UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of Earliest Event Reported) November 10, 2015

Matador Resources Company
(Exact name of registrant as specified in its charter)

Texas	001-35410	27-4662601
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

5400 LBJ Freeway, Suite 1500, Dallas, Texas	75240
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (972) 371-5200

Not Applicable
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 7.01 Regulation FD Disclosure.

Matador Resources Company expects to make presentations concerning its business to potential investors. The materials to be utilized during the presentations are furnished as Exhibit 99.1 hereto and incorporated herein by reference.

The information furnished pursuant to this Item 7.01, including Exhibit 99.1, shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and will not be incorporated by reference into any filing under the Securities Act of 1933, as amended, unless specifically identified therein as being incorporated therein by reference.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits

Exhibit No.	Description of Exhibit
99.1	Presentation Materials.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

MATADOR RESOURCES COMPANY

Date: November 10, 2015

By:	/s/ Craig N. Adams
Name:	Craig N. Adams
Title:	Executive Vice President

Exhibit Index

Exhibit No.	Description of Exhibit
99.1	Presentation Materials.

Exhibit 99.1

Investor Presentation

November 2015 **NYSE: MTDR**

Disclosure Statements

Safe Harbor Statement – This presentation and statements made by representatives of Matador Resources Company ("Matador" or the "Company") during the course of this presentation include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. "Forward-looking statements" are statements related to future, not past, events. Forward-looking statements are based on current expectations and include any statement that does not directly relate to a current or historical fact. In this context, forward-looking statements often address expected future business and financial performance, and often contain words such as "could," "believe," "would," "anticipate," "intend," "estimate," "expect," "may," "should," "continue," "plan," "predict," "potential," "project" and similar expressions that are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Actual results and future events could differ materially from those anticipated in such statements, and such forward-looking statements may not prove to be accurate. These forward-looking statements involve certain risks and uncertainties, including, but not limited to, the following risks related to Matador's financial and operational performance: general economic conditions; Matador's ability to execute its business plan, including whether Matador's drilling program is successful; changes in oil, natural gas and natural gas liquids prices and the demand for oil, natural gas and natural gas liquids; Matador's ability to replace reserves and efficiently develop its current reserves; Matador's costs of operations, delays and other difficulties related to producing oil, natural gas and natural gas liquids; Matador's ability to integrate the assets, employees and operations of Harvey E. Yates Company following its merger with one of Matador's wholly-owned subsidiaries on February 27, 2015; Matador's ability to make other acquisitions on economically acceptable terms; availability of sufficient capital to execute Matador's business plan, including from its future cash flows, increases in Matador's borrowing base and otherwise; weather and environmental conditions; and other important factors which could cause actual results to differ materially from those anticipated or implied in the forward-looking statements. For further discussions of risks and uncertainties, you should refer to Matador's SEC filings, including the "Risk Factors" section of Matador's most recent Annual Report on Form 10-K and any subsequent Quarterly Reports on Form 10-Q. Matador undertakes no obligation and does not intend to update these forward-looking statements to reflect events or circumstances occurring after the date of this presentation, except as required by law, including the securities laws of the United States and the rules and regulations of the SEC. You are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this presentation. All forward-looking statements are qualified in their entirety by this cautionary statement.

Cautionary Note – The Securities and Exchange Commission (SEC) permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves. Potential resources are not proved, probable or possible reserves. The SEC's guidelines prohibit Matador from including such information in filings with the SEC.

Definitions – Proved oil and natural gas reserves are the estimated quantities of oil and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Matador's production and proved reserves are reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Where Matador produces liquids-rich natural gas, the economic value of the natural gas liquids associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the natural gas liquids are extracted and sold. Estimated ultimate recovery (EUR) is a measure that by its nature is more speculative than estimates of proved reserves prepared in accordance with SEC definitions and guidelines and is accordingly less certain.

Company Summary

Matador History

Predecessor Entities

Foran Oil & Matador Petroleum

- Founded by Joe Foran in 1983 – most participants are still shareholders today
- Foran Oil funded with $270,000 in contributed capital from 17 friends and family members; evolved into Matador Petroleum Corporation
- Sold Matador Petroleum Corporation to Tom Brown, Inc.(1) in June 2003 for an enterprise value of $388 million in an all-cash transaction

Matador Today

Matador Resources Company Timeline

Matador has grown almost entirely through the drill bit, with a focus on unconventional reservoir plays

Pre – IPO

2003 · 2008 · 2009 · 2010 · 2011 · 2012

2003
Founded by Joe Foran with $6 million, a proven management and technical team and board of directors

2008
Sold Haynesville rights in ~9,000 net acres to CHK for ~$180 million; retained 25% participation interest, carried working interest and overriding royalty interest

2010-2011
Redeployed capital into the Eagle Ford early in the play, acquiring over 30,000 net acres for ~$100 million

2012, 2013 and 2014 capital spending focused primarily on developing Eagle Ford and transitioning to oil

Assembling Permian acreage position; begin delineation drilling program

Post – IPO

2012 · 2013 · 2014 · 2015

February 2012
IPO at $12.00; net cash proceeds of ~$136 million

September 2013
Follow-on Offering at $15.25; net cash proceeds of ~$142 million

May 2014
Follow-on Offering at $25.00; net cash proceeds of ~$181 million

February 2015
HEYCO Combination

April 2015
Inaugural High-Yield Offering of $400 million;
Follow-on Offering at $26.96; net cash proceeds of ~$187 million

October 2015
Sale of certain Loving County midstream assets for ~$143 million(2)

(1) Tom Brown acquired by Encana in 2004.
(2) Excluding customary purchase price adjustments.

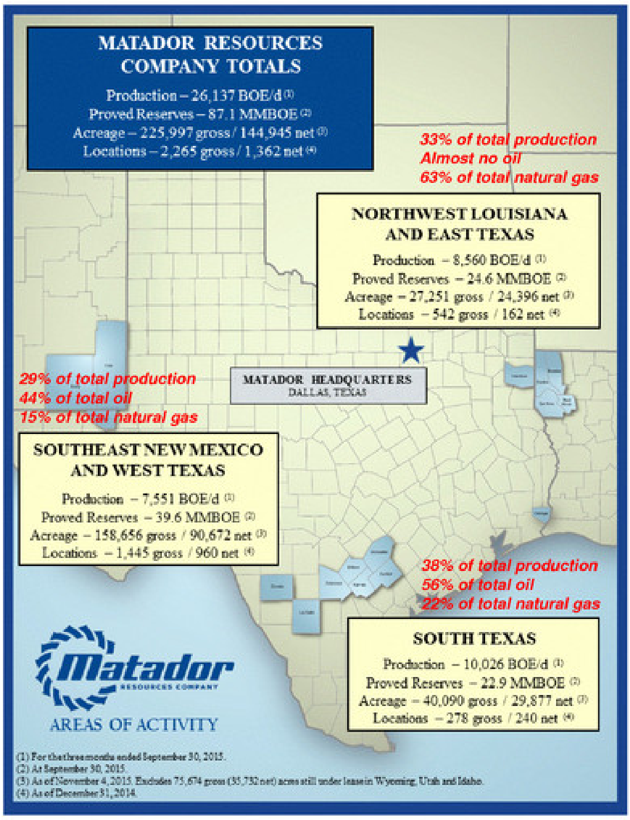
Company Overview

Exchange: Ticker	NYSE: MTDR
Shares Outstanding(1)	85.6 million common shares
Share Price(1)	$26.70/share
Market Capitalization(1)	$2.3 billion

	Actual 2014	*Previous 2015 Guidance*(2)	*Updated 2015 Guidance*(3)	*% YoY Change*
Capital Spending	$610 million	$425 million	$425 million	- 30%
Total Oil Production	3.3 million Bbl	4.4 to 4.5 million Bbl	4.4 to 4.5 million Bbl	+ 34%
Total Natural Gas Production	15.3 Bcf	26.0 to 27.0 Bcf	27.0 to 28.0 Bcf ↑	+ 80%
Oil and Natural Gas Revenues	$367.7 million	$290 to $300 million	$290 to $300 million(4)	- 20%
Adjusted EBITDA(5)	$262.9 million	$220 to $230 million	$220 to $230 million(4)	- 14%

(1) Market capitalization based on closing share price as of November 9, 2015 and shares outstanding as reported in the Form 10-Q for the quarter ended September 30, 2015.
(2) The Company raised its full-year 2015 guidance estimates on August 4, 2015.
(3) The Company raised its 2015 natural gas production guidance from 26.0 to 27.0 Bcf to 27.0 to 28.0 Bcf on November 4, 2015.
(4) Estimated 2015 oil and natural gas revenues and Adjusted EBITDA based upon the midpoint of 2015 guidance range as revised on August 4, 2015. Prices for oil and natural gas used in these estimates were $50.00/Bbl (WTI oil price of $55.00/Bbl less $5.00/Bbl differentials and transportation costs) and $3.00/Mcf (NYMEX Henry Hub natural gas price assuming regional differentials and uplifts from natural gas processing roughly offset), respectively, for the period October through December 2015 and weighted average realized prices for the period January through September 2015 of $47.36/Bbl and $2.83/Mcf.
(5) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Appendix.

Matador Resources Company – Operations Overview



Market Capitalization(1)	**$2.3 billion**	
Avg. Daily Production – Q3 2015(2)	**26,137 BOE/d**	+62%*
Oil (% total)	12,617 Bbl/d (48%)	
Natural Gas (% total)	81.1 MMcf/d (52%)	
Proved Reserves @ 9/30/2015	**87.1 million BOE**	+43%*
% Proved Developed	39%	
% Oil	49%	
2015E CapEx(3)	**$425 million**	
Gross Acreage(4)	**225,997 acres**	
Net Acreage(4)	**144,945 acres**	
Engineered Drilling Locations(5)	**2,265 gross / 1,362 net**	+139%**
Eagle Ford	278 gross / 240 net	
Permian	1,445 gross / 960 net	+440%**
Haynesville/Cotton Valley	542 gross / 162 net	

*Note: Represents increase as compared to each respective figure at or for the three months ended September 30, 2014.
**Note: Represents increase as compared to each respective figure at December 31, 2013.

(1) Market capitalization based on closing share price as of November 9, 2015 and shares outstanding as reported in the Form 10-Q for the quarter ended September 30, 2015.
(2) Average daily production for the three months ended September 30, 2015.
(3) 2015 estimated capital expenditures for operations only. Revised upwards from $350 million on August 4, 2015; does not include capital expenditures associated with the HEYCO transaction or two associated joint ventures.
(4) Presented as of November 4, 2015. Excludes 75,674 gross (35,732 net) acres still under lease in Wyoming, Utah and Idaho.
(5) Identified and engineered locations for potential future drilling, including specified production units and estimated lateral lengths, costs and well spacing using objective criteria for designation. Locations identified as of December 31, 2014, but including no locations at Twin Lakes and no locations associated with the HEYCO transaction or two associated joint ventures.

Matador's Execution History – "Doing What We Say"

Matador continues to execute on its core strategy of acquiring great assets, developing a highly professional, committed workforce, maintaining a strong balance sheet and generating significant shareholder returns

	At IPO[1]		September 2013 Follow-On[8]		September 30, 2015[10]
Oil Production	▪ 414 Bbl/d of oil ▪ 6% oil	12x growth in oil production	▪ 4,916 Bbl/d of oil ▪ 46% oil	157% growth in oil production	▪ 12,617 Bbl/d of oil ▪ 48% oil
Proved Reserves	▪ 27 MMBOE ▪ 1.1 MMBbl of oil ▪ 4% oil	11x growth in oil reserves	▪ 39 MMBOE ▪ 12.1 MMBbl of oil ▪ 31% oil	3.5x growth in oil reserves	▪ 87 MMBOE ▪ 42.5 MMBbl of oil ▪ 49% oil
PV-10[2] and Asset Coverage	▪ $155.2 million ▪ 24% of PV-10 in Eagle Ford ▪ PV-10 / debt of 2.0x	Over 3x growth in PV-10	▪ $522.3 million ▪ 90% of PV-10 in Eagle Ford ▪ PV-10 / debt of 2.1x	33% growth despite lower prices	▪ $692.7 million ▪ 88% of PV-10 in Eagle Ford / Permian ▪ PV-10 / debt of 1.7x
LTM Adjusted EBITDA[3]	▪ $50 million[4]	~200% growth	▪ $148 million	66% growth	▪ $245 million
Leverage[5]	▪ 1.5x[4]	Remained conservative	▪ 1.6x	Improved	▪ 1.0x[11] after midstream sale
Acreage	▪ ~7,500 net Permian acres	Over 4x growth in Permian acres	▪ ~32,900 net Permian acres	2.8x growth in Permian acres	▪ ~90,700 net Permian acres[12]
Enterprise Value ("EV")[6]	▪ $0.65 billion[7]	Doubled EV	▪ $1.2 billion[9]	125% growth	▪ $2.7 billion[13]

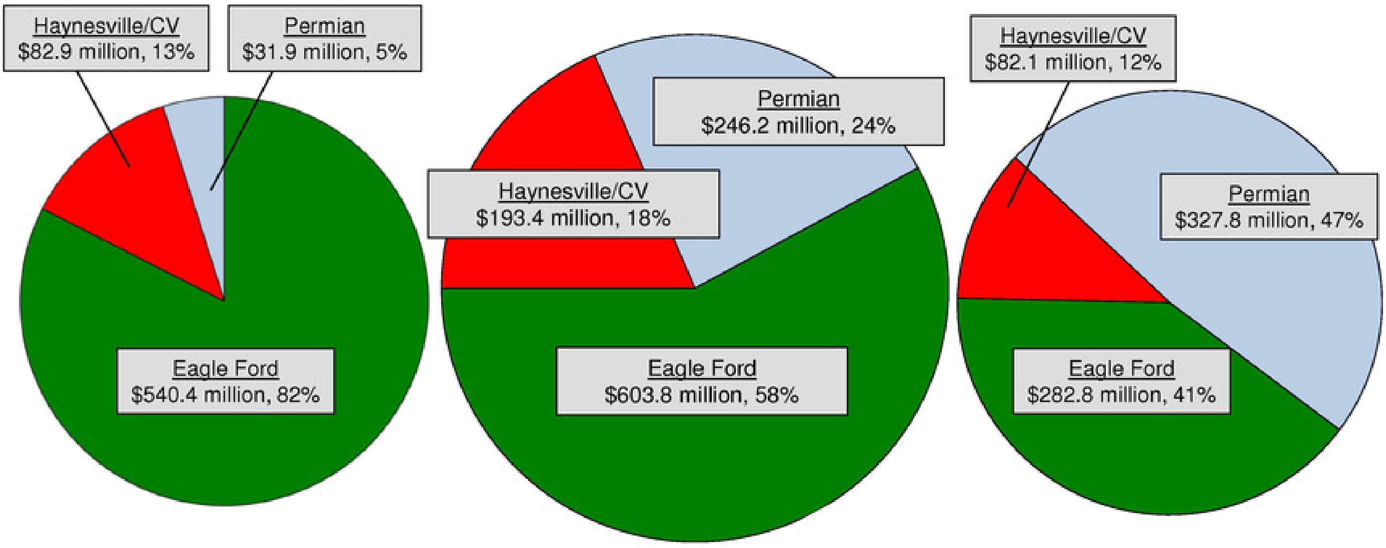
(1) Unless otherwise noted, at or for the nine months ended September 30, 2011.
(2) PV-10 is a non-GAAP financial measure. For a reconciliation of Standardized Measure (GAAP) to PV-10 (non-GAAP), see Appendix.
(3) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Appendix.
(4) At or for the twelve months ended December 31, 2011.
(5) Calculated as debt divided by LTM Adjusted EBITDA.
(6) Enterprise value equals market capitalization plus long-term debt.
(7) As of February 7, 2012 at time of IPO.
(8) Unless otherwise noted, at or for the three months ended June 30, 2013.
(9) As of September 1, 2013.
(10) Unless otherwise noted, at or for the three months ended September 30, 2015.
(11) Net debt at October 1, 2015 and LTM Adjusted EBITDA at September 30, 2015.
(12) As of November 4, 2015.
(13) Market capitalization based on closing share price as of November 9, 2015 and shares outstanding as reported in the Form 10-Q for the quarter ended September 30, 2015.

Selected Operating and Financial Results

	Three Months Ended			Nine Months Ended	
	September 30, 2015	June 30, 2015	September 30, 2014	September 30, 2015	September 30, 2014
Net Production Volumes:[1]					
Oil production (MBbl)	1,161	1,260	839	3,429	2,302
Natural gas production (Bcf)	7.5	7.0	3.8	21.1	9.9
Total oil equivalent production (MBOE)	2,405	2,421	1,481	6,941	3,956
Average daily oil equivalent production (BOE/d)	26,137	26,601	16,096	25,427	14,490
Revenues and Average Sales Prices:					
Oil and natural gas revenues (in millions)	$ 71.8	$ 87.8	$ 96.6	$ 222.1	$ 274.6
Average realized oil price, $/Bbl	$ 43.21	$ 54.37	$ 92.39	$ 47.36	$ 95.45
Average realized natural gas price, $/Mcf	$ 2.90	$ 2.78	$ 4.95	$ 2.83	$ 5.53
Total realized revenues, with realized derivatives (in millions)	$ 91.7	$ 101.6	$ 95.9	$ 274.3	$ 269.1
Average realized oil price, with realized derivatives, $/Bbl	$ 57.90	$ 62.72	$ 91.42	$ 59.61	$ 93.48
Average realized natural gas price, with realized derivatives, $/Mcf	$ 3.28	$ 3.24	$ 4.99	$ 3.31	$ 5.44
Operating Expenses (per BOE):					
Production taxes and marketing	$ 3.86	$ 4.24	$ 5.82	$ 3.83	$ 6.00
Lease operating	$ 6.20	$ 6.18	$ 9.25	$ 6.18	$ 8.78
Depletion, depreciation and amortization	$ 18.81	$ 21.39	$ 23.73	$ 20.67	$ 23.00
General and administrative[2]	$ 5.05	$ 5.35	$ 5.47	$ 5.55	$ 5.92
Total operating expenses[3]	$ 33.92	$ 37.16	$ 44.27	$ 36.23	$ 43.70
Cash operating expenses[4]	$ 14.38	$ 14.50	$ 19.84	$ 14.21	$ 19.52
Earnings (loss) per diluted common share:[5]					
Earnings (loss) per diluted common share[5]	$ (2.86)	$ (1.89)	$ 0.40	$ (5.58)	$ 0.92
Adjusted earnings per diluted share (non-GAAP)[5][6]	$ 0.03	$ 0.05	N/A[7]	$ 0.10	N/A[7]
Adjusted EBITDA[8] (in millions)	$ 58.0	$ 66.7	$ 66.8	$ 174.9	$ 192.6
Net Debt / LTM Adjusted EBITDA[8]	1.0[9]	1.4	1.0	1.0[9]	1.0

(1) Production volumes reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas.
(2) Includes approximately $0.73, $1.16, $0.70, $0.99 and $1.18 per BOE of non-cash, stock based compensation expense in the third quarter of 2015, the second quarter of 2015, the third quarter of 2015, the nine months ended September 30, 2015 and the nine months ended September 30, 2014.
(3) Total does not include the impact of full-cost ceiling impairments or immaterial accretion expenses.
(4) Cash operating expenses per BOE is a non-GAAP financial measure. For a definition of cash operating expenses per BOE and a reconciliation of cash operating expenses per BOE (non-GAAP) to operating expenses per BOE (GAAP), please Appendix.
(5) Attributable to Matador Resources Company shareholders.
(6) Adjusted earnings (loss) per common share is a non-GAAP financial measure. For a reconciliation of adjusted net income (non-GAAP) and adjusted earnings (loss) per common share (non-GAAP) to net income (GAAP) and earnings (loss) per common share (GAAP), see Appendix.
(7) Not calculated for three months and nine months ended September 30, 2014.
(8) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Appendix.
(9) Pro forma at September 30, 2015 for midstream sale on October 1, 2015.

Oil and Natural Gas Proved Reserves and PV-10(1) by Area



December 31, 2013

Total proved reserves = 51.7 million BOE

PV-10(1): $655.2 million
$93.42 oil / $3.67 natural gas

December 31, 2014

Total proved reserves = 68.7 million BOE

PV-10(1): $1,043.4 million
$91.48 oil / $4.35 natural gas

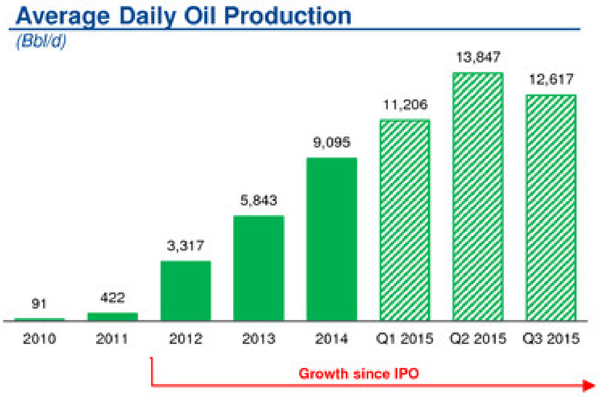
September 30, 2015

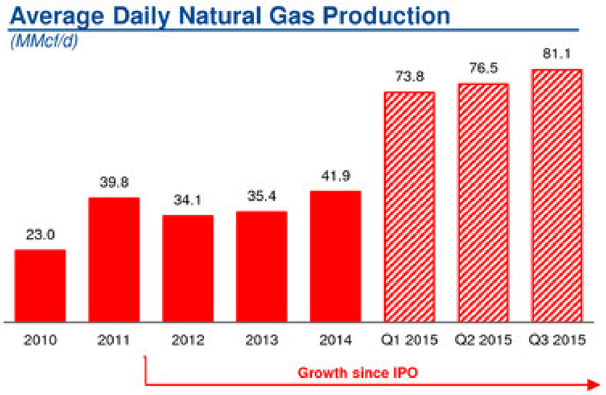
Total proved reserves = 87.1 million BOE

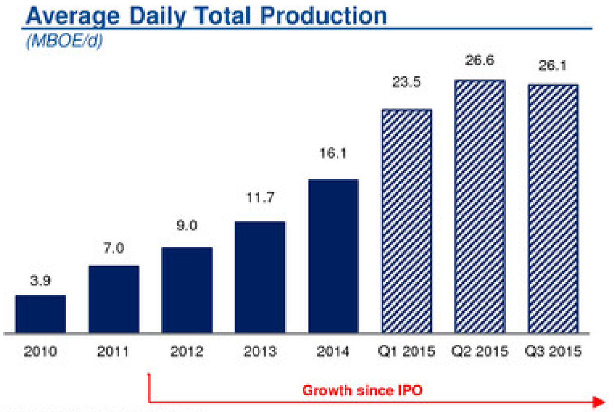
PV-10(1): $692.7 million
$55.73 oil / $3.06 natural gas

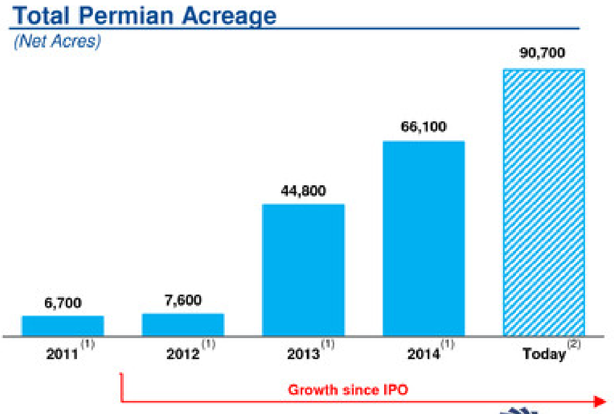
(1) PV-10 is a non-GAAP financial measure. For a reconciliation of Standardized Measure (GAAP) to PV-10 (non-GAAP), see Appendix.

Matador's Continued Growth in Production and Permian Position





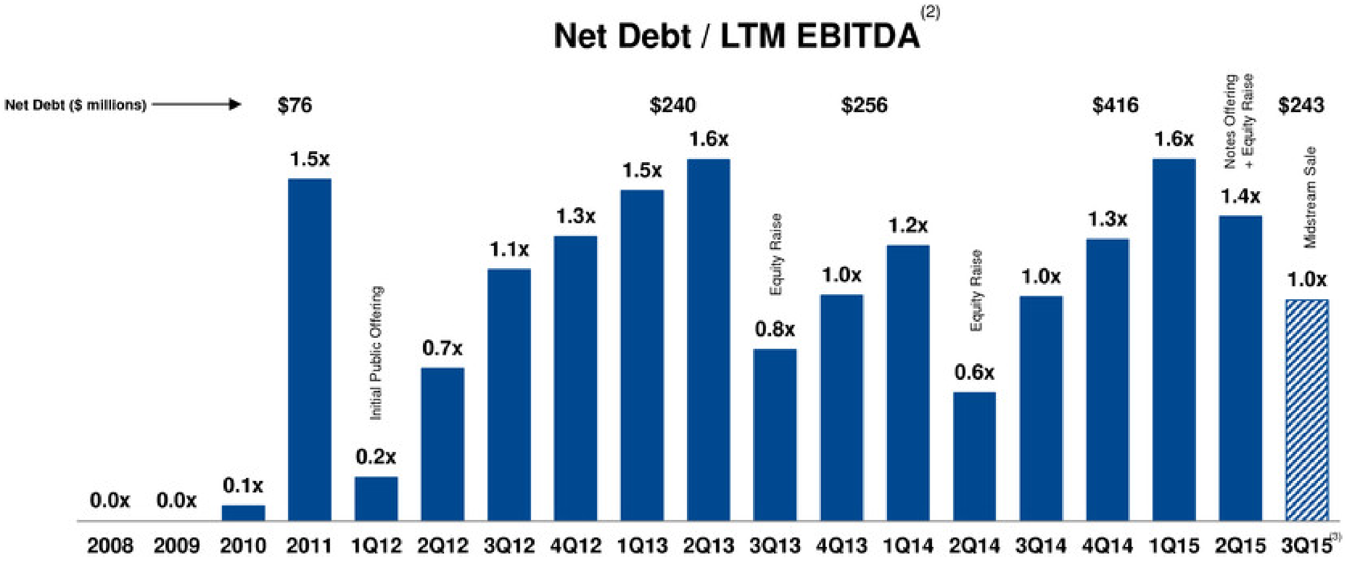




(1) At December 31 of each respective year.
(2) At November 4, 2015.

We Remain Committed to Keeping our Balance Sheet Strong

- **Preserved and enhanced liquidity through April 2015 equity and Senior Notes offerings and sale of Loving County midstream assets for ~$143 million[1] in October 2015 – substantial liquidity to execute planned drilling program through 2016**
- **Strong financial position with Net Debt/LTM Adjusted EBITDA[2][3] of 1.0x after close of midstream sale**
- **Target leverage at less than 2.0x Adjusted EBITDA[2], though profile typically more conservative**



(1) Excluding customary purchase price adjustments.
(2) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Appendix.
(3) Pro forma at September 30, 2015 for midstream sale on October 1, 2015.

Previous Oil Price Declines Have Created Opportunities for Matador[1]

Comparison of Major Oil Corrections and Major Matador Turning Points Since 1980

Date	Event	% Change in Oil Price	Length of Oil Price Decline (in trading days)	% Increase in Oil Price – 1-Year Post-Low	
1986	Saudi Market Share War	-67.2%	82	79.0%	A number of Mesa's top technical staff join Matador I
1988	Oil Glut	-43.7%	295	58.4%	Matador I buys key waterflood properties and New Mexico natural gas acreage
1991	Global Recession / End of Gulf War	-57.2%	90	5.4%	First interests in Amaker-Tippett acquired; becomes Matador I's largest field
1998	Asian Crisis	-59.6%	484	134.5%	Unocal exchanges NM properties for Matador I's stock
2001	Global Recession	-53.1%	290	46.2%	Matador I shifts to unconventionals (Marlan Downey joins Board)
2008	Great Recession	-78.4%	119	134.8%	Matador II builds Eagle Ford position and drills first Haynesville wells
	Average	**-59.9%**	**227**	**76.4%**	
2014-2015	Current Dip[2]	-59.8%	~300	?	-MTDR and HEYCO join forces -MTDR sells midstream assets to EnLink

(1) Includes Matador Resources Company, Foran Oil and Matador Petroleum Corporation and other predecessor entities.
(2) Length of oil price decline in trading days using high of $107.26 on June 20, 2014 and low of $38.24 on August 24, 2015.

Keys to Matador's Success Over Last 35 Years(1)

- **People**
  - *We have a strong, committed technical and financial team in place, and we continue to make additions and improvements to our staff, our capabilities and our processes*
  - *Board and Special Advisor additions have strengthened Board skills and stewardship*
- **Properties**
  - *Matador's acreage positions and multi-year drilling inventory are significant and located in three of the industry's best plays – Permian, Eagle Ford and Haynesville*
  - *Our property mix provides us with a balanced opportunity set for both oil and natural gas*
- **Process**
  - *Continuous improvement in all aspects of our business leading to more efficient operations, improved financial results and increased shareholder value*
  - *Gaining momentum as a successful publicly-held company*
- **Execution**
  - *Increase total BOE production by ~54%, with oil production expected to increase to ~4.45 million barrels and natural gas production expected to increase to ~27.5 Bcf in 2015*
  - *Maintain quality acreage positions in the Permian, Eagle Ford and Haynesville – successfully integrate HEYCO acreage in Permian*
  - *Reduce drilling and completion times and costs – improve operational efficiencies*
  - *Maintain strong financial position and technical and administrative teams*

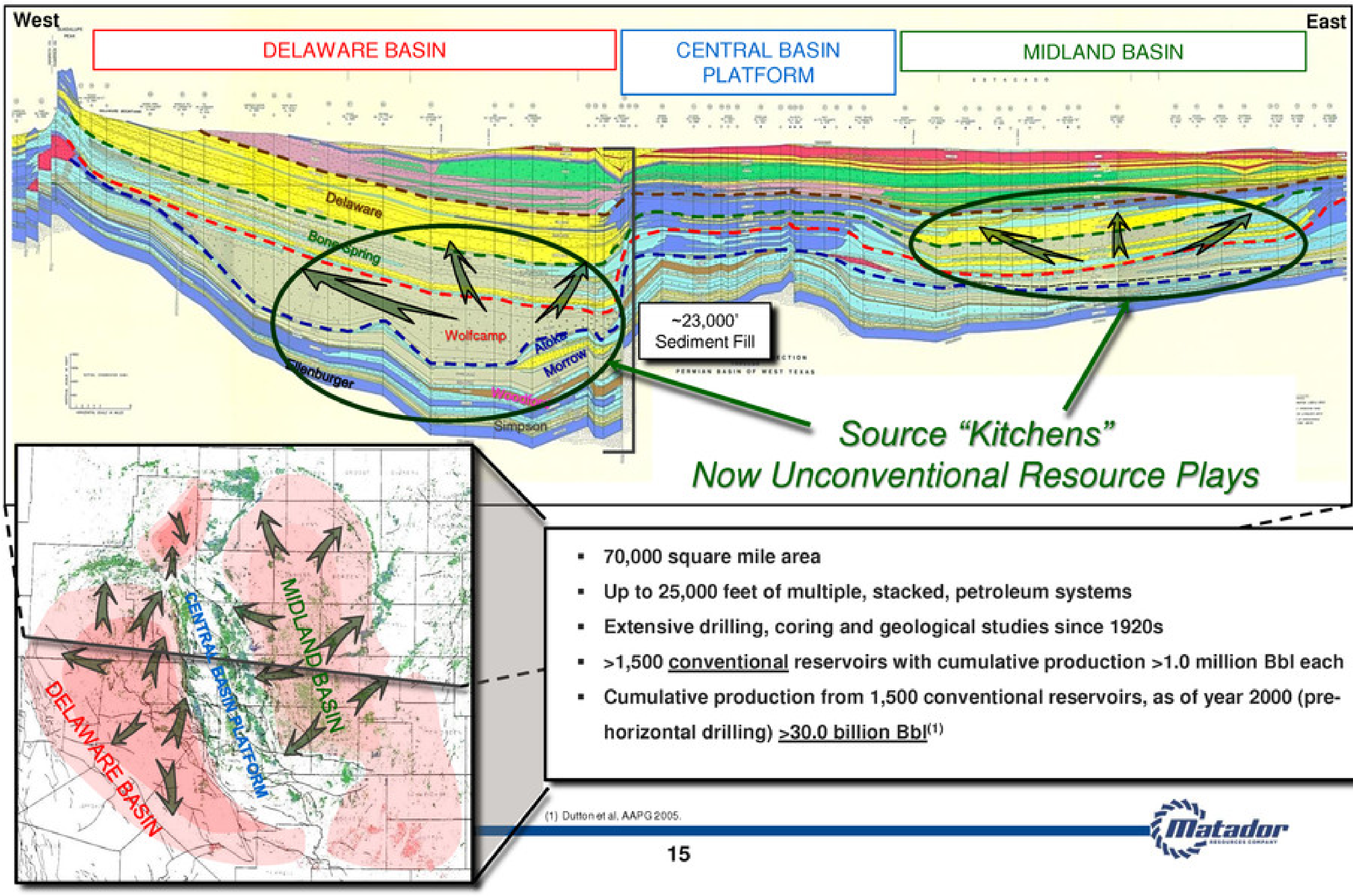
(1) Includes Matador Resources Company and its predecessor entities.



Permian (Delaware) Basin

Southeast New Mexico and West Texas

Delaware Basin – A "World Class" Hydrocarbon System



- 70,000 square mile area
- Up to 25,000 feet of multiple, stacked, petroleum systems
- Extensive drilling, coring and geological studies since 1920s
- >1,500 conventional reservoirs with cumulative production >1.0 million Bbl each
- Cumulative production from 1,500 conventional reservoirs, as of year 2000 (pre-horizontal drilling) >30.0 billion Bbl[(1)]

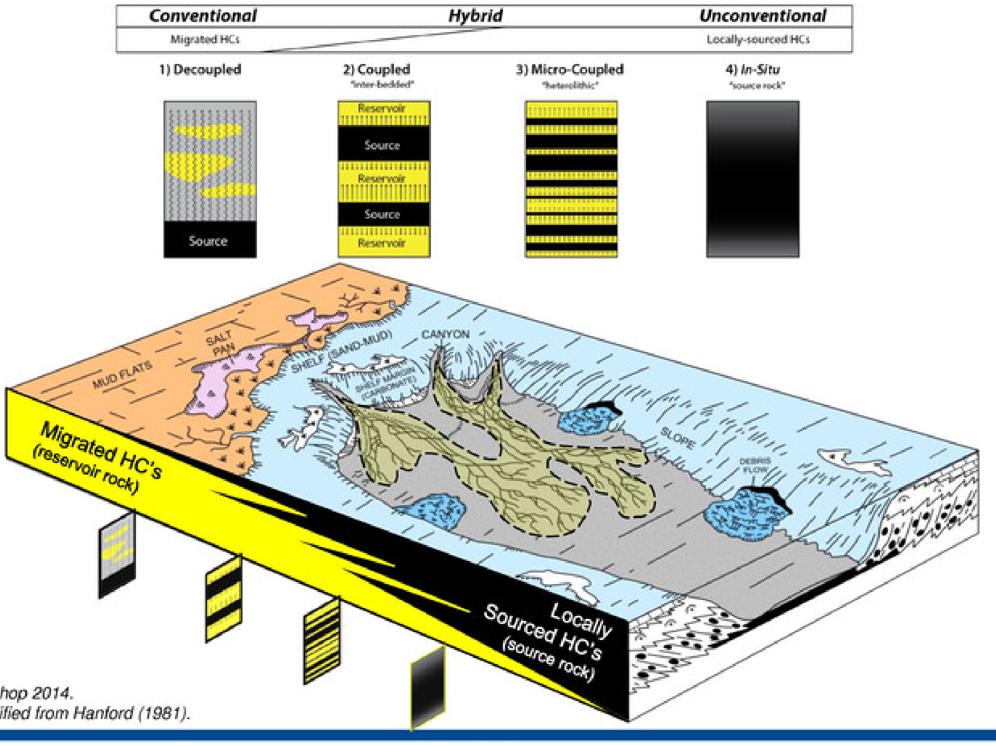
(1) Dutton et al, AAPG 2005.

Spectrum of Unconventional Play Types

In general there is no consensus on the what an "unconventional" reservoir is…

At Matador, we think of an unconventional reservoir as a spectrum of play types.

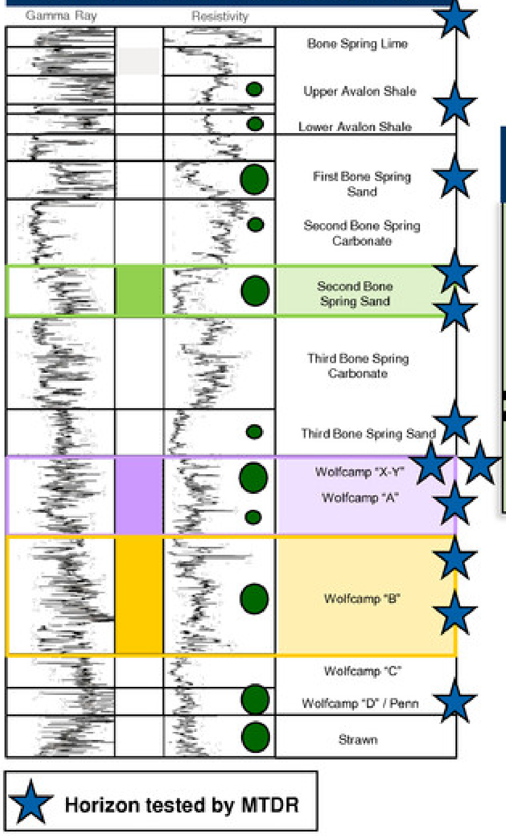
The distribution and quality of these play types are both spatially and temporally variable.



Play types from Bishop 2014.
Block diagram modified from Hanford (1981).

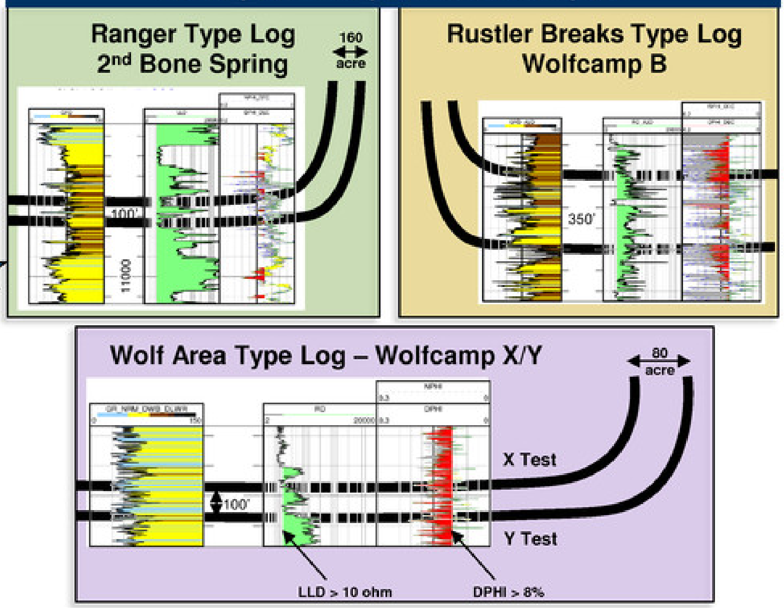
4,000 feet of Hydrocarbon Column Creates Opportunity

INTER-Formational Stacked Pay

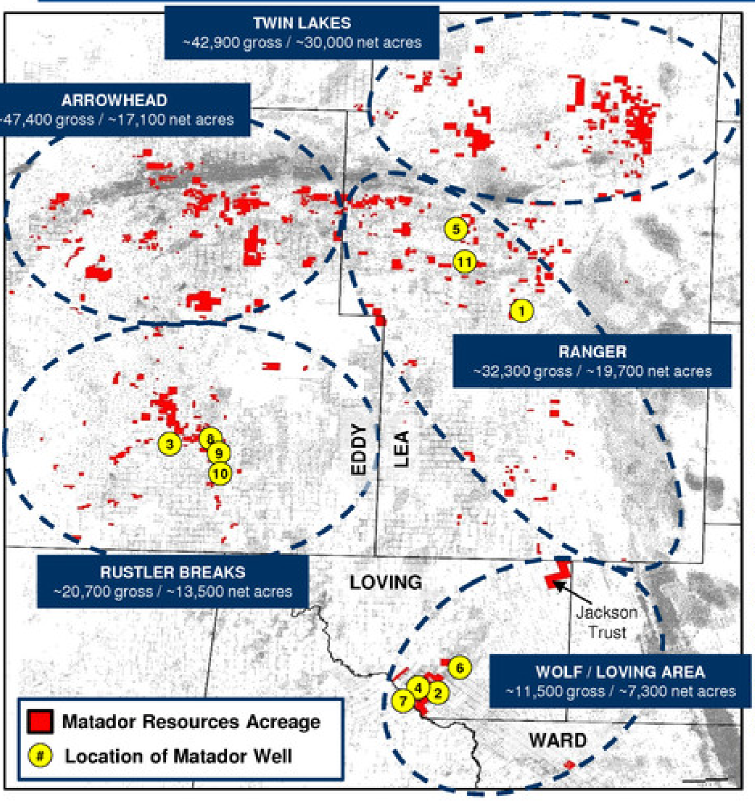


- Determining "Good, Better, Best" important as potential exceeds inter-formational stacked pay
- 2015 program will expand on intra-formational stacked pay tests performed in each asset area

INTRA-Formational Stacked Pays
Decoupled – Coupled – Micro-coupled



Permian Basin Acreage Position and Selective Well Results



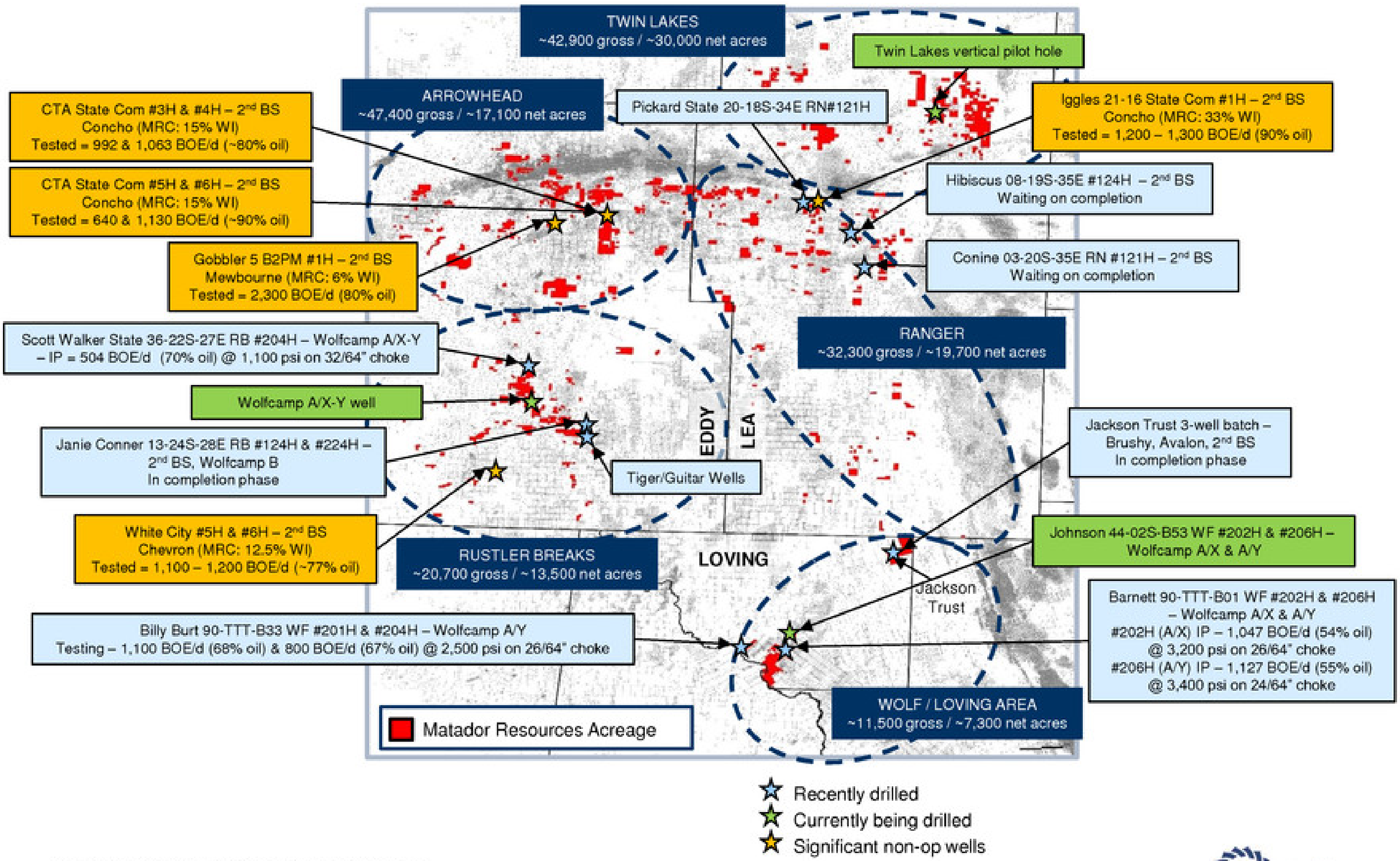
Permian Basin Total	
Gross Acres	**~158,700 acres**
Net Acres	**~90,700 acres**

Selected well performance(1)

	Cumulative Production			Recent Production		
Well	Months	Oil Eq. (BOE)	% Oil	Oil (Bbl/d)	Natural Gas (Mcf/d)	EUR(2) (MBOE)
1 **Ranger State 33-20S-35E RN #121H** (2nd Bone Spring)	23.5	228,000	91	170	130	650
2 **Dorothy White #1H** (Wolfcamp "A"/"X")	22.0	453,000	68	310	690	1,050
3 **Rustler Breaks 12-24S-27E RB #224H** (Wolfcamp "B")	18.0	221,000	41	90	920	700
4 **Norton Schaub 84-TTT-B33 WF #201H** (Wolfcamp "A"/"X")	16.0	315,000	68	480	1400	800
5 **Pickard State 20-18S-34E RN #121H** (2nd Bone Spring)	15.5	179,000	90	400	620	600
6 **Johnson 44-02S-B53 #204H** (Wolfcamp "A"/"X")	13.5	247,000	65	330	740	900
7 **Norton Schaub 84-TTT-B33 WF #2010H** (Wolfcamp "A")	11.0	119,000	72	150	390	450
8 **Guitar 10-24S-28E RB #202H** (Wolfcamp "A"/"X")	8.0	137,000	79	340	680	700
9 **Tiger 14-24S-28E RB #224H** (Wolfcamp "B")	7.5	191,000	44	270	2100	1,000
10 **Tiger 14-24S-28E RB #204H** (Wolfcamp "A/X-Y")	4.5	105,000	80	600	560	700
11 **Cimarron 16-19S-34E RN #134H** (3rd Bone Spring)	6.5	103,000	94	330	100	450

Note: All acreage at November 4, 2015. Some tracts not shown on map.
(1) As of early November 2015 unless otherwise noted.
(2) Estimated ultimate recovery, thousands of barrels of oil equivalent.

Permian Basin Acreage Position and Recent Test Results

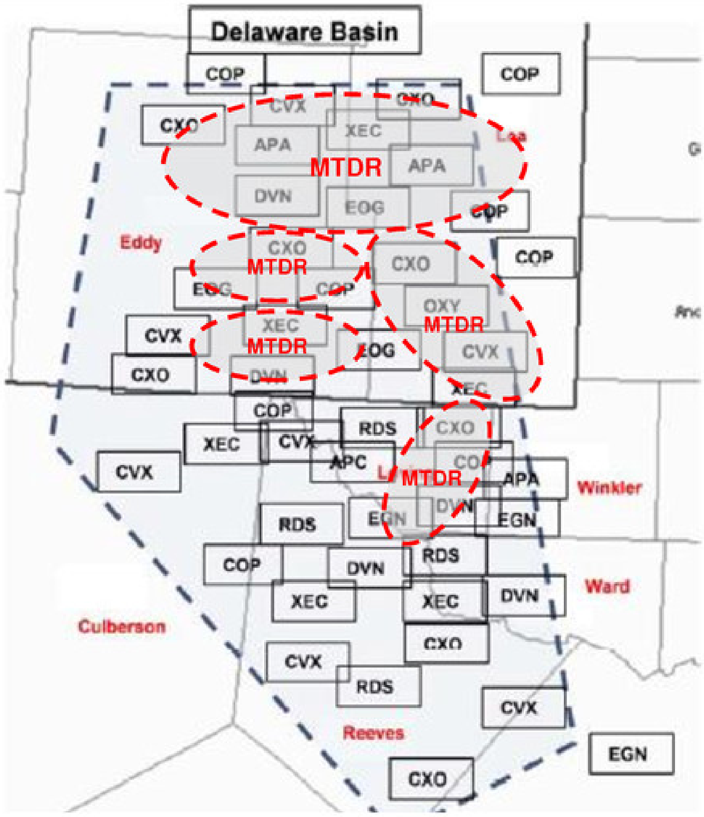


Note: All acreage at November 4, 2015. Some tracts not shown on map.

Matador is a Significant Delaware Basin Player

- **Matador's 90,700 net acres place it among the largest operators in the Delaware Basin**
  - *Matador holds **largest** Delaware Basin acreage position **among small and mid-cap** publicly traded energy companies(1)*
  - *Matador is the **second largest** operator in terms of the ratio of Delaware Basin acreage to enterprise value or market capitalization among all public traded energy companies(1)*

- **Key Operators in the Delaware Basin(2):**
  - *Oxy* — *1,500,000 net acres*
  - *Chevron* — *1,000,000 net acres*
  - *Shell* — *618,000 net acres*
  - *Concho* — *425,000 net acres*
  - *Cimarex* — *400,000 net acres*
  - *EOG* — *307,000 net acres*
  - *Anadarko* — *255,000 net acres*
  - *Apache* — *230,000 net acres*
  - *Conoco* — *150,000 net acres*
  - *Energen* — *113,000 net acres*
  - ***Matador*** — ***158,700 gross / 90,700 net acres***



Source: National Atlas, Company data, Goldman Sachs Global Investment Research.

(1) Based on an independent market analysis prepared by BMO Capital Markets in January 2015. Small and mid-cap publicly traded energy companies defined as those companies with an enterprise value between $500 million and $3.5 billion. Companies below $100 million in market capitalization were excluded in determining the ratio of Delaware Basin acreage to market capitalization. Matador acreage at November 4, 2015.
(2) Goldman Sachs Equity Research report dated April 1, 2015 (Singer).

Task at Hand – Understanding the Opportunities

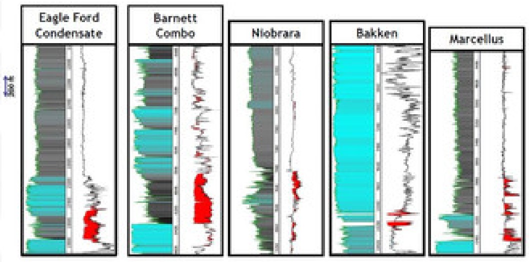
Most current unconventional plays target one or two zones across a trend area.

The Permian Basin has roughly two dozen unique targets within the Midland and Delaware sub-basins.

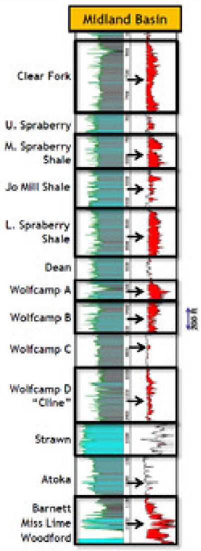
Objective: We want to drill and complete the best wells at the lowest cost.

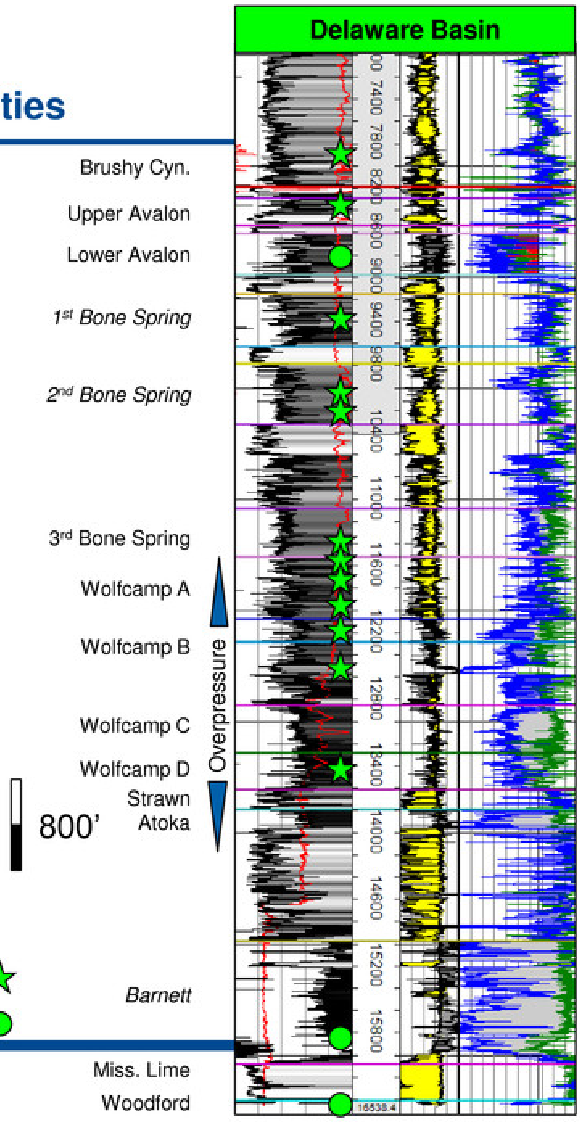
Challenge: How do we identify the best targets within multiple prospective intervals across a geologically complex basin?

Matador's geoscience staff is committed to bringing the best targets forward!



All logs plotted at same scale



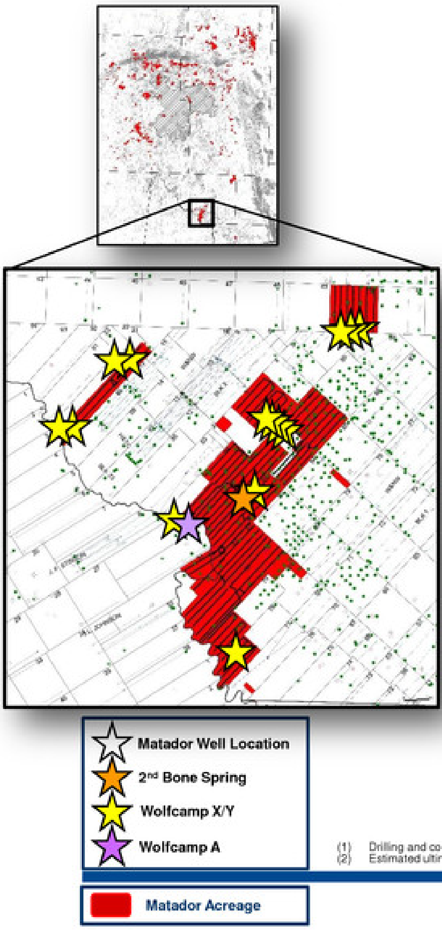


Tested by MTDR ★

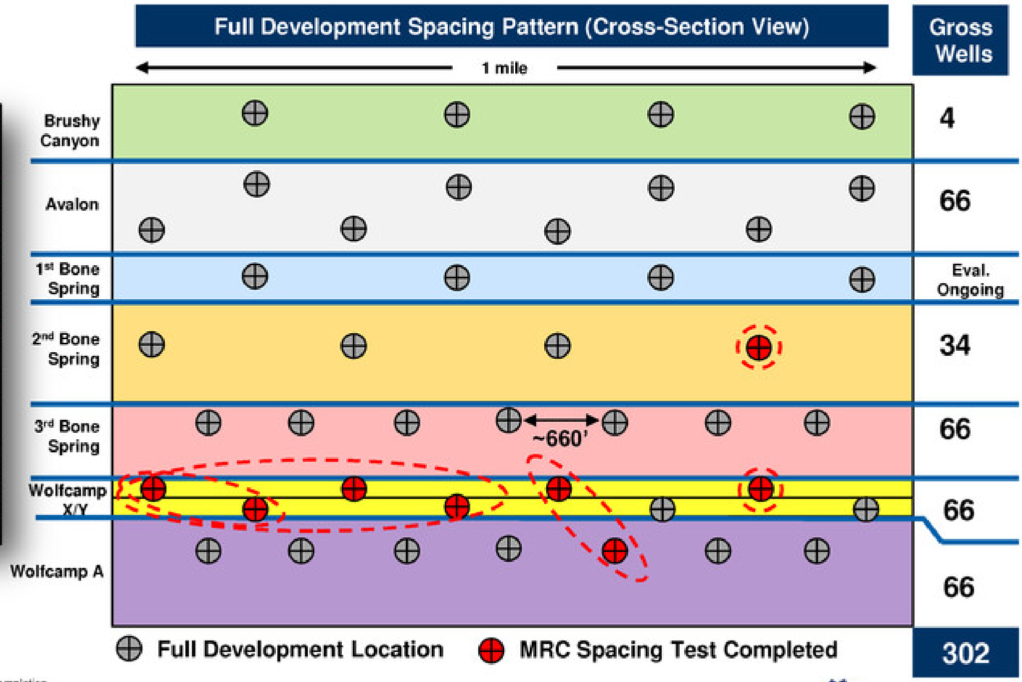
Tested by others ●

Images source: Pioneer Natural Resources Co. (NYSE: PXD)

Wolf Inventory – Multi-Pay Development Potential

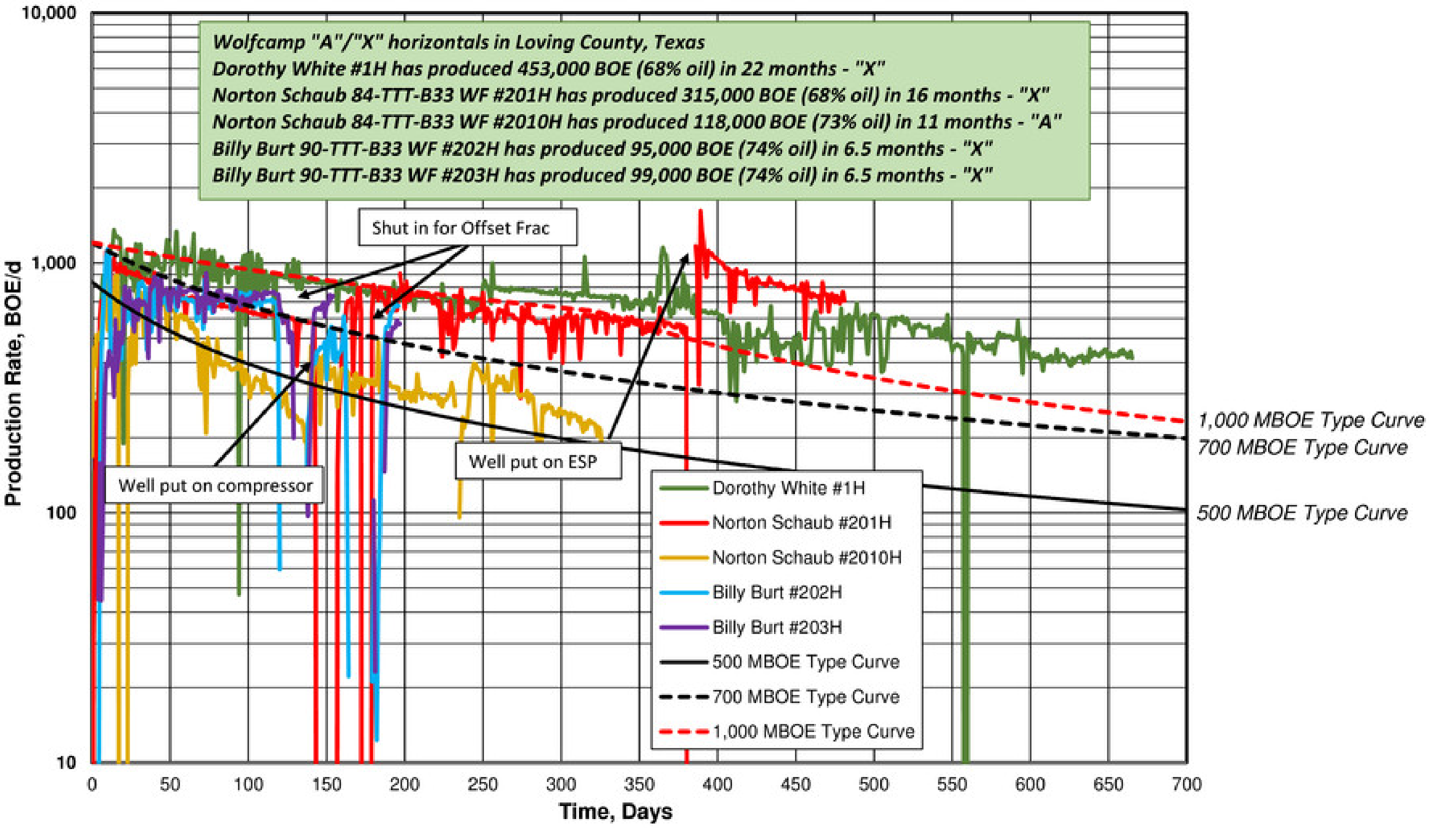


Development Well	D&C[1] CapEx	EUR[2] (MBOE)
Bone Spring	\$5.5 – \$6.5 million	450 – 600
Wolfcamp	\$6.5 – \$8.0 million	650 – 1,100



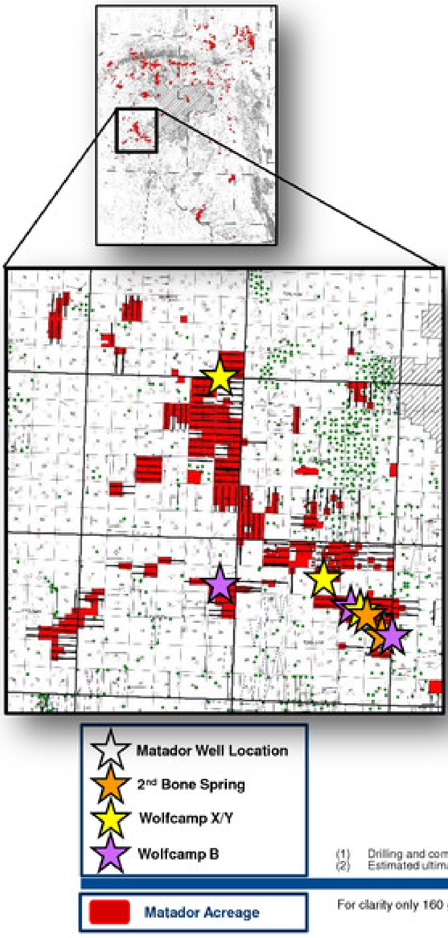
(1) Drilling and completion.
(2) Estimated ultimate recovery, thousands of barrels of oil equivalent.

Wolf Area Wolfcamp "A"/"X" Wells Performing Above Expectations

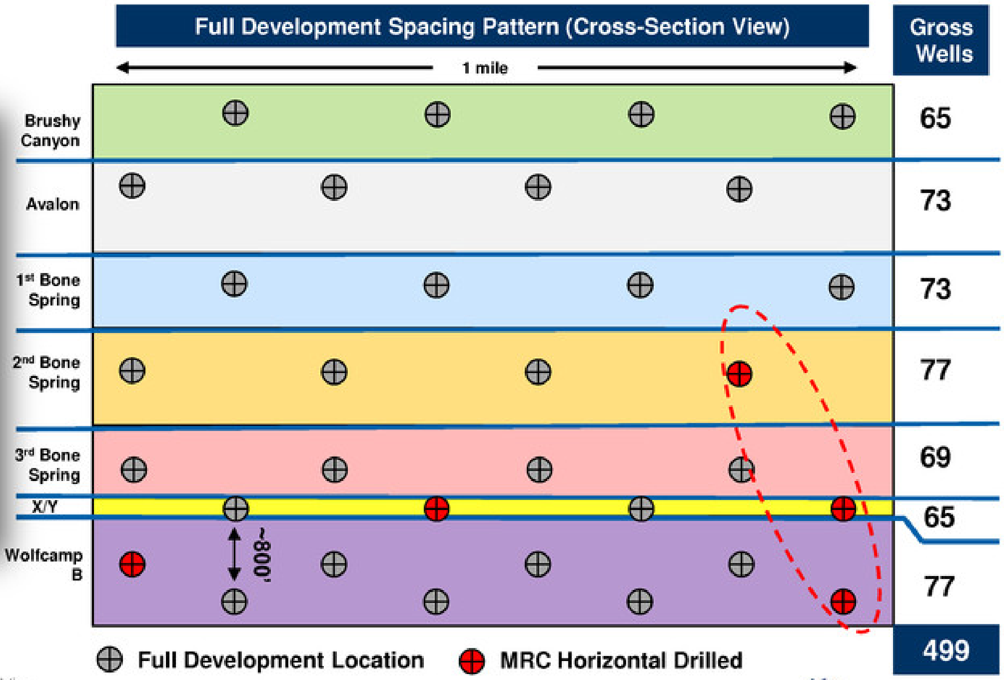


Note: Production as of early November 2015.

Rustler Breaks Inventory – Multi-Pay Development Potential



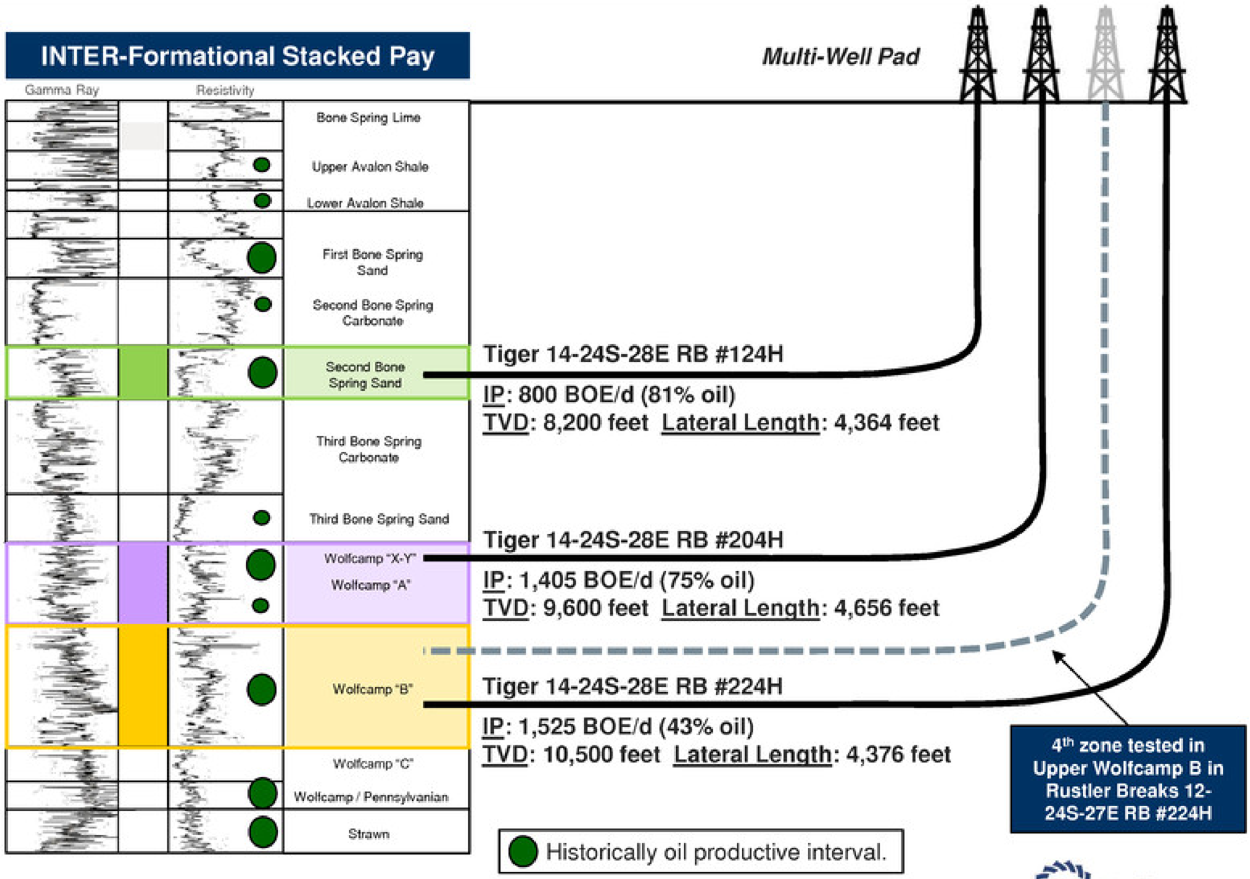
Development Well	D&C[1] CapEx	EUR[2] (MBOE)
Bone Spring	$4.0 – $5.0 million	300 – 600
Wolfcamp	$5.5 – $7.5 million	500 – 1,000



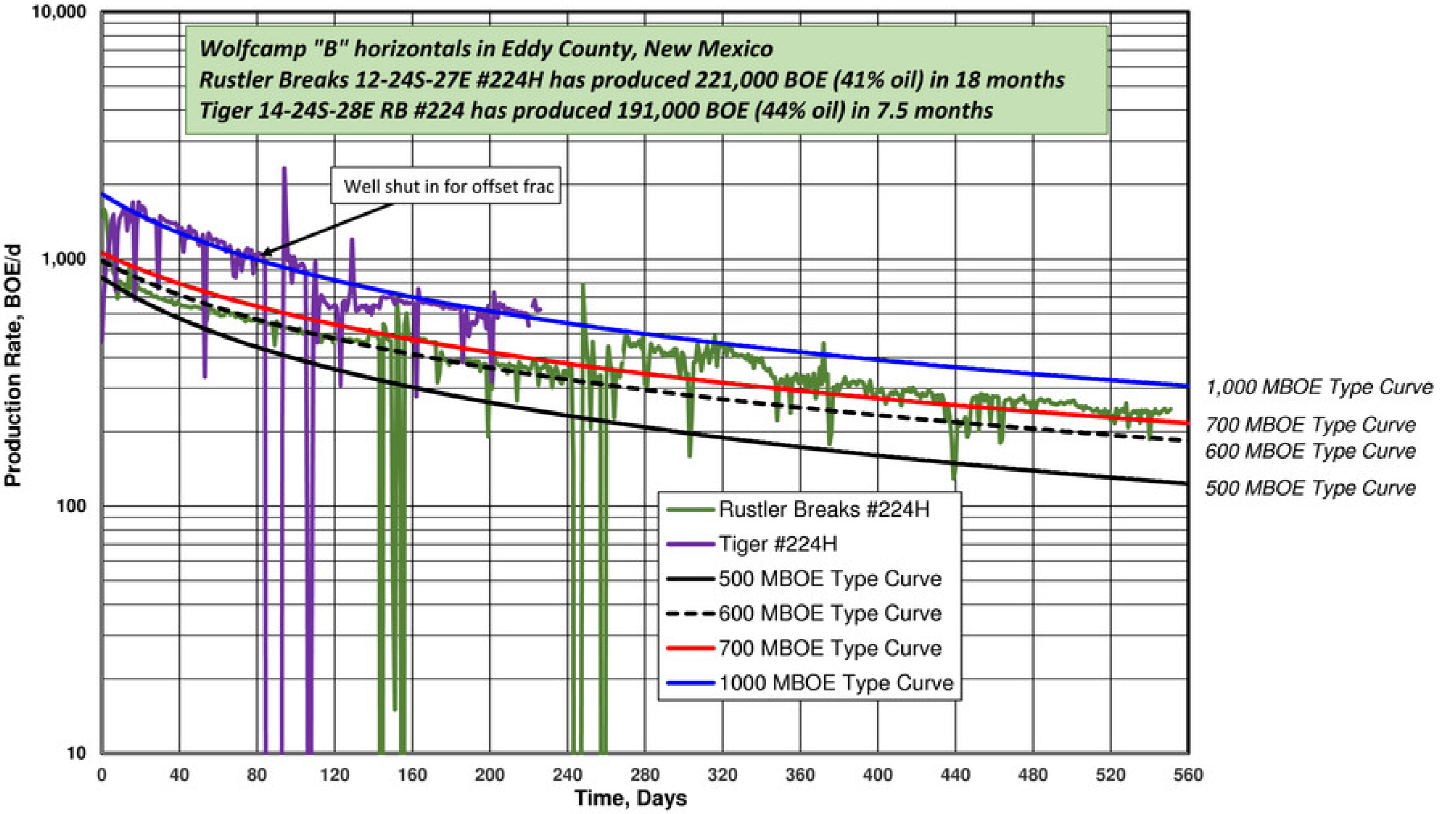
(1) Drilling and completion.
(2) Estimated ultimate recovery, thousands of barrels of oil equivalent.

For clarity only 160 gross ac. well slots shown

Matador's First Three-Zone Stacked Lateral Test at Rustler Breaks

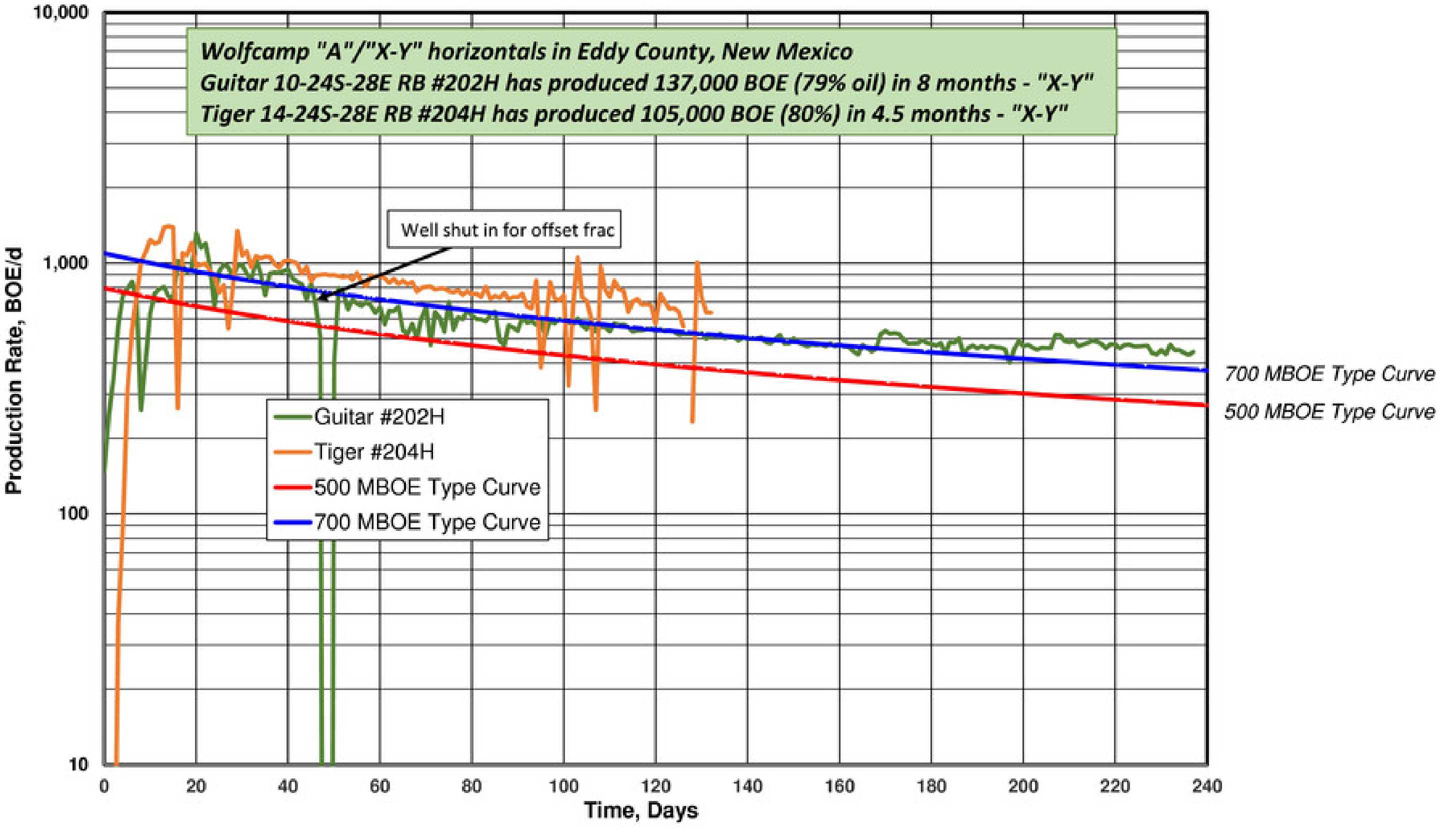


Rustler Breaks Wolfcamp "B" Wells Performing Above Expectations



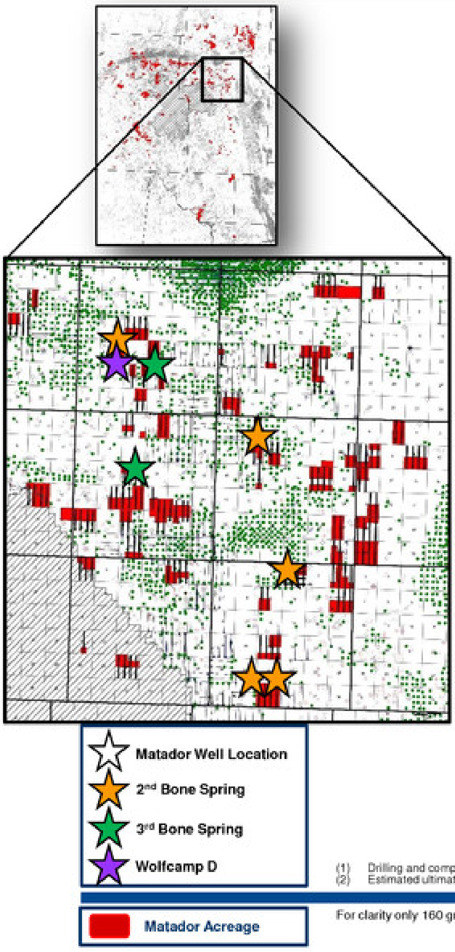
Note: Production as of early November 2015.

Rustler Breaks Wolfcamp "A"/"X-Y" Wells, Off to Strong Start



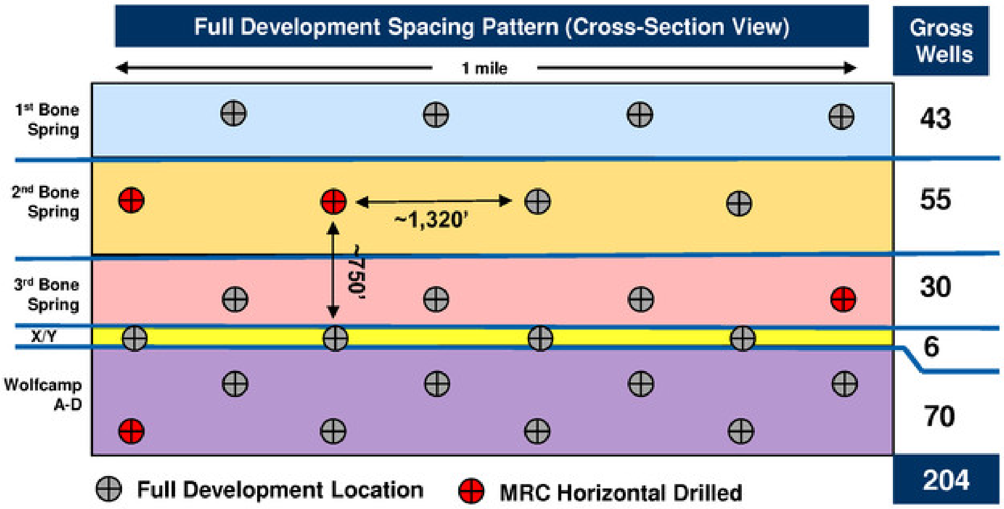
Note: Production as of early November 2015.

Ranger Inventory – Multi-Well Development Potential



Development Well	D&C(1) CapEx	EUR(2) (MBOE)
Bone Spring	$5.5 – $6.5 million	400 – 600
Wolfcamp	$7 – $9 million	200 – 800*

* Based on Volumetrics and 4-8% Recovery Factor

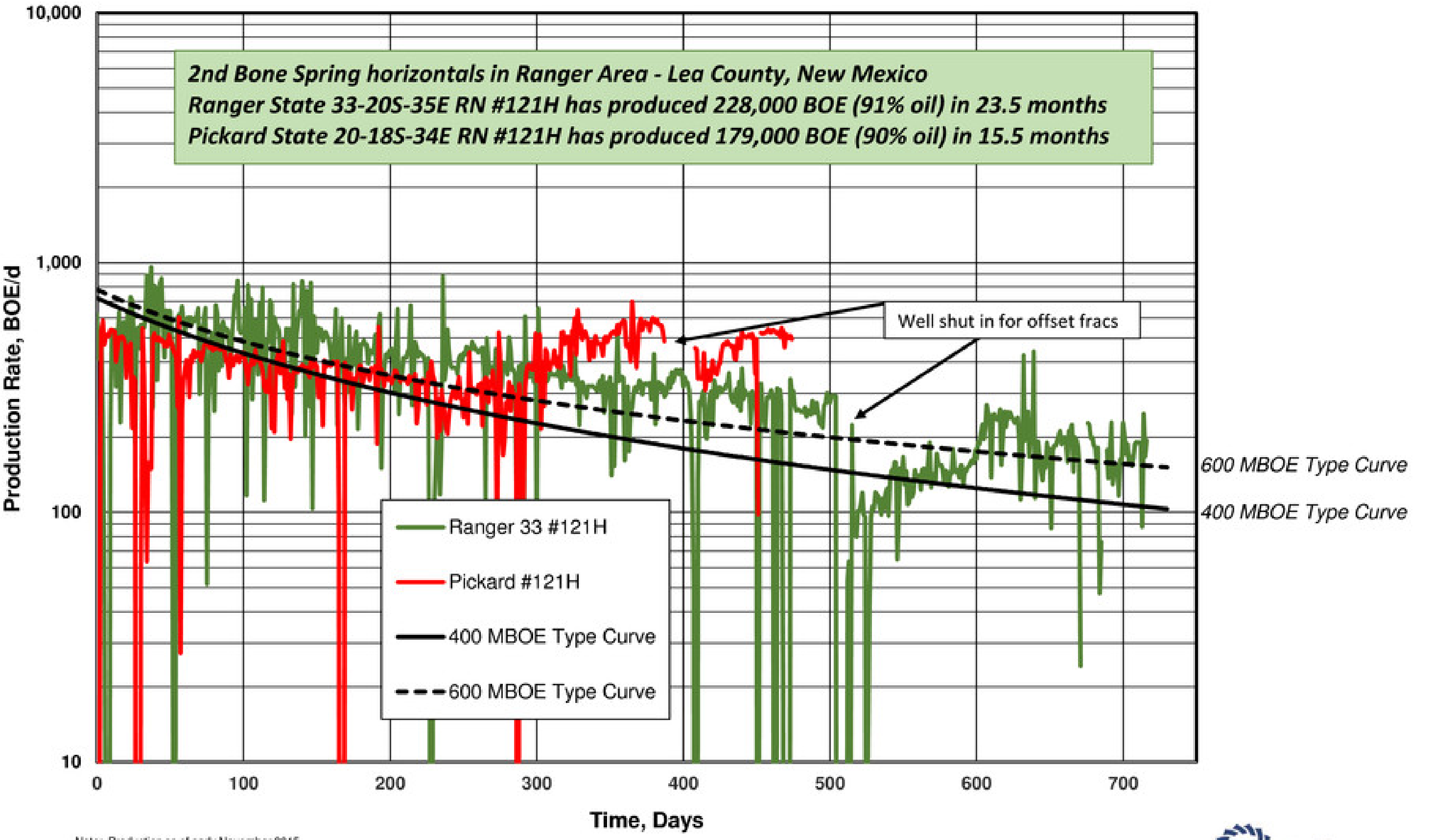


Location estimates do not include HEYCO acreage.

(1) Drilling and completion.
(2) Estimated ultimate recovery, thousands of barrels of oil equivalent.

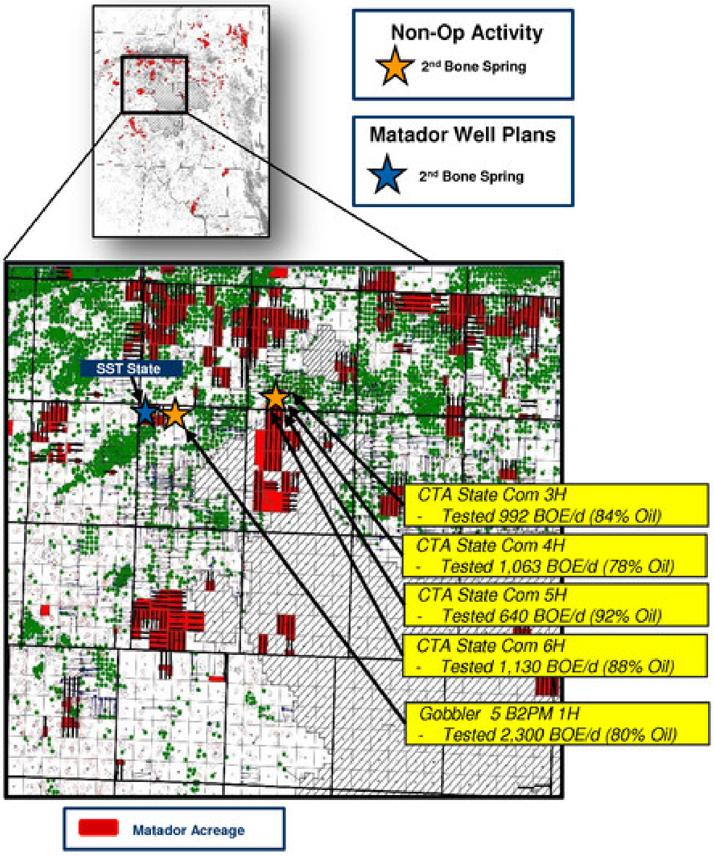
For clarity only 160 gross ac. well slots shown

Ranger Area Second Bone Spring Wells Performing Above Expectations



Note: Production as of early November 2015.

Arrowhead – HEYCO Acreage Provides Unique Opportunities

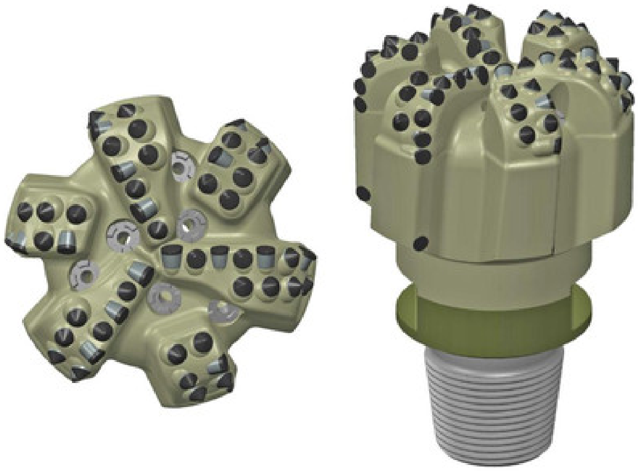


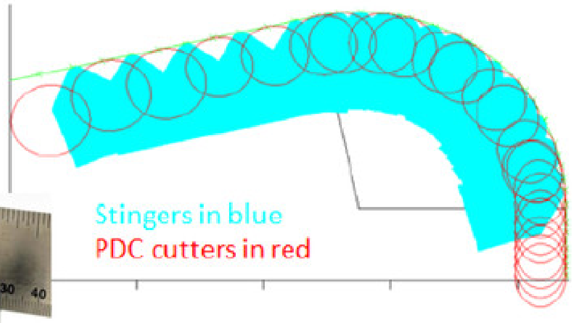
- **Most HEYCO acreage is Federal acreage**
  - Most held by production by older, vertical wells
  - Typically 87.5% NRI on most Federal acreage
  - Contiguous acreage aids in full development and minimizes costs for pads, facilities and LOE
- **Matador Operated Horizontal Plans (Q1 2016)**
  - SST State 06-19S-29E AH #123H & #124H
    - Second Bone Spring laterals
    - Offset to Mewbourne Gobbler wells (non-op)
- **Non-Operated Well Activity**
  - CTA State Com #3H: Tested 992 BOE/d (84% Oil); 143,000 BOE in first 7 months(1)
  - CTA State Com #4H: Tested 1,063 (78% Oil); 126,000 BOE in first 6 months(1)
  - CTA State Com #5H: Tested 640 BOE/d (92% Oil)
  - CTA State Com #6H: Tested 1,130 BOE/d (88% Oil)
  - Gobbler 5 B2PM #1H: Tested 2,300 BOE/d (80% Oil); 140,000 BOE in first 4 months(1)
  - Mewbourne, Concho, Cimarex wells provide operational data and reference points across Matador acreage

(1) As of early November 2015.

Future Bit Technology – The Evolution of the PDC bit

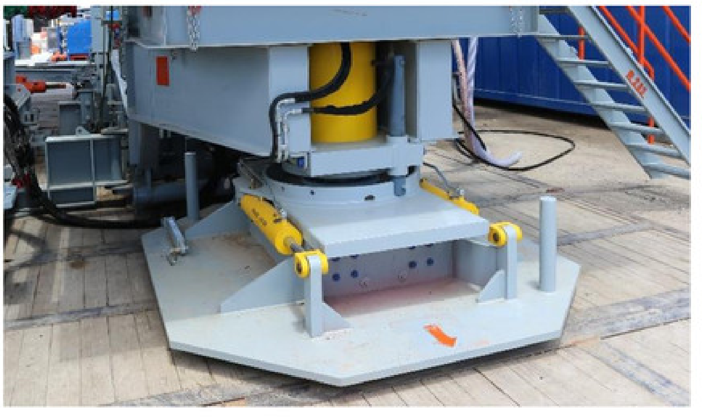
- Matador continues to be at the forefront of new bit technology
- Smith Bits latest technology StingBlade design
- StingBlade design features
  - *Alternating Stinger/PDC cutters*
  - *Stinger cutters cut troughs in the formation with the PDC cutters coming behind and removing the ridges*
  - *Stinger cutters do the hard work, PDC cutters keep the speed*
  - *Ultimate combination of speed, durability and steerability*





New Rig Technology for Horizontal Drilling – Saving Time and Money!

- **7,500 psi Pressure Rating**
  - Estimated reduction in drilling time of 20 to 25% in the lateral on Wolfcamp wells
- **Telescoping Flex-joint**
  - Estimated reduction in drilling time of 12 to 18 hours per well
- **Integrated Mud-Gas Separator**
  - Estimated savings of 50% compared to rental separator
- **BOP Wrangler**
  - Estimated reduction in drilling time of 12 hours per well
- **Walking System & V-door turned 90°**
  - Allows for batch-drilling and simultaneous operations
- **Reduced Downtime**

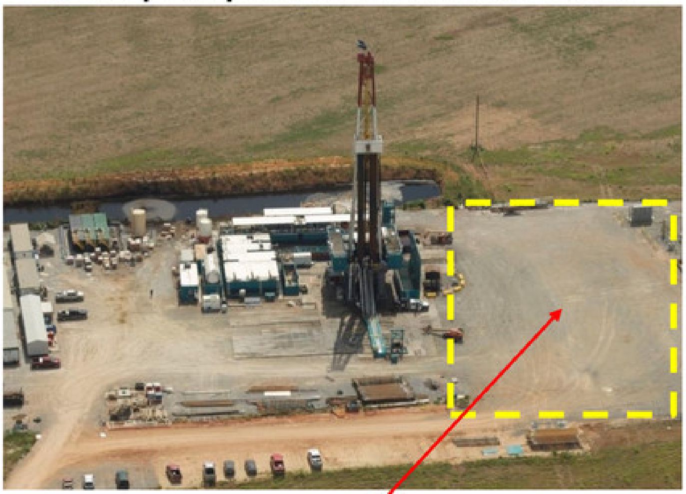


Latest Technology: Simultaneous Operations (Sim-Ops) Capable Rigs

Conventional Drilling Configuration

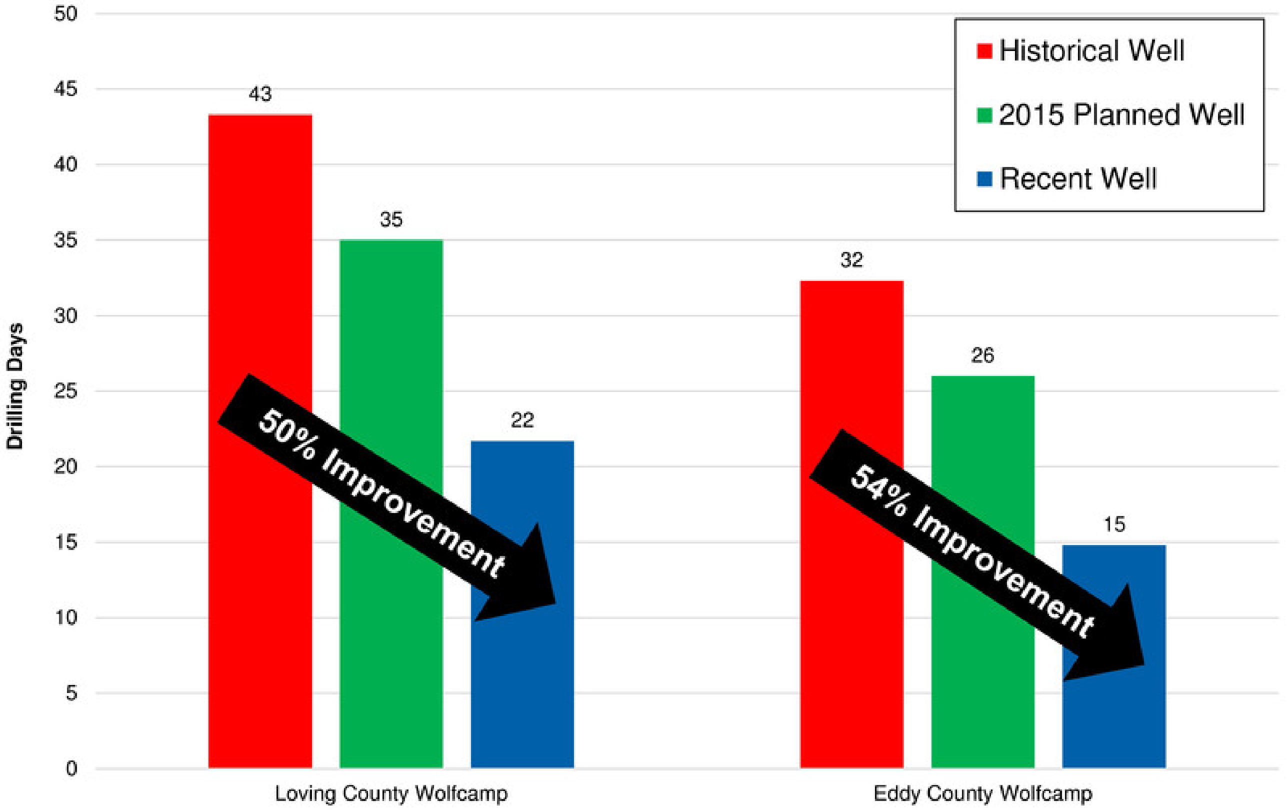
Drilling rig must leave location prior to frac operations

Sim-Ops Capable with V-door turned 90°



Space available for frac operations while simultaneously drilling on the same pad

Improving Wolfcamp Drilling Times Significantly in 2015

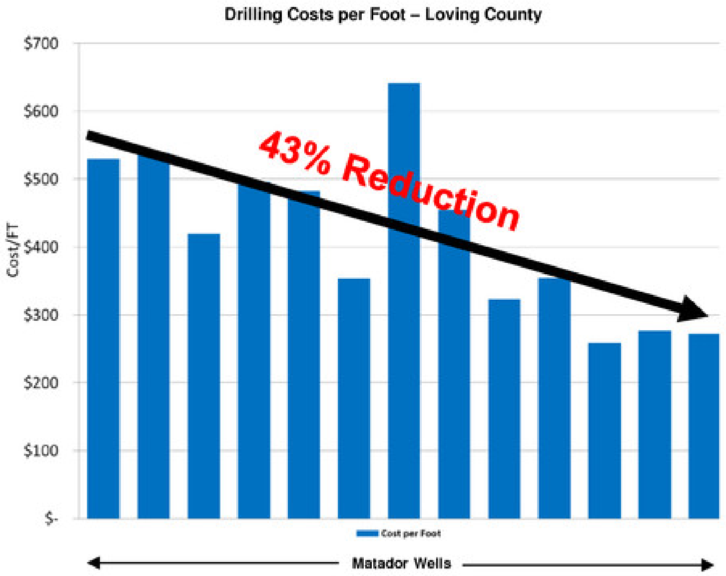


*Historical days averaged from 2014 wells.
*Recent days from Billy Burt 90-TTT-B33 WF #204H & Tiger 14-24S-28E RB #204H.

Cost Reduction Metrics (Drilling and Completion)

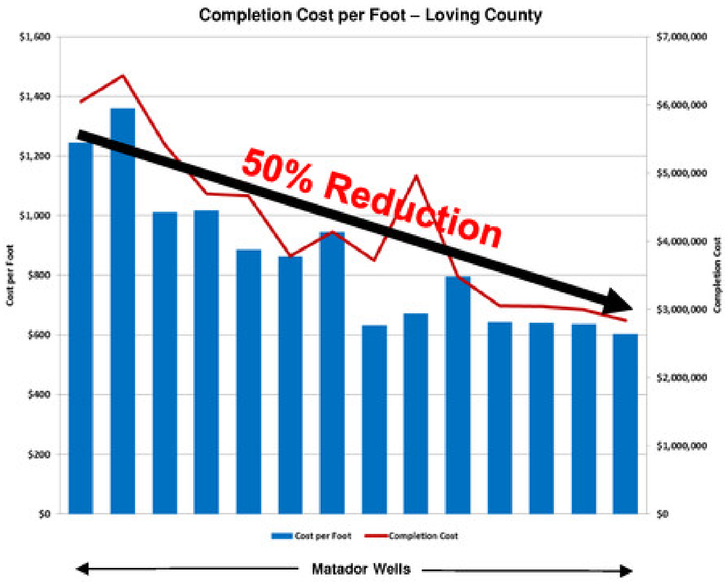
Drilling

- Overall cost reduced by 43% since first well
- Days down from 43 to 22 in the Wolfcamp
  - Cost improvements that can stay with us moving forward

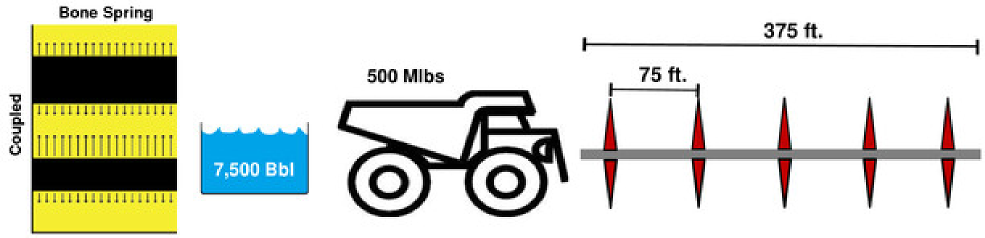


Completion

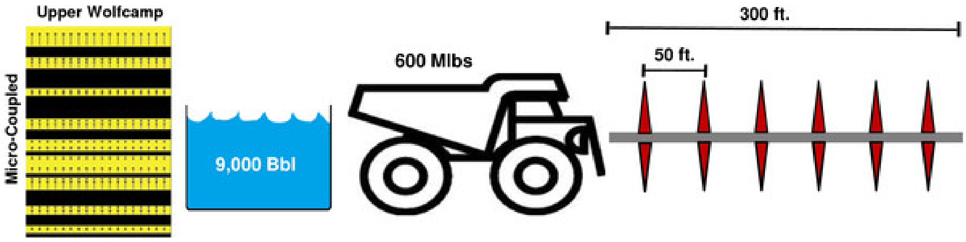
- Overall cost reduced by 50% since first well
- Cost of pumping and drill out has driven down costs
  - Drill out days down from using micro trips
  - Lowers the overall time per plug



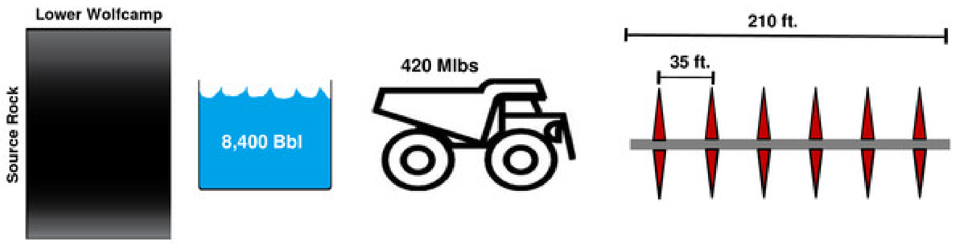
Evolution of Permian Basin Frac Design – Reservoir Specific



Gen 1	Gen 2
2,000 lbs/ft	1,333 lbs/ft
40 Bbl/ft	20 Bbl/ft
50' cluster spacing	75' cluster spacing



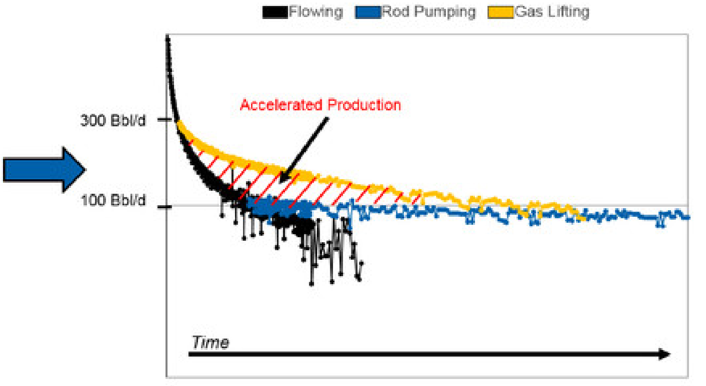
Gen 1	Gen 2
2,000 lbs/ft	2,000 lbs/ft
40 Bbl/ft	30 Bbl/ft
35' cluster spacing	50' cluster spacing



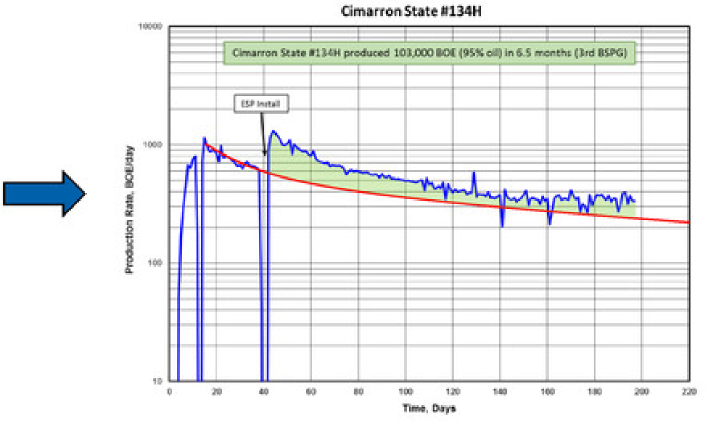
Gen 1	Gen 2
2,000 lbs/ft	TESTING SOON
40 Bbl/ft	
35' cluster spacing	

Optimizing Artificial Lift Operations Across the Basin

- **Optimizing Gas Lift Operations**
  - All 2nd Bone Spring wells on gas lift
  - Accelerates production while reducing LOE
  - Lower maintenance costs than rod pump
  - Helps wells recover faster from offset fracs

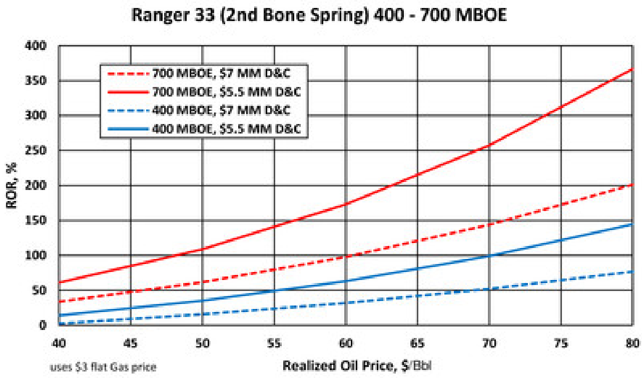


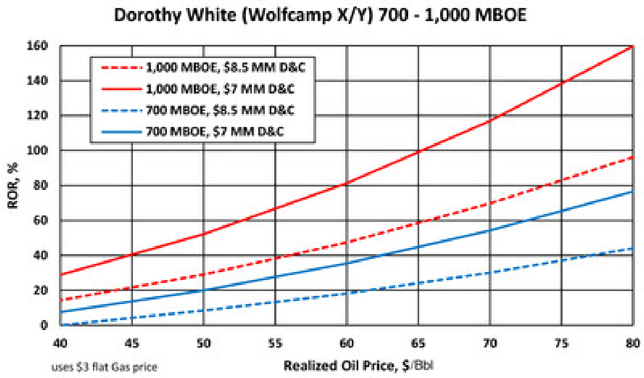
- **Starting to Use ESP's**
  - Accelerated production while maintaining a controlled drawdown of bottomhole pressure
  - BHP gauges aid in analyzing 3rd Bone Spring reservoir properties
  - Quick startup after shut in for maintenance = minimal downtime
  - Once on grid power, will be very quiet operation in Chicken/Lizard environment
  - Able to unload offset frac water even more effectively than gas lift

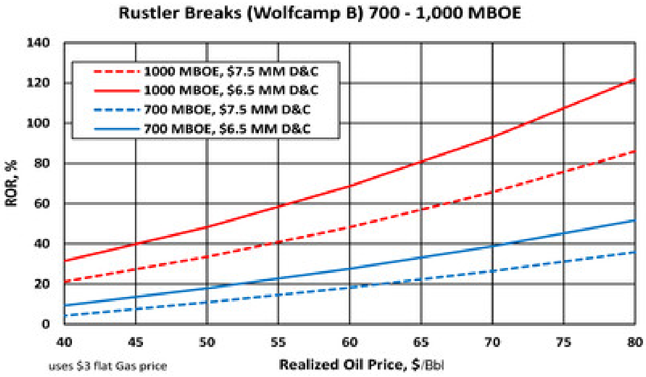


Note: Graph and data in gas lift figure above is for illustrative purposes only and not meant to reflect historical or forecasted data from actual well.

Permian Basin Economics – Oil Price Sensitivities



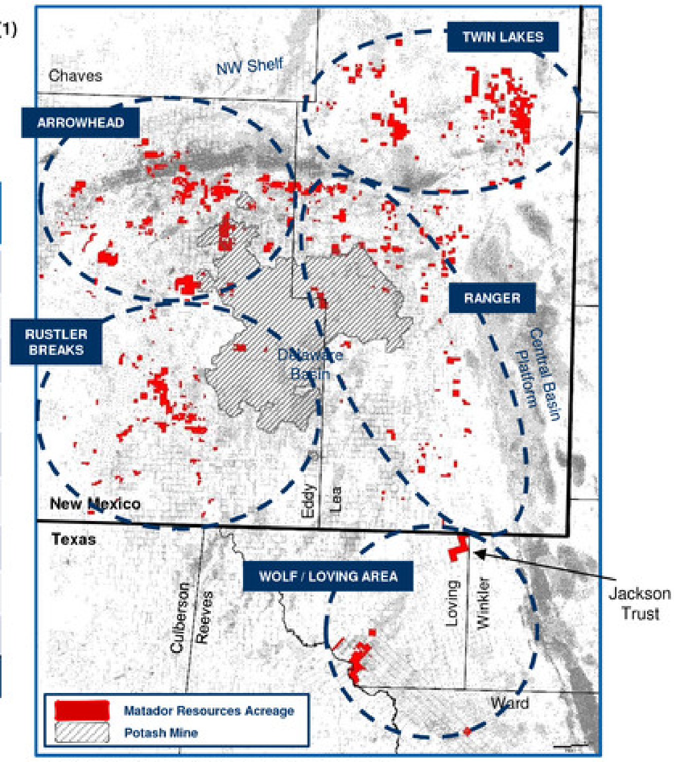




Significant Delaware Basin Inventory

- **Matador has identified 1,445 gross (960 net) locations(1)**
- **This inventory does not yet include the HEYCO properties (mostly Arrowhead prospect area) or Twin Lakes locations**

Formation	Gross Locations	Net Locations
Delaware Group	109	67
Avalon	160	112
1st Bone Spring	146	96
2nd Bone Spring	210	141
3rd Bone Spring	224	148
Wolfcamp X/Y	152	104
Wolfcamp A	207	134
Wolfcamp B	92	62
Wolfcamp D	145	96
TOTAL	**1,445**	**960**



Note: All acreage at November 4, 2015. Some tracts not shown on map.

(1) Identified and engineered locations for potential future drilling, including specified production units and estimated lateral lengths, costs and well spacing using objective criteria for designation. Locations identified as of December 31, 2014, but including no locations at Twin Lakes and no locations associated with the HEYCO transaction or two associated joint ventures. Note: Inventory only includes wells with >30% working interest.



Midstream

Longwood Gathering and Disposal Systems[1] in Delaware Basin

- ***Loving County, Texas***
  - Natural gas gathering
  - Water gathering
  - Oil gathering
  - Salt water disposal
    - Commercial facility disposing of 20,000 Bbl/d
    - Saved Matador $4 million to date
  - Cryogenic natural gas processing plant
    - Sold to EnLink for ~$143 million[2]

- ***Eddy County, New Mexico***
  - Natural gas gathering
  - Water gathering (Planned)
  - Oil gathering (Planned)
  - Salt water disposal (Planned)
  - Cryogenic natural gas processing plant
    - Plans to construct underway
    - Projected inlet capacity of 60MMcf/d
    - Projected on line in Q3 2016

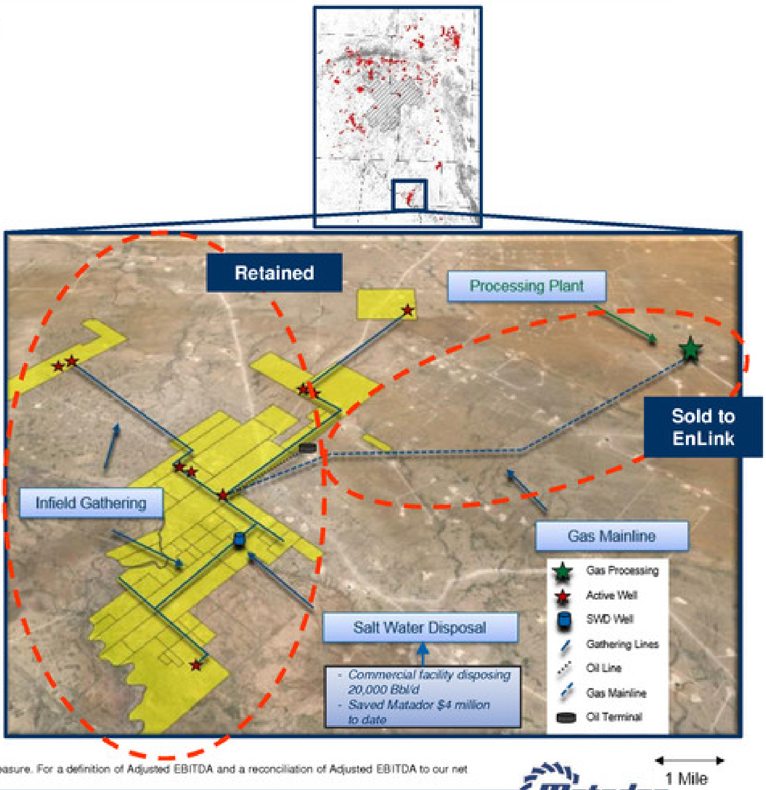
Longwood Gathering and Disposal Systems Activities

(1) Longwood Gathering and Disposal Systems, LP is an indirect wholly owned subsidiary of Matador Resources Company.
(2) Excluding customary purchase price adjustments.

Summary: Sale of Loving County Gas Gathering & Processing Assets

Matador sold certain Delaware Basin natural gas gathering and processing assets in Loving County, Texas to EnLink[(1)] for ~$143 million[(2)] in cash in October 2015.

- Assets include a cryogenic natural gas processing plant with ~35 MMcf per day of inlet capacity and six miles of high-pressure gathering pipeline which connects a Matador-owned gathering system to the plant
- Consideration for Sale
  - $143 million[(2)] in cash
  - Matador has ability to defer taxes through potential like-kind exchanges
  - Matador enters into 15-year, fixed fee gathering and processing agreement with EnLink[(1)]
    - Matador retains "priority one" service in exchange for a volume commitment
    - Matador dedicates current Loving County leasehold interests to EnLink – future leasehold acquisitions can be dedicated to EnLink at Matador's option
- Matador retains its natural gas gathering system up to a central delivery point and other Loving County midstream assets, including oil and water gathering systems and salt water disposal wells
- Solidifies Matador's already strong balance sheet and enhances its ample liquidity to execute its capital plans in 2015 and 2016 and further capitalize on its current opportunities in the Delaware Basin
  - Net Debt/LTM EBITDA[(3)] of ~1.0x following closing
  - Liquidity of over $500 million including nothing drawn against credit facility as of closing



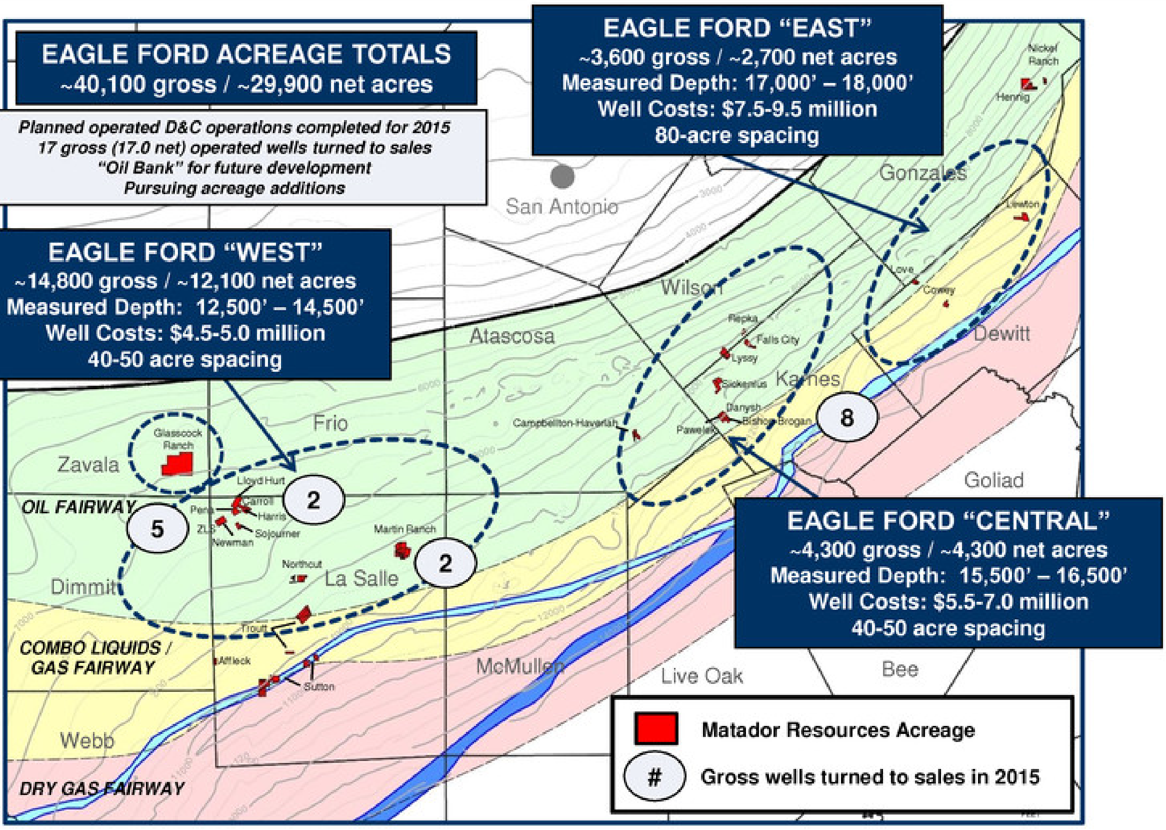
(1) A subsidiary of EnLink Midstream Partners, LP (NYSE: ENLK)
(2) Excluding customary purchase price adjustments.
(3) Net Debt at October 1, 2015. LTM Adjusted EBITDA at September 30, 2015. Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Appendix.

Matador
RESOURCES COMPANY

Eagle Ford

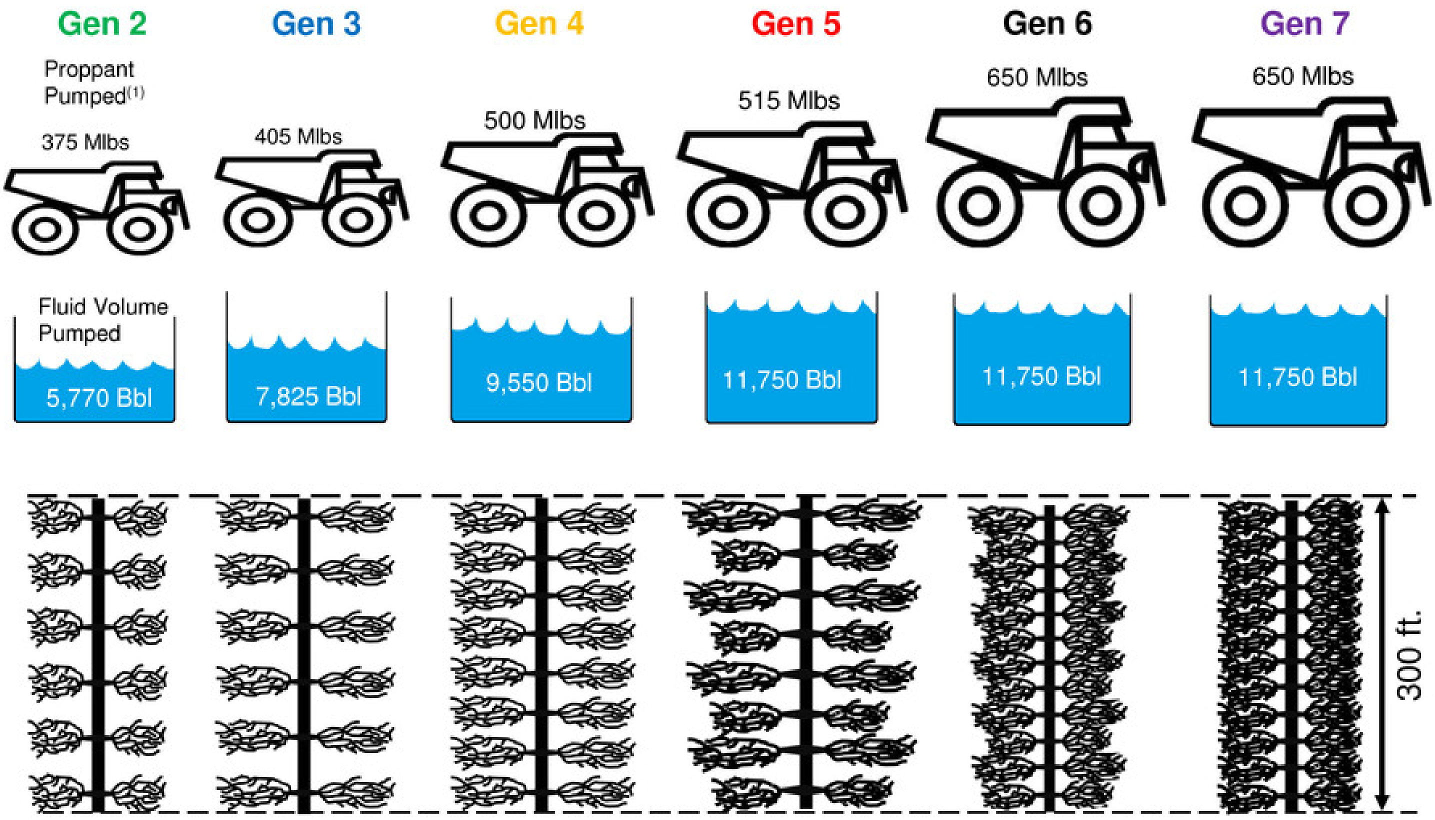
“Oil Bank”

Eagle Ford Is Still a Valuable Asset



Note: All acreage at November 4, 2015. Some tracts not shown on map.

Evolution of Matador Eagle Ford Frac Design



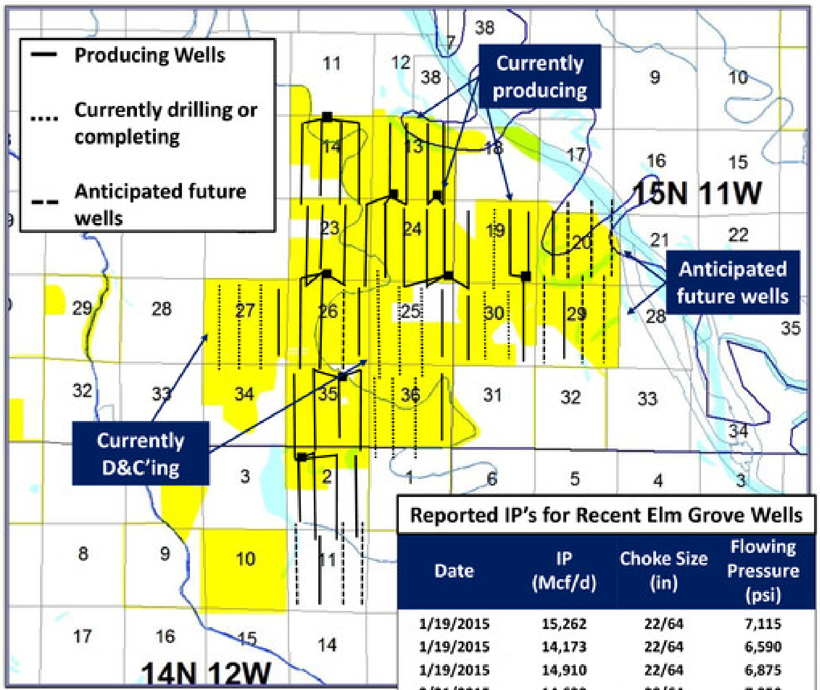
Note: Figure depicts proppant and fluid volume pumped per 300 ft. of horizontal wellbore.
(1) Mlbs = thousands of pounds of proppant pumped.



Haynesville Shale

"Gas Bank"

Haynesville – Chesapeake Elm Grove Operations



Reported IP's for Recent Elm Grove Wells

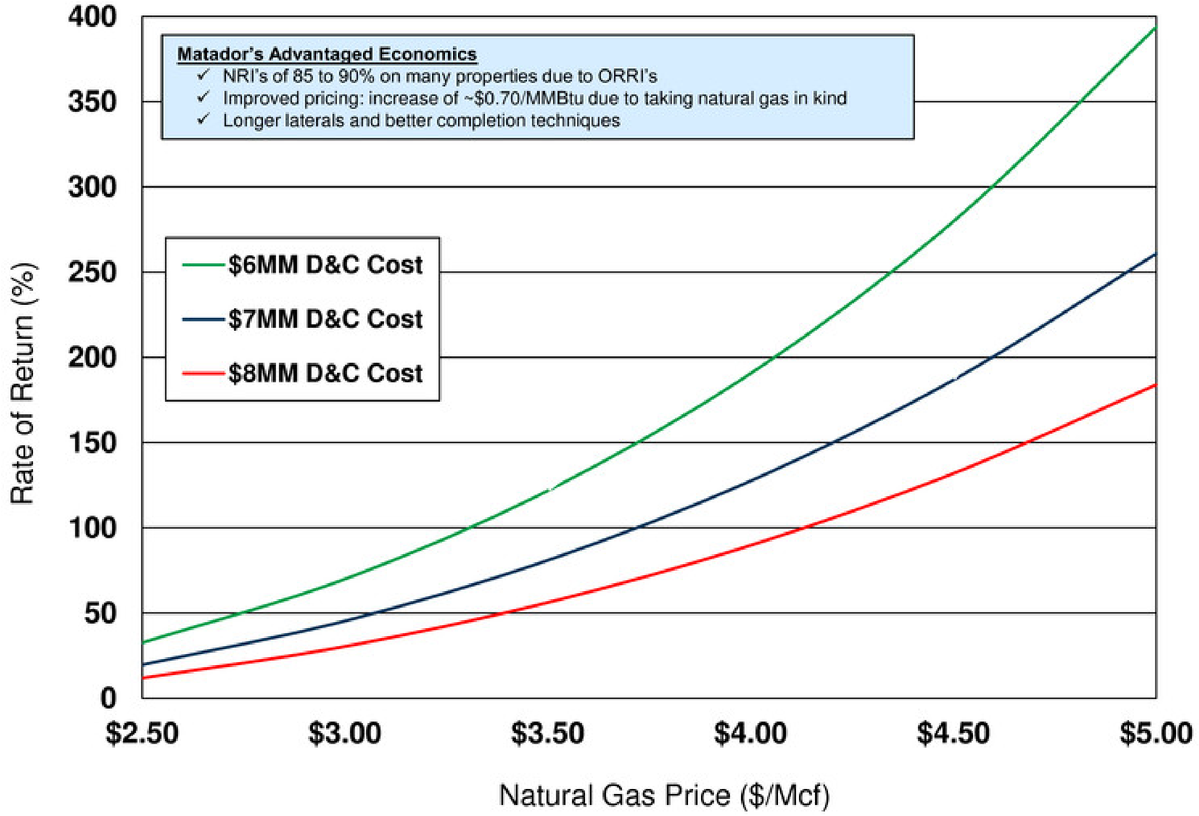
Date	IP (Mcf/d)	Choke Size (in)	Flowing Pressure (psi)
1/19/2015	15,262	22/64	7,115
1/19/2015	14,173	22/64	6,590
1/19/2015	14,910	22/64	6,875
2/21/2015	14,630	20/64	7,950
3/19/2015	15,506	22/64	6,720
3/19/2015	15,793	22/64	6,495
3/19/2015	14,661	20/64	6,255
7/11/2015	14,003	20/64	7,110
7/11/2015	12,613	20/64	6,260

Note: All acreage at November 4, 2015. Some tracts not shown on map.

2015 Haynesville Non-Op Program

- Estimated capital expenditures of ~$25 million for non-operated well participation interests
  - *Only ~6% of 2015 estimated capital expenditures*
  - *Originally budgeted ~$15 million for 2015*
- Haynesville & Cotton Valley average daily natural gas production up 137% to 51.3 MMcf/d in Q3 2015 from 21.6 MMcf/d in Q3 2014
- 31 gross (3.8 net) wells turned to sales throughout Tier 1 Haynesville in 2015
- Includes 18 gross (3.5 net) wells turned to sales on Elm Grove properties operated by Chesapeake in 2015 (shown on map at left)
- Chesapeake placed two additional wells on production in mid-July 2015
  - *Initial rates of ~12-14 MMcf/d of natural gas with drilling and completion costs of $7 to $7.5 million*
- Currently 12 gross (2.5 net) Chesapeake wells are in progress on our Elm Grove area

Economics of Tier 1 Wells (10 Bcf) Haynesville at Elm Grove



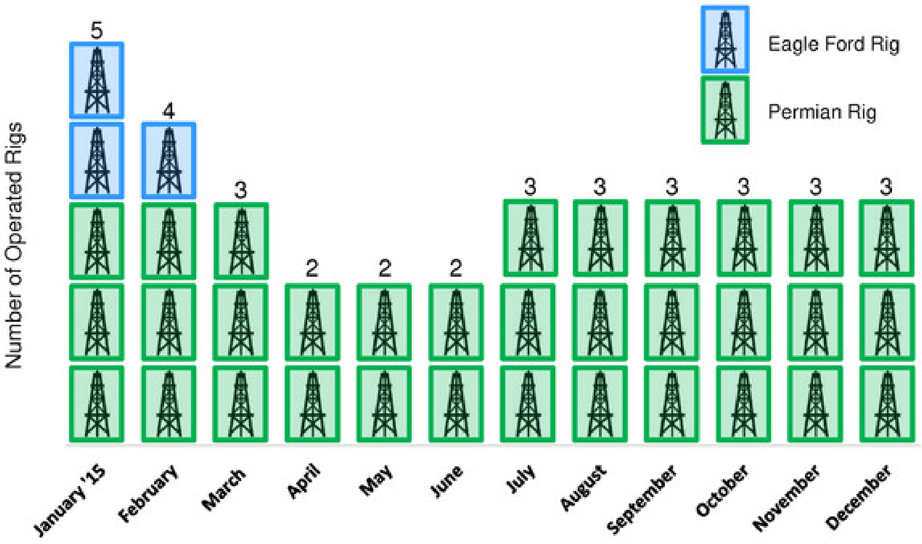
Note: Individual well economics only. Excludes costs prior to drilling (i.e. acquisition or acreage costs). Economics use a NRI / WI of 85% but actual interests vary. D&C cost = drilling and completion cost.



2015 Updated Capital Investment Plan

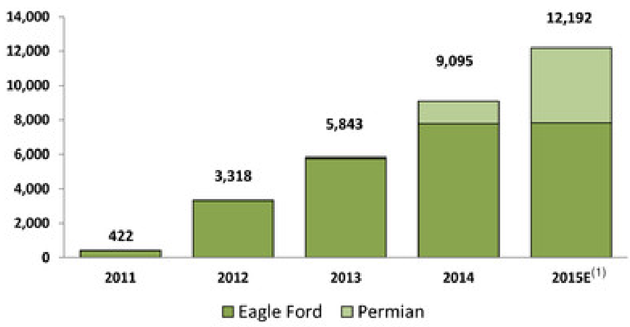
2015 Capital Investment Plan

- **At the beginning of 2015, reduced drilling program from 5 rigs to 2 rigs due to lower commodity prices, with primary focus on Permian (Delaware) Basin**
- **In late July 2015, took delivery of a third rig in the Delaware Basin**
- **Currently operating 3 rigs – all in the Delaware Basin**
  - *New-build rigs, latest technology and designed for simultaneous operations (Sim-Ops)*

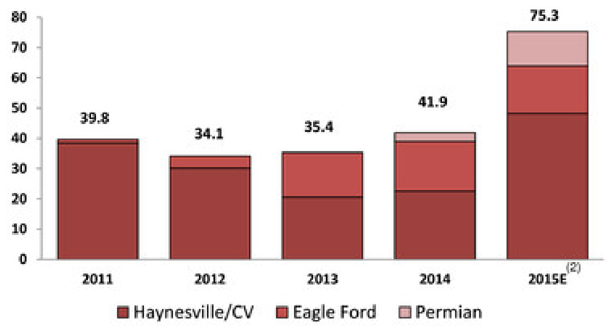


2015 Updated Production Estimates – Oil Equivalent Growth of ~54%(1)(2)

Oil Production Growth (Bbl/d)



Natural Gas Production Growth (MMcf/d)



2015E Oil Production

- *Estimated oil production of 4.4 to 4.5 million barrels*
  - 34% increase from 2014 despite decreased drilling
- *Average daily oil production of 12,200 Bbl/d, up from 9,100 Bbl/d in 2014*
  - Eagle Ford ~7,650 Bbl/d (63%)
  - Permian ~4,550 Bbl/d (37%)
- *Quarterly production peaked in Q2; Q4 2015 oil production up slightly as compared to Q4 2014 and Q1 2015*
  - Permian production increases 3.5-fold in 2015; Eagle Ford production relatively flat

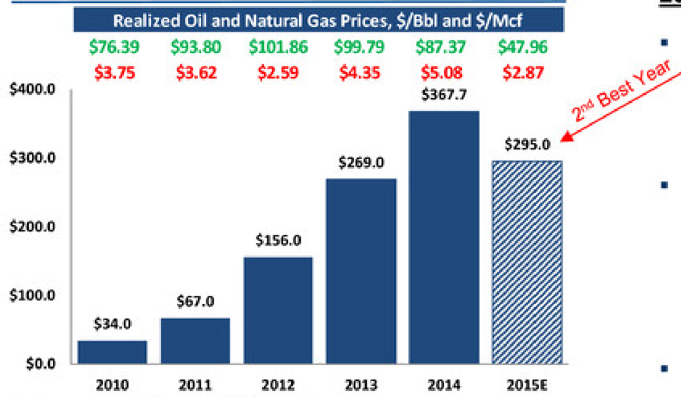
2015E Natural Gas Production

- *Estimated natural gas production of 27 to 28 Bcf*
  - 80% increase from 2014 despite decreased drilling; significant Haynesville impact
- *Average daily natural gas production of 75.3 MMcf/d, up from 41.9 MMcf/d in 2014*
  - Haynesville ~48.6 MMcf/d (65%)
  - Eagle Ford ~15.3 MMcf/d (20%)
  - Permian ~11.4 MMcf/d (15%)

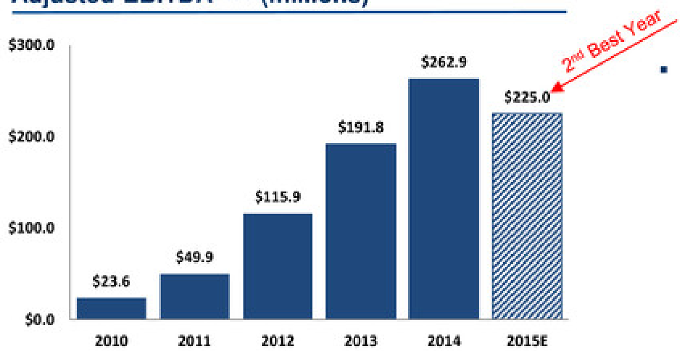
(1) At midpoint of 2015 total oil production guidance range as revised on August 4, 2015 to 4.4 to 4.5 million Bbl.
(2) At midpoint of 2015 total natural gas production guidance range as revised on November 4, 2015 to 27.0 to 28.0 Bcf.

2015 Updated Capital Investment Plan

Oil and Natural Gas Revenues[2] (millions)



Adjusted EBITDA[1][2] (millions)



2015E Revenues and Adjusted EBITDA[1][2]

- *Revenues and Adjusted EBITDA[1][2] growth significantly impacted by lower estimated 2015 realized oil and natural gas prices*
  - 2015E realized oil price of ~$48/Bbl vs ~$87/Bbl realized in 2014
  - 2015E realized natural gas price of ~$3.00/Mcf vs ~$5.00/Mcf in 2014
- *Estimated oil and natural gas revenues of $290 to $300 million*
  - Increased guidance on August 4, 2015 from $270 to $290 million
  - Decrease of ~20% from $367.7 million in 2014
  - Oil and natural gas hedges estimated to contribute $66 million in additional revenues in 2015, as compared to $5 million in 2014
- *Estimated Adjusted EBITDA[1][2] of $220 to $230 million*
  - Increased guidance on August 4, 2015 from $200 to $220 million
  - Decrease of ~14% from $262.9 million in 2014
- *~49% oil by volume, ~73% oil by revenue in 2015[2]; compared to ~57% oil by volume, ~79% oil by revenue in 2014*

(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net (loss) income and net cash provided by operating activities, see Appendix.
(2) Estimated 2015 oil and natural gas revenues, Adjusted EBITDA and production based upon the midpoint of 2015 guidance range as revised on August 4, 2015 and November 4, 2015. Prices for oil and natural gas used in these estimates were $50.00/Bbl (WTI oil price of $55.00/Bbl less $5.00/Bbl differentials and transportation costs) and $3.00/Mcf (NYMEX Henry Hub natural gas price assuming regional differentials and uplifts from natural gas processing roughly offset), respectively, for the period October through December 2015 and weighted average realized prices for the period January through September 2015 of $47.36/Bbl and $2.83/Mcf.



Appendix

Credit Agreement Status

- **Strong, supportive bank group led by Royal Bank of Canada**
- **Borrowing base reaffirmed on October 16, 2015 at $375 million based on June 30, 2015 reserves**
  - *Maturity of credit facility extended from December 2016 to October 2020*
  - *Bank group unanimous in supporting borrowing base affirmation and maturity extension*
- **No borrowings outstanding at November 4, 2015**
- **Net Debt/Adjusted EBITDA[(1)(2)] of 1.0x at October 1, 2015 following close of midstream sale**

TIER	Conforming Borrowing Base Utilization	LIBOR Margin	BASE Margin	Commitment Fee
Tier One	x < 25%	150 bps	50 bps	37.5 bps
Tier Two	25% < or = x < 50%	175 bps	75 bps	37.5 bps
Tier Three	50% < or = x < 75%	200 bps	100 bps	50 bps
Tier Four	75% < or = x < 90%	225 bps	125 bps	50 bps
Tier Five	90% < or = x < 100%	250 bps	150 bps	50 bps

- **Financial covenants**
  - *Maximum Total Debt to Adjusted EBITDA[(2)] Ratio of not more than 4.25:1.00*
  - *Under this covenant, Total Debt could be ~$1.1 billion based on LTM Adjusted EBITDA[(1)]*

(1) Net Debt at October 1, 2015 and LTM Adjusted EBITDA at Septermber 30, 2015.
(2) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA an a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Appendix.

Hedging Profile

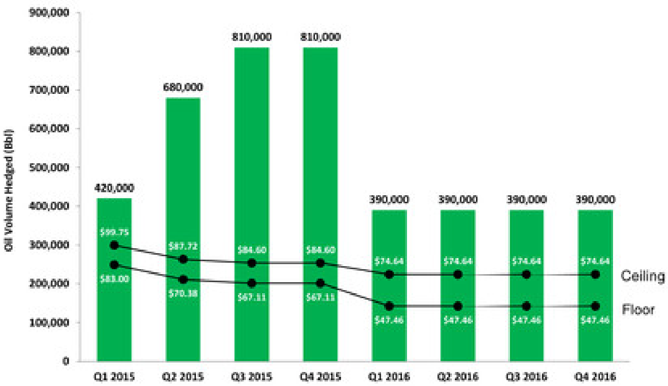
2015 Hedges[1]

- **Oil**: 0.5 million barrels of oil hedged for remainder of 2015 at weighted average floor and ceiling prices of $67/Bbl and $85/Bbl, respectively – Approximately 80% of oil hedged for remainder of 2015[2]
- **Natural Gas**: 2.6 Bcf of natural gas hedged for remainder of 2015 at weighted average floor and ceiling of $3.32/MMBtu and $4.02/MMBtu, respectively – Approximately 65% of natural gas hedged for remainder of 2015[2]
- **Natural Gas Liquids**: 0.6 million gallons of natural gas liquids hedged for remainder of 2015 at weighted average price of $1.02/gal
- *Oil and natural gas hedges estimated to add $66 million to projected oil and natural gas revenues in 2015*

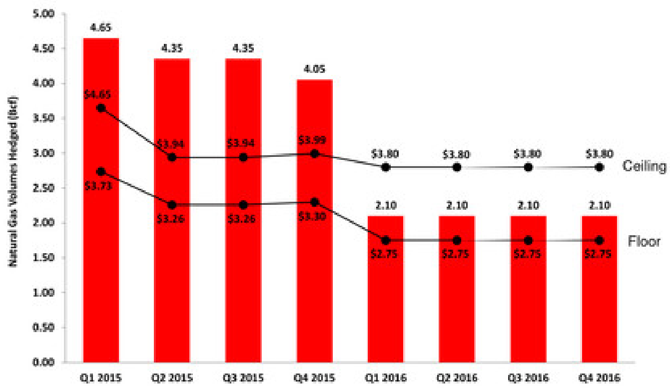
2016 Hedges

- **Oil**: 1.6 million Bbl of oil ($47/Bbl floor and $75/Bbl ceiling)
- **Natural Gas**: 8.4 Bcf of natural gas ($2.75/MMBtu floor and $3.80/MMBtu ceiling)

2015 Oil Hedges (Costless Collars)

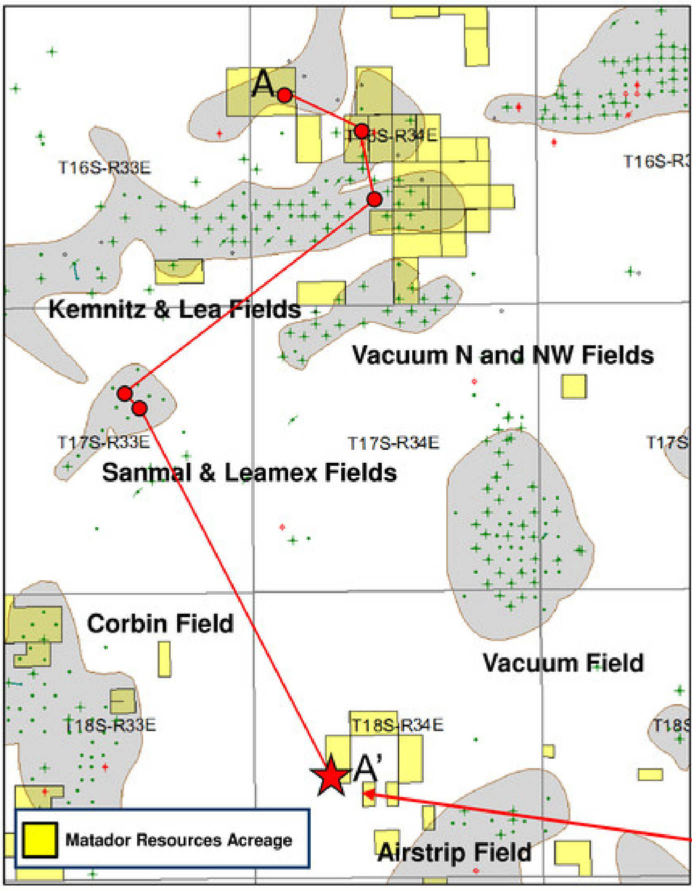


2015 Natural Gas Hedges (Costless Collars)



(1) At October 27, 2015.
(2) Based upon the midpoint of 2015 guidance range of 4.4 to 4.5 million Bbl of oil as revised upward on August 4, 2015 and 27.0 to 28.0 Bcf of natural gas as revised upward on November 4, 2015.

North Ranger-Twin Lakes Area Pennsylvanian/Wolfcamp Production Distribution



Townsend Field
166 wells
25 million Bbl, 49 Bcf

Kemnitz Field
94 wells
19 million Bbl, 78 Bcf

Sanmal and Leamex Fields
40 wells
3.4 million Bbl, 5.4 Bcf

Vacuum Field
135 wells
19 million Bbl, 48 Bcf

Corbin Field
77 wells
7.6 million Bbl, 18 Bcf

Airstrip Field
14 wells
0.26 million Bbl, 0.17 Bcf

Wolfcamp/ Upper Pennsylvanian Production

~74 million Bbl, 190 Bcf
~526 vertical wells

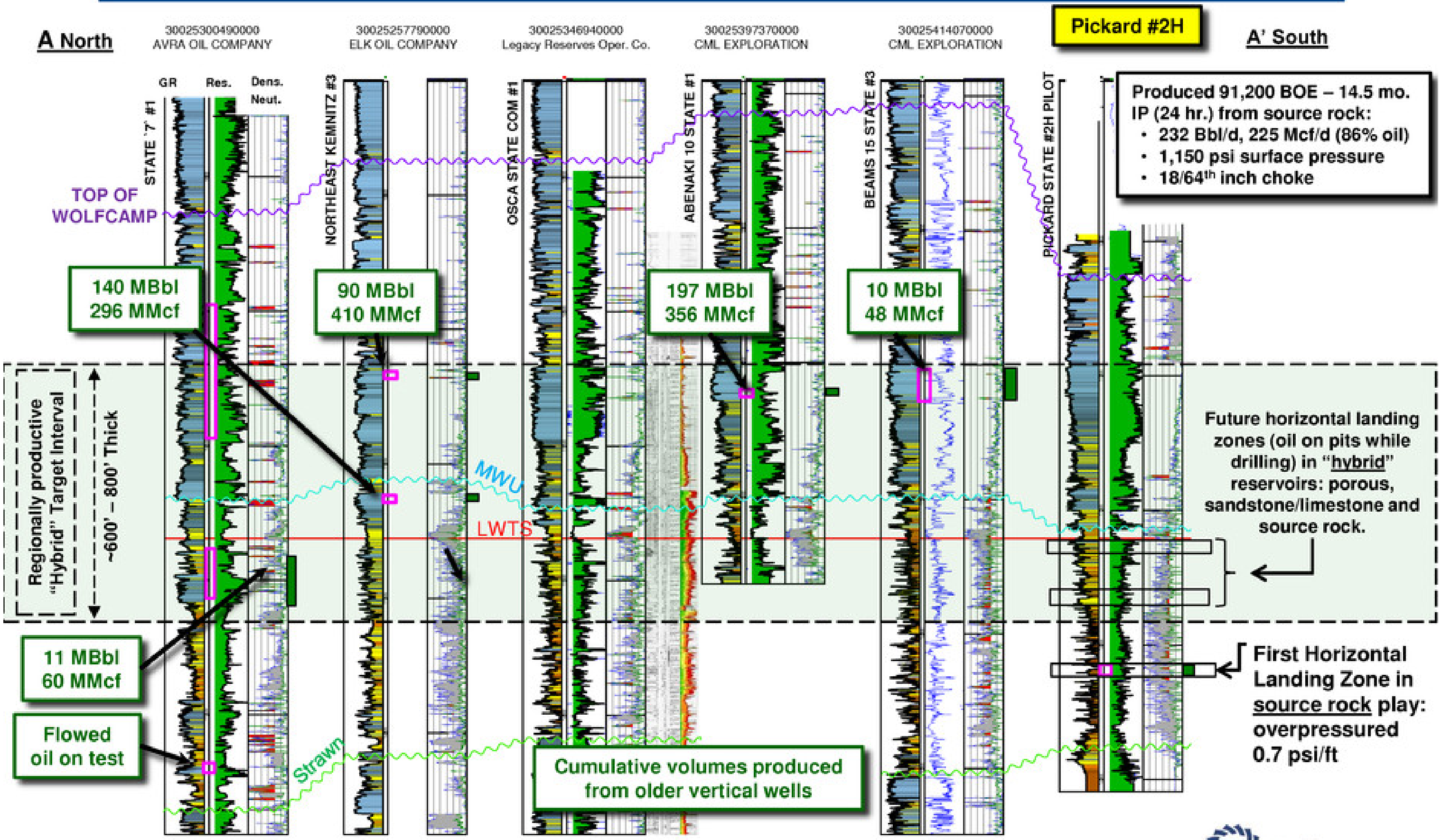
~141,000 Bbl per vertical well

MATADOR RESOURCES COMPANY
PICKARD STATE 20-18-34 #2H
Northern Delaware Horizontal Pennsylvanian/Wolfcamp Shale Test

Note: Information from public sources available as of November 2014.

Bcf = billions of cubic feet of natural gas.

Pennsylvanian/Wolfcamp "Hybrid" Production Target Interval



MMBbl = millions of barrels of oil.
Bcf = billions of cubic feet of natural gas.
MMcf = millions of cubic feet of natural gas.

Board of Directors – Expertise and Stewardship

Board Members	Professional Experience	Business Expertise
David M. Laney Lead Director	- Past Chairman, Amtrak Board of Directors - Former Partner, Jackson Walker LLP	Law and Investments
Reynald A. Baribault Director	- Vice President / Engineering and Co-founder, North Plains Energy, LLC - President and CEO, IPR Energy Partners, LLC - Former Vice President, Netherland, Sewell & Associates, Inc.	Oil and Gas Exploration & Development
Gregory E. Mitchell Director	- President and CEO, Toot'n Totum Food Stores	Petroleum Retailing
Dr. Steven W. Ohnimus Director	- Retired Vice President and General Manager, Unocal Indonesia	Oil and Gas Operations
Carlos M. Sepulveda, Jr. Director	- Executive Chairman of the Board, Triumph Bancorp, Inc. - Retired President and CEO, Interstate Battery System International, Inc. - Director and Audit Chair, Cinemark Holdings, Inc.	Business and Finance
Margaret B. Shannon Director	- Retired Vice President and General Counsel, BJ Services Co. - Former Partner, Andrews Kurth LLP	Law and Corporate Governance
Don C. Stephenson Director	- Retired Partner, Baker Botts L.L.P.	Law and Tax Strategy
George M. Yates Director	- Chairman & CEO of HEYCO Energy Group, Inc.	Oil and Gas Exploration & Development

Special Board Advisors – Expertise and Stewardship

Special Board Advisors	Professional Experience	Business Expertise
Ronney F. Coleman	- Retired President – North America, Archer - Former Vice President North America Pumping, BJ Services Co.	Oilfield Services
Marlan W. Downey	- Retired President, ARCO International - Former President, Shell Pecten International - Past President of American Association of Petroleum Geologists	Oil and Gas Exploration
John R. Gass	- VP, Eastern Hemisphere Operations, Nabors Drilling International Limited based in Dubai, UAE - Previously spent 28 years with Parker Drilling Company in various management roles	Oil and Gas Drilling
David F. Nicklin	- Retired Executive Director of Exploration, Matador Resources Company	Oil and Gas Exploration
Wade I. Massad	- Managing Member, Cleveland Capital Management, LLC - Formerly with KeyBanc Capital Markets and RBC Capital Markets	Capital Markets
Greg L. McMichael	- Retired Vice President and Group Leader – Energy Research of A.G. Edwards	Capital Markets
Dr. James D. Robertson	- Retired VP Exploration, Chief Geophysicist, ARCO International	Oil and Gas Exploration
Michael C. Ryan	- Partner, Berens Capital Management - Former Director, Matador Resources Company	International Business and Finance
W.J. "Jack" Sleeper, Jr.	- Retired President, DeGolyer and MacNaughton (Worldwide Petroleum Consultants)	Oil and Gas Executive Management

Proven Management Team – Experienced Leadership

Management Team	Background and Prior Affiliations	Industry Experience	Matador Experience
Joseph Wm. Foran Founder, Chairman and CEO	- Matador Petroleum Corporation, Foran Oil Company, James Cleo Thompson Jr.	35 years	Since Inception
Matthew V. Hairford President, Chair of Operating Committee	- Samson, Sonat, Conoco	31 years	Since 2004
David E. Lancaster EVP and CFO	- Schlumberger, S.A. Holditch & Associates, Inc., Diamond Shamrock	36 years	Since 2003
Craig N. Adams EVP – Land, Legal & Administration	- Baker Botts L.L.P., Thompson & Knight LLP	22 years	Since 2012
Van H. Singleton, II EVP – Land	- Southern Escrow & Title, VanBrannon & Associates	19 years	Since 2007
Bradley M. Robinson VP – Reservoir Engineering and CTO	- Schlumberger, S.A. Holditch & Associates, Inc., Marathon	38 years	Since Inception
Billy E. Goodwin VP – Drilling	- Samson, Conoco	31 years	Since 2010
G. Gregg Krug VP and Head of Marketing and Midstream	- Williams Companies, Samson, Unit Corporation	32 years	Since 2005
Matthew D. Spicer VP and General Manager of Midstream	- Matador Resources Company	2 years	Since 2014
Trent W. Green VP – Production	- HEYCO, Bass Enterprises, Schlumberger, S.A. Holditch & Associates, Inc., Amerada Hess	26 years	Since 2015
Robert T. Macalik VP and CAO	- Pioneer Natural Resources, PricewaterhouseCoopers (PwC)	13 years	Since 2015
Kathryn L. Wayne Controller and Treasurer	- Matador Petroleum Corporation, Mobil	31 years	Since Inception

Adjusted EBITDA Reconciliation

This investor presentation includes the non-GAAP financial measure of Adjusted EBITDA. Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. “GAAP” means Generally Accepted Accounting Principles in the United States of America. The Company believes Adjusted EBITDA helps it evaluate its operating performance and compare its results of operations from period to period without regard to its financing methods or capital structure. The Company defines Adjusted EBITDA as earnings before interest expense, income taxes, depletion, depreciation and amortization, accretion of asset retirement obligations, property impairments, unrealized derivative gains and losses, certain other non-cash items and non-cash stock-based compensation expense, and net gain or loss on asset sales and inventory impairment. Adjusted EBITDA is not a measure of net income (loss) or net cash provided by operating activities as determined by GAAP.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income (loss) or net cash provided by operating activities as determined in accordance with GAAP or as an indicator of the Company’s operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components of understanding and assessing a company’s financial performance, such as a company’s cost of capital and tax structure. Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner. The following table presents the calculation of Adjusted EBITDA and the reconciliation of Adjusted EBITDA to the GAAP financial measures of net income (loss) and net cash provided by operating activities, respectively, that are of a historical nature. Where references are pro forma, forward-looking or prospective in nature, and not based on historical fact, the table does not provide a reconciliation. The Company could not provide such reconciliations without undue hardship because such Adjusted EBITDA numbers are estimations, approximations and/or ranges. In addition, it would be difficult for the Company to present a detailed reconciliation on account of many unknown variables for the reconciling items.

Adjusted EBITDA Reconciliation

The following table presents our calculation of Adjusted EBITDA and reconciliation of Adjusted EBITDA to the GAAP financial measures of net income (loss) and net cash provided by operating activities, respectively.

(in thousands)	1Q 2011	2Q 2011	3Q 2011	4Q 2011	1Q 2012	2Q 2012	3Q 2012	4Q 2012	1Q 2013	2Q 2013	3Q 2013	4Q 2013
Unaudited Adjusted EBITDA reconciliation to Net (loss) Income:												
Net (loss) income	$ (27,596)	$ 7,153	$ 6,194	$ 3,941	$ 3,801	$ (6,676)	$ (9,197)	$ (21,188)	$ (15,505)	$ 25,119	$ 20,105	$ 15,374
Interest expense	106	184	171	222	308	1	144	549	1,271	1,609	2,038	768
Total income tax provision (benefit)	(6,906)	(46)	-	1,430	3,064	(3,713)	(593)	(188)	46	32	2,563	7,056
Depletion, depreciation and amortization	7,111	8,180	7,287	9,176	11,205	19,914	21,680	27,655	28,232	20,234	26,127	23,802
Accretion of asset retirement obligations	39	57	62	51	53	58	59	86	81	80	86	100
Full-cost ceiling impairment	35,673	-	-	-	-	33,205	3,596	26,674	21,230	-	-	-
Unrealized (gain) loss on derivatives	1,668	(332)	(2,870)	(3,604)	3,270	(15,114)	12,993	3,653	4,825	(7,526)	9,327	606
Stock-based compensation expense	53	128	1,234	991	(363)	191	(51)	363	492	1,032	1,239	1,134
Net loss on asset sales and inventory impairment	-	-	-	154	-	60	-	425	-	192	-	-
Adjusted EBITDA	**$ 10,148**	**$ 15,324**	**$ 12,078**	**$ 12,361**	**$ 21,338**	**$ 27,926**	**$ 28,631**	**$ 38,029**	**$ 40,672**	**$ 40,772**	**$ 61,485**	**$ 48,840**

(in thousands)	1Q 2011	2Q 2011	3Q 2011	4Q 2011	1Q 2012	2Q 2012	3Q 2012	4Q 2012	1Q 2013	2Q 2013	3Q 2013	4Q 2013
Unaudited Adjusted EBITDA reconciliation to Net Cash Provided by Operating Activities:												
Net cash provided by operating activities	$ 12,732	$ 6,799	$ 14,912	$ 27,425	$ 5,110	$ 46,416	$ 28,799	$ 43,903	$ 32,229	$ 51,684	$ 43,280	$ 52,278
Net change in operating assets and liabilities	(2,690)	8,386	(3,004)	(15,286)	15,920	(18,491)	(500)	(6,235)	7,126	(12,553)	15,265	(3,630)
Interest expense, net of non-cash portion	106	184	171	222	308	1	144	549	1,271	1,609	2,038	768
Current income tax (benefit) provision	-	(45)	(1)	-	-	-	188	(188)	46	32	902	(576)
Net (income) loss attributable to non-controlling interest in subsidiary	-	-	-	-	-	-	-	-	-	-	-	-
Adjusted EBITDA	**$ 10,148**	**$ 15,324**	**$ 12,078**	**$ 12,361**	**$ 21,338**	**$ 27,926**	**$ 28,631**	**$ 38,029**	**$ 40,672**	**$ 40,772**	**$ 61,485**	**$ 48,840**

(in thousands)	1Q 2014	2Q 2014	3Q 2014	4Q 2014	1Q 2015	2Q 2015	3Q 2015
Unaudited Adjusted EBITDA reconciliation to Net (loss) Income:							
Net (loss) income	$ 16,363	$ 18,226	$ 29,619	$ 46,563	$ (50,234)	$ (157,091)	$ (242,059)
Interest expense	1,396	1,616	673	1,649	2,070	5,869	7,229
Total income tax provision (benefit)	9,536	10,634	16,504	27,701	(26,390)	(89,350)	(33,305)
Depletion, depreciation and amortization	24,030	31,797	35,143	43,767	46,470	51,768	45,237
Accretion of asset retirement obligations	117	123	130	134	112	132	182
Full-cost ceiling impairment	-	-	-	-	67,127	229,026	285,721
Unrealized (gain) loss on derivatives	3,108	5,234	(16,293)	(50,351)	8,557	23,532	(6,733)
Stock-based compensation expense	1,795	1,834	1,038	857	2,337	2,794	1,755
Net loss on asset sales and inventory impairment	-	-	-	-	97	-	-
Adjusted EBITDA	**$ 56,345**	**$ 69,464**	**$ 66,814**	**$ 70,320**	**$ 50,146**	**$ 66,680**	**$ 58,027**

(in thousands)	1Q 2014	2Q 2014	3Q 2014	4Q 2014	1Q 2015	2Q 2015	3Q 2015
Unaudited Adjusted EBITDA reconciliation to Net Cash Provided by Operating Activities:							
Net cash provided by operating activities	$ 31,945	$ 81,530	$ 66,883	$ 71,123	$ 93,346	$ 20,043	$ 72,535
Net change in operating assets and liabilities	21,729	(15,221)	(586)	56	(45,234)	40,843	(20,846)
Interest expense, net of non-cash portion	1,396	1,616	673	1,649	2,070	5,869	6,678
Current income tax (benefit) provision	1,275	1,539	(156)	(2,525)	-	-	(295)
Net (income) loss attributable to non-controlling interest in subsidiary	-	-	-	17	(36)	(75)	(45)
Adjusted EBITDA	**$ 56,345**	**$ 69,464**	**$ 66,814**	**$ 70,320**	**$ 50,146**	**$ 66,680**	**$ 58,027**

Adjusted EBITDA Reconciliation

The following table presents our calculation of Adjusted EBITDA and reconciliation of Adjusted EBITDA to the GAAP financial measures of net income (loss) and net cash provided by operating activities, respectively.

	Year Ended December 31,							LTM at		Nine Months Ended	
(In thousands)	2008	2009	2010	2011	2012	2013	2014	6/30/2013	9/30/2015	9/30/2014	9/30/2015
Unaudited Adjusted EBITDA reconciliation to Net Income (Loss):											
Net income (loss)	$103,878	($14,425)	$6,377	($10,309)	($33,261)	$45,094	$110,771	($20,771)	($402,821)	$64,208	($449,384)
Interest expense	-	-	3	683	1,002	5,687	5,334	3,574	16,817	3,685	15,168
Total income tax (benefit) provision	20,023	(9,925)	3,521	(5,521)	(1,430)	9,697	64,375	(703)	(121,344)	36,675	(149,045)
Depletion, depreciation and amortization	12,127	10,743	15,596	31,754	80,454	98,395	134,737	97,801	187,242	90,970	143,477
Accretion of asset retirement obligations	92	137	155	209	256	348	504	307	560	371	427
Full-cost ceiling impairment	22,195	25,244	-	35,673	63,475	21,229	-	51,499	581,874	-	581,874
Unrealized loss (gain) on derivatives	(3,592)	2,375	(3,139)	(5,138)	4,802	7,232	(58,302)	13,945	(24,995)	(7,950)	25,356
Stock-based compensation expense	665	656	898	2,406	140	3,897	5,524	1,836	7,743	4,665	6,886
Net (gain) loss on asset sales and inventory impairment	(136,977)	379	224	154	485	192	-	617	97	-	97
Adjusted EBITDA	**$18,411**	**$15,184**	**$23,635**	**$49,911**	**$115,923**	**$191,771**	**$262,943**	**$148,105**	**$245,173**	**$192,624**	**$174,856**

	Year Ended December 31,							LTM at		Nine Months Ended	
(In thousands)	2008	2009	2010	2011	2012	2013	2014	6/30/2013	9/30/2015	9/30/2014	9/30/2015
Unaudited Adjusted EBITDA reconciliation to Net Cash Provided by Operating Activities:											
Net cash provided by operating activities	$25,851	$1,791	$27,273	$61,868	$124,228	$179,470	$251,481	$156,614	$257,047	$180,359	$185,924
Net change in operating assets and liabilities	(17,888)	15,717	(2,230)	(12,594)	(9,307)	6,210	5,978	(12,161)	(25,181)	5,922	(25,234)
Interest expense, net of non-cash portion	-	-	3	683	1,002	5,687	5,334	3,574	16,266	3,685	14,617
Current income tax (benefit) provision	$10,448	($2,324)	(1,411)	(46)	-	404	133	78	(2,820)	2,658	(295)
Net (income) loss attributable to non-controlling interest in subsidiary	-	-	-	-	-	-	17	-	(139)	-	($156)
Adjusted EBITDA	**$18,411**	**$15,184**	**$23,635**	**$49,911**	**$115,923**	**$191,771**	**$262,943**	**$148,105**	**$245,173**	**$192,624**	**$174,856**

Note: LTM is last 12 months.

Adjusted Net Income and Adjusted Earnings Per Share Reconciliation

Adjusted net income and adjusted earnings per common share are non-GAAP financial measures and are measured as net income (loss) attributable to Matador Resources Company shareholders, adjusted for dollar and per share impact of certain items, including unrealized gains or losses on derivatives, the impact of full cost-ceiling impairment charges, if any, and nonrecurring transaction costs for certain acquisitions along with the related tax effect for all periods. This non-GAAP financial information is provided as additional information for investors and is not in accordance with, or an alternative to, GAAP financial measures. Additionally, these non-GAAP financial measures may be different than similar measures used by other companies. The Company believes the presentation of adjusted net income and adjusted earnings per diluted common share provides useful information to investors, as it provides them an additional relevant comparison of the Company's performance across periods and to the performance of the Company's peers. In addition, these non-GAAP financial measures reflect adjustments for items of income and expense that are often excluded by securities analysts and other users of the Company's financial statements in evaluating the Company's performance. The table below reconciles adjusted net income and adjusted earnings per diluted common share to their most directly comparable GAAP measure of net income (loss) attributable to Matador Resources Company shareholders.

	Three Months Ended		Nine Months Ended
(In thousands, except per share data)	**6/30/2015**	**9/30/2015**	**9/30/2015**
Unaudited Adjusted Net Income and Adjusted Earnings Per Share Reconcilliation to Net Loss:			
Net loss attributable to Matador Resources Company shareholders	($157,091)	($242,059)	($449,384)
Total income tax benefit	(89,350)	(33,305)	(149,045)
Loss attributable to Matador Resources Company shareholders before taxes	(246,441)	(275,364)	(598,429)
Less non-recurring and unrealized charges to net income before taxes:			
Full-cost ceiling impairment	229,026	285,721	581,874
Unrealized (gain) loss on derivatives	23,532	(6,733)	25,356
Non-recurring transaction costs associated with the HEYCO merger	275	-	2,510
Adjusted income attributable to Matador Resources Company shareholders before taxes	6,392	3,624	11,311
Income tax expense	1,915	1,067	3,332
Adjusted net income attributable to Matador Resources Company shareholders	**$4,477**	**$2,557**	**$7,979**
Basic weighted average shares outstanding, without participating securities	82,938	84,685	80,481
Dilutive effect of participating securities	706	756	743
Weighted average shares outstanding, including participating securities - basic	83,644	85,441	81,224
Dilutive effect of options, restricted stock units and preferred shares	627	167	703
Weighted average common shares outstanding - diluted	84,271	85,608	81,927
Adjusted earnings per share attributable to Matador Resources Company shareholders (non-GAAP)			
Basic	**$0.05**	**$0.03**	**$0.10**
Diluted	**$0.05**	**$0.03**	**$0.10**

Cash Operating Expenses per BOE Reconciliation

Cash operating expenses per BOE is a non-GAAP financial measure and is measured as operating expenses per BOE excluding non-cash DD&A expense, non-cash stock-based compensation expense and non-recurring transaction costs associated with the HEYCO merger, each as adjusted on a per BOE basis. This non-GAAP financial information is provided as additional information for investors and is not in accordance with, or an alternative to, GAAP financial measures. Additionally, this non-GAAP financial measure may be different than similar measures used by other companies. The Company believes the presentation of cash operating expenses per BOE provides useful information to investors and other users of the Company's financial information in evaluating the Company's operating performance. The following table reconciles cash operating expenses per BOE (non-GAAP) to operating expenses per BOE (GAAP).

	Three Months Ended			Nine Months Ended	
	9/30/2014	6/30/2015	9/30/2015	9/30/2014	9/30/2015
Cash Operating Expenses per BOE Reconciliation to Operating Expenses per BOE:					
Total operating expenses (per BOE)(1)	$44.27	$37.16	$33.92	$43.70	$36.23
Depletion, depreciation and amortization expenses (per BOE)	(23.73)	(21.39)	(18.81)	(23.00)	(20.67)
Non-cash stock-based compensation expense (per BOE)	(0.70)	(1.16)	(0.73)	(1.18)	(0.99)
Non-recurring transaction costs (per BOE)	-	(0.11)	-	-	(0.36)
Cash operating expenses (per BOE)	**$19.84**	**$14.50**	**$14.38**	**$19.52**	**$14.21**

(1) Total does not include the impact of full-cost ceiling impairments or immaterial accretion expenses.

PV-10 Reconciliation

PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of the Company's properties. Matador and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies' properties without regard to the specific tax characteristics of such entities. PV-10 may be reconciled to the Standardized Measure of discounted future net cash flows at such dates by reducing PV-10 by the discounted future income taxes associated with such reserves.

	At September 30, 2011	At June 30, 2013	At December 31, 2013	At December 31, 2014	At September 30, 2015
PV-10 *(in millions)*	$155.2	$522.3	$655.2	$1,043.4	$692.7
Discounted Future Income Taxes *(in millions)*	$(11.8)	$(44.7)	$(76.5)	$(130.1)	$(18.9)
Standardized Measure *(in millions)*	$143.4	$477.6	$578.7	$913.3	$673.8