# Water Shutoff
# Production Engineering

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# Production Engineering

This course introduces the use of gel methods to reduce water production during oil and gas recovery.

Basic placement and permeability reduction properties of gelants and gels are discussed and compared to show what these materials can and cannot do.

We will discuss problem diagnosis, selection of treatment type, sizing, and placement of treatments for applications directed at various types of water production problems.

## Gel/Water Shutoff Topics

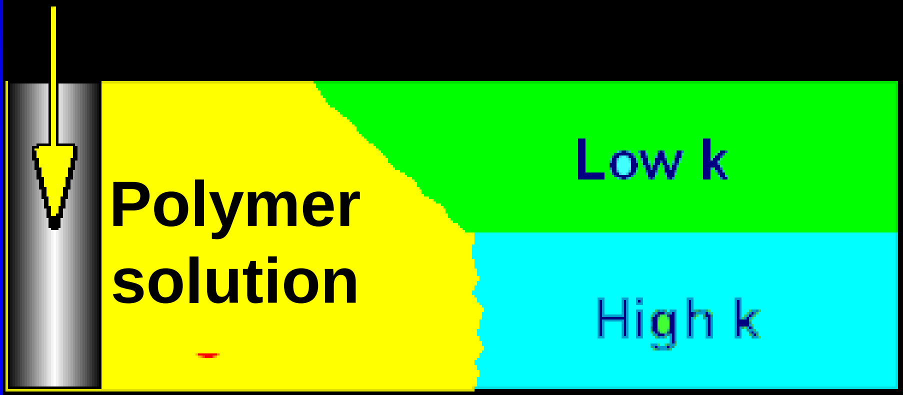
# POLYMER FLOODS VERSUS GEL TREATMENTS

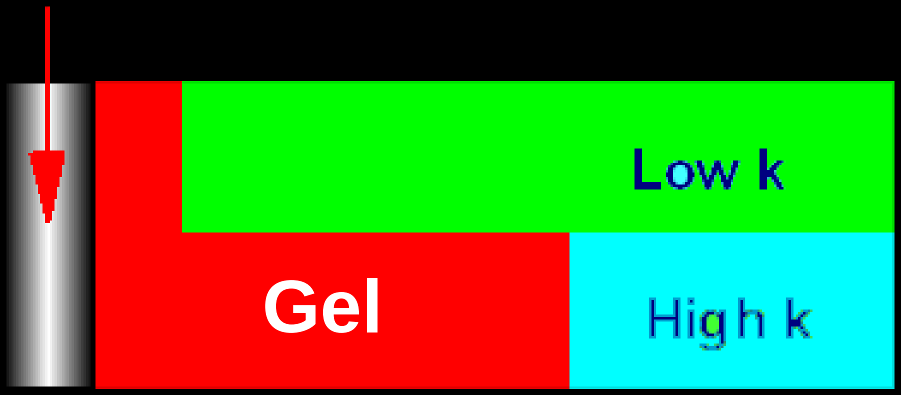
Polymer floods use polymer solutions. Gels add a crosslinker to the polymer solution.

- The "Windfall Profits Act of 1980" encouraged grouping the two methods together as "polymer augmented waterfloods".
- The Oil and Gas Journal does not distinguish the two methods in their biannual EOR survey.

**What is the difference?**

# Distinction between a gel treatment and a polymer flood.



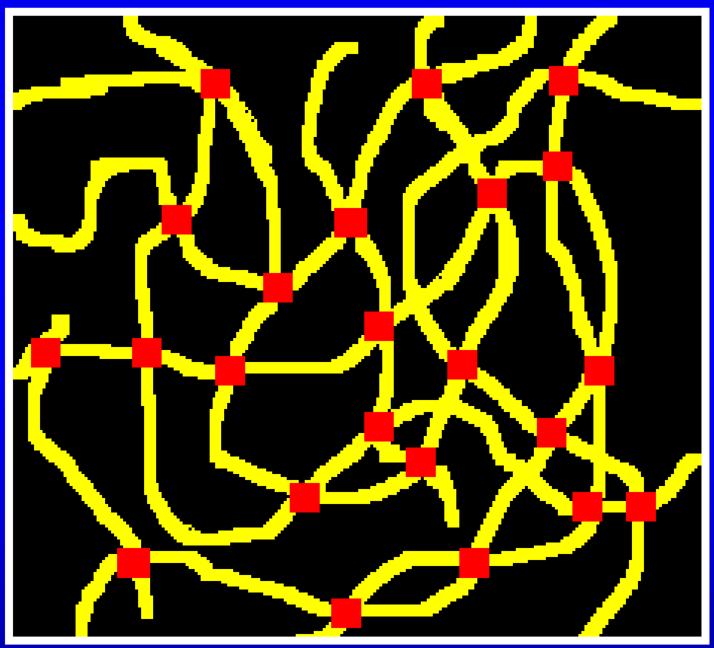




- For a polymer flood, polymer penetration into low-k zones should be <u>maximized.</u>
- For a gel treatment, gelant penetration into low-k zones should be <u>minimized.</u>

**VISCOUS POLYMER SOLUTION**

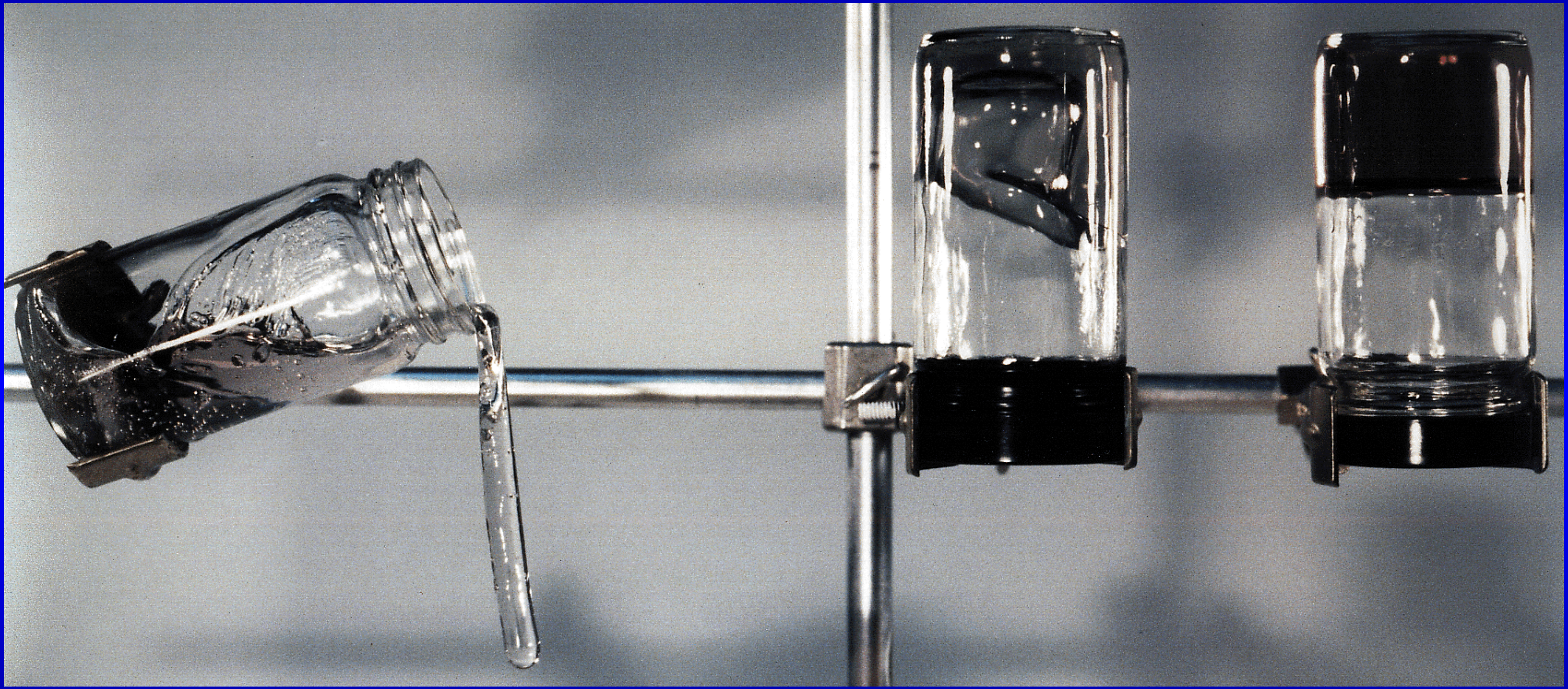
**CROSSLINKED POLYMER (GEL)**

Crosslink site



**Gelant = Polymer + crosslinker solution before gel formation.**
**Gel = Crosslinked structure after reaction.**

# Higher polymer & crosslinker concentrations yield stronger gels



**If not enough polymer or crosslinker is present, no gel forms.**

# GEL TREATMENTS ARE NOT POLYMER FLOODS

**Crosslinked polymers, gels, gel particles, and “colloidal dispersion gels”:**

- **Are not simply viscous polymer solutions.**
- **Do not flow through porous rock like polymer solutions.**
- **Do not enter and plug high-k strata first and progressively less-permeable strata later.**
- **Should not be modeled as polymer floods.**

**POLYMER FLOODING is best for improving sweep in reservoirs where fractures do not cause severe channeling.**

- **Great for improving the mobility ratio.**
- **Great for overcoming vertical stratification.**
- **Fractures can cause channeling of polymer solutions and waste of expensive chemical.**

**GEL TREATMENTS are best treating fractures and fracture-like features that cause channeling.**

- **Generally, low volume, low cost.**
- **Once gelation occurs, gels do not flow through rock.**

# WHY DO WE WANT TO REDUCE WATER PRODUCTION?

## REDUCE OPERATING EXPENSES

- Reduce pumping costs (lifting and re-injection):
  ~$0.25/bbl ($0.01 to $8/bbl range).
- Reduce oil/water separation costs.
- Reduce platform size/equipment costs.
- Reduce corrosion, scale, and sand-production treatment costs.
- Reduce environmental damage/liability.

## INCREASE HYDROCARBON PRODUCTION

- Increase oil production rate by reducing fluid levels and downhole pressures.
- Improve reservoir sweep efficiency.
- Increase economic life of the reservoir and ultimate recovery.
- Reduce formation damage.

## MAIN POINTS I THINK YOU NEED TO KNOW

1. What polymers, gelants, and gels can/cannot do.

2. Why determining whether flow is radial (into matrix) or linear (through fractures) is critical in EVERY application.

3. A strategy for attacking problems.

## PROPERTIES OF AVAILABLE GELANTS/GELS

1. Early in the gelation process, gelants penetrate readily into porous rock.

2. After gelation, gel propagation through porous rock is extremely slow or negligible.

3. The transition between these two conditions is usually of short duration.

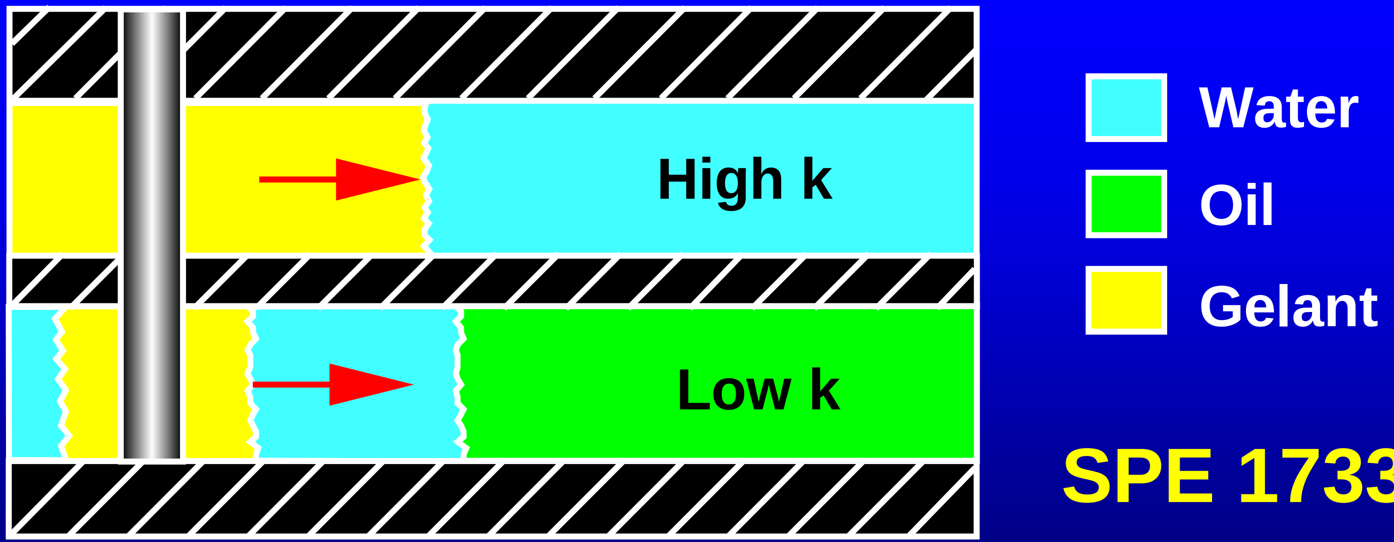
*SPERE* (Nov. 1993) 299-304; *IN SITU* 16(1) (1992) 1-16; and *SPEPF* (Nov. 1995) 241-248.

# BASIC CALCULATIONS

**Gelants can penetrate into all open zones.**

**An acceptable gelant placement is much easier to achieve in linear flow (fractured wells) than in radial flow.**

**In radial flow (unfractured wells), oil-productive zones must be protected during gelant placement.**




**SPE 17332**

# KEY QUESTIONS DURING BULLHEAD INJECTION OF POLYMERS, GELANTS, OR GELS

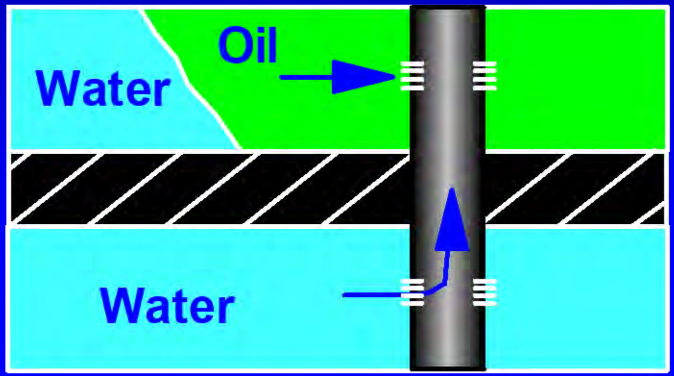
- Why should the blocking agent NOT enter and damage hydrocarbon productive zones?
- How far will the blocking agent penetrate into each zones (both water AND hydrocarbon)?
- How much damage will the blocking agent cause to each zone (both water AND hydrocarbon zones)?

## A STRATEGY FOR ATTACKING EXCESS WATER PRODUCTION

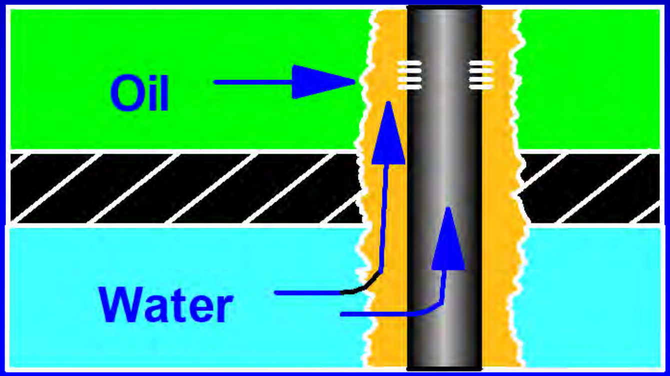
1. Consider and eliminate the easiest problems first.
2. Start by using information that you already have.

# CAUSES OF EXCESS WATER PRODUCTION

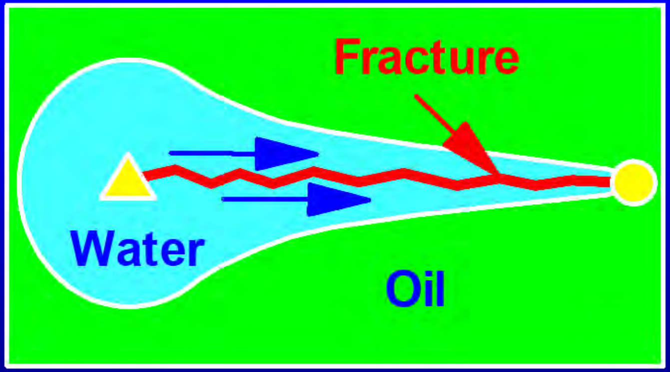
## Open Water Zone



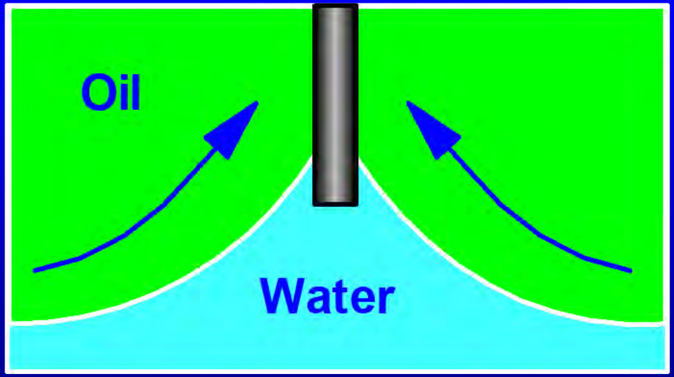

## Flow Behind Pipe and Casing Leaks




## Channeling from Injectors




## Coning or Cusping



# MAIN POINTS

Many different types of excess water production problems exist.

Each problem type requires a different approach (e.g., different blocking agent properties) for optimum solution.

Problem types should be adequately diagnosed before attempting a solution.

# WATER CONTROL METHODS

- Cement, sand plugs, calcium carbonate.
- Packers, bridge plugs, mechanical patches.
- Pattern flow control.
- In fill drilling/well abandonment.
- Horizontal wells.
- Gels.
- Polymer floods.
- Resins.
- Foams, emulsions, particulates, precipitates, microorganisms, nanoparticles.

## SOME MATERIALS FOR WATER SHUTOFF

### CEMENTS

+ Have excellent mechanical strength.
+ Have good thermal stability (up to 450°C).
- Do not penetrate readily into tight areas.
- Do not always form a good pipe-formation seal.

### RESINS

+ Can penetrate into rock matrix and tight areas.
o Stability depends on the particular resin (up to 250°C).
- Chemistry can be very temperamental.
- Are not reversible.
- Are expensive.

### GELS

+ Can penetrate into rock matrix and tight areas.
+ Reliability of gelation chemistry depends on the gelant.
- Have lower thermal stability than other materials (<175°C).
- Have low mechanical strength outside rock matrix.

# BASIC PROPERTIES OF GELANTS AND GELS

# A FEW OF THE HUNDREDS OF GEL SYSTEMS

Cr(III) acetate with high-Mw HPAM (Marcit CT)
Cr(III) acetate with low-Mw HPAM (Maraseal)
Cr(III) propionate HPAM (Aquatrol IV, Matrol III)
Cr(III) lactate/carboxylate HPAM. Cr(III) malonate HPAM
Preformed Particle Gels (PPG)
Nanoparticles (Nanospheres)

Silicates (Injectrol, Zonelock, Pemablock, Siljel V, Silica-Polymer-Initiator)
Sodium silicate + aminopropyltriethoxysilane (Smart Sealant)
In situ polymerization of acrylamides, acrylates, or derivatives (k-Trol, Permseal)
Polyethyleneimine with t-butylacrylate/acrylamide copolymers (H2Zero)

HCHO or HMTA and phenolic/hydroquininone crosslinkers with PAM co- and terpolymers (Phillips and Unocal processes,Unogel, Organoseal, Multigel)

Crosslinked AMPS, NVP, acrylamide/acrylate co & terpolymers (HE)

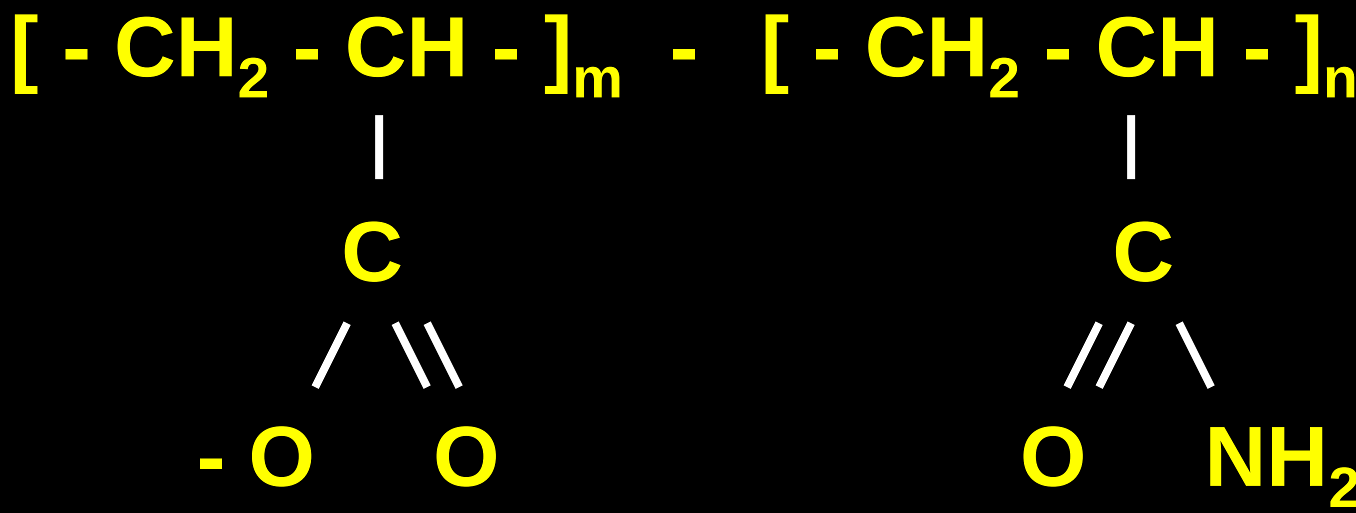
Amphoteric polymers and terpolymers (WOR-Con, Aquatrol I, AquaCon)
Hydrophobically modified polyDMAEMA (WaterWeb, CW-Frac)
Crosslinked expandable polymeric microparticles (Bright Water)

Al-citrate/HPAM (BP North Slope process)
Al-citrate/HPAM/CPAM (Cat-An, colloidal dispersion gel)
$AlCl_3/OH^-$ (DGS or Delayed Gelation System)
$Fe(OH)_3$ (Hungarian precipitation process)

# WHY CHOOSE ONE MATERIAL OVER ANOTHER?

- Cost
- Availability
- Sensitivity of performance to condition or composition variations
- Blocking agent set time
- Permeability reduction provided to water
- Permeability reduction provided to oil or gas
- Ability to withstand high-pressure gradients in porous rock
- Ability to withstand high-pressure gradients in fractures or voids
- Rheology and/or filtration properties
- Ability to penetrate into fractures or narrow channels behind pipe
- Stability at elevated temperatures
- Environmental concerns

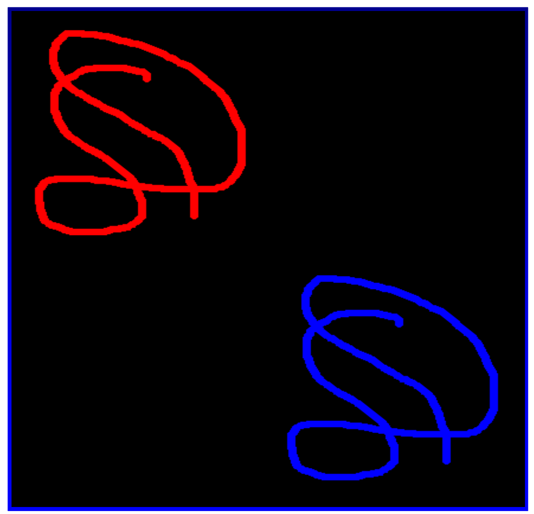
# "Polyacrylamide" or "HPAM" Polymers



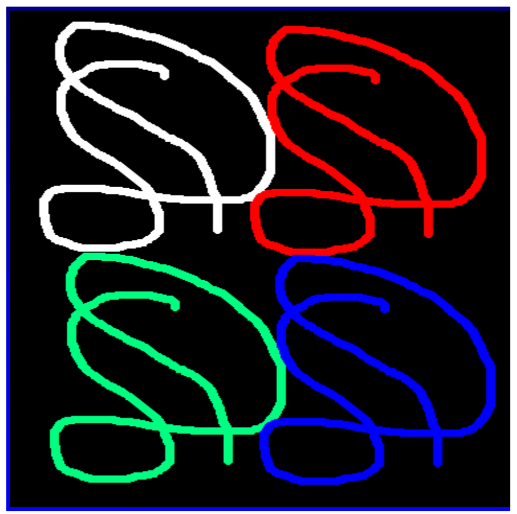

acrylate acrylamide

- "degree of hydrolysis" = m / (n + m)
- For high $M_w$ polymers: n ≈ 90,000, m ≈ 5,000 to 10,000
- Monomers are randomly positioned along the polymer chain

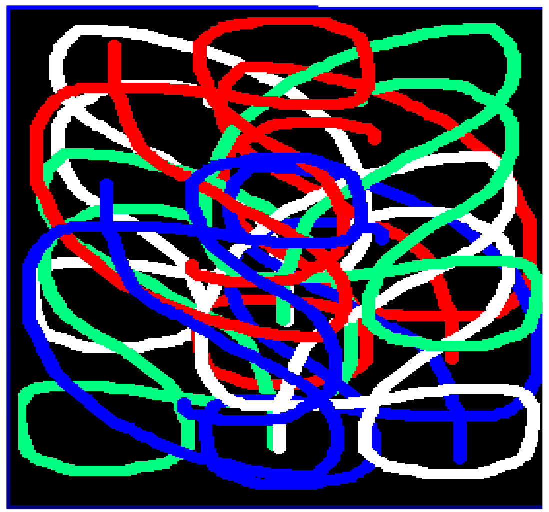
# CRITICAL OVERLAP CONCENTRATION – C*



DILUTE SOLUTION: C < C*

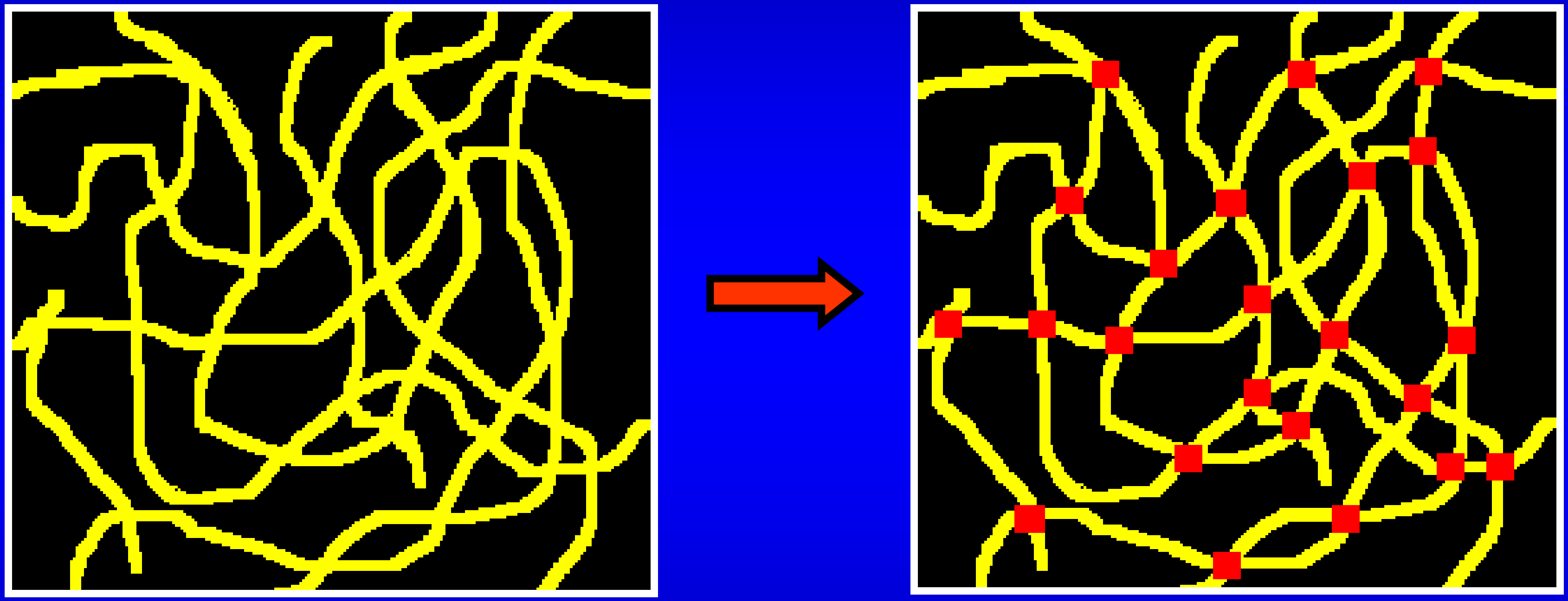


TOTAL POLYMER VOLUME = TOTAL SOLUTION VOLUME: C = C*



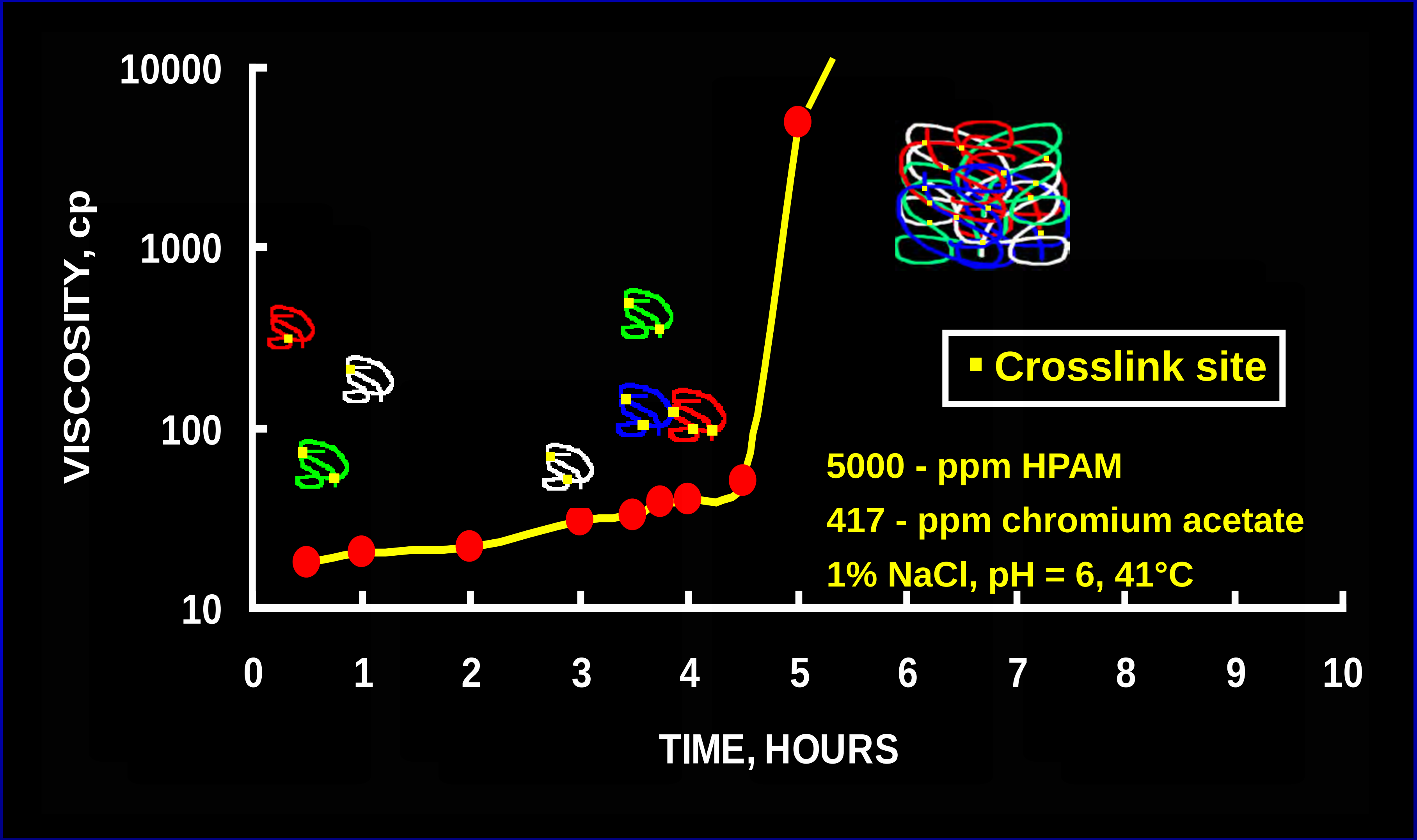
POLYMERS INTERTWINE: C > C*

# POLYMER CROSSLINKING



■ Crosslink site

# VISCOSITY VERSUS TIME DURING GELATION



# GELANTS VERSUS GELS

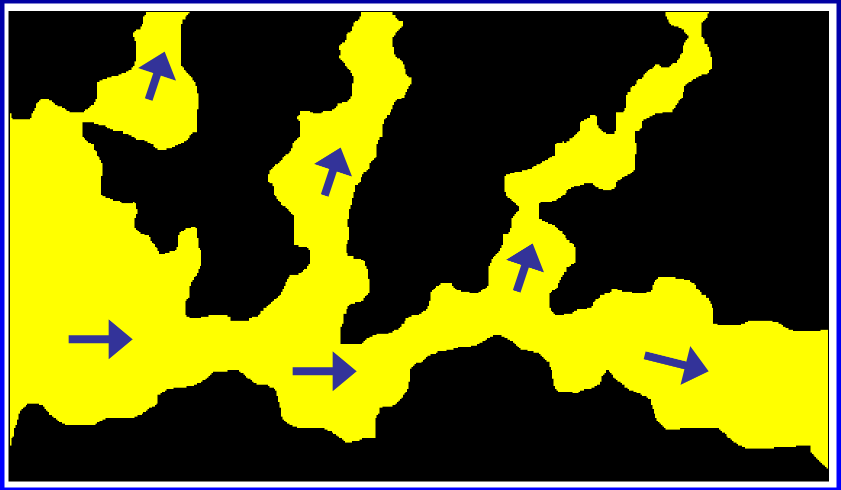
Polymer Solution [e.g., HPAM] + Crosslinking Agent [e.g., Cr(III)] = Gelant

**In a gelant, few crosslinks have been made. Gelants can flow into porous rock just like uncrosslinked polymer solutions.**

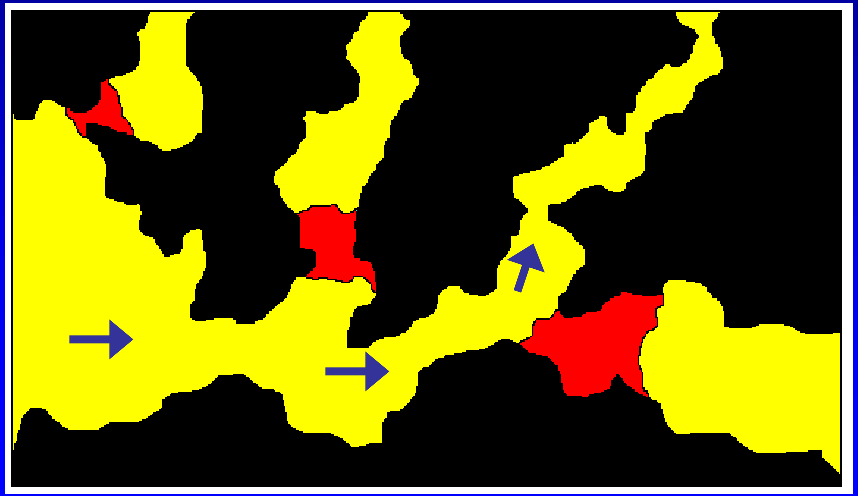
$$\text{Gelant} \xrightarrow[\text{(e.g. \sim 5 hrs)}]{\text{time}} \text{Gel}$$

**Gels are 3-dimensional crosslinked structures that will not enter or flow through porous rock.**

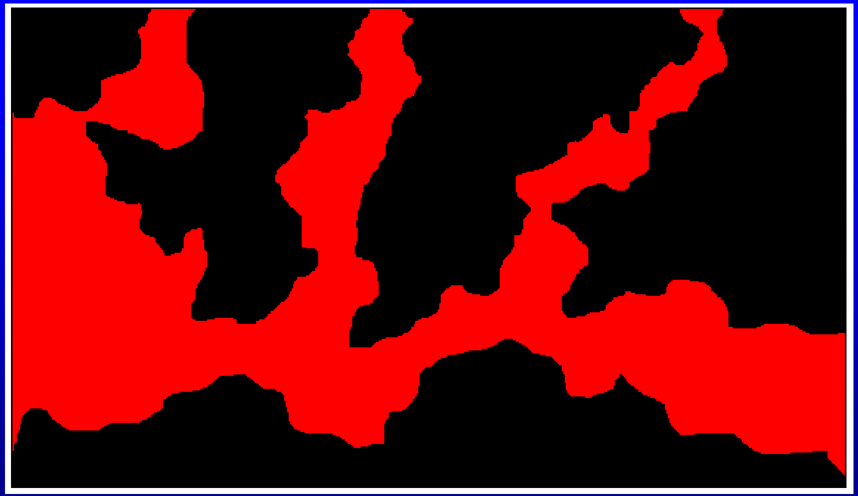
# GELANTS FLOW THROUGH POROUS ROCK; GELS DO NOT



Gelant flows freely like a polymer solution



Partial gel formation

Gel filling all aqueous pore space

## PROPERTIES OF AVAILABLE GELANTS/GELS

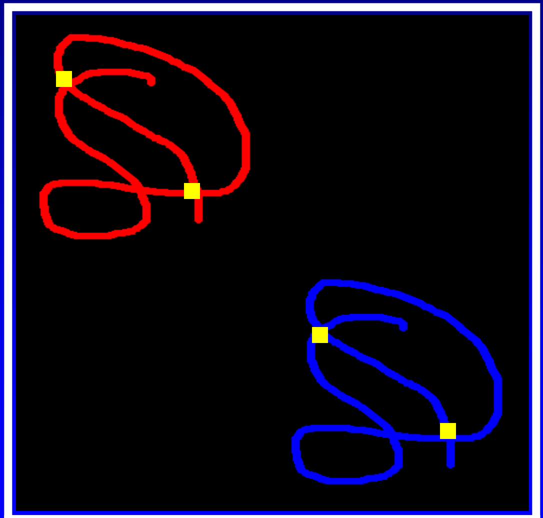
1. Early in the gelation process, gelants penetrate readily into porous rock.

2. After gelation, gel propagation through porous rock is extremely slow or negligible.

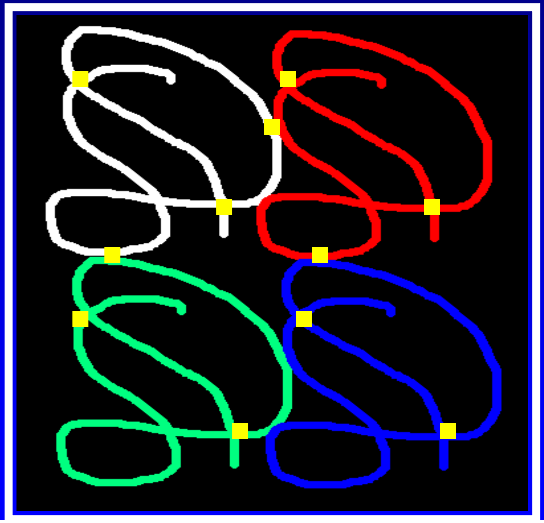
3. The transition between these two conditions is usually of short duration.

*SPERE* (Nov. 1993) 299-304; *IN SITU* 16(1) (1992) 1-16; and *SPEPF* (Nov. 1995) 241-248.

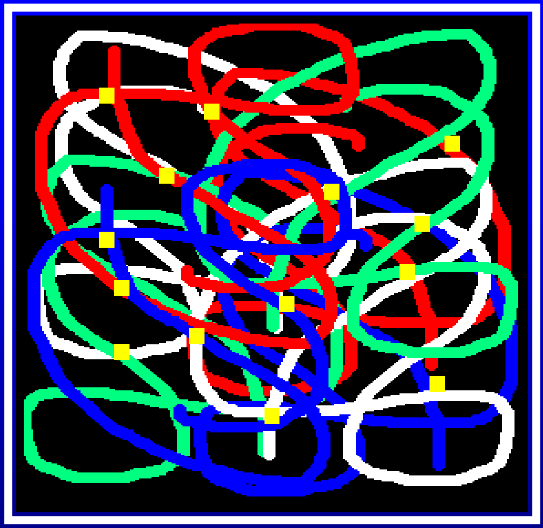
# GELATION DEPENDS ON POLYMER CONCENTRATIONS



C < C*: No gelation



C ≈ C*: Gelation may or may not occur



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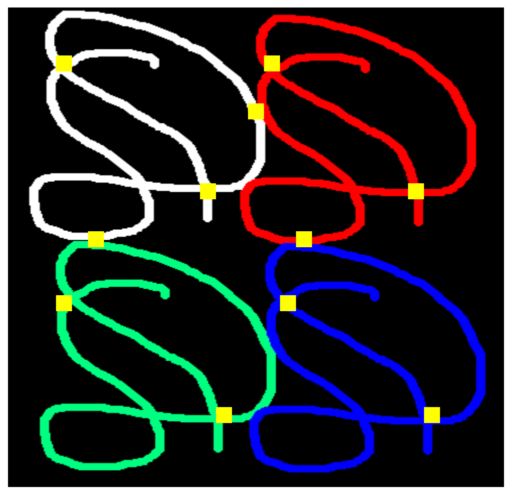
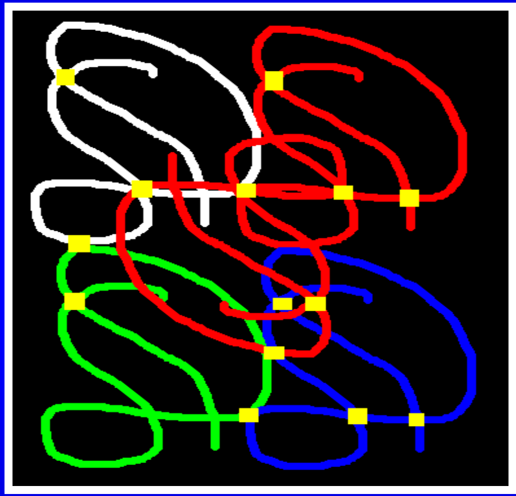
C >> C*: Best opportunity for 3D gel formation

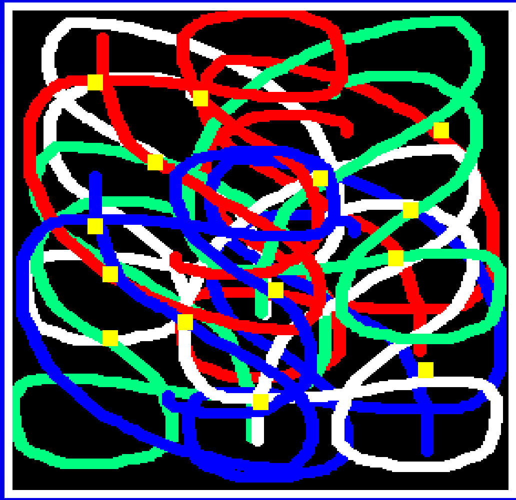
# ABOVE C*, HIGHER CONCENTRATIONS OF POLYMER STRENGTHEN THE GEL



Low gel strength



Intermediate gel strength



Strong gel

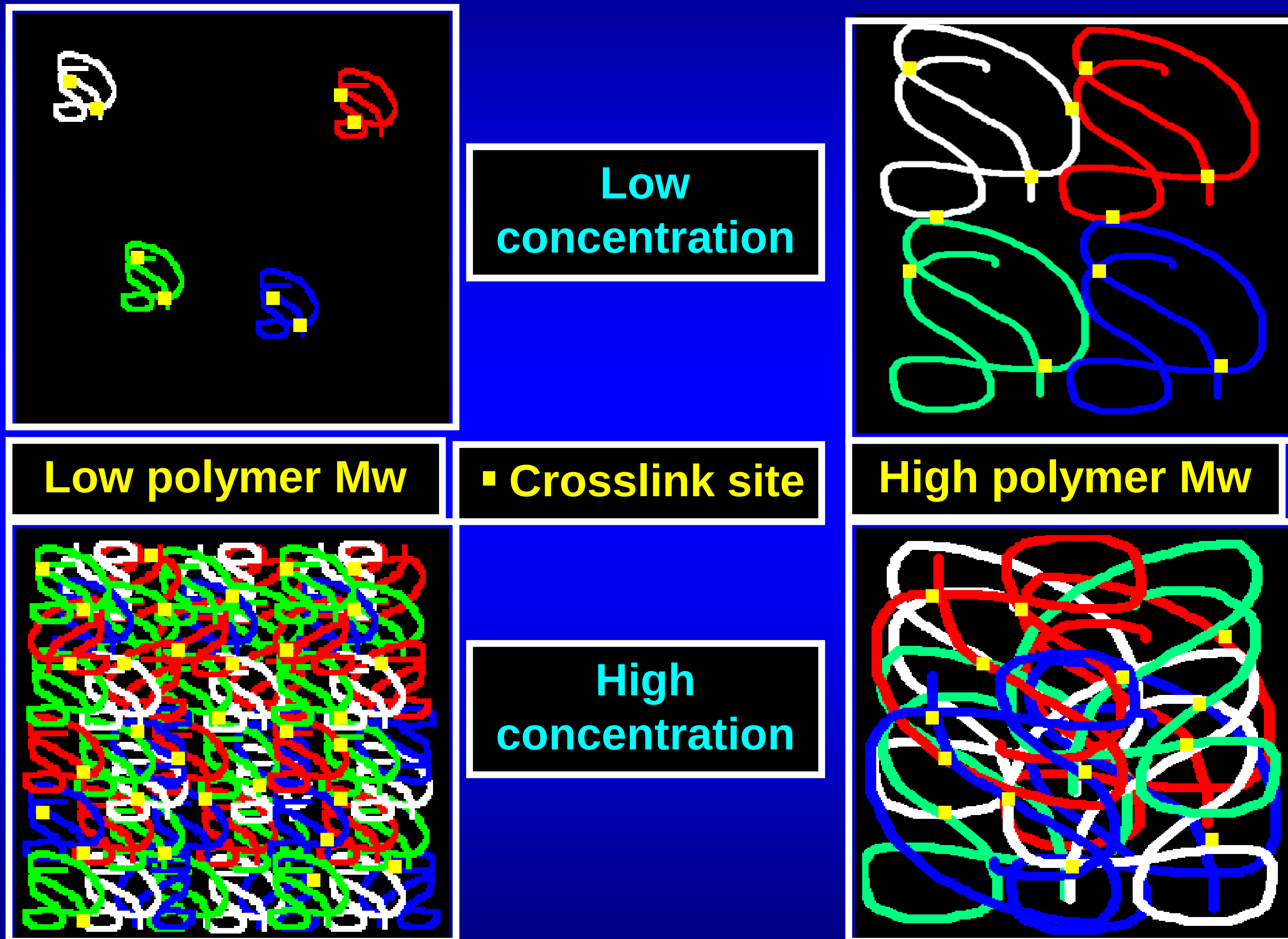
▪ Crosslink site

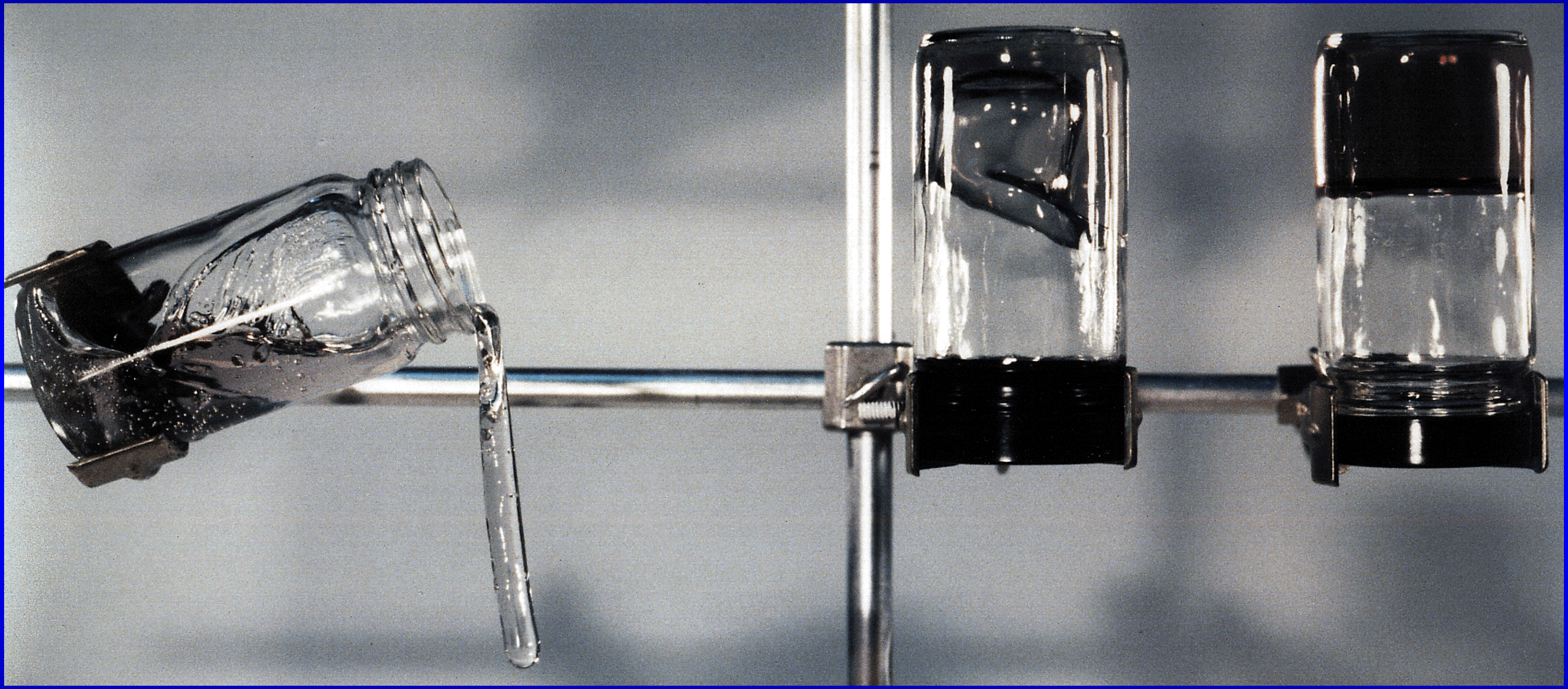
# UP TO A POINT, CROSSLINK DENSITY AFFECTS GEL STRENGTH

Viscous Fluid | Low gel strength | Strong gel

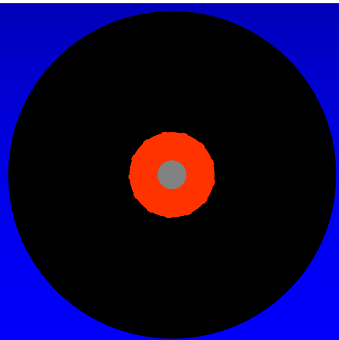
▪ Crosslink site

# HIGHER Mw POLYMERS REQUIRE LOWER CONCENTRATIONS FOR 3D GEL FORMATION



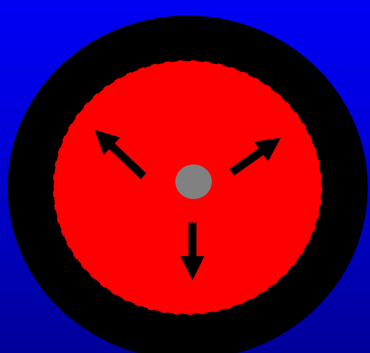


# GELATION TIME DETERMINES HOW FAR A GELANT CAN PENETRATE INTO POROUS ROCK

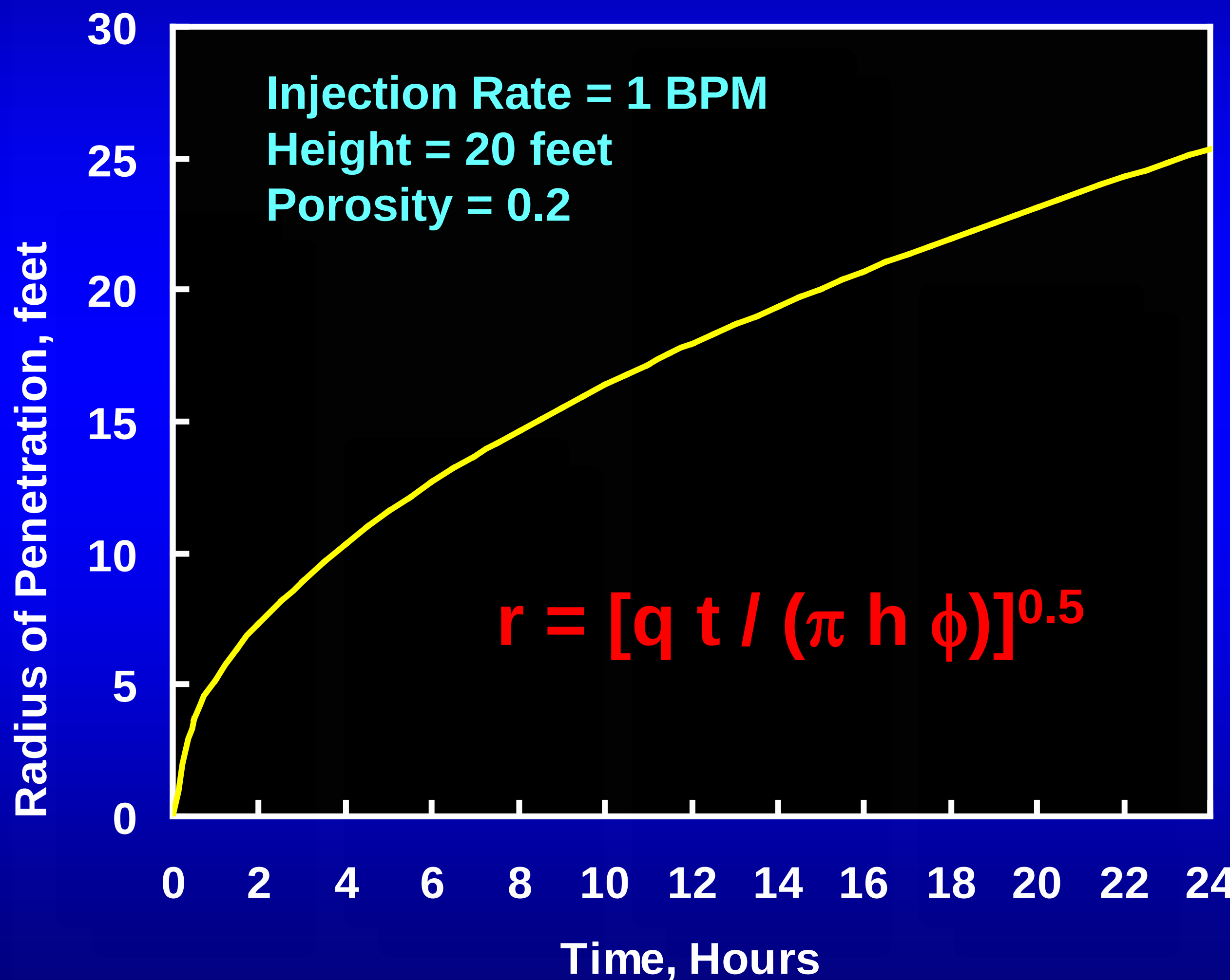


Fast gelation

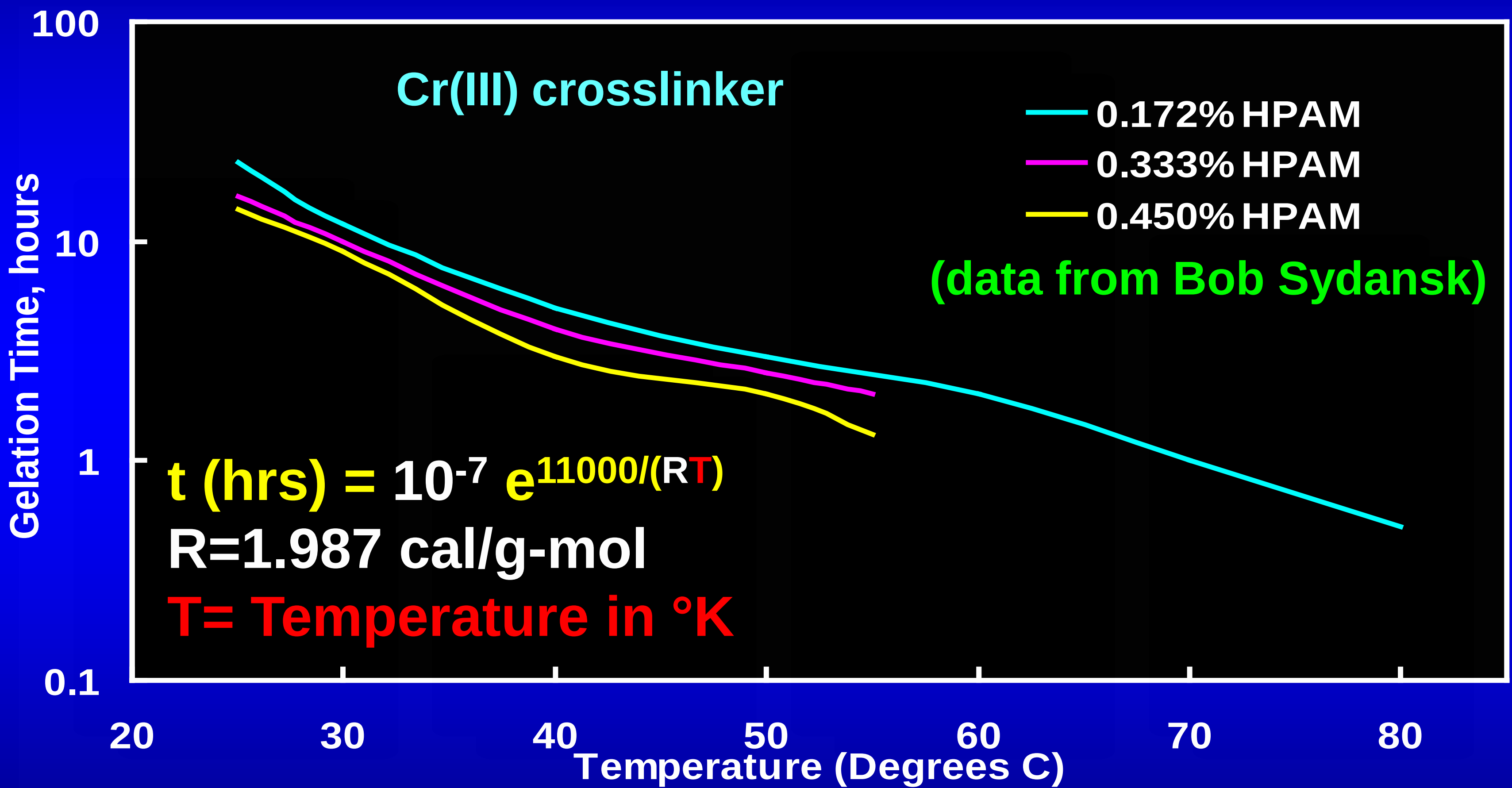
■ Gelant



Slow gelation



# GELATION TIME VERSUS TEMPERATURE




**Increasing temperature by 10º C halves gelation time.**

# GELATION TIMES FOR MOST COMMERCIAL GELANTS ARE FAIRLY SHORT EVEN AT MODERATE TEMPERATURES

**Some exceptions:**

- **BP's PEI crosslinked/t-butylacrylate-acrylamide polymers.**
- **Unocal's organically crosslinked polymers. SPE 37246 and *SPEPF* May 1996, 108 - 112.**
- **Phillips' organically crosslinked polymers. SPE 27826.**
- **Eniricerche's Cr(III) - malonate crosslinked polymers. *SPEPF* Nov. 1994, 273 - 279.**

## Some papers examining gels for elevated temperatures

SPE 190266, 188322, 183558, 179796, 173185, 163110, 129848, 127806, 120966, 104071, 98119, 97530, 90449, 77411, 72119, 50738, 39690, 37246, 27826, 27609.

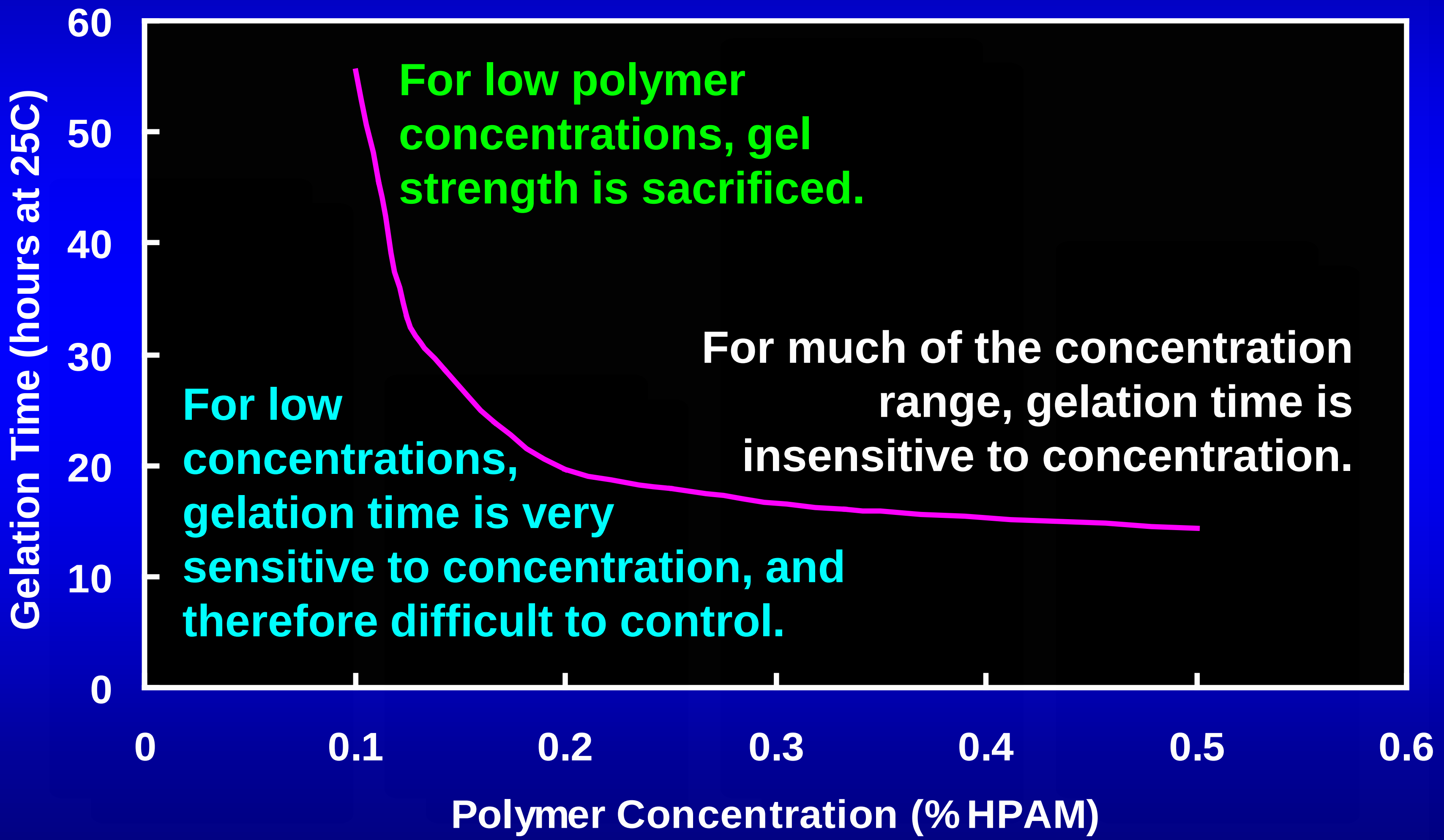
**KEY MESSAGES:**

1. HPAM polymers will hydrolyze at high temperature—risking gel syneresis if divalent cations are present.
2. Organic crosslinkers delay gelation but do not necessarily improve gel stability.
3. Polymers with high levels of ATBS or NVP promote polymer and gel stability.
4. More concentrated gels have greater stability.
5. Incorporating associative groups does not help stability.

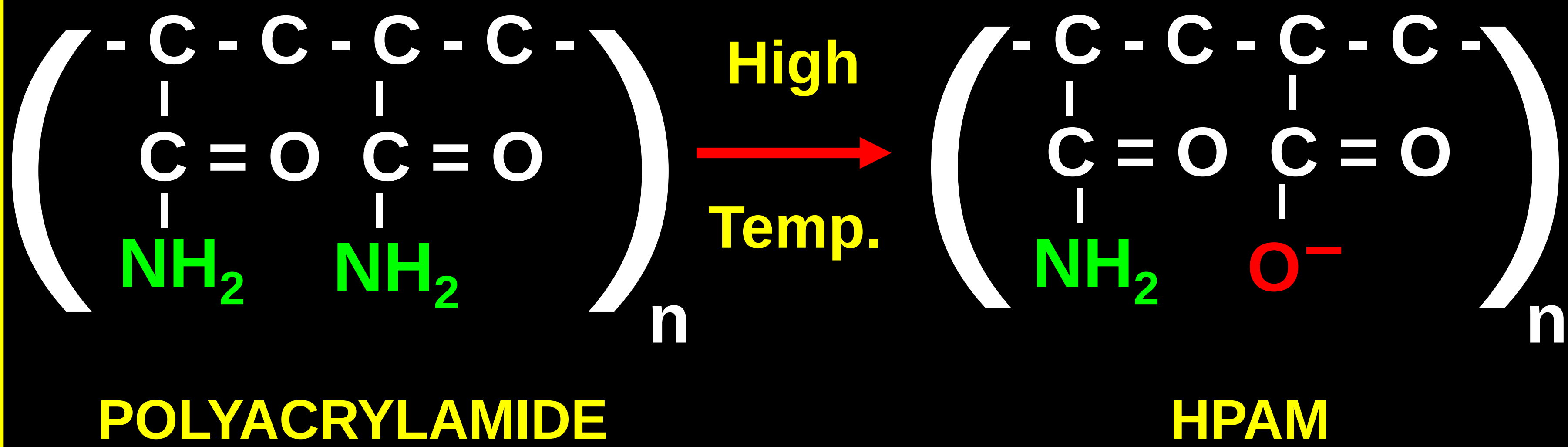
## METHODS TO INCREASE GELATION TIMES

- Vary salinity, pH, or concentrations of chemical additives. SPE 27609.
- Use an unhydrolyzed polyacrylamide. With time, hydrolysis at elevated temperatures increases the number of crosslinking sites. SPE 20214.
- Cool the near-wellbore region prior to gelant injection. SPE 28502.
- Use a chemical retarding agent (e.g., lactate). *SPEPF* (Nov 2000) 270-278.

# GELATION TIME VERSUS POLYMER CONCENTRATION



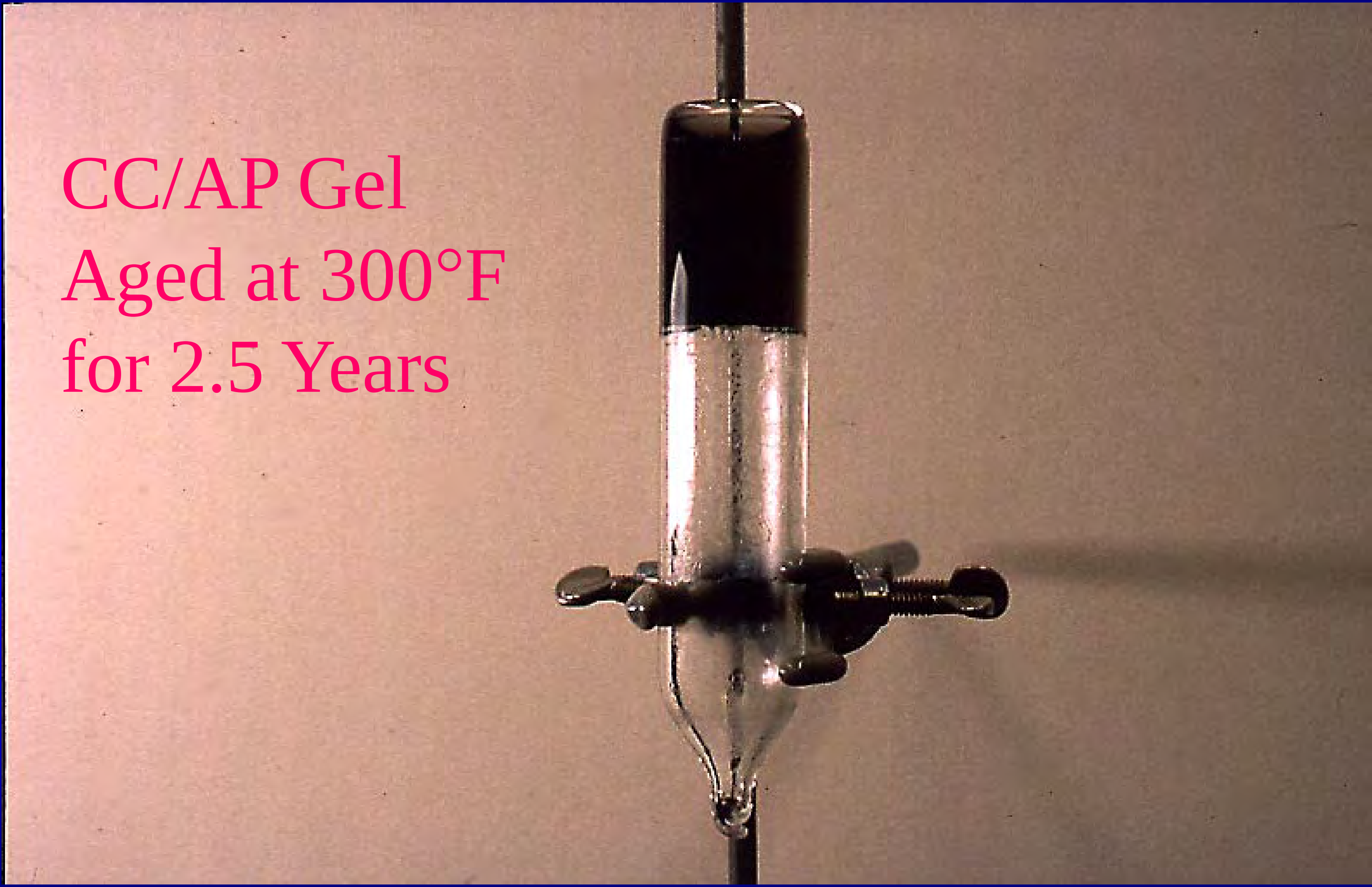
# POLYMER HYDROLYSIS




- Only carboxylate groups react with Cr(III), so Cr(III) crosslinking is delayed until enough $COO^-$ groups form.
- If too many $COO^-$ groups form, polymer precipitates if $Ca^{2+}$ or $Mg^{2+}$ is present.
- Trick only works at high temperatures (~120°C) with low-Mw polyacrylamide polymers.

# Gel Stability at Elevated Temperatures

- Some feel that gel stability is no better than the stability of the polymer in the gel.
- Gels can be made using polymers that are more stable than HPAM--e.g., amide/AMPS/NVP copolymers and terpolymers. *SPERE* Nov. 1987, 461-467.
- Some evidence exists that gel stability can be increased by using very rigid gels. SPE 20214.


CC/AP Gel
Aged at 300°F
for 2.5 Years

# Gelant Sensitivity to pH

- For most gelants, the gelation reaction is sensitive to pH.
- Clays, carbonates, and other reservoir minerals can change pH -- thus interfering with gelation.
- Need to buffer gelants or develop gelants that are less sensitive to pH changes.

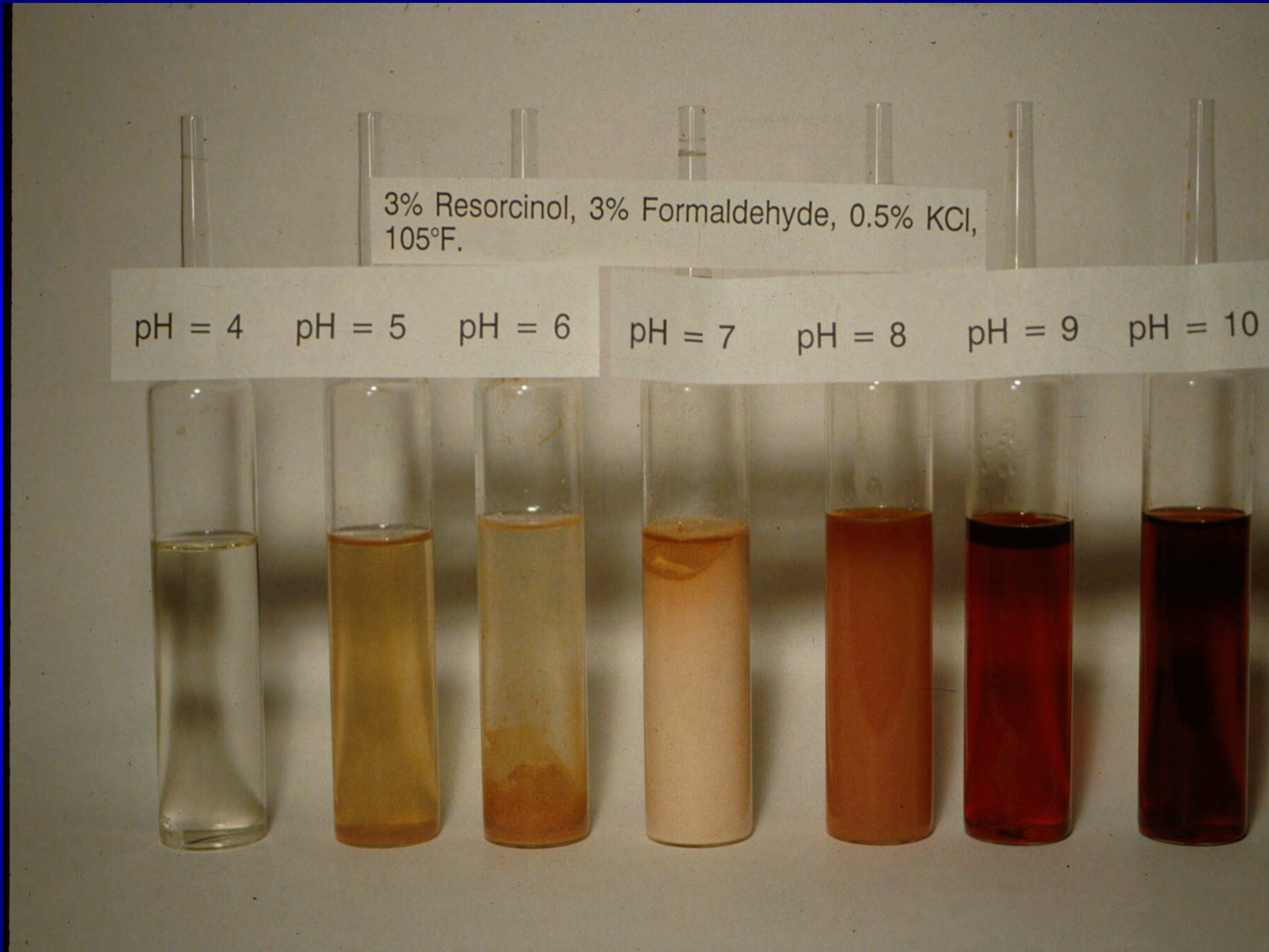
- Marathon: Cr(III)-acetate and lactate crosslinkers. SPE 17329.
- Phillips: Cr(III)-propionate crosslinker. *SPERE* Feb. 1988, 243-250.
- Eniricerche: Cr(III)-malonate and lactate crosslinkers. *SPEPF* Nov. 1994, 273-279.
- IFP: adsorbed polymers. SPE 18085.

Cr(IIII) can bind to:

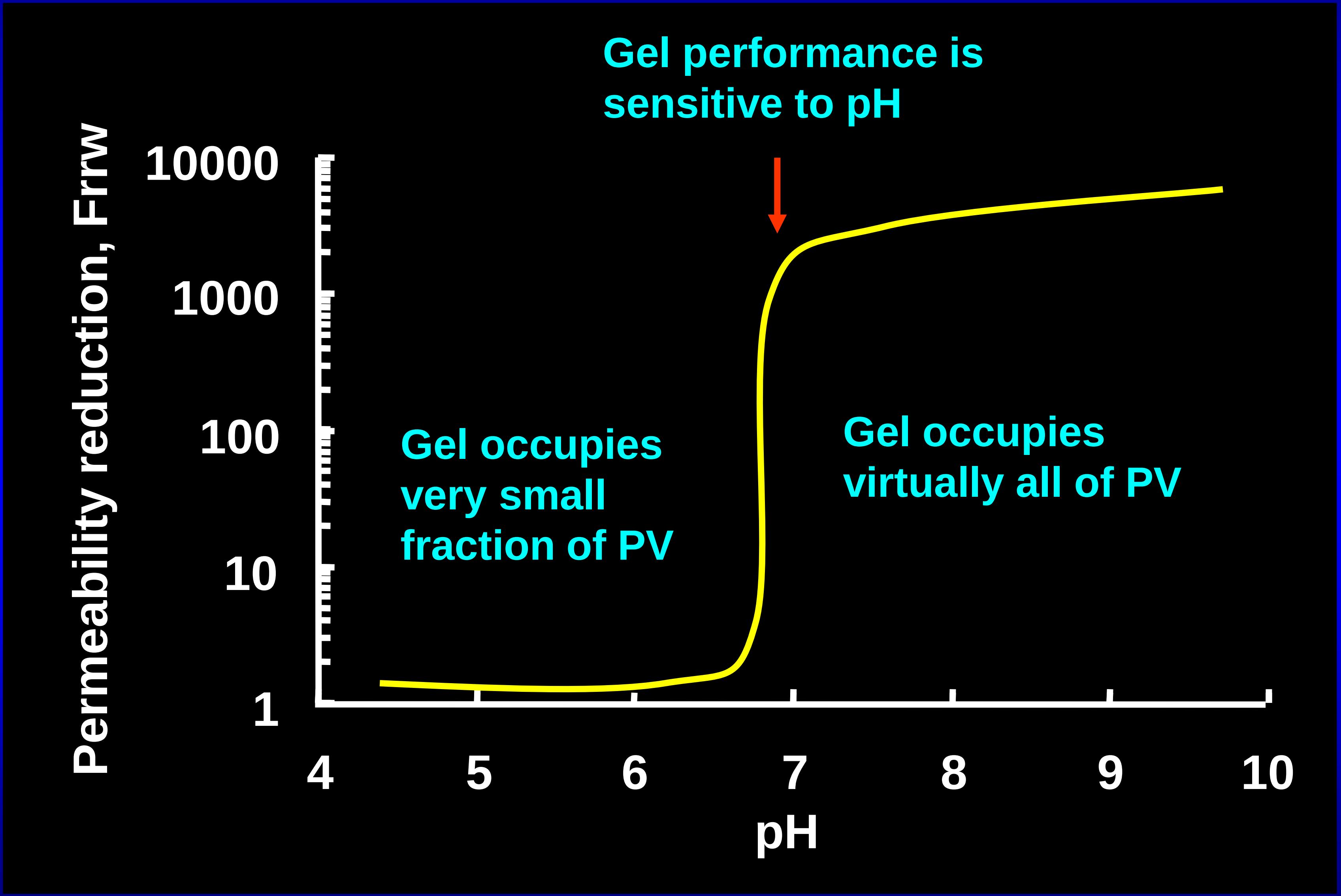
a. Polymer
b. Acetate or other carboxylate
c. Rock

Competition among the above affects gel stability, gel strength, gelant propagation, and gelation time.

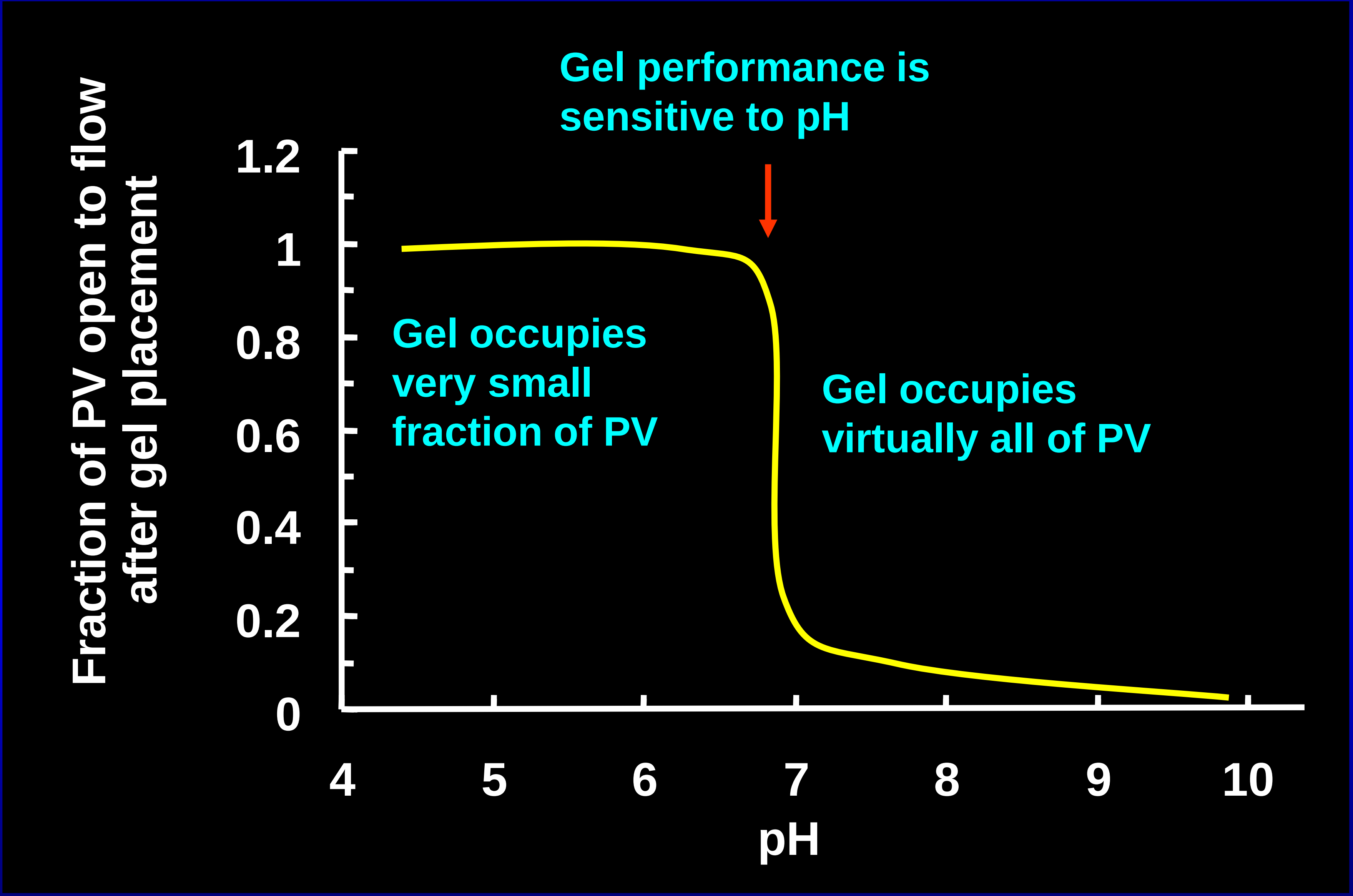
Gelation time at high temperatures can be varied by adjusting the ratio of acetate/lactate (or glycolate or malonate).


3% Resorcinol, 3% Formaldehyde, 0.5% KCl,
105°F.
pH = 4
pH = 5
pH = 6
pH = 7
pH = 8
pH = 9
pH = 10

# pH OF GELATION AFFECTS PERMEABILITY REDUCTION



# pH OF GELATION AFFECTS PV OCCUPIED BY GEL



Resistance factor = Water mobility ÷ Gelant mobility

$F_r = (k/\mu)_{water} / (k/\mu)_{gelant} \approx$ Gelant viscosity relative to water

Water residual resistance factor = $\dfrac{\text{Water mobility before gel placement}}{\text{Water mobility after gel placement}}$

$F_{rrw} = (k/\mu)_{water\ before\ gel} / (k/\mu)_{water\ after\ gel}$ = permeability reduction

Oil residual resistance factor = $\dfrac{\text{Oil mobility before gel placement}}{\text{Oil mobility after gel placement}}$

$F_{rro} = (k/\mu)_{oil\ before\ gel} / (k/\mu)_{oil\ after\ gel}$ = permeability reduction

## WEAK GELS

- Occupy a very small fraction of the pore volume.
- Usually consist of small gel particles that block pore throats.
- Provide low to moderate permeability reductions.
- Are usually unpredictable in particle size, particle concentration, and permeability reduction provided.

## ADSORBED POLYMERS

- Occupy a very small fraction of the pore volume.
- Usually block some fraction of the pore throats.
- Provide low to moderate permeability reductions.
- Because of mineralogical variations, are usually unpredictable in adsorption level and permeability reduction provided.

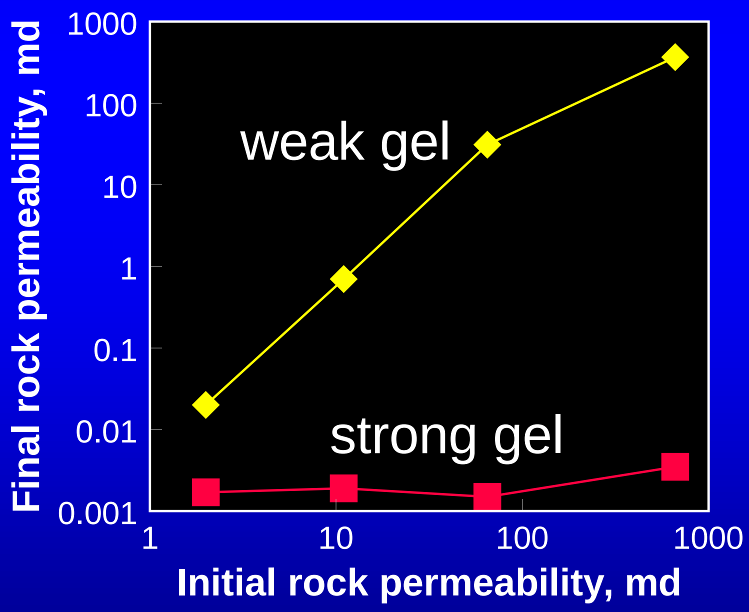
## PORE-FILLING GELS

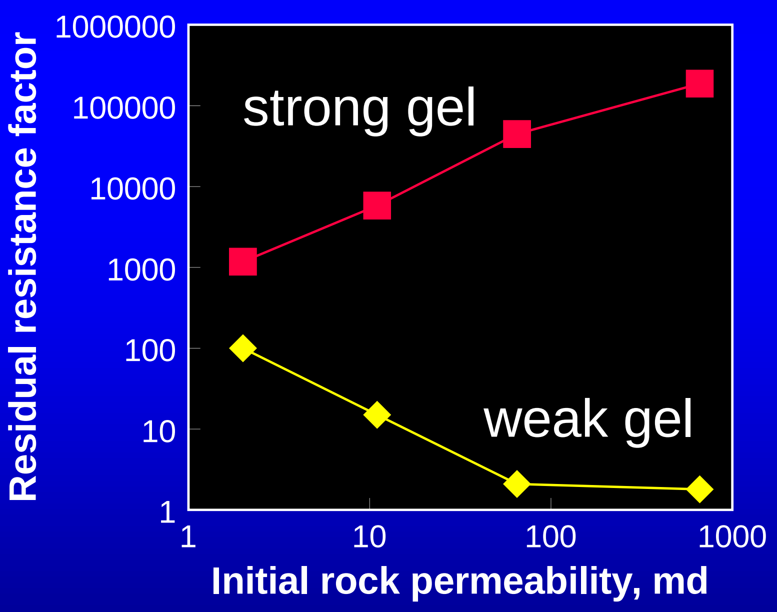
- Occupy most, if not all, of the aqueous pore space.
- Reduce permeabilities to microdarcy levels.
- Water flows through the gel itself.
- Provide high permeability reductions.
- Are much more predictable than weak gels and polymers.

# PERMEABILITY REDUCTION BY GELS

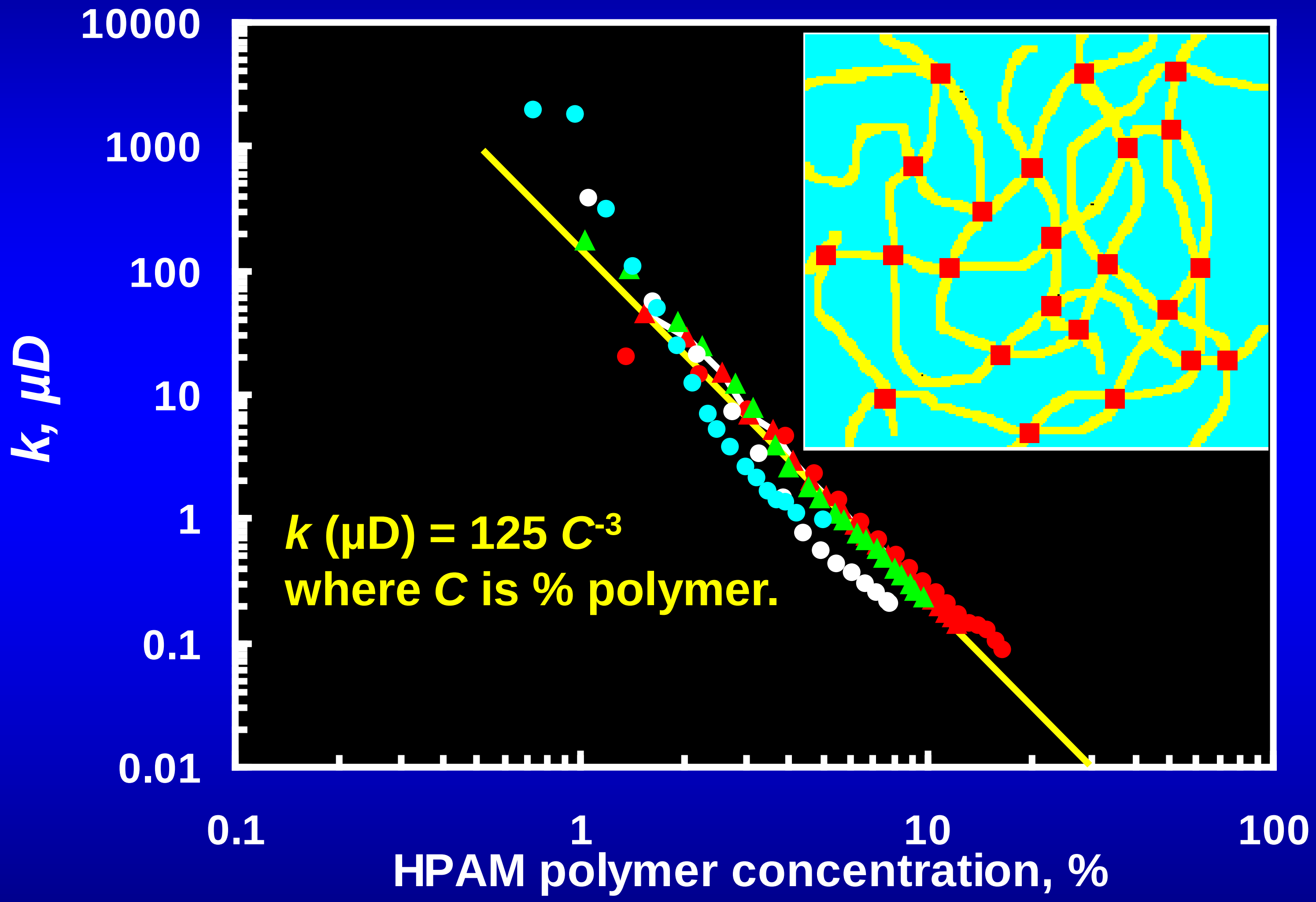
"Strong" gels reduce k of all rocks to the same low value.

"Weak" gels restrict flow in low-k rocks by a factor that is the same or greater than that in high-k rock.



# Water can flow through gels although gel permeability is very low.



## TREATING FRACTURES WITH GELANTS & GELS

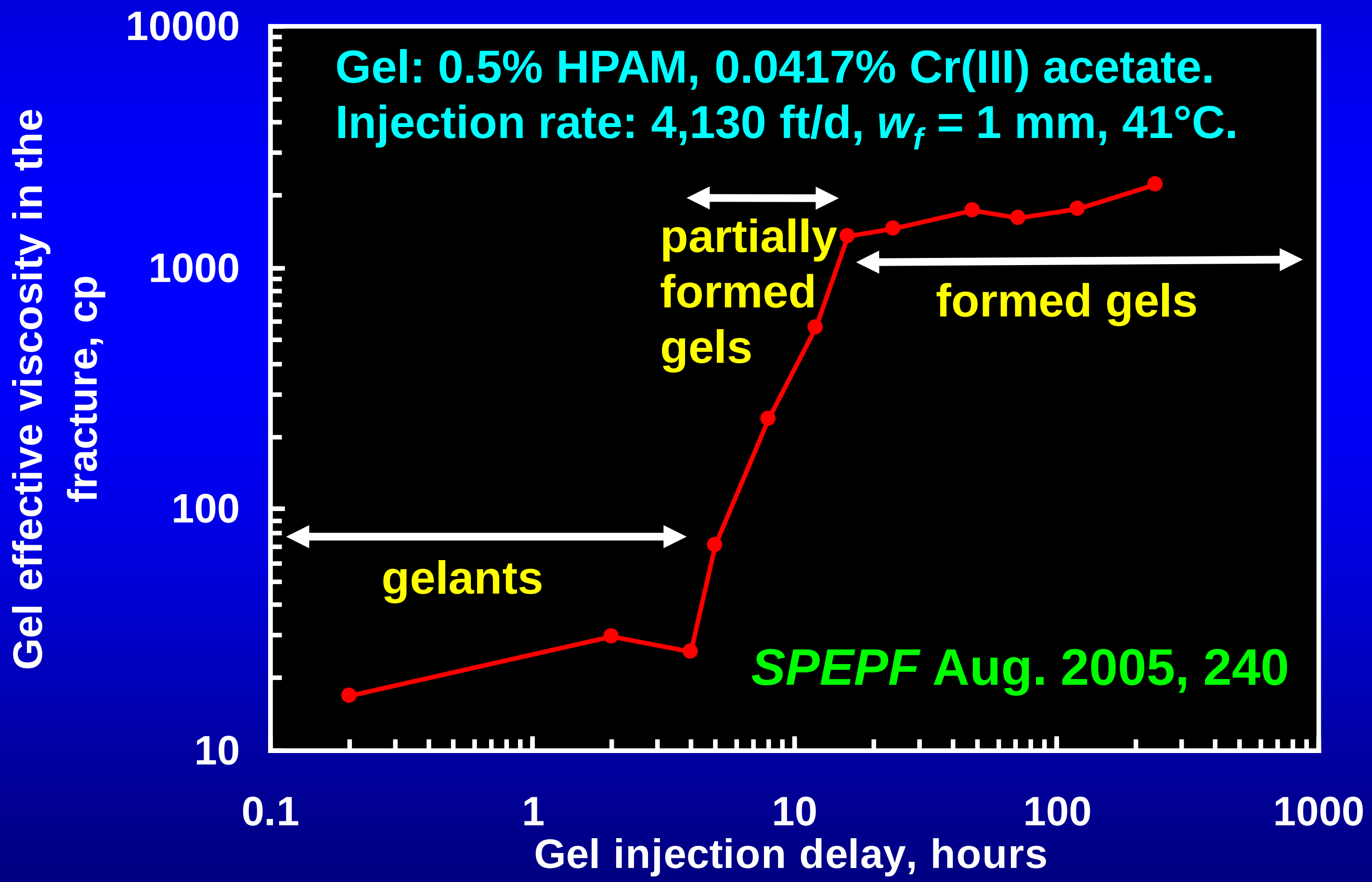
In most field applications, gel formulations:

- Enter the wellhead as gelants (very little crosslinking has occurred).
- Enter the formation as gelants or partially formed gels (i.e., shortly after the gelation time).

In small volume applications, gel formulations exist as fluid gelants or partially formed gels during most of the placement process.

In large volume applications, gel formulations exist as formed gels during most of the placement process.

- Compared with formed gels, gelants show much lower effective viscosities during placement in fractures.
- Low viscosities improve injectivity but often allow gravity segregation during placement in fractures.



## PLACING FORMED GELS IN FRACTURES

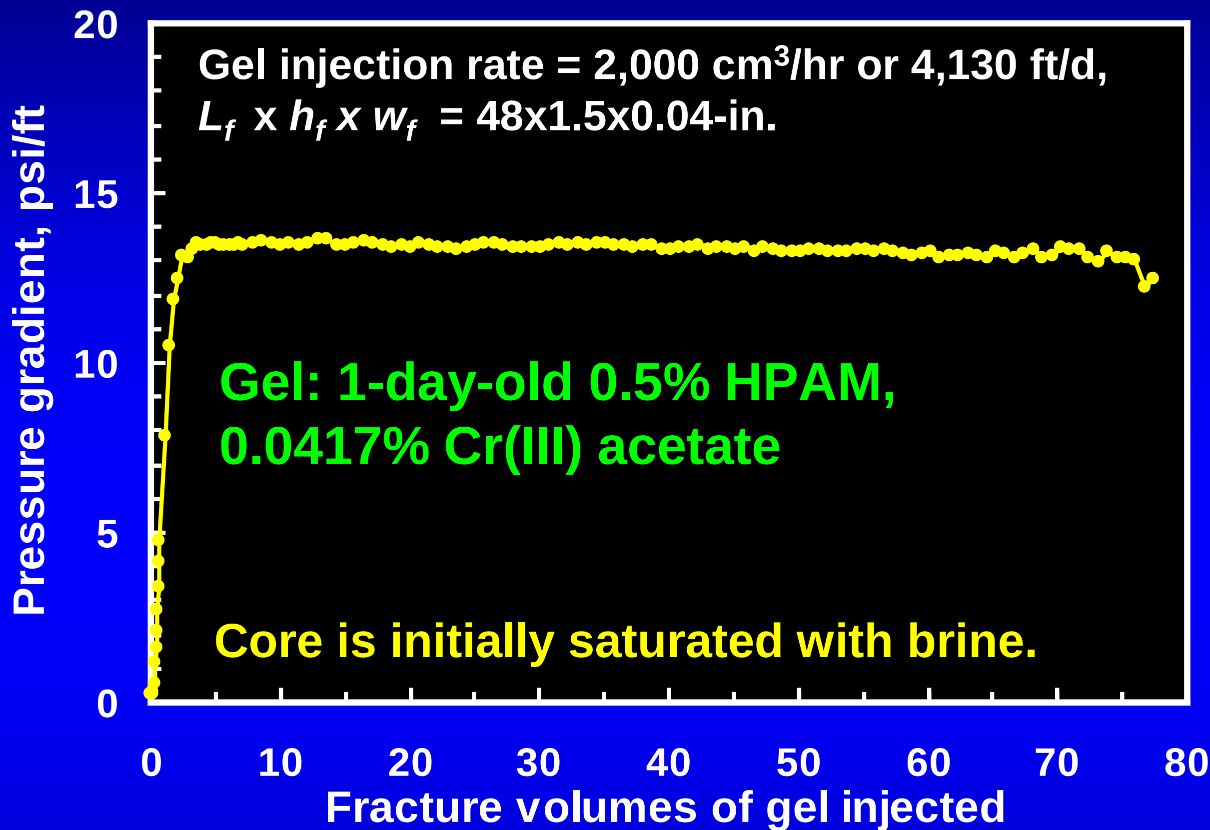
**Successful large-volume Cr(III)-acetate-HPAM gel treatments in naturally fractured reservoirs:**

- **Typically injected 10,000 to 15,000 bbls gel per injection well.**
- **Injection times greater than gelation time by ~100X.**
- **Gels extruded through fractures during most of the placement process.**

- **What are gel properties during extrusion through fractures?**
- **How far can the gels be expected to propagate?**
- **How will the gels distribute in a fracture system?**
- **How much gel should be injected?**

***SPEPF*** **(Nov. 2001) 225-232.**

## Pressure Behavior in a Fracture During Gel Extrusion

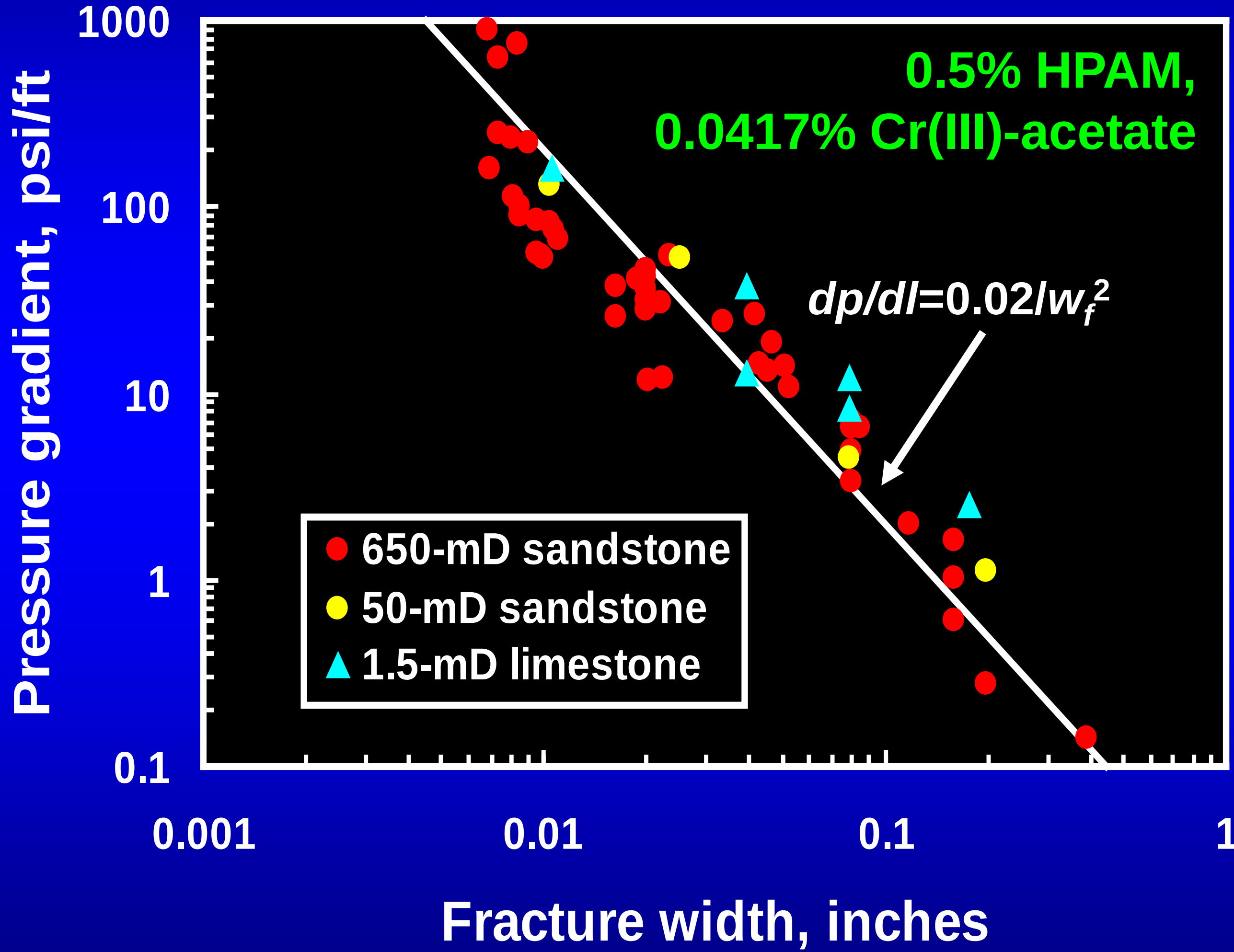



**After gel breaks through at the end of a fracture, pressure gradients are stable (no screen out or progressive plugging).**

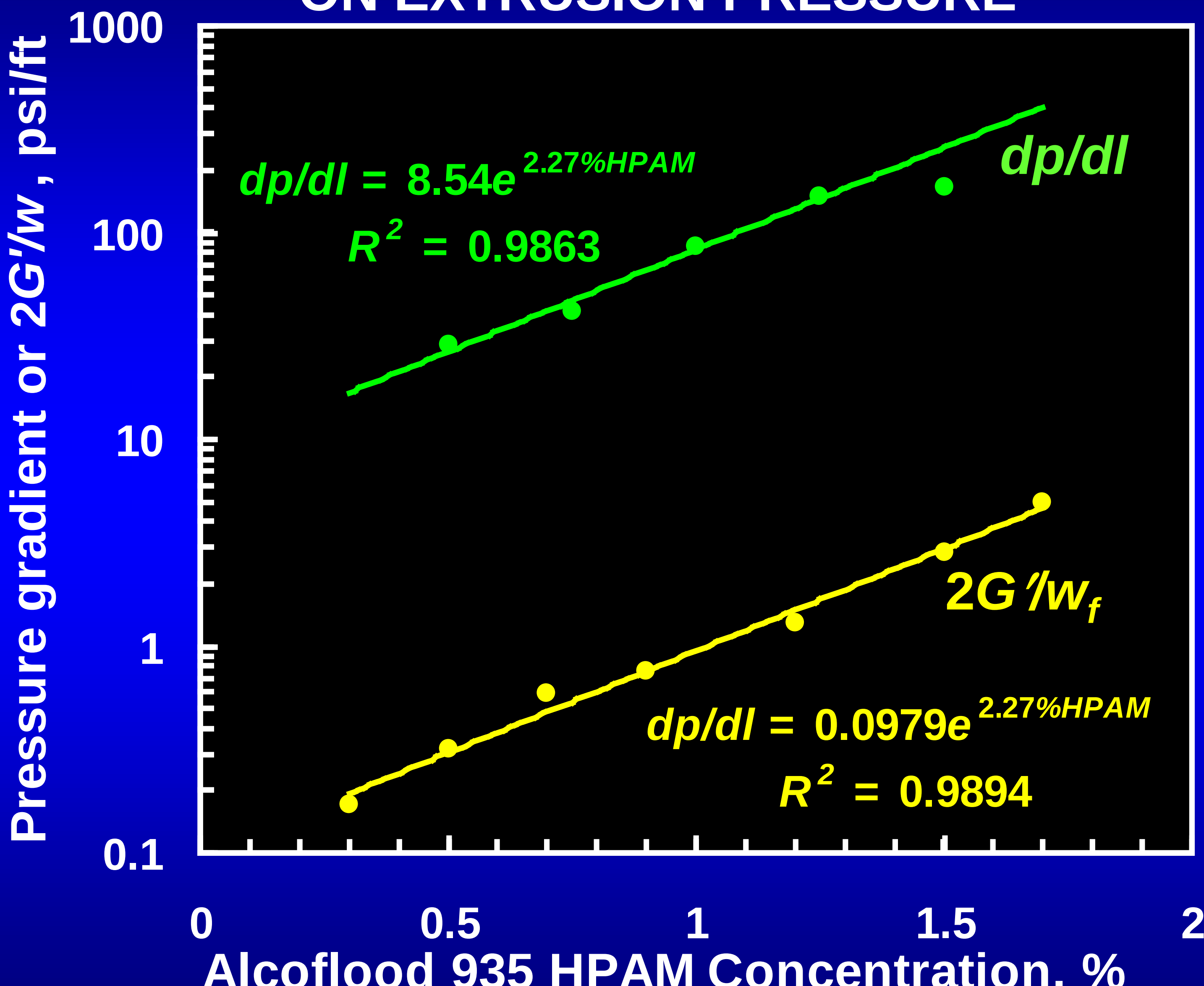
## PROPERTIES OF FORMED GELS IN FRACTURES

- A minimum pressure gradient must be met before a formed gel will extrude through a fracture.
- Once the minimum pressure gradient is met, the pressure gradient during gel extrusion is not sensitive to injection rate.
- The pressure gradient for gel extrusion varies inversely with the square of fracture width.

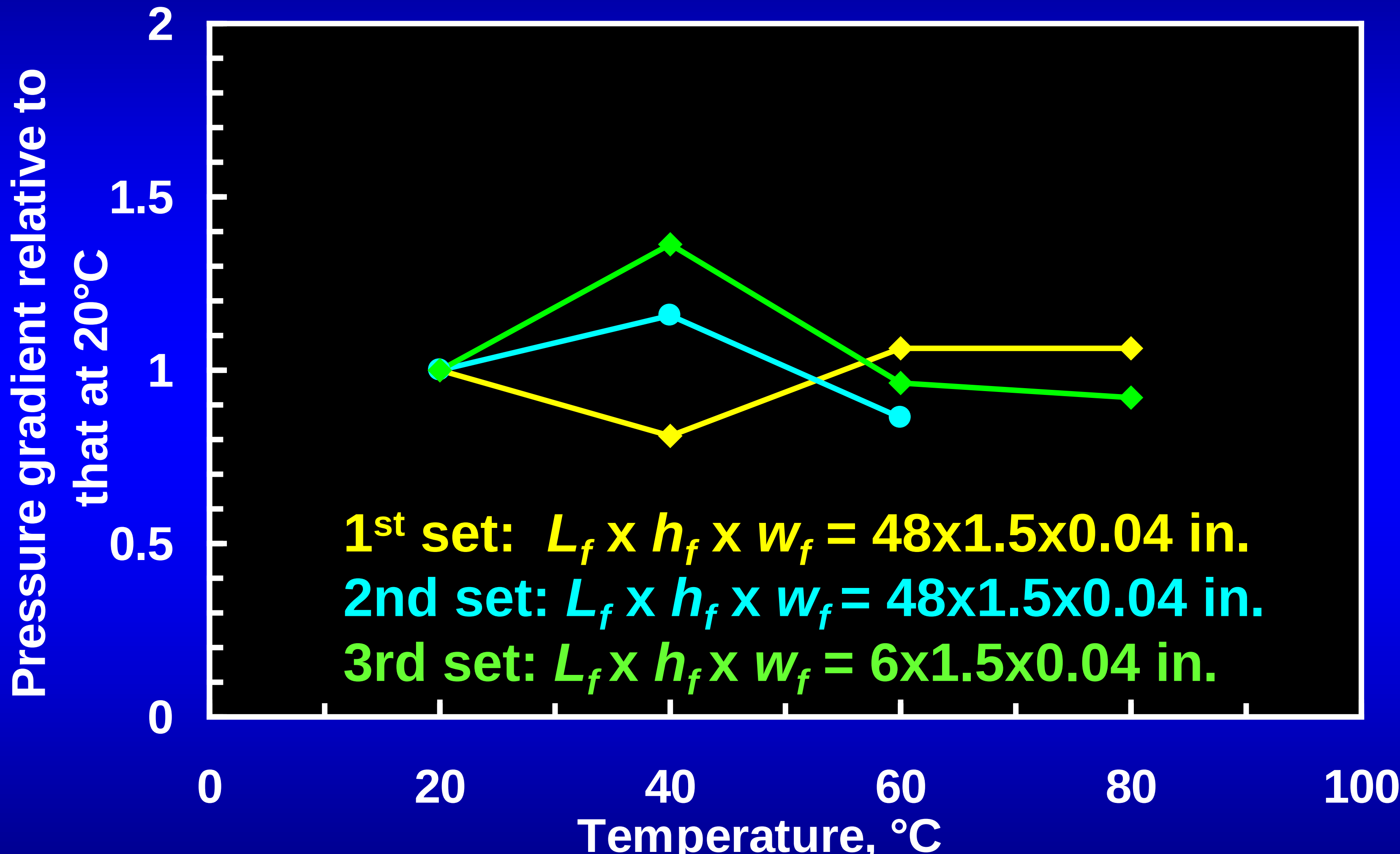
## Pressure gradients required to extrude a Cr(III)-acetate-HPAM gel through fractures



# EFFECT OF POLYMER CONCENTRATION ON EXTRUSION PRESSURE



# PRESSURE GRADIENTS DURING GEL EXTRUSION ARE NOT SENSITIVE TO TEMPERATURE



## GELS DEHYDRATE DURING EXTRUSION

Cr(III)-acetate-HPAM gel

Fracture: $L_f$ = 4 ft, $h_f$ = 1.5 in., $w_f$ = 0.04 in.

Injected 80 fracture volumes of gel (~4 liters)

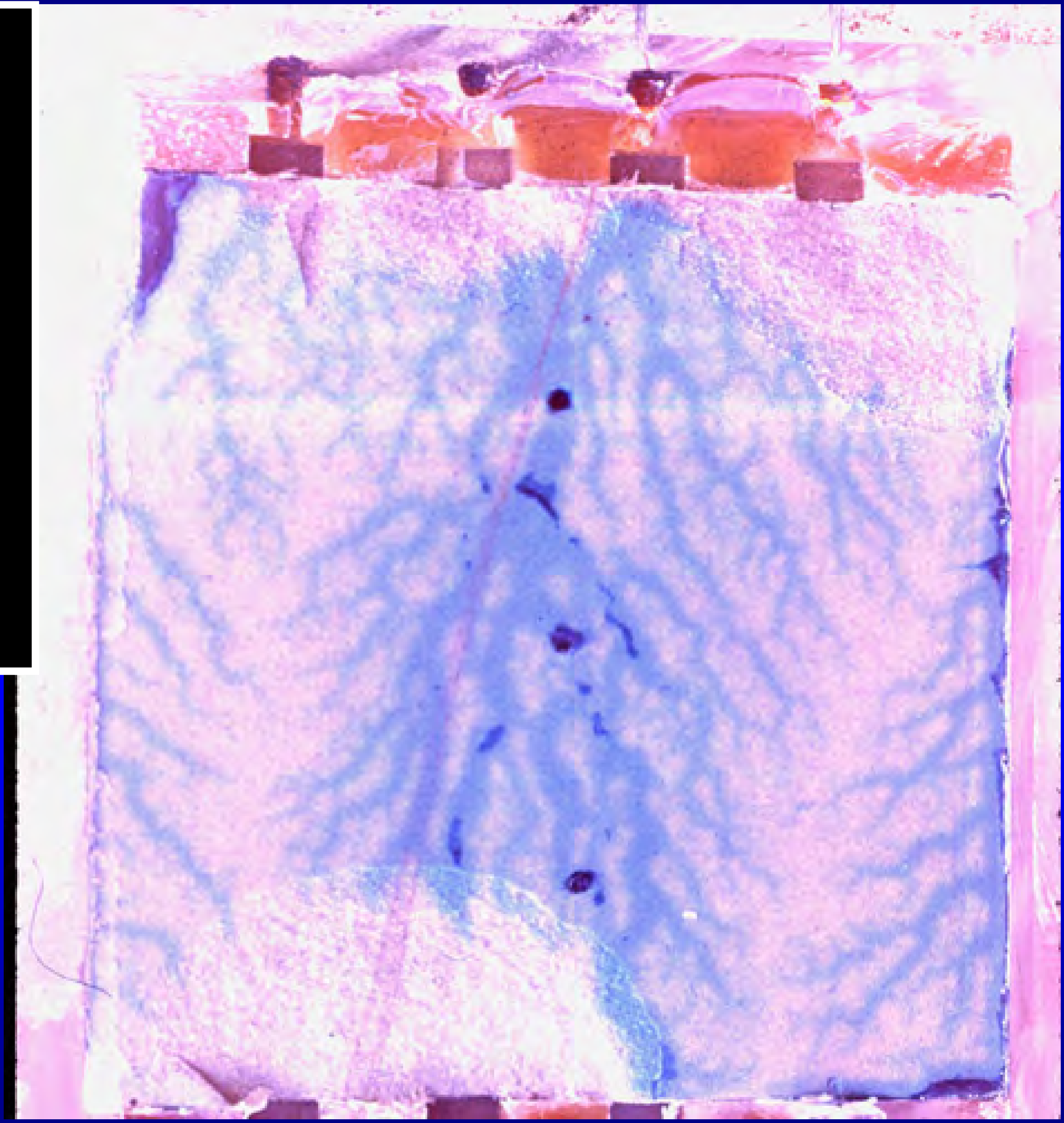
| Injection flux, ft/d | 413 | 1,030 | 4,130 | 33,100 |
|---|---|---|---|---|
| Average *dp/dl*, psi/ft | 28 | 29 | 40 | 18 |
| Gel breakthrough, fracture volumes | 15 | 6.0 | 4.0 | 1.7 |
| Average gel dehydration, $C/C_o$ | 27 | 17 | 11 | 4 |

## PROPERTIES OF Cr(III)-ACETATE-HPAM GEL DURING EXTRUSION THROUGH FRACTURES

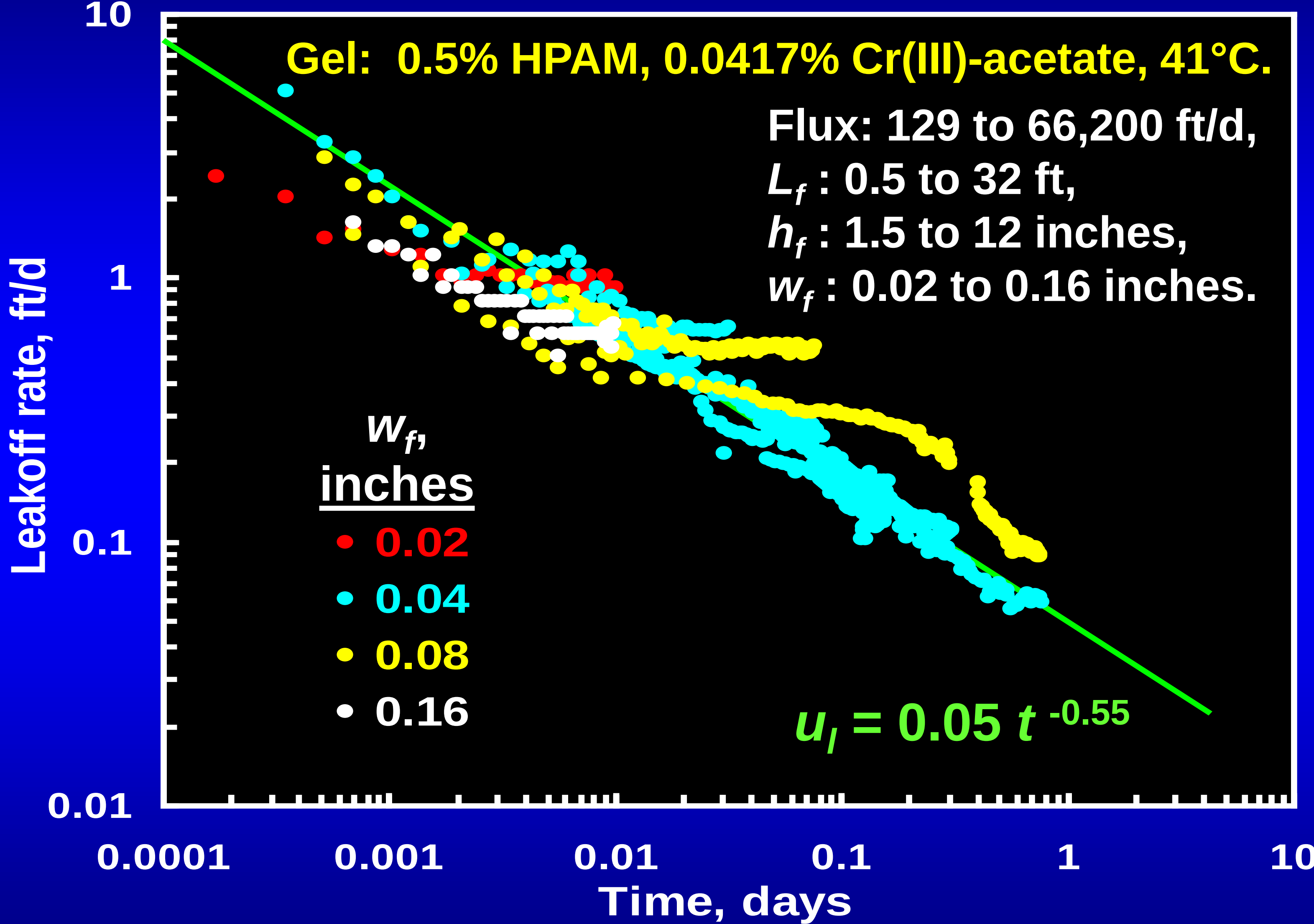
- **Gels dehydrate, thus retarding the rate of movement of the gel front.**
- **Although water leaks off through the fracture faces, crosslinked polymer cannot.**
- **Dehydrated (concentrated) gel is immobile.**
- **Mobile gel is the same as the injected gel.**
- **Mobile gel wormholes through immobile gel.**

**1-day-old 1X Cr(III)-acetate HPAM gel (in blue) wormholing through dehydrated gel that is 12 times more concentrated.**

**Fracture dimensions = 15x15x0.1 cm**



## Water Leakoff Rates From Gel During Extrusion



## WHAT IS THE RATE OF GEL PROPAGATION THROUGH A FRACTURE?

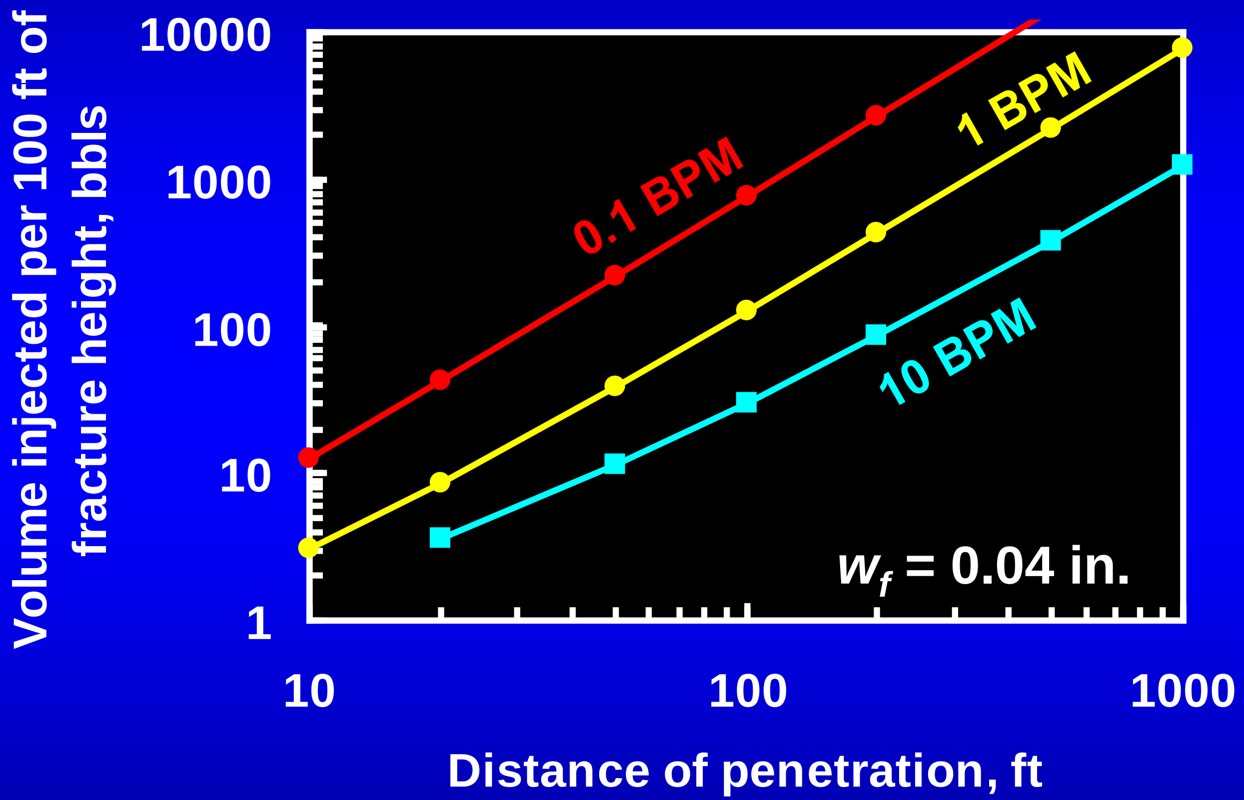
- **The rate of water loss from the gel is given by: $u_l = 0.05\ t^{-0.55}$. Combine with a mass balance.**

- **Assuming two fracture wings, the rate of gel propagation, $dL/dt$, is:**

$$dL/dt = [q_{tot} - 4h_f L\ u_l\ ] \ /\ [2\ h_f\ w_f]$$

$$dL/dt = [q_{tot} - 4h_f L\ 0.05\ t^{-0.55}] \ /\ [2\ h_f\ w_f]$$

## Predictions in Long Two-Wing Fractures



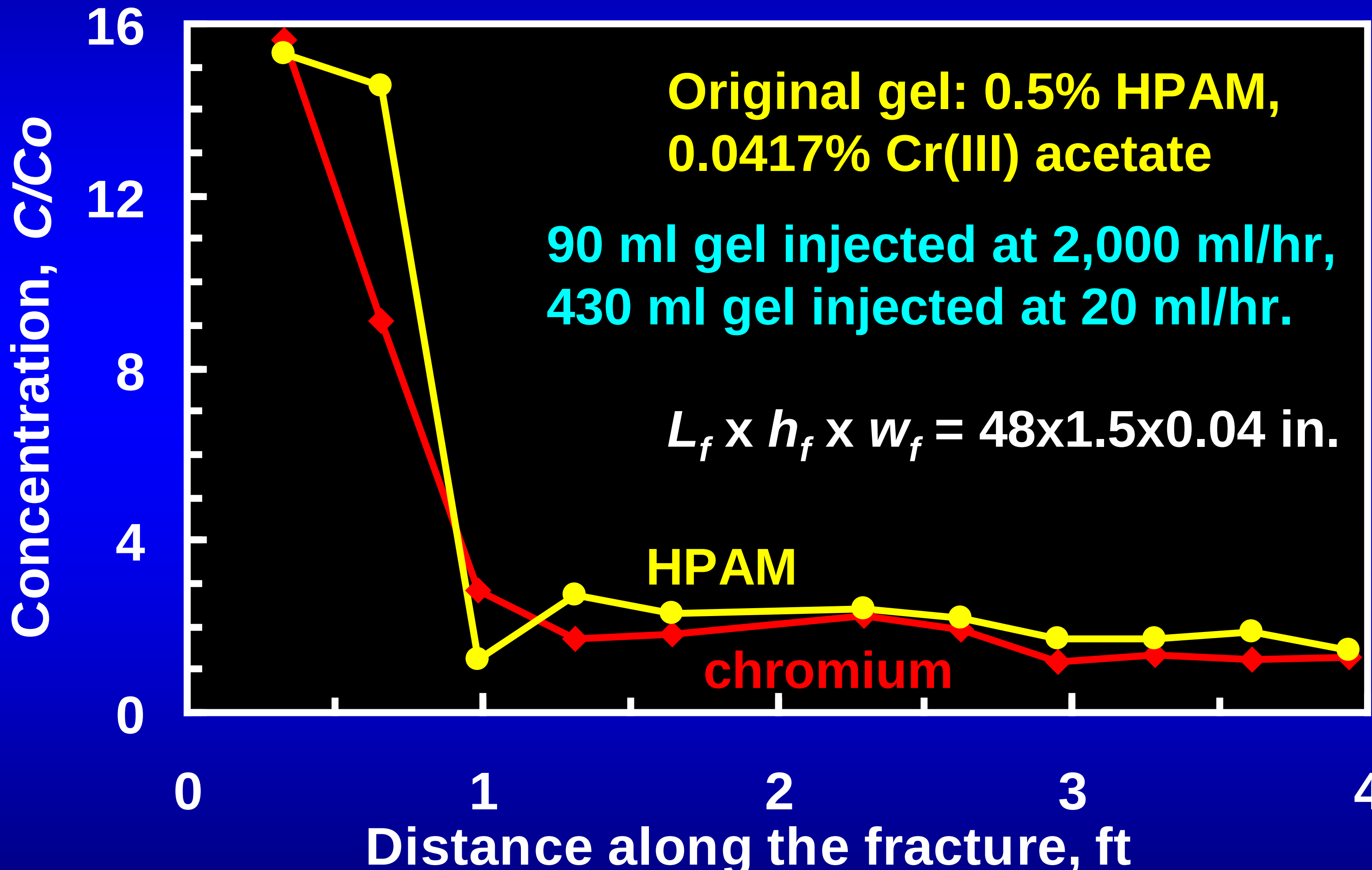
- The degree of gel dehydration depends on injection rate and time.

- When injecting gel into a fracture, can a more rigid gel plug be formed in the near wellbore portion of the fracture simply by reducing the injection rate?


Gel injected at low rate: maximum dehydration for greater rigidity and strength.

## COMPOSITION OF GEL IN THE FRACTURE.

**Injection rate = 2,000 ml/hr until fracture filled with gel.**
**Then the rate was dropped to 20 ml/hr.**



## PROPERTIES OF FORMED GELS DURING EXTRUSION THROUGH FRACTURES

- Dehydration limits the distance of GEL penetration along a fracture.
- For a given total volume of GEL injection, the distance of gel propagation will be maximized by injecting at the highest practical injection rate.
- To double the distance of GEL penetration into a long fracture, the GEL volume must be tripled.
- More concentrated, rigid GELS can be formed by injecting slower—decreasing the probability of gel washout.

## Dehydration of Gels in Fractures by Imbibition
### (Brattekas: SPE 153118, 169064, 173749, 180051, 190256)

- Water-wet rock can suck water out of gels in fractures—thus collapsing those gels.
- This action could be of value for fractures in oil zones because you want those fractures to remain open to flow.
- For fractures in water zones, if no oil is present, no capillary action occurs so the gels remain intact in the fracture and flow remains restricted.
- Depending on the salinity of the gel and water post-flush, the flow capacity of gel-filled fractures can be varied.

## PRE-FORMED PARTICLE GELS (PPGs) (Bai et al.)

- Are crosslinked polymers that are dried and ground to a desired particle size offsite.
- Swell upon contact with water.
- Swell less with more saline brines.
- Dehydrate during extrusion through fractures.
- Are expected to show performance similar to other preformed gels [e.g., extruded Cr(III)-acetate-HPAM].
- Bai references: SPE 190364, 190357, 180388, 188384, 188023, 187152, 182795, 181545, 180386, 179705, 176728, 176429, 175058, 174645, 172352, 171531, 170067, 169159, 169107, 169106, 169078, 164511, 129908, 115678, 113997, 89468, 89389.

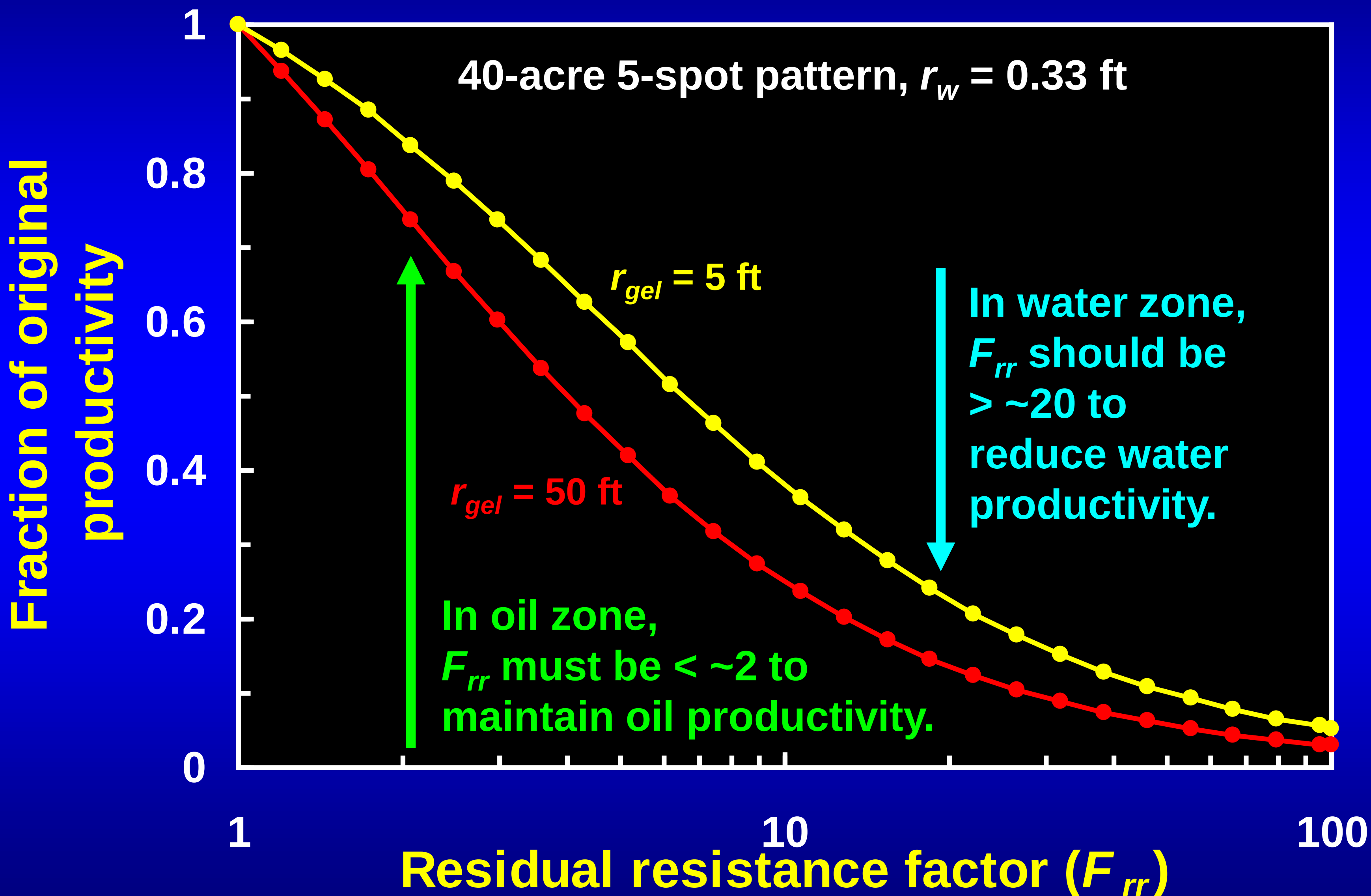
# DISPROPORTIONATE PERMEABILITY REDUCTION

- Some gels can reduce $k_w$ more than $k_o$ or $k_{gas}$.
- Some people call this “disproportionate permeability reduction” or “DPR”. Others call it “relative permeability modification” or “RPM”. It is the same thing!
- This property is only of value in production wells with distinct water and hydrocarbon zones. It has no special value in injection wells!!!
- NO KNOWN polymer or gel will RELIABLY reduce $k_w$ without causing some reduction in $k_o$ !!!

- **IDEALISTIC GOAL OF WATER SHUTOFF TECHNOLOGY:** **Materials that can be injected into any production well (without zone isolation) and substantially reduce the water productivity without significantly impairing hydrocarbon productivity.**

- **Most previous attempts to achieve this goal have used adsorbed polymers or "weak gels" and most previous attempts have focused on unfractured wells.**

# Radial Flow Requires That $F_{rro}$ < 2 and $F_{rrw}$ > 20



## Problems with adsorbed polymers and weak gels (suspensions of gel particles):

- They show large variations in performance.
- $F_{rr}$ values are greater in low-k rock than in high-k rock.
- $F_{rro}$ values must be reliably less than 2 for radial flow applications.

## Why do adsorbed polymers and weak gels show large performance variations?

- Mineralogy varies within rock, so the level of adsorption also varies.

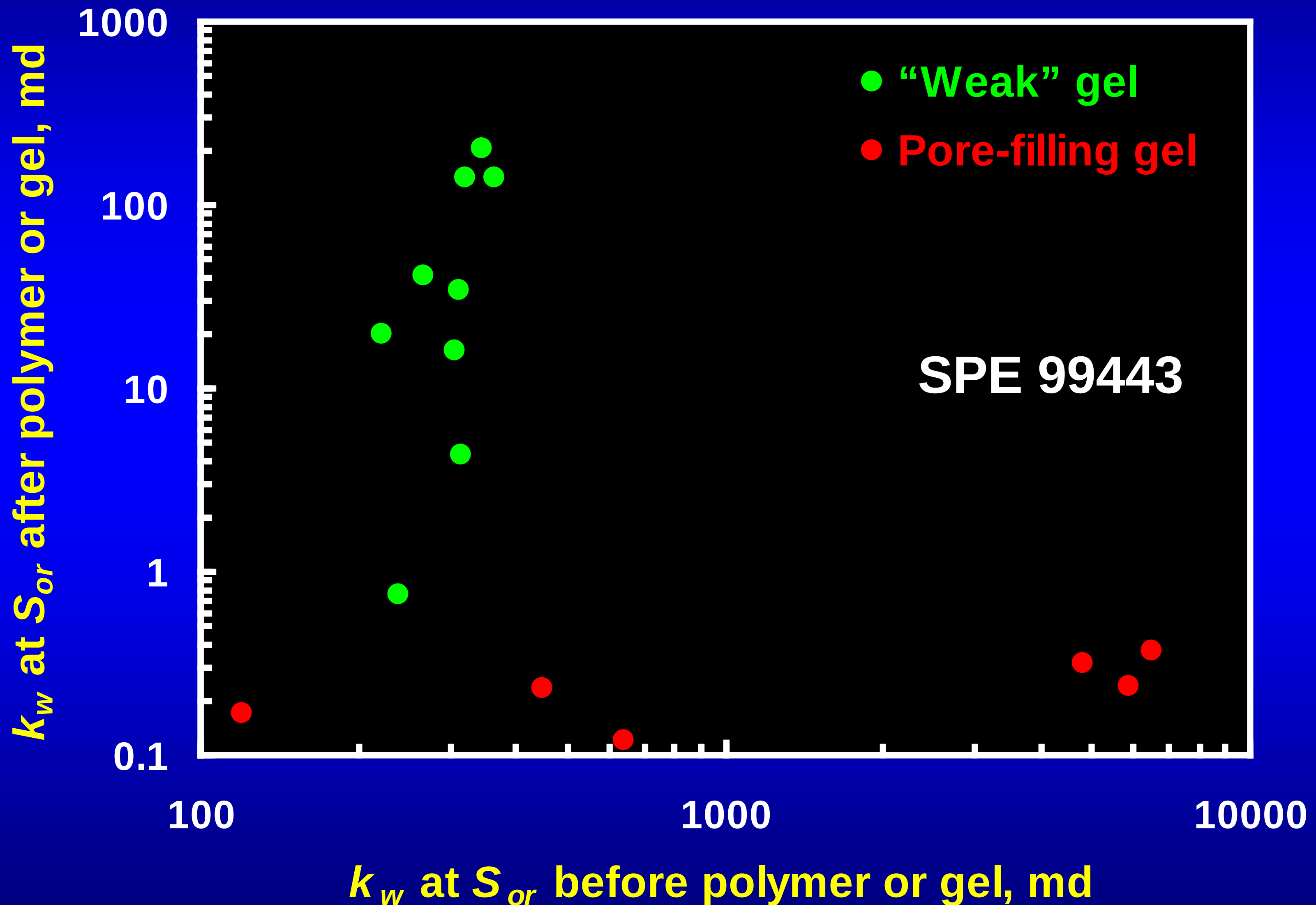
- Particle suspensions (e.g., weak gels) often have uncontrolled size distributions.

- Pore size distributions vary in rock.

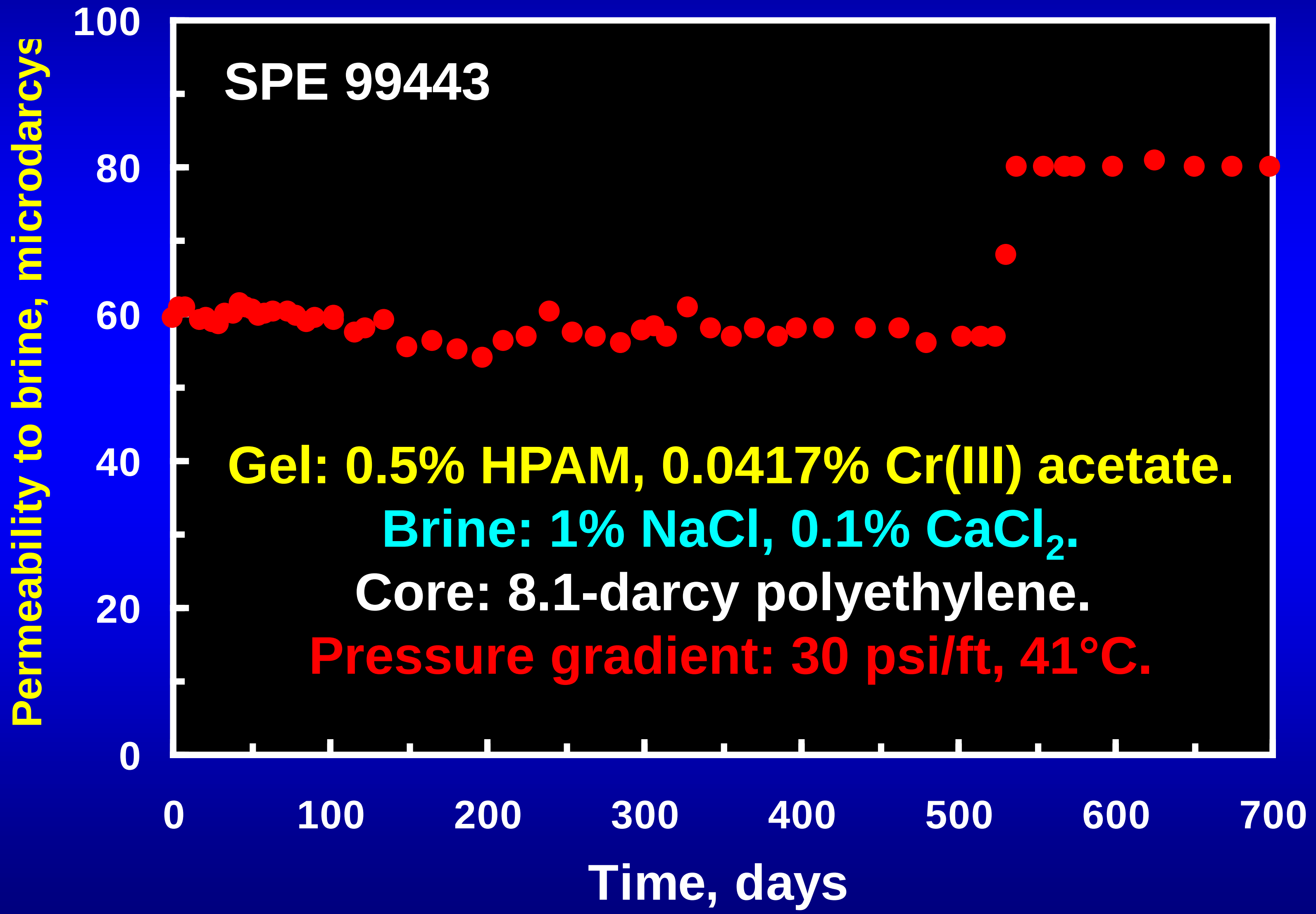
# Conceptual solution to variations and *k*-dependence of gel performance:
## USE A PORE FILLING GEL.

- Aqueous gels exhibit a finite, but very low permeability to water.
- If all aqueous pore space is filled with gel, $k_{gel}$ will dominate $k_w$ .
- So, rock with virtually any initial $k_w$ should be reduced to the same final $k_w$ .

## Pore filling gels are more reliable than adsorbing polymers or weak gels.



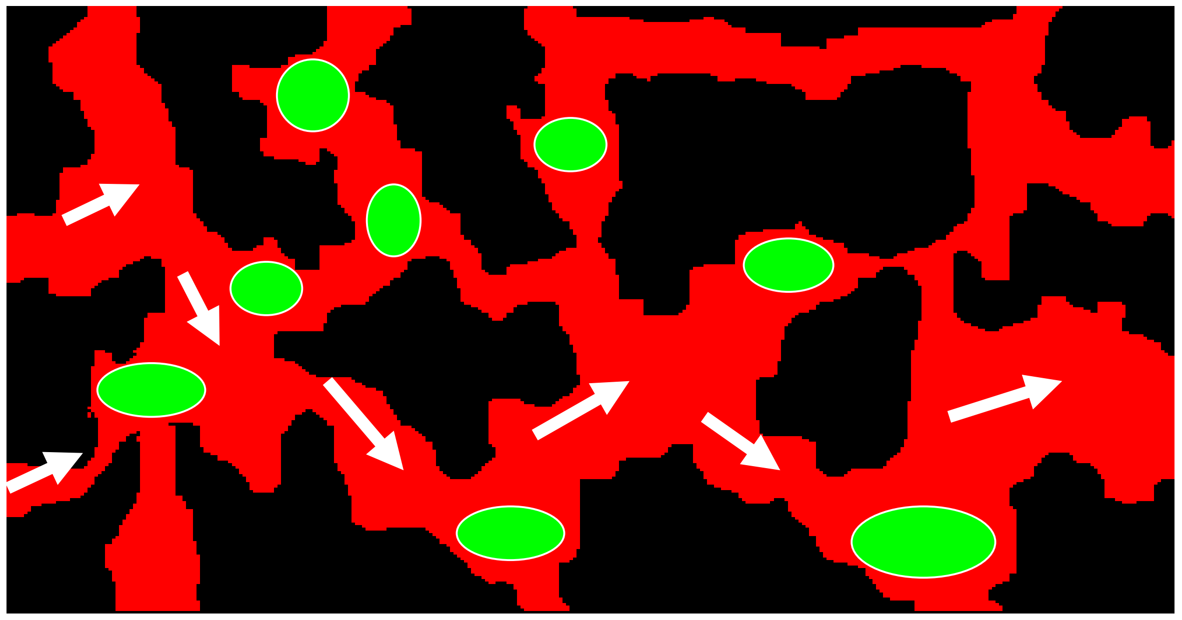
# $k_w$ can be quite stable to brine throughput and time.



# WHY DO GELS REDUCE $k_w$ MORE THAN $k_o$?

**FIRST WATER FLOW AFTER GEL PLACEMENT**

***SPEREE*** **(Oct. 2002) 355–364;** ***SPEJ*** **(Jun. 2006)**



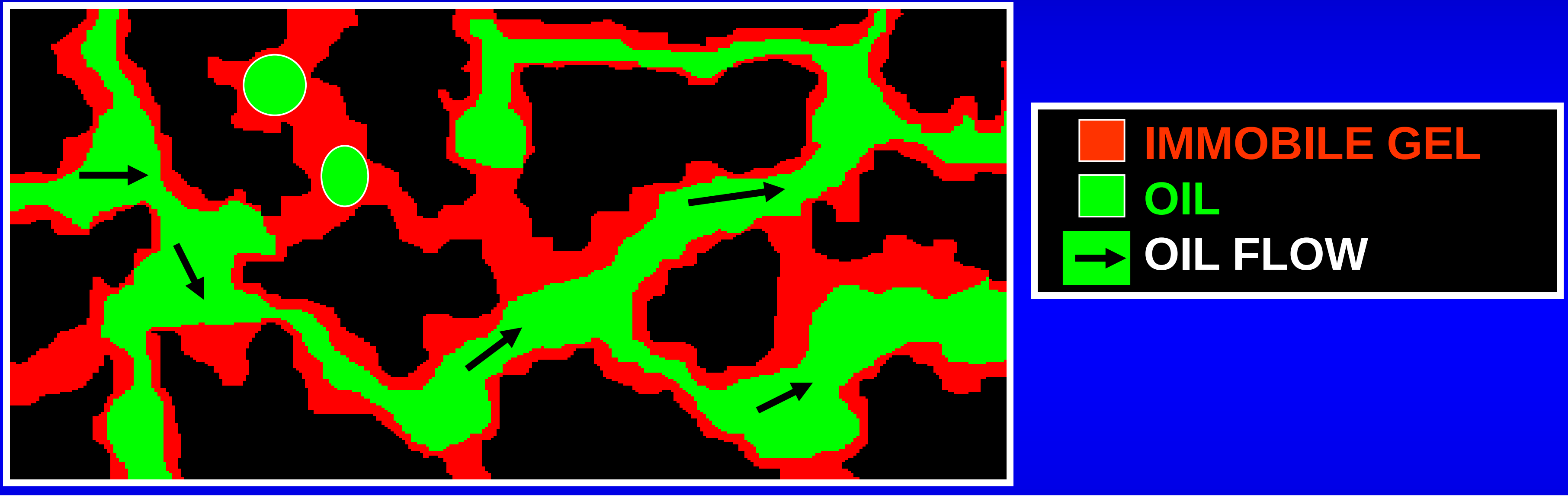
- IMMOBILE GEL
- OIL
- WATER FLOW THROUGH GEL

- **Strong gels fill all aqueous pore space.**
- **Water must flow through the gel itself.**
- **Gel permeability to water is typically in the µd range.**
- **Water residual resistance factor ($F_{rrw}$) is typically > 10,000.**

# WHY DO GELS REDUCE $k_w$ MORE THAN $k_o$?

## FIRST OIL FLOW AFTER GEL PLACEMENT

*SPEREE* (Oct. 2002) 355–364; *SPEJ* (Jun. 2006)

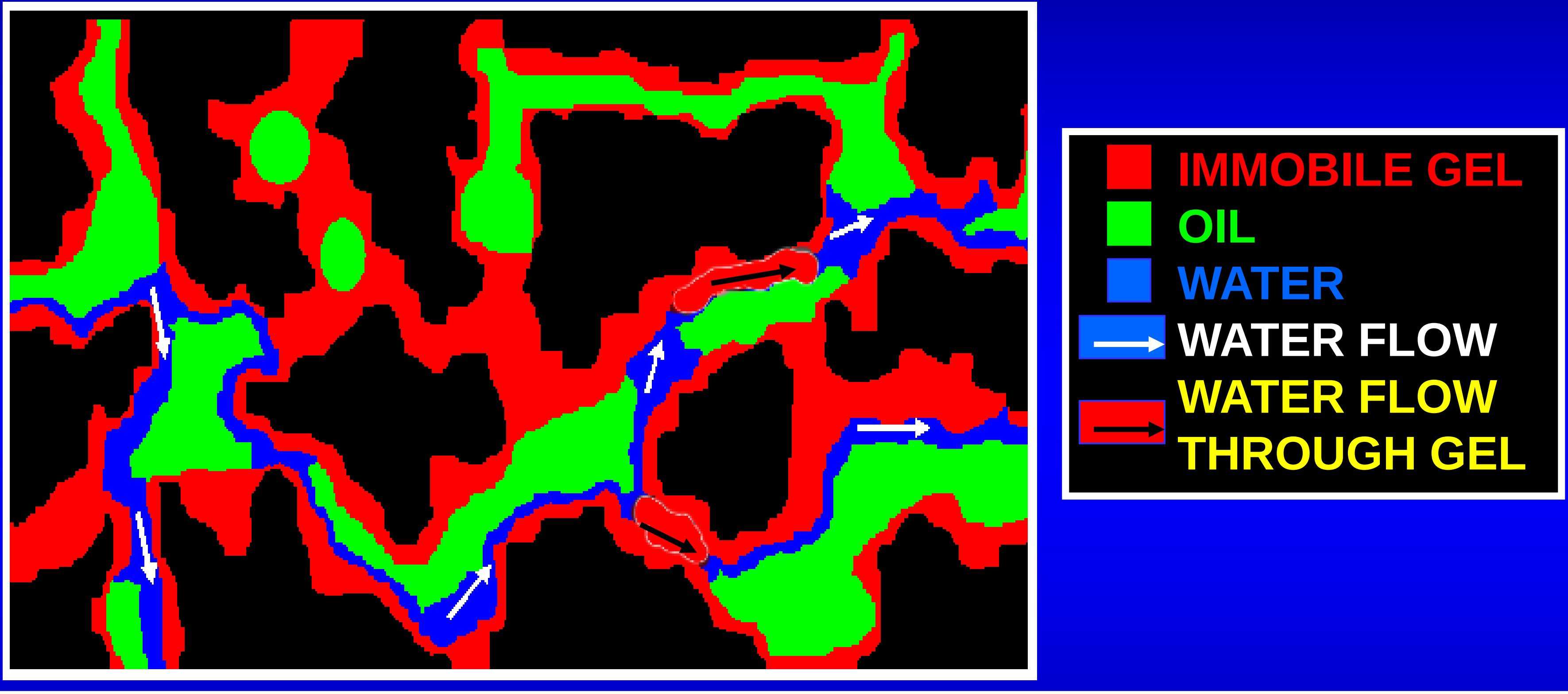




- Even with low pressure gradients, oil forces pathways through by destroying or dehydrating the gel.
- These oil pathways allow $k_o$ to be much higher than $k_w$.
- Even so, $k_o$ is lower than before gel placement.

# WATER FOLLOWING OIL AFTER GEL PLACEMENT

*SPEREE* (Oct. 2002) 355–364; *SPEJ* (Jun. 2006)




- Gel traps more residual oil.
- Increased $S_{or}$ causes lower $k_w$ ($k_w \approx 1000$ times lower after gel than before gel placement).

## A Challenge:

$F_{rro}$ must be reliably < 2 for radial applications, but $F_{rrw}$ must be reliably high (>100) for linear flow applications.

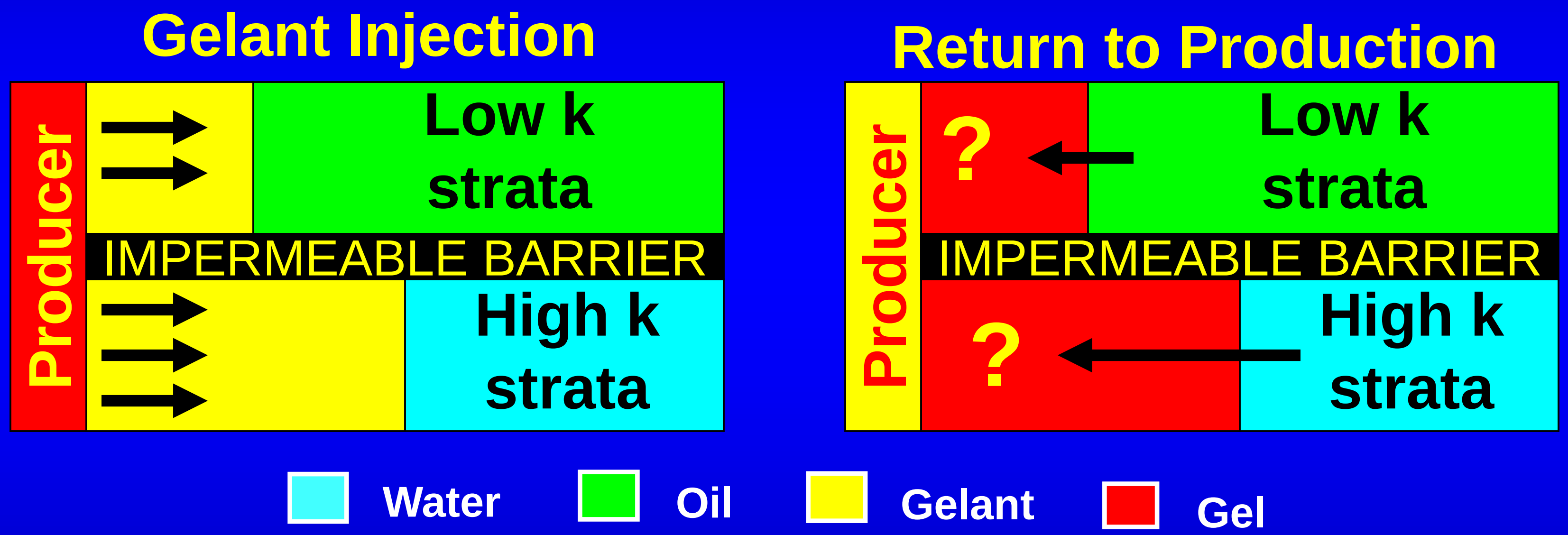
Can pore-filling gels meet this challenge?

## $F_{rrw}$ and final $F_{rro}$ values for pore filling Cr(III)-acetate-HPAM gels in Berea sandstone.

| Pre-gel $k_w$, md | HPAM in gel, % | Post-gel $k_w$, md | $F_{rrw}$ | Final $F_{rro}$ |
|---|---|---|---|---|
| 356 | 0.5 | 0.015 | 23,700 | 1.2 |
| 389 | 0.5 | 0.005 | 77,800 | 1.2 |
| 31 | 0.5 | 0.007 | 4,430 | 2.2 |
| 40 | 0.4 | 0.019 | 2,110 | 2.0 |
| 270 | 0.3 | 0.055 | 4,980 | 1.7 |

SPE 99443

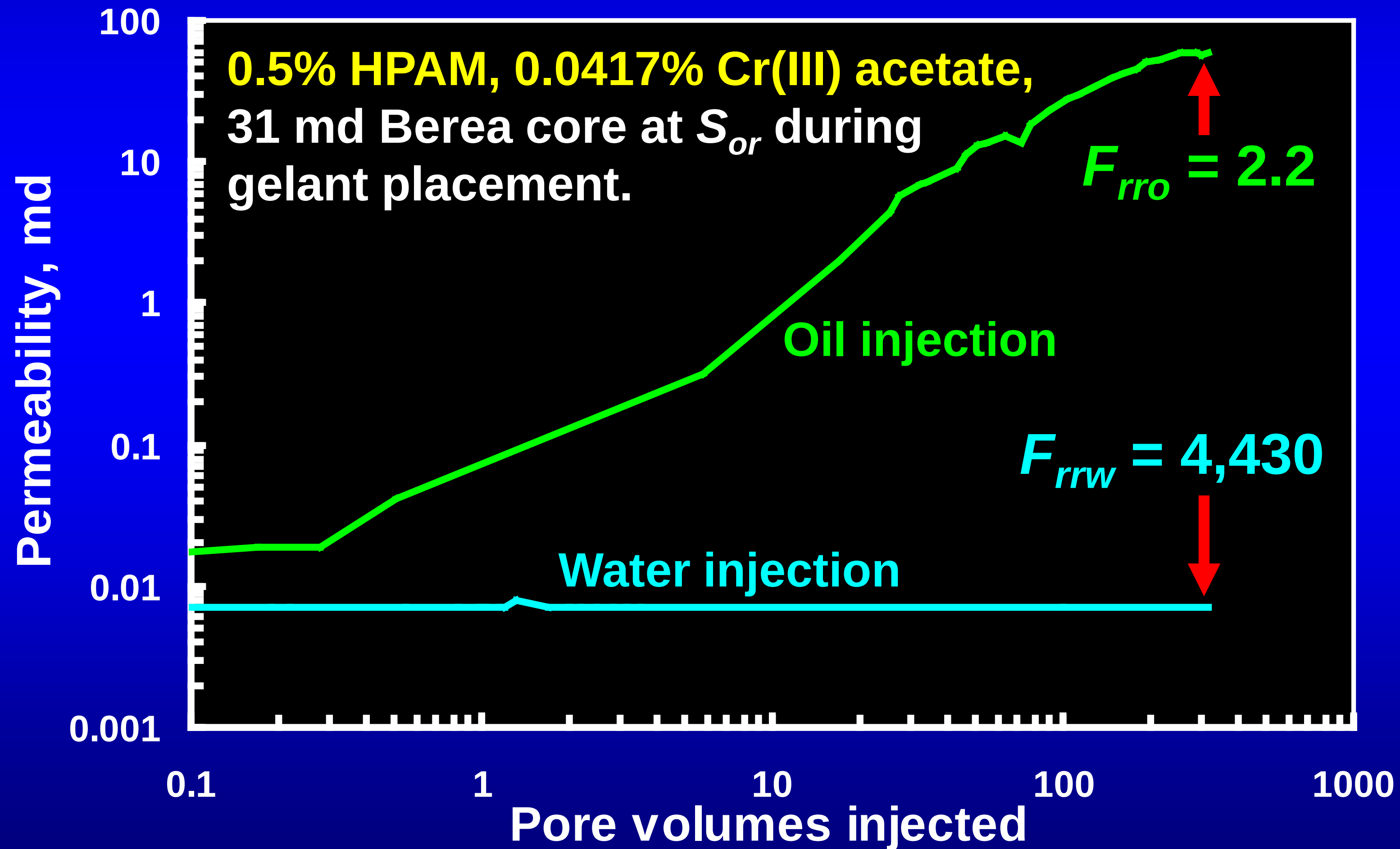
- Polymers and gelants usually enter both oil and water strata when placed.
- Oil must flow or wormhole through the water or gel bank to reach the well.



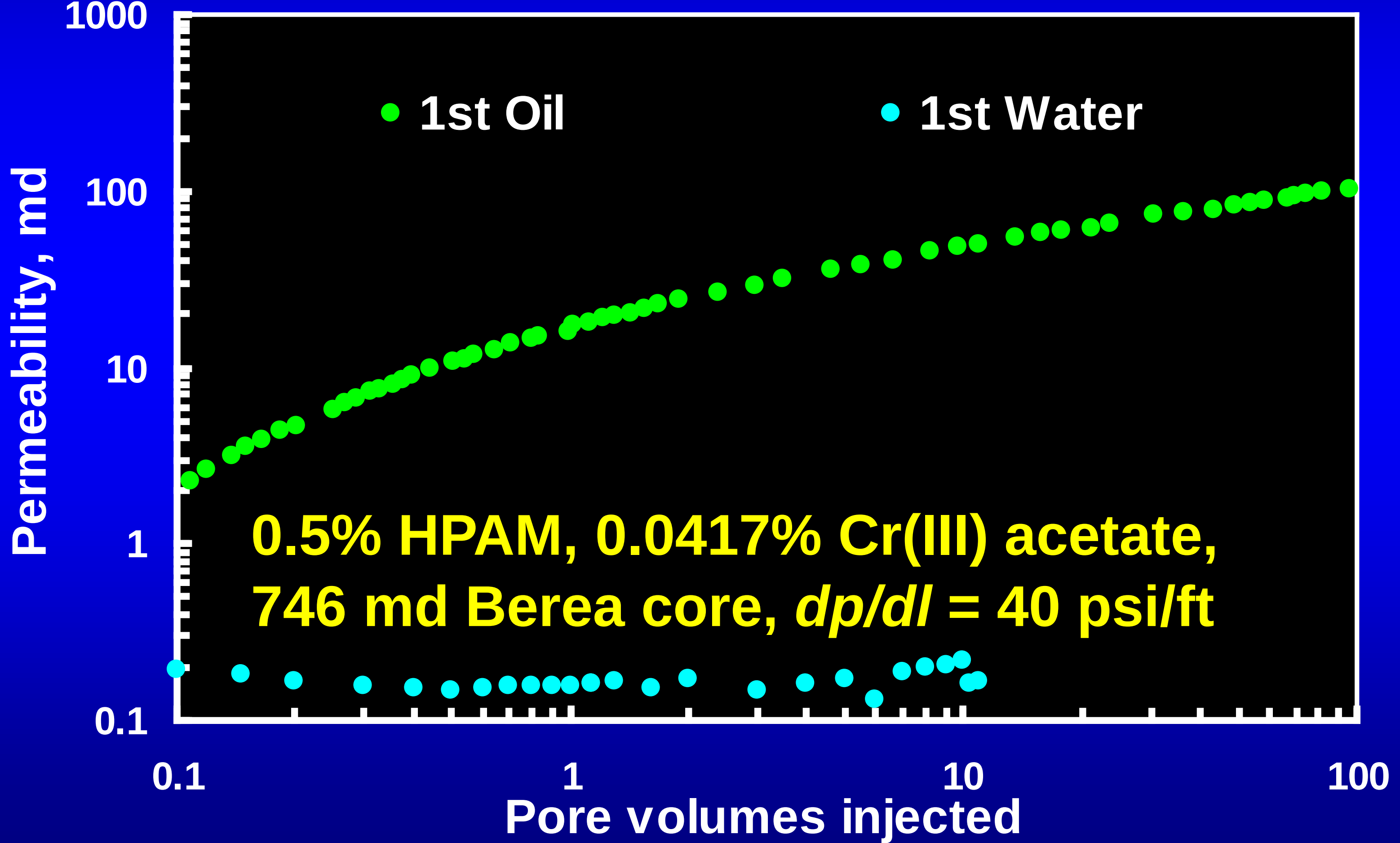

- For some polymers and gels, $k_w << k_o$.
- However, some time is needed for oil rates to recover.

## After gel placement, during water or oil flow,

- $k_w$ stabilized very quickly at a low value.
- $k_o$ rose gradually to a high value.

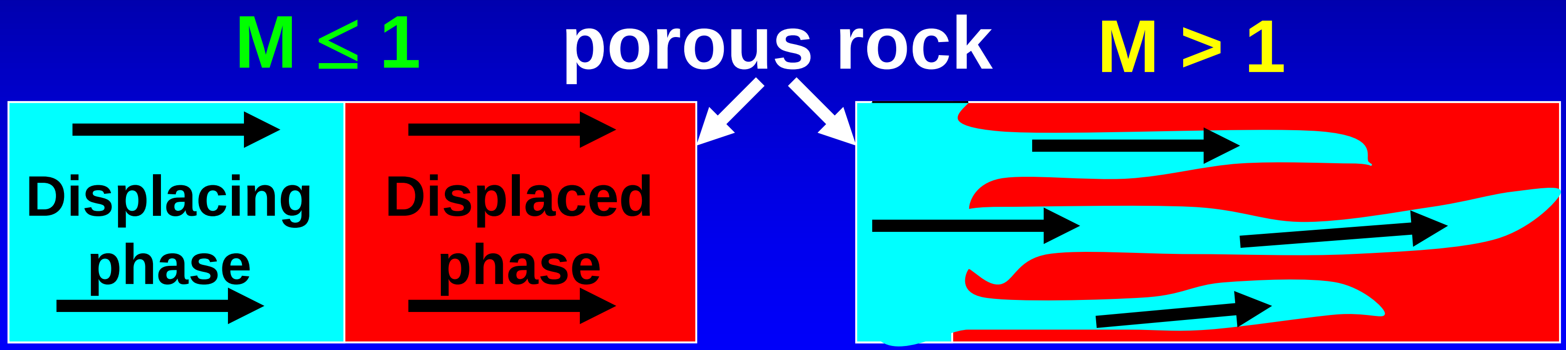


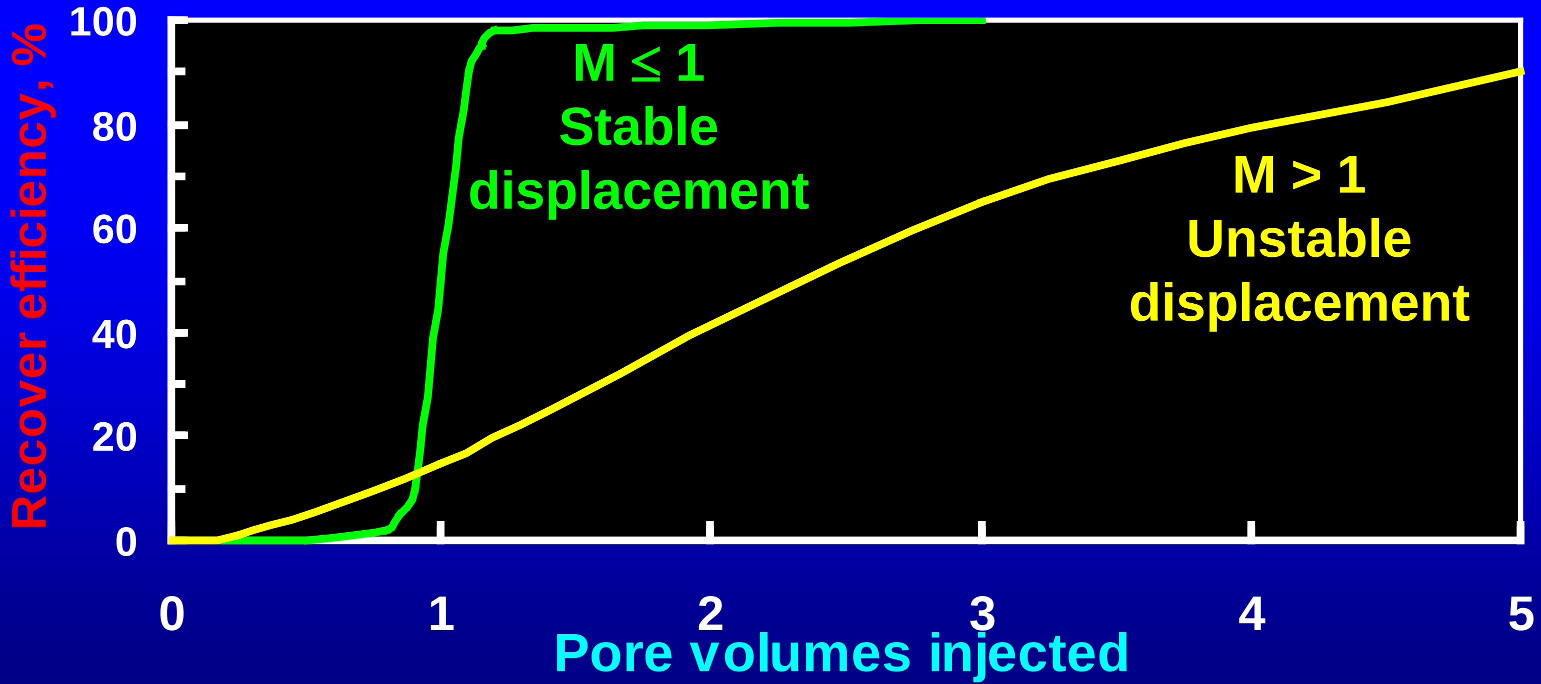
1. After gel placement, $k_o$ rose from 2 to 105 md in 100 PV ($F_{rro}$ = 4.8 @ 100 PV).
2. $k_w$ stabilized at 0.17 md very quickly ($F_{rrw}$ = 706).



# MOBILITY RATIO

$$M = (k/\mu)_{\text{displacing phase}} \, / \, (k/\mu)_{\text{displaced phase}}$$

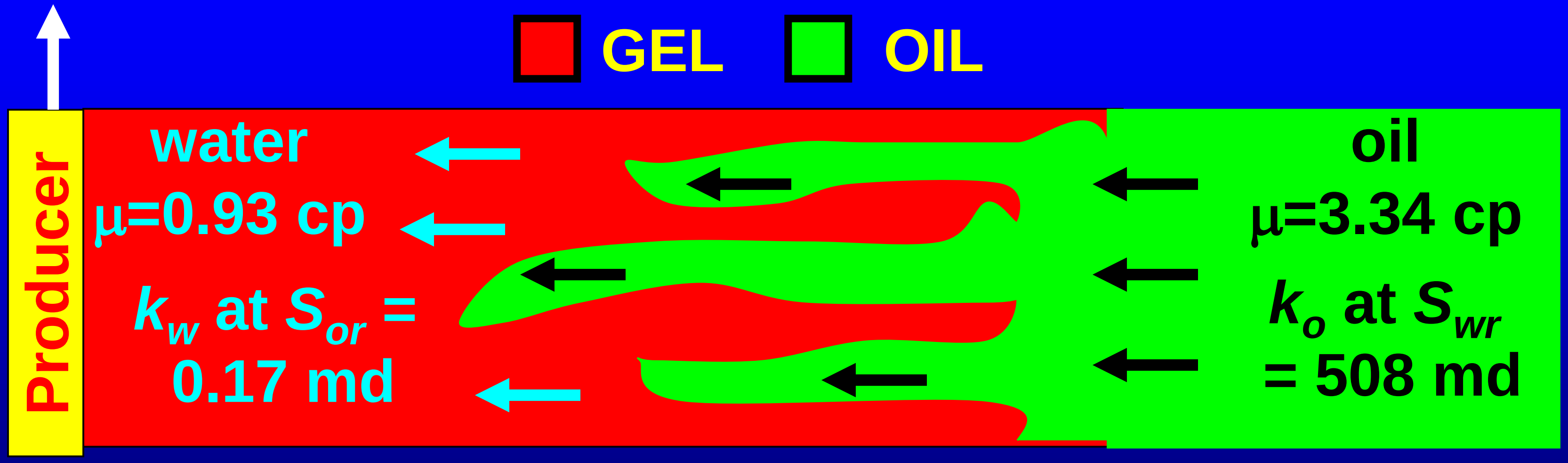


## What happens in an oil zone when a well is returned to production AFTER gel placement?

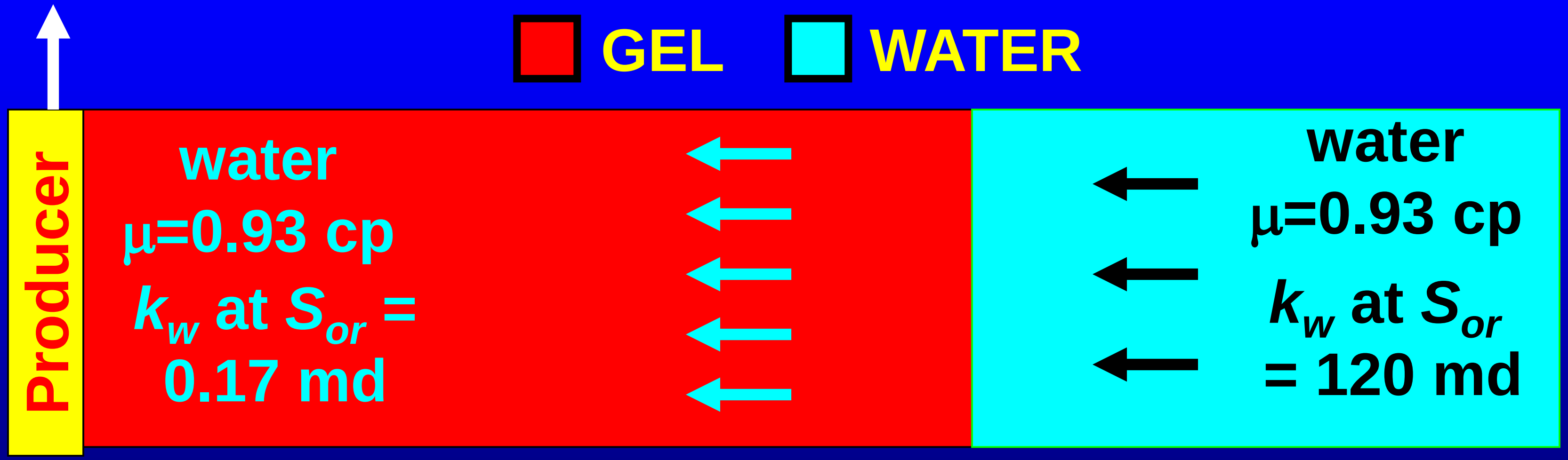
- Mobility ratio, M = $(k_o/\mu_o)/(k_w/\mu_w)$ = (508/3.34)/(0.17/0.93) = 830

- Displacement is very UNFAVORABLE!



**What happens in a water zone when a well is returned to production AFTER gel placement?**

- Initially mobility ratio also looks very unfavorable.
- HOWEVER, once the water enters the gel, it becomes part of the gel. So no viscous fingers form, and the displacement remains stable!



# DISPROPORTIONATE PERMEABILITY REDUCTION

- Pore-filling gels show much more reproducible behavior than weak gels or adsorbed polymers.
- For pore-filling gels, the first-contact brine residual resistance factor is typically determined by the inherent permeability of the gel to water.
- Re-establishing high $k_o$ values requires large oil throughput.
- Achieving large throughput values in short times requires small distances of gelant penetration.

# WHY CHOOSE ONE MATERIAL OVER ANOTHER?

- Cost
- Availability
- Sensitivity of performance to condition or composition variations
- Blocking agent set time
- Permeability reduction provided to water
- Permeability reduction provided to oil or gas
- Ability to withstand high-pressure gradients in porous rock
- Ability to withstand high-pressure gradients in fractures or voids
- Rheology and/or filtration properties
- Ability to penetrate into fractures or narrow channels behind pipe
- Stability at elevated temperatures
- Environmental concerns

# PLACEMENT CONCEPTS

## Objective of Water Shutoff Treatments

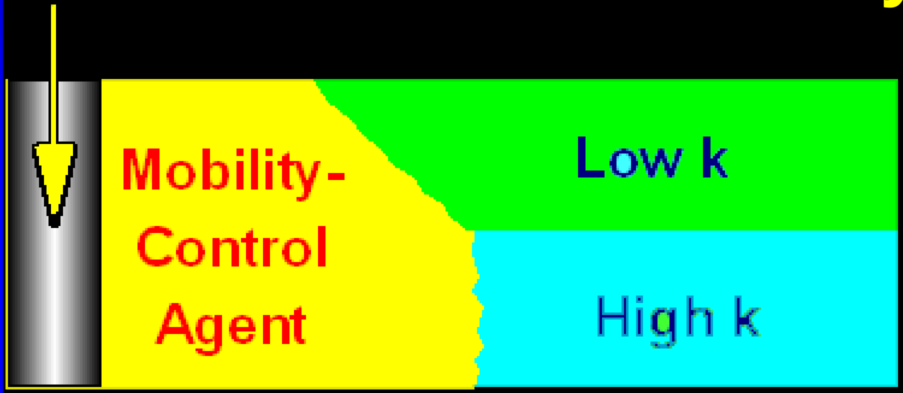
- Objective is to shut off water without seriously damaging hydrocarbon productive zones.
- Want to maximize blocking agent penetration into water-source pathways, while minimizing penetration into hydrocarbon zones.
- Want to maximize permeability reduction in water-source pathways, while minimizing permeability reduction in hydrocarbon zones.

# GEL TREATMENTS ARE NOT POLYMER FLOODS

Crosslinked polymers, gels, gel particles, and "colloidal dispersion gels":

- Are not simply viscous polymer solutions.
- Do not flow through porous rock like polymer solutions.
- Do not enter and plug high-k strata first and progressively less-permeable strata later.
- Should not be modeled as polymer floods.

# Distinction between a blocking agent And a mobility control agent.





- For a mobility control agent, penetration into low-k zones should be <u>maximized.</u>
- For a blocking agent, penetration into low-k zones should be <u>minimized.</u>

## KEY QUESTIONS DURING BULLHEAD INJECTION OF POLYMERS, GELANTS, OR GELS

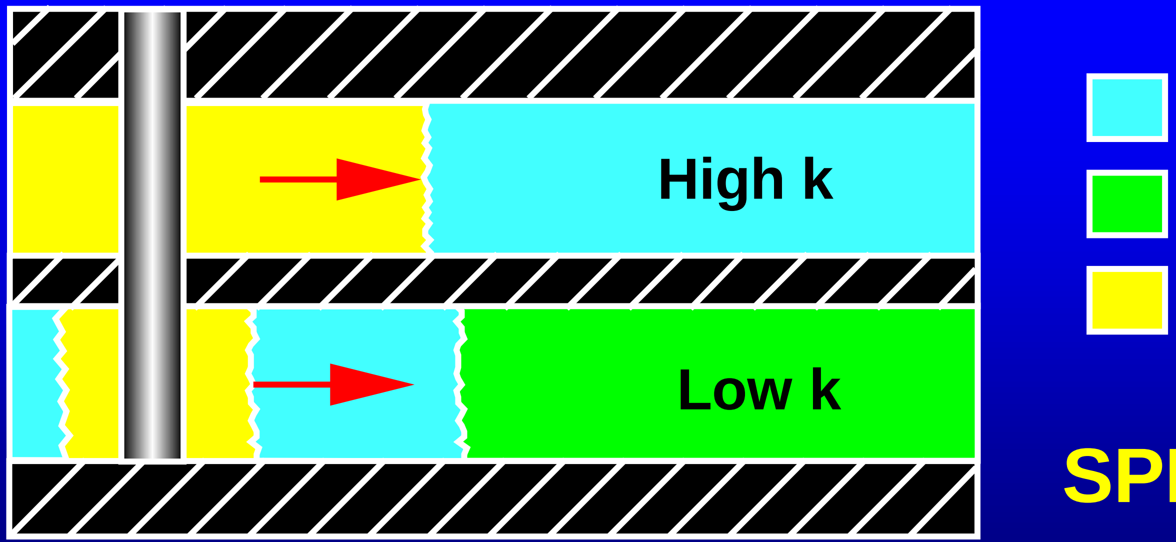
- **Why should the blocking agent NOT enter and damage hydrocarbon productive zones?**
- **How far will the blocking agent penetrate into each zones (both water AND hydrocarbon)?**
- **How much damage will the blocking agent cause to each zone (both water AND hydrocarbon zones)?**

# BASIC CALCULATIONS

**Gelants can penetrate into all open zones.**

**An acceptable gelant placement is much easier to achieve in linear flow (fractured wells) than in radial flow.**

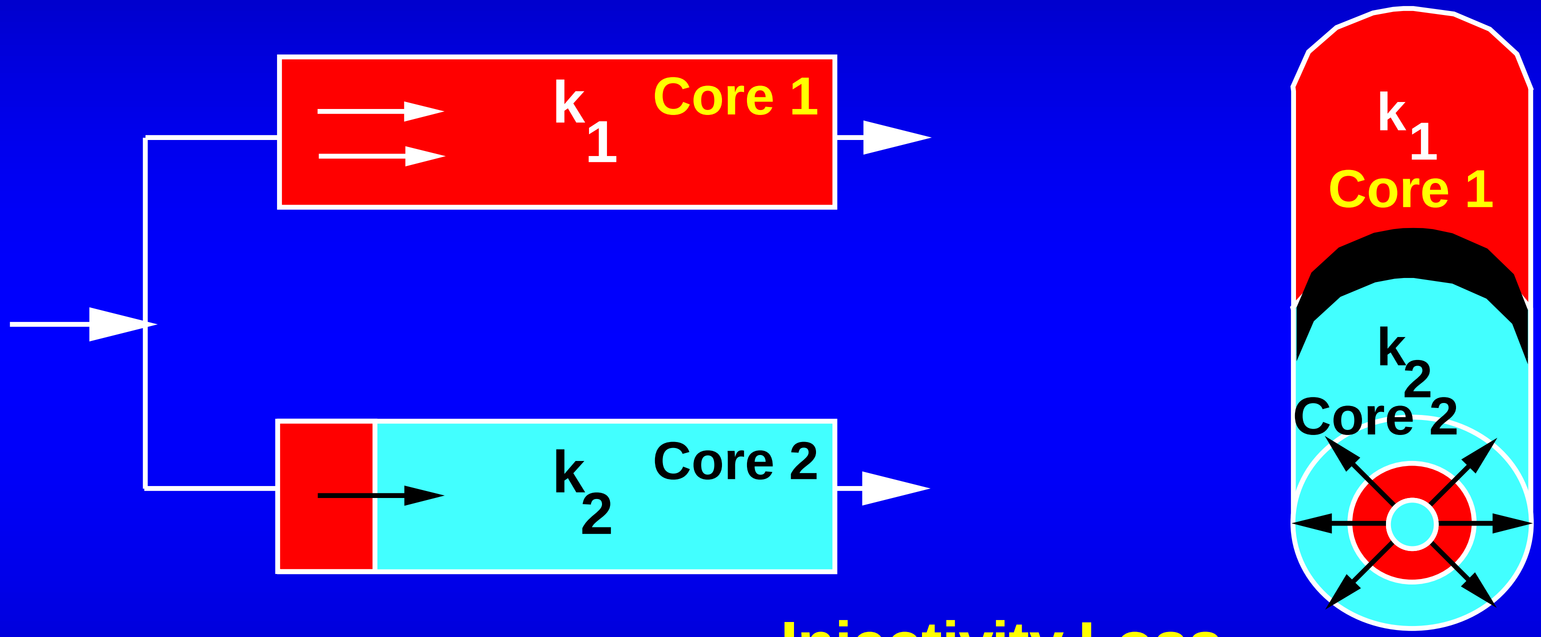
**In radial flow (unfractured wells), oil-productive zones must be protected during gelant placement.**

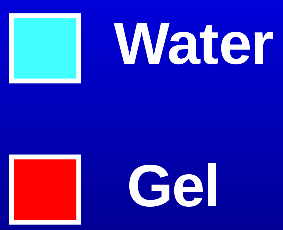



**SPE 17332**

# LINEAR vs RADIAL FLOW

## Example: $k_1/k_2 = 10$, $F_r = 1$, $F_{rr} = 10$

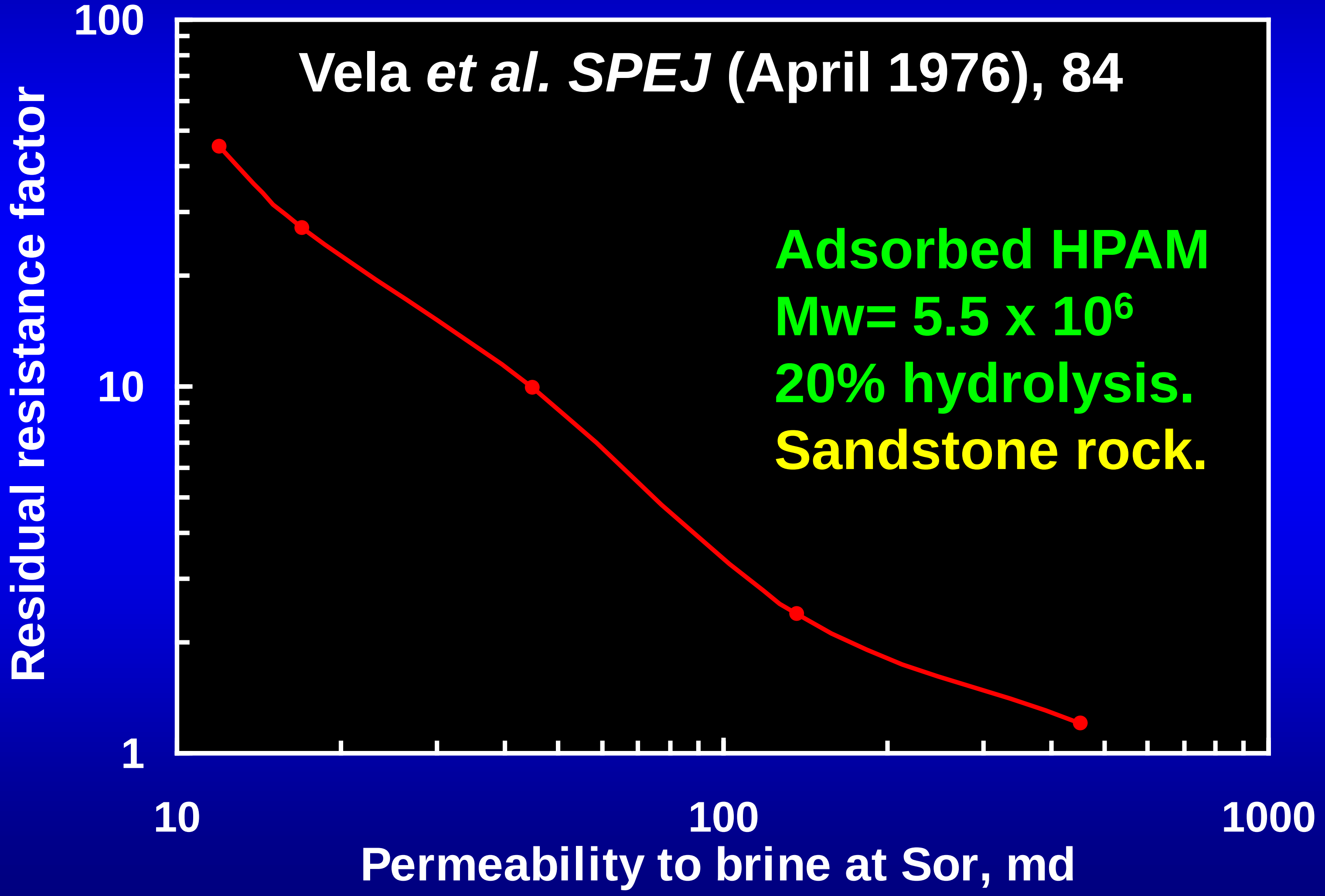



**Injectivity Loss**

| | Linear | Radial |
|---|---|---|
| Core 1: | 90% | 90% |
| Core 2: | 47% | 87% |

**Adsorbed polymers, “weak” gels, particle suspensions, and “dispersions” of gel particles reduce k in low-k rock more than in high-k rock.**



**Contrary to some claims, adsorbed polymers, "weak" gels, and gel "dispersions" can harm flow profiles!!!**

| Layer | $k_w$ @ $S_{or}$, md | Gel radius, ft | Permeability reduction factor ($F_{rrw}$) | Layer flow capacity, final/initial |
|---|---|---|---|---|
| 1 | 453 | 30 | 1.2 | 0.94 |
| 2 | 137 | 16.5 | 2.4 | 0.71 |
| 3 | 45 | 9.5 | 9.9 | 0.31 |
| 4 | 17 | 5.8 | 27 | 0.15 |
| 5 | 12 | 4.9 | 45 | 0.10 |

# GEL PLACEMENT IS CRITICALLY DIFFERENT IN RADIAL FLOW THAN IN LINEAR FLOW!!!

This conclusion is not changed by:

- Non-Newtonian rheology of gelants.
- Two-phase flow of oil and water.
- Fluid saturations, capillary pressure behavior.
- Anisotropic flow or pressure gradients.
- Pressure transient behavior.
- Well spacing, degree of crossflow.
- Chemical retention & inaccessible pore volume.
- Different resistance factors in different layers.
- Diffusion, dispersion, & viscous fingering.

See: http://baervan.nmt.edu/randy/gel_placement

**SITUATION:** Someone bullheads a conventional gel treatment into an “unfractured” well, without any special provision to protect oil zones. After the treatment, the flow profile “improved”.

- Possibility 1: The claim is true, we need to rewrite all the petroleum engineering texts, and someone deserves a Nobel prize.

- Possibility 2: The well actually contained a fracture, fracture-like feature or void channel.

- If fluids can cross flow out beyond the wellbore, does a flow profile mean anything?

**COMMON PHILOSOPHY:** "I don't care whether my high-permeability streak is a fracture or not. I just want to fix it."

Your treatment has a much better chance of success if you decide in advance whether you have linear flow through fractures or voids versus radial flow through matrix!!!

- The appropriate composition for a fracture or void is different than for matrix.
- The optimum treatment volume for a fracture or void is different than for matrix.
- The proper placement method for treating a fracture or void is different than for matrix.

# GELANTS

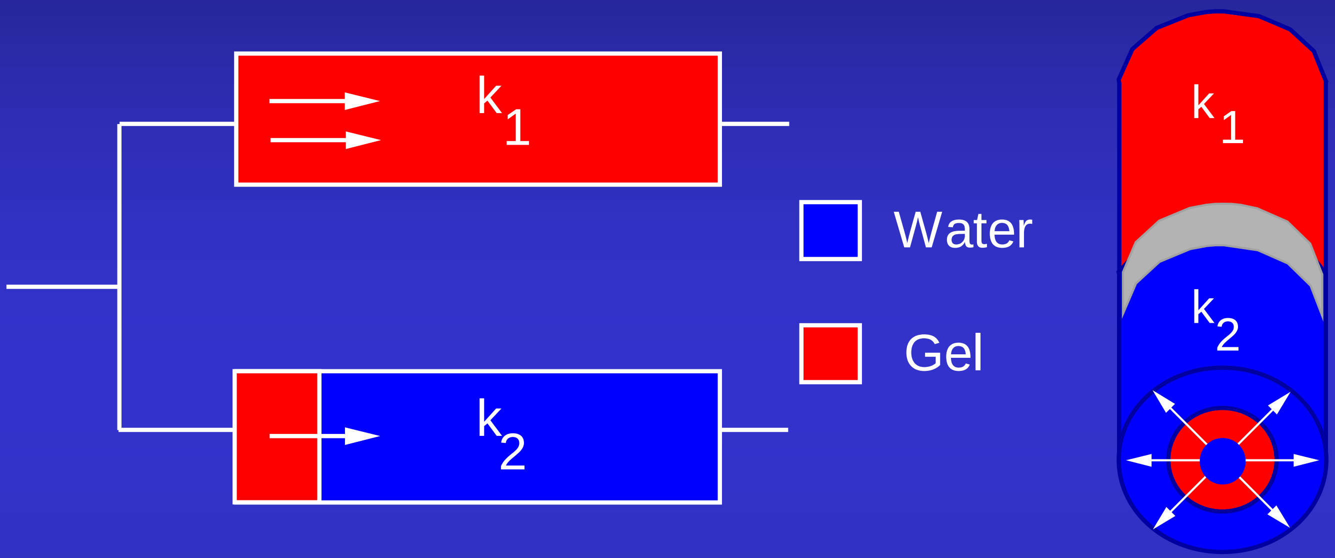
**LOW-VISCOSITY**

1. Acrylamide/acrylate monomer
2. Silicate solutions
3. Colloidal silica
4. Phenol-formaldehyde
5. Chromium-lignosulfonate
6. Dilute aluminum-citrate-HPAM/CPAM
7. Others

**HIGH-VISCOSITY**

1. Chromium-polyacrylamide
2. Chromium-xanthan
3. HPAM with organic crosslinkers
4. Others

# LINEAR vs RADIAL FLOW




**DEGREE OF GELANT PENETRATION**

| Linear | Radial |
|---|---|
| $L_{p2} / L_{p1}$ | $(r_{p2}-r_w)/ (r_{p1}-r_w)$ |

## SPE 17332

## Degree of Penetration for Parallel Linear Corefloods with Newtonian Fluids

$L_{p2}/L_{p1} = \{[1+(F_r^2 - 1)\,(k_2\phi_1)/(k_1\phi_2)]^{0.5} - 1\} / (F_r - 1)$

$F_r$ is resistance factor (effective viscosity)

If $F_r = 1$, then $L_{p2}/L_{p1} = (k_2\phi_1)/(k_1\phi_2)$

If $F_r$ is large, then $L_{p2}/L_{p1} = [(k_2\phi_1)/(k_1\phi_2)]^{0.5}$

# Degree of Penetration for Parallel Radial Corefloods with Newtonian Fluids (SPE 17332)

$$(\phi_i/k_i)\, r_{pi}^2\, [F_r \ln(r_{pi}/r_w) + \ln(r_{p1}/r_{pi}) + (1-F_r)/2] =$$

$$= (\phi_1/k_1)\, r_{p1}^2\, [F_r \ln(r_{p1}/r_w) + (1-F_r)/2]$$

$$+\, r_w^2\, (\phi_i/k_i - \phi_1/k_1)\, [\ln(r_{p1}/r_w) + (1-F_r)/2]$$

If $F_r = 1$ and $r_w << r_p$, then $r_{p2}/r_{p1} \cong [(k_2\phi_1)/(k_1\phi_2)]^{0.5}$

If $F_r$ is large and $r_{p1} \cong 100\, r_w$, then

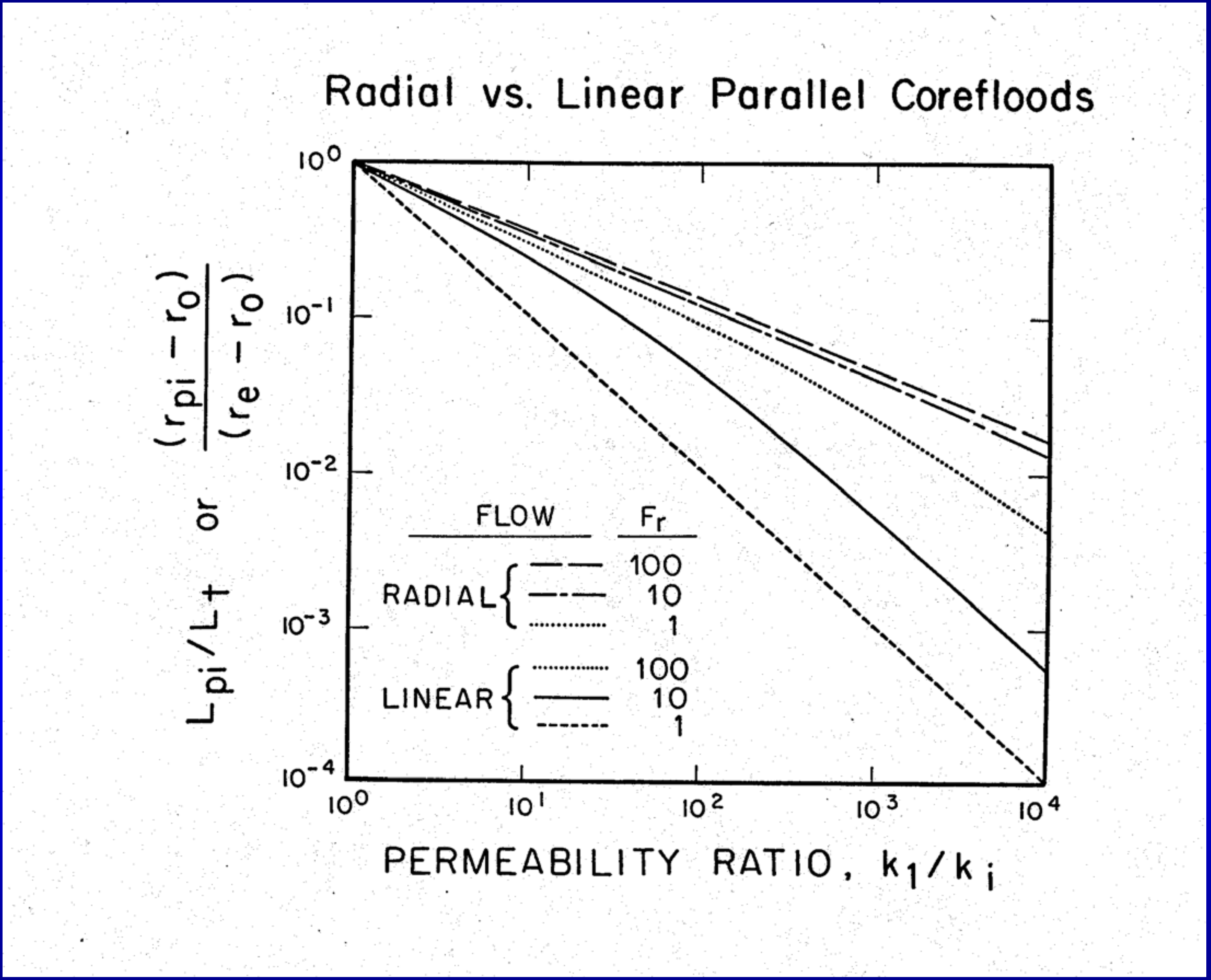
$$r_{p2}/r_{p1} \cong [(k_2\phi_1)/(k_1\phi_2)]^{0.5} / [1 + 0.13 \ln[(k_2\phi_1)/(k_1\phi_2)]]^{0.5}$$

## EFFECT OF GELANT VISCOSITY (RESISTANCE FACTOR) ON PLACEMENT

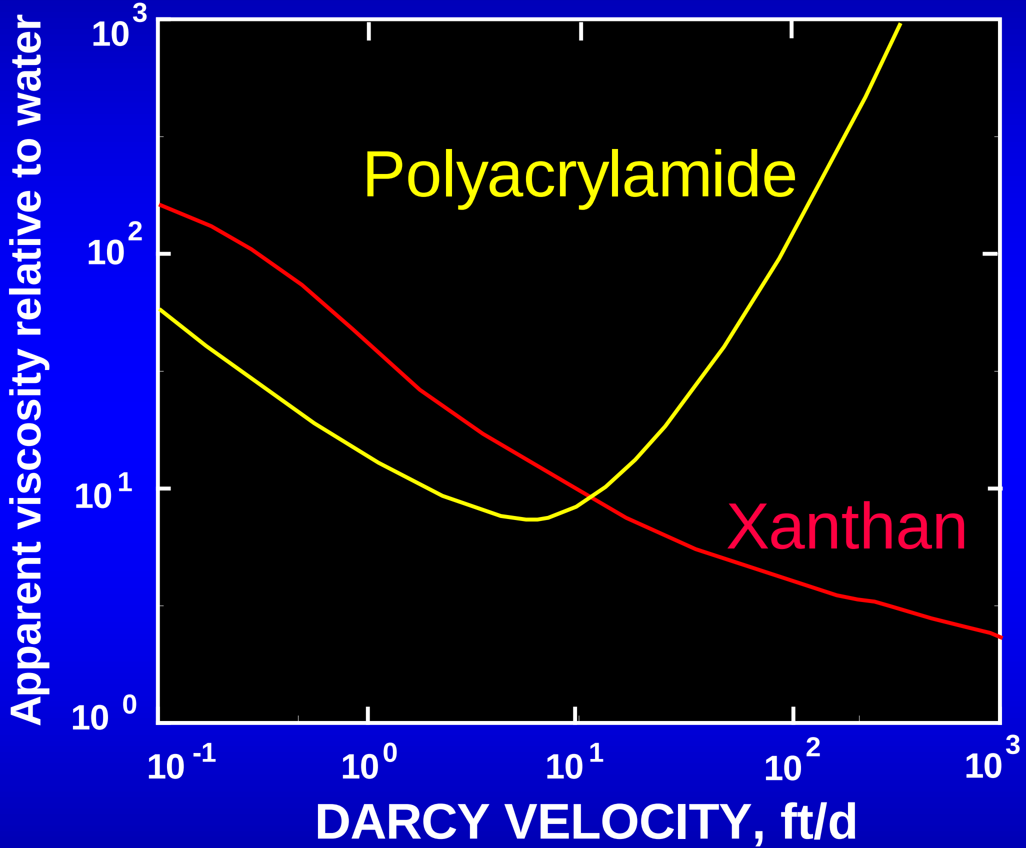
$k_1 = 10\ k_2$

$\phi = 0.2.\ L_{p1} = r_{p1} = 50$ ft. $r_w = 0.5$ ft.

| Resistance Factor | Linear flow $L_{p2}/L_{p1}$ | Radial flow $(r_{p2}-r_w)/(r_{p1}-r_w)$ |
|---|---|---|
| 1 | 0.100 | 0.309 |
| 10 | 0.256 | 0.369 |
| 100 | 0.309 | 0.376 |
| 1000 | 0.316 | 0.376 |

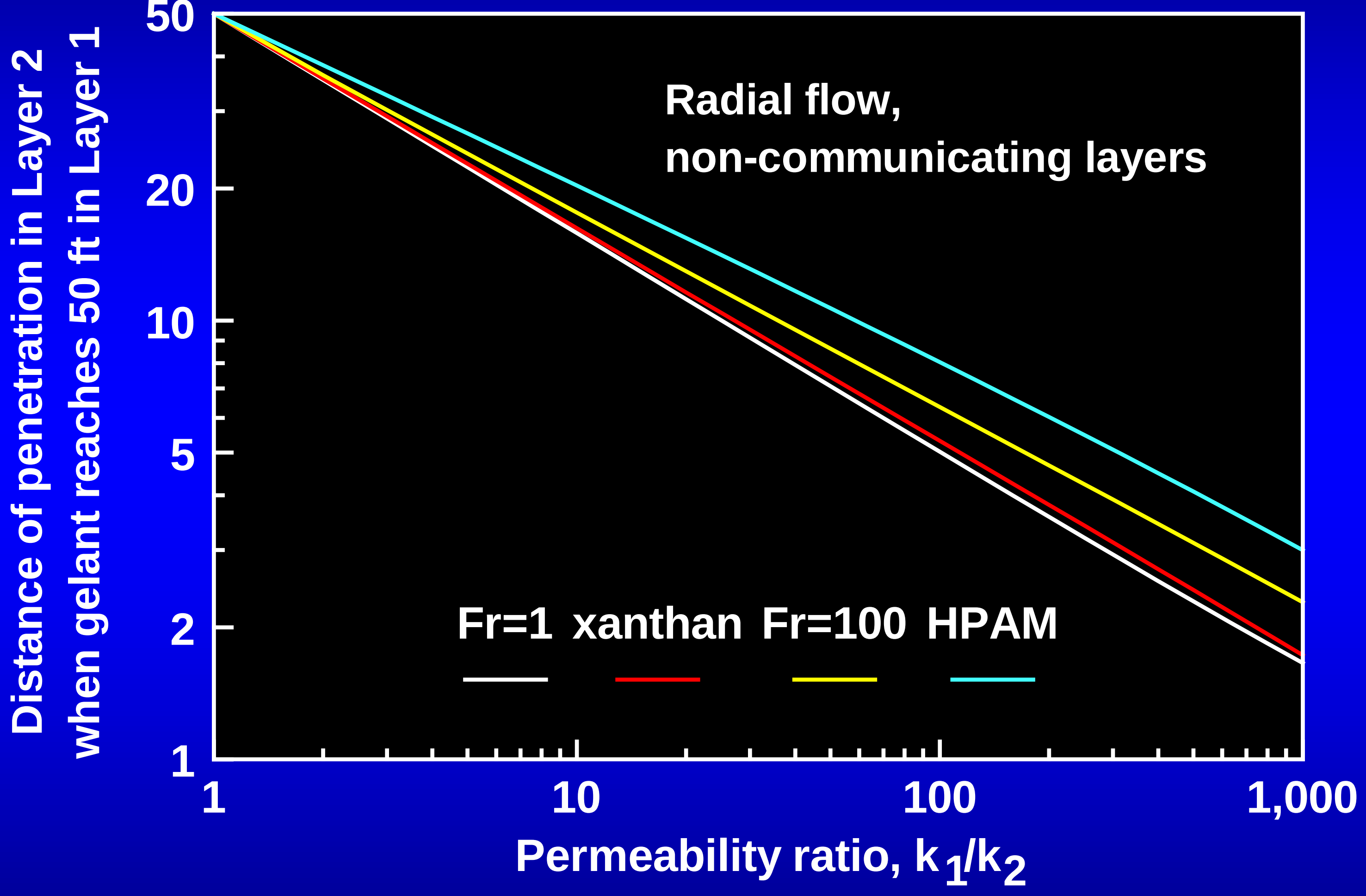

Radial vs. Linear Parallel Corefloods
$L_{pi}/L_t$ or $\frac{(r_{pi} - r_o)}{(r_e - r_o)}$
$10^0$
$10^{-1}$
$10^{-2}$
$10^{-3}$
$10^{-4}$
FLOW
$F_r$
RADIAL
100
10
1
LINEAR
100
10
1
$10^0$
$10^1$
$10^2$
$10^3$
$10^4$
PERMEABILITY RATIO, $k_1/k_i$

# Can rheology be exploited to optimize gel placement?

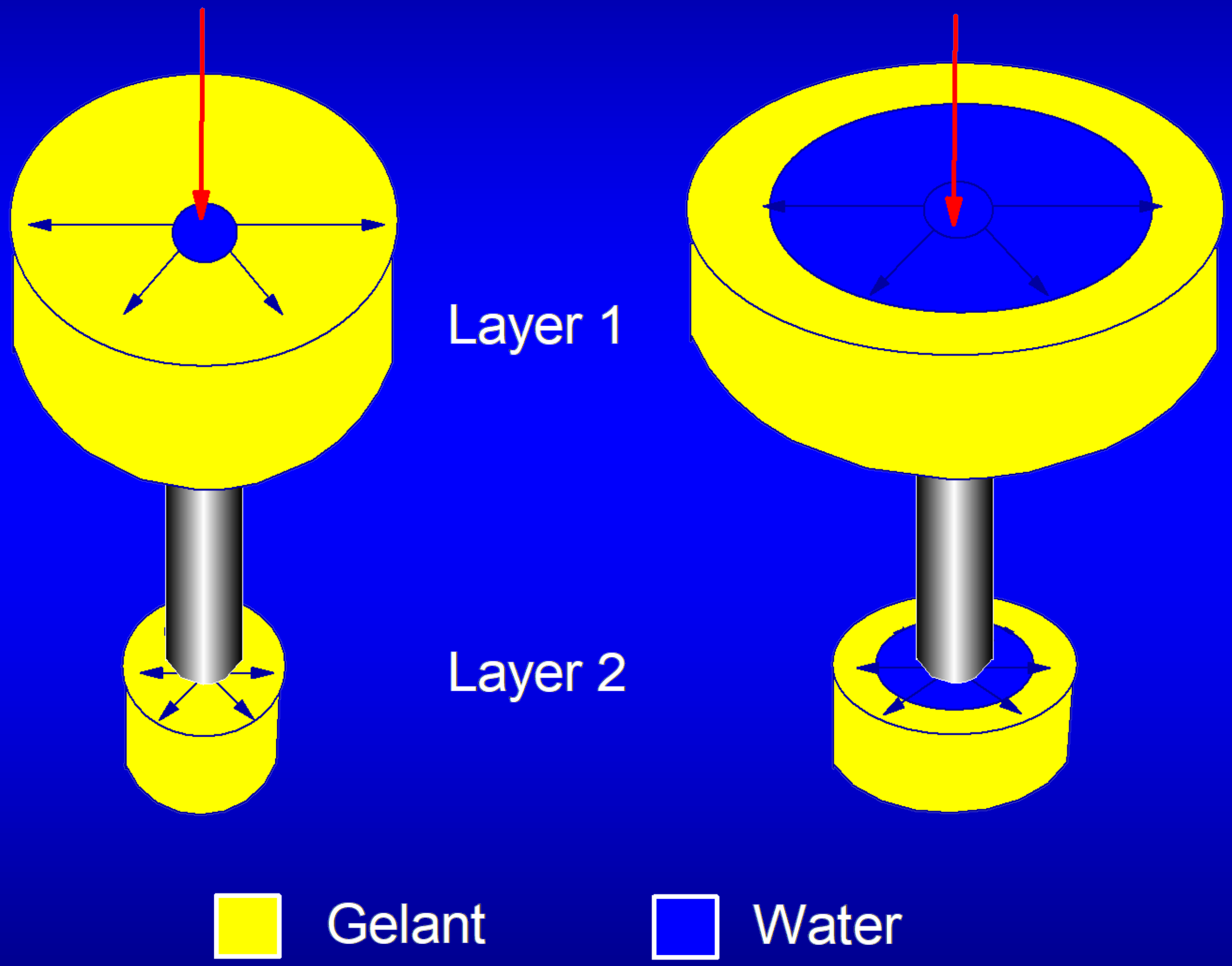



- **Not with currently available fluids and technology. See *SPERE* (May 1991) 212-218 and SPE 35450**

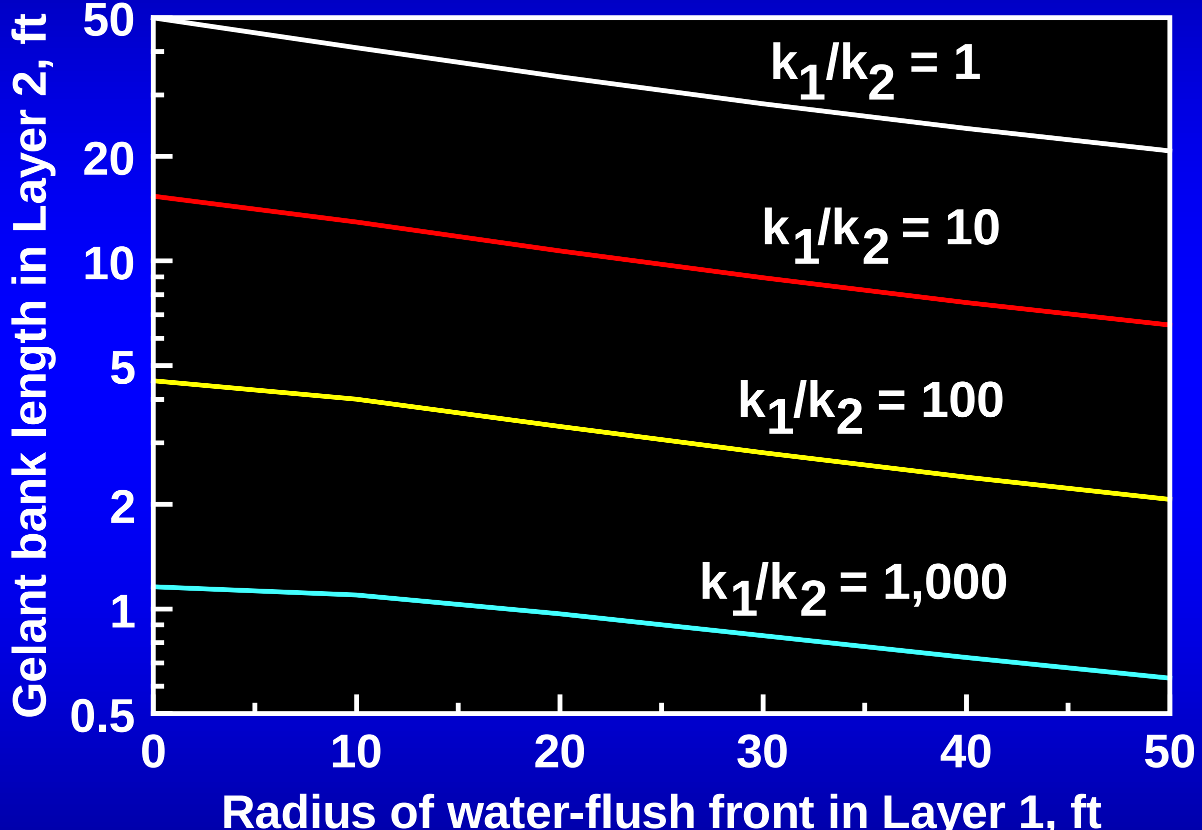
# Gelants Penetrate a Significant Distance into All Open Zones.



# Will a water post flush reduce the need for zone isolation?

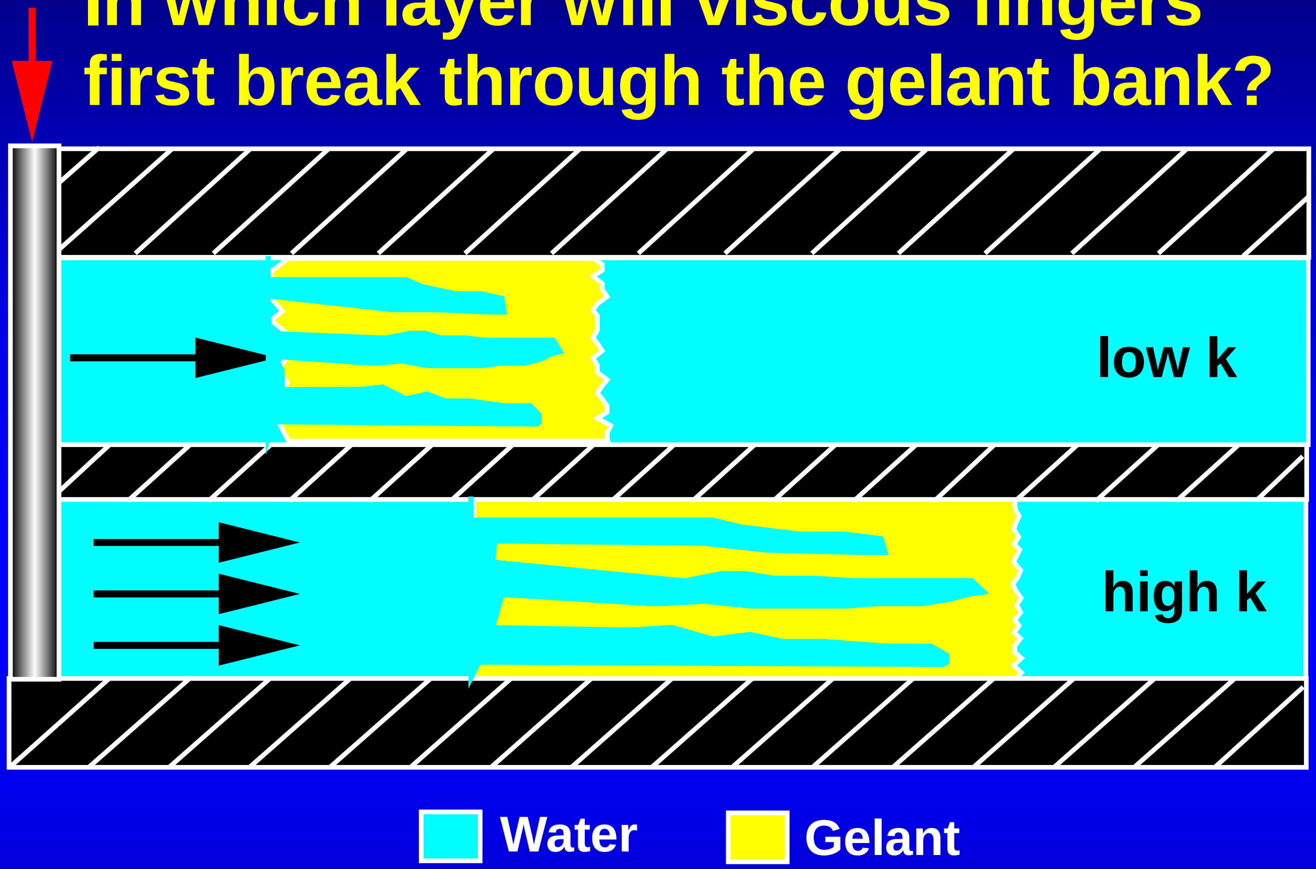


**For unit-mobility displacements, a water postflush will "thin" the gelant banks by about the same factor in all zones.**




**SPERE (Aug. 1991) 343-352 and SPE 24192**

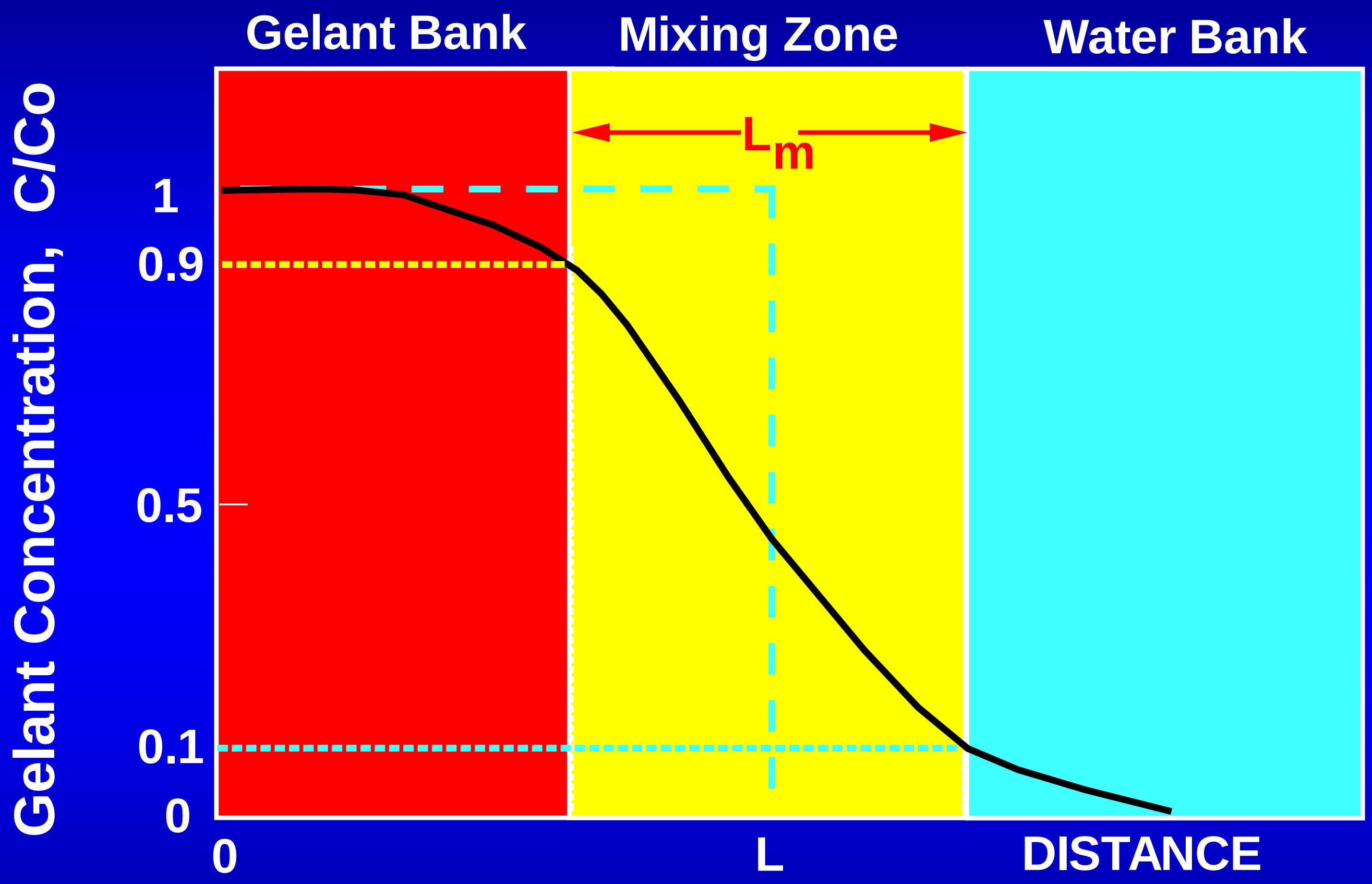
# In which layer will viscous fingers first break through the gelant bank?




**If no crossflow occurs, the viscous fingers will break through in all zones at about the same time.**

**SPERE (Aug. 1991) 343-352 and SPE 24192**

# DILUTION CAN PREVENT GELATION

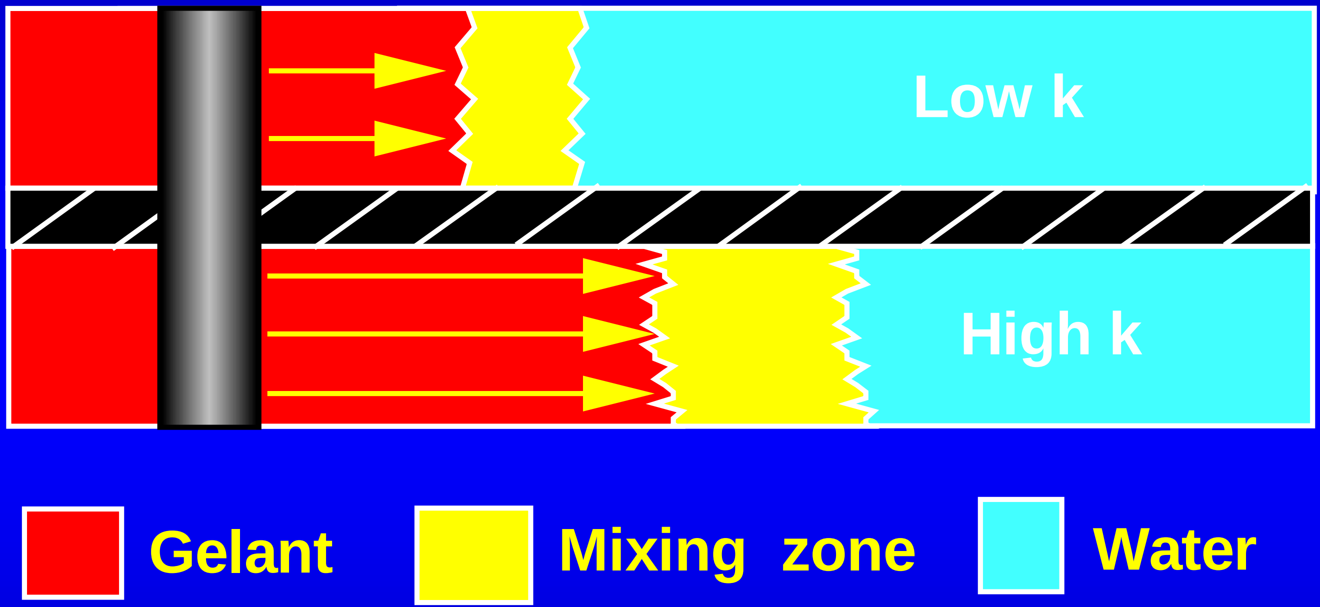



*SPERE* (Aug. 1991)
343-352

FOR DIFFUSION: $L_m \sim 3.62 \sqrt{Dt}$

FOR DISPERSION: $L_m \sim 3.62 \sqrt{\alpha L}$

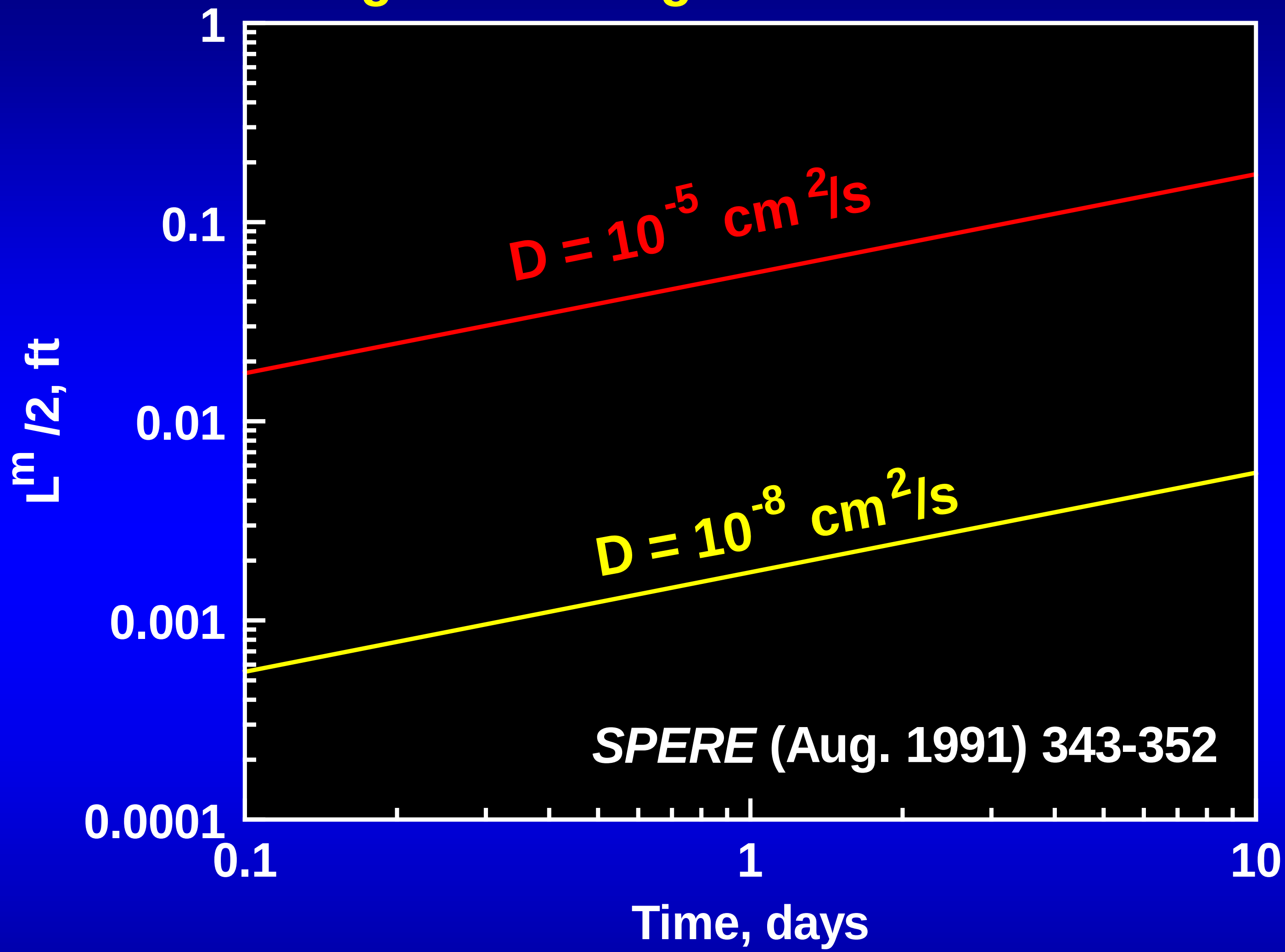
## Can diffusion and dispersion be exploited to destroy gelant banks in low-k zones while plugging high-k zones?




**Dispersion dilutes gelant banks by about the same factor in high-k zones as in low-k zones.**

***SPERE*** **(Aug. 1991) 343-352**

# Length of mixing zone due to diffusion




**Diffusion is too slow to destroy gelant banks unless the distance of gelant penetration is extremely small (< 0.2 ft).**

# CAN CAPILLARY PRESSURE PREVENT GELANT FROM ENTERING ZONES WITH HIGH OIL SATURATIONS?

1. During laboratory experiments, capillary effects could inhibit an aqueous gelant from entering an oil-wet core. However, in field applications, the pressure drop between injection and production wells is usually so large that capillary effects will not prevent gelant from entering oil-productive zones.
2. Regardless of the wettability of the porous medium, the capillary-pressure gradient will increase the fractional flow of water. If pressure gradients are large enough so that flow occurs, then capillary effects will always increase the depth of gelant penetration into oil-productive zones.
3. Under field-scale conditions, the effects of capillary pressure on gelant fractional flow are negligible. In particular, capillary pressure will not impede gelant penetration into oil-productive zones.

# DUAL INJECTION
# (S.V. Plahn, *SPEPF*, Nov. 1998, 243-249)

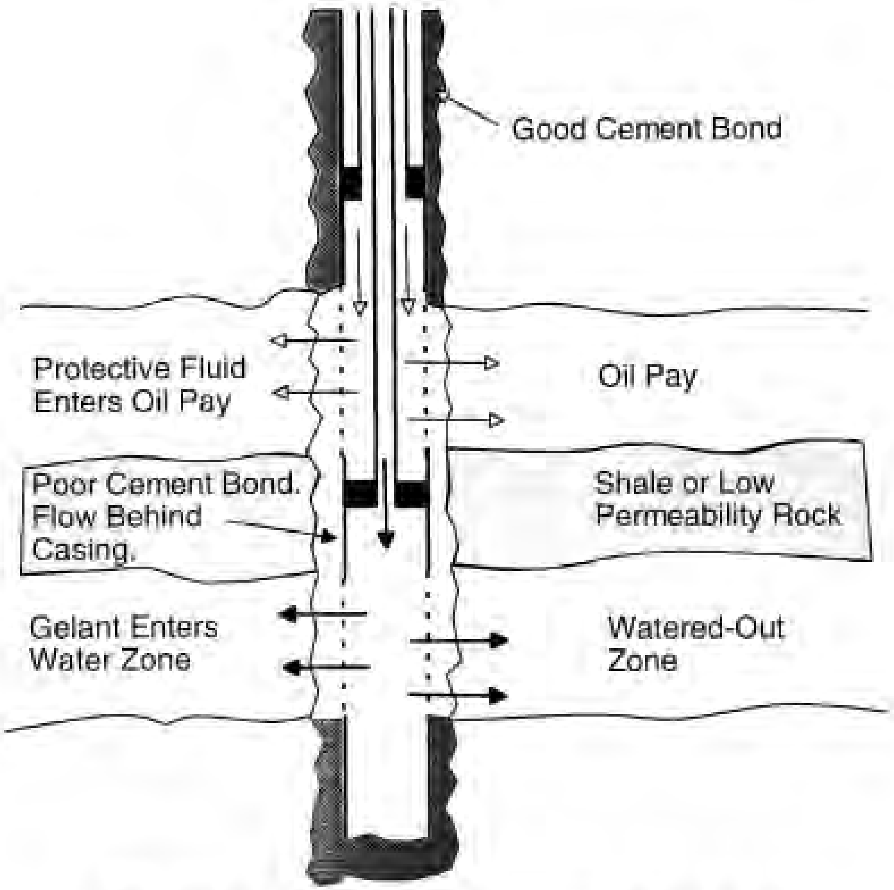



Fig. 3—Dual-injection with mechanical isolation.

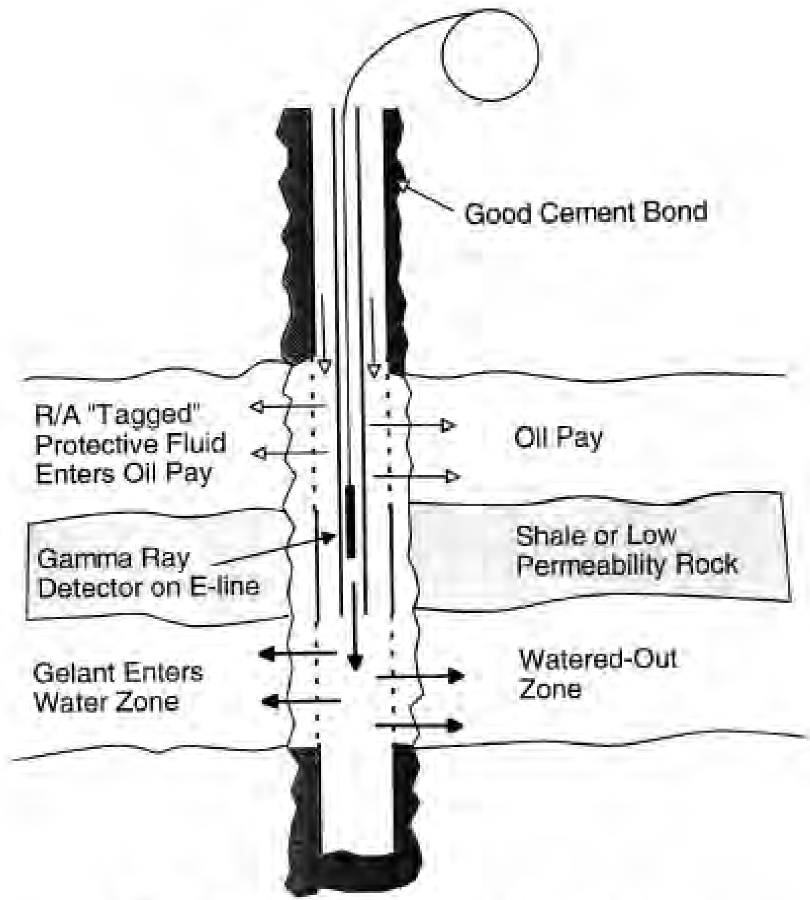
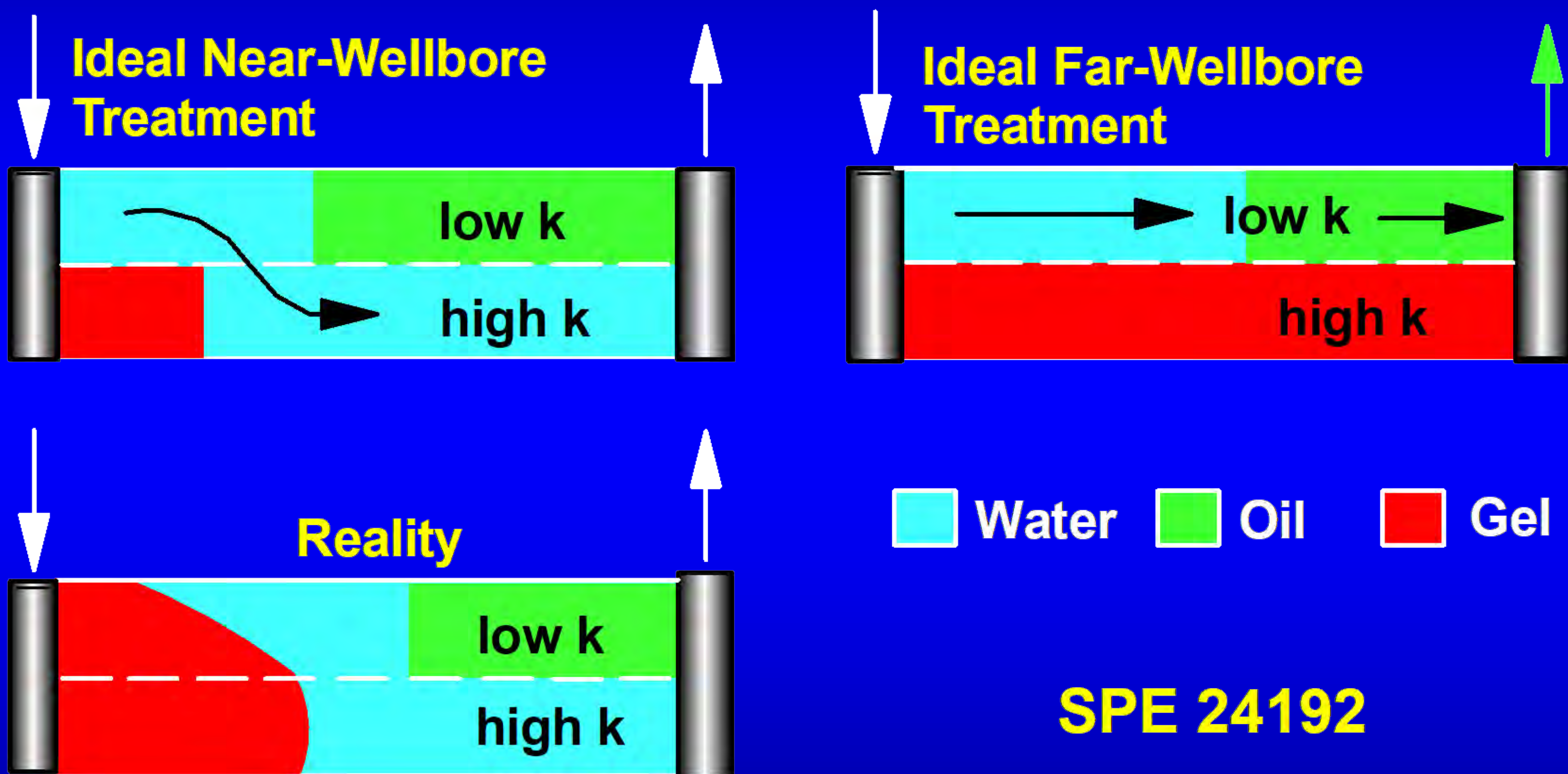



Fig. 5—Dual injection with interface tracking.

**Can be used for either vertical or horizontal wells.**

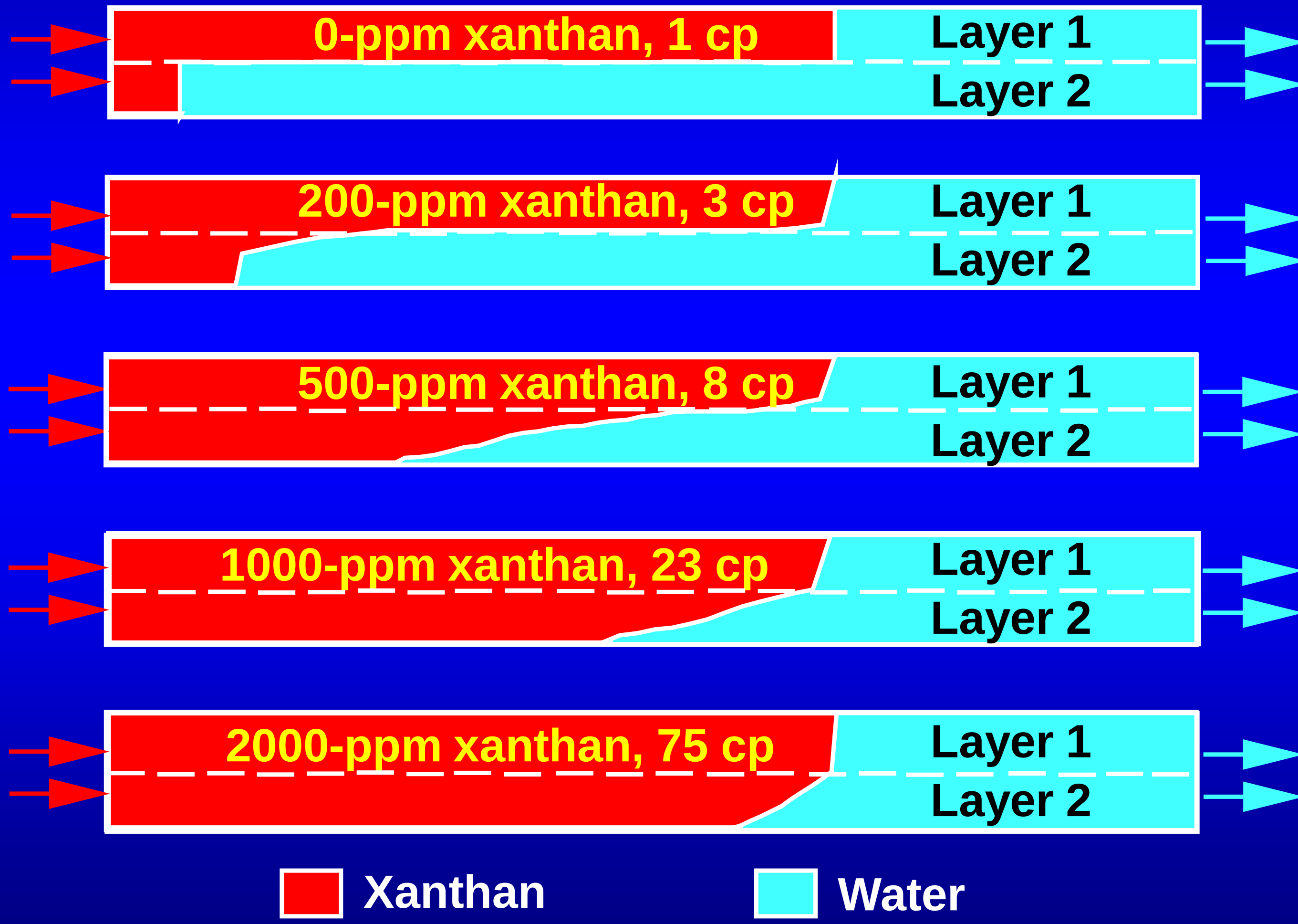
# Gel Placement in Heterogeneous Systems with Crossflow

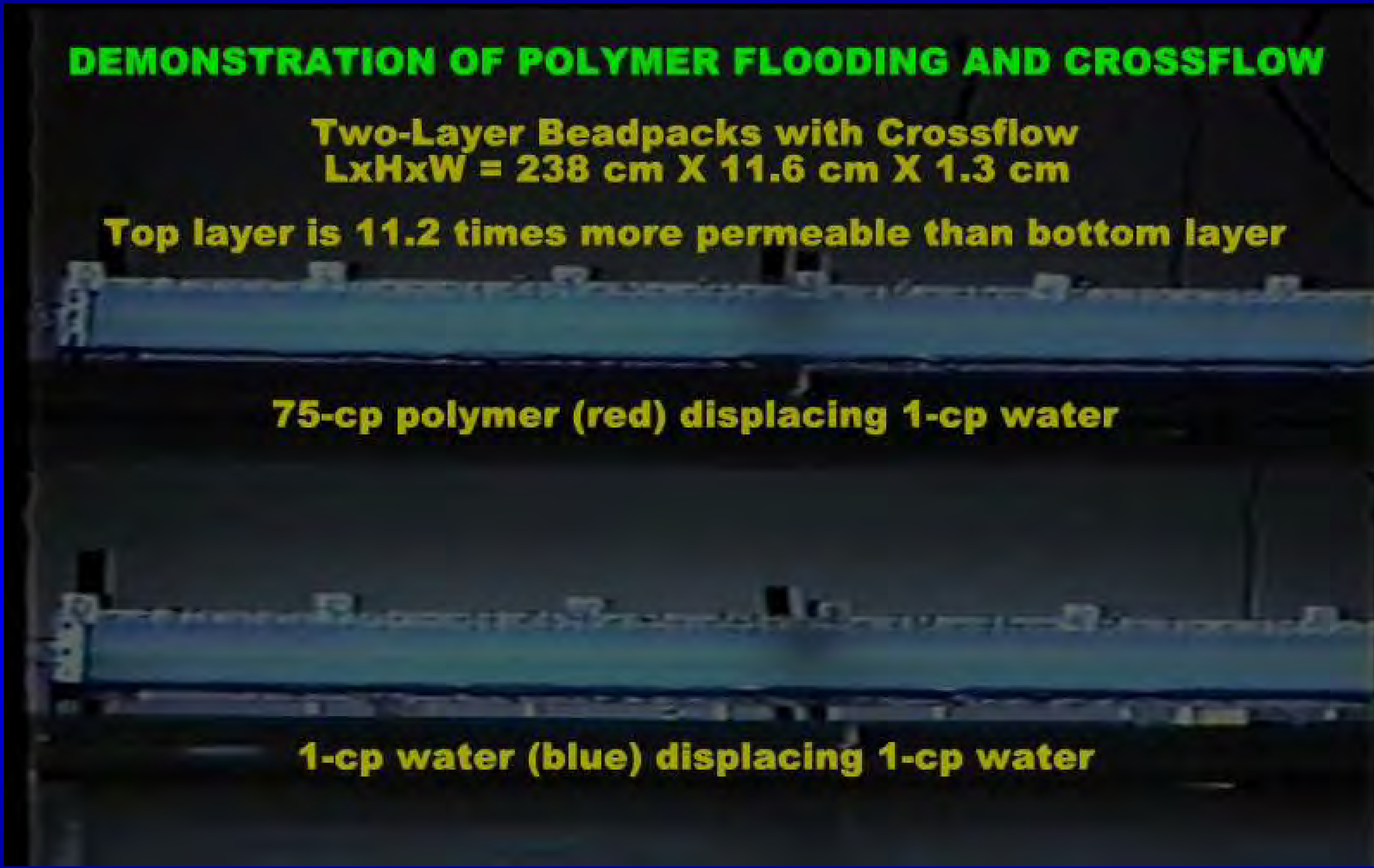



**SPE 24192**

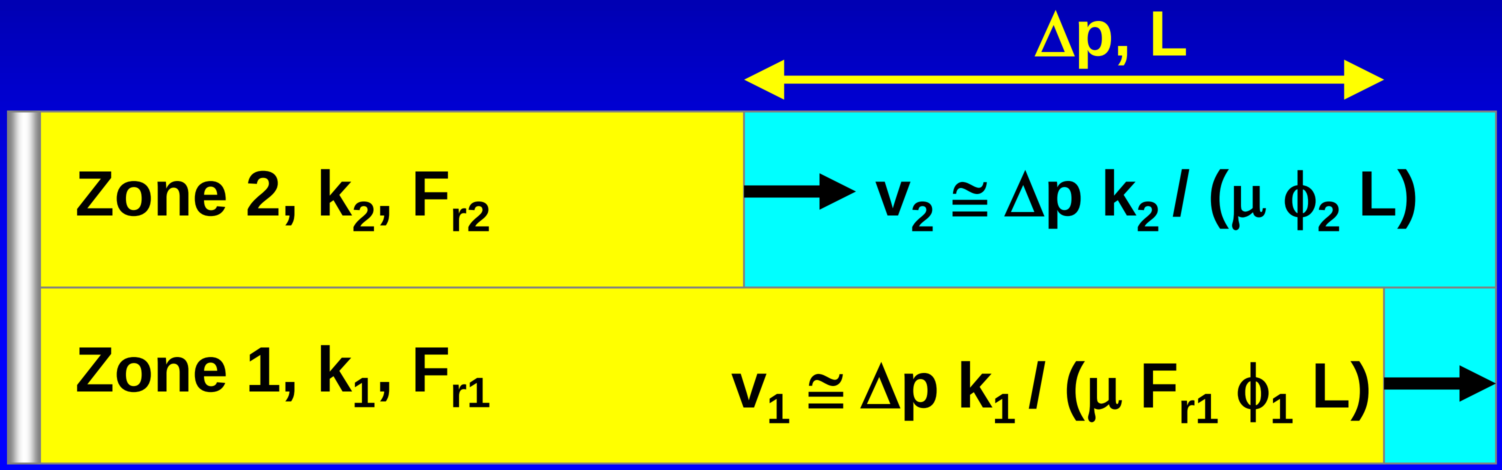
# CROSSFLOW MAKES GEL PLACEMENT MORE DIFFICULT!!!

**Crossflow in a two-layer beadpack. SPE 24192**
**Xanthan solutions displacing water; $k_1/k_2 = 11.2$.**




DEMONSTRATION OF POLYMER FLOODING AND CROSSFLOW
Two-Layer Beadpacks with Crossflow
LxHxW = 238 cm X 11.6 cm X 1.3 cm
Top layer is 11.2 times more permeable than bottom layer
75-cp polymer (red) displacing 1-cp water
1-cp water (blue) displacing 1-cp water

# Vertical Sweep Efficiency with Crossflow

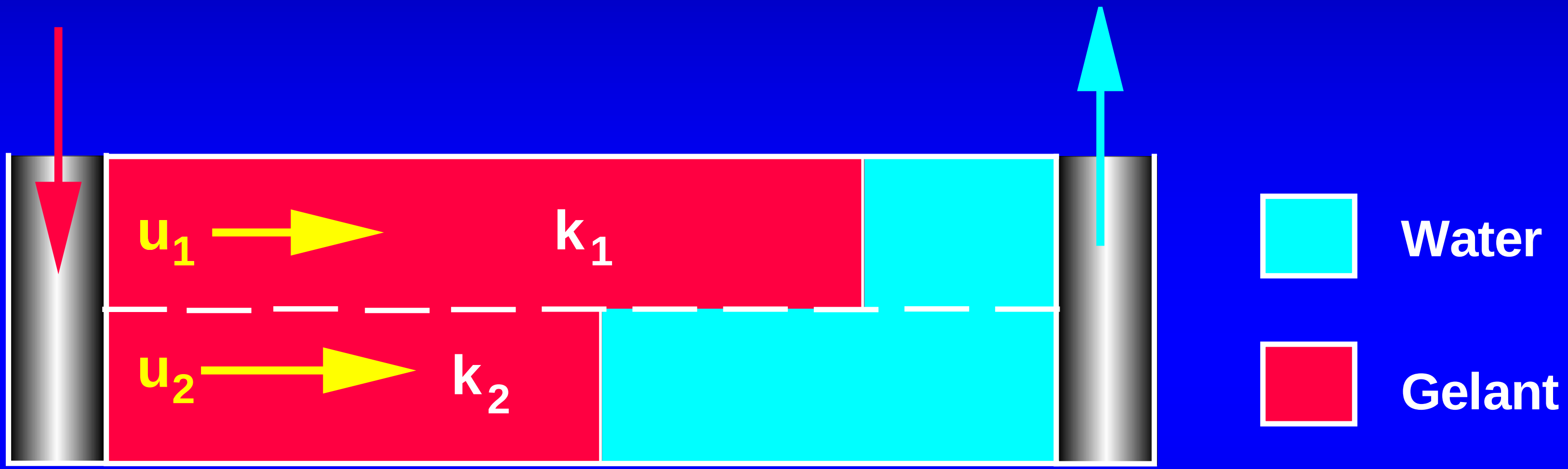



**At the front, $v_2 / v_1 \cong F_{r1}\, k_2\, \phi_1 / (k_1\, \phi_2)$**

**If $F_r = 1$ (water-like viscosity), sweep is the same with/without crossflow.**

**If $F_r > [k_2\, \phi_1 / (k_1\, \phi_2)]$, the front moves at the same rate in both layers.**

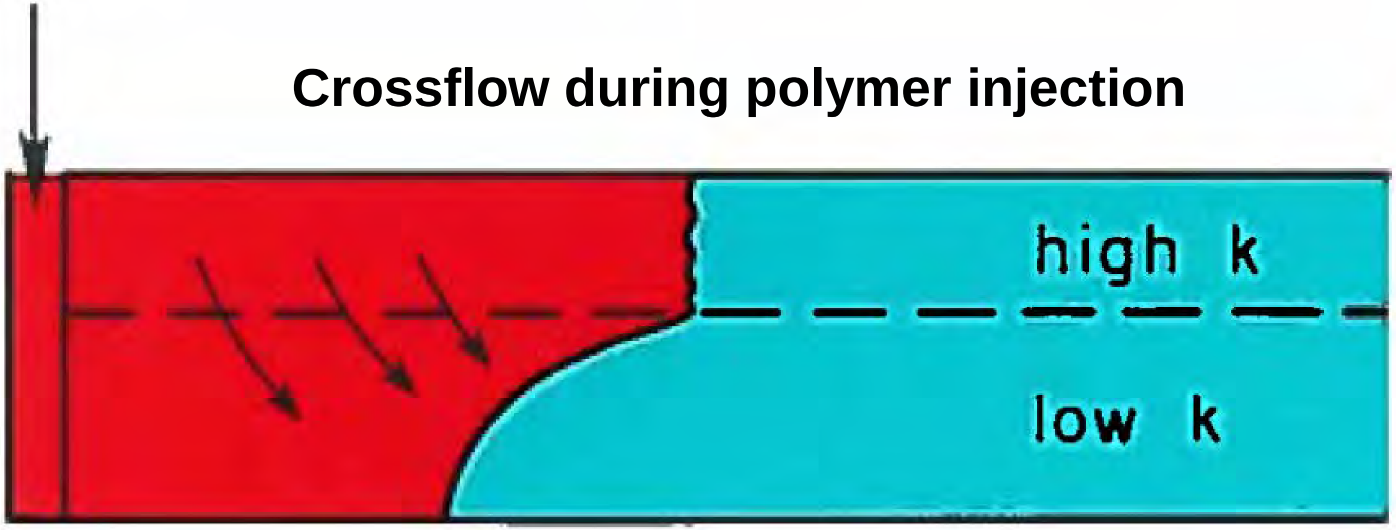
# Crossflow with Power-Law Fluids: $F_r = C\,u^n$
## Injection profiles are misleading




**Injection profiles are misleading with non-Newtonian fluids!**

| Fluid Rheology | $u_2 / u_1$ |
|---|---|
| General | $(k_2C_1/k_1C_2)^{-(n+1)}$ |
| Shear thinning | $< k_2 / k_1$ |
| Newtonian | $= k_2 / k_1$ |
| Shear thickening | $> k_2 / k_1$ |

## Crossflow during polymer injection




**Viscous fingering during water injection after polymer:**

**In which place will water fingers break through the polymer bank? IN THE HIGH-K PATH!**

# EFFECT OF GRAVITY ON GELANT PLACEMENT

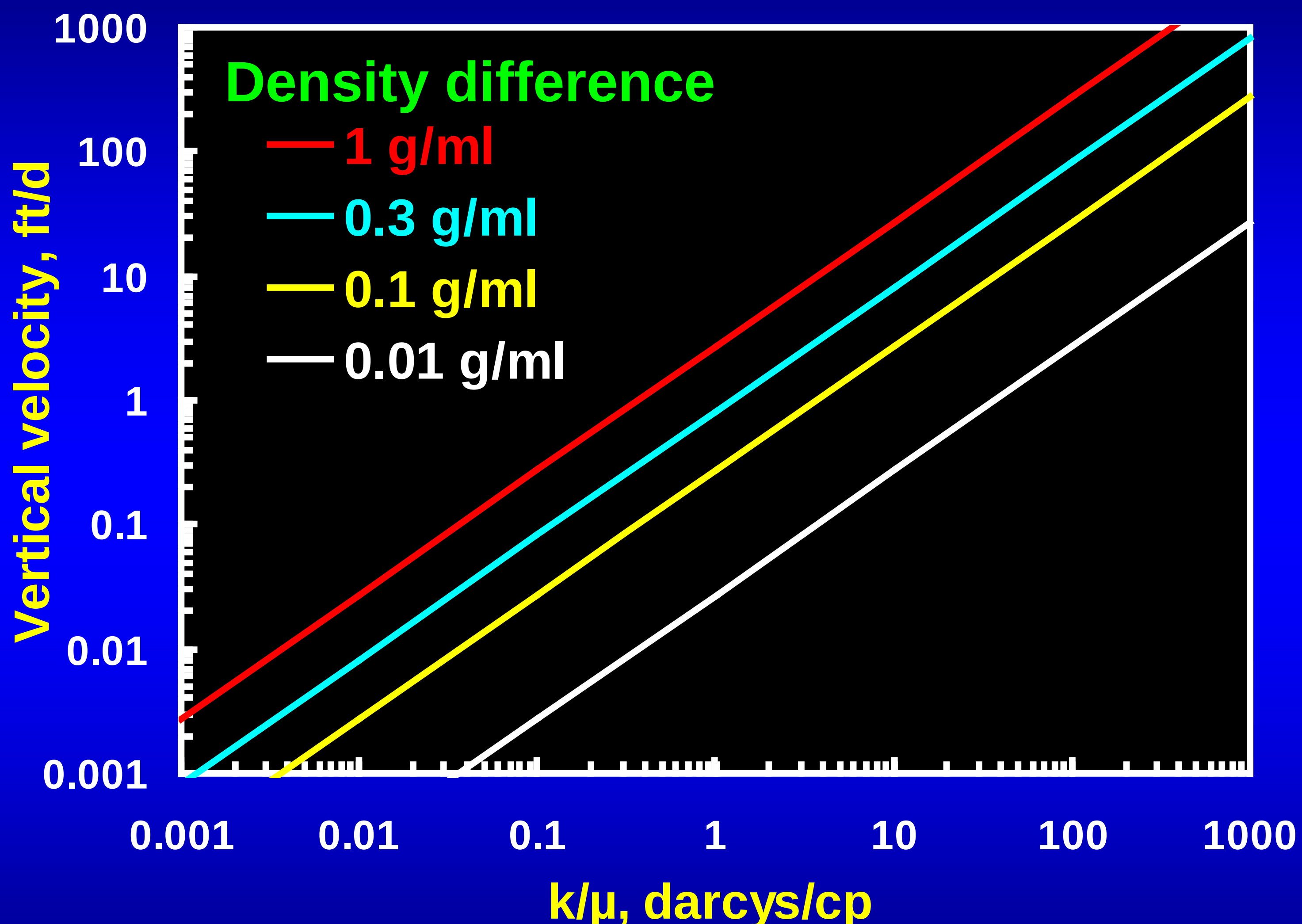
**Gravity component of the darcy equation:**

$$u_z = - k \, \Delta\rho \, g \, / \, [1.0133 \times 10^6 \, \mu]$$ **(Darcy units)**

**Dimensionless gravity number:**

$$G = [k \, \Delta\rho \, g \sin \theta] \, / \, [1.0133 \times 10^6 \, \mu \, u]$$

# EFFECT OF GRAVITY ON GELANT PLACEMENT




*SPEPF* (Nov. 1996) 241-248

## GRAVITY EFFECTS

1. During gelant injection into fractured wells, viscous forces usually dominate over gravity forces, so gravity will have little effect on the position of the gelant front.
2. During shut-in after gelant injection, a gelant-oil interface can equilibrate very rapidly in a fracture.
3. In radial systems (e.g., unfractured wells) viscous forces dominate near the wellbore, but gravity becomes more important deeper in the formation. Long gelation times will be required to exploit gravity during gelant injection in unfractured wells.

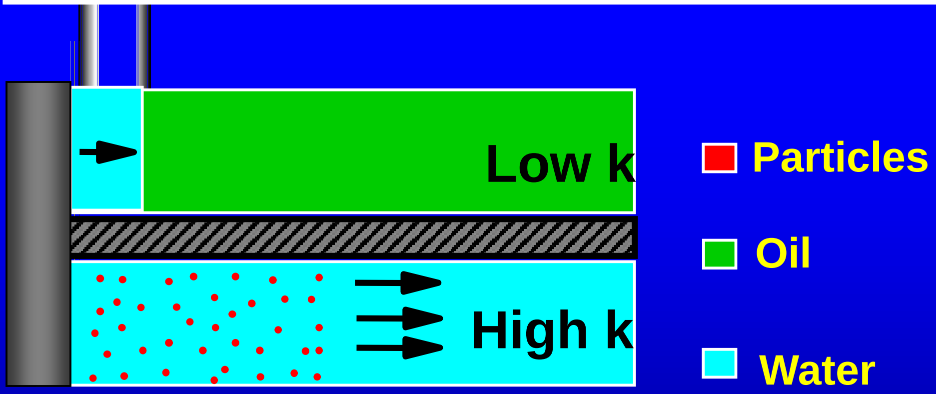
## Taking Advantage of Formation Damage

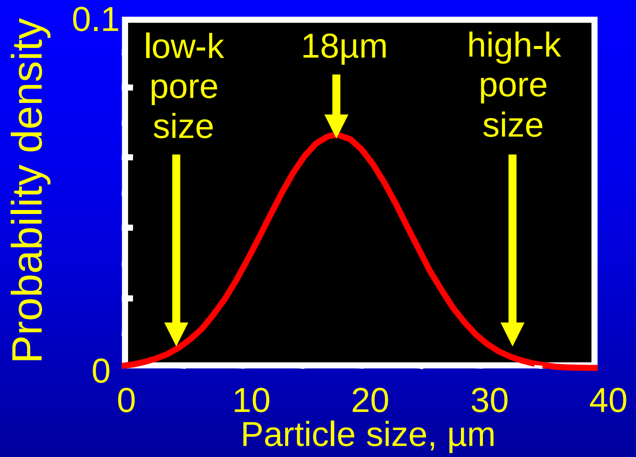
- If the hydrocarbon zones are damaged much more than water zones before a gel treatment, the formation damage may partially protect the hydrocarbon zones during gel placement.
- Stimulation fluids (e.g., acid) could be spotted to open the hydrocarbon zones after the gel treatment.
- This procedure will only work in special circumstances!

# PLACEMENT OF PARTICULATES

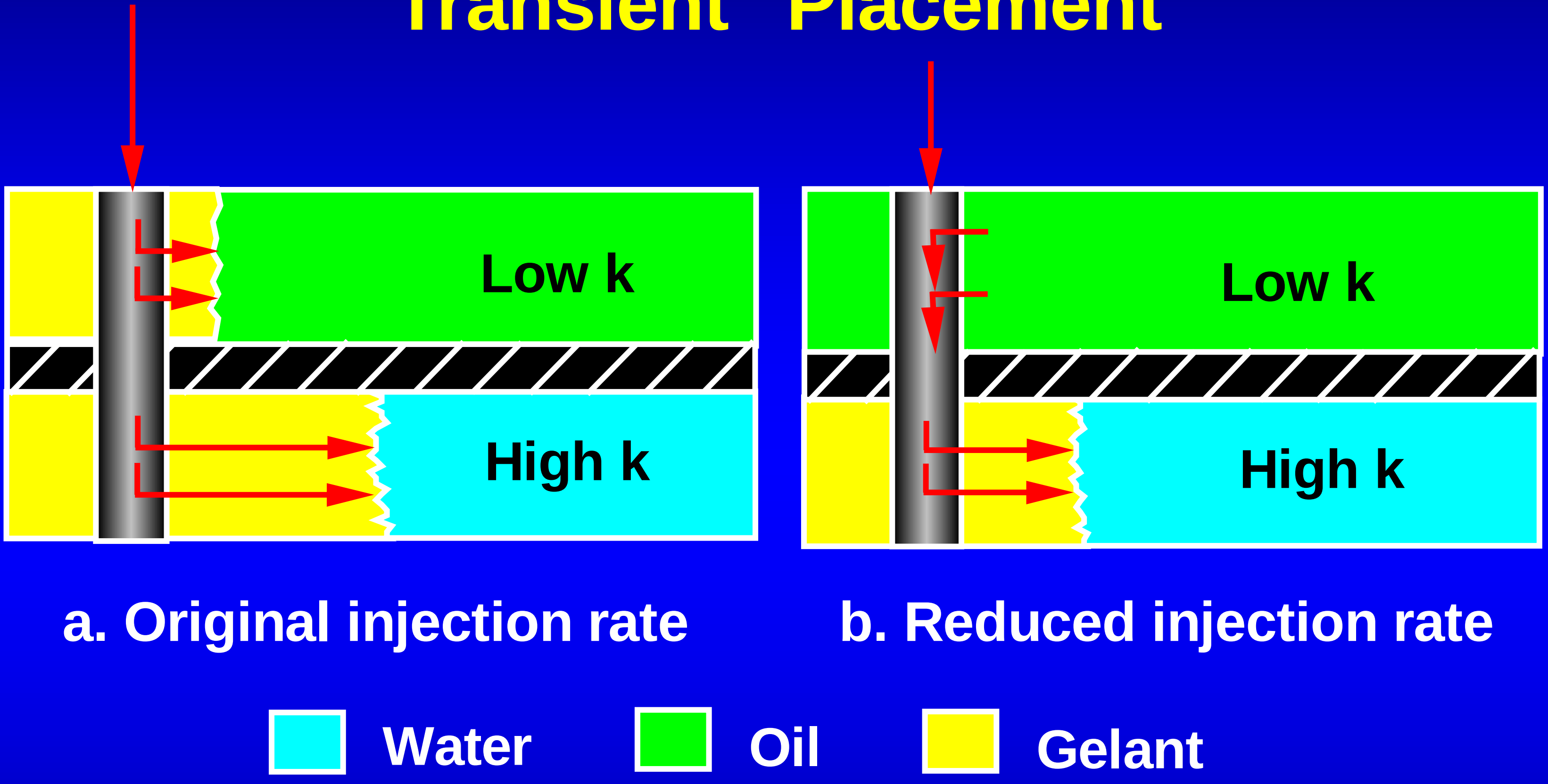
**To achieve placement superior to gels, particles must:**

- **be small enough to flow freely into high-k zones,**
- **be large enough not to enter low-k zones,**
- **not aggregate, adsorb, or swell during placement,**
- **have a sufficiently narrow size distribution.**



# "Transient" Placement




a. Original injection rate　　b. Reduced injection rate



DOE/BC/14880-10 (March 1995) 34-36

# "Transient" Placement

- If the average reservoir pressure in oil zones is much greater than that in water zones, fluids may crossflow in the wellbore in a certain range of wellbore pressures.
- To exploit this phenomenon during gelant placement, the proper wellbore pressure and duration of crossflow must be confirmed by measurement (e.g., flow log) before the gelant treatment.

# GEL PLACEMENT IS CRITICALLY DIFFERENT IN RADIAL FLOW THAN IN LINEAR FLOW!!!

**This conclusion is not changed by:**

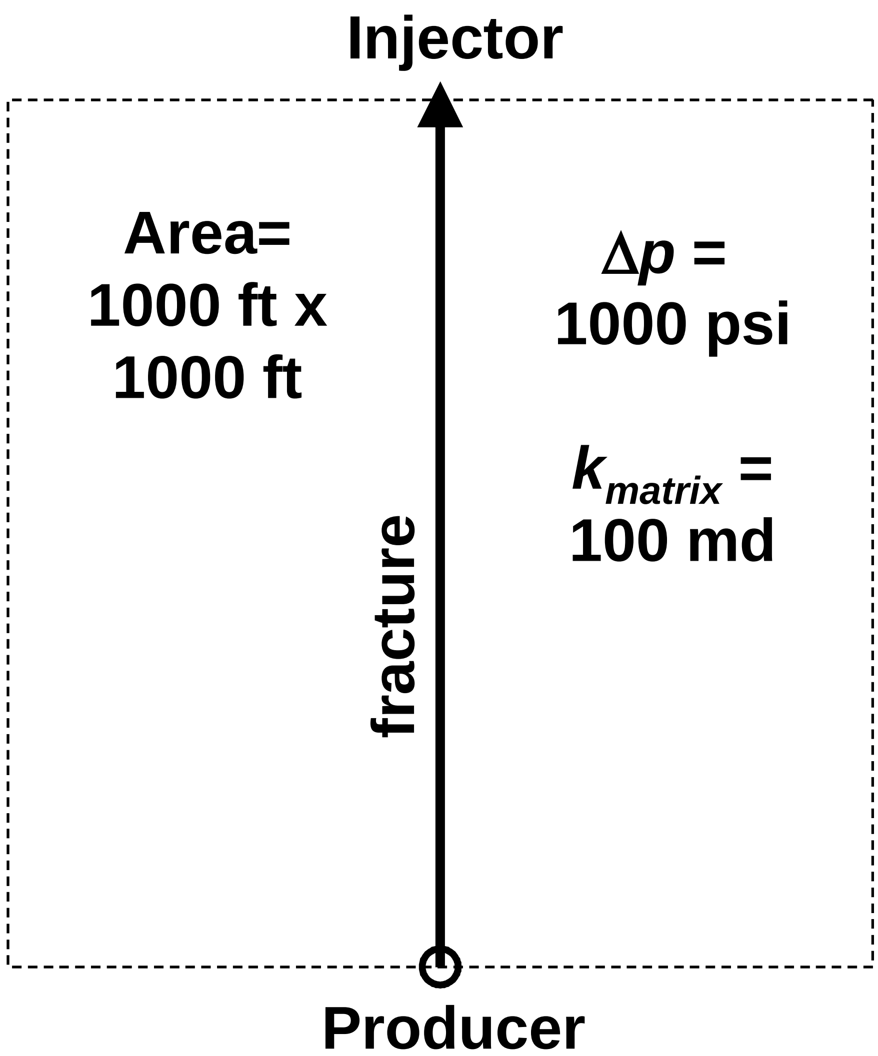
- Non-Newtonian rheology of gelants.
- Two-phase flow of oil and water.
- Fluid saturations, capillary pressure behavior.
- Anisotropic flow or pressure gradients.
- Pressure transient behavior.
- Well spacing, degree of crossflow.
- Chemical retention & inaccessible pore volume.
- Different resistance factors in different layers.
- Diffusion, dispersion, & viscous fingering.

See: http://baervan.nmt.edu/randy/gel_placement

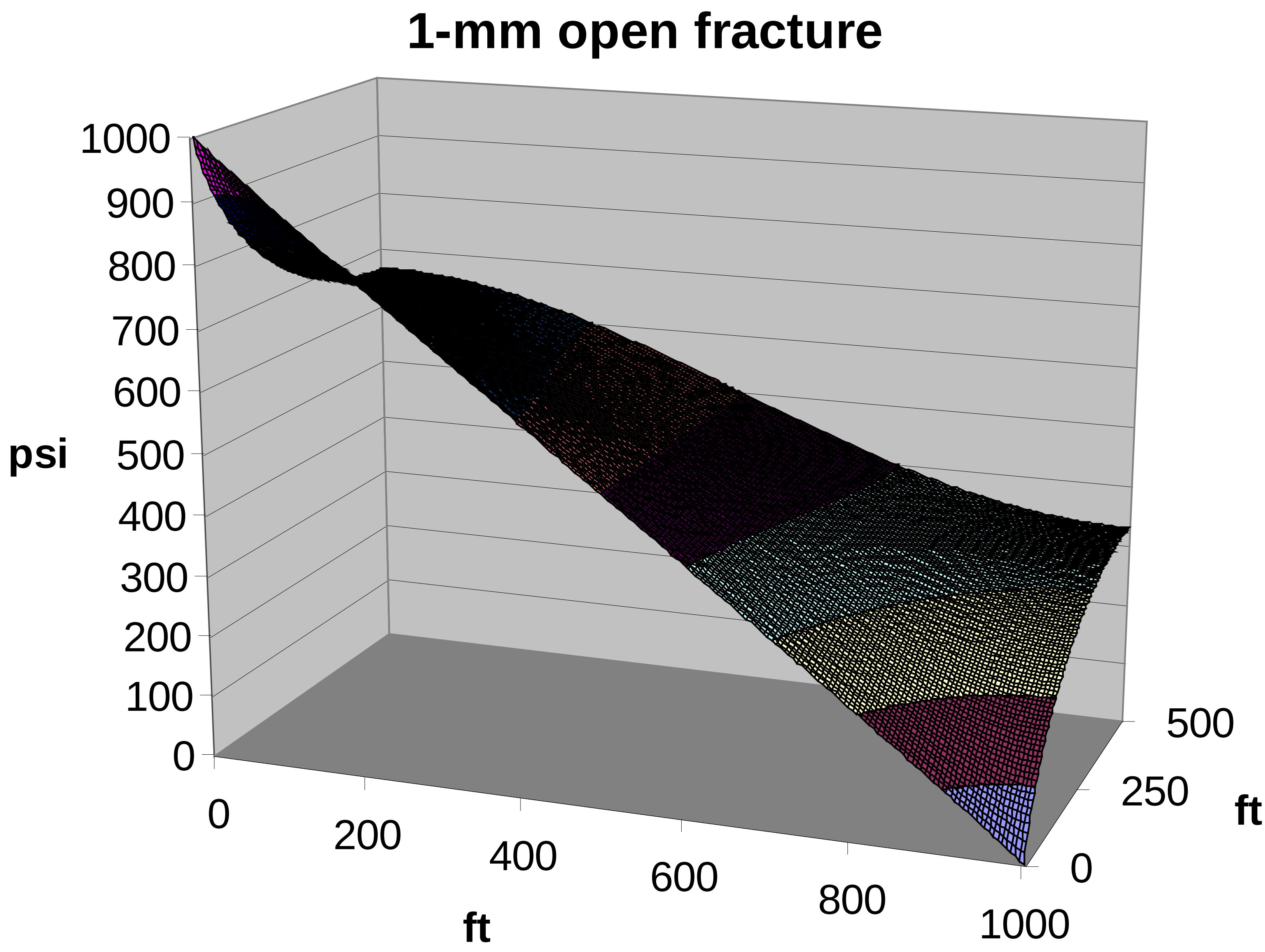
# Optimum Areal Placement Locations for Gel Plugs in Fractures

**Randy Seright**

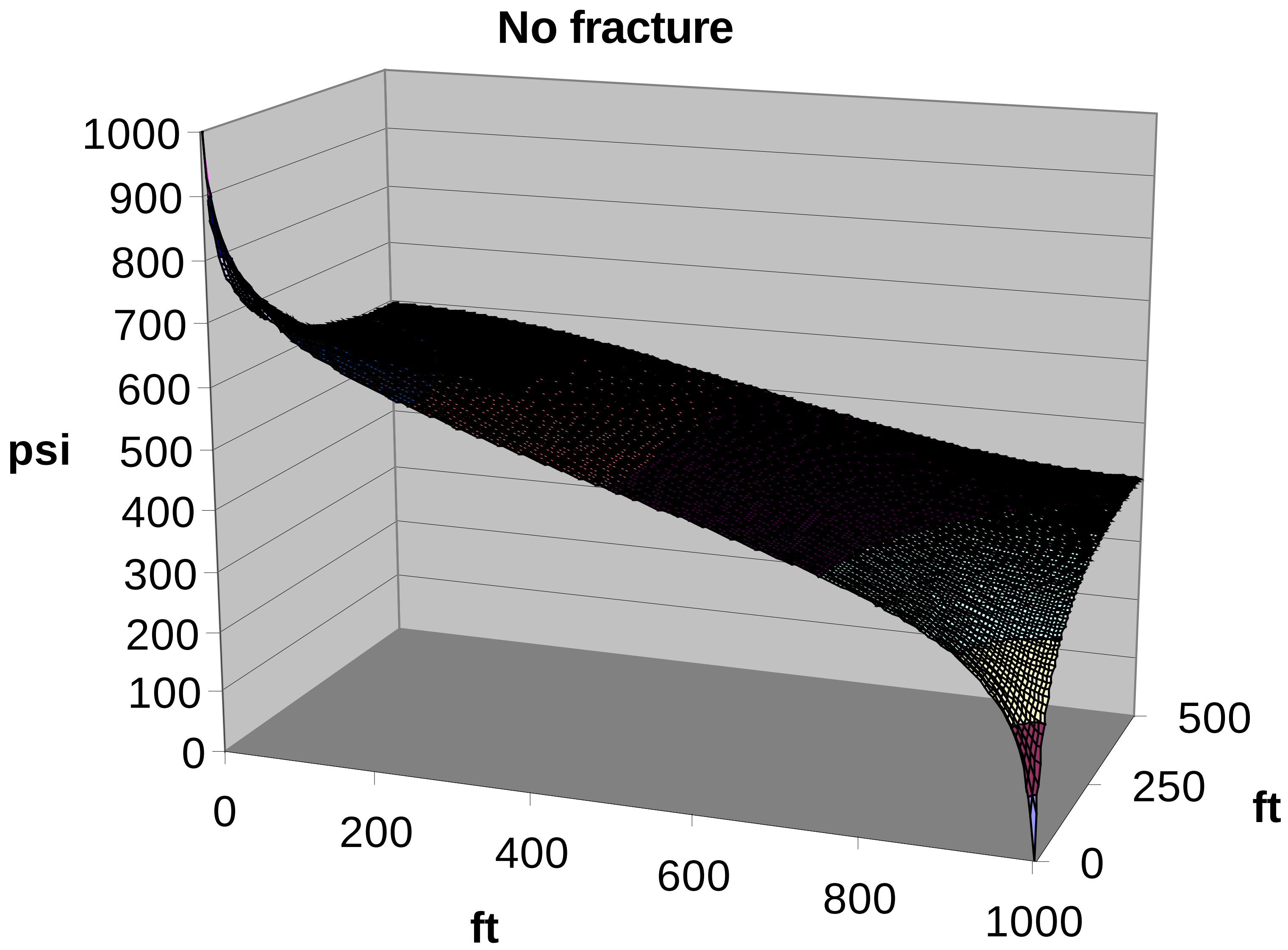
## Areal view of fracture connecting an injection well and a production well



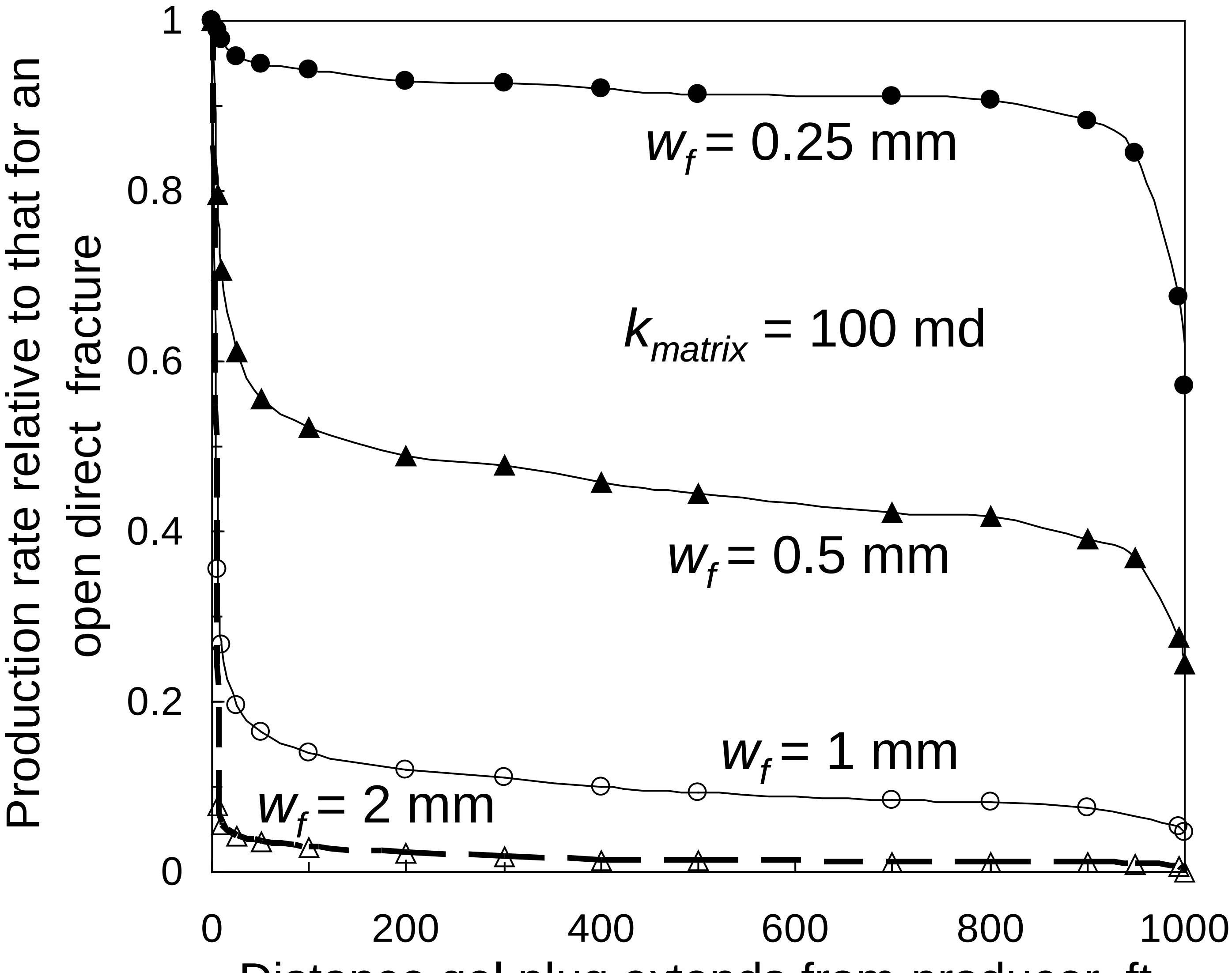
# Pressure distribution when 1-mm fracture was fully open



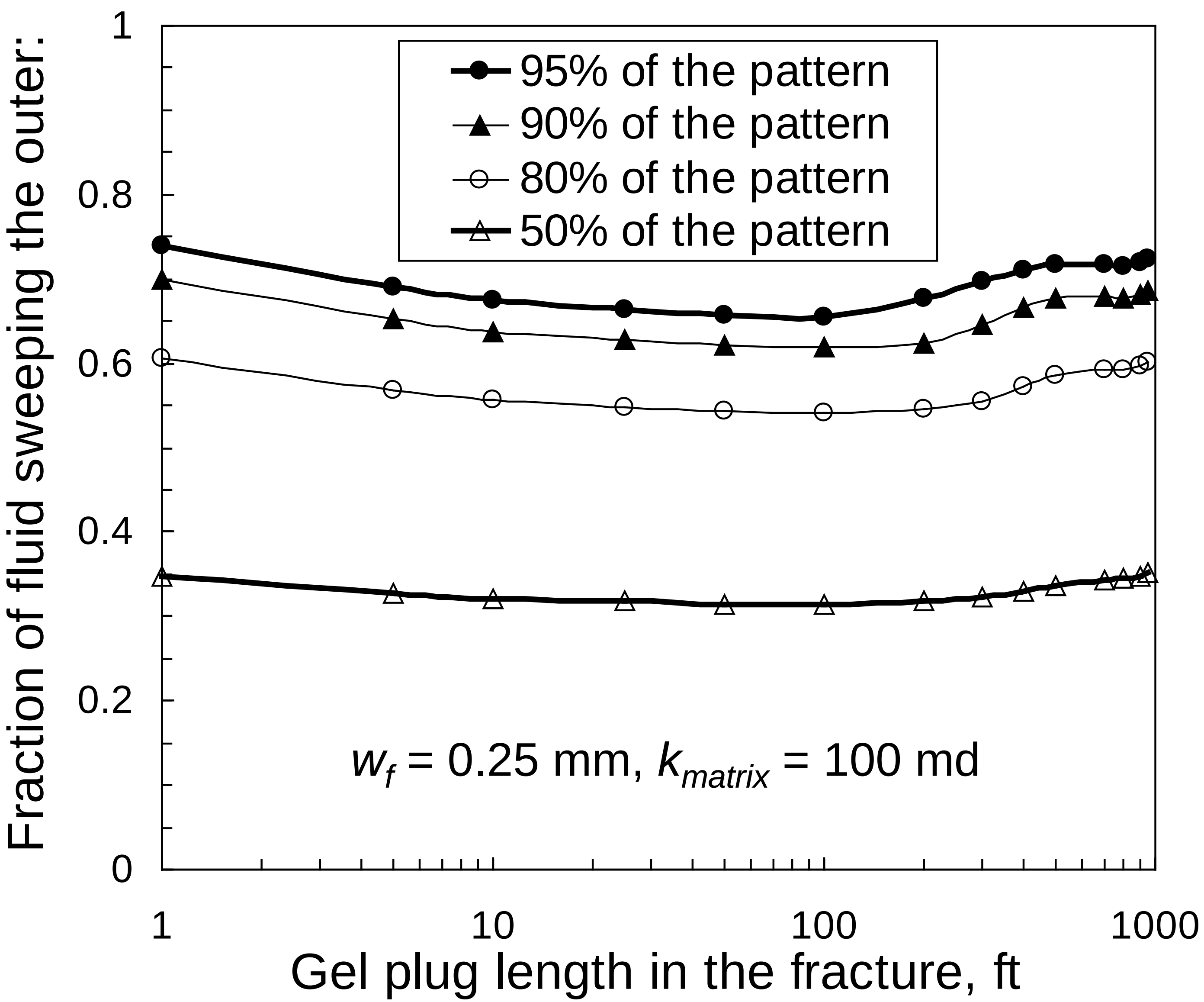
# Pressure distribution with no fracture

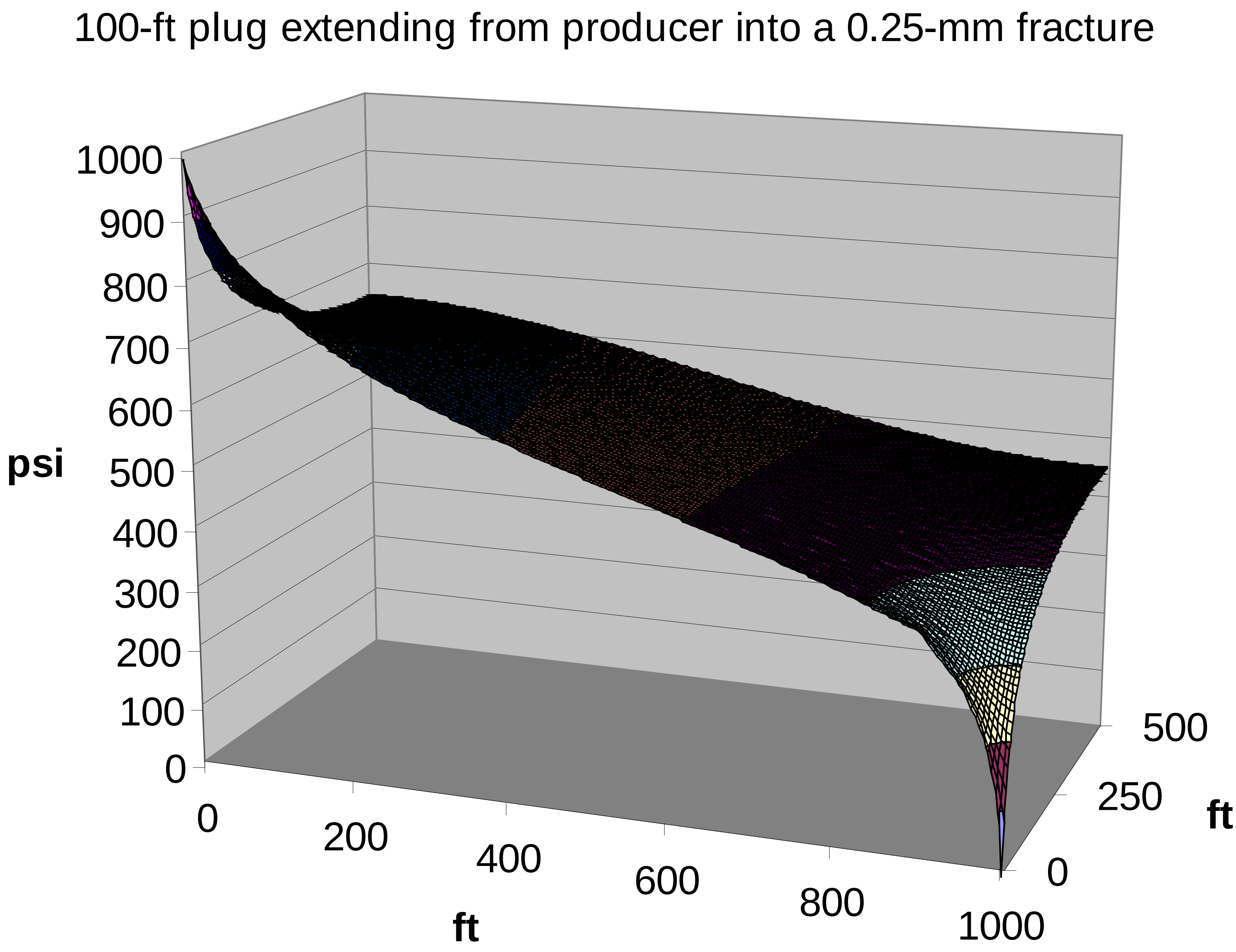


# A 25-ft Long Gel Plug Substantially Reduced Productivity in Moderate to Wide Fractures

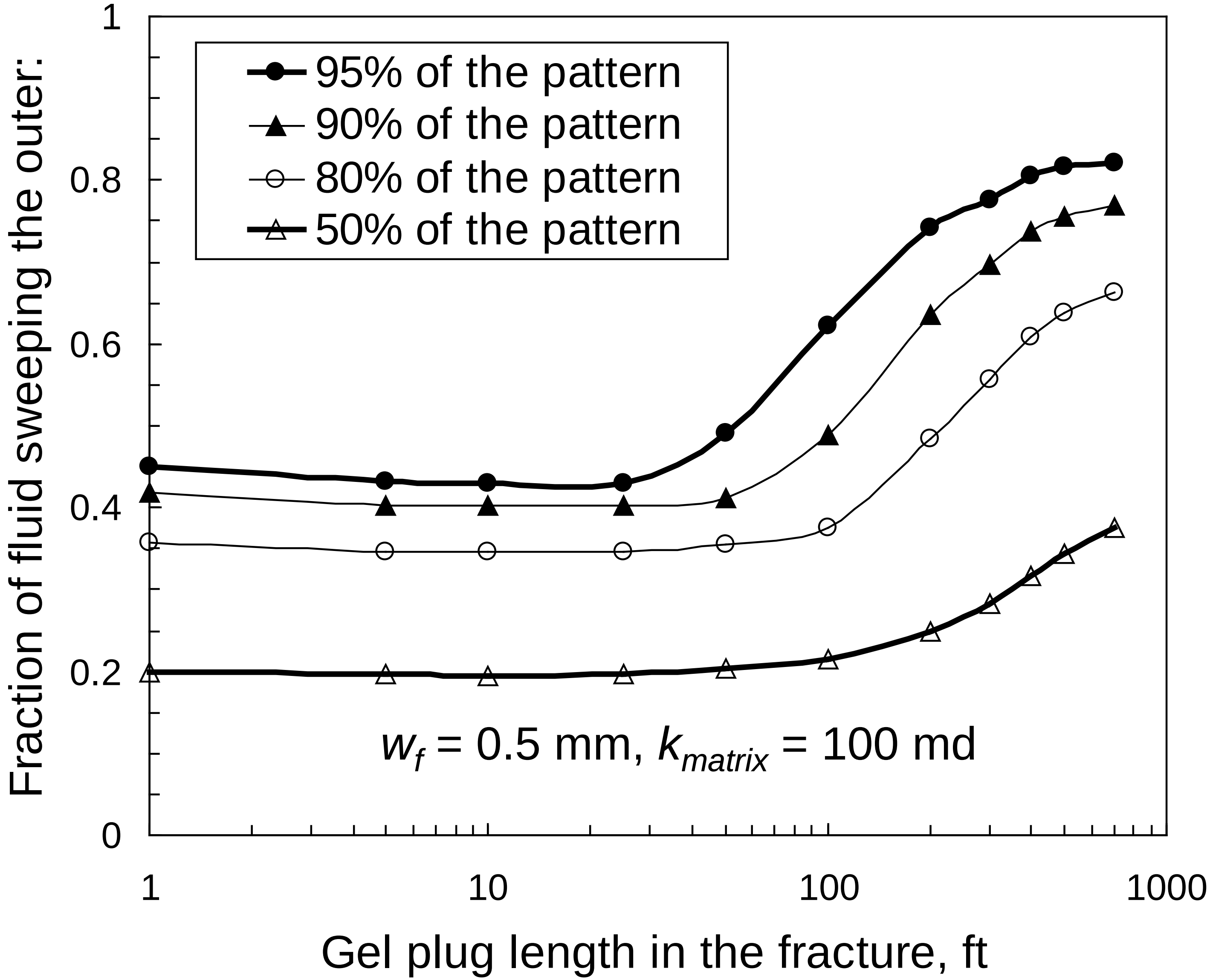


# Gel Plugs Were Not Needed in Narrow Fractures ($w_f \leq 0.25$ mm if $k_{matrix}$ = 100 md)

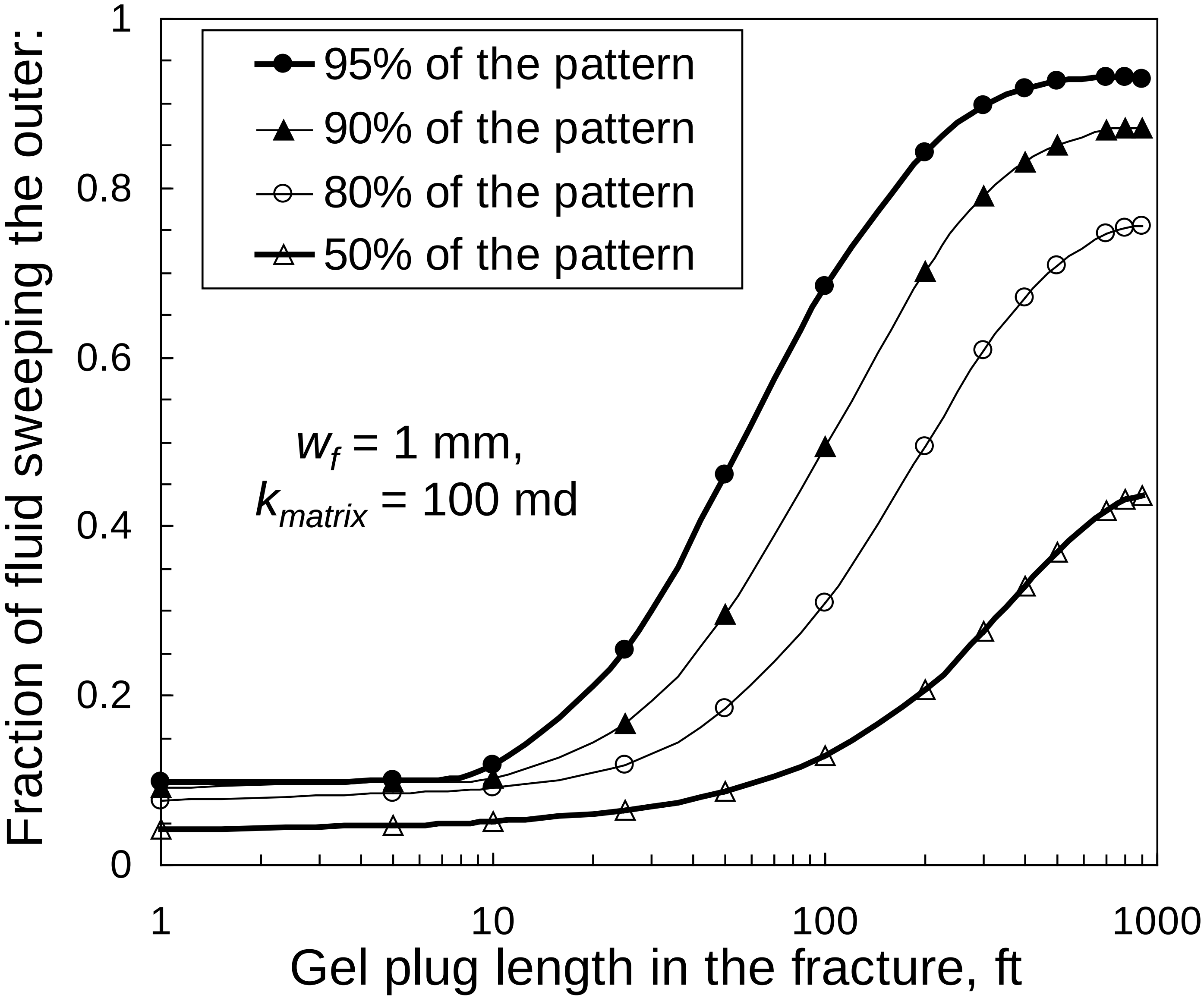



100-ft plug extending from producer into a 0.25-mm fracture
psi
1000
900
800
700
600
500
400
300
200
100
0
0
200
400
600
800
1000
ft
500
250
0
ft

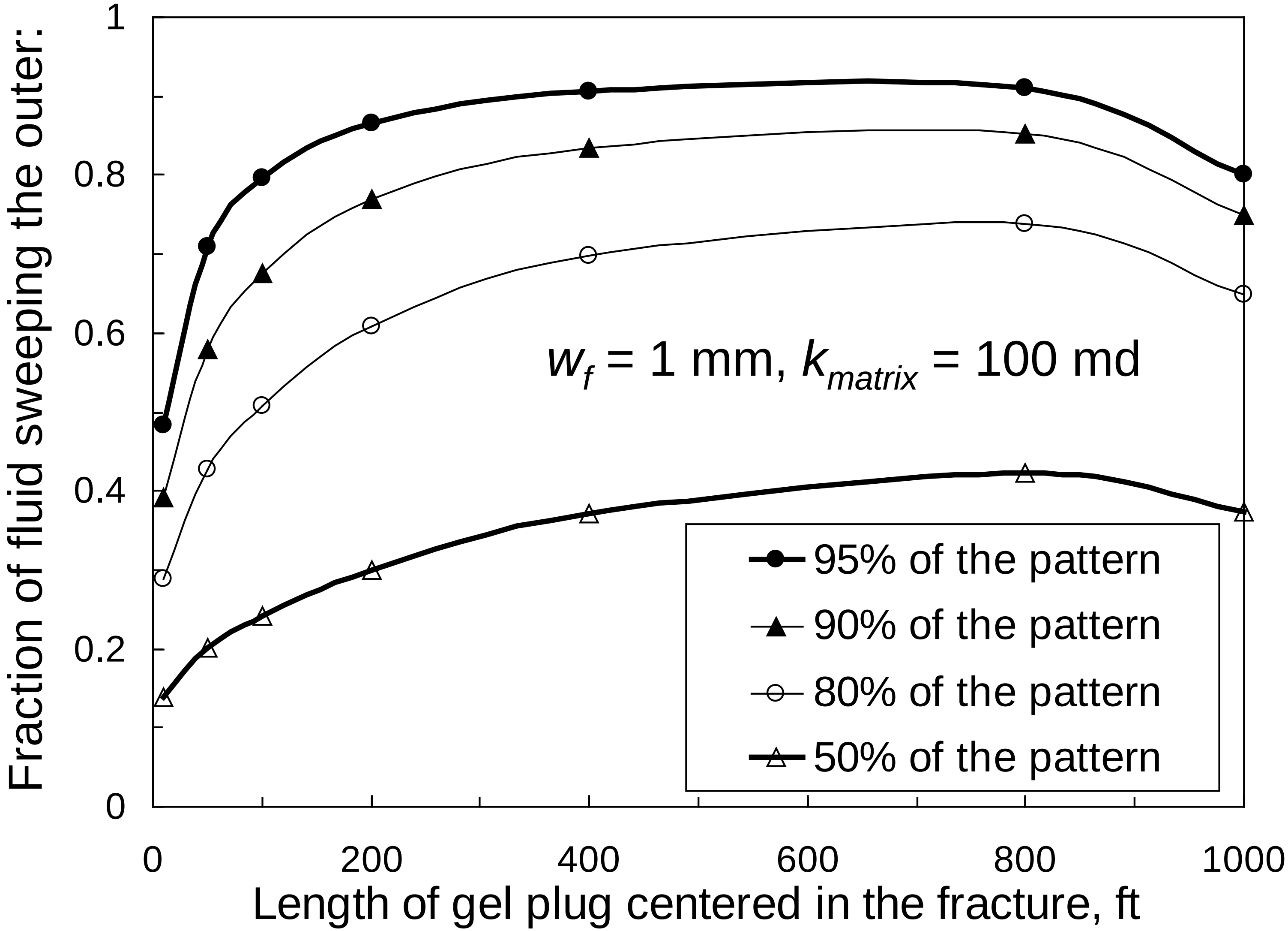
# If $w_f$ > 0.5 mm, Gel Plugs Filling > 10% of the Fracture Were Needed to Significantly Improve Sweep



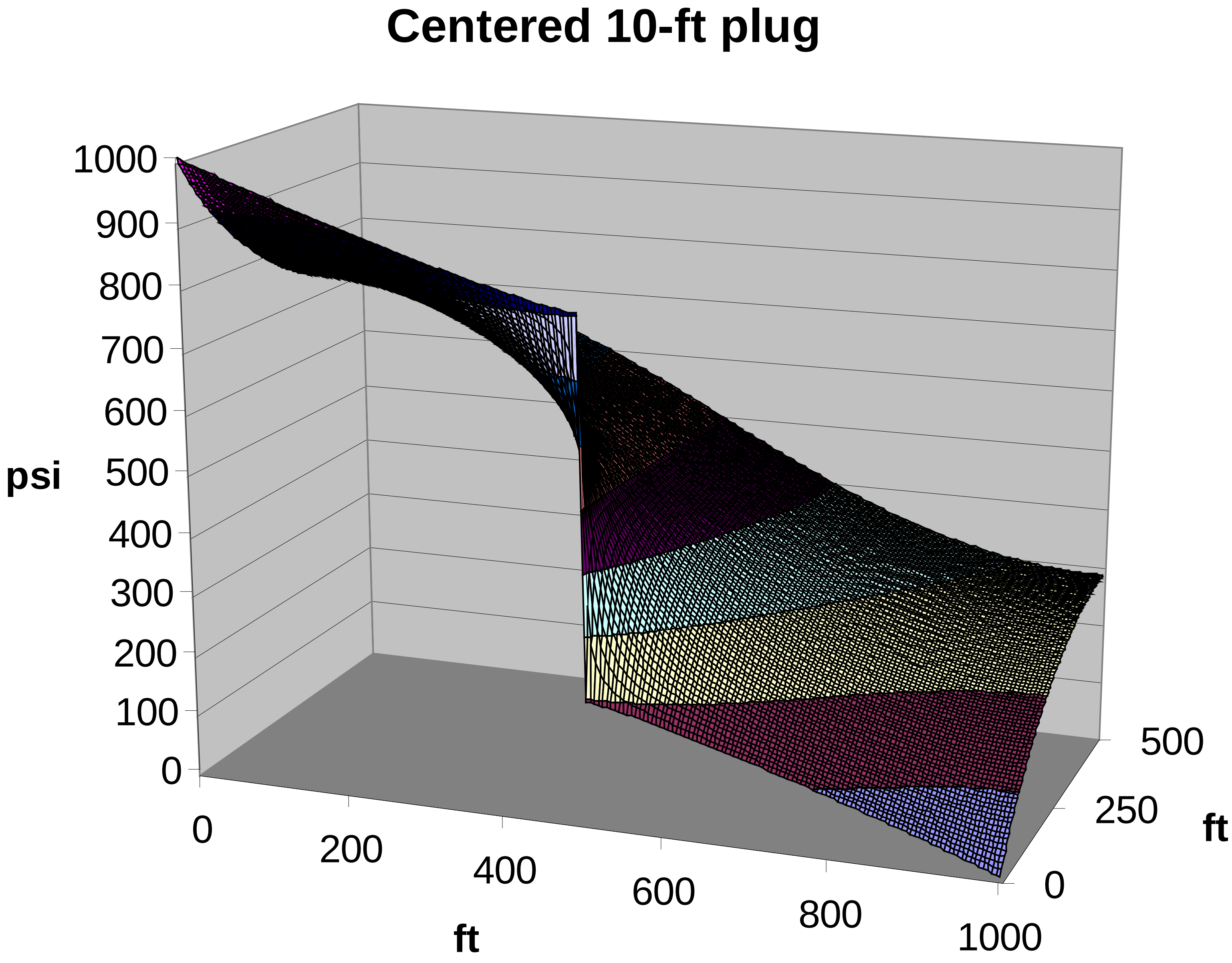
# If $w_f$ > 0.5 mm, Gel Plugs Filling > 10% of the Fracture Were Needed to Significantly Improve Sweep



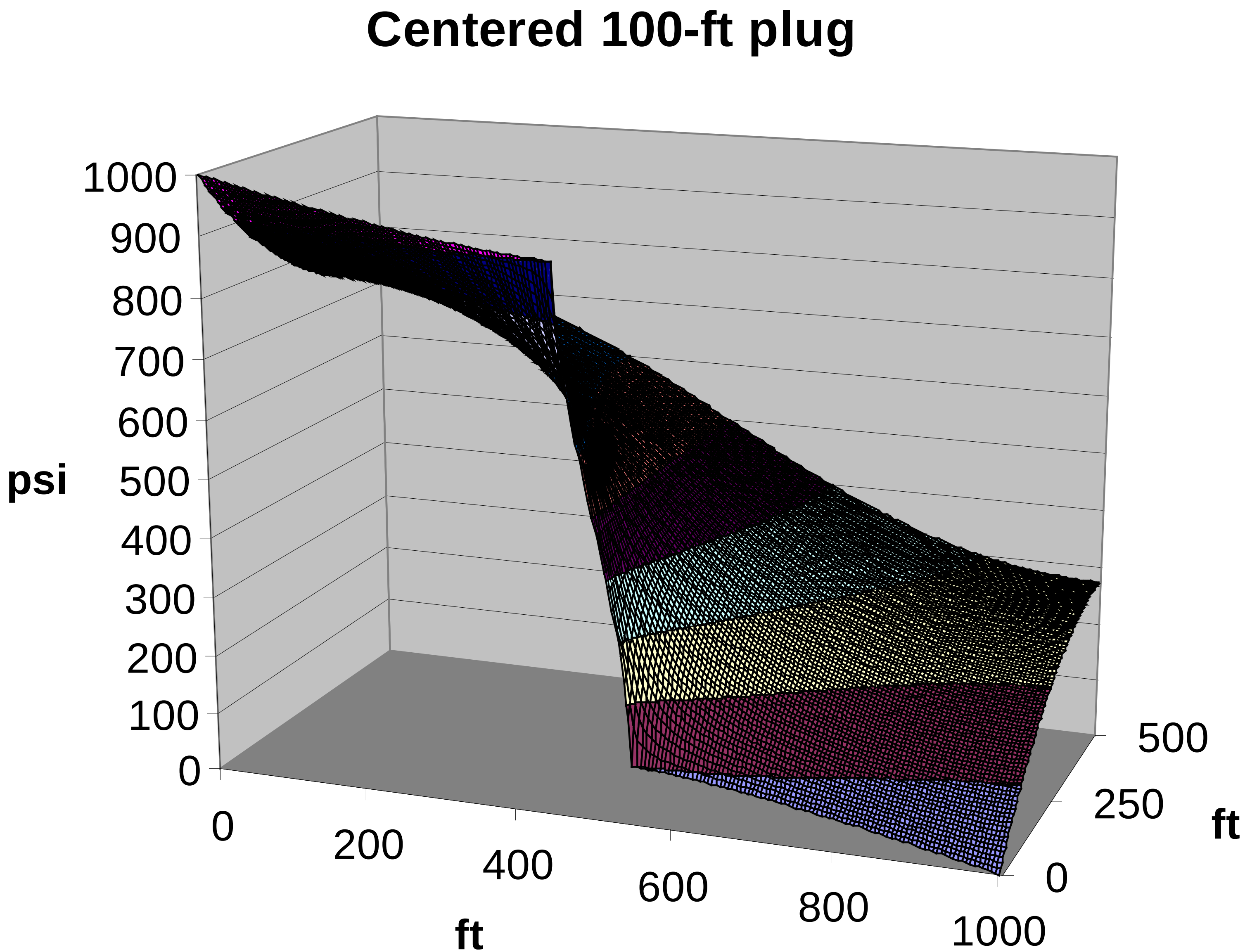
# For Plugs Centered in the Fracture, Sweep Improvement Was Not Sensitive to Plug Size if the Plugs Were Longer than 20% of the Fracture Length



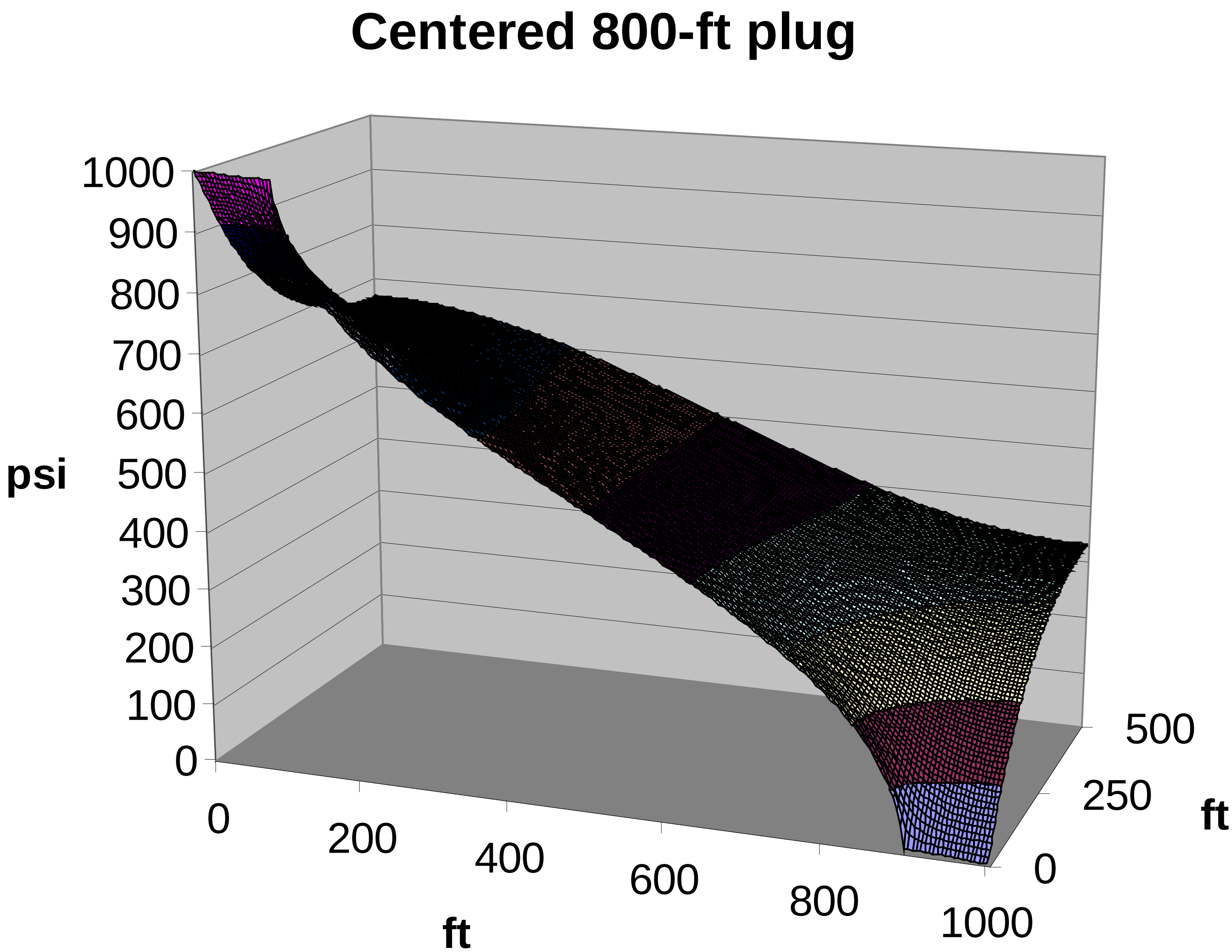
# Pressure distribution with a 10-ft plug centered in a 1-mm fracture



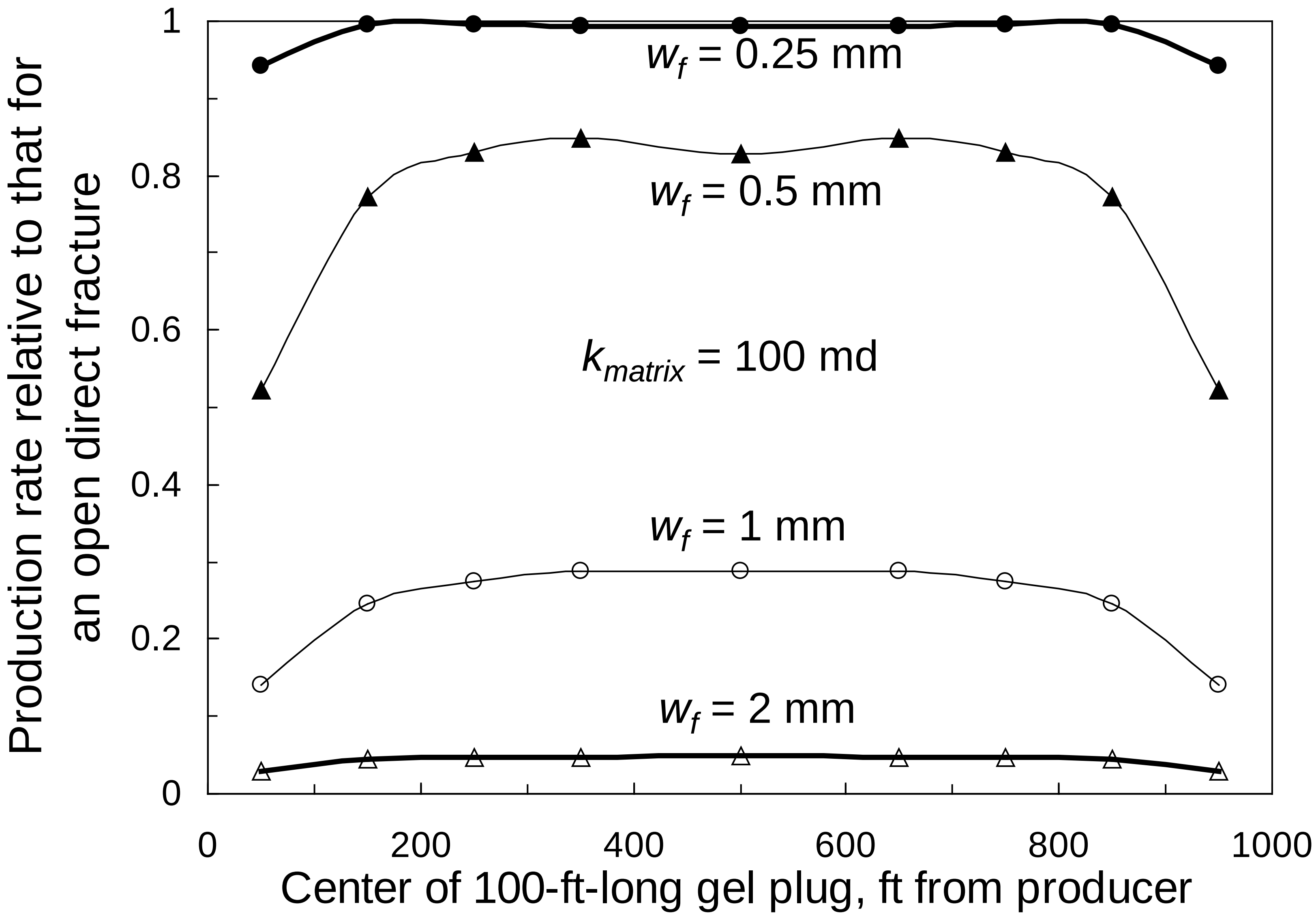
# Pressure distribution with a 100-ft plug centered in a 1-mm fracture



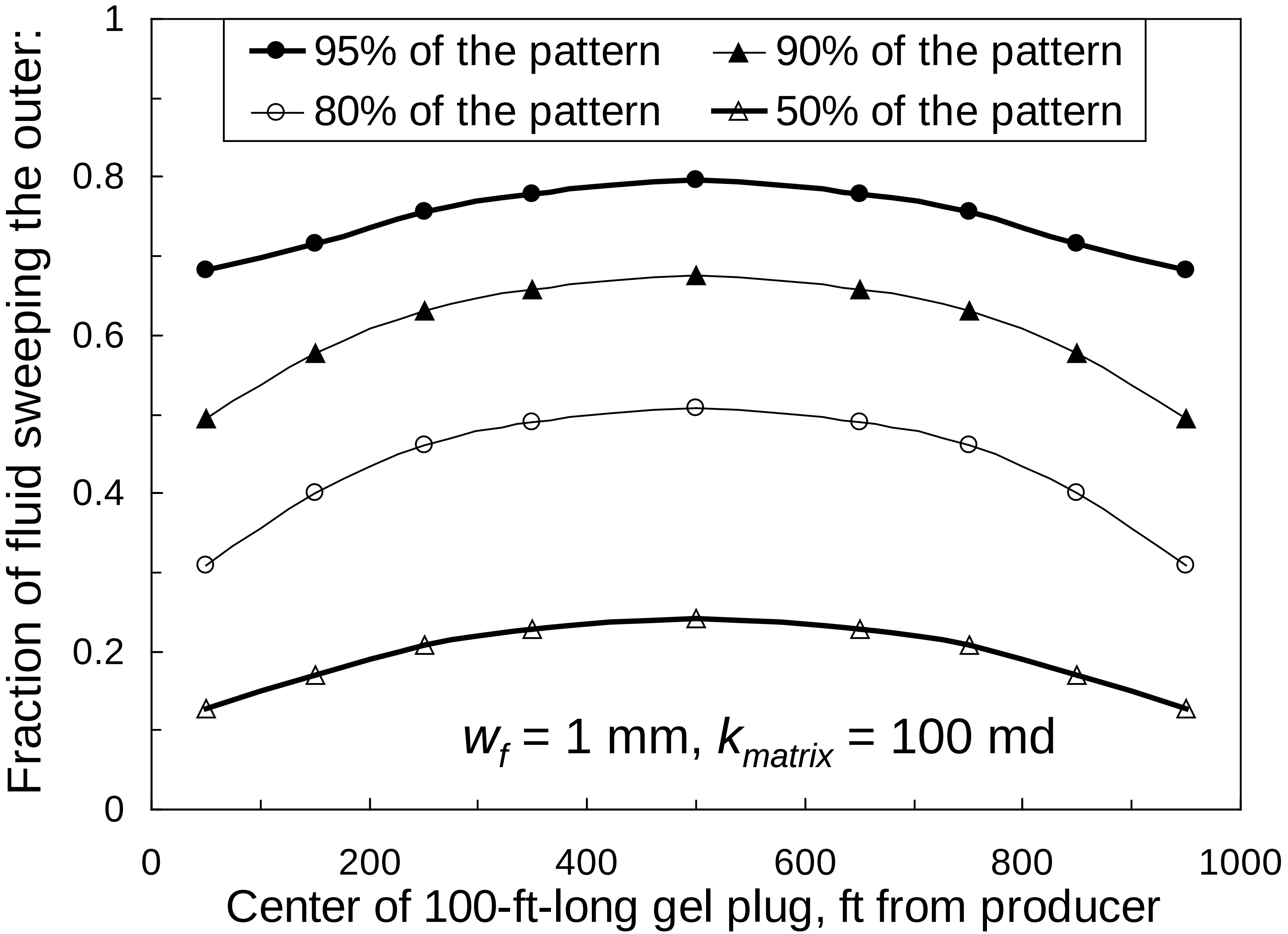
## Pressure distribution with a 800-ft plug centered in a 1-mm fracture

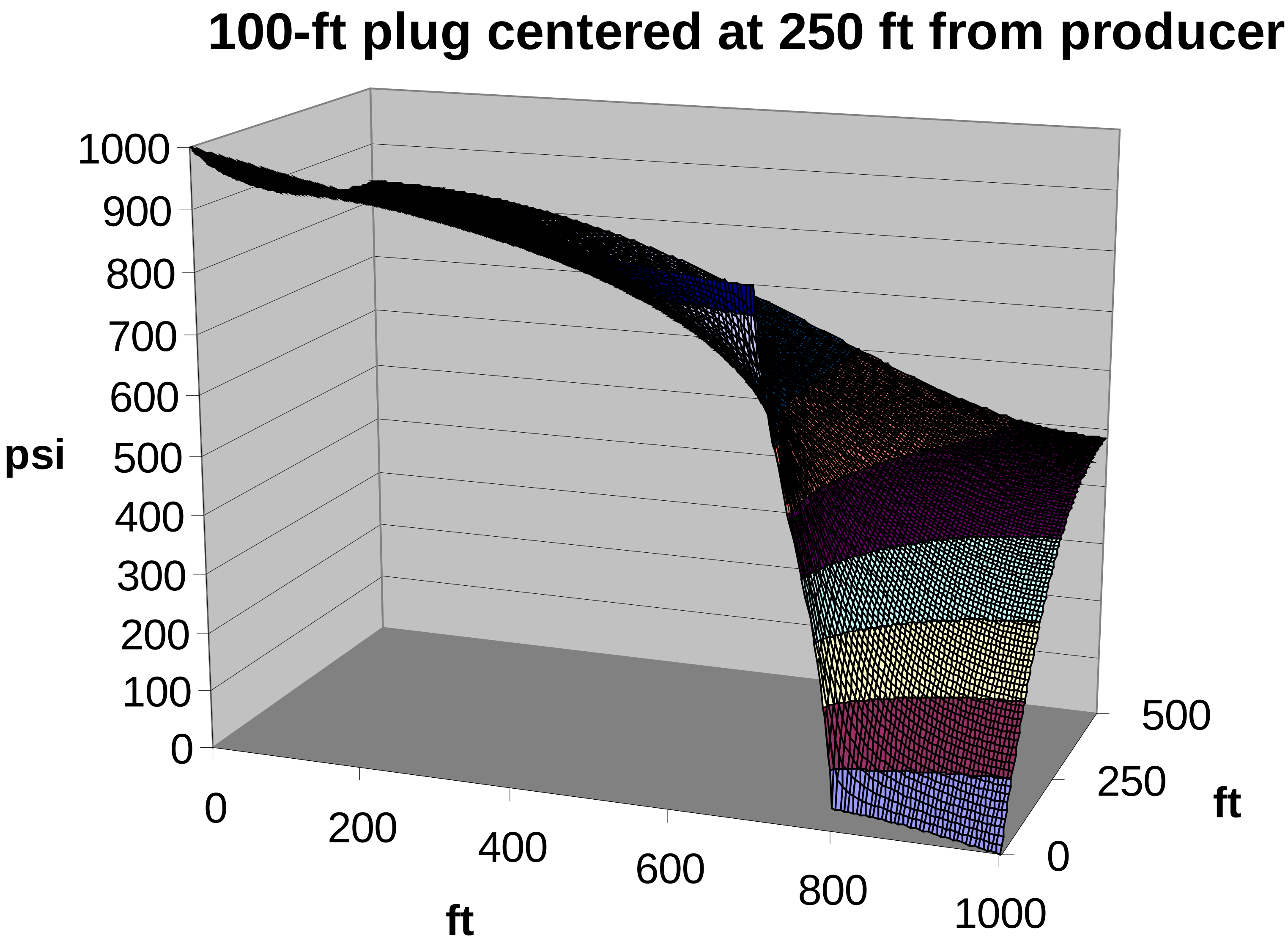


# Off-Centered Plugs Didn't Affect Rates Much if the Plugs Were Not Close to a Well



# Sweep Decreased as Plugs Moved Off-Center




100-ft plug centered at 250 ft from producer
psi
1000
900
800
700
600
500
400
300
200
100
0
0
200
400
600
800
1000
ft
0
250
500
ft

# Summary for Optimum Plug Placement:

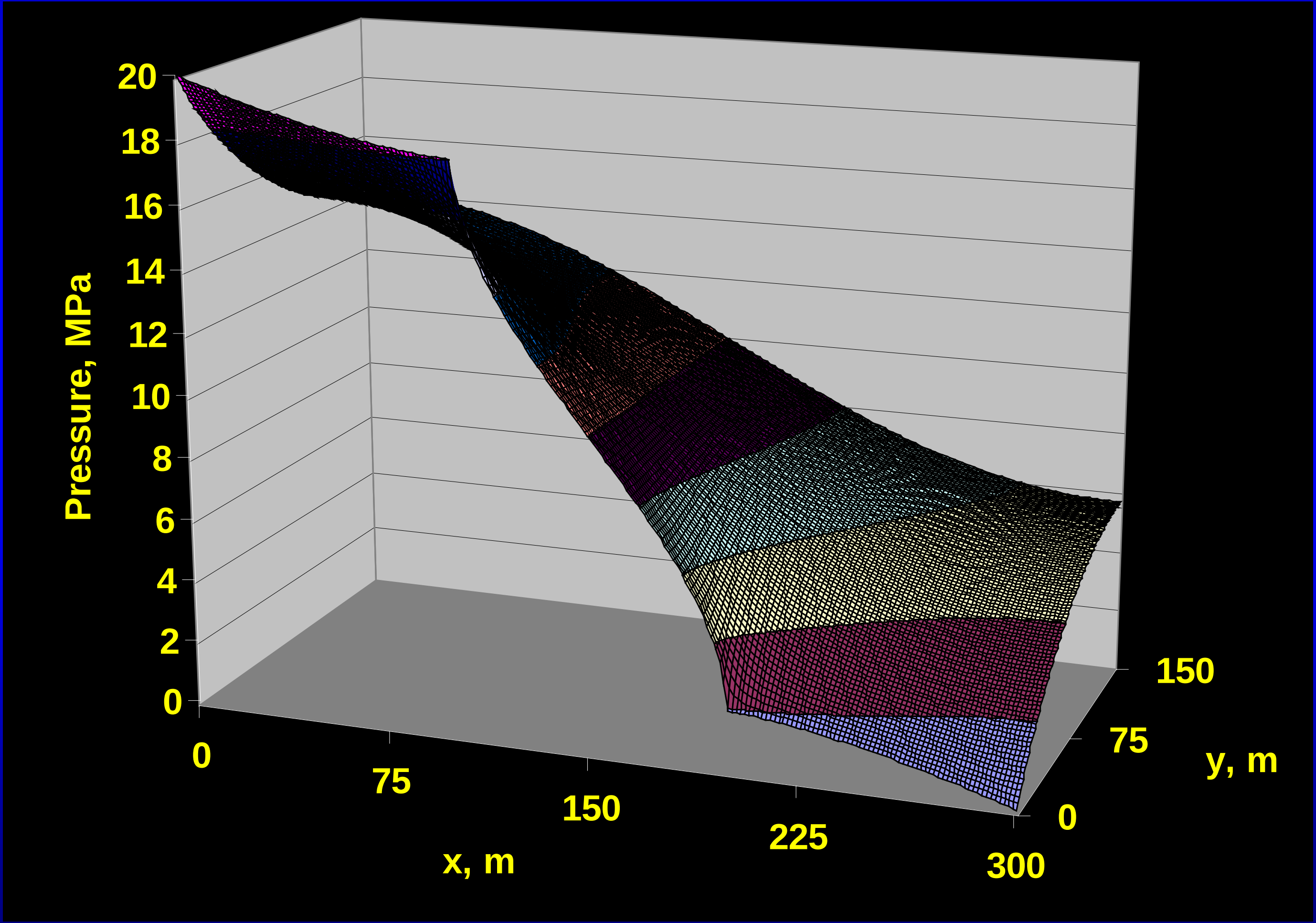
## Direct fracture channel between two vertical wells.

1. A small near-wellbore plug (e.g., 25-ft long) dramatically reduces pattern flow rates (e.g., water channeling), but does not improve pattern pressure gradients in a manner that enhanced oil displacement from deep within the reservoir.

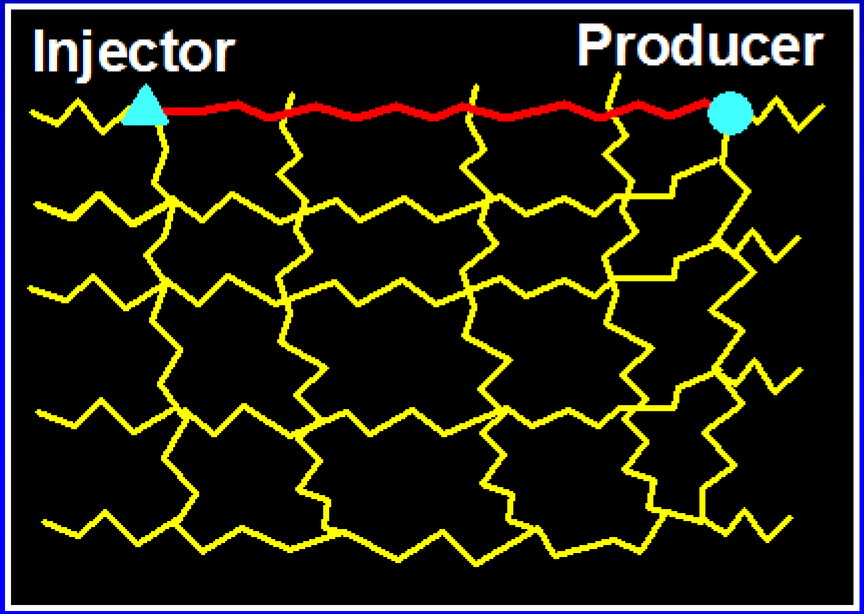
2. Significant improvements in oil displacement requires plugging of at least 10% (and preferably more than 20%) of the length of the offending fracture.

3. Ideally, this plug should be placed near the center of the fracture.

**When fractures cause severe channeling, restricting the middle part of the fracture provides the best possibility. (See our 2005 annual report).**



# NATURALLY FRACTURED RESERVOIRS




**When multiple fracture pathways are present, some benefit will result from plugging the middle part of the most conductive fracture. (E.g., a 90% water cut is better than a 99% water cut.)**

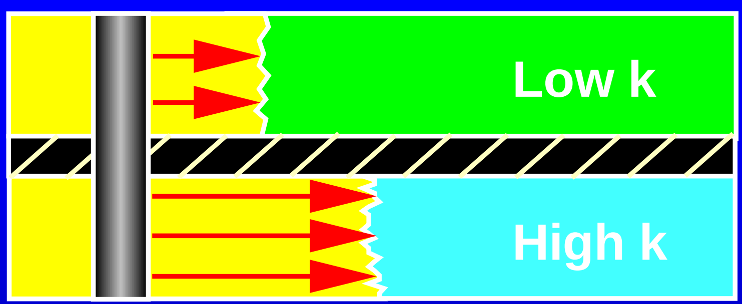
**MISCONCEPTION: Water-based polymers and gelants won't enter oil zones.**

**If this is true, why does a waterflood work?**

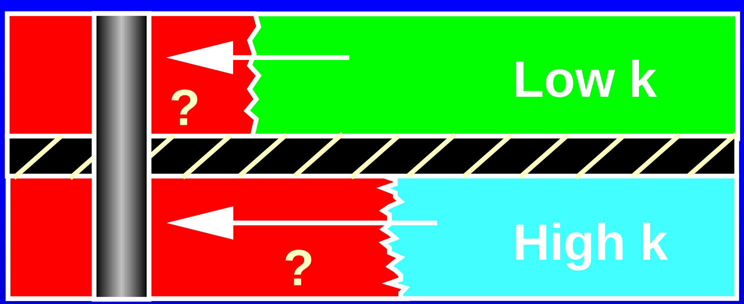
## GEL PLACEMENT IN PRODUCTION WELLS

## SPEPF (Nov. 1993) 276-284

### Gelant Injection




### Return to Production




**Relative permeability and capillary pressure effects will not prevent gelants from entering oil zones.**

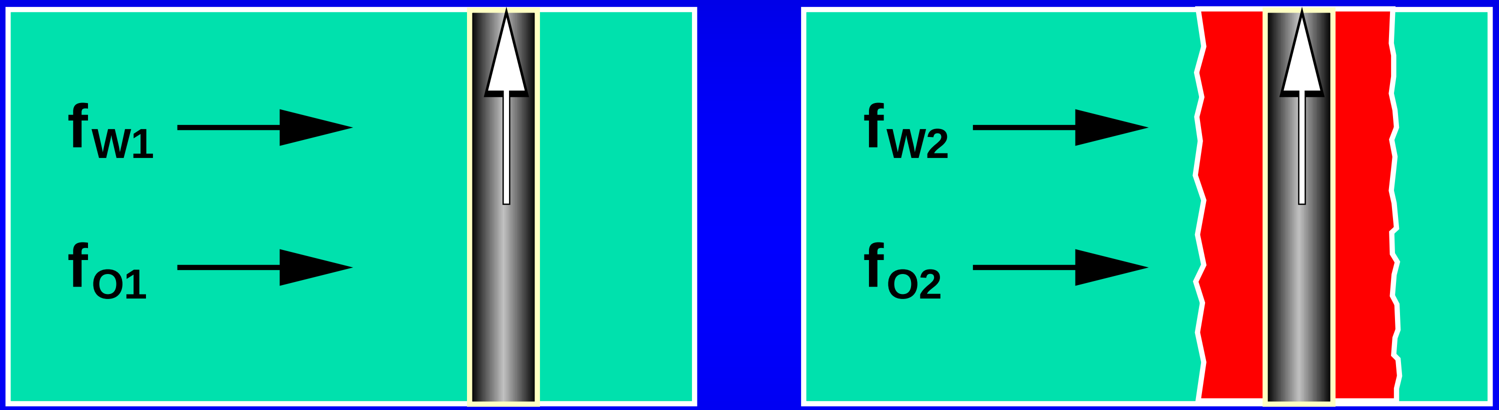
**To prevent damage to oil zones, gel must reduce $k_w$ much more than $k_o$.**

Water Oil Gelant Gel

# DISPROPORTIONATE PERMEABILITY REDUCTION

- Some gels can reduce $k_w$ more than $k_o$ or $k_{gas}$.
- Some people call this "disproportionate permeability reduction" or "DPR". Others call it "relative permeability modification" or "RPM". It is the same thing!
- This property is only of value in production wells with distinct water and hydrocarbon zones. It has no special value in injection wells!!!
- NO KNOWN polymer or gel will RELIABLY reduce $k_w$ without causing some reduction in $k_o$ !!!

In the absence of fractures, casing leaks, and flow behind pipe, gel treatments are not expected to improve the WOR from a single zone.



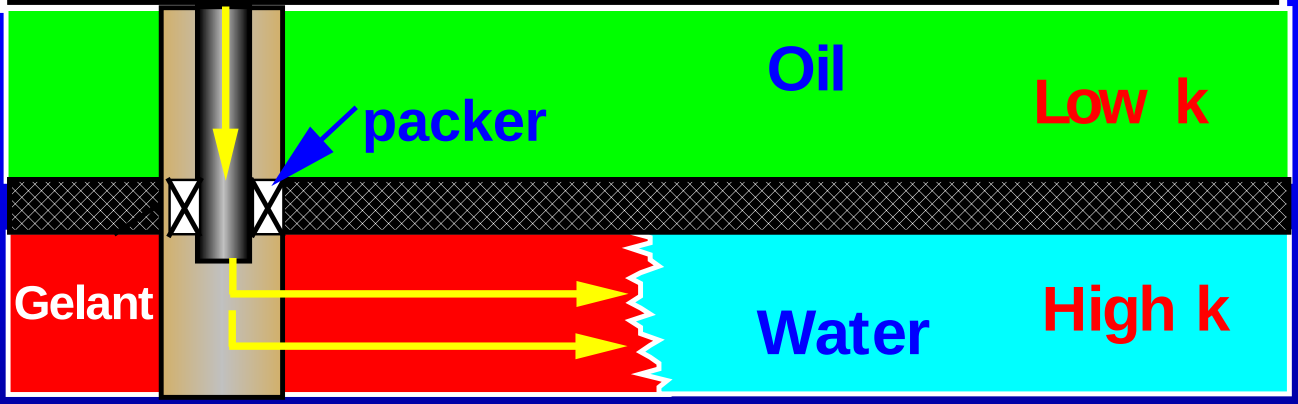

before gel

after gel: $f_{W2} = f_{W1}$ and $f_{O2} = f_{O1}$

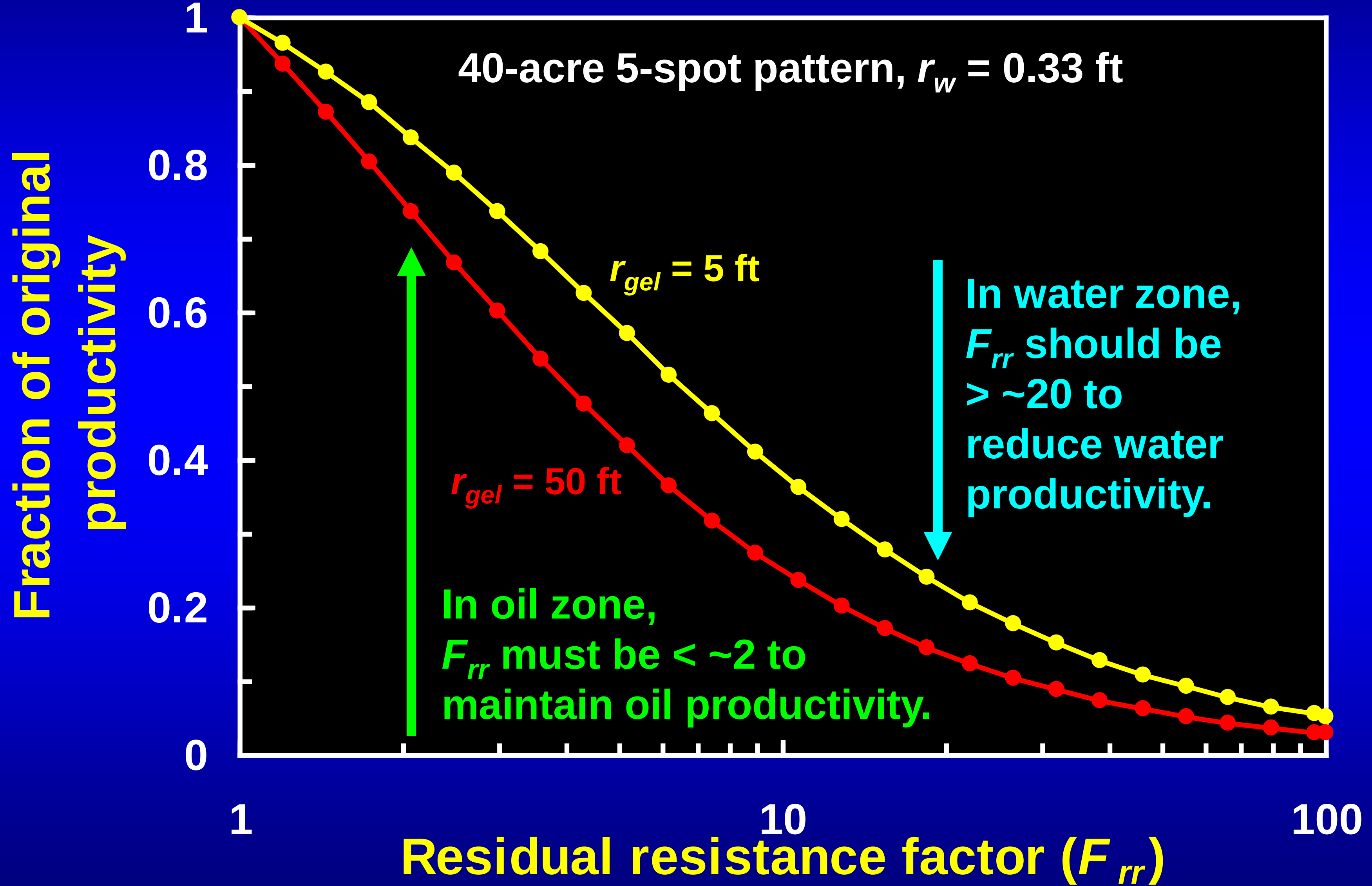
SPEPF (Nov. 1993) 276-284

## GEL TREATMENTS FOR RADIAL FLOW PROBLEMS

- Zones MUST be separated by impermeable barriers.
- Hydrocarbon-productive zones MUST be protected during gelant injection.
- Loss of water productivity or injectivity is not sensitive to radius of gelant penetration between 5 and 50 ft.
- Gel permeability reductions > 20 cause > 80% loss of water productivity.



# Radial Flow Requires That $F_{rro}$ < 2 and $F_{rrw}$ > 20

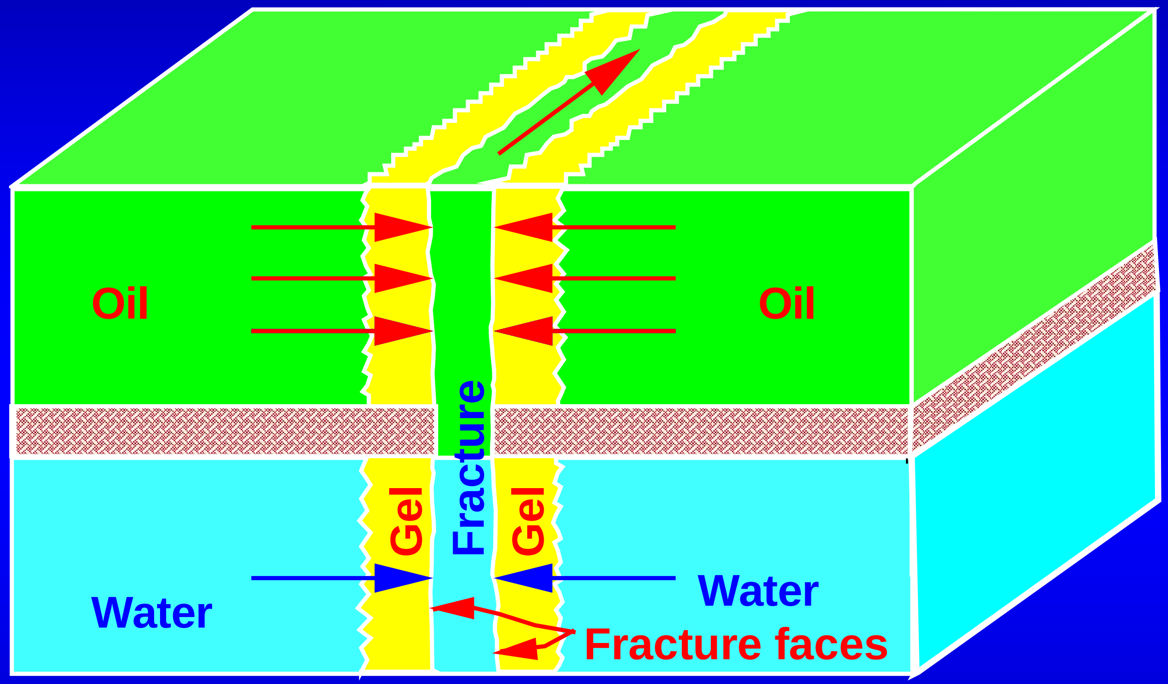


**With present technology, hydrocarbon zones MUST be protected during gelant placement in unfractured production wells.**

**To avoid this requirement, we need a gel that RELIABLY reduces $k_w$ by >20X but reduces $k_o$ by < 2X.**

# "DPR" or "RPM" is currently most useful in linear-flow problems (e.g., fractures)

## Gel Restricting Water Flow into a Fracture




**Equivalent resistance to flow added by the gel**

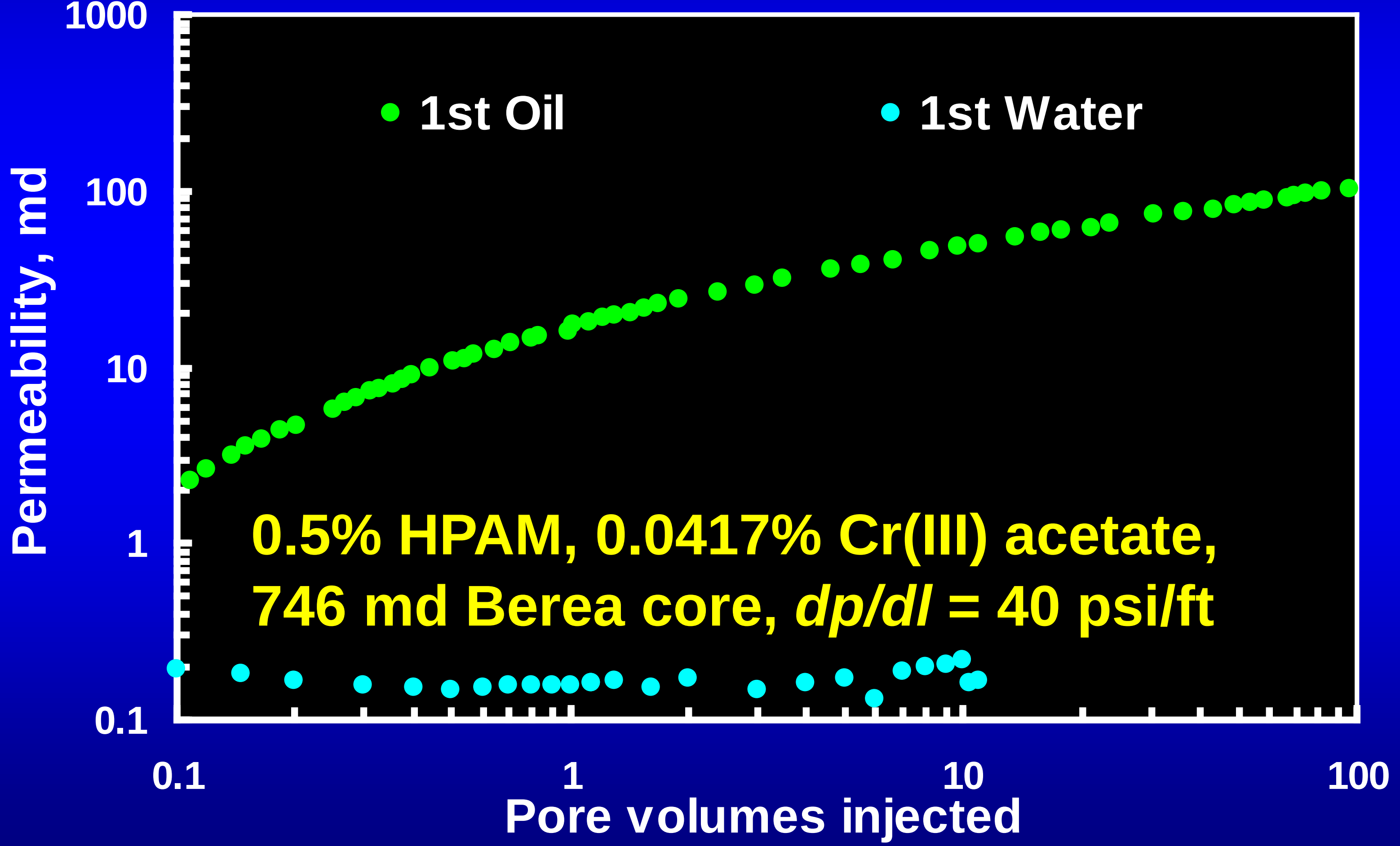
- **In oil zone: 0.2 ft x 50 = 10 ft.**
- **In water zone: 0.2 ft x 5,000 = 1,000 ft.**

***IN SITU* 17(3), (1993) 243-272**

## $F_{rrw}$ and final $F_{rro}$ values for pore-filling Cr(III)-acetate-HPAM gels in Berea sandstone.

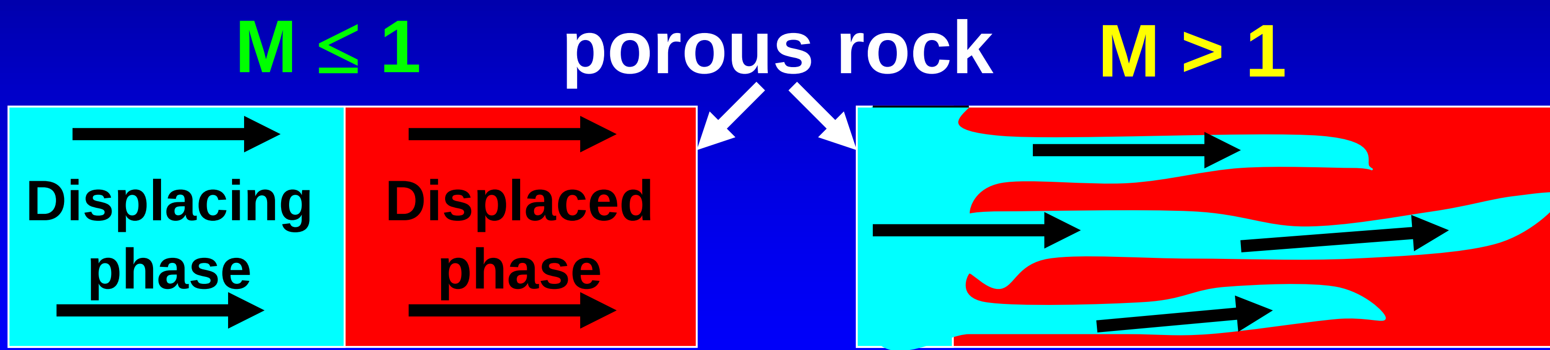
| Pre-gel $k_w$, md | HPAM in gel, % | Post-gel $k_w$, md | $F_{rrw}$ | Final $F_{rro}$ |
|---|---|---|---|---|
| 356 | 0.5 | 0.015 | 23,700 | 1.2 |
| 389 | 0.5 | 0.005 | 77,800 | 1.2 |
| 31 | 0.5 | 0.007 | 4,430 | 2.2 |
| 40 | 0.4 | 0.019 | 2,110 | 2.0 |
| 270 | 0.3 | 0.055 | 4,980 | 1.7 |

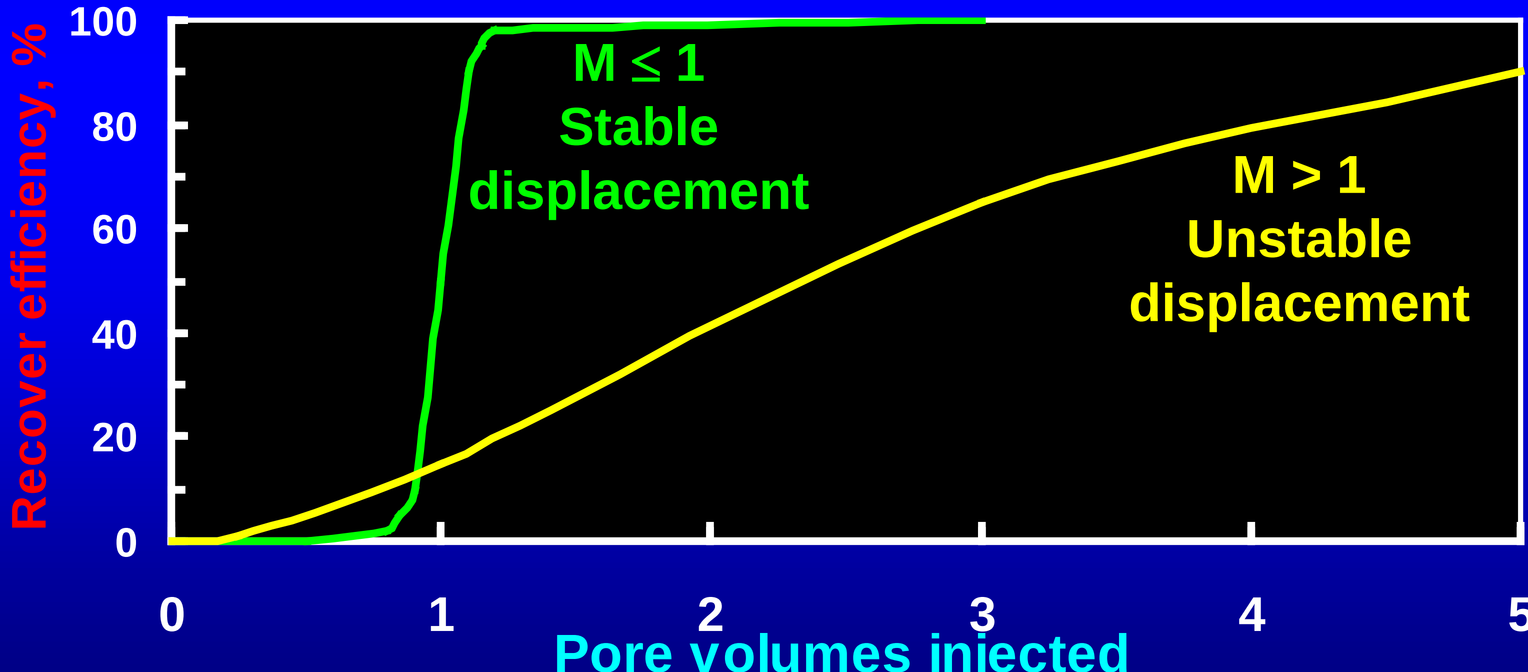
1. After gel placement, $k_o$ rose from 2 to 105 md in 100 PV ($F_{rro}$ = 4.8 @ 100 PV).
2. $k_w$ stabilized at 0.17 md very quickly ($F_{rrw}$ = 706).



# MOBILITY RATIO

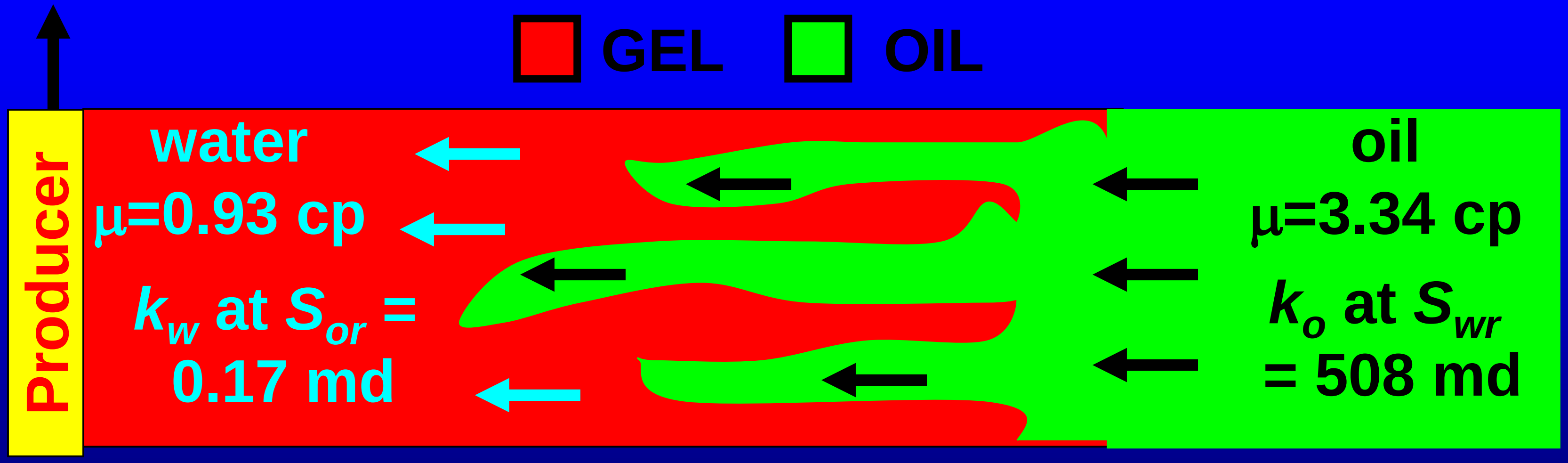
$$M = (k/\mu)_{\text{displacing phase}} \;/\; (k/\mu)_{\text{displaced phase}}$$



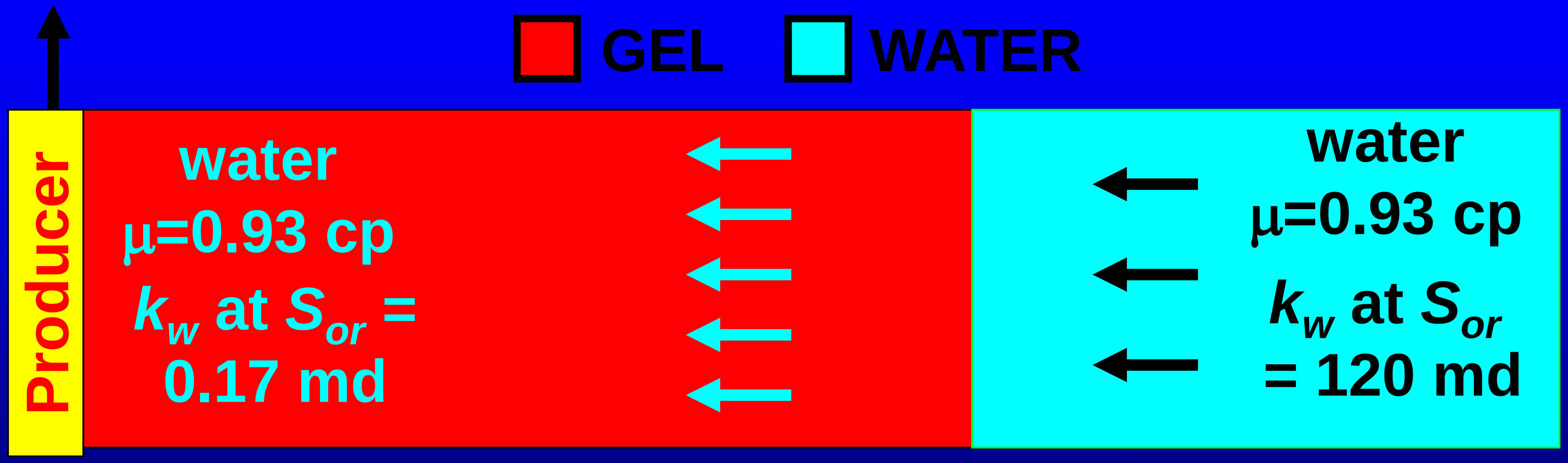
## What happens in an oil zone when a well is returned to production AFTER gel placement?

- Mobility ratio, M = $(k_o / \mu_o)/(k_w / \mu_w)$ = (508/3.34)/(0.17/0.93) = 830
- Displacement is very UNFAVORABLE!



**What happens in a water zone when a well is returned to production AFTER gel placement?**

- Initially mobility ratio also looks very unfavorable.
- HOWEVER, once the water enters the gel, it becomes part of the gel. So no viscous fingers form, and the displacement remains stable!

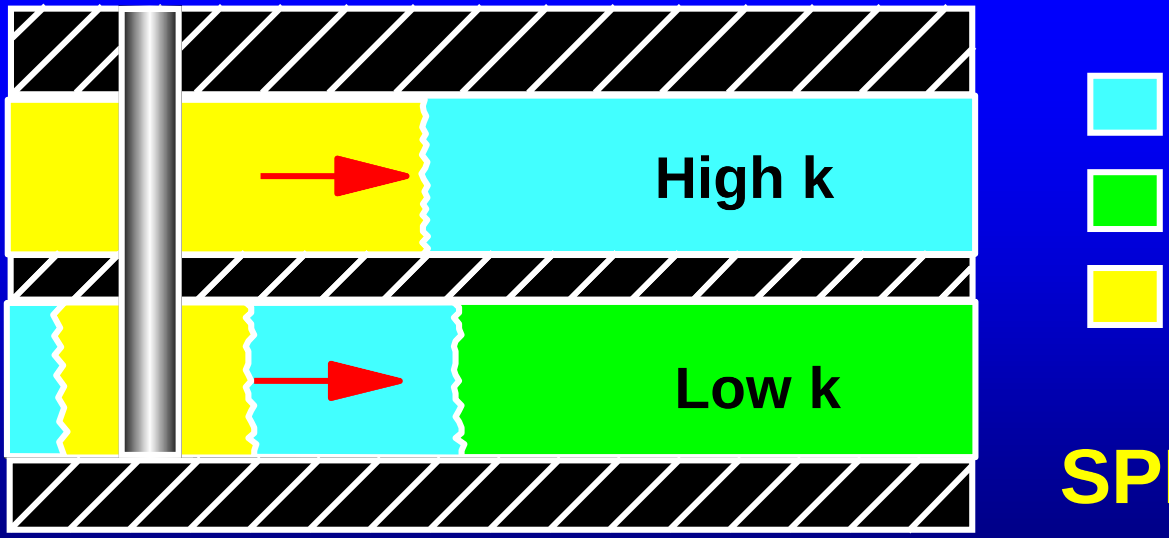


# KEY PLACEMENT POINTS

**Gelants can penetrate into all open zones.**

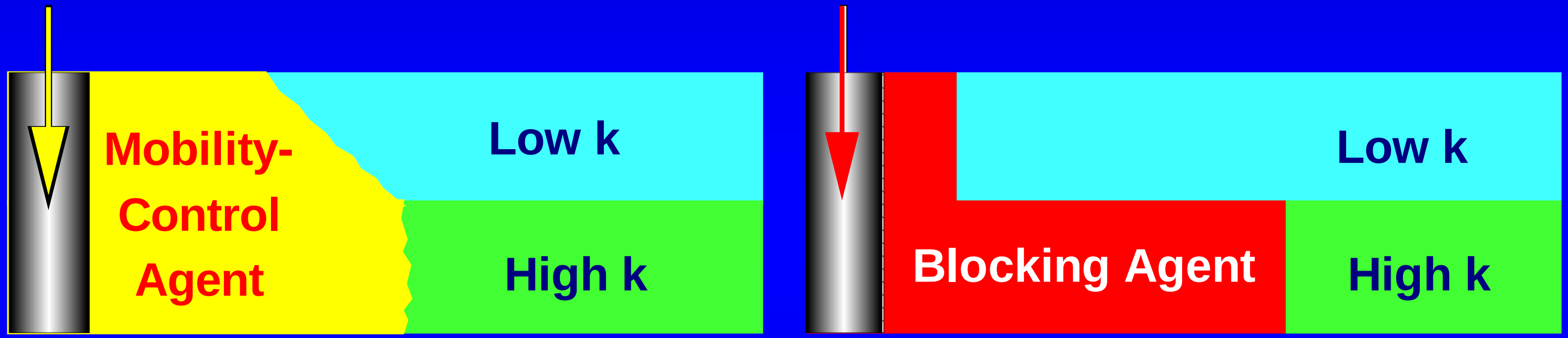
**An acceptable gelant placement is much easier to achieve in linear flow (fractured wells) than in radial flow.**

**In radial flow (unfractured wells), oil-productive zones must be protected during gelant placement.**




**SPE 17332**

## Distinction between a blocking agent and a mobility-control agent.




- For a mobility control agent, penetration into low-k zones should be maximized.
- For a blocking agent, penetration into low-k zones should be minimized.

# GEL TREATMENTS ARE NOT POLYMER FLOODS

Crosslinked polymers, gels, gel particles, and "colloidal dispersion gels":

- Are not simply viscous polymer solutions.
- Do not flow through porous rock like polymer solutions.
- Do not enter and plug high-k strata first and progressively less-permeable strata later.
- Should not be modeled as polymer floods.

**SPE 146087**

# A COMPARISON OF POLYMER FLOODING WITH IN-DEPTH PROFILE MODIFICATION

# BOTTOM LINE

1. In-depth profile modification is most appropriate for high permeability contrasts (e.g. 10:1), high thickness ratios (e.g., less-permeable zones being 10 times thicker than high-permeability zones), and relatively low oil viscosities.
2. Because of the high cost of the blocking agent (relative to conventional polymers), economics favor small blocking-agent bank sizes (e.g. 5% of the pore volume in the high-permeability layer).
3. Even though short-term economics may favor in-depth profile modification, ultimate recovery may be considerably less than from a traditional polymer flood. A longer view may favor polymer flooding both from a recovery viewpoint and an economic viewpoint.
4. In-depth profile modification is always more complicated and risky than polymer flooding.

**POLYMER FLOODING** is best for improving sweep in reservoirs where fractures do not cause severe channeling.

- Great for improving the mobility ratio.
- Great for overcoming vertical stratification.
- Fractures can cause channeling of polymer solutions and waste of expensive chemical.

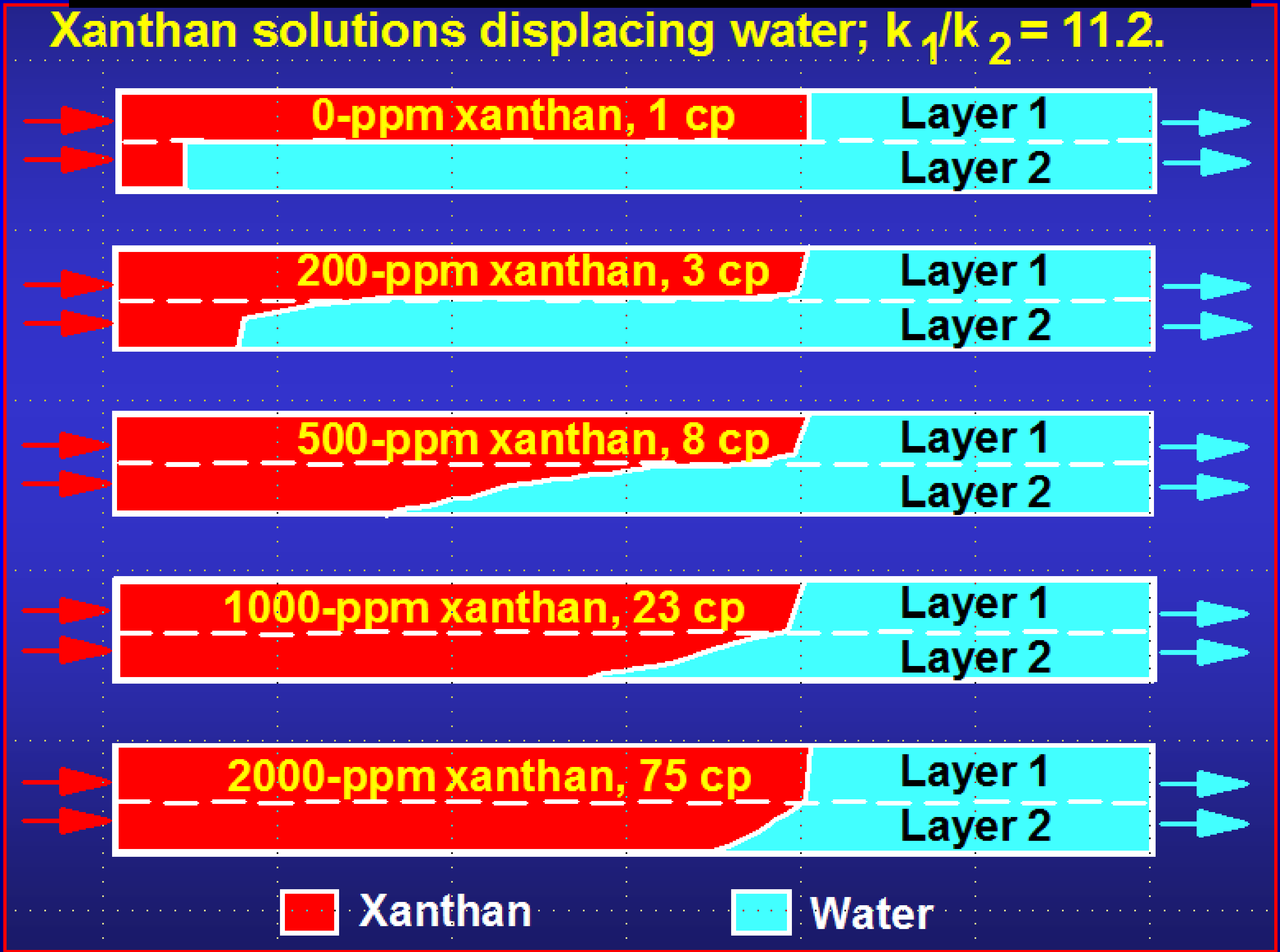
**GEL TREATMENTS** are best treating fractures and fracture-like features that cause channeling.

- Generally, low volume, low cost.
- Once gelation occurs, gels do not flow through rock.

**POLYMER FLOODING**

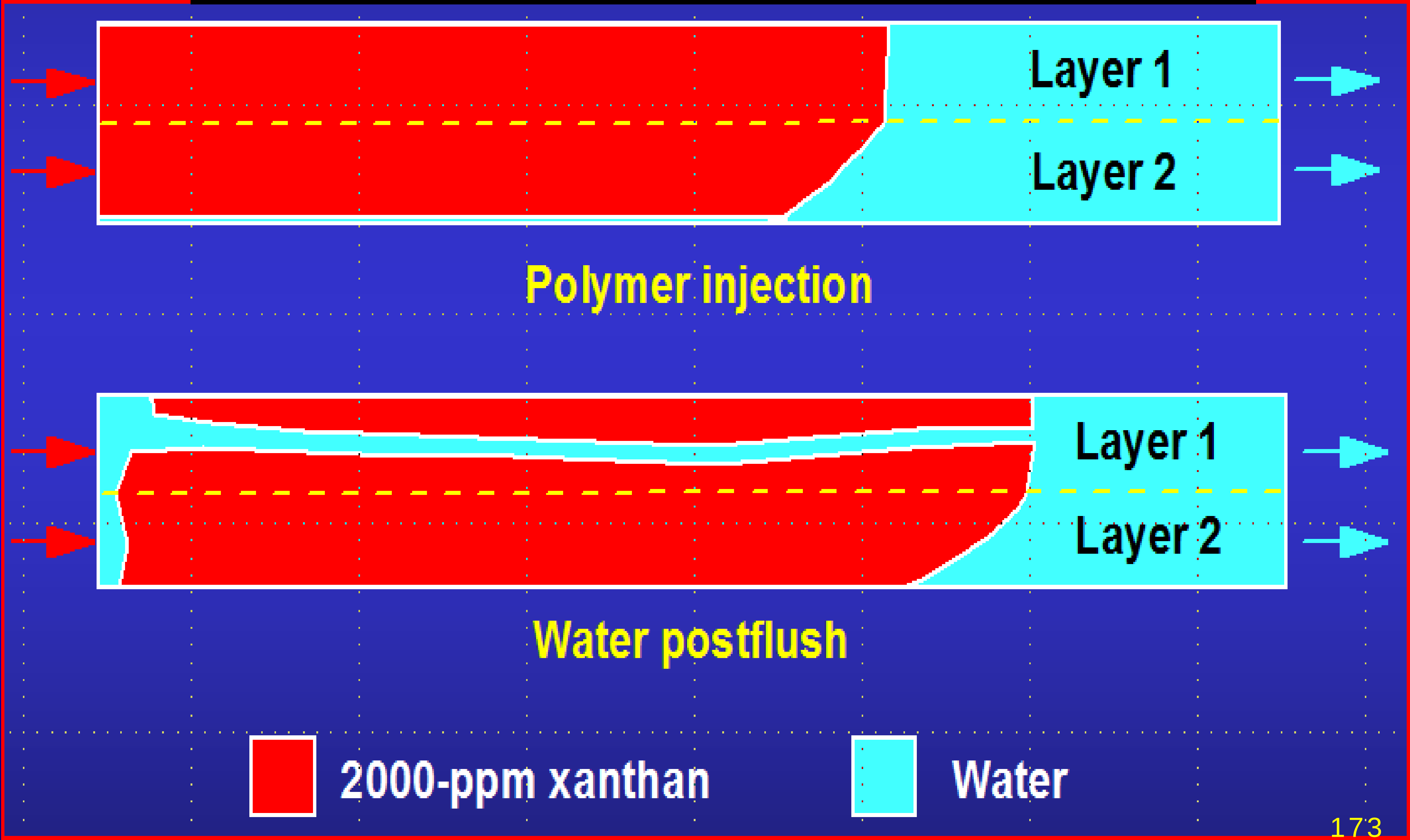
**As the viscosity of the injected fluid increases, sweep efficiency in the less-permeable layer increases.**

**http://baervan.nmt.edu/randy/**

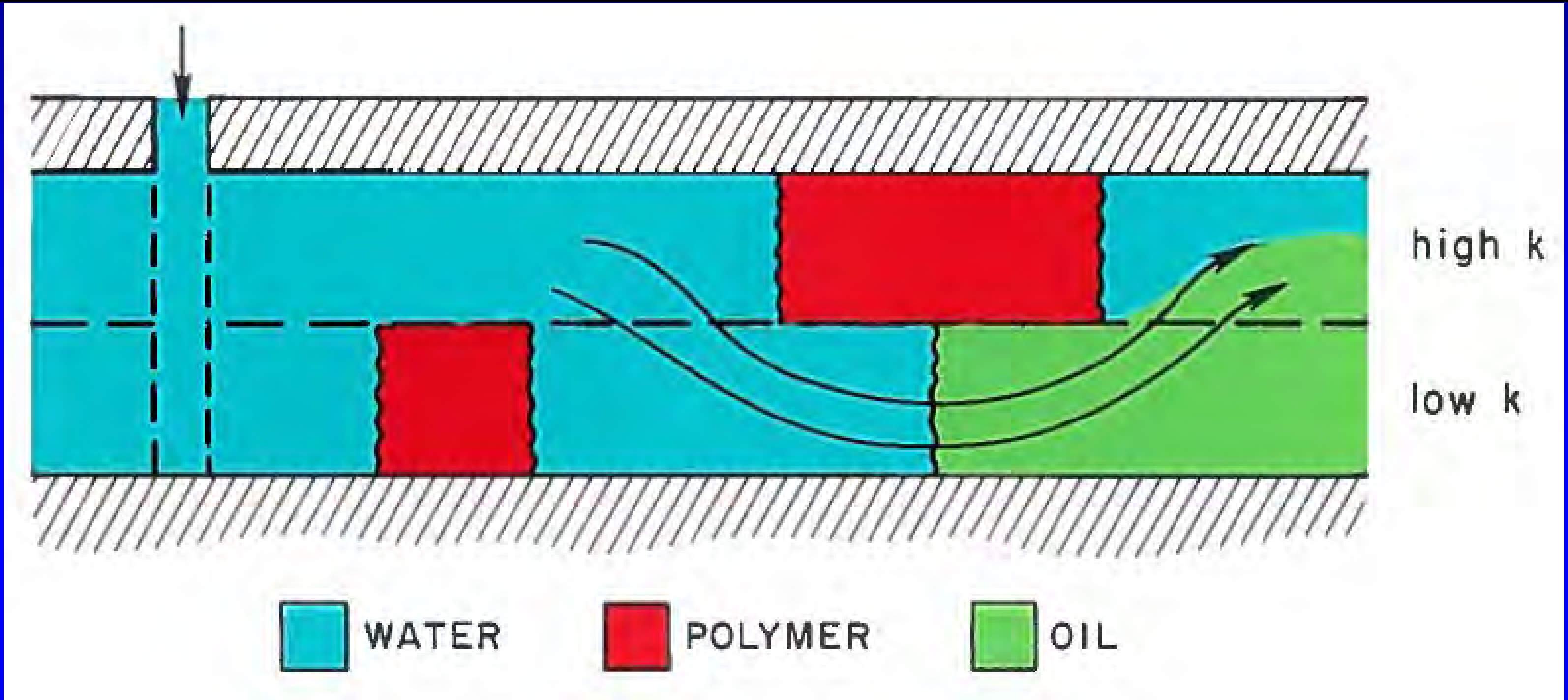


**After polymer or gel placement, injected water forms severe viscous fingers that channel exclusively through the high-permeability layer.**

**http://baervan.nmt.edu/randy/**

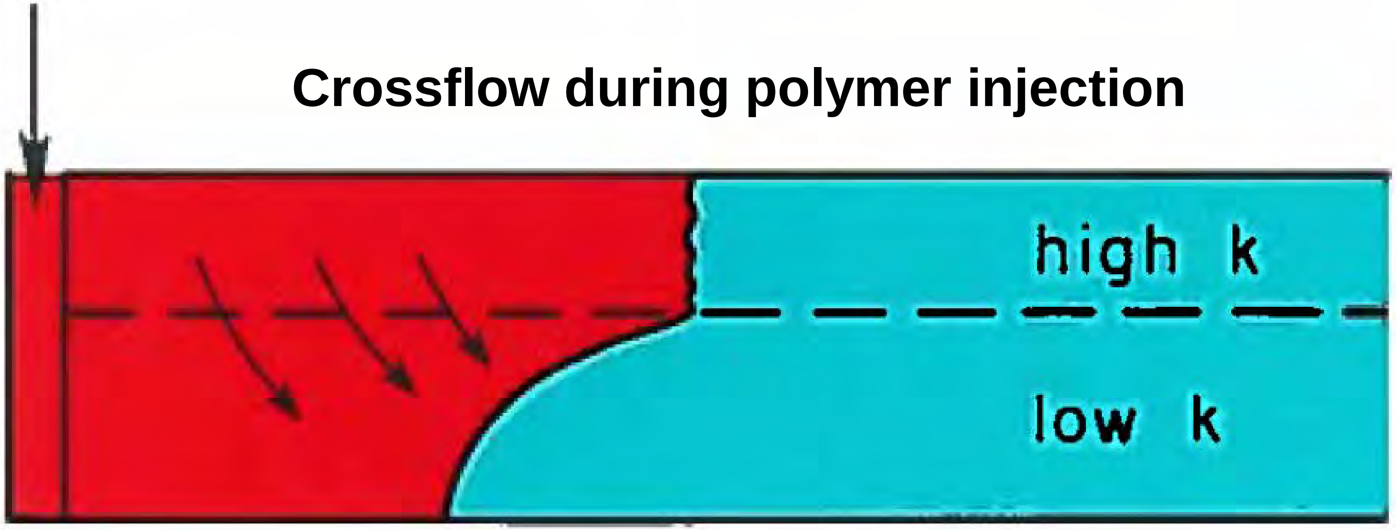


# INCORRECT VIEW OF POLYMER FLOODING



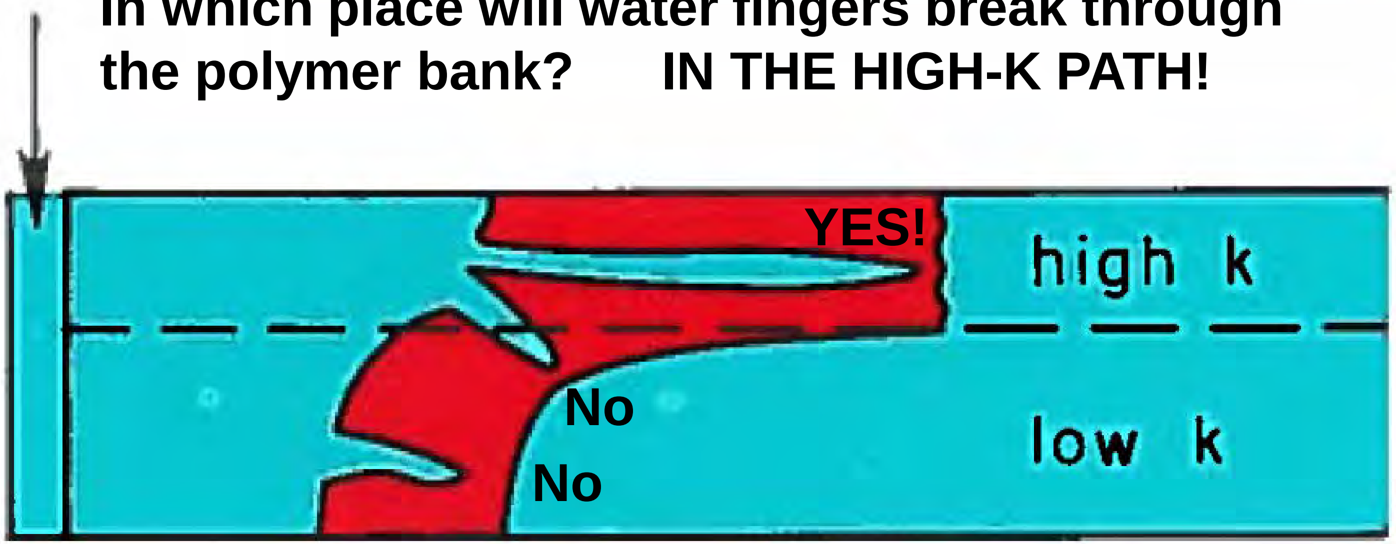

- **If this view was correct, we could use very small polymer banks and not worry so much about polymer degradation.**
- **This incorrect view is still being pushed in recent publications.**

## Crossflow during polymer injection



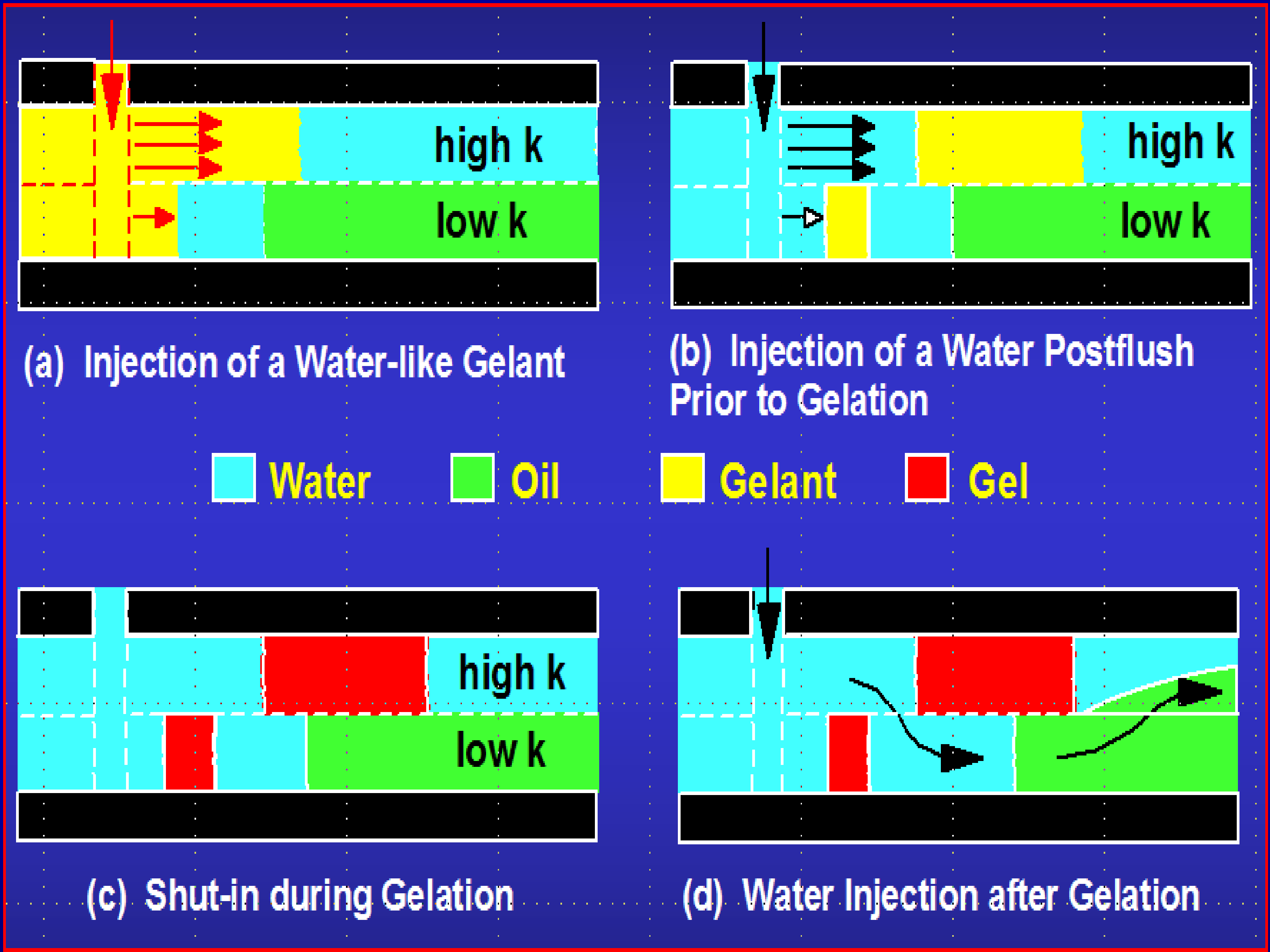

**Viscous fingering during water injection after polymer:**

**In which place will water fingers break through the polymer bank? IN THE HIGH-K PATH!**



## IN-DEPTH PROFILE MODIFICATION

**A specialized idea that requires use of a low-viscosity gelant.**



# ADVANTAGES AND LIMITATIONS

## ADVANTAGES:

1. Could provide favorable injectivity.
2. “Incremental” oil from this scheme could be recovered relatively quickly.

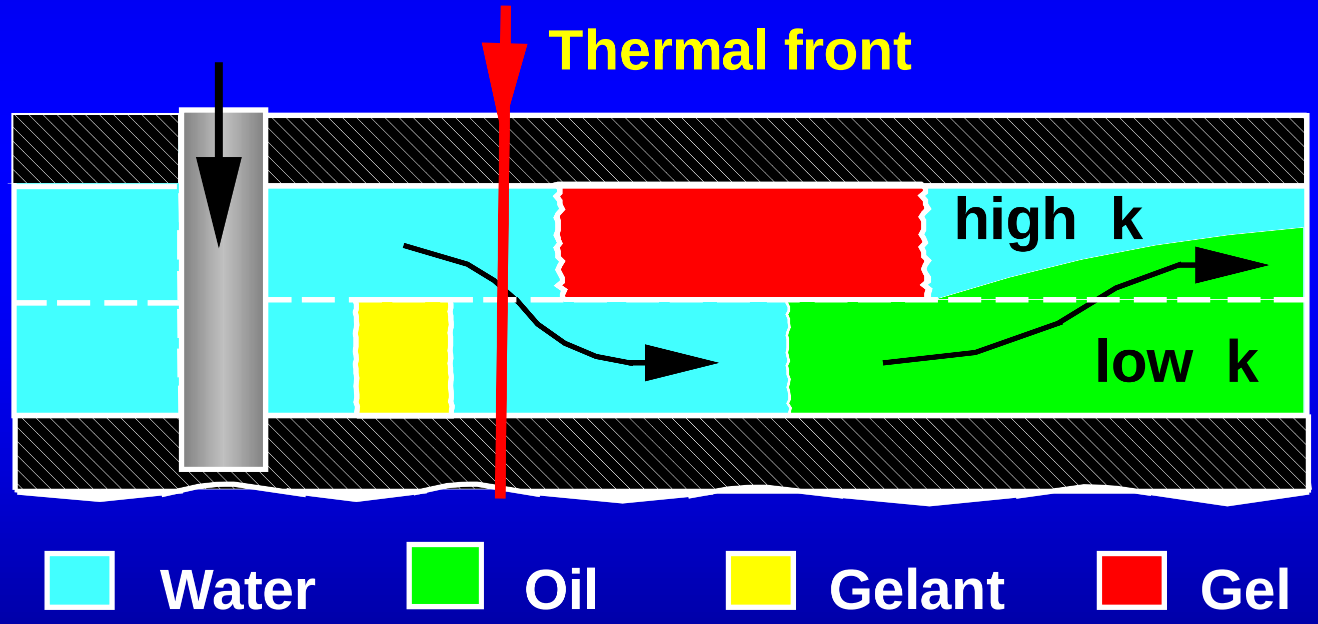
## LIMITATIONS:

1. Will not improve sweep efficiency beyond the greatest depth of gelant penetration in the reservoir.
2. Control & timing of gel formation may be challenging.
3. Applicability of this scheme depends on the sweep efficiency in the reservoir prior to the gel treatment.
4. Viscosity and resistance factor of the gelant must not be too large (ideally, near water-like).
5. Viscosity and resistance factor of the gelant should not increase much during injection of either the gelant or the water postflush

## Sophisticated Gel Treatment Idea from BP

**In-depth channeling problem, no significant fractures, no barriers to vertical flow:**

- BP idea could work but requires sophisticated characterization and design efforts,
- Success is very sensitive to several variables.




*J. Polym. Sci. & Eng.* (April 1992) 7(1-2) 33-43.

## BRIGHT WATER—A VARIATION ON BP's IDEA
## (SPE 84897 and SPE 89391)

- Injects small crosslinked polymer particles that "pop" or swell by ~10X when the crosslinks break.
- "Popping" is activated primarily by temperature, although pH can be used.
- The particle size and size distribution are such that the particles will generally penetrate into all zones.
- A thermal front appears necessary to make the idea work.
- The process experiences most of the same advantages and limitations as the original idea.

## BRIGHT WATER

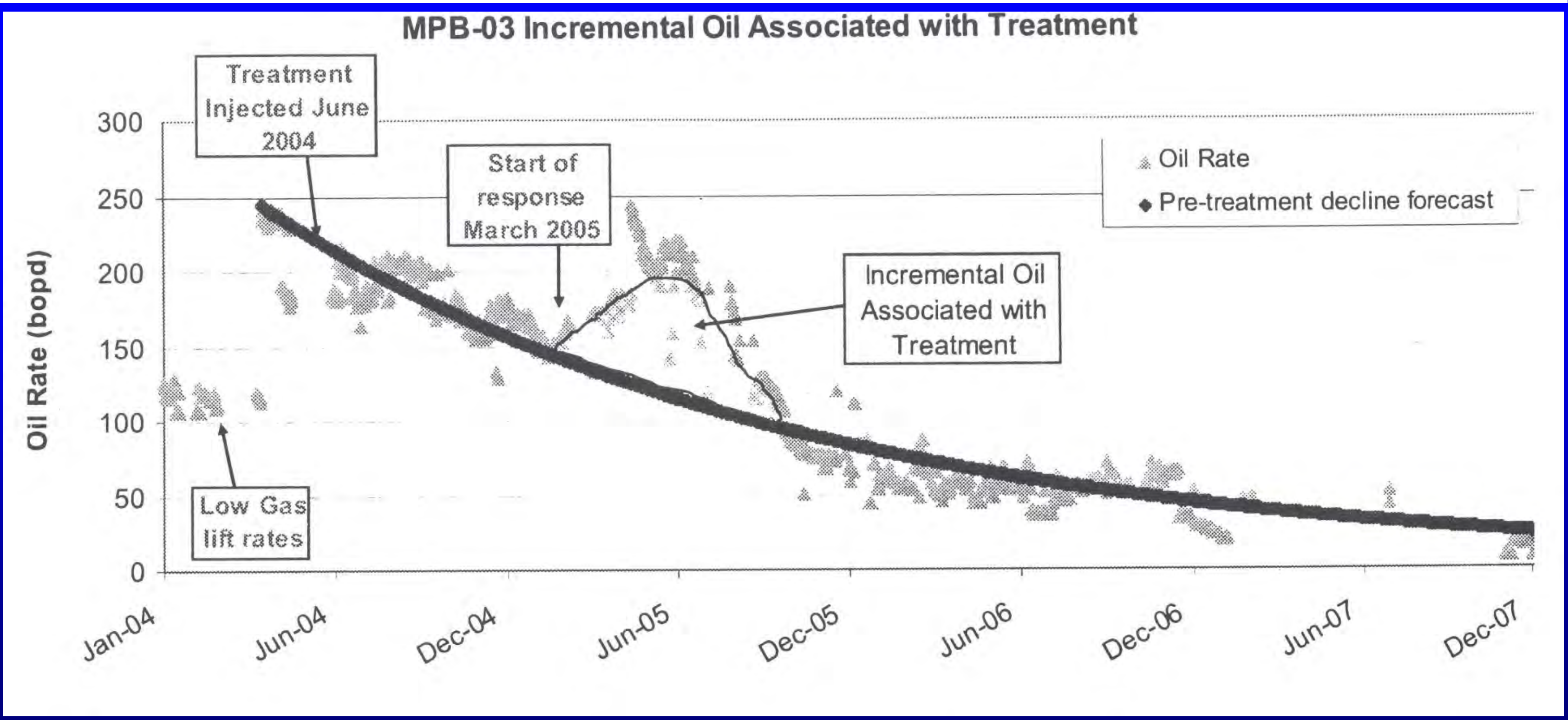
Had it origins ~1990.

Had an early field test by BP in Alaska.

Was perfected in a consortium of Mobil, BP, Texaco, and Chevron in the mid-1990s.

# BRIGHT WATER—RESULTS (SPE 121761)

- BP Milne Point field, North Slope of Alaska.
- Injected 112,000 bbl of 0.33% particles.
- Recovered 50,000 bbl of incremental oil.
- 0.39 bbl oil recovered / lb of polymer (compared with ~1 bbl oil / lb polymer for good polymer floods).



## For reservoirs with free crossflow between strata, which is best to use: Polymer Flooding or In-Depth Profile Modification?

Using simulation and analytical studies, we examined oil recovery efficiency for the two processes as a function of:

(1) permeability contrast (up to 10:1),
(2) relative zone thickness (up to 9:1),
(3) oil viscosity (up to 1,000 times more than water),
(4) polymer solution viscosity (up to 100 times more than water),
(5) polymer or blocking-agent bank size, and
(6) relative costs for polymer versus blocking agent.

# INJECTIVITY CONSIDERATIONS

1. Concern about injectivity losses has been a key motivation that was given for choosing in-depth profile modification over polymer flooding.
2. However, most waterflood and polymer flood injectors are thought to be fractured.
3. Fractures are especially likely to be present in hot reservoirs with cold-water injectors (Fletcher et al. 1991).
4. Even when injecting viscous polymer solutions (i.e., 200-300 cp), injectivity has not been a problem in field applications (Wang 146473) because fractures extend to accommodate the viscosity and rate of fluid injected.
5. Concerns when injecting above the parting pressure are to not allow fractures to (1) extend so far and in a direction that causes severe channeling and (2) extend out of zone.
6. Under the proper circumstances, injection above the parting pressure can significantly (1) increase injectivity and fluid throughput, (2) reduce the risk of mechanical degradation for HPAM, and (3) increase pattern sweep.

# ADDITIONAL CONSIDERATIONS

1. For small banks of popping-agent, significant mixing and dispersion may occur as that bank is placed deep within the reservoir—thus, diluting the bank and potentially compromising the effectiveness of the blocking agent. .
2. Since the popping material provides a limited permeability reduction (i.e., 11 to 350) and the popped-material has some mobility, the blocking bank eventually will be diluted and compromised by viscous fingering (confirmed by SPE 174672, Fabbri et al.). High retention (130 µg/g) is also an issue (SPE 174672).
3. If re-treatment is attempted for a in-depth profile-modification process, the presence of a block or partial block in the high-permeability layer will (1) divert new popping-agent into less-permeable zones during the placement process and (2) inhibit placement of a new block that is located deeper in the reservoir than the first block. These factors may compromise any re-treatment using in-depth profile

# BOTTOM LINE

1. In-depth profile modification is most appropriate for high permeability contrasts (e.g. 10:1), high thickness ratios (e.g., less-permeable zones being 10 times thicker than high-permeability zones), and relatively low oil viscosities.
2. Because of the high cost of the blocking agent (relative to conventional polymers), economics favor small blocking-agent bank sizes (e.g. 5% of the pore volume in the high-permeability layer).
3. Even though short-term economics may favor in-depth profile modification, ultimate recovery may be considerably less than from a traditional polymer flood. A longer view may favor polymer flooding both from a recovery viewpoint and an economic viewpoint.
4. In-depth profile modification is always more complicated and risky than polymer flooding.

## “COLLOIDAL DISPERSION” GELS (CDG) (ALUMINUM-CITRATE-HPAM, but sometimes low concentration Cr(III)-ACETATE-HPAM)

Two central claims have been made over the past 30 years. Two additional claims are more recent:

1. The CDG only enters the high-permeability, watered-out zones—thus diverting subsequently injected water to enter and displace oil from less permeable zones.
2. The CDG acts like a super-polymer flooding agent—add ~15-ppm Al to 300-ppm HPAM and make it act like a much more viscous polymer solution.
3. The CDG mobilizes residual oil.
4. The CDG acts like “Bright Water” (In depth profile modification)

## Examination of Literature on Colloidal Dispersion Gels for Oil Recovery: http://baervan.nmt.edu/groups/res-sweep/media/pdf/CDG%20Literature%20Review.pdf

**CDGs cannot propagate deep into the porous rock of a reservoir, and at the same time, provide $F_r$ and $F_{rr}$ that are greater than for the polymer without the crosslinker.**

**CDGs have been sold using a number of misleading and invalid arguments. Commonly, Hall plots are claimed to demonstrate that CDGs provide more $F_r$ and $F_{rr}$ than normal polymer solutions. But Hall plots only monitor injection pressures at the wellbore—so they reflect the composite of face plugging/formation damage, in-situ mobility changes, and fracture extension. Hall plots cannot distinguish between these effects—so they cannot quantify in situ $F_r$ and $F_{rr}$.**

## Examination of Literature on Colloidal Dispersion Gels for Oil Recovery: http://baervan.nmt.edu/groups/res-sweep/media/pdf/CDG%20Literature%20Review.pdf

Laboratory studies—where CDG gelants were forced through short cores during 2-3 hours—have incorrectly been cited as proof that CDGs will propagate deep (hundreds of feet) into the porous rock of a reservoir over the course of months.

In contrast, most legitimate laboratory studies reveal that the gelation time for CDGs is a day or less and that CDGs will not propagate through porous rock after gelation.

## Examination of Literature on Colloidal Dispersion Gels for Oil Recovery: http://baervan.nmt.edu/groups/res-sweep/media/pdf/CDG%20Literature%20Review.pdf

With one exception, aluminum from the CDG was never reported to be produced in a field application. In the exception, Chang reported producing 1 to 20% of the injected aluminum concentration.

Some free (unreacted) HPAM and aluminum that was associated with the original CDG can propagate through porous media. However, there is no evidence that this HPAM or aluminum provides mobility reduction greater than that for the polymer formulation without crosslinker.

# Colloidal Dispersion Gels for Oil Recovery:

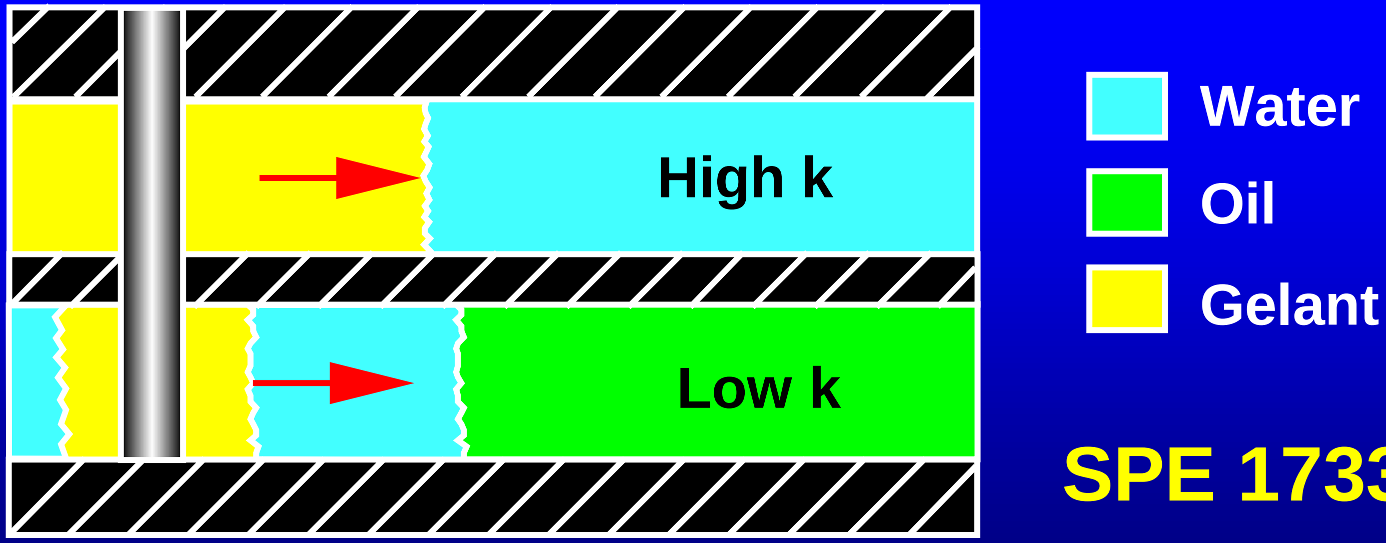
- Have enjoyed remarkable hype, with claims of substantial field success.
- Would revolutionize chemical flooding if the claims were true.
- Currently, no credible evidence exists that they flow through porous rock AND provide an effect more than from just the polymer alone (without crosslinker).
- Considering the incredible claims made for CDGs, objective labs ought to be able to verify the claims. So far, they have not.

# BASIC CALCULATIONS

**Gelants can penetrate into all open zones.**

**An acceptable gelant placement is much easier to achieve in linear flow (fractured wells) than in radial flow.**

**In radial flow (unfractured wells), oil-productive zones must be protected during gelant placement.**

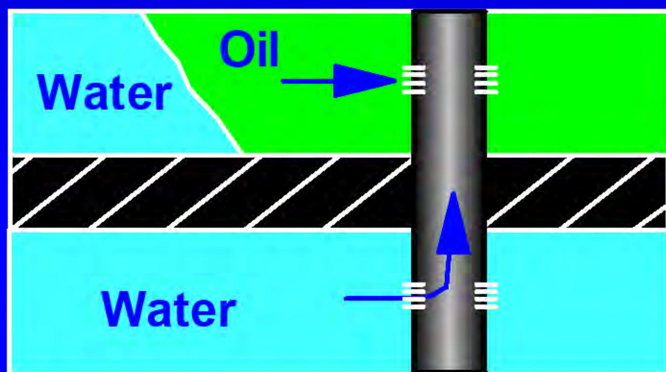



**SPE 17332**

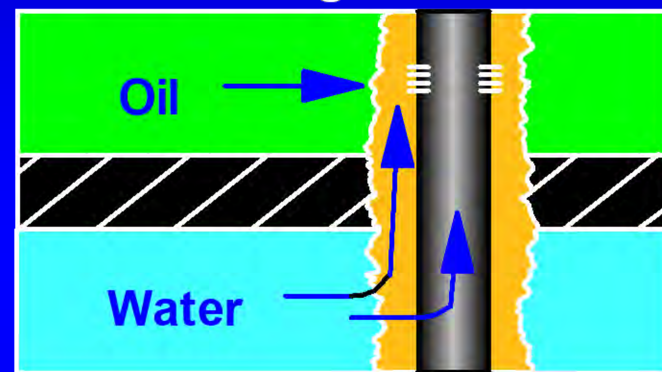
**A STRATEGY FOR ATTACKING EXCESS WATER PRODUCTION**
*SPEPF* (August 2003) pp. 158-169

# CAUSES OF EXCESS WATER PRODUCTION

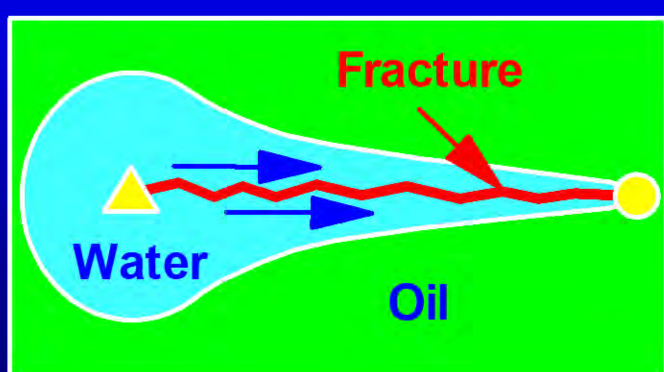
### Open Water Zone



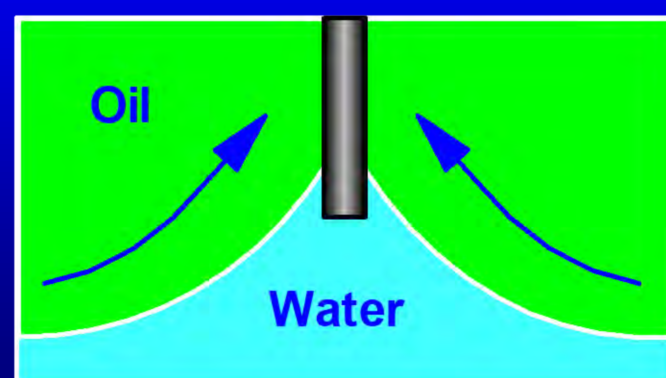

### Flow Behind Pipe and Casing Leaks




### Channeling from Injectors




### Coning or Cusping



# WATER CONTROL METHODS

- Cement, sand plugs, calcium carbonate.
- Packers, bridge plugs, mechanical patches.
- Pattern flow control.
- In fill drilling/well abandonment.
- Horizontal wells.
- Gels.
- Polymer floods.
- Resins.
- Foams, emulsions, particulates, precipitates, microorganisms.

# PROBLEM

**Operators often do not adequately diagnose the cause of their water production problems.**

## WHY NOT?

1. Diagnosis requires money and time,
2. Uncertainty about which methods are cost-effective for diagnosing specific problems,
3. Preconception that only one type of problem exists or that one method will solve all types of problems,
4. Some companies encourage a belief that they have "magic-bullet" solutions.

## A STRATEGY FOR ATTACKING EXCESS WATER PRODUCTION

1. Consider and eliminate the easiest problems first.
2. Start by using information that you already have.

## Excess Water Production Problems and Treatment Categories
## (Categories are listed in increasing order of treatment difficulty)

**Category A: "Conventional" Treatments Normally Are an Effective Choice**

1. Casing leaks without flow restrictions.
2. Flow behind pipe without flow restrictions.
3. Unfractured wells (injectors or producers) with effective crossflow barriers.

**Category B: Treatments with Gelants Normally Are an Effective Choice**

4. Casing leaks with flow restrictions.
5. Flow behind pipe with flow restrictions.
6. "Two-dimensional coning" through a hydraulic fracture from an aquifer.
7. Natural fracture system leading to an aquifer.

**Category C: Treatments with Preformed Gels Are an Effective Choice**

8. Faults or fractures crossing a deviated or horizontal well.
9. Single fracture causing channeling between wells.
10. Natural fracture system allowing channeling between wells.

**Category D: Difficult Problems Where Gel Treatments Should Not Be Used**

11. Three-dimensional coning.
12. Cusping.
13. Channeling through strata (no fractures), with crossflow.

# WHAT DIAGNOSTIC TOOLS SHOULD BE USED?

1. Production history, WOR values, GOR values
2. Pattern recovery factors, zonal recovery factors
3. Pattern throughput values (bubble maps)
4. Injection profiles, production profiles
5. Zonal saturation determinations (from logs, cores, etc.)
6. Injectivities, productivites (rate/pressure), step rate tests
7. Casing/tubing integrity tests (leak tests)
8. Temperature surveys, noise logs
9. Cement bond logs
10. Televiewers, FMI logs
11. Interwell transit times, water/hydrocarbon composition
12. Mud losses & bit drops while drilling
13. Workover & stimulation responses, previous treatments
14. Pressure transient analysis, Inter-zone pressure tests
15. Geological analysis, seismic methods, tilt meters
16. Simulation, numerical, analytical methods
17. Other

# DIAGNOSTICS

**We have A LOT of diagnostic methods available.**

**We need a strategy to decide which methods should be examined/applied first.**

**Possible approaches:**

1. **Use whatever tool is currently trendy and being pushed the hardest by my favorite service company.**
2. **Use the tools that have been popular in the past for this field.**
3. **Use a strategy that is focused finding the cause of channeling and/or excess water production.**

**Strategy:**

1. **Look for the easiest problems first.**
2. **Start by using information that you already have.**

# KEY QUESTIONS IN OUR APPROACH

1. Does a problem really exist?
2. Does the problem occur right at the wellbore (like casing leaks or flow behind pipe) or does it occur out beyond the wellbore?
3. If the problem occurs out beyond the wellbore, are fractures or fracture-like features the main cause of the problem?
4. If the problem occurs out beyond the wellbore and fractures are not the cause of the problem, can crossflow occur between the dominant water zones and the dominant hydrocarbon zones?

**Respect basic physical and engineering principles.**

**Stay away from black magic.**

# DOES A PROBLEM REALLY EXIST?

- Are significant volumes of mobile hydrocarbon present?
- Are recovery factors and/or WOR values much greater than neighboring wells or patterns?
- Are recovery values much less than expected after considering existing drive mechanism, existing stratification, structural position of the wells, injection fluid throughput, and existing mobility ratio?

# FIRST SET OF DIAGNOSTIC TESTS

**Recovery factor in view of:**

- **Producing water/oil ratio, GOR.**
- **Neighboring wells and patterns.**
- **Drive mechanism.**
- **Reservoir stratification.**
- **Structural position.**
- **Injection fluid throughput.**
- **Water/oil mobility ratio.**

# WOR DIAGNOSTIC PLOTS

**WOR vs. time can be very valuable in determining:**

1. **When the problem developed,**
2. **The severity of the problem,**
3. **What the problem is, IF VIEWED ALONG WITH OTHER INFORMATION.**

**BUT WOR or WOR derivative plots CANNOT by themselves distinguish between channeling and coning. See Chapter 2 of our 1997 Annual Report**

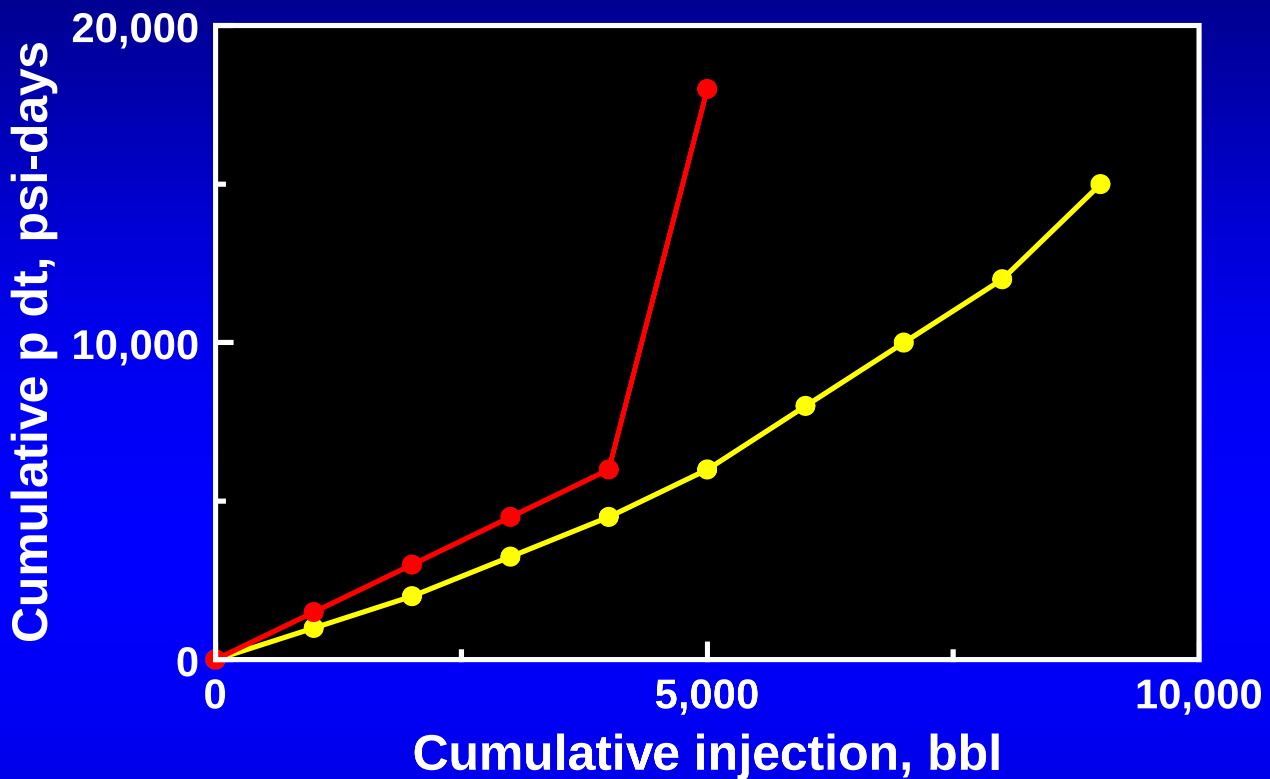
**Distinguishing between matrix and fracture problems is much more important than distinguishing between channeling and coning.**

## HALL PLOTS

- provide a useful indication of the rate of pressure increase,
- indicate when gelant injection must be stopped because of pressure limitations,
- do not indicate the selectivity of gel placement,
- do not indicate whether a treatment was sized properly.

Reference: DOE/BC/14880-5, pp. 73-80.

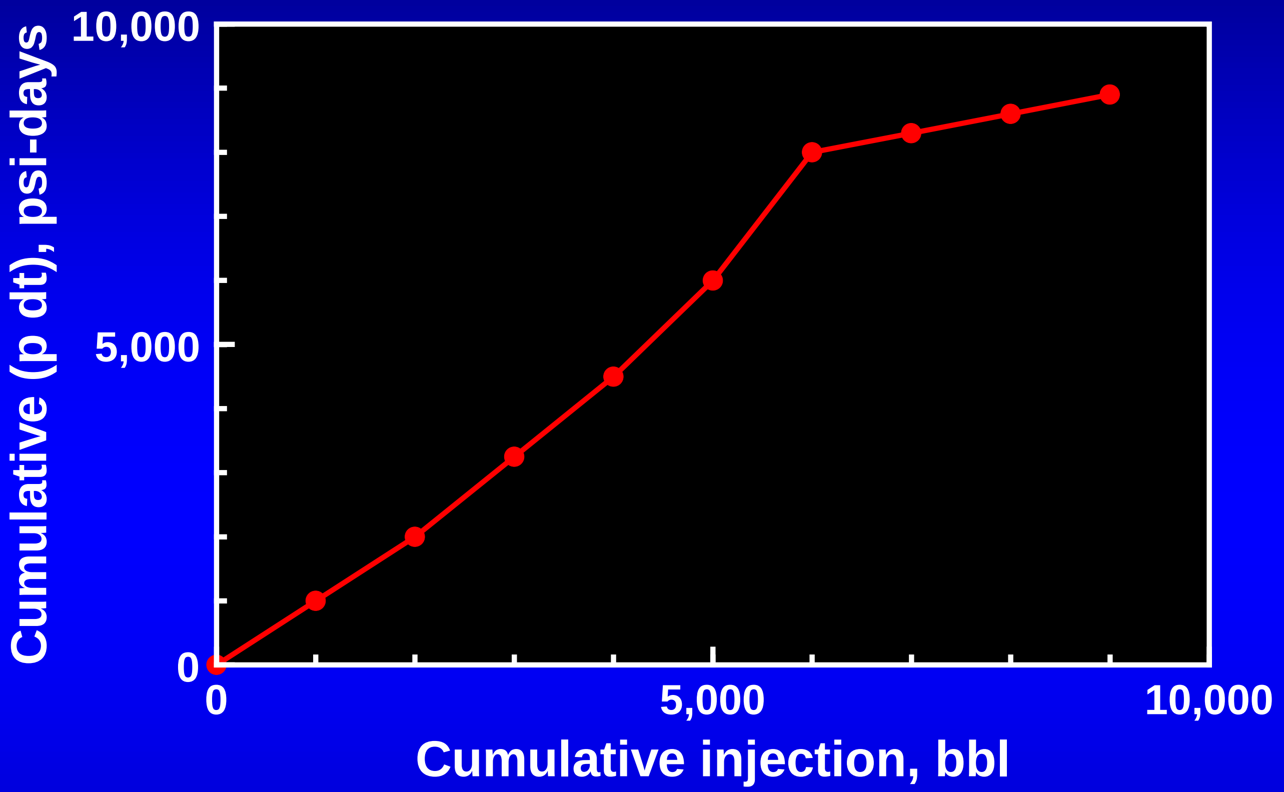
# HALL PLOTS FOR WELLS WITH RADIAL FLOW




**An increasing slope could result from:**

- plugging the high-k zones more than the low-k zones,
- plugging the low-k zones more than the high-k zones, or
- plugging all zones to the same extent (most likely possibility).

# HALL PLOTS FOR FRACTURED WELLS



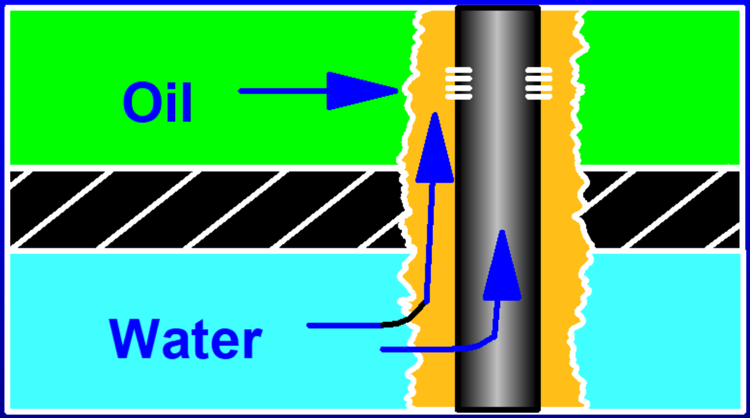

**A decreasing slope could result from:**

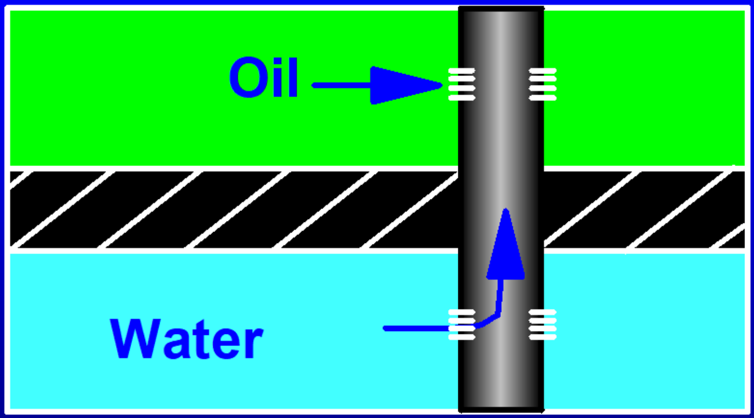
- opening or fracturing into previously unswept zones,
- re-opening a fracture that the gel had recently sealed,
- opening a fracture that cuts through all zones.

# CATEGORY A: EASIEST PROBLEMS

## "Conventional" Treatments Normally Are an Effective Choice

1. Casing leaks without flow restrictions (moderate to large holes).
2. Flow behind pipe without flow restrictions (typically no primary cement).
3. Unfractured wells (injectors or producers) with effective barriers to crossflow.



# SECOND SET OF DIAGNOSTIC TESTS

**Does the problem occur right at the wellbore?**

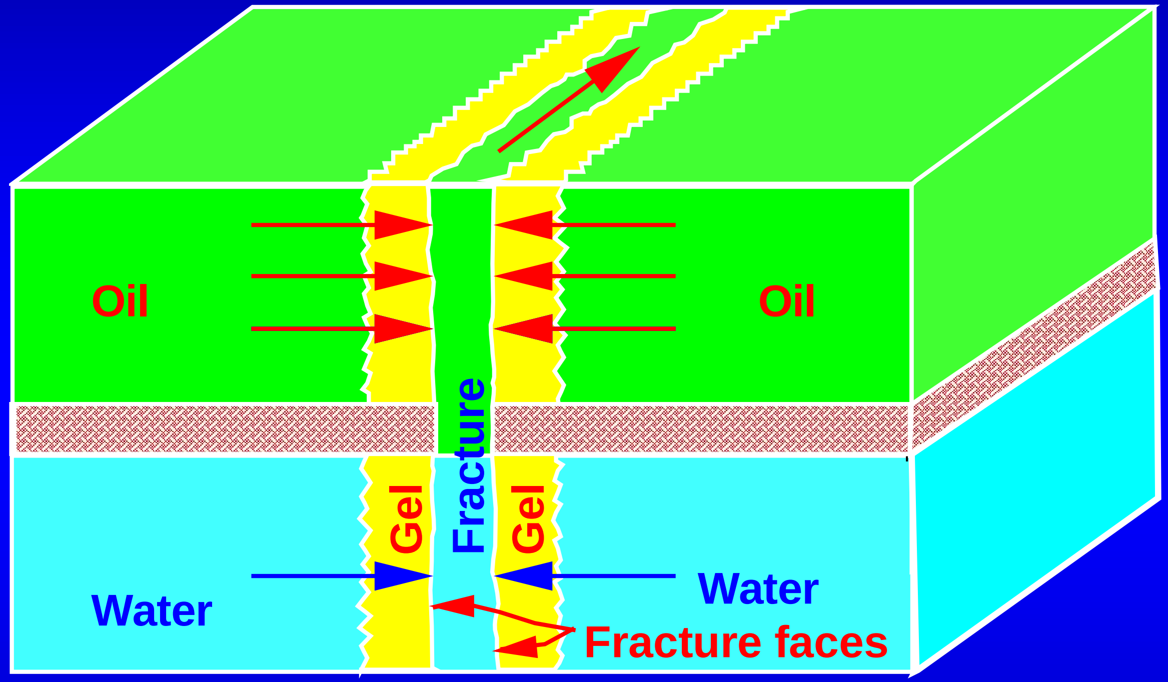
**Is the problem a leak or flow behind pipe?**

- **Leak tests/casing integrity tests**
- **Temperature surveys**
- **Radio-tracer flow logs**
- **Spinner surveys**
- **Cement bond logs**
- **Borehole televiewers**
- **Noise logs**

## CATEGORY B:
## INTERMEDIATE DIFFICULTY
### Treatments with GELANTS
### Normally Are an Effective Choice

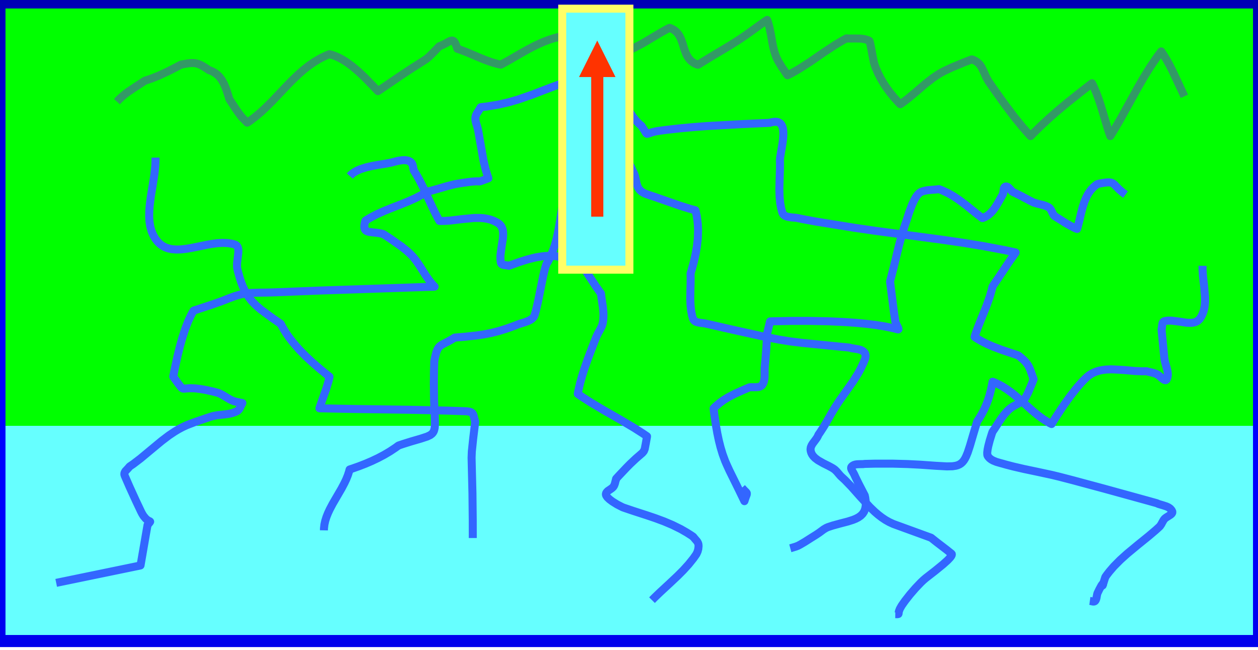
4. Casing leaks with flow restrictions (pinhole leaks).
5. Flow behind pipe with flow restrictions (narrow channels).
6. “Two-dimensional coning” through a hydraulic fracture from an aquifer.
7. Natural fracture system leading to an aquifer.

# Problem 6: "Two-dimensional coning" through a hydraulic fracture from an aquifer.




- Need a gel that reduces $k_w$ much more than $k_o$ or $k_{gas}$.

# Problem 7:
# Natural fracture system leading to an aquifer.



- Many successful gelant treatments applied in dolomite formations.
- Treatment effects were usually temporary.
- Recent, longer lasting successes seen with preformed gels.

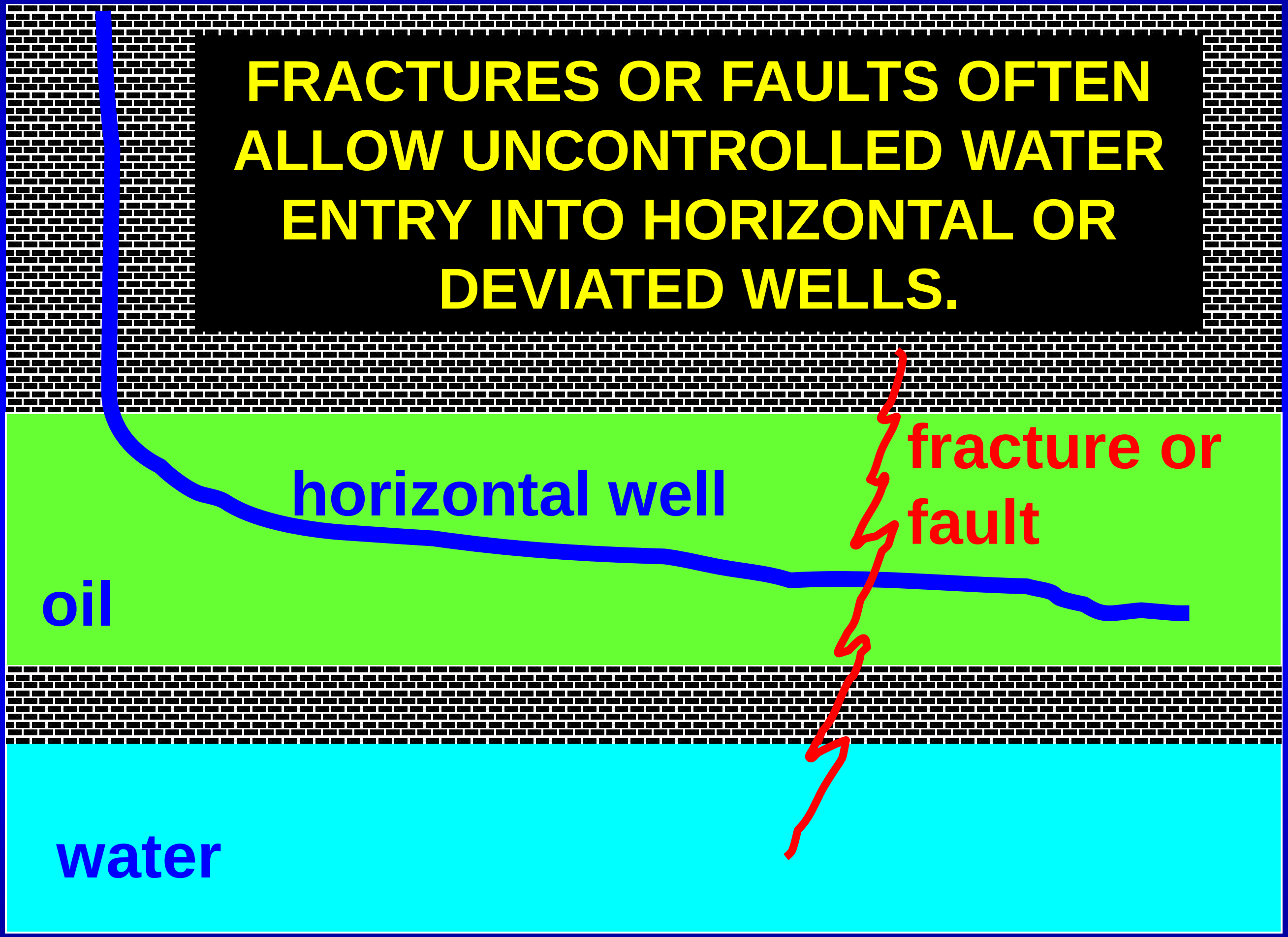
## CATEGORY C:

## INTERMEDIATE DIFFICULTY

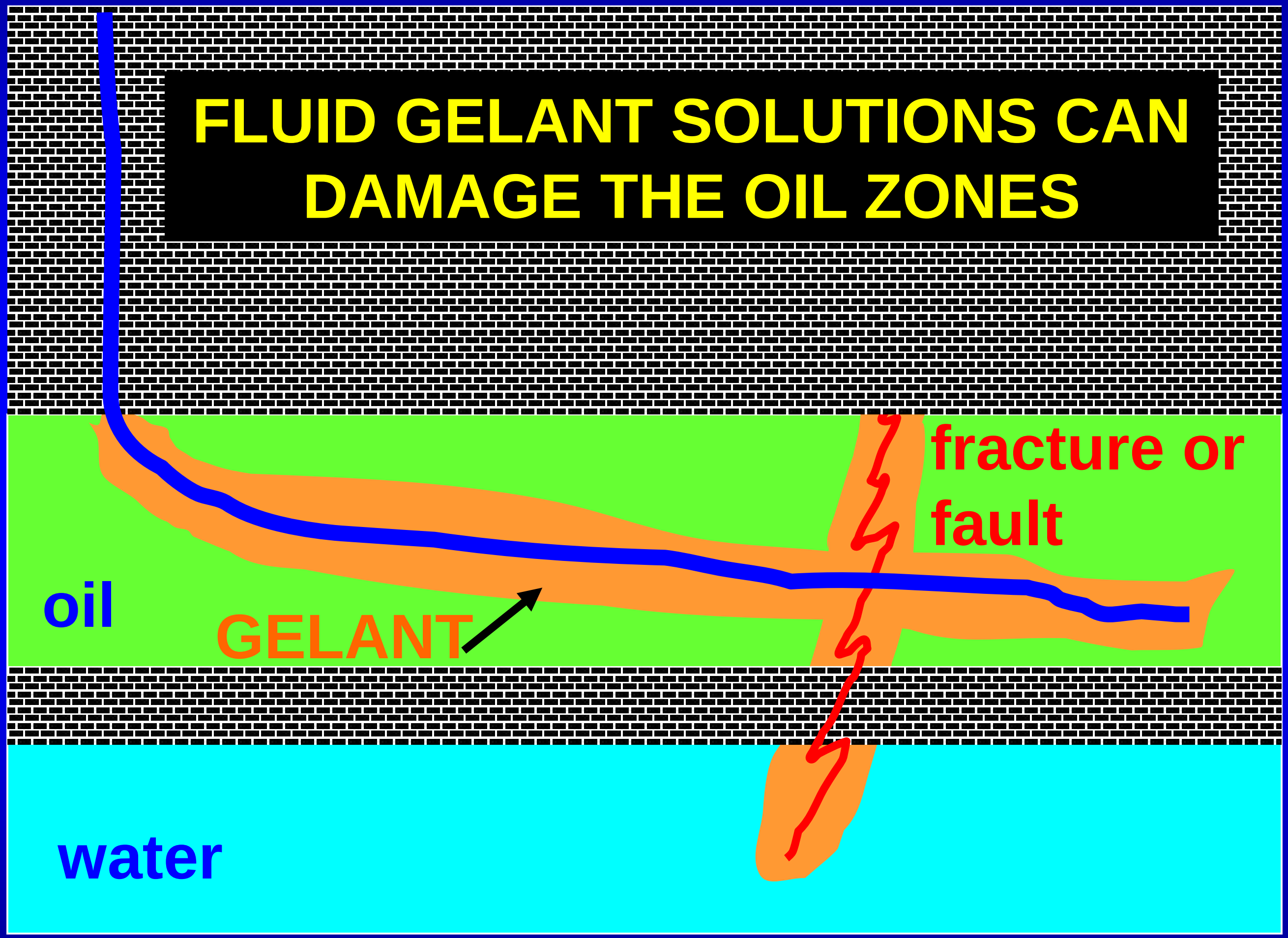
**Treatments with PREFORMED GELS Are an Effective Choice**

8. Faults or fractures crossing a deviated or horizontal well.
9. Single fracture causing channeling between wells.
10. Natural fracture system allowing channeling between wells.

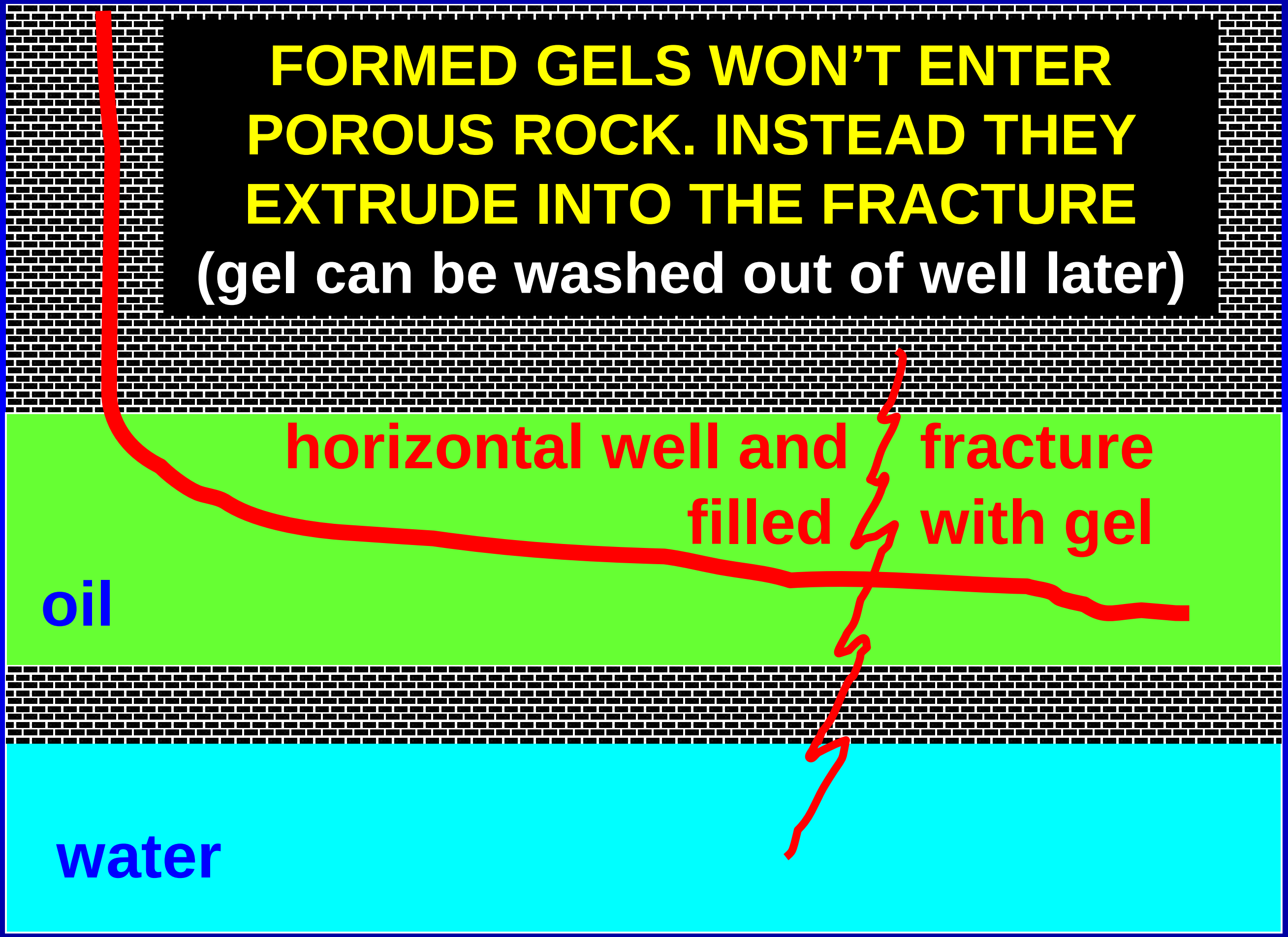
# Problem 8


FRACTURES OR FAULTS OFTEN ALLOW UNCONTROLLED WATER ENTRY INTO HORIZONTAL OR DEVIATED WELLS.
horizontal well
fracture or fault
oil
water

# Problem 8


FLUID GELANT SOLUTIONS CAN DAMAGE THE OIL ZONES
fracture or fault
oil
GELANT
water

# Problem 8: SPE 65527



# THIRD SET OF DIAGNOSTIC TESTS

## HELPFUL INITIAL INDICATORS OF FRACTURES

- **Well history (intentional stimulation).**
- **Injectivity or productivity much higher than expected from Darcy's law for radial flow.**
- **Results from step-rate tests.**

- **Speed of water breakthrough or other tracer.**

- **Fluid loss during drilling.**
- **Pulse test responses, or pumper observations.**

- **FMI logs**
- **Seismic**

**Does my well have a linear-flow problem?**
**(e.g., a fracture)**

**Injectivity or productivity data often provides a low-cost method for diagnosis.**

**Radial (matrix) flow probable:**

$$q/\Delta p \leq (\Sigma\ k\ h)/[141.2\ \mu\ \ln (r_e / r_w)]$$

**Linear (fracture-like) flow probable:**

$$q/\Delta p >> (\Sigma\ k\ h)/[141.2\ \mu\ \ln (r_e / r_w)]$$

# ESTIMATING FRACTURE CONDUCTIVITY FROM INJECTIVITY OR PRODUCTIVITY DATA

**Assume:**

- Vertical well with a vertical fracture
- If multiple fractures are present, the widest fracture dominates flow.
- The fracture has a much greater flow capacity than the matrix.
- The fracture has two wings.

$$q_{total} = q_{matrix} + q_{fracture} = (\Delta p\ h_f / \mu)\ [k_m/\ln(r_e/r_w) + 2k_f w_f/L_f]$$

$$k_f w_f = \{[q_{total}\ \mu/(\Delta p\ h_f)] - [k_m/\ln(r_e/r_w)]\}\ L_f / 2$$

## RELATION BETWEEN FRACTURE WIDTH, PERMEABILITY, AND CONDUCTIVITY

$k_f\ w_f$ (darcy-ft) = $1.13\text{x}10^{-5}\ (k_f)^{1.5}$, where $k_f$ is in darcys.

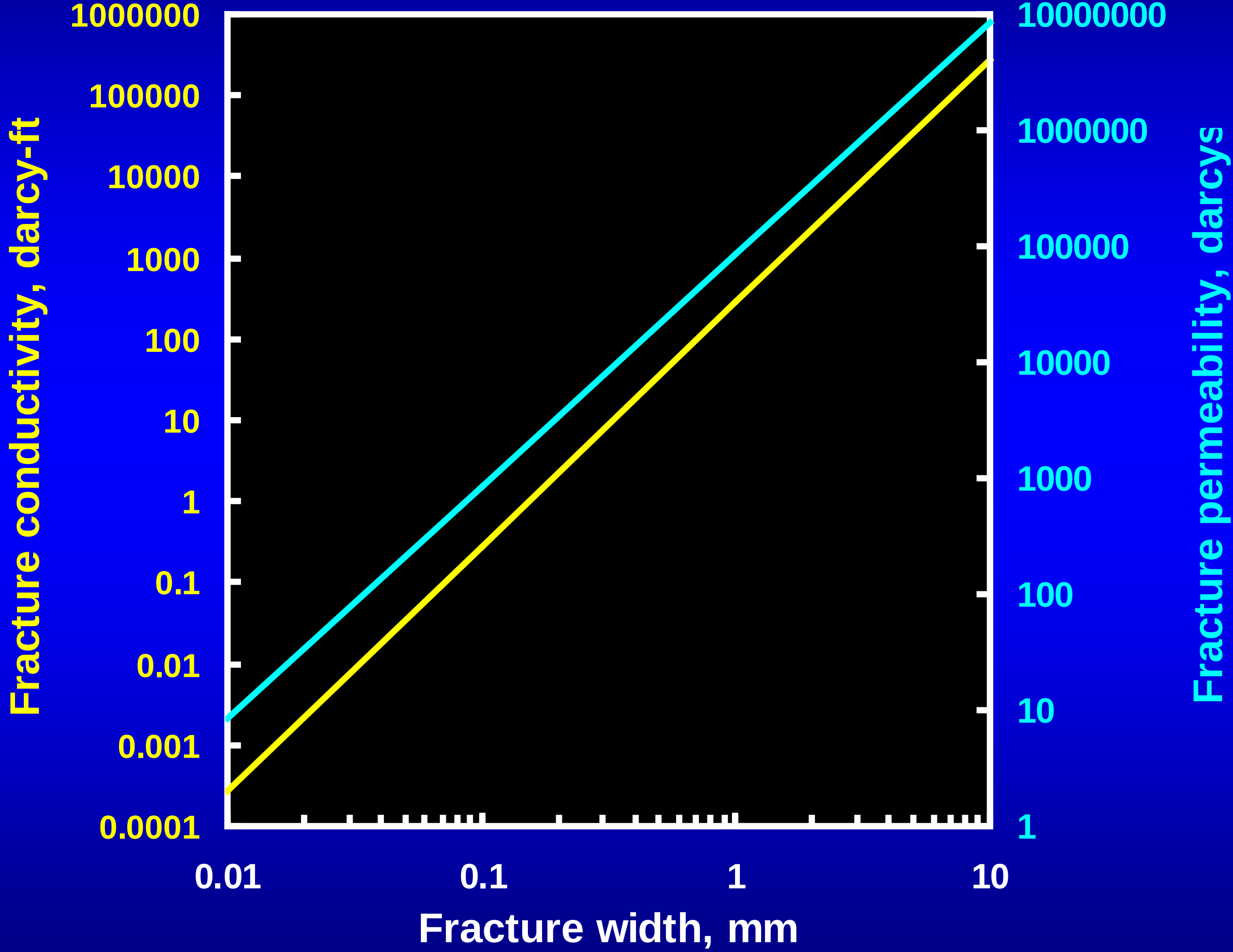
$k_f\ w_f$ (darcy-cm) = $3.44\text{x}10^{-4}\ (k_f)^{1.5}$, where $k_f$ is in darcys.

$w_f$ (ft) = $5.03\text{x}10^{-4}\ (k_f w_f)^{1/3}$, where $k_f w_f$ is in darcy-ft.

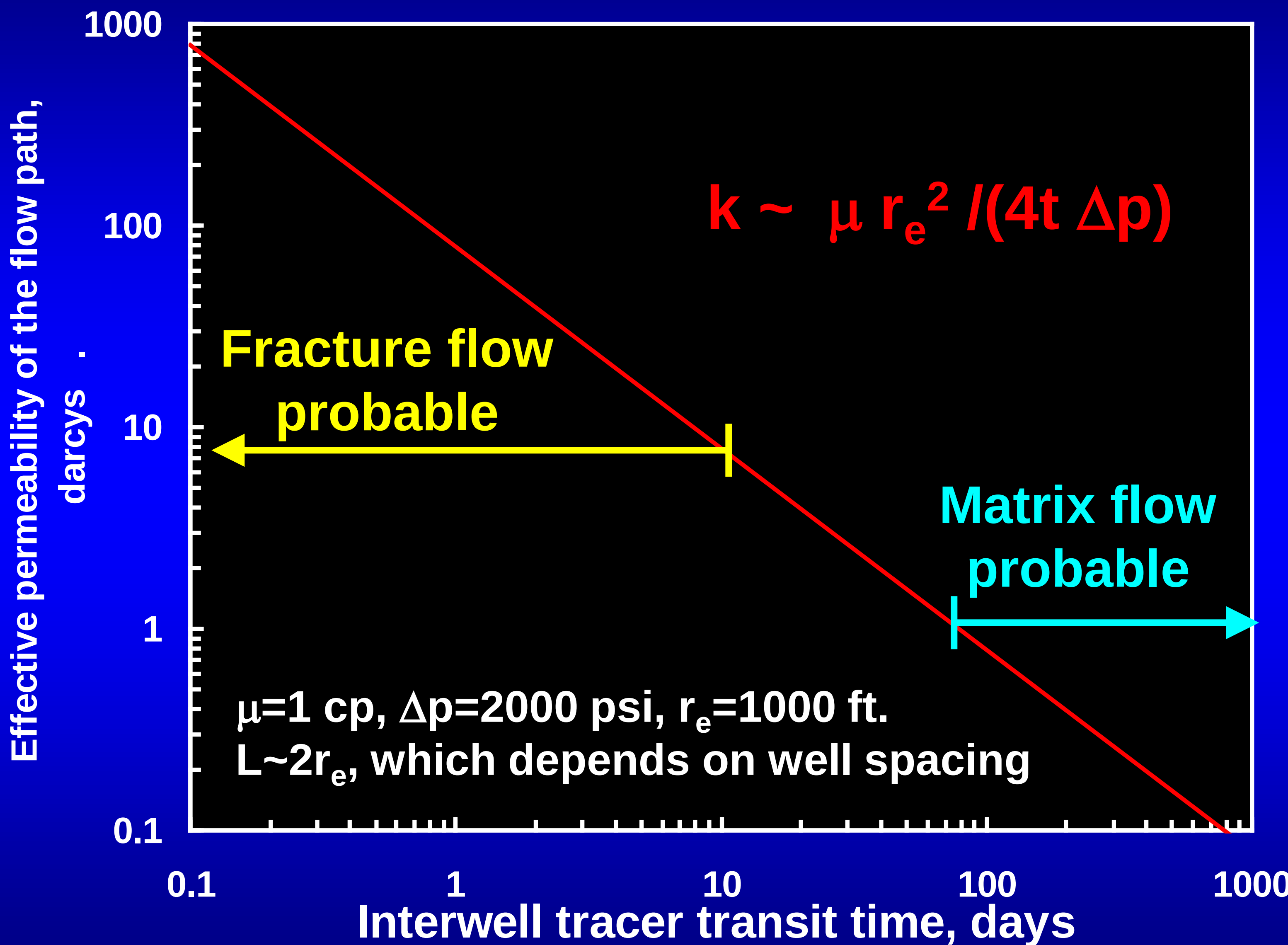
$w_f$ (mm) = $0.153\ (k_f w_f)^{1/3}$, where $k_f w_f$ is in darcy-ft.

$w_f$ (mm) = $3.44\text{x}10^{-3}\ (k_f)^{0.5}$, where $k_f$ is in darcys.

# THE WIDEST FRACTURE DOMINATES FLOW



# MATRIX OR FRACTURE FLOW?



## ESTIMATING FRACTURE PERMEABILITY FROM TRACER TRANSIT TIMES

**Assume the widest fracture dominates flow.**

$$k_f = q\mu L/[h_f w_f \Delta p] = (L h_f w_f/t)\mu L/[h_f w_f \Delta p] = (L^2 \mu)/(\Delta p\, t)$$

**Where:**

**L is fracture length (~distance between wells),**

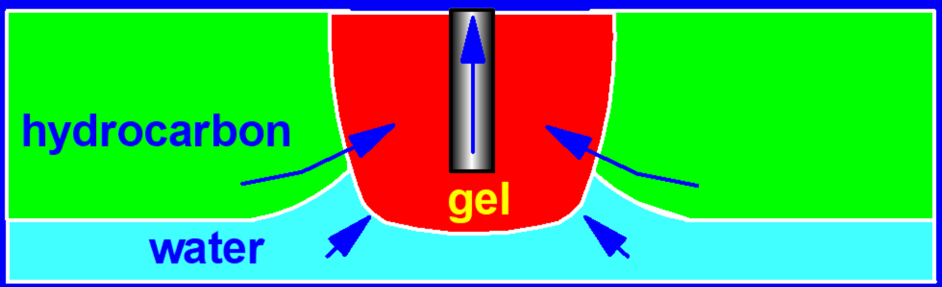
**μ is fluid viscosity (usually of water),**

**Δp is the pressure drop between wells,**

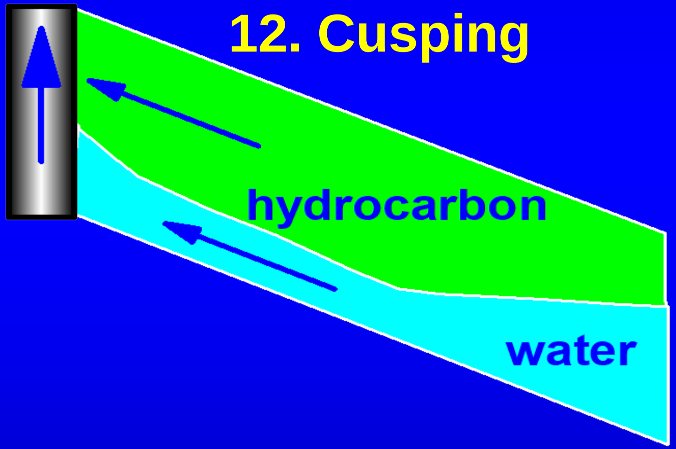
**t is tracer transit time between wells.**

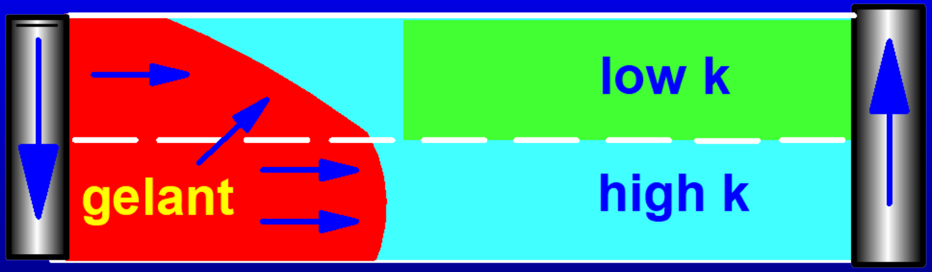
# CATEGORY D:
## MOST DIFFICULT PROBLEMS
## GELANT or GEL Treatments Should NOT Be Used

**11. Three-Dimensional Coning**




**12. Cusping**




**13. Channeling through strata (no fractures), with crossflow.**

# FOURTH SET OF DIAGNOSTIC TESTS

**Is the problem accentuated by crossflow?**

- Pressure test between zones,
- Various logs for determining fluid saturations, permeabilities, porosities, and lithologies
- Injection/production profiles
- Simulation
- Seismic and geophysical methods

# PREDICTING EXCESS WATER PRODUCTION
## FACTORS LEADING TO PROBLEMS

1. Bad cement or factors inhibiting cementation.
2. Corrosive brines or gases.
3. Wellbore abuse during work-overs or well interventions.
4. Natural fractures (if oriented wrong).
5. Large permeability contrasts.
6. Low permeability rock (if induced fractures are oriented wrong).
7. Viscous oils or unfavorable mobility ratios.
8. Close proximity of an aquifer or gas cap.
9. Crossflow, under the wrong conditions (Items 5, 6, and 7 above).
10. Particulates or emulsions in injection water.

## A STRATEGY FOR ATTACKING EXCESS WATER PRODUCTION

1. Consider and eliminate the easiest problems first.
2. Start by using information that you already have.

## Excess Water Production Problems and Treatment Categories
## (Categories are listed in increasing order of treatment difficulty)

**Category A: "Conventional" Treatments Normally Are an Effective Choice**

1. Casing leaks without flow restrictions.
2. Flow behind pipe without flow restrictions.
3. Unfractured wells (injectors or producers) with effective crossflow barriers.

**Category B: Treatments with Gelants Normally Are an Effective Choice**

4. Casing leaks with flow restrictions.
5. Flow behind pipe with flow restrictions.
6. "Two-dimensional coning" through a hydraulic fracture from an aquifer.
7. Natural fracture system leading to an aquifer.

**Category C: Treatments with Preformed Gels Are an Effective Choice**

8. Faults or fractures crossing a deviated or horizontal well.
9. Single fracture causing channeling between wells.
10. Natural fracture system allowing channeling between wells.

**Category D: Difficult Problems Where Gel Treatments Should Not Be Used**

11. Three-dimensional coning.
12. Cusping.
13. Channeling through strata (no fractures), with crossflow.

# KEY QUESTIONS IN OUR APPROACH

1. Does a problem really exist?
2. Does the problem occur right at the wellbore (like casing leaks or flow behind pipe) or does it occur out beyond the wellbore?
3. If the problem occurs out beyond the wellbore, are fractures or fracture-like features the main cause of the problem?
4. If the problem occurs out beyond the wellbore and fractures are not the cause of the problem, can crossflow occur between the dominant water zones and the dominant hydrocarbon zones?

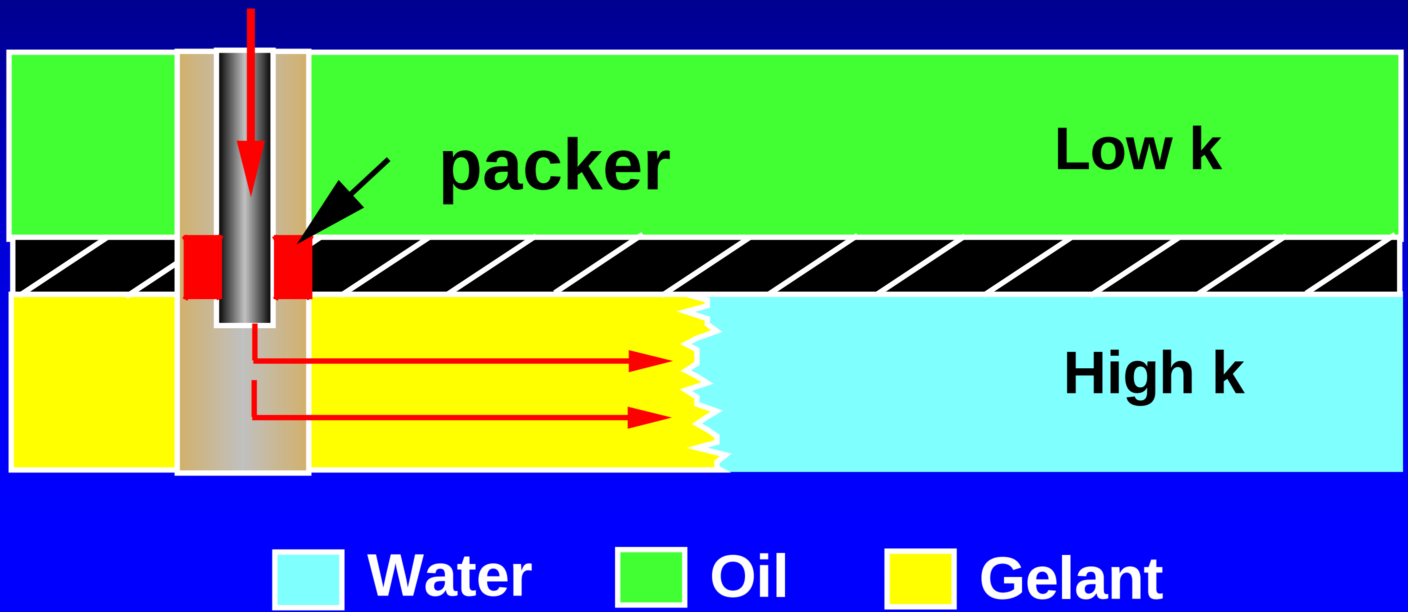
Respect basic physical and engineering principles.
Stay away from black magic.

# FIELD EXAMPLES

# QUESTIONS FOR FIELD PROJECTS

- Why did you decide there was a problem?
- What did you do to diagnose the problem?
- What types of solutions did you consider?
- Why did you chose your solution over others?
- How did you size and place the treatment?
- Did it work? How do you know?
- What would you do different next time?

# UNFRACTURED WELLS WITHOUT CROSSFLOW



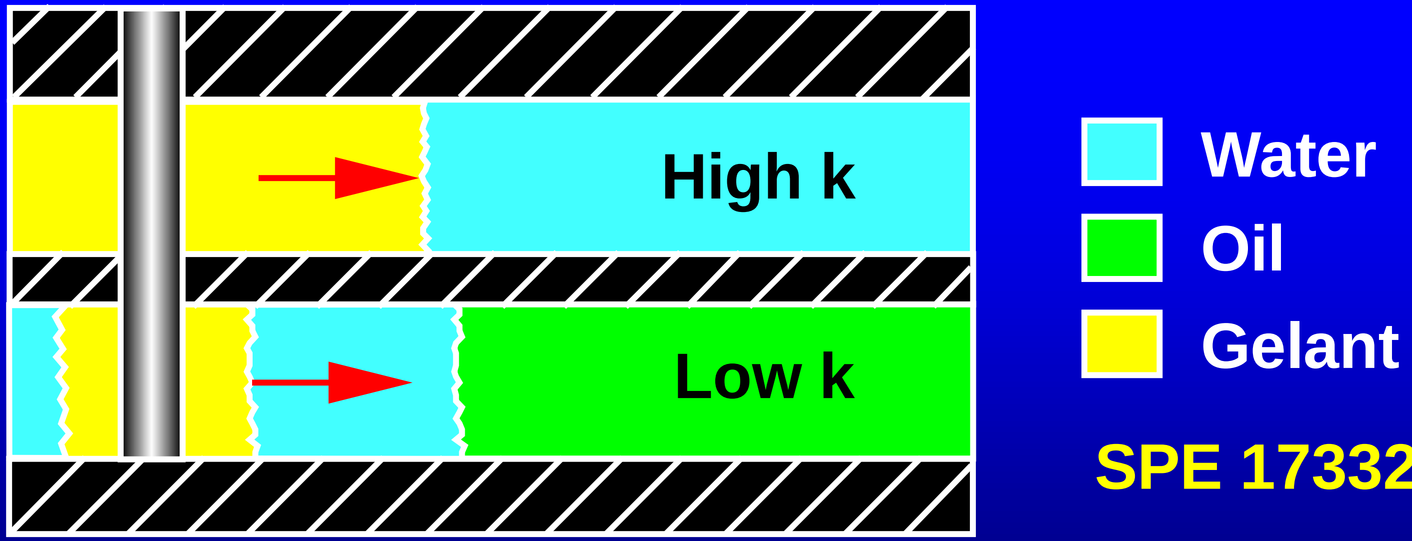

**Possible Solutions**

- Cement
- Sand plugs (if water zone is on the bottom)
- Mechanical devices (bridge plugs, packers)
- Gels
- Resins

# Blocking Agent Placement

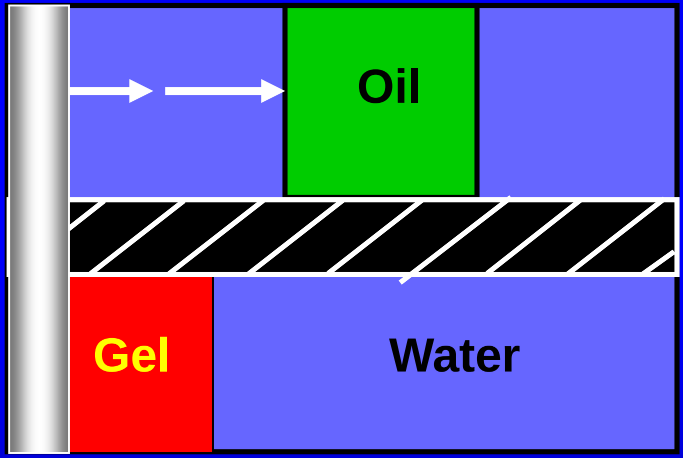
- In both injection wells and production wells, gelants and similar blocking agents can penetrate into all open zones.

- In radial flow (unfractured wells), oil-productive zones must be protected during gelant placement.

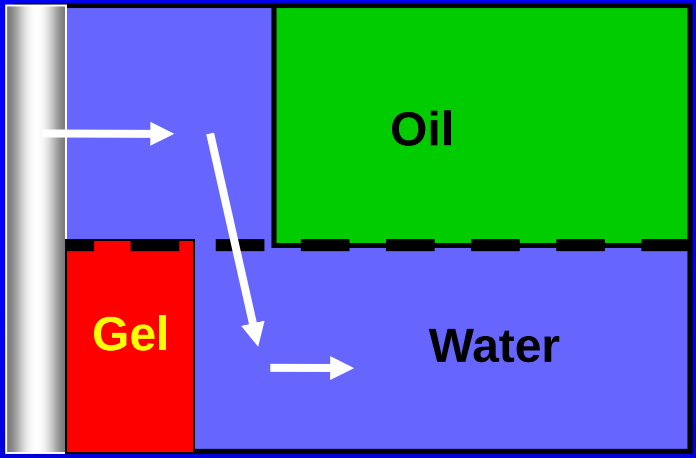



SPE 17332

**Without crossflow--
gel can be effective.**

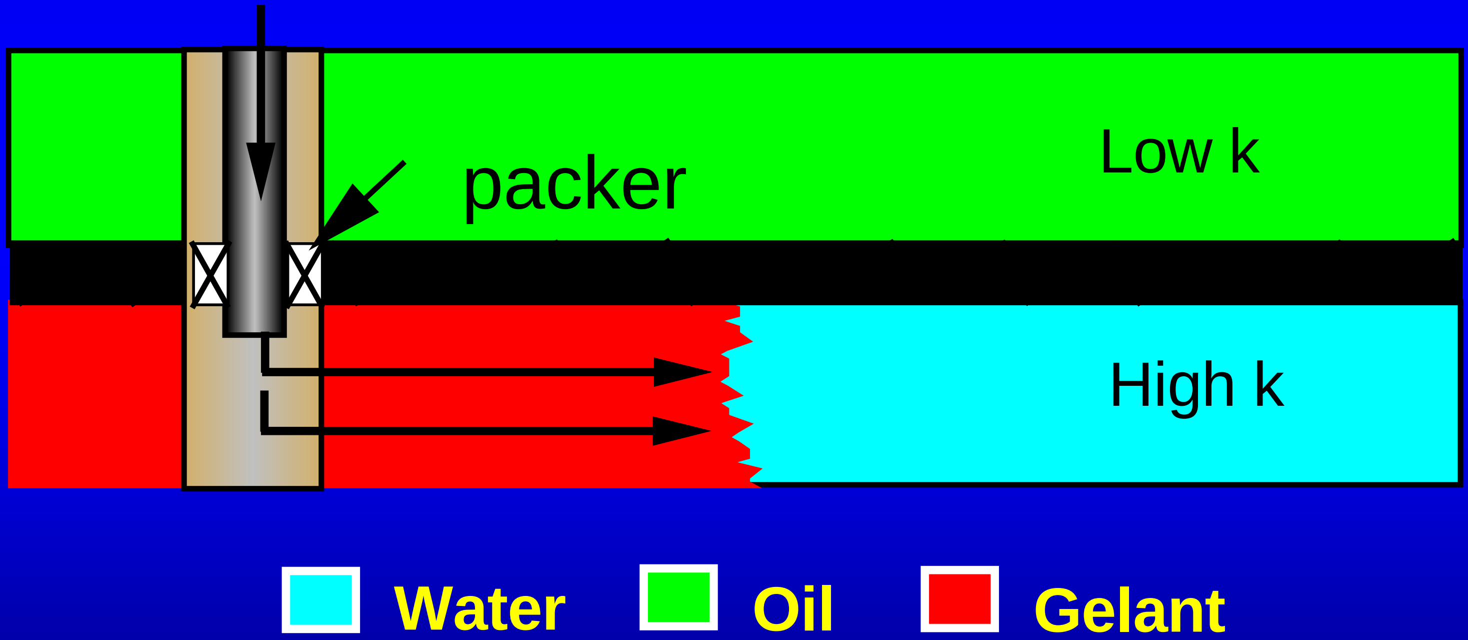



**With crossflow--
gel is ineffective.**

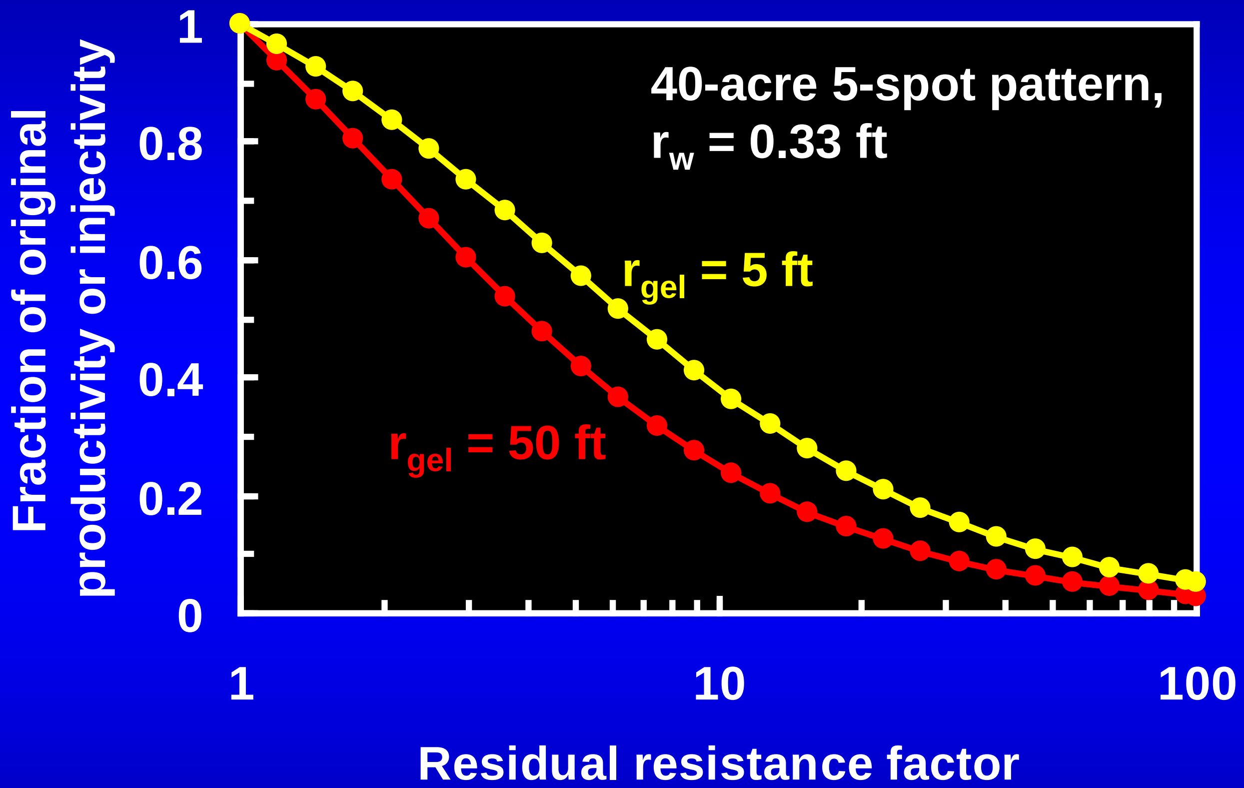


**In-depth channeling problem, no vertical fractures, no vertical communication, zone isolation used:**

- **Inject enough gelant to get desired injectivity or productivity reduction in the water zone.**



# IN RADIAL FLOW, LOSSES ARE MORE SENSITIVE TO PERMEABILITY REDUCTION THAN TO RADIUS OF GELANT PENETRATION




**This figure applies to both injection and production wells.**
**It also applies to both oil and water production.**

## SPE 24193

## Shell Canada's Profile Control Gel Treatments in a Miscible IOR Project

- Virginia Hills Beaverhill Lake Unit, Alberta.
- Field discovered in 1957.
- Waterflood started in 1963 (36% OOIP ultimate).
- Miscible flood started in 1989 (8% OOIP IOR).
- 52 producers, 14 injectors, inverted 9-spot.

- Stratified Devonian reef reservoir.
- 5 separate zones spread over 250 ft.
- k varies from 5 to 1000 mD. $\phi$ varies from 5 to 15%.
- Reservoir pressure can vary from 2600 to 4000 psi within a given wellbore (depending on the zone).
- 80-acre spacing. 220°F (105°C), 4% TDS salinity.

## SPE 24193: Shell's Gel Treatments: Choice of Treatment

**Want to flood all zones simultaneously.**

- Mechanical methods were used in 9 of 14 injectors.
- Minimum spacing between packers must be 30 ft.
- Minimum spacing between perforations: 5 ft.
- In wells selected for gel treatments, 90% of fluid was entering 10% of the pay interval.
- Phenol-formaldehyde was stable at 220°F, 4% salinity.

- 11% phenol-formaldehyde mixed in fresh water.
- 1 cp gelant. Gelation time: 90 minutes at 220°F.
- Injection water temperature: 85°F (30°C).
- Injected solvent (gas) temperature: 40°F (4°C).
- Core tests indicated gel caused 20X k reduction.
- Gelant volume: 20 bbl/ft to reach 20-23 ft radius.
- Injection rate: 2 bbl/min. Pump time: ~ 2 hours.
- Zone isolation during gelant injection.

# SPE 24193, Shell Canada Injector Treatment

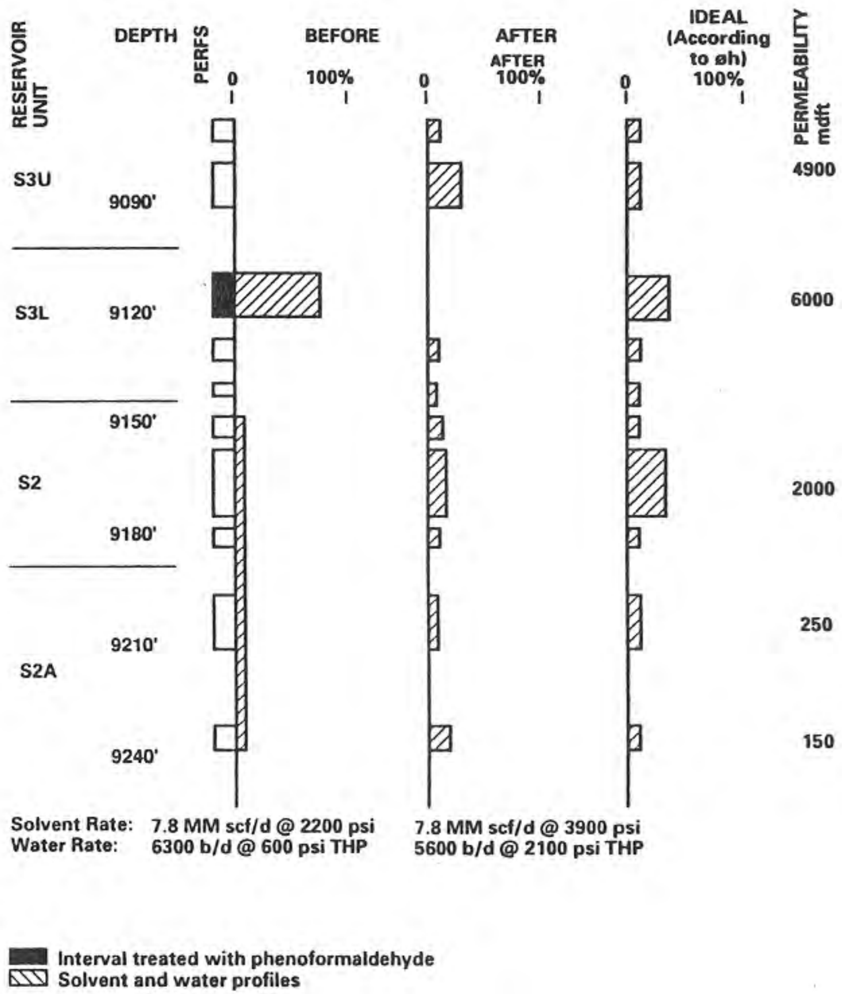



Figure 8
Phenoformaldehyde Treatment - Well 12-25 Miscible Injector

# SPE 24193, Shell Canada Injector Treatment

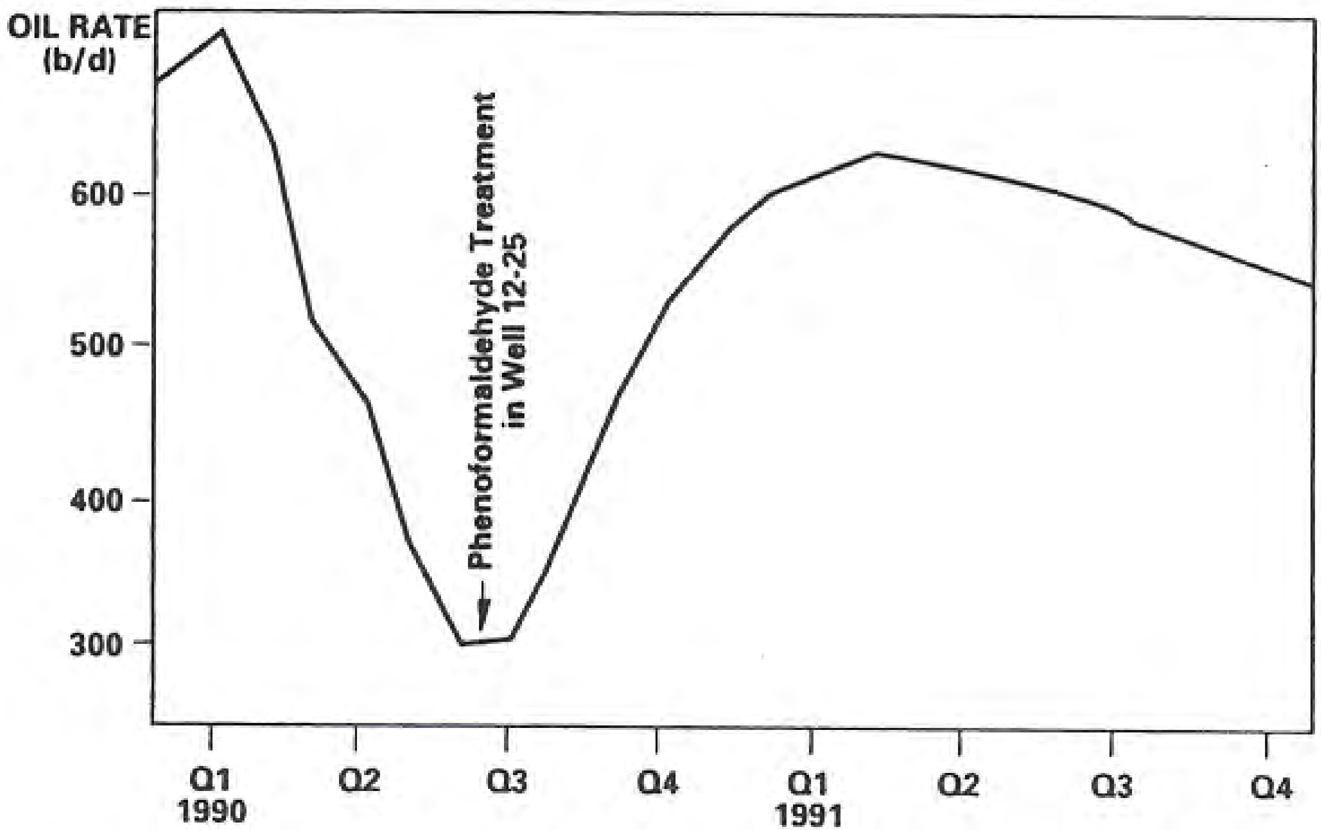



Figure 9

Monthly Oil Production from Pattern 12-25

# SHELL CANADA: PROBLEM 1

Shell found that their phenol-formaldelhyde gel (that contained 11% active material) reduced permeability of a 500-md core by a factor of 20. Does this result suggest that a strong gel formed?

**Expected Values:**

$k_{gel\ inherent} = 125\ C^{-3} = 125\ (11)^{-3} = 0.094\ \mu D$

$F_{rrw} = k_{brine\ before\ gel} / k_{gel\ inherent} = 0.5/0.094 \times 10^{-6} = 5.3 \times 10^{6}$

versus 20 actual.

It looks like a very weak gel formed.

# SHELL CANADA: PROBLEM 2

**Shell found that their phenol-formaldelhyde gel, when placed to a 20 ft radius from injection Well 12-25, reduced the flow capacity of a 10-ft-thick thief zone (at 9120 ft) to an undetectable level. Assume $r_e$=1000 ft, $r_w$=0.5 ft, and static downhole pressure was 3950 psi. $\mu_w$=0.25 cp. Before gel placement, the wellhead pressure was 600 psi with an injection rate of 5670 BWPD. After gel placement, the wellhead pressure was 2100 psi.**

**2A. What water flow rate into the thief zone would have been expected if $F_{rrw}$ was really 20?**

**2B. If our limit of flow detection was 100 BPD, what was the minimum actual in situ $F_{rrw}$?**

# SHELL CANADA: PROBLEM 2A

$r_p$=20 ft, h=10 ft, depth=9120 ft, $r_e$=1000 ft, $r_w$=0.5 ft, $p_r$= 3950 psi, $\mu_w$=0.25 cp. Before gel placement, the wellhead p=600 psi at 5670 BWPD. After gel placement, the wellhead p=2100 psi and flow was undetectable into the thief zone. What water flow rate into the thief zone would have been expected if $F_{rrw}$ was really 20?

$q = \Delta p\ kh\ /[141.2\ \mu\ \ln(r_e/r_w)]$    $k = q\ 141.2\ \mu\ \ln(r_e/r_w)]/(\Delta p\ h)$

k=5670(141.2)0.25[ln(1000/0.5)]/[10(600+9120(0.433)-3950)]

k = 254 md

$q = \{\Delta p\ k\ h\ /[141.2\ \mu]\}\ /\ [F_{rr}\ \ln(r_p/r_w) + \ln(r_e/r_p)]$

q = [2100+9120(0.433)-3950]254(10)/[141.2(0.25) /
[20 ln(20/0.5) + ln(1000/20)]

q = 1945 BPD

# SHELL CANADA: PROBLEM 2B

$r_p$=20 ft, h=10 ft, depth=9120 ft, $r_e$=1000 ft, $r_w$=0.5 ft, $p_r$= 3950 psi, $\mu_w$=0.25 cp. Before gel placement, the wellhead p=600 psi at 5670 BWPD. After gel placement, the wellhead p=2100 psi and flow was undetectable into the thief zone. If our limit of flow detection was 100 BPD, what was the minimum actual in situ $F_{rrw}$?

$$q = \{\Delta p\ k\ h\ /[141.2\ \mu]\}\ /\ [F_{rr}\ \ln(r_p/r_w) + \ln(r_e/r_p)]$$

$$100 = [2100+9120(0.433)-3950]254(10)/[141.2(0.25)\ /\ [F_{rrw}\ \ln(20/0.5) + \ln(1000/20)]$$

Minimum in situ $F_{rrw}$ = 409

So the gel formed much stronger in the field than in the laboratory.

# SHELL CANADA: PROBLEM 3

**Shell placed their phenol-formaldelhyde gel to a 20 ft radius in injection Well 4-20. In a 16-ft-thick thief zone (at 9165 ft), 3220 BWPD was injected at 1750 psi WHP. Assume $r_e$=1000 ft, $r_w$=0.5 ft, and static downhole pressure was 3968 psi. $\mu_w$=0.25 cp. After gel placement, the injection rate was 275 BWPD at 1400 psi WHP. What was the in situ residual resistance factor ($F_{rrw}$)?**

$k = q\ 141.2\ \mu\ \ln(r_e/r_w)]/(\Delta p\ h)$

$k=3220(141.2)0.25[\ln(1000/0.5)]/[16(1750+9165(0.433)-3968)]$

**k = 31 md**

$q = \{\Delta p\ k\ h\ /[141.2\ \mu]\}\ /\ [F_{rr}\ \ln(r_p/r_w) + \ln(r_e/r_p)]$

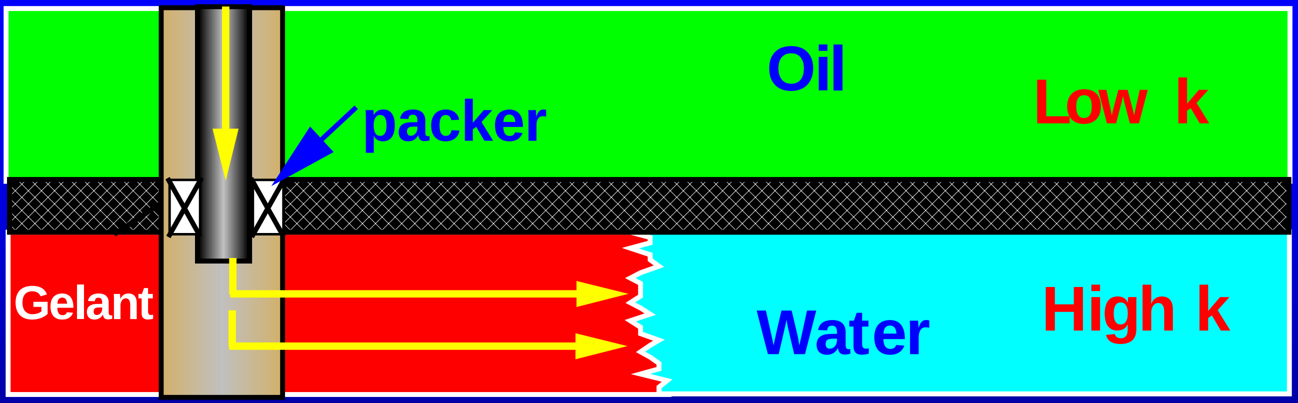
$275 = [1400+9165(0.433)-3968]31(16)/[141.2(0.25)\ /$

$[F_{rrw}\ \ln(20/0.5) + \ln(1000/20)]$

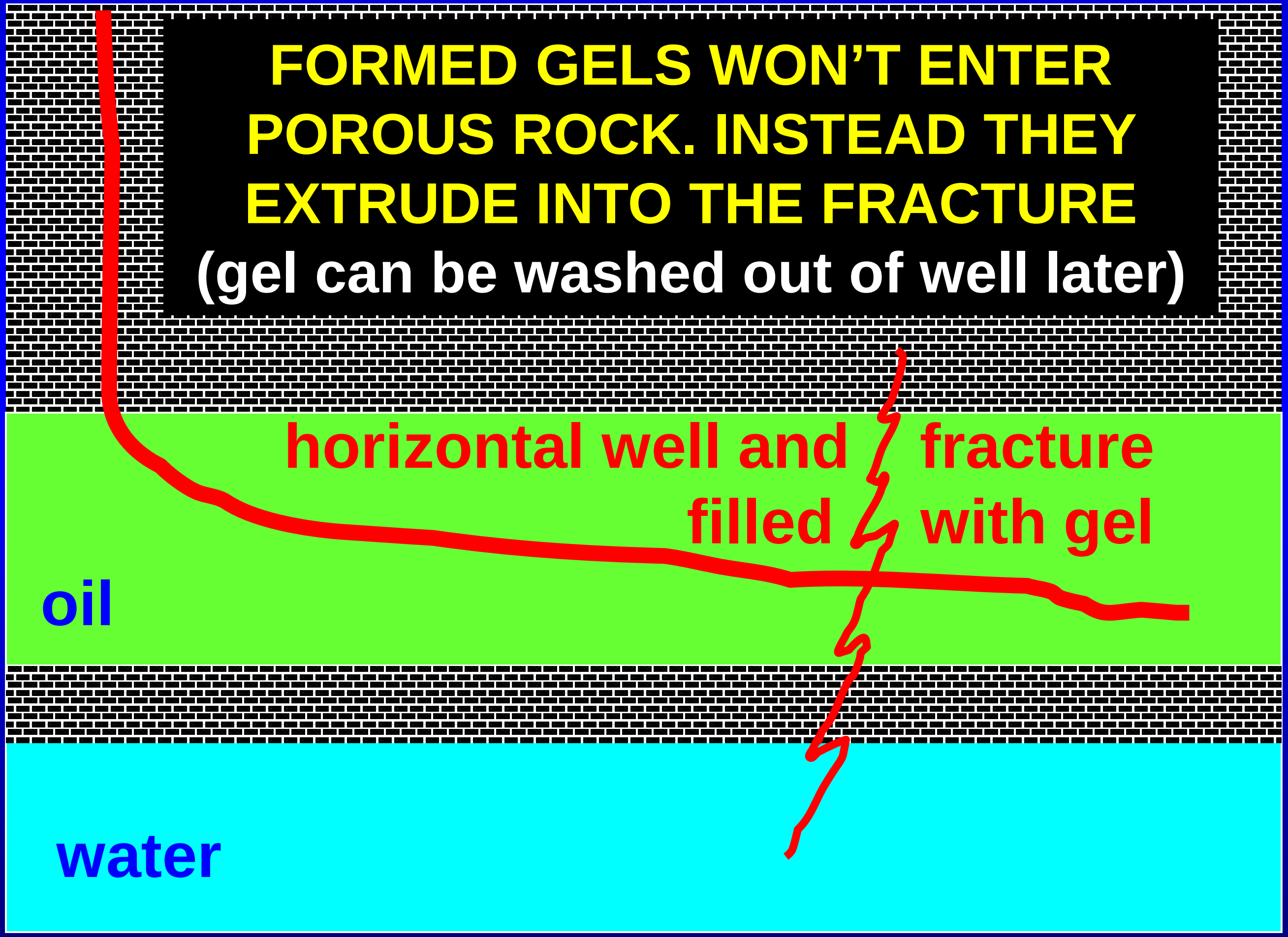
**In situ $F_{rrw}$ = 18, which is similar to the lab value of 20.**

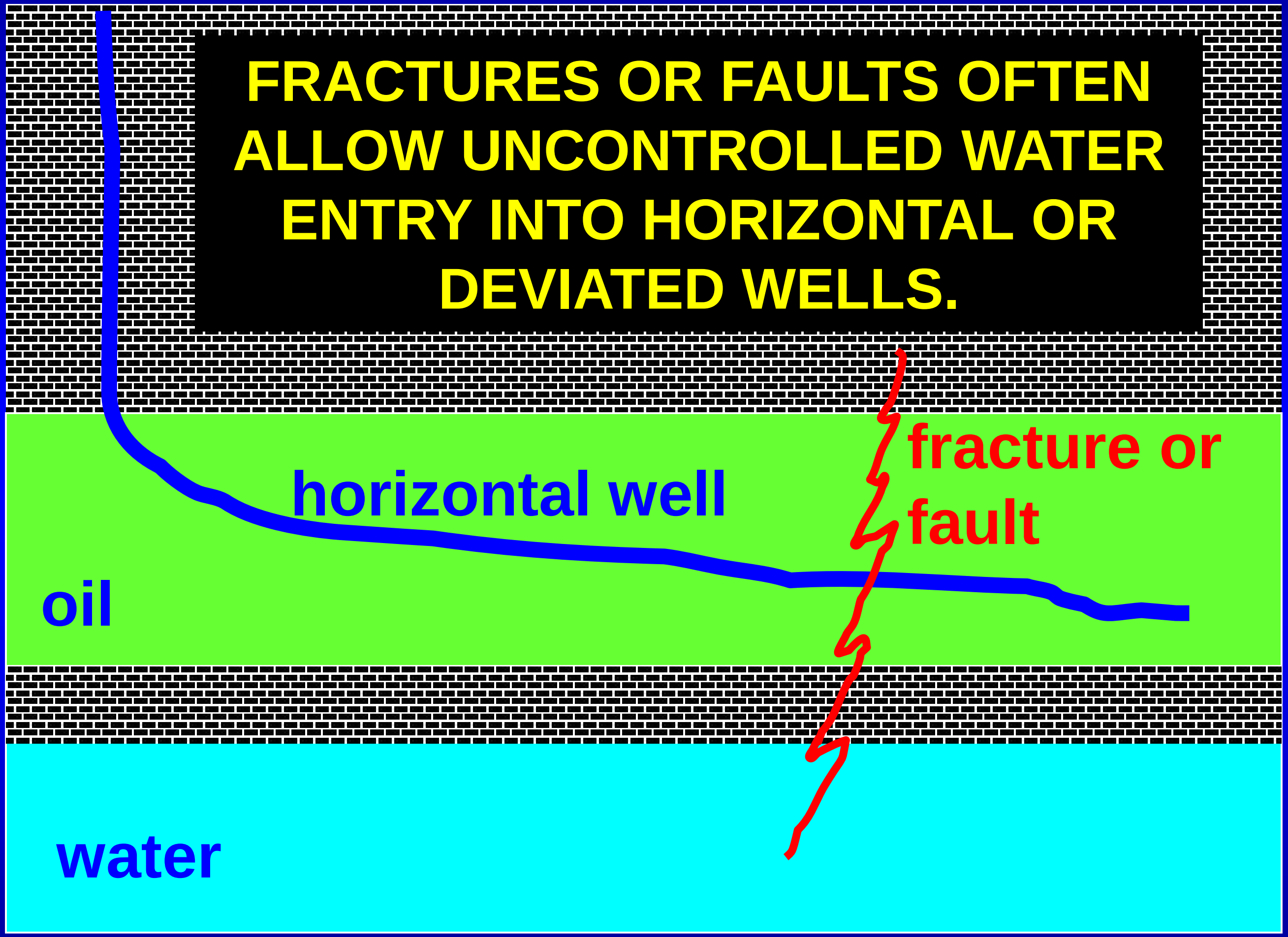
## GEL TREATMENTS FOR RADIAL (MATRIX) FLOW PROBLEMS

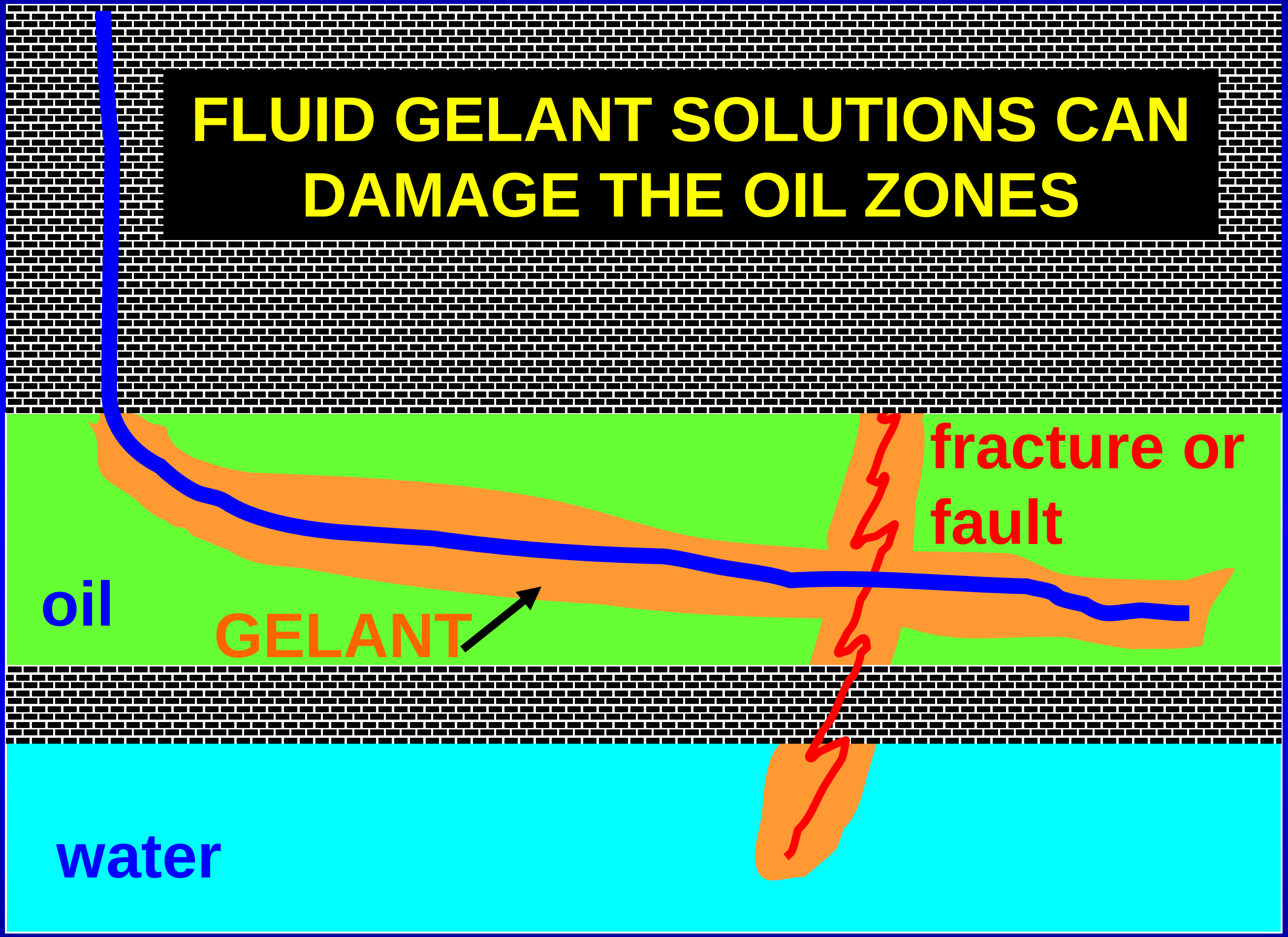
- Zones MUST be separated by impermeable barriers.
- Hydrocarbon-productive zones MUST be protected during gelant injection.
- Loss of water productivity or injectivity is not sensitive to radius of gelant penetration between 5 and 50 ft.
- Gel permeability reductions > 20 cause > 80% loss of water productivity.

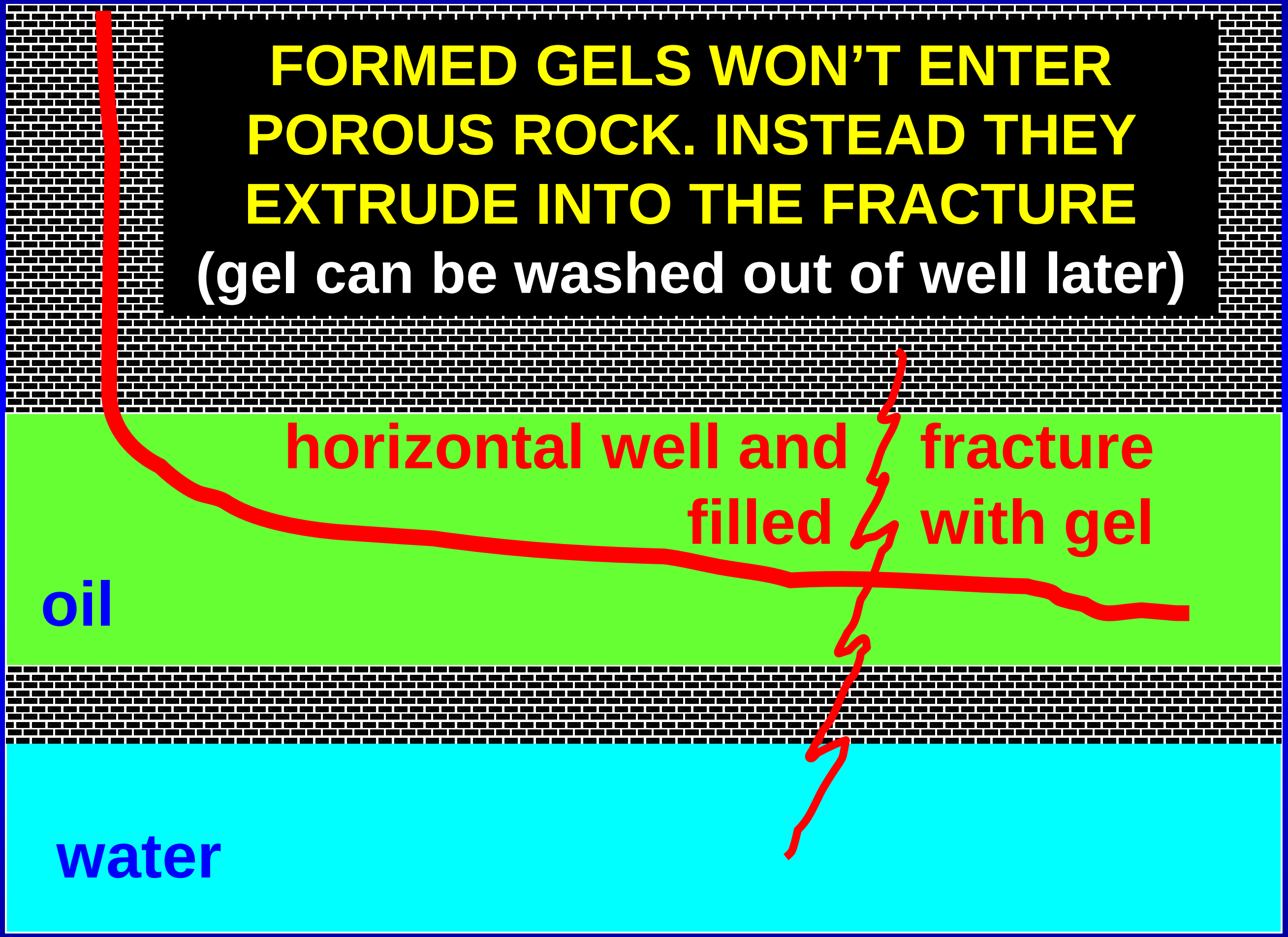


**SPE 29475 & SPE 65527:** ARCO's (Bob Lane) use of Cr(III)-acetate-HPAM gels to plug a fault intersecting a horizontal well.




FRACTURES OR FAULTS OFTEN ALLOW UNCONTROLLED WATER ENTRY INTO HORIZONTAL OR DEVIATED WELLS.
horizontal well
fracture or fault
oil
water


FLUID GELANT SOLUTIONS CAN
DAMAGE THE OIL ZONES
fracture or
fault
oil
GELANT
water


FORMED GELS WON'T ENTER POROUS ROCK. INSTEAD THEY EXTRUDE INTO THE FRACTURE
(gel can be washed out of well later)
horizontal well and fracture filled with gel
oil
water

**SPE 29475**

**ARCO's (Bob Lane) use of Cr(III)-acetate-HPAM gels**
**to plug a fault intersecting a horizontal well**

- **Prudhoe Bay near-horizontal (85°) well.**
- **11,853-ft length, 9009-ft true vertical depth.**
- **Initial production was 1,500 BOPD with 24% water cut. After 3 months: 400 BOPD with 90% water cut.**
- **Reservoir pressure ~3,200 psi.**

## SPE 29475: Problem Diagnosis

- Lost circulation noted during drilling at 11,327 ft.
- Gamma ray/neutron logs showed washed out shale at 11,335 ft.
- Cement bond log indicated poor cementing above 11,338 ft.
- Spinner log indicated most fluid coming from 11,327 to 11,345 ft.
- Temperature anomaly at 11,338 ft.
- Water analysis indicated all of it was formation water.

**Conclusion:** A fault-like conduit exists near 11,338 ft that connects to the underlying Sadlerochit aquifer.

## SPE 29475: Treatment, Sizing, and Placement

- 12,000 bbl Cr(III)-acetate-HPAM gel. (Cement squeeze was expensive and unlikely to work.)
- Treatment sizing was subjective. (12,000 bbl was all they felt that they could afford.)
- Bullhead injection of gel.
- Pump time was 100 hours. Gel was extruded into the fault during placement.
- Well shut in for 5 days to allow gel to cure.

## GEL INJECTION SEQUENCE

| Polymer, wt % | Wellhead pressure, psi | Volume, bbls |
| --- | --- | --- |
| 0.3 | 400 – 0 | 22 (preflush) |
| 0.3* | 0 – 250 | 2,045 |
| 0.45* | 225 – 525 | 5,500 |
| 0.6* | 500 – 675 | 3,225 |
| 0.9* | 725 – 800 | 740 |
| 0.3 | 800 | 100 (postflush) |

2 BPM injection rate throughout.

*[HPAM]/[Cr(III) acetate] = 12/1.

## TREATMENT RESULTS

| Time | Oil rate, BOPD | Water rate, BWPD | Water cut, % | Oil PI, BOPD/psi | Water PI, BWPD/psi |
|---|---|---|---|---|---|
| 11/93 | 466 | 4,290 | 90 | 0.32 | 2.95 |
| Post-job | 543 | 1,700 | 76 | 0.24 | 0.74 |
| + 1 mon. | 727 | 1,895 | 72 | 0.30 | 0.78 |
| + 1 year | 665 | 2,175 | 77 | | |
| + 1.5 years | 567 | 2,410 | 81 | | |

## CONNECTING LABORATORY & FIELD RESULTS
## (SPE 65527)

- Was the problem a fault or fracture?
- How wide was the fault or fracture?
- How far into the fault should the gel penetrate?
- Was the injected material a gel or gelant?
- How effectively did the gel seal the fault?

## WAS THE PROBLEM A FAULT OR FRACTURE?

- Matrix or fracture flow?
- Fracture flow: $q/\Delta p >> k\ h\ /\ [141.2\ \mu\ \ln\ (r_e\ /\ r_w)]$.
- (4,290 BWPD + 466 BOPD)/[1,450 psi] = 3.3 BPD/psi.
- (100 mD x 0.1 x 18 ft)/[141.2 x 0.3 x 6] = 0.7 BPD/psi.
- 3.3 / 0.7 = 4.7.

Therefore, a fracture-like flow problems exists.

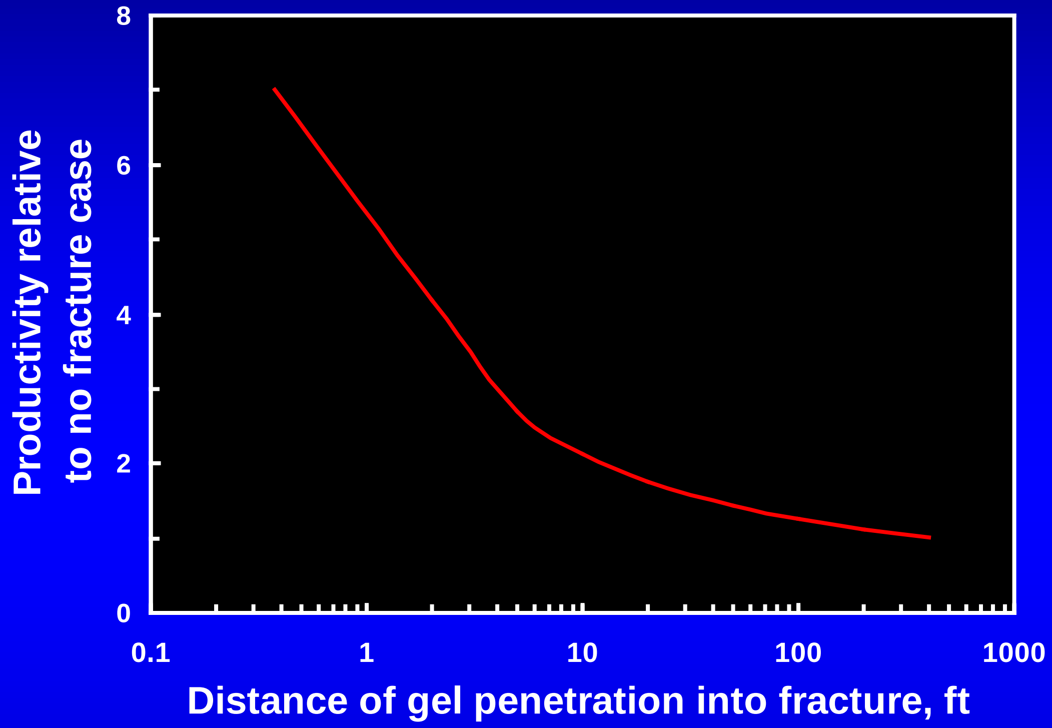
## HOW WIDE WAS THE FAULT OR FRACTURE?

- Assume all water comes from fault.
- Radial flow into fracture:

  $q/\Delta p = k_f w_f / [141.2 \mu \ln (r_e / r_w)].$
- Assume all water comes from fault: q = 4,290 BPD.

  Water PI = $q/\Delta p$ = 2.95 BWPD/psi.
- $\mu = 0.3$ cp.
- $\ln (r_e / r_w) \sim 6$.
- $k_f w_f = 2.95 \times 141.2 \times 0.3 \times 6 =$ 0.75 darcy-ft.
- $w_f = 12 \times 5.03 \times 10^{-4} \times (k_f w_f)^{1/3} =$ 0.0055 in. = 0.14 mm

## HOW FAR SHOULD THE GEL PENETRATE?




- **For single fractures that cut horizontal wells, only moderate gel penetration is needed.**
- **Conclusion is not valid in vertical wells or if multiple fractures or a natural fracture system is present.**

## WAS THE INJECTED MATERIAL A GEL OR GELANT?

- Injection rate: 2 BPM.
- Volume from wellhead to fault: 225 barrels.
- Transit time from wellhead to the fault: ~2 hours.
- Gelation time at 26°C: ~15 hours.
- Gelation time at 90°C: ~10 minutes.
- Total injection time: ~100 hours.

Injected material was gel during most, if not all of the gel placement process.

## HOW EFFECTIVELY DID GEL SEAL THE FAULT?

**BEFORE GEL:**

- Radial flow into fracture: $q/\Delta p = k_f w_f / [141.2 \mu \ln (r_e / r_w)]$.
- Water PI = $q/\Delta p$ = 2.95 BWPD/psi.
- $\mu$ = 0.3 cp, $\ln (r_e / r_w) \sim 6$.
- $k_f w_f$ = 2.95 x 141.2 x 0.3 x 6 = 0.75 darcy-ft.

**AFTER GEL:**

- Water PI = $q/\Delta p$ = 0.78 BWPD/psi.
- $k_f w_f$ = 0.78 x 141.2 x 0.3 x 6 = 0.198 darcy-ft.

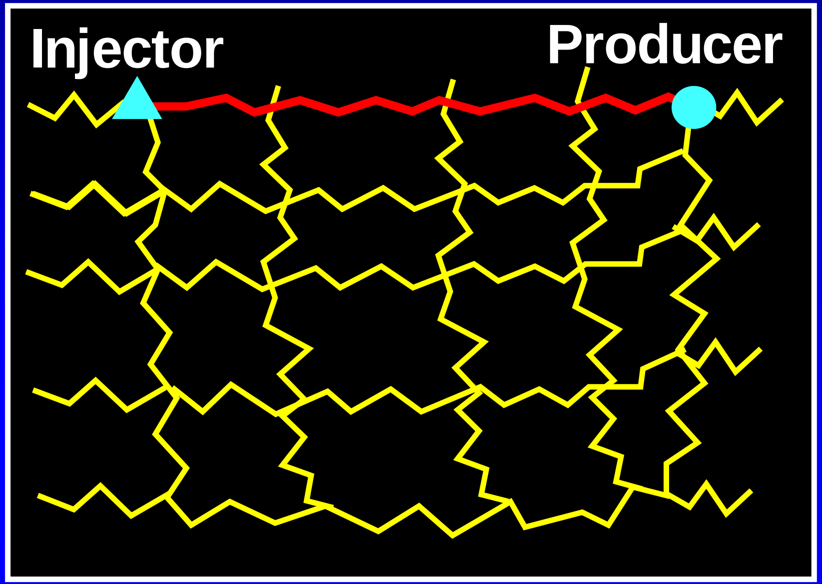
**REDUCTION IN FRACTURE CONDUCTIVITY:**

- (0.75-0.198)/0.75 = 74% reduction.
- Implies fault is not completely sealed but calculation is conservative because it assumes all water came from the fault.

- Simple calculations can give at least a rudimentary indication of the width of the fracture or fault that causes excess water production—which is relevant to the choice of gel.

- During field applications, accurate flowing and static downhole pressures should be made at least before and after the gel treatment is applied. Some very useful insights can also be gained if downhole pressures are measured during gel injection.

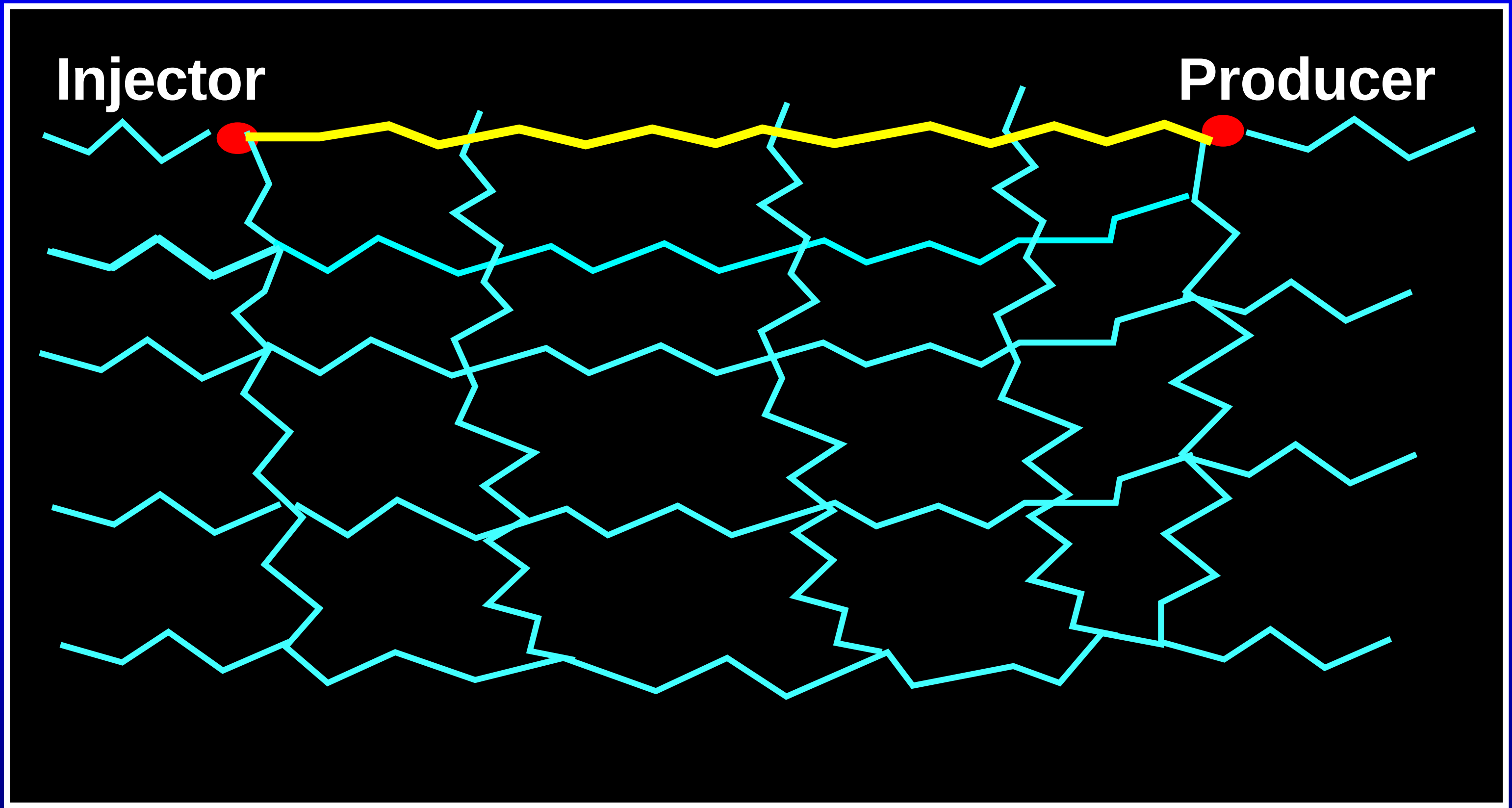
# NATURALLY FRACTURED RESERVOIRS




- Want to restrict fluid channeling through the most direct fracture(s).
- Don't want to damage the secondary fractures (since they are important in allowing high well injectivities and productivities).

## Naturally fractured reservoirs:

- Impressive well-documented cases,
- Greatest successes used large gel volumes,
- Optimum sizing unknown.



## GEL EXTRUSION THROUGH FRACTURES

- Formed GELS injected instead of GELANT solutions.
- Gels extrude through fractures—no flow in porous rock.
- Successful field applications in treating:
  - Fractures or faults that cross horizontal wells.
  - Water or gas channeling through natural fractures.
- Gel dehydration and pressure gradients depend on $w_f$ .
- Interwell tracers and injectivity/productivity data can indicate $w_f$ for the most serious fracture(s).
- Gel sizing procedure is under development but:
  - Fastest injection yields the greatest gel penetration.
  - Slower injection increases gel's staying power.
  - At a given rate, a 3X increase in gel volume yields a 2X increase in distance of gel penetration.
- More information: SPE 65527, *SPEPF* (Nov. 1999) 269-276, *SPEPF* (Nov. 2001) 225-231.

# Cr(III)-acetate-HPAM Treatments to Reduce Channeling during WAG $CO_2$ Projects in Fractured Sandstone Reservoirs

| | Wertz | Rangely |
|---|---|---|
| SPE paper | 27825 | 56008 |
| μ oil, cp | 1.38 | 1.7 |
| k, md | 13 | 10 |
| Lithology | sandstone | sandstone |
| Thickness, ft | 240 | 175 |
| T, °C | 74 | 71 |
| No. of treatments | 8 | 44 |
| HPAM, ppm | 5000-8000 | 3000-8000 |
| Treatment size, bbl | 10,000-20,000 | 8,900-20,000 |
| EOR/well, BOPD | 100-300 | 21 |
| EOR, total bbl | 735,000 | 685,000 |
| Total cost, $ | 963,000 | 2,060,500 |

## SPE 39612: Chevron's Large Volume Gel Treatments in Injection Wells During a $CO_2$ Flood in a Naturally Fractured Reservoir

- Rangely field. Weber eolian sandstone.
- 675 ft gross thickness, 175 ft net pay.
- 6 distinct sand units
- $\phi$=11%, k=10 mD.
- 376 producers, 278 injectors
- Discovered: 1933. First produced: 1944. Perpherial waterflood since 1958. Pattern waterflood since 1969.
- $CO_2$ flood since 1986.

## SPE 39612: Chevron's Rangely Field

## Problem Diagnosis

- Extreme variability in $CO_2$ performance from pattern to pattern.
- Several patterns with rapid breakthrough.
- Pattern reports showed "under and over processed" zones.
- Chevron created a sophisticated rating system to quantify the merit for treatment.

## SPE 39612: Chevron's Rangely Field

## Did Fractures Cause the Problem?

- Injectivity was 23X greater than expected from Darcy's Law for radial flow.
- $CO_2$ breakthrough noted at 24 hrs with 1,300' well spacing--55 ft/hr propagation rate.
- Average effective permeability = 10 md, yet they routinely placed 10,000 bbls of polymer gel into formation.
- Linear flow character seen in injection well fall-off test data.

## Chevron's Rangely Field—
## Conformance Methods Applied

- Selective injection equipment (SPE 21649).
- Water-alternating-gas (SPE 27755).
- Recompletion (SPE 27756).
- Pattern realignment (SPE 27756).
- Gelled foams (SPE 39649).
- Gels (SPE 39612).

## SPE 39612: Chevron's Gel Treatments

## Treatment Design

- Water injected for ~1 week before treatment.
- Cr(III)-acetate-HPAM gel.
- 10,000-20,000 bbl injected per treatment.
- Typical injection time: 8-10 days.
- 0.5% HPAM in gel mostly, but ramped up to 0.85% HPAM at end.
- Flushed with 3 tubing volumes of water at end.
- Shut well in for 1 week.
- Inject water first on return to injection.

## SPE 39612: Chevron's Gel Treatments

## Range of Responses (44 Treatments Total)

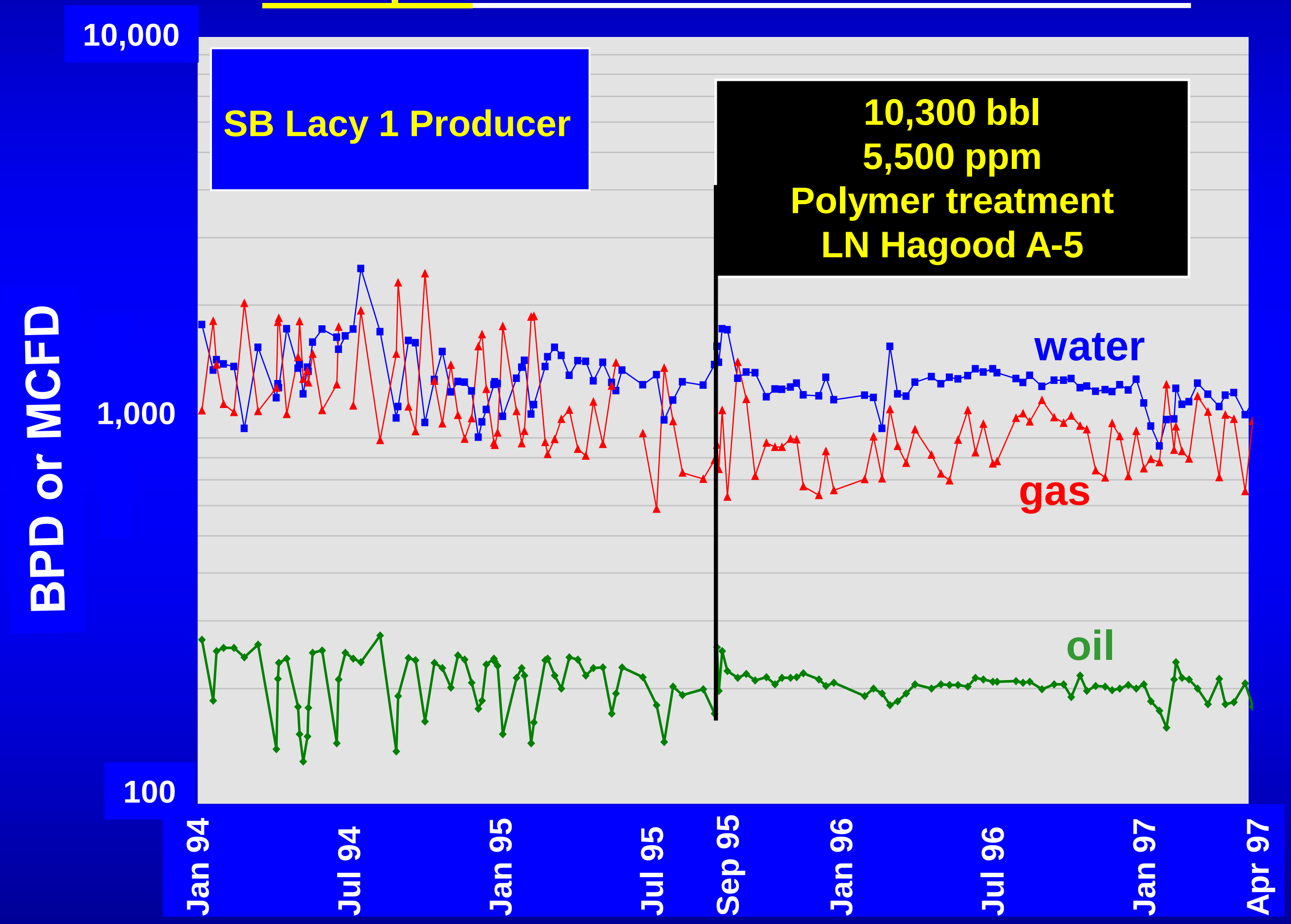
- No response.
- Smoothing of production.
- Reduction in water.
- Reduction in gas.
- Areal sweep improvement.
- Oil rate increase.
- Reduction or elimination of oil decline.
- Better pattern $CO_2$ retention & utilization.

## SPE 39612: Chevron's Gel Treatments
## Example: Treatment Smooths Production

- Rapid breakthrough from injector to producer.
- No other producers supported.
- Thief appeared confined to one zone.
- Previous attempts at near-wellbore control were unsuccessful.
  - Liner, selective perforations.
  - Small-volume Cr(III)-acetate-HPAM treatments.

## SPE 39612: Chevron's Gel Treatments

## Example: Treatment Smooths Production



## SPE 39612: Chevron's Gel Treatments
## Results: 1994-1996

- Investment = $2,060,500.
- ROR: 365%. Payout: 8 Months.
- IOR: 685,000 BO.
- Success Rate: 80%.
- Average change per treated well:

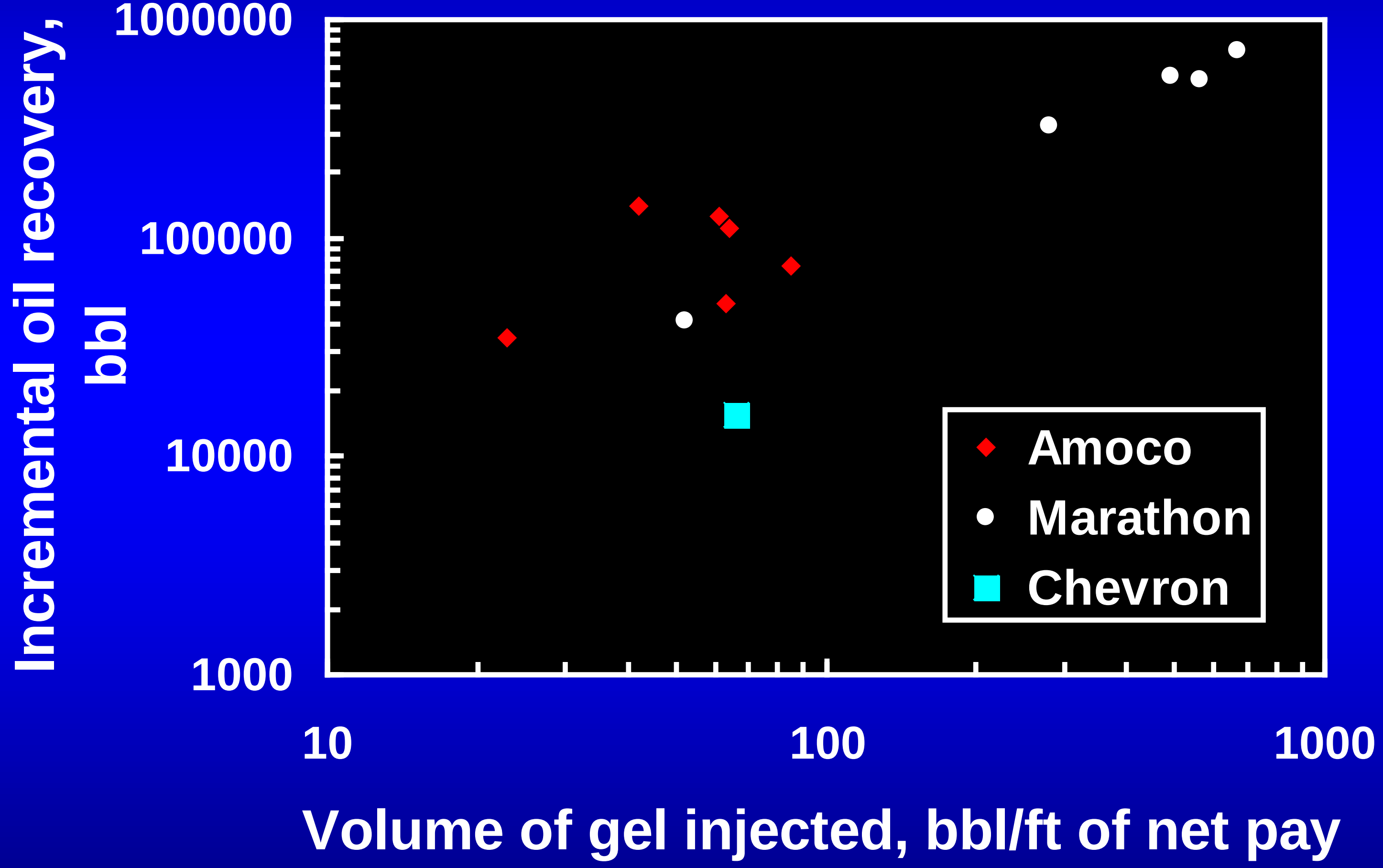
  +20 BOPD, -100 BWPD, -100 MCFPD

## SPE 39612: Chevron's Gel Treatments

## Lessons Learned

- Rapid communication and associated poor $CO_2$ economic performance are the most important candidate selection criteria.
- Larger, >15,000 bbl treatments have been successful.
- Chase well treatments are highly successful.
- Best results have been in the best part of the field.
- $CO_2$ thief should also be $H_2O$ thief.
- $H_2O$ injection rate > 1,200 BPD.
- Avoid high BHP area of field.
- Post-job reservoir management critical.

•Incremental oil recovery generally increased with gel treatment size.



## Good Papers Where Naturally Fractured Injection Wells Were Treated

- Amoco's large-volume gel treatments in $CO_2$ injectors. SPE 27825.
- Marathon's large-volume gel treatments in waterflood injectors. SPE 27779 & *O&GJ* 1/20/92.
- Imperial's large-volume gel treatments waterflood injectors. SPE 38901.
- Chevron's use of multiple methods in the same field, including recompletions, polymer gels, gelled foams, pattern realignment and selective injection equipment. SPE 21649, 27755, 27756, 30730, 35361.
- Kinder Morgan SACROC treatments. SPE 169176

## SACROC/KELLY-SNYDER FIELD SPE 169176

- Kinder Morgan WAG $CO_2$ flood. 19-md limestone.
- 500-1200 sacks of cement worked for some of the worst channeling problems.
- Mechanical methods sometimes helped if distinct zones were watered out.
- Crystalline polymer squeezes were the least successful method.
- 5000-10000 bbl Cr(III)-acetate-HPAM treatments did not last long. Judged too small.
- ~20,000 bbl Cr(III)-acetate-HPAM treatments.
- 5000-12000-ppm HPAM.
- Ending injection of 30,000-ppm HPAM or cement.

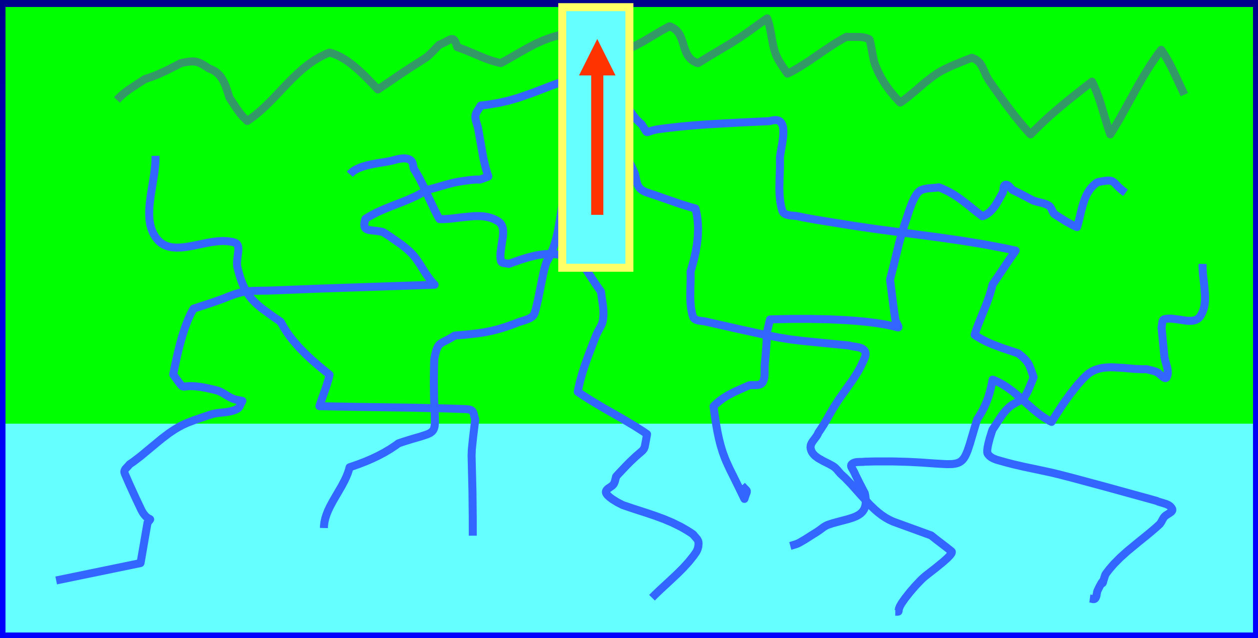
## SACROC/KELLY-SNYDER FIELD SPE 169176

- In "P1" area, 29 treatments with ~13000 bbl gel/treatment—reducing GOR from 30 to 20 mcf/bbl and producing 770000 bbl EOR at a cost of $1.88/bbl.
- In "P2" area, 30 treatments with ~17000 bbl gel/ treatment—yielding $1.50 cost/bbl EOR.
- Biggest problem has been produced polymer. Suggested solution: build injection pressure more rapidly (e.g., by increasing HPAM content).
- In total, have injected over one million bbl of polymer during 77 treatments.

## DETAILS OF ONE GEL TREATMENT.
## KUPARUK RIVER UNIT—ALASKA
## SPE 179649

- ConocoPhillips. Miscible hydrocarbon WAG.
- Highly fractured/faulted multilayer sandstone.
- A single 45000-bbl Cr(III)-acetate-HPAM treatment, increasing HPAM from 0.3%-1%.
- Describes detailed methodology associated with the design, execution, and assessment of the treatment.

# Natural fracture system leading to an aquifer.



- Many successful polymer/gelant treatments were applied to reduce water production.
- Treatment effects were usually temporary.
- Optimum treatment materials, sizing, and design are currently unknown.
- HOW SHOULD THESE TREATMENTS BE DESIGNED AND EVALUATED?

# *JPT*, April 1993, 356-362
# Phillips' Polymer and Gel Treatments in Naturally Fractured Production Wells

- Arbuckle formation of western Kansas.
- Naturally fractured dolomite reservoirs produced by bottom-water drive.
- k ~ 140 md; oil column ~ 20 ft; completion interval ~ 5 ft.
- Pre-treatment production:
  - 5 to 20 BOPD
  - 500 to 1,600 BWPD

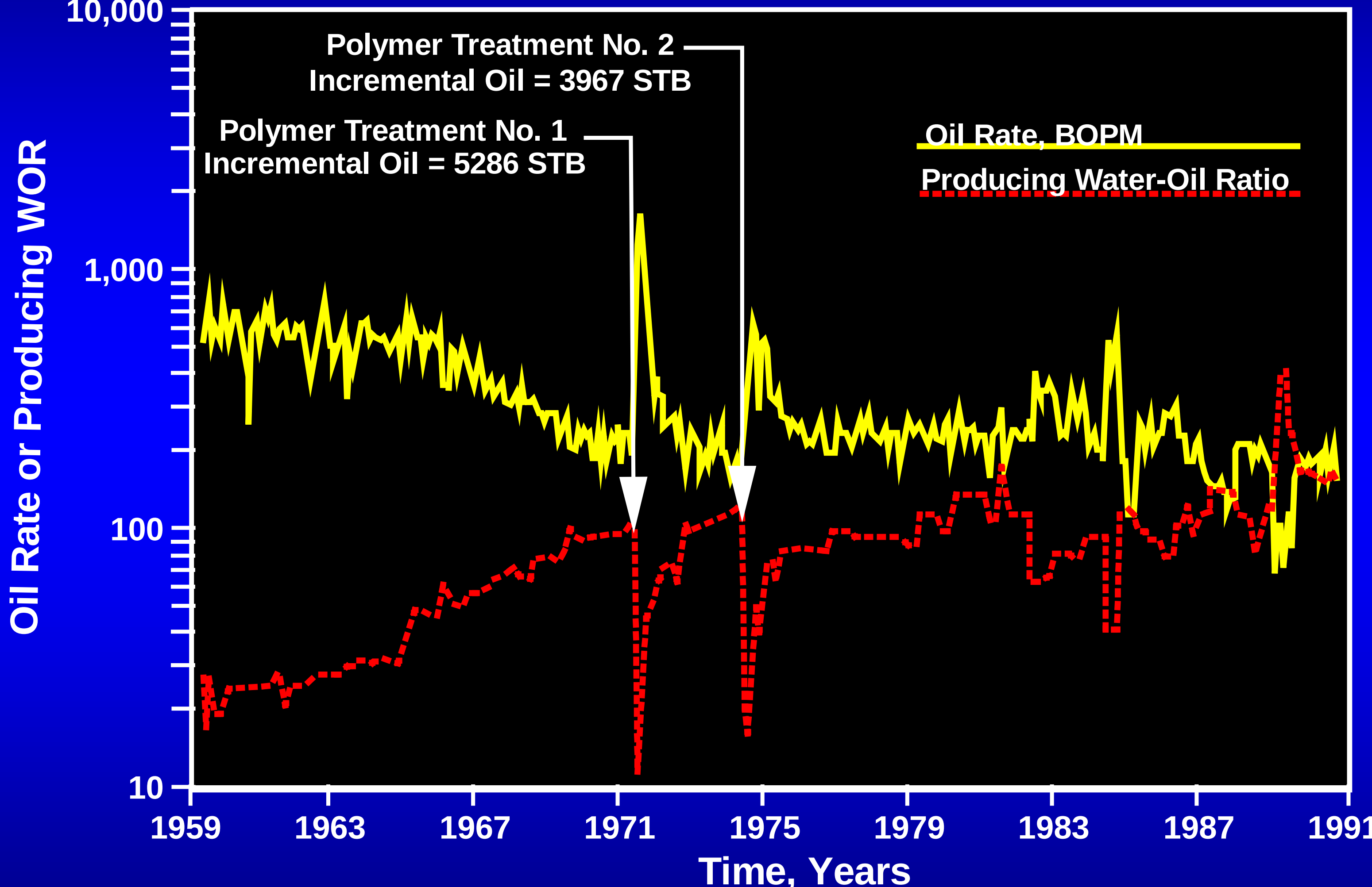
## JPT, April 1993, 356-362
## Phillips' Polymer and Gel Treatments: Problem Diagnosis

- Reservoirs were well known to be naturally fractured.
- Pretreatment productivities, q/dp, were 10-100 times greater than values expected for unfractured wells.

## *JPT*, April 1993, 356-362
## Phillips' Polymer and Gel Treatments: Choice of Treatment, Sizing, and Placement

- Performed in the 1970's -- early in the development of the technology.
- Applied 37 treatments with 8 different polymer-crosslinker combinations.
- Average treatment size: 1070 lbs polymer. (Range: 390 to 1400 lbs).
- Treatments sizes subjective.
- Bullhead injection.

## Phillips' well Hendrick #2 production response to polymer treatments ( *JPT*, April 1993)



## JPT, April 1993, 356-362
## Phillips' Polymer and Gel Treatments: Treatment Results

- Average incremental recovery: 1.9 STB/lb polymer. (Range: -1 to 13 STB/lb).
- Average treatment lifetime: 12 months. (Range: 2 to 43 months).
- Gel treatments typically reduced total fluid productivity by a factor of two, so the fractures were restricted but still open.
- Uncrosslinked polymers worked as well as gels.
- Many other materials have been used in the Arbuckle formation. Some say that anything will work.

## *JPT*, April 1993, 356-362
## Phillips' Polymer and Gel Treatments: Treatment Results

- IOR, treatment lifetime, and WOR reduction did not correlate well with:
  - lbs. polymer injected (390 - 1,400 lbs/well),
  - type of polymer or gel treatment (8 types used),
  - productivity reduction induced by the treatment (1 - 5),
  - structural position of the completion,
  - completion type,
  - fluid level before the treatment,
  - Arbuckle reservoir.

## *JPT*, April 1993, 356-362
## Phillips' Polymer and Gel Treatments: Questions

- Why did IOR not correlate with important variables?
- Why did treatments using uncrosslinked HPAM perform as well as any other type of polymer or gel?
  - Uncrosslinked HPAM has some unknown special property. NO
  - Uncrosslinked HPAM happened to be applied in the best wells. MAYBE
  - pH or other changes induced by the rock inhibited gelation. YES!
- What is the mechanism of action for water shutoff treatments in naturally fractured productions wells?
  - Partial plugging of fractures?
  - Selective plugging of porous rock next to fractures?
  - Other?

# Gel Treatments Applied to the Kansas Arbuckle Formation Per SPE Paper 89464

- Over 250 gel treatments had been applied in the Kansas Arbuckle fractured carbonate formation (2000-2003)
- Incremental oil production was the driver for conducting these gel treatments
  – Often reduced water production by a factor exceeding 10 (not mentioned in this paper)

- 7 gel treatments were studied where BHP & buildup pressure data were obtained
  - Water-production rates decreased in every well (53–90%)
  - Incremental oil production obtained from 5 out of 6 wells that were produced for 6 mo.
  - Oil PI increased following the gel jobs
  - Incremental oil production increased with increasing volume of gel injected (for the open hole completions)
  - “The duration of the response should be a function of the volume of gelant injected…”

# Economics of Arbuckle Gel Treatments

(Source: PTTC website, R. Reynolds, 10/03)

- ~300 treatments
  - By over 30 operators
  - Analyzed the performance of 37 treated wells
  - Shutoff 110,000,000 bbl water
  - Gross IOP = 1,600,000 bbl oil
- "All of the wells have responded with significant reduction in water production…." (2/03 Reynolds quote)

## FIELD OPERATIONAL ISSUES

**Robert Lane, SPE 37243**

1. Sampling and quality assurance.
2. Polymer handling.
3. Rigup issues.
4. Treatment execution issues.
5. Chemical incompatibilities.
6. Post-treat well operations.

# SAMPLING AND QUALITY ASSURANCE

1. Laboratory samples and testing conditions must be representative of field materials and conditions. (Vendors sometimes provide samples to labs that are different from field products.)
2. Water used in lab tests must be representative of field water. (Field & lab people MUST communicate any important changes, like water source changes.)
3. Lab tests in the field MUST verify the behavior of delivered products (e.g., polymer ability to dissolve, polymer solution viscosity, gel times).
4. Pumps, mixers, and filters must not shear degrade the polymer.
5. Field samples for testing should be drawn near the wellhead.

# POLYMER HANDLING

**Solid grade polymer (>90% active):**

- Minimizes shipping costs.
- Requires specialized mixing equipment.
- Residue or incomplete hydration creates fisheyes.

**Solution concentrate (~20% active):**

- Easily pumped and diluted
- Less complex mixing equipment.
- Can be prepared "on the fly", minimizing waste.
- Has significantly higher shipping costs.

**Liquid, slurry, or emulsion polymers (30-50% active):**

- Easily pumped and diluted (if lines are clean & dry).
- Less complex mixing equipment; injection on the fly.
- Intermediate shipping costs.
- Special care required for clean dry lines, tanks, etc.

# FILTRATION

Views vary on what and where filters should be used.

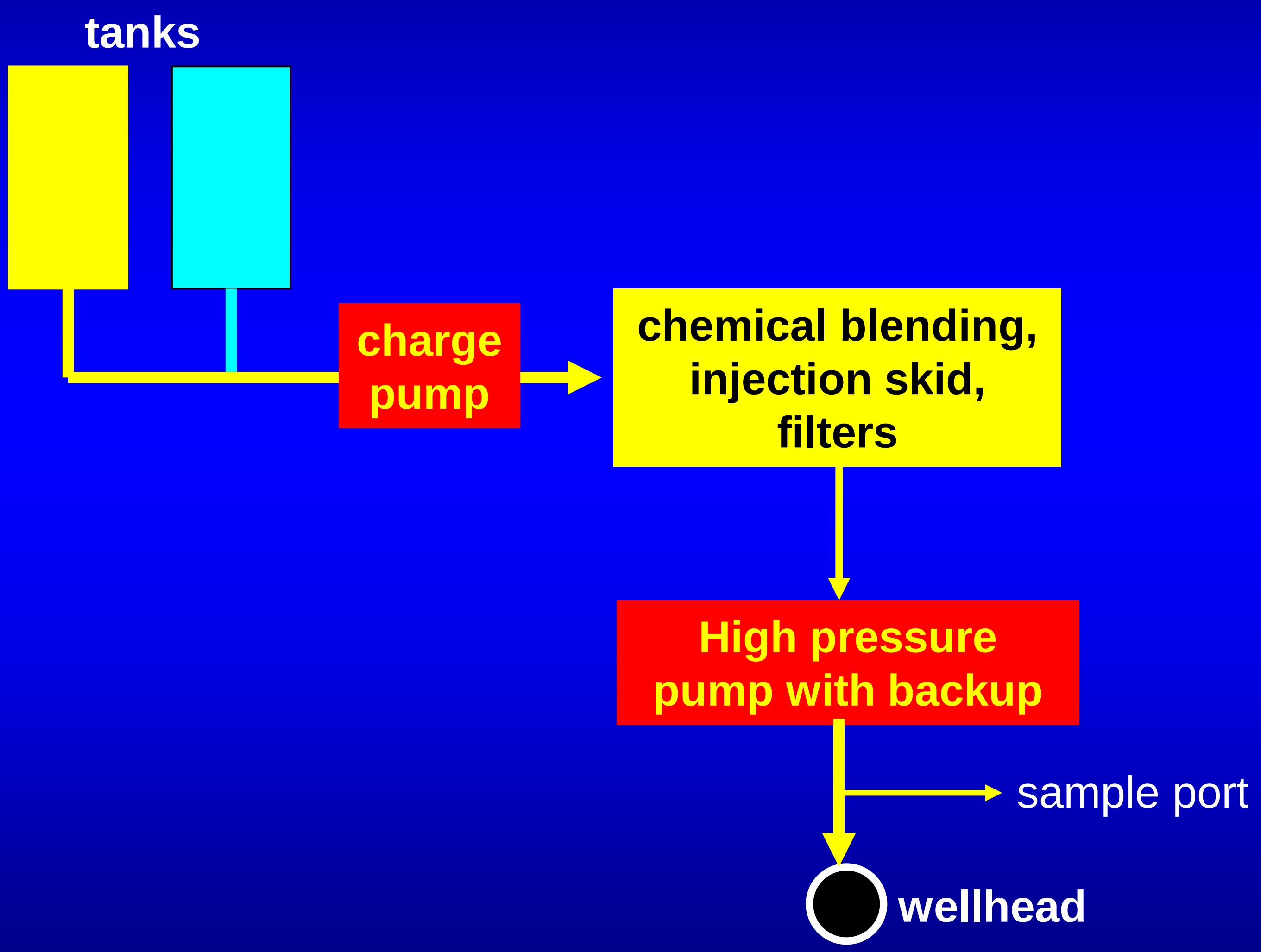
Advisable to have two filters (10 µm) in parallel downstream of the mixing equipment.

- Avoids well plugging.
- Gives a quality check on polymer preparation.

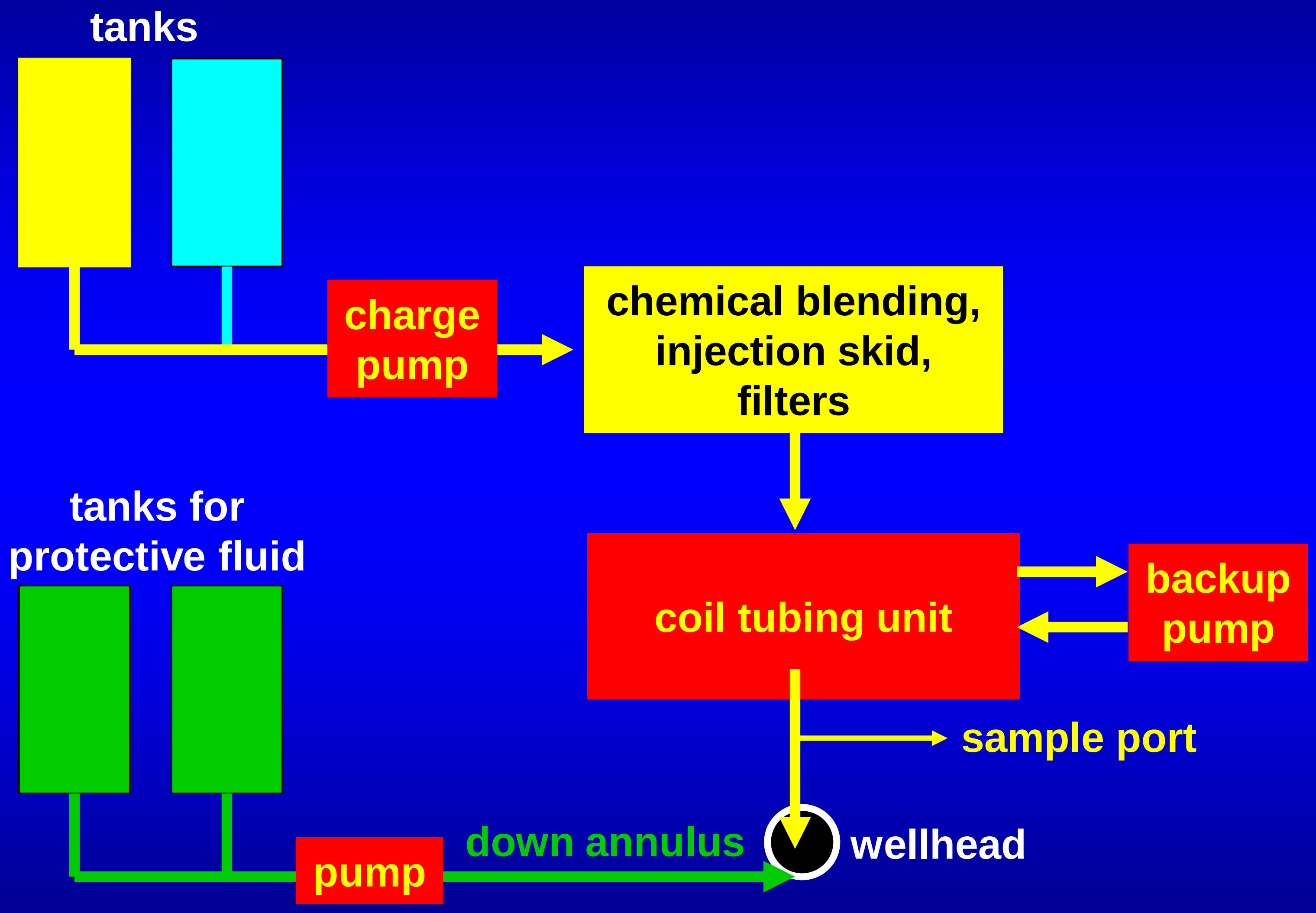
## RIG UP ISSUES

1. Many equipment configurations are possible.
2. Other things being equal, simpler is better.
3. All transport trucks, tanks, hoses, pumps, lines and mixing equipment MUST be clean and inspected by someone who has a major stake in project success.
4. “Clean” means carefully flushed with water compatible with gelant.
   - Residual water must be clear with neutral pH.
   - No oily or solid residues.
   - With slurry polymer, lines, tanks, etc. must be DRY.
5. Temperature extremes should be avoided, especially for connecting hoses.

# SIMPLE RIG UP EXAMPLE



# COMPLEX RIG UP EXAMPLE



# RIG UP ISSUES—TANKS, PUMPS & HOSES

1. Many tank options exist (frac tanks, transport trucks, etc). Tanks should be sized so refilling and switching occurs at reasonable times (hours not minutes).
2. Low-pressure hoses, tanks, charge pumps, blenders, and filters used before the final high pressure pump.
3. Pumps, mixers, and filters must be selected to minimize mechanical degradation of the polymer.
4. Locate filtration equipment at blender discharge.
5. Although "on the fly" mixing is conceptually attractive, polymer mixing is often inadequate.
6. High pressure injection pump is the final equipment before the wellhead.
7. Sample port must be close to the wellhead.

# TREATMENT EXECUTION ISSUES

1. Gelation time usually determines the pump time (except for some large treatments in fractures).
   - Downtime during pumping must be avoided.
   - Good polymer/gel quality control is needed.
   - Equipment redundancy can reduce downtime.
2. Surface equipment may limit the surface pressure. It’s best to have a pump with a high rate limit.
3. Parting pressure often limits downhole pressure.
4. Pressure drop from surface to formation is usually negligible unless coiled tubing is used.
5. Hall plots help monitor pressure trends. (They do NOT indicate where the gel is placed.)

# CHEMICAL INCOMPATIBILITIES

- **Cationic corrosion inhibitors precipitate with anionic polymers (e.g., HPAM).**
- **Scale inhibitors can destroy gels made with metal crosslinkers [e.g., Cr(III)].**

- **Don't apply these chemicals too soon before or after a gel treatment.**
- **Check lines, equipment and make-up water for these contaminants.**
- **Lab tests may help to establish compatibility.**

- **Rust, crude components, emulsion breakers, defoamers, water clarifiers, floatation aids, oxygen scavengers, $H_2S$, and chlorine may affect gel chemistry.**

## POST-TREATMENT WELL OPERATIONS

- Shut-in times depend on the gel and the nature of the problem treated.
- After shut-in, bring the well back into full service gently (over the course of days or weeks rather then hours).
- Post-treatment procedures should consider whether the gel treatment will be compromised (corrosion inhibitors, injecting above parting pressure, acid jobs, etc.).

## REVIEW OF THE MOST IMPORTANT CONCEPTS

- The cause of the water production problem must be identified.
- Different design, sizing, and placement procedures must be used for different types of problems.
- For radial flow, hydrocarbon-productive zones must be protected during placement of chemical blocking agents.

## GEL TREATMENTS ARE NOT POLYMER FLOODS

**Crosslinked polymers, gels, gel particles, and "colloidal dispersion gels":**

- **Are not simply viscous polymer solutions.**
- **Do not flow through porous rock like polymer solutions.**
- **Do not enter and plug high-k strata first and progressively less-permeable strata later.**
- **Should not be modeled as polymer floods.**

## A STRATEGY FOR ATTACKING EXCESS WATER PRODUCTION

1. Consider and eliminate the easiest problems first.
2. Start by using information that you already have.

## Excess Water Production Problems and Treatment Categories
## (Categories are listed in increasing order of treatment difficulty)

**Category A: "Conventional" Treatments Normally Are an Effective Choice**

1. Casing leaks without flow restrictions.
2. Flow behind pipe without flow restrictions.
3. Unfractured wells (injectors or producers) with effective crossflow barriers.

**Category B: Treatments with Gelants Normally Are an Effective Choice**

4. Casing leaks with flow restrictions.
5. Flow behind pipe with flow restrictions.
6. "Two-dimensional coning" through a hydraulic fracture from an aquifer.
7. Natural fracture system leading to an aquifer.

**Category C: Treatments with Preformed Gels Are an Effective Choice**

8. Faults or fractures crossing a deviated or horizontal well.
9. Single fracture causing channeling between wells.
10. Natural fracture system allowing channeling between wells.

**Category D: Difficult Problems Where Gel Treatments Should Not Be Used**

11. Three-dimensional coning.
12. Cusping.
13. Channeling through strata (no fractures), with crossflow.

# KEY QUESTIONS IN OUR APPROACH

1. Does a problem really exist?
2. Does the problem occur right at the wellbore (like casing leaks or flow behind pipe) or does it occur out beyond the wellbore?
3. If the problem occurs out beyond the wellbore, are fractures or fracture-like features the main cause of the problem?
4. If the problem occurs out beyond the wellbore and fractures are not the cause of the problem, can crossflow occur between the dominant water zones and the dominant hydrocarbon zones?

**Respect basic physical and engineering principles.**
**Stay away from black magic.**

## MAIN POINTS I THINK YOU NEED TO KNOW

1. What polymers, gelants, and gels can/cannot do.

2. Why determining whether flow is radial (into matrix) or linear (through fractures) is critical in EVERY application.

3. A strategy for attacking problems.

## PROPERTIES OF AVAILABLE GELANTS/GELS

1. Early in the gelation process, gelants penetrate readily into porous rock.

2. After gelation, gel propagation through porous rock is extremely slow or negligible.

3. The transition between these two conditions is usually of short duration.

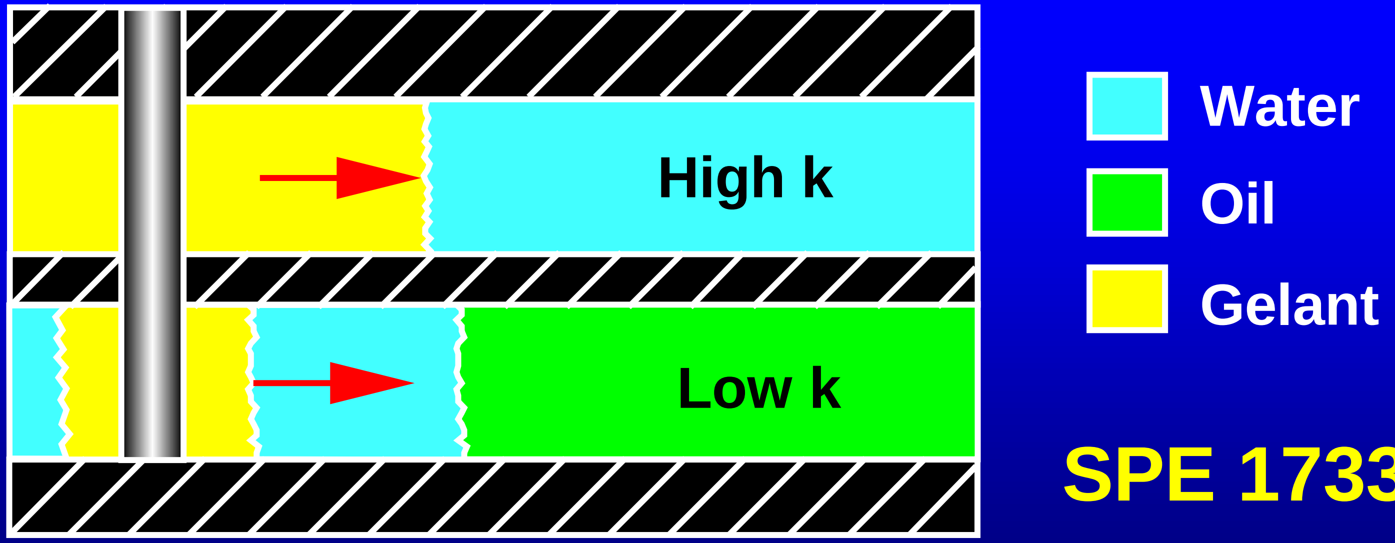
*SPERE* (Nov. 1993) 299-304; *IN SITU* 16(1) (1992) 1-16; and *SPEPF* (Nov. 1995) 241-248.

# BASIC CALCULATIONS

**Gelants can penetrate into all open zones.**

**An acceptable gelant placement is much easier to achieve in linear flow (fractured wells) than in radial flow.**

**In radial flow (unfractured wells), oil-productive zones must be protected during gelant placement.**




**SPE 17332**