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) May 20, 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 the 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: May 20, 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

MATADOR RESOURCES COMPANY

Investor Presentation

May 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

Post – IPO

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

Assembling Permian acreage position; begin delineation drilling program

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

(1) Tom Brown acquired by Encana in 2004.

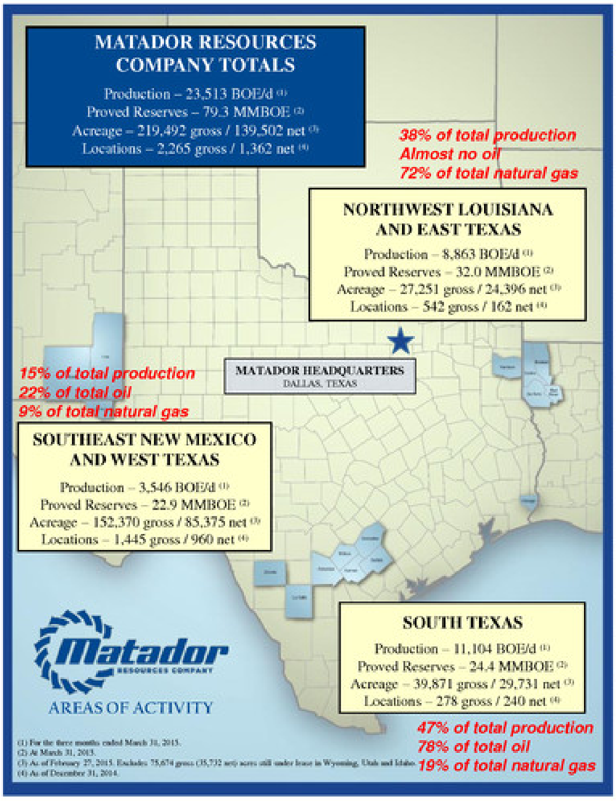
Company Overview

Exchange: Ticker	NYSE: MTDR
Shares Outstanding(1)	85.4 million common shares
Share Price(2)	$26.37/share
Market Capitalization(1)(2)	$2.3 billion

	2014 Actual	*2015 Guidance*	*% Change*
Capital Spending	$610 million	$350 million(3)	- 43%
Total Oil Production	3.3 million Bbl	4.1 to 4.3 million Bbl(4)	+ 27%
Total Natural Gas Production	15.3 Bcf	24.0 to 26.0 Bcf(3)	+ 63%
Oil and Natural Gas Revenues	$367.7 million	$270 to $290 million(5)	- 24%
Adjusted EBITDA(6)	$262.9 million	$200 to $220 million(5)	- 20%

(1) Shares outstanding as reported in the Form 10-Q for the quarter ended March 31, 2015.
(2) As of May 18, 2015.
(3) As reaffirmed on May 6, 2015; does not include capital expenditures associated with the HEYCO transaction or two proposed associated joint ventures.
(4) The Company raised its 2015 oil production guidance from 4.0 to 4.2 million Bbl to 4.1 to 4.3 million Bbl on May 6, 2015.
(5) Estimated 2015 oil and natural gas revenues and Adjusted EBITDA based on production guidance range as provided on May 6, 2015. Estimated average realized 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 April through December 2015.
(6) 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 – Q1 2015(2)	**23,513 BOE/d**	+98%**
Oil (% total)	11,206 Bbl/d (48%)	
Natural Gas (% total)	73.8 MMcf/d (52%)	
Proved Reserves @ 3/31/2015	**79.3 million BOE**	+45%**
% Proved Developed	42%	
% Oil	41%	
2015E CapEx(3)	**$350 million**	
% Permian	~70%	
% Oil and Liquids	~96%	
Gross Acreage(4)	**219,492 acres**	
Net Acreage(4)	**139,502 acres**	+43%*
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 December 31, 2013.
**Note: Represents increase as compared to each respective figure at or for the three months ended March 31, 2014.
(1) Market capitalization based on closing share price as of May 14, 2015 and shares outstanding as reported in the Form 10-Q for the quarter ended March 31, 2015.
(2) Average daily production for the three months ended March 31, 2015.
(3) 2015 estimated capital expenditures for operations only; does not include capital expenditures associated with the HEYCO transaction or two proposed associated joint ventures.
(4) Presented as of February 27, 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.

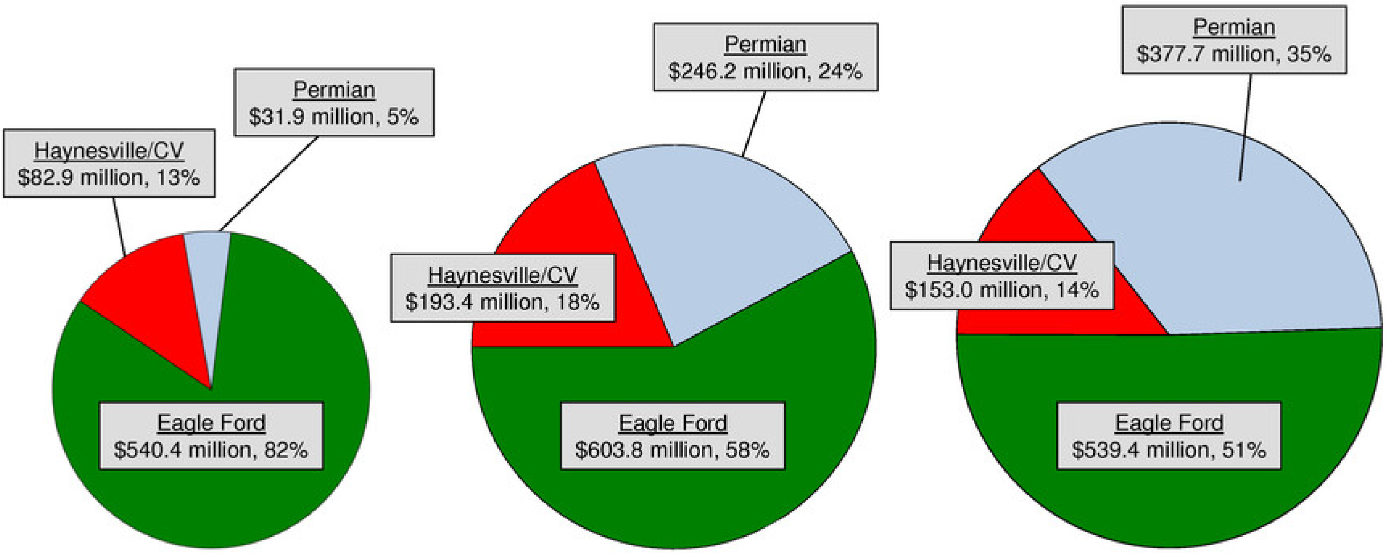
Matador's Execution History – "Doing What We Say"

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]		March 31, 2015[10]
Oil Production	▪ 414 Bbl/d of oil ▪ 6% oil	12x growth in oil production	▪ 4,916 Bbl/d of oil ▪ 46% oil	128% growth in oil production	▪ 11,206 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	2.7x growth in oil reserves	▪ 79 MMBOE ▪ 32.5 MMBbl of oil ▪ 41% 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	Doubled PV-10	▪ $1.07 billion ▪ 50% of PV-10 in Eagle Ford ▪ PV-10 / debt of 2.5x
LTM Adjusted EBITDA[3]	▪ $50 million[4]	~200% growth	▪ $148 million	74% growth	▪ $257 million
Leverage[5]	▪ 1.7x	Remained conservative	▪ 1.7x	Improved	▪ 1.6x[11]
Acreage	▪ ~7,500 net Permian acres	Over 4x growth in Permian acres	▪ ~32,900 net Permian acres	2.6x growth in Permian acres	▪ ~85,400 net Permian acres[12]
Enterprise Value ("EV")[6]	▪ $0.65 billion[7]	Doubled EV	▪ $1.2 billion[9]	117% EV 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) For the twelve months ended December 31, 2011.
(5) Calculated as debt divided by LTM Adjusted EBITDA.
(6) Enterprise value equals market capitalization plus borrowings under our revolving credit agreement.
(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 March 31, 2015.
(11) Pro forma at March 31, 2015 after giving effect to the April 2015 offering of $400 million of Senior Notes and the April 2015 equity offering.
(12) As of February 27, 2015.
(13) Market capitalization based on closing share price as of May 14, 2015 and shares outstanding as reported in the Form 10-Q for the quarter ended March 31, 2015 filed.

Oil and Natural Gas Proved Reserves and PV-10[1] Growth 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

March 31, 2015

Total proved reserves = 79.3 million BOE

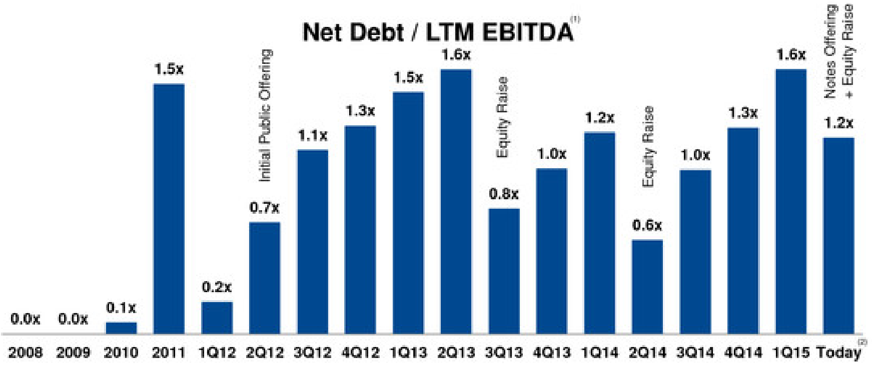
PV-10[1]: $1,070.1 million
$79.21 oil / $3.88 natural gas

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

Financial Strategy

- **Be prudent with our investors' capital**
  - *Reduced drilling program from 5 rigs at YE2014 to 2 rigs currently due to lower commodity prices, with primary focus on Permian (Delaware) Basin*
  - *2015E CapEx highest in Q1 2015 but falls quickly thereafter – second half of 2015 close to cash flow at $55 per Bbl oil price*
  - *Proven and experienced management team and Board of Directors have demonstrated ability to manage through industry cycles*

- **Committed to maintaining strong, conservative balance sheet**
  - *Strong, conservative financial position with Net Debt/LTM Adjusted EBITDA[(1)(2)] of 1.2x*
  - *Preserve and enhance liquidity through April 2015 equity and Senior Notes offerings – substantial liquidity to execute planned drilling program*
  - *Target leverage at less than 2.0x Adjusted EBITDA[(1)], though profile typically more conservative*



- **Hedging program designed to protect cash flows and provide stability to drilling program**

- **Flexibility to manage liquidity and maintain conservative balance sheet**
  - *Most drilling is operated; low level of non-operated drilling obligations; few long-term drilling rig or service contract commitments*
  - *Expectations of increased cash flow and borrowing base increases as proved reserves are added*

(1) 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.
(2) LTM Adjusted EBITDA at March 31, 2015 and Net Debt at May 6, 2015.

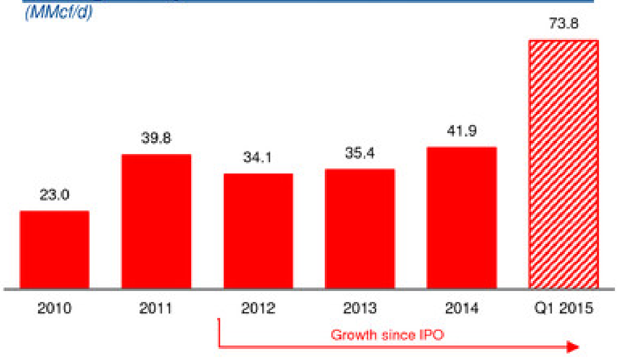
Matador's Continued Production Growth

Average Daily Oil Production

(Bbl/d)

Average Daily Natural Gas Production

(MMcf/d)



Average Daily Total Production

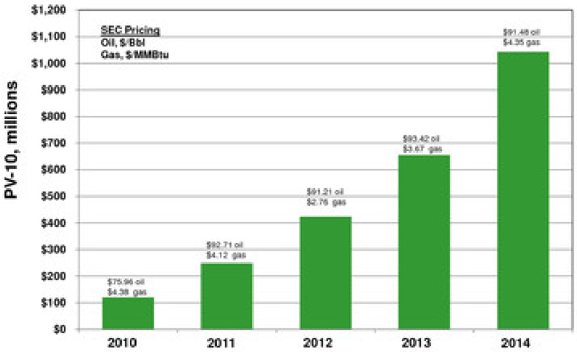
(MBOE/d)

Oil Production Mix

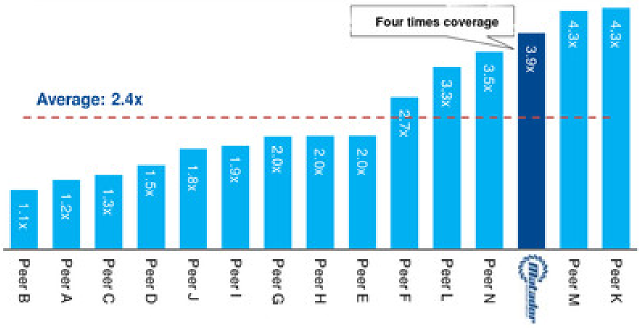
(% of Average Daily Production)

Matador Has Experienced Strong Reserves and Adjusted EBITDA[1] Growth in Recent Years

Growth in PV-10[2] Over Last 5 Years



Proved PV-10[2] / YE 2014 Net Debt

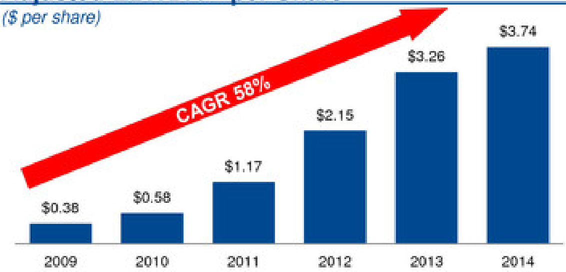


PV-10[2] per Share

($ per share)

Adjusted EBITDA[1] per Share

($ per share)



(in thousands)	Shares[3]	PV-10[2]	Adj. EBITDA[1]
2009	40,123	$70,359	$15,184
2010	41,037	$119,869	$23,635
2011	42,718	$248,700	$49,911
2012	53,957	$423,200	$115,923
2013	58,777	$655,200	$191,771
2014	70,229	$1,043,400	$262,943

Note: "Proved PV-10/YE 2014 Net Debt" analysis prepared by RBC Capital Markets. Average does not include Matador. Matador figures are pro forma at December 31, 2014 after giving effect to the recent HEYCO Merger, the April 2015 offering of $400 million of Senior Notes and the April 2015 equity offering. Peer group chosen by RBC includes SFY, CRK, ROSE, SN, PVA, AREX, GDP, CWEI, JONE, BCEI, CRZO, PE, RSPP, FANG. Average does not include Matador. Source: Company filings, metrics pro forma for announced acquisitions. Market data as of April 2, 2015.

(1) 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.
(2) PV-10 is a non-GAAP financial measure. For a reconciliation of Standardized Measure (GAAP) to PV-10 (non-GAAP), see Appendix.
(3) Weighted Average Basic Shares Outstanding.

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]	-59.5%	~190	?	**MTDR and HEYCO join forces**

(1) Includes Matador Resources Company, Foran Oil and Matador Petroleum Corporation and other predecessor entities.
(2) Length of oil price decline using high of $107.26 on June 20, 2014 and low of $43.46 on March 17, 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 production by ~43%, with oil production expected to increase to ~4.2 million barrels and natural gas production expected to increase to ~25 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*

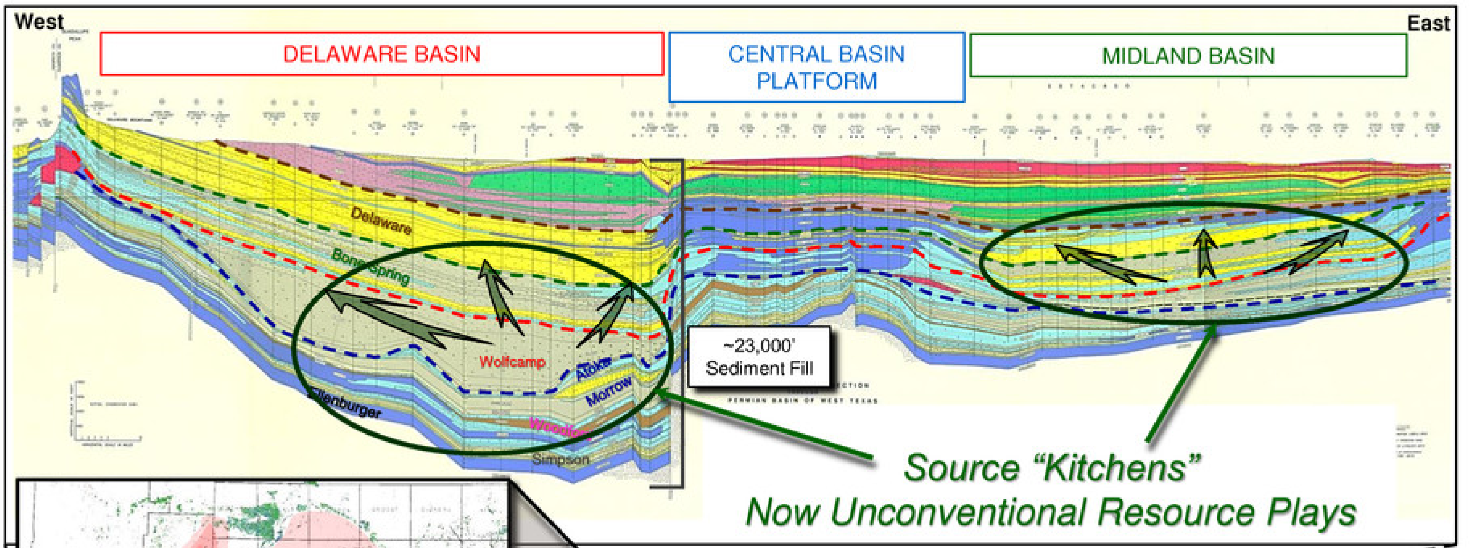
(1) Includes Matador Resources Company and its predecessor entities.

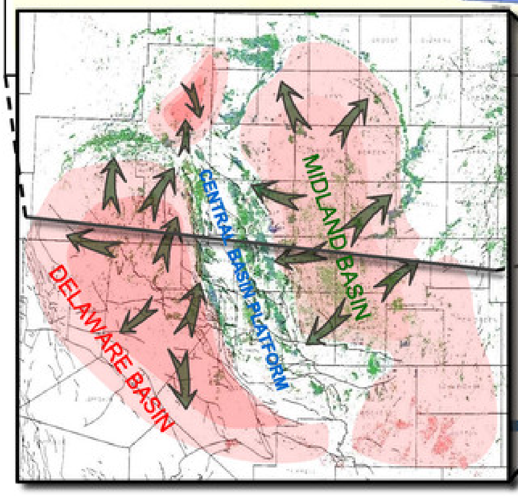


Permian Basin

Southeast New Mexico and West Texas

Delaware Basin – A "World Class" Hydrocarbon System

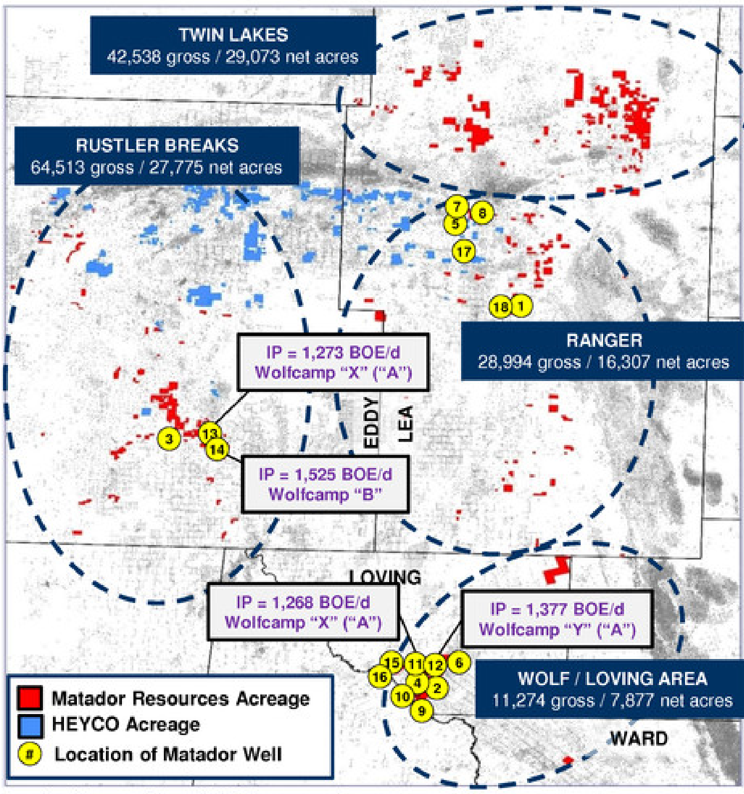




- 70,000 square mile area
- Up to 25,000 feet of multiple, stacked, petroleum systems
- Extensive drilling, coring and geological studies since 1920s
- >1,500 conventional reservoirs with cumulative production >1.0 million Bbl each
- Cumulative production from 1,500 conventional reservoirs, as of year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

(1) Dutton et al, AAPG 2005

Permian Basin Acreage Position and Recent Test Results



Note: All acreage at February 27, 2015. Some tracts not shown on map.
(1) As of April 28, 2015.
(2) Formerly the Ranger 33 State Com #1H.
(3) Formerly the Rustler Breaks 12-24-27 #1H.
(4) Formerly the Pickard State 20-18-34 #1H.
(5) Estimated ultimate recovery, thousands of barrels of oil equivalent.
(6) Flowing surface pressure.

Successful performance of initial horizontal wells(1)

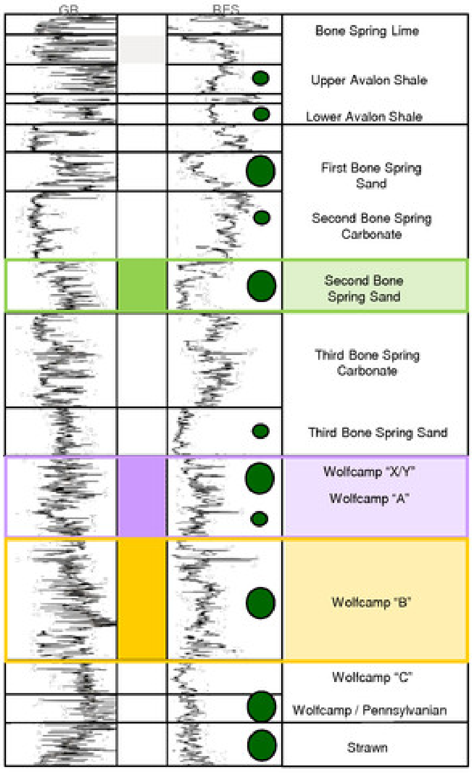
	Well	Cumulative Production			Recent Production		
		Months	Oil Eq. (BOE)	% Oil	Oil (Bbl/d)	Natural Gas (Mcf/d)	EUR(2) (MBOE)
1	Ranger State 33-20S-35E RN #121H(3) (2nd Bone Spring)	17	197,000	91%	250	200	650
2	Dorothy White #1H (Wolfcamp "A"/"X")	15.5	358,000	67%	400	1,100	1,050
3	Rustler Breaks 12-24S-27E #224H(4) (Wolfcamp "B")	12	170,000	42%	125	1,200	700
4	Norton Schaub #1H (Wolfcamp "A"/"X")	9	180,000	72%	400	1,200	750
5	Pickard State 20-18S-34E RN #121H(5) (2nd Bone Spring)	9	100,000	93%	250	120	500
6	Johnson 44-02S-B53 #204H (Wolfcamp "A"/"X")	7	179,000	64%	350	1,100	900
7	Pickard State 20-18-34 #2H (Wolfcamp "D")	10	47,500	85%	105	150	200
8	Jim Rolfe 22-18-34 RN State #131Y (3rd Bone Spring)	6.5	16,100	73%	40	100	65

Recent activity and 24-hour initial potential tests

	Well	Date	Oil Eq. (BOE/d)	Oil (Bbl/d)	Natural Gas (Mcf/d)	% Oil	P_i(6) (psi)	Choke (inches)
9	Arno #1H (Wolfcamp "A"/"X")	Mid-Sept 2014	1,110	300	4,900	27%	4,100	26/64th
10	Norton Schaub 84-TTT-B33 WF #2010H (Wolfcamp "A")	Late Dec 2014	875	608	1,600	69%	2,600	28/64th
11	Barnett 90-TTT-B01-WF #201H (Wolfcamp "A"/"X")	Early Mar 2015	1,268	720	3,300	57%	3,225	26/64th
12	Barnett 90-TTT-B01-WF #205H (Wolfcamp "A"/"Y")	Mid-Feb 2015	1,377	738	3,800	54%	3,475	26/64th
13	Guitar 10-24S-28E RB #202H (Wolfcamp "A"/"X")	Early Apr 2015	1,273	1,008	1,600	79%	2,190	26/64th
14	Tiger 14-24S-28E RB #224H (Wolfcamp "B")	Early Apr 2015	1,525	650	5,300	43%	3,900	26/64th
15	Billy Burt 90-TTT-B33 WF #202H (Wolfcamp "A"/"X")	Early May 2015	1,028	683	2,100	66%	3,025	26/64th
16	Billy Burt 90-TTT-B33 WF #203H (Wolfcamp "A"/"X")	Flowing back after fracture treatment						
17	Cimarron 16-19S-34E RN #134H (3rd Bone Spring)	Early May 2015	804	754	303	94%	725	26/64th
18	Ranger State 33-20S-35E RN #122H (2nd Bone Spring)	Flowing back after fracture treatment						

4,000 feet of Hydrocarbon Column Creates Opportunity

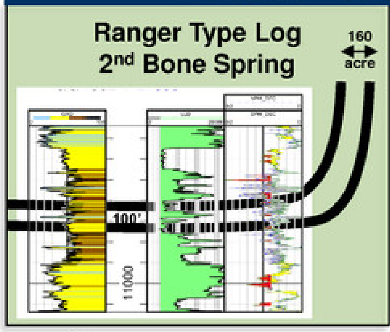
INTER-Formational Stacked Pay

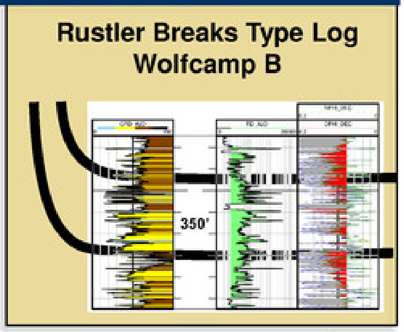


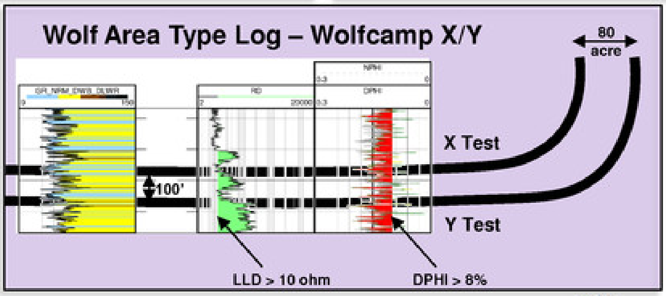
- Determining "Good, Better, Best" important as potential exceeds inter-formational stacked pay
- 2015 program will expand on intra-formational stacked pay tests performed in each asset area

INTRA-Formational Stacked Pays

Decoupled – Coupled – Micro-coupled



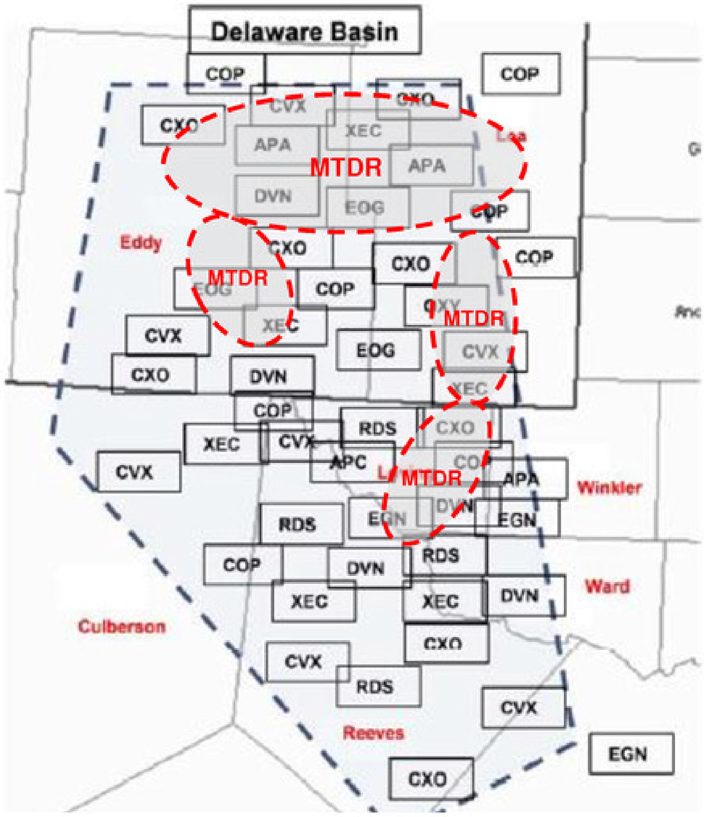




Matador is a Significant Delaware Basin Player

- **Matador's 85,400 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*

- **Key Operators in the Delaware Basin[(2)]:**
  - *Oxy* — *1,500,000 net acres*
  - *Chevron* — *1,000,000 net acres*
  - *Shell* — *618,000 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*** — ***152,000 gross / 85,400 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.
(2) Goldman Sachs Equity Research report dated April 1, 2015 (Singer).

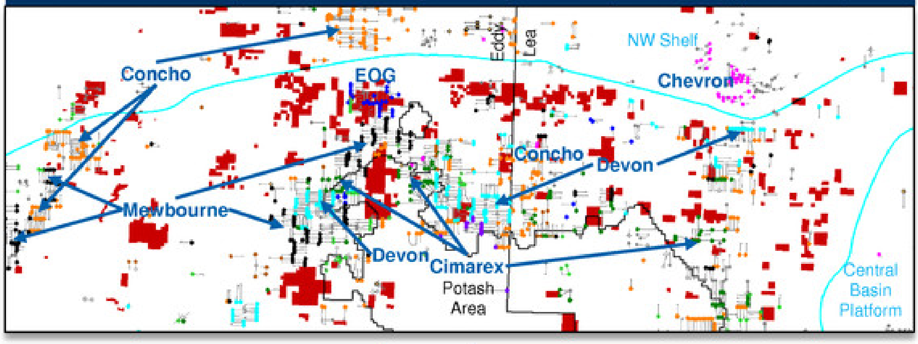
Matador's Acreage Among Other Significant Delaware Basin Activity

Other Operators

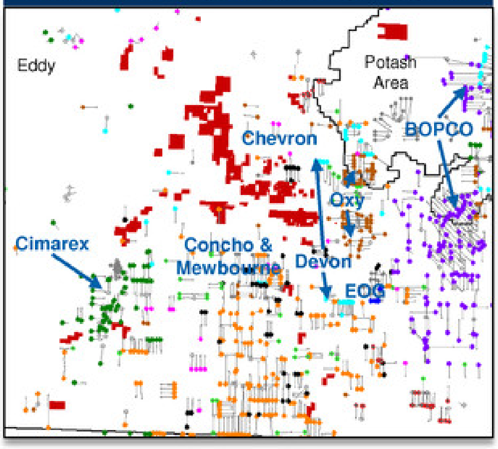
- CONCHO
- CIMAREX
- DEVON
- EOG
- MEWBOURNE
- ANADARKO
- BOPCO
- SHELL
- YATES
- OXY
- ENERGEN
- CHEVRON
- APACHE
- RKI EXPLORATION
- BHP BILLITON

Matador Acreage

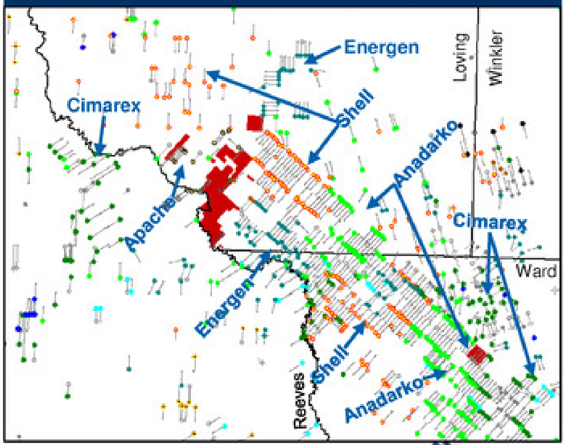
Northern Delaware (HEYCO and Ranger Prospect Areas) – Lea/Eddy Counties, NM



Rustler Breaks Prospect Area – Eddy County, NM

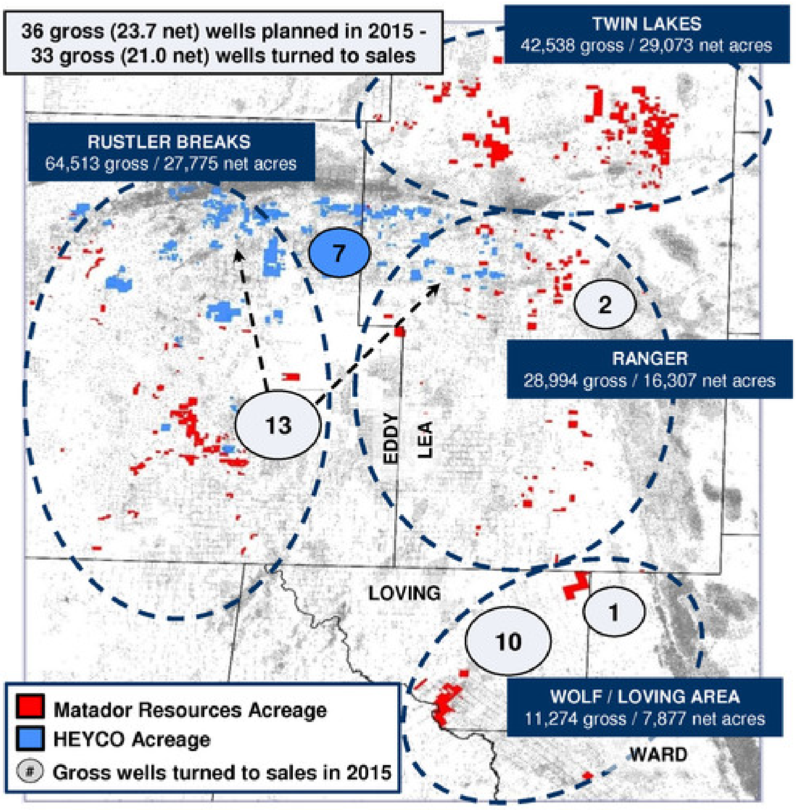


Wolf Prospect Area – Loving County, TX



Note: Horizontal wells shown based upon publicly available data as of March 31, 2015.

2015 Permian Basin Drilling Plan

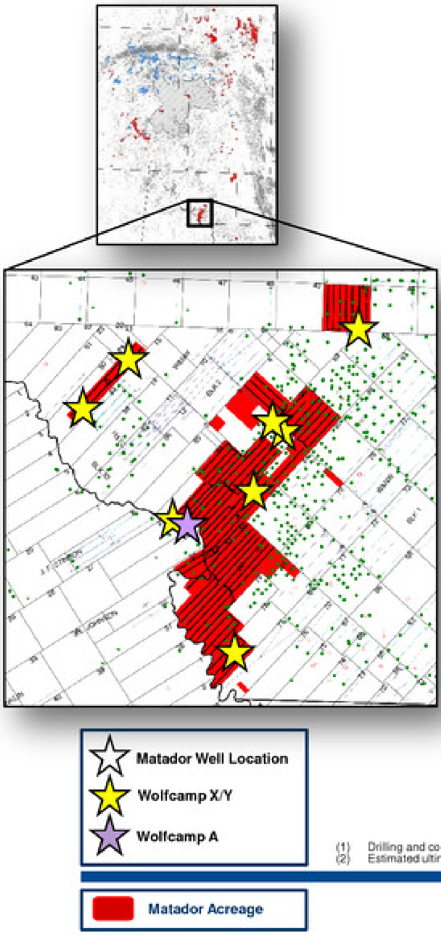


2015 Permian Basin Program

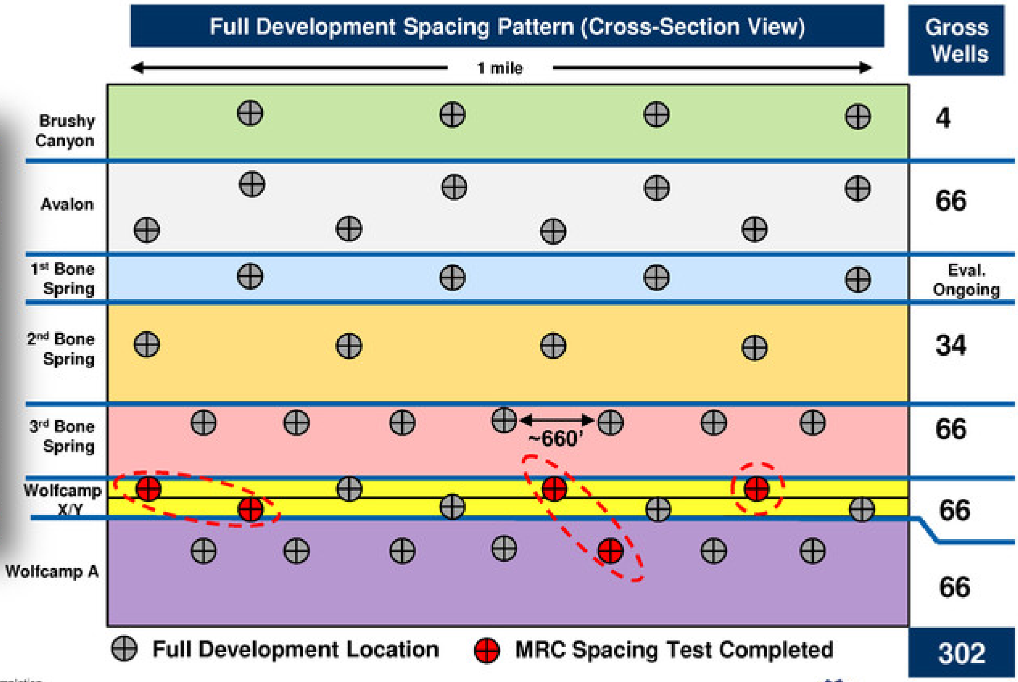
- Estimated capital expenditures of ~$245 million, including ~$32 million for land/seismic and facilities and ~$38 million for midstream initiatives at Wolf
- 36 gross (23.7 net) wells planned for 2015, with 33 gross (21.0 net) wells turned to sales
- **Wolf/NE Loving Area**
  - *11 gross (9.4 net) wells testing primarily Wolfcamp "X/Y", including initial test of NE Loving acreage in Wolfcamp "A"*
- **Rustler Breaks Area**
  - *13 gross (8.9 net) wells testing 2nd Bone Spring, Wolfcamp "X/Y" and Wolfcamp "B" targets*
- **Ranger Area**
  - *2 gross (2.0 net) wells testing 2nd and 3rd Bone Spring*
- **HEYCO Acreage**
  - *7 gross (0.7 net) non-operated wells testing 2nd and 3rd Bone Spring; also includes ~$5 million for workovers*
  - *Will likely drill wells on HEYCO acreage in lieu of certain wells planned in Rustler Breaks area in latter half of 2015*
- **Twin Lakes Area**
  - *No tests at Twin Lakes area planned for 2015*
  - *Longer-term acreage; seeking JV partner*

Note: All acreage at February 27, 2015. Some tracts not shown on map.

Wolf Inventory – Multi-Pay Development Potential

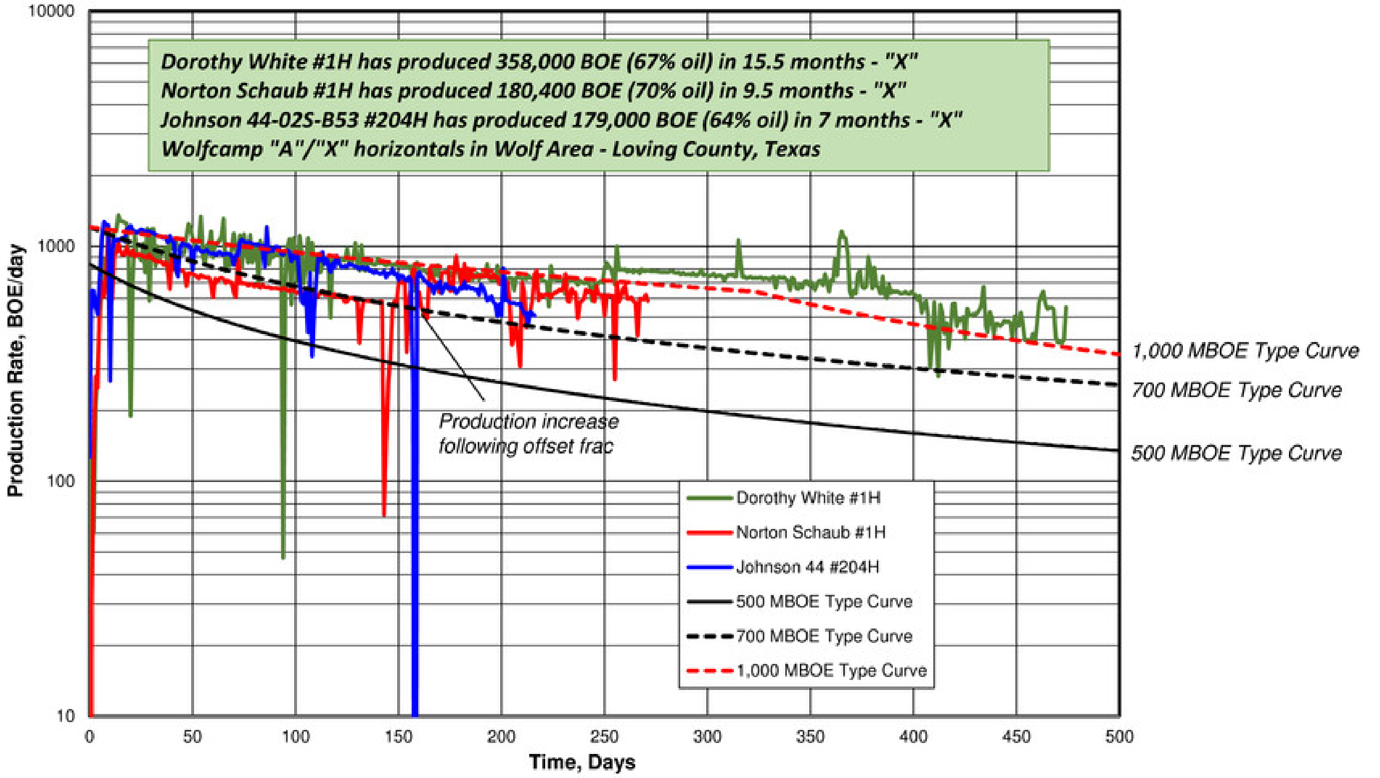


Development Well	D&C[(1)] CapEx	EUR[(2)] (MBOE)
Bone Spring	\$7 – \$8 million	450 – 600
Wolfcamp	\$8 – \$9 million	650 – 1,100



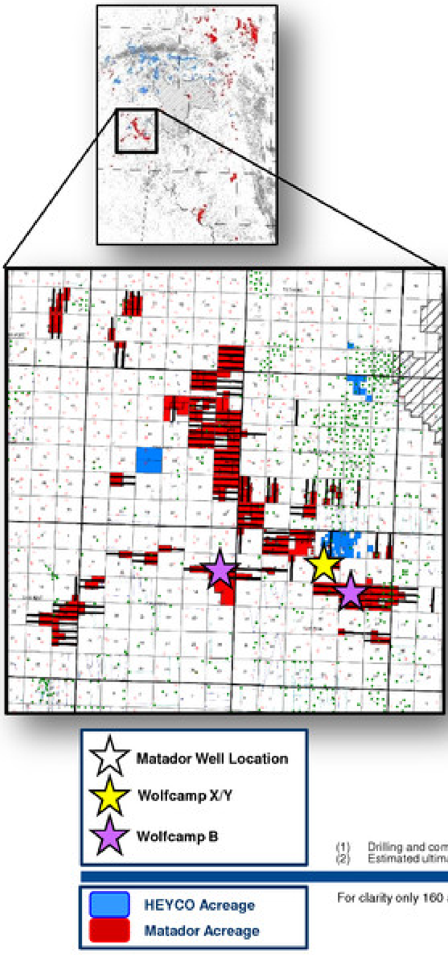
(1) Drilling and completion.
(2) Estimated ultimate recovery, thousands of barrels of oil equivalent.

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

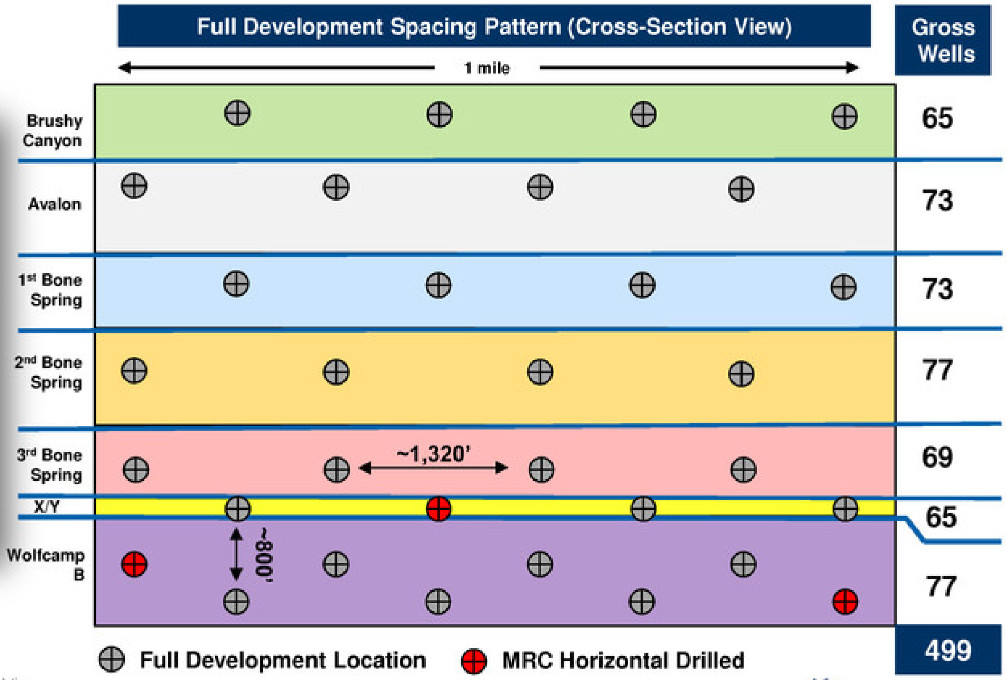


Note: Production as of April 28, 2015.

Rustler Breaks Inventory – Multi-Pay Development Inventory



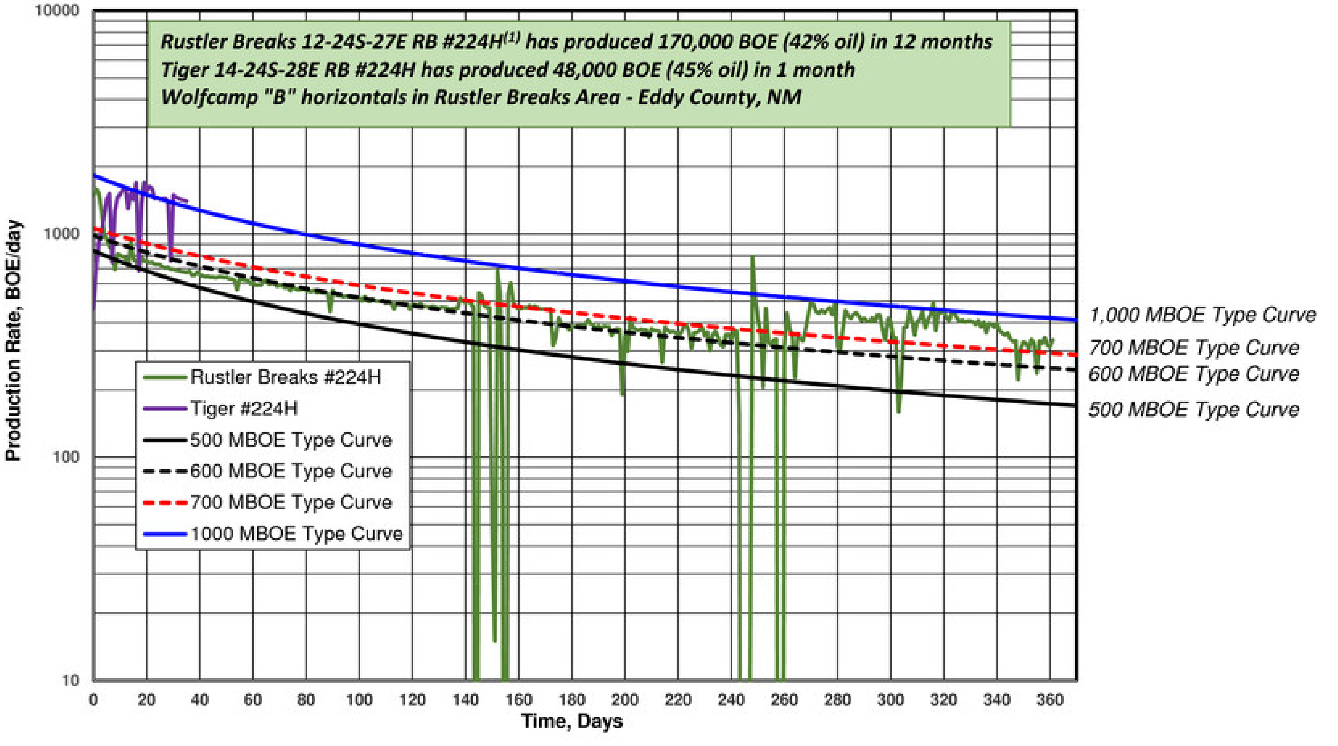
Development Well	D&C[(1)] CapEx	EUR[(2)] (MBOE)
Bone Spring	$5.25 – $6.25 million	350 – 650
Wolfcamp	$7 – $8 million	600 – 1,000



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

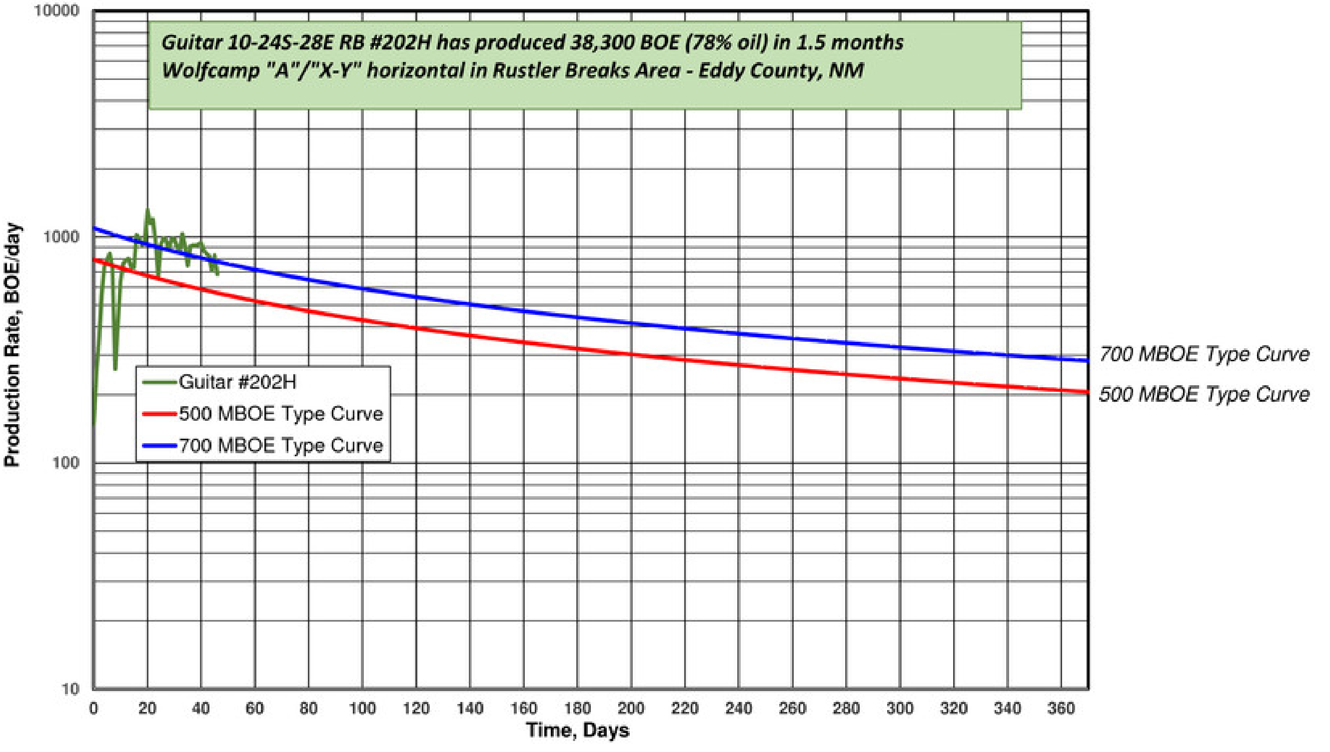
For clarity only 160 ac. well slots shown

Rustler Breaks Wolfcamp "B" Wells Performing Above Expectations



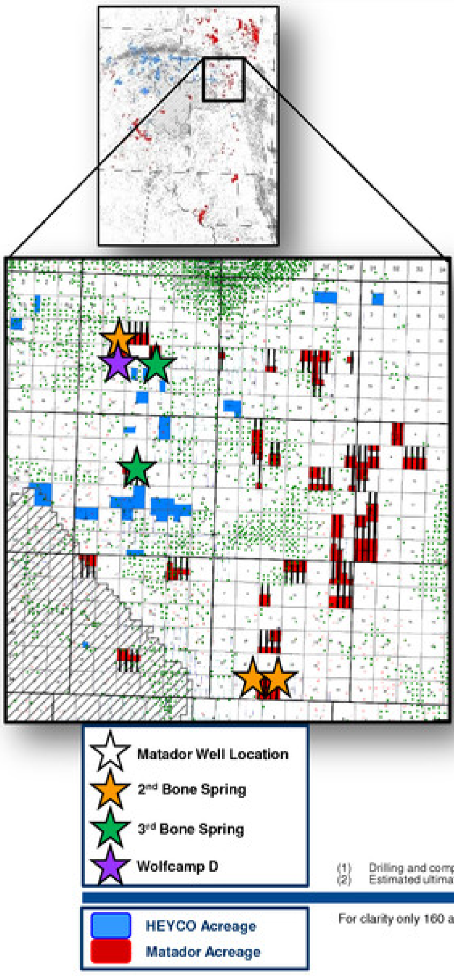
Note: Production as of April 28, 2015.
(1) Formerly the Rustler Breaks 12-24-27 #1H

Rustler Breaks Wolfcamp "A" Well Off to Strong Start



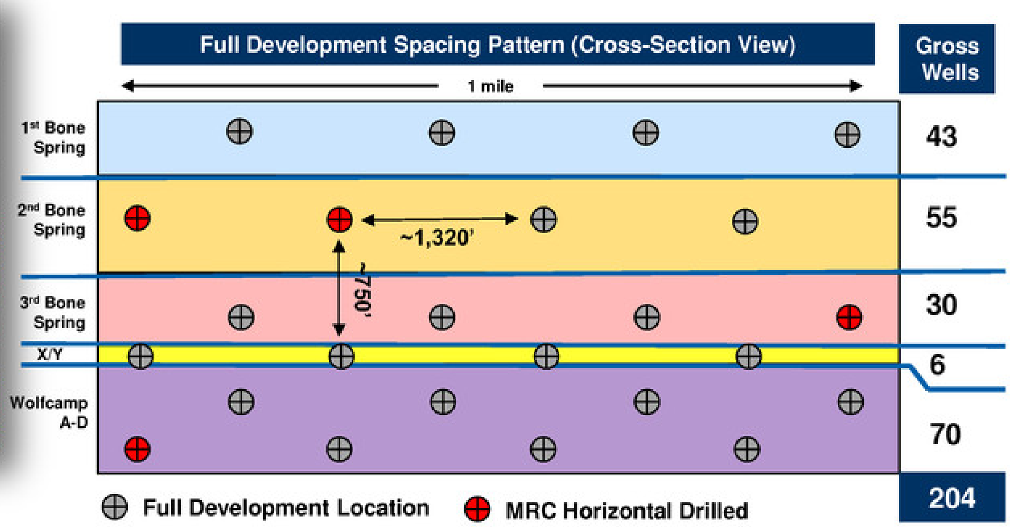
Note: Production as of April 28, 2015.

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	$8 – $9 million	200 – 800*

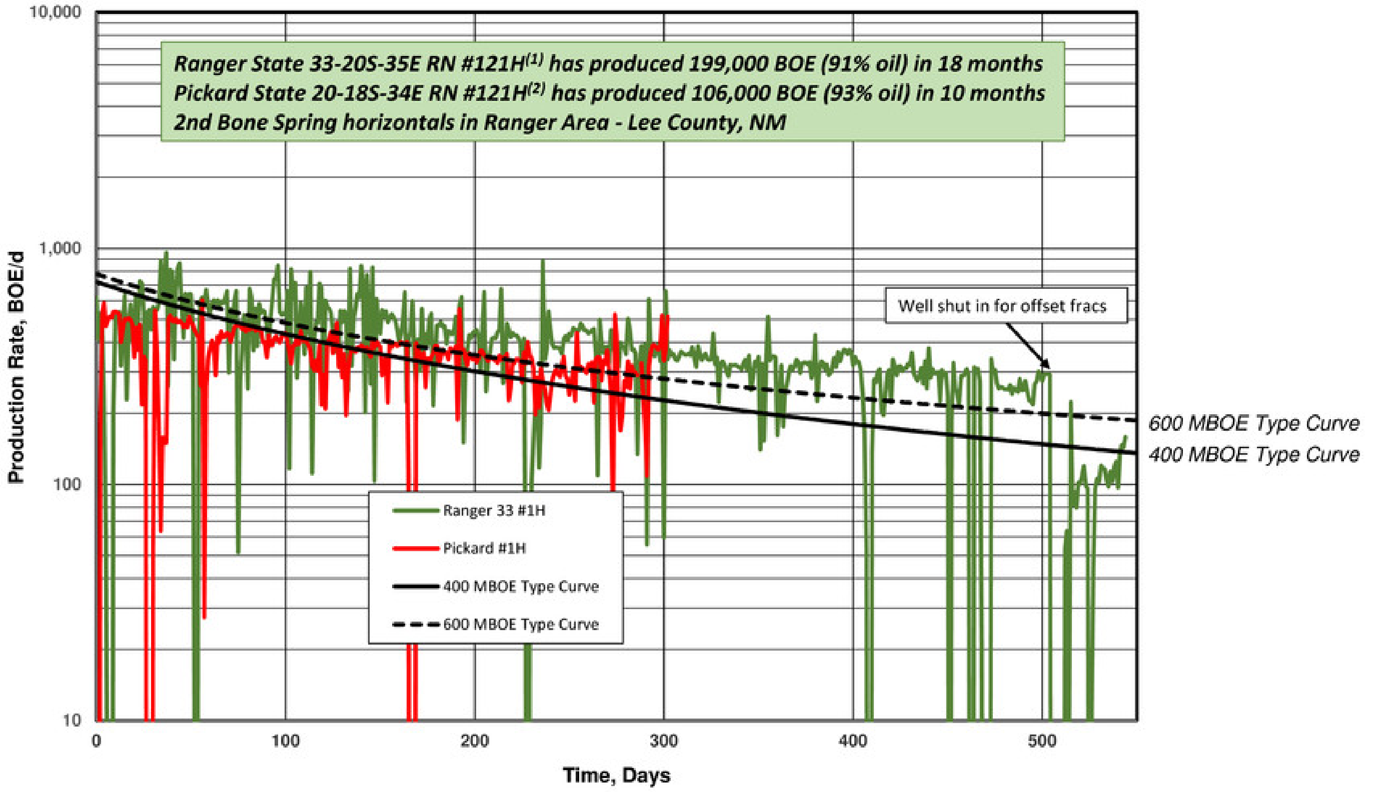
* Based on Volumetrics and 4-8% Recovery Factor



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

For clarity only 160 ac. well slots shown

Ranger Area Second Bone Spring Wells Performing Above Expectations

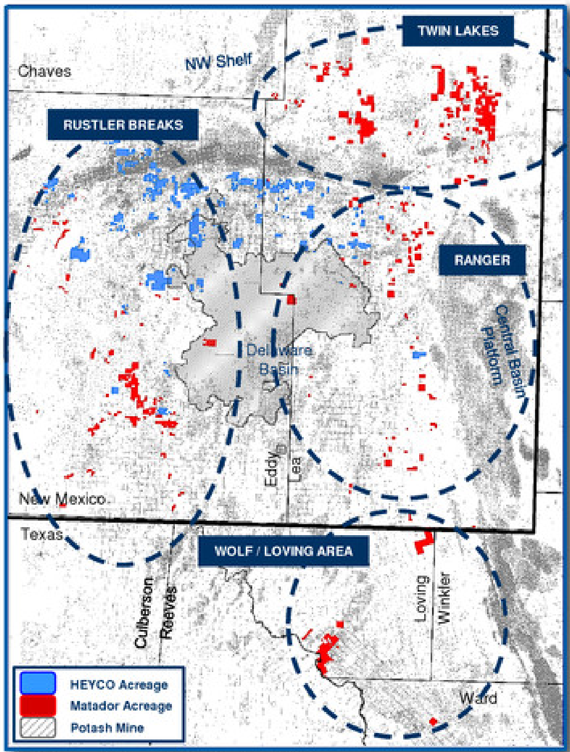


Note: Production as of May 17, 2015.
(1) Formerly the Ranger 33 State Com #1H.
(2) Formerly the Pickard State 20-18-34 #1H.

Significant Delaware Basin Inventory

- **Matador has identified 1,445 gross (960 net) locations[(1)]**
- **This inventory does not yet include the HEYCO properties 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**

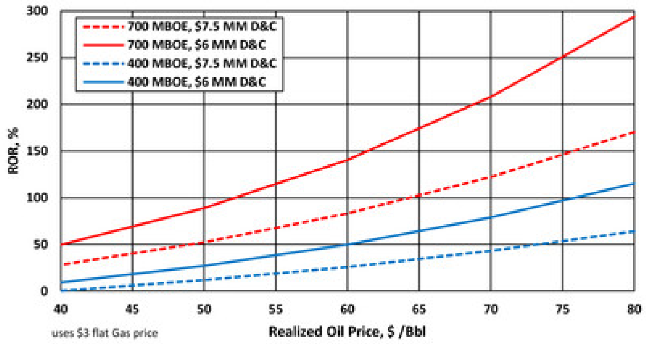


Note: All acreage at February 27, 2015. Some tracts not shown on map.

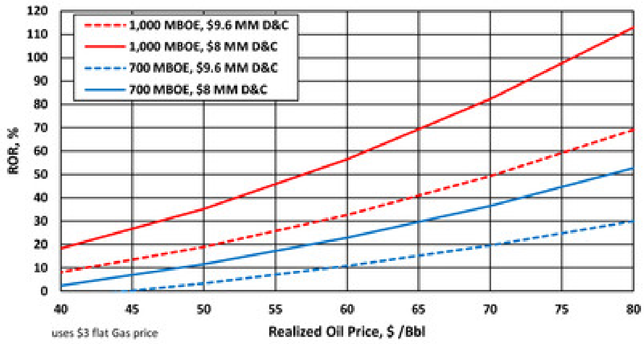
(1) Identified and engineered locations for potential future drilling, including specified production units and estimated lateral lengths, costs and well spacing using objective criteria for designation. Locations identified as of December 31, 2014, but including no locations at Twin Lakes and no locations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

Permian Basin Economics – Oil Price Sensitivities

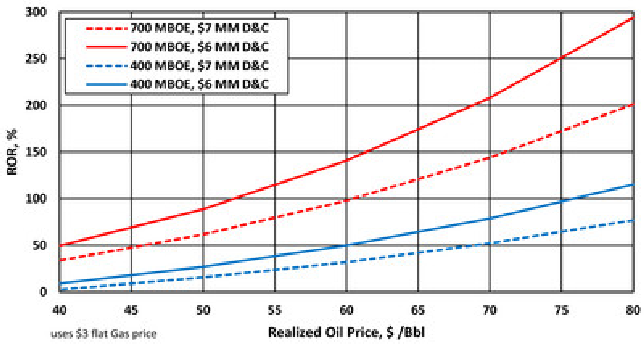
Ranger 33 400 - 700 MBOE ROR vs Oil Price



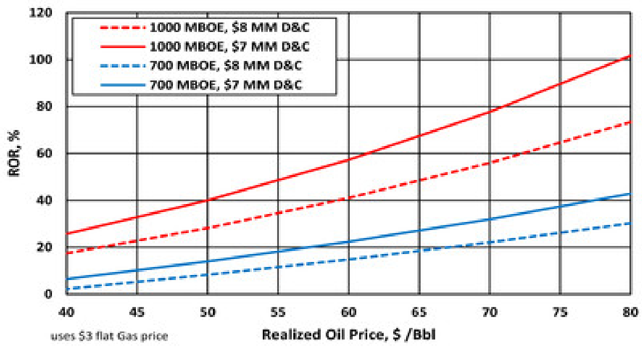
Dorothy White 700 - 1,000 MBOE ROR vs Oil Price



Rustler Breaks 2nd Bone Spring 400 - 700 MBOE ROR vs Oil Price



Rustler Breaks Wolfcamp B 700 - 1,000 MBOE ROR vs Oil Price

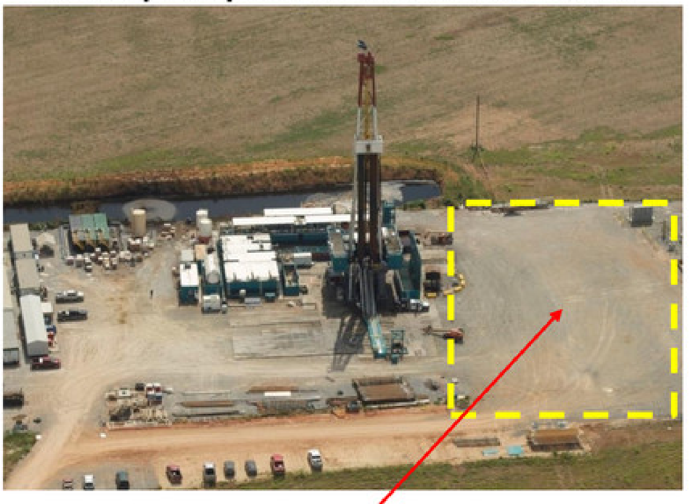


Latest Technology: Simultaneous Operations (Sim-Ops) Capable Rigs

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

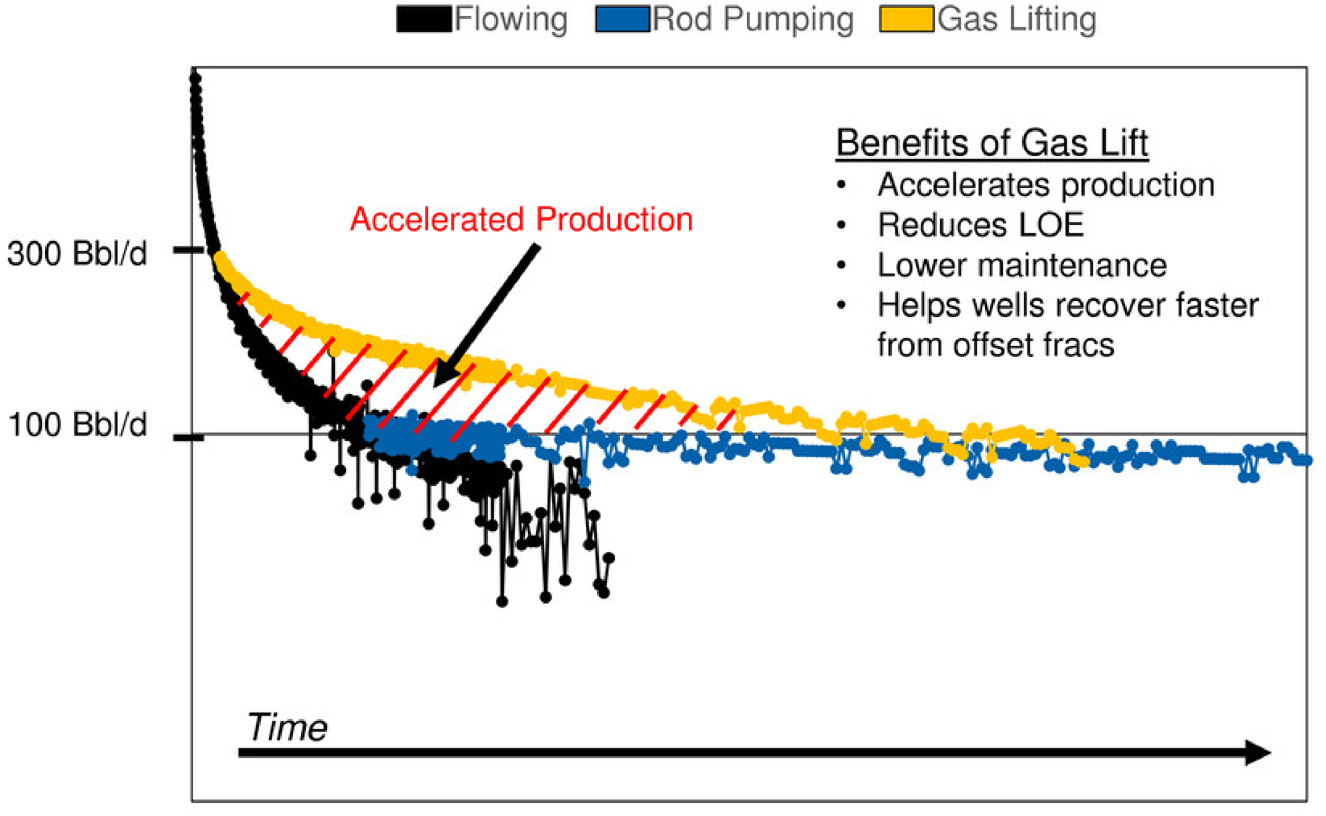
New Rig Improvements

- **7,500 psi Pressure Rating**
  - Estimated reduction in drilling time of 15 to 20% 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 Test Stump**
  - Estimated reduction in drilling time of 12 hours per well
- **Walking System & V-door turned 90°**
  - Allows for batch-setting and simultaneous operations

Efficiency gains save approximately $540,000 per well

...equivalent to a **$3.00/Bbl uplift in oil prices**

Artificial Lift Reducing Natural Production Declines

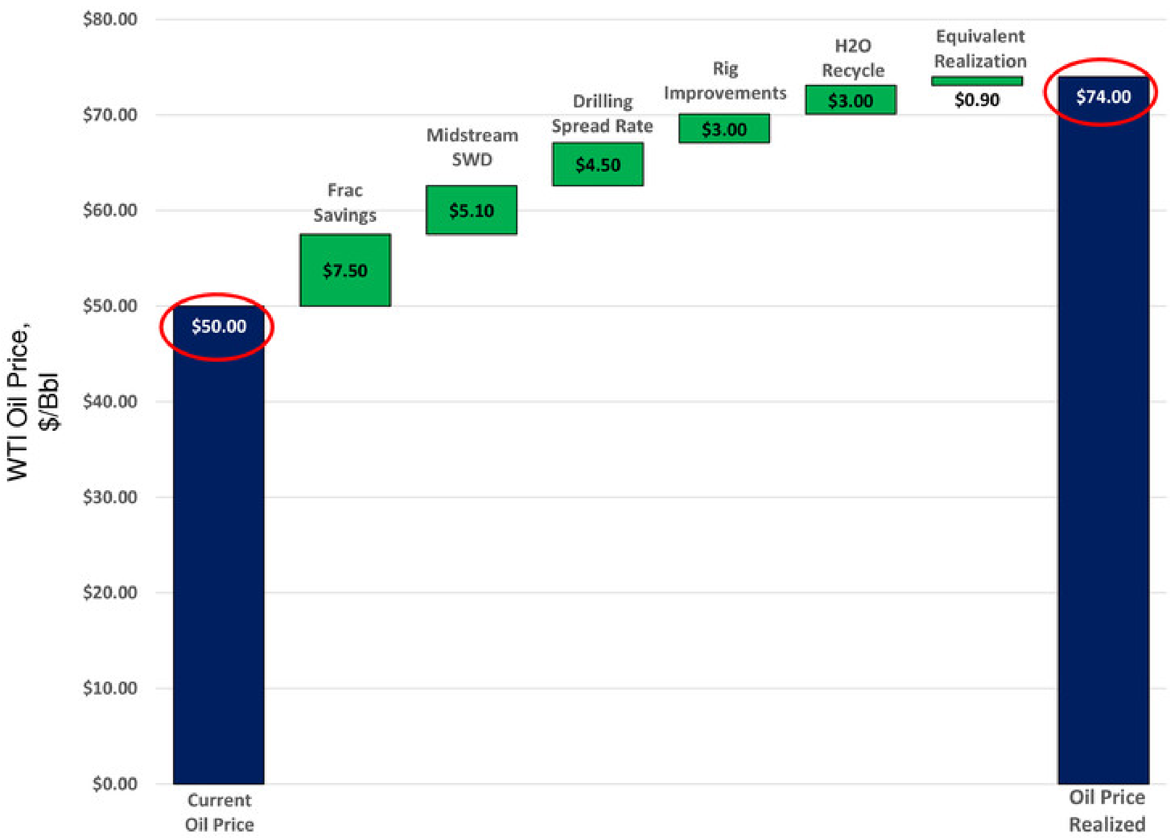


Benefits of Gas Lift

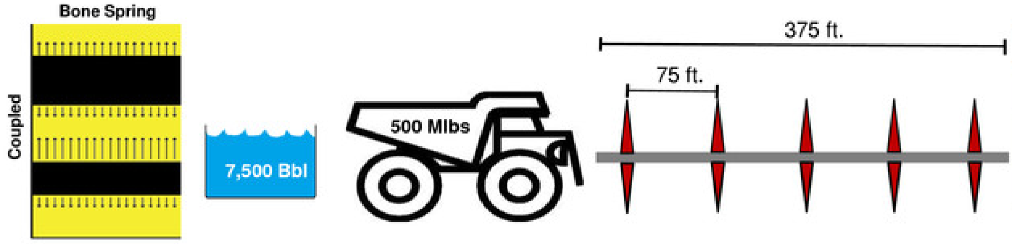
- Accelerates production
- Reduces LOE
- Lower maintenance
- Helps wells recover faster from offset fracs

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

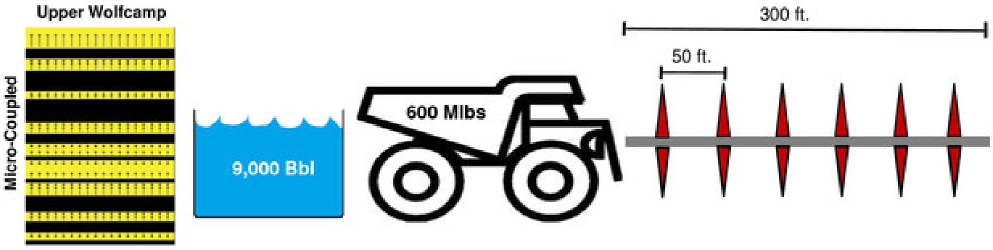
Total Prospective Equivalent Oil Price Uplifts



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
2,000 lbs/ft
40 Bbl/ft
35' cluster spacing



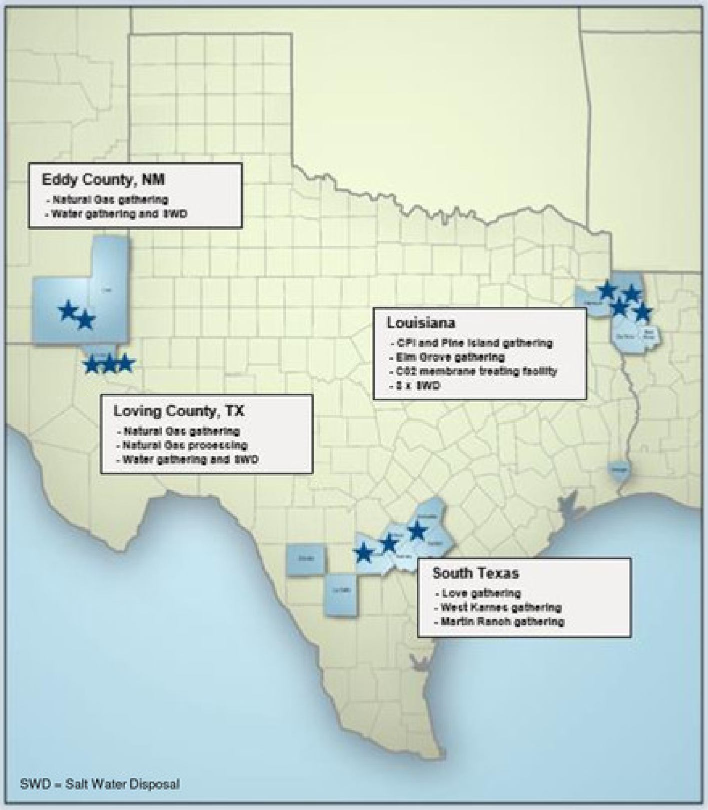
Midstream

Longwood Gathering and Disposal Systems[1] in Delaware Basin

- ***Loving County, Texas***
  - Natural gas gathering and compression
  - Water gathering
  - Salt water disposal
  - Oil gathering
  - Cryogenic natural gas processing plant

- ***Eddy County, New Mexico***
  - Natural gas gathering and compression
  - Water gathering
  - Salt water disposal (under evaluation)

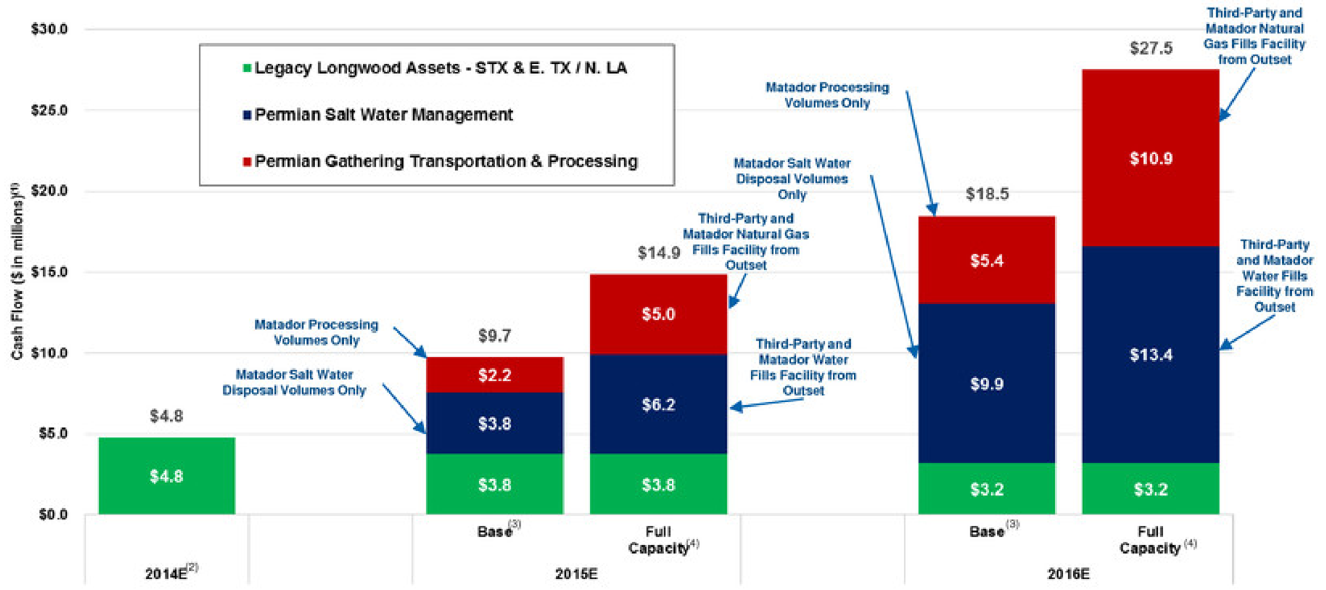
Longwood Gathering and Disposal Systems Activities



(1) Longwood Gathering and Disposal Systems, LP is an indirect wholly owned subsidiary of Matador Resources Company.

Midstream Initiatives Growing into Respectable Stand-Alone Business

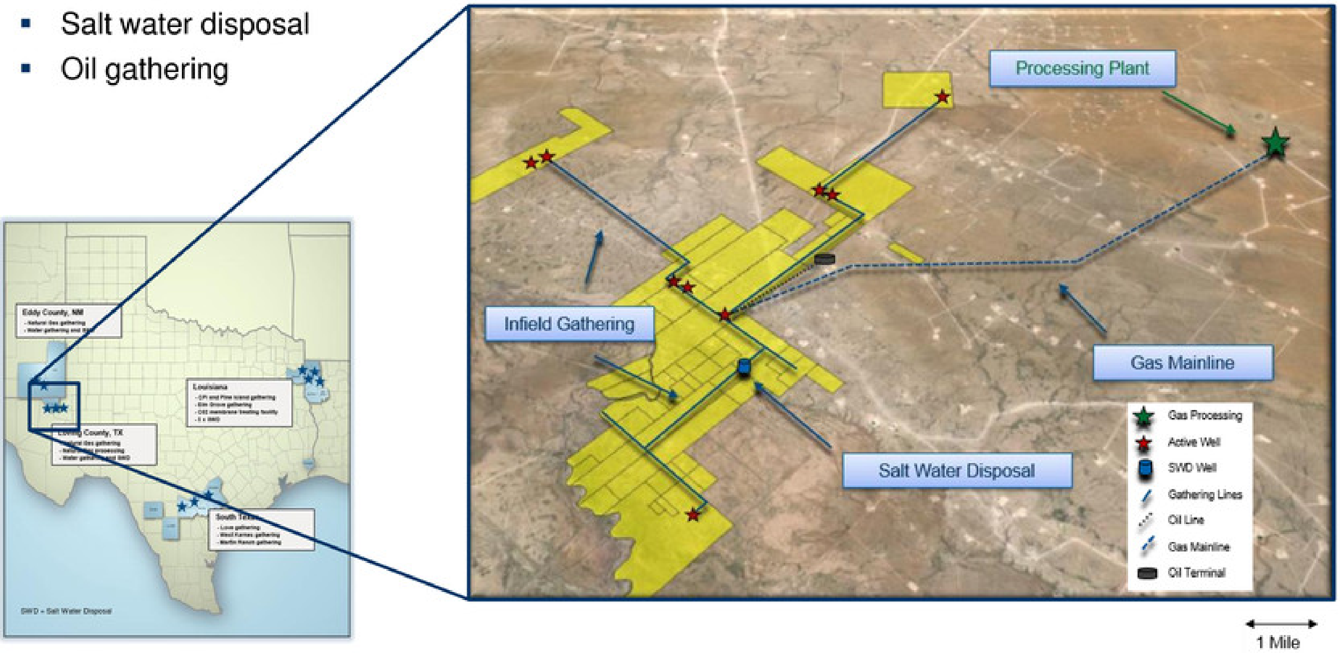
- **Expect to spend ~$38 million on midstream initiatives in the Permian Basin in 2015**
- **Matador expects Longwood to be able to support its own sources of financing**
- **Additional third-party volumes and a contemplated natural gas processing facility in Rustler Breaks provide upside to these forecasts**



(1) Estimated cash flow figures exclude allocations for general and administrative and certain other expenses. Cash flow presented is not necessarily incremental to Matador's other businesses.
(2) 2014 cash flow is an estimate as the Company has not historically viewed its midstream operations as a separate business as such operations have been immaterial.
(3) Base Case assumes no third-party natural gas processing or salt water disposal volumes for the Loving County natural gas processing facility and salt water disposal facility. Matador, as the "anchor tenant", would provide all of the estimated volumes in the Base Case scenario.
(4) Full Capacity Case assumes the Loving County natural gas processing facility and salt water disposal facility operate at capacity once each facility is operational through a combination of estimated volumes provided by Matador as the "anchor tenant" and by other third-party producers.

Loving County, Texas – Biggest Midstream Project to Date

- Natural gas gathering and compression
- Cryogenic natural gas processing plant
- Water gathering
- Salt water disposal
- Oil gathering

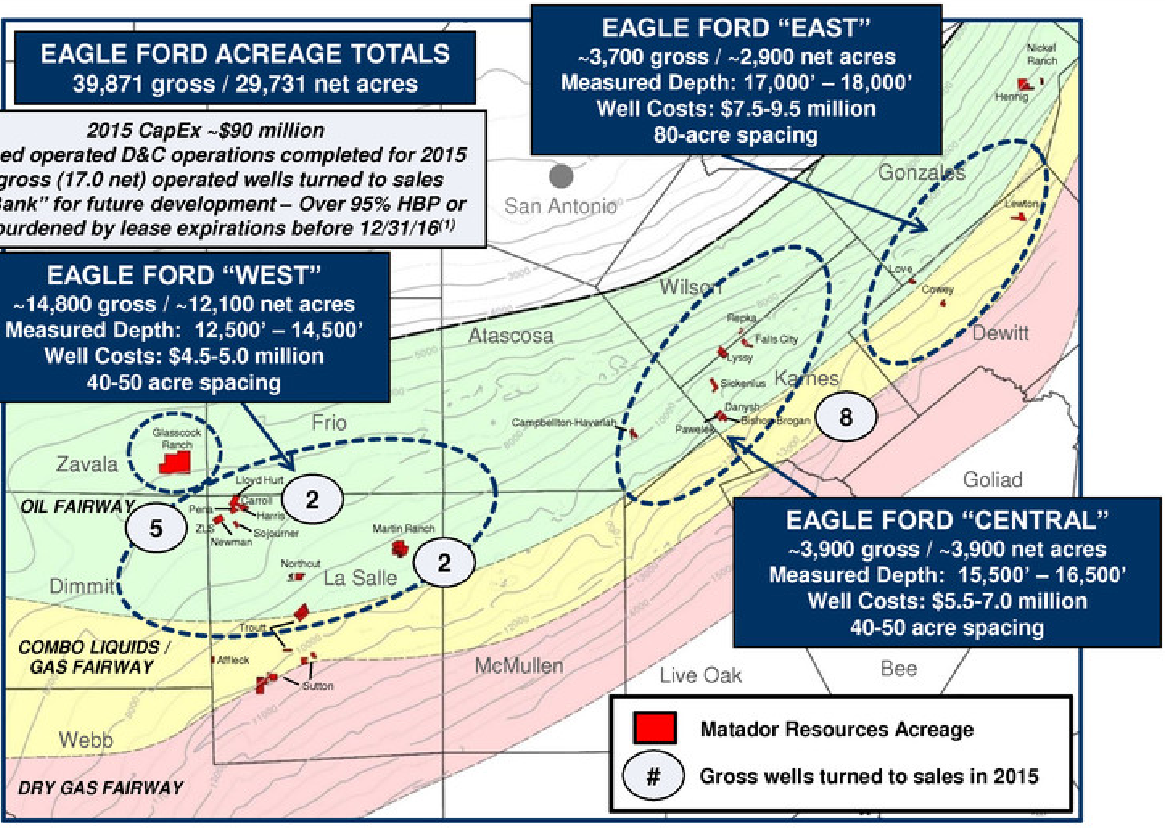




Eagle Ford

“Oil Bank”

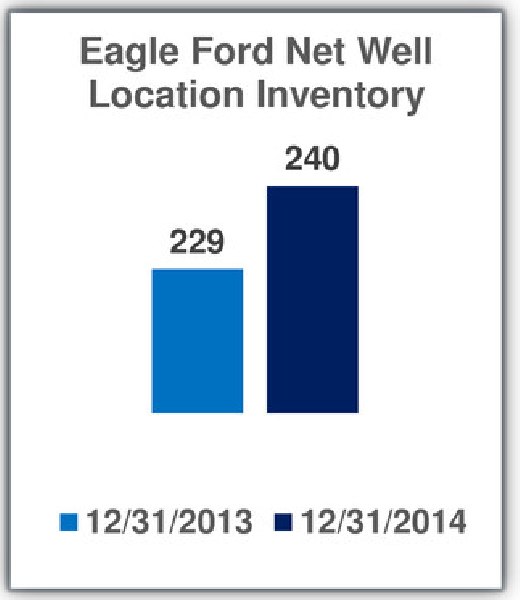
Eagle Ford Overview



Note: All acreage at February 27, 2015. Some tracts not shown on map.
(1) At December 31, 2014.

Eagle Ford – 2014 Accomplishments

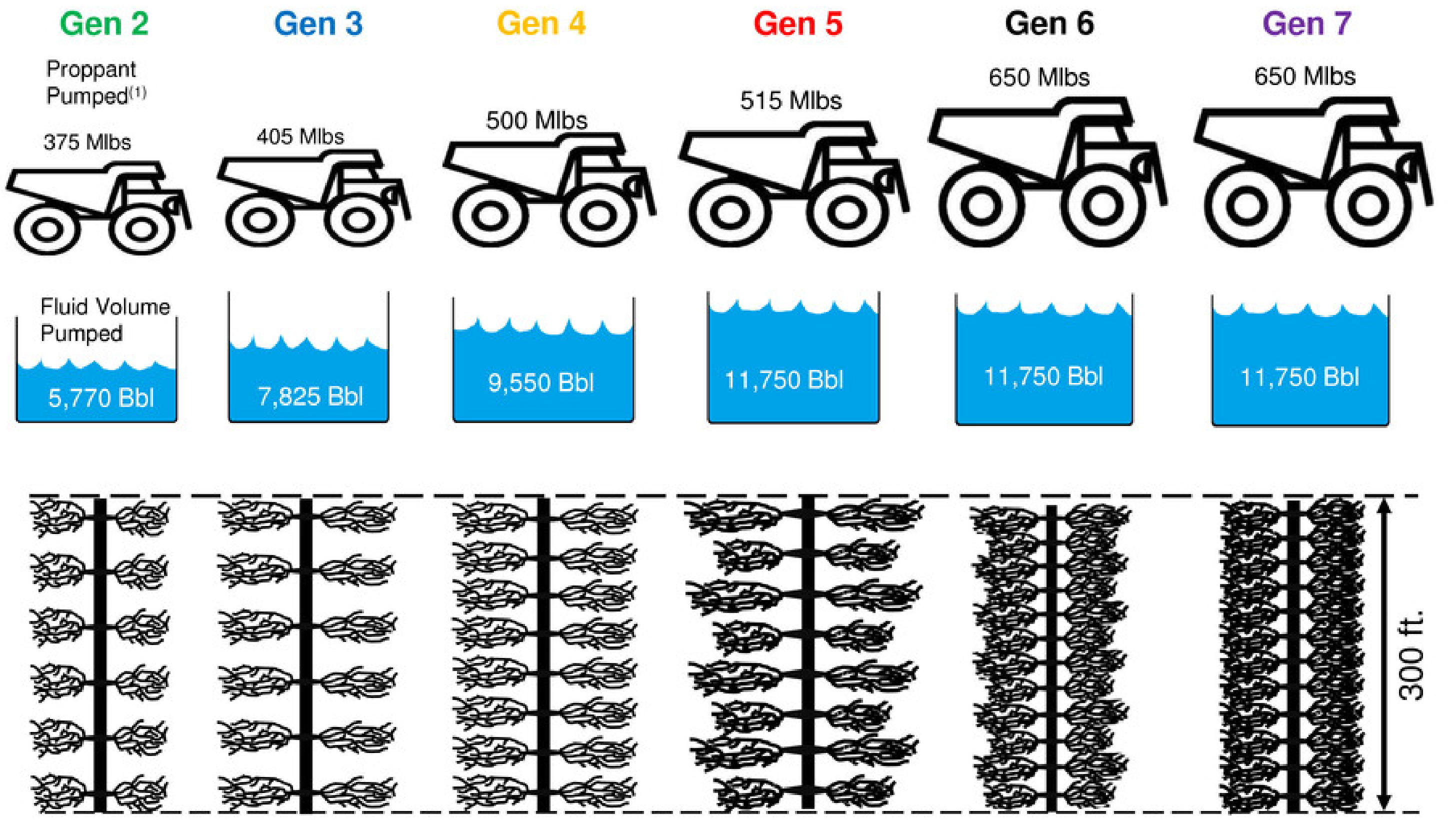
- Increased net oil production rate by 44% from ~6,400 Bbl/d in Q4 2013 to ~9,100 Bbl/d in Q4 2014
- Added 2,900 net acres, more than replacing 2014 Eagle Ford drilled inventory of ~36 net wells (See chart to the right)
- Evolved from Generation 5 to 7 frac designed for closer well spacing
  - 26% more proppant
  - Tighter perforation cluster spacing
  - More consistent proppant distribution
- Improved efficiencies
  - Completed 187,123 lateral feet within 15' target window
  - Drilled 90% of operated wells in batch mode on 40 to 50 acre spacing
- Reduced well costs by ~15% from $6.5 to $5.5 million per well in the western portion of our acreage
- Reserves growth[1]
  - Increased proved reserves by approximately 10% from 20.2 to 22.3 million BOE
  - Increased proved developed reserves by approximately 44% from 11.1 to 16.0 million BOE



Note: **Batch drilling** is the process by which multiple horizontal wells are drilled from a single pad. In batch drilling, the surface holes for each well are drilled first and then the production holes, including the horizontal laterals for each well, are drilled. **Pad drilling** is the process by which multiple horizontal wells are drilled from a single pad. In pad drilling, each well on the pad is drilled to total depth before the next well is initiated.

(1) From December 31, 2013 to December 31, 2014.

Evolution of Matador Eagle Ford Frac Design



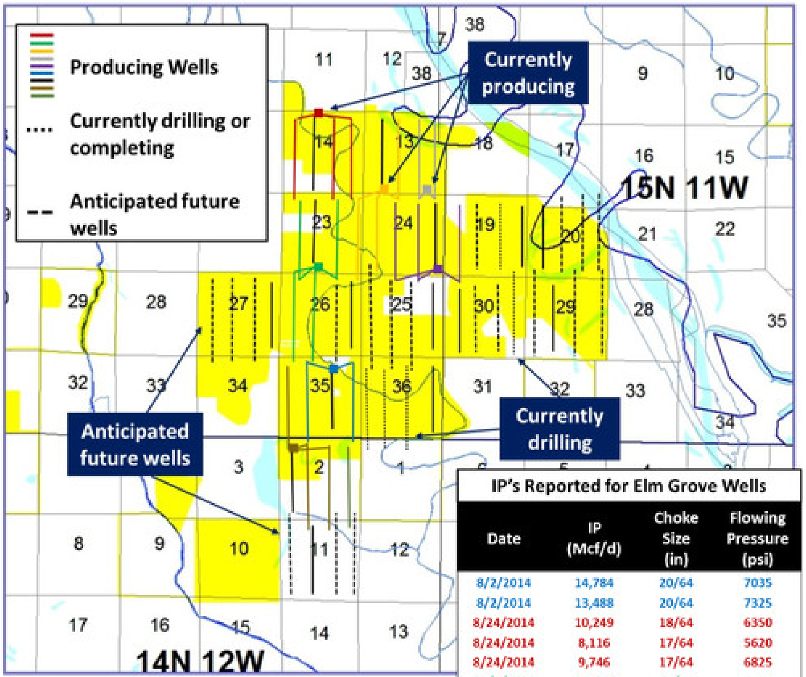
Note: Figure depicts proppant and fluid volume pumped per 300 ft. of horizontal wellbore.
(1) Mlbs = thousands of pounds of proppant pumped.



Haynesville Shale

"Gas Bank"

Haynesville – Chesapeake Elm Grove Operations



IP's Reported for Elm Grove Wells

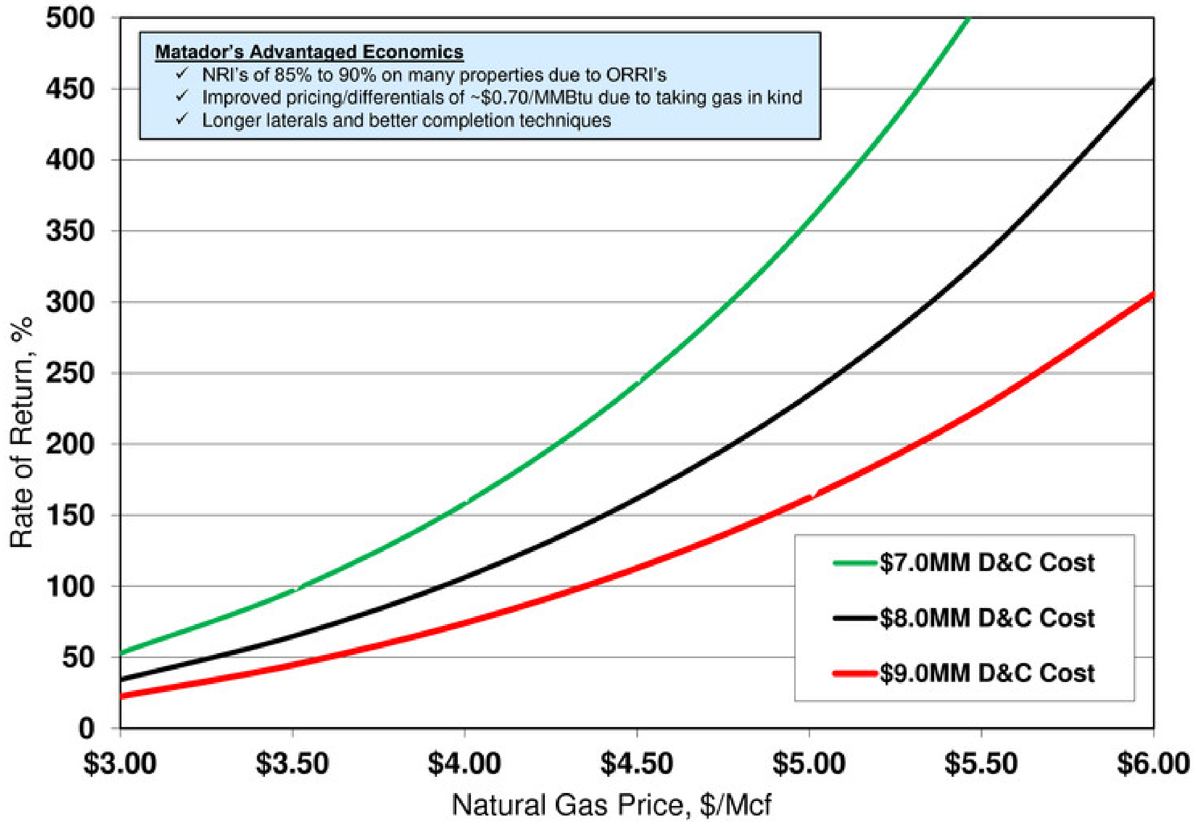
Date	IP (Mcf/d)	Choke Size (in)	Flowing Pressure (psi)
8/2/2014	14,784	20/64	7035
8/2/2014	13,488	20/64	7325
8/24/2014	10,249	18/64	6350
8/24/2014	8,116	17/64	5620
8/24/2014	9,746	17/64	6825
10/3/2014	13,872	20/64	7530
10/3/2014	13,632	20/64	7245
10/3/2014	14,112	20/64	7395
10/3/2014	14,424	20/64	7025
12/6/2014	13,080	20/64	7450
12/6/2014	13,440	20/64	7200
12/22/2014	13654	20/64	7215
12/22/2014	12305	18/64	7090
1/19/2015	15262	22/64	7115
1/19/2015	14173	22/64	6590

- Successful 2014 non-op drilling program, primarily by Chesapeake at Elm Grove
  - *17 gross (3.8 net) wells with estimated recoveries of 8 to 12 Bcf and well costs of \$7 to \$8 million (below Chesapeake's original AFEs and Matador's expectations)*
- Haynesville average daily natural gas production up over 3-fold to 35.0 MMcf/d in Q4 2014 from 11.1 MMcf/d in Q4 2013 – currently over 55 MMcf/d

2015 Haynesville Non-Op Drilling Program

- Estimated capital expenditures of ~\$15 million for non-operated well participation interests
  - *Represents only ~4% of 2015 estimated capital expenditures*
- 38 gross (3.0 net) wells throughout Tier 1 Haynesville; 33 gross (2.3 net) wells turned to sales
- Includes 10 gross (1.8 net) wells turned to sales on Elm Grove properties operated by Chesapeake in 2015 (shown on map at left)
- Chesapeake placed seven additional wells on production in Q1 2015
  - *Initial rates of ~12-15 MMcf/d of natural gas at flowing tubing pressures of 6,000 to 8,000 psi*

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



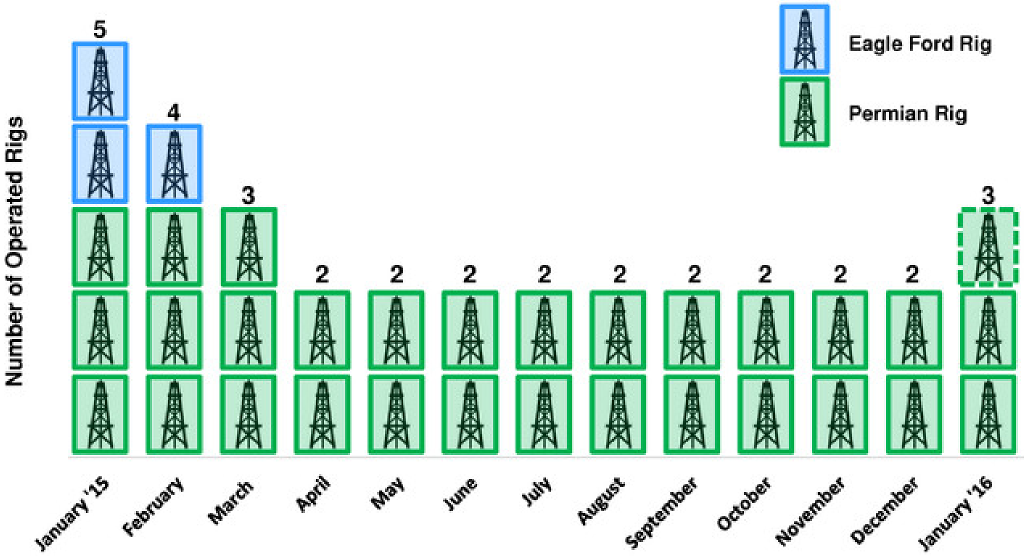
Note: Individual well economics only. Excludes costs prior to drilling (i.e. acquisition or acreage costs). Economics use a NRI / WI of 85% but actual interests vary. Natural gas price differential = ($0.55)/Mcf. D&C cost = drilling and completion cost.



2015 Capital Investment Plan

2015 Capital Investment Plan – Reduced Drilling Program in 2015

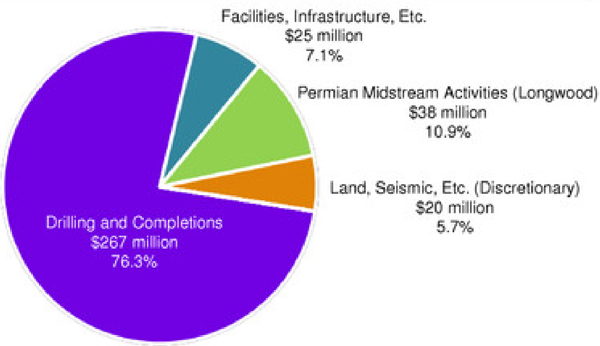
- **Reduced drilling program from 5 rigs to 2 rigs due to lower commodity prices, with primary focus on Permian (Delaware) Basin**
- **Currently operating 2 rigs – both in the Delaware Basin**
  - *Possible addition of a third drilling rig in the Permian as early as late summer 2015[(1)]*
  - *New-build rigs, latest technology and designed for simultaneous operations (Sim-Ops)*



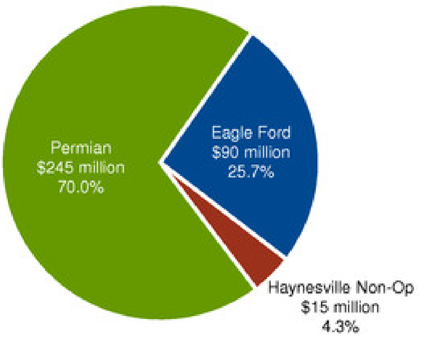
(1) As announced May 6, 2015.

2015 Capital Investment Plan Summary

2015E CapEx by Expense Type



2015E CapEx by Region

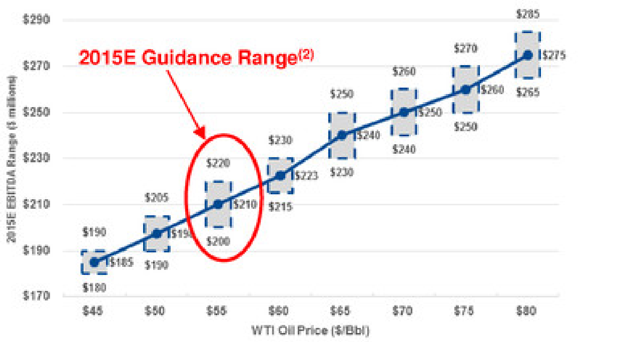


- 2015E CapEx of ~$350 million
  - *Decrease of ~43% from 2014 CapEx of ~ $610 million*
  - *Estimated service cost reductions of 15 to 20% as observed through January 2015, but further cost reductions expected (up to 50% on some services)*
  - *Does not include any CapEx associated with HEYCO merger (cash and assumed debt of $36.6 million) or two potential associated joint ventures*
- 2015E CapEx highest in Q1 2015 – falls quickly thereafter
  - *Q1 at $163 million (47%); Q2 at $71 million (20%); Q3 and Q4 at $58 million each (remaining 33%) – close to cash flow at $55 per Bbl oil*
- Permian Basin drilling program will focus on Wolf development, further delineation of Ranger and Rustler Breaks areas and integration of HEYCO acreage
  - *Represents ~70% of 2015E CapEx*
  - *Includes ~$38 million for midstream initiatives*
- Eagle Ford development will be temporarily suspended – over 95% of acreage held by production or not subject to near-term expirations[1]
  - *Represents ~26% of 2015E CapEx*
- Haynesville development includes continued selective participation in non-operated wells, primarily CHK drilling at Elm Grove; Haynesville acreage ~100% held by production
  - *Represents only ~4% of 2015E CapEx*

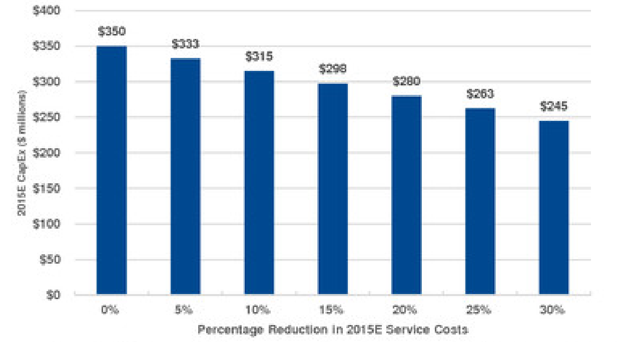
(1) At December 31, 2014.

Commodity Price and CapEx Estimates Significantly Impact Forecasts

Sensitivity of 2015E Adjusted EBITDA(1) to Oil Price



Sensitivity of 2015E CapEx to Cost Reductions

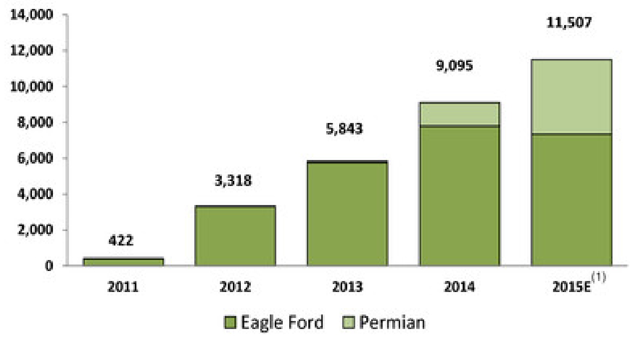


- *Relatively small improvements in oil price and cost reductions can significantly improve financial forecasts and reduce estimated CapEx*
- *$10/Bbl increase in oil price improves Adjusted EBITDA(1) by ~$25 million*
- *10 to 15% in additional cost reductions reduce CapEx by $35 to $50 million*
- *$10/Bbl increase in oil price and additional 15% in CapEx reductions reduce operating cash outspend by ~$75 million – about half of current estimates*
- *Matador technical teams focused on reducing both operating costs and capital expenditures in 2015 and continuing to improve well performance*

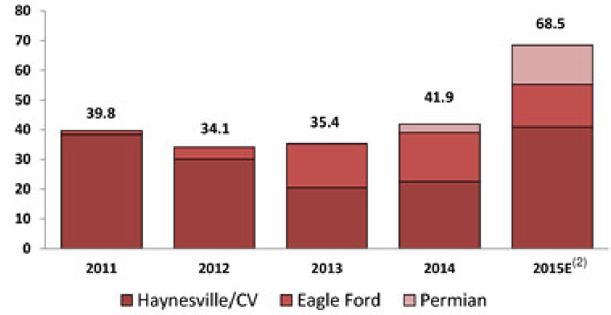
(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net (loss) income and net cash provided by operating activities, see Appendix.
(2) Estimated 2015 Adjusted EBITDA based upon production guidance range for 2015 as reaffirmed on April 6, 2015. Estimated average realized 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 January through December 2015.

2015 Production Estimates – Oil Equivalent Growth of ~43%

Oil Production Growth (Bbl/d)



Natural Gas Production Growth (MMcf/d)



2015E Oil Production

- *Estimated oil production of 4.1 to 4.3 million barrels*
  - 27% increase from 2014 despite decreased drilling
- *Average daily oil production of 11,500 Bbl/d, up from 9,100 Bbl/d in 2014*
  - Eagle Ford ~7,350 Bbl/d (64%)
  - Permian ~4,150 Bbl/d (36%)
- *Quarterly production peaks in Q2; Q4 2015 oil production relatively flat to Q4 2014 and Q1 2015*
  - Q1 oil production relatively flat
  - Permian production increases over three-fold in 2015; Eagle Ford production declines by 5%

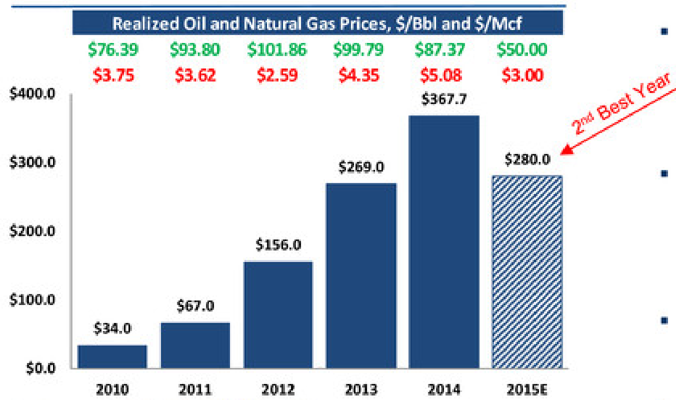
2015E Natural Gas Production

- *Estimated natural gas production of 24 to 26 Bcf*
  - 63% increase from 2014 despite decreased drilling; significant Haynesville impact
  - Quarterly production peaks in Q2; Q4 2015 natural gas production up ~12% over Q4 2014
- *Average daily natural gas production of 68.5 MMcf/d, up from 41.9 MMcf/d in 2014*
  - Haynesville ~42.7 MMcf/d (62%)
  - Eagle Ford ~14.5 MMcf/d (21%)
  - Permian ~11.3 MMcf/d (17%)

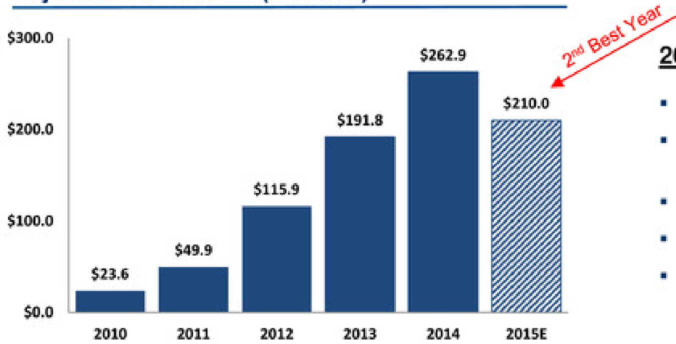
(1) Estimated daily average oil production at midpoint of 2015 guidance range. The Company raised its 2015 oil production guidance from 4.0 to 4.2 million Bbl to 4.1 to 4.3 million Bbl on May 6, 2015.
(2) Estimated daily average natural gas production at midpoint of 2015 guidance range of 24.0 to 26.0 Bcf as reaffirmed on May 6, 2015.

2015 Financial Estimates

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 $50/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 $270 to $290 million*
  - Decrease of ~24% from $367.7 million in 2014
  - Oil and natural gas hedges estimated to contribute $55 million in additional revenues in 2015, as compared to $5 million in 2014
- *Estimated Adjusted EBITDA[(1)(2)] of $200 to $220 million*
  - Decrease of ~20% from $262.9 million in 2014
- *~50% oil by volume, ~73% oil by revenue in 2015[(2)]; compared to ~57% oil by volume, ~79% oil by revenue in 2014*

2015E Operating Cost Estimates (Unit Costs per BOE)

- *Production taxes/marketing = $4.00; $5.65 in 2014 (reduced revenues)*
- *Lease operating = $7.25; $8.75 in 2014 (gas volumes, operating efficiencies, service costs)*
- *G&A = $5.25; $5.48 in 2014 (additional staff)*
- *Operating cash costs, excluding interest = $16.50; ~$20.00 in 2014*
- *DD&A = $22.75; $22.95 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 and Adjusted EBITDA based upon the midpoint of 2015 production guidance range as provided on May 6, 2015. Estimated average realized 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 January through December 2015.

Summary and 2015 Guidance

- **Moving from 5 rigs to 2 rigs in 2015; currently operating 2 rigs in Delaware Basin**
  - *Possible addition of a third drilling rig in the Permian Basin as early as late summer 2015*[(1)]
- **Permian drilling focused on Wolf development and further delineation of Ranger and Rustler Breaks prospect areas, plus integration of HEYCO acreage**
- **Eagle Ford drilling temporarily suspended as over 95% of acreage held-by-production or not subject to near-term expiration**[(2)]

	2014 Actual	*2015 Guidance*	*% Change*
Capital Spending	$610 million	$350 million[(3)]	- 43%
Total Oil Production	3.3 million Bbl	4.1 to 4.3 million Bbl[(4)]	+ 27%
Total Natural Gas Production	15.3 Bcf	24.0 to 26.0 Bcf[(3)]	+ 63%
Oil and Natural Gas Revenues	$367.7 million	$270 to $290 million[(5)]	- 24%
Adjusted EBITDA[(6)]	$262.9 million	$200 to $220 million[(5)]	- 20%

(1) As announced May 6, 2015.
(2) At December 31, 2014.
(3) As reaffirmed on May 6, 2015; does not include capital expenditures associated with the HEYCO transaction or two potential associated joint ventures.
(4) The Company raised its 2015 oil production guidance from 4.0 to 4.2 million Bbl to 4.1 to 4.3 million Bbl on May 6, 2015.
(5) Estimated 2015 oil and natural gas revenues and Adjusted EBITDA at midpoint of 2015 production guidance range as provided on May 6, 2015. Estimated average realized 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 April through December 2015.
(6) 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.



Appendix

Board of Directors and Special Advisors – 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
Michael C. Ryan Director	- Partner, Berens Capital Management	International Business and Finance
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
George M. Yates Director	- Chairman & CEO of HEYCO Energy Group, Inc.	Oil and Gas Exploration & Development

Special Board Advisors	Professional Experience	Business Expertise
Marlan W. Downey Special Board Advisor	- Retired President, ARCO International - Former President, Shell Pecten International - Past President of American Association of Petroleum Geologists	Oil and Gas Exploration
John R. Gass Special Board Advisor	- 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
Wade I. Massad Special Board Advisor	- Managing Member, Cleveland Capital Management, LLC - Formerly with KeyBanc Capital Markets and RBC Capital Markets	Capital Markets
Greg L. McMichael Special Board Advisor	- Retired Vice President and Group Leader – Energy Research of A.G. Edwards	Capital Markets
Dr. James D. Robertson Special Board Advisor	- Retired VP Exploration, Chief Geophysicist, ARCO International Oil and Gas Company	Oil and Gas Exploration
Edward R. Scott, Jr. Special Board Advisor	- Former Chairman, Amarillo Economic Development Corporation - Law Firm of Gibson, Ochsner & Adkins	Law, Accounting and Real Estate Development
W.J. "Jack" Sleeper, Jr. Special Board Advisor	- 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 and James Cleo Thompson Jr.	34 years	Since Inception
Matthew V. Hairford President	-	Samson, Sonat, Conoco	30 years	Since 2004
David E. Lancaster EVP, COO and CFO	-	Schlumberger, S.A. Holditch & Associates, Inc., Diamond Shamrock	35 years	Since 2003
Craig N. Adams EVP – Land & Legal (General Counsel)	-	Baker Botts L.L.P., Thompson & Knight LLP	22 years	Since 2012
Ryan C. London EVP and General Manager	-	Matador Resources Company (Began as intern)	11 years	Since 2004
Van H. Singleton, II EVP – Land	-	Southern Escrow & Title, VanBrannon & Associates	18 years	Since 2007
Bradley M. Robinson VP and CTO	-	Schlumberger, S.A. Holditch & Associates, Inc., Marathon	37 years	Since Inception
Billy E. Goodwin VP – Drilling	-	Samson, Conoco	30 years	Since 2010
G. Gregg Krug VP – Marketing	-	Williams Companies, Samson, Unit Corporation	31 years	Since 2005
Trent W. Green VP – Production	-	HEYCO, Bass Enterprises, Schlumberger, S.A. Holditch & Associates, Inc., Amerada Hess	26 years	Since 2015
Jennifer S. Queen VP – Human Resources & Administration	-	Baker Botts L.L.P., McKenna Long & Aldridge LLP	22 years	Since 2015
Sandra K. Fendley VP and CAO	-	J-W Midstream, Crosstex Energy	23 years	Since 2013
Kathryn L. Wayne Controller and Treasurer	-	Matador Petroleum Corporation, Mobil	30 years	Since Inception

Hedging Profile

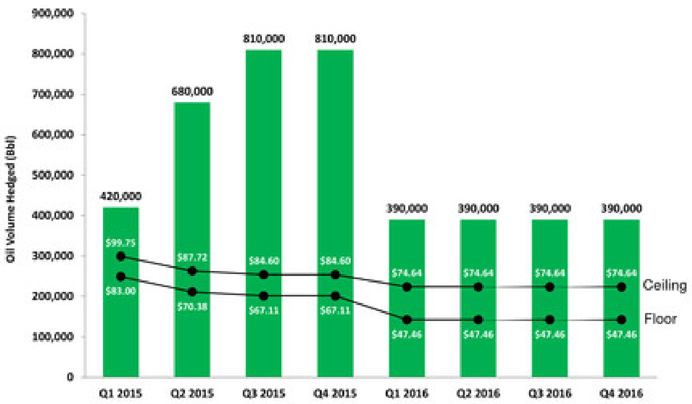
2015 Hedges[(1)]

- **Oil Hedges**: 2.2 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 Hedges**: 9.9 Bcf of natural gas hedged for remainder of 2015 at weighted average floor and ceiling of $3.28/MMBtu and $3.96/MMBtu, respectively – Approximately 70% of natural gas hedged for remainder of 2015[(2)]
- **Natural Gas Liquids**: 2.5 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 $60 million to projected oil and natural gas revenues in 2015*

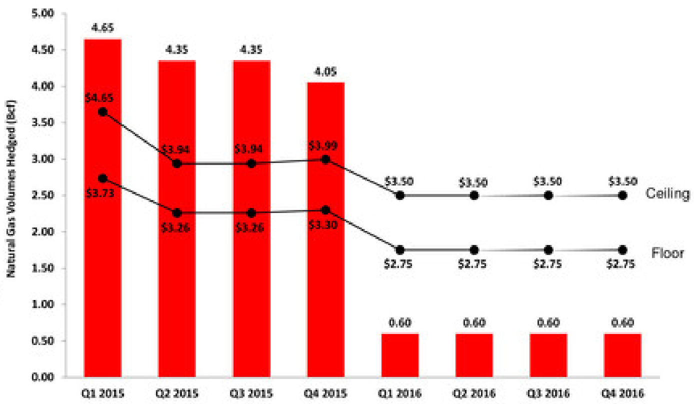
2016 Hedges

- 1.6 million Bbl of oil ($47/Bbl floor and $75/Bbl ceiling) and 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 May 14, 2015.
(2) Based upon the midpoint of 2015 guidance range of 4.1 to 4.3 million Bbl of oil as revised on May 6, 2015 and 24.0 to 26.0 Bcf for natural gas as reaffirmed on May 6, 2015.

Credit Agreement Status

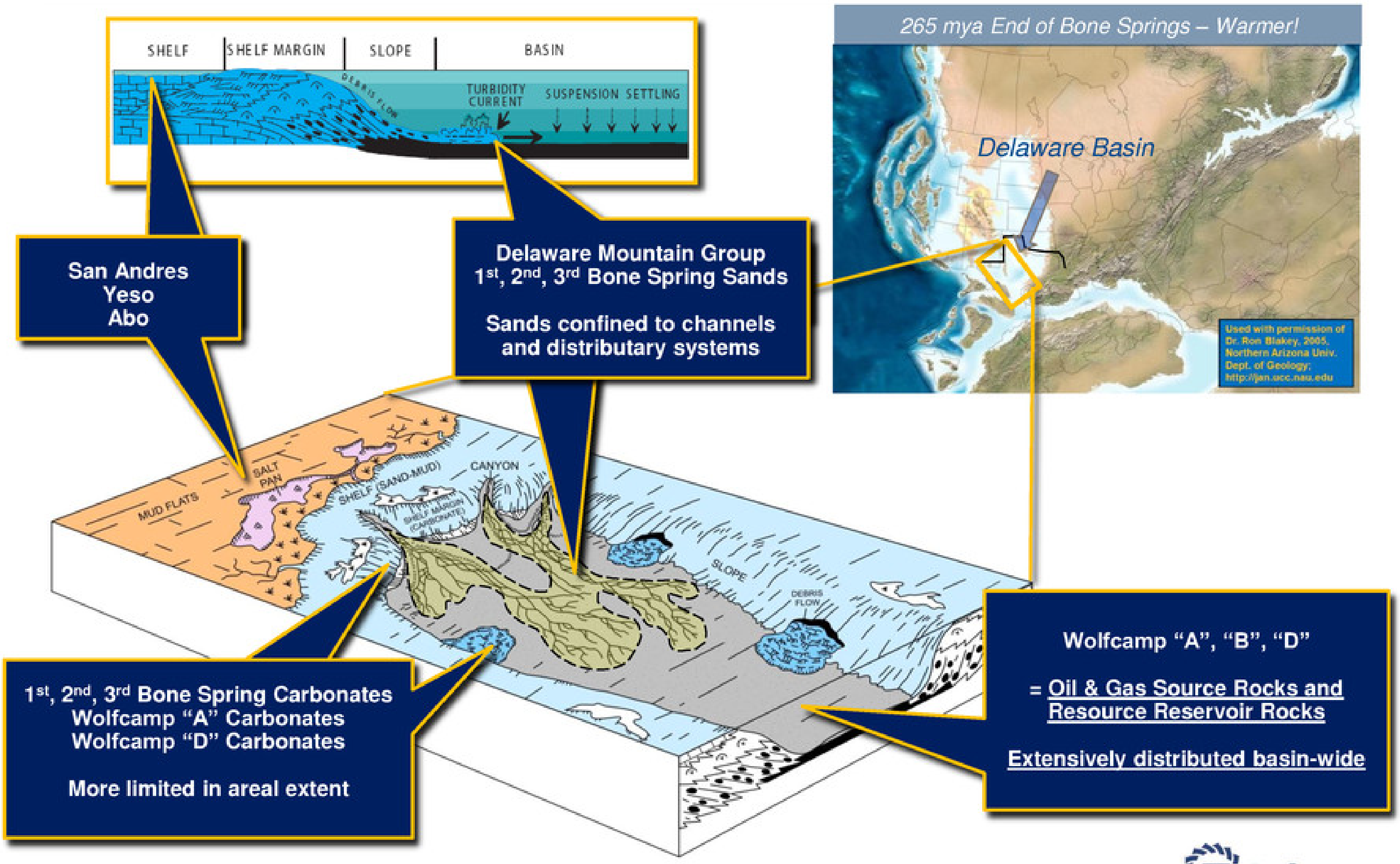
- **Strong, supportive bank group led by Royal Bank of Canada**
- **Borrowing base at $375 million based on December 31, 2014 reserves**
  - *Bank group affirmed $375 million conforming borrowing base in April 2015*
  - *Retained full $375 million conforming borrowing base upon closing of Senior Notes offering*
- **Borrowings outstanding of $340 million at December 31, 2014 and $30 million on April 14, 2015; repaid $380 million following closing of Senior Notes Offering on April 14, 2015**
  - *No borrowings outstanding at May 6, 2015.*
- **Net Debt/Adjusted EBITDA(1)(2) of 1.2x**

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

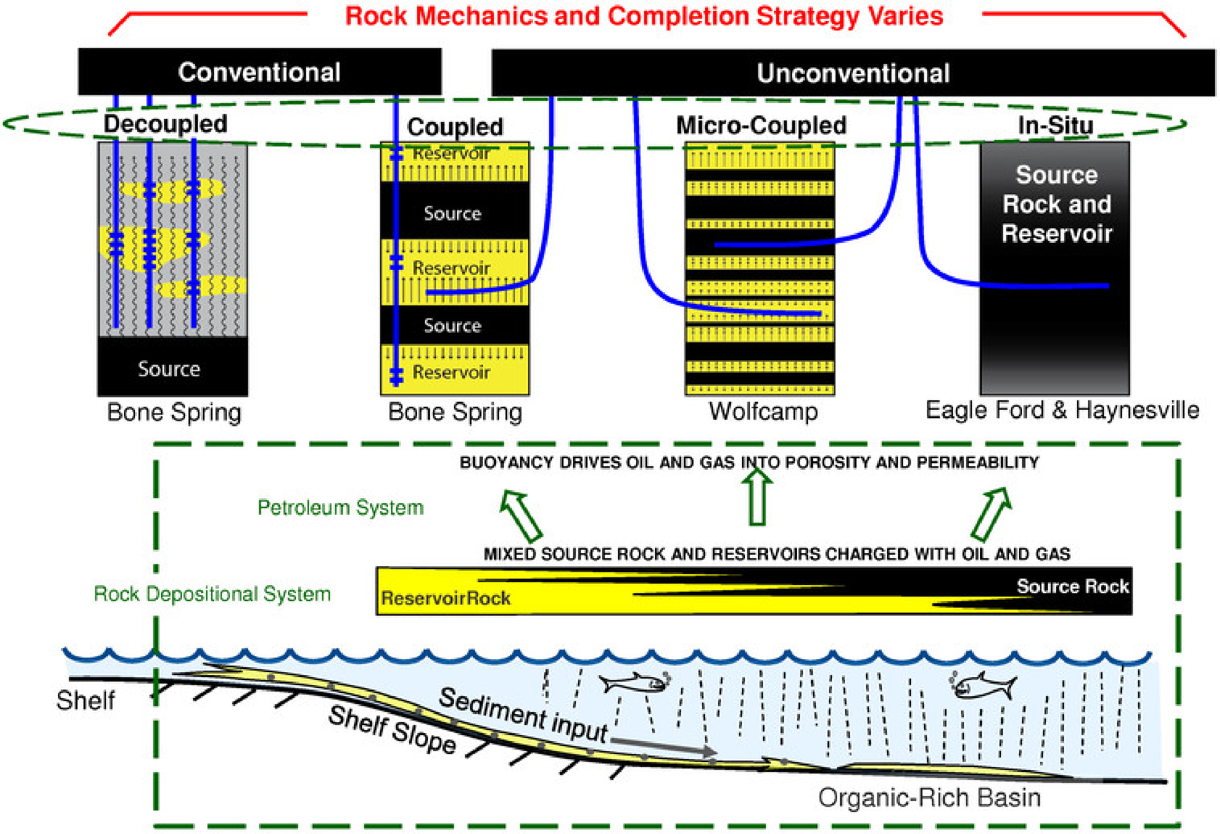
- **Financial covenants**
  - *Maximum Total Debt to Adjusted EBITDA(2) Ratio of not more than 4.25:1.00*
  - *Under this covenant, Total Debt could be ~$1.1 billion based on LTM Adjusted EBITDA(1)*

(1) LTM Adjusted EBITDA at March 31, 2015 and Net Debt at May 6, 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.

“Wolf-Bone” Geological Setting, Predicting Where the Better Rocks Are



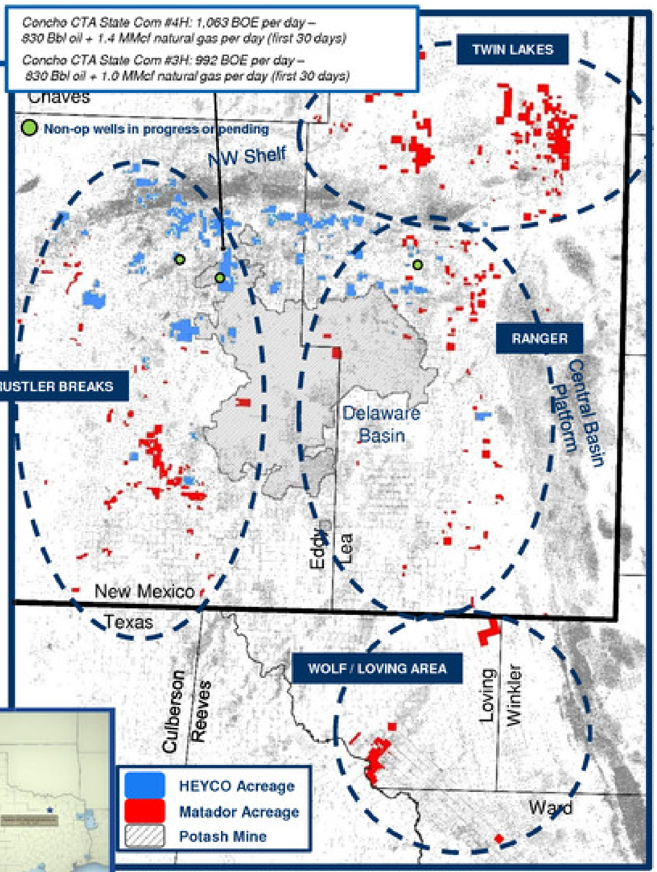
Understanding the Petroleum Systems for Maximum Oil Recovery



Note: Diagram Modified from Bishop (2014).

Delaware Basin Combination Attributes

- **Matador added approximately 58,600 gross (18,200 net) acres located in the northern Delaware Basin in Lea and Eddy Counties, New Mexico from privately-held Harvey E. Yates Company ("HEYCO")**
  - *Strategically links Matador's existing Ranger and Rustler Breaks prospect areas*
- **Over 95% of added acreage consists of state and federal leases and essentially all acreage is held by production from existing wells and production units**
  - *Favorable net revenue interests, most above 80% to as high as 87.5%, enhance returns*
  - *Held-by-production status allows for flexible development*
- **Matador holds largest Delaware Basin acreage position among small and mid-cap publicly traded energy companies(1)**
- **Matador became the second largest operator in terms of the ratio of Delaware Basin acreage to enterprise value or market capitalization among all publicly traded energy companies(1)**
- **Average net daily production of approximately 530 BOE per day (approximately 70% oil) in Q4 2014**
  - *Average net daily production includes contributions from the CTA State Com #3H and #4H*
- **Net PDP reserves of 1.3 million BOE at September 1, 2014 (approximately 60% oil)(2)**
  - *Excludes reserves contributions from the CTA State Com #3H and #4H*
  - *No proved developed non-producing ("PDNP") or proved undeveloped ("PUD") reserves have been assigned to these properties*

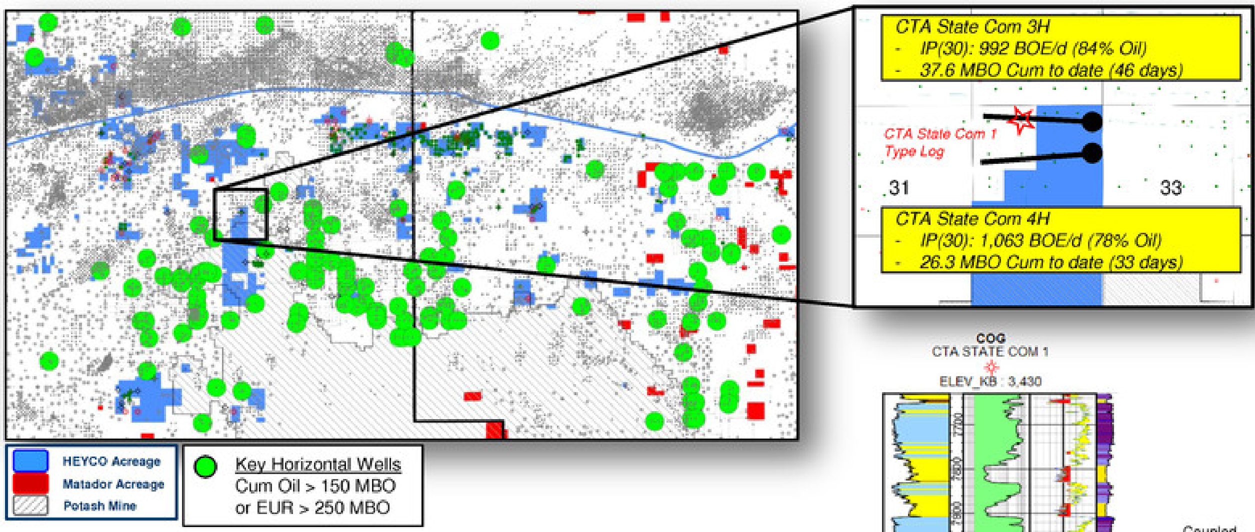


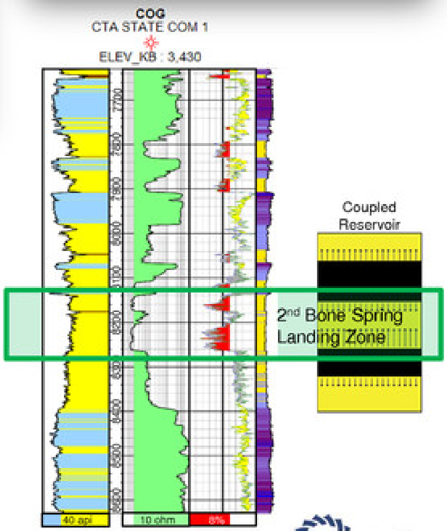
Note: All acreage at February 27, 2015. Some tracts not shown on map.

(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.

(2) PDP reserves at September 1, 2014 based on an independent reserves analysis prepared by Netherland, Sewell & Associates, Inc.

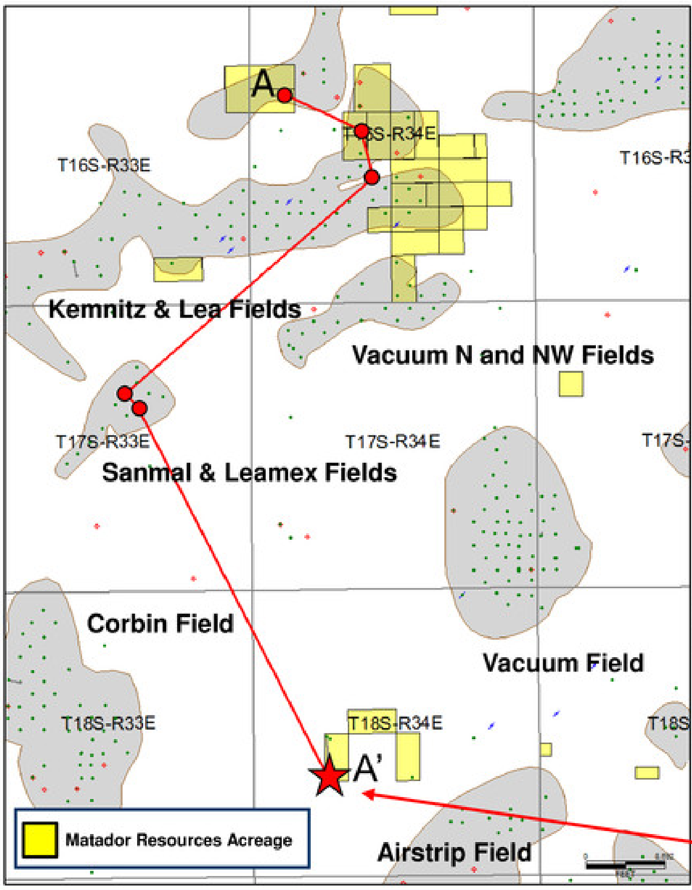
Combination Acreage a Strategic Fit





- HEYCO combination facilitates horizontal development and upsized fracture treatments in a proven area
  - Contiguous acreage provides opportunity for long laterals
- Many acreage blocks compete favorably with Matador inventory
- Matador will pursue operations wherever possible
- Extensive workover program has commenced

North Ranger-Twin Lakes Area Pennsylvanian/Wolfcamp "D" Production Distribution



MATADOR RESOURCES COMPANY
PICKARD STATE 20-18-34 #2H

Townsend Field
166 wells
25 million Bbl, 49 Bcf

Kemnitz Field
94 wells
19 million Bbl, 78 Bcf

Sanmal and Leamex Fields
39 wells
3.3 million Bbl, 5.5 Bcf

Vacuum Field
137 wells
17 million Bbl, 39 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

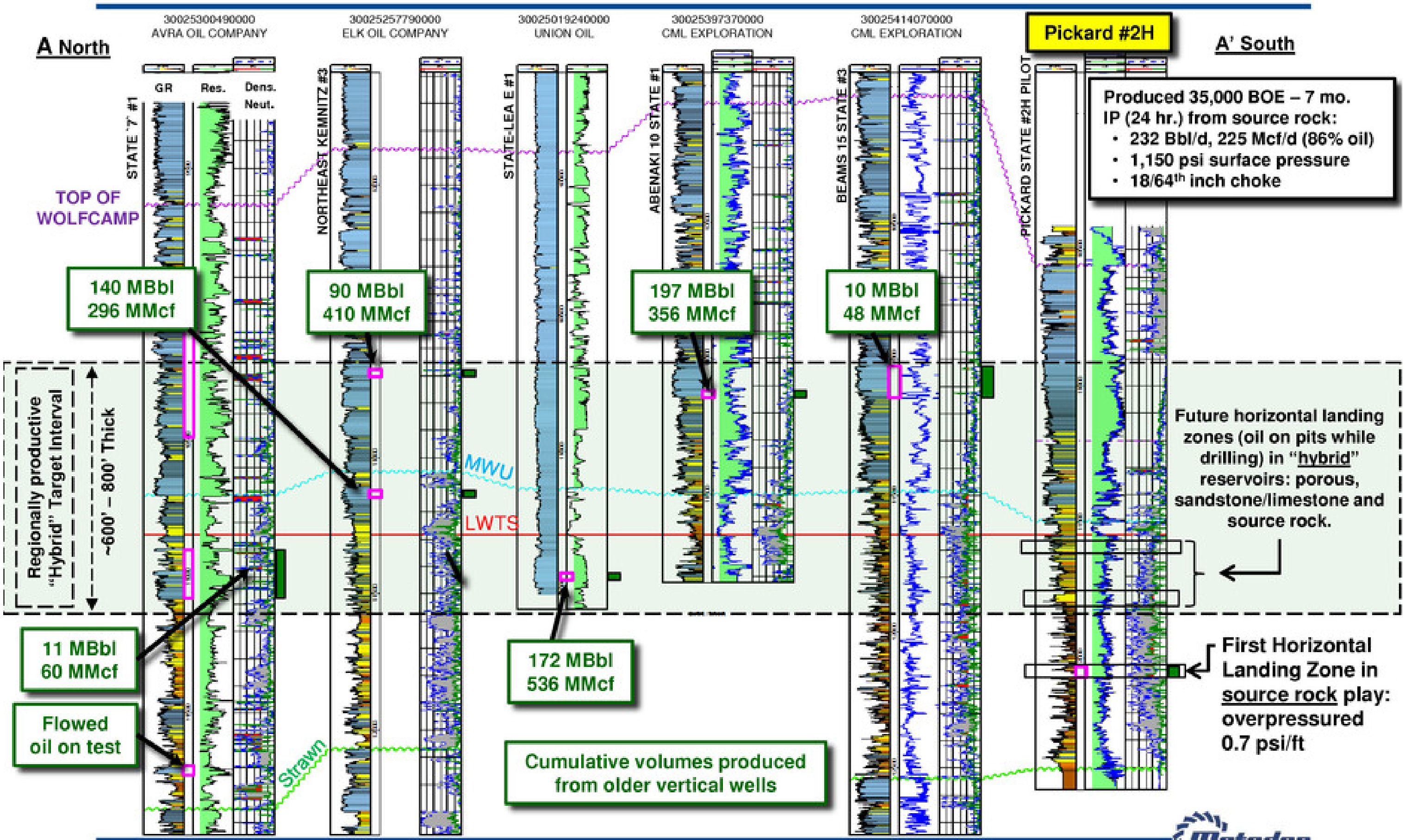
~72 million Bbl, 190 Bcf
~527 vertical wells

~137,000 Bbl per vertical well

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

Bcf = billions of cubic feet of natural gas.

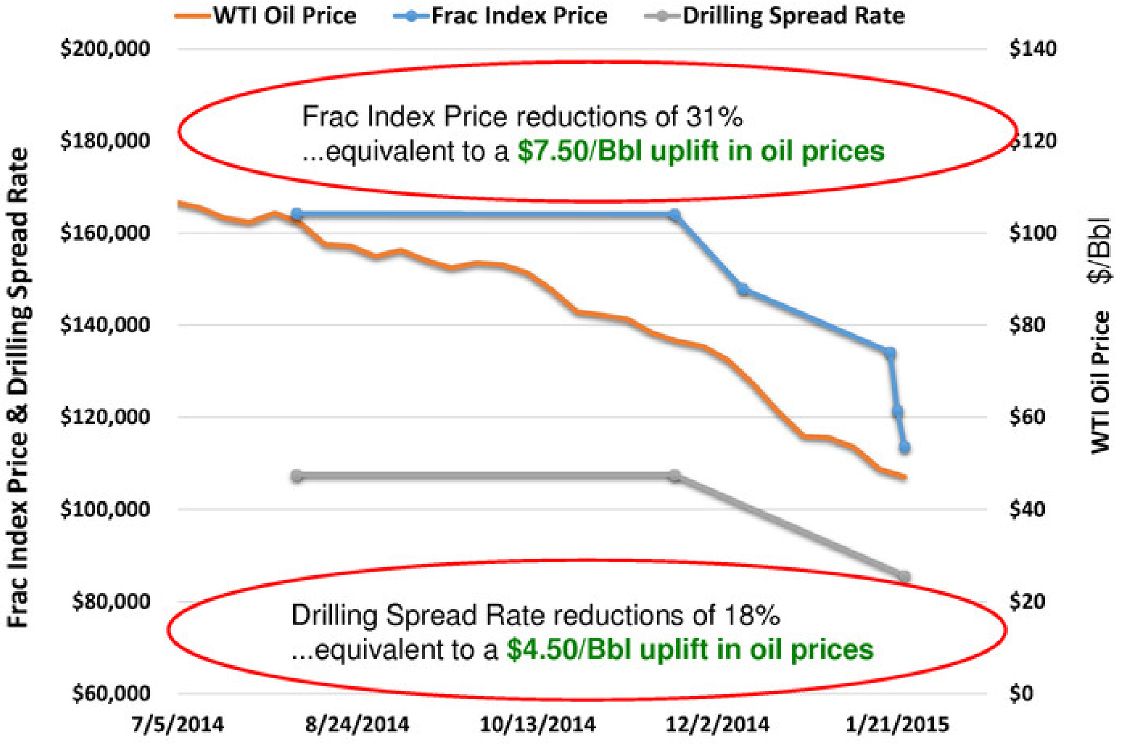
Pennsylvanian/Wolfcamp "D" "Hybrid" Production Target Interval



Matador Resources Company

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

WTI Oil Price and Service Prices



Note: Frac Index Price represents average stage cost on a 22 stage well completion with 25# cross-linked gel, 400,000 lb. 30/50 white sand per stage, 65 barrels per minute average treating rate, 8,500 psi average treating pressure, 4,000 gallons of acid per stage, and 7,000 Bbl clean fluid per stage. This does not represent the current Matador design in any area and/or the current stage cost.

Infrastructure Development

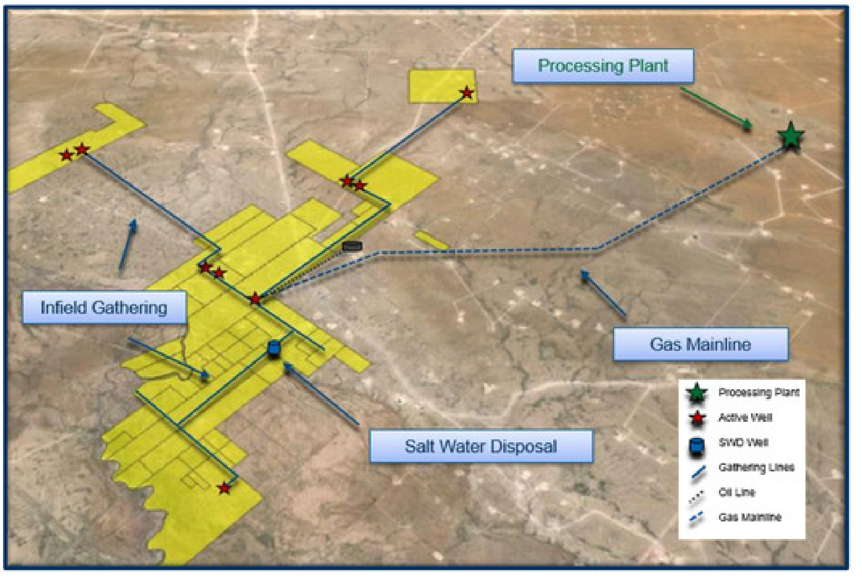
Saltwater disposal savings

$1.30/Bbl of produced water

...equivalent to a **$5.10/Bbl uplift in oil prices**

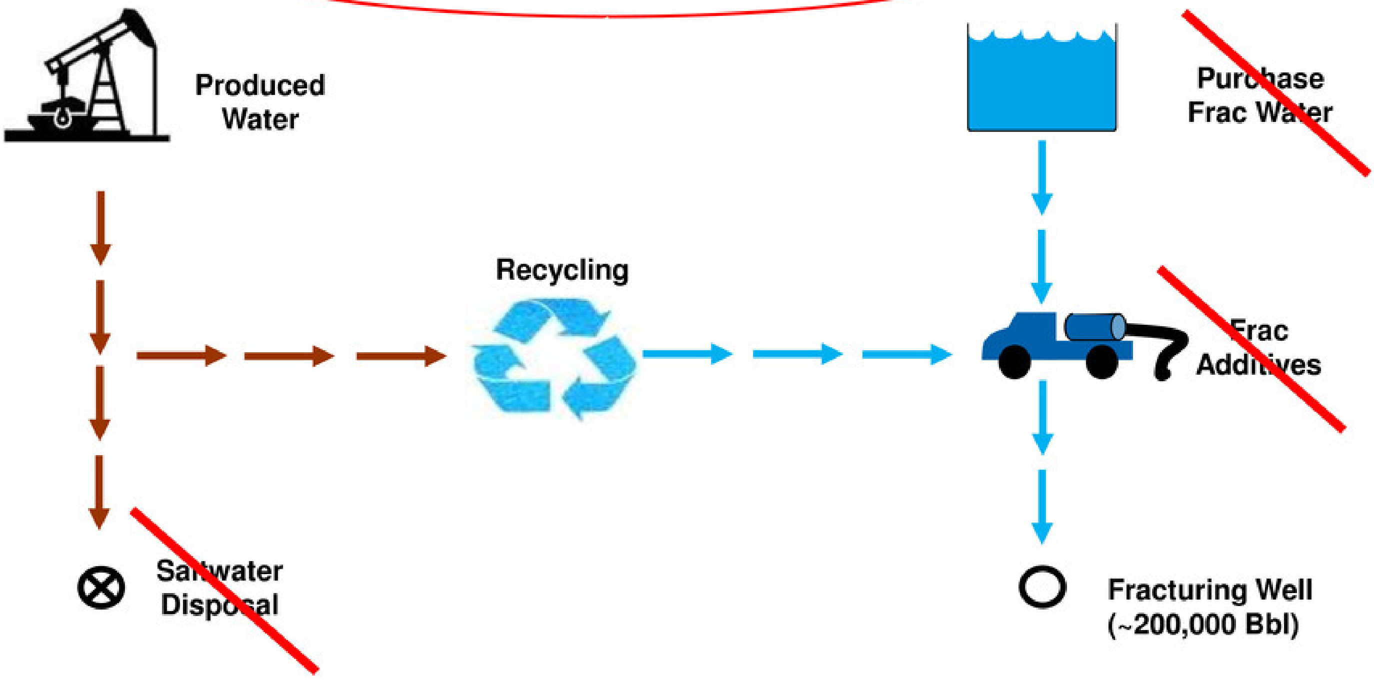
Oil pipeline fee reduction

...an uplift of **$0.90/Bbl in oil prices**



Potential Water Recycling Savings for Loving County

Potential savings of up to $600,000 per well
...equivalent to a **$3.00/Bbl uplift in oil prices**



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 December 31, 2009	At December 31, 2010	At September 30, 2011	At December 31, 2011	At March 31, 2012	At June 30, 2012	At September 30, 2012	At December 31, 2012	At March 31, 2013
PV-10 *(in millions)*	$70.4	$119.9	$155.2	$248.7	$329.6	$303.4	$363.6	$423.2	$438.1
Discounted Future Income Taxes *(in millions)*	$(5.3)	$(8.8)	$(11.8)	$(33.2)	$(42.2)	$(21.9)	$(29.7)	$(28.6)	$(31.1)
Standardized Measure *(in millions)*	$65.1	$111.1	$143.4	$215.5	$287.4	$281.5	$333.9	$394.6	$407.0

	At June 30, 2013	At September 30, 2013	At December 31, 2013	At March 31, 2014	At June 30, 2014	At September 30, 2014	At December 31, 2014	At March 31, 2015
PV-10 *(in millions)*	$522.3	$538.6	$655.2	$739.8	$826.0	$952.0	$1,043.4	$1,070.1
Discounted Future Income Taxes *(in millions)*	$(44.7)	$(52.5)	$(76.5)	$(86.2)	$(103.0)	$(116.9)	$(130.1)	$(120.9)
Standardized Measure *(in millions)*	$477.6	$486.1	$578.7	$653.6	$723.0	$835.1	$913.3	$949.2

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	1Q 2014	2Q 2014	3Q 2014	4Q 2014	1Q 2015
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	$ 16,363	$ 18,226	$ 29,619	$ 46,563	$ (50,234)
Interest expense	106	184	171	222	308	1	144	549	1,271	1,609	2,038	768	1,396	1,616	673	1,649	2,070
Total income tax provision (benefit)	(6,906)	(46)	-	1,430	3,064	(3,713)	(593)	(188)	46	32	2,563	7,056	9,536	10,634	16,504	27,701	(26,390)
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	24,030	31,797	35,143	43,767	46,470
Accretion of asset retirement obligations	39	57	62	51	53	58	59	86	81	80	86	100	117	123	130	134	112
Full-cost ceiling impairment	35,673	-	-	-	-	33,205	3,596	26,674	21,230	-	-	-	-	-	-	-	67,127
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	3,108	5,234	(16,293)	(50,351)	8,557
Stock-based compensation expense	53	128	1,234	991	(363)	191	(51)	363	492	1,032	1,239	1,134	1,795	1,834	1,038	857	2,337
Net loss on asset sales and inventory impairment	-	-	-	154	-	60	-	425	-	192	-	-	-	-	-	-	97
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**	**$ 56,345**	**$ 69,464**	**$ 66,814**	**$ 70,320**	**$ 50,146**

(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	1Q 2014	2Q 2014	3Q 2014	4Q 2014	1Q 2015
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	$ 31,945	$ 81,530	$ 66,883	$ 71,123	$ 93,346
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)	21,729	(15,221)	(586)	56	(45,234)
Interest expense	106	184	171	222	308	1	144	549	1,271	1,609	2,038	768	1,396	1,616	673	1,649	2,070
Current income tax (benefit) provision	-	(45)	(1)	-	-	-	188	(188)	46	32	902	(576)	1,275	1,539	(156)	(2,525)	-
Net loss attributable to non-controlling interest in subsidiary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	(36)
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**	**$ 56,345**	**$ 69,464**	**$ 66,814**	**$ 70,320**	**$ 50,146**

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	LTM at	LTM at
(In thousands)	2008	2009	2010	2011	2012	2013	2014	6/30/2013	9/30/2014	3/31/2015
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)	$79,582	$44,174
Interest expense	-	-	3	683	1,002	5,687	5,334	3,574	4,453	6,008
Total income tax (benefit) provision	20,023	(9,925)	3,521	(5,521)	(1,430)	9,697	64,375	(703)	43,730	28,449
Depletion, depreciation and amortization	12,127	10,743	15,596	31,754	80,454	98,395	134,737	97,801	114,772	157,177
Accretion of asset retirement obligations	92	137	155	209	256	348	504	307	470	499
Full-cost ceiling impairment	22,195	25,244	-	35,673	63,475	21,229	0	51,499	-	$67,127
Unrealized loss (gain) on derivatives	(3,592)	2,375	(3,139)	(5,138)	4,802	7,232	(58,302)	13,945	(7,345)	(52,853)
Stock-based compensation expense	665	656	898	2,406	140	3,897	5,524	1,836	5,801	6,066
Net (gain) loss on asset sales and inventory impairment	(136,977)	379	224	154	485	192	0	617	-	97
Adjusted EBITDA	**$18,411**	**$15,184**	**$23,635**	**$49,911**	**$115,923**	**$191,771**	**$262,943**	**$148,105**	**$241,463**	**$256,744**

	Year Ended December 31,							LTM at	LTM at	LTM at
(In thousands)	2008	2009	2010	2011	2012	2013	2014	6/30/2013	9/30/2014	3/31/2015
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	$232,636	$312,882
Net change in operating assets and liabilities	(17,888)	15,717	(2,230)	(12,594)	(9,307)	6,210	5,978	(12,161)	2,292	(60,985)
Interest expense	-	-	3	683	1,002	5,687	5,334	3,574	4,453	6,008
Current income tax (benefit) provision	$10,448	($2,324)	(1,411)	(46)	0	404	133	78	2,082	(1,142)
Net loss attributable to non-controlling interest in subsidiary	0	0	0	0	-	0	17	0	0	(19)
Adjusted EBITDA	**$18,411**	**$15,184**	**$23,635**	**$49,911**	**$115,923**	**$191,771**	**$262,943**	**$148,105**	**$241,463**	**$256,744**

Note: LTM is last 12 months.

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.

	Six Months Ended					
(In thousands)	12/31/2011	6/30/2012	12/31/2012	6/30/2013	12/31/2013	6/30/2014
Unaudited Adjusted EBITDA reconciliation to Net (Loss) Income:						
Net (loss) income	$ 10,135	$ (2,875)	$ (30,385)	$ 9,615	$ 35,479	$ 34,589
Interest expense	393	309	693	2,881	2,806	3,012
Total income tax (benefit) provision	1,430	(649)	(781)	78	9,619	20,170
Depletion, depreciation and amortization	16,463	31,119	49,335	48,466	49,929	55,827
Accretion of asset retirement obligations	113	111	145	162	186	241
Full-cost ceiling impairment	0	33,205	30,270	21,229	-	-
Unrealized loss (gain) on derivatives	(6,474)	(11,844)	16,646	(2,701)	9,933	8,342
Stock-based compensation expense	2,225	(172)	312	1,524	2,373	3,629
Net loss on asset sales and inventory impairment	154	60	425	192	-	-
Adjusted EBITDA	**$ 24,439**	**$ 49,264**	**$ 66,660**	**$ 81,446**	**$ 110,325**	**$ 125,810**

	Six Months Ended					
(In thousands)	12/31/2011	6/30/2012	12/31/2012	6/30/2013	12/31/2013	6/30/2014
Unaudited Adjusted EBITDA reconciliation to Net Cash Provided by Operating Activities:						
Net cash provided by operating activities	$ 42,337	$ 51,526	$ 72,702	$ 83,912	$ 95,558	$ 113,475
Net change in operating assets and liabilities	(18,290)	(2,571)	(6,735)	(5,425)	11,635	6,509
Interest expense	393	309	693	2,881	2,806	3,012
Current income tax provision (benefit)	(1)	-	-	78	326	2,814
Adjusted EBITDA	**$ 24,439**	**$ 49,264**	**$ 66,660**	**$ 81,446**	**$ 110,325**	**$ 125,810**