EPA Hydraulic Fracturing Technical Workshop
Well Construction and Operations

Evaluating Hydraulic Fracture Propagation in a Shallow Sandstone Interval, South Texas

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Background

- This is a case study of a water flooded oil reservoir in South Texas.
- The productive interval is a tight, multilayer, Cretaceous-age sandstone with true vertical depth ranging from 1200-1700 ft.
- Over 1000 production and water injection wells have been completed in the area over past 50 years.
- Hydraulic fracturing is normally employed to stimulate well productivity in the study area. A standard treatment design features the use of viscous 25 lb/1000 guar borate fracturing fluid and 12/20 mesh proppant injected at a high rate (e.g., 40 bbl/min.)
- Although diagnostic fracture injection testing (DFIT) analysis indicates that the minimum principle stress is horizontal, tiltmeter mapping, tracer surveys, an offset-well corehole project and treating pressure analysis indicate that most of the fracture propagation is horizontal (normal to the overburden stress) and that the vertical fracture component (normal to the minimum horizontal stress) is contained within the pay interval.
- Because of the limited vertical hydraulic fracture propagation, limited entry or multi-stage treatment methods are employed to establish hydraulic fractures in each of the productive reservoir sand compartments.

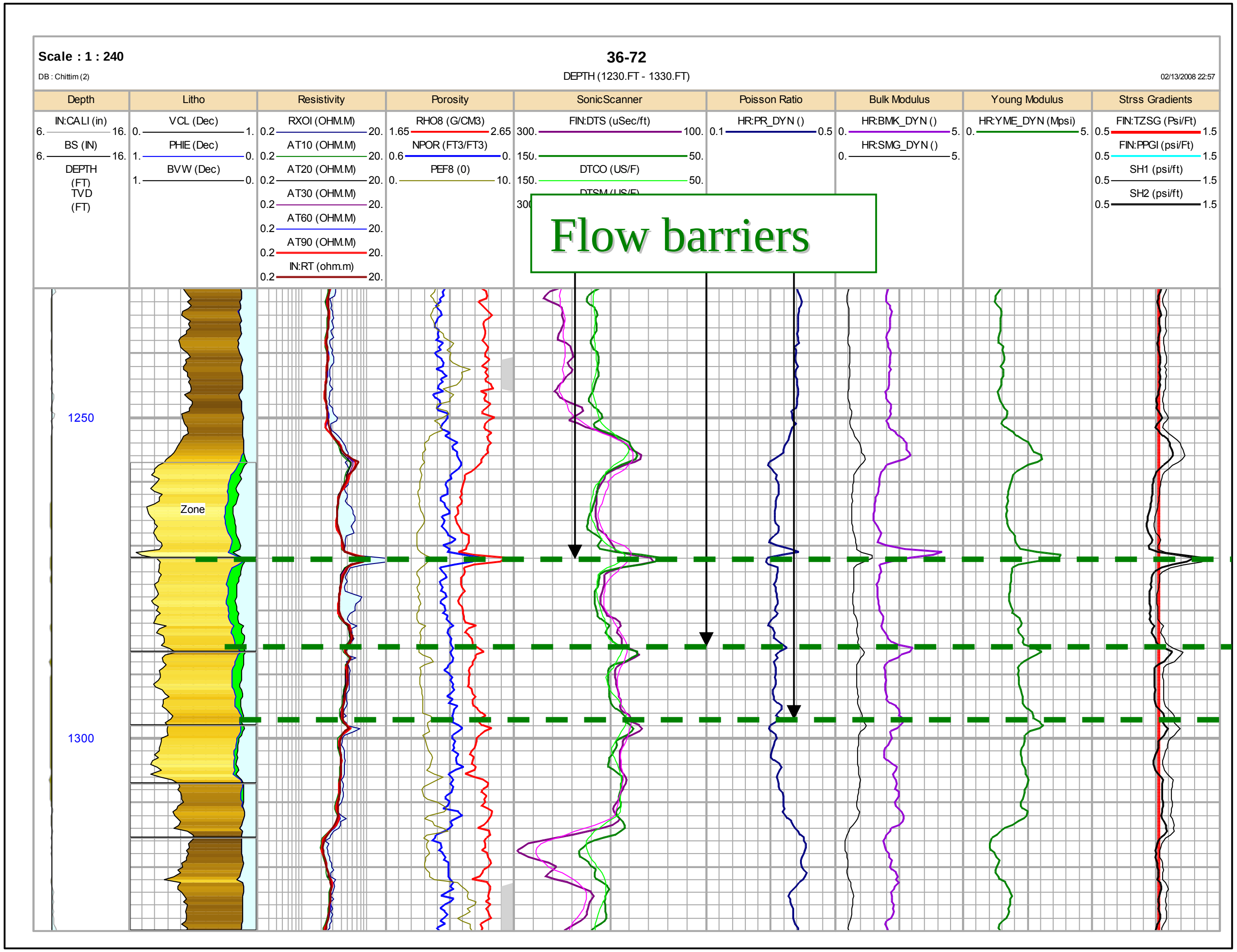
Geologic Overview

- The formation is composed of sandstones and shales.

- The sandstone units are a series of deltaic deposits reworked by marine processes.

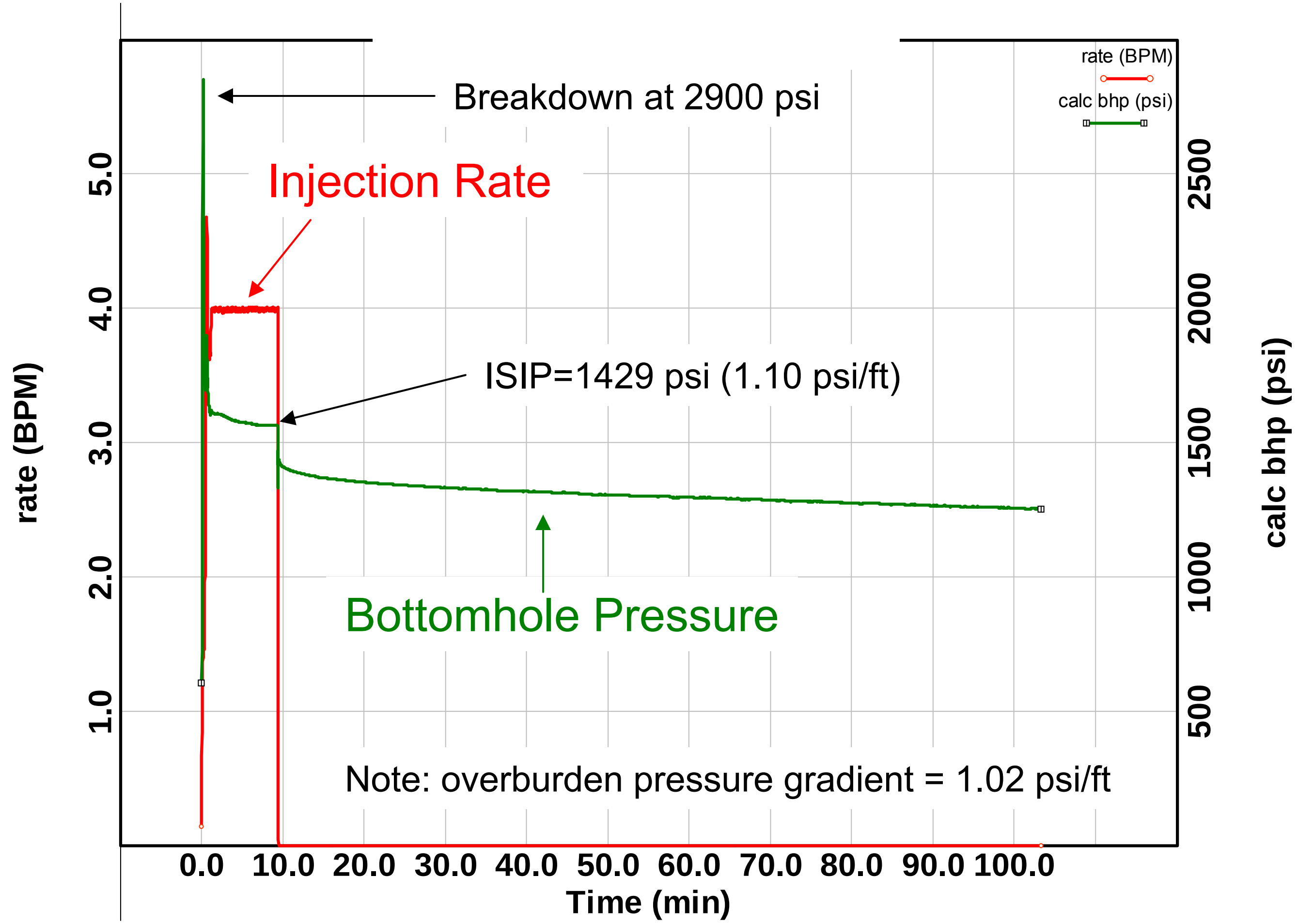
- Characteristics of the productive sandstone interval:
  - reservoir depth ranges from 1200 – 1700 feet TVD
  - average porosity: 20%
  - average permeability: 4 md
  - oil gravity: 39 API

Log Suite



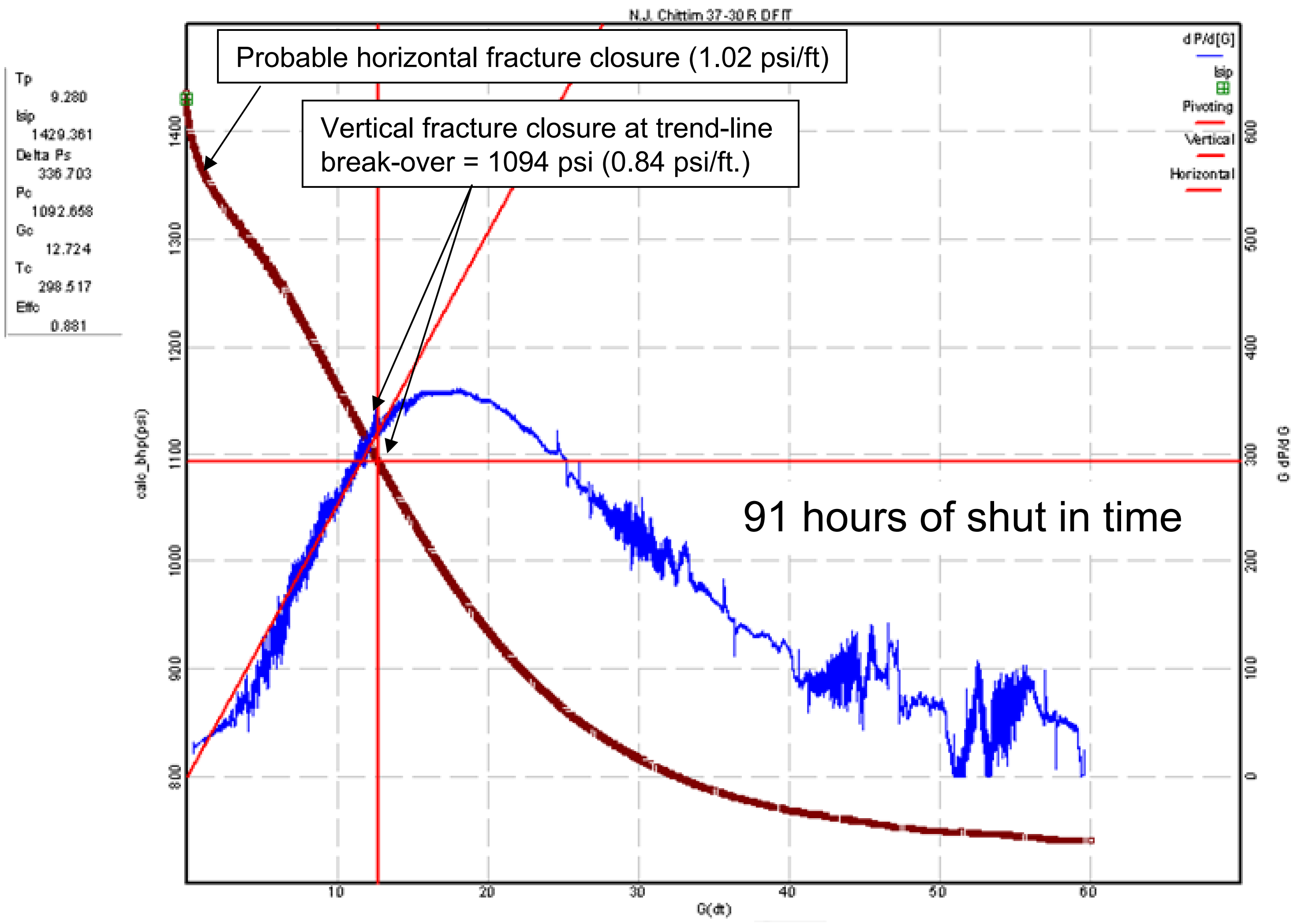
Log analysis provides estimates of reservoir properties

Diagnostic Fracture Injection Test (DFIT) Rate and Pressure Data



Low volume fracture injection tests can be analyzed to provide estimates of in-situ stress and reservoir transmissibility (kh/u)

DFIT G-dp/dG Plot



Vertical fracture closure is a proxy for minimum horizontal stress (S_3)

Poroelastic Equation for Estimating In-Situ Horizontal Stress

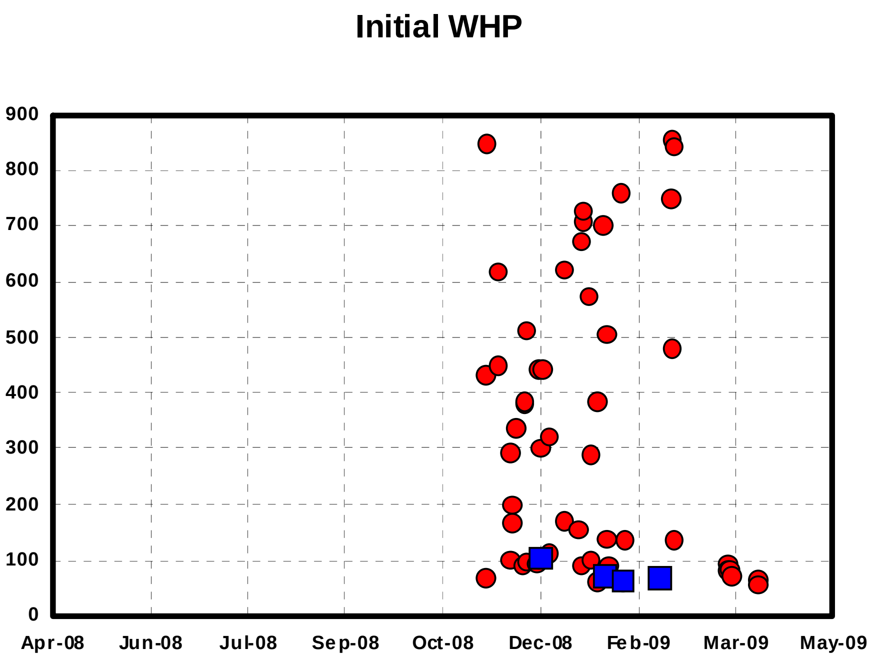
$$\sigma_h = \left[\frac{\nu}{1-\nu}\left(\sigma_v - \alpha_v \mathrm{P_r}\right)\right] + \alpha_h \mathrm{P_r} + \sigma_t$$

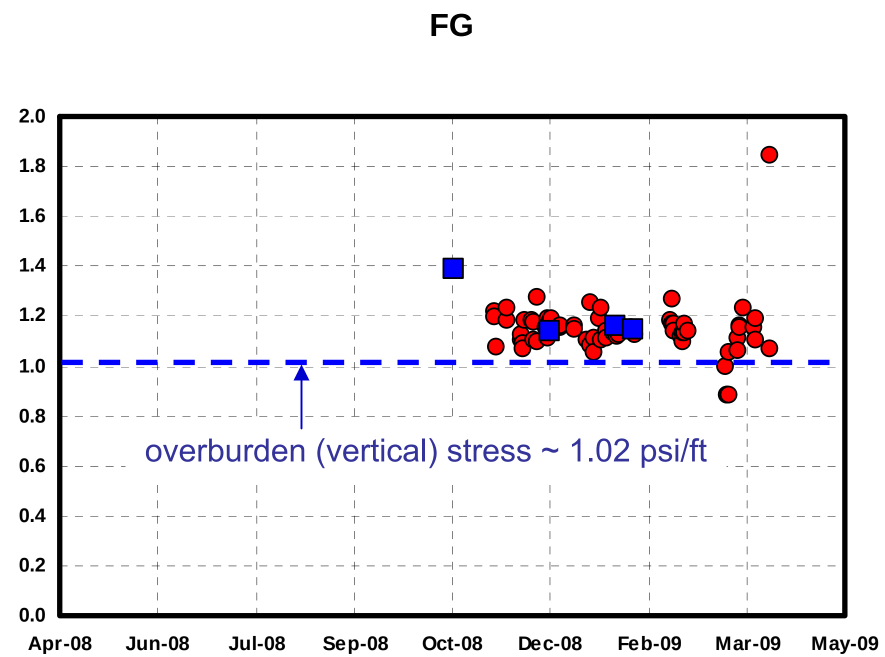
Where,

σ_v = overburden stress, psi = 1331 psi (1.02 psi/ft; bulk density log)
v = Poisson's ratio = 0.31 (from dipole sonic log computation)
α_v = vertical Biot's parameter = 1.0
α_h = horizontal Biot's parameter = 1.0
P_r = reservoir pore pressure, 718 psi (0.55 psi/ft; DFIT)
σ_t = external (tectonic) stress, psi = 0 psi (assumed)
σ_h = minimum horizontal stress, psi = 1047 psi (predicted from above)
σ_h = minimum horizontal stress, psi = 1094 psi (observed from DFIT)

There is reasonable agreement with predicted and measured in-situ stress

Bottomhole Treating Pressure Behavior





Variability in initial reservoir pressure is due to injection/ withdrawal imbalances within the field.

Regardless of initial pore pressure, hydraulic fracturing pressure (FG) is regulated by the overburden stress.

Post-Treatment Multi Test Hole Study

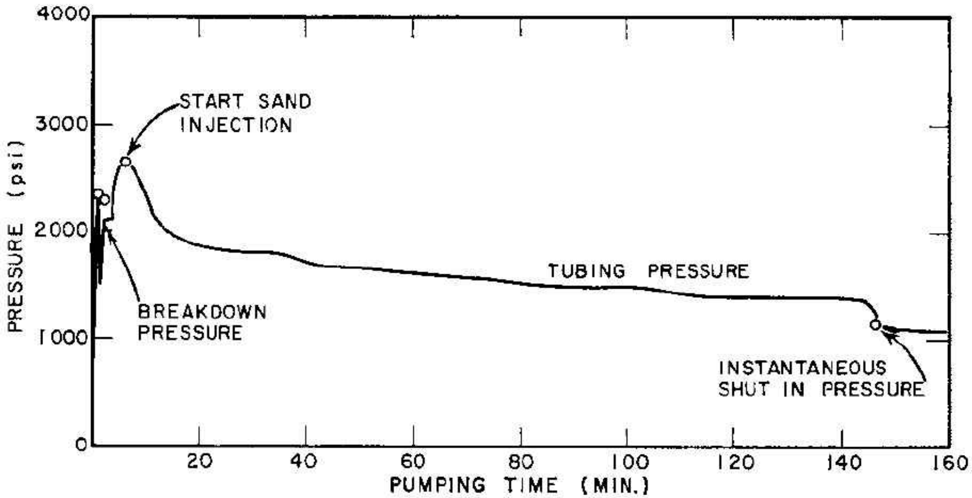


FIG. 1—PRESSURE CHART OF WELL NO. 37-1.

From SPE paper 1571 (1961)

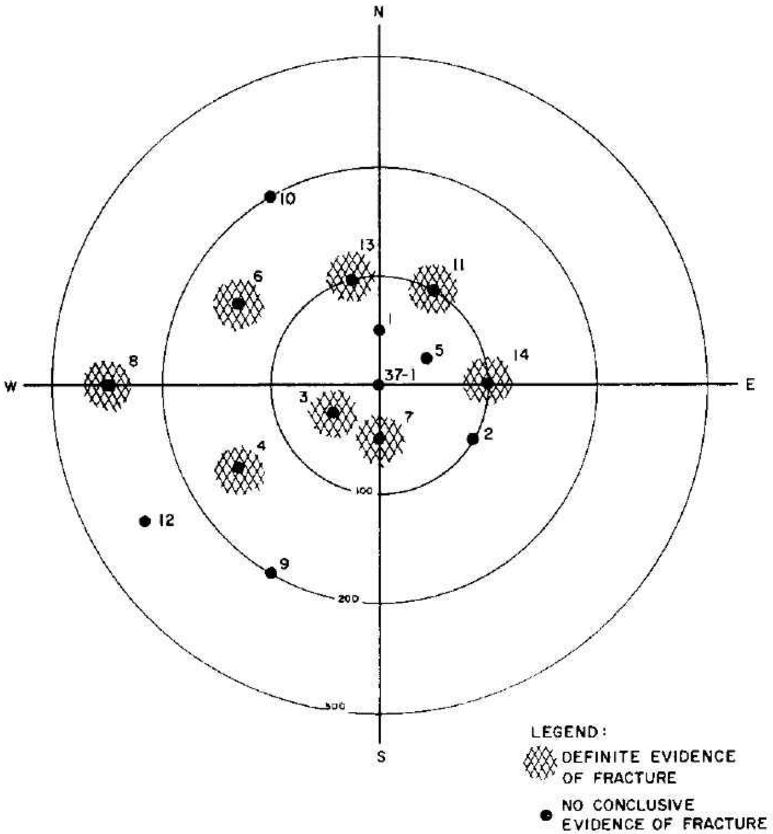


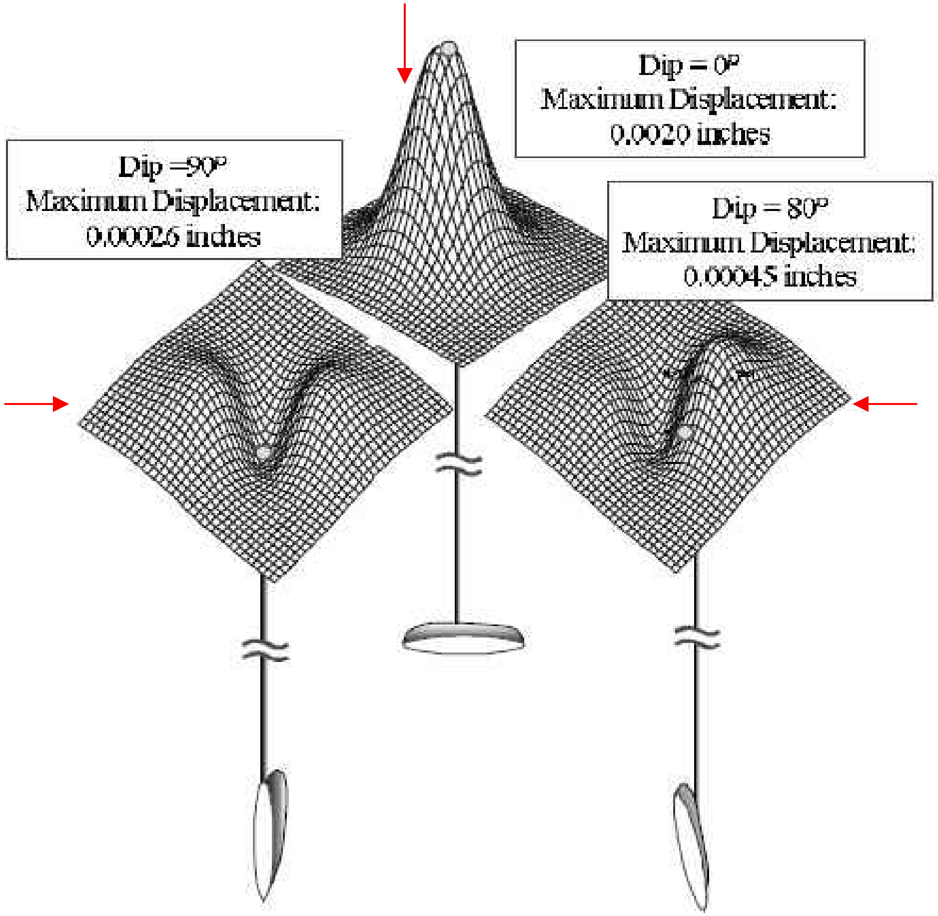
FIG. 5—CHITTIM RANCH FRACTURE STUDY, MAVERICK COUNTY, TEX.: 1 IN. = 100 FT; 15° GRID.

An extensive horizontal fracture was "excavated"

Surface Tiltmeter Deformation Visualization

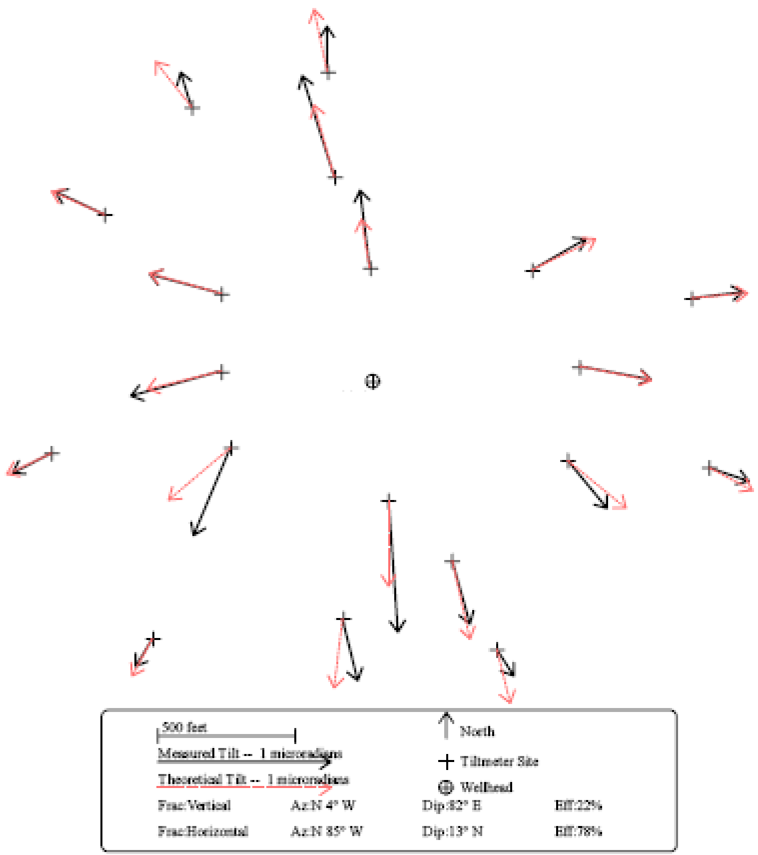
horizontal fracture
(domed or conical feature)

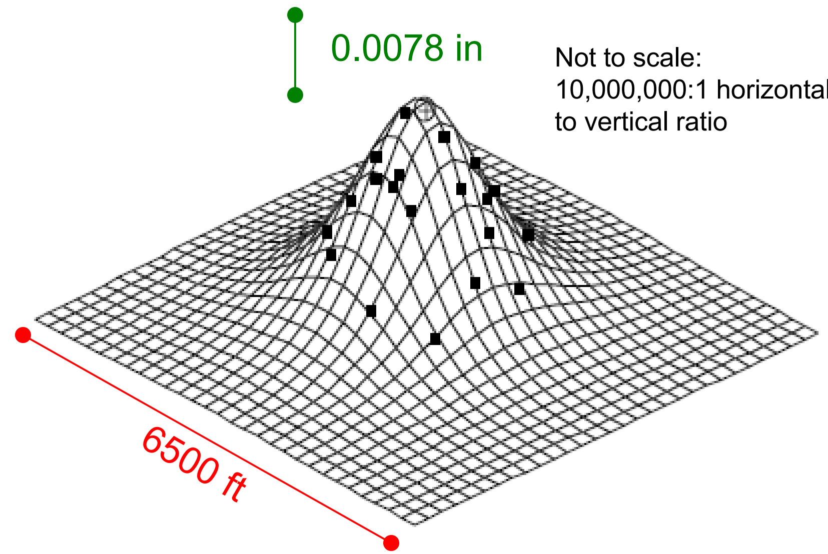
vertical fracture
(trough feature)



dipping fracture
(asymmetrical
trough feature)

Tilt Vector Diagram & Surface Deformation Visualization, Example from Study Area

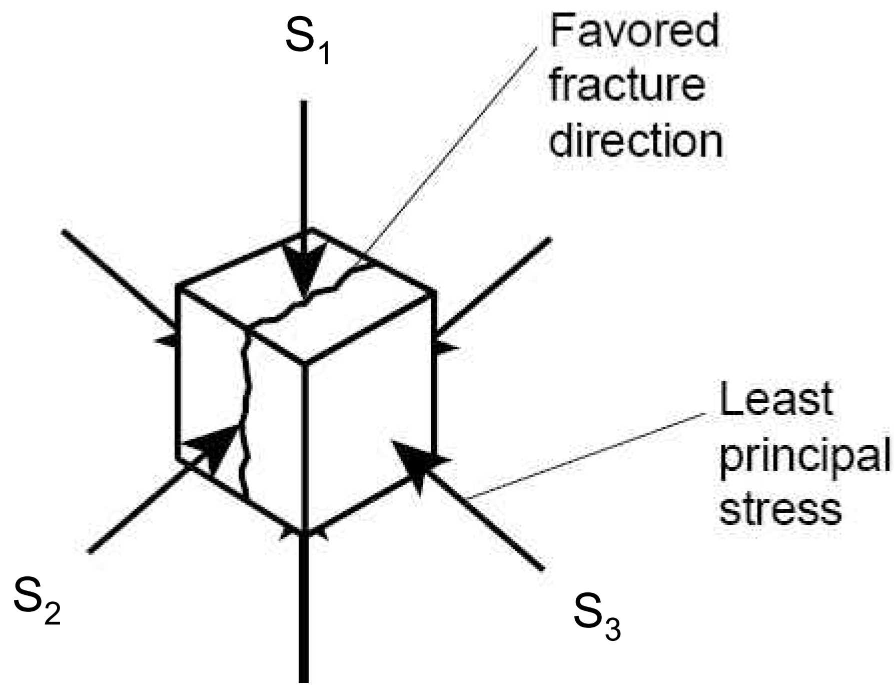




Surface displacement during the treatment was equal to the thickness of 2 sheets of paper

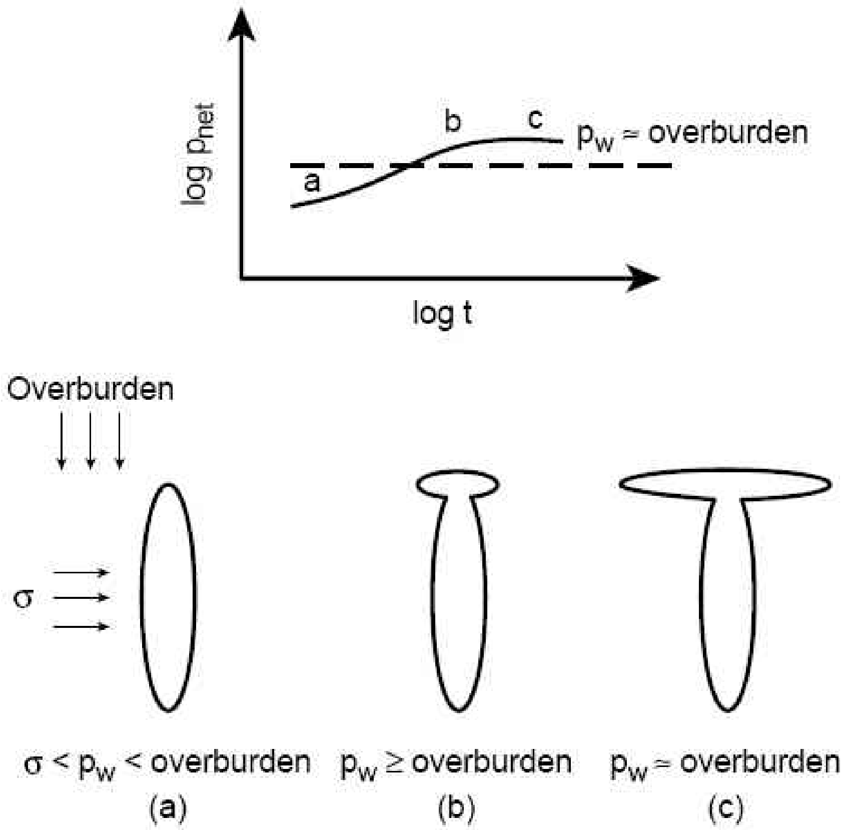
Tiltmeter mapping results show the classic signature of a horizontally-dominant hydraulic fracture system. Horizontal fracture component is 78-90%

Hydraulic Fractures Open Normal to the Least Principal Stress



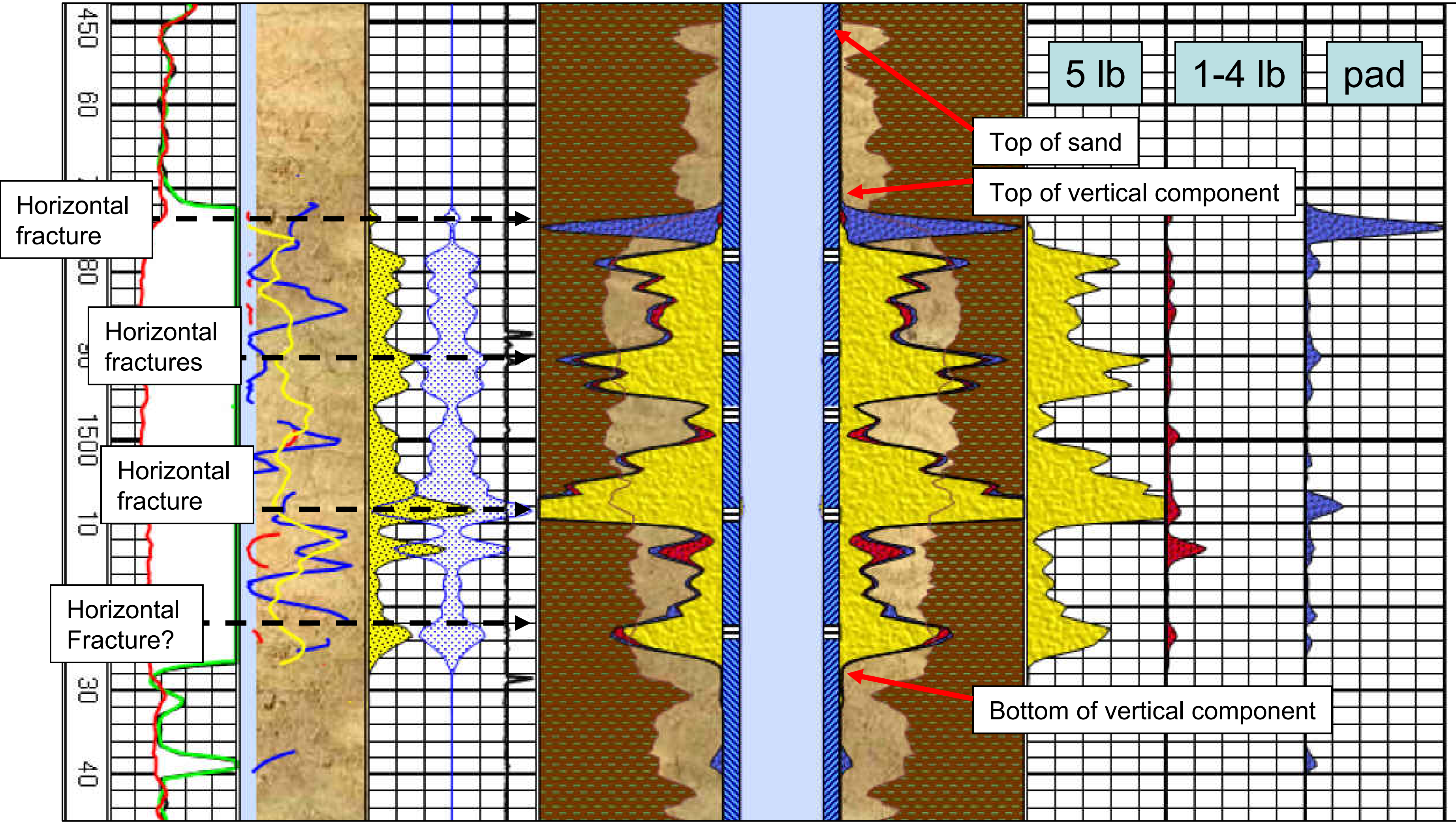
But it's a little more complicated than this in shallow reservoirs

T-Shaped Fractures



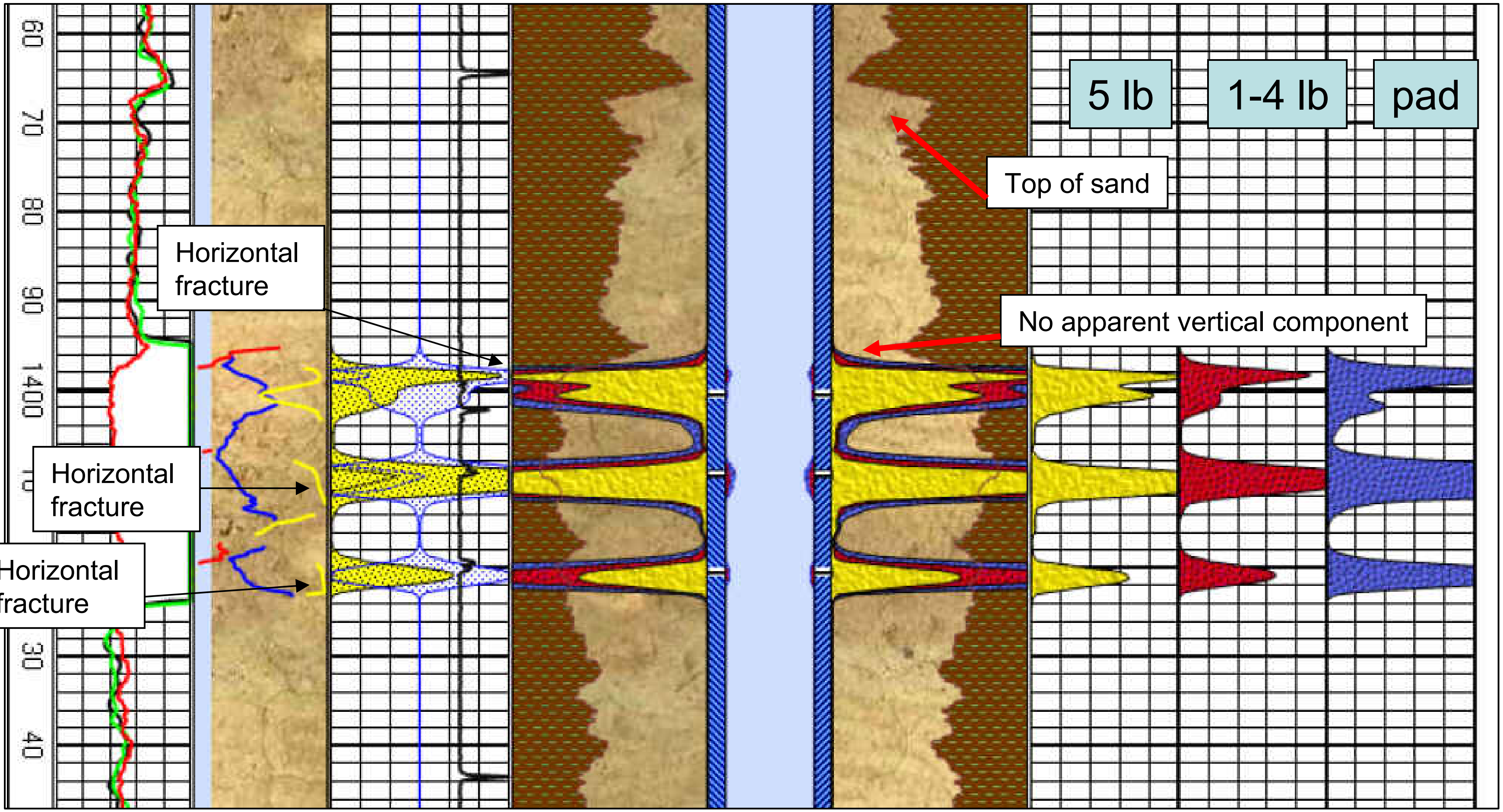
This routinely happens when the difference between horizontal and vertical principal stresses is small, as is the case with shallow reservoirs

Five Zone Limited Entry Treatment: Well A



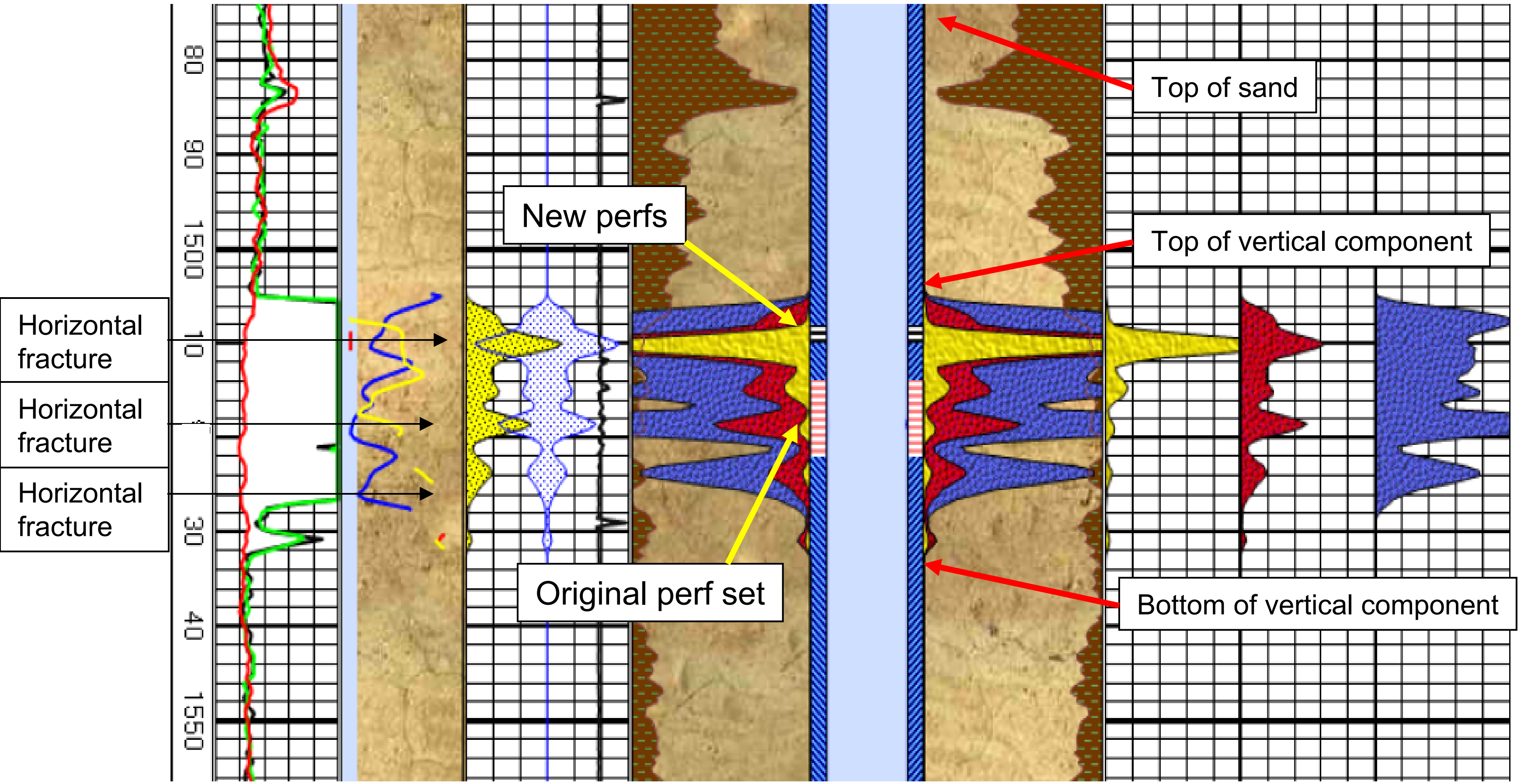
Top of fractured interval is capped by a horizontal fracture

Three Zone Limited Entry Treatment: Well B



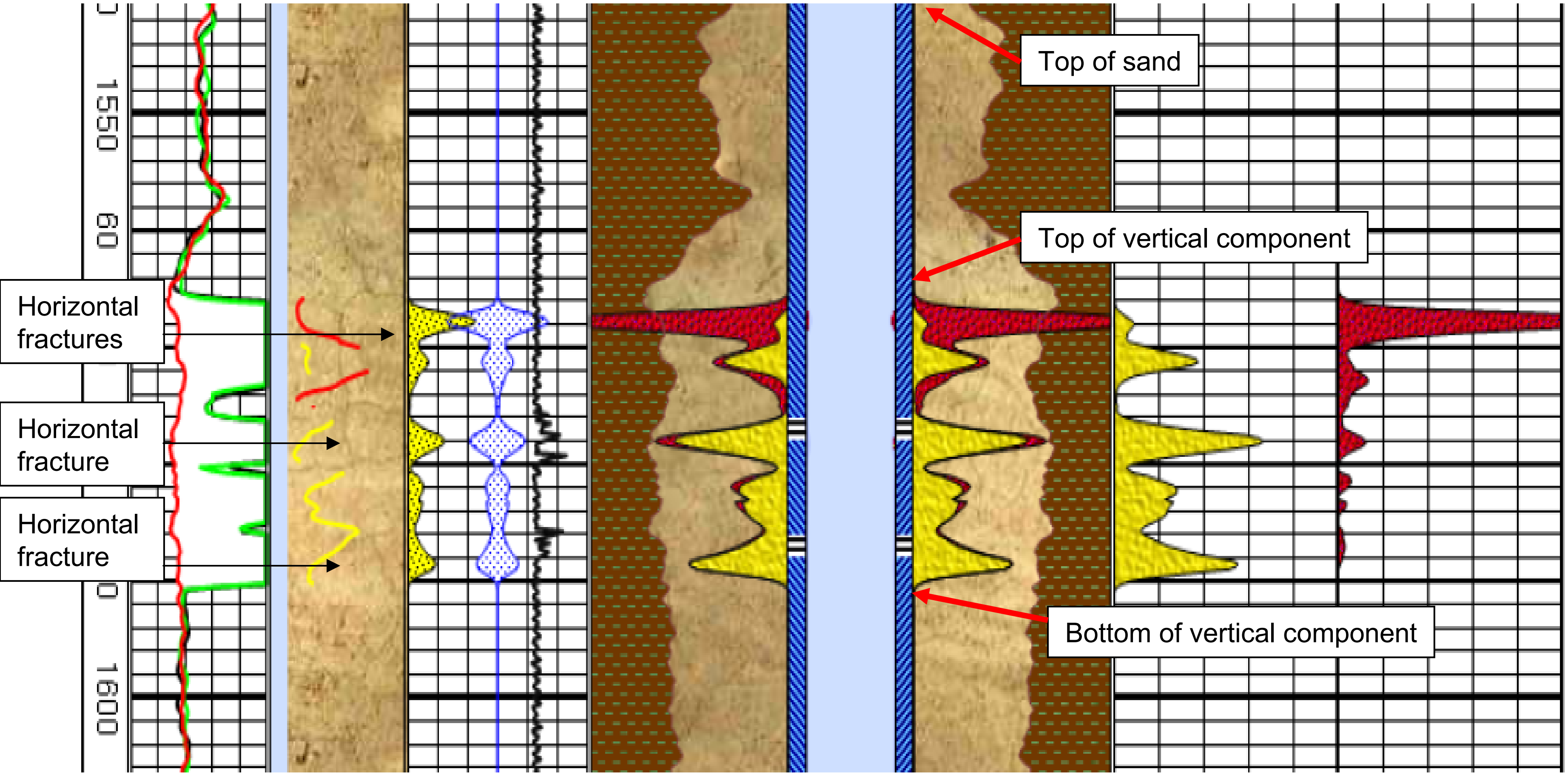
Dominant horizontal fracture signature

Recompletion Tracer Log: Well C



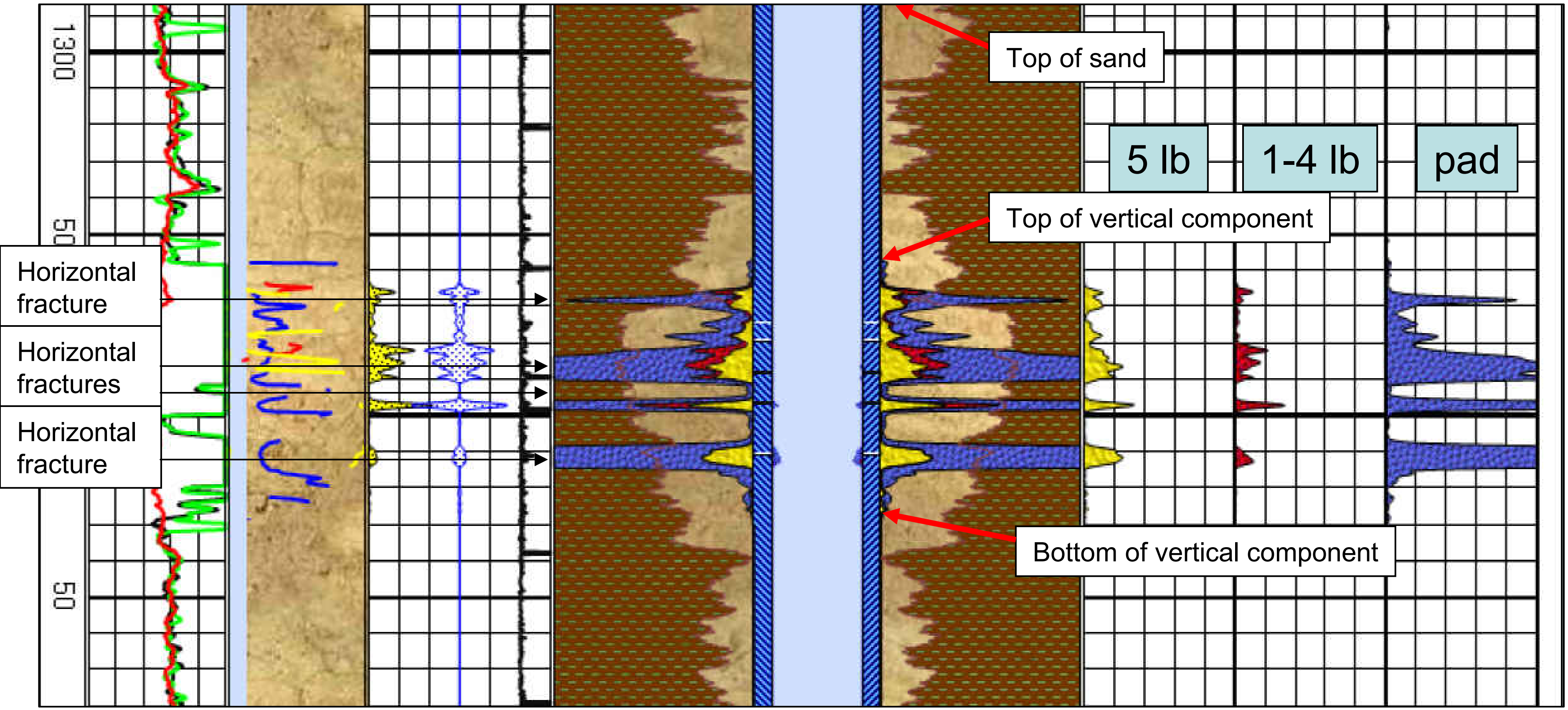
Hydraulically fracturing via the new perf set increased oil production by 10 fold. This response is indicative of the lack of vertical connectivity from the previously fractured original perf set.

Two Zones with Ball Sealer Diversion: Well D



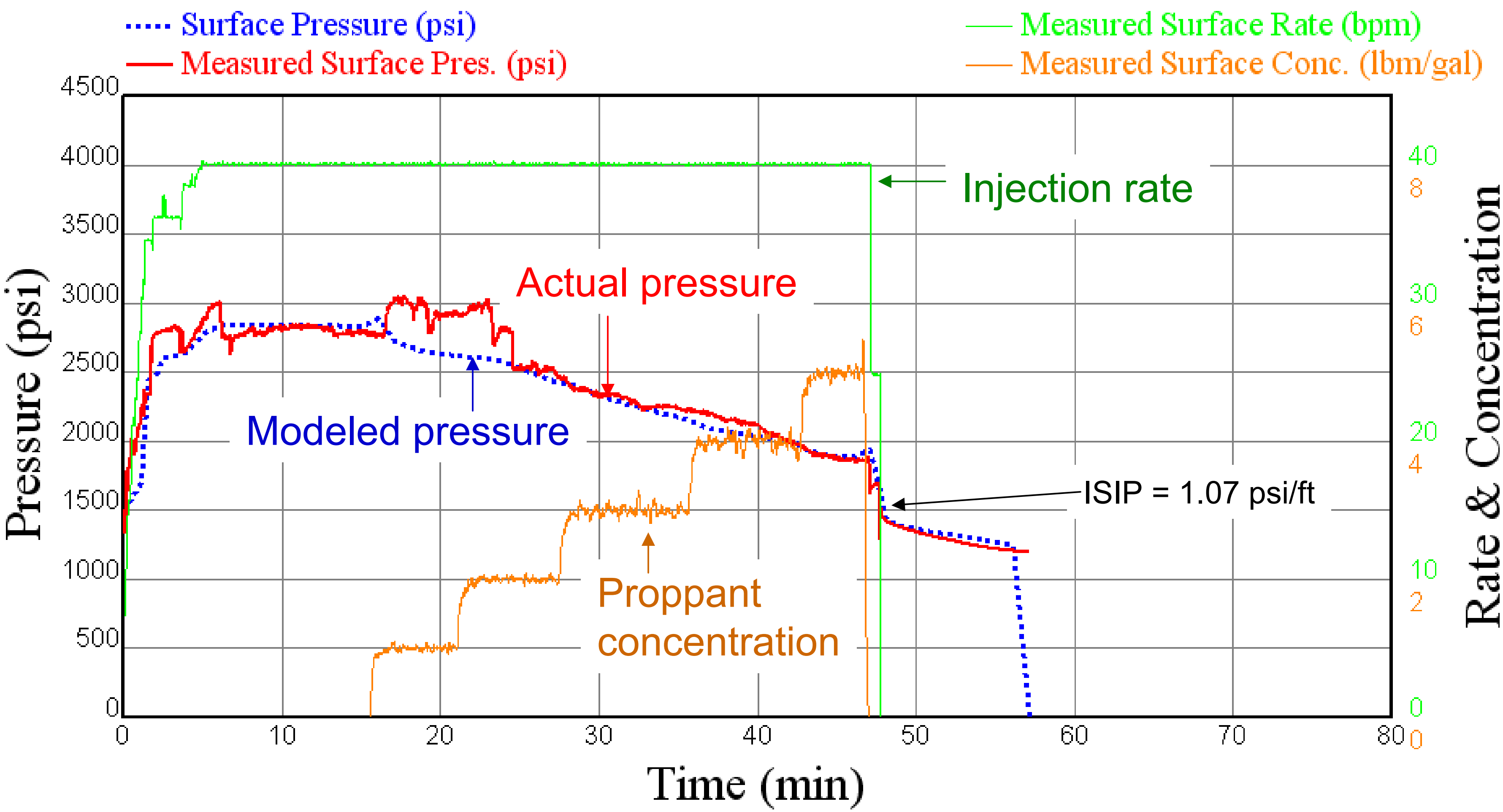
Top of fractured interval is capped by a horizontal fracture

Five Zone Limited Entry Treatment: Well E



Top of fractured interval is capped by a horizontal fracture

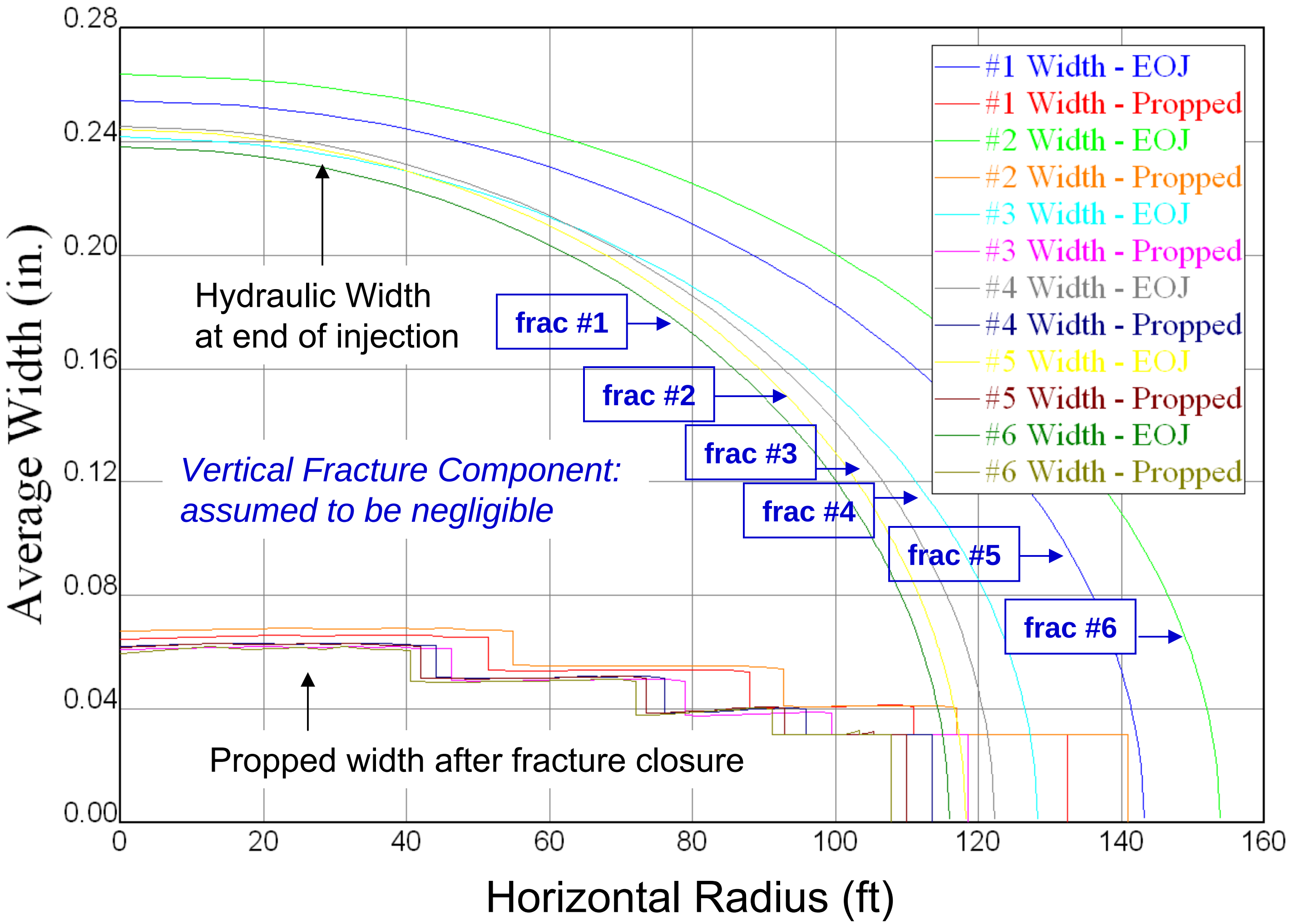
Treatment Pressure History Evaluation: Well E



Actual results matched computer modeled results indicating good control of the process

Hydraulic Fracture Modeling Results: Well E

Width vs radial position for each horizontal fracture



Summary

- **Conditions are favorable for propagating horizontal fractures in shallow reservoirs.**
  - There is a small difference between the overburden (vertical) and minimum horizontal principal stresses.
  - The net pressure required to extend a vertical fracture is in excess of the horizontal-to-vertical stress difference.

- **Fracture geometry can be estimated from the treatment pressure response.**
  - Horizontal fractures propagate radially and require decreasing net pressure to grow.
  - Vertical fractures eventually propagate elliptically (length-to-height aspect ratio of greater than one) and require increasing net pressure to grow.

- **Vertical fracture growth is contained within the pay sand.**
  - Core hole, tiltmeter, tracer survey and treating pressure analysis indicate that horizontal fracturing is the dominant mode of fracture propagation even though the minimum in-situ stress is not vertical.

- **Methods are employed to control the hydraulic fracturing process.**
  - There is a strong financial incentive to contain fracture propagation within the target sandstone intervals.
  - Treatment designs are modeled and evaluated with computer-based processes.
  - Limited entry or selective multi-stage frac treatments are necessary to achieve fracture propagation in all the sub-intervals in the study area.