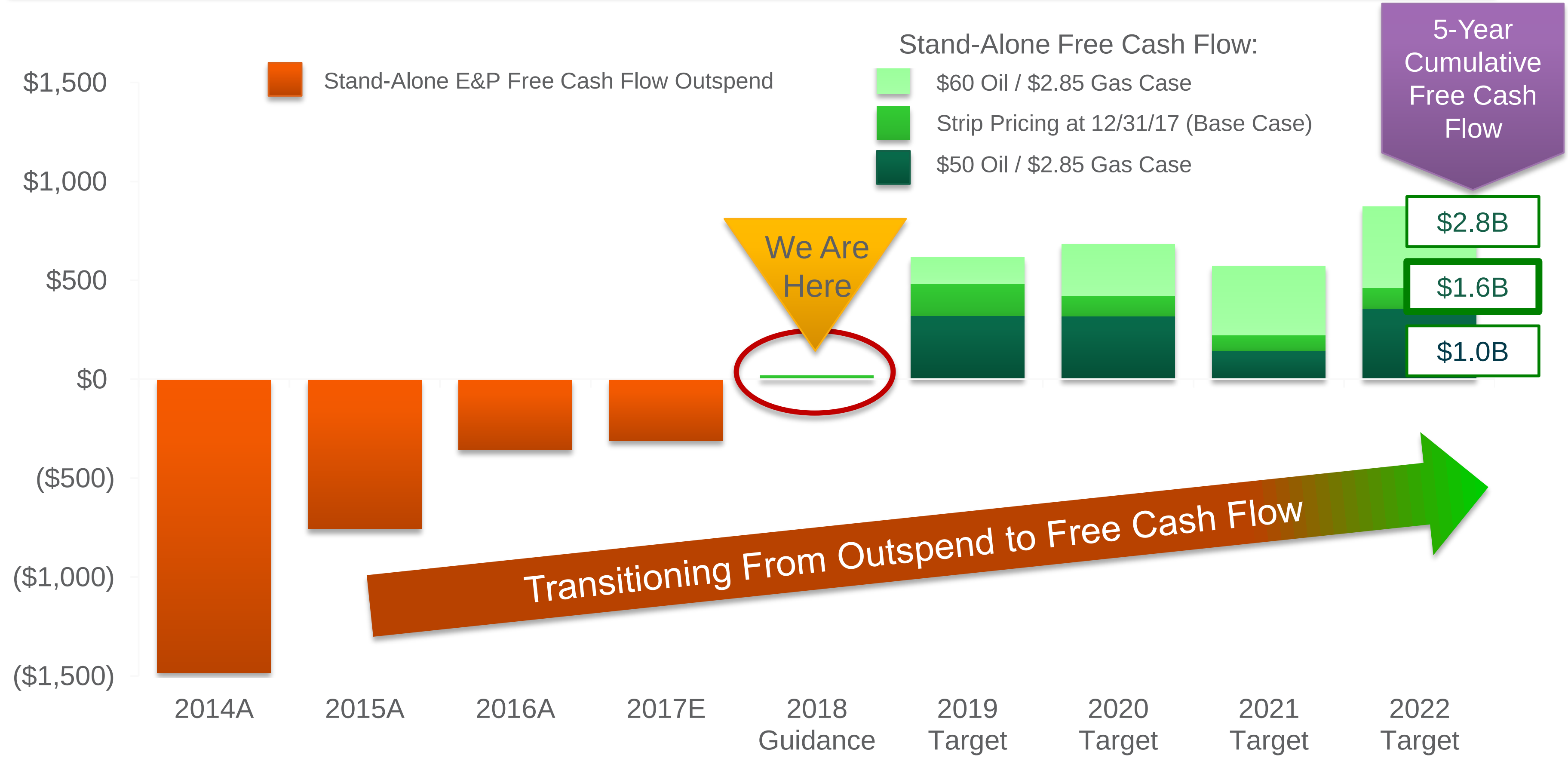
2018 & 2019 Full Cycle Returns

Single Well Economics



Note: Half cycle burdened with 60% of AM fees to give credit for AM ownership/distributions and variable firm transportation fees. See Appendix for further detail behind full cycle and half cycle single well economics; WACC calculated using CAPM.

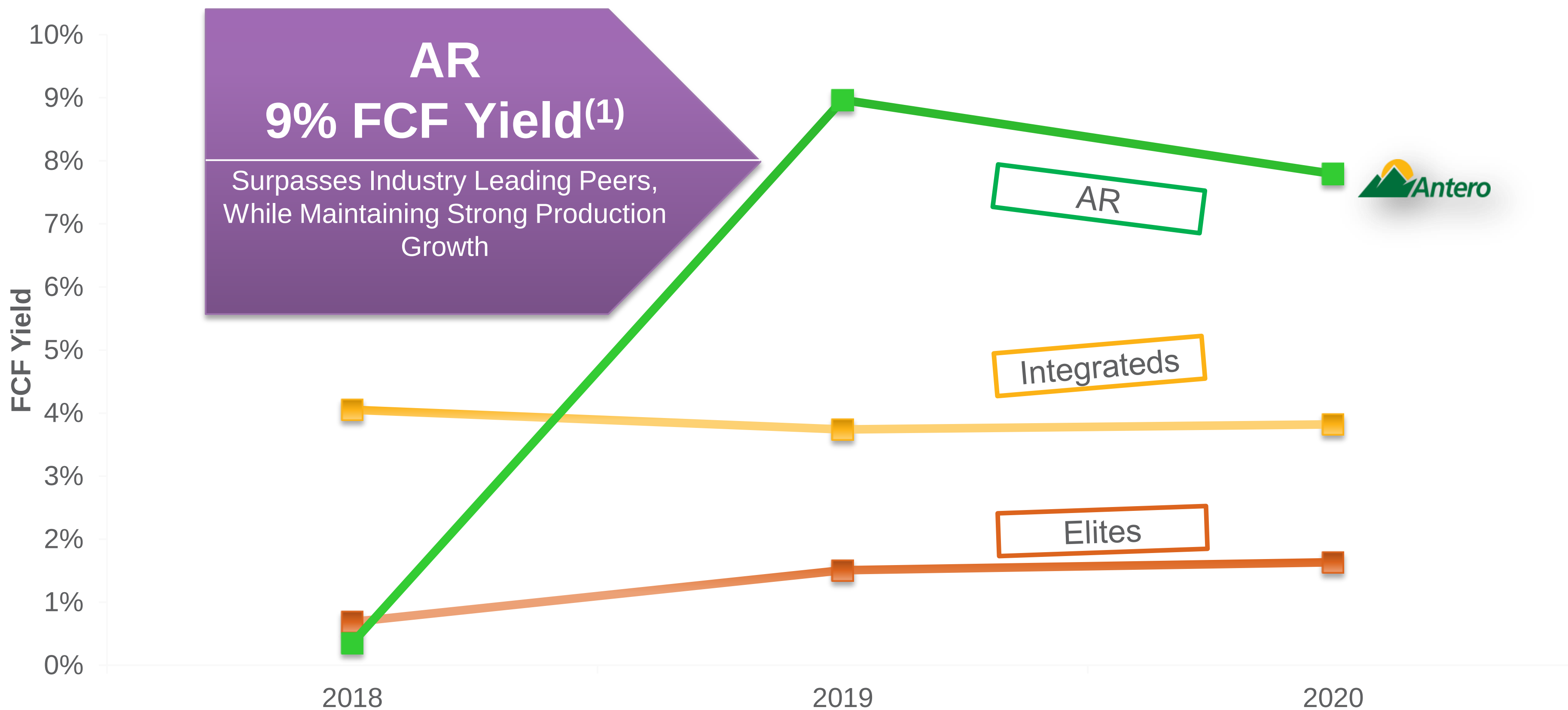
Over $1.6B of Targeted Free Cash Flow from 2018 to 2022 at Strip Pricing Including Maintenance Land Capital Expenditures



D&C Capital Investment Fully Funded with Cash Flow

Note: See definitions for free cash flow and assumptions behind long-term targets in Appendix; free cash flow definition includes $200MM maintenance land spending, but excludes $300MM discretionary land spending.

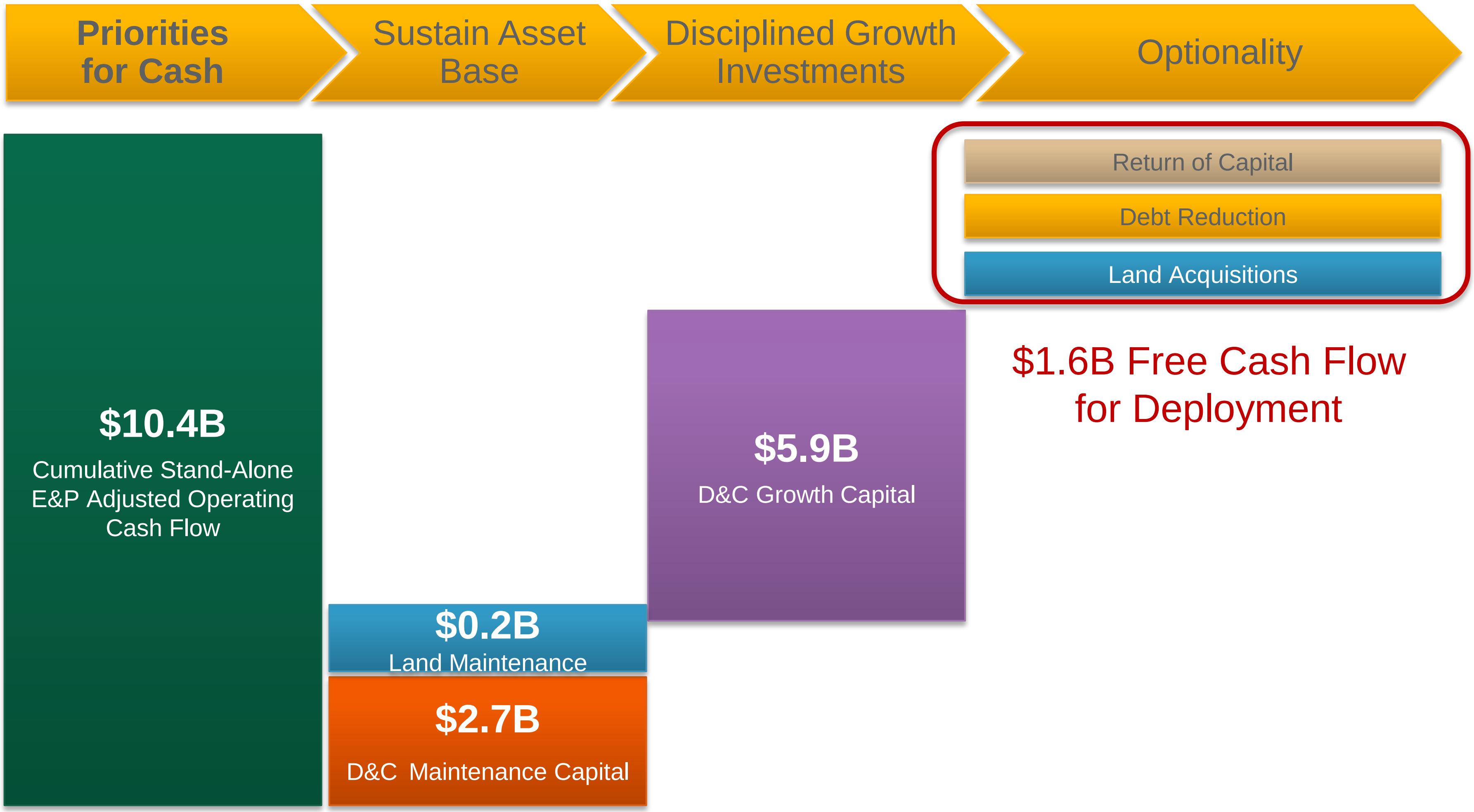
Attractive Free Cash Flow Yield



Free Cash Flow Yields Exceed Both Best-In-Class Peers & Integrated Oil & Gas Companies

Note: See definitions for free cash flow and assumptions behind long-term targets in Appendix. "Elite" group of peers includes COG, CXO, EOG, FANG, PXD, XEC; "Integrated" group includes XOM & CVX.
Source: Bloomberg. Represents free cash flow yield for the base case at 12/31/17 strip pricing.
(1) Represents free cash flow divided by current market capitalization as of 2/9/18.

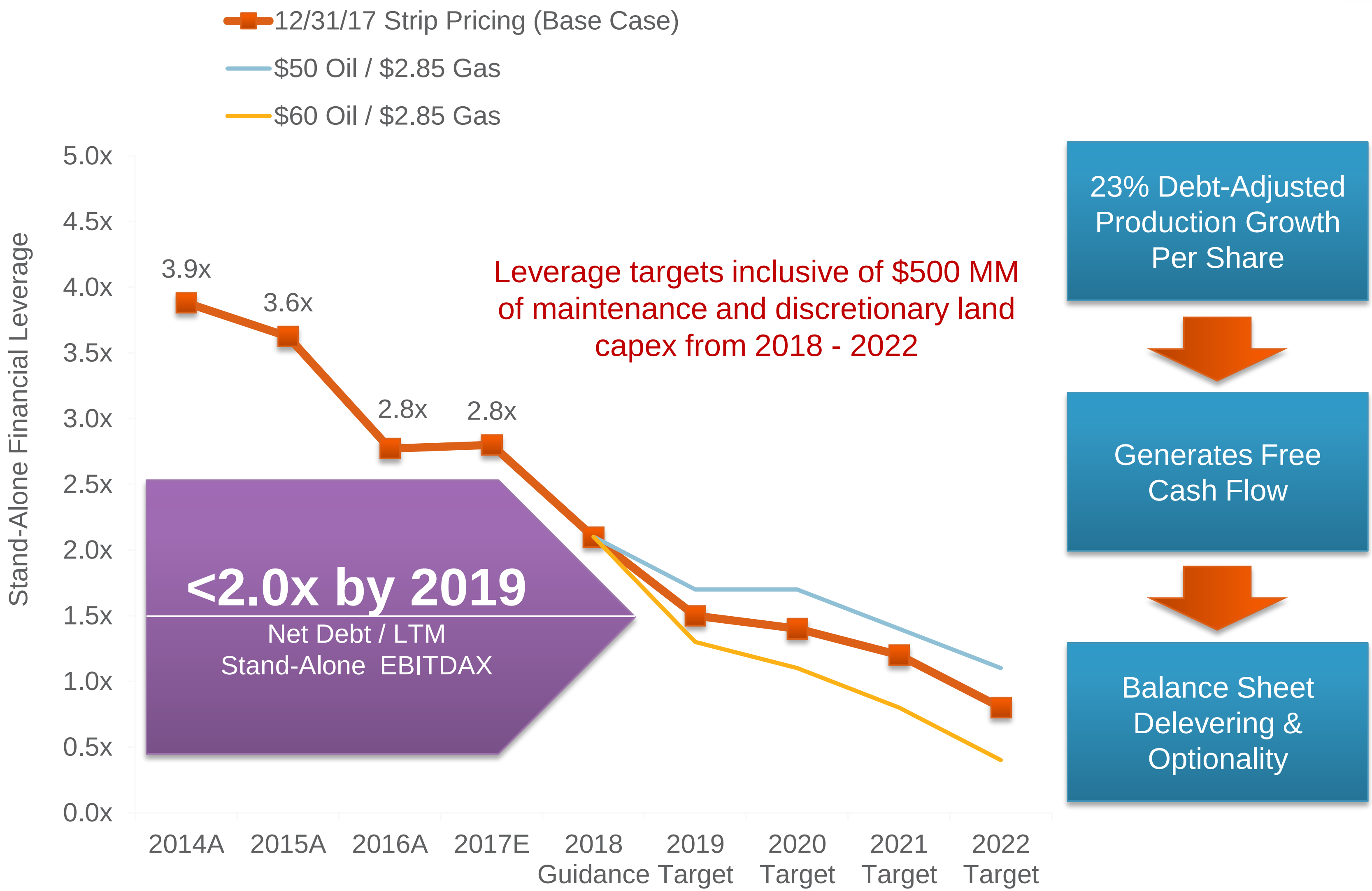
Shareholder Interests in Focus: 5-Year Cash Priorities



Significant Financial Flexibility with Cash Flow in Excess of Maintenance Capital

Note: See Appendix for key definitions and assumptions. Adjusted stand-alone E&P operating cash flow includes $250MM in earn-out payments on water business.

Cash Flow Growth → Dramatic Delevering

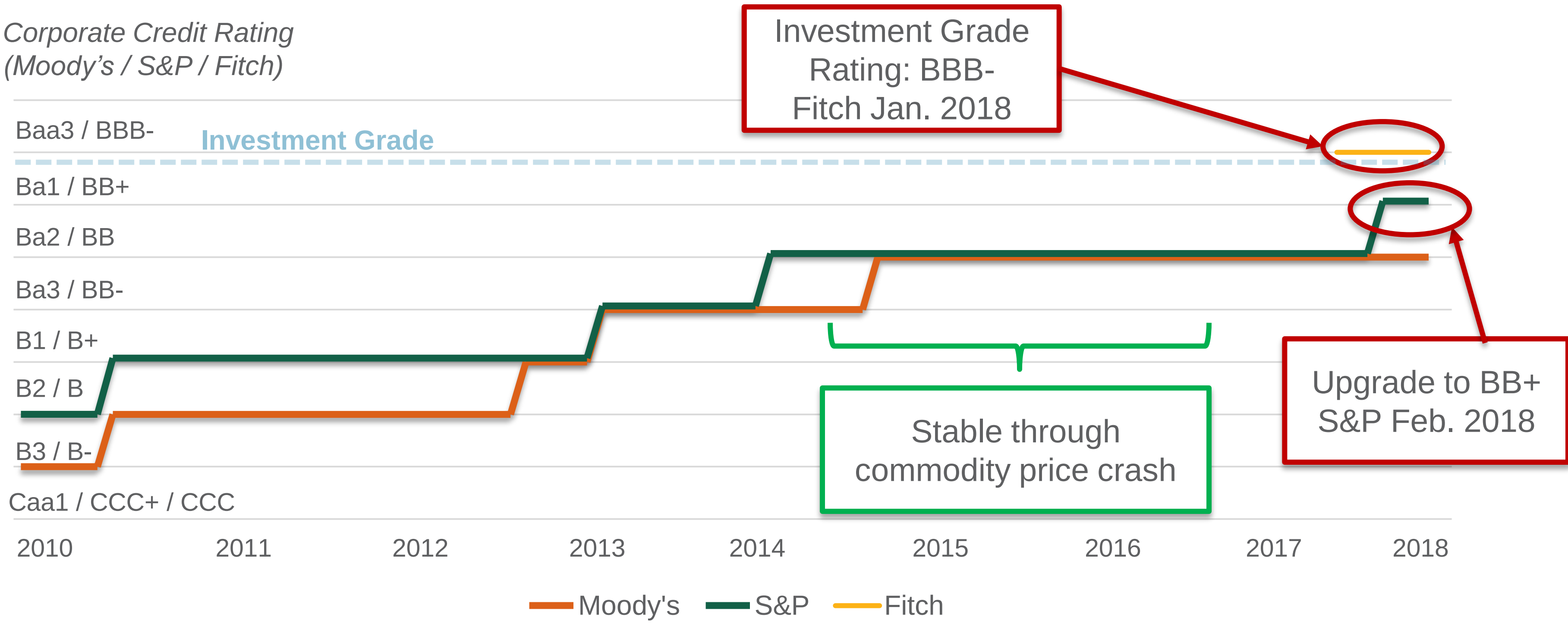


Note: See Appendix for key definitions and assumptions. Stand-alone financial leverage is calculated by dividing year-end stand-alone debt by last twelve months stand-alone adjusted EBITDAX. Note all free cash flow after land spending is assumed to be used for debt reduction.

Corporate Credit Ratings History

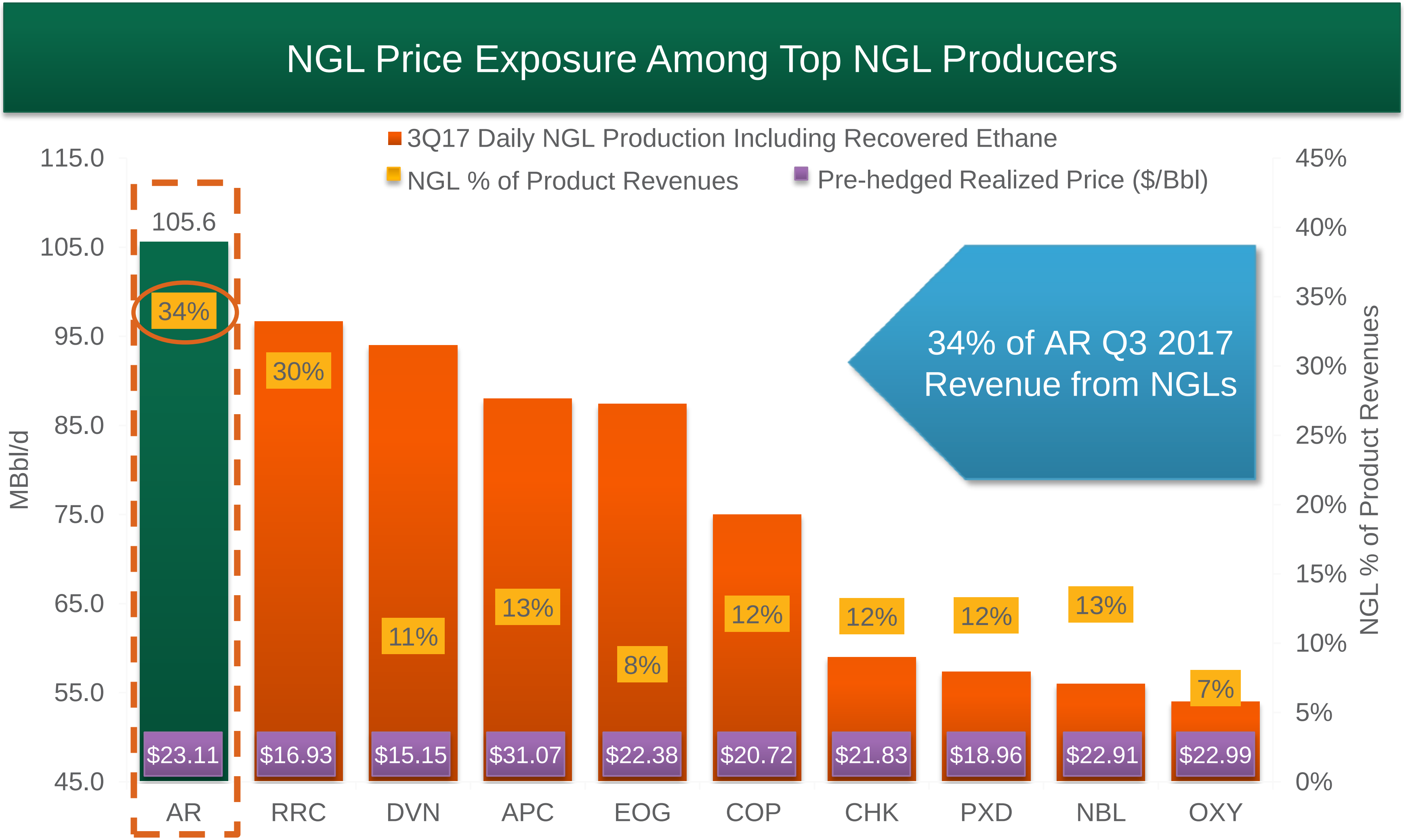
Stable Credit Ratings with Consistent Upgrades from the Beginning of the Decade Through the Downturn

Investment Grade Rating from Fitch (BBB-) & Recent Upgrade from S&P (BB+)



Credit Markets Have a Strong Appreciation for Antero Momentum

Largest NGL Producer in the U.S.

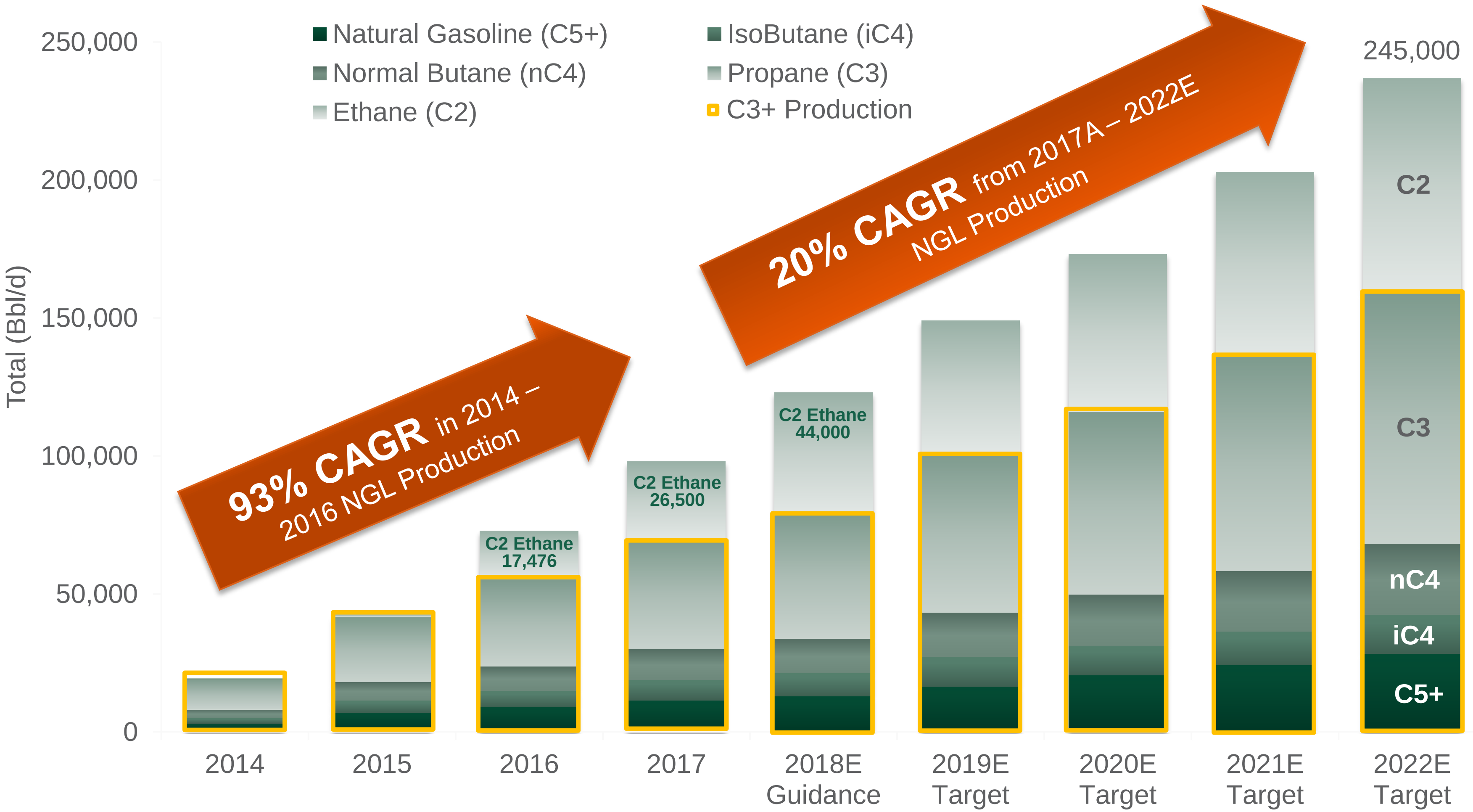


Antero Has The Highest NGL Price Exposure Among Top NGL Producers

Source: SEC filings and company press releases.
Note: Realized prices are weighted average including ethane (C2) where applicable.

Rapidly Growing NGL Production

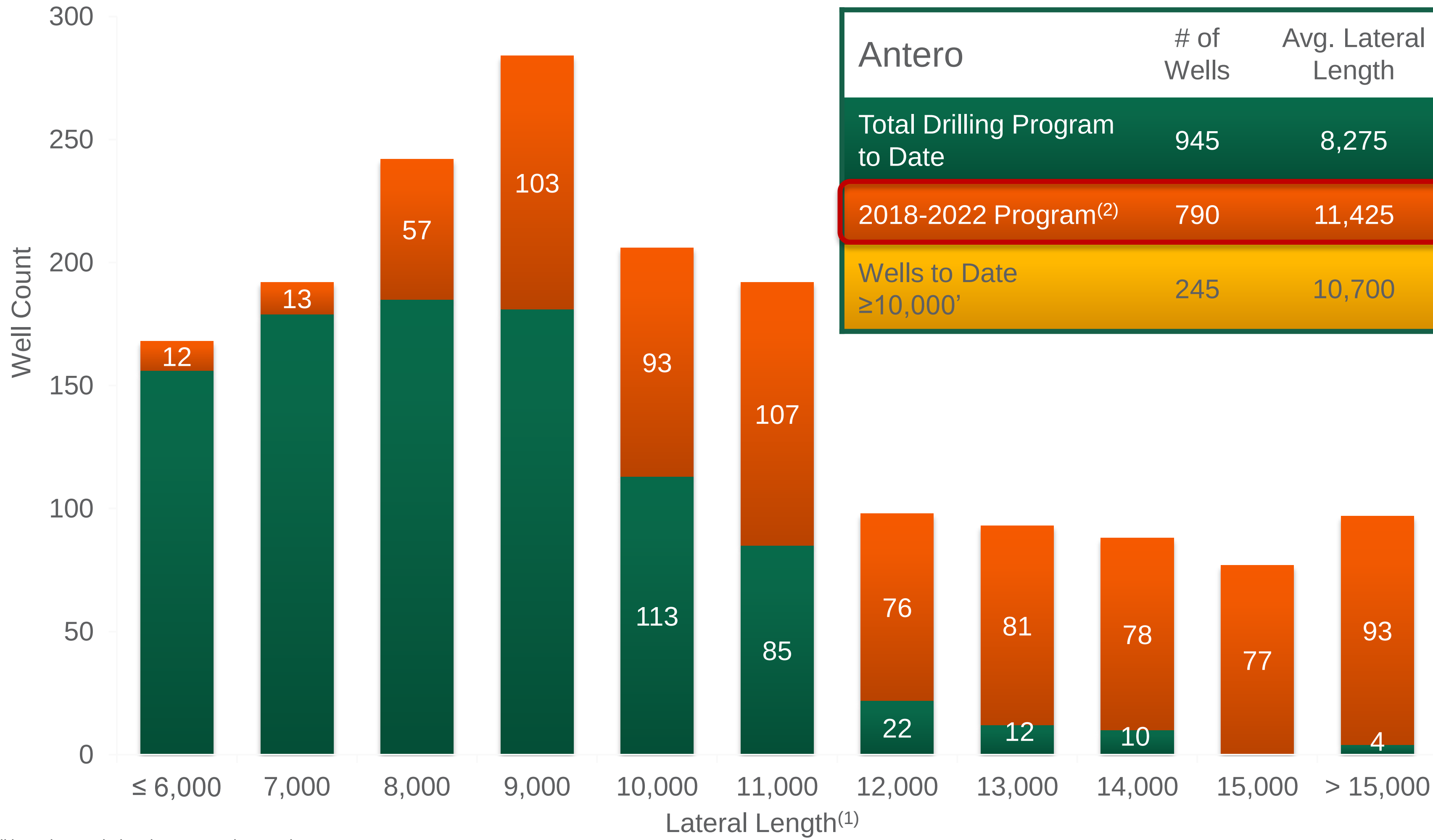
Antero NGL Production Growth by Purity Product



20% CAGR in NGL Production Through 2022

Note: Excludes condensate. See Appendix for further assumptions around long-term targets.

Antero Historical & Future Lateral Length Program

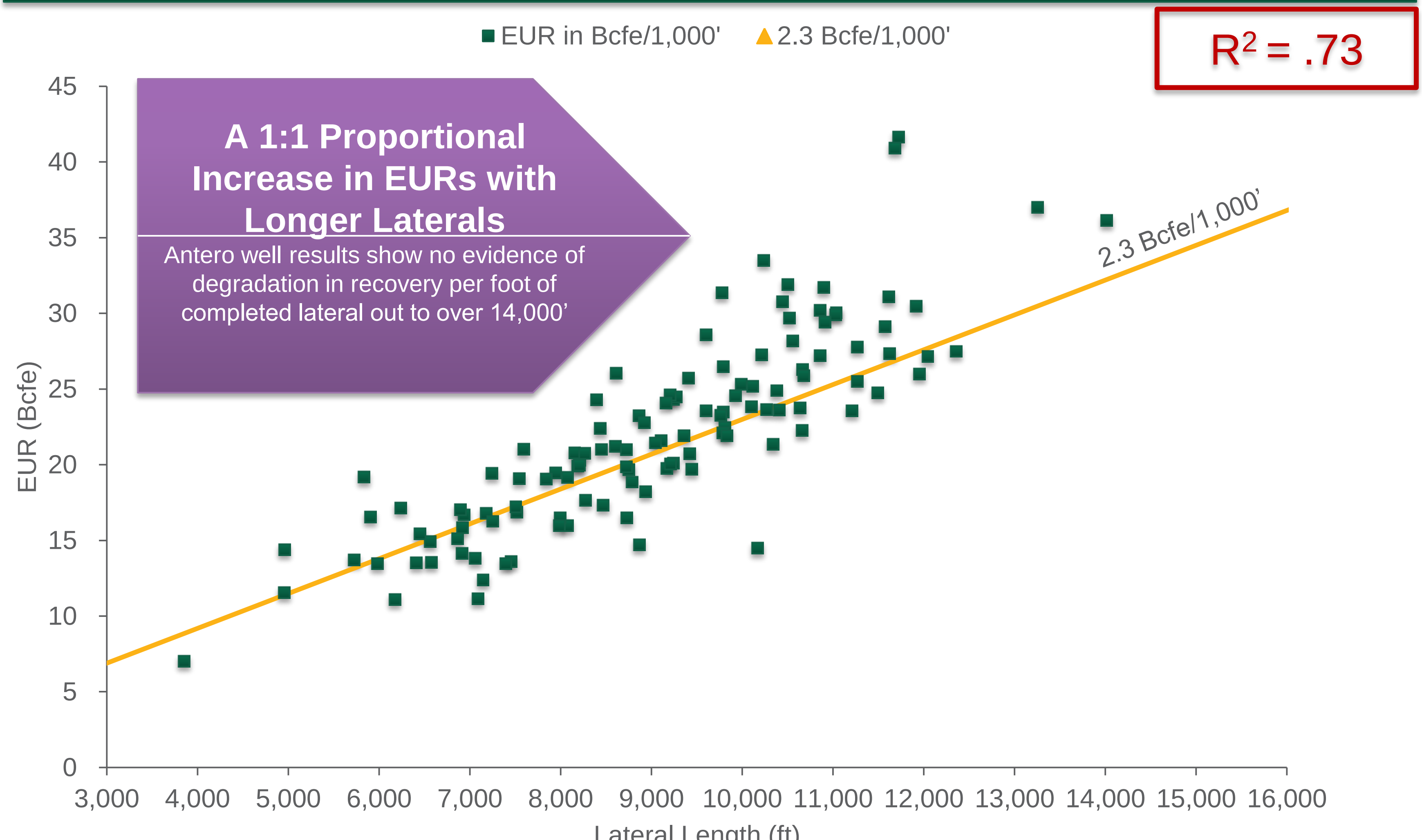


Antero	# of Wells	Avg. Lateral Length
Total Drilling Program to Date	945	8,275
2018-2022 Program(2)	790	11,425
Wells to Date ≥10,000'	245	10,700

(1) *All laterals rounded to the nearest thousand.*
(2) *Represents wells placed to sales.*

Longer Laterals Scale the Resource

EURs by Marcellus Lateral Lengths



Note: Assumes ethane rejection.

Declining Well Costs → Longer Laterals the Next Step

41% | 43% Lower Costs

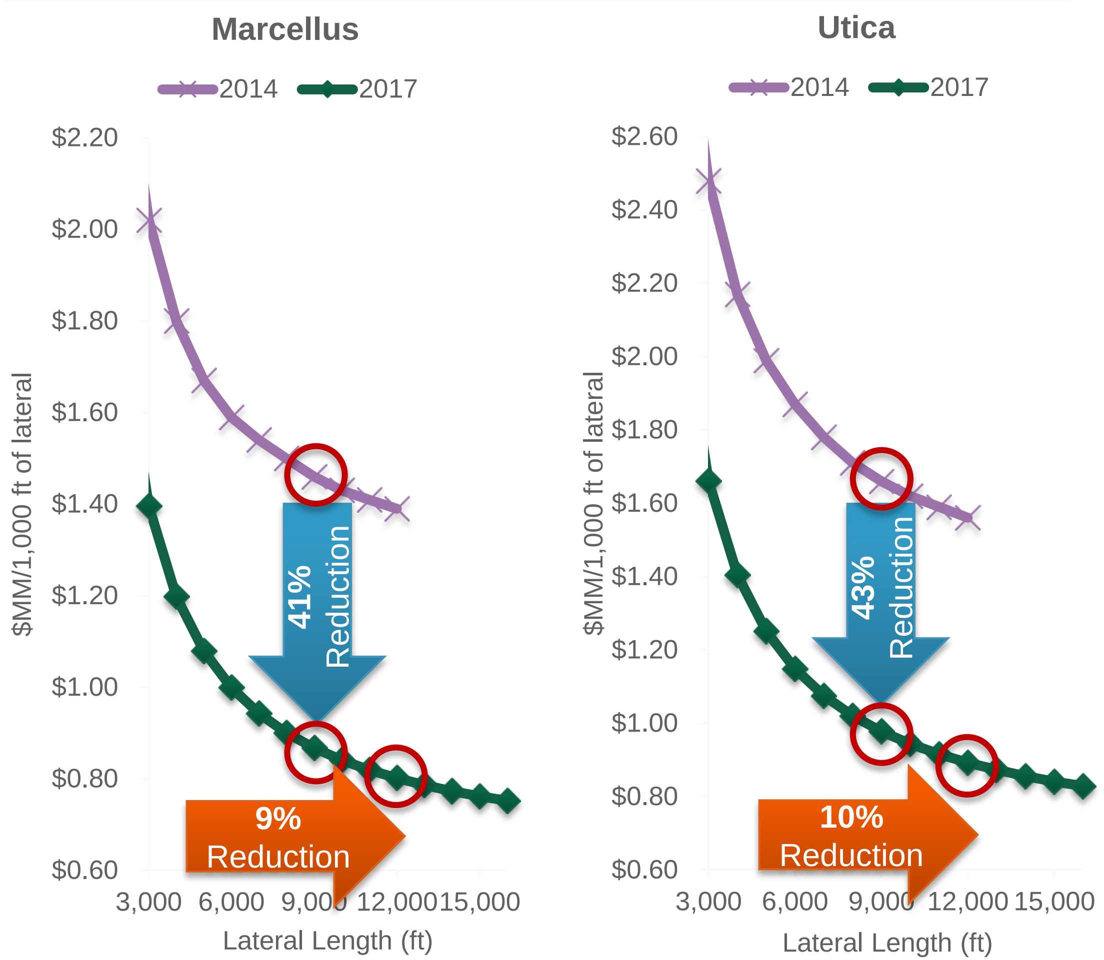
Marcellus | Utica reduction in well costs from 2014 to 2017 for a 9,000' lateral

- 54% from efficiencies
- 45% from service costs

9% | 10% Cost Benefit

Marcellus | Utica reduction in well cost per 1,000' lateral going from 9,000' to 12,000' laterals

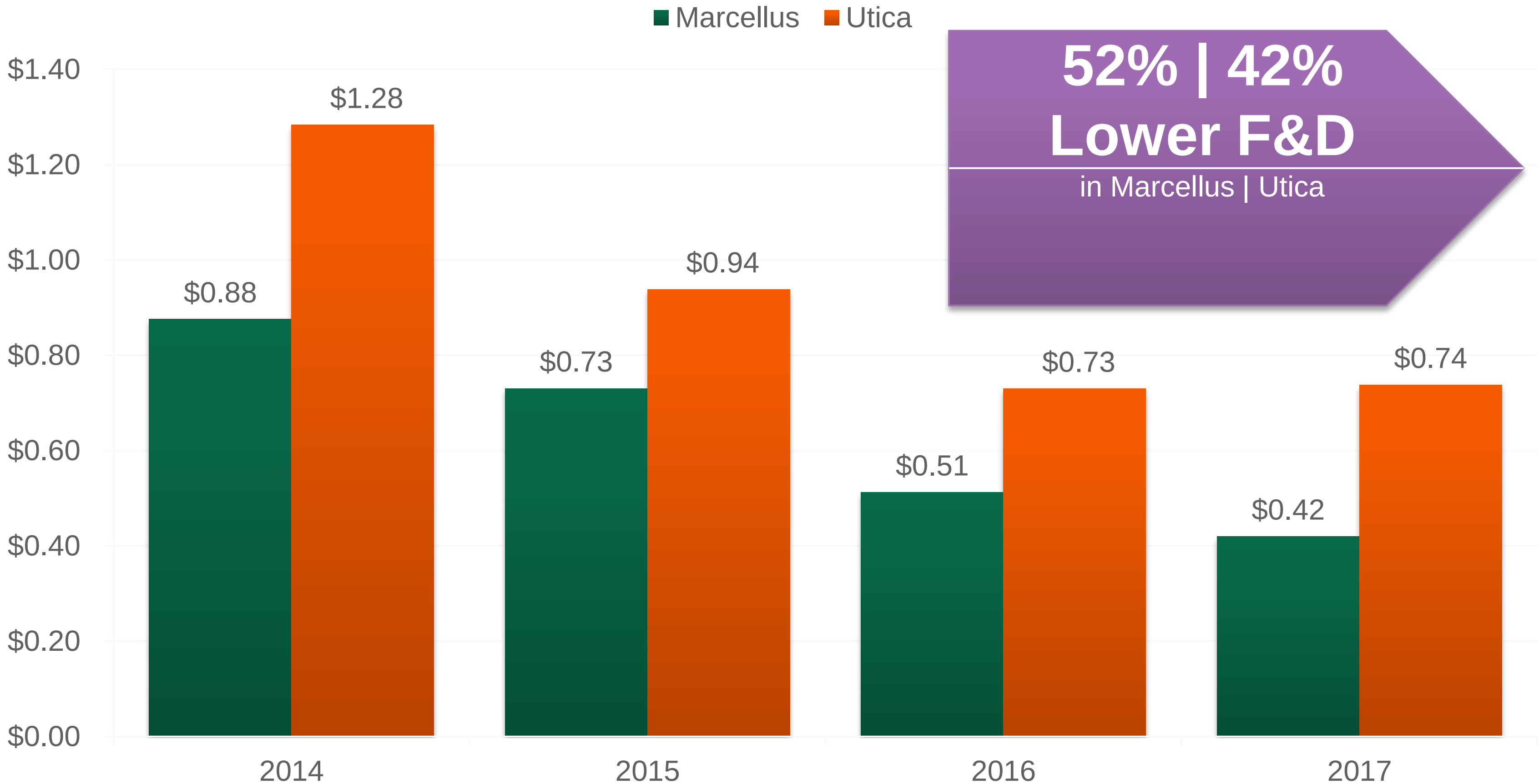
Historical Well Costs



Note: Well costs reflect 2,000 pound per foot completions. See Appendix for further assumptions.

Results in Dramatically Lower F&D Cost

F&D Cost per Mcfe(1)(2)



Dramatic Improvement in Operating Efficiencies, Lower Service Costs and Higher Well Recoveries Have Driven F&D Costs Materially Lower

(1) *Ethane rejection assumed.*
(2) *F&D cost is defined as current D&C cost per 1,000' lateral divided by net EUR per 1,000' lateral assuming 85% NRI in Marcellus and 81% NRI in Utica. Please see "Antero Definitions" and "Antero Non-GAAP Measures" in the Appendix.*

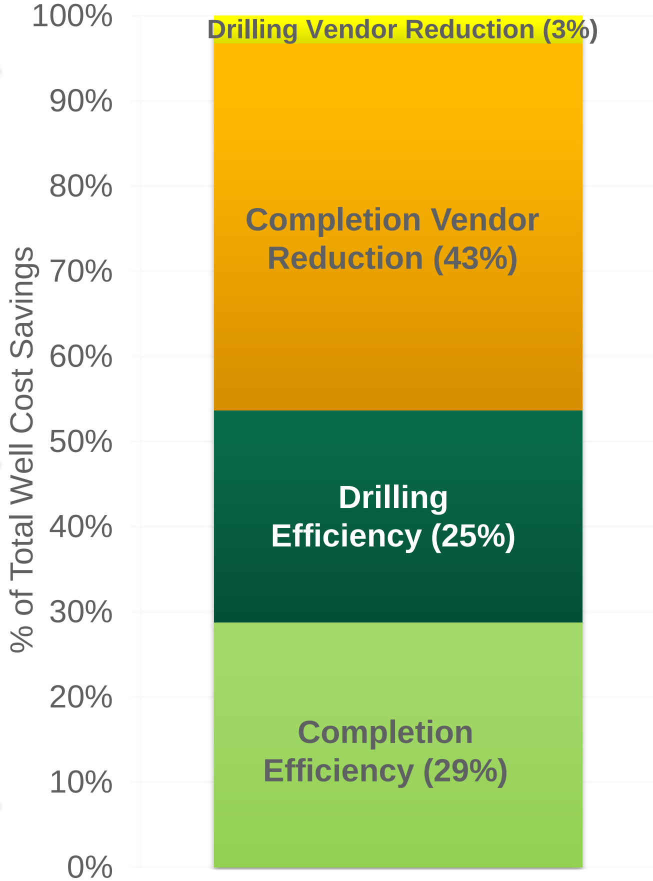
Operating Evolution Continues

42%
Decline in well costs since 2014

46%
Vendor-related cost reductions

54%
Permanent cost efficiencies

Total Well Cost Savings in the Marcellus(1)



Working Every Angle

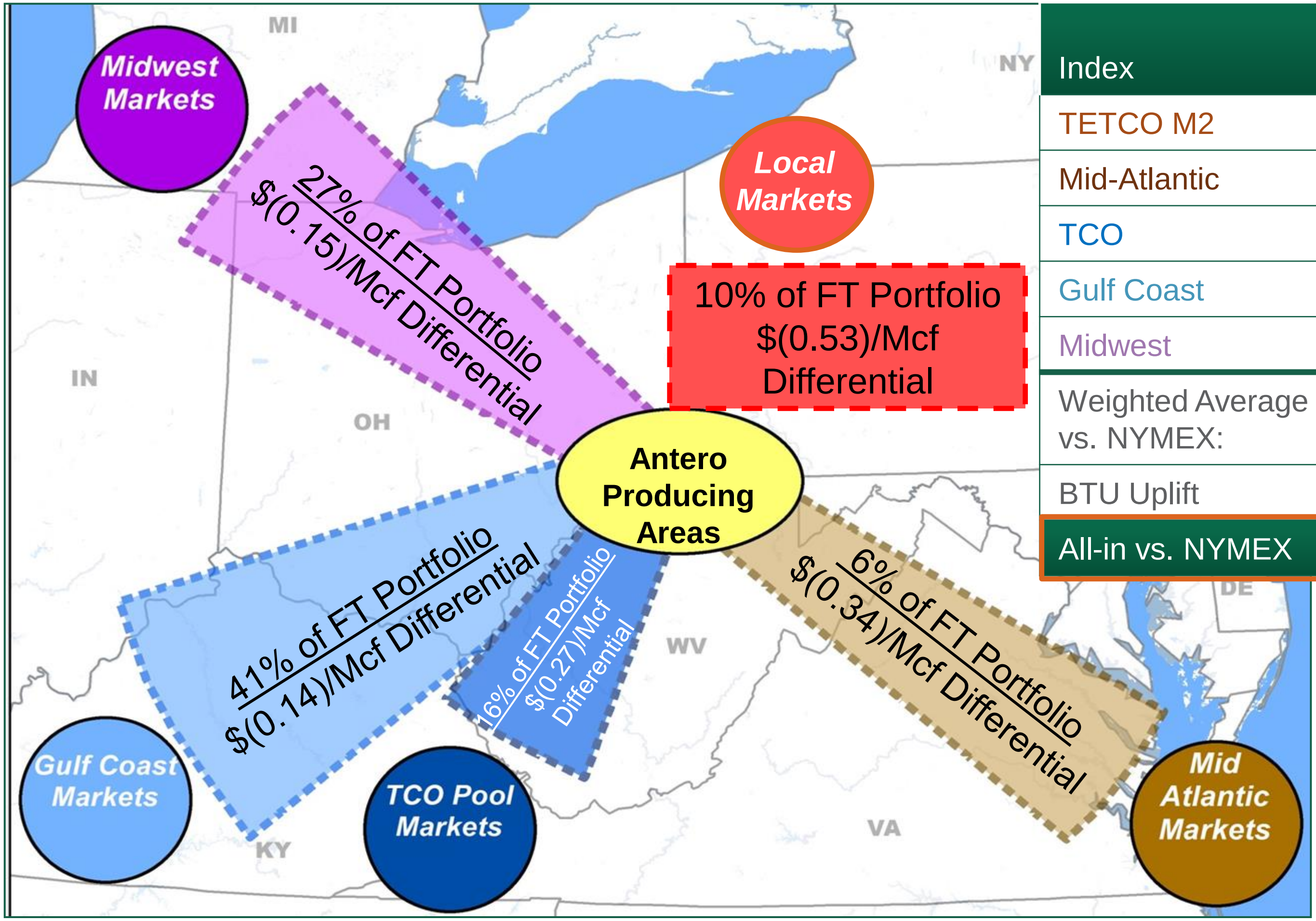
Next Steps in Efficiency Evolution

- **Fit-for-purpose rigs improves cycle times**
  - Enhanced walking and dual operation capabilities
- **Concurrent operations**
  - Larger pads allowing for production at one end and drilling at the other
  - More wells per pad
- **Automated completion equipment → increase stages per day**
- **Reduced cluster spacing → higher potential recoveries**
- **100 Mesh Sand → easier pumping with fewer screenouts and less cost**
- **Self-Sourcing Sand → reduce supply cost**
- **Improved Drillout Efficiency**

(1) *Based on Marcellus 9,000 foot lateral and 2,000 pounds per foot AFE.*

2018 Natural Gas Market Mix

Antero Firm Transportation Portfolio in 2018



Index	Differential	% of Gas Sold
TETCO M2	$(0.53)	10%
Mid-Atlantic	$(0.34)	6%
TCO	$(0.27)	16%
Gulf Coast	$(0.14)	41%
Midwest	$(0.13)	27%
Weighted Average vs. NYMEX:	$(0.21)	100%
BTU Uplift	$0.24	
All-in vs. NYMEX	+$0.03	

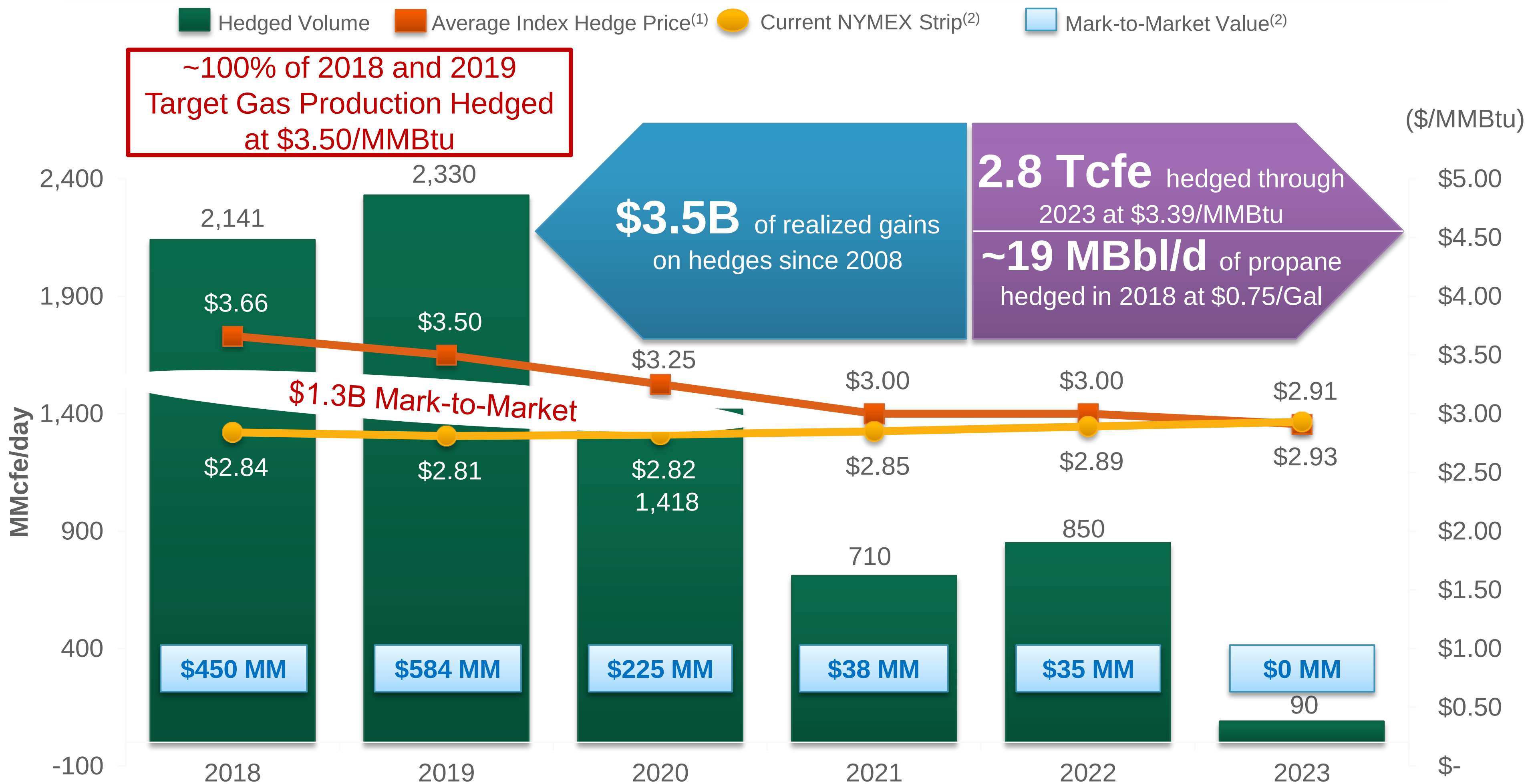
+$0.00 - $0.05
forecasted premium to NYMEX after BTU uplift

90% of Antero Gas Is Sold In Favorably Priced Markets

Note: Based on 2018 strip pricing as of 12/31/2017. See Appendix for further assumptions.

Well Hedged at High Prices Relative to Strip

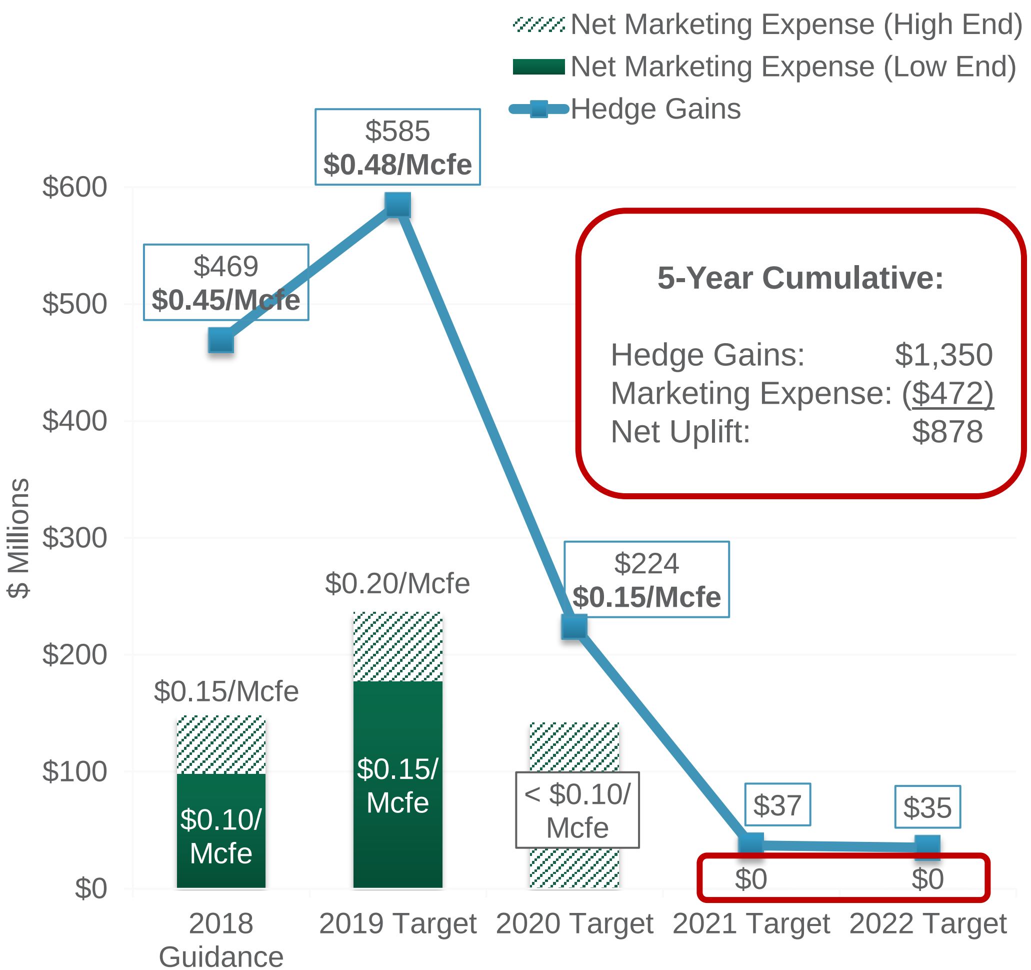
Commodity Hedge Position



~$1.3B Mark-To-Market Unrealized Gains Based On 12/31/2017 Prices

(1) Weighted average index price based on volumes hedged assuming 6:1 gas to liquids ratio. Includes 19,000 Bbl/d of propane hedged at $0.75/gallon and 4,000 Bbl/d of oil hedged at $55.97/Bbl for 2018 only.
(2) As of 12/31/17.

A Paired Trade – Hedges Support Firm Commitments



Hedge Portfolio Supports Firm Commitments

Firm Transportation Portfolio

Allows Antero to achieve:

Premium Price Certainty

Less volatility and greater surety in realized prices

Effectively Hedge NYMEX Index

A key advantage as our product is delivered to NYMEX-related markets

Hedge Gains More than Offset Marketing Expense – Hedges Support FT Commitments

Antero Profile Should Drive Multiple Expansion

	# of Companies	Median Debt/ Adjusted EBITDAX	Median EV/ 2018 Adj. EBITDAX
U.S. Publicly Traded E&Ps	51	3.1x	6.1x
Leverage < 3.0x ✓	24	1.5x	6.6x
Enterprise Value > $10B ✓	17	1.8x	7.2x
Production Growth >15% ✓	9	1.5x	9.1x
Leverage <2.0x ✓ in 2019	6	1.3x	9.8x
Free Cash Flow ✓ in 2018	6	1.3x	9.8x

AR 2018E EBITDAX Multiple: 4.6x

EOG FANG
CXO COG
PXD XEC

Permian & Appalachia

Premium for:

- Scale
- Growth
- Low Leverage
- FCF Generation

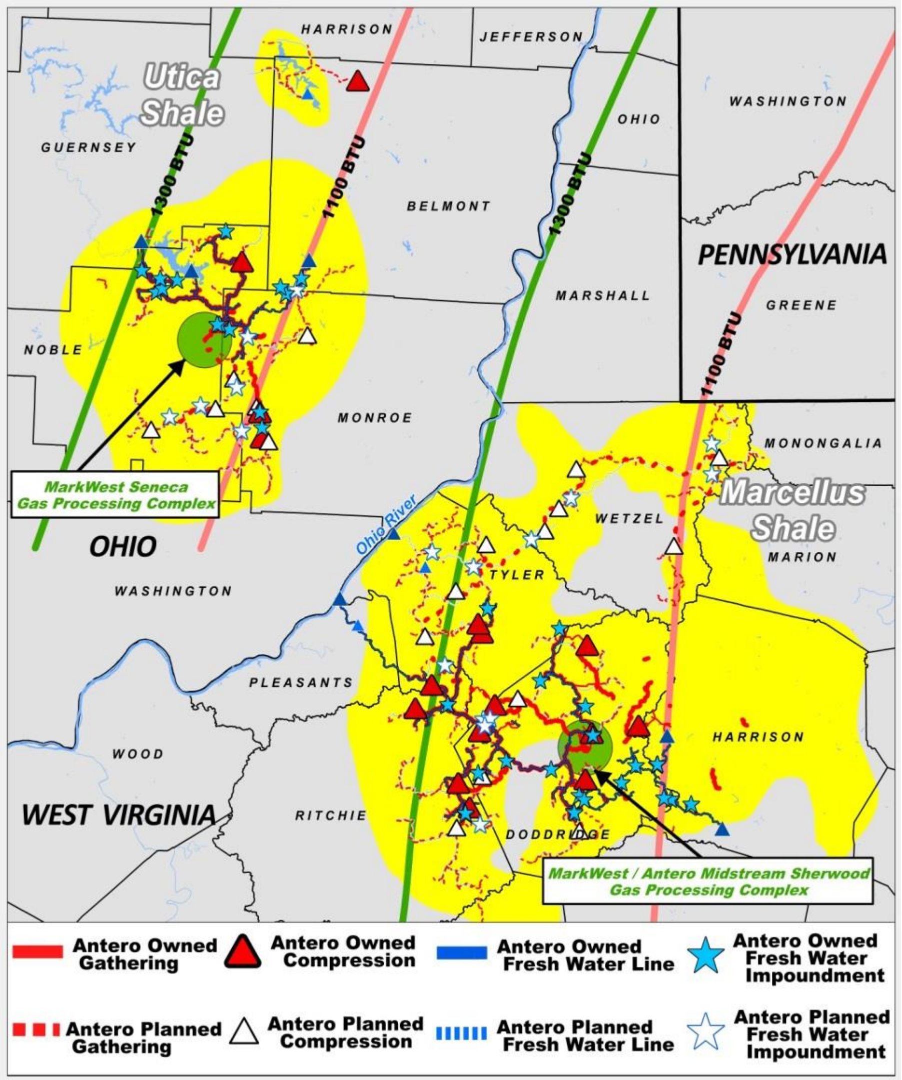
Joining an Elite Group of E&Ps With Scale, Double Digit Growth, Low Leverage & Free Cash Flow Generation

Source: Bloomberg & Antero Estimates as of 2/9/18.

(1) Adjusted EBITDAX and Adjusted Operating Cash Flow are non-GAAP measures. For additional information regarding these measures, please see "Antero Definitions" and "Antero Non-GAAP Measures" in the Appendix.

Antero Midstream At A Glance

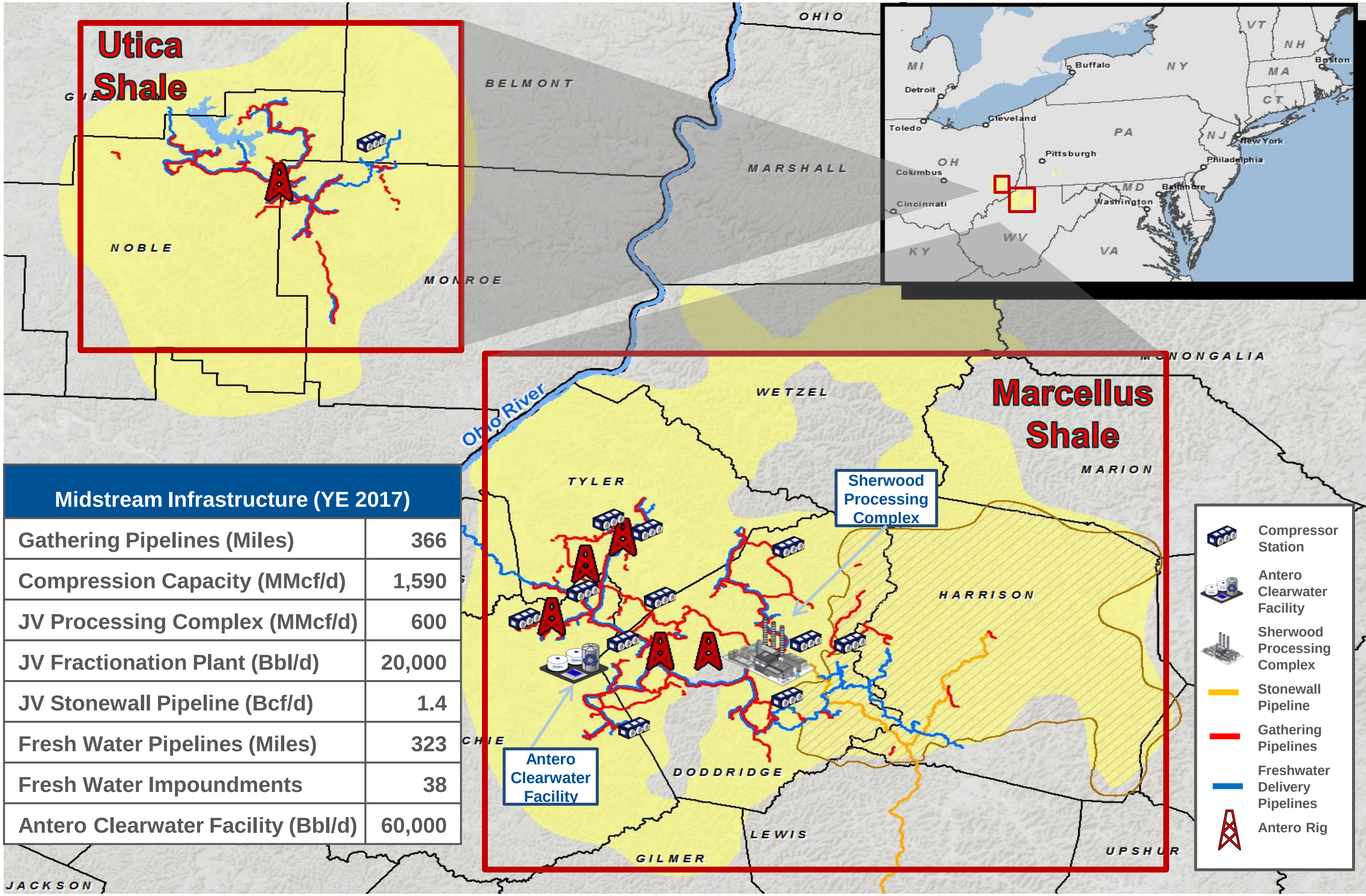
Market Cap…………………......	$5.2B
Enterprise Value….............…	$6.3B
LTM Adjusted EBITDA[(1)]……..	$513 MM
% Gathering/Compression	57%
% Water	43%
Net Debt/LTM EBITDA…….	2.1x
Corporate Debt Rating……….	Ba2 / BB+ /BBB-
Gross Dedicated Acres[(2)]…….	562,000



AM LISTED NYSE®

Note: Equity market data as of 2/9/2018. Balance sheet data as of 9/30/2017.

1. *LTM Adjusted EBITDA as of 9/30/17. Adjusted EBITDA is a non-GAAP measure. For additional information regarding this measure, please see "Antero Midstream Non-GAAP Measures" in the Appendix.*
2. *Represents acres dedicated for gathering and compression. Excludes 146,000 gross acres dedicated to third parties for gathering and compression services.*

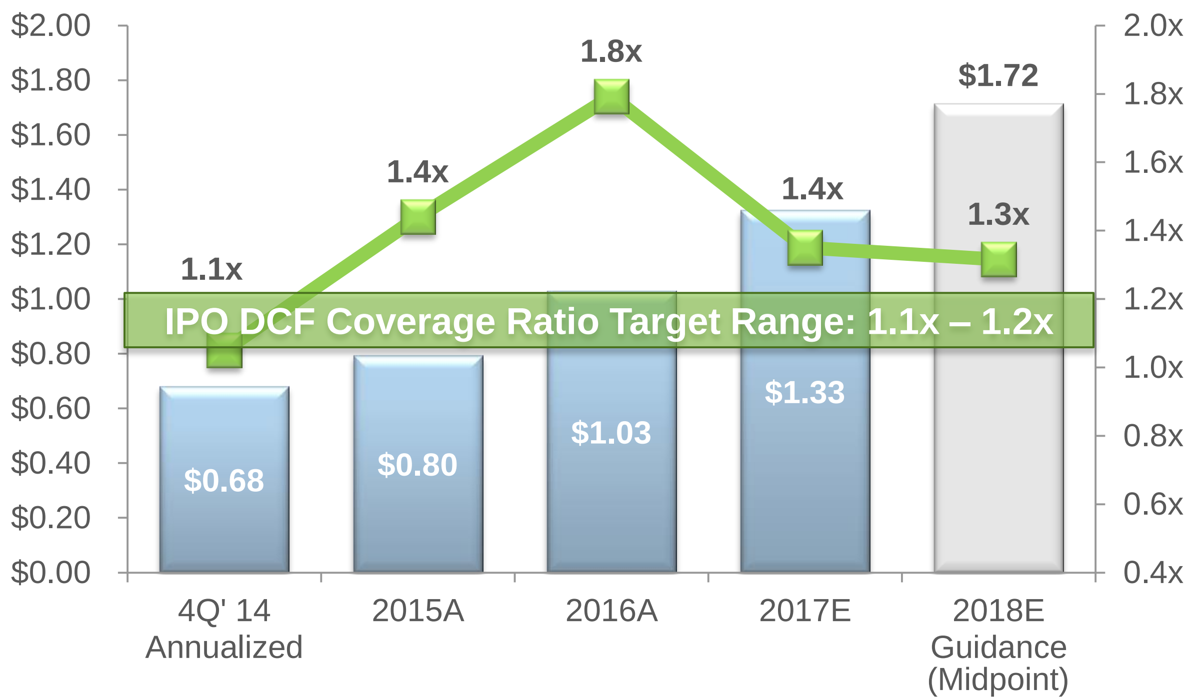


Midstream Infrastructure (YE 2017)	
Gathering Pipelines (Miles)	366
Compression Capacity (MMcf/d)	1,590
JV Processing Complex (MMcf/d)	600
JV Fractionation Plant (Bbl/d)	20,000
JV Stonewall Pipeline (Bcf/d)	1.4
Fresh Water Pipelines (Miles)	323
Fresh Water Impoundments	38
Antero Clearwater Facility (Bbl/d)	60,000

Delivering on November 2014 AM IPO Promise

Delivered on distribution growth through the downturn and exceeded DCF coverage targets at IPO by 22%

AM Distribution Per Unit and DCF Coverage



	IPO Year - 2014	2018 Guidance	
Distributable Cash Flow[(1)]:	$53 MM	$575 MM - $625 MM	+1,032%
Adjusted EBITDA[(1)]:	$67 MM	$705 MM - $755 MM	+990%

1. Adjusted EBITDA and Distributable Cash Flow are non-GAAP measures. For additional information regarding these measures, please see "Antero Midstream Non-GAAP Measures" in the Appendix.

5-year Organic Project Backlog Reduction

$500MM in Capital Efficiencies Reduce 5-Year Backlog to $2.7B with No Change in Throughput Targets

Midstream Capex Savings → **Optimized Capital** → **Higher EURs** → **Longer Laterals**

~$500MM
Capital Efficiencies
Captured From New AR Development Plan and AM infrastructure plan

Continued shift to Marcellus with higher recoveries

~$425MM
Optimized Capital Allocation

~$50MM
from Higher EURs

Fewer pads with unchanged throughput

~$25MM
from Lateral Lengths

Shorter pipeline mileage

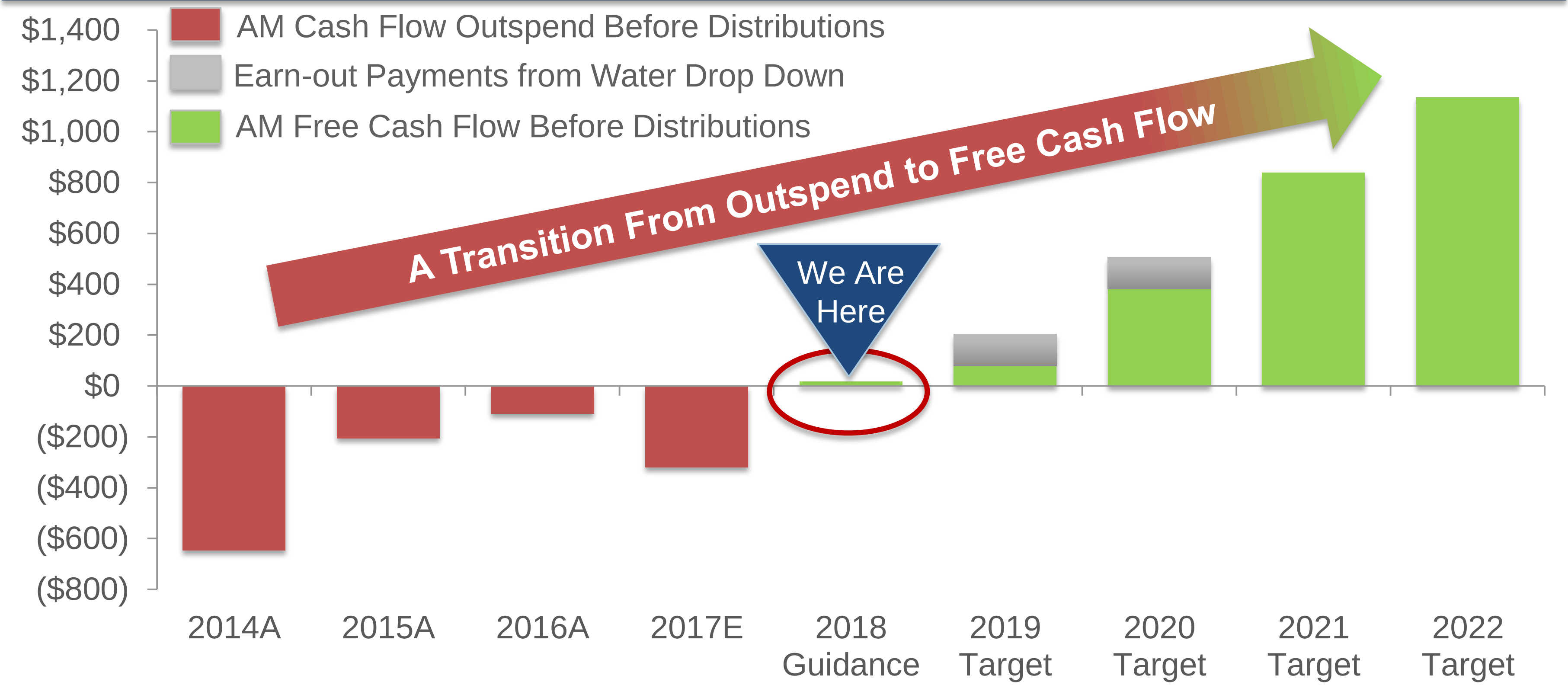
Capital Efficiency Drives Free Cash Flow Generation

Significant Investment in Gathering, Compression, Fresh Water

Significant Investment in Processing, Fractionation, Wastewater

Leverage existing asset base and realization of "full build-out EBITDA multiples"

Over $2.4 billion of Free Cash Flow from 2018 – 2022 Before Distributions



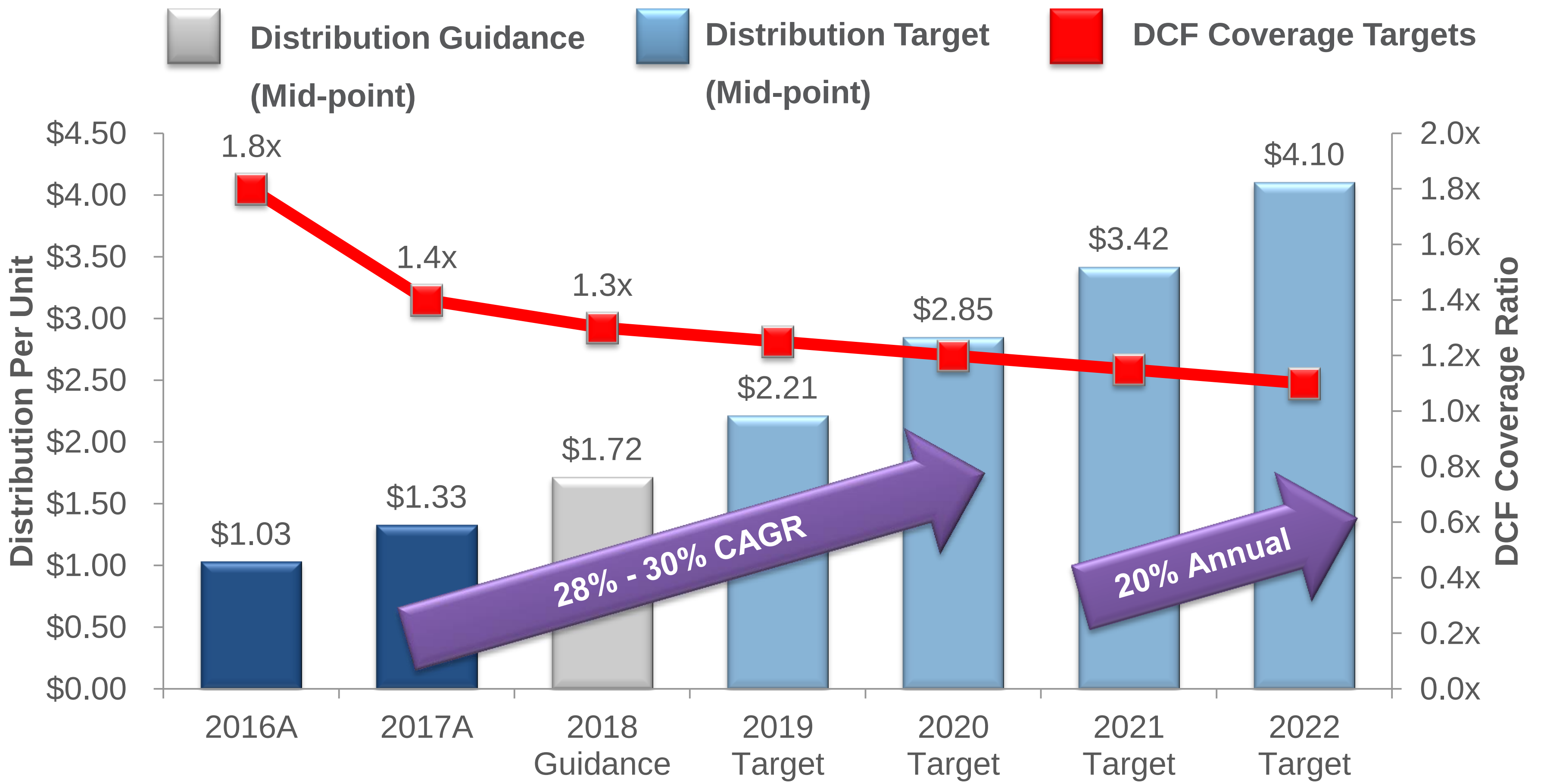
Note: Includes water earnings and capital invested on a recast basis prior to drop down and excludes drop down purchase price

Free Cash Flow is a non-GAAP measure. For additional information regarding this measure, please see "Antero Midstream Non-GAAP Measures" in the Appendix..

Long-Term Distribution and Coverage Targets

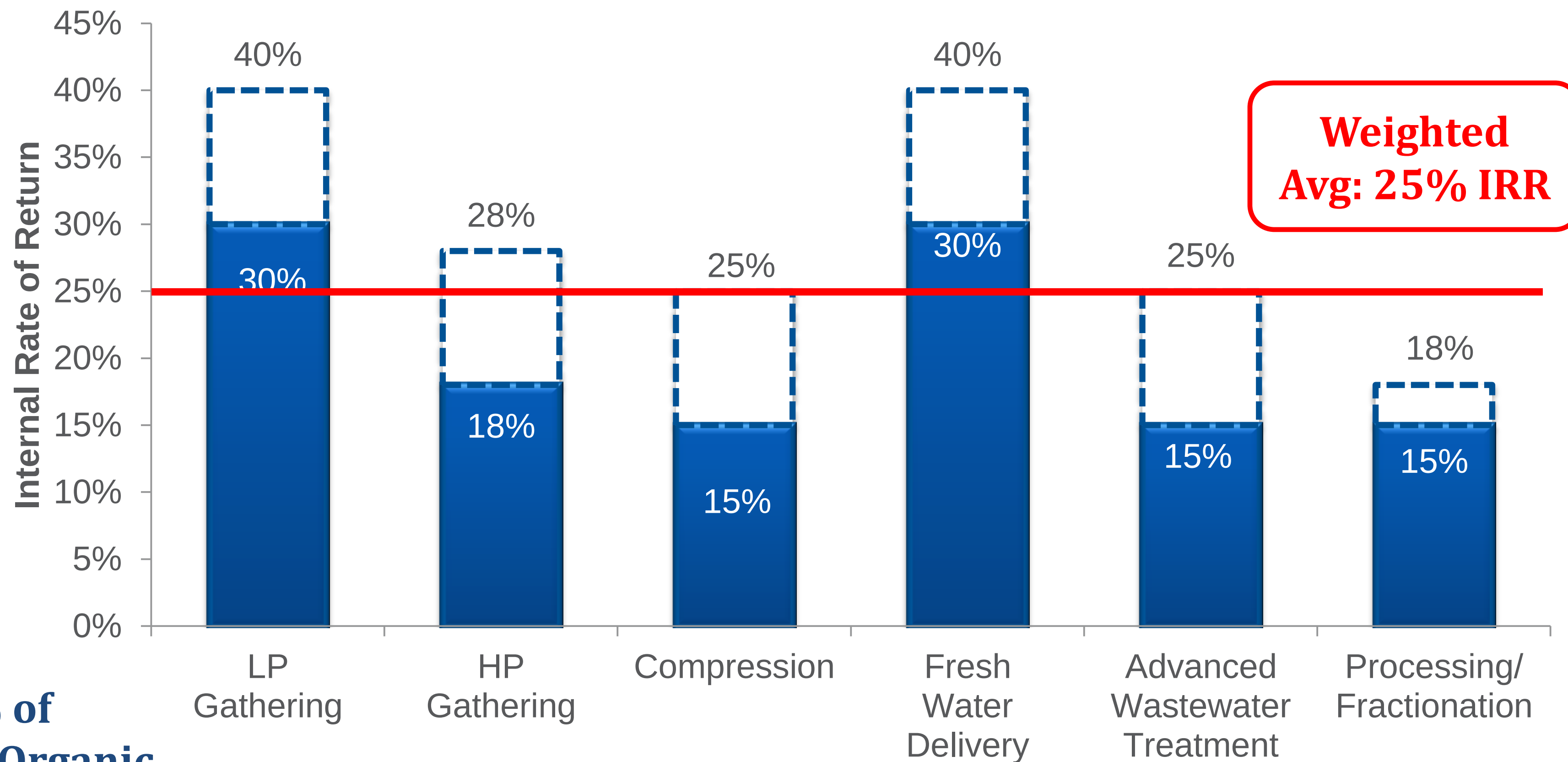
Unchanged capital investment philosophy with disciplined financial policies result in ability to target peer-leading distribution growth through 2022

Long-Term Distribution Targets and DCF Coverage



"Just-in-time" capital investment philosophy drives attractive project IRR's

AM Project Economics by Investment



% of 5-year Organic Project Backlog	LP Gathering	HP Gathering	Compression	Fresh Water Delivery	Advanced Wastewater Treatment	Processing/ Fractionation
	17%	12%	29%	12%	-	30%

Most Integrated Natural Gas & NGL Business in the U.S.

53% of LP Units

World Class E&P Operator in Appalachia

A Leading Northeast Infrastructure Platform

Contiguous Core Acreage Position Allows for Long Lateral Drilling and Significant Capital Efficiencies

Largest NGL Producer in the U.S. Leads to Peer Leading Cash Flow Margins

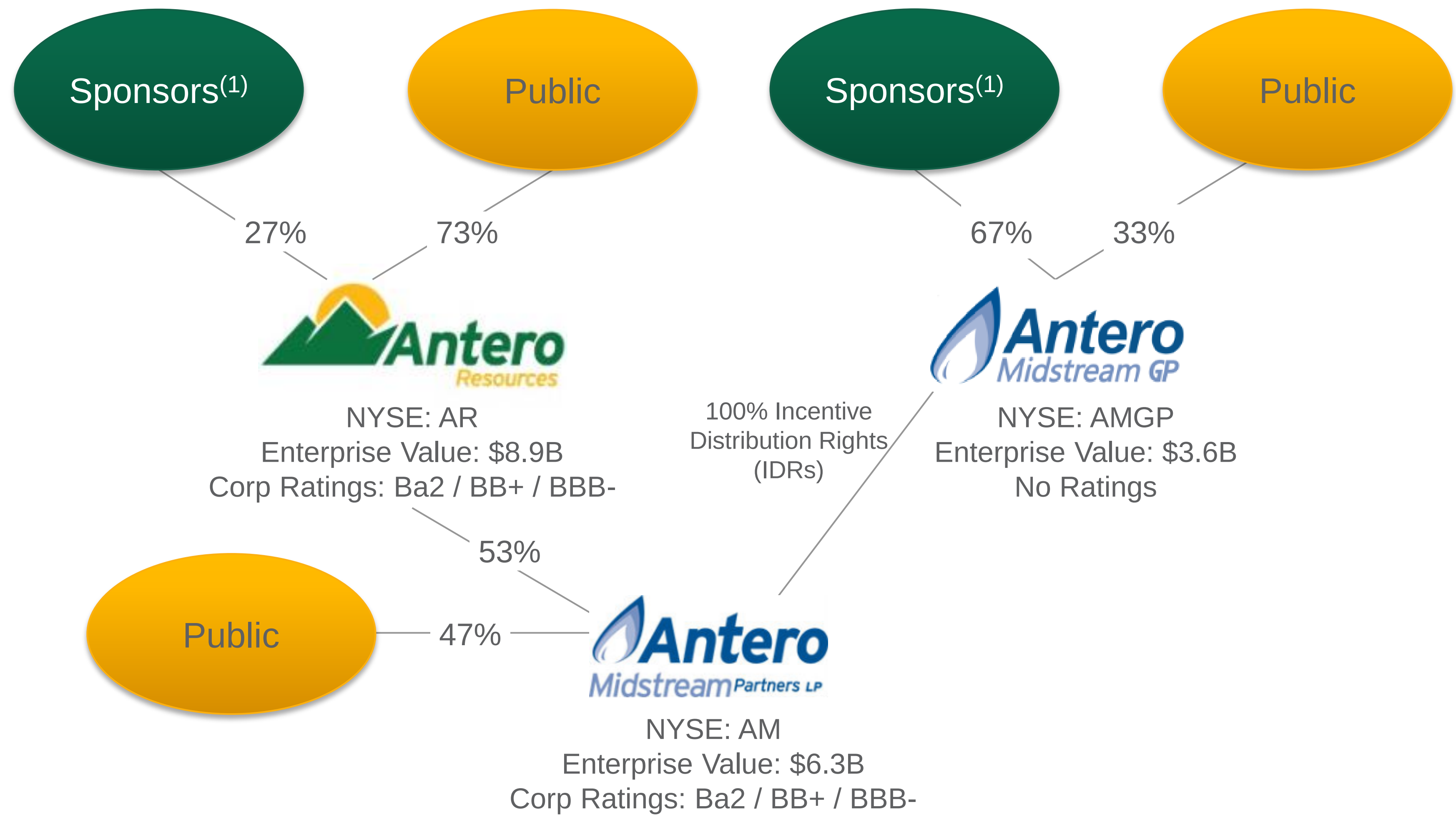
Optimized 5-Year Plan Results in High Return Drilling & Free Cash Flow

Midstream Ownership & Integration Delivers Value and Just-in-Time Infrastructure Buildout

Appendix

Organizational Structure

A $16B Family Valuation



Note: Enterprise value as of 02/09/18.
(1) Sponsors represent Warburg Pincus, Yorktown & senior management.

2018 Guidance

	Stand-Alone E&P	Consolidated
Net Daily Production (Bcfe/d)	~2.7	
Net Liquids Production (BBl/d)	~130,000	
Natural Gas Realized Price Differential to Nymex	$0.00 to $0.05 Premium	
C3+ NGL Realized Price *(% of Nymex WTI)*	62.5% – 67.5%	
Cash Production Expense ($/Mcfe)	$2.10 – $2.20	$1.65 – $1.75
Marketing Expense ($/Mcfe) (10% Mitigation Assumed)	$0.10 – $0.15	
G&A Expense ($/Mcfe) *(before equity-based compensation)*	$0.125 – $0.175	$0.15 - $0.20
Adjusted EBITDAX	$1,700 – $1,800	$2,050 – $2,150
Adjusted Operating Cash Flow	$1,480 – $1,600	$1,750 – $1,900
Net Debt / LTM Adjusted EBITDAX	Low 2x	Mid 2x
D&C Capital Expenditures ($MM)	$1,500	$1,300
Land Capital Expenditures ($MM)	$150 ($25MM Maintenance)	$150 ($25MM Maintenance)

Note: See Appendix for key definitions.
(1) Includes lease operating expense, gathering, compression, processing and transportation expense and production and ad valorem taxes.

Antero Long-Term Target Project Assumptions

	In-Service Date
Rover Phase 2	2Q 2018 (April 1)
Mariner East 2	2Q 2018
WB Xpress West	4Q 2018
WB Xpress East	4Q 2018
Mountaineer Xpress / Gulf Xpress	YE 2018

Note: Based on publicly available information.

Antero Guidance and Long-Term Target Assumptions

	Stand-Alone E&P	Consolidated
Net Daily Production (MMcfe/d)	20% CAGR through 2020 and 15% Growth in each of 2021 and 2022	
Natural Gas Realized Price Differential to Nymex	$0.00 to $0.05 Premium (2018) $0.00 to $0.10 Premium (2019 – 2022)	
C3+ NGL Realized Price *(% of Nymex WTI)*	62.5% – 67.5% (2018) 72% (2019+) – ME2 Fees Booked to Transport Costs	
Realized Oil Price Differential to WTI	($5.00) – ($6.00)	
Cash Production Expense ($/Mcfe)(1)	$2.10 - $2.20 (2018) $2.10 – $2.25 (2019 – 2022)	$1.65 - $1.75 (2018) $1.65 – $1.75 (2019 – 2022)
Marketing Expense ($/Mcfe)	$0.10 - $0.15 (2018) $0.15 – $0.20 (2019) <$0.10 (2020) $0.00 (2021 – 2022)	
G&A Expense ($/Mcfe) *(before equity-based compensation)*	$0.125 – $0.175 (2018 – 2019) $0.10 – $0.15 (2020 – 2022)	$0.15 - $0.20 (2018 – 2019) $0.10 – $0.15 (2020 – 2022)
Cash Interest Expense ($/Mcfe)	$0.175 – $0.225 (2018 – 2019) $0.10 – $0.15 (2020 – 2021) <$0.10 (2022)	$0.25 – $0.30 (2018 – 2019) $0.20 – $0.25 (2020 – 2022)
Well Costs ($MM / 1,000') (Assumes 12,000' completions at 2,000 lbs. per foot of proppant)	Marcellus: $0.95 MM Utica: $1.07 MM	Marcellus: $0.80 MM Utica: $0.95 MM

(1) Includes lease operating expense, gathering, compression, processing and transportation expense and production and ad valorem taxes.

Antero Guidance and Long-Term Target Assumptions (Cont.)

	Stand-Alone E&P	Consolidated
Adjusted Operating Cash Flow(1)	$10.4B (Cumulative 2018 – 2022)	N/A
Annual D&C Capital Expenditures ($MM)	$1,500 – $1,600 (2018 – 2020) $1,700 – $2,000 (2021 – 2022)	$1,300 – $1,400 (2018 – 2021) $1,600 – $1,700 (2022)
Land Maintenance Expenditures ($MM)(2)	~$200 (Cumulative 2018 – 2022)	
Free Cash Flow(1)	$1.6B (Cumulative 2018 – 2022)	N/A
Leasehold Growth Capital Expenditures ($MM)	~$300 (Cumulative 2018 – 2022)	
Number of Well Completions	790 well completions	
Marcellus EUR per 1,000' of Lateral	2.0 Bcf/1,000'; 2.5 Bcfe/1,000' (25% ethane recovery)	
Utica EUR per 1,000' of Lateral	2.0 Bcfe/1,000' (ethane rejection)	

Note: See Appendix for key definitions.

(1) Adjusted Operating Cash Flow and Free Cash Flow are non-GAAP financial measures. For additional information regarding these measures, please see the following pages ("Antero Definitions" and "Antero Non-GAAP Measures").

(2) Includes leasehold capital expenditures required to achieve targeted working interest percentage.

Guidance Summary - 2018

Guidance	2017 Guidance	2018 Guidance	Change
Net Income ($MM)	$305 - $345	$435 - $480	+41%
Adjusted EBITDA ($MM)	$520 - $560	$705 - $755	+35%
DCF ($MM)	$405 - $445	$575 - $625	+41%
Distribution Growth	28 – 30%	28 – 30%	-
DCF Coverage	1.30x – 1.45x	1.25x - 1.35x	-7%
Maintenance Capex ($MM)	$65	$65	0%
Growth Capex ($MM)	$735	$585	-20%
Total Capex ($MM)	$800	$650	-19%

Adjusted EBITDA and Distributable Cash Flow are non-GAAP measures. For additional information regarding these measures, please see "Antero Midstream Non-GAAP Measures" in the Appendix.

2018 Product Revenue Buildup

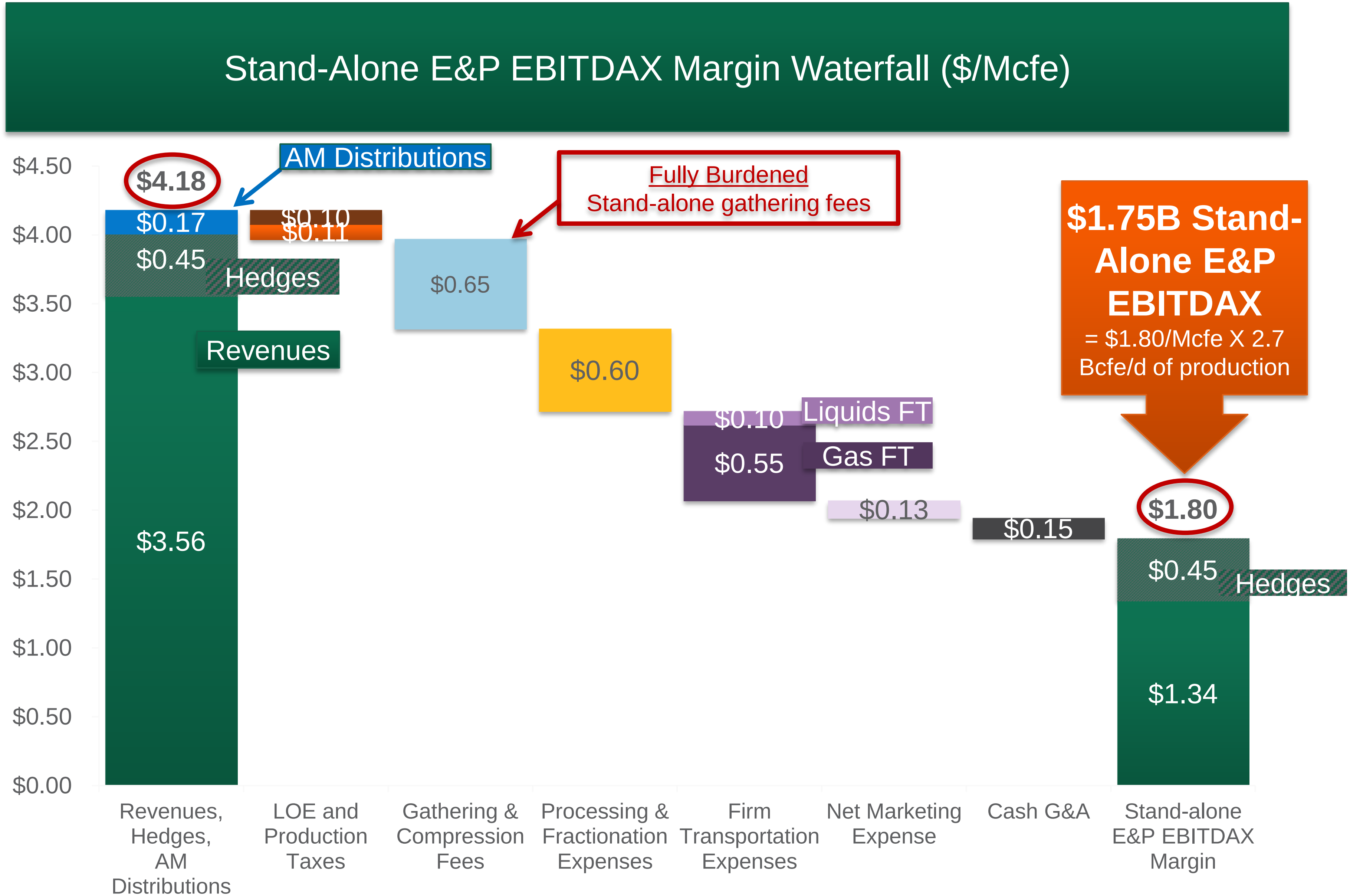
38%
Liquids as a Percent of Total Volume

$1.5B
Liquids Revenue

43% | 38%
Pre- | Post- Hedge Liquids as Percent of Revenue

	Product	Volumes (Guidance)	Realized Price	Revenues	% of Total Revenue
Natural Gas	GAS	1,925 MMcf/d	$2.85/Mcf	$2.0B	52%
NGLs	C2	44 MBbl/d	$10/Bbl	$0.2B	5%
	C3+	77.5 MBbl/d	$39/Bbl	$1.1B	28%
Crude		9.5 MBbl/d	$54/Bbl	$0.2B	5%
Hedges	$	N/A	$0.45/Mcfe	$0.4B	10%
		2,700 MMcfe/d	**$4.00/Mcfe**	**$3.9B**	**100%**

Note: See Appendix for key assumptions

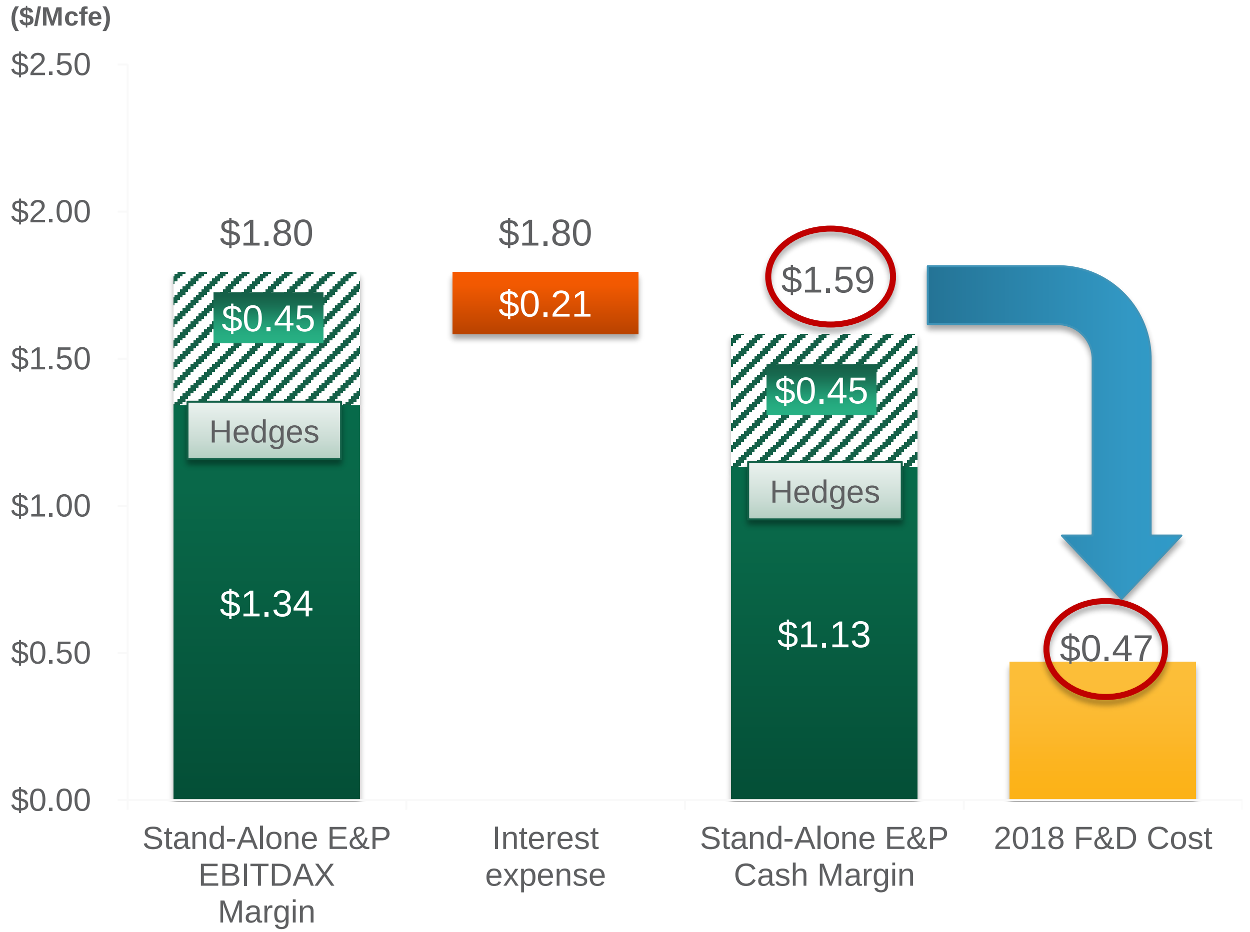

Stand-Alone E&P EBITDAX Margin Waterfall ($/Mcfe)
$4.50
$4.00
$3.50
$3.00
$2.50
$2.00
$1.50
$1.00
$0.50
$0.00
$4.18
AM Distributions
$0.17
$0.45
Hedges
Revenues
$3.56
$0.10
$0.11
Fully Burdened
Stand-alone gathering fees
$0.65
$0.60
$0.10
Liquids FT
$0.55
Gas FT
$0.13
$0.15
$1.75B Stand-Alone E&P EBITDAX
= $1.80/Mcfe X 2.7 Bcfe/d of production
$1.80
$0.45
Hedges
$1.34
Revenues, Hedges, AM Distributions
LOE and Production Taxes
Gathering & Compression Fees
Processing & Fractionation Expenses
Firm Transportation Expenses
Net Marketing Expense
Cash G&A
Stand-alone E&P EBITDAX Margin

Attractive 2018 E&P Margins and Recycle Ratio

3.4x
Recycle Ratio(1)

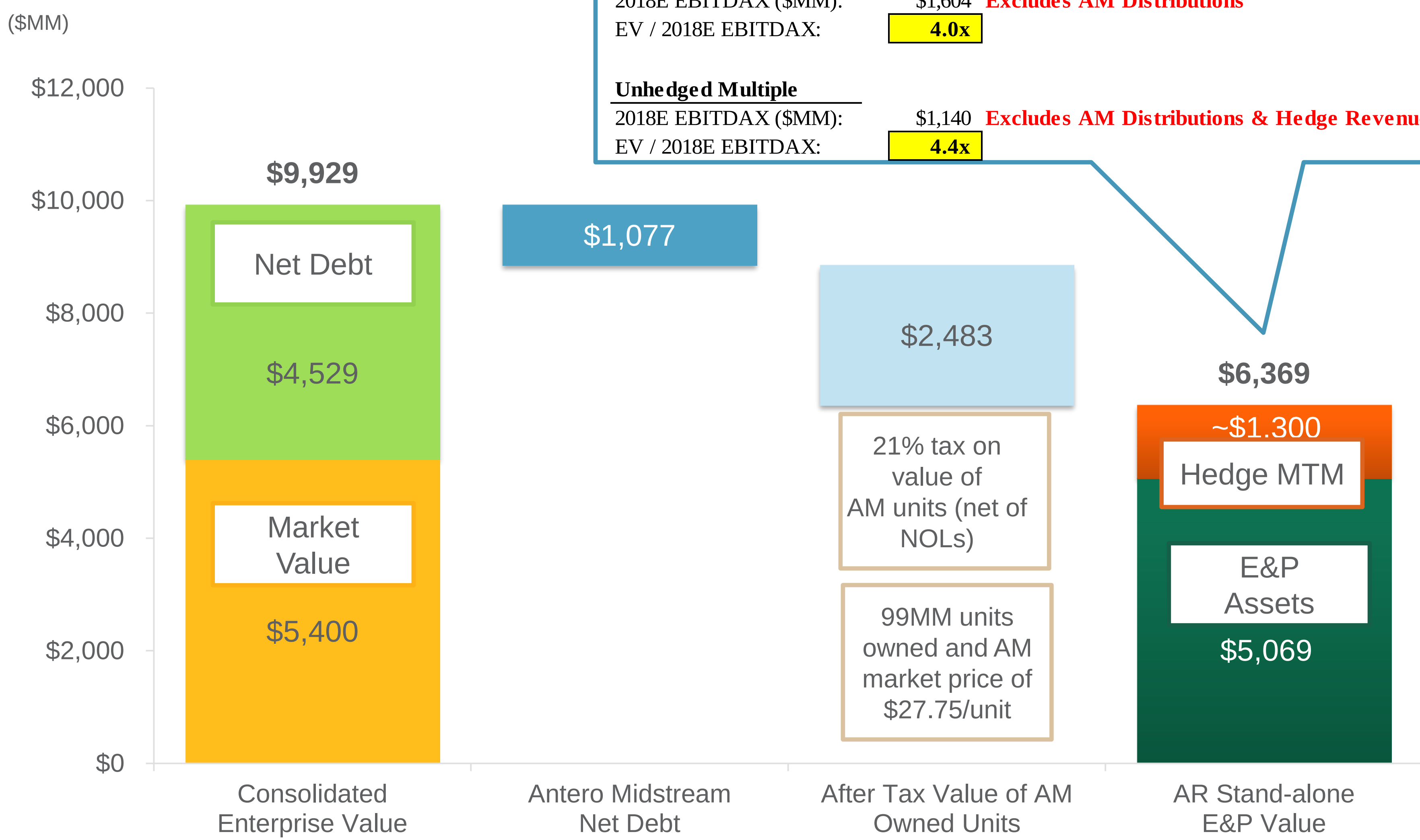
2.7x Unhedged
Recycle Ratio(1)

Antero Fully Burdened Stand-Alone E&P Cash Margins ($/Mcfe)



Note: Assumes $0.17/Mcfe in distributions from AM. Based on EURs from Antero 2018 development program.
(1) Represents stand-alone, fully burdened E&P basis, based on 2018 development program. Unhedged recycle ratio excludes net marketing expense of $0.125.

Antero Consolidated and Stand-Alone Enterprise Value

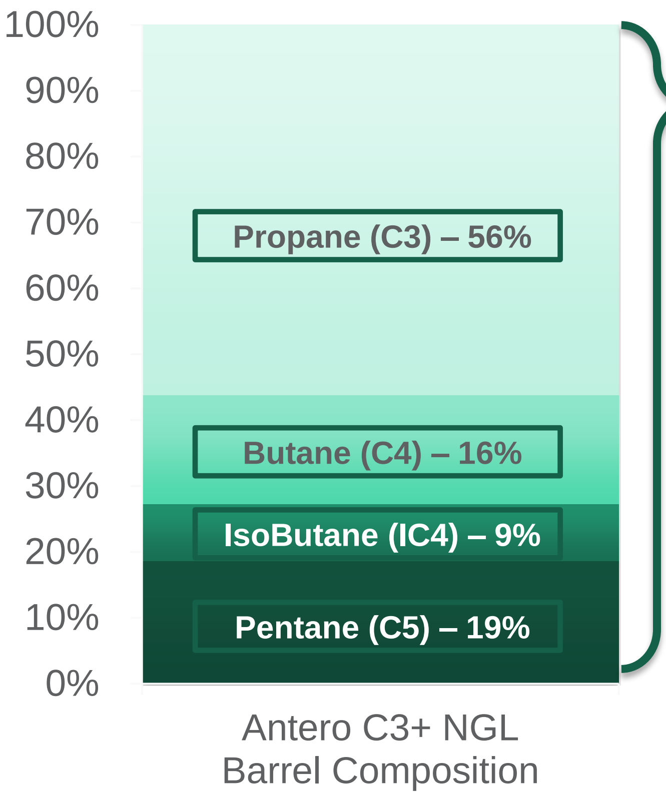


Hedged Multiple		
2018E EBITDAX ($MM):	$1,604	Excludes AM Distributions
EV / 2018E EBITDAX:	4.0x	
Unhedged Multiple		
2018E EBITDAX ($MM):	$1,140	Excludes AM Distributions & Hedge Revenues
EV / 2018E EBITDAX:	4.4x	

Note: Data as of 9/30/17, except AM unit price as of 2/9/18 and hedge mark-to-market as of 12/31/17.

2018 C3+ NGL Pricing & Market Mix

Antero 2018 C3+ NGL Production Netbacks



Weighted Average C3+ $/Bbl	Pre-ME2	Post-ME2
Realized Pricing Location	Houston, PA	Marcus Hook Dock
Mont Belvieu Price(1)	$41.00	$41.00
Differential/Uplift Net of Cost(2)	$(5.50)	+$2.00
Antero Realized C3+ Price	$35.50	$43.00
% of WTI	60%	72%
2018 Weighted Average	62.5% - 67.5% of WTI	
2018 Weighted Average	~$39/Barrel	

Antero projects C3+ NGL price to be ~62.5% to 67.5% of WTI in 2018

Note: Based on 2018 strip pricing as of 12/31/17.
(1) Based on weighted average Antero C3+ NGL barrel composition times individual purity product price.
(2) Uplift assumes strip NGL pricing for Northwest Europe and Far East Index before ME2 fees, which will be included in the GPT expense item.

Significant Value Derived from Midstream Ownership

Antero Midstream Targeted Distributions to Antero Resources

Note: Represents distribution growth targets for AR owned units through 2022. As of 9/30/17, AR owns 98.9 million AM units.

D&C Capital Math

($MM)

	2018	2019	2020
Total Well Completions (I.e. First Sales)	145	155	160
Average Lateral	9,700	10,500	11,600
Adjusted Well Count (I.e. Based on Capital Timing)	155	157	150
Average Lateral	9,700	10,500	11,600
Total Adjusted Lateral Feet	1,503,500	1,648,500	1,740,000
Cost per Lateral Foot ($MM/1,000) - Lateral Savings ONLY [1]	$0.86	$0.83	$0.81
Implied D&C	$1,293	$1,368	$1,409
Savings from Concurrent Ops. / Increasing Stages per Day		($24)	($79)
Adjusted Capital Cost	**$1,293**	**$1,344**	**$1,330**
Implied Cost per Lateral Foot ($MM/1,000)	*$0.86*	*$0.82*	*$0.76*

(1) *Based on Marcellus AFE, which assumes inflation on consumable products (i.e. sand/chemicals).*

Antero Assumptions: Single Well Economics

SWE Cost Type	Description of Cost	Half Cycle	Full Cycle
Well Costs	• Drilling and completion costs • Assumes well costs for a 12,000' lateral, 2,000 lbs of proppant per lateral foot and both fresh and flowback water • Utica Condensate regime assumes 1,500 lbs or proppant per lateral foot	Marcellus: $10.6MM Utica South/Dry: $12.2MM Utica Beaver: $11.5MM (60% AM water fees)	Marcellus: $11.4MM Utica South/Dry: $12.8MM Utica Beaver: $12.2MM (100% AM water fees)
Working Interest / Net Royalty Interest	• Reflects Antero's average WI/NRI in the respective plays	Marcellus: 100% / 85% Utica: 100% / 81%	
Midstream Gathering Fees	• Midstream low pressure, high pressure and compression fees	60% of AM gathering fees	100% of AM gathering fees
Firm Transportation[1]	• FT costs may include both demand and variable fees associated with expected production	Variable FT costs only of $0.06/Mcf (variable fees associated with expected production)	Fully utilized FT costs of $0.54/Mcf (including both demand and variable fees)
General & Administrative Costs	• General and administrative costs associated with Antero	None	$750,000 per well
Land	• Assumes 12,000' well with 660'/1,000' spacing for Marcellus/Utica respectively and $3,600 per acre	None	Marcellus - $655,000 per well Utica - $1,087,000 per well
Spud to FP Timing	• Provides a timeframe for initial spud to first production	184 days spud to FP	
Realized Pricing	• Commodity price assumptions	12/31 strip pricing (weighted)	

(1) SWEs exclude marketing expenses and related commodity hedge contracts that support Antero's firm transportation portfolio

Single Well Economics: Marcellus – In Ethane Rejection

Classification	Highly-Rich Gas/Condensate	Highly-Rich Gas	Rich Gas	Dry Gas
Modeled BTU	1313	1250	1150	1050
EUR (Bcfe):	32	29	26	24
EUR (MMBoe):	5.3	4.9	4.3	3.9
% Liquids:	33%	24%	11%	0%
Well Cost ($MM):	10.6	10.6	10.6	10.6
Bcfe/1,000’:	2.7	2.5	2.2	2.0
Net F&D ($/Mcfe)(1):	$0.40	$0.43	$0.49	$0.53
Net Direct Operating Expense ($/Mcfe):	$1.26	$1.33	$1.39	$1.05
Transportation Expense ($/Mcfe):	$0.04	$0.05	$0.06	$0.06
Pre-Tax NPV10 ($MM):	25.5	15.9	6.9	4.7
Pre-Tax Half Cycle ROR:	168%	74%	30%	23%
Payout (Years):	1.1	1.7	3.1	4.0
Gross Core Locations in BTU Regime:	447	935	495	874

Cumulative Volumes	Highly-Rich Gas/Condensate		Highly-Rich Gas		Rich Gas		Dry Gas	
	Gas (Mmcf)	Oil (Mbbl)	Gas (Mmcf)	Oil (Mbbl)	Gas (Mmcf)	Oil (Mbbl)	Gas (Mmcf)	Oil (Mbbl)
Year 1	4,300	116	4,300	24	4,300	0	4,300	0
Year 2	6,500	143	6,500	31	6,500	0	6,500	0
Year 3	7,900	152	7,900	36	7,900	0	7,900	0
Year 4	9,100	157	9,100	40	9,100	0	9,100	0
Year 5	10,200	161	10,200	44	10,200	0	10,200	0
Year 10	13,900	176	13,900	57	13,900	0	13,900	0
Year 20	18,500	194	18,500	73	18,500	0	18,500	0

Note: SWE cost assumptions reflect average costs per Mcfe on the first five years of the life of a well.
F&D cost is defined as current D&C cost per 1,000’ lateral divided by net EUR per 1,000’ lateral assuming 85% NRI in Marcellus. Please see “Antero Definitions” and “Antero Non-GAAP Measures” in the Appendix.

Classification	Condensate	Highly-Rich Gas/ Condensate	Highly-Rich Gas	Rich Gas	Dry Gas
Modeled BTU	1275	1235	1215	1175	1050
EUR (Bcfe):	13	25	29	28	26
EUR (MMBoe):	2.2	4.2	4.8	4.6	4.4
% Liquids	40%	30%	21%	16%	0%
Well Cost ($MM):	10.8	11.5	12.2	12.2	12.2
Bcfe/1,000':	1.1	2.1	2.4	2.3	2.2
Net F&D ($/Mcfe)(1):	1.03	0.57	0.53	0.55	0.57
Net Direct Operating Expense ($/Mcfe):	1.18	1.32	1.44	1.47	0.85
Transportation Expense ($/Mcfe):	$0.04	$0.05	$0.05	$0.06	$0.07
Pre-Tax NPV10 ($MM):	7.5	16.3	11.8	8.3	9.6
Pre-Tax Half Cycle ROR:	45%	121%	54%	37%	38%
Payout (Years):	1.9	1.0	1.8	2.3	2.4
Gross 3P Locations in BTU Regime:	187	102	22	27	206

Cumulative Volumes	Condensate		Highly-Rich Gas/ Condensate		Highly-Rich Gas		Rich Gas		Dry Gas	
	Gas (Mmcf)	Oil (Bbl)	Gas (Mmcf)	Oil (Bbl)	Gas (Mmcf)	Oil (Bbl)	Gas (Mmcf)	Oil (Bbl)	Gas (Mmcf)	Oil (Bbl)
Year 1	1,600	129	4,300	110	5,600	6	5,400	0	5,500	0
Year 2	2,300	153	5,800	127	7,700	8	7,500	0	8,200	0
Year 3	2,800	166	6,900	138	9,100	9	8,800	0	10,000	0
Year 4	3,300	176	7,700	146	10,200	10	9,900	0	11,400	0
Year 5	3,600	186	8,400	152	11,100	11	10,800	0	12,500	0
Year 10	5,000	219	10,900	175	14,500	14	14,100	0	16,500	0
Year 20	6,700	258	14,000	202	18,700	19	18,200	0	21,200	0

Note: SWE cost assumptions reflect average costs per Mcfe on the first five years of the life of a well.
F&D cost is defined as current D&C cost per 1,000' lateral divided by net EUR per 1,000' lateral assuming 81% NRI in Utica. Please see "Antero Definitions" and "Antero Non-GAAP Measures" in the Appendix.

Antero Non-GAAP Measures

Consolidated Adjusted EBITDAX, Stand-alone E&P Adjusted EBITDAX, Consolidated Adjusted Operating Cash Flow, Stand-alone E&P Adjusted Operating Cash Flow and Free Cash Flow are financial measures that are not calculated in accordance with U.S. generally accepted accounting principles ("GAAP"). The non-GAAP financial measures used by the company may not be comparable to similarly titled measures utilized by other companies. These measures should not be considered in isolation or as substitutes for their nearest GAAP measures. The Stand-alone measures are presented to isolate the results of the operations of Antero apart from the performance of Antero Midstream, which is otherwise consolidated into the results of Antero.

Consolidated Adjusted EBITDAX and Stand-alone E&P Adjusted EBITDAX

The GAAP financial measure nearest to Consolidated Adjusted EBITDAX is net income or loss including noncontrolling interest that will be reported in Antero's consolidated financial statements. The GAAP financial measure nearest to Stand-alone E&P Adjusted EBITDAX is Stand-alone net income or loss that will be reported in the Parent column of Antero's guarantor footnote to its financial statements. While there are limitations associated with the use of Consolidated Adjusted EBITDAX and Stand-alone E&P Adjusted EBITDAX described below, management believes that these measures are useful to an investor in evaluating the company's financial performance because these measures:

- are widely used by investors in the oil and gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate and compare the results of Antero's operations (both on a consolidated and Stand-alone basis) from period to period by removing the effect of its capital structure from its operating structure; and
- is used by management for various purposes, including as a measure of Antero's operating performance (both on a consolidated and Stand-alone basis), in presentations to the company's board of directors, and as a basis for strategic planning and forecasting. Consolidated Adjusted EBITDAX is also used by the board of directors as a performance measure in determining executive compensation. Consolidated Adjusted EBITDAX, as defined by our credit facility, is used by our lenders pursuant to covenants under our revolving credit facility and the indentures governing the company's senior notes.

There are significant limitations to using Consolidated Adjusted EBITDAX and Stand-alone E&P Adjusted EBITDAX as measures of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect the company's net income on a consolidated and Stand-alone basis, the lack of comparability of results of operations of different companies and the different methods of calculating Adjusted EBITDAX reported by different companies. In addition, Consolidated Adjusted EBITDAX and Stand-alone E&P Adjusted EBITDAX provide no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax position.

Antero Non-GAAP Measures

Antero has not included a reconciliation of Consolidated Adjusted EBITDAX or Stand-alone E&P Adjusted EBITDAX to their nearest GAAP financial measures for 2018 because it cannot do so without unreasonable effort and any attempt to do so would be inherently imprecise. Antero is able to forecast the following reconciling items between Consolidated Adjusted EBITDAX and Stand-alone E&P Adjusted EBITDAX to net income from continuing operations including noncontrolling interest:

(in thousands)	**Consolidated**		**Stand-alone E&P**	
	Low	**High**	**Low**	**High**
Interest expense	$250,000	$300,000	$200,000	$220,000
Depreciation, depletion, amortization, and accretion expense	950,000	1,050,000	800,000	900,000
Impairment expense	100,000	125,000	100,000	125,000
Exploration expense	5,000	15,000	5,000	15,000
Equity-based compensation expense	95,000	115,000	70,000	90,000
Equity in earnings of unconsolidated affiliate	30,000	40,000	N/A	N/A
Distributions from unconsolidated affiliates	40,000	50,000	N/A	N/A
Distributions from limited partner interest in Antero Midstream	N/A	N/A	166,000	170,000

Antero has a significant portfolio of commodity derivative contracts that it does not account for using hedge accounting, and forecasting unrealized gains or losses on this portfolio is impracticable and imprecise due to the price volatility of the underlying commodities. Antero is also forecasting no impact from franchise taxes, gain or loss on early extinguishment of debt, or gain or loss on sale of assets, for 2018. For income tax expense (benefit), Antero is forecasting a 2018 effective tax rate of 18% to 19%.

Antero Non-GAAP Measures

Consolidated Adjusted Operating Cash Flow, Stand-alone E&P Adjusted Operating Cash Flow and Free Cash Flow

The GAAP financial measure nearest to Consolidated Adjusted Operating Cash Flow is cash flow from operating activities as reported in Antero's consolidated financial statements. The GAAP financial measure nearest to Stand-alone E&P Adjusted Operating Cash Flow and Free Cash Flow is Stand-alone cash flow from operating activities that will be reported in the Parent column of Antero's guarantor footnote to its financial statements. Management believes that Consolidated Adjusted Operating Cash Flow and Stand-alone E&P Adjusted Operating Cash Flow are useful indicators of the company's ability to internally fund its activities and to service or incur additional debt on a consolidated and Stand-alone basis. Management believes that changes in current assets and liabilities, which are excluded from the calculation of these measures, relate to the timing of cash receipts and disbursements and therefore may not relate to the period in which the operating activities occurred and generally do not have a material impact on the ability of the company to fund its operations. Management believes that Free Cash Flow is a useful measure for assessing the company's financial performance and measuring its ability to generate excess cash from its operations.

There are significant limitations to using Consolidated Adjusted Operating Cash Flow, Stand-alone E&P Adjusted Operating Cash Flow and Free Cash Flow as measures of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect the company's net income on a consolidated and Stand-alone E&P basis, the lack of comparability of results of operations of different companies and the different methods of calculating Consolidated Adjusted Operating Cash Flow and Stand-alone E&P Adjusted Operating Cash Flow reported by different companies. Consolidated Adjusted Operating Cash Flow and Stand-alone E&P Adjusted Operating Cash Flow do not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital, income taxes, franchise taxes, exploration expenses, and other commitments and obligations.

Antero has not included reconciliations of Consolidated Adjusted Operating Cash Flow, Stand-alone E&P Adjusted Operating Cash Flow and Free Cash Flow to their nearest GAAP financial measures for 2018 because it would be impractical to forecast changes in current assets and liabilities. However, Antero is able to forecast the earn out payments expected from Antero Midstream associated with the water drop down transaction that occurred in 2015, each of which is a reconciling item between Stand-alone E&P Adjusted Operating Cash Flow and Free Cash Flow, as applicable, and cash flow from operating activities as reported in the Parent column of Antero's guarantor footnote to its financial statements. Antero forecasts these items to be $125 million in each of 2019 and 2020. Additionally, Antero is able to forecast lease maintenance expenditures and Stand-alone drilling and completion capital, each of which is a reconciling item between Free Cash Flow and its most comparable GAAP financial measure. For the 2018 to 2022 period, Antero forecasts cumulative lease maintenance expenditures of $200 million and cumulative Stand-alone E&P drilling and completion capital of $8.6 billion.

AR Stand-Alone E&P Adjusted EBITDAX Reconciliation

($ in millions)	**Three Months Ended** **<u>09/30/2017</u>**	**LTM Ended** **<u>09/30/2017</u>**
Operating loss	$(114.1)	$(235.8)
Commodity derivative fair value losses	66.0	181.3
Net cash receipts on settled derivatives instruments	61.5	326.9
Depreciation, depletion, amortization and accretion	176.9	720.1
Impairment of unproved properties and accretion	41.0	198.8
Exploration expense	1.6	9.1
Change in fair value of contingent acquisitions consideration	(2.6)	(15.8)
Equity-based compensation expense	19.2	78.6
Gain on sale of assets	-	(93.8)
AM distributions net to AR ownership	34.8	126.8
Segment E&P Adjusted EBITDAX	**$284.3**	**$1,296.2**

Consolidated Adjusted EBITDAX Reconciliation

($ in millions)	**Quarter Ended** **9/30/2017**	**LTM Ended** **9/30/2017**
Net income including noncontrolling interest	$(90.0)	$(197.3)
Commodity derivative fair value gains	66.0	181.3
Net cash receipts on settled derivatives instruments	61.5	326.9
Gain of sale on assets	-	(97.6)
Interest expense	70.1	273.2
Loss on early extinguishment of debt	-	16.9
Income tax expense	(45.1)	(160.5)
Depreciation, depletion, amortization and accretion	207.6	835.3
Impairment of unproved properties	41.0	198.8
Exploration expense	1.6	9.1
Equity-based compensation expense	26.4	105.7
Equity in earnings of unconsolidated affiliate	(7.0)	(11.3)
Distributions from unconsolidated affiliates	4.3	17.8
Consolidated Adjusted EBITDAX	**$336.4**	**$1,498.3**

Regarding Hydrocarbon Quantities

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserve estimates (collectively, "3P"). Antero has provided internally generated estimates for proved, probable and possible reserves in this presentation in accordance with SEC guidelines and definitions. The estimates of proved, probable and possible reserves as of December 31, 2016 included in this presentation have been audited by Antero's third-party engineers. Unless otherwise noted, reserve estimates as of December 31, 2016 assume ethane rejection and strip pricing.

Actual quantities that may be ultimately recovered from Antero's interests may differ substantially from the estimates in this presentation. Factors affecting ultimate recovery include the scope of Antero's ongoing drilling program, which will be directly affected by commodity prices, the availability of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals and other factors; and actual drilling results, including geological and mechanical factors affecting recovery rates.

In this presentation:

- "3P reserves" refer to Antero's estimated aggregate proved, probable and possible reserves as of December 31, 2016. The SEC prohibits companies from aggregating proved, probable and possible reserves in filings with the SEC due to the different levels of certainty associated with each reserve category.
- "EUR," or "Estimated Ultimate Recovery," refers to Antero's internal estimates of per well hydrocarbon quantities that may be potentially recovered from a hypothetical future well completed as a producer in the area. These quantities do not necessarily constitute or represent reserves within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System or the SEC's oil and natural gas disclosure rules.
- "Condensate" refers to gas having a heat content between 1250 BTU and 1300 BTU in the Utica Shale.
- "Highly-Rich Gas/Condensate" refers to gas having a heat content between 1275 BTU and 1350 BTU in the Marcellus Shale and 1225 BTU and 1250 BTU in the Utica Shale.
- "Highly-Rich Gas" refers to gas having a heat content between 1200 BTU and 1275 BTU in the Marcellus Shale and 1200 BTU and 1225 BTU in the Utica Shale.
- "Rich Gas" refers to gas having a heat content of between 1100 BTU and 1200 BTU.
- "Dry Gas" refers to gas containing insufficient quantities of hydrocarbons heavier than methane to allow their commercial extraction or to require their removal in order to render the gas suitable for fuel use.