Goldman Sachs Global Energy Conference

January 5, 2017

Antero Resources

FORWARD-LOOKING STATEMENTS

This presentation contains 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 statements, other than statements of historical facts, included in this presentation that address activities, events or developments that Antero Resources Corporation and its subsidiaries (collectively, the “Company” or “Antero”) expects, believes or anticipates will or may occur in the future are forward-looking statements. The words “believe,” “expect,” “anticipate,” “plan,” “intend,” “estimate,” “project,” “foresee,” “should,” “would,” “could,” or other similar expressions are intended to identify forward-looking statements. However, the absence of these words does not mean that the statements are not forward-looking. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include estimates of the Company’s reserves, expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including as to the Company’s drilling program, production, hedging activities, capital expenditure levels and other guidance included in this presentation. These statements are based on certain assumptions made by the Company based on management’s experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include the factors discussed or referenced under the heading “Item 1A. Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2015 and in the Company’s subsequent filings with the SEC.

The Company 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 our control, incident to the exploration for and development, production, gathering and sale of natural gas 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 “Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2015 and in the Company’s subsequent filings with the SEC.

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.

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

ANTERO PROFILE

Market Cap………………..... $7.4 billion

Enterprise Value(1)…...........…$13.3 billion

LTM EBITDAX……….....……$1.4 billion

Net Debt/LTM EBITDAX(2)…3.2x

Net Production (3Q 2016)… 1,875 MMcfe/d

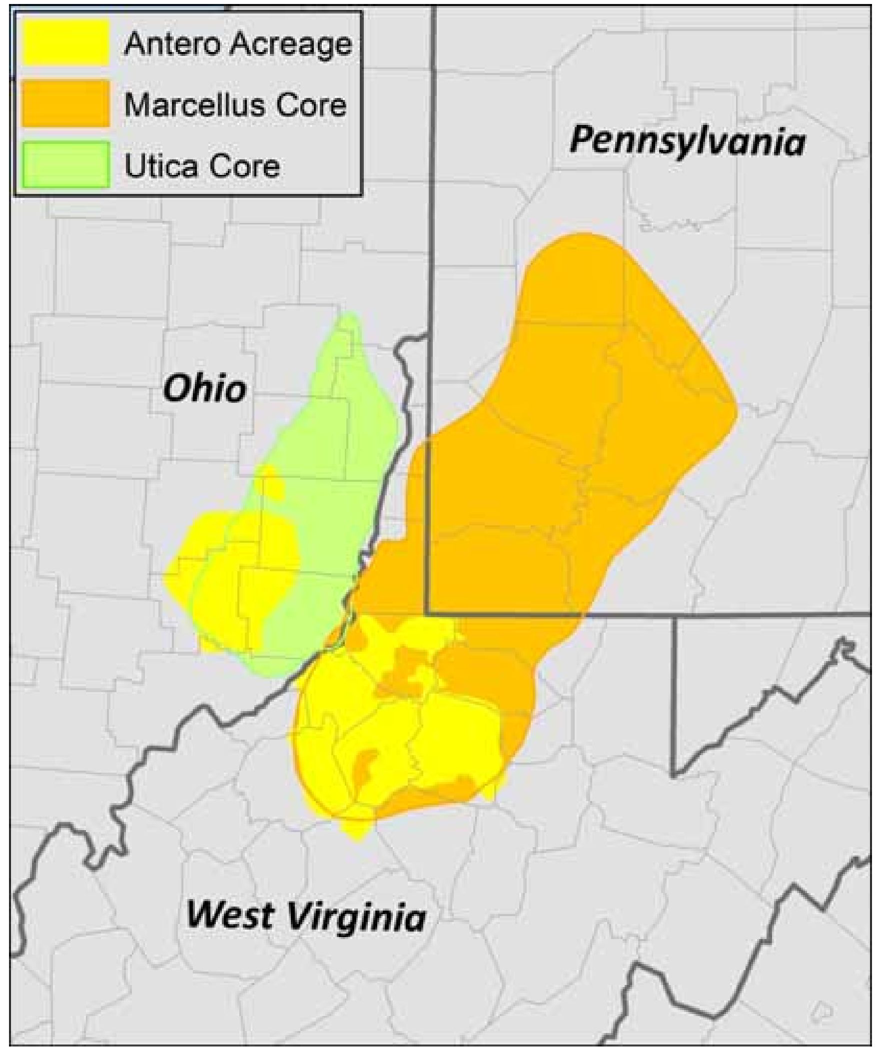
% Liquids..........................26%

3P Reserves(3)…………..….... 42.1 Tcfe

% Natural Gas…………...... 80%

Net Acres(4)……………….…. 629,000

AR LISTED NYSE

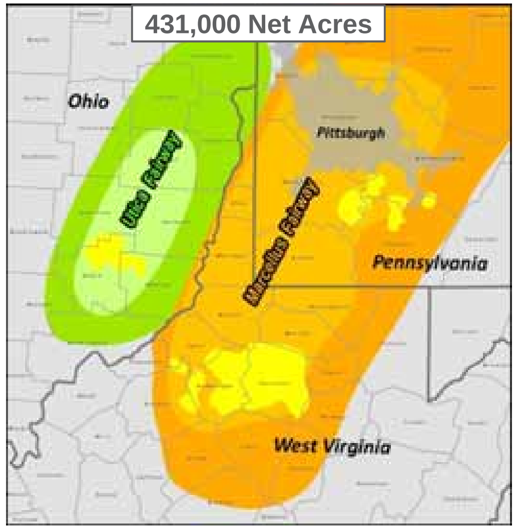


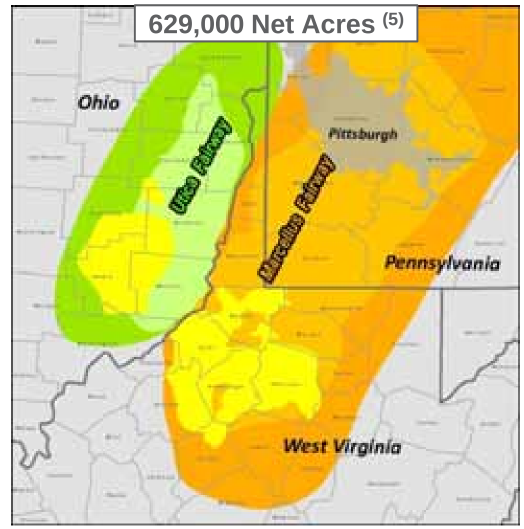
1. Based on market cap plus net debt plus minority interest ($1.4 billion) on a consolidated basis.
2. Pro forma for $175 million AR PIPE transaction on 10/3/2016 and $170 million AR acreage divestiture that closed on 12/16/2016.
3. 3P reserves pro forma for third party acreage acquisition closed on 9/15/2016 and acreage divestiture that closed 12/16/2016 and assuming ethane rejection.
4. Net acres pro forma for acreage divestiture that closed on 12/16/2016 and additional leasing and acquisitions year-to-date.

DELIVERING ON OCTOBER 2013 IPO PROMISE

	At IPO (October 2013)	Current	Change
Acreage:	431,000 Net Acres	629,000 Net Acres (5)	+46%

Leading consolidator since IPO adding ~200,000 net acres





	At IPO (October 2013)	Current	Change
Net Production (1):	458 MMcfe/d	1,875 MMcfe/d	+309%
LTM EBITDAX (2):	$457 Million	$1,368 Million	+199%
3P Reserves (3):	27.7 Tcfe	42.1 Tcfe	+52%
Public Float (4):	14%	68%	+386%

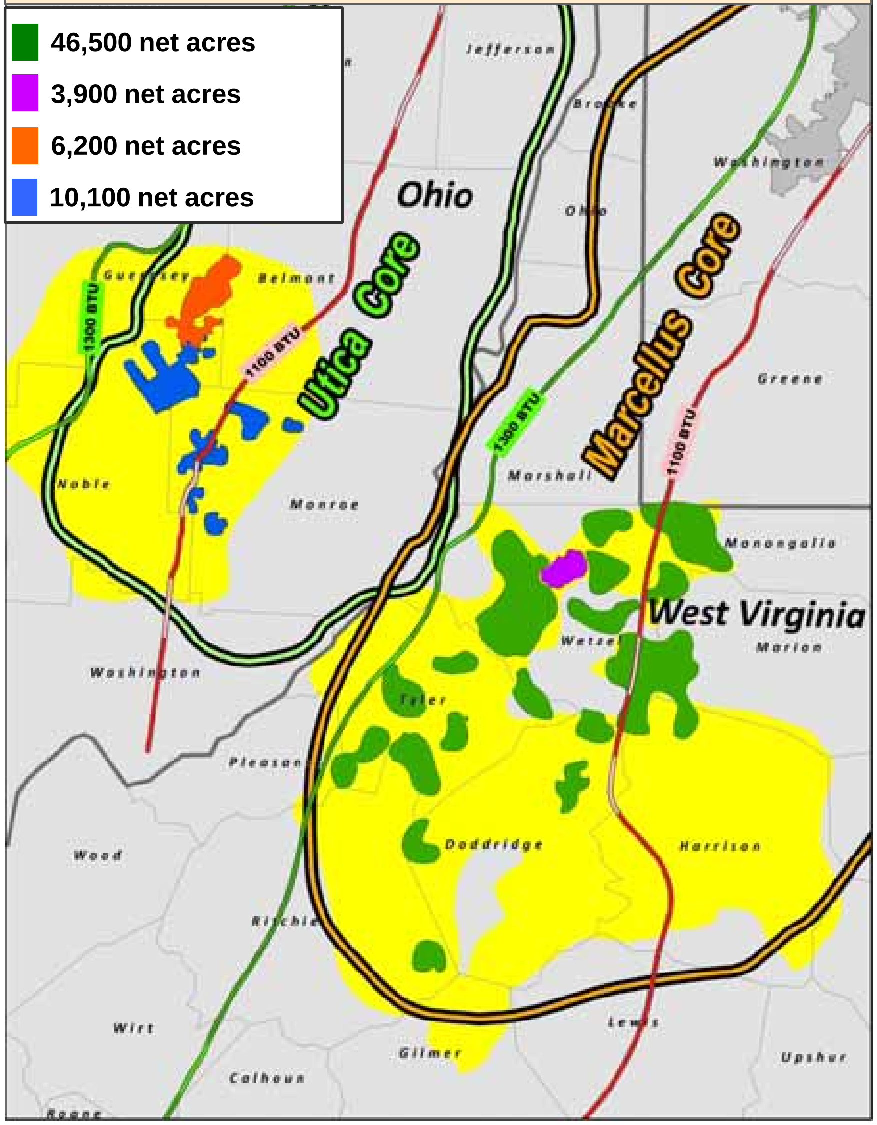
1. Represents 2Q 2013 and 3Q 2016 net production, respectively.
2. Represents LTM EBITDAX as of 6/30/13 and 9/30/16, respectively.
3. 3P reserves are as of year-end 2015, pro forma for announced acreage acquisitions and divestitures.
4. Current float defined as portion of shares outstanding that are freely tradable excluding 57 million shares held by Warburg Pincus Funds, 16 million shares held by Yorktown Energy Funds and 26 million shares held by Antero NEOs.
5. Pro forma for PA acreage divestiture closed on 12/16/2016.

A LEADING CONSOLIDATOR IN APPALACHIA

Activity

- Antero capitalized on the industry environment in 2016 to acquire approximately 66,700 net acres in the core of the Marcellus and Utica Shale plays
- Four of the key acquisitions are shown on the map to the right
- Consolidated acreage position drives efficiencies:
  - *Longer laterals*
  - *More wells per pad*
  - *Higher utilization of gathering, compression and water infrastructure*
  - *Facilitates central water treatment avoiding reinjection*
- 2017 land capital budget at $200 million to further consolidate core acreage
- Supports long-term growth outlook

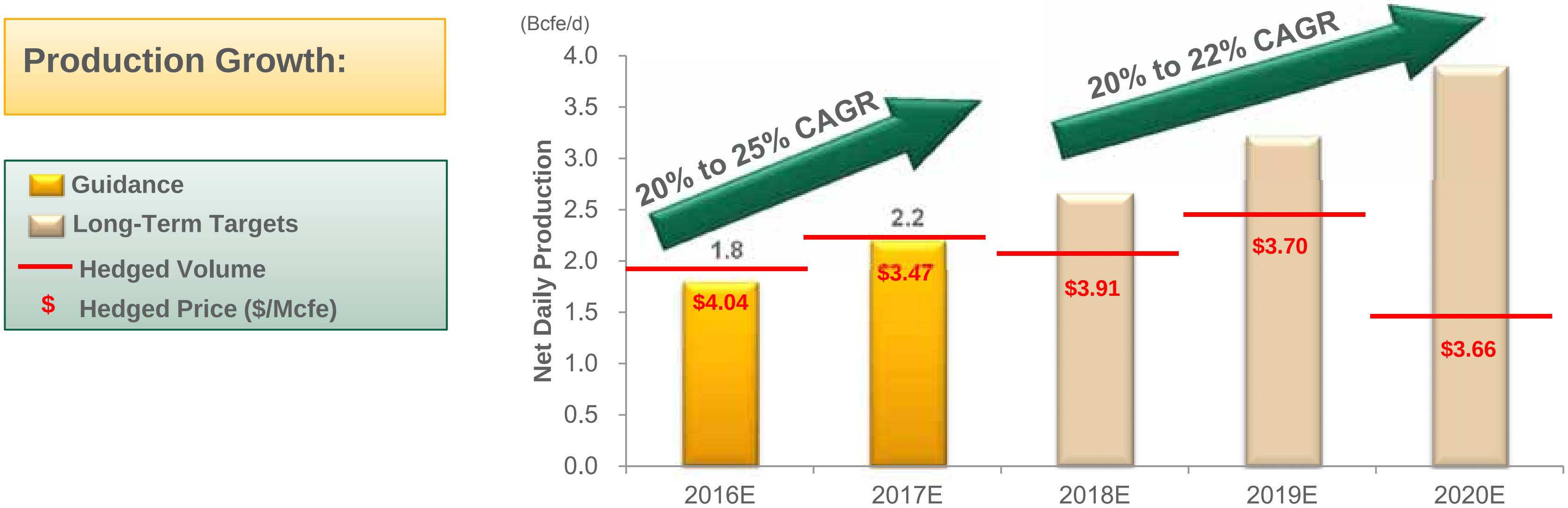
2016 Acquisitions and Antero Footprint



2017 GUIDANCE AND LONG TERM OUTLOOK ANNOUNCED

Antero Resources

Production Growth:



	2017 Guidance	2018 - 2020 Long Term Targets
D&C Capital:	$1.3 Billion	Modest annual increases within Cash Flow from Operations
Consolidated Cash Flow from Operations(1):	In line with D&C capital	Doubling by 2020
Leverage(1):	3.0x to 3.5x	Declining to mid-2s by 2018
Hedging:	96% Hedged at $3.47/Mcfe	58% Hedged at $3.76/Mcfe

1. *Assuming 12/31/16 strip pricing averaging $3.63/MMBtu for natural gas and $56/Bbl for oil.*

KEY DRIVERS BEHIND LONG TERM OUTLOOK

1 Drilling Inventory — Deep Drilling Inventory

2 Capital Efficiency — Improving Capital Efficiencies

3 Well Performance — Strong Well Performance

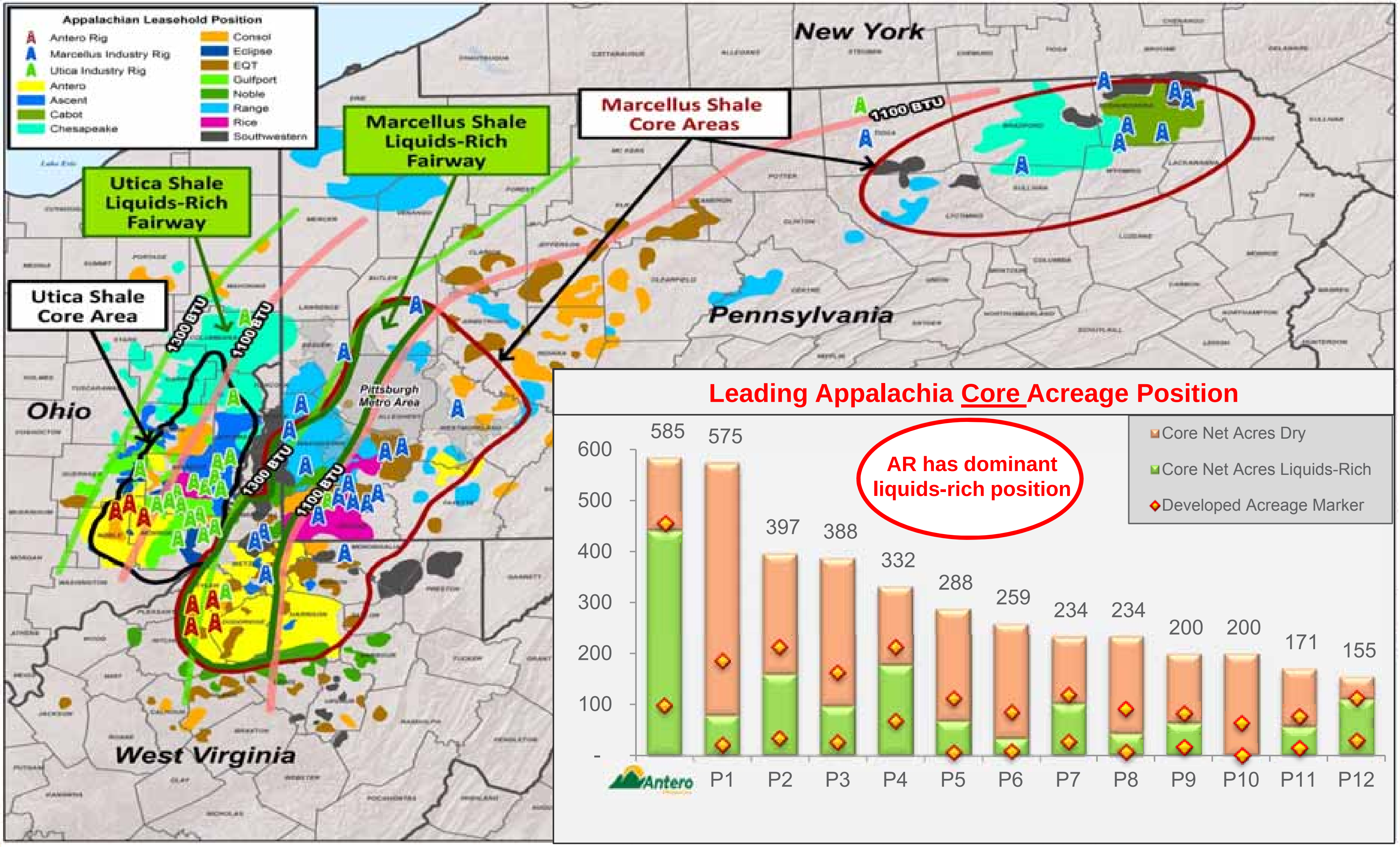
4 Price Realizations — Visible, Attractive Price Realizations

5 Cash Flow Growth — Significant Cash Flow Growth and Declining Leverage Profile

6 Balance Sheet — Solid Balance Sheet with Abundant Liquidity

DRILLING INVENTORY – LARGEST CORE ACREAGE POSITION IN APPALACHIA

Antero has the largest core acreage position in Appalachia, particularly as it relates to undeveloped acreage and is running 36% of the total rigs in liquids-rich core areas

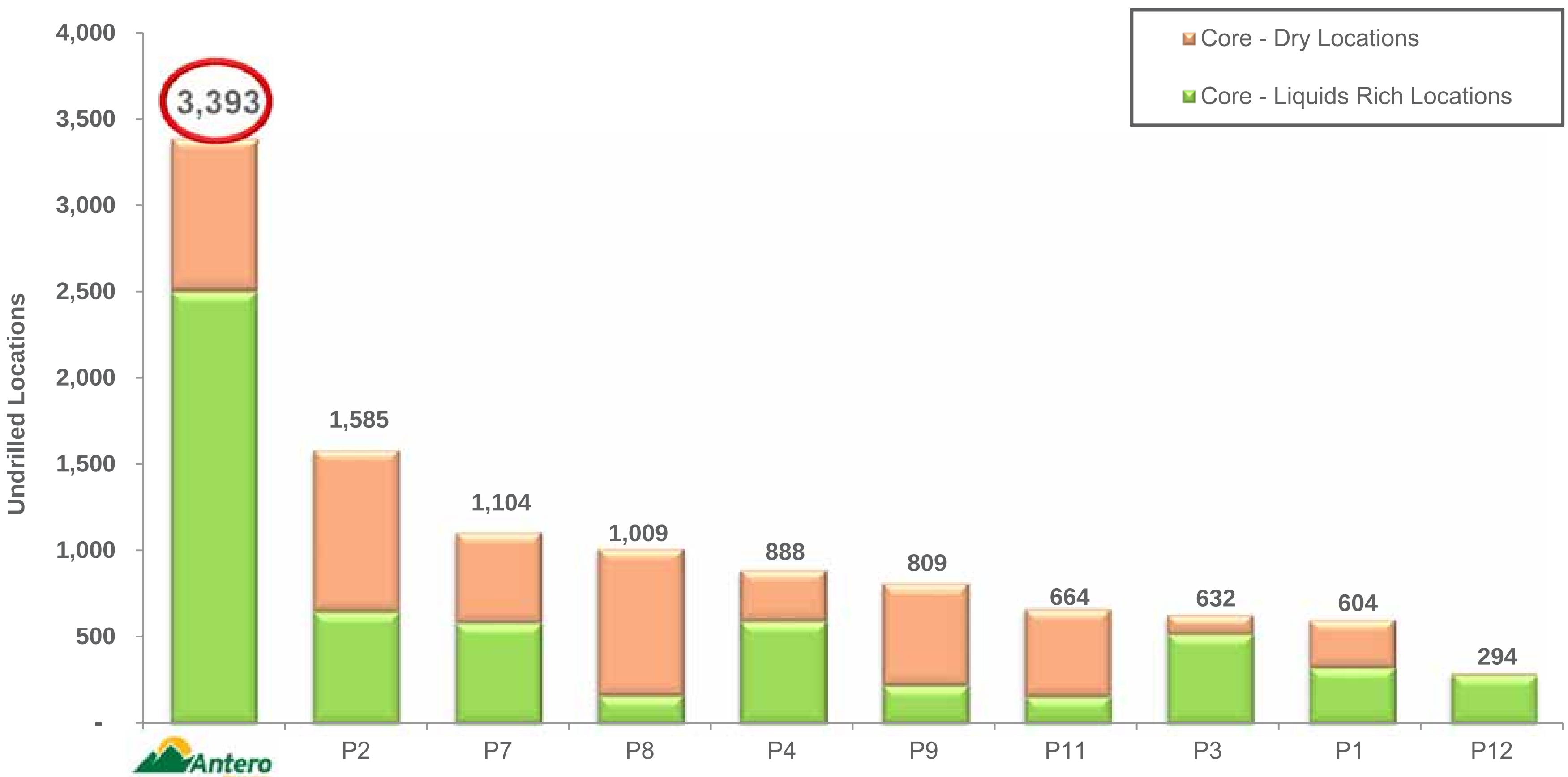


Source: Core outlines based upon Antero geologic interpretation, well control and peer acreage positions based on investor presentations, news releases and 10-K/10-Qs. Rig information per RigData as of 12/30/2016. Competitor leasehold positions analyzed include Ascent (private), CHK, CNX, COG, CVX, EQT, GPOR, NBL, RICE, STO, SWN, RRC.

DRILLING INVENTORY – LARGEST CORE DRILLING INVENTORY IN APPALACHIA

Antero has greater than 2x as many core drilling locations of its nearest competitor and 4x as many core liquids-rich locations as nearest competitor

Undrilled Core Southwest Marcellus and Utica Locations (1)(2)



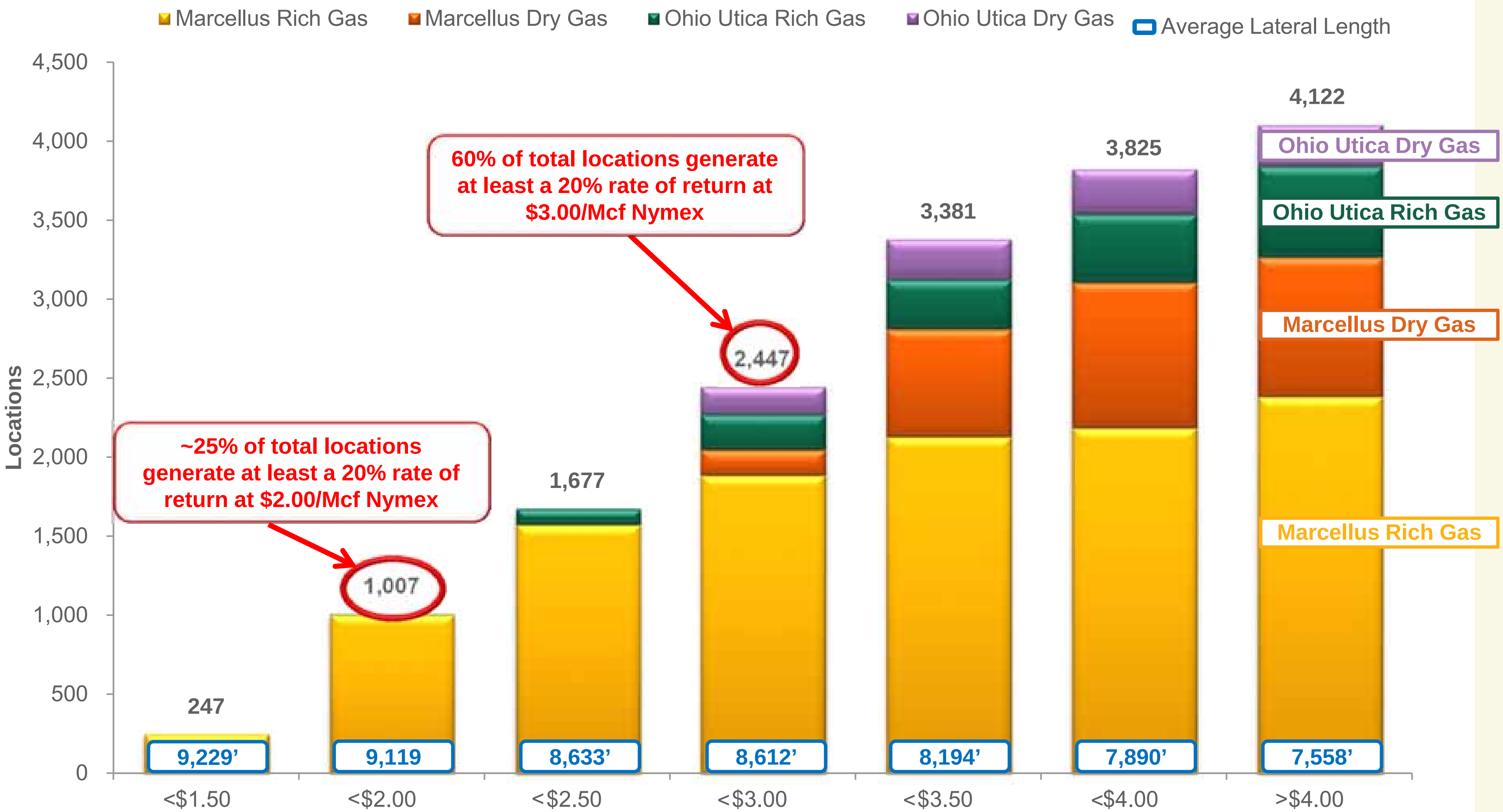
Avg. Lateral Length	8,253'	6,507'	7,584'	8,750'	5,923'	6,698'	8,690'	8,398'	8,669'	7,531'

1. Peers include Ascent, CHK, CNX, EQT, GPOR, NBL, RICE, RRC, SWN .
2. Based on Antero technical review of geology and well control to delineate core areas and peer acreage positions both drilled and undrilled. Excludes Northeast Pennsylvania core locations.

DRILLING INVENTORY – LOW BREAKEVEN PRICES

Antero has a 14 year drilling inventory at $3.00 natural gas or less at the 2017 development pace (170 completions)

Cumulative Drilling Inventory – Breakeven Prices at 20% ROR (1)(2)

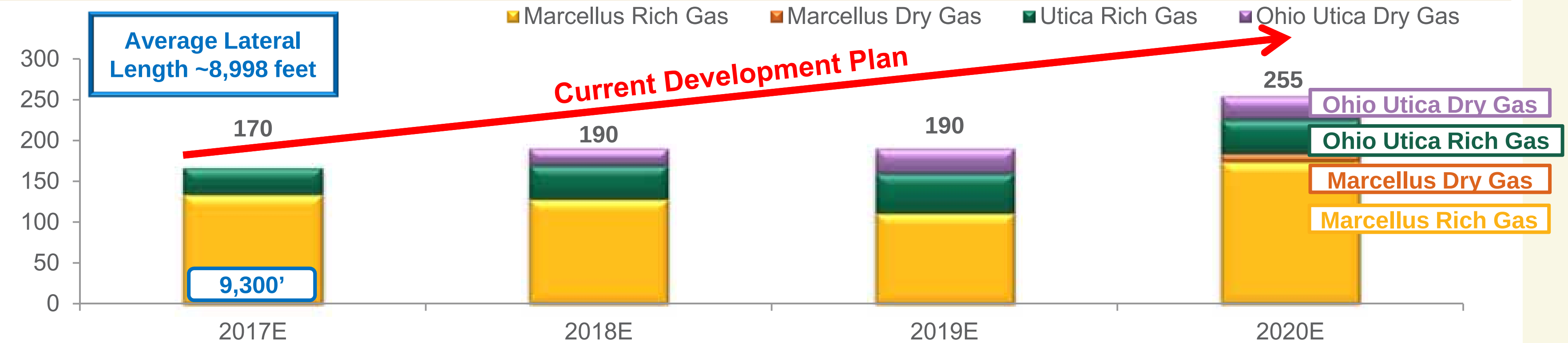


1. *Marcellus and Utica 3P locations as of 12/31/15, updated for 2016 leasehold and acreage transactions, including SWN acreage acquisition and PA divestiture. Categorized by breakeven price solving for a 20% BTAX ROR and assuming 50% of AM fees due to AR ownership of AM. Assumes strip pricing for oil which averages $56.00/Bbl over the next five years and 50% of WTI for NGLs ($27/Bbl).*
2. *Includes 3,393 total core locations plus 219 non-core 3P locations, 194 3P locations with laterals less than 4,000 feet and 316 locations that have been placed in operation throughout the course of 2016.*

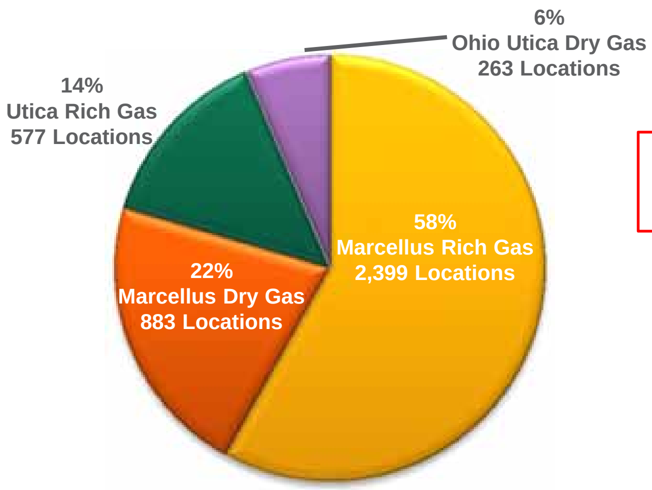
DRILLING INVENTORY – MULTI-YEAR GROWTH ENGINE

Antero plans to develop over 800 horizontal locations in the Marcellus and Ohio Utica by the end of the decade while utilizing less than 20% of its current 3P drilling inventory

Planned Antero Well Completions by Year



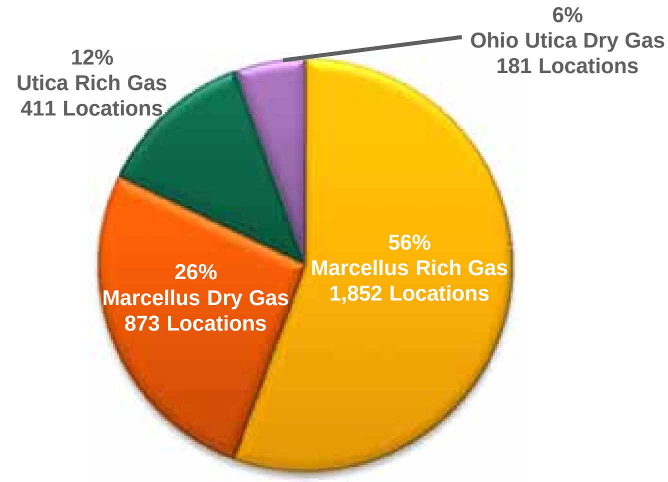
CURRENT UNDRILLED 3P LOCATIONS BY BTU REGIME[1]



4,122 Locations

ESTIMATED YE 2020 UNDRILLED 3P LOCATIONS

Expect to place >800 new Marcellus and Ohio Utica wells to sales by YE 2020



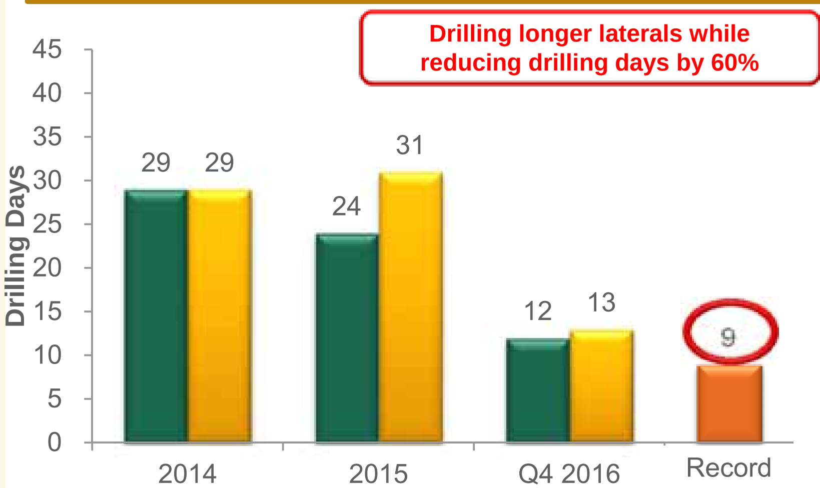
3,317 Locations

1. *Marcellus and Utica 3P locations as of 12/31/15, updated for 2016 leasehold and acreage transactions, including SWN acquisition and PA divestiture. Excludes WV/PA Utica Dry locations.*

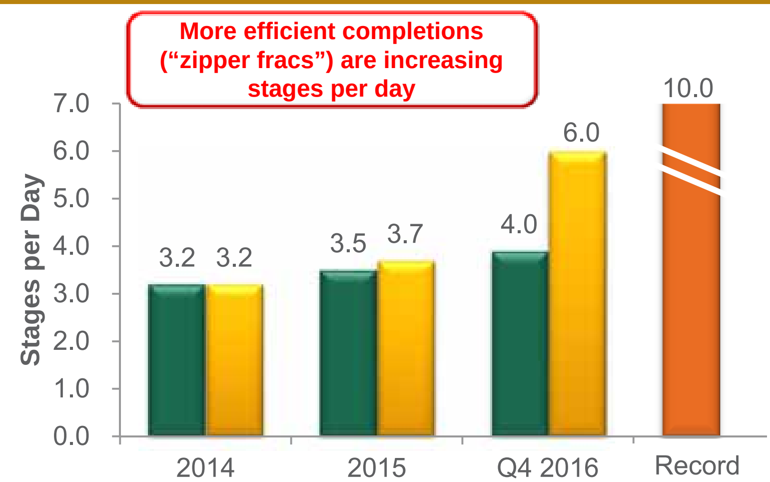
CAPITAL EFFICIENCY – CONTINUOUS OPERATING IMPROVEMENT

Driving drilling and completion efficiencies which continues to lower well costs

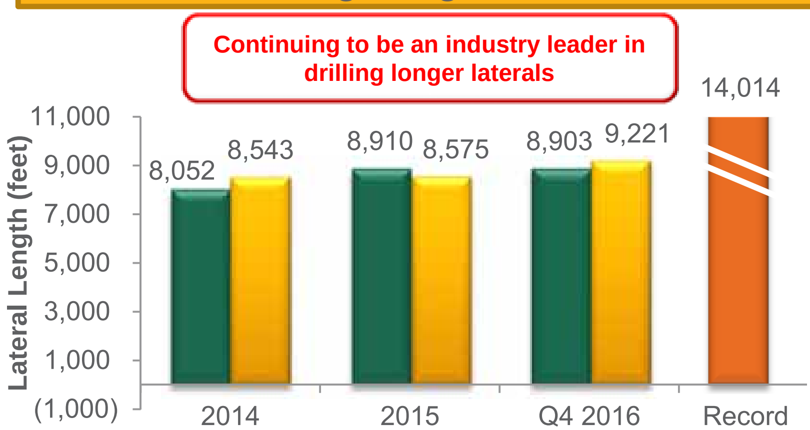
Dramatic Decrease in Drilling Days



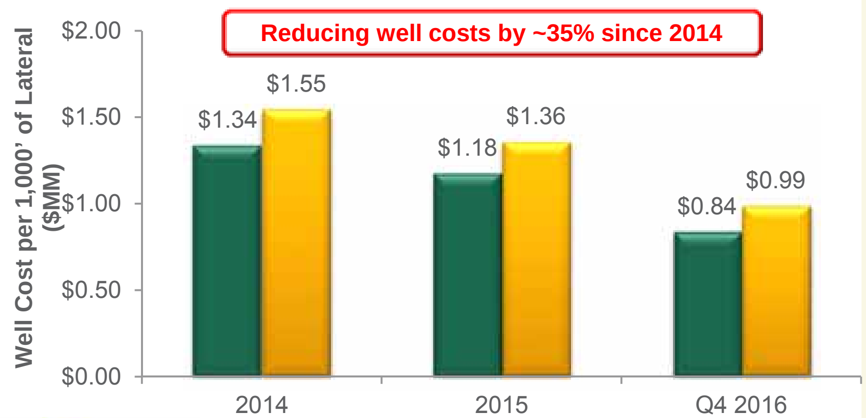
Increasing Completion Stages per Day



Drilling Longer Laterals



Declining Well Costs per 1,000’

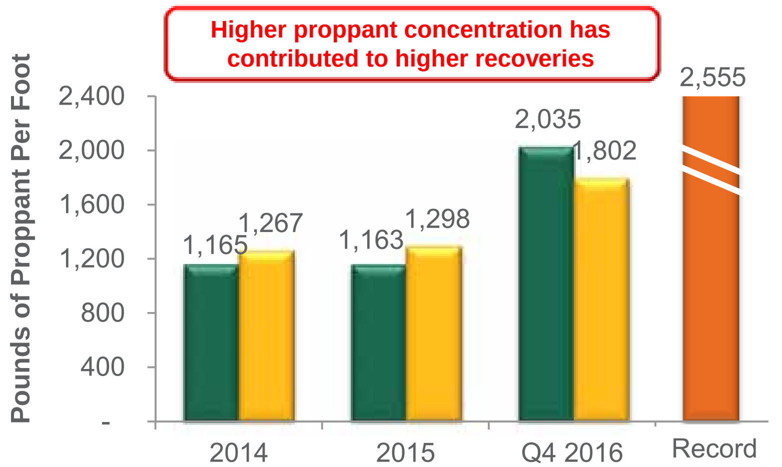


Marcellus Utica

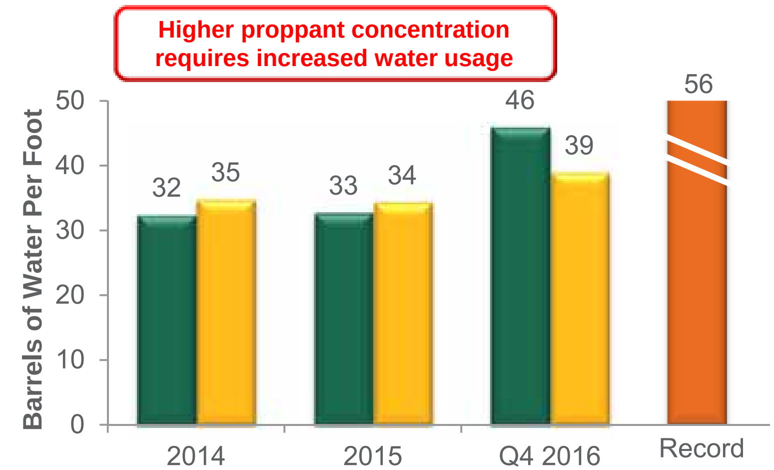
CAPITAL EFFICIENCY – DRAMATICALLY LOWER F&D COST

Enhanced completion designs have contributed to improved recoveries and capital efficiency

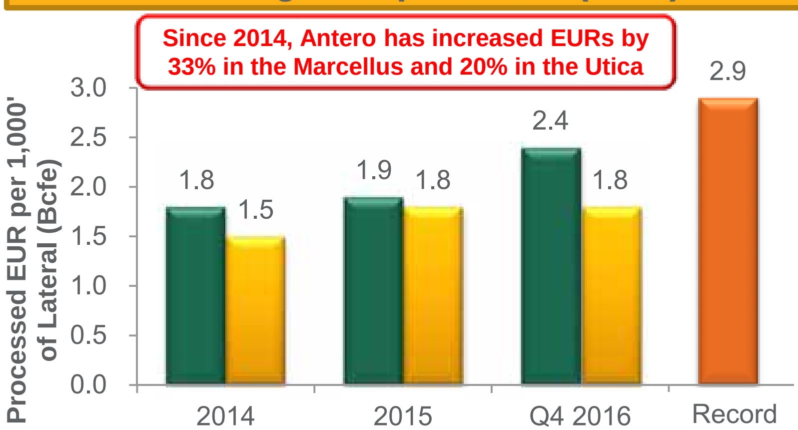
Increasing Proppant Per Foot



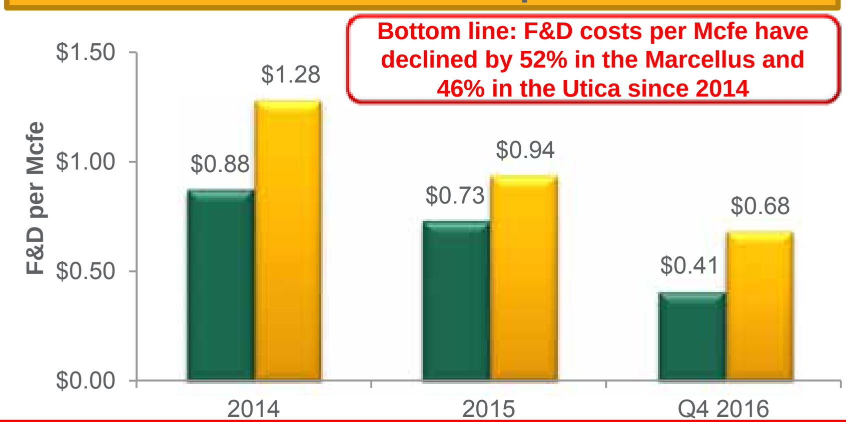
Increasing Water Per Foot



Increasing EUR per 1,000' (Bcfe)(1)(2)



Much Lower F&D Cost per Mcfe(2)(3)

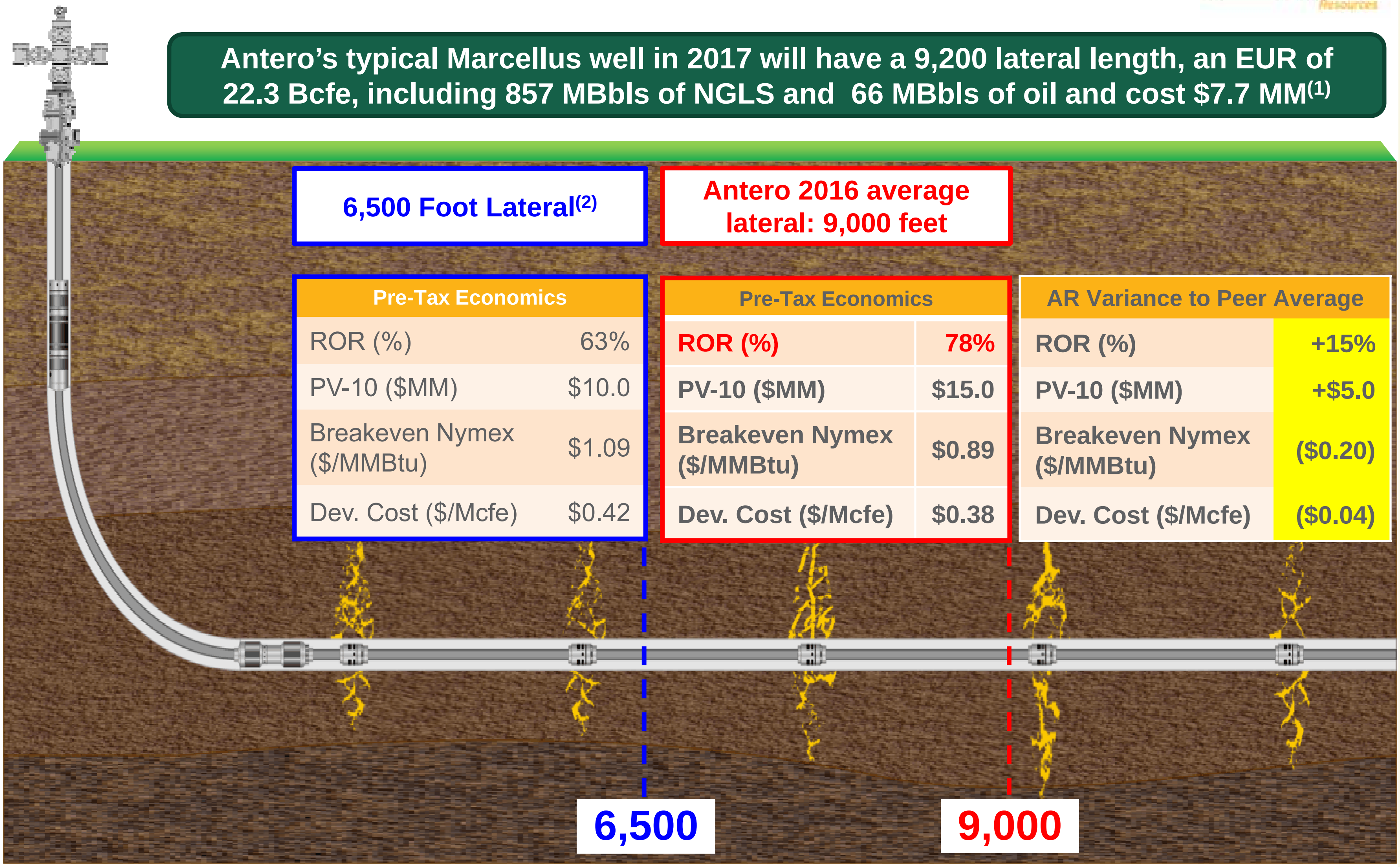


Marcellus Utica

1. Based on statistics for wells completed within each respective period.
2. Ethane rejection assumed.
3. 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.

CAPITAL EFFICIENCY – LONGER LATERALS IMPROVE ROR

Antero's typical Marcellus well in 2017 will have a 9,200 lateral length, an EUR of 22.3 Bcfe, including 857 MBbls of NGLS and 66 MBbls of oil and cost $7.7 MM[(1)]



6,500 Foot Lateral[(2)]

Pre-Tax Economics	
ROR (%)	63%
PV-10 ($MM)	$10.0
Breakeven Nymex ($/MMBtu)	$1.09
Dev. Cost ($/Mcfe)	$0.42

Antero 2016 average lateral: 9,000 feet

Pre-Tax Economics	
ROR (%)	78%
PV-10 ($MM)	$15.0
Breakeven Nymex ($/MMBtu)	$0.89
Dev. Cost ($/Mcfe)	$0.38

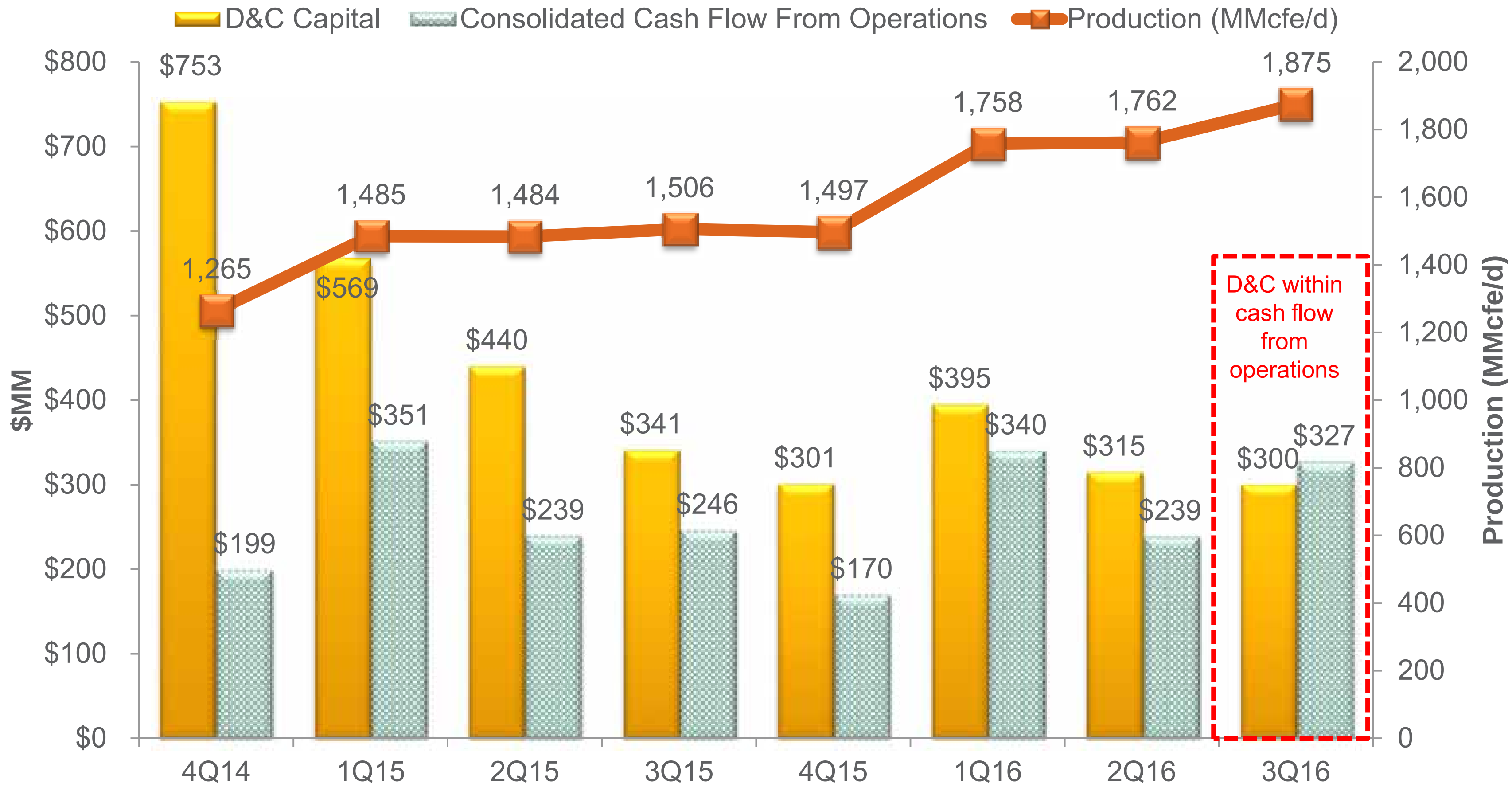
AR Variance to Peer Average	
ROR (%)	+15%
PV-10 ($MM)	+$5.0
Breakeven Nymex ($/MMBtu)	($0.20)
Dev. Cost ($/Mcfe)	($0.04)

NOTE: Assumes 2.0 Bcf/1,000' type curve for the Antero Marcellus Highly-Rich Gas/Condensate (1275 – 1350 Btu).

1. *Assumes ethane rejection.*
2. *Represents 2016 Marcellus average for peers including: CNX, COG, EQT, RICE, RRC based on public guidance.*

CAPITAL EFFICIENCY – DRIVING CASH FLOW GROWTH

Antero's capital efficiency has reduced outspend while maintaining its growth profile and is expected to deliver cash flow from operations higher than drilling and completion capex through 2020

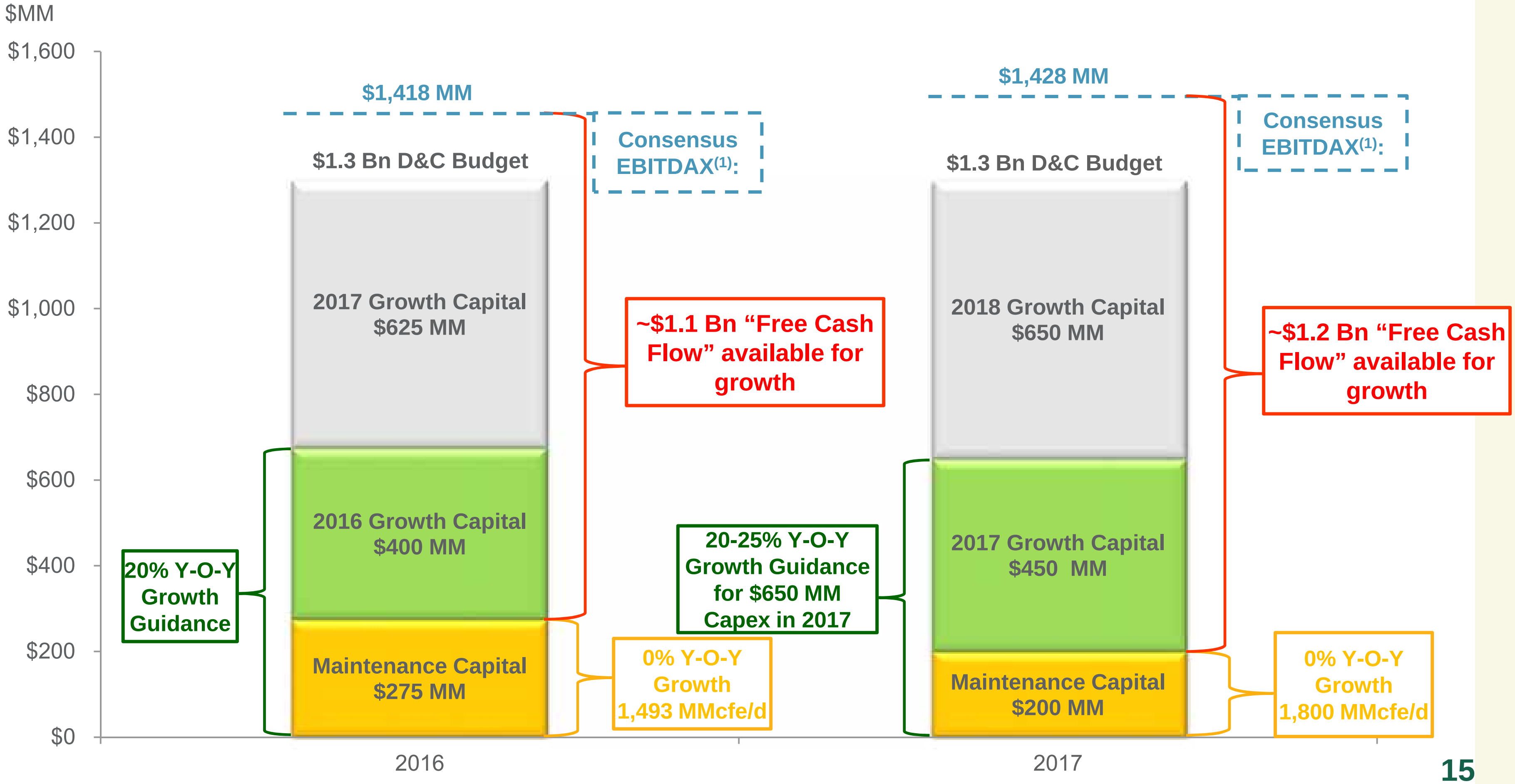


Rigs	21	16	11	10	10	9	7	5

CAPITAL EFFICIENCY – ABUNDANT “FREE CASH FLOW” AVAILABLE FOR GROWTH

Antero can deliver 20% to 25% year-over-year net production growth in 2017 by spending only $650 million in 2017

Antero Drilling & Completion Capital Budget

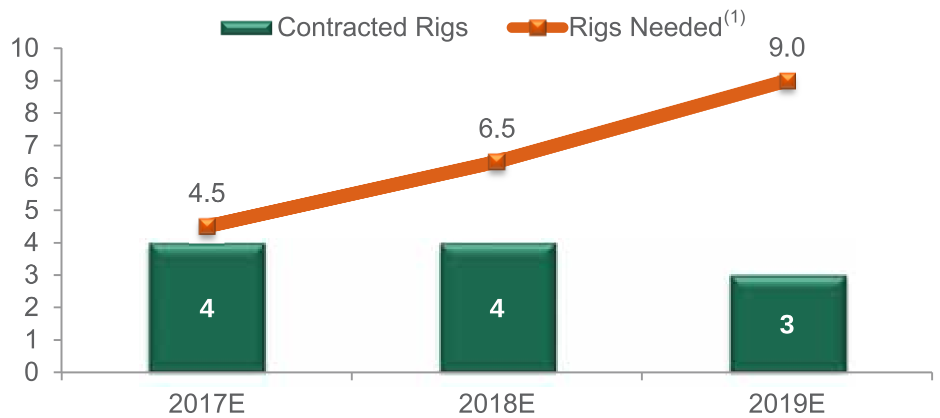


1. Bloomberg as of 12/30/16.

CAPITAL EFFICIENCY – MITIGATING SERVICE COST EXPOSURE

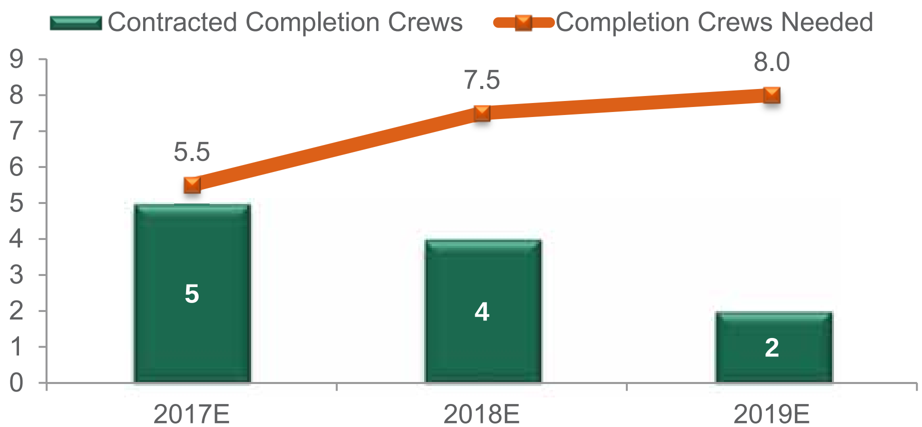
Antero has limited its exposure to service cost increases over the next few years through long-term agreements with drilling contractors and completion services

Drilling Rigs



Since 2014, approximately 50% of the reduction in well costs was driven by efficiency gains and 50% through service cost reductions.

Completion Crews



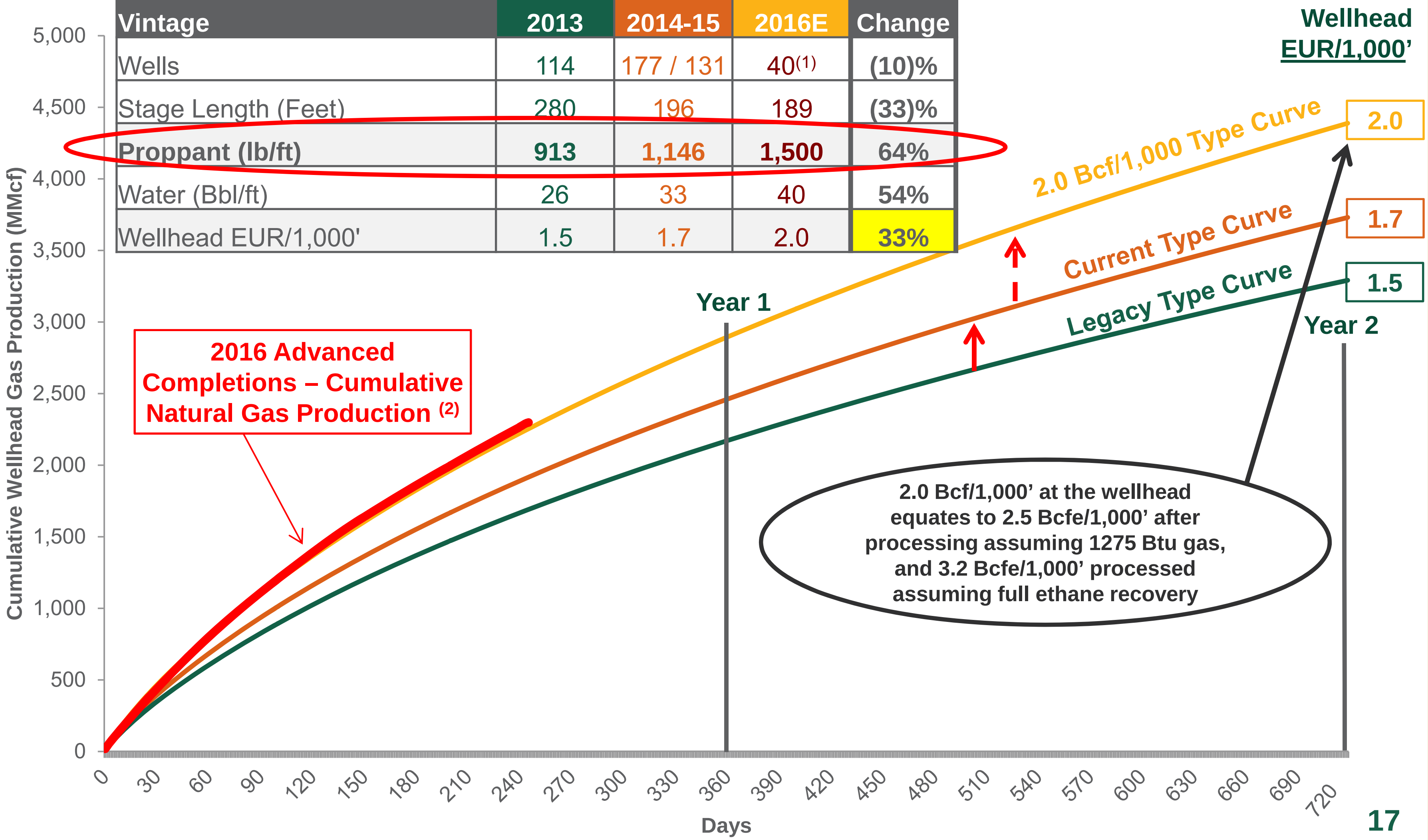
By maintaining drilling and completion momentum during the commodity downturn, Antero had the opportunity to lock in many of the best crews at attractive long-term contracted rates

1. *Excludes intermediate rigs used to drill to kick-off point.*

WELL PERFORMANCE – OPTIMIZING WELL RECOVERIES WITH HIGHER INTENSITY COMPLETIONS

Marcellus Cumulative Natural Gas Production Curves (Normalized to 9,000' Lateral)

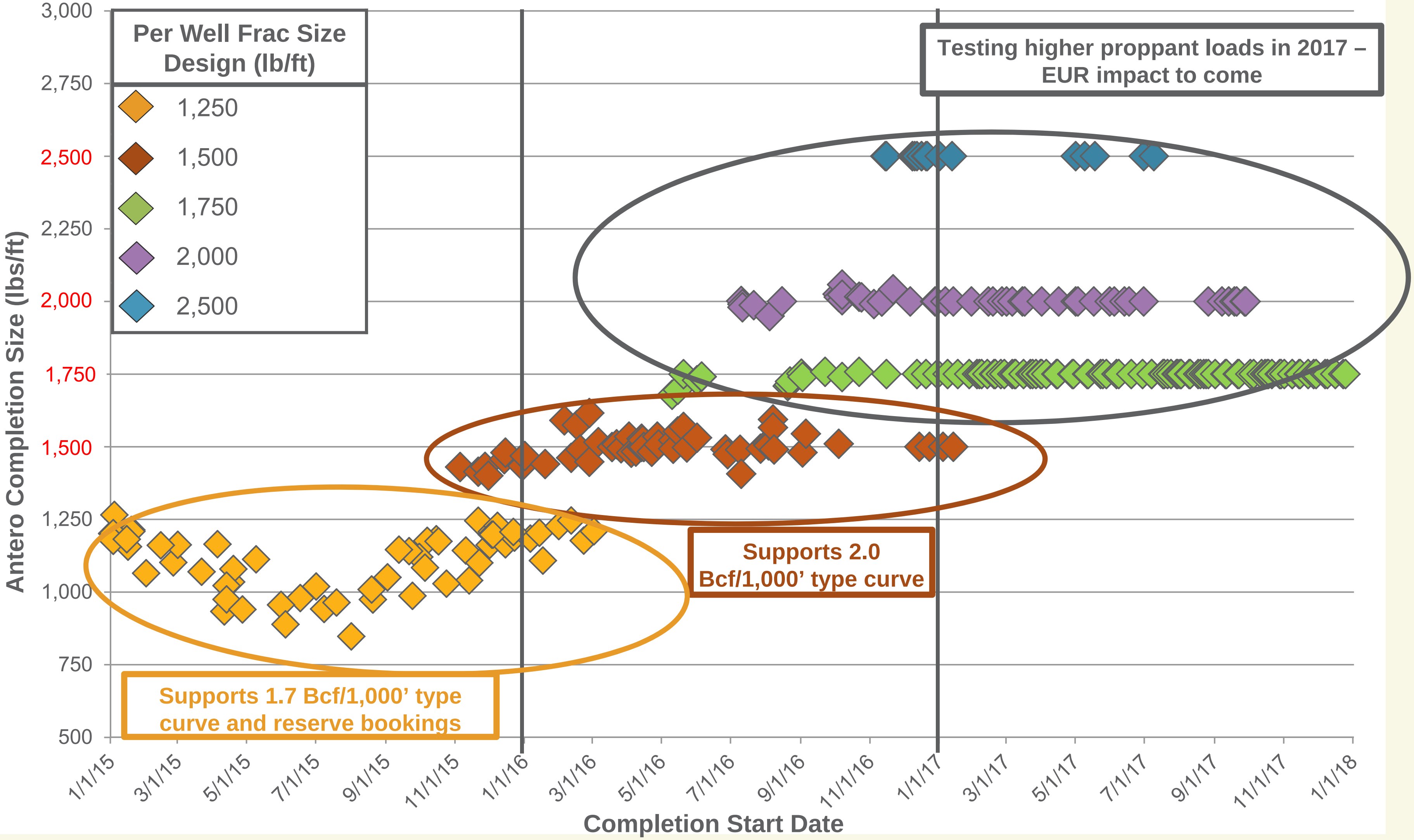
Vintage	2013	2014-15	2016E	Change
Wells	114	177 / 131	40[1]	(10)%
Stage Length (Feet)	280	196	189	(33)%
Proppant (lb/ft)	**913**	**1,146**	**1,500**	64%
Water (Bbl/ft)	26	33	40	54%
Wellhead EUR/1,000'	1.5	1.7	2.0	**33%**



1. Represents 2016 year-to-date advanced completion wells only.
2. Includes condensate at 6:1 gas/condensate ratio.

WELL PERFORMANCE – MARCELLUS COMPLETION SIZE EVOLUTION

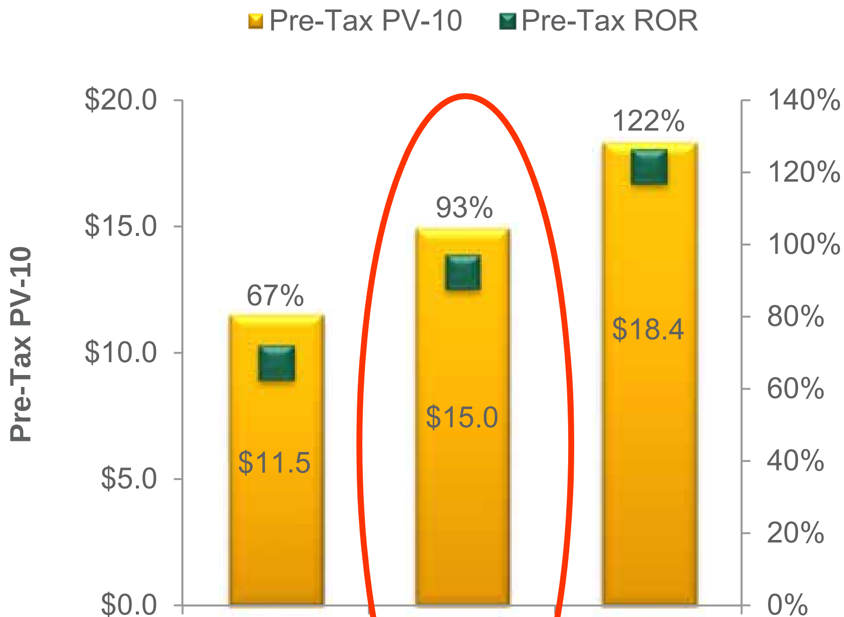
Antero plans to continue to increase proppant intensity in 2017 primarily utilizing 1,750 and 2,000 lb/ft completions in the Marcellus



WELL PERFORMANCE – IMPROVING MARCELLUS RETURNS

Antero expects to complete 114 wells in 2017 in the highly-rich gas regimes where 2016 advanced completions are tracking 2.0 Bcf/1,000' of lateral

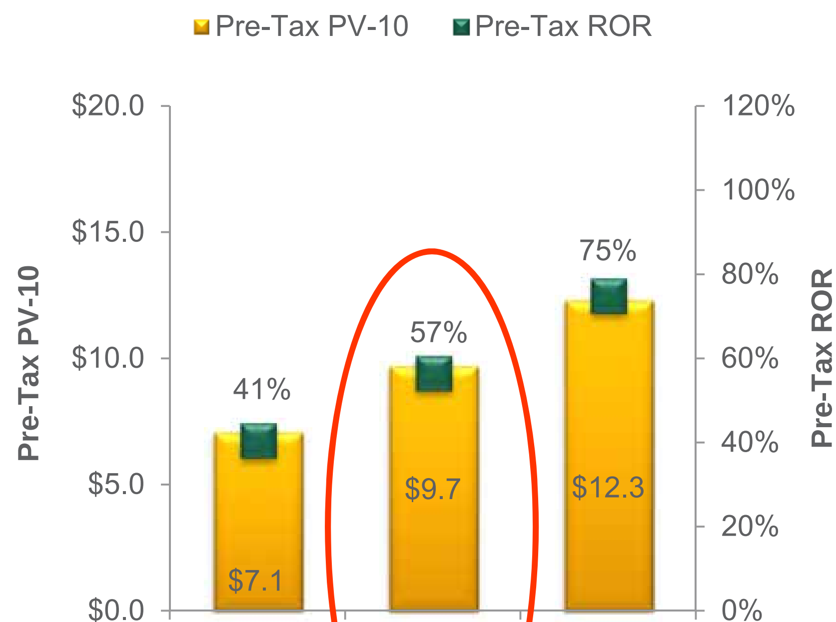
Highly-Rich Gas/Condensate[1]



Wellhead Bcf/1,000':	1.7	2.0	2.3
Processed Bcfe/1,000':	2.3	2.7	3.1

20 Planned 2017 Completions

Highly-Rich Gas[1]



Wellhead Bcf/1,000':	1.7	2.0	2.3
Processed Bcfe/1,000':	2.1	2.5	2.8

94 Planned 2017 Completions

2016 Advanced Completion Results

1. See Appendix for SWE assumptions and 12/30/2016 pricing.
2. Assumes ethane rejection.

PRICE REALIZATIONS – ANTERO FIRM TRANSPORT MITIGATES NORTHEAST BASIS RISK

Antero Expected Pricing: 2017-2020 ($/MMBtu)	
Forecasted Realized Natural Gas Price [(1)]	Nymex + ~$0.10
- Average FT Expense (operating expense)	$(0.46)
- Average Net Marketing Expense	$(0.10)
= Net Natural Gas Price vs. Nymex	$(0.46)
Dom South and Tetco M2 Realized Natural Gas Strip [(2)]	Nymex - $(0.84)
Antero Pricing Relative to Northeast Differential	+$0.38

Even with the relative tightening of local basis indicated in the futures market, Antero's expected netback through the end of the decade (after deducting FT and marketing costs) is $0.38 per MMBtu higher than the local Dominion South and TETCO M2 indices

1. *Based on management forecast of net production, BTU of future production and the 2017 through 2020 futures strip for various indices that Antero can access with its firm transport portfolio.*
2. *Assumes 50/50 DOM S and TETCO M2 split, from ICE futures as of 12/30/2016.*

PRICE REALIZATIONS – FAVORABLE PRICE INDICES

Antero expects to realize a premium to NYMEX gas prices before hedges through 2020

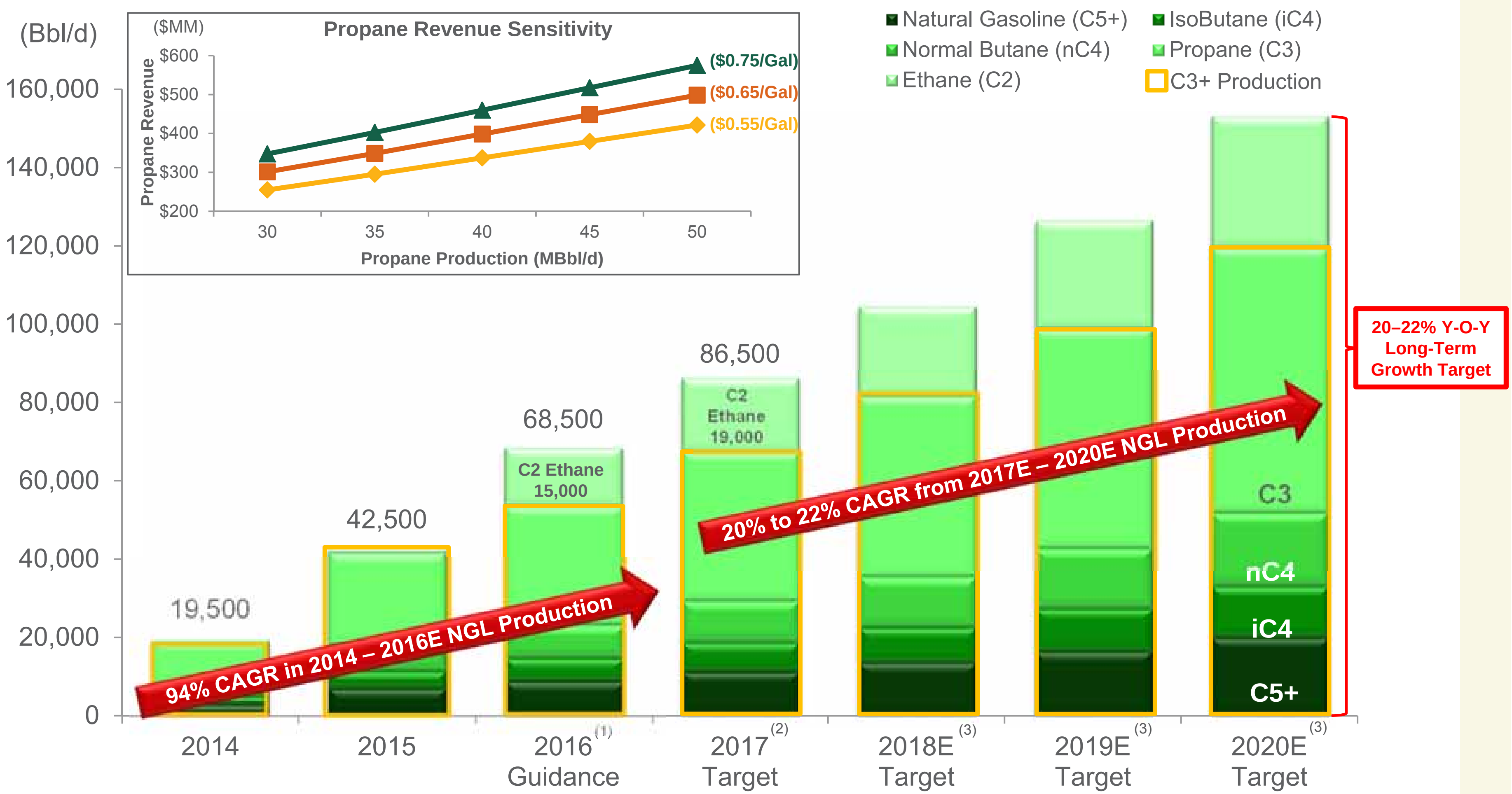
($/Mcf)	2016E	2017E	2018-2020 Target
NYMEX NEW YORK MERCANTILE EXCHANGE[(1)]	$2.46	$3.63	$2.96
Basis Differential to NYMEX[(1)]	$(0.20)	$(0.29)	$(0.17) - $(0.22)
BTU Upgrade[(2)]	$0.23	$0.34	$0.32
Realized Gas Price	$2.49	$3.68	$3.06 - $3.11
Premium to Nymex without Hedges	+$0.03	+$0.05	$0.10 - $0.15
Estimated Realized Hedge Gains	$1.91	$0.01	$0.60
Realized Gas Price with Hedges	$4.40	$3.69	$3.66 - $3.71
Premium to NYMEX with Hedges	+$1.94	+$0.06	+$0.70 - +$0.85

1. *Based on 12/30/2016 strip pricing.*
2. *Based on BTU content of residue sales gas.*

PRICE REALIZATIONS – NGL GROWTH AND EXPOSURE

ANTERO IS THE LARGEST C3+ LIQUIDS PRODUCER IN THE NORTHEAST

NGL Production Growth by Purity Product (Bbl/d)

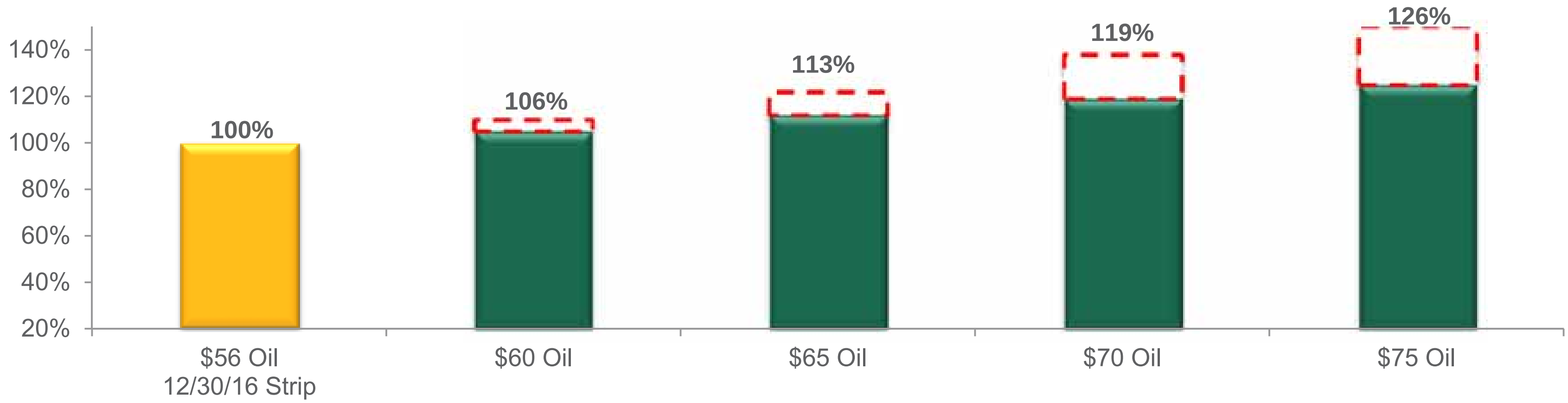


1. Assumes 15,000 Bbl/d of ethane and 53,500 Bbl/d of C3+, respectively, per guidance release on 9/6/2016. C3+ barrel composition based on 3Q16 actual barrel composition.
2. C3+ production growth midpoint guidance of 26%. Excludes condensate.
3. Assumes midpoint of 20 – 22% year-over-year equivalent production growth in 2018-2020. For illustrative purposes C3+ production growth assumed at same rate.

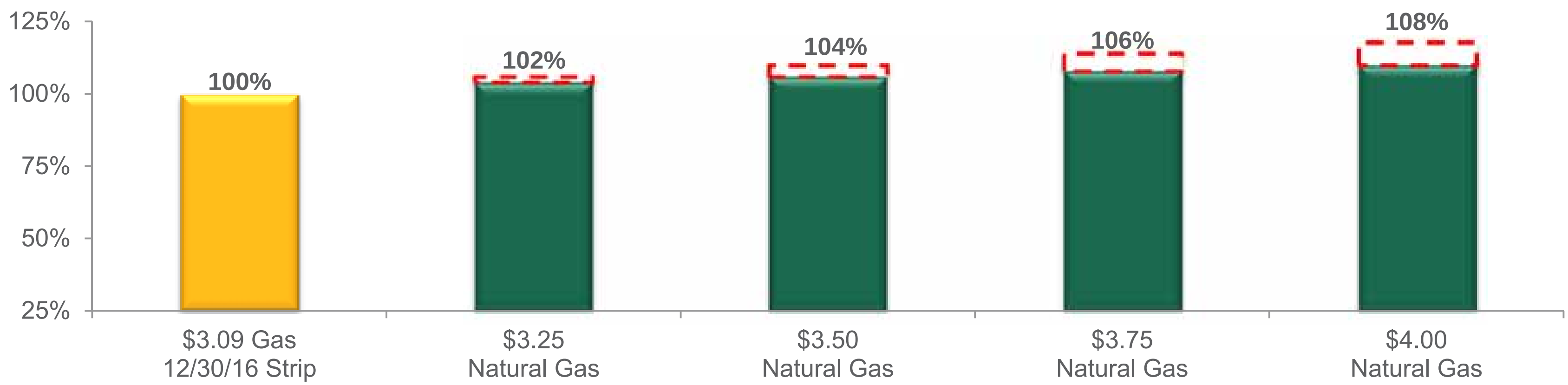
PRICE REALIZATIONS – HIGH LEVERAGE TO LIQUIDS PRICES AND LIMITED DOWNSIDE EXPOSURE TO NATURAL GAS PRICES

Antero has hedged only 8% of its 3P reserve base leaving significant cash flow upside to commodity price improvements

Cumulative EBITDAX Liquids Pricing Exposure 2017 – 2020



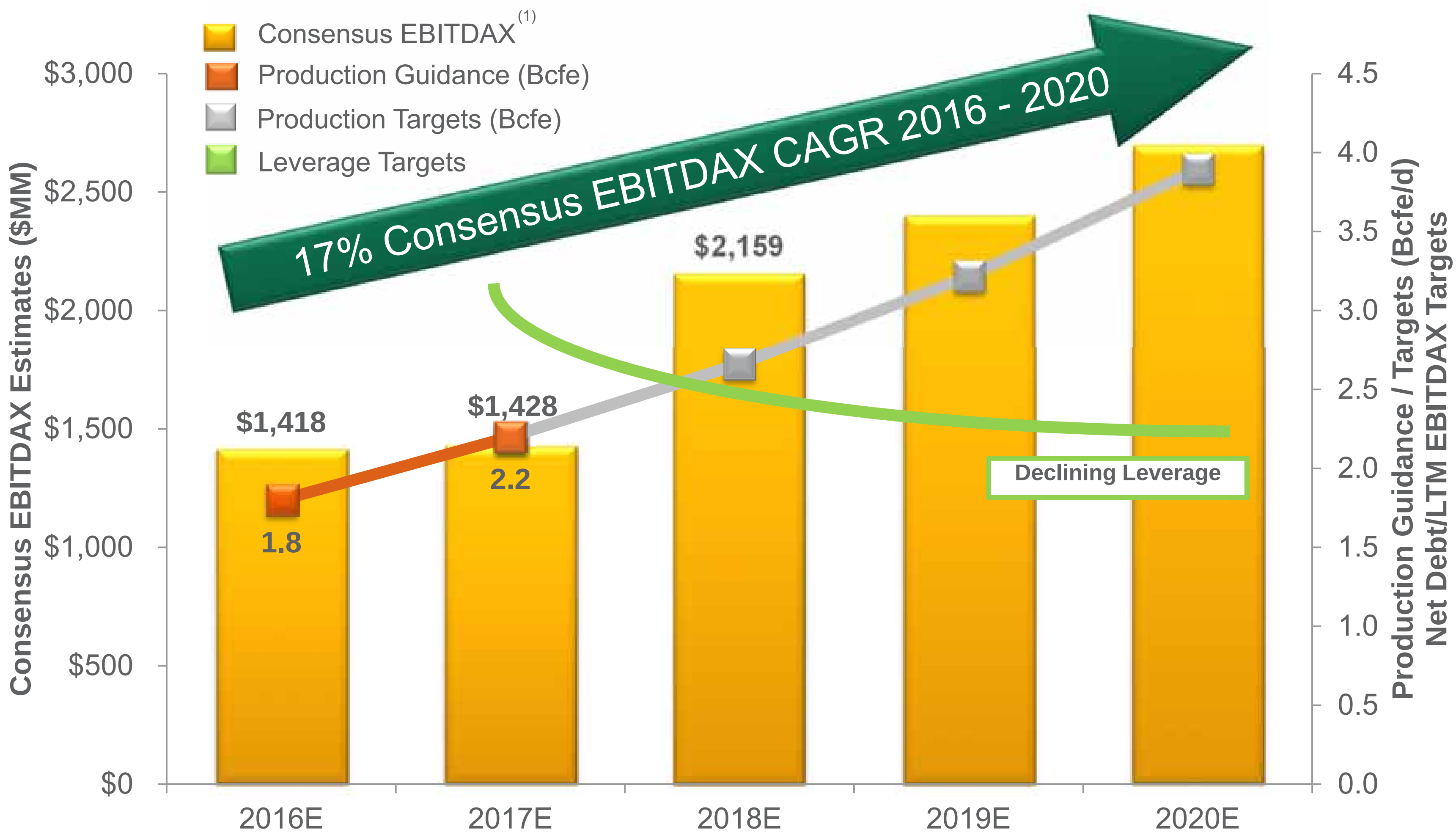
Cumulative EBITDAX Natural Gas Pricing Exposure 2017 – 2020



Note: For natural gas pricing sensitivity, oil prices assume strip pricing as of 12/30/16. For oil pricing sensitivity, natural gas prices based on strip pricing as of 12/30/16.

SIGNIFICANT CASH FLOW GROWTH – DRIVES DECLINING LEVERAGE PROFILE

Visible cash flow growth given hedges, firm transportation portfolio, and capital efficient long-term development plan targeting 20% to 22% production CAGR

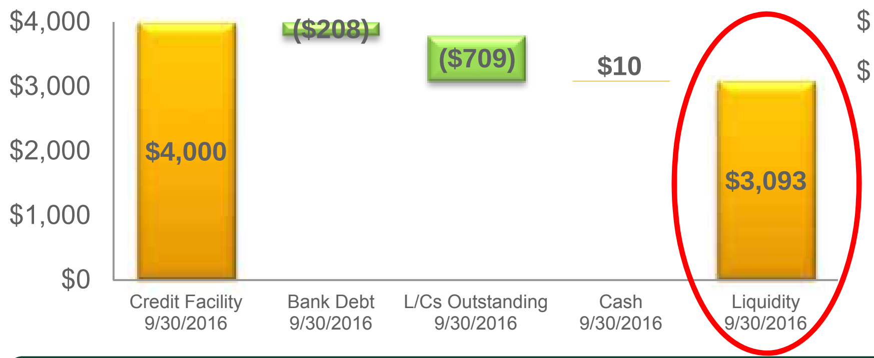


1. *Bloomberg Consensus EBITDAX estimates as of 12/30/2016.*

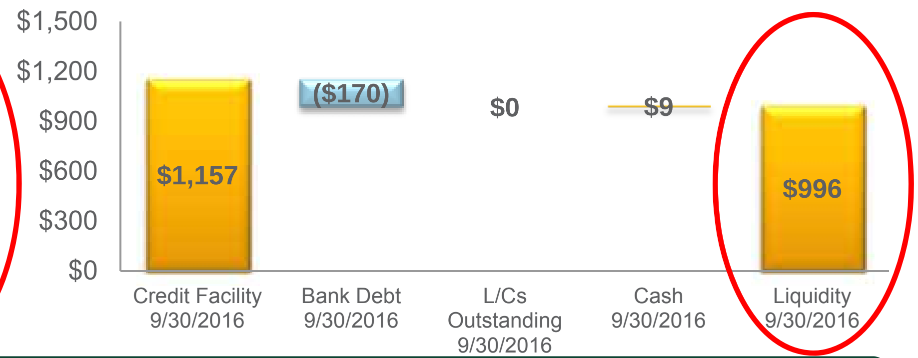
BALANCE SHEET – LIQUIDITY & DEBT TERM STRUCTURE

- Approximately $4.1 billion of combined AR and AM financial liquidity as of 9/30/2016 (1)(2), including $600 million senior note offering
- No leverage covenant in AR bank facility, only interest coverage and working capital covenants

PRO FORMA AR LIQUIDITY POSITION ($MM)(1)(2)

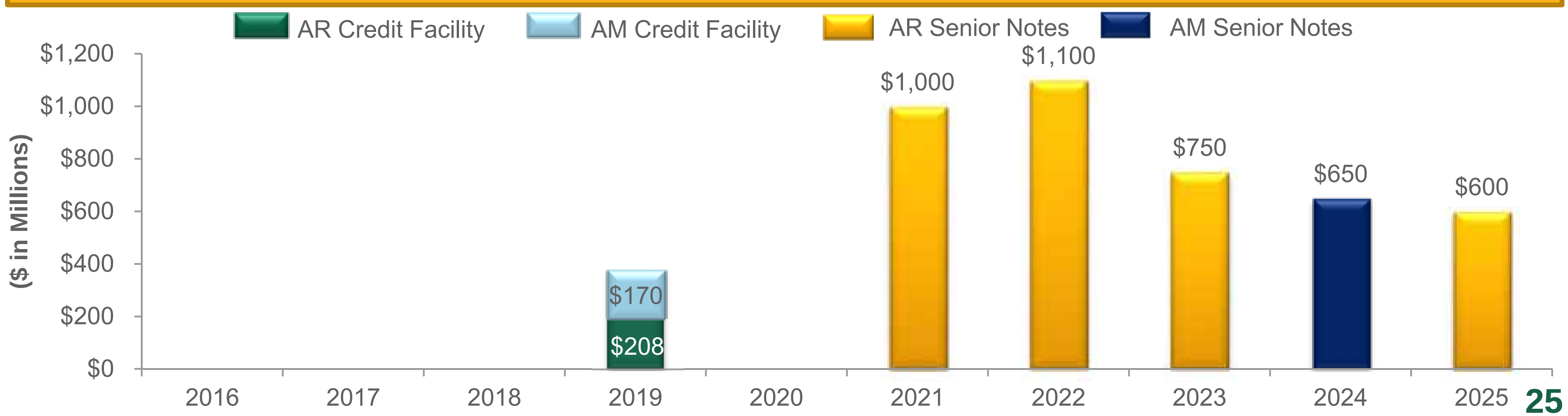


PRO FORMA AM LIQUIDITY POSITION ($MM)



Recent credit facility increases, equity and high yield offerings have allowed Antero to reduce its cost of debt to 5.1% and significantly enhance liquidity with an average debt maturity of January 2023

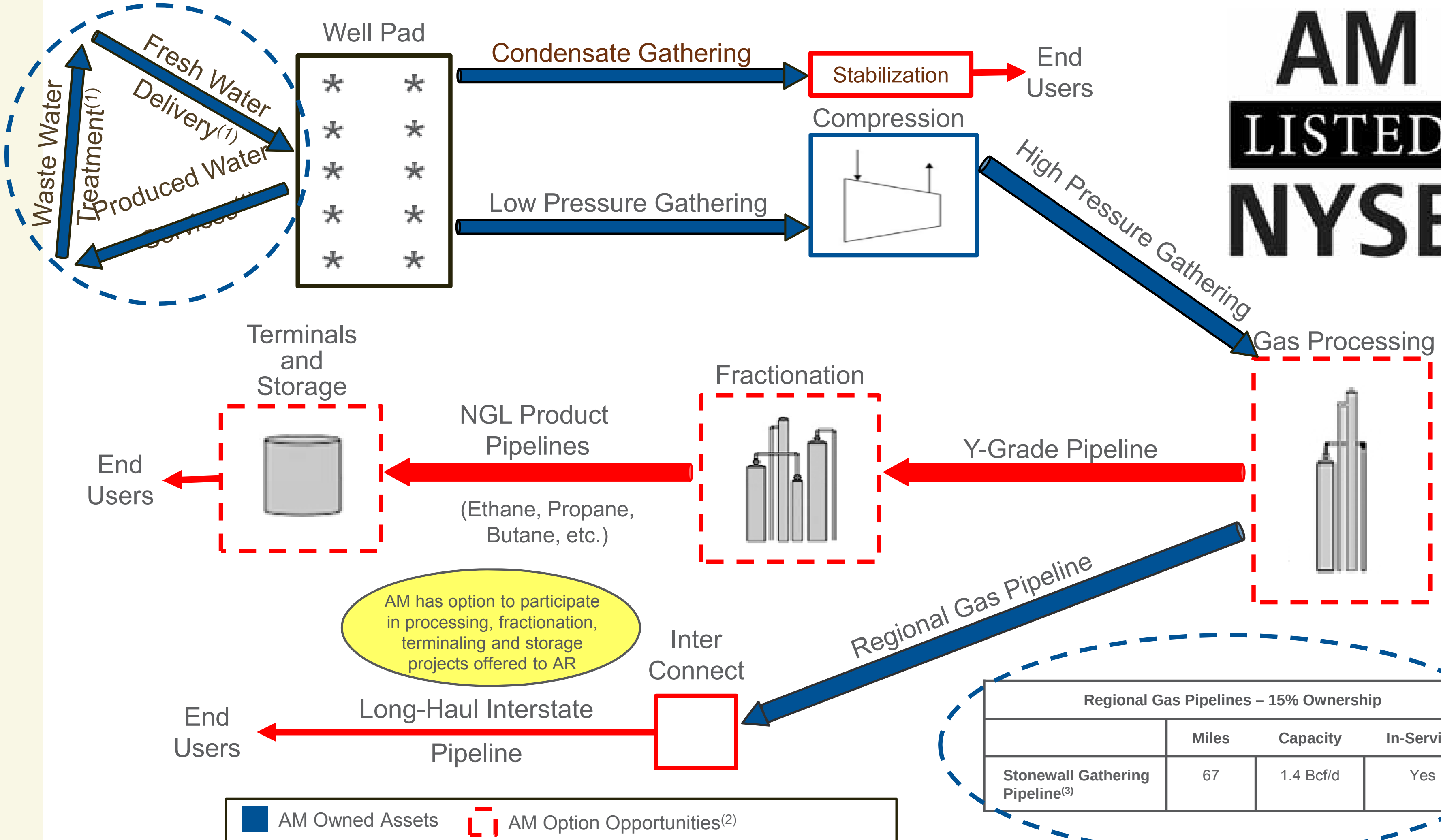
PRO FORMA DEBT MATURITY PROFILE(1)(2)



1. Pro forma for $175 million AR PIPE on 10/3/2016 with net proceeds used to repay AR bank debt and $170 million AR acreage divestiture closed on 12/16/2016.
2. Pro forma for $600 million 5.00% AR senior notes offering closed on 12/21/2016 to refinance $525 million 6% senior notes due 2020 callable at 103% and including transaction expenses.

ANTERO MIDSTREAM – FULL VALUE CHAIN MODEL

Owns a 61% limited partnership interest in Antero Midstream, which has a $2.4 billion project inventory for gathering, compression and water infrastructure buildout through 2020, simply meeting the infrastructure needs of Antero Resources



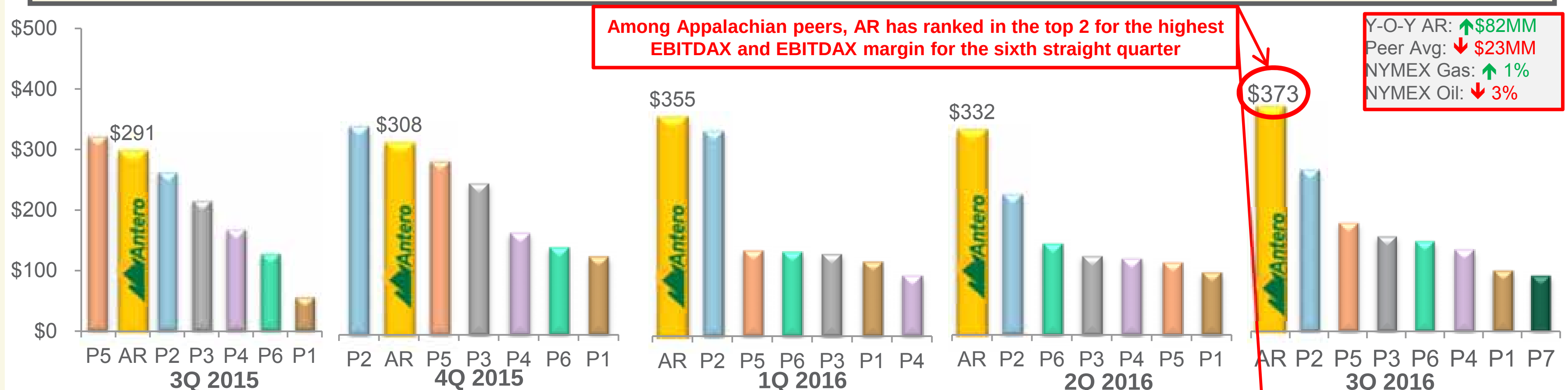
Regional Gas Pipelines – 15% Ownership			
	Miles	Capacity	In-Service
Stonewall Gathering Pipeline[3]	67	1.4 Bcf/d	Yes

1. Acquired by AM from AR for a $1.05 billion upfront payment and a $125 million earn out in each of 2019 and 2020.
2. Antero Midstream has a right of first offer on 225,000 dedicated gross acres for processing and fractionation pro forma for recent acreage acquisition.
3. Antero Midstream owns 15% stake in Stonewall pipeline.

HIGHEST EBITDAX & MARGINS AMONG APPALACHIAN PEERS

Antero has extended its lead among Appalachian Basin peers in both EBITDAX and EBITDAX margin

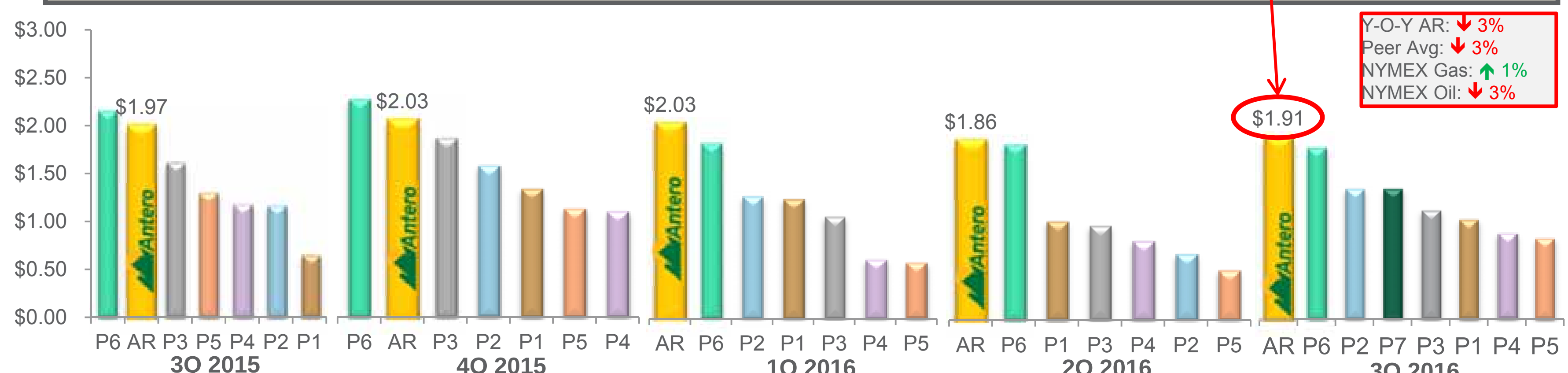
Quarterly Appalachian Peer Group Consolidated EBITDAX ($MM)(1)



AR Peer Group Ranking – Improving Over Time

3Q 2015	4Q 2015	1Q 2016	2Q 2016	3Q 2016
#2	#2	#1	#1	#1

Quarterly Appalachian Peer Group EBITDAX Margin ($/Mcfe)(1)



AR Peer Group Ranking – Top Tier

3Q 2015	4Q 2015	1Q 2016	2Q 2016	3Q 2016
#2	#2	#1	#1	#1

Note: AR, RICE and EQT EBITDAX margin excludes EBITDA from midstream MLP associated with noncontrolling interest. AR consolidated EBITDAX margin for 3Q 2016 was $2.16/Mcfe. CNX excludes EBITDAX contribution from coal operations.

1. Source: Public data from form 10-Qs and 10-Ks and Wall Street research. Peers include COG, CNX, EQT , GPOR, RICE, RRC and SWN where applicable

2017 – 2020 OUTLOOK

Macro

- **Significant natural gas demand growth through 2020**
- **Continued oil and NGL price recovery**

Antero

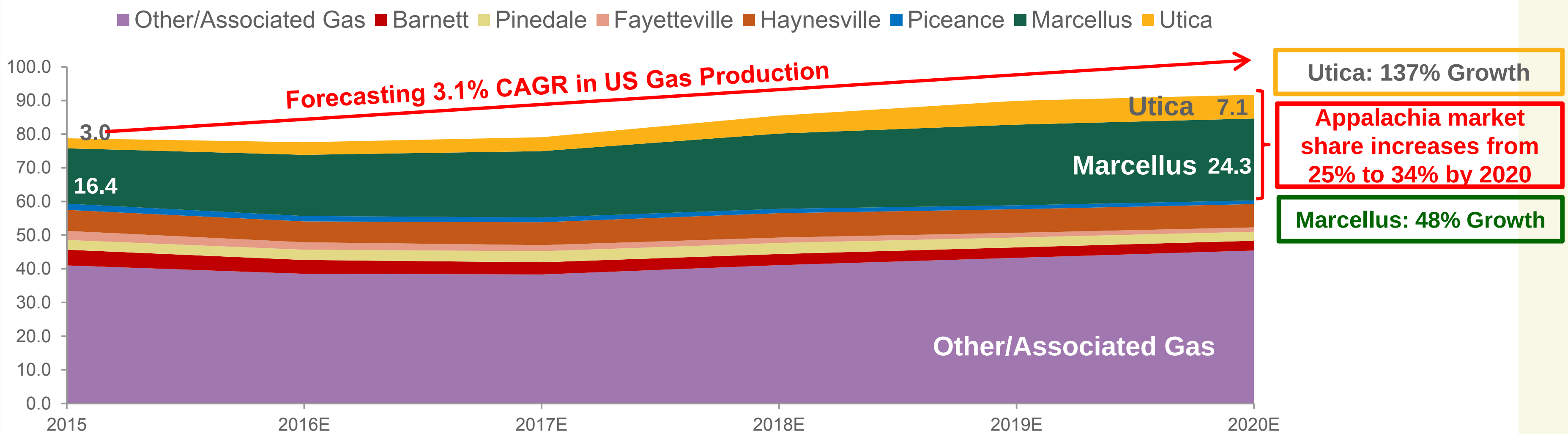
- **20% to 25% production growth guidance for 2017**
- **20% to 22% production growth CAGR targets for 2018 – 2020**
  - *Forecast a $0.05 to $0.15/Mcf premium to NYMEX natural gas prices through 2020*
  - *58% of production targets hedged through 2020 at $3.76/MMBtu*
- **24% to 26% liquids contribution to production**
- **Maintaining D&C spending within consolidated cash flow from operations through 2020**
- **Declining leverage profile to "mid – 2s"**
- **Investing $2.4 billion in midstream project inventory with AM through 2020, with upside exposure to full value chain opportunities**
- **Strong commitment to health, safety and environment**

APPENDIX

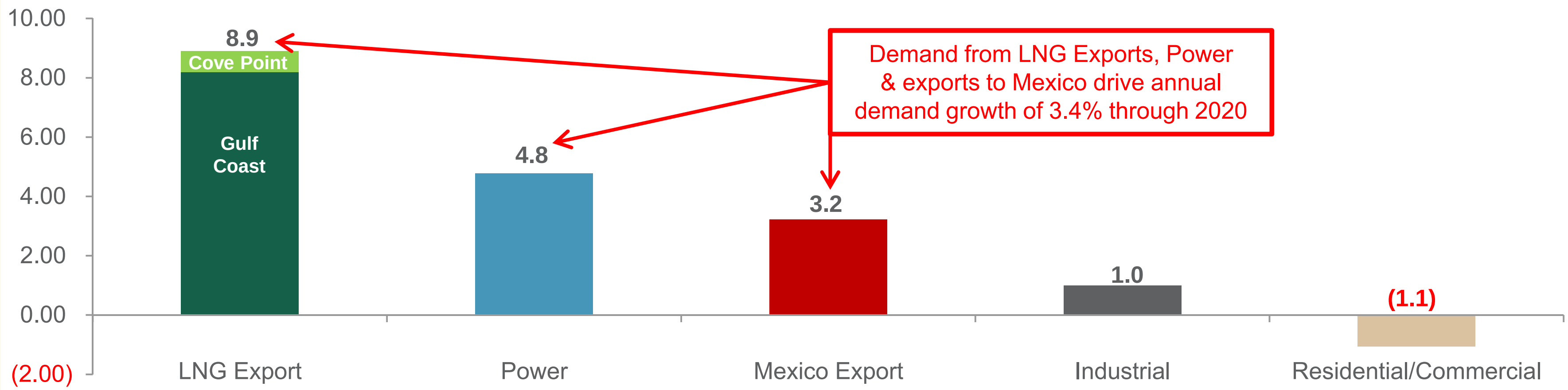
APPALACHIA WILL SUPPLY NATURAL GAS DEMAND GROWTH

- As LNG exports, Mexico exports and power generation drive demand, gas supply growth through 2020 is expected to be primarily driven by the Marcellus and Utica shales, given their low full cycle cost position and increasing takeaway capacity from the northeast
  - *Appalachia represents 93% of the forecasted 12.9 Bcf/d supply growth from 2015 to 2020*

US Gas Production Growth by Basin 2015-2020E (Bcf/d)



Total Incremental US Natural Gas Demand Growth of 16.8 Bcf/d Forecast for 2015-2020E

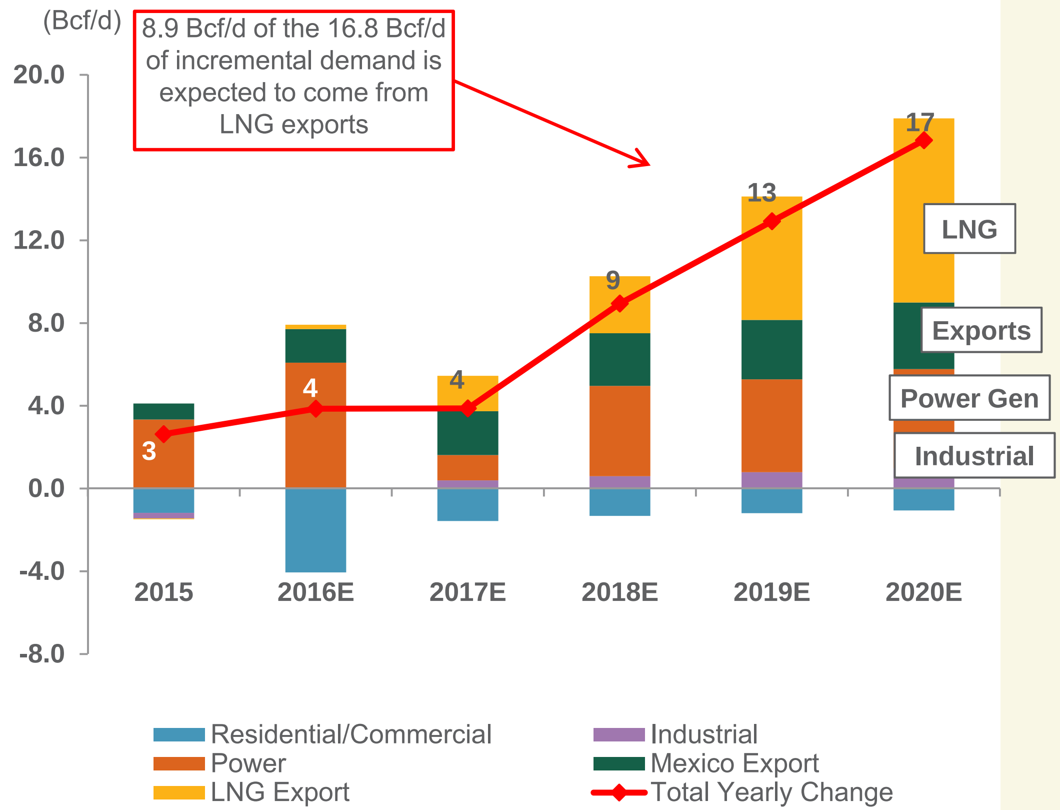


Source: Tudor, Pickering & Holt Research updated 11/25/2016. LNG demand sourced from Natural Gas Intelligence article dated December 23, 2016.

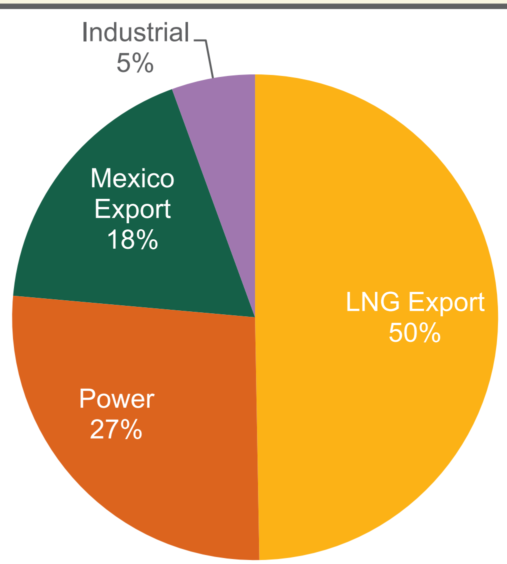
17 BCF/D OF INCREMENTAL GAS DEMAND BY 2020

- Significant demand growth expected for U.S. natural gas
- More than 70% of the ~17 Bcf/d in incremental gas demand forecast by 2020 is expected to be generated from exports:
  - *LNG: 8.9 Bcf/d (~53%)*
  - *Mexico: 3.2 Bcf/d (~19%)*
- Of the 8.9 Bcf/d of expected incremental demand from LNG export projects, over 70% of the projects have secured the necessary DOE and FERC permits

Projected Incremental Natural Gas Demand Through 2020



Incremental Demand Growth Through 2020 by Category



Source: Tudor, Pickering & Holt Research updated 11/25/2016.

ANTERO RESOURCES – 2017 GUIDANCE

Key Operating & Financial Assumptions

Key Variable	2017 Guidance[1]
Net Daily Production (MMcfe/d)	**2,160 – 2,250**
Net Residue Natural Gas Production (MMcf/d)	1,625 – 1,675
Net C3+ NGL Production (Bbl/d)	65,000 – 70,000
Net Ethane Production (Bbl/d)	18,000 – 20,000
Net Oil Production (Bbl/d)	5,500 – 6,500
Net Liquids Production (Bbl/d)	88,500 – 96,500
Natural Gas Realized Price Premium to NYMEX Henry Hub Before Hedging ($/Mcf)[2][3]	+$0.00 – $0.10
Oil Realized Price Differential to NYMEX WTI Oil Before Hedging ($/Bbl)	$(7.00) – $(9.00)
C3+ NGL Realized Price (% of NYMEX WTI)[2]	45% – 50%
Ethane Realized Price (Differential to Mont Belvieu) ($/Gal)	$0.00
Operating:	
Cash Production Expense ($/Mcfe)[4]	$1.55 – $1.65
Marketing Expense, Net of Marketing Revenue ($/Mcfe)	$0.075 – $0.125
G&A Expense ($/Mcfe)	$0.15 – $0.20
Operated Wells Completed	170
Drilled Uncompleted Wells	30
Capital Expenditures ($MM):	
Drilling & Completion	$1,300
Land	$200
Total Capital Expenditures ($MM)	**$1,500**

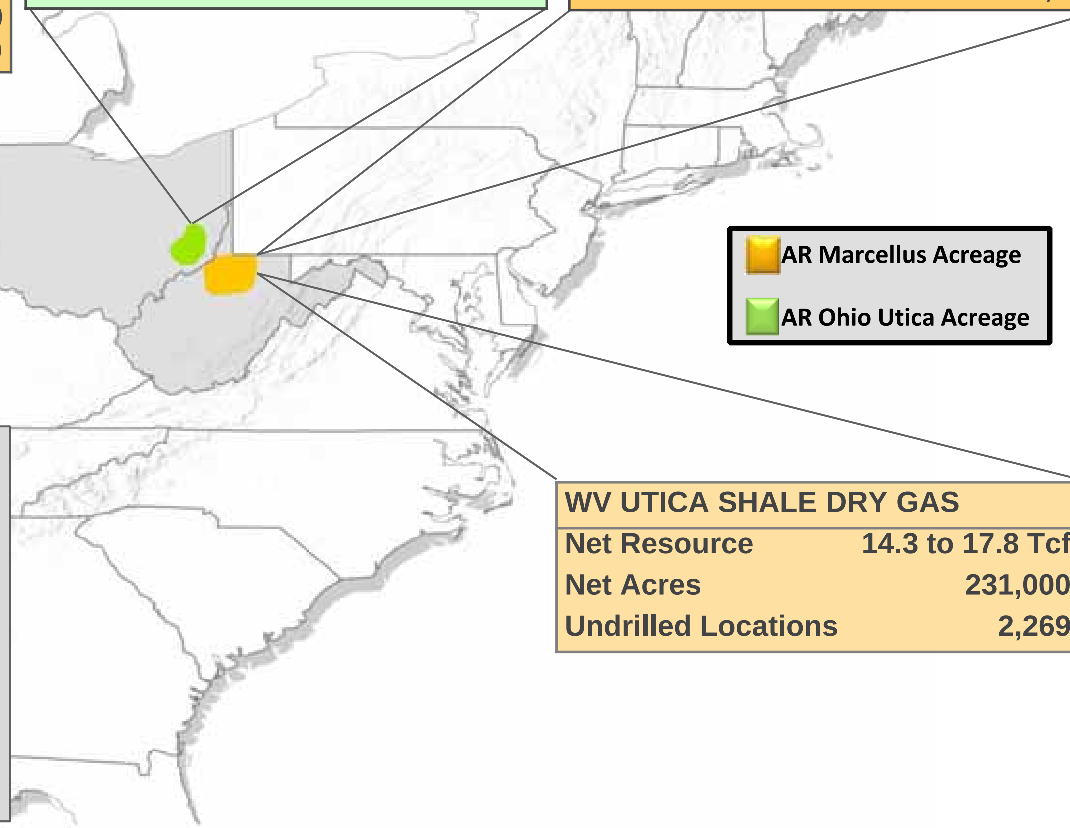
1. Guidance per press release dated 01/04/2017.
2. Based on current strip pricing as of December 30, 2016.
3. Includes Btu upgrade as Antero's processed tailgate and unprocessed dry gas production is greater than 1000 Btu on average.
4. Includes lease operating expenses, gathering, compression and transportation expenses and production taxes.

MOST ACTIVE OPERATOR IN APPALACHIA

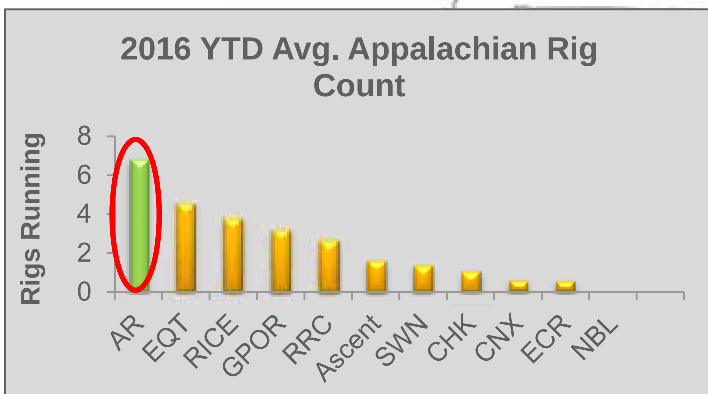
AR COMBINED TOTAL – 12/31/15 RESERVES Assumes Ethane Rejection	
Net Proved Reserves	13.2 Tcfe
Net 3P Reserves[(1)]	42.1 Tcfe
Strip Pre-Tax 3P PV-10[(2)]	$12.7 Bn
Net 3P Reserves & Resource[(1)]	57 to 60 Tcfe
Net Acres[(3)]	629,000
Undrilled Locations	4,122[(1)]

OHIO UTICA SHALE CORE	
Net Proved Reserves	1.8 Tcfe
Net 3P Reserves	7.5 Tcfe
Strip Pre-Tax 3P PV-10[(2)]	$2.5 Bn
Net Acres	145,000
Undrilled 3P Locations	840

MARCELLUS SHALE CORE	
Net Proved Reserves	11.4 Tcfe
Net 3P Reserves[(1)]	34.6 Tcfe
Strip Pre-Tax 3P PV-10[(2)]	$10.2 Bn
Net Acres[(3)]	484,000
Undrilled 3P Locations[(1)]	3,282



WV UTICA SHALE DRY GAS	
Net Resource	14.3 to 17.8 Tcf
Net Acres	231,000
Undrilled Locations	2,269



Note: 2015 SEC prices were $2.56/MMBtu for natural gas and $50.13/Bbl for oil on a weighted average Appalachian index basis.
1. *3P reserve additions are unaudited. 14 to 18 Tcf Utica dry resource in WV/PA.*
2. *3P reserve pre-tax PV-10 based on annual strip pricing for first 10-years and flat thereafter as of December 31, 2015.*
3. *Marcellus acreage pro forma for acreage divestiture announced on 10/26/2016 and additional leasing and acquisitions year-to-date.*

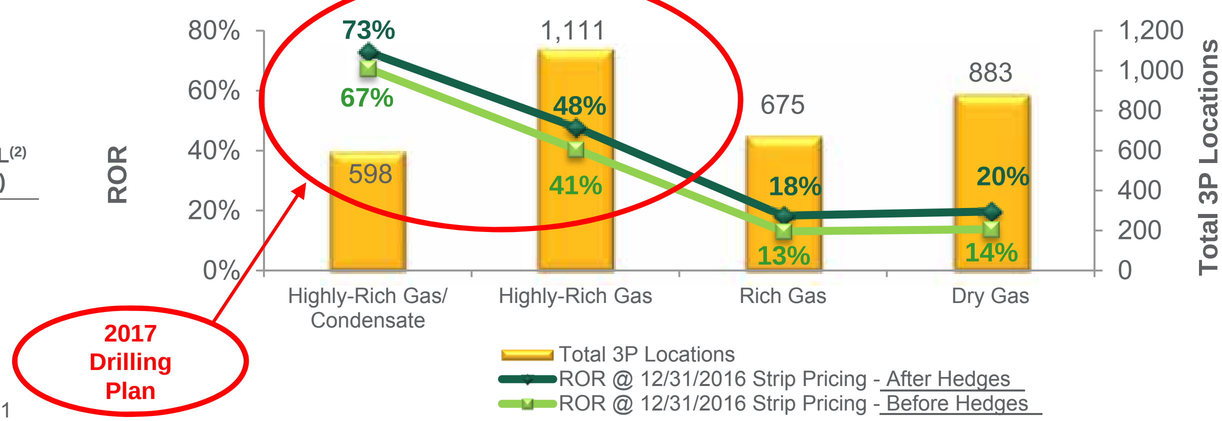
MARCELLUS SINGLE WELL ECONOMICS
– IN ETHANE REJECTION

Assumptions

- Natural Gas – 12/30/2016 strip
- Oil – 12/30/2016 strip
- NGLs –~50% of Oil Price 2017+

	NYMEX ($/MMBtu)	WTI ($/Bbl)	C3+ NGL[2] ($/Bbl)
2017	$3.61	$56	$28
2018	$3.14	$57	$30
2019	$2.87	$56	$30
2020	$2.88	$56	$30
2021	$2.90	$56	$30
2022-26	$2.93-$3.46	$57-$58	$30-$31

Marcellus Well Economics and Total Gross Locations[1]



Classification	Highly-Rich Gas/ Condensate	Highly-Rich Gas	Rich Gas	Dry Gas
Modeled BTU	**1313**	**1250**	**1150**	**1050**
EUR (Bcfe):	20.8	18.8	16.8	15.3
EUR (MMBoe):	3.5	3.1	2.8	2.6
% Liquids:	33%	24%	12%	0%
Lateral Length (ft):	9,000	9,000	9,000	9,000
Well Cost ($MM):	$7.8	$7.8	$7.8	$7.8
Bcfe/1,000’:	2.3	2.1	1.9	1.7
Net F&D ($/Mcfe):	$0.45	$0.49	$0.55	$0.60
Direct Operating Expense ($/well/month):	$1,353	$1,353	$1,353	$1,353
Direct Operating Expense ($/Mcf):	$0.96	$0.96	$1.20	$0.74
Transportation Expense ($/Mcf):	$0.44	$0.44	$0.44	$0.44
Pre-Tax NPV10 ($MM):	$11.5	$7.1	$0.7	$0.8
Pre-Tax ROR:	67%	41%	13%	14%
Payout (Years):	1.2	1.9	6.6	6.3
Gross 3P Locations in BTU Regime[3]:	661	1,048	675	883

1. *12/30/2016 pre-tax well economics based on 1.7 Bcf/1,000’ type curve for a 9,000’ lateral, 12/30/2016 natural gas and WTI strip pricing for 2017-2026, flat thereafter, NGLs at ~50% of WTI thereafter, and applicable firm transportation and operating costs including 50% of Antero Midstream fees. Well cost estimates include $1.2 million for road, pad and production facilities.*
2. *Pricing for a 1225 BTU y-grade ethane rejection barrel. NGLs at ~50% of WTI for 2017 and thereafter. NGL prices are forecast to increase in 2017 relative to WTI due to projected in-service date of Mariner East 2 project allowing for a significant increase in AR NGL exports via ship.*
3. *Undeveloped well locations as of 12/31/2015 adjusted for 6/30/2016 net acreage and pro forma for 625 added through recent acreage acquisition.*

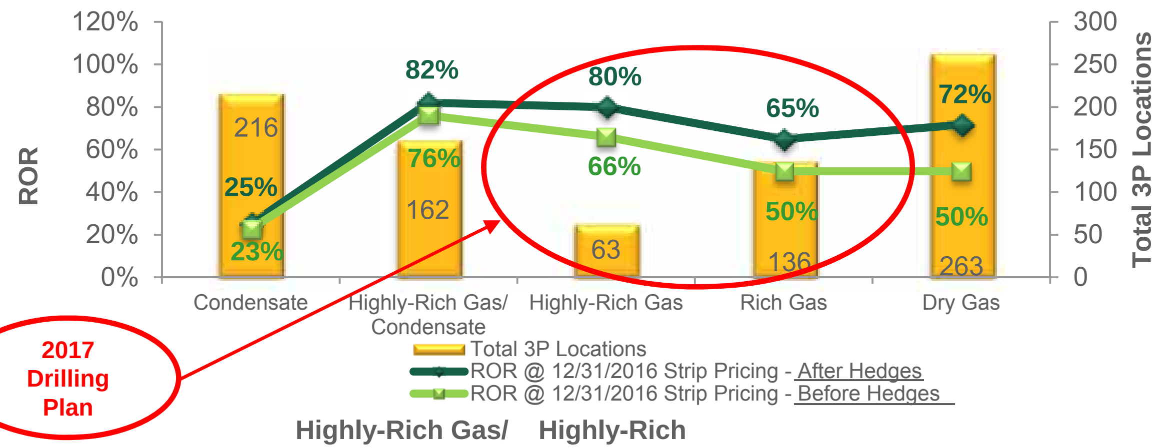
UTICA SINGLE WELL ECONOMICS – IN ETHANE REJECTION

Assumptions

- Natural Gas – 12/30/2016 strip
- Oil – 12/30/2016 strip
- NGLs –~50% of Oil Price 2017+

	NYMEX ($/MMBtu)	WTI ($/Bbl)	C3+ NGL[2] ($/Bbl)
2017	$3.61	$56	$28
2018	$3.14	$57	$30
2019	$2.87	$56	$30
2020	$2.88	$56	$30
2021	$2.90	$56	$30
2022-26	$2.93-$3.46	$57-$58	$30-$31

Utica Well Economics and Gross Locations[1]

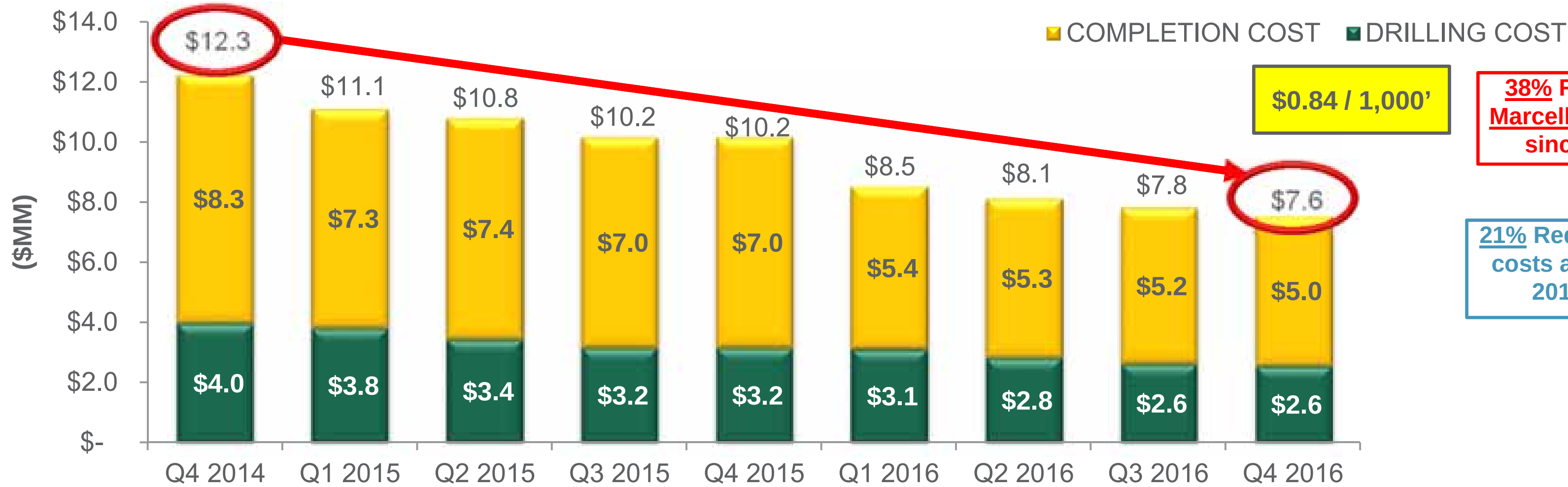


Classification	Condensate	Highly-Rich Gas/ Condensate	Highly-Rich Gas	Rich Gas	Dry Gas
Modeled BTU	**1275**	**1235**	**1215**	**1175**	**1050**
EUR (Bcfe):	9.9	17.9	25.0	24.1	21.4
EUR (MMBoe):	1.7	3.0	4.2	4.0	3.6
% Liquids	39%	31%	19%	15%	0%
Lateral Length (ft):	9,000	9,000	9,000	9,000	9,000
Well Cost ($MM):	$8.9	$8.9	$9.4	$9.4	$9.4
Bcfe/1,000':	1.1	2.0	2.8	2.7	2.4
Net F&D ($/Mcfe):	$1.10	$0.61	$0.47	$0.48	$0.54
Fixed Operating Expense ($/well/month):	$3,011	$3,011	$3,011	$3,011	$1,353
Direct Operating Expense ($/Mcf):	$1.04	$1.04	$1.04	$1.04	$0.54
Direct Operating Expense ($/Bbl):	$2.93	$2.93	$2.93	-	-
Transportation Expense ($/Mcf):	$0.53	$0.53	$0.53	$0.53	$0.53
Pre-Tax NPV10 ($MM):	$3.27	$10.6	$11.4	$8.9	$8.8
Pre-Tax ROR:	23%	76%	66%	50%	50%
Payout (Years):	3.3	1.1	1.2	1.4	1.4
Gross 3P Locations in BTU Regime[3]:	216	176	49	136	263

1. 12/30/2016 pre-tax well economics based on a 9,000' lateral, 12/30/2016 natural gas and WTI strip pricing for 2016-2025, flat thereafter, NGLs at 37.5% of WTI for 2016 and ~50% of WTI thereafter, and applicable firm transportation and operating costs including 50% of Antero Midstream fees. Well cost estimates include $1.2 million for road, pad and production facilities.
2. Pricing for a 1225 BTU y-grade ethane rejection barrel. NGLs at 37.5% of WTI for 2016 and ~50% of WTI for 2017 and thereafter. NGL prices are forecast to increase in 2017 relative to WTI due to projected in-service date of Mariner East 2 project allowing for a significant increase in AR NGL exports via ship.
3. Undeveloped well locations as of 12/31/2016. 3P locations representative of BTU regime; EUR and economics within regime will vary based on BTU content.

WELL COST REDUCTIONS

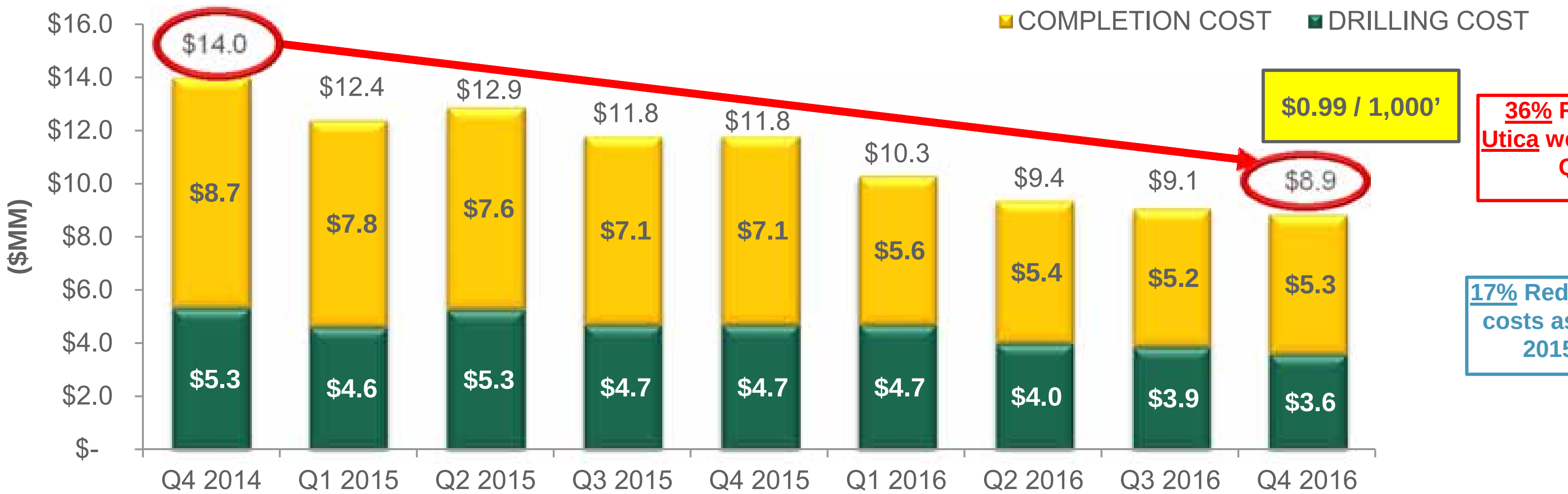
Marcellus Well Cost Reductions for a 9,000' Lateral ($MM)[1]



38% Reduction in Marcellus well costs since Q4 2014

21% Reduction vs. well costs assumed in YE 2015 reserves

Utica Well Cost Reductions for a 9,000' Lateral ($MM)[2]



36% Reduction in Utica well costs since Q4 2014

17% Reduction vs. well costs assumed in YE 2015 reserves

NOTE: Based on statistics for drilled wells within each respective period.

1. Based on 200 ft. stage spacing.

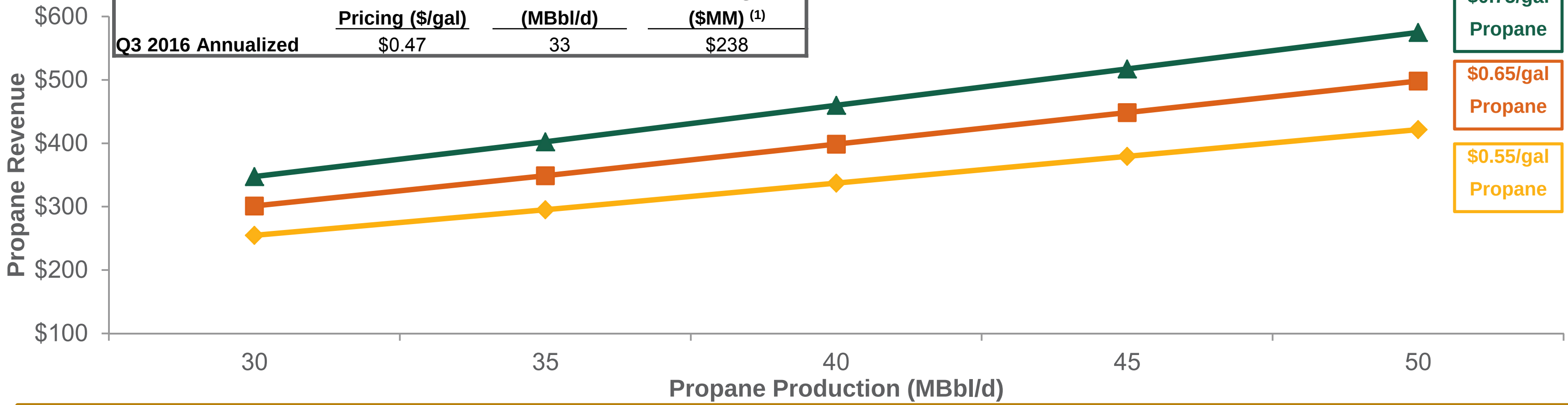
2. Based on 175 ft. stage spacing.

UPSIDE IN C3+ PRICE RECOVERY

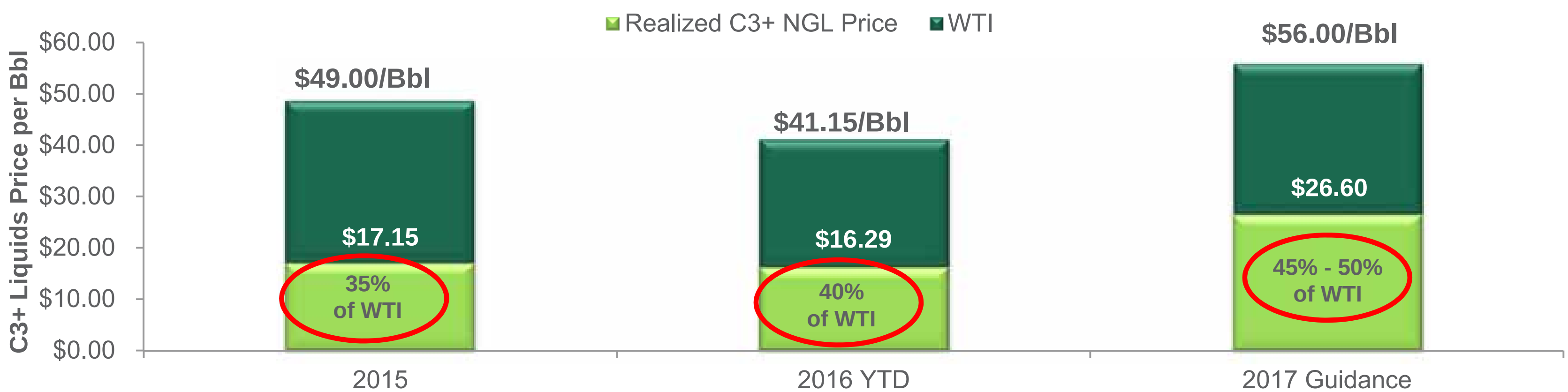
EVERY $0.10/GAL INCREASE IN PROPANE DRIVES AN INCREMENTAL $45 MILLION INCREASE IN ANNUAL REVENUE [1]

Revenue Sensitivity to Propane Recovery

	Mont Belvieu Pricing ($/gal)	Production (MBbl/d)	Propane Revenue @ MTB ($MM) [1]
Q3 2016 Annualized	$0.47	33	$238



C3+ NGL Pricing Guidance [2]

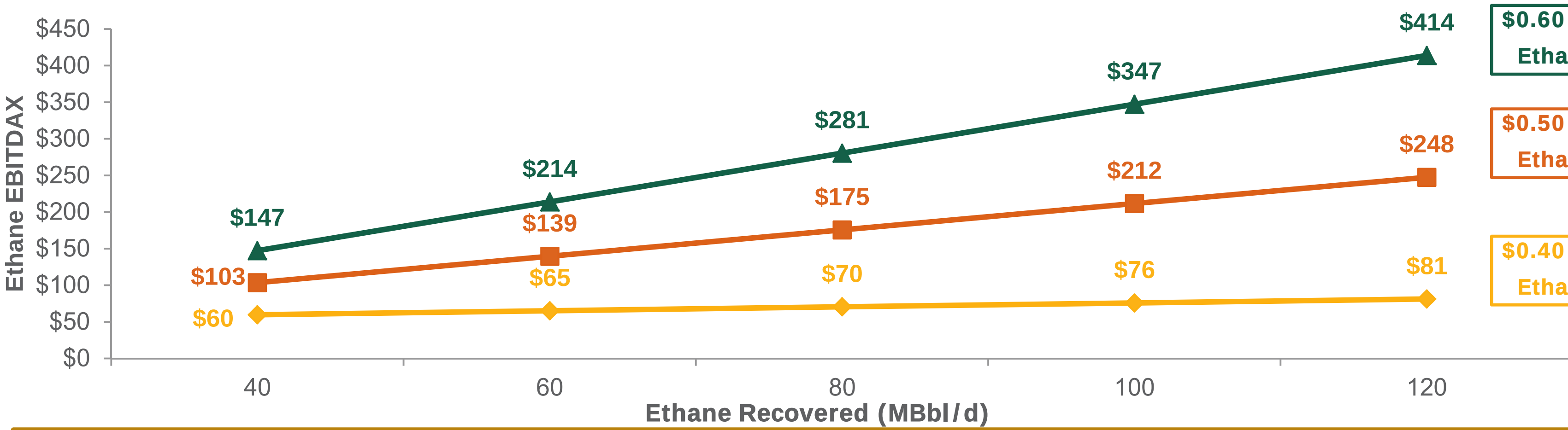


1. *Based on Mont Belvieu (MB) pricing as of 12/30/2016, before Northeast differentials.*
2. *Based on strip pricing as of 12/30/2016 and associated NGL differentials to Mont Belvieu.*

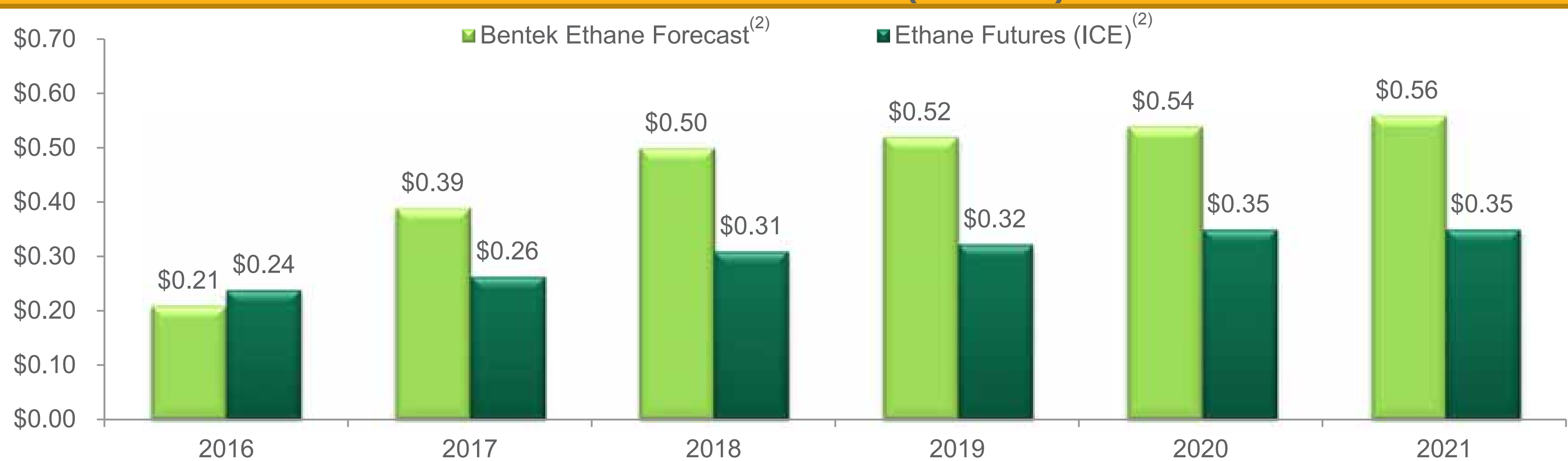
ANTERO HAS SIGNIFICANT EXPOSURE TO UPSIDE IN ETHANE (C2) PRICES

BENTEK FORECASTS ETHANE PRICES TO INCREASE TO MORE THAN $0.50 / GALLON BY 2018 AND BEYOND

Incremental EBITDAX Attributable to Ethane Recovery(1)



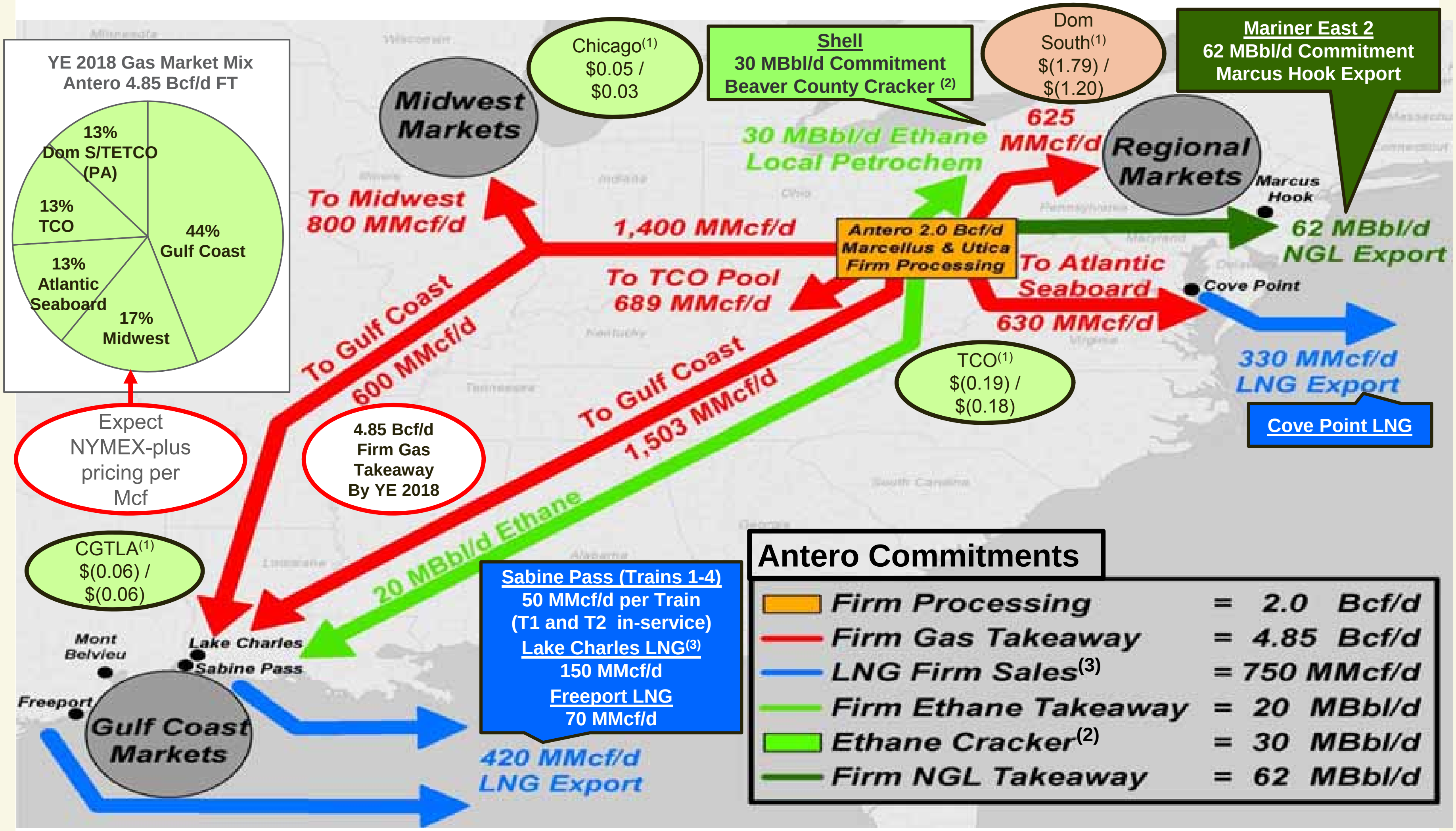
Ethane Price Forecasts ($/Gallon)(1)



1. *Represents incremental EBITDA associated with ethane recovery (vs. rejection) at prices ranging from $0.40 to $0.60 per gallon. Assumes (1) ATEX costs are sunk up to 20,000 Bbl/d, (2) $3.00 NYMEX natural gas prices and (3) Borealis firm sale at NYMEX plus pricing.*
2. *Ethane futures data from ICE as of 9/30/2016. Bentek forecast as of 4/26/2016.*
3. *Represents ethane price required to match TCO strip sales price on a realized basis, assuming 20,000 Bbl/d of ATEX costs are sunk.*

LARGEST FT PORTFOLIO IN NORTHEAST

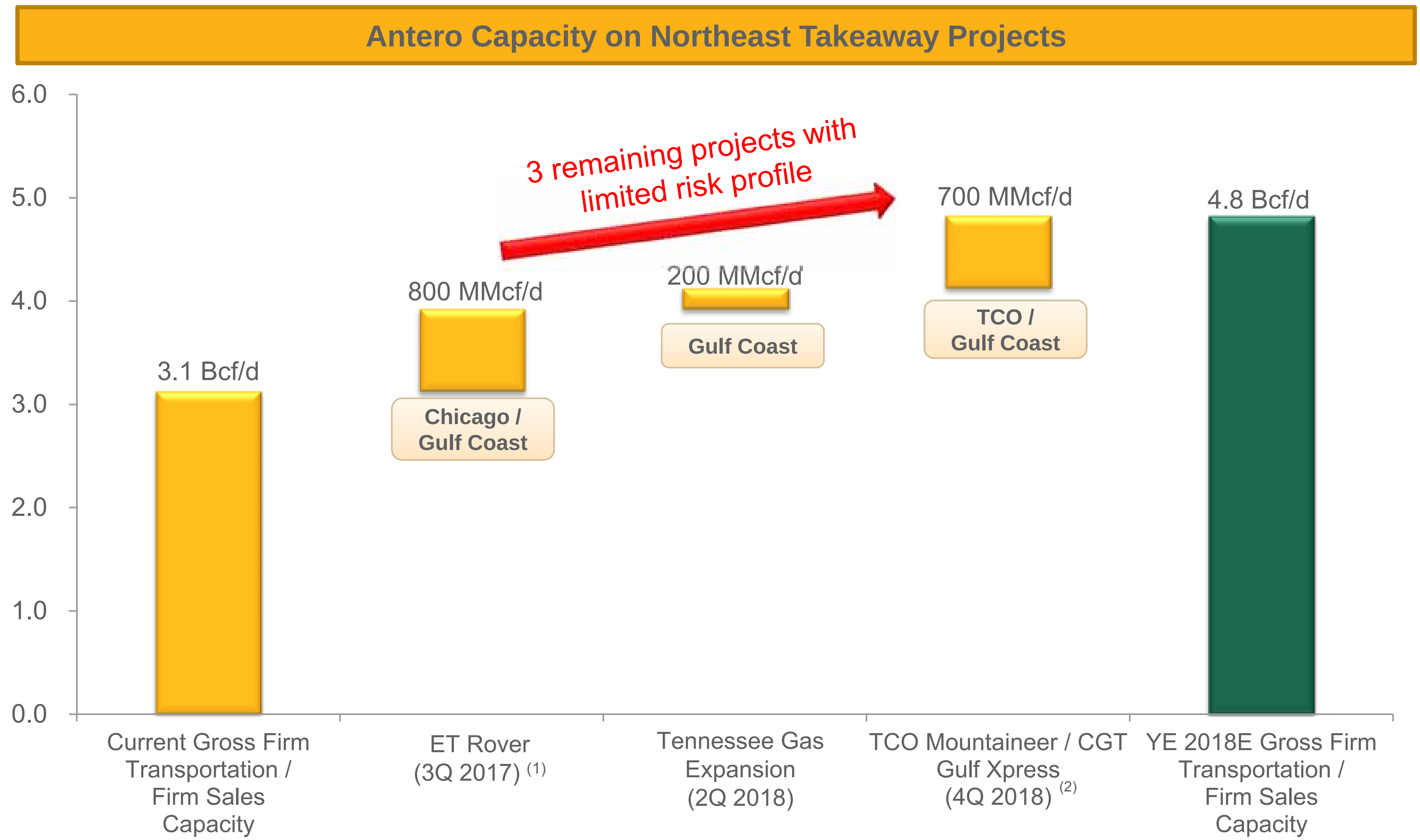
Antero Long Term Firm Processing & Takeaway Position (YE 2018) – Accessing Favorable Markets



1. November 2016 and full year 2017 futures basis, respectively, provided by Intercontinental Exchange dated 9/30/2016. Favorable markets shaded in green.
2. Shell announced final investment decision (FID) on 6/7/2016.
3. Lake Charles LNG 150 MMcf/d commitment subject to Shell FID.

INCREMENTAL ANTERO TAKEAWAY CAPACITY

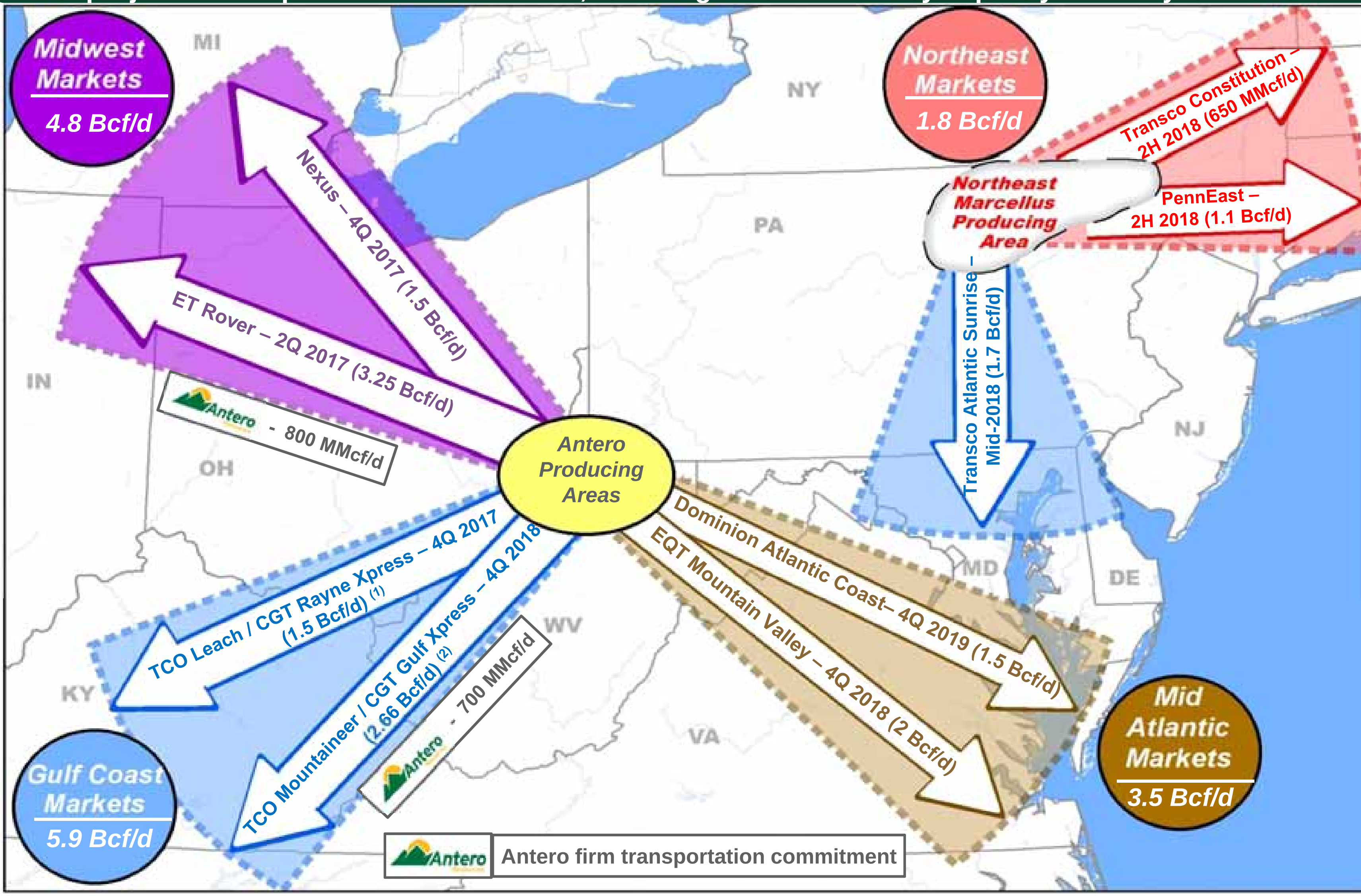
Approximately 65% of Antero's expected firm transportation capacity is in service today



1. *Antero has contracted for downstream capacity of 800 MMcf/d that would be available today if Rover were in-service.*
2. *Represents 700 MMcf/d of capacity on TCO Mountaineer that can be sold into TCO pool and 183 MMcf/d of capacity available on CGT Gulf Xpress to the Gulf Coast markets.*

KEY APPALACHIAN TAKEAWAY PROJECTS

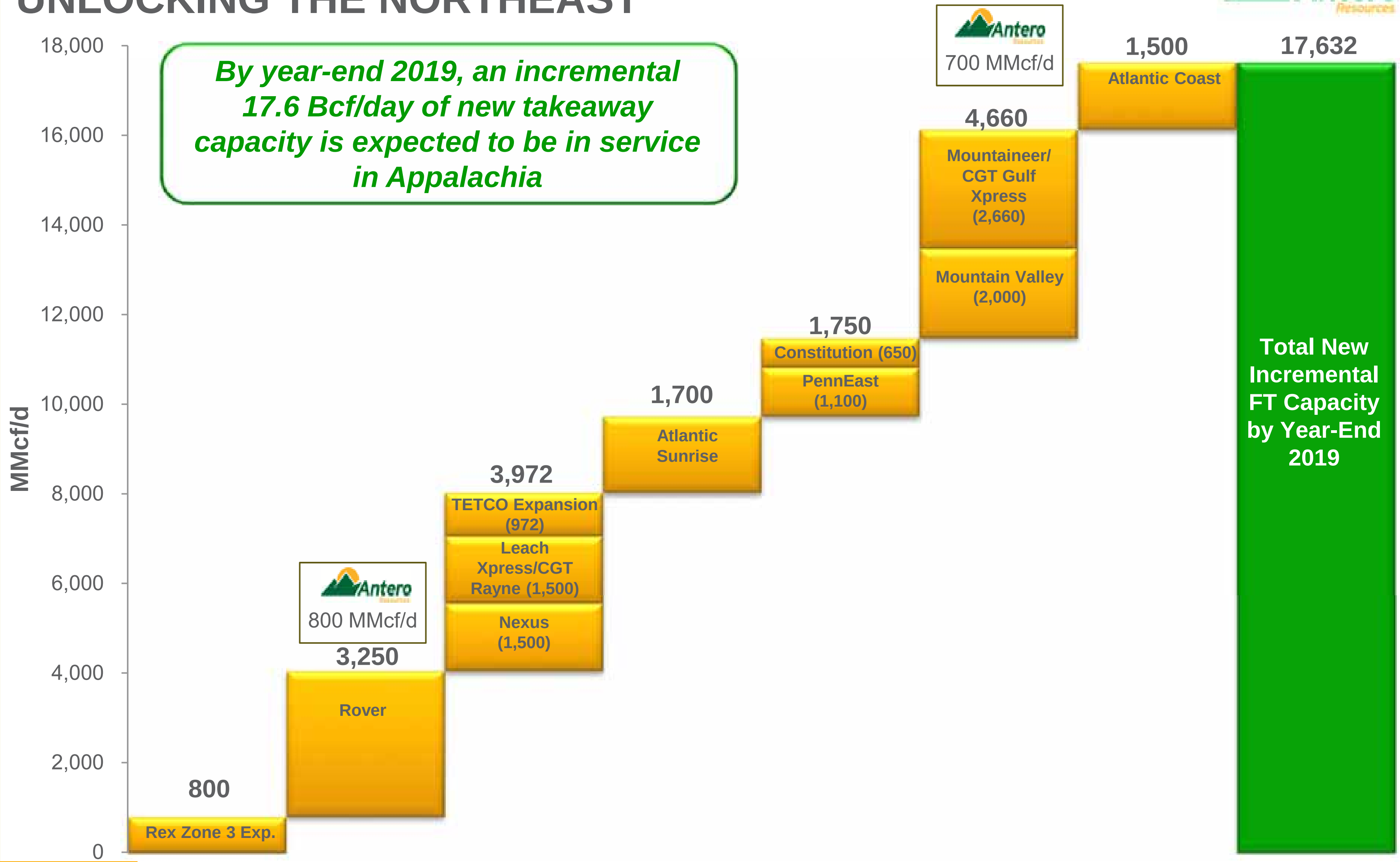
Based on current publicly disclosed in-service dates, by the end of 2019, nine major incremental projects are expected to be in service, resulting in new takeaway capacity of nearly 16 Bcf/d



Source: Public filings and press releases. Excludes Rex Zone 3 and TETCO expansions.

1. *1.05 Bcf/d capacity available to move gas from Leach to the Gulf on CGT Rayne Xpress.*
2. *860 MMcf/d of capacity available on CGT Gulf Xpress to move gas to the Gulf Coast markets.*

KEY APPALACHIAN NEW TAKEAWAY PROJECTS: UNLOCKING THE NORTHEAST

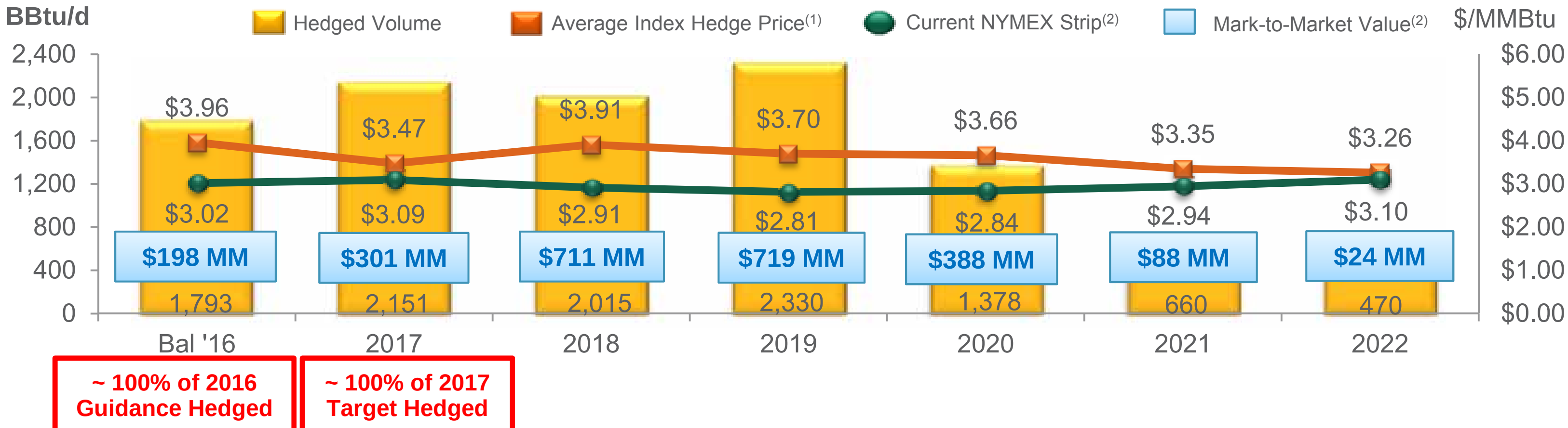


Cumulative Capacity (Bcf/d)	4Q 2016	3Q 2017	4Q 2017	2Q 2018	2H 2018	4Q 2018	4Q 2019	Total
	0.8	4.1	8.0	9.7	11.5	16.1	17.6	17.6

LARGEST GAS HEDGE POSITION IN U.S. E&P

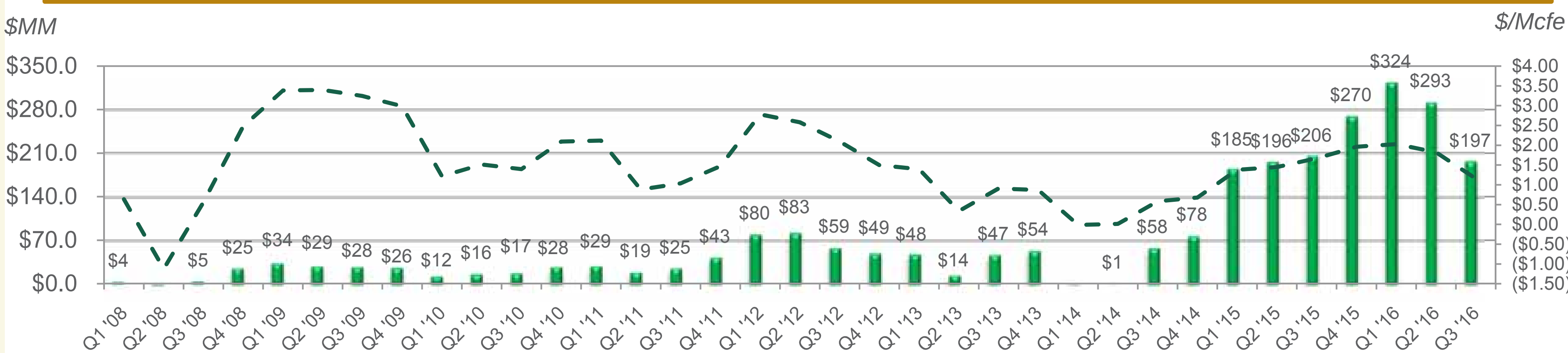
~$2.4 billion mark-to-market unrealized gain based on 9/30/2016 prices with 3.5 Tcfe hedged from October 1, 2016 through year-end 2022 at $3.65 per MMBtu

Commodity Hedge Position



- **Hedging is a key component of Antero's business model due to the large, repeatable drilling inventory**
- **Antero has realized $2.6 billion of gains on commodity hedges since 2008 with gains realized in 33 of last 35 quarters**

Quarterly Realized Gains/(Losses) – 1Q '08 - 3Q '16



1. *Weighted average index price based on volumes hedged assuming 6:1 gas to liquids ratio; excludes impact of TCO basis hedges. 30,000 Bbl/d of propane hedged in 2016, 27,500 Bbl/d hedged in 2017 and 2,000 Bbl/d hedged in 2018. 20,000 Bbl/d of ethane hedged in 2017 and 1,000 Bbl/d of oil hedged in 2017.*
2. *As of 9/30/2016.*

STRONG BALANCE SHEET AND HIGH FLEXIBILITY

Antero Resources (NYSE:AR)

Pro Forma 9/30/2016 Debt[1]

Debt Type	$MM
Credit facility	$208
6.00% senior notes due 2020	-
5.375% senior notes due 2021	1,000
5.125% senior notes due 2022	1,100
5.625% senior notes due 2023	750
5.00% senior notes due 2025	600
Total	**$3,658**

Liquid Non-E&P Assets

Asset Type	$MM
Commodity derivatives[2]	$2,430
AM equity ownership[3]	3,134
Cash	10
Total	**$5,574**

Liquid "non-E&P assets" of $5.6 Bn significantly exceeds total debt of $3.7 billion pro forma for recent transactions

Pro Forma Liquidity

Asset Type	$MM
Cash	$10
Credit facility – commitments[4]	4,000
Credit facility – drawn	(208)
Credit facility – letters of credit	(709)
Total	**$3,093**

Approximately $3.1 billion of liquidity at AR pro forma for recent transactions plus an additional $3.1 billion of AM units

Antero Midstream (NYSE:AM)

9/30/2016 Debt [1]

Debt Type	$MM
Credit facility	$170
5.375% senior notes due 2024	650
Total	**$820**

Liquid Assets

Asset Type	$MM
Cash	$9
Total	**$9**

Only 15% of AM credit facility capacity drawn following recent $650 million senior notes offering

Liquidity

Asset Type	$MM
Cash	$9
Credit facility – capacity	1,157
Credit facility – drawn	(170)
Credit facility – letters of credit	-
Total	**$996**

Approximately $1.0 billion of liquidity at AM following recent senior notes offering

1. *All balance sheet data as of 9/30/2016. Antero Resources pro forma for $175 million private placement on 10/3/2016, $170 million AR acreage divestiture closed on 12/16/2016 and $600 million 5.00% AR senior note offering closed on 12/21/2016 to refinance $525 million 6% senior notes due 2020 callable at 103% and including transaction expenses.*
2. *Mark-to-market as of 9/30/2016.*
3. *Based on AR ownership of AM units and closing price as of 12/30/2016.*
4. *AR credit facility commitments of $4.0 billion, borrowing base of $4.75 billion.*

ANTERO CAPITALIZATION – CONSOLIDATED

($ in millions)	9/30/2016	Pro Forma[4] 9/30/2016	As Adjusted Pro Forma[5] 9/30/2016
Cash	$19	$19	$19
AR Senior Secured Revolving Credit Facility	605	260	208
AM Bank Credit Facility	170	170	170
6.00% Senior Notes Due 2020	525	525	-
5.375% Senior Notes Due 2021	1,000	1,000	1,000
5.125% Senior Notes Due 2022	1,100	1,100	1,100
5.625% Senior Notes Due 2023	750	750	750
5.00% Senior Notes Due 2025			600
5.375% Senior Notes Due 2024 – AM	650	650	650
Net Unamortized Premium	6	6	6
Total Debt	$4,806	$4,461	$4,483
Net Debt	$4,787	$4,442	$4,465
Financial & Operating Statistics			
LTM EBITDAX[1]	$1,368	$1,368	$1,368
LTM Interest Expense[2]	$249	$243	$241
Proved Reserves (Bcfe) (12/31/2015)	13,215	13,215	13,215
Proved Developed Reserves (Bcfe) (12/31/2015)	5,838	5,838	5,838
Credit Statistics			
Net Debt / LTM EBITDAX	3.5x	3.2x	3.3x
Net Debt / Net Book Capitalization	37%	35%	35%
Net Debt / Proved Developed Reserves ($/Mcfe)	$0.82	$0.76	$0.76
Net Debt / Proved Reserves ($/Mcfe)	$0.36	$0.34	$0.34
Liquidity			
Credit Facility Commitments[3]	$5,157	$5,157	$5,157
Less: Borrowings	(775)	(430)	(378)
Less: Letters of Credit	(709)	(709)	(709)
Plus: Cash	19	19	19
Liquidity (Credit Facility + Cash)	**$3,692**	**$4,037**	**$4,089**

AR LISTED NYSE

AM LISTED NYSE

1. *LTM and 9/30/2016 EBITDAX reconciliation provided in Appendix.*
2. *LTM interest expense adjusted for all capital market transactions since 1/1/2015.*
3. *AR lender commitments at $4.0 billion and borrowing base capacity at $4.75 billion. AM credit facility capacity at $1,157 million.*
4. *Pro forma for $175 million AR PIPE on 10/3/2016 with net proceeds used to repay bank facility and $170 million AR acreage divestiture announced on 10/26/2016 and expected to close in December 2016.*
5. *Pro forma for $600 million 5.00% AR senior notes offering announced on 12/7/2016 to refinance $525 million 6.00% senior notes at 103% and including transaction expenses. Assumes redemption of 6% senior notes.*

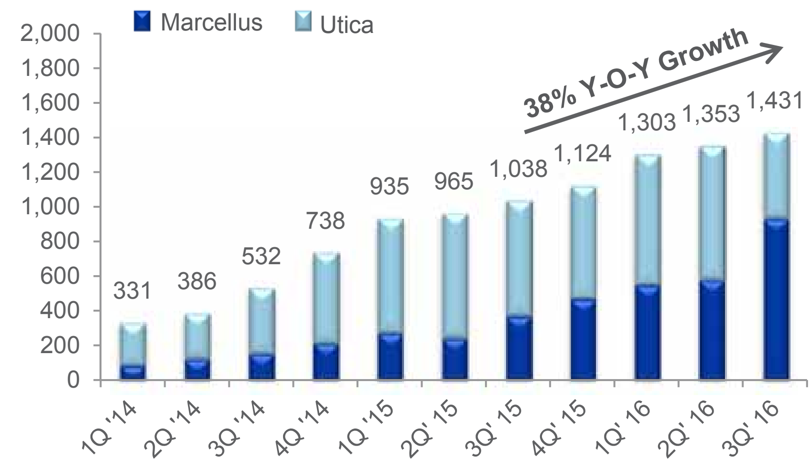
ANTERO RESOURCES EBITDAX RECONCILIATION

EBITDAX Reconciliation

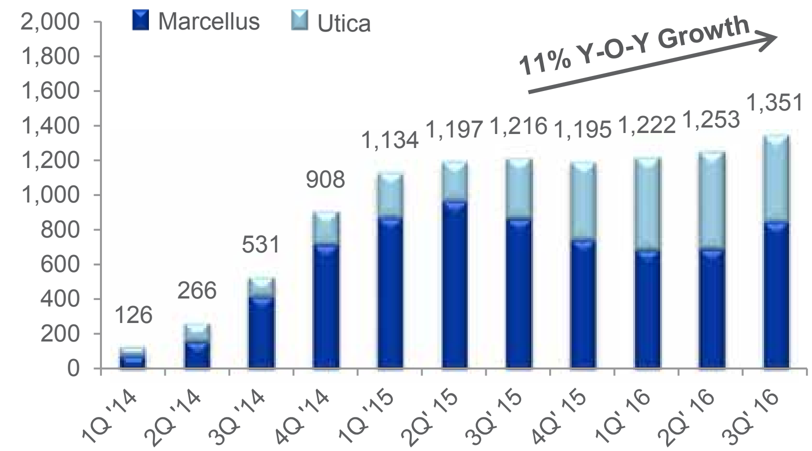
($ in millions)	Quarter Ended 9/30/2016	LTM Ended 9/30/2016
EBITDAX:		
Net income including noncontrolling interest	$268.2	$(121.1)
Commodity derivative fair value (gains)	(530.4)	(670.7)
Net cash receipts on settled derivatives instruments	196.7	1,083.5
Interest expense	59.8	246.1
Income tax expense (benefit)	140.9	(153.6)
Depreciation, depletion, amortization and accretion	199.7	752.1
Impairment of unproved properties	11.8	107.9
Exploration expense	1.2	4.0
Equity-based compensation expense	26.4	94.3
Equity in earnings of unconsolidated affiliate	(1.5)	(2.0)
Contract termination and rig stacking	0.0	27.6
Consolidated Adjusted EBITDAX	**$372.8**	**$1,368.1**

HIGH GROWTH MIDSTREAM THROUGHPUT

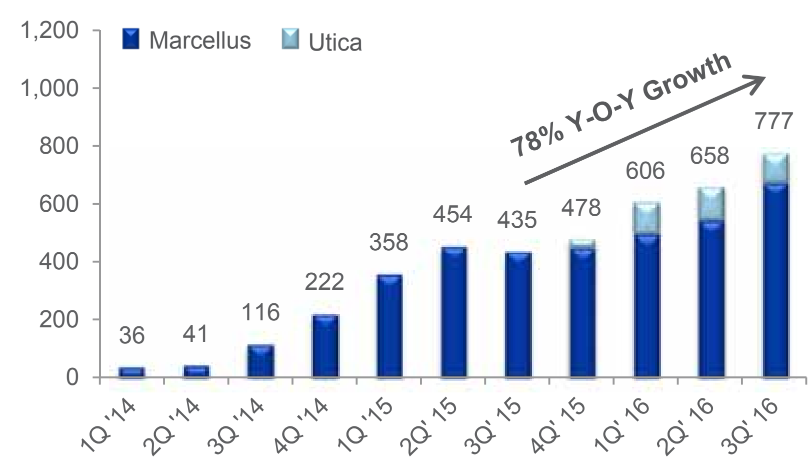
Low Pressure Gathering (MMcf/d)



High Pressure Gathering (MMcf/d)



Compression (MMcf/d)



Adjusted EBITDA ($MM)(1)

Note: Y-O-Y growth based on 3Q'15 to 3Q'16.

ANTERO MIDSTREAM EBITDA RECONCILIATION

EBITDA and DCF Reconciliation

$ in thousands	Nine months ended September 30, 2015	Nine months ended September 30, 2016
Reconciliation of Net Income to Adjusted EBITDA and Distributable Cash Flow:		
Net income	$110,097	$163,352
Interest expense	5,266	12,885
Depreciation expense	63,515	74,100
Accretion of contingent acquisition consideration	-	10,384
Equity-based compensation	17,663	19,366
Equity in earnings from unconsolidated affiliate	-	(2,027)
Adjusted EBITDA	$196,541	$278,060
Pre-Water Acquisition net income attributed to parent	(40,193)	-
Pre-Water Acquisition depreciation expense attributed to parent	(18,767)	-
Pre-Water Acquisition equity-based compensation expense attributed to parent	(3,445)	-
Pre-Water Acquisition interest expense attributed to parent	(2,326)	-
Adjusted EBITDA attributable to the Partnership	131,810	278,060
Cash interest paid - attributable to Partnership	(2,215)	(11,751)
Cash reserved for payment of income tax witholding upon vesting of Antero Midstream LP equity-based compensation awards	-	(3,000)
Cash to be received from unconsolidated affiliate	-	2,998
Maintenance capital expenditures attributable to Partnership	(10,001)	(16,156)
Distributable Cash Flow	$119,594	$250,151

CAUTIONARY NOTE

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, 2015 included in this presentation have been audited by Antero’s third-party engineers. Unless otherwise noted, reserve estimates as of December 31, 2015 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, 2015. 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.