OPEC Imposes 'Swing Producer' Role upon U.S. Shale: Evidence and Implications

By Jim Krane and Mark Agerton*

Introduction

When OPEC declared in November that it would not cut production to boost oil prices, shock waves cascaded across the global oil sector. Oil prices had been dropping since June 2014, and OPEC's announcement propelled prices lower. By December, oil prices were half of what they had been in June. Now, emerging data show that those shock waves also disrupted the booming growth in the U.S. shale oil sector.

Starting in January, U.S. shale producers reacted to the new price environment by idling rigs and reducing the number of wells drilled. Those actions, in turn, reduced the amount of new oil brought to market. The cutbacks accelerated through February and March.

Taken together, it appears that market signals produced a collective "swing" response from shale producers that is helping to balance global markets, but via a new and untested channel. Since the 1970s, most of the market-reactive cuts in crude oil production have been orchestrated by the OPEC cartel.

Shale's unique characteristics are now allowing it to assume a swing role. These include a cost structure that differs from the front-loaded investment required by conventional oil and gas production. Shale allows short lead times and smaller initial investment, along with lower barriers to entry and exit. Since shale wells are characterized by steep production decline curves, companies invest in real time, drilling and producing when prices warrant. When prices are too low to support drilling, production is restricted by the natural limits of fluid flows within low-porosity rock. Shale oil production withers without constant investment.

This process heralds a new dynamic in the oil sector, one in which the short-run U.S. supply response to price fluctuations is much more elastic. Past experience has shown that price corrections have largely been unable to affect conventional oil production, given the long investment lead times and the much shallower production decline curves. Conventional projects, whether onshore or offshore, tend to produce oil for years or decades, compared to shale wells, where flows typically drop off within a few months.

During times when conventional oil production overshot demand, markets would continue to be oversupplied until an intervening body like OPEC – or in prior decades, the Texas Railroad Commission – stepped in to reduce quotas.

To date, there has been little quantitative evidence of a non-OPEC supply response to the collapse in oil prices. Anecdotal reports have described declining investment, job cuts, and a 60% drop in the number of onshore drilling rigs in operation. The U.S. Energy Information Administration (EIA) forecasts that onshore U.S. production will shift into decline in the current quarter.[1]

Missing from these reports are figures detailing numbers of wells drilled, whether levels of new oil production had declined, and, if so, which basins bore the brunt of those declines.

We present emerging data from the Austin-based analytics firm Drillinginfo to reveal an industry in retrenchment. The data show firms setting aside drilling plans in less-productive zones and focusing efforts on their most productive acreage and highest efficiency extraction techniques. The following sections illustrate the magnitude of shale's short-term price response.

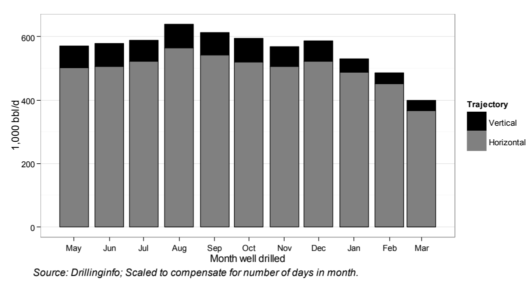

Figure 1: New national oil production by well trajectory

National Results

Across the continental United States, data from Drillinginfo show a 30% decline in estimated new oil production brought onstream in a given month, from about 580,000 barrels per day (bbl/d) in May 2014 to just over 400,000 bbl/d in March 2015. Although new production fluctuates between May and December, Figure 1 shows the steep drop in new production that starts to take hold after December, after falling oil prices became a concern. Monthly production growth slipped by 10% in January, 17% in February and by another 9% in March.

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See footnotes at end of text.

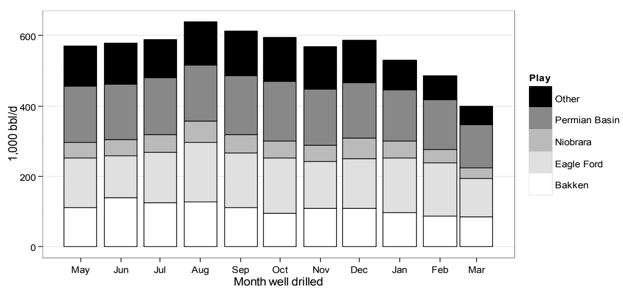
It bears emphasizing that the slowdown in growth, where it applies, does not mean that overall U.S. oil production has decreased. It means that production growth is occurring at a decreasing rate.

New oil-directed well starts showed greater declines, dropping by 48%, from 1,851 in May 2014 to under 971 in March. Drilling dropped by the largest amount, 23%, in January, as oil prices reached new lows below $50/bbl. As the new price environment held roughly constant, monthly drilling dropped again by 9% in February and 19% in March.

Nationwide, drilling cutbacks affected vertical wells more than the horizontal wells typically drilled in hydraulic fracturing in shale plays. Overall a total of 658 horizontal wells were drilled in March 2015, representing a 35% drop from May 2014. Just 313 vertical wells were drilled in March, down 63% from May.

Play-by-Play

Among major oil-rich shale plays, the reactions to OPEC's late November decision appeared first in the Permian Basin of West Texas and the Bakken formation in North Dakota. New production in January was down 8% from December in the Permian and 11% in the Bakken. (In the smaller Niobrara play in Colorado, new production in January was 17% below that of December.) By contrast, the falling price of oil did not appear to affect production in South Texas' Eagle Ford formation. There, new production rose by 9% in January over the previous month.



Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 2: New national oil production by play

By March 2015, however, falling global oil prices had undermined activity in all three major oil shale plays – the Permian, Bakken and Eagle Ford – by nearly equal amounts. Each play saw predicted new production drop by 24% below levels in May 2014.

Other signs of a slowdown are evident in the falling rig count, as well as rising average well productivity. Data from Baker Hughes shows the number of land-based U.S. drilling rigs nearly halving from 1,594 in early May 2014 to 696 one year later.

At the same time, productivity of horizontal, oil-directed wells was up 11%, from an average of 456 bbl/d per well in May 2014 to 515 bbl/d in March 2015. Rising well productivity conforms to expectations that firms would shift away from low-producing wells in non-core areas and concentrate on drilling horizontal wells in their most productive acreage.

Methodology

The Drillinginfo index tracks new onshore wells that have been drilled across most of the lower 48 U.S. states since May 2014. The index predicts peak monthly production from each new well by averaging actual results from neighboring wells. The index thus provides a short-term indicator of drilling activity and probable output at precise locations.

It is worth emphasizing that the Drillinginfo production index estimates *maximum monthly new oil production* that is likely to flow from a given well drilled in a given month. This "new production" is a fraction of overall U.S. oil production. Thus, even if the index showed zero new production for March, production could still rise, as wells drilled earlier in the year came online. Given the recent spate of drilling of wells that have gone uncompleted, data for most recent months may actually overestimate production.

Our second data source, the standard Baker Hughes rig count, details the number of drilling rigs (oil and gas, horizontal and vertical) operating in each U.S. county in a given week. The rig count comprises the industry's main indicator of activity, despite offering no indication of number of wells drilled or expected production.

Permian Basin

Among the major U.S. oil formations, the earliest fall-off in drilling appears to have occurred in the Permian Basin. After a strong October, a steep 65% reduction in vertical drilling took place, from 364 oil wells drilled in October to 129 in March 2015. Many of these vertical wells are in the eastern Permian's Midland Basin where production involves enhanced oil recovery using vertical "infill" wells in mature fields. Infill drilling, like that of shale, allows producers to cut activity when prices dictate.

Horizontal drilling in the Permian remained relatively constant until January, when it, too, began to decline. By March 2015, horizontal drilling was down by 32% from its peak in December 2014.

As mentioned, production in the Permian was an early casualty of the OPEC decision, down 24% overall between May 2014 and March. However, estimates of new production from vertical wells dropped by a much larger 54%, with horizontally drilled wells down by just 17% over the same period.

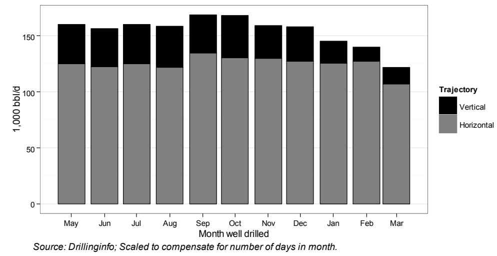


Figure 3: New oil production from Permian basin by well trajectory

Eagle Ford Formation

The Eagle Ford shale of South Texas was initially advantaged by proximity to transport infrastructure and Gulf Coast refineries. Drillinginfo data show that predicted new oil production actually increased in December and January, when other regions were beginning to pare back. However, as low prices persisted, drilling and new production fell dramatically. From February to March, drilling in the Eagle Ford dropped by 33%, from 250 wells to 167 wells. New oil production dropped by 28%.

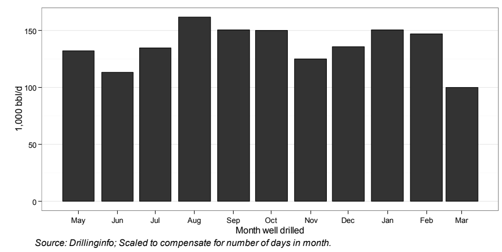


Figure 4: New oil production from Eagle Ford Shale

The Bakken Formation

The story in North Dakota's Bakken Formation also reveals a steady downward trend. Measured from last June, when Bakken drilling and new production reached a recent peak, March saw 45% fewer wells spudded and a nearly 40% reduction in new oil. The fall-off between January and February was particularly steep.

The North Dakota Department of Mineral Resources' mid-April report supports these findings, describing an atmosphere of continuing decreases in rig numbers and well completions. Due to the high cost of shipping oil to market from North Dakota, crude prices at the wellhead hovered near $30/bbl, at a time when West Texas Intermediate was selling above $55 in Cushing, Okla. The rig count dropped nearly 60% in less than four months between January and April. "Oil price is by far the biggest driver behind the slowdown," the report states. "Operators report postponing completion work to avoid high initial oil production at very low prices …"[2]

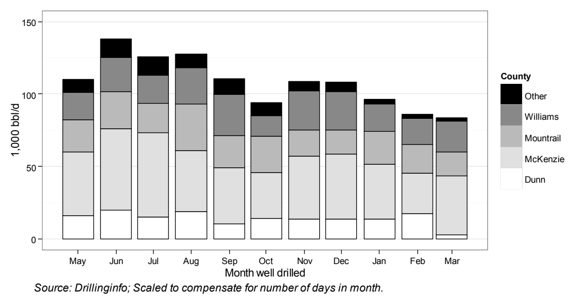


Figure 5: New oil production in Bakken Formation by county

Other Areas of Onshore Oil Production

Decreases in oil production and drilling frequency are also in evidence in some smaller and lesser-known tight oil plays, as well as areas that lie outside the geographical boundaries of the major shale formations. Four areas in particular underwent sharp declines in both new wells drilled and new oil production, Drillinginfo data show. Those were the Eaglebine formation in East Texas, the Mississippian Lime formation in Kansas and Oklahoma, the Granite Wash in Oklahoma and Texas, and areas denoted on Figure 6 by "other," which include locations outside of defined formations. Breakeven costs in these areas tend to be higher than those in major plays. Combined, these four areas saw new oil production drop by 24% between May 2014 and March 2015, with a pronounced 56% drop from 120,000 bbl/d in December to just under 53,000 bbl/d in March.

Slipping new production coincides with a declining well count. The number of oil-directed wells drilled in these four areas shrank from 641 in May to 248 in March.

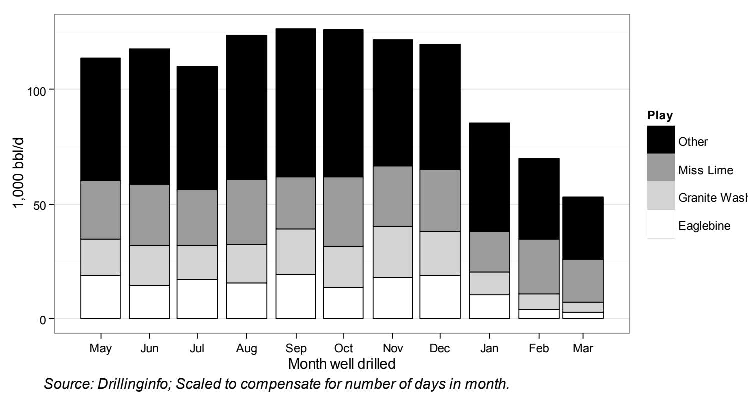


Figure 6: New oil production from minor plays

Discussion

Beyond the statistics above, there are solid economic and geologic reasons why North American light tight oil (LTO) is well suited to become a global source of "swing supply," as well as strong rationale why decreases in production might lag expectations. LTO is relatively high-cost in comparison to most conventional oil production. Standard economic theory predicts that when prices decline, high-cost suppliers should be the first to halt production as price dips below cost.

Reality is more complex. As mentioned, shale oil production has attributes that allow it to respond in a more elastic manner than conventional projects, which involve years of planning and big initial capital expenditures. Once costs are sunk, conventional production tends to proceed, not least because big startup investments may be accompanied by large shutdown costs, such as in offshore production. In these cases, financial models typically require years of steady production regardless of short-term price volatility. In similar fashion, unconventional oil sands production in Canada, typically more expensive than LTO on a per-barrel basis, is also less responsive to price fluctuations once investments are sunk.

But a number of countervailing factors have also supported LTO production despite lower prices. Costs of oilfield services and land have come down as producers drill fewer wells, allowing some producers to stay in business. Firms have also hedged production or sold volumes forward, which insulates them against current prices and requires that they keep drilling. Likewise, some firms remain at work because they have already paid crews or find it costly to cancel contracts.

Finally, wells drilled in different regions of a formation produce different quantities of oil. Wells in "sweet spots" might remain profitable in a price environment that does not support production elsewhere. Put another way, falling prices have driven up average well productivity.

Conclusion

The U.S. shale sector has been an early responder to the low oil price environment that has characterized markets since November. Few other producers have responded in similar fashion. Of those which have cut, only the slowdown in Canada's shale basins appeared related to falling prices.[3]

Although the actual changes in output are modest, the implications are not. The swing producer role held by Saudi Arabia since the mid-1970s appears to be in flux. At times when the Saudis decline to adjust production in line with market signals, that role may revert to higher-cost areas of production, including North American shale.

In contrast to the production quotas orchestrated by OPEC – and in an earlier era, by the Texas Railroad Commission – the ongoing response is being driven by independent actions of firms responding to price signals. In the case of shale, unique characteristics allow this to happen. These include relatively high costs, short lead times for investment, steep production decline curves, and requirements for continuous investment and drilling to maintain output.

U.S. shale will probably be unable, by itself, to assume the mantle of global swing supplier. For one thing, American crude tends to serve domestic markets; producers are currently prohibited by law from exporting U.S. crude oil. For another, falling costs have allowed firms to reach profitability at lower prices. The CEO of one shale producer announced in May that steady oil prices of $65/bbl would allow his firm to resume production in Texas and North Dakota.[4]

The price-responsiveness of shale may even help reduce the duration of the current oil bust. By contrast, the last oil downturn extended for nearly two decades, between the mid-1980s and early 2000s. It was exacerbated by the onset of huge projects in Alaska, the North Sea, and the Gulf of Mexico that could not respond to falling oil prices.

Shale's low barriers to entry, which allowed small companies and investors to quickly move into the oil business, appear to be complemented by low barriers to exit, which allow them to move away when prices reverse. If OPEC and Saudi Arabia shift away from their swing producer roles, the nimble characteristics of U.S. shale producers appear ready to provide global markets with alternate and useful source of spare capacity.

Footnotes

[1] Short-Term Energy Outlook, U.S. Department of Energy, May 12, 2015; http://www.eia.gov/forecasts/steo/report/us_oil.cfm

[2] Director's Cut, April 14, 2015. North Dakota Department of Mineral Resources; https://www.dmr.nd.gov/oilgas/directorscut/directorscut-2015-04-14.pdf

[3] International Energy Agency Oil Market Report, Apr. 15, 2015. https://www.iea.org/oilmarketreport/omrpublic/currentreport/

[4] Bradley Olson. "Shale Giants See Growth Again After 40% Price Climb." Bloomberg News. May 5, 2015. http://www.bloomberg.com/news/articles/2015-05-05/eog-resources-will-resume-major-oil-growth-at-stable-65-price