Perforating for Hydraulic Diversion Efficiency in Perforation Cluster Breakdown in Horizontal Wells

International Perforating Symposium
Galveston Texas
May 13, 2014
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PERFORATORS.ORG
INTERNATIONAL PERFORATING FORUM

Completion Type

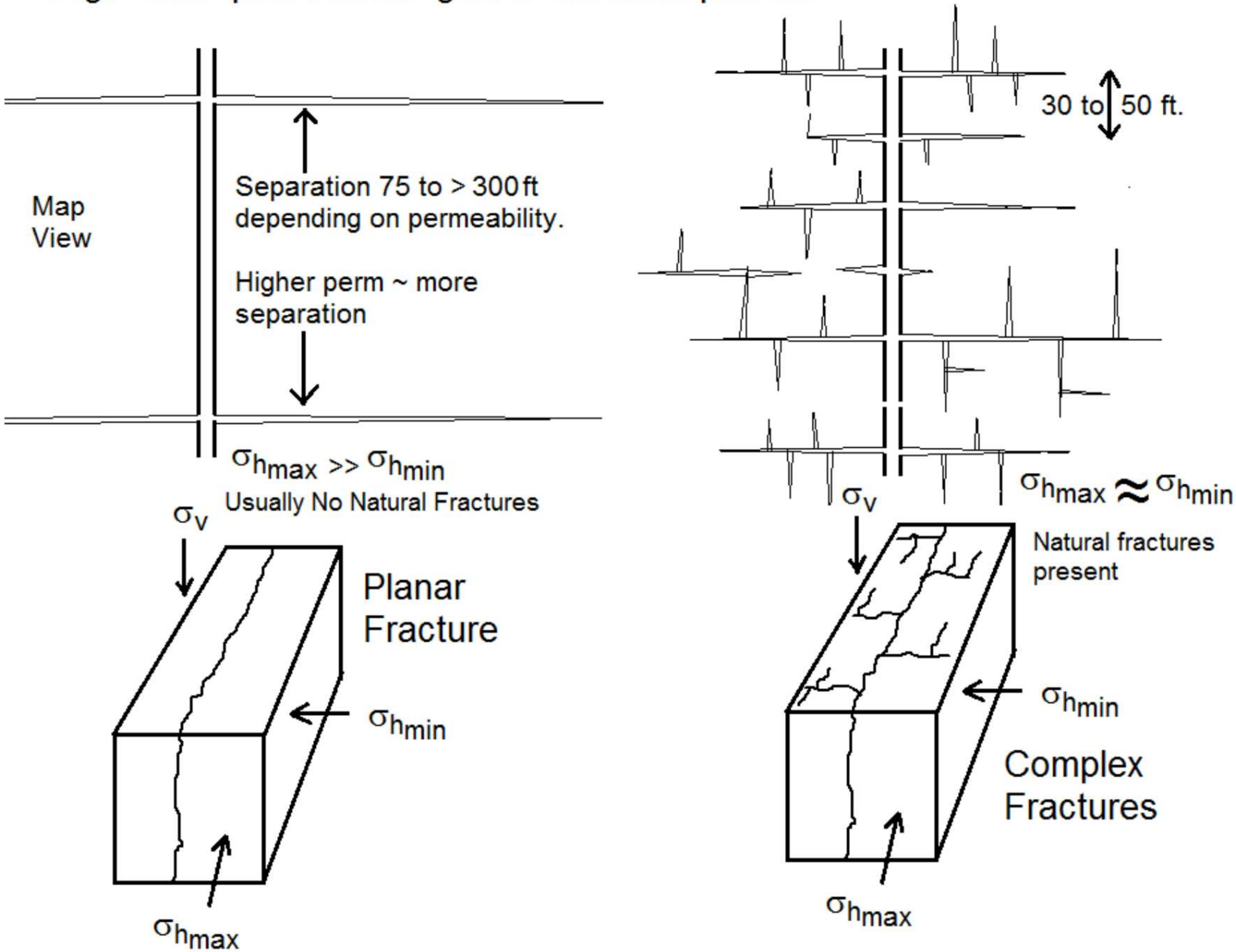
- In US ~ 80% Plug & Perf.
  - Maximum flexibility
- In Canada ~ 80% Packer and Sleeve.
  - Maximum speed
- The Type of Completion You Need is the Best Fit for Your Application.
- HOWEVER – the formation decides what fracture type will be possible.

Fracture Types

- Planar:
  - long half length,
  - much easier to prop,
  - much easier to model.
- Complex:
  - only in naturally fractured formations,
  - cannot easily predict,
  - cannot easily prop,
  - can open 10 to 100 x contact area with formation,

Planar vs. Complex Fracturing - What will the formation allow?

Left: Planar fractures with wide separation.
Right: Complex fracturing with narrow separation.



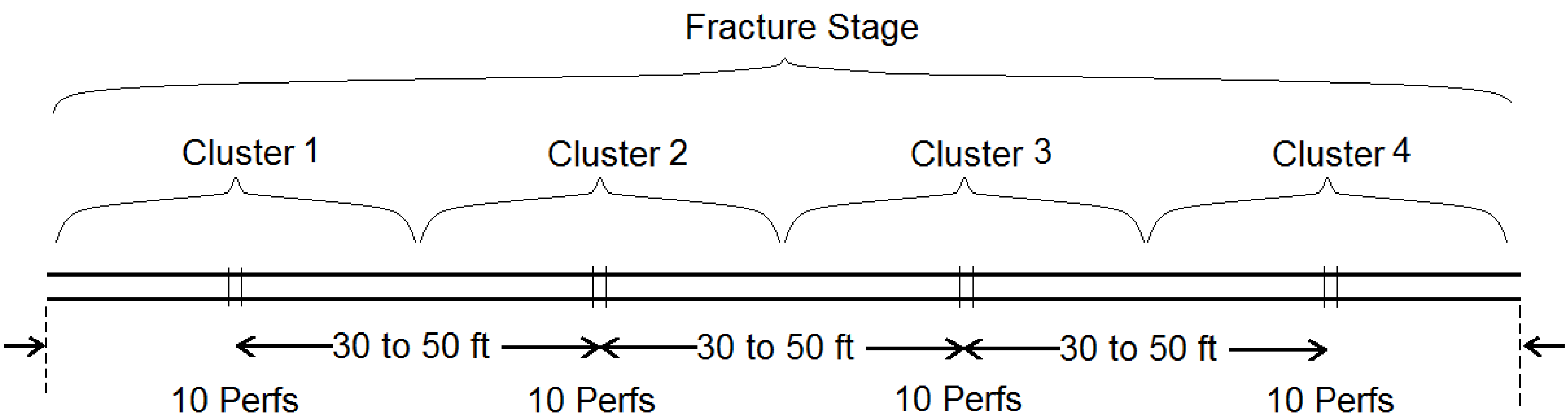
Hydraulic Diversion <u>Range</u>

- First perforation friction seen at about 0.5 bpm/perf (21 gallon per minute through a 0.5” hole).
- Actual backpressure resistance seen at about 1.0 to 1.5 bpm/perf.
- Effective diverting seen at 2.0 to 2.5 bpm/perf.
- Very high friction pressure seen at 3.0 bpm/perf. Sand cutting is very likely.

Perforation Cluster Layout in a Horizontal Well

How many clusters? What spacing? How long is a cluster? How many perfs?

Assume 120 to 200 ft fracture stage. 30 to 50 ft cluster spacing. 2' cluster length. 4 clusters.
Surface Injection Rate - 80 bpm. Total volume per fracture stage = 10,000 bbl salt water.
Perforations - 40 perfs, 1/2" diameter. 10 Perfs per cluster 2.0 bpm/perf

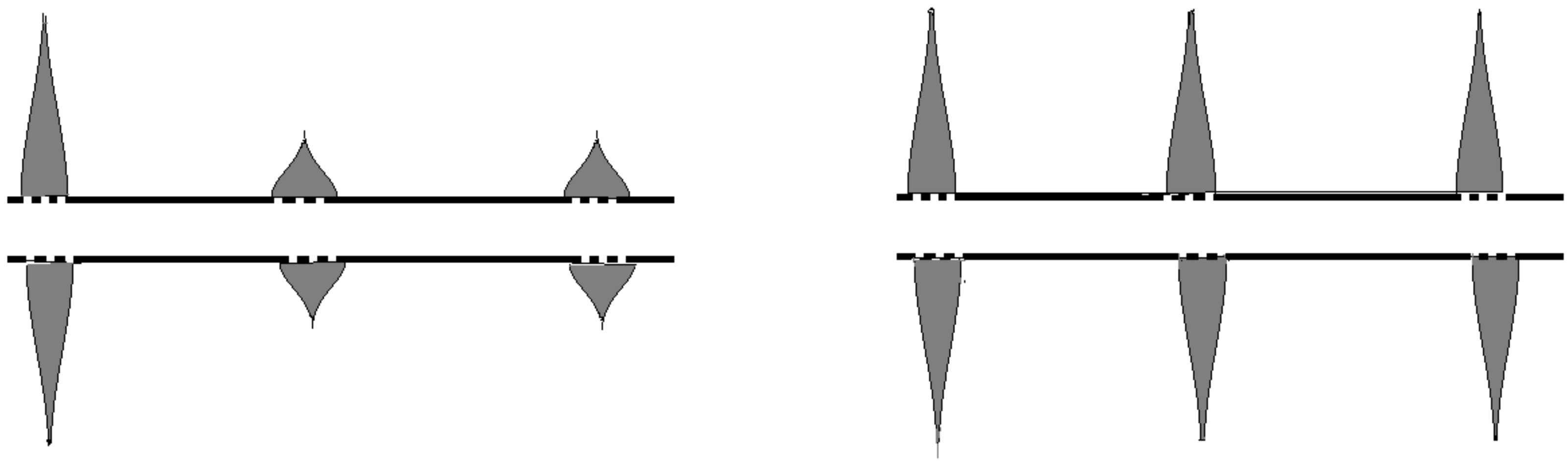


Perfect Split Rate per Cluster = 20 bpm/perf cluster

Perfect Split Volume per Cluster = 2500 bbls

Can the perforation design help even up the amount of frac fluid each cluster gets?

Clusters Within a Single Frac Stage

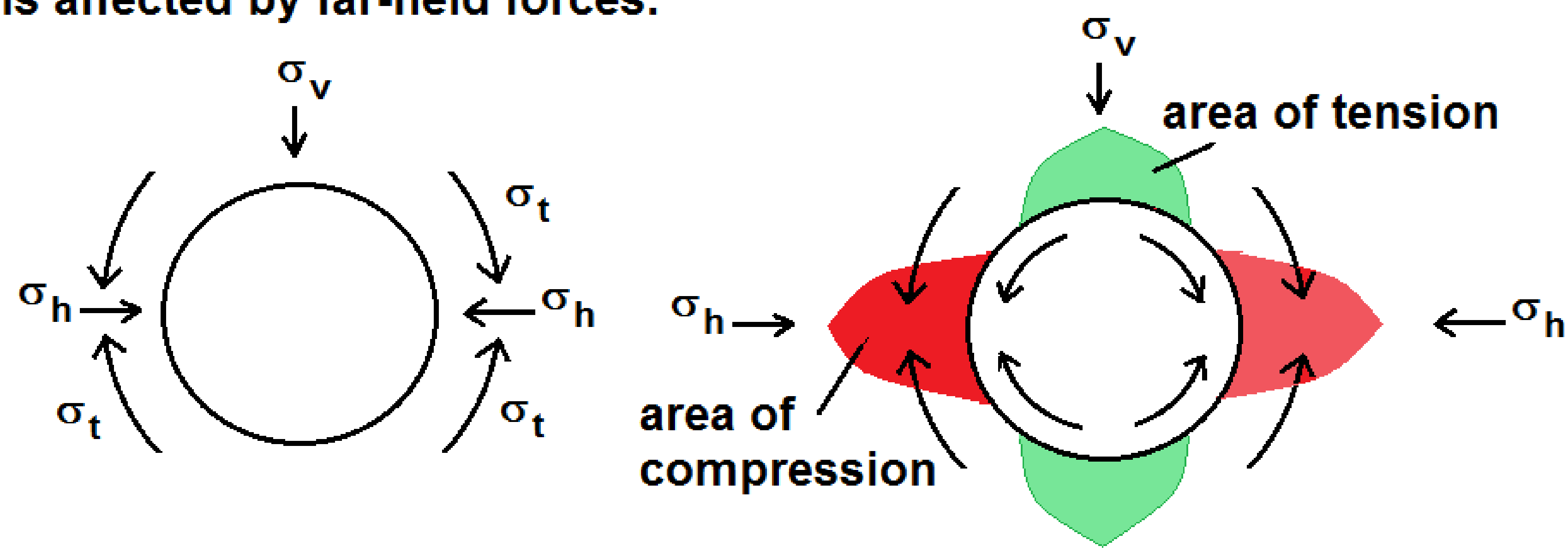


- Lack of diversion (hydraulic, ball sealers, viscosity, mechanical, etc.) will generate inequity.

Fractures initiate at top an bottom of the Horizontal well.

– Fractures must re-orientate from Near-field to far-field stresses

Figure - Local forces around a wellbore. Areas of tension are most likely point of fracture initiation, but reorientation of the fracture may occur as the developing fracture extension leaves the near-well and is affected by far-field forces.



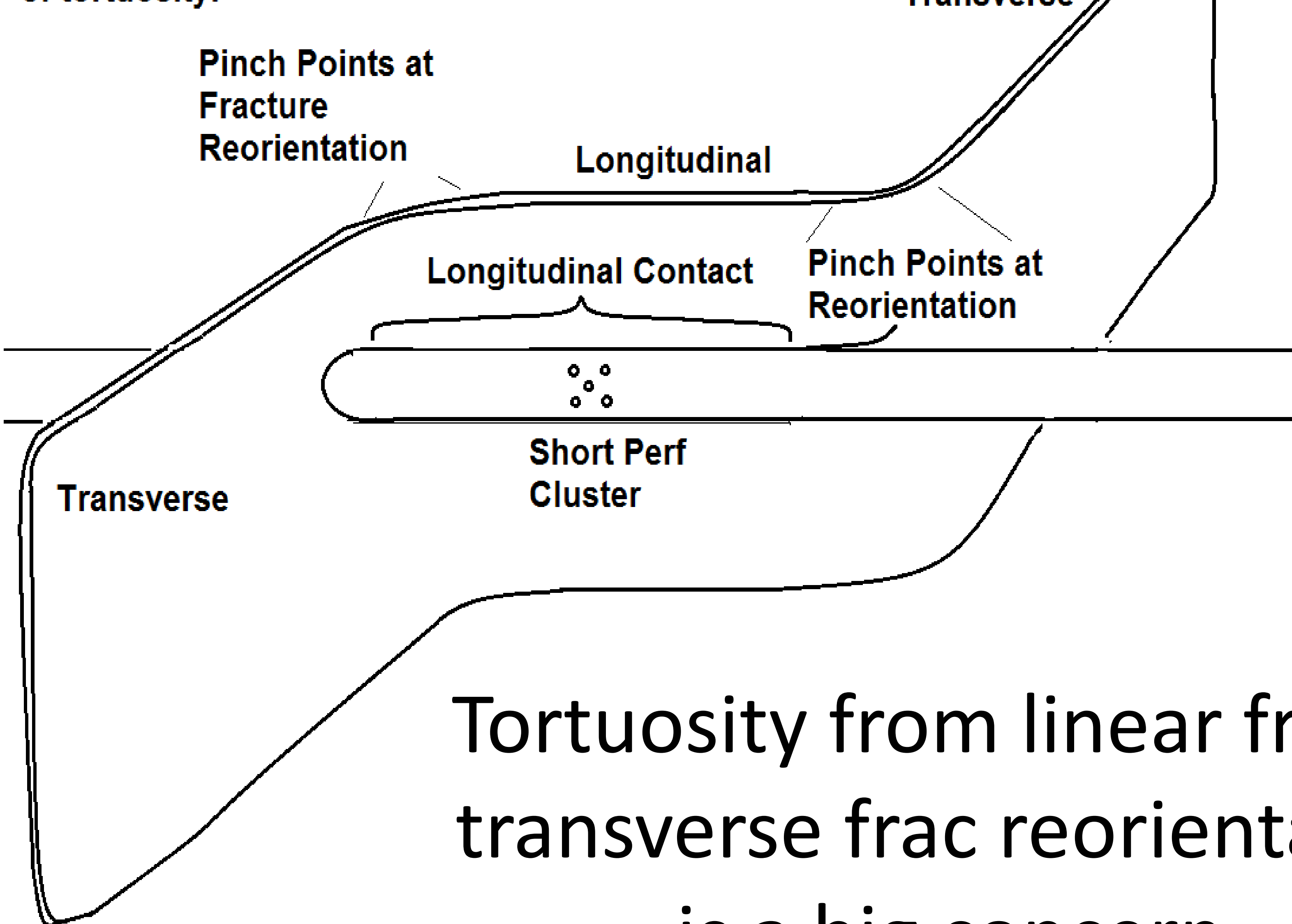


Figure - Areas where the fracture initiates as longitudinal and reorients to transverse may be areas of tortuosity.

Tortuosity from linear frac to transverse frac reorientation is a big concern.

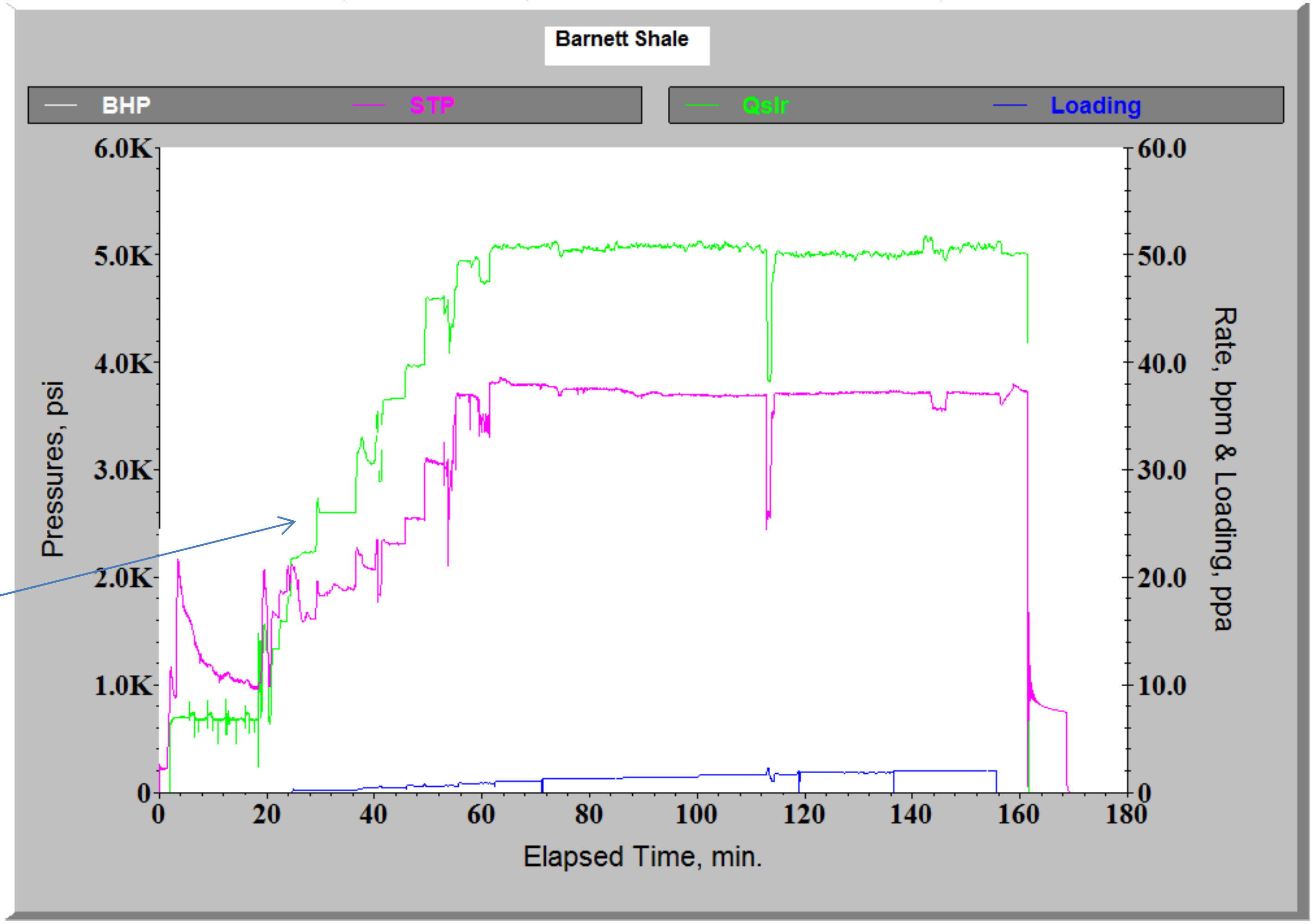
Frac Breakdown

- Frac gradient is usually 0.65 psi/ft to 0.85+ psi/ft.

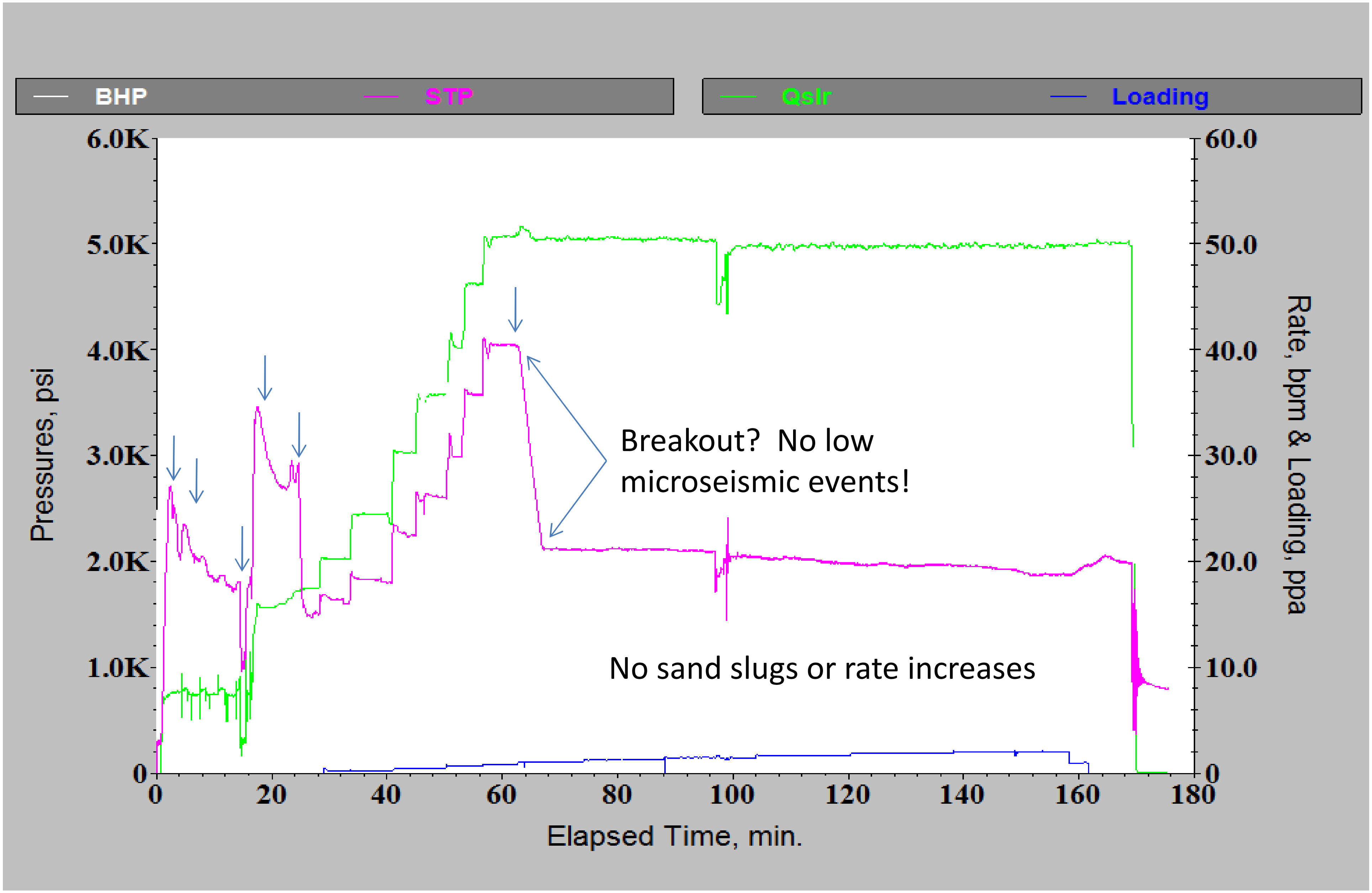
Breakdown pressure usually spikes and drops back at the frac is formed.

Acid, ball sealers, XGL, and other operations may be necessary to develop a single frac per cluster.

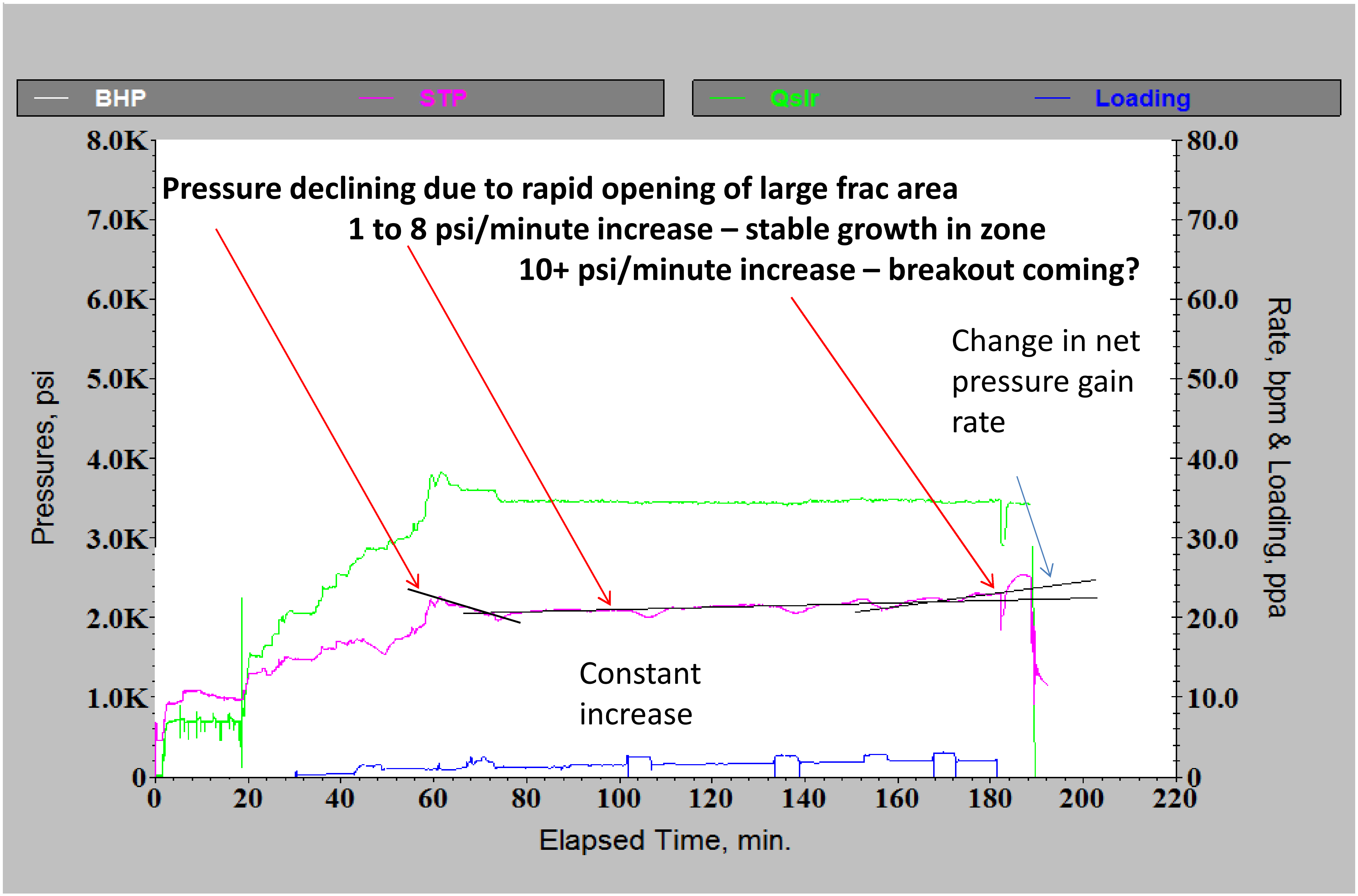
This job was slowly ramped up to develop natural fractures and avoid fracturing downward.



Multiple Breakdowns



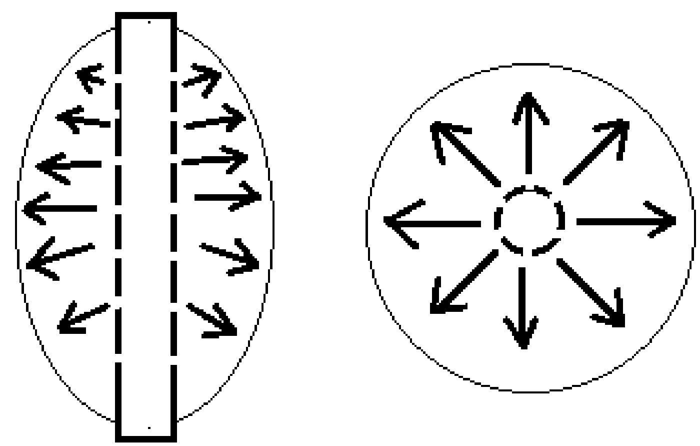
Pressure Trends



How do fractures from vertical & horizontal wells differ?

- Much more formation contact for a single fracture from a vertical well.
- Very different behavior.

Figure - Ideal early fracture growth from a vertical well (left) and a horizontal well (right) in a formation without laminations.



For a 50 ft thick zone with vertical planar fracture in 5-1/2” casing: vertical well has 100’ of contact with the formation horizontal well has 1.4’ of contact with formation.

Natural Fractures are Another Challenge

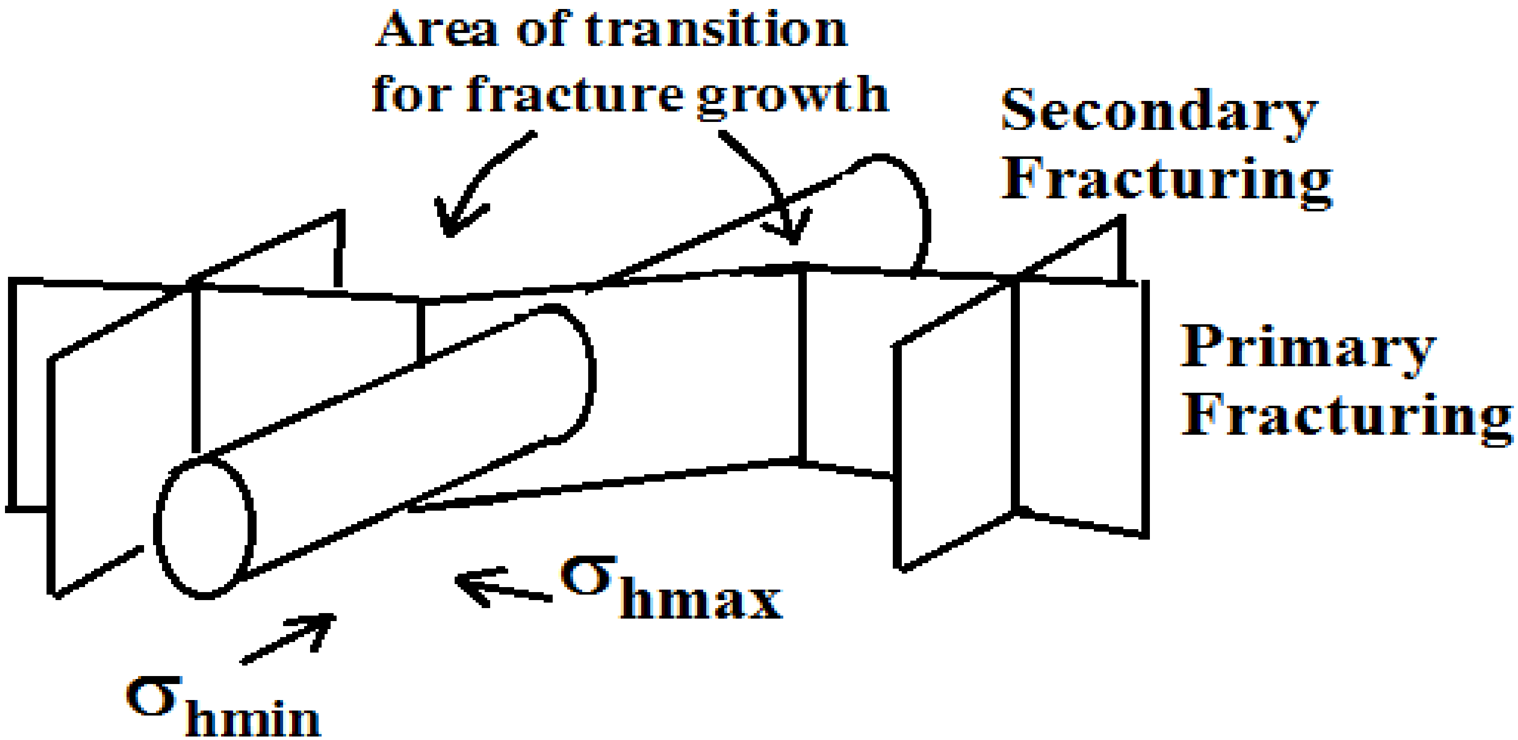


Figure - Area of fracture growth transition in near-well to far-field stresses where fracture and flow toruosity may likely occur. (Modified from Wallace, et.al., 2014)

From the Pump Chart to the formation

Figure - Fracture Pump Chart - Frac Initiation - Multiple Breakdowns

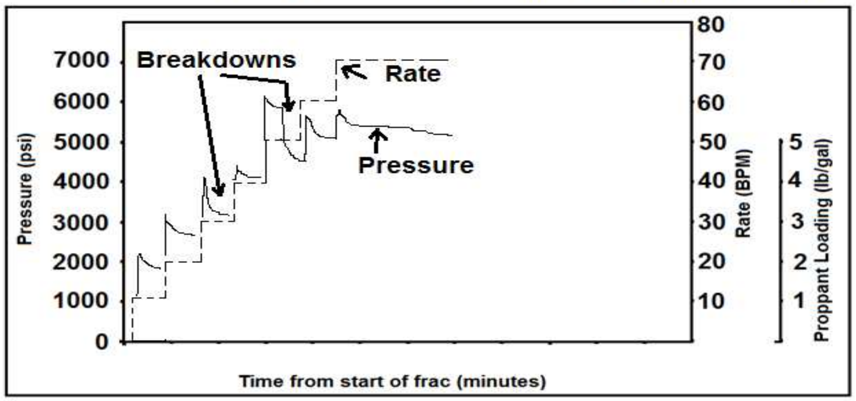
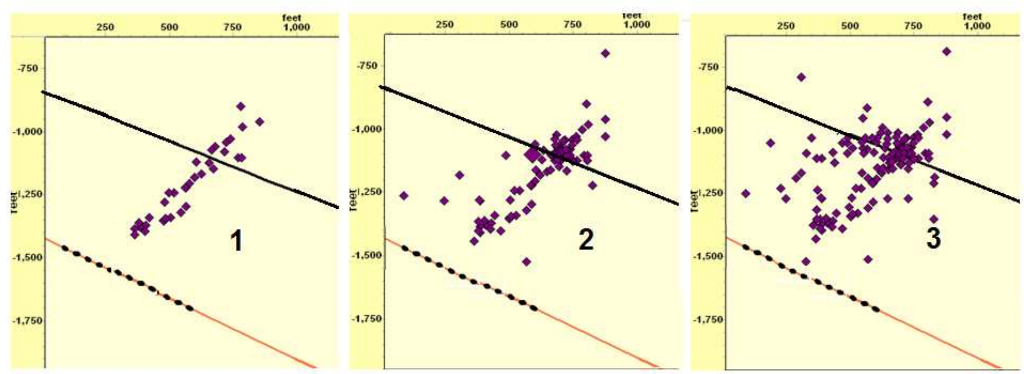


Figure - Microseismic sequence of a single stage of a frac in Barnett shale. The first points indicate a planar development, followed by widening of the microseismic cloud with points in a linear trend.



Conclusions

- The formation is the control in fracture type.
- Rate of injection rate arise and frac fluid type make a difference.
- Hydraulic diversion is a key piece of the puzzle:
  - Each formation and completion design is different.
  - Look for best diversion in the 2.0 to 2.5 bpm/perf range.