Horizontal Well Stimulation Optimization

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Selecting Horizontal vs Vertical Wells

- Can vertical wells be stimulated effectively?
- Can vertical wells drain the reservoir (contact the required volume)?
- Can vertical infill wells be drilled economically?
- Can field development economics be improved by switching to horizontals?

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Selection of Horizontal Well Completion/Stimulation Method

- Know the reservoir
  - Deliverability (kv, kh, Pi, GLR)
  - Stress field magnitude and orientation
  - Drainage area shape and size
- Define the well
  - Maximum possible length
  - Limitations on orientation
  - Expected skin damage
  - Options for completion
    - Cased/cemented; open-hole; uncemented liner

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Selection of Stimulation Method

- No stimulation or cleanup
- Acid or mud-cleanup Wash
- Longitudinal acid frac
- Transverse acid fracs (multiples)
- Longitudinal propped frac
  - Longitudinal frac with “hair” on it
- Transverse propped fracs (multiples)

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Factors Affecting Horizontal versus Vertical Well Performance

- Flow path in proppant pack
- Near-well tortuosity and flow restrictions
- Reservoir drainage area
- Interference of multiple transverse fractures
- Drainage aspect ratio

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Maximum Attainable Effective Xf Depends on:

- Reservoir permeability
- Frac fluid cleanup
- Producing water-cut and condensate yield
- Applied drawdown
- Created fracture length
- Average proppant concentration
- Applied closure stress
- Reservoir rock “hardness”

Effective frac length is usually much shorter than expected

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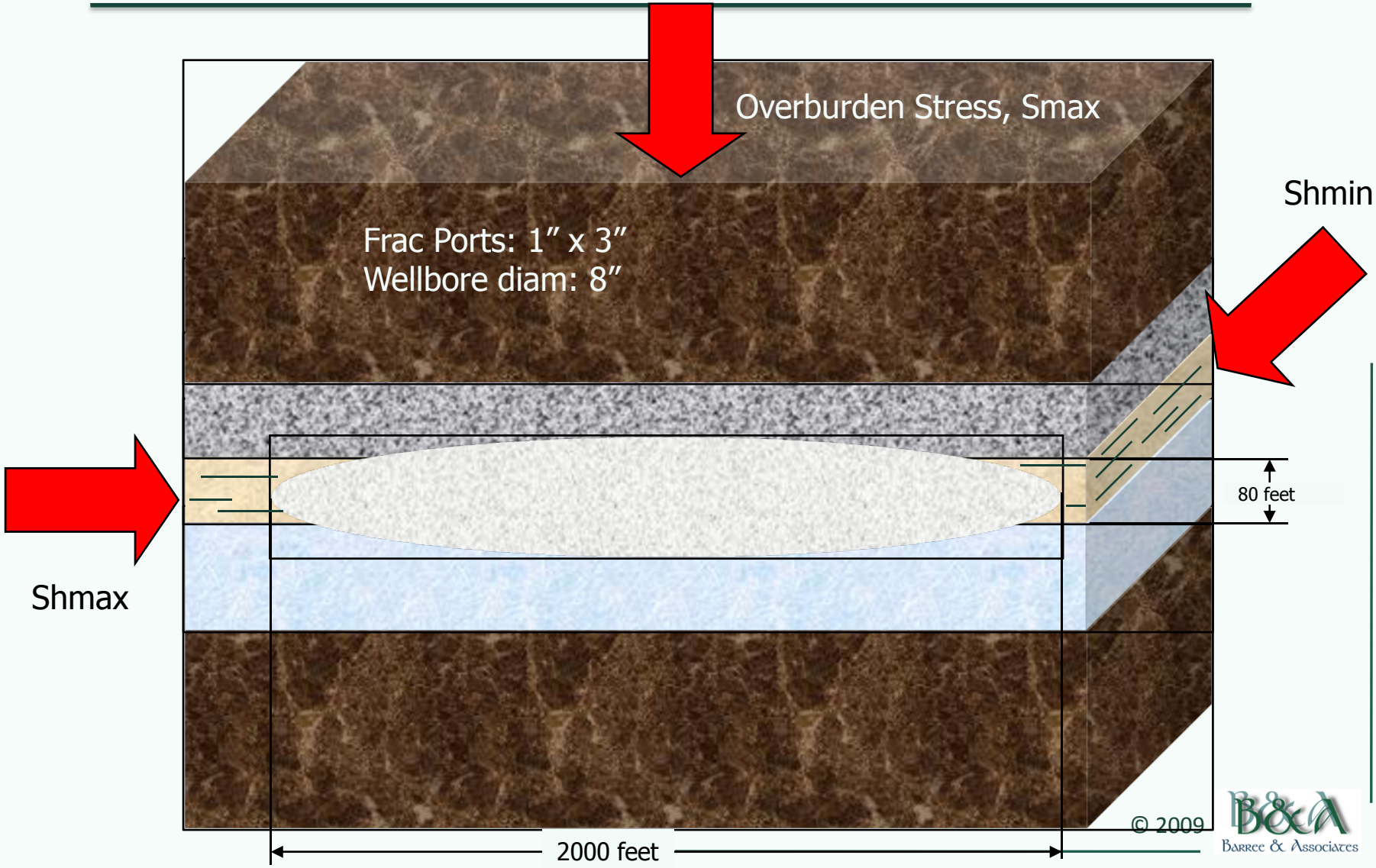
Growth of Fractures in a Layered Medium



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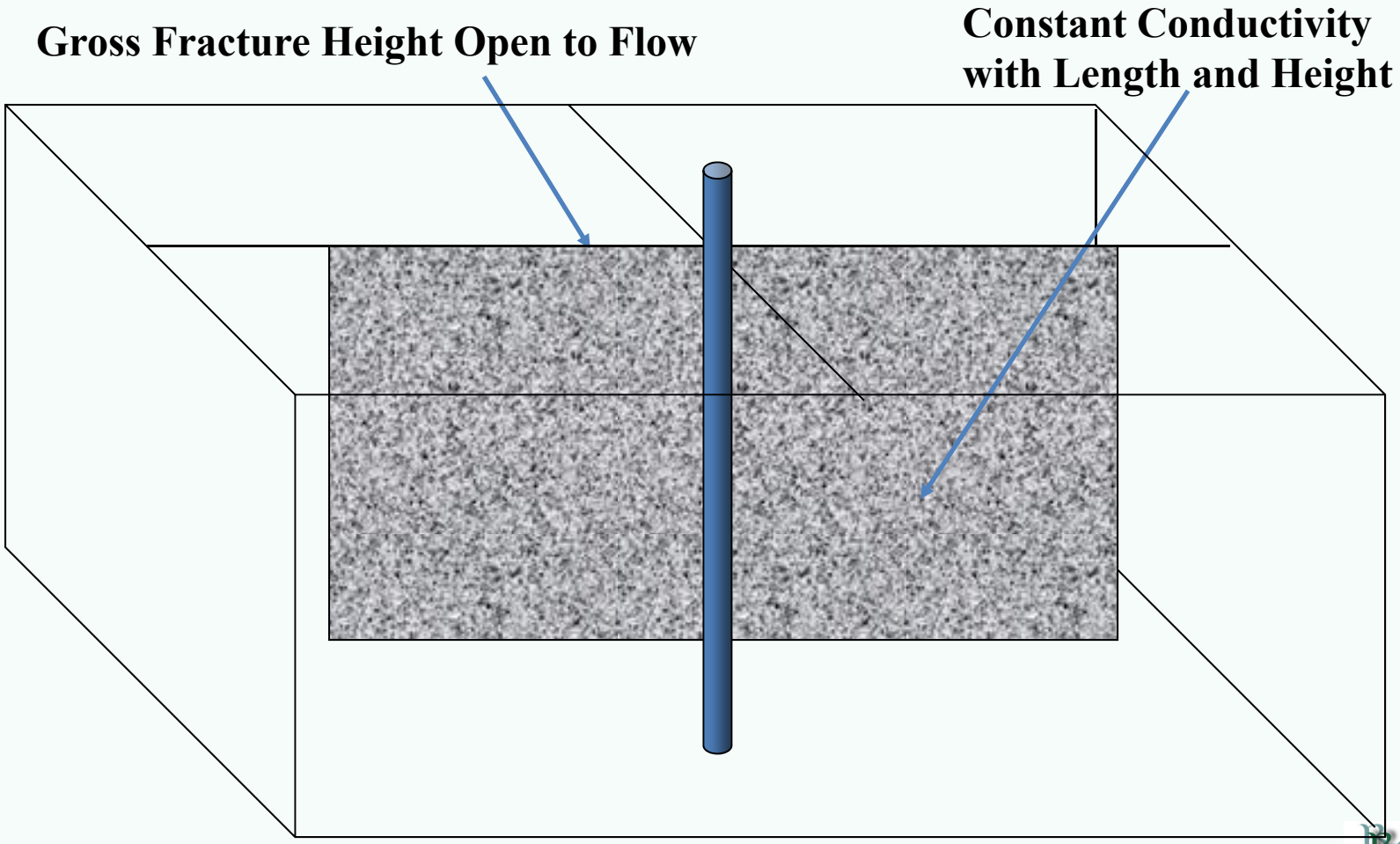
Assumed Fracture Geometry for Productivity Estimates: Vertical Well



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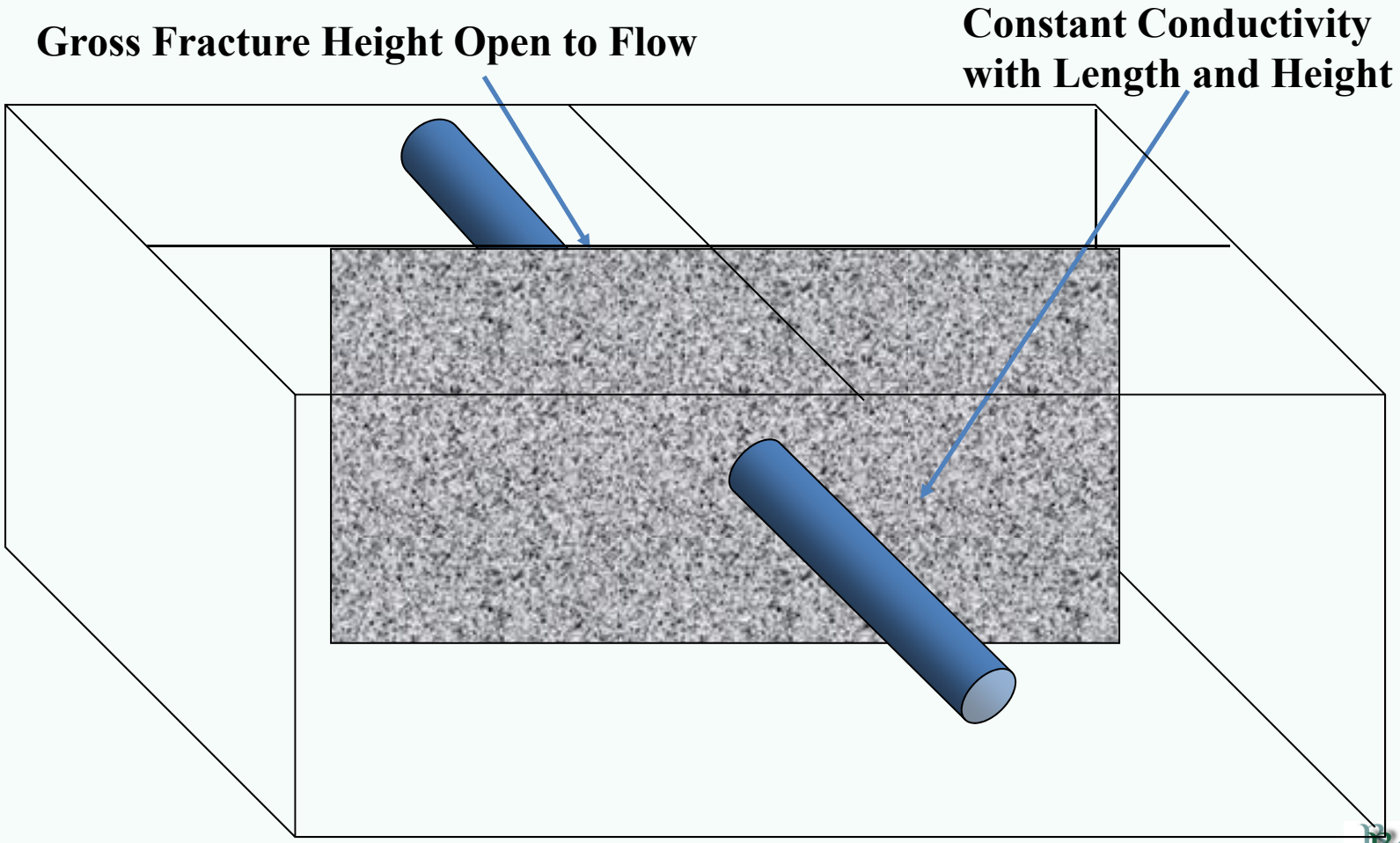
Assumed Fracture Geometry for Productivity Estimates: Horizontal Transverse



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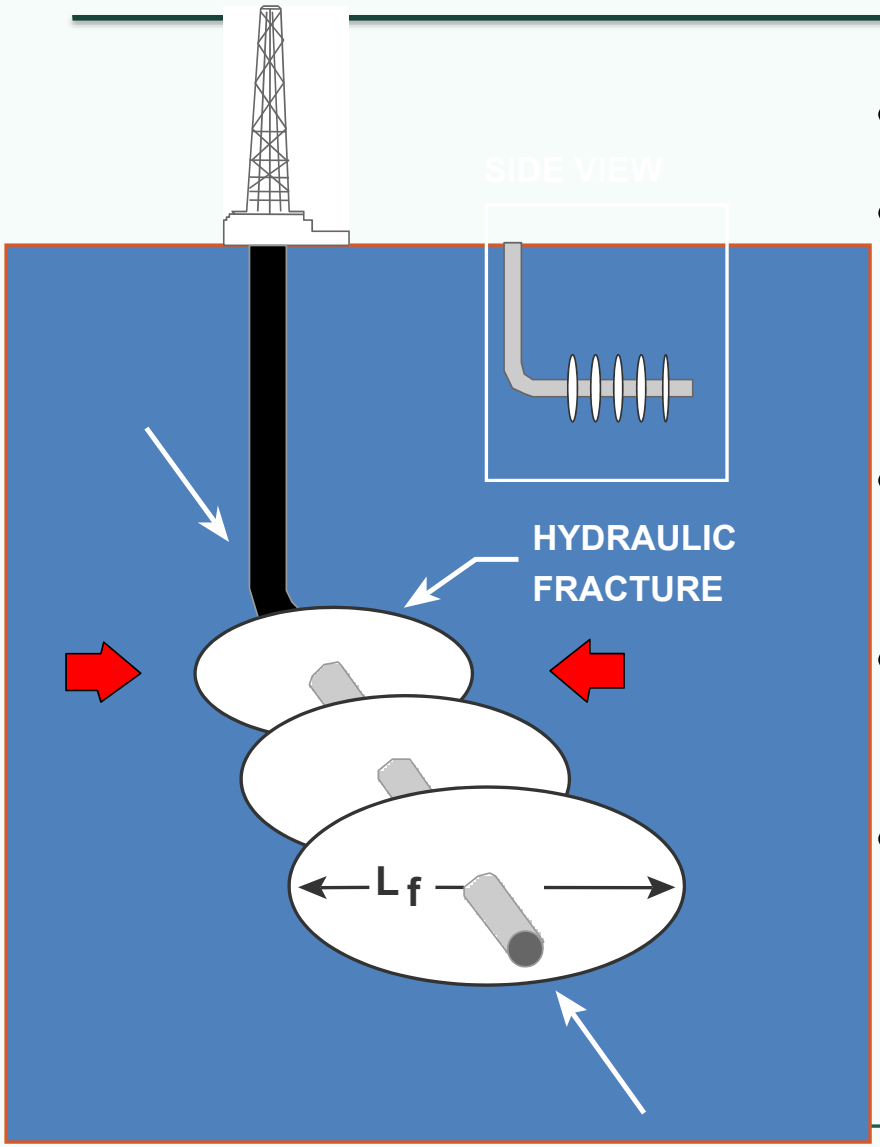
Multiple Transverse Fractures



- Thick reservoirs
- Long Xf possible
  - Low perm
  - Efficient stimulations
- Compartmentalized reservoirs
- Linear reservoir flow "channels"
- Difficult and expensive to place in desired locations

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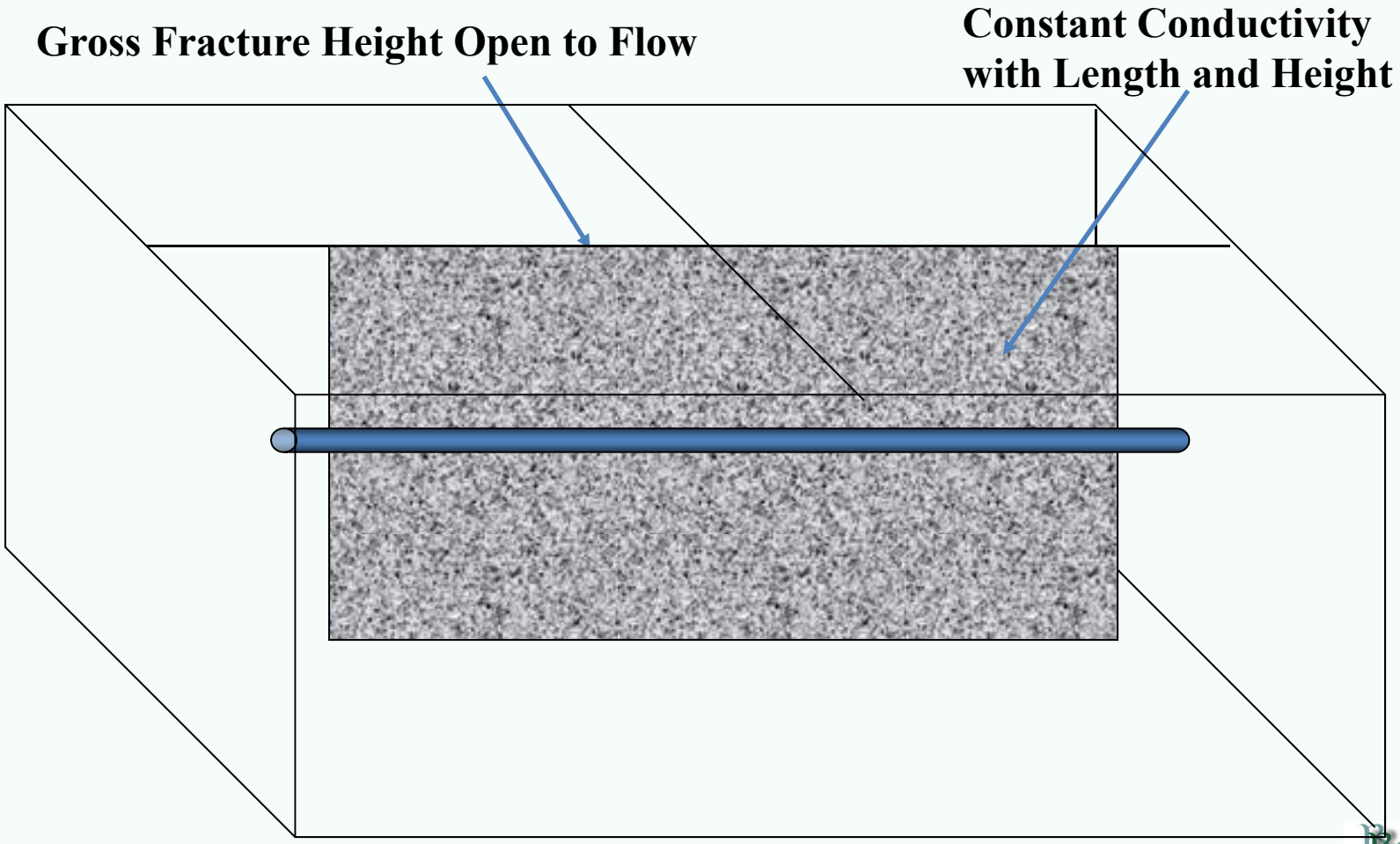
Assumed Fracture Geometry for Productivity Estimates: Horizontal Longitudinal



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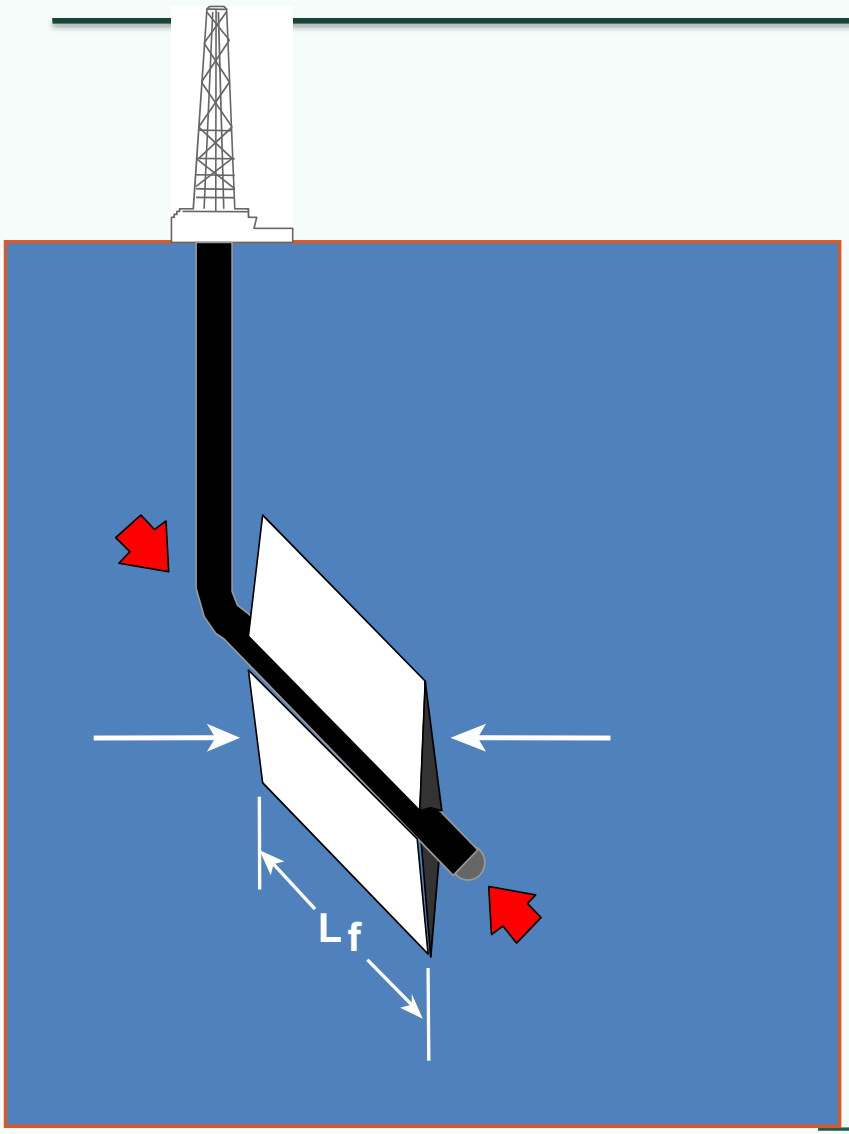
Longitudinal Fractures



- Thin reservoir sections
- Low kv/kh in thick reservoirs
- Better when effective Xf is low
- Better in continuous reservoirs
- Large volume treatments
- Easy to place and pump effectively

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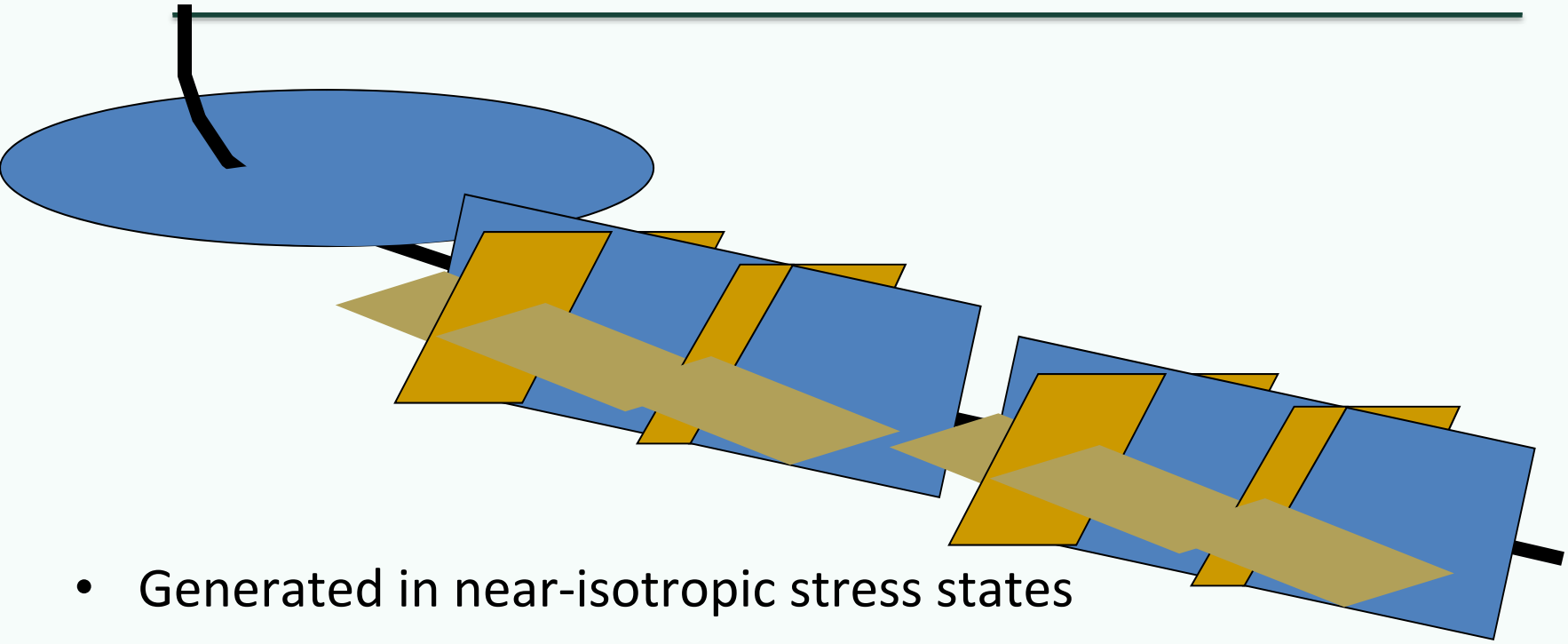
Complex Longitudinal with “Hair”



- Generated in near-isotropic stress states
- Usually results from intended longitudinal fracs
- More of an accident or “gift” than an intentional result

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Direction of Fracture Growth

- Controlled by in-situ stress field
  - Magnitude of all three principal stresses
  - Principal stress axis
  - Degree of overpressure or depletion
- Direction of well (azimuth)
- Deviation of well from vertical

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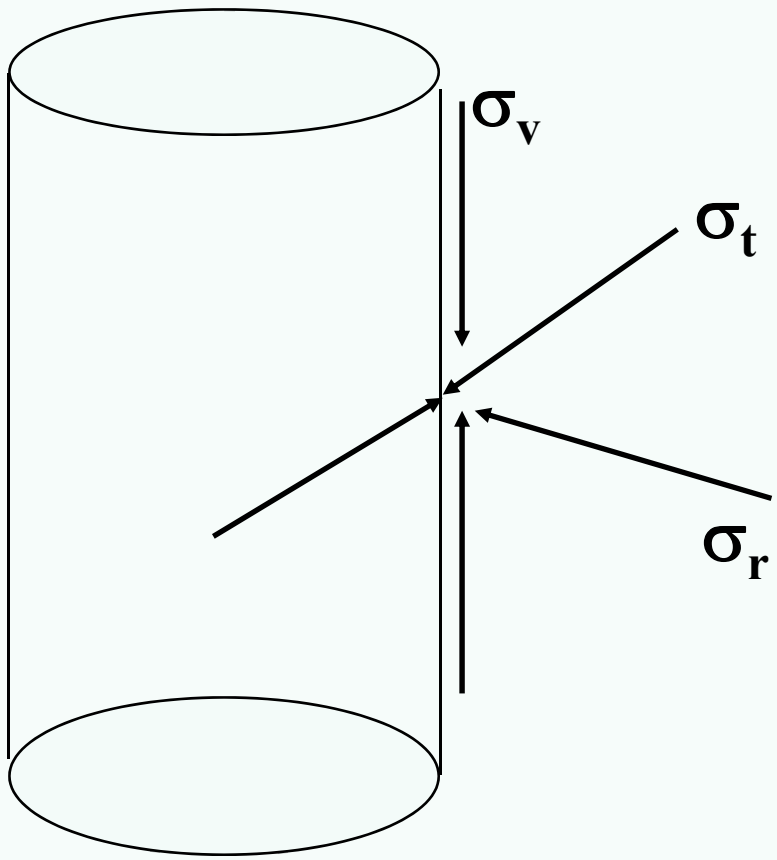
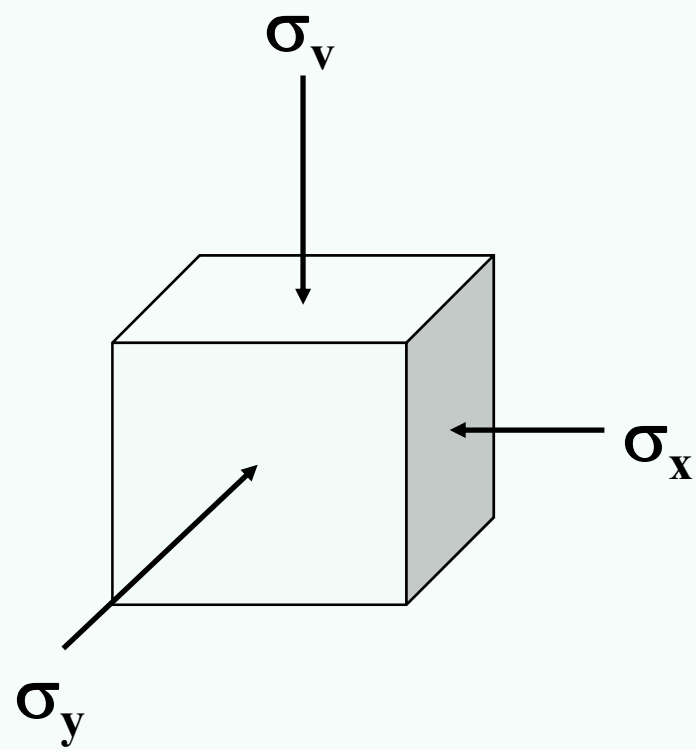
Radial Coordinate System of Stresses around a Wellbore





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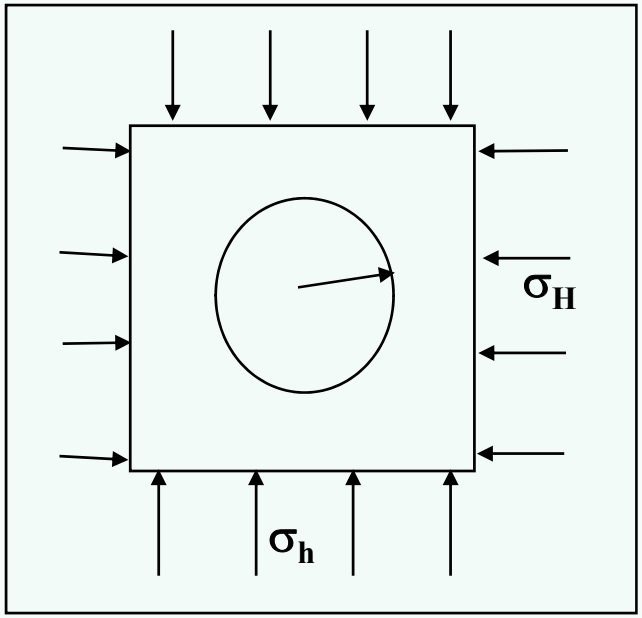
Stresses Vary with Direction and Distance from Well

$$\sigma_r = \frac{\sigma_h + \sigma_H}{2}\left(1 - \frac{r_w^2}{r^2}\right) + \frac{\sigma_h - \sigma_H}{2}\left(1 - 4\frac{r_w^2}{r^2} + 3\frac{r_w^4}{r^4}\right)\cos 2\theta + \frac{r_w^2}{r^2}\left(P_w - \alpha P_o\right)$$

$$\sigma_t = \frac{\sigma_h + \sigma_H}{2}\left(1 + \frac{r_w^2}{r^2}\right) - \frac{\sigma_h - \sigma_H}{2}\left(1 + 3\frac{r_w^4}{r^4}\right)\cos 2\theta - \frac{r_w^2}{r^2}\left(P_w - \alpha P_o\right)$$

$$\sigma_v = P_{ob} - \alpha P_o$$



P_o = far field pore pressure
P_w = wellbore fluid pressure
P_{ob} = overburden pressure
r = distance from wellbore
σ_H = maximum horizontal stress
σ_h = minimum horizontal stress
θ = angle from direction of minimum stress

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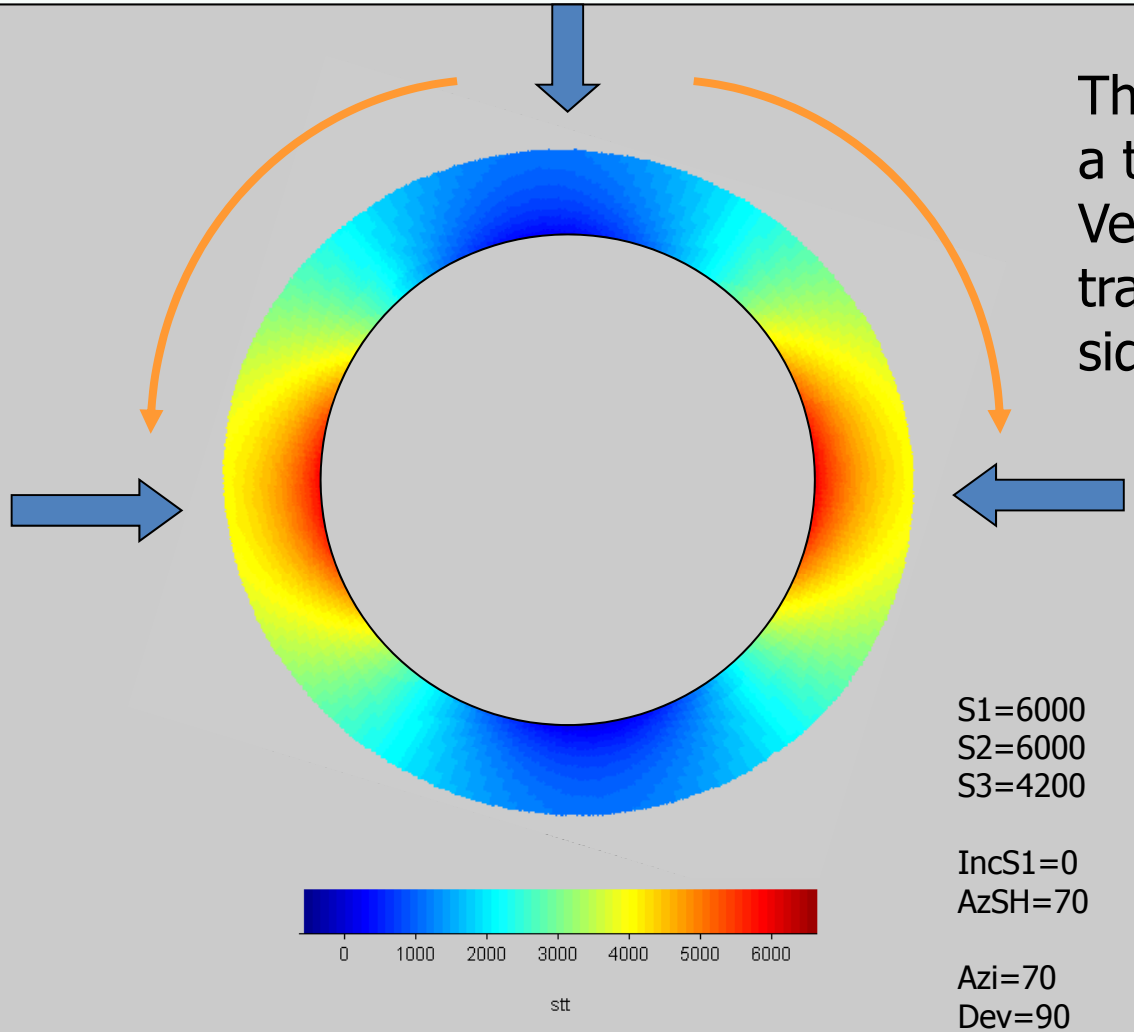
Tangential Stress Distribution Around a Horizontal Well



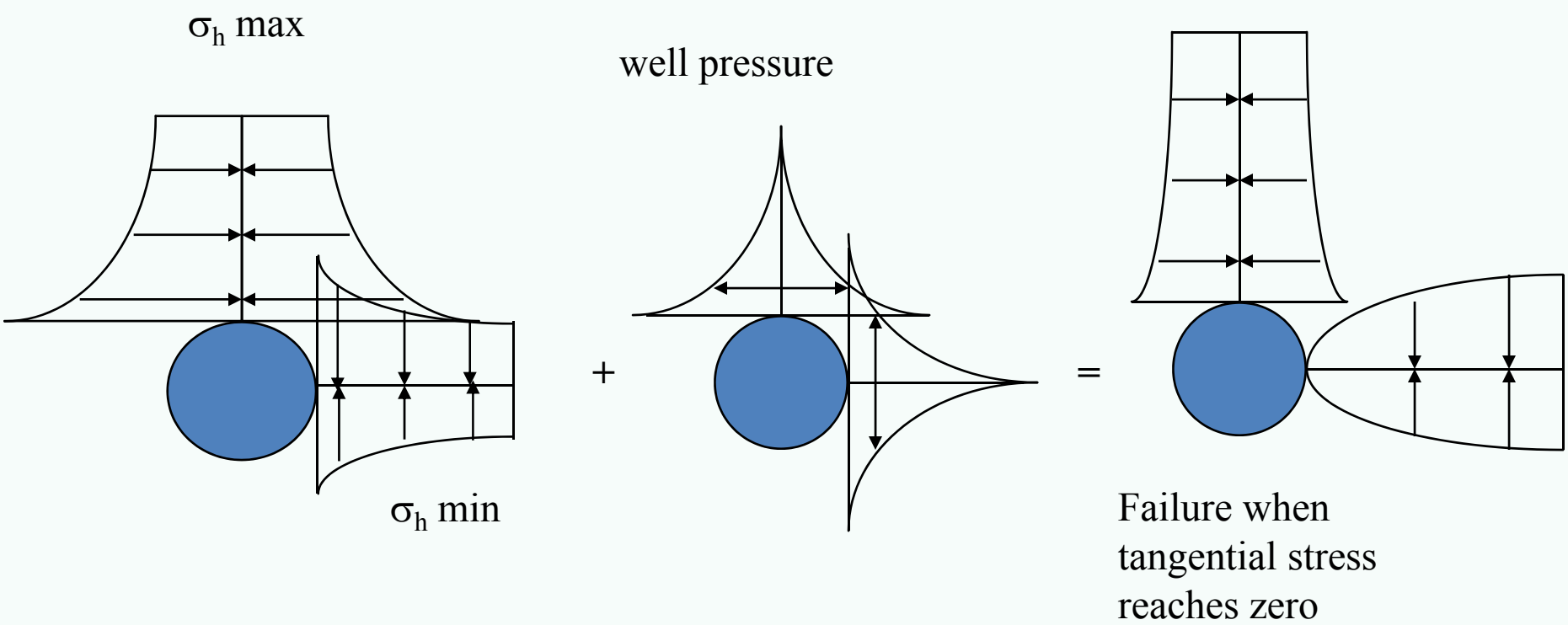
The wellbore acts as a tunnel arch: Vertical stress is transmitted to the sides of the hole

S1=6000
S2=6000
S3=4200

IncS1=0
AzSH=70

Azi=70
Dev=90

Fracture Initiation at Point of Minimum Tangential Stress



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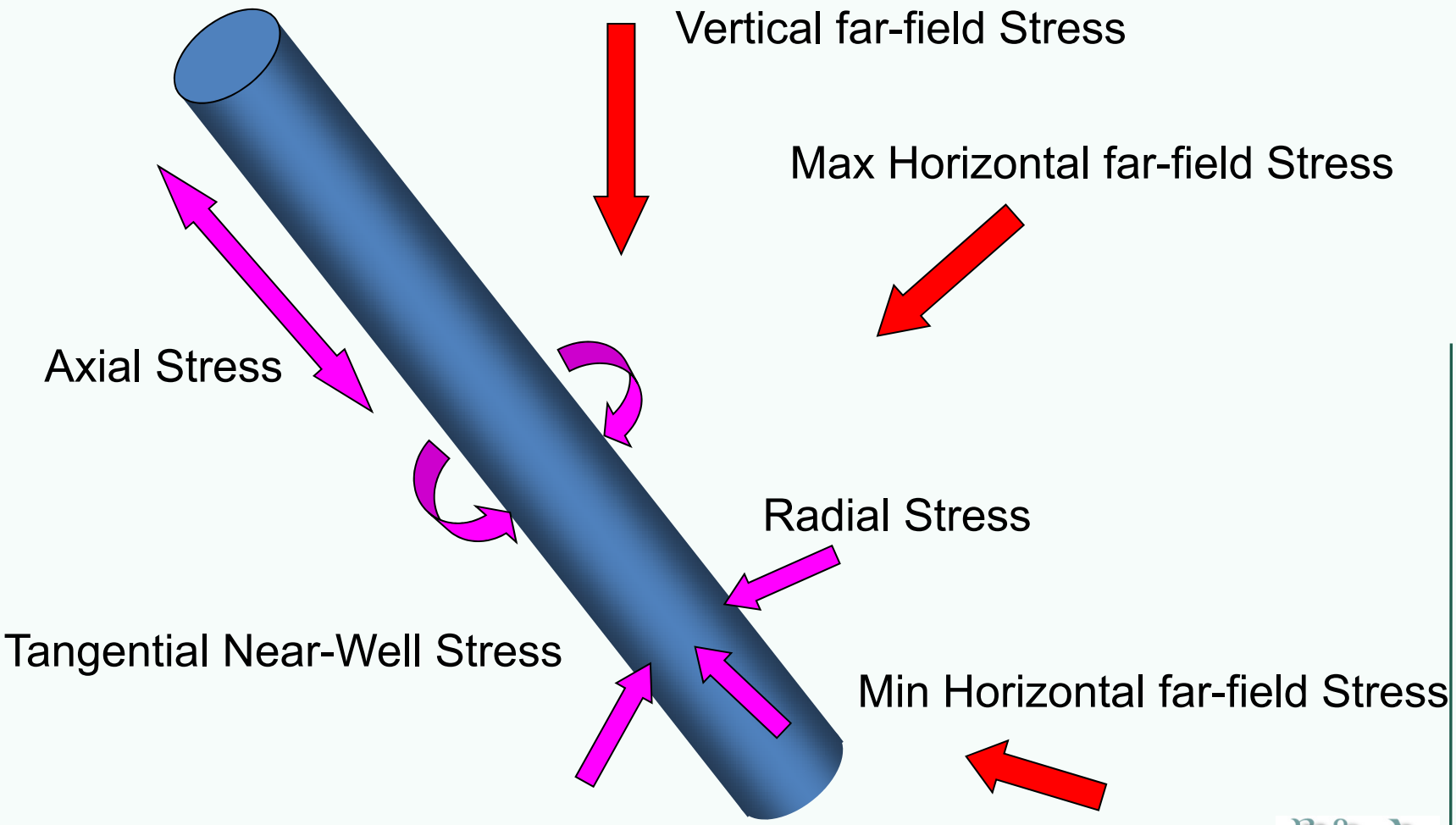
Borehole Stability: Near-Well Stress State



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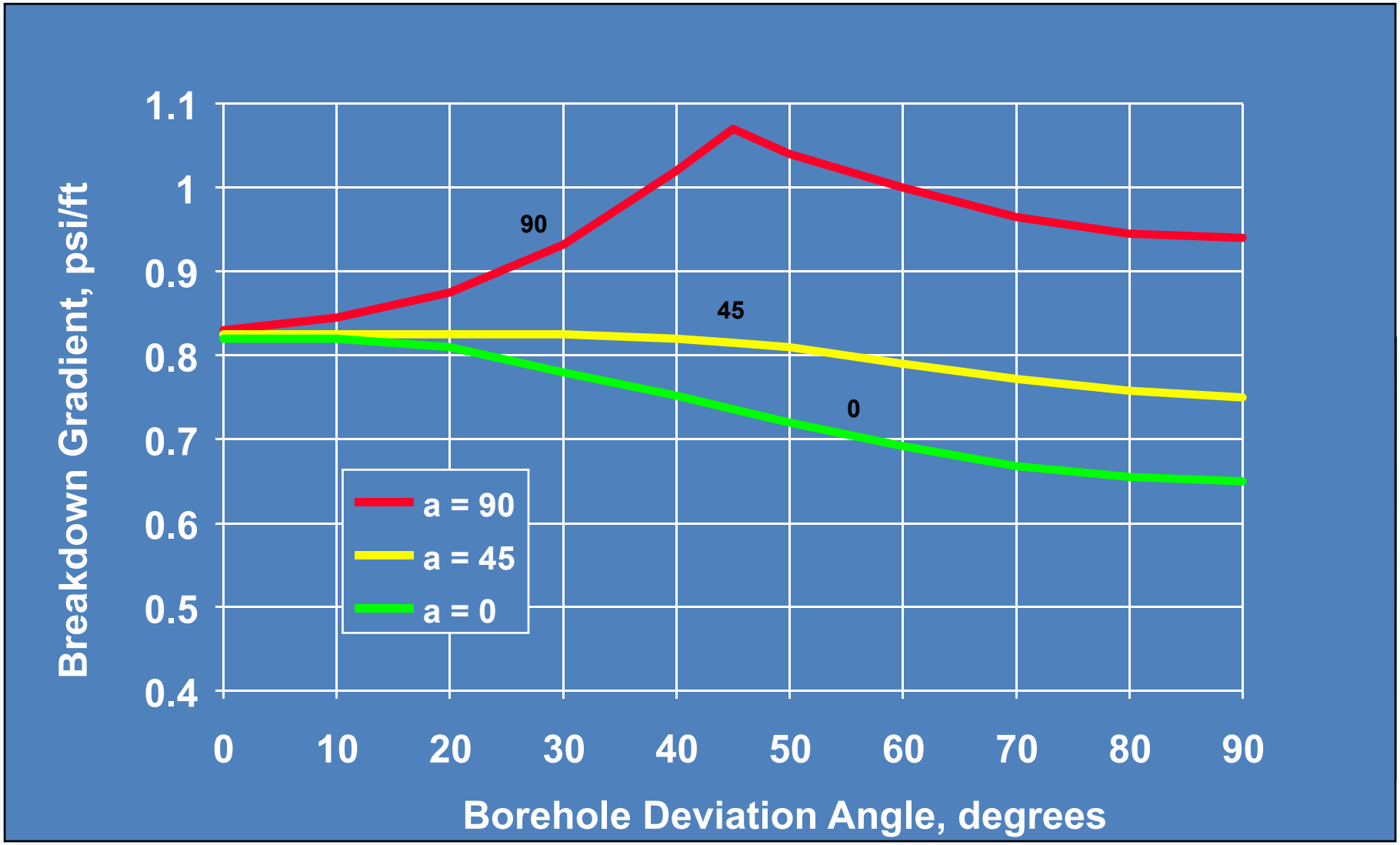
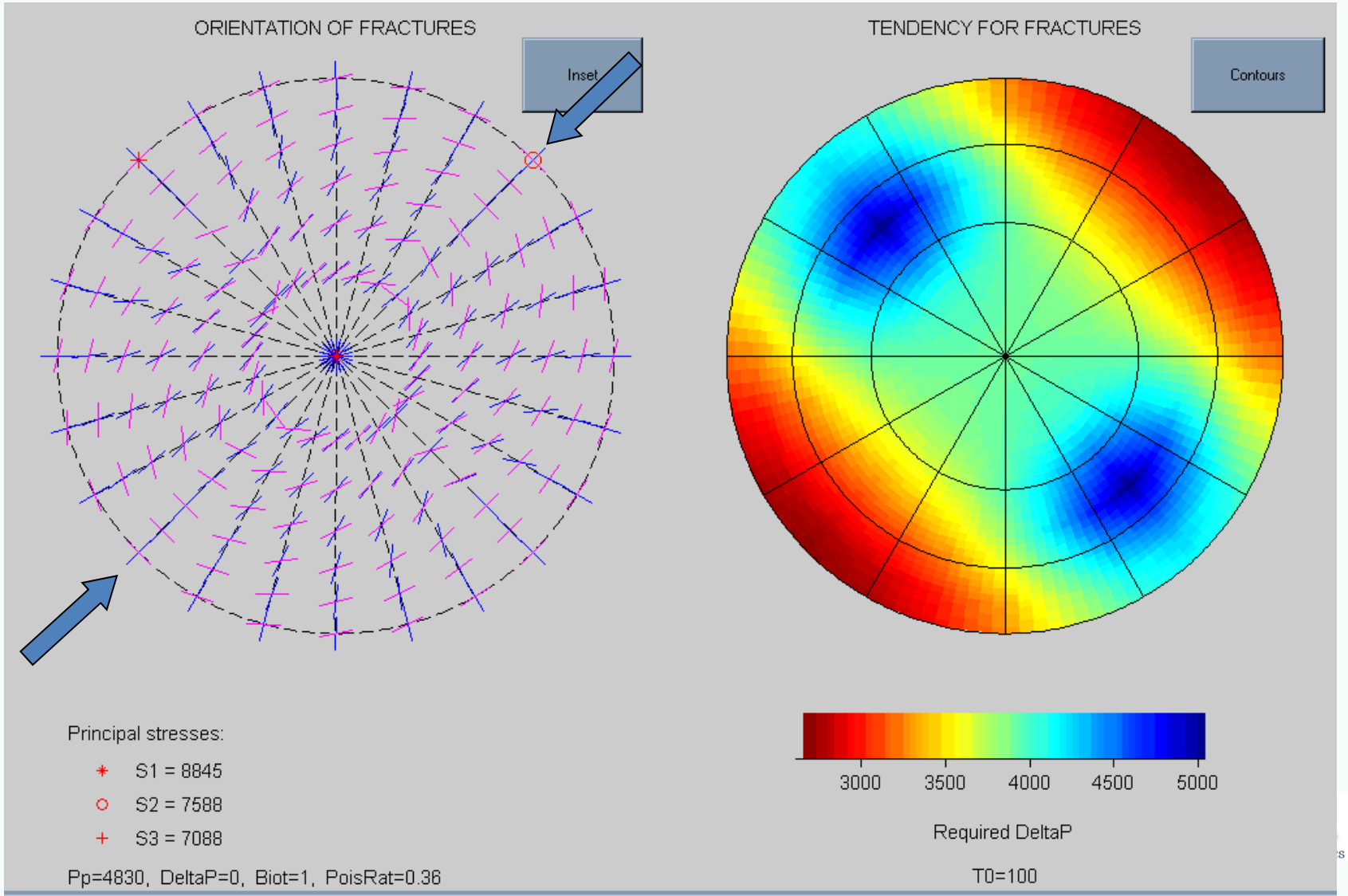
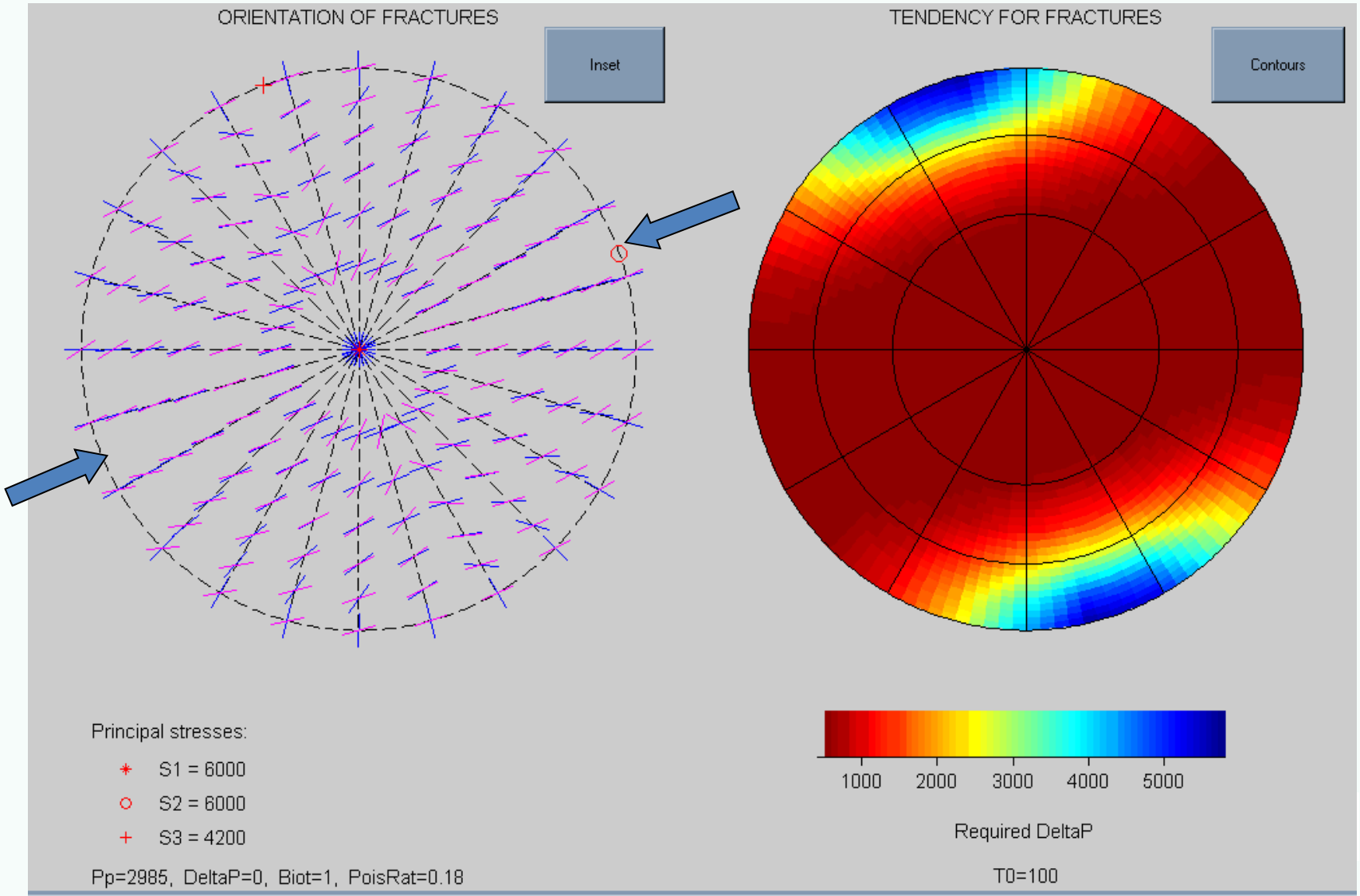
High Treating Pressures in Deviated Wells



Preferred Fracture Direction for a Normal Fault Environment



Preferred Frac Direction for a Thrust- or Strike-Slip Fault Environment



Predicting Production from Multiple Transverse Fractures

- Determine reservoir performance from vertical wells
  - Reservoir flow capacity (kh)
  - Effective Half Length (xf)
  - Original Gas in Place (OGIP) contacted by vertical
- Generate a metric to evaluate completion efficiency of multiply fractured wells
- Determine the number of fractures to place in a lateral for effective reservoir drainage

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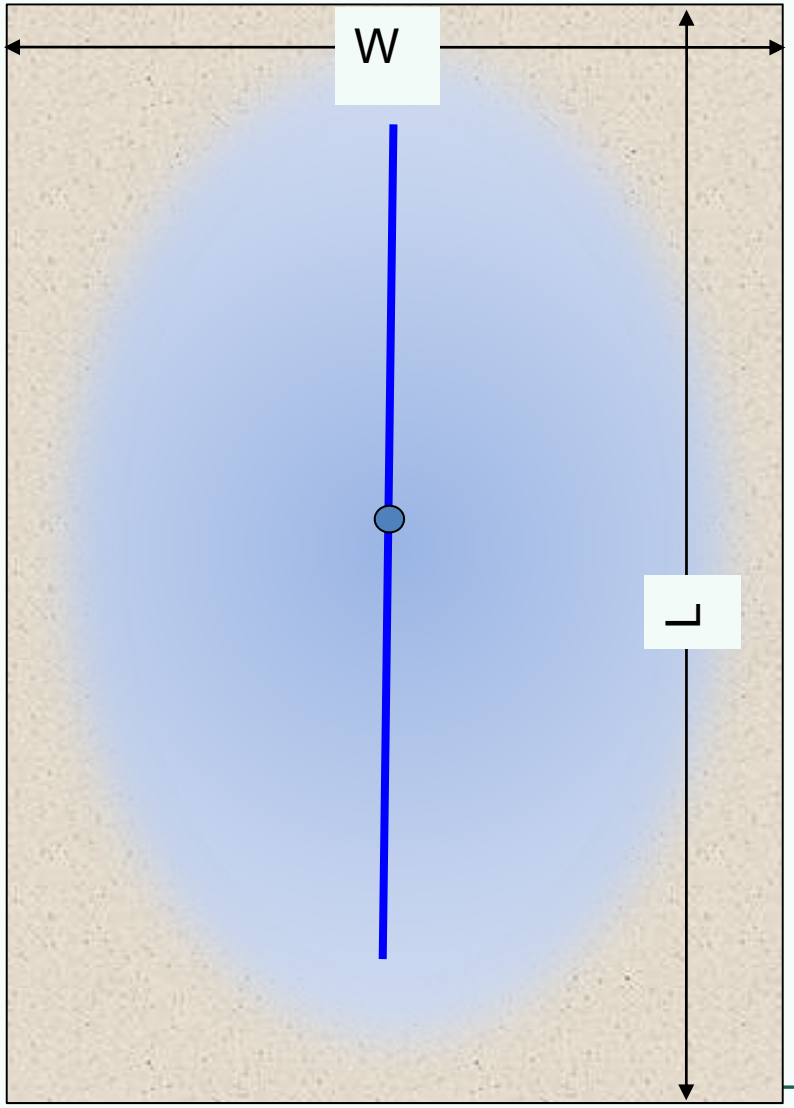
Horizontal Well Production Characterized by Vertical Well Performance



- Vertical well performance is needed to determine reservoir properties:
  - KH, P*, Xf, A, L/W
- Vertical transverse fracs on the lateral are assumed to clean-up and perform like the vertical-well frac
- The reservoir is assumed to be isotropic and homogeneous along the lateral

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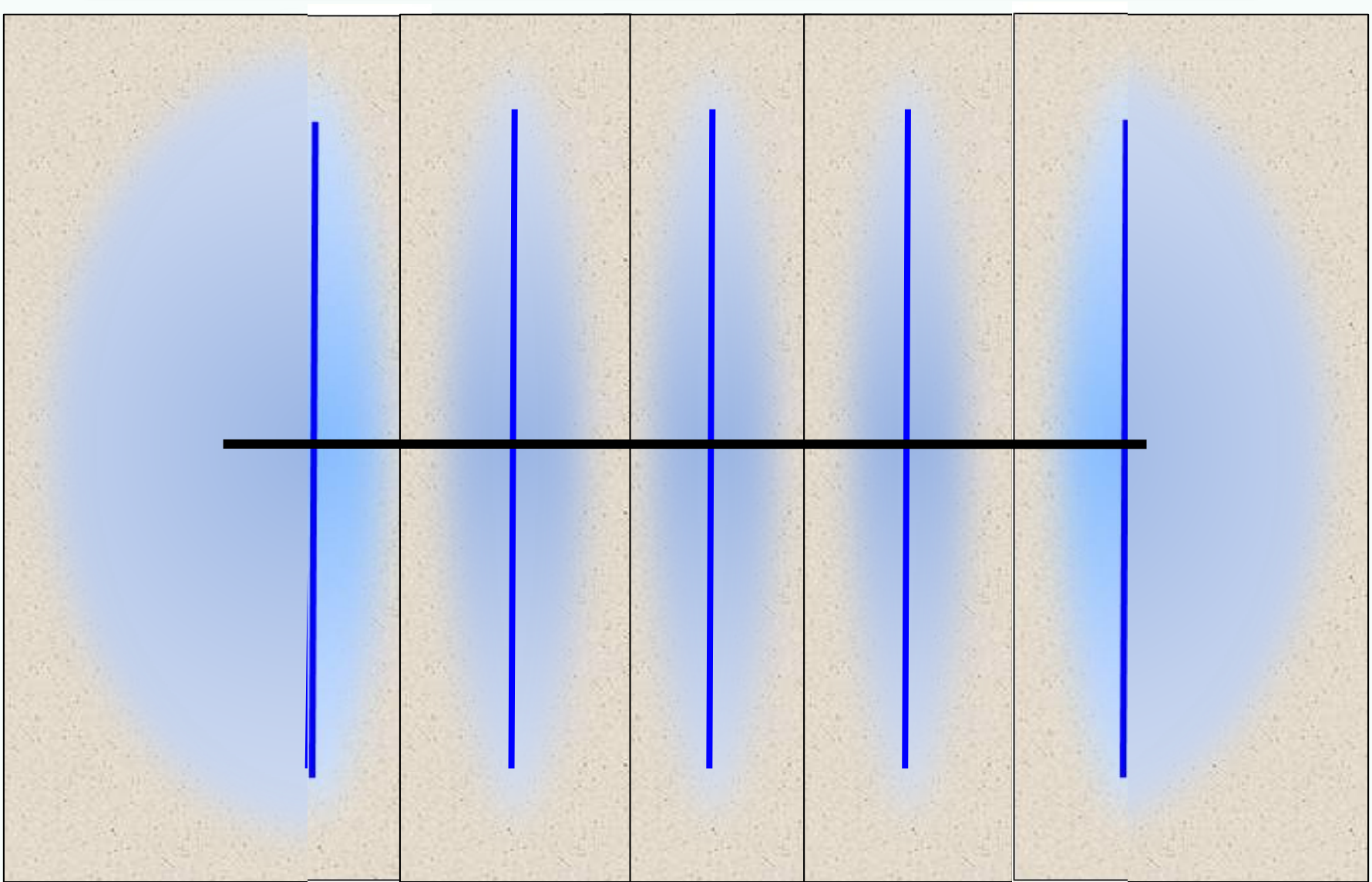
Horizontal Wells: Composite Transverse Fracs



Model Setup – 2 Cases

- Single Phase Gas simulator with separate fractures contributing to flow against a constant surface pressure
- Analyze total well response as a single zone to determine composite properties
- Case 1 – Variable kh in each fracture
- Case 2 – Variable Xf in each fracture

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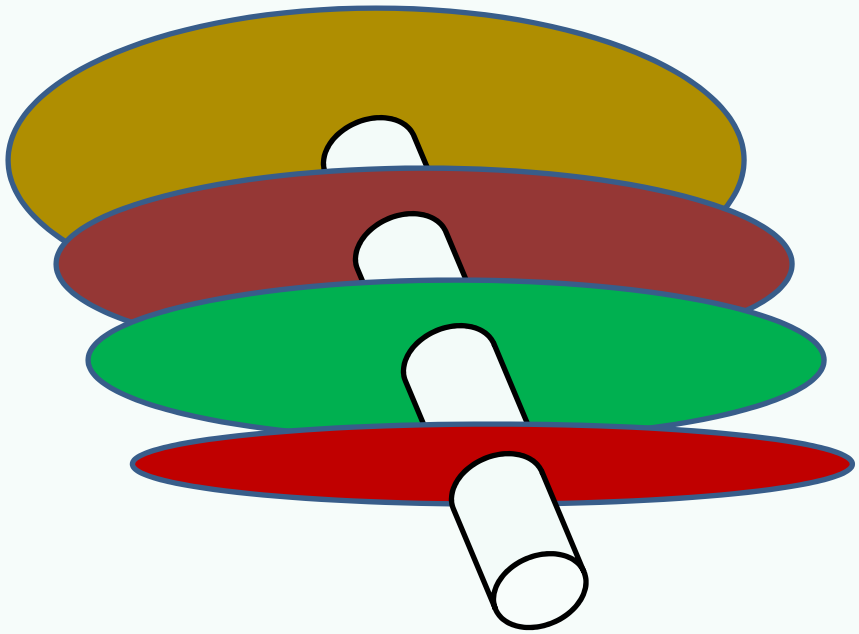
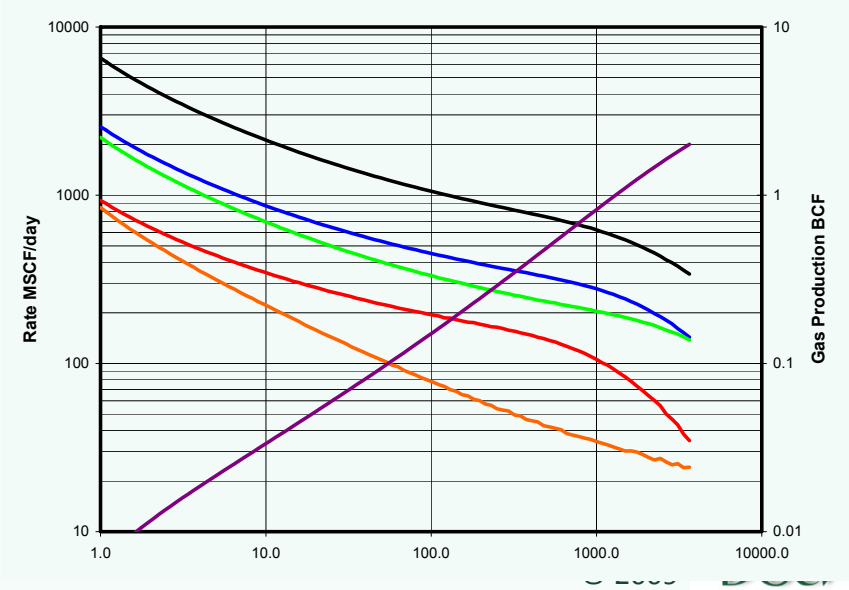
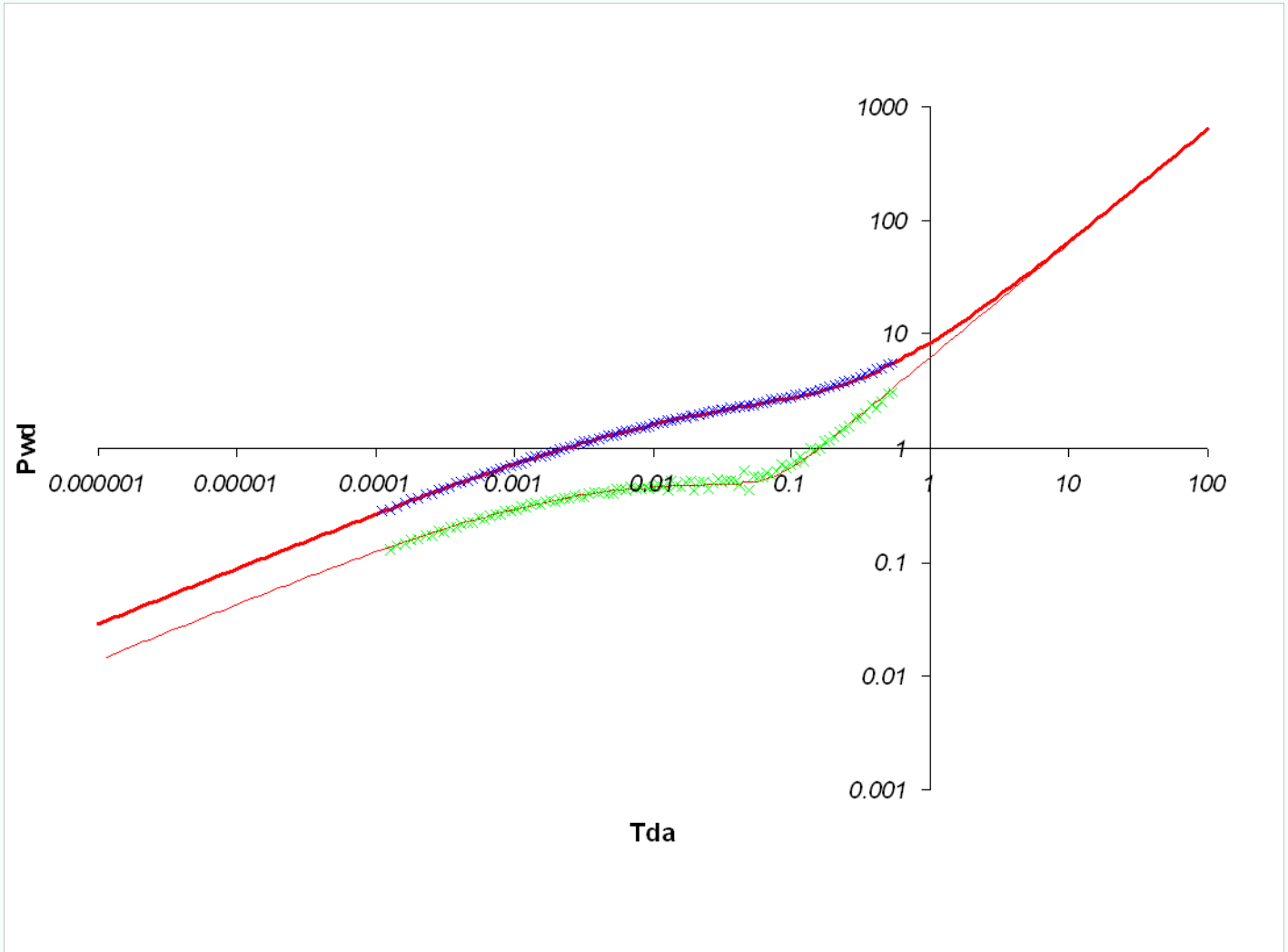
Case 1 – Variable Flow Capacity kh

	Height (ft)	Permeability (md)	kh (md-ft)
Fracture 1	20	0.05	1.0
Fracture 2	5	0.1	0.5
Fracture 3	50	0.001	0.05
Fracture 4	25	0.025	0.625
		Total	2.175





Case 1 – Type Curve Match



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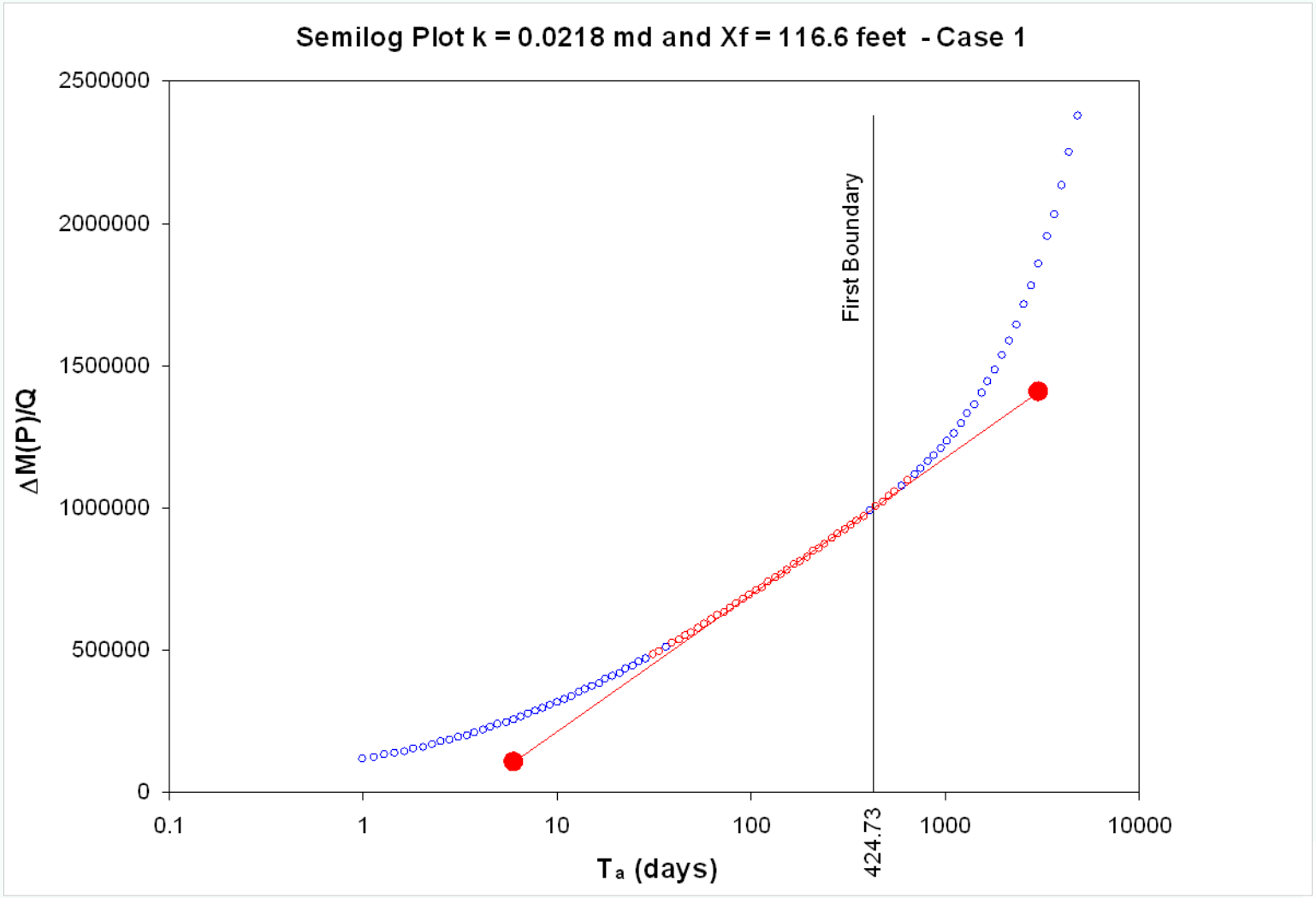
Case 1 – Semilog Plot



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Case 1 – Single Zone Composite Analysis

- Xf = 117 ft (actual 150 ft)
- OGIP = 6.61 BCF (actual 13.2 BCF)
  - Half the net pay does not contribute to production

$$kh = \frac{\sum k_i h_i}{\sum h_i}$$

- kh = 2.18 mdft (actual kh 2.18 mdft)
- Flow capacity from multiple fractures is accurately measured by a single composite analysis

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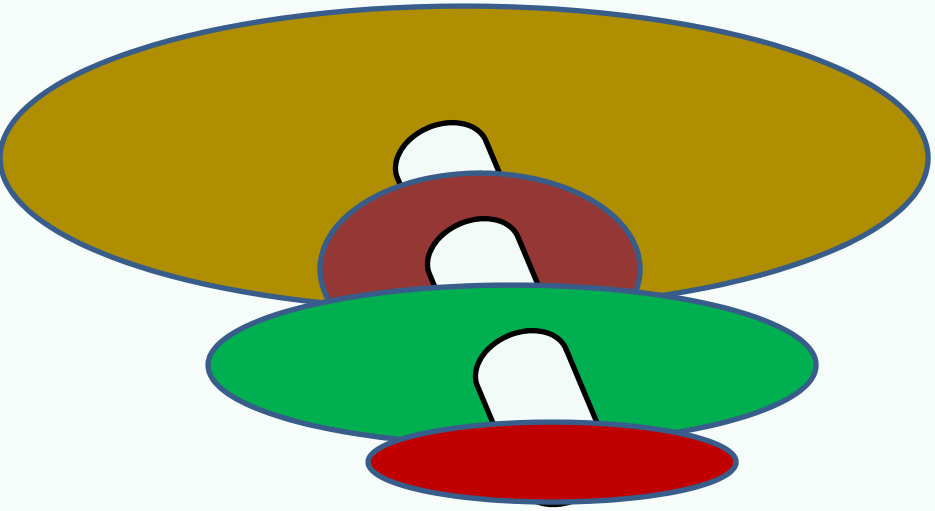
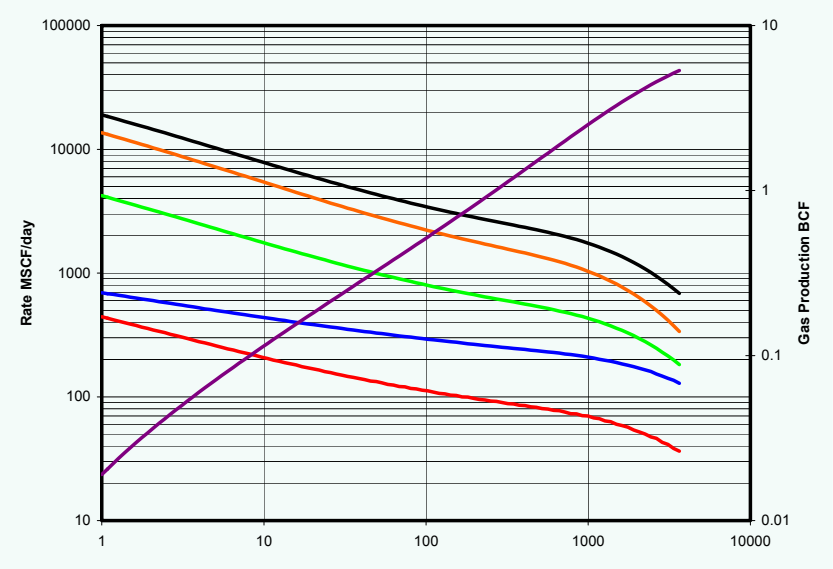
Case 2 – Variable Half Length Xf

	Height (ft)	Permeability (md)	Xf (ft)
Fracture 1	20	0.05	50
Fracture 2	5	0.05	150
Fracture 3	50	0.05	500
Fracture 4	25	0.05	300





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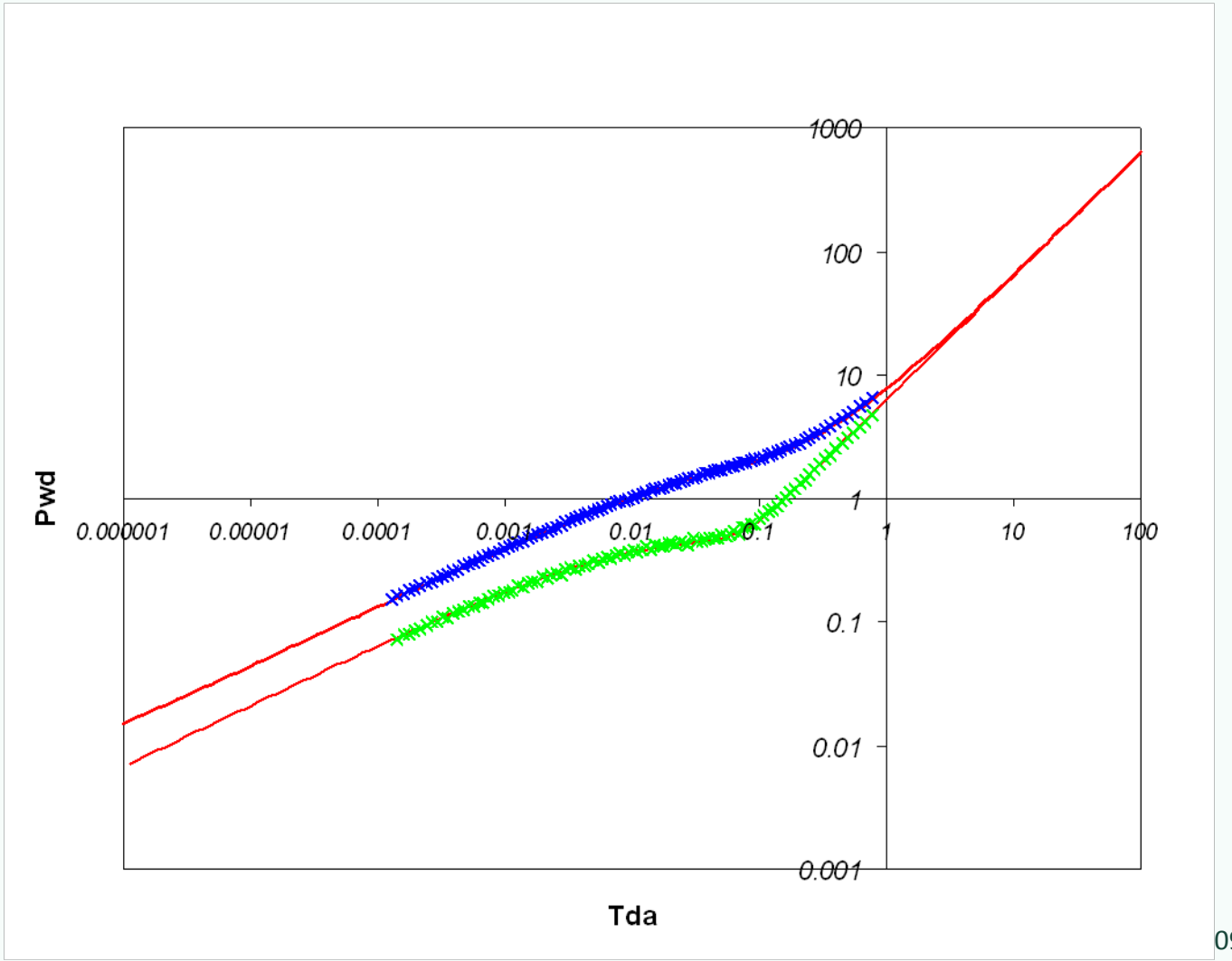
Case 2 – Type Curve Match



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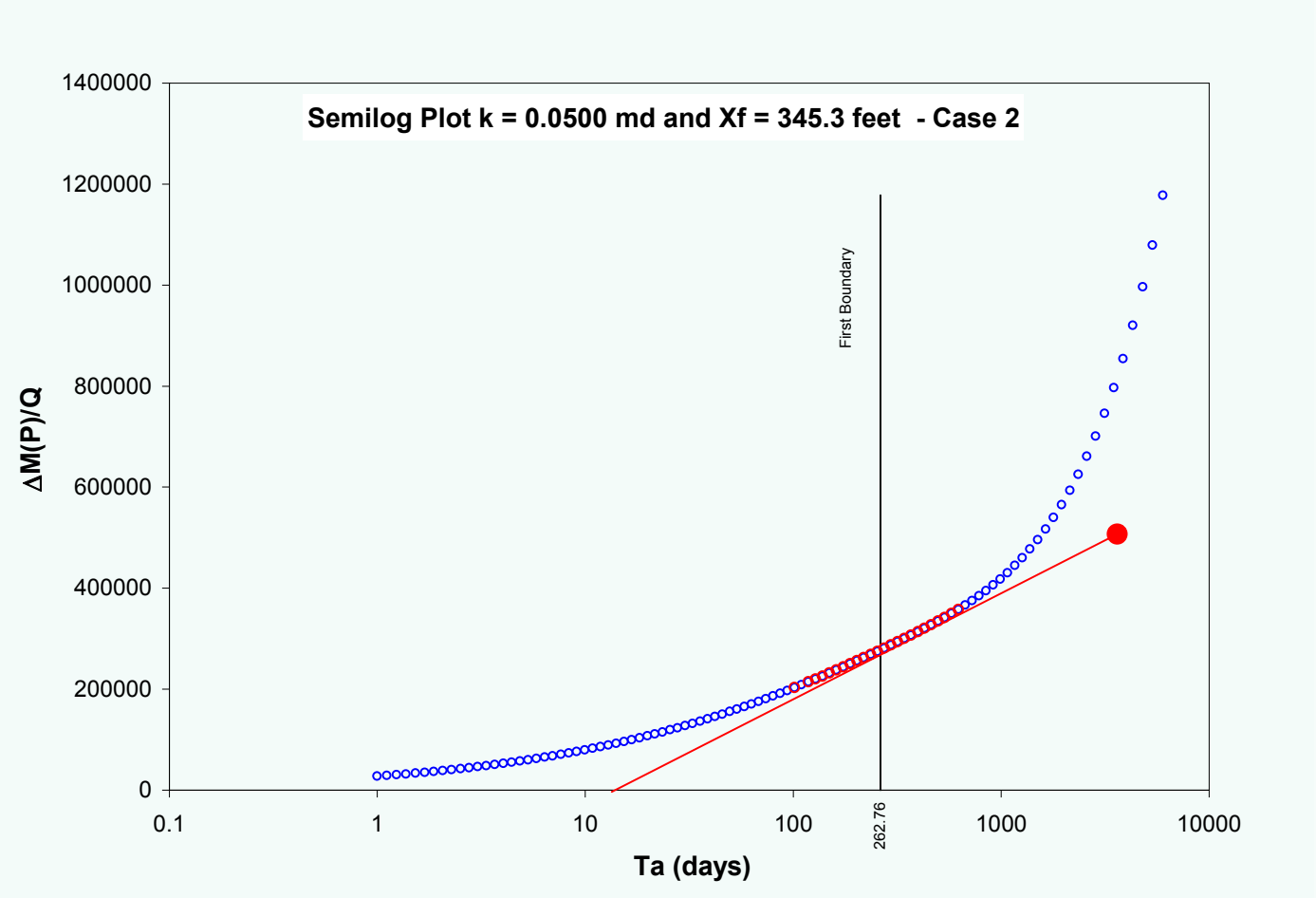
Case 2 – Semilog Plot



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Case 2 – Single Zone Composite Analysis

- kh = 5 md.ft (actual 5 md.ft)
- OGIP = 13.23 BCF (actual 13.23)

$$X_f = \frac{\sum h_i X_f}{\sum h_i}$$

- Xf = 342 ft (semilog plot shows 345 ft)
- For a system with little permeability variation the Xf will be the height averaged individual Xf of each of the fractures. As the variance in permeability increases the measured Xf decreases

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Fracture Efficiency

- As more fractures are added to a lateral the total well kh should increase
- Assuming a constant kh for each fracture

- Average kh should be measured from a single vertical fracture

$$\text{Fracture Efficiency} = \frac{(kh)_{\text{Horizontal}}}{n\,(kh)_{\text{Average}}}$$

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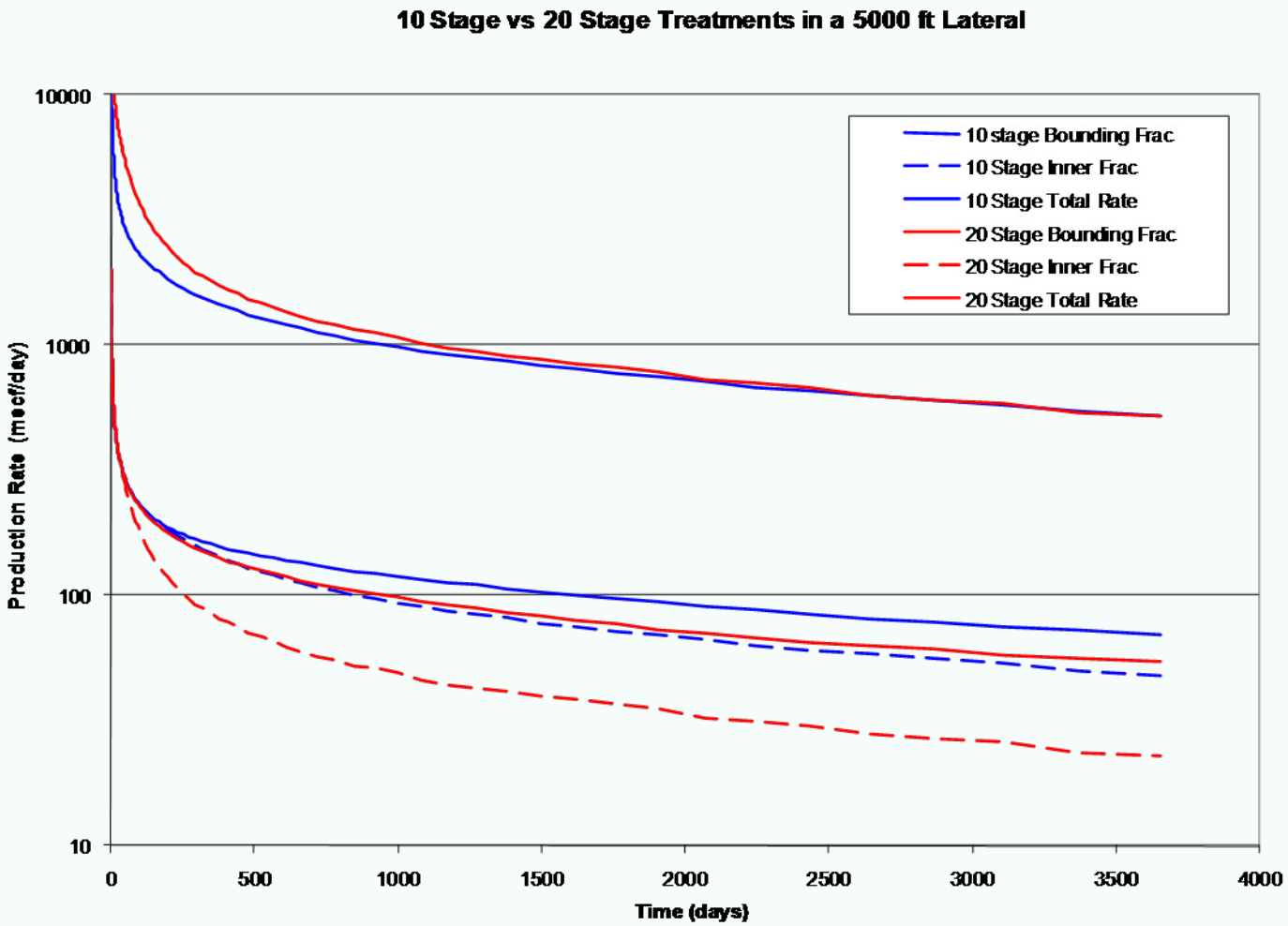
Production Rate Decline for Internal and External Fractures



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Fracture Spacing Equation

- Based on the radius of investigation formula the time to interfere for a given spacing can be calculated

$$\text{Fracture Spacing (ft)} = 0.3135\sqrt{\frac{kt}{\phi\mu c_t}}$$

time, t in days

permeability, k in millidarcy

porosity, ϕ

viscosity, μ in cp

total compressibility, c_t in 1/psi

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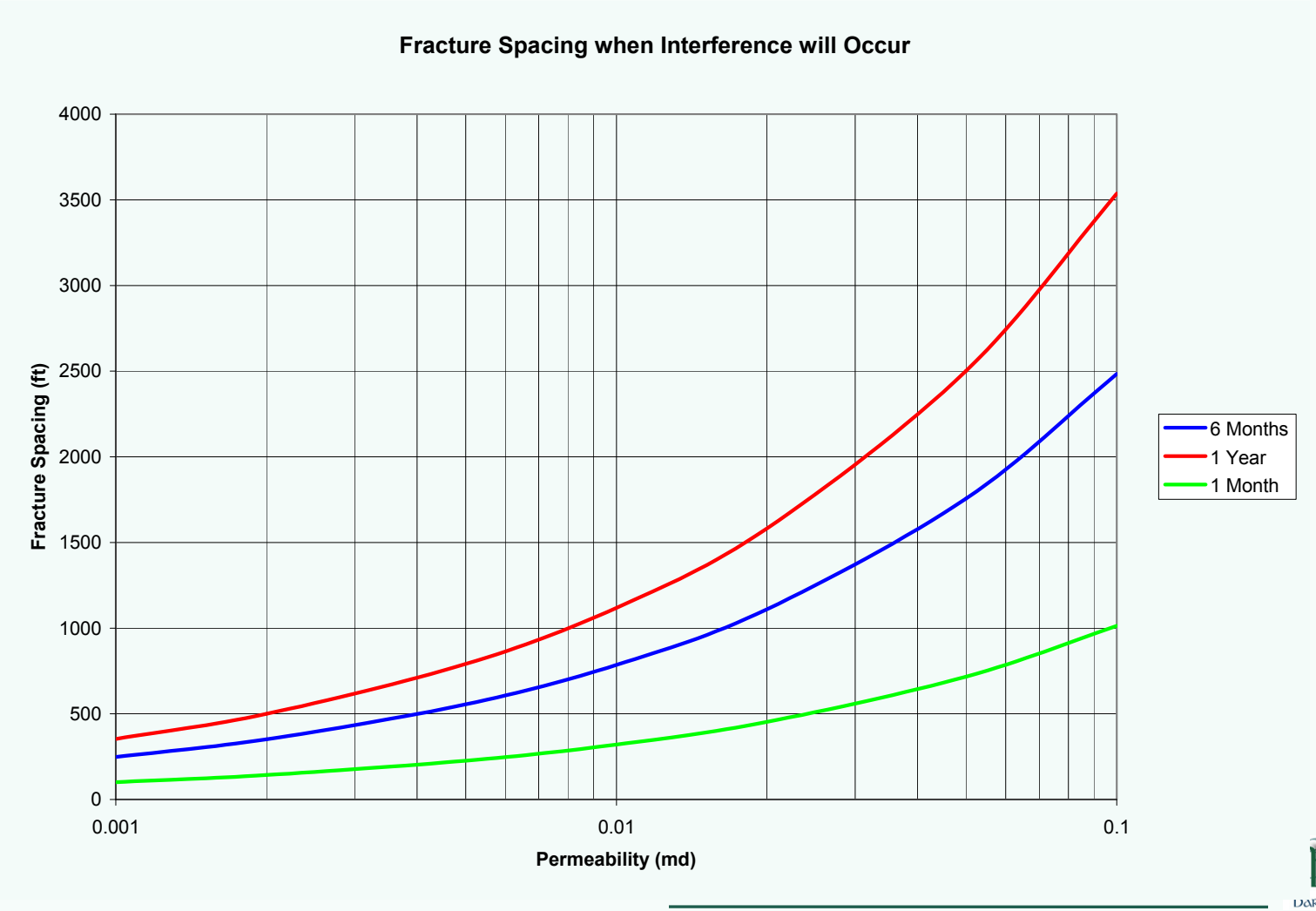
Fracture Spacing



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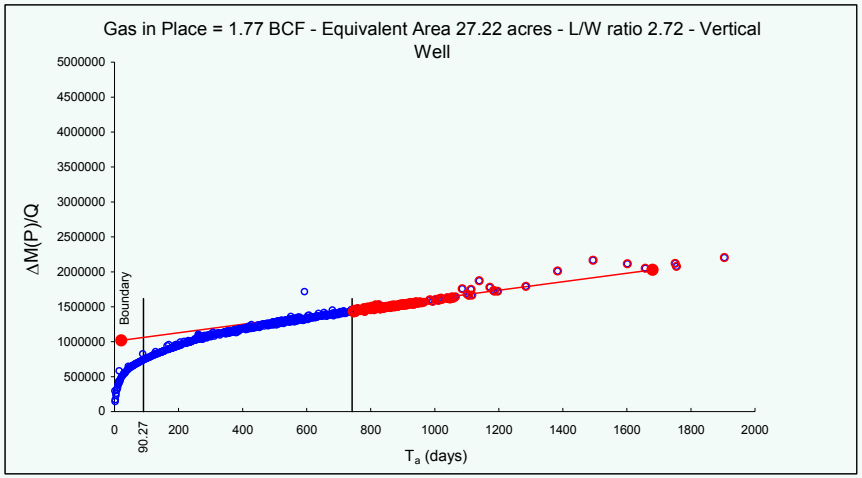
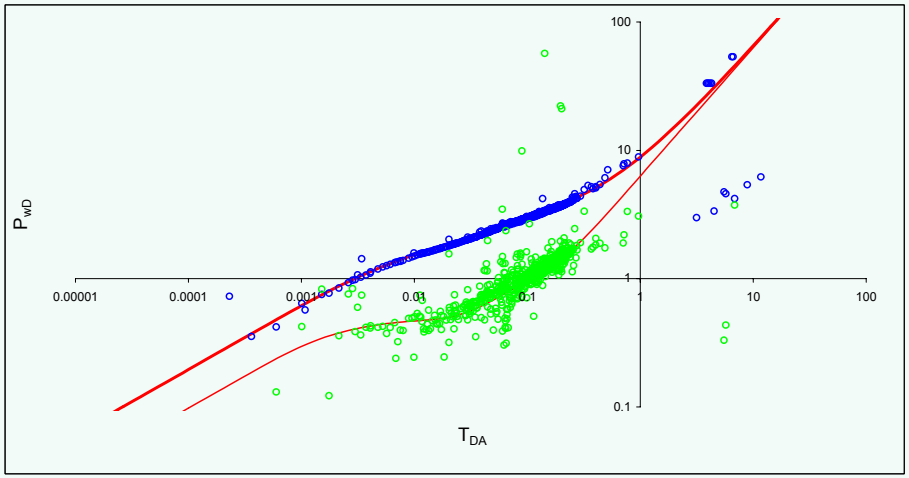
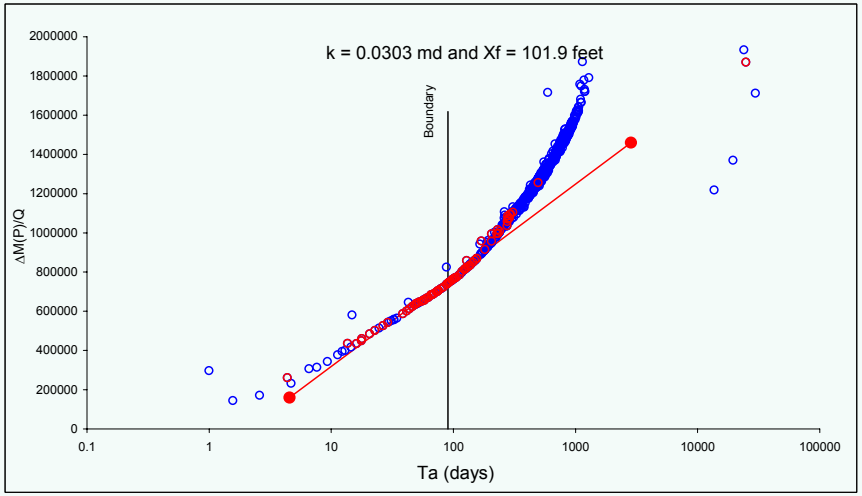
Field Example – Vertical Well

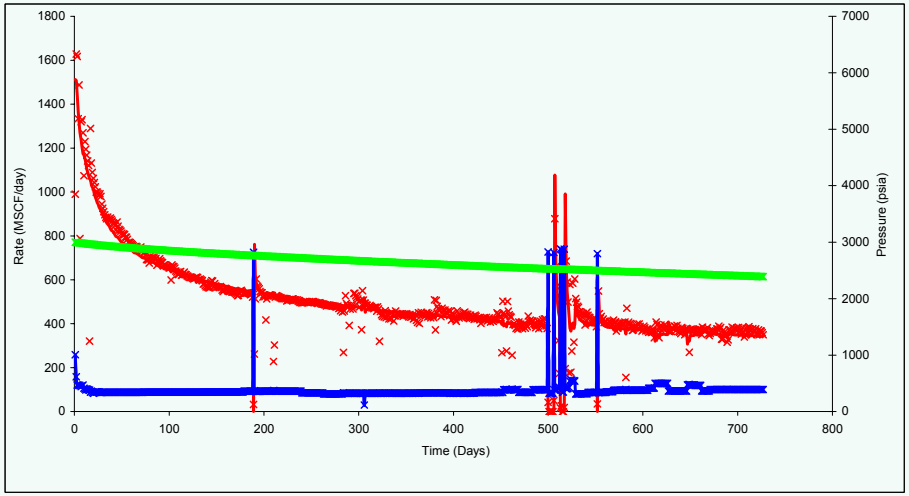
Vertical Well

Volumetric OGIP = 1.82 BCF









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Field Example – Vertical Well

- Vertical Well Production Analysis
  - kh - 2.4 md.ft
  - Infinite conductivity half length 102 ft
  - Gas in place 1.77 BCF

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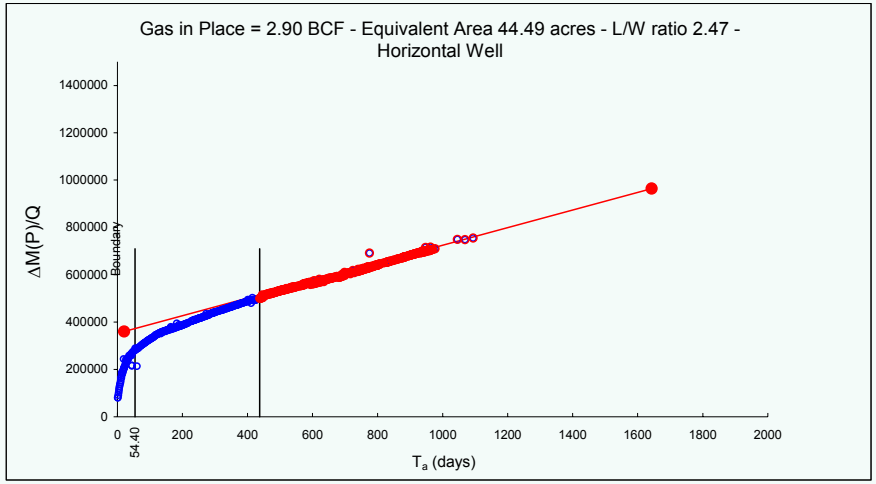
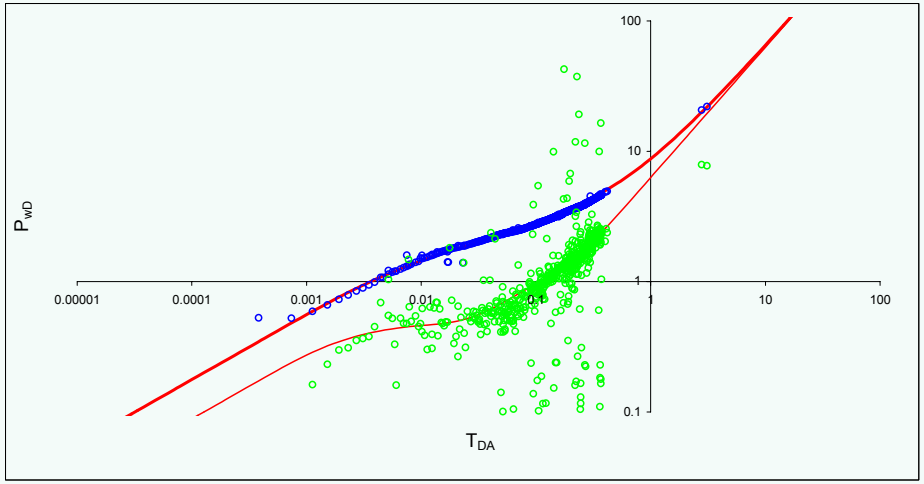
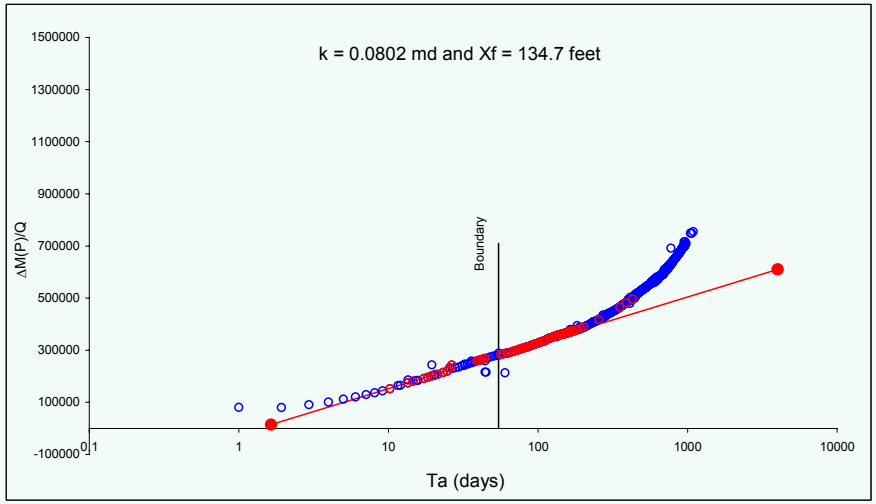
Field Example – Horizontal Well

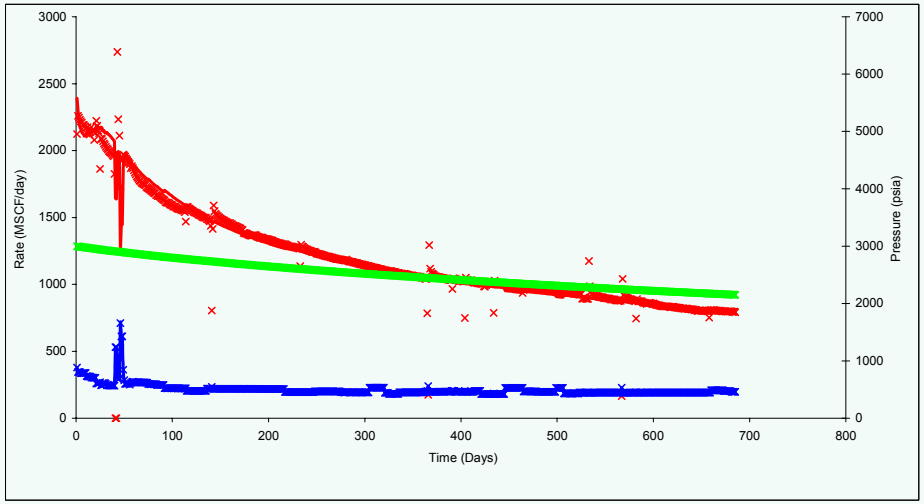
Horizontal Well

Volumetric OGIP = 2.93 BCF









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Field Example - Summary

- Horizontal Well
  - 12 fractures in a 4000 ft lateral
  - 363 ft actual spacing
  - Kh 6.32 md.ft
  - Infinite conductivity Half Length 135 ft
  - Gas in place 2.90 BCF
- Fracture Efficiency = 6.32 / 12*2.4
  - 22% (3 out of 12 fractures contributing)
- Fracture Spacing
  - Based on 6 month interference time a fracture spacing of 1360 ft is more appropriate (3 fractures)
  - The fractures interfere after 12.6 days at a spacing of 363 ft

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Summary

- Flow capacity (kh) from production analysis of multiple fractures is accurate
- Xf from production analysis is a poor method to evaluate completion efficiency
- For an efficient completion kh from each layer should add (total kh = number fracs * average single layer kh)
- Increasing lateral length and distance between the bounding fractures will increase contacted reserves
- Placing more fractures in a lateral than the permeability can support leads to destructive interference

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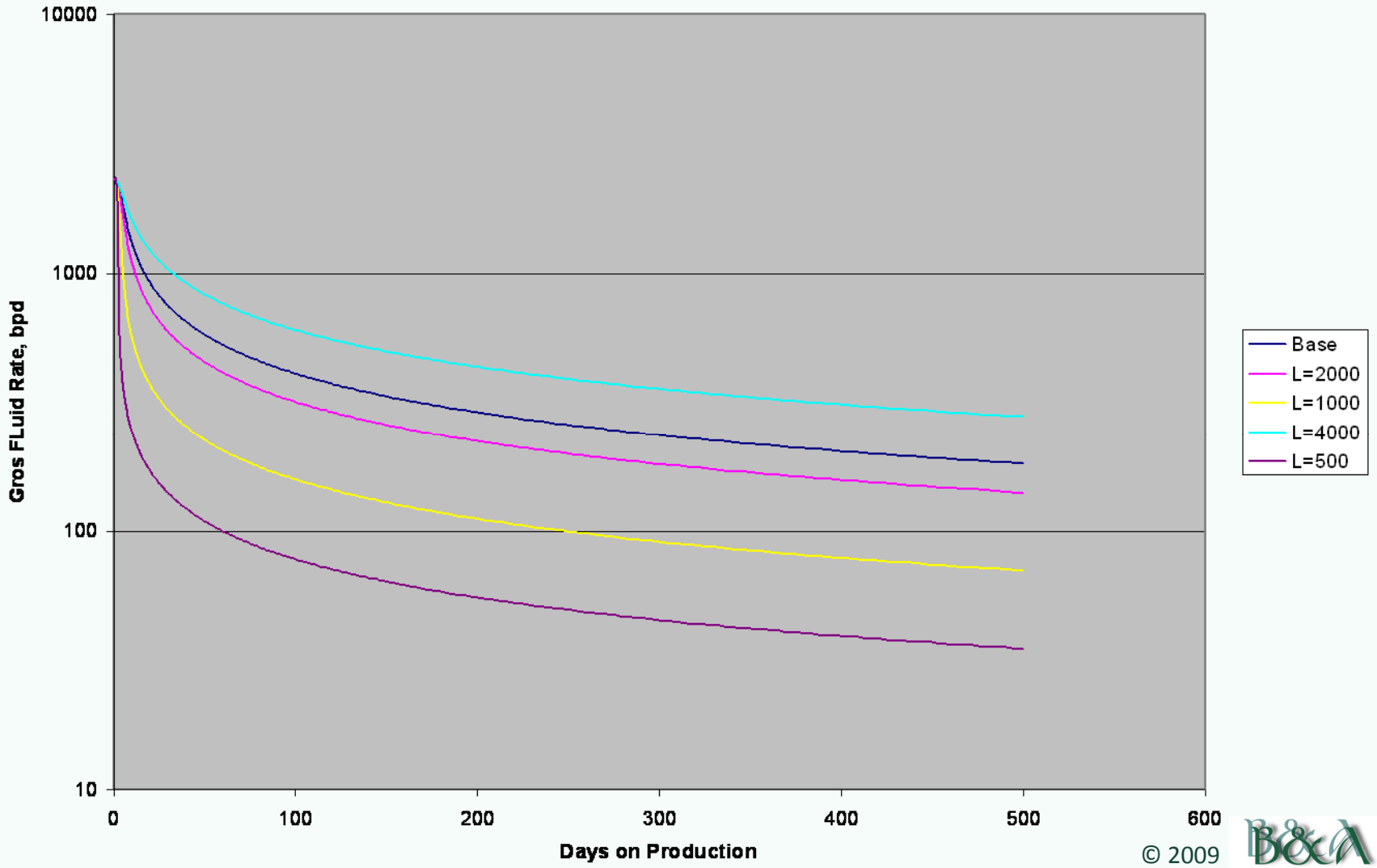
Effect of Producing Lateral Length on Production Rate



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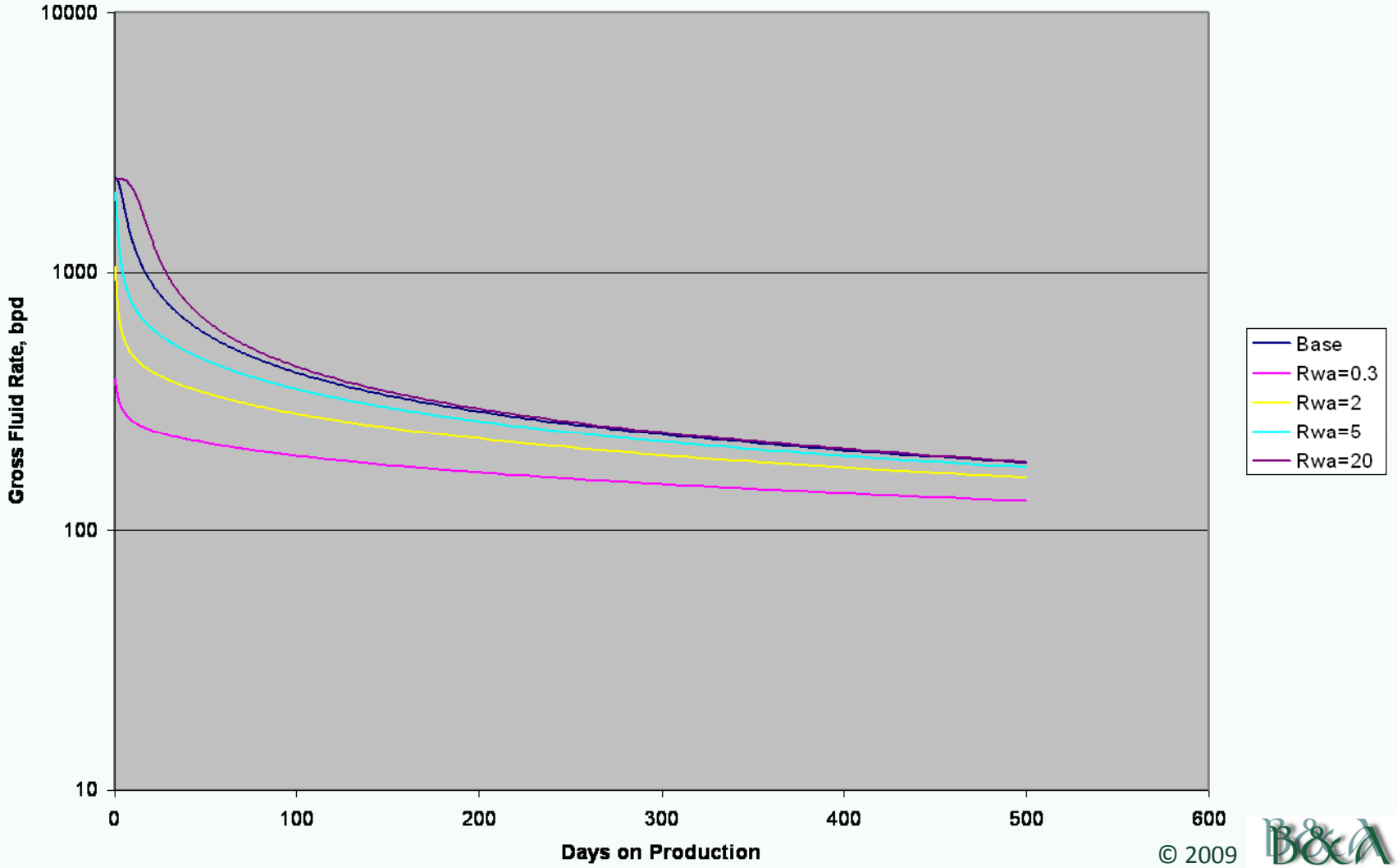
Effect of Stimulation (Rwa) on Production Rate



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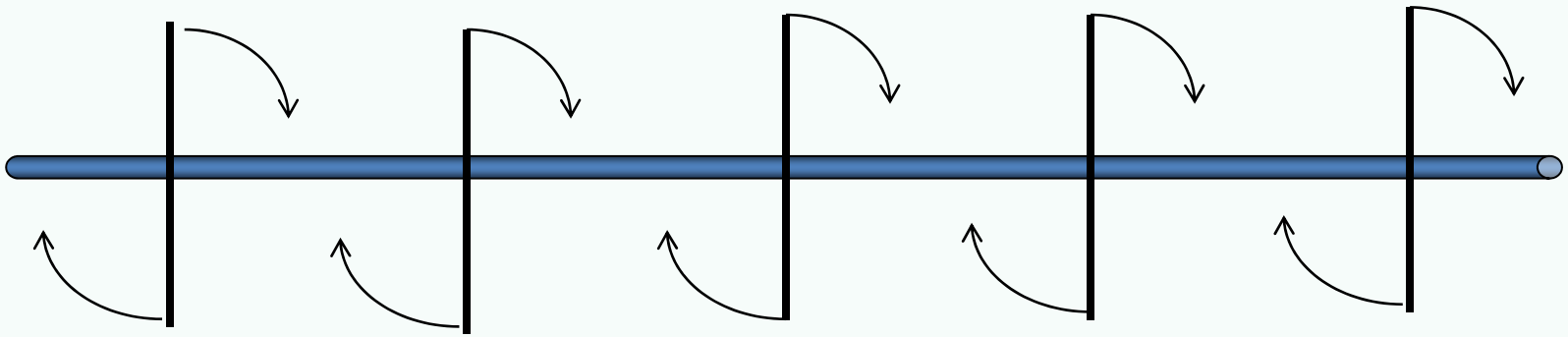
Comparing Transverse and Longitudinal Fracs



- If KH is additive for each transverse frac
  - Does the number of producing fracs times effective length exceed drilled lateral length?
  - Is the production dominated by secondary joints and fractures?
  - Can a longitudinal frac expose more area?

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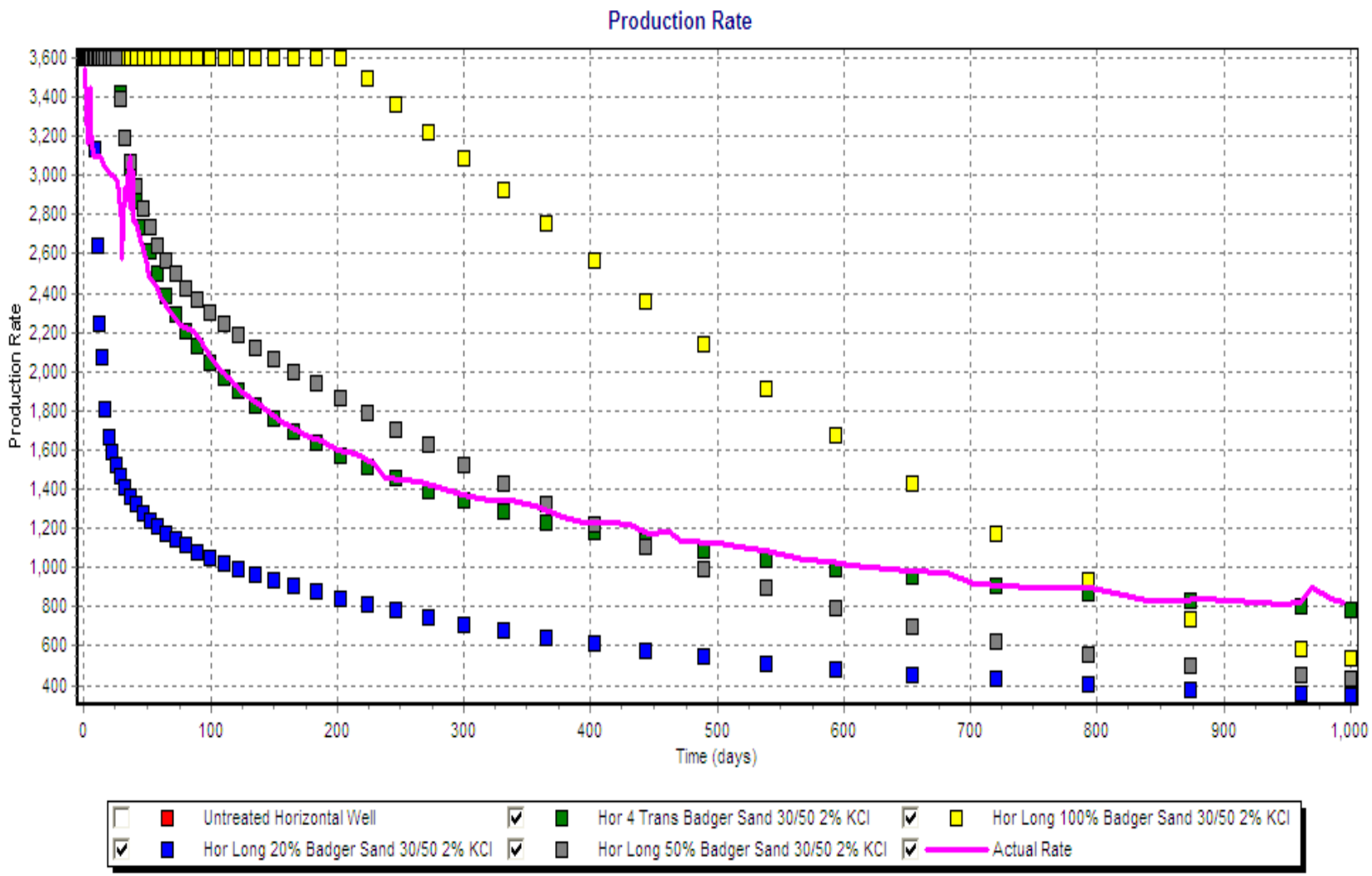
Comparison of Predicted Transverse and Longitudinal Frac Performance in Low Perm System



Recommendations for Horizontal Well Completions

- Maximize productive well length
- Establish communication with the reservoir across entire well length
- Extensive stimulation outside the well (frac-length) is not critical
- Propagation of secondary fractures (off longitudinal) may be beneficial (not clear from production response)

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Cemented vs. Uncemented Liners and Open-hole Completions

- Cemented liners and/or casing
  - Only for matrix-flow systems
  - Only when borehole stability is questionable
  - When zonal isolation for stimulation is absolutely necessary
- Uncemented liners (with limited perfs)
  - Longitudinal fracs (acid and propped)
  - Re-entering or re-activating existing fractures
- Open-hole completions
  - Only in hard, competent rock
  - Good for surface acid-wash completions
  - Acid and water-fracs for opening existing natural fractures
    - Poor control of fluid entry
    - Difficult to ensure multiple fractures treated

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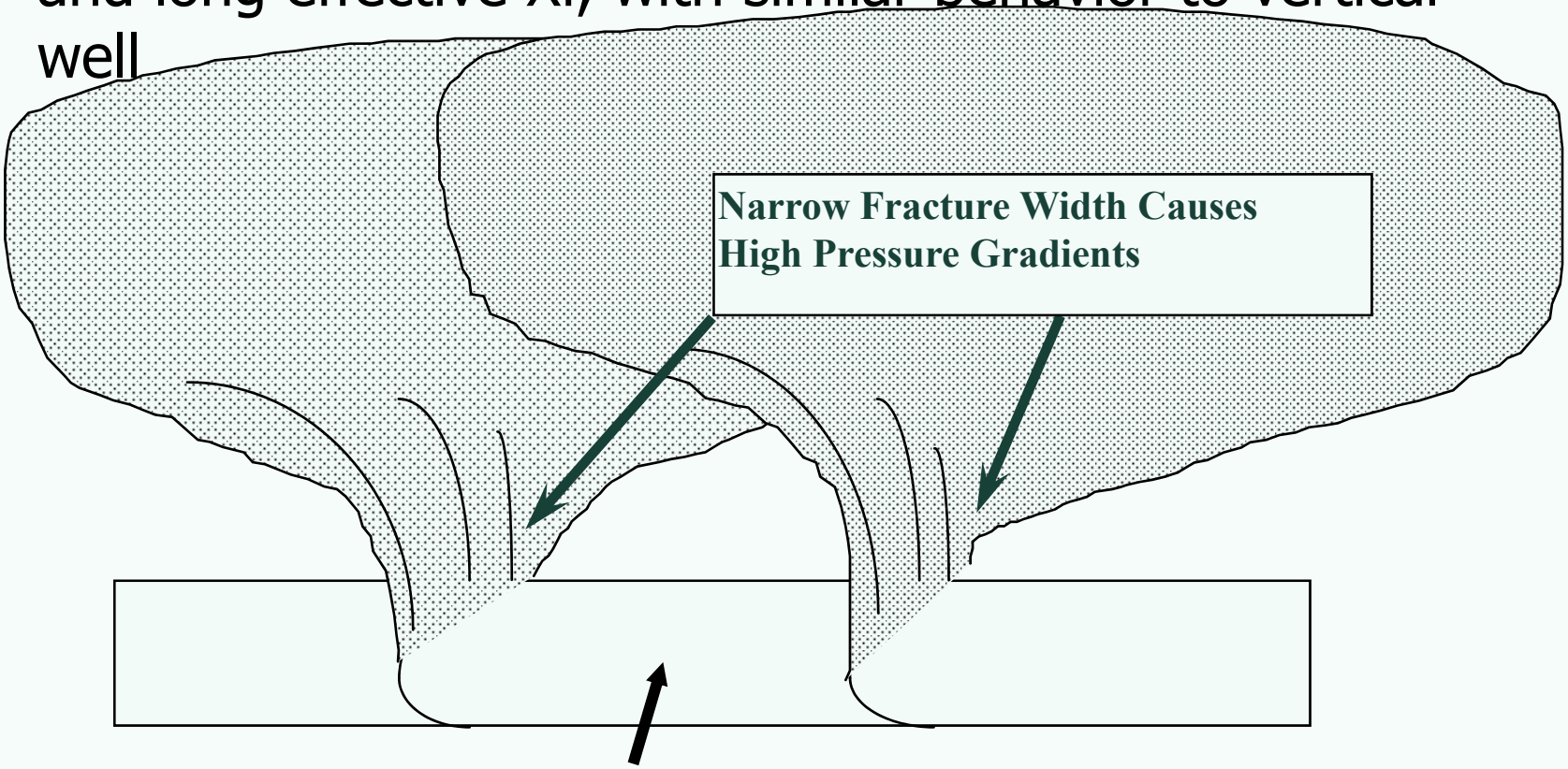
Fracturing with Cemented Liners

Long flow path in fracture requires high conductivity and long effective Xf, with similar behavior to vertical well



No production allowed through cemented section

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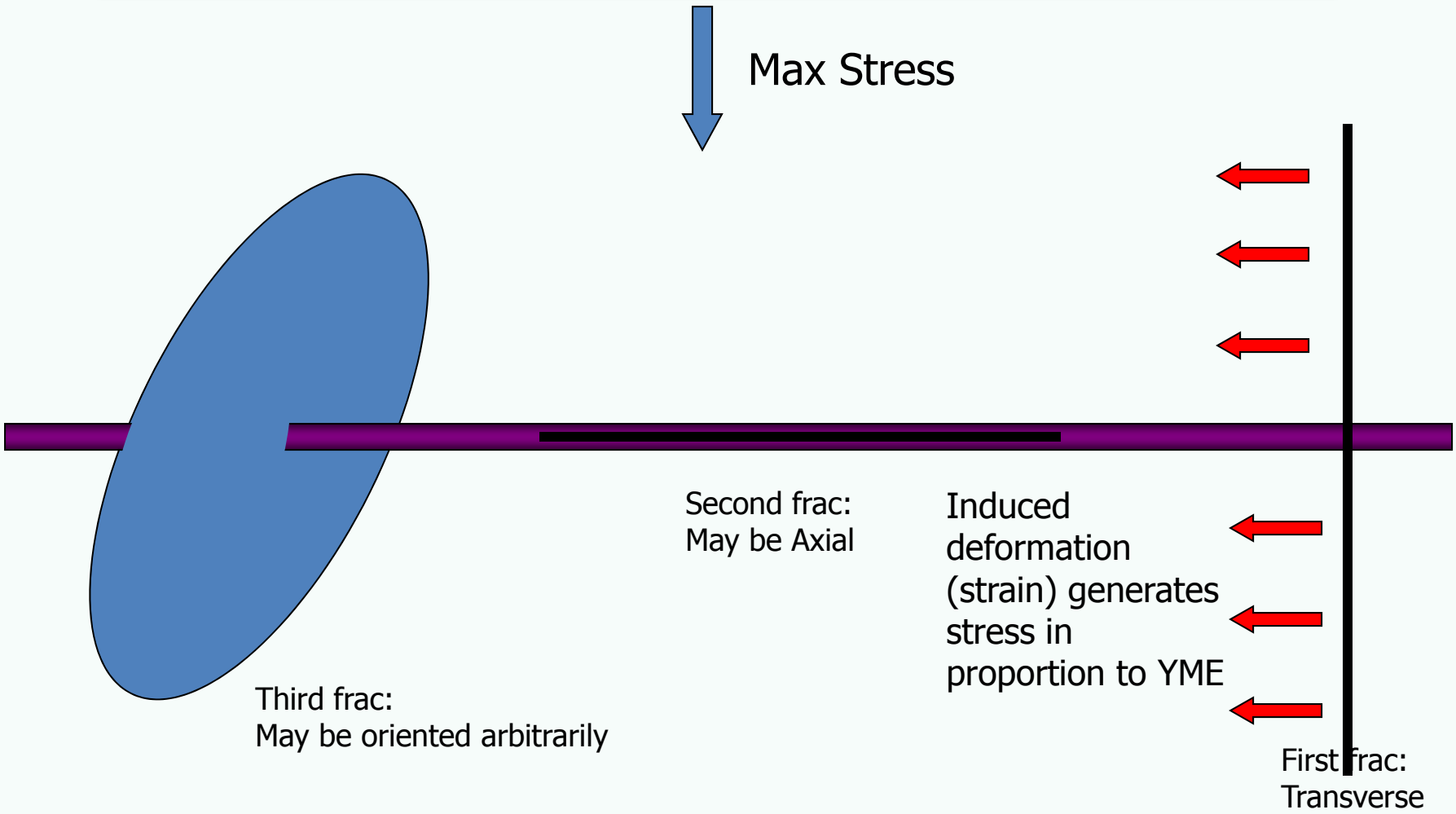
Stress Shadowing and Frac Re-Orientation



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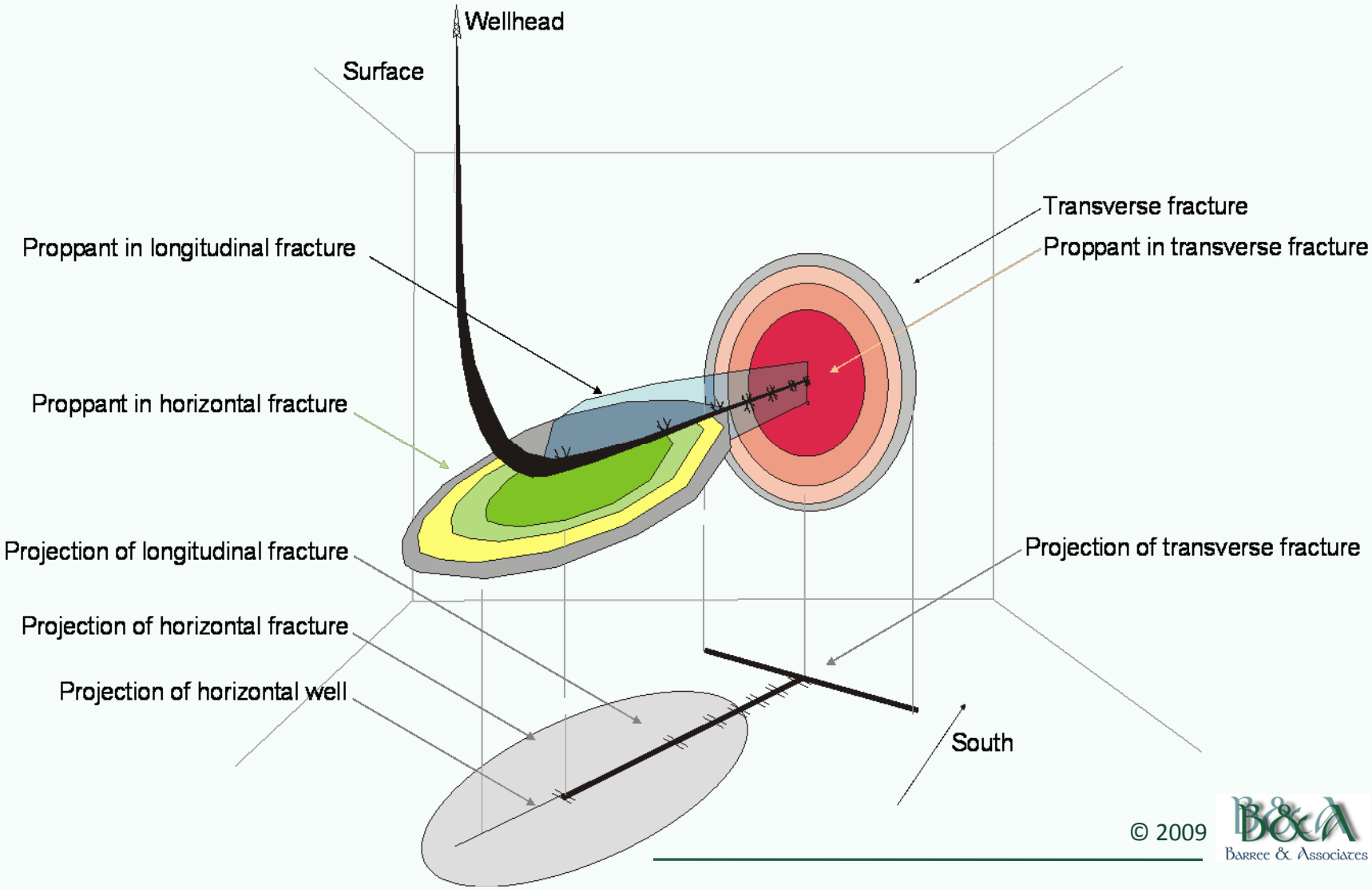
Typical Observation of Multiple Fracs in Horizontal Wells



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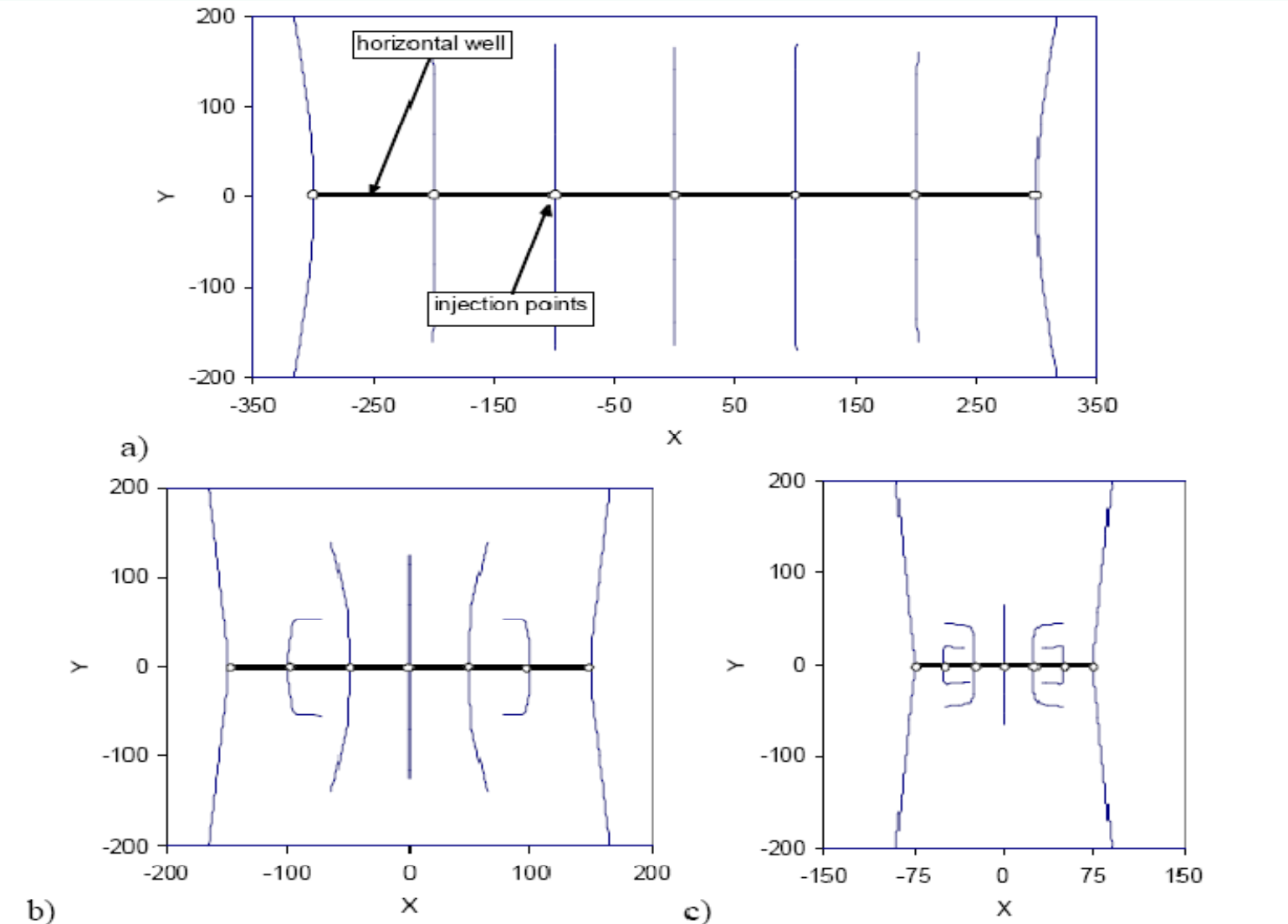
Interaction of Fractures: Simultaneous Injection into 11 Fractures



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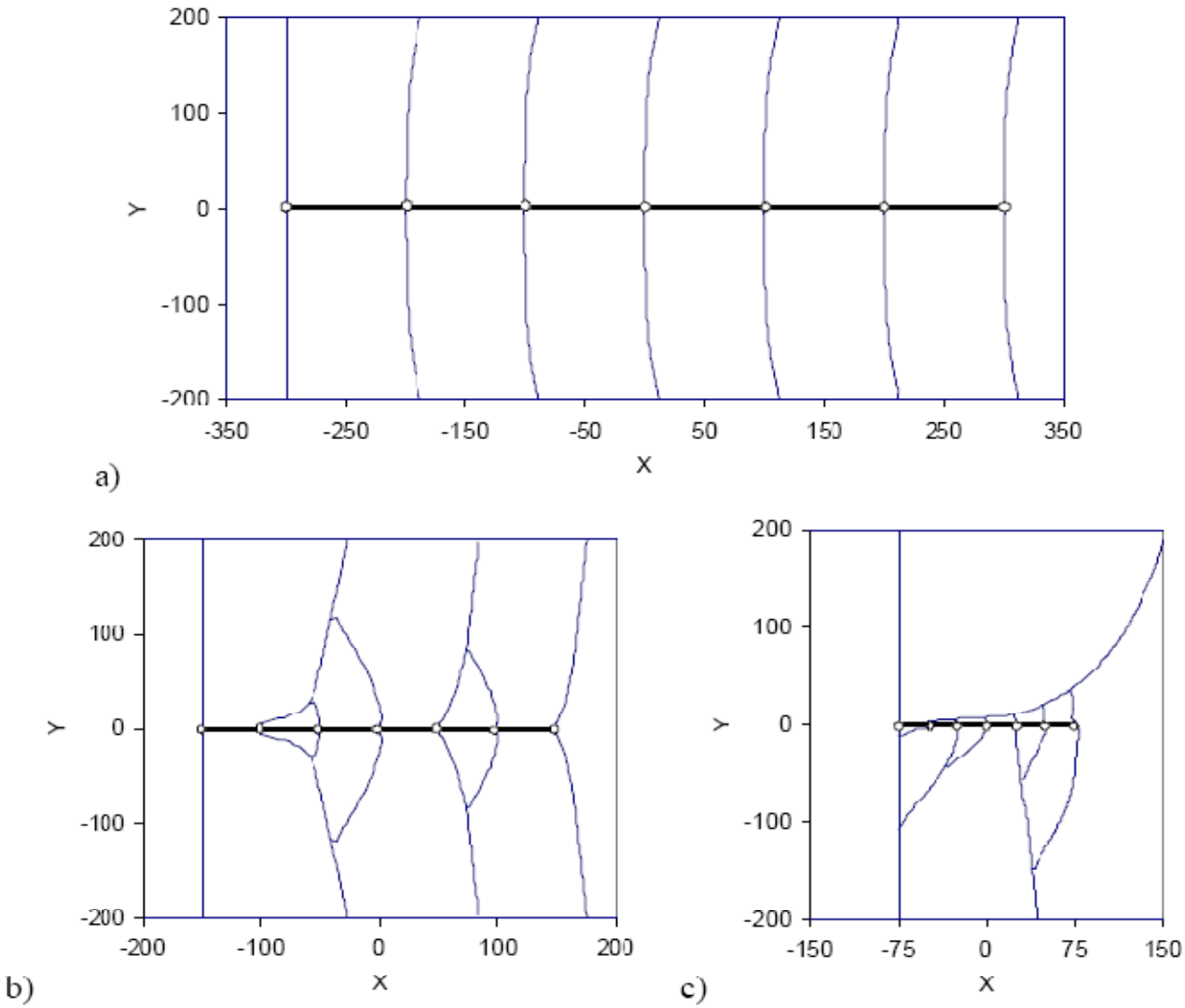
Injection into 7 Sequentially Propagated Fractues



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Achieving Diversion and Fracturing the Entire Lateral

- Cemented liner with limited-entry perforating
  - Limit number and size of perforations
- Multiple plug and perf stages
- Open-hole with liner and external packers
  - Chemical “swell” packers (Halliburton)
  - Hydraulic-set packers
  - Inflatable OH packers
- Sliding sleeve and frac-ports for individual stages
- Dynamic diversion with uncemented liners

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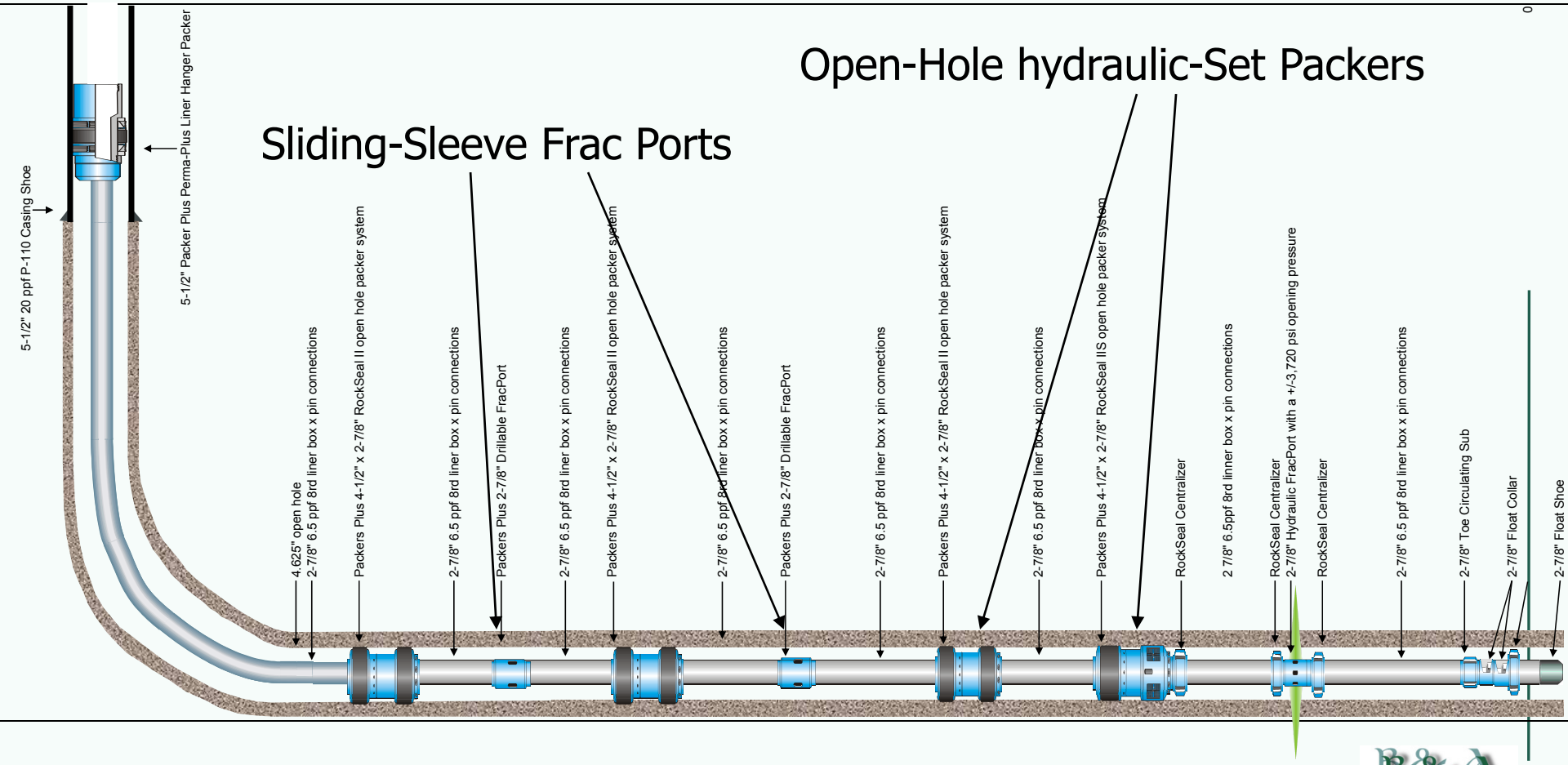
Packers Plus Mechanical Isolation System for Open-Hole Stacked-Fracs



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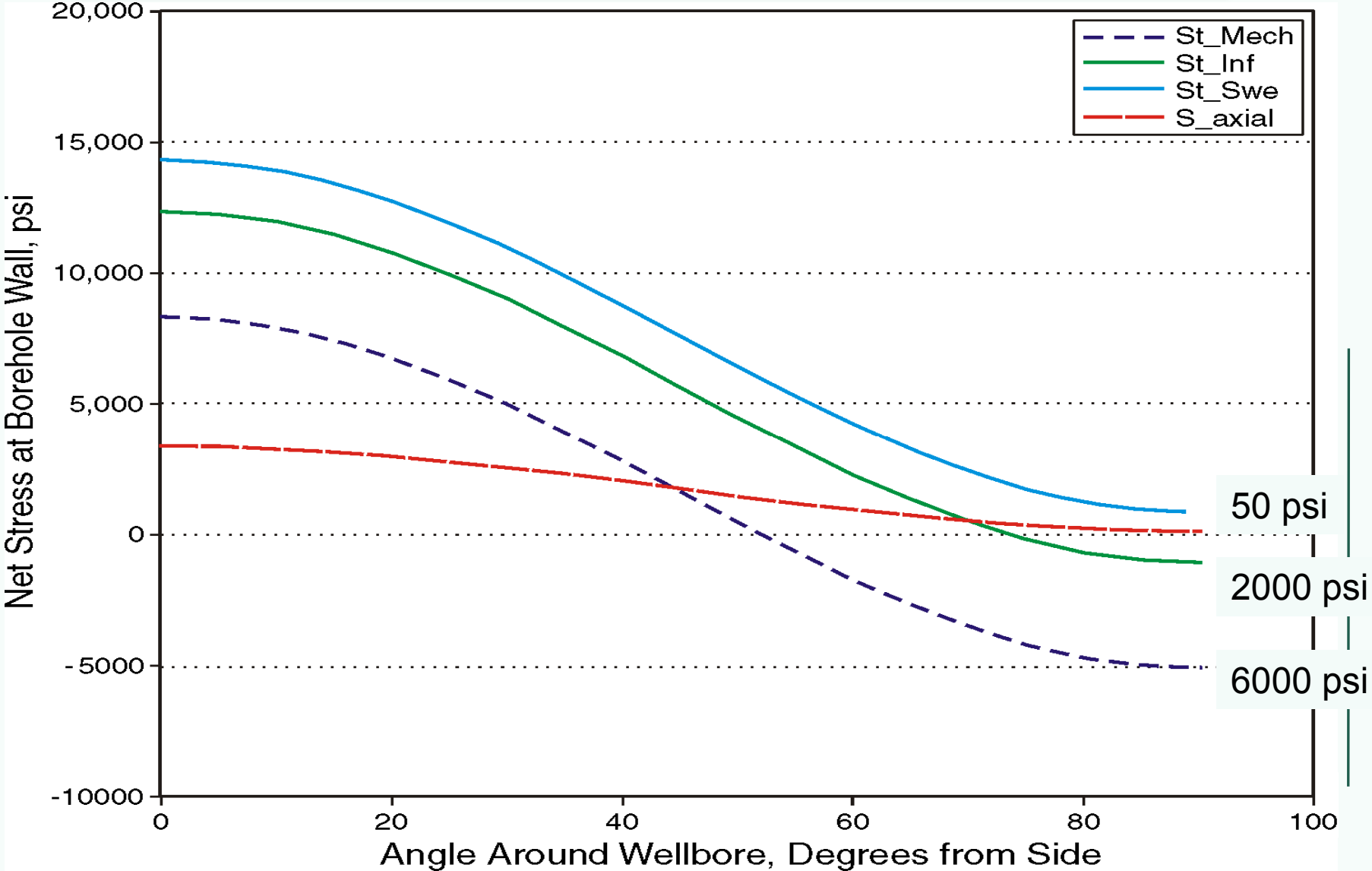
Wellbore Tangential Stress Exerted by Packer Setting Pressure



Diversion in Uncemented-Liner Fracs

- Limited-entry perfs (pre-drilled or shot in-place)
  - Few holes
  - Large perf spacing
- Perf Balls
  - Only plug perfs
  - No diversion in annulus
- Large sand (gravel) in annulus and perfs
  - Bridges in frac opening
  - Diverts in annulus
- Dynamic pressure gradient in annulus
- Combination of balls and gravel is recommended

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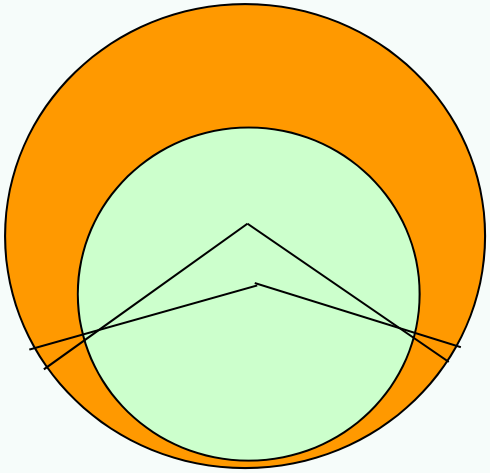
Estimation of Annular Friction

Hole Diam=	8.75	6.125	6.125	8.75	6.125	6.125	3.992
Liner OD=	7	4.5	3.5	5.5	2.675	0	0
Area(sqin)=	21.6475369	13.5603902	19.8435755	36.3737524	23.8446882	29.464703	12.5161554
Perim(in)=	30.8975637	20.8994451	19.0773214	28.1643781	17.5740693	19.242255	12.5412379
HydDiam(in)=	2.8024911	2.59535889	4.16066282	5.16592303	5.42724348	6.125	3.992



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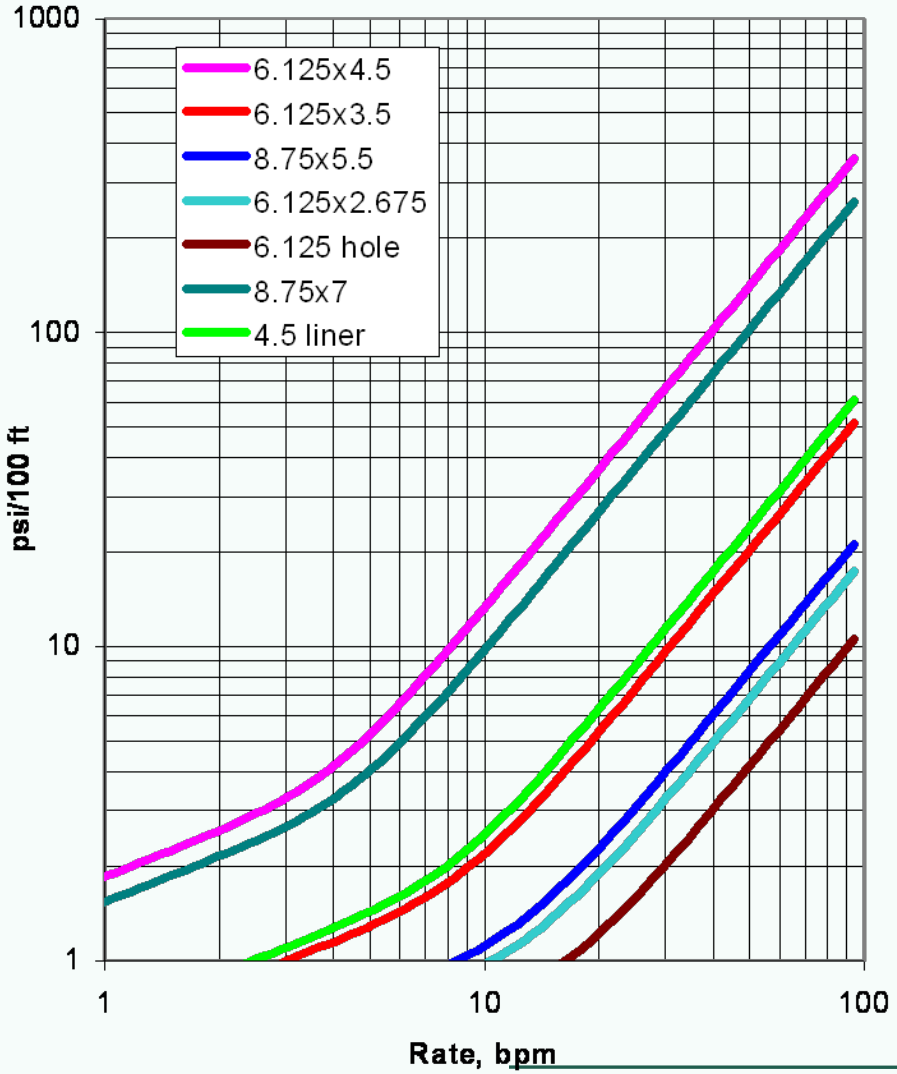
Annular Friction Pressure Results



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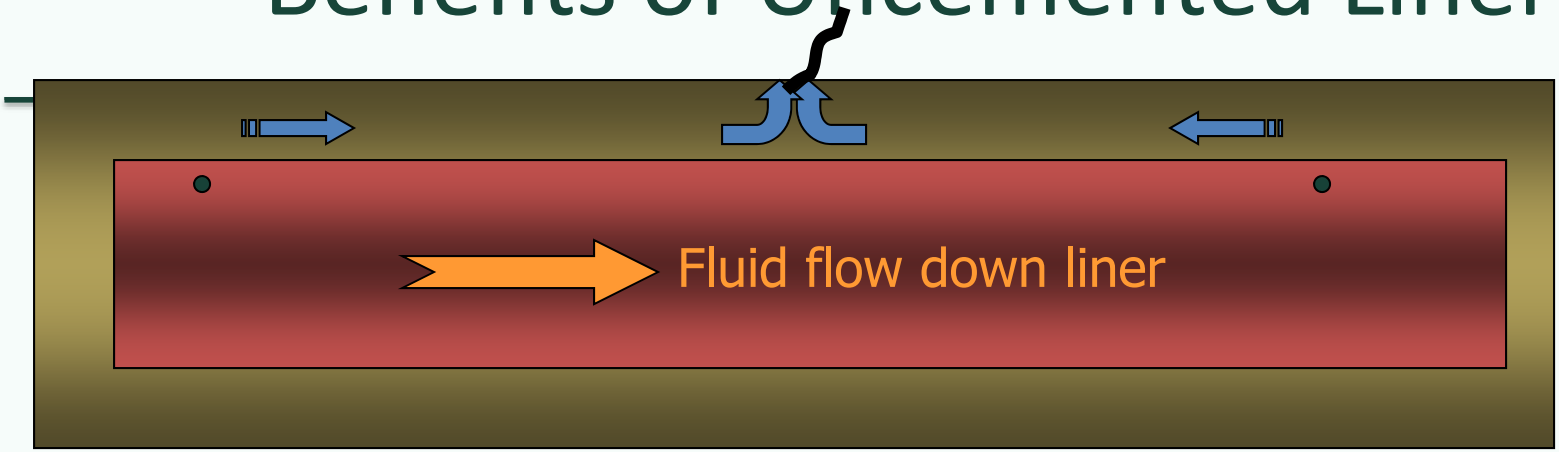
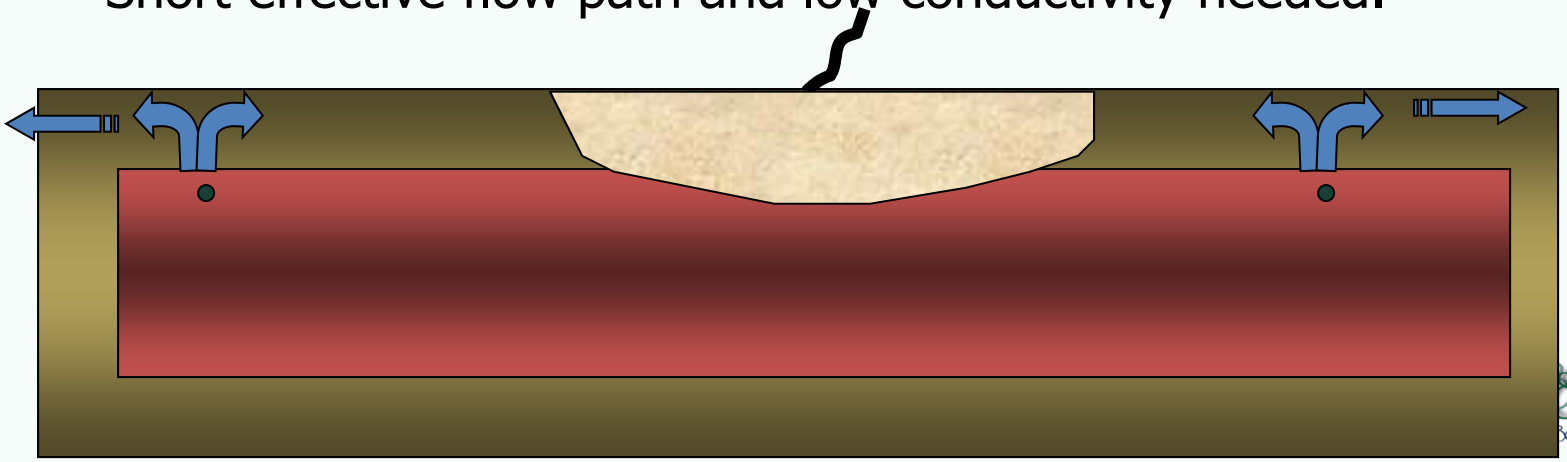
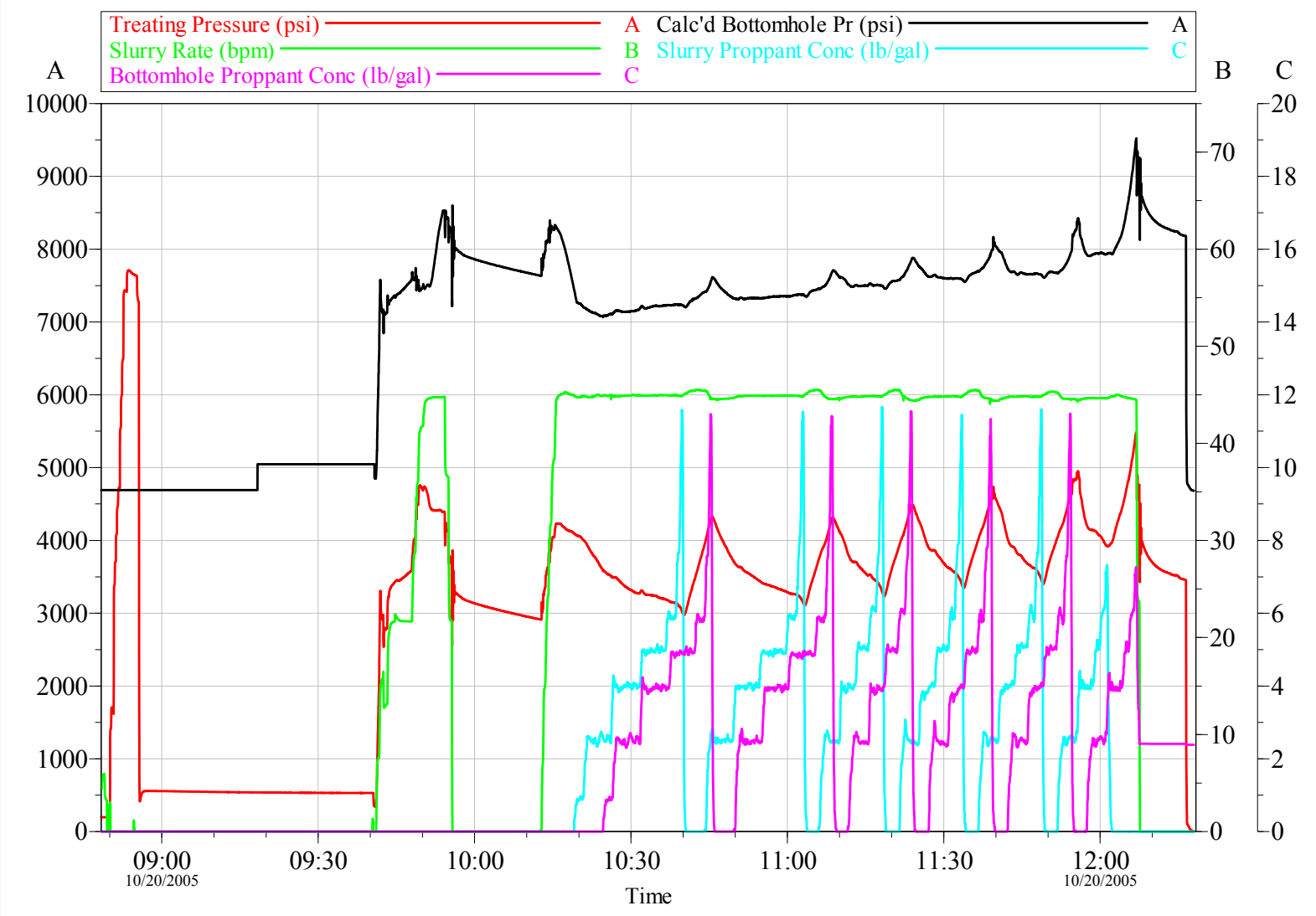
Benefits of Uncemented Liners



Fluid flow in annulus is always toward fluid exit (open fracture).
High dP in annulus allows diversion of fluid from different perfs.
Screenout of first-open fracs builds flow resistance.
Later slurry diverted to new fractures.
Short effective flow path and low conductivity needed.



Treating Pressure for 4000' Lateral Frac with Balls with Dynamic Diversion



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Summary and Conclusions

- The selection of a stimulation/completion design cannot be made without an accurate reservoir description
- Reservoir geometry and drainage pattern may control well performance
- Reservoir response to stimulation in vertical wells should be understood
- In almost all cases, maximizing **productive** lateral length is the primary goal

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General Guidelines

- If the reservoir has high matrix kh
  - Attempt minimal drilling damage or surface wash
  - Well azimuth is not critical
- With pre-existing natural fractures (open or mineralized)
  - Drill across fractures and attempt to re-open
  - Acid-frac or prop-frac through uncemented liner
- Low matrix kh or low kv/kh
  - Must design for propped frac
  - Longitudinal fracs where vertical well Xf is poor
  - Transverse fracs only when Xf>250 ft is possible

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Shear Domain Stimulation

- Different ideas about when and where it can work
  - Nearly isotropic horizontal stresses
    - Open and extend fractures in all directions
    - Pumped at high frac rate to maintain injection above leakoff rate
  - High horizontal stress anisotropy
    - Elevate pore pressure and relieve net stress causing massive shear failure over large area
    - Requires injection “below frac pressure” and access to large reservoir volume for pore pressure change
- Simul-frac designs
  - Enhance shear stimulated volume by pumping into parallel wells simultaneously

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