CLR Investor Presentation

October 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.

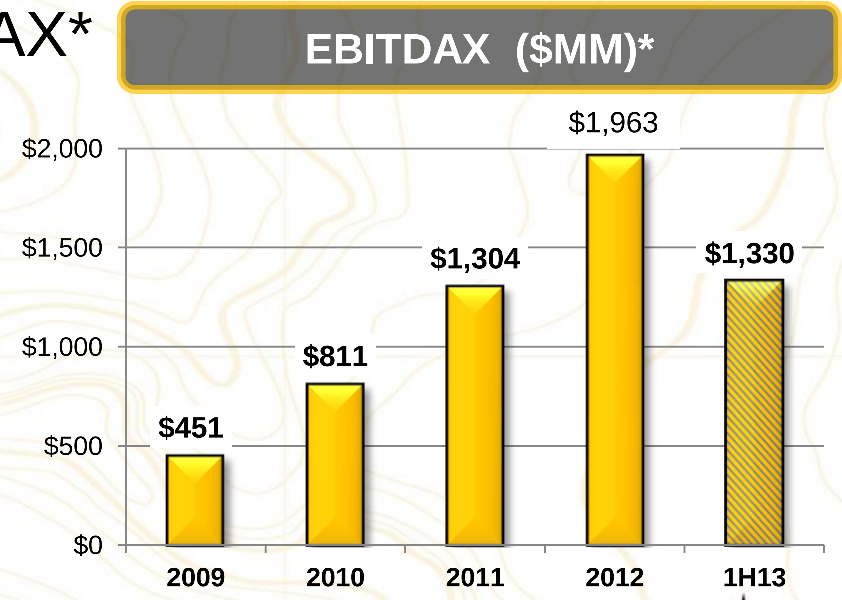
The Company cautions readers that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond the Company's control, incident to the exploration for, and development, production, and sale of, crude oil and natural 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.

Firing on all Cylinders: Strong 2Q13 Results

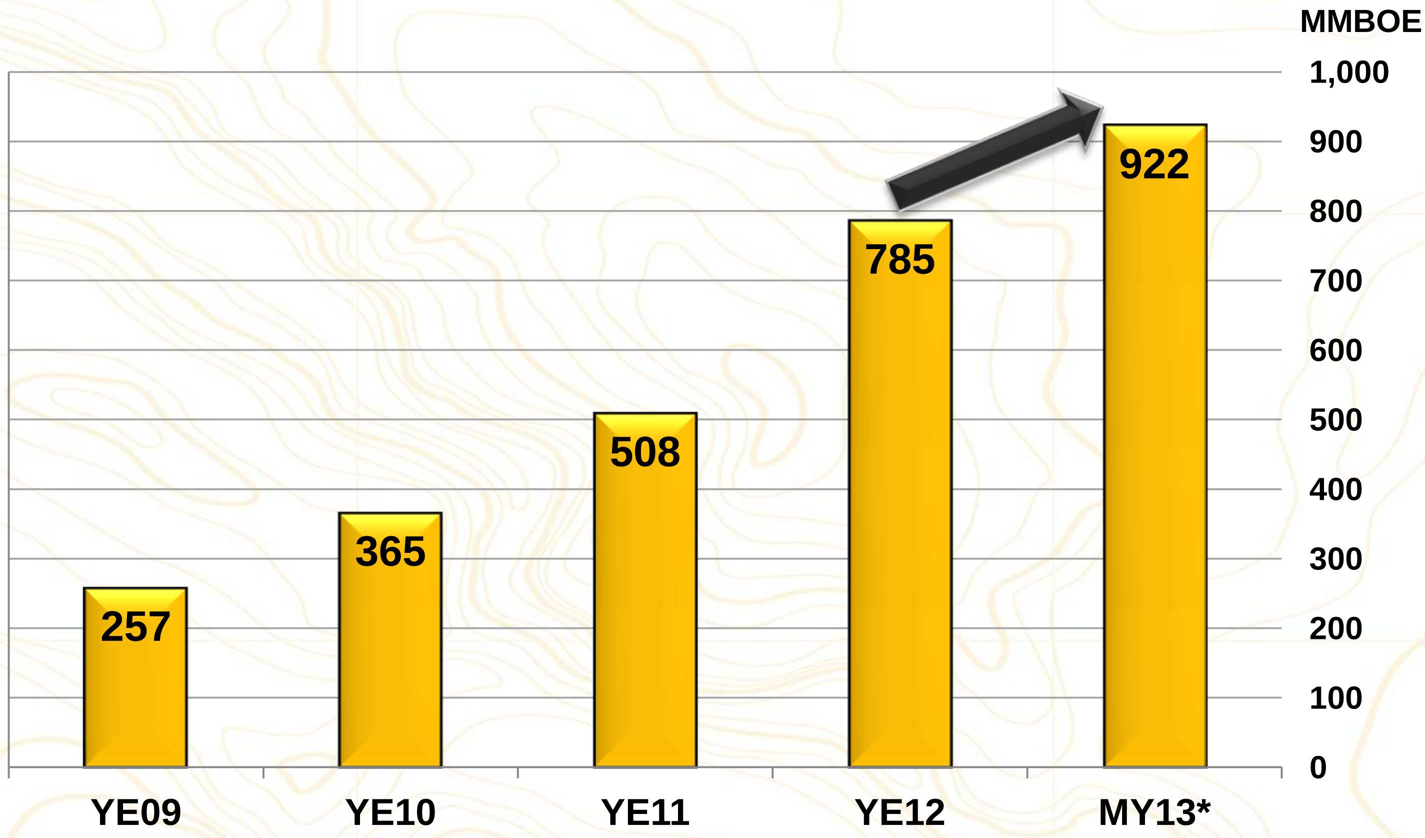
- Tightening 2013 production targets upward to 38%-40%
  - ✓ Maintaining 2013 non-acquisition capex target of $3.6 billion
  - ✓ 2014 non-acquisition capex target of $4.05 billion, 26%-32% production growth
- Consistent production growth, 71% oil
  - ✓ 135,700 Boepd in 2Q13: production +12% sequentially, +43% over 2Q12
    - Bakken production: 88,000 Boepd in 2Q13, +14% sequentially
    - SCOOP production: 17,550 Boepd in 2Q13, +23% sequentially
- Current production 140,000 Boepd (8/7/13)
- Record $708MM 2Q13 EBITDAX*
  - ✓ +14% sequentially, +68% over 2Q12
- Organic reserve adds
  - ✓ 922 MMBoe mid-year 2013 proved reserves, +17% over YE12
- Efficiencies drive lower costs
  - ✓ Bakken operated well costs target reduced to $8.0MM by YE13



*See "EBITDAX Reconciliation to GAAP" in Appendix for a reconciliation of net income to EBITDAX.

Mid-Year 2013 Proved Reserves

17% Increase in Proved Reserves since YE12:
Mid-Year Reserves are 87% Operated and 70% Crude Oil



*Based on internal estimates.

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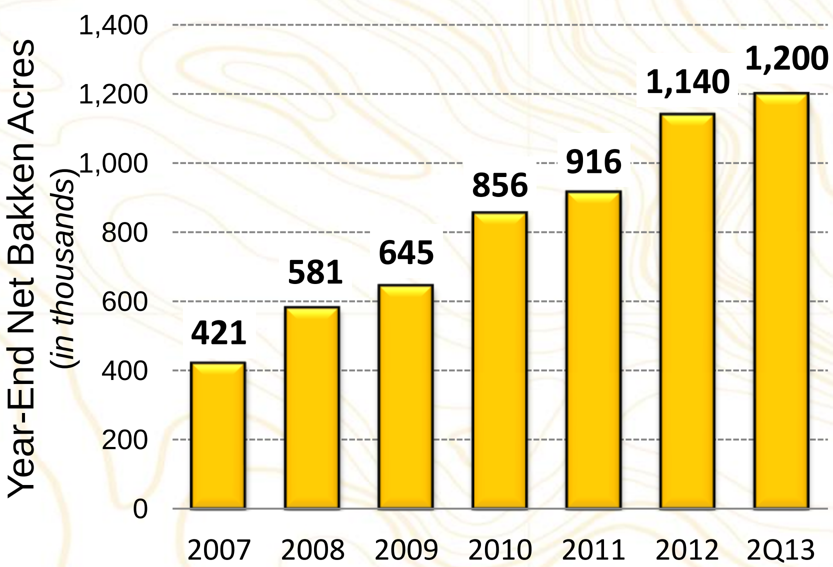
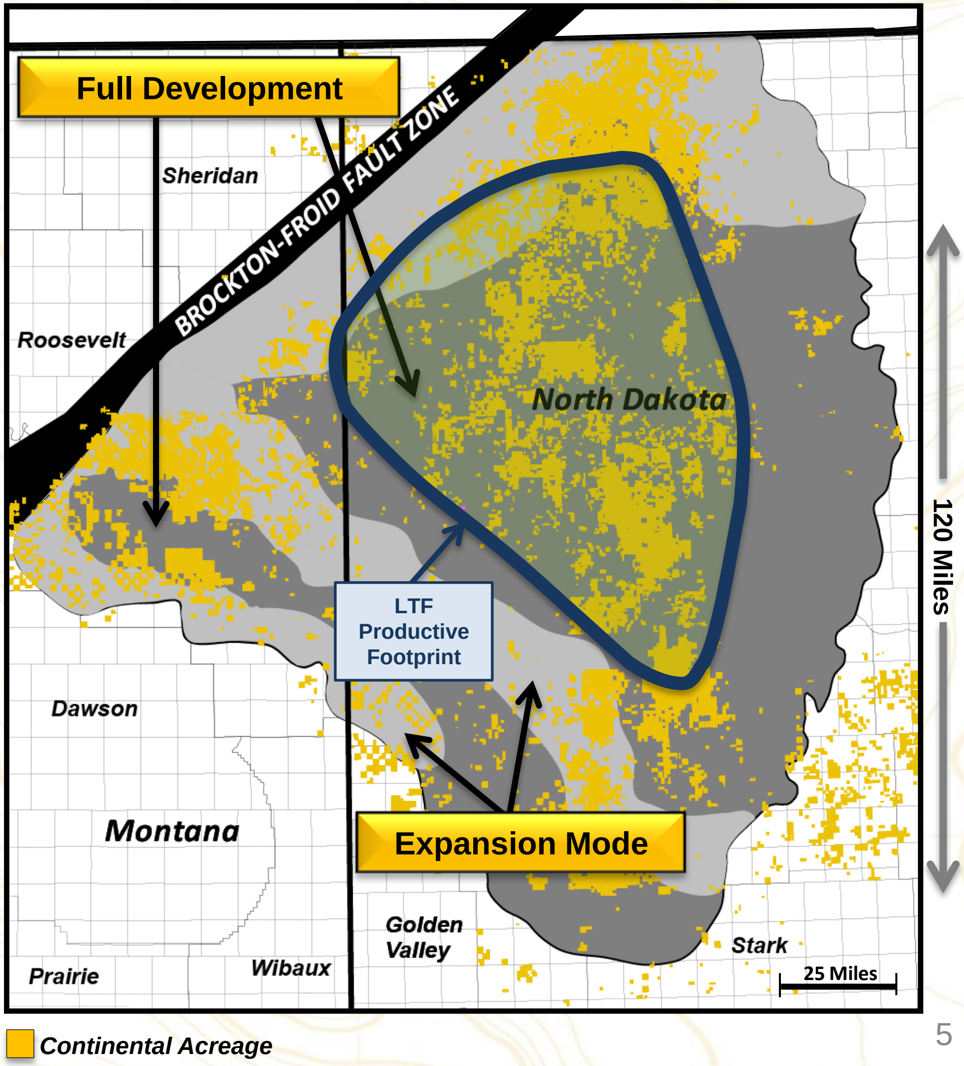
#1 Leaseholder in the Bakken

- 1.2 million net acres at 2Q13
  - +21% YOY since 2Q13
- 98% HBP on de-risked leasehold by YE2013
- 96% HBP for both de-risked and exploratory leasehold by YE2017

Continental's Acreage Growth





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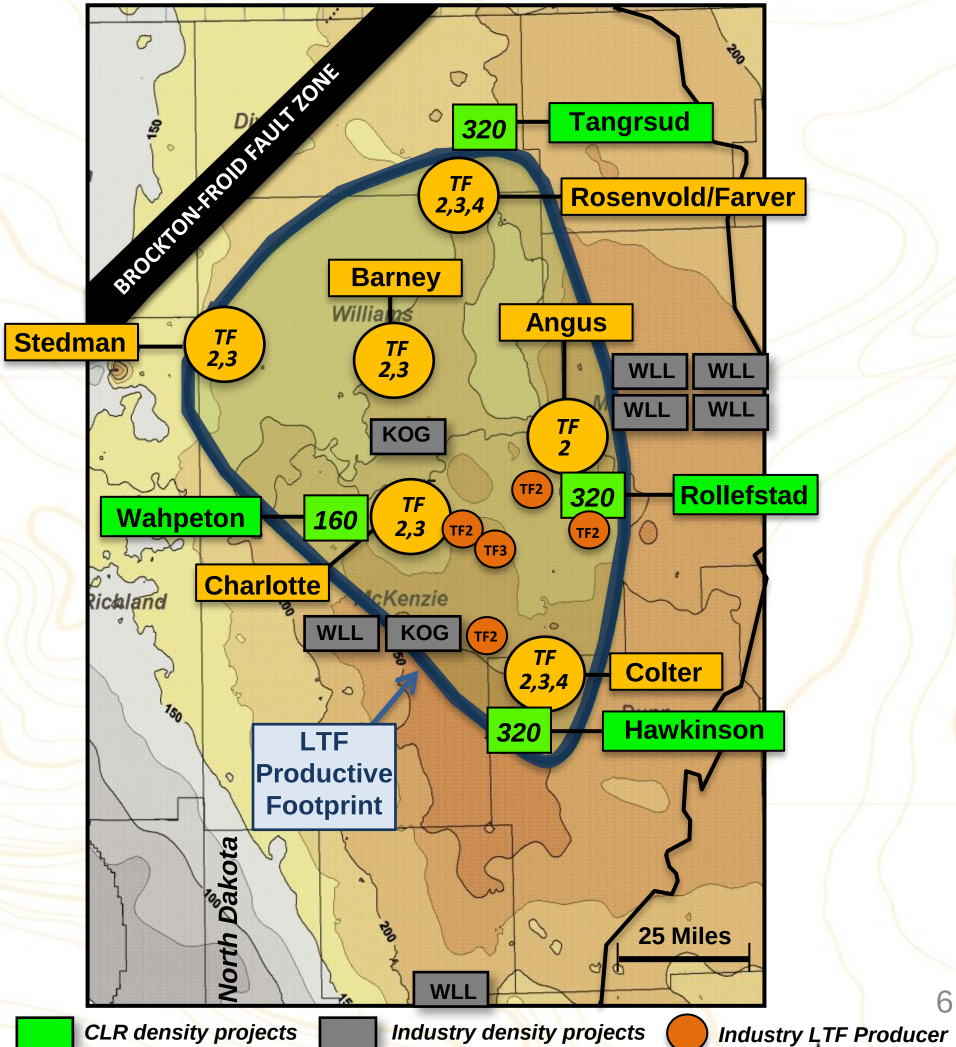
Leading the Delineation of the Three Forks

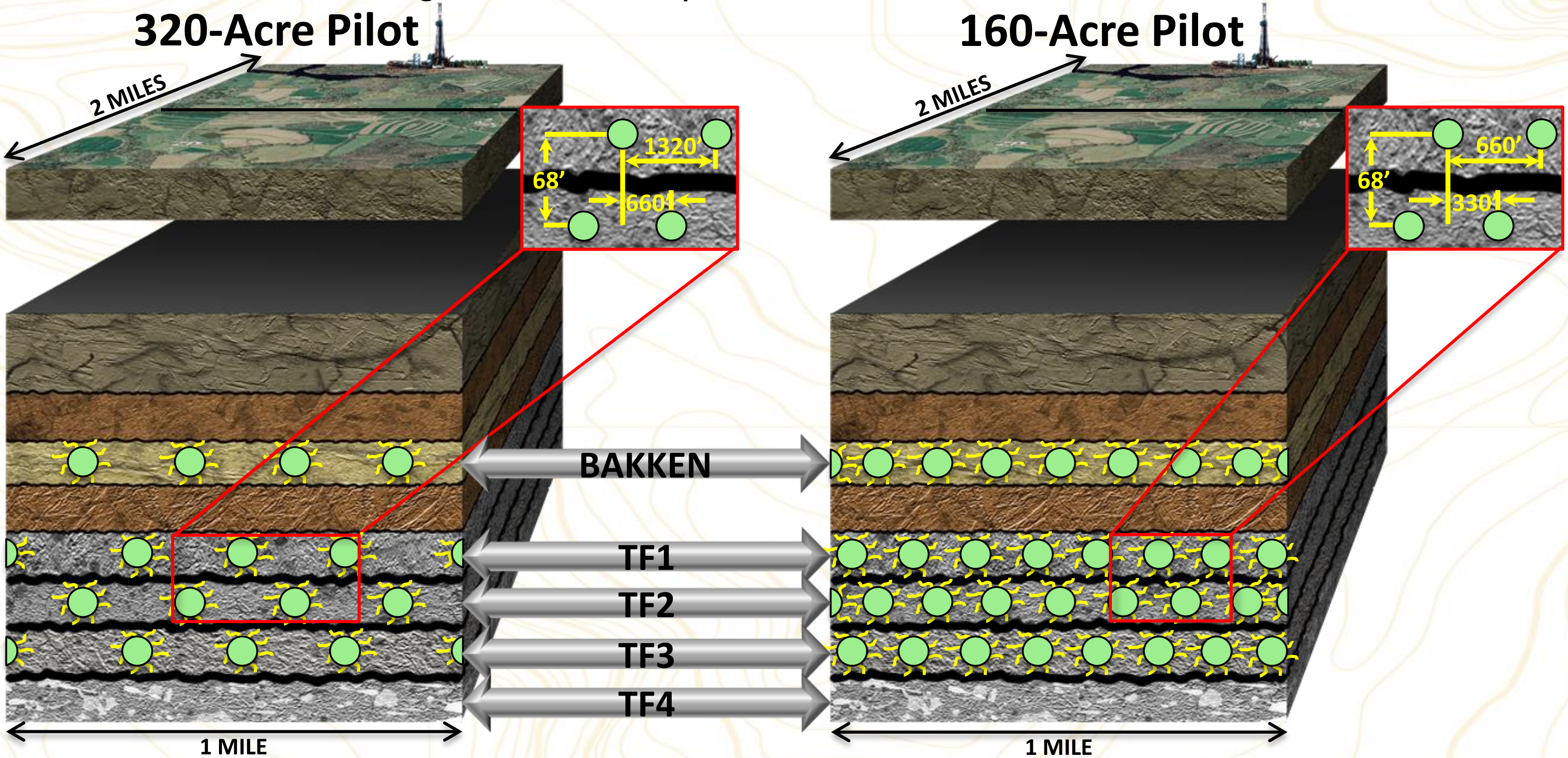
- **Lower Three Forks activity delineates potential productive footprint of 3,800 square miles**
- **18 Lower Three Forks producers**
  - By operator:
    - CLR: 13 wells
    - EOG, COP, XTO, ZEN: 5 wells
  - Total wells tested:
    - TF2: 10 wells
    - TF3: 6 wells
    - TF4: 2 wells
  - Results consistent with expectations based on core work and areas tested
- **Evidence suggests**
  - Unique reserves in areas with little faulting or structure (5 of 6 areas tested)
  - Production interference can occur in areas with more severe faulting and natural fracturing, but not widespread

Three Forks Thickness Map



160 & 320-Acre Pilot Density Projects: 2013-14

Hawkinson, Rollefstad, Tangsrud and Wahpeton



- 3 project areas, $212MM net cost
- 1,320 ft. same-zone spacing
- 34 gross (23 net) wells
- Microseismic monitoring

- 1 project area, $55MM net cost
- 660 ft. same-zone spacing
- 13 gross (6 net) wells

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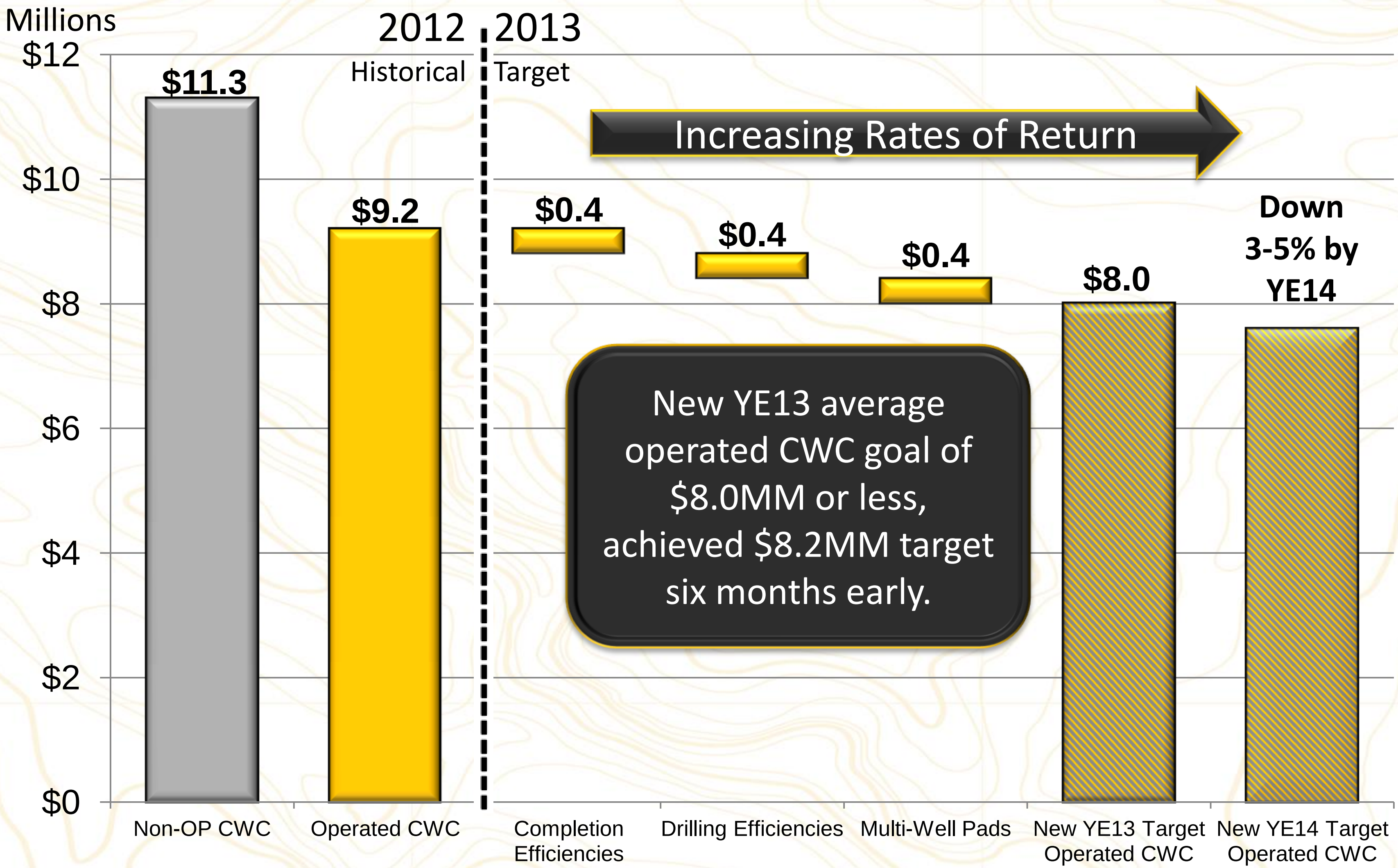
CLR: The Premier Bakken Operator



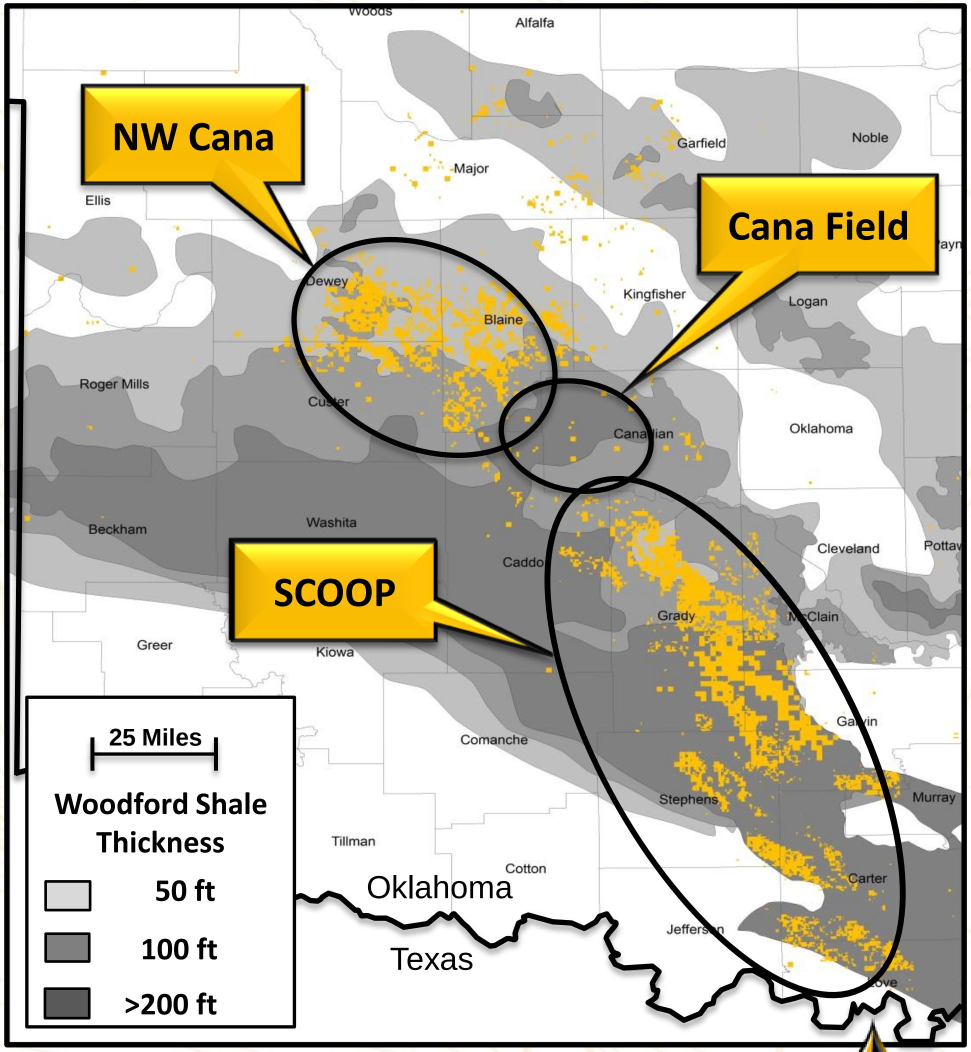
**Weighted average well cost, pads and single wells.*
CWC = Completed well cost

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

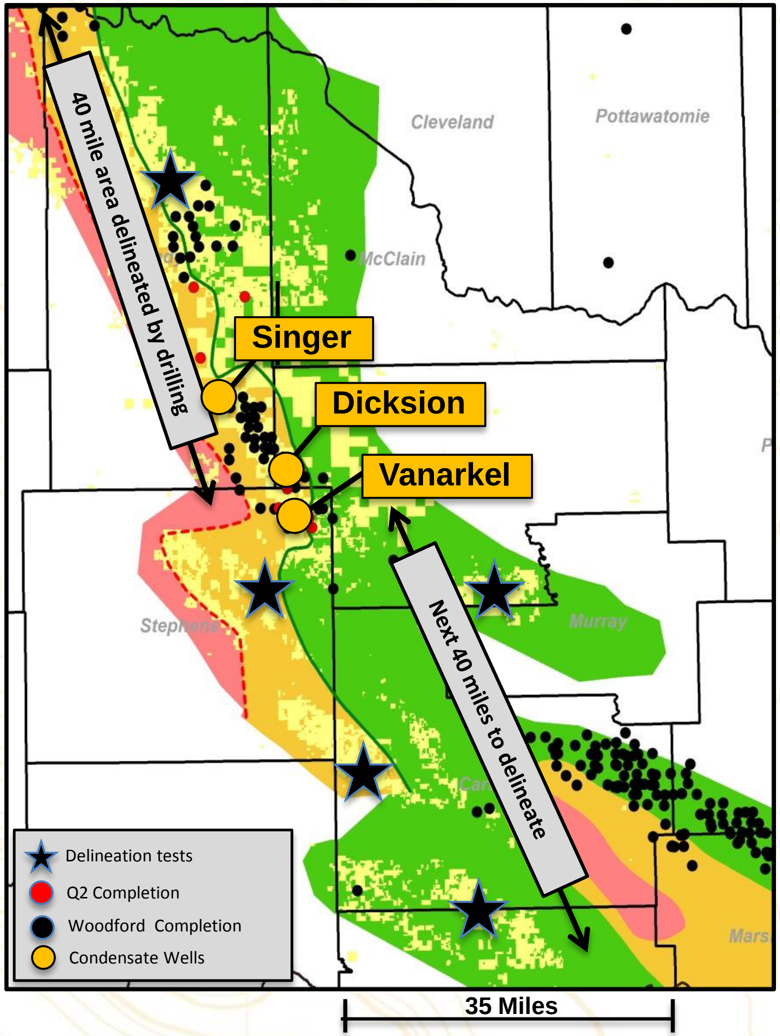
SCOOP Source: Woodford Shale

70 BBo remains in place



SCOOP: Gaining Momentum in Size and Scale

- **Produced 17,550 net Boepd for 2Q13**
  - 23% increase since 1Q13
  - 435% increase since 2Q12
- **Leasehold increased to 277,000 net acres**
- **First cross-unit well completed**
  - Singer 1-18-7XH (1,915 Boepd, 37% oil)
- **Oil and condensate fairways being defined**
  - 10 CLR operated rigs, increasing to 12 in 3Q 2013
- **Participated in 50 net (93 gross) completions**
- **8 net (14 gross) wells completed 2Q13**
  - Condensate wells avg. IP: 1,490 Boepd (29% oil)
  - Oil wells avg. IP: 1,460 Boepd (55% oil)
- **Recently completed operated wells:**
  - Vanarkel 1-15H (50% WI): 2,045 Boepd (44% oil)
  - Singer 1-18-7XH (77% WI): 1,915 Boepd (37% oil)
  - Dicksion 1-21H (80% WI): 1,590 Boepd (45% oil)



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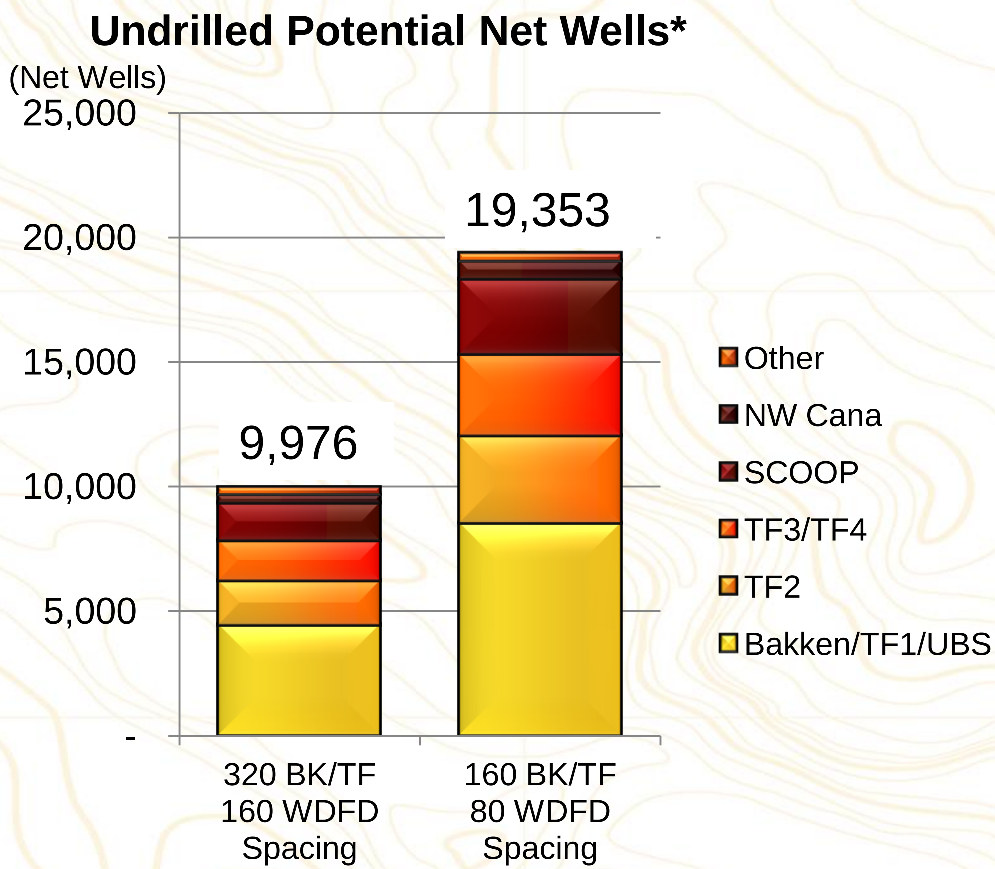
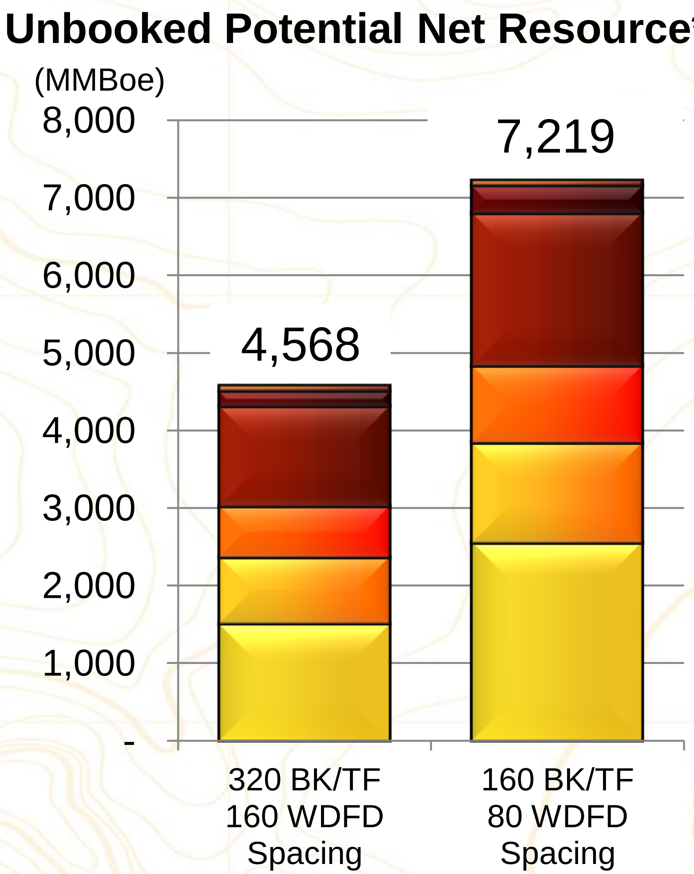
Realizing CLR's Unrisked Resource Potential

Mid-Year 2013 proved reserves: 922 MMBoe





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

Progress Report for Five-Year Plan

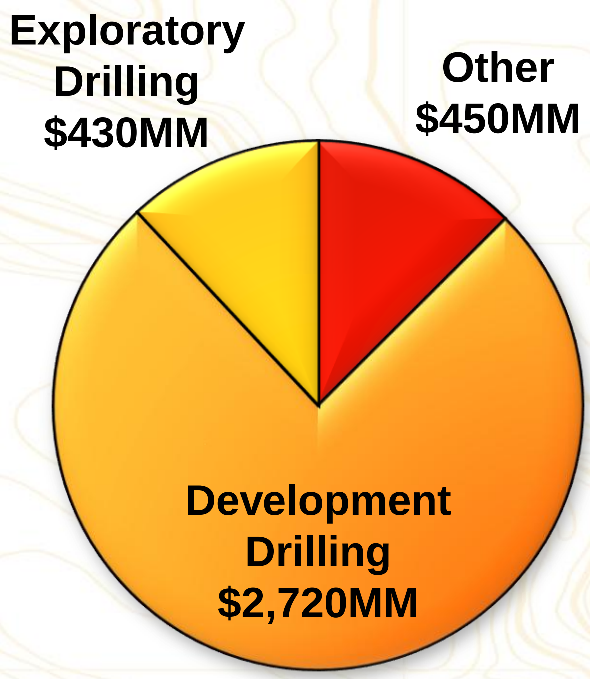
Metrics and Measurements of Success

	Status/Forecast				
Objective	**2013**	**2014**	**2015**	**2016**	**2017**
Triple production by 2017	✔+	✓			
Triple proved reserves by 2017	✔	✓			
Exploration:					
- Confirm lower Three Forks	✔	✓			
- Expand, de-risk Bakken	✔	✓			
- Expand, de-risk SCOOP	✔	✓			
Operating excellence and efficiency	✔+	✓			
Financial flexibility	✔+	✓			

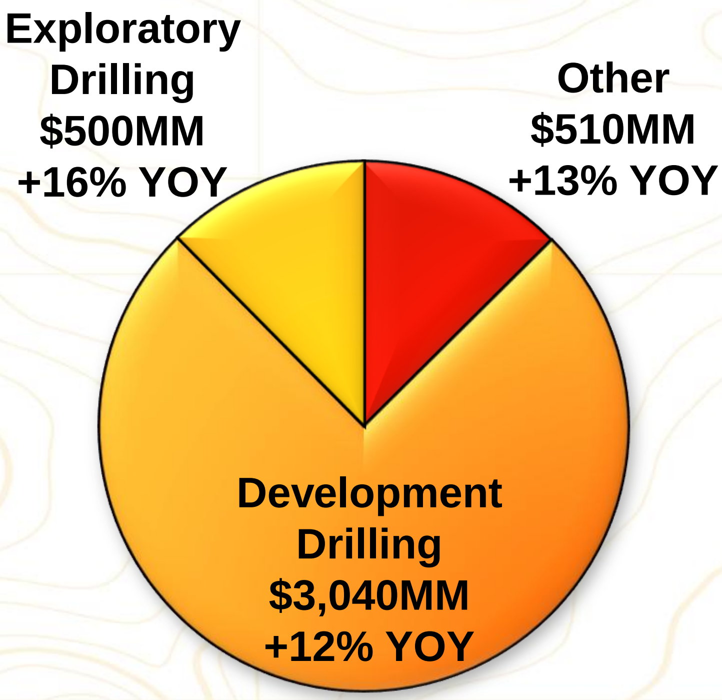
✓	New yearly target
✔	On track to accomplish
+	Should exceed goal

2013-14 Total Capital Expenditure Budgets

2013 Total Capital Expenditures: $3.6B



2014 Total Capital Expenditures: $4.05B

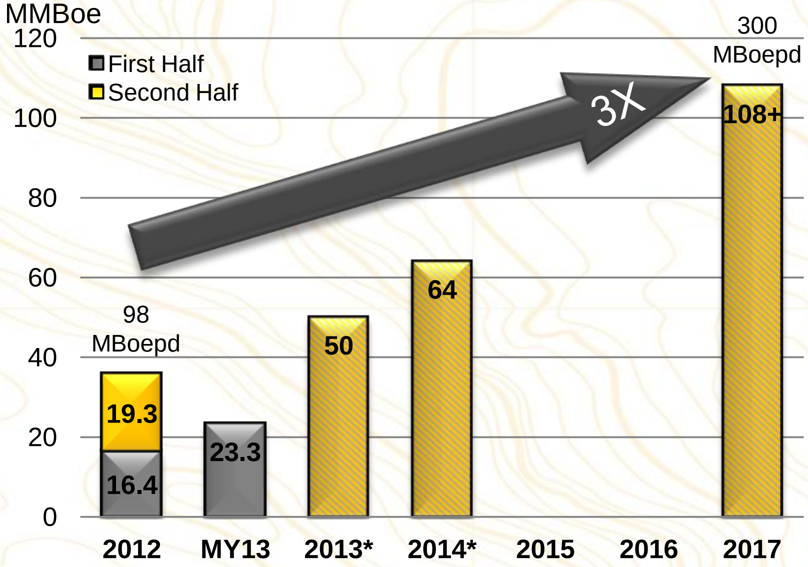


	2013	2014	
Average operated rigs	35	43	+ 23% YOY
Gross wells	900	1,090	+ 21% YOY
Net wells	329	400	+ 22% YOY

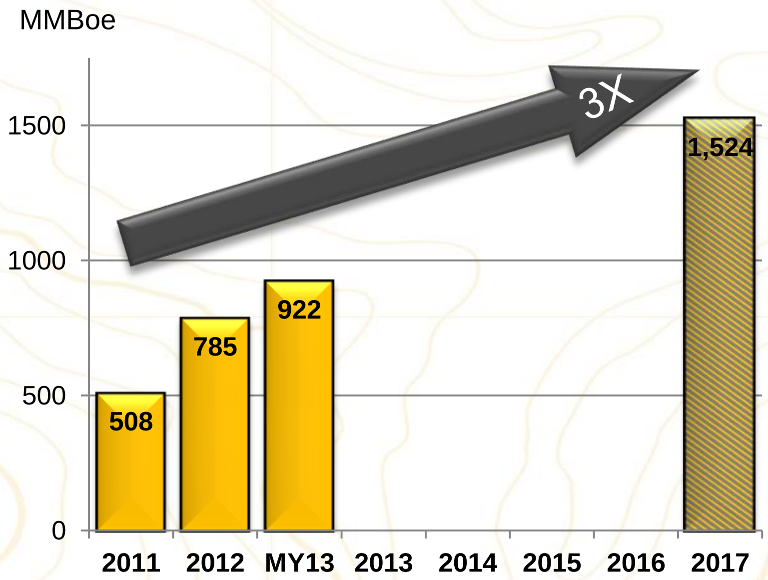
**Excludes acquisition capital expenditures.*

CLR Clear Vision for Growth

Production



Proved Reserves



- **Operating excellence with focus on safety and continued cost-efficiency**
- **Unmatched oil growth from existing portfolio with continued exploration**
- **Continue to develop marketing strategy to reach premier markets**
- **Maintain balance sheet strength and flexibility**

**Midpoint of guidance range.*

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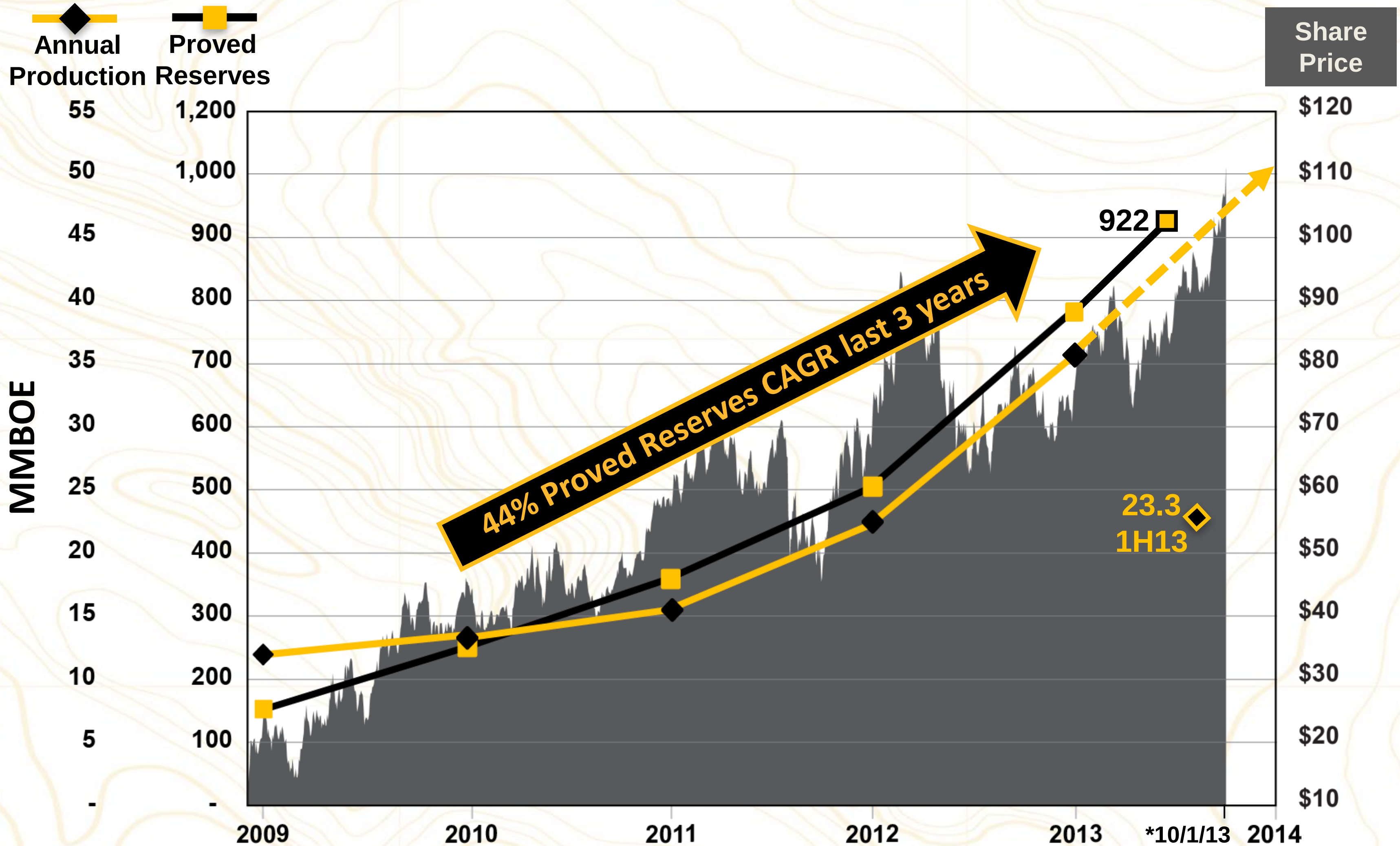
CLR: Production, Reserve and Stock Growth



*Closing stock price as of day shown.

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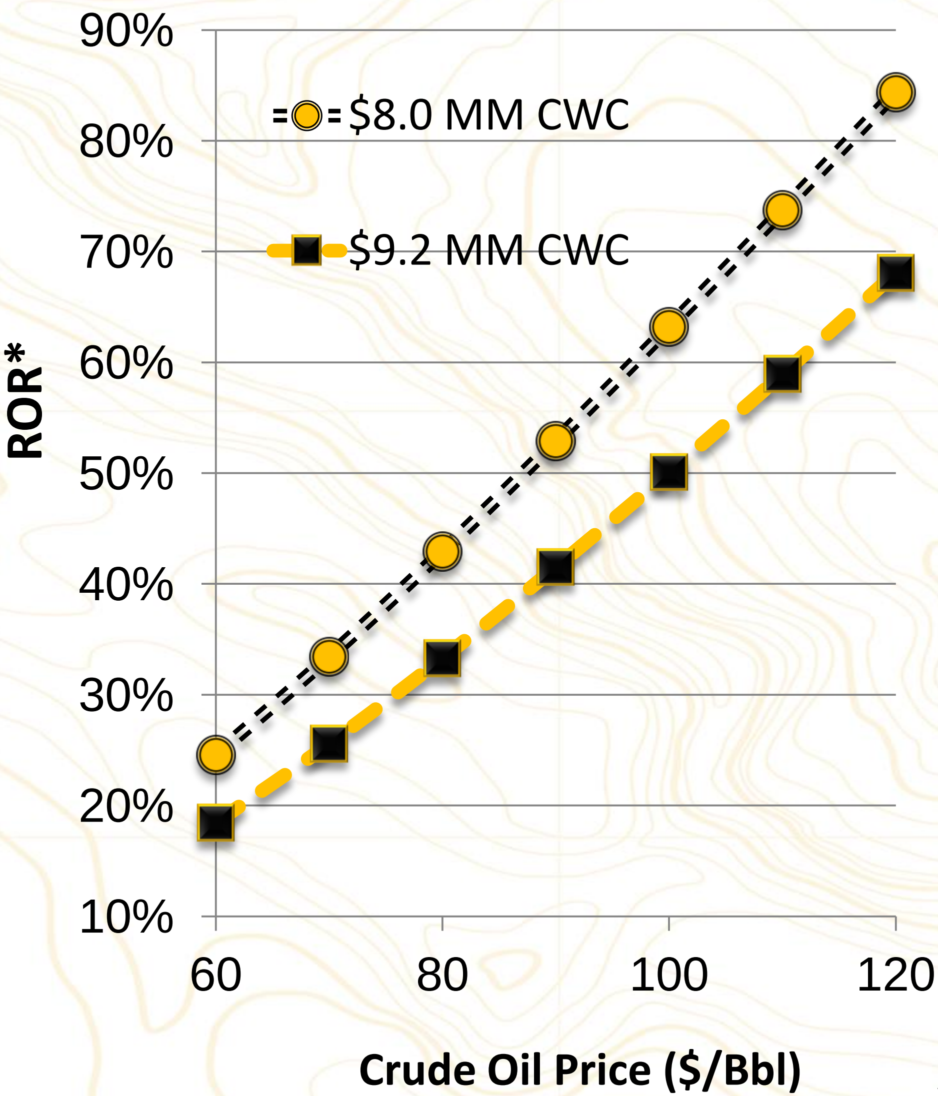
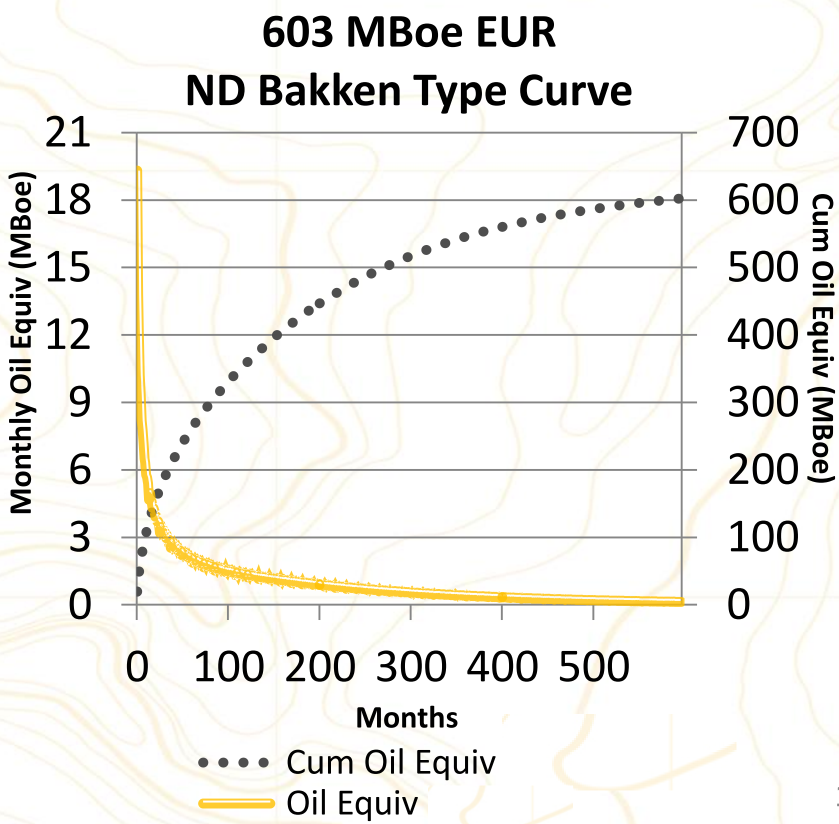
Appendix

Bakken Well Economics



- Average operated CWC
  - $9.2MM (2012)
  - $8.2MM (Achieved)
  - $8.0MM or less (Target YE13)

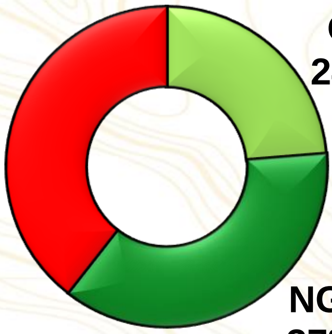


Assumes $7 differential. CWC = Completed Well Cost

SCOOP Economics

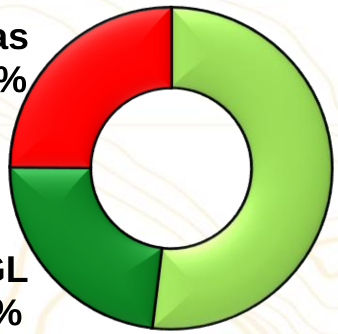
Condensate Fairway

EUR = 1,190 MBoe (61% liquids)**



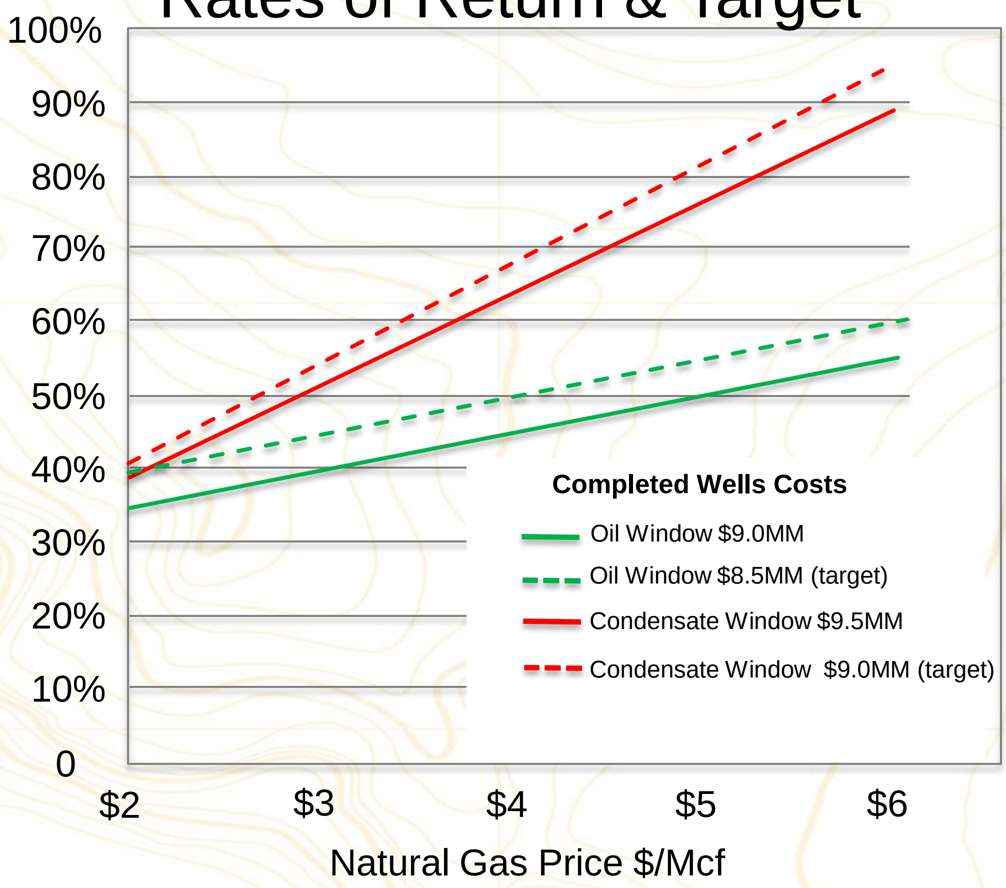
Oil Fairway

EUR = 626 MBoe (75% liquids) **



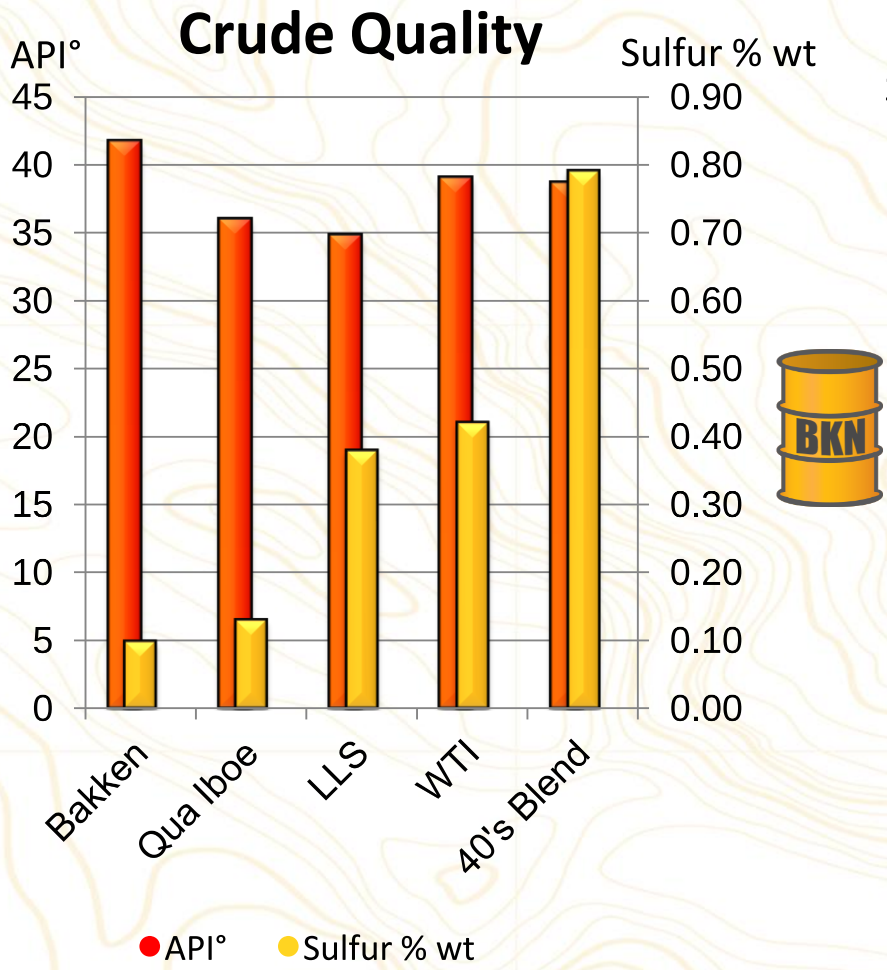
***Expected EUR and Yield*

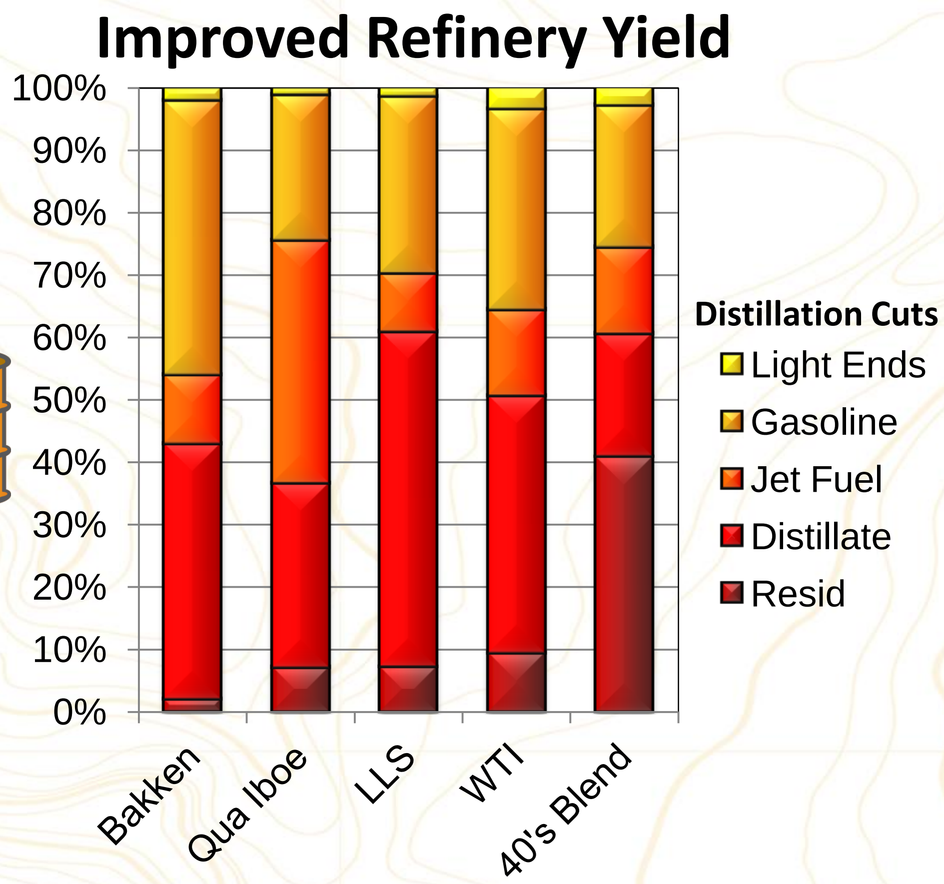
Rates of Return & Target*



*Oil Price $90 Gas Diff Premium +85%

America's Premium Light Sweet Crude





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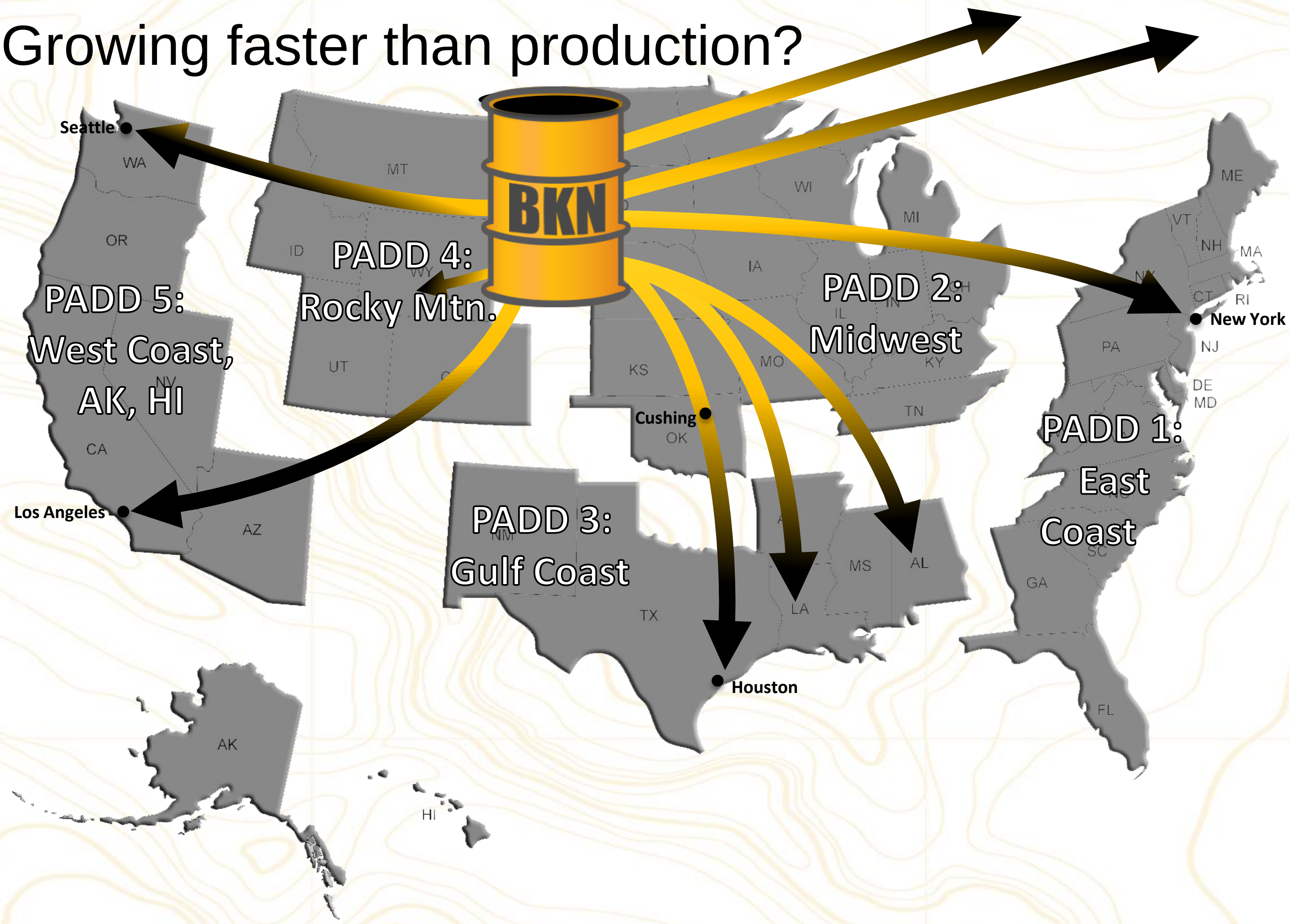
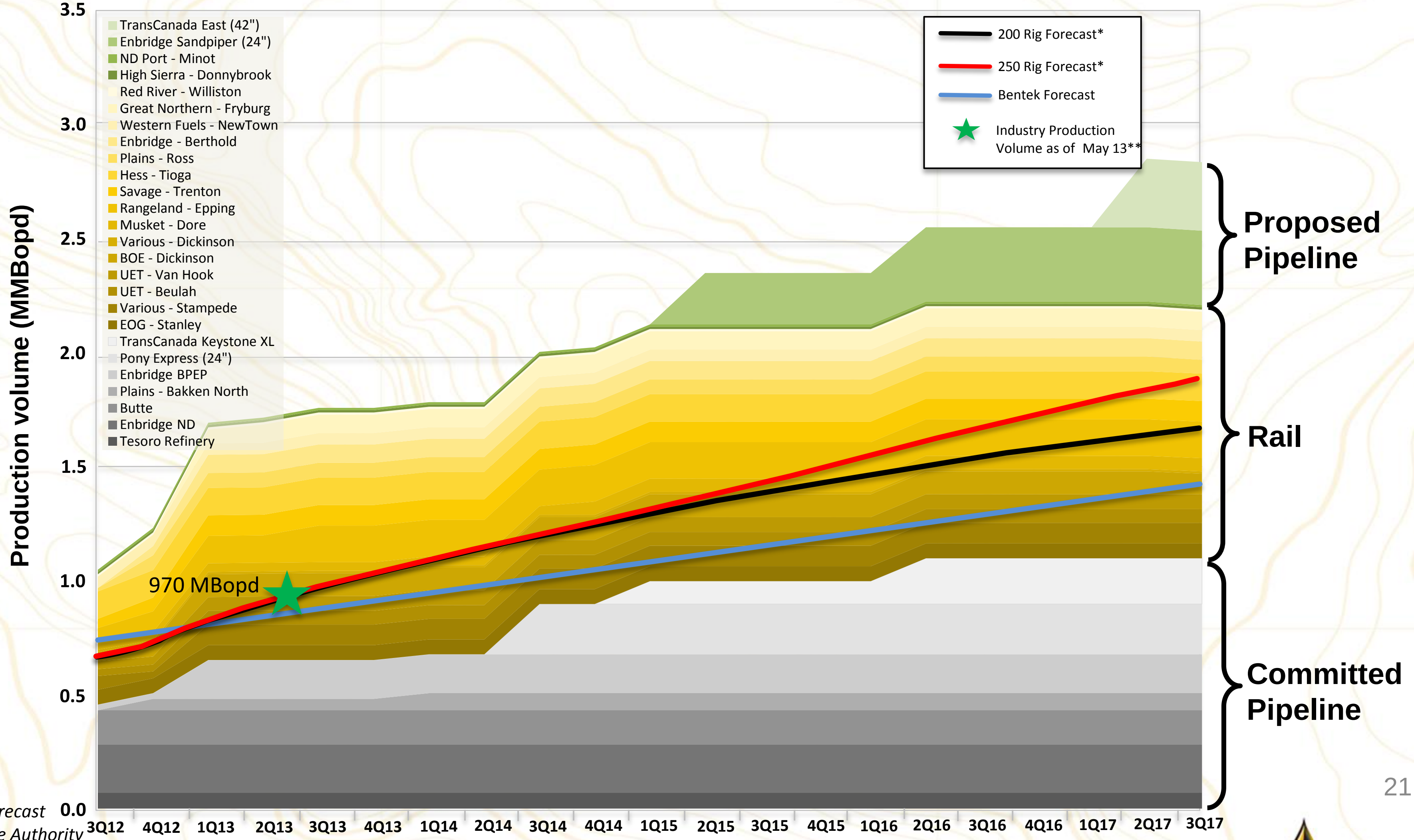
The Market for Bakken Premium Quality…

Growing faster than production?



Williston Basin Evacuation Capacity

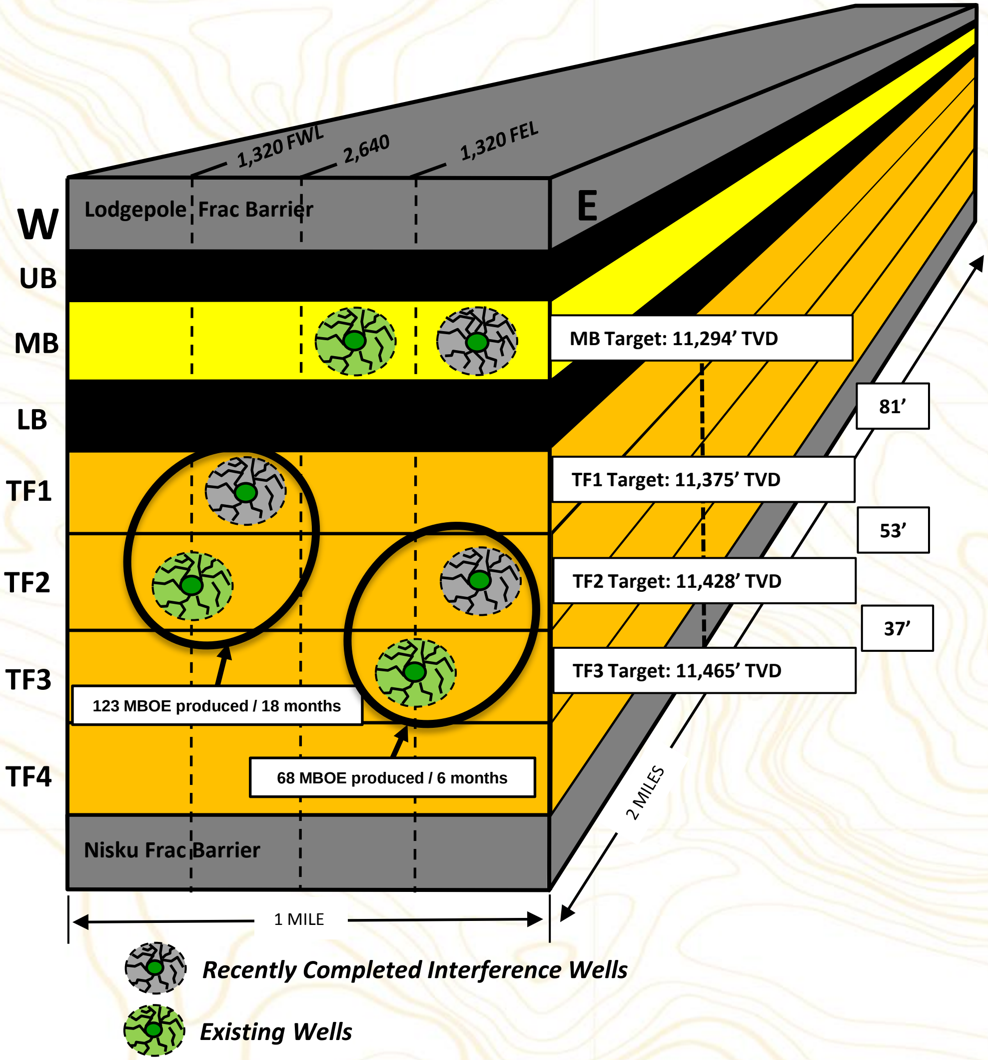


*CLR 2013 forecast

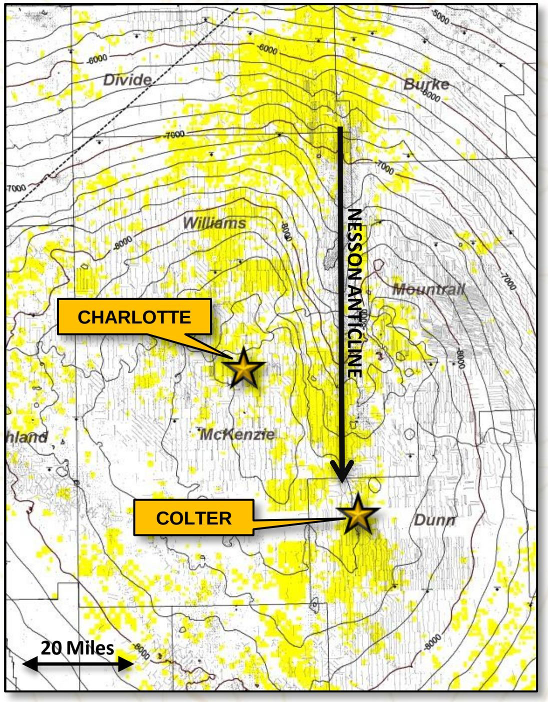
**ND Pipeline Authority

Charlotte Unit Testing Complete

McKenzie County, ND



Bakken Structure- 200' Contours

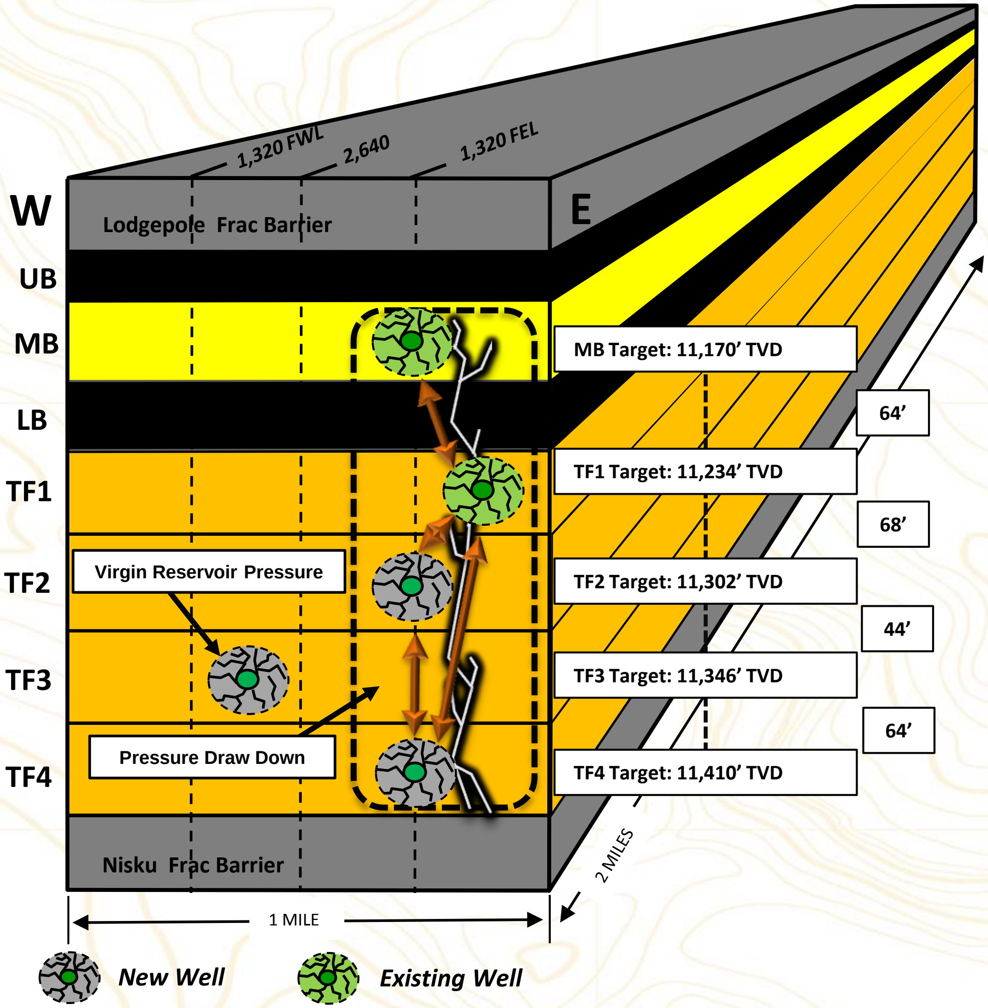


- **TF2 and TF3 proven productive**
- **Charlotte 2-22H and 3-22H have cumulatively produced 123,000 Boe and 68,000 Boe**
- **No evidence of production interference between wells**

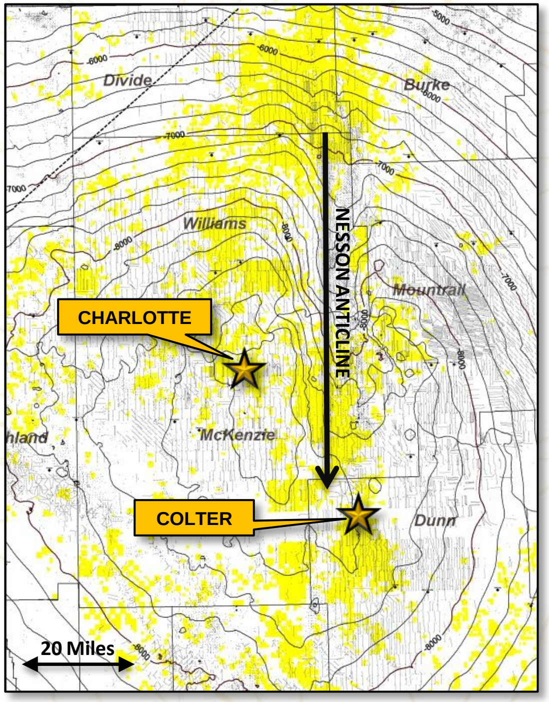
Bench	Charlotte	IP Boepd (in order of completion)
TF2	2-22H	1,396
TF3	3-22H	950
TF1	4-22H	1,365 (interference test)
TF2	6-22H	730

Colter Unit Lower TF Testing

Dunn County, ND

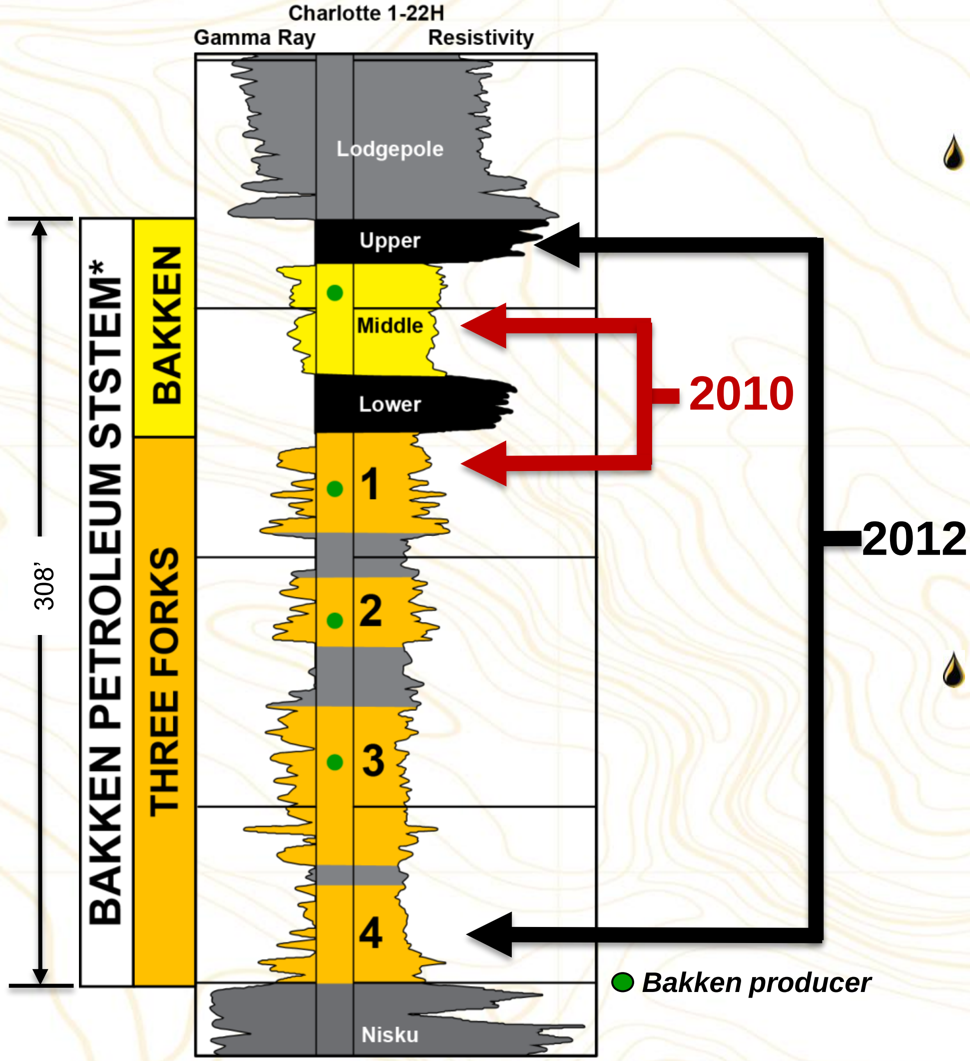


Bakken Structure- 200' Contours



- **Colter TF2 and TF4 tests exhibit pressure draw down**
  - Colter MB and TF1 have produced 530 MBoe
  - Tectonic fractures (Nesson Anticline) communicating benches
- **Colter TF3 producing at 1,750 Boe per day at 3,200 psi (strong pressure)**

Tight Oil Resource Plays: Larger than We Think!



- 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.

Cost Discipline Driving Excellent Margins

	Years Ended December 31				
	2009	2010	2011	2012	YTD June 2013
Realized oil price ($/Bbl)	$54.44	$70.69	$88.51	$84.59	$88.50
Realized natural gas price ($/Mcf)	$3.22	$4.49	$5.24	$4.20	$5.11
Oil production (Bopd)	27,459	32,385	45,121	68,497	91,077
Natural gas production (Mcfpd)	59,194	65,598	100,469	174,521	225,467
Total production (Boepd)	37,324	43,318	61,865	97,583	128,655
EBITDAX ($000's) (1)	$450,648	$810,877	$1,303,959	$1,963,123	$1,329,635
Key Operational Statistics (per Boe) (2)					
Average oil equivalent price (excludes derivatives)	$45.10	$59.70	$73.05	$66.83	$71.68
Production expense	$6.89	$5.87	$6.13	$5.49	$5.79
Production tax and other	$3.37	$4.82	$6.42	$6.42	$6.61
G&A (3)	$2.19	$2.35	$2.36	$2.38	$2.11
Interest	$1.72	$3.34	$3.40	$3.95	$4.66
Total cash costs	**$14.17**	**$16.38**	**$18.31**	**$18.24**	**$19.17**
Cash margin	**$30.93**	**$43.32**	**$54.74**	**$48.59**	**$52.51**
Cash margin %	**69%**	**73%**	**75%**	**73%**	**73%**

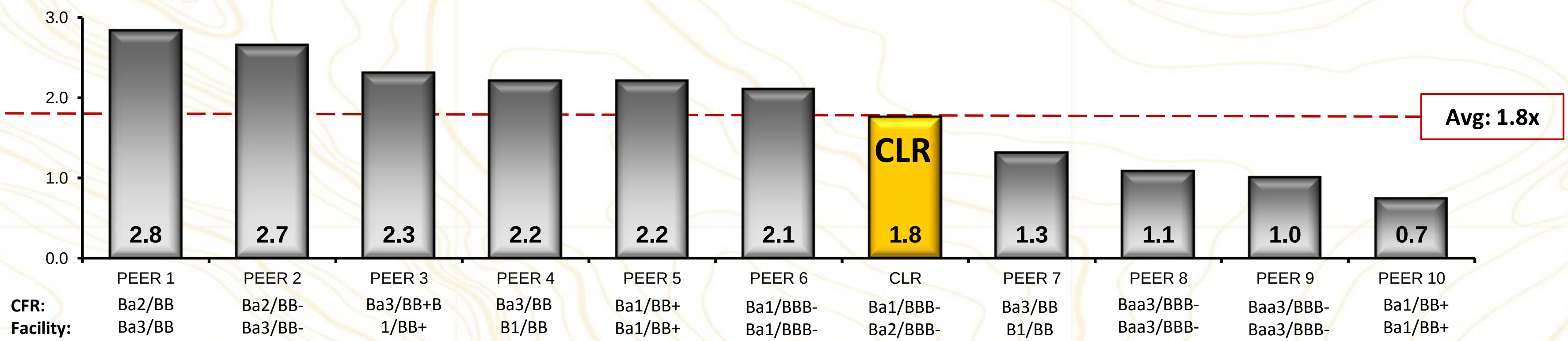
1) *See "EBITDAX Reconciliation to GAAP" in Appendix for a reconciliation of net income to EBITDAX.*
2) *Average costs per Boe have been computed using sales volumes and exclude any effect of derivative transactions.*
3) *Excludes G&A related to Equity based compensation and relocation expense.*

Capital Flexibility & Efficiency

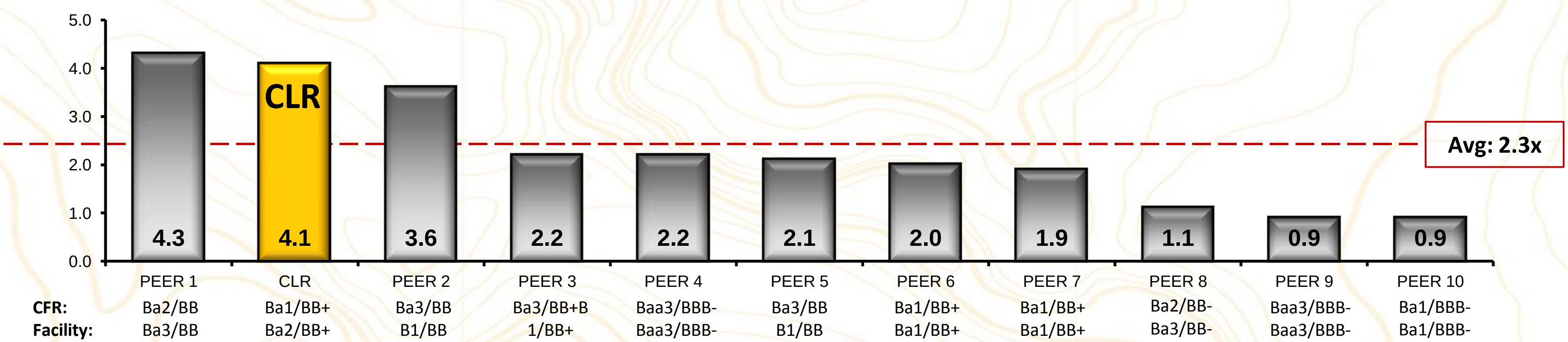
Credit Statistics & Ratings Analysis

Source: public disclosures and SEC filings

Total Debt / EBITDAX



Recycle Ratio—Industry Leader[1]



(1) Recycle Ratio is calculated as the LTM profit per BOE divided by the 3-year average F&D cost per BOE

2014 Operational and Financial Guidance

As of September 10, 2013

	2013	2014
Production growth (YOY)	38% to 40%	***26% to 32%***
Capital expenditures (non-acquisition)	$3.6B	***$4.05B***
<u>Operating Expenses:</u>		
Production expense per Boe	***$5.60 to $6.00***	***$5.60 to $6.10***
Production tax (% of oil & gas revenue)*	8% to 9%	***8% to 9%***
DD&A per Boe	***$18.50 to $19.50***	***$17.50 to $19.50***
G&A expense per Boe**	***$2.00 to $2.50***	***$2.00 to $2.50***
Non-cash equity compensation per Boe	***$0.70 to $0.80***	***$0.70 to $0.90***
<u>Average Price Differentials:</u>		
NYMEX WTI crude oil (per barrel of oil)	***($6.00) to ($8.00)***	***($8.00) to ($11.00)***
Henry Hub natural gas (per Mcf)	+$1.00 to $1.50	***+$1.00 to $1.50***
Income tax rate	37%	***37%***
Deferred taxes	90% to 95%	***90% to 95%***

All changes from previous or initial guidance are represented in bold and italic.

**Does not include other expenses, such as natural gas transportation fees, which could represent another 1%. **Excludes non-cash equity compensation.*

Quarterly Cash Flow

	Six months ended 6/30/12	1Q 2013	2Q 2013	YTD 6/30/13
			In thousands	
Net income	$ 474,778	$ 140,627	$ 323,270	$ 463,897
Adjustments to reconcile net income to net cash provided by operating activities:				
Non-cash expenses	269,885	428,913	310,090	739,003
Changes in assets and liabilities	26,167	(111,429)	65,474	(45,955)
Net cash provided by operating activities	770,830	458,111	698,834	1,156,945
Net cash used in investing activities	(1,773,492)	(873,153)	(977,024)	(1,850,177)
Net cash provided by financing activities	978,255	437,859	440,057	877,916
Net change in cash and cash equivalents	(24,407)	22,817	161,867	184,684
Cash and cash equivalents at beginning of period	53,544	35,729	58,546	35,729
Cash and cash equivalents at end of period	$ 29,137	$ 58,546	$ 220,413	$ 220,413

INDEPENDENT MEANS

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.

See the following page for reconciliations of our net income and operating cash flows to EBITDAX for the applicable periods.

EBITDAX Reconciliation to GAAP (cont'd)

The following tables provide reconciliations of our net income and operating cash flows to EBITDAX for the periods presented:

In thousands	2009	2010	2011	2012	2Q 2013	1H 2013
Net income	$ 71,338	$ 168,255	$ 429,072	$ 739,385	$ 323,270	$ 463,897
Interest expense	23,232	53,147	76,722	140,708	61,378	108,853
Provision for income taxes	38,670	90,212	258,373	415,811	189,858	272,448
Depreciation, depletion, amortization and accretion	207,602	243,601	390,899	692,118	236,790	450,468
Property impairments	83,694	64,951	108,458	122,274	79,712	119,793
Exploration expenses	12,615	12,763	27,920	23,507	11,151	20,965
Impact from derivative instruments:						
Total (gain) loss on derivatives, net	1,520	130,762	30,049	(154,016)	(199,056)	(114,225)
Total realized gain (loss) (cash flow) on derivatives, net	569	35,495	(34,106)	(45,721)	(4,752)	(11,562)
Non-cash (gain) loss on derivatives, net	2,089	166,257	(4,057)	(199,737)	(203,808)	(125,787)
Non-cash equity compensation	11,408	11,691	16,572	29,057	9,756	18,998
EBITDAX	$ 450,648	$ 810,877	$ 1,303,959	$ 1,963,123	$ 708,107	$ 1,329,635

In thousands	2009	2010	2011	2012	2Q 2013	1H 2013
Net cash provided by operating activities	$ 372,986	$ 653,167	$ 1,067,915	$ 1,632,065	$ 698,834	$ 1,156,945
Current income tax provision	2,551	12,853	13,170	10,517	5,830	5,830
Interest expense	23,232	53,147	76,722	140,708	61,378	108,853
Exploration expenses, excluding dry hole costs	6,138	9,739	19,971	22,740	5,349	12,902
Gain (loss) on sale of assets, net	709	29,588	20,838	136,047	(349)	(213)
Excess tax benefit from stock-based compensation	2,872	5,230	--	15,618	--	--
Other, net	(3,890)	(3,513)	(4,606)	(7,587)	2,539	(637)
Changes in assets and liabilities	46,050	50,666	109,949	13,015	(65,474)	45,955
EBITDAX	$ 450,648	$ 810,877	$ 1,303,959	$ 1,963,123	$ 708,107	$ 1,329,635