How much more change is coming?

Commercial Plays & Basins

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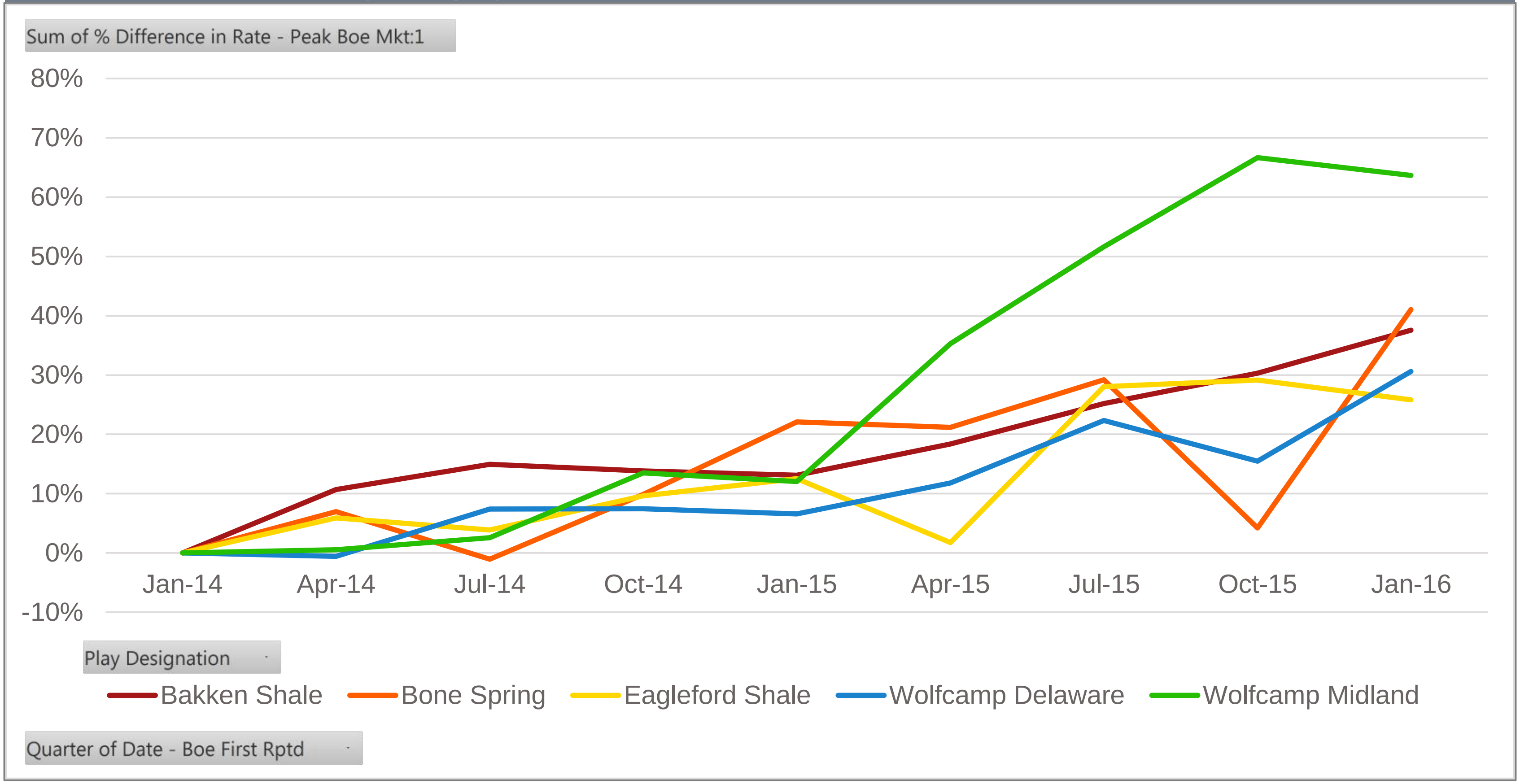
Overview – main themes

- IHSMarkit has found oil break-even prices to have fallen significantly since early 2014 – on average, break-even prices (excluding efficiencies and transportation) have fallen at least $30/bbl WTI. This drop is a combination of several factors:
  - High-grading (drilling only the better acreage) has accounted for ~35%
  - In-field learnings has accounted for ~6%
  - Service sector cost reductions account for ~40%
  - Operational changes account for ~20%
- As the oil price troughed in early 2016, the industry expects break-evens to rise, though quantifying the response and identifying the cause has been elusive. IHSMarkit expects the changes to be both structural (45% more efficient) and cyclical (55%) though the timing of this response is still a point of discussion and speculation.
- Entering 2018, break-even prices in major oil plays are expected to have risen ~$5.00 (excluding efficiencies and transportation), making for a net improvement of $25.00/bbl since early 2014, with the remainder likely coming in the following 18 months.

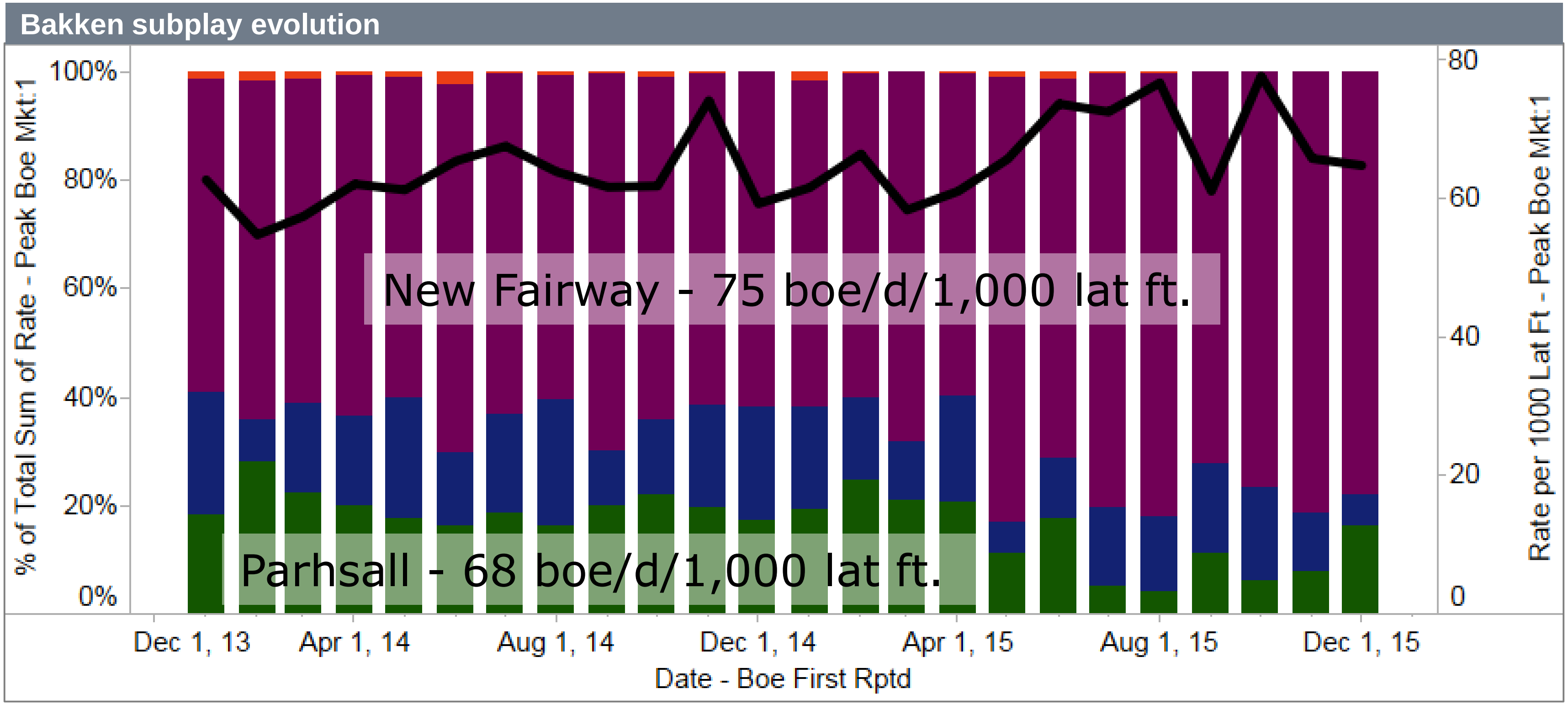
Oil price fell, peak rates went up – but why?

Peak rate evolution in major oil plays



- Since early 2014, peak rates for wells in the major oil plays have seen a consistent increase averaging over a 30% improvement. This increase in per-well production has buoyed production in the face of falling oil prices. However, as more oil is sourced from each well, the implication is that fewer wells are needed to maintain production.

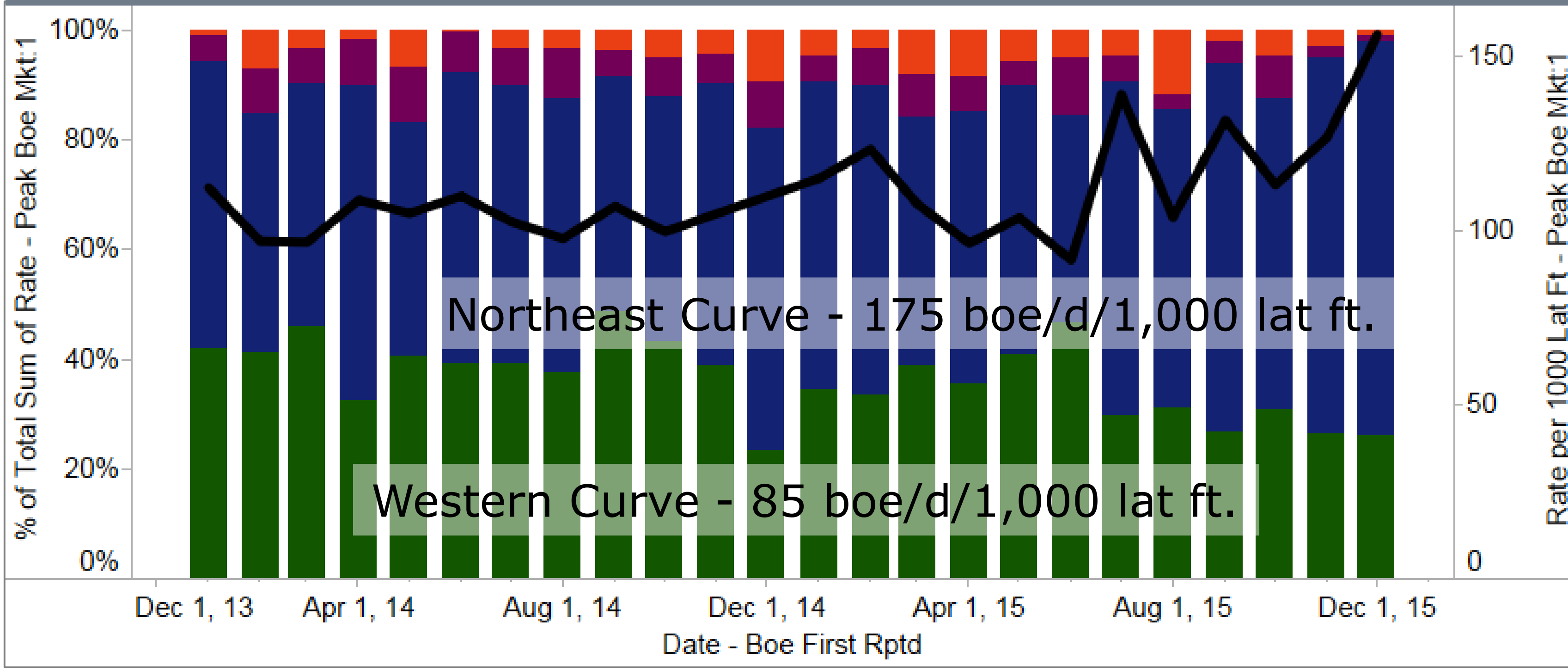
Bakken high-grading had already happened



- High-grading in the Bakken was already underway when oil prices fell. EOG had largely exited the Parshall and was turning the asset into a cash-generator, funding activities in the Eagle Ford and Permian. The primary high-grading in the Bakken was to terminate activity in the lower productivity Periphery subplay. This has led to a modest increase in the play's average productivity, but given the maturity and well control in the play, operational efficiencies were mostly already captured.

Eagle Ford showed upswing from coring up

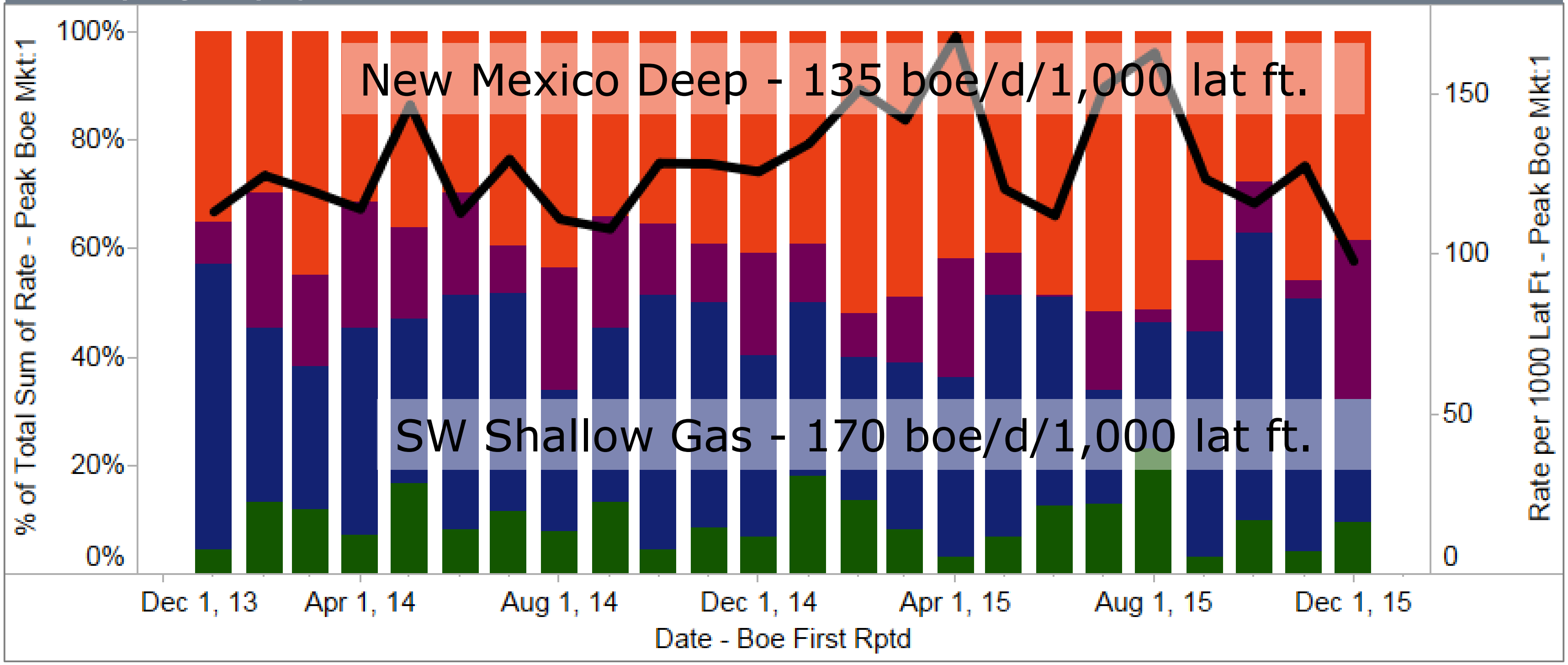
Eagle Ford subplay evolution



- Given its point in development, the Eagle Ford has seen the greatest average productivity increases from high-grading, going from 100 boe/d per 1,000 lateral feet to nearly 150. Unlike the Bakken, the variation between subplays is relatively high, perhaps causing concern of productivity degradation as rigs return to activity in less prolific regions of the play.

Bone Spring heterogeneity didn't help much

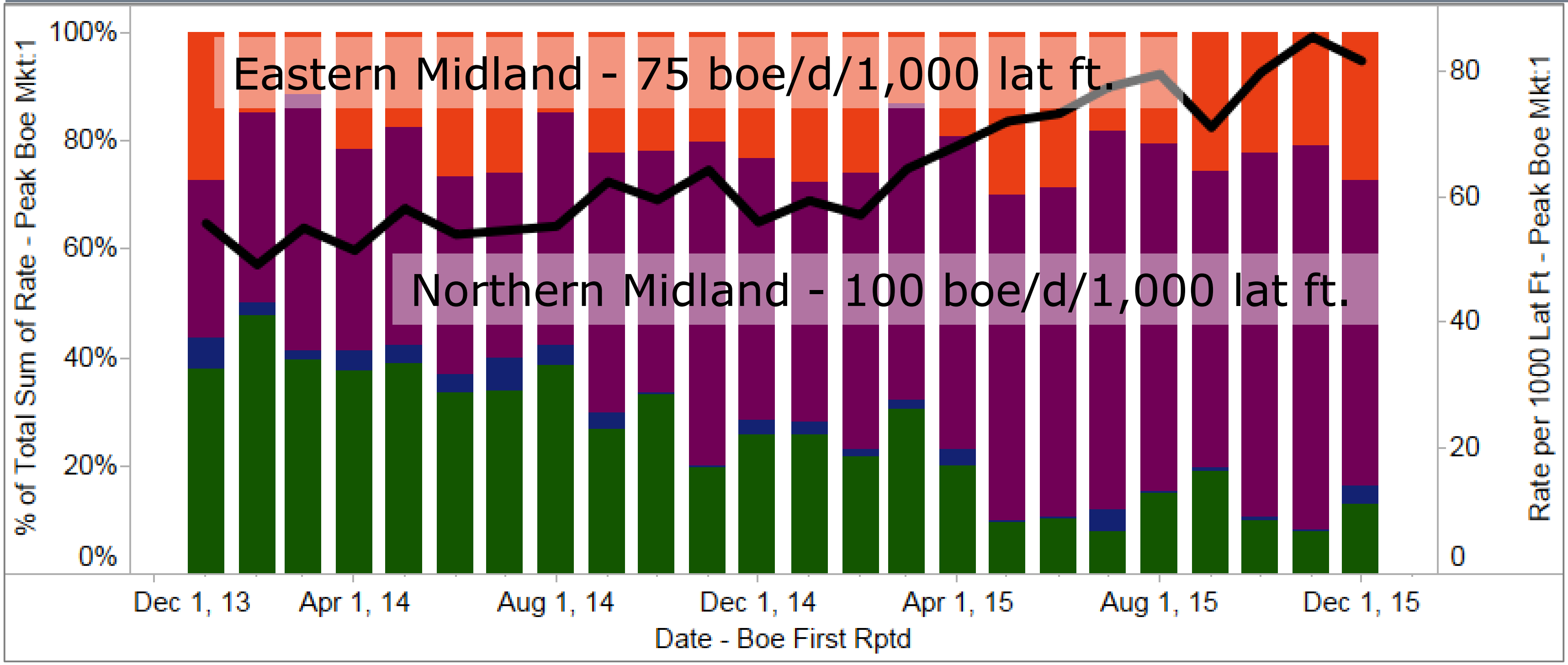
Bone Spring subplay evolution



- The Bone Spring (Permian Basin Delaware) has shown the highest average productivity of any North American unconventional. However, due to lack of correlation between geography and geology (the play's productivity is more governed by the producing zone), high-grading by subplay has not shown any results. Bench productivity has improved slightly since mid-2014, but given the mix of bench and location, overall play productivity has not shown more production per foot of well bore.

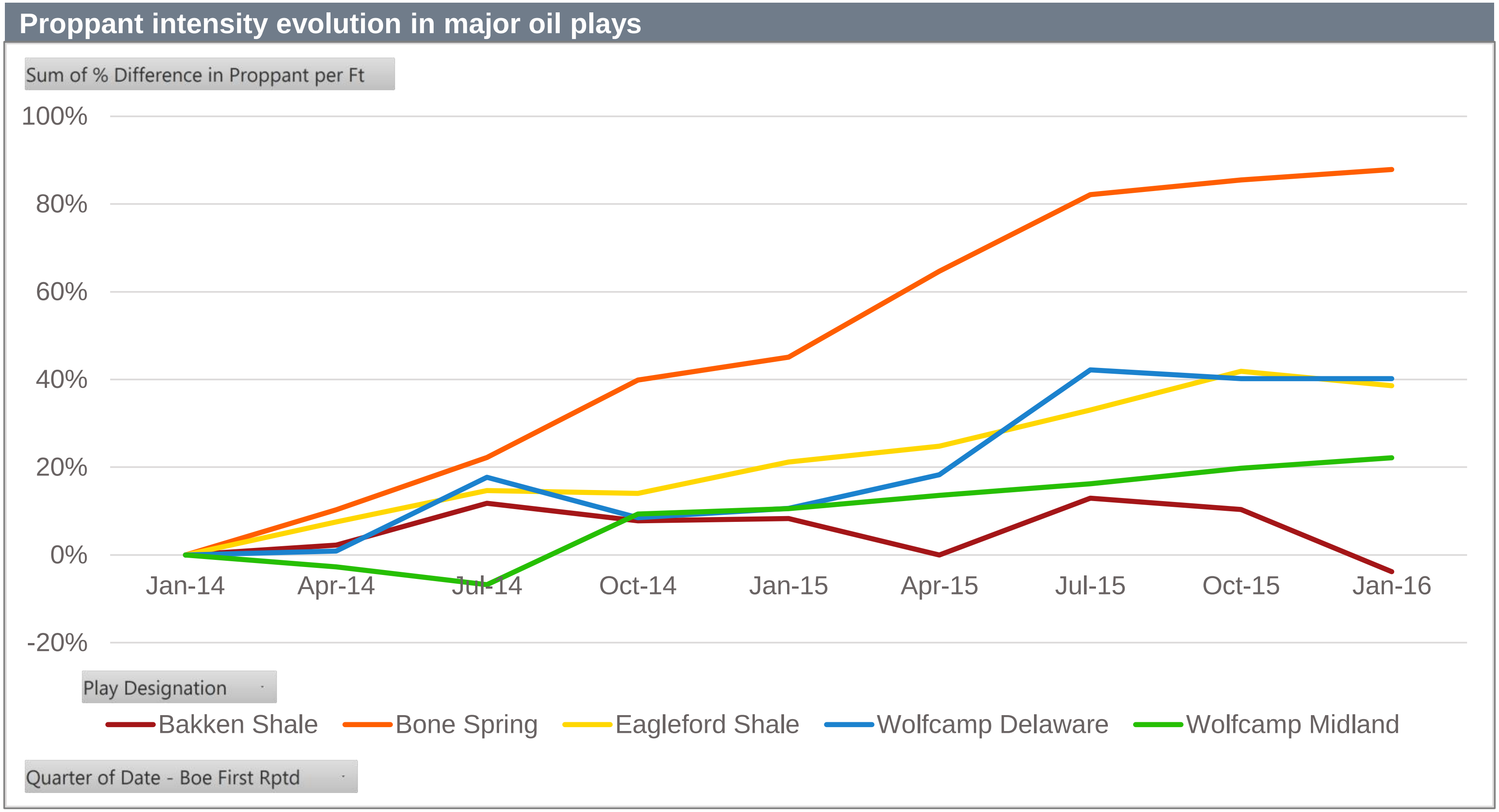
Wolfcamp Midland migration had striking results

Wolfcamp Midland subplay evolution



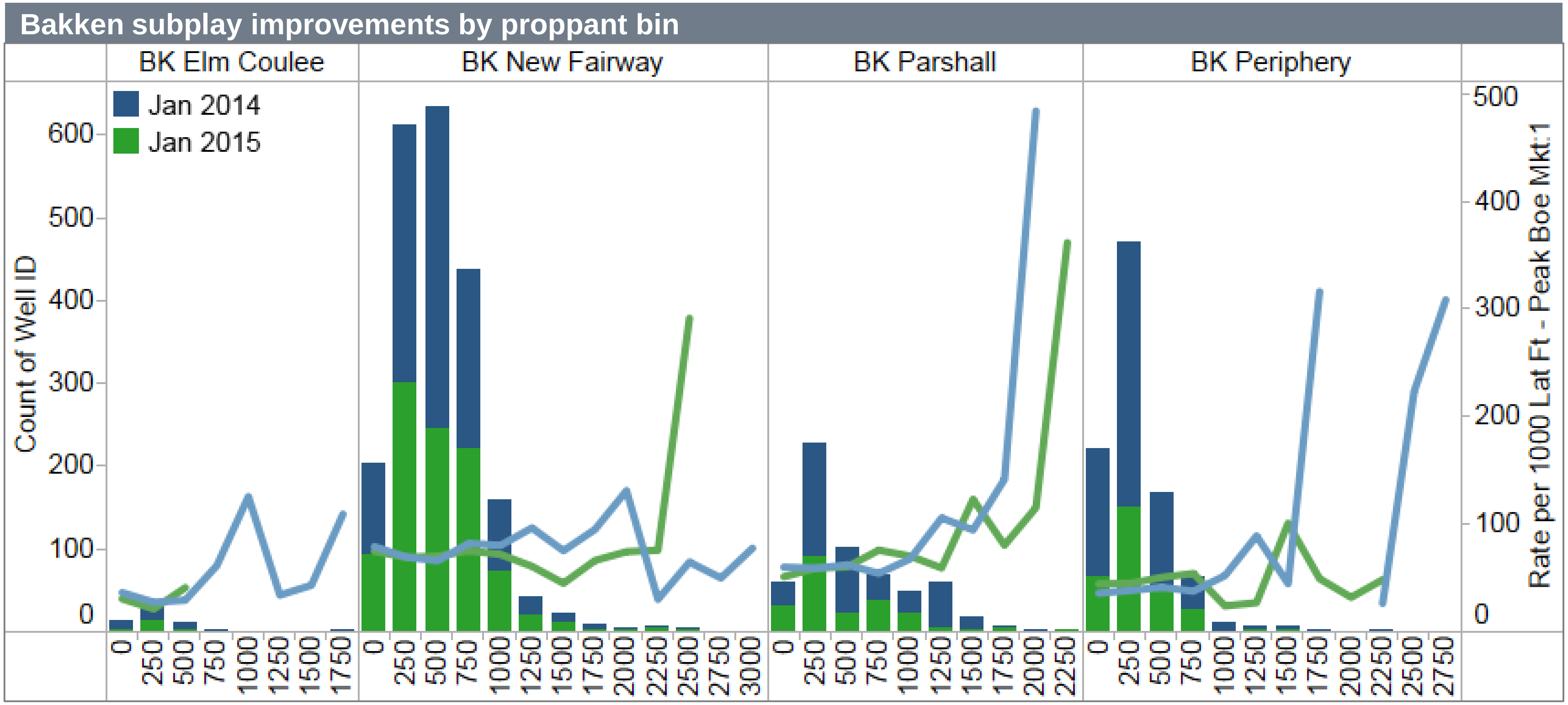
- The Wolfcamp Midland has shown the greatest improvement in overall play productivity, primarily driven by operator migration. As the play has been successfully delineated, operators have curtailed activity in the Southern Midland, while operators in the northwest have increased rigs and drilling activity. The Northern Midland subplay has also shown a productivity increase, further increasing the play's average.

Let’s beat the rock harder, too!



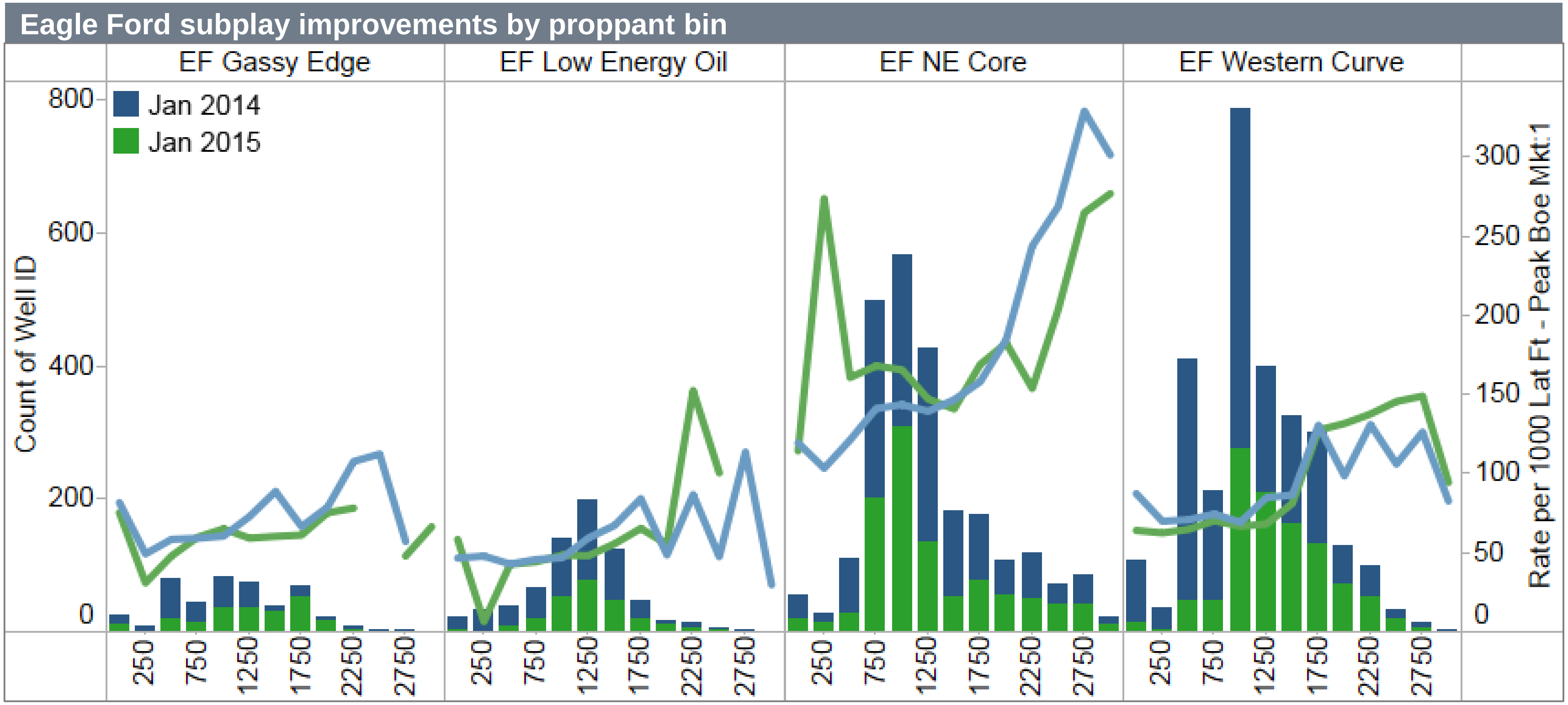
- Pioneered by EOG during 2014, proppant intensities (measured by lbs of sand per lateral foot) have been increasing across most major oil plays. Through much of 2015 and early 2016, operators were pushing the limits of proppant loading and seeing a corresponding increase in productivity. However, the most recent data has given indications this may be plateauing.

Did same-place Bakken wells improve?



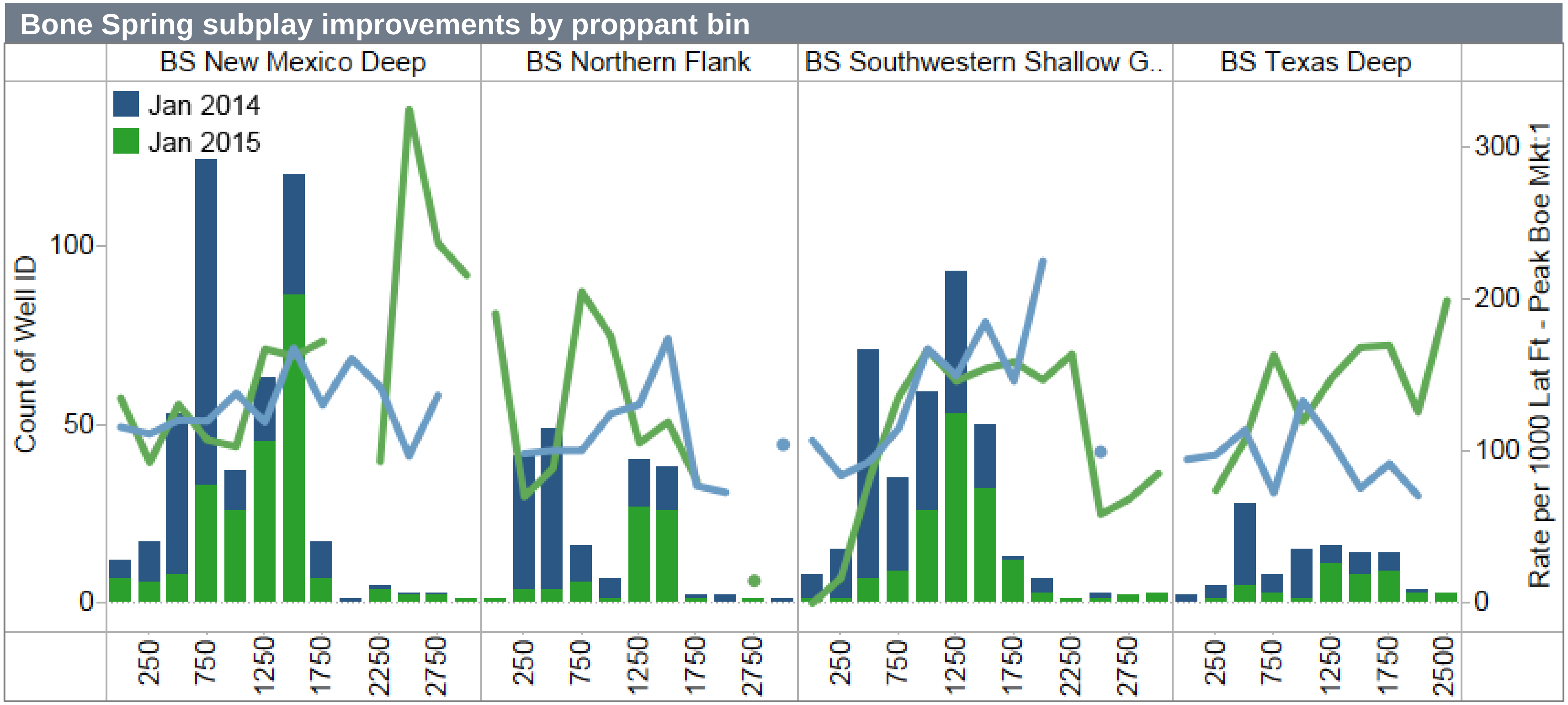
- Normalizing productivity (peak production per lateral foot) for proppant intensities and subplays, wells in the Bakken do not appear to be production more hydrocarbons than in 2014. Operators continue to experiment with various proppant intensities, though perhaps less so than other plays. As the Bakken has shifted from a growth engine to base load (low base decline, minimal investment, cash flow positive), it is unsurprising that operators are not pursuing optimizing wells as in other plays.

Eagle Ford year-over-year not getting much better



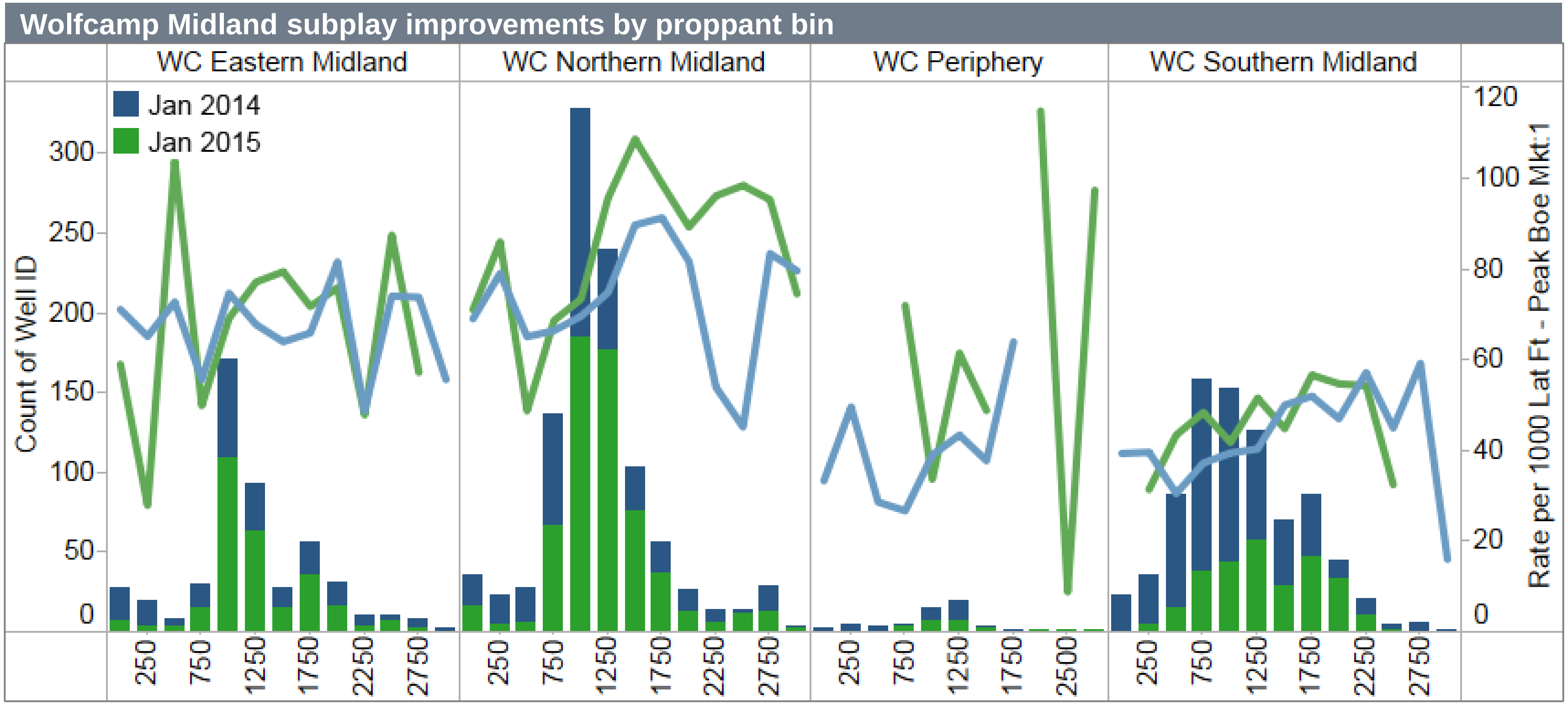
- The Eagle Ford, when normalized for geography and proppant intensity, has shown negligible changes since 2014. Thus, while the Eagle Ford has seen improvements in average productivity, operators have leveraged only “bigger wells, bigger fracs” to get “bigger production”.

Bone Spring has shown no significant improvements



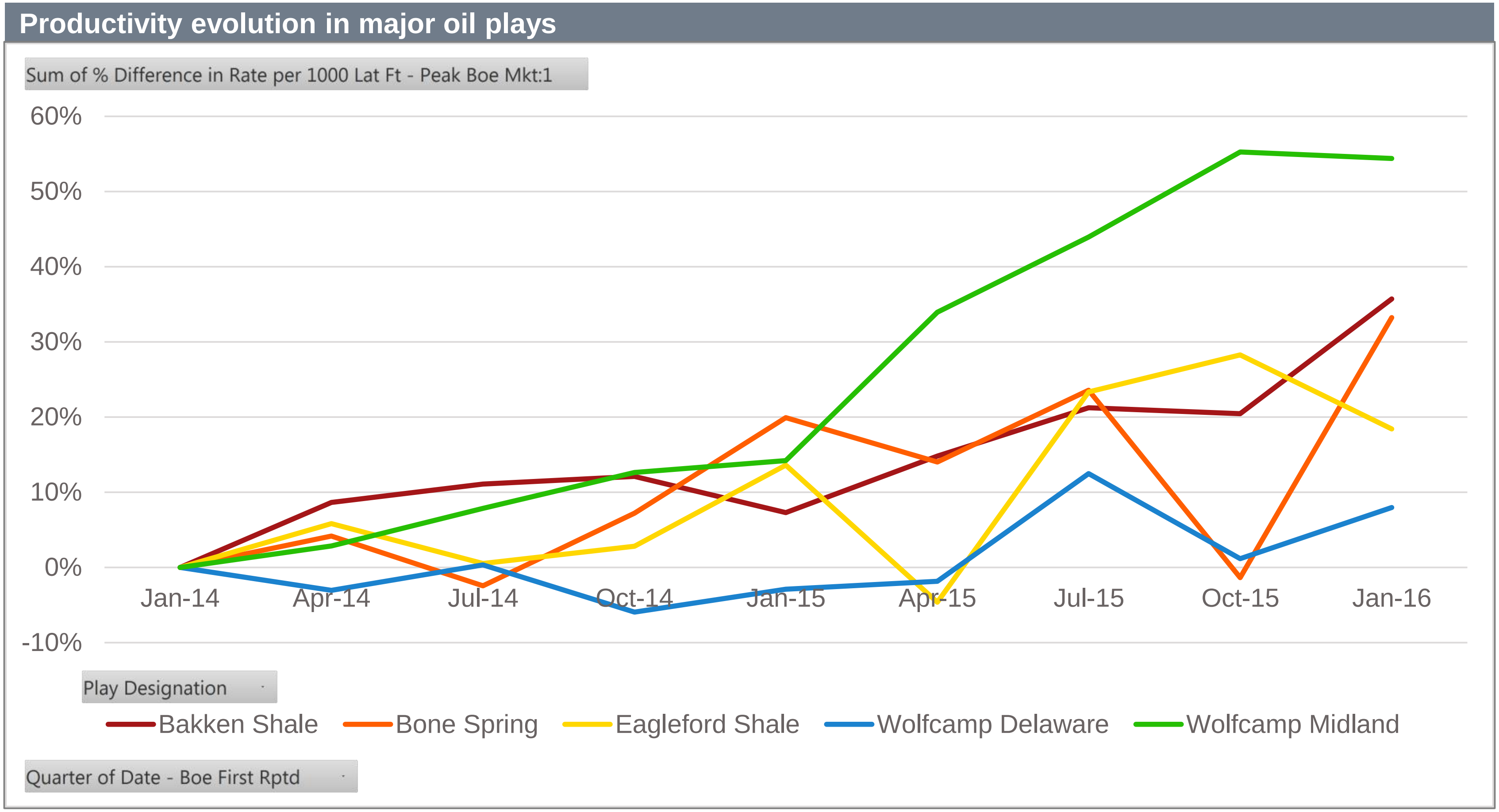
- The Bone Spring shows a similar trend of negligible improvements (when normalizing for geography, proppant intensity, and lateral length). Similarly, completing the same analysis for benches yields similar findings – operators have primarily leveraged laterals and completion techniques to generate more production. While these practices are not insignificant and will remain despite activity levels and oil prices, they do not indicate a better understanding of how to more efficiently produce from the reservoir.

Wolfcamp Midland – same story



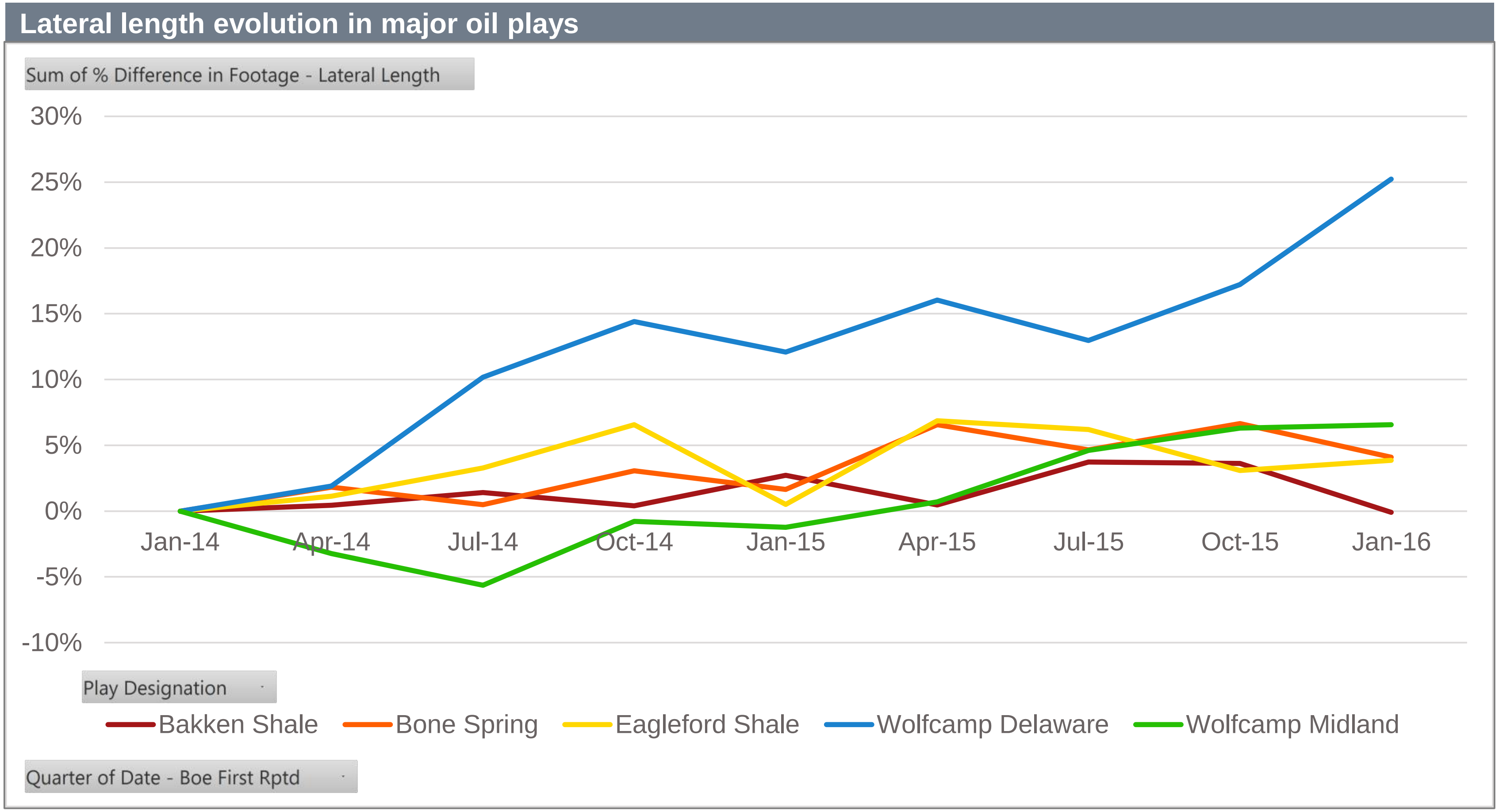
- Despite showing the greatest improvements in overall play productivity, the Wolfcamp Midland has benefitted primarily from operator migration (high-grading) and not a better understanding of the reservoir. Generally, no operator has appeared able to show evidence of an increased understanding, either.

Factors compound to more production per foot



- Per foot productivity has increased across major plays, primarily driven by high-grading and proppant loading. As activity returns, productivity pushed down, though is likely to remain relatively flat as operational improvements provide some support to counterbalance the impact.

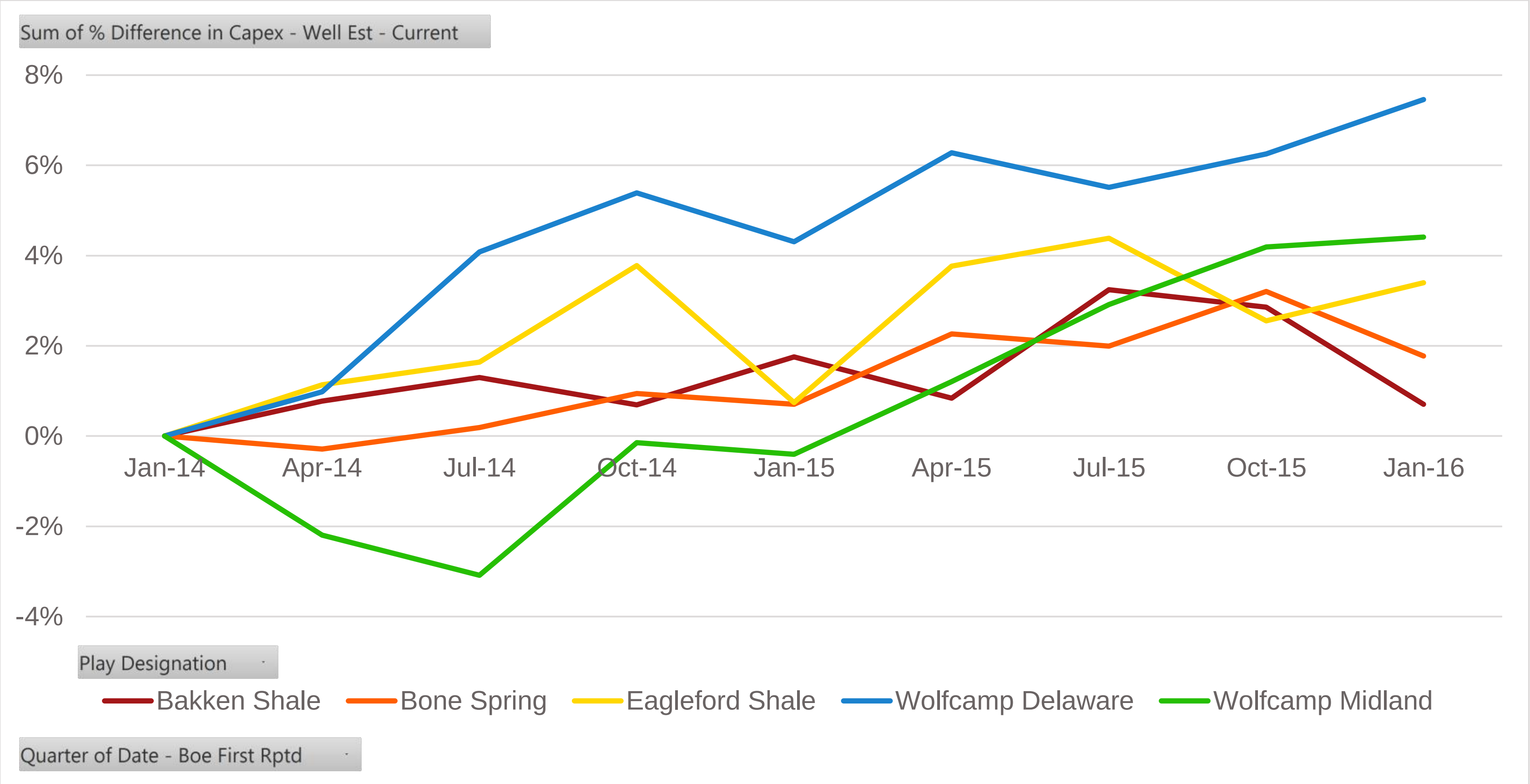
More production per foot and longer laterals



- After settling on a steady-state of well design in the Eagle Ford and Bakken, lateral lengths have seen increases up to 5% since 2014. Bakken operators are somewhat limited in their ability to drill lateral longer than 2 miles, but Eagle Ford operators are continuing to push the bounds. Permian wells have seen faster adoption of longer laterals, with many operators continuing to push further.

Longer laterals + more proppant = higher cost?

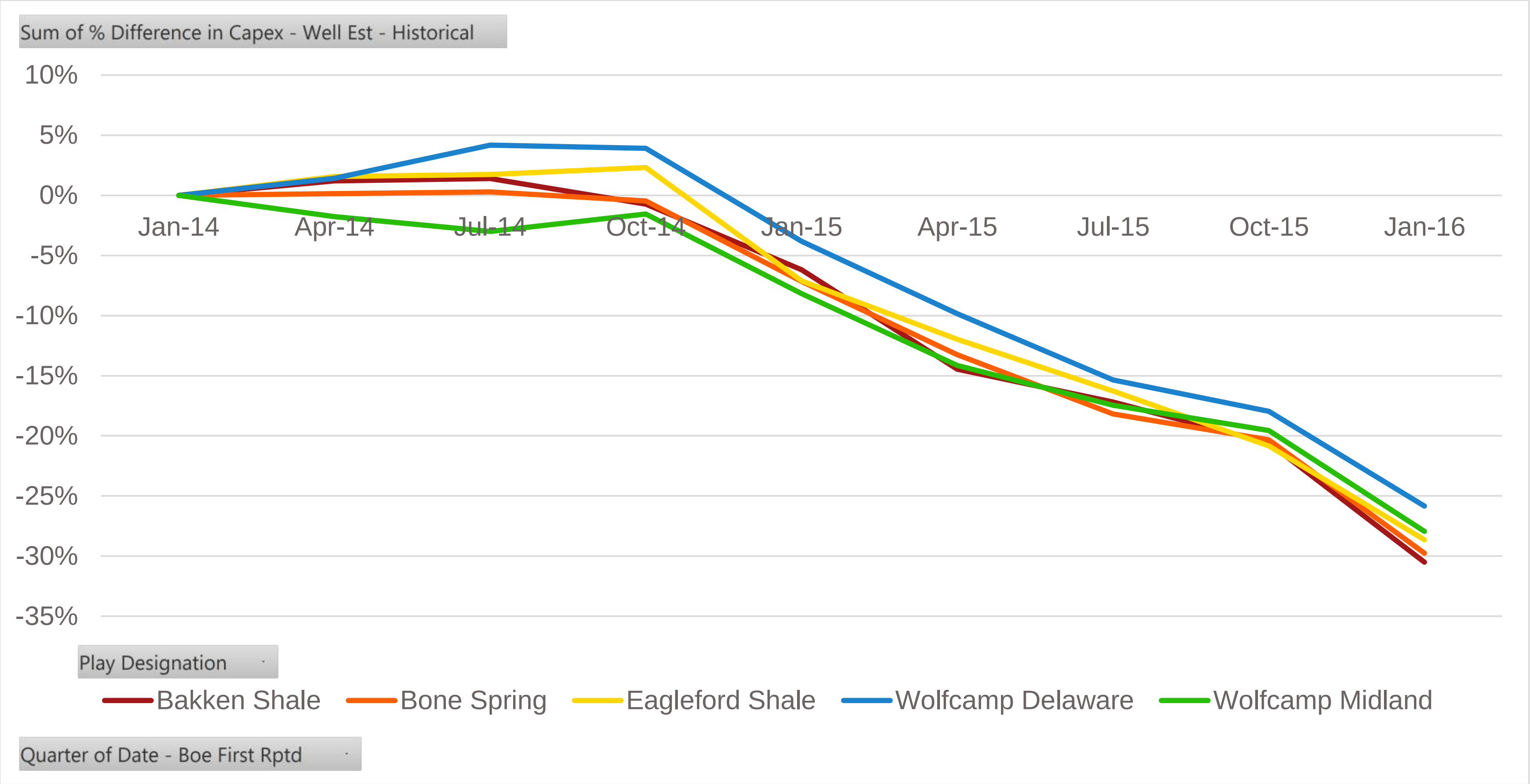
Current cost evolution in major oil plays



- With well complexities increasing due to longer laterals, more proppant, and more fluid, "normalized" costs (excluding changes in costs) have risen slightly. As more operators enact the shift to bigger and more intense wells and completions, the normalized price will certainly increase, though likely not enough to offset the improved break-evens.

Drastic service sector pricing cuts buoyed economics

Real cost evolution in major oil plays



- Across all basins, idled equipment and low demand meant service companies lost pricing power, essentially cutting costs to their lowest level where companies met cash costs, but are not covering longer term expenses such as R&D, interest, and maintaining staff. As demand returns and equipment is retired, eventually the service sector should regain pricing power.

Where do we go from here?

- Generally, break-evens for oil plays have fallen ~$30/bbl, omitting efficiency gains (fewer drill days) and transportation costs. IHS generally attributes the change as follows:

Service sector cost reductions (40%):	($12)
High-grading (35%):	($11)
Learnings (6%):	($1.80)
Operations (19%):	($5.70)
Total	($30.00)

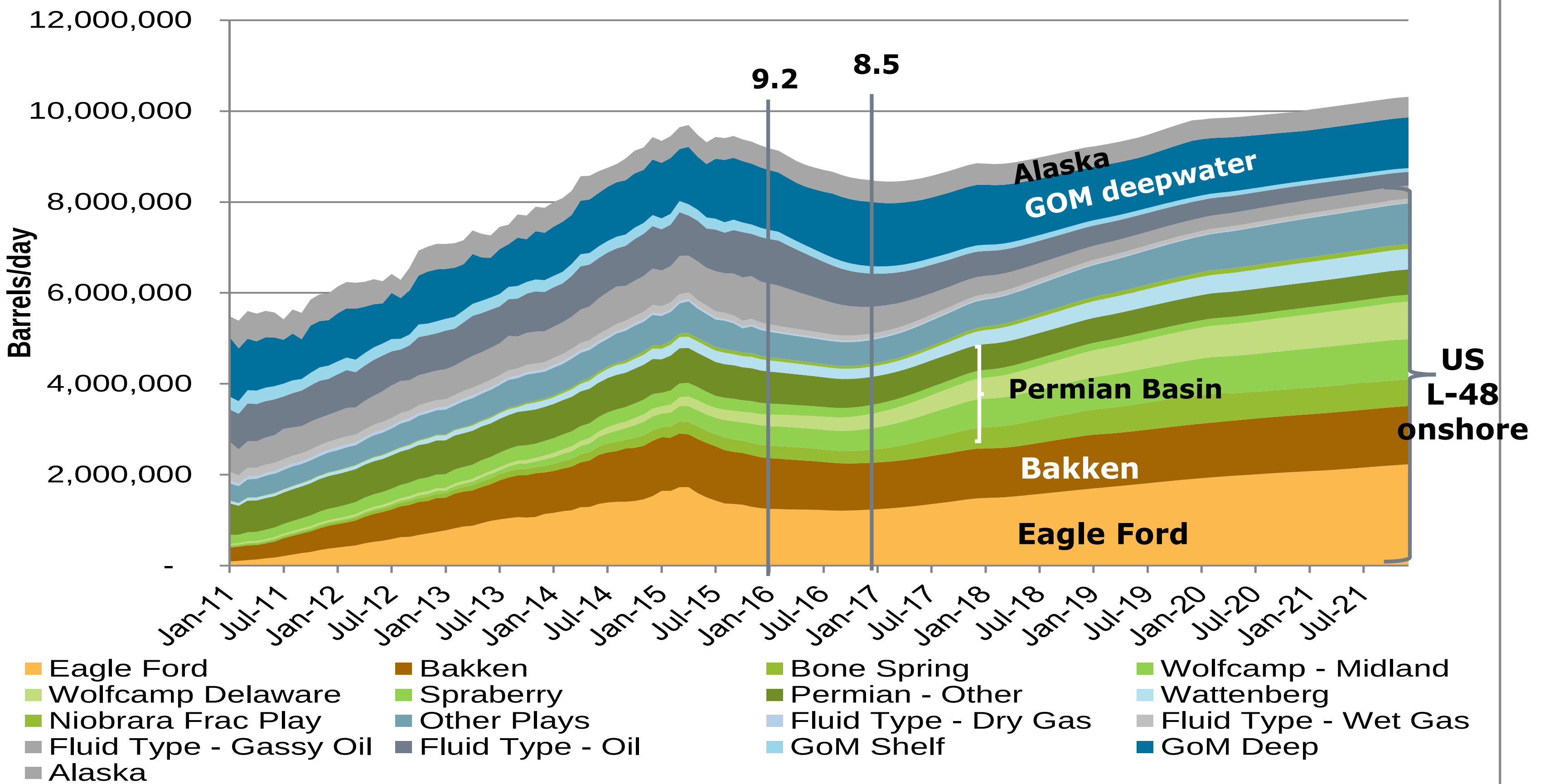
Going forward, some gains will remain (structural), while some will be eroded due to changes in the industry (cyclical). In the next 18-24 months, the impact of these factors will net out as follows:

Service sector cost reductions (30%):	($9)	Net change +$3
High-grading (20%):	($6)	Net change +$5
Learnings (8%):	($2.40)	Net change ($0.60)
Operations (25%):	($7.50)	Net change ($1.80)
Total:	($24.90)	**Net change +$5.10**

The net impact of changes to service sector costs rebounding with oil price, coupled with the inherent low grading of adding rigs back to the field, partially offset by modest gains in learnings and operations will raise the average break-even by roughly $5.00/bbl. Note this does not include any efficiencies gained from drilling faster or reductions in transportation costs.

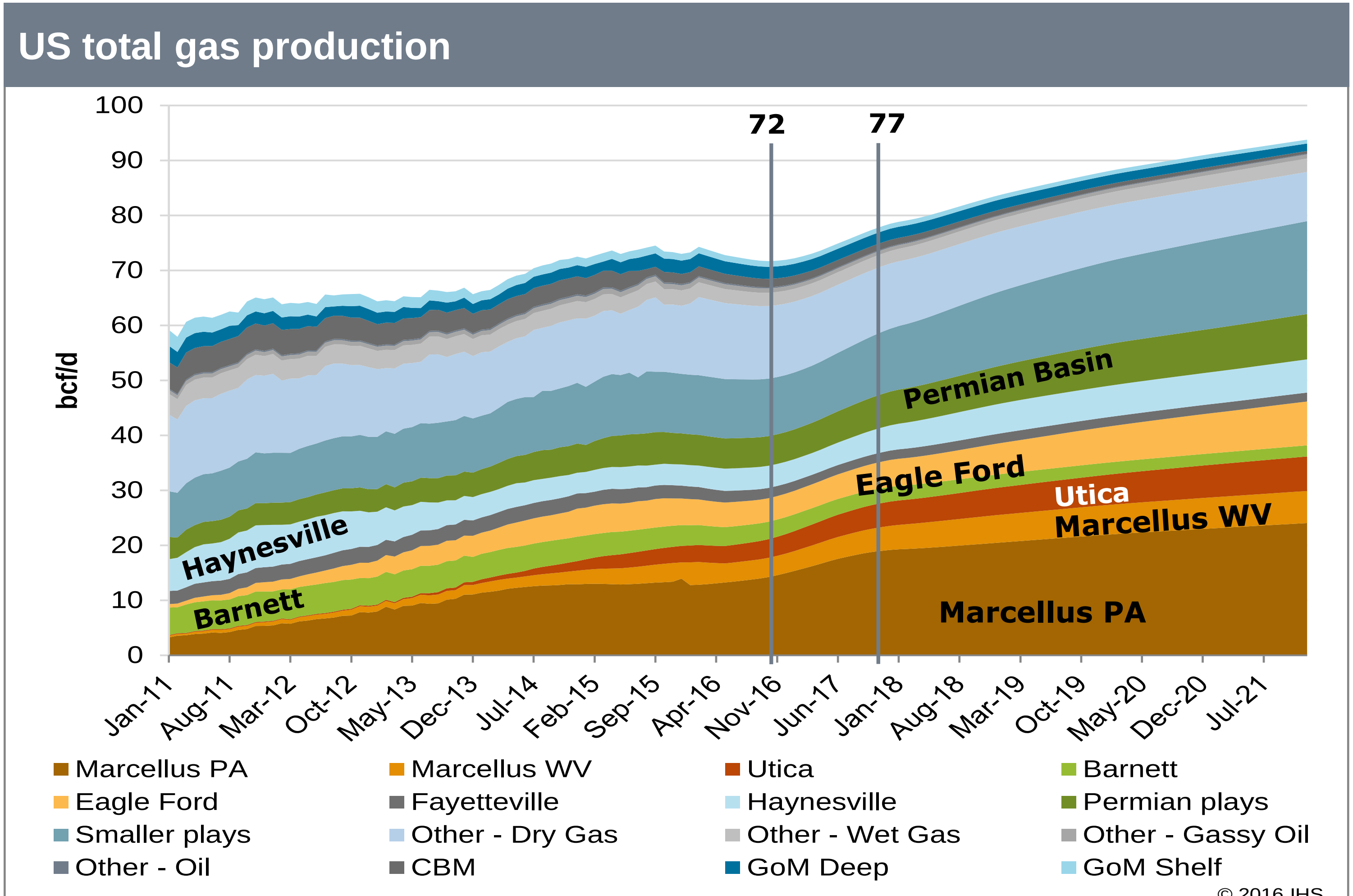
U.S. production projected to trough in early 2017, followed by modest growth through the near-term

US total liquids production



Source: IHS

Sustained lower prices and capital constraints keep a lid on near-term production growth



Source: IHS

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	Production	Cost
Structural	**Well Design** Lat length Proppant **Learning**	D&C Efficiency Opex Other well costs Basis
Cyclical	Inter-play high-grading Intra-play high-grading	Service sector unit cost