Key Takeaways

- Oil and gas production is defying the odds and still increasing despite a drastic drop in oil, and to a lesser extent, natural gas prices.
- More than 1,000 rigs have exited the rig fleet since October 2014, but the bulk of those rigs lost are less efficient, vertical and directional rigs.
- Producers are becoming more efficient at extracting oil and gas by reducing the number of days it takes to drill a well and by drilling more wells with fewer rigs.
- High grading, which involves the targeting of a producer’s most productive and economic acreage, is helping yield increased production with fewer wells drilled.
- A growing backlog of drilled but uncompleted wells, which Bentek estimates could be as high as 4,000 wells, poses a significant downside risk to continued production growth.
- The large backlog of wells contains as much as 1 MMb/d of oil and 6 Bcf/d of natural gas. This will likely leave the market extremely oversupplied and prices depressed through 2016.

What happened the past six months?

The US crude oil market witnessed an unprecedented collapse in commodity prices the past six months as persistent supply growth overwhelmed traditional sources of demand. In October 2014, the benchmark price for US oil, West Texas Intermediate (WTI), traded at an average of $84/barrel. By March 2015, WTI had fallen more than $35/barrel to an average of $47/barrel (see Fig. 1), but has since rebounded the past two months. Natural gas prices have also dropped during this time, due to steady increases in associated gas production from major oil plays and burgeoning production from the Marcellus and Utica shales. In 2014, Henry Hub averaged $4.34/MMBtu. That contrasts with a 2015 year-to-date average of $2.77/MMBtu. Producers have responded to the lower price environment, scaling back drilling activity in almost every major play. Since peaking at...
2,151 rigs on October 24, 2014, the US rig count has been cut in half, leaving only 1,001 active rigs in the lower 48 states as of the week ending May 29. However, despite falling commodity prices, production of oil has just started to come off the past two months, while natural gas production continues to increase as producers lay down less efficient rigs, focus drilling activity on their highest performing and most economic acreage, and find new ways of padding their bottom lines. With drilling efficiencies improving by the day and production maintaining its upward trajectory in the face of the steepest slowdown in drilling activity since 2009, this begs the question... will oil and gas production finally flatten or decline, and if so, when?

**US rig count cut in half**

Rig counts in all major US plays have plummeted the past six months, as producers scale back drilling plans in 2015 following the oil price drop (see Fig.2). Of the nation’s five major oil basins (Anadarko, Permian, Eagle Ford, Bakken, and Denver Julesburg), the Anadarko has seen the steepest drop on a percentage basis, falling 64% since the end of October 2014, or 166 rigs. On an absolute basis, the drop in the Permian has been most pronounced, with 304 rigs exiting the basin since late October, leaving only 252 rigs as of May 29. Additionally, the Eagle Ford has shed 115 rigs, while the Bakken and Denver Julesburg basins have lost 82 rigs and 28 rigs, respectively, or roughly 49% and 43% of their rig fleet.

Drilling activity has also declined in dry gas plays, though at a much slower rate than oil plays. The Haynesville has lost just two rigs since late October 2014, while the rig count in the Marcellus dry gas window in Northeast Pennsylvania has fallen by 12 rigs, a 26% drop. In the Northeast’s wet gas windows (Utica and Marcellus Wet), rigs have also declined at a slower pace than other oily and wet plays. The rig count in the Wet Marcellus and Utica region is down 27%, or 24 rigs, since the end of October 2014.

![Fig. 2: Rig Count by Area](image-url)
Where does production stand?

US oil and gas production continues to push higher despite the drastic cut in rigs. Bentek estimates total US oil production currently stands at 9.36 MMb/d, 360 Mb/d higher than levels witnessed in October 2014, prior to the oil price collapse. Likewise, US dry gas production is hovering around 72.7 Bcf/d, 2.7 Bcf/d higher than October 2014’s average (see Fig. 3).

![Fig. 3: US Oil and Gas Production](image)

Why does production continue to grow?

Drilling more wells with fewer rigs

There are a number of reasons why production is pushing higher. First among them, producers are becoming more efficient at drilling wells, due to advancements in drilling methods and technology. New drilling techniques, like pad drilling, are allowing producers to drill multiple wells on one pad, reducing the time it takes to move from one well location to the next. Rigs are also becoming more efficient at drilling wells because of increased horsepower, new computerized control systems and greater mobility. For example, WPX’s “walking rig,” which was recently deployed from WPX’s acreage in the Piceance to the San Juan Basin, has the ability to walk from one well bore to the next without being disassembled, thereby reducing the “non-productive” time of rigs, or the lag time between drilling multiple wells. In 2010, one horizontal rig on average drilled one well per month in the US. Today, one rig can drill about 1.5 wells per month (refer to Fig. 4). In mature plays, such as the Eagle Ford, where producers have a greater understanding of the geology of the basin, the number of wells drilled per rig per month has increased from one well in 2010 to two wells in 2015 (see Fig. 5). In less developed plays, like the Permian, where producers are still conducting exploratory drilling in order to evaluate the most economic parts of the basin, drilling efficiencies lag the US average (refer to Fig. 6).
**Defying the Odds**

**June 1, 2015**

**Drill times falling**

Drilling efficiencies have also helped reduce the time it takes to drill a well, allowing producers to extract higher volumes of oil and gas more quickly. While drill times have come down in all key producing basins over the past five years (see Fig. 7), the Eagle Ford, Bakken and Delaware Basin have experienced the steepest drop in drill times since 2012, with a 44%, 42% and 38% reduction, respectively. However, the recent decline in the Permian Basin from 4Q2014 to 1Q2015 is notable. The average number of days to drill a well in the Permian’s Delaware Basin has fallen from 32 days in the fourth quarter of 2014 to 26 days in the first quarter of 2015, a 20% reduction in drill time.

**Fig. 7: Days to Drill a Well**

![Bar chart showing days to drill a well for different basins from 2012 to 2015.](image)

**High Grading**

Falling drill times suggest producers are focusing drilling activity and shifting rigs to their core acreage, or “sweet spots,” where they can realize higher production volumes at a lower drill time and cost. This process, known as high grading, involves the allocation of capital to a producer’s highest returning assets. High grading acreage allows producers to grow production even in an environment when capital expenditures and drilling activity are slowing.

As an example, let’s take a typical horizontal well in the New Mexico portion of the Permian Basin (see Fig.8). Assuming an average IP rate and typical decline curve for a horizontal well and the current level of horizontal drilling activity, Delaware NM Basin gas production would increase from a 2015 average of 1.36 Bcf/d to an average of 1.39 Bcf/d in 2020, a 30 MMcf/d increase. Now, let’s assume producers cut drilling activity by 20%. In this scenario, production falls by 96 MMcf/d to 1.2 Bcf/d in 2020. In the final scenario, let’s assume producers high grade their acreage. As such, Bentek has increased the IP rate for a typical horizontal well by 20%. Under the increased IP rate and decreased drilling activity scenario, production would only decline by 12 MMcf/d from 2015 to 2020. But, of note, production in the near-term (the balance of 2015 and 2016) in the high grading scenario rises above the base case forecast before declining in the out years. So, while one would...
expect a 20% reduction in drilling to lead to a 20% drop in production, high grading indicates that production can still grow even in an environment when rigs and drilling are being slashed.

**Fig. 8: Delaware-NM High Grading Scenario**

Rig economics: *shift from vertical to horizontal rigs and the Productivity Per Rig (PPR) index*

The shift from conventional drilling (less efficient vertical and directional rigs) to unconventional drilling (more efficient horizontal rigs) is also contributing to continued production growth. While all rig types have declined since October 2014, vertical and directional rigs in the US have experienced the steepest drop, falling 64%, or 504 rigs, compared with a 47% drop in horizontal rigs, or 643 rigs.

The economics and productivity of horizontal rigs trump that of vertical rigs, leading to the situation where the loss of vertical and directional rigs is not translating to production declines on a national scale. The figures on the next page provide a measure of the productivity per rig (deemed the PPR index) in each of the major US basins by estimating cumulative oil and gas produced from one rig in one year based on average initial production (IP) rates and first year declines in each play. This index helps illustrate why horizontal rigs are preferred to vertical rigs, but also more importantly, in which basins rigs are most productive.

Figures 9 and 10 below illustrate 30-day IP rates and the quantity of oil and gas one rig can produce in one year (PPR) for each of the nation’s five major oil plays (Anadarko, Bakken, Eagle Ford, Permian and Denver Julesburg). Across the five major basins, average 30-day initial production (IP) rates from wells drilled with horizontal rigs are 373 b/d and 1,012 Mcf/d, respectively, which is roughly six times higher than the IP rate from an average vertical rig in these five regions. As well, the average annual cumulative production of oil after one year from a horizontal oil rig is 23,844 barrels per day, about four times higher than the one-year cumulative production from a vertical oil rig. The average one-year cumulative production from a horizontal gas rig is 70 MMcf/d, also about four times higher than a vertical gas rig.
More importantly, the PPR can help identify how productive one rig can be in one year in each basin. According to the PPR charts above, the Eagle Ford boasts the highest initial production rate and cumulative production level after one year for a single horizontal rig, with a cumulative production of 7,613 b/d for oil and 30,672 Mcf/d for gas. The Bakken’s cumulative oil production from one horizontal rig in a year is a close second to the Eagle Ford because the production mix is heavily weighted towards oil, but the amount of gas produced from a horizontal rig in the Bakken in one year is significantly lower than the Eagle Ford at 9,599 Mcf/d. Interestingly, a horizontal Permian rig yields the lowest cumulative production after one year for gas and the second lowest recovery for oil despite boasting the most active rigs of any basin in the country at present. This can likely be traced to the fact that producers are still in the exploration phase and continue to evaluate the Permian’s best acreage. However, once the Permian matures and IP rates and efficiencies begin to improve, the economics of the play will likely rival those of the Eagle Ford.
**Hedging**

The impact of hedges cannot be ignored when assessing why production has remained strong in the face of falling commodity prices. A number of producers indicated in recent earnings calls that a portion, if not all, of their production was hedged for 2015. On the oil side, producers such as Concho Resources, Devon Energy, Noble Energy and Pioneer Natural Resources have all indicated they have a portion of their production hedged in the $70-90 per barrel range in 2015. On the gas side, Antero Resources, Pioneer Resources and Range Resources are well hedged for 2015, with swaps or collar floors in excess of $4/MMBtu. Such a strategy allows producers to realize higher prices and improved returns at a time when actual spot prices are much lower, incentivizing drilling and continued production growth.

**Internal Rates of Return by Basin**

Producers’ rates of return have plummeted in the falling price environment. To calculate the internal rate of return (IRR) for a typical well in every major US play, Bentek uses a half-cycle cost model, which estimates the impact of the marginal well being drilled. The half-cycle cost model excludes any costs incurred before drilling begins, such as land acquisition and seismic surveys. The primary components feeding the model are drilling and completion costs, initial production rates, production mix, decline curves, regional price assumptions for all commodities (oil, gas and NGLs) and tax/royalty rates. As well, the IRR model calculates rates of return based on the 12-month forward average strip for the nearest oil, gas and NGL pricing hub.

**IRRs pre-price drop**

In October 2014, when oil prices were hovering around $80-90 per barrel, returns in most of the major US oil plays exceeded 40%. Atop the stack were the Eagle Ford oil window, Anadarko’s Cleveland play, and the Permian’s Delaware basin, which boasted IRRs around 70%. The table below breaks out the IRRs by basin prior to the oil price collapse compared to the IRR calculated at current price levels.

![Fig. 11: Basin IRRs in July 2014 vs. June 2015](image-url)
Note the price assumptions for the July 2014 IRRs assumed a 12-month forward average curve for each regional pricing point. For gas, the range was $3.18-4.41/Mcf. For oil, Bentek assumed a 12-month forward average curve for WTI +/- a regional differential that ranged from $91.69-100.27/barrel. And for NGLs, Bentek assumed an average of the 12-month forward curve based on a Mont Belvieu price ranging from $26.04-44.25/barrel. By comparison, the prices for the June 2015 IRRs assumed a range of $1.86-2.95/Mcf for natural gas, $48.06-66.17/barrel for oil and $20.05-27.10/barrel for NGLs.

**IRR**s post-price drop

At current prices, producers are struggling to earn a return in excess of 20% in most plays across the US. The Permian Delaware and Eagle Ford oil window stand atop the IRR stack, with returns just above 30%, though a number of other plays, including the Bakken, DJ and Anadarko are close behind, with returns near 20-25%.

**How lower service costs change basin economics**

In the current price environment, multiple producers have indicated through negotiation they expect, and in some instances have already seen, service costs come down 10-20%. To capture the impact of reduced service costs on each play’s rate of return, Bentek incorporated into its IRR model the lower service costs reported by producers during Q1 earnings calls by collecting a sample of producers from each basin and averaging their announced cuts to service costs. Though a 10% reduction does little to improve the economics of each US play, Bentek believes producers that are able to cut service costs by 20% may witness as much as a 10% increase in rates of return, while a 30% cut in service costs could push rates of return 20% higher.

**What will it take for production to flatten or decline?**

The biggest threat to continued production growth is not only a sustained low price environment, but also a growing backlog of drilled but uncompleted wells. Numerous producers across all basins have stated plans to defer the completion of wells until service costs come down and/or commodity prices improve. As this backlog of wells increases and more wells are deferred until prices rebound, Bentek expects oil and gas production to level off and eventually decline.

**How many wells are currently backlogged in the US?**

Bentek ran scenario analyses for oil and gas production assuming three completion scenarios in an effort to quantify the number of wells that have been backlogged, but also to identify the point at which oil and gas production would flatten or decline, due to the growing backlog of wells. The first scenario assumes producers complete 90% of wells drilled (defer completion of 10%), the second assumes producers complete 80% of wells drilled (defer completion of 20%) and the final scenario assumes 70% of wells drilled are completed (defer completion of 30%). In each scenario, Bentek assumes producers intentionally started deferring well completions in December 2014, roughly two months after the price collapse. In the 90% scenario, Bentek believes the inventory of backlogged wells could be as high as 3,000 wells. In the 80% scenario, the inventory of wells could be as high
as 3,600 wells. And in the final scenario, which assumes 70% of wells drilled are completed, Bentek estimates about 4,200 wells could be backlogged.

**Impact of deferred well completions on production**

The presence of a large and growing number of backlogged wells will eventually impact oil and gas production, prompting production declines and/or significantly slower growth rates as illustrated by the scenario analysis depicted in figure 13. Currently, US natural gas production is averaging roughly 72.7 Bcf/d, while crude oil production is just shy of 9.4 MMb/d. Assuming the current number of wells drilled is carried forward into the future, Bentek believes that natural gas production would only decline between now and the end of 2015 under a scenario in which producers defer 30% of wells drilled through the end of the year. Delaying 30% of wells drilled would leave gas production at a mark of 72.6 Bcf/d come December 2015. In the 90% and 80% completion scenarios, gas production would average 74 Bcf/d and 73.3 Bcf/d, respectively in December 2015, slightly higher than the current production level.

Crude oil production is more sensitive to delayed well completions. In every completion scenario, crude oil production would decline between now and the end of the year. This can be traced to the fact that moving oil through low permeability rock is harder than moving gas through low permeability rock, which results in steeper first year declines of oil wells than gas wells. As such, when the drilling and completion of wells slows down, there is a quicker impact to oil production than gas production. If producers complete 90% of wells drilled, crude oil production would average 9.3 MMb/d in December 2015, while it would average 9.0 MMb/d and 8.8 MMb/d in the 80% and 70% completion scenarios.
How much production do the backlogged wells possess?

Bentek estimates as much as 696 Mb/d of oil and 4.1 Bcf/d of natural gas is waiting to flood the market if there are 3,000 wells in inventory. This assumes an average IP rate of 232 b/d for oil and 1,363 Mcf/d for gas. If there are roughly 3,600 wells backlogged, that translates to about 835 Mb/d of oil and 4.9 Bcf/d of natural gas. And if the backlog of wells is closer to 4,200 wells, as much as 975 Mb/d of oil and 5.7 Bcf/d gas could be waiting to come online.

**Bentek’s production outlook for 2015 and 2016**

Bentek’s expects US oil production to average 9.38 MMb/d in 2015, in line with the current mark and roughly 765 Mb/d higher than 2014’s mark. Slight declines are forecast through the balance of the summer, before production rebounds in Q4. In 2016, Bentek expects oil production to increase further to an average of 9.48 MMb/d. On the gas side, Bentek is calling for US gas production to average 73 Bcf/d in 2015, 4.3 Bcf/d higher than 2014’s average, with a similar dip anticipated the balance of the summer before rebounding in Q4. This growth will be driven by the Northeast, where new infrastructure will help relieve supply bottlenecks. In 2016, Bentek expects natural gas to increase to an average of 74.3 Bcf/d, with the Northeast again pacing production gains.

**Risks to the forecast**

There are numerous risks associated with this forecast. The bullets below highlight the risks that production comes in above and below Bentek’s current base case forecast.

**Risks that oil and gas production exceeds our current forecast:**

- A slew of backlogged wells are completed in the next year. A number of producers have said they expect prices to rebound in late 2015 and early 2016, at which time they will complete more wells and start producing more oil and gas.
• Producers may have locked in hedges in spring 2015 for the latter half of 2015 and 2016 at/over $60 per barrel, incentivizing the completion of some backlogged wells.
• Geopolitical risk drives oil prices higher even in the current oversupplied market, incenting a production response from producers.
• Associated gas production from major oil plays increases as producers begin completing their backlog of drilled, but uncompleted wells.
• Roughly 4 Bcf/d of new natural gas pipeline projects will commence service in 2015. While Bentek does not expect all these projects to fill immediately given weak gas prices in the Northeast and a lack of demand to absorb this supply, there is a risk production exceeds Bentek’s forecast should pipeline expansions fill faster than anticipated.

**Risks that oil and gas production dips below our current forecast:**

• The oversupply situation becomes further exacerbated as drilling efficiencies and a drive by producers and OPEC to maintain market share pressures prices, prompting the marginal producer to stop drilling and slow production.
• A lack of global refined products demand decreases the need for US refined products and thus demand for US crude, pressuring prices and squeezing the marginal producers.
• Associated gas production declines if producers further delay the completion of drilled, but uncompleted wells.
• Northeast pipeline expansions fill slower than expected, due to a lack of downstream or due to low gas/NGL prices, which may deter producers from turning on wells and bringing more production online.

**Conclusion**

The oil price collapse has had a substantial impact on US drilling activity. The US rig count has been cut in half, the number of wells drilled has plummeted and producer capital expenditures have decreased. However, producers are adapting to the new energy landscape by cutting less efficient rigs, negotiating lower service costs, scaling back drill times and shifting drilling activity to their most productive and economic acreage. Incredibly, oil and gas production has persevered despite the challenging price environment.

However, it seems likely that a persistent low price environment will eventually inhibit production growth as producers defer the completion of an increasing number of wells. Though such a deferral of wells may eventually bring with it stagnating and/or declining production, the potential for a wave of production to hit the market from that same inventory of backlogged wells once the right price signal exists cannot be ignored. This inventory of wells will help keep the US market oversupplied and place significant pressure on oil and gas prices. For oil, such price relief is lacking given current regulations prohibiting exports of crude oil. However, for natural gas, new sources of new demand, specifically LNG exports, in the latter half of the decade, should provide relief to the current depressed price environment.
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