



# 42<sup>nd</sup> Annual Howard Weil Energy Conference

March 25, 2014



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# Forward-Looking Statements

- This communication contains forward-looking information regarding Halcón Resources that is intended to be covered by the safe harbor for "forward-looking statements" provided by the Private Securities Litigation Reform Act of 1995. Forward-looking statements are based on Halcón Resources' current expectations, beliefs, plans, objectives, assumptions and strategies. Forward-looking statements often, but not always, can be identified by using words such as "expects", "anticipates", "plans", "estimates", "potential", "possible", "probable", or "intends", or where Halcón Resources states that certain actions, events or results "may", "will", "should", or "could" be taken, occur or be achieved. Statements concerning oil, natural gas liquids and gas reserves also may be deemed to be forward-looking in that they reflect estimates based on certain assumptions including that the resources involved can be economically exploited. Forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those reflected in the statements. These risks include, but are not limited to: operational risks in exploring for, developing and producing crude oil and natural gas; uncertainties involving geology of oil and natural gas deposits; the timing of and potential proceeds from planned divestitures; uncertainty of reserve estimates; uncertainty of estimates and projections relating to future production, costs and expenses; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; health, safety and environmental risks and risks related to weather such as hurricanes and other natural disasters; uncertainties as to the availability and cost of financing; fluctuations in oil and natural gas prices; risks associated with derivative positions; inability to realize expected value from acquisitions, inability of our management team to execute plans to meet our goals; shortages of drilling equipment, oil field personnel and services; unavailability of gathering systems, pipelines and processing facilities; and the possibility that laws, regulations or government policies may change or governmental approvals may be delayed or withheld. Additional information on these and other factors which could affect Halcón Resources' pro forma operations or financial results are included in Halcón Resources' reports on file with the SEC. Investors are cautioned that any forward-looking statements are not guarantees of future performance and actual results or developments may differ materially from the projections in the forward-looking statements. Forward-looking statements are based on assumptions, estimates and opinions of management at the time the statements are made. Halcón Resources does not assume any obligation to update forward-looking statements should circumstances or such estimates or opinions change.

# Cautionary Statements

- The SEC requires oil and gas companies, in their filings with the SEC, to disclose proved reserves, which are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions (using unweighted average 12-month first day of the month prices), operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The SEC also permits the disclosure of separate estimates of probable or possible reserves that meet SEC definitions for such reserves, however, we currently do not disclose probable or possible reserves in our SEC filings.
- We may use the terms “resource potential” and “EUR” in this presentation to describe estimates of potentially recoverable hydrocarbons that the SEC rules prohibit from being included in filings with the SEC. These are based on the Company’s internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. These quantities do not constitute “reserves” within the meaning of the Society of Petroleum Engineer’s Petroleum Resource Management System or SEC rules. “EUR,” or Estimated Ultimate Recovery, refers to our management’s internal estimates based on per well hydrocarbon quantities that may be potentially recovered from a hypothetical future well completed as a producer in the area. For areas where the Company has no or very limited operating history, EURs are based on publicly available information relating to operations of producers operating in such areas. For areas where the company has sufficient operating data to make its own estimates, EURs are based on internal estimates by the Company’s management and reserve engineers.
- “Drilling locations” represent the number of locations that we currently estimate could potentially be drilled in a particular area estimated by well spacing assumptions applicable to that area. The actual number of locations drilled and quantities that may be ultimately recovered from the Company’s interests will differ substantially. There is no commitment by the Company to drill all of the drilling locations which have been attributed these quantities.
- Factors affecting ultimate recovery include: (1) the scope of our on-going drilling program, which will be directly affected by factors that include the availability of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals and other factors; and (2) actual drilling results, including geological and mechanical factors affecting recovery rates. In addition, our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

# Company Profile

## Significant Resource Opportunity



**Other**  
22.8 MMBoe Proved Reserves <sup>(1)</sup>

**Bakken/Three Forks**  
~142,000 Net Acres  
90.5 MMBoe Proved Reserves <sup>(1)</sup>

**El Halcón**  
~100,000 Net Acres  
22.7 MMBoe Proved Reserves <sup>(1)</sup>

**TMS**  
~307,000 Net Acres

### Key Statistics <sup>(1) (2)</sup>

Total Proved Reserves:	136 MMBoe
% Proved Developed:	40%
% Oil:	84%
% Operated:	92%
Total Proved PV10:	\$2,765 MM
Net Unrisked Resource Potential:	~1.4 BBoe
4Q13 Net Daily Prod:	~40,217 Boe/d

Note: See "Cautionary Statement Regarding Hydrocarbon Quantities" on page 3 for a description of EURs and resource potential.

(1) Proved reserves and PV10 as of 12.31.13 as estimated by Halcón's independent reserve engineers using unweighted average first-day-of-the-month commodity prices for the year ended 12.31.13 and in accordance with SEC rules relating to reporting of reserves; Proved reserves, PV10 and 4Q13 production inclusive of non-core assets in East Texas currently under contract for sale.

(2) Current net resource potential estimate calculated by Halcón's internal reserve engineers and inclusive of non-core assets in East Texas currently under contract for sale.

# 2013 Pro Forma Reserves Reconciliation

Reserves Reconciliation (MMBoe)	Proved Reserves	PF Proved Reserves
As of 12.31.12	108.8	82.8
Extensions, discoveries and additions	69.7	69.7
Purchases	3.2	-
Sales	(23.3)	-
Production	(12.2)	(10.0)
Revisions of previous estimates & pricing	(10.3)	(9.0)
As of 12.31.13	136.0	133.5

**60.7 MMBoe Organic Reserve Additions (including revisions)**

**609% Organic Reserve Replacement**

**61% Organic Reserve Growth**

Note: Data inclusive of non-core assets in East Texas currently under contract for sale.

# On Track to Deliver

## What we have done...

- Built a formidable oil company in two years by acquiring assets, leasing property and drilling in liquids-rich basins
- Formed a concentrated asset base via drilling and divestitures
- Created significant growth, which is expected to continue:

	Feb '12	Dec '13 <sup>(1)</sup>	% Δ
Proved Reserves	~21 MMBoe	~136 MMBoe	+548%
% Liquids	~68%	~91%	+34%
PV10	~\$392 MM	~\$2,765 MM	+605%
Daily Production	~4 MBoe	~40.2 MBoe	+905%
Divested Production	NM	~9.0 Boe/d	NM

## ...has lead to this

**Three scalable, crude oil core resource plays each with a deep drilling inventory (~4,000 total gross operated locations) <sup>(2)</sup>**



**Dedicated asset teams focused on efficiency and optimization; Halcón Field Services working midstream/infrastructure opportunities in all core areas**



**Exploration upside**



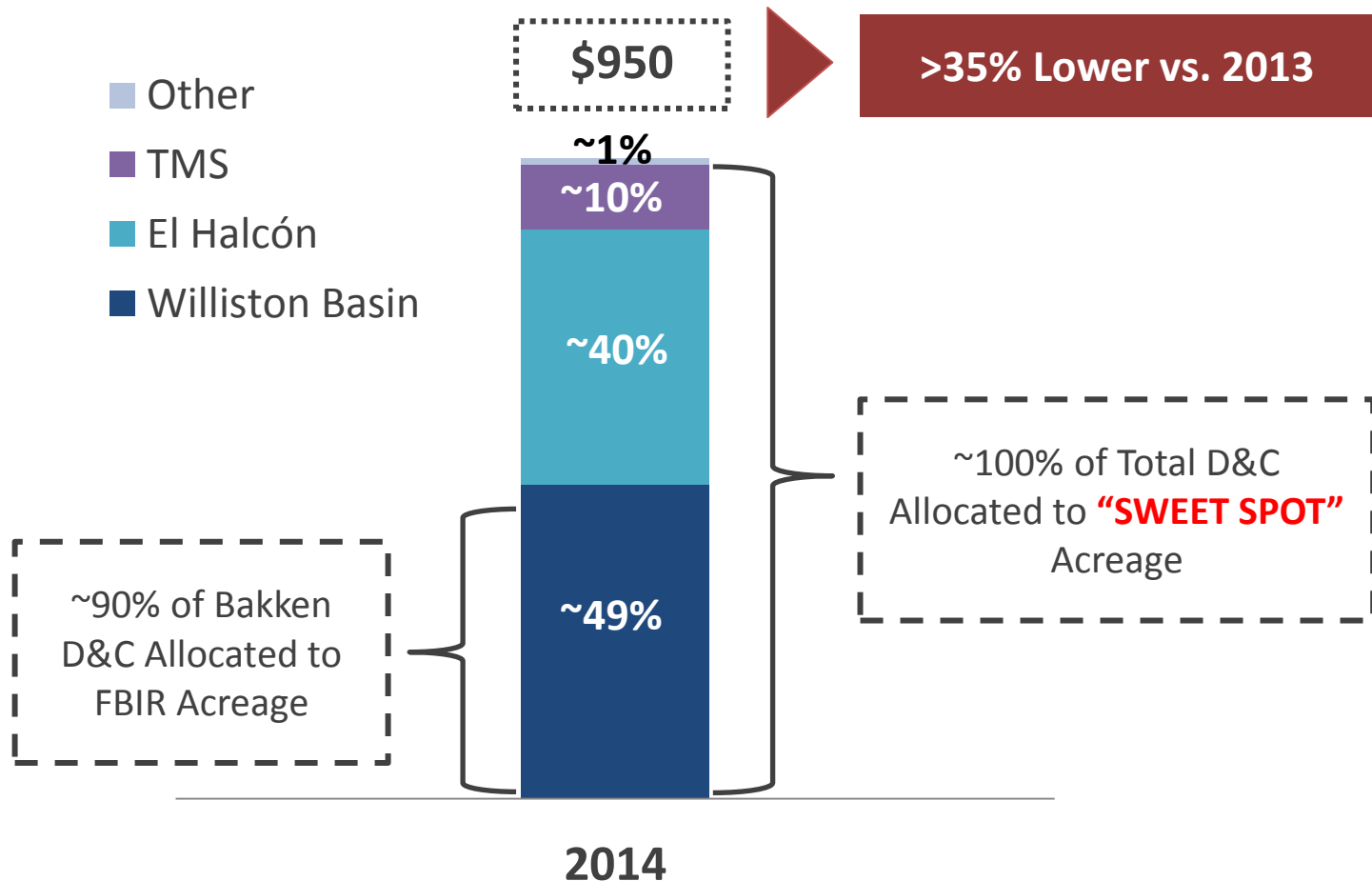
**Expected 2014 PF production growth of >60% with D&C capex decrease of >35%**

(1) Proved reserves and PV10 as of 12.31.13 as estimated by Halcón's independent reserve engineers using unweighted average first-day-of-the-month commodity prices for the year ended 12.31.13 and in accordance with SEC rules relating to reporting of reserves; Proved reserves, PV10 and 4Q13 production inclusive of non-core assets in East Texas currently under contract for sale; Divested production data represents production impact from all assets sold in 2013 including non-core assets in East Texas currently under contract for sale.

(2) Assumptions: Bakken (4-7 wells/DSU); Three Forks (4-7 wells/DSU in 1<sup>st</sup>-2<sup>nd</sup> benches in FBIR); El Halcón (140 acre spacing) and TMS (160 acre spacing – 78% operated)

# Drilling in Most Economic Areas in 2014...

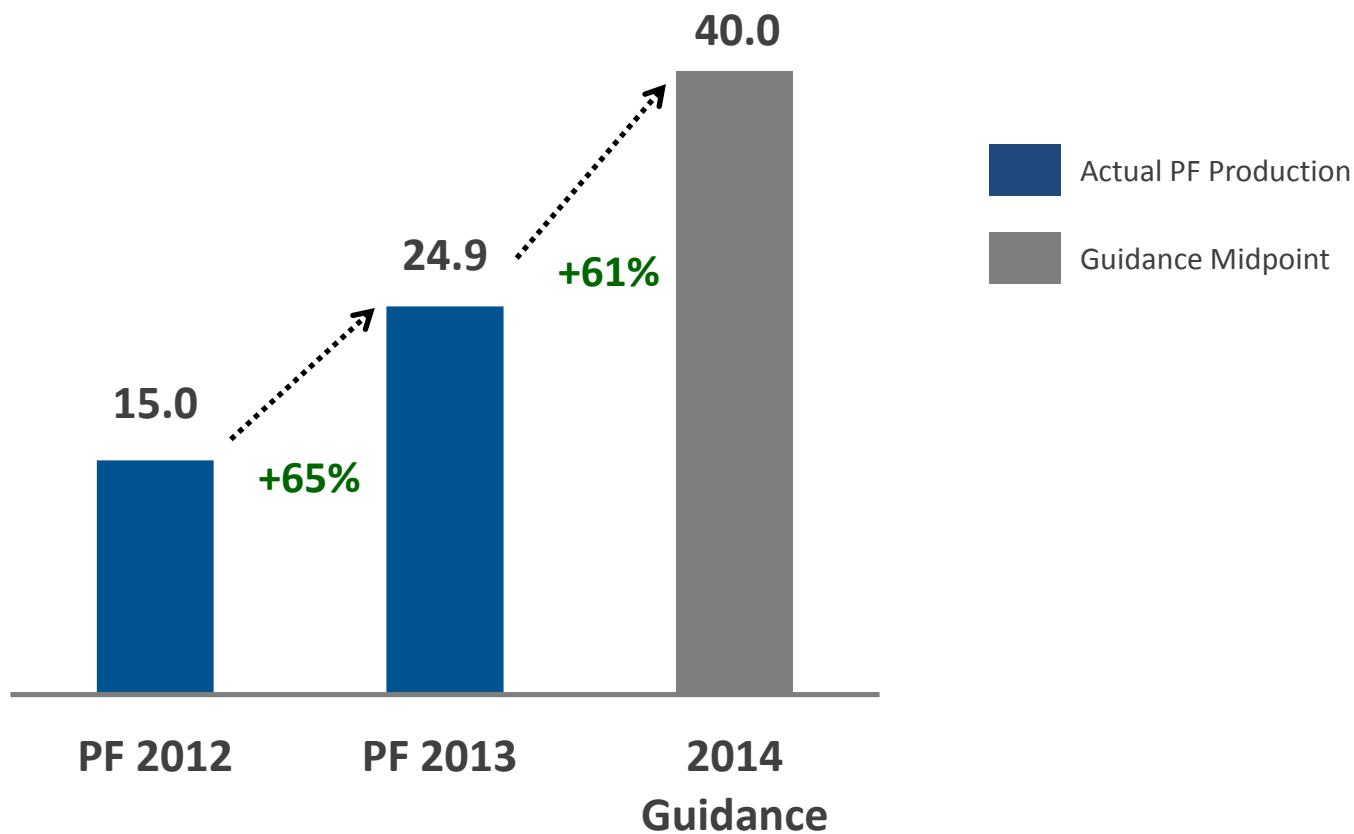
D&C Capex by Area (\$ in millions)



# ...Leading to Strong Production Growth

## Growth Assets in Place and De-Risked

### Pro Forma Production Growth (MBoe)/d <sup>(1)</sup>



(1) Pro forma to include all acquisition and divestiture activity to date, including non-core assets in East Texas currently under contract for sale; Pro forma production reconciliation on slide 37.

# Tuscaloosa Marine Shale (TMS)

## New Core Play Established - ~307,000 Net Acre Position

### Scalable Shale Play with Significant Upside Potential

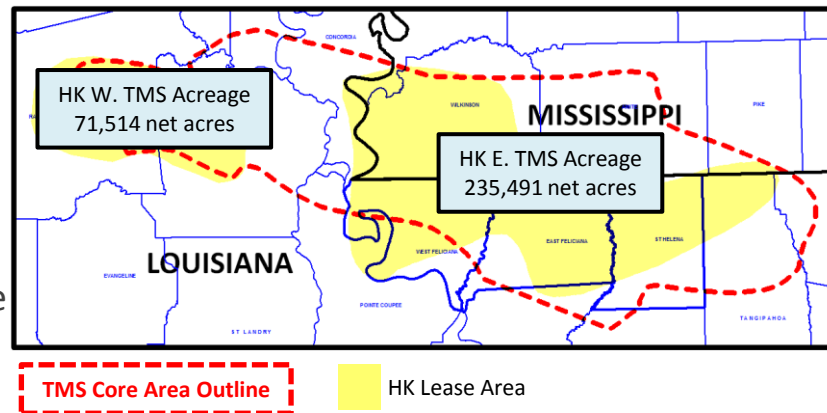
- Black oil reservoir in Mississippi and Louisiana (~94% oil, 42° gravity)
- Proximity to Gulf Coast = LLS pricing premium
- Favorable regulatory environment
- Increased industry activity with improved results

### HK Acreage Position

- Scaled, concentrated, highly operated position and favorable lease terms provide for efficient resource development
- Data sharing arrangements w/ other operators provide technical/operating data across entire play
- Significant increase to HK's drilling inventory
- **Evaluating JV options for entire TMS acreage position**

### 2014 Activity

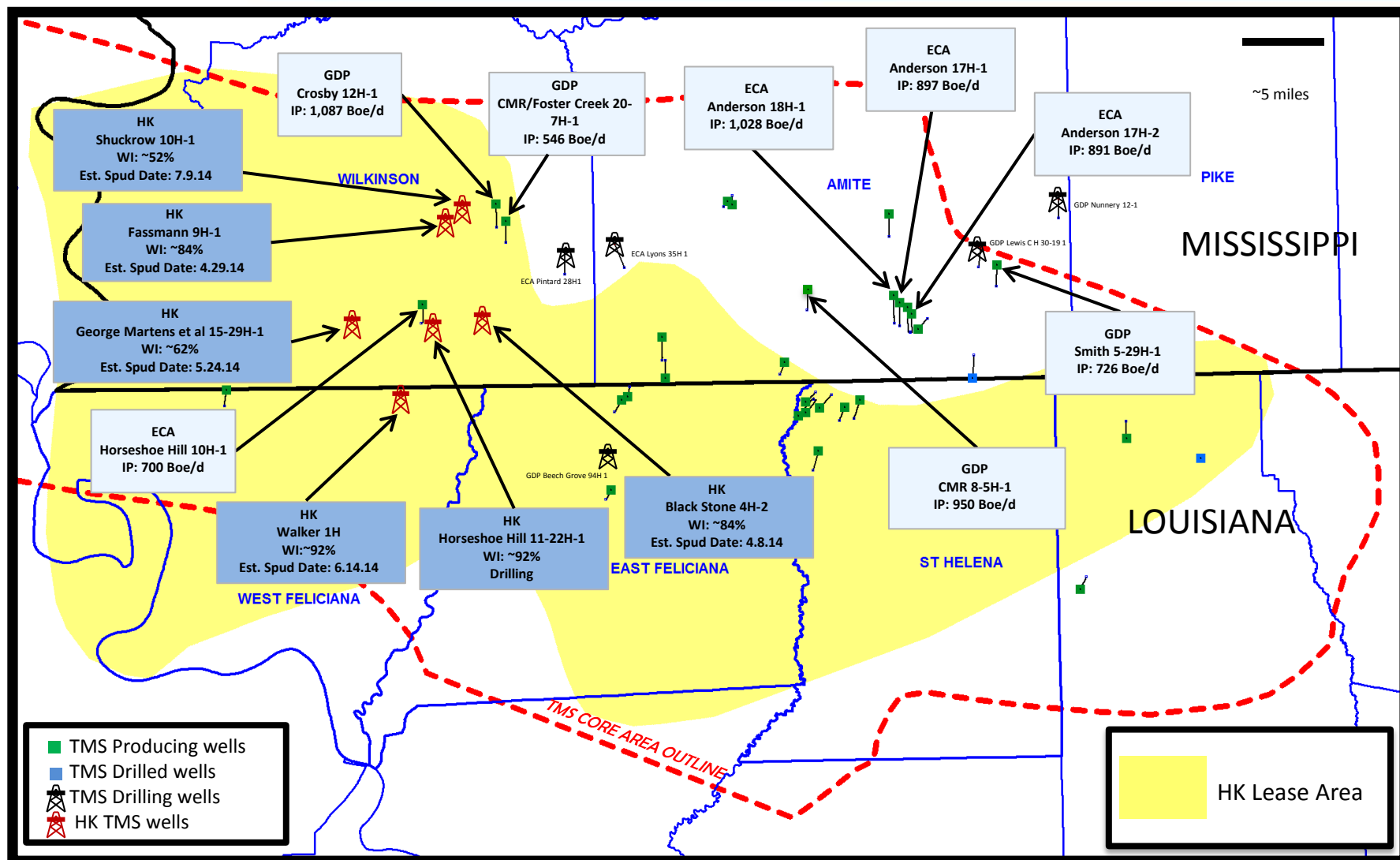
- Spud first Eastern TMS well on 3.14.14 in Wilkinson County, MS; Second well expected to spud in April in Wilkinson County, MS
- Expect to spud 10-12 gross operated wells w/ two rigs



### KEY TMS TECHNICAL FACTS

- Stratigraphic equivalent to Eagle Ford Shale play
- 140-190' organic rich shale target
- 11,500-14,500' depth range
- 4.5-5.5% total porosity
- 1.8-4.5% TOC by volume
- Natural fractures
- Black oil window with GOR <1000
- Pressure gradient: .65-.70 psi/ft

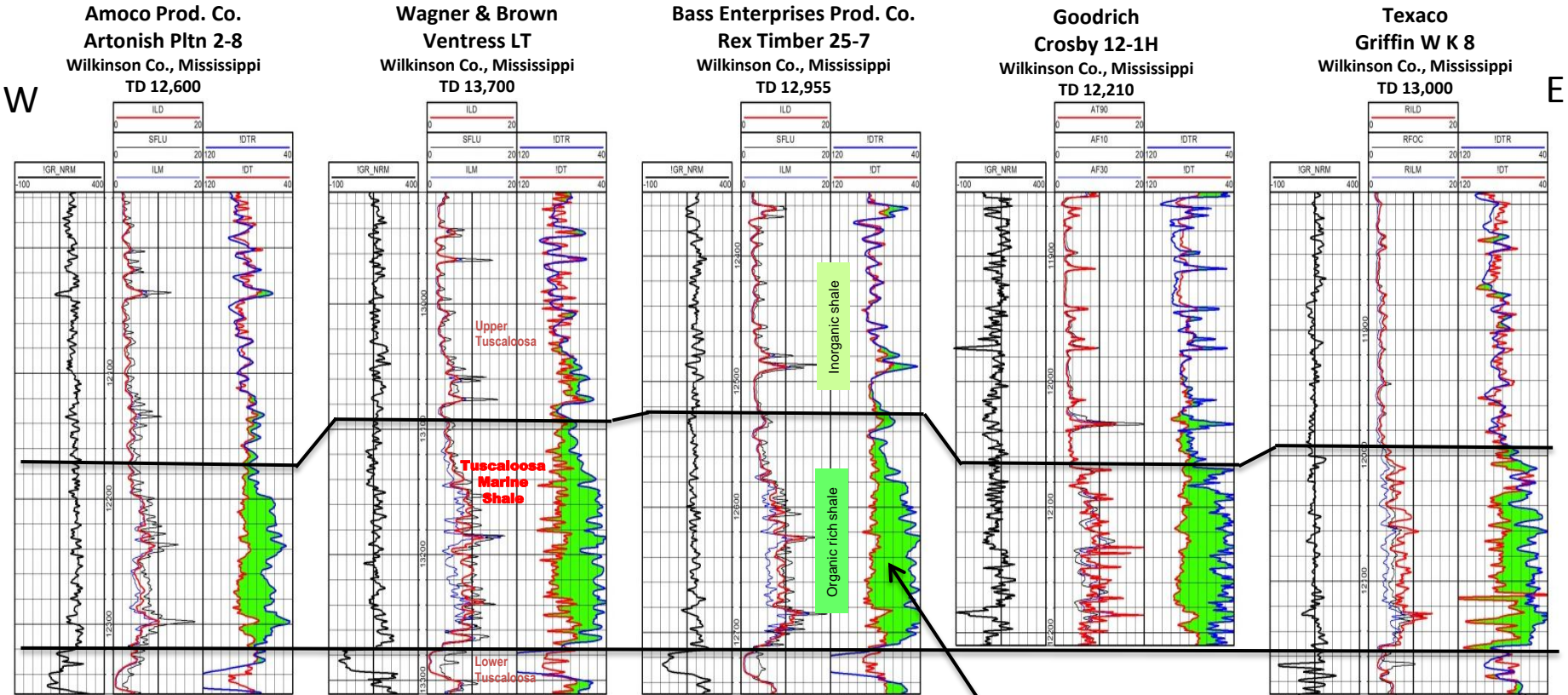
# Activity Map



Source: Company investor presentations and publicly available information.

Note: Comp wells referenced on map were completed with frac design similar to the frac design HK intends to utilize.

# West to East TMS Cross Section

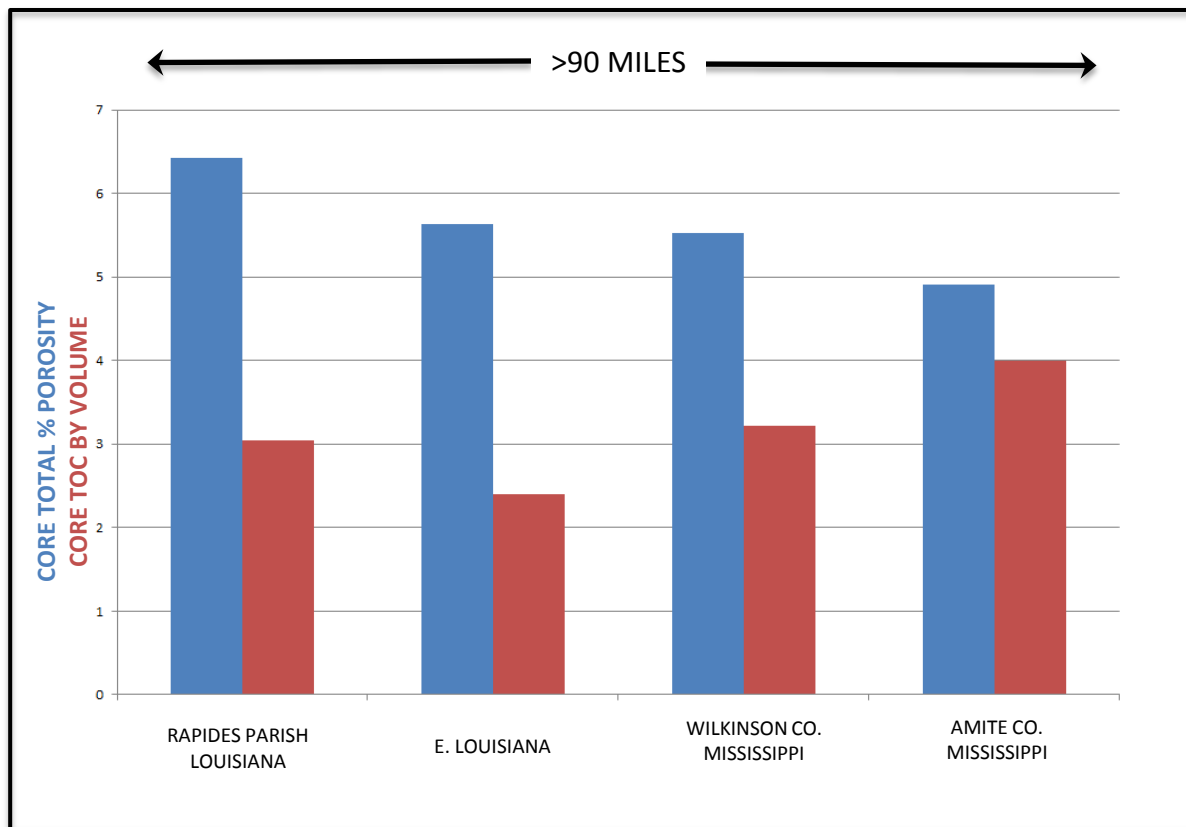


## "Passey Method"

- Organic-rich shales have slower sonic travel times and higher resistivities than inorganic shales.
- When normalized to an inorganic shale baseline, the sonic curve separates from the resistivity curve.
- Separation is directly proportional to TOC and maturity.
- Passey Method is widely used when density data is not available due to hole wash-out.

# TOC and Porosity

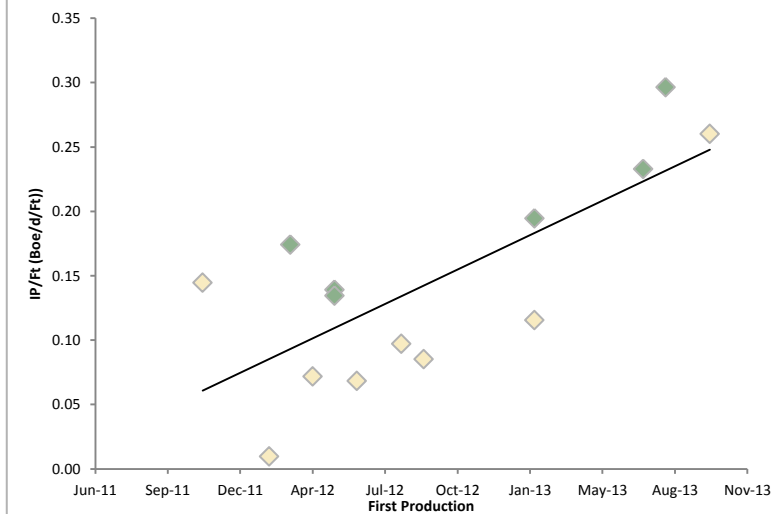
## Similar Properties Across Trend



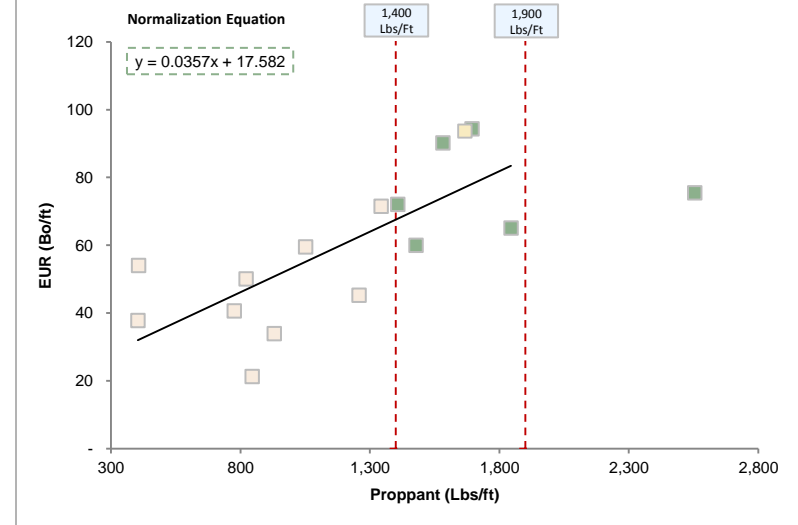
# Well Performance Improving Rapidly

Historical Industry Practice	Current Industry Practice	Halcón Planned Practice
☒ Shorter lateral: 2,000' – 5,000'	☑ Longer lateral: 6,000'+	☑ Longer lateral: 7,200'+
☒ Lateral placement varied, trial and error	☑ Lateral placement well-defined	☑ Lateral placement well-defined
☒ Slickwater frac	☑ Hybrid frac	☑ Hybrid frac
☒ Less than 1,400 lbs proppant / foot	☑ 1,400+ lbs proppant / foot	☑ 1,600+ lbs proppant / foot
☒ 70'+ cluster spacing	☑ 66' or less cluster spacing	☑ 50' cluster spacing

24-Hour IP Rates (per Foot) Over Time



EUR vs. Proppant (per Foot)

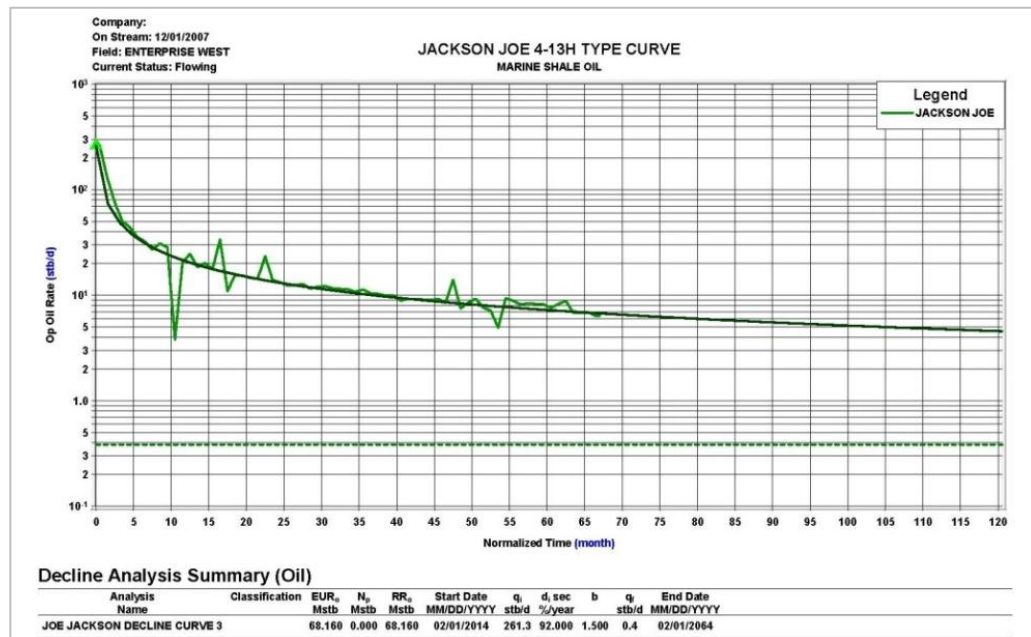


■ Wells Used to Construct HK Type Curve

# HK Type Curve Methodology

- HK has analyzed all horizontal TMS wells drilled to date
- Broad range of results, reflecting variety of drilling/completion techniques
- Six wells representing the current industry practices used to construct HK Base Case type curve
- “b” factor based on three wells with over four years of production history with “b” factors ranging from 1.3 to 1.7 (e.g. Joe Jackson 4-13H)

Well	Effective Lateral Length (Ft)	Q <sub>i</sub>	D <sub>i</sub>	Q <sub>f</sub>	D <sub>f</sub>	Life (Yrs)	Cluster Spacing (Ft)	Proppant (Lbs/Ft)	As is EUR/Ft <sup>(1)</sup>		Normalized to 7,200'	
									Bo/Ft	Boe/Ft <sup>(2)</sup>	MBo	MBoe <sup>(2)</sup>
Average	5,509	1,014	86.8	6.0	6.0	36.1	54	1,747	79	84		
Implied 7,200' Lateral TC Parameters	7,200	1,375 <sup>(3)</sup>	86.8	6.0	6.0	39.5	50	1,600	79	84	566	605



Source: Company presentations and press releases; HK estimates and publicly available information.

(1) As is EUR/Ft equivalent to projected EUR/Ft for optimized well set.

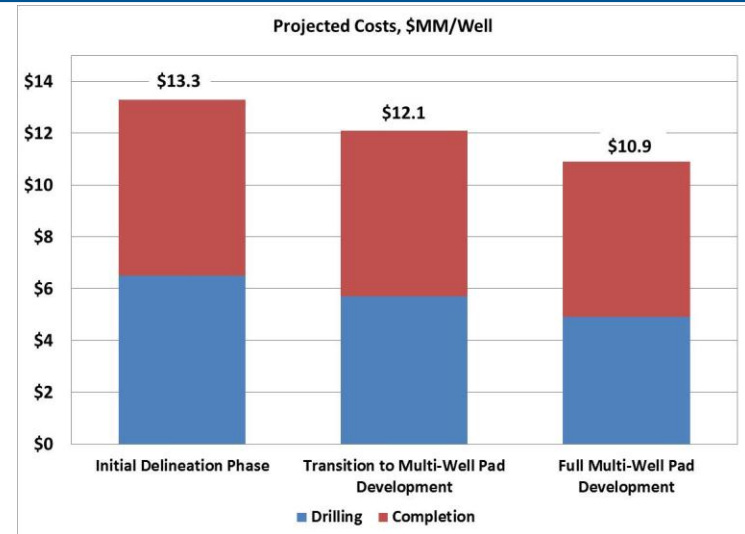
(2) Represents wellhead EUR assuming GOR of 0.404 Mcf/Bo, post-shrink gas yield of 64% and NGL yield of 90 Bo/MMcf.

(3) Type curve D<sub>i</sub> held constant; Varied Q<sub>i</sub> to achieve desired EUR with b factor of 1.5.

# Dedicated Experienced Asset Team

## Projected Well Cost (\$MMs)

- Initial Delineation Phase
  - First wells in the program
  - Spud to rig release = 48 days
- Transition to Multi-Well Pad Development
  - Multi-rig program, majority of wells still drilled from single well pads
  - Increased efficiencies reduce drill time (spud to rig release) to 35 days
  - Completion costs reduced by 10% utilizing a dedicated crew
- Full Multi-Well Pad Development
  - Multi-rig program, nearly all drilling from multi-well pads
  - Savings of \$2.4MM/well, or 18%, when drilling multiple development wells from one location



## Drilling Efficiencies

- Achieve improvements similar to those achieved in El Halcón
- Target drill time of 30 days
  - Improved bit technologies: Higher strength/more abrasion resistant cutters.
  - Improved motor technologies: Higher differentials leading to less stalling and higher ROP
  - Drill 8-3/4" hole to TD; Larger tools are more durable, fewer trips to change out tools

# Learning Curve

## Drilling

- Utilizing rig and crew from successful El Halcón area
- Focus on reducing chances of hole instability problems
  - Drill the intermediate section (vertical) with oil based mud
  - Set intermediate casing +/- 100' into the top of the TMS at up to 30°
  - Drill large (8.5") production hole to reduce equivalent circulating density
- Refine target zone to avoid unstable intervals

## Completion Design

- Hybrid design yielding consistent results
- Build on recent industry success:
  - Continue study of treatments to date
  - Use of proven clay stabilizer – choline chloride
  - Focus on efficient proppant placement
  - Optimize cluster spacing, stage size, proppant type
  - Optimize hydraulic horsepower

## Post-Completion Cleanout

- Prevention of casing restrictions
  - Modify frac design to minimize chance of pressure spikes and casing deformation
- Evaluate alternatives to milling out plugs with coil tubing
  - Use of a snubbing unit and work string

# TMS Conclusions – The Oil is There!

1 TMS represents one of the most attractive emerging crude oil resource plays in North America

2 Large, concentrated, highly operated position with favorable lease terms provide for efficient development

3 Halcón is uniquely suited to successfully develop the TMS, with one of the largest acreage positions and operational experience in analogous shale plays

4 Joint venture options being evaluated, but not necessary; No change to announced 2014 D&C capex budget

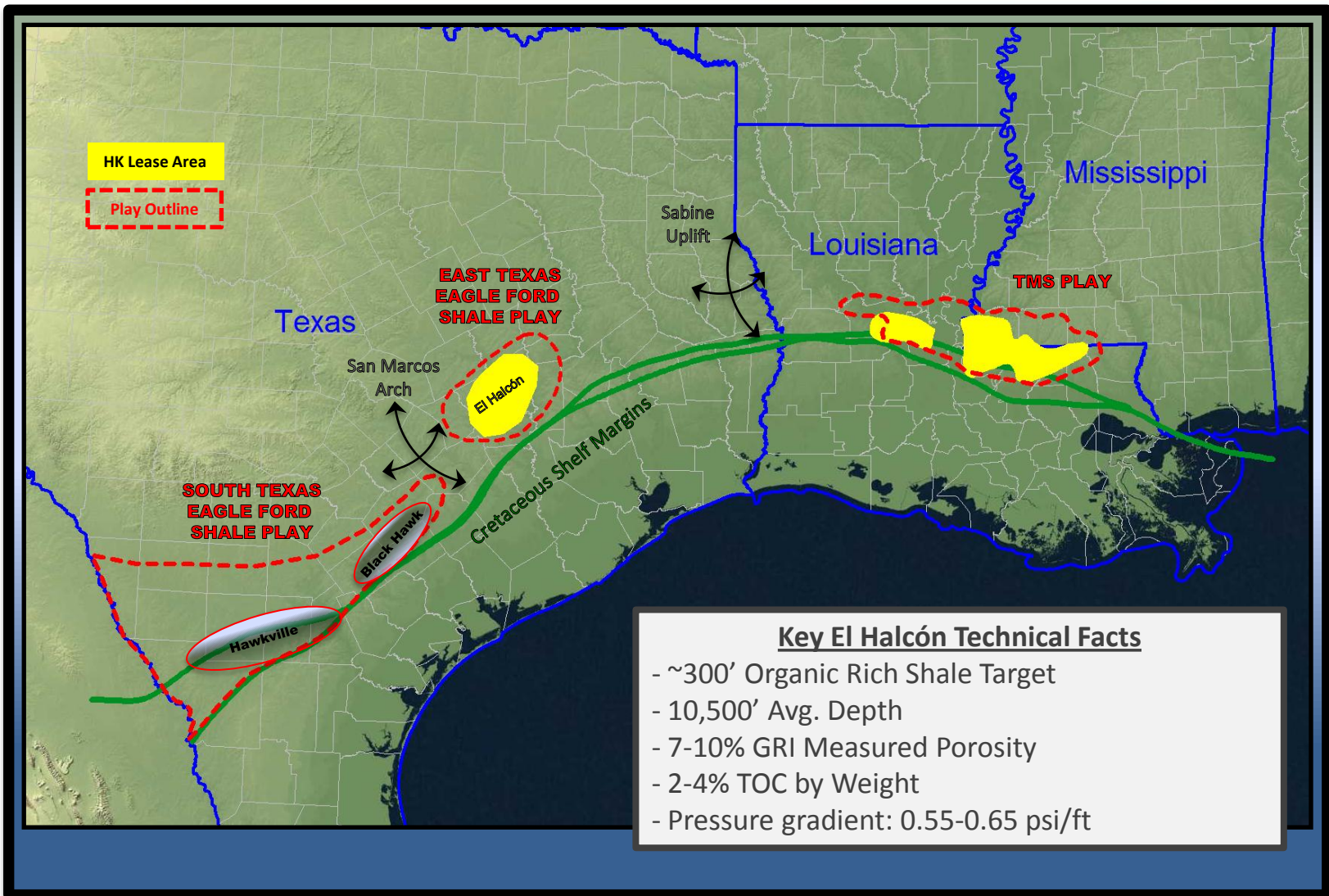
5 ~235,000 net acres in the Eastern core of activity represents a scaled land position that is not replicable given consolidation of the play

6 ~72,000 net acres in the Western portion provides meaningful upside opportunities as the play continues to develop and expand

7 Recent well results demonstrate the underlying technical merits and compelling economics of the play

8 Favorable operating environment with pro-oil and gas community and access to LLS market

# Geologic Setting

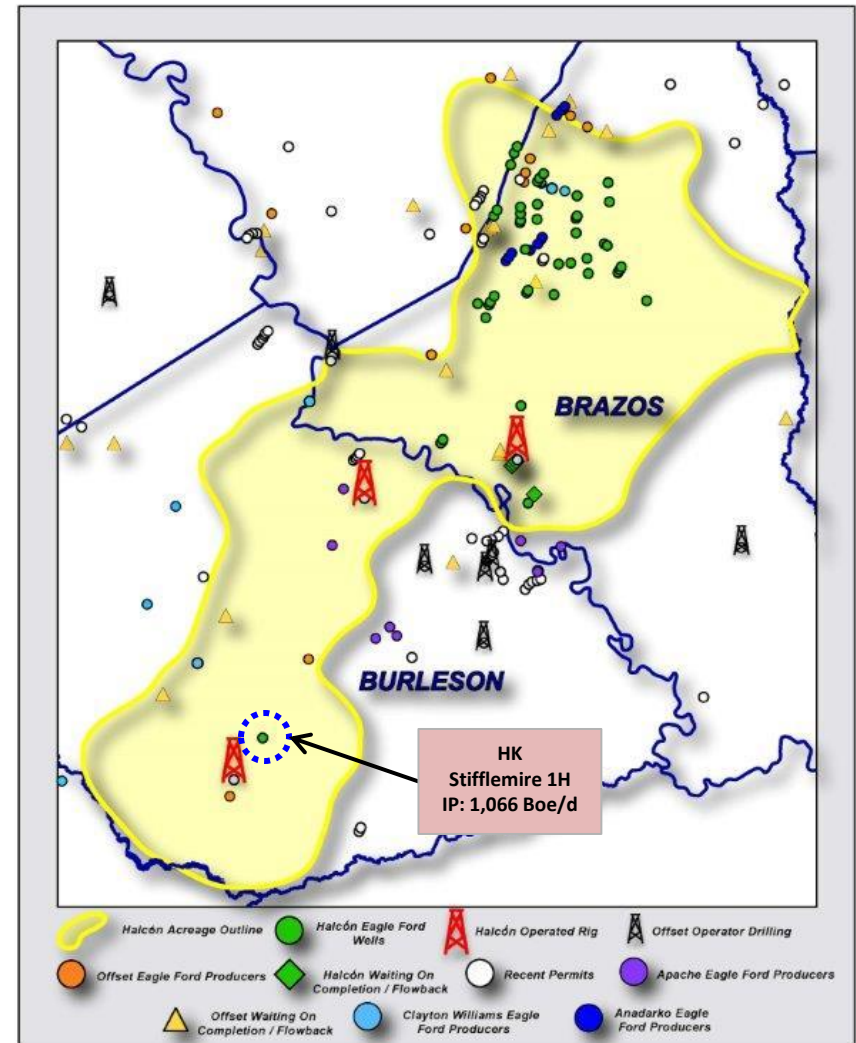


# El Halcón

## Eagle Ford Shale – AGAIN...

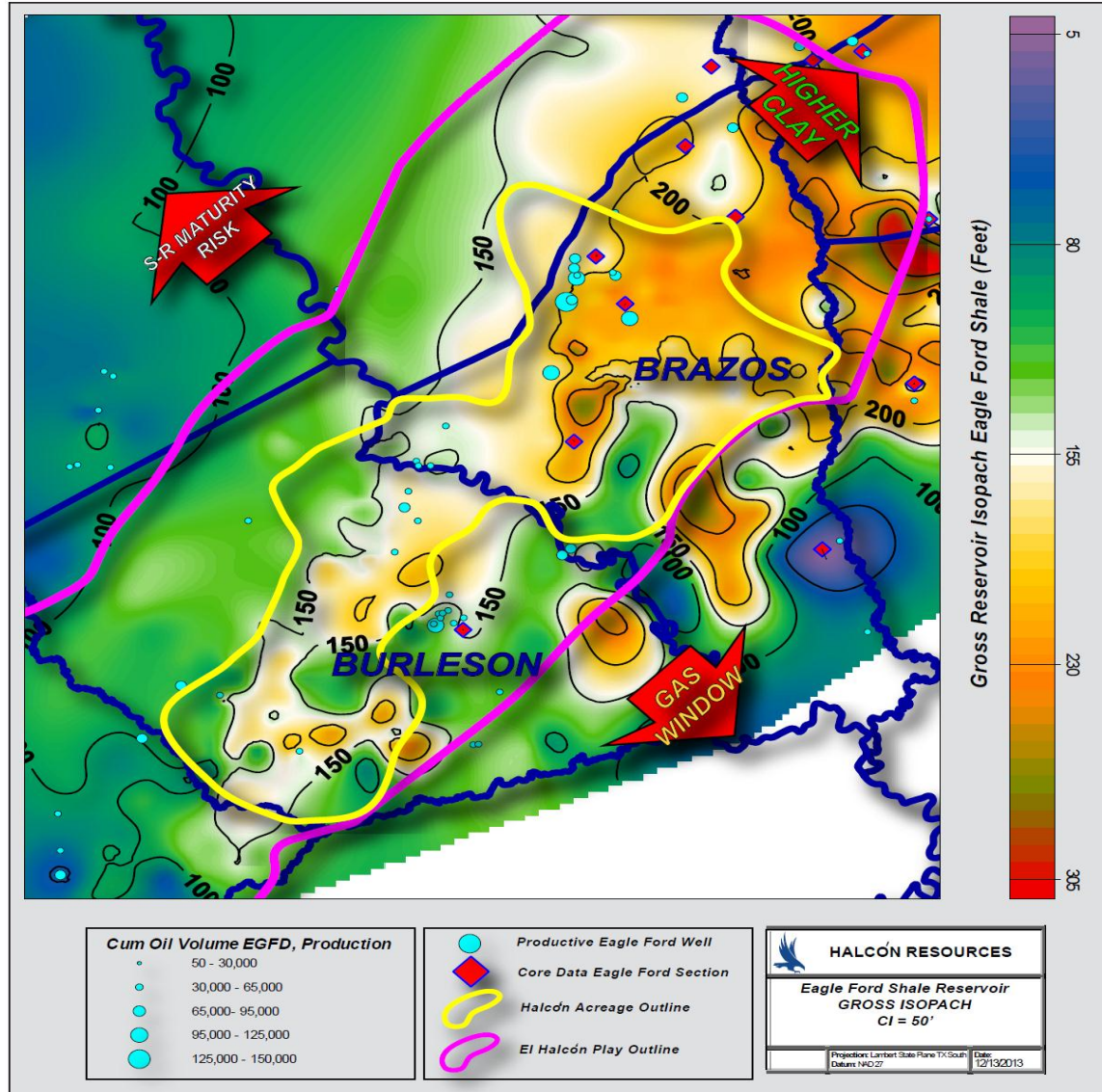
### Key Highlights

- ~100,000 net acres leased – target achieved
  - Acreage in “**SWEET SPOT**” of play
  - ~1,000+ future locations to drill assuming 800’ spacing
- 2014 Outlook
  - Expect to spud 40-50 gross operated wells w/ three rigs
- Improving Well Economics
  - Reduced drilling days and lower frac cost
  - Optimization of D&C techniques ongoing
  - Optimizing artificial lift type and installation timing
- Recent Well Performance
  - Lateral length directly correlating to EUR for wells completed with sufficient volume of proppant
  - Early stage results from step out wells to the South are very encouraging
    - Stifflemire 1H (1<sup>st</sup> Burleson County well)
    - IP: 1,066 Boe/d (87% oil)



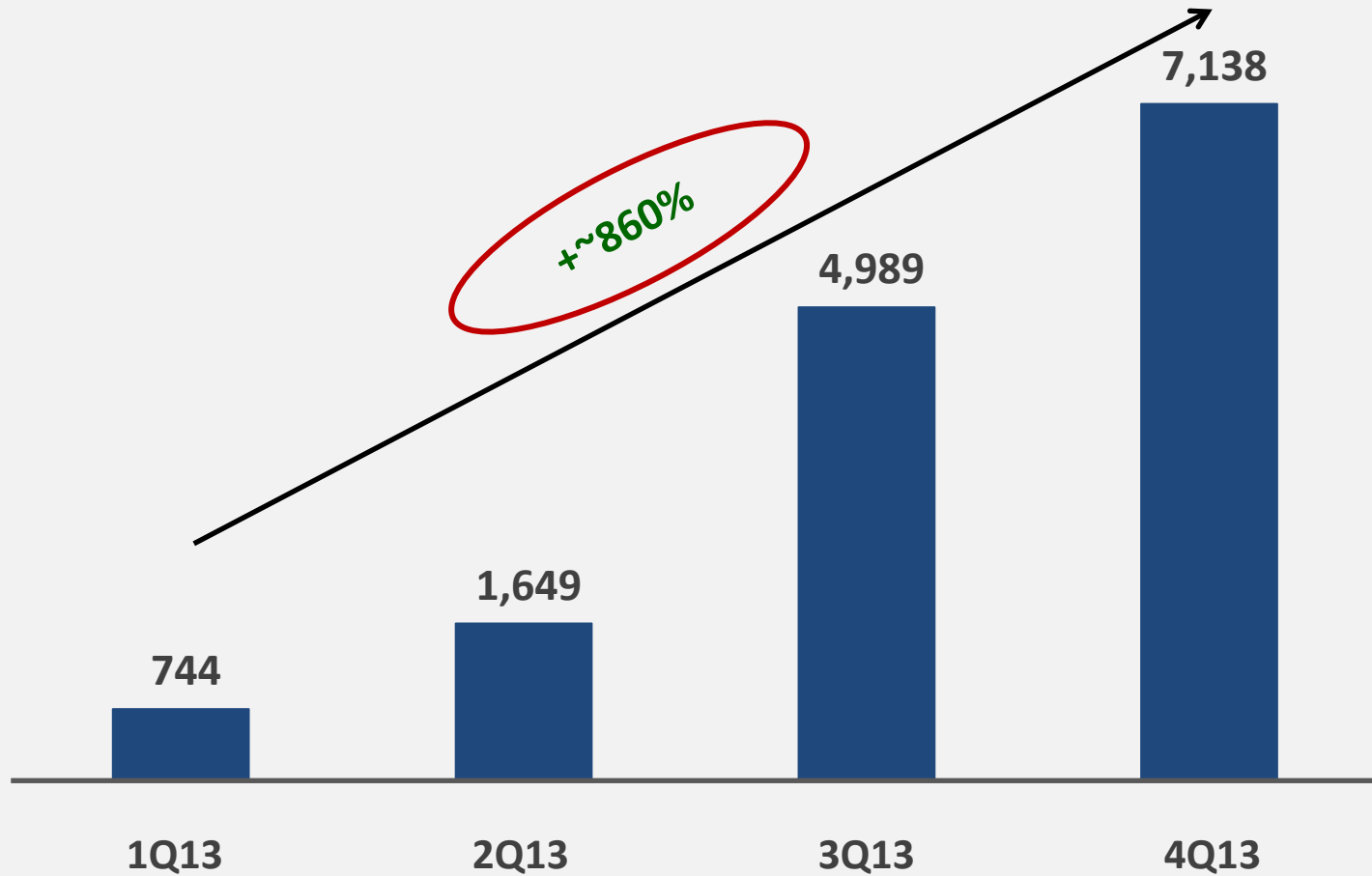
# El Halcón (East TX Eagle Ford Shale) Isopach

HK Acreage Located in **"SWEET SPOT"** of Play

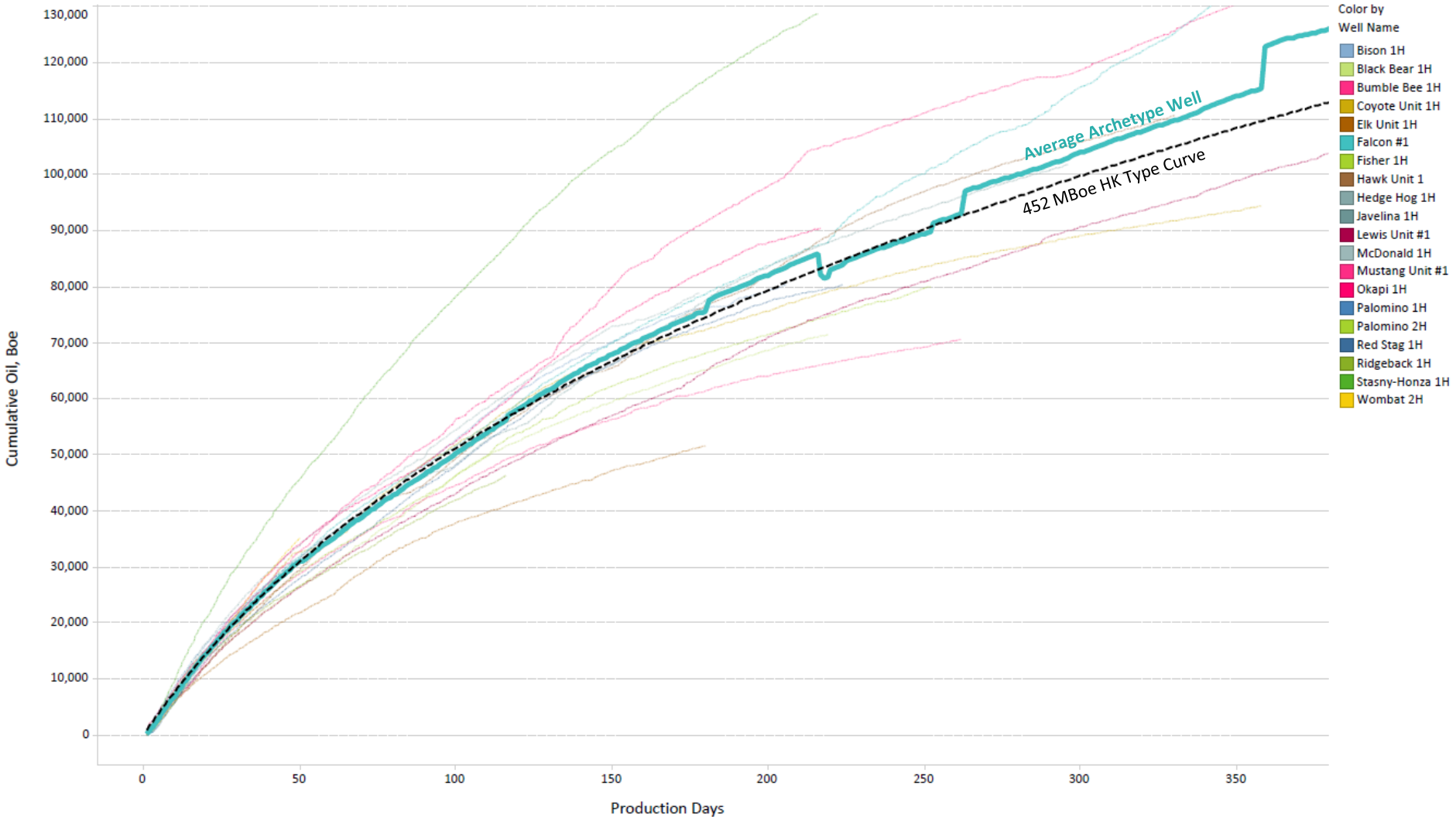


# Rapid Production Growth Expected to Continue

El Halcón 2013 Net Daily Production Growth



# Wells Outperforming Type Curve



Note: Archetype wells spaced a minimum of 750 feet apart and completed with 1,200 lbs, or more, of proppant per lateral foot.

# Continuing to Optimize Completion & Well Design...

## Completion Design

- Recent production results support 1,500 lbs/ft to be optimum sand loading
- Testing increased stage spacing while holding sand loading constant
  - Also evaluating increasing perf cluster density, varying proppant types, and fluid systems

## Lateral Length

- Lateral length directly correlates to EUR for wells frac'd with sufficient proppant
- Working to find most economic completed lateral length
  - Current planned laterals range from 7,000' to 9,000'

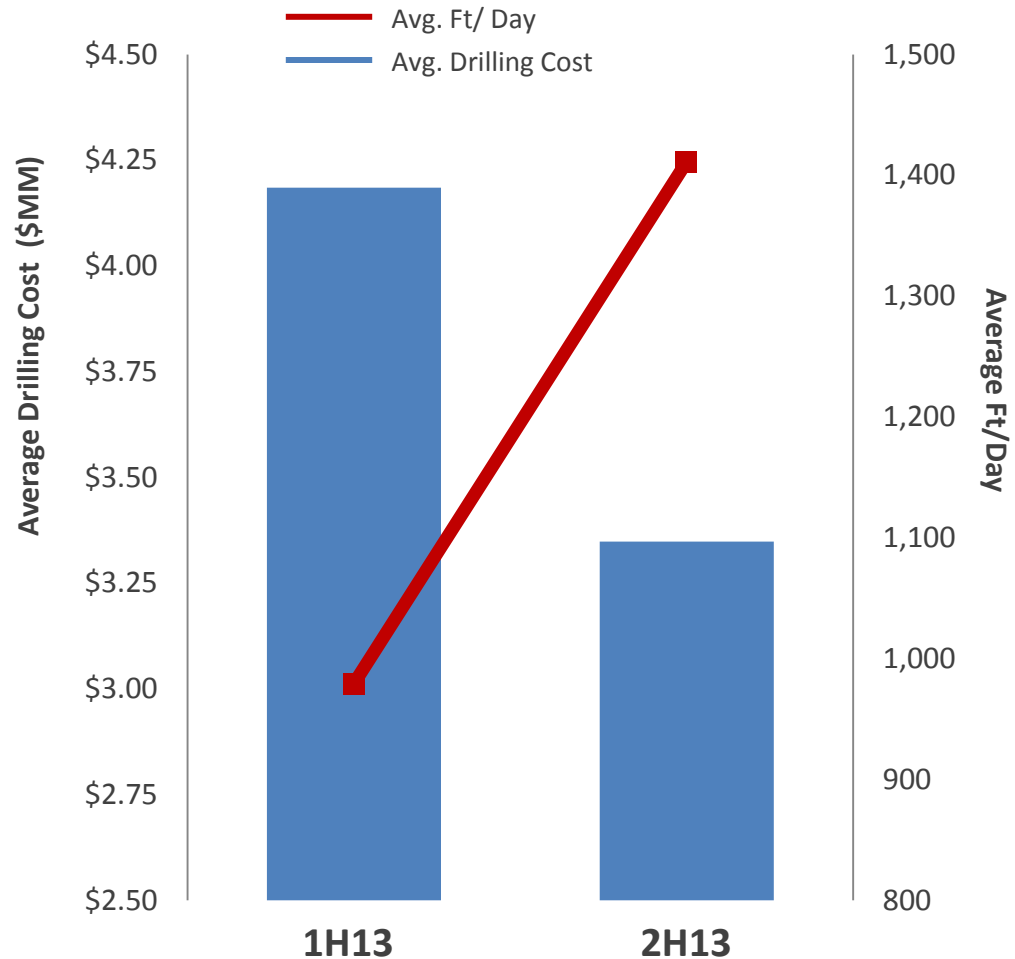
## Spacing

- Well spacing pilot tests continue in El Halcón
  - Testing 1,000' and 800' spacing

# ...While Driving Drilling Performance Improvements

- El Halcón 2013 Results (45 wells)
  - Avg. Drilling Days : 15.97 days spud to TD
  - Avg. Feet/Day: 1,225'
  - Avg. Drilled Lateral Length: 7,663'
  - Avg. Drilling Cost: \$3.7 MM
- 2013 Drilling Highlights
  - 3Q13 (13 Wells)
    - Avg. Drilling Days: 13.09 days spud to TD
    - Avg. Lateral Length: 7,432'
  - 4Q13 (13 Wells)
    - Avg. Drilling Days: 12.55 days spud to TD
    - Avg. Lateral Length: 7,999'
- Best in Class Wells
  - Ridgeback 1H
    - Drilling Days: 7.29 days spud to TD
    - Feet/Day: 2,216' and 7,389' Lateral
  - McDonald 2H
    - Drilling Days: 6.96 days spud to TD
    - Feet/Day: 2,070' and 6,507' Lateral

2013 Average: Field Costs and Ft/Day

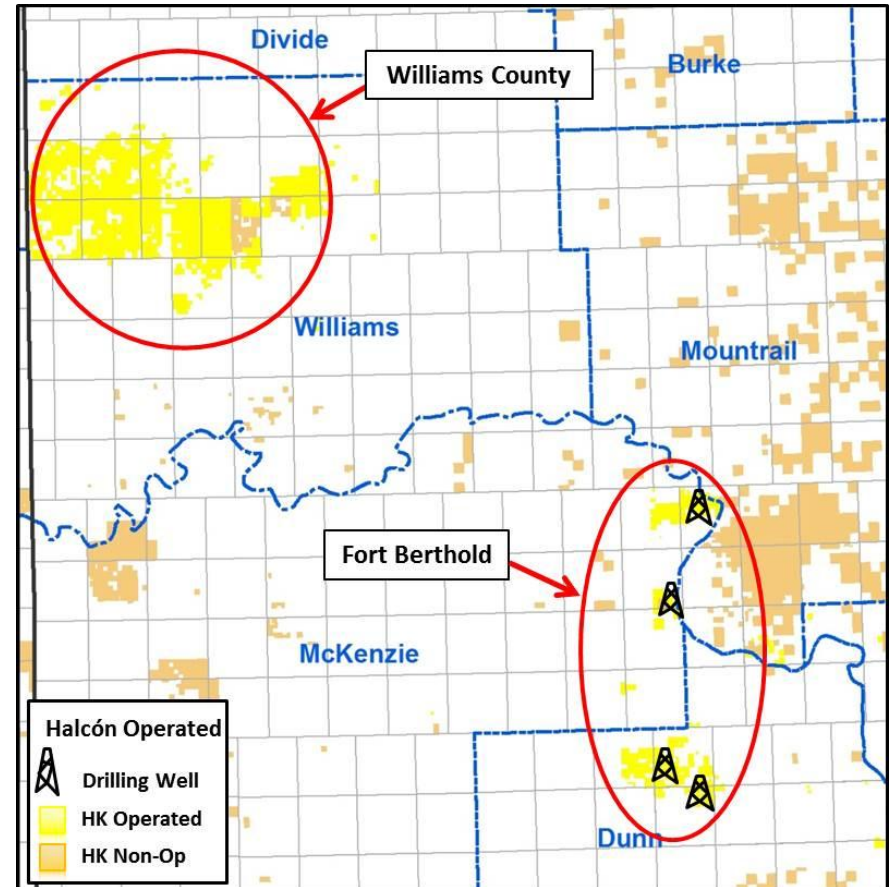


# Bakken / Three Forks

## Inventory Growing and Type Curve Estimates Revised Higher

### Key Highlights

- 2014 Outlook
  - Expect to spud 40-50 gross operated wells (~95% in FBIR) w/ four rigs
  - Expect to participate in 200-225 gross non-op wells (Avg. WI 3%)
- New slickwater FBIR wells outperforming all wells drilled/completed with prior methods
- Material inventory upside
  - Recent downspacing tests indicate potential for up to 16 wells per DSU in FBIR area
- Cost reduction opportunities
  - Efficiencies related to pad drilling & simultaneous-ops
  - Completion modifications: proppant type, fluid type, pumping services
  - Electrification of fields







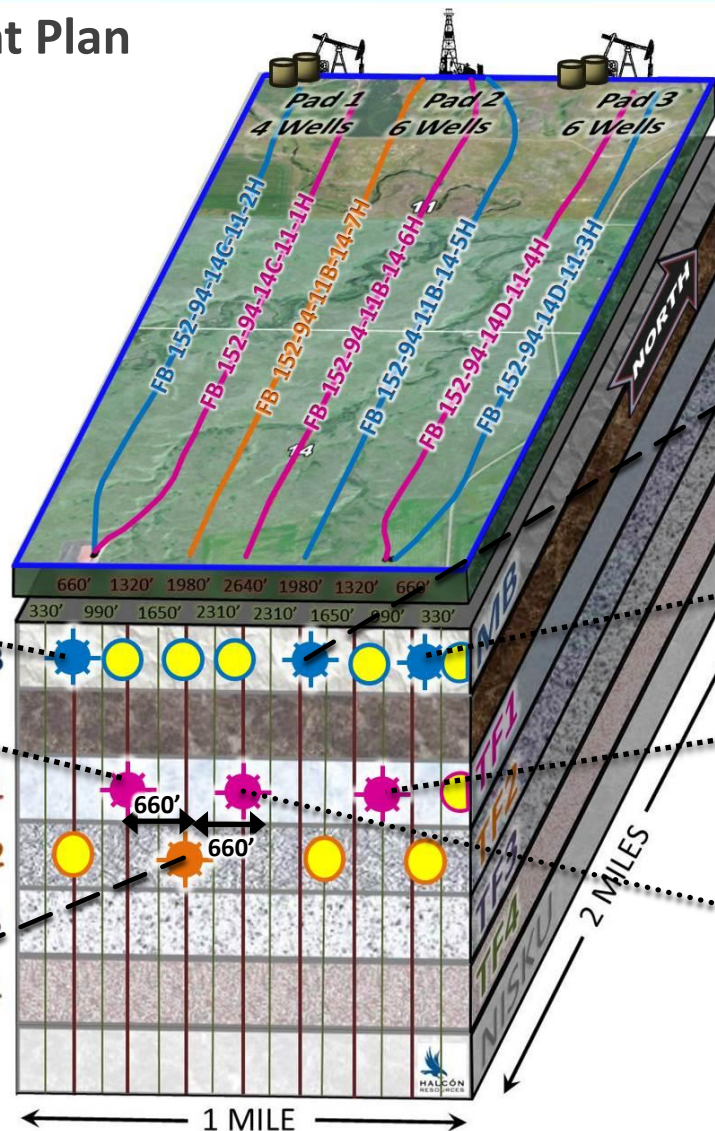
# Successful Three Forks Downspacing Tests

## Capitol Pad Development Plan

McKenzie County, ND

HK – 71% WI

-  Producing MB Well
-  Producing TF Well
-  Producing TF2 Well
-  Potential Infill Locations



**FB 14C-11-2H (MB)<sup>(1)</sup>**  
24HR IP: 1,195 BOED

**FB 14C-11-1H (TF1)<sup>(1)</sup>**  
24HR IP: 1,586 BOED

**FB 11B-14-7H (TF2)**  
24HR IP: 2,390 BOED

**FB 11B-14-5H (MB)**  
24HR IP: 3,182 BOED

**FB 14D-11-3H (MB)**  
24HR IP: 2,390 BOED

**FB 14D-11-4H (TF1)**  
24HR IP: 3,517 BOED

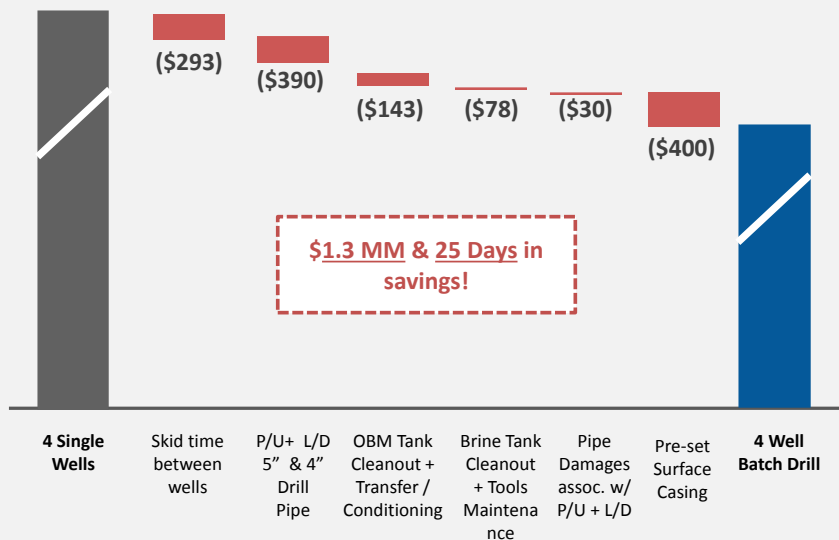
**FB 11B-14-6H (TF1)**  
24HR IP: 3,018 BOED

(1) Well put online in 2011 and drilled/completed by predecessor operator using old completion techniques.

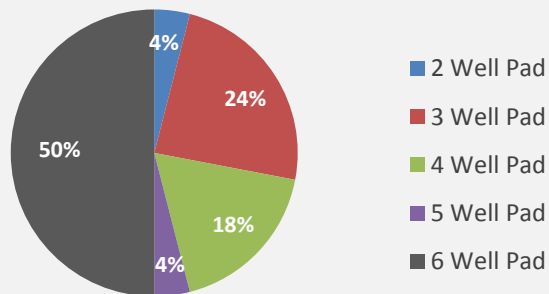


# Field Optimization = Improved Economics

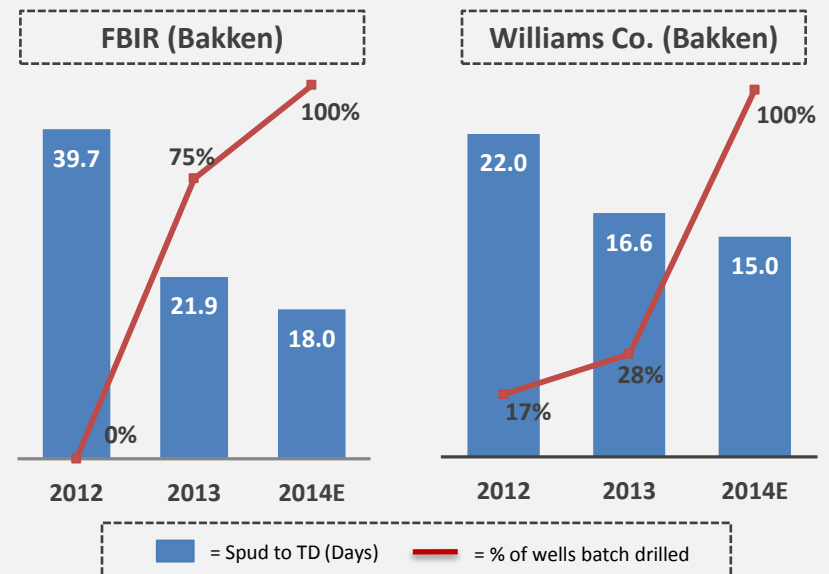
## Single Well Drill vs. 4 Well Batch Drill on Pad Site



- Completing transition to pad/batch drilling
- 100% of wells will be drilled on multi-well pads in 2014

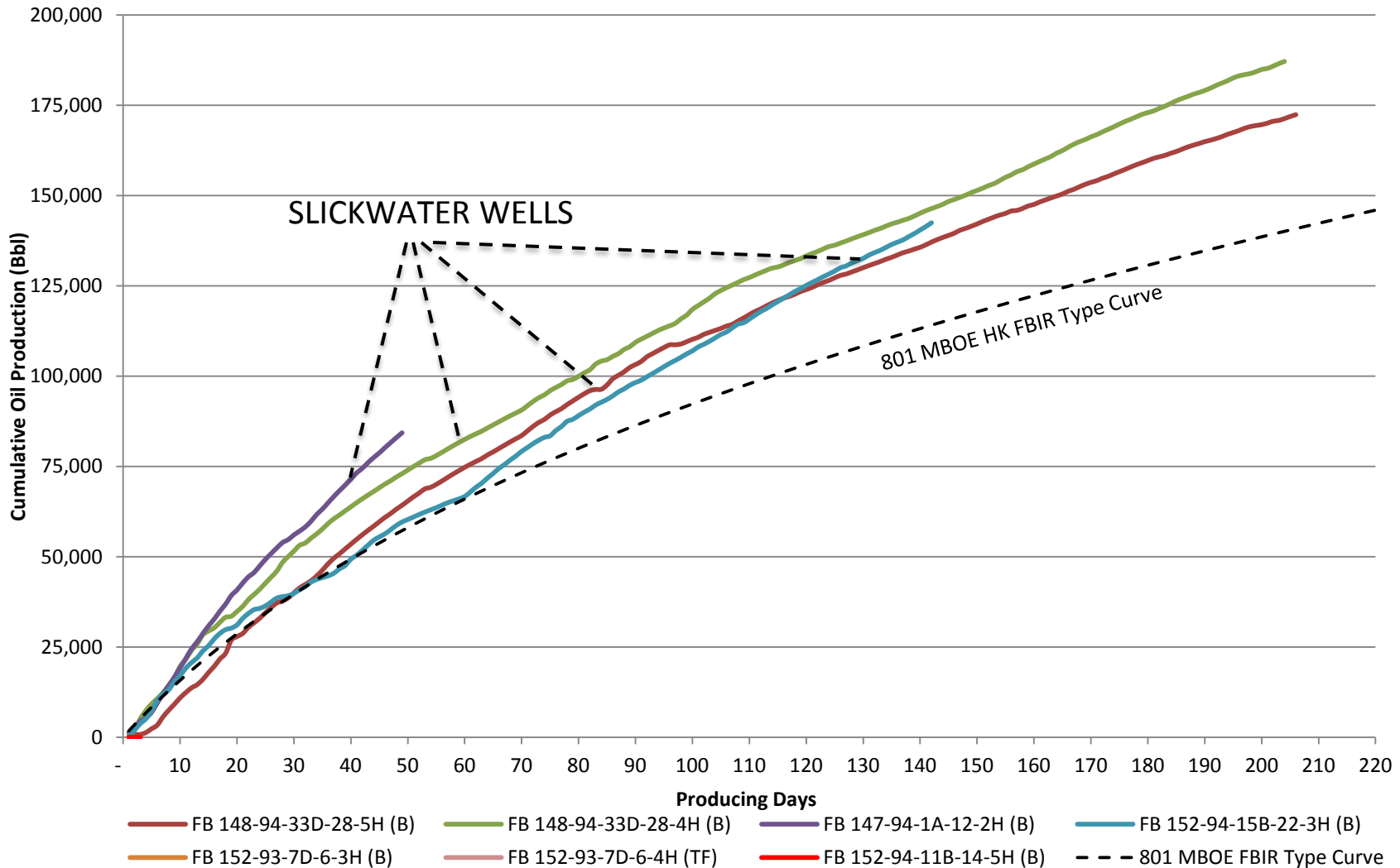


## Average Spud to Total Depth Drilled Days



- Spud to TD: Recent Highlights
  - FBIR: 15.25 days
  - Williams County: 12.2 days
- HK/Industry Record FBIR 10k' Lateral (Bakken): 4.15 days
  - Fastest 10k' lateral ever drilled in FBIR, Eastern McKenzie and Dunn Counties
- HK Record Williams Co. 10k' Lateral (Bakken): 3.75 days

# FBIR Slickwater Wells Outperforming = Upside



# Financial Highlights

## 1 Fund growth and capital expenditures prudently

- Maintain announced budget
- All capital directed to highest return assets

## 2 Focus on liquidity

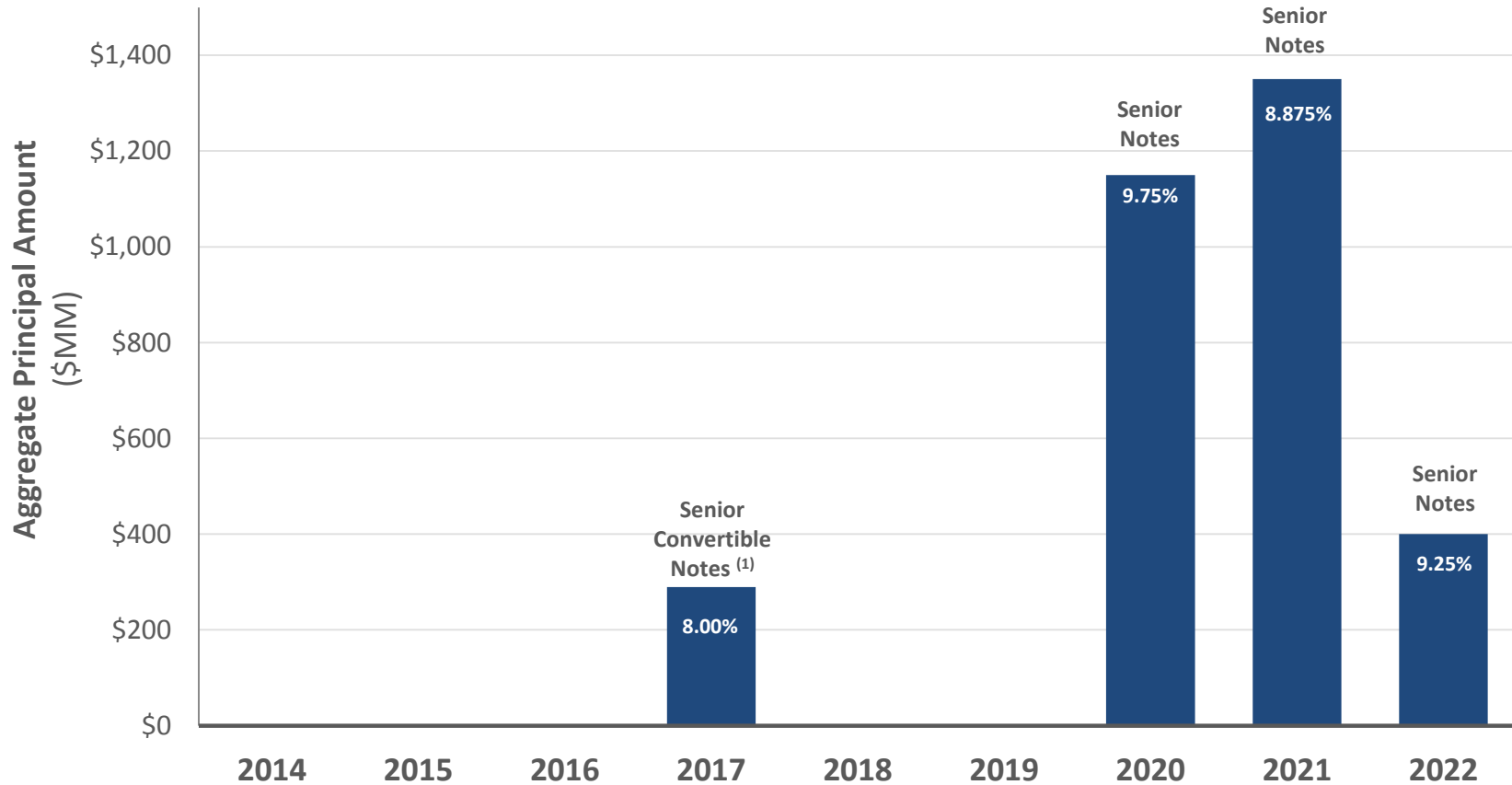
- Expect borrowing base to continue to increase as production and reserves grow
- Continue to monetize non-core assets to supplement liquidity

## 3 Active Hedging Program

- Hedge program designed to protect cash flow and capital expenditure plans
- Target 80% of expected production over the next 18 – 24 months

# No Near-term Debt Maturities

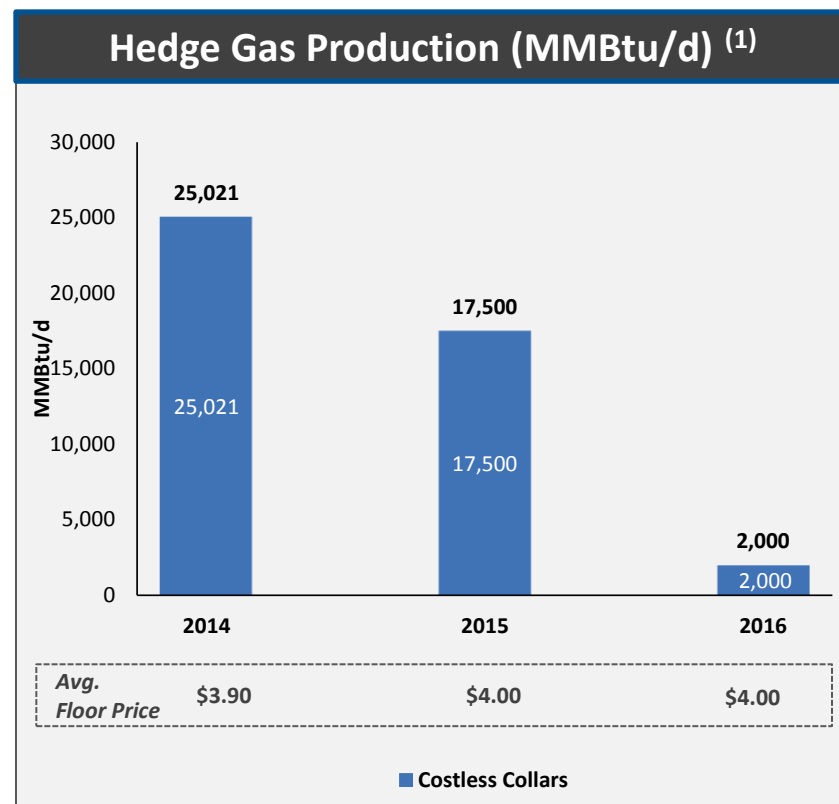
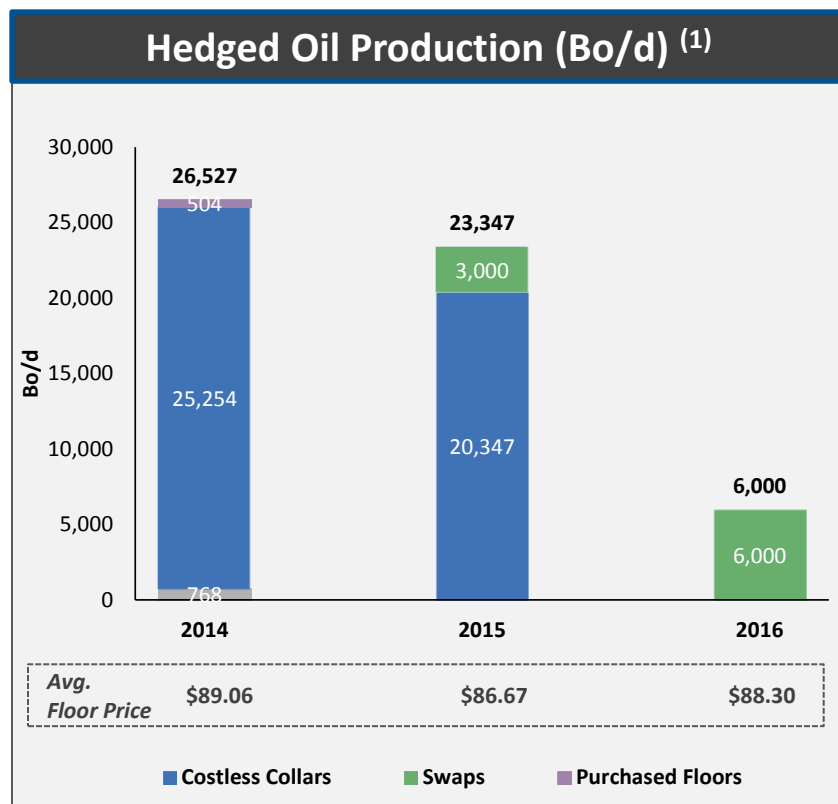
## Debt Maturity Schedule



(1) Includes \$14.7 MM of interest paid-in-kind in 2012.

# Active Hedging Program to Protect Cash Flow

- Designed to support capital program and protect cash flow
- Target 80% of expected production over the next 18-24 months
- Average Floor Price: \$89 in 2014; \$87 in 2015



(1) As of 3.21.14.

# Ample Liquidity to Fund Capital Program

## Pro Forma Capitalization (\$ in Millions)

	HK <u>12.31.2013</u>	Borrowing <u>Base Redetermination</u>	Non-Core East Texas <u>Asset Divestiture <sup>(1)</sup></u>	Pro Forma HK <u>12.31.2013</u>
Cash and Cash Equivalents	\$2.8		\$450.0	\$452.8
Revolving Credit Facility	\$0.0			\$0.0
8.000% Senior Convertible Notes due 2017	259.4			259.4
9.750% Senior Notes due 2020	1,152.1			1,152.1
8.875% Senior Notes due 2021	1,372.4			1,372.4
9.250% Senior Notes due 2022	400.0			400.0
Total Debt	<u>\$3,183.8</u>			<u>\$3,183.8</u>
Total Stockholders' Equity	<u>\$1,447.6</u>			<u>\$1,447.6</u>
Total Capitalization	\$4,631.4			\$4,631.4
Proved Reserves (MMBoe) <sup>(2)</sup>	136.0		(16.3)	119.7
% Liquids	91.5%		(0.2%)	91.3%
% Proved Developed	40.2%		0.2%	40.3%
Q4 2013 Production (Boe/d)	40,217		(3,861)	36,356
LQA EBITDA	\$715.5		(\$90.3)	\$625.2
Total Net Debt / Book Capitalization	68.7%			59.0%
Total Net Debt / Proved Reserves (\$/Boe)	\$23.40			\$22.82
Total Net Debt / Proved Developed Reserves (\$/Boe)	\$58.25			\$56.58
Total Net Debt / Q4 2013 Production (\$/Boe/d)	\$79,095			\$75,118
Total Net Debt / LQA EBITDA	4.4x			4.4x
Borrowing Base	\$700.0	\$100.0	(\$100.0)	\$700.0
Liquidity <sup>(3)</sup>	\$702.8			\$1,152.8

(1) Expected to close in 2Q14.

(2) As of 12.31.13 as estimated by Halcón's independent reserve engineers.

(3) Liquidity defined as undrawn revolver capacity plus cash on hand.



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# Appendix



# 2014 Operating and Financial Guidance Summary

		1Q14E	2014E
<b><u>Production (Boe/d)</u></b>			
Total	Low High	34,000 36,000	38,000 42,000
% Oil			85%
% NGLs			5%
% Gas			10%
<b><u>Operating Costs and Expenses (\$/Boe)</u></b>			
Lease Operating & Workover	Low High		\$8.00 \$10.00
Production Taxes	Low High		\$6.00 \$8.00
Cash G&A	Low High		\$7.00 \$9.00
Gathering, Transportation & Other	Low High		\$1.00 \$2.00
<b><u>Drilling &amp; Completion Capex (\$ in millions)<sup>(1)</sup></u></b>			<b>\$950</b>

Note: Guidance accounts for non-core assets in East Texas currently under contract for sale with anticipated close in 2Q14.

(1) Excludes capitalized interest and G&A.

# 2013 Pro Forma Production Reconciliation

	1Q13	2Q13	3Q13	4Q13	2013
<b>Actual (Boe/d)</b>	<b>26,022</b>	<b>29,165</b>	<b>37,707</b>	<b>40,217</b>	<b>33,329</b>
<b>Acquisition Impact (Boe/d) <sup>(1)</sup></b>	<b>1,147</b>	<b>965</b>	<b>169</b>	<b>-</b>	<b>566</b>
Closed 5.7.13 – Gasco El Halcón	307	161	-	-	116
Closed 7.15.13 – Resolute Williston Basin	840	804	169	-	450
<b>Non-Core Divestitures Impact (Boe/d) <sup>(1)</sup></b>	<b>(9,568)</b>	<b>(10,259)</b>	<b>(9,597)</b>	<b>(6,588)</b>	<b>(8,997)</b>
Closed 7.19.13 – Fayette/Gonzales Counties Eagle Ford	(1,392)	(1,884)	(322)	-	(894)
Closed 10.15.13 – Conventional	(1,269)	(1,270)	(1,226)	(205)	(990)
Closed 10.25.13 – Conventional	(1,640)	(1,497)	(1,423)	(489)	(1,260)
Closed 12.20.13 – Conventional	(1,800)	(1,821)	(1,729)	(1,586)	(1,733)
Closed 12.31.13 – Wilcox	(319)	(517)	(482)	(447)	(442)
PSA Signed 2.25.14 - East Texas	(3,148)	(3,270)	(4,415)	(3,861)	(3,678)
<b>Pro Forma (Boe/d)</b>	<b>17,601</b>	<b>19,871</b>	<b>28,279</b>	<b>33,629</b>	<b>24,898</b>

(1) Production impact based on specified closing dates.

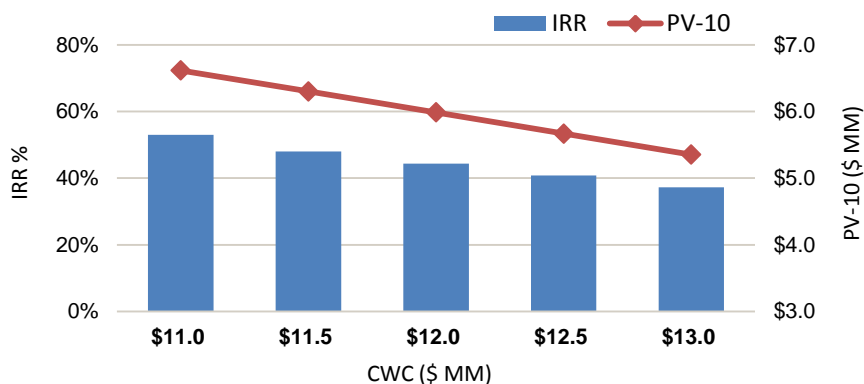
# 2013 Proved Reserves Reconciliation

Proved Reserves Reconciliation	Oil (MBbls)	Gas (MMcf)	NGL (MBbls)	Total MBoe
<b>As of 12.31.12</b>	<b>87,378</b>	<b>96,145</b>	<b>5,383</b>	<b>108,785</b>
Extensions, discoveries and additions	61,160	25,364	4,344	69,731
Purchases	2,770	1,791	162	3,231
Sales	(17,417)	(25,717)	(1,611)	(23,314)
Production	(10,148)	(8,003)	(683)	(12,165)
Revisions of previous estimates & pricing	(9,233)	(19,832)	2,237	(10,301)
<b>As of 12.31.13</b>	<b>114,510</b>	<b>69,748</b>	<b>9,832</b>	<b>135,967</b>

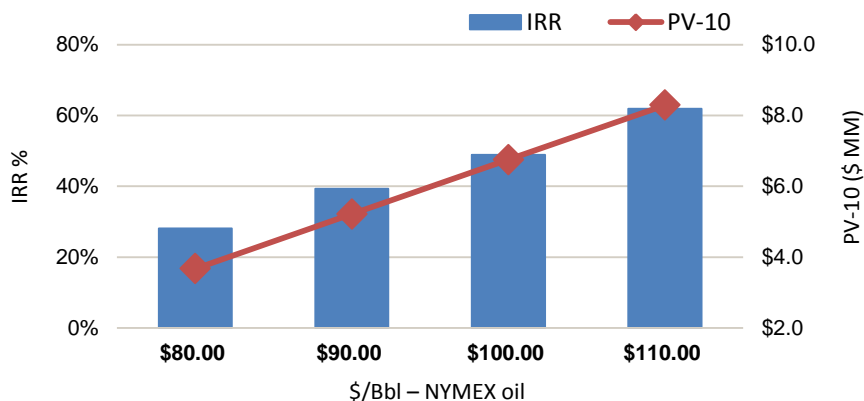
Notes: Proved reserves as of 12.31.13 as estimated by Halcón's independent reserve engineers using unweighted average first-day-of-the-month commodity prices for the year ended 12.31.13 and otherwise in accordance with SEC rules relating to reporting of reserves; Proved reserves inclusive of non-core assets in East Texas currently under contract for sale.

# TMS 605 Mboe Type Curve

## Investment Sensitivity to Completed Well Cost <sup>(1)</sup>



## Investment Sensitivity to NYMEX Oil Price <sup>(2)</sup>



## Type Curve Details

Gross EUR	Oil (MBbl)	566
	Gas (MMcf)	229
	<b>Total (MBoe)</b>	<b>605</b>
Diffs <sup>(3)</sup>	Oil (% of NYMEX)	101%
	Gas (% of NYMEX)	138%
Other	IP (Boe/d)	1,470
	Spud to Production	90 days
	b factor	1.5
	Di	87%
	Df	6%
	Lateral Length (ft)	7,200
	Avg. Royalty Burden	22%
	Avg. Working Interest	66%
	Avg. Net Revenue Interest	51%

Note: See “Cautionary Statements” on page 3 for a description of EURs; Completed Well Costs (CWC) include drilling and completion expenses, royalties, LOE, gathering, transportation, production taxes and connection expenses.

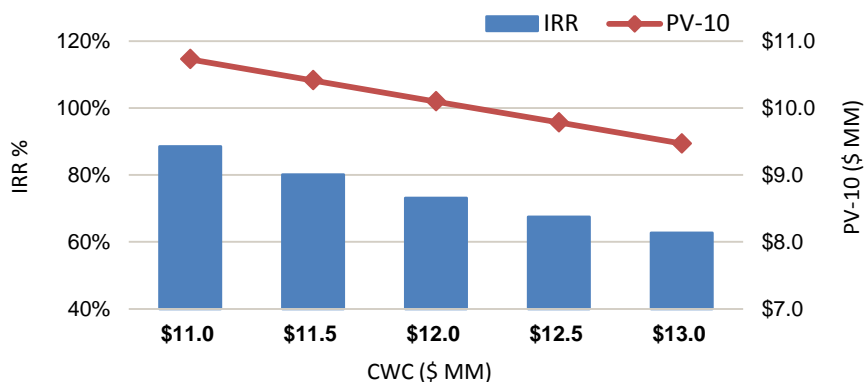
(1) Assumes flat pricing of \$95/bbl oil and \$4.50/MMBtu gas.

(2) Assumes \$12 MM CWC & \$4.50/MMBtu gas.

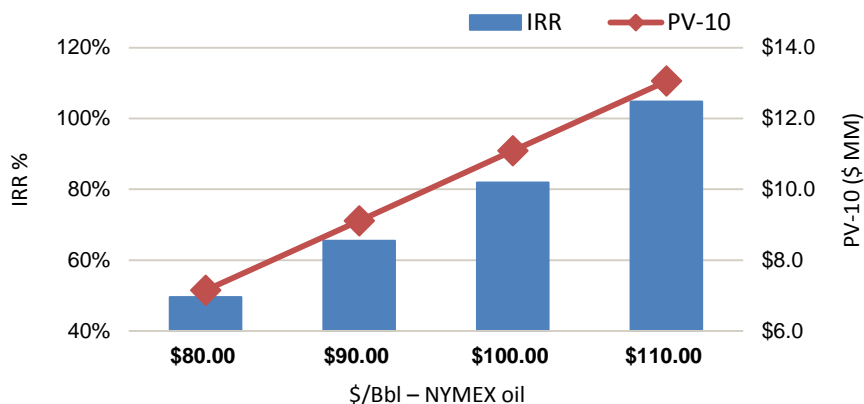
(3) Gathering, transportation and processing fees incorporated; Gas differentials presented on a gross wellhead basis including differential uplift for high BTU/NGL content.

# TMS 792 MBoe Type Curve

## Investment Sensitivity to Completed Well Cost <sup>(1)</sup>



## Investment Sensitivity to NYMEX Oil Price <sup>(2)</sup>



## Type Curve Details

Gross EUR	Oil (MBbl)	742
	Gas (MMcf)	300
	<b>Total (MBoe)</b>	<b>792</b>
Diffs <sup>(3)</sup>	Oil (% of NYMEX)	101%
	Gas (% of NYMEX)	138%
Other	IP (Boe/d)	1,537
	Spud to Production	90 days
	b factor	1.5
	Di	84%
	Df	6%
	Lateral Length (ft)	7,200
	Avg. Royalty Burden	22%
	Avg. Working Interest	66%
	Avg. Net Revenue Interest	51%

Note: See “Cautionary Statements” on page 3 for a description of EURs; Completed Well Costs (CWC) include drilling and completion expenses, royalties, LOE, gathering, transportation, production taxes and connection expenses.

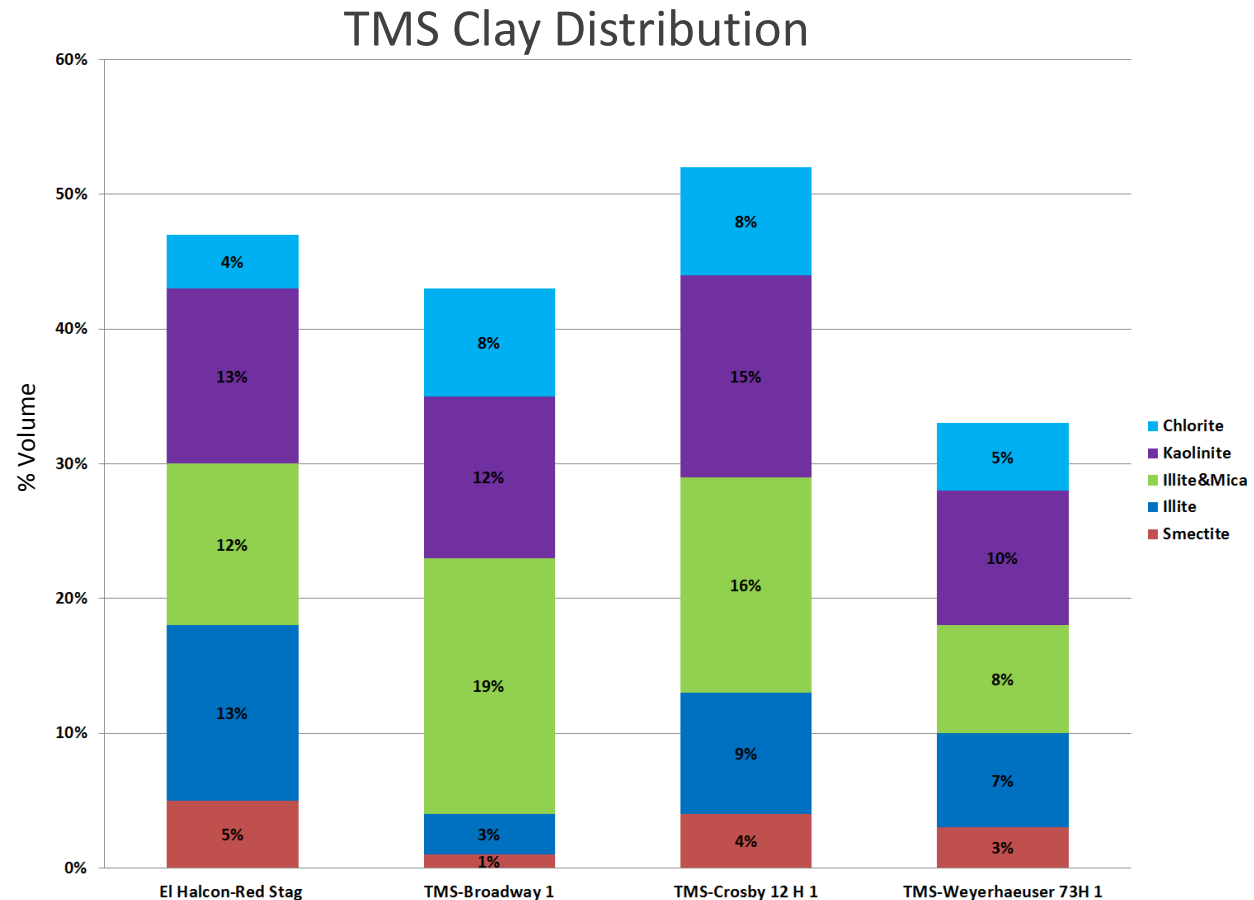
(1) Assumes flat pricing of \$95/bbl oil and \$4.50/MMBtu gas.

(2) Assumes \$12 MM CWC & \$4.50/MMBtu gas.

(3) Gathering, transportation and processing fees incorporated; Gas differentials presented on a gross wellhead basis including differential uplift for high BTU/NGL content.

# TMS Lithology

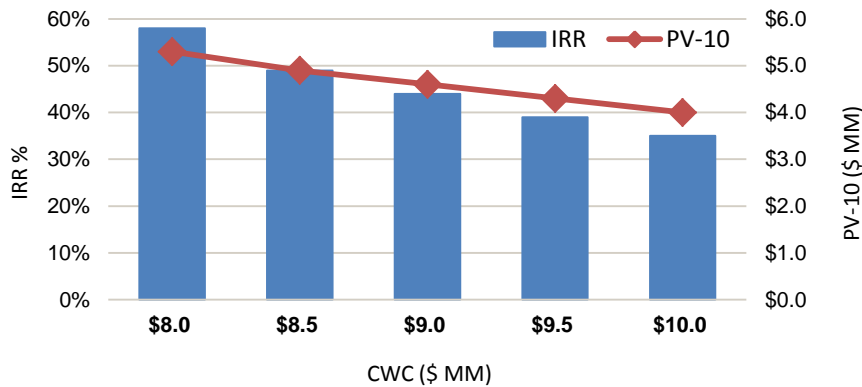
- Total clay content is high, but % of swelling clays (smectite) is low
- Total clay and smectite in TMS is very similar to East TX Eagle Ford Shale (El Halcón)



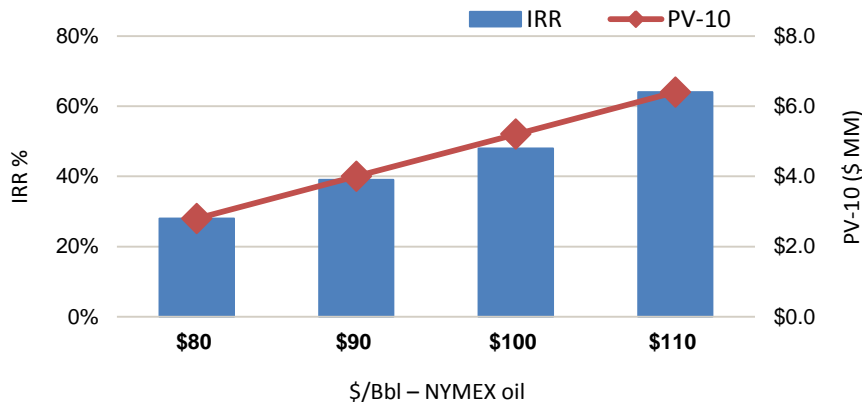
# New El Halcón 452 MBoe Type Curve

## EUR Increases by ~22%

### Investment Sensitivity to Completed Well Cost <sup>(1)</sup>



### Investment Sensitivity to NYMEX Oil Price <sup>(2)</sup>



### Type Curve Details

Gross EUR	Oil (MBbl)	420
	Gas (MMcf)	189
	<b>Total (MBoe)</b>	<b>452</b>
Diffs <sup>(3)</sup>	Oil (% of NYMEX)	99%
	Gas (% of NYMEX)	180%
Other	IP (Boe/d)	770
	Spud to Production	60 days
	B factor	1.3
	Di	81%
	Df	6%
	Lateral Length (ft)	7,500
	Avg. Royalty Burden	~25%
	Avg. Working Interest	~70%
	Avg. Net Revenue Interest	~53%

Note: See "Cautionary Statements" on page 3 for a description of EURs; Completed Well Costs (CWC) include drilling and completion expenses, royalties, LOE, gathering, transportation, production taxes and connection expenses.

(1) Assumes flat pricing of \$95/bbl oil and \$4.50/MMcf gas.

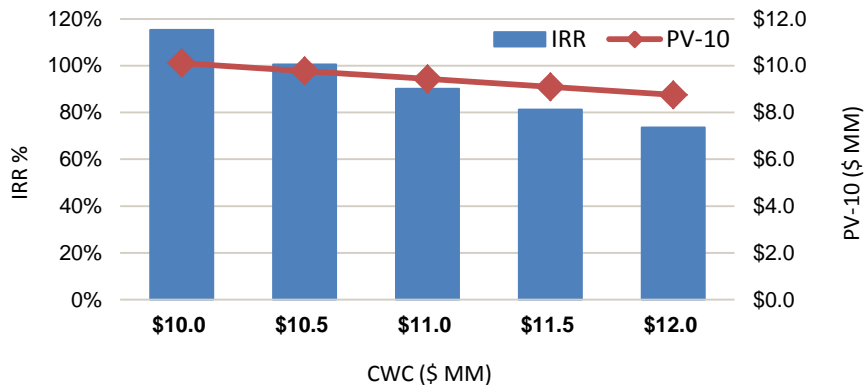
(2) Assumes \$9 MM CWC & \$4.50MMcf/gas.

(3) Gathering, transportation and processing fees incorporated; Gas differentials presented on a gross wellhead basis including differential uplift for high BTU/NGL content.

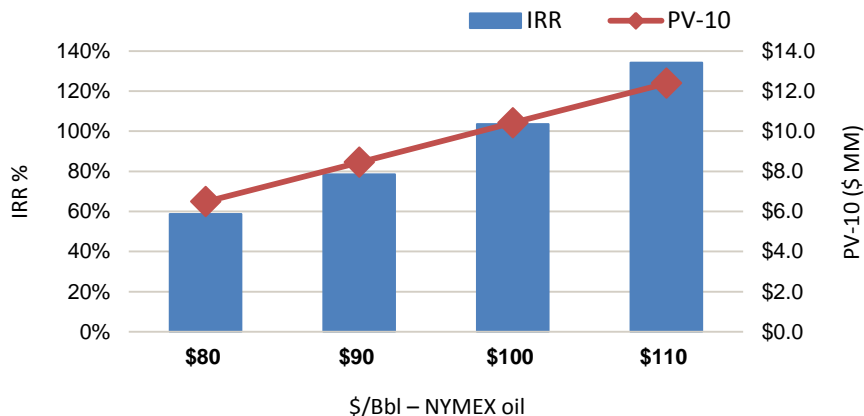
# New FBIR 801 MBoe Type Curve – MB/TFS

## EUR Increases by 39%

### Investment Sensitivity to Completed Well Cost <sup>(1)</sup>



### Investment Sensitivity to NYMEX Oil Price <sup>(2)</sup>



### Type Curve Details

Gross EUR	Oil (MBbl)	687
	Gas (MMcf)	687
	<b>Total (MBoe)</b>	<b>801</b>
Diffs <sup>(3)</sup>	Oil (% of NYMEX)	86%
	Gas (% of NYMEX)	74%
Other	IP (Boe/d)	2,042
	Spud to Production	90 days
	B factor	1.4
	Di	85%
	Df	8%
	Lateral Length (ft)	9,500
	Avg. Royalty Burden	~20%
	Avg. Working Interest	~69%
	Avg. Net Revenue Interest	~55%

Note: See “Cautionary Statements” on page 3 for a description of EURs; Completed Well Costs (CWC) include drilling and completion expenses, royalties, LOE, gathering, transportation, production taxes and connection expenses.

(1) Assumes flat pricing of \$95/bbl oil and \$4.50/MMcf gas.

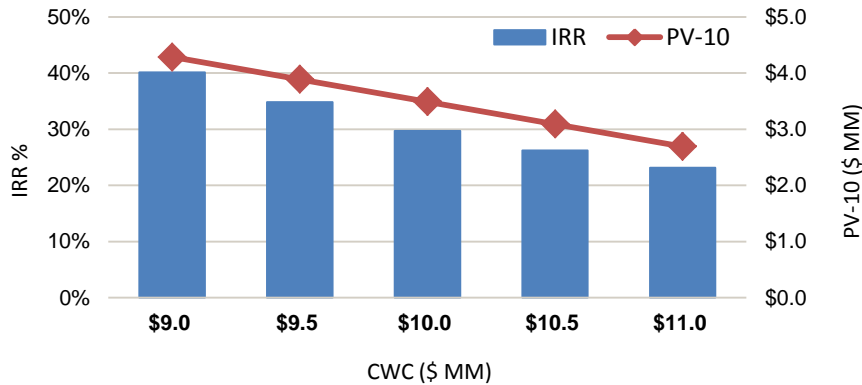
(2) Assumes \$11 MM CWC & \$4.50/MMcf gas.

(3) Gathering, transportation and processing fees incorporated; Gas differentials presented on a gross wellhead basis including differential uplift for high BTU/NGL content.

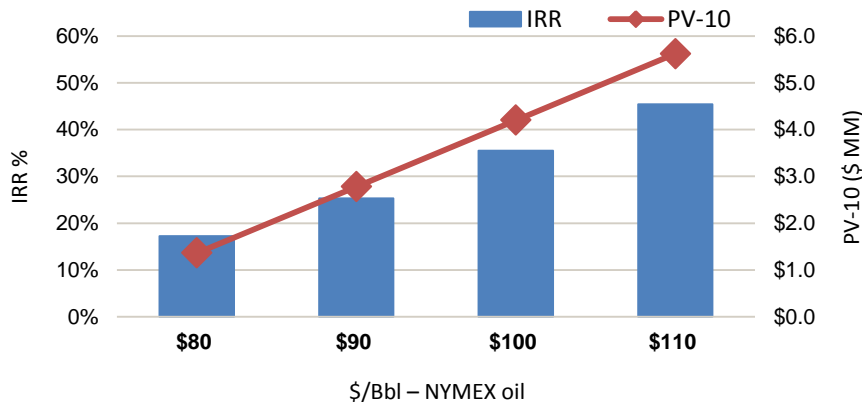
# New Williams County 477 MBoe Type Curve

## EUR Increases by 43%

### Investment Sensitivity to Completed Well Cost <sup>(1)</sup>



### Investment Sensitivity to NYMEX Oil Price <sup>(2)</sup>



### Type Curve Details

Gross EUR	Oil (MBbl)	415
	Gas (MMcf)	373
	<b>Total (MBoe)</b>	<b>477</b>
Diffs <sup>(3)</sup>	Oil (% of NYMEX)	86%
	Gas (% of NYMEX)	90%
Other	IP (Boe/d)	754
	Spud to Production	90 days
	B factor	1.3
	Di	74%
	Df	8%
	Lateral Length (ft)	9,500
	Avg. Royalty Burden	~20%
	Avg. Working Interest	~81%
	Avg. Net Revenue Interest	~65%

Note: See "Cautionary Statements" on page 3 for a description of EURs; Completed Well Costs (CWC) include drilling and completion expenses, royalties, LOE, gathering, transportation, production taxes and connection expenses.

(1) Assumes flat pricing of \$95/bbl oil and \$4.50/MMcf gas.

(2) Assumes \$10 MM CWC & \$4.50/MMcf gas.

(3) Gathering, transportation and processing fees incorporated; Gas differentials presented on a gross wellhead basis including differential uplift for high BTU/NGL content.

# Derivative Detail as of 3.21.14

## Oil Hedge Summary

	FY 2014				FY 2015			FY 2016		
	Volume (Bbls)	Ceiling / Swap Price <sup>(1)</sup>	Floor Purchased <sup>(1)</sup>	Floor Sold <sup>(1)</sup>	Volume (Bbls)	Ceiling / Swap Price <sup>(1)</sup>	Floor Purchased <sup>(1)</sup>	Volume (Bbls)	Ceiling / Swap Price <sup>(1)</sup>	Floor Purchased <sup>(1)</sup>
Three-Way Collars	280,500	\$99.59	\$95.00	\$70.00	-	-	-	-	-	-
Collars	9,217,750	\$96.52	\$88.86	-	7,426,750 <sup>(2)</sup>	\$93.88	\$86.01	-	-	-
Swaps	-	-	-	-	1,095,000 <sup>(2)</sup>	\$91.17	-	2,196,000 <sup>(3)</sup>	\$88.30	-
Purchased Floors	184,000	-	\$90.00	-	-	-	-	-	-	-
<b>Total (Bbls)</b>		<b>9,682,250</b>				<b>8,521,750</b>			<b>2,196,000</b>	
<b>Total (Bbls/d)</b>		<b>26,527</b>				<b>23,347</b>			<b>6,000</b>	
<b>Wtd. Avg. Price (\$/Bbl) <sup>(4)</sup></b>		<b>\$89.06</b>				<b>\$86.67</b>			<b>\$88.30</b>	

## Gas Hedge Summary

	FY 2014				FY 2015			FY 2016		
	Volume (MMBtu)	Ceiling / Swap Price <sup>(1)</sup>	Floor Purchased <sup>(1)</sup>	Floor Sold <sup>(1)</sup>	Volume (MMBtu)	Ceiling / Swap Price <sup>(1)</sup>	Floor Purchased <sup>(1)</sup>	Volume (MMBtu)	Ceiling / Swap Price <sup>(1)</sup>	Floor Purchased <sup>(1)</sup>
Collars	9,132,500	\$4.40	\$3.90	-	6,387,500	\$4.68	\$4.00	732,000	\$ -	\$ 4.00
Swaps	-	-	-	-	-	-	-	-	-	-
<b>Total (MMBtu)</b>		<b>9,132,500</b>				<b>6,387,500</b>			<b>732,000</b>	
<b>Total (MMBtu/d)</b>		<b>25,021</b>				<b>17,500</b>			<b>2,000</b>	
<b>Wtd. Avg. Price (\$/MMBtu) <sup>(4)</sup></b>		<b>\$3.90</b>				<b>\$4.00</b>			<b>\$4.00</b>	

## Combined Oil and Gas Hedge Summary

	FY 2014	FY 2015	FY 2016
<b>Total (Boe)</b>	<b>11,204,333</b>	<b>9,586,333</b>	<b>2,318,000</b>
<b>Total (Boe/d)</b>	<b>30,697</b>	<b>26,264</b>	<b>6,333</b>

(1) Weighted average price.

(2) Includes 3,000 Bbl/d of swaps and 3,000 Bbl/d of collars extendable into 2016 at the counterparty's option.

(3) Includes 6,000 Bbl/d of swaps extendable into 2017 at the counterparty's option.

(4) Based on floors purchased for collars and 3 way collars.

# Oil Hedging Details as of 3.21.14

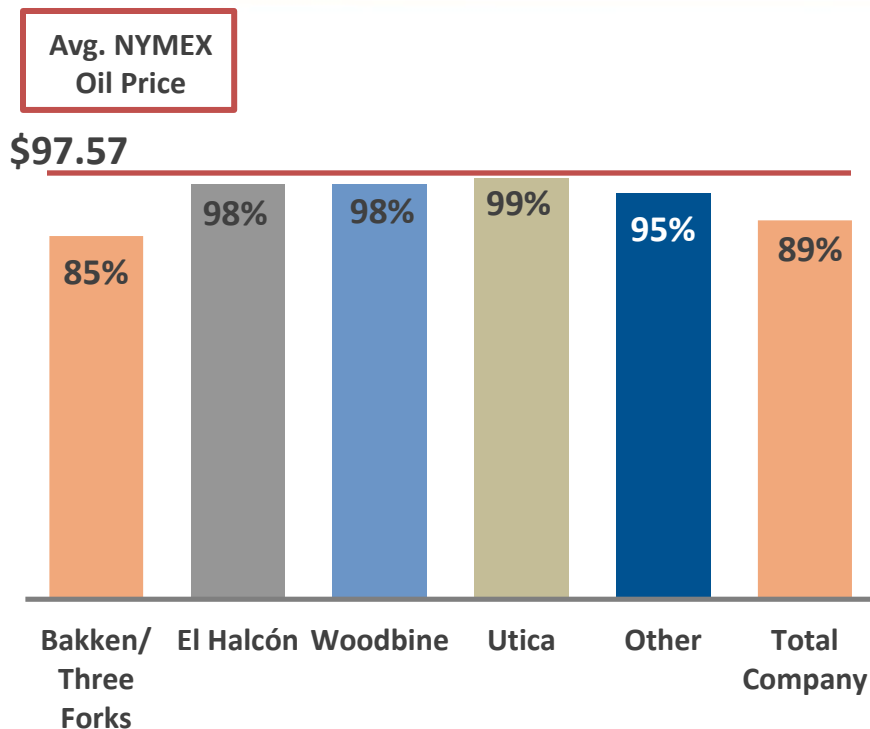
- The following table details the expected impact to pre-tax income (in millions, except prices) from the settlement of our derivative contracts at various NYMEX oil prices

Period	Oil Prices (\$/Bbl)				
	\$70.00	\$80.00	\$90.00	\$100.00	\$110.00
Q1'14	\$45.2	\$21.5	\$0.7	(\$8.7)	(\$31.9)
Q2'14	45.5	21.6	0.7	(8.8)	(32.3)
Q3'14	43.9	19.3	(0.7)	(11.0)	(34.4)
Q4'14	43.9	19.3	(0.7)	(11.0)	(34.4)
Q1'15	37.4	13.4	0.3	(18.1)	(42.2)
Q2'15	37.9	13.5	0.3	(18.3)	(42.7)
Q3'15	28.4	10.0	0.3	(14.3)	(32.7)
Q4'15	28.4	10.0	0.3	(14.3)	(32.7)

*Note: Assumes \$5 LLS to WTI differential.*

# Oil & Gas Marketing

4Q13 HK Oil Differentials by Area <sup>(1)</sup>



4Q13 Total HK Differentials

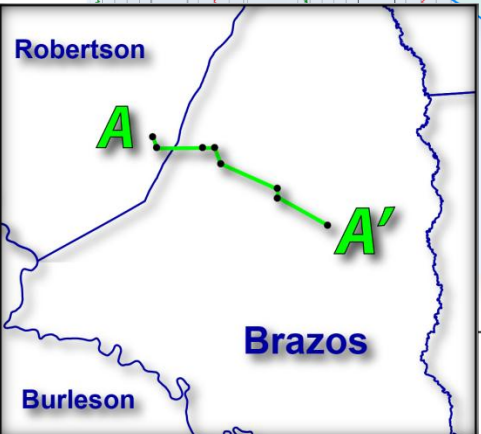
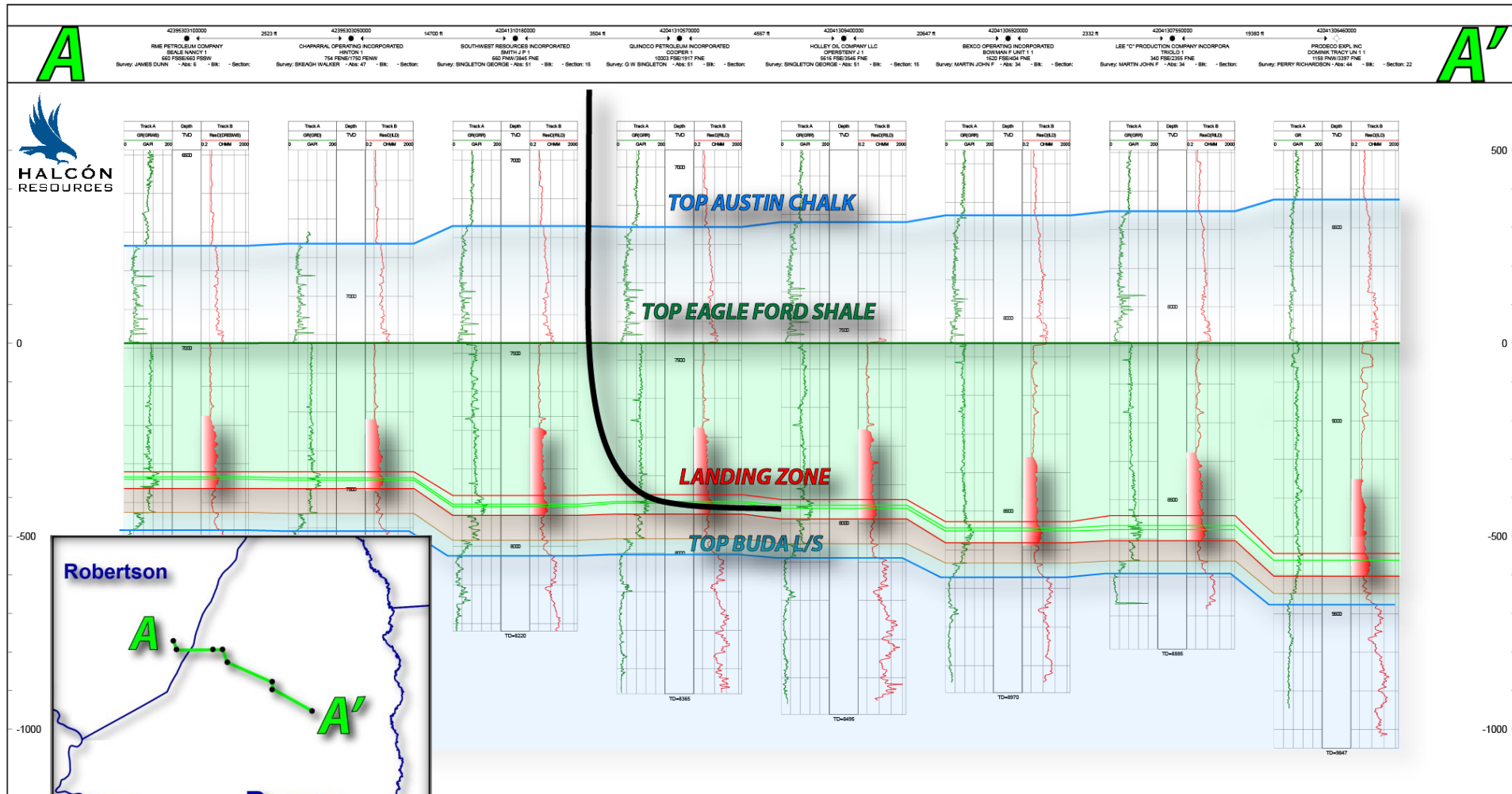
Oil Differential (vs. NYMEX Oil)	89%
NGL Differential (vs. NYMEX Oil)	39%
Gas Differential (vs. NYMEX Gas)	90%

## 2014 Marketing Highlights

- Williston Basin
  - Oil Marketing
    - Expect 85-90% of production to be connected to pipeline by year-end
      - Potential to reduce transportation costs by \$1-2/Boe
  - Gas Marketing
    - All existing gas production under contract to be tied into pipeline with midstream companies
- El Halcón
  - Oil Marketing
    - No constraints on takeaway capacity
    - 100% of oil is trucked from the wellhead
    - No long-term contracts for oil production
  - Gas Marketing
    - No constraints on takeaway capacity
    - Currently receiving NGL uplift of \$3.50-\$4.50/Mcf

(1) Data not adjusted for hedge impact; 4Q13 differentials include non-core assets in East Texas currently under contract for sale.

# El Halcón Cross Section



# Halcón Ownership

(in thousands)

Owner	Basic		Dilutive Securities						Fully Diluted		Net Diluted <sup>(6)</sup>	
	Shares	Percent	Conv. Debt <sup>(1)</sup>	Conv. Preferred <sup>(2)</sup>	Warrants <sup>(3)</sup>	RSAs <sup>(4)</sup>	PSUs <sup>(5)</sup>	Options	Shares	Percent	Shares	Percent
HALRES LLC <sup>(7)</sup>	-	-	64,371	-	36,667	-	-	-	101,038	17.0%	-	0.0%
Insiders/Affiliates <sup>(8)</sup>	184,953	44.5%	-	7,074	-	2,095	1,604	7,606	203,333	34.1%	184,953	44.5%
Public Shareholders	229,875	55.4%	-	48,968	-	-	-	-	278,844	46.8%	229,875	55.4%
Employees	357	0.1%	-	-	-	3,269	-	8,717	12,343	2.1%	357	0.1%
<b>Shares Outstanding</b>	<b>415,185</b>	<b>100%</b>	<b>64,371</b>	<b>56,043</b>	<b>36,667</b>	<b>5,365</b>	<b>1,604</b>	<b>16,322</b>	<b>595,557</b>	<b>100%</b>	<b>415,186</b>	<b>100%</b>

(1) Not convertible into common shares until 2.8.14 at \$4.50/share; calculated to include accrued PIK interest. Company can redeem all convertible debt outstanding after 2.8.14 at principal without penalty.

(2) Represents perpetual preferred stock convertible by holders into HK common shares at anytime at \$6.16/share.

(3) HALRES LLC warrants exercisable at \$4.50/share.

(4) Restricted Stock Awards (RSAs) as of 2.27.14.

(5) Performance Share Units (PSUs) as of 2.27.14.

(6) Net diluted shares for warrants, options and RSAs calculated using treasury method and 1Q14 HK avg. stock price of \$3.66 per share through 3.21.14. Shares underlying convertible debt and preferred stock are included in net diluted share count only if calculated to be dilutive in any given period.

(7) Includes EnCap Investments L.P., Liberty Energy Holdings LLC, Mansfeldt Investment Corp and members of the Halcón management team; management led group owns approximately 10% of HALRES LLC.

(8) Includes common shares issued to Petro-Hunt Holdings, LLC and Canada Pension Plan Investment Board, both with insider/affiliate classification due to Board representation.



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