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) March 18, 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: March 18, 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.

Investor Presentation

March 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
- Sold 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

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

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

2003 — 2008 — 2010 — 2012 — 2014 — 2015

Matador has grown almost entirely through the drill bit, with focus on unconventional reservoir plays, initially in Cotton Valley and Haynesville

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

(1) Tom Brown acquired by Encana in 2004.

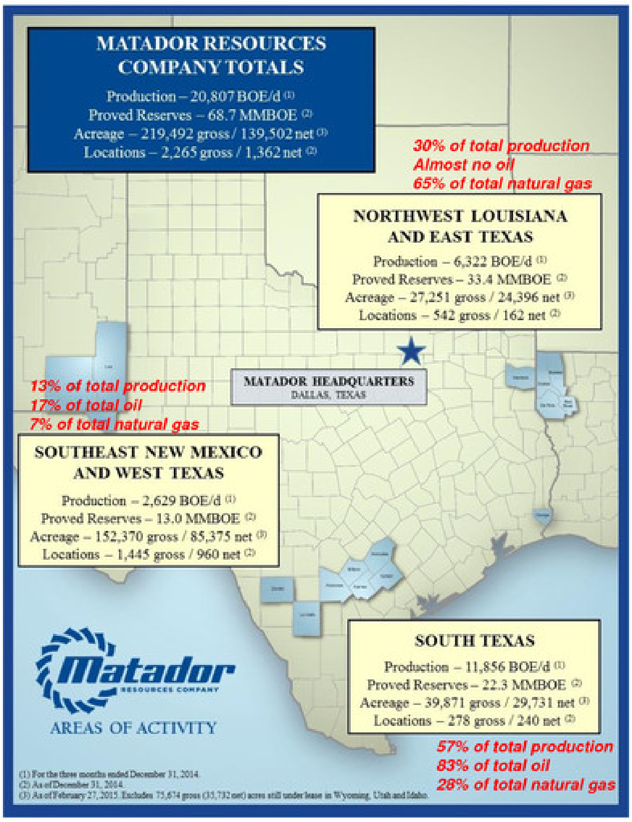
Company Overview

Exchange: Ticker	NYSE: MTDR
Shares Outstanding(1)	76.7 million common shares
Share Price(2)	$20.91/share
Market Capitalization(1)(2)	$1.6 billion

	2014 Actual	*2015 Guidance*(3)	*% Change*
Capital Spending	$610 million	$350 million	- 43%
Total Oil Production	3.32 million Bbl	4.0 to 4.2 million Bbl	+ 23%
Total Natural Gas Production	15.3 Bcf	24.0 to 26.0 Bcf	+ 63%
Oil and Natural Gas Revenues	$367.7 million	$270 to $290 million(4)	- 24%
Adjusted EBITDA(5)	$262.9 million	$200 to $220 million(4)	- 20%

(1) Shares outstanding as reported in the Form 10-K for the year ended December 31, 2014 filed on March 2, 2015.
(2) As of March 9, 2015.
(3) As reaffirmed on March 2, 2015; does not include capital expenditures associated with the HEYCO transaction.
(4) Estimated 2015 oil and natural gas revenues and Adjusted EBITDA based on production guidance range as reaffirmed on March 2, 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.
(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)	**$1.6 billion**	
Avg. Daily Production – Q4 2014(2)	**20,807 BOE/d**	+74%*
Oil (% total)	11,062 Bbl/d (53%)	
Natural Gas (% total)	58.5 MMcf/d (47%)	
Proved Reserves @ 12/31/2014	**68.7 million BOE**	+33%*
% Proved Developed	45%	
% Oil	35%	
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 year-over-year increase.
(1) Market capitalization based on shares outstanding as reported in the Form 10-K for the year ended December 31, 2014 filed on March 2, 2015 and closing share price as of March 9, 2015.
(2) Average daily production for the three months ended December 31, 2014.
(3) 2015 estimated capital expenditures for operations only; does not include capital expenditures associated with the HEYCO transaction.
(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 in the Permian Basin.

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[7]		December 31, 2014[9]
Oil Production	▪ 414 Bbl/d of oil ▪ 6% oil	12x growth in oil production	▪ 4,916 Bbl/d of oil ▪ 46% oil	125% growth in oil production	▪ 11,062 Bbl/d of oil ▪ 53% 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	Doubled oil reserves	▪ 69 MMBOE ▪ 24.2 MMBbl of oil ▪ 35% oil
PV-10[2]	▪ $155.2 million ▪ 24% in Eagle Ford $91.00 oil / $4.16 gas	Over 3x growth in PV-10	▪ $522.3 million ▪ 90% in Eagle Ford $88.13 oil / $3.44 gas	Doubled PV-10	▪ $1.04 billion ▪ 58% in Eagle Ford $91.48 oil / $4.35 gas
LTM Adjusted EBITDA[3]	▪ $50 million[4]	~200% growth	▪ $148 million	78% growth	▪ $263 million[10]
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[11]
Enterprise Value ("EV")[5]	▪ $0.65 billion[6]	Doubled EV	▪ $1.2 billion[8]	67% EV growth	▪ $2.0 billion[12]

(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. Note oil prices shown in $/Bbl and natural gas prices shown in $/MMBtu.
(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) Enterprise value equals market capitalization plus borrowings under our revolving credit agreement.
(6) As of February 7, 2012 at time of IPO.
(7) Unless otherwise noted, at or for the three months ended June 30, 2013.
(8) As of September 1, 2013.
(9) Unless otherwise noted, at or for the three months ended December 31, 2014.
(10) For the year ended December 31, 2014.
(11) As of February 27, 2015.
(12) As of March 9, 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 in being a successful publicly-held company*
- **Execution**
  - *Increase total production by ~40%, with oil production expected to increase to ~4.1 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*

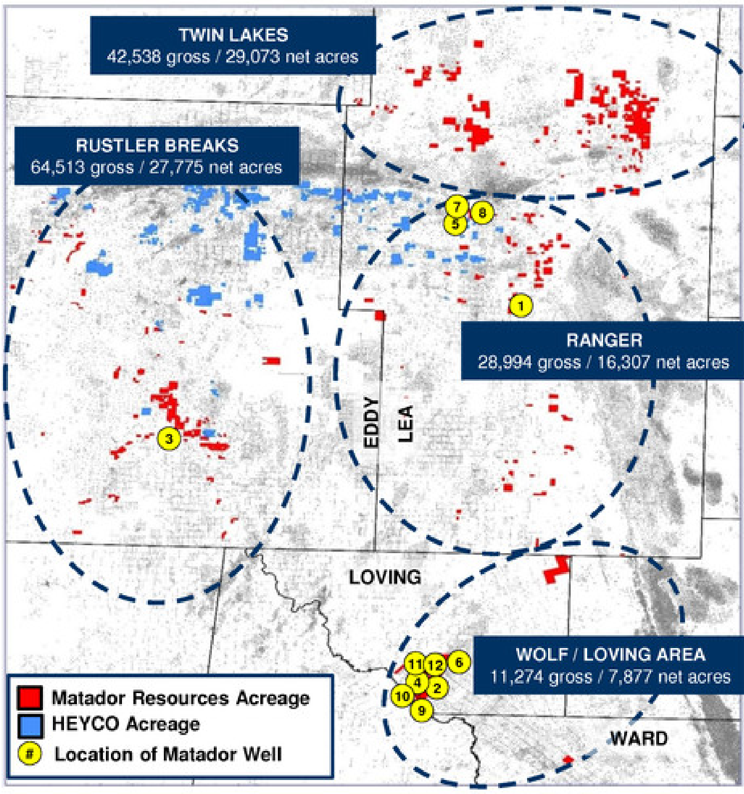
(1) Includes Matador Resources Company and its predecessor entities.



Permian Basin

Southeast New Mexico and West Texas

Permian Basin Acreage Position



Permian Basin Total	
Gross Acres	152,370 acres
Net Acres	85,375 acres

Successful performance of initial horizontal wells[1]

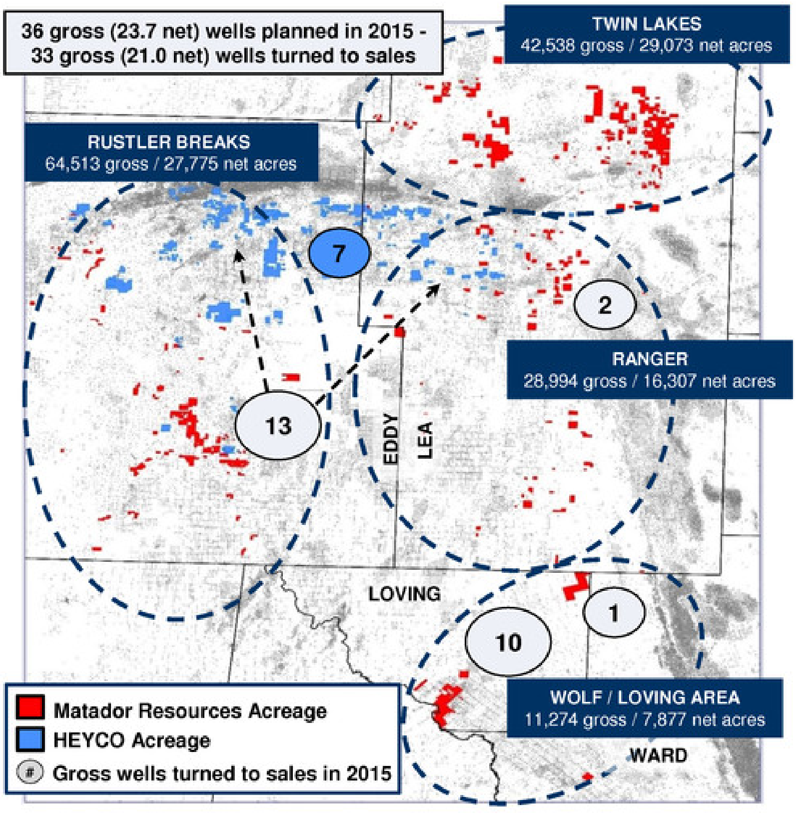
	Well	Cumulative Production Months	Cumulative Production Oil Eq. (BOE)	Cumulative Production % Oil	Current Production Oil (Bbl/d)	Current Production Natural Gas (Mcf/d)	EUR[2] (MBOE)
1	Ranger 33 State Com #1H (2nd Bone Spring)	15	184,000	91%	190	130	600
2	Dorothy White #1H (Wolfcamp "X")	12.5	310,000	66%	450	1,700	1,000
3	Rustler Breaks 12-24-27 #1H (Wolfcamp "B")	9	134,000	43%	140	1,250	600
4	Norton Schaub #1H (Wolfcamp "X")	6	122,000	69%	500	1,600	700
5	Pickard State 20-18-34 #1H (2nd Bone Spring)	6	71,000	92%	330	180	400
6	Johnson 44-02S-B53 #204H (Wolfcamp "X")	4	117,000	65%	530	1,800	800
7	Pickard State 20-18-34 #2H (Wolfcamp "D")	7	35,000	86%	125	200	200
8	Jim Rolfe 22-18-34 RN State #131Y (3rd Bone Spring)	3	8,000	95%	44	10	70

Recent activity and 24-hour initial potential tests

	Well	Date	Oil Eq. (BOE/d)	Oil (Bbl/d)	Natural Gas (Mcf/d)	% Oil	P_f[3] (psi)	Choke (inches)
9	Arno #1H (Wolfcamp "X")	Mid-Sept 2014	1,110	300	4,900	27%	4,100	26/64
10	Norton Schaub 84-TTT-B33 WF #2010H (Wolfcamp "A")	Late Dec 2014	875	608	1,600	69%	2,600	28/64
11	Barnett 90-TTT-B01-WF #201H (Wolfcamp "X")	Early Mar 2015	1,268	720	3,300	57%	3,225	26/64
12	Barnett 90-TTT-B01-WF #205H (Wolfcamp "Y")	Mid-Feb 2015	1,377	738	3,800	54%	3,475	26/64

Note: All acreage at February 27, 2015. Some tracts not shown on map.
(1) As of January 31, 2015.
(2) Estimated ultimate recovery, thousands of barrels of oil equivalent.
(3) Flowing surface pressure.

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 "substitute" wells on HEYCO acreage for 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.

Matador Resources Company

HEYCO Combination Overview

Matador has combined assets with Harvey E. Yates Company ("HEYCO"), headquartered in Roswell, New Mexico, a subsidiary of HEYCO Energy Group, Inc., including certain oil and natural gas producing properties and undeveloped acreage located in Lea and Eddy Counties, New Mexico

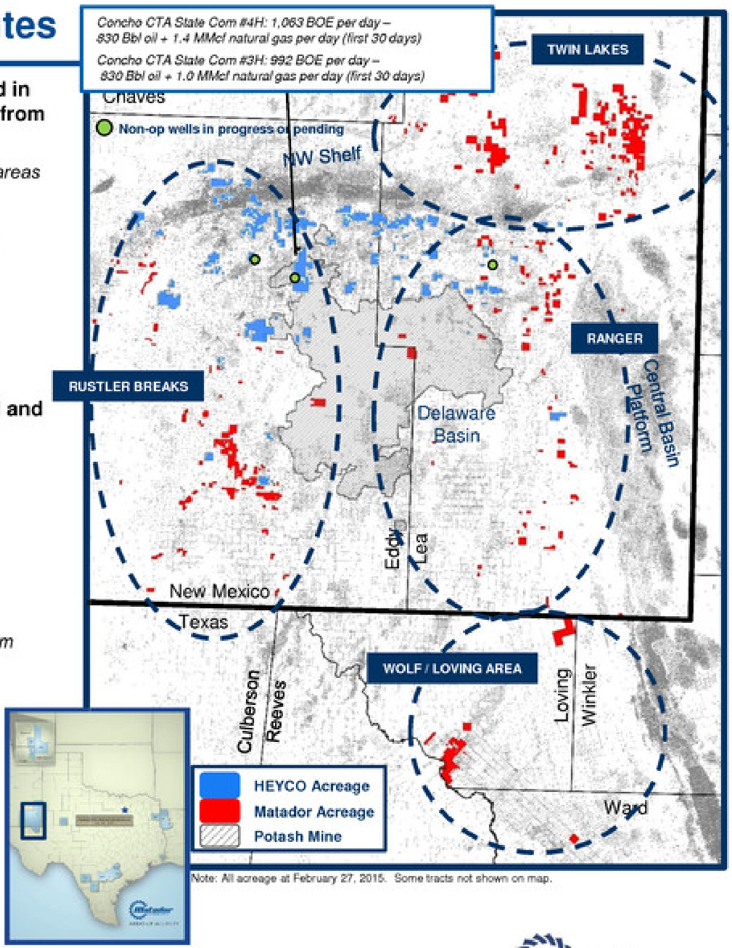
- **HEYCO was privately owned by members of the Harvey E. Yates family of Southeastern New Mexico, who have been active in the oil and natural gas business in the Delaware Basin since the 1920s**
- **Consideration for the combination**
  - **$36.6 million in cash (including assumed debt obligations)(1)**
  - **3,300,000 shares of Matador Common Stock**
  - **150,000 shares of newly created Series A Convertible Preferred Stock(2)**
- **Mr. George M. Yates, CEO of HEYCO Energy Group, Inc., shall join Matador's Board of Directors on or before April 15, 2015**
- **Upon closing of the transaction, HEYCO Energy Group, Inc. became one of the largest shareholders in Matador Resources Company, owning approximately 6% of the equity of the combined entity**
- **Closed February 27, 2015**

(1) Includes $3.0 million Matador paid for customary purchase price adjustments, including adjusting for production, revenues and operating and capital expenditures from September 1, 2014 to closing.

(2) Each share of Series A Preferred Stock will automatically convert into ten shares of Matador common stock, subject to customary anti-dilution adjustments, upon the vote and approval by Matador's shareholders of an amendment to Matador's Amended and Restated Certificate of Formation to increase the number of shares of authorized Matador common stock. Each share of Series A Preferred Stock is entitled to ten votes on each matter submitted to Matador's shareholders for vote. Beginning on August 27, 2015 and until such time as the Series A Preferred Stock is converted to common stock, the holders will be entitled to a quarterly dividend of $1.80 per share. Neither the issuance of the Series A Preferred Stock nor the common stock issued in connection with this business combination will be registered under the Securities Act of 1933, as amended, and neither the Series A Preferred Stock nor such common stock may be offered or sold in the United States absent such registration or an applicable exemption from registration requirements. As part of this transaction, the Company has entered into a registration rights agreement with HEYCO Energy Group, Inc. providing certain demand and piggyback registration rights, with demand registration rights exercisable on or after February 27, 2016.

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*

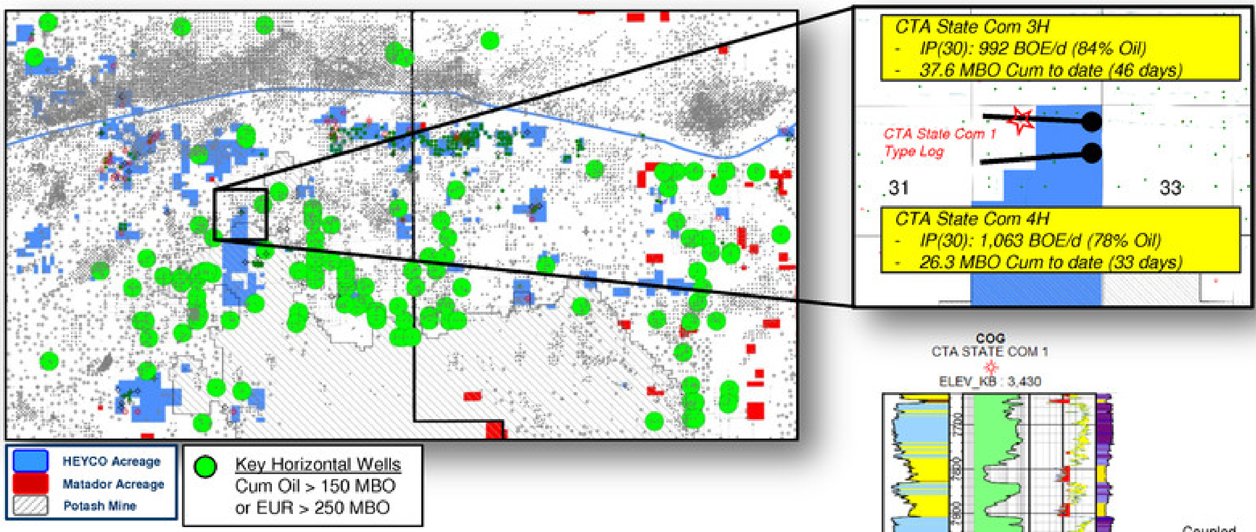


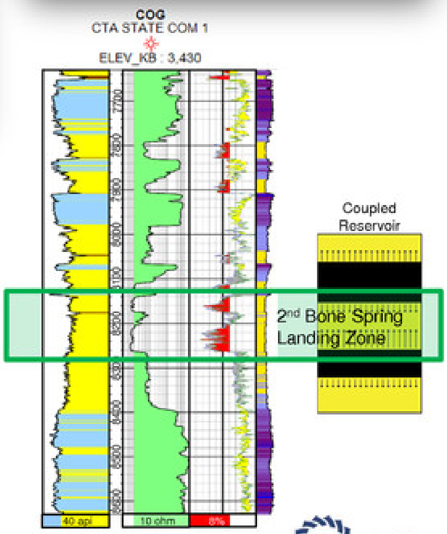
Note: All acreage at February 27, 2015. Some tracts not shown on map.

(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

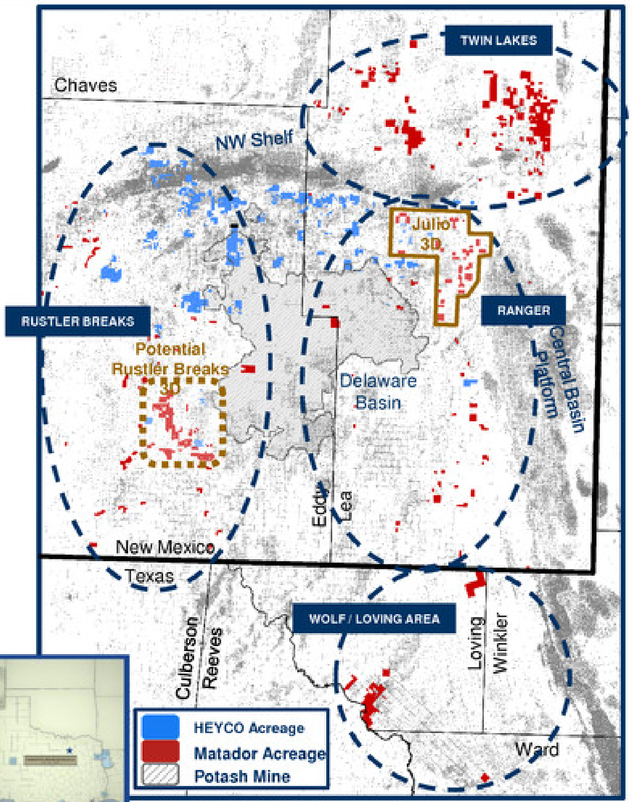




- HEYCO combination facilitates horizontal development and upsized fracture treatments in a proven area
  - Contiguous acreage provides opportunity for long laterals
- Many acreage blocks complement Matador inventory
- Matador will pursue operations wherever possible
- Extensive workover program has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

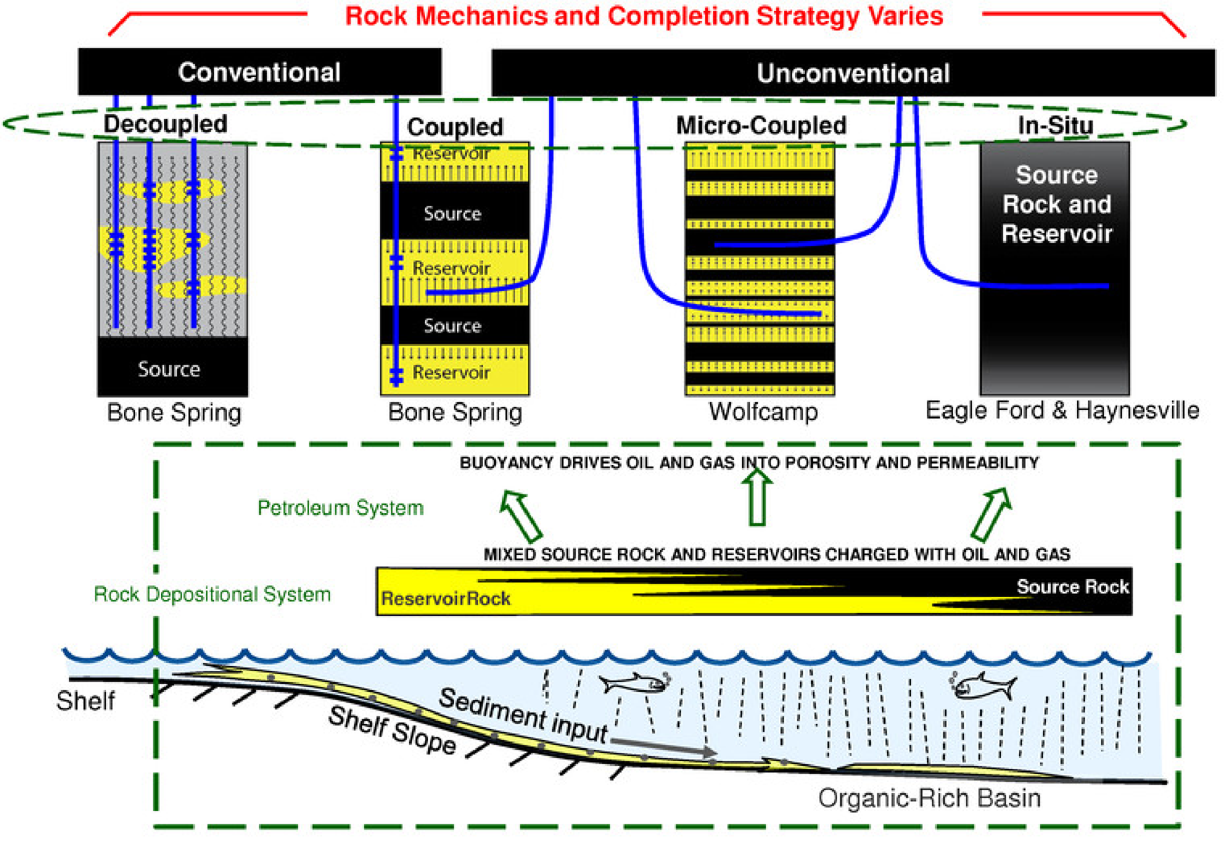
The Key: Good Science, Technology and Execution

- **Attractive Targets:**
  - ~4,000 feet of productive oil bearing zones
- **Wolf:**
  - High quality Wolfcamp and Bone Spring reservoir sands interbedded with source rock; *micro-seismic and 3D seismic interpretation* currently under way
- **HEYCO-Ranger:**
  - Sweet spots for porosity, permeability, oil source, migration and entrapment: *stacked reservoirs* at point of entry into the basin (1st, 2nd, 3rd Bone Spring and Wolfcamp)
  - Ongoing formation evaluation: *core analysis and petrophysics* (CoreLab consortium)
  - One of two companies to acquire *122 square miles of new 3D seismic* data in the Ranger area (Q4 2014)
- **Rustler Breaks:**
  - Dominated by *high permeability submarine fan deposits* with multiple stacked targets in Wolfcamp and Bone Spring
  - Formation evaluation and preparations for potential Rustler Breaks *3D seismic acquisition*
- **Twin Lakes:**
  - Prioritizing reservoir and target inventory focusing on Pennsylvanian-Wolfcamp *micro-coupled source rocks*; existing 3D seismic interpretation under way
- **Cross-Training of Disciplines**



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

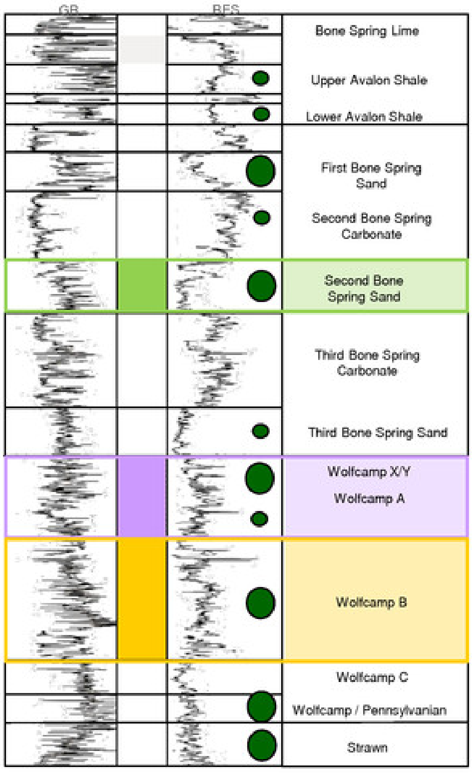
Understanding the Petroleum Systems for Maximum Oil Recovery



Note: Diagram Modified from Bishop (2014).

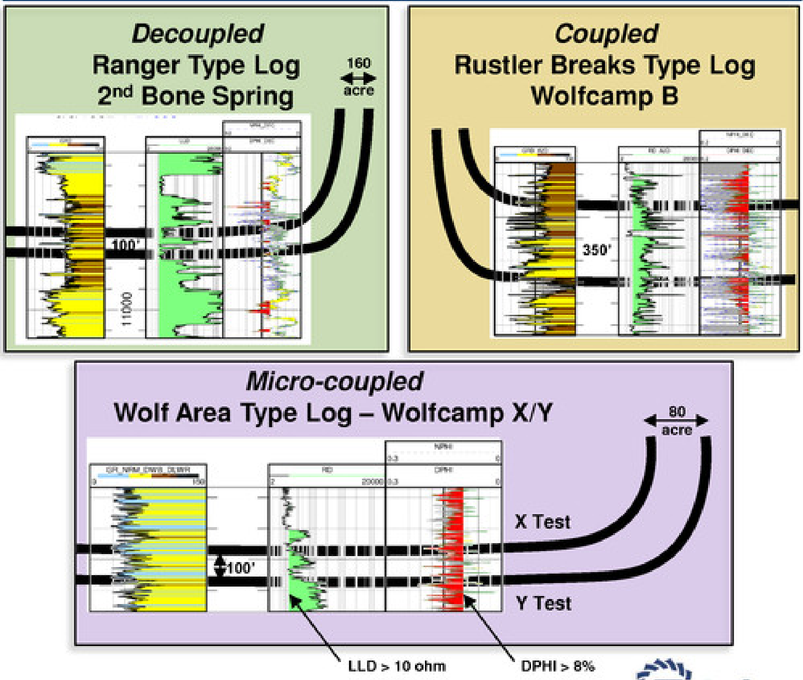
4,000 Feet of Hydrocarbon Column Creates Opportunity

INTER-Formational Stacked Pay

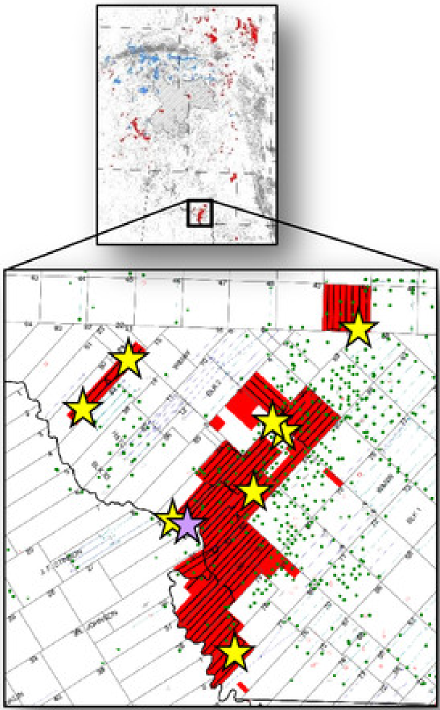


- Determining "Good, Better, Best" important as potential exceeds inter-formational stacked pay
- 2015 program will expand on intra-formational stacked pay tests performed in each asset area

INTRA-Formational Stacked Pays



Well Inventory – Wolf



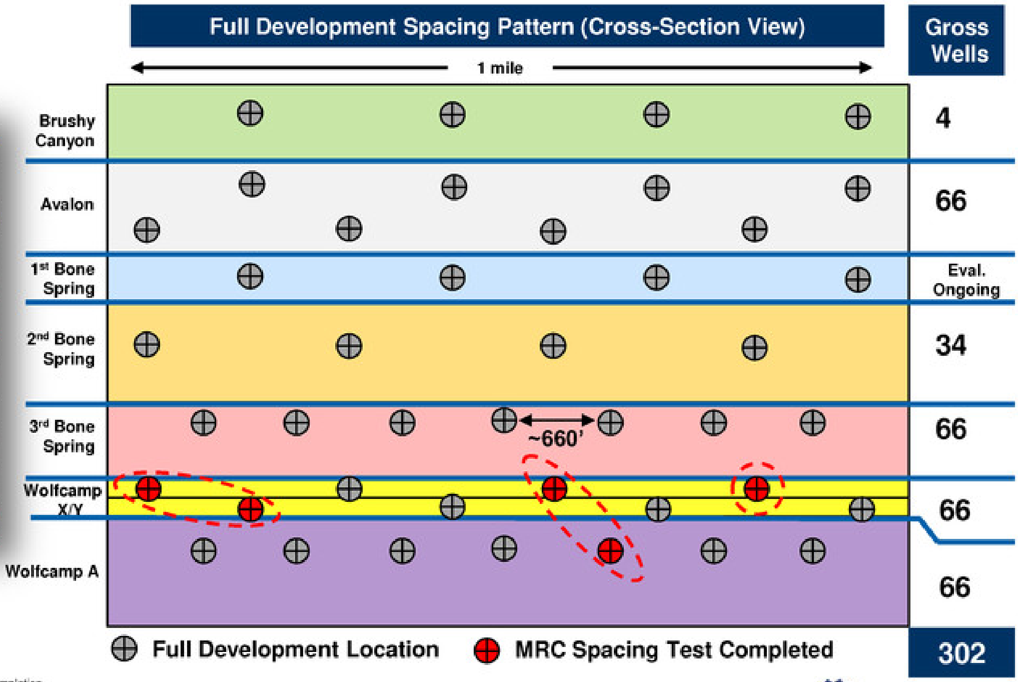
Matador Well Location

Wolfcamp X/Y

Wolfcamp A

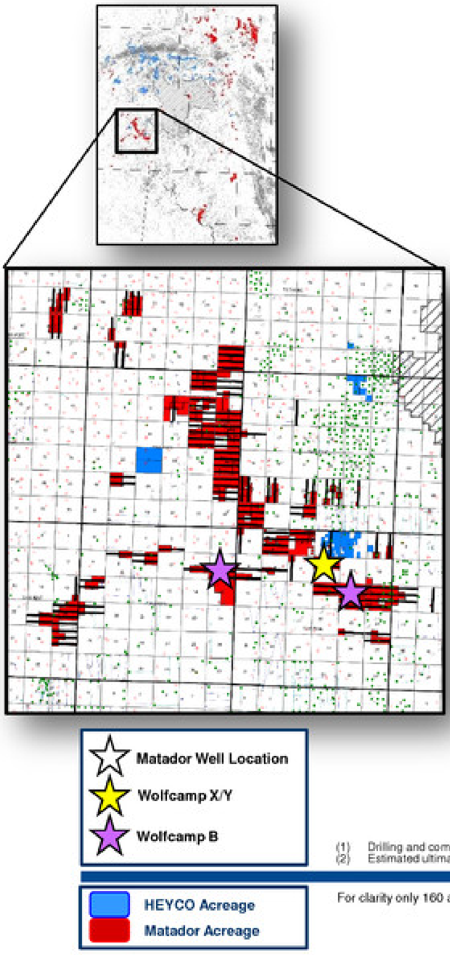
Matador Acreage

Development Well	D&C(1) CapEx	EUR(2) (MBOE)
Bone Spring	$7 – $8 million	450 – 600
Wolfcamp	$9 – $10 million	650 – 1,100

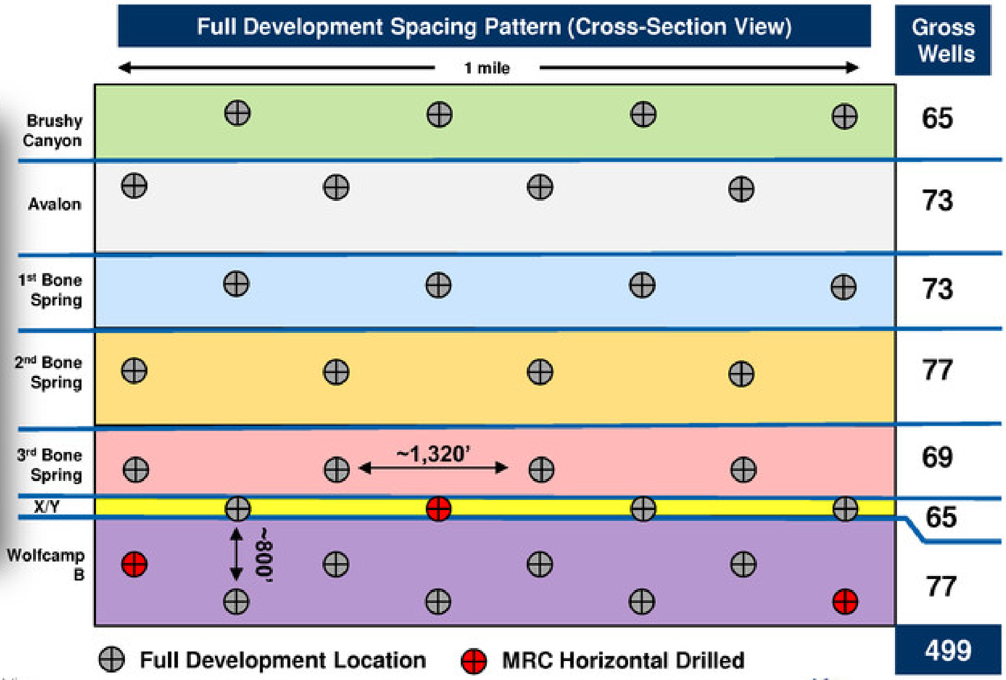


(1) Drilling and completion.
(2) Estimated ultimate recovery, thousands of barrels of oil equivalent.

Well Inventory – Rustler Breaks



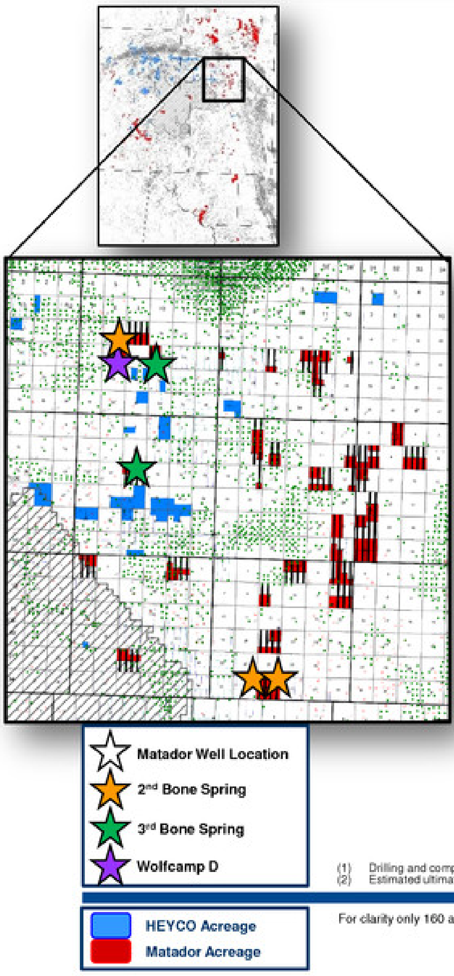
Development Well	D&C[1] CapEx	EUR[2] (MBOE)
Bone Spring	$6 – $7 million	350 – 650
Wolfcamp	$7 – $8 million	500 – 900



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

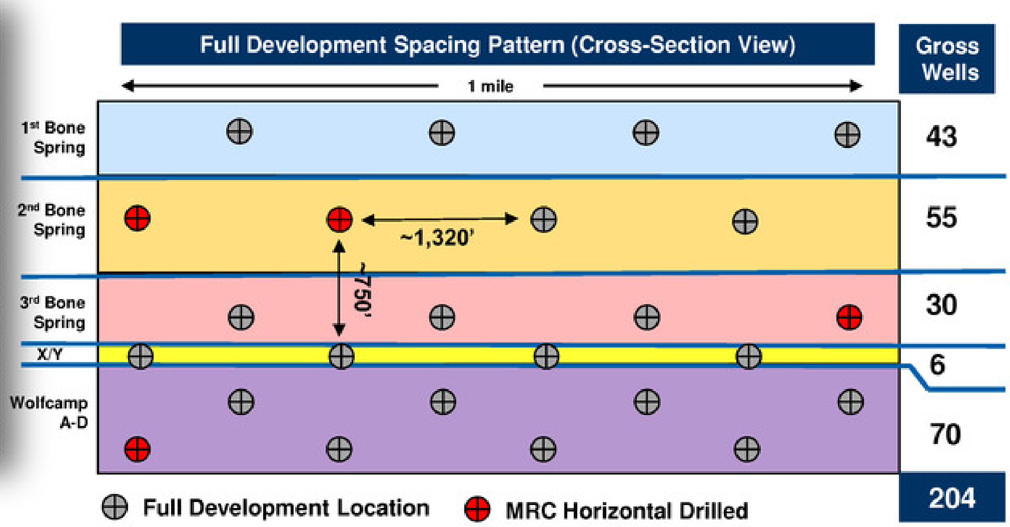
For clarity only 160 ac. well slots shown

Well Inventory – Ranger



Development Well	D&C(1) CapEx	EUR(2) (MBOE)
Bone Spring	$7 – $8 million	400 – 600
Wolfcamp	$8 – $9 million	200 – 800*

* Based on Volumetrics and 4-8% Recovery Factor



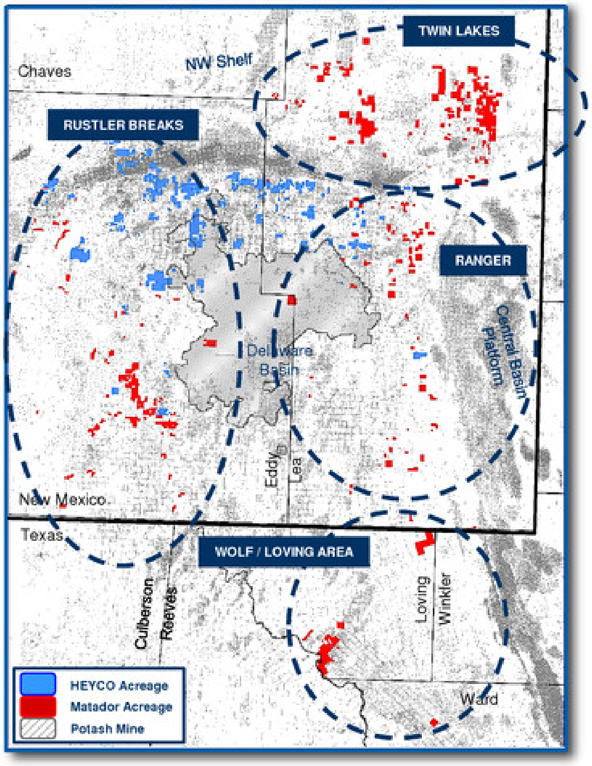
(1) Drilling and completion.
(2) Estimated ultimate recovery, thousands of barrels of oil equivalent.

For clarity only 160 ac. well slots shown

Delaware Basin Inventory

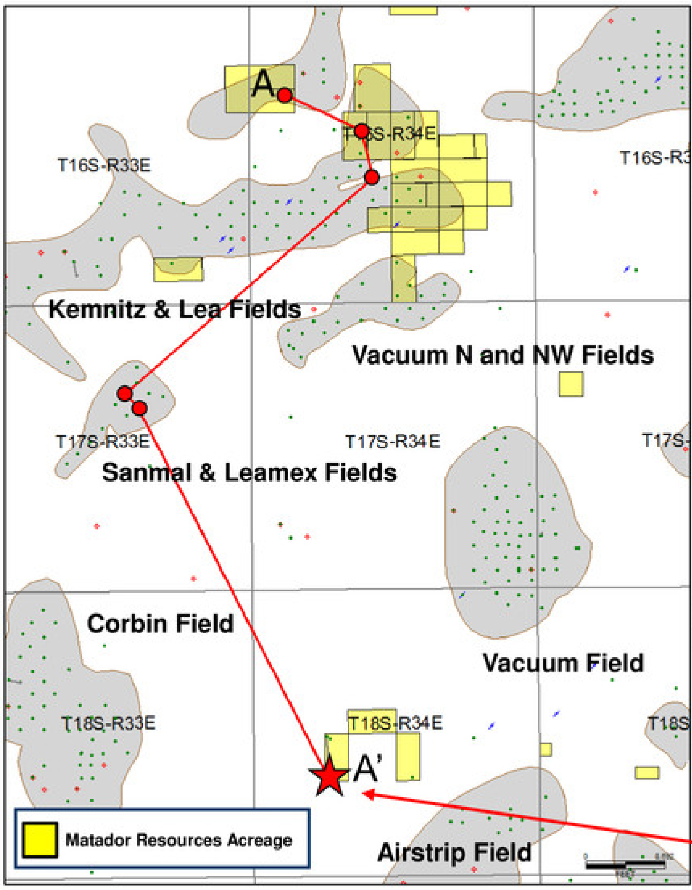
- **Matador has identified 1,445 gross (960 net) locations**
- **This inventory does not yet include the HEYCO properties or Twin Lakes locations**

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: Inventory only includes wells with >30% working interest.

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



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

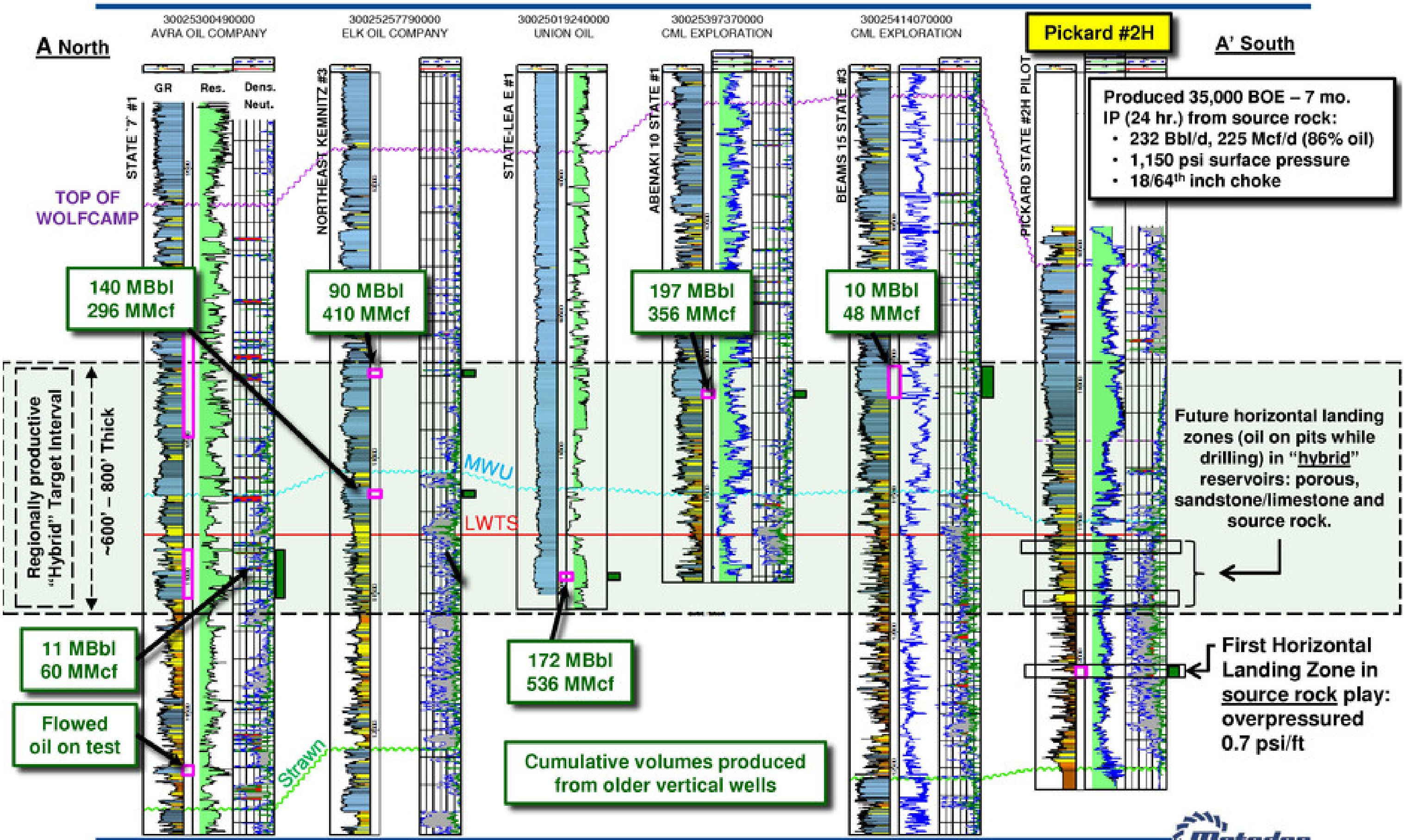
~137,000 Bbl per vertical well

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

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

Bcf = billions of cubic feet of natural gas.

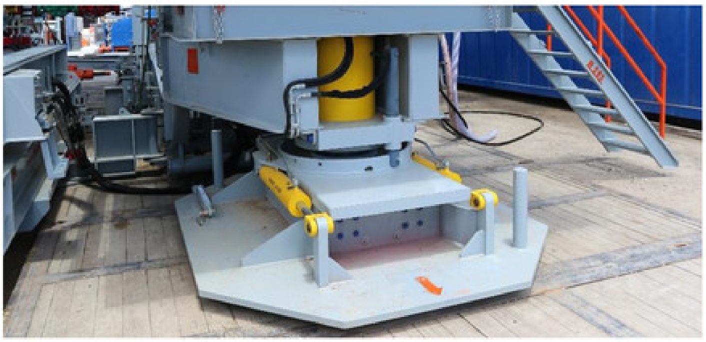
Pennsylvanian/Wolfcamp "D" "Hybrid" Production Target Interval



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

Commodity Prices vs. Cost Savings vs. Efficiency Gains

- **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



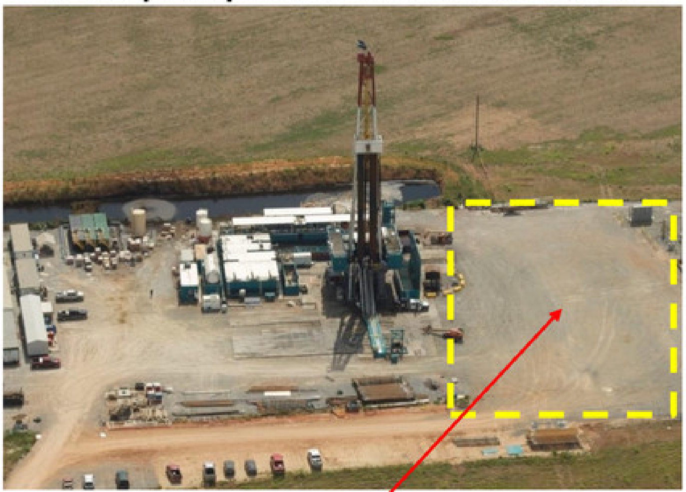
Efficiency gains save approximately $540,000 per well

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

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

Conventional Drilling Configuration

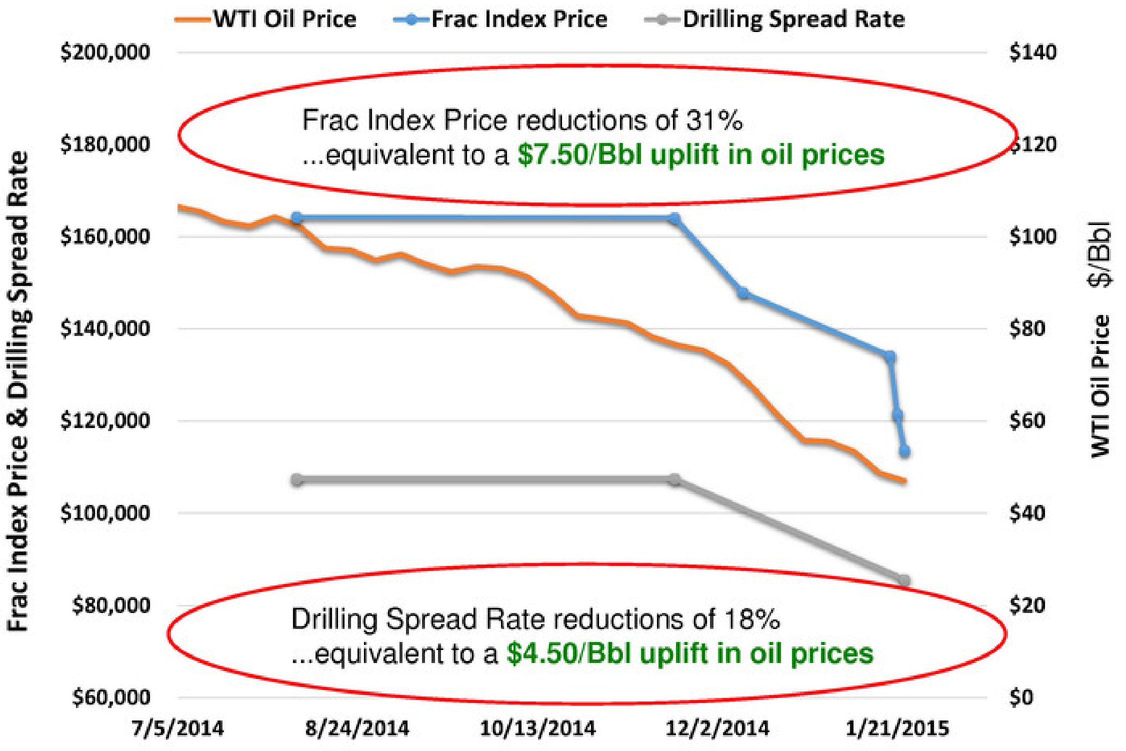
Sim-Ops Capable with V-door turned 90°



Drilling rig must leave location prior to frac operations

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

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: Cost Savings and Efficiency Gains

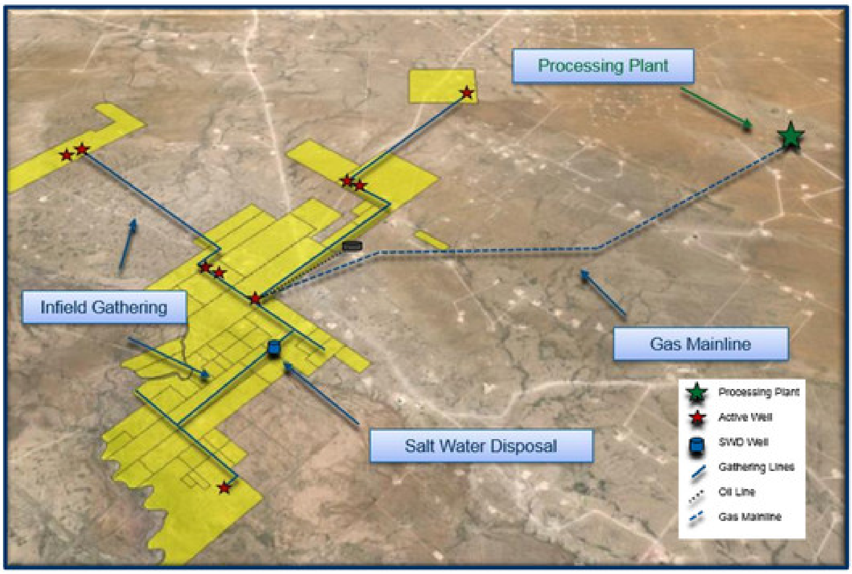
Saltwater disposal savings

$1.30/Bbl of produced water

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

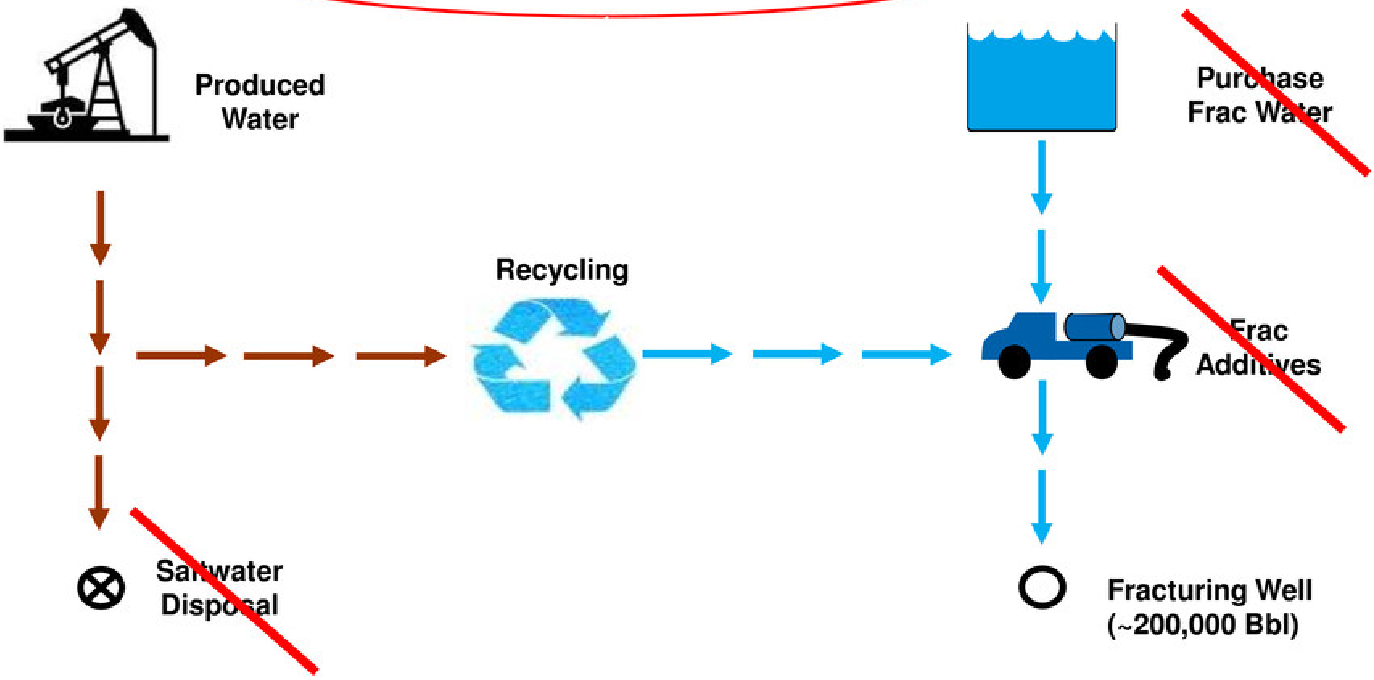
Oil pipeline fee reduction

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

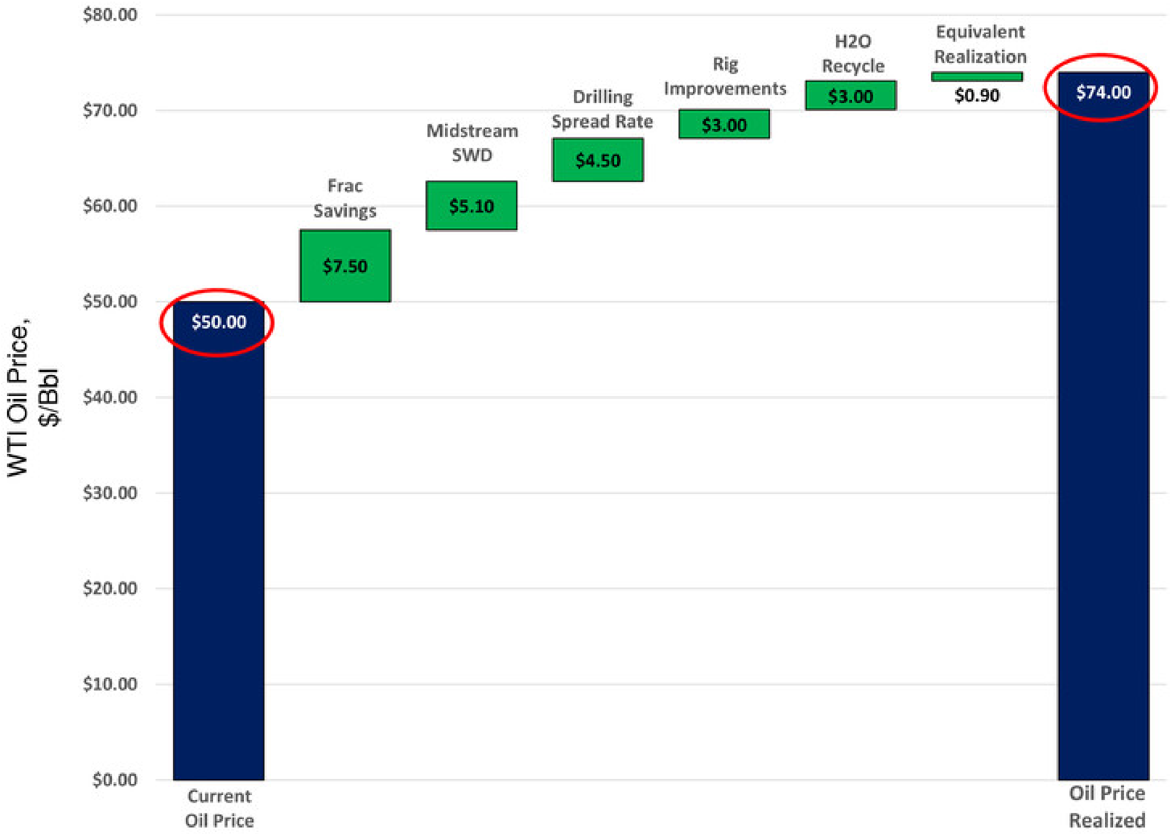


Potential Water Recycling Savings for Loving County

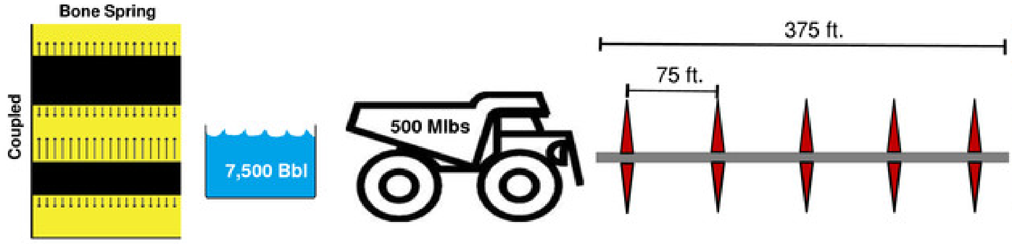
Potential savings of up to $600,000 per well
...equivalent to a **$3.00/Bbl uplift in oil prices**



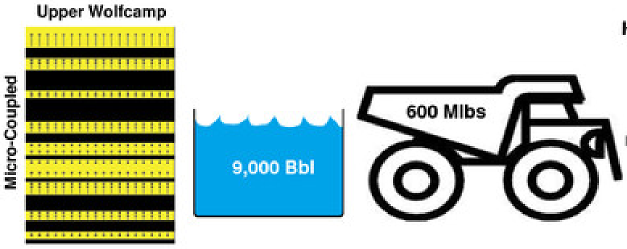
The Potential of Total Prospective Equivalent Oil Price Uplifts



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



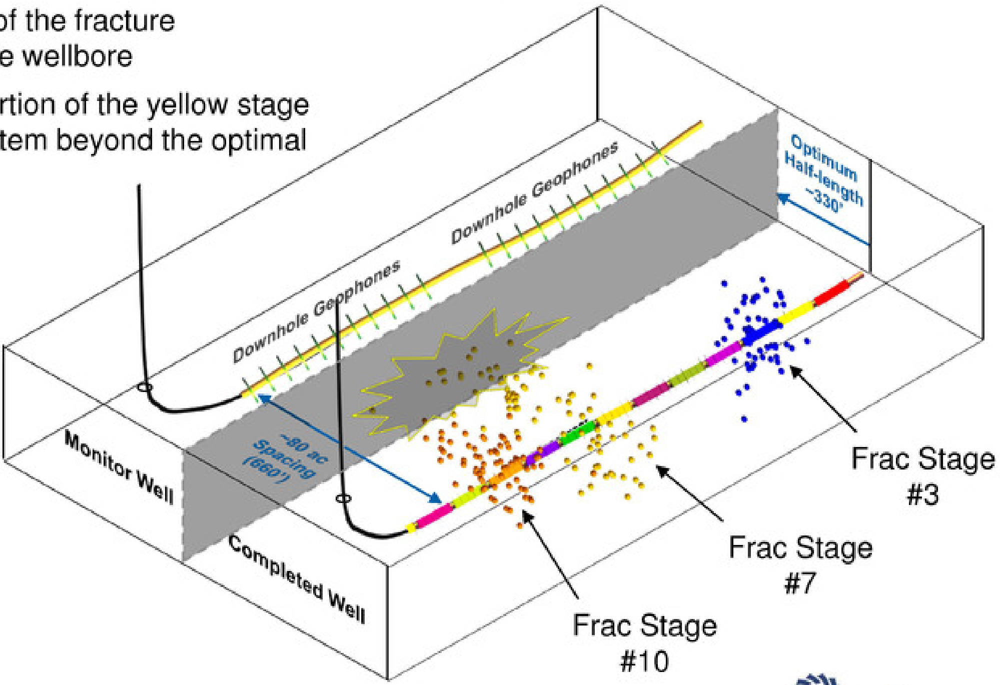
Gen 1	Gen 2
2,000 lbs/ft	2,000 lbs/ft
40 Bbl/ft	30 Bbl/ft
35' cluster spacing	50' cluster spacing

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

Microseismic in Wolf Prospect

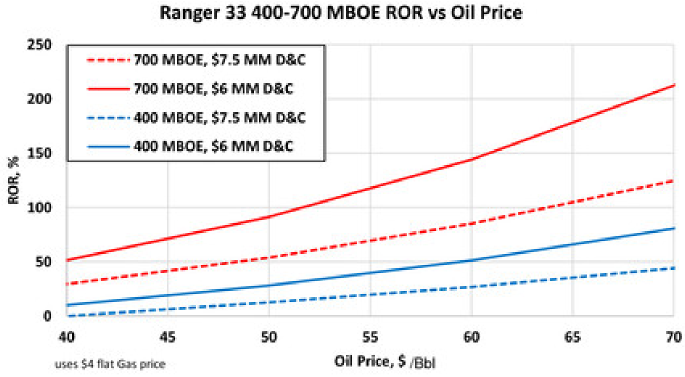
- Fractures generate sonic events as they propagate through the rock
- Microseismic uses downhole geophones installed in offset horizontals to measure these sonic events
- Half-length is a measure of the fracture propagation away from the wellbore
- In this example, only a portion of the yellow stage propagated a fracture system beyond the optimal half-length

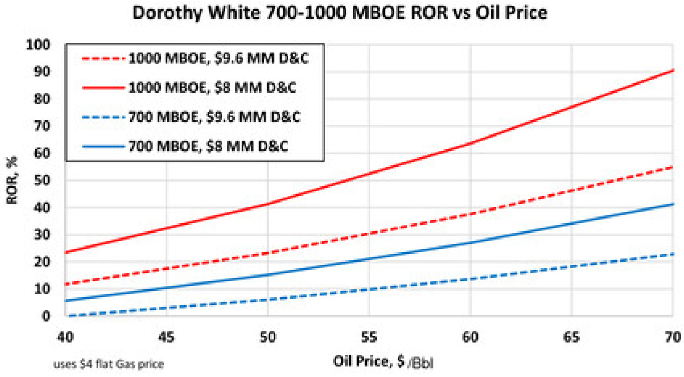
80-acre spacing appears optimal for Wolfcamp X/Y development

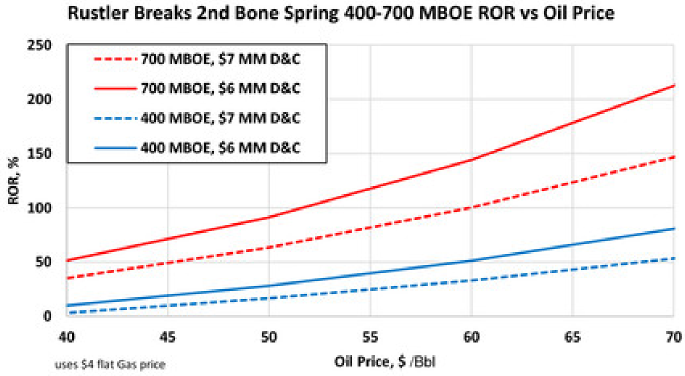


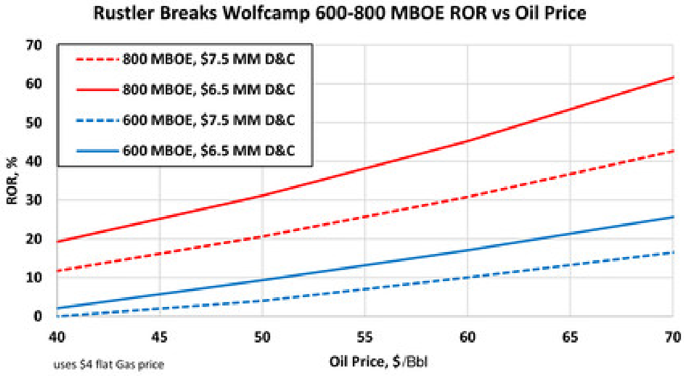
Note: Only three frac stages shown for clarity.

Permian Basin Economics – Oil Price Sensitivities







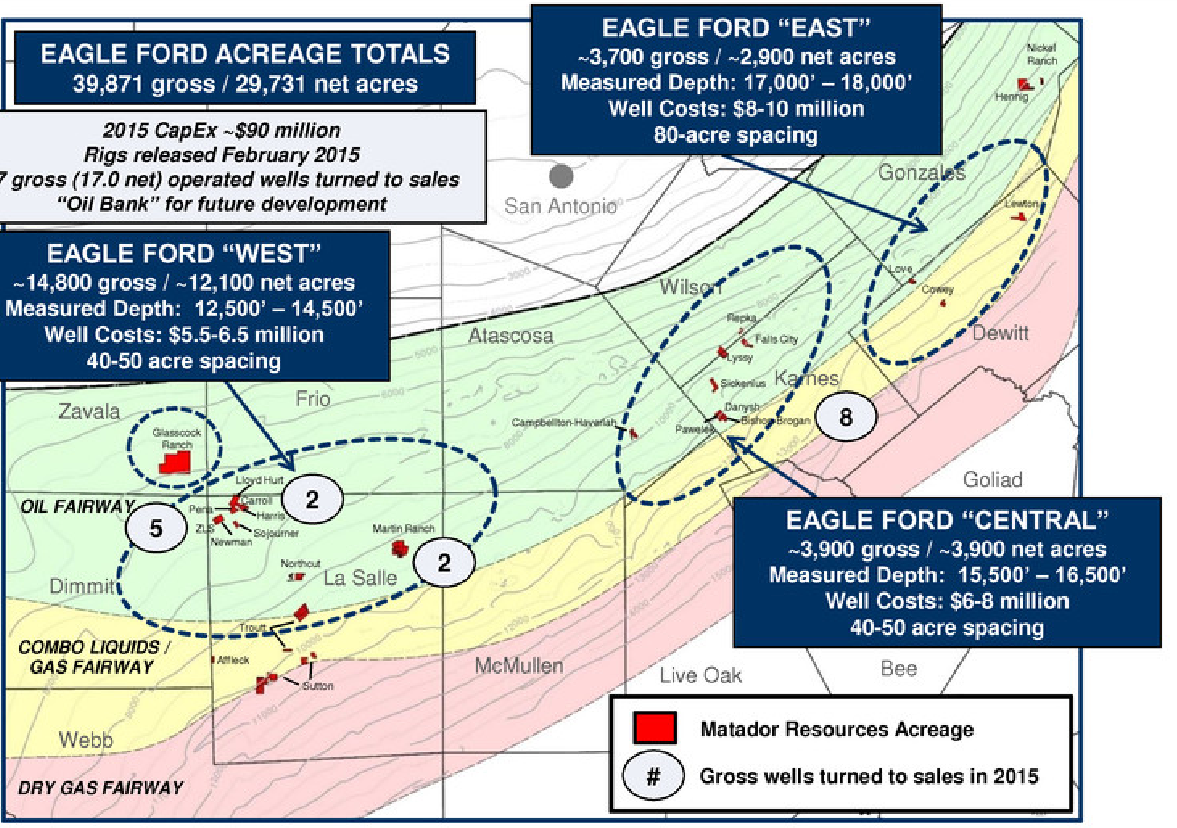




Eagle Ford

"Oil Bank"

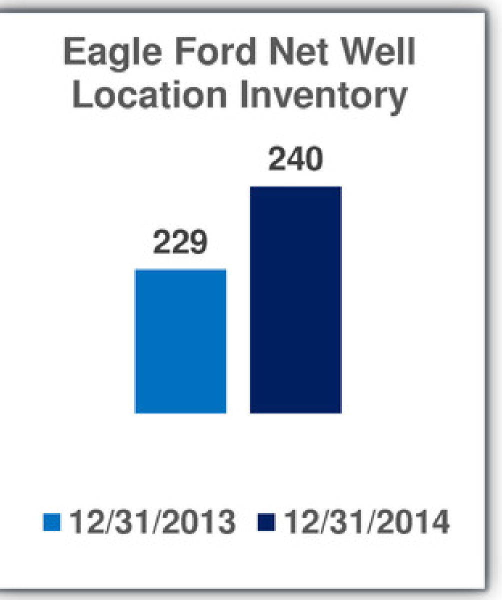
Eagle Ford Overview



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

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

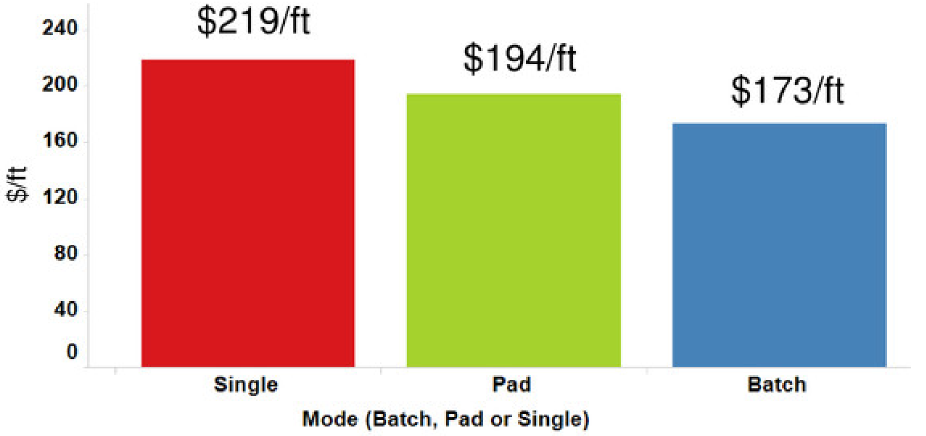


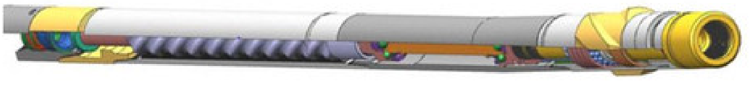
Note: **Batch drilling** is the process by which multiple horizontal wells are drilled from a single pad. In batch drilling, the surface holes for each well are drilled first and then the production holes, including the horizontal laterals for each well, are drilled. **Pad drilling** is the process by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

Eagle Ford Drilling – Cost Reductions and Efficiency Gains

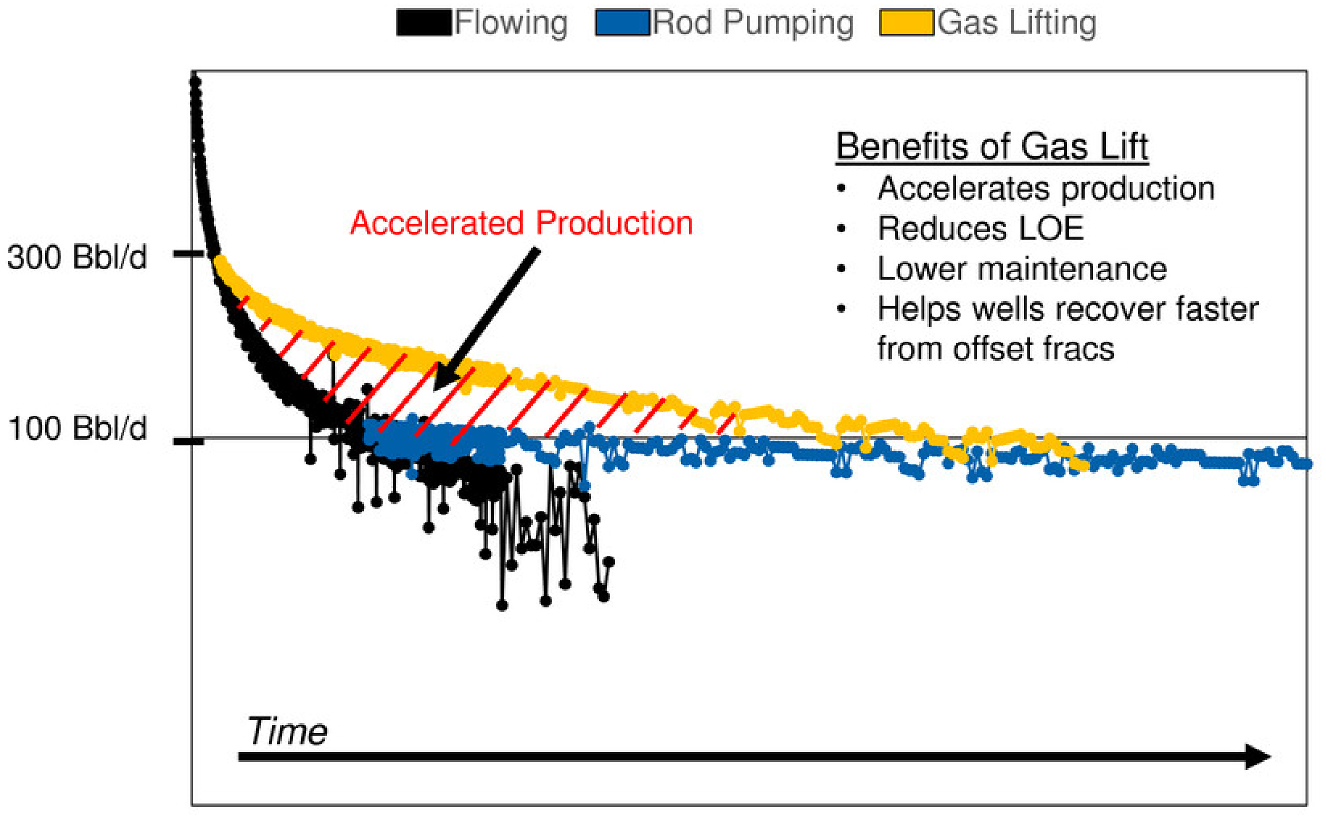
- Batch mode cut costs by
  - ~10% vs pad drilling
  - ~21% vs single well drilling
- Shaved 2.5 days per well
  - Modern rigs
  - Latest technology & equipment
  - Improved drilling techniques
- Expecting ~28% pricing reduction in 2015





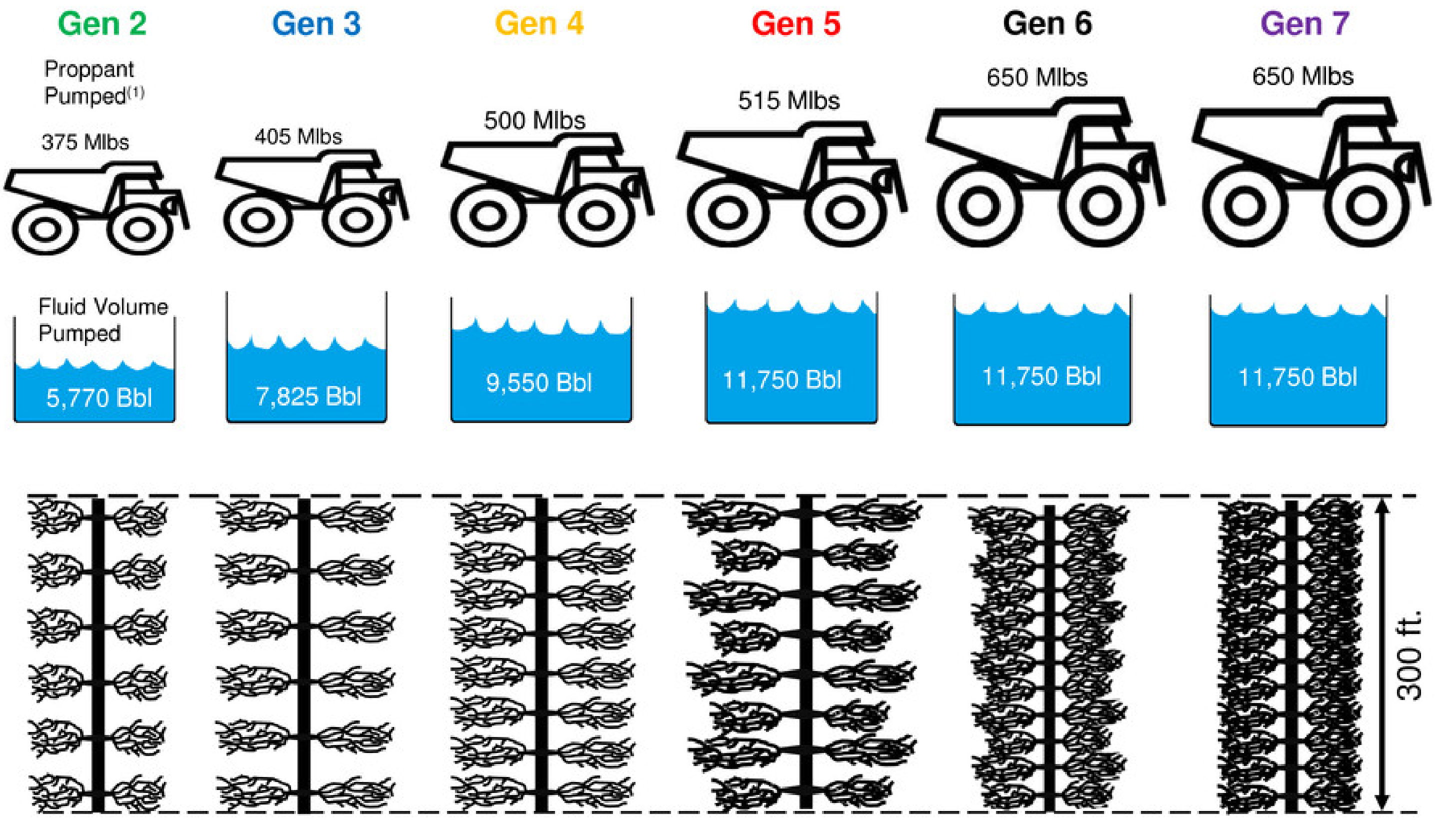
Note: **Batch drilling** is the process by which multiple horizontal wells are drilled from a single pad. In batch drilling, the surface holes for each well are drilled first and then the production holes, including the horizontal laterals for each well, are drilled and **Pad drilling** is the process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

Artificial Lift Reducing Natural Production Declines



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

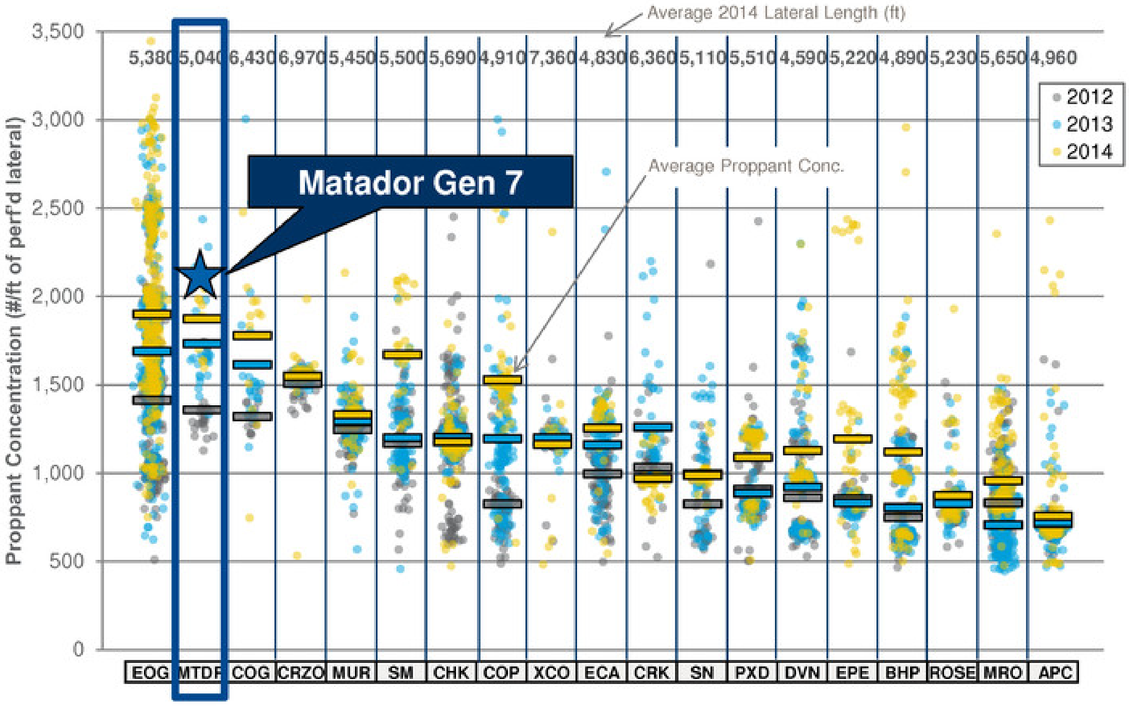
Evolution of Matador Eagle Ford Frac Design



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

Eagle Ford Completions – Industry Comparison

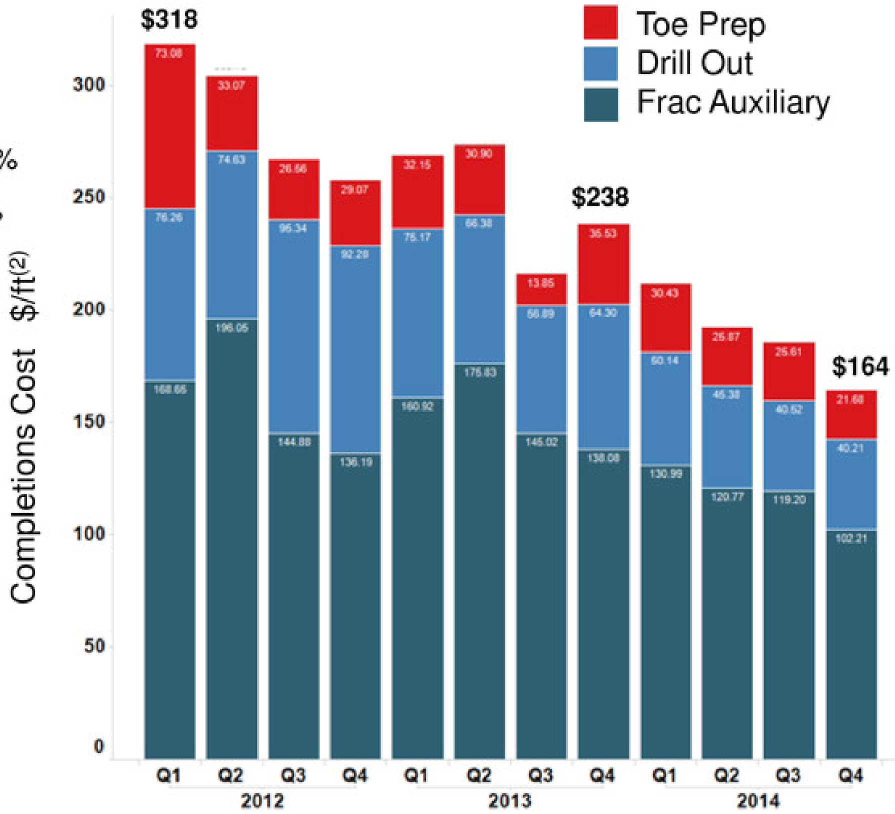
Matador designs some of the biggest fracs in the Eagle Ford



Source: ITG Investment Research.

Eagle Ford Completions – Cost Reductions

- Non-frac completion costs cut by:
  - ~50% since Q1 2012 (savings of over $750,000 per well[1])
    - Cut toe-prep costs by ~70%
    - Cut drill out costs by ~47%
    - Cut other costs by ~40%
  - ~31% since Q4 2013



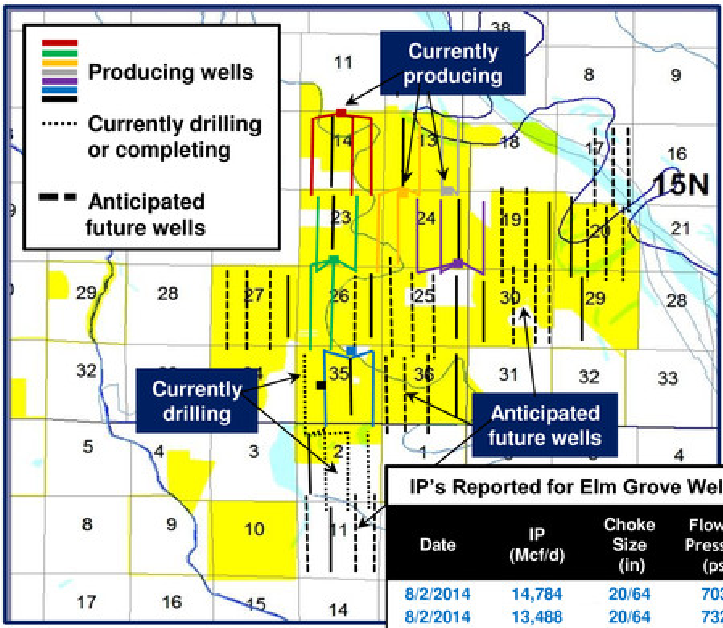
(1) Normalized to 5,000 foot lateral.
(2) Per completed lateral foot.



Haynesville Shale

"Gas Bank"

Haynesville – Chesapeake Elm Grove Operations



IP's Reported for Elm Grove Wells

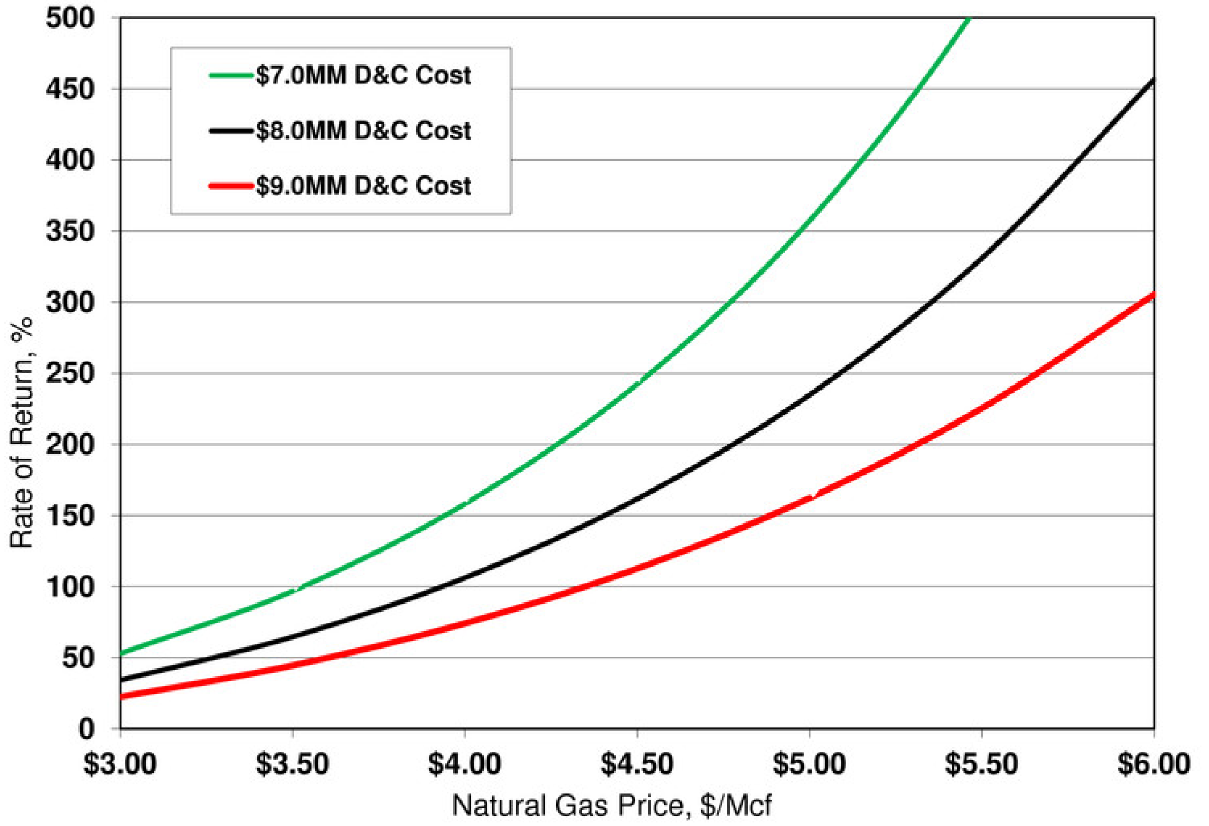
Date	IP (Mcf/d)	Choke Size (in)	Flowing Pressure (psi)
8/2/2014	14,784	20/64	7035
8/2/2014	13,488	20/64	7325
8/24/2014	10,249	18/64	6350
8/24/2014	8,116	17/64	5620
8/24/2014	9,746	17/64	6825
10/3/2014	13,872	20/64	7530
10/3/2014	13,632	20/64	7245
10/3/2014	14,112	20/64	7395
10/3/2014	14,424	20/64	7025
12/6/114	13,080	20/64	7450
12/6/2014	13,440	20/64	7200

- 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 50 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 three additional wells on production in late January 2015
  - *Each of these three wells came on at initial rates of ~15 MMcf/d at flowing tubing pressures of 6,000 to 7,000 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.

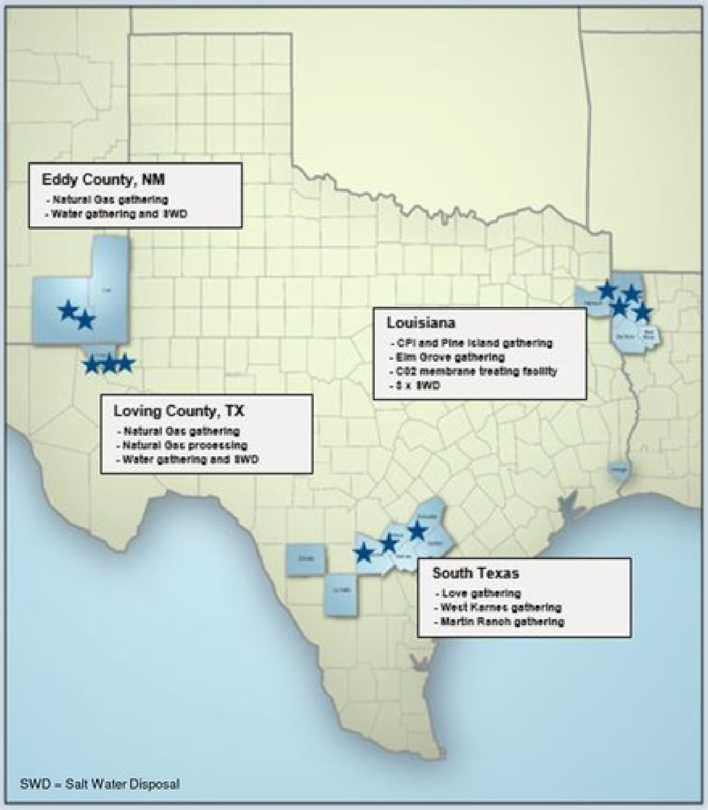
Midstream

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)

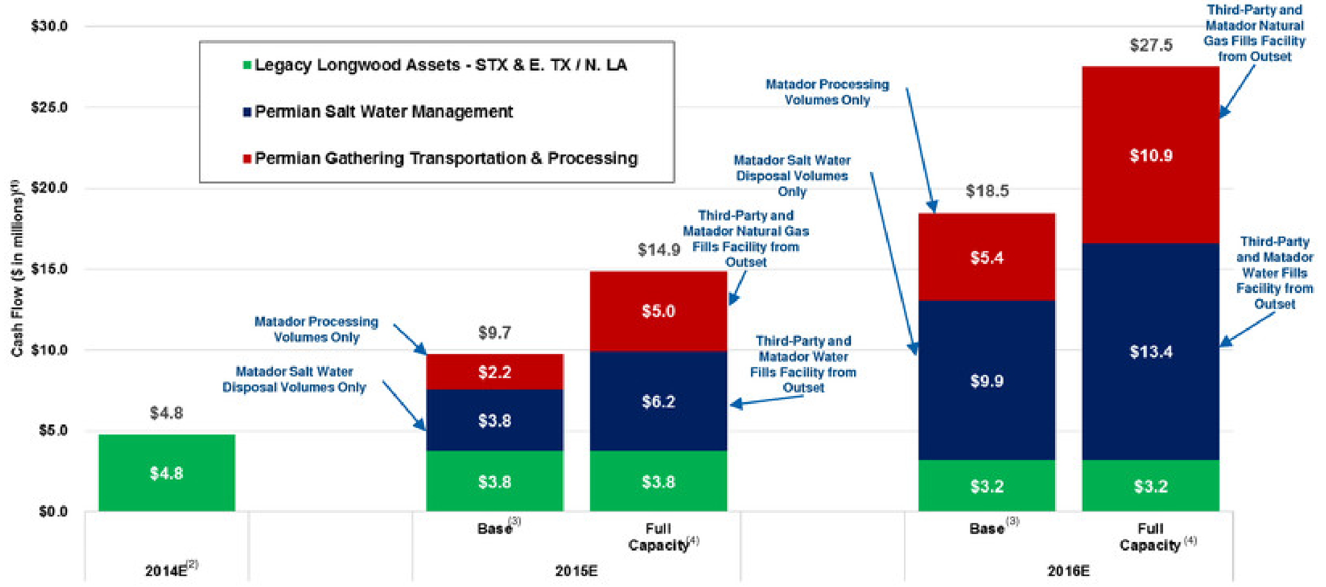
Longwood Gathering and Disposal Systems Activities



(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

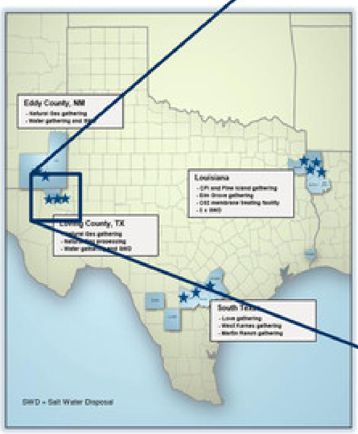
- Expect to spend ~$38 million on midstream initiatives in the Permian Basin in 2015
- Matador expects Longwood to be able to support its own sources of financing
- Additional third-party volumes and a contemplated natural gas processing facility in Rustler Breaks provide upside to these forecasts

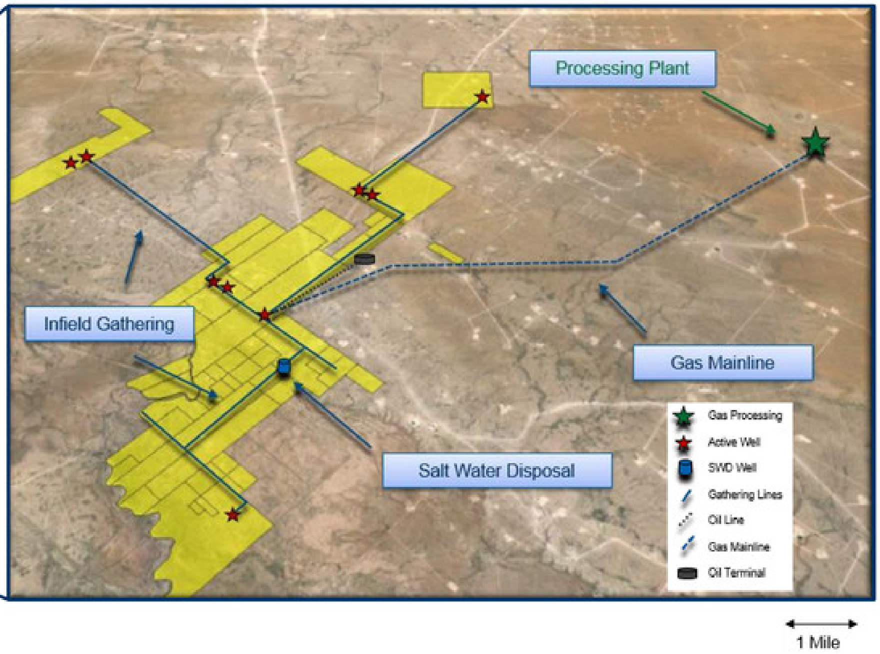


(1) Estimated cash flow figures exclude allocations for general and administrative and certain other expenses. Cash flow presented is not necessarily incremental to Matador's other businesses.
(2) 2014 cash flow is an estimate as the Company has not historically viewed its midstream operations as a separate 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

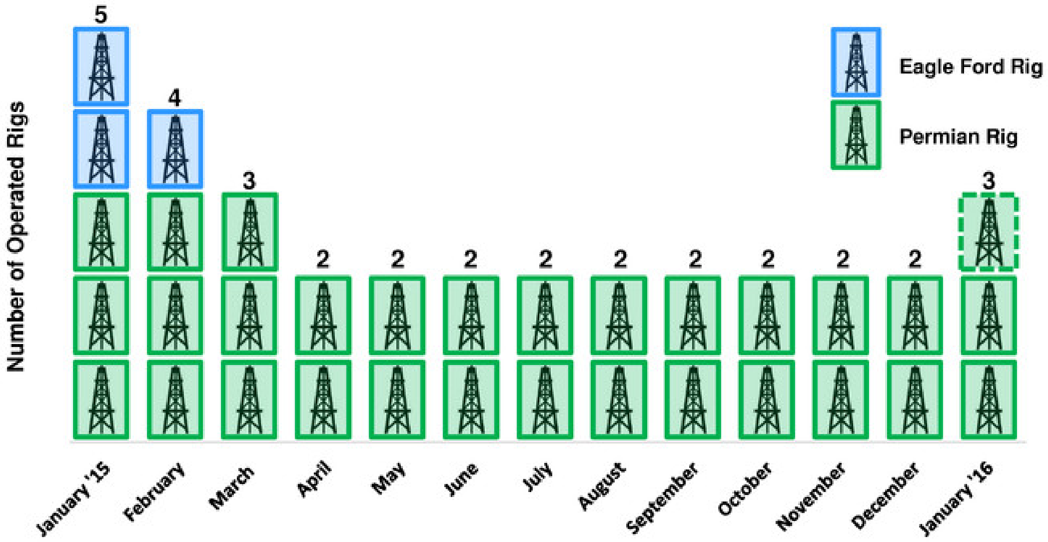




2015 Capital Investment Plan

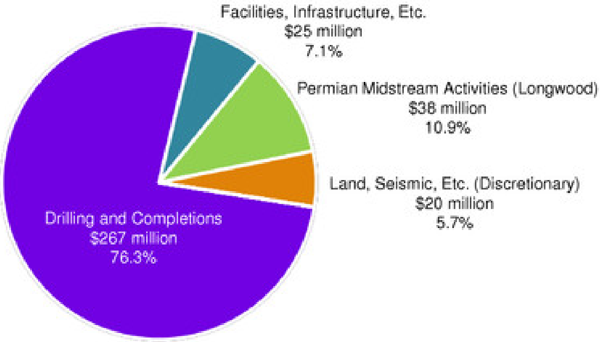
2015 Capital Investment Plan – Reducing Drilling Program in 2015

- **Reducing drilling program from 5 rigs to 2 rigs due to lower commodity prices, with primary focus on Permian (Delaware) Basin**
- **Plan to be operating 2 rigs by start of Q2 2015 – both in the Permian Basin**
  - *Have just released third rig – currently operating 2 rigs in Permian Basin*
  - *New-build rigs, latest technology and designed for simultaneous operations (Sim-Ops)*

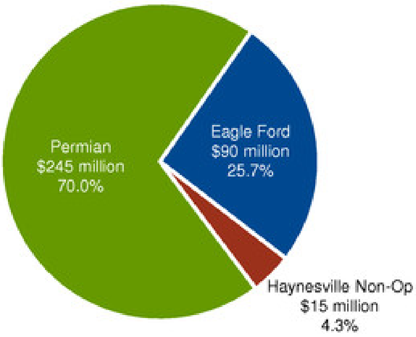


2015 Capital Investment Plan Summary

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 combination (cash and assumed debt of $36.6 million)*
- 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
  - *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*

Shifting Focus to the Permian in 2015 – Detail of 2015E CapEx

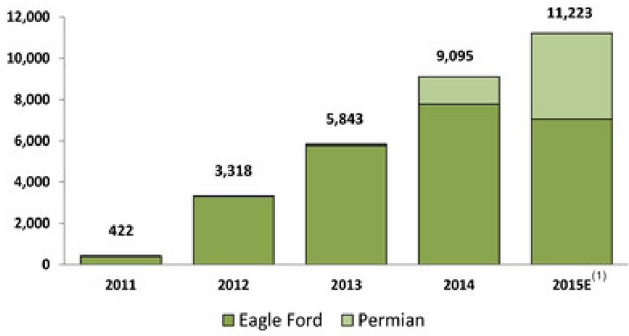
	2014 Drilled, 2015 Anticipated Completion(1)		2015 Anticipated Drilling & Completion		2015 Anticipated Drilling, 2016 Anticipated Completion(2)		2015 Anticipated First Sales(2)		2015E CapEx	
	Gross Wells(3)	Net Wells(3)	Gross Wells(3)	Net Wells(3)	Gross Wells(3)	Net Wells(3)	Gross Wells(3)	Net Wells(3)	*(in millions)*	
South Texas										
Eagle Ford	9	9.0	8	8.0	-	-	17	17.0	$77.0	22.0%
Facilities/Pipelines/Etc.	-	-	-	-	-	-	-	-	$8.0	2.3%
Land/Seismic/Etc.	-	-	-	-	-	-	-	-	$5.0	1.4%
Area Total	9	9.0	8	8.0	-	-	17	17.0	$90.0	25.7%
West Texas/Southeast New Mexico										
Permian Basin	3	2.6	30	18.4	3	2.7	33	21.0	$175.0	50.0%
Midstream Activities (Longwood)	-	-	-	-	-	-	-	-	$38.0	10.9%
Facilities/Pipelines/Etc.	-	-	-	-	-	-	-	-	$17.0	4.9%
Land/Seismic/Etc.	-	-	-	-	-	-	-	-	$15.0	4.3%
Area Total	3	2.6	30	18.4	3	2.7	33	21.0	$245.0	70.0%
Northwest Louisiana										
Haynesville Shale	19	1.3	14	1.0	5	0.7	33	2.3	$15.0	4.3%
Total	**31**	**12.9**	**52**	**27.4**	**8**	**3.4**	**83**	**40.3**	**$350.0**	**100.0%**

- ***70% of our 2015 capital investments directed toward the Permian Basin***

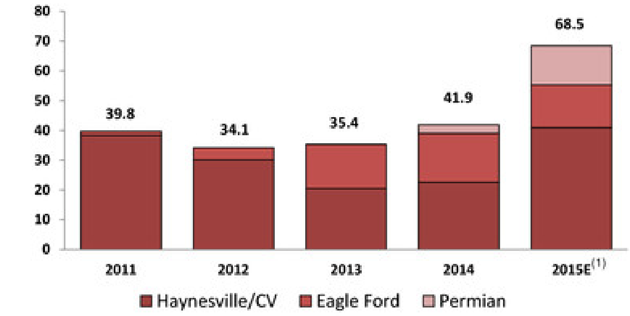
Note: All CapEx figures are operations capital expenditures only and exclude any capital expenditures associated with the HEYCO transaction.
(1) A portion of the CapEx associated with some of these wells was incurred in 2014, as some wells were already being completed at December 31, 2014.
(2) Some wells drilled in late 2015 will not be completed and turned to sales until early 2016. As a result, they do not contribute to our estimated oil and natural gas production volumes for 2015.
(3) Includes Matador operated and non-operated wells.

2015 Production Estimates – Oil Equivalent Growth of ~41%

Oil Production Growth (Bbl/d)



Natural Gas Production Growth (MMcf/d)



(1) Estimated daily average oil and natural gas production at midpoint of 2015 guidance range.

2015E Oil Production

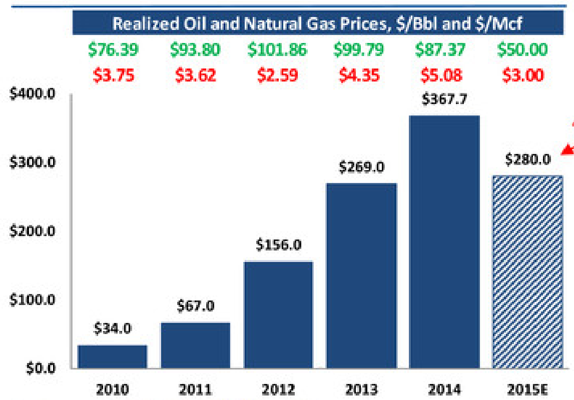
- *Estimated oil production of 4.0 to 4.2 million barrels*
  - 23% increase from 2014 despite decreased drilling
- *Average daily oil production of 11,200 Bbl/d, up from 9,100 Bbl/d in 2014*
  - Eagle Ford ~7,000 Bbl/d (63%)
  - Permian ~4,200 Bbl/d (37%)
- *Quarterly production peaks in Q2; Q4 2015 oil production relatively flat to Q4 2014*
  - Q1 down ~12% sequentially due to Eagle Ford shut-ins
  - Permian production increases three-fold in 2015; Eagle Ford production declines by 10%

2015E Natural Gas Production

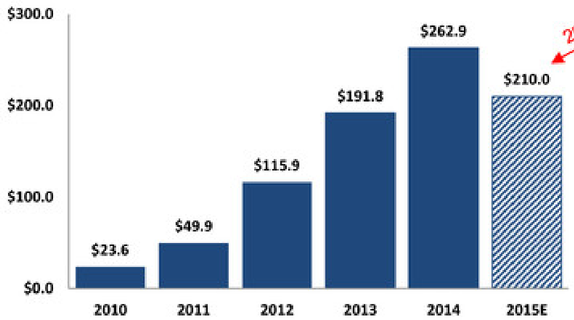
- *Estimated natural gas production of 24 to 26 Bcf*
  - 63% increase from 2014 despite decreased drilling; significant Haynesville impact
  - Quarterly production peaks in Q2; Q4 2015 natural gas production up ~12% over Q4 2014
- *Average daily natural gas production of 68.5 MMcf/d, up from 41.9 MMcf/d in 2014*
  - Haynesville ~40.9 MMcf/d (60%)
  - Eagle Ford ~14.4 MMcf/d (21%)
  - Permian ~13.2 MMcf/d (19%)

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 estimated $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)

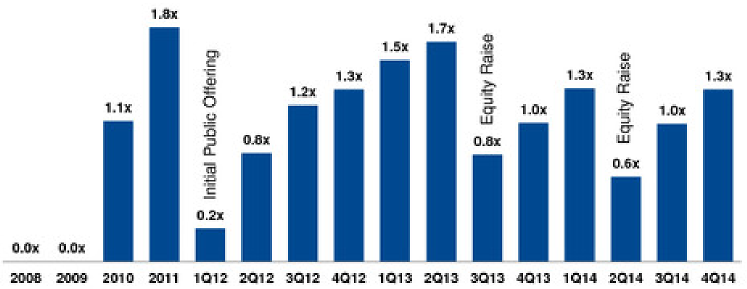
- *Production taxes/marketing = $4.00; $5.65 in 2014 (reduced revenues)*
- *Lease operating = $7.25; $8.75 in 2014 (gas volumes, operating efficiencies, service costs)*
- *G&A = $5.25; $5.48 in 2014 (additional staff)*
- *Operating cash costs, excluding interest = $16.50; ~$20.00 in 2014*
- *DD&A = $22.75; $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 reaffirmed on March 2, 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.

Funding for 2015 Capital Investment Plan

- **Anticipate funding 2015 capital expenditures through operating cash flows, borrowings under revolving credit facility, other bank debt and additional funding via capital markets**
  - *Estimated operating capital outspend of ~$150 million in 2015 with estimated $350 million in operations CapEx*
  - *Additional service cost reductions may also reduce estimated CapEx and outspend as 2015 continues*
  - *Continued improvements in well results, commodity prices and growth in midstream revenues may also mitigate outspend*
- **Strong leverage position with YE 2014 Debt/Adjusted EBITDA(1) ~1.3**
  - *History of low leverage and prudent financial management*

Debt / LTM EBITDA(1)

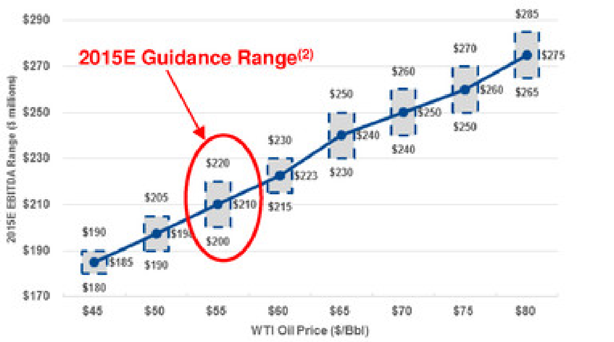


- **Simple capital structure; no high-yield debt or "exotic" financial arrangements on balance sheet**
- **Flexibility to manage liquidity**
  - *Almost all 2015 drilling is operated and no significant non-operated drilling obligations*
  - *$20 million estimated for additional discretionary land/seismic acquisitions*
  - *New drilling contracts are two-year term agreements; no long-term pumping contracts; good relationships with vendors*

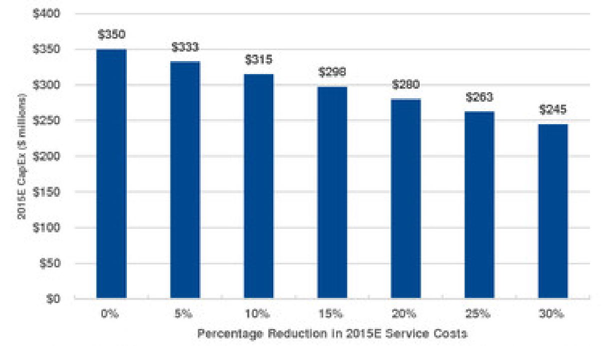
(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Appendix.

Commodity Price and CapEx Estimates Significantly Impact Forecasts

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



Sensitivity of 2015E CapEx to Service Cost Reductions



- *Relatively small improvements in oil price and service 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 service 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 March 2, 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, with 2 rigs operating in Permian after Q1 2015**
- **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**

	2014 Actual	*2015 Guidance(1)*	*% Change*
Capital Spending	$610 million	$350 million	- 43%
Total Oil Production	3.32 million Bbl	4.0 to 4.2 million Bbl	+ 23%
Total Natural Gas Production	15.3 Bcf	24.0 to 26.0 Bcf	+ 63%
Oil and Natural Gas Revenues	$367.7 million	$270 to $290 million(2)	- 24%
Adjusted EBITDA(3)	$262.9 million	$200 to $220 million(2)	- 20%

(1) As reaffirmed on March 2, 2015; does not include capital expenditures associated with the HEYCO transaction.
(2) Estimated 2015 oil and natural gas revenues and Adjusted EBITDA at midpoint of 2015 production guidance range as reaffirmed on March 2, 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.
(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.



Appendix

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

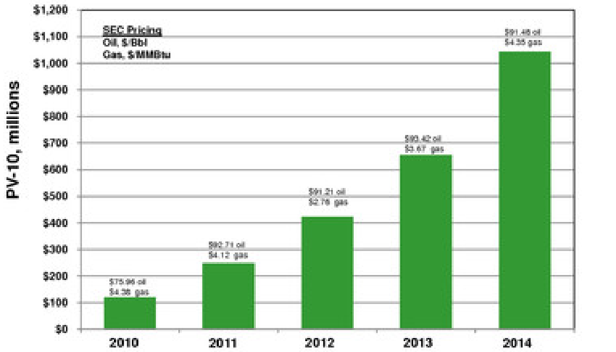
Comparison of Major Oil Corrections and Major Matador Turning Points Since 1980

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	-57.2%	~171	?	**MTDR and HEYCO join forces**

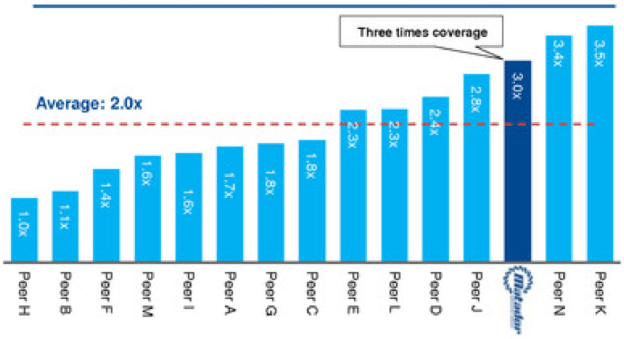
(1) Includes Matador Resources Company and its predecessor entities as of February 2015.

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

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

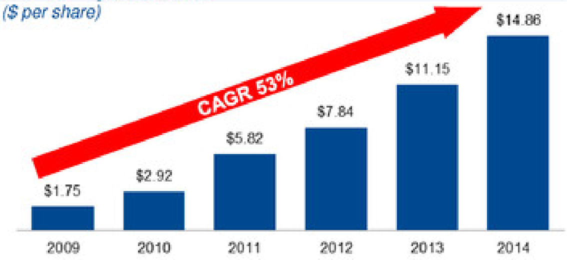


Proved PV-10[(2)] / Q3 2014 Net Debt



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

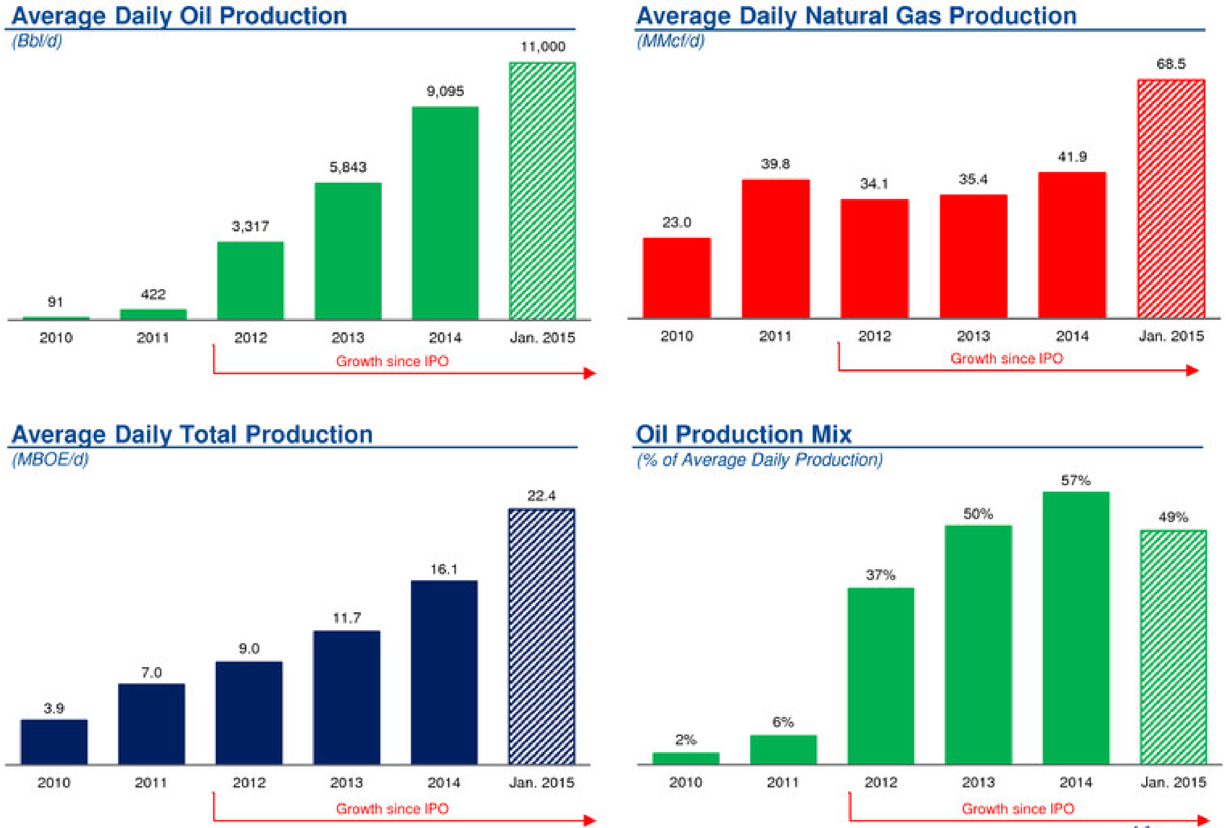
Note: "Q3 2014 Net Debt / LTM Adjusted EBITDA" analysis prepared by RBC Capital Markets. Peer group chosen by RBC includes SFY, CRK, ROSE, SN, PVA, AREX, GDP, CWEI, JONE, BCEI, CRZO, PE, RSPP, FANG. Average does not include Matador. Source: Company filings, metrics pro forma for announced acquisitions. Market data as of January 29, 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.

Matador's Continued Production Growth



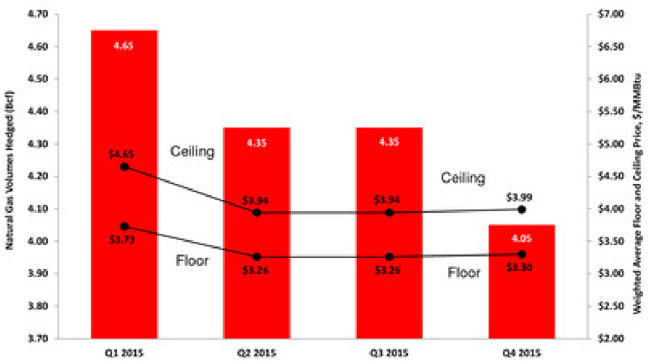
2015 Hedging Profile

2015 Hedges

- **Oil Hedges**: ~1.7 million barrels of oil hedged for 2015 at weighted average floor and ceiling prices of ~$83/Bbl and ~$100/Bbl, respectively – Approximately 41% of oil hedged for 2015(1)
- **Natural Gas Hedges**: 17.4 Bcf of natural gas hedged for 2015 at weighted average floor and ceiling of $3.40/MMBtu and $4.14/MMBtu, respectively – Approximately 70% of natural gas hedged for 2015(1)
- **Natural Gas Liquids**: 3.8 million gallons of natural gas liquids hedged for 2015 at weighted average price of $1.02/gal
- Oil and natural gas hedges estimated to add $56 million to projected oil and natural gas revenues in 2015

Oil Hedges (Costless Collars)

Natural Gas Hedges (Costless Collars)



(1) Based upon the midpoint of 2015 guidance range of 4.0 to 4.2 million barrels for oil and 24.0 to 26.0 Bcf for natural gas as reaffirmed on March 2, 2015.

Credit Agreement Status

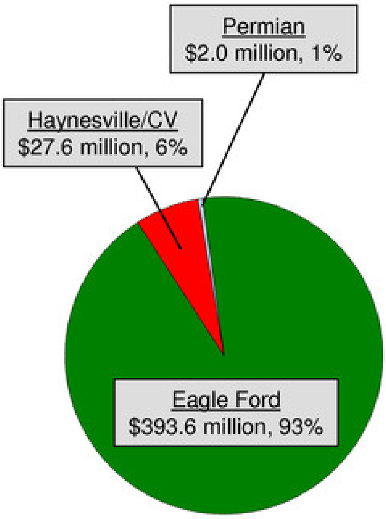
- **Strong, supportive bank group led by Royal Bank of Canada**
- **Borrowing base at $450 million ($375 million conforming) based on July 31, 2014 reserves**
  - *Not yet redetermined for YE 2014 reserves additions*
- **Borrowings outstanding of $340 million at December 31, 2014 and $395 million at March 16, 2015**
- **YE 2014 Net Debt/Adjusted EBITDA[1] of ~1.3**

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
Tier Six	100% < or = x < 110%	300 bps	200 bps	50 bps
Tier Seven	x = or > 110%	375 bps	275 bps	50 bps

- **Financial covenants**
  - *Maximum Total Debt to Adjusted EBITDA[1] 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) 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.

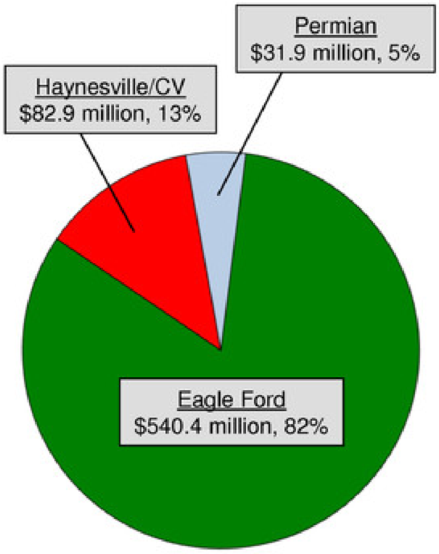
Oil and Natural Gas Proved Reserves and PV-10[1] Growth By Area



YE 2012

Total proved reserves = 23.8 million BOE

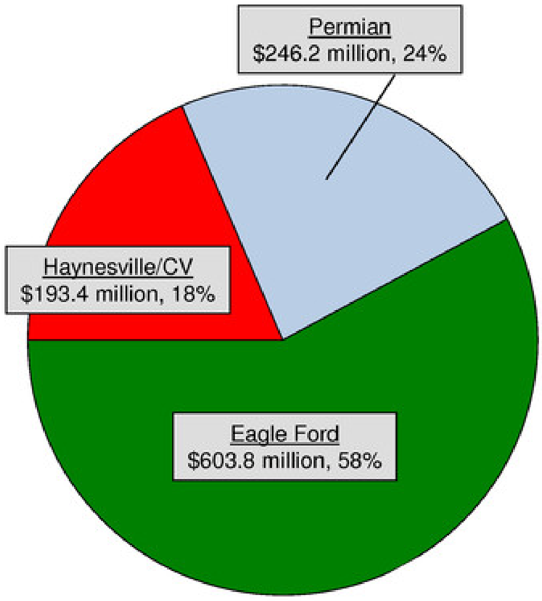
PV-10[1]: $423.2 million
$91.21 oil / $2.76 natural gas



YE 2013

Total proved reserves = 51.7 million BOE

PV-10[1]: $655.2 million
$93.42 oil / $3.67 natural gas



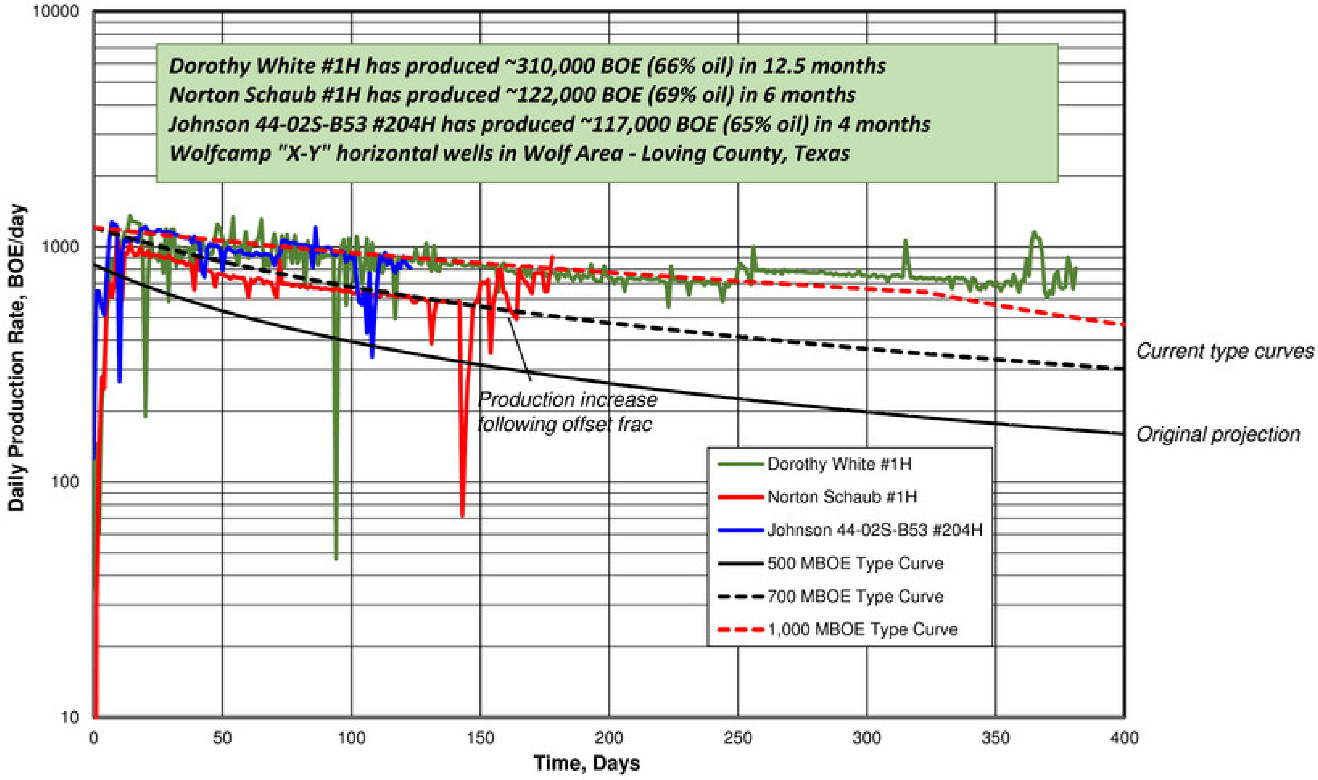
YE 2014

Total proved reserves = 68.7 million BOE

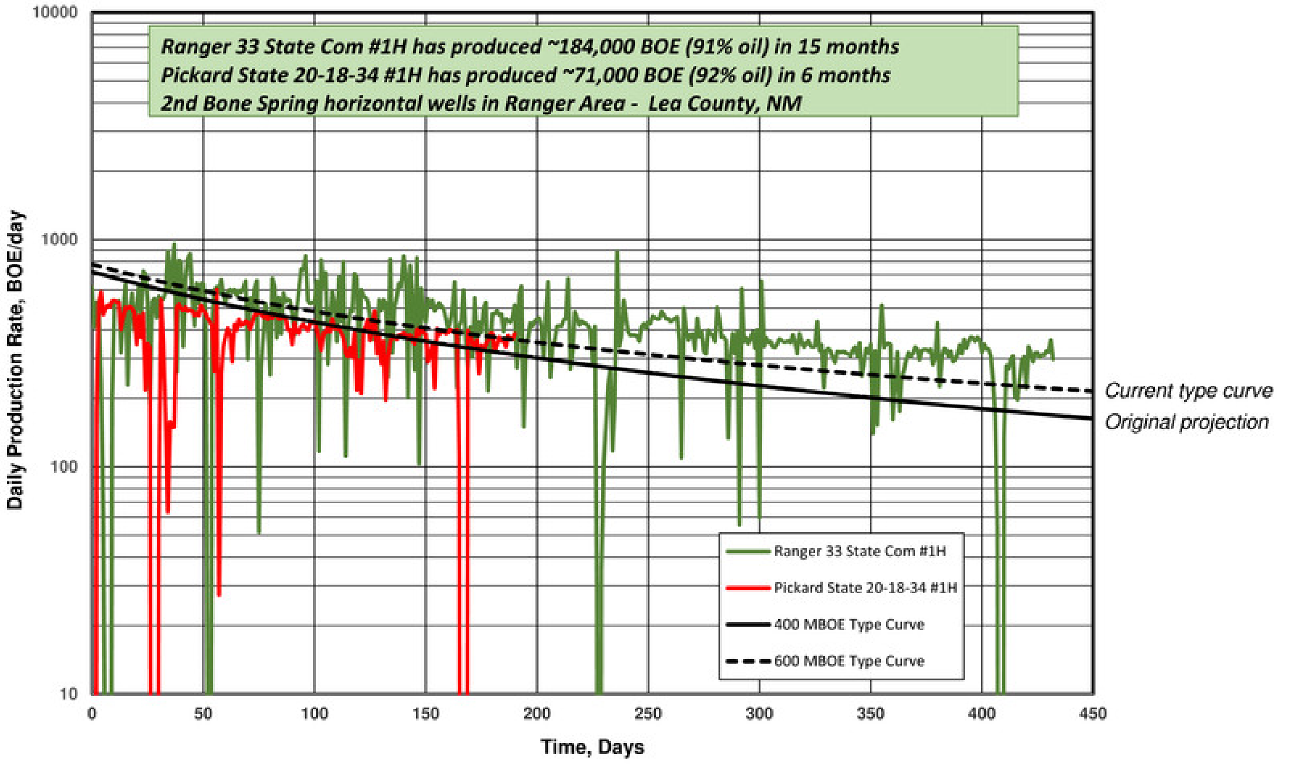
PV-10[1]: $1,043.4 million
$91.48 oil / $4.35 natural gas

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

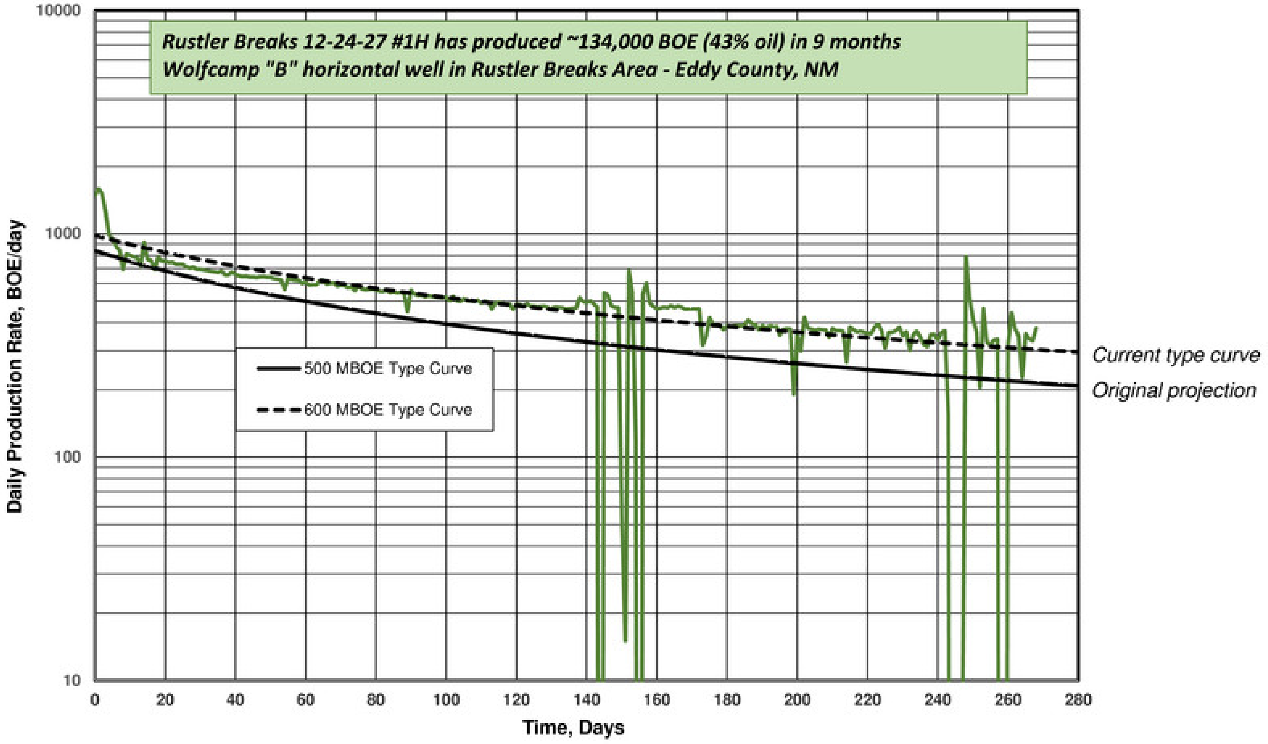
Wolf Area Wolfcamp "X/Y" Wells Performing Above Expectations



Ranger Area 2nd Bone Spring Wells Performing Above Expectations



Rustler Breaks Wolfcamp "B" Well Performing Above Expectations



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
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	- 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

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
David F. Nicklin Executive Director of Exploration	-	ARCO, Senior Geological Assignments in UK, Norway, Indonesia, China and the Middle East	43 years	Since 2007
Craig N. Adams EVP – Land & Legal (General Counsel)	-	Baker Botts L.L.P., Thompson & Knight LLP	21 years	Since 2012
Ryan C. London EVP and General Manager	-	Matador Resources Company (Began as intern)	10 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

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. We have not provided a reconciliation of PV-10 to Standardized Measure at December 31, 2014. We could not provide such a reconciliation without undue hardship because we have not completed the audit of our December 31, 2014 financial statements. In addition, it would be difficult for us to present a detailed reconciliation on account of many unknown variables for the reconciling items.

	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
PV-10 *(in millions)*	$70.4	$119.9	$155.2	$248.7	$329.6	$303.4	$363.6	$423.2
Discounted Future Income Taxes *(in millions)*	$(5.3)	$(8.8)	$(11.8)	$(33.2)	$(42.2)	$(21.9)	$(29.7)	$(28.6)
Standardized Measure *(in millions)*	$65.1	$111.1	$143.4	$215.5	$287.4	$281.5	$333.9	$394.6

	At March 31, 2013	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
PV-10 *(in millions)*	$438.1	$522.3	$538.6	$655.2	$739.8	$826.0	$952.0	$1,043.4
Discounted Future Income Taxes *(in millions)*	$(31.1)	$(44.7)	$(52.5)	$(76.5)	$(86.2)	$(103.0)	$(116.9)	$(130.1)
Standardized Measure *(in millions)*	$407.0	$477.6	$486.1	$578.7	$653.6	$723.0	$835.1	$913.3

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 forward-looking or prospective in nature, and not based on historical fact, the table does not provide a reconciliation. Similarly, the table does not provide a reconciliation with respect to the estimated Adjusted EBITDA range provided for the year ended December 31, 2014. 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 2012	2Q 2012	3Q 2012	4Q 2012	1Q 2013	2Q 2013	3Q 2013	4Q 2013	1Q 2014	2Q 2014	3Q 2014	4Q 2014
Unaudited Adjusted EBITDA reconciliation to												
Net (loss) Income:												
Net (loss) income	$ 3,801	$ (6,676)	$ (9,197)	$ (21,188)	$ (15,505)	$ 25,119	$ 20,105	$ 15,374	$ 16,363	$ 18,226	$ 29,619	$ 46,563
Interest expense	308	1	144	549	1,271	1,609	2,038	768	1,396	1,616	673	1,649
Total income tax provision (benefit)	3,064	(3,713)	(593)	(188)	46	32	2,563	7,056	9,536	10,634	16,504	27,701
Depletion, depreciation and amortization	11,205	19,914	21,680	27,655	28,232	20,234	26,127	23,802	24,030	31,797	35,143	43,767
Accretion of asset retirement obligations	53	58	59	86	81	80	86	100	117	123	130	134
Full-cost ceiling impairment	-	33,205	3,596	26,674	21,230	-	-	-	-	-	-	-
Unrealized (gain) loss on derivatives	3,270	(15,114)	12,993	3,653	4,825	(7,526)	9,327	606	3,108	5,234	(16,293)	(50,351)
Stock-based compensation expense	(363)	191	(51)	363	492	1,032	1,239	1,134	1,795	1,834	1,038	857
Net loss on asset sales and inventory impairment	-	60	-	425	-	192	-	-	-	-	-	-
Adjusted EBITDA	**$ 21,338**	**$ 27,926**	**$ 28,631**	**$ 38,029**	**$ 40,672**	**$ 40,772**	**$ 61,485**	**$ 48,840**	**$ 56,345**	**$ 69,464**	**$ 66,814**	**$ 70,320**

(In thousands)	1Q 2012	2Q 2012	3Q 2012	4Q 2012	1Q 2013	2Q 2013	3Q 2013	4Q 2013	1Q 2014	2Q 2014	3Q 2014	4Q 2014
Unaudited Adjusted EBITDA reconciliation to												
Net Cash Provided by Operating Activities:												
Net cash provided by operating activities	$ 5,110	$ 46,416	$ 28,799	$ 43,903	$ 32,229	$ 51,684	$ 43,280	$ 52,278	$ 31,945	$ 81,530	$ 66,883	$ 71,123
Net change in operating assets and liabilities	15,920	(18,491)	(500)	(6,235)	7,126	(12,553)	15,265	(3,630)	21,729	(15,221)	(586)	56
Interest expense	308	1	144	549	1,271	1,609	2,038	768	1,396	1,616	673	1,649
Current income tax (benefit) provision	-	-	188	(188)	46	32	902	(576)	1,275	1,539	(156)	(2,525)
Net loss attributable to non-controlling interest in subsidiary	-	-	-	-	-	-	-	-	-	-	-	17
Adjusted EBITDA	**$ 21,338**	**$ 27,926**	**$ 28,631**	**$ 38,029**	**$ 40,672**	**$ 40,772**	**$ 61,485**	**$ 48,840**	**$ 56,345**	**$ 69,464**	**$ 66,814**	**$ 70,320**

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

	Year Ended December 31,							LTM at	LTM at
(In thousands)	2008	2009	2010	2011	2012	2013	2014	6/30/2013	9/30/2014
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
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
Interest expense	-	-	3	683	1,002	5,687	5,334	3,574	4,453
Current income tax (benefit) provision	$10,448	($2,324)	(1,411)	(46)	0	404	133	78	2,082
Net loss attributable to non-controlling interest in subsidiary	0	0	0	0	-	0	17	0	0
Adjusted EBITDA	**$18,411**	**$15,184**	**$23,635**	**$49,911**	**$115,923**	**$191,771**	**$262,943**	**$148,105**	**$241,463**

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.

(In thousands)	Six Months Ended					
	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**

(In thousands)	Six Months Ended					
	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**