The Agility of Shale Oil Production

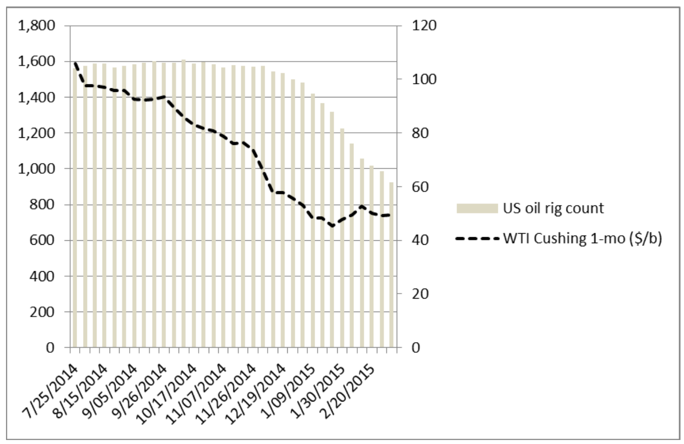
By Ross McCracken*

Oil production is diverse, ranging from stripper wells producing as little as a few 10s of barrels a day on the Texan plains to the prolific 30,000 b/d Brazilian offshore wells drilled deep into the subsalt layers of the Campos Basin, to give but two examples. Each mode of production has different sensitivities both to short-term changes in the oil price and to changes in longer-term expectations. For a multi-billion dollar offshore project, it is the latter that dominates decision-making, but for the new beast on the block, shale oil, it is the former.

As such, shale oil has changed the short-run supply-side dynamics of the oil industry. It is also evident that the economics of shale oil come in not at the top of the cost curve, as might be expected for what was so recently an oil frontier, but in the middle. Estimates vary, but U.S. shale oil at least looks pretty secure at $60/b, certainly cheaper than Venezuelan heavy oil, Canadian oil sands or the Arctic, but more expensive than the onshore giant fields of the Middle East.

These two factors–shale's responsiveness to short-term movements in the oil price and its mid-ranking position in the cost curve–will together have a major impact on the oil industry's entire investment cycle.

Shale Oil Indicators



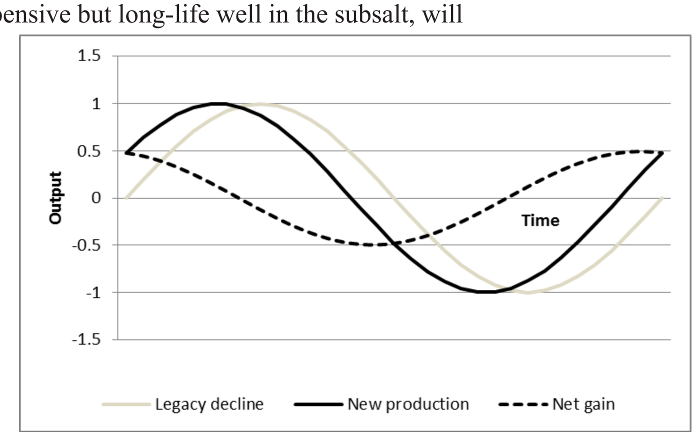
The price of front-month U.S. marker crude West Texas Intermediate, priced at Cushing, Oklahoma, fell from $106.95/b July 23 to below $50/b in January 2015. The response of the U.S. shale oil industry was rapid.

The U.S oil rig count, as reported by Baker-Hughes, started to drop in October, with a sharp contraction in activity evident by January. The count fell from 1,609 for the week ending October 10 to 922 for the week ending March 6.

Any decline in actual shale oil output naturally lags this contraction in drilling activity, a notable feature of which is that the rate of well completions fell quicker than the rate of new well drilling.

Shale oil wells produce the bulk of their output in the first 24 months and decline rapidly thereafter. Each individual well is also relatively cheap to drill and the completion costs make up a significant part of the total drilling cost.

So while Petrobras, with a prolific ready-to-complete, expensive but long-life well in the subsalt, will move from drilling to completion regardless of the oil price drop, the U.S. shale oil driller will weigh the cost of completion against the possibility of an upturn in the oil price in the short-term because this is when the shale well will be most productive.



There is also the likelihood that well completion costs will fall due to the lack of drilling activity. The backlog of drilled but uncompleted shale oil wells represents a new phenomenon in the oil industry, akin to a form of storage.

However, in assessing the impact on output of the decline in U.S. drilling activity, the rapid depletion rate of shale oil wells also has to be taken into account. As drilling activity stalls, new production falls, but the legacy declines from the earlier, more active drilling period continue to increase.

The result is that the net gain from shale production declines sharply. The supply curves relating to new production and legacy declines can be represented as two sine waves, one behind the other, producing a third curve – the net gain.

The U.S. Energy Information Administration has, since November 2013, produced a Drilling Activity Report on seven key shale plays. This shows for each play the expected level of new production, the loss attributable to legacy declines and the net gain for the month ahead. In total, the projections demonstrate a very close correlation with the theoretical sine curves.

The EIA's projection for April, made in March, forecast a net gain in U.S. shale output from the Bakken, Eagle Ford, Haynesville, Marcellus, Niobrara,

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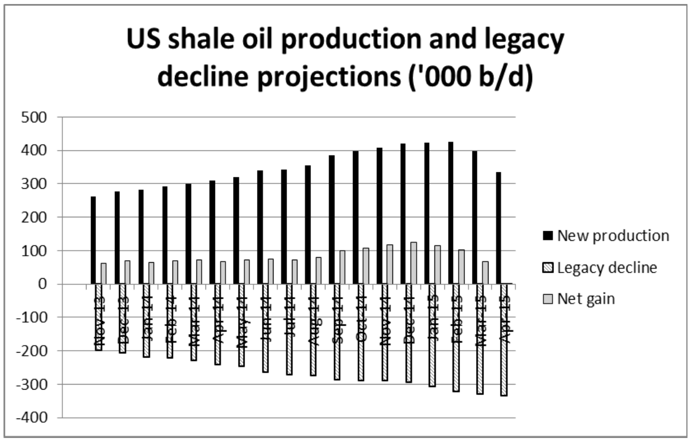


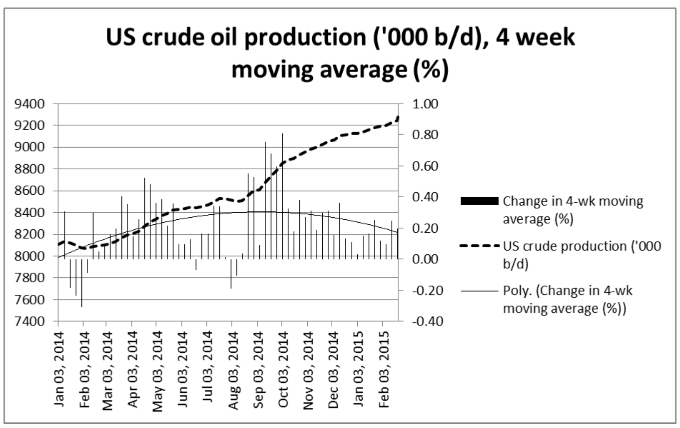
Permian and Utica regions of just 1,000 b/d. Output, for the first time, from the Bakken, Eagle Ford and Niobrara regions was expected to contract.

New production reached its peak at 425,000 b/d in February, but the net gain had already peaked earlier in December at 125,000 b/d. Legacy declines were catching up and continue to grow, reaching a projected record 335,000 b/d in April. Following these trends, and on the assumption that U.S. crude prices remain around $50/b, U.S. shale oil output as a whole should start to contract in May, just nine months after the oil price started its precipitous decline and just six months after the rig count started to fall.

The impact on total U.S. crude production is lagged again because shale oil makes up only a proportion of the total, albeit a growing one. In 2010, tight oil made up under 1 million b/d of total U.S. crude production, but this had risen to over 3 million b/d by the second half of 2013, suggesting it may now make up about 38% of total U.S. crude production of just over 9 million b/d.

The conventional side of the industry takes longer to slow down. U.S. offshore crude production, for example, should increase this year, owing to several large fields coming on-stream based on investment decisions made five years ago and exploration wells drilled up to a decade before.

Nevertheless, based on the EIA's weekly supply estimates, while total U.S. crude production was still rising at end-February, the rate of output growth has been slowing since October 2014, supporting analysts' projections that total U.S. crude supply may start to contract by the end of 2015.



What happens if oil prices increase again? In a period of new activity, the supply response should also be quick because legacy declines will start to fall at the same time that new production starts to rise again. Legacy declines will begin to reflect the weak activity period engendered by low prices. And there is also that backlog of well completions to work down.

This has significant implications for the longer investment cycle of the conventional oil industry. U.S. shale oil may make the harsh short-term adjustments that put the more sluggish conventional industry back in the money, but any price recovery will promote a resurgence in shale oil output long before the conventional industry can deliver production from a reversal of the cuts in capital expenditure expected this year and next.

Shale oil's cost basis and its responsiveness to short-term changes in the oil price suggest that it will not be the long-term victim of OPEC's current output policy. Instead, it will be Venezuelan heavy oil, the Arctic and the like, where capital costs are high, project sizes large and investment cycles long.

Shale oil makes up only a proportion of U.S. crude output and a fraction of total world output, but the conditions are in place for its expansion, whatever hardships it may face today. Should shale formations north of the U.S. border, Argentina's Vaca Muerta or Russia's Bazhenov prove just as prolific as the U.S. shale plays, they should take market share from other frontier production areas. In this new, turn-on, turn-off oil supply world, the investment risk associated with a 20-25 year conventional offshore development, for example, becomes much more uncertain.