



PIONEER

NATURAL RESOURCES

Investor Presentation

May 2013



NYSE: PXD
www.pxd.com

Forward-Looking Statements

Except for historical information contained herein, the statements, charts and graphs in this presentation are forward-looking statements that are made pursuant to the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995. Forward-looking statements and the business prospects of Pioneer are subject to a number of risks and uncertainties that may cause Pioneer's actual results in future periods to differ materially from the forward-looking statements. These risks and uncertainties include, among other things, volatility of commodity prices, product supply and demand, competition, the ability to obtain environmental and other permits and the timing thereof, other government regulation or action, the ability to obtain approvals from third parties and negotiate agreements with third parties on mutually acceptable terms, the receipt of approvals required to consummate the Company's Southern Wolfcamp joint interest transaction, litigation, the costs and results of drilling and operations, availability of equipment, services, resources and personnel required to complete the Company's operating activities, access to and availability of transportation, processing, fractionation and refining facilities, Pioneer's ability to replace reserves, implement its business plans or complete its development activities as scheduled, access to and cost of capital, the financial strength of counterparties to Pioneer's credit facility and derivative contracts and the purchasers of Pioneer's oil, NGL and gas production, uncertainties about estimates of reserves and resource potential and the ability to add proved reserves in the future, the assumptions underlying production forecasts, quality of technical data, environmental and weather risks, including the possible impacts of climate change, the risks associated with the ownership and operation of an industrial sand mining business and acts of war or terrorism. These and other risks are described in Pioneer's 10-K and 10-Q Reports and other filings with the Securities and Exchange Commission. In addition, Pioneer may be subject to currently unforeseen risks that may have a materially adverse impact on it. Pioneer undertakes no duty to publicly update these statements except as required by law.

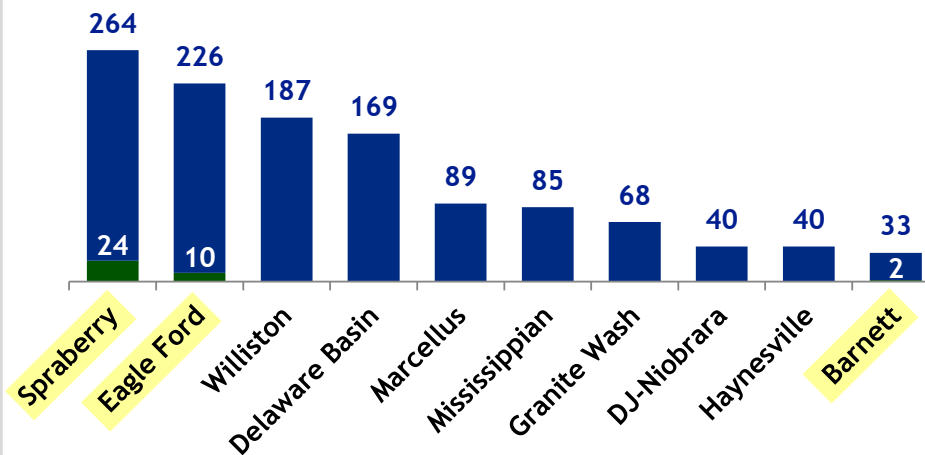
Please see the slides included in the Appendix of this presentation for other important information.

Pioneer At A Glance

Total Enterprise Value (\$B)	\$20
2013 Drilling Capex (\$B)	\$2.8
Q1 2013 Production (MBOEPD)	171
2012 Reserves (BBOE)	1.1
2012 Reserves + Resource (BBOE)	>9.0

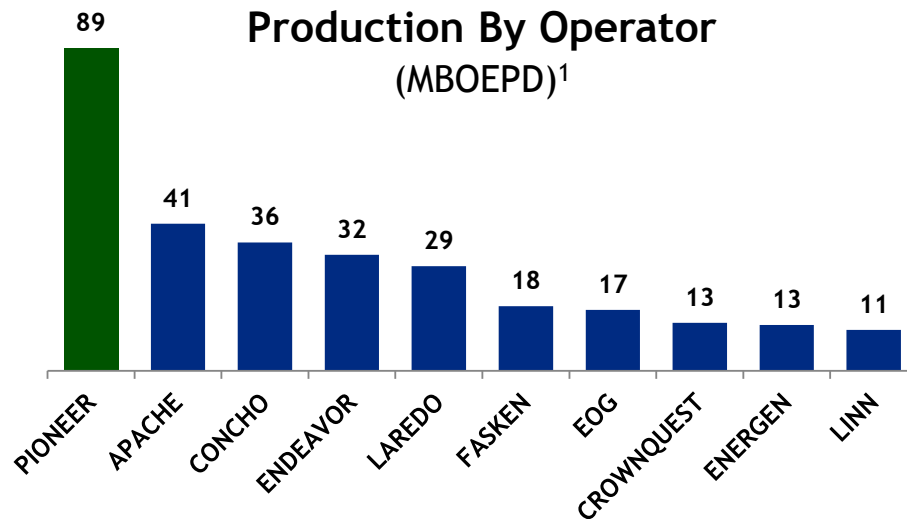
- Resource-focused strategy, with activity concentrated in 3 of the most active U.S. fields
- Best performing energy stock in S&P 500 since 2009
- Third largest oil producer in Texas
- Operating in core Spraberry/Wolfcamp asset since early 1980s
 - PXD holds ~900,000 acres in Spraberry/Wolfcamp
 - Largest producer in Spraberry/Wolfcamp with 24 rigs operating (9 horizontal and 15 vertical) and 7,000+ producing wells
 - Preeminent, low-cost operator benefitting from vertical integration strategy
- Attractive derivative positions and vertical integration protect margins
- Strong investment grade financial position

Top U.S. Fields By Rig Count¹
(Pioneer Operated Count in Green - 36 rigs)



1) Baker Hughes Rig Count (3/22/13) and PXD Internal

Spraberry/Wolfcamp Gross Production By Operator (MBOEPD)¹

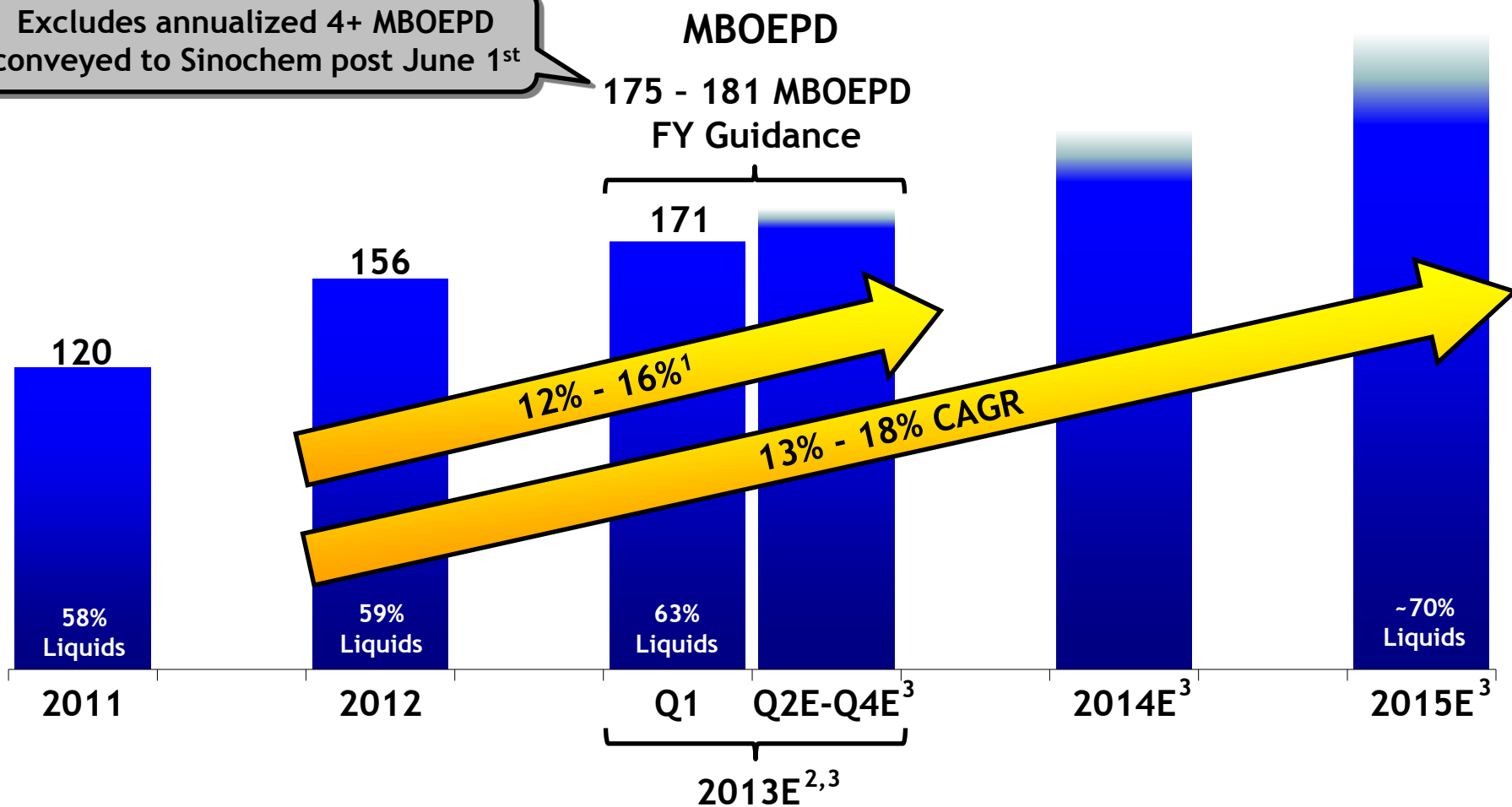


1) Year-end 2012 IHS data, gross reported oil and wet gas

Targeting 13% - 18% Compound Annual Production Growth for 2013 - 2015

High end of 2013-2015 growth range assumes \$100 oil / \$4.25 gas; low end assumes \$85 oil / \$3.25 gas

Excludes annualized 4+ MBOEPD conveyed to Sinochem post June 1st



1) Assumes \$85/Bbl oil price and \$3.25/MMBtu gas price

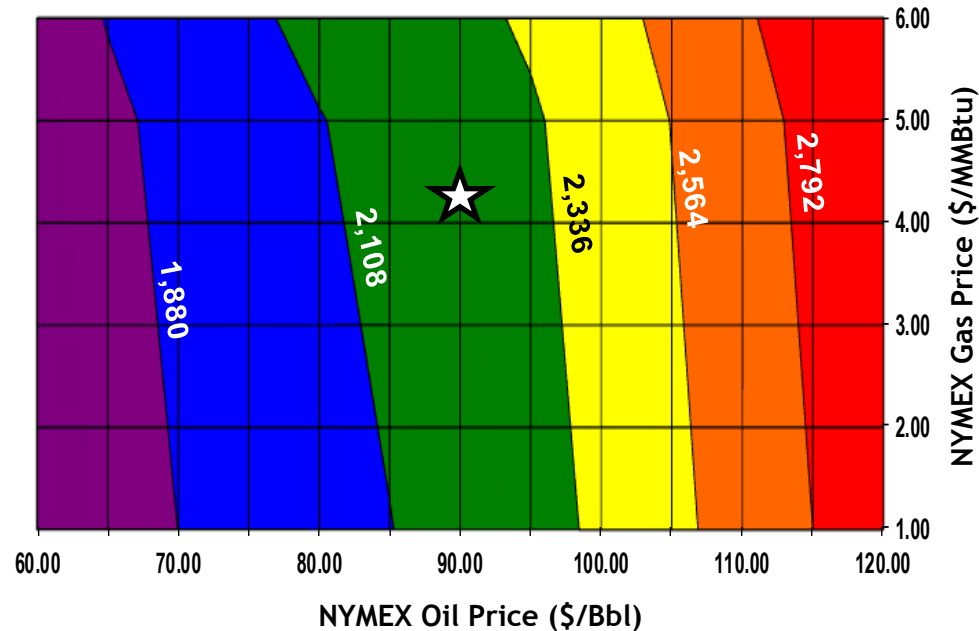
2) Excludes production attributable to the 40% joint interest transaction with Sinochem in the southern Wolfcamp area assuming a June 1, 2013 closing

3) Assumes no ethane rejected into the gas stream due to low ethane prices

2013E Capital Spending and Cash Flow¹

- Capital program of \$3.0 B includes:
 - Drilling Capital: \$2.75 B
 - \$1,225 MM northern Spraberry/Wolfcamp area
 - \$400 MM for horizontal program
 - \$625 MM for vertical program
 - \$200 MM for infrastructure & automation
 - \$425 MM southern Wolfcamp joint interest area²
 - \$575 MM Eagle Ford Shale
 - \$185 MM Barnett Shale Combo
 - \$190 MM Alaska
 - \$150 MM Other (includes land capital for existing assets)
 - \$240 MM Other Capital
 - \$25 MM vertical integration
 - \$70 MM sand mine expansion
 - \$145 MM buildings, field offices and other
- Capital program funded from:
 - \$2.4 B operating cash flow and cash on hand
 - \$0.6 B joint interest cash proceeds²

Sensitivity to Commodity Prices (\$ MM)



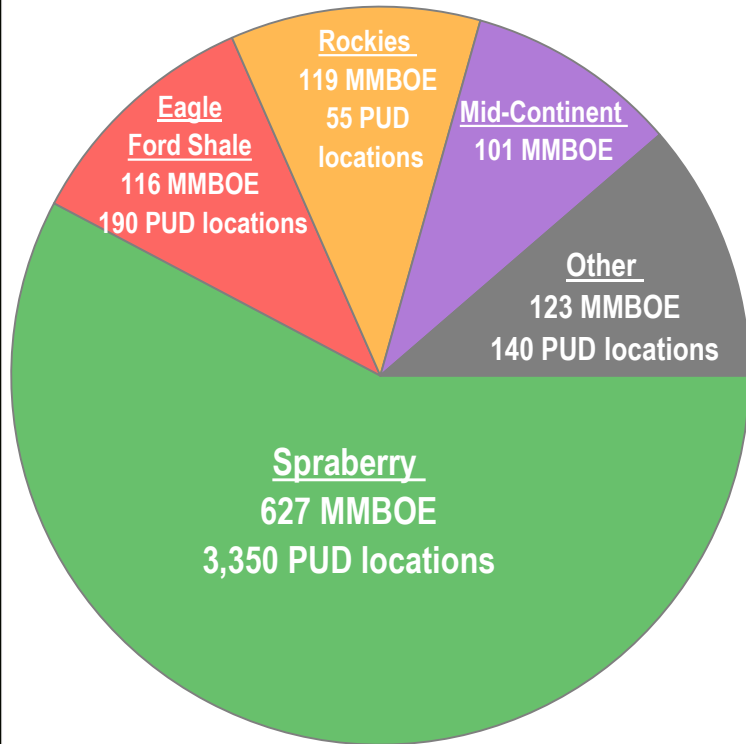
☆ \$90/bbl oil and \$4.25/mcf gas

1) Capital spending excludes acquisitions, asset retirement obligations, capitalized interest and G&G G&A
 2) Pioneer incurs 100% of capital costs from January 1st through estimated closing date of June 1st; Pioneer will be reimbursed by Sinochem for 40% of this amount as an adjustment at closing (not credited to cost incurred); Sinochem pays 40% of capital costs and carries Pioneer for 75% of Pioneer's 60% of capital costs post closing

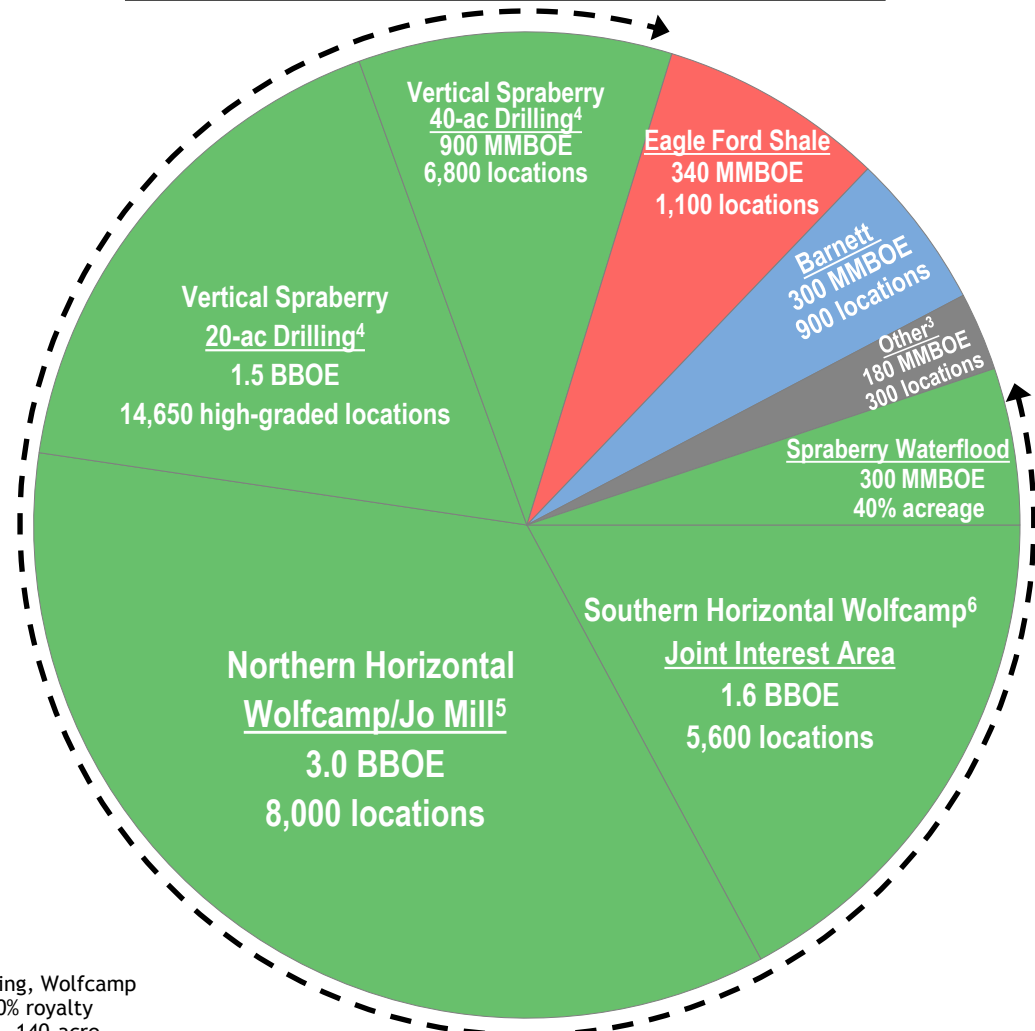
Pioneer's Significant Proved Reserves and Resource Potential¹

Proved Reserves + Estimated Net Resource Potential of >9 BBOE and >40,000 Drilling Locations

12/31/12 Proved Reserves: 1.1 BBOE²



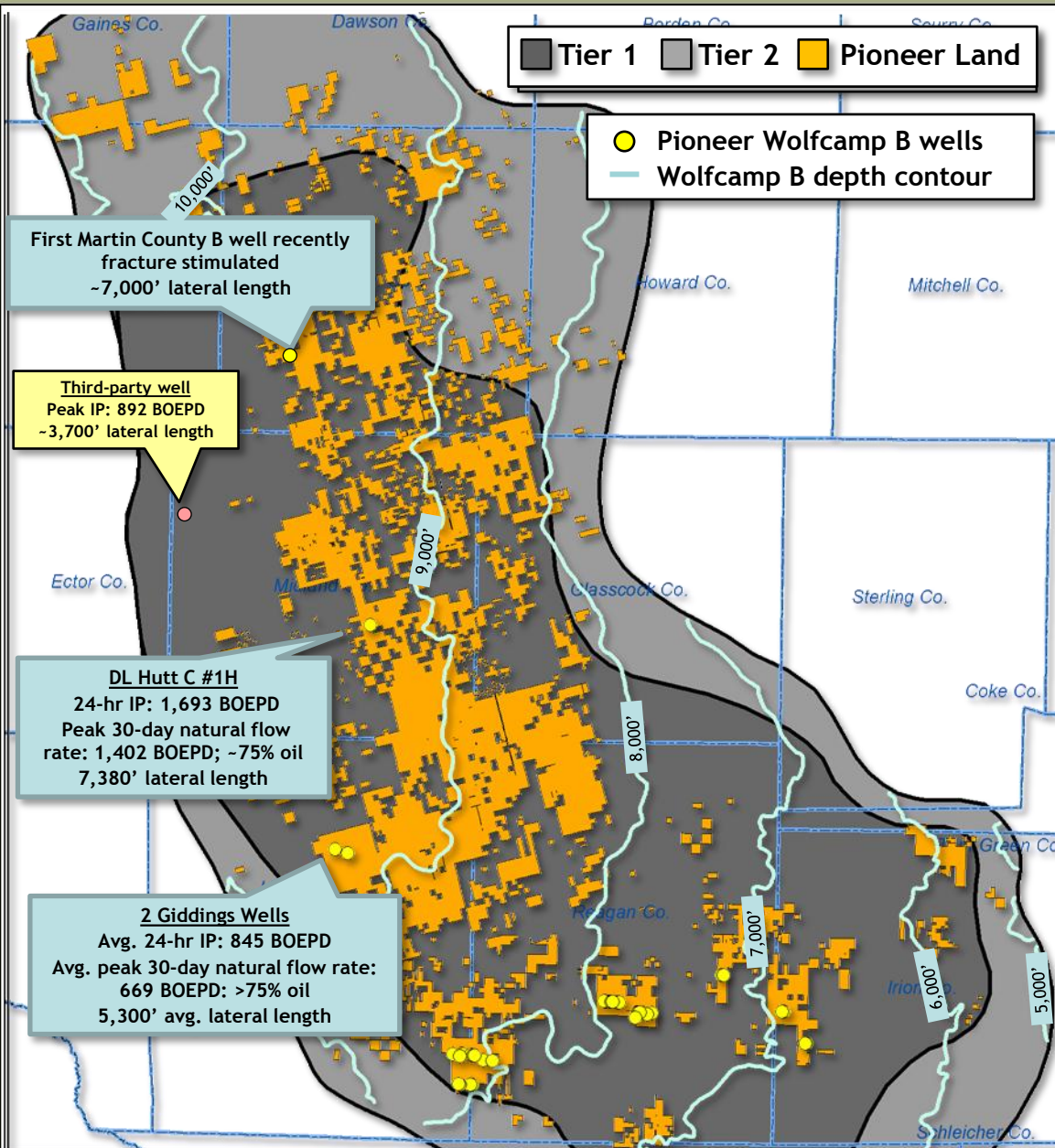
Additional Net Resource Potential: >8 BBOE



Permian >7 BBOE

- 1) All drilling locations shown on a gross basis
- 2) SEC pricing of \$94.84/Bbl for oil and \$2.76/MMBtu for gas (NYMEX)
- 3) Primarily reflects Alaska, Raton and South Texas
- 4) Includes vertical well potential from Wolfcamp and deeper intervals
- 5) Assumes average EUR of 500 MBOE per well, >600,000 gross acres, 140-acre spacing, Wolfcamp A, B & D and Jo Mill intervals (excludes Spraberry Shale interval potential) and 20% royalty
- 6) Assumes average EUR of 575 MBOE per well, 5,600 locations, 207,000 net acres, 140-acre spacing, laterals in all intervals (A, B, C & D), 25% royalty and Pioneer's 60% share (reduced by ~1 BBOE associated with joint interest transaction)

Wolfcamp B Interval Prospectivity Map



- Tier 1 is highest prospectivity acreage, as determined by several geologic properties, including:
 - Original oil in place (OOIP)
 - Kerogen content
 - Thermal maturity
 - Porosity
 - Brittle mineral fraction (fracability, low clay content)

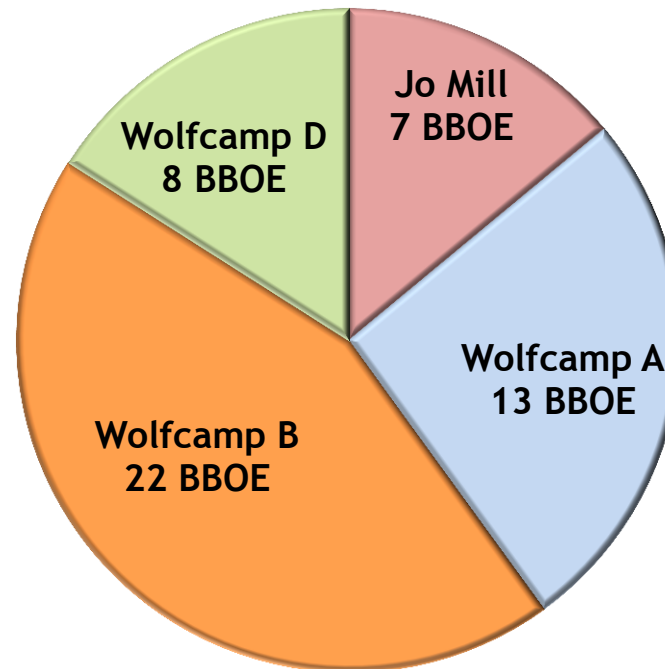
- Geologic maps based on:
 - >70,000 logs
 - >1,400 square miles of 3-D seismic
 - >4,000 feet of core

Industry Wolfcamp B Prospectivity

- 4.8 MM risked acres (Upper B and Lower B)
- >34,000 potential well locations on 140-acre spacing
- 450 MBOE to 1 MMBOE EUR per well

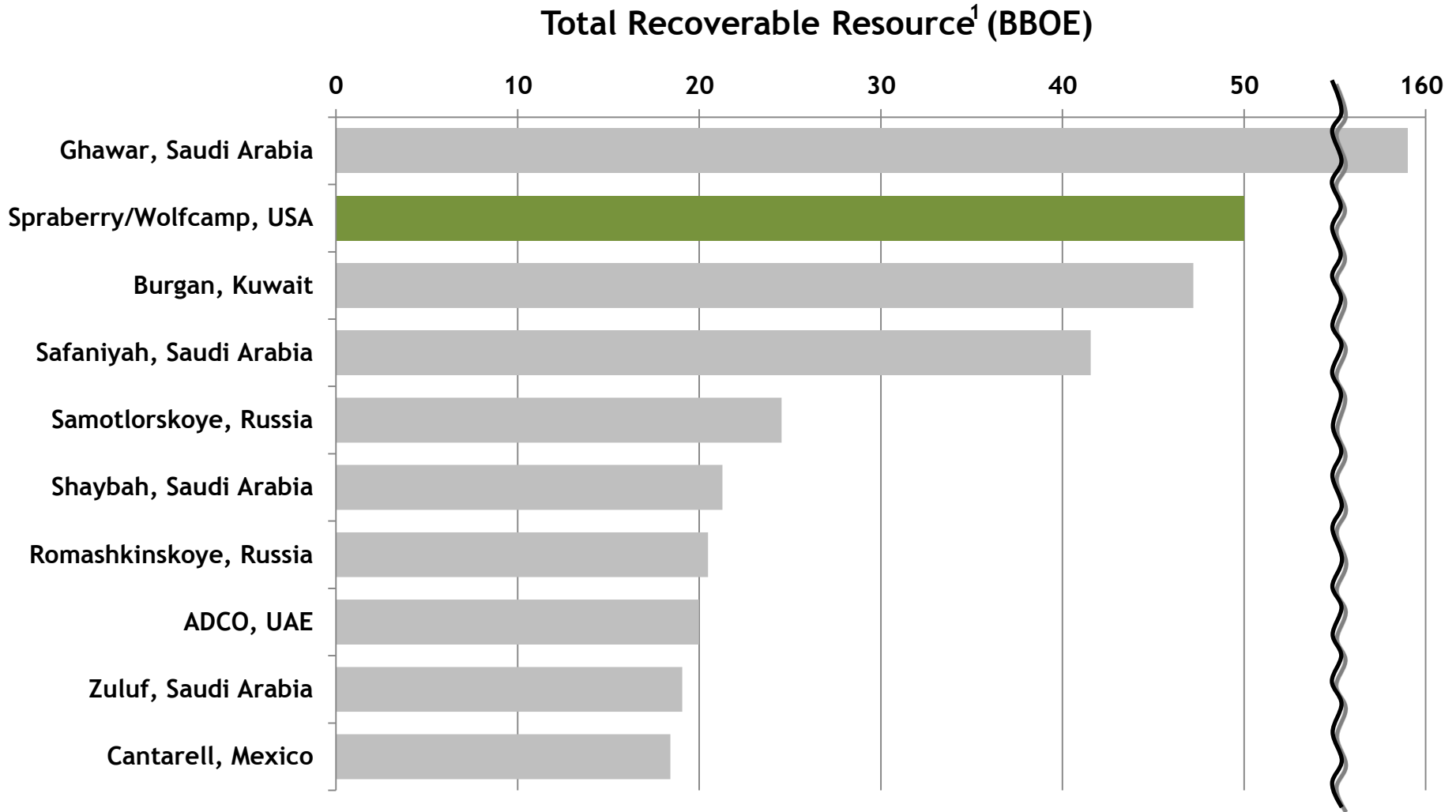
~22 BBOE Resource Potential

50 BBOE Recoverable Resource Potential by Industry Midland Basin Wolfcamp and Jo Mill Shales



- 50 BBOE recoverable resource potential by industry in four shale intervals where successful horizontal wells have been drilled
- Additional horizontal potential in two more Spraberry intervals, Strawn, Atoka and Barnett/Woodford intervals
- Assumes 140-acre spacing; down-spacing potential exists

Largest Oil Fields Worldwide

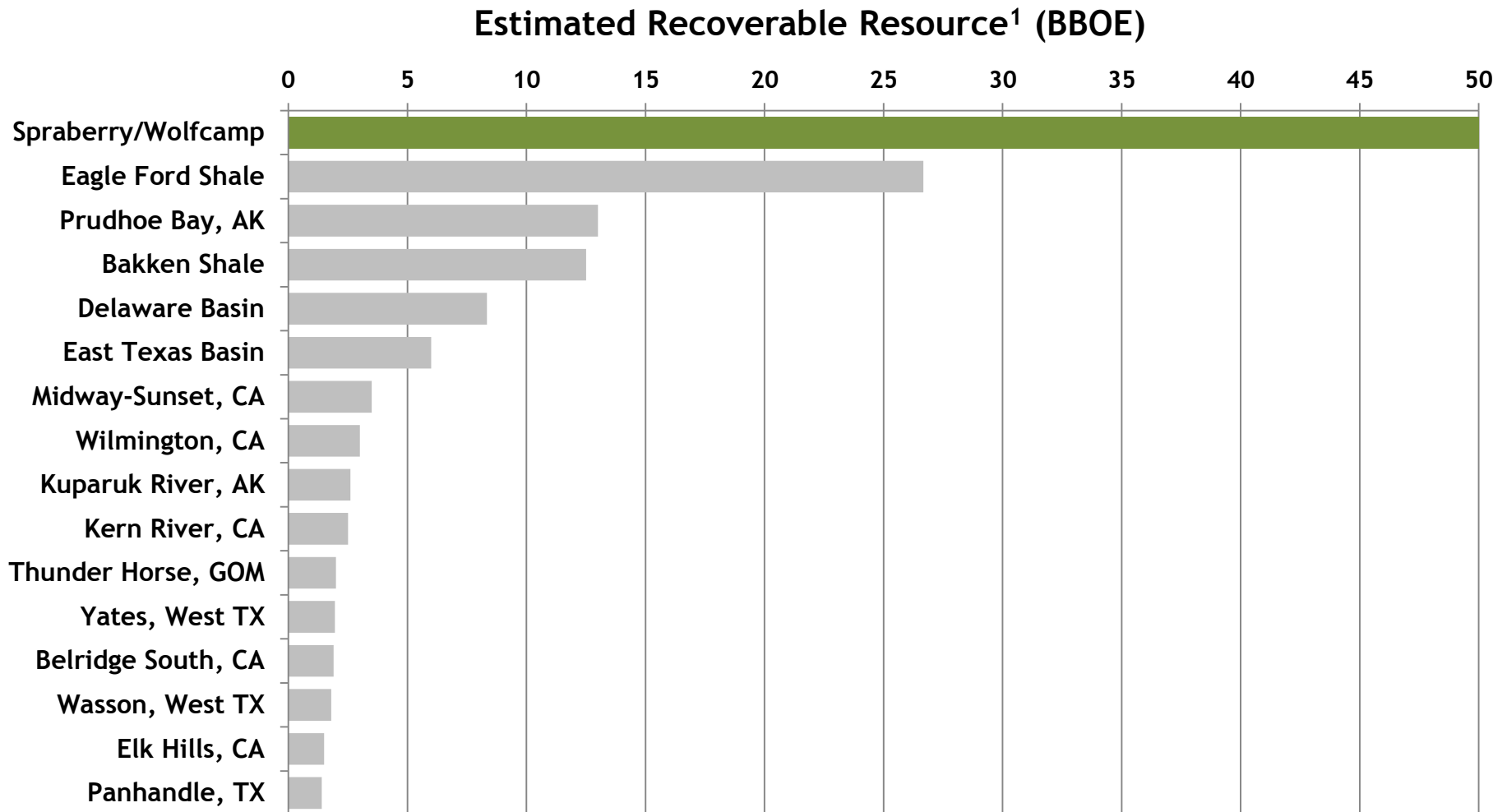


Spraberry/Wolfcamp is the 2nd largest oil field in the world

1) Total recoverable reserves includes oil and gas for all fields

Source: Wood Mackenzie for international fields; Spraberry/Wolfcamp from Pioneer

Largest U.S. Oil Fields

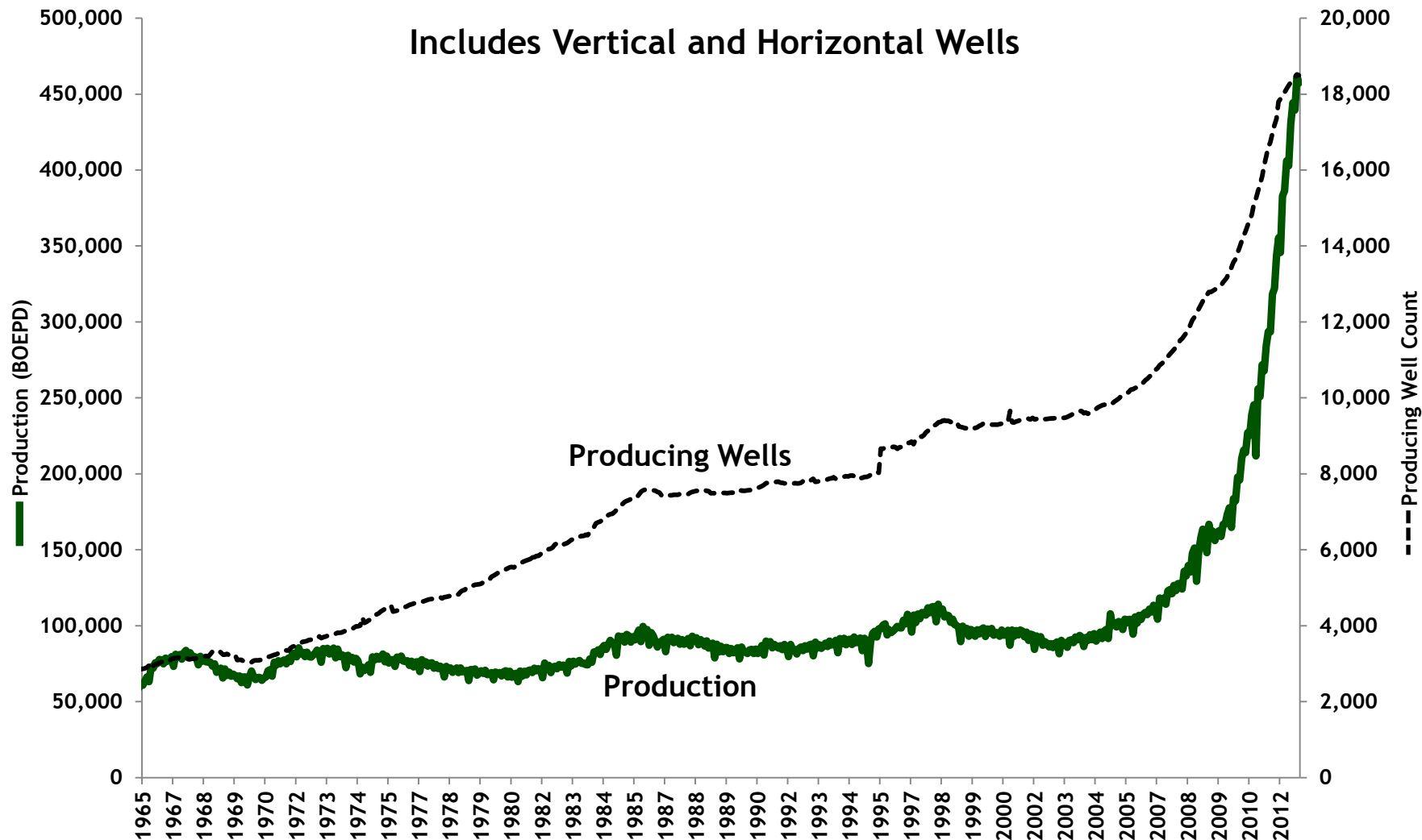


Spraberry/Wolfcamp is the largest oil field in the U.S.

Source: DOE, EIA, ITG and other sources

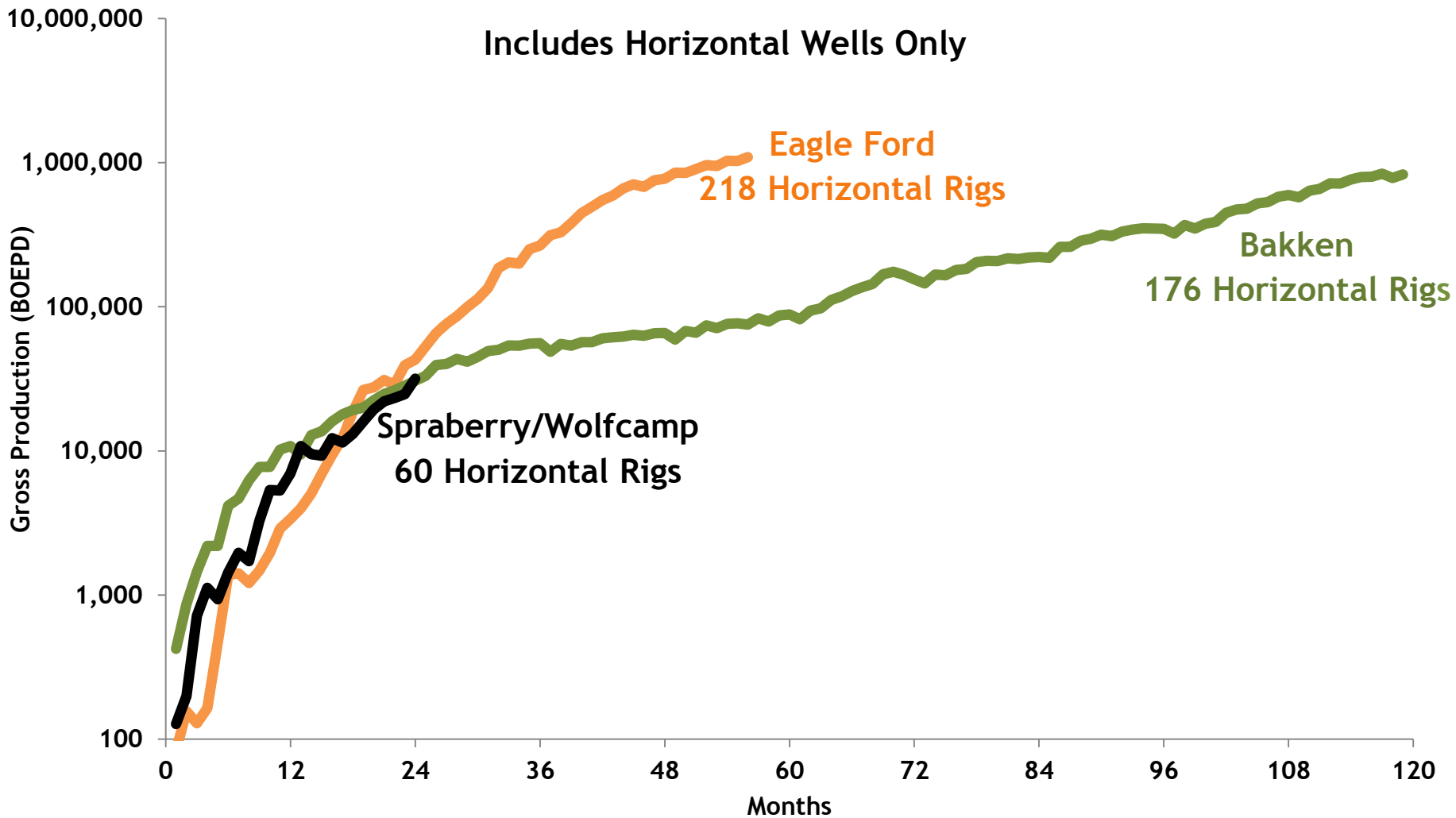
1) Cumulative production + estimated recoverable resource

Spraberry/Wolfcamp Production History



- From 2009 to 2012, production growth primarily attributable to increased vertical activity
- Post 2012, production growth expected to be driven by horizontal activity

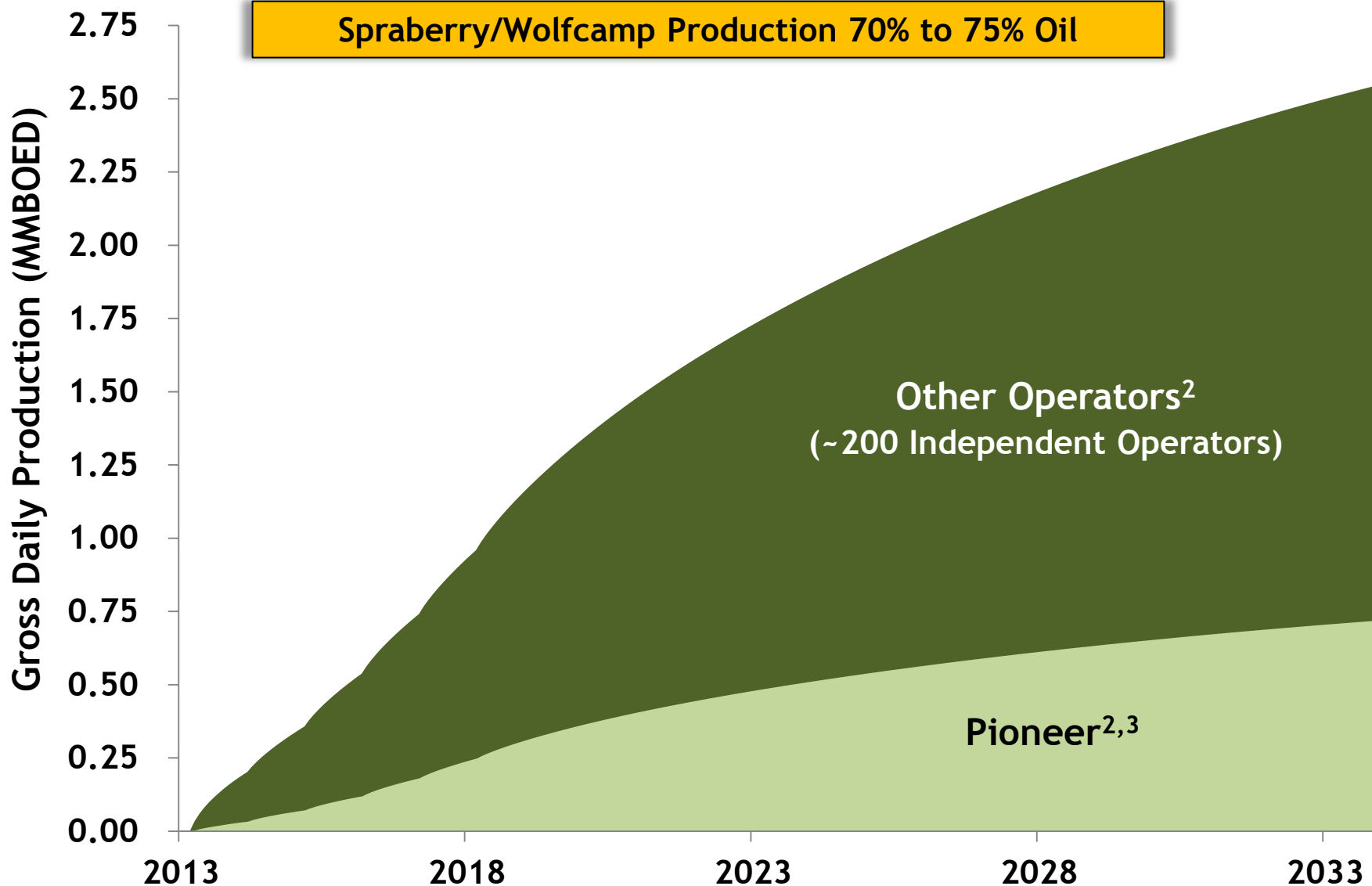
Production Growth Profiles For 3 Largest U.S. Oil Shale Plays



Spraberry/Wolfcamp horizontal growth trajectory similar to Bakken and Eagle Ford

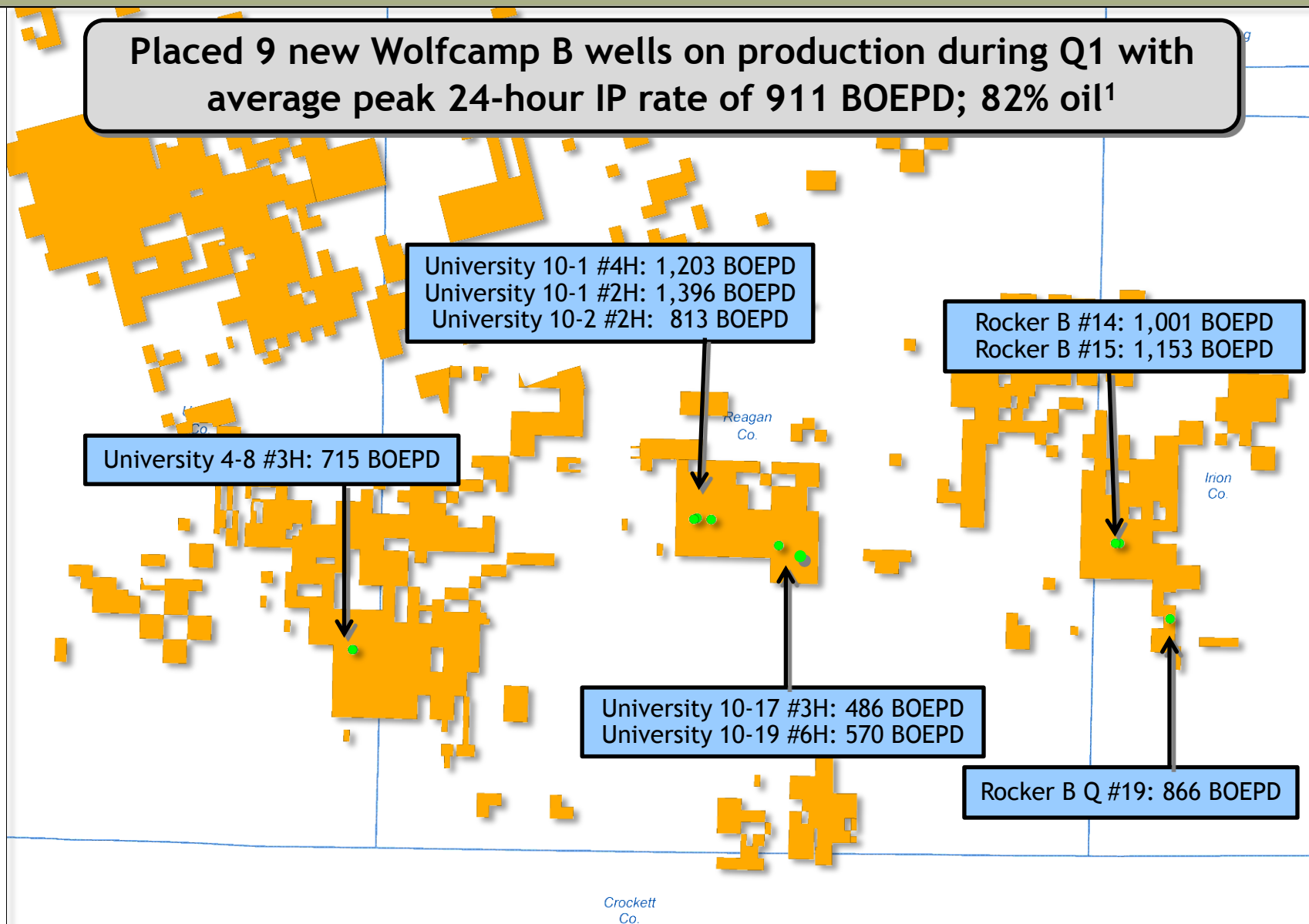
Note: Production data is from IHS and represents incremental production for the play beginning when horizontal drilling activity began in earnest; Rig count data from Baker Hughes as of 3/22/13 for selected counties identified on slide 9 for Spraberry/Wolfcamp; Initial month is November 2010 for Spraberry/Wolfcamp, April 2008 for Eagle Ford and January 2003 for Bakken

Spraberry/Wolfcamp Horizontal Drilling Production Growth Profile¹



- 1) Potential impediments to achieving this forecast include oil price, capital, infrastructure (Midland and oil field) and people
- 2) Assumes ramp from 60 horizontal rigs in 2013 (~10 Pioneer rigs) to ~170 rigs per year in 2018 and thereafter (~50 Pioneer rigs)
- 3) Includes royalties and joint interest partner's share of production in southern Wolfcamp

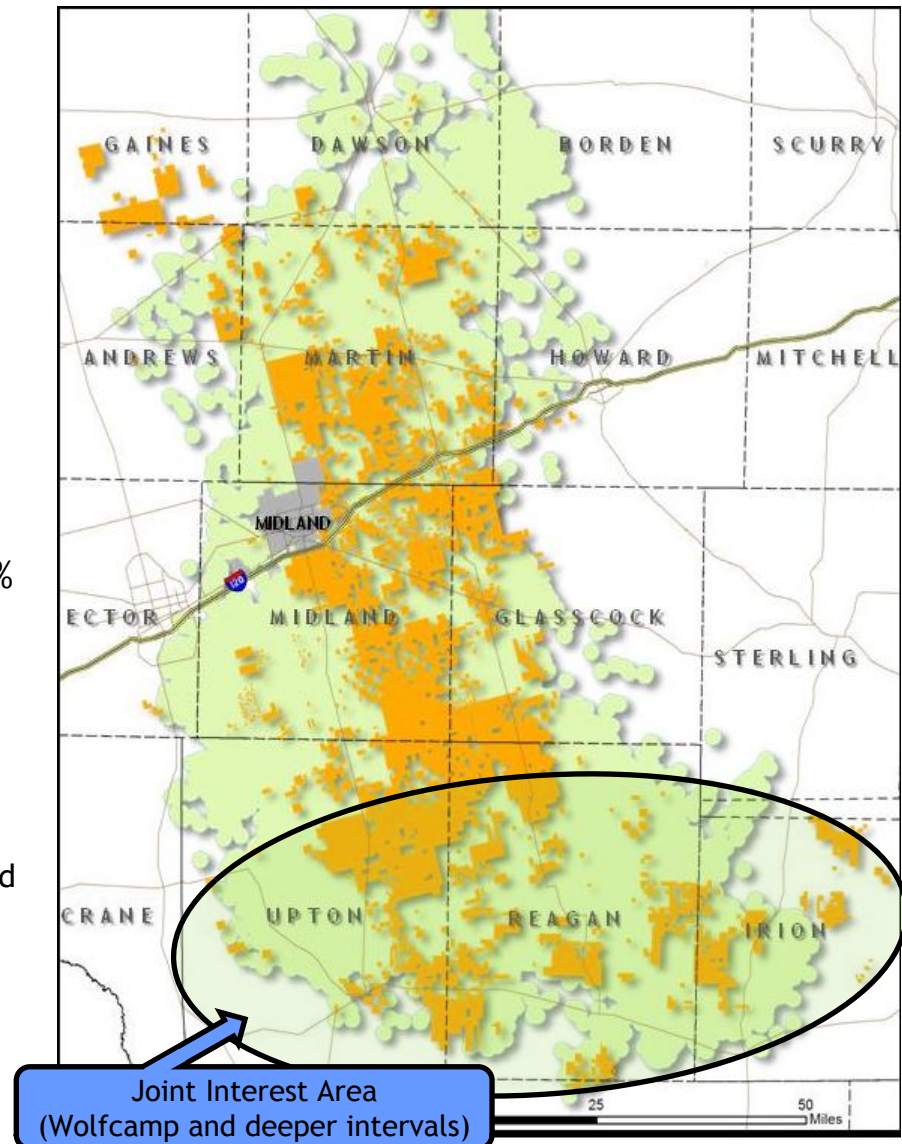
Placed 9 new Wolfcamp B wells on production during Q1 with average peak 24-hour IP rate of 911 BOEPD; 82% oil¹



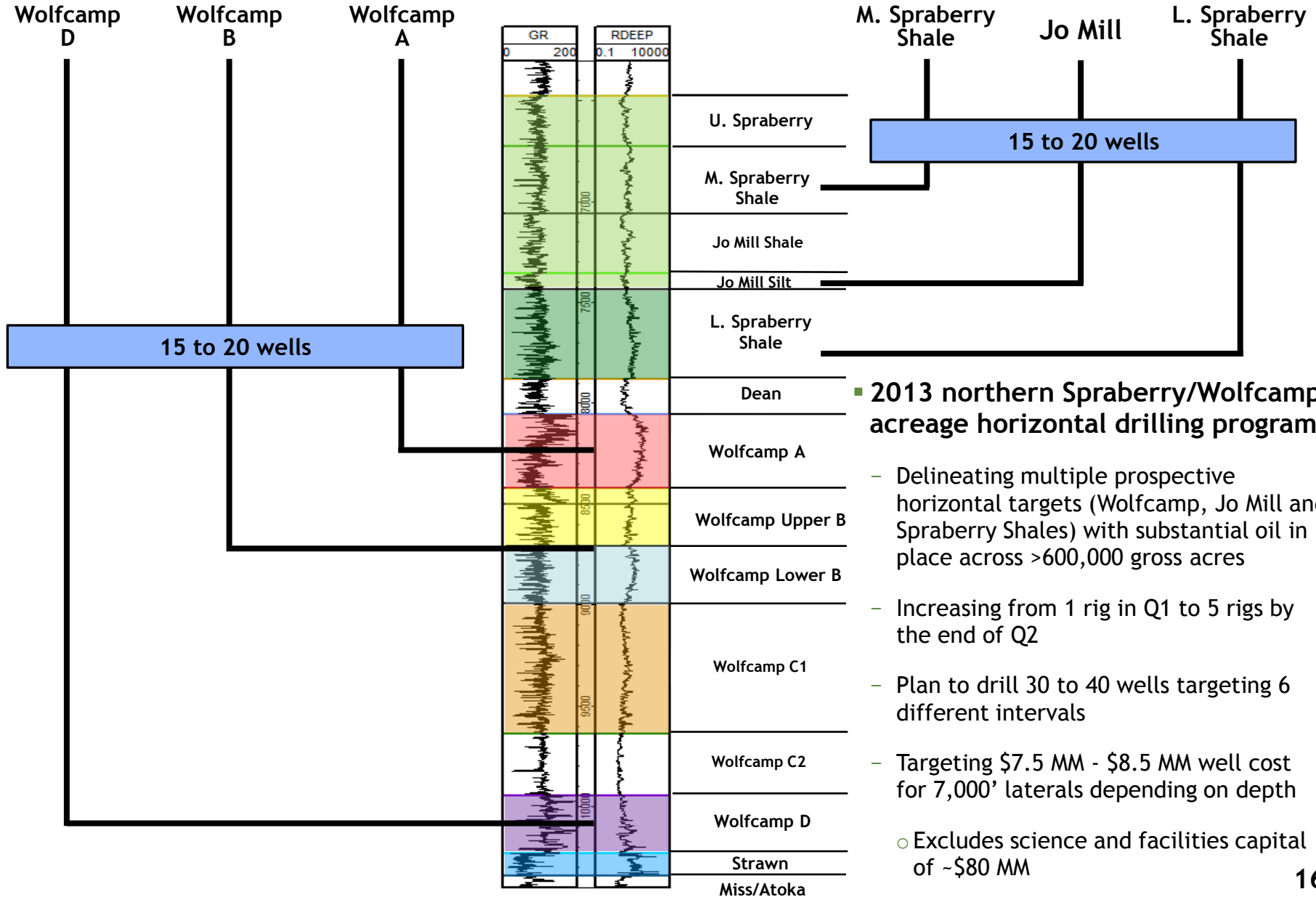
1) Lateral lengths average -7,100', except for University 10-1 #4H at -9,600'

Southern Wolfcamp Joint Interest Area Drilling Program

- **Currently running 7 rigs; expect to increase to 10 rigs in 2014 and 13 rigs in 2015**
 - Equates to 86 wells in 2013, 120 wells in 2014 and 165 wells in 2015
- **2013 drilling program continues to focus on delineating acreage**
 - Testing multiple Wolfcamp intervals
 - Targeting \$7.5 MM - \$8.0 MM gross development well cost for 8,300' lateral
 - Expect to drill >20 10,000' laterals in 2013; ~20% additional cost generates EUR increase of 40% - 60%
 - Expect ~70% pad drilling
 - Evaluating horizontal downspacing opportunities
 - Pumped 5 Wolfcamp B slickwater fracs through April; early results encouraging
 - Potential savings of up to \$1.0 MM/well compared to hybrid fracs
 - Expect gross science costs of ~\$20 MM
- **Drilling program for 2014 and beyond primarily focused on development drilling and accelerating production growth**



Northern Spraberry/Wolfcamp Acreage - Pioneer's 2013 Drilling Plan



Pioneer's Q2 Northern Spraberry/Wolfcamp Drilling Plan

- Initial rig drilled first two horizontal Wolfcamp Shale wells in Midland County

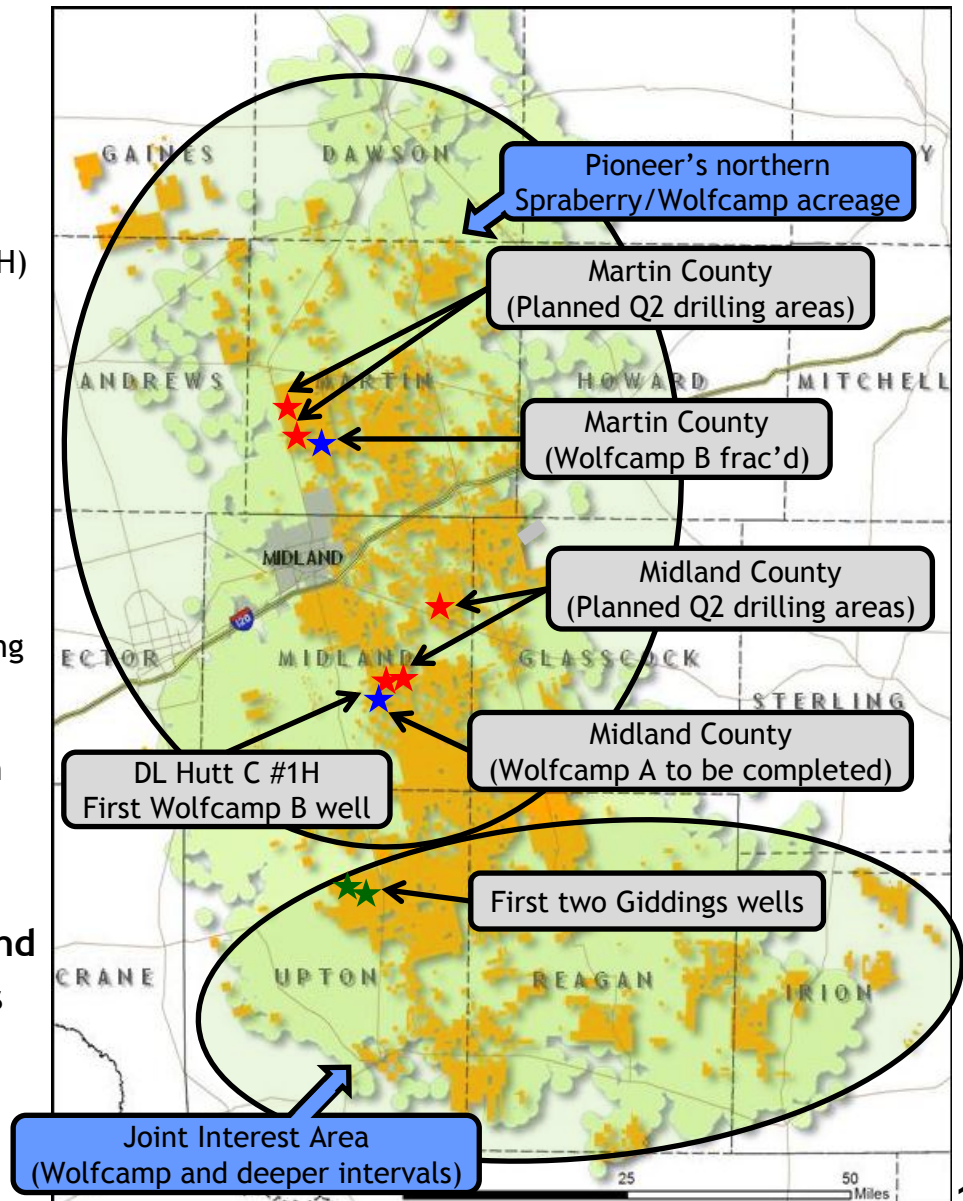
- ~25 miles north of highly successful Giddings horizontal Wolfcamp Shale wells
- First well completed in Wolfcamp B interval (DL Hutt C #1H)
- Second well expected to be completed in late May/early June in Wolfcamp A interval
- Rig moved to Martin County and drilled first Wolfcamp B well; recently fracture stimulated

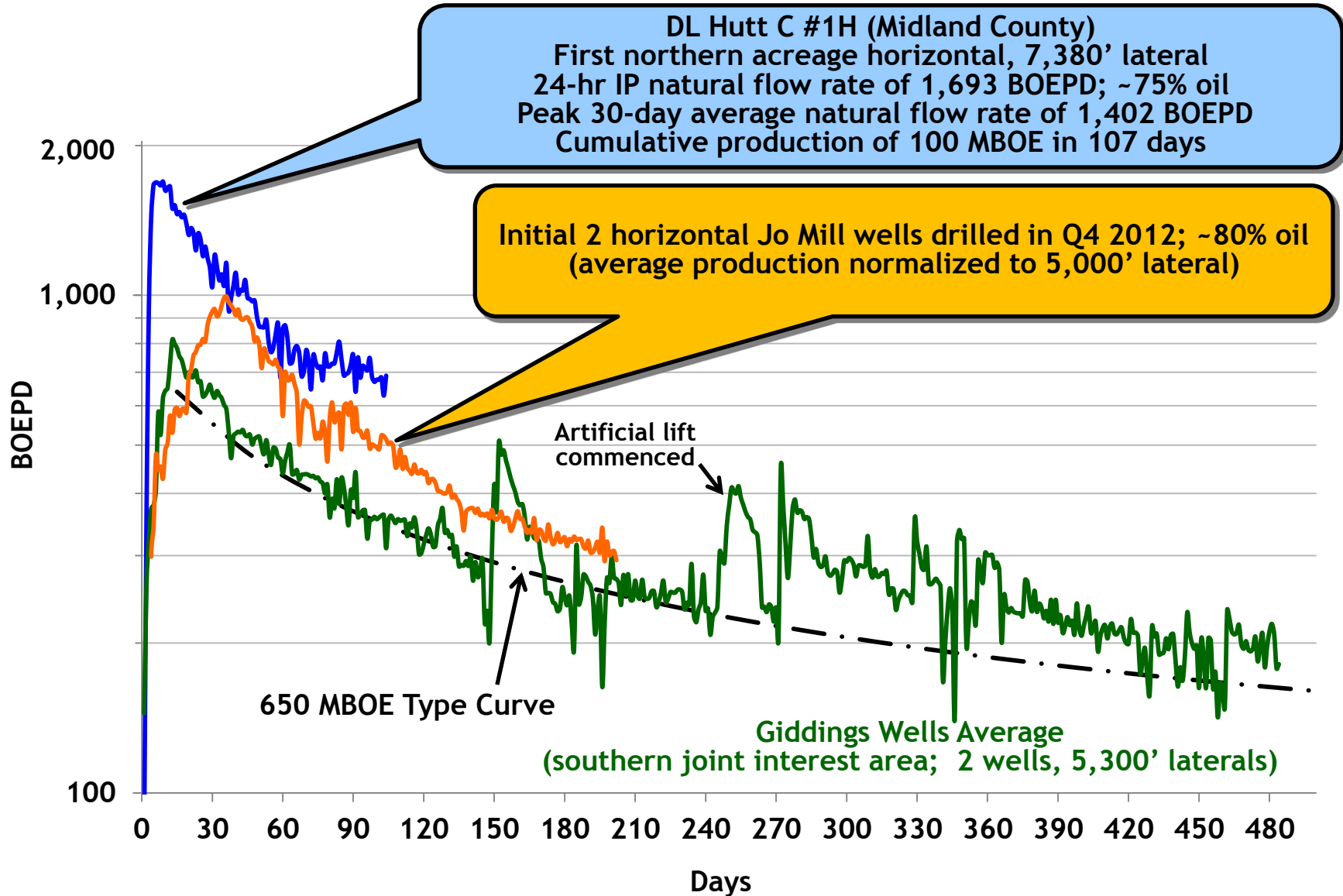
- Adding 4 horizontal rigs during Q2

- 3 rigs as planned and 1 additional rig to focus on developing the Hutt lease
- Capital for the incremental rig expected to be absorbed in existing 2013 drilling budget of \$2.75 billion

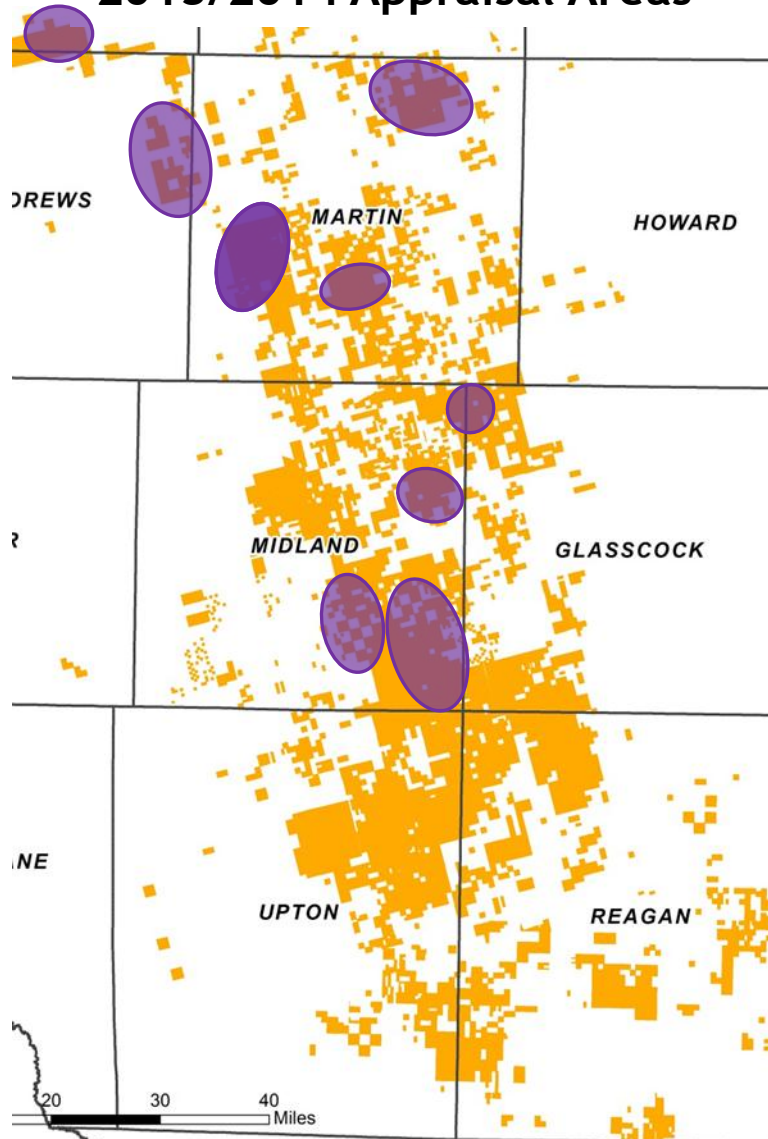
- 5-rig program will consist of 3 rigs focused on Wolfcamp Shales and 2 rigs focused on Jo Mill and Spraberry Shales in Midland and Martin counties

- Expect each rig to drill initial wells on 2-well pads to gain efficiencies; wells will be completed after second well on pad is drilled





2013/2014 Appraisal Areas



- **2013 drilling program expected to cost ~\$400 MM**
 - Appraise prospective acreage and confirm additional resource potential across 6 stacked intervals on >600,000 gross acres; totals >3 MM gross acres
 - Resource potential in Wolfcamp and Jo Mill intervals across northern Spraberry/Wolfcamp acreage estimated to be 3 BBOE
 - Deliver year-end 2013 horizontal production exit rate of 5 MBOEPD to 7 MBOEPD
 - Improve capital efficiency compared to vertical drilling
- **Expect to ramp up to 6 - 8 rigs during 2014 at a full-year cost of ~\$600 MM**
 - Continue appraisal program and development drilling
 - May also test horizontal drilling in deeper intervals below the Wolfcamp Shale

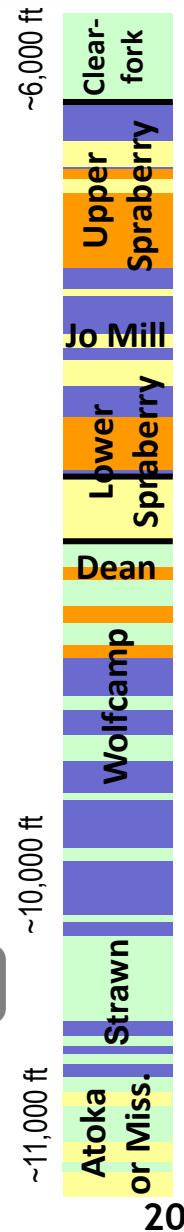
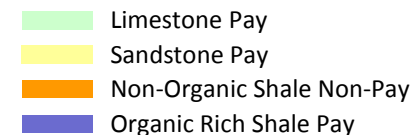
Spending \$1 B over 2 years to confirm ~3 BBOE of resource potential and add substantial NAV

Spraberry Vertical Drilling Program

- Deeper drilling expected to account for 90% of 2013 vertical drilling program
- 2013 drilling program includes 15 vertical rigs that are forecast to drill ~300 wells
 - Required to meet continuous drilling obligations
- 15 rigs to 20 rigs required to keep vertical production flat
- Drilled 75 vertical wells in Q1; 130 vertical wells placed on production
 - Decreased frac bank by 55 vertical wells during Q1

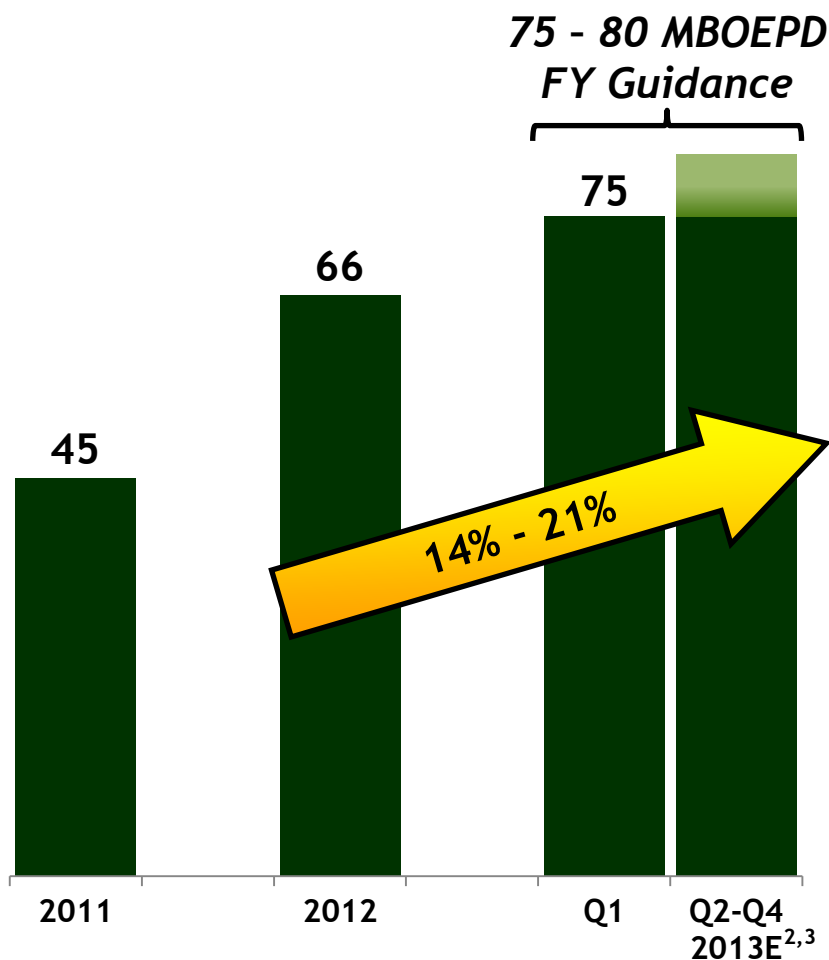
	Potential Incremental EUR (MBOE) ¹	Prospective PXD Acreage
Strawn	30	~85%
Atoka	50 - 70	40% - 50%
Mississippian	15 - 40	~20%

Deeper drilling provides potential to add up to 100 MBOE to a vertical Wolfcamp well EUR



1) Compares to average vertical well completed through the Lower Wolfcamp with an average EUR of 140 MBOE

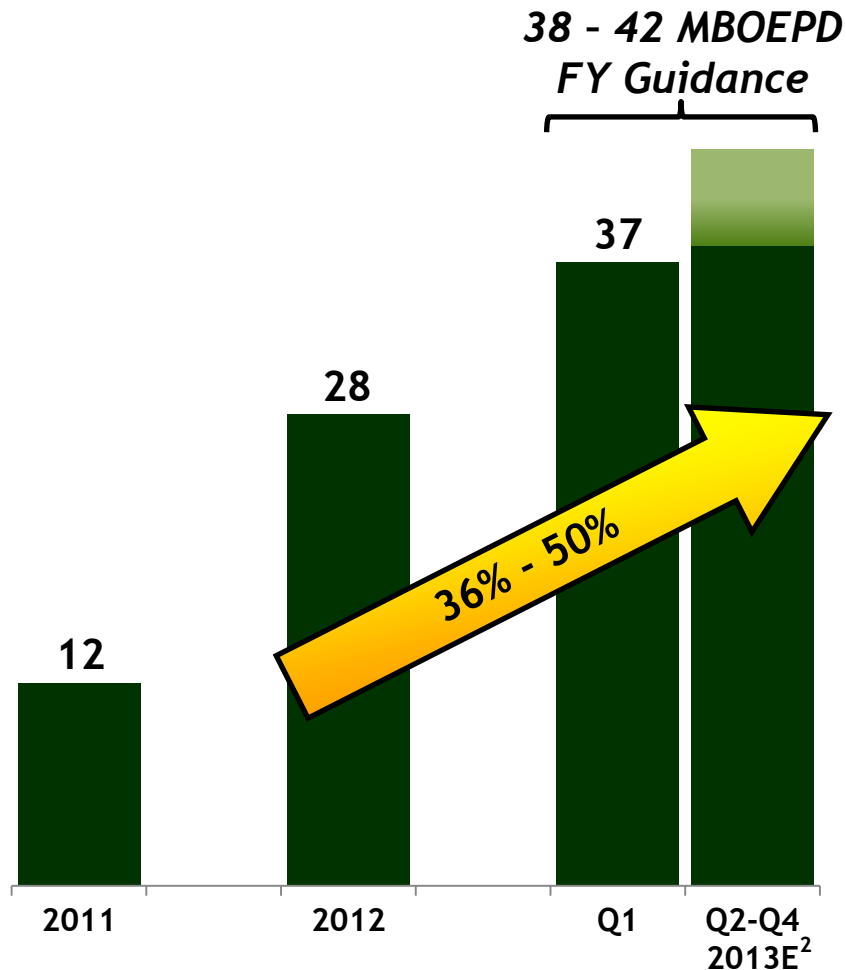
Sraberry/Wolfcamp Net Production¹ (MBOEPD)



- Q1 production benefited by ~2,000 BOEPD from reduction in vertical frac bank of 55 wells
- Q1 production negatively impacted by ~2,700 BOEPD due to reduced ethane recoveries resulting from Spraberry area gas processing facilities operating above capacity
- New gas processing capacity of 200 MMCFPD (Driver plant) came on line in mid-April, alleviating the ethane recovery issue
- Expect horizontal production to increase from an average of 2 MBOEPD in 2012 to 11 MBOEPD to 14 MBOEPD in 2013²
 - Q1 horizontal production of ~5,000 BOEPD

1) Includes production from Strawn, Atoka and Mississippian intervals in Spraberry vertical wells and horizontal Wolfcamp Shale, Jo Mill and Spraberry Shale wells
 2) Production reduced after June 1st to reflect the divested volumes associated with the southern Wolfcamp joint interest transaction
 3) Assumes no ethane rejected into the gas stream due to low ethane prices

Eagle Ford Shale Net Production¹ (MBOEPD)



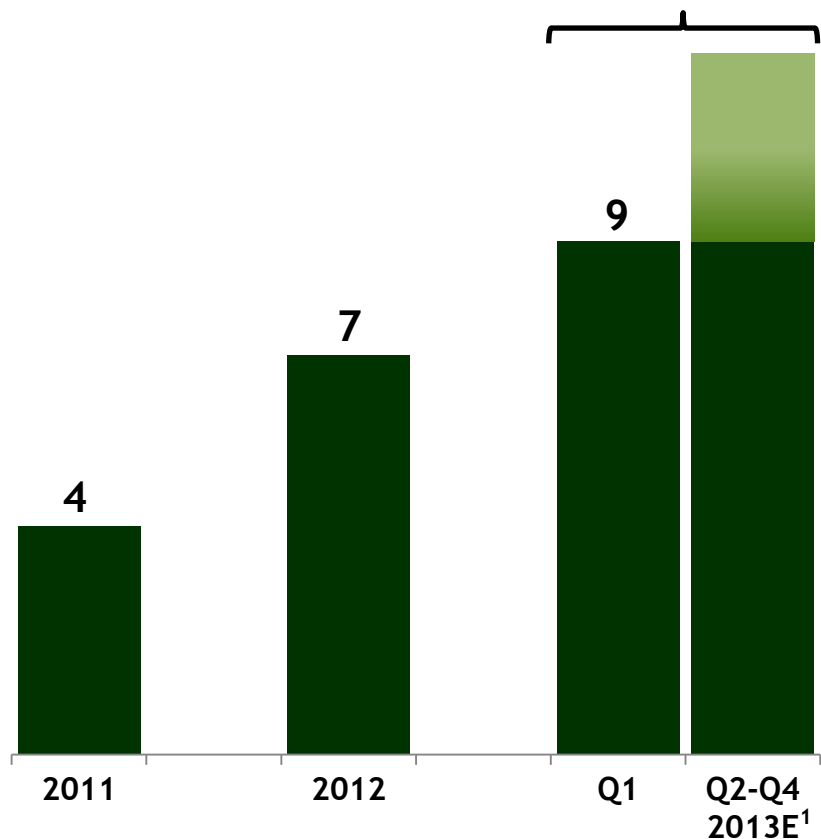
- Drilled 37 wells in Q1; 35 wells placed on production
- Expect to drill ~130 wells in 2013
 - Drilling essentially all liquids-rich wells
 - ~80% pad drilling, up from 45% in 2012
 - Saves \$600 M to \$700 M per well and allows 130 wells to be drilled with 10 rigs vs. 12 rigs last year
 - Evaluating downspacing
- Expanding use of white sand proppant to deeper areas to further define its performance limits
 - ~70% of 2013 program
 - 22 wells stimulated using white sand in Q1
 - Early well performance similar to direct offset ceramic-stimulated wells
 - Reduces frac cost by ~\$700 M
- Well cost: \$7 MM to \$8 MM
- 11 CGPs on line; expect to add 12th during 2014

1) Reflects Pioneer's ~35% share of gross production

2) Assumes no ethane rejected into the gas stream due to low ethane prices

Barnett Shale Net Production (MBOEPD)

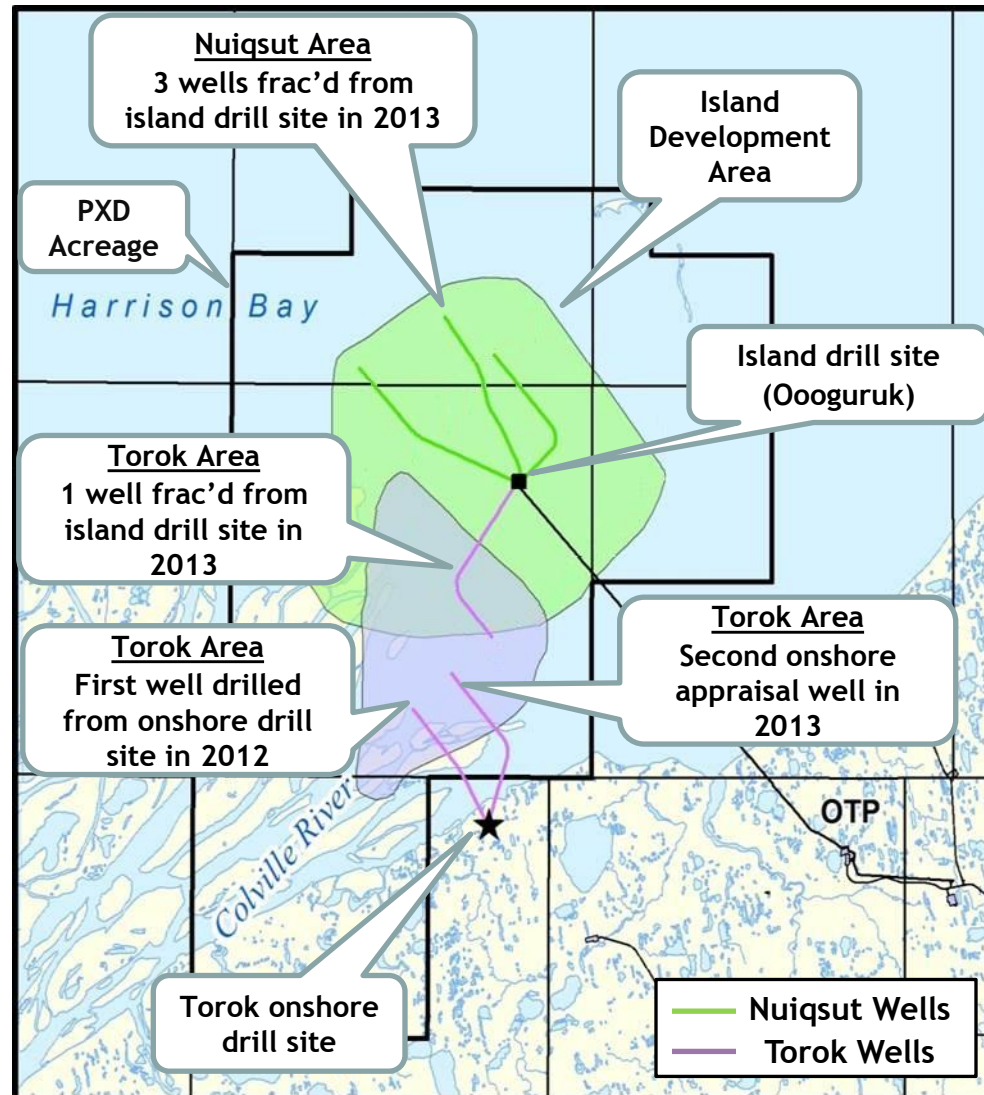
**9 - 12 MBOEPD
FY Guidance**



- Drilled 8 wells in Q1; 4 wells placed on production
- Increased rig count from 1 rig to 2 rigs in April to hold high-graded acreage
 - ~25% of ~80,000 net acreage position currently HBP
 - Drilling data and petrophysical and seismic analysis have identified highest-return areas across Pioneer's acreage (reflects ~40,000 net acres of remaining ~60,000 non-HBP net acres)
 - 2-rig drilling program required to hold the higher-return acreage over next 3 years
- Well cost for 5,000' lateral reduced to ~\$2.9 MM
 - Reflects improved drilling and completion performance
 - Gross EUR: ~400 MBOE (16% oil, 42% NGLs, 42% gas)

1) Assumes no ethane rejected into the gas stream due to low ethane prices

- Q1 net production: ~4 MBOPD
- 1-rig development program continues from the Ooguruk island drill site targeting Nuiqsut and Torok intervals
 - Following first successful mechanically diverted frac on a Nuiqsut well in 2012 (produced ~685 MBO in 12 months), frac'd 3 Nuiqsut wells and 1 Torok well during Q1 2013
 - First 2 Q1 2013 Nuiqsut wells on production with peak gross production rates of ~3,500 BOPD and ~3,000 BOPD to date (both wells still unloading)
 - Remaining 2 wells frac'd in Q1 2013 expected to be on production during May
- Expect Q2 production to be negatively impacted by scheduled third-party processing facility downtime during June
- Torok resource potential increased to 75 MMBO to 100 MMBO from 50 MMBO originally
 - Initial 2012 onshore Torok well retested in Q1 2013 at a facility-limited rate of ~2,800 BOPD gross
 - Logs from second onshore Torok well drilled in Q1 2013 confirm high quality reservoir rock



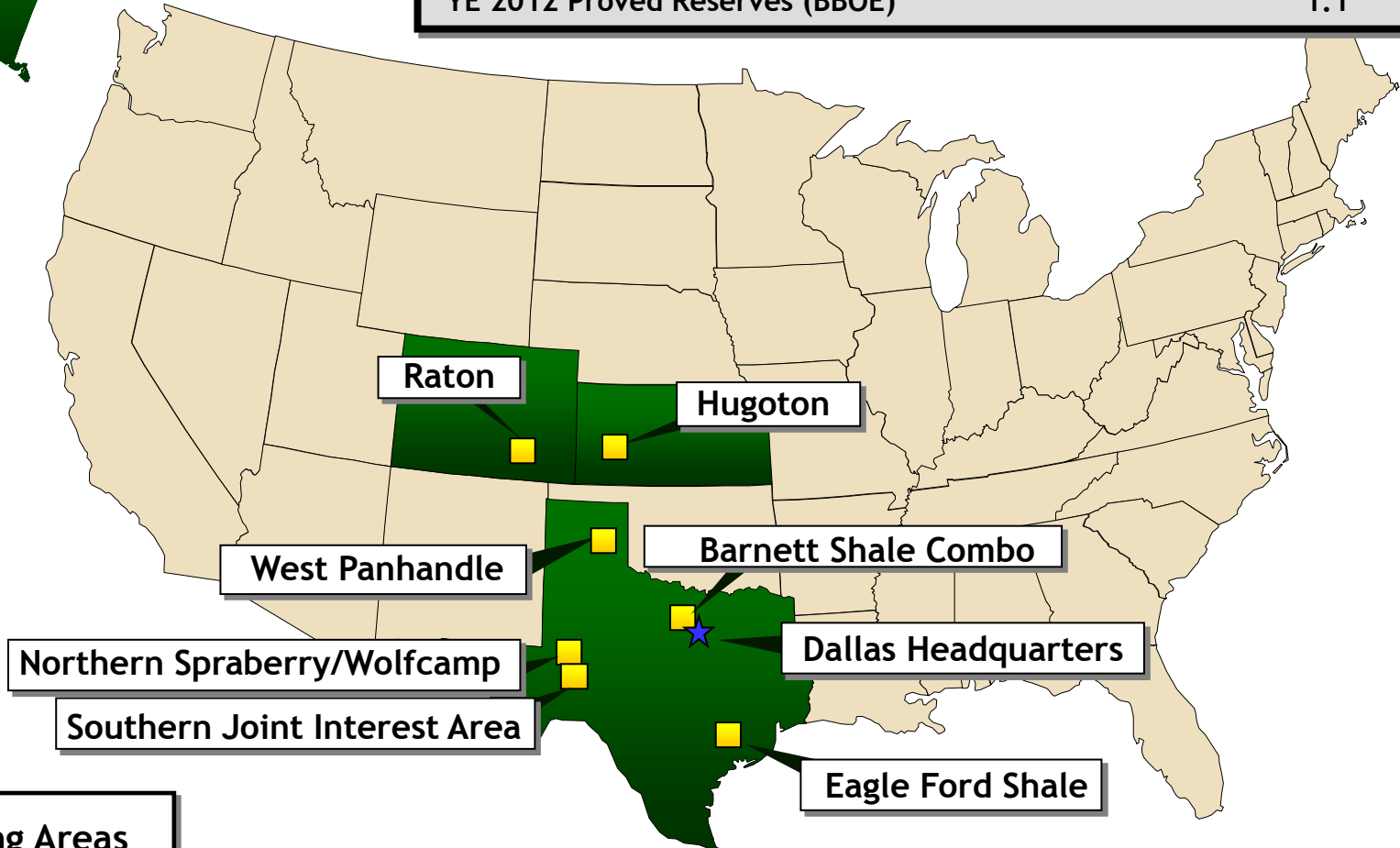
**Total Pioneer Net Resource Potential:
125 MMBO - 150 MMBO**

- U.S. asset base
- High oil exposure from proved reserves + estimated net resource potential of >9 BBOE
- Drilling program focused in three liquids and resource rich core assets in Texas
 - Spraberry Vertical
 - Horizontal Wolfcamp Shale
 - Joint venture and recent successful equity offering accelerate future development
 - Eagle Ford Shale
- Strong production growth profile
- Vertical integration substantially improving execution and returns
- Attractive derivative positions protect margins
- Strong investment grade financial position

Appendix

Pioneer - Large Independent U.S. E&P Company

Total Enterprise Value (\$B)	\$20
2012 Operating Cash Flow (\$B)	\$1.8
2012 Drilling Expenditures (\$B)	\$2.8
2012 Drillbit F&D (\$/BOE)	\$17.72
Q1 2013 Production - 63% Liquids (MBOEPD)	171
2012 Reserve Replacement (%)	264%
YE 2012 Proved Reserves (BBOE)	1.1



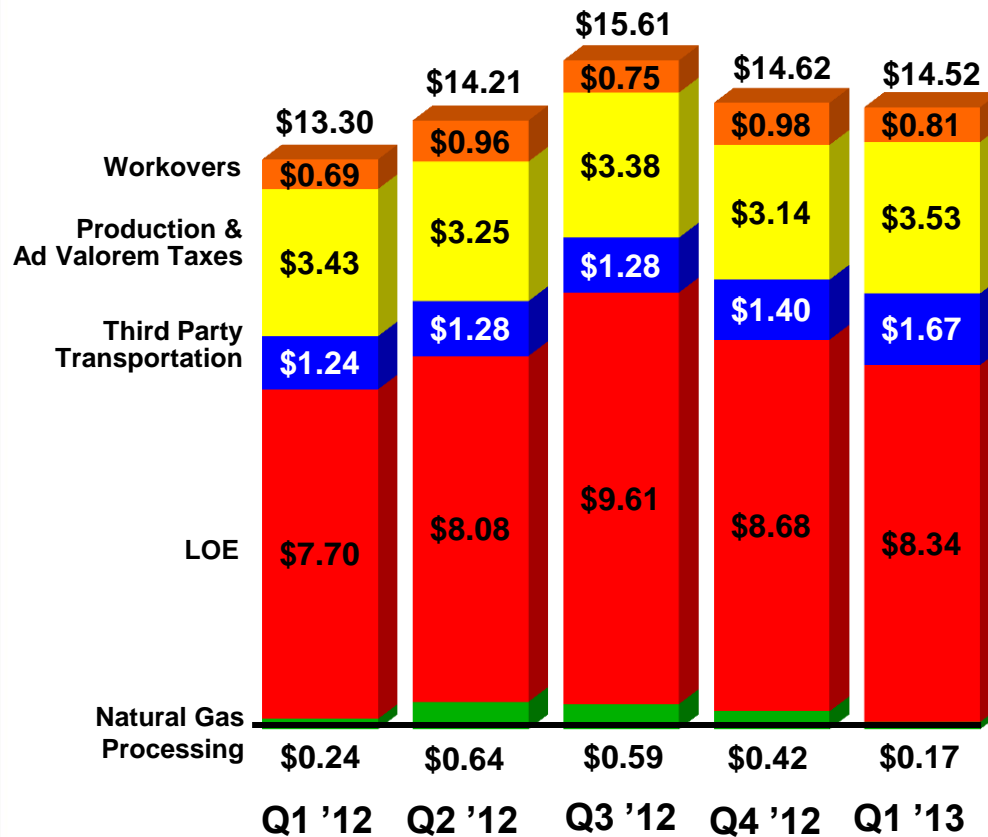
Strong 2012 Reserve Additions¹

- **Added 161 MMBOE from the drillbit, or 264% of full-year production, at a drillbit F&D cost of \$17.72 per BOE**
 - Reflects significant drilling campaigns in horizontal Wolfcamp Shale, Spraberry vertical, Eagle Ford Shale and Barnett Shale Combo plays
- **All-in reserve replacement of 87 MMBOE, or 144% of full-year production at an all-in F&D cost of \$34.46 per BOE, including:**
 - Negative pricing revisions of 82 MMBOE due to significant decline in gas prices
 - Negative technical revisions of 27 MMBOE; performance improvements of 53 MMBOE offset by 80 MMBOE of vertical Spraberry PUDs moved to the probable category as the Company shifts to more horizontal drilling in the Spraberry field based on successful horizontal Wolfcamp Shale drilling results
- **Reserve mix**
 - 100% U.S.
 - 45% oil / 21% NGLs / 34% gas
 - 58% PD / 42% PUD
- **Proved Reserves / Production: ~18 years**
- **PD Reserves / Production: ~10 years**

	Year-end '12 Proved Reserves (MMBOE)
Spraberry	627
Raton	119
Eagle Ford	116
Mid-Continent	101
Barnett Shale	55
Alaska	44
South Texas	23
Other	1
Total	1,086

1) Reflects 2012 SEC pricing (12-month average) of \$94.84/Bbl for oil and \$2.76/MMBtu for gas (NYMEX) as compared to 2011 SEC pricing of \$96.13/Bbl for oil and \$4.12/MMBtu for gas (NYMEX)

Production Costs (per BOE)¹



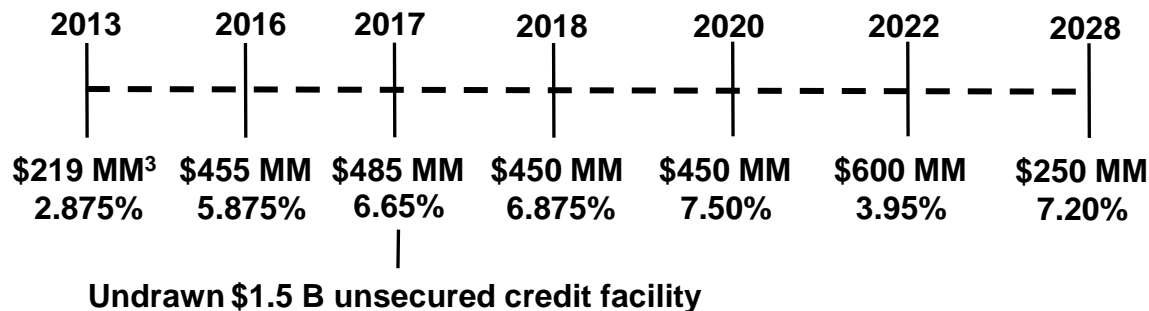
- Q1 2013 production cost essentially flat compared to Q4 2012

1) All periods presented have been restated to exclude discontinued operations and intercompany eliminations

Liquidity Position (03/31/13)¹

Net debt (net of cash balance of \$430 MM):	\$2.4 B
Unsecured credit facility availability:	\$1.5 B
Net debt-to-book capitalization:	26%

Maturities and Balances²



- Unsecured credit facility matures in 2017
- Investment grade rated
- All outstanding convertible senior notes due 2038 will be redeemed on May 16, 2013, subject to holders' right of conversion³

1) Excludes \$154 MM of borrowings under PSE's \$300 MM credit facility that matures in March 2017

2) Excludes net discounts and deferred hedge losses of -\$46 MM

3) Convertible senior notes due 2038; based on trading value, interest rate reduced to 2.375% from 2.875% effective January 15, 2013; holders of \$261 MM in principal amount exercised their right to convert and were settled during Q1 2013; holders of an additional \$21 MM in principal amount have exercised their right to convert and will be settled in Q2

Production (MBOEPD)¹

	Q1 '12	Q2 '12	Q3 '12	Q4 '12	Q1 '13
Spraberry	62	64 ²	69 ³	69 ⁴	75 ⁵
Eagle Ford Shale	23	24	29	35	37
Raton	26	25	25	24	23
Mid-Continent	18	18	18	17	17
Barnett	6	7	7	9	9
South Texas	7	6	6	6	5
Alaska	4	5	5	4	4
Other	1	2	1	1	1
Total	147	151	160	165	171

1) All periods presented have been restated to exclude discontinued operations

2) Q2 '12 production negatively impacted by -4,800 BOEPD due to unplanned third party fractionation capacity shortfalls at Mont Belvieu

3) Q3 '12 production benefited by -1,800 BPD from partial NGL inventory drawdown at Mont Belvieu, but offset by a production loss of -4,000 BOEPD due to continuing ethane rejection and 3rd party fractionation capacity constraints at Mont Belvieu

4) Q4 production was negatively impacted by -1,700 BOEPD due to reduced ethane recoveries at Spraberry gas processing facilities

5) Q1 production was negatively impacted by -2,700 BOEPD due to reduced ethane recoveries at Spraberry gas processing facilities

Production By Commodity By Area¹

PXD Production by Area

		Q1 '12	Q2 '12	Q3 '12	Q4 '12	Q1 '13
Wolfcamp/Spraberry	Oil (BOPD)	40,781	43,310	45,239	46,540	52,694
	NGL (BOEPD)	12,460	10,768	14,138	11,262	12,864
	Gas (MCFD)	53,691	57,827	57,095	64,607	58,653
	Total (BOEPD)	62,190	63,716	68,893	68,570	75,333
Eagle Ford	Oil (BOPD)	8,782	8,922	10,087	11,671	12,741
	NGL (BOEPD)	5,280	5,999	8,549	9,462	10,133
	Gas (MCFD)	50,586	55,673	65,048	81,823	86,305
	Total (BOEPD)	22,493	24,200	29,477	34,770	37,257
Raton	Oil (BOPD)	-	-	-	-	-
	NGL (BOEPD)	-	-	-	-	-
	Gas (MCFD)	154,768	152,026	148,188	144,245	138,358
	Total (BOEPD)	25,795	25,338	24,698	24,041	23,060
Mid-Continent	Oil (BOPD)	3,350	3,045	3,243	3,063	3,202
	NGL (BOEPD)	6,790	6,922	7,223	7,466	6,511
	Gas (MCFD)	49,147	47,354	46,914	41,398	41,250
	Total (BOEPD)	18,332	17,859	18,285	17,429	16,589
Barnett	Oil (BOPD)	910	1,138	1,217	1,574	1,445
	NGL (BOEPD)	2,463	2,799	2,472	3,289	3,038
	Gas (MCFD)	17,257	18,736	19,132	25,168	24,159
	Total (BOEPD)	6,248	7,060	6,878	9,058	8,510
South Texas	Oil (BOPD)	76	66	90	66	79
	NGL (BOEPD)	1	2	1	1	2
	Gas (MCFD)	39,845	37,440	36,495	34,037	31,609
	Total (BOEPD)	6,718	6,308	6,173	5,740	5,349
Alaska	Oil (BOPD)	3,695	4,875	4,404	4,102	3,707
	NGL (BOEPD)	-	-	-	-	-
	Gas (MCFD)	-	-	-	-	-
	Total (BOEPD)	3,695	4,875	4,404	4,102	3,707
Other	Oil (BOPD)	78	71	62	53	71
	NGL (BOEPD)	491	470	441	458	441
	Gas (MCFD)	4,127	3,657	3,493	3,539	3,502
	Total (BOEPD)	1,257	1,151	1,085	1,101	1,095
Total Cont Ops	Oil (BOPD)	57,672	61,427	64,342	67,069	73,939
	NGL (BOEPD)	27,485	26,960	32,824	31,938	32,989
	Gas (MCFD)	369,421	372,713	376,365	394,817	383,836
	Total (BOEPD)	146,727	150,506	159,893	164,810	170,900

1) All periods presented have been restated to exclude discontinued operations

- **Continue to use derivatives to mitigate commodity price exposure in order to insure funding for development programs and to maintain strong financial position**
 - Target >50% on rolling 3 year basis
- **Continue to use a variety of derivative instruments, but focus will be on providing floor protection while retaining upside; primary derivative instruments will be:**
 - Collars
 - Collars with short puts (three-way collars)
 - Puts
- **Enter derivative agreements only with counterparties that are “A” rated or better**
- **Actively monitor credit exposure to each counterparty and counterparty credit trends**
- **No margin requirements with counterparties**

Open Commodity Derivative Positions as of 4/30/2013 (includes PSE)

Oil	Q2 2013	Q3 2013	Q4 2013	2014	2015
Swaps - WTI (BPD)	3,000	3,000	3,000	-	-
NYMEX WTI Price (\$/BBL)	\$ 81.02	\$ 81.02	\$ 81.02	-	-
Three Way Collars - (BPD)¹	68,750	72,750	75,750	69,000	26,000
NYMEX Call Price (\$/BBL)	\$ 119.42	\$ 119.74	\$ 120.47	\$ 114.05	\$ 104.45
NYMEX Put Price (\$/BBL)	\$ 92.38	\$ 92.53	\$ 91.90	\$ 93.70	\$ 95.00
NYMEX Short Put Price (\$/BBL)	\$ 74.18	\$ 74.50	\$ 74.39	\$ 77.61	\$ 80.00
% Total Oil Production	~95%	~95%	~95%	~75%	~25%

Oil Basis Protection	Q2 2013	Q3 2013	Q4 2013	2014	2015
Midland/Cushing Swaps (BPD)	5,000	-	-	-	-
Price Differential (\$/BBL)	\$ (5.75)	-	-	-	-
Cushing/LLS Swaps (BPD)	-	-	2,000	-	-
Price Differential (\$/BBL)	-	-	\$(9.30)	-	-
Spraberry Fixed Differential²	26,000	28,000	30,000	33,000	35,000
Price Differential (\$/BBL)	\$ (1.75)	\$ (1.75)	\$ (1.75)	\$ (1.75)	\$ (1.75)

1) When NYMEX price is above call price, PXD receives call price. When NYMEX price is between put price and call price, PXD receives NYMEX price. When NYMEX price is between the put price and the short put price, PXD receives put price. When NYMEX price is below the short put price, PXD receives NYMEX price plus the difference between the short put price and put price

2) Market transaction representing Midland/Cushing differential; not a derivative

Open Commodity Derivative Positions as of 4/30/2013 (includes PSE)

Natural Gasoline	Q2 2013	Q3 2013	Q4 2013	2014	2015
Three Way Collars - (BPD) ^{1,2}	1,064	1,064	1,064	1,000	-
Mont Belvieu Call Price (\$/BBL)	\$ 105.28	\$ 105.28	\$ 105.28	\$ 109.50	-
Mont Belvieu Put Price (\$/BBL)	\$ 89.30	\$ 89.30	\$ 89.30	\$ 95.00	-
Mont Belvieu Short Put Price (\$/BBL)	\$ 75.20	\$ 75.20	\$ 75.20	\$ 80.00	-
% Total NGL Production	<5%	<5%	<5%	<5%	-

Ethane	Q2 2013	Q3 2013	Q4 2013	2014	2015
Collars - (BPD) ³	1,341	2,500	2,500	3,000	-
Mont Belvieu Call Price (\$/BBL)	\$ 12.60	\$ 12.68	\$ 12.68	\$ 13.72	-
Mont Belvieu Put Price (\$/BBL)	\$ 10.50	\$ 10.50	\$ 10.50	\$ 10.78	-
% Total NGL Production	<5%	<5%	<5%	<5%	-
% Total Liquids	-65%	-65%	-65%	-55%	-15%

1) When NYMEX price is above call price, PXD receives call price. When NYMEX price is between put price and call price, PXD receives NYMEX price. When NYMEX price is between the put price and the short put price, PXD receives put price. When NYMEX price is below the short put price, PXD receives NYMEX price plus the difference between the short put price and put price

2) Represent collar contracts with short puts that reduce price volatility of natural gasoline forecasted for sale by the Company at Mont Belvieu, Texas-posted prices

3) Represent collar contracts that reduce the price volatility of ethane forecasted for sale by the Company at Mont Belvieu, Texas-posted prices

Open Commodity Derivative Positions as of 4/30/2013 (includes PSE)

Gas	Q2 2013	Q3 2013	Q4 2013	2014	2015	2016
Swaps - (MMBTUPD)	172,500	172,500	165,870	175,000	20,000	-
NYMEX Price (\$/MMBTU) ¹	\$ 5.05	\$ 5.05	\$ 5.10	\$ 4.02	\$ 4.31	-
Collars - (MMBTUPD)	150,824	152,500	152,500	-	-	-
NYMEX Call Price (\$/MMBTU) ¹	\$ 6.24	\$ 6.22	\$ 6.22	-	-	-
NYMEX Put Price (\$/MMBTU) ¹	\$ 4.99	\$ 4.98	\$ 4.98	-	-	-
Three Way Collars - (MMBTUPD)^{1,2}	-	-	-	115,000	285,000	20,000
NYMEX Call Price (\$/MMBTU)	-	-	-	\$4.70	\$ 5.07	\$ 5.36
NYMEX Put Price (\$/MMBTU)	-	-	-	\$4.00	\$ 4.00	\$ 4.00
NYMEX Short Put Price (\$/MMBTU)	-	-	-	\$3.00	\$ 3.00	\$ 3.00
% Total Gas Production	~80%	~80%	~80%	~70%	~70%	<5%

Gas Basis Swaps	Q2 2013	Q3 2013	Q4 2013	2014	2015	2016
Spraberry (MMBTUPD)	52,500	52,500	52,500	-	-	-
Price Differential (\$/MMBTU)	\$ (0.23)	\$ (0.23)	\$ (0.23)	-	-	-
Mid-Continent (MMBTUPD)	50,000	50,000	50,000	20,000	-	-
Price Differential (\$/MMBTU)	\$ (0.30)	\$ (0.30)	\$ (0.30)	\$ (0.19)	-	-
Gulf Coast (MMBTUPD)	60,000	60,000	60,000	-	-	-
Price Differential (\$/MMBTU)	\$ (0.14)	\$ (0.14)	\$ (0.14)	-	-	-

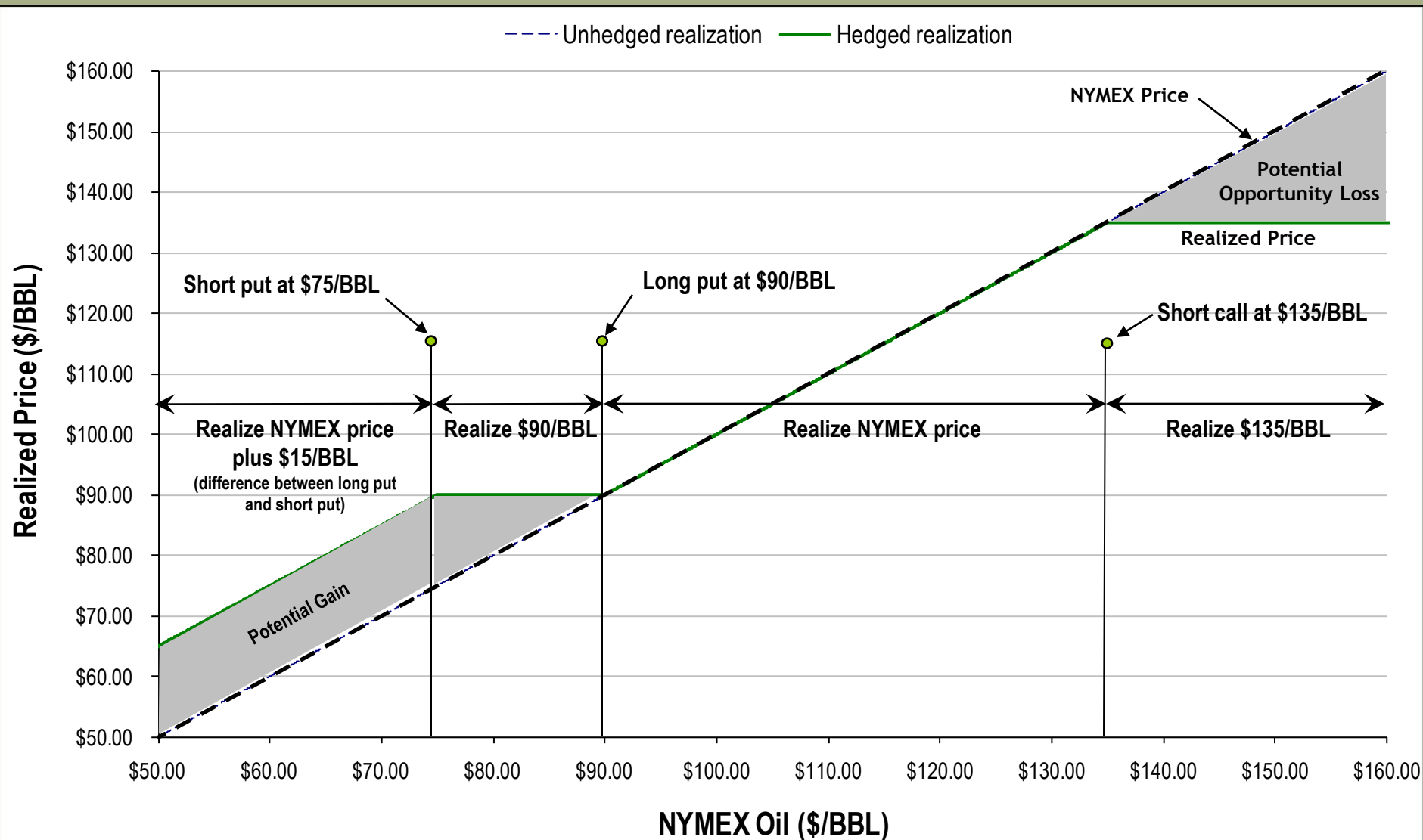
1) Represents the NYMEX Henry Hub index price or approximate NYMEX price based on historical differentials to the index price at the time the derivative was entered into
 2) When NYMEX price is above call price, PXD receives call price. When NYMEX price is between put price and call price, PXD receives NYMEX price. When NYMEX price is between the put price and the short put price, PXD receives put price. When NYMEX price is below the short put price, PXD receives NYMEX price plus the difference between short put price and put price

PSE Derivative Position as of 4/30/2013

Oil	Q2 2013	Q3 2013	Q4 2013	2014	2015
Swaps (BPD)	3,000	3,000	3,000	-	-
NYMEX Price (\$/BBL)	\$81.02	\$81.02	\$81.02	-	-
Three-Way Collars (BPD) ¹	1,750	1,750	1,750	5,000	-
NYMEX Call Price (\$/BBL)	\$116.00	\$116.00	\$116.00	\$105.74	-
NYMEX Put Price (\$/BBL)	\$88.14	\$88.14	\$88.14	\$100.00	-
NYMEX Short Put Price (\$/BBL)	\$73.14	\$73.14	\$73.14	\$80.00	-
% Oil Production	-85%	-85%	-85%	-85%	-
Gas					
Swaps (MMBTUPD)	2,500	2,500	2,500	5,000	-
NYMEX Price (\$/MMBTU)	\$6.89	\$6.89	\$6.89	\$4.00	-
Three-Way Collars (MMBTUPD) ¹	-	-	-	-	5,000
NYMEX Call Price (\$/MMBTU)	-	-	-	-	\$5.00
NYMEX Put Price (\$/MMBTU)	-	-	-	-	\$4.00
NYMEX Short Put Price (\$/MMBTU)	-	-	-	-	\$3.00
Collars (MMBTUPD)	824	2,500	2,500	-	-
NYMEX Call Price (\$/MMBTU)	4.50	4.50	4.50	-	-
NYMEX Put Price (\$/MMBTU)	4.00	4.00	4.00	-	-
% Gas Production	-45%	-70%	-70%	-70%	-65%
% Total Production	-65%	-70%	-70%	-70%	-10%
Gas Basis Swaps	Q2 2013	Q3 2013	Q4 2013	2014	2015
Spraberry (MMBTUPD)	2,500	2,500	2,500	-	-
Price Differential (\$/MMBTU)	(0.31)	(0.31)	(0.31)	-	-

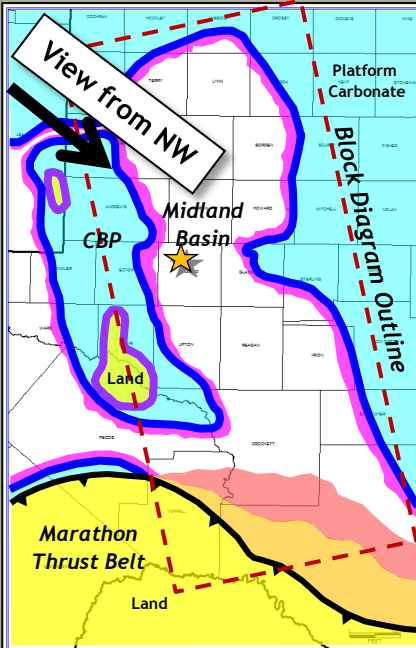
1) When NYMEX price is above call price, PSE receives call price. When NYMEX price is between put price and call price, PSE receives NYMEX price. When NYMEX price is between the put price and the short put price, PSE receives put price. When NYMEX price is below the short put price, PSE receives NYMEX price plus the difference between the short put price and put price

Three-Way Collars (\$75 by \$90 by \$135 example)

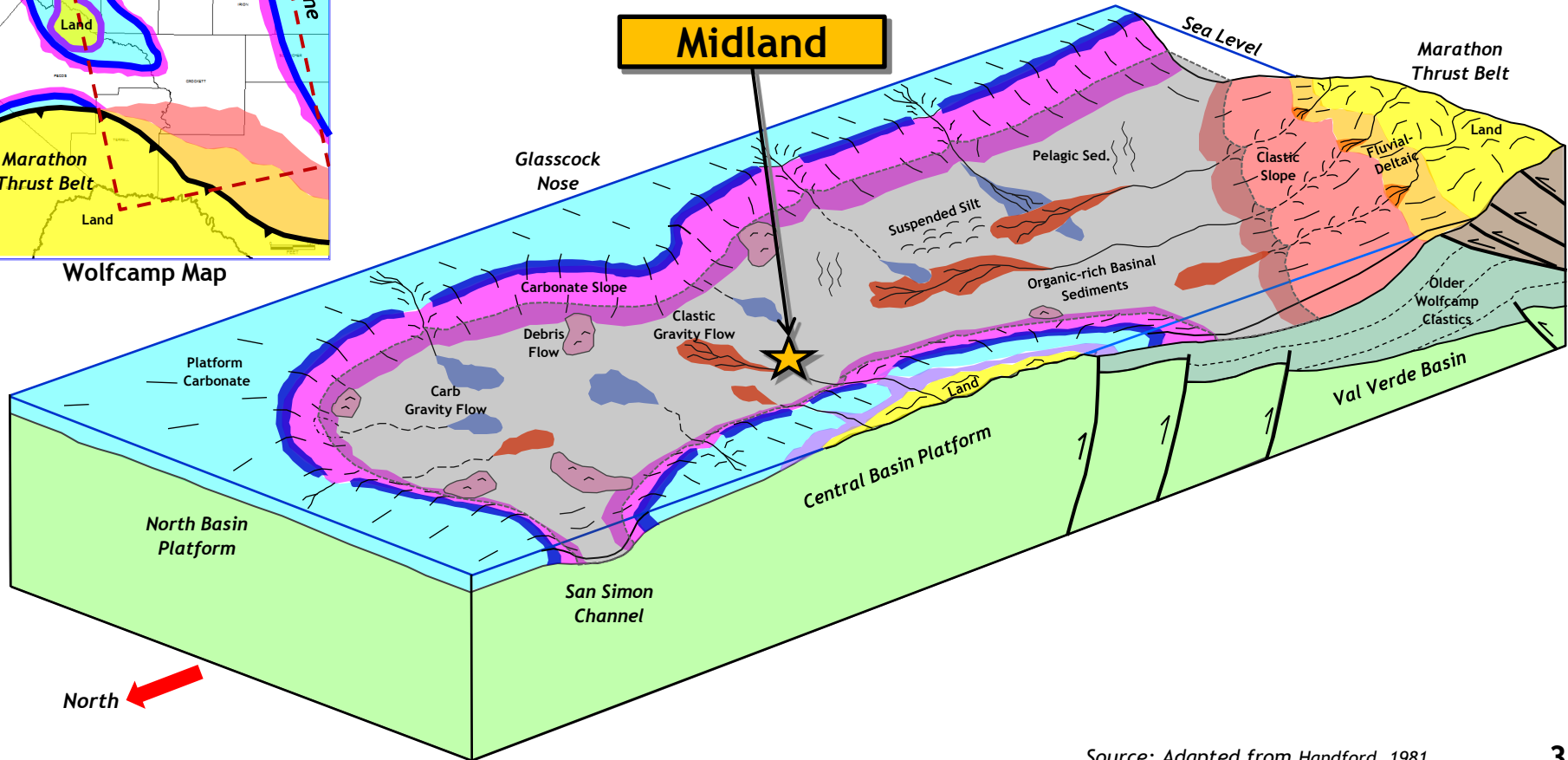


Three way collars protect downside while providing better upside exposure than traditional collars or swaps

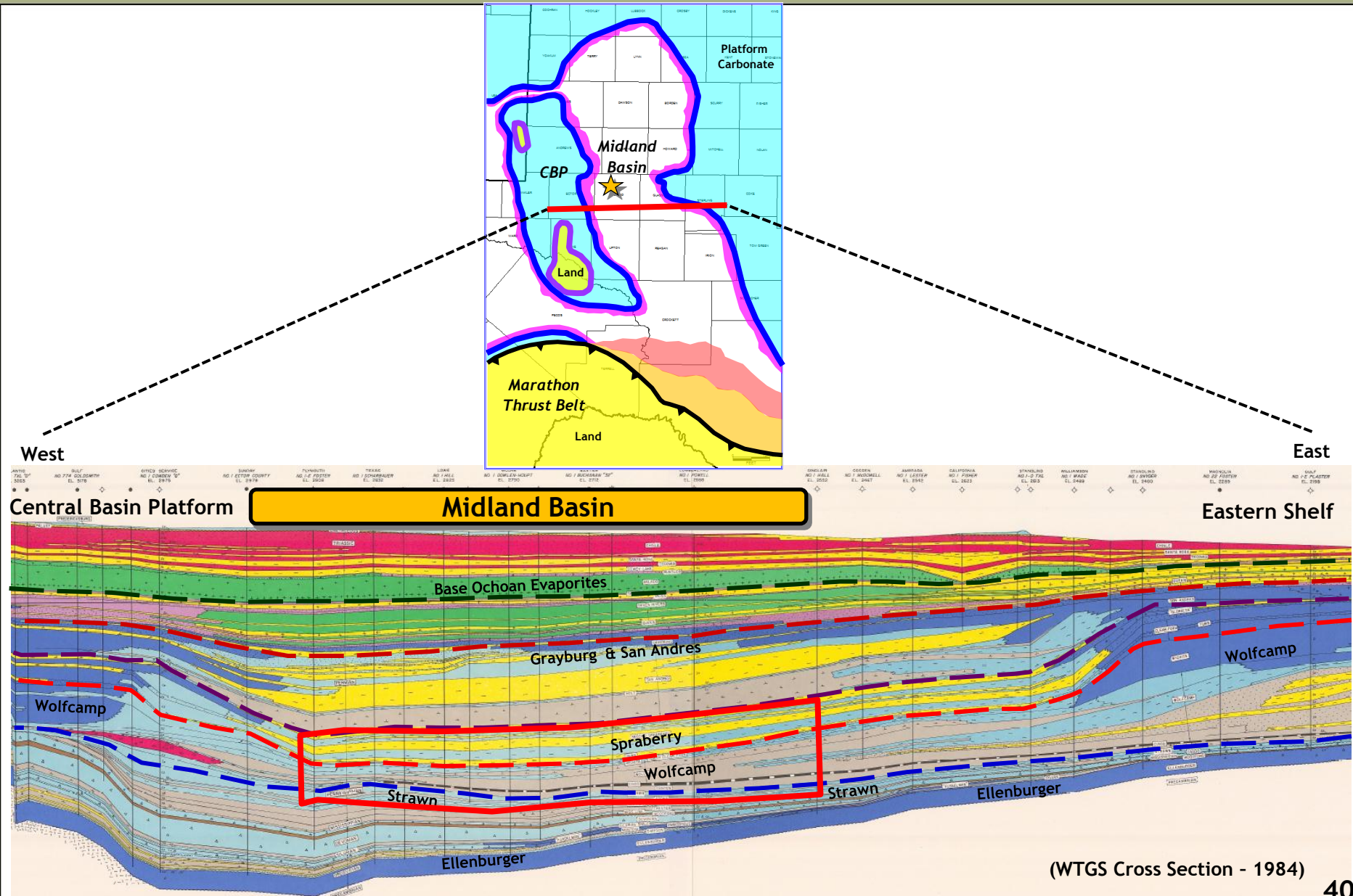
Wolfcamp Depositional Model - Midland Basin



- | | | |
|------------------------------|-------------------------|---|
| Platform Carbonate | Land | Pelagic Sediments |
| Shelf Edge Carbonate | Clastic Detrital | Silt Cloud in Suspension |
| Slope Sediments & Reef Talus | Fluvial - Deltaic | Anaerobic Zone (Organic-rich Sediments) |
| Carbonate Debris Flows | Delta | |
| Carbonate Gravity Flows | Clastic Slope Sediments | |
| Basinal Sediments | Clastic Gravity Flows | |



Deposition of Midland Basin

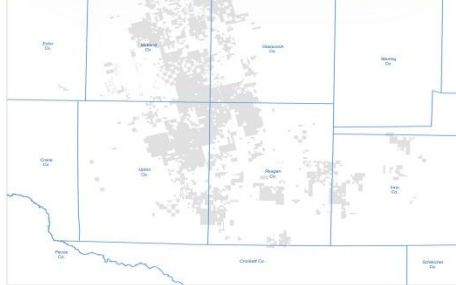


(WTGS Cross Section - 1984)

Progression of Spraberry/Wolfcamp Field Development¹

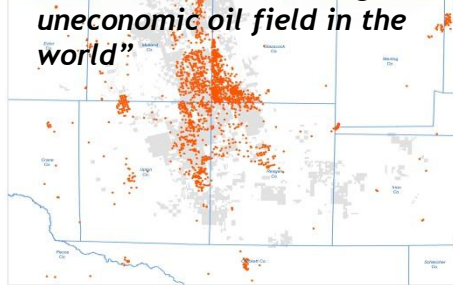
1940s - Discovery

- 1943 - Trace oil found from well drilled on the Abner Spraberry farm in Dawson County
- 1949 - Seaboard #2-D Lee drilled by Seaboard Oil Company IP'd at 319 BOPD



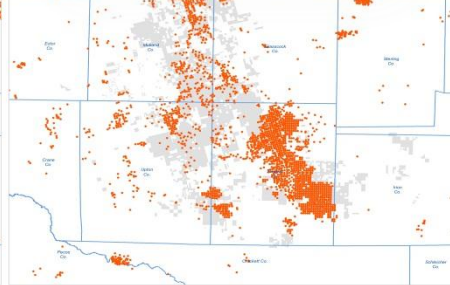
1950s - Early Development

- Major oil company development; principally Texaco, Phillips and Mobil
- 1951 - Time⁽²⁾ magazine cites as most active oil field in U.S.
- 1953 - Considered "largest uneconomic oil field in the world"



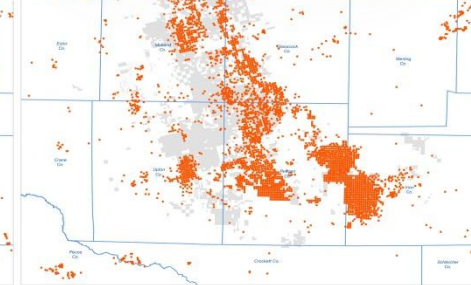
1960s - Field extension

- Continued development by Majors with a few minor Independents



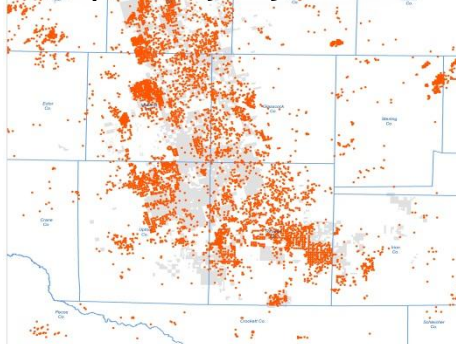
1970s - Dramatic expansion

- Continued development by Majors and Independents



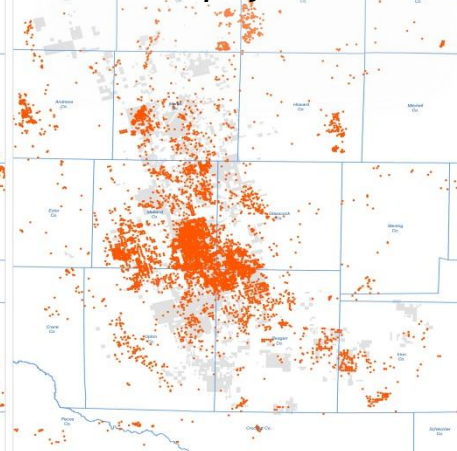
1980s - Expansion & Infill

- Independents including Parker & Parsley (Pioneer's predecessor Company) become large players; less emphasis by Majors



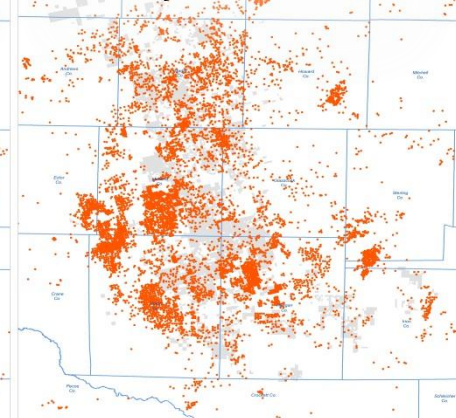
1990s - Infill and efficiency

- Independents become the dominant player



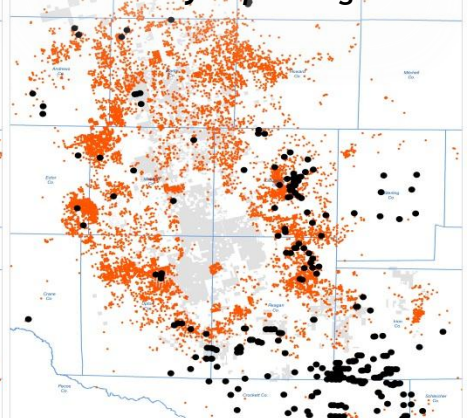
2000s - Infill and efficiency

- Independents continue to dominate the landscape driven by Pioneer



2010s - Deeper and horizontals

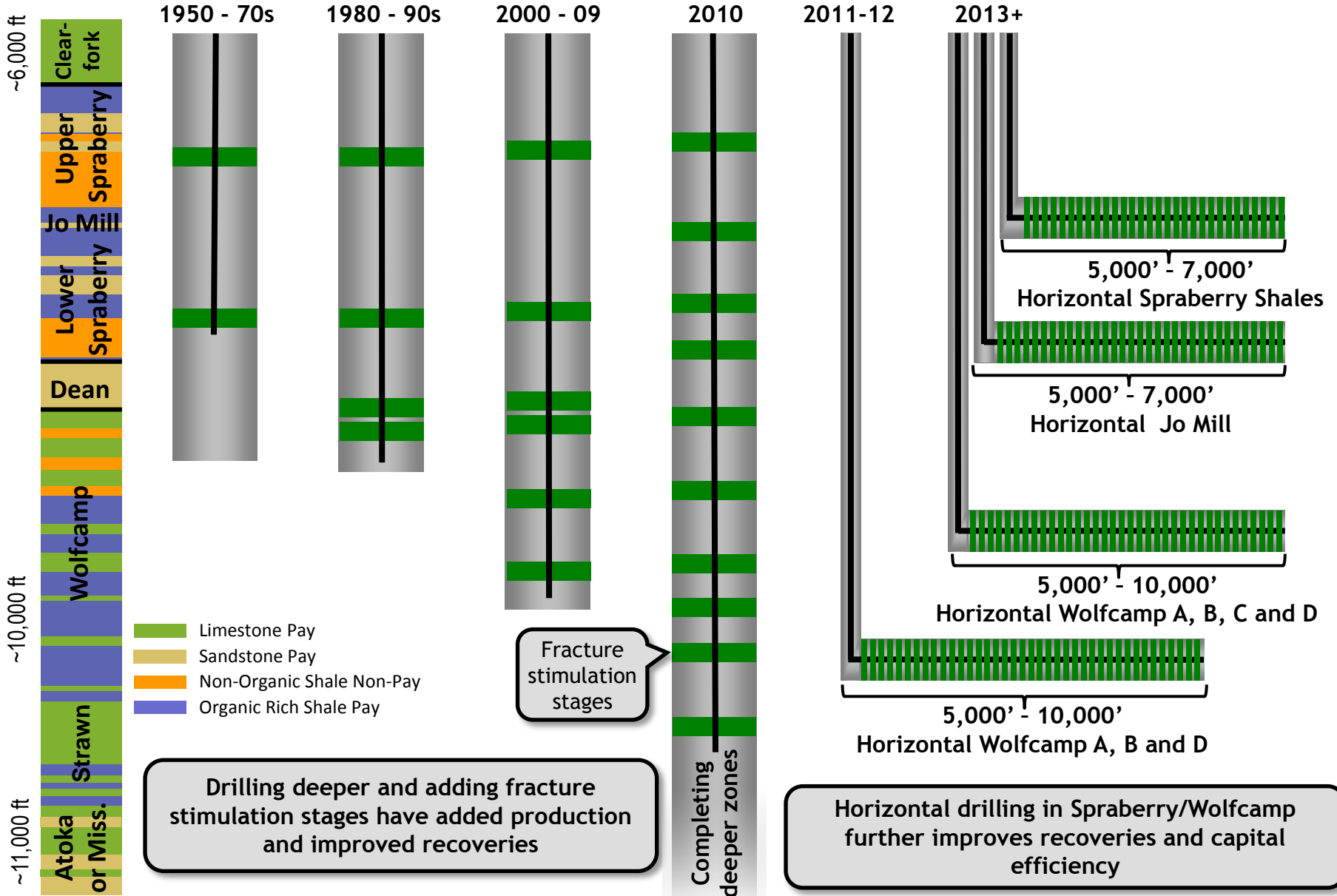
- Independents lead the charge going deeper; Horizontal oil shale activity expanding



1) Source: IHS Energy

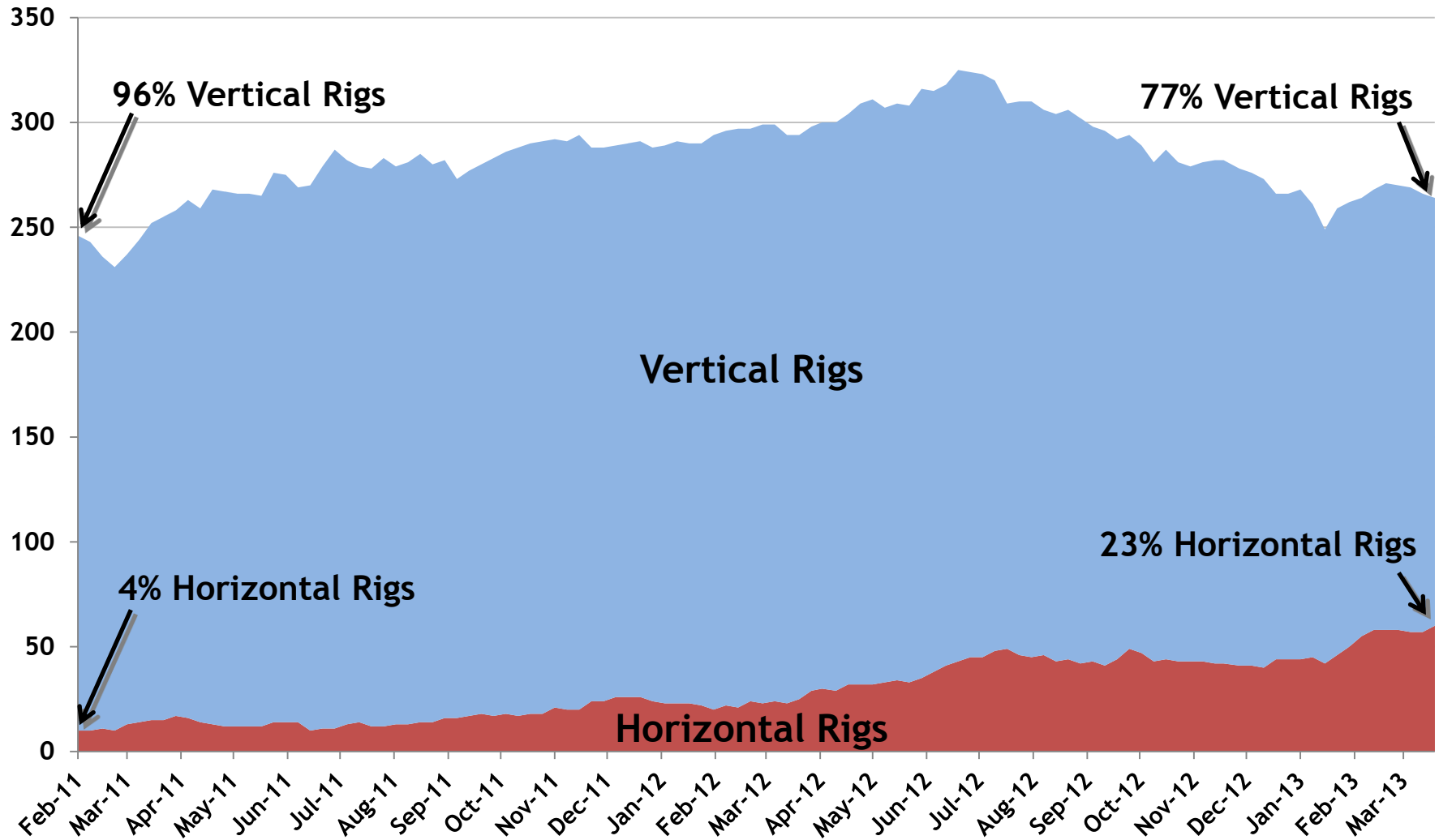
2) October 8, 1951. OIL: The Spraberry Trend, retrieved from <http://www.time.com/time/magazine/article/0,9171,859404,00.html>

History of Spraberry/Wolfcamp Completions



Spraberry/Wolfcamp Rig Count

Counties: Andrews, Borden, Crockett, Dawson, Ector, Gaines, Glasscock, Howard, Irion, Martin, Midland, Mitchell, Reagan, Schleicher, Scurry, Sterling, Tom Green and Upton



Wolfcamp Comparison to Other Major U.S. Oil Shale Plays

Major U.S. Oil Shale Play Characteristics

Attribute	Units	Wolfcamp Shale ¹	Eagle Ford ² (Oil Window)	Bakken ³
Age		Permian	Cretaceous	Devonian/Mississippian
Basin		Midland	South Texas	Williston
TVD Depth	ft	5,500 - 11,000	7,500 - 11,000	9,000 - 11,000
Thickness	ft	1,500 - 2,600	50 - 350	25 - 125
OOIP/Section	MMBO	80 - 220	30 - 90	10 - 20
Porosity	%	2 - 10	4 - 11	5 - 8
Quartz	%	20 - 50	10 - 25	30 - 60
Carbonate	%	10 - 60	60 - 75	30 - 80
Clay	%	10 - 45	10 - 40	25
TOC	%	2 - 6	1 - 7	2 - 18
Permeability	nd	10 - 3,000	40 - 1,300	50,000 - 500,000
Pressure Gradient	psi/ft	0.55 - 0.70	0.65 - 0.70	0.43 - 0.75
Recovery Factor	%	3 - 15	3 - 10	8 - 15

Wolfcamp geology compares favorably to other major oil shale plays

1) Pioneer internal research (modified according to recent core and petrophysical data); multiple intervals

2) EOG Analyst Conference April 2010

3) Tudor, Pickering, Holt, "The Bakken Momentum Continues" November 2011, Hart Energy Bakken Playbooks 2008 and 2010, Jarvie - AAPG Section Meeting 2008

Rigs - Vertical vs. Horizontal

Vertical Rig



Horizontal Rig



Vertical Drilling - Sand Supply for Fracs



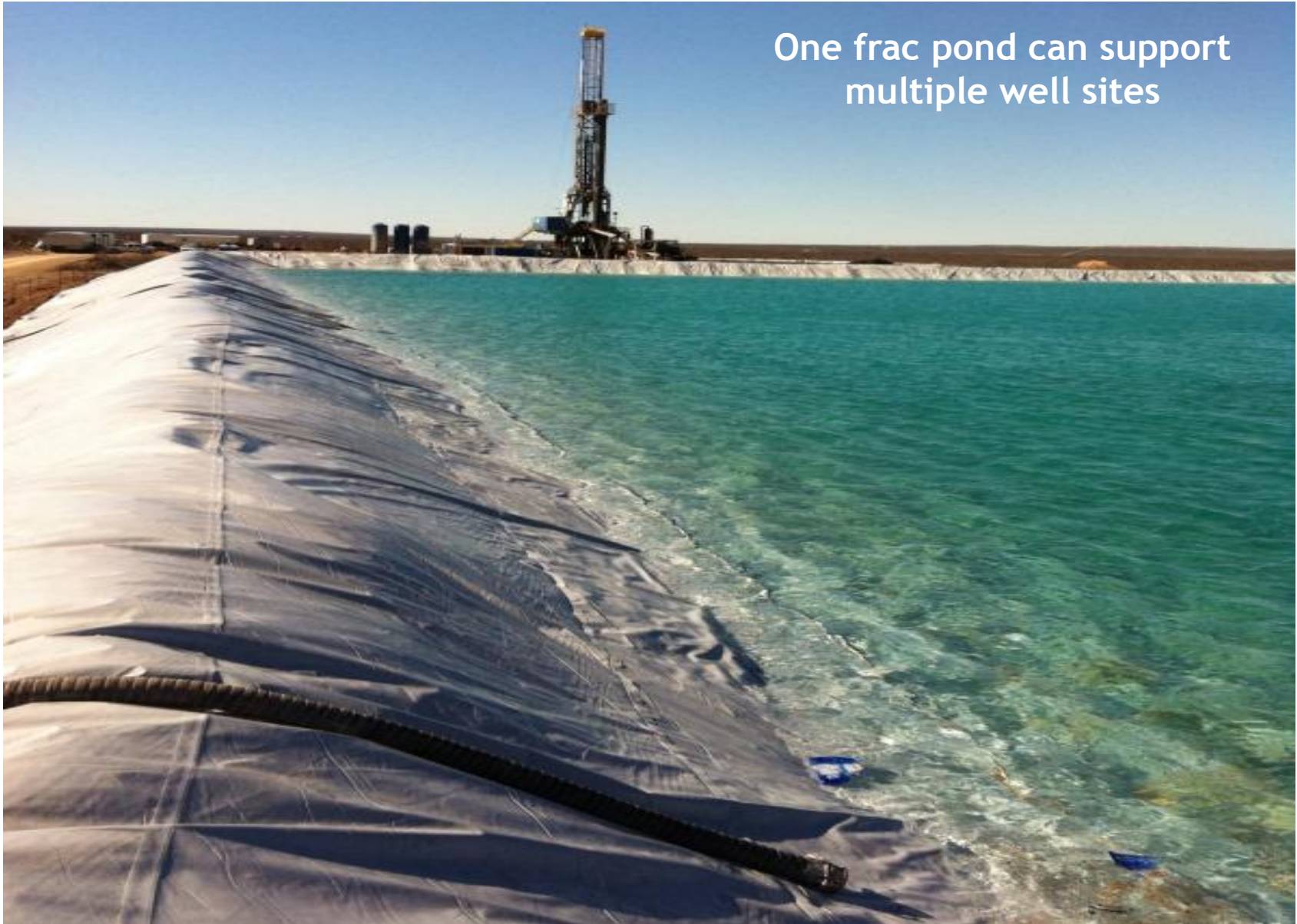
Portable Sand Silos For Horizontal Wells



Vertical Drilling - Water Supply for Fracs from Frac Tanks



One frac pond can support
multiple well sites



Vertical Drilling - Tank Battery, Separators and Pumping Unit



DL Hutt Horizontal Tank Battery and Separators



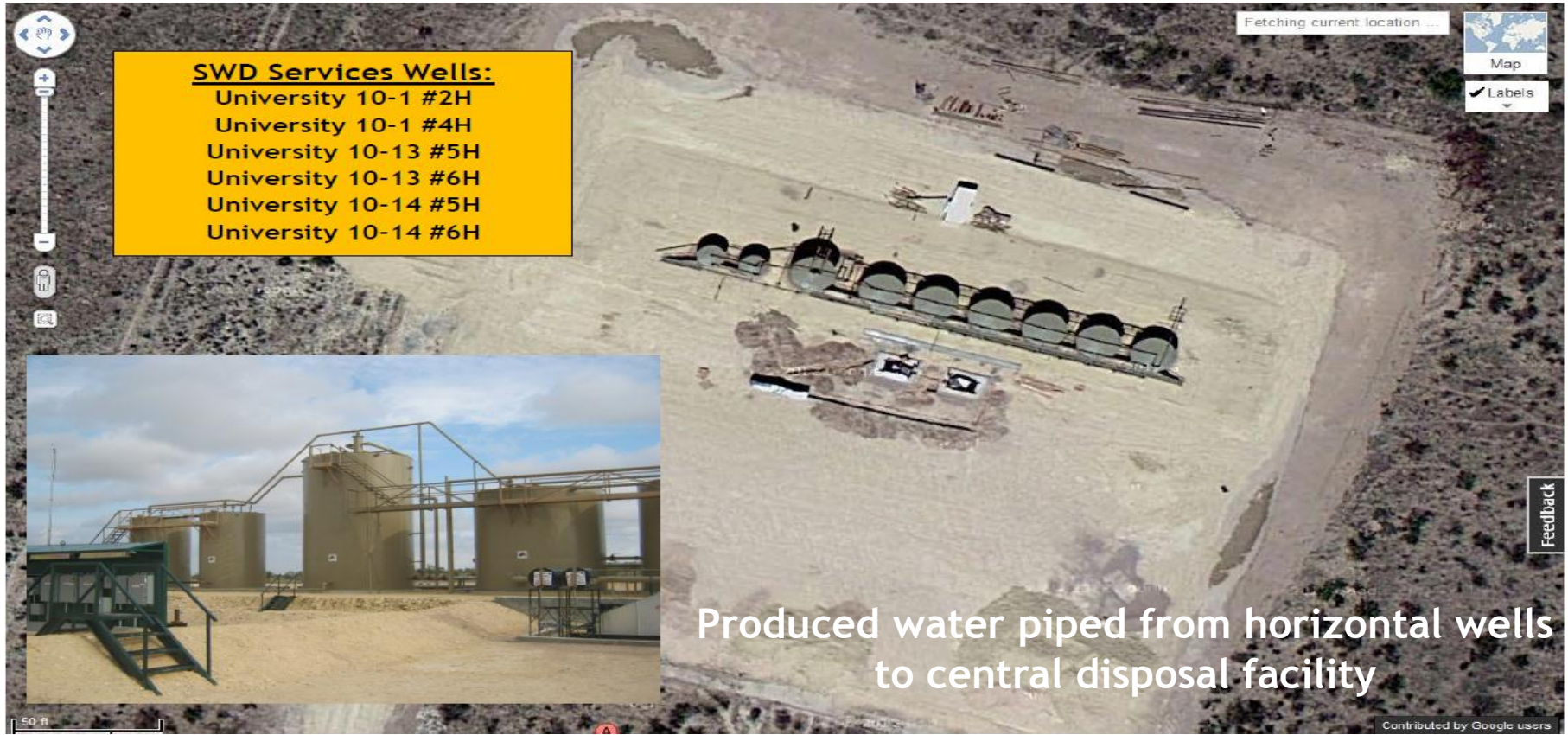
DL Hutt Separators and Compressor Station for gas lift



Water Disposal - Vertical vs. Horizontal Wells



Trucks haul produced water from vertical wells to disposal site



SWD Services Wells:

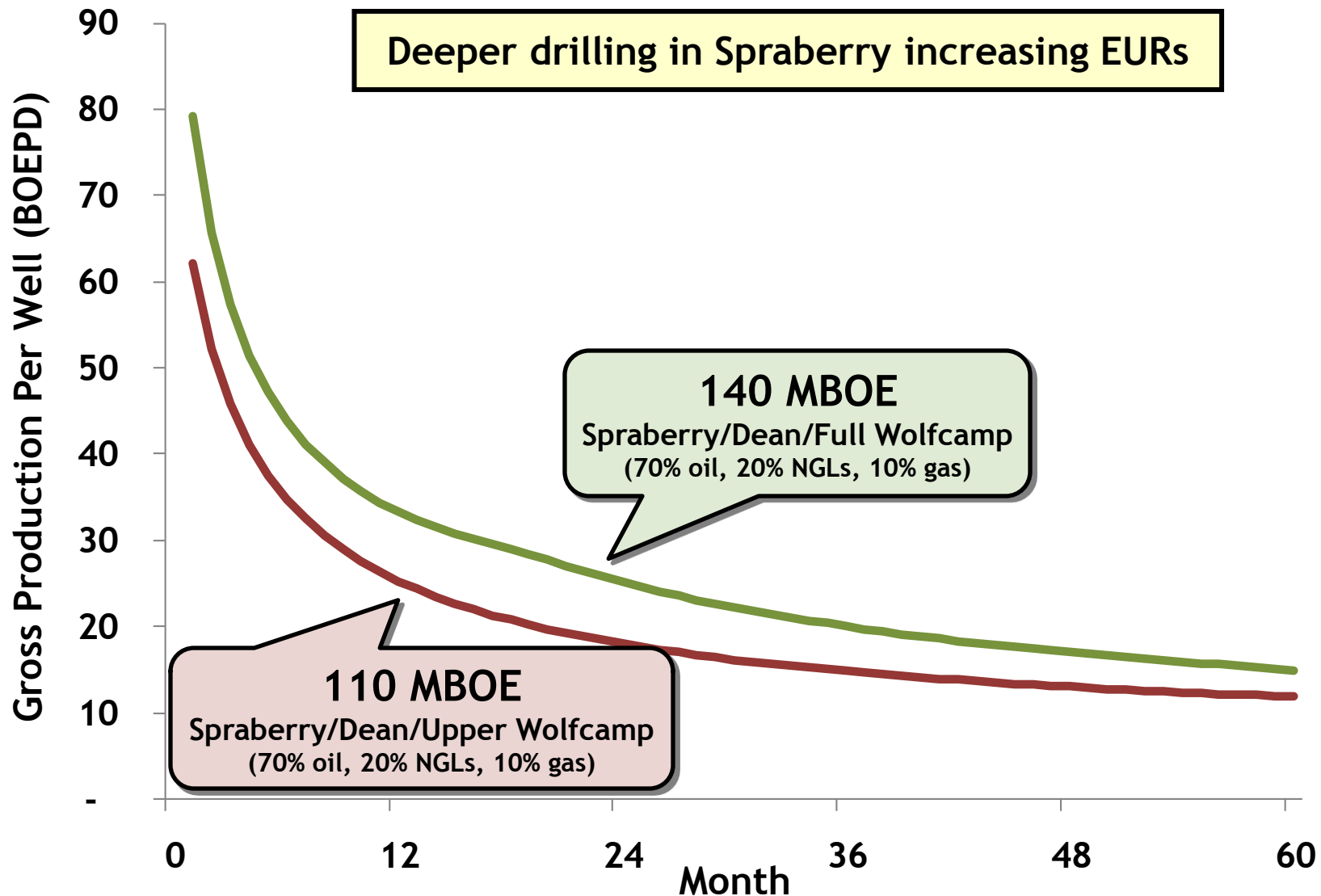
- University 10-1 #2H
- University 10-1 #4H
- University 10-13 #5H
- University 10-13 #6H
- University 10-14 #5H
- University 10-14 #6H

Produced water piped from horizontal wells to central disposal facility

Permian Basin Man Camp

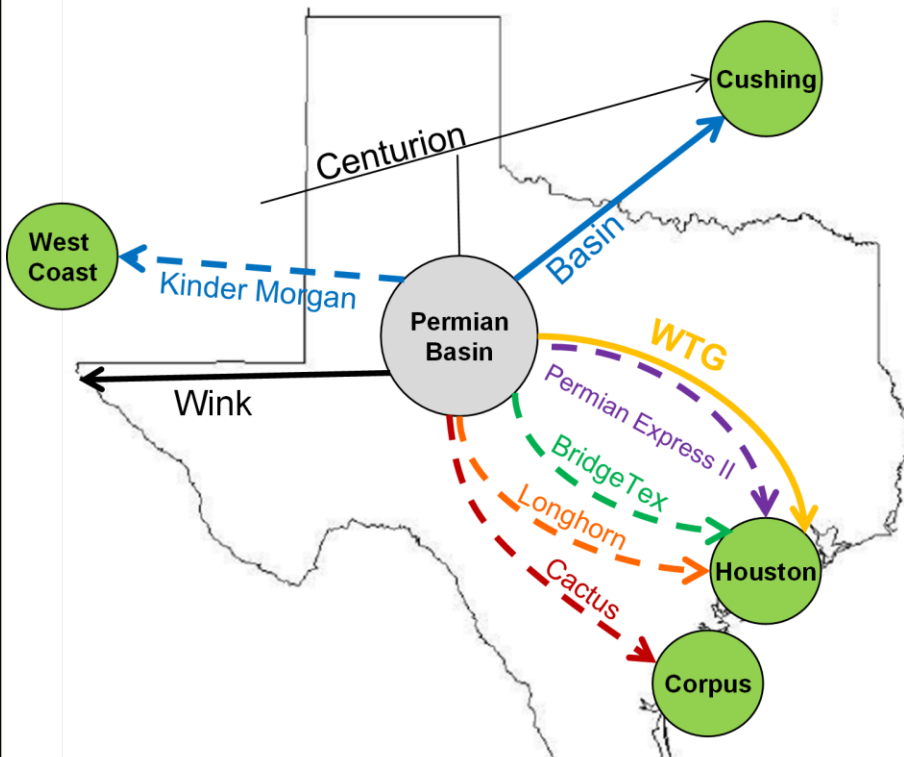


140 MBOE Spraberry 40-Acre Vertical Well Type Curve

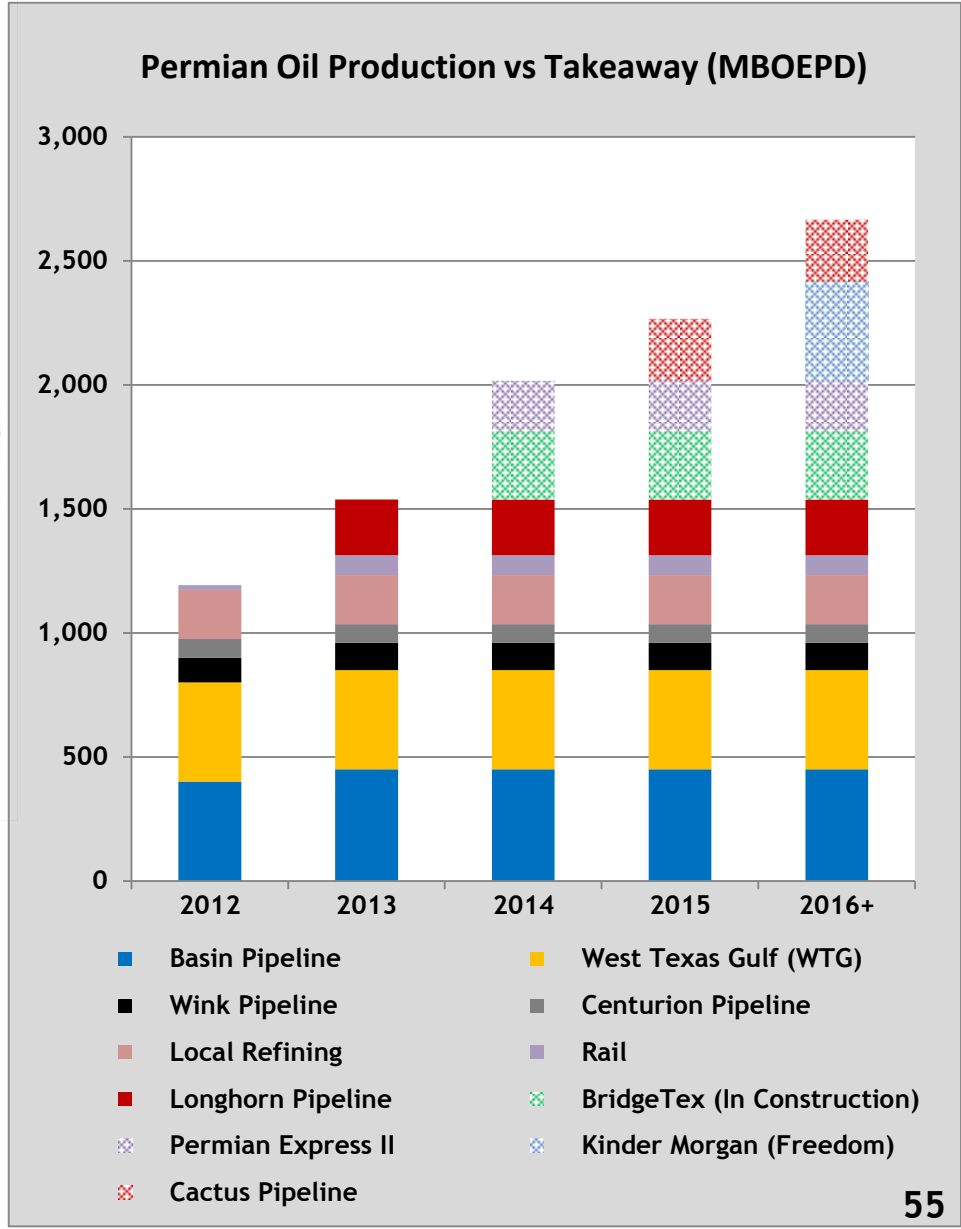


Strawn / Atoka / Mississippian Potential Not Included

Permian Oil Production Takeaway Options

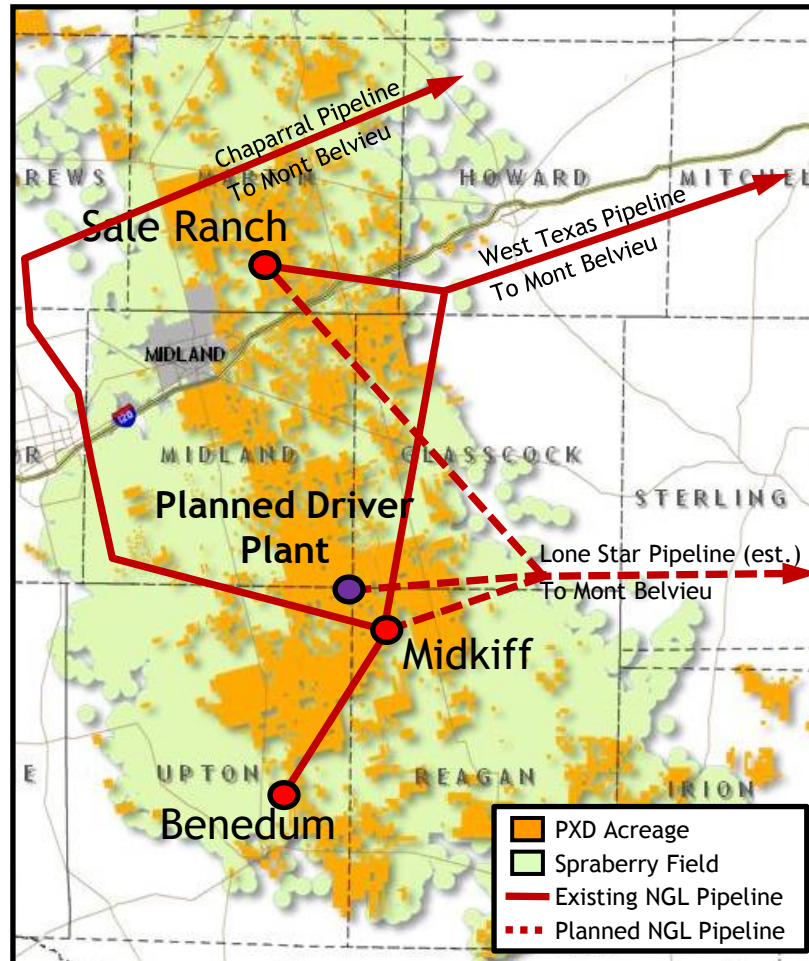


Permian Basin Crude Takeaway Capacity			
	Name	Capacity	Time Frame
Current	Basin	450,000	
	West Texas Gulf	400,000	
	Wink	120,000	
	Local Refinery	200,000	
	Rail	80,000	
	Total Current	1,250,000	
Planned	Longhorn	225,000	2Q-3Q 2013
	BridgeTex	278,000	2014
	Permian Express II	200,000	3Q-4Q 2014
	Cactus	250,000	3Q 2015
	Freedom	400,000	2016+



Gas Processing

- **Midkiff / Benedum / Driver**
 - Current capacity: 460 MMCFD¹
 - PXD production makes up ~40% of throughput
 - Includes 200 MMCFD¹ Driver Plant which came online April 2013
- **Sale Ranch**
 - Current capacity: 120 MMCFD¹
 - Jameson Plant interconnect adds 40 MMCFD
 - PXD production makes up ~15% of Sale Ranch throughput
- **Expect Capacity Additions in the Benedum Area for 2014**



Pipeline NGL Takeaway to Mont Belvieu

- **Chaparral & West Texas Pipelines**
 - PXD production throughput of ~9 MBPD
- **Lone Star Pipeline**
 - 4 MBPD to PXD increasing to 16 MBPD by 2020
 - Will connect to all PXD gas processing plants
- **Expect >425 MBPD, or ~50%, increase in fractionation capacity at Mont Belvieu in 2013**

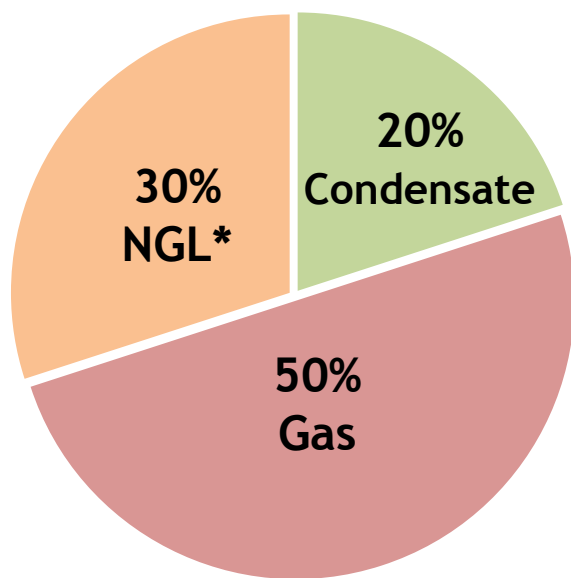
Expanding processing capacity and contracted takeaway to support Pioneer's aggressive production growth

1) Wet gas stream with ~160 BBL/MMSCF NGL yield

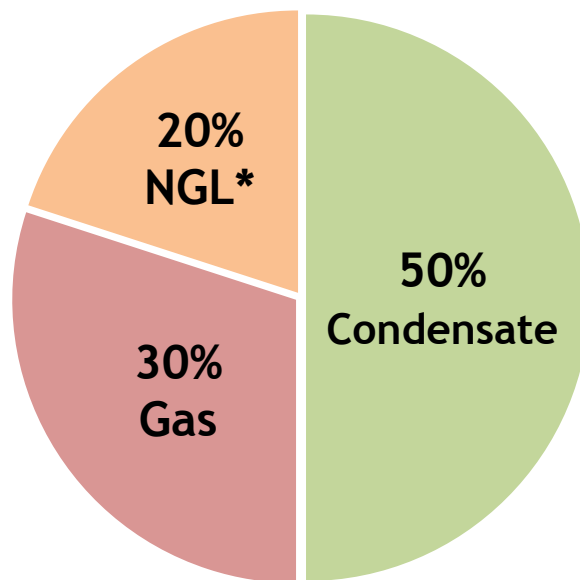
- Spraberry/Wolfcamp production has the potential to reach 2.5 million BOEPD with 70% - 75% oil over the next 20 years
- Combined with production growth from the Eagle Ford, Bakken and the remainder of the Permian Basin, the U.S. will significantly reduce crude oil imports
 - Could eventually result in the need for domestic crude oil to be exported
- Creation of hundreds of thousands of new long-term jobs
- Tremendous economic benefits at the local, state and federal levels
- Major reduction in the foreign trade deficit
- Greater U.S. energy security

Eagle Ford Shale Resource Breakdown

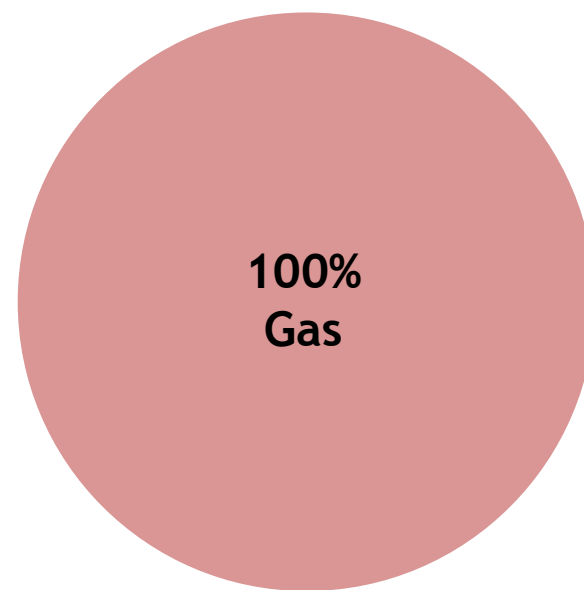
Lean Condensate
~45% of Acreage
(60 BBL/MMSCF)



Rich Condensate
~35% of Acreage
(200 BBL/MMSCF)



Dry Gas
~20% of Acreage



*NGLs are 50% ethane, 25% propane, 15% butanes and 10% heavier liquids

PXD's Vertical Integration Reduces Costs and Enhances Execution

Spraberry

3 vertical frac fleets (~20,000 HP each)
3 horizontal frac fleets (~35,000 HP each)
15 drilling rigs
Well service equipment¹

Barnett Shale Combo

1 frac fleet
(30,000 HP)
1 coiled tubing unit

Eagle Ford Shale

2 frac fleets
(50,000 HP each)
2 coiled tubing units

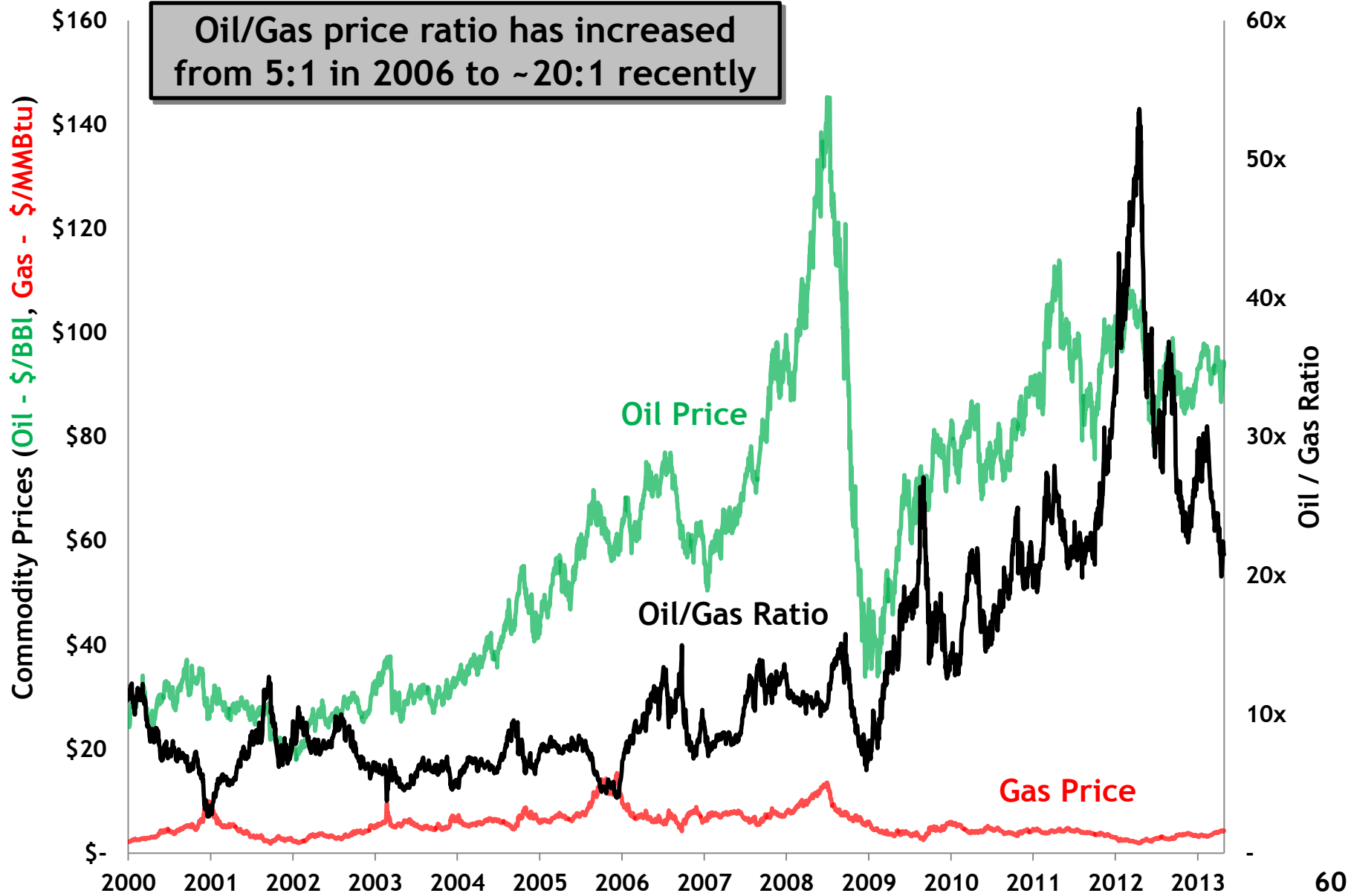
← Brady sand mine →

Current frac capacity: ~300,000 HP
13th largest pressure pumping company in North America



1) Includes pulling units, frac tanks, hot oilers, water trucks, blowout preventers, construction equipment and fishing tools

Oil/Gas Price Ratio Trending Up Since 2006



An audit of proved reserves follows the general principles set forth in the standards pertaining to the estimating and auditing of oil and gas reserve information promulgated by the Society of Petroleum Engineers ("SPE"). A reserve audit as defined by the SPE is not the same as a financial audit. Please see the Company's Annual Report on Form 10-K for a general description of the concepts included in the SPE's definition of a reserve audit.

"Finding and development cost per BOE," or "all-in F&D cost per BOE," means total costs incurred divided by the summation of annual proved reserves, on a BOE basis, attributable to revisions of previous estimates, purchases of minerals-in-place, discoveries and extensions and improved recovery. Consistent with industry practice, future capital costs to develop proved undeveloped reserves are not included in costs incurred.

"Drillbit finding and development cost per BOE," or "drillbit F&D cost per BOE," means the summation of exploration and development costs incurred divided by the summation of annual proved reserves, on a BOE basis, attributable to technical revisions of previous estimates, discoveries and extensions and improved recovery. Consistent with industry practice, future capital costs to develop proved undeveloped reserves are not included in costs incurred.

"Reserve replacement" is the summation of annual proved reserves, on a BOE basis, attributable to revisions of previous estimates, purchases of minerals-in-place, discoveries and extensions and improved recovery divided by annual production of oil, NGLs and gas, on a BOE basis.

"Drillbit reserve replacement" is the summation of annual proved reserves, on a BOE basis, attributable to technical revisions of previous estimates, discoveries and extensions and improved recovery divided by annual production of oil, NGLs and gas, on a BOE basis.

Cautionary Note to U.S. Investors --The U.S. Securities and Exchange Commission (the "SEC") prohibits oil and gas companies, in their filings with the SEC, from disclosing estimates of oil or gas resources other than "reserves," as that term is defined by the SEC. In this presentation, Pioneer includes estimates of quantities of oil and gas using certain terms, such as "resource," "resource potential," "EUR", "oil in place" or other descriptions of volumes of reserves, which terms include quantities of oil and gas that may not meet the SEC's definitions of proved, probable and possible reserves, and which the SEC's guidelines strictly prohibit Pioneer from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being recovered by Pioneer. U.S. investors are urged to consider closely the disclosures in the Company's periodic filings with the SEC. Such filings are available from the Company at 5205 N. O'Connor Blvd., Suite 200, Irving, Texas 75039, Attention Investor Relations, and the Company's website at www.pxd.com. These filings also can be obtained from the SEC by calling 1-800-SEC-0330.