THE UNCONVENTIONAL RESOURCE COMPANY

MAGNUM HUNTER RESOURCES CORPORATION

Investor Presentation

June 2015

Who We Are

- Magnum Hunter Resources is an exploration and production company focused in two of the most prolific unconventional resource shale plays in North America; the Marcellus and Utica Shales of West Virginia and Ohio
- Redirected reserve and production focus to natural gas from oil over the last two years (80% natural gas, 10% ngls and 10% oil)
- Current management team assumed leadership of the Company over 5 years ago in 2009 and has decades of combined energy industry experience
- Appalachian focused asset base provides the Company with the flexibility to allocate capital to the highest EUR properties within the portfolio
- Achieved "Shale Scale" with significant acreage positions in the Appalachian Basin
- Ownership in a ~175 mile gas gathering system located in the Appalachian Basin
- Significant insider ownership of management aligns with shareholder interest

Key Metrics	
Current Market Capitalization	~$400 MM
Current Enterprise Value	~$1,750 MM
Proved Reserves(1)	869.2 Bcfe
3P Reserves(2)	991.4 Bcfe
Contingent Resources(3)	5,346.6 Bcfe

(1) Consists of total proved reserves as of March 31, 2014
(2) 3P Reserves consist of proved, probable and possible reserves (Proved as of March 31, 2015 and Probable / Possible as of December 31, 2014)
(3) The contingent resource estimate is an internal estimate prepared by Magnum Hunter that includes its Utica Shale potential on its vast lease acreage holdings as of June 30, 2014

Where We Operate

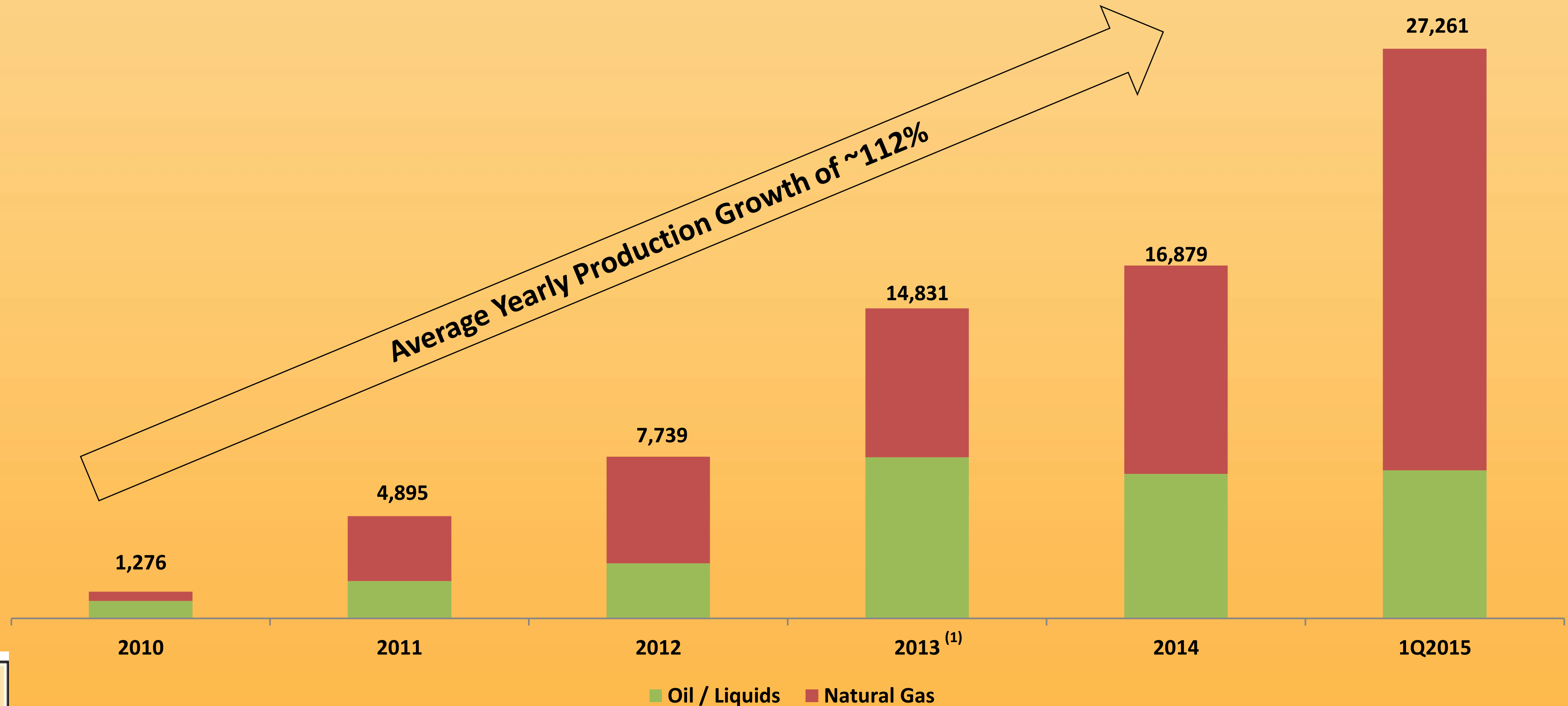
- A natural gas focused company with assets based in the heart of the Marcellus and Utica Shale plays
- ~175 mile gas gathering system strategically located in Ohio and West Virginia moving over 400,000 MMBtu/d with seven existing interconnects

Appalachia March 31, 2015 Proved Reserves				
	(Bcfe)	% PDP	% Natural Gas	Gross Drilling Locations[(1)]
Appalachia	817.5	38.4%	79.6%	1,438

(1) Represents total potential drilling locations reflecting current acreage position and reserve report as of June 30, 2014

Production Growth

- 2015 estimated production anticipated to increase ~77% - 101% compared to 2014
- 2014 reported production increased ~44% compared to 2013 (after asset sales)
- 2013 production increased 92% to 14,831 Boepd(1) compared to 7,739 Boepd in 2012



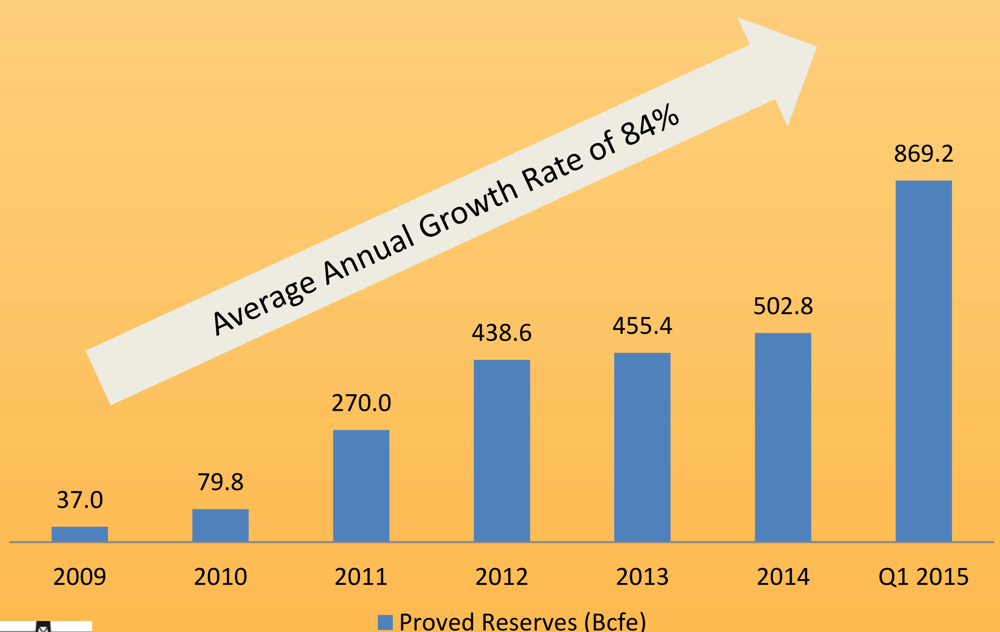
Note: The production numbers referenced above include production from continuing operations (excludes Eagle Ford assets and other discontinued operations)
(1) Includes, on a pro forma basis, 2,925 Boe/d of actual production from discontinued operations, and estimated shut-in production volumes of 2,061 Boe/d

Proved Reserve Growth Consistency

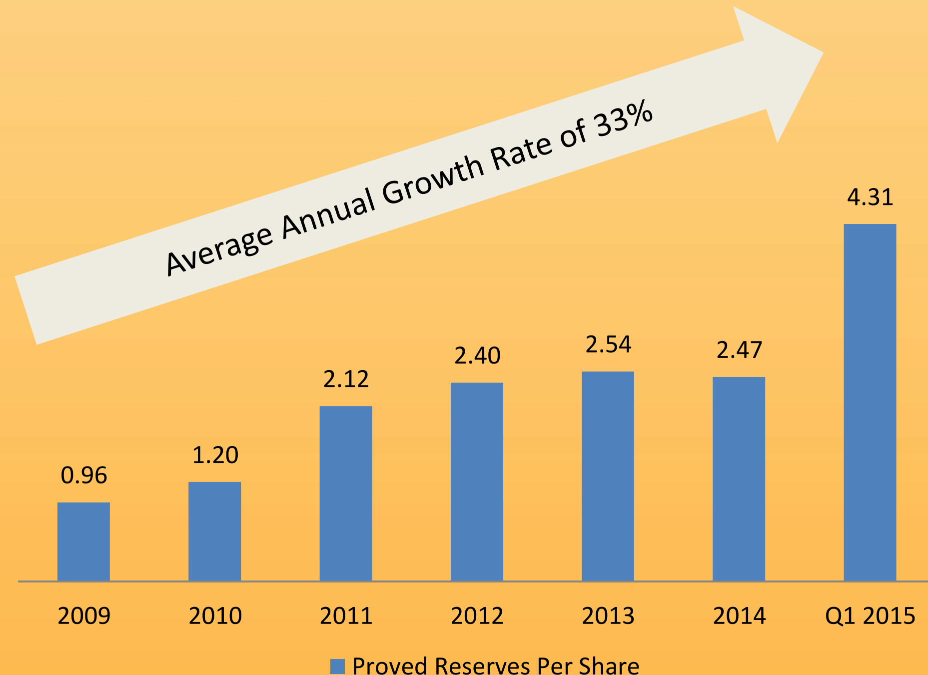
➢ **Track record of proved reserve growth since inception**

- Approximately 869.2 Bcfe of proved reserves at March 31, 2015 (75.3% natural gas) - up 73% year over year)
- Expect to significantly increase proved reserves in the Utica Shale during 2015 due to new production pad drilling
- The Company's reserve life (R/P ratio) of its proved reserves based on current production is ~8.5 years
- The Company replaced ~266% of its 2014 production with reserve additions

Proved Reserves (Bcfe)(A)

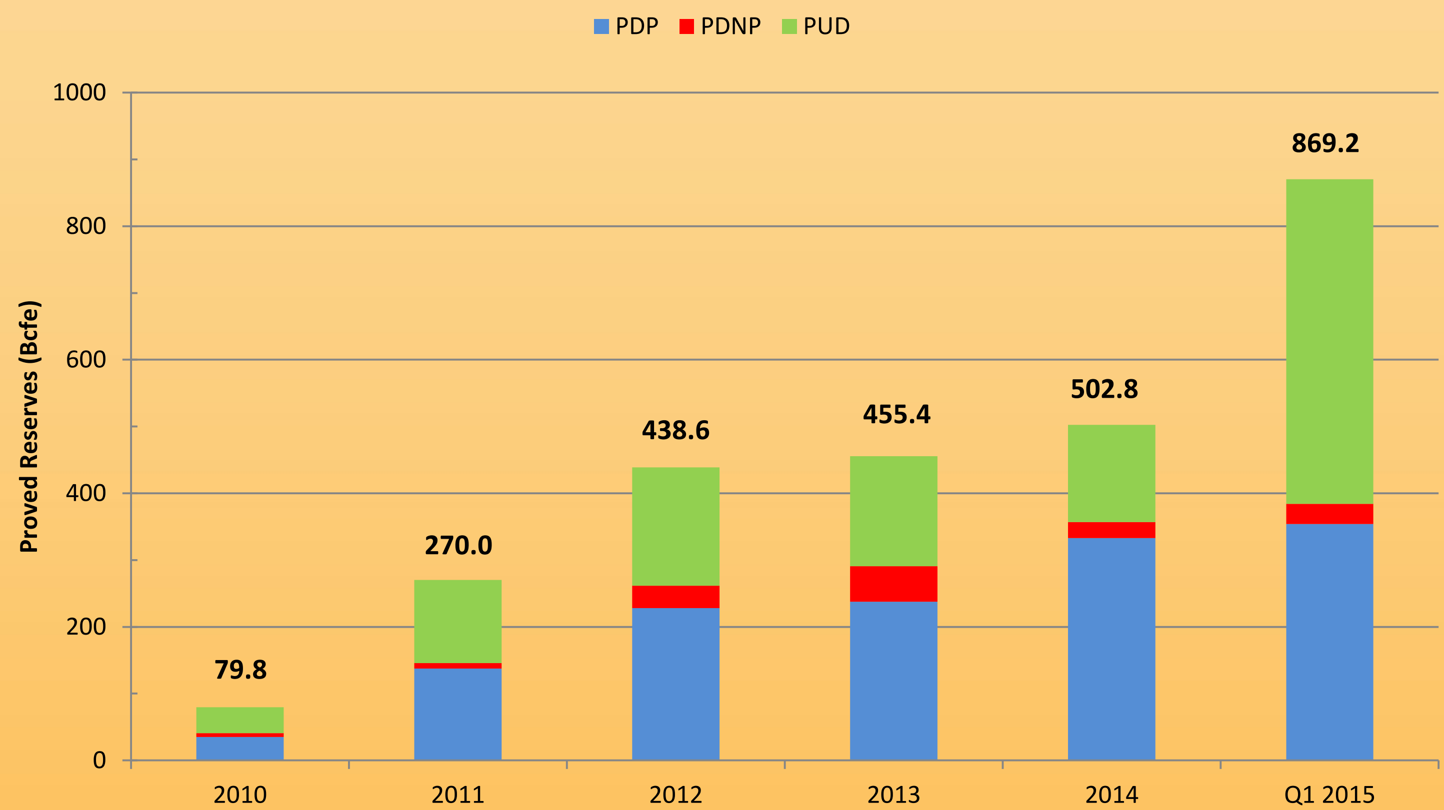


Proved/3P Reserves (Mcfe) / Share(B)



(A) Proved reserves based upon respective year-end reserve reports and 3/31/2015 reserve report
(B) Calculation based on average of common shares outstanding on annual basis

Proved Reserves History



SEC Pricing	2010	2011	2012	2013	2014	Q1 2015
Oil Price ($/STB)	$79.43	$96.19	$94.71	$96.78	$94.99	$82.72
Gas Price ($/MMBTU)	$4.37	$4.11	$2.75	$3.67	$4.31	$3.84

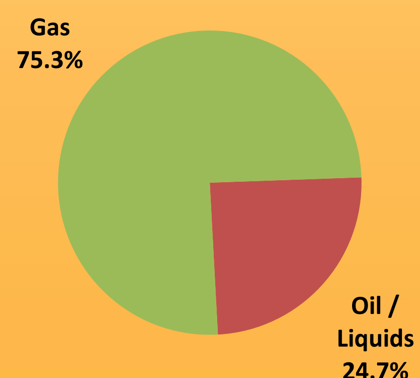
Reserves Summary

- Extensive inventory of low-risk development drilling locations in the Marcellus Shale and Williston Basin
- Significant exploration potential in the wet/dry gas window of the Utica Shale in Ohio and West Virginia

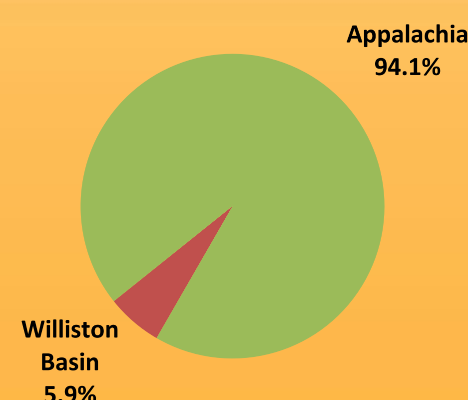
Reserves Summary

	Net Reserves as of March 31, 2015 (SEC PRICING)				December 31, 2014
Category	Liquids (MMBbls)	Gas (Bcf)	Total (Bcfe)	% of Total Proved	PV-10 ($MM)
PDP	17.4	249.5	354.3	40.8%	$707
PDNP	0.7	25.9	30.0	3.5%	43
PUD	17.6	379.3	484.9	55.8%	159
Total Proved Reserves	**35.7**	**654.7**	**869.2**		**$909**
Probable / Possible	9.9	62.6	122.2		189
Total 3P Reserves	**45.6**	**717.3**	**991.4**		**$1,098**
Contingent Resources	140.3	4,505.0	5,346.6		
Total Contingent Resources	**185.9**	**5,222.3**	**6,338.0**		

Proved Reserve Allocation

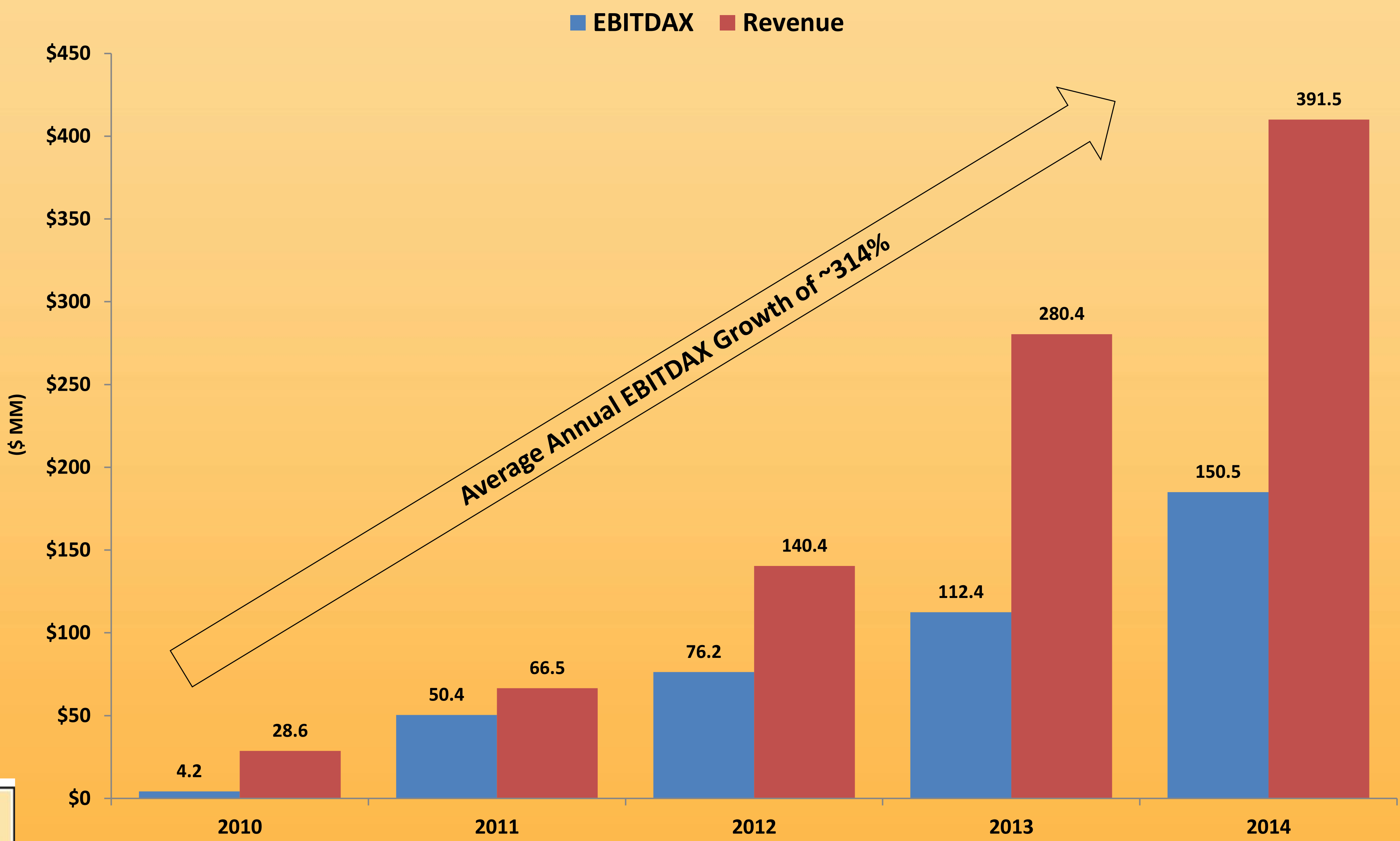


Proved Reserves by Region



Note: Contingent Resources represents reserves as of June 30, 2014

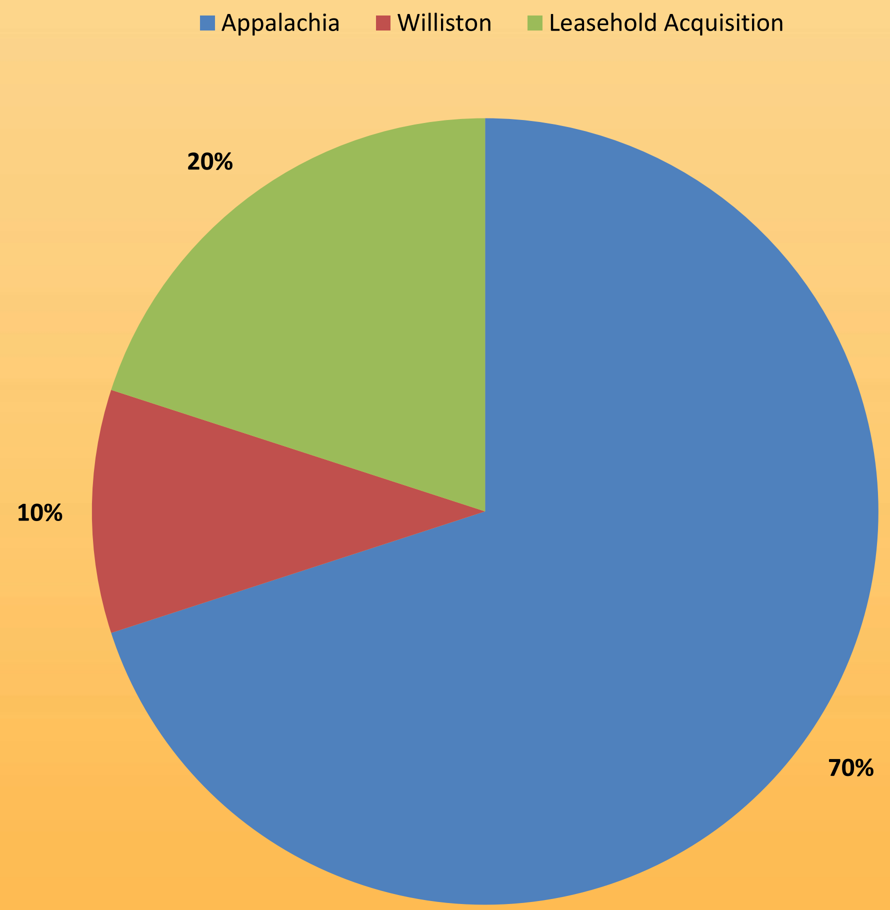
Consistent Growth Continues



* See Appendix of this presentation for a non-GAAP reconciliation table

Breakdown of Capital Expenditures

2015 Capital Budget Breakdown



Total: $100 Million

Substantial Leasehold Inventory

As of January 31, 2015	**Developed Acreage** [1]		**Undeveloped Acreage** [2]		**Total Acreage**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Appalachian Basin [3]						
Marcellus Shale	61,901	59,566	28,792	20,368	90,693	79,933
Utica Shale	73,591	67,885	65,748	60,210	139,339	128,095
Magnum Hunter Production	116,422	40,020	201,799	168,289	318,221	208,309
Other	13,726	13,726	73	17	13,799	13,742
Total	**265,640**	**181,195**	**296,412**	**248,884**	**562,052**	**430,079**
South Texas						
Other[4]	1,777	880	618	546	2,395	1,426
Total	**1,777**	**880**	**618**	**546**	**2,395**	**1,426**
Williston Basin - USA						
North Dakota	93,637	37,901	49,227	27,749	142,864	65,650
Total	**93,637**	**37,901**	**49,227**	**27,749**	**142,864**	**65,650**
MHR TOTAL	**361,054**	**219,976**	**346,256**	**277,179**	**707,310**	**497,155**

(1) Developed acreage is the number of acres allocated or assignable to producing wells or wells capable of production
(2) Undeveloped acreage is lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage includes proved reserves
(3) Approximately 55,585 Gross Acres and 48,207 Net Acres overlap in our Utica Shale and Marcellus Shale
(4) Pertains to certain miscellaneous properties in Texas and Louisiana

Appalachian Division

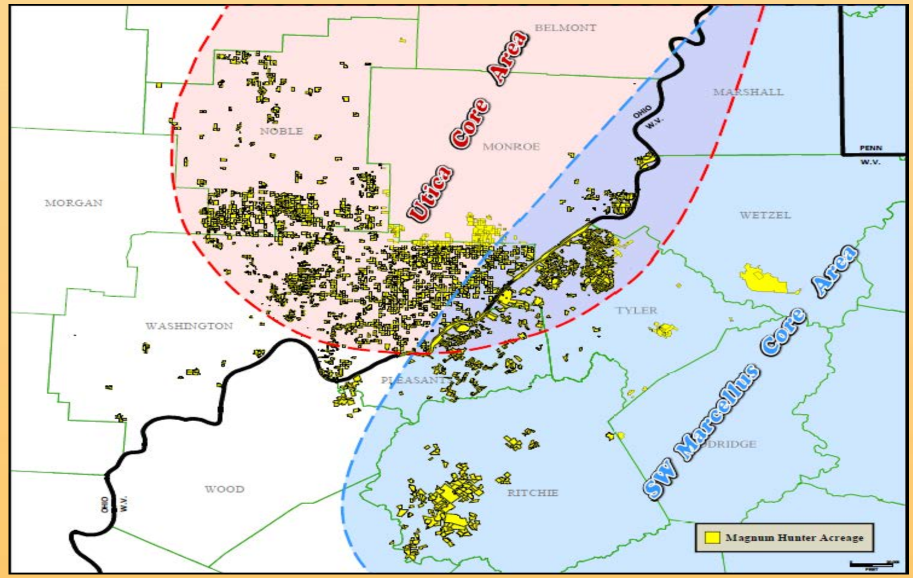
(Ohio, West Virginia and Kentucky)

Appalachian Division Overview

Overview

- **Proved Reserves and PV-10**
  - Total proved reserves of **817.5** Bcfe as of 3/31/15
  - Proved producing reserves of **313.8** Bcfe as of 3/31/15
  - PV-10 of $765.8 million as of 12/31/14
- **Acreage Position**
  - **~430,000** net acres in the Appalachian Basin
  - **~80,000** net acres located in the Marcellus Shale
    - 387 gross remaining Marcellus well locations(1)
  - **~128,000** net acres prospective for the Utica Shale
    - 464 gross remaining Utica well locations(1)

Areas of Operation



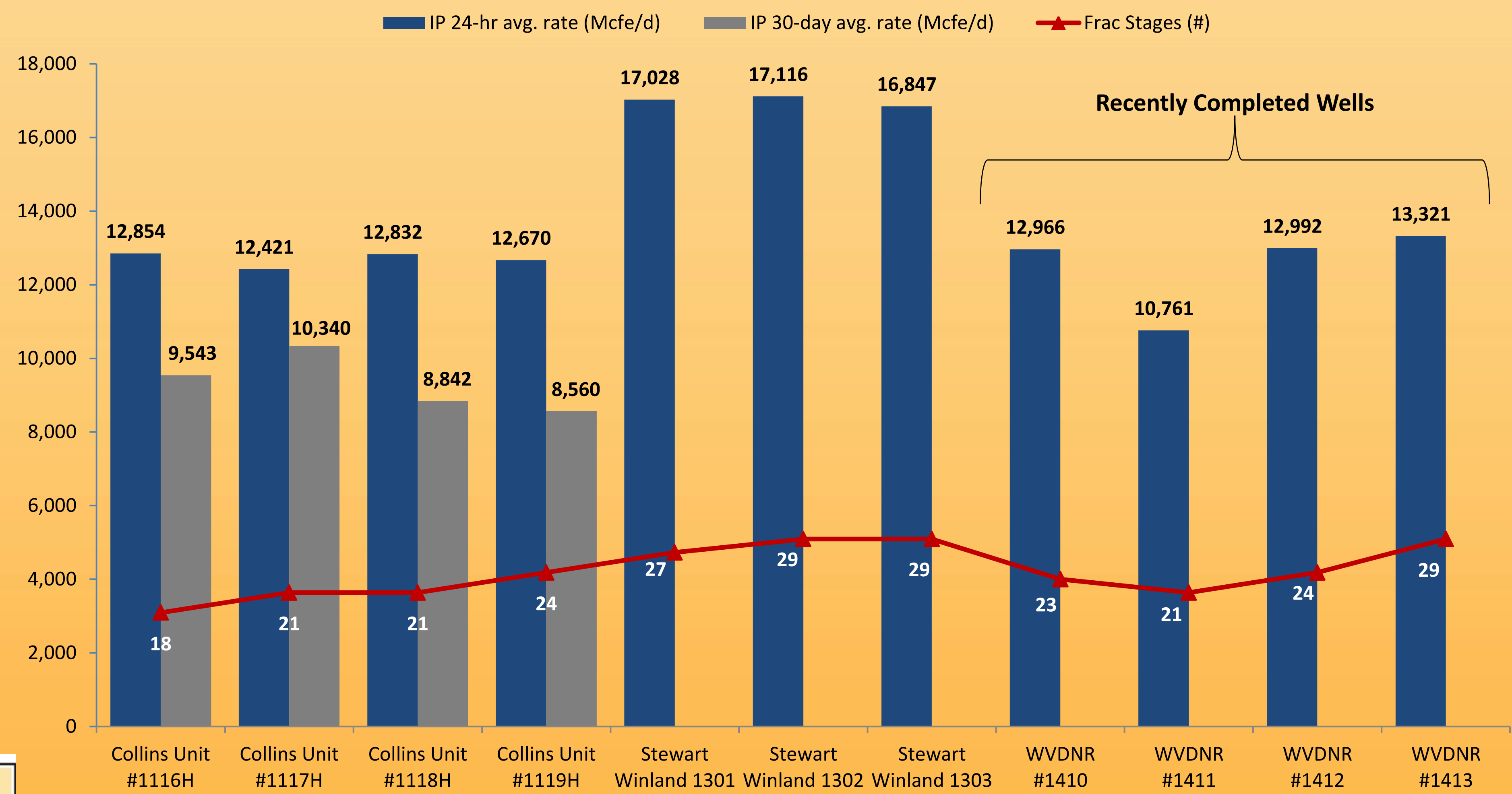
Utica and Marcellus Shale Overview

- 62 gross wells have been drilled and completed to-date
  - 20 wells in Tyler County, WV
  - 36 wells in Wetzel County, WV
  - 5 wells in Monroe County, OH
  - 1 well in Washington County, OH
- 2015 Drilling and Completion Operations:
  - Bring online 11 wells (3 Marcellus and 8 Utica)

(1) Marcellus/Utica well locations only contemplate locations with a working interest > 70%

Marcellus Shale Recent Well Results

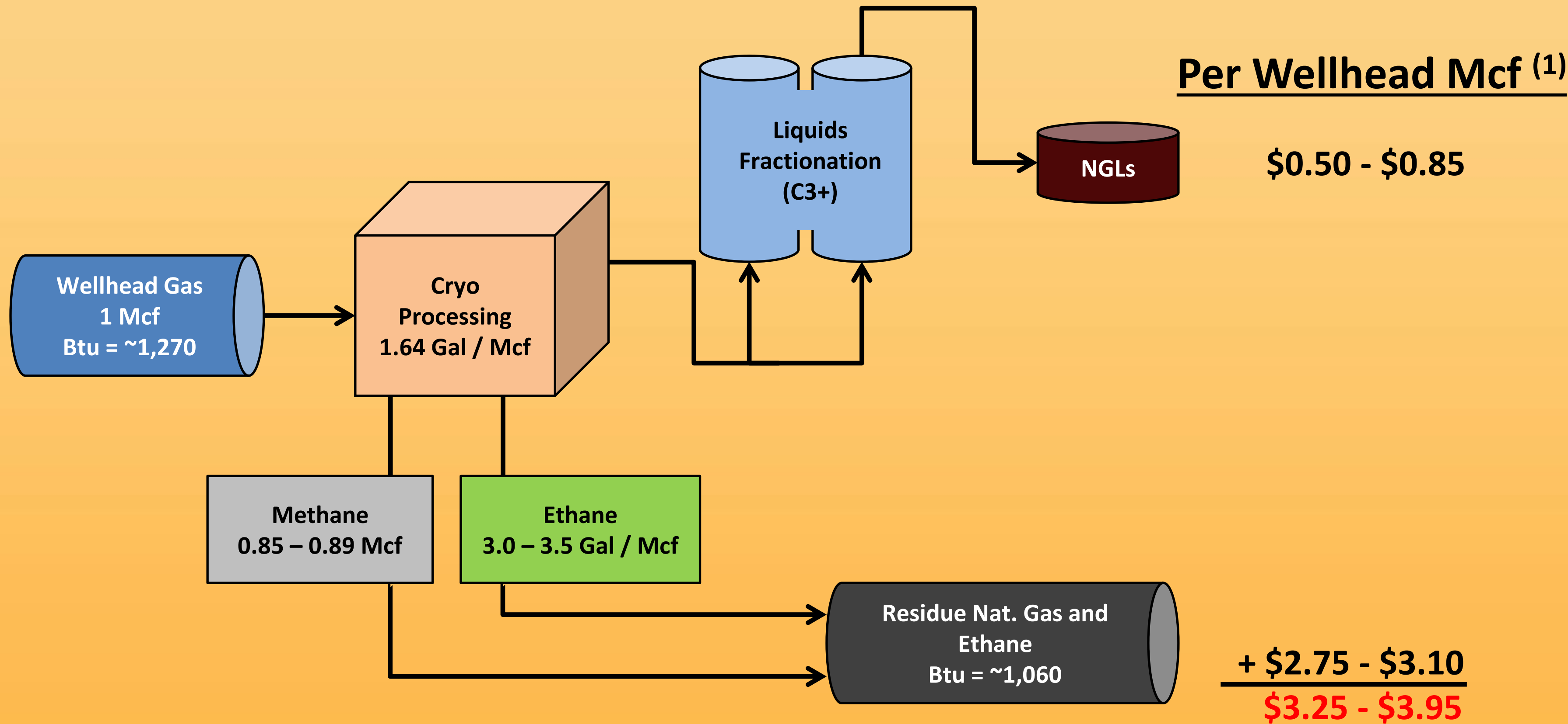
Marcellus Operated Well Results



Please note that the Stewart Winland and WVDNR wells reflect peak production rates

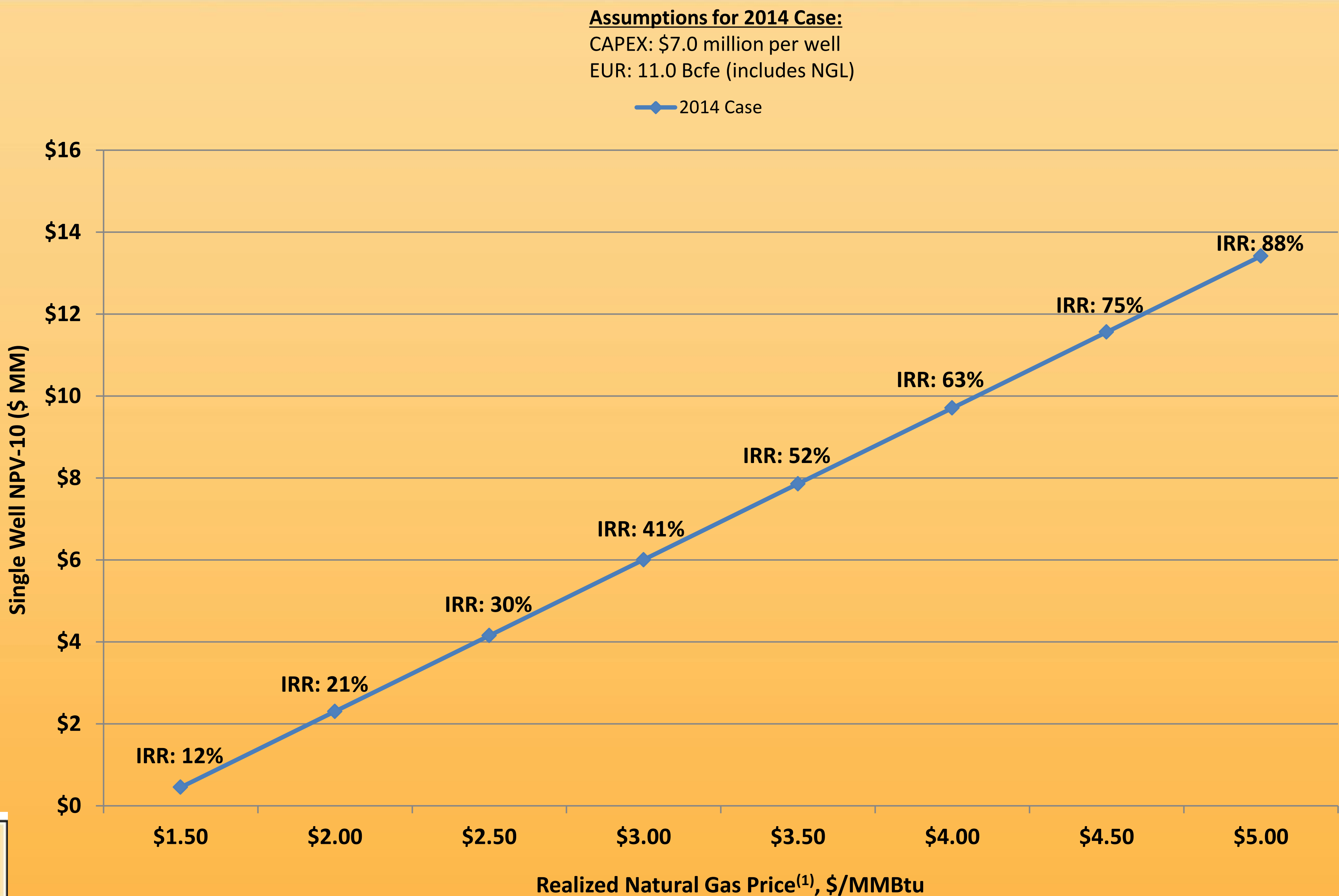
NGL Uplift in Appalachia

- Following the startup of the Mobley Processing Plant in December 2012, Magnum Hunter has realized an uplift in NGLs on a per wellhead Mcf basis between $0.50 - $0.85
- The Company has 200 MMcf/d of dedicated processing capacity at the Mobley Plant



(1) All values shown are versus wellhead production in Mcf.

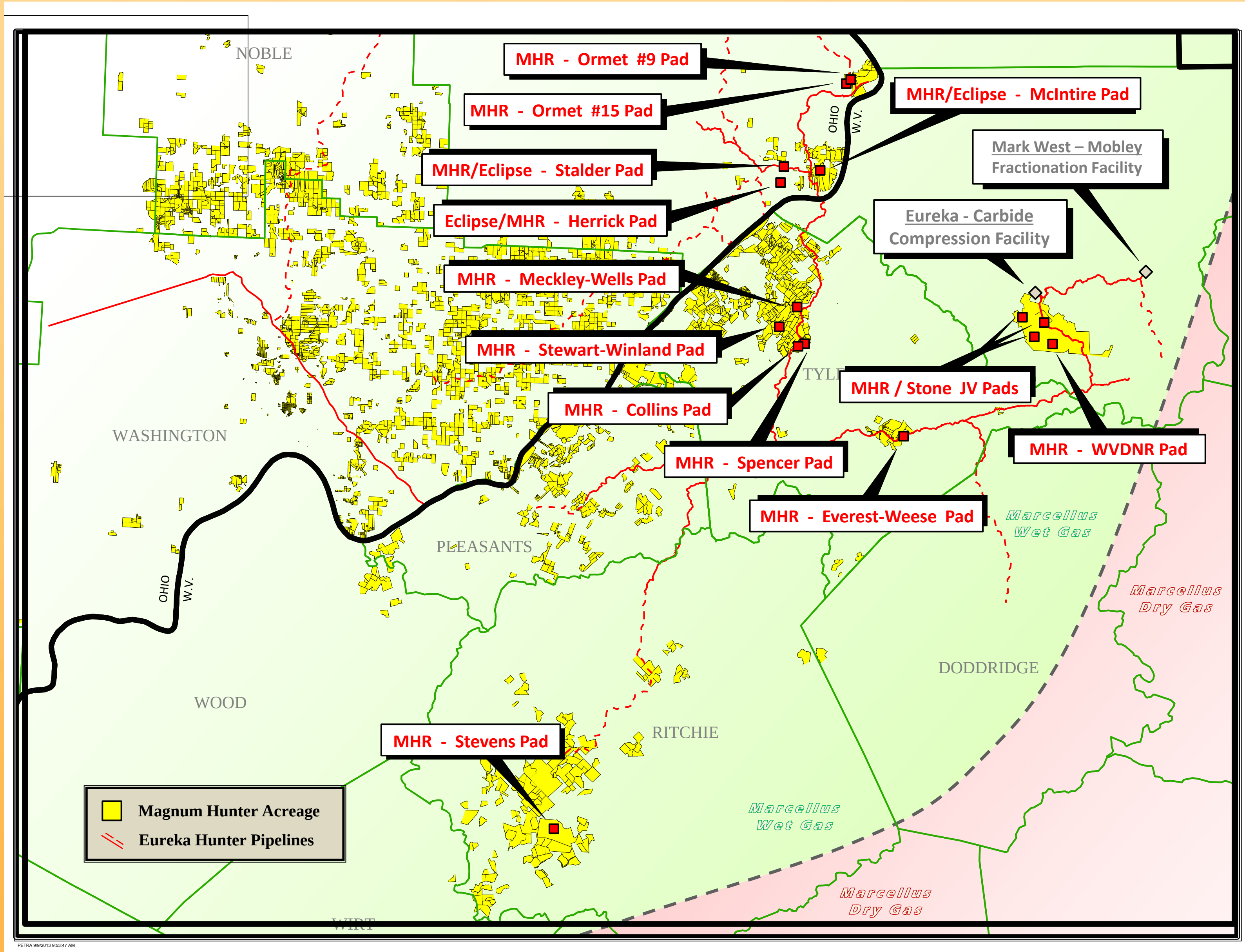
Economic Sensitivity of Marcellus "Magnum Rich"



Note: Assumes realized oil price of $60.00/Bbl and realized NGL price of $30.00/Bbl (50% of realized oil price)

(1) NYMEX natural gas (HH) spot pricing as of 3/11/2015 was $2.82 per MMBtu

Marcellus Shale



Note: MHR owns approximately 80,000 net acres in the Marcellus Shale.

Results Indicate Best Shale Play in US

Shale Play Comparison Chart

Parameter	Ohio/West Va./Penn. Utica Shale / Point Pleasant	Wyoming/Colorado DJ Basin Niobrara	Texas Eagle Ford	N. Dakota Bakken
Lithology	**Calcareous Shale**	Chalk/marl	Calcareous Shale	Silty Dolomite
Lithology Descriptor	**Shale with carbonate stringers**	Like Limestone	Like Limestone	More Dolomitic
Storage Capacity				
Formation Thickness	**100'-300'**	150'-300'	75'-300'	< 150'
Porosity	**3-16%**	6-10%	4-15%	8-12%
Water Saturation (Sw)	**5-10%**	35-90%	15-45%	15-25%
OOIP per section (MMBOE)	**20-35**	30+	30-50	10-15
Productive Capacity				
Clay Content	**~10-25%**	10-40%	8-11%	5-10%
Total Organic Carbon (TOC)	**2-6%**	2-6%	5%	9%
Ability to Fracture Stimulate	**na**	Brittleness varies, 250' frac length	Brittle, fracs easy, 500' frac length	Brittle, fracs easy, 500+' frac length
Permeability	**< 0.1 mD**	< 0.1 mD	< 0.1 mD	< 0.1 mD
Reservoir Pressure (psi/ft)	**~0.5-0.85**	0.4-0.6	0.5-0.8	0.5-0.7
Gas-Oil-Ratio (GOR)	**~3,000**	0-10,000+	500-2,000	500-1,000
Development Parameters				
Depth	**7,000'-11,000'**	6,000'-8,000'	6,000'-8,000'	7,000'-11,000'
Well Cost ($MM)	**8.0-10.0**	4.0-6.0	9.0	10.0
Spacing (acres/well)	**80-160**	~160	80-160	100-200
EUR (MBOE/well)	**600+**	175-350	450-700	300-1,000

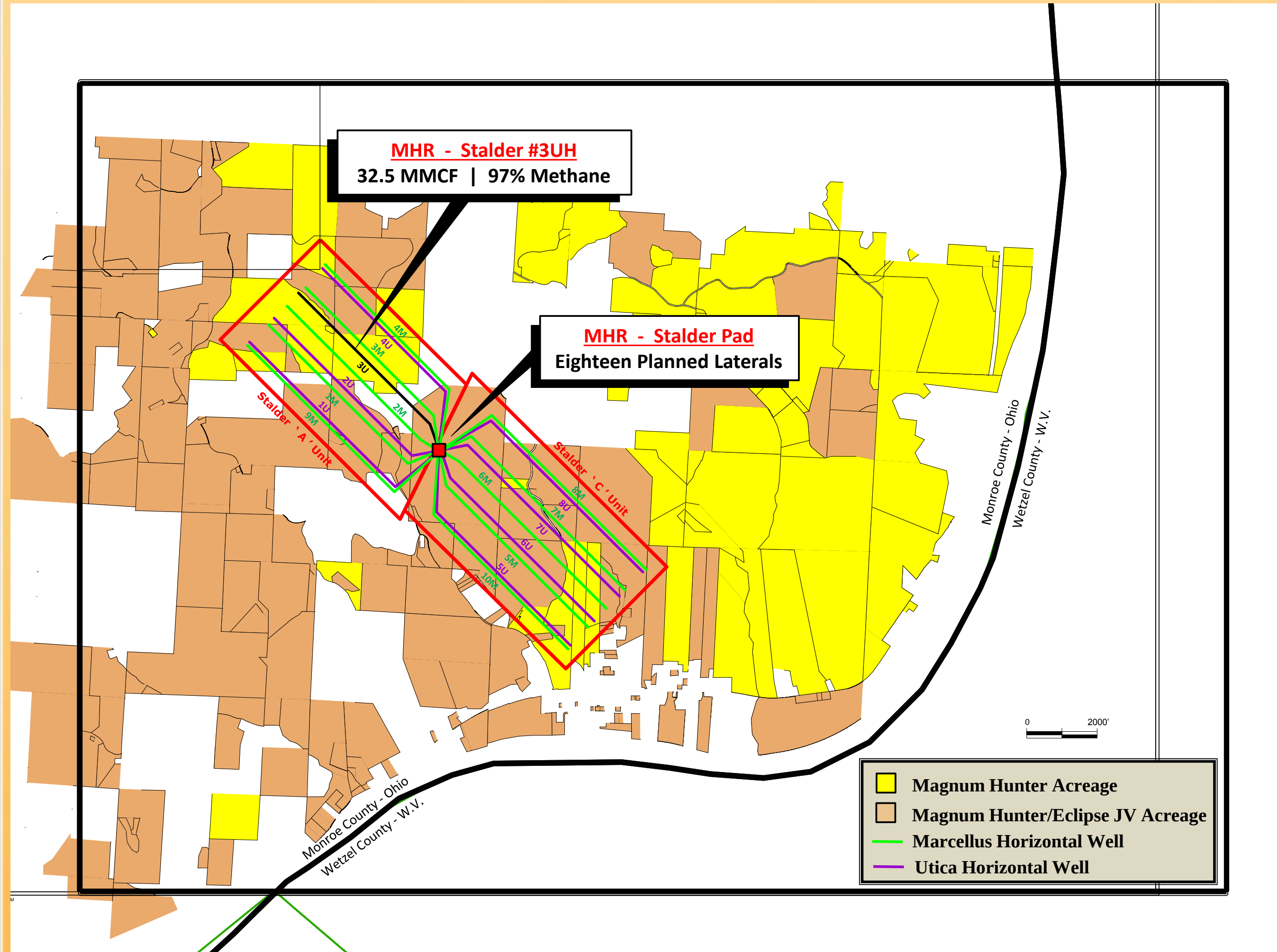
Utica Asset Transactions

Announced Date	Buyer(s)	Seller(s)	Total Transaction Value ($MM)	Acreage	Implied $ / Acre
Apr-15	Gulfport Energy Corporation	Paloma Partners	$300	24,000	$12,500
Nov-14	Antero Resources	Undisclosed	$185	12,000	$15,417
Jul-14	PDC	Undisclosed	$35	13,000	$2,692
Jul-14	**Magnum Hunter Resources; Triad Hunter**	**Ormet Corporation**	**$23**	**1,700**	**13,353**
Jun-14	American Energy Partners, LP	East Resources	$1,750	75,000	$23,333
May-14	Antero Resources	Undisclosed	$95	6,363	$14,930
Feb-14	GPOR	Rhino	$185	8,200	$22,561
Jan-14	American Energy Partners, LP	Paloma Partners	$442	26,000	$17,000
Jan-14	American Energy Partners, LP	XOM	$600	30,000	$20,000
Jan-14	American Energy Partners, LP	Hess Corporation	$924	74,000	$12,486
Aug-13	**Magnum Hunter Resources; Triad Hunter**	**MNW Energy, LLC**	**$142**	**32,000**	**4,441**
Aug-13	Undisclosed company(ies)	EnerVest, Ltd.	$228	18,190	$12,551
Aug-13	Undisclosed company(ies)	EV Energy Parnters, L.P.	$56	4,345	12,888
Feb-13	Gulfport Energy Corporation	Wexford Capital LP	$220	22,000	10,000
Jan-13	Carrizo Oil & Gas Incorporated	Avista Capital Partners LLC	$63	11,200	5,634
Dec-12	Gulfport Energy Corporation	Wexford Capital LLC	$372	37,000	10,054
Jun-12	Halcon Resources	Undisclosed	$194	31,809	6,099
Feb-12	**Magnum Hunter Resources; Triad Hunter**	**Undisclosed**	**$25**	**12,186**	**2,035**

Mean	**$324**	**24,389**	**$12,110**
Median	**$190**	**20,095**	**$12,526**

Source: IHS Herold, Raymond James, Deutsche Bank and Company(ies) press releases.

Stalder Pad Drilling Locations



Magnum Hunter announced the initial production results from the first Utica horizontal well on the Stalder Pad on 2/14/14

- Tested at a peak rate of 32.5 MMCF of natural gas per day
- Drilled to a true vertical depth of 10,653 feet with a 5,050 foot horizontal lateral
- Successfully fracked with 20 stages

The first Marcellus horizontal well on the Stalder Pad has been completed and tested

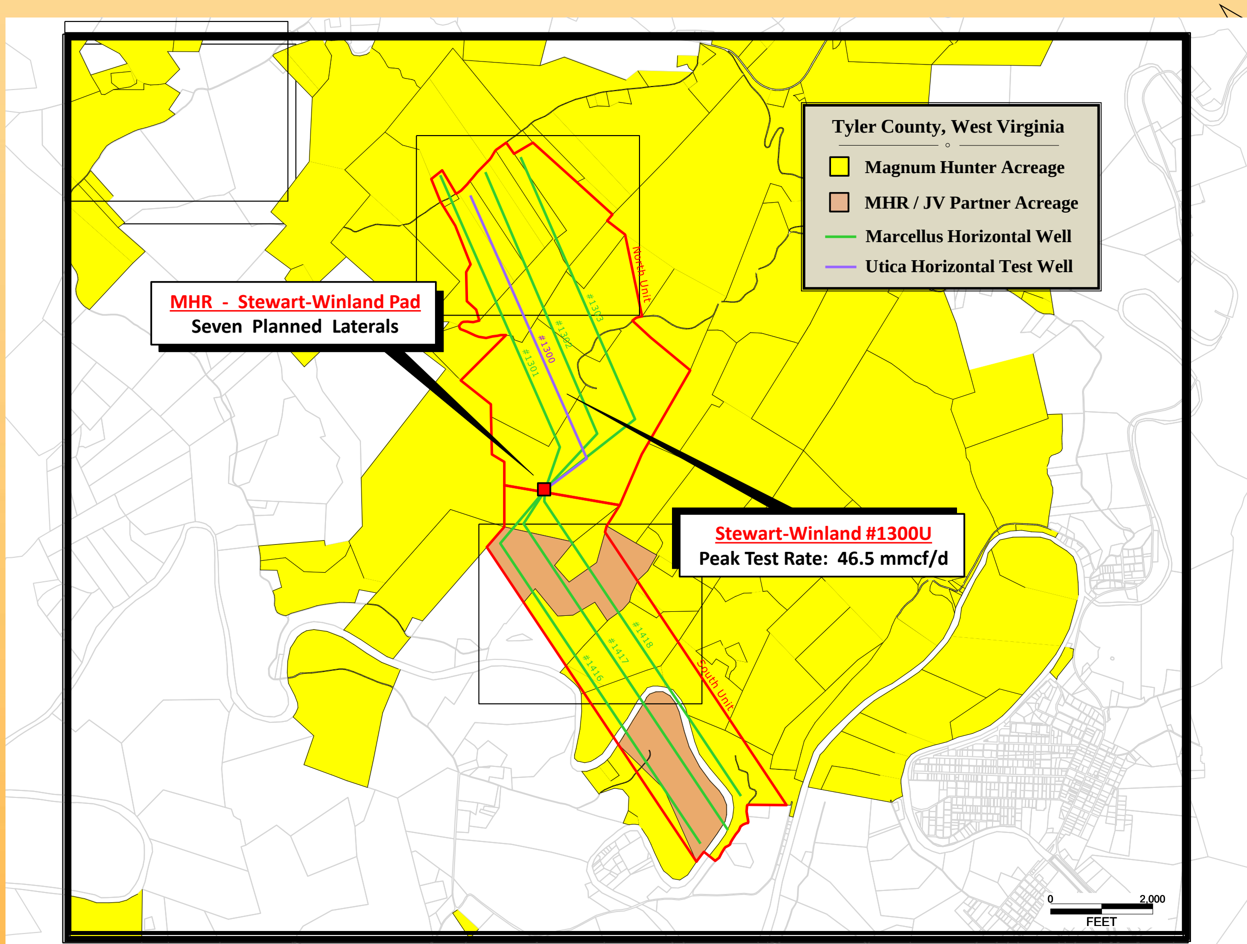
- Drilled to a true vertical depth of 6,070 feet with a 5,474 foot horizontal lateral

Currently testing three new horizontal Utica wells (Stalder #6UH, Stalder #7UH and Stalder #8UH)

- All five wells will be placed on production in February 2015

Pad Drilling in Appalachia

Stewart-Winland Pad Drilling Locations



The Stewart-Winland Pad located in Tyler County, WV has seven planned laterals

- Four wells have been drilled and completed on the North Unit (3 Marcellus and 1 Utica)
- Three wells will be drilled on the South Unit (3 Marcellus)

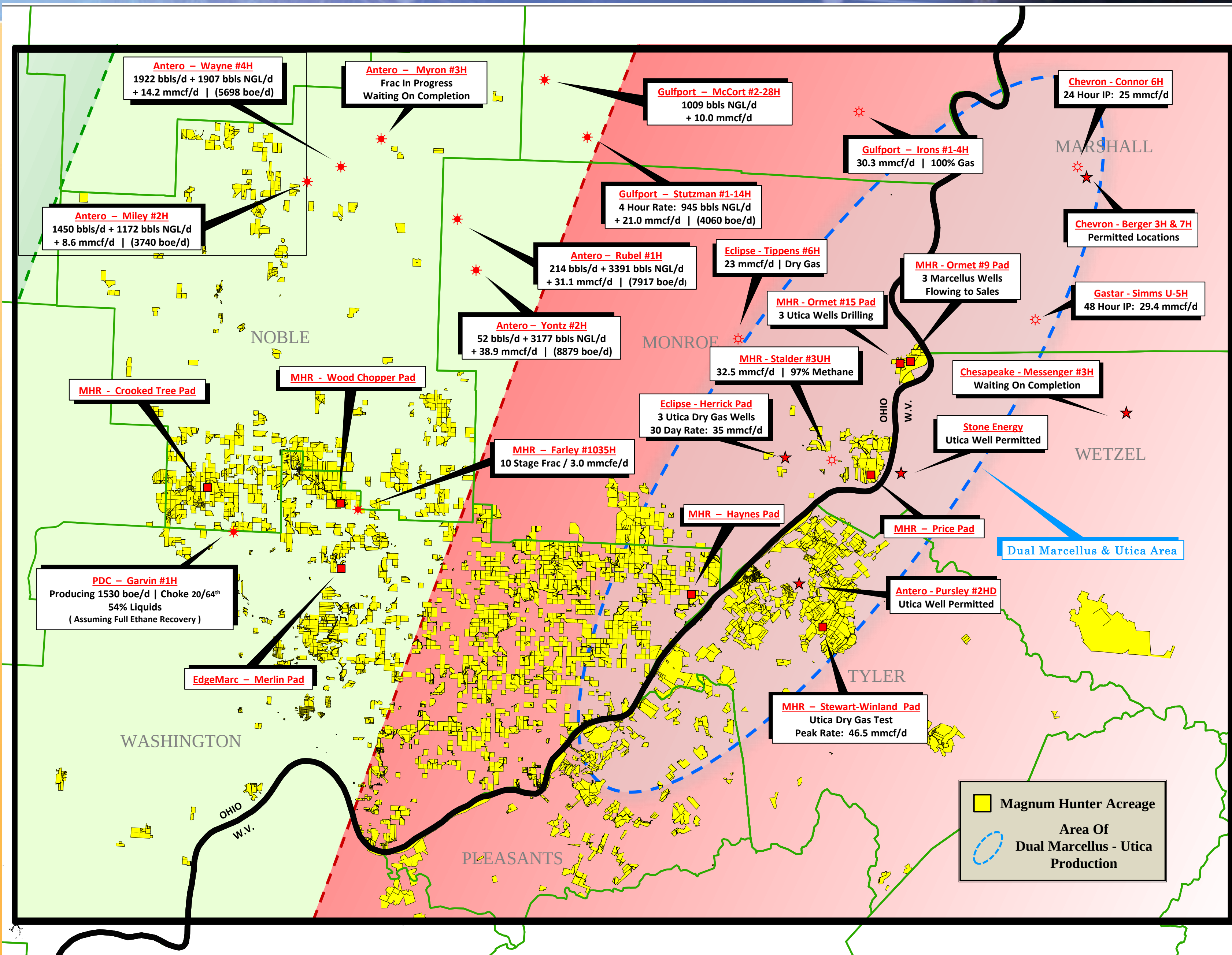
Utica Well was fracture stimulated (22 stages) and tested at a peak rate of 46.5 MMCF

The three Marcellus wells tested at peak rates of 17.0 MMCFE, 17.1 MMCFE and 16.8 MMCFE, respectively

Immediate take-away capacity on the Eureka Hunter Pipeline system allowed all wells to be tied in and flow to sales

Fracing Operations

Utica Shale – Recent Well Results



Note: MHR currently owns approximately 128,000 net acres in the Utica Shale

"Best in Class" – Dry Gas Utica

Well Name	County	Operator	Peak Rate (MMcfe/d)	Peak Rate (Boe/d)	% Gas	Lateral Length	Stages
Stewart Winland 1300U	**Tyler, WV**	**MHR**	**46.5**	**7,750**	**100%**	**5,289**	**22**
Bigfoot 9H	Belmont, OH	RICE	41.7	6,948	100%	6,957	40
Stalder #3UH	**Monroe, OH**	**MHR**	**32.5**	**5,417**	**100%**	**5,050**	**20**
Irons 1-4H	Belmont, OH	GPOR	30.3	5,050	100%	6,629	23
Simms U5H	Marshall, WV	GST	29.4	4,900	100%	4,447	25
Connor 6H	Marshall, WV	CVN	25.0	4,167	100%	6,451	N/A
Shroyer	Monroe, OH	ECR	21.3	3,550	100%	7,819	N/A
Tippens #6H	Monroe, OH	ECR	19.4	3,233	100%	4,424	23
Brown 10H	Jefferson, OH	CHK	8.7	1,445	100%	4,424	N/A
Average			**28.3**	**4,718**	**100%**	**5,721**	**25.5**

New Marcellus/Utica Production Planned in 2015

Well Name[1]	Location	MHR Working Interest	MHR Net Revenue Interest	Estimated Gross Production[2]		Estimated Net Production[2]		Anticipated Timing
				Boe/d[3]	Mcfe/d	Boe/d[3]	Mcfe/d	
Farley #1306H	Washington County, Ohio	100%	85%	1,667	10,000	1,417	8,502	8/31/15
Farley #1304H	Washington County, Ohio	100%	85%	1,667	10,000	1,417	8,502	8/31/15
Farley #1305H	Washington County, Ohio	100%	85%	500	3,000	425	2,550	8/31/15
Ormet #8-15UH	Monroe County, Ohio	100%	95%	2,917	17,500	2,771	16,625	9/30/15
Ormet #9-15UH	Monroe County, Ohio	100%	95%	2,917	17,500	2,771	16,625	9/30/15
Ormet #10-15UH	Monroe County, Ohio	100%	95%	2,917	17,500	2,771	16,625	9/30/15
Wells-Meckley #1401	Tyler County, West Virginia	100%	87%	755	4,530	657	3,941	10/31/15
Wells-Meckley #1402	Tyler County, West Virginia	100%	87%	755	4,530	657	3,941	10/31/15
Stephens #1407 MH	Ritchie County, West Virginia	100%	87%	755	4,530	657	3,941	11/1/15
McNabb UH	Noble County, Ohio	89%	78%	1,667	10,000	1,300	7,802	12/31/15
Reed UH	Noble County, Ohio	85%	73%	1,667	10,000	1,217	7,301	12/31/15
				18,183	**109,090**	**16,059**	**96,355**	

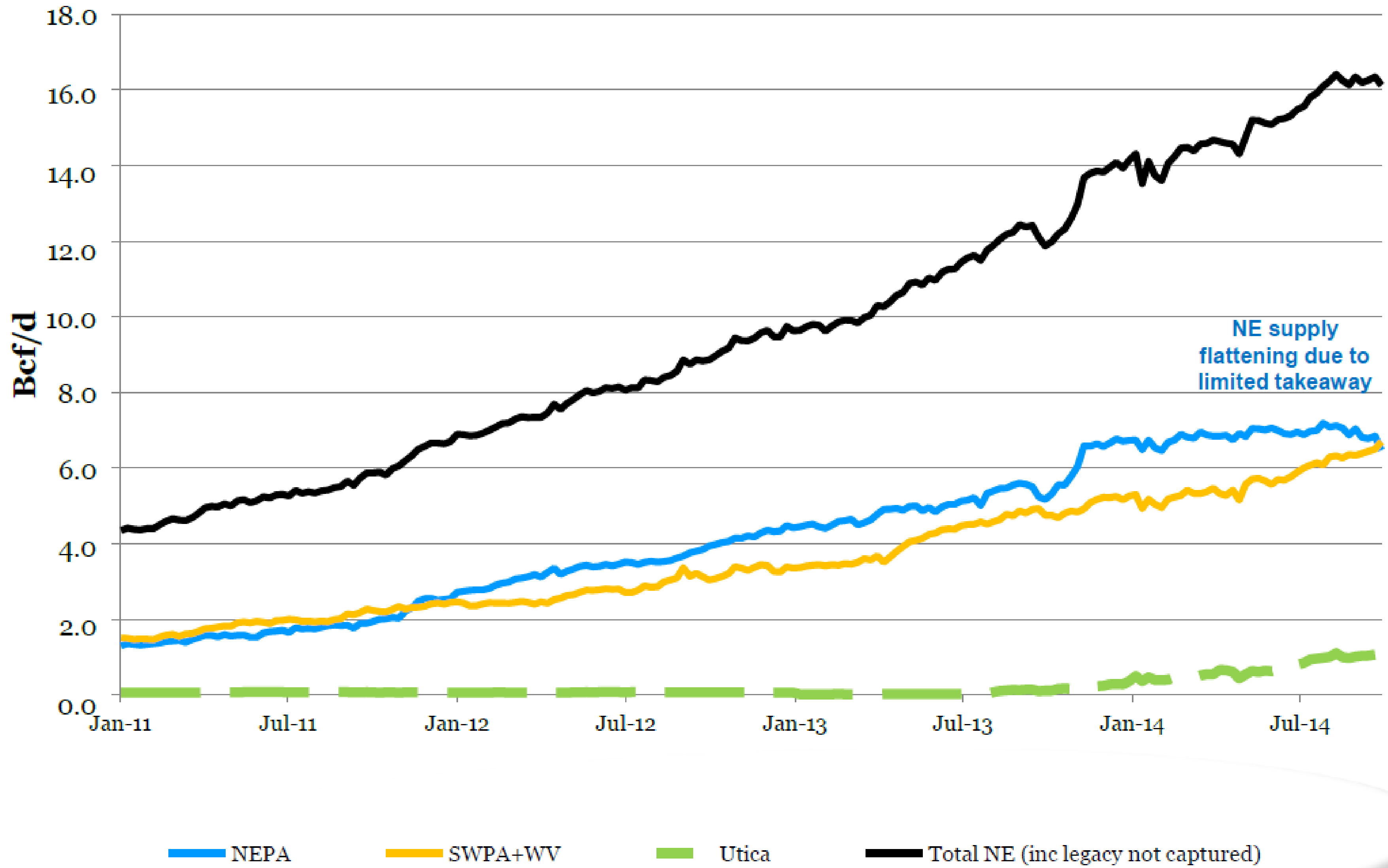
Note: This information constitutes forward-looking statements and is subject to the qualifications on the last page of this investor presentation
(1) Wells are currently in the process of drilling, completing, and/or waiting on sales
(2) Based on estimated IP-30 day rate (average daily amount of production during the first 30 days of production)
(3) Includes NGLs and condensate

Eureka Hunter Midstream

Eureka Hunter Highlights

Location	• Southeastern Ohio • Northern West Virginia
Basins	• 2014 Dry Utica - ~30% of volumes • 2014 Wet Marcellus - ~70% of volumes • 2015E Dry Utica - ~40% of volumes • 2015E Wet Marcellus - ~60% of volumes
HP Pipeline	• 2013 - 80 miles • 2014 - 160 miles • 2015E - ~185 miles
Compression	• 2014 - 12,060 BHP • 2015 - 19,630 BHP
Capacity	• 2013 - 0.3 Bcf/day • 2014 - 2.0 Bcf/day • 2015E - 2.3 Bcf/day
Exit Rate	• 2013 - 0.16 Bcf/day • 2014 - 0.4 Bcf/day • 2015E - 0.9 Bcf/day
Interconnects	• Processing plants: 4 • Transmissions: 5 • Under Construction: 2
Contracts	• Current Customers - 10 • Potential Customers - 5

Appalachian Natural Gas Production



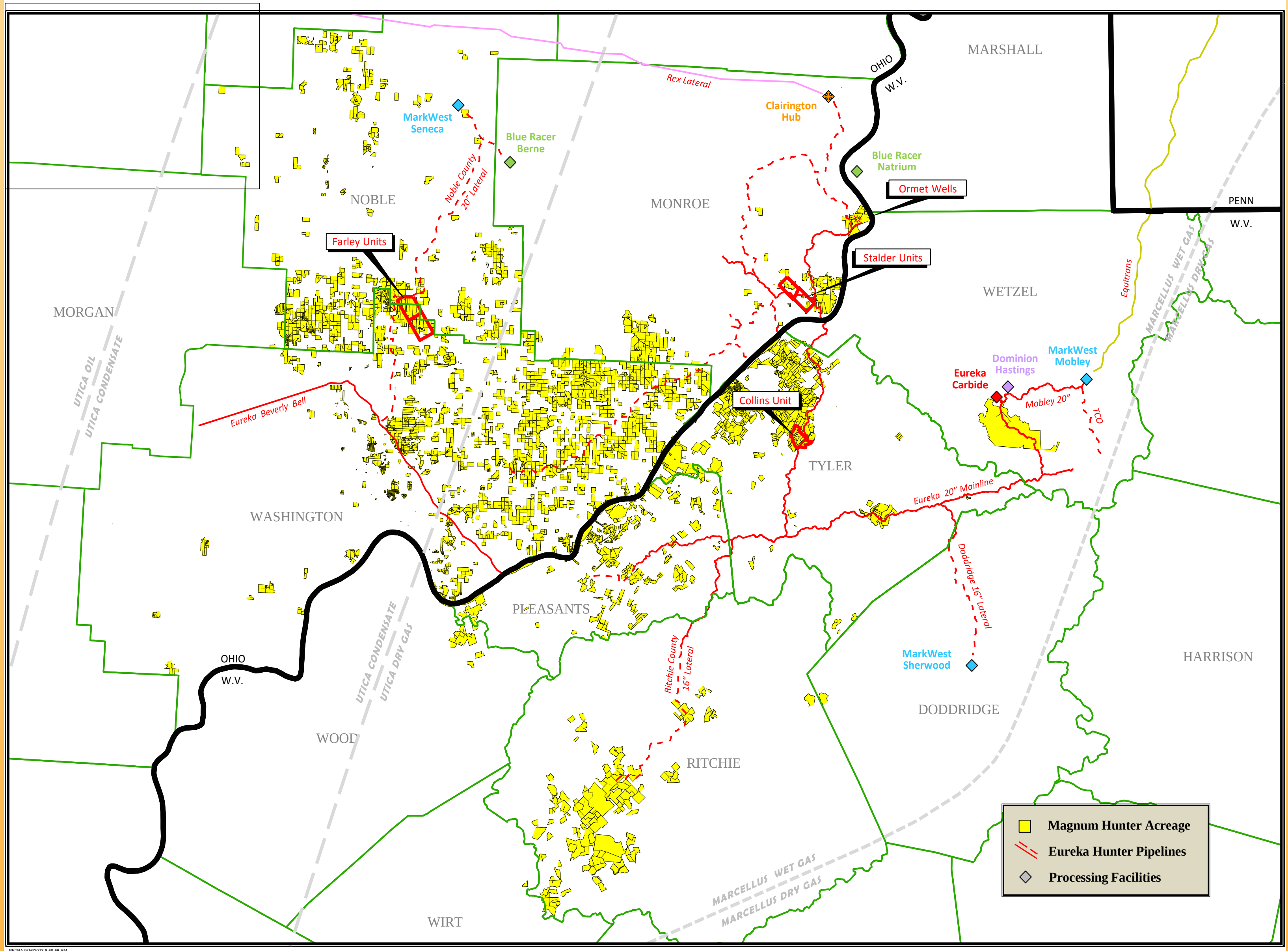
Source – Ventyx LCI, Bloomberg

Contracted vs. Gathered Volumes

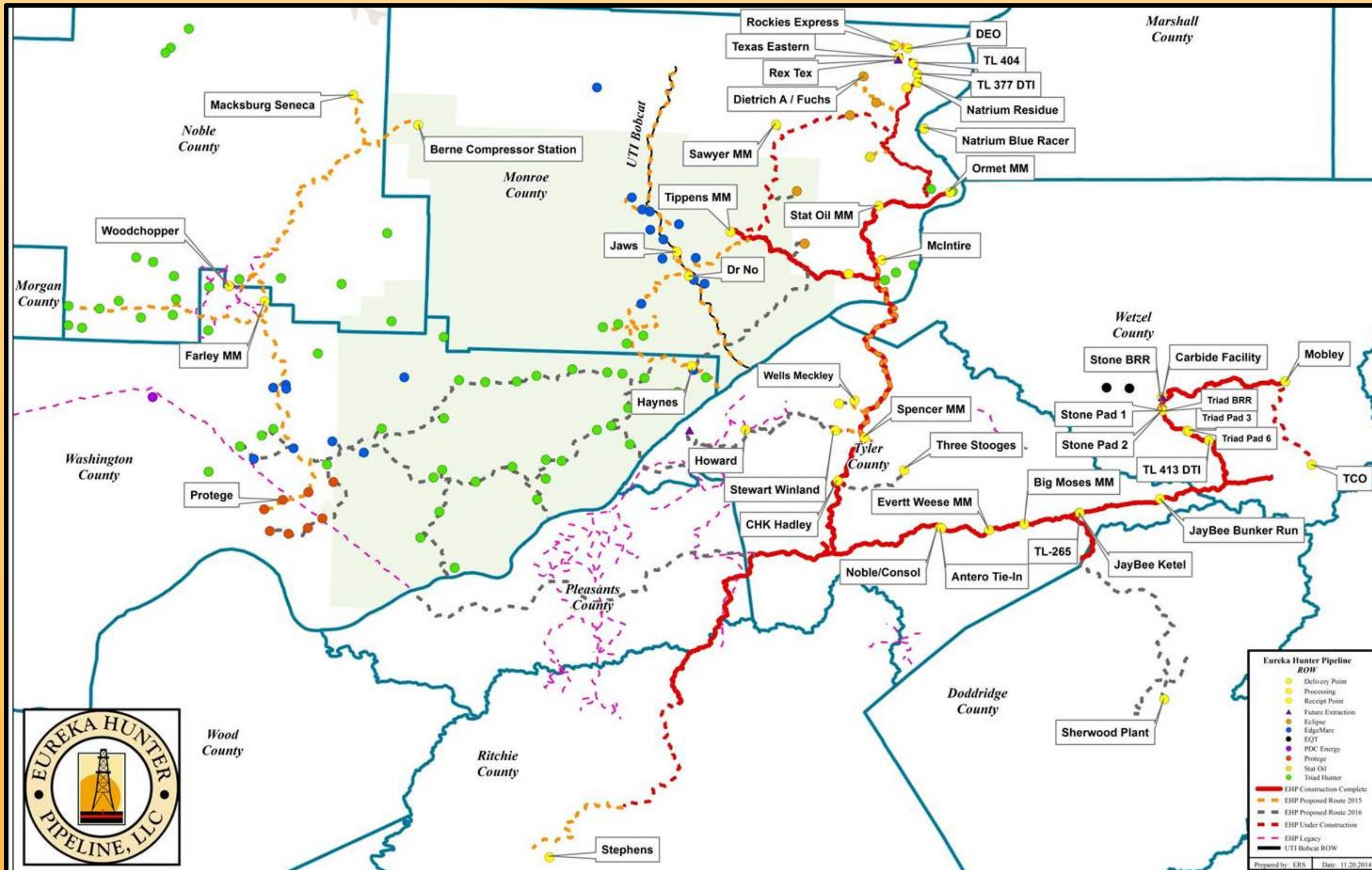
Eureka Hunter Pipeline	1Q 2013	2Q 2013	3Q 2013	4Q 2013	1Q 2014	2Q 2014	3Q 2014	4Q 2014	1Q 2015
High Pressure Reservation Volume (MMBtu/d)									
Magnum Hunter	87,950	92,339	75,000	75,000	83,500	96,000	111,400	135,000	135,000
Third-Parties	35,000	47,000	88,000	88,000	88,000	88,000	85,400	146,300	187,261
Total	**122,950**	**139,339**	**163,000**	**163,000**	**171,500**	**184,000**	**196,800**	**281,300**	**322,261**
High Pressure Throughput Volume (MMBtu/d)									
Magnum Hunter	21,880	29,276	39,421	54,306	70,023	85,466	67,570	76,302	147,951
Third-Parties	29,350	37,011	44,120	63,713	83,967	139,745	169,313	187,123	266,396
Total	**51,230**	**66,287**	**83,541**	**118,019**	**153,991**	**225,211**	**236,884**	**263,426**	**414,347**

Recent peak throughput rate of ~623,713 MMBtu/d in March 2015
Average quarterly throughput increase of ~31% over the last two years

Eureka Hunter Utica Exposure

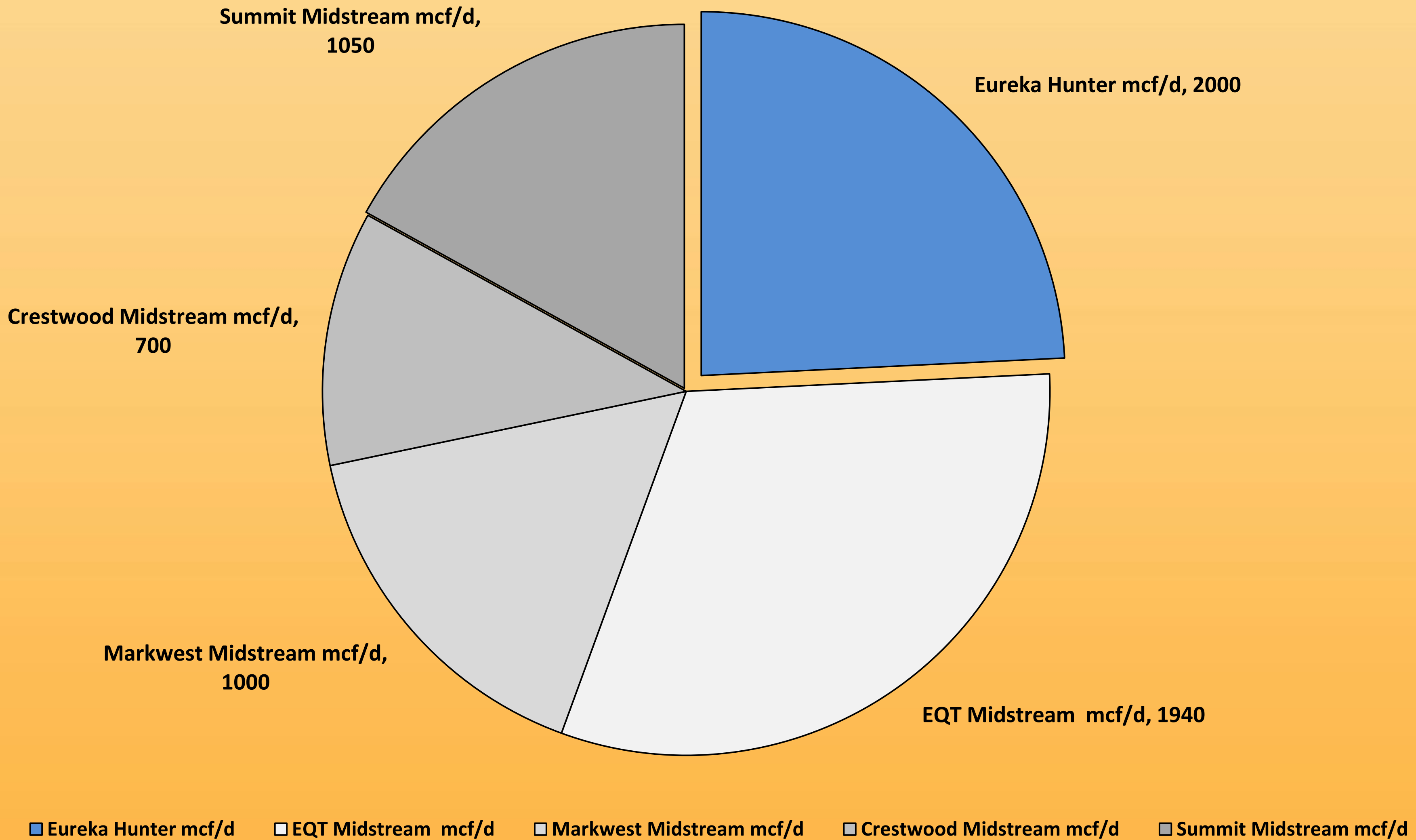


Eureka Hunter Utica Exposure

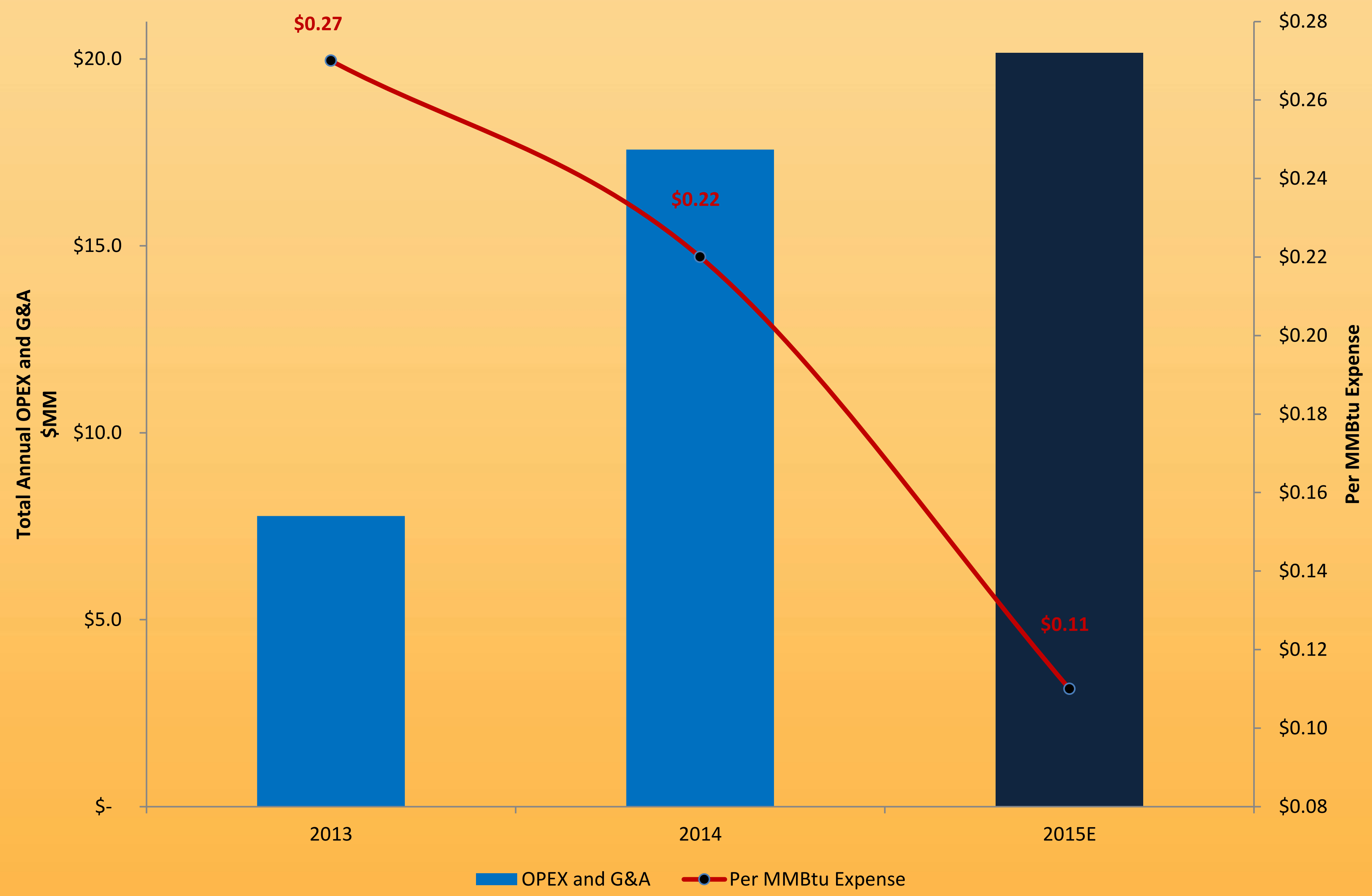


How Do We Measure Up

Gathering Capacity Marcellus / Utica Operations



Operating Cost



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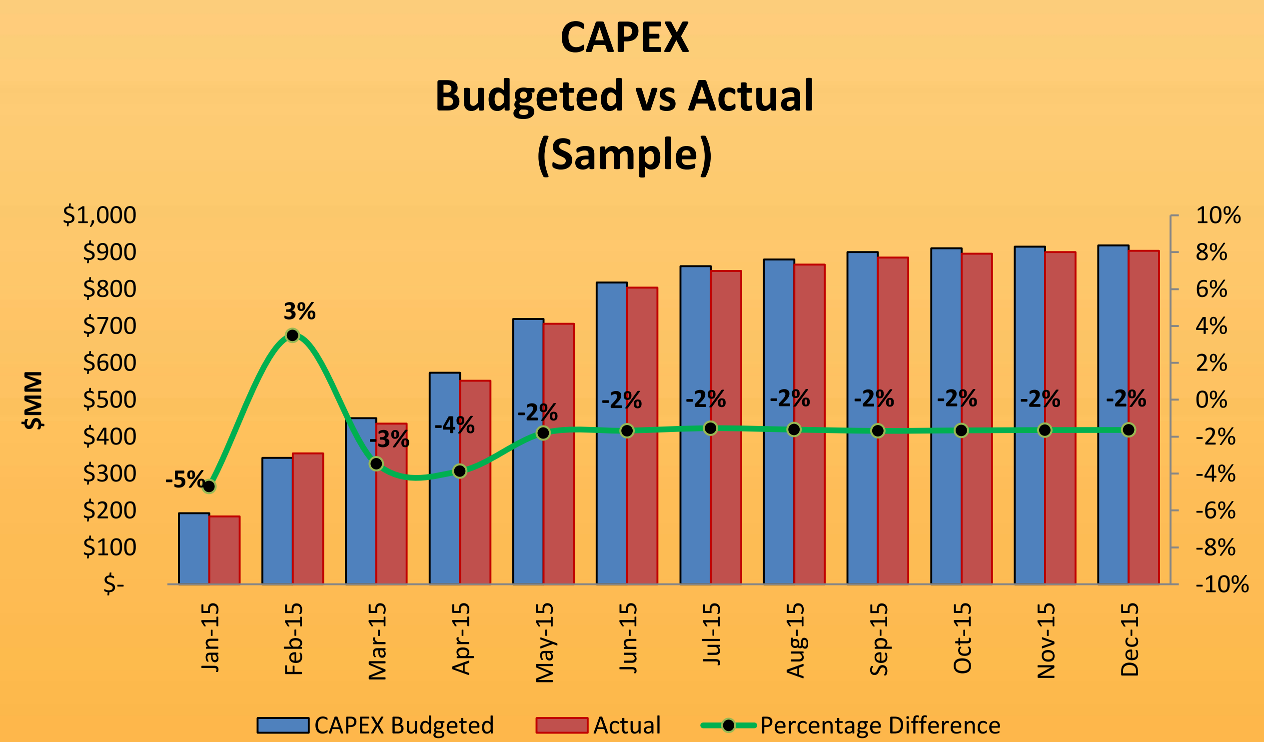
Performance Metrics

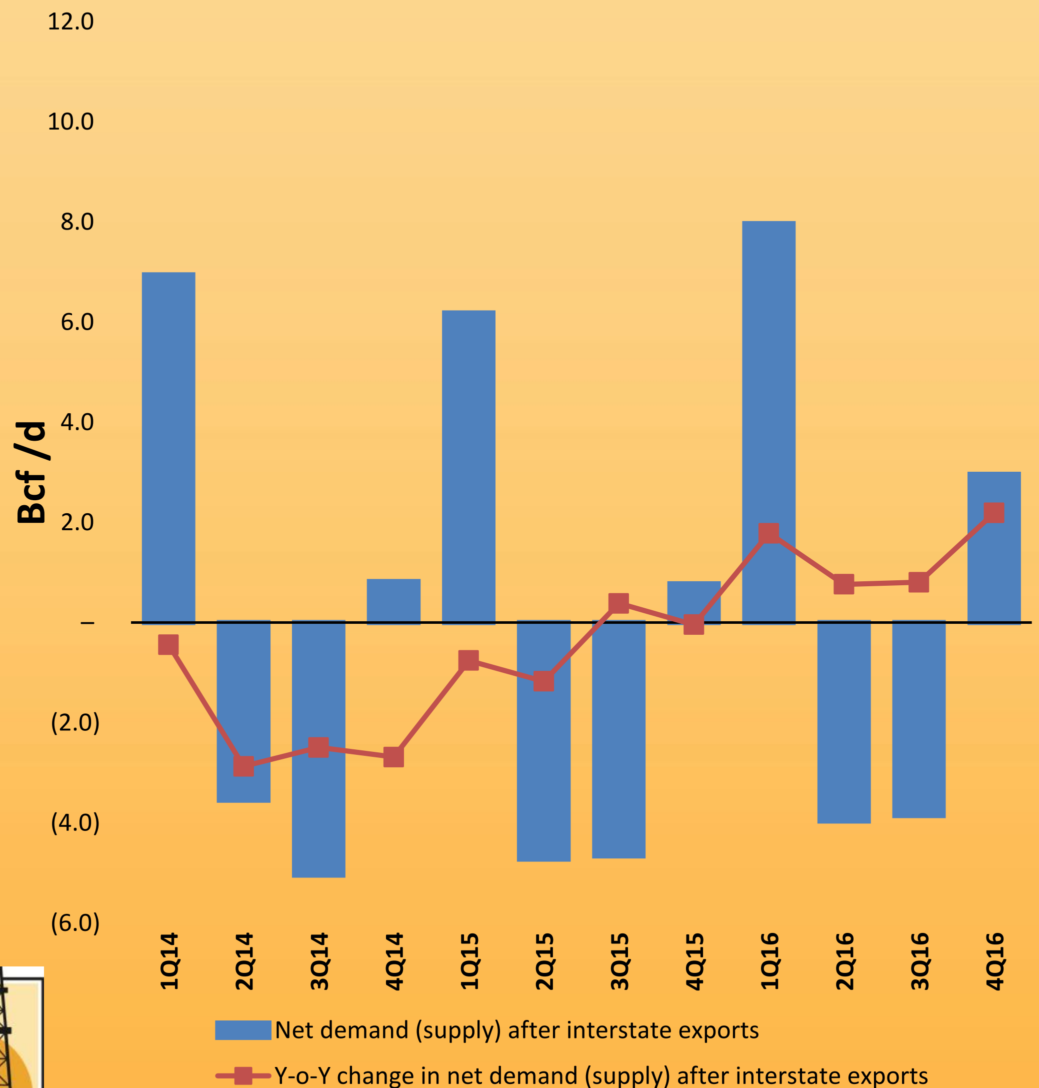
- **Cost**
  - Goal is to reduce the cost per mile of installation by 10%
    - Maintain current level of quality
  - Manage timelines with producers per contractual obligations within 5%
  - Manage budget CAPEX with in +/- 5% not to exceed the $91.6



Note: This information constitutes forward-looking statements and is subject to the qualifications on the last page of this investor presentation

Appalachia Differentials

Appalachia Net Demand



Source: Wall Street Research

Overview

- **Seasonal winter demand to drive better pricing in Q4 2014 and Q1 2015**
- **Pricing improvements in 2015+ expected as year-over-year demand is positive**
- **New Interconnects will continue to reduce differential volatility:**
  - Dominion Transmission Interconnect (Completed)
  - Markwest Mobley Wet (Completed)
  - Columbia Interconnect (Completed)
  - Blue Racer Wet Interconnect (Completed)
  - Blue Racer Dry Interconnect (Completed)
  - Spectra Interconnect (Completed)
  - REX Interconnect (Completed)
  - DTI 265 Wet (Completed)
  - DTI 413 Wet (Completed)
  - Dominion-East Ohio Interconnect (2Q 2015)

Midstream Outlook – Proposed Interstates

Pipeline	Project	Receipt Area	Delivery Area	Capacity	Rate	In Service
ANR	2015 Lebanon Reversal	Lebanon	Glenn Karn	350,000	Tariff	Nov-15
TETCO	U2GC	Uniontown	Lebanon-Gas City	425,000	Tariff	Nov-15
Rockies Express	East to West	Clarington	Lebanon-REX Z3	1,800,000	$0.50	Jun-16
Texas Gas Transmission	Ohio Louisiana Access	Lebanon	TGT Z1-SL	450,000	$0.15	Jun-16
Texas Gas Transmission	Southern Indian Market Lateral	Lebanon	TGT Zone 3	150,000	$0.32	Jul-16
Columbia Gas	Leach Xpress	Clarington, other OH & WV	Leach	1,500,000	$0.55	Nov-16
Columbia Gulf	Rayne Xpress	Leach	Mainline, Rayne	1,200,000	$0.30	Nov-16
Rockies Express	Clarington West	Clarington	Lebanon and Pts West	2,400,000	$0.40-$0.45	Jan-17
Texas Gas	Northern Supply Access	Lebanon	Perryville and LA	584,000	$0.32-$0.35	Apr-17
Energy Transfer	Rover	Clarington	Defiance/Dawn	2,750,000	$0.80	Jun-17
ANR	East	Clarington	Michcon	2,000,000	$0.77	Nov-17
	East	Clarington	Dawn (2nd del option)		$1.26	Nov-17
Columbia Gas	WB Xpress	Broadrun, WV	Loudoun, VA	1,200,000	$0.75	Jun-18
EQT	Mountain Valley	Mobley, EQT Sunrise	Transco Zone 5	2,000,000	$0.65-$0.75	Oct-18

Eureka Hunter Pipeline - Construction

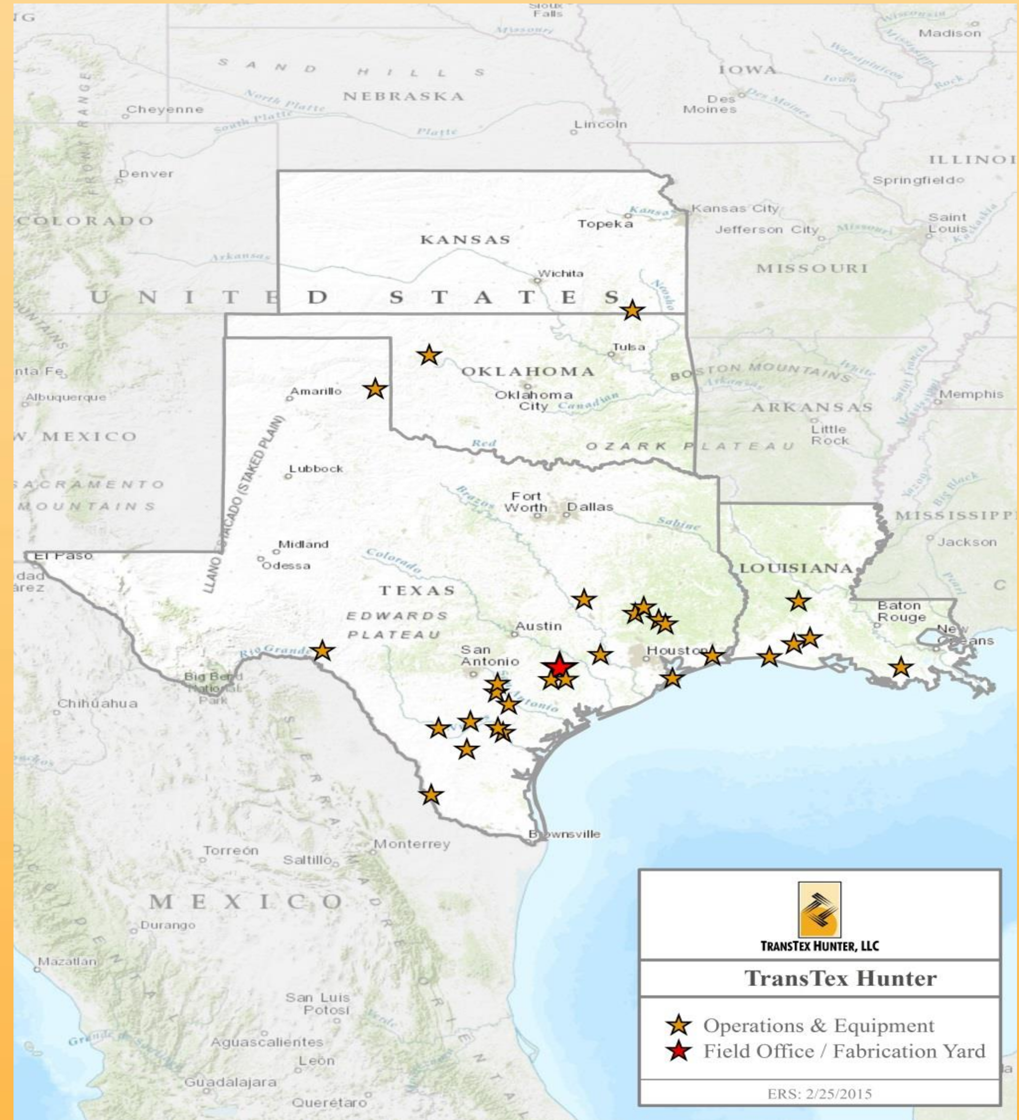
Challenging Terrain

Welding Up Pipeline Connection

Strung Pipe Before Being Lowered

TransTex Hunter Overview

Equipment & Services	• Treating for H_2S and CO_2 Removal • Gas Processing / Dew Point Control • Production Equipment / Dehydration • Gas Coolers • Facility Operations & Maintenance • Turnkey Installations • Engineering and Design
Key Areas of Operations	• Eagle Ford Shale • S. Louisiana / Gulf Coast • Granite Wash / Texas Panhandle
Recent Activity	• 7 contracts = $101k/Month Recurring Rev. • Associated Non-Recurring Rev. = $2.1M • 3 opportunities pending execution of contract
Projected Growth 2014 vs. 2015	• Revenue - $2,102,894 (Increase of ~22%) • EBITDA - $2,500,914 (Increase of ~172%)
Expansion Areas	• Permian Basin (H_2S Gas Treating) • Appalachia (Condensate Stabilization/Processing) • Bakken (Condensate Stabilization / Processing)
Customers	• 22 Current Customers • 10 New Customers in past 12-months



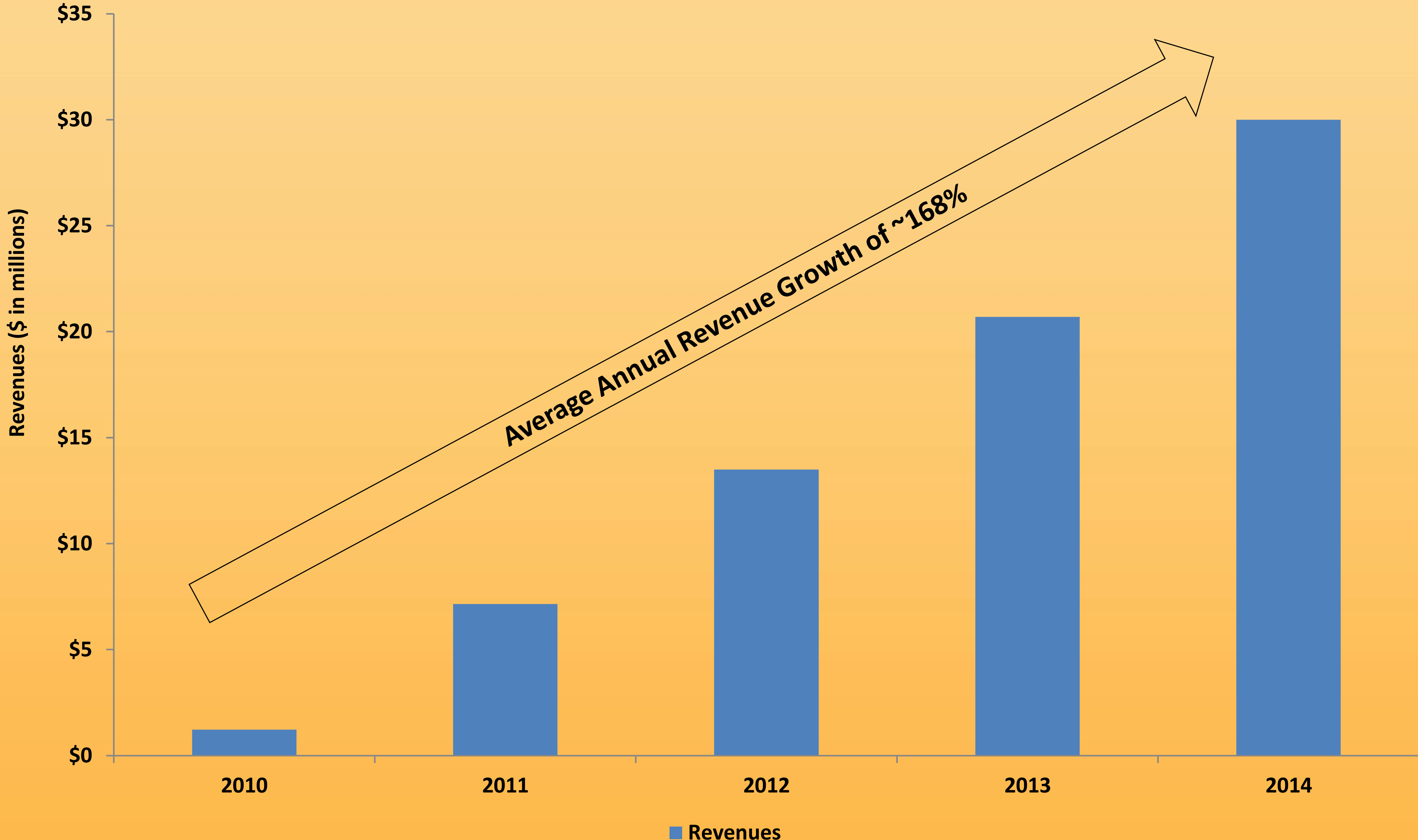
TransTex Hunter Amine Plants

Alpha Hunter Drilling

Drilling Fleet Overview

- **Current fleet of six (6) drilling rigs:**
  - **One (1) – Schramm TXD 500**
    - **Rig #7**
      - **Spud first well (Stalder Pad) on July 1, 2013**
      - **Contract Rate of $24,000/day**
      - **Two (2) year term with Triad Hunter**
  - **Five (5) – Schramm TXD 200**
    - **Rig #4**
      - **Contracted with EQT through December 2015**
      - **Contract Rate of $12,500/day**
    - **Rig #5**
      - **Contracted with EQT through December 2015**
      - **Contract Rate of $12,500/day**
    - **Rig #6**
      - **Contracted with EQT through December 2015**
      - **Contract Rate of $12,500/day**
    - **Rig #8**
      - **Contracted with EQT through December 2015**
      - **Contract Rate of $12,500/day**
    - **Rig #9**
      - **Currently rotating with EQT rigs for maintenance**
      - **Scheduled to go back to work for AEP May 2015**
      - **Contract Rate of $12,500/day**

Alpha Hunter Growth Continues



Alpha Hunter Experience

Company	# of Wells Drilled
AEP	14
Bretagne	1
CNX Gas	8
Consol	3
Central WV Oil & Gas	1
Dominion	34
Eagle Ford Hunter	15
Eclipse	44
EQT	342
EXCO Resources	57
Green Hunter Water	4
Hildreth	7
PetroEdge	1
Rex Energy	2
Rogers & Son	1
Rouzer Oil	5
Triad Hunter	26
Virco	1
TOTAL WELLS DRILLED[(1)]	**566**

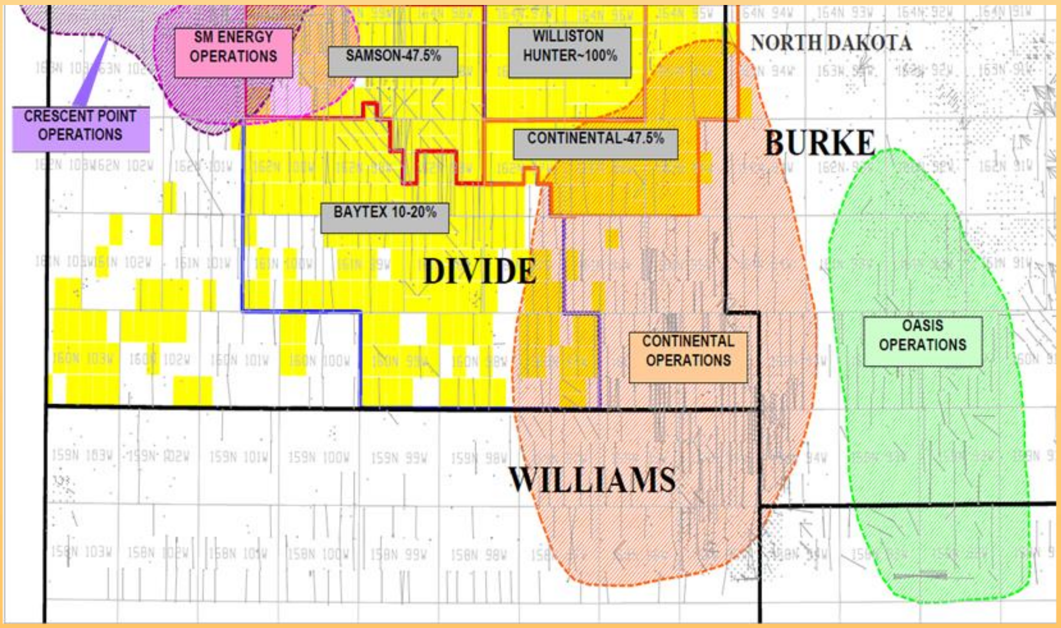
Year	# of Wells Drilled
2010	51
2011	64
2012	69
2013	148
2014[(1)]	234
TOTAL	**566**

Williston Basin Assets

(Non-Core Assets)

Williston Basin Overview

Areas of Operation



	Williston Basin Year-End 2014 Proved Reserves			
	(MMBoe)	% PDP	% Natural Gas	Gross Drilling Locations(1)
Williston Basin	7.9	66.3%	7.4%	1,530

Overview

- **Proved Reserves and PV-10**
  - Total proved reserves of **7.9** MMBoe as of 12/31/14
  - Proved producing reserves of **5.2** MMBoe as of 12/31/14
  - Total Proved PV-10 of $143.5 million as of 12/31/14
  - PDP PV-10 of $130.1 million as of 12/31/14
- **Acreage**
  - **~65,700** net acres in the Williston Basin
    - All acreage located in North Dakota
- **Drilling Opportunities**
  - Drilling locations target the Middle Bakken/Three Forks Sanish
  - 178 gross producing wells in Divide County, North Dakota
- **New 2015 Completions**
  - 7 gross wells brought on production

(1) Represents total potential drilling locations reflecting current acreage position and reserve report as of June 30, 2014

Financial Overview

Financial Strategy

- **Capital spending driven by rates of return across all operating areas**
  - 2015 capital budget of $100 million will focus predominately on high return areas in the Appalachian Basin
  - Closed Calgary and Denver offices in January of 2015 with substantial overhead reduction
  - Moving Houston Headquarters to Dallas April 1, 2015 to further reduce G&A
  - Continued emphasis on G&A reductions with asset sales coupled with a decreased reliance on third-party consultants
- **Maintain manageable credit ratios and liquidity while managing growth**
  - Second Lien loan structure protects against potential borrowing base reductions due to commodity prices
  - Raised a total of $180 million of new common equity in 2014
  - Closed on over $210 million of non-core asset divestitures in 2014
  - Potential additional non-core asset divestitures
  - Goal is to ultimately simplify balance sheet
- **Maintain an active hedging program to support economic returns and ensure strong coverage metrics**
  - Target rolling 50% hedging program one to two years forward – will hedge further opportunistically

Liquidity Initiatives

Liquidity Initiatives

Events in Progress	Structure	Liquidity Impact	Status
Letters of credit removal (associated with firm transportation agreements)	AMA agreement with large gas marketing firms	~$39.3 Million	Negotiating definitive agreement
Sale of Eureka Hunter ownership	Additional equity sell down	Up to ~$50 Million	Investment Bank marketing ownership
Utica Joint Venture	Cash portion upfront with large drilling carry	~$25 - $50 Million	Negotiating definitive agreement
Sale of non-core undeveloped leases	Sale of 5,210 net acres in West Virginia	$40.8	Signed PSA
Marcellus Joint Venture	Potential drilling program of $100 Million	TBD	Negotiating terms with thrid parties
Sale of additional non-core undeveloped leases	Sale of up to ~20,000 net acres in West Virginia and Ohio	~$140 - $200 Million	Offers being solicited
S-3 Universal Registration Statement	Gives the Company the option to sell many forms of different securities as a backstop	Up to $500 Million	SEC approval anticipated soon

Total Non-Dilutive Liquidity Additions of Up to ~$305 Million(1)

Note: This information constitutes forward-looking statements and is subject to the qualifications on the last page of this investor presentation
(1) Excludes any proceeds from potential sales of securities

Adjusted EBITDAX Reconciliation

	FYE 2010	FYE 2011	FYE 2012	FYE 2013	FYE 2014
Net income (loss) from continuing operations	(22.3)	(76.7)	(119.7)	(204.1)	(137.8)
Unrealized (gain) loss on derivatives	3.1	4.2	(10.9)	17.1	73.6
Net interest expense	3.6	12.0	51.6	72.4	86.3
Income taxes expense (benefit)	-	(0.7)	(19.3)	(70.3)	-
Impairment of oil and gas properties	0.3	22.9	3.8	10.0	301.3
	-	-	-	-	0.7
Depreciation, depletion and amortization	8.9	49.1	59.7	99.2	146.9
Non-Cash stock compensation expense	6.3	25.1	15.7	13.6	11.4
Non-Cash 401K matching expense	-	-	1.4	1.9	2.0
Exploration expense	0.9	1.5	78.2	97.3	118.5
(Gain) loss on sale of assets	(0.1)	(0.2)	0.6	44.7	(2.5)
Unrealized (gain) loss on investments	-	-	-	0.8	1.0
Non-recurring transaction and other expense	3.4	13.2	15.1	29.8	26.1
Non-recurring charge for reduction of capital account in Eureka Hunter Holdings	-	-	-	-	32.6
Gain on deconsolidation of Eureka Hunter Holdings					(509.6)
Total Adjusted EBITDAX	**$4.2**	**$50.4**	**$76.2**	**$112.4**	**$150.5**

Average Annual Increase of Adjusted EBITDAX of ~308%

Please note Adjusted EBITDAX includes net income from continuing operations (excludes net income from discontinued operations) and reflects Adjusted EBITDAX as reported in prior earnings release

Non-Core Divestiture Overview

- **Focused on divesting non-core assets to redeploy capital into Utica / Marcellus**
- **Over $700 million raised since beginning of 2013**

Asset Sales	Value ($MM)
Completed in 2013	
Eagle Ford Sale	$401.0
Gain on Sale of PVA Stock	$10.6
Burke County, North Dakota - Non-Operated Properties	$32.5
North Dakota - Madison Waterfloods - Operated Properties	$45.0
Red Star Gold	$1.5
Subtotal for 2013	**$490.6**
Completed in 2014 YTD	
Other Eagle Ford Shale Properties - Atascosa County (1)	$24.5
Alberta Properties	$8.7
Williston Hunter Canada, Inc. - Saskatchewan, Canada	$67.5
Vadis Field - West Virginia	$0.5
Non-Core North Dakota Non-Op	$23.0
Bakken Non-Op (Baytex)	$84.8
Richardson & Rock Creek Fields (WV Waterfloods)	$1.1
Subtotal for 2014	**$210.1**
In Process (Est.)	
Kentucky Gas Properties	$45.0 - $70.0 (Est.)
Subtotal for 2015	**$45.0 - $70.0** (Est.)
Total Non-Core Assets	**$745.7 - $770.7** (Est.)

(1) Includes $15.0 million of cash and $9.5 million of stock

MHR Net Asset Value*

($ in thousands)		Assumptions		Valuation	
		Low	High	Low	High
Total Proved Reserves PV-10 (12/31/2014) [(1)]				**909,300**	**909,300**
		$/acre			
Undeveloped Acreage [(2)]		**Low**	**High**		
Williston Basin U.S.	42,700	$3,000	$5,000	$128,100	$213,500
Marcellus	48,000	$7,500	$12,500	$360,000	$600,000
Utica - Wet	50,000	$10,000	$15,000	$500,000	$750,000
Utica - Dry	68,000	$12,500	$16,500	$850,000	$1,122,000
Other Appalachia	165,000	$50	$100	$8,250	$16,500
Total				**$1,846,350**	**$2,702,000**
Total E&P Assets				**$2,755,650**	**$3,611,300**
Certain Other Assets (12/31/2014)					
Eureka Hunter Pipeline - MHR Share of Estimated Total Market Value [(3)]				$437,400	$680,400
Alpha Hunter Drilling [(4)]				$20,000	$40,000
Total				**$457,400**	**$720,400**
Total Asset Value				**$3,213,050**	**$4,331,700**
Less (12/31/2014):					
. Series C Preferred				$100,000	$100,000
Series D Preferred				$221,244	$221,244
Series E Preferred				$95,069	$95,069
2nd Lien Term Loan				$340,000	$340,000
Senior Notes				$600,000	$600,000
Other Debt				$25,609	$25,609
Total				**$1,381,922**	**$1,381,922**
Net Asset Value				**$1,831,128**	**$2,949,778**
Shares Outstanding [(5)]				199.4	199.4
Net Asset Value per Share				**$9.18**	**$14.79**

* See Appendix for information regarding NAV, PV-10 and Standardized Measure
(1) Includes the proved reserves from year-end 2014 reserve report
(2) Approximate amount of undeveloped acreage as of December 31, 2014
(3) Based on MHR's estimated total market valuation of Eureka Hunter Pipeline of between $1.0 billion and $1.5 and MHR's approximate 48% equity ownership of Eureka Hunter Pipeline
(4) MHR's estimated FMV of Alpha Hunter Drilling
(5) As of August 7, 2014 there were ~199.4 million shares outstanding

A Focused Company on the Right Path

- Proven management and technical team in place committed to proper capital allocation for future growth
- Successful proven track record in the development and highgrading of key resource plays in the US
- Improved balance sheet ($180 MM of new Equity) and over $210 MM of non-core divestitures completed in 2014
- Sold over $700MM in oil properties over the last two years
- Substantial decrease in G&A due to Appalachia focus
- Continued focus on operational efficiency and net margin expansion
- Commitment to best practices regarding financial and operational procedures

Equity Research Coverage / Contact Information

Magnum Hunter Resources (NYSE: MHR)

Equity Research Analyst Coverage:

BMO Capital Markets
Canaccord Genuity
Capital One Southcoast
Credit Suisse Securities
Deutsche Bank Securities
GMP Securities
Imperial Capital
KeyBanc Capital Markets
KLR Group
MLV Partners
RBC Capital Markets
Robert W. Baird & Co.
Stephens
Stifel Nicolaus
SunTrust Robinson Humphrey
Topeka Capital Markets
UBS Securities
Wunderlich Securities

Website: www.magnumhunterresources.com

Headquarters: 909 Lake Carolyn Pkwy., Suite 600
Irving, TX 75039
(832) 369-6986

Contact: Investor Relations
ir@magnumhunterresources.com

Appendix

Net Asset Value

Although Magnum Hunter does not consider "Net Asset Value" and "Net Asset Value Per Share" to be "non-GAAP financial measures," as defined in SEC rules, Magnum Hunter uses Net Asset Value as an estimate of fair value. Net Asset Value and Net Asset Value Per Share should not be considered as alternatives to PV-10, GAAP Stockholders Equity or GAAP per share net income (loss) amounts. Magnum Hunter's NAV calculation is based on numerous assumptions that may change as a result of future activities or circumstances.

PV-10

PV-10 is the present value of the estimated future cash flows from estimated total proved reserves after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of future income taxes. The estimated future cash flows are discounted at an annual rate of 10% to determine their "present value." We believe PV-10 to be an important measure for evaluating the relative significance of our oil and gas properties and that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and investors in evaluating oil and gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating the Company. We believe that PV-10 is a financial measure routinely used and calculated similarly by other companies in the oil and gas industry. However, PV-10 should not be considered as an alternative to the standardized measure as computed under GAAP.

The standardized measure of discounted future net cash flows relating to Magnum Hunter's total proved oil and natural gas reserves is as follows:

December 31, 2014

		Unaudited
Future cash inflows	$	3,282,768
Future production costs		1,443,121
Future development costs		219,509
Future income tax expense		-
Future net cash flows		1,620,138
10% annual discount for estimated timing of cash flows		(710,875)
Standardized measure	$	909,263
PV-10 as of December 31, 2014 (1)	$	909,263

December 31, 2013

Standardized measure as previously reported	$	844,510
PV-10:		
Add: income taxes		
Undiscounted income taxes		149,367
10% discount factor		(71,807)
Future discounted income taxes		77,560
PV-10 as previously reported		922,070
Less 2014 Divestitures		(176,300)
PV-10 as of December 31, 2013, adjusted for 2014 divestitures	$	745,770

(1) as of December 31, 2014, standardized measure of discounted future cash flows and PV-10 are the same due to the Company's income tax position.

Forward-Looking Statements

The statements and information contained in this presentation that are not statements of historical fact, including any estimates and assumptions contained herein, are "forward looking statements" as defined in Section 27A of the Securities Act of 1933, as amended, referred to as the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, referred to as the Exchange Act. These forward-looking statements include, among others, statements, estimates and assumptions relating to our business and growth strategies, our oil and gas reserve estimates, estimates of oil and natural gas resource potential, our ability to successfully and economically explore for and develop oil and gas resources, our exploration and development prospects, future inventories, projects and programs, expectations relating to availability and costs of drilling rigs and field services, anticipated trends in our business or industry, our future results of operations, our liquidity and ability to finance our exploration and development activities and our midstream activities, market conditions in the oil and gas industry and the impact of environmental and other governmental regulation. In addition, with respect to any pending transactions described herein, forward-looking statements include, but are not limited to, statements regarding the expected timing of the completion of proposed transactions; the ability to complete proposed transactions considering various closing conditions; the benefits of any such transactions and their impact on the Company's business; and any statements of assumptions underlying any of the foregoing. In addition, if and when any proposed transaction is consummated, there will be risks and uncertainties related to the Company's ability to successfully integrate the operations and employees of the Company and the acquired business. Forward-looking statements generally can be identified by the use of forward-looking terminology such as "may," "will," "could," "should," "expect," "intend," "estimate," "anticipate," "believe," "project," "pursue," "plan" or "continue" or the negative thereof or variations thereon or similar terminology.

These forward-looking statements are subject to numerous assumptions, risks, and uncertainties. Factors that may cause our actual results, performance, or achievements to be materially different from those anticipated in forward-looking statements include, among others, the following: adverse economic conditions in the United States and globally; difficult and adverse conditions in the domestic and global capital and credit markets; changes in domestic and global demand for oil and natural gas; volatility in the prices we receive for our oil, natural gas and natural gas liquids; the effects of government regulation, permitting and other legal requirements; future developments with respect to the quality of our properties, including, among other things, the existence of reserves in economic quantities; uncertainties about the estimates of our oil and natural gas reserves; our ability to increase our production and therefore our oil and natural gas income through exploration and development; our ability to successfully apply horizontal drilling techniques; the effects of increased federal and state regulation, including regulation of the environmental aspects, of hydraulic fracturing; the number of well locations to be drilled, the cost to drill and the time frame within which they will be drilled; drilling and operating risks; the availability of equipment, such as drilling rigs and transportation pipelines; changes in our drilling plans and related budgets; regulatory, environmental and land management issues, and demand for gas gathering services, relating to our midstream operations; and the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity.

These factors are in addition to the risks described in the "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" sections of the Company's 2013 annual report on Form 10-K, as amended, filed with the Securities and Exchange Commission, which we refer to as the SEC, and subsequently filed quarterly reports on Form 10-Q. Most of these factors are difficult to anticipate and beyond our control. Because forward-looking statements are subject to risks and uncertainties, actual results may differ materially from those expressed or implied by such statements. You are cautioned not to place undue reliance on forward-looking statements contained herein, which speak only as of the date of this document. Other unknown or unpredictable factors may cause actual results to differ materially from those projected by the forward-looking statements. Unless otherwise required by law, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. We urge readers to review and consider disclosures we make in our reports that discuss factors germane to our business. See in particular our reports on Forms 10-K, 10-Q and 8-K subsequently filed from time to time with the SEC. All forward-looking statements attributable to us are expressly qualified in their entirety by these cautionary statements.

The SEC requires oil and natural gas companies, in filings made with the SEC, to disclose proved reserves, which are those quantities of oil and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations.

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates. Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project. Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves. Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the Company believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir. Where direct observation has defined a highest known oil (“HKO”) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

The term “contingent resources” is a broader description of potentially recoverable volumes than probable and possible reserves, as defined by SEC regulations. In this presentation disclosure of “contingent resources” represents a high estimate scenario, rather than a middle or low estimate scenario. Estimates of contingent resources are by their nature more speculative than estimates of proved, probable, or possible reserves and accordingly are subject to substantially greater risk of actually being realized by the Company. We believe our estimates of contingent resources and future drill sites are reasonable, but such estimates have not been reviewed by independent engineers. Estimates of contingent resources may change significantly as development provides additional data, and actual quantities that are ultimately recovered may differ substantially from prior estimates.

Note Regarding Non-GAAP Measures

This presentation includes certain non-GAAP measures, including Adjusted EBITDAX and PV-10, which are described in greater detail in this presentation. Management believes that these non-GAAP measures, which may be defined differently by other companies, better explain the Company's results of operations in a manner that allows for a more complete understanding of the underlying trends in the Company's business, and are also measures that are important to the Company’s lenders. However, these measures should not be viewed as a substitute for those determined in accordance with GAAP.