SHALE TECHNOLOGY:

MOORE'S LAW OR TURGOT'S?

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SAILINGSTONE
CAPITAL PARTNERS LLC

Executive Summary

In the last decade, we have witnessed seismic changes in the oil and gas industry, particularly regarding the economics of North American unconventional production. A significant portion of these advances have been attributed to technology, which many observers expect to be a continued source of deflation into the future. In this paper, we attempt to disaggregate structural improvements in well economics from cyclical ones in order to better understand whether we are in a period of accelerating productivity gains, *à la* Moore's Law, or if we have reached the point of diminishing returns.[1]

[1] Anne Robert Jacques Turgot was a French statesman and Sorbonne-educated economist whose seminal work *Reflections on the Production and Distribution of Wealth* pre-dated Adam Smith's *The Wealth of Nations* by more than a decade. He was the first economist to recognize the law of diminishing returns, arguing that "each increase [in an input] would be less and less productive."

Introduction

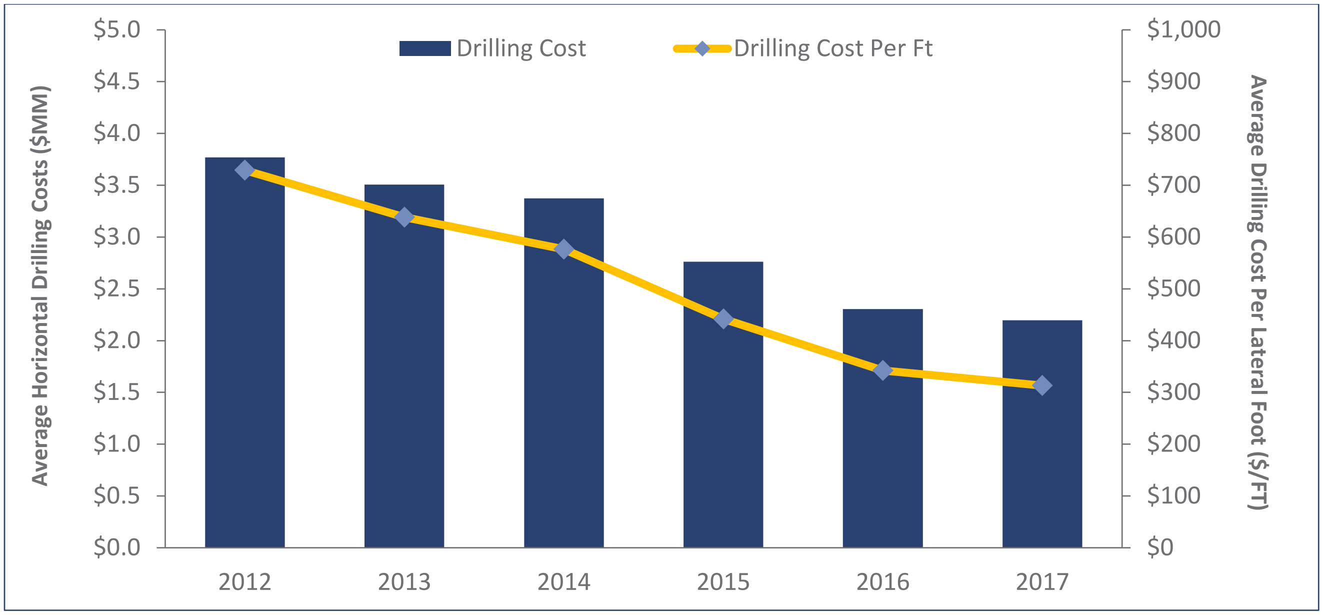
The impact of technology on the global oil and gas industry is indisputable. Oil prices have fallen almost 50% in the last decade, in no small part due to the emergence of U.S. unconventional supply growth. Domestic natural gas prices have fallen even more, and a country which once banned the construction of gas-fired power plants out of fears of resource scarcity is now on the verge of becoming one of the commodity's largest exporters. Ten years into the "shale revolution", the industry has accomplished far more than anyone could have expected back in the early days of the Barnett Shale. That success has fostered a belief in some circles that the E&P business will be transformed into a technology play, with "AI" and "big data" increasingly a part of the oil patch lexicon. In fact, many industry observers now incorporate annual "productivity gains" into their forecasts of future well results and commodity price assumptions. While we have no doubt that technology will continue to play a vital role in the evolution of the industry, we question how much of the recent results are due to structural factors, versus cyclical ones, and wonder whether future improvements will be as linear and homogeneous as conventional wisdom suggests. These issues bear consideration, as the answers will shape forward-looking assessments of both individual well economics and, perhaps more importantly, inventory depth. These factors, in turn, are the basis for estimating asset values as well as the magnitude and cost structure of potential sources of supply. In other words, understanding the impact of technology is critical to understanding the future of the E&P industry.

The application of technology is a means to end, a way to improve the overall economics of a business. Thus, determining the impact of technology on the oil and gas industry is best understood by analyzing changes to well-level returns, which are a function of both cash flows and capital intensity. Since a). all producers are price takers and b). operating costs do not fluctuate meaningfully across operator or basins for a given commodity, the primary determinant of changes in well economics is capital efficiency: the amount of money spent to drill and complete a well relative to cumulative production from that well over time. In addition to analyzing improvements in per-well economics, it is also important to understand the breadth of these changes. Thus, studying the impact of technology on the oil and gas industry comes down to an assessment of three variables: costs, productivity and inventory.

Costs

There are two basic components to well costs: drilling and completion. It is clear from the data that drilling costs per well have fallen over the last five years. A significant portion of this gain has been from reductions in drilling times – for a given day rate, faster spud-to-spud times create permanent cost savings.

EXHIBIT 1 | DRILLING COSTS ARE FALLING—ALL BASINS

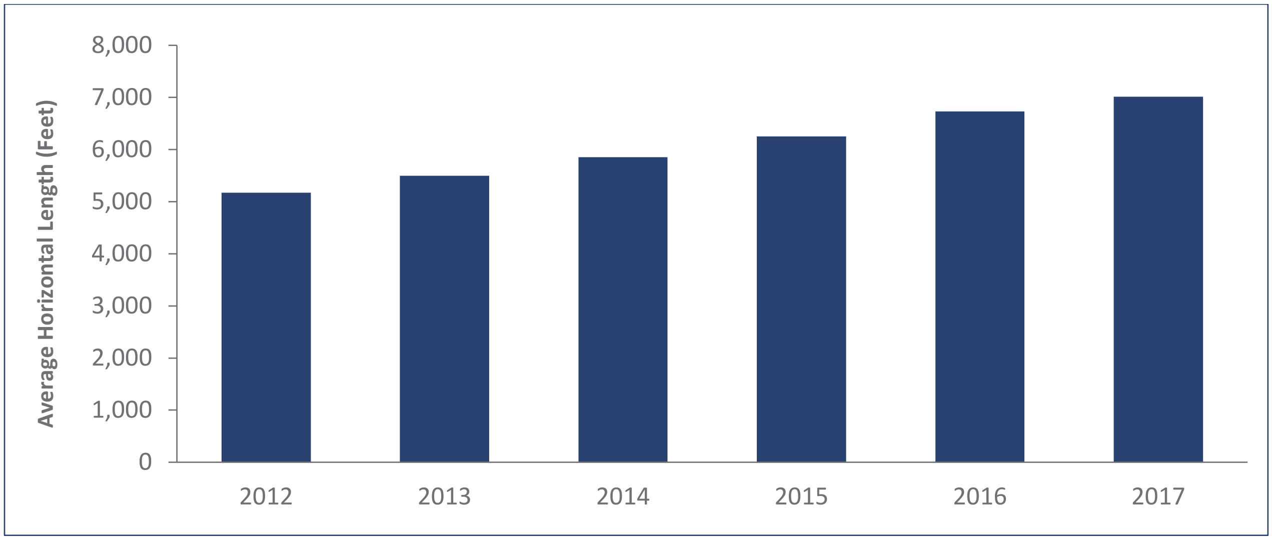


Source: IHS Markit and SailingStone Capital Partners

The reduction in absolute drilling costs is even more impressive as lateral lengths have also increased, meaning that total lateral feet drilled per day has risen at a faster rate than rig productivity on a per-well basis. Today, a typical rig can drill twice as many wells and over 2.5x the lateral footage per year relative to its peer in 2012.

Faster, more efficient drilling is one of the key structural improvements in overall well economics that can be ascribed to technology. Going forward, however, it seems unlikely that we will witness a step change in lateral length such as the one that occurred between 2012–2017, when average lateral lengths increased from 5,000’ to over 7,000’, including some wells reaching out more than 12,000’. Another 40–50% improvement is improbable absent significant industry consolidation given the disjointed ownership position across most basins, complicated further by existing vertical and horizontal wellbores.

EXHIBIT 2 | AVERAGE HORIZONTAL WELL LATERAL LENGTH—ALL BASINS

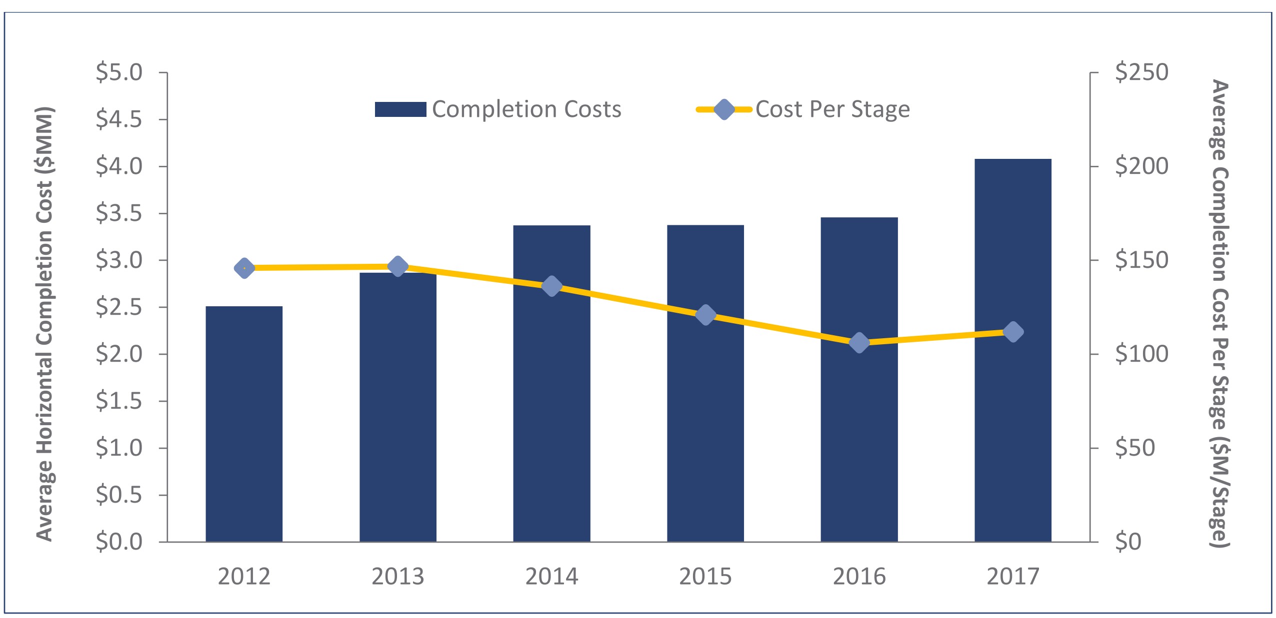


Source: IHS Markit and SailingStone Capital Partners

Thus, while we believe that there will be continued efficiency gains from longer laterals, they likely will be much less significant than what has already occurred.

In contrast to the drilling side of the equation, per-well completion costs have gone up over the last five years.

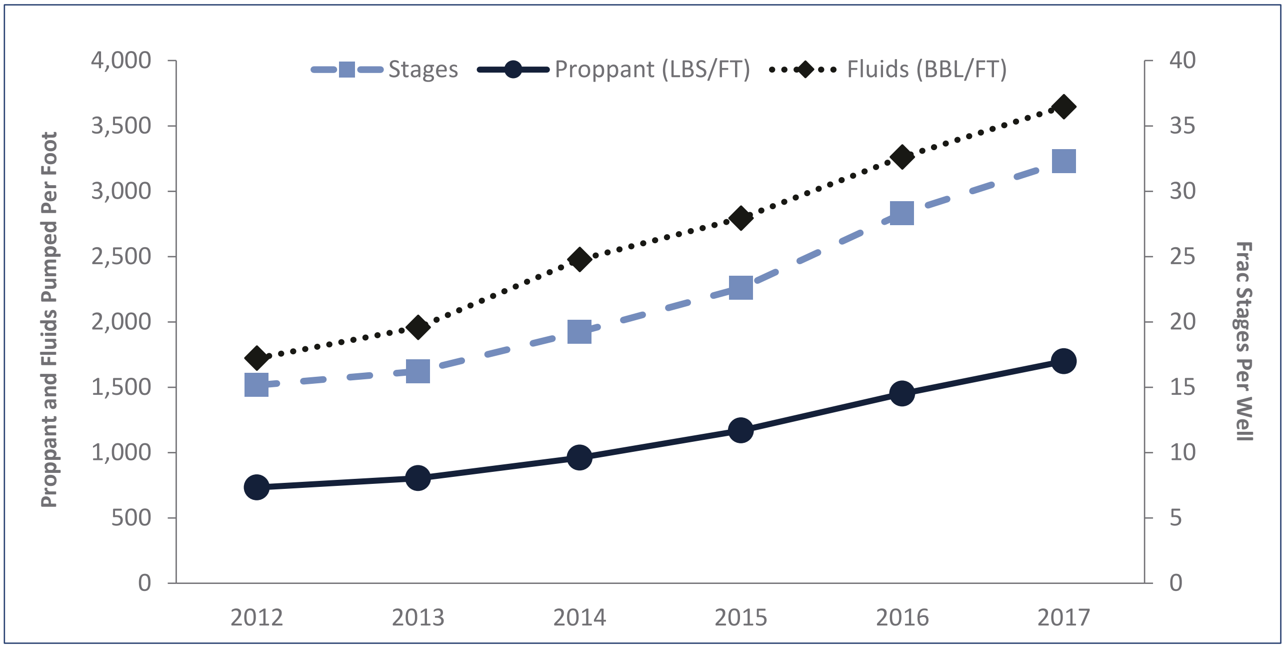
EXHIBIT 3 | COMPLETION COSTS PER WELL ARE RISING . . .



Source: IHS Markit and SailingStone Capital Partners

Proppant-, cluster- and stage-intensity have increased across all the plays, as more energy is being deployed to stimulate near-wellbore reservoir and connect a greater volume of fractured rock.

EXHIBIT 4 | . . . DRIVEN BY INCREASES IN COMPLETION INTENSITY—ALL BASINS



Source: IHS Markit and SailingStone Capital Partners

Part of the rapid increase in completion intensity is a function of cyclical pricing. With unit-level completion costs down, some operators have attempted to overcome challenging geology by substantially increasing the energy deployed down hole. In some cases, this "bigger hammer" approach has been effective in boosting well recoveries and returns. However, these gains are highly sensitive to increases in service pricing given the significant differences in service intensity between high- and low-quality rock. This fact is evident even when looking at ultra-core well economics between two plays. For instance, leading edge completions in the Haynesville require 4x more proppant/ft than core Northeast Marcellus wells, but generate 40% lower estimated ultimate recoveries ("EUR") and more than 30% lower returns. According to our work, a 20% increase in unit service costs eliminates about 80% of the remaining core locations in the Haynesville, but a commensurate change in the Northeast Marcellus only reduces well returns by about 5–10% and has a de minimis impact on core inventory.

EXHIBIT 5 | HAYNESVILLE vs. MARCELLUS SERVICE INTENSITY

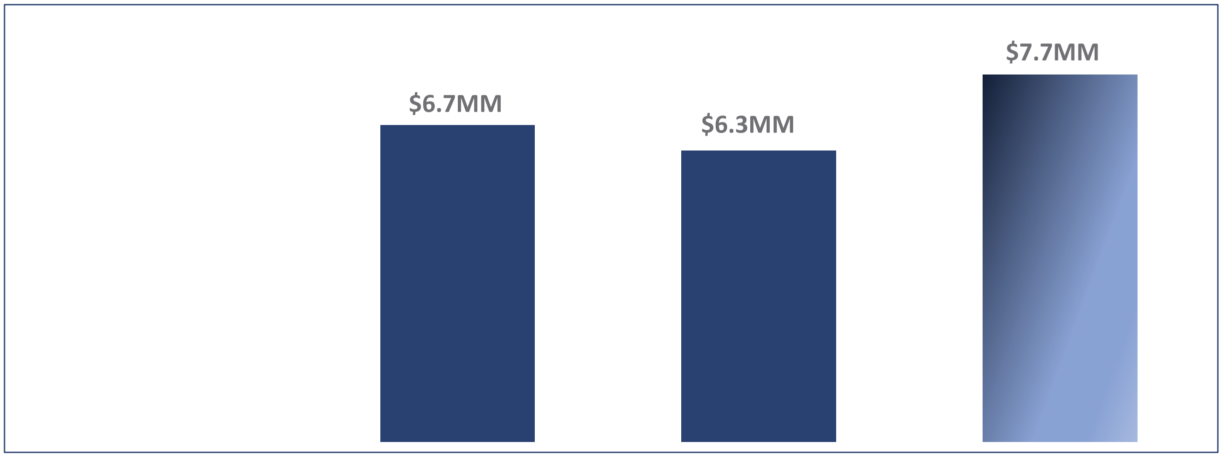
Core Wells	EUR per ft bcf/1,000 ft	Proppant lbs/ft	Cost per ft $mm/1,000 ft	IRR @ $3.00
Haynesville	2.5	5,000	$1.4	28%
Marcellus	4.0	1,250	$0.8	45%

Source: SailingStone Capital Partners.

This material is not intended to forecast or predict future events and is based upon a variety of estimates and assumptions. Past performance does not guarantee future returns.

Another way to put the combination of cyclically low service costs and service demand elasticity into perspective is to look at what current well costs would be using 2014, or closer to peak, completion costs (drilling costs are unchanged).

EXHIBIT 6 | WELL COSTS ADJUSTED FOR COMPLETION INFLATION—ALL BASINS



	2014	2017	2017 Adjusted
Average lateral length	5,854	7,016	7,016
% change vs. 2014	—	20%	20%
$/lateral foot	$1,145	$898	$1,097
% change vs. 2014	—	–22%	–4%

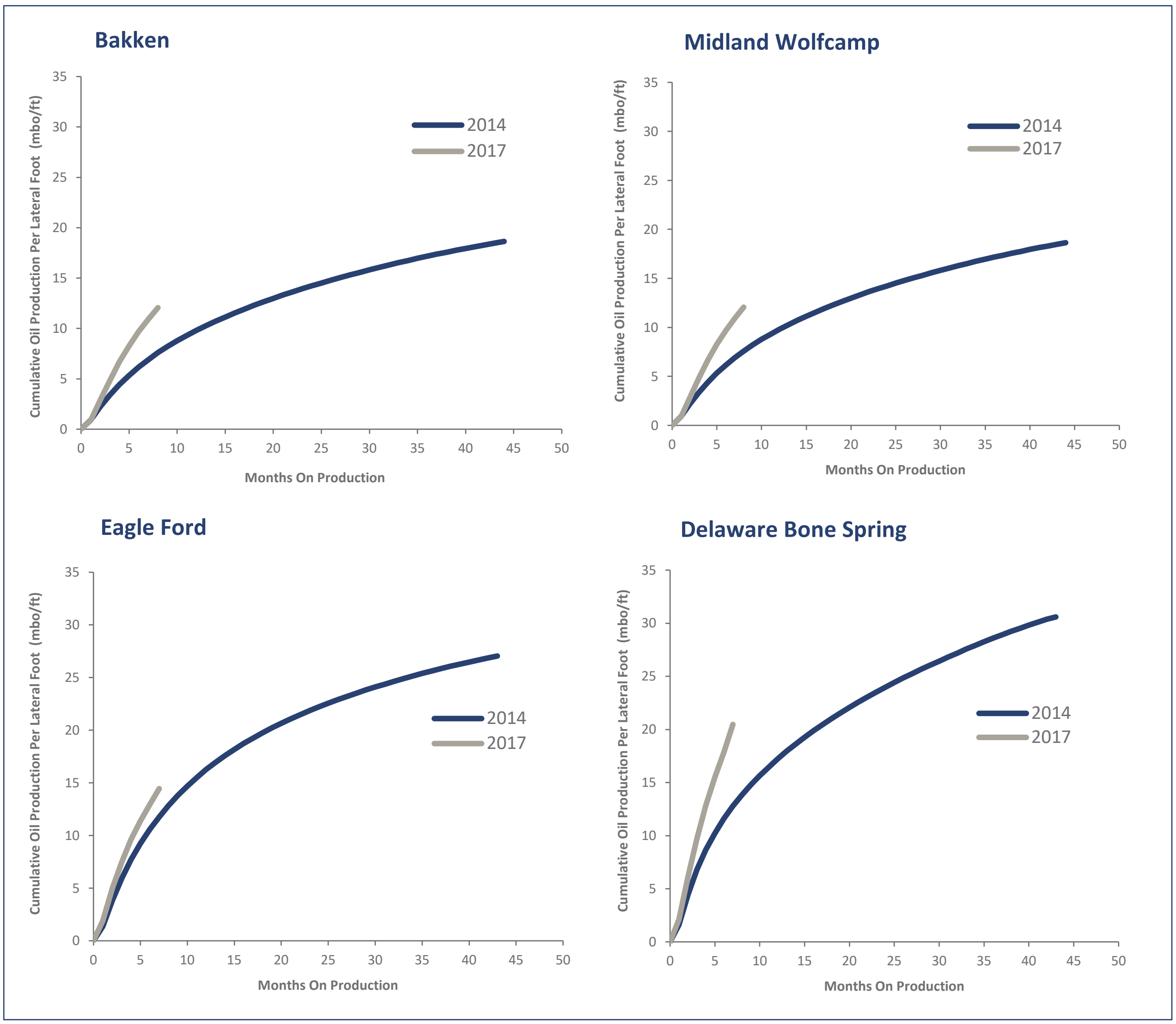
Source: IHS Markit and SailingStone Capital Partners

This analysis helps highlight the impact of cyclical cost deflation. Savings from more efficient drilling appear to be the biggest structural reduction in technology-related costs, while completions will be more exposed to pro-cyclical pricing dynamics as activity levels fluctuate. Extrapolating current well costs into the future, or building an excel model where service inflation is offset by "future productivity gains", seems overly simplistic and ignores the realities of both geology and the pricing dynamics of the service industry. As service costs normalize, we expect cost curves to steepen given the differences in service intensity, both within plays (core vs. non-core) and across plays. This, in turn, will put upward pressure on commodity prices while simultaneously reducing the number of economic locations in more marginal acreage. Since technology hasn't resulted in substantially cheaper wells, once we adjust service costs to more mid-cycle levels, the more relevant question is the impact of technology on productivity.

Productivity

Changes to well productivity are best understood on a per-lateral foot basis, either as initial production ("IP") or estimated ultimate recovery. This allows for a standardized comparison of wells with different lateral lengths. We looked at average cumulative oil production per lateral foot in the key oil basins, and it appears that productivity has improved over the last few years, driven by longer laterals and enhanced completions.

EXHIBIT 7 | AVERAGE WELL PERFORMANCE HAS BENEFITED FROM TECHNOLOGY



Source: IHS Markit and SailingStone Capital Partners

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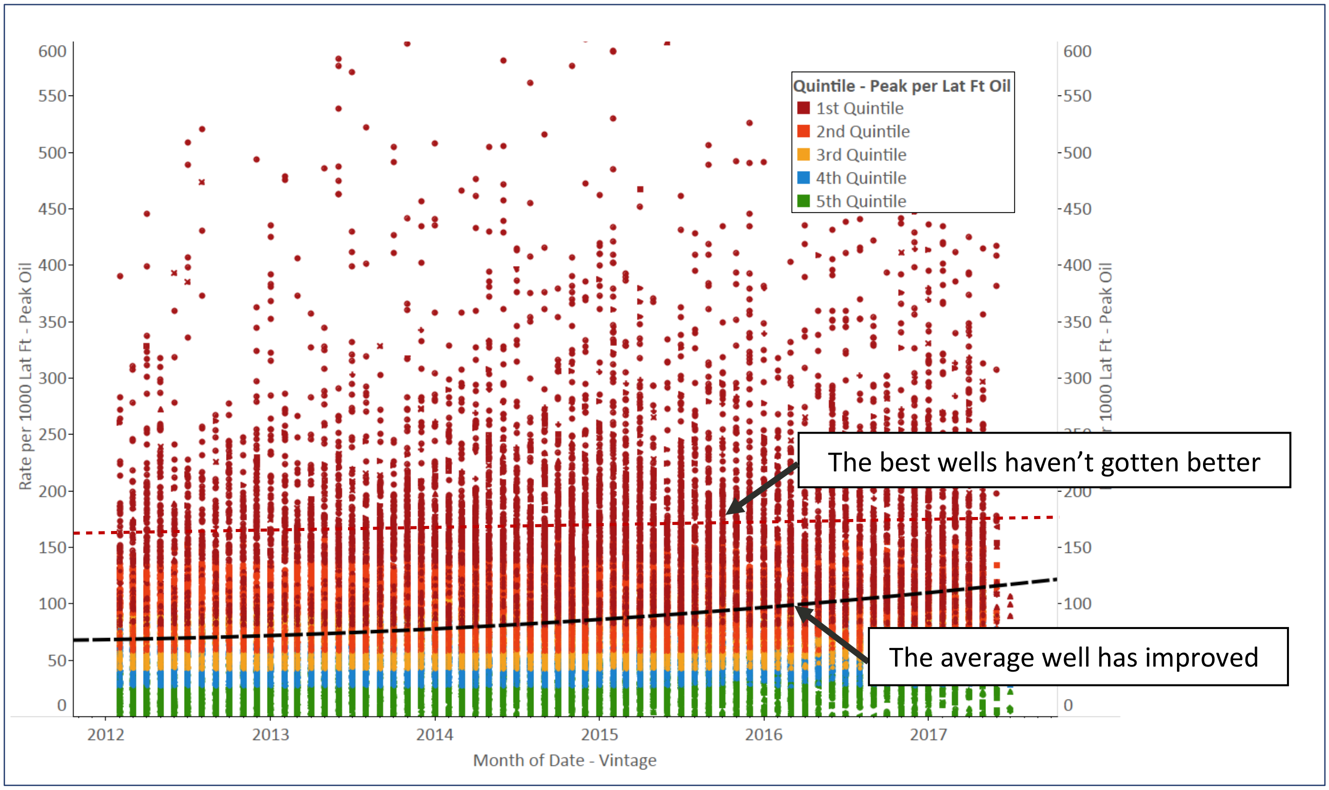
However, when looking at top quintile wells, oil rate per lateral foot is largely unchanged over the same time frame.

EXHIBIT 8 | WELL PRODUCTIVITY BY QUINTILE—MIDLAND, DELAWARE, BAKKEN & EAGLE FORD



Source: IHS Markit and SailingStone Capital Partners

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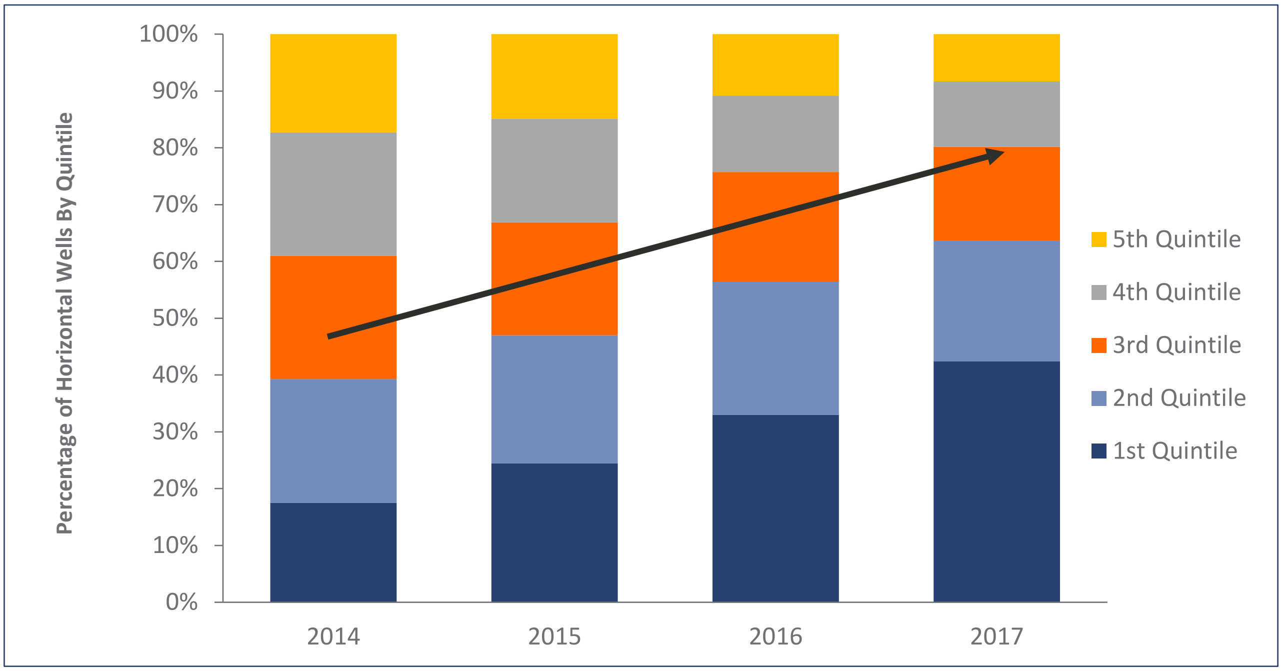
So, the best wells aren't getting meaningfully better, but the average well is. What's happened? There's only one answer: the industry is drilling fewer bad (higher quintile) wells. While this trend is promising, it doesn't answer the question. We need to know whether this is a structural dynamic (companies have optimized completion recipes so that they can overcome poor geology), or a cyclical one (the industry high graded during the downturn, and will low grade as core inventory is depleted and as commodity prices recover).

Disaggregating the averages provides the answer to the question. The industry has been high grading, a natural response to a downturn in commodity prices, but hardly reflective of a new technological paradigm.

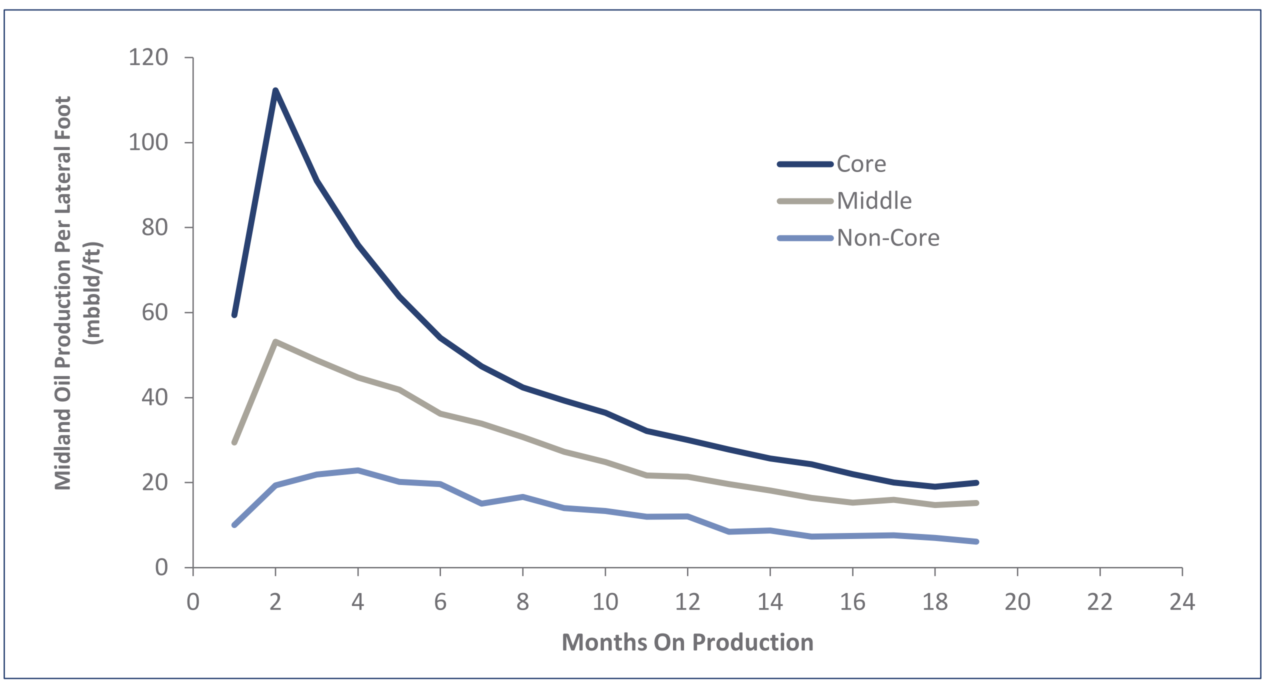
EXHIBIT 9 | COMPANIES HIGH GRADED IN THE DOWNTURN—MIDLAND, DELAWARE, BAKKEN & EAGLE FORD



Source: IHS Markit and SailingStone Capital Partners

Given the obvious pattern of high grading, it is important to appreciate how quickly well results degrade as you move down the quality spectrum.

EXHIBIT 10 | MIDLAND BASIN 2016 VINTAGE CORE vs. NON-CORE TYPE CURVES

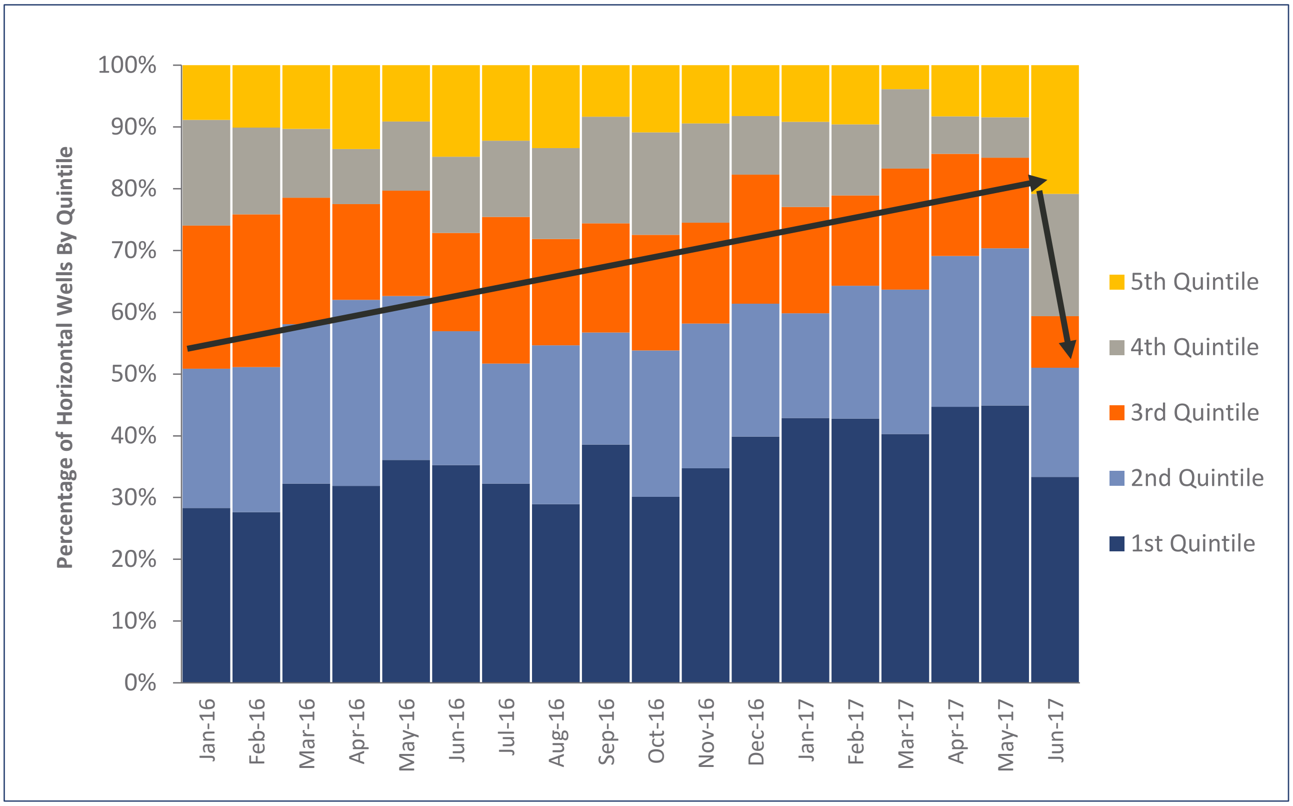


Source: IHS Markit and SailingStone Capital Partners

A core well in the Midland Basin has twice the EUR per lateral foot vs a non-core well. For a given well cost, capital intensity more than doubles as you move into non-core acreage, and well-level returns fall from 60% to 15% at a $50/bbl oil price. These are hardly immaterial differences in economics.

Thus, we believe that a primary driver of the recent improvements in average well results is high grading, which by definition is not repeatable. In fact, in some basins we may be starting to witness the ugly consequence of cherry picking wells in a downturn – low grading.

EXHIBIT 11 | DRILLING ACTIVITY LEVEL BY QUARTER—MIDLAND, DELAWARE, BAKKEN & EAGLE FORD

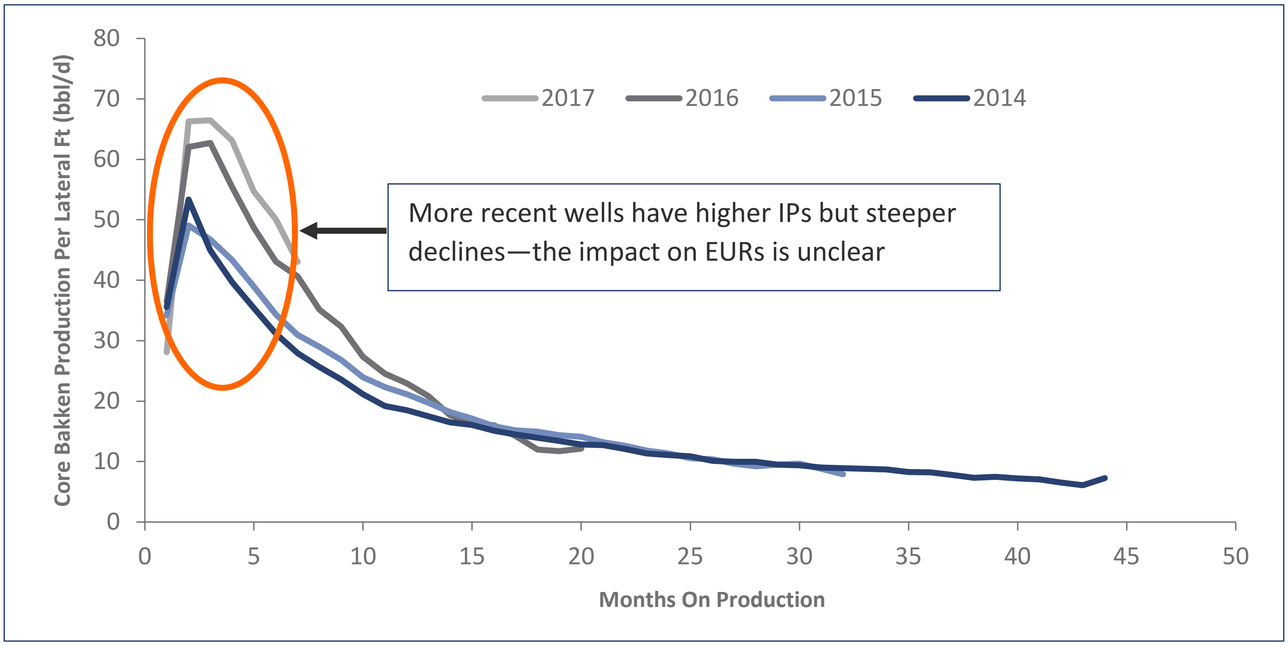


Source: IHS Markit and SailingStone Capital Partners

Given the structural differences in economics between core and non-core acreage, we believe that, over time, the inevitable mean reversion of well quality will offset a significant portion of the benefits derived from continued completion design improvements.

The second problem with many of the conclusions regarding well productivity is that they typically are derived from IP rates, since this is readily available data, and is often quoted in corporate press releases. However, initial production rates don't necessarily correlate with recoveries. In other words, a more expensive, energy-intensive completion may increase the upfront production rate, but may not lead to meaningfully more oil recovered over the life of the well. The reality is that we are still somewhat data constrained, as the average 2016 well only has about 12 months of production data available. But, there are some early indications in more mature plays like the Bakken which suggest that the higher rates are generating steeper declines, and thus potentially lower recoveries.

EXHIBIT 12 | BAKKEN WELLS BY VINTAGE



Source: IHS Markit and SailingStone Capital Partners

At a time when the industry is struggling to balance growth with capital discipline, spending more money to generate higher IPs today at the expense of a steeper corporate decline rate and lower future cash flows doesn't seem to make much sense.

So, we can observe that the industry has been high grading, which is by definition unsustainable. And, we see little evidence to suggest that technology has closed the significant gap in productivity and economics which exists between core and non-core acreage. This leads us to the most critical issue, which we believe is largely misunderstood by the markets today. What is the impact of technology on inventory?

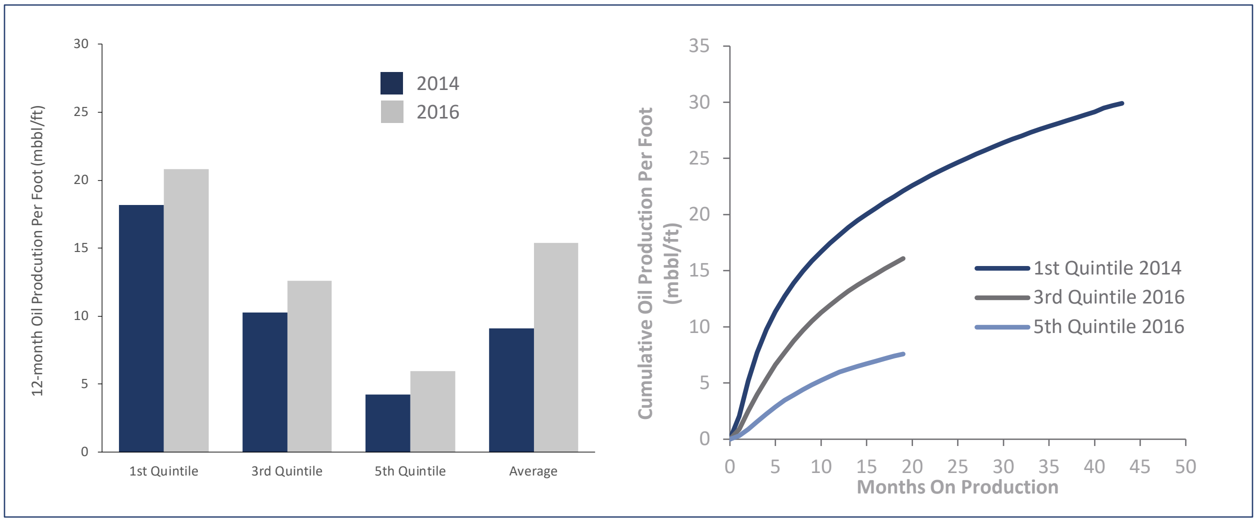
Inventory

Conventional wisdom has it that the application of new technologies to an old industry has created tens if not hundreds of thousands of new locations which can be drilled profitably at relatively low commodity prices. It is undeniable that horizontal drilling and new completion designs have allowed producers to access previously uneconomic hydrocarbons. As a result, industry reserve lives are much longer than they were a decade ago. However, it is also true that the combination of technology and industry behavior appears to be *reducing* inventory at the bottom of the cycle.

In terms of technology, longer laterals consistently have generated superior well results, as productivity per lateral foot has improved while the costs of the vertical entry as well as much of the surface infrastructure can be distributed across a longer span of producing pipe. But, by definition, one 10,000' lateral is the equivalent of two 5,000' laterals. Moreover, to execute a program of 10,000' laterals, you need contiguous acreage blocks, which are difficult to find given the fragmented nature of land ownership in the cores of many basins. This is complicated further by the existence of legacy wellbores, which is a particularly acute issue in oil plays. Finally, proppant-intensive completions impede the ability to downspace by fracturing rock across a greater aerial extent and thus more efficiently draining the reservoir. This is beneficial from a per-well economic perspective, but likely reduces the number of locations available to be drilled in the future.

Another way that technology could add to inventory is by expanding the core. Unfortunately, while technology has improved the economics of most wells, there is no evidence to support the contention that traditionally marginal acreage is approaching economic parity with the very best acreage. The most economic wells are still being drilled in the best rock, and the gap between core and non-core remains wide. The chart below focuses on Midland Basin Wolfcamp wells. On the left, it is evident that productivity per lateral foot has improved for all quintiles of wells. And, the result of high-grading is obvious as well, when looking at the significant improvement in the average well's productivity. But the chart on the right highlights the key conclusion – 2014 core wells are still vastly superior to wells drilled in average or low-quality rock using the most advanced completion designs. Technology can enhance productivity, but it doesn't trump geology.

EXHIBIT 13 | WELL PRODUCTIVITY—IMPROVING BUT NOT TRANSFORMING



Source: IHS Markit and SailingStone Capital Partners

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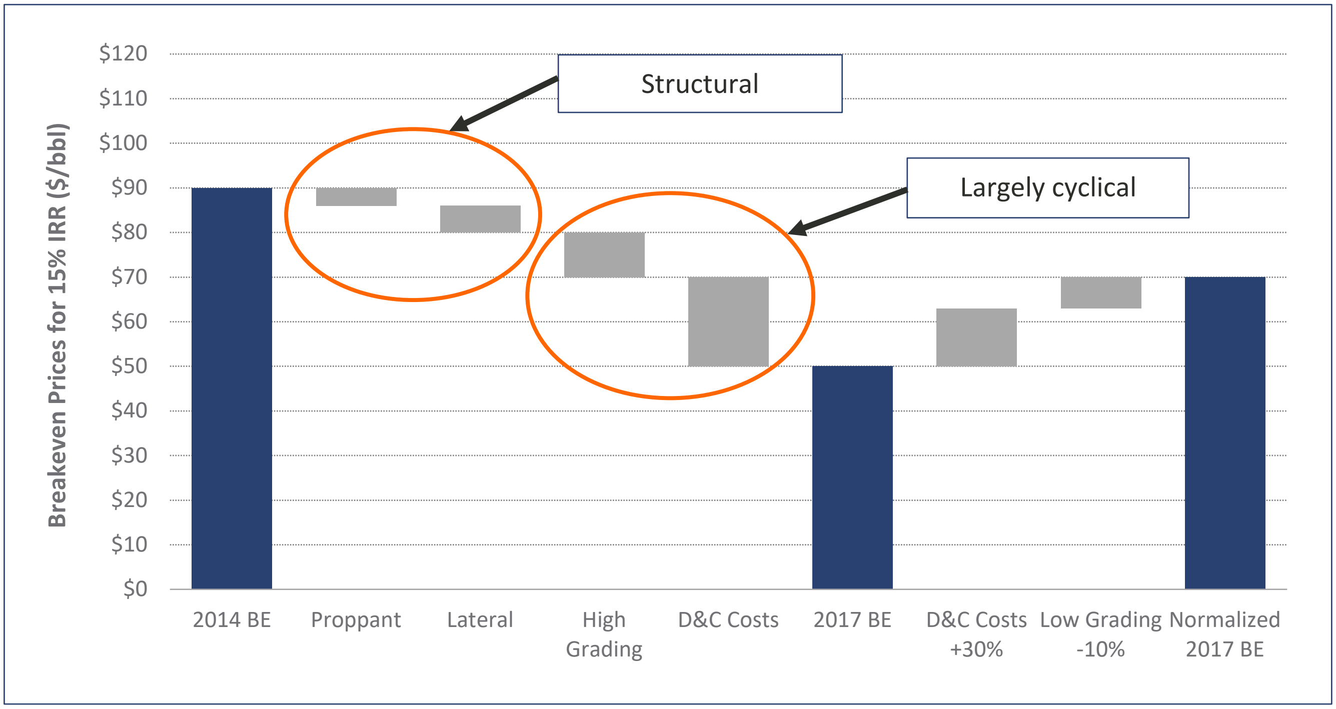
In terms of the industry's behavior, we recently published a note discussing the focus on growth at the expense of value creation. The obvious impact on inventory is that it is being depleted at a time when most companies are struggling to generate attractive corporate returns and service costs are beginning to rise. The other observation is that in the rush to acquire acreage (and why acquire acreage if, in fact, you have decades of profitable drilling in front of you?), companies must drill to hold their land position, and to create enough production growth so that they can hope to justify the purchase price. Because these wells frequently are being drilled with leading-edge completions that allow companies to press release high short-term IP rates, pressure sinks are created which have been shown to materially *reduce* the productivity and economics of wells that are drilled in the future. This is the so-called "parent-child" issue, which even in core acreage has proven to sterilize numerous locations that may appear attractive on a spreadsheet.

Longer laterals and more energy-intensive completions clearly enhance *individual* well results, but it isn't obvious at all that technology is increasing the number of future core locations left to drill. Furthermore, the industry is high grading, and well productivity drops precipitously as you move out of the core. So, as Tier 1 inventory is drilled out, we believe that well results will deteriorate as well. More importantly, we don't agree with the consensus that the U.S. has decades of core locations left to exploit. Instead, we believe that outside of the Permian basin, core reserve lives are less than five years, and that the Permian could have five to ten years left. This conclusion is supported by a recent Wood Mackenzie analysis, which states "The Eagle Ford and Bakken together account for almost half of current US tight oil production. But we have new doubts that these plays will offer long-term commercial drilling inventory as operators move out beyond the sweet spots." Technology may help to arrest the rate of decline for mature unconventional plays, but we have not seen any data to suggest that companies are turning low quality rock into core acreage. That isn't technology – it is alchemy.

Conclusion

We have conducted an analysis to better understand the impact of technology on well economics across the major unconventional basins, and the results are conclusive – most of the recent reductions in costs are cyclical, and a significant portion of the assumed productivity gains are as well, generated from unsustainable levels of high-grading, and the lack of consistent correlation between IP rates and EURs. The following chart highlights these conclusions by disaggregating the reduction in break-even commodity price for an average Eagle Ford basin oil well into its component parts, and then normalizing for mid-cycle service costs and the reversal of high grading.

EXHIBIT 14 | EAGLE FORD BREAK-EVEN ANALYSIS



Source: IHS Markit and SailingStone Capital Partners

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Of the $40 reduction in break-even commodity price, about $10 is explicitly tied to longer laterals and the benefits of more energy-intensive completions. Even if we assume that mid-cycle service costs are below 2014 levels, and that a portion of what appears to be "high grading" is, in fact, due to technology-related productivity improvements, "normalized" break-evens remain well above both conventional wisdom and the forward commodity strip. In summary, the impact of technology on the oil and gas business looks less like a revolution, where permanent, structural gains are made which alter the outlook for the future, and more like an industrial application, where small efficiency gains are wrung out of a process, with diminishing returns over time. In other words, oil patch technology appears to be more "six sigma" than "Moore's Law".

These observations matter on both the micro- and macro-level. From a company-specific standpoint, it's obvious what happens when you reduce both the number and assumed capital efficiency of the remaining drilling locations – net asset values fall, discretionary cash flow shrinks and companies may turn to relatively expensive acquisitions to back-fill the inventory gap. In fact, we attribute a significant amount of A&D activity over the last few years to this conclusion, which runs counter to most companies' published assessments of inventory depth and future capital efficiency metrics. As a result, we remain concerned that the U.S. oil and gas industry continues to over-capitalize assets in the pursuit of production growth, and that many participants either are ignoring how that approach undermines their ability to optimize the economic value of their acreage, or simply don't care. We don't see the depth of inventory which many companies reference, due to the lack of contiguous land packages, the lack of data to validate claims of x number of wells across y zones in each section of a play, or the reality of leaseholds which have not been developed with long-term value creation in mind. We appreciate that individual companies hold a competitive advantage due to their ability to deploy technology and improve returns relative to the rest of the industry. However, we do not believe that the advantage is nearly as ubiquitous as conventional wisdom would have you believe.

In terms of North American natural gas, supply today is dominated by low-cost shale plays which barely existed a decade ago. The technology that allowed production from Appalachia to grow from zero to 27bcf/d, or almost a third of total production, has now migrated into gas-prone shale oil basins, further depressing both spot prices and the futures strip. While we acknowledge the scale and competitive cost position of North America's natural gas endowment, we remain concerned that investors, consumers and regulators are placing too much faith in a seemingly limitless resource which does, in fact, have a finite life. As we move into the next decade, we believe that the call on higher-cost sources of shale gas will rise as core inventory is depleted.

From a global oil standpoint, U.S. unconventional production has been one of the primary sources of supply growth over the last several years, driven by technological advancements in drilling times, lateral lengths and completion intensity. Today, many forecasters suggest that the industry can continue to increase annual production by more than 1mm barrels per day far into the future at current commodity prices. But, we are wary of the extrapolation of averages following a period of cyclical declines in commodity prices, activity levels, and service costs combined with the proliferation of high grading. In an environment where OPEC spare capacity represents about one year of demand growth, and the backlog of international non-OPEC projects is set to peak in the next year or two, relying on short-cycle U.S. unconventional production may be a mistake if we are correct about the depth and quality of the remaining resource base. For both oil and natural gas, the future impact of technology increasingly may be around reducing the rate of commodity price inflation, rather than being a permanent source of deflation.

We believe that there are serious implications from these conclusions, which cannot and will not be solved through the application of technology. First, commodity prices are likely to surprise to the upside over the intermediate term, as the remaining core locations are exploited and incremental demand growth is met by less capital efficient sources of supply. Second, companies with real inventory depth, and the operating capability and management discipline to develop their assets in a rational manner, are likely undervalued, while those who have touted "success" via externally financed production growth and false claims of half-cycle capital efficiency will, at some point, be forced to reconcile their promises with the cold reality of data.

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