Continental
RESOURCES

Investor Update

August 2016

rock solid.

OUR ASSETS OUR PEOPLE OUR OUTLOOK

NYSE: CLR

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, forecasts or expectations regarding the Company's business and statements or information concerning the Company's future operations, performance, financial condition, production and reserves, schedules, plans, timing of development, rates of return, budgets, costs, business strategy, objectives, and cash flows, 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 these assumptions and expectations are reasonable, they are inherently subject to numerous business, economic, competitive, regulatory and other risks and uncertainties, most of which are difficult to predict and many of which are beyond the Company's control. No assurance can be given that such expectations will be correct or achieved or the assumptions are accurate. The risks and uncertainties include, but are not limited to, commodity price volatility; the geographic concentration of our operations; financial, market and economic volatility; the inability to access needed capital; the risks and potential liabilities inherent in crude oil and natural gas exploration, drilling and production and the availability of insurance to cover any losses resulting therefrom; difficulties in estimating proved reserves and other revenue-based measures; declines in the values of our crude oil and natural gas properties resulting in impairment charges; our ability to replace proved reserves and sustain production; the availability or cost of equipment and oilfield services; leasehold terms expiring on undeveloped acreage before production can be established; our ability to project future production, achieve targeted results in drilling and well operations and predict the amount and timing of development expenditures; the availability and cost of transportation, processing and refining facilities; legislative and regulatory changes adversely affecting our industry and our business, including initiatives related to hydraulic fracturing; increased market and industry competition, including from alternative fuels and other energy sources; and the other risks described under Part I, Item 1A Risk Factors and elsewhere in the Company's Annual Report on Form 10-K for the year ended December 31, 2015, 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 on which such statement is made. 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. Except as expressly stated above or otherwise required by applicable law, the Company undertakes no obligation to publicly correct or update any forward-looking statement whether as a result of new information, future events or circumstances after the date of this presentation, or otherwise.

Readers are cautioned that initial production rates are subject to decline over time and should not be regarded as reflective of sustained production levels. In particular, production from horizontal drilling in shale oil and natural gas resource plays and tight natural gas plays that are stimulated with extensive pressure fracturing are typically characterized by significant early declines in production rates.

We use the term "EUR" or "estimated ultimate recovery" to describe potentially recoverable oil and natural gas hydrocarbon quantities. We include these estimates to demonstrate what we believe to be the potential for future drilling and production on our properties. These estimates are by their nature much more speculative than estimates of proved reserves and require substantial capital spending to implement recovery. Actual locations drilled and quantities that may be ultimately recovered from our properties will differ substantially. EUR data included herein remain subject to change as more well data is analyzed.

2Q 2016 Highlights

Updating guidance due to strong outperformance

- Full-year production guidance raised to 210,000 to 220,000 Boe per day
- Exit rate production guidance raised to 195,000 to 205,000 Boe per day
- Production expense lowered to $3.75 to $4.25 per Boe
- Total G&A (cash and non-cash) lowered to $1.85 to $2.45 per Boe
- NYMEX WTI crude oil differential lowered to ($7.00) to ($8.00) per Bo

Company agrees to sell non-strategic SCOOP leasehold for $281 million

- Will retain ~384,000 net acres in SCOOP Woodford after close
- Includes 550 net Boe per day production with minimal proved reserves (less than 1%)
- Proceeds from pending sale to be utilized to pay down debt

Excellent results extend over-pressured STACK oil window west

- Madeline 1-9-4XH IP: 3,538 Boe per day (71% oil), 9,600' lateral
- Frankie Jo 1-25-24XH: IP 2,627 Boe per day (56% oil), 9,700' lateral

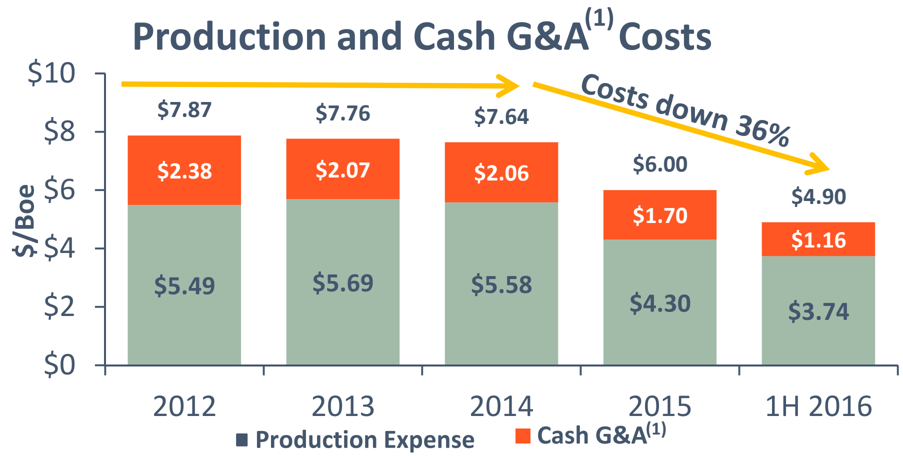
Enhanced completions uplift SCOOP Woodford oil EURs by ~30%

- 1.3 MMBoe EUR (62% oil) for 9,800-foot lateral
- 32% ROR at $9.8 million CWC, $45 WTI and $2.50 gas

Operational efficiencies continue to translate to the bottom line

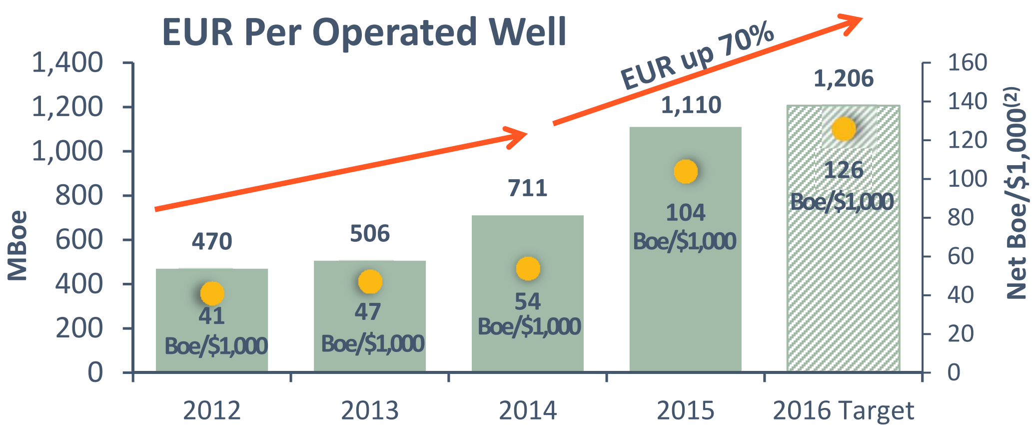
- STACK oil window target CWC down $500,000 to $9.0 million
- Production expense down 13% over 2015 average and down 33% over 2014 average

CLR Capital Efficiency Taken to New Level
Structural Improvement Since 2014



From FY 2014 to 1H 2016:

- Combined Production and Cash G&A[1] costs DOWN 36%



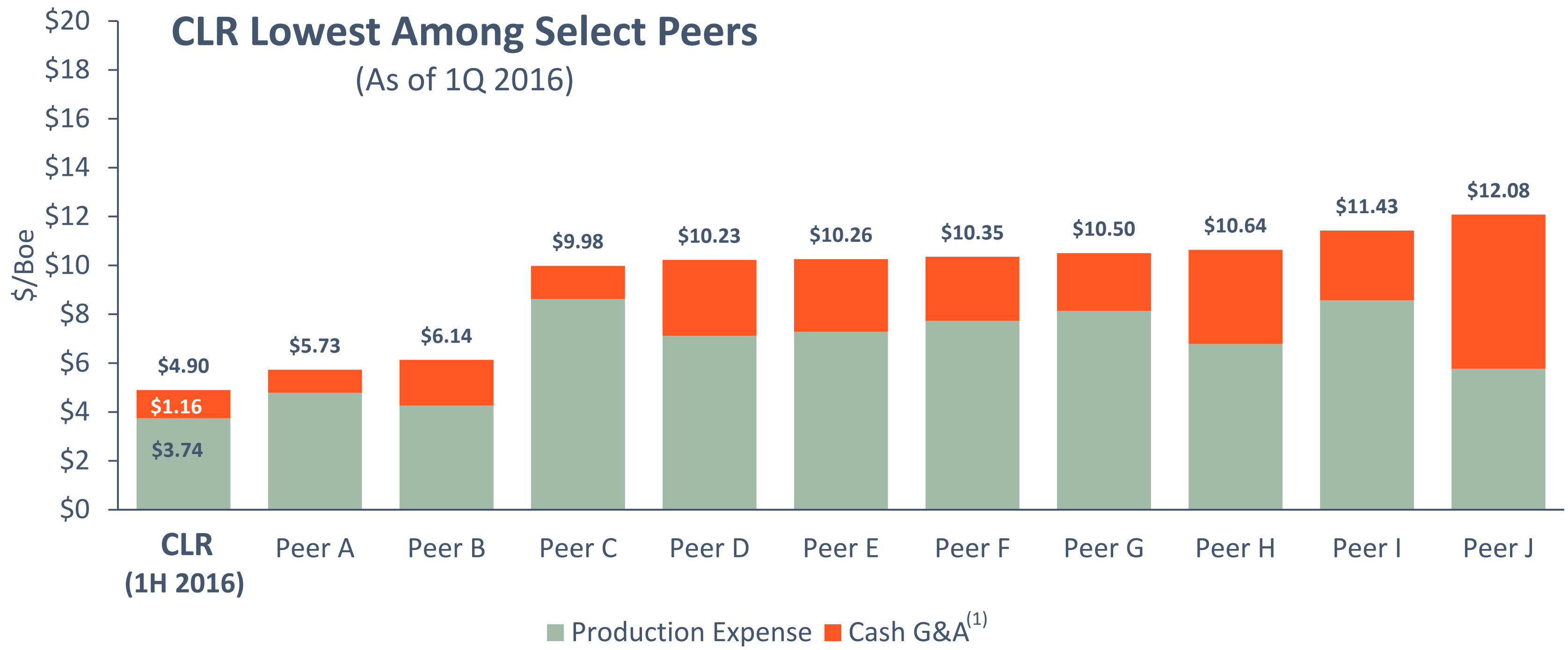
From FY 2014 to FY 2016 target:

- EUR per operated well UP 70%
- Capital efficiency[2] (Boe/$ invested) UP 133%

1. See "Cash G&A Reconciliation to GAAP" on slide 36 for a reconciliation of GAAP Total G&A per Boe to Cash G&A per Boe, which is a non-GAAP measure
2. Average net revenue interest of 82% assumed for net capital efficiency

Note: Capital efficiency based on reserves developed per dollar invested

CLR Production Expense and Cash G&A[1] Comparison



Peers include: CXO, DVN, EOG, NBL, NFX, OAS, PXD, WLL, WPX and XEC

Note: Production expense for peer group includes gathering expense where applicable; cash G&A excludes equity based compensation
Source: GMP Securities, June 2016

1. See "Cash G&A Reconciliation to GAAP" on slide 36 for a reconciliation of CLR GAAP Total G&A per Boe to CLR Cash G&A per Boe, which is a non-GAAP measure

CLR Delivering Exceptional Shareholder Value

Key Strengths

Top quartile assets in U.S. [1]
Capital efficiency more than doubled since 2014[2]
Lowest production expense per Boe among select oil-weighted peers[3]

Key Catalysts

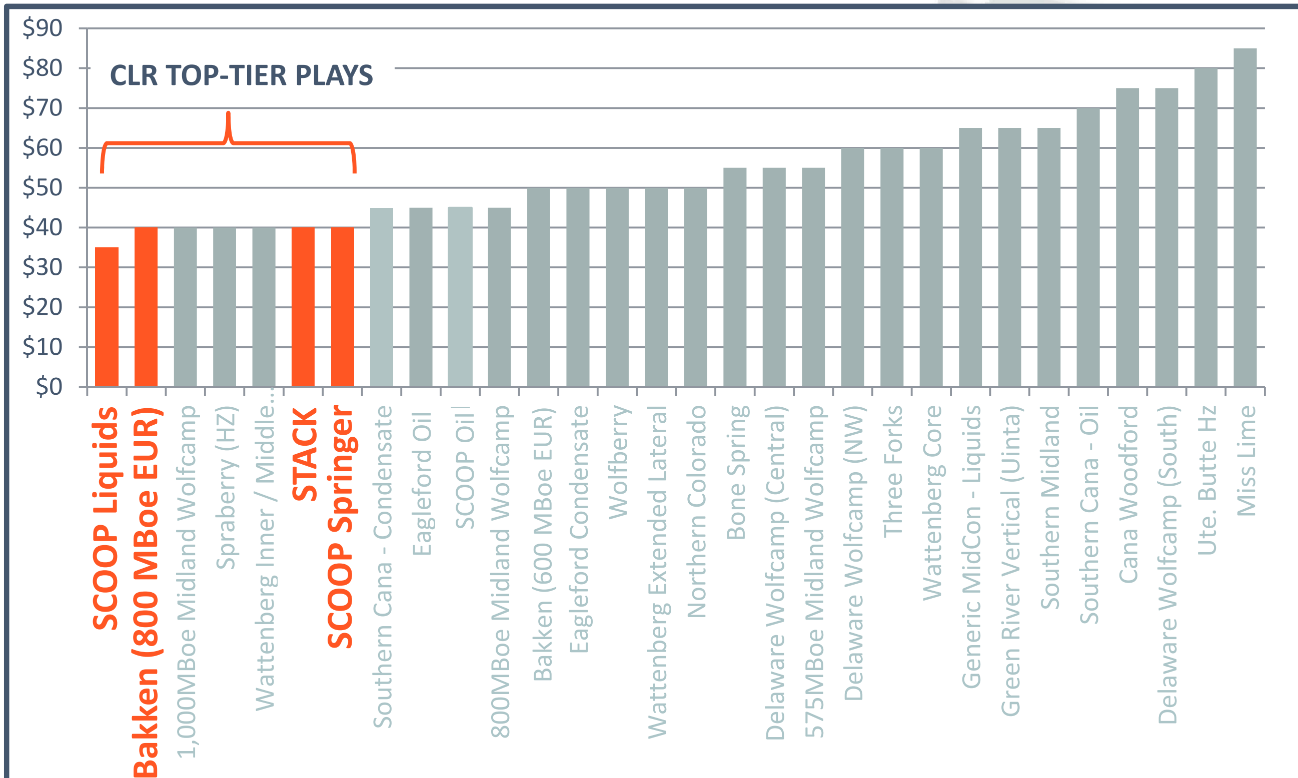
STACK Meramec	Adds up to 25% to CLR net unrisked resource potential
Bakken DUCs	~190 gross operated wells at YE 2016, ~850 MBoe average EUR per well
Bakken core	10+ years of drilling ~775 MBoe average per well (assuming 15 rigs)
SCOOP Springer	Oil asset ready for full-field development
Enhanced completions	Improving well performance in all plays
19 operated rigs	Maintained momentum and grew expertise during the last 18 months
Strong balance sheet	Ample liquidity

1. See slide 7 for supporting detail
2. See slide 4 for supporting detail
3. See slide 5 for supporting detail

CLR Assets Are in Top Quartile of U.S. Plays

It All Comes Down to the Rocks

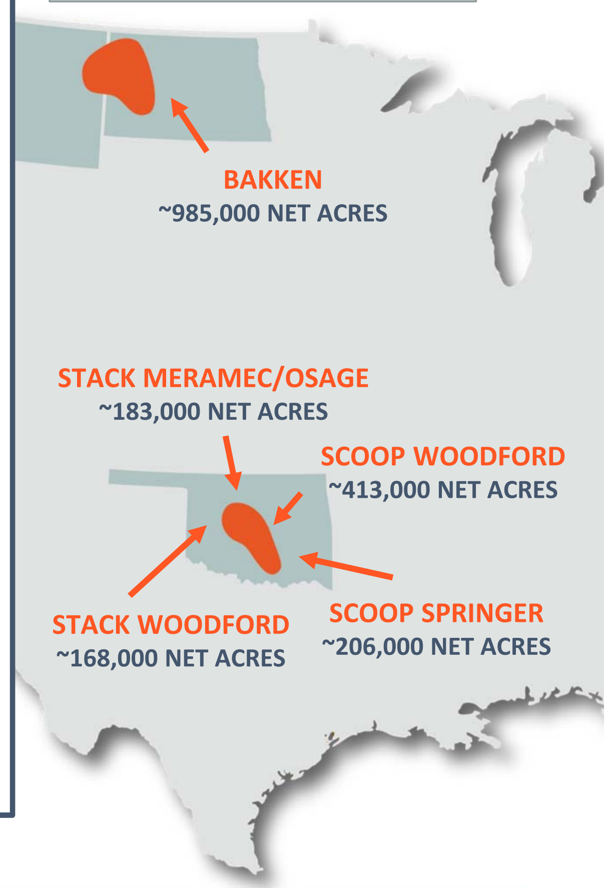
Single Well Breakeven For North American Oil Plays[1]



1. To generate a 10% after-tax IRR

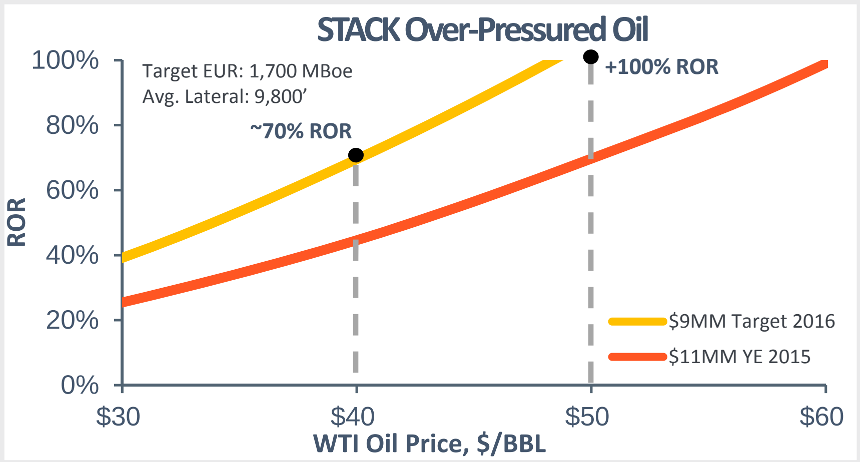
Source: Evercore ISI, January 2016

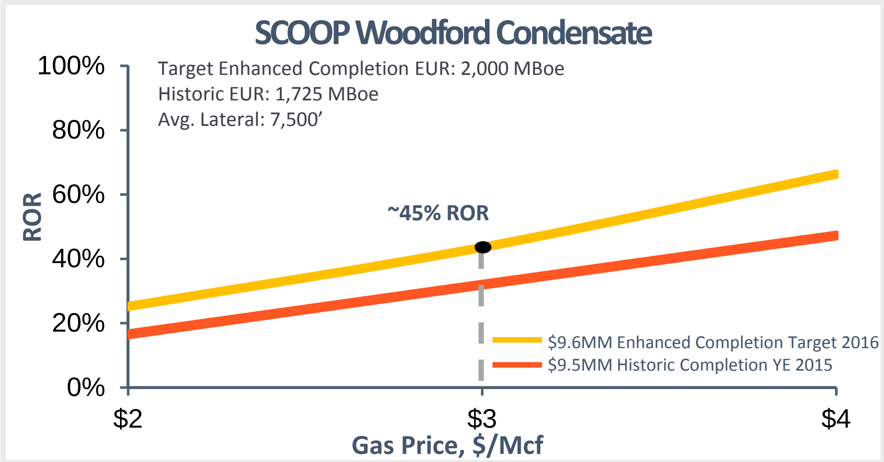
~2.0 Million
Net Reservoir Acres

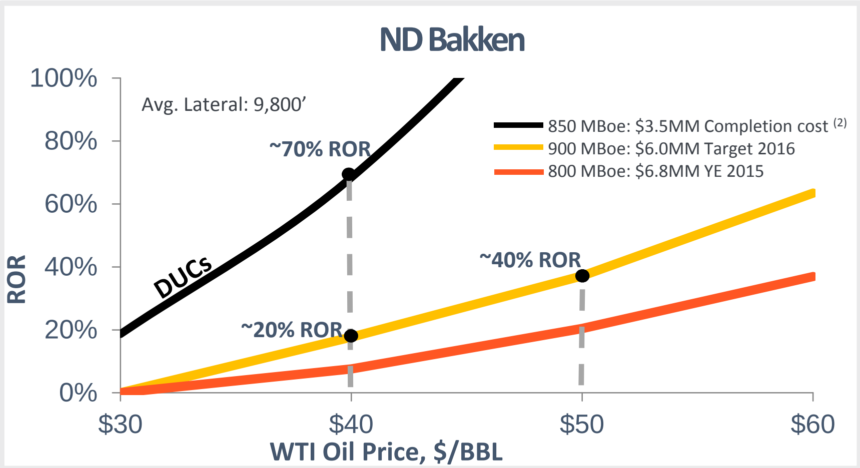


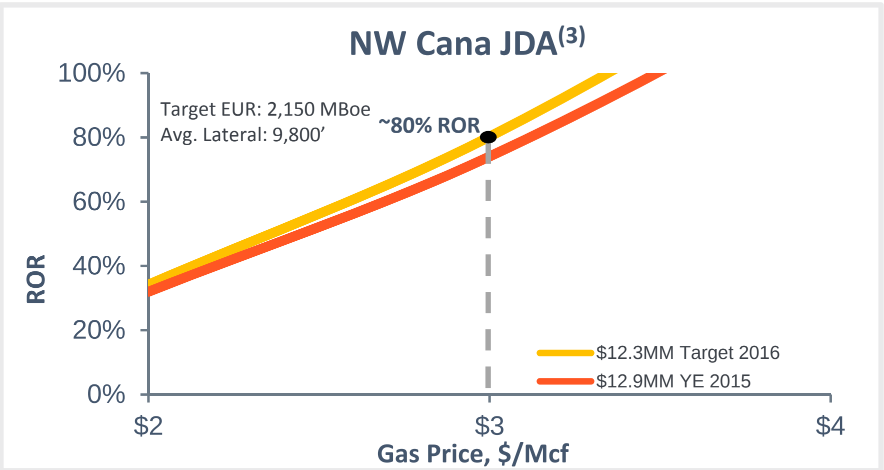
Note: Post sale the Company will retain ~384,000 net acres in SCOOP Woodford and ~191,000 net acres in SCOOP Springer

Top-Tier Rates of Return(1)





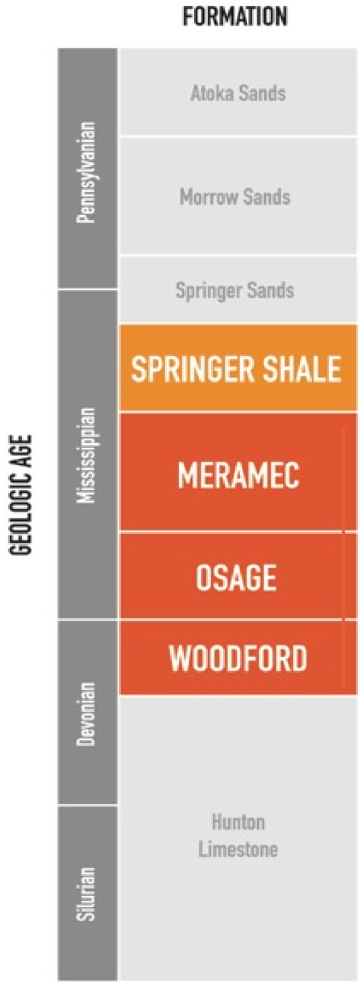




1. Pre-tax rate of return (ROR) is based on projected cash flow and time value of money; costs include completed well cost, production expense, severance tax and variable operating costs. $2.50 gas is used for oil price sensitivities and $45 WTI is used for gas price sensitivities. The description of the ROR calculation applies to any ROR reference appearing in this presentation.
2. Estimated ~190 gross operated DUC's at YE 2016, $3.5MM gross incremental completion cost
3. NW Cana economics factor in a ~50% carry from JDA participant

SCOOP & STACK

Leading Acreage Positions in Top-Tier Plays



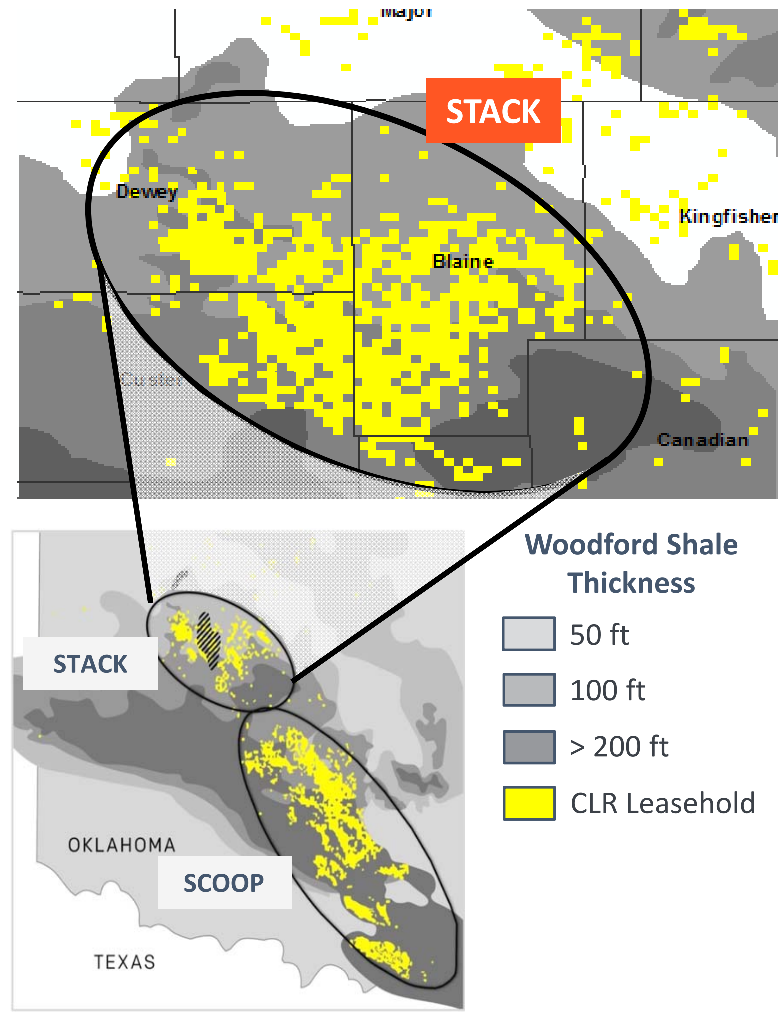
~970,000 Net Reservoir Acres

STACK Meramec/Osage
~183,000 Net Acres

STACK Woodford
~168,000 Net Acres

SCOOP Woodford
~413,000 Net Acres

SCOOP Springer
~206,000 Net Acres



Note: Post sale the Company will retain ~384,000 net acres in SCOOP Woodford and ~191,000 net acres in SCOOP Springer

STACK 2Q 2016 Results

Expanding Meramec's Proven Productive Footprint

2 excellent step-out wells extend over-pressured oil window 17 miles west of Verona

2 confirmation wells completed near Verona

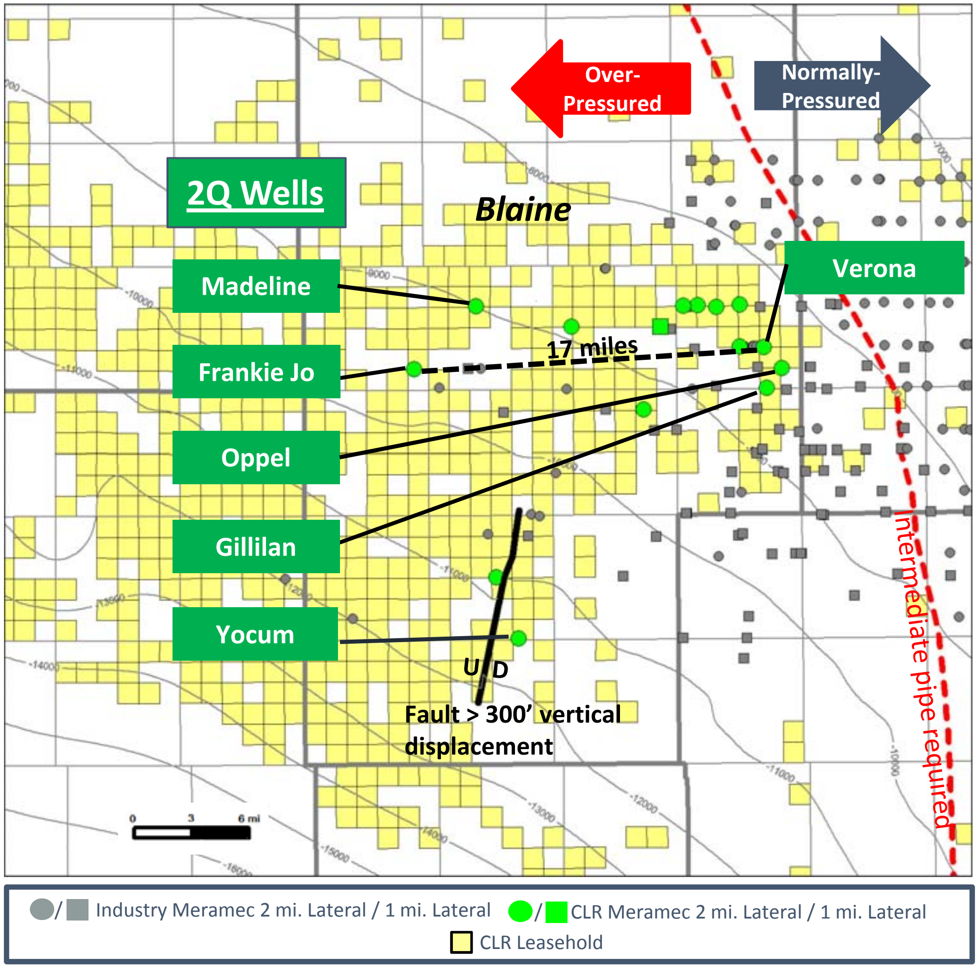
1 excellent gas producer completed 18 miles south of Verona

Over-pressured oil window

Well Name	IP (Boepd) / Flowing Pressure	LL
Madeline 1-9-4XH	3,538 (71% oil) / 4,500 psi	9,581'
Frankie Jo 1-25-24XH	2,627 (56% oil) / 4,320 psi	9,746'
Gillilan 1-35-24XH	2,439 (70% oil) / 2,030 psi	9,885'
Oppel 1-25-24XH	1,308 (76% oil) / 1,670 psi	7,132'

Over-pressured gas window

Yocum 1-35-26XH	2,355 (99% gas) / 4,810 psi	9,288'



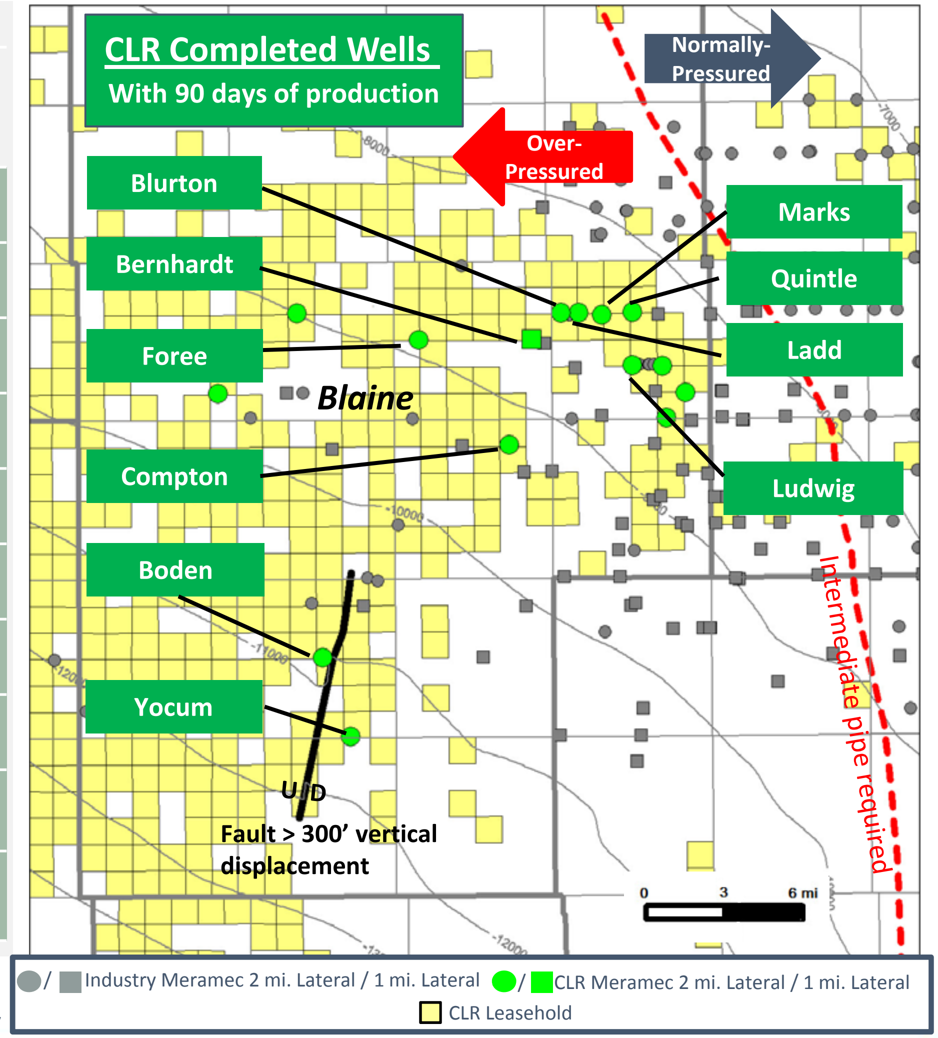
STACK: Exceptional, Repeatable Meramec Results

Competes with Best Oil Plays in U.S.

Data as of August 1, 2016

Well Name	Prod. Days	Cum. Production (MBoe)	Current Rate (Boepd)	Current Flowing Pressure
Boden(1)	172	361 (27% oil)	1236 (26% oil)	4215 psi
Ludwig(1)(2)	310	279 (74% oil)	767 (70% oil)	1575 psi
Compton(1)	157	221 (70% oil)	704 (68% oil)	1235 psi
Yocum	104	179 (99% gas)	1621 (99% gas)	2495 psi
Blurton(1)	204	176 (76% oil)	636 (74% oil)	1145 psi
Ladd(1)	284	171 (75% oil)	610 (72% oil)	1095 psi
Marks	327	144 (58% oil)	162 (52% oil)	710 psi
Foree	107	110 (60% oil)	713 (48% oil)	840 psi
Quintle(1)	98	109 (72% oil)	897 (69% oil)	930 psi
Bernhardt (1-mile)	99	45 (72% oil)	343 (71% oil)	605 psi

1. Wells not produced at maximum capacity
2. Current rates are prior to June 9, 2016 when well was shut in for stimulation for Ludwig density



STACK
Leasehold Position Increasing – Well Costs Decreasing

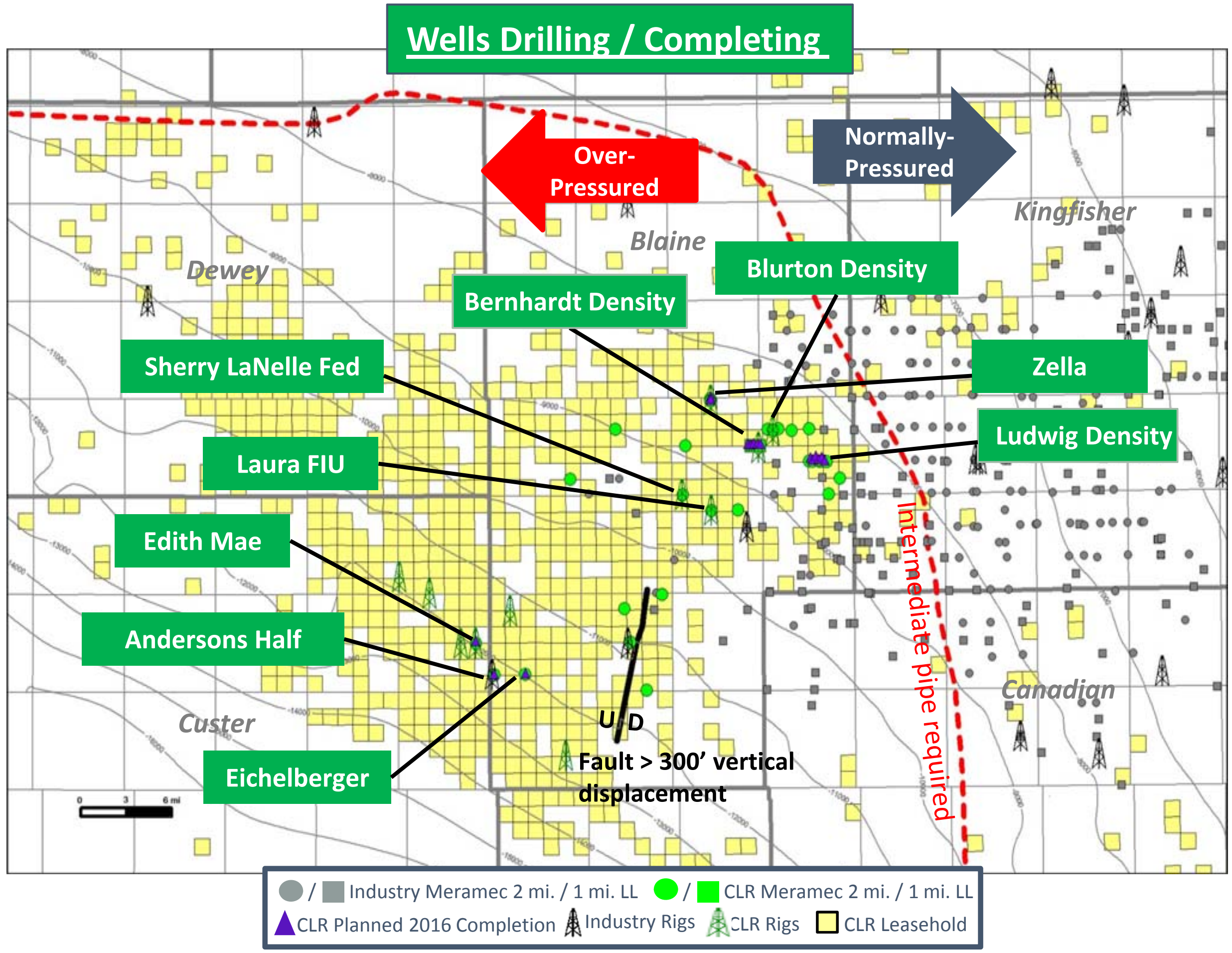
183,000 net acres
- +27,000 net acres over YE 2015

~95% of acreage in over-pressured window
- Reservoir 700' – 1,200' thick
- ~40% oil, ~40% liquids-rich, ~20% gas
- 60% HBP by YE 2016

Project over 1,200 potential net Meramec and Woodford drilling locations
- Targeting 2 Meramec zones on average, 1 Woodford zone
- 12 wells per 1,280-acre unit

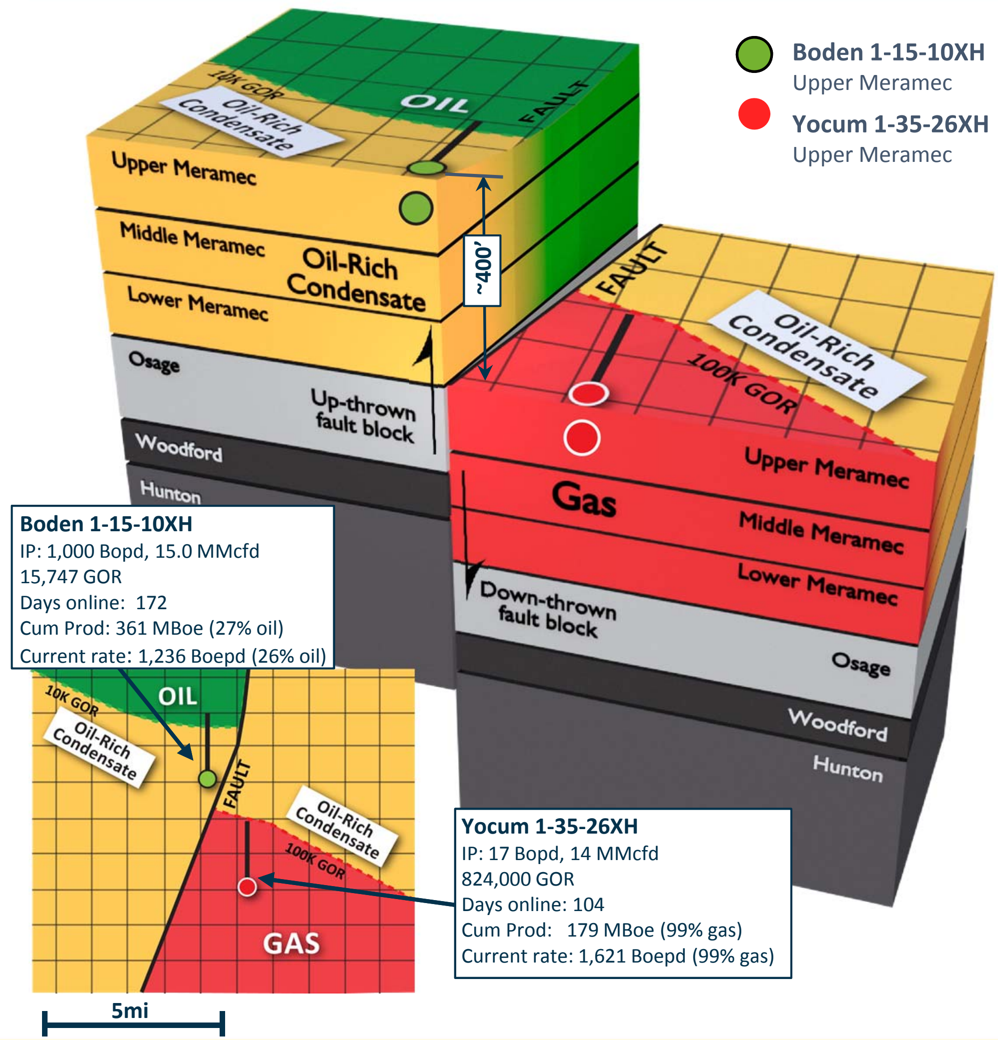
Oil window CWC down 10%
- Target CWC $9.0 million, down $1 million from initial 2016 target
- Cycle times down 8%, ~27 days spud-to -TD

Current activity
- 6 rigs drilling Meramec
- 5 rigs drilling Woodford
- 3 density tests underway in oil window



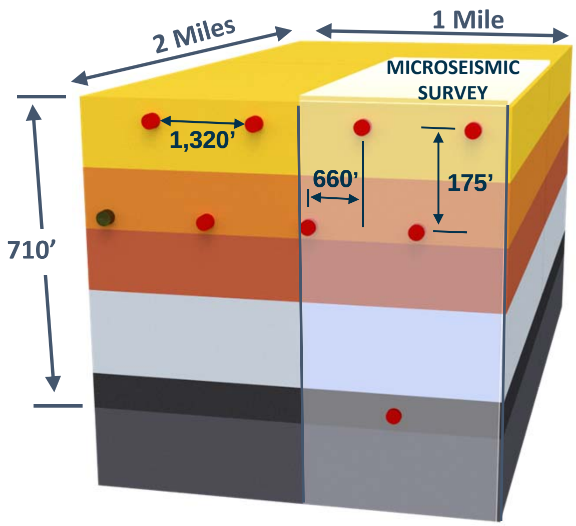
Boden-Yocum
Unique Results Defined by Fault

- Yocum designed to test down-thrown side of fault identified from 3D seismic east of Boden
- Up to 525’ of vertical displacement on fault
- Boden on up-thrown side of fault in condensate window
- Yocum on down-thrown side of fault in gas window
- Only fault of this magnitude identified by 3D seismic/well control that could influence production
- Results increase acreage in gas window by 2%



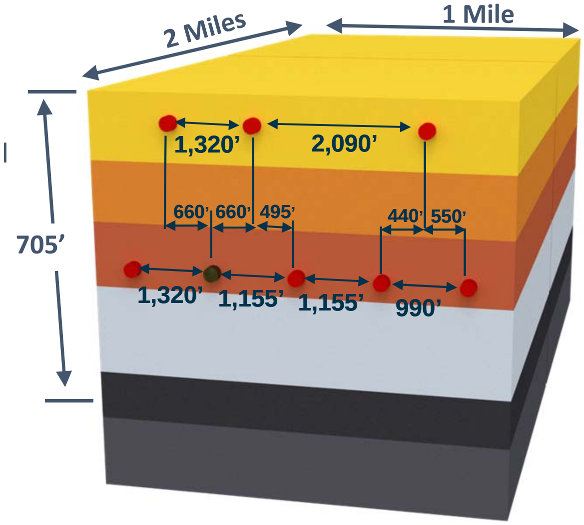
Continental Resources

STACK
Density Pilots in Over-Pressured Oil Window Underway



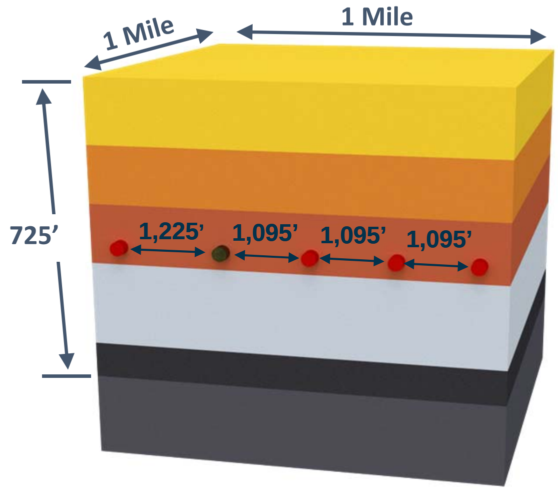
Ludwig Density Pilot

- Completion underway
- Drilling cost down 28% from parent well
- Enhanced completions
- Results expected 4Q 2016



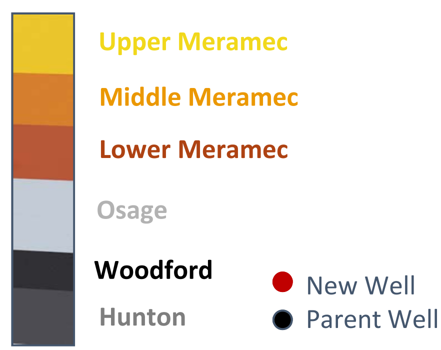
Blurton Density Pilot

- Drilling commenced in late 2Q 2016
- Enhanced completions
- Results expected 2017



Bernhardt Density Pilot

- Drilling commenced in 2Q 2016
- Enhanced completions
- Results expected late 2016/early 2017

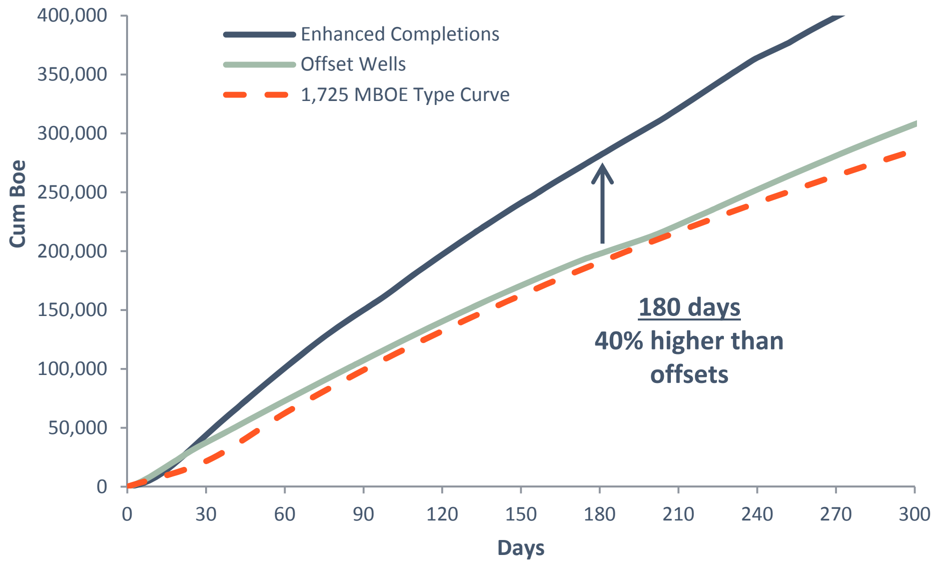


SCOOP Woodford Condensate
Growing Through Step-Outs and Enhanced Completions

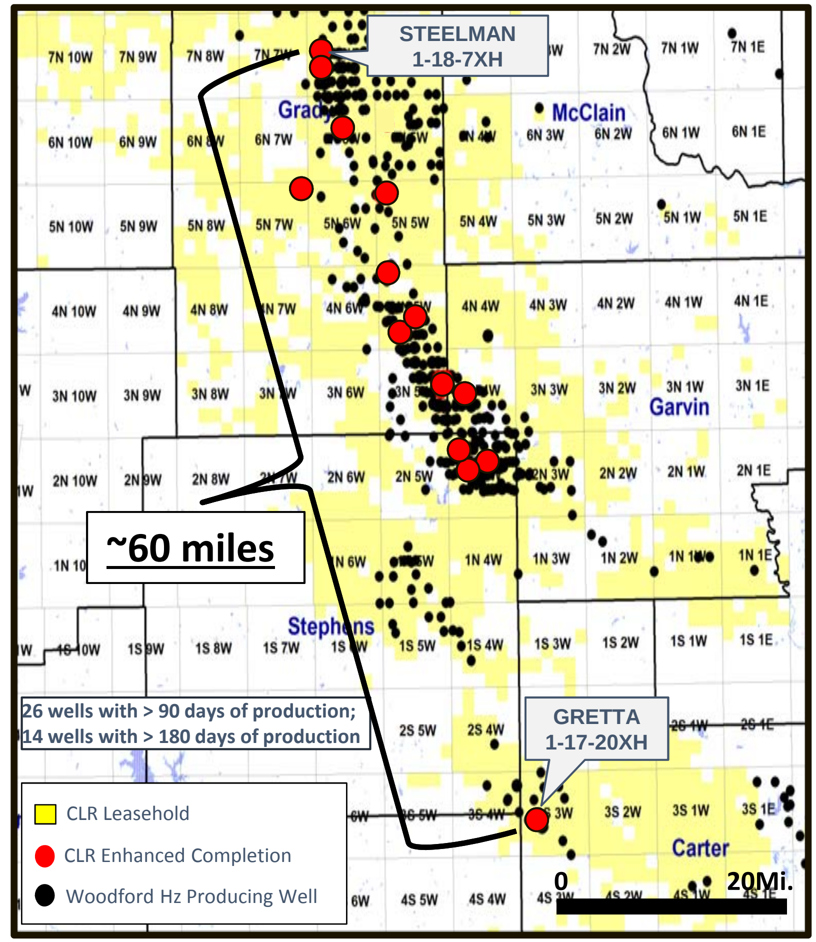
Enhanced completions increasing performance

- Delivering 40% production uplifts
- Increased type curve EUR by 15% to 2,000 MBoe
- > 100% ROR for incremental capital of $400,000[1]
- ~50% more proppant per foot on average

4 rigs drilling



Widespread, Repeatable Results

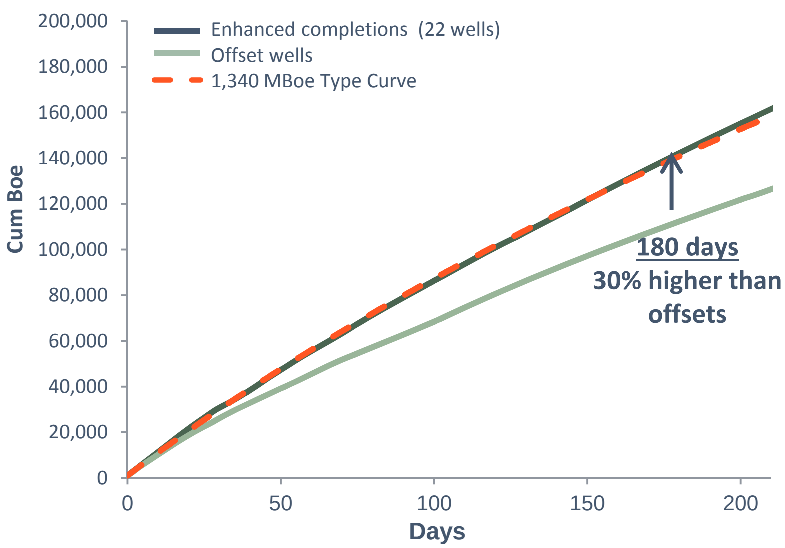


1. When compared to offset production at $45 WTI and $2.50 natural gas

SCOOP Woodford Oil
Enhanced Completions Increase EUR By ~30%

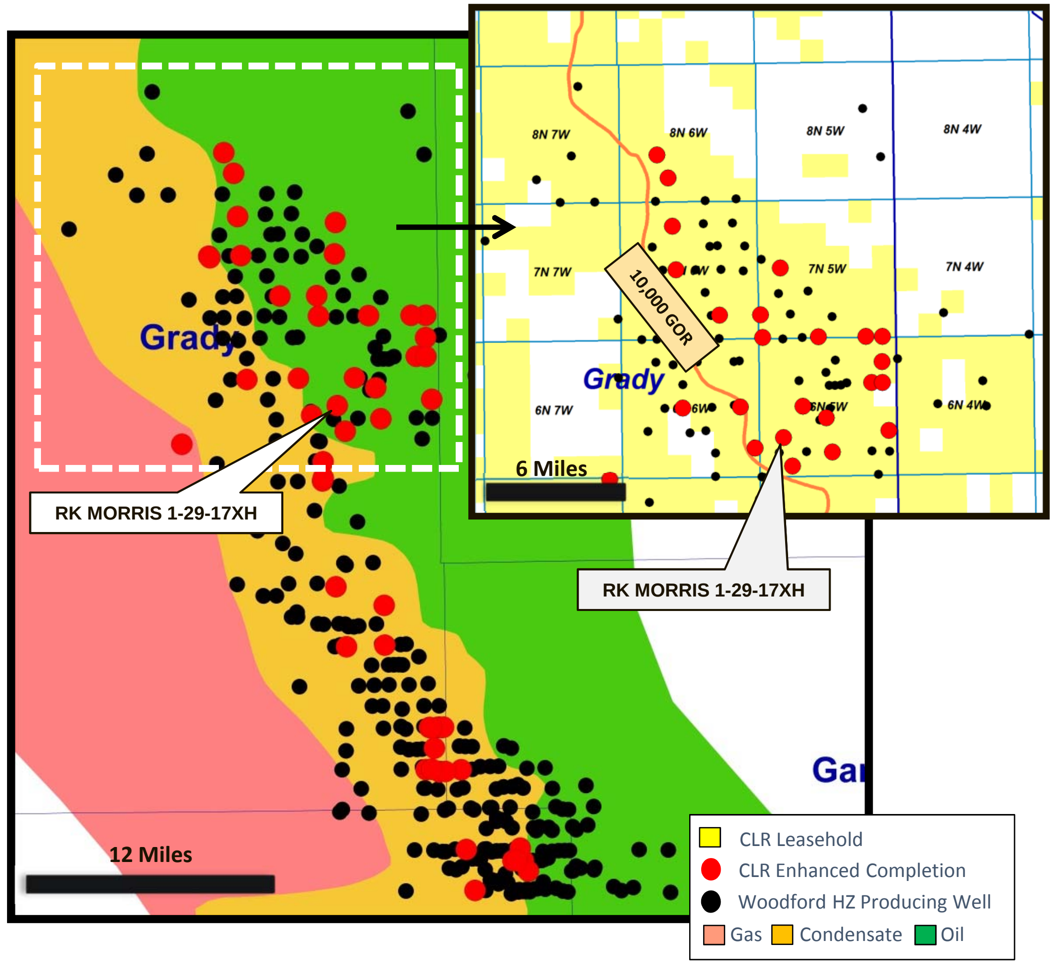
22 enhanced completions outperform legacy offsets

- ~30% increase in 180-day rate
- ~30% increase in EUR to 1.3 MMBoe per well (62% oil) for 9,800-foot lateral
- 32% ROR[(1)] for $9.8 million CWC
- At least 50,000 net acres upgraded to new EUR model



1. Assumes $45 WTI and $2.50 natural gas

Oil Window Enhanced Completions



SCOOP Woodford

Pending Non-Strategic Asset Sale

PSA signed

$281 million sale price

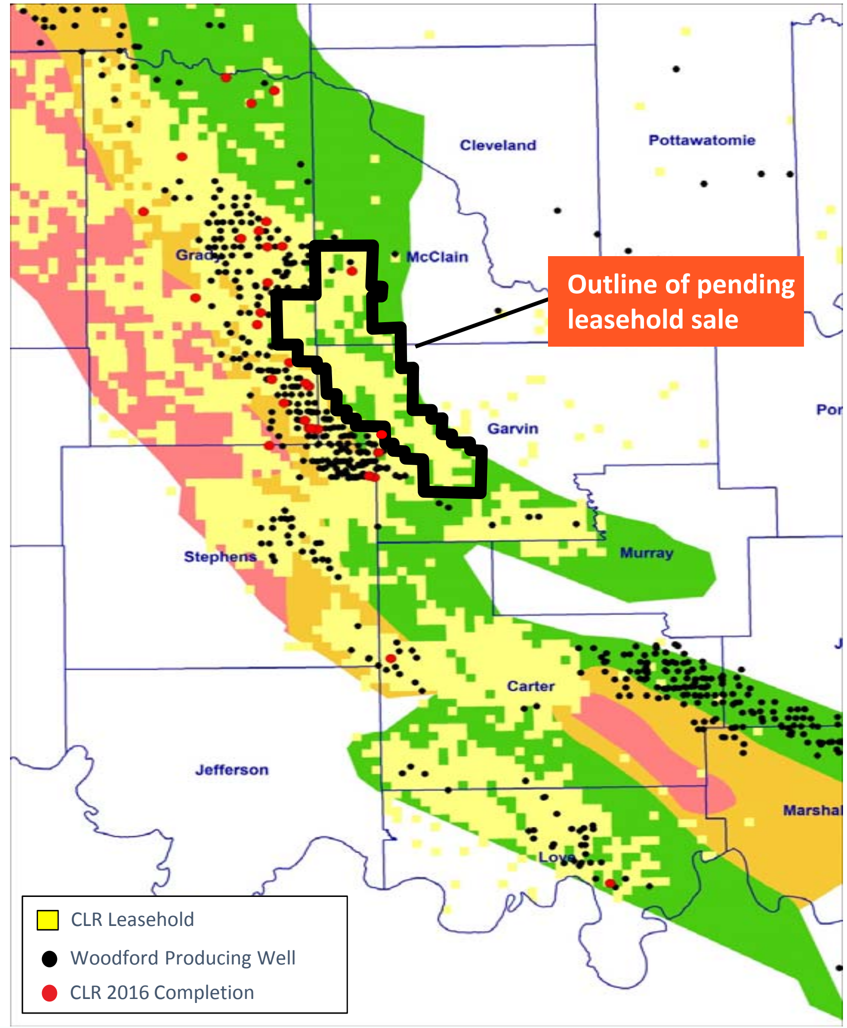
~29,500 net acres

- Non-strategic acreage
- Company will retain ~384,000 net acres of leasehold in SCOOP Woodford upon closing

Current production of ~550 net Boepd

Minimal proved reserves (less than 1%)

Additional opportunities for non-strategic asset sales across the Company



Bakken
Focusing On the Core at Reduced Costs

Average EUR up 13% from 2015

- 2016 target average EUR: 900 MBoe per well(1)
- 2015 average EUR: 800 MBoe per well(1)

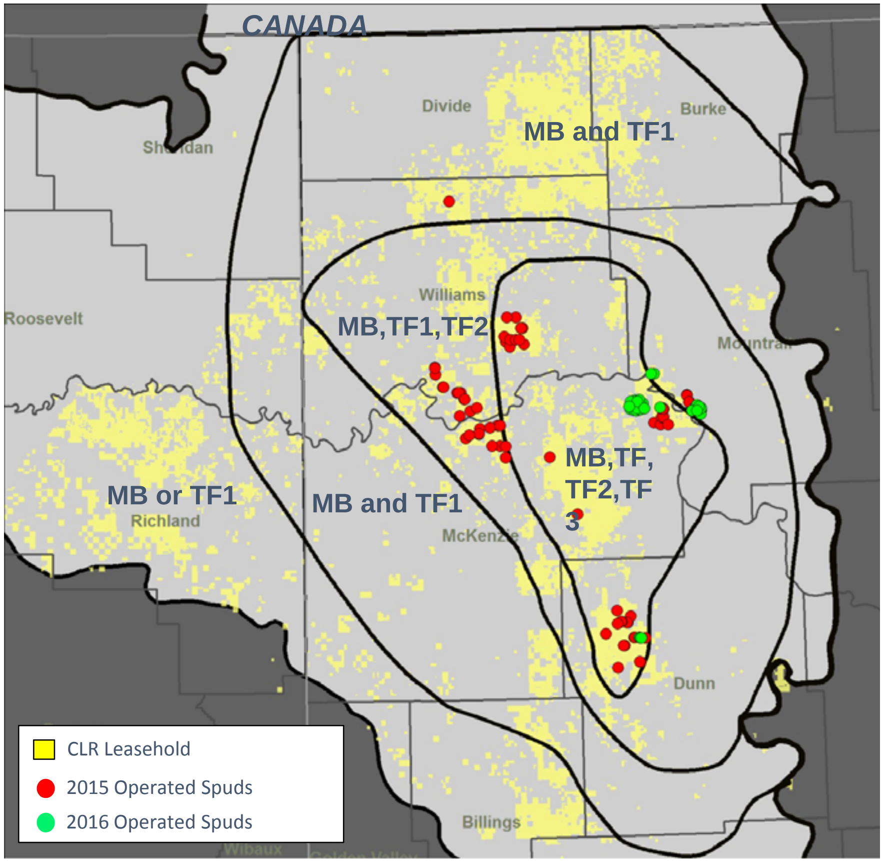
Enhanced CWC reduced to $6.2 million

- Down from $600,000(2) from YE 2015
- Targeting $6.0 million by YE 2016

Valuable DUC(3) inventory

- Projecting ~190 DUCs(4) at YE 2016
- 850 MBoe average EUR
- $3.5 million incremental completion cost
- Over 100% ROR for incremental completion cost for DUCs at $45 WTI and $2.50 gas

Outlines of Productive Bakken and Three Forks Reservoirs

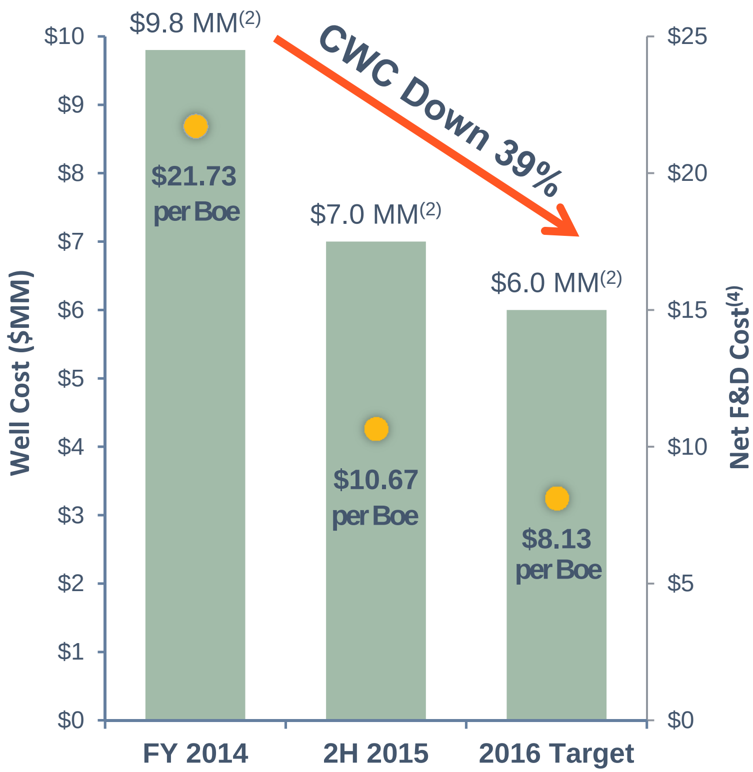


1. Target EUR for 2015 and 2016 spuds, normalized to 9,800’ lateral
2. For two-mile laterals with 30-stages
3. DUCs are a gross operated number
4. Up from 135 DUCs at YE 2015

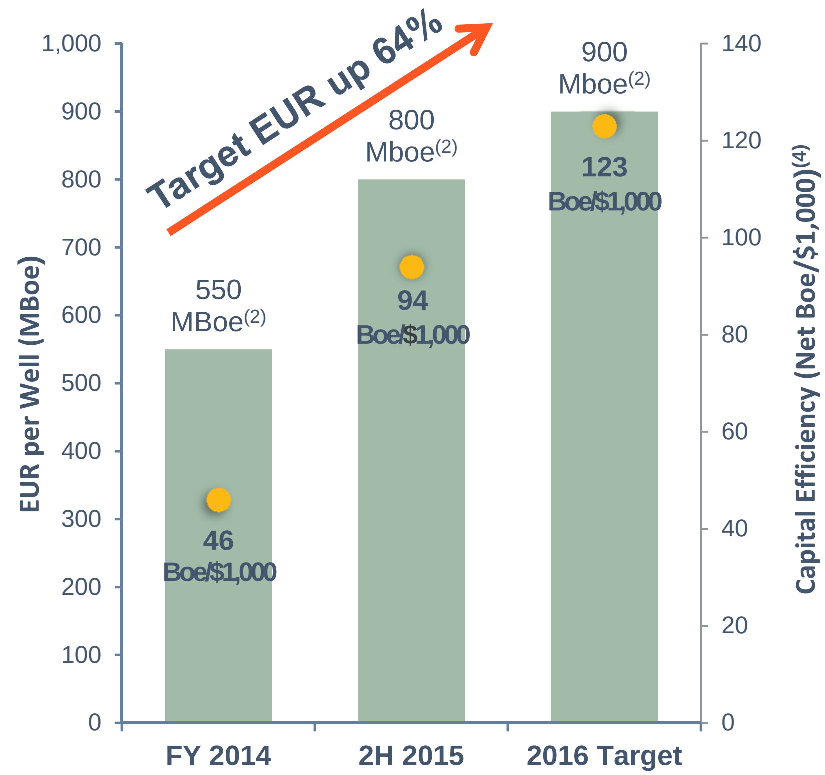
Bakken

Capital Efficiency Taken to New Level

F&D[1] Costs per Boe Down 63%



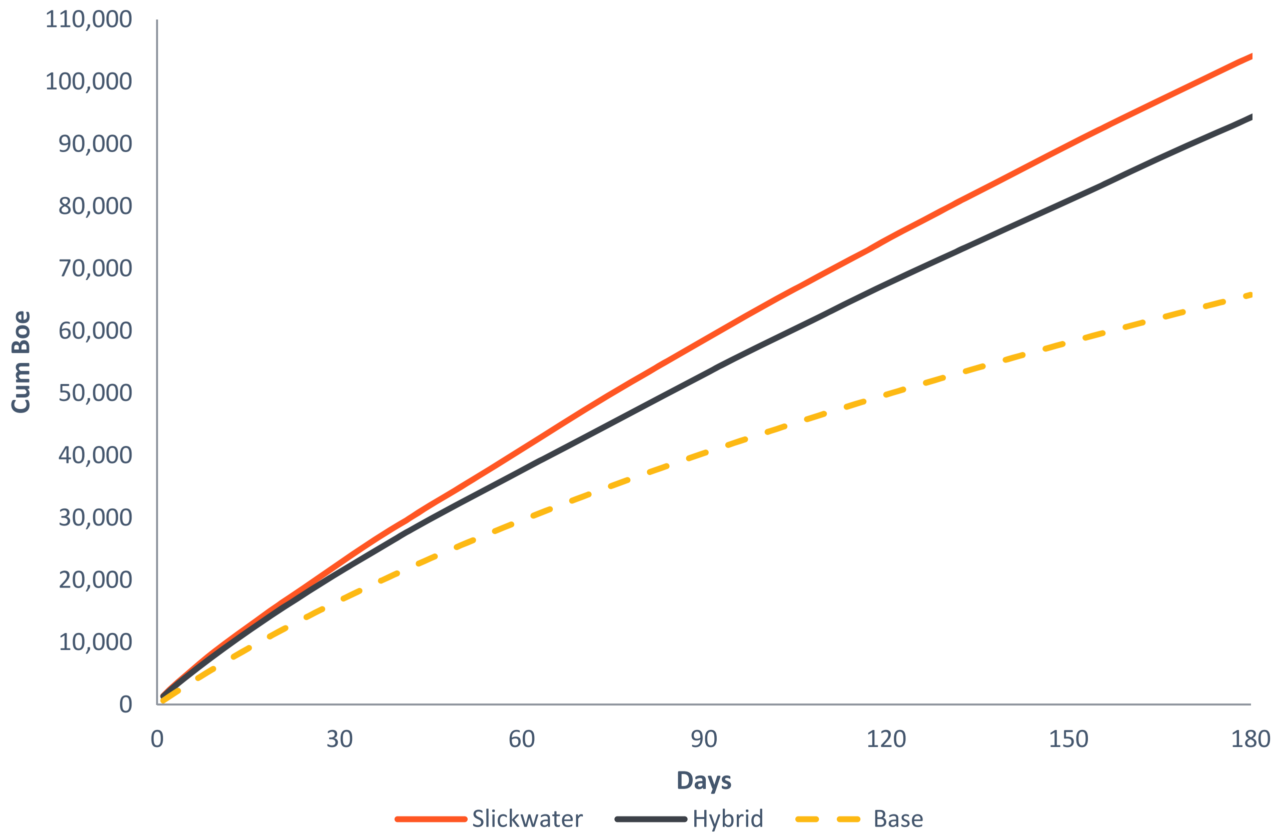
Capital Efficiency[3] Up 167%



1. F&D Cost is computed by taking the CWC divided by Boe
2. CLR-Operated North Dakota MB, TF1 & TF2 wells spud in 2014, 2015 and 2016 Projected
3. Capital efficiency based on reserves developed per dollar invested
4. Average net revenue interest of 82% assumed for net F&D and net capital efficiency

Bakken Enhanced Completions
Continue to Deliver

~25% to ~40% EUR uplift



Production Uplift

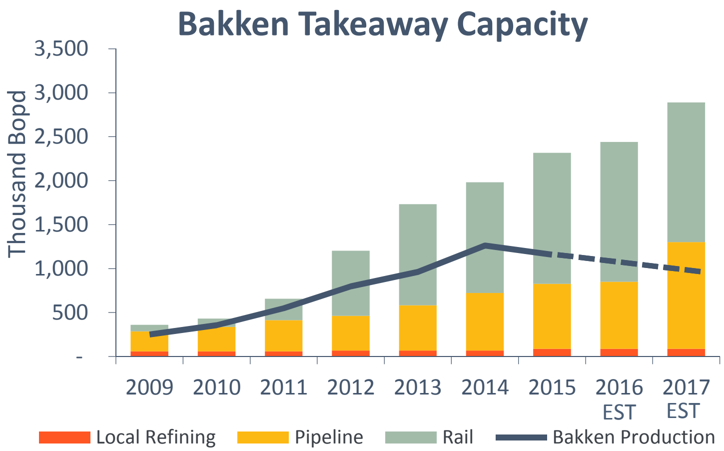
~60% Slickwater (54 Wells)

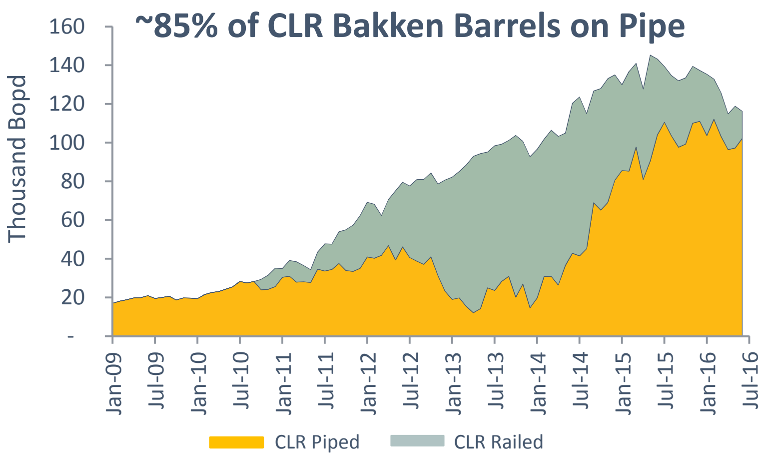
~45% Hybrid (72 Wells)

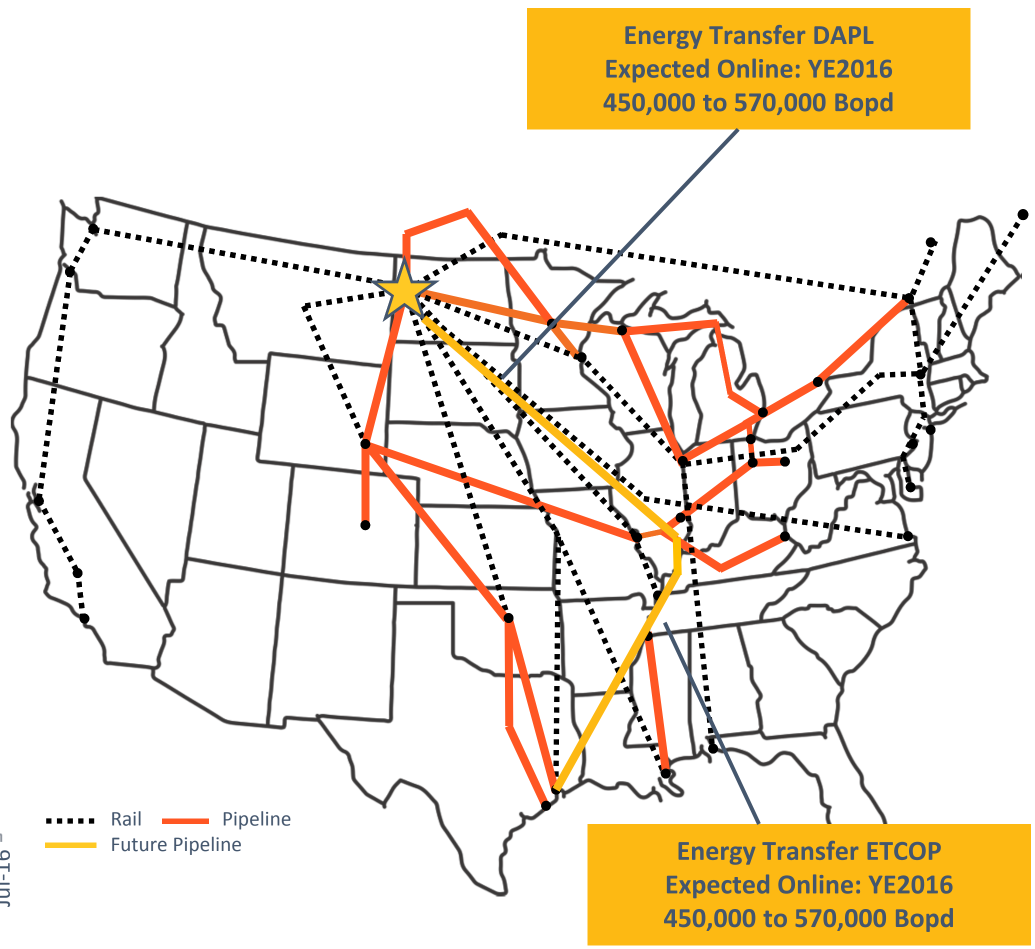
Average Standard Completion Offsetting Legacy Wells

Note: Enhanced Slickwater and Hybrid 30-stage Well Completions in Williams and McKenzie Counties

CLR Bakken Differentials Decreasing
Through Increased Pipeline Capacity

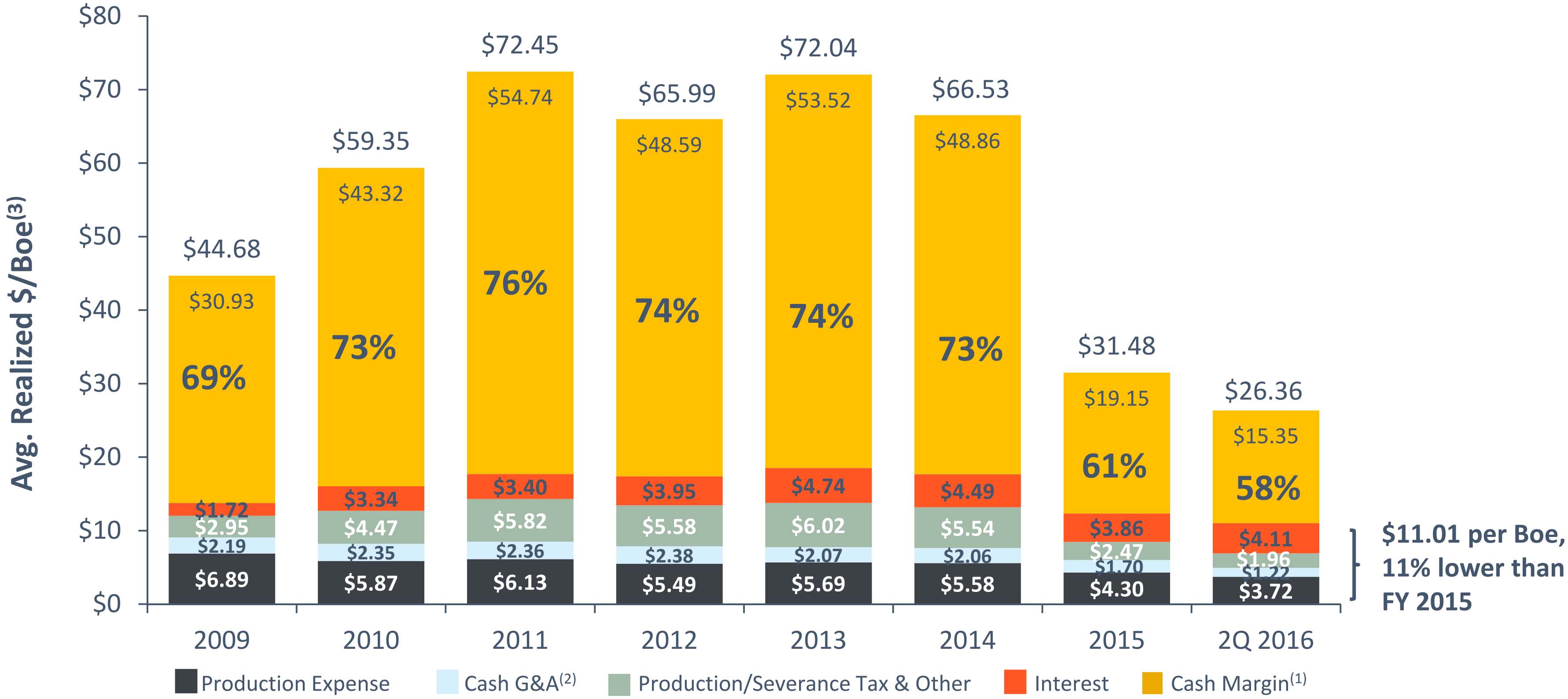






North Dakota Pipeline Authority and CLR estimates

Low Costs[1]
Competitively Positions CLR in Any Environment



1. Cash margin presented on this slide represents the Company's average sales price for a period expressed in barrels of oil equivalent (Boe) less production expenses, production taxes, G&A expenses (exclusive of non-cash equity compensation expenses), and interest expense, all expressed on a per-Boe basis. Cash margin does not reflect all activities of the Company that give rise to cash inflows and outflows and specifically excludes income and costs associated with derivative settlements, service operations, exploration activities, asset dispositions, and various non-operating activities. These items are excluded from the computation of cash margin because they can vary significantly from period to period in a manner that does not correlate with changes in the Company's production and sales volumes. Therefore, these items are not typically utilized by management on a per-Boe basis in assessing the performance of the Company's E&P operations from period to period. See "Continuing to Deliver Strong Margins" on slide 32 for additional details on the method for calculating cash margin.
2. See "Cash G&A Reconciliation to GAAP" on slide 36 for a reconciliation of GAAP Total G&A per Boe to Cash G&A per Boe, which is a non-GAAP measure
3. Based on average oil equivalent price (excluding derivatives and including natural gas)

Strong Liquidity & Financial Profile

Unsecured Credit Facility

- **Ample liquidity** with $2.75 billion revolver and ability to upsize to $4.0 billion[1]
- **~$1.93 billion available on revolver as of July 31, 2016**
- **No borrowing base redetermination**
- **2-year extension option beyond 2019[1]**

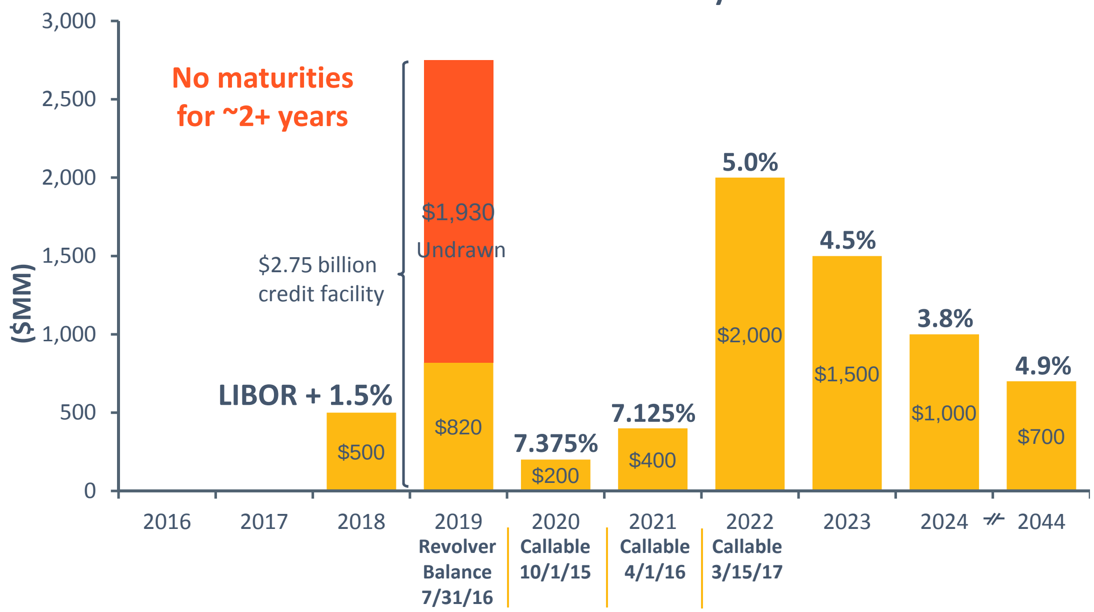
Financial Strength

- **No near-term debt maturities** (Earliest is $500 million in 11/2018)
- **4.3% average interest rate**

Financial Metrics[2]

Net Debt[3]/ 2Q 2016 Annualized EBITDAX[4]	3.38x	Net Debt[3] / TTM EBITDAX[4]	4.11x
Net Debt[3]/2Q 2016 Avg. Daily Production	$32,531	Net Debt[3]/YE 2015 Proved Reserves	$5.82

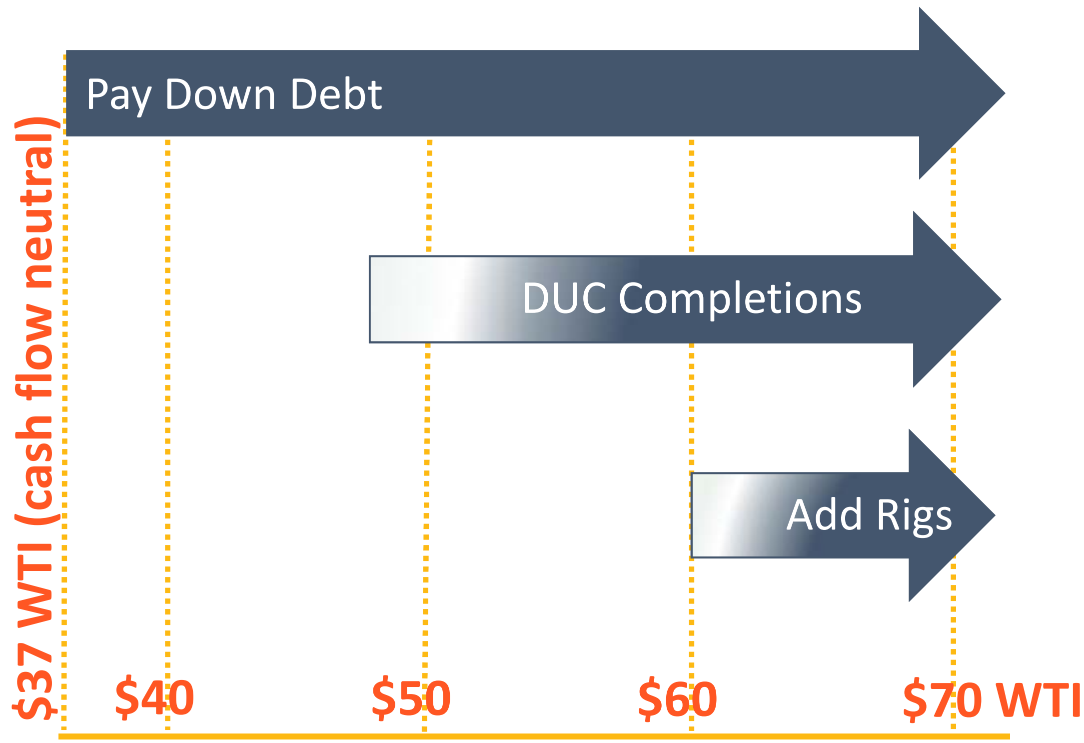
Debt Maturities Summary



1. With lender consent
2. All ratios are as of 6/30/16, except where noted
3. Net Debt is a non-GAAP measure and represents the total face value of debt of $7.2 billion plus outstanding letters of credit of $0.5 million, less cash and cash equivalents of $16.6 million as determined under GAAP
4. See appendix for reconciliation of GAAP net income and net cash provided by operating activities to EBITDAX, which is a non-GAAP measure

Continental's Strategy Moving Forward

- Disciplined growth based on sustainable crude oil supply/demand fundamentals and price
- WTI above $37: Strengthen balance sheet first
- Mid-to-upper $40s: Consider working down Bakken DUCs and reduce debt further
- At $60+: Consider adding drilling rigs



Updated 2016 Guidance

Production & Capital	Updated 2016 Guidance	Previous 2016 Guidance
Production (Boe per day)	**210,000 - 220,000**	205,000 – 215,000
Capital expenditures (non-acquisition)	$920 million	$920 million
Operating Expenses		
Production expense ($ per Boe)	**$3.75 - $4.25**	$4.25 - $4.75
Production tax (% of oil & gas revenue)	6.75% - 7.25%	6.75% - 7.25%
Cash G&A expense[1] ($ per Boe)	**$1.20 - $1.60**	$1.25 - $1.75
Non-cash equity compensation ($ per Boe)	$0.65 - $0.85	$0.65 - $0.85
DD&A ($ per Boe)	$20.00 - $22.00	$20.00 - $22.00
Average Price Differentials		
NYMEX WTI crude oil ($ per barrel of oil)	**($7.00) - ($8.00)**	($7.00) - ($9.00)
Henry Hub natural gas[2] ($ per Mcf)	$0.00 - ($0.65)	$0.00 - ($0.65)
Income tax rate	38%	38%
Deferred taxes	90% - 95%	90% - 95%

Bolded item above in guidance denotes a change from the previous disclosure

1. See "Cash G&A Reconciliation to GAAP" on slide 36 for a reconciliation of GAAP Total G&A per Boe to Cash G&A per Boe, which is a non-GAAP measure
2. Includes natural gas liquids production in differential range

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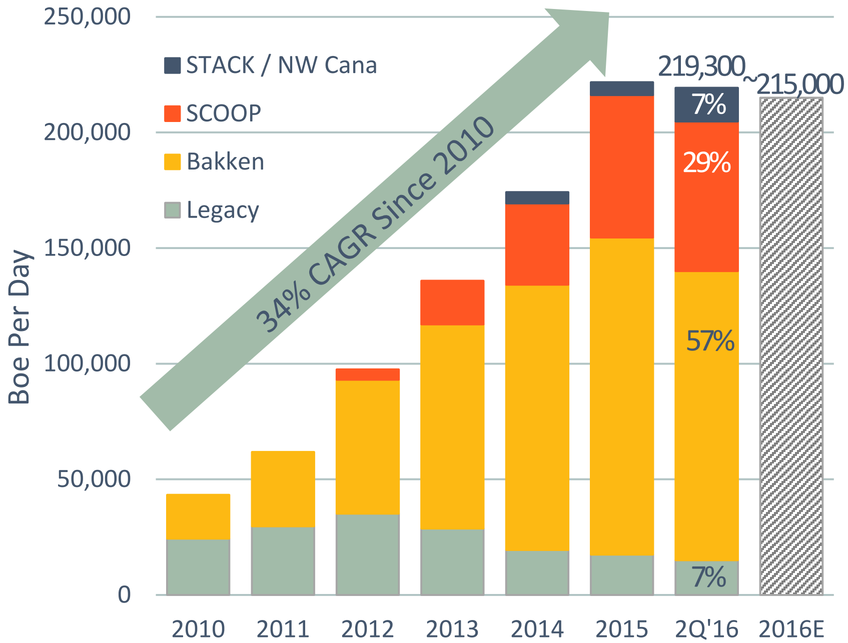
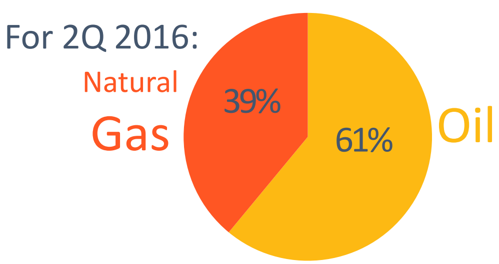
REFERENCE MATERIALS

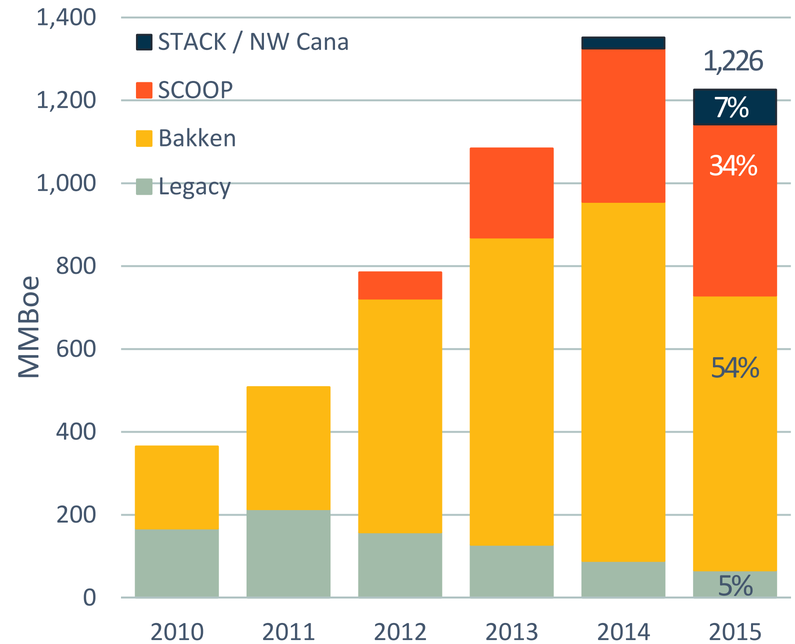
Historical Organic Growth

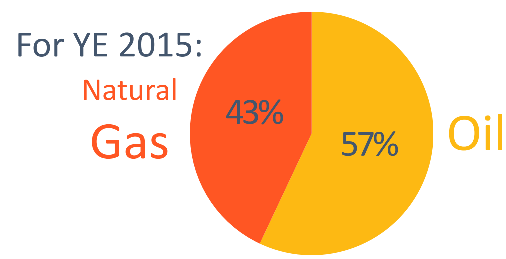
Targeting 210,000 to 220,000 Boe per Day Average in 2016



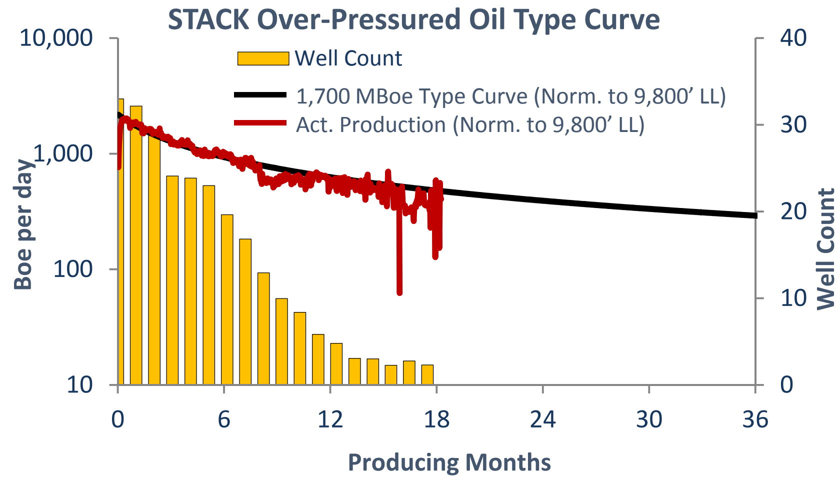


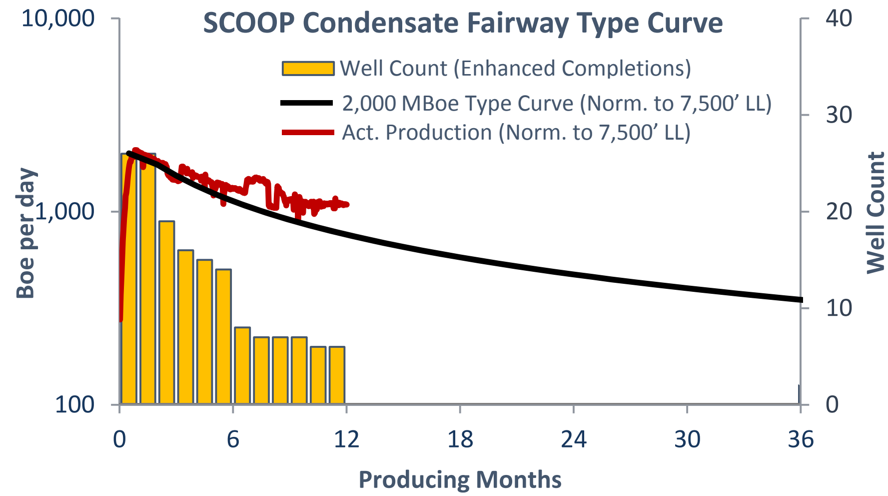
Total Proved Reserves Down 9% YOY with 47% Reduction in WTI Prices

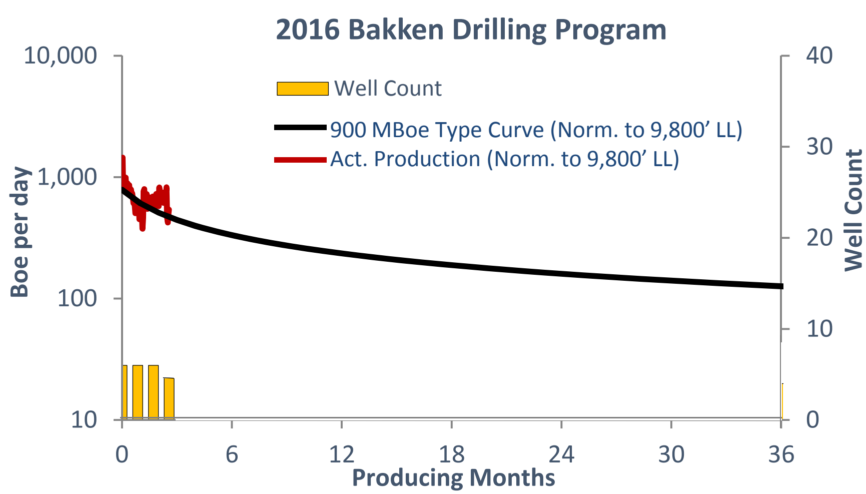


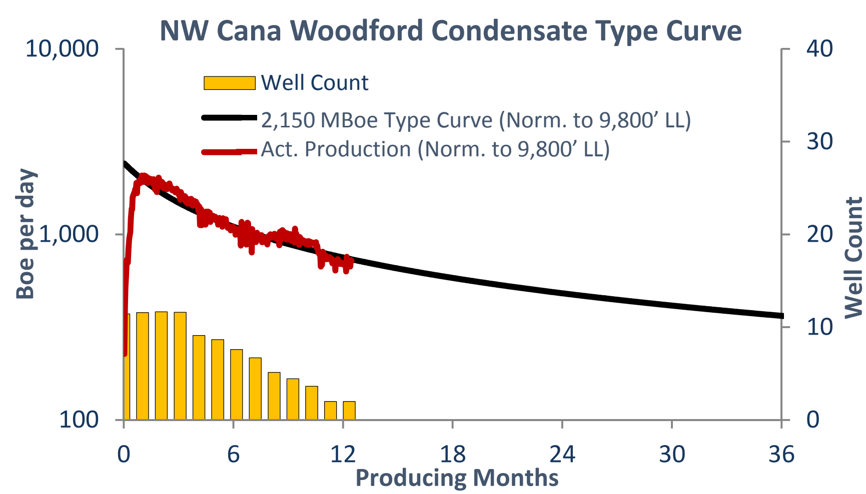


Company Enhanced Completions Type Curves



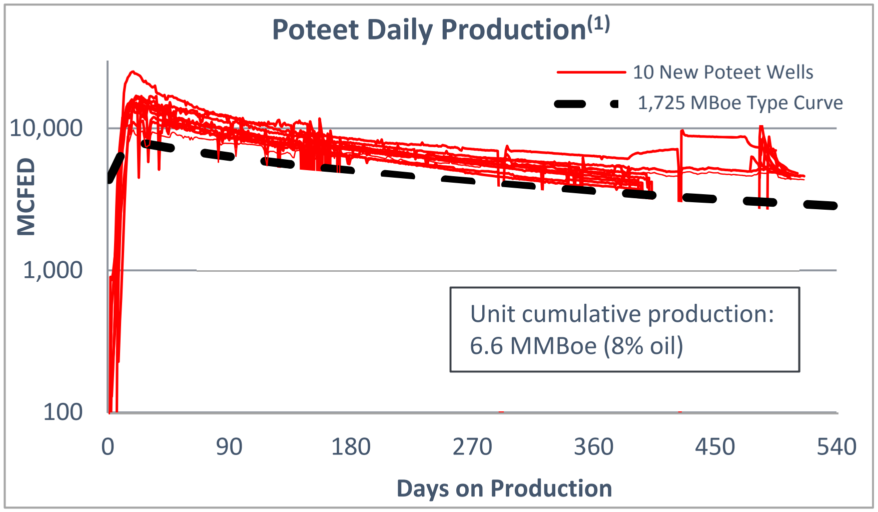


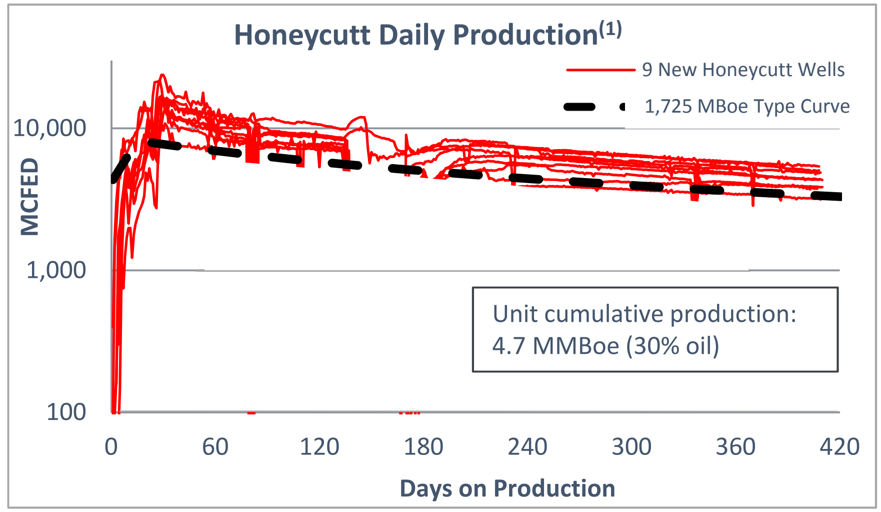


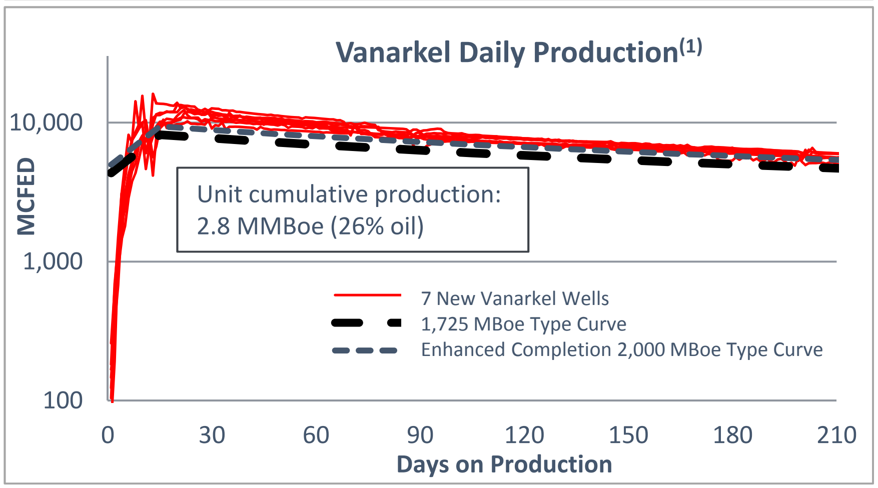


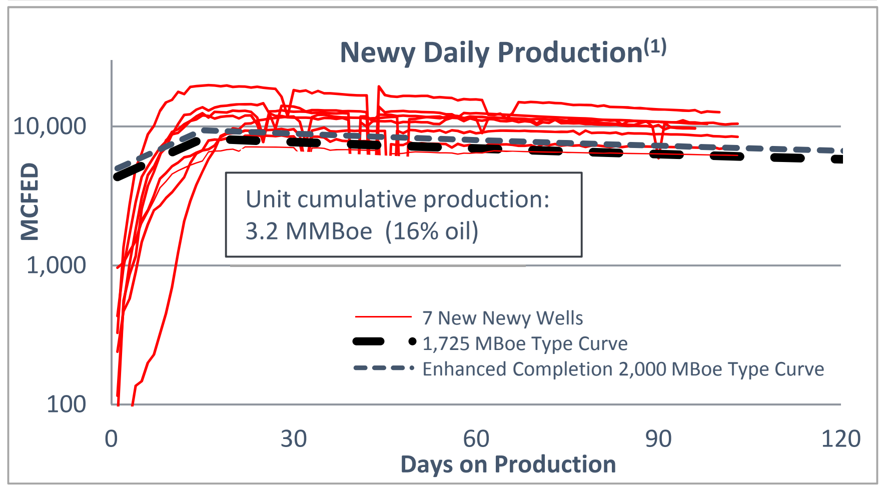
SCOOP Woodford

Condensate Window Density Projects – Strong Repeatable Results





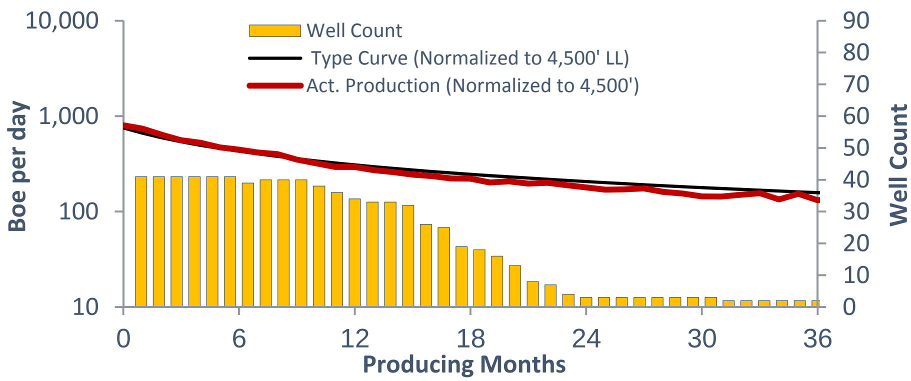


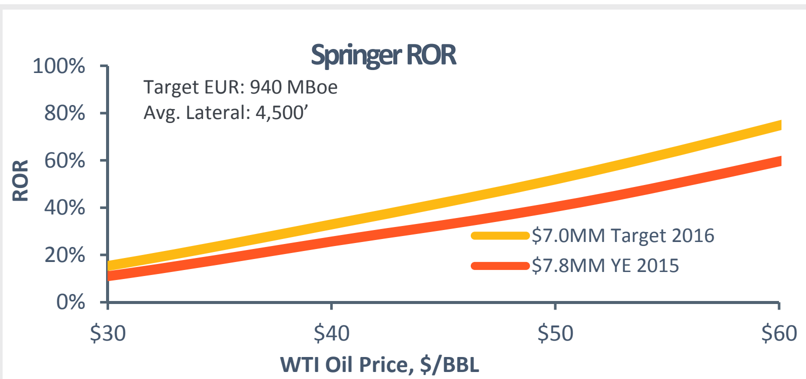


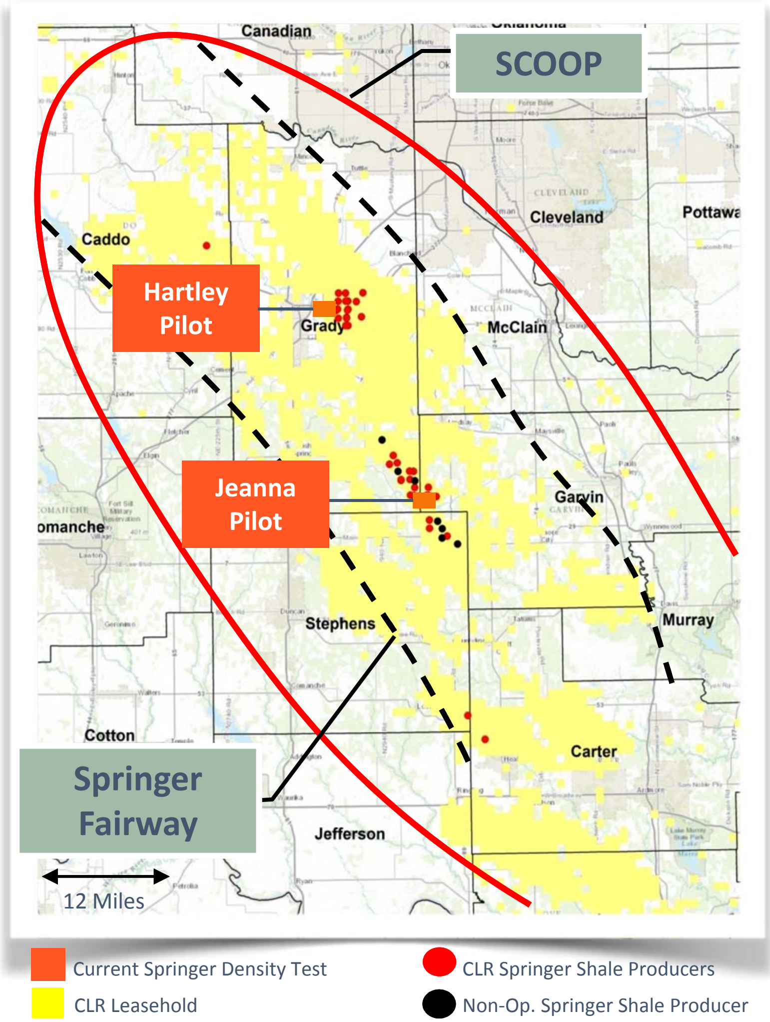
1. Normalized to 7,500' lateral

SCOOP Springer
Oil Asset Waiting for Higher Prices

Historical results in line with 940 MBoe type curve







Untested upside

- Longer laterals – 7,500' to 10,000'
- Enhanced completions

Continental RESOURCES

Continuing to Deliver Strong Margins(1)

	2009	2010	2011	2012	2013	2014	2015	2Q 2016
Realized oil price ($/Bbl)	$54.44	$70.69	$88.51	$84.59	$89.93	$81.26	$40.50	$38.38
Realized natural gas price ($/Mcf)	$2.95	$4.26	$4.87	$3.73	$4.87	$5.40	$2.31	$1.31
Oil production (Bopd)	27,459	32,385	45,121	68,497	95,859	121,999	146,622	133,044
Natural gas production (Mcfpd)	59,194	65,598	100,469	174,521	240,355	313,137	450,558	517,677
Total production (Boepd)	37,324	43,318	61,865	97,583	135,919	174,189	221,715	219,323
EBITDAX ($000's)(2)	$450,648	$810,877	$1,303,959	$1,963,123	$2,839,510	$3,776,051	$1,978,896	$528,109
Key Operational Statistics (per Boe)(3)								
Average oil equivalent price (excludes derivatives)	$44.68	$59.35	$72.45	$65.99	$72.04	$66.53	$31.48	$26.36
Production expense	$6.89	$5.87	$6.13	$5.49	$5.69	$5.58	$4.30	$3.72
Production tax and other	$2.95	$4.47	$5.82	$5.58	$6.02	$5.54	$2.47	$1.96
Cash G&A(4)	$2.19	$2.35	$2.36	$2.38	$2.07	$2.06	$1.70	$1.22
Interest	$1.72	$3.34	$3.40	$3.95	$4.74	$4.49	$3.86	$4.11
Total of selected costs	**$13.75**	**$16.03**	**$17.71**	**$17.40**	**$18.52**	**$17.67**	**$12.33**	**$11.01**
Cash margin(1)	**$30.93**	**$43.32**	**$54.74**	**$48.59**	**$53.52**	**$48.86**	**$19.15**	**$15.35**
Cash margin %	**69%**	**73%**	**76%**	**74%**	**74%**	**73%**	**61%**	**58%**

1. Cash margin represents the Company's average sales price for a period expressed in barrels of oil equivalent (Boe) less production expenses, production taxes, G&A expenses (exclusive of non-cash equity compensation expenses), and interest expense, all expressed on a per-Boe basis. Cash margin does not reflect all activities of the Company that give rise to cash inflows and outflows and specifically excludes income and costs associated with derivative settlements, service operations, exploration activities, asset dispositions, and various non-operating activities. These items are excluded from the computation of cash margin because they can vary significantly from period to period in a manner that does not correlate with changes in the Company's production and sales volumes. Therefore, these items are not typically utilized by management on a per-Boe basis in assessing the performance of the Company's E&P operations from period to period.
2. See "EBITDAX reconciliation to GAAP" on slide 33 for a reconciliation of GAAP net income and net cash provided by operating activities to EBITDAX, which is a non-GAAP measure.
3. Average costs per Boe have been computed using sales volumes and exclude any effect of derivative transactions.
4. See "Cash G&A Reconciliation to GAAP" on slide 36 for a reconciliation of GAAP Total G&A per Boe to Cash G&A per Boe, which is a non-GAAP measure

EBITDAX Reconciliation to GAAP

We use a variety of financial and operational measures to assess our performance. Among these measures is EBITDAX. We define EBITDAX as earnings (net income (loss)) 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, non-cash equity compensation expense, and losses on extinguishment of debt. EBITDAX is not a measure of net income or net cash provided by operating activities 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. Further, 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. We exclude the items listed above from net income (loss) and net cash provided by operating activities 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 (loss) or net cash provided by operating activities 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.

See the following page for reconciliations of our net income (loss) and net cash provided by operating activities to EBITDAX for the applicable periods.

EBITDAX Reconciliation to GAAP

The following tables provide reconciliations of our net income (loss) and net cash provided by operating activities to EBITDAX for the periods presented:

In thousands	2009	2010	2011	2012	2013	2014	2015	2Q 2016	TTM at 6/30/16
Net income (loss)	$ 71,338	$ 168,255	$ 429,072	$ 739,385	$ 764,219	$ 977,341	$ (353,668)	$ (119,402)	$ (539,827)
Interest expense	23,232	53,147	76,722	140,708	235,275	283,928	313,079	81,922	322,449
Provision (benefit) for income taxes	38,670	90,212	258,373	415,811	448,830	584,697	(181,417)	(72,632)	(325,516)
Depreciation, depletion, amortization and accretion	207,602	243,601	390,899	692,118	965,645	1,358,669	1,749,056	441,761	1,815,339
Property impairments	83,694	64,951	108,458	122,274	220,508	616,888	402,131	66,112	322,737
Exploration expenses	12,615	12,763	27,920	23,507	34,947	50,067	19,413	1,674	9,703
Impact from derivative instruments:									
Total (gain) loss on derivatives, net	1,520	130,762	30,049	(154,016)	191,751	(559,759)	(91,085)	78,057	(26,062)
Total cash received (paid), net	569	35,495	(34,106)	(45,721)	(61,555)	385,350	69,553	38,778	110,903
Non-cash (gain) loss on derivatives, net	2,089	166,257	(4,057)	(199,737)	130,196	(174,409)	(21,532)	116,835	84,841
Non-cash equity compensation	11,408	11,691	16,572	29,057	39,890	54,353	51,834	11,839	45,452
Loss on extinguishment of debt	--	--	--	--	--	24,517	--	--	--
EBITDAX (non-GAAP)	$ 450,648	$ 810,877	$ 1,303,959	$ 1,963,123	$ 2,839,510	$ 3,776,051	$ 1,978,896	$ 528,109	$ 1,735,178

In thousands	2009	2010	2011	2012	2013	2014	2015	2Q 2016	TTM at 6/30/16
Net cash provided by operating activities	$ 372,986	$ 653,167	$ 1,067,915	$ 1,632,065	$ 2,563,295	$ 3,355,715	$ 1,857,101	$ 218,819	$ 1,438,010
Current income tax provision (benefit)	2,551	12,853	13,170	10,517	6,209	20	24	6	26
Interest expense	23,232	53,147	76,722	140,708	235,275	283,928	313,079	81,922	322,449
Exploration expenses, excluding dry hole costs	6,138	9,739	19,971	22,740	25,597	26,388	11,032	1,468	9,119
Gain on sale of assets, net	709	29,588	20,838	136,047	88	600	23,149	96,907	97,522
Excess tax benefit from stock-based compensation	2,872	5,230	--	15,618	--	--	13,177	--	13,177
Other, net	(3,890)	(3,513)	(4,606)	(7,587)	(1,829)	(17,279)	(10,044)	(3,049)	(12,930)
Changes in assets and liabilities	46,050	50,666	109,949	13,015	10,875	126,679	(228,622)	132,036	(132,195)
EBITDAX (non-GAAP)	$ 450,648	$ 810,877	$ 1,303,959	$ 1,963,123	$ 2,839,510	$ 3,776,051	$ 1,978,896	$ 528,109	$ 1,735,178

ADJUSTED Earnings Reconciliation to GAAP

Our presentation of adjusted earnings and adjusted earnings per share that exclude the effect of certain items are non-GAAP financial measures. Adjusted earnings and adjusted earnings per share represent earnings and diluted earnings per share determined under U.S. GAAP without regard to non-cash gains and losses on derivative instruments, property impairments and gains and losses on asset sales. Management believes these measures provide useful information to analysts and investors for analysis of our operating results. In addition, management believes these measures are used by analysts and others in valuation, comparison and investment recommendations of companies in the oil and gas industry to allow for analysis without regard to an entity's specific derivative portfolio, impairment methodologies, and property dispositions. Adjusted earnings and adjusted earnings per share should not be considered in isolation or as a substitute for earnings or diluted earnings per share as determined in accordance with U.S. GAAP and may not be comparable to other similarly titled measures of other companies. The following tables reconcile earnings and diluted earnings per share as determined under U.S. GAAP to adjusted earnings and adjusted diluted earnings per share for the periods presented.

	2Q 2016		2Q 2015		1H 2016		1H 2015	
In thousands, except per share data	$	Diluted EPS	$	Diluted EPS	$	Diluted EPS	$	Diluted EPS
Net income (loss) (GAAP)	$ (119,402)	$ (0.32)	$ 403	$ 0.00	$(317,727)	$ (0.86)	$(131,568)	$ (0.36)
Adjustments:								
Non-cash loss on derivatives	116,835		17,919		114,972		8,599	
Property impairments	66,112		76,872		145,039		224,432	
Gain on sale of assets	(96,907)		(20,573)		(97,016)		(22,643)	
Total tax effect of adjustments	(32,548)		(26,171)		(61,646)		(64,189)	
Total adjustments, net of tax	53,492	0.14	48,047	0.13	101,349	0.28	146,199	0.40
Adjusted net income (loss) (Non-GAAP)	$ (65,910)	$ (0.18)	$ 48,450	$ 0.13	$ (216,378)	$ (0.58)	$ 14,631	$ 0.04
Weighted average diluted shares outstanding	370,435		370,873		370,248		369,448	
Adjusted diluted net income (loss) per share (Non-GAAP)	$ (0.18)		$ 0.13		$ (0.58)		$0.04	

Cash G&A Reconciliation to GAAP

Our presentation of cash general and administrative ("G&A") expenses per Boe is a non-GAAP measure. We define cash G&A per Boe as total G&A determined in accordance with U.S. GAAP less non-cash equity compensation expenses and corporate relocation expenses, expressed on a per-Boe basis. We report and provide guidance on cash G&A per Boe because we believe this measure is commonly used by management, analysts and investors as an indicator of cost management and operating efficiency on a comparable basis from period to period. In addition, management believes cash G&A per Boe is used by analysts and others in valuation, comparison and investment recommendations of companies in the oil and gas industry to allow for analysis of G&A spend without regard to stock-based compensation programs which can vary substantially from company to company. Cash G&A per Boe should not be considered as an alternative to, or more meaningful than, total G&A per Boe as determined in accordance with U.S. GAAP and may not be comparable to other similarly titled measures of other companies.

The following table reconciles total G&A per Boe as determined under U.S. GAAP to cash G&A per Boe for the periods presented.

	2009	2010	2011	2012	2013	2014	2015	2Q 2016	1H 2016
Total G&A per Boe (GAAP)	$3.03	$3.09	$3.23	$3.42	$2.91	$2.92	$2.34	$1.82	$1.68
Less: Non-cash equity compensation per Boe	($0.84)	($0.74)	($0.73)	($0.82)	($0.80)	($0.86)	($0.64)	($0.60)	($0.52)
Less: Relocation expenses per Boe	-	-	($0.14)	($0.22)	($0.04)	-	-	-	-
Cash G&A per Boe (non-GAAP)	$2.19	$2.35	$2.36	$2.38	$2.07	$2.06	$1.70	$1.22	$1.16