THE OXFORD INSTITUTE FOR ENERGY STUDIES

October 2019

Prospects for US shale productivity gains

OXFORD ENERGY COMMENT

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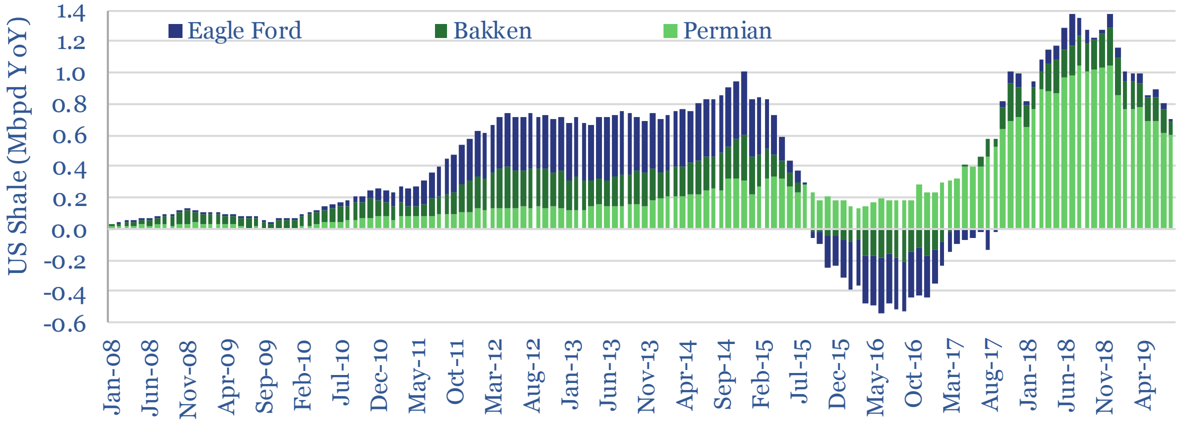
1. Introduction: What has undermined shale's confidence in 2019?

US Shale performance has been disappointing this year (see Figure 1). Most international organisations have been revising down their 2020 US shale production forecasts. The downgrade reflects lower oil prices, lower rig counts, capital constraints, pipeline bottlenecks and a negative trend in well-productivity.[1] After all, 2019 has been a punishing environment for any company to lower its production guidance, raise its capex or report an operational mishap.

Figure 1: Shale growth has slowed from +1.4 mb/d at YE18 to +0.7 mb/d in the latest data



Source: EIA, TSE[2]

One of the major factors behind the revision in forecasts has been a decline in well productivity. Many commentators have been eager to call a 'peak' in Permian productivity, or suggest that the basin is running out of resources. The reasons for this pessimism lie within the data: Based on reported numbers from the EIA, the implied 30-day production rate from new wells in the Permian basin has now fallen 20 percent year-on-year (YoY) to 610 b/d. With an average 30-day IP-rate of 610 b/d and despite the fact that the Permian completed a vast 485 wells per month over the first half of 2019, the month-on-month growth has been slowing down markedly as compared to last year. Production additions ran at 290kbpd per month, outpacing base declines of 240kbpd/month, yielding 40kbpd/month of net growth.

Weaker well productivity has important implications for the long-term prospects of US shale. Figure 2 shows that at 2018's well productivity, Permian production would cap out at 10 mb/d in 2023, when 500 rigs are adding 700kbpd new supply each month, matching 700kbpd of base declines from a 10 mb/d industry. Figure 3 shows what happens if Permian productivity continues compounding at around 11% pa. Now those same 500 rigs can add around 1 mb/d of production per month by 2025, outpacing the rise in the basin's monthly decline rate. And so production keeps on growing to around 20 mb/d.

The crucial point about rising productivity is that it allows shale to ramp up to such lofty levels without increasing aggregate capex. And thus, even with increasing calls for capital discipline around the industry, higher well productivity would make it possible to achieve higher than 20 mb/d of aggregate shale production, while the industry also generates $300bn of aggregate free cash flow, in 2021-25, at a $50 oil price input (Figure 3-4). Conversely, if productivity fails to grow, then the ascent of shale only

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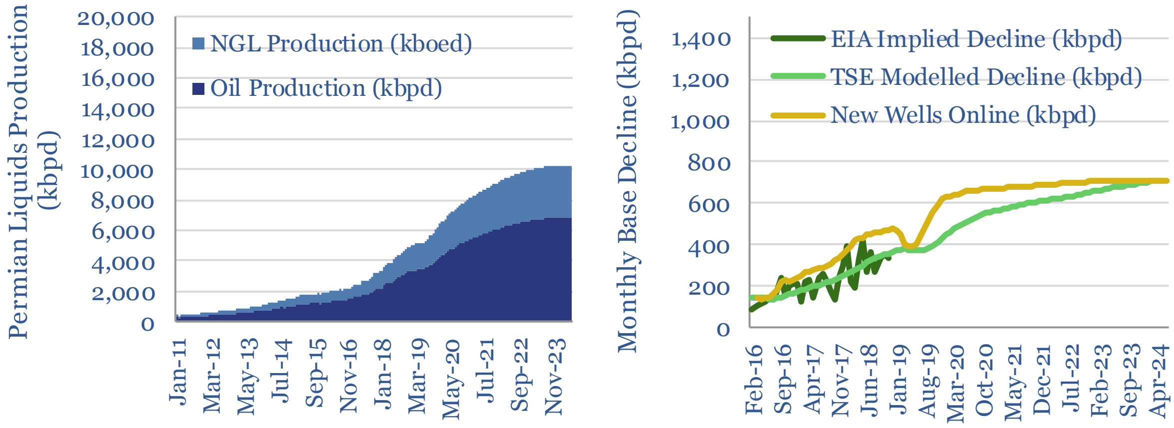
[1] For instance, C.M. Matthews & R. Elliott,'Shale Boom Is Slowing Just When the World Needs Oil Most', Wall Street Journal, September 29, 2019; N. Cunningham (2019), 'Weakening Shale Productivity "VERY Bullish" For Oil Prices', September 10, Oilprice.com; N. Cunningham (2019), 'Be Wary Of Unrealistic Shale Growth Expectations', March 4, 2019, Oilprice.com.

[2] Underlying data behind all the exhibits in this document can be downloaded from https://thundersaidenergy.com/

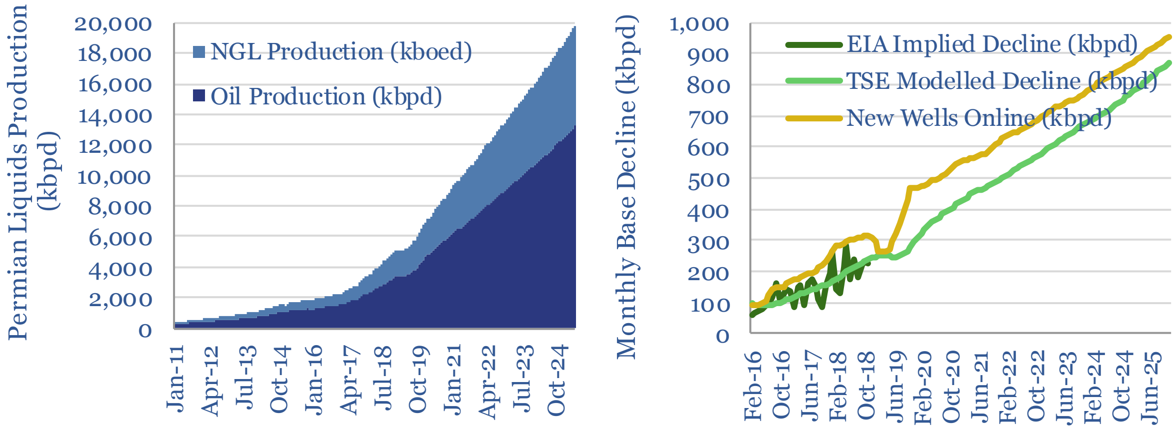
reaches 10 mb/d by 2025 and at $50/bbl oil, no FCF is generated (Figure 4). In short, assumptions about productivity are key to predicting US shale potential and its profitability as an industry.

Figure 2: With flat shale productivity, the Permian is set to ‘peak’ at 10 mb/d in 2023



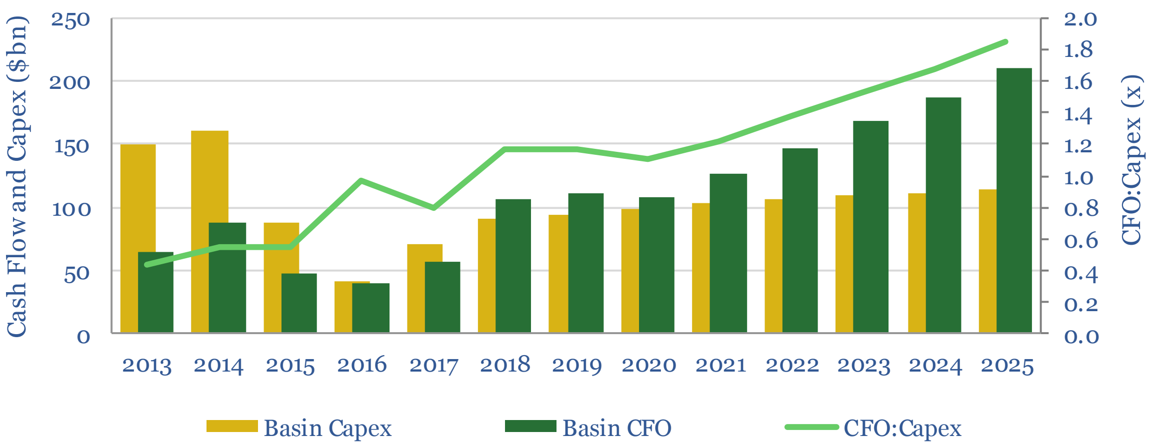
Source: EIA, IEA, Baker Hughes, Companies, TSE modelling

Figure 3: With increasing shale productivity, the Permian can break 20 mb/d



Source: EIA, IEA, Baker Hughes, Companies, TSE modelling

Figure 4: Productivity gains would enable the shale industry to ramp up to >20 mb/d by 2025, while also generating $300bn of free cash flow at $50/bbl oil

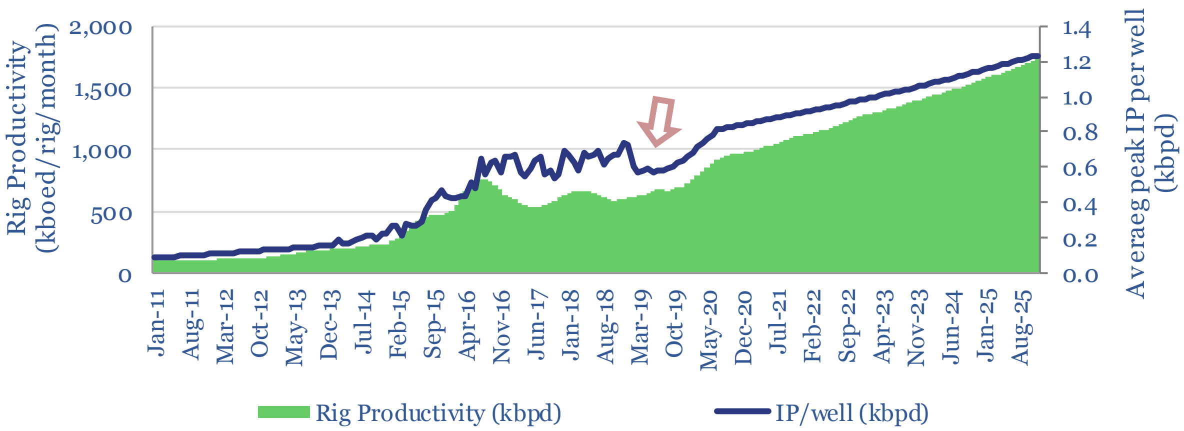


Source: EIA, IEA, Baker Hughes, Companies, TSE modelling

2. Why has shale's initial productivity declined?

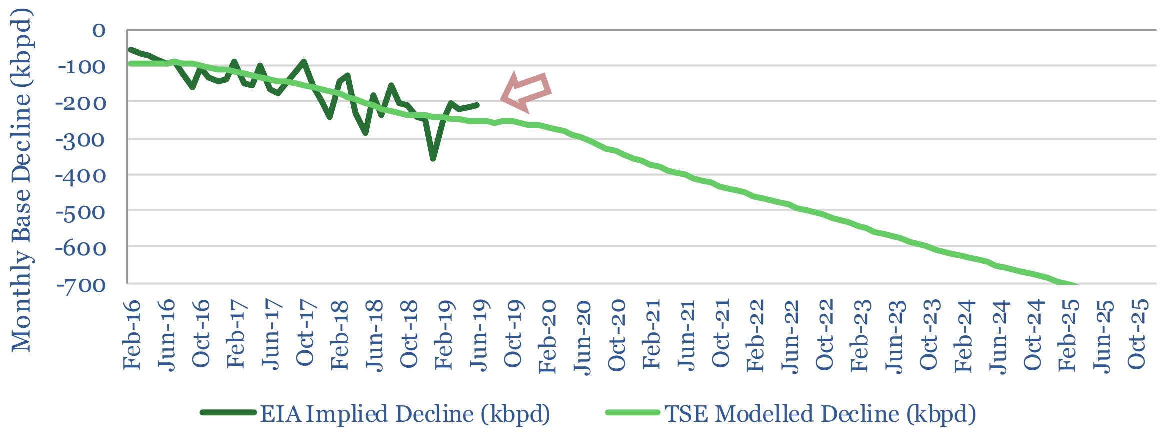
A key question concerns the causes behind the latest productivity decline and whether this decline is permanent. The answer to this question is not straightforward. When completing shale wells, an operator must make decisions on forty different dimensions (see Appendix for a detailed description). The multi-dimensional complexity is staggering. It overlooks a vast deal of completion complexity to leap to the conclusion that six months of disappointing productivity data connote a resource problem. Indeed, if the Permian were 'peaking', one would not expect the resource quality to deteriorate over a period of months, but years. 50,000 shale wells have been drilled in the basin to-date and we estimate another 50,000 can be completed, out to 2025, before resource degradation bites. Instead, it is necessary to delve into the data, to assess their significance.

Figure 5: Initial-month well productivity



Source: EIA, IEA, Baker Hughes, Companies, TSE modelling

Figure 6: Permian decline rates



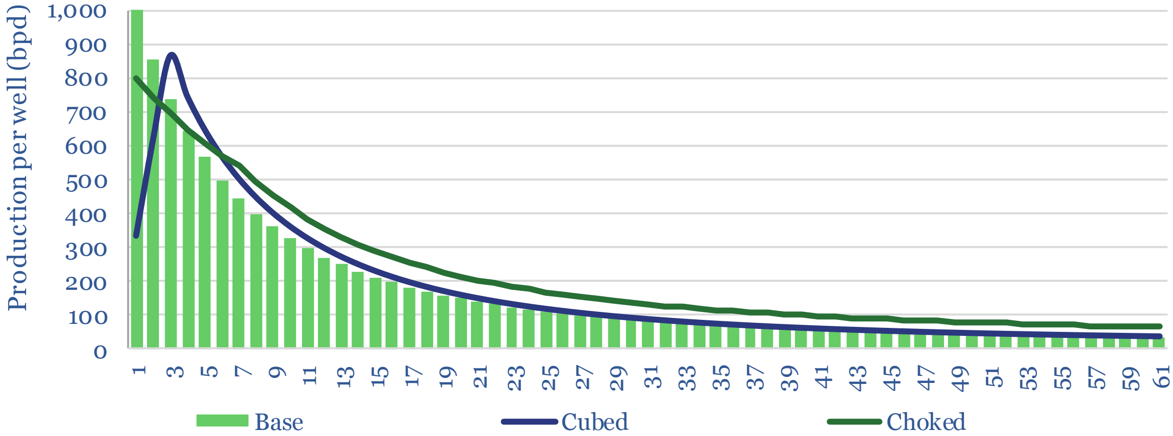
Source: EIA, IEA, Baker Hughes, Companies, TSE modelling

The data imply that completion designs are changing to yield less oil up front (Figure 5), but also lower declines (Figure 6). This need not be a net negative for overall recovery factors, and could even be a net positive. Specifically, our shale models forecast a monthly base decline for the Permian, using type curves that match historical data around the basin. This type curve is applied to each month’s cohort of wells. In 2Q19, based on the numbers of completed wells, a monthly decline rate of 250kbpd around the Permian was expected. In fact, the monthly decline has averaged 210kbpd since March. It implies wells are being brought online at a slower pace and are declining at a slower pace.

Are production profiles changing? Figure 7 shows two possibilities, which might explain the combination of lower IPs and lower declines: if more wells are being co-developed in “cube” pad designs, or if wells are being choked as they are flowed back.

Cube development is often cited as an antidote to parent-child issues in shale: If an operator fracs a parent well, then comes back months later to frac a nearby infill well, the stress shadow from the ‘parent’ will distort the fracture propagation in the ‘child’. Instead of propagating evenly, the fractures from the child well will propagate back towards the low-pressure rocks around the parent. The remaining rock will be under-stimulated, reducing productivity by around 20-40%. And if the fracture breaks through to the parent well, physically impacting it, then it is known as a ‘frac hit’.

Figure 7: Greater use of cube developments or well-choking would yield lower initial flow rates and lower subsequent decline rates



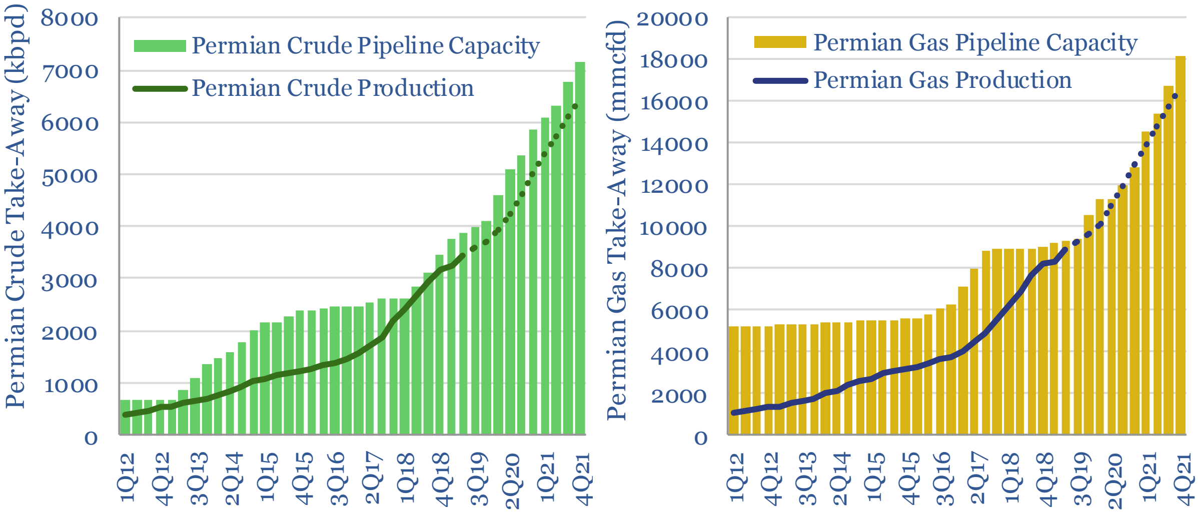
Source: EIA, IEA, Baker Hughes, Companies, TSE modelling

Parent-child issues are mitigated by co-development, aka ‘zipper fracs’, ‘tank development’ or ‘cube development’. Fraccing all of the nearby wells at the same time avoids pressure depletion, allowing even propagation of the fractures. However, fraccing multiple wells simultaneously takes longer. Over a number of months, several wells may be stimulated. But they are not flown back until stimulation has been completed in the entire area. This would artificially lower the “production per frac stimulation” in the month of the fracture treatment. But these wells would come on later, lowering the apparent decline rate in the basin. In fact operators alluded to co-development, giving evidence that this is happening. For example, ExxonMobil stated in its 2Q19 results: “There is communication between these horizontal benches. And if you go in and drill one bench now and expect to come back years later and drill the other benches, we do see or we do believe there's communication between the benches and it should dissipate. And our belief is that drilling of multiple benches simultaneously in the approach that I laid out appears to be the right way to go”.

Choking wells as they are flown back is another development decision that could explain lower initial production rates and lower long-term declines. Slower flowback can avoid flushing proppant out of fractures, thereby increasing production per well by around 15-30%.

Midstream bottlenecks provide the other reason to flow wells back on a choke. Flow the well back more slowly and you have fewer hydrocarbons to evacuate. Oil pipelines have had limited spare capacity this year. But gas pipeline capacity shortages have been severe (Figure 8). Gas flaring in the Permian reached a record of 660mmcfd in 1Q19 according to Rystad Energy, up from 200mmcfd in 2017. Gas pricing went negative at the Waha Hub in 2Q19. This bottleneck should be relieved from September, when Kinder Morgan’s new, 2bcfd Gulf Coast Express pipeline starts up, and as it ramps up in 4Q19. A further 2bcfd follows, with the Permian Express pipeline in late 2020. Operators also partly alluded to lower flowbacks. Using ExxonMobil as an example again, the company stated *"Drilling a single well and applying a larger completion with higher intensity fracture can yield higher IPs, but it may yield lower ultimate recovery versus drilling several wells with less intense completions"*.

Figure 8: Permian Crude and Gas Pipeline Capacity



Source: Companies, TSE modelling

Finally, the commentary on 2Q19's conference calls dispelled fears over rapid resource degradation. ExxonMobil stated the 'rocks and well performance is extremely strong'. Occidental brought online its best ever well in the Greater Sand Dunes area, with an IP24 of 9.5kboed. EOG's output beat the high end of production guidance for the second consecutive quarter. Chevron's management addressed the fears over Permian resource degradation directly, stating 'I'm not too worried about what some people see as a problem with these individual Permian wells'.

3. Peak 'Productivity' and Terminal Declines? Not Really

Last quarter's financial results or productivity data are already in the rear-view mirror. We argue in this comment that the best insights into the future potential of shale productivity are gained by reviewing the technical literature, which presents the ideas operators and service companies are looking to implement across their acreage in the future. The best, representative body of technical papers is the array presented at the prestigious, annual URTEC conference. If shale productivity was finally stalling, and the resource base was starting to deteriorate, one might expect to see the following trends in the technical literature:

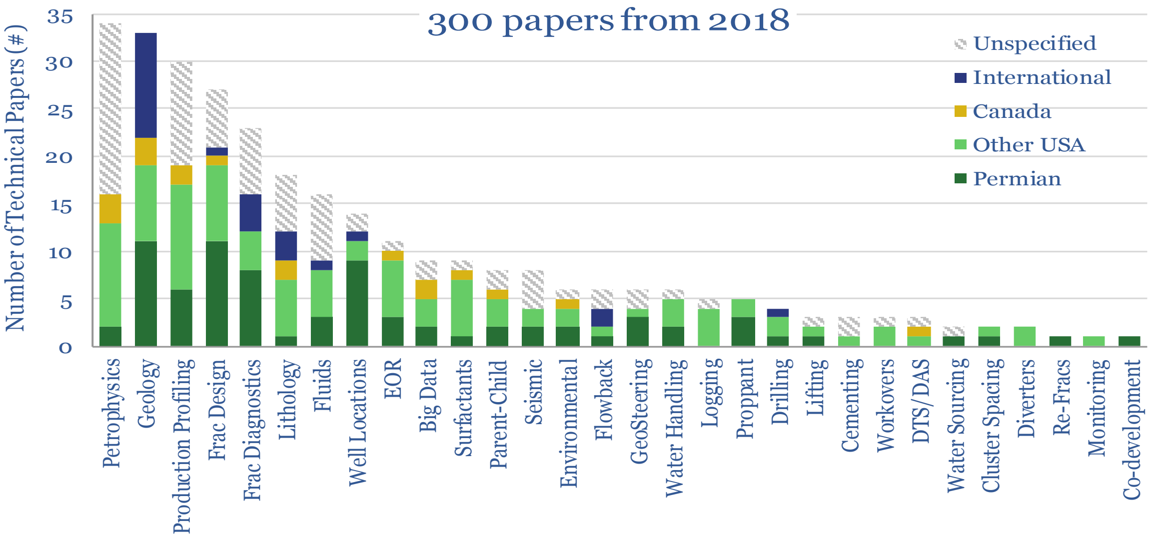
- ***Number.*** Shale productivity growth has been driven by technical research and development. Hence a slowdown in research and development within the technical literature might be expected to correlate with slowing productivity. However, this does not appear to case. 300 technical papers were published from around the shale industry at 2018's URTEC conference. This rose to 350 technical papers at 2019's URTEC conference (Figure 9).

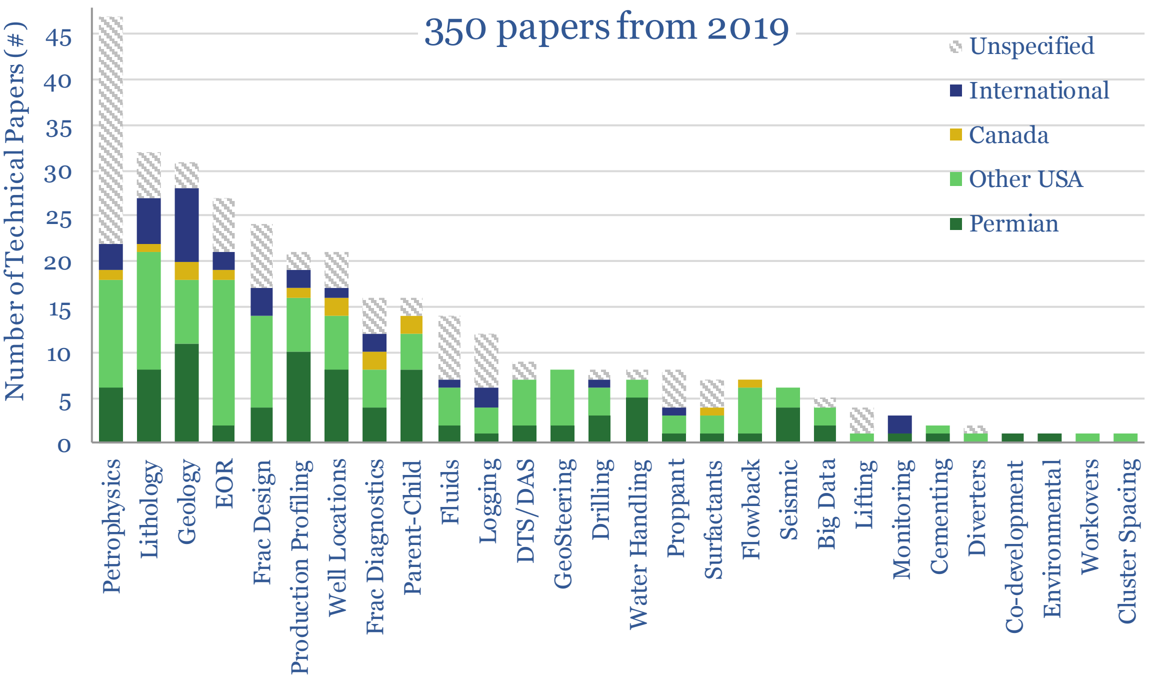
- ***Quality*** is distinct from quantity. We scored all the technical papers, to assess whether they might drive productivity higher, using a 1-5 scale. For 2018, the average score was 2.98. For 2019, it rose to 3.11 (Figure 10). 111 papers from the 2019 sample should materially contribute to improving future shale productivity, up from 93 in 2018.

- ***Expansion.*** If resource were running scarce in maturing basins, such as the Permian, Eagle Ford and Bakken, one might expect the industry's focus to start shifting elsewhere. Again, this was not the case. 38% of the papers filed around the industry focused on one of these core three basins in 2018, rising to 41% of all the technical papers in 2019 (Figure 11).

- ***Mysteries***. Once the petrophysics of hydraulic fracturing are fully understood, productivity gains may slow. But in 2019, the industry attacked the many remaining mysteries of petrophysical modelling with a new vigor, rising from 34 such papers in 2018 to 47 in 2019. Models increasingly incorporate anisotropy (from 12 in 2018 to 18 in 2019), wettability (11 vs 11), natural fractures (15 vs 11) and richer, multi-disciplinary data.

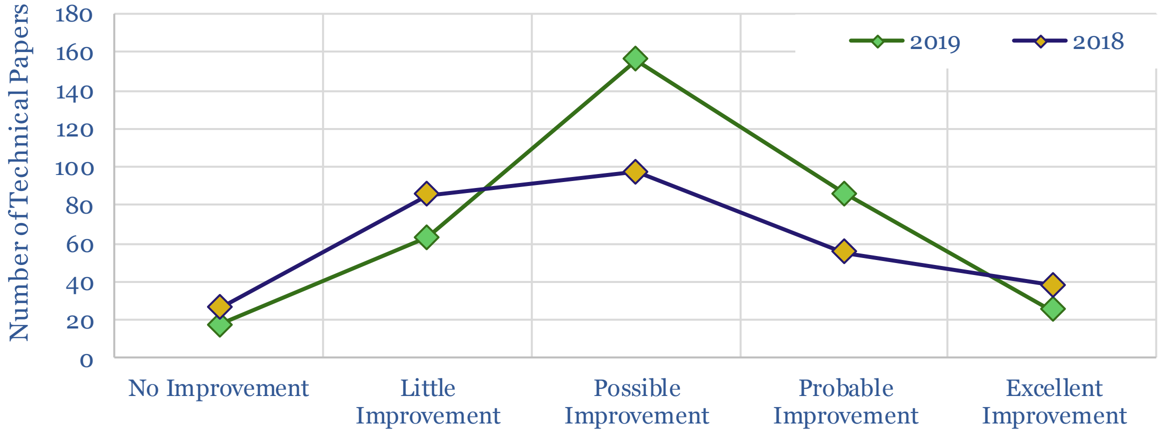
Figure 9: Number of technical papers published at 2018 and 2019 URTEC conferences





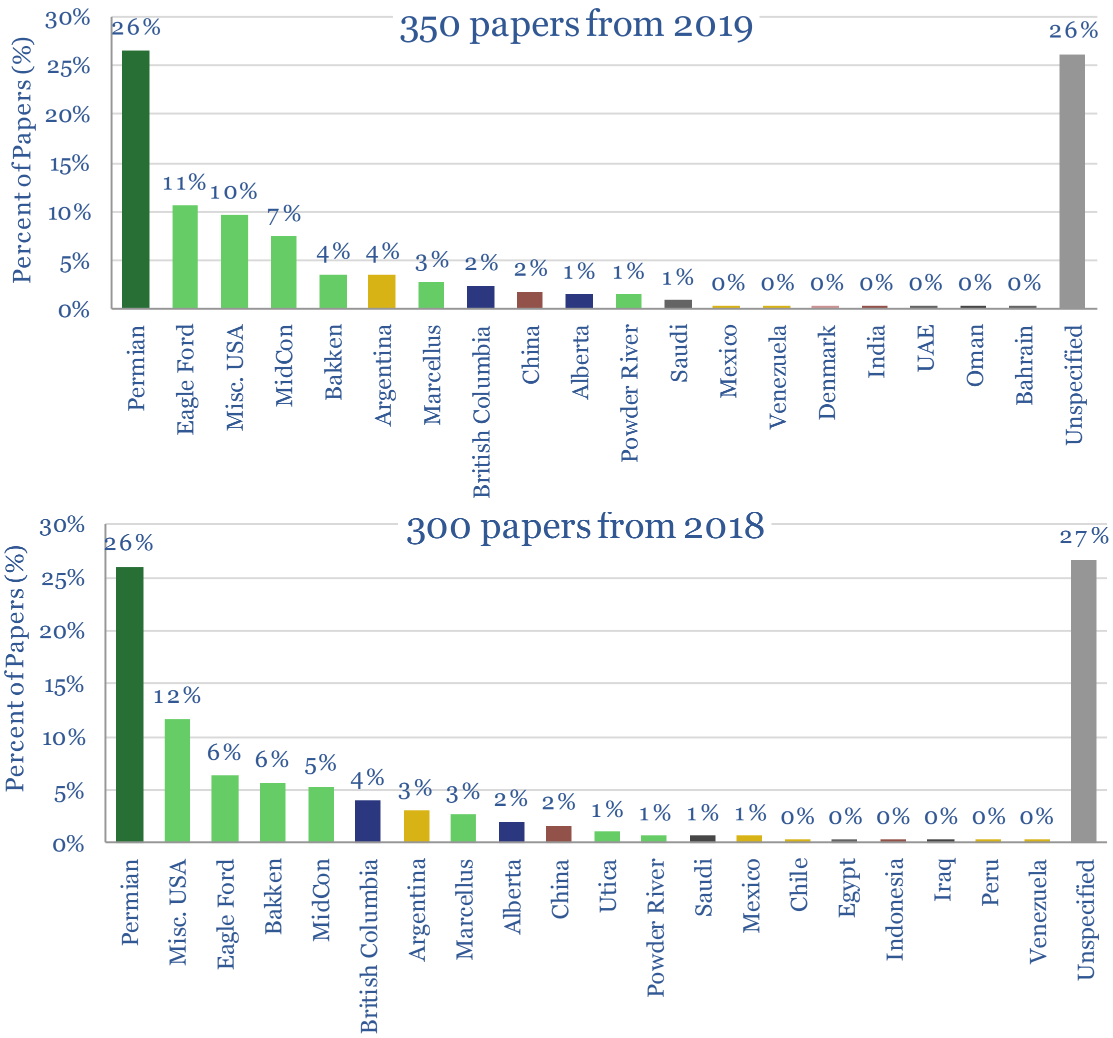
Source: 650 technical papers, TSE

Figure 10: Assessment of 2019's shale technical papers



Source: 650 technical papers, TSE

Figure 11: Technical papers published at 2018 and 2019 URTEC conferences by basin

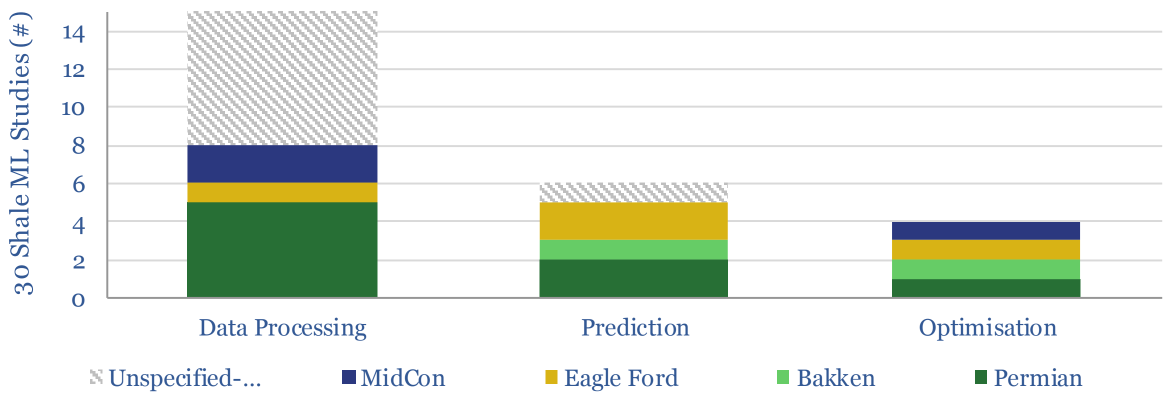


Source: 650 technical papers, TSE

- ***Problems*** increasingly being cited with the resource. The number of papers published into "parent-child" effects did increase from 8 in 2018 to 16 in 2019. 42% of these papers were in the Permian and 13% in the Eagle Ford. However, only one of these papers was unabashedly negative. Another noted that tight well spacing in the Marcellus would lead to more interference and lower EURs, but nevertheless, this scenario yielded higher NPVs per acre.[3] Others found the impacts of frac hits to be lower: one example in Reagan County, in the Midland basin finds *'The majority of parent wells were found to receive either small [Frac Driven Interactions] or no FDI at all; thus, FDIs do not appear to pose a major risk to reserves within the study area'.*[4] All the other papers offered tangible solutions. The most promising avenue is advanced geo-mechanical modelling, combined with frac diagnostic data, to optimise well spacings. But pre-loads, diverters and cube development were also discussed and were shown to be effective.

Digitalization is one of the most exciting routes to improve shale productivity. And there was no sign of any slowdown in the industry's adoption of digital technologies. Last year, 97% of our sample of 300 shale papers was 'data driven'. 32% of the papers from 2018 used advanced computer modelling, which will ultimately inform decisions in the field. This rose to 44% in 2019. But just five papers from 2018 used machine learning, or around 1.7% of the total papers. In 2019, the percentage of papers using machine learning quintupled to 25, or 7% of the total papers. Despite the YoY improvement, the industry remains far away from the aspiration of optimising its completions in real-time based on machine-learning algorithms. Most often, so far, machine learning in shale has been used to interpolate missing log data, classify lithology in cuttings/cores or predict type curves (Figure 12).

Figure 12: Most machine-learning in shale is for simple data-processing; only a handful of models optimise well placement, drilling or completion parameters



Source: 650 technical papers, TSE

Moreover, our sample includes 98 papers from 2018-19, to improve aspects of shale-development on the fly. 2019 included very high calibre papers, across different topics (Figure 13). 38% were in the Permian. These include:

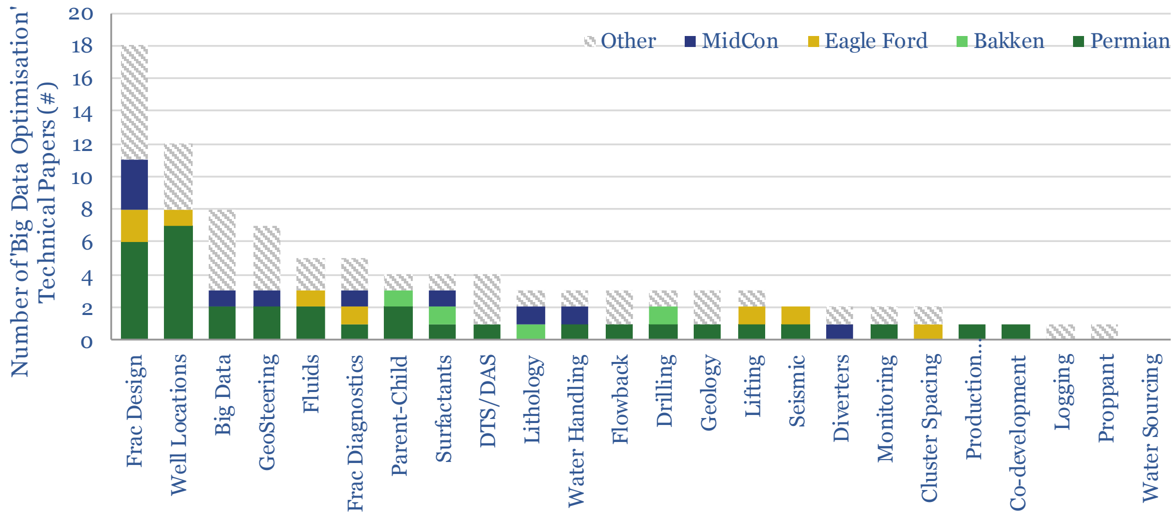
- ***Real time data from pressure gauges*** were used to map fracture propagation, instantaneously, in one study from the University of Texas and Devon Energy. The model's accuracy is not materially worse than a fully coupled 3-D poro-elastic simulation, and yet the

[3] Khodabakhshnejad, A., Zeynal, A. R., & Fontenot, A. (2019). The Sensitivity of Well Performance to Well Spacing and Configuration - A Marcellus Case Study. URTEC 2019.
[4] McDowell, B., Yoelin, A., & Pottebaum, B. (2019). Production Effects From Frac-Driven Interactions in the Southeastern Midland Basin, Reagan County, Texas. Unconventional Resources Technology Conference.

run-time is cut from 4-minutes to 1-second. This real-time capability is expected *"to greatly advance field capabilities for on the fly fracture design optimization".*[5]

- ***BP completed its most productive ever well in the San Juan basin***, choked at 13mmcfd for 7-months, based on a novel frac design, which was informed by modelling work that optimised the well location to overcome stress-shadowing effects. The well design included both diverters and a *"step up technique for increasing pumping rates during the pad stage".*[6]
- ***15-22% higher perforation efficiency*** was achieved in the Powder River basin by using drillbit geomechanics to measure variability along lateral wells, and then space each stage to minimise the minimum horizontal stress around it. The workflow is developed by Services firm, Fracture ID.[7]

Figure 13: The most common use of big data-optimisation studies was in frac design, but also to determine better well locations, geosteering and frac fluids



Source: 650 technical papers, TSE

The most noticeable trend in the entire corpus of 650 technical papers that we reviewed, is the explosion of interest into shale-EOR[8] in 2019. There were 14 studies into shale-EOR in 2018, rising 2.3x to 32 studies in 2019. They are summarised in Fig 14.

What is surprising in the subsequent 2019 technical literature is the emerging dominance of CO_2 as the preferred injectant for huff-n-puff EOR in shale. The technical literature continues to de-risk this technology: 25 of our studies model the process extensively, to comprehend how CO_2 will swell oil, reduce viscosity, vaporize oil, change oil wettability and pressurise wells. Some of the papers also use advanced diagnostic techniques, such as scanning electron microscopy or infra-red.

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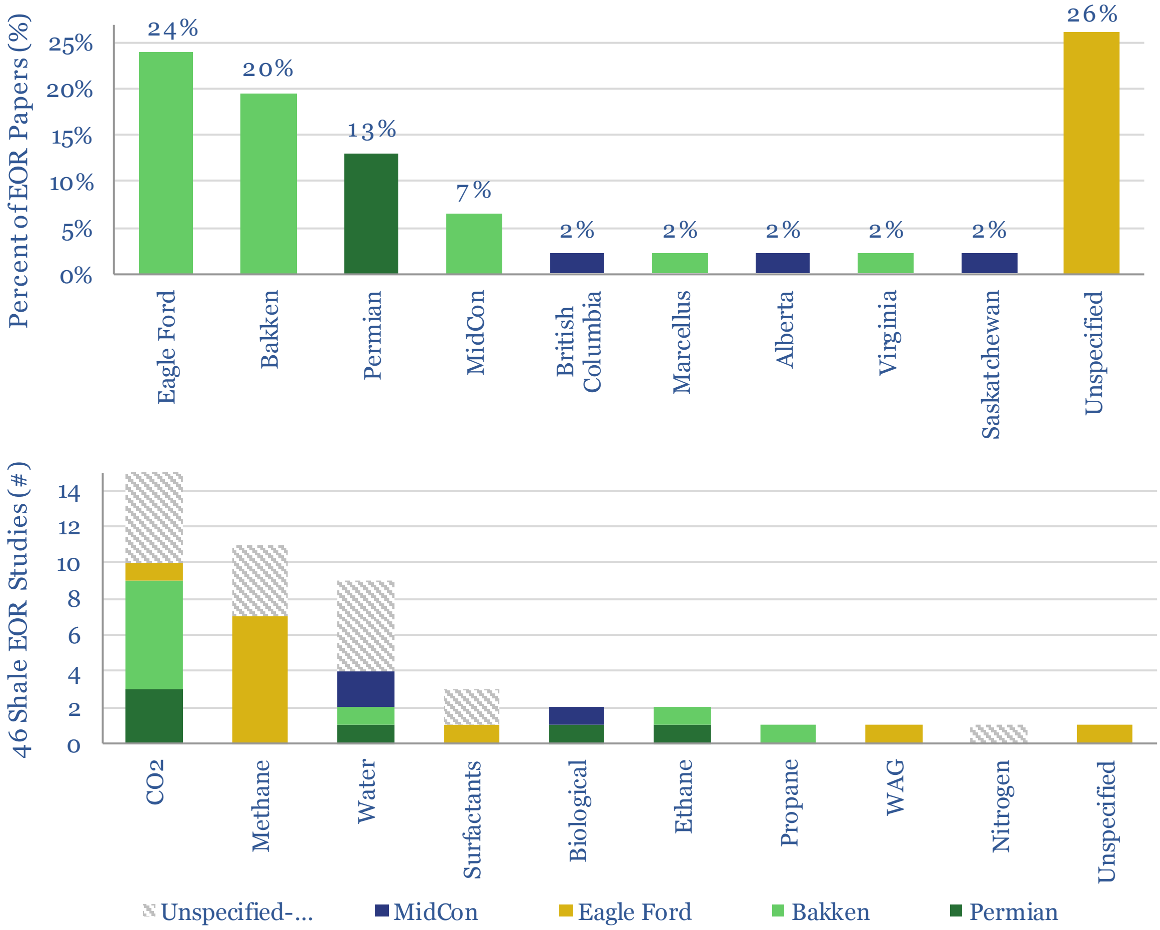
[5] Elliott, B., Machanda, R. & Seth, P. (2019). Interpreting Inter-Well Poroelastic Pressure Transient Data: An Analytical Approach Validated with Field Case Studies. URTEC 2019.
[6] French, S., Gil, I., Cawiezel, K., Yuan, C., Gomaa, A., & Schoderbek, D. (2019). Hydraulic Fracture Modeling and Innovative Fracturing Treatment Design to Optimize Perforation Cluster Efficiency, Lateral Placement, and Production Results in a Mancos Shale Gas Appraisal Well. URTEC, 2019.
[7] Scott, E., Ramos, C., & Romberg, E. (2019, July 31). Drill Bit Geomechanics and Fracture Diagnostics Optimize Completions in the Powder River Basin. URTECT, 2019.
[8] TSE's full review of the Shale-EOR opportunity can be downloaded here: https://thundersaidenergy.com/2019/05/22/shale-eor-container-class/

Figure 14: 46 papers into Shale-EOR are concentrated in the Eagle Ford (mainly using natural gas) and in the Bakken and Permian (mainly using CO2-EOR).



Source: 650 technical papers, TSE

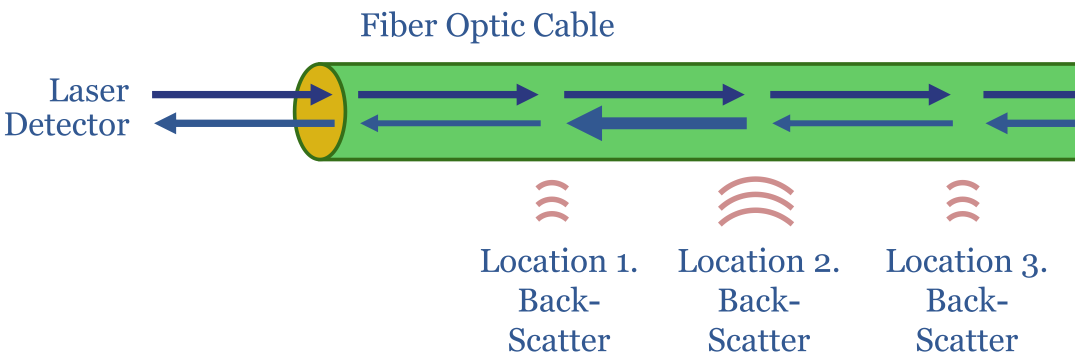
One of the challenges for EOR that we have identified is the need for effective containment downhole, in order to implement a huff-n-puff. But interestingly, a small number of papers began testing foams which could improve containment. At the more experimental stage, biological processes are being used to enhance recovery in shales. A field test was conducted of injecting microbial nutrients to a shale well, allowing beneficial microbes to degrade residual fracturing fluids, effectively unblocking the flow of further oil: 25kbbls of incremental oil was thus recovered from a horizontal well in the Permian, with an IRR above 100%.[9] Another study lab-tested Woodford cores and suggested that enzymes could be used to improve recovery factors by 20-25%.[10]

Distributed Acoustic Sensing is another technology that can drive further shale-productivity[11]. By running a fiber-optic cable down a well, it is possible to “hear” flow along the well, meter-by-meter, in real time (Figure 1). This can be used to optimise completions. The best studies to-date have achieved around 25% production uplifts and around 10% cost-savings using DAS. The 2019 technical

[9] Jin, X., Pavia, M., Samuel, M., Shah, S., Zhang, R., & Thompson, J. (2019). Field Pilots of Unconventional Shale EOR in the Permian Basin. URTEC-2019.
[10] Salahshoor, S., Gomez, S., & Fahes, M. (2019). Experimental Investigation on the Application of Biological Enzymes for EOR in Shale Formations. URTEC-2019.
[11] TSE’s full review of the DAS opportunity can be downloaded here: https://thundersaidenergy.com/downloads/distribution-costs-ships-trucks-trains-and-deliveries/

literature provides further progress. The number of studies using the technology trebled from 3 in 2018 to 9 in 2019. Pioneer, Conoco, Devon and Apache all published papers trialling the technology. In a paper with Optasense, in the SCOOP/STACK, Devon concluded that *"Current fiber-optic technology can provide enough sensitivity to map seismic anomalies which we can integrate with temperature and strain data for an improved reservoir description".*[12] In a paper from the Permian, Pioneer concluded *"time frequency analysis enhances the ability to monitor and optimize well treatments".*[13]

Figure 1: Distributed Acoustic Sensing to "hear" along fiber-optic cable



There are also some final frontier-areas that stood out from the technical literature, which will also continue to improve shale productivity:

- Fluids and surfactants remain an exciting area, aiming to optimise the chemistry of hydraulic fracturing. These two topics drew 14 and 7 papers, respectively, in 2019. In one example, in the Permian, an optimal class of surfactants was modelled to uplift production rates by 39%, by altering the wettability of the shale, so that more oil is expelled.[14] Further examples are shown in our full database.

- Controlled flowback of wells was one of the methods we postulated above to explain the observation of lower initial production rates and lower decline rates. In this vein, results were presented by Schlumberger, keeping bottom-hole pressures and production rates within a secure operating envelope in the Powder River Basin, reducing the flowback of proppant from 75,000 lbs per well, to 30 lbs. The 15 wells using this methodology thus became the top quartile producers within the play.[15]

- Soaking times. Apache tested the impacts of soaking times, finding that imbibition of fluids to the formation during long shut-ins can increase the gas flow-rates, and decrease the water-rates in shale. This may be helpful as gas flow can drive oil flow, while 8:1 water-cuts on the Delaware side of the Permian are placing a strain on water disposal infrastructure.[16]

- Multi-laterals. Conoco and Halliburton tested a new Level 4 junction to improve the viability of multi-lateral development in the Eagle Ford. The test was successful in "mechanically and

[12] Chavarria, J. A., Kahn, D., Langton, D., Cole, S., & Li, X. (2019, July 31). Time-Lapse WAW VSP Imaging of an Unconventional Reservoir Using DAS Fiber Optics. URTEC-2019.
[13] Jayaram, V., Hull, R., Wagner, J., & Zhang, S. (2019, July 31). Hydraulic Fracturing Stimulation Monitoring with Distributed Fiber Optic Sensing and Microseismic in the Permian Wolfcamp Shale Play. URTEC-2019.
[14] Bidhendi, M. M., Kazempour, M., Ibanga, U., Nguyen, D., Arruda, J., Lantz, M., & Mazon, C. (2019). A Set of Successful Chemical EOR Trials in Permian Basin: Promising Field and Laboratory Results. URTEC 2019.
[15] Campos, M., Potapenko, D., Moncada, K., & Krishnamurthy, J. (2019, July 31). Advanced Flowback in the Powder River Basin: Securing Stimulation Investments. URTEC 2019.
[16] Ibrahim, A. F., Ibrahim, M., & Chester, P. (2019, July 31). Developing New Soaking Correlation for Shale Gas Wells. URTEC 2019.

hydraulically isolated during the stimulation of both laterals". We are positive on multi-laterals, as they can amortise the costs of vertical wellbores across multiople horizontals. But the barrier so far has been the structural integrity of the junctions where the second lateral is kicked off[17].

4. Conclusions

Fears over the shale industry re-erupted in 2019. Some worry that the best resources have now been produced and productivity has peaked. However, we find these conclusions are premature, as they are based on backward-looking, volatile data. By contrast, to provide forward-looking indicators, we have assessed the industry's innovation across a longitudinal sample of 650 technical papers from 2018-2019. Our methodology is very different from listening to the commentary on earnings calls, which tends to be backwards looking, very high-level, and shies away from technological innovations that are on the cusp of commercialisation. We believe the trends in US shale are still constructive. The quantity, quality, basin-focus, technical-focus and methodologies of these papers all imply continued productivity gains, not problems. The most exciting innovation areas are in enhanced oil recovery, digital instrumentation, machine learning, advanced modelling and overcoming parent-child issues. Therefore it is premature to discount the shale industry yet.

[17] Wilcox, D., Cappiello, S., Sevilla, M., Shafer, E., Gill, G., Kress, I., & Sanchez, N. (2019, July 25). Multilaterals: An Unconventional Approach to Unconventional Reservoirs. URTEC 2019.

Appendix. There are at least forty variables to optimise in a typical shale well

Variables to Optimise		Observations
Geology	- Landing Depth - Sweet Spots - Geological Features	- Automated geosteering finds the best landing zone in real-time - Basin models still improving; new sweet spots demarcated each year - Advanced models place wells around natural fractures / barriers
Pads	- Well Spacing - Pad Design - Lateral Orientation - Zipper Fracs - Completion Order	- Balanced using data, to maximise acreage's stimulated rock volume - E.g., two larger wells can recover more oil than three smaller wells - Fracturing can be oriented by positioning wells relative to SH-Max - Zipper-fracs, "cube" design or pre-loads improve productivity - Advanced models prioritise well ordering based on data
Stages	- Plug'n'Perf or Sleeves? - Stage Positioning - Stage Sequencing - Stage Spacing - Stage Isolation - Heels	- Plug'n'perf ubiquitous, but some still see potential in pinpoint fracs - Improved when grouped across similar rock (e.g., Poisson's Ratio) - c50s/well average; 30% uplifts tailoring each stage to local rock - c200ft average. More stages allows for greater precision. - Monitored to avoid leakage inhibiting stage-productivity by 50% - Distinct design and remedies to overcome missed pay proneness
Perforations	- Depth - Geometry - Clusters per Stage - Cluster Spacing - Flow Per Cluster - Distributed Sensing	- Limited entry unlocks more resource than long frac wings - Geometric clusters rubble-ize better than variable clusters - c8 guns/stage is average, some use >15, DAS helps optimise number - Some studies find 50% uplift from 2x tighter spacing; others don't - Heel-side clusters still most likely to take disproportionate flow - Real-time cluster visibility with 100x better signal:noise ratios
Fracturing Fluids	- Rate - Viscosity - Acidity - Surfactants - Salinity - Clay Stabilizers - Interactions with rock - Other Additives	- Ave is c35bbls/ft, at 0.4bbls/ft/min. Doubling can double EUR. - Low-viscosity, friction-reduced fluids outperform gels/hybrids - Complex. Breaks rock, alters wettability, but also clay chemistry - c15-30% EUR uplifts observed for emulsifying surfactants / SASI - c5-10% uplifts achieved by lower salinity injectants - c70% uplifts from avoiding detrimental clay chemistry - c20% uplifts from tailoring frac fluids to mineralogy - c30-50%+ uplifts from nano-scale additives via ion-exchange
Proppant	- Concentration - Size - Strength - Variation - End of Stage	- c1,750lbs/ft ave. Each additional 1,000T raises type curve 15-20% - Low costs of 100-mesh justify lower crush strength - Ceramic- and resin-coated proppants often not cost-effective - Real-time monitoring avoids screen-outs or runaway clusters - Preserve larger fractures with stronger or rod-shaped proppants
Diverters	- Diverter Drops - Near-field or far-field - Diverter Types	- Doubling pods reduces half-length c15%; may uplift EUR 30%+ - Diverter size determines distance travelled into formation - Pods outperform sand-ramps; polymer decomposition varies
Flowback	- Flowback Rates - Pump Monitoring - Pump Optimisation - Re-Fracturing - Enhanced Recovery	- c15-30% uplifts from preserving more proppant in formation - c5% production uplifts diagnosing pump outages in real-time - c5% production uplifts achieved by machine learning on pumps - 30-50% production uplifts achieved by best targeting of missed pay - 1.5-2x production uplifts achievable via huff'n'puff

Source: OnePetro, TSE