What if Shale Doesn't Recover?

A decade of trends will be reversed.

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Data Sources for This Publication
EIA
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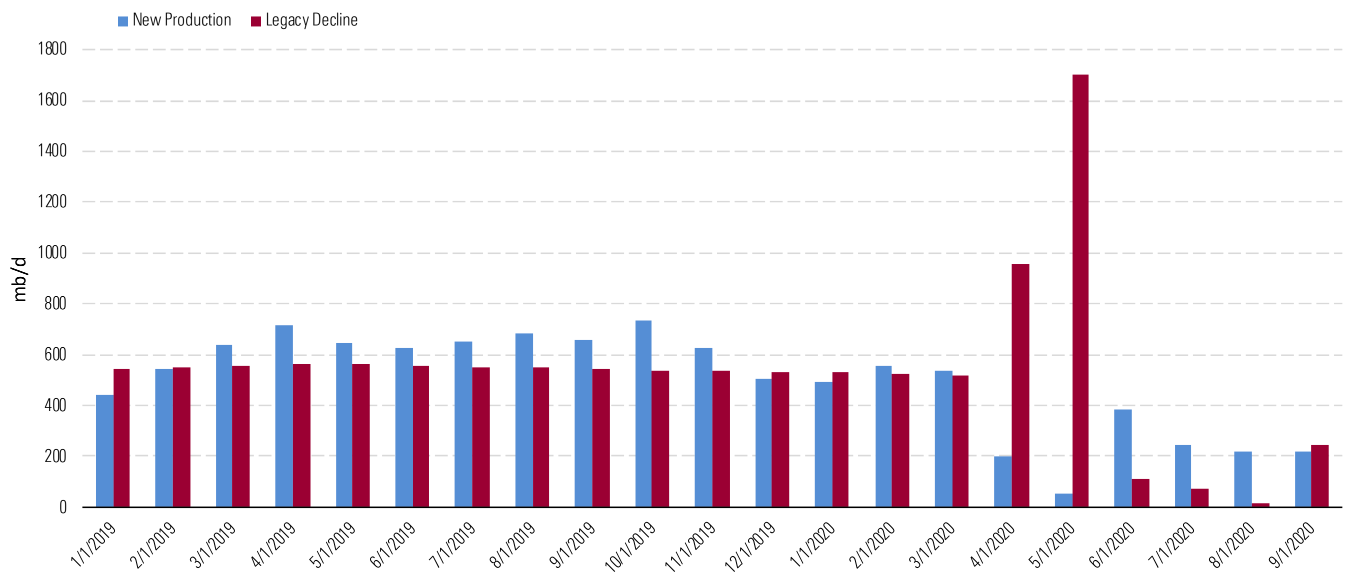
Boom and Bust

Shale output topped out at 9.2 million barrels/day in November 2019 according to the Energy Information Administration August Drilling Productivity Report released yesterday. Average production in 2019 was 8.6 million barrels/day, which was 6.5 mmb/d above the average in 2011—the year shale oil took off—a fourfold increase in nine years. Shale weathered two booms and busts over the past decade with the last downturn starting when production levelled off in late 2019 followed by a 1.3 mmb/d plunge in April and May 2020 in response to the coronavirus pandemic. This note takes a high-level look at the consequences if shale production doesn’t recover from the latest crash.

Legacy Decline

Average shale production through September 2020 is estimated by the EIA at 8.0 mmb/d with output expected to continue declining for the rest of this year and next. Drilling rig counts are at historic lows and Rystad Energy analysis indicates drilling permits dipped to a 10-year monthly low in July. Exhibit 1 shows monthly EIA drilling productivity data since January 2019 with new production coming online (blue bars) and legacy production declines (red bars). The production declines represent shrinking output from older wells that naturally decline over time. In order for overall output to increase, new production has to exceed legacy declines. For most of 2019 except January and December, new production exceeded declines, resulting in annual average growth of 1.2 mmb/d in 2019 over 2018. This year new production exceeded declines in February and March with a slight decline in January. During April and May legacy declines shot up to 950 thousand barrels/day and 1.7 mmb/d respectively. In reality these declines were actually shut-ins of legacy wells in response to very low crude prices that averaged less than $17/barrel in April. Some of that production is now back online in response to higher crude prices, leading to decline rates slowing in June, July and August and new production exceeding declines in those months - even as production continued to fall. The EIA estimates for September indicate a return to a higher decline rate over new output, suggesting the underlying decline in shale production continues. We believe shale output declines will continue into 2021 at least until prices increase above $50/barrel levels that incentivize new drilling.

Exhibit 1 New Production and Legacy Declines in U.S. Shale Basins



Source: EIA, Morningstar.

Expected output declines are underlined by producers reporting cutbacks in drilling and completion budgets during the second quarter. These cutbacks reflect lower prices but also a sober investment environment where stockholders demand cash is returned to them rather than sunk into new wells. A swelling tide of concern over the oil industry's environmental impact is also reducing the investor base in hydrocarbon extraction and challenging essential infrastructure like pipelines (see our August note Is Bakken Now a Fair-Weather Shale Play?).

With this lower production environment, we set out below the consequences we expect for the U.S. oil business considering a continued pullback in shale production.

Producers

As detailed above we expect shale production to continue declining overall at least through the end of 2021. Any drilling carried out in shale basins this year and next will target sweet spots where drilling and production costs are low and/or well productivity is high. That means producers are looking to drill acreage with high initial production rates that realize a rapid return even when prices are low. Production costs can also be reduced by economies of scale such as those employed by larger producers such as ExxonMobil and Chevron (see our March 2020 note: New Mexico's Permian Shale Factory) who are able to harvest Permian basin acreage on an industrial scale. Cost-cutting and efficiency will take precedence in harvest mode with no hunting for new plays.

Midstream

Midstream companies take care of crude distribution from the wellhead to the refinery–in return for per-barrel tolls. They have enjoyed a decade of almost uninterrupted expansion in the shale era but now face challenges with lower and/or declining output. Their principal role is providing transportation to market–a combination of short-distance gathering systems that collect crude from the wellhead and deliver it to regional hubs where long-distance trunk line pipelines carry larger volumes to market centers such as Cushing, Oklahoma in the Midwest or the Gulf Coast. They then offer pipeline or waterborne connections from the trunk line to refineries or storage facilities. During the latest shale boom between 2017 and 2020, growing export volumes meant midstream companies extended networks to marine docks on the Gulf Coast.

Pipelines already up and running should continue to operate (barring unforeseen circumstances such as the permit discrepancies threatening the Dakota Access pipeline in North Dakota). In most cases existing pipelines have a cushion of minimum volume commitments from shippers that require tariff payments even if they aren't being used. These take-or-pay clauses are only jeopardized when shippers go bankrupt. Where midstream companies will lose out is the volumes above their minimum commitments. These volumes can be lucrative when production is expanding as they allow a pipeline's own marketing operation to benefit from higher price differentials caused by congestion.

During and after the first shale downturn following the price crash of 2015, midstream companies moved to secure revenue streams by consolidating their networks. That meant providing producers with a full-service route to market–including gathering systems, trunk lines and distribution to refineries and/or export docks at the Gulf Coast. This approach allows them to maximize tariffs by adding connection fees and more lucrative final mile charges at distribution systems to extract a maximum rent from every barrel in their system. Companies with limited pipeline networks or a single trunk line project will lose out in the face of this consolidation by larger players.

Although not our focus here, we note midstream companies have weathered a volatile financial environment during the shale era. Since large-scale infrastructure is very expensive, midstream companies rely on raising capital to expand their networks. In the first shale boom they typically used the Master Limited Partnership model to raise cash from private investors. After the first shale bust in 2015 that model lost favor and the midstream sector turned to private equity and in a few larger cases such as Kinder Morgan, transformed to C Corporation structures. Today the oil industry has lost investor sentiment, and companies and stock prices are static at best. Without prospects for new infrastructure driven by production growth, midstream companies struggle to maintain revenues to cover debt.

Refiners

At the downstream end of the crude oil business are refiners–nowadays located either domestically or overseas. They have benefited greatly from the shale era since a growing bounty of crude put downward pressure on prices and increased margins. As we detailed in a note last month (see U.S. Refiners' Worst Second Quarter in a Decade) that happy picture has now disintegrated in light of the demand destruction caused by COVID-19. From a position of strength, picking and choosing between competing crudes at discounted prices, refiners now face shrinking refined product margins and a juggling act balancing production with lower market consumption to avoid stockpiles.

If the shale slump turns out to be long-lasting, then refiners need to adjust to new circumstances. They can no longer expect cheap crude as a birthright and will have to shop around for the qualities they need to optimize refinery configurations. That could mean buying more imports if they can't optimize yields with shale crude. The opposite could also be true if gasoline demand returns closer to prelockdown levels while diesel and jet fuel consumption doesn't recover as well. That would mean refineries processing light shale crude can max gasoline yields at the expense of middle distillates. If that trend continues, we may see refineries converting processing capabilities to run more shale at the expense of imported grades that are typically heavier.

If demand doesn't fully recover refiners need to deal with overcapacity. That process has already begun with Marathon permanently closing two plants at the end of July and Phillips 66 announcing the conversion of a Californian refinery to producing renewable diesel. There are a number of other plants up for sale in a market where buyers are thin on the ground, suggesting further closures could follow. Refiners face immediate pressures from lower margins as well as medium- and long-term pressure from a declining market as consumers turn to alternatives like electric cars. Refiners are considering or have already invested in renewable fuels such as biodiesel (see our September 2019 note: Six-Fold Increase in Renewable Diesel Capacity Coming). With little prospect of future expansion in the fuels market and COVID-19providing a taste of things to come with lower demand, refiners must now navigate a difficult path after a decade of relative health.

We expect the issues and effects raised in this note to be driving themes in the U.S. crude market through the end of 2021. The road won't be smooth for any sector from upstream through midstream to downstream. A process of adjustment to lower production, transport volumes and processing is set to reverse the bounty that shale growth bought to the industry in 2011. As is always the case, retraction and reduced activity make it harder sell to investors.

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