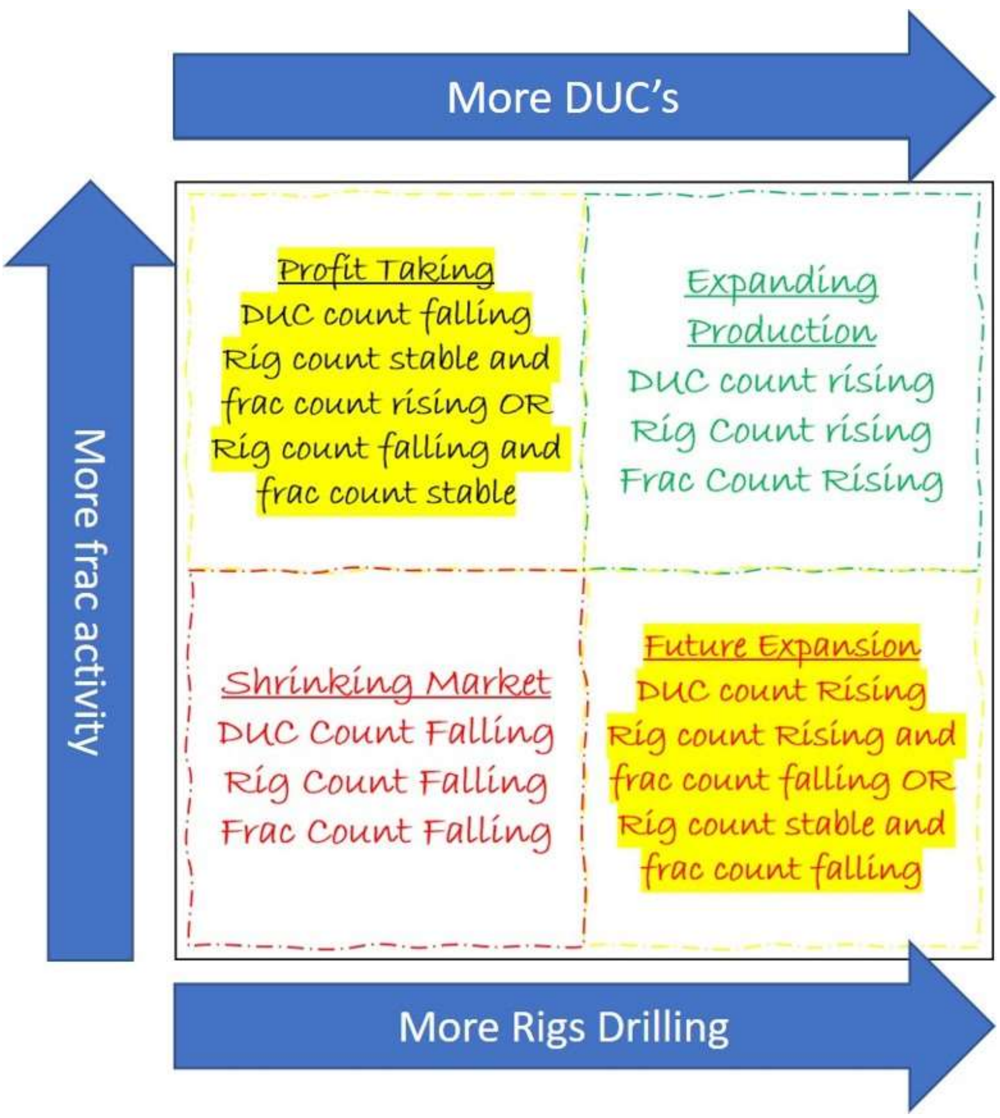
US Oil and Gas Shale Industry Activity and Forecast

Back in early July of this year, I wrote an article you can find here: discussing the inventory of drilled uncompleted wells in the US shale plays. https://www.linkedin.com/pulse/what-significance-duc-eric-gagen The key takeaway from this article was that by looking at the number of DUC's, rigs working and frac spreads/fleets working can be used to understand what is driving activity. Once this is understood, you can make a reasonable prediction about what will happen next. Since then a lot of things have happened but can we use this technique and some easily available data to see where we are as an industry now? Can we make some predictions about where activity is going next? This discussion may seem long but there are lots of pictures. If all you want is an up or down forecast, skip to the last page, but I encourage you to read the whole thing, since you will be able to make your own assessments if you do.

The Method

The basic conditions and outcomes are on the chart below from the article in July.



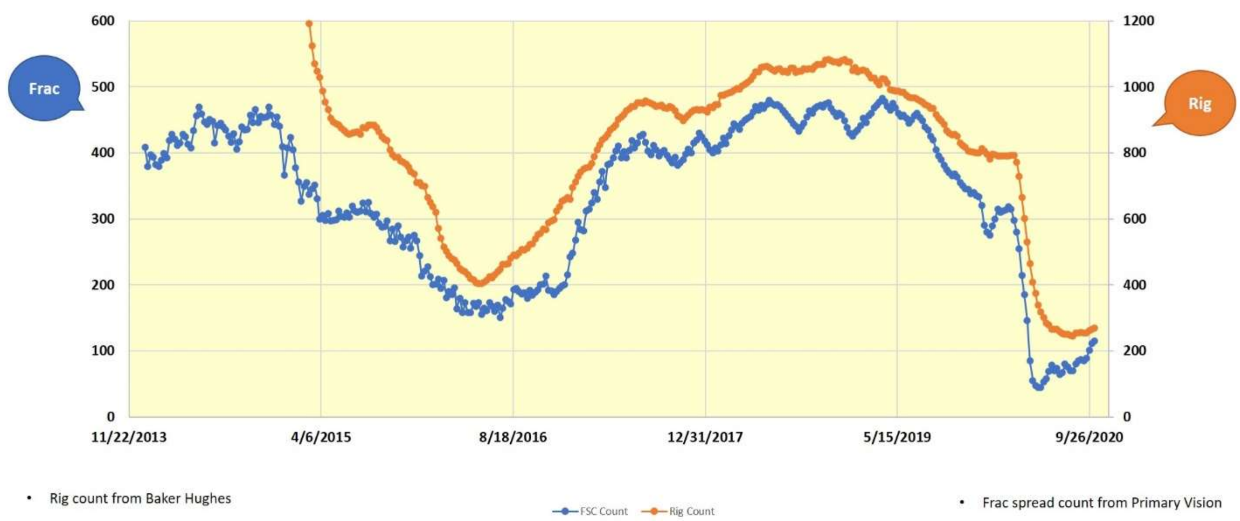
This method can be used at any scale – for a country, for a basin, for a company, or for a region. One frustrating factor about a lot of activity levels and forecasts is that they require accurate information about the # of DUC wells, the # of rigs working, etc. The simplification allowed by this method means that you do not necessarily need an accurate count (although that's always helpful) What is really required is a consistent and repeatable method of counting each of the 3 key criteria.

Data Sources

A lot of information sources are available to track DUC's rig's working and frac fleets working. For the purpose of this discussion I will use 3 free open sources. For rig counts, Baker Hughes is the industry standard: https://rigcount.bakerhughes.com/rig-count-overview The total US count is a reasonable proxy for the # of rigs in the US working on horizontal oil and gas wells. There are a few rigs working on other sorts of projects, but not enough to create significant distortions. Other services, long effort searching the web or a paid subscription can provide much more detailed information on various basins, on oil and gas activity, etc. The 2nd source is Primary Vision https://twitter.com/primaryvision?lang=en for fracturing spreads working. They provide free of charge a total number of fracturing spreads working in the US. Again, for more detailed information there are a variety of other options available. The last source of information is DUC's https://www.eia.gov/petroleum/drilling/ On this page is buried and incredibly useful table of information: https://www.eia.gov/petroleum/drilling/xls/duc-data.xlsx There have been a lot of arguments about how accurate the EIA DUC count is. Compared with various paid or proprietary databases I have had the opportunity to use, there is some merit to these arguments, but one thing is true – the EIA counts track the general trends and directions of the other ones I have seen. The EIA report has another advantage which we will take advantage of: A count of the number of wells completed and drilled on a monthly basis. Outside of paid or proprietary databases this information is often unavailable. Many state regulatory bodies do not make public reports about the number of wells drilled or completed until long after it actually takes place which is the reason that rig counts and frac spread counts are used as a proxy for this data.

Rig and Fracturing Activity

First a big picture of activity for the USA as a whole:



Past experience has shown that it takes ~ 2 rigs working to keep one frac spread working, so the number of each working has been shown on different scales to bring them in line with one another. This 2:1 ratio was established in 2015 when low prices drove efficiency of each type of work in different ways and has held ever since.

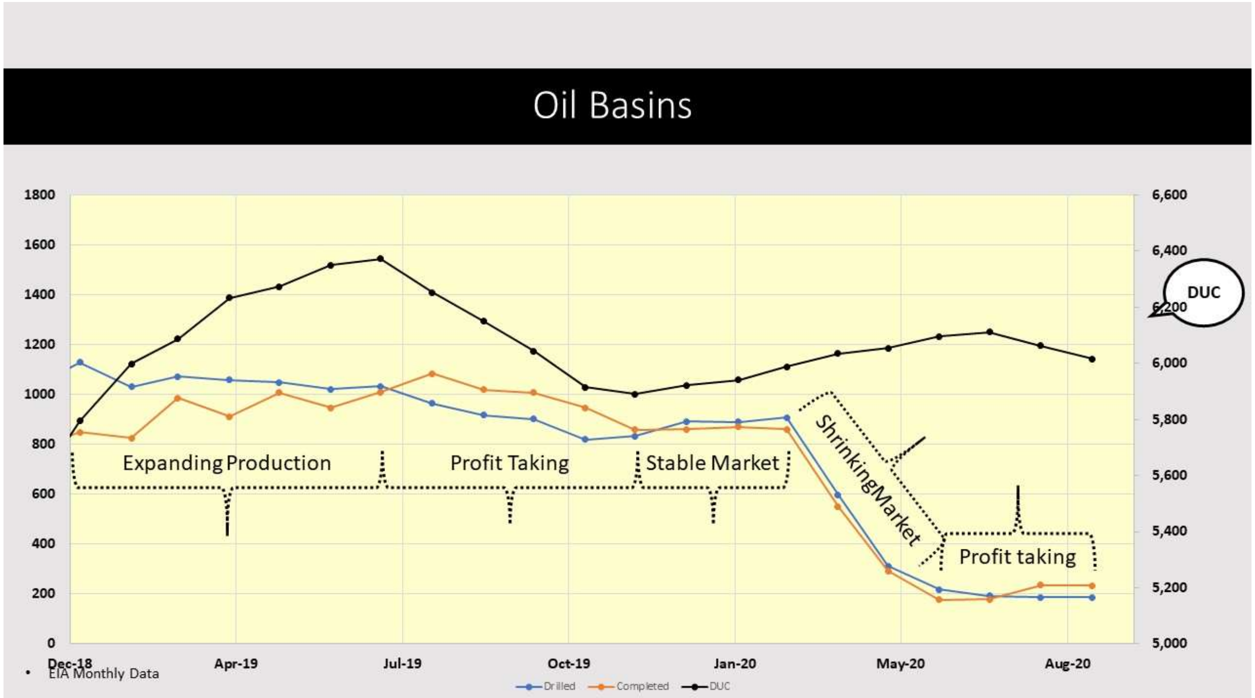
A zoom into the last 2 years produces an interesting result all by itself even before looking at DUC numbers:

When a gradual slowdown went to a nosedive in March and April fracturing activity dropped faster than rig activity. At the time in July I said “since roughly the start of April 2020 the ratio has been 3 or more rigs working for every 1 frac crew working. This means a DUC build due to a lack of completion activity.” However there was not yet any available data to support that hypothesis.

Starting in late July the inverse has taken place: The number of fracturing fleets working has been proportionally oversized compared to the number of rigs working. Instead of a 2:1 ratio it has been a 1.6:1 ratio – nearly exactly the opposite of the 3:1 ratio that ruled from April to mid July.

Integrating the data together

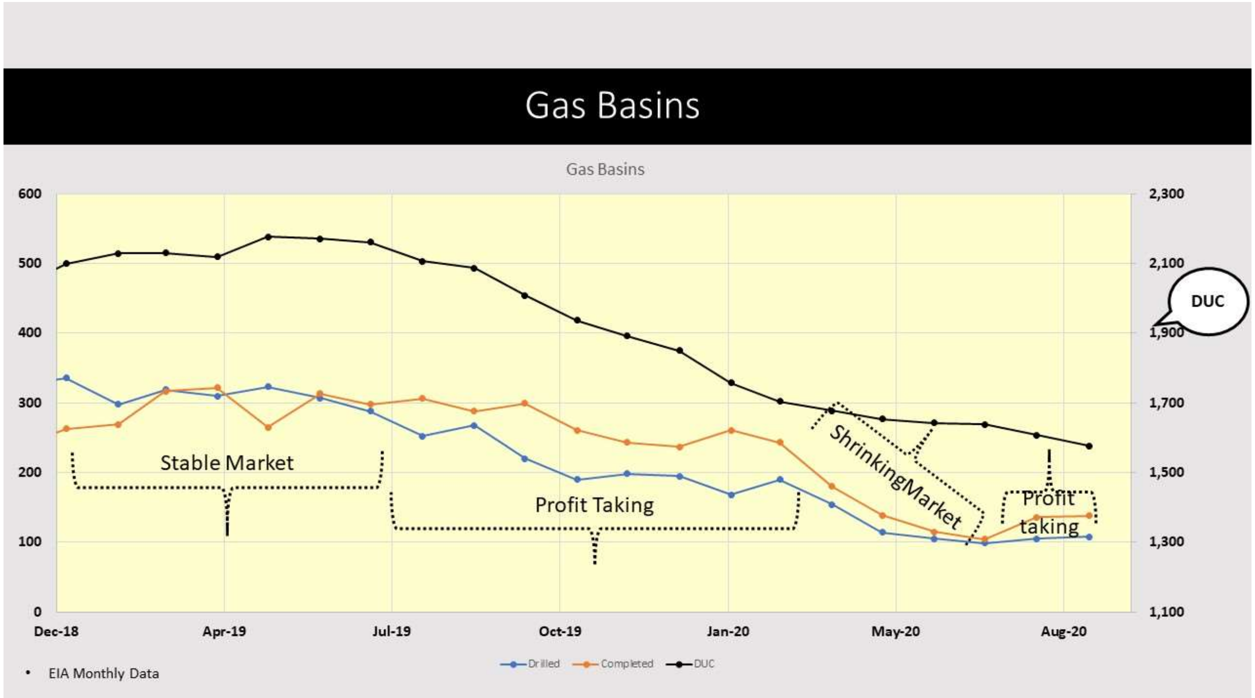
Using the data from the EIA, with direct information on the number of wells completed and drilled as well as a DUC count, a clearer picture emerges



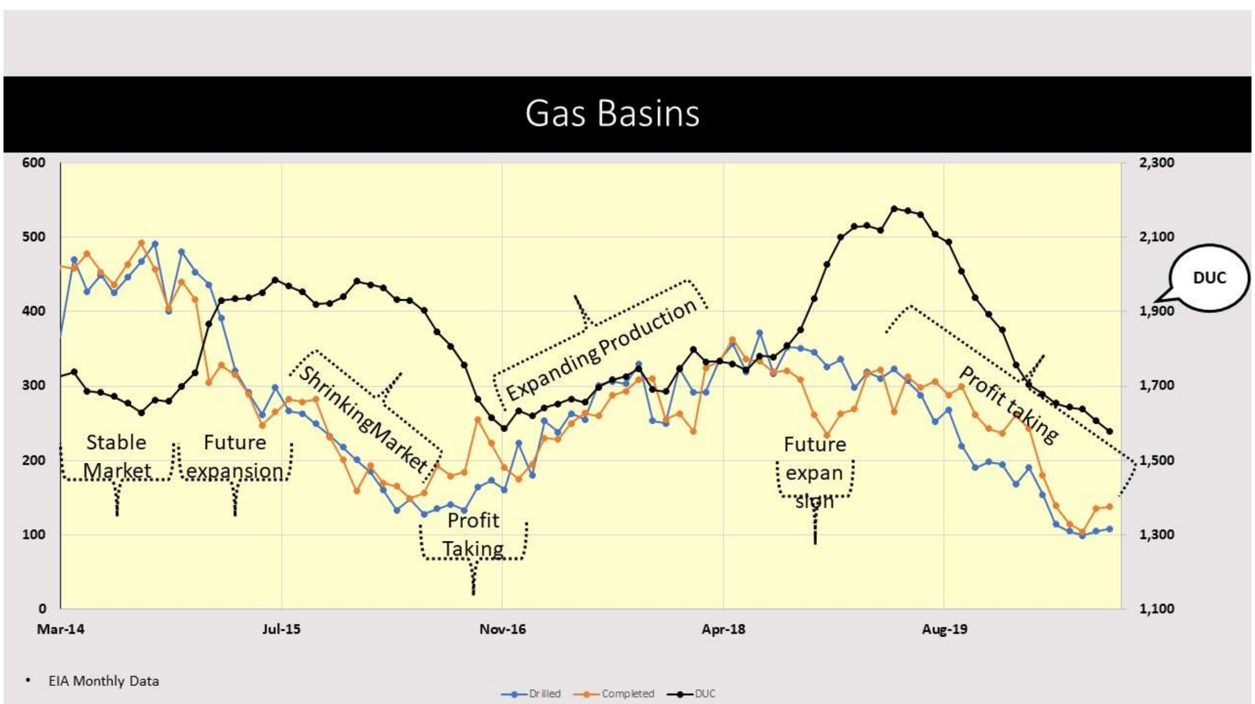
All major US oil basins (Permian, Eagleford, Bakken, Niobrara)

Utilizing the criteria from our box chart on the first page, I have labelled each region of the chart based on what economic situation was driving activity in each time period. One question which everyone wants answered is when the oil market might return to growth, or market stabilization. The answer, at least in part can be determined by looking at the activity of the natural gas based markets and basins first.

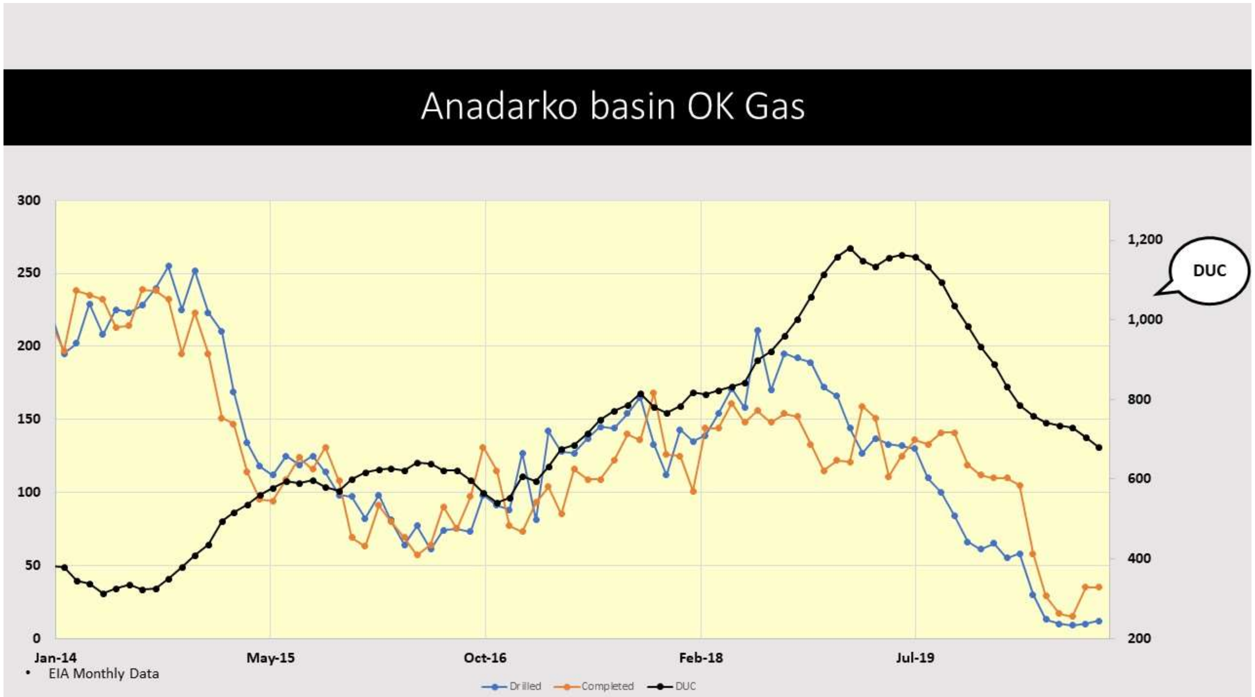
Natural Gas Basin Data and Forecast



Distinct from the oil market which has had several different cycles taking place over the past couple of years, the gas market consisting of the Haynesville, Anadarko and Appalachain basins has seen a rather steady drawdown in DUC's over the last 2 years, with no signs of an increase in sight. On a larger time scale the results are even clearer:



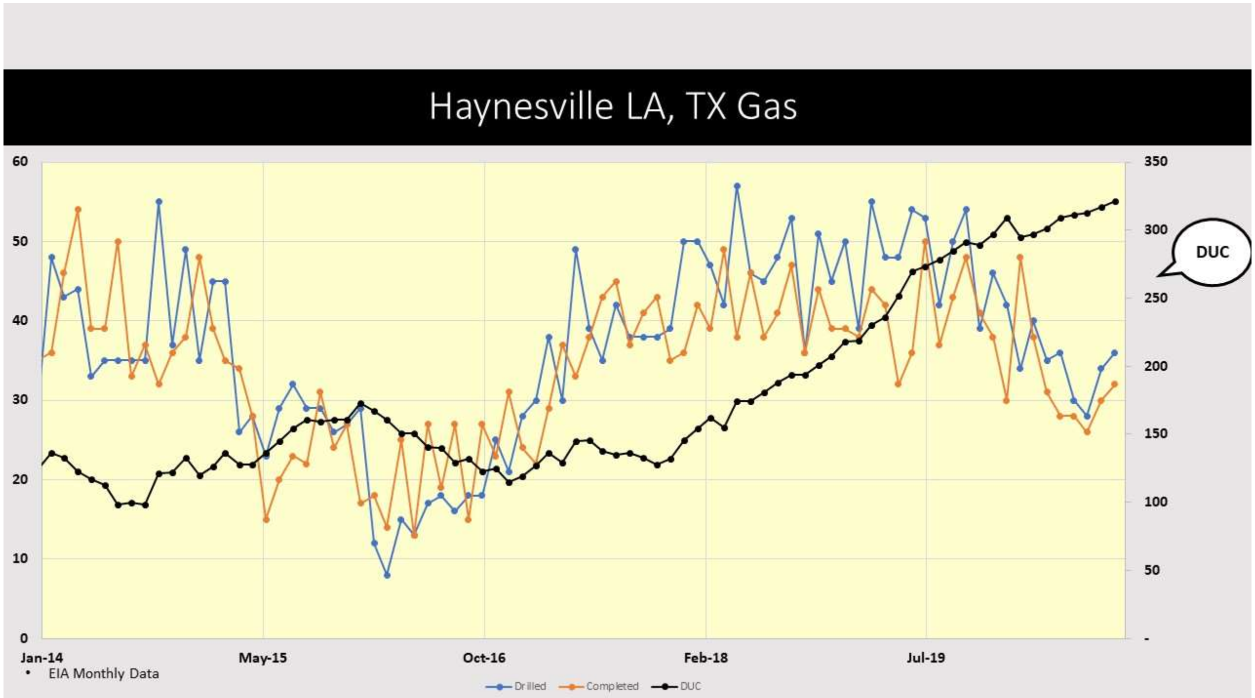
Gas basins have been seeing slowing activity since late 2018 with no sign in sight. The coronavirus 'collapse' in activity which is so clear in the oil basins chart is far more muted in the gas activity market since things were already in a general decline in markets already. However each of the 3 major basins involved in natural gas production have distinct trends of their own. They are ranked in order from lowest to highest current activity.



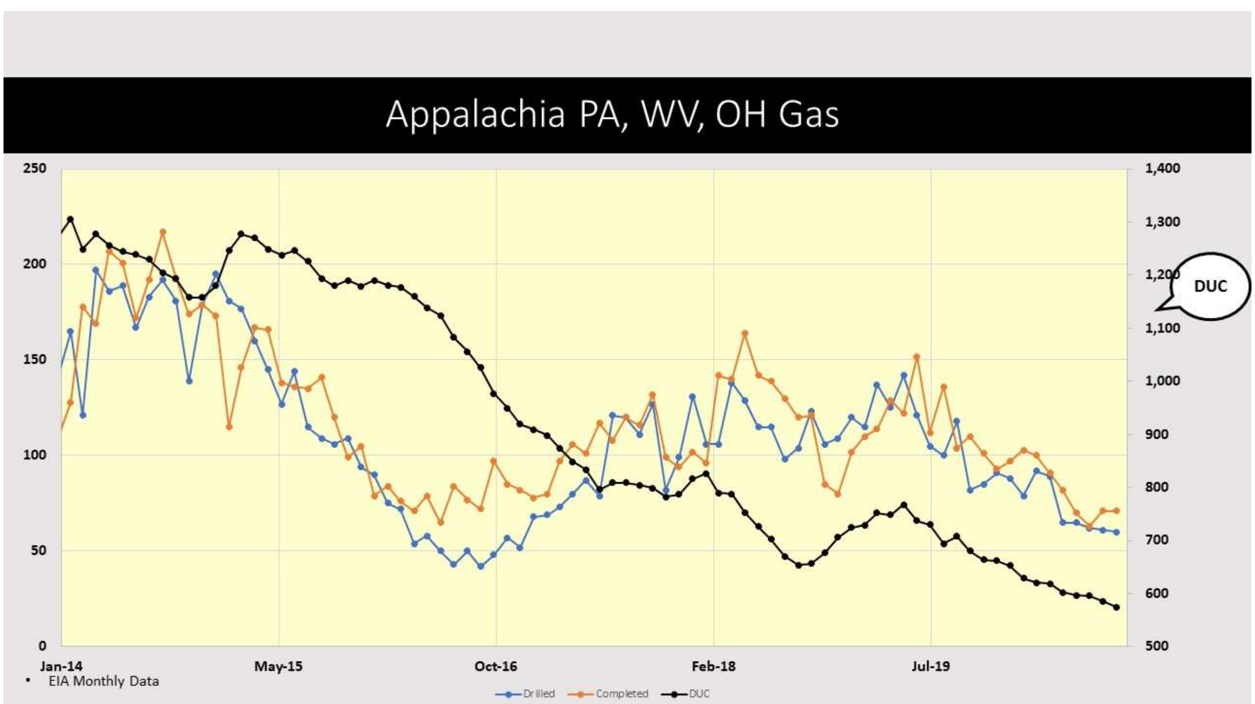
In Oklahoma the Anadarko Basin saw a strong uptick in general activity in 2015 to mid 2018. At that point 3 different factors came into play creating reduced activity:

- A realization that the play which had been thought to be condensate/oil rich was not, thus reducing cashflow
- A realization that long term EUR (Estimated Ultimate Recovery) in many wells was going to be limited due to water production
- General saturation of the domestic natural gas market in the United States.

Activity in the Anadarko Basin should not be expected to recover unless demand for natural gas rises significantly or some unforeseen event takes place because of what is going on in the other natural gas focused basins in the USA. Activity was already falling when the coronavirus hit in the spring of 2020 and the 'recovery' since that time has been mainly completing already drilled wells. DUC counts are falling, and a recent uptick in fracturing activity without a corresponding increase in drilling activity indicates that this will continue to be the case for some time.



The Haynesville shale play in North Louisiana and Northeast Texas is in a very different place. Activity has been high and rising through the entire period from late 2015 until the dip caused by the initial coronavirus outbreak in the spring of 2020. The dip was very modest and activity is already bouncing back, both in drilling and completions. The Haynesville shale is advantaged because of its position close to LNG (Liquifed Natural Gas) export terminals as well as its position close to supply and demand hubs in the US. The Haynesville is in recovery and looks to be rebounding strongly. It should continue to do so because it is a low cost provider of natural gas with a wide range of possible customers nearby.

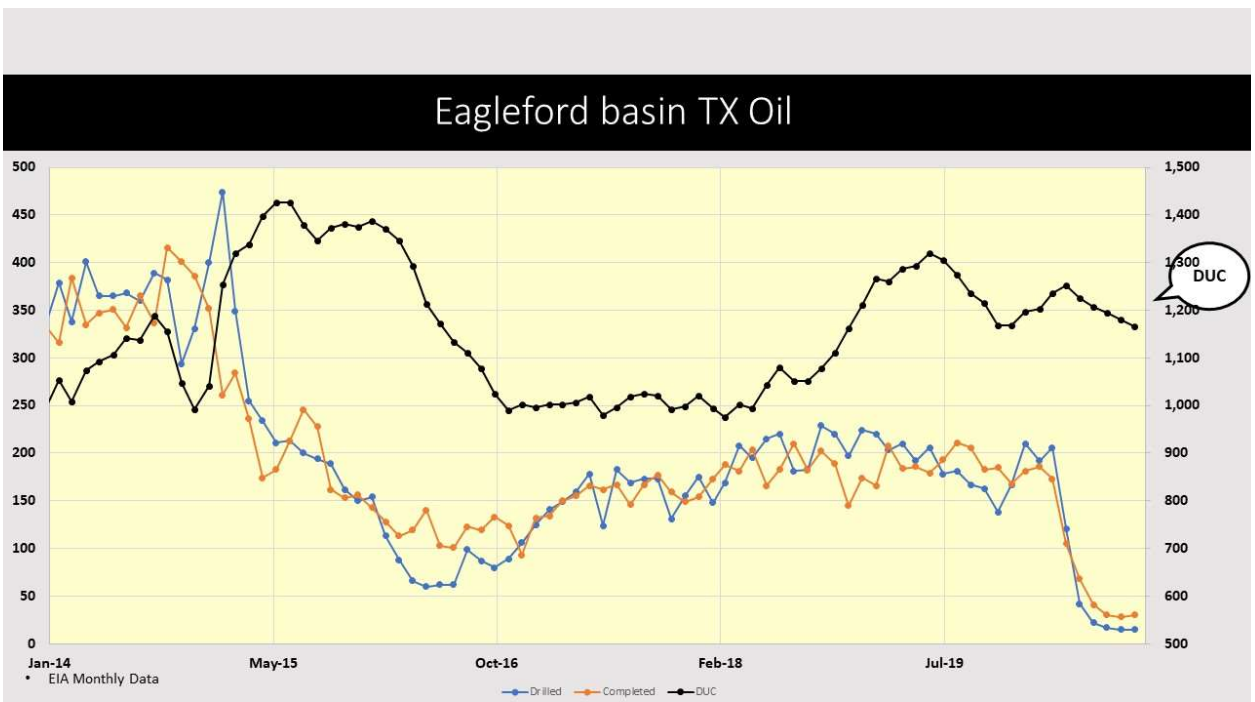


EPG Solutions

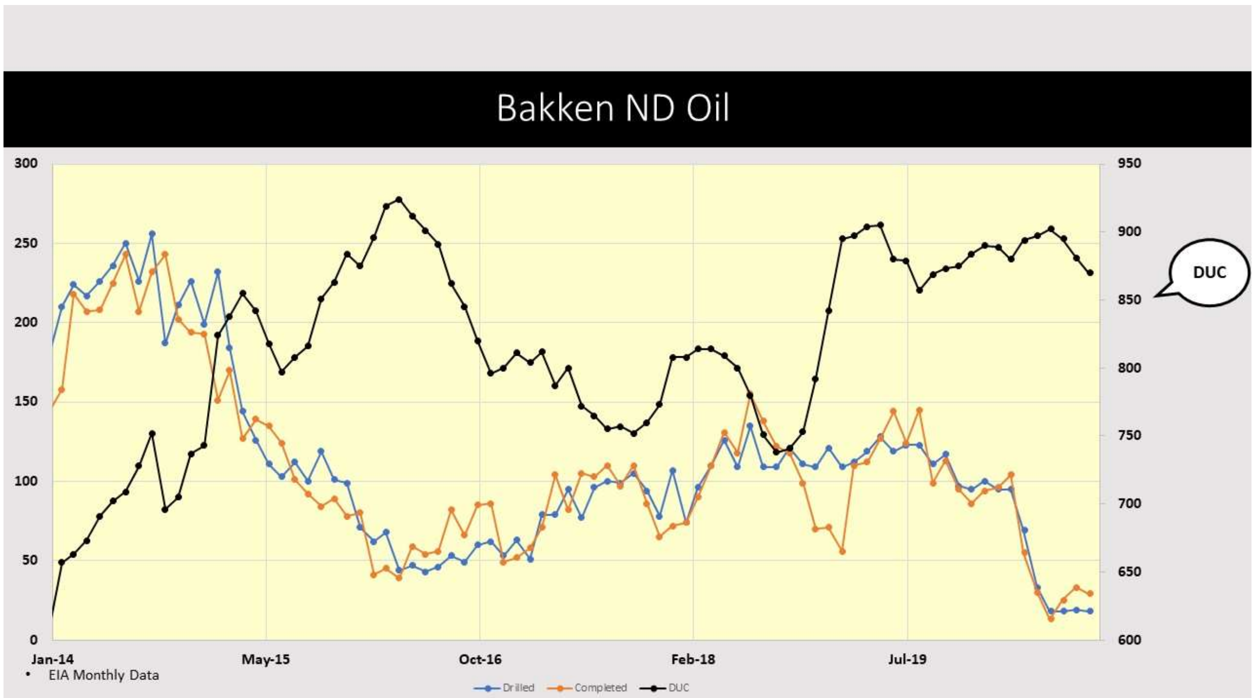
And here is the big driver for gas markets; the Appalachia region. There is some oil-based activity, but the vast majority is gas driven. Production from this basin has been extremely high and has met every possible demand within range of pipelines and export terminals which it is connected to. Anyone looking at the oil play chart and wondering when it 'must' turn around can look at this graph and see that it does not have to. Activity in the Appalachia region had a slight period of improvement in the winter of 2018/19 but never really rebounded from the fall in 2015/16 and has seen a steady decline in DUC's remaining having fallen by more than 50%, as the economic conditions simply will not support a lot of new drilling. In contrast with every other region there is no noticeable effect from the coronavirus epidemic in the spring of 2020. Instead existing trends merely continue. It seems very unlikely that there will be any return to activity in this region any time soon. A lot of pundits have been proclaiming that this winter will see a rise in gas prices, and a corresponding increase in gas directed drilling and completion. This seems unlikely since the market is so well supplied in general. There may well indeed be price fluctuations, but it seems unlikely to generate any changes in activity. Recent profit taking in the form of a slight uptick in well completions has been paired with a continued decline in wells drilled, indicating that the region is moving even deeper in to profit taking and contraction than it has been previously.

Oil Basin Data and Forecast

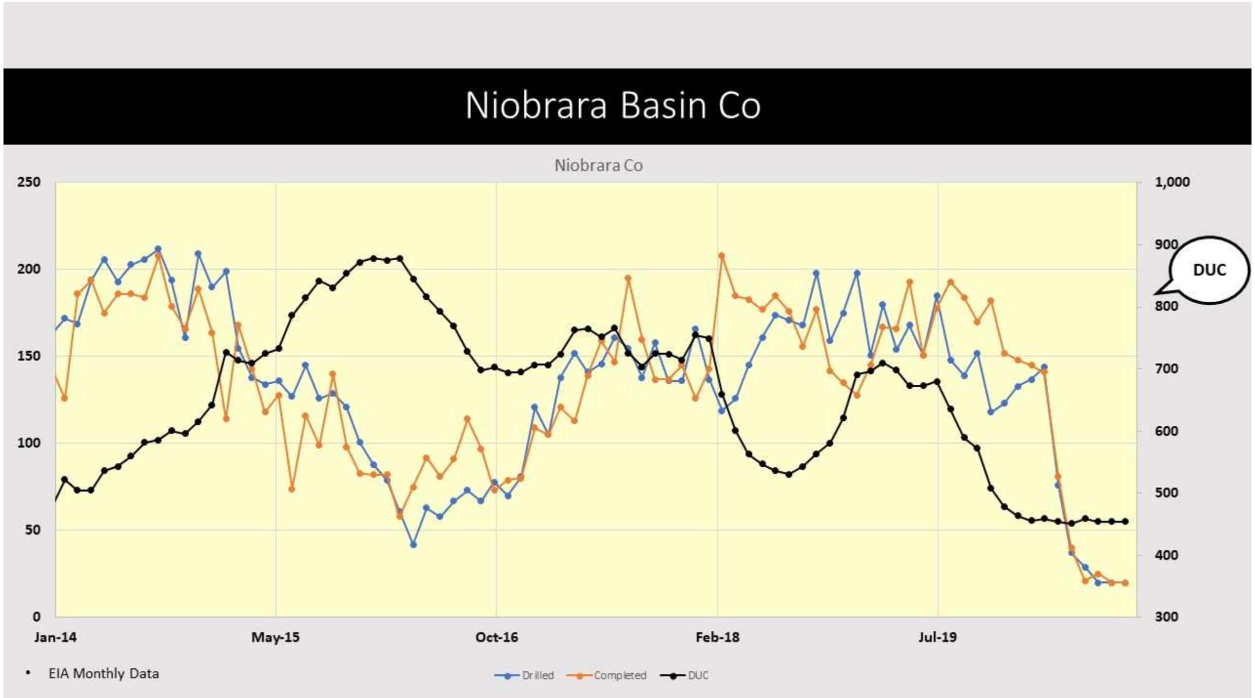
There are four major oil basins and like gas basins, they will be reviewed in reverse order from least to greatest current activity.



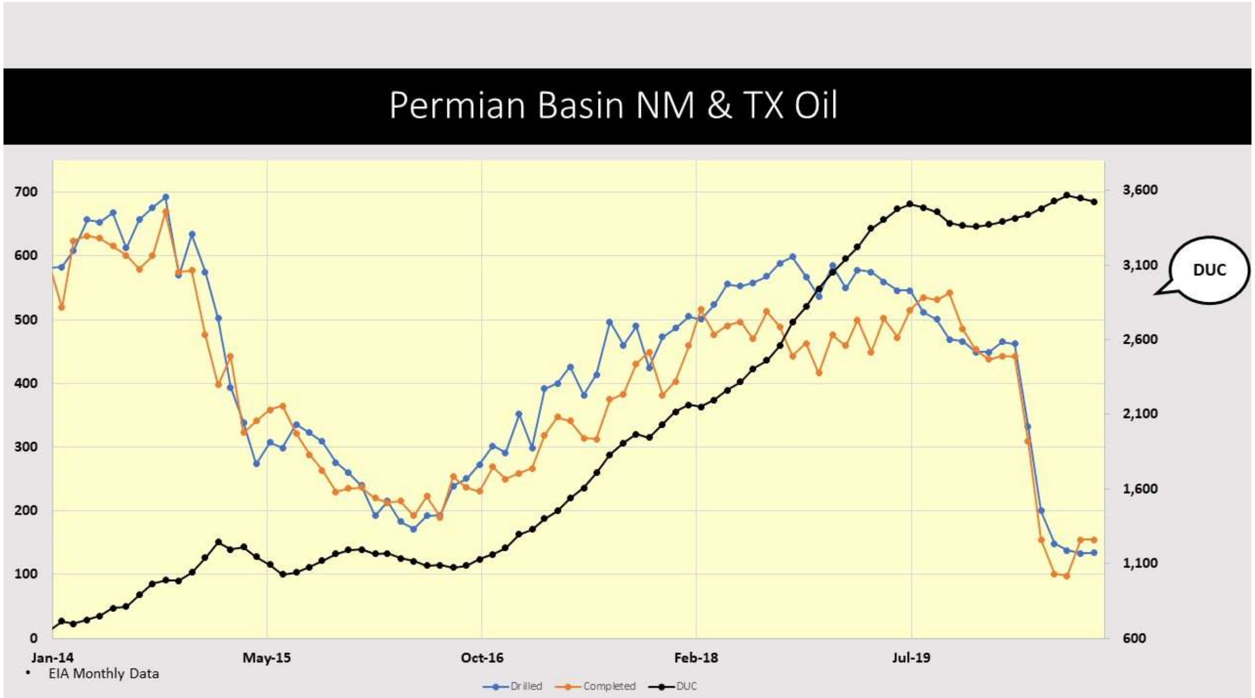
The most mature oil directed basin has seen the hardest fall in activity, and for the last five years has been the second most active oil directed basin behind the Permian. Now it is one of the smallest. This is in line with previous activity changes. When oil prices declined in 2015, the Eagleford saw a sharp decline in activity, followed by a slow but steady return afterwards. Operators in this region have a variety of markets available to them with easy access to a variety of refineries and exports, so they are strongly affected by changes in posted prices. Currently the Eagleford is entering a period of profit taking similar to the one which was in force for most of 2015 and 2016. I would expect a slow and modest recovery for the Eagleford – there are a lot of DUC's available for completion but the region as a whole is very mature, and operators are showing, and have shown in the past some discipline in responding to price increases. One wild card is natural gas prices and demand. The Eagleford has a large and productive gas window which has generally not been aggressively pursued. Now that general oilfield infrastructure in the Eagleford is more mature some companies may target it for lower cost incremental productivity.



The Bakken is the next smallest market at present and shows greater variation than the Eagleford basin. Where the Eagleford activity shows gradual and modest expansion after the crash in 2015 the Bakken has a lot more variability. This is strongly related to infrastructure difficulties in getting crude out of the basin and towards areas with greater demand for oil. I would expect the Bakken to show a stronger increase in activity in response to oil prices than the Eagleford has. One reason for this is that in the time period from mid 2018 until the coronavirus related decline in the spring of 2020 production in the Bakken region was limited by regional pipeline capacity. The strong drop in new drilling and completion since that time has reduced the productive capacity of the basin temporarily meaning that new wells placed on production now and in the near future will not be constrained by high pipeline tariffs or the need to ship product out by costly rail methods. There is a historically large inventory of DUC's in this basin which will make very attractive candidates for completion with even small increases in oil prices.



The Niobrara basin has been the smallest oil directed shale basin for overall activity in the last 4 years, but is now on a par with, or even more active than the Bakken and the Eagleford in terms of current activity. Drilling and completion activity have stabilized and do not show a recent excess in completions compared to wells drilled as every other oil and gas basin does in the data. This is a sign of a balanced market. Note that the DUC count is low and stable in this area also. No rapid increase in activity in response to increased oil prices is likely to take place because there simply is not the inventory of wells awaiting completion to allow it. An increase in rig count would be required first, and most operators will not do that until they are confident prices will be higher for long enough to still be there by the time the wells are placed on production.



The Permian is the 'newest' or 'youngest' oil directed basin, and as such has seen a different pattern of activity than the others. Just as everywhere else, there was a decline in activity in 2015 but this was followed by a strong steady and unrelenting expansion from 2016 to 2019. Wells being drilled continually outpaced wells being completed, as the expansion wore on, partly due to an increase in pad drilling, and partly as a result of low availability of fracturing crews and equipment. The market softened in late 2019 and early 2020 before COVID pulled all activity back. With a large inventory of DUC's and a lot of available fracturing and rig services, the Permian is poised to be able to put large amounts of oil on production quickly if oil prices rise or stabilize, either by completing DUC's or by drilling new wells. The basin was nearing a point where pipeline constraints were becoming a serious problem in late 2019. Just as in the Bakken, the recent drop in activity has eased those concerns, and in addition while some infrastructure projects were delayed or cancelled many others were to far advanced to stop. The Permian has the ability to influence oil prices, so if producers here get to aggressive in the face of decent oil prices they will. Recent infrastructure improvements in pipeline capacity and the reduction in the rapid pace of drilling have allowed natural gas gathering systems to catch up to some degree which will bring more gas to market from the Permian in the future.

Conclusions

This spring and early summer represented an enormous reset of the tight shale oil and gas industry. Moving forward, unless coronavirus concerns become worse, the economic situation should show some improvement, and this forecast assumes there is some modest general economic growth in the next couple of years, enough that depletion of some existing production will spur new drilling and production.

Basin	Currrent condition	Short term (6 months)	Long Term (1-2 years)	Notes

Anadarko (gas)	Profit taking (contraction)	No change	Stabilization	Activity will stabilize, probably slightly above current levels.
Appalachia (gas)	Profit taking (contraction)	No Change	No Change	activity slowly fading away. No change until serious demand changes take place
Haynesville (gas)	Expanding production	No change	Minor slowdown or stabilization	Will eventually fill export demand and face increased competition from high GOR oil shale wells in TX
Bakken (oil)	Profit taking (contraction)	Minor improvement	modest improvement	Lots of DUC's plenty of pipeline capacity available
Eagleford (oil)	Profit taking (contraction)	Stable activity	Minor improvement	Operators historically cautious opportunity for gas window
Niobrara (oil)	Stable activity	Stable activity	Minor improvement	No inventory of wells ready to put on production
Permian (oil)	Profit taking (contraction)	Minor improvement	Modest improvement	Major ability to increase production if conditions are right. More gas will come to market

Demand for oil is hard to predict of course, but the Bakken, Eagleford and Permian basin have so many DUC's out there that short term completion activity will be reasonably good. Gas markets are fully supplied or oversupplied both domestic and export so only the 'best' wells will get put on production – those which are close to demand centers and reasonably cheap to put on production. Except in the Haynesville this mostly means very few new wells. An increasing amount of gas demand in the near term will be met by associated gas from the Eagleford and Permian basins. Not only do oil wells tend to produce more gas as they age, but Permian infrastructure now allows more of that gas to reach market. In addition the Eagleford has a gas prone section which could be easily exploited if operators see an opportunity for incremental expansion.