ANTERO
RESOURCES

Company Overview

January 2013

Antero Resources Snapshot

- **Private E&P company headquartered in Denver, Colorado – extensive shale experience**
  - Drilled and operated over 330 horizontal shale wells in Barnett, Woodford, Marcellus and Utica Shales
- **Appalachian Shale-Focused – a "pure play" company with upstream and midstream assets**
  - Marcellus Shale: 294,000 net acres all located in the southwestern core area, 124 horizontal wells completed
  - Utica Shale: 78,000 net acres all located in the southern core of the play, 3 horizontal wells completed
  - Upper Devonian Shale: 194,000 net acres (overlying Marcellus Shale), 2 horizontal wells completed
- **High production growth** – 103% increase year-over-year to 355 MMcfe/d net today including 1,800 Bbl/d of liquids
  - Additional 90 MMcfe/d of net production (including 3,800 Bbl/d of liquids) constrained/shut-in waiting on pipeline, compression or processing
- **Large resource base** – Over 28 Tcfe of unrisked resource will continue to feed high growth in existing 3.8 Tcfe[(1)] proved reserve base as of September 30, 2012

- **Low cost leader** – $0.99/Mcfe 3-year Marcellus development costs through 2011 per JP Morgan analysis[(2)]
  - $0.90/Mcfe average operated net development cost over past three years
  - $0.82/Mcfe estimated net future development cost in 3P reserve base
- **Rapidly growing liquids exposure** – 3% by production volume today, forecast to grow to ~40% by 2014
- **Large long-term hedge position** – 786 Bcf hedged at $5.03/MMBtu NYMEX-equivalent[(3)] through 2018

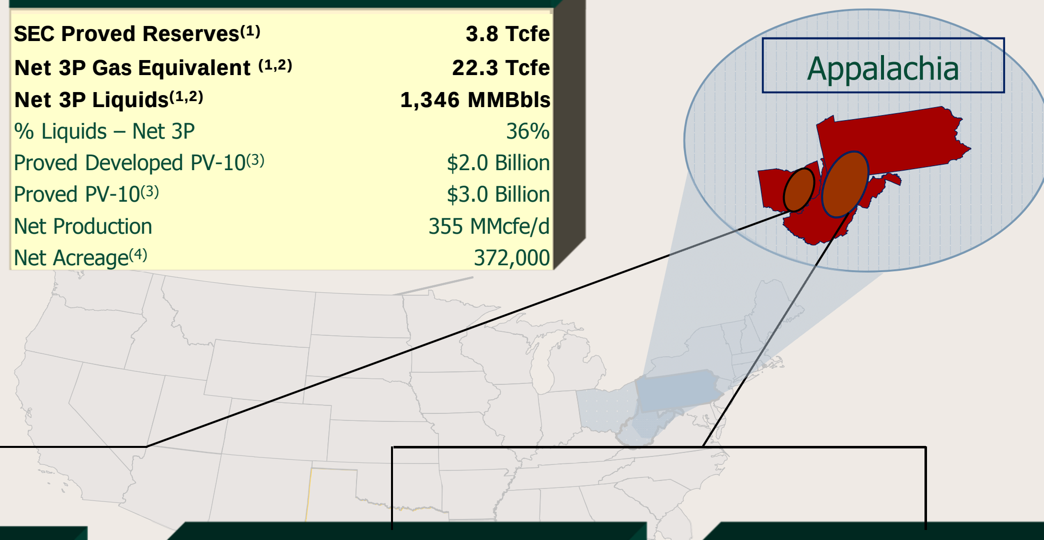
- **Infrastructure emphasis** – Gathering, compression and processing infrastructure either in place or committed and underway
- **Strong liquidity to fuel low cost growth** – ~$1.2 billion[(4)] of undrawn borrowing base capacity and $302 million in cash at September 30, 2012 pro forma for the recent 6% senior notes offering and Piceance divestiture

1. *9/30/2012 SEC reserves using a 9/30/2012 SEC price deck of $3.00/MMBtu for Appalachia. Reserves prepared internally using SEC reserve methodology and pricing. WTI SEC price averaged $95.17/Bbl.*
2. *Source: Proved developed F&D research prepared by JP Morgan Research report dated 5/11/2012. Includes all total drilling and completion costs but excludes land and acquisition costs for all companies. Defined as total drilling and completion capital expenditures for the period divided by PDP and PDNP volumes added after adding back production for the period. Adjusted for sale of Antero's Arkoma and Piceance assets.*
3. *In order to compare hedges across basins, hedged basin prices are converted by Antero to NYMEX-equivalent prices using current basis differentials in the over-the-counter futures market.*
4. *Lender commitments under facility are $700 million which can be expanded to the full $1.275 billion borrowing base upon bank approval. Undrawn capacity as of 9/30/2012.*

Low Cost Liquids-Rich Reserve Base

- Excludes Piceance properties – divestiture closed December 21, 2012

Total	
SEC Proved Reserves[1]	**3.8 Tcfe**
Net 3P Gas Equivalent [1,2]	**22.3 Tcfe**
Net 3P Liquids[1,2]	**1,346 MMBbls**
% Liquids – Net 3P	36%
Proved Developed PV-10[3]	$2.0 Billion
Proved PV-10[3]	$3.0 Billion
Net Production	355 MMcfe/d
Net Acreage[4]	372,000



Appalachia–Utica Shale	
SEC Proved Reserves[1]	**95 Bcfe**
Net 3P [1,2]	**2,613 Bcfe**
Net 3P Liquids[1,2]	**207 MMBbls**
% Liquids – Net 3P	48%
Net Production	2 MMcfe/d
Net Acreage	78,000

Appalachia–Marcellus Shale	
SEC Proved Reserves[1]	**3,697 Bcfe**
Net 3P [1,2]	**19,695 Bcfe**
Net 3P Liquids[1,2]	**1,139 MMBbls**
% Liquids – Net 3P	35%
Net Production	348 MMcfe/d
Net Acreage	294,000

Appalachia–Upper Devonian Shale	
SEC Proved Reserves[1]	**10 Bcfe**
Net Resource [1,2]	**4,295 Bcfe**
Net Resource Liquids[1,2]	**213 MMBbls**
% Liquids – Net 3P	30%
Net Production	5 MMcfe/d
Net Acreage[4]	194,000

1. *9/30/2012 SEC reserves using a 9/30/2012 SEC price deck of $3.00/MMBtu for Appalachia. Reserves prepared by internal reserve engineers using SEC reserve methodology and pricing. WTI SEC price averaged $95.17/Bbl. Assumes processing in the Marcellus beginning in 4Q 2012 and ethane recovery beginning in 1Q 2014.*
2. *See note on page 33 for 3P and resource definition.*
3. *Includes hedge PV-10 value of $1.1 billion.*
4. *Subset of total Marcellus acreage based on geological analysis. Not included in Antero's net acreage total.*

Antero Unrisked Net Resource Potential

- Including net 3P reserves of 22 Tcfe[1], Antero has 28 – 29 Tcfe of unrisked net resource potential
- Rich gas focused resource base includes almost 1.8 billion barrels of liquids
- Over 4,100 gross operated undrilled locations
- Excludes Piceance properties – divestiture closed December 21, 2012

Area	Resource	Gas (Tcf)	Liquids (MMBbls)	Net Resource Potential (Tcfe)	Gross Operated Undrilled Locations[2]
Appalachia	Marcellus Shale	13 – 14	1,243	20 – 21	2,751
Appalachia	Utica Shale	2	310	4	538
Appalachia	Upper Devonian Shale	2 – 3	217	4	837
TOTAL		**18**	**1,770**	**28 – 29**	**4,126**

Significant Marcellus, Utica and Upper Devonian Shale Liquids Exposure

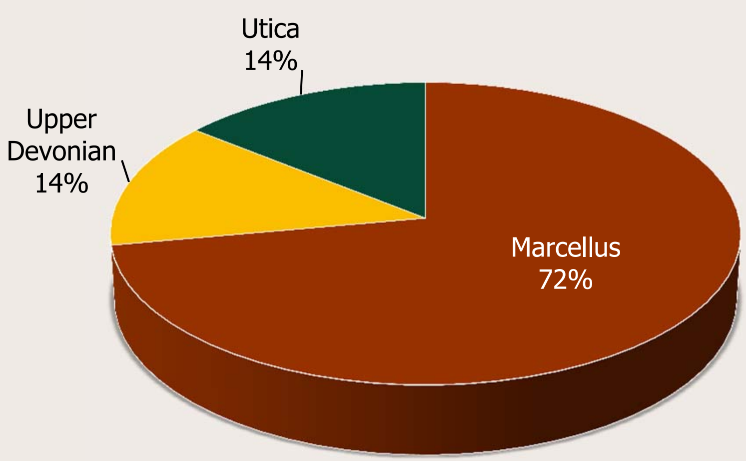
1. *All 3P reserves as of 9/30/2012. Resource estimates internally generated by Antero.*
2. *Represents total resource potential locations reflecting current acreage position.*

Appalachian Shale-Focused Resource Base

- 72% of Antero's resource base is in the Marcellus Shale
- 37% of resource base is liquids by volume
- Excludes Piceance properties – divestiture closed December 21, 2012

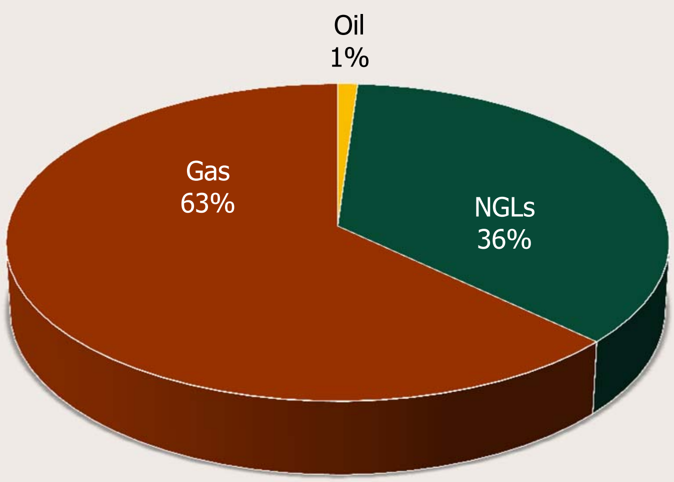
Unrisked Net Resource Potential(1)

By Area



28 Tcfe

By Product

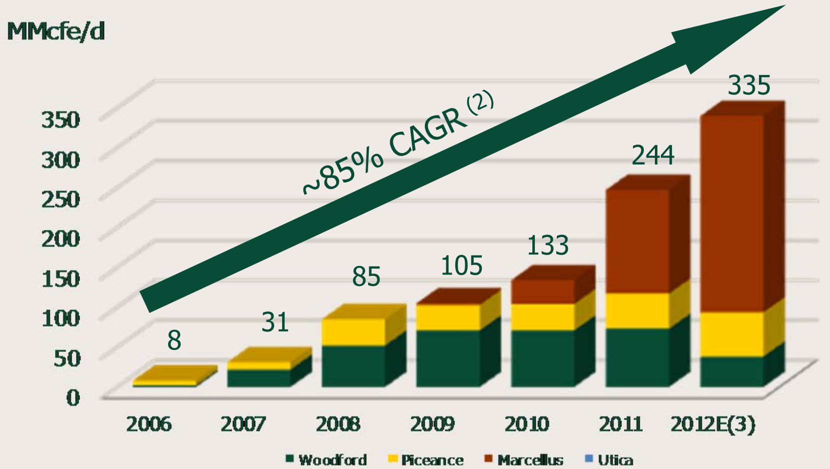


28 Tcfe

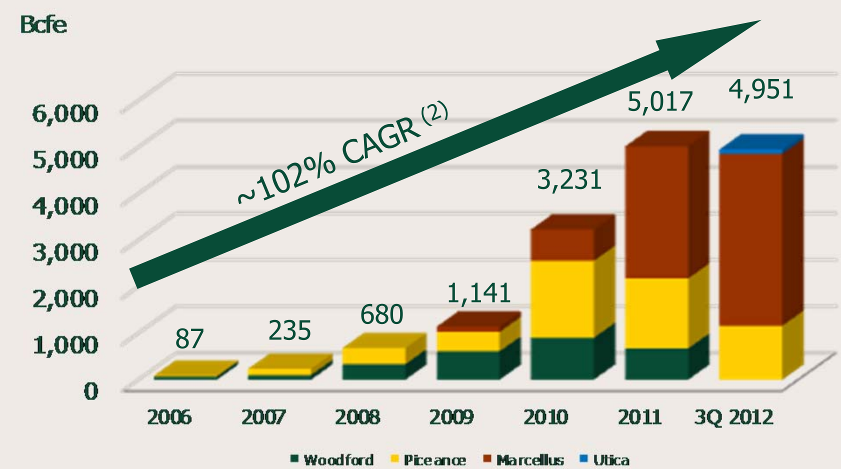
1. *All 3P reserves as of 9/30/2012. Resource estimates internally generated by Antero.*

Strong Track Record of Growth

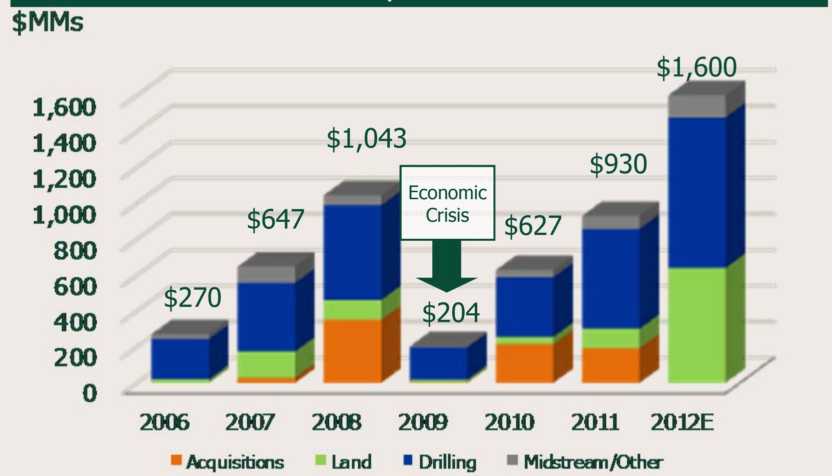
Average Net Daily Production



Net Proved SEC Reserves (1)



Antero Capital Allocation



Operated Well Completions

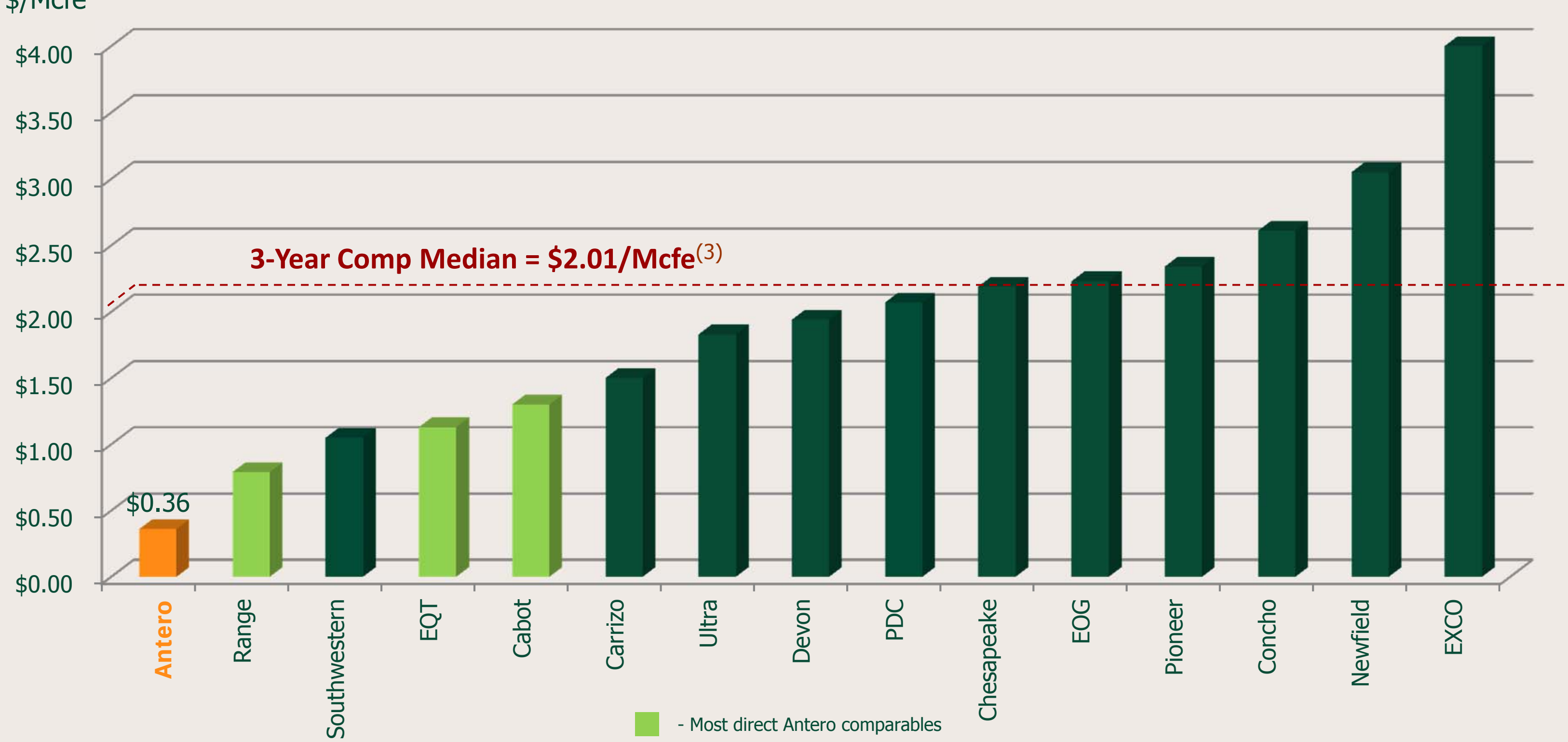
1. *Proved reserves for 2006, 2007 and 2008 represent previously effective SEC methodology. 2009, 2010, 2011 and 9/30/2012 proved reserves based on current SEC reserve methodology and pricing and are prepared internally excluding Arkoma Basin reserves which were sold on June 29, 2012.*
2. *CAGR = Compound Annual Growth Rate.*
3. *Antero net production guidance for 2012 including partial year contribution from Arkoma and full year contribution from Piceance.*

Industry Leading Finding Costs

- Includes all drilling, land and acquisition expenditures

Industry 3-Year All-in Finding Costs through 2011(1)

- 2011 Antero all-in finding costs were \$0.46/Mcfe
- 3-year Antero all-in finding costs were \$0.36/Mcfe through 2011(2)



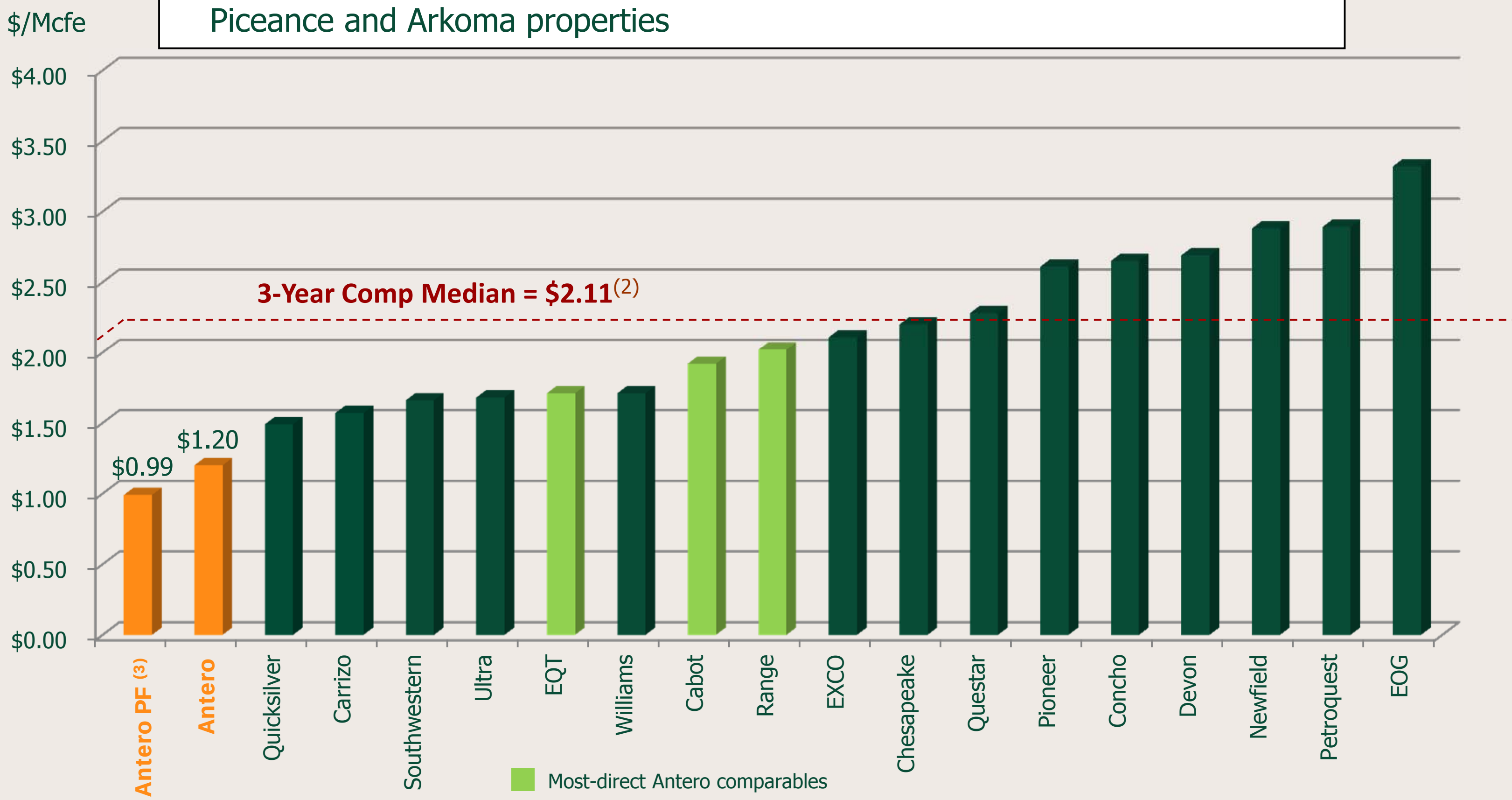
1. *Source: Caris & Company Year-end Reserve Analysis report dated March 16, 2012.*
2. *Antero finding costs calculated over 3 years using 12/31/2011 SEC reserves, including Arkoma and Fayetteville. Reserves were audited by DeGolyer & MacNaughton (Appalachia, Arkoma and Fayetteville) and Ryder Scott (Piceance).*
3. *Median calculated for comparable company set used in this graph.*

Industry Leading Development Costs

- Per Mcfe development cost excluding land is a better measure of capital efficiency than finding costs
  - Antero was the leader in 3-year development costs through 2011 – includes Piceance and Arkoma assets

Industry 3-Year Development Costs through 2011(1)

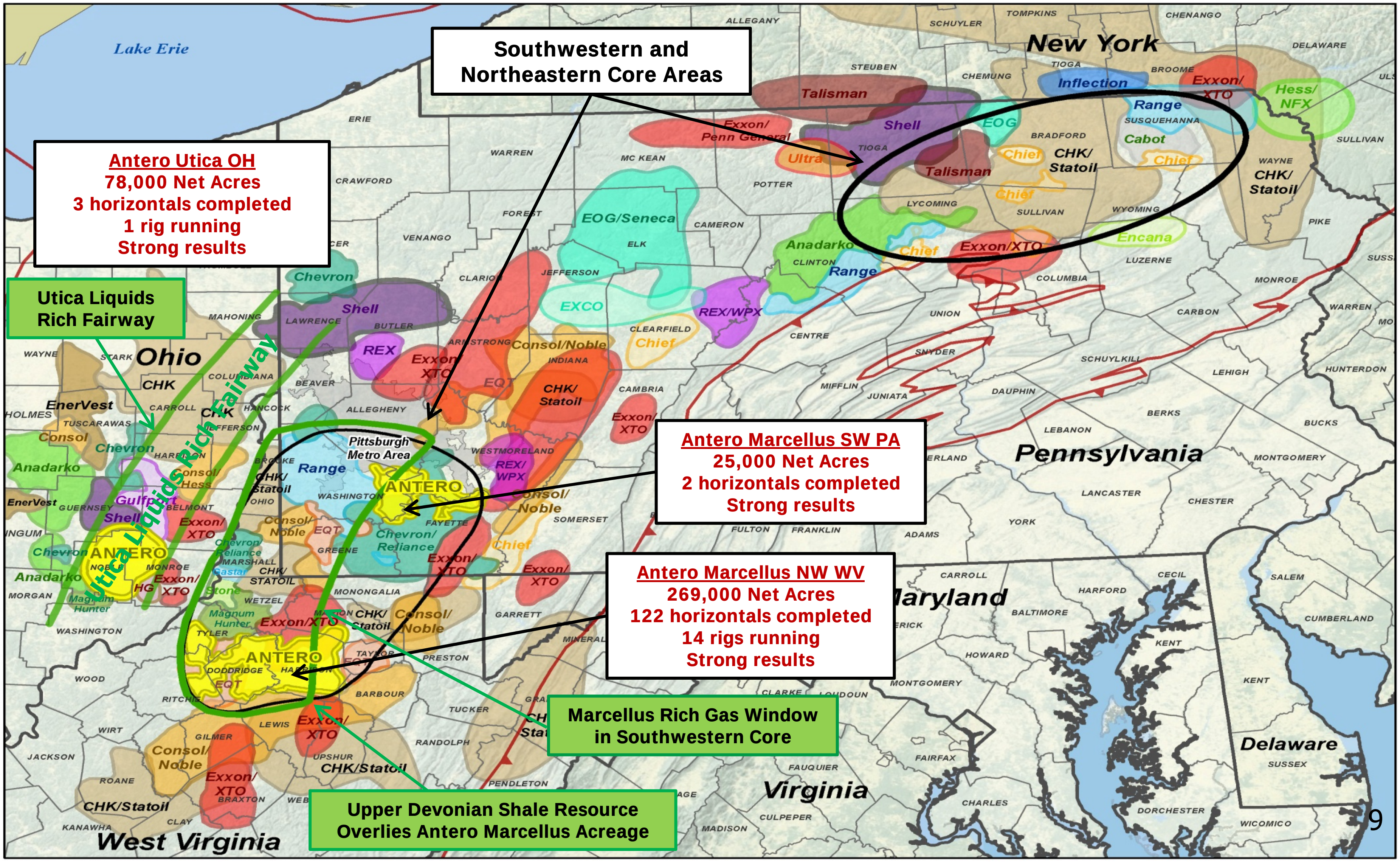
- Antero's 3-year development cost was only $0.99/Mcfe excluding the divested Piceance and Arkoma properties



1. *Source: Proved developed F&D research prepared by JP Morgan Research report dated 5/11/2012. Includes all total drilling and completion costs but excludes land and acquisition costs for all companies. Defined as total drilling and completion capital expenditures for the period divided by PDP and PDNP volumes added after adding back production for the period.*
2. *Median calculated for comparable company set used in this graph.*
3. *Pro forma for divestiture of Arkoma and Piceance properties – calculated by Antero.*

Asset Overview

Appalachian Basin – Overview



Source: Company presentations and press releases.

Antero Marcellus Shale

ANTERO RESOURCES

Summary

- 294,000 net acres of leasehold in southwestern core of the Marcellus play
  - 55% HBP with additional 21% not expiring for 5-plus years
  - Over 80% of acreage has rich gas processing potential
- 100% operated by Antero
- 3.7 Tcfe of proved reserves / 19.7 Tcfe of 3P reserves
- 348 MMcfe/d current net operated production, including 1,700 Bbl/d of NGLs and oil
- Operating 14 drilling rigs currently and 2 frac crews 24/7
- Antero has completed 124 consistently strong horizontal wells, 120 of which are online
  - Demonstrated ability to drill wells with long laterals (7,000 ft +) in less than 30 days
  - 100% drilling success rate

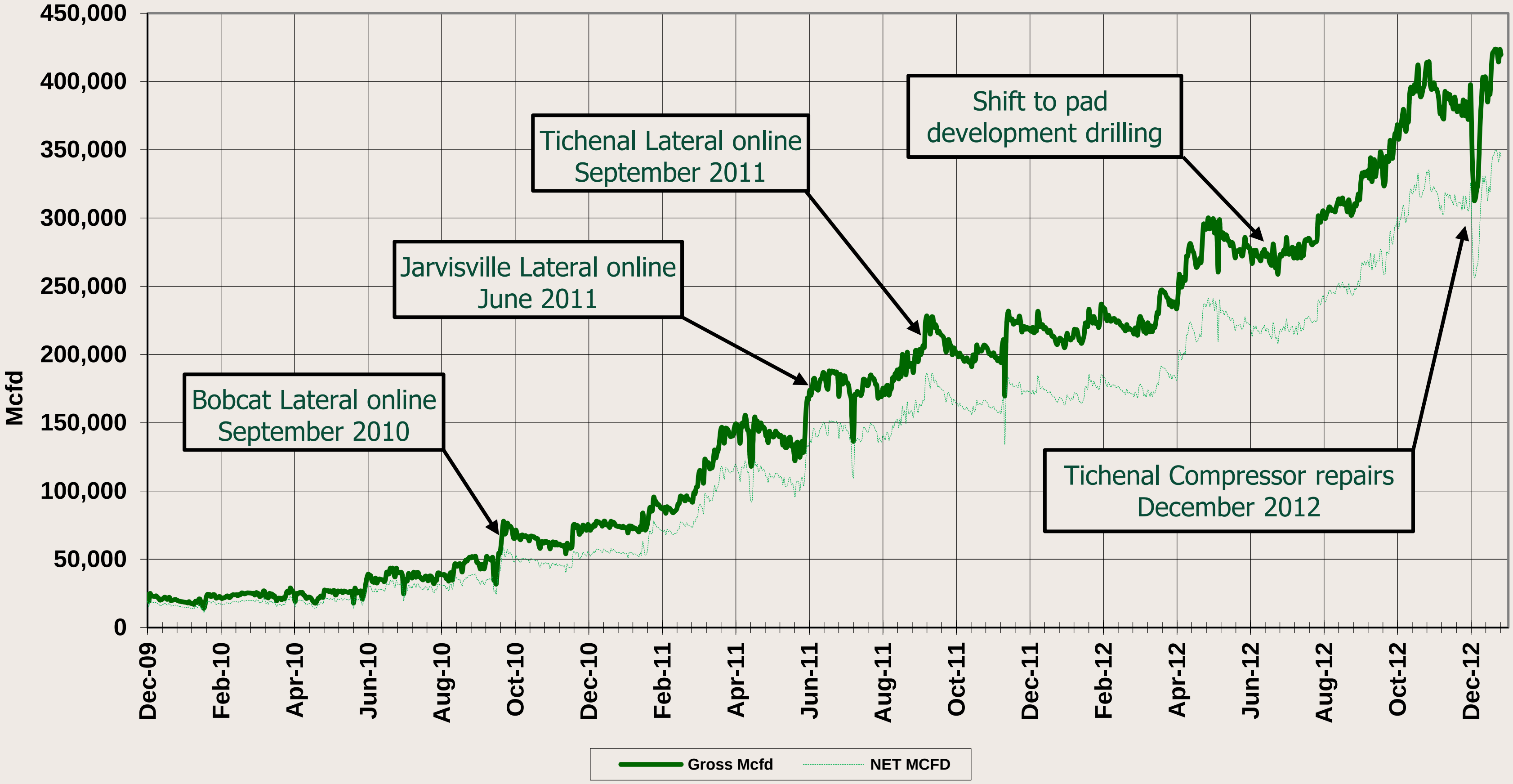
Fully Integrated

- 200 MMcf/d Sherwood I processing plant placed on line in October 2012 – fully dedicated to Antero
  - 200 MMcf/d Sherwood II processing plant expected to go into service 2Q 2013
- 872,000 MMBtu/d of long-haul firm transportation or firm sales secured
  - 460,000 MMBtu/d of back-haul firm transportation to Gulf Coast
- Committed to 20,000 Bbl/d ethane takeaway capacity on Enterprise ATEX pipeline to Mont Belvieu expected to be in service 1Q 2014

Strong Marcellus Growth

- Antero has rapidly grown its Marcellus production over the past three years while building out midstream infrastructure

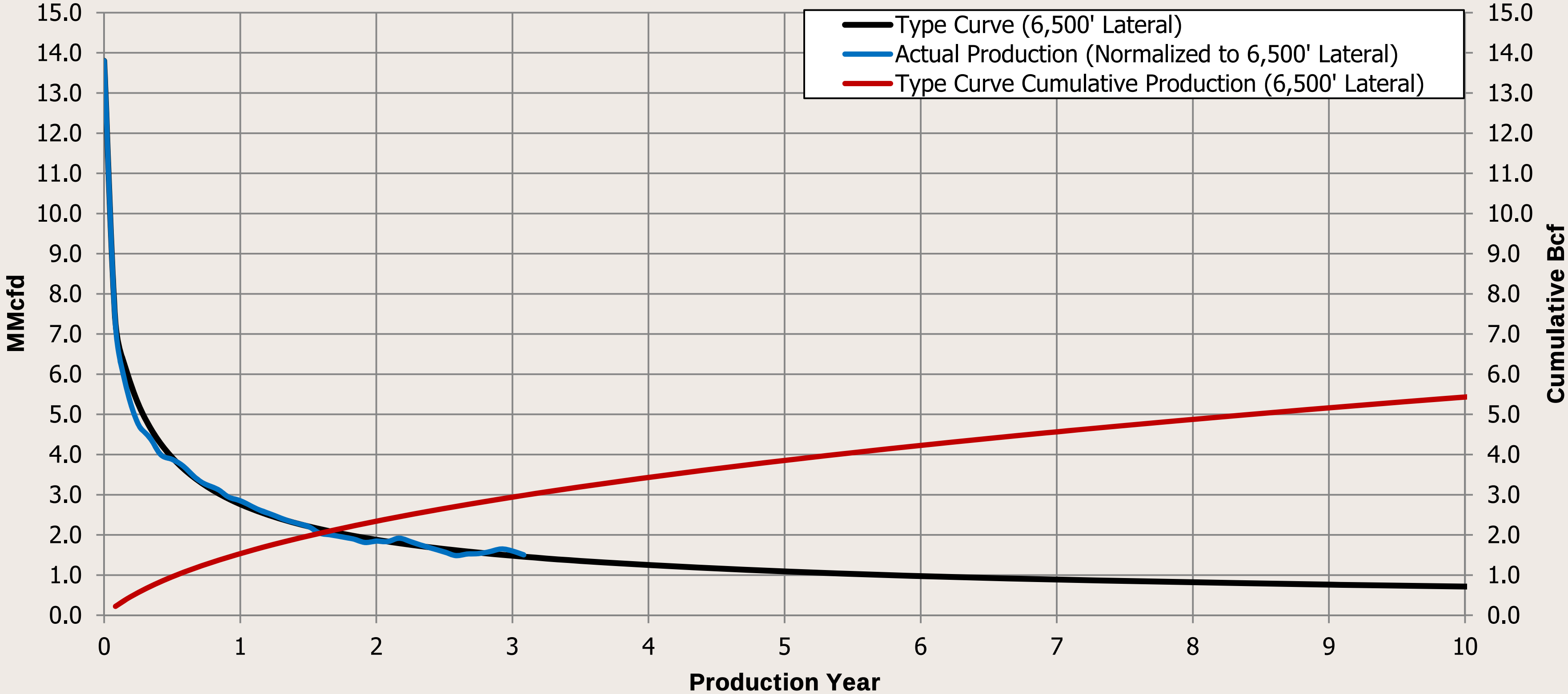
Antero Gross Operated Marcellus Production



Antero Marcellus Type Curve Support

- Antero has over 3 years of production history to support its 1.5 Bcf/1,000' of lateral recovery assumption as demonstrated by the graph and table below
  - DeGolyer & MacNaughton (D&M), Antero's third party reserve auditor, supports this type curve
- Antero's average 24-hour peak rate is 13.8 MMcfe/d in the Marcellus

	24-hour peak	30-day avg. rate	90-day avg. rate	180-day avg. rate	365-day avg. rate	730-day avg. rate
MMcfd	13.8	7.8	6.1	5.0	4.0	2.5
# of wells	124	111	102	86	61	23

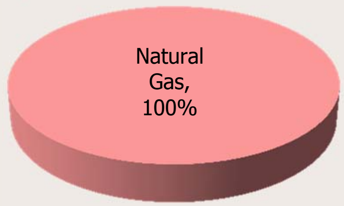


Note: *Type curve reflects pre-processed wellhead production.*
1. Wells normalized to time-zero; production for each well normalized to 6,500' lateral length.

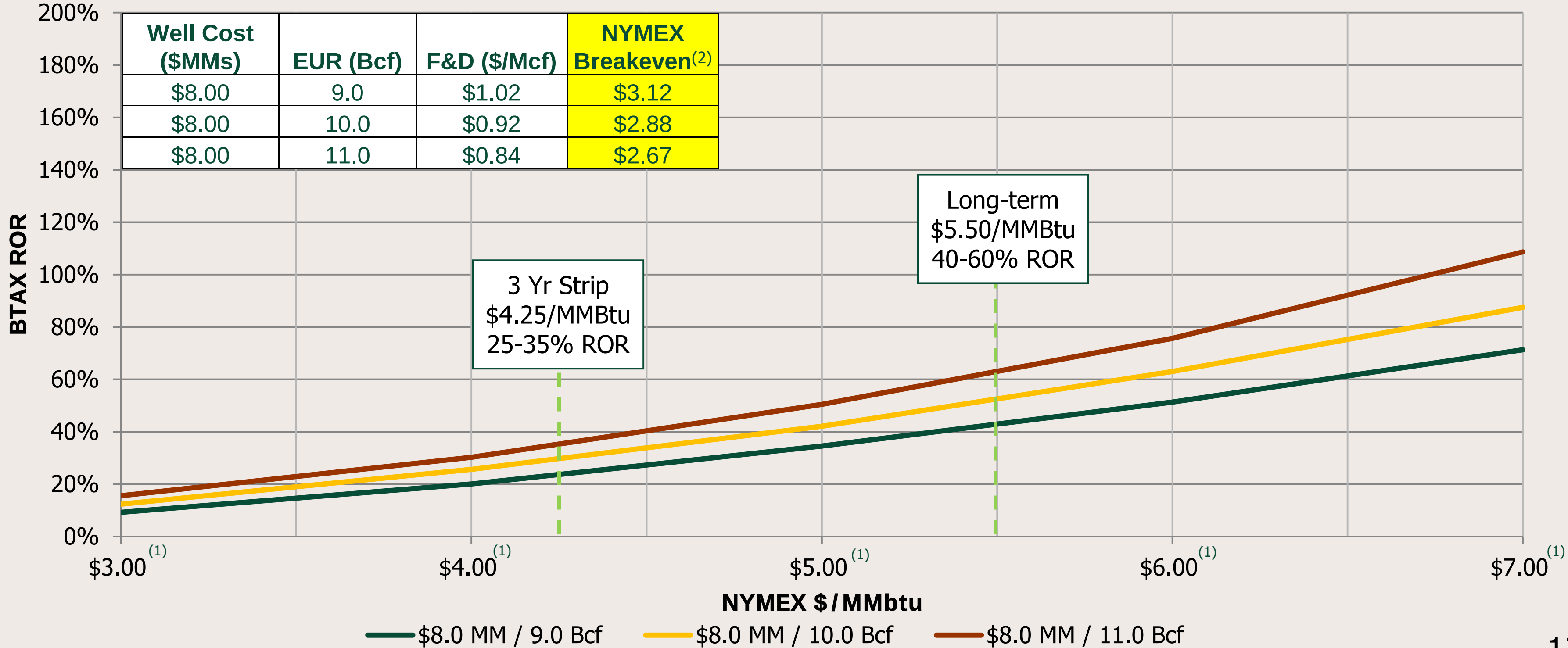
Marcellus Shale Well Economics – Horizontal Lean Gas

- Assumes 1050 BTU gas – no processing, lean gas
- Estimated 482 gross horizontal drilling locations in the lean gas category (1000 to 1050 BTU)

Antero Average for First 124 Horizontal Wells			
Lateral Length	**Well Cost ($ MM)**	**EUR (Bcf)**	**Net F&D ($/Mcf)**
6,798	$8.4	10.2	$0.95



Well Cost ($MMs)	EUR (Bcf)	F&D ($/Mcf)	NYMEX Breakeven[2]
$8.00	9.0	$1.02	$3.12
$8.00	10.0	$0.92	$2.88
$8.00	11.0	$0.84	$2.67

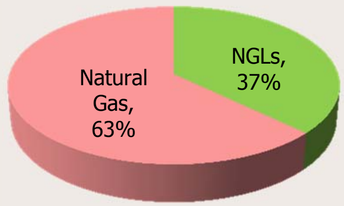


1. Fixed NYMEX gas prices with appropriate basis adjustment to the Marcellus area. 85% NRI assumed.
2. Defined as 10% before tax rate-of-return.

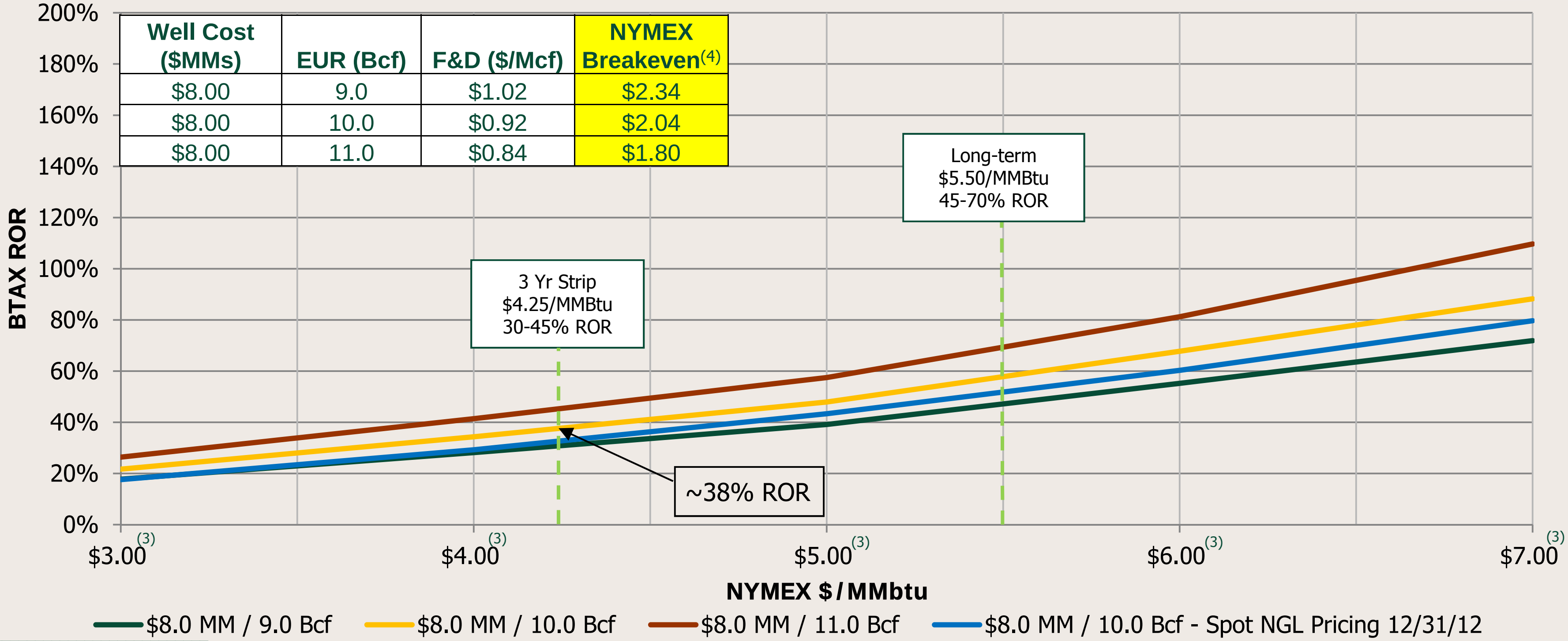
Marcellus Shale Well Economics – Horizontal Rich Gas

- Assumes 1150 BTU gas and includes processing margin at $90.00/Bbl oil and 12-month historical NGL price correlations[1]
- Estimated 1,343 gross horizontal drilling locations in the 1050 to 1250 BTU category[2]

Antero Average for First 124 Horizontal Wells			
Lateral Length	**Well Cost ($ MM)**	**EUR (Bcf)**	**Net F&D ($/Mcf)**
6,798	$8.4	10.2	$0.95



Well Cost ($MMs)	EUR (Bcf)	F&D ($/Mcf)	NYMEX Breakeven[4]
$8.00	9.0	$1.02	$2.34
$8.00	10.0	$0.92	$2.04
$8.00	11.0	$0.84	$1.80

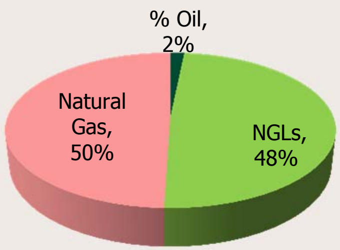


1. *No processing capacity is available until plant completed (October 2012) and no ethane takeaway available until Enterprise ethane pipeline is online (expected 1Q 2014). Well economics include fixed fee cost tariff on ATEX ethane pipeline scheduled to be online in 1Q 2014.*
2. *Economics will vary considerably depending on Btu and other factors.*
3. *Fixed NYMEX gas prices with appropriate basis adjustment to the Marcellus area. 85% NRI assumed.*
4. *Defined as 10% before tax rate-of-return.*

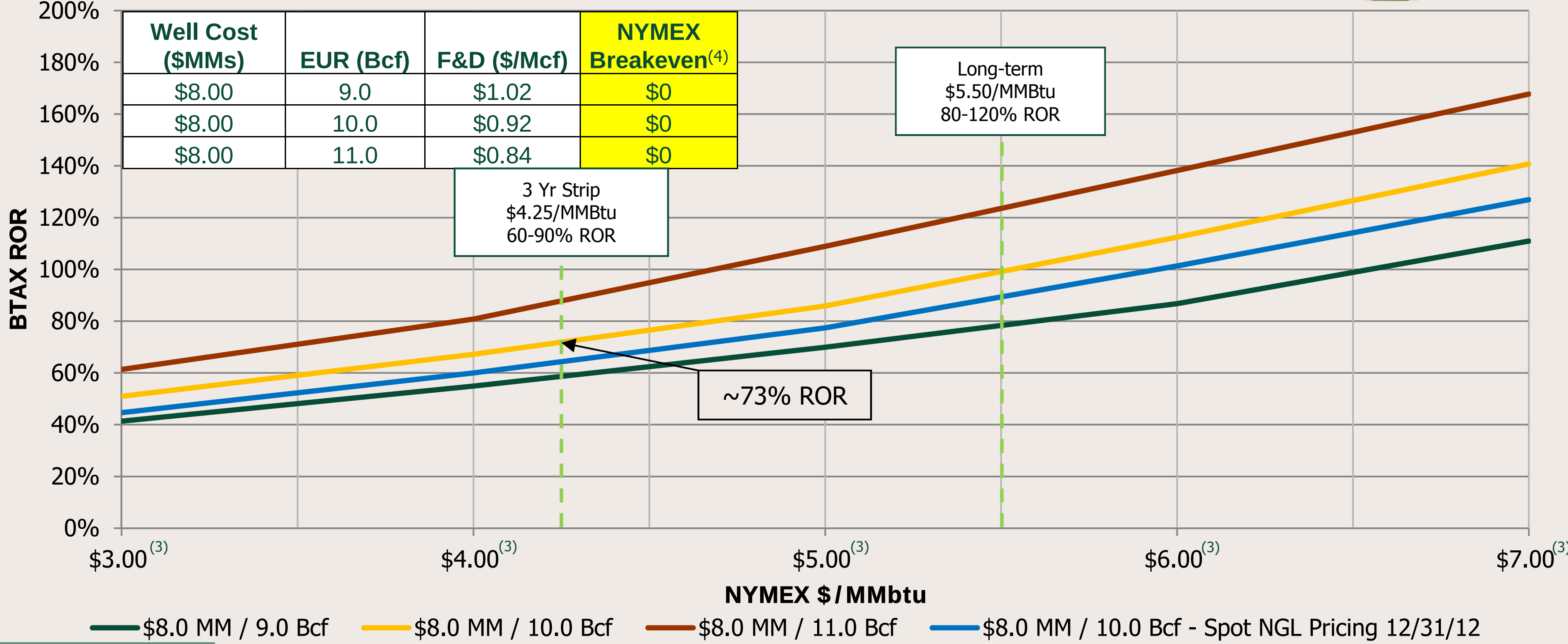
Marcellus Shale Well Economics – Horizontal Highly-Rich Gas

- Assumes 1250 BTU gas and includes processing margin at $90.00/Bbl oil and 12-month historical NGL price correlations(1)
- Estimated 926 gross horizontal drilling locations in the 1250 to 1350 BTU category(2)

Antero Average for First 124 Horizontal Wells			
Lateral Length	**Well Cost ($ MM)**	**EUR (Bcf)**	**Net F&D ($/Mcf)**
6,798	$8.4	10.2	$0.95



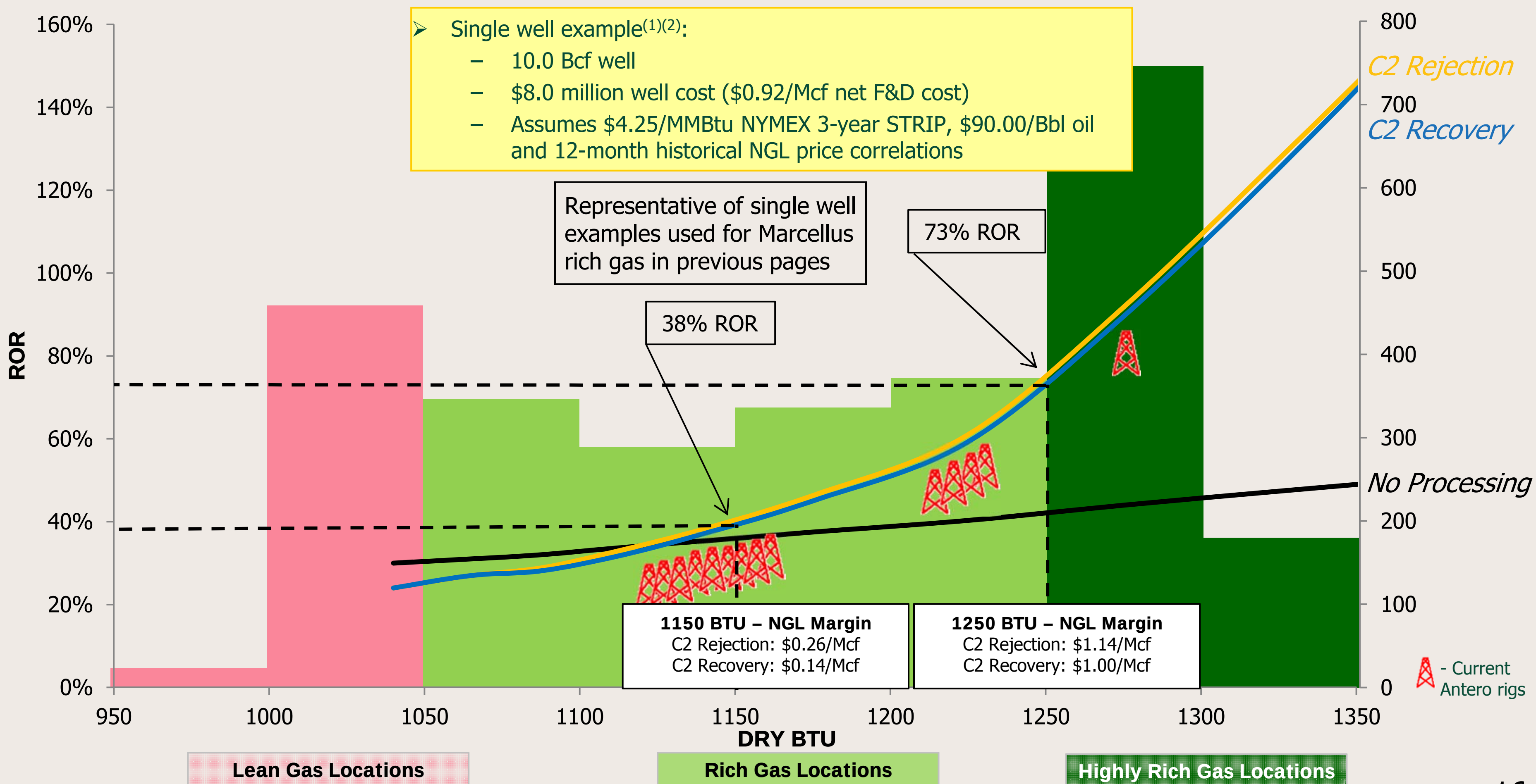
Well Cost ($MMs)	EUR (Bcf)	F&D ($/Mcf)	NYMEX Breakeven(4)
$8.00	9.0	$1.02	$0
$8.00	10.0	$0.92	$0
$8.00	11.0	$0.84	$0



1. *No processing capacity is available until plant completed (October 2012) and no ethane takeaway available until Enterprise ethane pipeline is online (expected 1Q 2014). Well economics include fixed fee cost tariff on ATEX ethane pipeline scheduled to be online in 1Q 2014.*
2. *Economics will vary considerably depending on Btu and other factors.*
3. *Fixed NYMEX gas prices with appropriate basis adjustment to the Marcellus area. 85% NRI assumed.*
4. *Defined as 10% before tax rate-of-return.*

Marcellus Processing Economics

- Dramatic improvement in returns by processing higher BTU gas – Antero's Marcellus rich gas leasehold spans the 1050 to 1350 Btu spectrum
- Antero has 2,269 gross processable locations

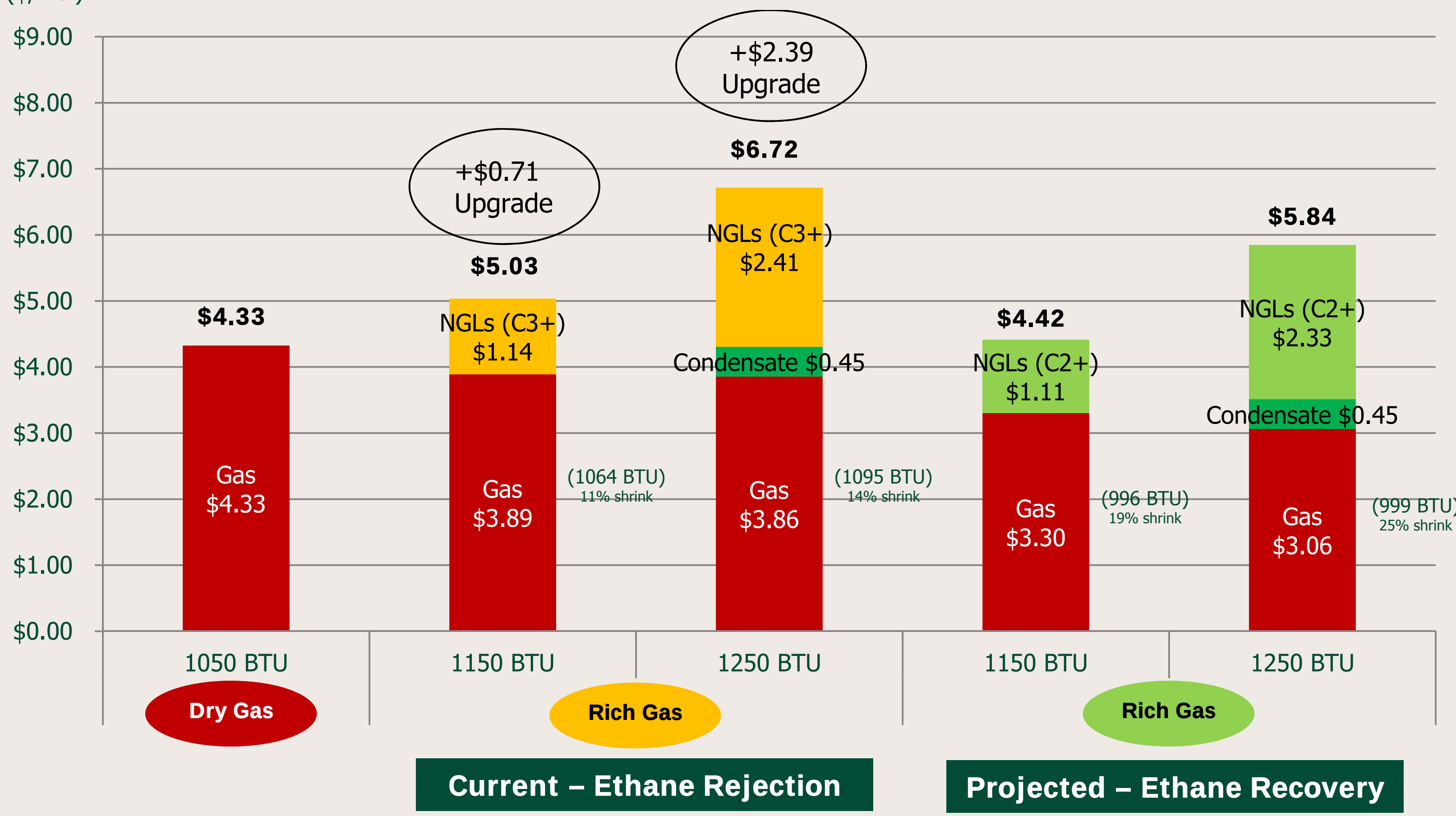


1. Assumes SEC price deck of $2.78/MMbtu for Appalachia, $95.05/Bbl WTI and 12-month NGL price correlations. 85% NRI assumed.
2. No processing capacity is available until plant completed (October 2012) and no ethane takeaway available until Enterprise ethane pipeline is online (expected 1Q 2014). Well economics include fixed fee cost tariff on ATEX ethane pipeline scheduled to be online in 1Q 2014.

Marcellus Rich Gas – Liquids and Processing Upgrade

- Marcellus rich gas and highly rich gas acreage provides a significant advantage in well economics – assuming $4.25/MMBtu NYMEX, $90.00/Bbl WTI and <u>current spot</u> NGL pricing correlation
- Upgrade analysis demonstrates that ethane recovery is not economic at current ethane price

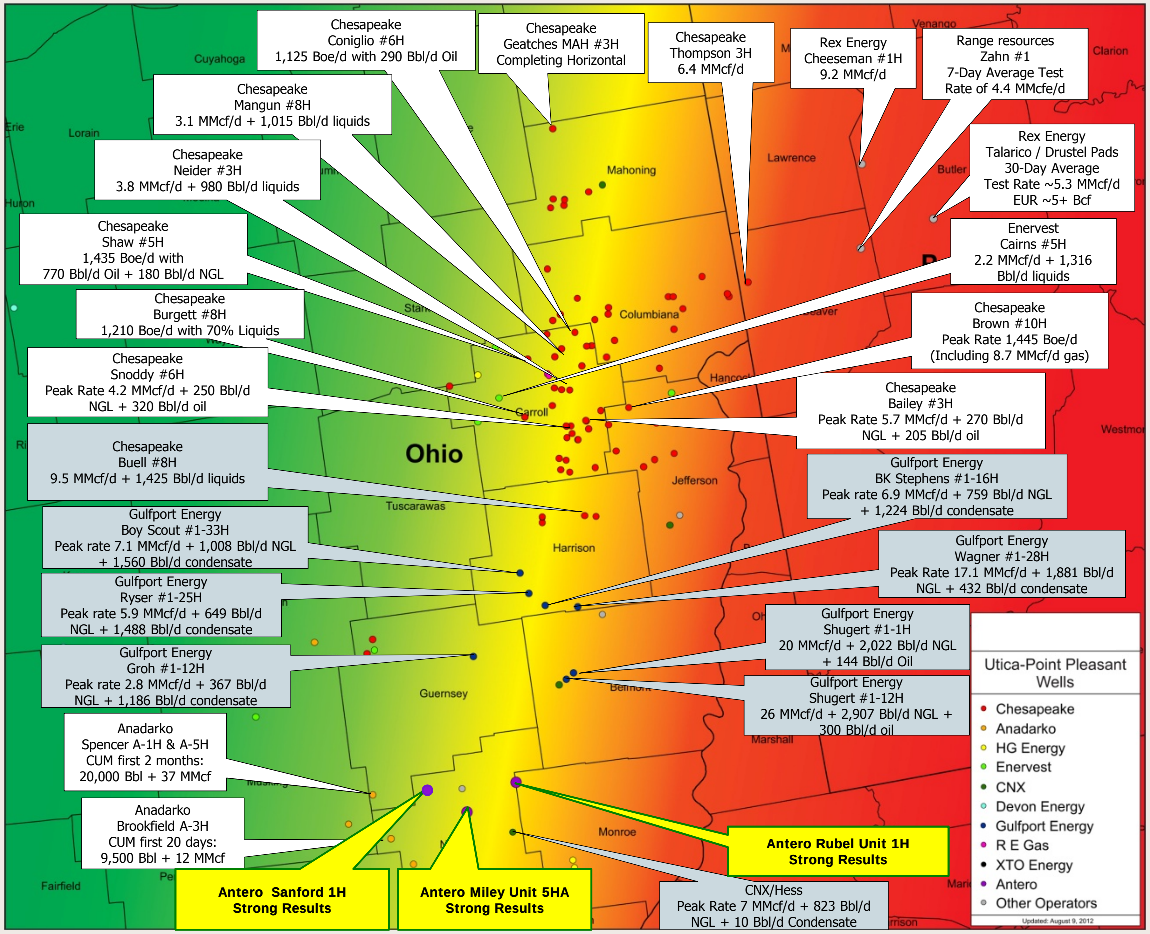
$ / Wellhead Mcf(1)



1. *Assumes $4.25/MMBtu NYMEX, $90.00/Bbl WTI and current spot prices. 1.054 and 2.070 (ethane rejection) and 3.332 and 5.145 (ethane recovery) GPM s used, all processing costs, shrink and fuel included. No processing capacity is available until plant completed (October 2012) and no ethane takeaway available until Enterprise ethane pipeline is online (expected 1Q 2014). Ethane recovery well economics include fixed fee cost tariff on ATEX ethane pipeline scheduled to be online in 1Q 2014.*

Antero Utica Shale

Utica Shale Industry Activity



Summary

- 78,000 net acres of leasehold in southern core of the Utica play
  - 23% HBP and additional 77% not expiring for 5-plus years
  - Over 90% of acreage has rich gas processing potential
- 100% operated by Antero
- Operating one drilling rig with second rig to be added 1Q 2013
- 95 Bcfe of proved reserves / 2.6 Tcfe of 3P reserves
- Three wells completed with strong results – one well online and two wells waiting on pipeline, compression
- 100% drilling success rate

Fully Integrated

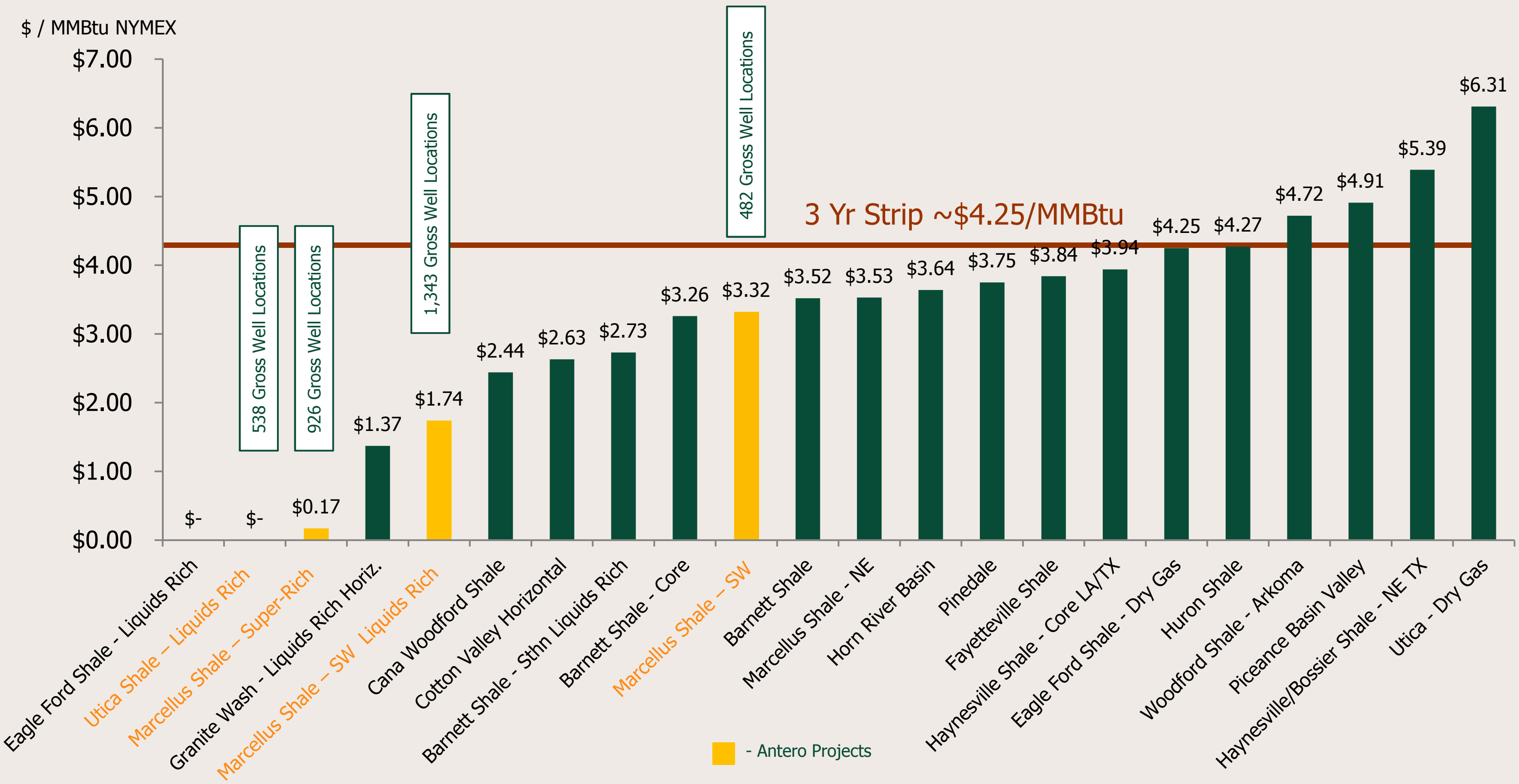
- 50 MMcf/d of firm refrig processing capacity 2Q 2013
- 200 MMcf/d Seneca I cryogenic processing plant online in 3Q 2013
- Access to 20,000 Bbl/d of ethane takeaway capacity on Enterprise ATEX pipeline to Mont Belvieu expected to be in service 1Q 2014

Source: Company presentations and press releases.

Low Break Even Gas Price Portfolio

- Antero is low on the cost curve with a very attractive drilling portfolio of 100% operated projects – Antero projects highlighted in orange with gross undrilled horizontal well locations in boxes

NYMEX Break Even Price (15% ATAX ROR) – Credit Suisse Analysis[(1)]



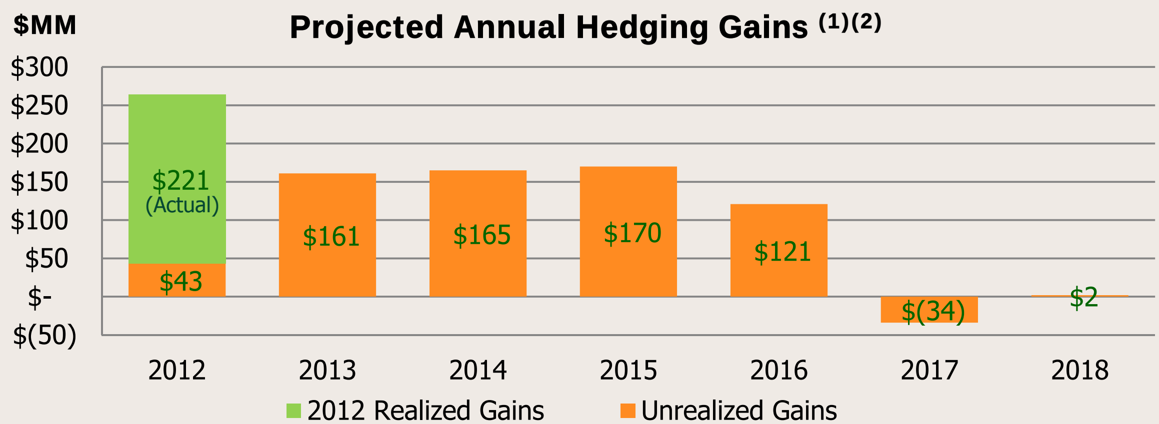
1. *Source: Credit Suisse report dated 10/2/2012 – Break even price is for 15% after tax rate-of-return; assumes $90.00/Bbl WTI.*

Strong Hedge Position

- Antero expects to realize approximately $620 million[1] of hedge gains over the next six years from its current 786 Bcfe hedge book which averages $5.03/MMBtu NYMEX-equivalent, assuming current STRIP prices
  - Protects future cash flow thereby supporting drilling plans and production growth
  - Piceance hedges have been monetized; excluded from table but included in graph below

Current Antero Hedge Position – October 1, 2012 through 2018[2]

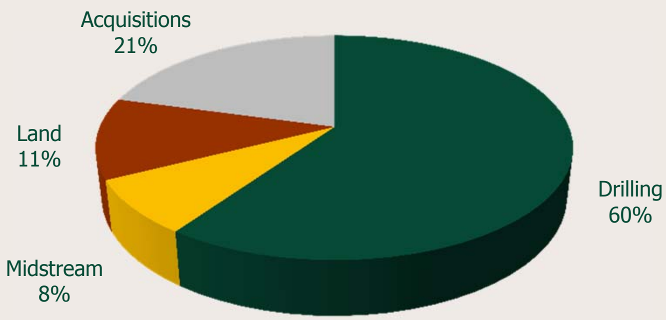
Natural Gas Swaps	Hedged Volume (MMBtu/d)	NYMEX-Equivalent Price ($/MMBtu)[2]	% of forecasted net tailgate gas production
2012	210,537	$5.42	60%
2013	317,020	$4.99	61%
2014	370,000	$5.23	
2015	390,000	$5.40	
2016	502,500	$5.04	
2017	420,000	$4.37	
2018	105,000	$4.88	



1. Based on current STRIP gas prices and undiscounted. Includes $221 million of realized hedge gains through September 2012 including realized gains from divested Arkoma assets through 6/30/2012.
2. Virtually all hedges are fixed price swaps, hedged to the basin. Basin prices are converted by Antero to NYMEX-equivalent prices using current basis differentials in the over-the-counter futures market.

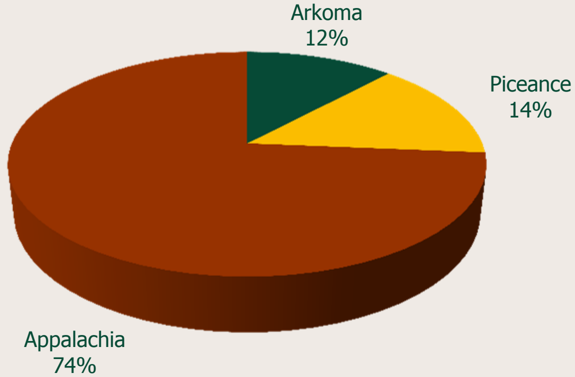
2011 and 2012E Capital Budget

2011 Capex Budget by Type



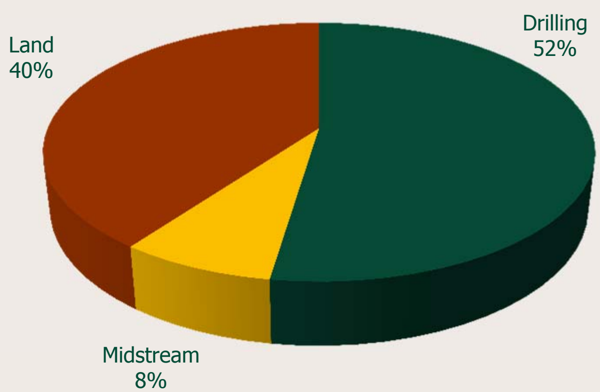
Total: $930MM

2011 Capex Budget by Basin



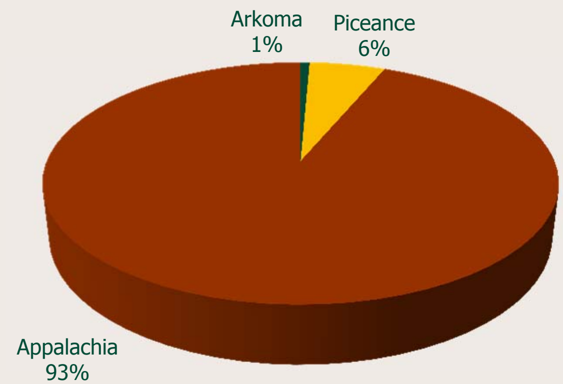
Total: $930MM

2012E Capex Budget by Type



Total: $1,600MM

2012E Capex Budget by Basin



Total: $1,600MM

Current Financial Summary

Pro Forma Capital Structure

$ millions	12 mos. 12/31/2008	12 mos. 12/31/2009	12 mos. 12/31/2010	12 mos. 12/31/2011	Non-GAAP LTM 9/30/2012	Adjusted for Senior Notes Offering LTM 9/30/2012	Further Adjusted for Piceance Sale LTM 9/30/2012
Summary Operating Results							
Production (Bcfe) (1)	32	38	49	89	117	117	96
EBITDAX (1)	$207	$201	$198	$341	$431	$431	$332
Cash interest expense (1)(2)	$38	$36	$56	$68	$86	$100	$97
Proved reserves (Bcfe) (3)	680	1,141	3,231	5,017	4,951	4,951	3,792
Proved developed reserves (Bcfe) (3)	239	245	457	845	1,004	1,004	799
Proved PV 10 (3)	$649	$625	$1,858	$4,103	$3,534	$3,534	$2,974
Summary Capitalization							
Cash and cash equivalents	$39	$11	$9	$3	$17	$17	$302
Bank credit facility	397	142	100	365	447	152	0
2nd lien credit facility	225	375	0	0	0	0	0
Subordinated debt	0	0	25	25	25	25	25
Senior notes	0	0	525	925	925	1,225	1,225
Total debt	$622	$517	$650	$1,315	$1,397	$1,402	$1,250
Members' equity	1,164	1,393	1,490	1,461	1,461	1,461	1,461
Non-controlling interest	29	30	0	0	0	0	0
Total book capitalization	$1,815	$1,940	$2,140	$2,776	$2,858	$2,863	$2,711
Net debt	$583	$506	$641	$1,312	$1,380	$1,385	$948
Credit Statistics							
Net debt / net book capitalization	32.8%	26.2%	30.1%	47.3%	48.6%	48.7%	39.4%
Net debt / EBITDAX	2.8x	2.5x	3.2x	3.9x	3.2x	3.2x	2.9x
EBITDAX / interest expense (1)	5.5x	5.6x	3.5x	5.0x	5.0x	4.3x	3.4x
Net debt / proved reserves ($/Mcfe) (3)	$0.86	$0.44	$0.20	$0.26	$0.28	$0.28	$0.25
Net debt / proved developed reserves ($/Mcfe) (3)	$2.44	$2.07	$1.40	$1.55	$1.38	$1.38	$1.19
Net debt / production ($/Mcfed)	$6,671	$4,860	$4,775	$5,372	$4,301	$4,317	$3,617
Proved PV 10 / net debt (3)	1.1x	1.2x	2.9x	3.1x	2.6x	2.6x	3.1x

1. *Production, EBITDAX and cash interest expense are non-GAAP as they include discontinued operations until transaction closing per 2008 - 2011 10-K and 10-Q dated 9/30/2012.*
2. *Represents cash interest paid for credit facility and $950 million of existing bonds and notes. Pro forma for $300 million senior notes offering with 6% coupon.*
3. *LTM 9/30/2012 assumes internally prepared reserves using SEC reserve methodology and pricing.*

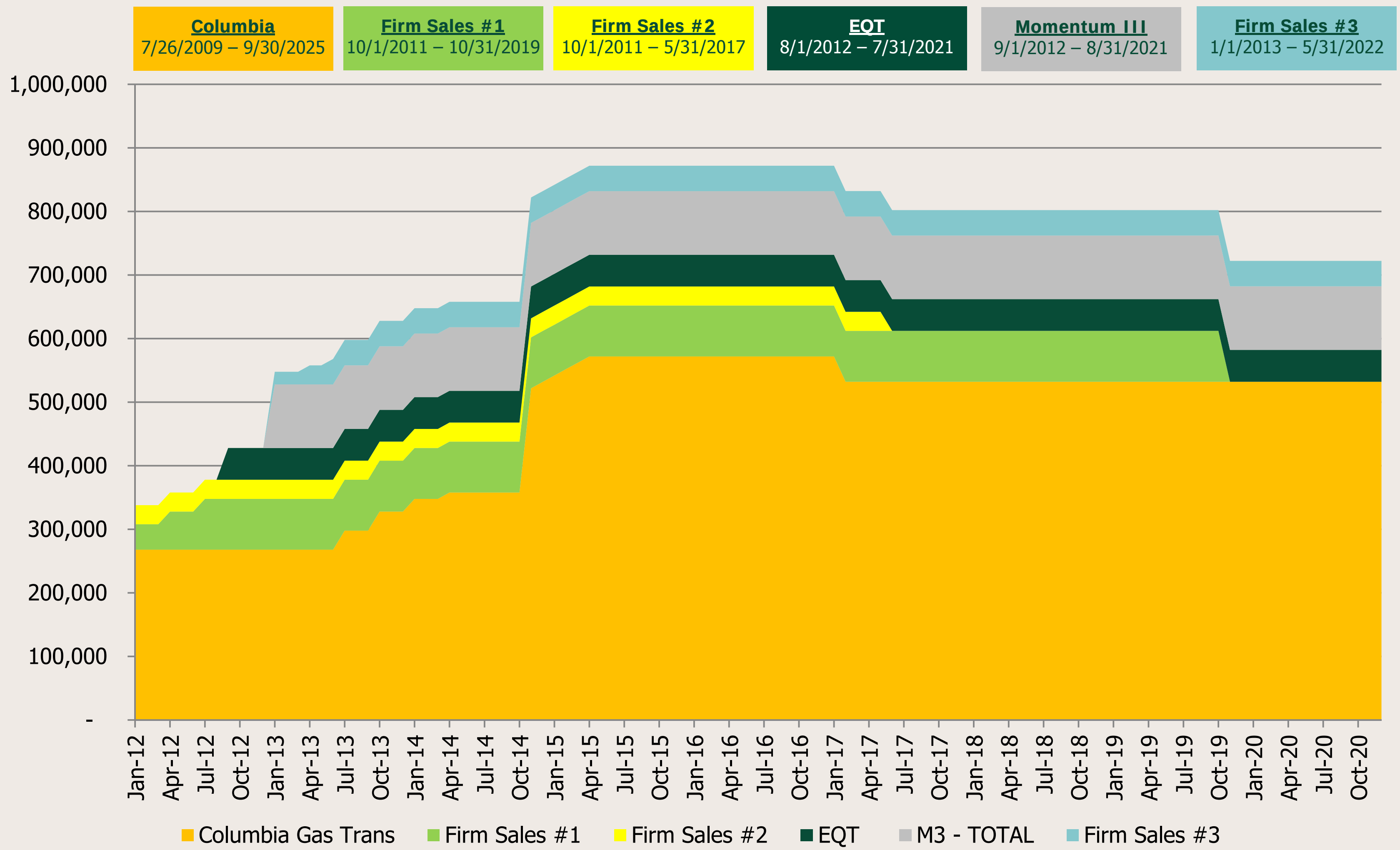
Key Credit Strengths

World class asset base with scale	▪ Liquids-rich Marcellus and Utica shale plays are two of the top U.S. shale plays ▪ Antero has scale in both these plays – 294,000 net acres in the Marcellus Shale and 78,000 net acres in the Utica Shale
Large, low risk drilling inventory	▪ 100% drilling success rate in the 129 horizontal wells in Marcellus, Utica and Upper Devonian Shales to date ▪ Over 3,200 gross horizontal drilling locations in the Marcellus and Utica; an additional 800 horizontal locations have been identified in the Upper Devonian
Low cost leader	▪ $0.99/Mcfe 3-year development cost leader through 2011 per JPMorgan equity research – excluding Arkoma and Piceance ▪ $0.90/Mcfe average operated net development cost over past three years – excluding Arkoma and Piceance
Rapid production growth with liquids exposure	▪ 103% Marcellus production growth over past twelve months ▪ 3% liquids by production volume today forecast to grow to ~40% by 2014
Large long-term hedge position	▪ 61% of estimated 2013 dry gas production hedged at $4.99/Mmbtu NYMEX-equivalent ▪ 786 Bcf hedged at $5.03/MMBtu NYMEX-equivalent(1) through 2018
Strong liquidity	▪ ~$1.2 billion of undrawn borrowing base capacity and $302 million in cash at September 30, 2012 pro forma for the recent Notes offering and Piceance divestiture(2)

1. *Assumes 1000 Btu average heat content. Excluding Rockies hedges.*
2. *Lender commitments under facility are $700 million which can be expanded to the full $1.275 billion borrowing base upon bank approval. Undrawn capacity as of 9/30/2012. Notes offering and Piceance divestiture reduced the borrowing base from $1.650 billion and lender commitments from $950 million.*

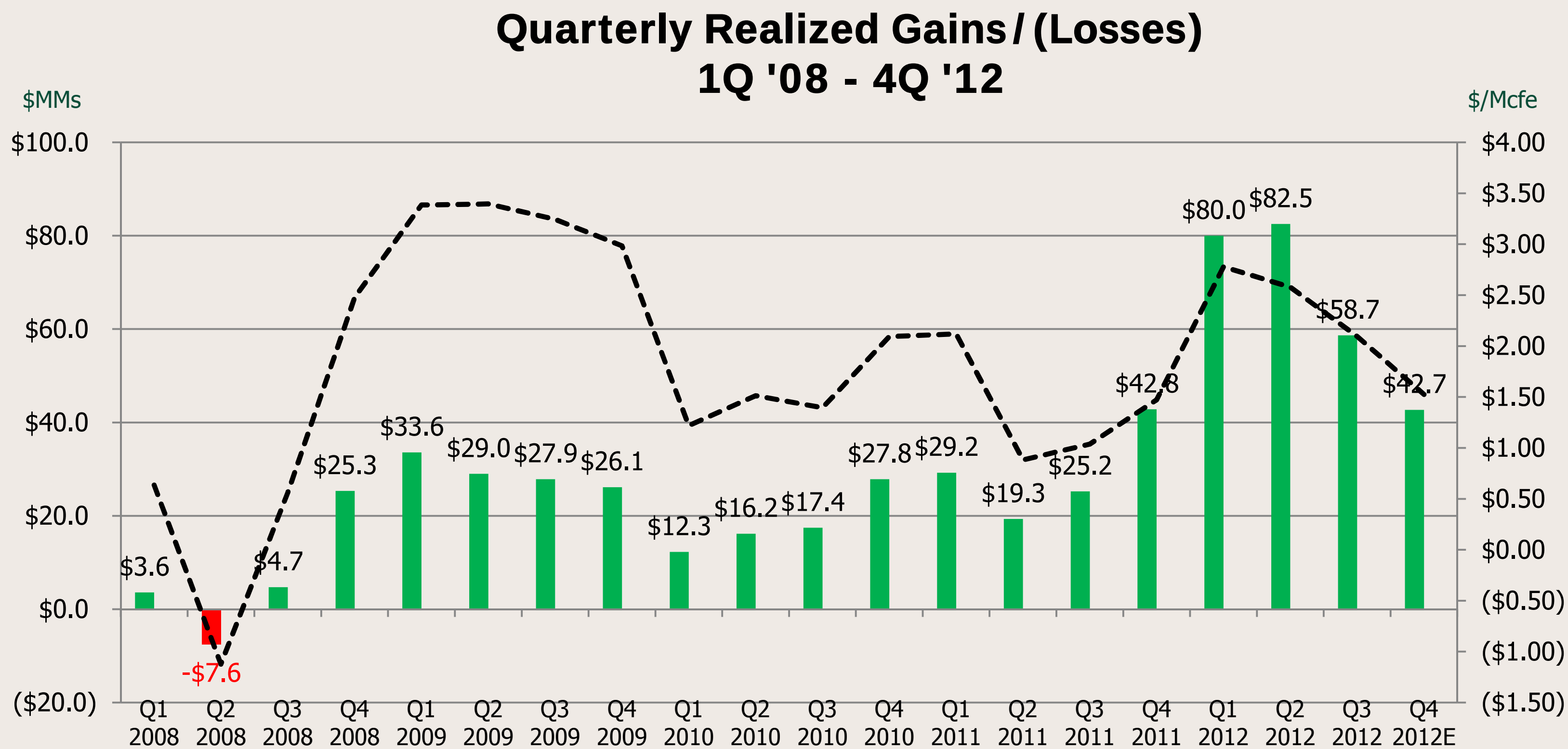
Appendix

Firm Transportation/Sales Commitments – Appalachia



Historical Antero Hedging Results

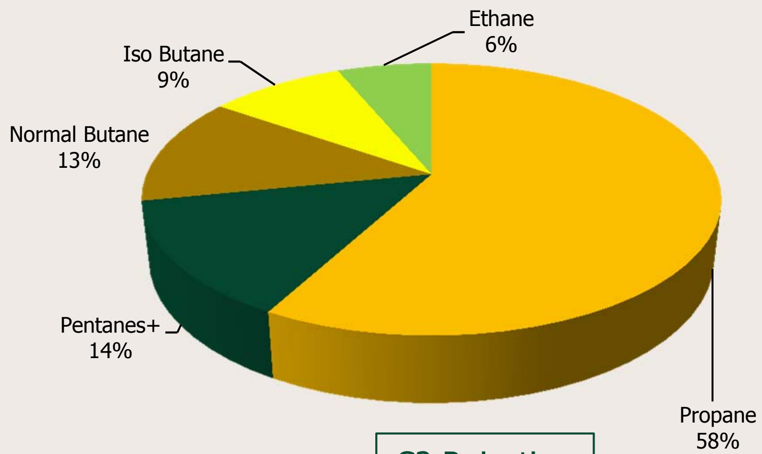
- Antero has realized almost $600 million of gains on commodity hedges over the past five years
  - Gains realized in 19 of last 20 quarters



Marcellus Processing Barrels – 1150 BTU

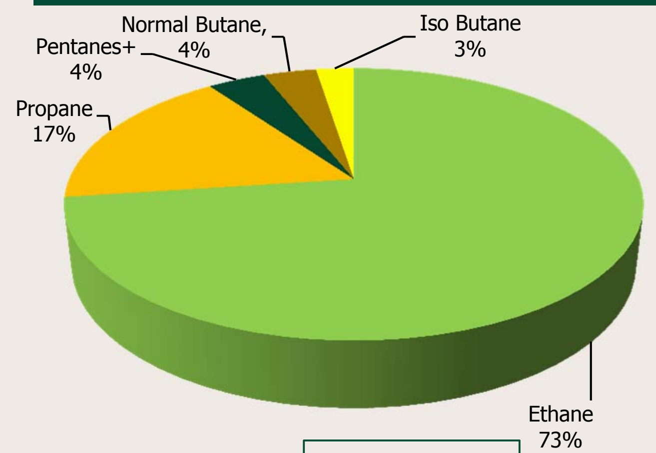
ANTERO RESOURCES

NGL Barrel - Volume



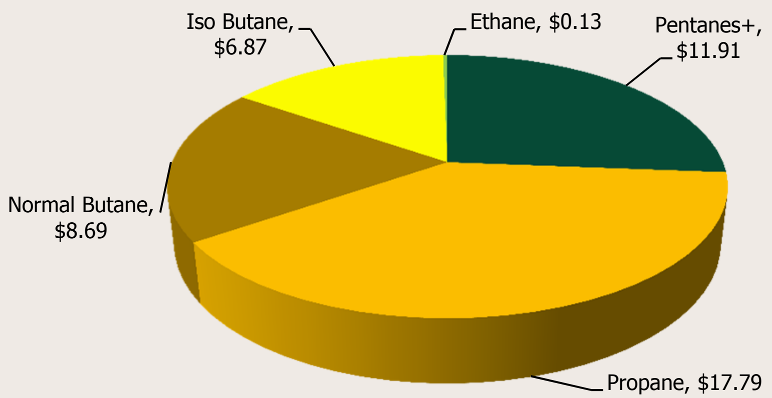
C2 Rejection

NGL Barrel - Volume



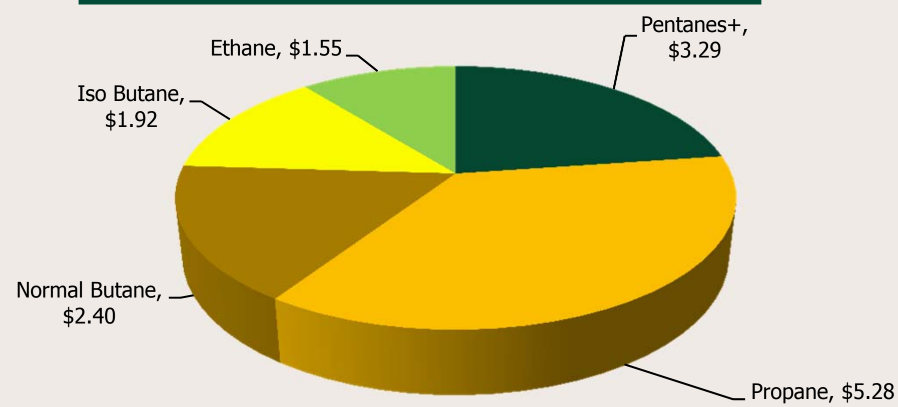
C2 Recovery

Current NGL Value - $45.39 / Bbl(1)



C2 Rejection

Current NGL Value - $14.45 / Bbl(1)

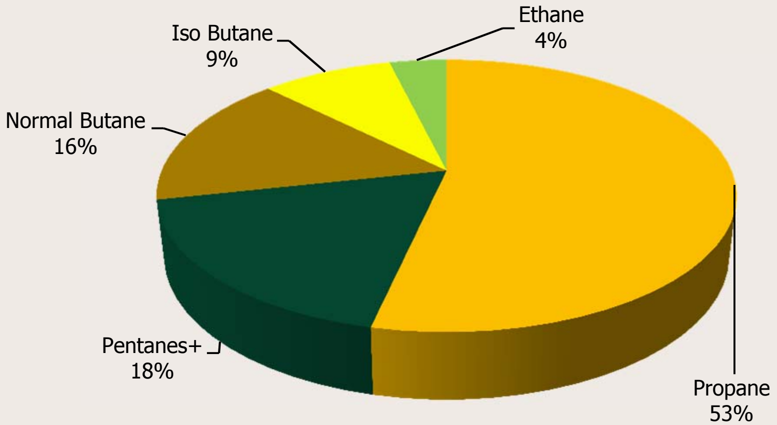


C2 Recovery

1. *Assumes $90.00/Bbl WTI pricing and current spot NGL prices.*

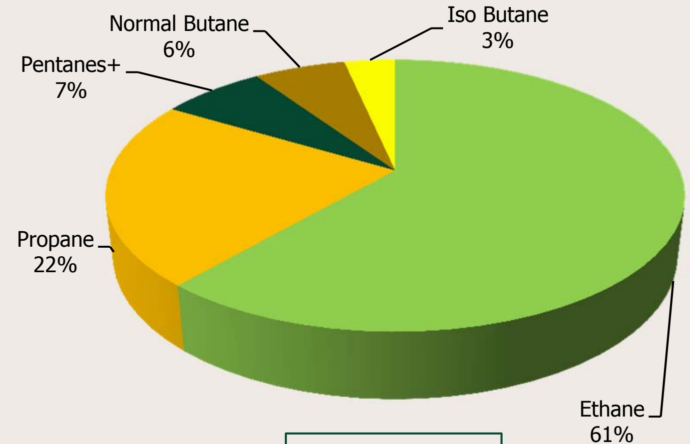
Marcellus Processing Barrels – 1250 BTU

NGL Barrel - Volume



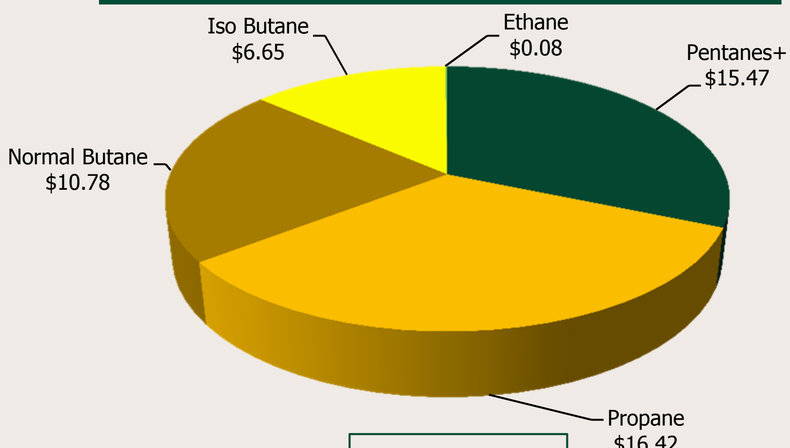
C2 Rejection

NGL Barrel - Volume



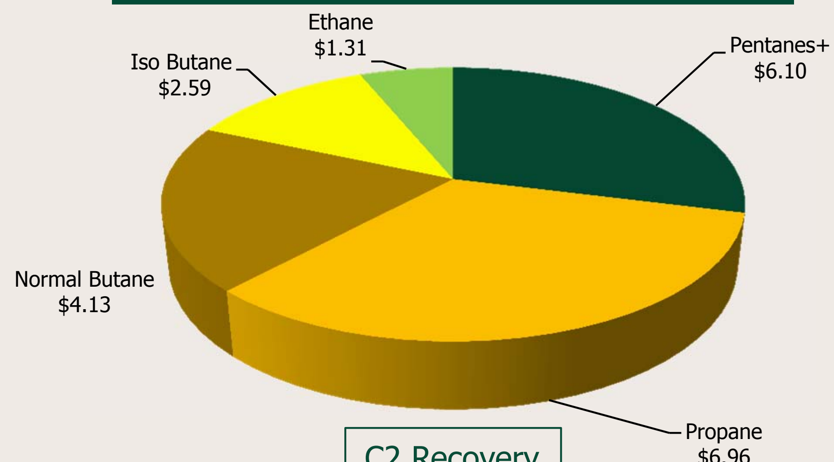
C2 Recovery

Current NGL Value - $49.40 / Bbl(1)



C2 Rejection

Current NGL Value - $21.09 / Bbl(1)



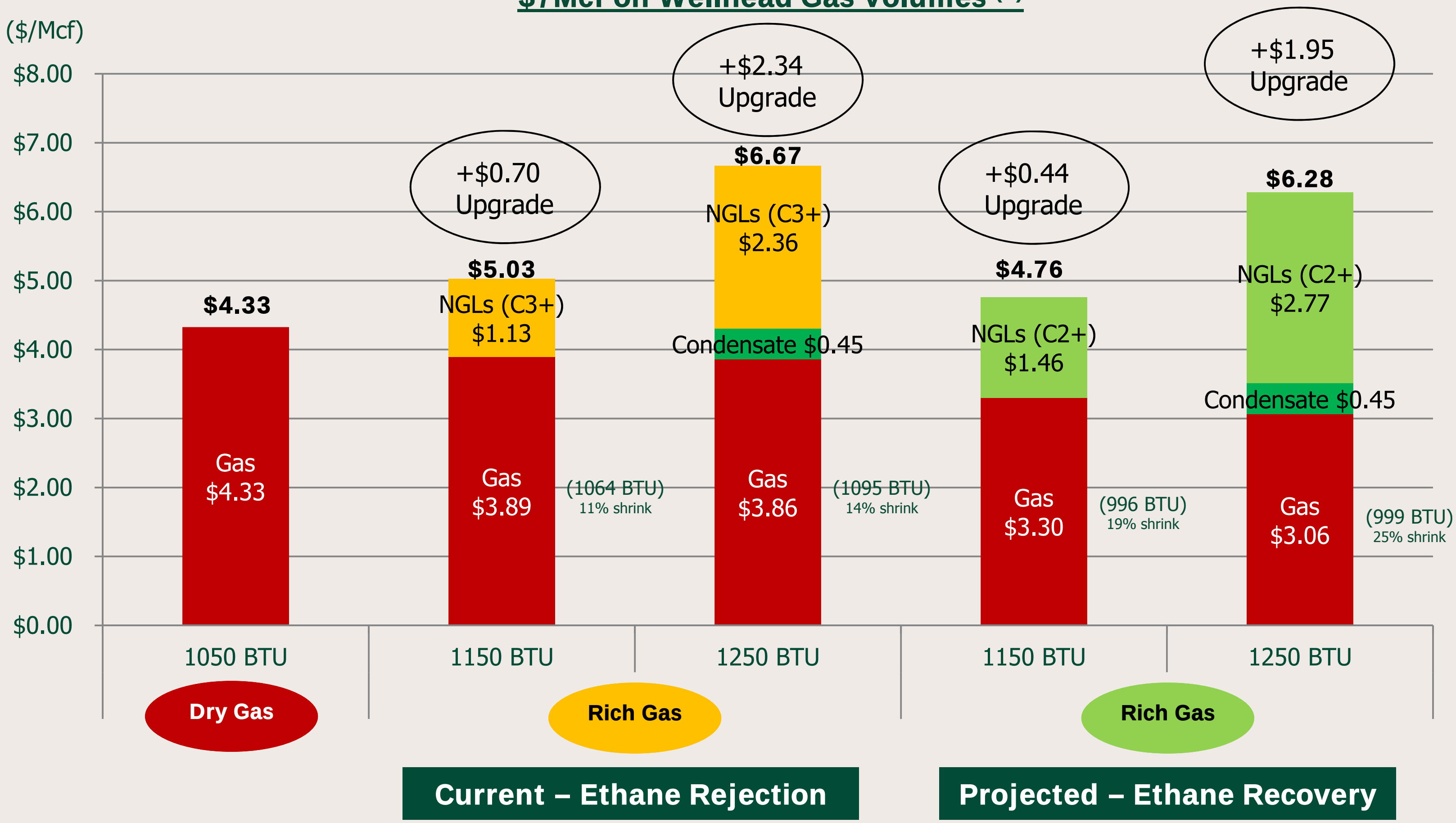
C2 Recovery

1. *Assumes $90.00/Bbl WTI pricing and current spot NGL prices.*

Marcellus Rich Gas Provides Liquids and Processing Upgrade

- Marcellus rich gas and highly rich gas acreage provides a significant advantage in well economics – assuming $4.25/MMBtu NYMEX, $90.00/Bbl WTI and 12-month historical NGL pricing correlation
- Upgrade analysis demonstrates that ethane recovery is not economic at current ethane prices

$ / Mcf on Wellhead Gas Volumes (1)



1. *Assumes $4.25/MMBtu NYMEX, $90.00/Bbl WTI and current NGL 12 month correlation. 1.054 and 2.070 (ethane rejection) and 3.332 and 5.145 (ethane recovery) GPMs used, all processing costs, shrink and fuel included. No ethane takeaway available until Enterprise ethane pipeline is online (expected 1Q 2014). Ethane recovery well economics include fixed fee cost tariff on ATEX ethane pipeline.*

Antero EBITDAX Reconciliation

EBITDAX

	9 Months Ended	
Antero Resources LLC	9/30/2011	9/30/2012
EBITDAX:		
Net income (loss)	87,276	147,502
Unrealized loss (gain) on commodity derivative contracts	(151,520)	111,649
Gain on sale of Arkoma Basin assets	0	(291,190)
Loss on sale of Arkoma Basin assets	0	0
Interest expense and other	51,362	71,046
Provision (benefit) for income taxes	74,941	112,610
Depreciation, depletion, amortization and accretion	68,107	107,058
Impairment of unproved properties	6,828	4,572
Exploration expense	5,902	8,150
Stock compensation expense	0	0
Loss on compressor station sale	8,700	0
Other	708	2,992
EBITDAX from Continuing Operations	152,304	274,389
EBITDAX from Discontinued Operations	81,482	49,355
EBITDAX	233,786	323,744

Piceance EBITDAX Reconciliation

ANTERO RESOURCES

9/30/12 LTM EBITDAX

Antero Resources LLC	Pro Forma Ex-Piceance and Pipeline
EBITDAX:	
Net income (loss)	(39,532)
Unrealized loss (gain) on commodity derivative contracts	(243,033)
Gain on sale of Oklahoma midstream assets	(291,190)
Loss on sale of Arkoma Basin assets	427,232
Interest expense and other	67,117
Provision (benefit) for income taxes	256,479
Depreciation, depletion, amortization and accretion	140,532
Impairment of unproved properties	6,482
Exploration expense	9,889
Stock compensation expense	0
Franchise taxes included in general and administrative expenses	4,720
Expenses related to acquisition of business	(230)
Noncontrolling interest in Centrahoma	0
SG&A	(6,453)
Loss on compressor station sale	0
EBITDAX	332,013

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 LLC and its subsidiaries (collectively, the "Company") expects, believes or anticipates will or may occur in the future are forward-looking statements. The words "believe," "expect," "anticipate," "plan," "intend," "foresee," "should," "would," "could," or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature. 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 in the Company's filings with the SEC.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the 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 "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2011.

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.

Cautionary Note Regarding Hydrocarbon Quantities

The U.S. Securities and Exchange Commission (SEC) permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserve estimates (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 reserves included in this presentation have been audited by Antero's third-party engineers. Antero's estimate of probable and possible reserves was prepared by Antero's internal reserve engineers, has not been reviewed by third-party engineers, and is provided in this presentation because management believes it is useful information that is widely used by the investment community in the valuation, comparison and analysis of companies. Antero does not plan to include probable and possible reserve estimates in its filings with the SEC.

We use certain other terms in this presentation relating to estimates of hydrocarbon volumes that the SEC's guidelines prohibit us from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved, possible or probable reserves as defined by SEC regulations and accordingly are substantially less certain and no discount or other adjustment is included in the presentation of such numbers. 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 our 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 September 30, 2012. 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.

"Unrisked Resource" refers to Antero's internal estimates of hydrocarbon quantities that Antero's management believes may be potentially discovered through exploratory drilling or recovered with additional drilling. Unrisked resource may not constitute 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. Actual quantities that may be ultimately recovered from Antero's interests will differ substantially. Factors affecting ultimate recovery include the scope of our 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. Estimates of unrisked resource may change significantly as development of Antero's resource plays provides additional data.

"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.