The Impact of the Permian Production Tsunami: Lessons From Natural Gas

Summary

How will growth in the Permian Basin affect oil prices? This is one of the key questions today for investors in the oil patch. We believe that the Permian, the largest of the “second-wave” oil shale plays, may play a significant role in keeping oil prices within a narrow band for the next few years. We base our analysis on a comparison to the natural gas market, which may be a few years ahead of the oil market, and on our understanding of the evolution of shale plays.

Comparison To Gas

For investors attempting to forecast the oil market there may be no better analogue than the U.S. gas market. While the gas market is domestic and the oil market is global, there are many similarities. Furthermore, the unconventional boom that began in natural gas subsequently spread to oil, meaning that gas market dynamics may provide a leading indicator for the oil market.

From 2005 to 2009 the first wave of unconventional (shale) gas developments (Barnett, Fayetteville, Woodford, Haynesville, Pinedale) occurred. These new plays ramped up volumes, displaced the upper end of the cost curve, and reset the pricing dynamic. Then, when investors thought they had seen the majority of new gas plays, the Utica and Marcellus emerged, representing two of the largest gas plays in North America. The Marcellus and Utica inserted themselves at the front end of the cost curve, and squeezed out higher cost supply. The net result was a structural shift down in gas pricing. Despite relatively strong demand dynamics, the gas market since then has traded with a floor around $2/mcf (the cash cost of production) and a cap of $4/mcf where significant volumes can be brought back into the market from the large, first-wave sources.

Today, the oil market appears on the cusp of a similar trend. While the initial phase of tight oil plays (Bakken, Eagle Ford, Niobrara, Miss Lime) is maturing, the Permian juggernaut is only beginning to ramp up. An analysis of production intensity in unconventional plays suggests the Permian could reach 5-10 MMboepd (65% oil), depending on assumptions of how many benches are ultimately pervasive and commercially developed across the acreage. In its company filings, Pioneer alone recently guided to 2026 volumes of 1 MMboepd. This low cost volume, if delivered, would undoubtedly shift the U.S. liquids cost curve and create a lower marginal cost for oil.

While this abundance of supply should have negative consequences for oil prices, the impact is unlikely to be as significant as the gas market. In gas, the Utica/Marcellus grew to 22 bcfpd in a 74 Bcfpd U.S. gas market, ultimately accounting for 30% of total production. The Permian, even in the most optimistic scenario, may account for 7-8 MMbopd of a 96 MMbopd global market, or just 8%. Offsetting this growth, the gas market had the benefit of strong demand growth (15 Bcfpd of incremental demand since 2005). The oil market will also add 4-5 MMbopd of demand as the Permian ramps up, suggesting the net volumes that need to be squeezed out of the market will be more limited (around 3-4 MMbopd), unless OPEC aggressively adds volumes.

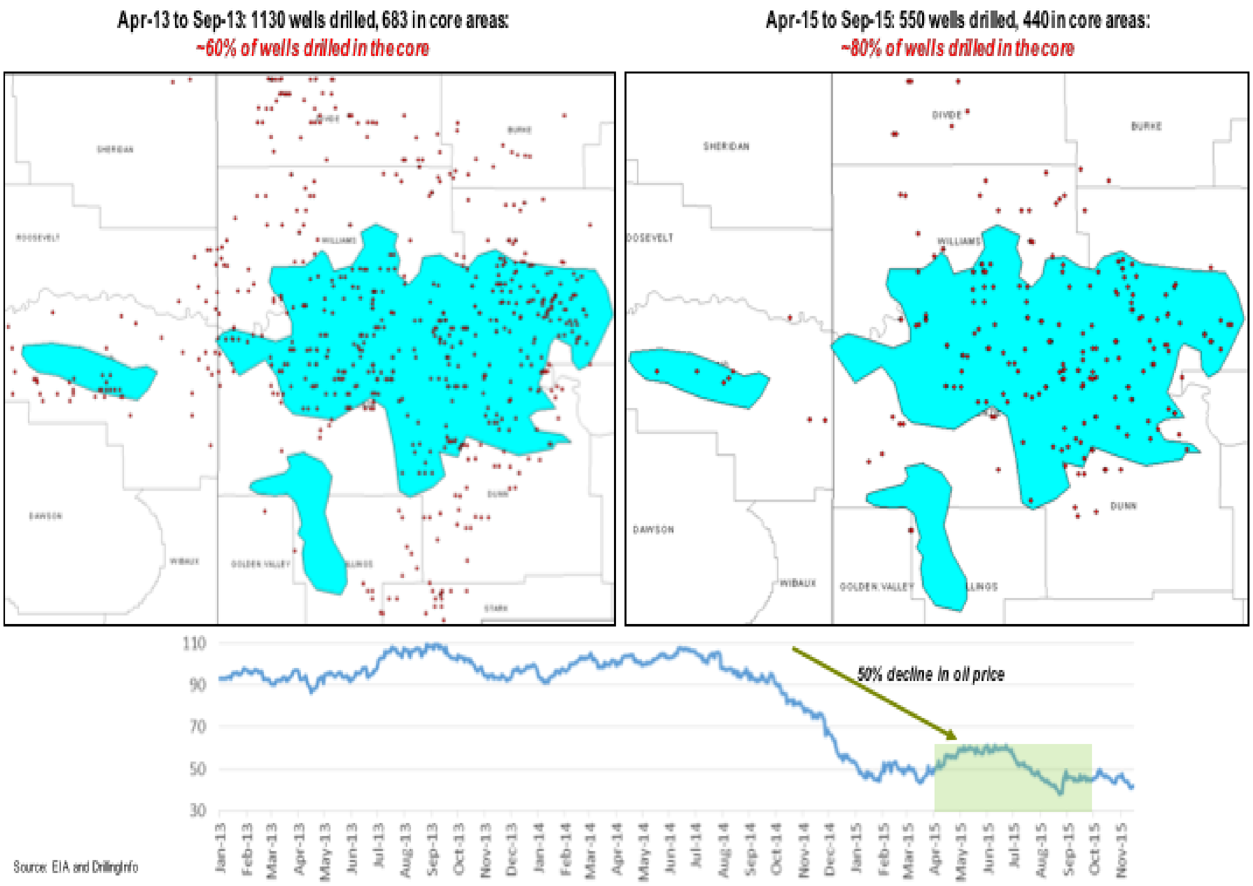
Combined, these factors would suggest a period of range bound oil prices around $40-60/bbl, albeit for a shorter period than we saw in the gas market (eight years), before prices begin moving up again. The data also suggests that if/when the Marcellus and Utica ultimately plateau and begin rising up the cost curve, U.S. gas prices will start to rise.

Commodity Price Framework

Over the long term, oil and gas prices are set by the marginal cost of supply. Over the last 15 years this has trended up, driven by the decline in average well performance. Over the last decade, the rise of shale plays materially altered the cost curve by injecting large volumes across the cost spectrum, making the analysis more complicated. The gradational nature of the shale plays has made it hard to argue that all unconventional gas is at a certain point in the cost curve. However, the structural framework remains proven. When demand is strong, incremental supply is incentivized to be delivered usually at the upper end of the cost curve. When demand is weak and prices drop, this production is rapidly removed from the system. Like the market as a whole, shale plays themselves "expand" and "contract" with price.

We can see how this played out in the Bakken in the figures below. In 2013, by which time the core of the Bakken was already well-understood, nearly half of all wells were drilled outside the core, supported by high oil prices. In 2015, however, over 80% of wells drilled were in the best areas, effectively lowering the marginal cost of Bakken oil in the midst of a lower oil price environment.

Drilling Activity across the Bakken at Peak and Trough Oil Prices

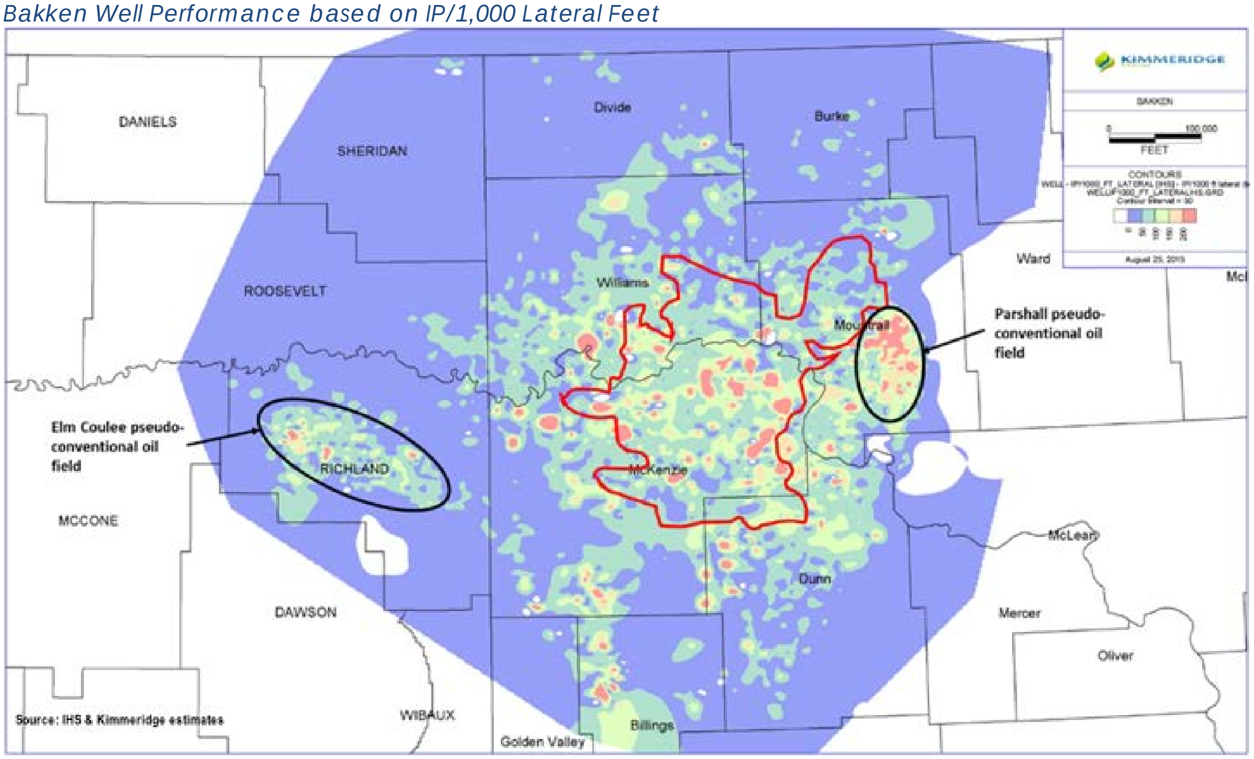


In the U.S. gas market, the marginal molecule of gas for the last decade has come from fringe or tier 2 acreage in shale plays and vertical conventional gas wells. As a result, while the Marcellus and Utica have grown, conventional production sources have declined, even with strong demand growth from coal to gas-fired power switching. In oil, the upper end of the cost curve is dominated by onshore U.S. stripper wells, the deepwater and oil sands, albeit the latter two have much lower levels of elasticity to price. As U.S. onshore low cost supply grows (Permian, SCOOP/STACK) these should be expected to decline, with the rate of this squeeze defined by GDP growth and oil demand.

The Evolution of an Unconventional Play

Over the last decade the industry's understanding of shale plays has changed measurably. Early thinking suggested these plays were homogeneous, but over time the industry has come to understand that shale plays are much like Venn diagrams, where a confluence of overlapping geological features creates a core, outside of which well performance deteriorates.

Bakken Well Performance based on IP/1,000 Lateral Feet



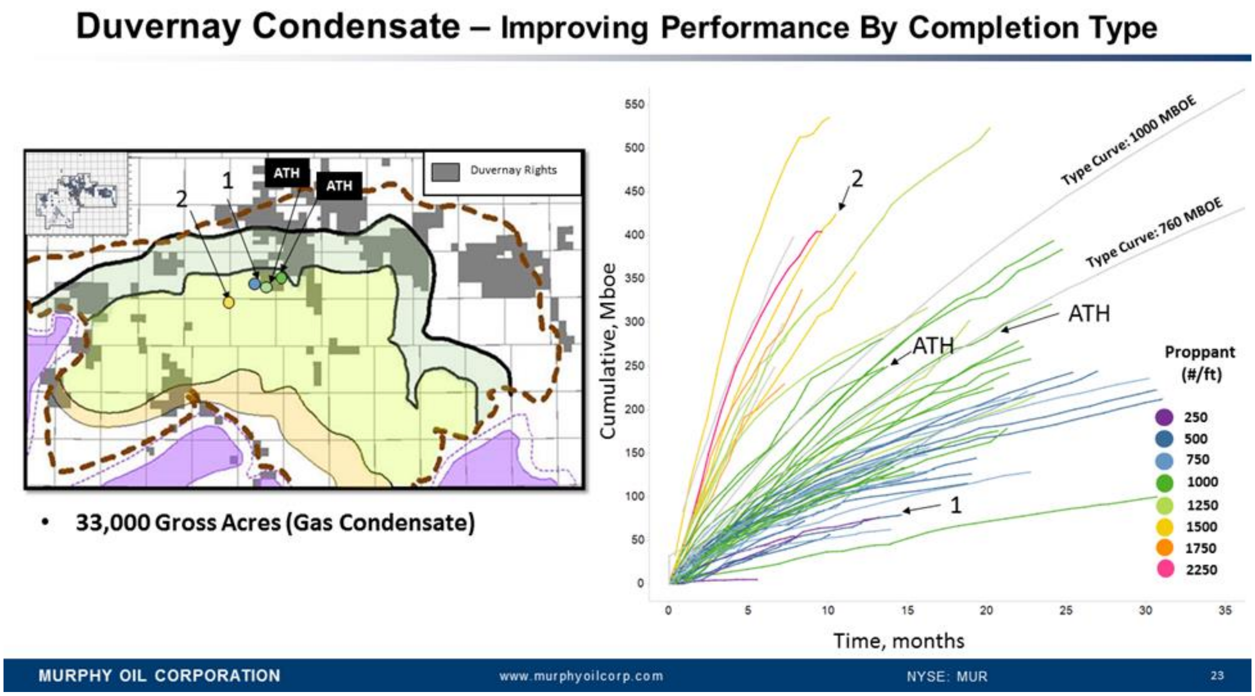
Source: Kimmeridge Analysis & HPDI

The variation in well performance across the Bakken is significant. This variation demonstrates how a single shale play can span the entire U.S. cost curve, greatly complicating any "break-even" analysis. We're thus often presented with gross generalizations about the average well in any play when considering supply curves (see later analysis), which also underappreciate the fact that over time, well performance is not uniform, as the best prospects in a de-risked play are drilled first.

Reviewing other mature unconventional plays shows the same trend, i.e. that over time shale plays undergo the same geologic evolution, with well performance first improving due to better drilling and completion techniques and then declining driven by the trend towards downspacing and/or the move out of the core. This makes logical sense; as they say in Texas, "you skin the best rabbits first".

Consider a hypothetical new shale play. When first discovered, the initial wells are expensive and well EURs (estimated ultimate recoverability) are modest. However, as the operator begins to understand the rock and optimizes completion design and landing zone, drilling costs decline and well EURs rise. These factors lead to a rapid decline in F&D costs and a rise in the recycle ratio and NPV/well, which in turn accrues to the value of the acreage (see Appendix 1).

Duvernay Well Performance versus Completion Design



Source: Murphy Oil

At some point the operator reaches a peak where tighter frac spacing does not yield incrementally better results relative to the cost of the fracs, where drilling days cannot be reduced further and where the core of the Venn diagram has been drilled out and down-spaced. At this point an operator has two choices, each resulting in the same outcome: (i) drill tighter wells in the core or (ii) move to less productive acreage that may be thinner, less mature, have more clay, etc. Either way, this leads to lower EURs which the operator attempts to offset by further lowering costs, although these typically have little room for improvement at this stage. As a result F&D costs begin to rise again and the asset begins to migrate back up the cost curve.

Review of the U.S. Gas Market and Associated Cost Curve

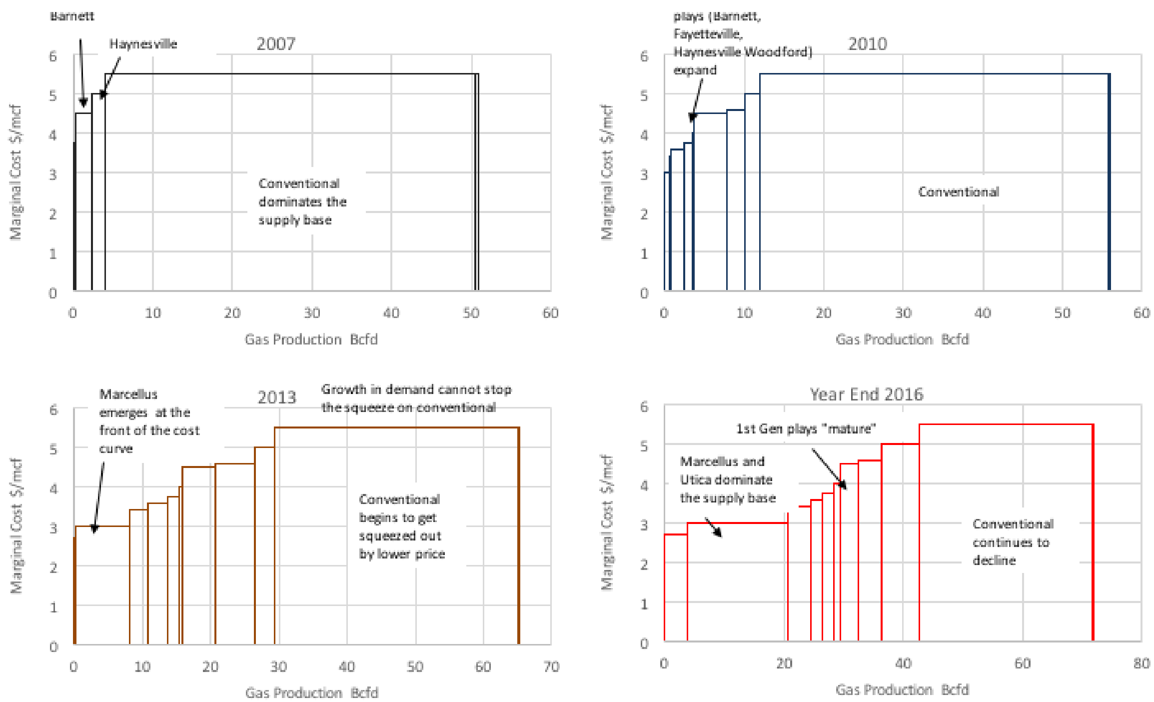
So what does this mean for the U.S. gas market? As highlighted above, each shale play is gradational and its position on the cost curve moves over time. As a result, to generate a U.S. gas cost curve that is truly accurate, one would need to model each well, and its contribution to total production, adjusted for the capital cost of drilling in the year it was added. With over 570,000 wells drilled in the last 40 years it is clearly a mammoth and unrealistic approach to model the sector this way. This leaves two options:

1) Take public 10-k data and build a boe cost curve for the United States (see previous Kimmeridge research)
2) Take individual shale pure plays to estimate the marginal cost for each play on average

While the second approach has fundamental flaws, it does allow us to understand the evolution of the gas market.

In 2007, shale gas was largely unheard of outside of Texas and Louisiana where the Haynesville/Bossier and Barnett were in development. Early on, their cost base was high but falling, and these first generation plays began to add supply at the front end of the U.S. gas cost curve. By 2010 these plays had grown to nearly 13 Bcfpd, and while demand had grown from 50 Bcfpd to 56 Bcfpd, it was not enough to preserve all the high-cost conventional production that began to be squeezed out. By 2013 these first generation plays had peaked, but by then the Marcellus and Utica had begun to ramp up. Coupled with improved frac completion techniques, these second wave plays brought additional gas to the front end of the cost curve. By the end of 2016, the growth in these two assets alone had added 20 Bcfpd of supply, almost 30% of the total market, pushing first generation shale plays into decline and further accelerating the drop off in conventional production despite a significant expansion in the demand base.

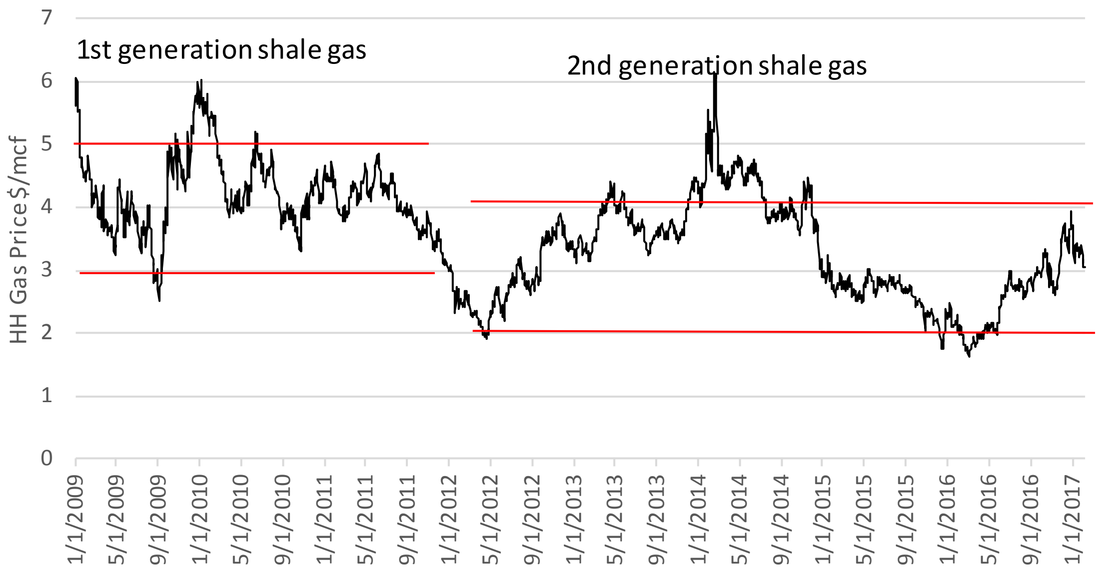
Schematic Cost Curves for the U.S. Gas Market 2007-Present



Source: Kimmeridge Research & EIA

Today the trend continues. While the Utica and Marcellus continue to grow, so does demand, driven by newly emerging LNG exports (over 12 Bcfpd of consumption growth over the next five years), exports to Mexico and continued growth in gas-fired power generation. However, this demand growth is not sufficient to offset the growth in second generation shale volumes, thus higher-cost, conventional molecules continue to be squeezed out of the market. Moreover, one of the reasons pricing hasn't reached the upper end of the marginal cost range is that the base decline of conventional wells is low, so no new wells in this category are needed to keep production up with demand. We believe that second generation shale gas has, on average, replaced 3.5% of the gas market each year with new supplies. Since this is close to the base decline rate for conventional gas, very few or no new conventional wells will be drilled.
The net result of this phenomenon has been that gas prices have been range bound with the upper end of the range set by the price at which incremental shale gas can be brought to the market (close to $4/mcf), and the floor set by the cash cost in the Marcellus/Utica where even some of the best producers are cash negative on a daily basis.

U.S. Henry Hub Gas Prices

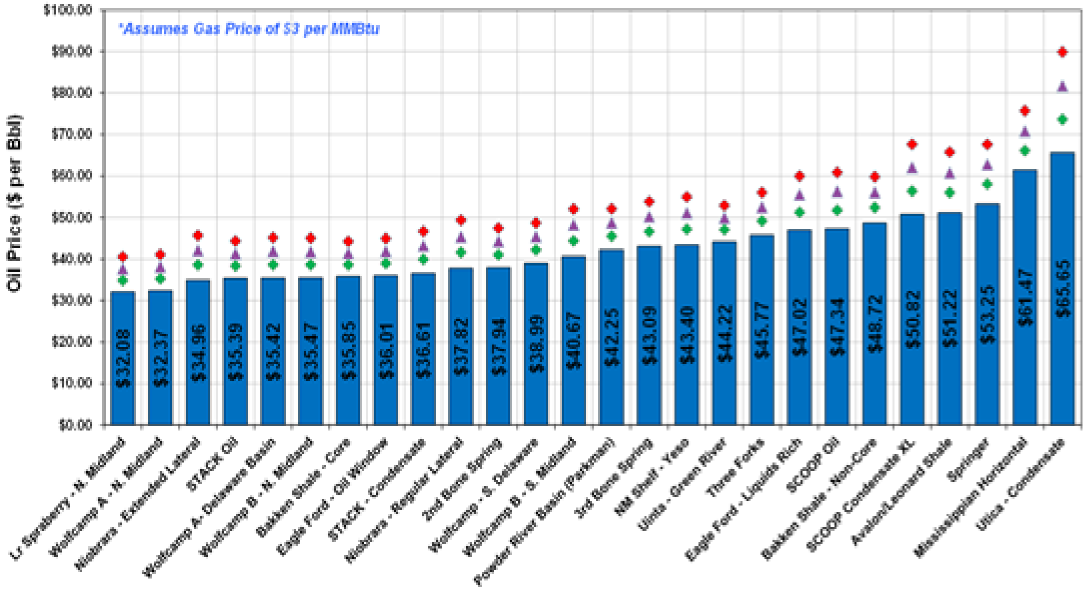


Source: Bloomberg

The U.S. Oil Cost Curve and Rise of the Permian

We believe there is significant read-across from the gas market to oil. As the first generation of oil plays matures (Bakken, Niobrara and Eagle Ford), a second generation has come in at the front end of the U.S. cost curve, with resource basins that are larger and have lower costs. Most notable of these are the Wolfcamp A and B in the Midland and Delaware Basins, which are already recognized as being the lowest-cost barrels in the U.S., and are also expansive. For example, the Eagle Ford core, defined by wells over 1,000 boepd IPs, occupies 2.6MM acres, and the core of the Bakken occupies 1.3MM acres. In comparison, the core of the Midland occupies 0.8MM acres and the core of the Delaware some 3.5MM acres. When comparing peak production per area in the first generation oil shale plays and applying these to the much larger Permian Basin, this would suggest that peak production from the Permian could be 5 MMboepd if only one interval is developed, and up to three times that amount if the Wolfcamp B, C and/or Bone Springs is also proven successful across the area.

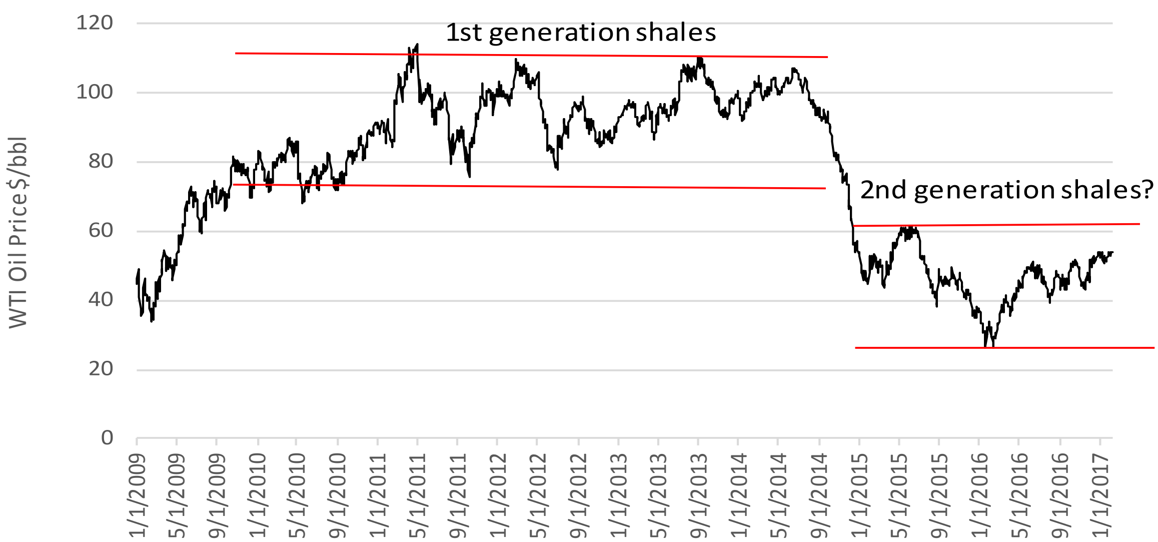
Relative Shale Oil Economics



Source: TPH Research

The enormous growth potential in the Permian is clearly negative for oil pricing, but the question is how negative. Whereas the growth in the Utica and the Marcellus ultimately came to account for 30% of the U.S. gas market, even at 10-15 MMboepd of which 65% could be oil, the Permian would only add an incremental 8 MMbopd from today's rates, and this would most likely be over a 4-5 year period. Furthermore, relative to the global oil market of 96.6 MMbopd, with circa 1.5 MMbopd of growth each year, this volume is smaller and more easily absorbed, leaving only 2 MMbopd of other production to be "squeezed out" over a four-year period to accommodate the growth.

U.S. WTI Oil Prices



Source: Bloomberg

Implications for Royalties and New Play Developments

Looking at the implications for Kimmeridge and its investors, our research suggests that:

- The volume growth from the Permian is likely to exceed expectations, as the Delaware dominates the cost curve, and that as an owner of Permian minerals, price downside will be more than offset by volume trends;
- New play development will have to be cost competitive with the Delaware to accrue value (there will be a limited tail wind from higher prices);
- Buying known plays will have limited upside from areal expansions since prices are unlikely to move up materially in the near term and as the assets mature, they will move up the cost curve and lower the value of incremental locations;
- Timing entry into new plays will matter more than ever with periods of commodity price optimism (upper $50s/$60/bbl), coupled with cycles of conservatism (low $40s/bbl); and
- The Permian gas supply (potentially an additional 10 Bcfpd) represents a further threat to any recovery in the U.S. gas market.

These trends also suggest that when the Marcellus and Utica mature, driven by incremental down spacing and the migration out of the core of the play, gas prices are likely to rise again, especially given the demand backdrop. Given how long prices have traded sideways, any such move would lead to a material repricing of assets for those with the confidence or foresight to move.

Appendix 1: The relationship between EUR, PD F&D, Recycle Ratios, NPV/well and the value of acreage

The return on drilling an oil well is driven by the capital cost of drilling the well and the cash flow associated with the production from the well. The cash flow generation from a single well is in turn a product of the reserves per well and the average price for those reserves less the cost of extraction which is predominantly comprised of royalty payments to the land owner, operating costs like electricity, submersible pumps, pipeline tariffs, severance taxes, etc. and SG&A.

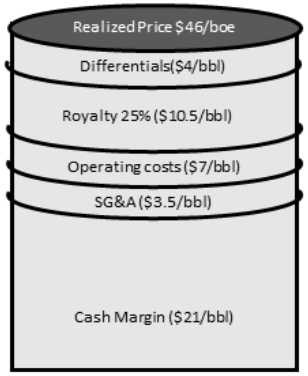
The second key factor in drilling a well is the capital cost which is predominantly driven by depth (the vertical hole), the lateral length and the number of frac stages. While depth, lateral length and frac stages all add cost, they also theoretically add reserves (deeper -> more pressure, longer lateral -> more exposure, and more fracs -> more surface area). Taking the capital cost divided by reserve additions gives a proven developed finding and development cost (PD F&D), a simple measure of the cost of adding a unit of reserves.

Furthermore, by taking the cash flow per boe divided by the PD F&D, we are able to calculate the recycle ratio which is a measure of capital efficiency. This is similar to the NPV per well, taking the discounted cash flow from the well along with the capital cost of drilling the well. Ultimately these two measures are correlated – a higher recycle ratio leads to a higher NPV/well. This NPV/well is the value accrued to a land or lease holder by de-risking the asset. For example, if the NPV/well rises, then a buyer can pay more for the land and still deliver a good return. Moreover, the more geologic intervals on a section, the greater the NPV/well or tighter the net spacing, further driving this number higher.

The reason these metrics are so important is because:

- Operating cash flow per boe shows relatively little variation amongst operators once adjusted for oil/gas split. This means operators do not have much ability to control this beyond deciding where in the oil/gas window you want to lease; and
- Over time, well costs converge over depth with similar frac designs, with the exception of lateral length (hence the value of aggregated land positions with longer horizontals).

Consequently outperformance, and the net value of acreage is driven almost entirely by the ability to access large EUR resources. Multiple stacked horizons are an ideal way to access large EUR per acre, which explains the value of the Permian and why the feeding frenzy over acreage there has been so intense. Moreover, it highlights how this resource will add significant volumes at the front of the U.S. cost curve.



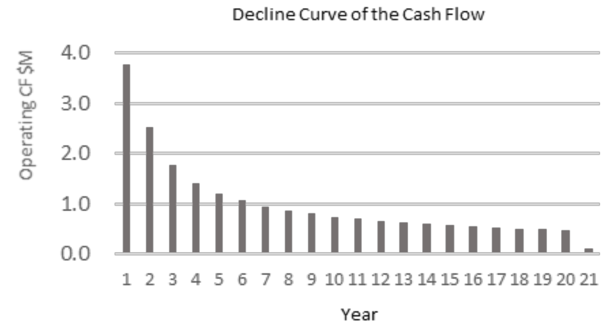
EUR = 1MMboe

X

Cash Margin ($21/bbl)

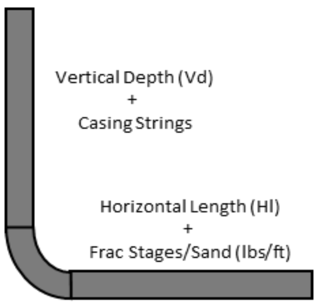
=

=



Cash flow over time = $21M with an NPV10 of $12.1M

Capital Cost of Drilling



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Vd = 10,000ft, 15 days @125k/day = $1.875M
Hl = 4500ft, 7 days @125/day = $0.875M
Casing etc = $0.5M
Frac stages = 32 @125k/stage = $4M
Surface/facilities = $0.5M
Land cost = $0.75M

All in cost $8.5M

PD F&D
$8.5M/1MMboe
$8.5/boe

=

Recycle Ratio
($21/boe)/($8.5/boe)
247%

NPV10 = $4.3M.
NPV20 = $1.5M

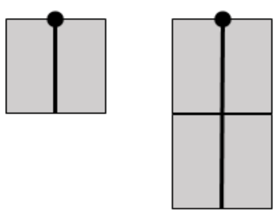
Well Spacing (160 acres)
Implied acreage value
PV10: $4.3M/160 =$26,875/acre
PV20: $1.5M/160 = $9375/acre

Hence front end of the cost curve asset are driven by lower well costs, higher cash margins and higher EURs, delivering lower PD F&D, higher recycle ratios, higher NPV/well and accruing value to the acreage holder

Value of land aggregation

4500ft lateral
$8.5M cost
1MMboe EUR

9500ft lateral
$10M cost
2MMboe EUR



Recycle ratio 1 = 247%
CF/boe = $21/boe
$8.5M/1MMboe = PD F&D $8.5/boe
NPV10 = $4.3M
NPV/acre (160 acre spacing) = $26,875/acre

Recycle ratio 2 =420 %
CF/boe = $21/boe
$10M/2MMboe = PD F&D $5/boe
NPV 10 = $15.1M
NPV/acre (320 spacing) = $47,300/acre

Value of a project = NPV/well x repeatability x volumetric extent (area and benches)

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