

An oil drilling rig is illuminated at night, standing in a field of rolling hills under a dark blue sky. The rig's lights create a bright focal point against the dark landscape.

**CLR Investor Update
Raymond James Conference
March 4th, 2013**

INDEPENDENT

MEANS



Continental
RESOURCES

Forward-Looking Information

Cautionary Statement for the Purpose of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995:

This presentation includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements included in this presentation other than statements of historical fact, including, but not limited to, statements or information concerning the Company's future operations, performance, financial condition, production and reserves, schedules, plans, timing of development, returns, budgets, costs, business strategy, objectives, and cash flow, are forward-looking statements. When used in this presentation, the words "could," "may," "believe," "anticipate," "intend," "estimate," "expect," "project," "budget," "plan," "continue," "potential," "guidance," "strategy," and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Forward-looking statements are based on the Company's current expectations and assumptions about future events and currently available information as to the outcome and timing of future events. Although the Company believes that the expectations reflected in the forward-looking statements are reasonable and based on reasonable assumptions, no assurance can be given that such expectations will be correct or achieved or that the assumptions are accurate. When considering forward-looking statements, readers should keep in mind the risk factors and other cautionary statements described under Part I, Item 1A. Risk Factors included in the Company's Annual Report on Form 10-K for the year ended December 31, 2012, registration statements and other reports filed from time to time with the Securities and Exchange Commission (SEC), and other announcements the Company makes from time to time.

The Company cautions readers that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond the Company's control, incident to the exploration for, and development, production, and sale of, crude oil and natural gas. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating crude oil and natural gas reserves and in projecting future rates of production, cash flows and access to capital, the timing of development expenditures, and the other risks described under Part I, Item 1A. Risk Factors in the Company's Annual Report on Form 10-K for the year ended December 31, 2012, registration statements and other reports filed from time to time with the SEC, and other announcements the Company makes from time to time.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. Should one or more of the risks or uncertainties described in this presentation occur, or should underlying assumptions prove incorrect, the Company's actual results and plans could differ materially from those expressed in any forward-looking statements. All forward-looking statements are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that the Company, or persons acting on its behalf, may make.

Except as otherwise required by applicable law, the Company disclaims any duty to update any forward-looking statements to reflect events or circumstances after the date of this presentation.

Continental Resources, Inc.

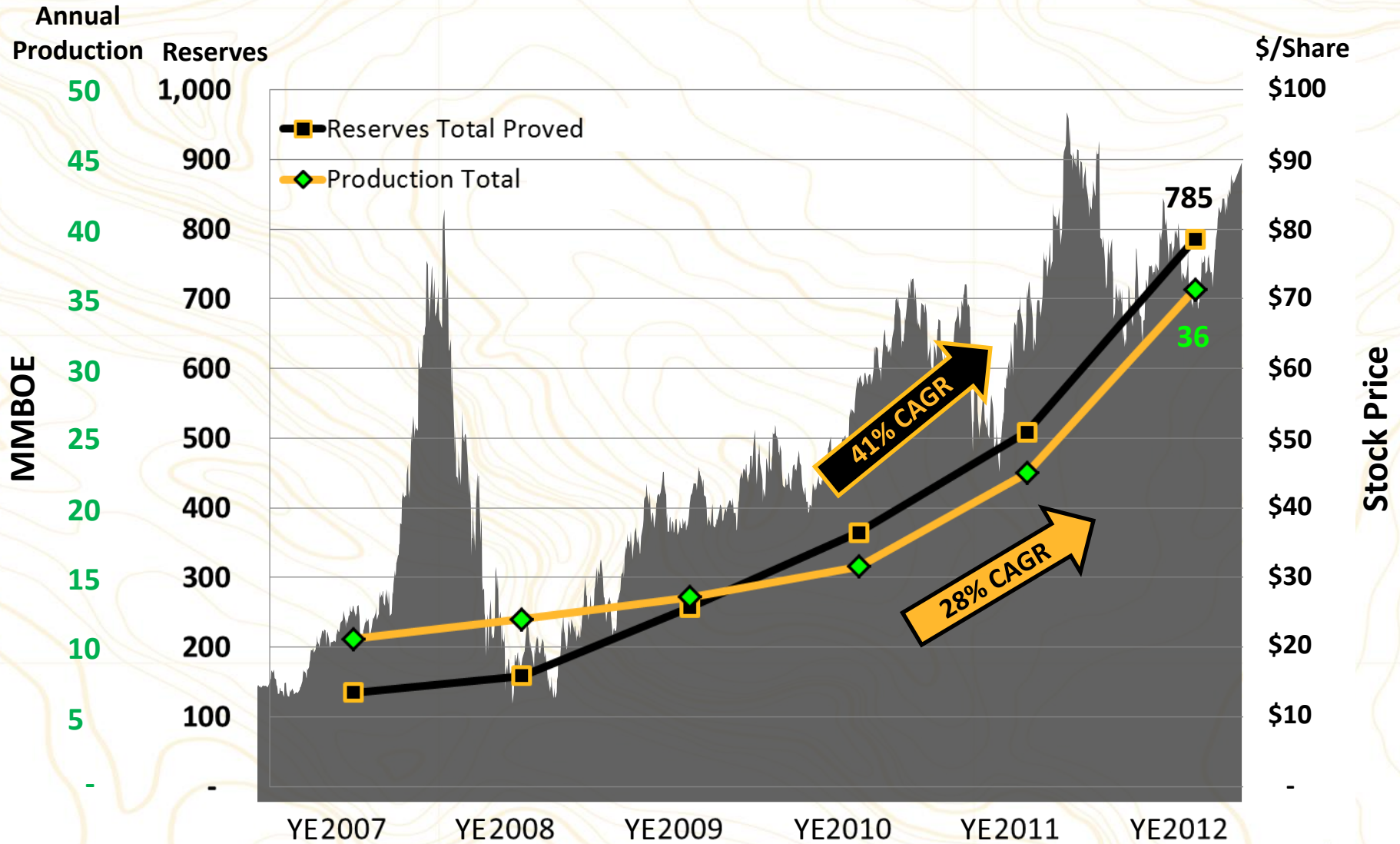
- 🔥 #1 oil producer in Williston Basin
- 🔥 #1 liquids producer in the Rockies*
- 🔥 785 MMBoe proved reserves at YE2012 – 54% YOY gain
- 🔥 Strong 2012 operating results
 - ✓ Averaged 106,831 Boepd in 4Q — 42% increase over 4Q 2011
 - ✓ \$594.5 Million EBITDAX in 4Q — 44% increase over 4Q 2011
 - ✓ \$2.0 Billion EBITDAX for full-year 2012; +51% YOY**
- 🔥 58% production growth in 2012 (YOY)

**Rocky Mountain Oil Journal **See reconciliation of EBITDAX to GAAP net income in the Appendix.*

INDEPENDENT MEANS

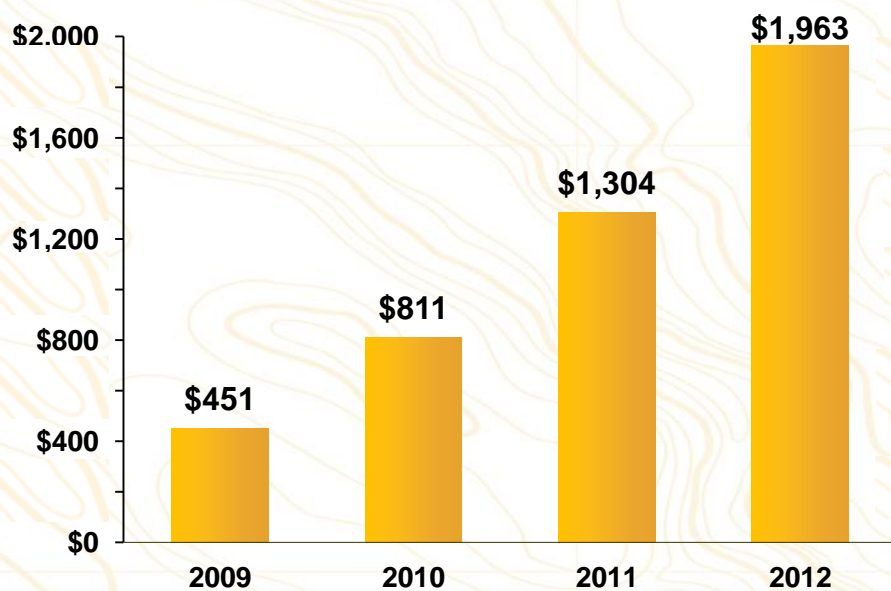


Production, Reserve and Stock Growth

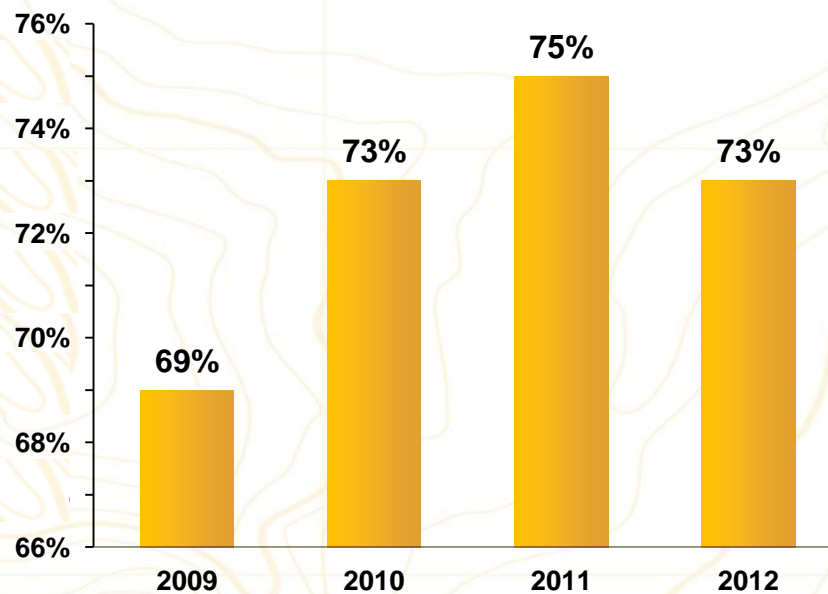


Strong EBITDAX and Cash Margins

EBITDAX (\$MM)¹

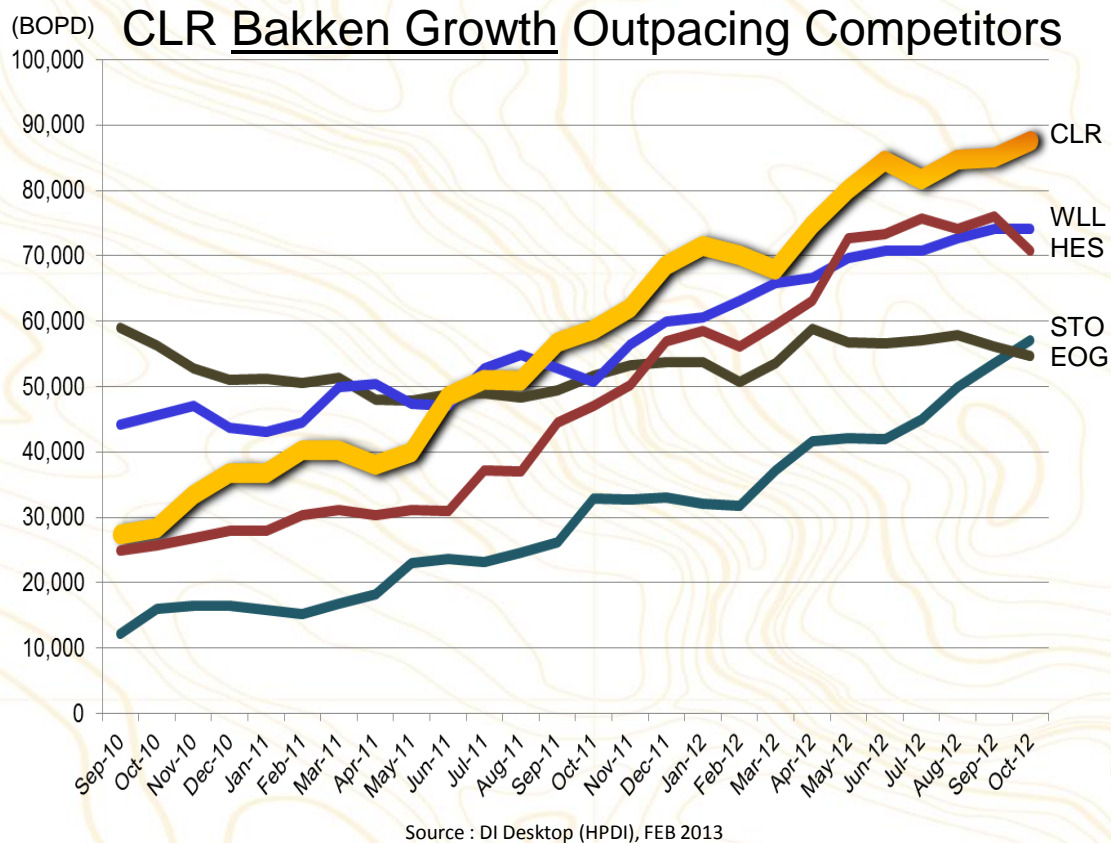


Cash Margins (%)



¹ See reconciliation of EBITDAX to GAAP net income in the Appendix.

#1 Producer, Driller and Leasehold Owner

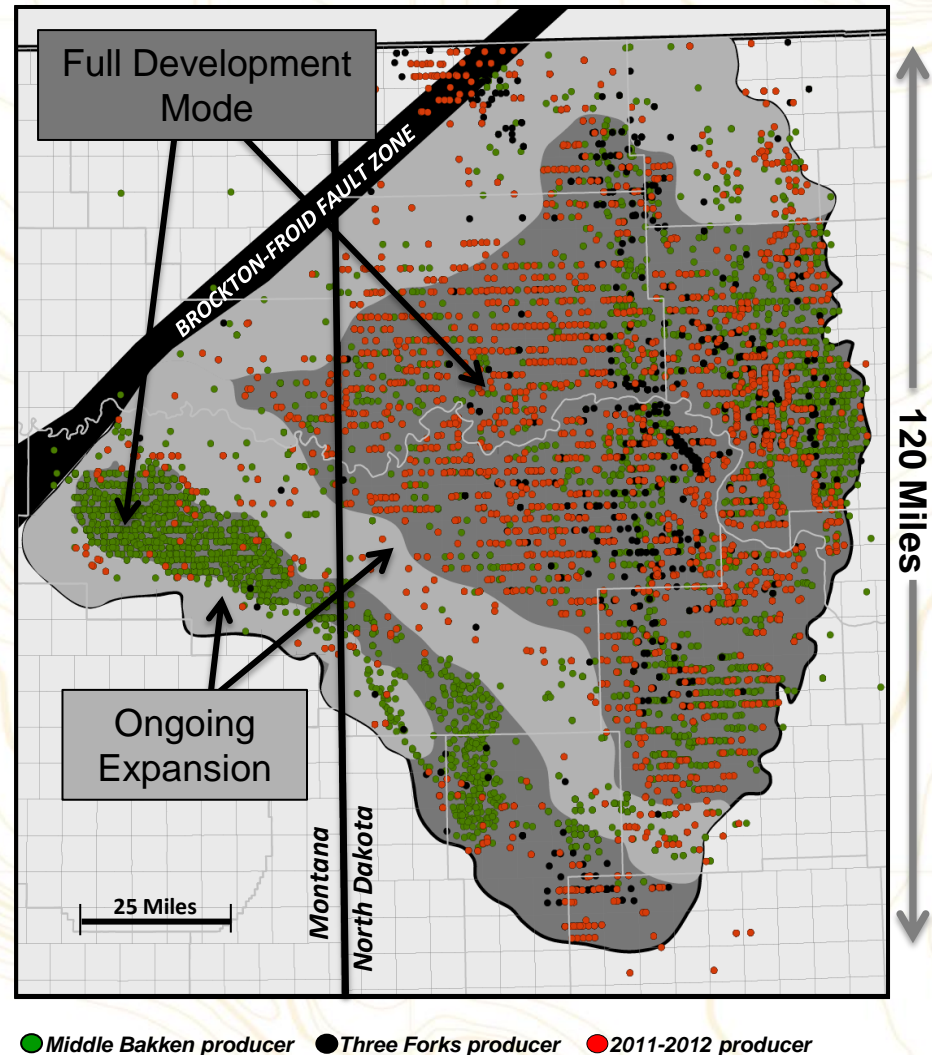


- 🔥 68 MBoepd for 4Q12, (13% of basin production)
- 🔥 21 CLR operated rigs, (11% of industry)
- 🔥 1.1 MM net acres
- 🔥 Net unrisked potential*
 - 3.0 BBoe
 - 3,439 locations
- 🔥 Assets continue to grow:
 - Vertically
 - Geographically
 - Strategically

*Based on 320-acre spacing, as of 12/31/12.

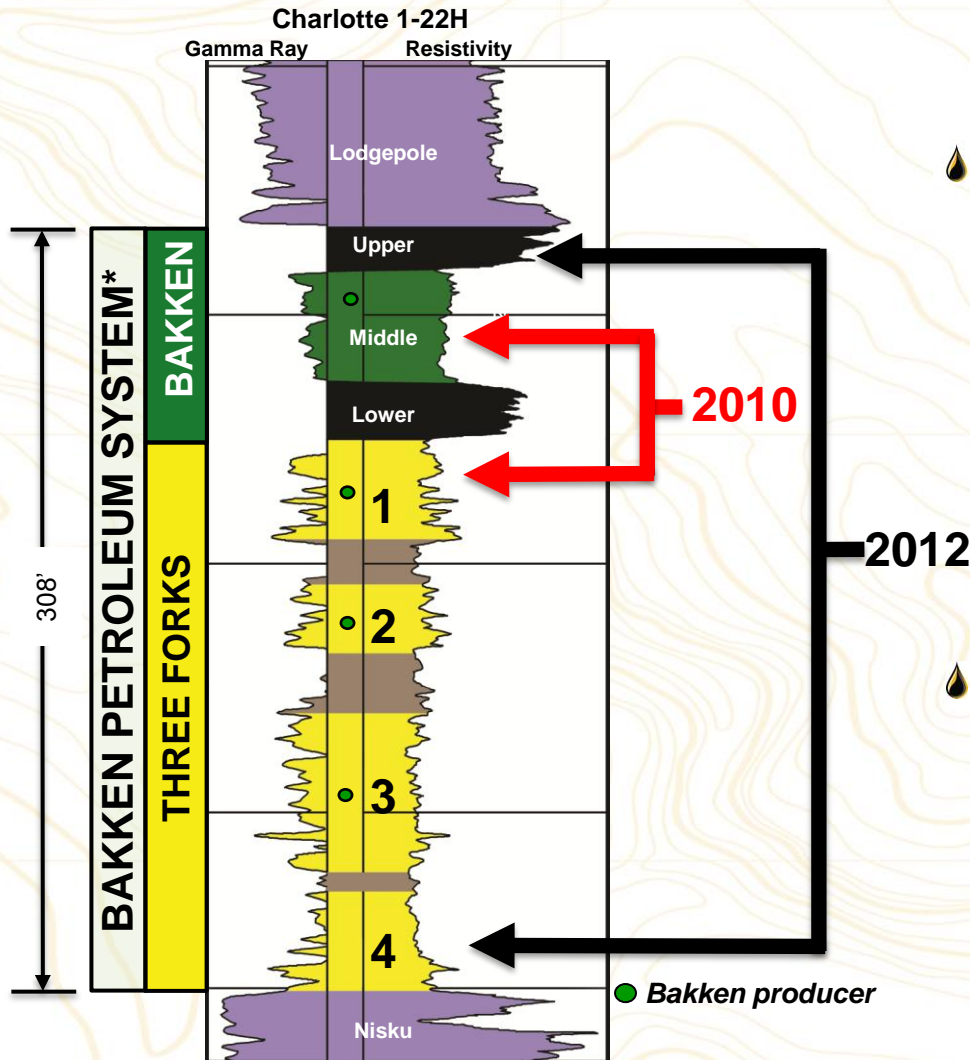
MB + TF1: Early Stages of Development

- 🔥 Massive oil field of unprecedented magnitude
 - 15,000 sq. miles
 - 87% proven productive
- 🔥 Real oil play
 - 24 BBoe technically recoverable*
 - 83% crude oil
- 🔥 We're just getting started!
 - Less than 1 well drilled per 1280-acre unit
 - 4-to-8 wells per zone to be drilled in full development



*24 BBoe = 20 Bbo (3.5%) + 4 Bboe Natural Gas at 320-acre spacing per zone, (Oct. 2010), not including any reserves from the lower TF benches.

World Class Oil Field



- 🔥 Prior to Lower TF:
 - 577 BBo in place (2010)
 - 24 BBoe recoverable**
 - 20 BBo (3.5% recovery factor)
 - 320-acre spacing per zone

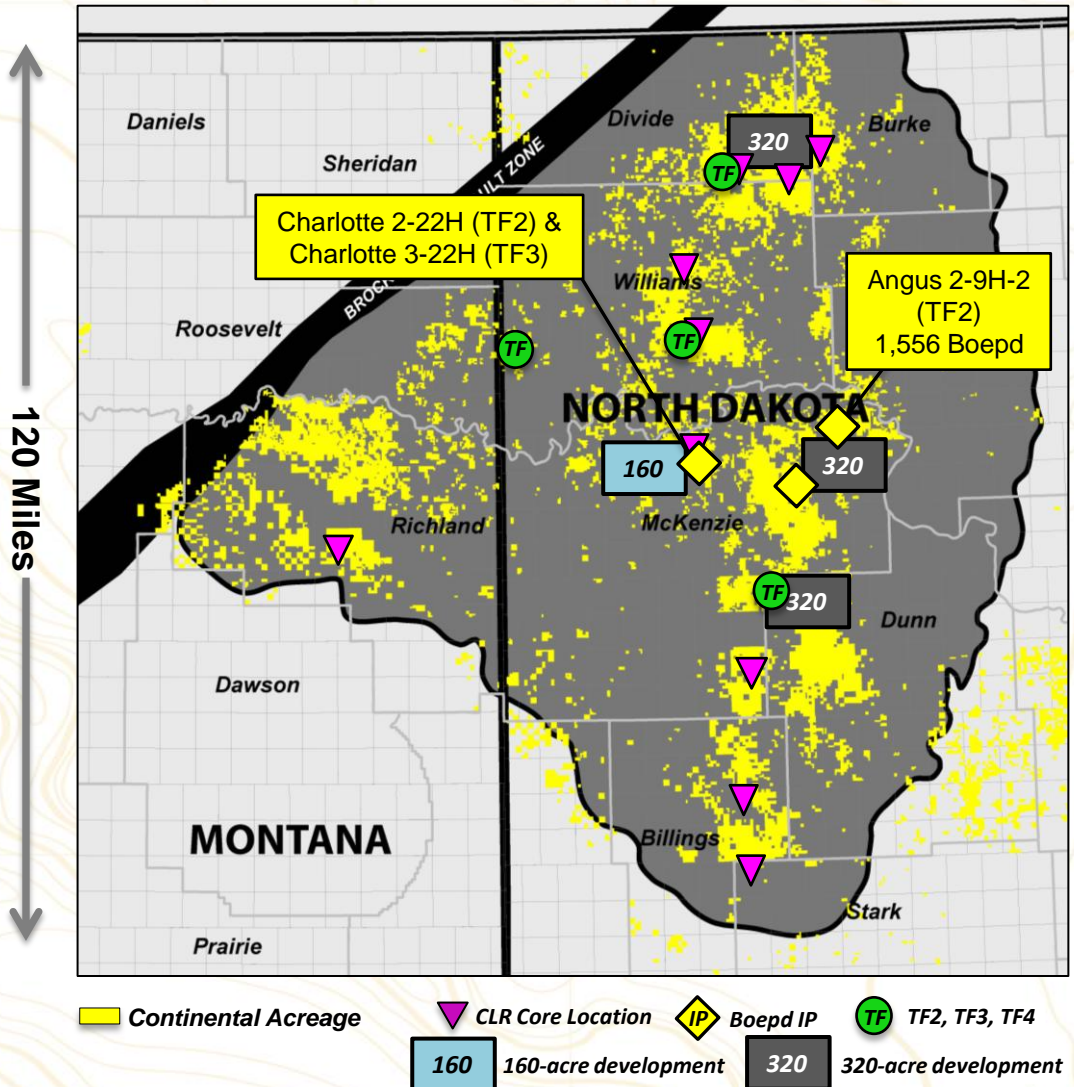
- 🔥 Now: Estimate +57%
 - 903 BBo in place (2012)
 - 32 BBo recoverable @ 3.5%
 - 36 BBo @ 4%
 - 45 BBo @ 5%

*The Bakken Petroleum System ranges in thickness from 250 feet to 400 feet

**24 BBoe = 20 Bbo (3.5%) + 4 Bboe Natural Gas at 320-acre spacing per zone, (Oct. 2010), not including any reserves from the lower TF benches.

Commanding Bakken Acreage Position

- 🔥 Drilled ~20% of all TF wells*
- 🔥 1.1 million net acres YE 2012
 - +24% YOY since 2011
- 🔥 Proved separation of MB + TF1
- 🔥 10-well coring program

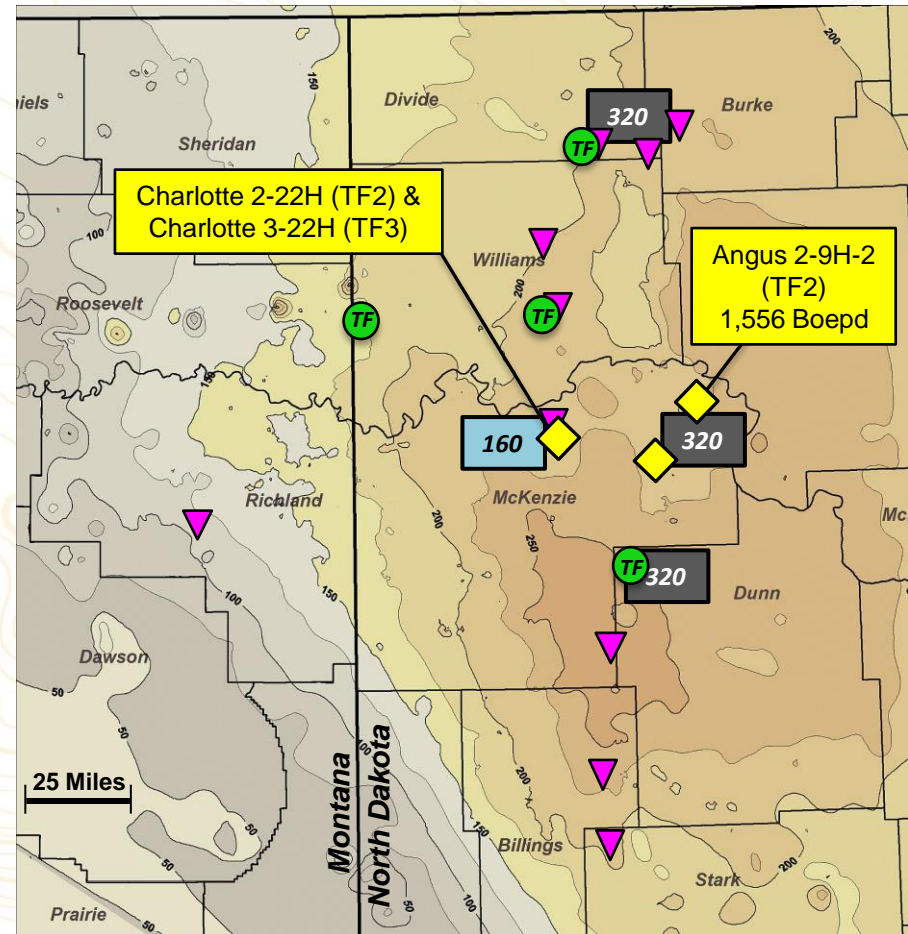


*Source: IHS, 1390 TF industry wells (2/20/13)

CLR: Three Forks Pioneer

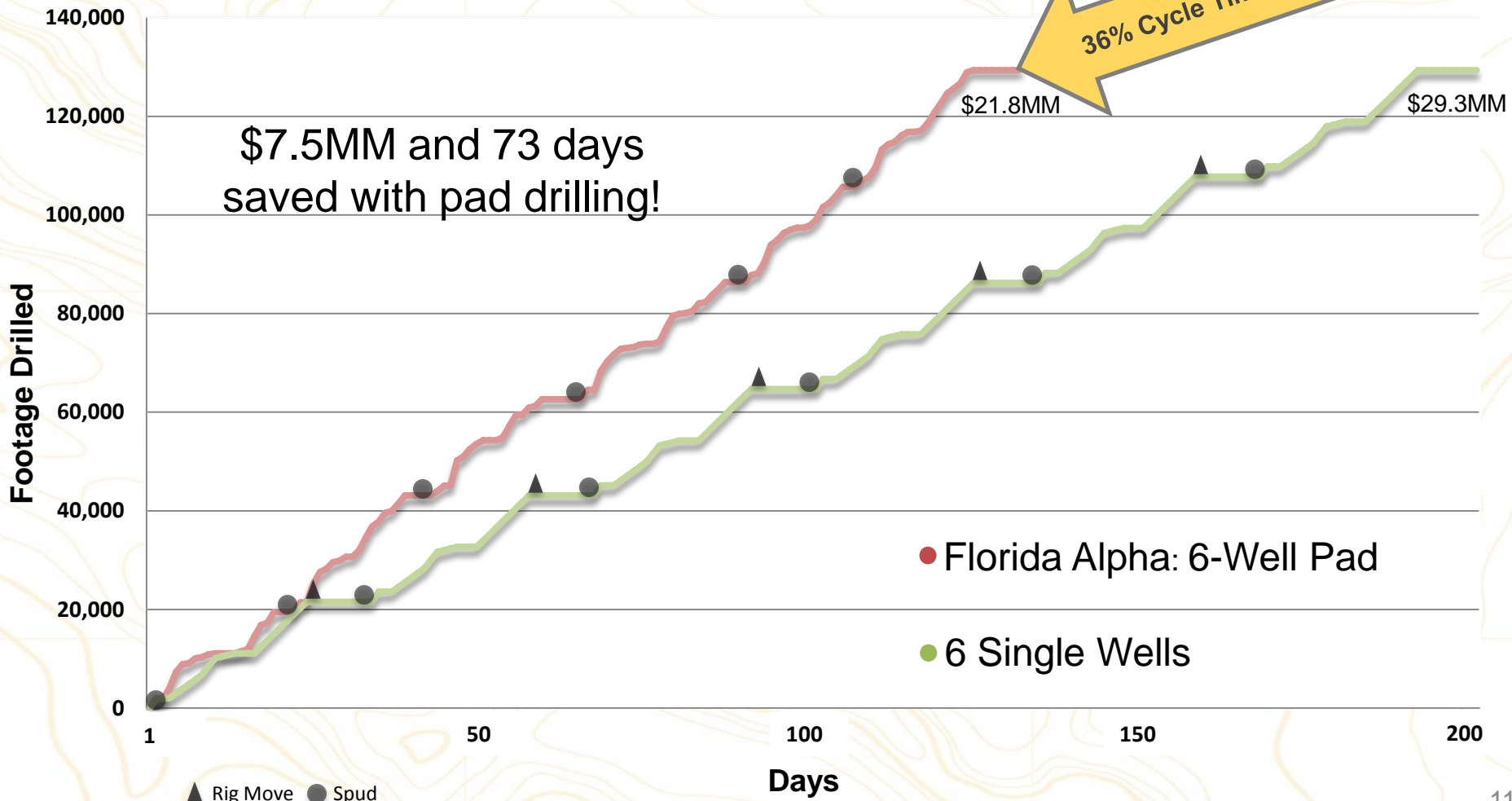
- 🔥 Completed first TF2 and TF3 producers
- 🔥 10-well coring program
- 🔥 Bakken exploration capex 2013*
 - Twenty well lower TF exploratory and appraisal: \$70MM
 - 320-acre density tests: \$161MM
 - 160-acre density tests: \$36MM

Three Forks Isopach Map



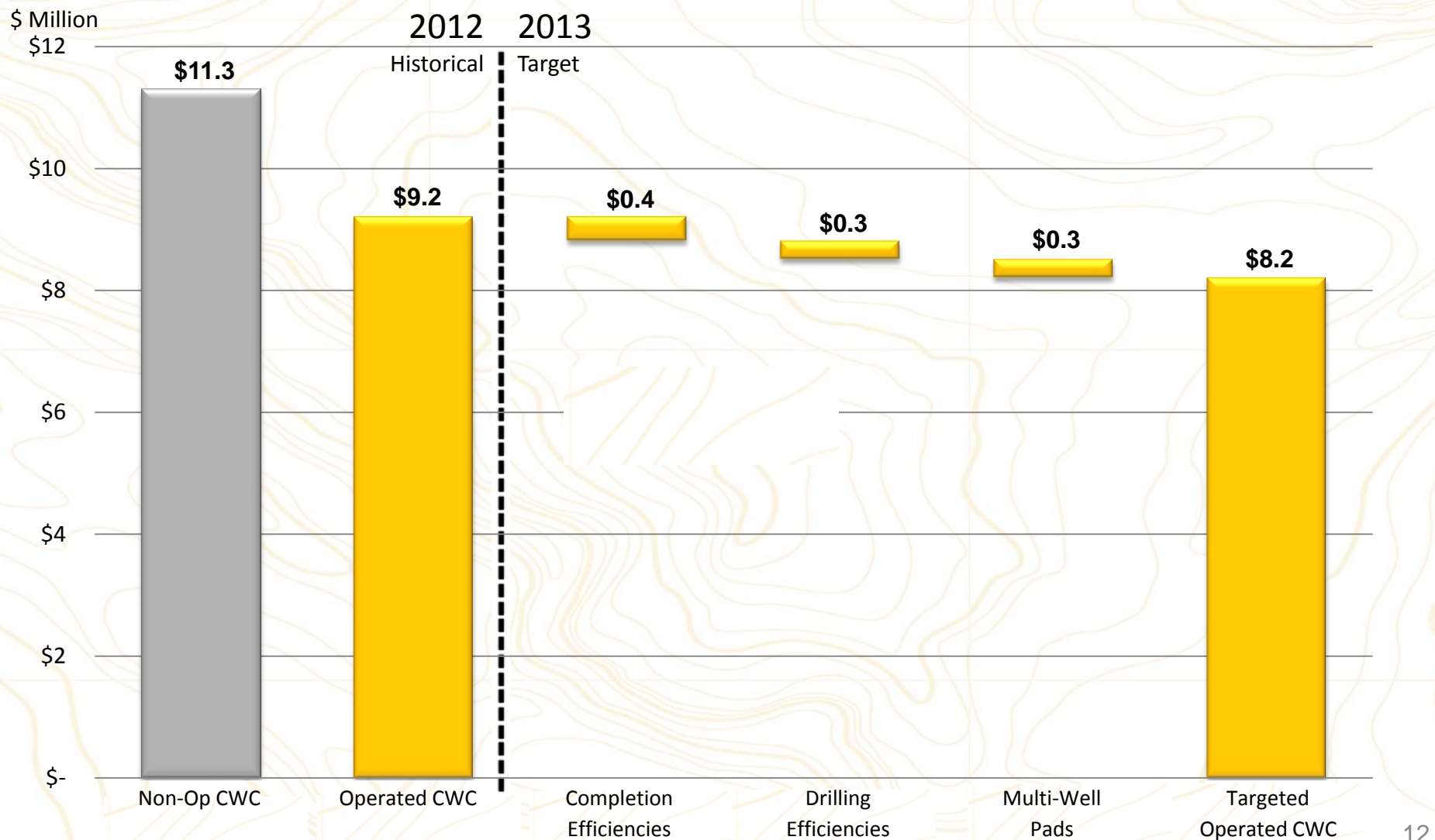
*47 wells budgeted.

Pad Drilling = Lower Completed Well Cost



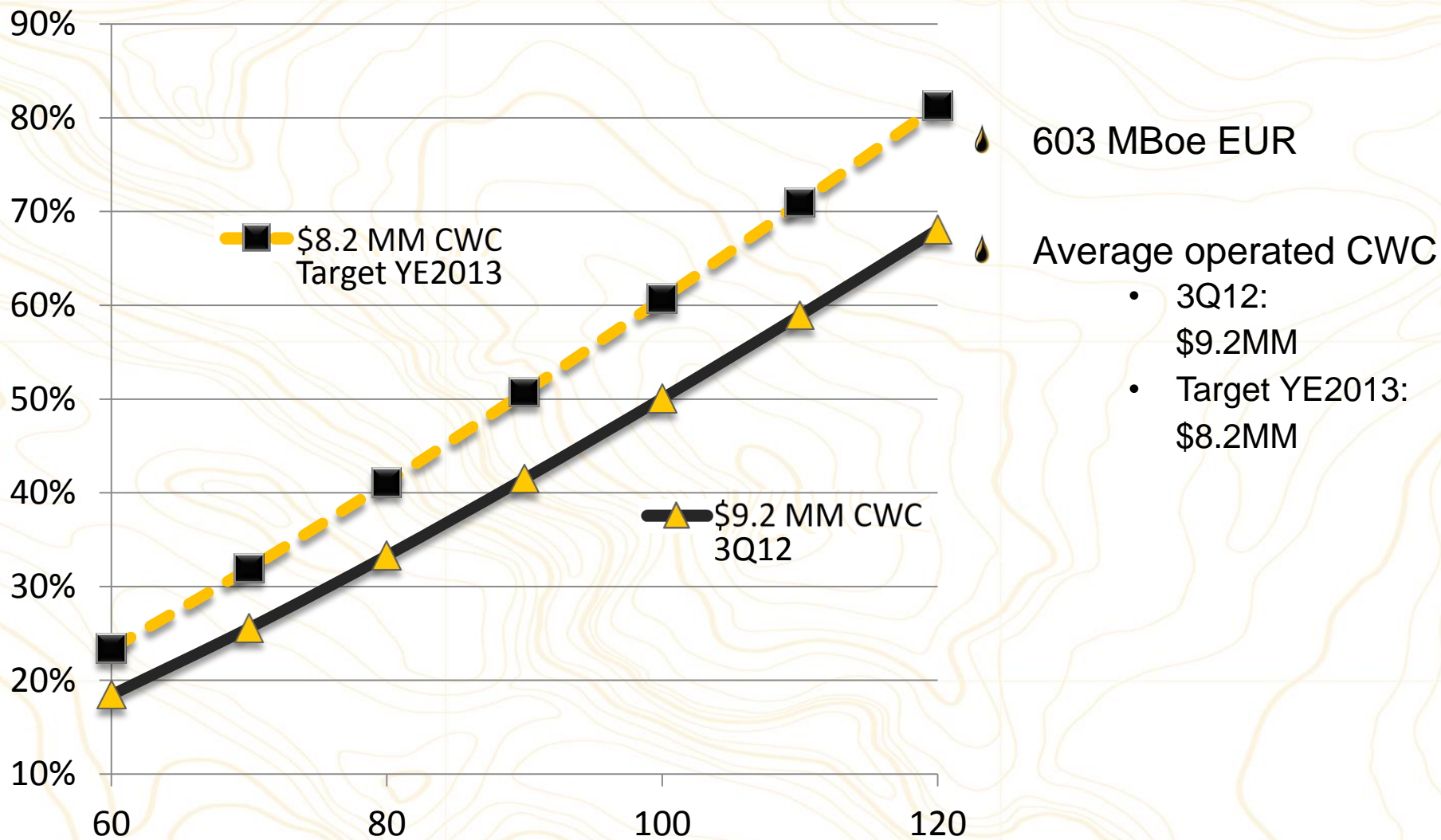
*Spud to rig release cost

Low Cost Bakken Operator



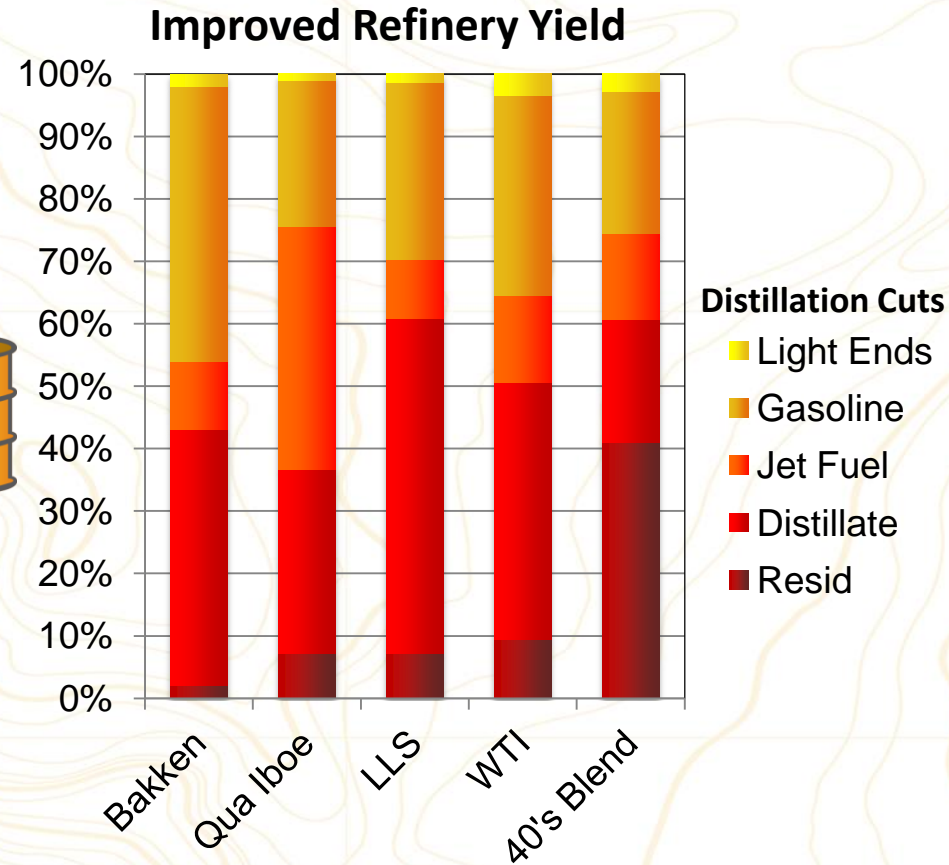
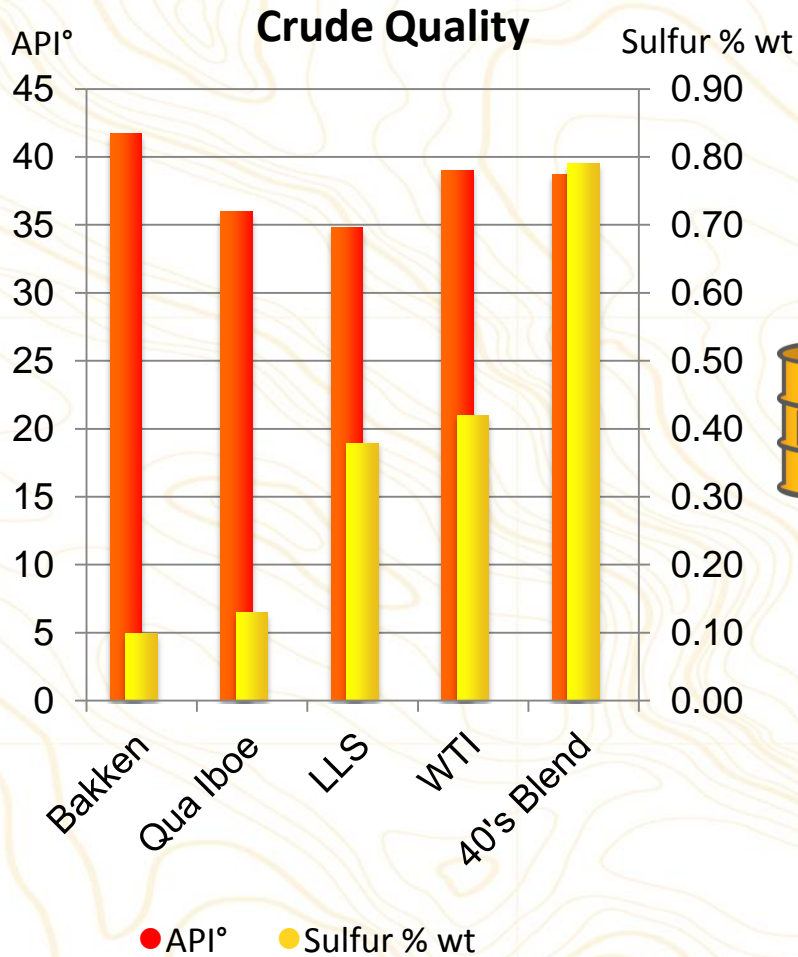
*Weighted average well cost, pads and single wells. CWC = Completed well cost

Bakken Well Economics

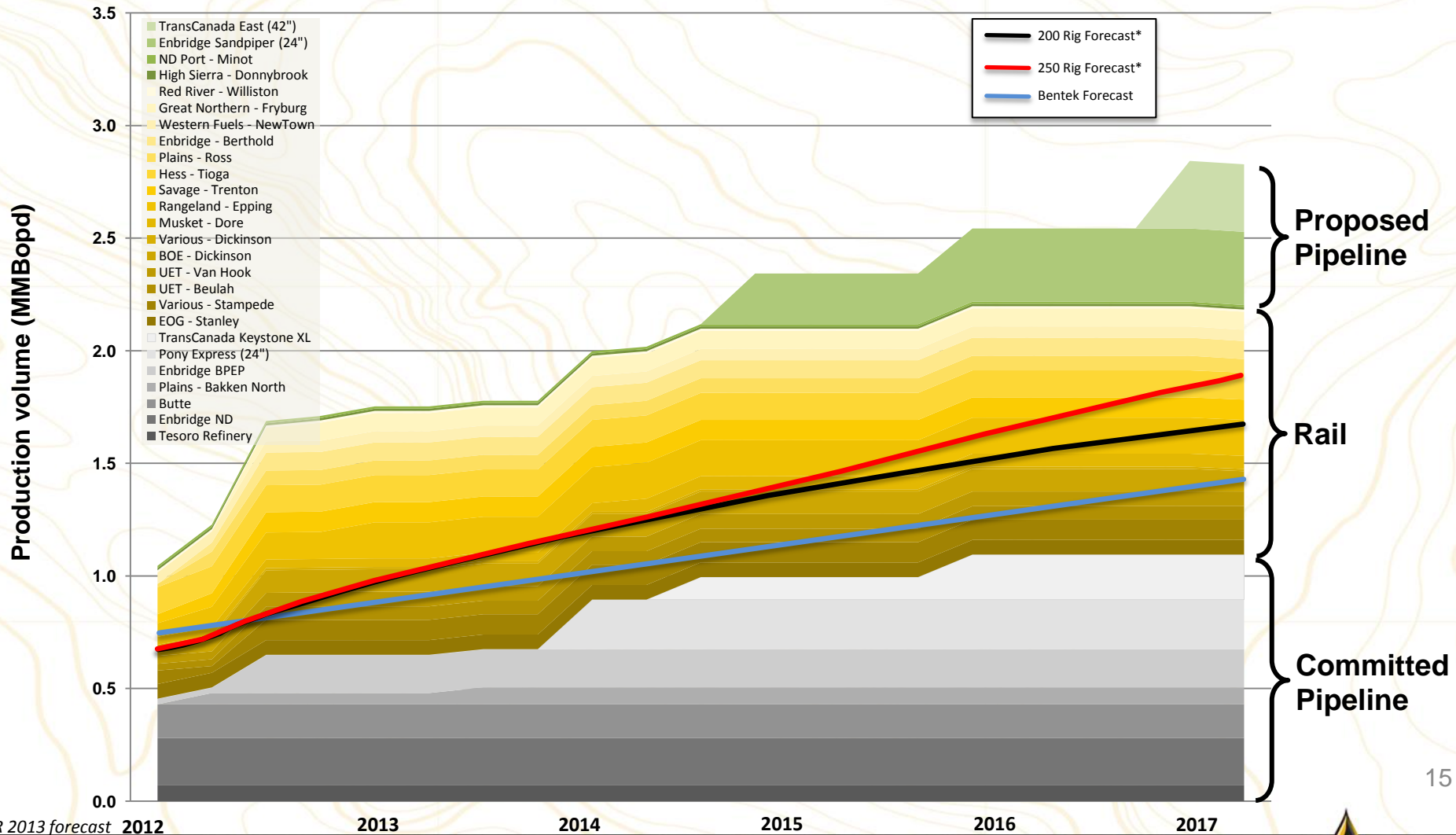


*Assumes \$7 differential. CWC = Completed Well Cost

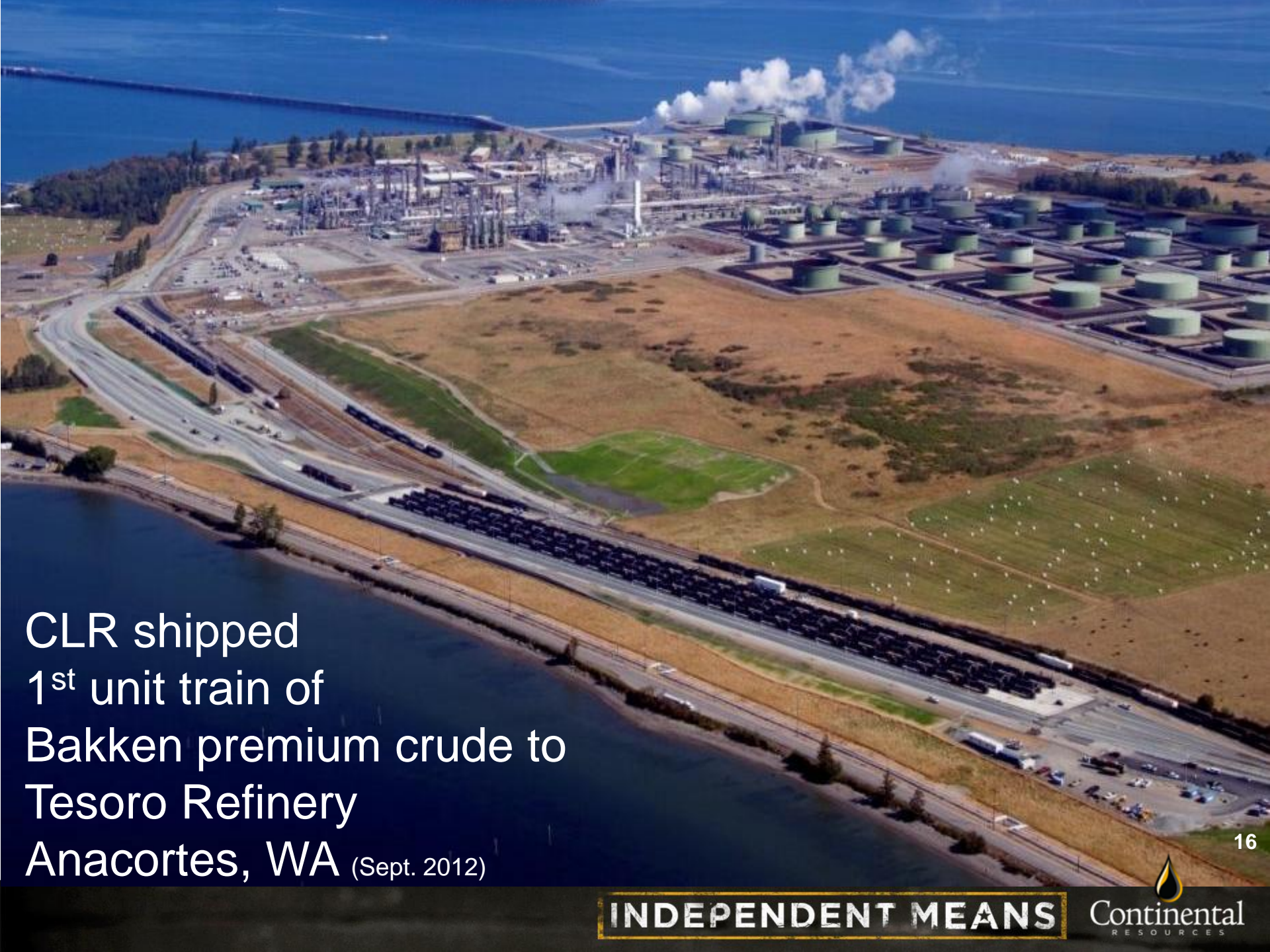
America's Premium Light Sweet Crude



Williston Basin Evacuation Capacity



*CLR 2013 forecast 2012



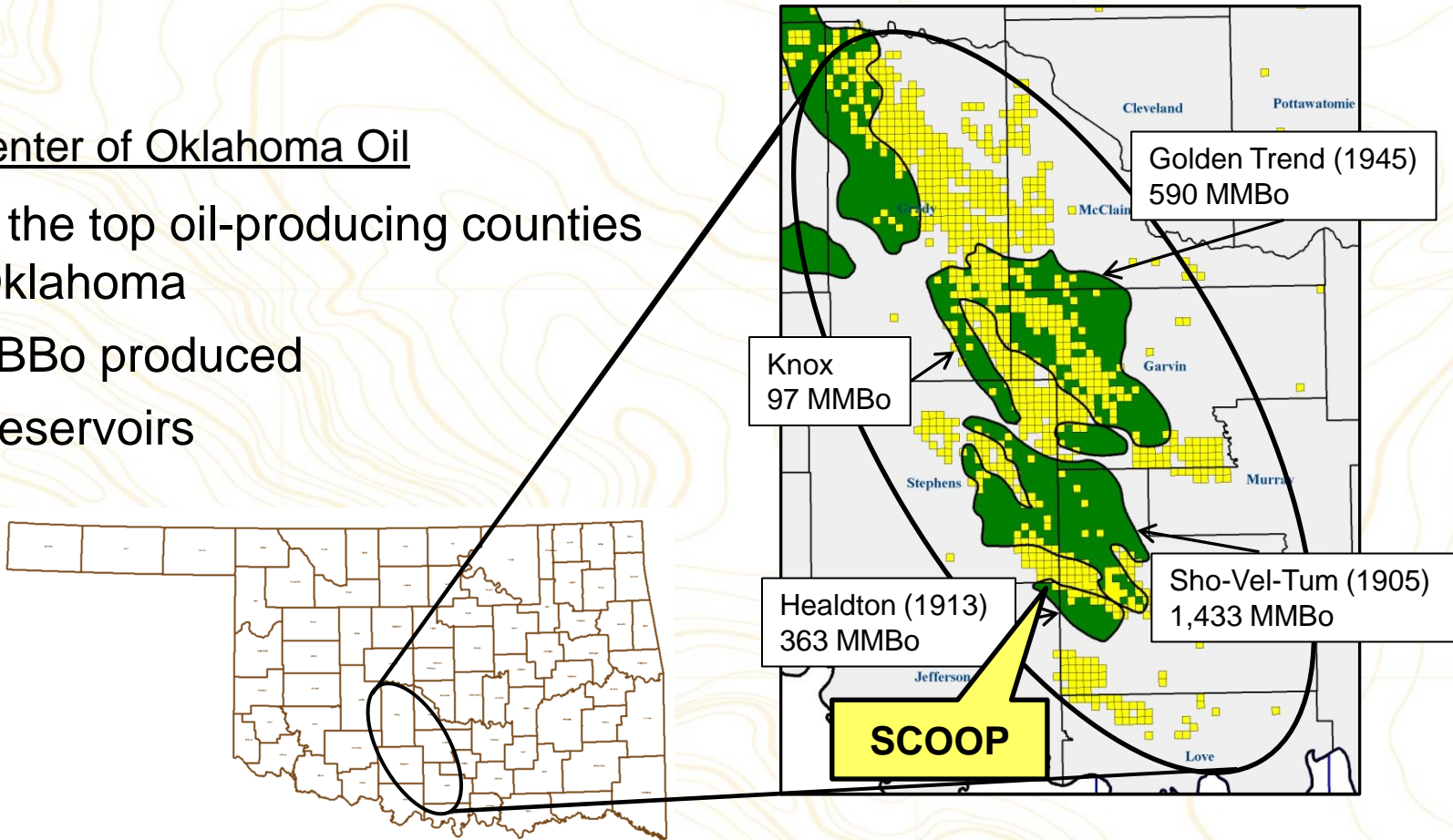
CLR shipped
1st unit train of
Bakken premium crude to
Tesoro Refinery
Anacortes, WA (Sept. 2012)

The Scope of the SCOOP:

South Central Oklahoma Oil Province

Epicenter of Oklahoma Oil

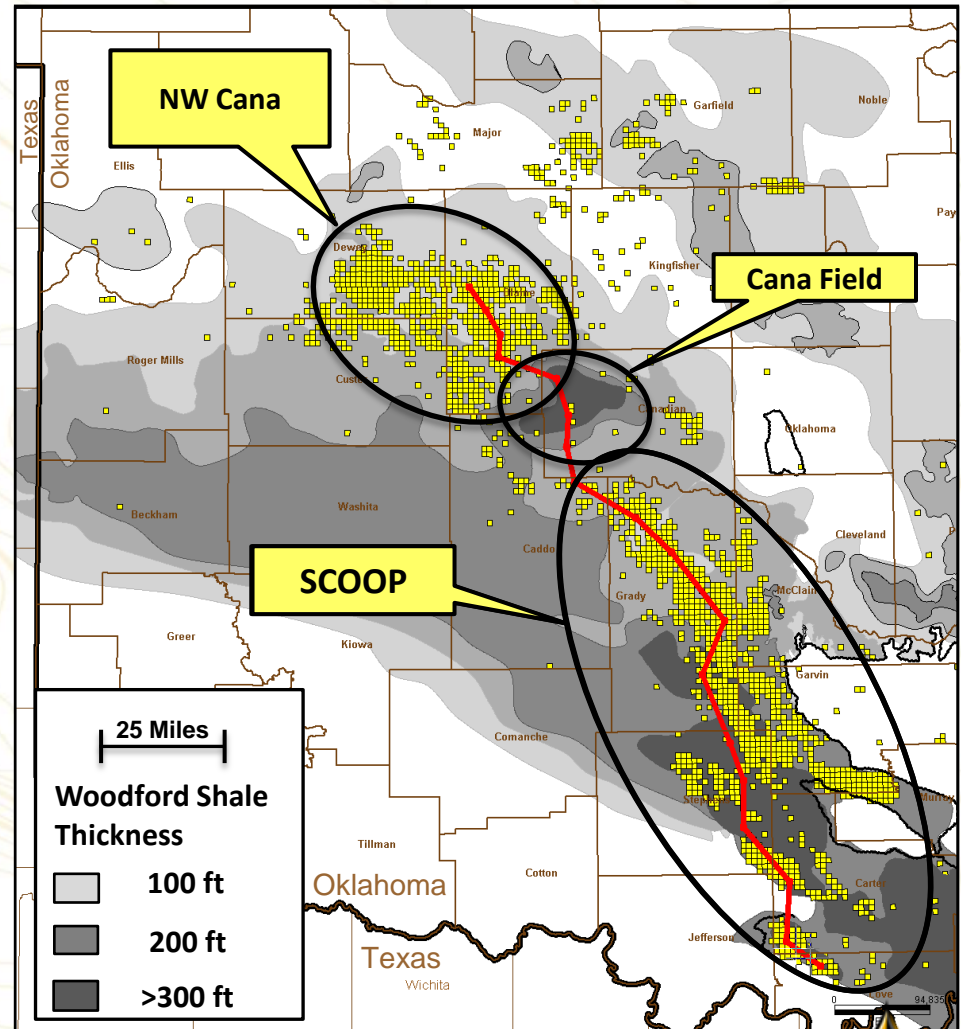
- 3 of the top oil-producing counties in Oklahoma
- 3.2 BBo produced
- 60 reservoirs



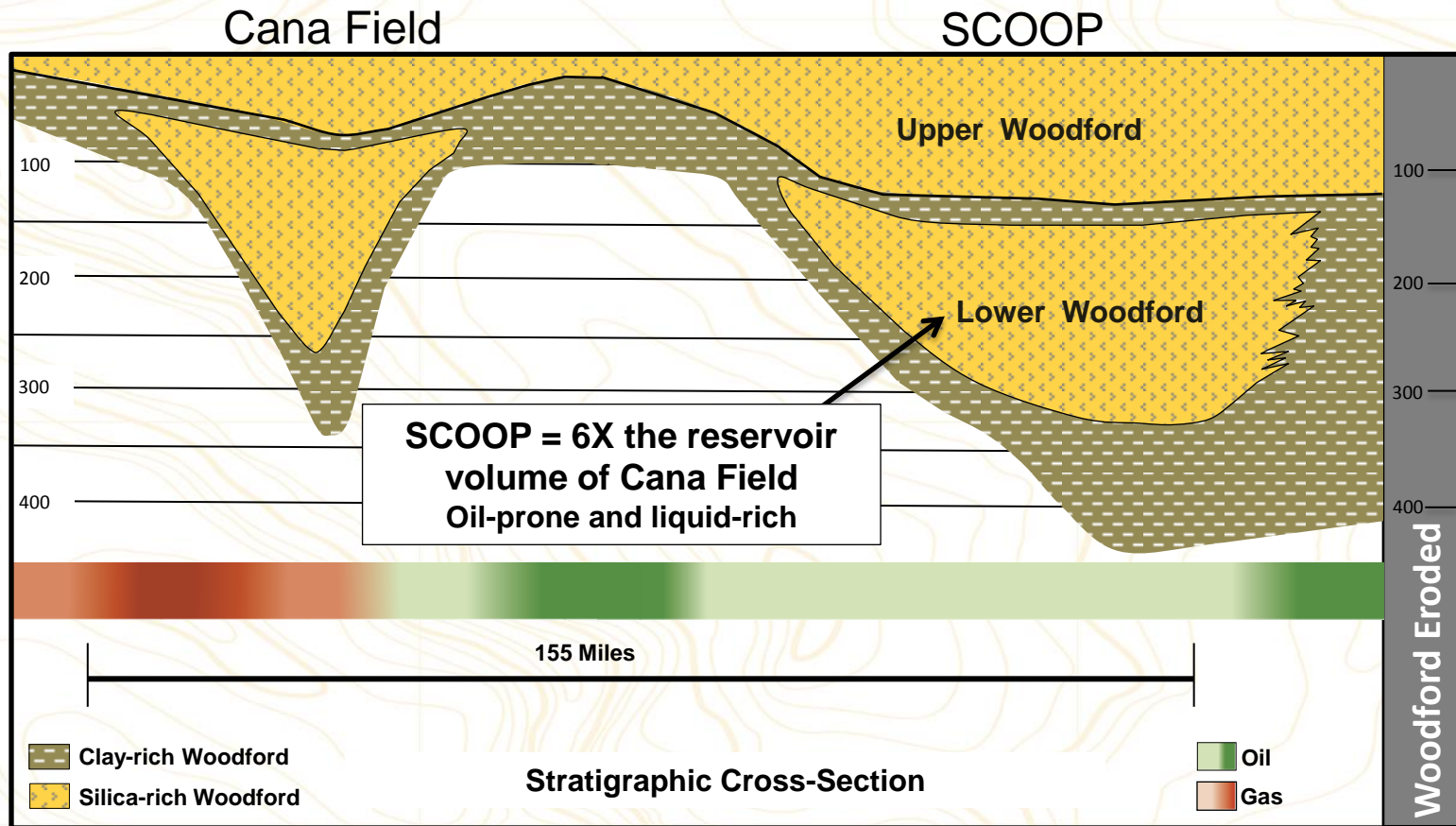
SCOOP: A New, High-Impact Resource Play

- 🔥 South Central Oklahoma Oil Province
- 🔥 World-class resource shale
 - Up to 400' of oil-rich shale
 - Dual reservoir target
- 🔥 Excellent siliceous and highly fractured reservoir

*SCOOP Source:
Woodford Shale
70 BBo remains in place*



SCOOP is Premium Woodford



CLR's Commanding Position in SCOOP

Lease

- 🔥 94,000 net acres at YE 2010
- 🔥 218,000 net acres at YE 2012
- 🔥 245,000 net acres as of Feb. 2013
 - 261% increase since YE 2010

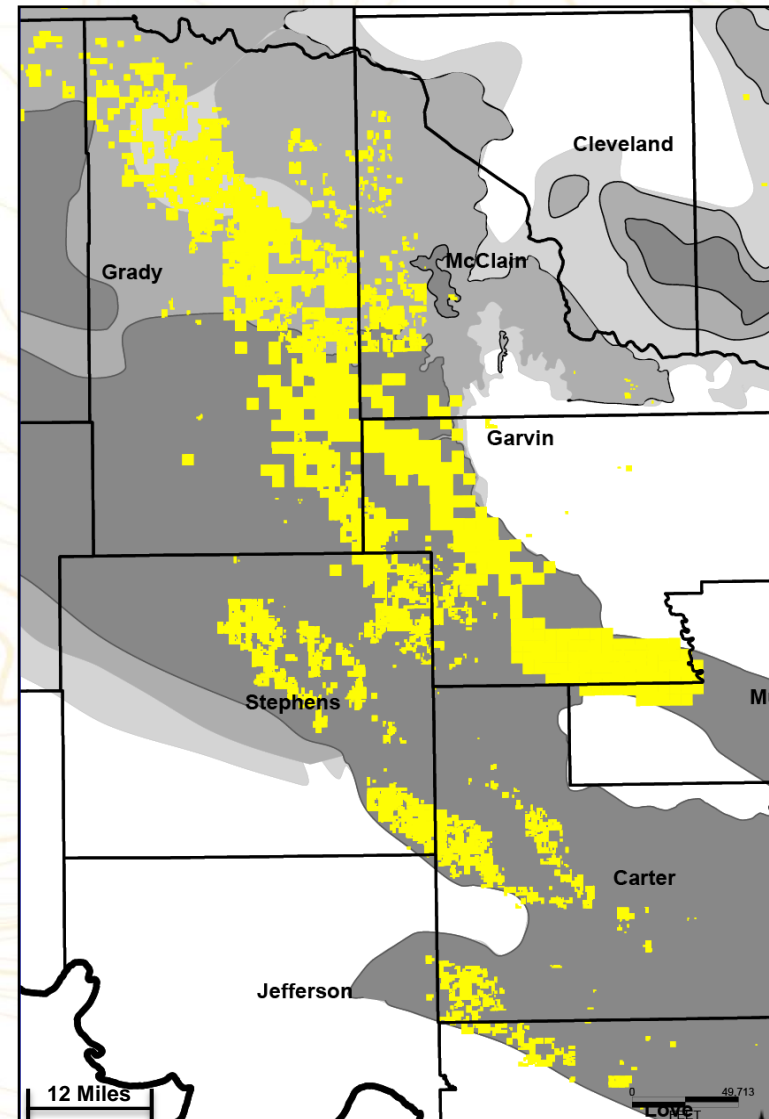
Unrisked Resource Inventory

- 🔥 2 BBoe net unbooked reserve potential to CLR with 3,035 net undrilled locations*

Commercial

- 🔥 40%-70% ROR

*Unrisked, based on 80-acre spacing



Recent SCOOP Activity

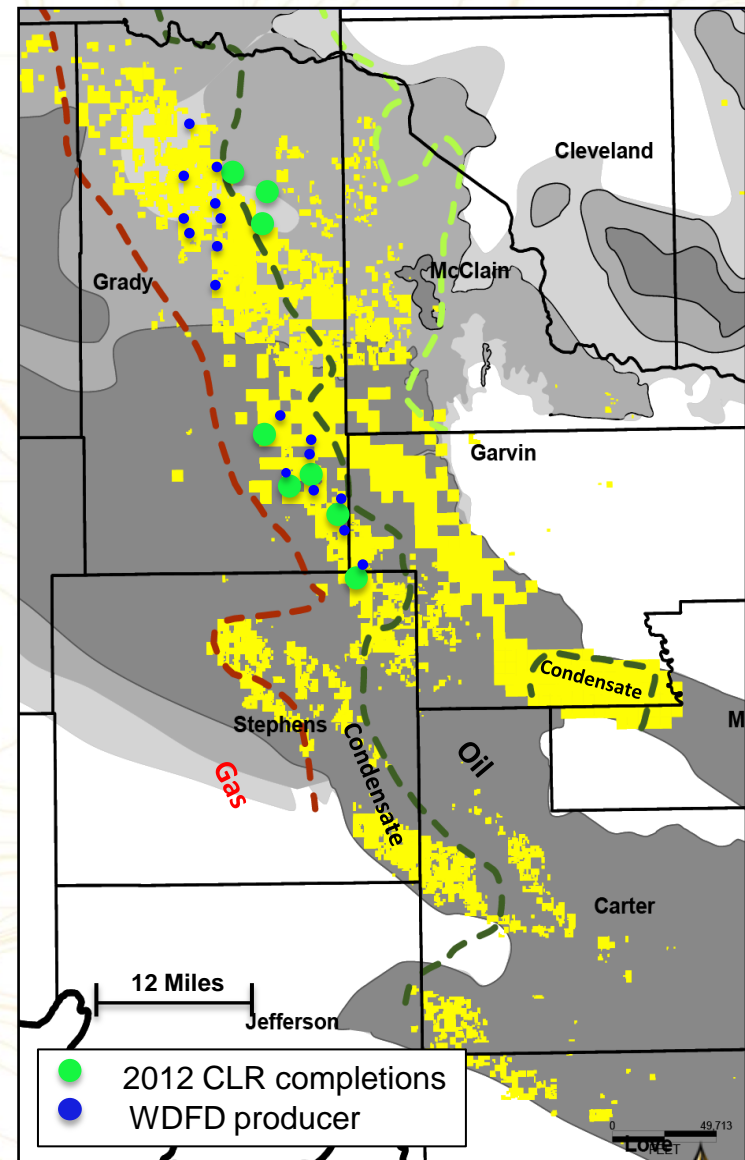
Oil fairway

Elliot 1-35H: 633 Boepd (67% oil)
Nightingale 1-16H: 523 Boepd (78% oil)

Condensate fairway

Lowrance 1-10H : 1,580 Boepd (38% oil)
Wooten 1-28H: 1,103 Boepd (25% oil)
Cosby 1-13H: 1,761 Boepd (23% oil)

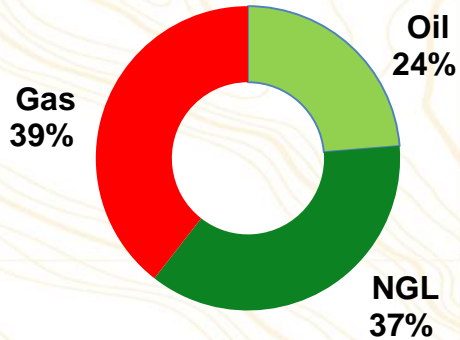
- 🔥 Drilled or participated in 68 wells to date
- 🔥 >600 square miles de-risked
- 🔥 Broad repeatable liquids fairway
- 🔥 6 CLR operated rigs, increasing to 12 by 3Q 2013



SCOOP Economic Performance

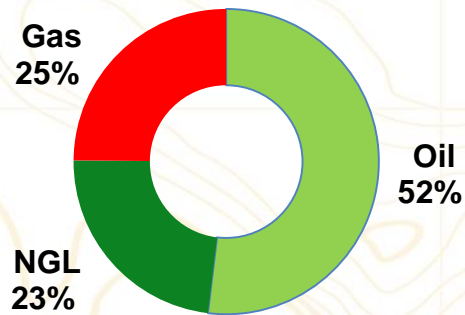
Condensate Fairway

EUR = 1190 MBoe (61% liquids)**

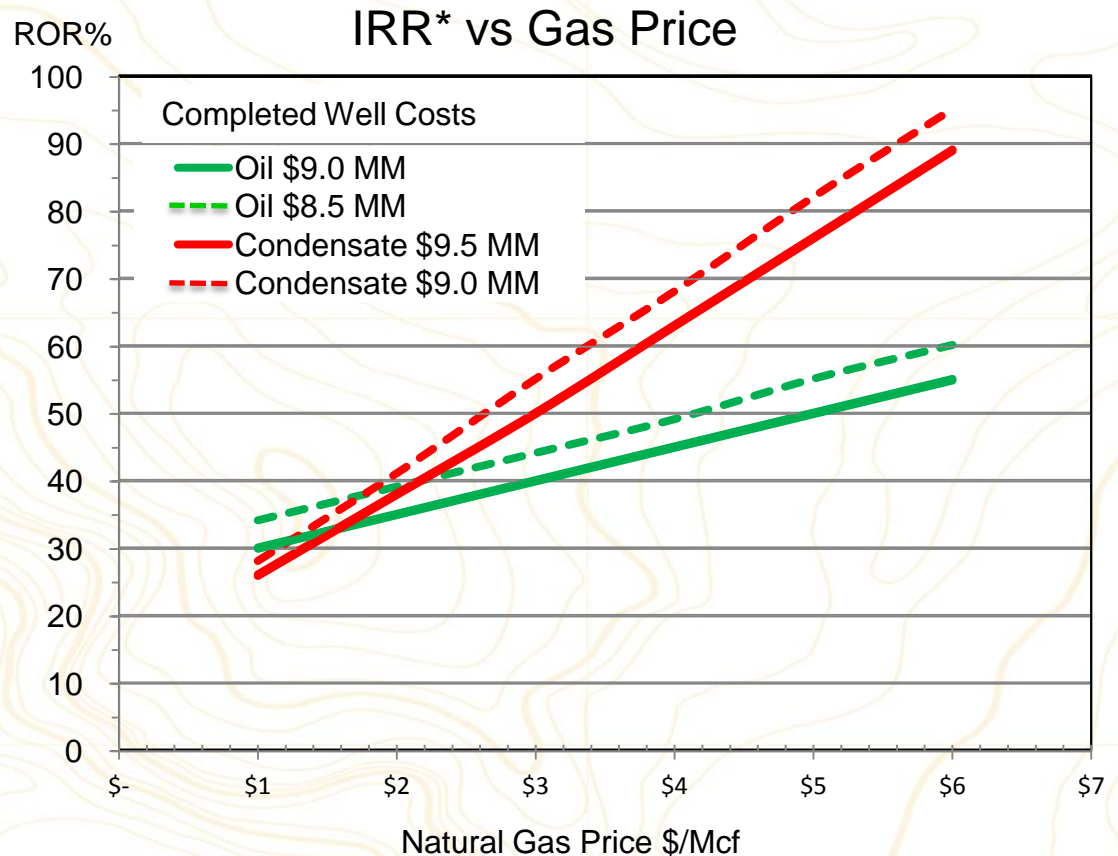


Oil Fairway

EUR = 626 MBoe (75% liquids)**



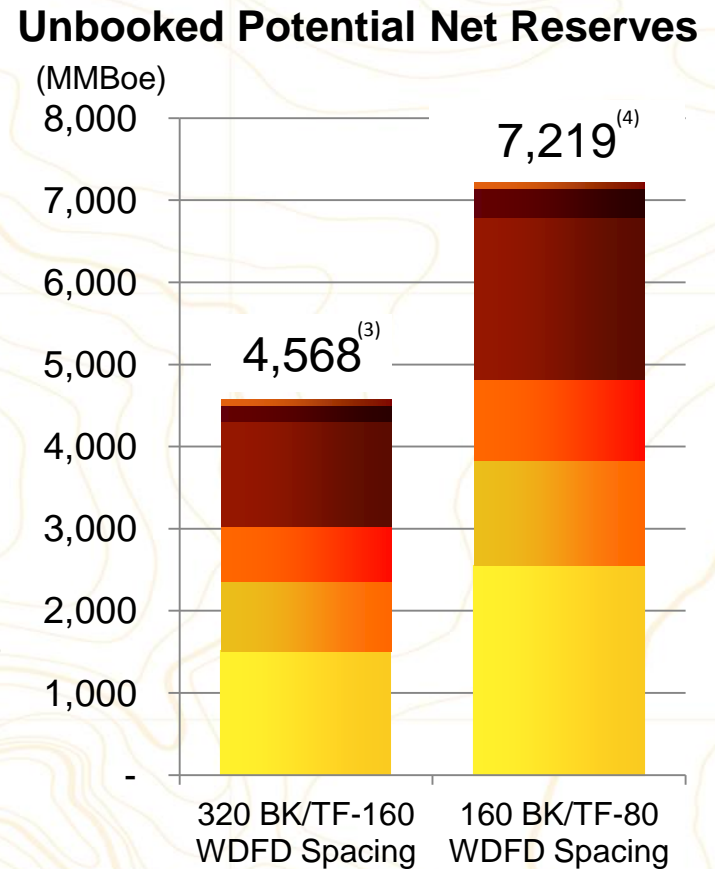
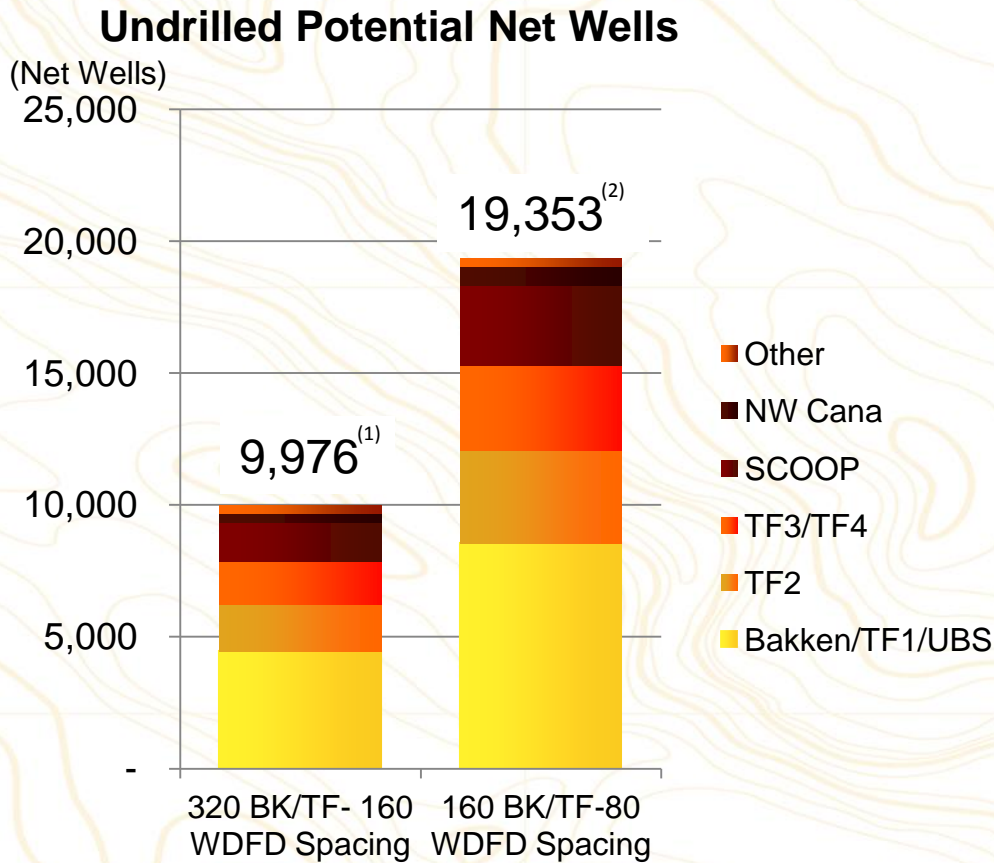
**Expected EUR and Yield



*Oil Price \$90 Gas Diff Premium +85%

Realizing CLR's Unrisked Resource Potential

Continental 2012 proved reserves: 785 MMBoe

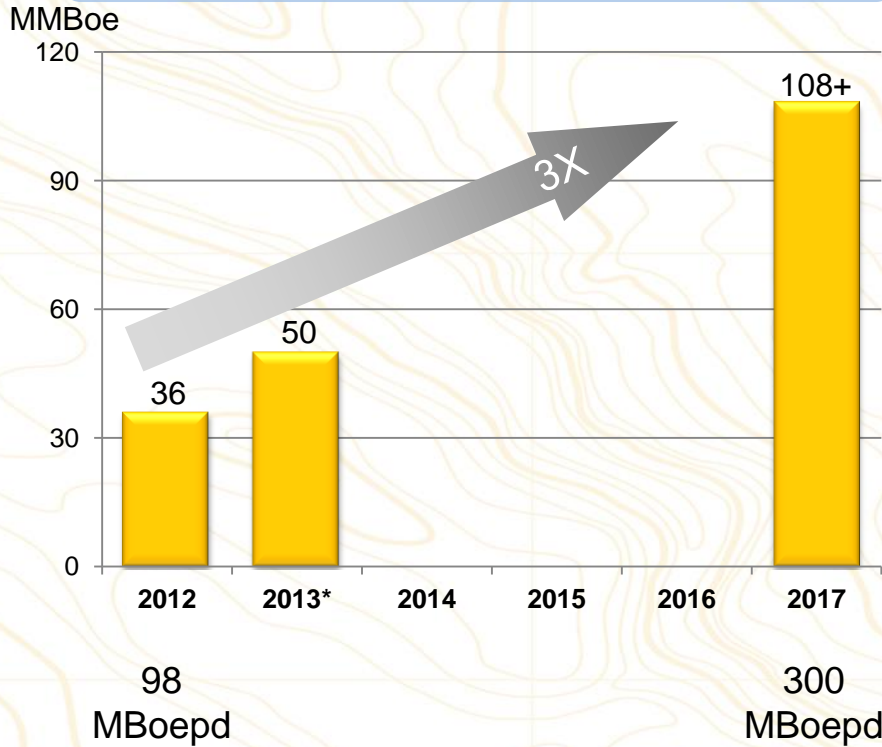


*Calculations exclude non-prospective acreage. Estimates as of Dec. 31, 2012.

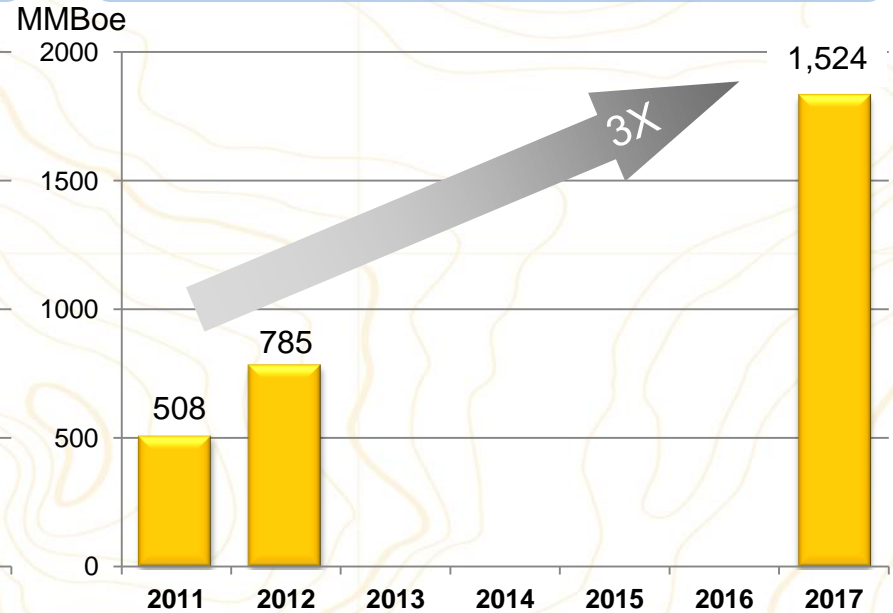
**Since 9/30/2012: (1) Increase of 13% and 1,126 net wells, (2) Increase of 14% and 2,403 net wells, (3) Increase of 11% and 468 net proved reserves, (4) Increase of 3% and 219 net proved reserves.

5-Year Target: Another Triple!

Production



Proved Reserves

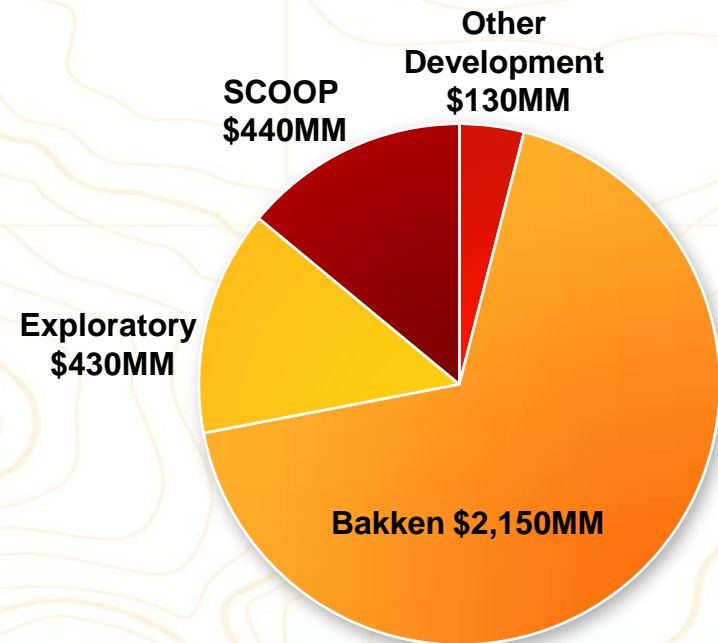
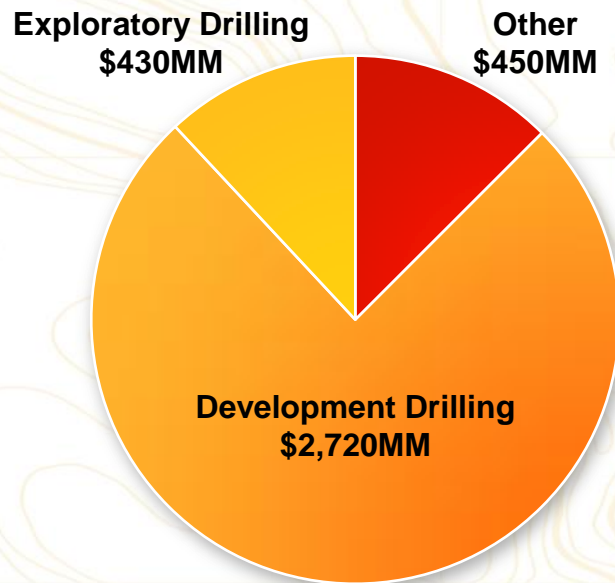


*Midpoint of 35% to 40% guidance range.

2013 Capital Expenditures Budget

Total Capital Expenditures (\$3.6B)

Drilling Capital Allocation (\$3.15B)



| | <u>2012</u> | <u>2013</u> |
|-----------------------|-------------|-------------|
| Average operated rigs | 33 | 35 |
| Gross wells | 847 | 724 |
| Net wells | 286 | 309 |

*Excludes acquisition capital expenditures.

Summary: CLR's Clear Vision of Growth

- 🔥 Deliver unmatched oil growth from existing portfolio
- 🔥 Operating excellence with focus on safety and continued cost efficiency
- 🔥 Bring value forward by tripling production and proved reserves by YE 2017
- 🔥 Enhance marketing strategy to reach premier markets
- 🔥 Maintaining strong balance sheet, financial flexibility, and hedging strategy to secure future cash flow

Appendix

INDEPENDENT
MEANS



Continental
RESOURCES

2013 Operational and Financial Guidance

| | |
|--|-------------------|
| 2013 Production growth range | 35% to 40% |
| Capital expenditures* | \$3.6B |
| Price differentials: | |
| WTI crude oil (per barrel of oil) | \$5.00 to \$7.00 |
| Henry Hub natural gas (per Mcf) | +\$1.00 to \$1.50 |
| Operating expenses: | |
| Production expense per Boe | \$5.20 to \$5.60 |
| Production tax as a percent of oil and gas revenues** | 8% to 9% |
| DD&A per Boe | \$19 to \$21 |
| G&A expense per Boe*** | \$2.20 to \$2.70 |
| Non-cash equity compensation per Boe | \$0.70 to \$0.90 |
| Income tax rate | 37% |
| Deferred taxes | 90% to 95% |

* Excludes acquisition capital expenditures

**Does not include other expenses, such as natural gas transportation fees, which could represent another 1%.

***Excludes non-cash equity compensation

Swaps and Collars

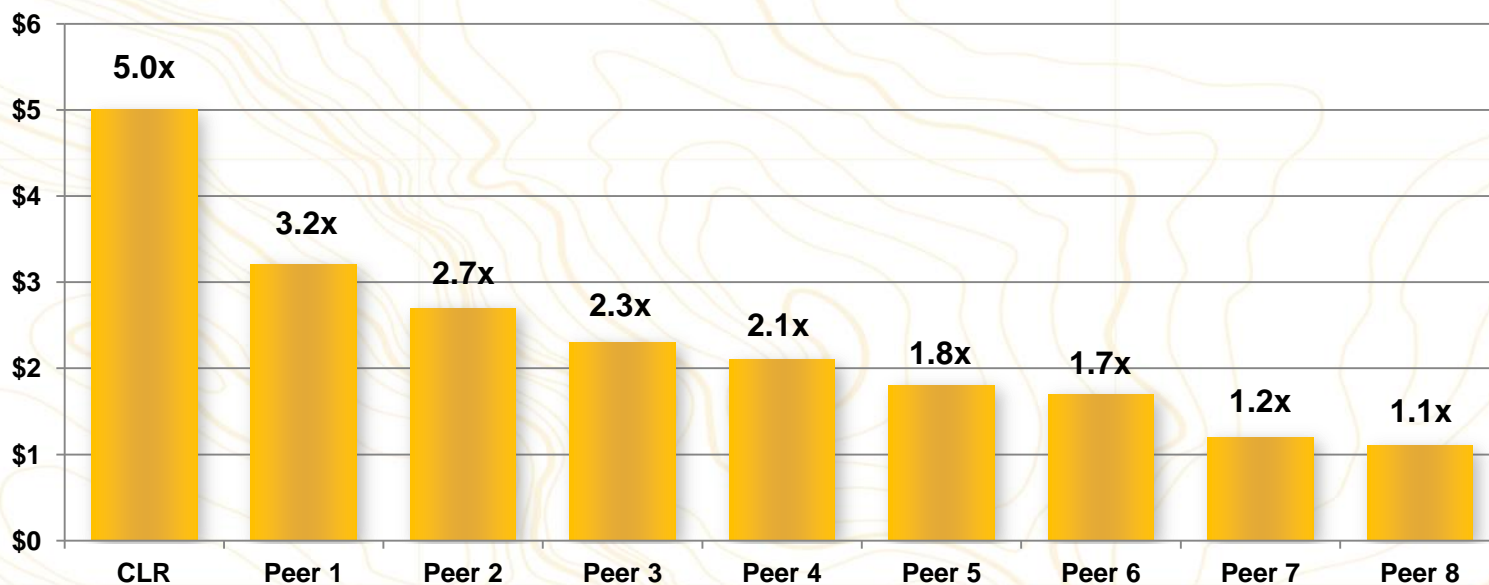
As of 12/31/12

| Crude Oil Derivative Positions | | | Swaps | <u>Collars Wtd. Avg. Price</u> | |
|---|---------------|--|------------------------|--------------------------------|----------------|
| <u>Period and Type of Contract</u> | <u>Bbls</u> | | <u>Wtd. Avg. Price</u> | <u>Floor</u> | <u>Ceiling</u> |
| January 2013 - December 2013* | | | | | |
| Swaps - WTI | 11,862,500 | | \$92.66 | | |
| Swaps - Brent | 3,467,500 | | \$108.49 | | |
| Collars - WTI | 8,760,000 | | | \$86.92 | \$99.46 |
| January 2014 - December 2014 | | | | | |
| Swaps - WTI | 10,311,250 | | \$96.20 | | |
| Swaps - Brent | 6,570,000 | | \$100.66 | | |
| Collars - Brent | 2,190,000 | | | \$90.83 | \$107.13 |
| January 2015 - December 2015 | | | | | |
| Swaps - Brent | 1,277,500 | | \$98.48 | | |
| Natural Gas Derivative Positions | | | Swaps | | |
| <u>Period and Type of Contract</u> | <u>MMBtus</u> | | <u>Wtd. Avg. Price</u> | | |
| January 2013 - December 2013* | | | | | |
| Swaps - Henry Hub | 18,250,000 | | \$3.76 | | |

*For 2013 approximately 77% of forecasted crude oil production and approximately 33% of forecasted natural gas production is hedged.

Capital Efficiency

Recycle Ratio – Industry Leader⁽¹⁾⁽²⁾



1 Recycle ratio is calculated as the 3-yr average profit per BOE divided by the 3-yr average F&D cost per BOE

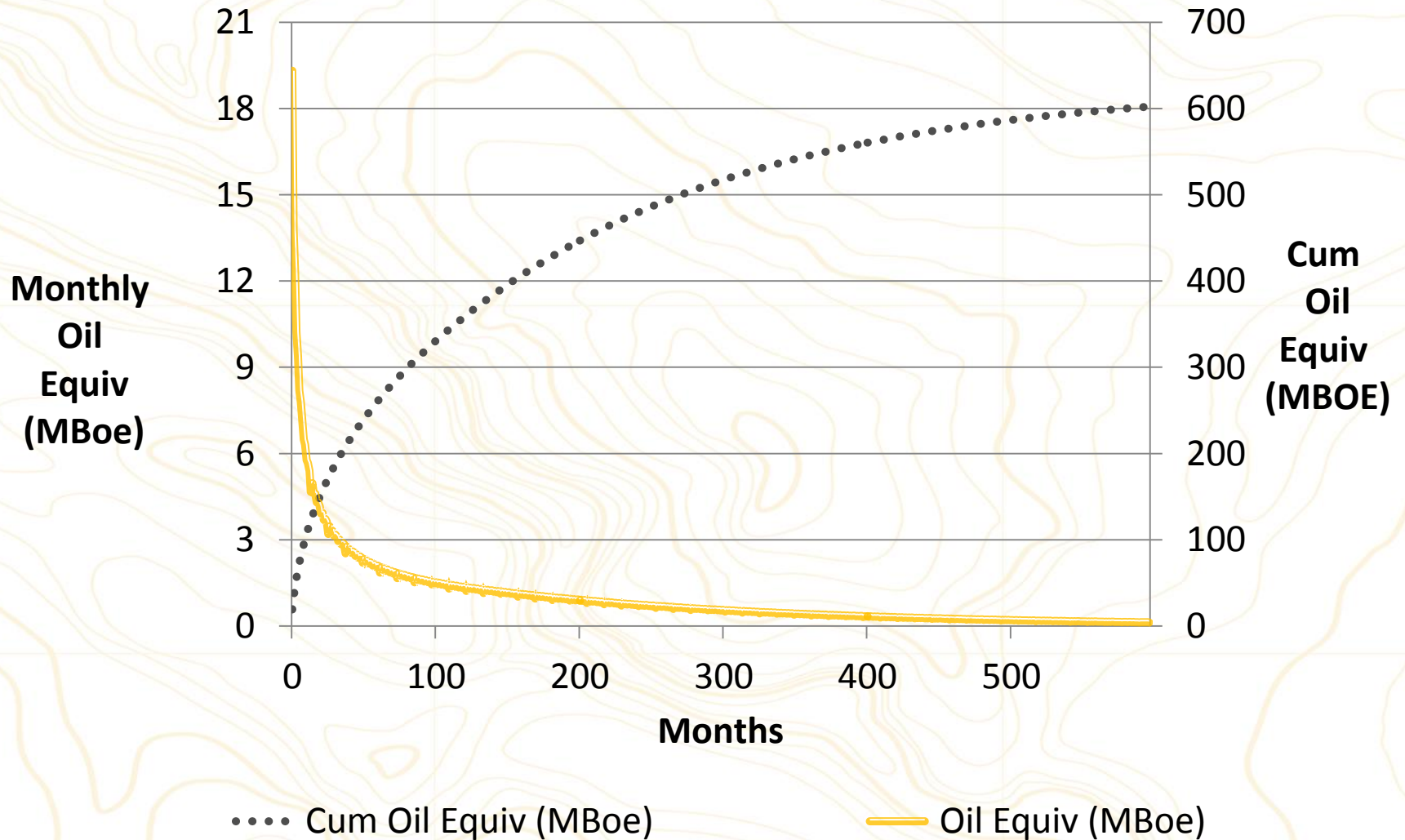
2 Peers include APC, CHK, CXO, DNR, DVN, PXP, SD and WLL. Source: KeyBanc, 2/25/2013

EBITDAX Reconciliation to GAAP

We use a variety of financial and operational measures to assess our performance. Among these measures is EBITDAX. EBITDAX represents earnings (net income) before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, non-cash gains and losses resulting from the requirements of accounting for derivatives, and non-cash equity compensation expense. EBITDAX is not a measure of net income or operating cash flows as determined by GAAP. Management believes EBITDAX is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income in arriving at EBITDAX because those amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. EBITDAX should not be considered as an alternative to, or more meaningful than, net income or operating cash flows as determined in accordance with GAAP or as an indicator of a company's operating performance or liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of EBITDAX. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies. We believe that EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet future debt service requirements, if any. Our revolving credit facility requires that we maintain a total funded debt to EBITDAX ratio of no greater than 4.0 to 1.0 on a rolling four-quarter basis. This ratio represents the sum of outstanding borrowings and letters of credit under our revolving credit facility plus our note payable and senior note obligations, divided by total EBITDAX for the most recent four quarters. We were in compliance with this covenant for all periods presented. The following table represents a reconciliation of our net income to EBITDAX for the periods presented:

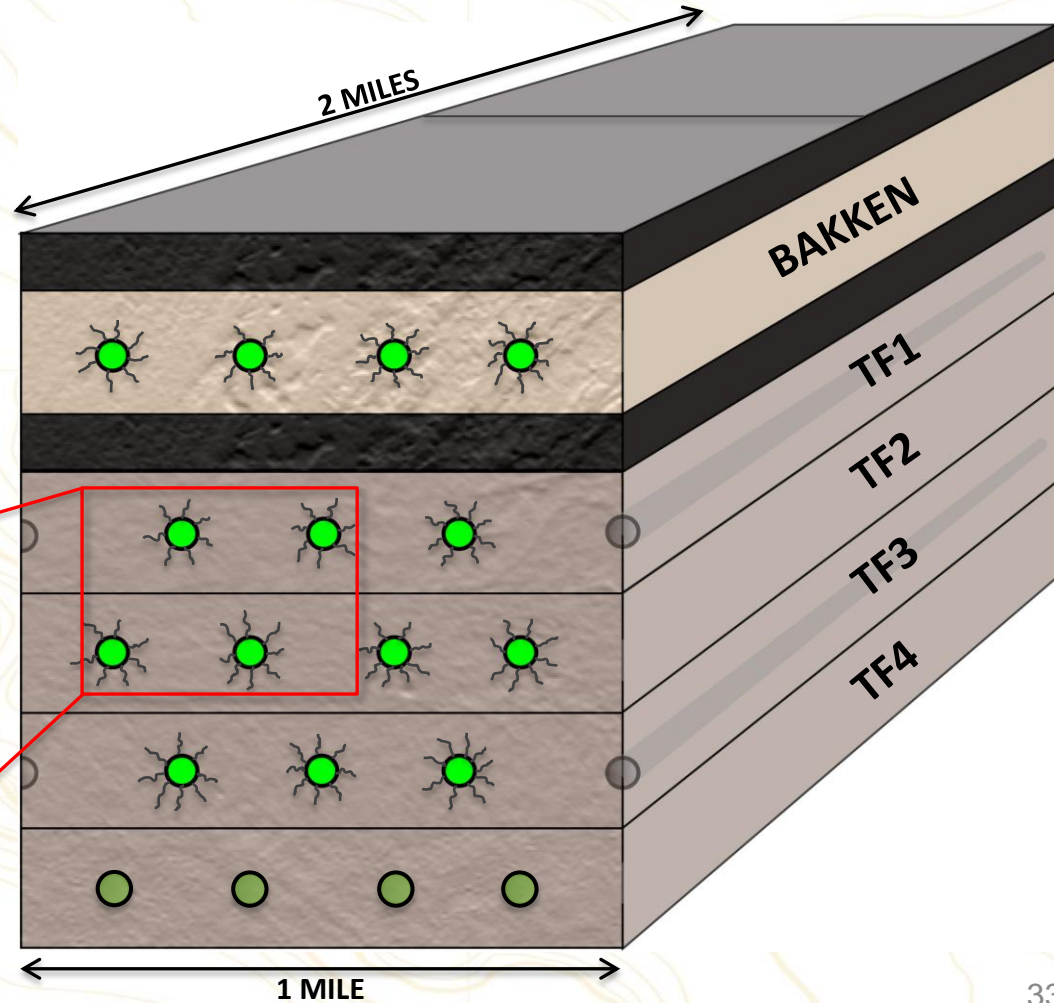
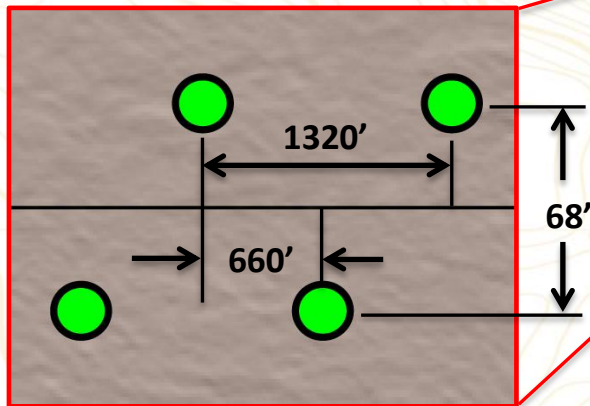
| | Year Ended December 31, | | | | |
|--|-------------------------|------------|--------------|--------------|------------|
| | 2009 | 2010 | 2011 | 2012 | 4Q 2012 |
| | <i>in thousands</i> | | | | |
| Net income | \$ 71,338 | \$ 168,255 | \$ 429,072 | \$ 739,385 | \$ 220,511 |
| Interest expense | 23,232 | 53,147 | 76,722 | 140,708 | 45,534 |
| Provision for income taxes | 38,670 | 90,212 | 258,373 | 415,811 | 99,992 |
| Depreciation, depletion, amortization and accretion | 207,602 | 243,601 | 390,899 | 692,118 | 192,271 |
| Property impairments | 83,694 | 64,951 | 108,458 | 122,274 | 29,121 |
| Exploration expenses | 12,615 | 12,763 | 27,920 | 23,507 | 5,755 |
| Impact from derivative instruments: | | | | | |
| Total (gain) loss on derivatives, net | 1,520 | 130,762 | 30,049 | (154,016) | (9,639) |
| Total realized (cash flow) gain (loss) on derivatives, net | 569 | 35,495 | (34,106) | (45,721) | 2,655 |
| Non-cash (gain) loss on derivatives, net | 2,089 | 166,257 | (4,057) | (199,737) | (6,984) |
| Non-cash equity compensation | 11,408 | 11,691 | 16,572 | 29,057 | 8,252 |
| EBITDAX | \$ 450,648 | \$ 810,877 | \$ 1,303,959 | \$ 1,963,123 | \$ 594,452 |

Bakken Type Curve



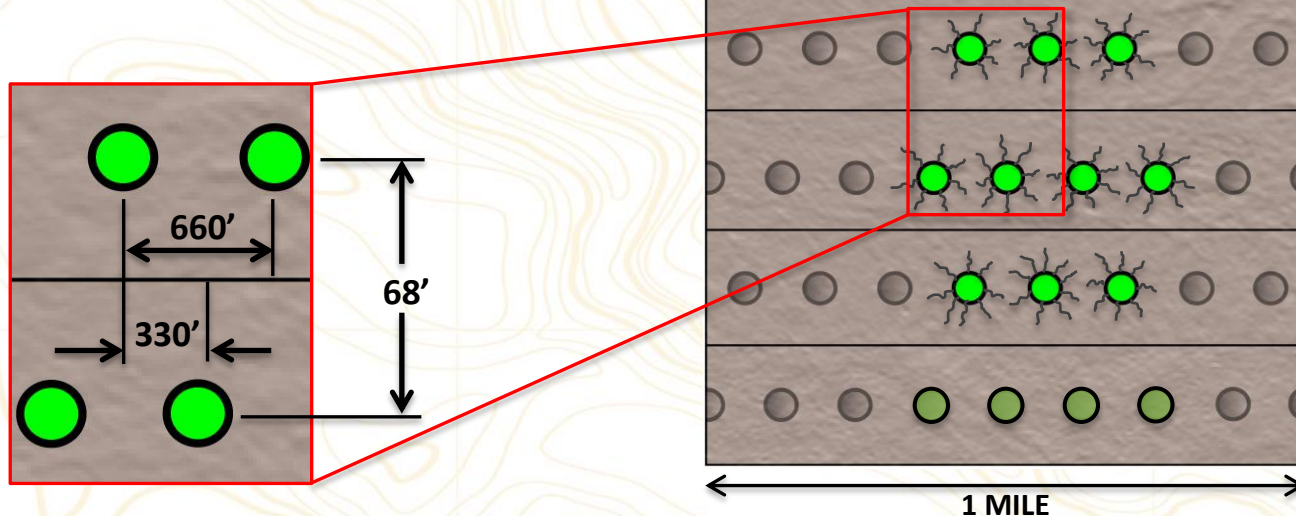
320-Acre Pilot Density Projects

- 3 tests
- Micro-seismic monitoring
- 1320' same zone inter-well spacing/660' offset



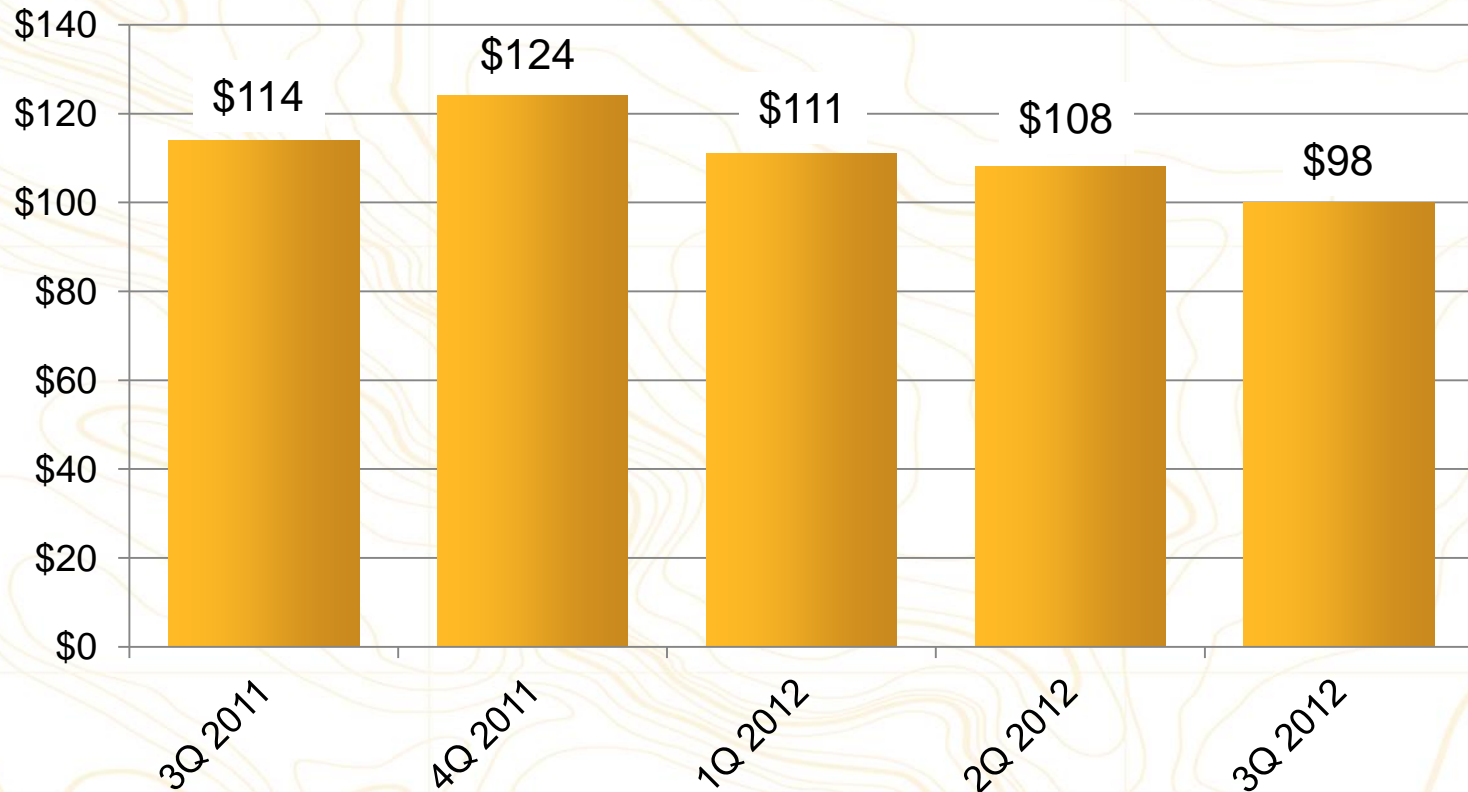
160-Acre Pilot Density Project

660' inter-well spacing between same-zone wells



Decreasing Stimulation Costs per Stage

\$ Thousands
Per Stage

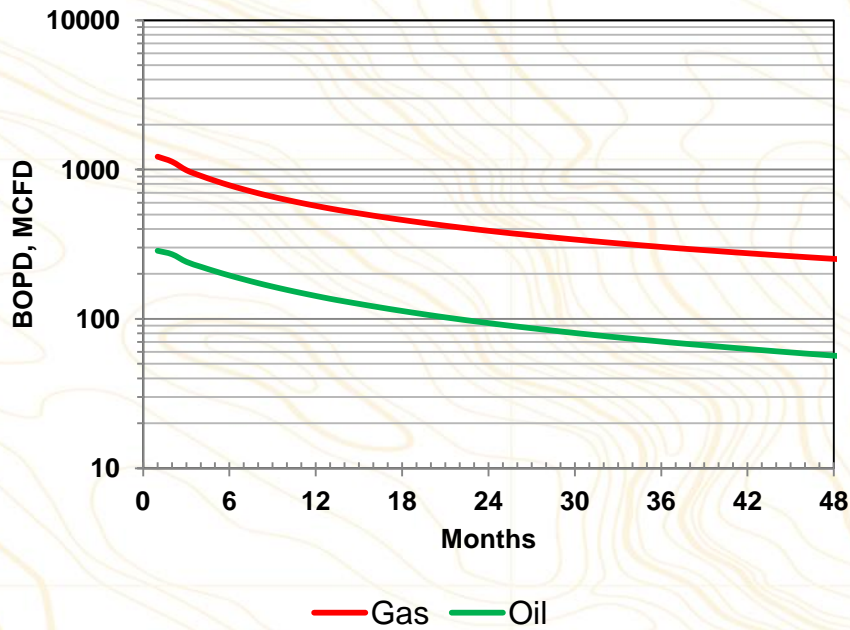


*Costs include pumping services, wireline, water, packers and plugs.

SCOOP Type Curves

Oil Fairway Type Curve

EUR: 626 MBoe (75% liquids)



Condensate Fairway Type Curve

EUR: 1190 MBoe (61% liquids)

