FarFrac

The Need For Tailored Frac Designs

SIPES Midland Chapter Luncheon – October 28, 2026



Agenda

01	**The Permian by the Numbers**	Drilling, completions and productivity trends since 2010
02	**Framing the Problem**	Optimization levers, the 3P's, and the data we need
03	**Verticals vs. Horizontals**	Near-wellbore is the bottleneck
04	**Viscosity in Practice**	Slickwater vs. HVFR – execution and production
05	**Rethinking Lbs/ft**	Designing per cluster, not per lateral foot

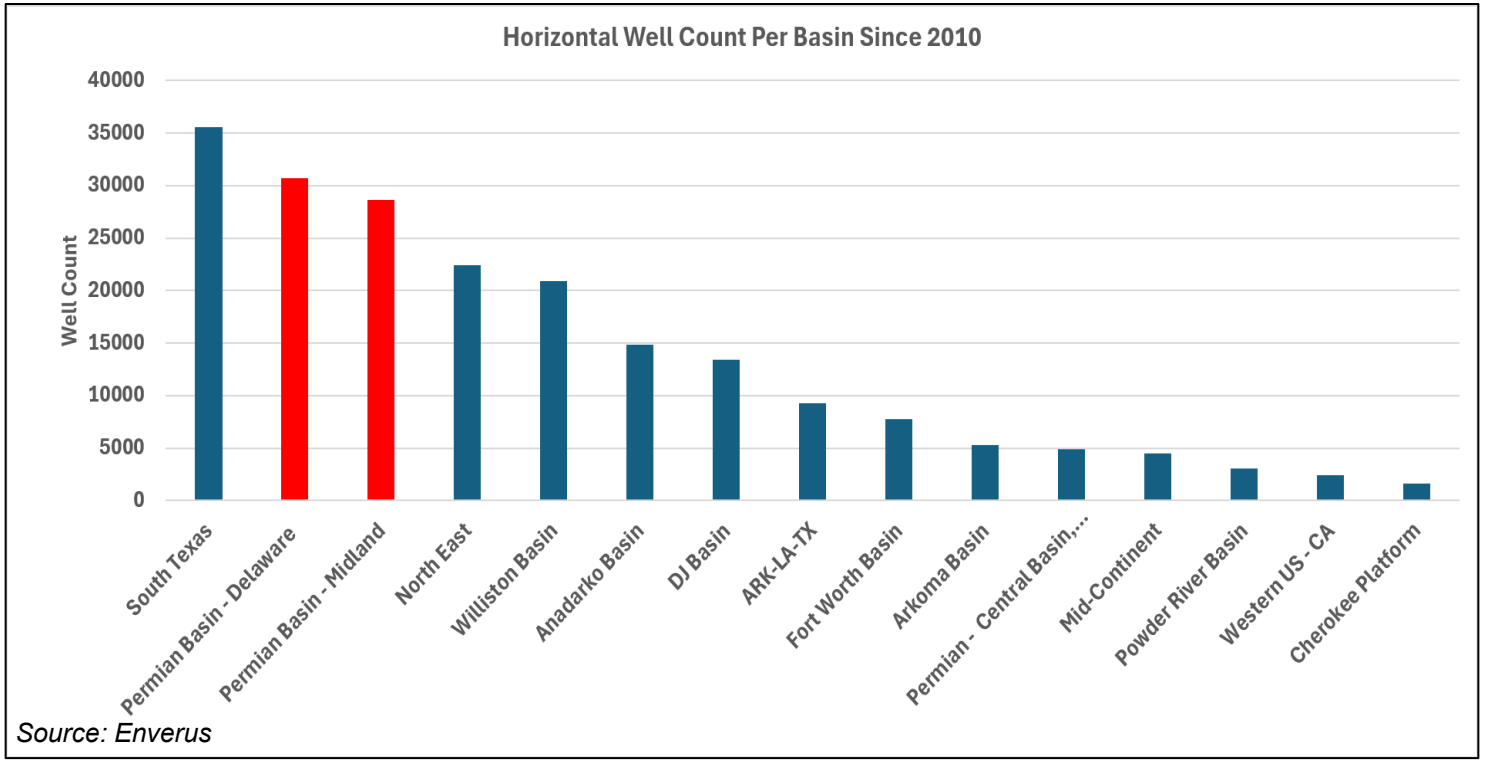
01

The Permian by the Numbers

Drilling, completions and productivity trends since 2010

Horizontal Wells Drilling Statistics

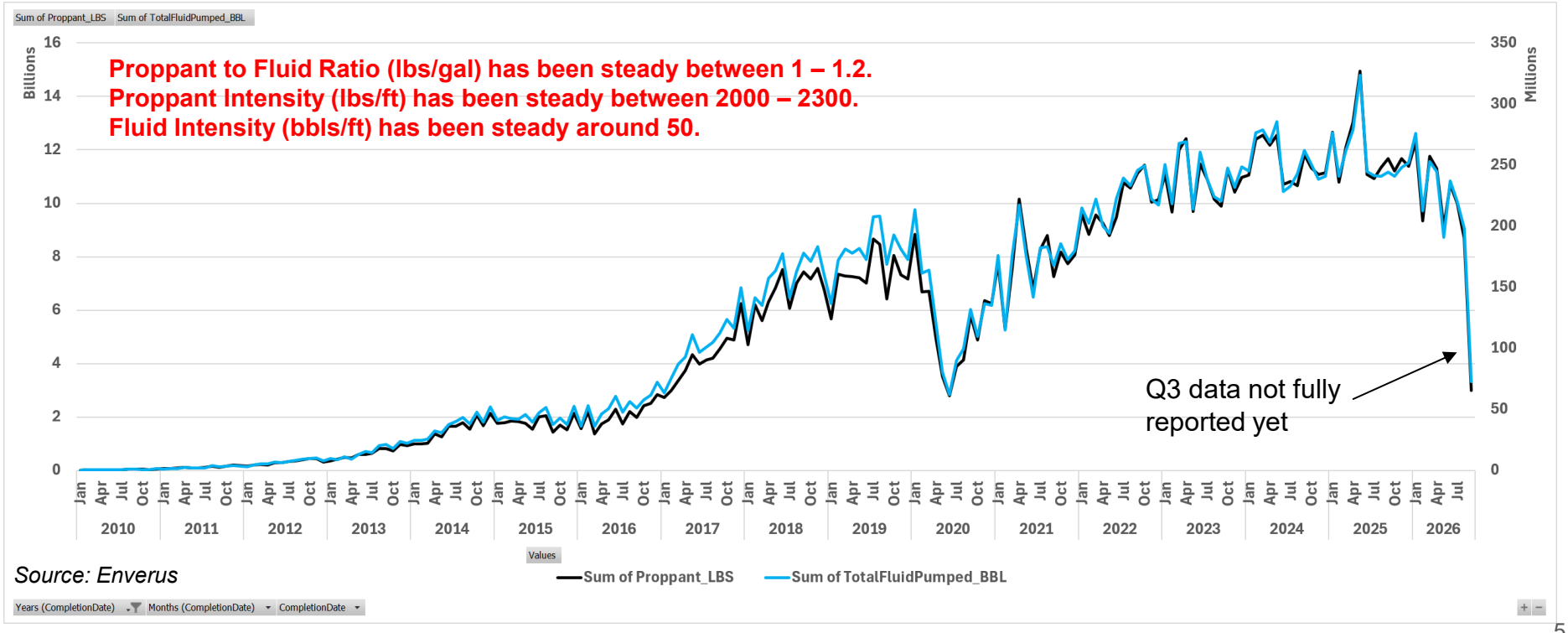
- We've drilled around 65,000 horizontal wells in the Permian Basin since 2010.
- 545 million feet of lateral has been drilled in the Permian which equates to 103,281 miles



Source: Enverus

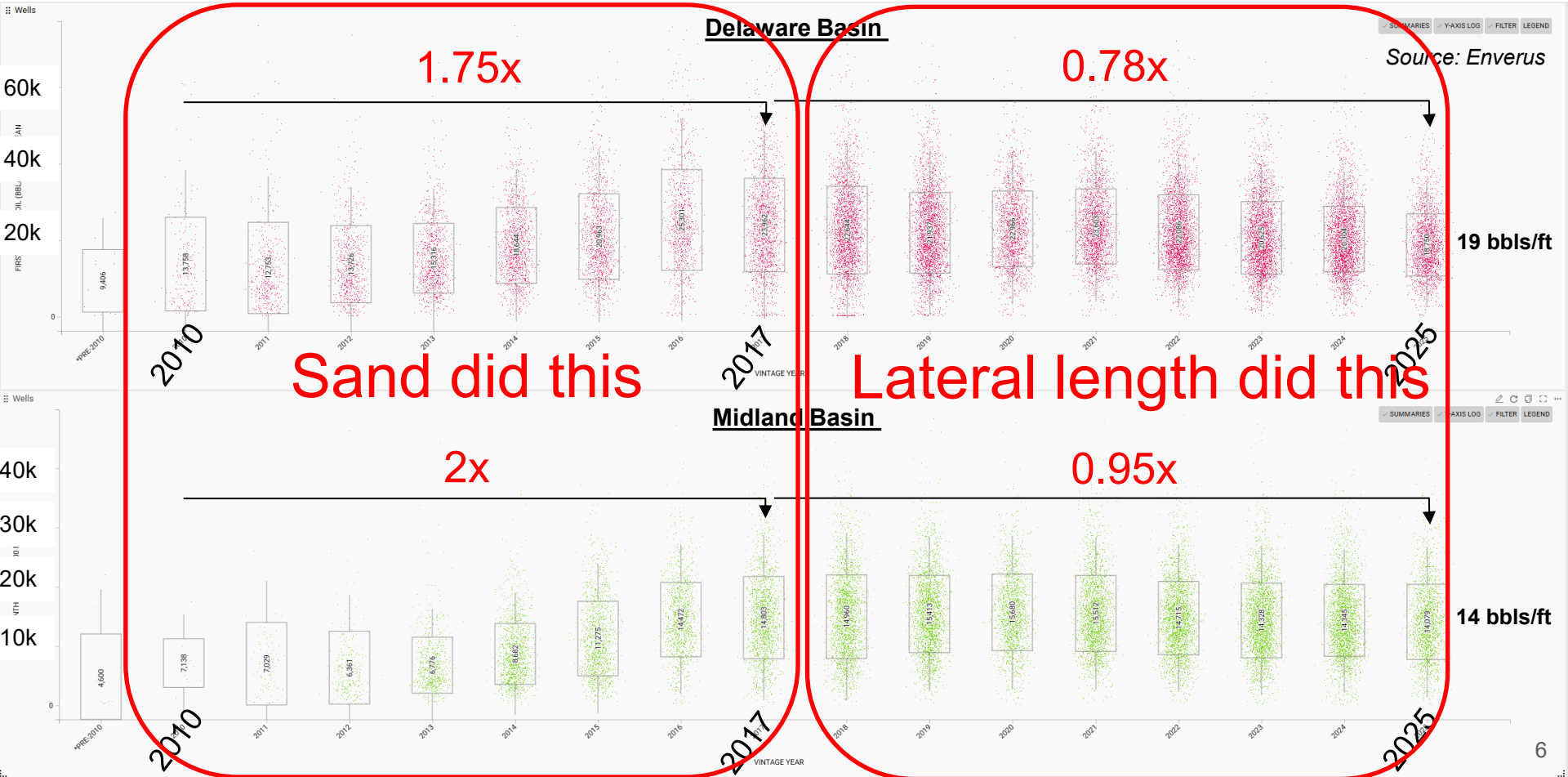
Horizontal Wells Completions Statistics – Permian Basin

- We've pumped 1.07 Trillion pounds of sand since 2010 – 23.77 million sand trucks – enough to line them up 7.2 times around earth's circumference OR 75% on its way to the moon.
- We've pumped 24.35 billion barrels of water since 2010 – farming in Texas uses 57.4 billion barrels annually.

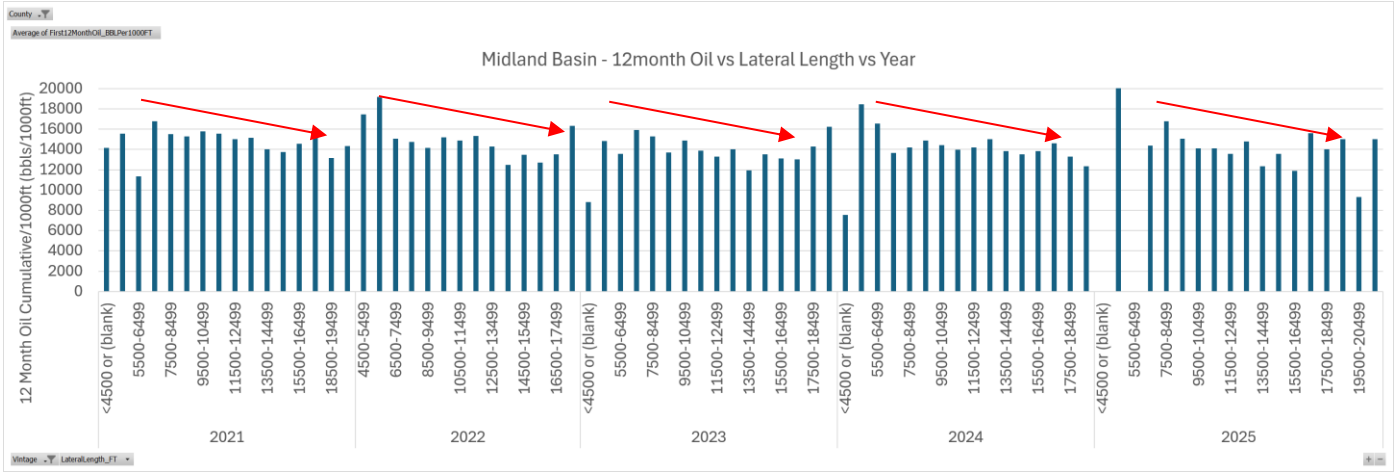


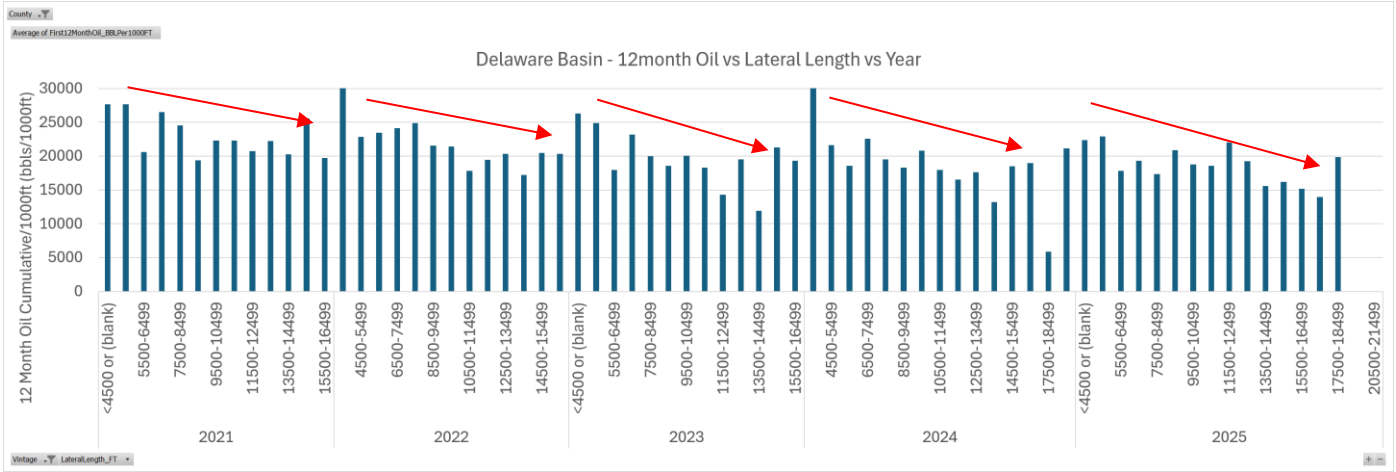
Source: Enverus

1 Year Cumulative Oil per 1,000 ft of Lateral per Year



1 Year Cumulative Oil / 1000ft vs Lateral Length Buckets vs Time





Source: Enverus

Summary

- Wells have gotten longer and as a result, more sand and water is pumped per well
  - But proppant and fluid intensity has stabilized
  - Efficiencies have improved which has driven down cost
- 1 year oil production per well (mean) in the Midland and Delaware Basin has **2.5x** from 72,000 bbls in 2014 to 178,000 bbls in 2025.
- 1 year oil production per well normalized by lateral length has only **1.9x** from 1.2 bbls/ft in 2014 to 2.3 bbls/ft in 2025.
- Horizontal wells have been economically successful
  - Companies are still quoting single digit recovery factors

02

Framing the Problem

Optimization levers, the 3P’s, and the data we need

Optimization Levers For **Primary Recovery** of Modern Horizontal Wells

- Landing point optimization (LPO)
- Frac design
- Chemistry
- Stacked Laterals

Geologists and Engineers OWN this decision

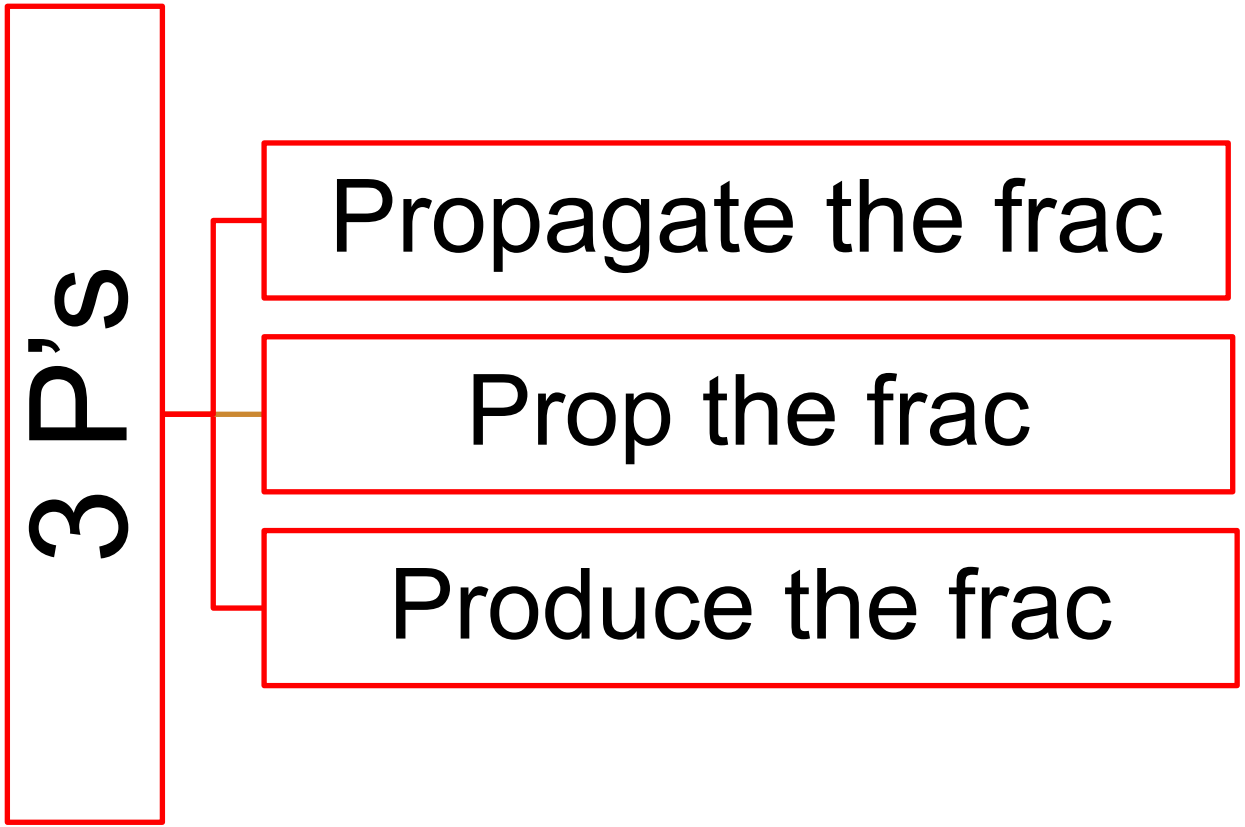
- Well Spacing

Partially own it, but driven by land and booked inventory

- Parent-Child

Engineers own this, but every well pad is different vintage, designs, pressures, etc. Downside can be minimized.

The Foundation Of A Frac Design – 3P’s

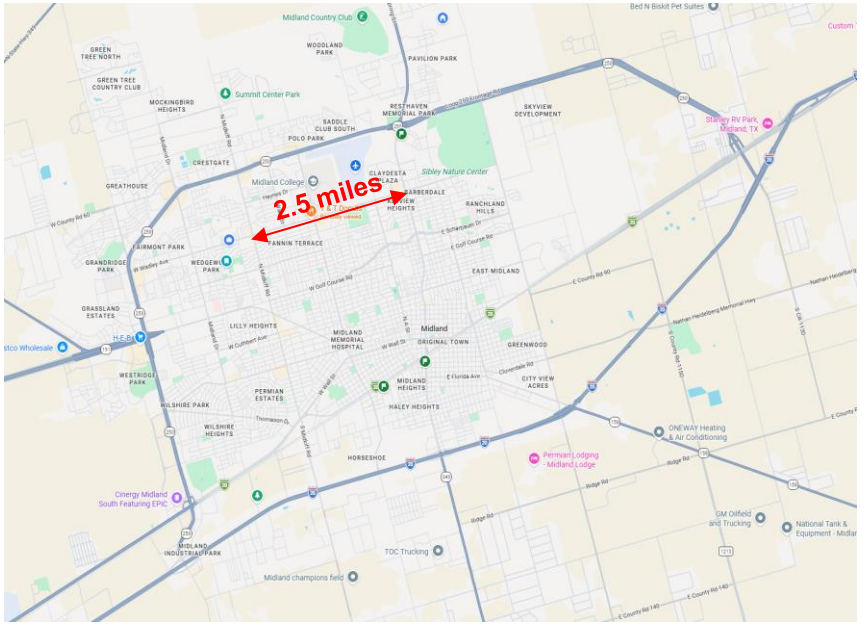


We Need To Start With DATA

- ❑ Logs – ø, K, Sw, mineralogy
- ❑ Dipole sonic – must have for rock mechanics

Stresses drive hydraulic fracturing and you can't estimate stresses without a dipole sonic. Every pilot OH logging run should have a dipole sonic.

- ❑ Image logs – rock fabric, natural fractures
- ❑ Pressures – injection tests, pressure fall-off's
- ❑ We need lots of logs (and seismic) to properly characterize the reservoir



Log curves are 0.5 ft vertical resolution

Most horizontal wells casing is 5.5" OD (0.458 ft)

NEEDLE IN A HAYSTACK

03

Verticals vs. Horizontals

Why the near-wellbore is the bottleneck

Verticals vs Horizontals

A horizontal well is a series of multiple vertical wells.

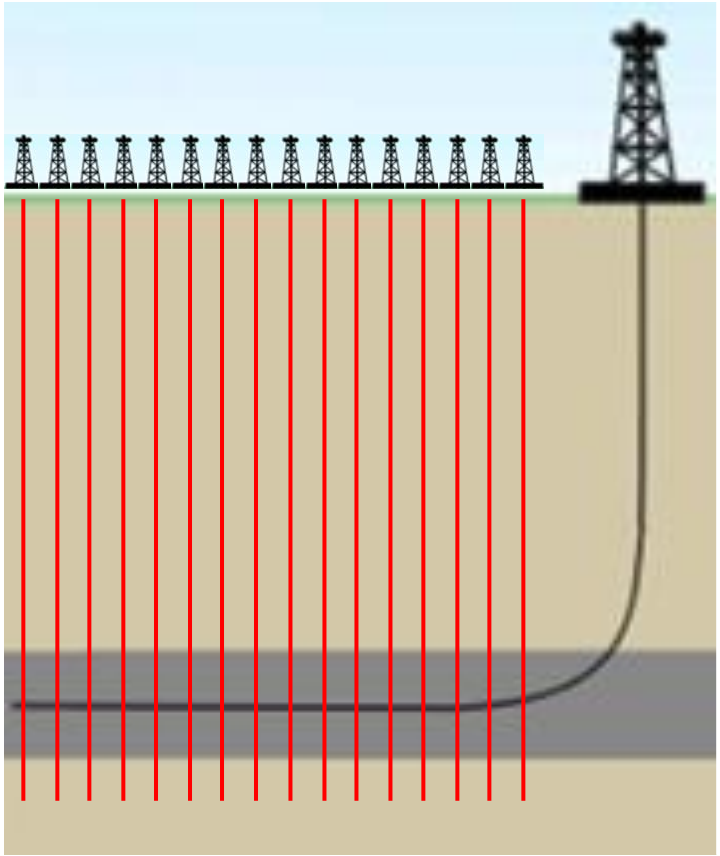


Image source: Shale oil and gas handbook, Sohrab, Alireza, 2017
Modified by FarFrac LLC

- **Vertical Benchmark –**

Avg Midland basin Wolfberry vertical well makes 12,000 BO in 1 year from 6-8 zones ≈ 1,500 BO in 1 year/zone

- **Horizontal Benchmark –**

Avg Midland basin 2 mile horizontal well in 2025 makes 140,000 BO in 1 year from ONE zone.

- 2 mile horizontal well has 500 clusters = 500 x 1500 = 750,000 BO

- **140k vs 750k ------ huge mis-match**

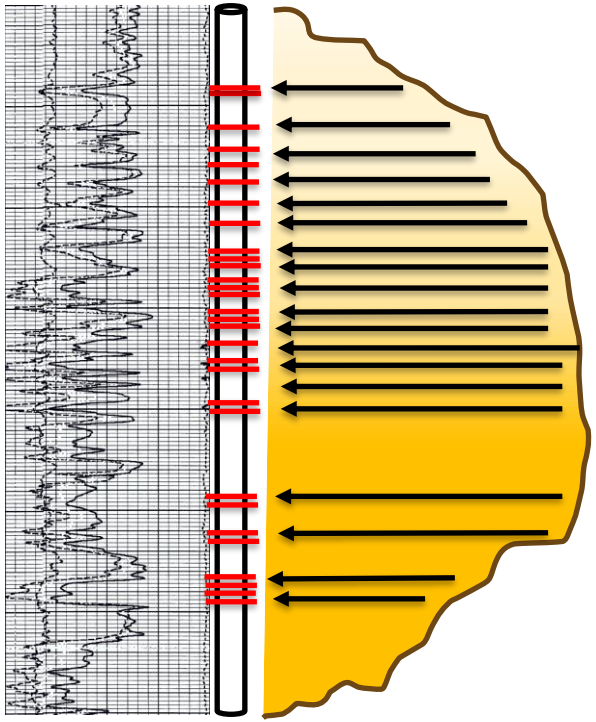
- Make any other bullish arguments like poor cluster efficiency, pressure interference, etc. and we still can't resolve the difference in mis-match.

Verticals vs Horizontals

Think Wolfberry or Wolfbone

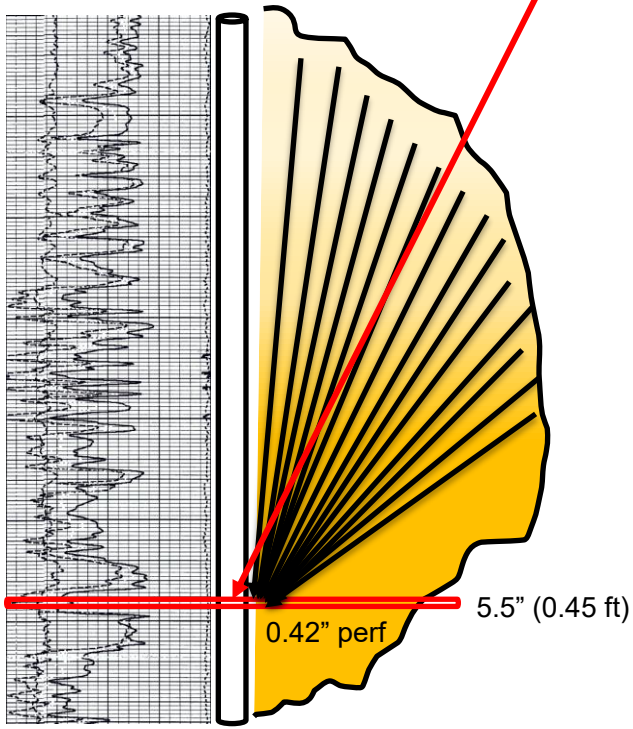
200ft Gross Pay
10-20 clusters
20-120 shots

Numerous Access points
along the bedding plane
Kv=Kh/10

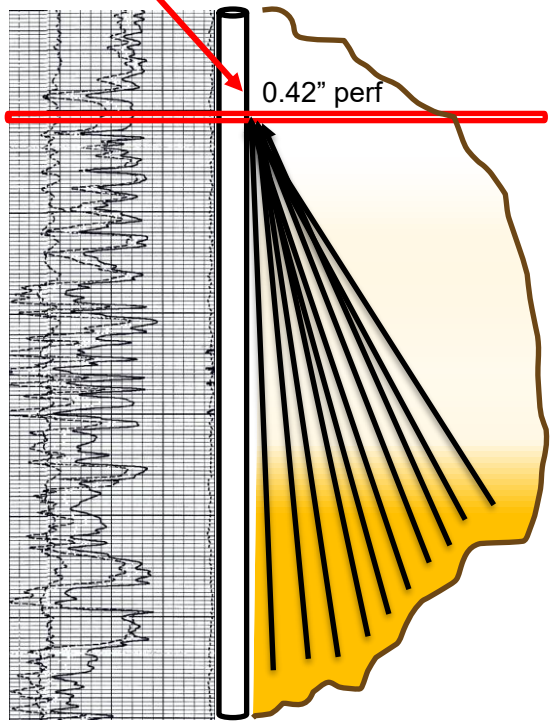


Stress is highest around the wellbore

ONE Access point
Tortuous Flow Path – Patchy proppant
Kv=Kh/10

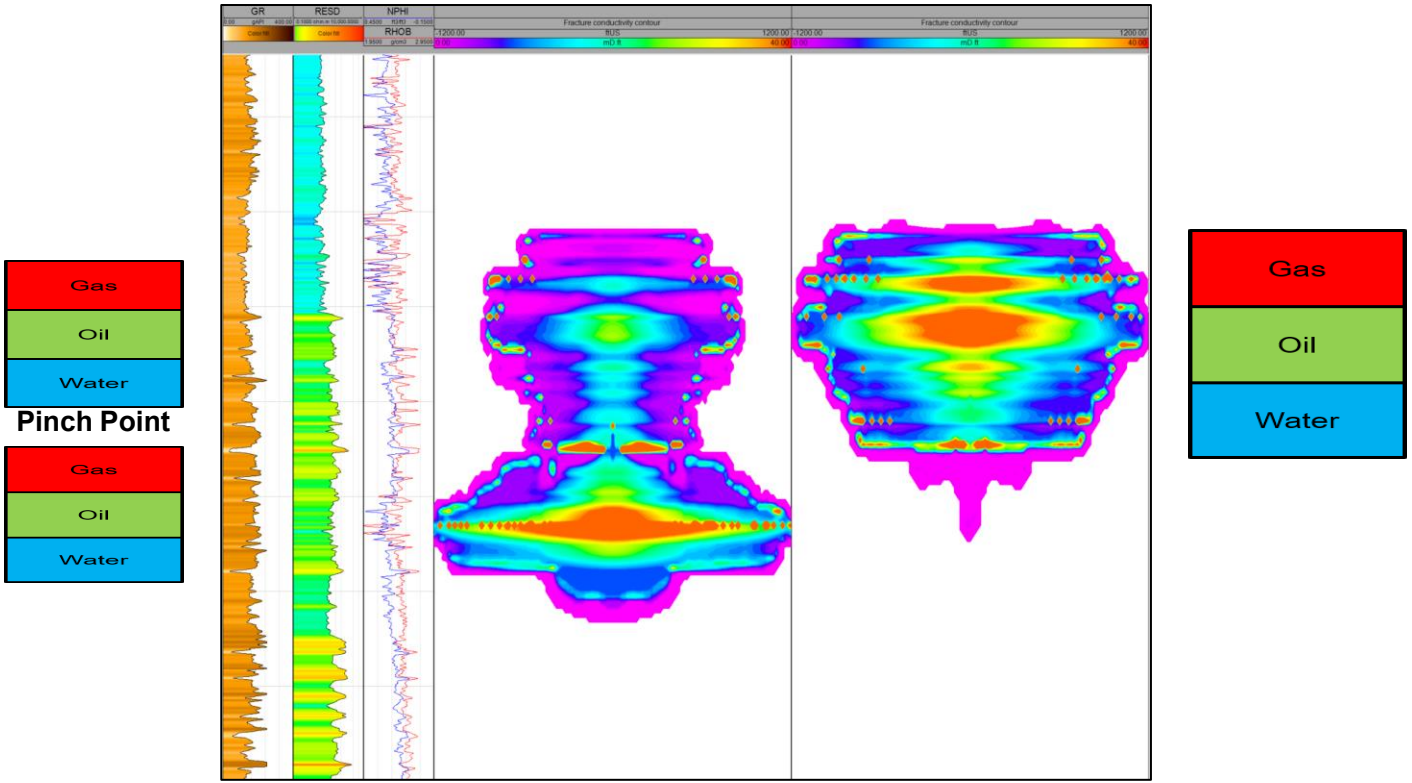


ONE Access point
Proppant Settles
Tortuous flow path – Patchy proppant
NWB is the bottleneck



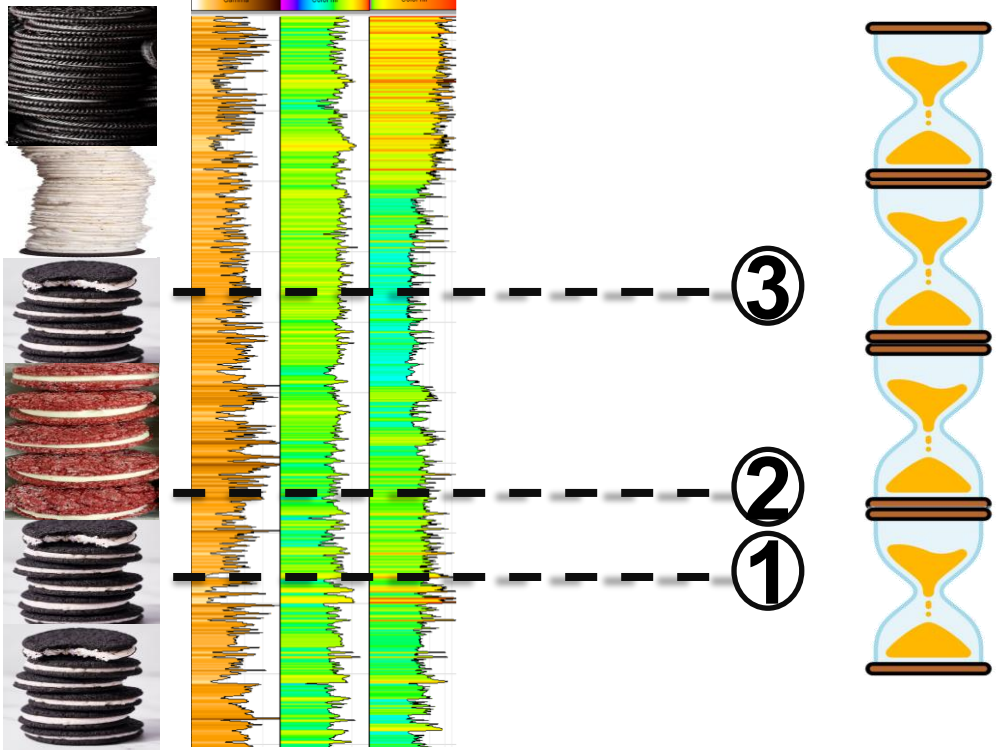
Hydraulic Fractures Are Man-Made Separators

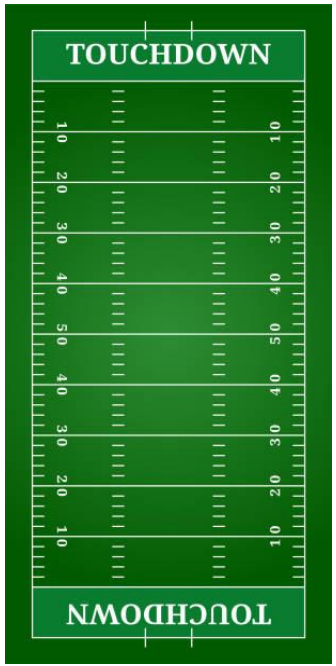
- Reservoir matrix permeability = Micro-Darcy to Nano-Darcy
- Hydraulic fracture permeability = **Darcy** – Conventional Reservoir
- Gas will migrate out first, leaving behind the heavier ends of the oil

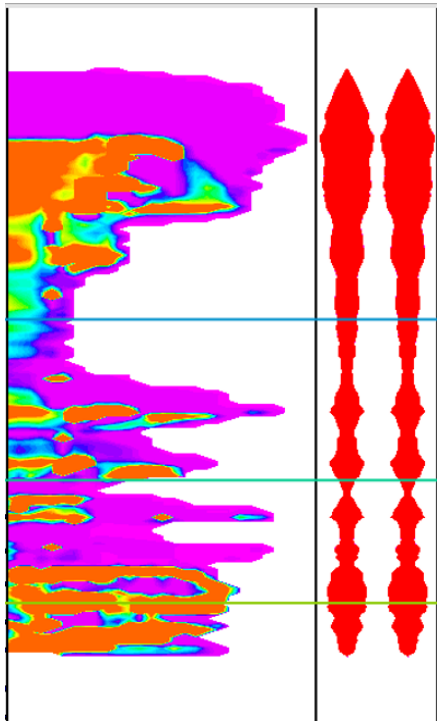


Tortuous Flow Path – Patchy Proppant Pack

By combining reservoir data like petrophysics and geomechanics with a frac design in a physics based frac model, we can predict how a frac will grow and how proppant will be distributed.



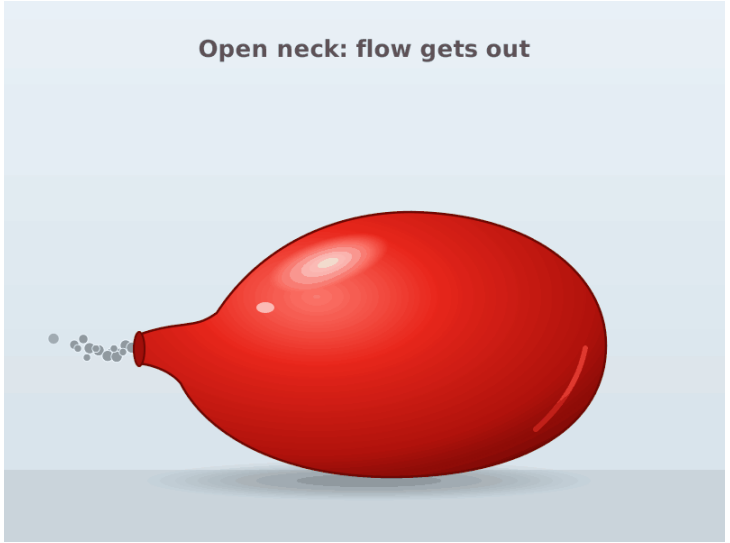




Pinch Out Analogs



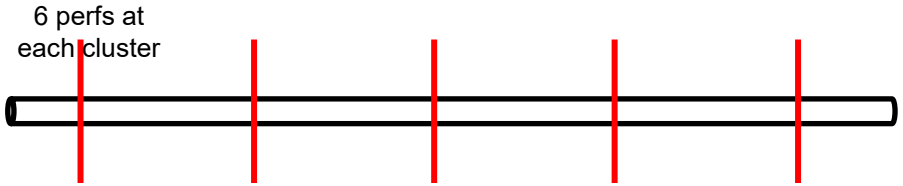




Importance of Landing & Steering The Lateral

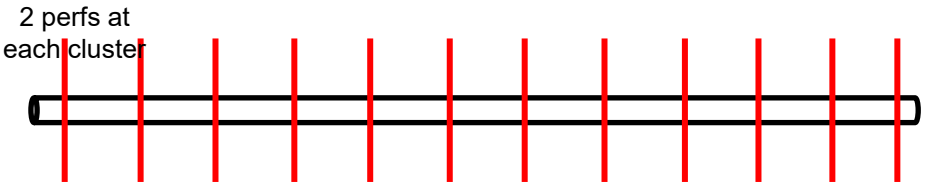
2010-2016

3-5 clusters per stage; 60 deg perf phasing



2017-2026

8-15 clusters per stage; 0-180 deg perf phasing



Some Rough Math:

2020-2026 design – 2 miles lateral = 500 clusters per well

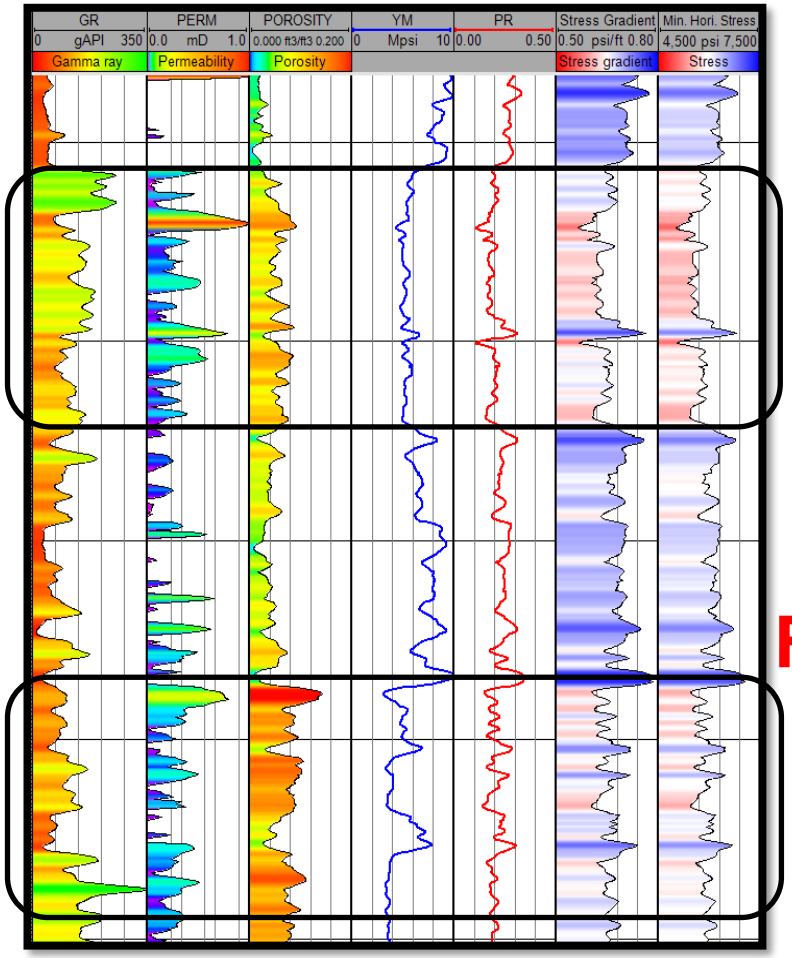
	Oil Rate per Day	Rate per Cluster per Day	Rate per Cluster per hour	Rate per Cluster per hour
Initial production	2000 BO/day	4 BO/day	0.166 BO/hr	7 gals/hr
3-6 months later	500 BO/day	1 BO/day	0.0416 BO/hr	1.75 gals/hr
12 months later	200 BO/day	0.4 BO/day	0.0166 BO/hr	0.7 gals/hr



Image source: Darkvision

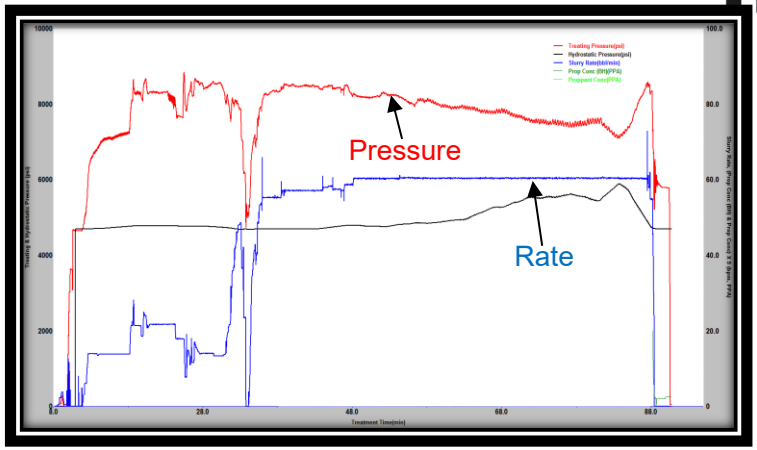
Area open to flow is a teeny-tiny % of the lateral length drilled

Impact of Landing On The Frac Execution

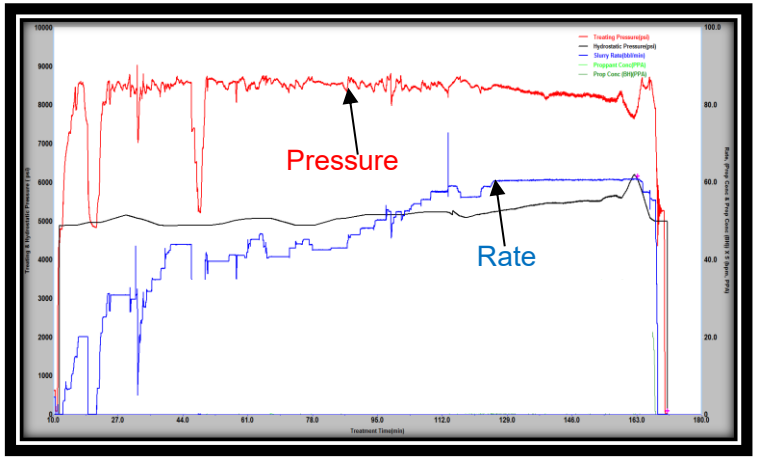


FRAC IT ALL

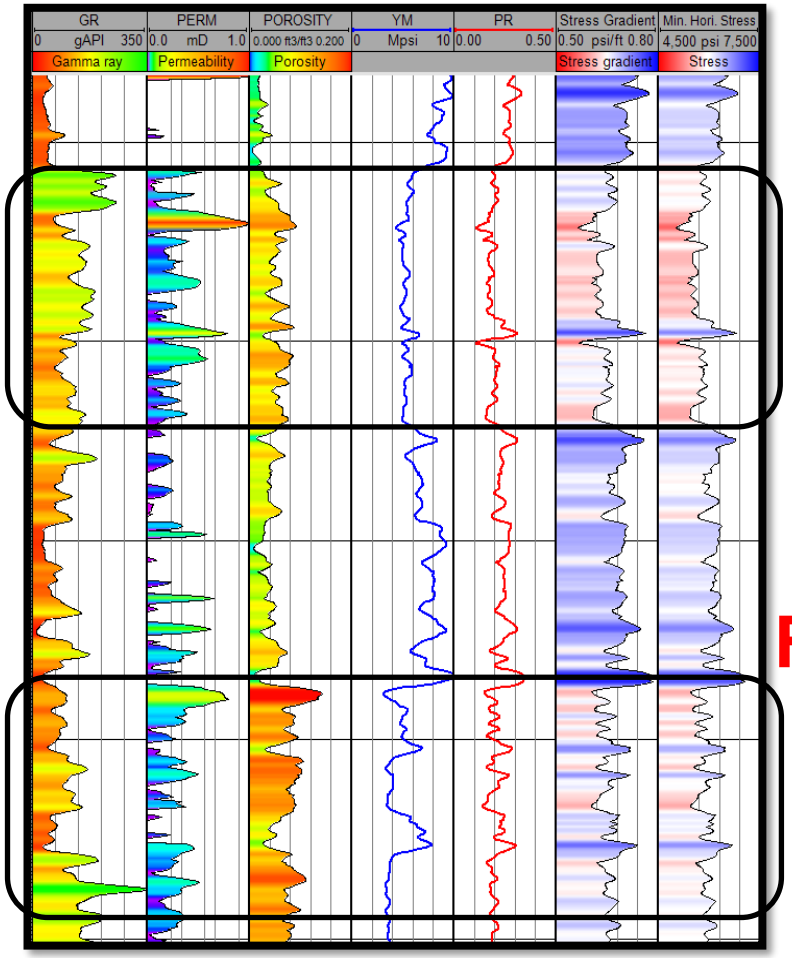
1.5 Hours



2.5 Hours

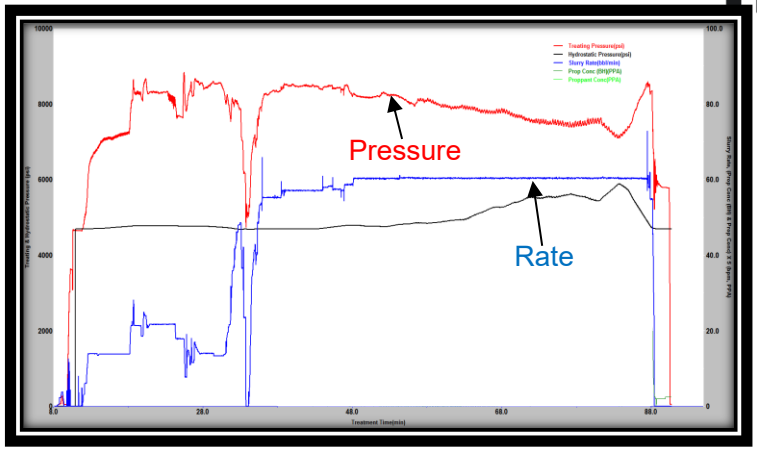


Impact of Landing On The Frac Execution

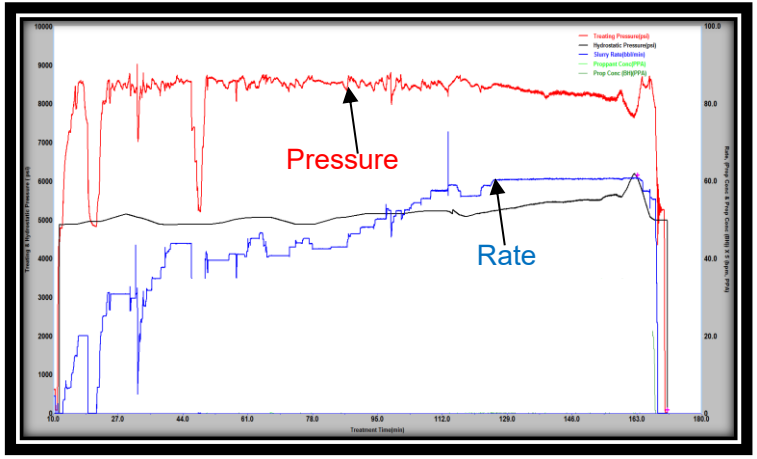


FRAC IT ALL

1.5 Hours



2.5 Hours



How Do We Overcome The Choke?

Choke at the perfs affects placement of frac's and the long-term production

Near wellbore frac width is the key – bigger the width, easier the placement

- Higher rate per frac → Higher Width → But we're limited here
- Higher viscosity → Higher Width → We control this

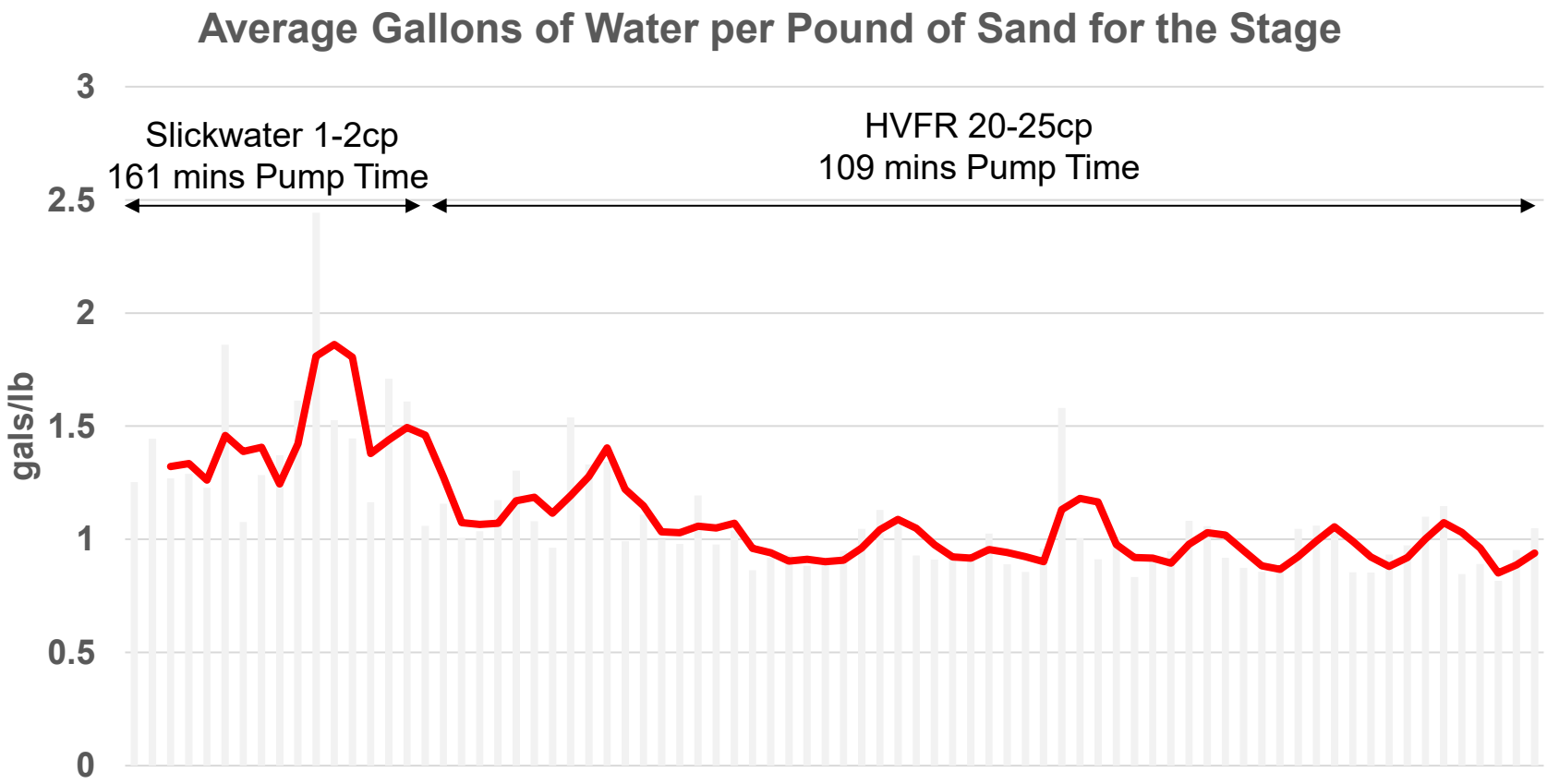
A better landing, a better frac placement and better propped frac will always overcome other issues

04

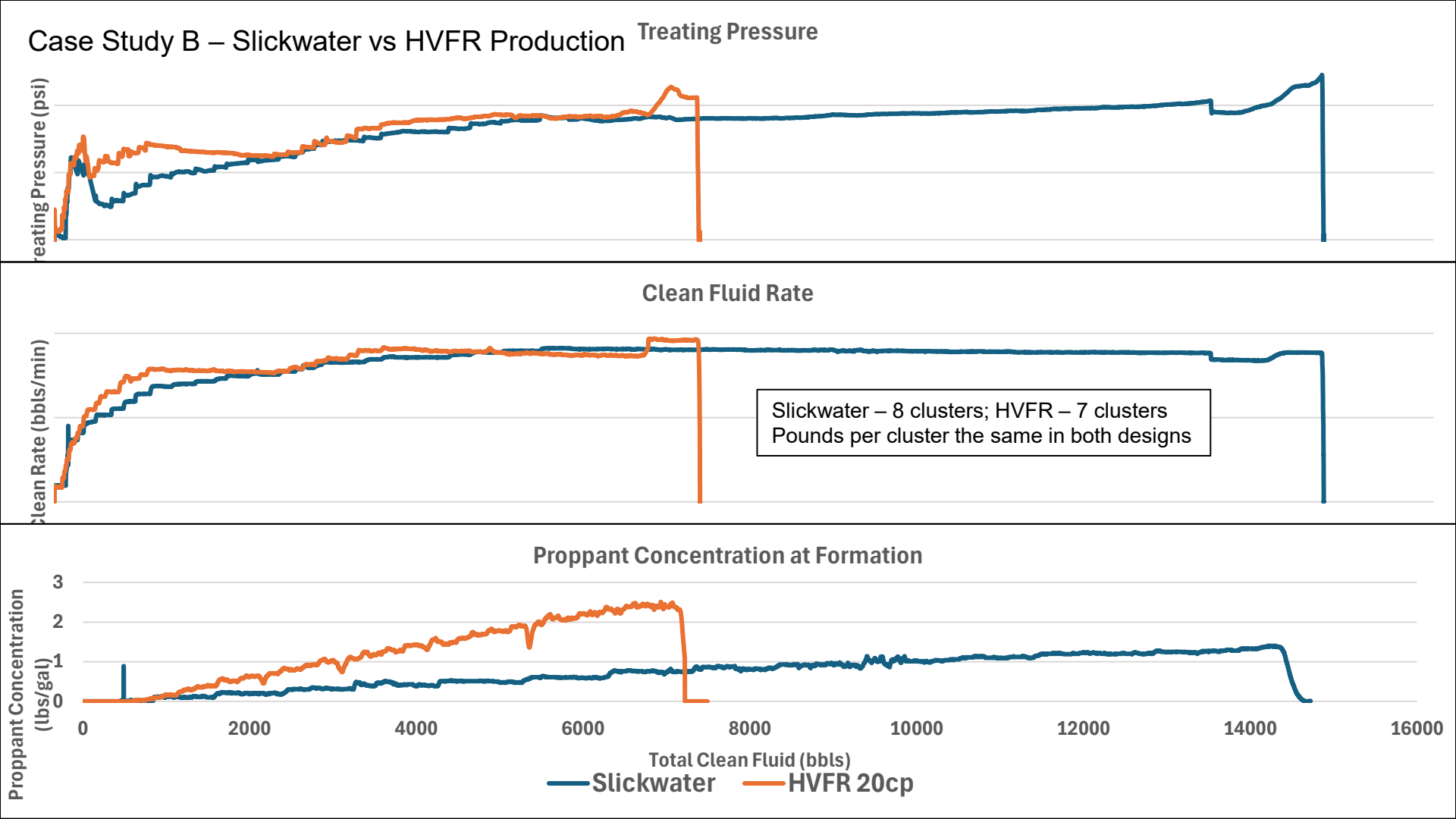
Viscosity in Practice

Slickwater vs. HVFR – execution and production

Case Study A – Effect of Viscosity on Ease of Frac'ing



Case Study B – Slickwater vs HVFR Production

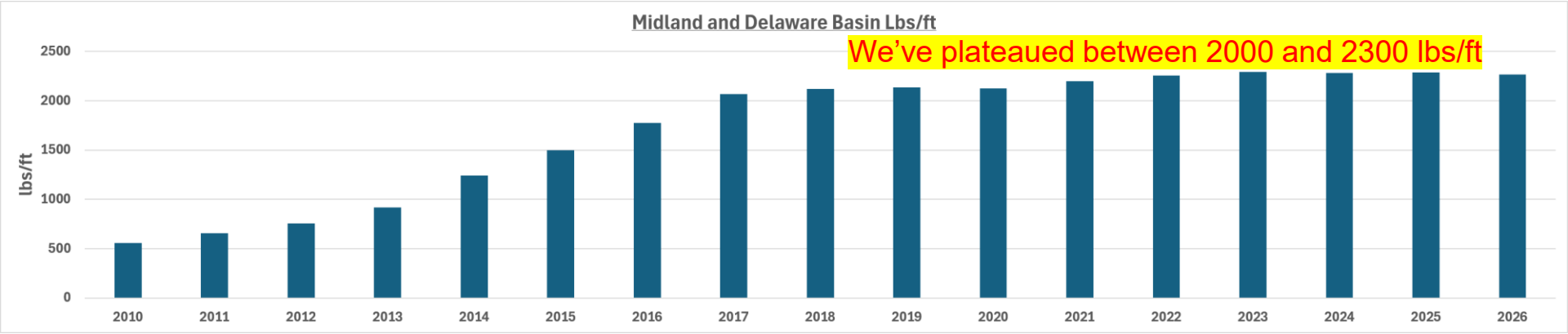


05

Rethinking Lbs/ft

Designing sand per cluster, not per foot

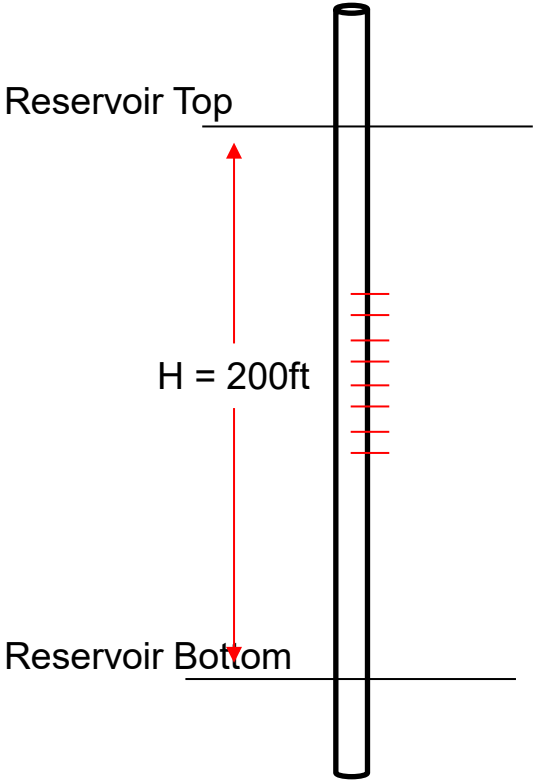
Permian Proppant Intensity – Lbs/ft



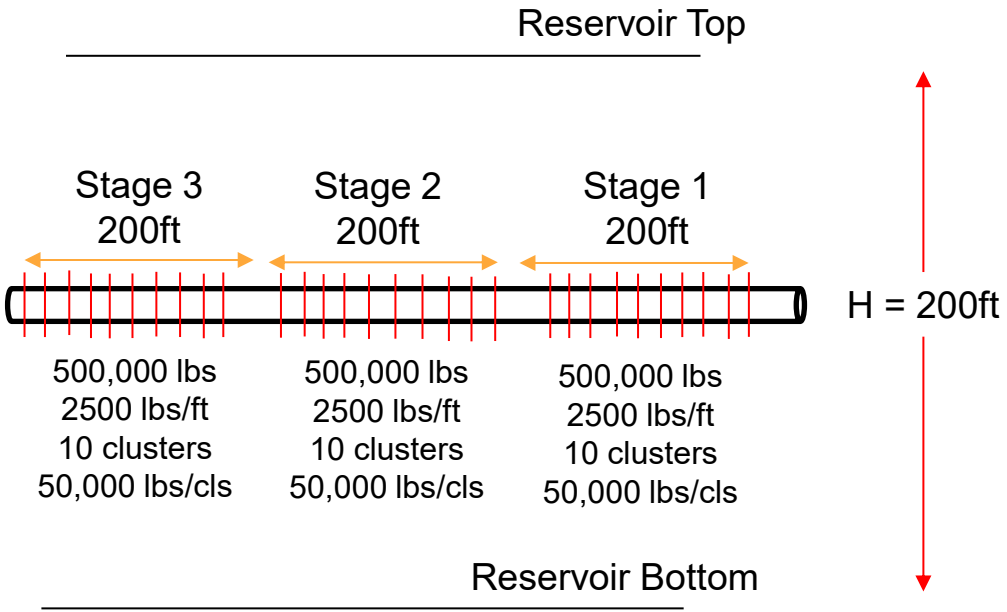
- ❑ Since 2017, we've kept the **proppant intensity flat**
- ❑ Since 2017, we've **tightened cluster spacing**
- ❑ Since 2017, we've **increased the number of clusters per well**
- ❑ Since 2017, we've **reduced the number of perfs per cluster**
- ❑ Effectively, we've **reduced the proppant volume per cluster**
- ❑ Effectively, we've **reduced the pump rate per cluster**

We've altered frac geometry

Lbs/ft Dilemma Between Vertical and Horizontal Wells



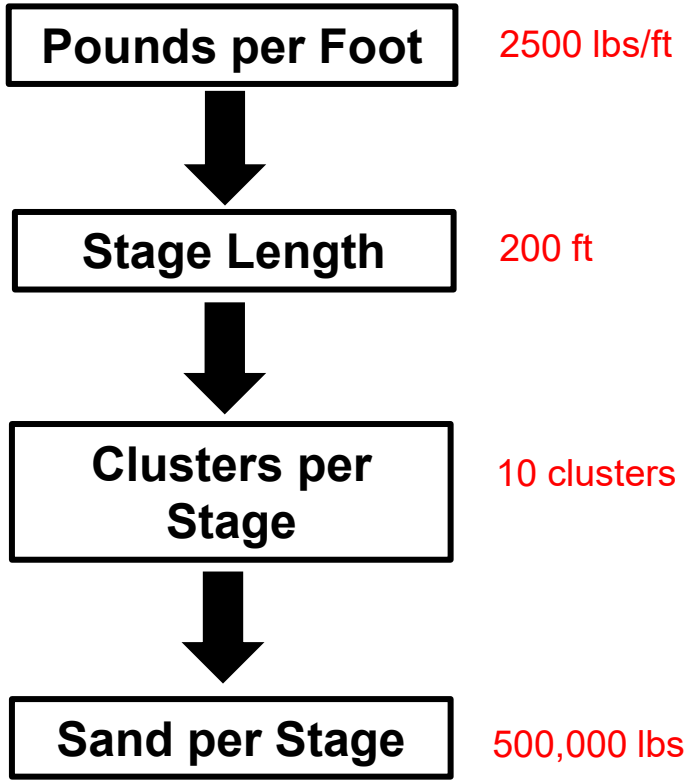
500,000 lbs frac job per 200 ft =
2500 lbs/ft



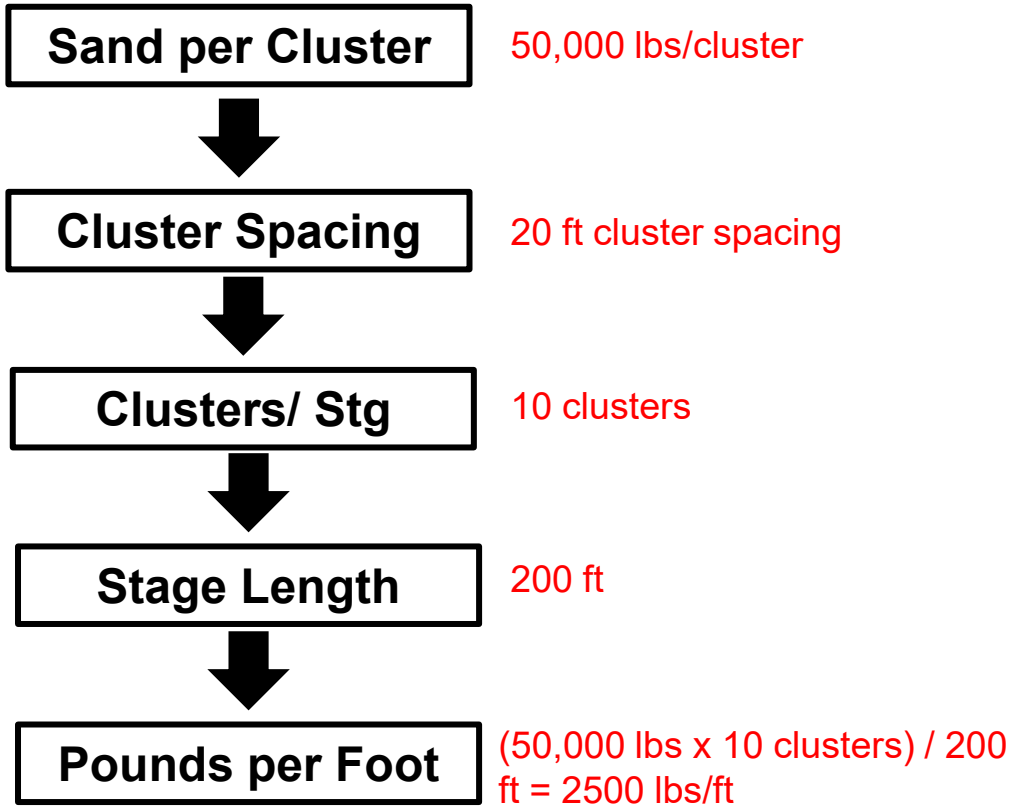
If each cluster in a horizontal well had 500,000 lbs, we would need 4 MM lbs of sand per stage. That would equate to 20,000 lbs/ft

Pounds of Sand per Foot of Lateral

Current Workflow

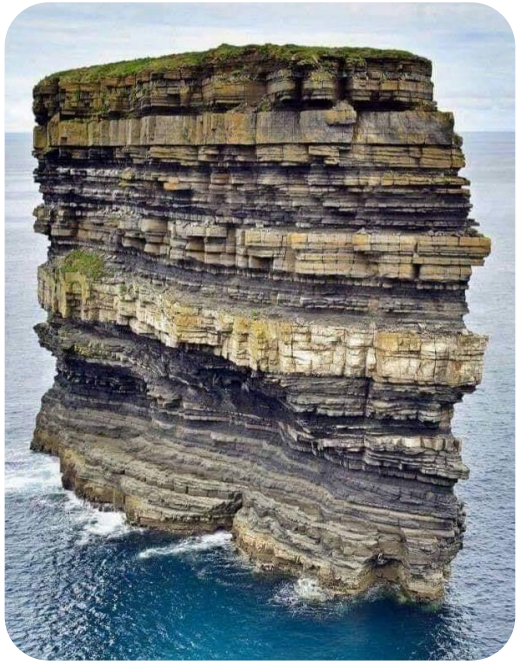


Proposed Workflow



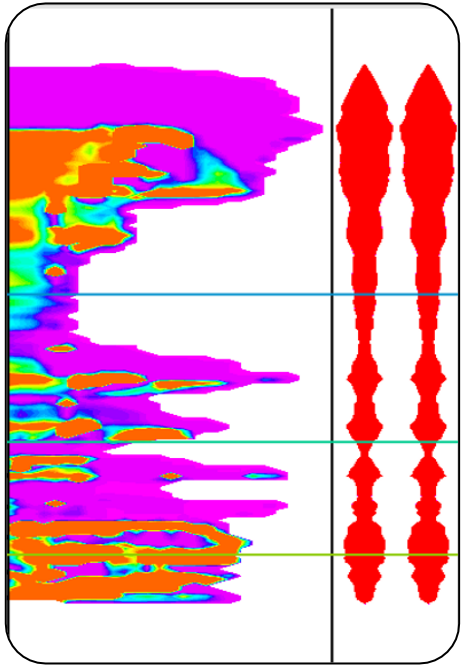
Conclusion – Cookie Cutter Designs Are Behind Us

THE ROCK MATTERS

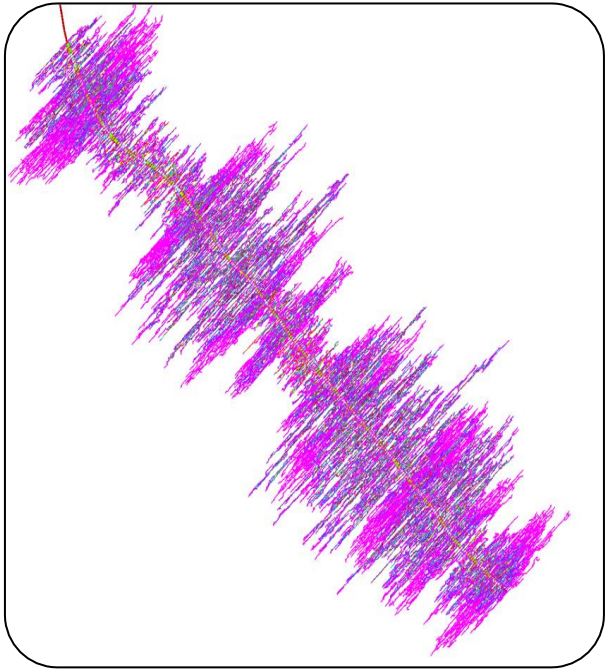


Downpatrick Head, County Mayo, Ireland

LAND THE WELL BASED ON A FRAC MODEL



DESIGN THE FRAC FOR THE ROCK



SOLVING THE MULTI-VARIATE COMPONENT

FarFrac

The Need For Tailored Frac Designs

SIPES Midland Chapter Luncheon – October 28, 2026

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