SPE de Argentina Asociación Civil

HYDRAULIC FRACTURING IN UNCONVENTIONAL RESERVOIRS

OVERVIEW, RECENT TRENDS AND CHALLENGES

Nov 19th, 2019

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Source: freeworldeconomicreport.com, 2017

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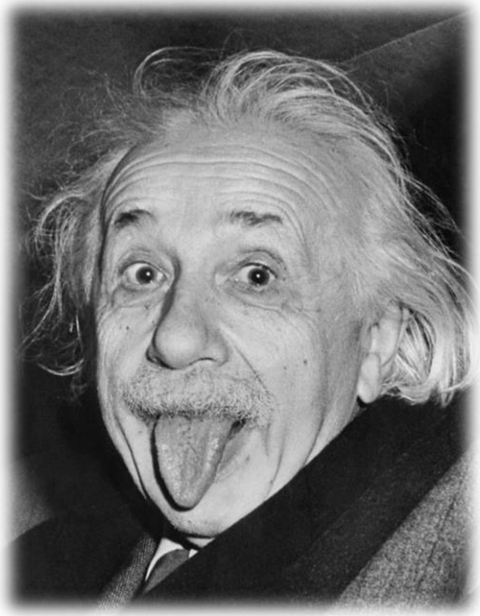
Initial Quote

"If you can't explain it simply, you don't understand it well enough".



Source: Getty Images

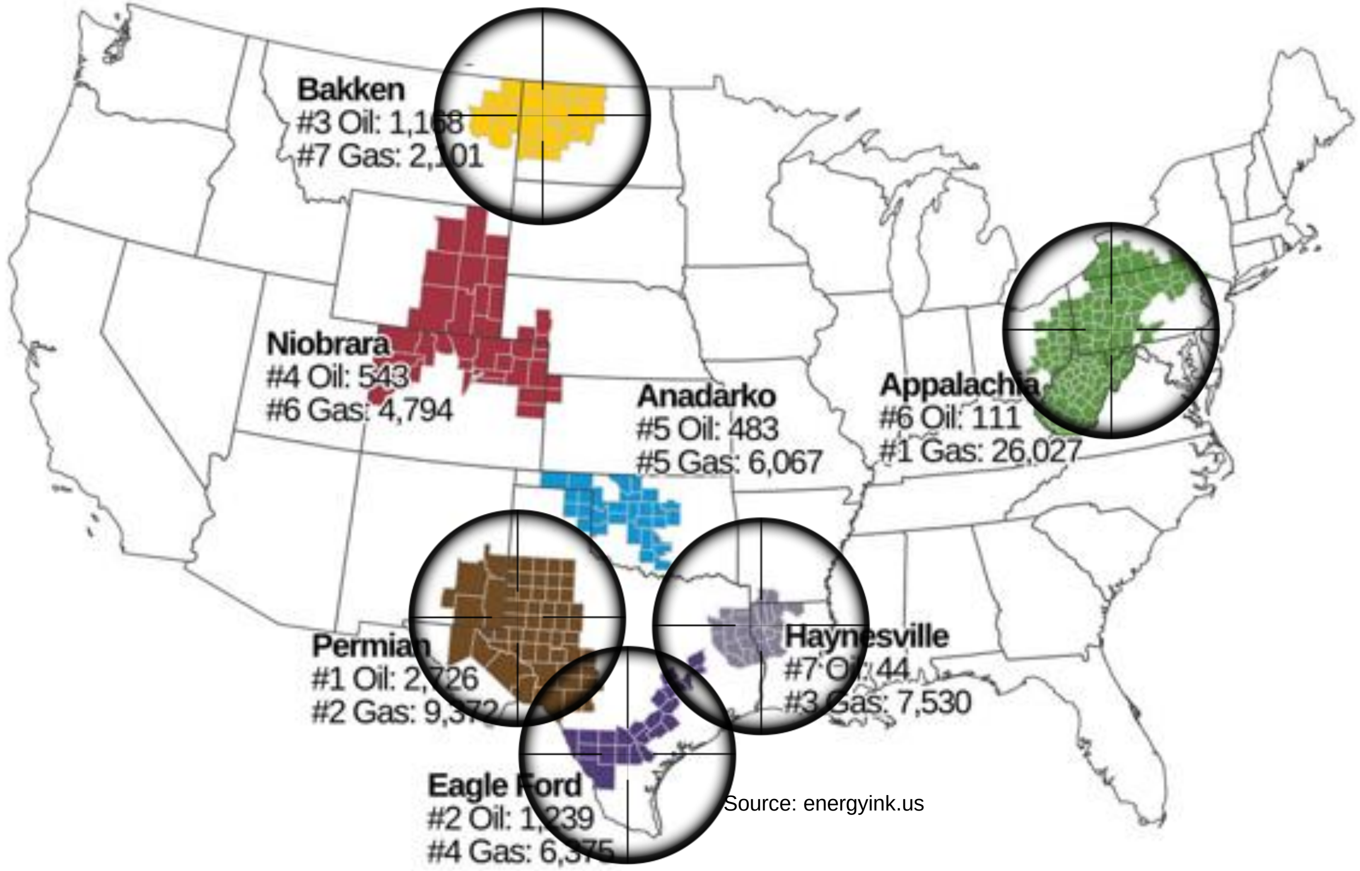
Source: Wikimedia Commons

World Geopolitical & Economical Context

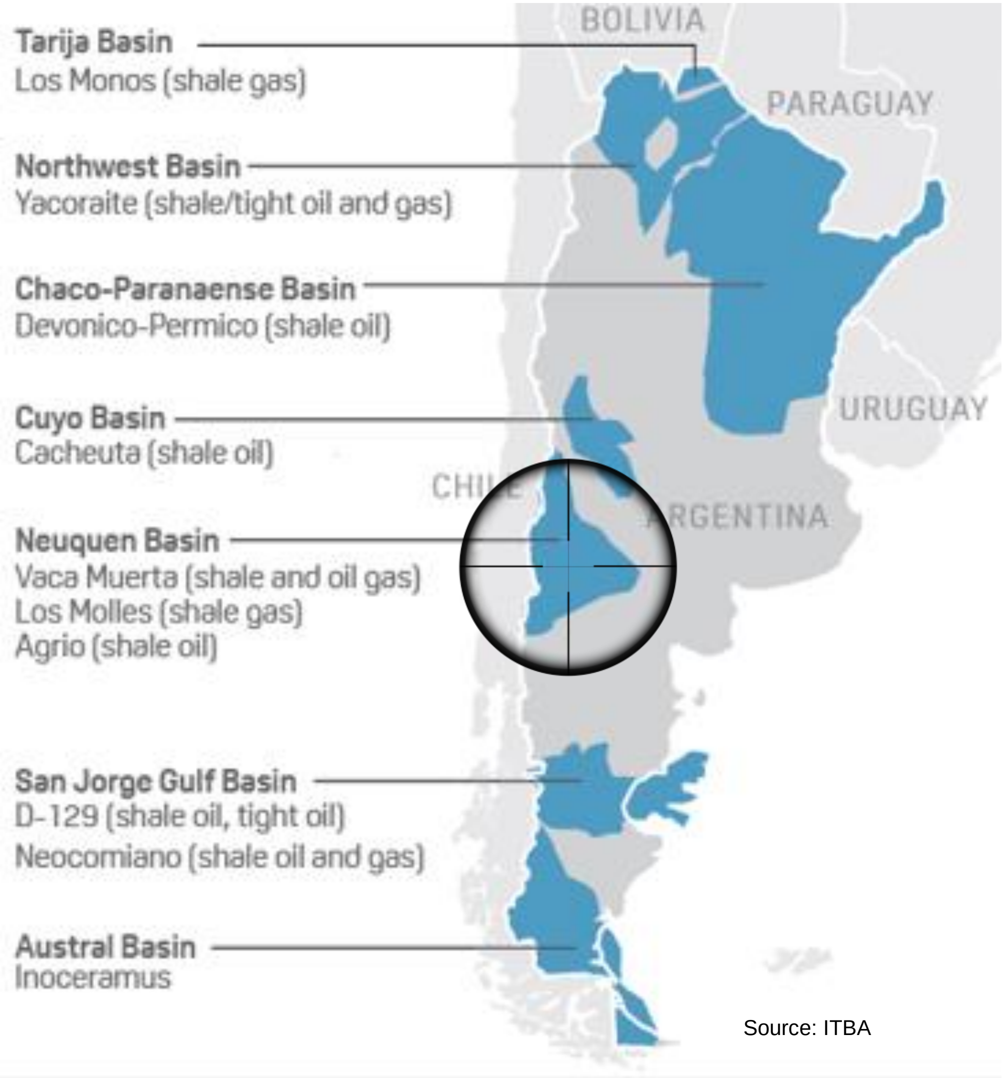
- ✓ Despite the increasing proliferation of alternative energy sources, oil and gas production continues to play an important role in the global economy.
- ✓ Oil price averages at ~ 60 USD/bbl. No signs of rise in the short term. OPEC in the path of stability for 2020.
  - Oil price mostly decoupled from conflicts in Middle East.
- ✓ US ranks as the country with the highest oil and gas production in the world.
  - A large portion of oil production comes from tight oil and gas mostly from tight and shale gas plays.
  - Resurgence of downstream industry. Cheap gas is a major reason why.
  - LNG export is a reality but friction with Europe and Asia has emerged.
- ✓ Not all companies are making money in the shale business.
  - Several companies have filed bankruptcy. Private and small public companies are the most affected ones.
  - Wall street has put serious doubts and investors are retracting their interest in shale. Panic amongst investors!
  - Unfortunately not all analyses have proved right and have some bias but the damage has been done.
  - In response companies are reducing budgets, staff, production goals and focusing on returns for investors rather than optimizing reservoir management. Majors continue pouring billions arguing integrated well-to-refinery network is key.
  - Service companies are struggling as a consequence of operators' expending cuts. Layoffs.
- ✓ Argentina on top of world issues has its own "difficulties". (Sorry, but I am limited in time to discuss this topic).

Source: freepngclipart.com

US & ARG's Most Important Shale Plays – On Development

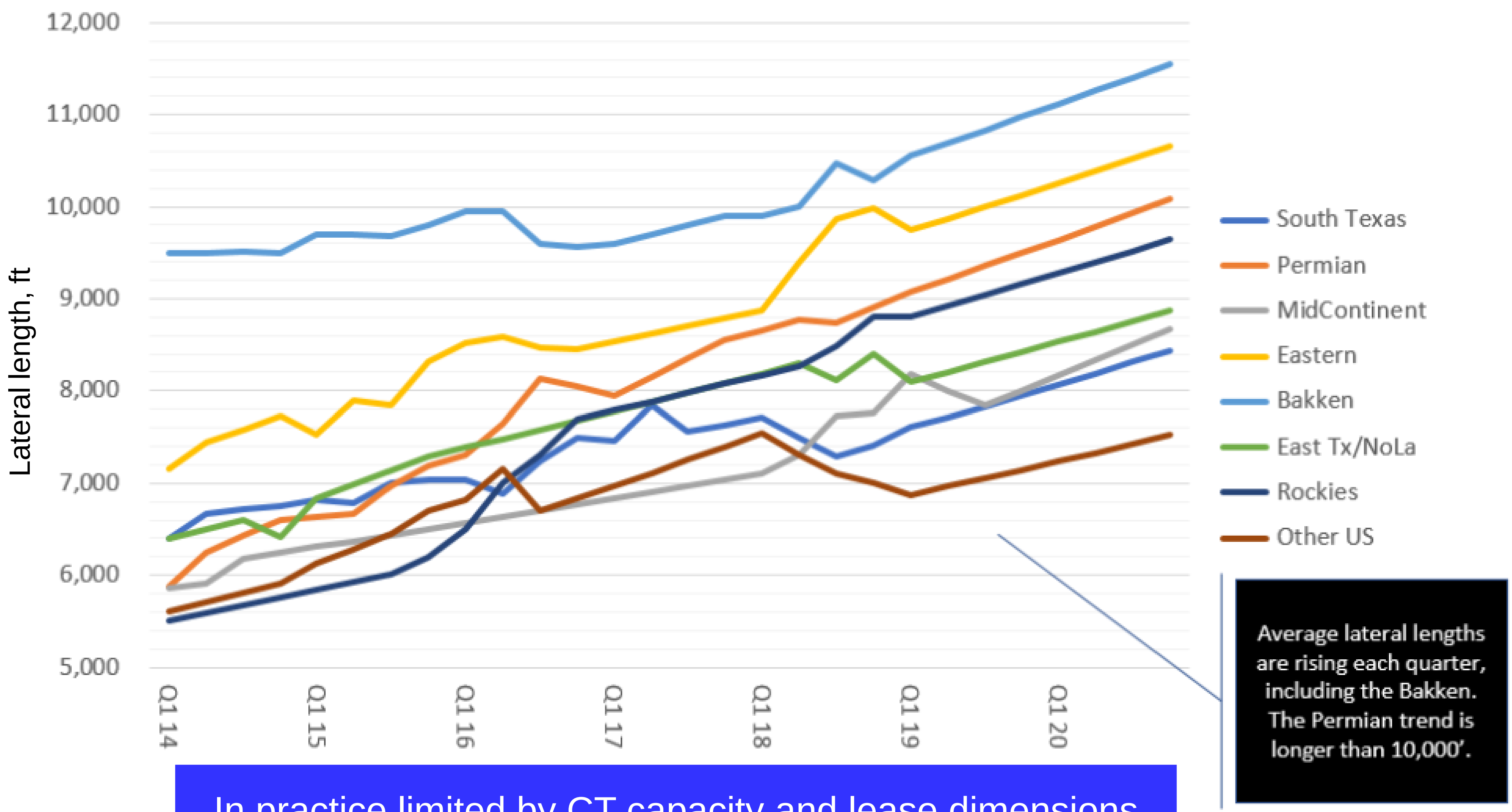


Source: energyink.us



Source: ITBA

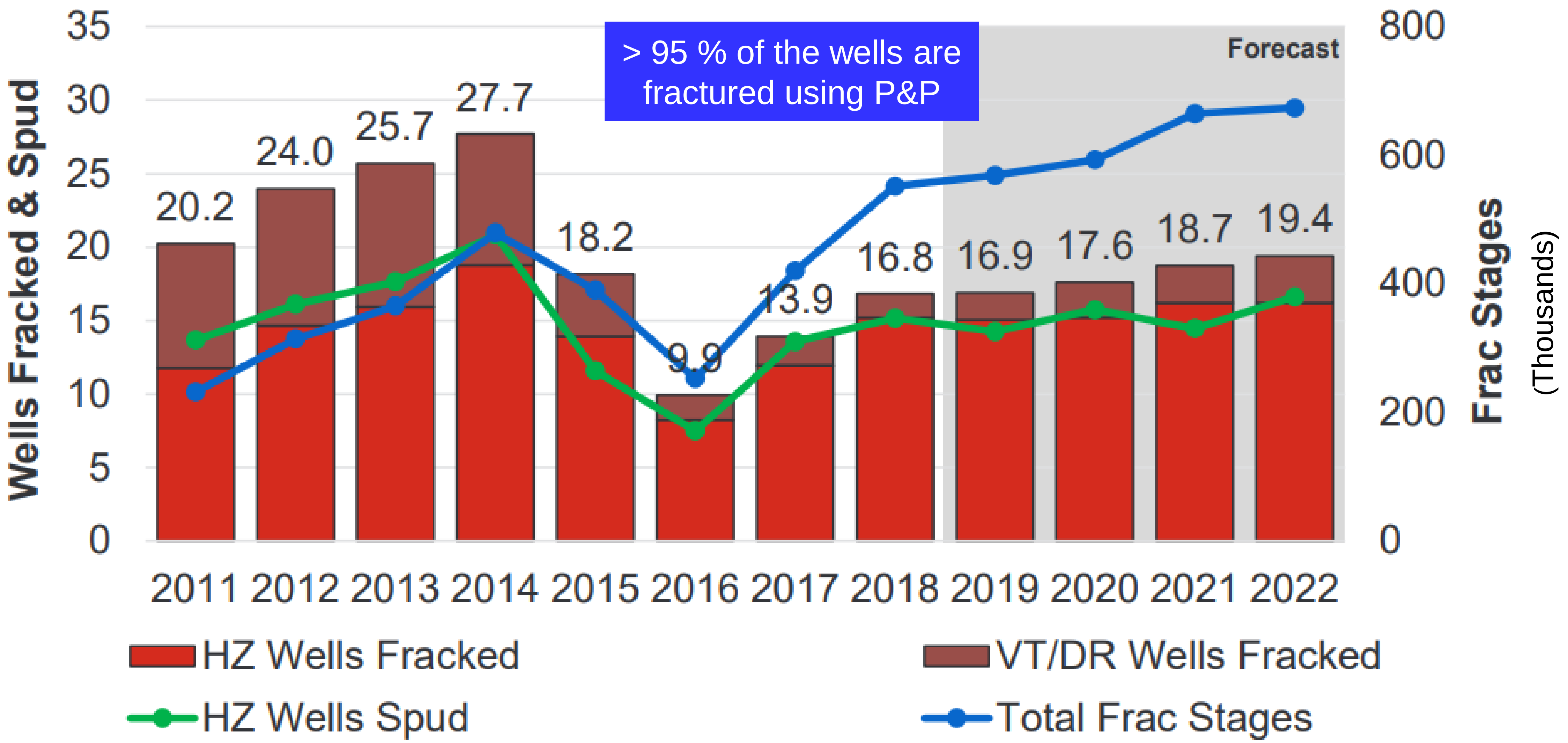
US Horizontal Wells – Lateral Length (average)



In practice limited by CT capacity and lease dimensions

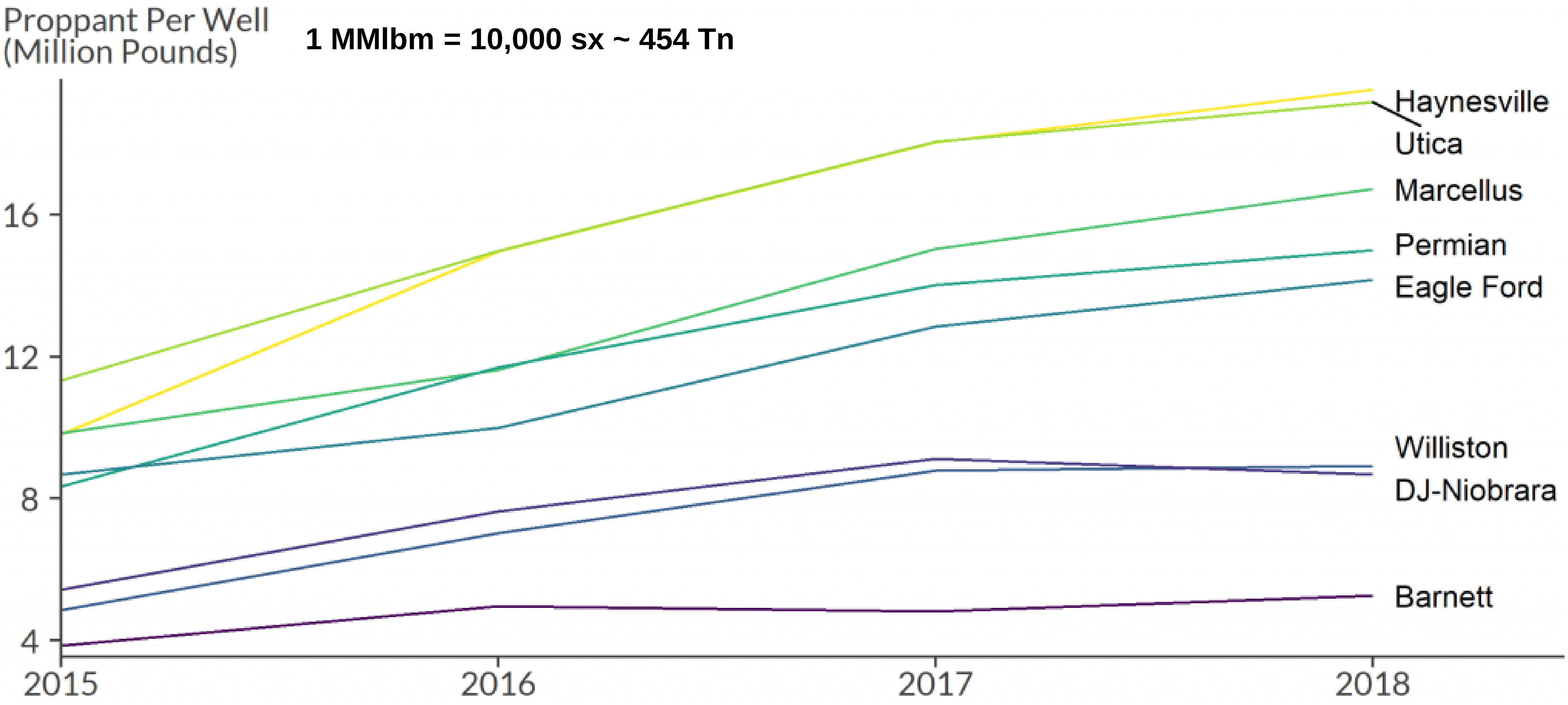
Source: Spears & assoc., 2019

US Horizontal Wells – Stage Count



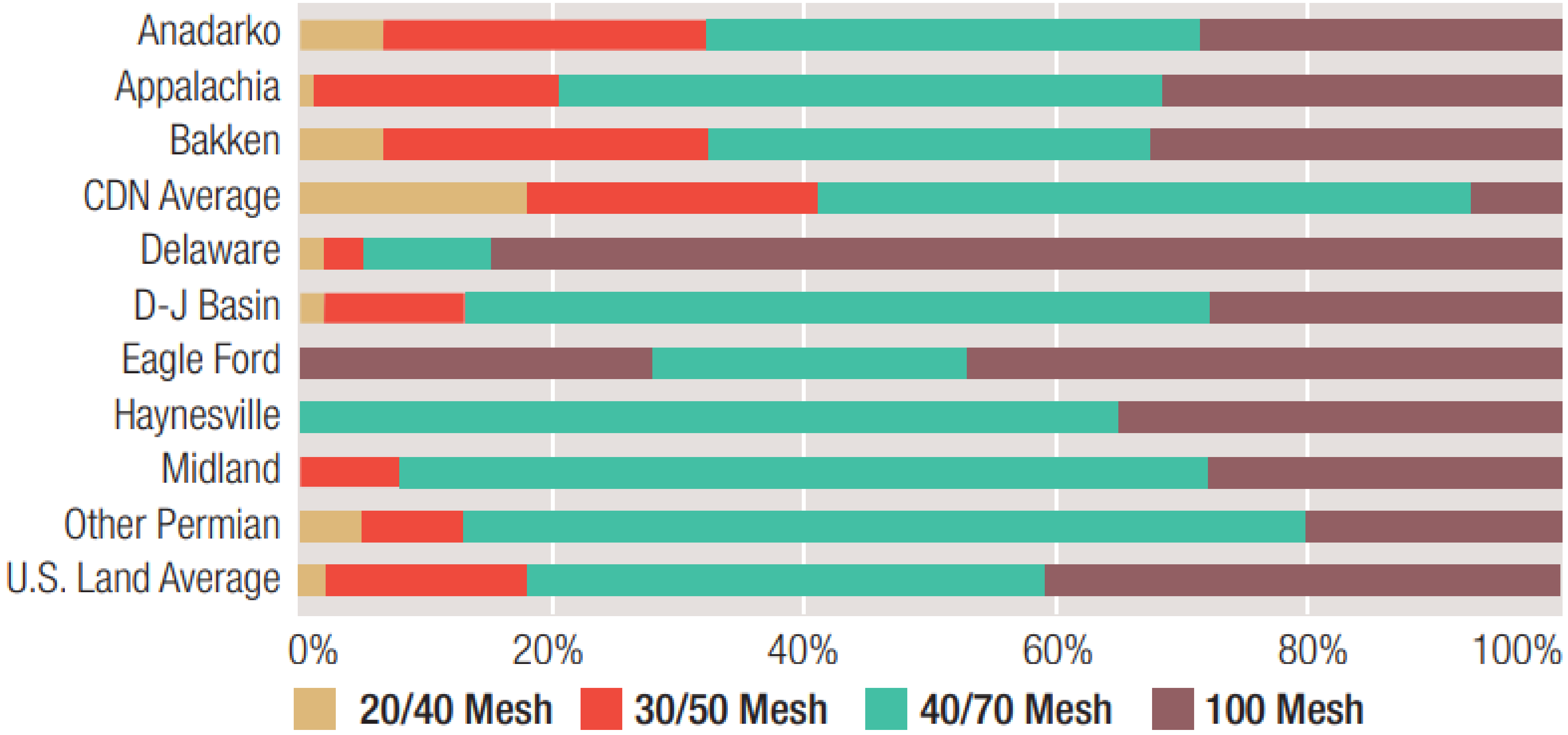
Source: Rystad Energy, 2019

US Horizontal Wells – Proppant per Well (average)



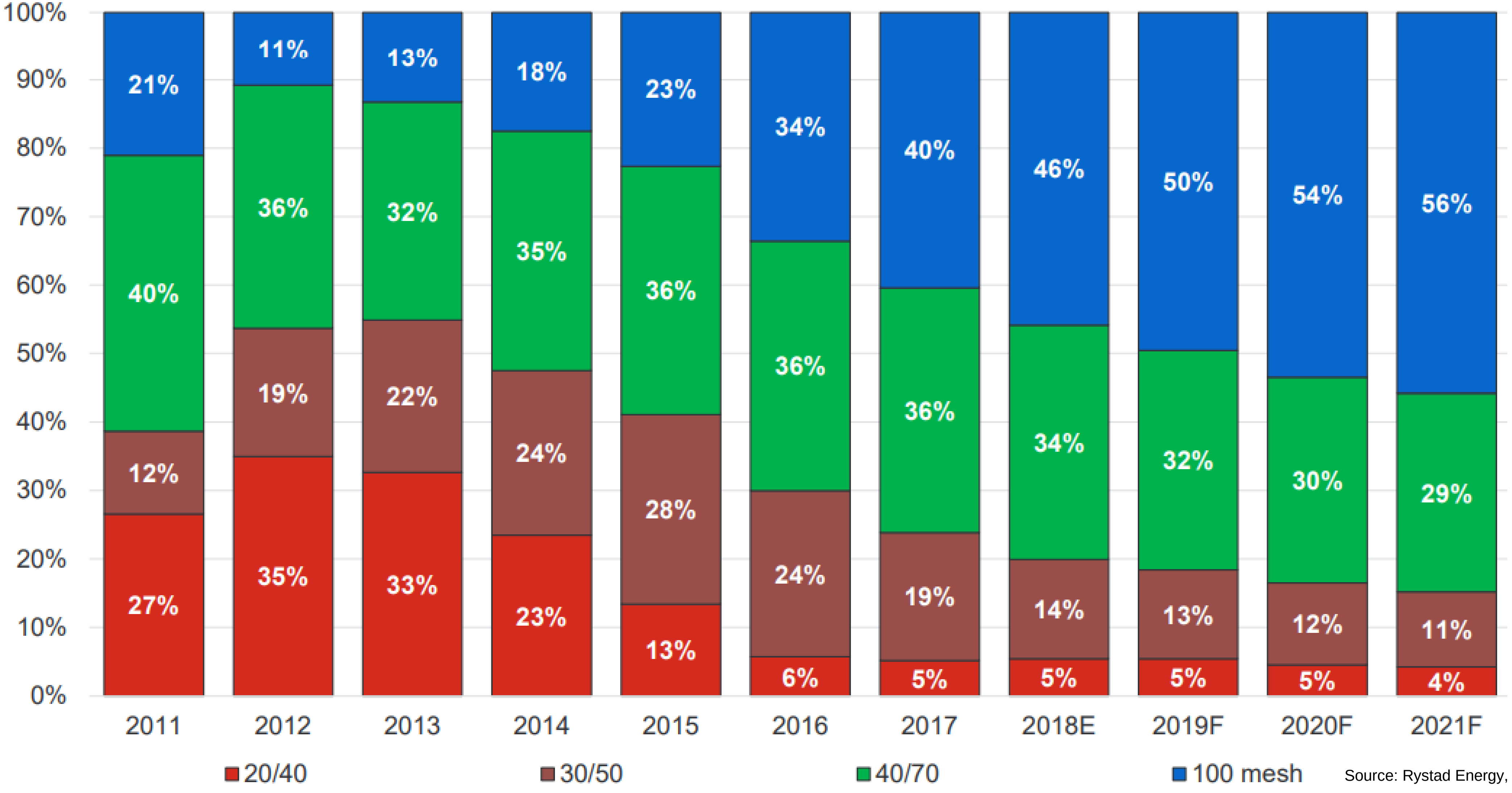
Source: Energent, 2019

US Horizontal Wells – Proppant Consumption per Mesh



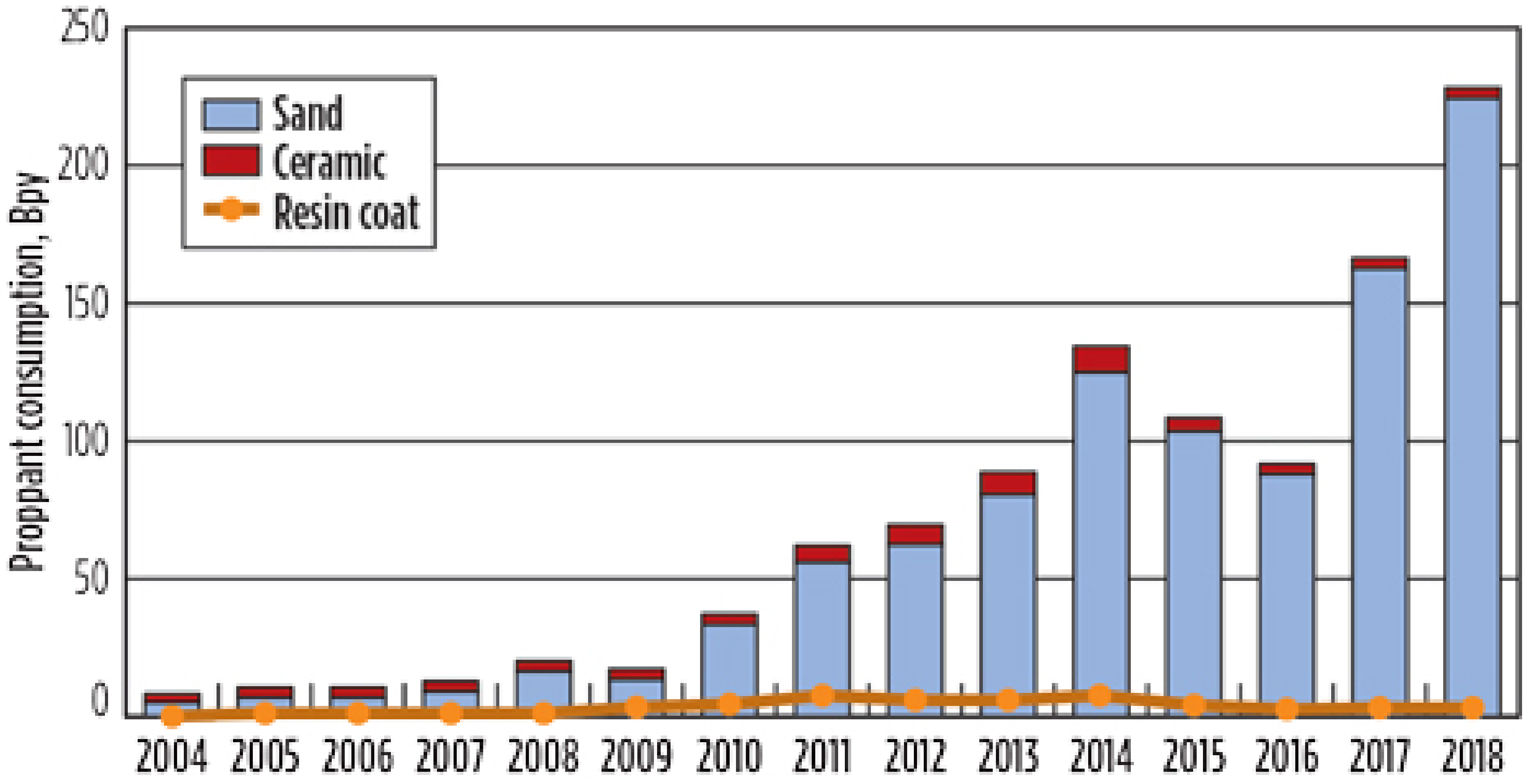
Source: HIS Markit, Seaport Global Securities, 2018

US Horizontal Wells – Proppant Consumption per Mesh



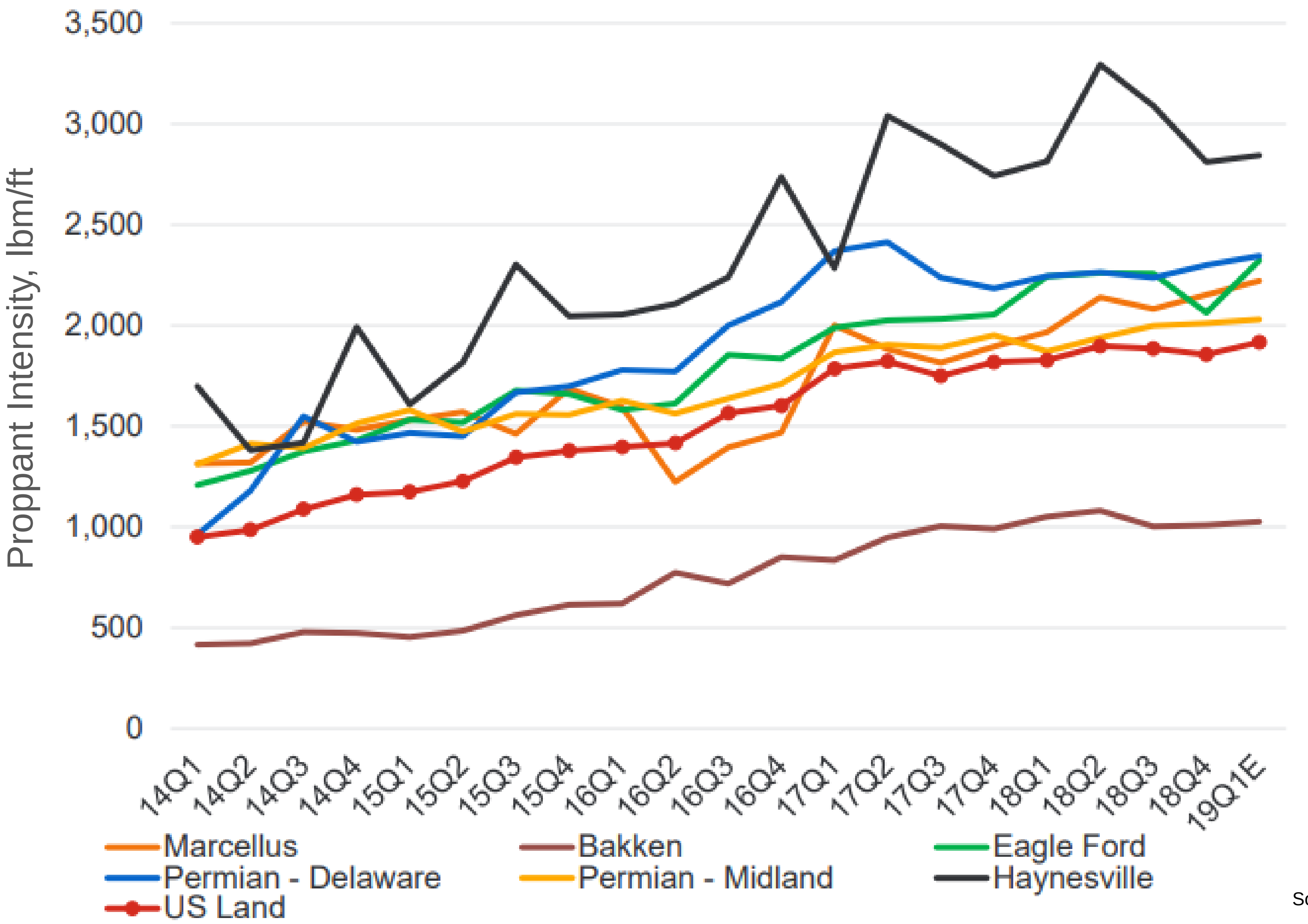
Source: Rystad Energy, 2019

US Proppant Consumption per Type



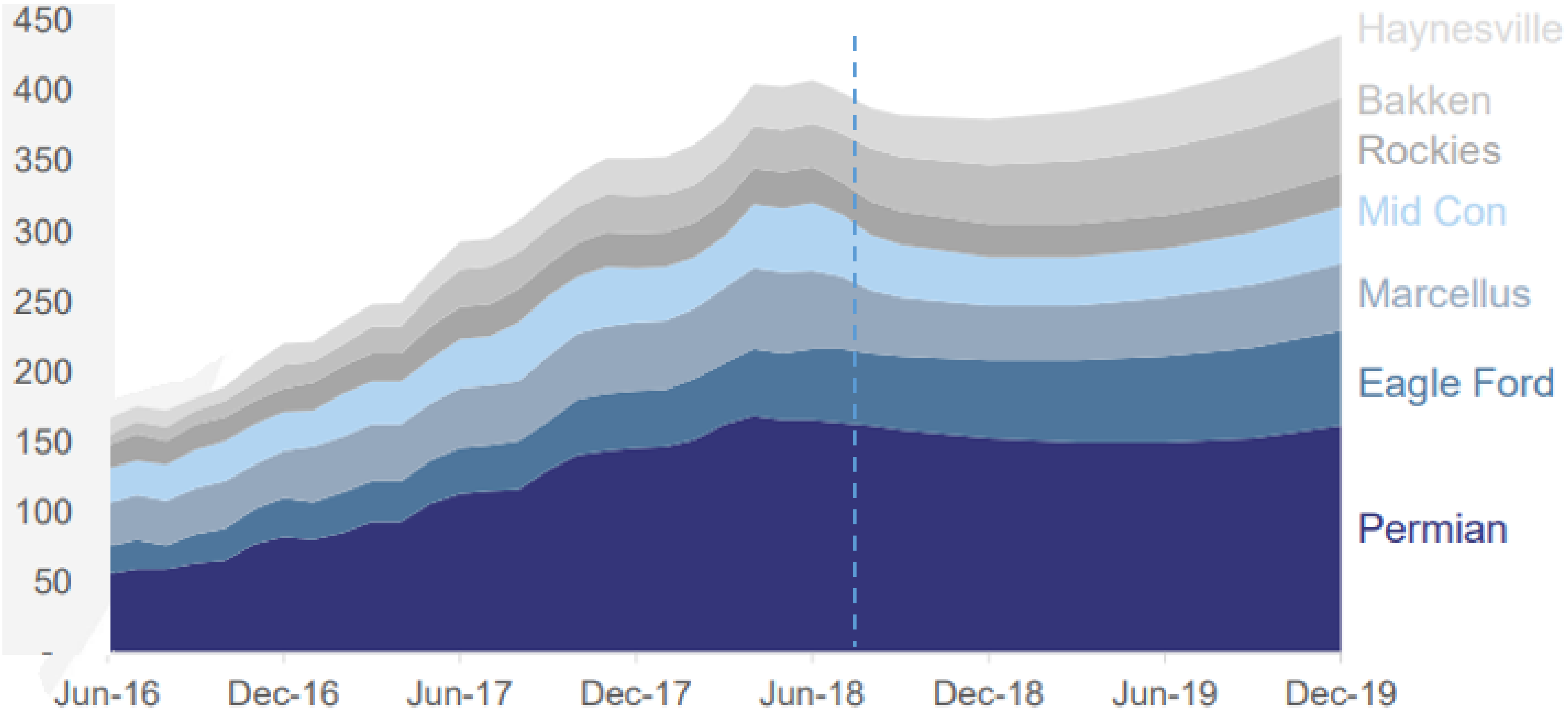
Source: KELRIK Proptester, 2019

US Horizontal Wells – Proppant Intensity



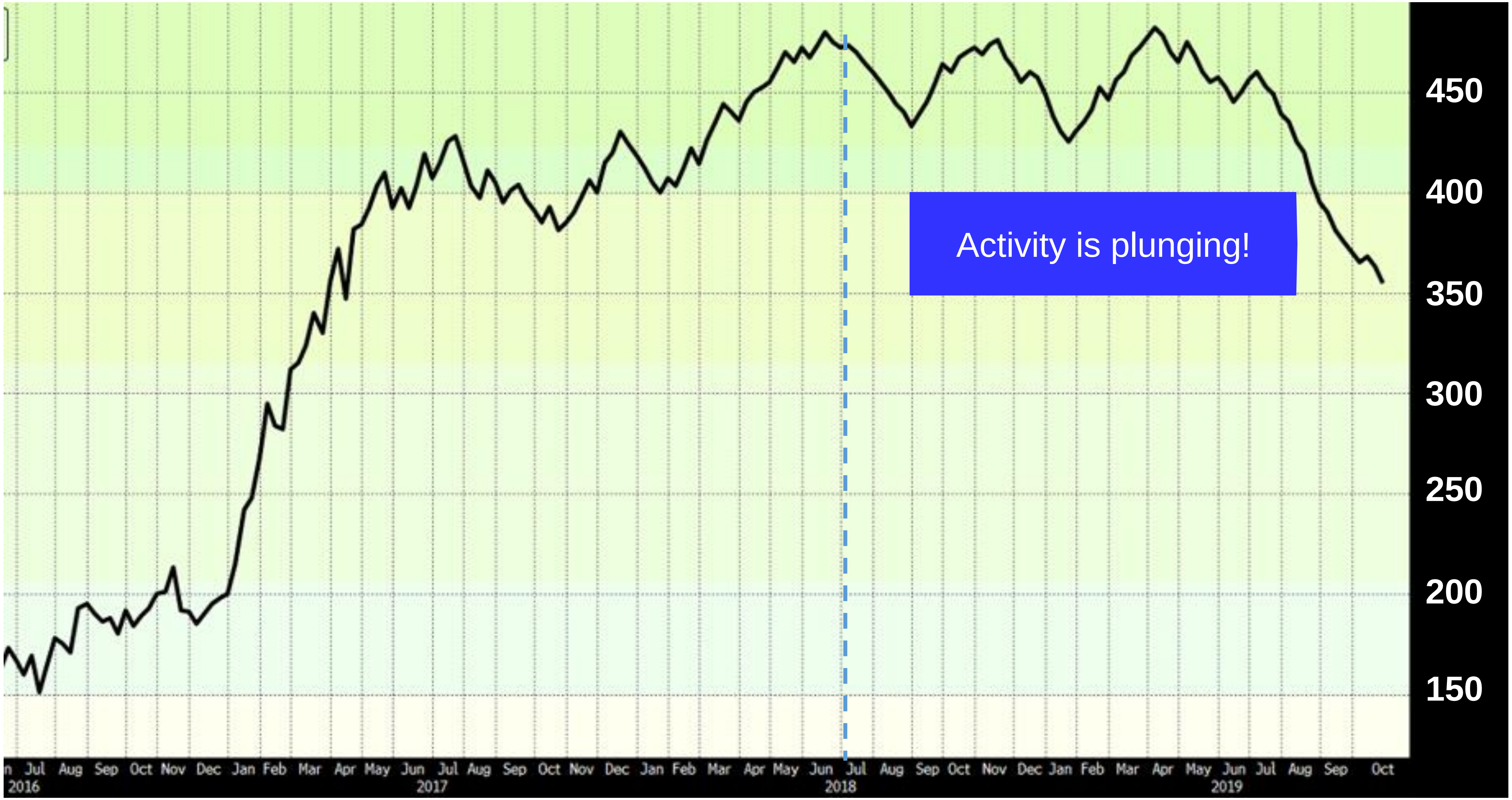
Source: Rystad Energy, 2019

US Active Frac Crews and Forecast by Play



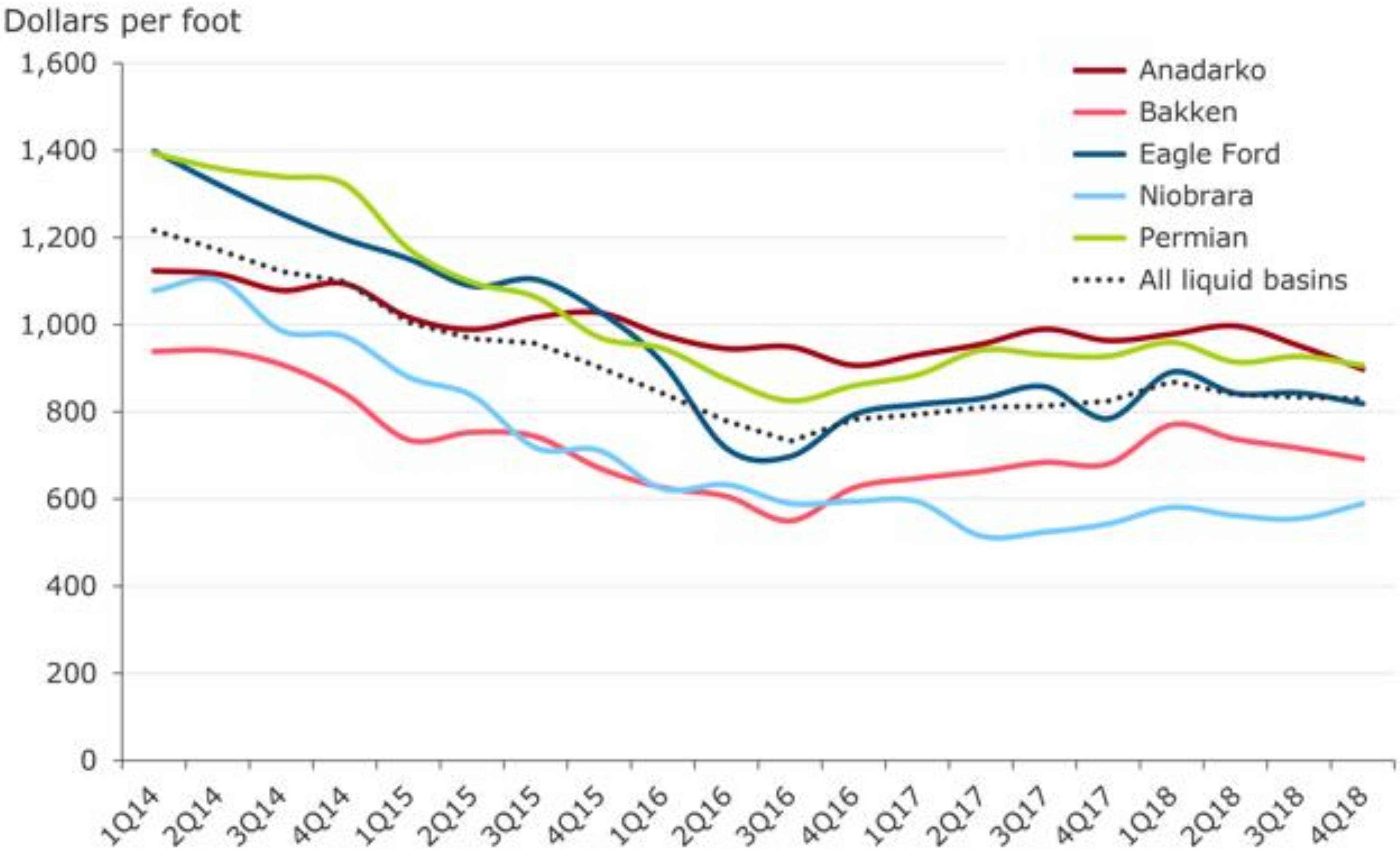
Source: COVIA, 2018

US Active Frac Crews – Reality Check



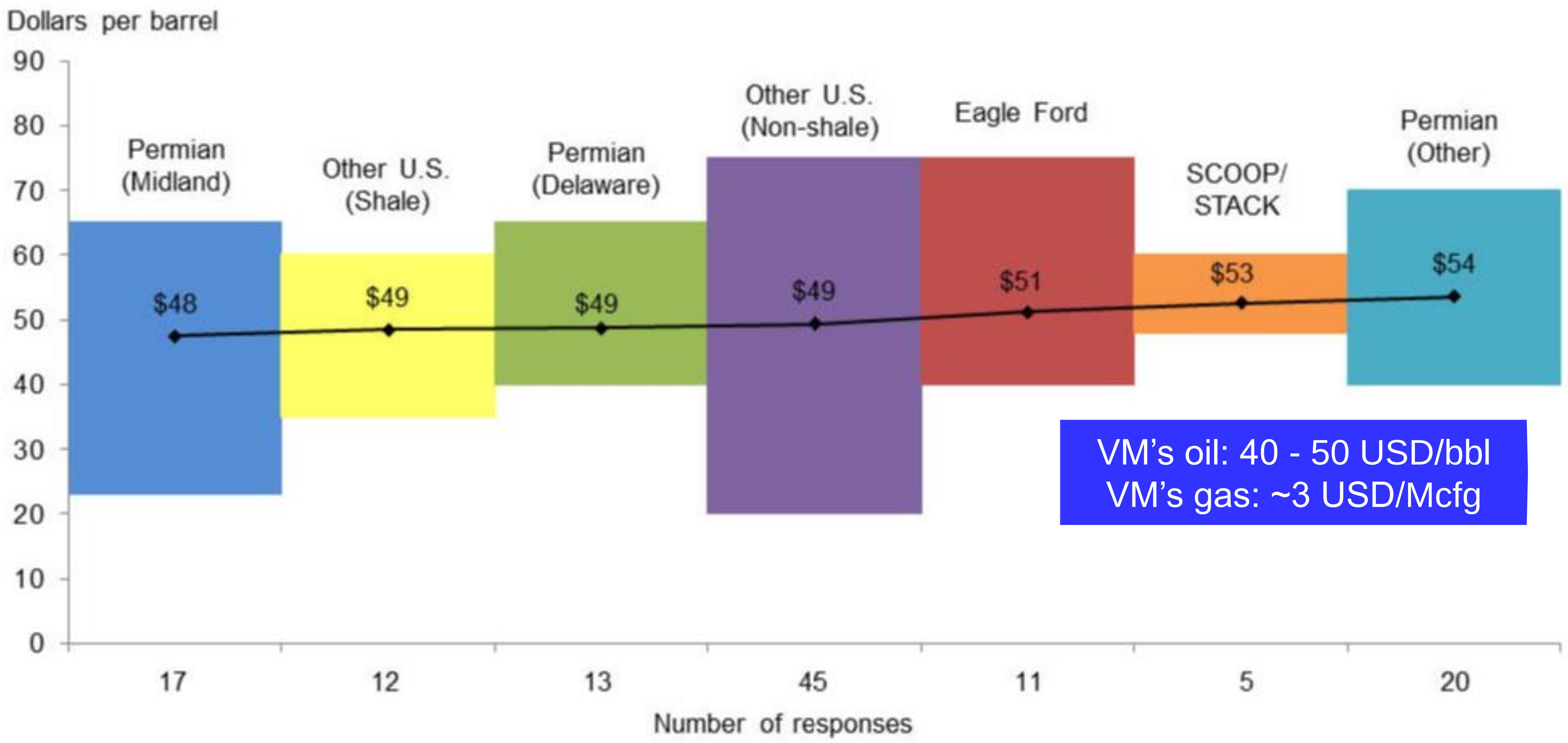
Source: Bloomberg, 2019

US Shale Plays – Average D&C Cost per Lateral Length



Source: Rystad Energy, 2019

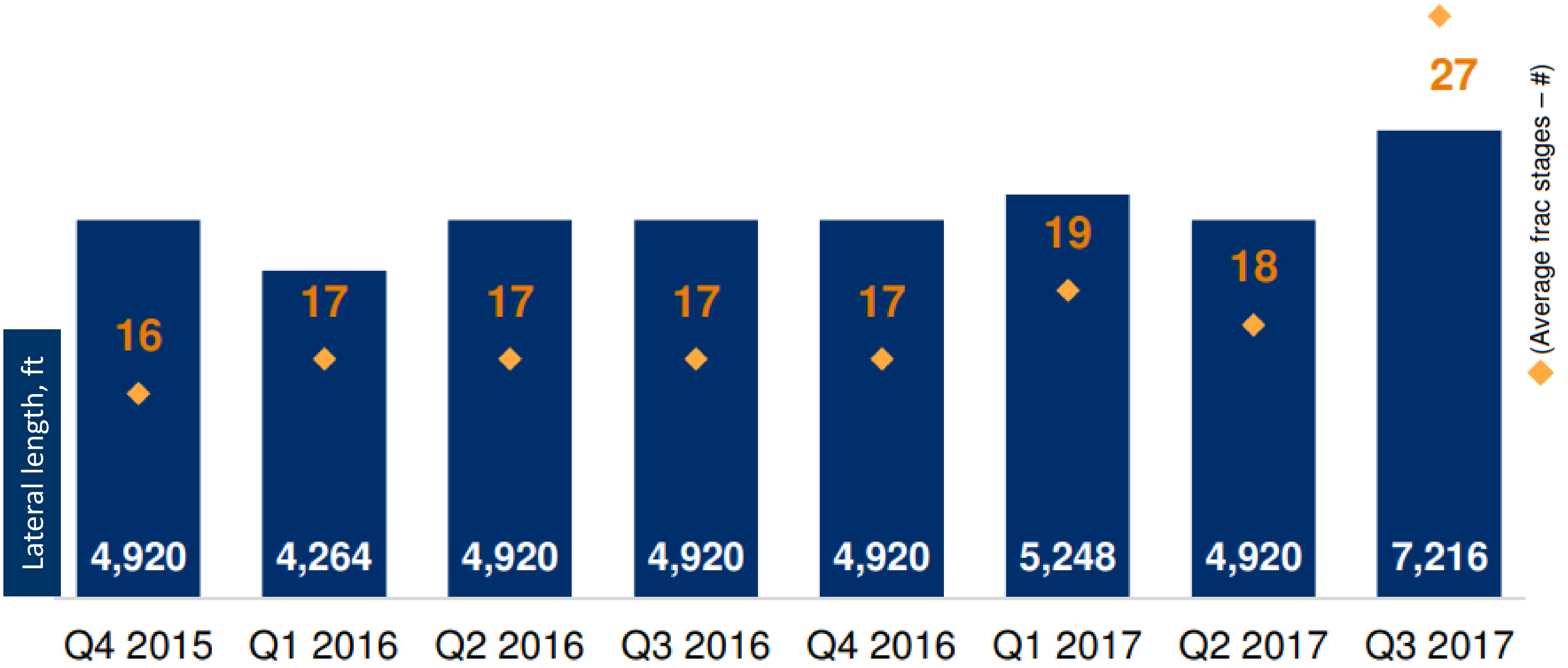
US Basins – Breakeven Oil Price



VM's oil: 40 - 50 USD/bbl
VM's gas: ~3 USD/Mcfg

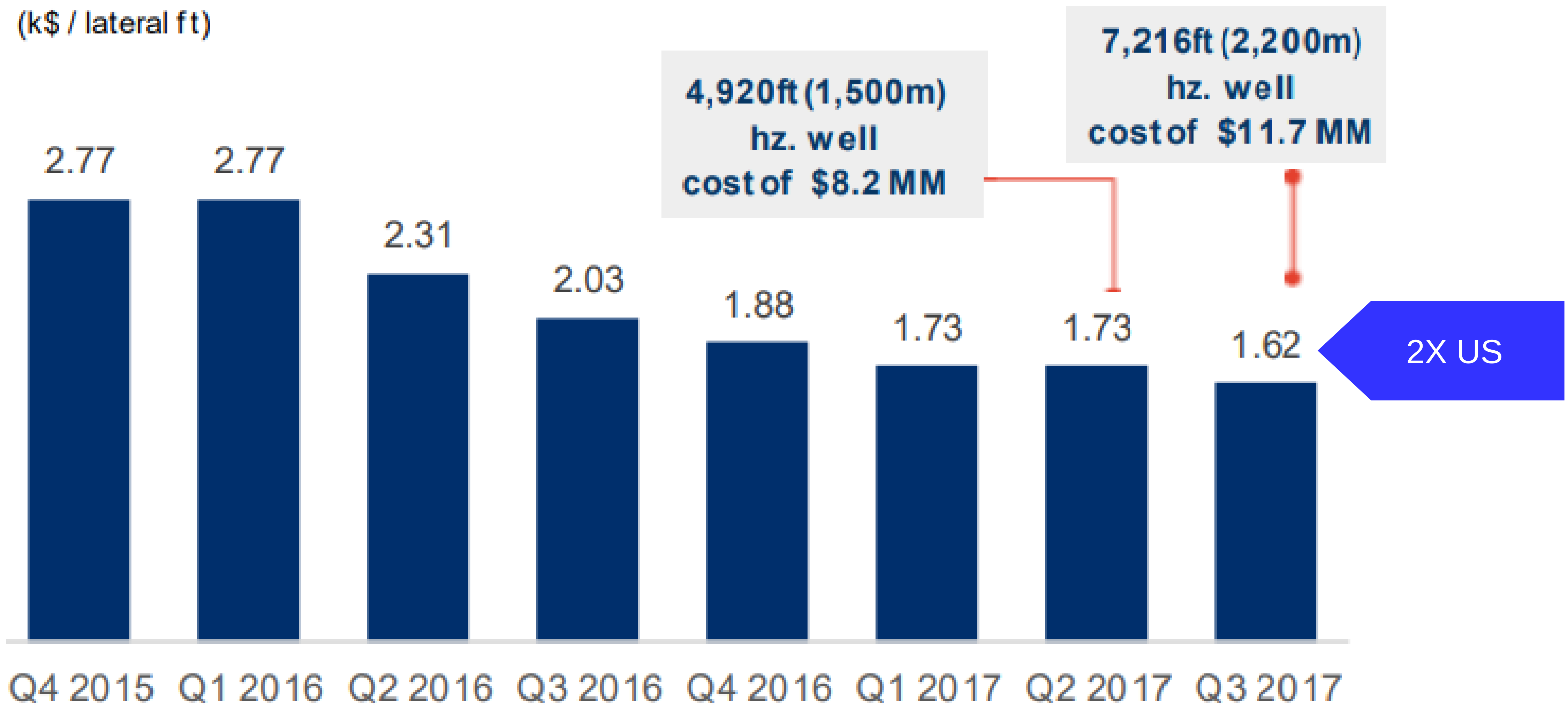
Source: Federal Reserve Bank of Dallas, 2019

ARG Vaca Muerta Shale Play – Average Lateral Length



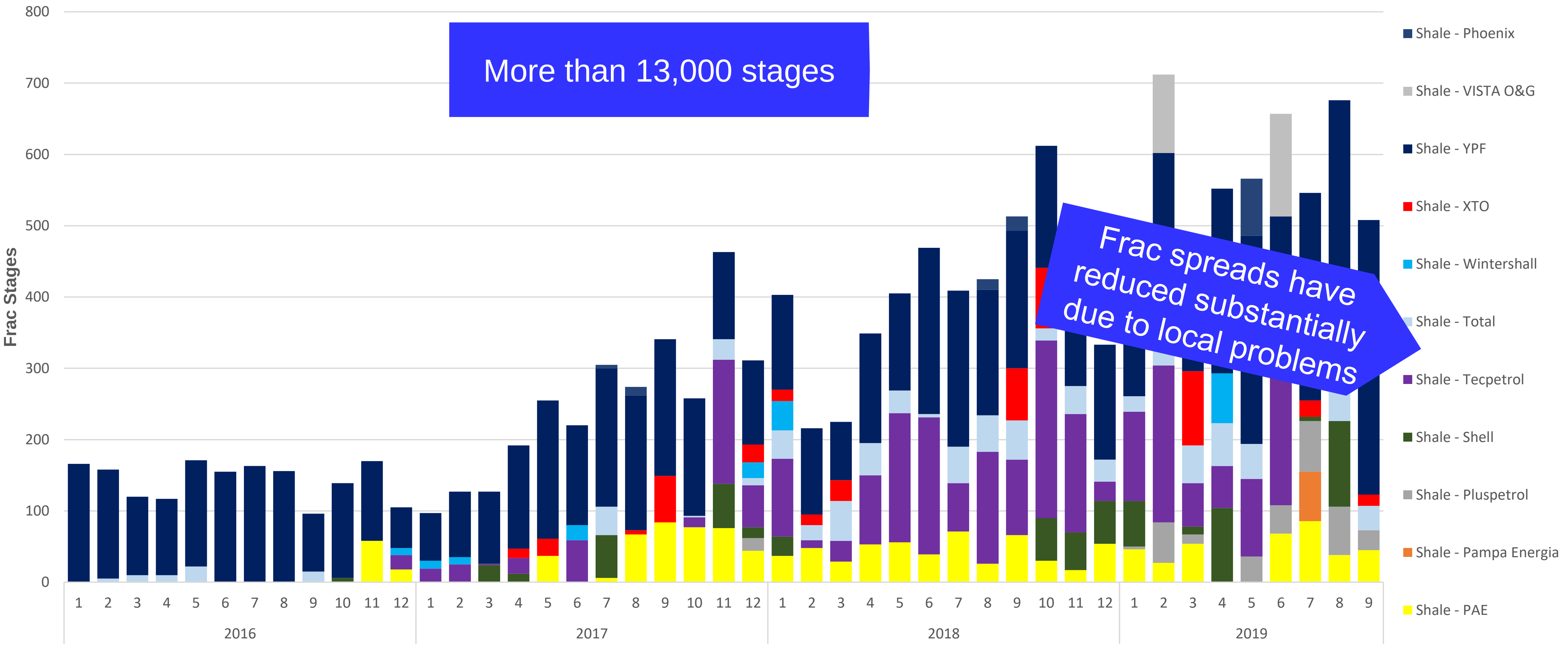
Source: Vista O&G's investor presentation, 2019

ARG Vaca Muerta – Average D&C Cost per Lateral Length



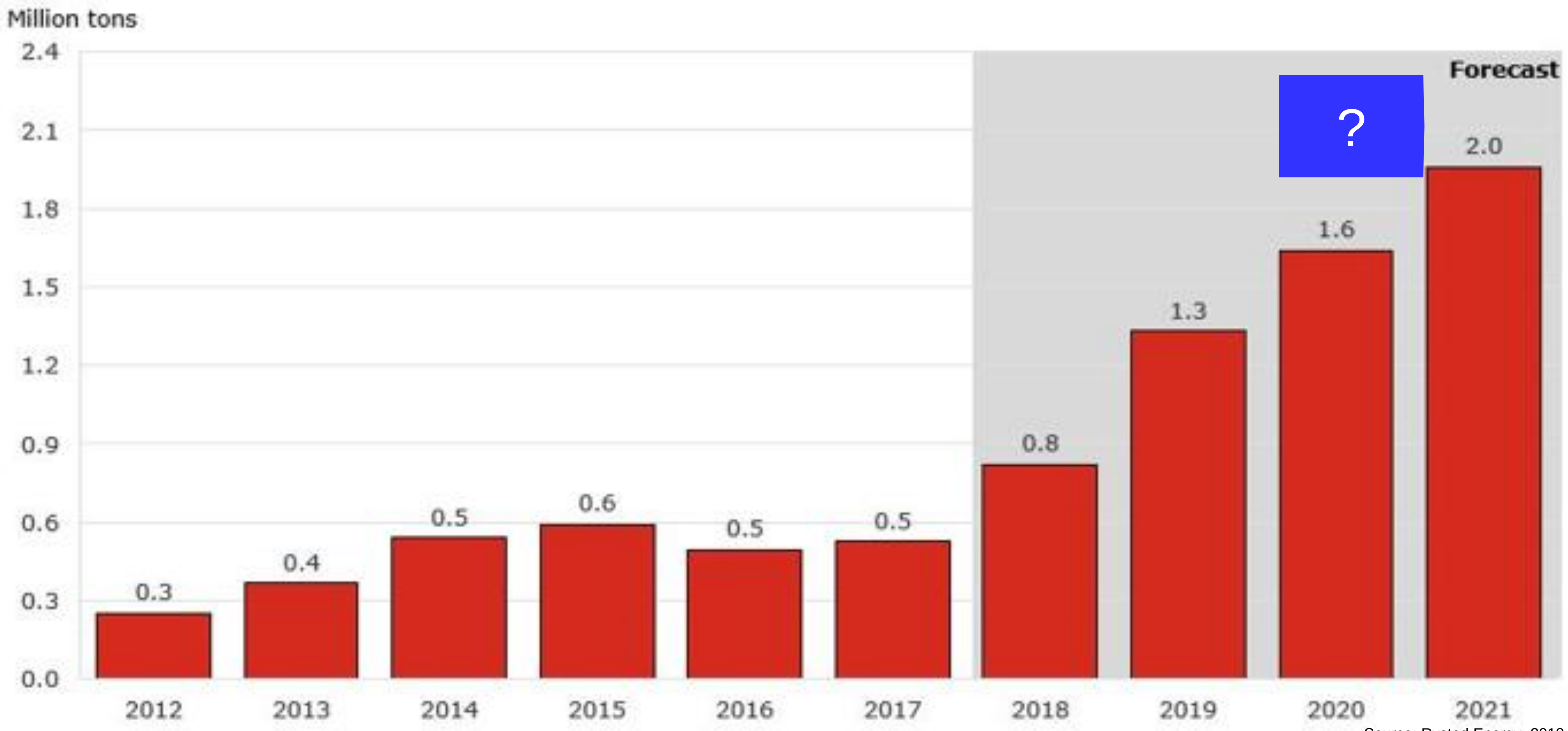
Source: Vista O&G's investor presentation, 2019

ARG Vaca Muerta Shale Play – Frac Stages per Month



Source: Luciano Fucello's Compilation

ARG Vaca Muerta – Proppant Consumption and Demand



Source: Rystad Energy, 2018

ARG vs US's Shale Plays – Comparison at a Glance

US

- Five prolific basins concentrate mostly all unconventional production (BOE): Permian, Appalachia, Eagle Ford, Bakken and Haynesville.
- Average lateral length: >2,600 m.
- Stages pumped: >500,000 / yr.!
- Stages per well: 50 – 60+.
- Stage spacing: 15 – 100 ft.
- Cluster per stage: 5 – 17.
- Spacing between clusters: 3 – 15.
- Proppant per stage: 250,000 – 500,000 lbm.
- Proppant intensity: 1,500 – 2,500 lbm/ft.
- Fluid intensity: 50 – 65 bbl/ft.
- Fluids: slick-water, hybrids and HVFR.

Argentina

- Only shale play in development: Vaca Muerta.
- 1013 wells drilled (47 % H) and 871 on production.
- Average lateral length: 1,500 – 2,500 m.
- Stages pumped: >13,000 in total.
- Stages per well: 25 – 35.
- Stage spacing: 50 – 100 m.
- Cluster per stage: 5 – 7.
- Spacing between clusters: 5 – 20.
- Proppant per stage: 450,000 – 600,000 lbm.
- Proppant intensity: 1,500 – 3,500 lbm/ft
- Fluid intensity: 25 – 65 bbl/ft.
- Fluids: hybrids & HVFR.

ARG vs US's Shale Plays – Latest Design Evolutions

US

- Longest lateral well: 5,977 m. (Marcellus).
- Stages pumped in a well: +80. (Bakken).
- Stage spacing: 30 m.
- Cluster per stage: 15.
- Spacing between clusters: 3 m.
- Proppant per stage: 760,000 lbm. (Haynesville)
- Proppant intensity: 5,000 lbm/ft. (Haynesville).
- Fluid intensity: 55 bbl/ft. (Bakken)
- Proppant: 100 mesh, 200 mesh, 400 mesh, 40/70.

Argentina

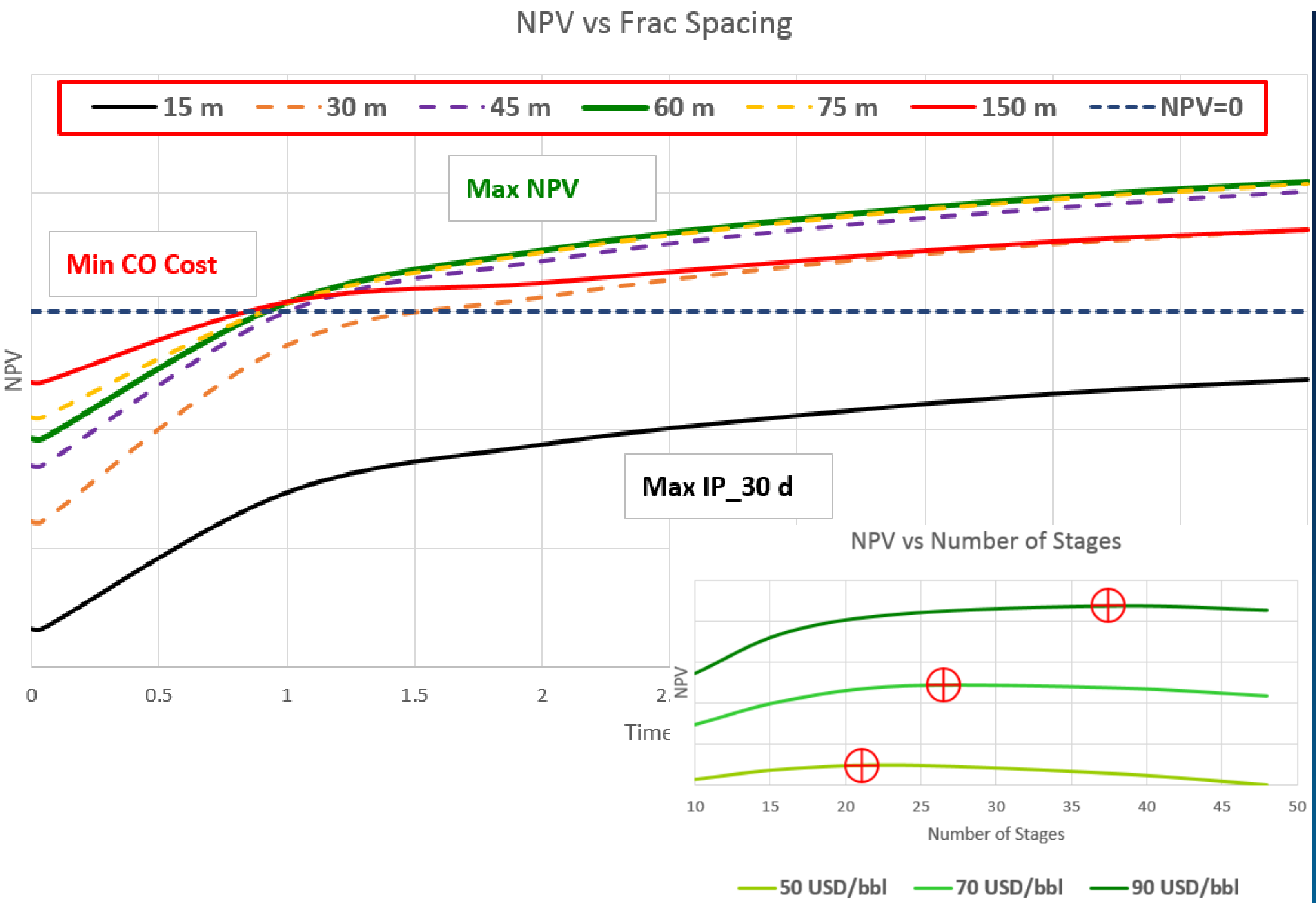
- Longest lateral well: 3,362 m.
- Stages pumped in a well: 54.
- Stage spacing: 50 m.
- Cluster per stage: 10.
- Spacing between clusters: 5 m.
- Proppant per stage: 4,500 – 6,000 lbm.
- Proppant intensity: 3,250 lbm/ft
- Fluid intensity: 65 bbl/ft.
- Proppant: 100 mesh, 40/70, 30/70.

Summary of Metrics

Maximizing reservoir access

- ✓ Longer laterals that access more rock and hydrocarbons at a lower incremental cost. Shale well economics align with a smaller footprint.
- ✓ Increase of proppant mass and fluid volumes. Fluid volumes has increased to 33 barrels per lateral foot while average proppant mass increased to more than 1,600 pounds/foot.
- ✓ Reduction of chemical additives and related volumes. Migration from x-linked to slickwater, and more recently, to high-viscosity friction reducers (HVFR). Adoption of cheaper and lower-quality, locally sourced sands (in-basin sand).
- ✓ Denser fracture distribution:
  - Stage counts and stage intensity are increasing mainly because of longer laterals and higher stage intensity. Average stage spacing has been reduced to about 200 feet/stage in 2017.
  - Pump rates per lateral foot have increased to 0.42 barrels a minute/foot in 2017 to improve diversion along the lateral. Frac fleet specs have been updated to match these new requirements mainly horsepower.
  - Cluster count per stage has increased substantially. Extreme limited-entry with fewer perforations per cluster for better overall fracture distribution is a common practice (diversion effectiveness). Use of degradable diverters as part of the process.

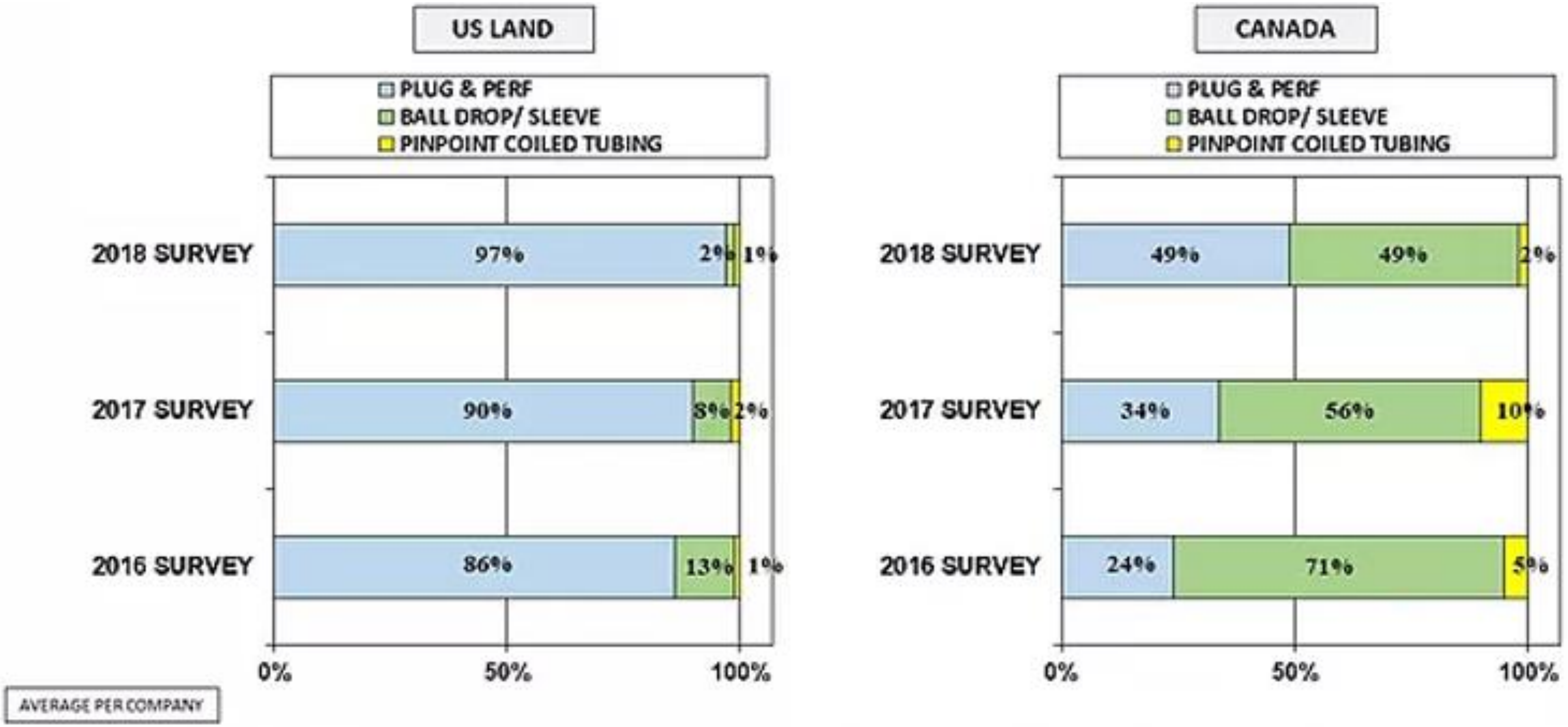
Positive Well Economics = Profitability – This Never Changes!



Key drivers

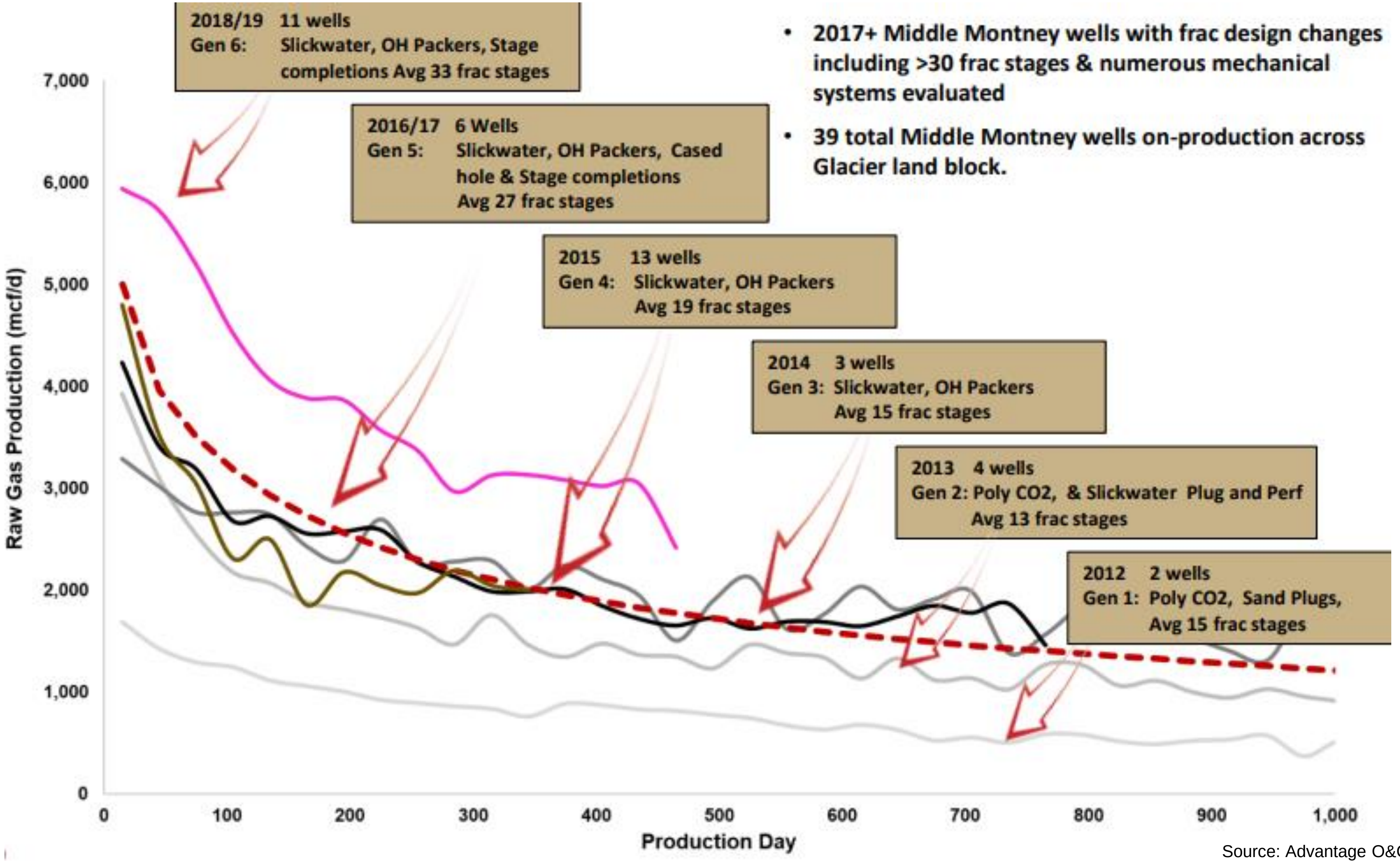
- Profitability is the main driver for a successful development.
- All other aspects underpin the primary driver.
- Do not focus on highest IP nor lowest well cost.
- Oil and gas price are key components of economics so have a clear picture of the boundaries before it is too late.
- EUR @ 30 yr. does not make any sense.
  - If project does not fly in 3 – 5 yr., think it twice before moving on.

Techniques Use – Plug & Perf vs Sleeves vs CT Based



Source: Kimberlite, 2019

Canadian's Completions are Also Migrating to P&P



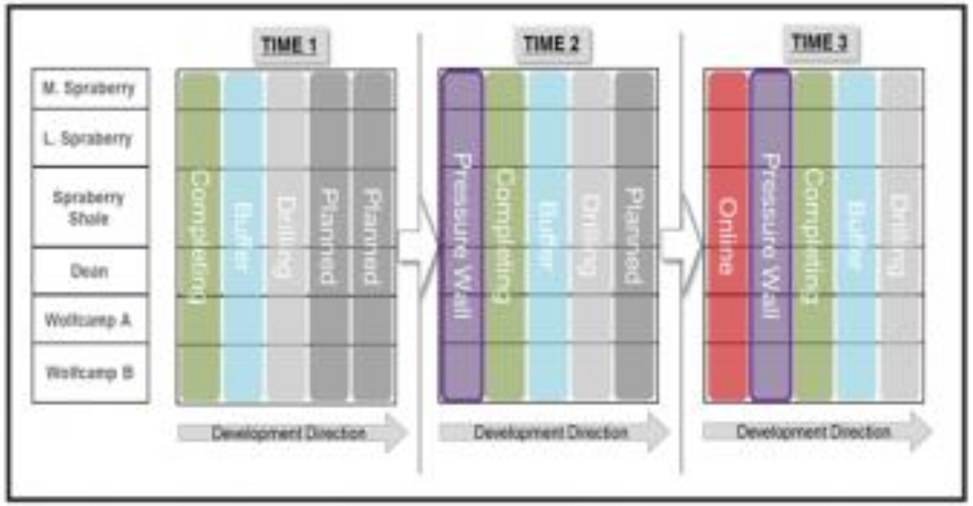
- 2017+ Middle Montney wells with frac design changes including >30 frac stages & numerous mechanical systems evaluated
- 39 total Middle Montney wells on-production across Glacier land block.

Source: Advantage O&G, 2019

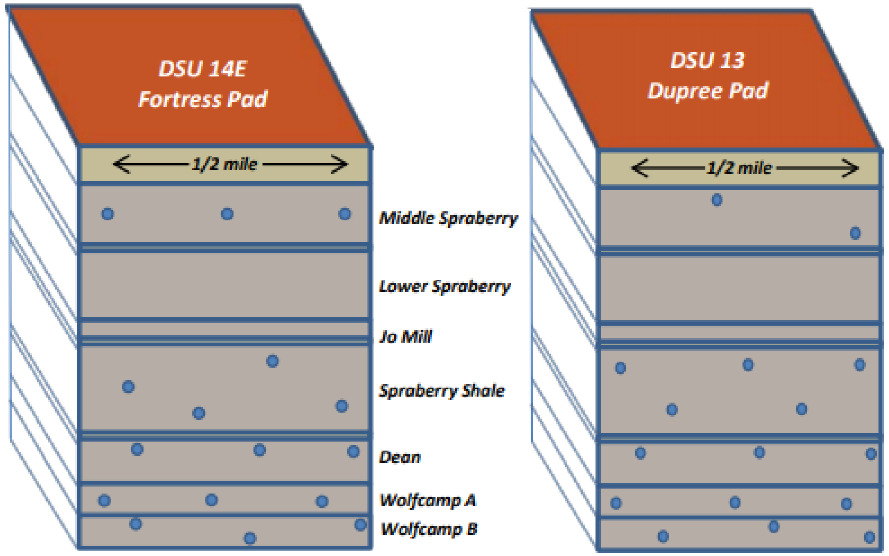
Sequenced Developments – Not Everyone is Convinced!

Sequenced development – objective: to maximize value

- ✓ Aka.
  - Cube or tank completions. Sequential or rolling developments.
- ✓ Reasoning behind the concept.
  - Unperturbed reservoir will be less prone to be affected by frac hits.
  - Need to have a strong understanding of the geomechanics of the “cube”, its limits and the barriers that define vertical and horizontal isolation. In essence you understand how the fractures propagates and grow which is directly linked to the prevention of frac hits.
- ✓ Pros
  - Integrated planning and logistics. Enhanced operational efficiency.
  - Optimized resources recovery. Minimized well interference.
- ✓ Cons.
  - Production is delayed substantially.
  - Significant upfront expenditures.
  - Not feasible for early developments. Need to know well spacing first!



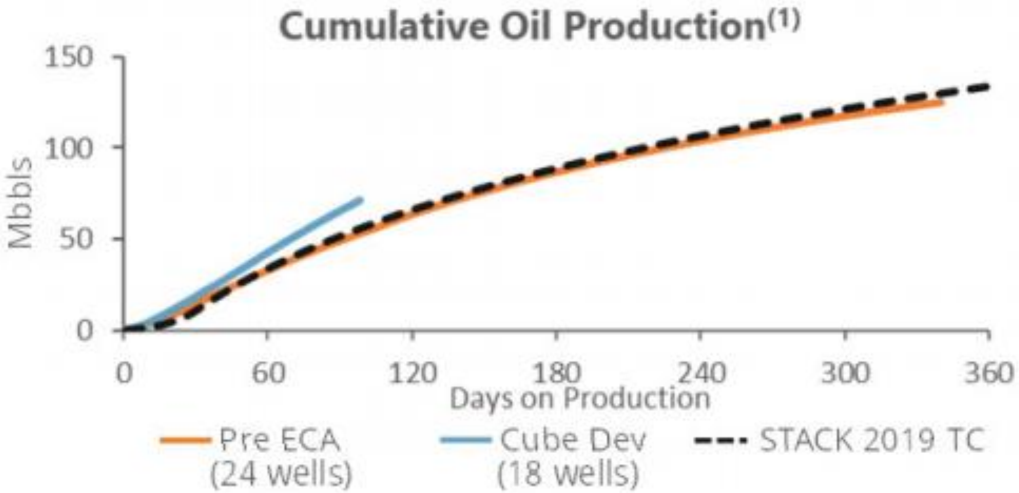
Source: QEP, 2019

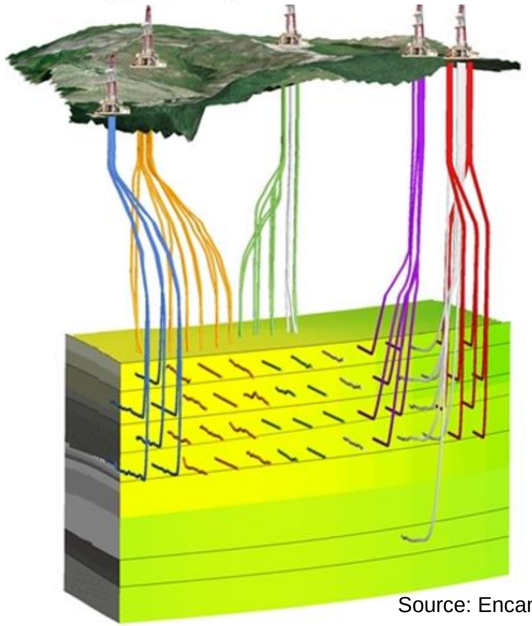


Sequenced Developments – Maximizing Value

Sequenced development – actual challenges and results

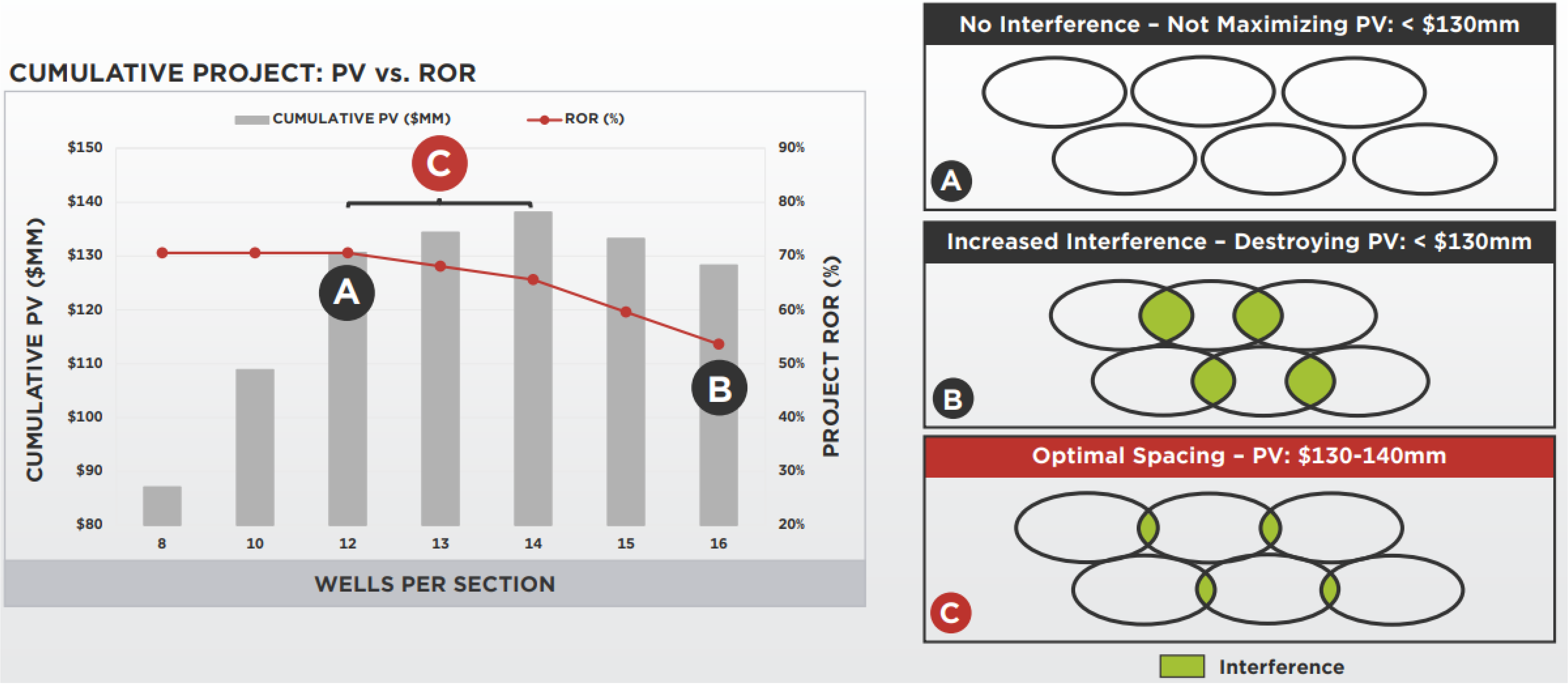
- ✓ Success.
  - Only few companies have been successful using the concept.
  - Good understanding of well spacing.
  - Adequate management of shareholder expectations.
- ✓ Failure.
  - Some companies follow the pack without knowing the key elements.
  - Decision to reduce well spacing and to go into cube development at the same time with poor results.
  - Field tests with negative results but considered positive for future developments.





Source: Encana, 2019

Sequenced Developments – Maximizing Value

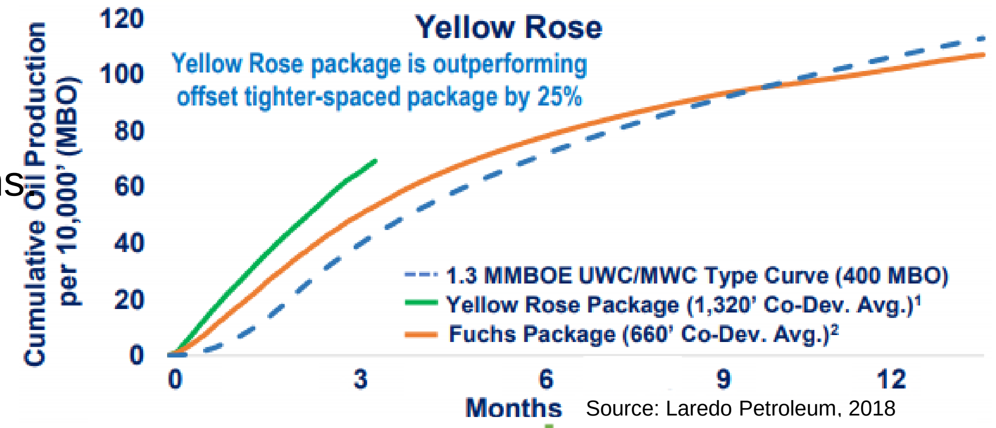


Source: Cimarex, 2019

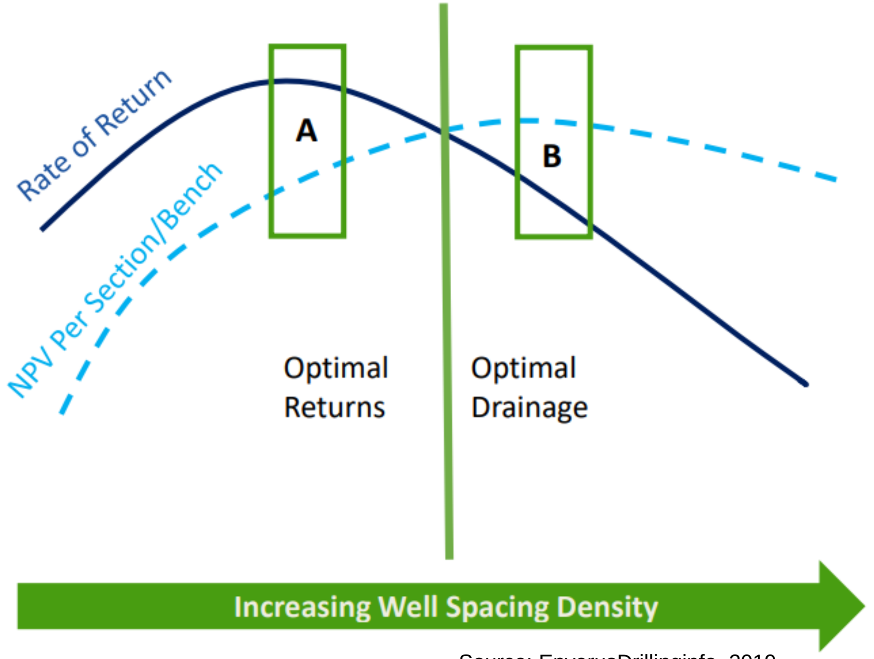
Well Spacing – Wider Seems to be the New Rule

Where we came from? – Evidence

- ✓ Frac hits. Parent-child well effects.
  - Multiple interactions between close-by wells, even in zipper completions.
  - Child wells with lower production compared to parent wells.
- ✓ Development strategy. Field tests.
  - Tighter array and stacked developments.
  - In general tighter spacing tests (more wells) showed less cum production and higher costs.
- ✓ Operator's grading by investors. Investors want their money back!
  - On profitability = achieving sustainable free cash flow.
  - On value growth.
- ✓ Industry's immediate reaction.
  - Transition from reservoir to economic management.
  - Distribute more dividend payments to shareholders.
  - Increase well spacing and reduce capital expenditure!
  - An engineered reaction or pure market pressure?



Source: Laredo Petroleum, 2018

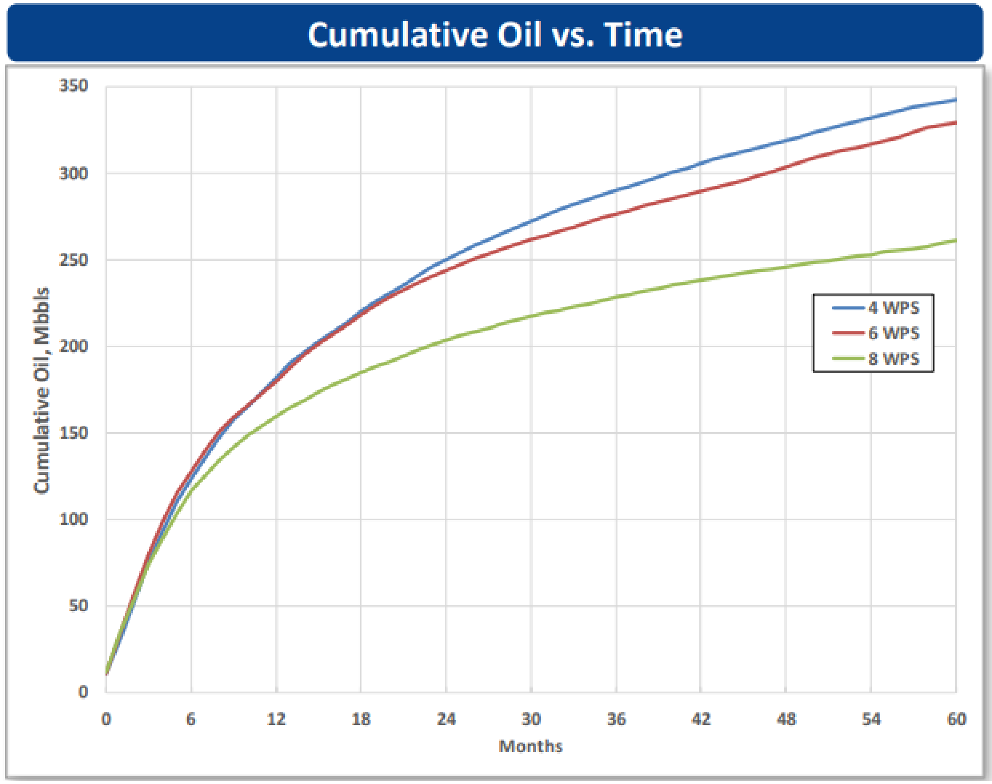


Source: EnverusDrillinginfo, 2019

Well Spacing – Metrics Can be Tricky!

What went wrong? – Evidence

- ✓ Pilot tests.
  - In general results are just evaluated for a short time. A year maximum.
  - Unless extremely narrow spacing is experimented, during the first year several tests will show similar results.
  - But at certain point in time departure will be important and well economics will be punished. Time is an important variable to study.
  - Too late for many wells that were drilled based on wrong conclusions.
- ✓ Reservoir simulations.
  - Based on this approach it is possible to recover more oil if wells are spaced out in a narrow pattern. More wells per section.
  - The problem is that this is only one piece of the puzzle!
  - An optimum well spacing program must consider all aspects. Do not believe in excess on simulators, rely on real data!
- ✓ Well spacing evolution
  - From many at 200 – 300 ft to current 800 to 1,200 ft and even wider.
  - Well spacing depends on reservoir fluid type.

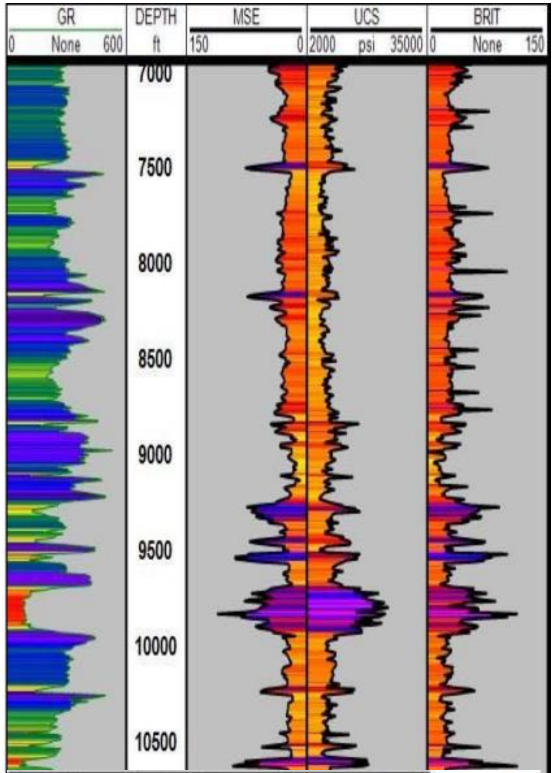


Source: Valdez, 2019

Where to Perforate? – New Approach

Conceptual basis: in rocks with similar fracability.

- ✓ Fracability is mainly a function of rock mineralogy, anisotropy, natural fractures and pore pressure.
  - Fracability is in essence the susceptibility of the rock to be hydraulically fractured.
  - Stress log is the output after computing multiple logs, pre-frac injections and lab tests which all are time consuming and expensive to be run on a regular basis.
  - Fracability is a proxy for UCS and for the stress log. But cheaper and quicker.
- ✓ New methods rely on existing data that are not taken advantage of. No need of extra information.
  - Mainly cuttings, drilling data, mud logging, routine logs. Offset wells with full suite of logs or lab tests to be used for calibration purposes only.
  - After cleaning data, Mechanical Specific Energy (MSE) index is calculated which is and excellent proxy for the stress log. Different equations in the public domain.
  - The output is a map of the variability of the rock along the horizontal section.
- ✓ Challenges.
  - How to calculate MSE at downhole conditions. Have a good torque and drag model, know specific hydraulic energy and mud motor performance.



Color	Hardness	MSE
(yellow)	HD 1	0-20K
(orange)	HD 2	20-30K
(red)	HD 3	30-50K
(blue)	HD 4	50-85K
(magenta)	HD 5	85-135K
(green)	HD 6	135-200K
(grey)	HD 7	200K +

Hardness Increases

Source: cjenergy.com

Advances in Perforating – Technologies and Practices

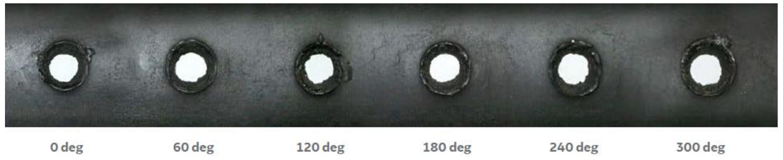
New technologies, improved performance and efficiency

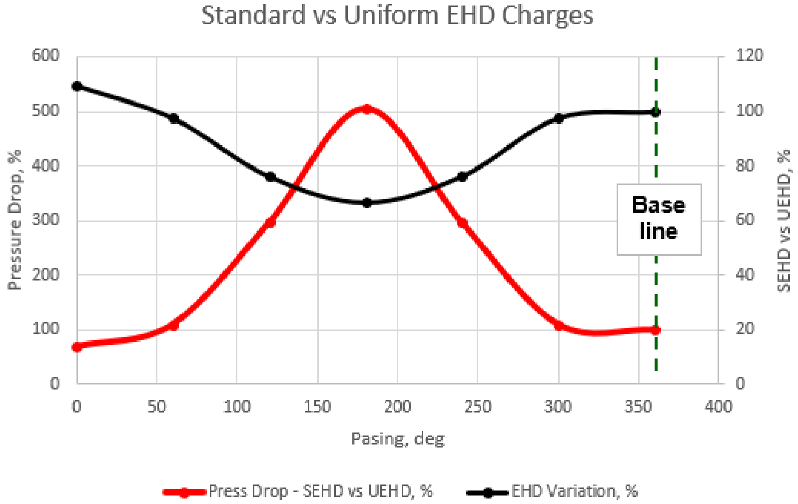
Source: alliedhorizontal.com

- ✓ A single misfire, a partially set plug or a plug setting failure cause a lot of downtime with its associated costs. Multi-cluster perforating need high reliability to have high efficiency.
  - Fully factory-assembled casing guns. Quick connection. Safer. Higher reliability.
- ✓ Optimum reservoir contact when uniform treatment distribution is used.
  - Diversion mainly based on extreme limited entry perforating. Controlled pressure drop thru perfs.
  - Standard charges do not provide uniform entrance hole diameter.
  - Different pressure drop in each perforation. Inefficient frac initiation.
  - Response: consistent or uniform entrance hole diameter charges.

Source: bhge.com

Source: Green, 2019



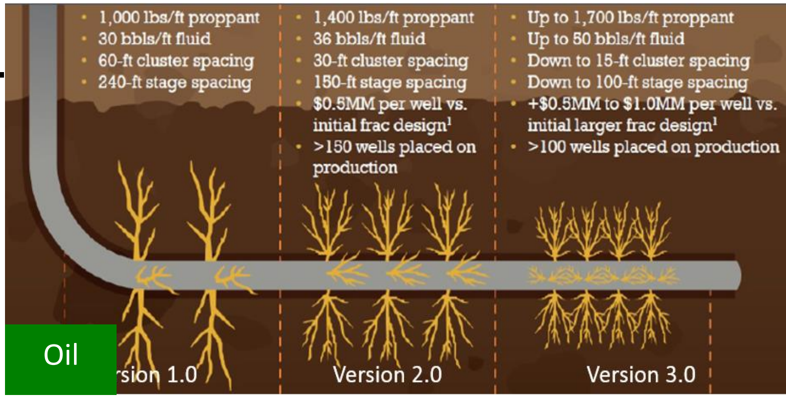


- ✓ Preferentially fracture should initiate in a single plane to avoid multi fractures.
  - Standard charges located at separated distance between each other. Configuration is against optimum condition.
  - New assemblies with very short distance between charges.

High Density or Intensity Completions

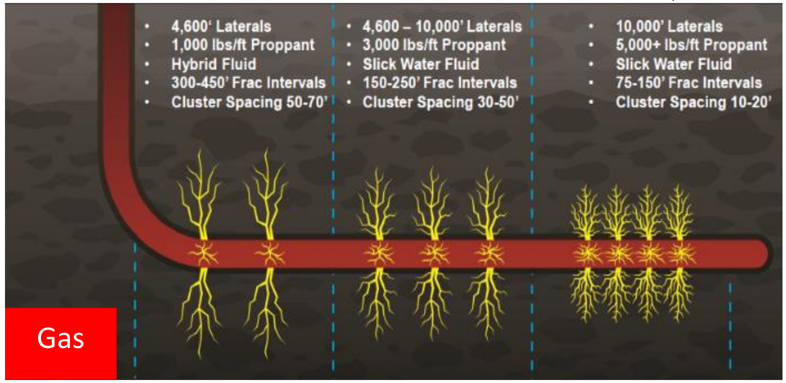
Reasoning behind the concept

- ✓ Difficult to move fluids from regions relatively far away from wellbore (> 30 m.).
- ✓ Hard to create long uniform and conductive fracture from every single cluster.
  - More difficult to keep them open once the well is put on production.
  - Detrimental stress effects on fracture and proppant can not be mitigated easily.
- ✓ For the same stage spacing, shorter clusters spacing means more fractures per unit of length.
  - Enhanced stimulated volume close to the wellbore.
  - Need to use in association with extreme limited entry perforating practices and diverters.
  - Higher pumping rates required to get decent diversion.
  - Current practices: spacing in the order of 10 to 15 ft and from 10 to 25 clusters.
  - For the same volume of fluid and proppant more clusters means shorter fracs.
- ✓ Stress shadowing effect still present.
  - More complexity is created. Narrower fractures.



Source: Pioneer Resources, 2017

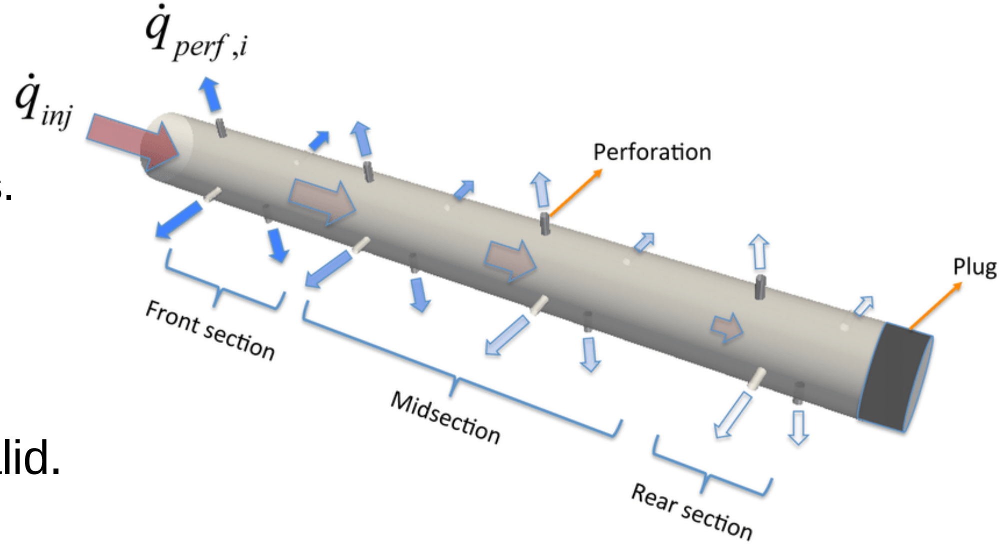
Source: Goodrich Petroleum, 2017



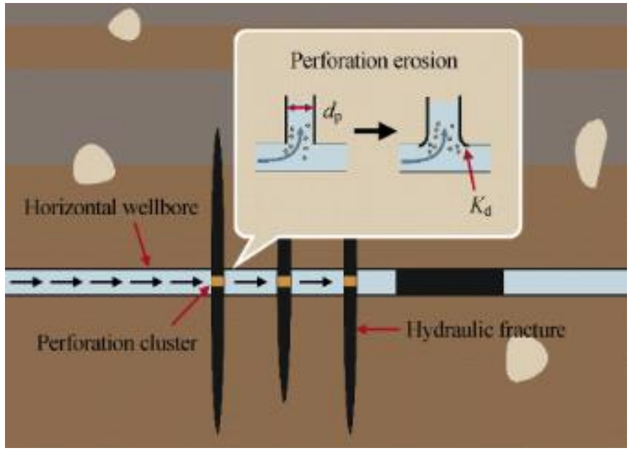
High Density or Intensity Completions

Technical considerations

- ✓ Adding only more clusters does not provide any benefits.
  - Need to be combined with extreme limited entry perforation practices.
  - Adequate pumping rates to match previous technical approach.
  - Use of diverters.
  - Engineered cluster design in terms of number of holes per cluster.
- ✓ Still the concept of perforating rock with similar stress values is valid.
  - Similar mineralogy and pore pressure.
  - In general clusters are unevenly spaced.
- ✓ How to ensure that all clusters receive an evenly distribution of treatment?
  - Energy equation (Bernoulli's eq.) does not provide right answers.
  - Need to include momentum equation to enhance the solution.
  - Need to include stress shadowing effects. Impact on fracture width.
  - Need to consider multiphase flow (proppant-fluid interaction) and settling.
  - Need to consider 2-D fluid flow instead of simplistic 1-D.



Source: geomechsoftware.com

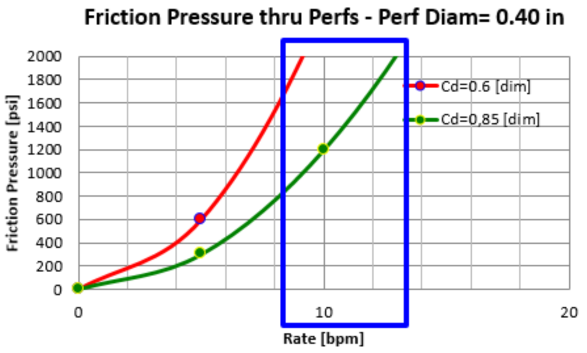


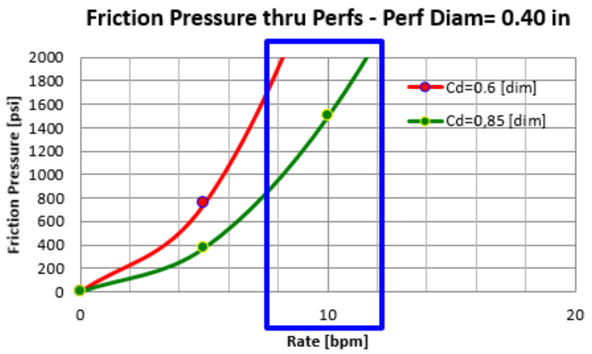
Source: Yongming et al., 2018

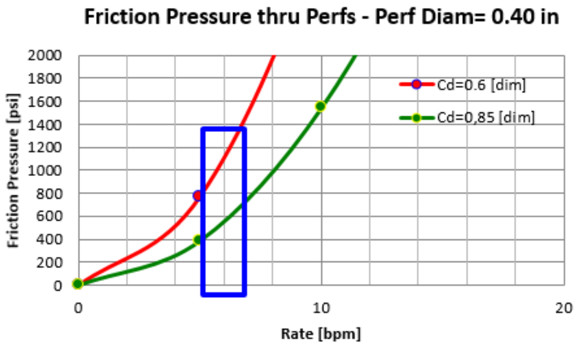
High Density or Intensity Completions

Technical considerations

- ✓ First approach. Single cluster design: 1 ft – 3 spf – 120° – 0.4 in EHD. No diverters.
  - Extreme limited entry perf asks at least for 2,000 psi differential. 2,500 psi is the new rule.
  - No sand, no erosion: at least 9 bpm are required per cluster.
  - Sand at 3 ppg with erosion: at least 11.5 bpm
  - For 10 clusters 115 bpm per stage are required. Industry is using between 70 to 90 bpm. Are we getting full diversion?
- ✓ Bob Barree's rule of thumb asks for at least 2 bpm/hole for standard limited entry treatments, therefore 6 bpm are needed.
  - Using this approach will bring poor diversion to our design.
  - This rule of thumb needs to be updated accordingly.
- ✓ Assume 10-clusters design pumping at 90 bpm. Uniform pump rate distribution.
  - First cluster see momentum equivalent to 90 bpm but subsequent clusters see less.
  - Consequence: uneven fluid and proppant distribution.
  - Cluster closer to the heel tends to receive more fluid and proppant.



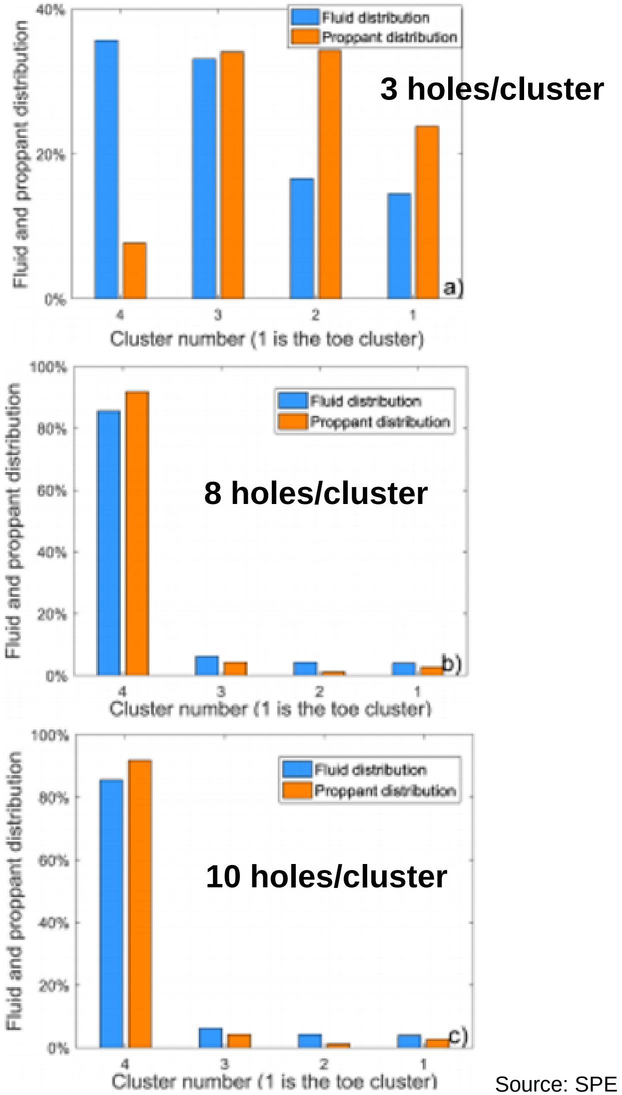




High Density or Intensity Completions

Factors affecting treatment distribution

- ✓ Perforations related.
  - Perforations per cluster (uniform or tapered). Single hole per cluster, a new idea?
  - Hole size. Are all holes of the same diameter?
- ✓ Treatment schedule related.
  - Proppant size, density, concentration, proppant ramp-up speed.
  - Frac fluid type (transport and settling mechanisms).
  - Pumping rate.
- ✓ General trends. Need to run your own simulations!
  - Low diversion: treatment becomes more heel-biased.
  - Tapered perforations with more holes near the toe brings more uniform distribution.
  - When many clusters are used a tapered design is better than an uniform one.
  - High density proppants tend to make treatment distribution less uniform.
  - Smaller proppant concentration and slow proppant ramp-up promotes more uniform distribution.



Source: SPE 194360

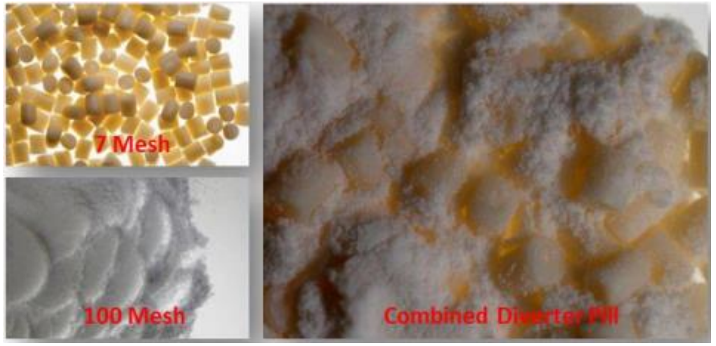
Mechanical Diversion – Evolution and New Technologies

New technologies, improved efficiency

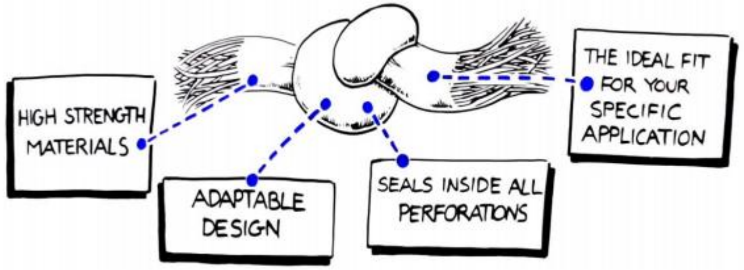
- ✓ Optimum reservoir contact when uniform treatment distribution is obtained.
  - Mechanical diversion is the second main mechanism after extreme limited entry perforating.
  - Standard technologies: rock salt, benzoic acid flakes, proppant slugs, ball sealers, fibers. Many were non-degradable materials. Issues to remove them.
  - New technologies: biodegradable ball sealers, degradable fibers and solid particles of different shape and size, dissolvable pods.
  - Diversion can be intra-stage or inter-stage.
- ✓ Other uses.
  - Refracturing.
  - Elimination of plugs. Hydraulic fracturing of zones below a collapsed casing.
- ✓ Design for effective diversion.
  - Balls and solid particles required an engineered design for better results.
  - Pods requires less engineering. 1 pod per each perf. Just define pod size.
  - Pods can divert even in deformed perforations by erosion.

Source: lowes.ca

Source: perfsealers.com

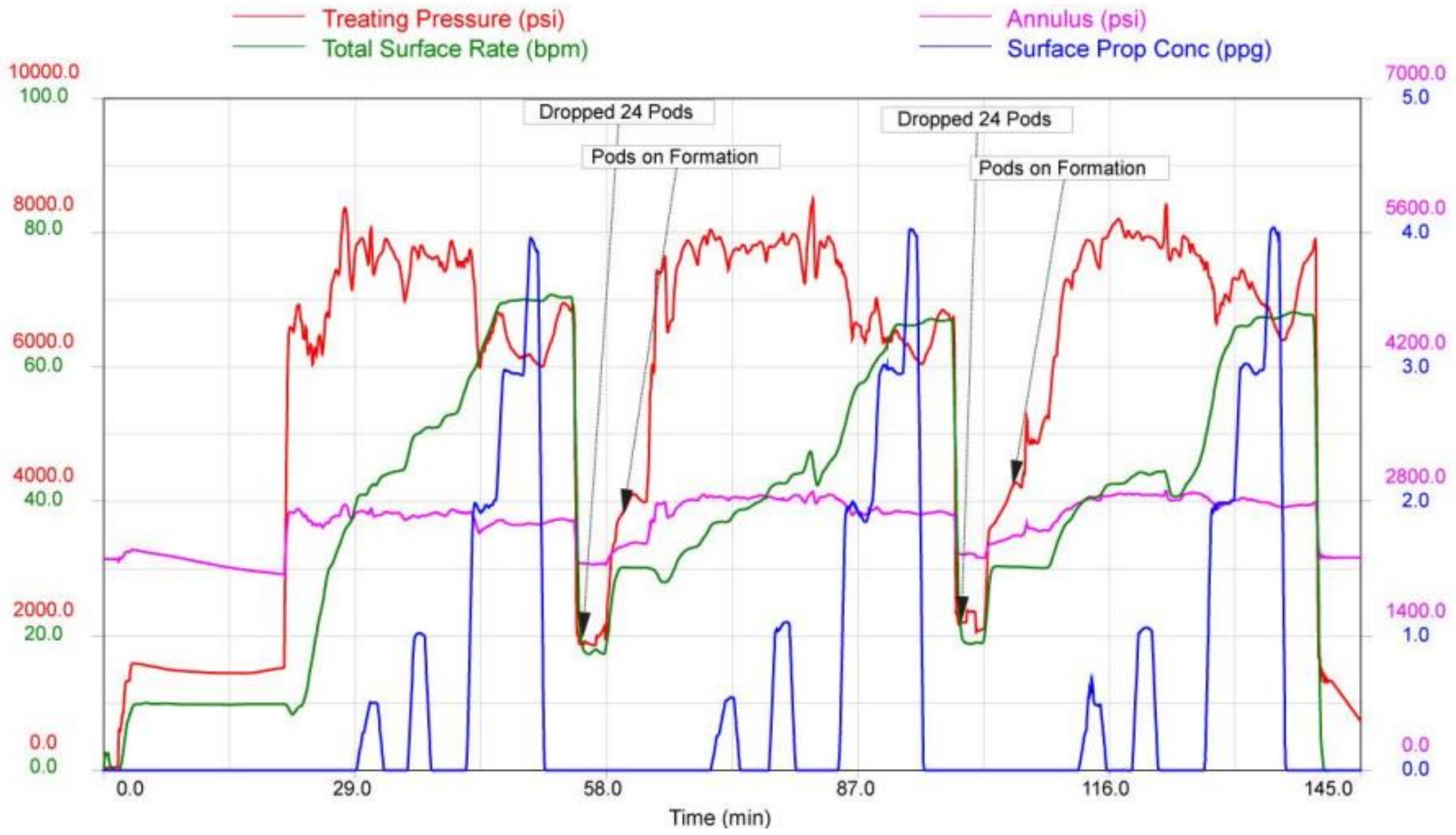


Source: SPE 190023



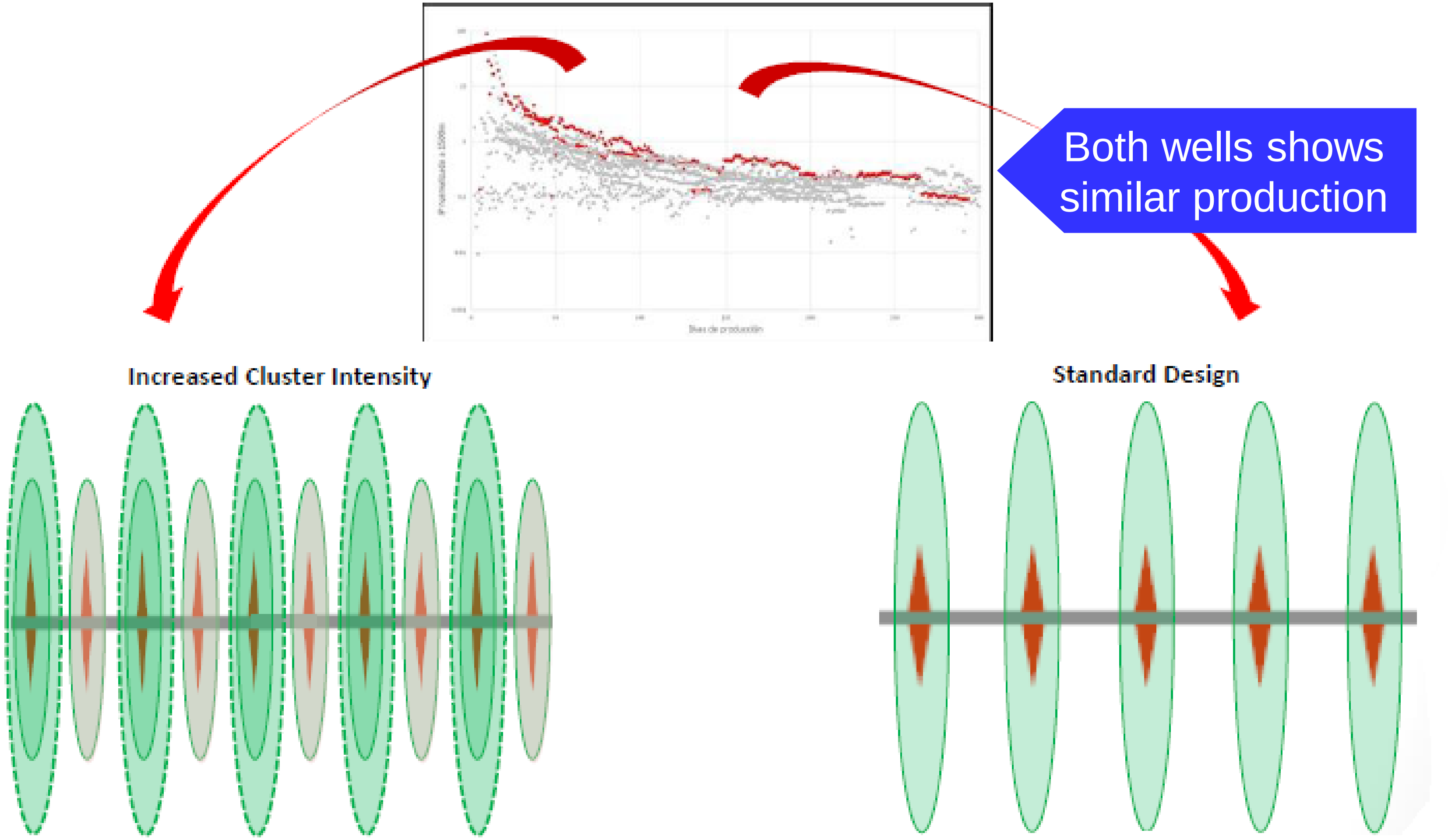
Source: Rodgerson, 2019

Mechanical Diversion – Intra-stage Example



Cluster Efficiency – Do We Have a Clear Understanding?

Similar lateral length and total amount of proppant. Only clusters strategy is different



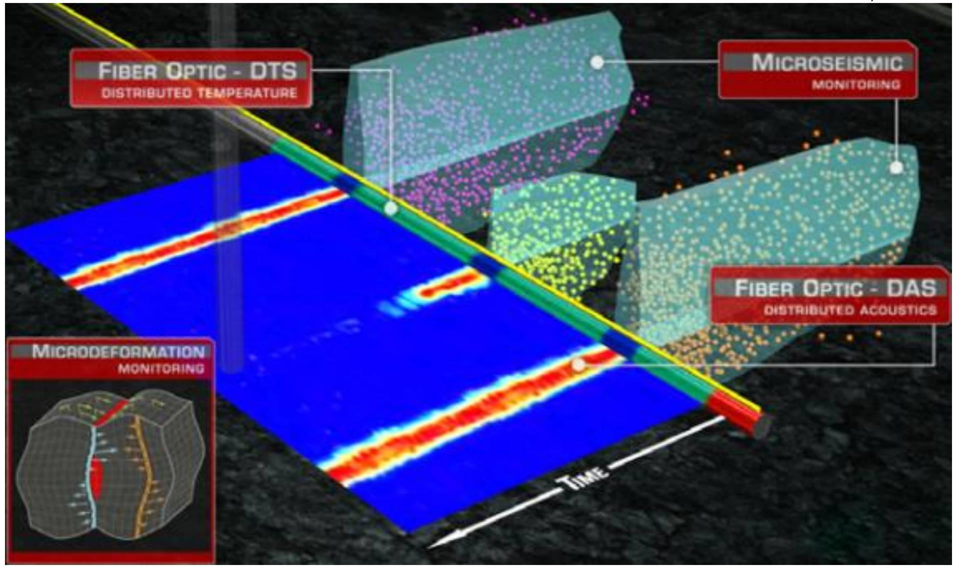
Source: Acosta et al., 2019

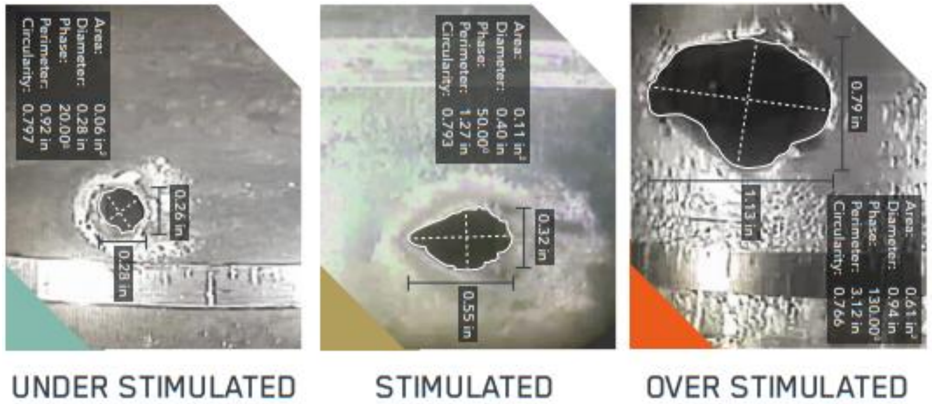
Cluster Efficiency – How to Measure it?

Objective: to have uniform treatment distribution among all clusters

- ✓ Many different approaches to meet the objective.
  - Not too many technologies to evaluate results.
  - Well to well productivity comparison is not the best approach.
  - Need to know how much is produced from every cluster.
- ✓ PLT on tractor or CT.
  - Intrusive. Propeller threshold limit may lead to wrong results.
- ✓ DTS/DAS.
  - Permanent installations bring more information but are more expensive and complex.
- ✓ Downhole camera.
  - Possible to see which clusters took fluid but not if they are producing.
- ✓ Microseismic mapping.
  - With current closer spacing among clusters, it is really difficult to assess if they are taking fluid.

Source: Halliburton, 2015





Source: Evcam.com

Frac Fluids Evolution – Most Used by Industry

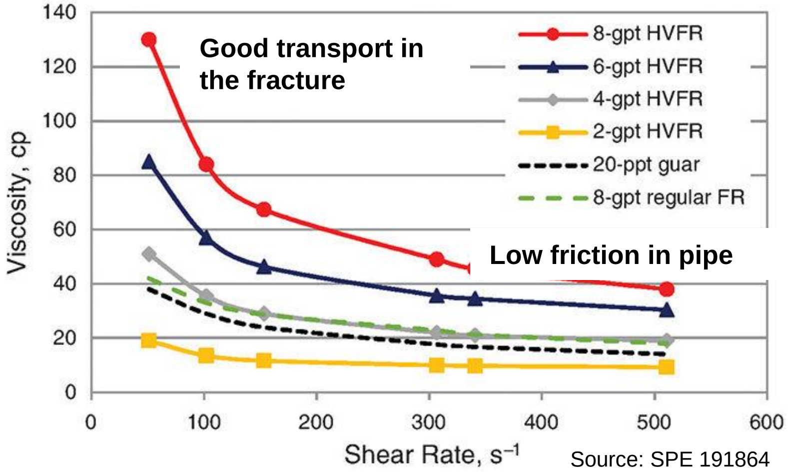
Where we come from – issues

- ✓ X-linked fluids.
  - Originally designed to optimize proppant transport at high concentrations in reservoirs with medium to high permeability. Leak-off is an important parameter in frac design to maximize frac geometry.
  - Costly, damage to formation always a concern, multiple additives, polymer breakdown and cleanout issues.
- ✓ Slick water.
  - Response to high cost of x-linked fluids. Water + friction reducer. Need high rate to transport proppant at relatively low concentrations. Viscosity not the main mechanism in proppant transportation. Maximum capacity 2 ppg.
  - Low cost, mostly used in tight and shale applications (low to ultra low permeability). Leak-off is not an issue.
- ✓ Hybrid designs.
  - The best of both worlds. In general a sequence of slick water, linear gel and x-linked fluid tailored to tight and shale applications. Moderate cost. Still a lot of additives for the different fluids. Logistics is an issue.
- ✓ HVFR
  - An evolution of slick water approach. Low cost. Minimum number of additives. Transport capacity is adjusted just by changing friction reducer concentration. High regained permeability. Use of breakers is not always necessary.
  - High adoption from industry. Be careful, not all products behave in the same way. Run your own tests!

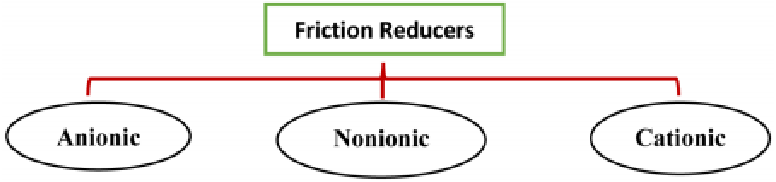
Frac Fluids Evolution – Current Trends

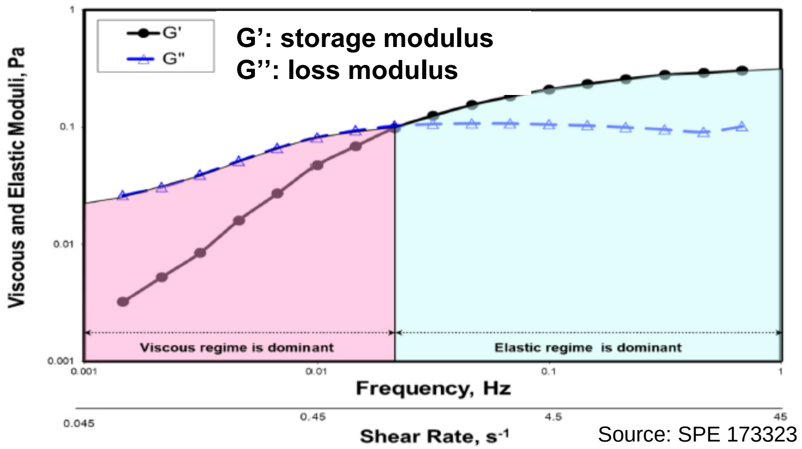
High Viscosity Friction Reducers (HVFRs)

- ✓ If friction reducer concentration is increased, apparent viscosity increases as well. Apparent viscosity is a function of shear rate.
  - Viscosity is a proportional constant term only valid for Newtonian fluids.
- ✓ New products have better apparent viscosity than standard friction reducers at the same concentration.
  - Multiple developments, different products. Same objective but different results.
- ✓ HVFR distintive features.
  - Need to understand fluid rheology behavior. Elasticity vs viscosity.
  - When G’>G’’ fluids are elastic and deemed better propant carriers.
  - Proppant settling is highly reduced. Improved sand-transport capacity.
  - Possible to pump proppants at higher concentrations.
  - Broken fluid is water-like with little or no solid residue. Enhanced productivity!
  - New chemistry allows produced waters with relatively high TDS to be used.



Source: SPE 191864



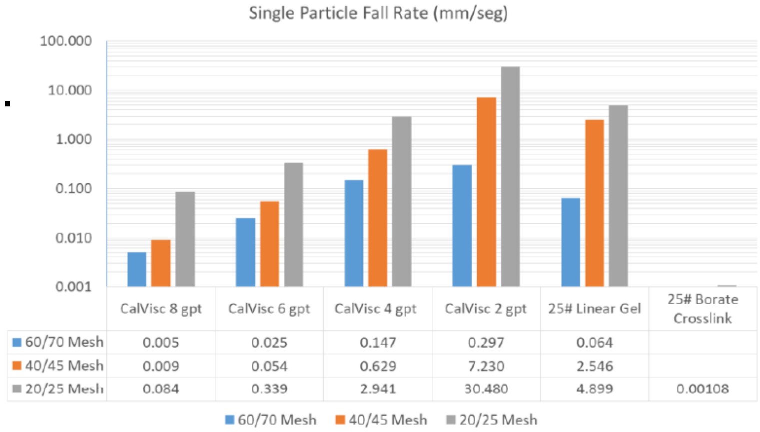


Source: SPE 173323

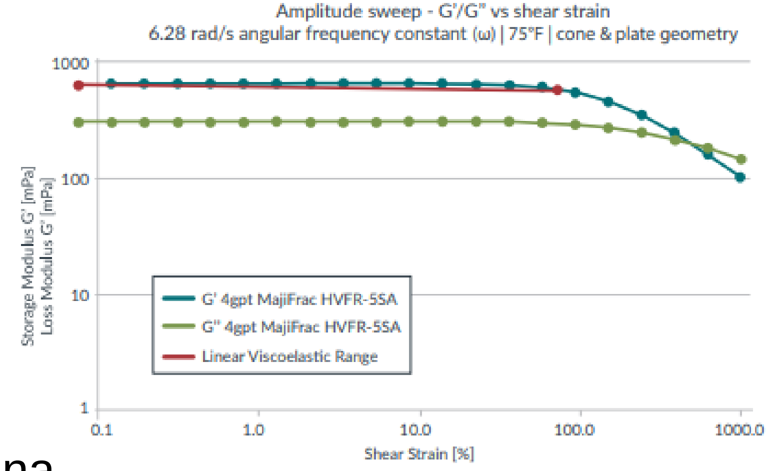
High Viscosity Friction Reducers – Summary

Main advantages

- ✓ Provided as much as 80% pipe friction reduction during fracturing treatments.
- ✓ Use less water compared with conventional slickwater treatments.
- ✓ Reduces chemical use by 33-48%. Less additives. Less logistics.
- ✓ Reduces freshwater, proppant, and equipment requirements compared with conventional fluid systems.
- ✓ Higher fracturing conductivities compared with linear and crosslinked gels.
- ✓ Better proppant placement compared with hybrid fluids and crosslinked gels.
- ✓ A less viscous fluid system creates more fracture complexity.
- ✓ Better hydrocarbon production results compare to or greater than other fluids.
- ✓ Simplifies operations by reducing screen out risks.
- ✓ Improves flexibility to design treatments that balance technical, economic, and operational goals.
- ✓ Reduces frac fluid cost by ~30% on a volume basis. Proven in US and Argentina.

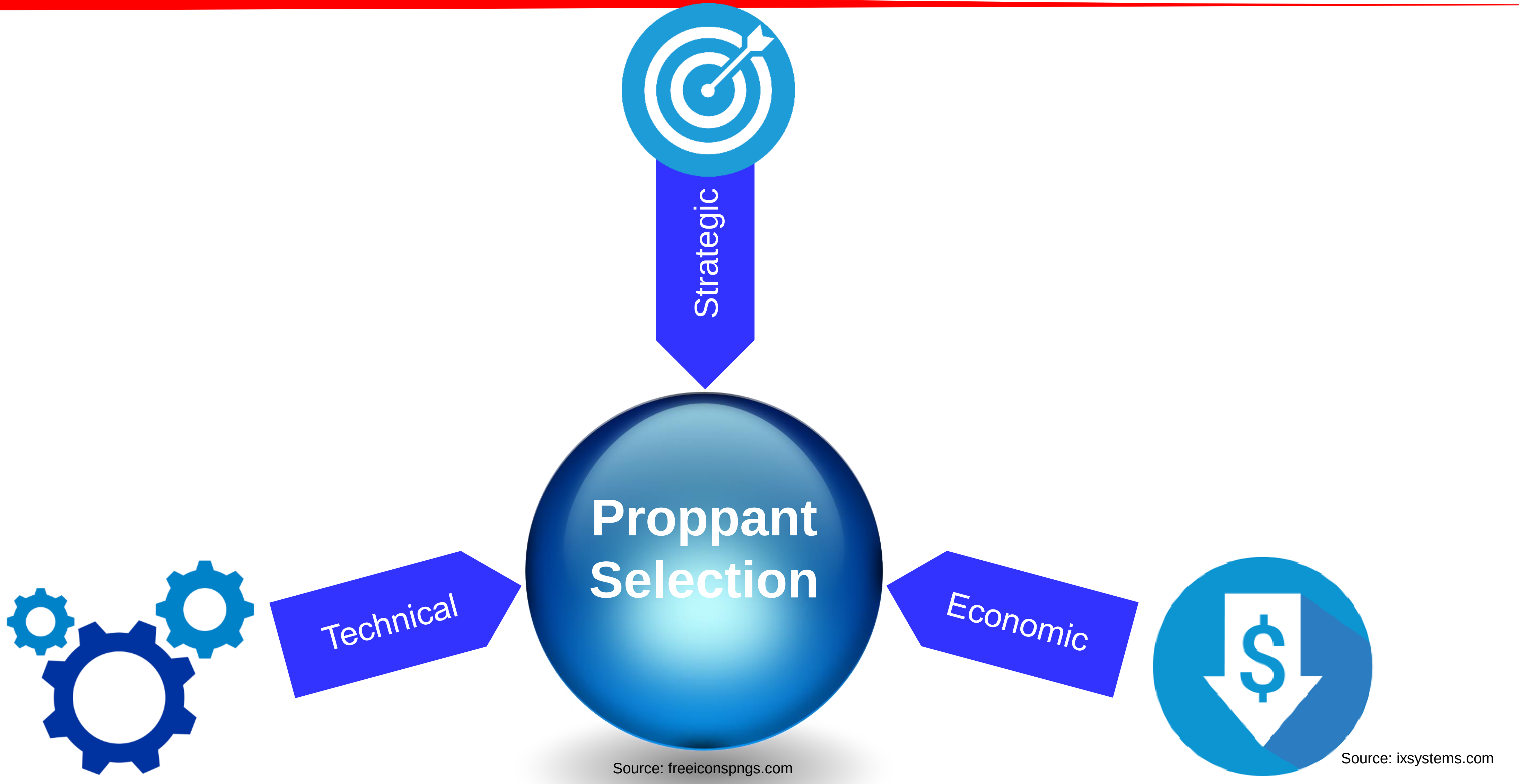


Source: Morales, 2019

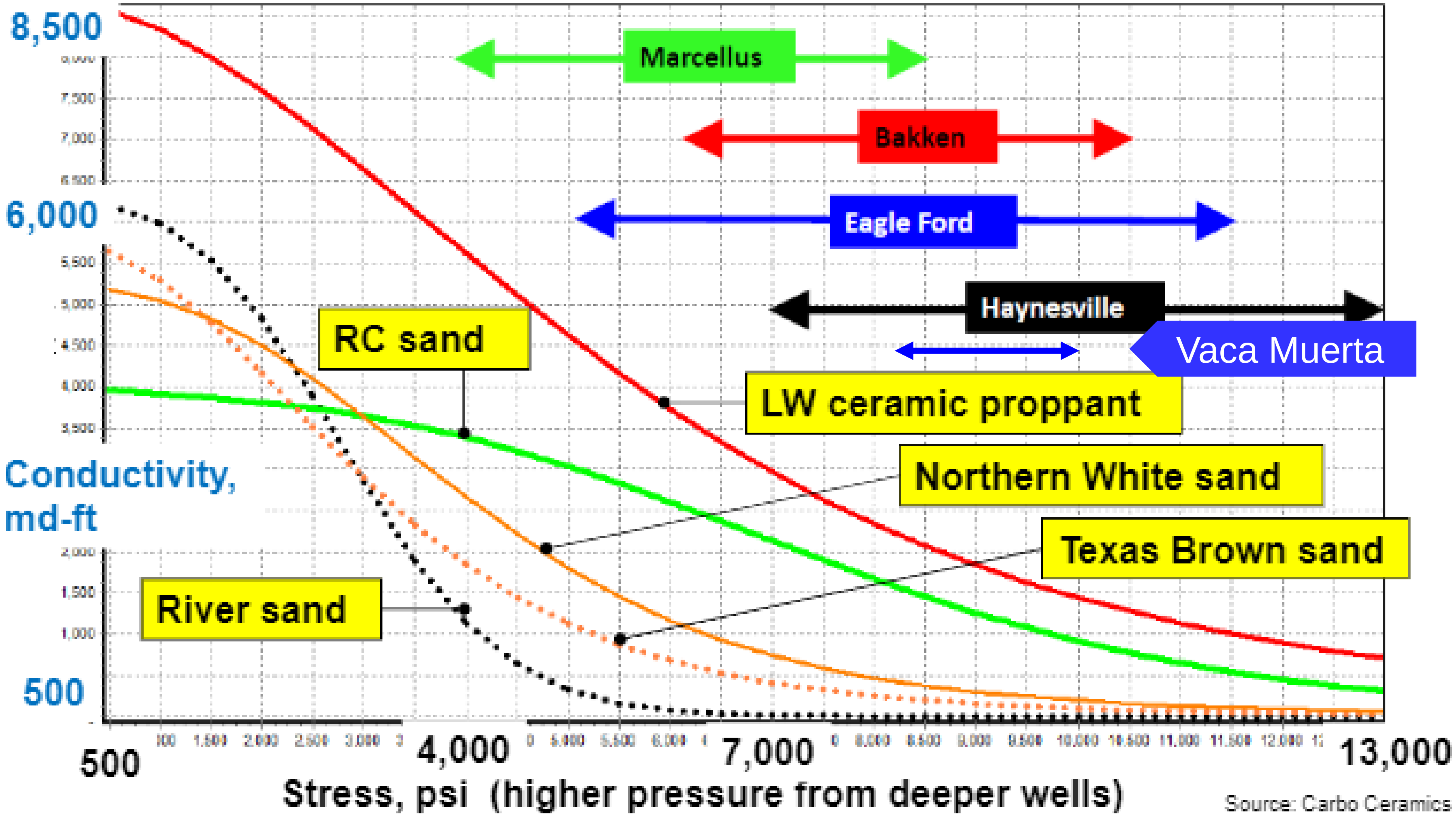


Source: Tendeka, 2019

Proppant Selection – A Tricky Dilemma



Proppant Selection Based on Conductivity



Proppant

Situation & challenges

- ✓ Proppant accounts for about 15 to 25% of the total well cost. Completion costs about 45 - 55%.
  - One of the main drivers.
- ✓ Originally northern white and brown sands were used on a regular basis (API specs).
  - Transportation costs and high demand did not allow reductions in unit price. Manufacturing process does not have room to improve (mature process).
- ✓ Multiple new mines come into market to satisfy demand and to compete for a piece of the market.
  - Some reductions in unit price but overstock.
- ✓ Appearance of new mines close to producing basins (in-basin sand) offering proppant with lower quality (even non-API) but at highly reduced pricing.
  - Quick adoption by operators eager to continue reducing overall well cost. Improved economics.
- ✓ Conductivity seems to be not important.
- ✓ Migration to lower mesh sizes (from 20/40 to 30/70 or 40/70) and even 100/200/400 mesh
  - Smaller sizes have better crushing properties.
  - Finer sands can be transported inside smaller fractures. Some operators trying micro and nano proppants.

Proppant

Industry reaction and response

- ✓ Minegate sand prices rarely exceeds 30 USD/tn even for Northern White sands.
  - If you can get a product with a higher quality for the same price it is worth purchasing it.
- ✓ Multiple mines has declared bankruptcy and many other are in the same route if conditions do not change.
  - Mines in general decided to stop producing.
- ✓ Still oversupply dominates the market making difficult for pricing to rebound at least in the short term.
- ✓ Although these conditions are excellent other issues are complicating the scenario
  - Shortage of qualified truck drivers and excessive road traffic are the main bottleneck in the last mile even for in-basin sands.
  - Limitations to transport oil and gas to refineries or ports
- ✓ Conductivity seems not to be important.
- ✓ Migration to lower mesh sizes (from 20/40 to 30/70 or 40/70) and even 100 mesh
  - Smaller sizes have better crushing properties.
  - Finer sands can be transported inside smaller fractures. Some operators trying nano-proppants but they are expensive

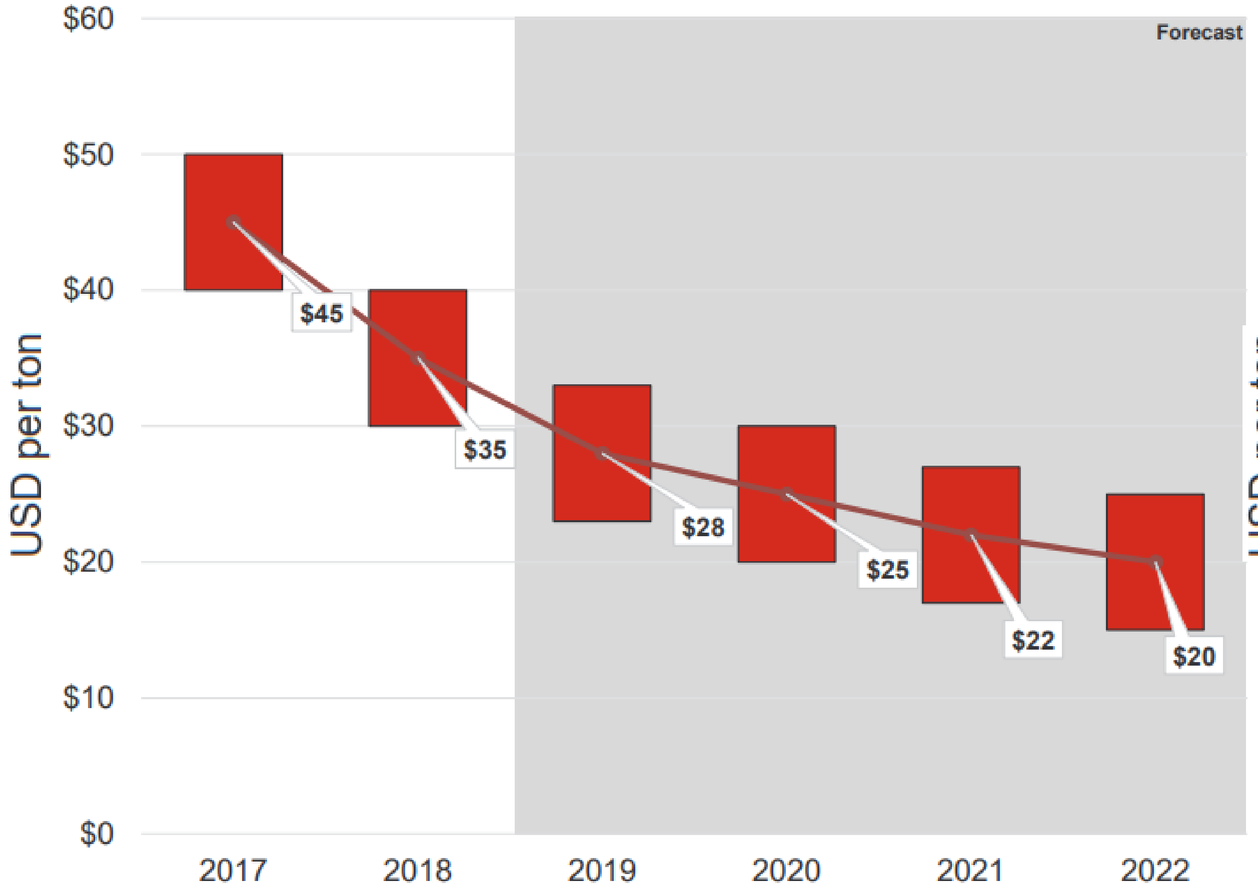
In-basin Frac Sand – A Disruptive Paradigm Shift?

Statements and opinions behind its utilization…I'm not saying they are true…let's see

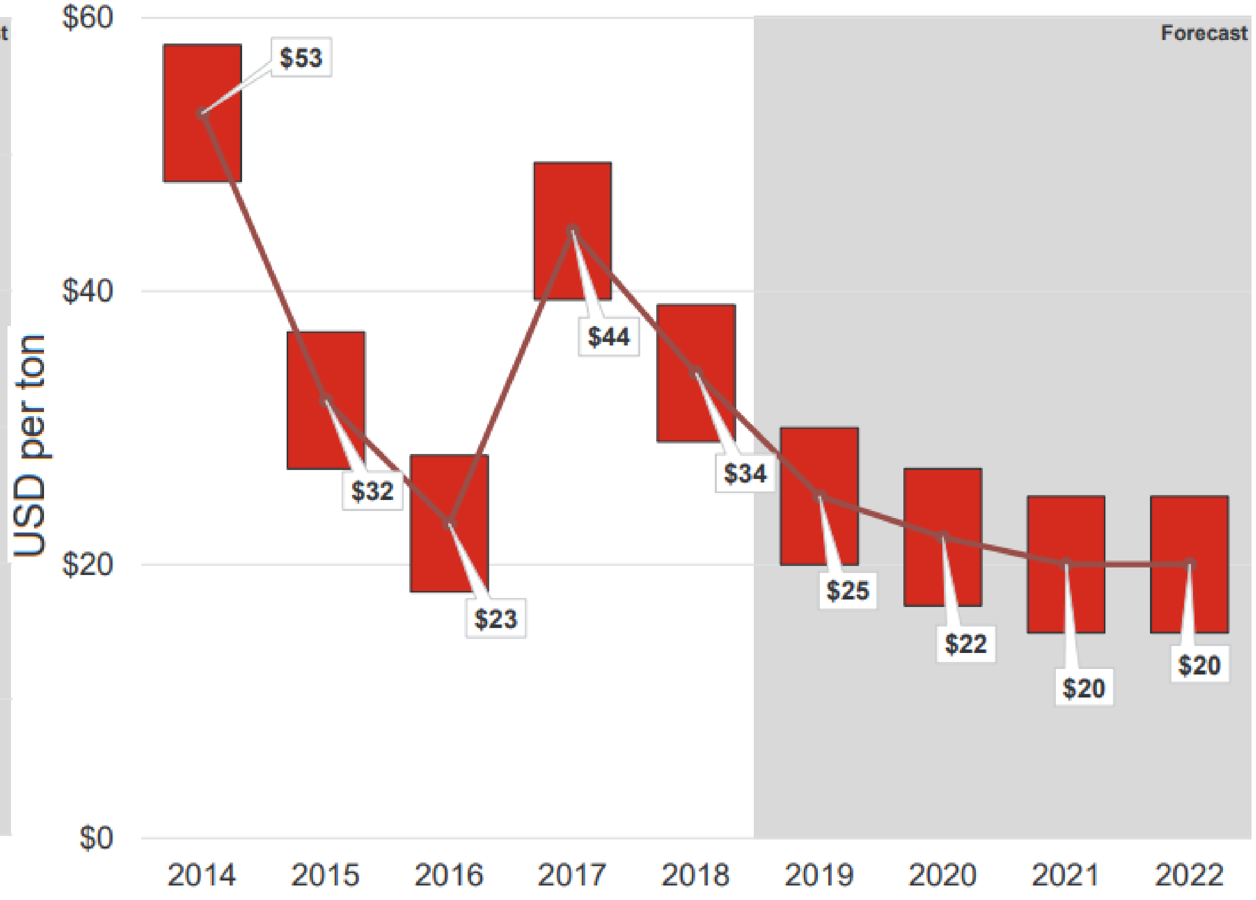
- ✓ "It is way than cheaper than northern white!".
  - Well economics are much better.
- ✓ "Production per fracture is so low that conductivity is actually not necessary".
  - Production is not impaired.
- ✓ "Increased use of finer sand in replacement of coarser mesh sizes allows more options in the market"
  - Finer sand has better crushing-related properties. Mechanical and other properties are not compromised.
  - Better when you use slick water treatments.
  - Option to use non-API sand.
  - In line with the no-need of conductivity in the proppant pack.
- ✓ "Last mile logistics is improved".
  - Silica dust is not an issue.
  - Possible to mitigate potential traffic congestion, demurrage and minimum storage capacity.
  - Box and silo solutions are the preferred options.
- ✓ "We haven't seen negative impact on production in the first 30 days so we are confident about the product".

In-basin Frac Sand Minegate Price – Permian vs NWS

Permian

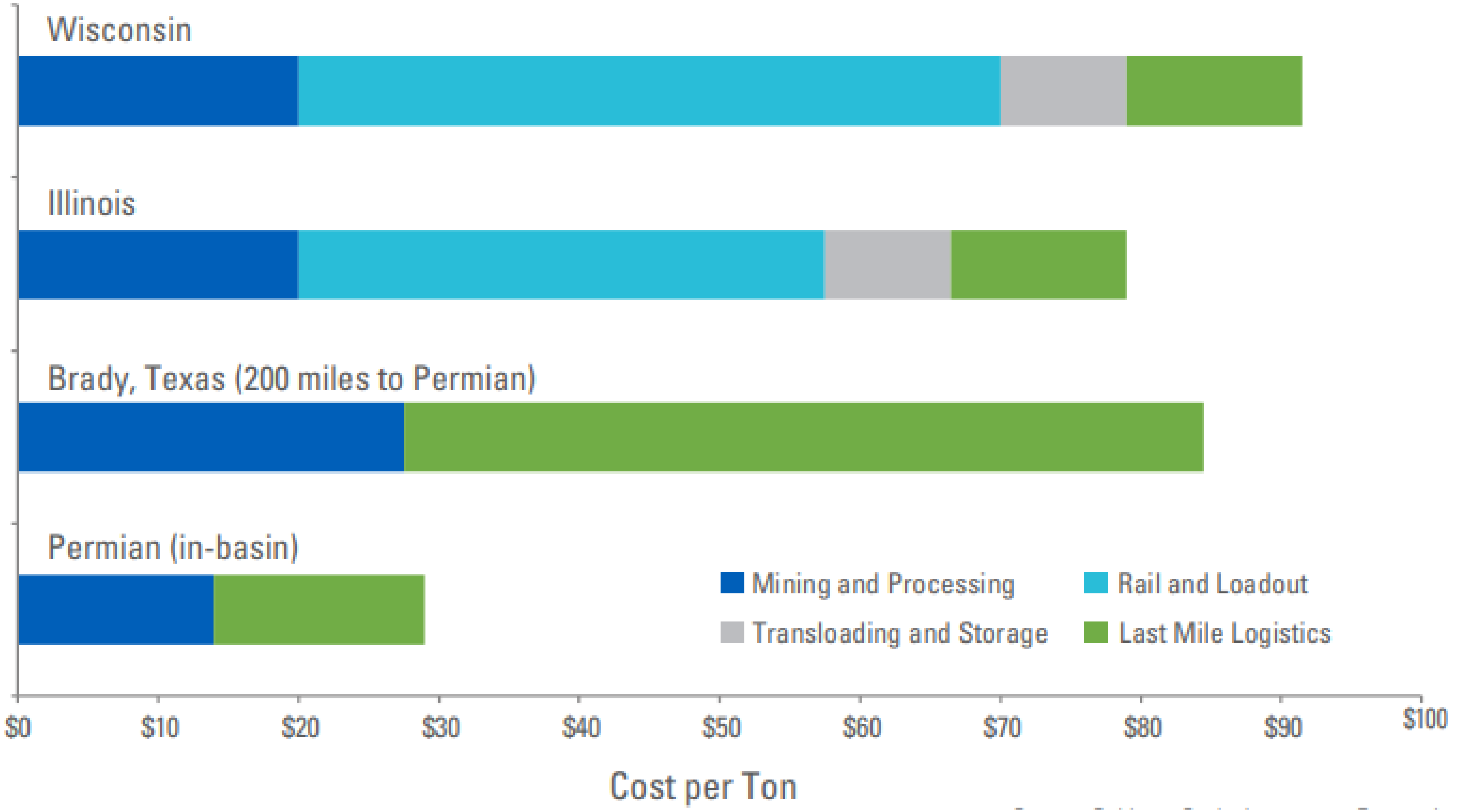


NWS



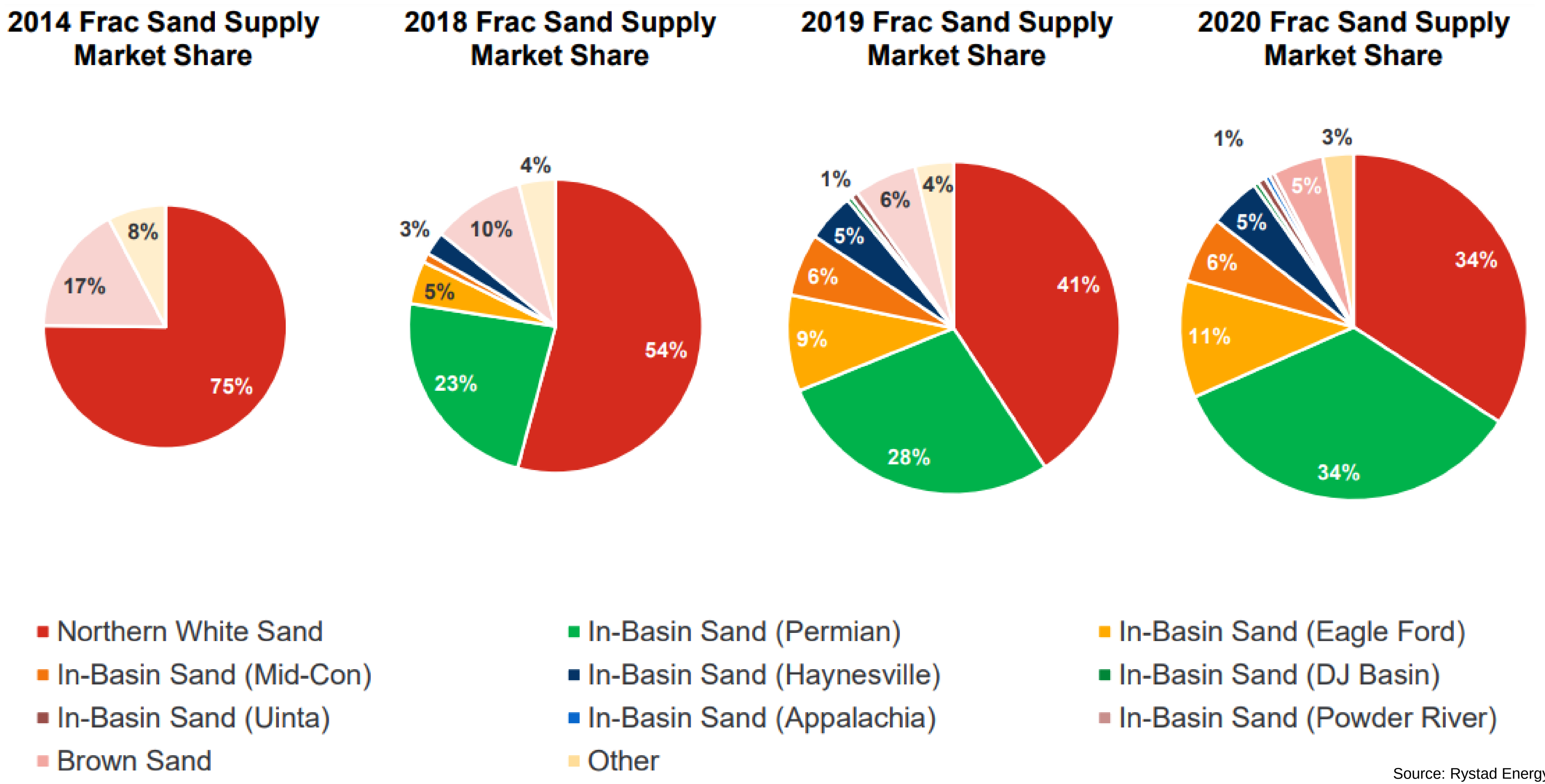
Source: Rystad Energy, 2019

Frac Sand Transportation Costs to Permian



Source: Goldman Sachs

In-basin Frac Sand – Market Share and Forecast



Source: Rystad Energy, 2019

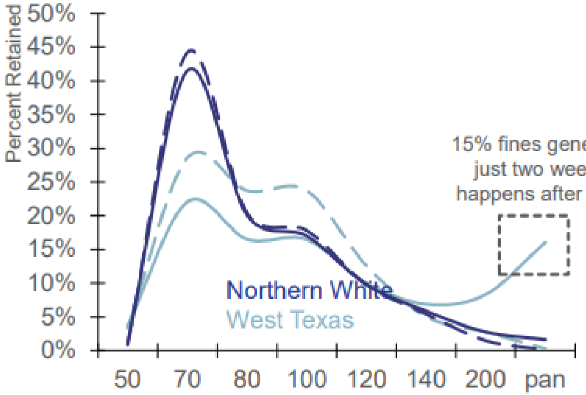
In-basin Frac Sand – Impact on Product Properties

Is mother nature creating all sands in the same way?

✓ Material quality.

- Northern white accounts for more than 99 % quartz. Monocrystalline grains. Main source of its strength.
- Brown and in-basin sands have more impurities, cleavage, polycrystalline grains.
- Impurities (e.g. clay, silt, iron minerals) react with acidic fluids creating insoluble products. More fines (higher turbidity).
- More spherical grains provide higher permeability. Angularity causes more turbulence (extra pressure drop = waste of energy).

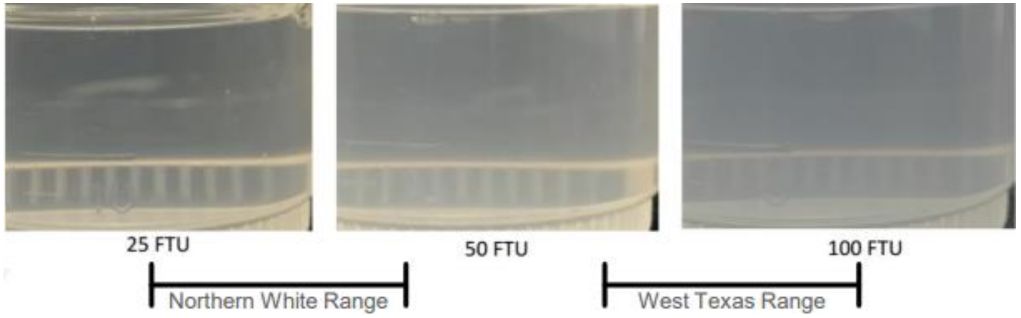
Particle size distribution before and after testing



Source: COVIA, 2019

Texas In-basin	Texas Brown	NWS

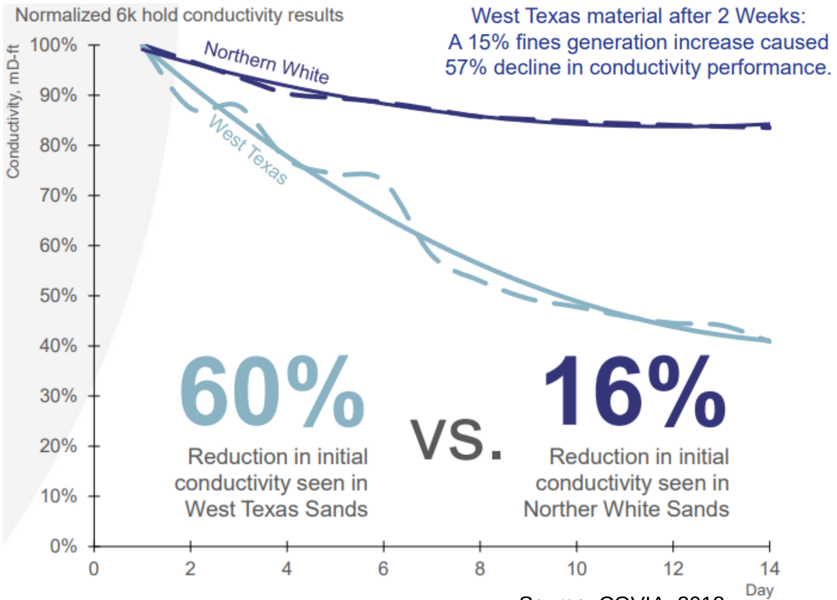
Spec.	40/70 In-basin, TX	40/70 Voca, TX	40/70 Unifrac
K value	5,000 psi	6,000 psi	>9,000
Spher. & Round.	0.7 / 0.6	>0.6 / >0.6	0.8 / 0.8
Turbidity	<100	<75	<50
Acid Solubility	<3	<2	<0.6



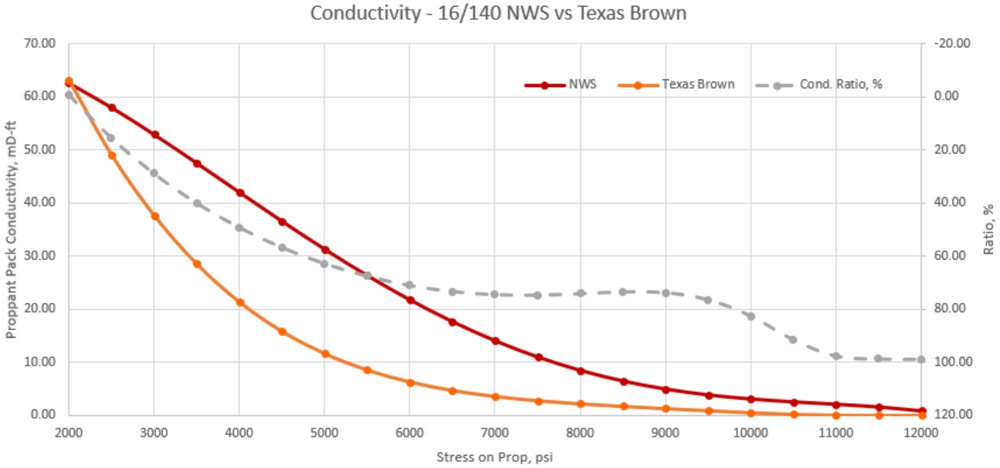
In-basin Frac Sand – Impact on Production

The good, the bad and the ugly

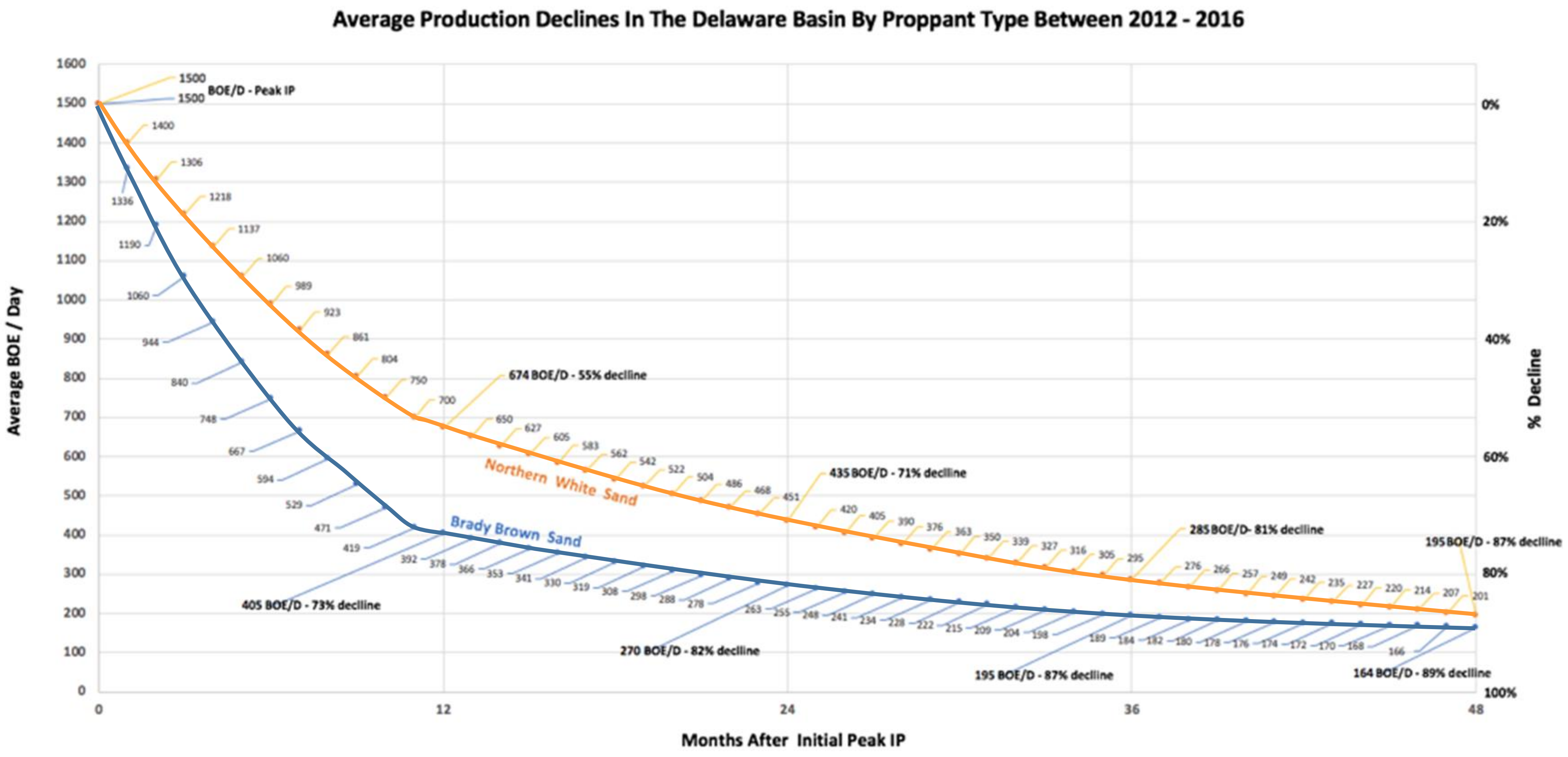
- ✓ Proppant pack conductivity is mainly a function of the mechanical properties of the material, the size of conduit, the effective stress on proppant and the reservoirs fluids that flow through the pack.
  - A hard truth: proppant pack degrades in time no matter what proppant you use. The lower the proppant quality, the sooner the degradation. Multiple factors (e.g. embedment, fines, spalling, crushing, diagenesis).
  - Effective stress is the bad guy. Deeper plays suffer the effect more than shallower ones (e.g. Delaware vs Midland in the Permian).
  - Oil has higher viscosity than gas so oil wells are more affected.
- ✓ Productivity KPIs.
  - If you are just planning to use IP for your metrics you will not see distinguishable differences. At initial time the effective stress on proppant is not enough to cause a significative difference in the degradation of the proppant pack.
  - Problems will come months later as actual decline is not as expected. Well economics would plunge. Savings may wipe out in just few months!



Source: COVIA, 2018

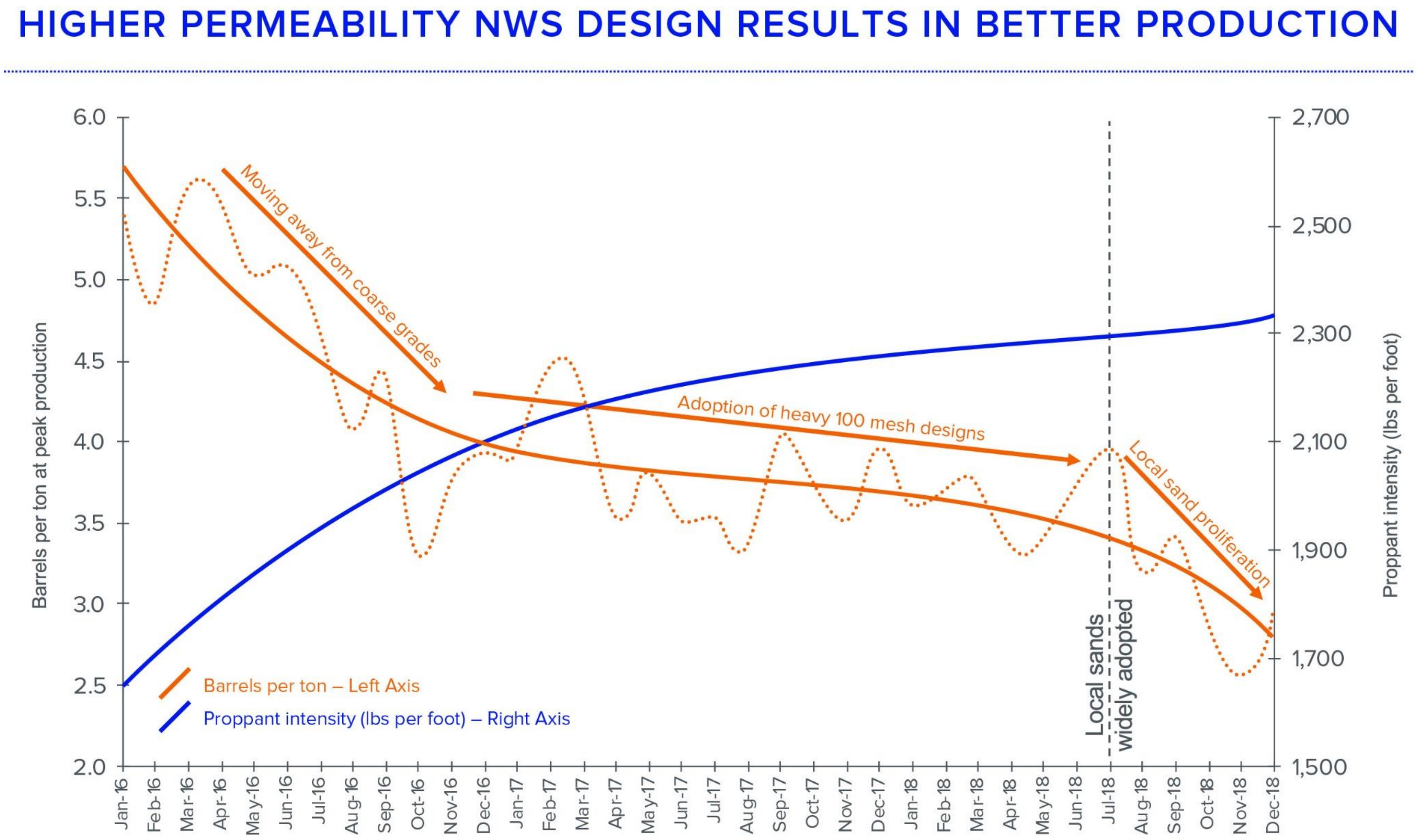


US Delaware Basin – Production Decline per Sand Type



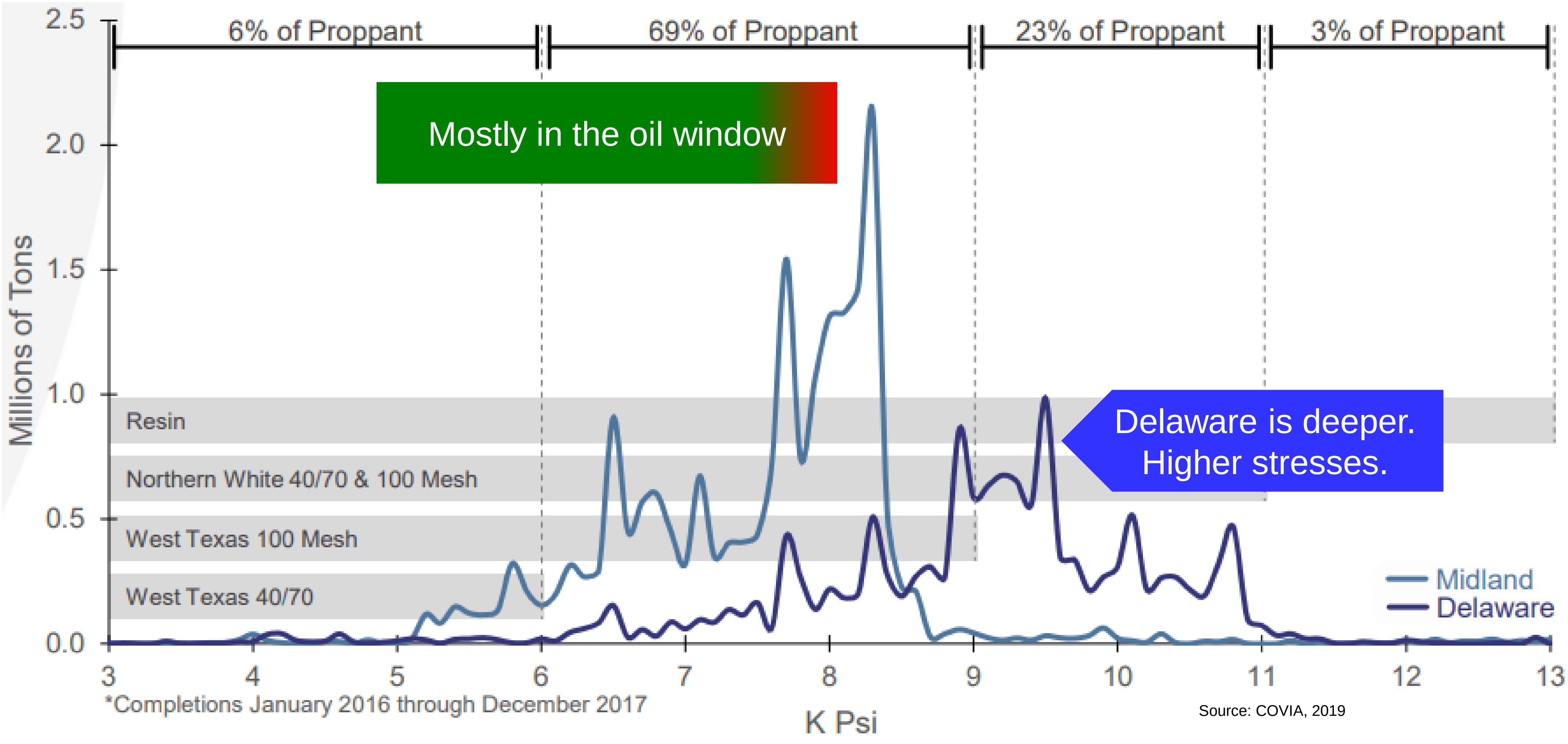
Source: Rystad Energy, 2019

In-basin Frac Sand – Design vs Productivity Evolution

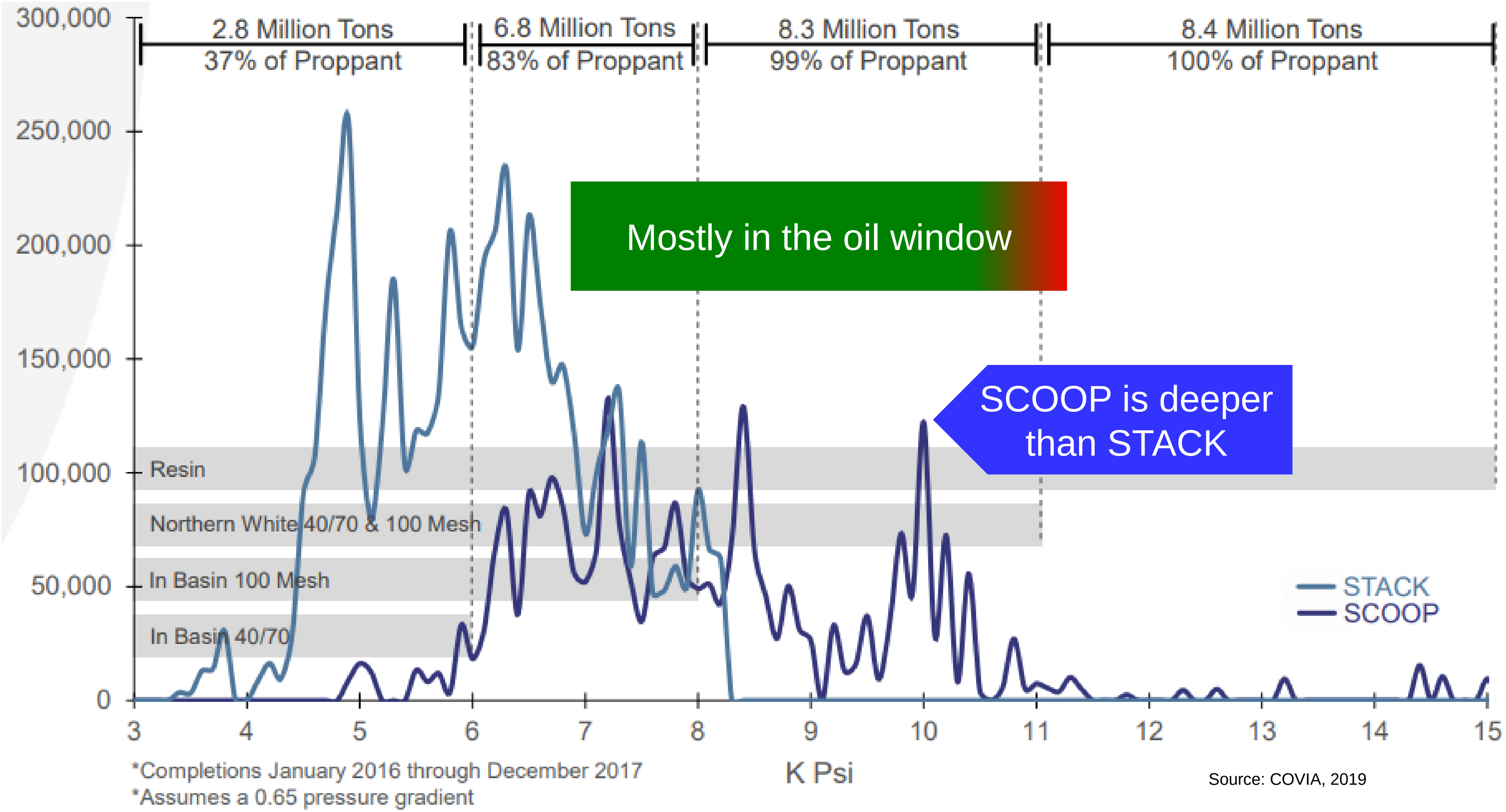


Source: COVIA, 2019

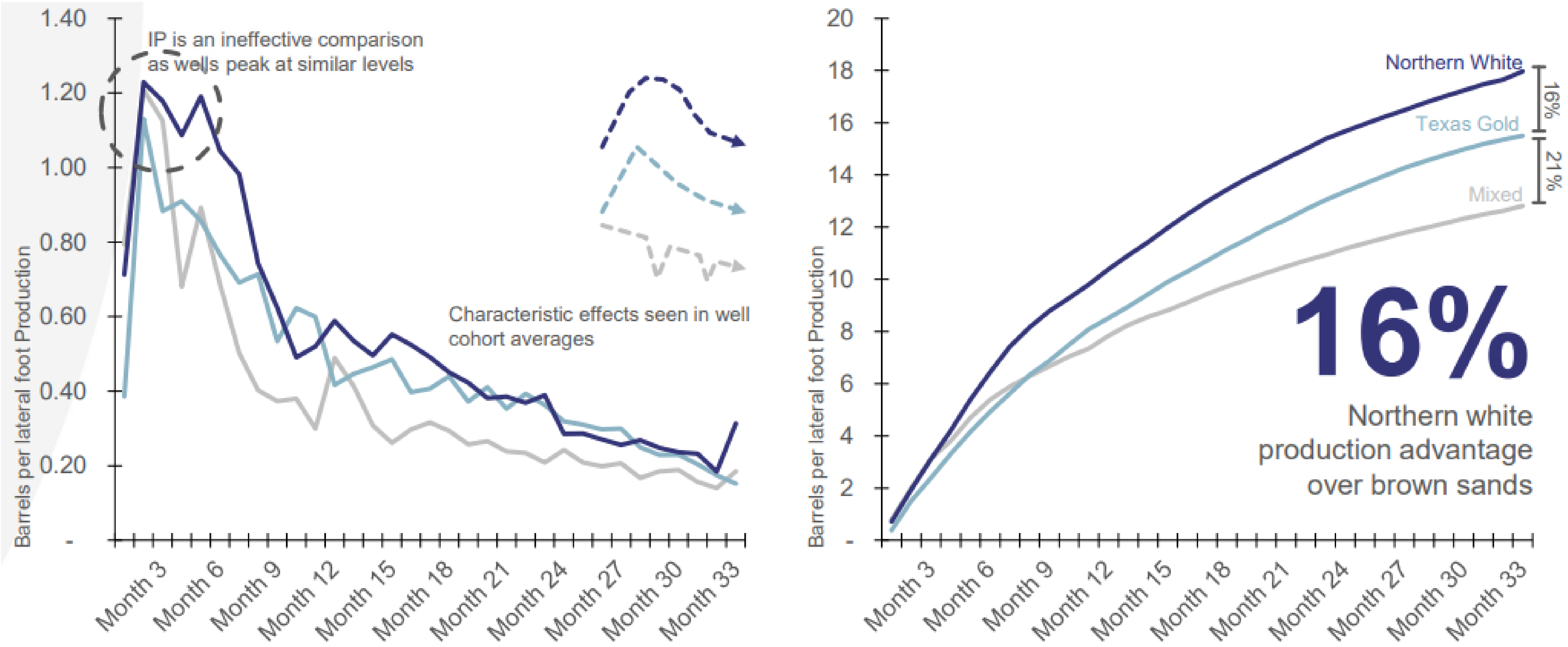
Permian – Proppant Utilization



MidCon – Proppant Utilization



In-basin Frac Sand – Impact on Production



Source: COVIA, 2018

In-basin Frac Sand – Real Facts

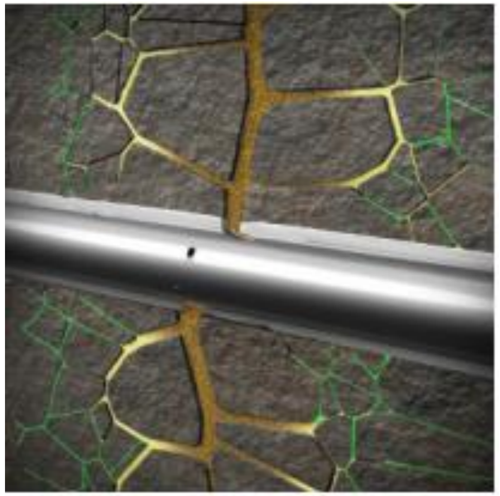
Statements and opinions behind its utilization…I'm not saying they are true…let's see

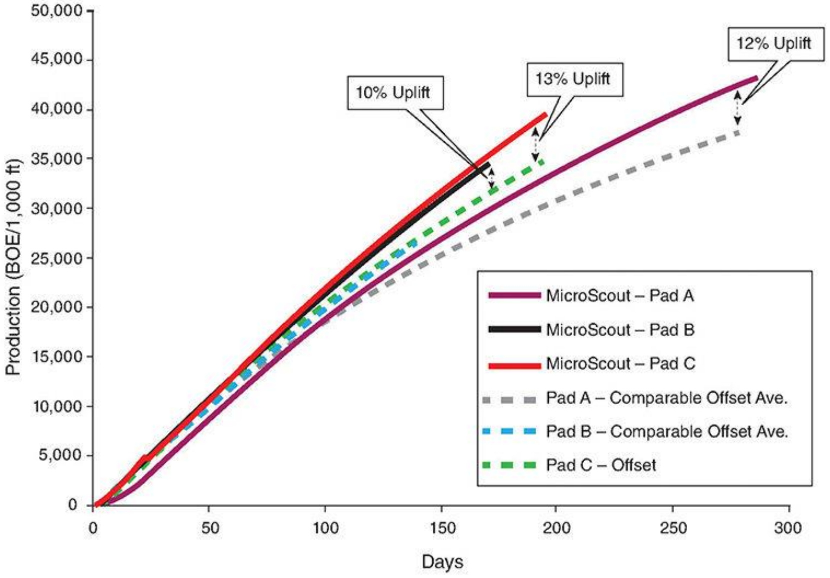
- ✓ "It is way cheaper than northern white!".
  - Well economics are much better.
- ✓ "Production per fracture is so low that conductivity is actually not necessary".
  - Production is not impaired.
- ✓ "Increased use of finer sand in replacement of coarser mesh sizes allows more options in the market"
  - Finer sand has better crushing-related properties. Mechanical and other properties are not compromised.
  - Better when you use slick water treatments.
  - Option to use non-API sand.
  - In line with the no-need of conductivity in the proppant pack.
- ✓ "Last mile logistics is improved".
  - Silica dust is not an issue.
  - Possible to mitigate potential traffic congestion, demurrage and minimum storage capacity.
  - Box and silo solutions are the preferred options.
- ✓ "We haven't seen production impact in the first 30 days of production so we are confident about the product".

Finer than 100 Mesh – Micro and Nano Proppants

In the pursuit of better propped fracture networks

- ✓ Latest field and lab tests have shown that conventional mesh sizes are not fully transported beyond the main fractures, even 100 mesh.
  - Deep proppant transportation inside the main fracture is limited.
  - Secondary and tertiary fractures do not receive any conventional proppant. Basically due to reduced width and frac fluid transporting capacity.
- ✓ Production from “fracture network” around main fracture is quickly lost.
  - Steep decline rate is a clear evidence.
  - What if we can prop those tiny fracs? Would they sustain production longer?
- ✓ Response from industry.
  - Operators testing 200 and 400 mesh. Some tests using nano-proppants.
  - Originally silica flour. Currently coarser distributions are the norm. Other materials as fly ash are also utilized. Transported as concentrated slurry.
  - 200 mesh has K-values in the order of 13,000 psi. It is possible to transport it even with slick water deep into the fractures. Usual concentrations of 0.1 ppg.
  - Natural availability is limited. Manufactured product. More expensive.



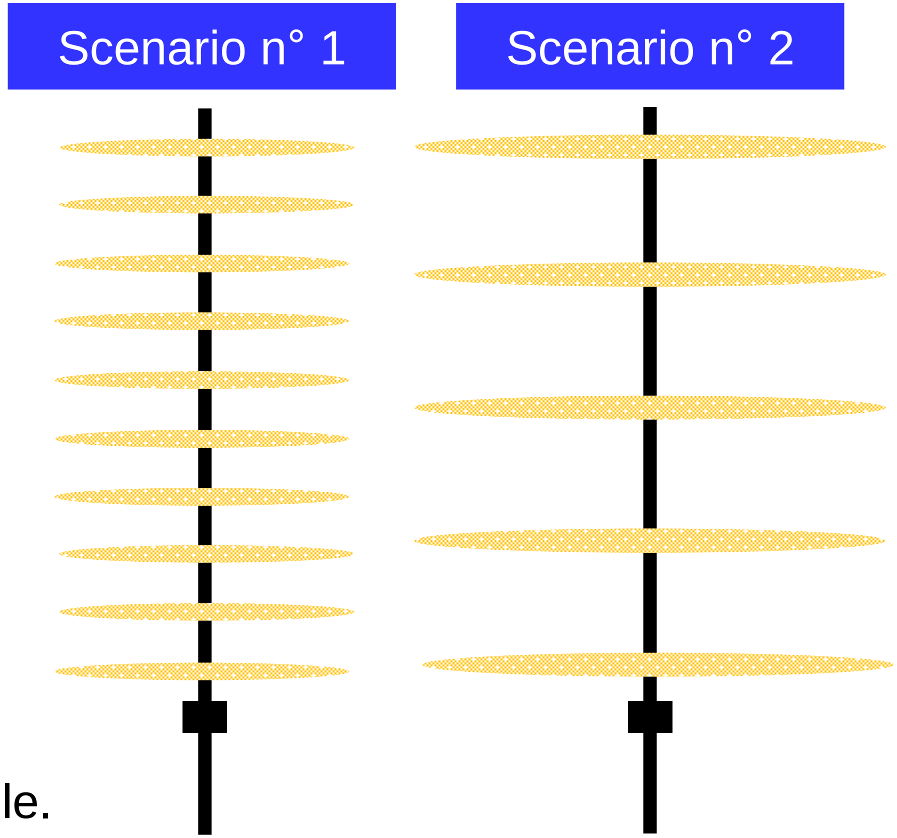


Source: Halliburton, 2017

Proppant Intensity Metrics – A Good Proxy?

Case Analysis

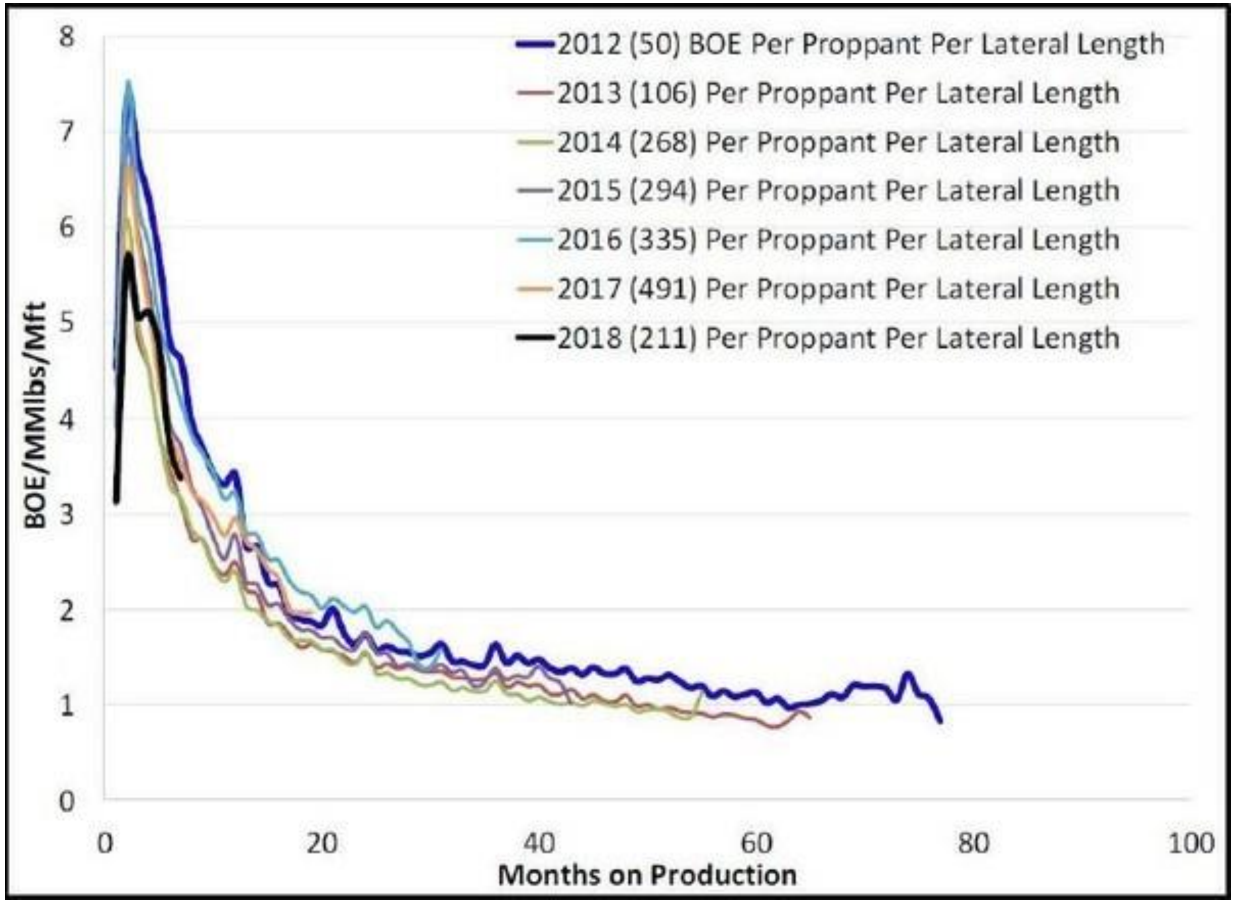
- ✓ Scenario n° 1
  - 50 m frac spacing. 10 clusters.
  - 550,000 lbm of proppant. Uniform proppant distribution.
  - Proppant per cluster: 55,000 lbm.
  - Proppant intensity: ~3,350 lbm/ft.
- ✓ Scenario n° 2
  - 50 m frac spacing. 5 clusters.
  - 550,000 lbm of proppant. Even proppant distribution.
  - Proppant per cluster: 110,000 lbm.
  - Proppant intensity: ~3,350 lbm/ft.
- ✓ Both provides same results in terms of proppant intensity. Questionable.
  - Easy to use because data is publicly available (total proppant and well length).
  - Not useful as proxy for productivity! Analysis can be completely wrong!
  - Be careful when you normalize data. Understand what factors affect productivity the most. What length do you use to normalize?



Frac Hits – Parent-child Issue – Midland Basin

Actual problem example

- ✓ Production analysis.
  - Production adjusted for lateral length and pounds of sand per foot to make them comparable by year. Apples to apples.
  - While IP rates have gone up significantly over the past seven years as the wells got longer and amount of sand used increased… the older wells produce more oil, for less money.
  - The Permian wells aren't getting better every year… they are actually getting worse.
  - The issue for the entire Permian Basin relates to parent-child wells. Every year, every company is drilling a higher percentage of child wells and those wells are simply not as powerful as the parent wells."
- ✓ Is this going to continue?
  - No. Companies are reacting towards the understanding the problem and setting mitigation strategies.

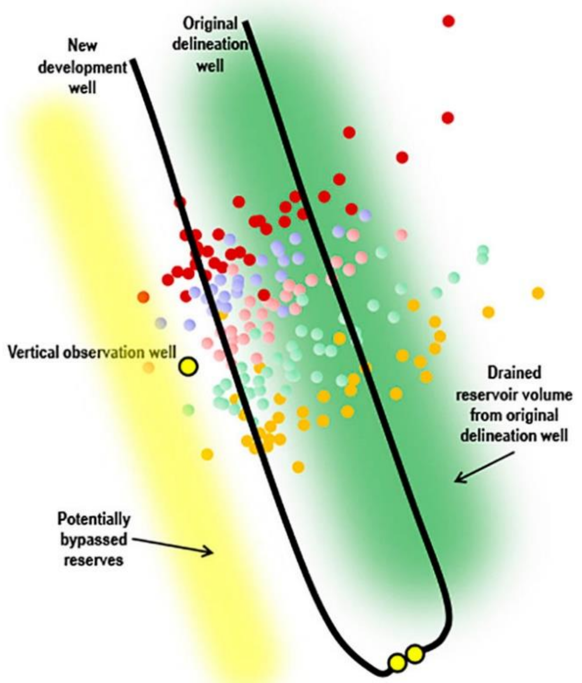


Source: oiland gas-investments.com

Frac Hits – A Nightmare or Just a Bad Dream?

The issue

- ✓ Frac hits or well bashing are the cause of hydraulic fractures intersecting other fracture network in an offset well, the wellbore itself or both.
  - Most likely to occur in parent-child conditions where parent well has been on production for a while after fracturing.
  - Stimulated volume around the parent well has depleted to certain value which causes a reduced stress zone.
  - From energy perspective easier for the fractures in the child well to propagate towards the parent well.
  - Worst case scenario is when proppant reaches the other well sanding it up.
- ✓ Frac hits can impair well productivity and integrity.
  - In general parent’s well productivity is negatively affected. Wells do not come back to original production rate. Only in certain cases there is a positive effect.
  - Pressure wave can damage casing, wellhead and other components of the parent well, thus requiring a costly workover to reestablish well integrity and associated production.
  - Child productivity is affected as well as stimulated volume is reduced as a consequence of selective propagation fairways.



Source: Halliburton.com


Source: eagleford.training

Frac Hits – Main Factors

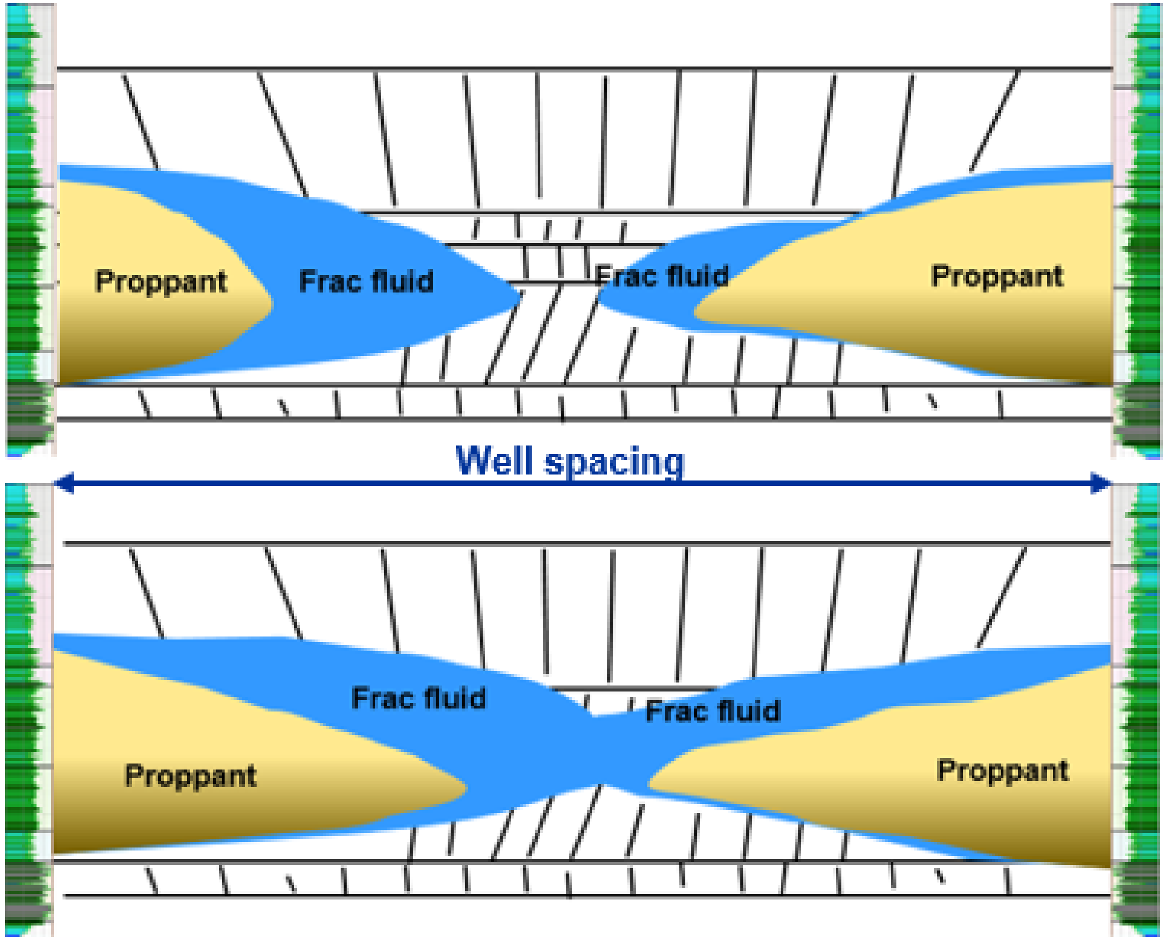
Understanding the issue and mitigation strategies, do we have any responsibility?

- ✓ Probability and severity are a function of several parameters.
  - Well spacing.
  - Parent well fracture design.
  - Period of depletion, extend and amount of depletion, drawdown of parent well.
  - Reservoir fluids.
  - Treatment design in the child well. Asymmetric fracture growth and dominant fracture.
- ✓ Mitigation strategies.
  - Optimized well spacing. In general increase well spacing.
  - Adequate parent and child well fracture design.
  - Completion of all the wells at approximately the same time. Cube, tank, sequential or rolling developments.
  - All wells start producing at around the same time. All wells have same initial pressure.
  - Refracturing.
  - Repressurization or pre-loading of parent well.
  - Shutting in parent well for a long time.
  - Do nothing! Pump and pray…

Frac Hits – Mitigation Strategies

Optimized well spacing

- ✓ Originally mostly all operators in US moved into reduced spacing to accommodate more wells which brought the issue of frac hits.
- ✓ No frac hits mean that spacing is too wide.
  - You are nor producing reserves between wells.
- ✓ Ideal situation.
  - Wells slightly "talk" while they are being fractured.
  - Some interactions are experienced (e.g. pressure, water production increase, detection of tracers, etc.).
  - When wells are put on production, no further communication is experienced. One well produces independently from the other one.
- ✓ Real world.
  - Interaction depends mainly of completion and frac design.
  - Need to optimize well spacing to maximize recovery on a continuous basis.



Frac Hits – Mitigation Strategies

Repressurization or pre-loading – fighting water with water

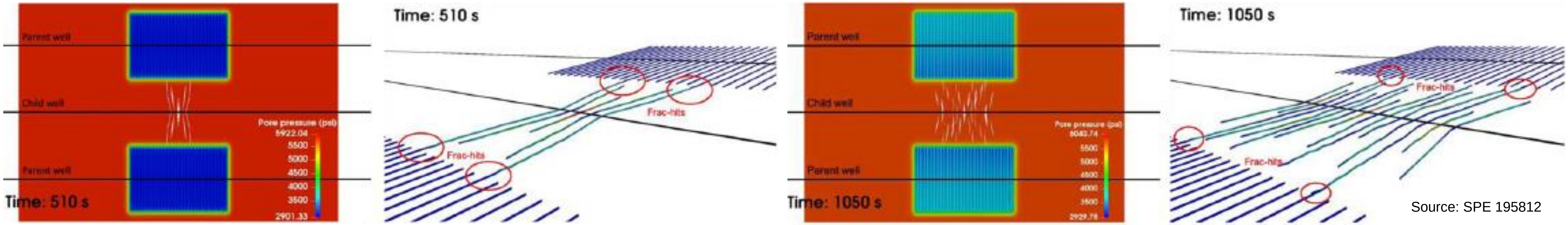
- ✓ Key factors.
  - Only volume very close to the parent well is temporarily repressurized.
  - Increase in pressure induces poroelastic stress to increase as well creating a high-stress barrier that repel fractures from child well to hit parent well.
  - It requires an engineered quantitative design (e.g. injection time, volume, fluid, etc.), otherwise frac hits will still be observed. It is common to pump at least for a month as a minimum.
  - No intention at all of repressurizing depleted zone around the parent well. Unreasonable amount of fluids required which turns this option an uneconomical option and difficult to bring back production to original levels.
  - Even if water is the most common fluid used for repressurization the use of gas has certain advantages.
  - Injection of water in gas wells can cause water blockage. Injection of gas in oil well may improve productivity in oil-rich reservoirs.
- ✓ Other considerations.
  - Well must be stimulated as soon as possible as effect is of short duration.
  - For the same pressure drawdown, the total stress change is higher in oil wells than in gas wells. Frac hits are more probable in a black-oil reservoir and less likely in a gas one with volatile oil reservoir in between.

Frac Hits – Mitigation Strategies

Child completion design

✓ Increase number of clusters and application of extreme limited entry perforation.

- This approach leads toward more uniform fluid and proppant distribution.
- For the same amount of fluid and proppant is expected that each cluster takes less amount of both resulting in shorter fractures and less probability of hitting the parent well in theory.
- Extreme limited entry creates large stress shadow effects leading to narrower fractures that coupled with very low leakoff makes faster propagation of fractures toward the parent well.
- This strategy in essence just delays the problem but does not solve it completely.



Source: SPE 195812

Frac Hits – Other Actions

Proactive approach

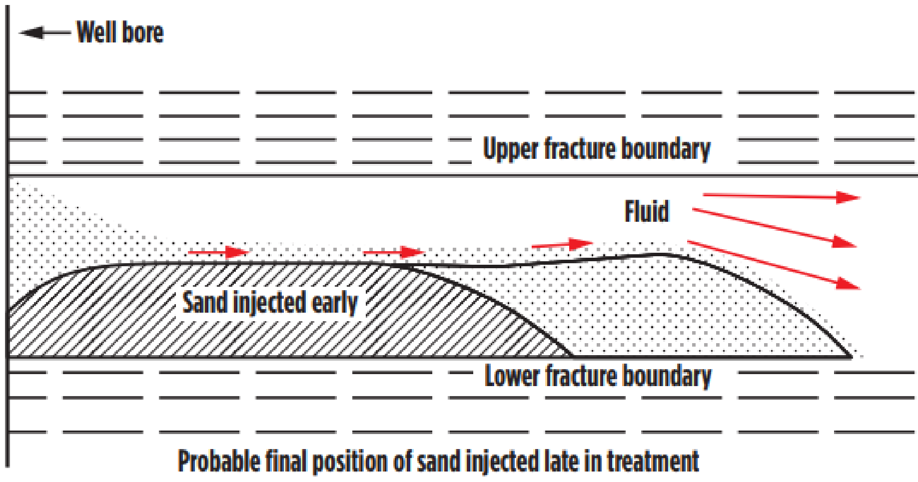
- ✓ There are many other things you can do to understand better and develop a solid mitigation strategy.
- ✓ Pre-fracturing.
  - Provide notice to involved parties (inside and outside the company). Rule in certain US states.
  - Replace and/or protect surface and downhole equipment. Use plugs, BPV, etc.
- ✓ During the fracturing process.
  - Monitor pressure in offset wells.
  - Monitor production and water cut in nearby wells.
  - Activate permanent micro seismic mapping if available and monitor.
- ✓ Post fracturing.
  - Monitor tracers in offset wells.
  - Analyze pressure behavior in other wells.
  - Perform workovers in affected wells to clean out potential proppant, replace damaged equipment, etc.
  - Install new artificial lift systems in case you need to produce more water.
  - Integrate all information and develop a mitigation strategy, validate existing one or update it.

Source: abracontrols.com

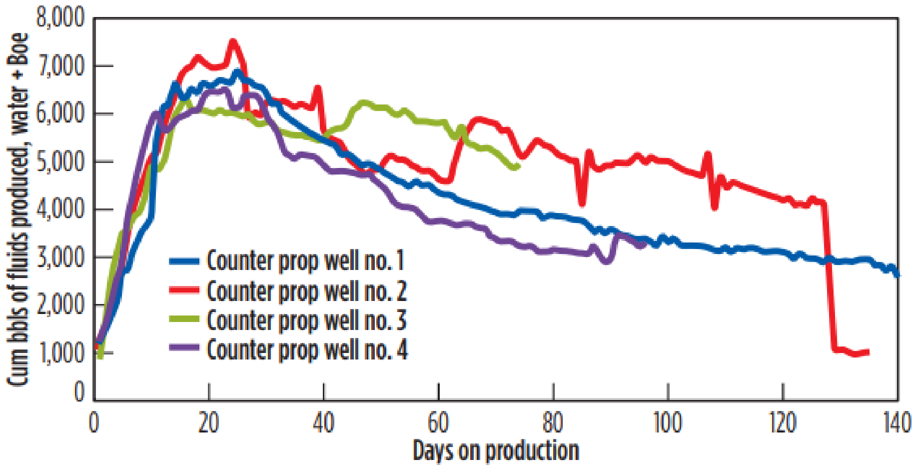
Frac Design – CounterProp Technique

Counterintuitive approach but with positive results

- ✓ Developed and promoted by John Ely (one of the last alive frac legends).
  - A radical thinker who does not follow the pack in many aspects of frac design.
- ✓ Fundamentals.
  - When slickwater is pumped, proppant transportation leads to the formation of sand banks. Mostly all proppant pumped firstly stays closer to perfs.
  - Reason why fine sand is observed during early flowback.
  - So if you want to have coarser sand close to perforations, you need to pump different mesh sizes in reverse order.
- ✓ Design at a glance.
  - Pump huge volumes of slick water and fine sand (40/70 first and 100 mesh).
  - Pump at high rate (at least 80 bpm) to have adequate transportation.
  - Maximum proppant concentration in the order of 2 to 2.5 ppg.
  - Results have been validated in the Rockies and Permian.



Source: John Ely, 2019



Plug Mill-out and Flowback Nexus – Fundamentals

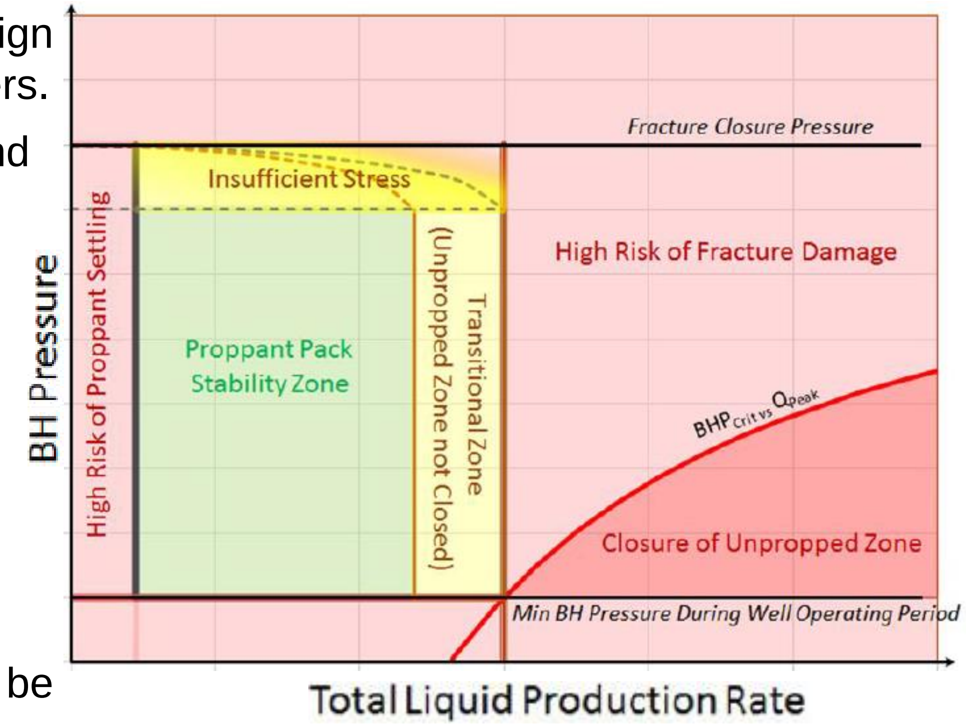
Integrated fluid management for better results

- ✓ Flowback importance.
  - Critical process as it can cause highly detrimental effects if not properly optimized.
  - Necessary to develop a safe operating envelope to prevent early proppant flowback, proppant crushing, damage of near-wellbore proppant pack, loss of micro-fracture production network, reservoir energy, etc. Mostly are not fully reversible processes.
  - Flowback starts as soon the well starts making fluid during and after plugs mill-out.
- ✓ Flowback control.
  - By controlling downhole pressure thru the use of an optimized choke size sequence to extend the period of natural flow (increased cumulative production). This approach goes against well economics as small chokes are recommended. Best solution must contemplate both sides.
- ✓ Controlling parameters.
  - Sensitivity of pressure drawdown, differential pressure across proppant pack.
  - Liquid production rates, reservoir fluid main phase. Viscosity of produced fluids.
  - Fracture parameters that affect proppant pack stability such as closure pressure, proppant type, reservoir pressure, etc. Fracture closure takes a long time to stabilize its proppant pack. During this period fractures at all levels are fragile.
  - Created fracture (planar vs complex).

Plug Mill-out and Flowback Nexus – Best Practices

Integrated fluid management for better results

- ✓ Flowback balance during plug mill-out.
  - Difference between injection rate and annulus returns. Magnitude and sign are directly related to instantaneous flow rate in or out perforation clusters.
  - Maintaining a close to zero balance helps protecting fracture network and potential proppant flowback. Minimize dynamic changes.
- ✓ Flowback during early production phase.
  - At the beginning minimum choke sizes must be used (8/64” – 12/64”).
  - Drawdown in the order of 10 to 200 psi/day are standard but a better strategy is to use 10 – 100 psi/day to minimize stress peak impact on proppant. Aggressive flowback practices must be avoided.
  - While the well is making fracturing water and oil and gas cut are lows, choke size must be small as well and drawdown strategy must be conservative. Once water has decreased substantially, choke sizes can be gradually increased. Avoid sudden changes to mitigate water hammer effects on proppant and destabilize proppant pack.
  - Build a Secure Operating Envelope chart to have a better understanding of your particular condition



Source: URTEC-285-2019

Q & A Session

Source: chartcons.com

Source: latinschool.org

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