POLYMER FLOODING

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Polymer Flooding Topics

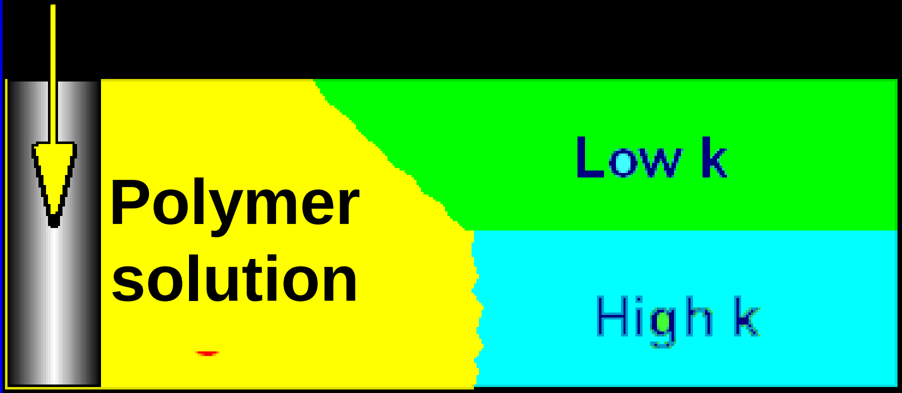
POLYMER FLOODS VERSUS GEL TREATMENTS

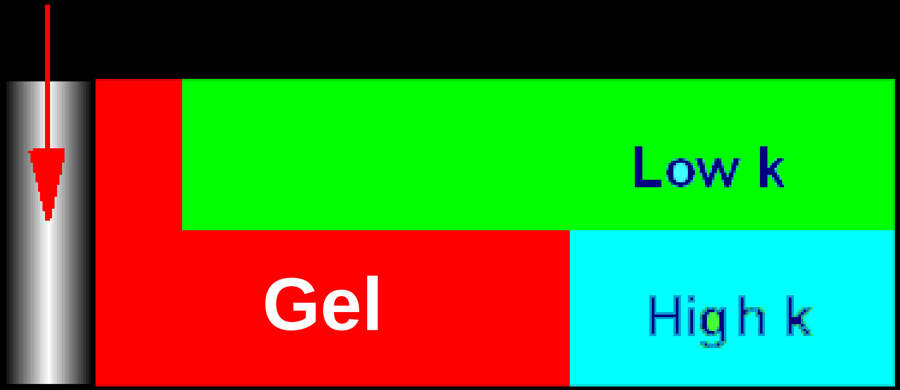
Polymer floods use polymer solutions. Gels add a crosslinker to the polymer solution.

- 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.



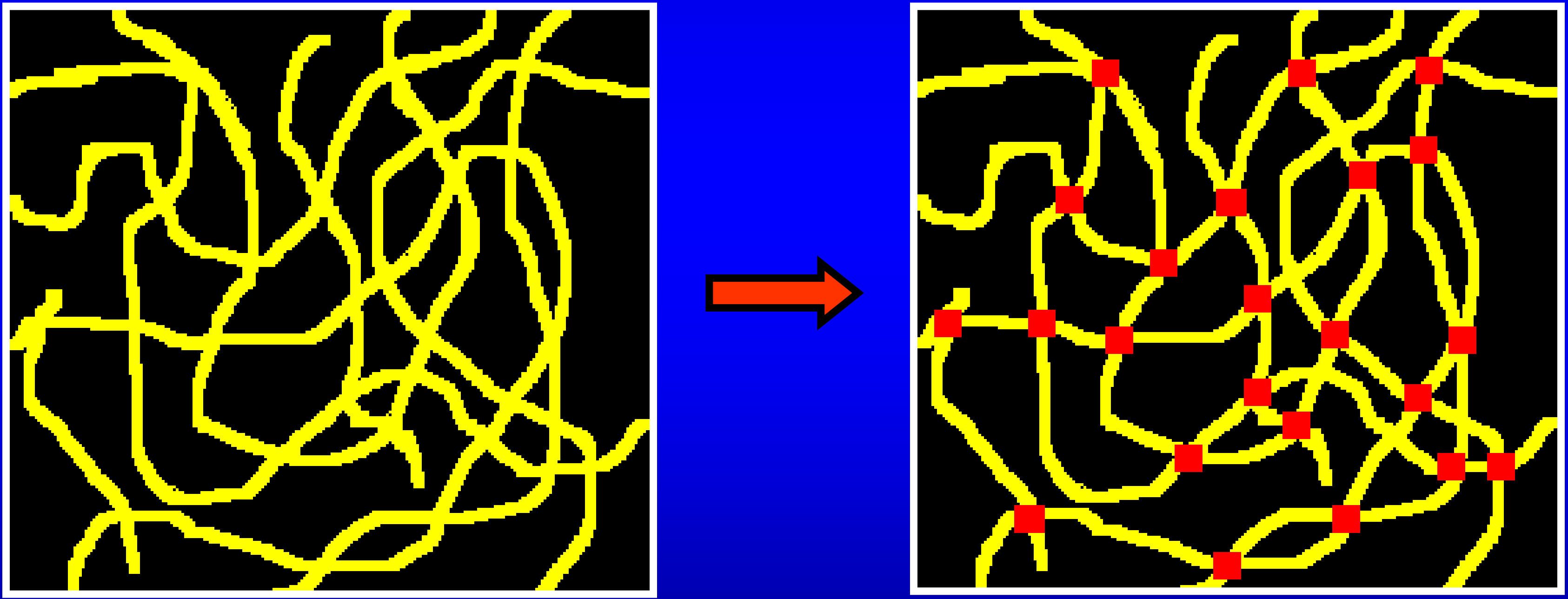


- For a polymer flood, polymer penetration into low-k zones should be maximized.
- For a gel treatment, gelant penetration into low-k zones should be minimized.

VISCOUS POLYMER SOLUTION

CROSSLINKED POLYMER (GEL)

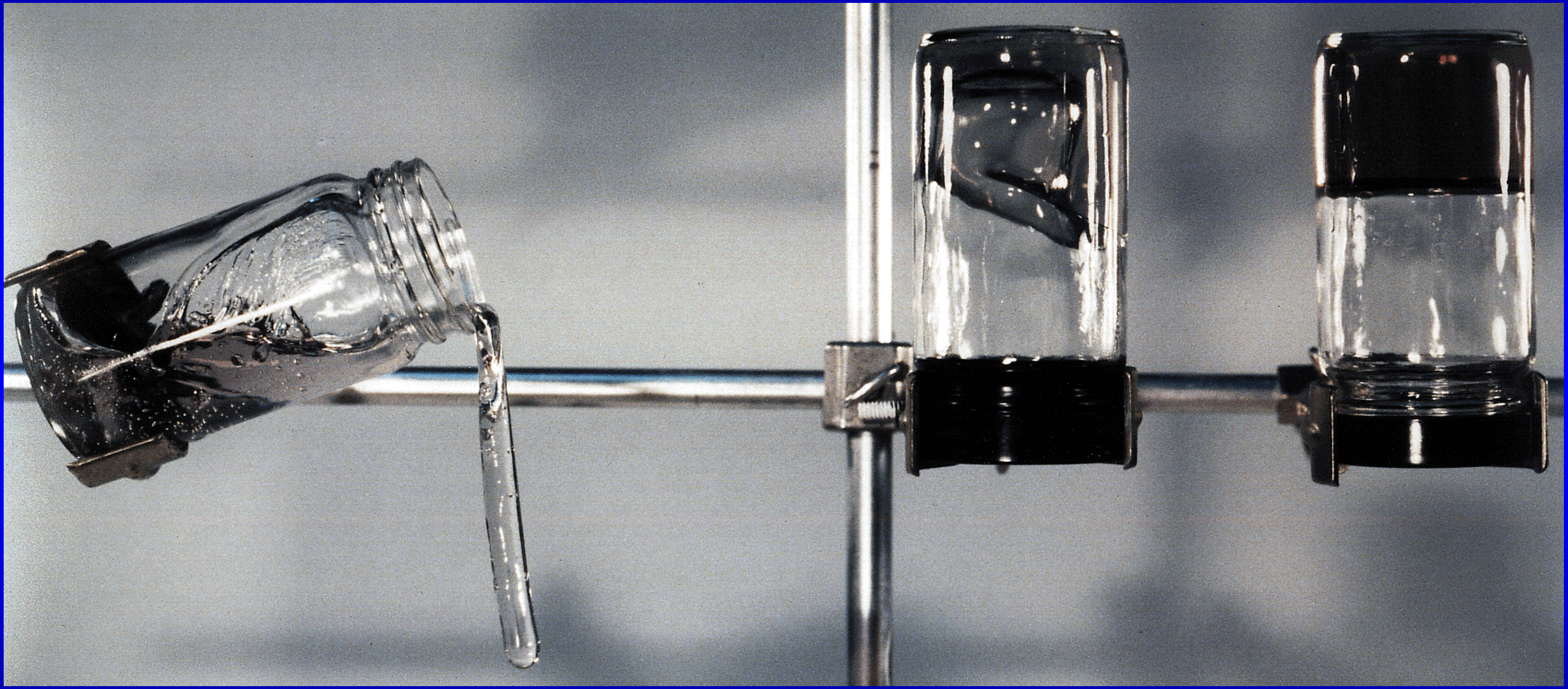
🟥 Crosslink site



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.

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 stops.

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

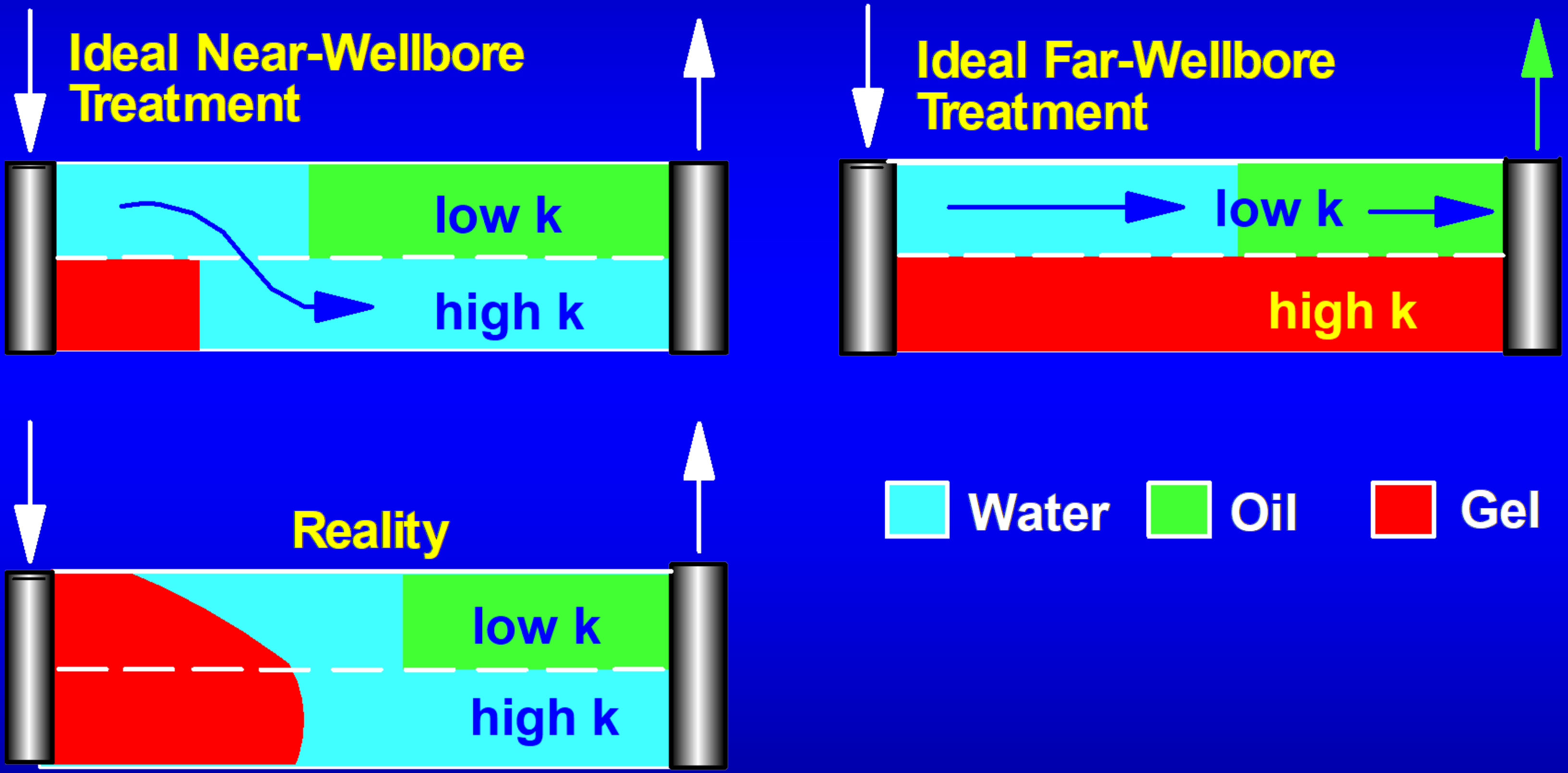
SPERE (Nov. 1993) 299-304; *IN SITU* 16(1) (1992) 1-16; and *SPEPF* (Nov. 1995) 241-248.

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.**

UNFRACTURED RESERVOIRS WITH CROSSFLOW



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

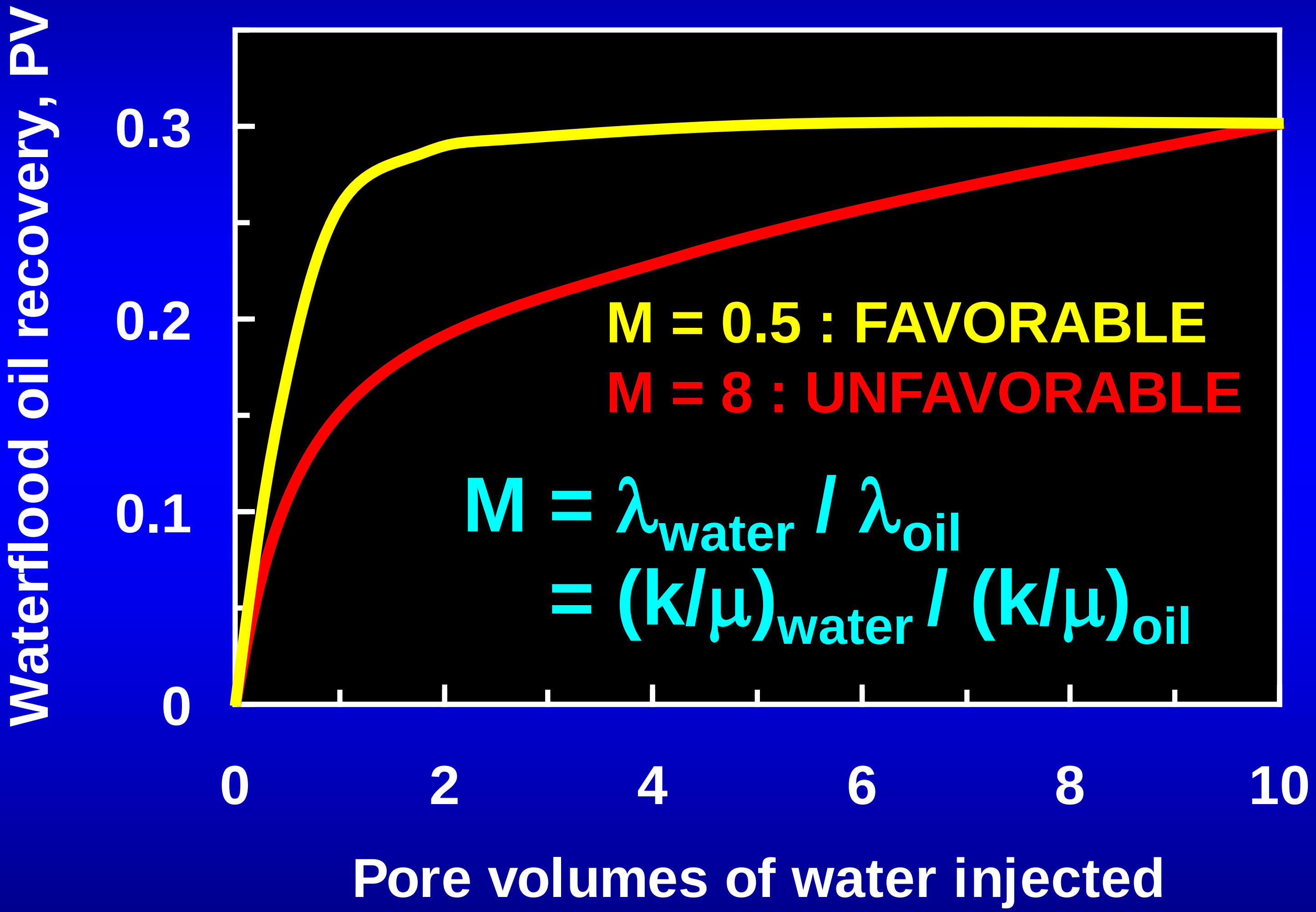
- Great for improving the mobility ratio.
- Great for overcoming vertical stratification.
- Fractures can cause channeling of polymer solutions and waste of expensive chemical.

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.

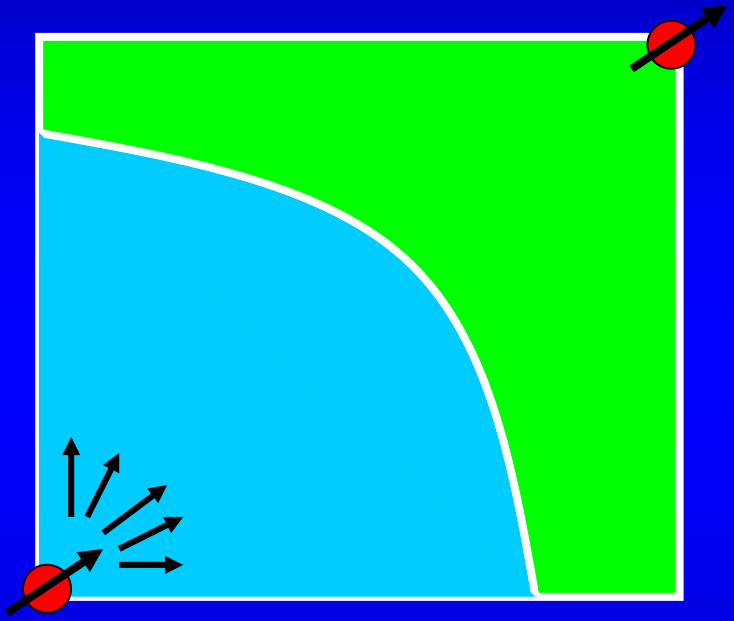
OVERVIEW OF POLYMER FLOODING

EFFECT OF MOBILITY RATIO (M) ON WATERFLOOD OIL RECOVERY

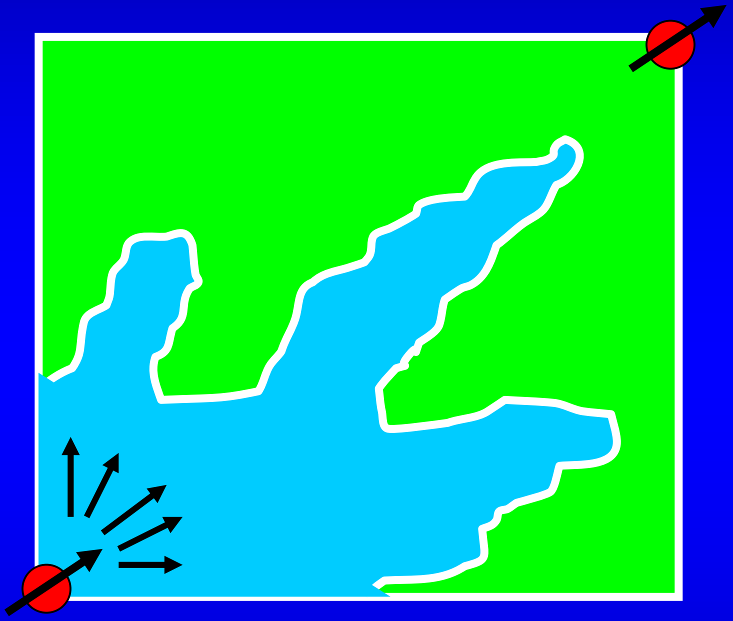


$$M = \lambda_{water} / \lambda_{oil}$$
$$= (k/\mu)_{water} / (k/\mu)_{oil}$$

EFFECT OF MOBILITY RATIO ON AERIAL SWEEP EFFICIENCY



M < 1: FAVORABLE

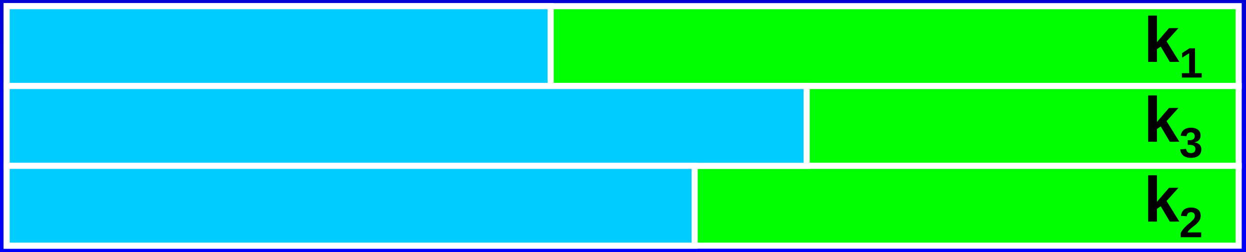


M > 1: UNFAVORABLE

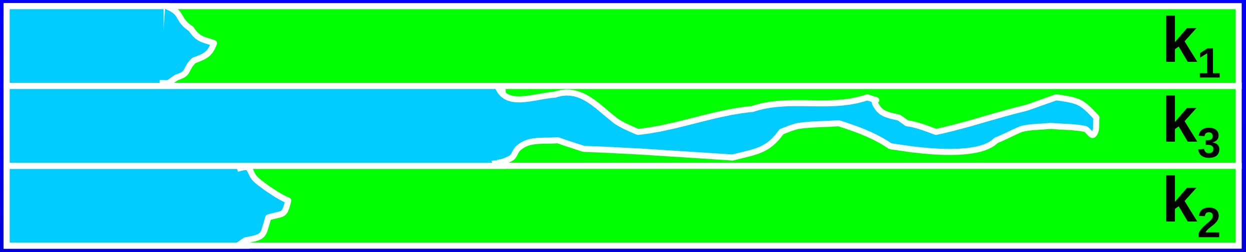
$$M = (k/\mu)_{water} / (k/\mu)_{oil}$$

EFFECT OF MOBILITY RATIO (M) ON VERTICAL SWEEP EFFICIENCY

M < 1: FAVORABLE



$k_1 < k_2 < k_3$



M > 1: UNFAVORABLE

$$\boxed{M = (k/\mu)_{water} \,/\, (k/\mu)_{oil}}$$

POLYMER FLOODING

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

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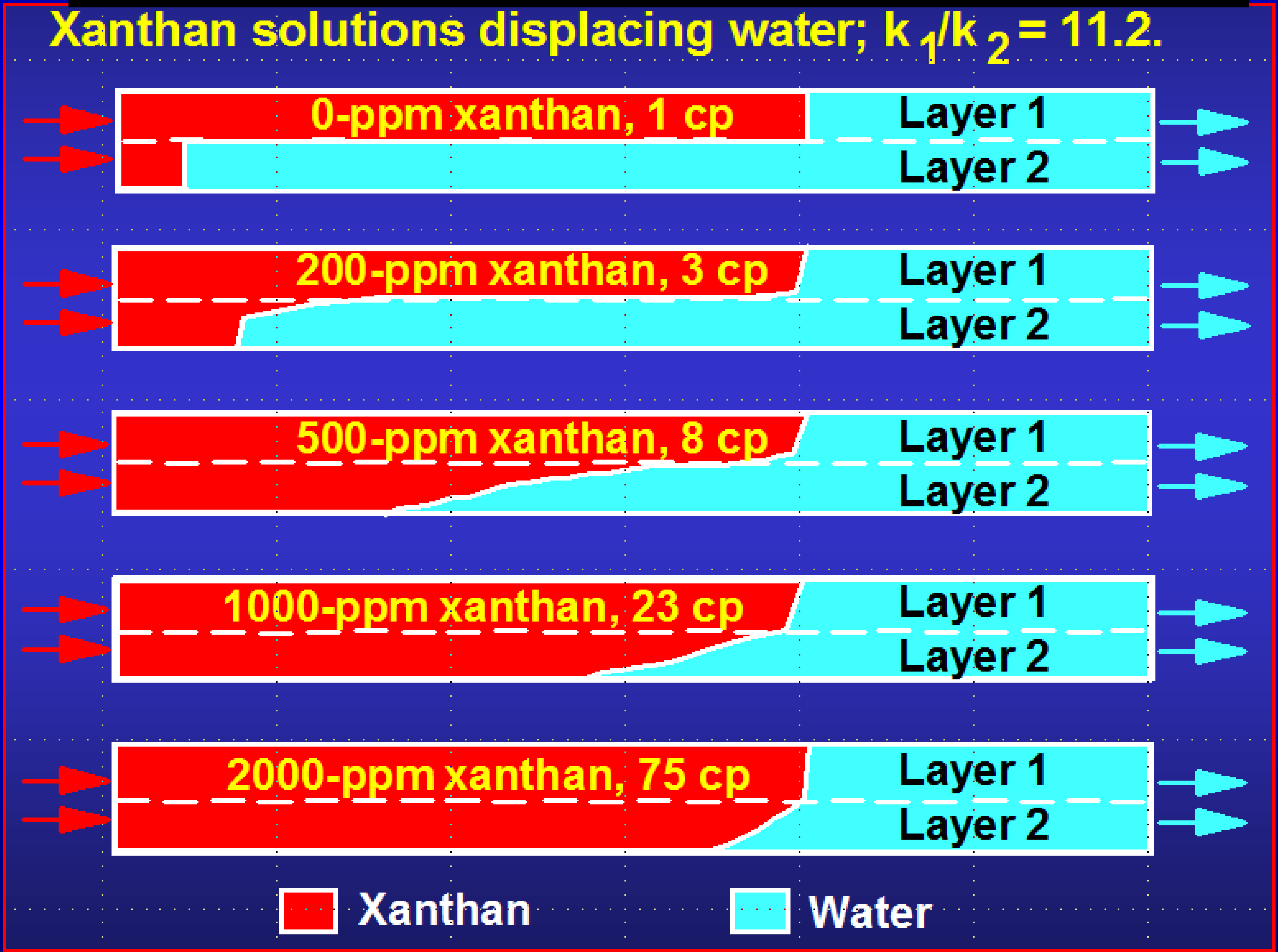

Xanthan solutions displacing water; $k_1/k_2 = 11.2$.

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

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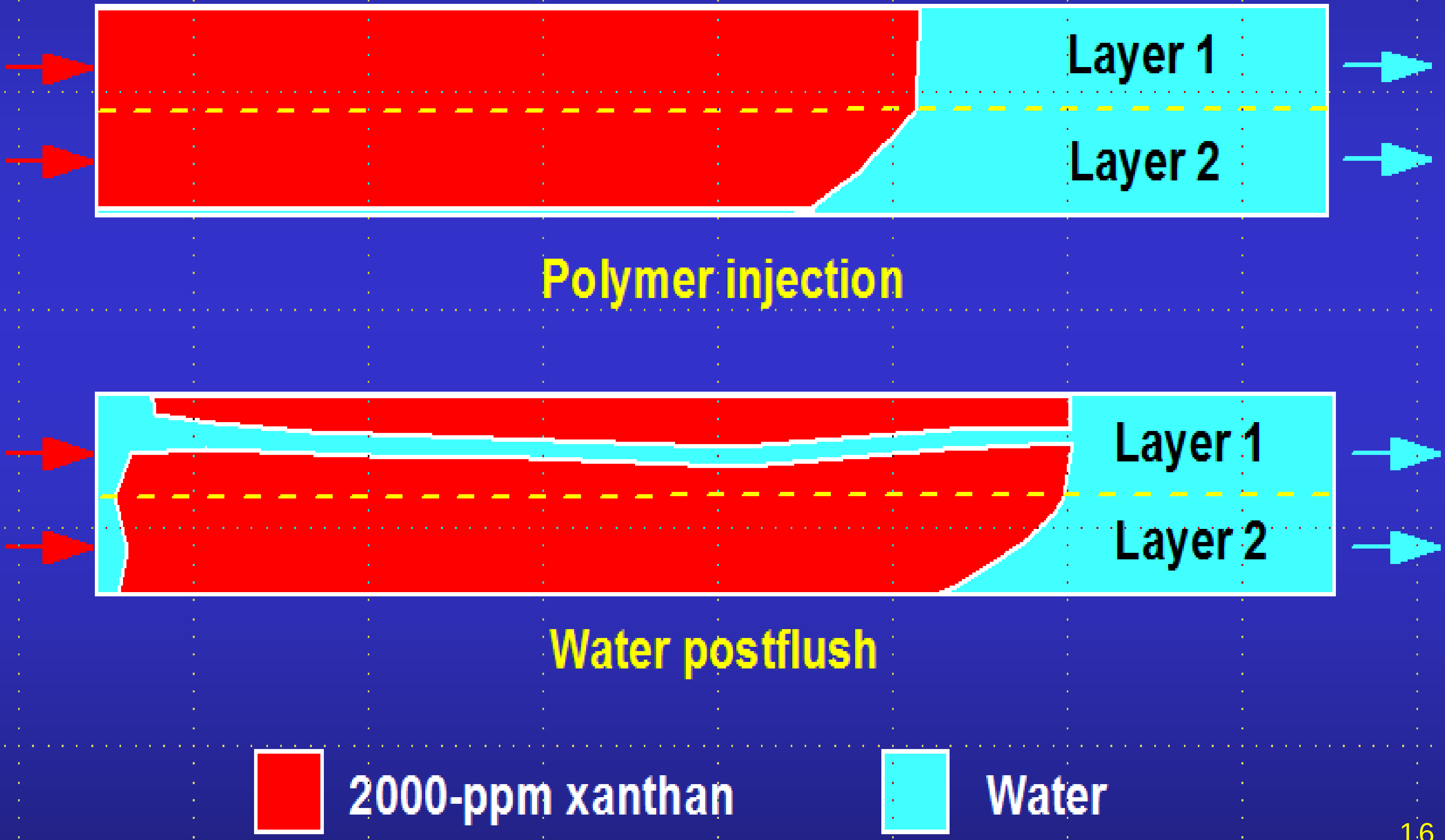
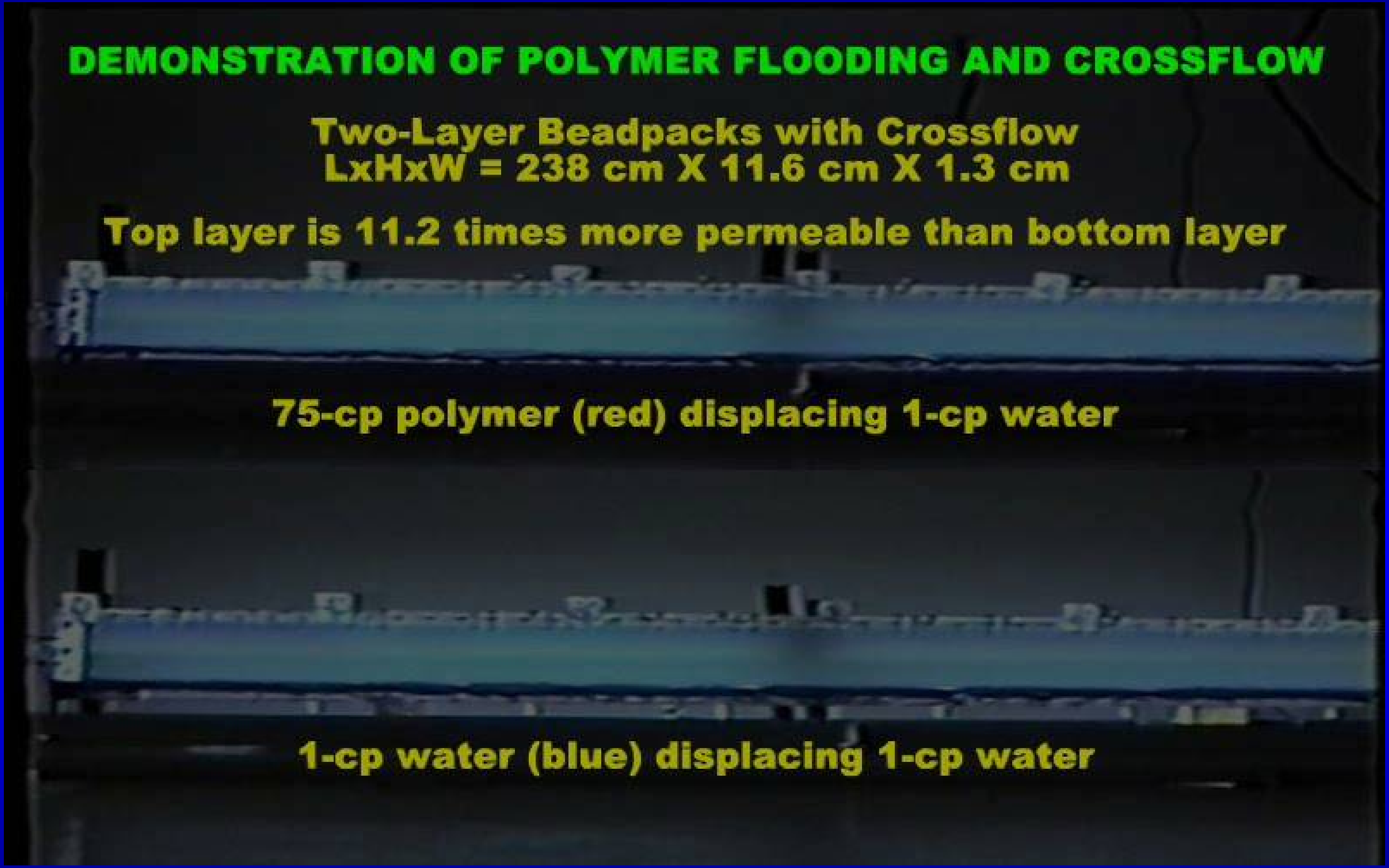




DEMONSTRATION OF POLYMER FLOODING AND CROSSFLOW

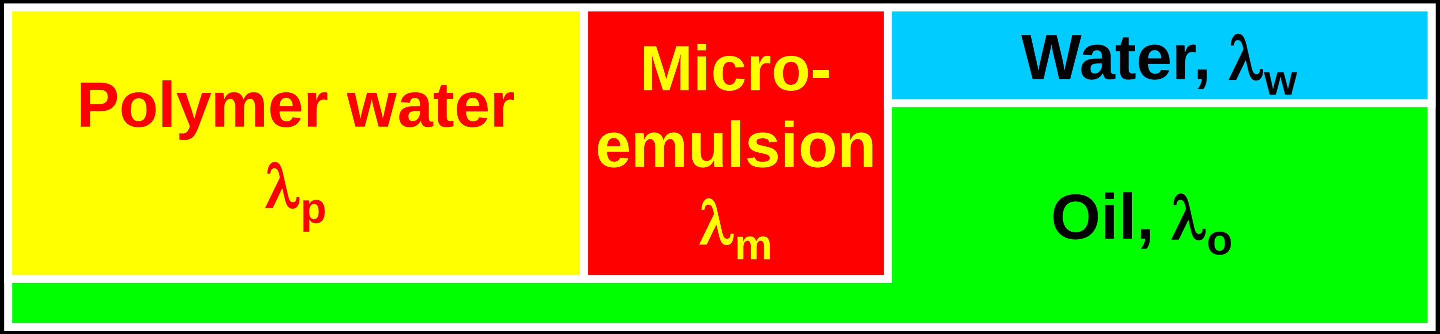
Two-Layer Beadpacks with Crossflow
LxHxW = 238 cm X 11.6 cm X 1.3 cm

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

MOBILITY CONTROL



Polymer water λ_p

Micro-emulsion λ_m

Water, λ_w

Oil, λ_o

Favorable displacement at microemulsion front requires:

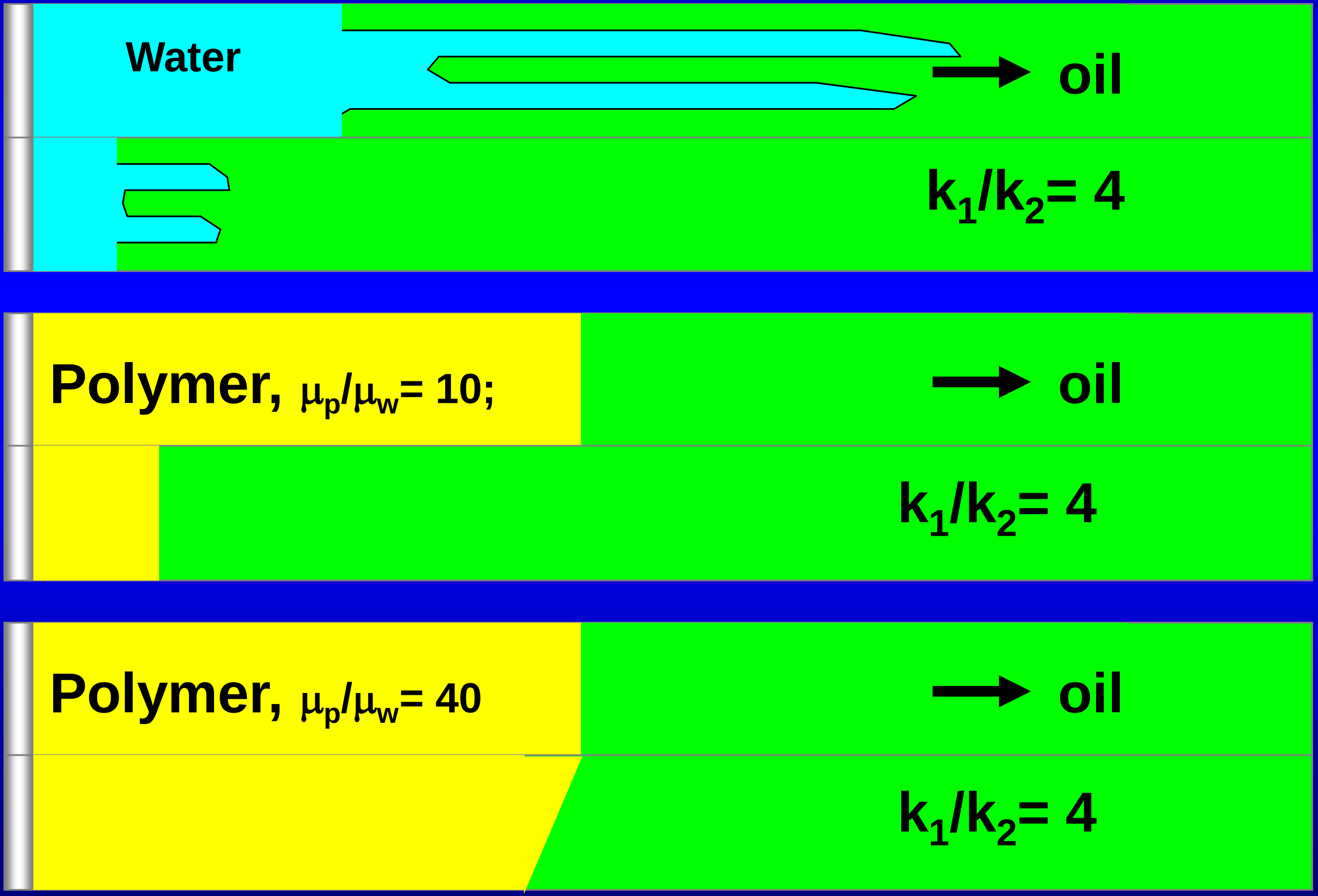
$$\lambda_m \leq \lambda_o + \lambda_w$$

Favorable displacement at microemulsion rear requires:

$$\lambda_p \leq \lambda_m$$

SELECTION OF POLYMER VISCOSITY

- Want to make the water flood mobility ratio favorable.
- Want to overcome the permeability contrast.



Water
flood:
$M = 10$

Polymer
flood:
$M \sim 1$

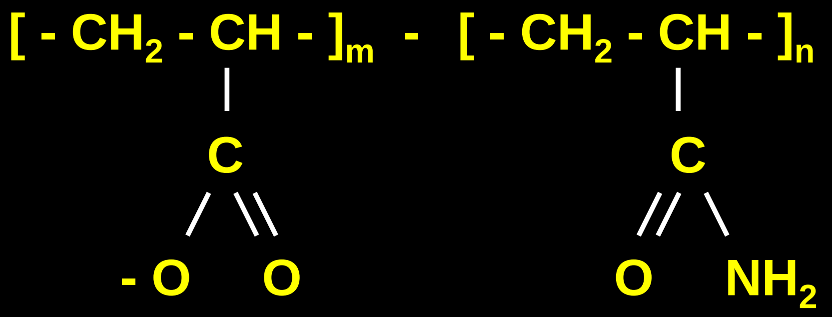
Polymer
flood:
$M \sim 0.25$

IDEAL PROPERTIES FOR MOBILITY CONTROL AGENTS

- Low cost or high cost-effectiveness.
- Allows high injectivity.
- Effective when mixed with reservoir brines (up to 20% total dissolved solids).
- Resistant to mechanical degradation (up to 1000 $m^3/m^2/d$ flux when entering porous rock).
- 5 to 10 year stability at reservoir temperature (up to 150°C).
- Resistant to microbial degradation.
- Low retention (e.g., adsorption) in porous rock.
- Effective in low-permeability rock.
- Effective in the presence of oil or gas.
- Not sensitive to O_2, H_2S, pH, or oilfield chemicals.

FLEXIBLE vs SEMI-RIGID ROD POLYMERS

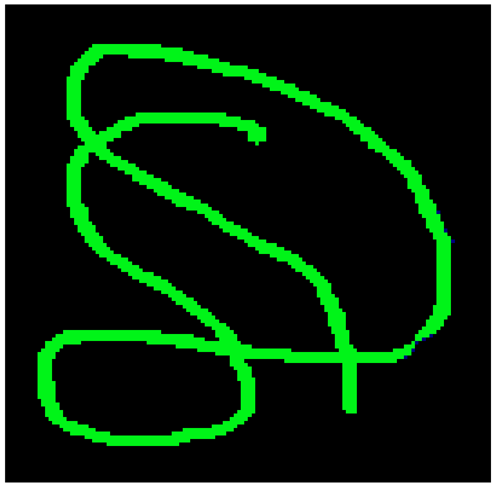
"Polyacrylamide" or "HPAM" Polymers



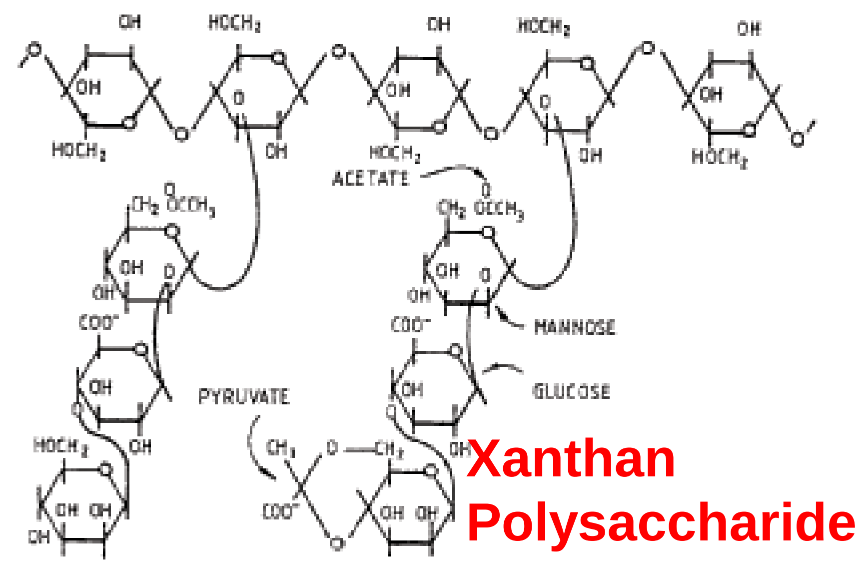
$$[-CH_2-\underset{\substack{|\\ C\\ /\ \backslash\backslash\\ -O\quad O}}{CH}-]_m\ -\ [-CH_2-\underset{\substack{|\\ C\\ //\ \backslash\\ O\quad NH_2}}{CH}-]_n$$

acrylate

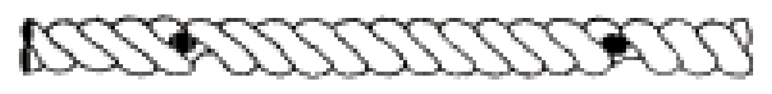
acrylamide



Flexible coil

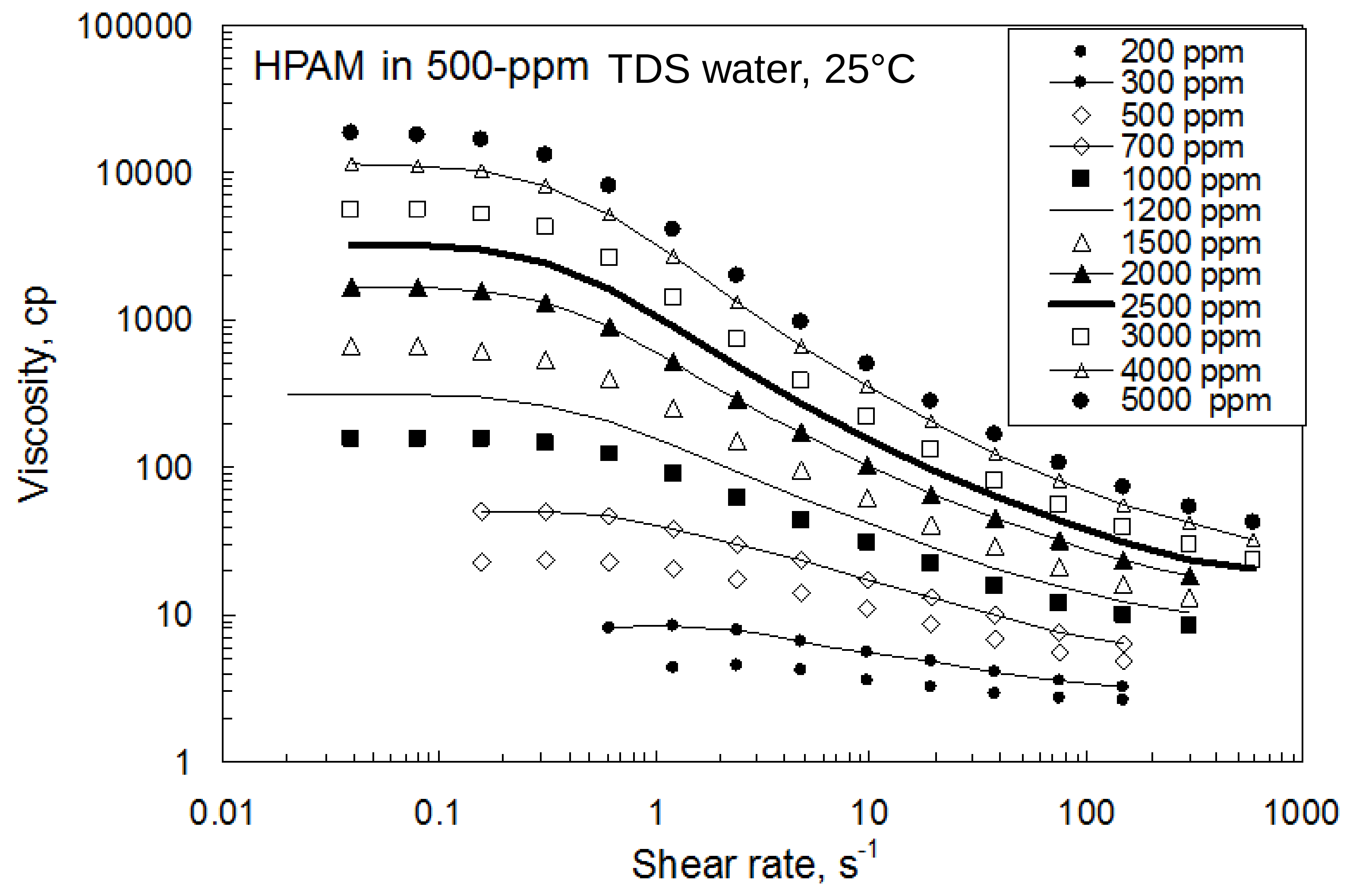


Xanthan Polysaccharide

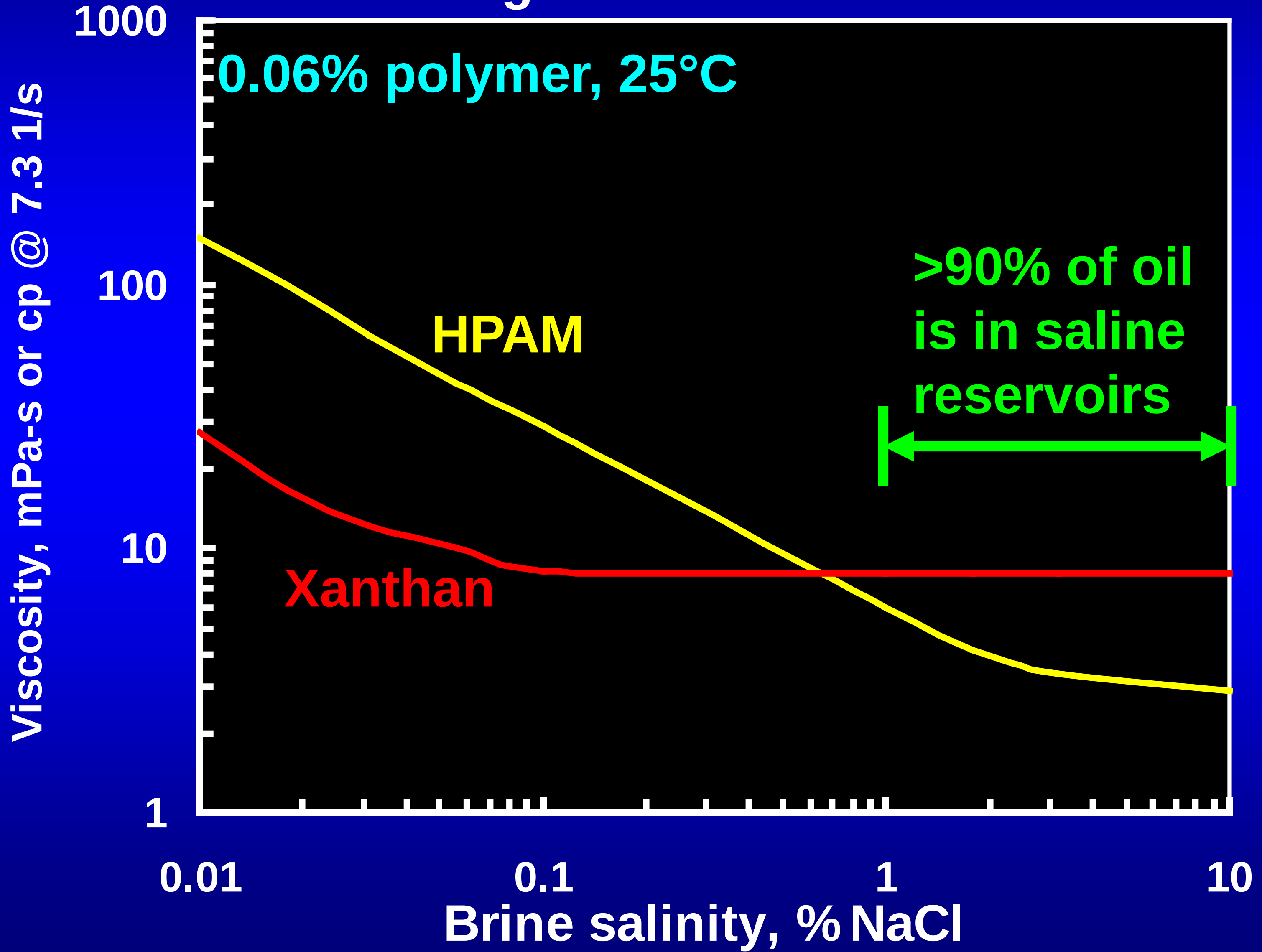


Double helix, semi-rigid rod.

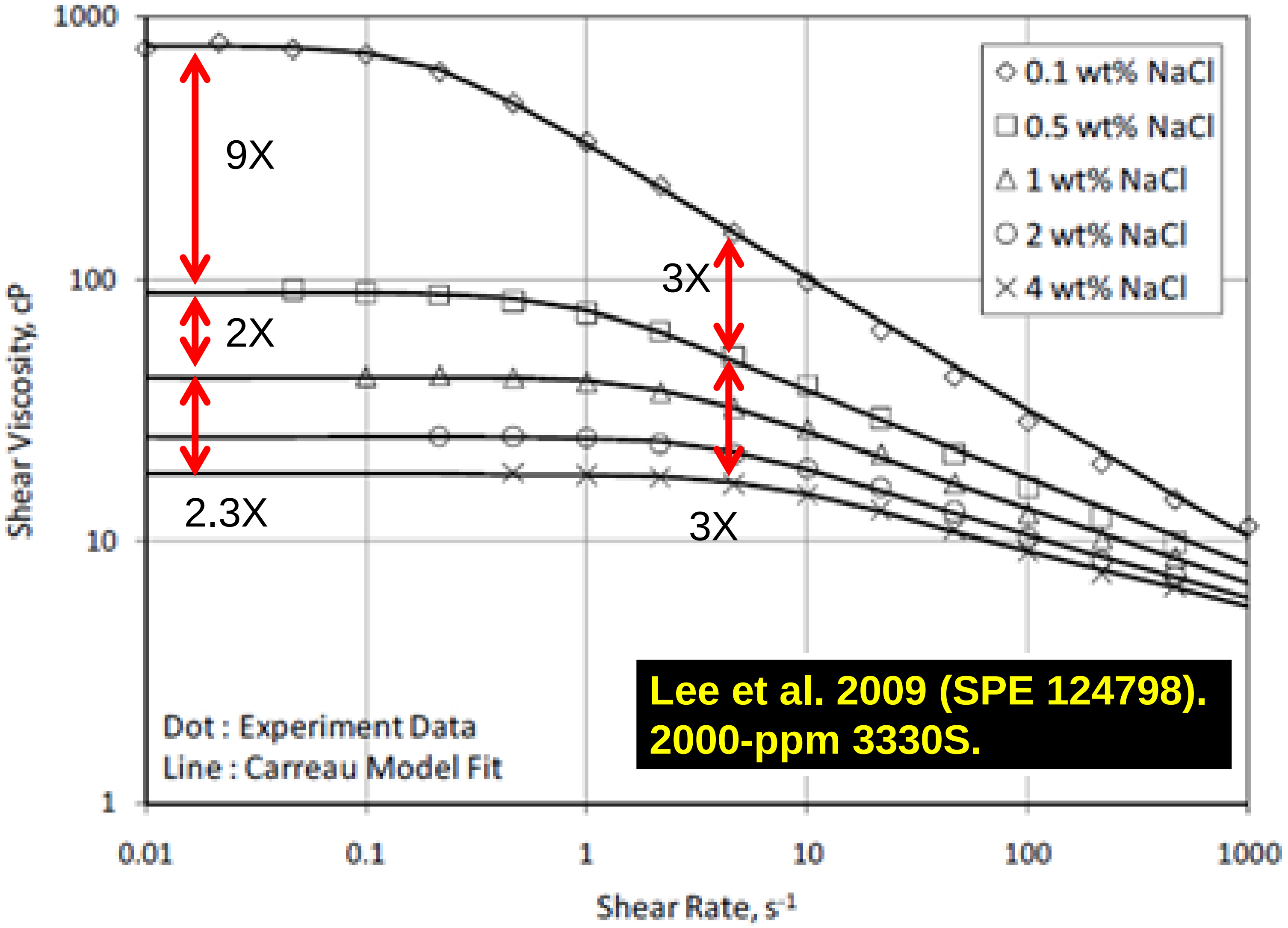
- **Viscosity depends on shear rate and concentration.**



Both HPAM and xanthan are charged polymers, but the rod-like xanthan gives higher viscosities at moderate to high salinities.

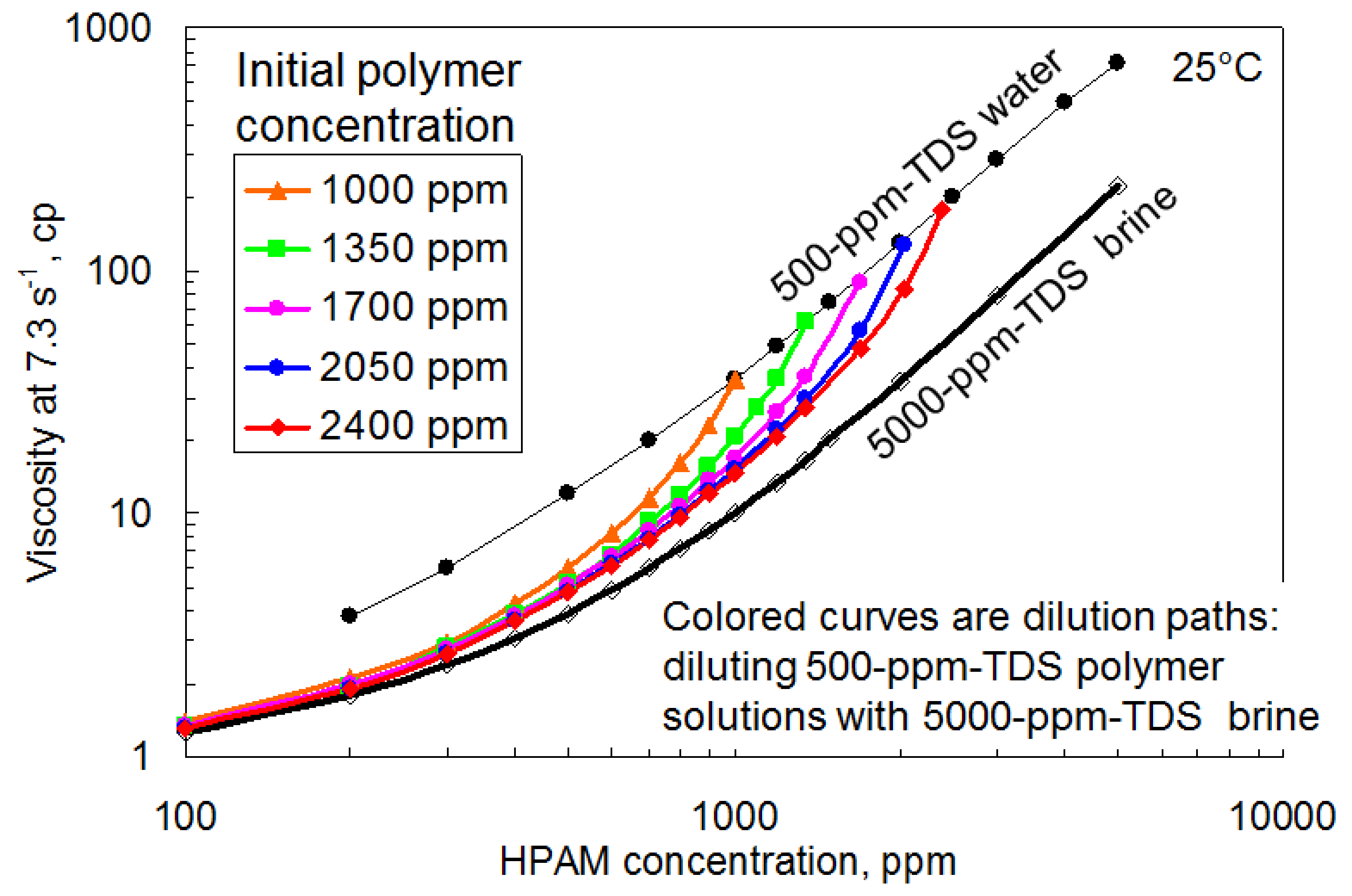


HPAM VISCOSITY DECREASES WITH INCREASED SALINITY



Lee et al. 2009 (SPE 124798). 2000-ppm 3330S.

- **For a given HPAM concentration, HPAM provides 3.5 times the viscosity in 500-ppm-TDS brine than in 5000-ppm-TDS brine.**



MECHANICAL (OR SHEAR) DEGRADATION

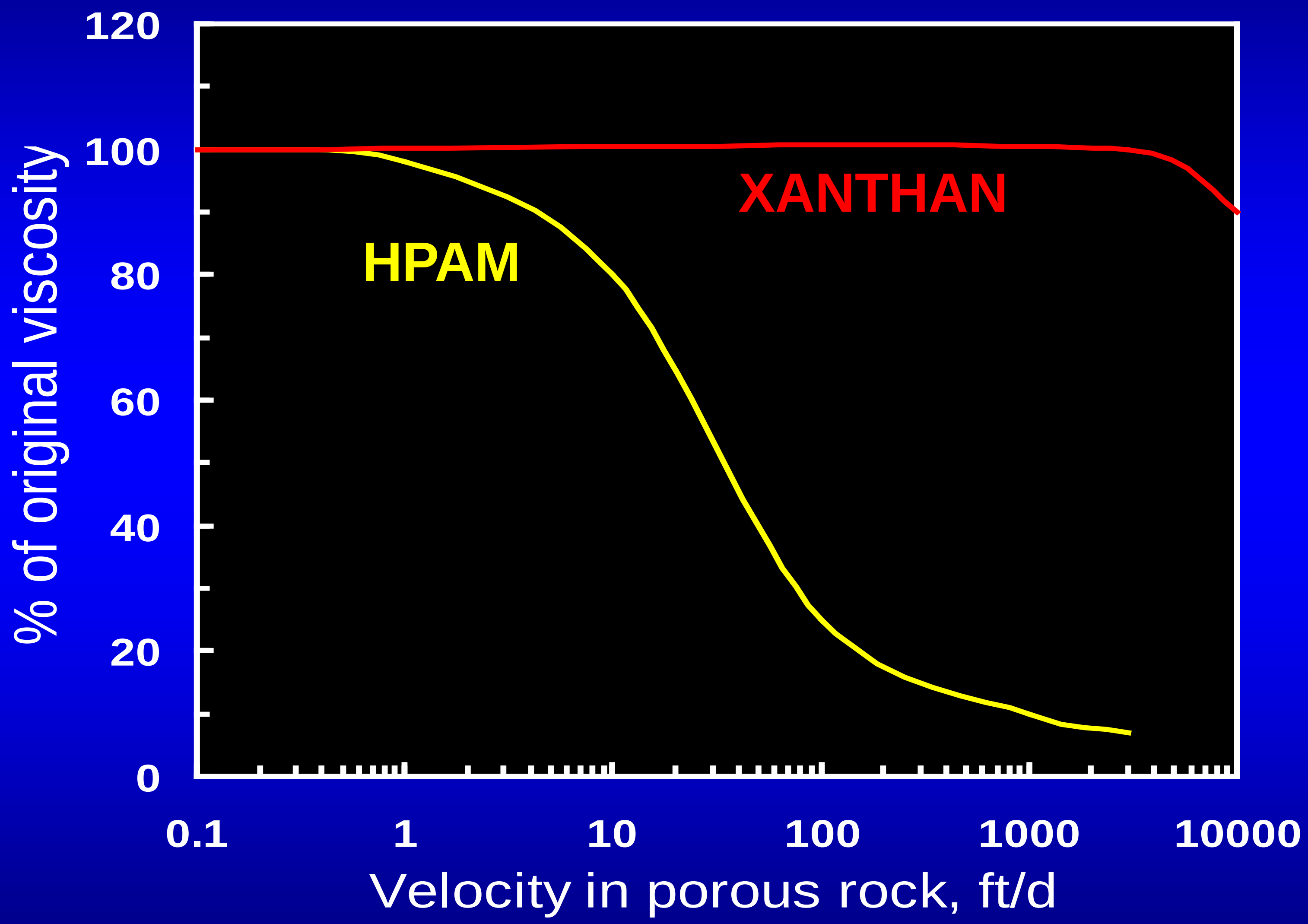
SURFACE FACILITIES

- Mixers, pumps, filters, valves, meters.
- Degradation generally can be minimized through good design (avoiding flow constrictions).

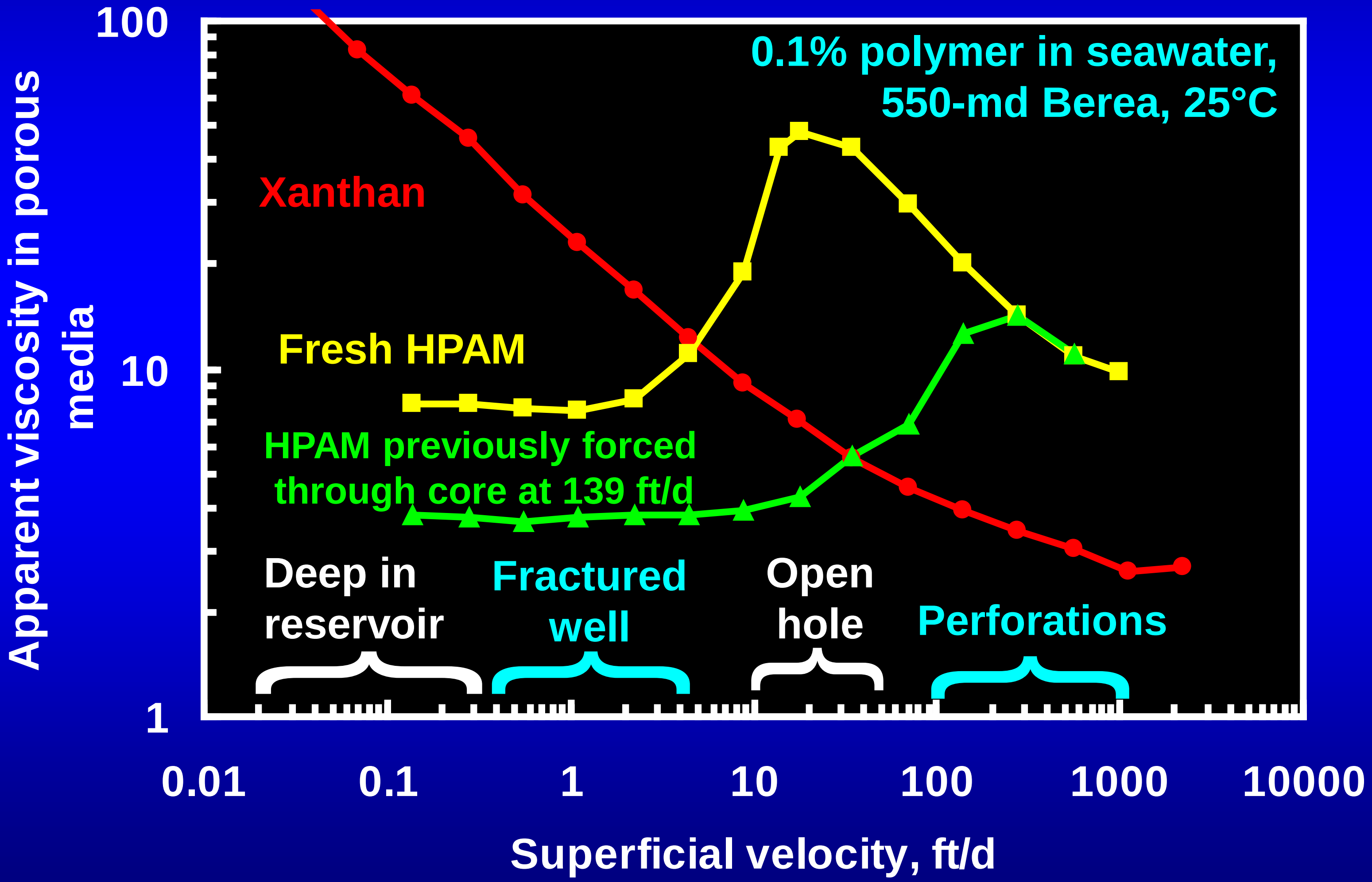
DOWNHOLE

- Depends on the nature of the completion.
- Increased area at the rock interface decreases fluid velocity and degradation.

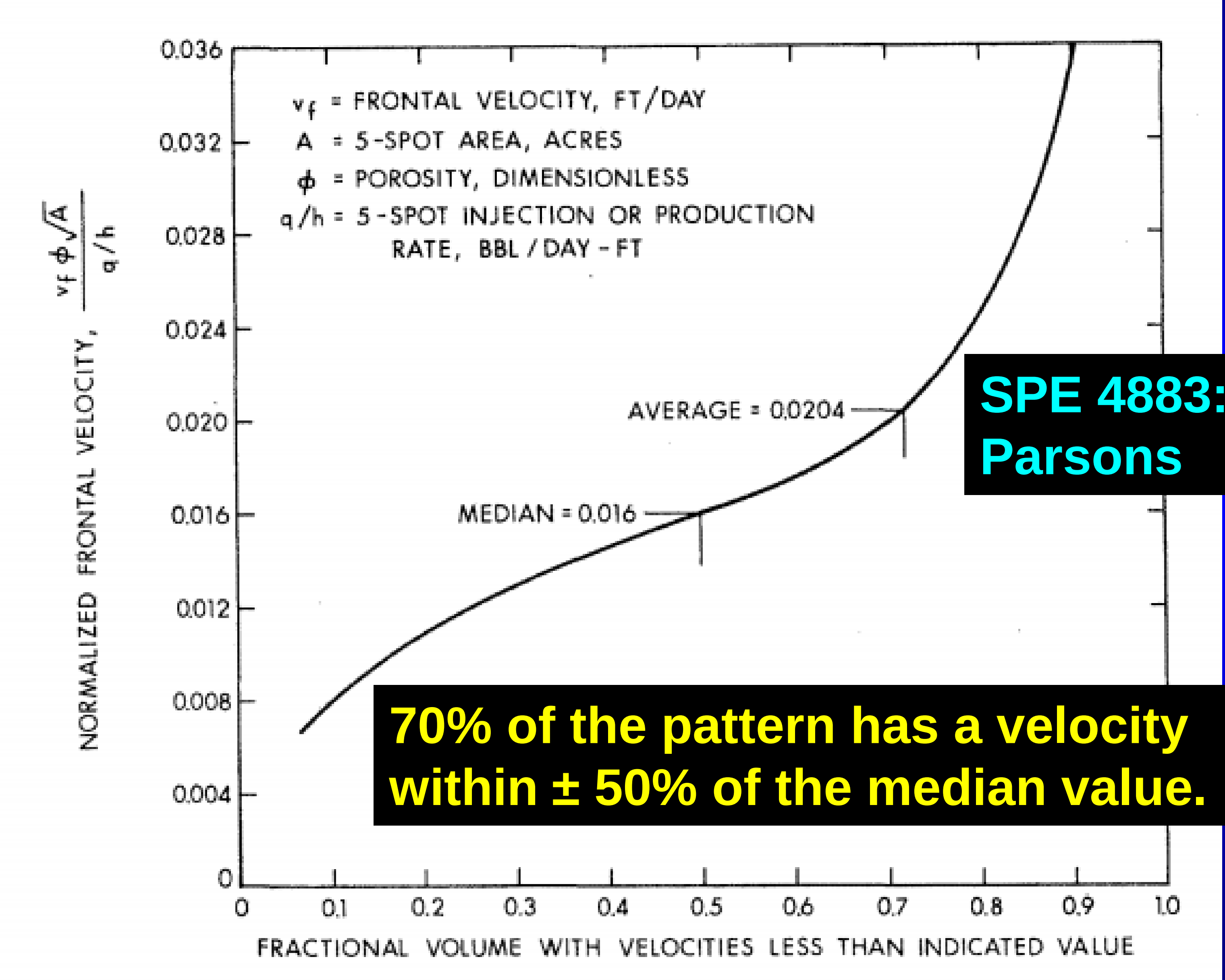
RESISTANCE TO MECHANICAL DEGRADATION



Although both xanthan and HPAM show shear thinning in viscometers, HPAM shows shear thickening in porous media—important to injectivity.



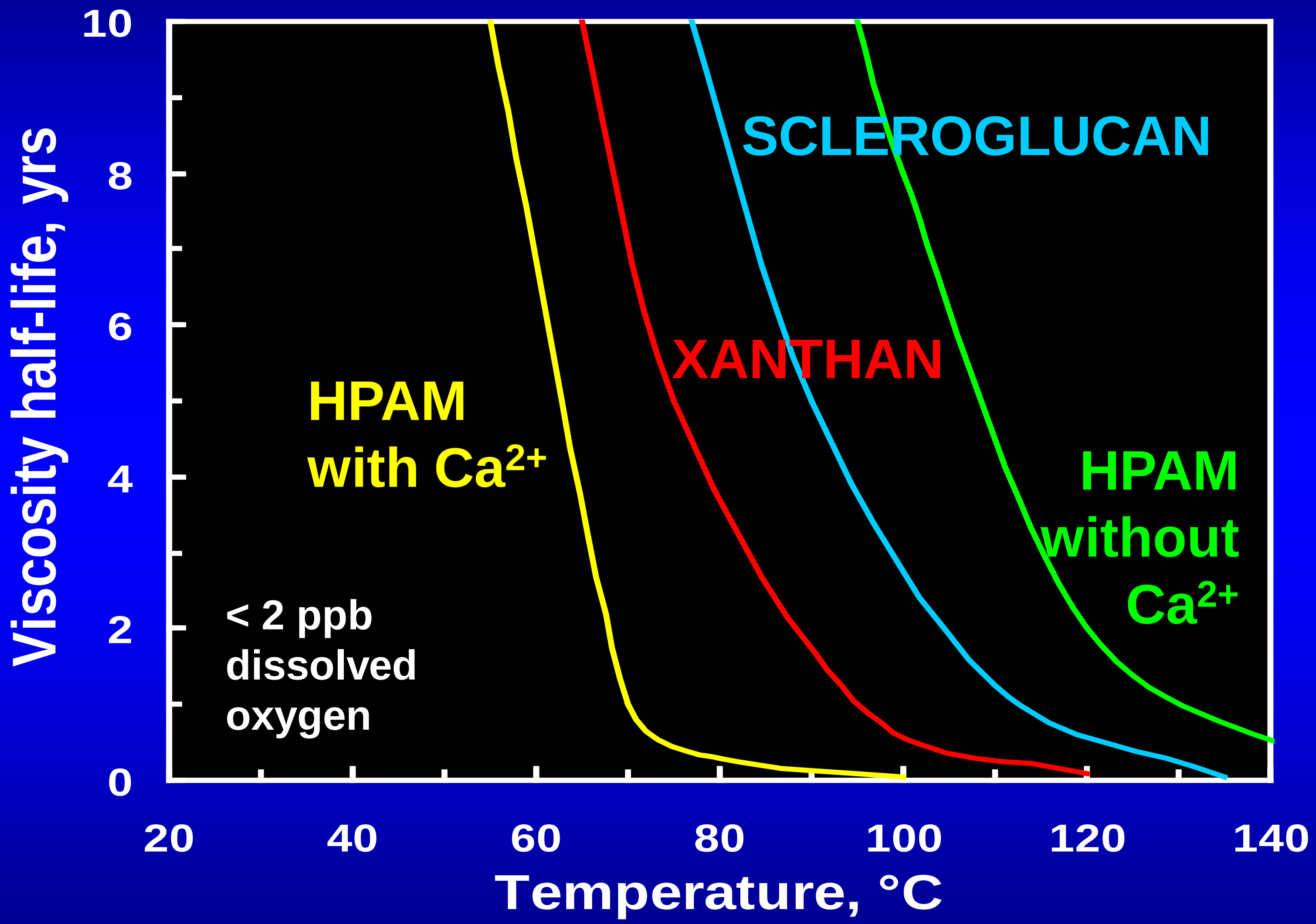
Velocities in a Five-Spot Pattern (1-layer)



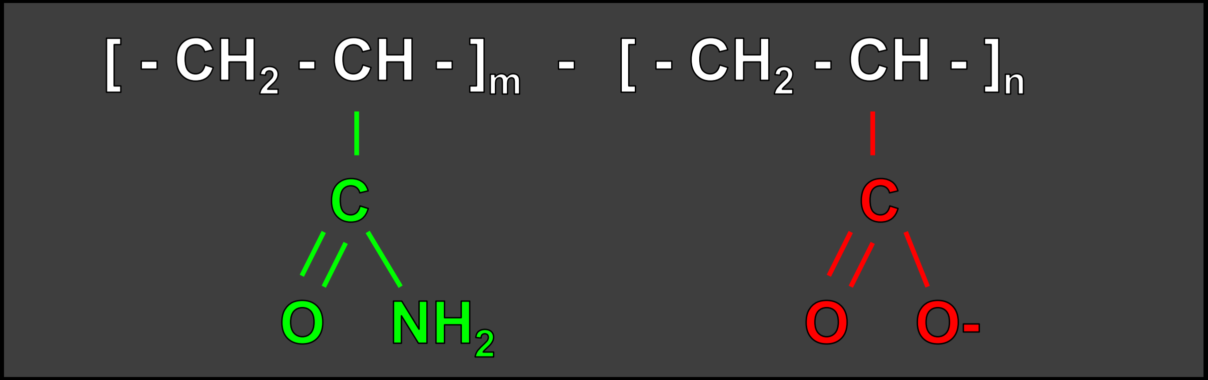
SPE 4883: Parsons

70% of the pattern has a velocity within ± 50% of the median value.

STABILITY AT ELEVATED TEMPERATURES



What is the upper temperature limit for HPAM use in chemical EOR?



- Above 60°C, acrylamide groups hydrolyze to form acrylate groups.
- If the degree of hydrolysis is too high and too much Ca^{2+} or Mg^{2+} is present, HPAM polymers precipitate.

Temperature, °C:	75	88	96	204
Max Ca^{2+} + Mg^{2+}, mg/L:	2000	500	270	20

(from Moradi-Araghi and Doe, 1987)

THERMAL, CHEMICAL, & BIO-DEGRADATION

- Both HPAM and xanthan are very susceptible to oxidative degradation. Fortunately, most reservoirs contain no free oxygen.
- HPAM's C-C main chain is very resistant to thermal breaking if O_2 or free radicals are absent.
- Xanthan's C-O main chain is susceptible to hydrolysis above 70°C.
- HPAM's amide groups are susceptible to hydrolysis above 60°C, leading to polymer precipitation if Ca^{2+} or Mg^{2+} are present.
- HPAM is much more resistant to bio-degradation than xanthan.

BIODEGRADATION of BIOPOLYMERS

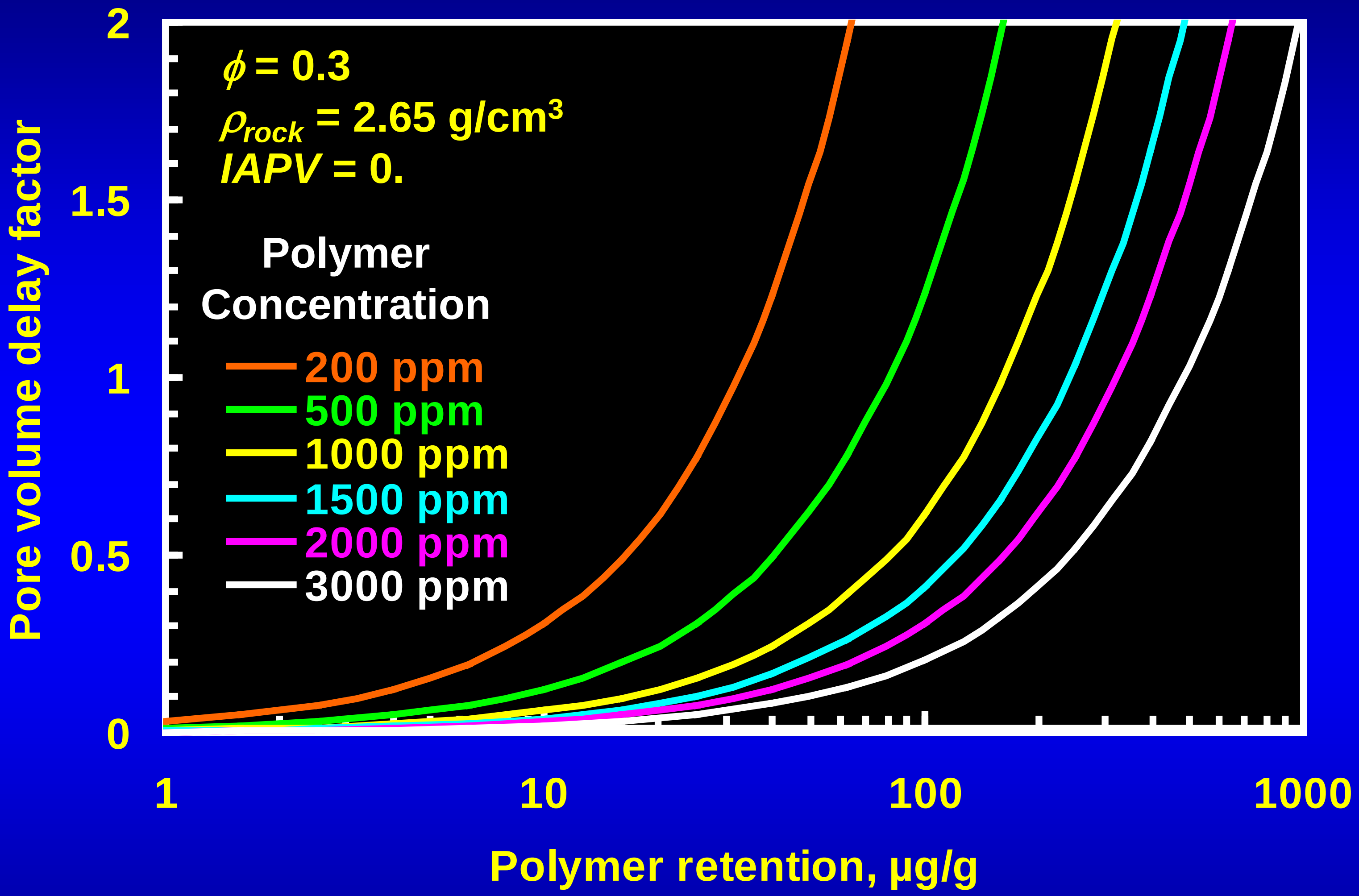
1. Hire a competent microbiologist.

2. Identify all microorganisms in the reservoir/brine/polymer system.

3. Identify which combination of microorganisms degrade the polymer.

4. Identify which biocide prevents the degradation.

Polymer bank delay factors associated with polymer retention.



10 µg/g & 1500 ppm polymer: delay = 0.04 PV.

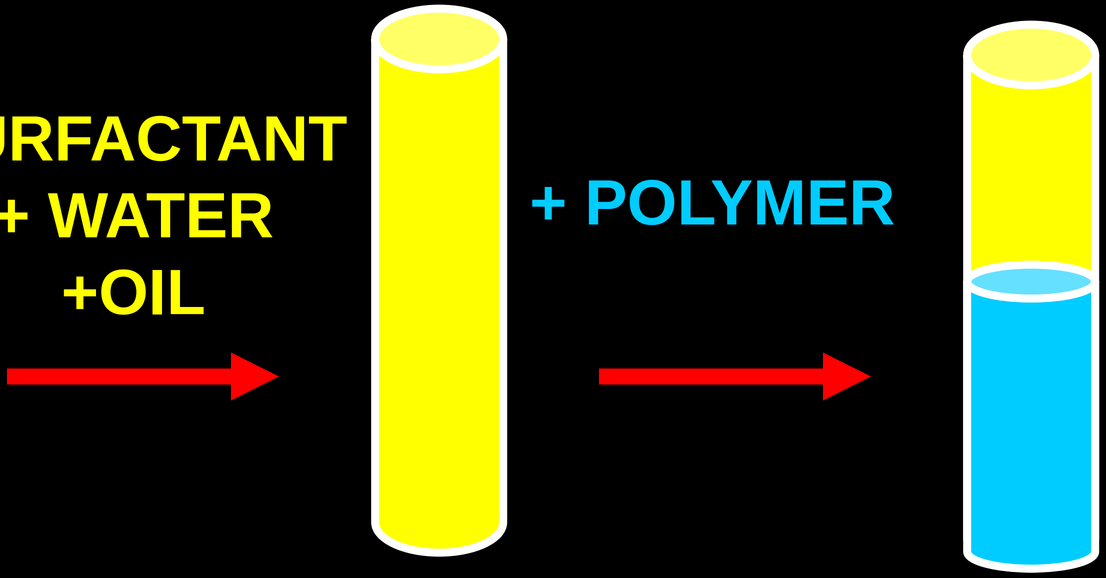
100 µg/g & 1500 ppm polymer: delay = 0.41 PV.

200 µg/g & 1500 ppm polymer: delay = 0.82 PV.

POLYMER RETENTION (ADSORPTION, MECHANICAL ENTRAPMENT, PRECIPITATION) CAN VARY WITH

Mineralogy
Permeability & Pore Structure
Polymer Molecular Weight
Polymer Composition
Water Salinity & Hardness
Wettability
Temperature
Residual Saturations
Surfactant Compatibility

SURFACTANT – POLYMER INTERACTION



SURFACTANT
+ WATER
+OIL

+ POLYMER

MICRO-
EMULSION
PHASE

POLYMER
PHASE

SINGLE PHASE
MICROEMULSION

Some Recent Polymer Flooding Projects

Daqing: SPE 144294, 77871, 77872, 109682, 99441

Shengli: SPE 169692. Shuanghe: SPE 50933.

Pelican Lake: SPE165234 166256, 169062

Wainwright: SPE 154050. Other Canadian: 169062

East Bodo: 09-02-55 PETSOC. Rapdan: 27820

Tambaredjo: SPE 154567, 164121, 169027, 138728

Windalia: SPE 165253

Dalia: SPE 116672, 135735, 174699

Marmul: SPE 18092, 154465, 154665, 169714

Mangala: SPE 169146, 154159, 155162, 113347

Bockstedt: 169158/169032. Matzen: SPE 169043.

Other German (older): SPE 24118, 24121, 24120

Argentina projects: SPE 166078, 166255, 174627, 181210, 185487, 185526, 185535.

SPE 129899

POTENTIAL FOR POLYMER FLOODING VISCOUS OILS

BOTTOM LINE

1. Higher oil prices, modest polymer prices, increased use of horizontal wells, and controlled injection above the formation parting pressure all help considerably to extend the applicability of polymer flooding in reservoirs with viscous oils.
2. A high mobile oil saturation, degree of heterogeneity, and relatively free potential for crossflow in reservoirs also promote the potential for polymer flooding.
3. For existing EOR polymers, viscosity increases roughly with the square of polymer concentration—a fact that aids the economics for polymer flooding of viscous oils.
4. Reduced injectivity may be a greater concern for polymer flood application than the chemical cost of viscous polymer solutions.

Thermal methods can’t be used for some viscous oils—because of thin zones, ambient cold, environmental constraints, permafrost, etc.

Is polymer flooding viable for viscous oils?

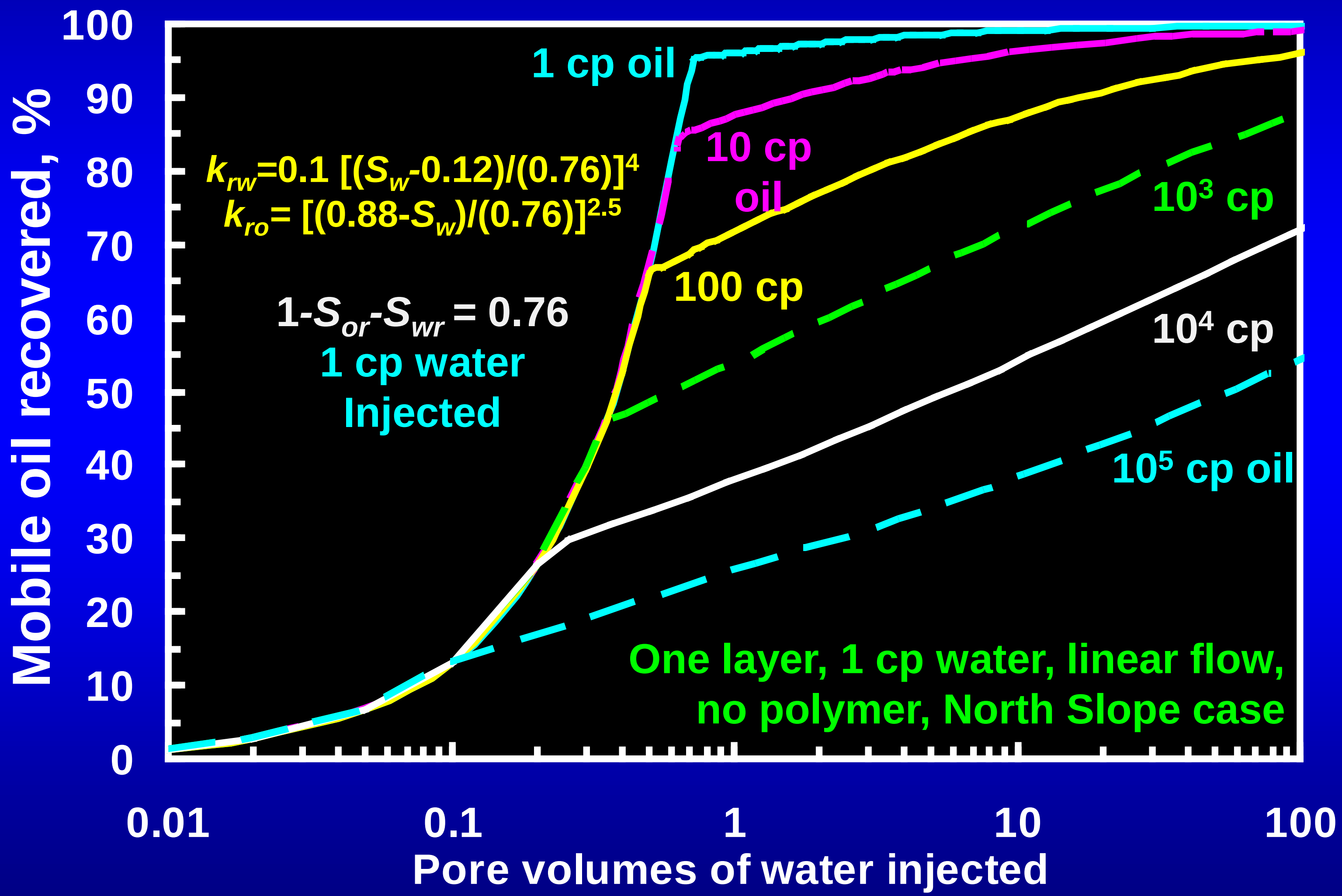
Old (1997) screening criteria for polymer flooding:

- **~150-cp oil was the upper limit because of (1) polymer costs and (2) injectivity losses.**

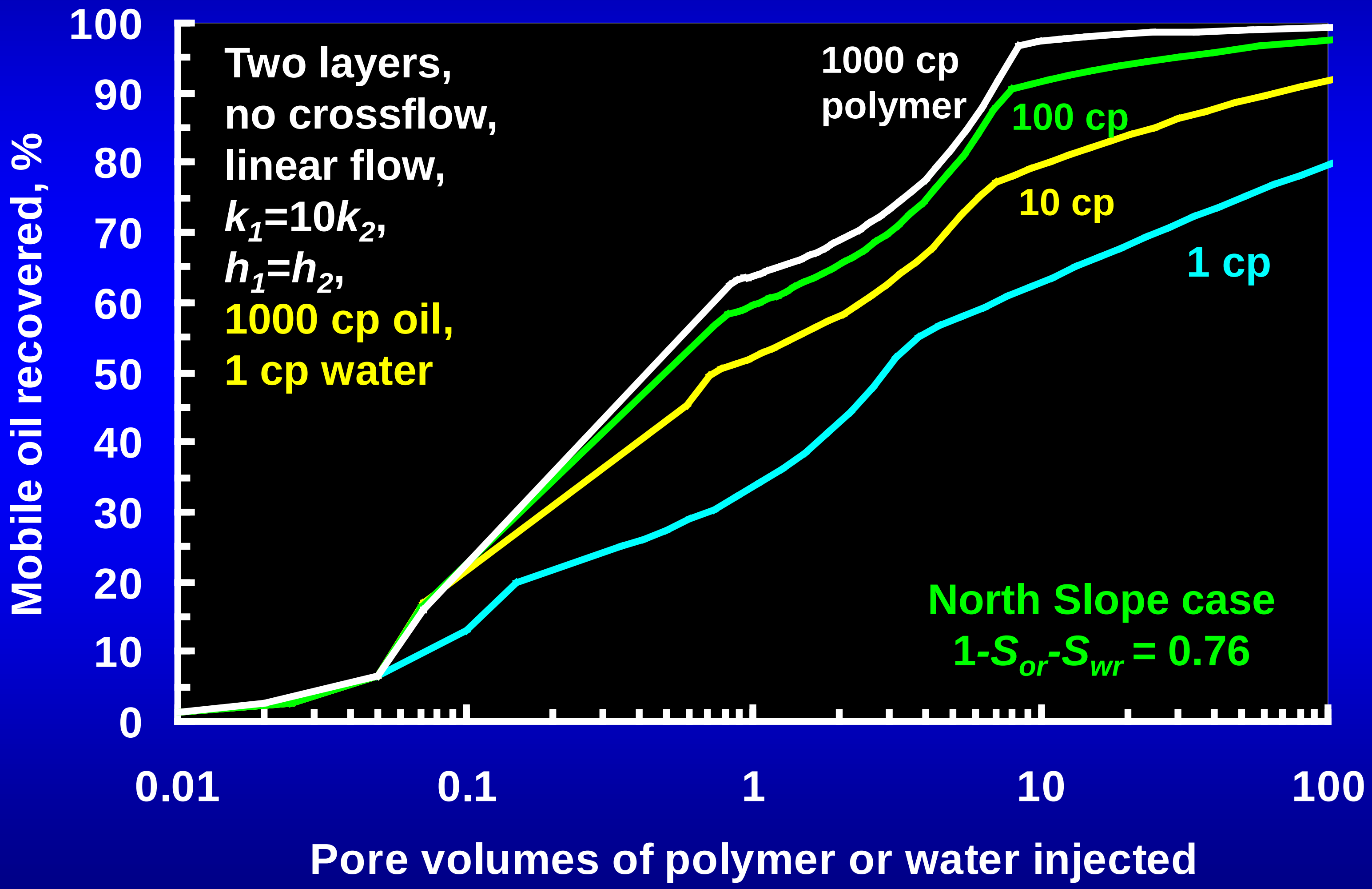
Changes since the old screening criteria:

- **Higher oil prices (>$40-$100 versus ~$20/bbl).**
- **Modest polymer prices ($1-$1.50 versus $2/lb).**
- **Greater use of horizontal wells.**
- **Controlled injection above the parting pressure.**

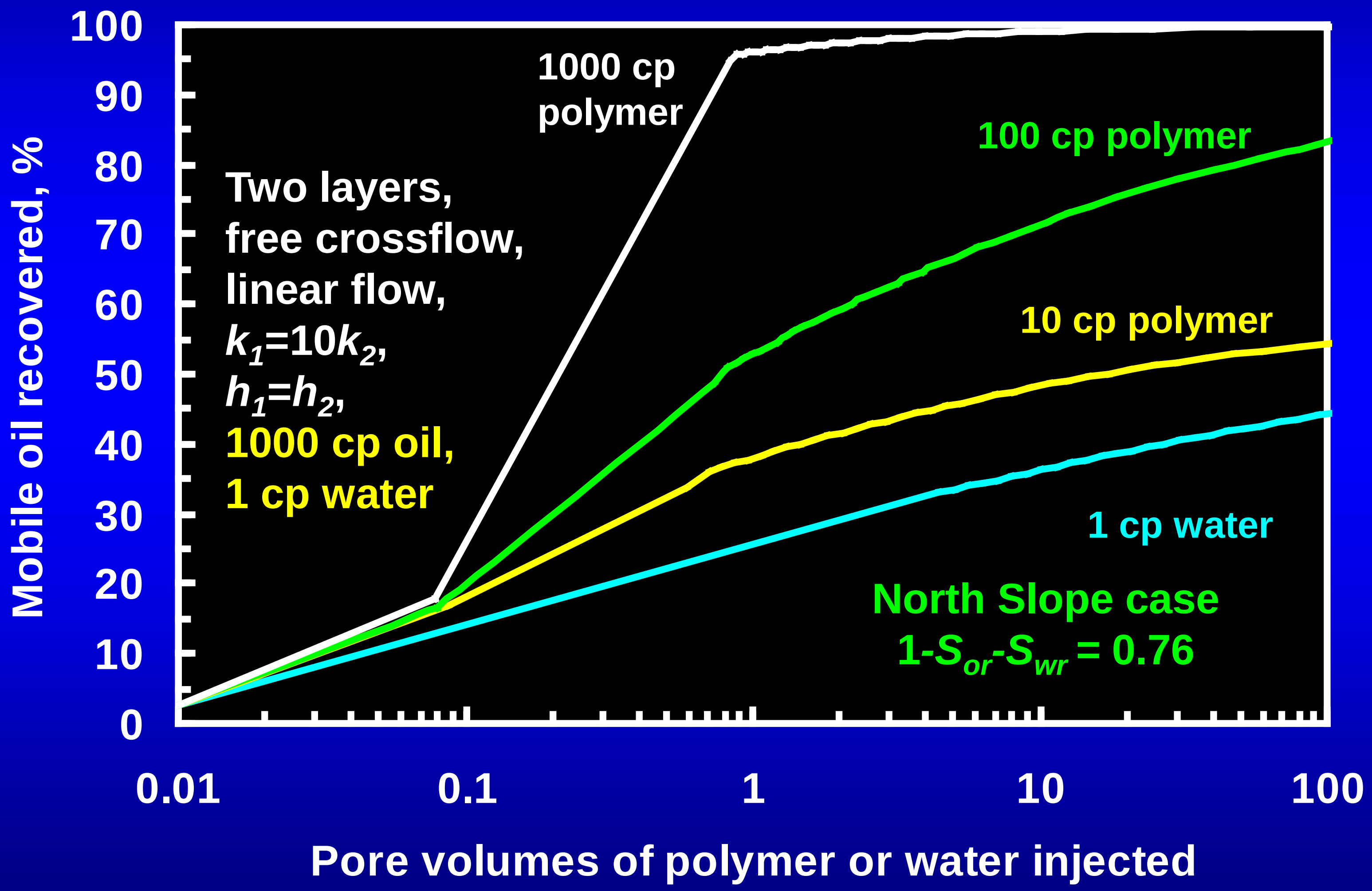
Even with no heterogeneity (i.e., one layer), reducing the oil/water viscosity ratio substantially improves oil displacement efficiency.



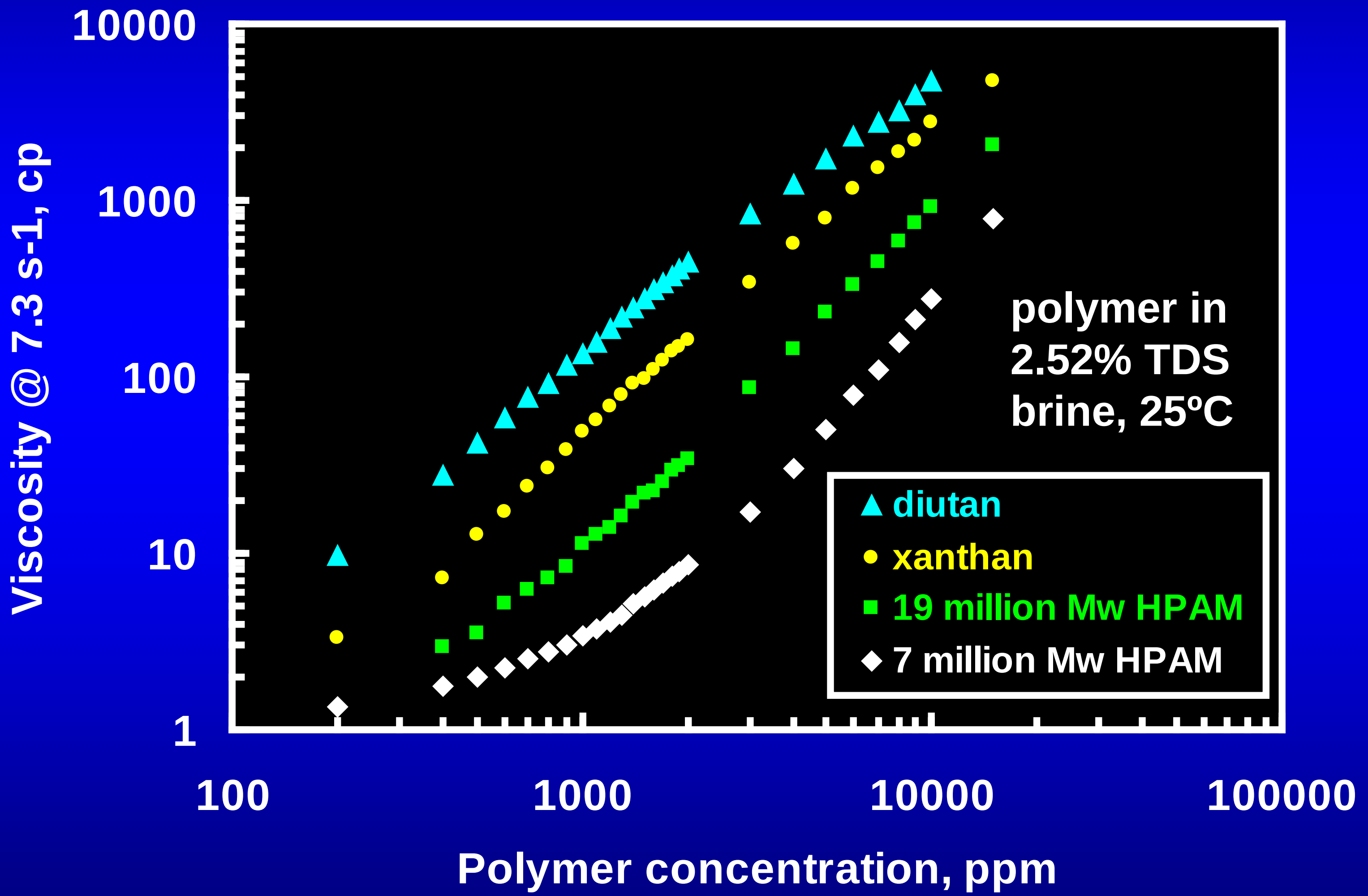
For cases with no crossflow, a 10-cp polymer solution provides noticeable sweep improvement.



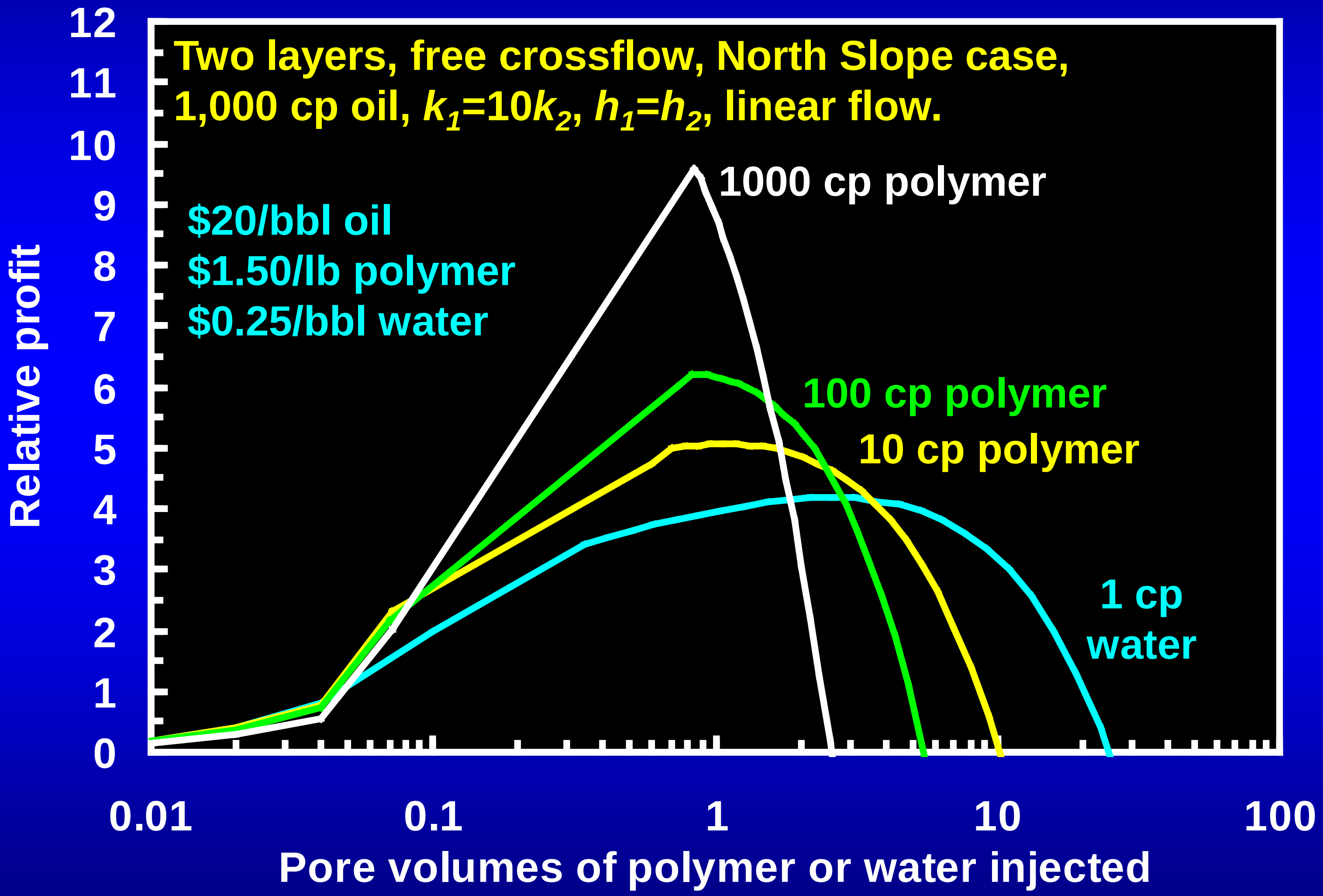
For cases with crossflow, substantial improvements in sweep efficiency can occur, especially when using very viscous polymer solutions.



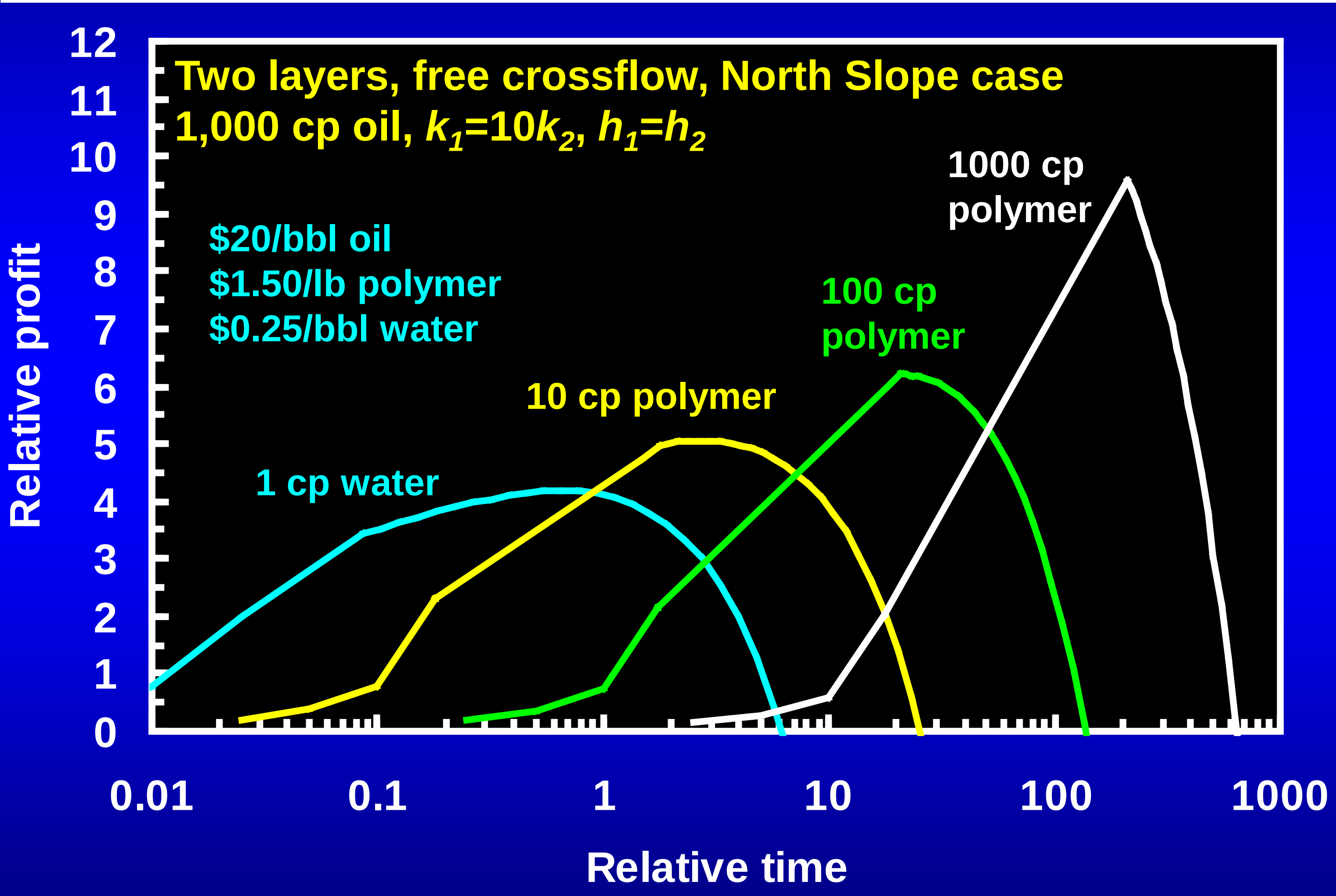
Polymers are more efficient viscosifiers at high concentrations: $\mu \sim C^2$ (i.e., only 40% more polymer is needed to double the viscosity).



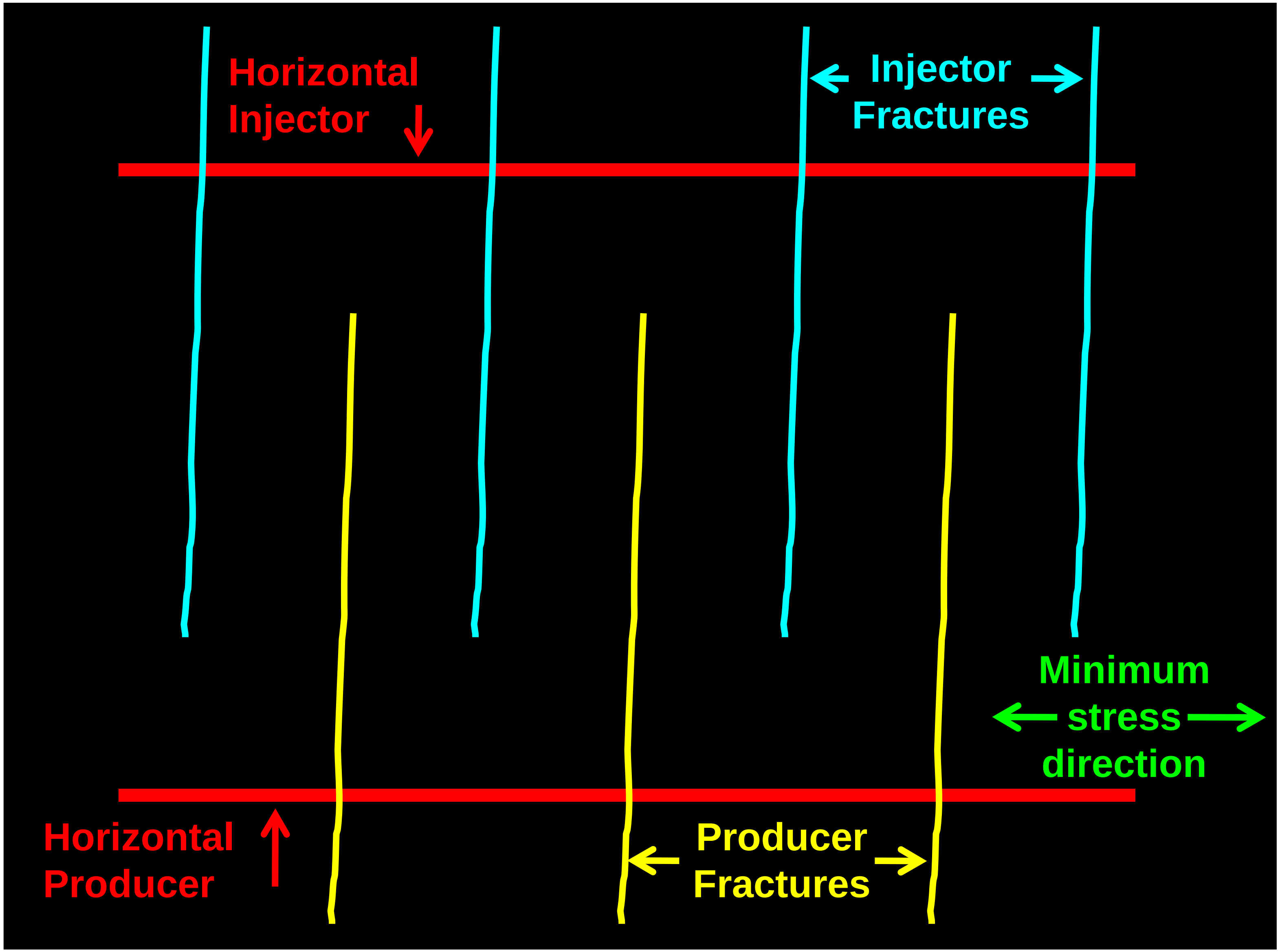
If polymer could be injected as readily as water, injection of very viscous polymer solutions would be preferred.



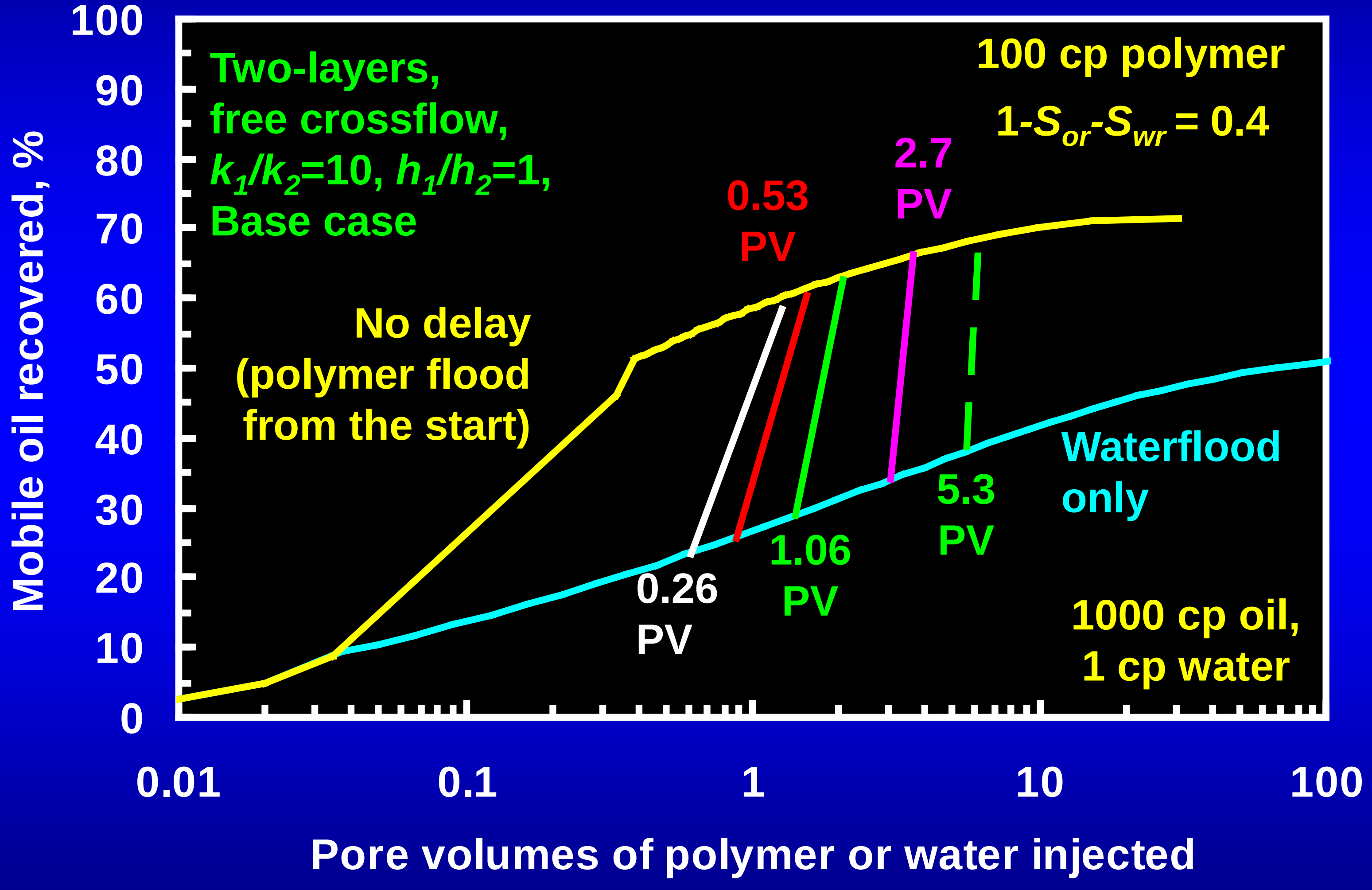
If polymer injectivity varies inversely with polymer viscosity, injection of less viscous polymer solutions would be preferred.
INJECTIVITY MAY BE MORE IMPORTANT THAN POLYMER COST.



Scheme to Maximize Polymer Injectivity/Productivity



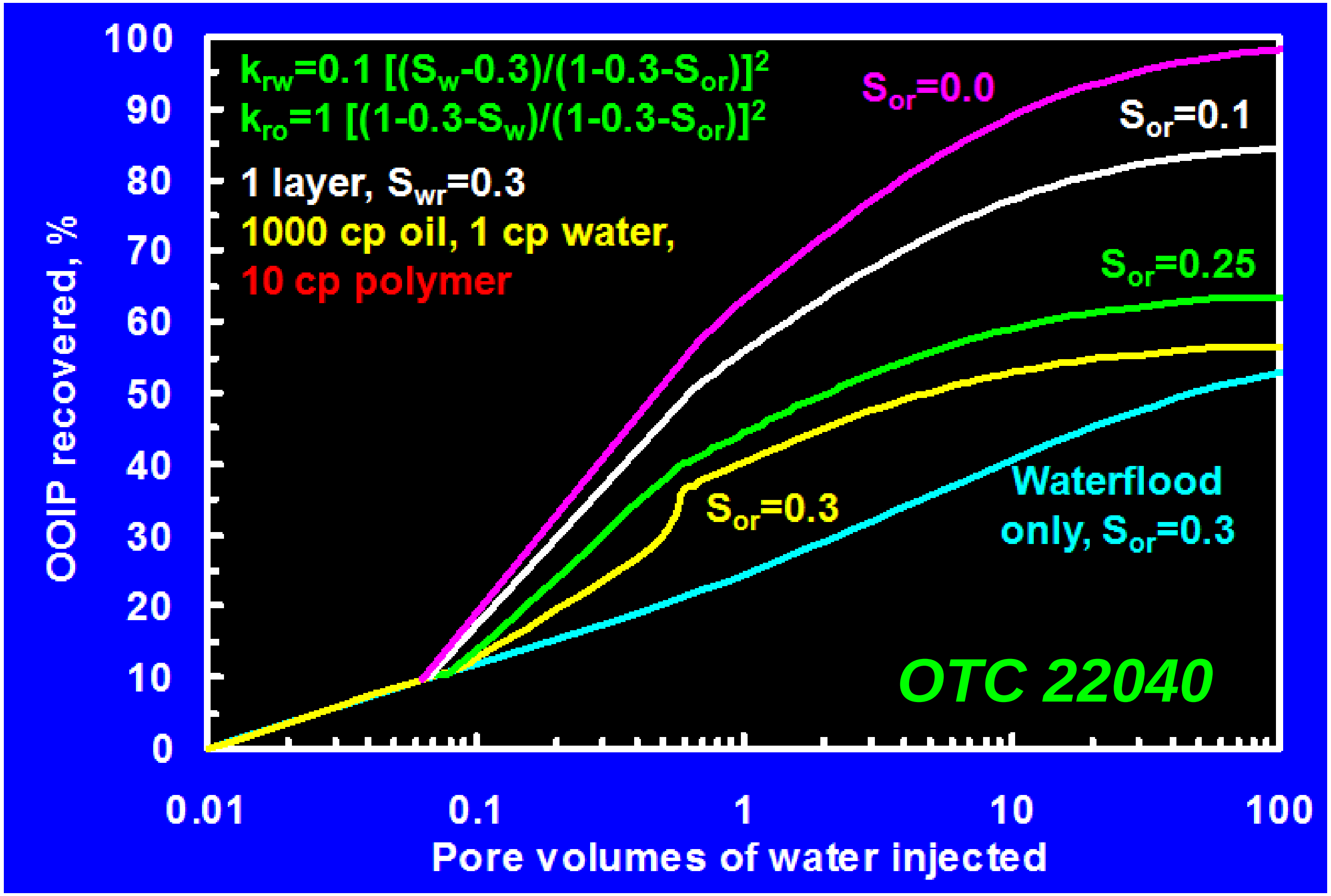
Does a delay before starting the polymer flood hurt performance?



OTC 22040

Can viscoelastic polymer solutions reduce the S_{or} below that for waterflooding?.

1. Daqing says yes; UT Austin says maybe not.
2. Does it matter for viscous oils? (yes)



MODELING RECOVERY EFFICIENCY

1. Fractional flow calculations are just a simple guide. Certainly, there are things that they can’t do.
2. Simulations can provide much more insight IF they are set up and performed correctly.
3. Simulations MUST be benchmarked against known answers and common sense.
4. In my experience, obtaining nonsense answers from simulations of polymer flooding (and gel treatments) is the norm—not the exception.
5. This occurs primarily because of inappropriate assumptions put into simulations.

BOTTOM LINE

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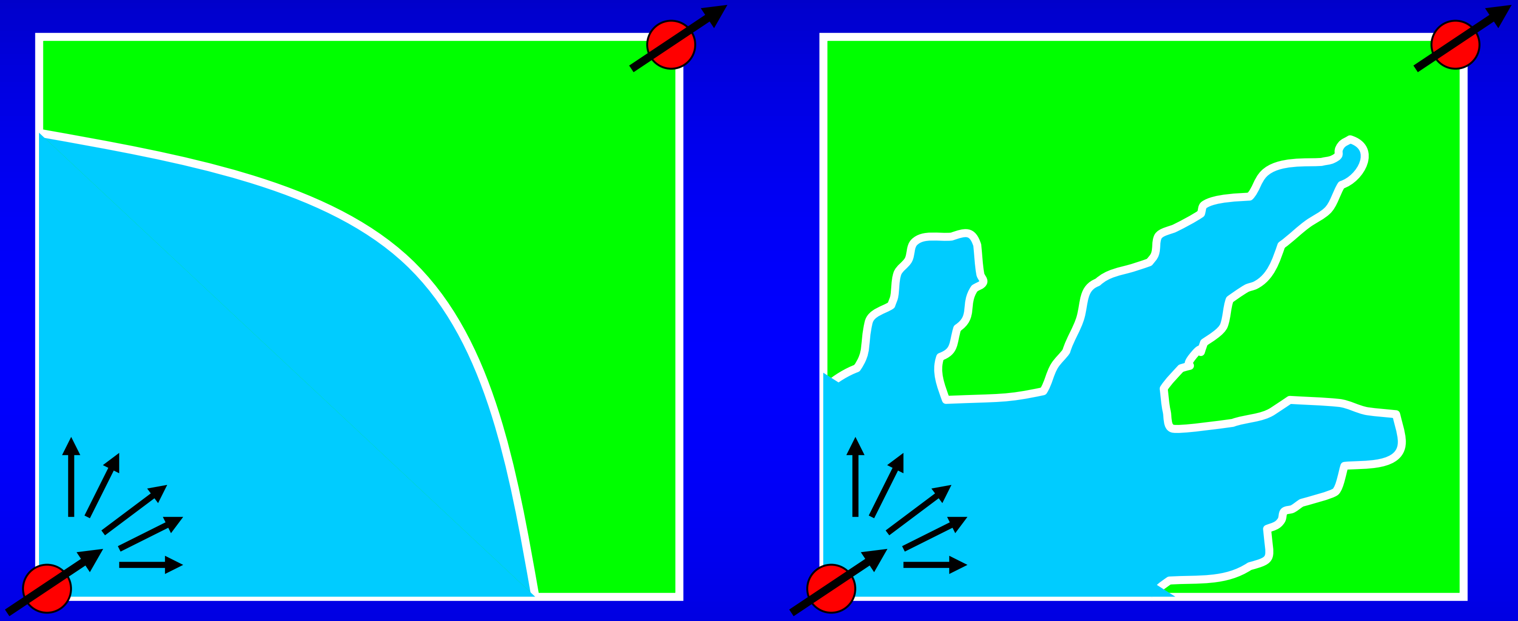
ESSENTIALS OF VISCOUS FINGERING



M < 1: FAVORABLE

M > 1: UNFAVORABLE

$$M = (k/\mu)_{water} / (k/\mu)_{oil}$$

Essentials of Viscous Fingering

- “Fingers” prefer high-k pathways—leading to a semantics argument on the importance of fingering versus channeling. Let’s focus on a “homogeneous” porous medium.

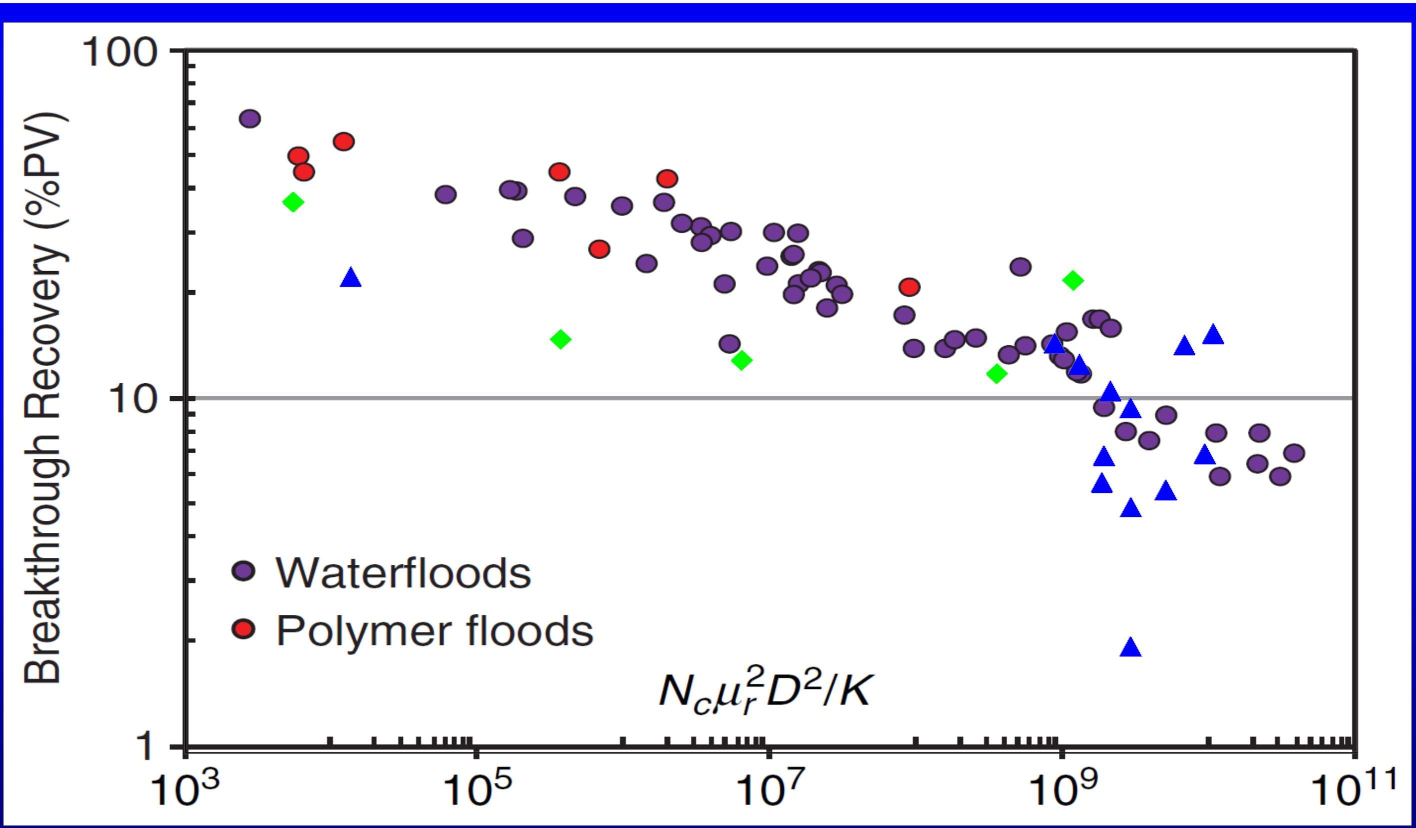
- As the mobility ratio increases, fingering gets worse—longer, narrower fingers and less fingers.

- Fingering makes sweep efficiency worse than predicted by Buckley-Leverett.

- Fingering in wide paths (like a reservoir layer) is worse than in a narrow path (like a lab core or slim tube).

Immiscible Fingering Correlation from Doorwar & Mohanty: SPE 173290

- **Fingering gets worse with increased oil/water viscosity ratio (μ_r), flow area (D) & capillary number ($N_c = v\,\mu / \sigma$).**



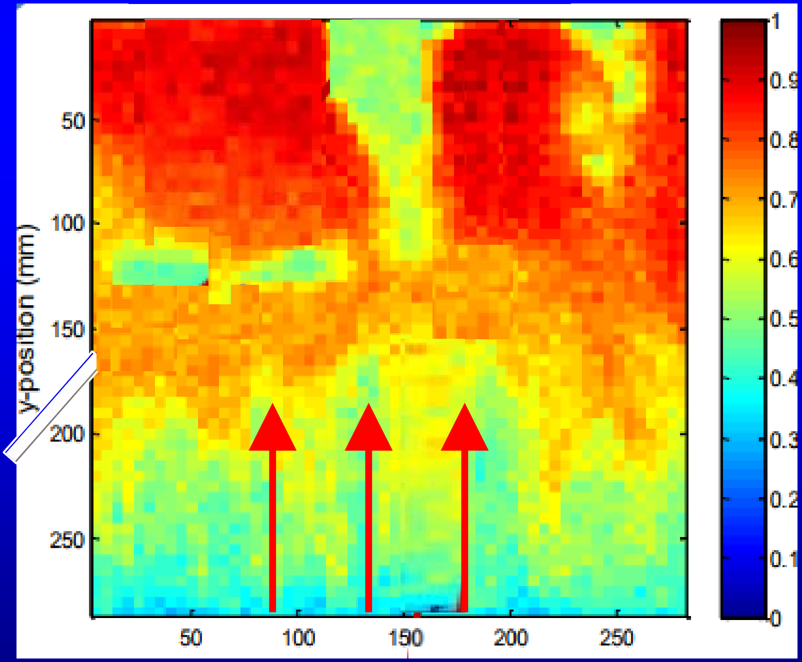
Essentials of Viscous Fingering

- **In water-wet media, capillary action can mitigate water fingering through oil, especially at lower rates.**
- **Fingering is generally worse for immiscible displacements than miscible displacements.**
- **Severity of fingering is a strong function of mobility ratio.**
- **SO FINGERING PROVIDES A STRONG INCENTIVE TO DECREASE THE MOBILITY RATIO TOWARD UNITY (i.e, accentuates the benefits predicted by Buckley-Leverett).**

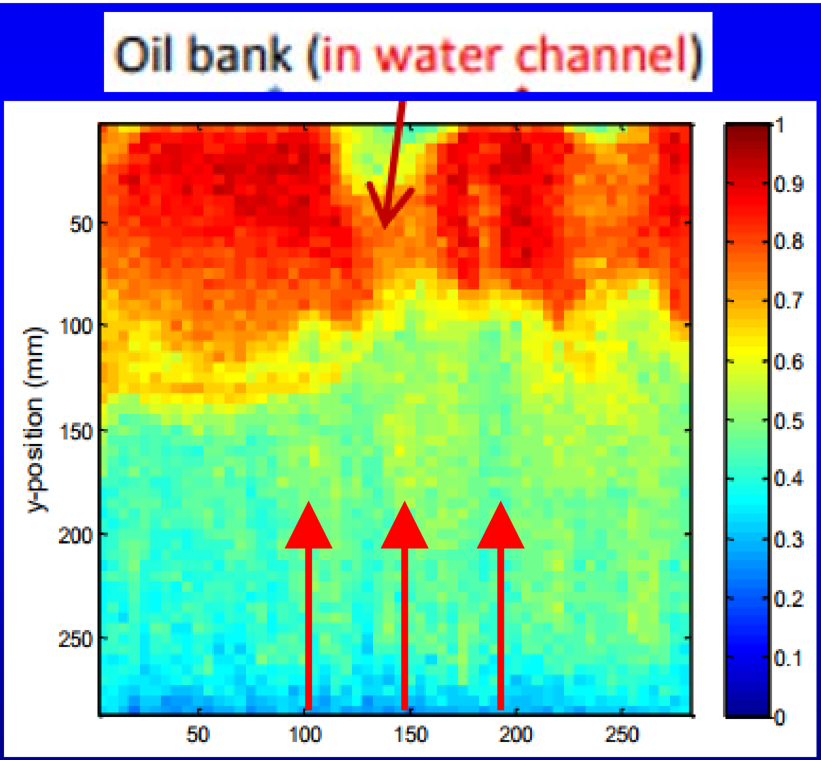
Fingers can aid viscous oil recovery

SPE 169740 (Skauge et al.)

- **2-D X-ray visualization studies with 616-cp oil.**
- **Fingers from previous water flooding appear to provide a preferred path for oil flow during polymer flooding.**



0.13 PV polymer



0.24 PV polymer

SPE 179543

How Much Polymer Should Be Injected during a Polymer Flood?

Bottom Line

1. Base-case method: $F_r = M * k_1/k_2$. (You must be realistic about your choices of mobility ratio and perm contrast.)
2. Injection above the formation parting pressure and fracture extension are crucial to achieving acceptable injectivity—especially for vertical injectors—increasing injectivity, sweep efficiency, and reducing mechanical degradation. The key is to understand the degree of fracture extension so that fractures do not extend out of zone or cause severe channeling.
3. Many field cases exist (Daqing, Suriname, Canadian floods) with no evidence that fractures caused severe polymer channeling or breaching the reservoir seals, in spite of injection significantly above the formation parting pressure.
4. Experience and technical considerations favor using the largest practical polymer bank. Channeling can be severe when water injection occurs after polymer injection.
5. Although graded banks are commonly used or planned in field applications, more work is needed to demonstrate their utility and to identify the most appropriate design procedure.

What polymer viscosity/concentrations were used in the past?

1960-1980: (Manning *et al*. 1983)

MEDIAN VALUES: 250-260 ppm HPAM (2-10 cp); 17%PV

Why so little? Because of an incorrect belief that HPAM provides a significant permeability reduction in a reservoir (either resistance factor is >2X viscosity or residual resistance factor is >2).

Why is this belief wrong?

1. **The very high Mw part of HPAM that causes this effect is destroyed by mechanical degradation and removed by flow through a few feet of porous rock. So it will not materialize deep in a reservoir.**
2. **During brine injection to displace polymer, the effect is usually seen because of insufficient flushing of lab cores.**

What polymer viscosity/concentrations were used in the past?

1980-1990: (Seright 1993)

MEDIAN VALUES: 460 ppm HPAM (5-10 cp); 10% PV

Category 1: **Legitimate polymer floods typically using 1000-1500 ppm HPAM and 25-100% PV.**

Category 2: **Tax floods whose only goal was to achieve a reduction from the Windfall Profits Tax Act of 1980. Very little polymer. Very little engineering. Very little project surveillance.**

Consequence

"Statistical analysis" of polymer floods from this period lead to the erroneous conclusion that polymer flooding is applicable in virtually every conventional oil reservoir (SPE 168220).

What polymer concentrations, viscosities, and bank sizes were used in the past?

1960-1980: (Manning *et al*. 1983)
MEDIANS: 250-260 ppm HPAM; 6 cp; 17%PV
1980-1990: (Seright 1993)
MEDIANS: 460 ppm HPAM; 8 cp; 10%PV

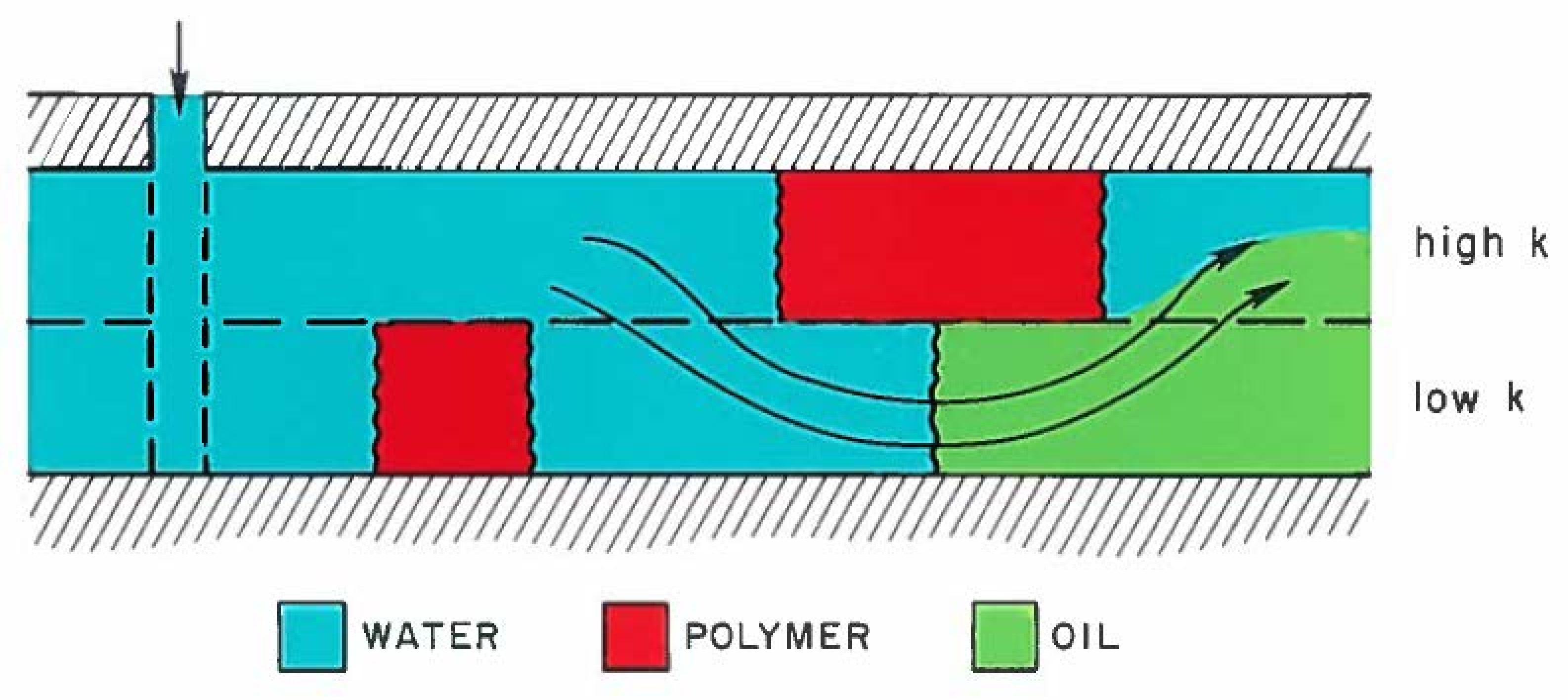
Why so little?

1. **An incorrect belief that HPAM reduced permeability substantially, even in high-permeability strata.**

2. **An incorrect belief that water injected after the polymer would be diverted into and displace oil from low-permeability strata.**

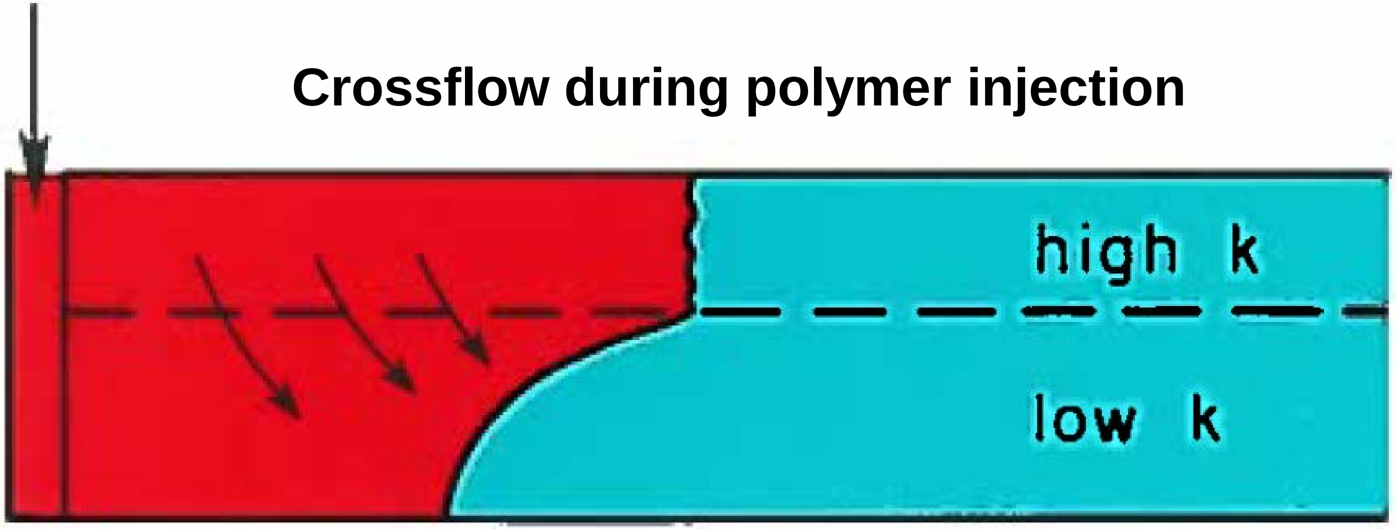
1990-present: MEDIANS: 1400 ppm HPAM; 30 cp; 50%PV

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

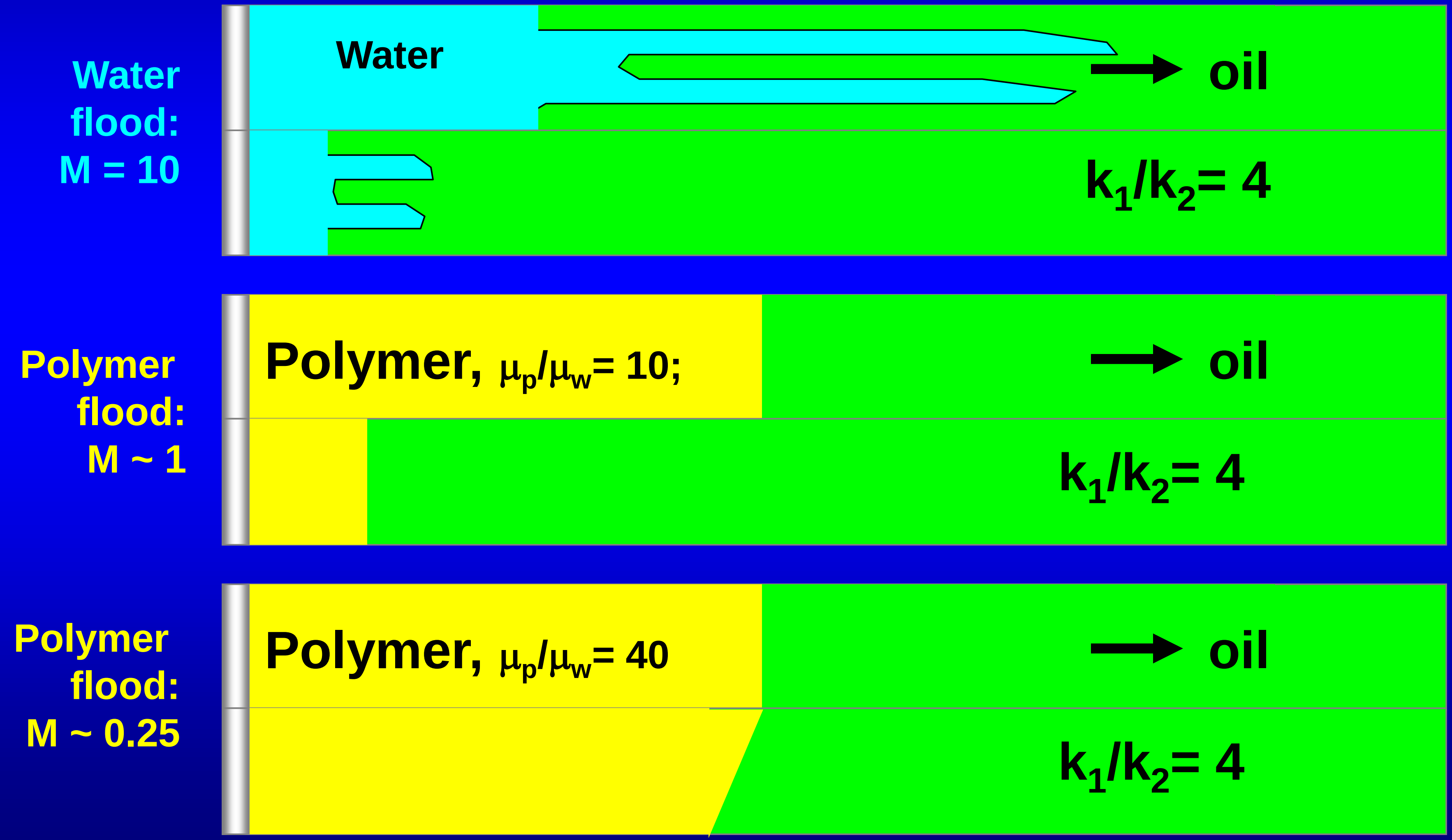


Viscous fingering during water injection after polymer:

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

SELECTION OF POLYMER VISCOSITY

- Want to make the water flood mobility ratio favorable.
- Want to overcome the permeability contrast.



Water flood: M = 10

Polymer flood: M ~ 1

Polymer flood: M ~ 0.25

Needed Resistance Factor = (Mobility Contrast) x (Permeability Contrast)

Simplified Conversion From Dystra-Parsons Coefficient of Permeability Variation (K_v) to Permeability Contrast (k_{cont} or k_1/k_2)

K_v	k_{cont} or k_1/k_2
0.4	2
0.5	2.5
0.6	3.5
0.7	5.1
0.8	8.8
0.9	23

Must have clearly identifiable zones.

Recent Polymer Floods

Field	C_{poly}, ppm	μ_{poly}, cp	μ_o @ Res. T, cp
Daqing, China (1996-~2008)	1000-1300	40-50	9-10
Daqing, China (~2008-2015)	2000-2500	150-300	9-10
Gudao/Shengli, China	2000	25-35	50-150
Shengtao/Shengli, China	1800	30-50	10-40
ShuangHe, China	1090	93	7.8
Bohai Bai, China	1200-2500	98	30-450
Pelican Lake, Canada	600-3000	13-50	1000-3000
East Bodo, Canada	1500	50-60	417-2000
Mooney, Canada	1500	20-30	100-250
Seal, Canada	1000-1500	25-45	3000-7000
Suffield Caen, Canada	1300	32	69-99
Wainwright, Canada	2100-3000	25	100-200
Dalia, Angola	900	3	1-11
Diadema, Argentina	1500-3000	15-40	100
El Corcobo, Argentina	1000	20-25	160-300
Matzen, Austria	900	10	19
Canto do Amaro, Brazil	1000	30	50
Carmopolis, Brazil	500	40	10.5
Buracica, Brazil	500	10	7-20
Bockstedt, Germany	300 (biopoly)	25	11-29
Mangala, India	2000-2500	20	9-22
Marmul, Oman	1000	15	80-90
Tambaredjo, Suriname	1000-2500	45-140	325-2209

Why Do Some Polymer Floods Inject Much Less Polymer Than The Base-case Calculation?

“Relative permeabilities allow much more favorable displacement than expected.”

“Resistance factor & residual resistance factor limit the need for viscous polymer solutions.”

“Viscous solutions reduce injectivity too much.”
“Viscous solutions cause fracture channeling.”
“Viscous solutions cause flow out of zone.”

“Economics limit polymer concentrations.”

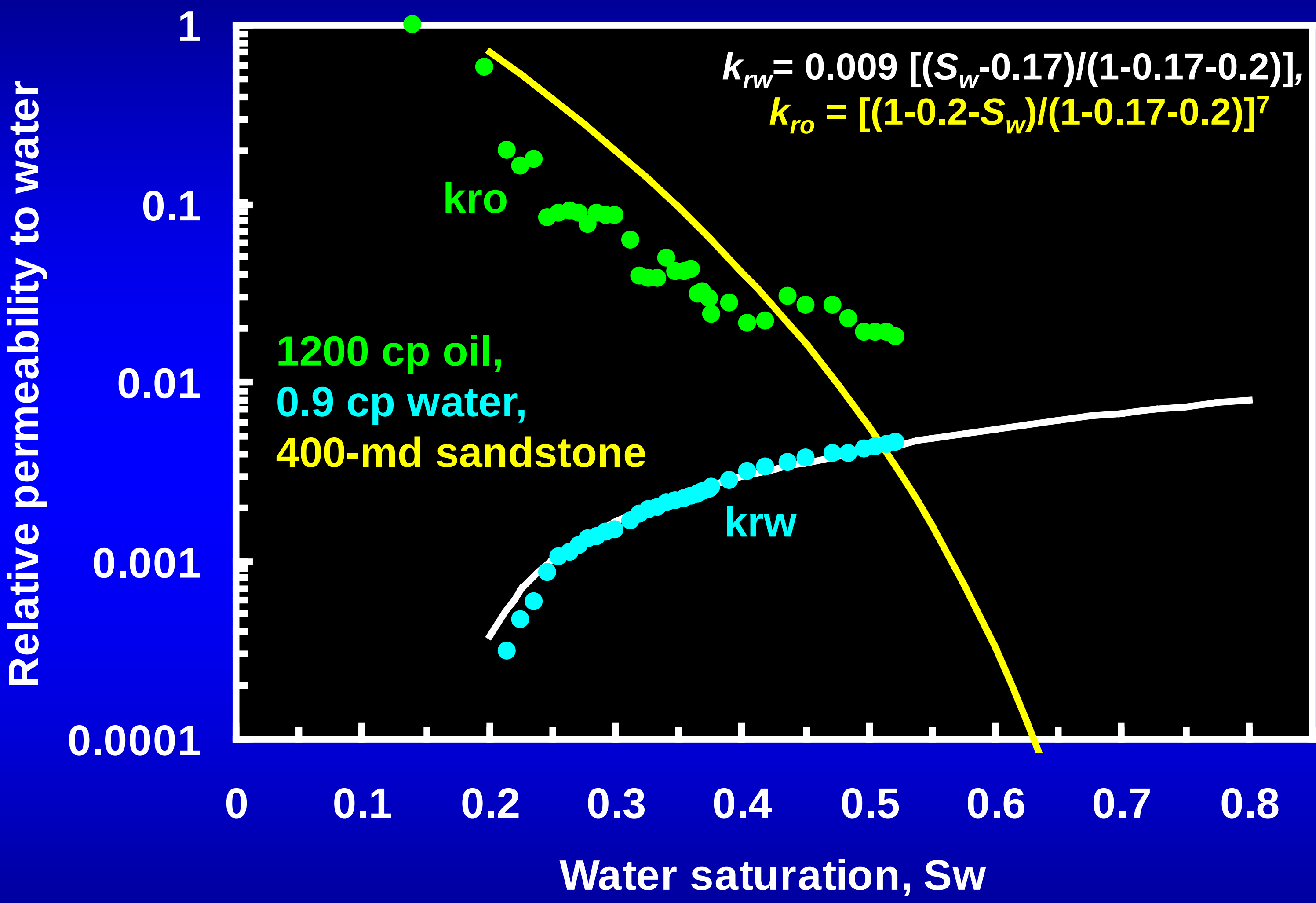
Why Do Some Polymer Floods Inject Much Less Polymer Than The Base-Case Calculation?

"Relative permeabilities allow much more favorable displacement than expected."

If true, this is a good reason to choose low polymer concentrations, BUT …

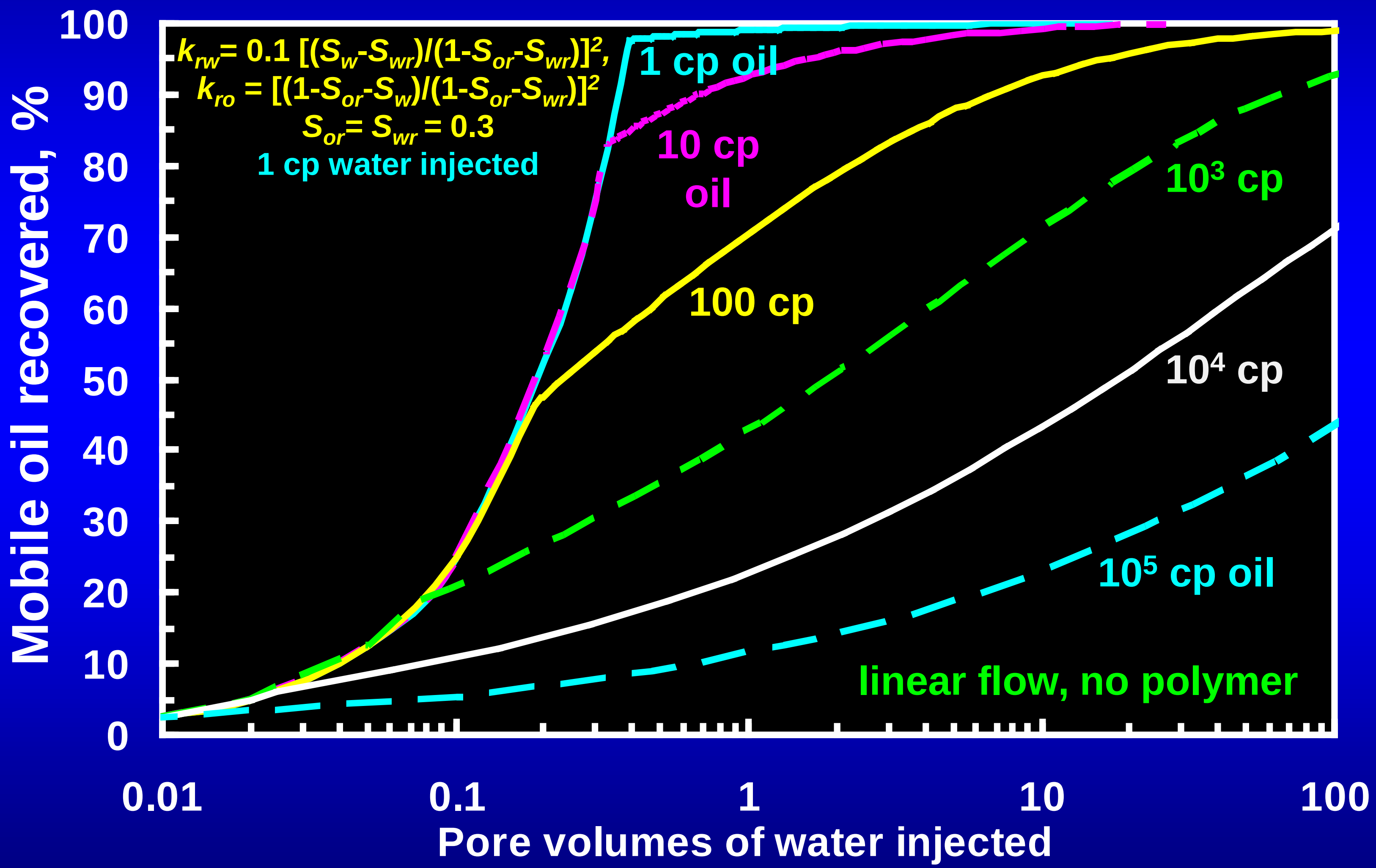
1. Relative k curves are difficult to obtain for viscous oils (Maini 1998).
2. Injecting insufficient water gives an unrealistically low relative permeability to water.
3. Use of mobility ratios at the shock front do not always correlate well with displacement efficiency.
4. Underestimating the polymer requirements leads to early polymer breakthrough.

Favorable relative permeability characteristics can occur with viscous oils, but you must confirm that you have them.

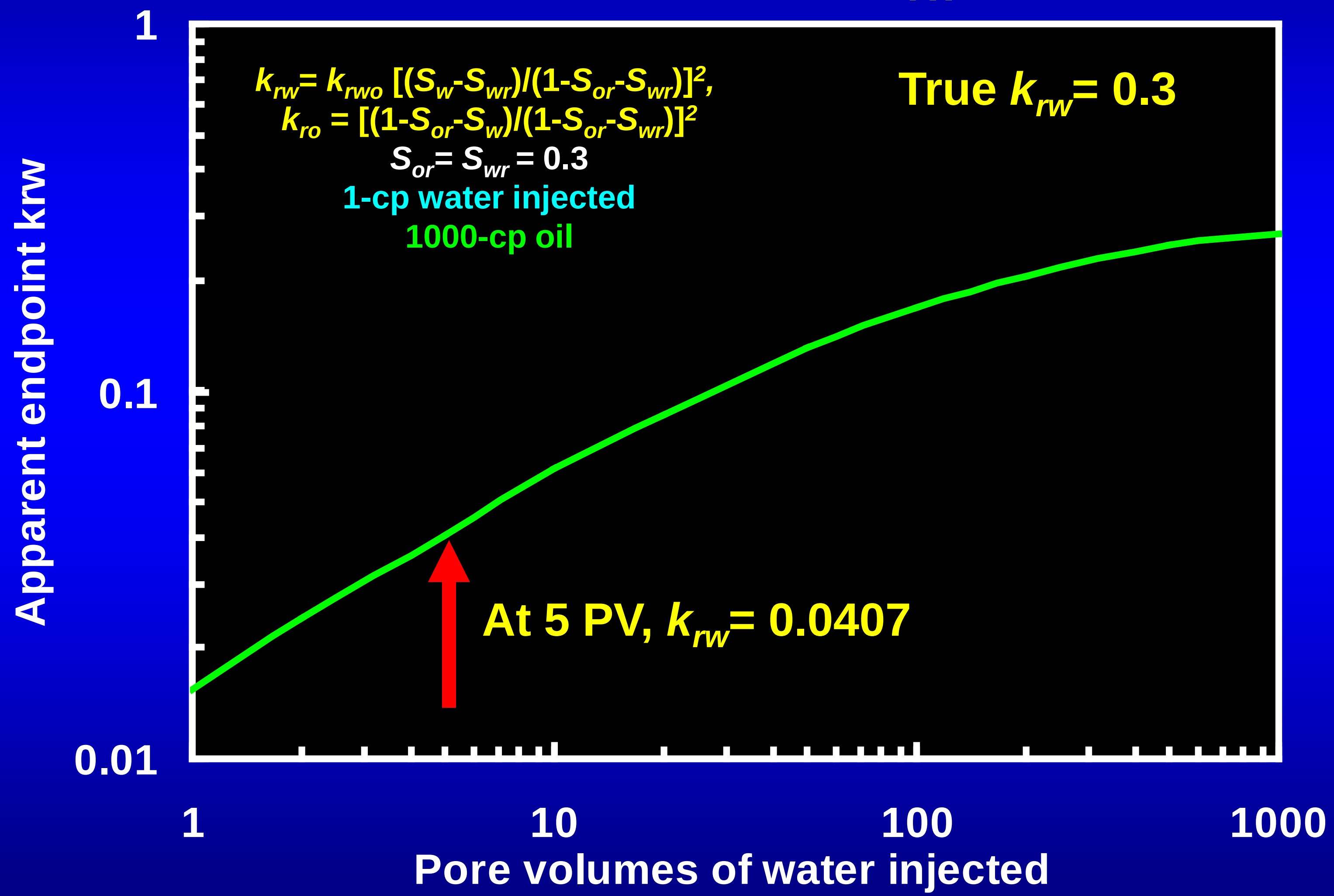


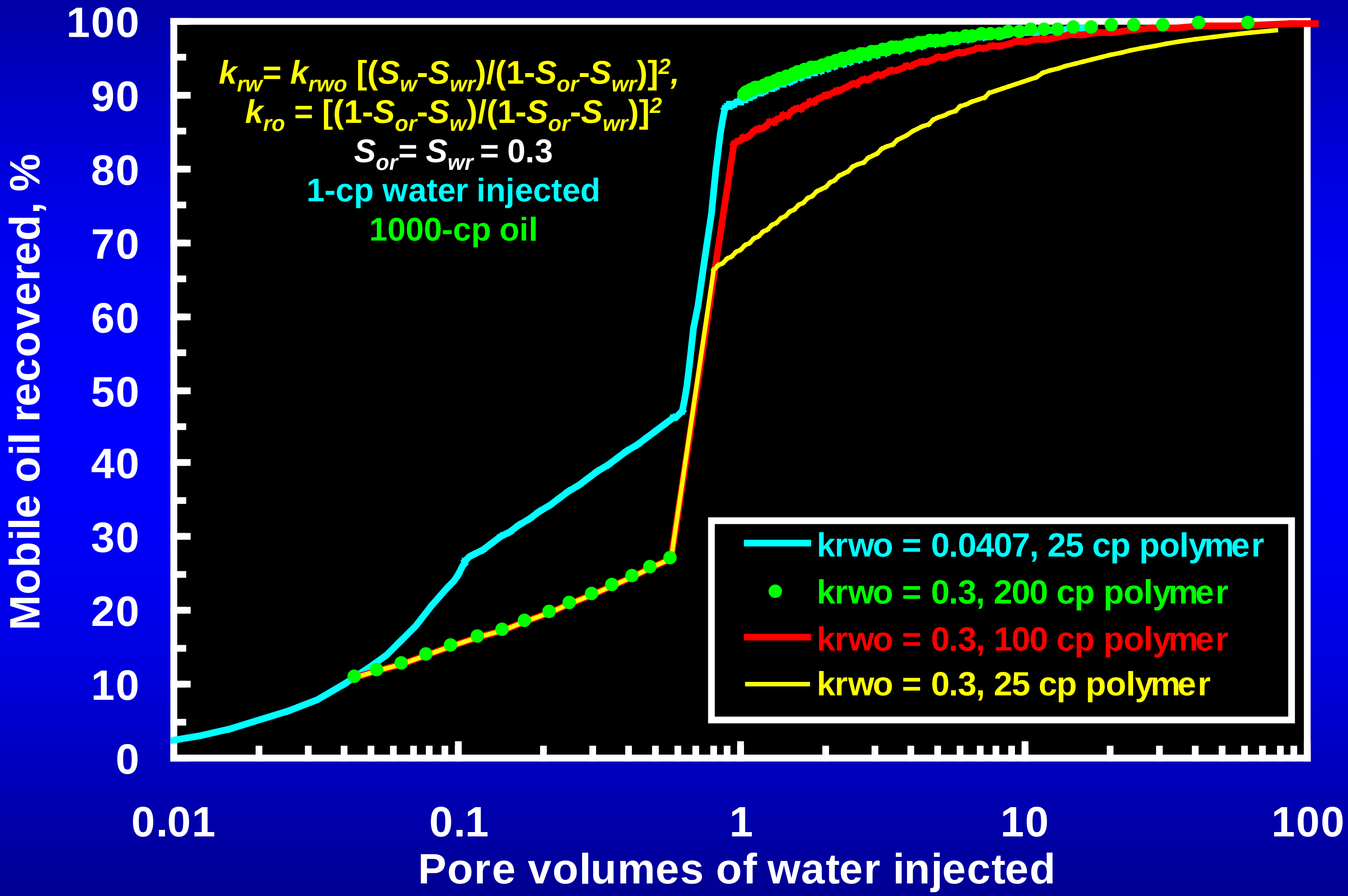
For the above case, flooding with 25 cp polymer performed as well as with 50 cp or 200 cp polymer. (6 & 15 cp was not as good.)

Even with no heterogeneity (i.e., one layer), reducing the oil/water viscosity ratio substantially improves oil displacement efficiency.



Insufficient throughput yields misleadingly low k_{rw} values





$k_{rw} = k_{rwo}\,[(S_w - S_{wr})/(1 - S_{or} - S_{wr})]^2$,

$k_{ro} = [(1 - S_{or} - S_w)/(1 - S_{or} - S_{wr})]^2$

$S_{or} = S_{wr} = 0.3$

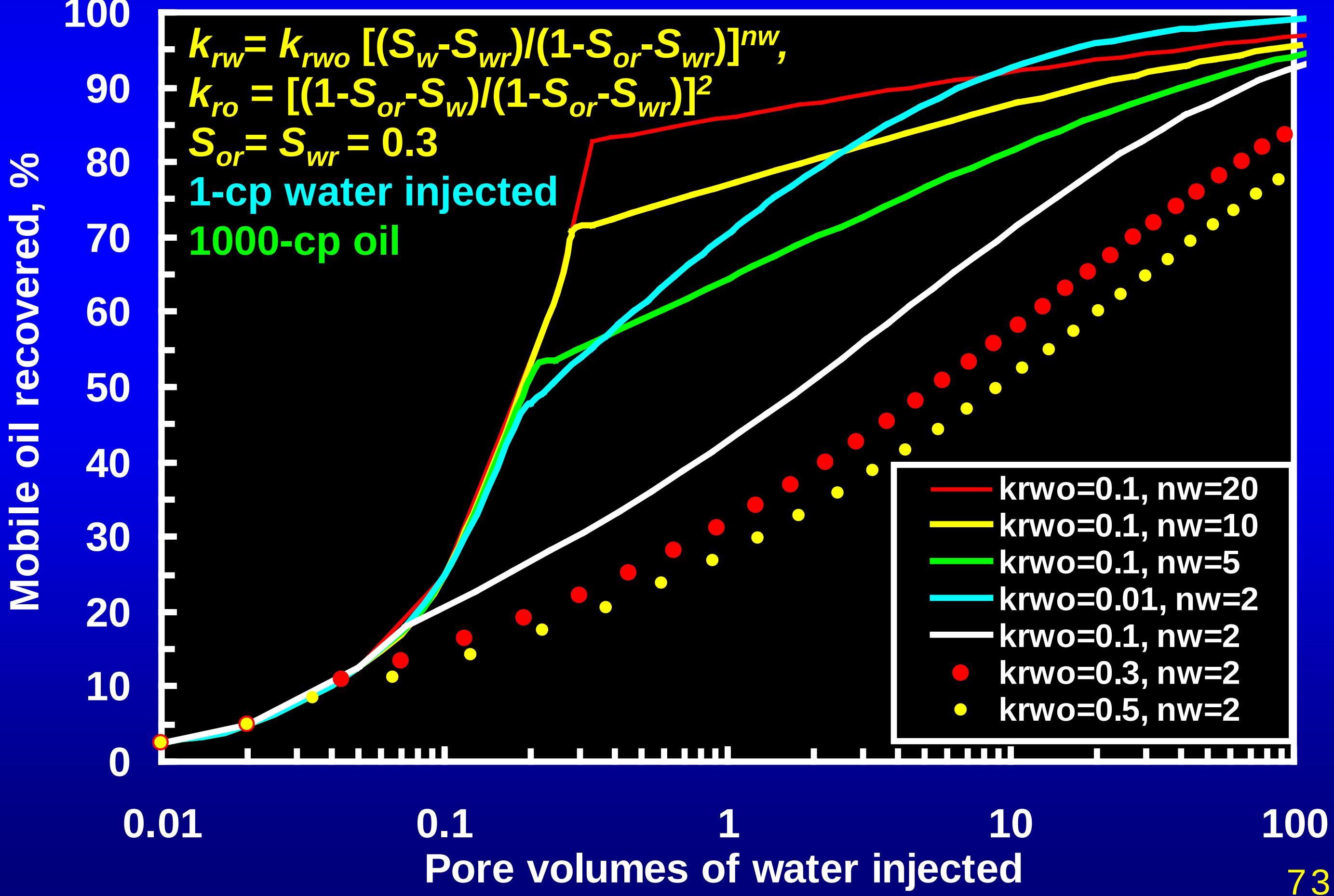
1-cp water injected

1000-cp oil

Favorable displacements can be seen if k_{rwo} is low or nw is high. But are these values realistic?

k_{rwo}	nw	Endpoint mobility ratio	Mobility ratio at shock front	Mobile oil recovery at 1 PV
0.5	2	500	1.92	27%
0.3	2	300	1.87	32%
0.1	2	100	1.80	43%
0.01	2	10	1.40	71%
0.1	5	100	2.04	64%
0.1	10	100	1.62	77%
0.1	20	100	1.14	86%

Mobility ratio at the shock front is not always the best indicator of an efficient displacement.



Why Do Some Polymer Floods Inject Much Less Polymer Than The Base-case Calculation?

“Resistance factor & residual resistance factor limit the need for viscous polymer solutions.”

1960's Dow HPAM Claim

HPAM can reduce water mobility both by increasing water viscosity and by reducing permeability:

$$\lambda = k / \mu$$

Resistance factor (F_r or *RF*)

$$F_r = (k / \mu)_{brine} / (k / \mu)_{polymer}$$

This effect is typically seen in short laboratory cores using fresh, gently-handled solutions.

Mechanical degradation and/or flow through a few feet of reservoir destroys this effect.

Pye, *JPT*, August, 1964

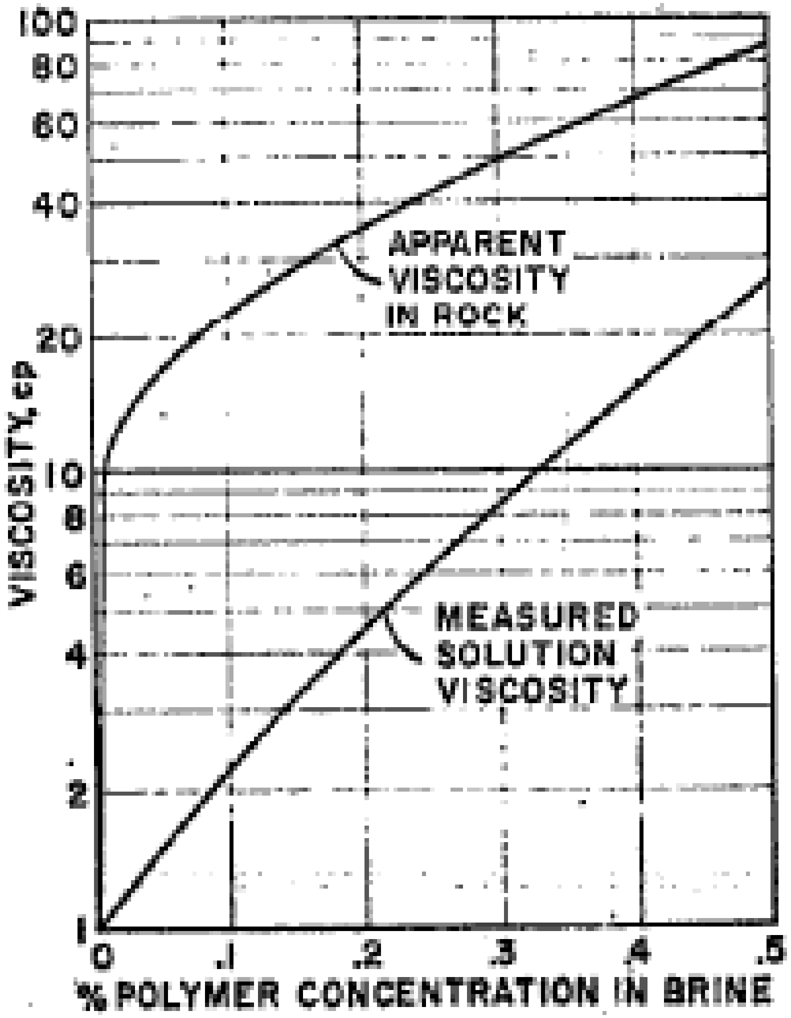


Fig. 1—Polymer Resistance Effect in 250-md Berea Sandstone

Resistance factor (F_r or *RF*) $= (k / \mu)_{brine} / (k / \mu)_{polymer}$

Residual Resistance Factor (F_{rr} or *RRF*)
$= (k / \mu)_{brine\ before\ polymer} / (k / \mu)_{brine\ after\ polymer}$

RRF is a measure of permeability reduction caused by polymer.

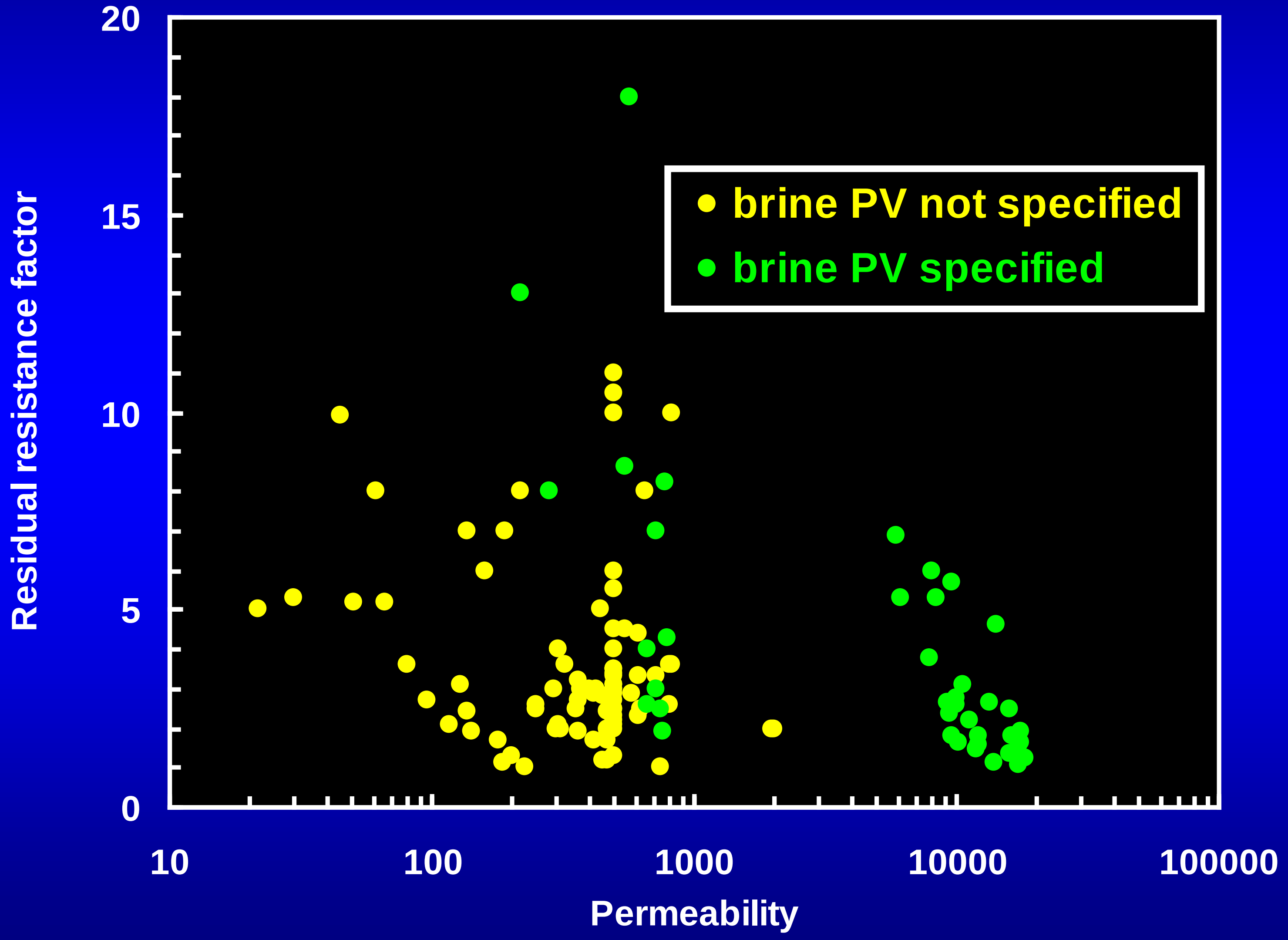
If RRF = 1, the polymer causes no permeability reduction, so a large polymer bank must be used.

If RRF = RF, a very small polymer bank can be used.

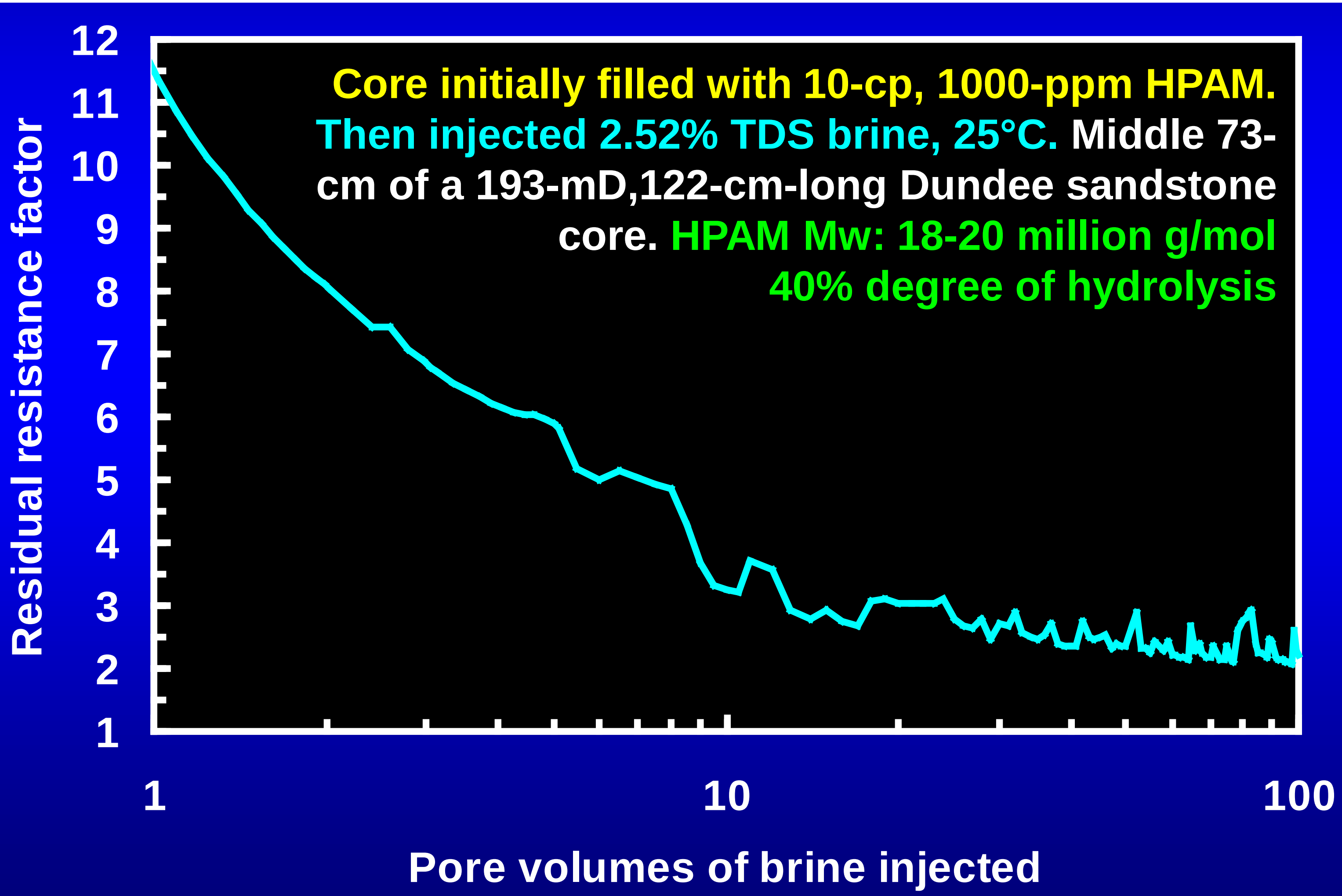
High RRF values occur when (1) not enough brine is injected, (2) no internal pressure taps are used during core floods, (3) rock permeability is too low to allow polymer propagation.

Most real polymer flood RRF values are less than 2.
Simulations should assume RRF =1 to be conservative.

- Most literature values for RRF do not report PV injected.
- Those that do usually injected less than 10 PV of brine.



- **If not enough brine is flushed to sweep out the polymer, a high residual resistance factor (RRF) is seen.**
- **Real RRF values rarely exceed 2 unless *k* is low.**
- **A conservative polymer flood design assumes RRF=1.**



Core initially filled with 10-cp, 1000-ppm HPAM. Then injected 2.52% TDS brine, 25°C. Middle 73-cm of a 193-mD,122-cm-long Dundee sandstone core. HPAM Mw: 18-20 million g/mol 40% degree of hydrolysis

Permeability reduction is greater in low-permeability rock than in high-permeability rock.

This effect could harm vertical sweep efficiency.

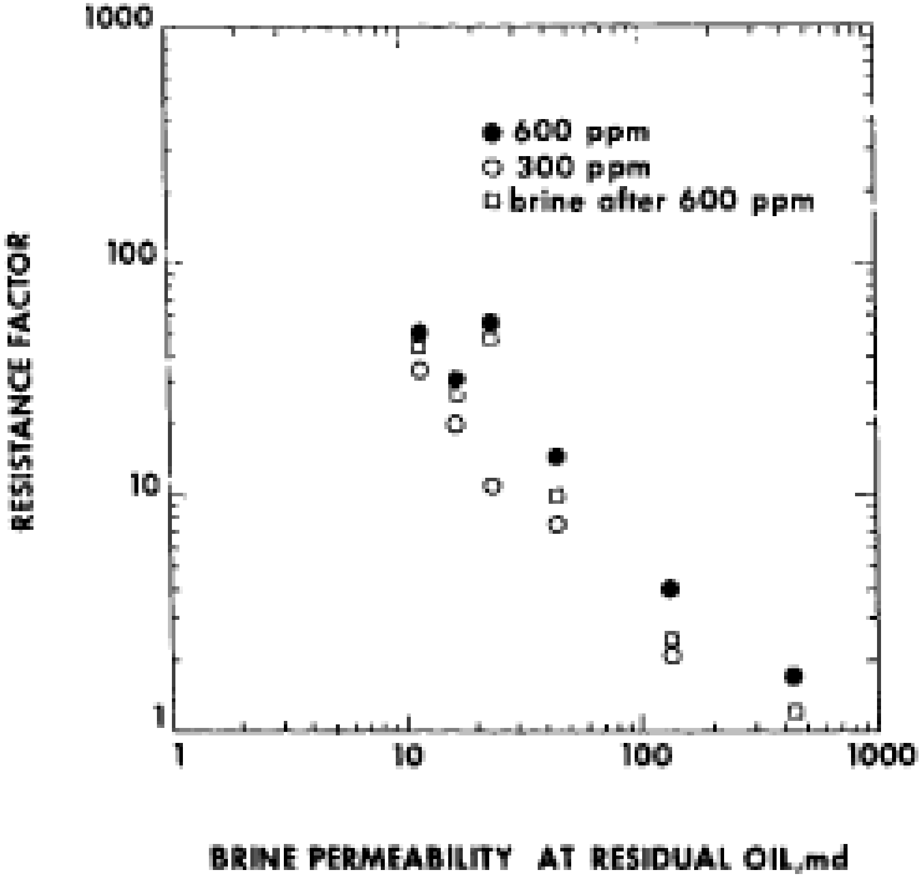
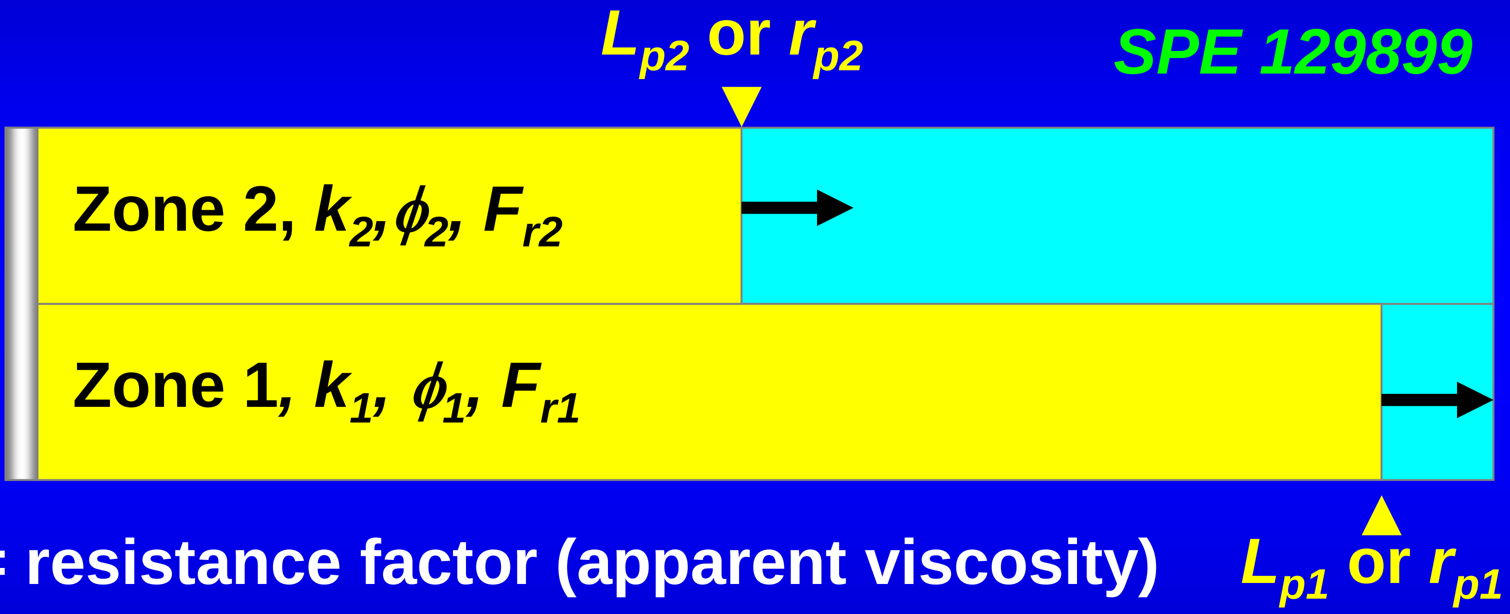


FIG. 4 — VARIATION OF POLYMER RESISTANCE FACTORS WITH PERMEABILITY.

Vela et al. SPE 5102

HPAM
Mw= 5.5 x 10^6
20% hydrolysis.
Sandstone rock.

If polymer molecular weight is too high, F_r values increase with decreasing k. (A pore-plugging effect.)
What if $F_{r1} < F_{r2}$? How does that affect vertical sweep?

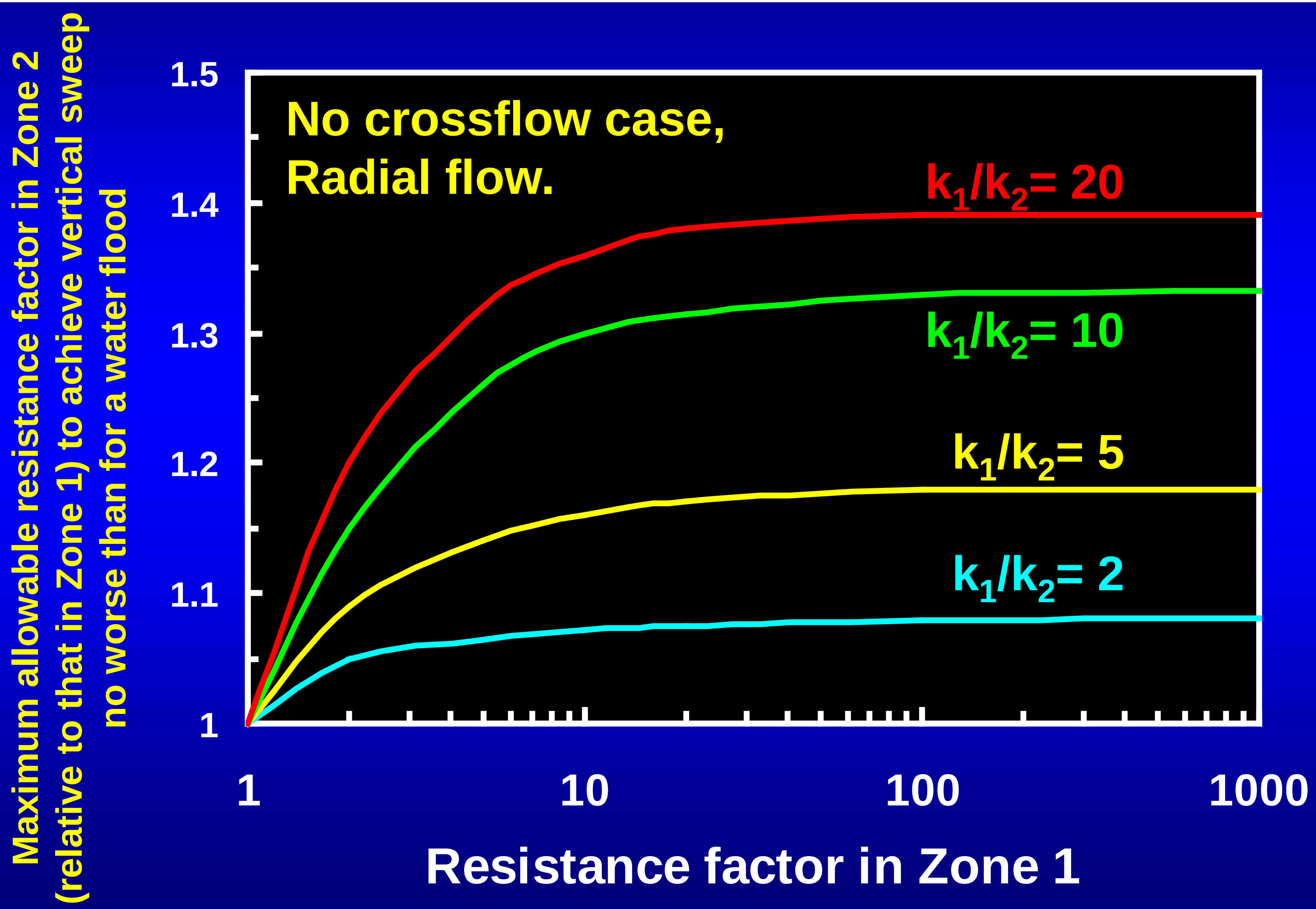


SPE 129899

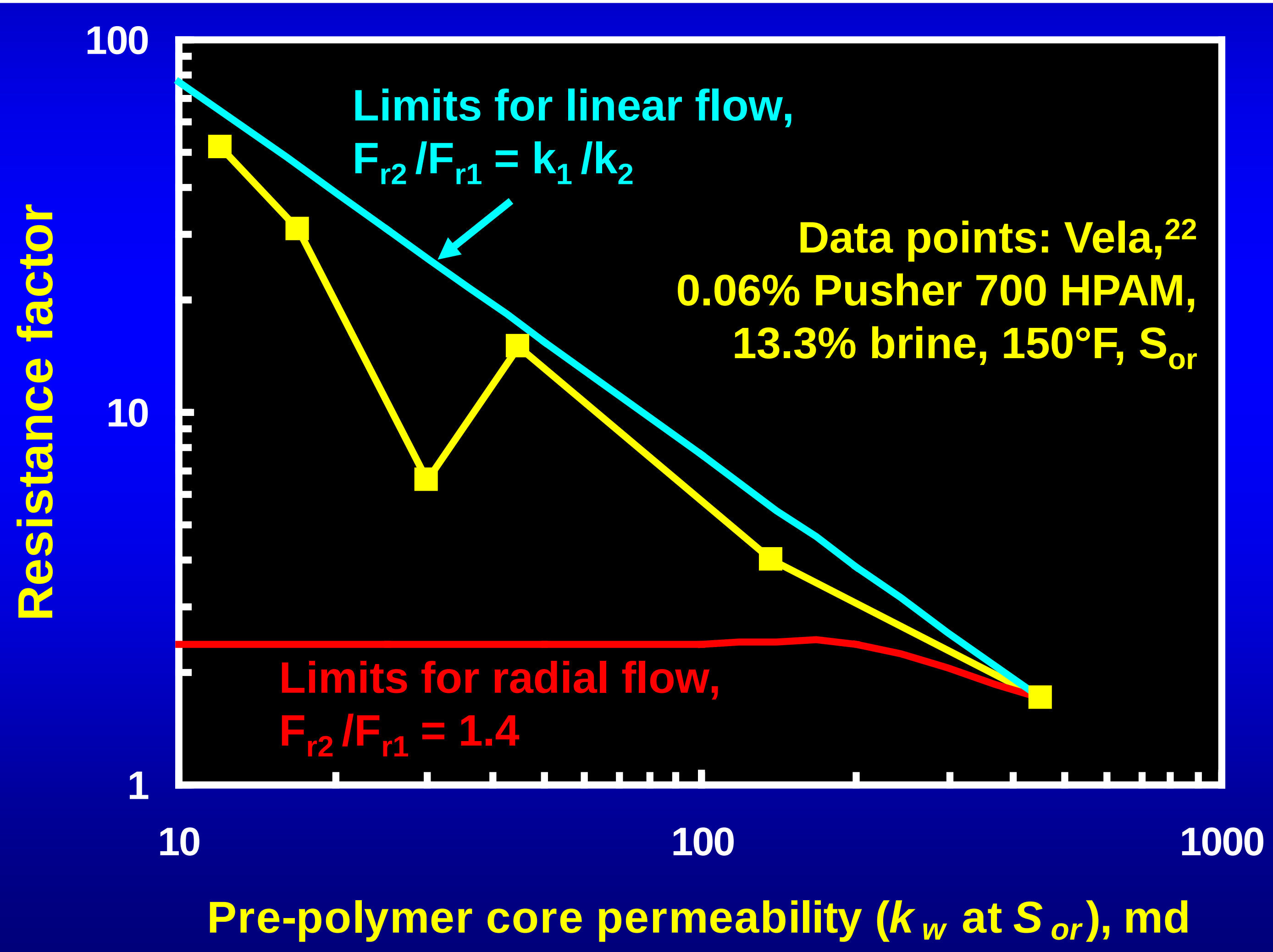
F_r = resistance factor (apparent viscosity)

For radial flow & no crossflow, F_{r2}/F_{r1} must be < 1.4.
For linear flow & no crossflow, F_{r2}/F_{r1} must be < k_1/k_2.
For free crossflow, vertical sweep is insensitive to F_{r2}/F_{r1}.

For polymers, F_r values often increase with decreasing k. What if $F_{r1} \neq F_{r2}$? For radial flow, F_{r2} must be < 1.4 F_{r1}.



For polymers, F_r values often increase with decreasing k.
What if $F_{r1} \neq F_{r2}$? If no crossflow, vertical sweep is far more tolerant to F_{r2} / F_{r1} for linear flow than for radial flow.
If fluids can crossflow, then F_{r2} / F_{r1} matters little.



HPAM Effectiveness versus Permeability and Molecular Weight. From Wang et al. 2008, SPE 109682

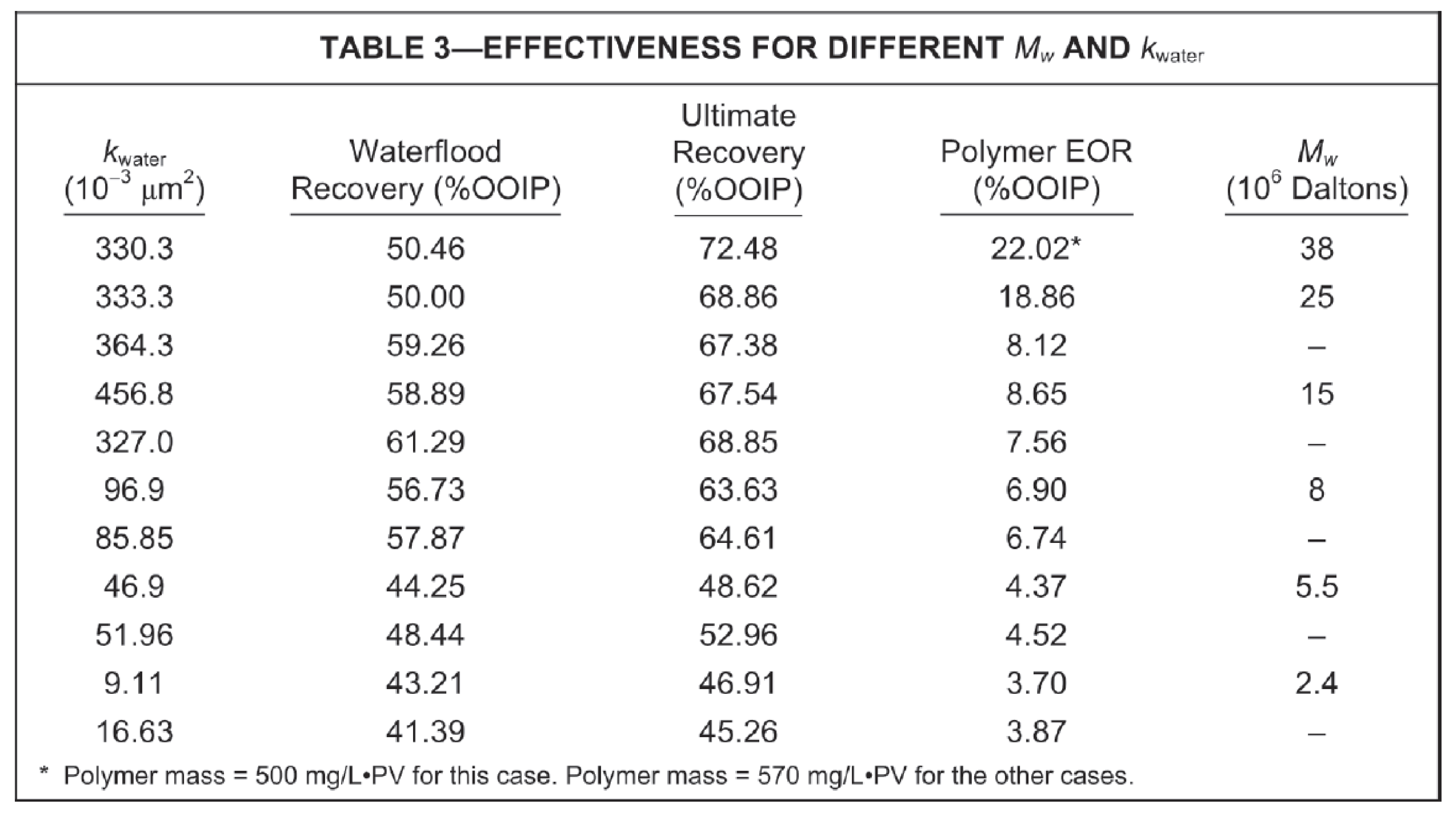


TABLE 3—EFFECTIVENESS FOR DIFFERENT M_w AND k_{water}

k_{water} (10^{-3} μm^2)	Waterflood Recovery (%OOIP)	Ultimate Recovery (%OOIP)	Polymer EOR (%OOIP)	M_w (10^6 Daltons)
330.3	50.46	72.48	22.02*	38
333.3	50.00	68.86	18.86	25
364.3	59.26	67.38	8.12	–
456.8	58.89	67.54	8.65	15
327.0	61.29	68.85	7.56	–
96.9	56.73	63.63	6.90	8
85.85	57.87	64.61	6.74	–
46.9	44.25	48.62	4.37	5.5
51.96	48.44	52.96	4.52	–
9.11	43.21	46.91	3.70	2.4
16.63	41.39	45.26	3.87	–

* Polymer mass = 500 mg/L•PV for this case. Polymer mass = 570 mg/L•PV for the other cases.

Why Do Some Polymer Floods Inject Much Less Polymer Than The Base-case Calculation?

"Viscous solutions reduce injectivity too much."

Injection has occurred above the formation parting pressure for the vast majority of polymer floods.

Fractures simply extend to accommodate the rate and viscosity of the fluid injected.

So injectivity is not a problem unless a pressure constraint is imposed. What is a reasonable pressure constraint?

Why Do Some Polymer Floods Inject Much Less Polymer Than The Base-case Calculation?

“Viscous solutions reduce injectivity too much.”
“Viscous solutions cause fracture channeling.”

Cases exist where rapid polymer channeling has occurred through fractures—but only for a limited fraction of the existing wells.

Deal with those wells on a case-by case basis:
(1) reduce polymer viscosity/injection rate, (2) shut-in the well or re-align flow, (3) gel treatments.

DAQING

Were fractures present?

YES

Fracture widths:

- **1.5 to 5 mm from injectivity analysis during polymer injection.**
- **0 to 1.8 mm from injectivity analysis during water injection.**
- **~0.01 mm from interwell tracer analysis of polymer breakthrough.**

DAQING

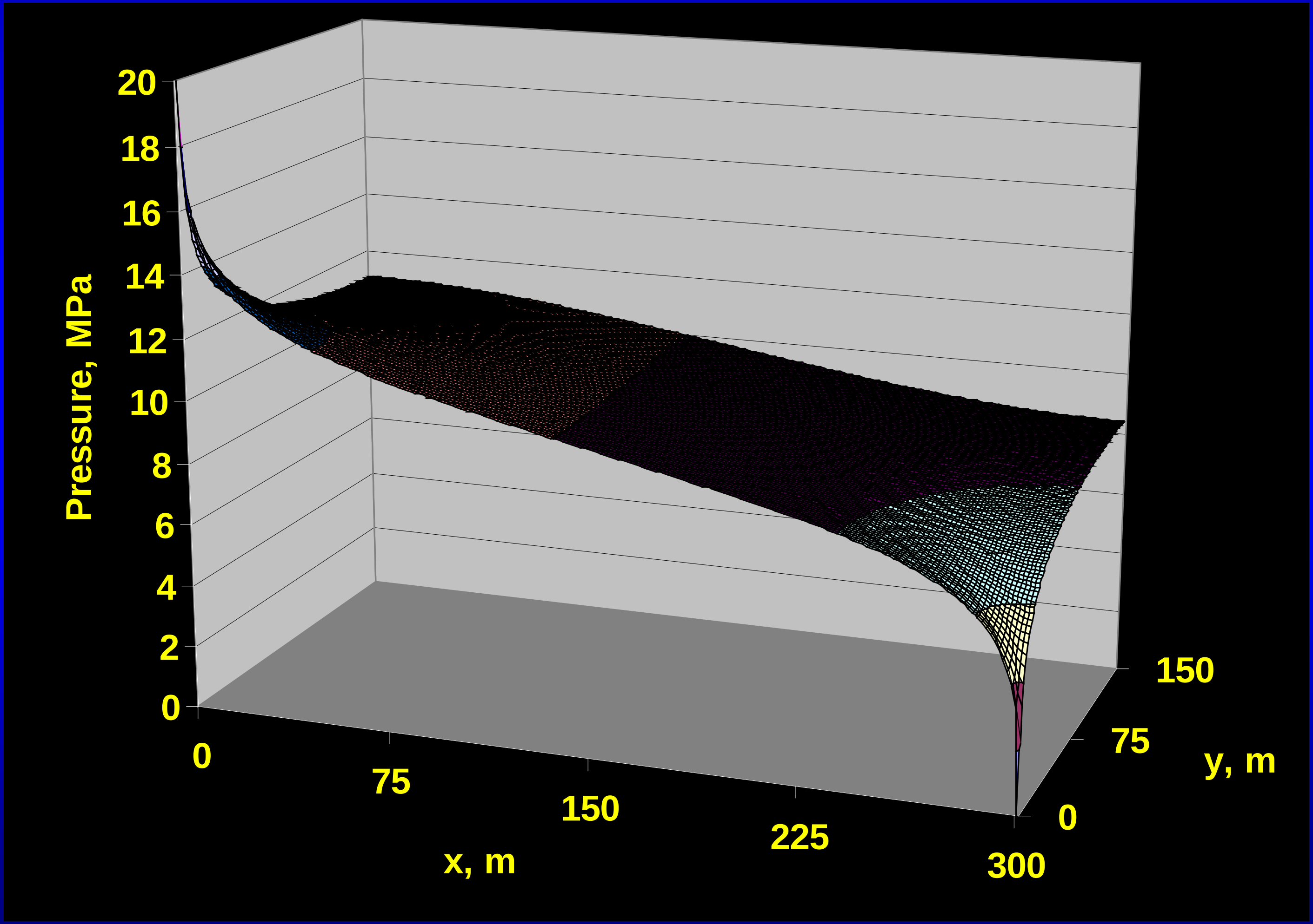
Why were the fractures apparently wider during polymer injection than during water injection?

Higher pressures during polymer injection could have flexed the fractures open wider than during water injection.

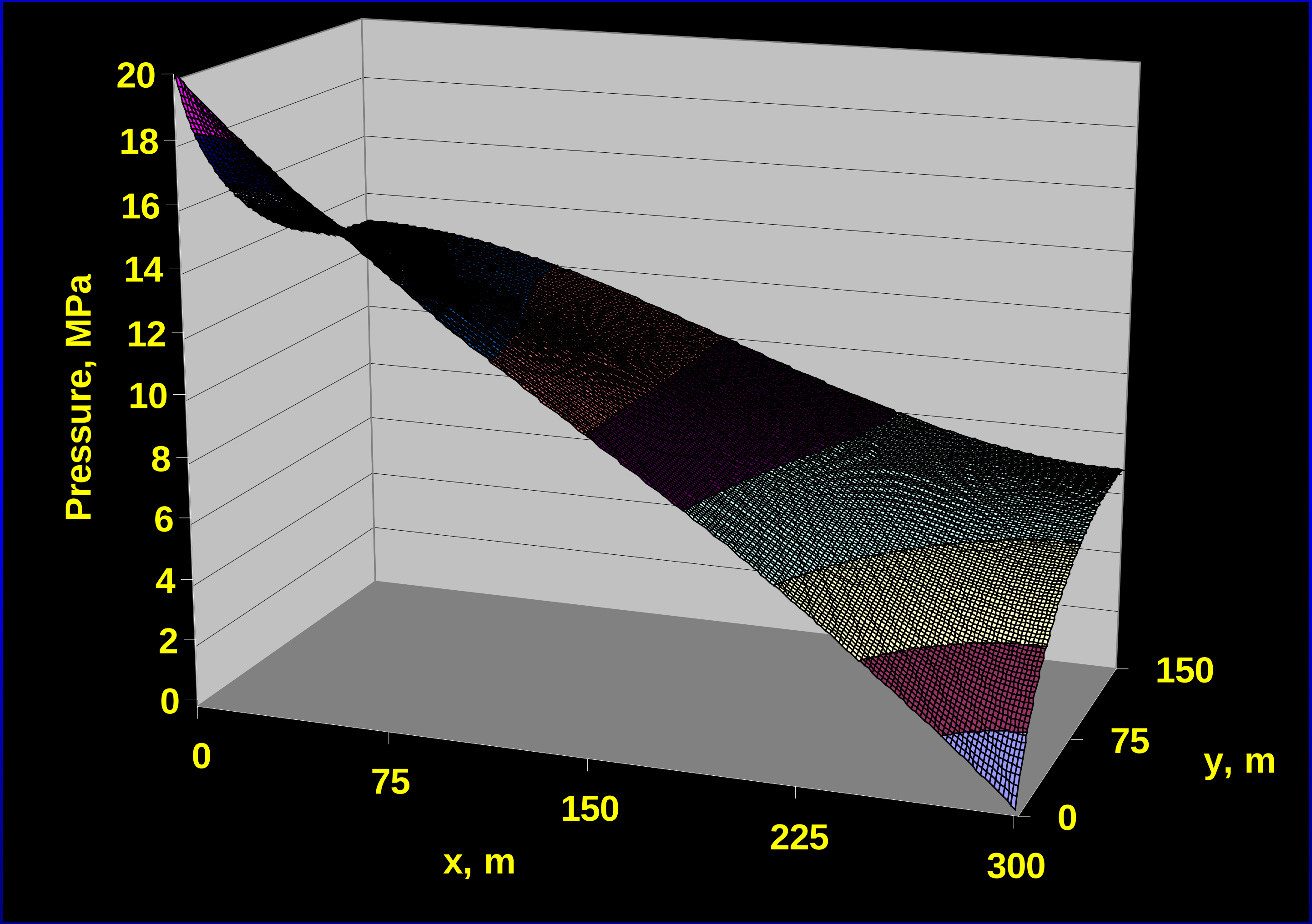
Why were fracture widths from injectivity analysis greater than from tracers?

Fractures were wider near wells than deep in the formation.

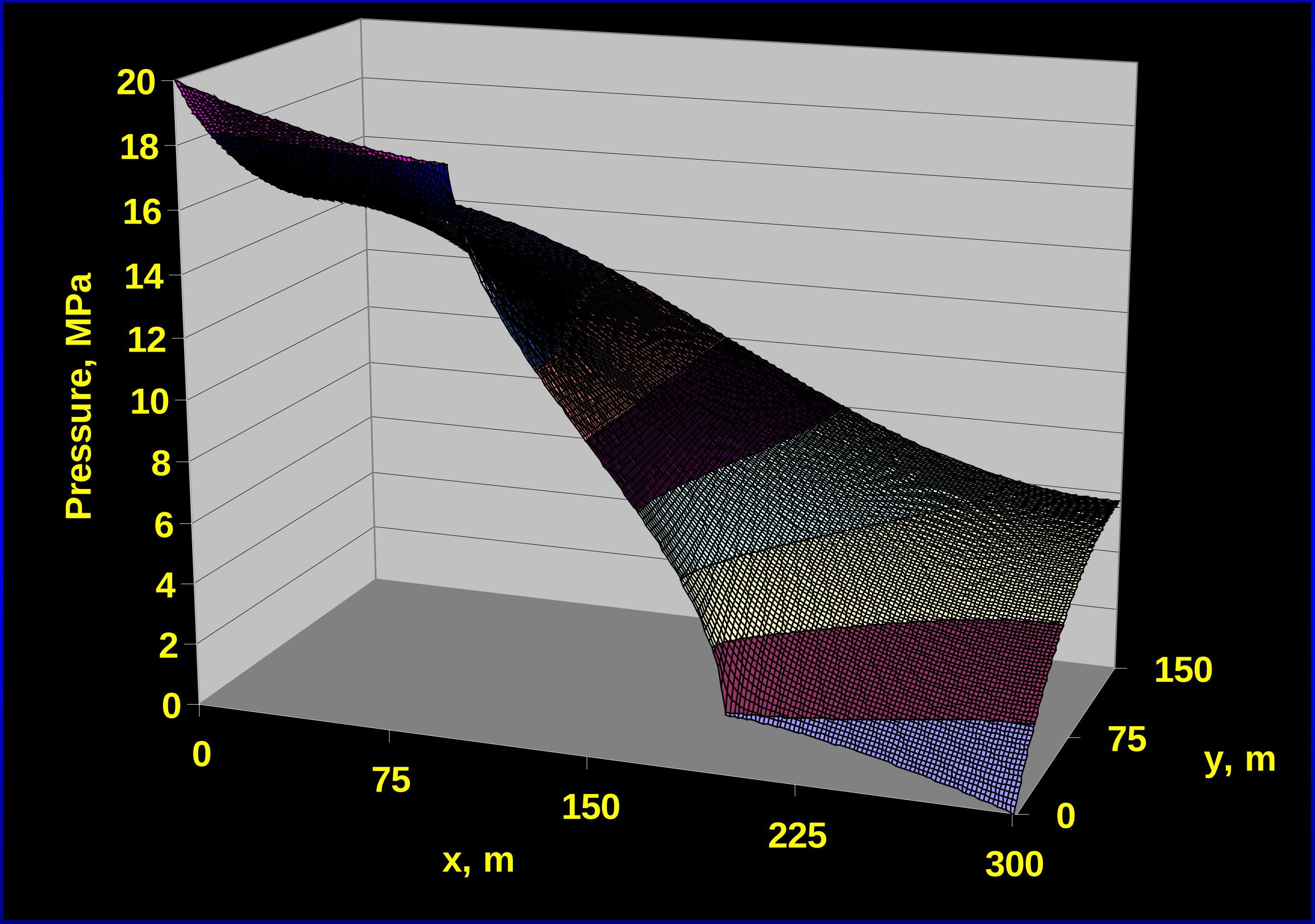
Normal Radial flow: No channeling, but low injectivity/productivity, and low pressure gradients within most of the pattern.



A 1-mm open fracture between two wells allows high injection/production rates but also allows severe channeling.



Restricting the middle third of the fracture provides the best possibility.



Moderate-length fractures can substantially increase injectivity and productivity and can improve areal sweep efficiency.

Moderate-length fractures could have considerable value for future EOR projects at Daqing if very viscous fluids must be injected to maintain mobility control.

Utilizing fractures in this way requires a good understanding of fracture formation, length, width, height, and orientation.

Why Do Some Polymer Floods Inject Much Less Polymer Than The Base-Case Calculation?

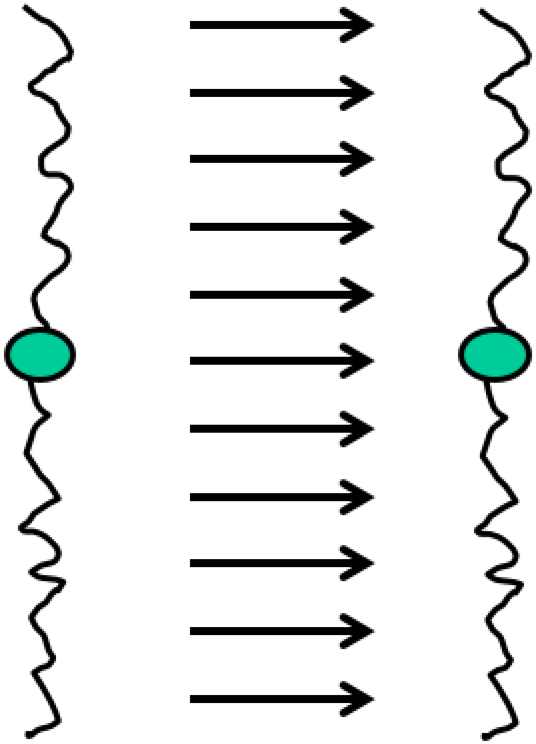
"Viscous solutions reduce injectivity too much."

Injection has occurred above the formation parting pressure for most polymer floods.

Fractures simply extend to accommodate the rate and viscosity of the fluid injected. So injectivity may not be a limitation, depending on the pressure constraint that is imposed.

What is a reasonable pressure constraint? What degree of fracture extension is too far?

Importance of Identifying Fracture Trends in the Reservoir

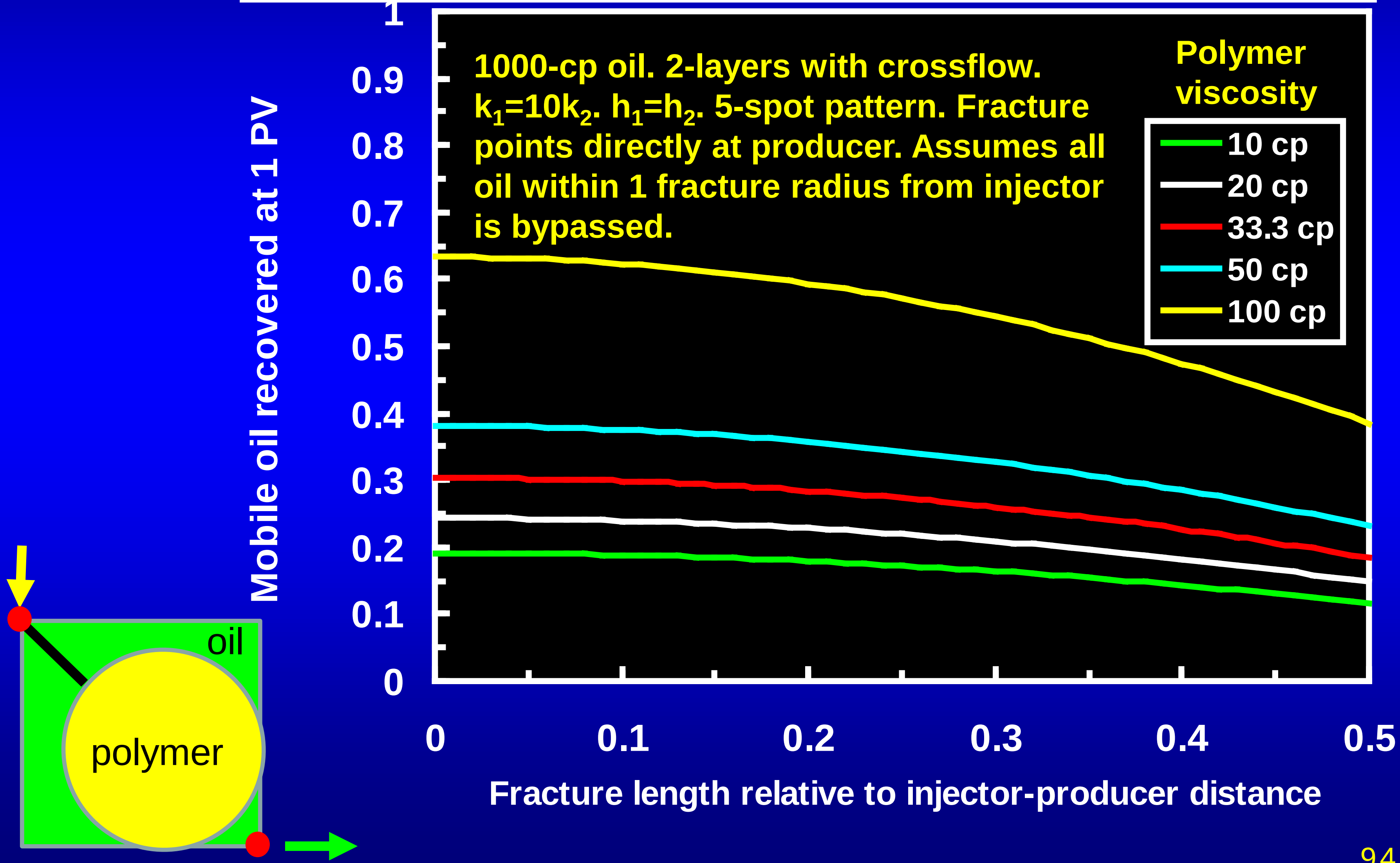


Positive effect on sweep

Negative effect on sweep

Increasing fracture length to 30% of the total interwell distance reduces sweep efficiency from 0.63 to 0.53.

Increasing polymer viscosity from 10 to 100 cp increases recovery from 0.16 to 0.54.



1000-cp oil. 2-layers with crossflow. $k_1=10k_2$. $h_1=h_2$. 5-spot pattern. Fracture points directly at producer. Assumes all oil within 1 fracture radius from injector is bypassed.

Injectivity and Fracture Extension

Tambaredjo Field (Suriname), Moe Soe Let et al. (2012): horizontal fractures extended <30 ft from the injection well (well spacing was 300 ft).

Matzen Field (Austria), Zechner et al. (2015): vertical fractures only extended 43 ft from the injection well (well spacing was 650-1000 ft).

No problems were reported with injectivity, or of fractures compromising the reservoir seals or causing severe channeling during the Daqing project (Han 2015), even injecting 150-300-cp polymer.

Will Fractures Break “Out of Zone”?

Difficult to predict.

De Pater (SPE 173359) notes, in general, that actual growth of fracture height has been less than predicted by simulations.

Ratios up to 80:1 have been noted for fracture length to fracture height in soft formations (SPE 173359).

Since injectivity is so important to the economics of a polymer flood, it is worthwhile to determine the limits of acceptable fracture extension.

Why Do Some Polymer Floods Inject Much Less Polymer Than The Base-case Calculation?

“Economics limit polymer concentrations.”

Why Do Some Polymer Floods Inject Much Less Polymer Than The Base-Case Calculation?

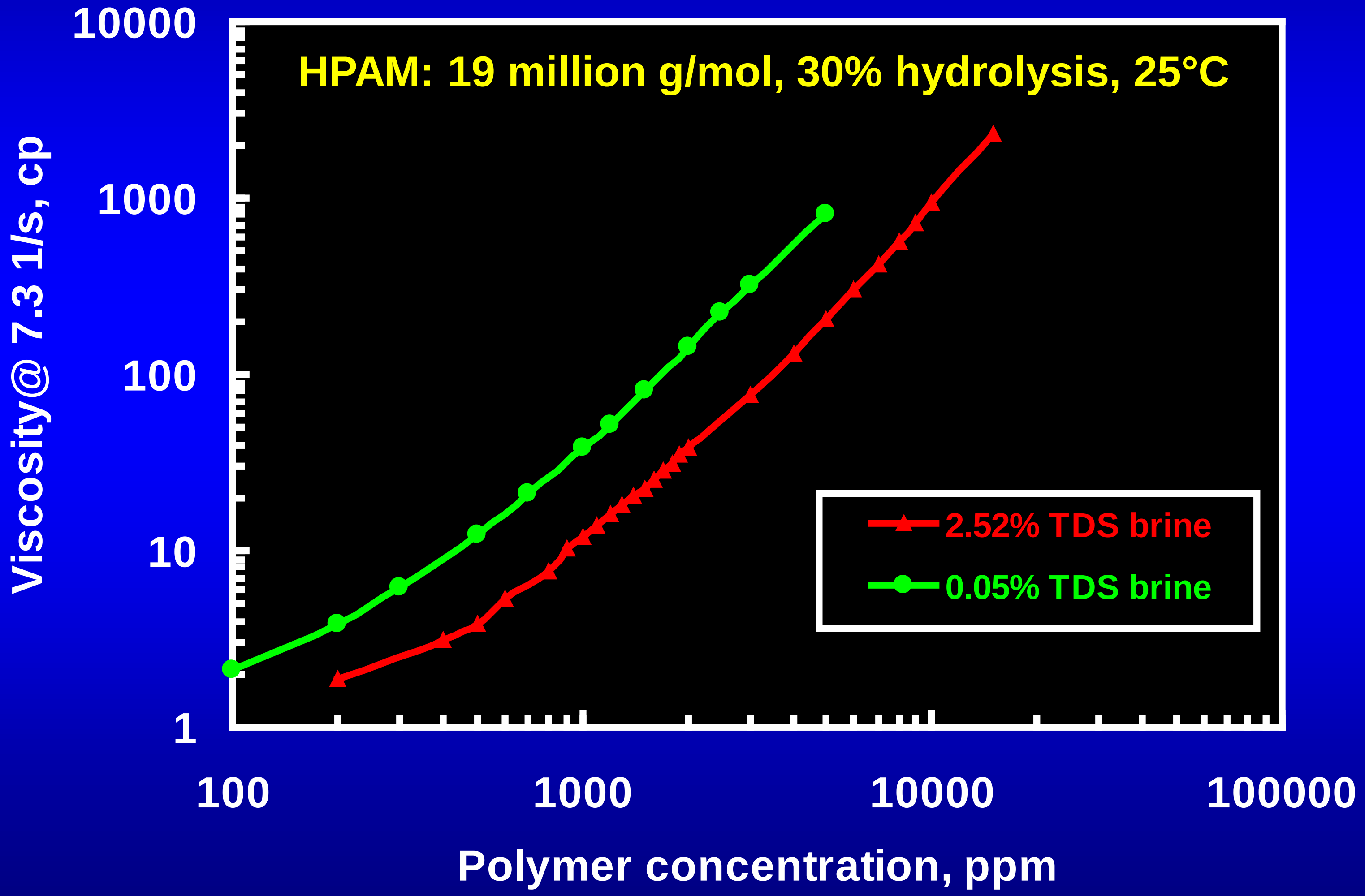
"Economics limit polymer concentrations" (to a value less than that given by the base-case calculation).

This is not true if injectivity is not restricted.

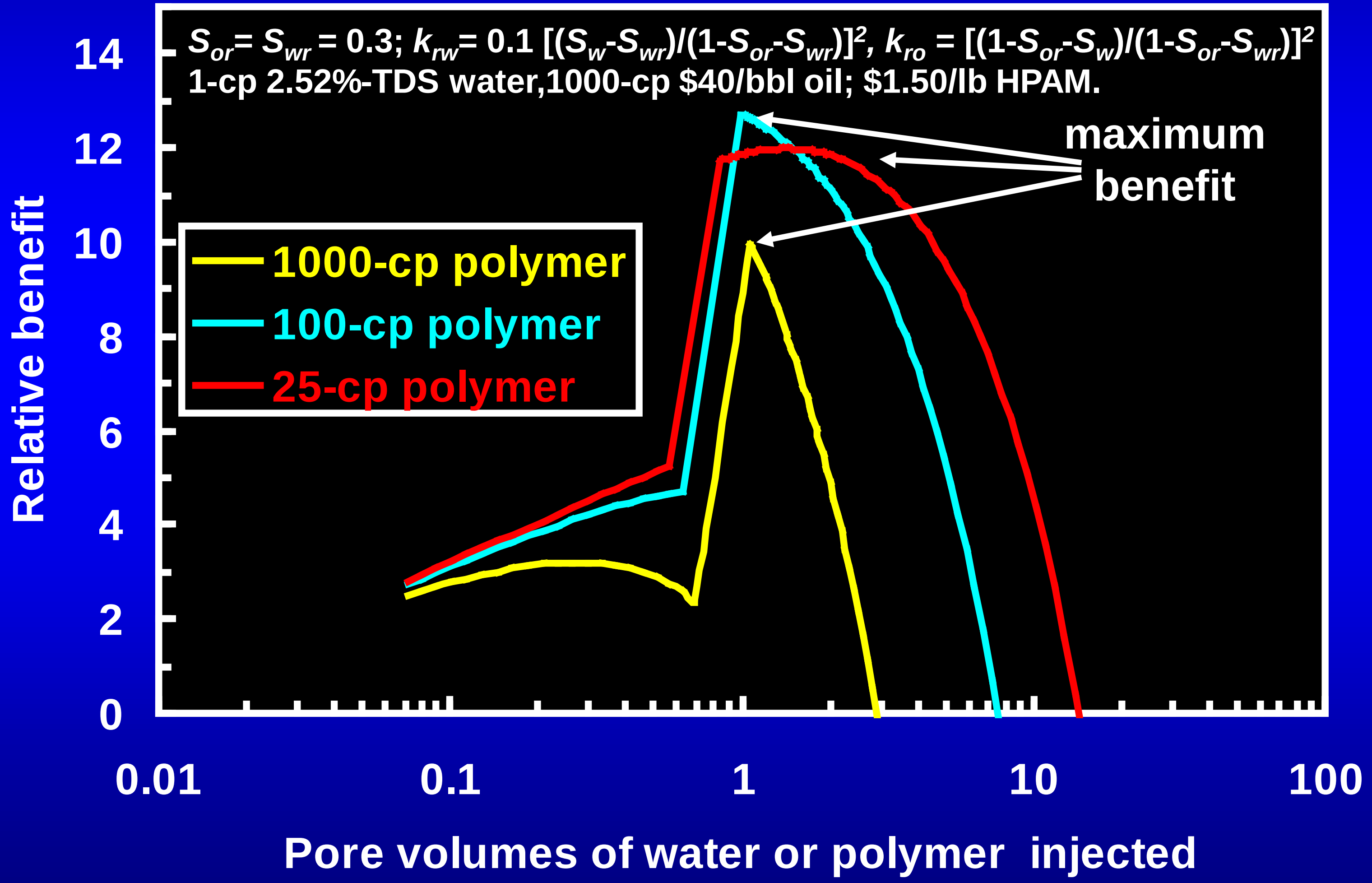
Factors favoring use of higher viscosities:

- Viscosity vs polymer concentration relation.
- Value of produced oil / cost of injected polymer.
- Capital outlay.
- Delayed polymer breakthrough.

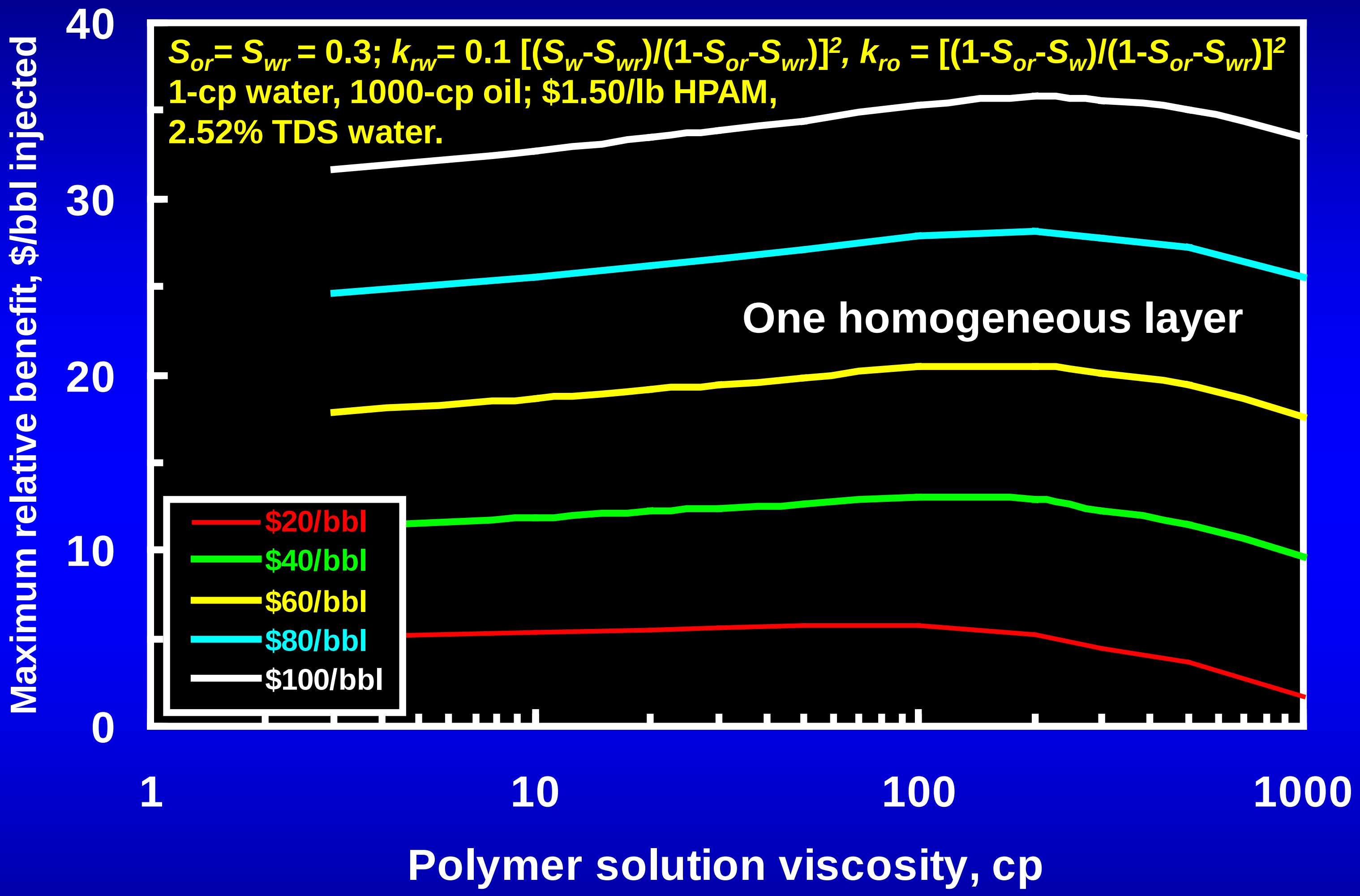
Polymers are more efficient viscosifiers at high concentrations: $\mu \sim C^2$ (i.e., only 40% more polymer is needed to double the viscosity).



At some PV, a peak is seen in the total value of the produced oil minus the cost of injected polymer (and minus other costs).

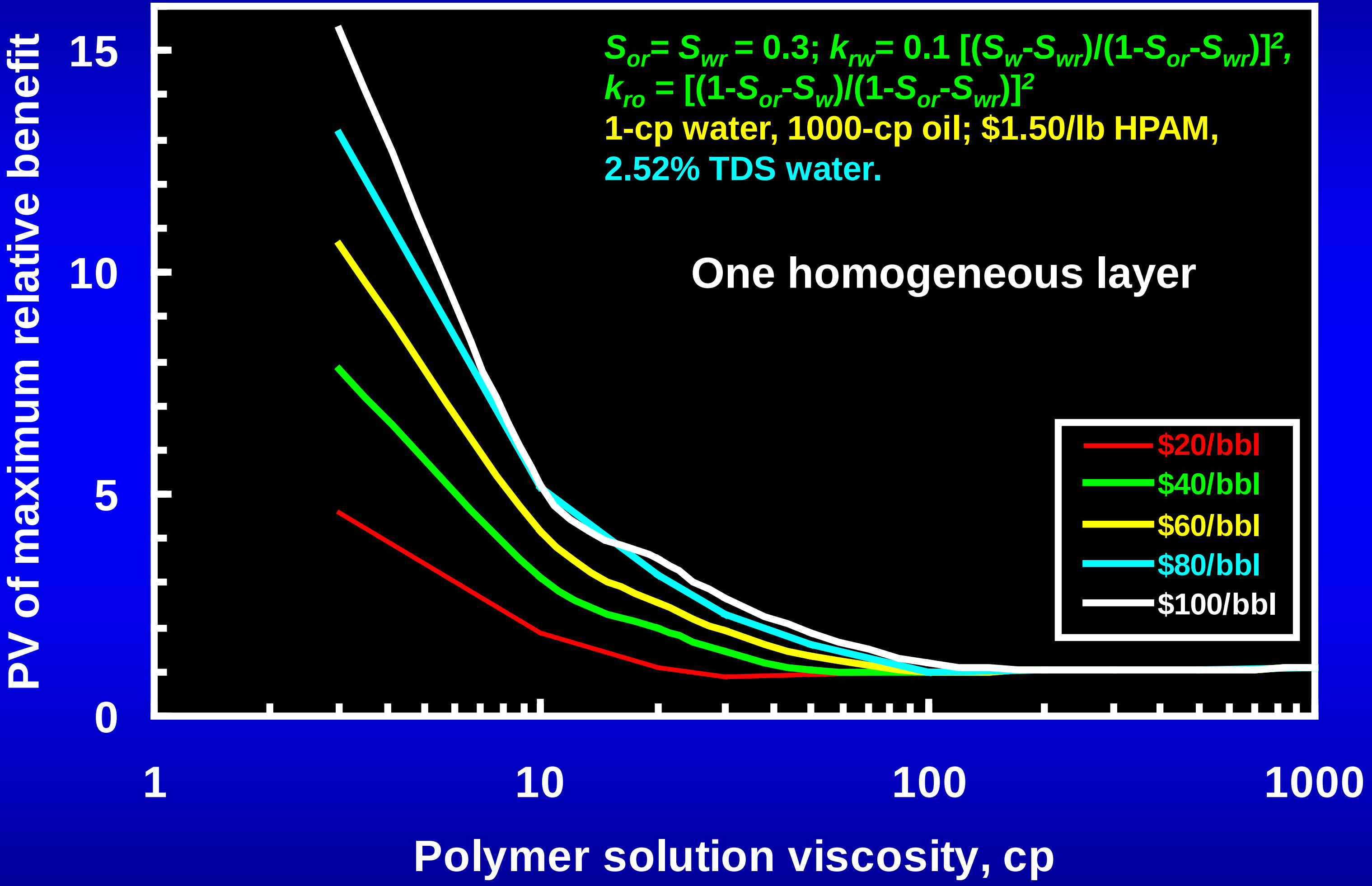


With one homogeneous layer, the maximum ratio of produced oil value to injected polymer cost is insensitive to polymer viscosity.

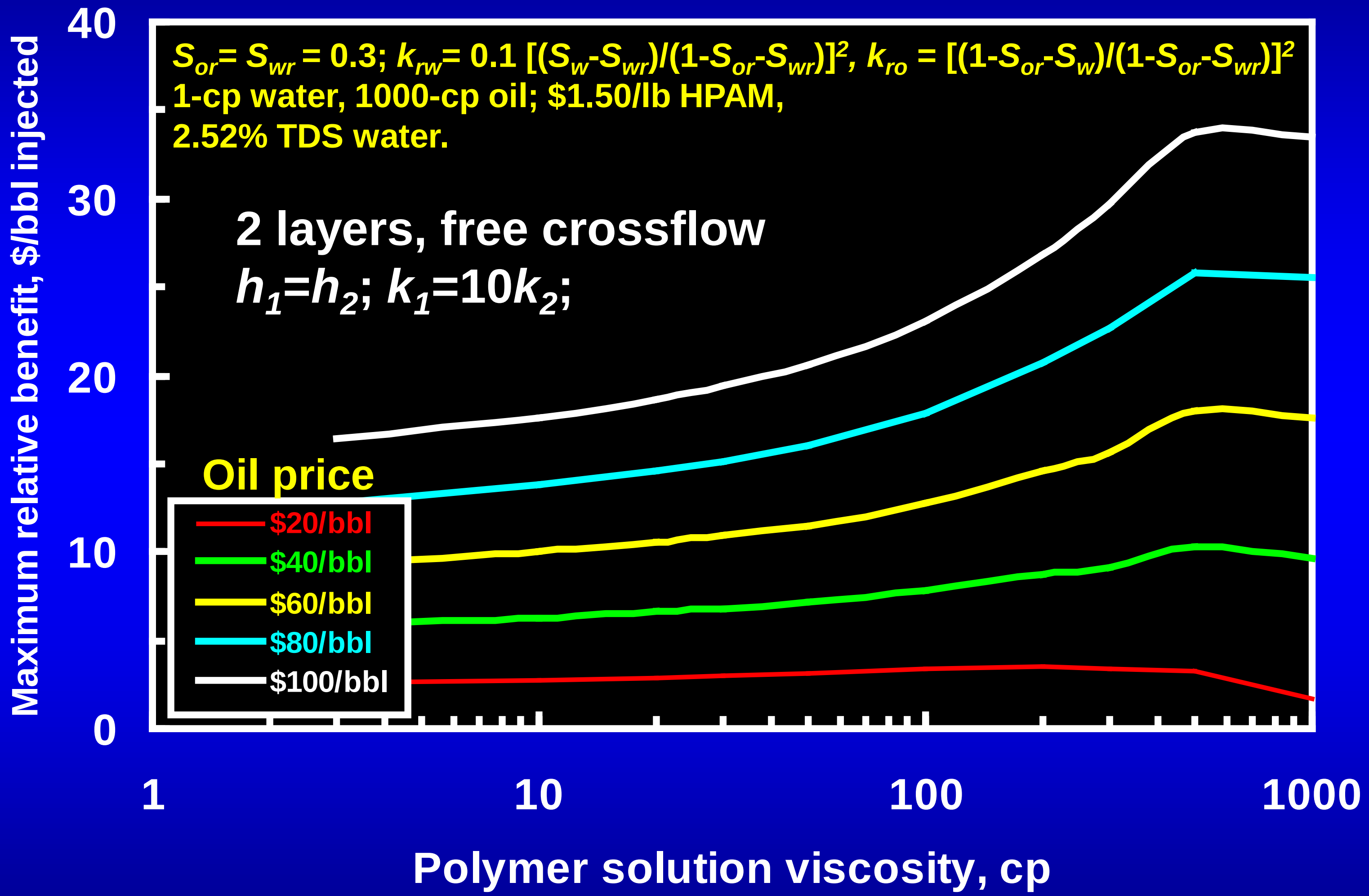


Including capital costs for polymer dissolution equipment favors using higher polymer viscosities.

However, the PV for the maximum benefit increases substantially with decreasing polymer viscosity.



Heterogeneity favors using higher polymer viscosities.

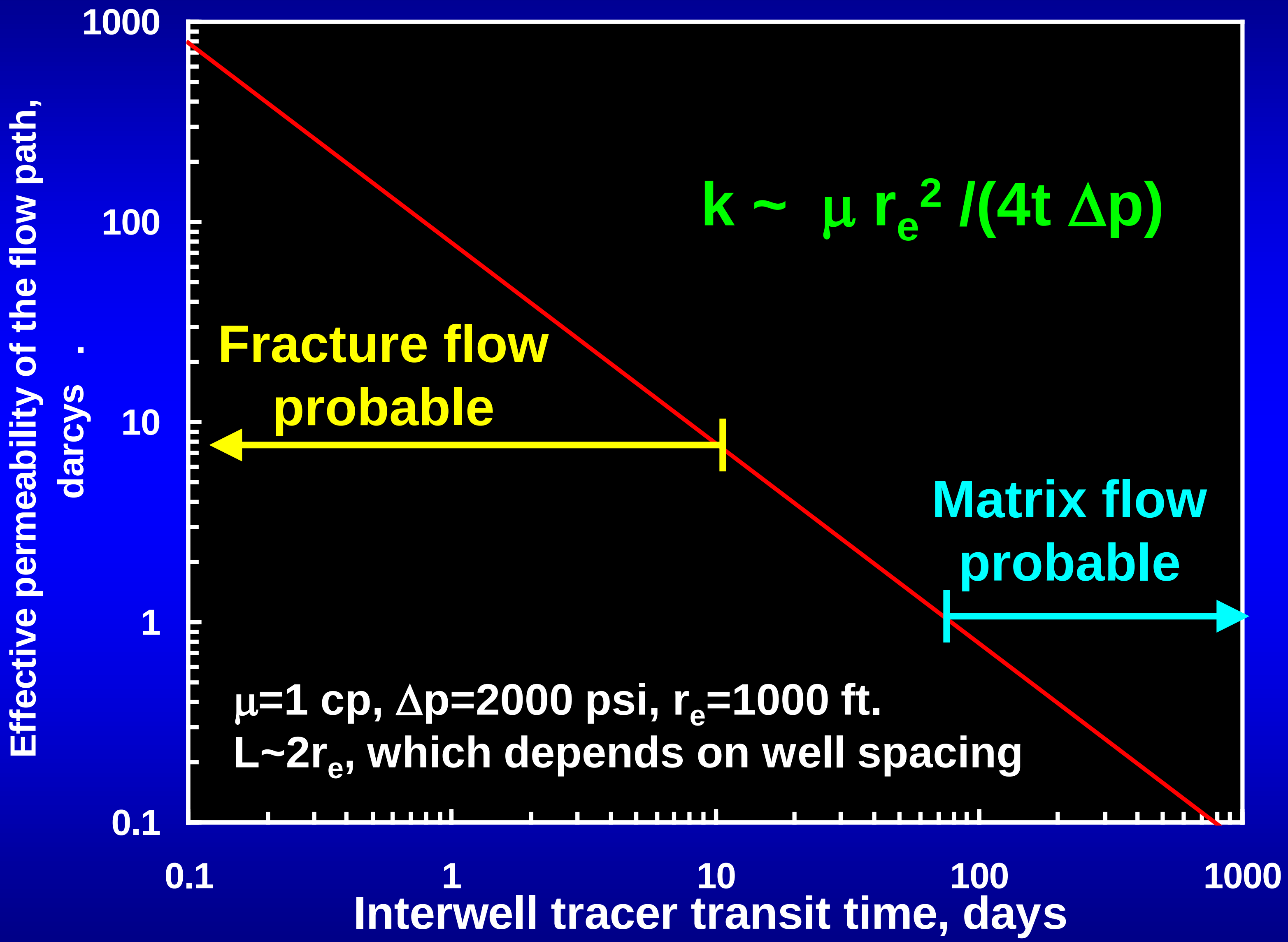


A DILEMMA FOR POLYMER FLOODING

1. Injecting above the parting pressure is often necessary for adequate injectivity.
2. If polymer breaks through early, how can you tell if it is because of a fracture or viscous fingering?
3. If breakthrough occurs from a fracture, you should decrease the injection rate and/or polymer viscosity.
4. If breakthrough occurs from viscous fingering, you should increase the polymer viscosity.

- Transit through fractures that cause severe channeling should occur fast—days or less.
- Transit through viscous fingers typically takes months.

MATRIX OR FRACTURE FLOW?



$k \sim \mu r_e^2 / (4t \Delta p)$

μ=1 cp, Δp=2000 psi, r_e=1000 ft.

L~2r_e, which depends on well spacing

Should more polymer be injected than the base-case design?

Wang Demin (Daqing, China)

- **Injected 150-300 cp HPAM solutions in thousands of wells to displace 10-cp oil.**
- **HPAM solutions reduced S_{or} from 36.8% (with waterflooding) to 21.75% (for polymer flooding) using a constant capillary number under oil-wet, weakly oil-wet, and mixed-wet conditions.**
- **The mechanism is not understood, and this effect is not always in operation, so you must check for it on a case by case basis.**

When should polymer injection be reduced or stopped?

Technical Considerations

- Assume residual resistance factor is one.
- Small polymer banks do not exclusively enter high-permeability zones and divert subsequently injected water into low-permeability zones.
- Water injected after polymer fingers almost exclusively through the high-permeability path.

When should polymer injection be reduced or stopped?

Economic Considerations

- **Depends on oil price, polymer cost, well-spacing, and many individual factors specific to the field. So a “one-size-fits-all” formula is not available (PETSOC-09-02-55, SPE 109682, SPE 114342, SPE 179603).**

- **Daqing has the most experience and reports with this question. Others are just facing it now.**

- **A major flaw with many simulations has been incorrect handling of polymer injectivity (artificially restricting injectivity in the simulator by assuming no fractures are open).**

Should You Grade the Polymer Bank?

Claridge (SPE 6848, 14230) developed a method for decreasing polymer viscosity near the end of a flood—most appropriate for homogeneous reservoirs.

Cyr (1988) argued that grading won't work in heterogeneous reservoirs.

After 1 PV of polymer, Daqing saw water breakthrough indication at ~0.02 PV of water (but 0.23 PV to stability).

Our experiments with k_1/k_2=11.2:1—during water injection after polymer, water breakthrough in the high-k layer occur after advancing the front by 70% with 8 cp polymer, 40% for 23-cp polymer, and 25% for 75-cp polymer.

Strategies When Oil Prices Fall

- Maintain injection viscosity and rate?
- Switch to water injection immediately?
- Grade the polymer bank?
- Slow the injection rate?
- Stop injection and rely on compaction drive?
- Other?

Bottom Line

1. Base-case method: $F_r = M * k_1/k_2$. (You must be realistic about your choices of mobility ratio and perm contrast.)
2. Injection above the formation parting pressure and fracture extension are crucial to achieving acceptable injectivity—especially for vertical injectors—increasing injectivity, sweep efficiency, and reducing mechanical degradation. The key is to understand the degree of fracture extension so that fractures do not extend out of zone or cause severe channeling.
3. Many field cases exist (Daqing, Suriname, Canadian floods) with no evidence that fractures caused severe polymer channeling or breaching the reservoir seals, in spite of injection significantly above the formation parting pressure.
4. Experience and technical considerations favor using the largest practical polymer bank. Channeling can be severe when water injection occurs after polymer injection.
5. Although graded banks are commonly used or planned in field applications, more work is needed to demonstrate their utility and to identify the most appropriate design procedure.

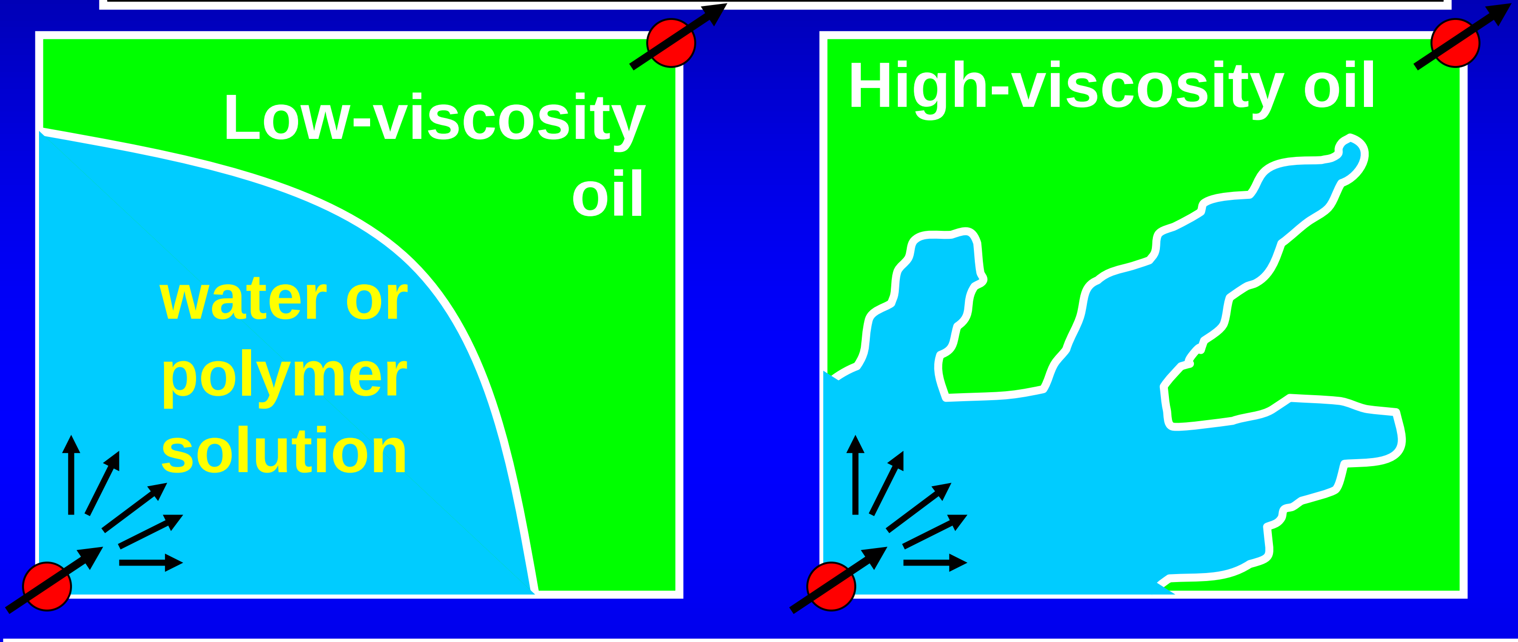
SPE 129200

Polymer Rheology in Porous Media

Rheology: Bottom Line

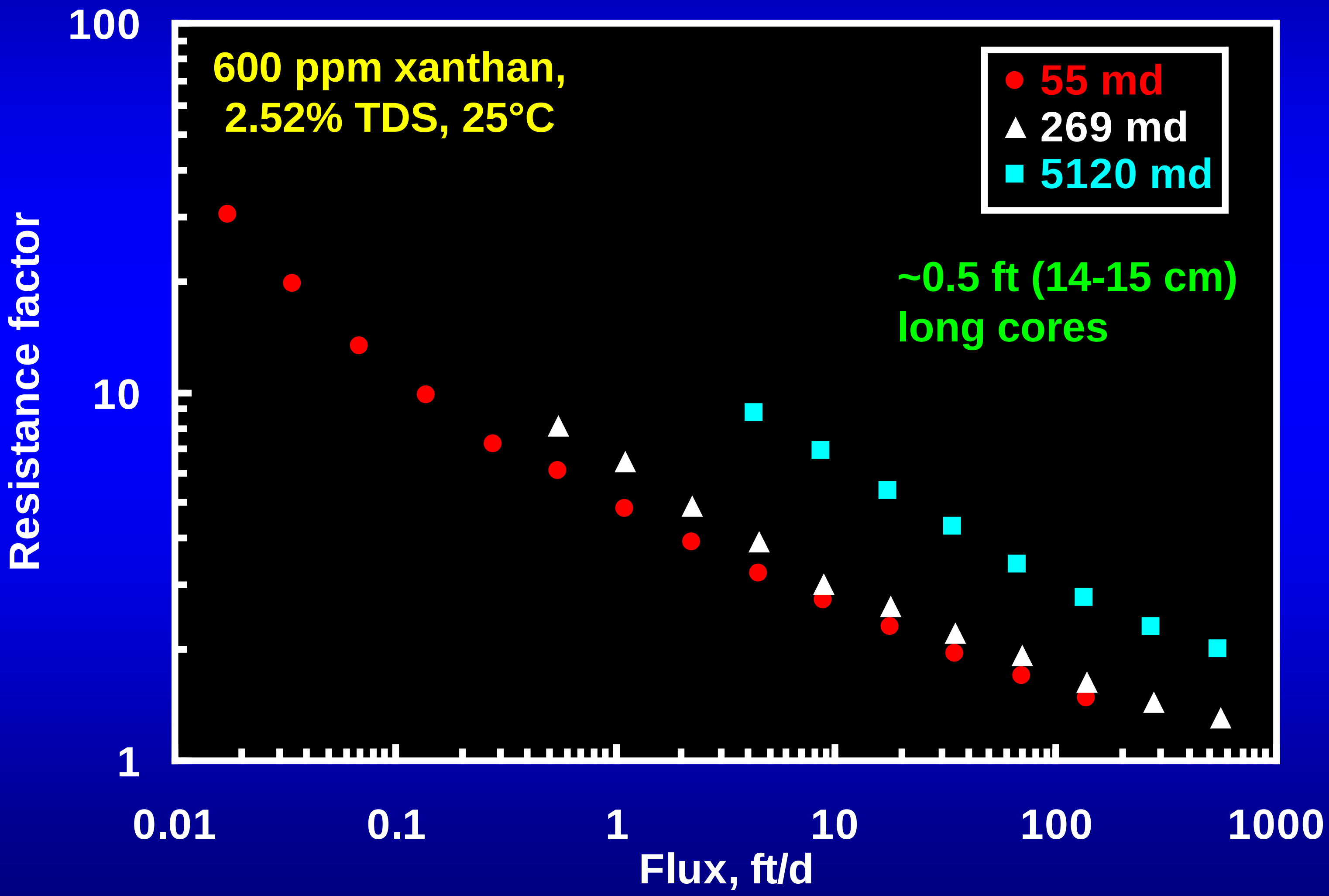
1. The low-shear-rate viscosity is the best indicator of resistance factor deep in a formation, if you don't have good data from corefloods.
2. If your corefloods indicate low-flux resistance factors that are much higher than low-shear-rate viscosities, be suspicious—do more tests.
3. Unless your water is VERY fresh or polymer concentration is high, HPAM shows near-Newtonian or slight shear-thinning behavior at low flux and shear-thickening at higher flux: This increases the probability that the polymer must be injected above the fracture pressure.
4. Under realistic reservoir conditions, shear-thinning behavior (e.g., xanthan use) is not bad for sweep efficiency.
5. If you want to use non-Newtonian behavior in your simulator, compare your results with Newtonian behavior to see if the results make sense.

When Displacing Viscous Oils, Viscous Polymer Solutions May Be Needed to Improve Sweep Efficiency

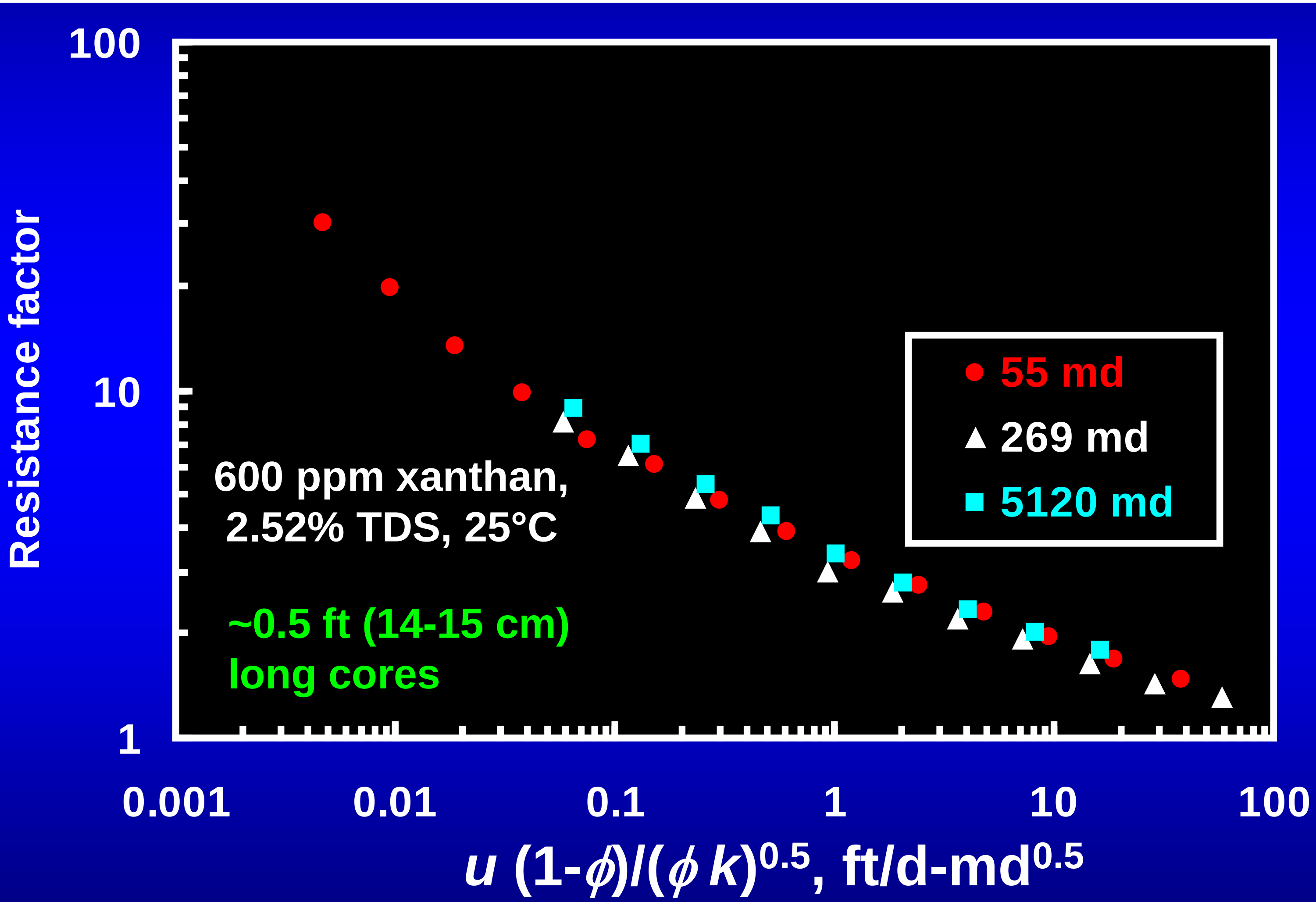


Resistance factors (effective viscosities in porous media) at low velocities determine the sweep efficiency during polymer or chemical floods.

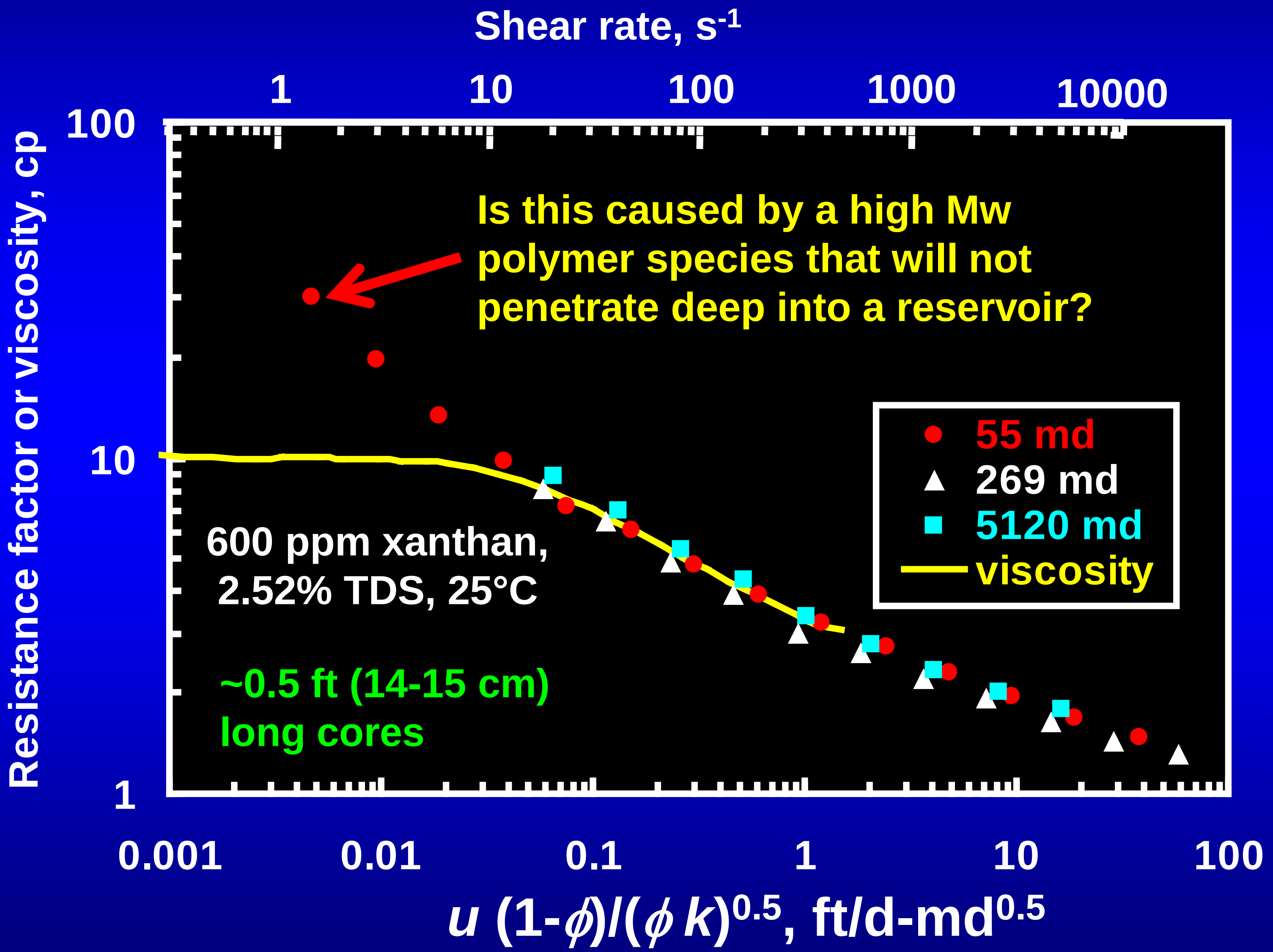
Xanthan shows shear thinning in porous media.



Xanthan solutions show shear-thinning behavior in porous media and resistance factors correlate well using the capillary bundle parameter, $u\ (1-\phi)/(\varphi k)^{0.5}$.



At low velocities in short cores with low permeability (e.g., 55 md), fresh xanthan solutions show shear thinning, whereas viscosity data predicts Newtonian behavior.

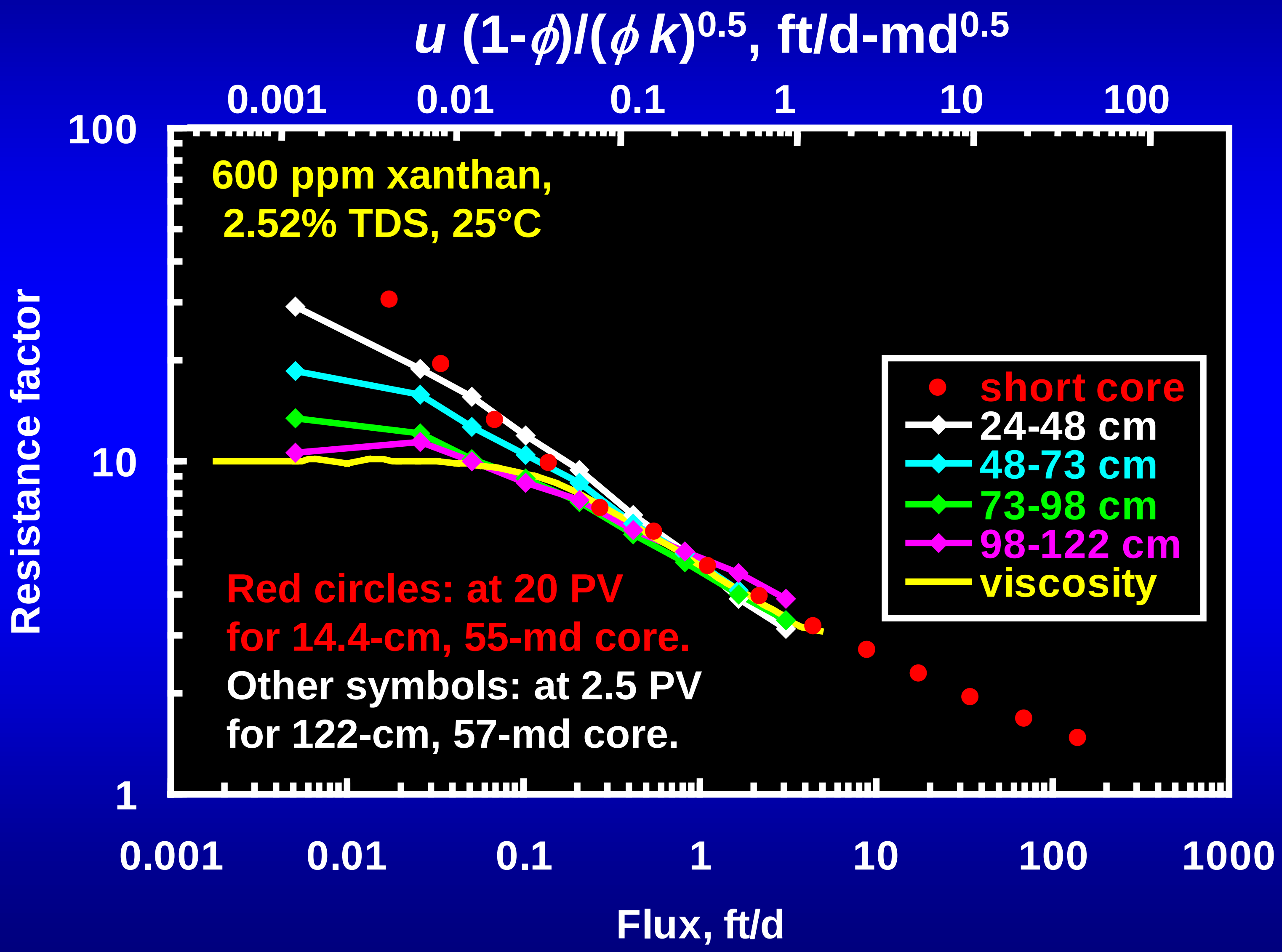


Is this caused by a high Mw polymer species that will not penetrate deep into a reservoir?

600 ppm xanthan, 2.52% TDS, 25°C

~0.5 ft (14-15 cm) long cores

If the polymer first flows through a few feet of rock, resistance-factor-versus-flux data closely follows expectations from viscosity-versus-shear-rate data.



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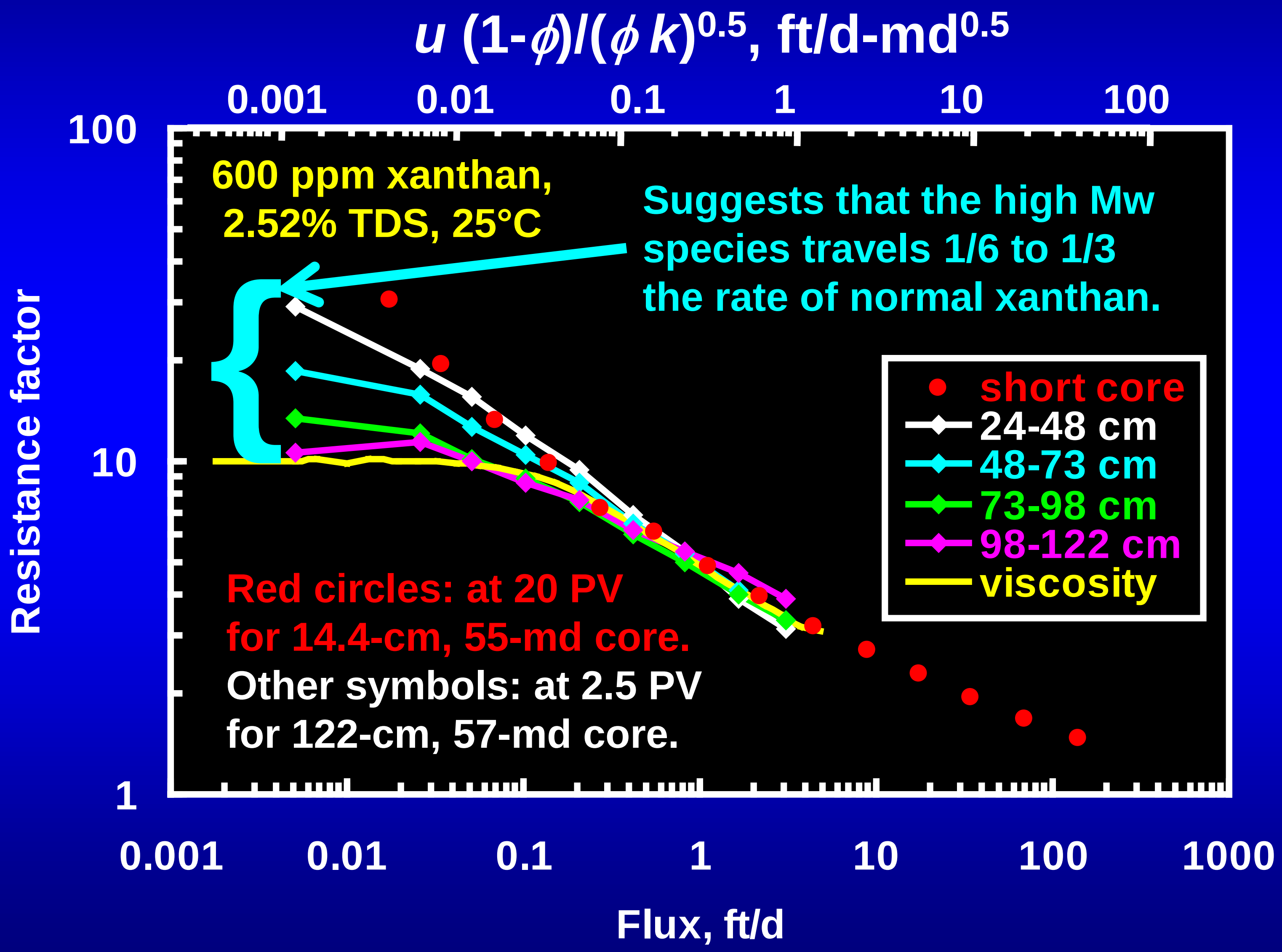


1960's Dow HPAM Claim

HPAM can reduce water mobility both by increasing water viscosity and by reducing permeability:

$$\lambda = k / \mu$$

Resistance factor (F_r or *RF*)

$$F_r = (k / \mu)_{brine} / (k / \mu)_{polymer}$$

This effect is typically seen in short laboratory cores using fresh, gently-handled solutions.

Can permeability reduction really be exploited in a useful way in a real polymer flood?

Pye, *JPT*, August, 1964

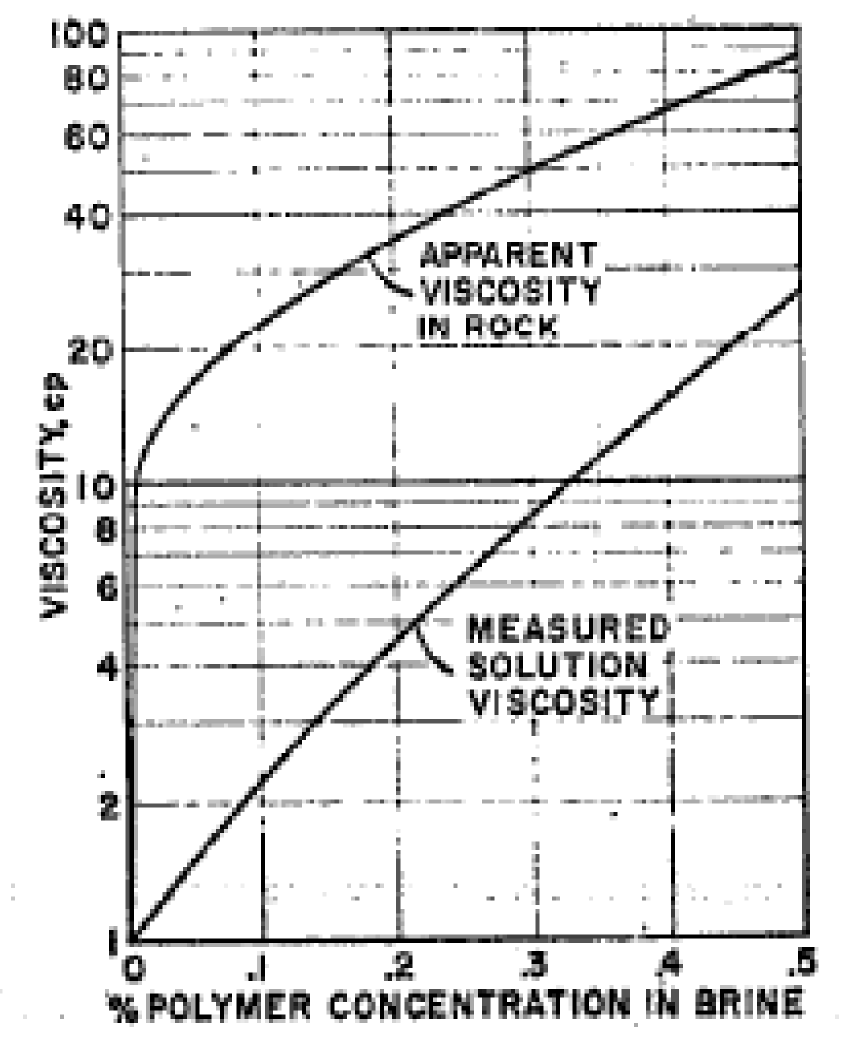
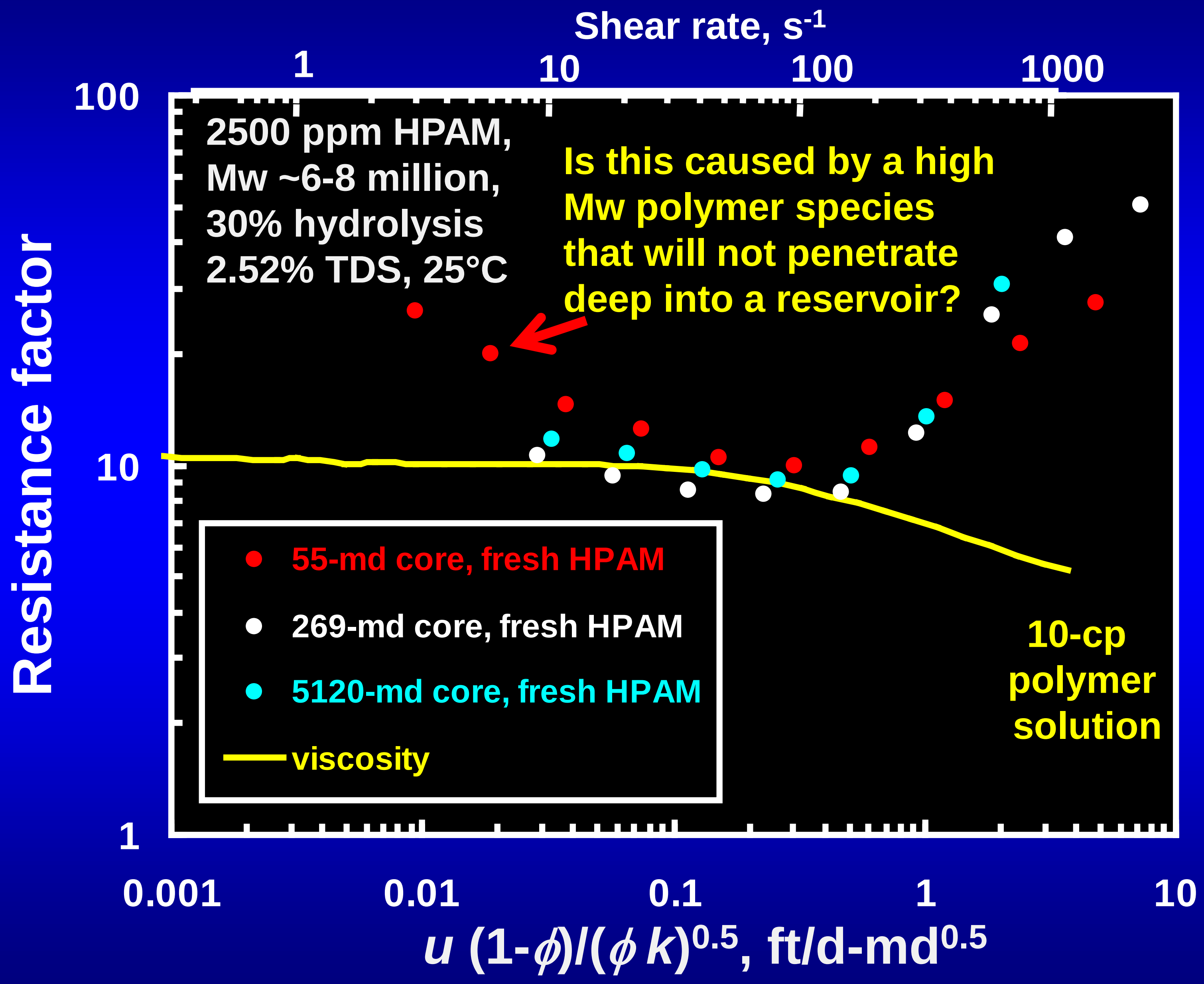
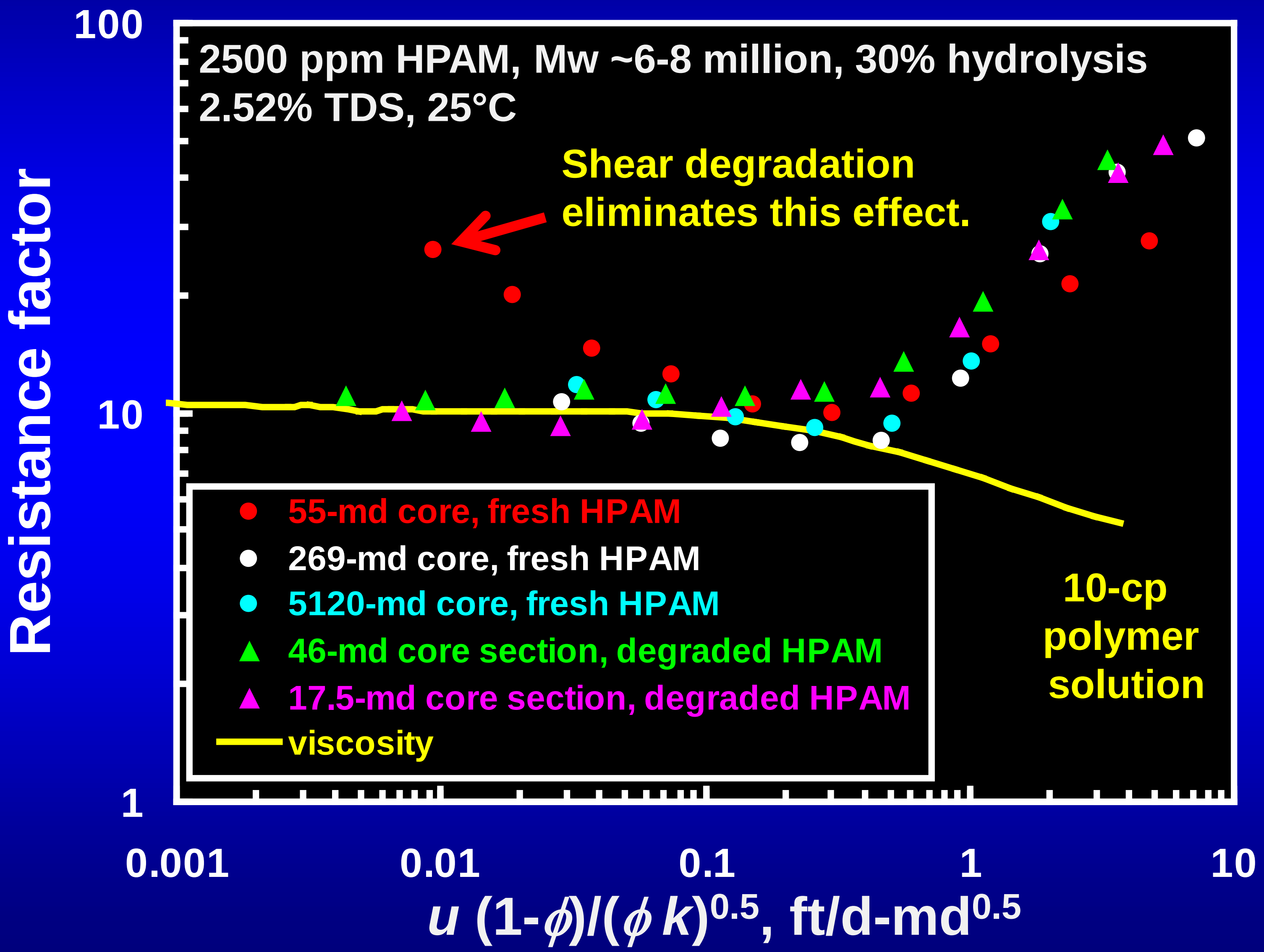


FIG. 1—POLYMER RESISTANCE EFFECT IN 250-MD BEREA SANDSTONE

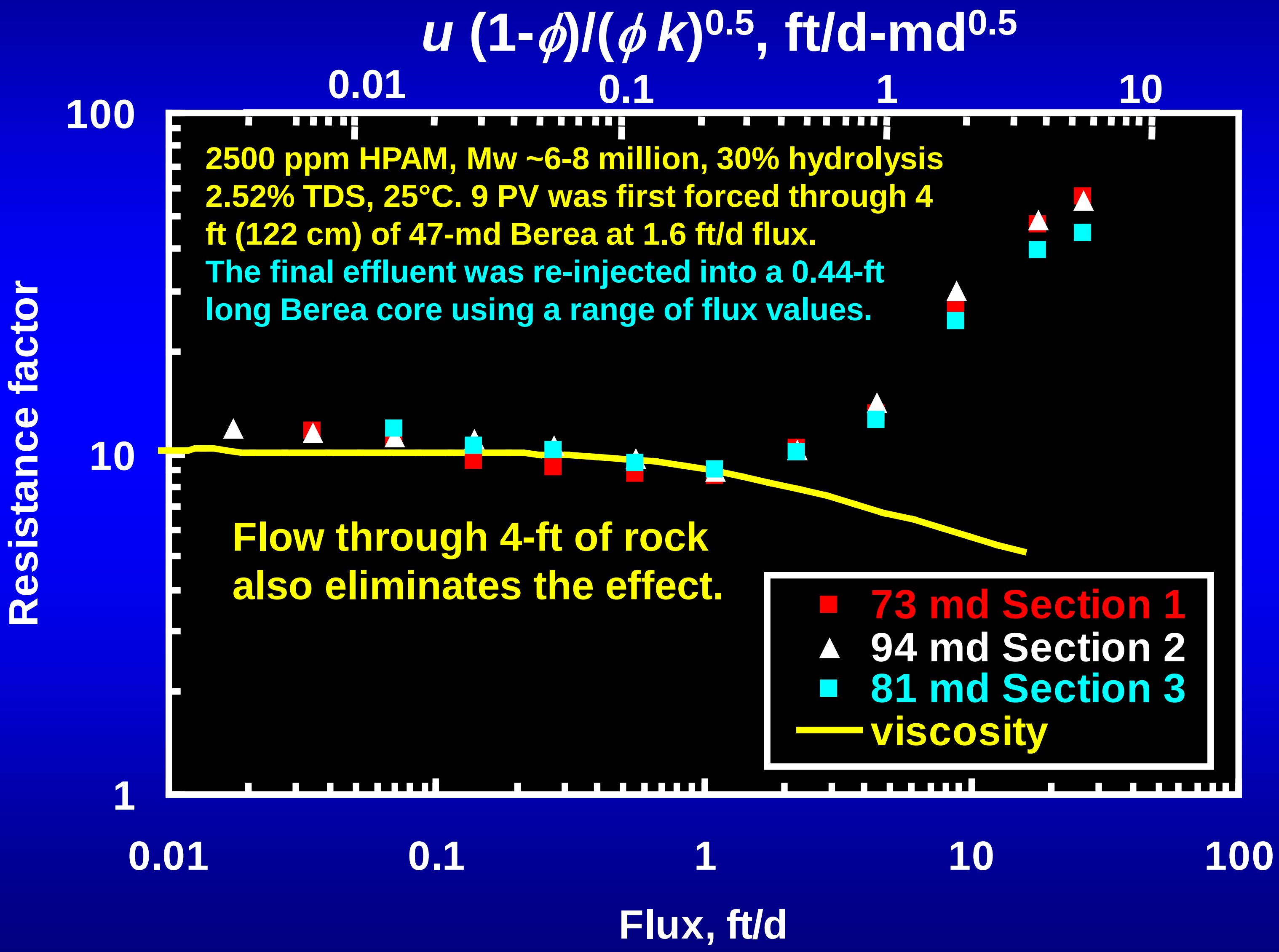
HPAM Behavior in Porous Media



Shear thinning can be seen for fresh HPAM solutions at low flux, especially in low-*k* cores. However, exposure to high flux or pressure gradient can reduce or eliminate this effect.



Shear thinning can be seen for fresh HPAM solutions at low flux, especially in low-*k* cores. However, flow through a few feet of porous media can reduce or eliminate this effect.

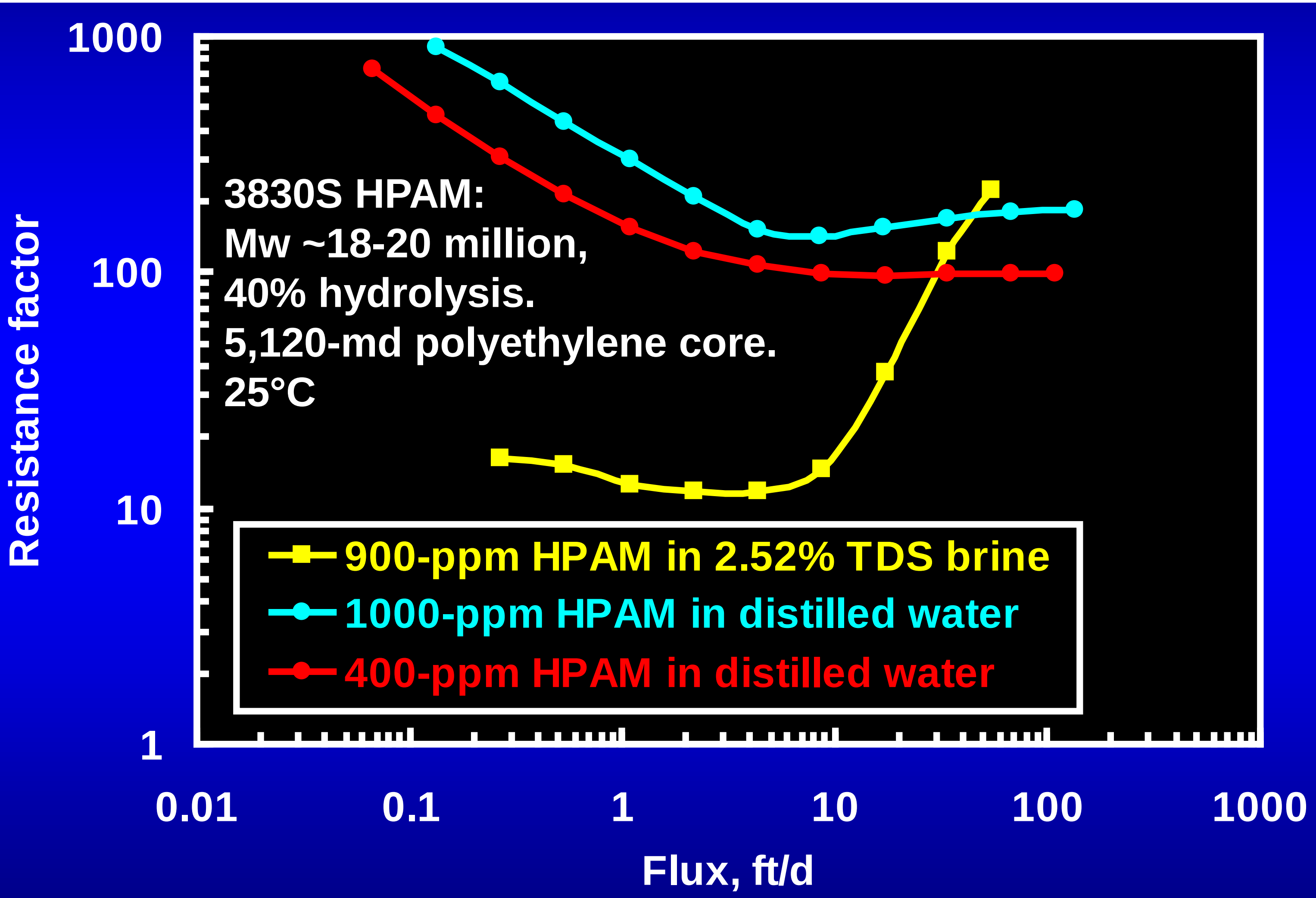


2500 ppm HPAM, Mw ~6-8 million, 30% hydrolysis 2.52% TDS, 25°C. 9 PV was first forced through 4 ft (122 cm) of 47-md Berea at 1.6 ft/d flux.

The final effluent was re-injected into a 0.44-ft long Berea core using a range of flux values.

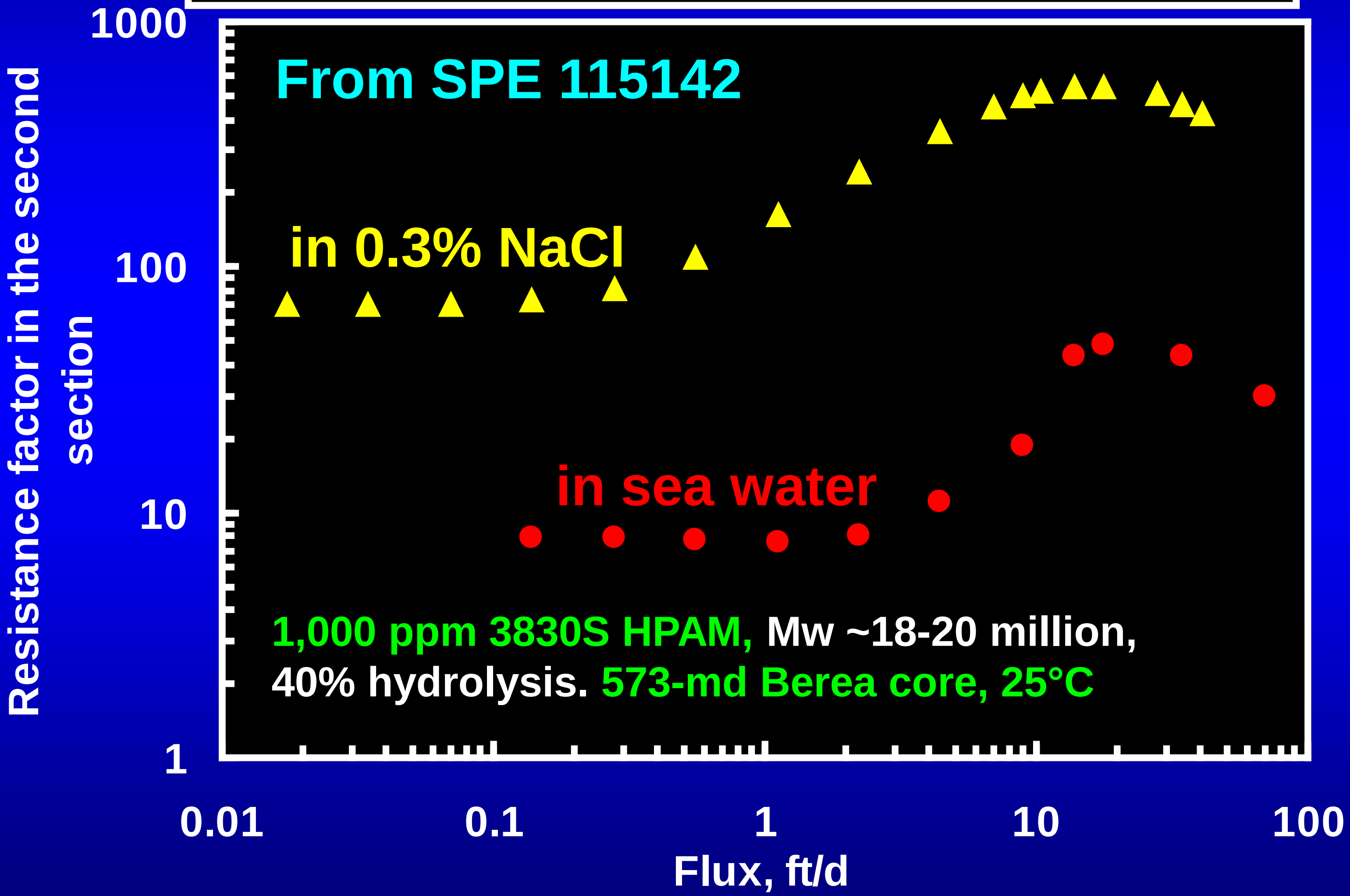
Flow through 4-ft of rock also eliminates the effect.

For HPAM solutions with a sufficiently low salinity and/or sufficiently high polymer concentration, shear thinning can be observed in porous media at moderate to low fluxes.

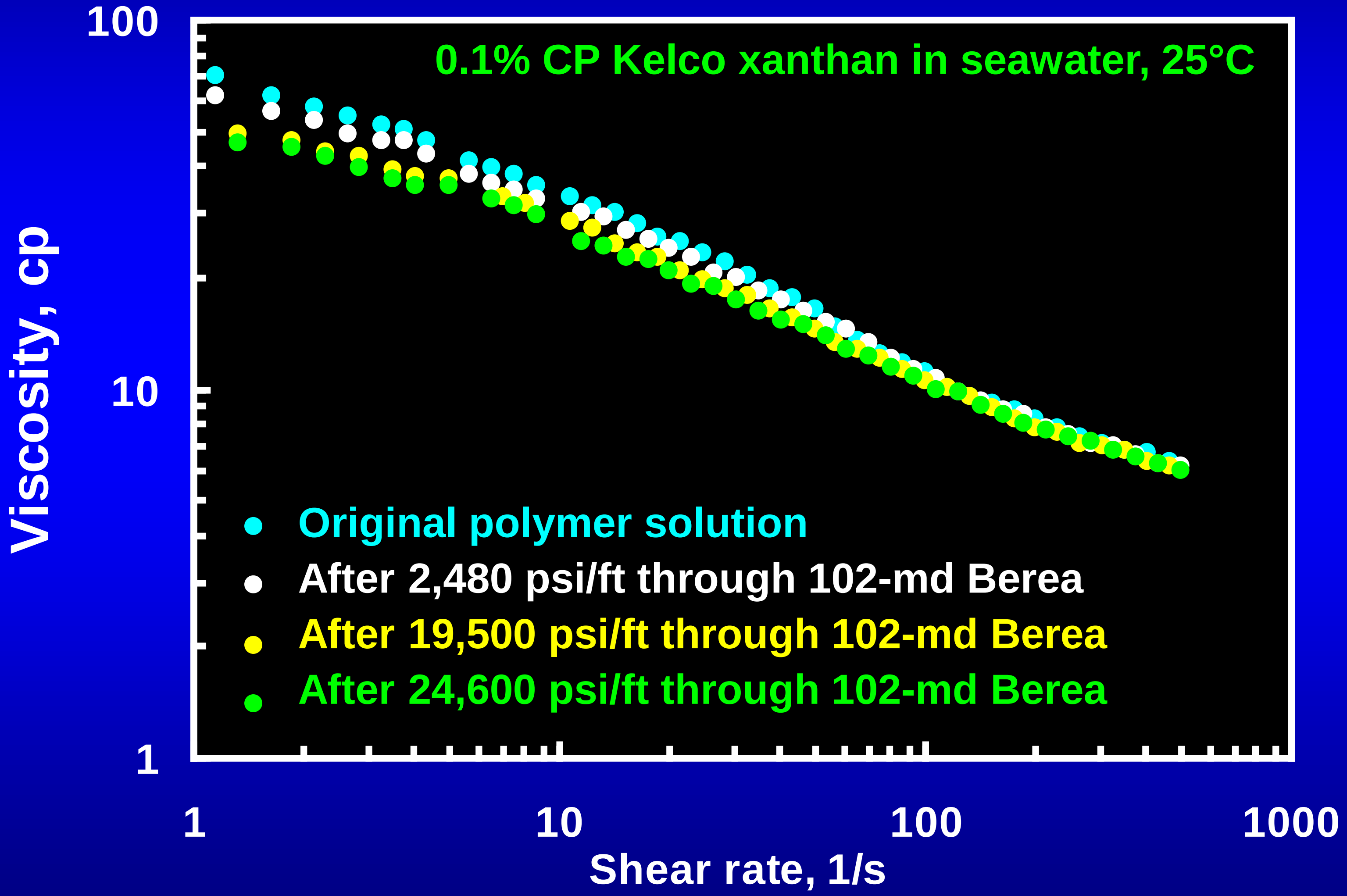


HPAM Rheology in Porous Rock:

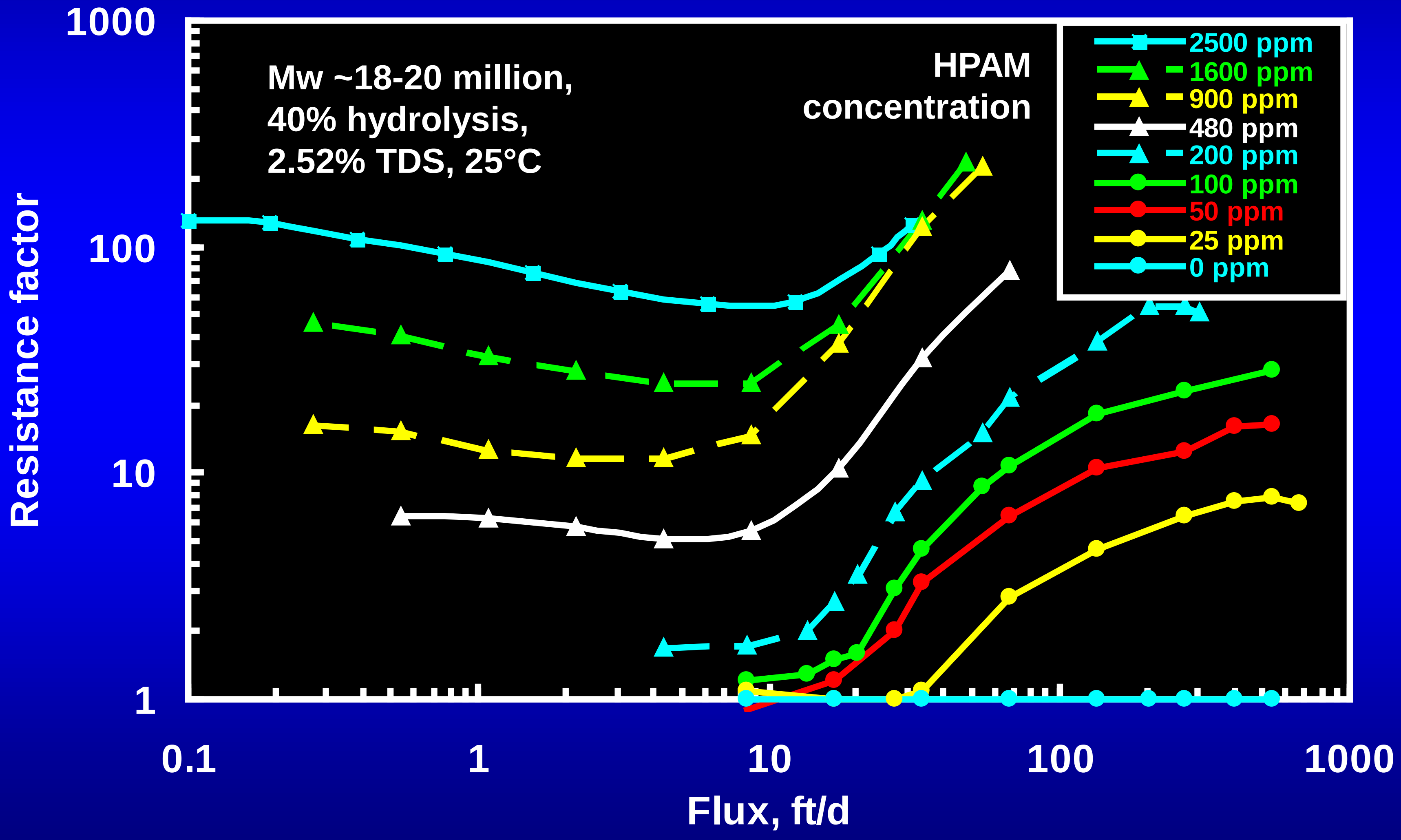
1) Newtonian at low flux,
2) shear thickening at intermediate flux,
3) mechanical degradation at high flux.



- Xanthan is remarkably resistant to mechanical (shear) degradation.



Effect of Polymer Concentration on 3830S HPAM in a 5120 md Core



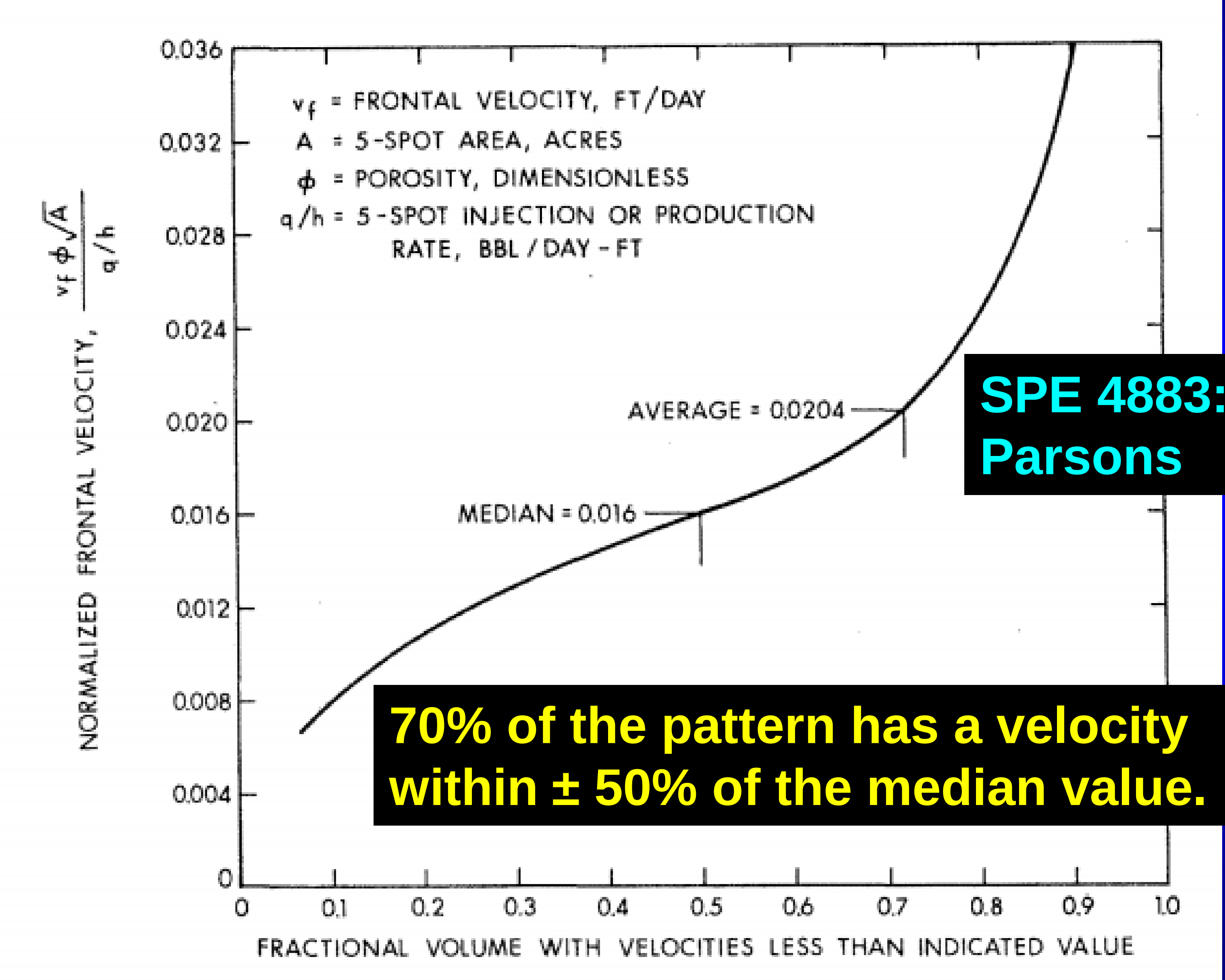
Why does HPAM show “shear thickening” in porous media?

Conventional views: Caused by elongational flow and/or dis-entanglement of polymer molecules as they are forced into pore throats.

New view: Caused by “elastic turbulence” (SPE 174654).

Almost always a “near-wellbore” phenomena (so it affects injectivity, but not so much oil displacement).

Velocities in a Five-Spot Pattern (1-layer)



SPE 4883: Parsons

70% of the pattern has a velocity within ± 50% of the median value.

Rheology in Porous Media

Until recently, most commercial chemical flood simulators assumed shear thinning behavior for polymers at moderate to high velocities in porous media.

The assumption is ok for xanthan biopolymers, but is wrong for HPAM (polyacrylamides)—the main EOR polymer.

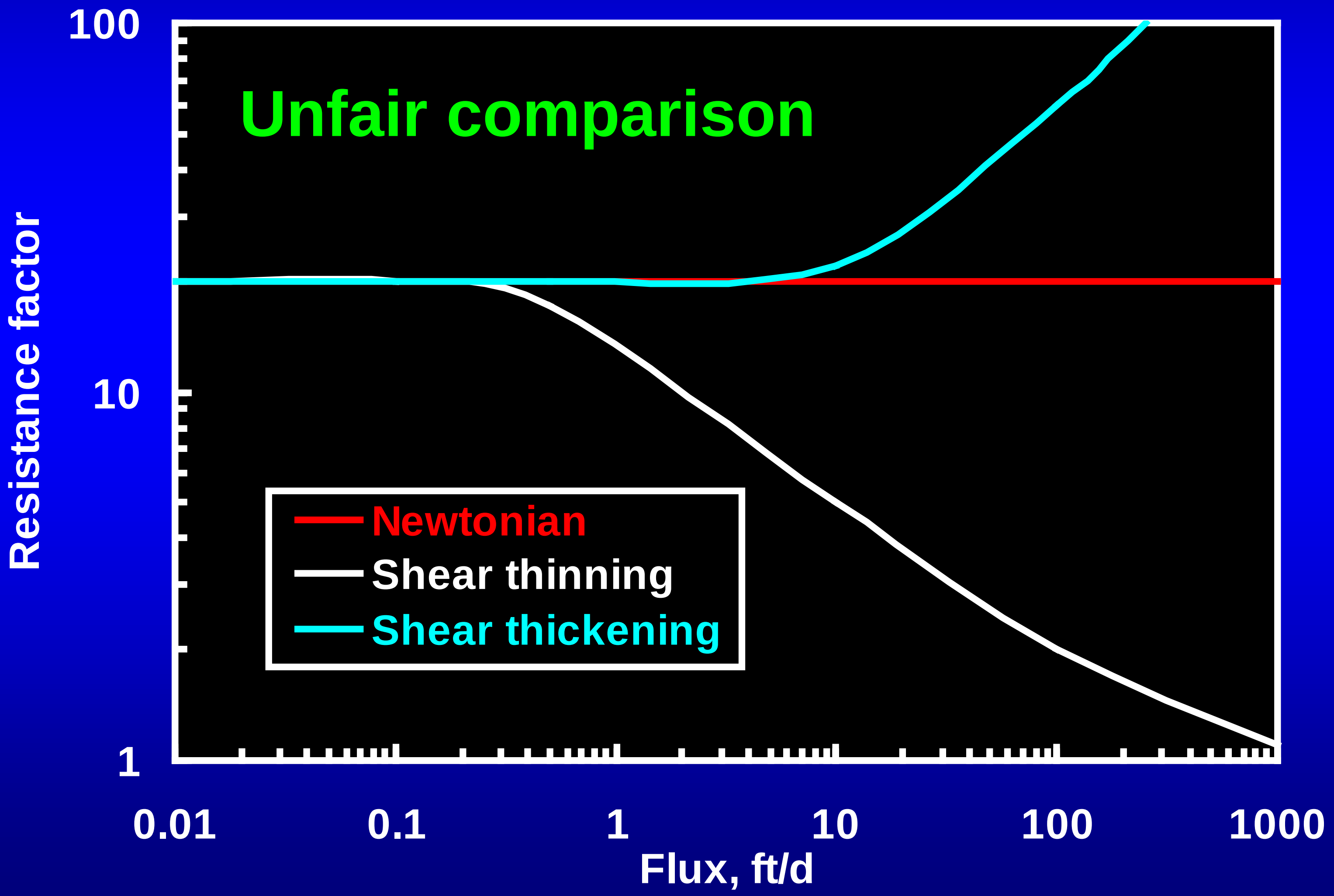
This incorrect assumption for HPAM results in overly optimistic injectivity estimates if vertical wells are not fractured.

IMPACT OF RHEOLOGY ON SWEEP EFFICIENCY

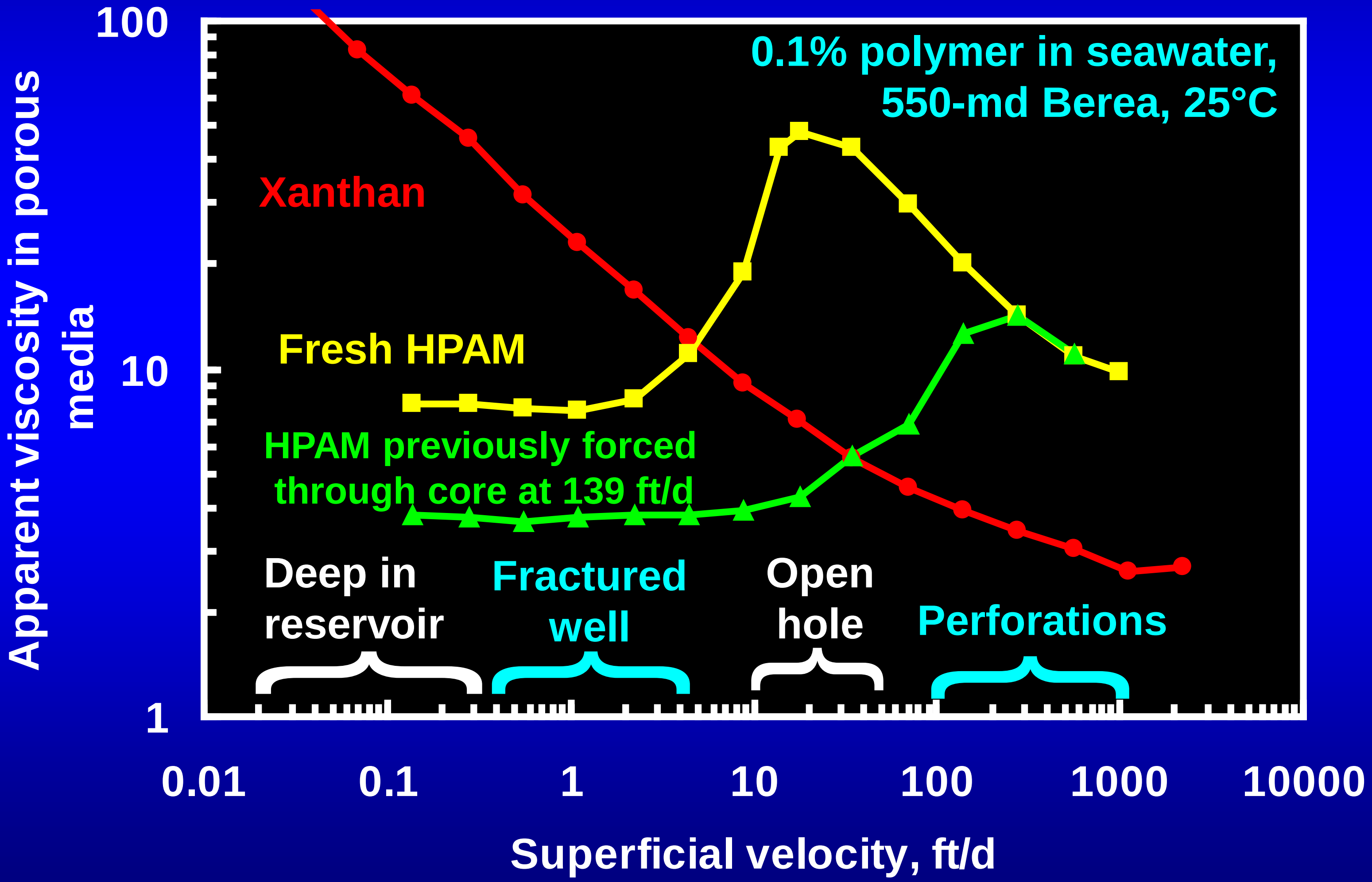
- Based on numerical work, some researchers suggested that shear-thinning rheology has a substantial negative impact on sweep efficiency.
- In part, their argument is based on work from Jones (1980), where layers with different permeability were completely filled with polymer. However, a very different result occurs if polymer is injected to *DISPLACE* water/oil from a multilayer system!
- Negative assessments of shear-thinning can also be obtained by an incorrect characterization of polymer rheology: i.e., assuming that a Newtonian fluid is always more viscous than a shear-thinning fluid.
- Our analysis indicates:
  - Shear-thinning fluids can provide a worse vertical sweep than Newtonian or shear-thickening fluids IF (1) no crossflow occurs between layers AND (2) the injection rates and pressure gradients are unrealistically high OR if polymer flood mobility ratio remains high (under specialized circumstances with viscous oils).
  - However, for realistic reservoir conditions and polymer properties, rheology has little impact on vertical sweep.
  - The overall resistance factor at low flux has a greater impact vertical sweep efficiency.
- Experimental verification can be found at:
  - http://baervan.nmt.edu/randy.

Rheology assumed by some researchers:

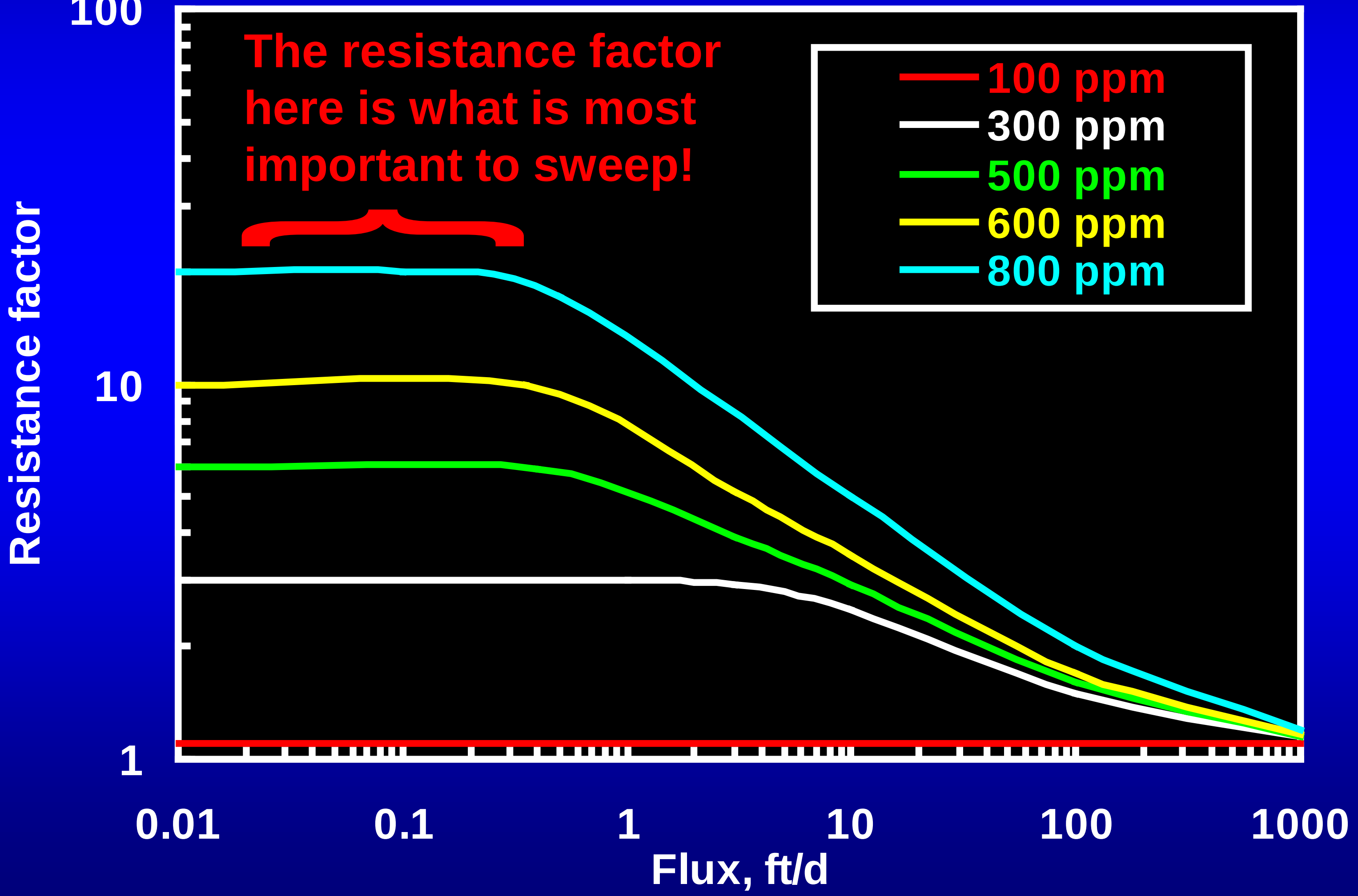
With their assumptions, of course shear-thickening will provide the best sweep efficiency (because it always provides the highest resistance factor) and shear-thinning will be worst.



If polymers are compared at constant polymer concentration or constant polymer cost, a different conclusion may be reached.



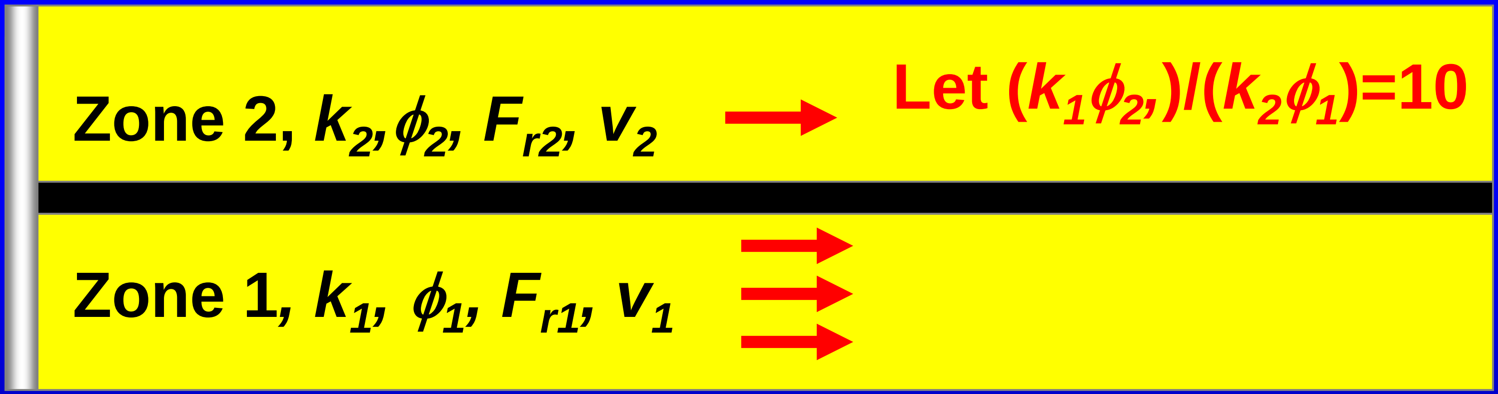
For real fluids, the low-flux resistance factor or zero-shear viscosity increases with increasing polymer concentration and with the level of shear thinning.



Rheology and Sweep Efficiency

Some suggest that shear thinning fluids are bad for vertical sweep efficiency (Jones 1980).

If two zones are completely filled with polymer solution, the flow profile for a shear-thinning fluid will be worse than for a Newtonian fluid.



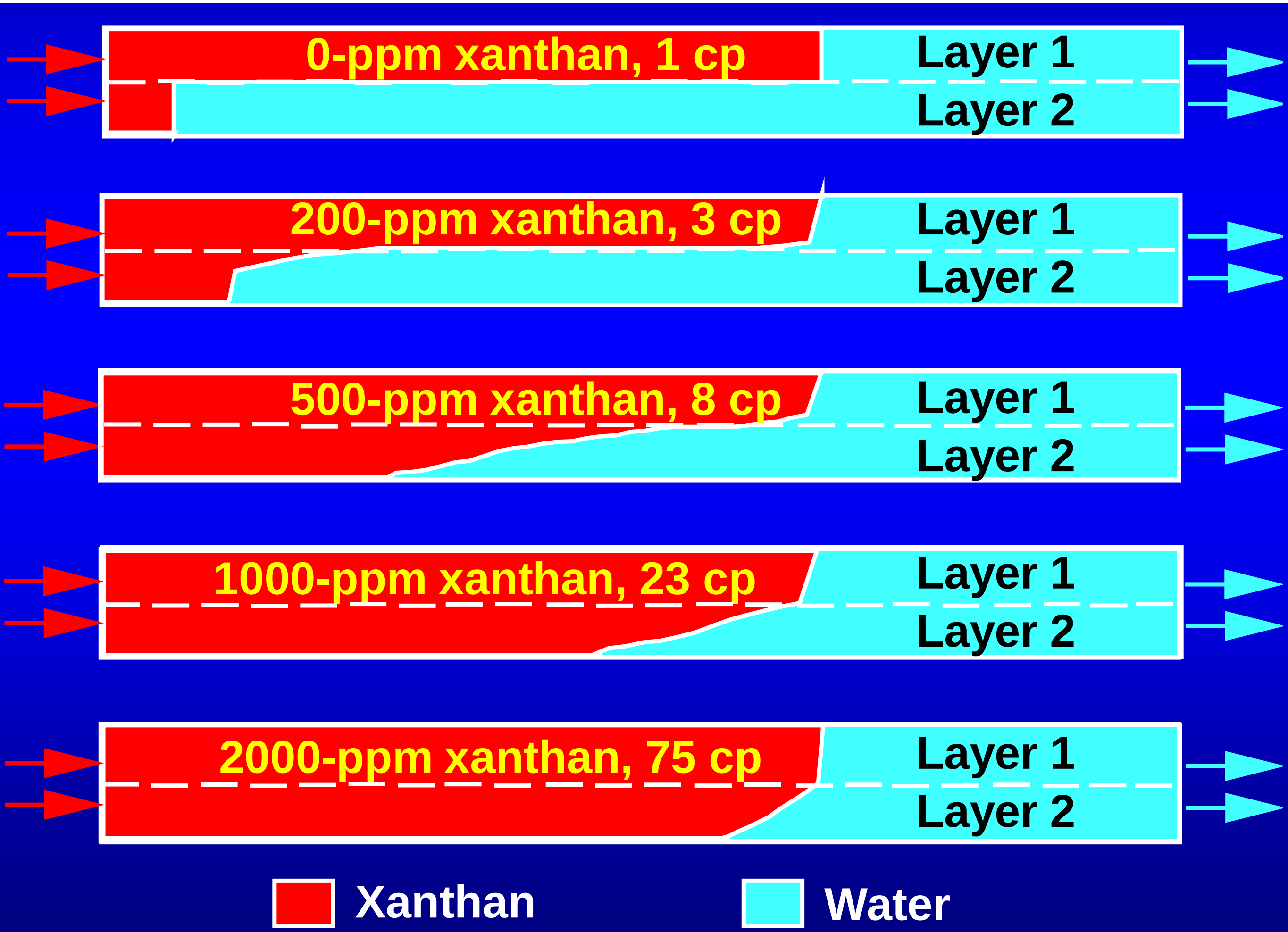
Let $(k_1\phi_{2,})/(k_2\phi_1)=10$

Zone 2, $k_{2,}\phi_{2,}\ F_{r2,}\ v_2$

Zone 1, $k_1,\ \phi_1,\ F_{r1},\ v_1$

- $v_1/v_2 \sim (k_1/k_2) = 10$ for a Newtonian fluid (e.g., water).
- For a shear-thinning fluid, $F_r \sim (v\phi)^{(n-1)}\ (k/\phi)^{(1-n)/2}$
- If $k_1/k_2=10$ and $n=0.5$, $v_1/v_2 \sim (k_1/k_2)^{1.5} = 32$

However, a very different result occurs if polymer is injected to DISPLACE water/oil from a multilayered reservoir!



Rheology for viscous solutions in multiple layers

Apparent shear rate in rock: $\gamma_1 / \gamma_2 = (u_1/k_1)^{0.5} / (u_2/k_2)^{0.5}$

WITH 2 LAYERS AND NO CROSSFLOW (SPE 17332):

For viscous solutions: $u_1/u_2 \approx (k_1/k_2)^{0.5}$

So, $\gamma_1 / \gamma_2 \approx 1$ and polymer solutions exhibit the same effective viscosity at a given distance from the well.

WITH 2 LAYERS AND FREE CROSSFLOW:

At the polymer front: $u_1/u_2 \approx 1$, so $\gamma_1 / \gamma_2 \approx (k_2/k_1)^{0.5}$

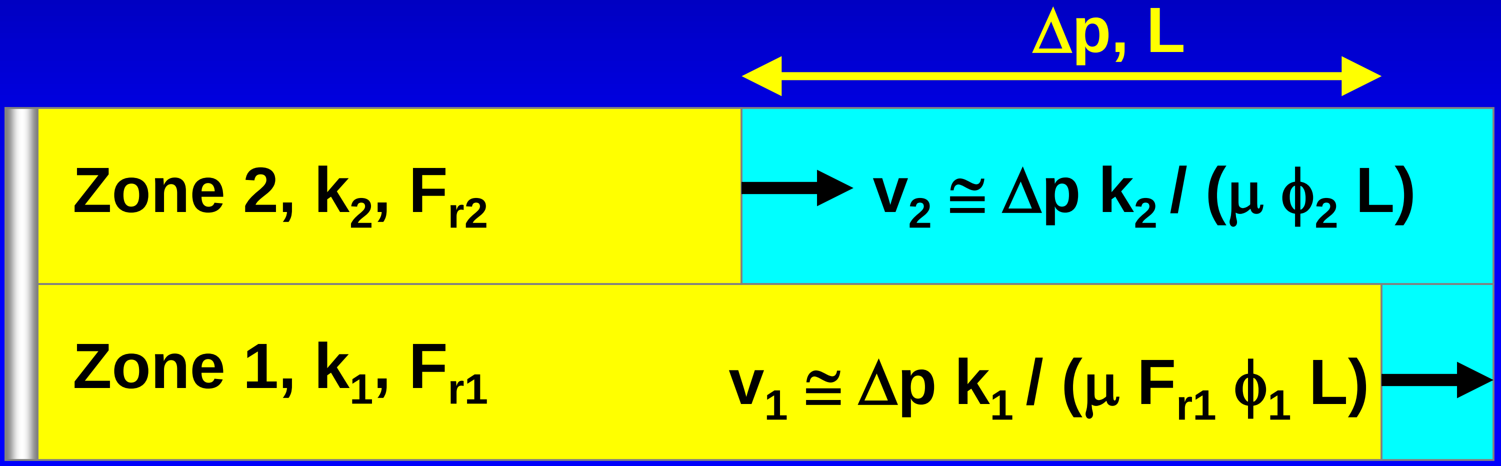
So $\gamma_1 < \gamma_2$

Shear thinning fluid: Viscosity is lower in low-k layer.

Upstream: $\gamma_1 / \gamma_2 \approx (k_1/k_2)^{0.5/n}$ So $\gamma_1 > \gamma_2$

Shear thinning fluid: Viscosity is higher in low-k layer.

UNDERSTANDING THE IMPACT OF RHEOLOGY AND CROSSFLOW ON VERTICAL FLOW PROFILES



Δp, L

Zone 2, k_2, F_{r2}

$v_2 \cong \Delta p\, k_2 / (\mu\, \phi_2\, L)$

Zone 1, k_1, F_{r1}

$v_1 \cong \Delta p\, k_1 / (\mu\, F_{r1}\, \phi_1\, L)$

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

- **For a shear-thinning fluid, $F_r \sim (v\phi)^{(n-1)}\, (k/\phi)^{(1-n)/2}$**
- **Near the well, if n=0.5, $v_1/v_2 \sim (k_1/k_2)^{1.5}$, so the flow profile *appears* worse, even though vertical sweep is as good as it can be.**

Rheology: Bottom Line

1. The low-shear-rate viscosity is the best indicator of resistance factor deep in a formation, if you don't have good data from corefloods.
2. If your corefloods indicate low-flux resistance factors that are much higher than low-shear-rate viscosities, be suspicious—do more tests.
3. Unless your water is VERY fresh or polymer concentration is high, HPAM shows near-Newtonian or slight shear-thinning behavior at low flux and shear-thickening at higher flux: This increases the probability that the polymer must be injected above the fracture pressure.
4. Under realistic reservoir conditions, shear-thinning behavior (e.g., xanthan use) is not bad for sweep efficiency.
5. If you want to use non-Newtonian behavior in your simulator, compare your results with Newtonian behavior to see if the results make sense.

SPE 115142

INJECTIVITY CHARACTERISTICS OF EOR POLYMERS

INJECTIVITY: BOTTOM LINE

1. For most previous polymer floods, injection has occurred above the formation parting (fracture) pressure—even though the operators insisted that they did not.
2. This is not bad, so long as fracture extension is controlled so that fractures don't (a) let fluids "flow out of zone" or (b) extend far enough to cause channeling.
3. Be realistic. If you can't live with the injectivity reduction associated with a viscous fluid, don't insist that you are going to inject below the parting pressure.
4. If you are willing to inject above the parting pressure, spend some time understand how the fractures will extend and the consequences.
5. Don't forget about productivity for production wells!

Objectives:

- Estimate injectivity losses associated with polymer solutions if fractures are not open.
- Estimate the degree of fracture extension if fractures are open.

Factors Affecting Polymer Solution Injectivity:

- Debris/microgels/undissolved polymer
- Rheology in porous media
- Mechanical degradation
- Displacement of residual oil (not considered here)

Injectivity:

- Defined as injection rate divided by pressure drop from the wellbore into the formation.
- Want a high injectivity to allow rapid displacement and recovery of oil.

- Polymers are needed for mobility control for most chemical flooding projects:
- The viscous nature of polymer solutions will necessarily reduce injectivity unless the well intersects a fracture.
- Fractures can cause severe channeling and/or injection out of zone for expensive EOR fluids.

FILTER TESTS

- Measure how low it takes for a given volume of a given polymer soution to pass through a given filter under a given pressure drop.
- Primary value is to keep polymer suppliers honest during field applications.
- Are not a good indicator of injectivity.
- Are of modest value in comparing polymers.

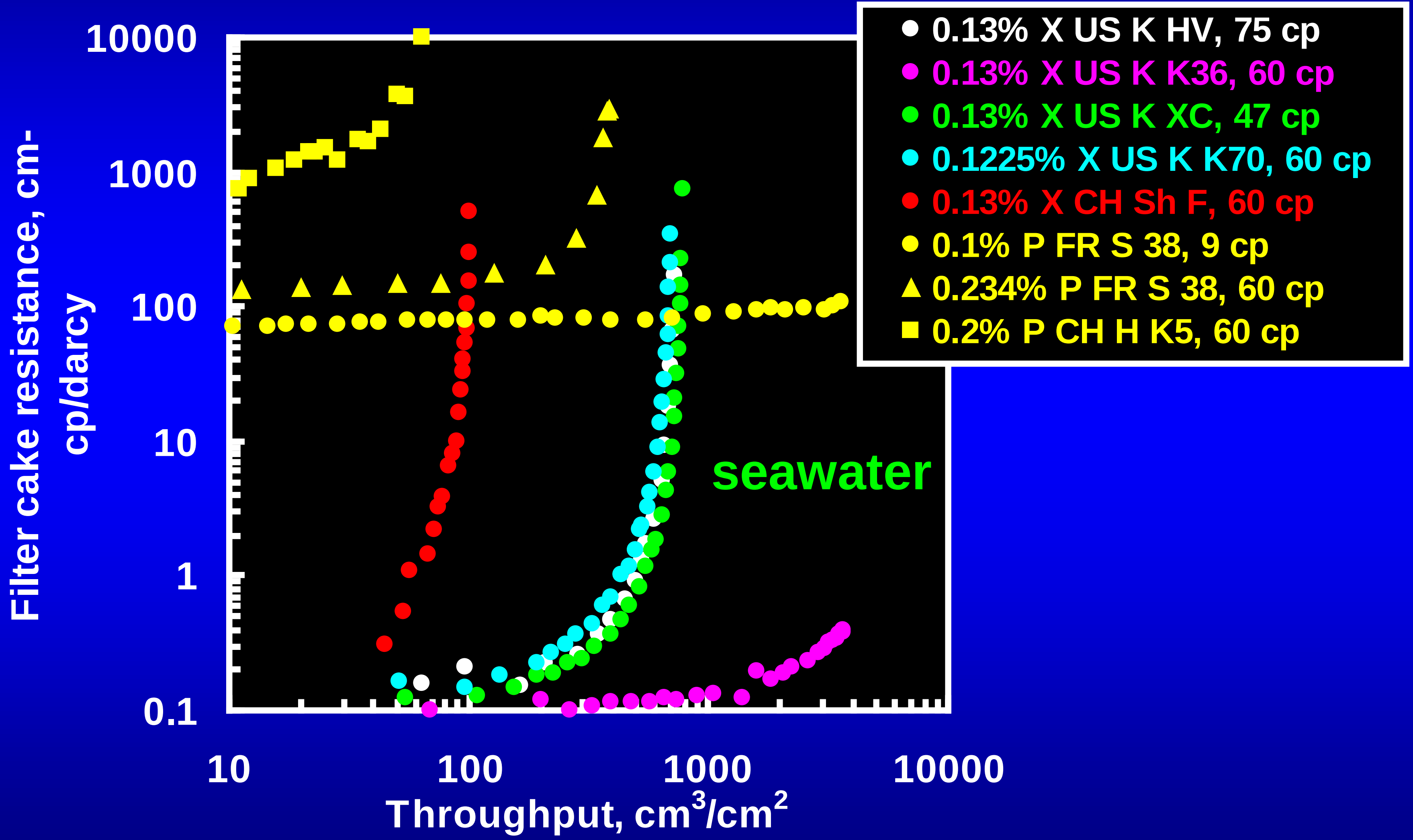
Plugging of Rock Face During Polymer Injection

- Throughput for field EOR projects:
  - ~ 10^5 - 10^6 cm^3/cm^2 for unfractured vertical wells.
  - ~ 10^3 - 10^4 cm^3/cm^2 for fractured vertical wells.

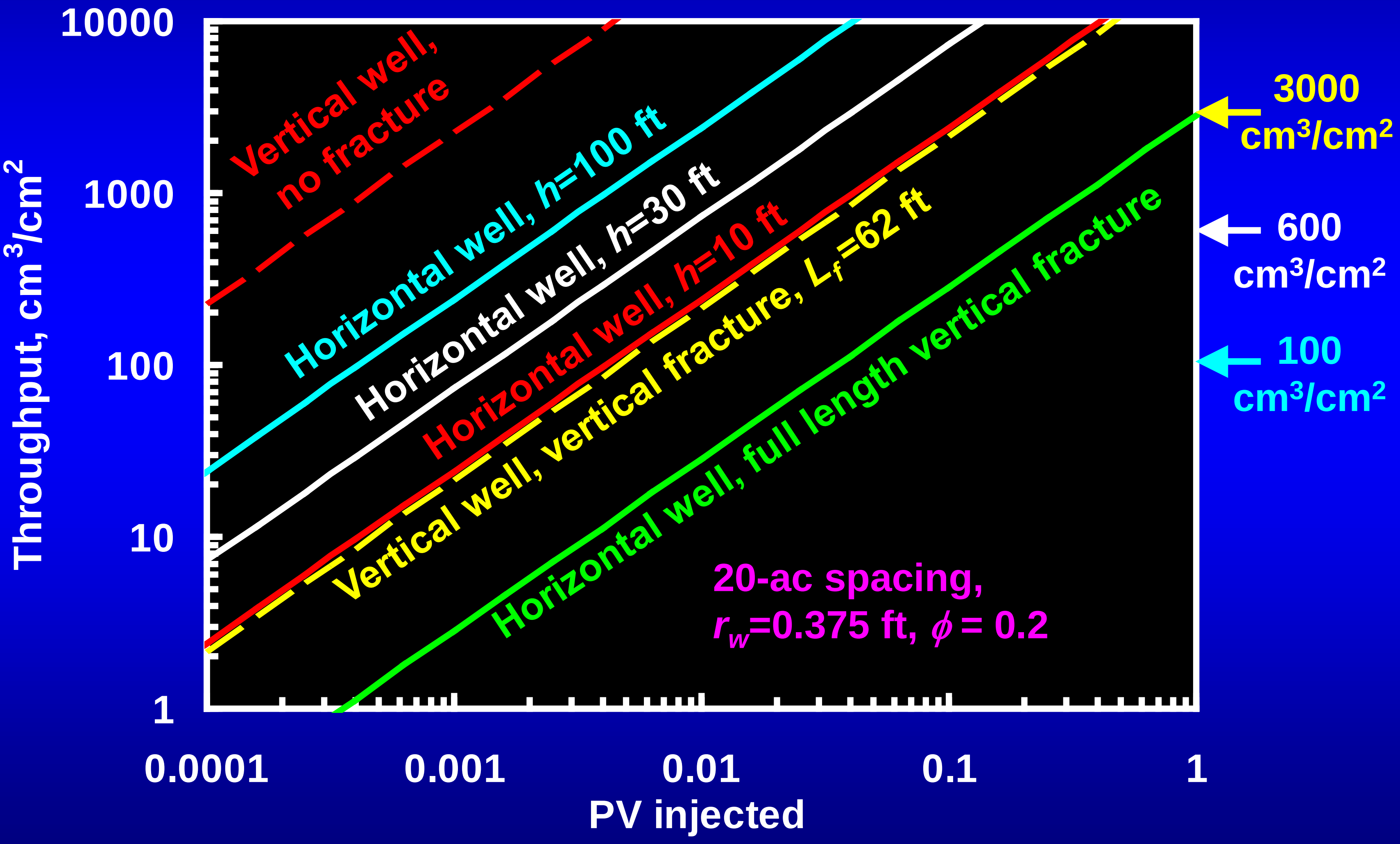
- Previous lab filter tests
  - Used less than 40 cm^3/cm^2 throughput.
  - Typically use “filter ratios”. $[(t_{500}-t_{400})/ t_{200}-t_{100})]$
  - Do not correlate with injection into rock.

- We developed a new filter test:
  - Using throughputs over 2,000 cm^3/cm^2.
  - That correlates with injection into cores.

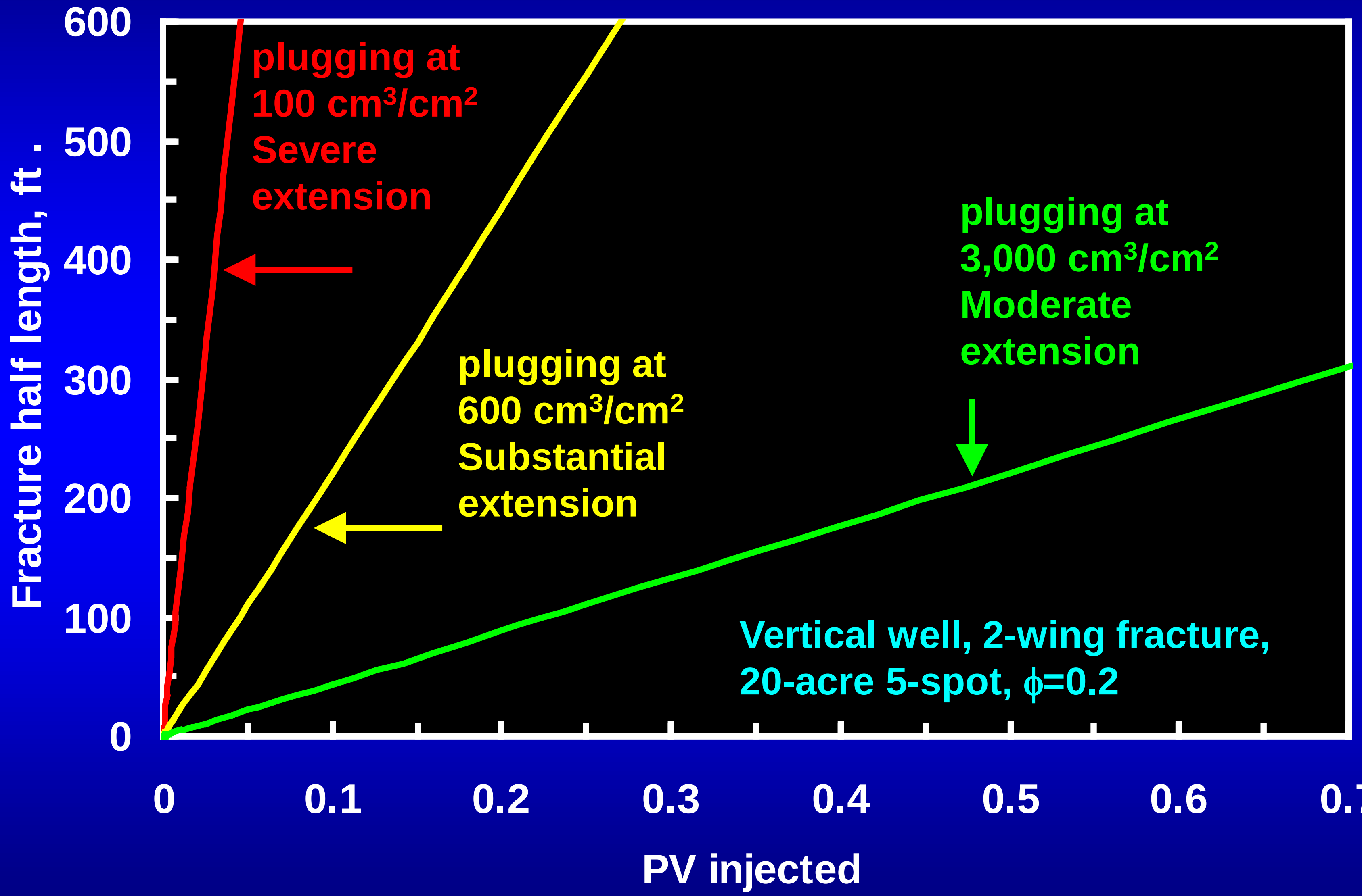
- For both xanthan and HPAM solutions, filterability varies a lot, depending on polymer source.



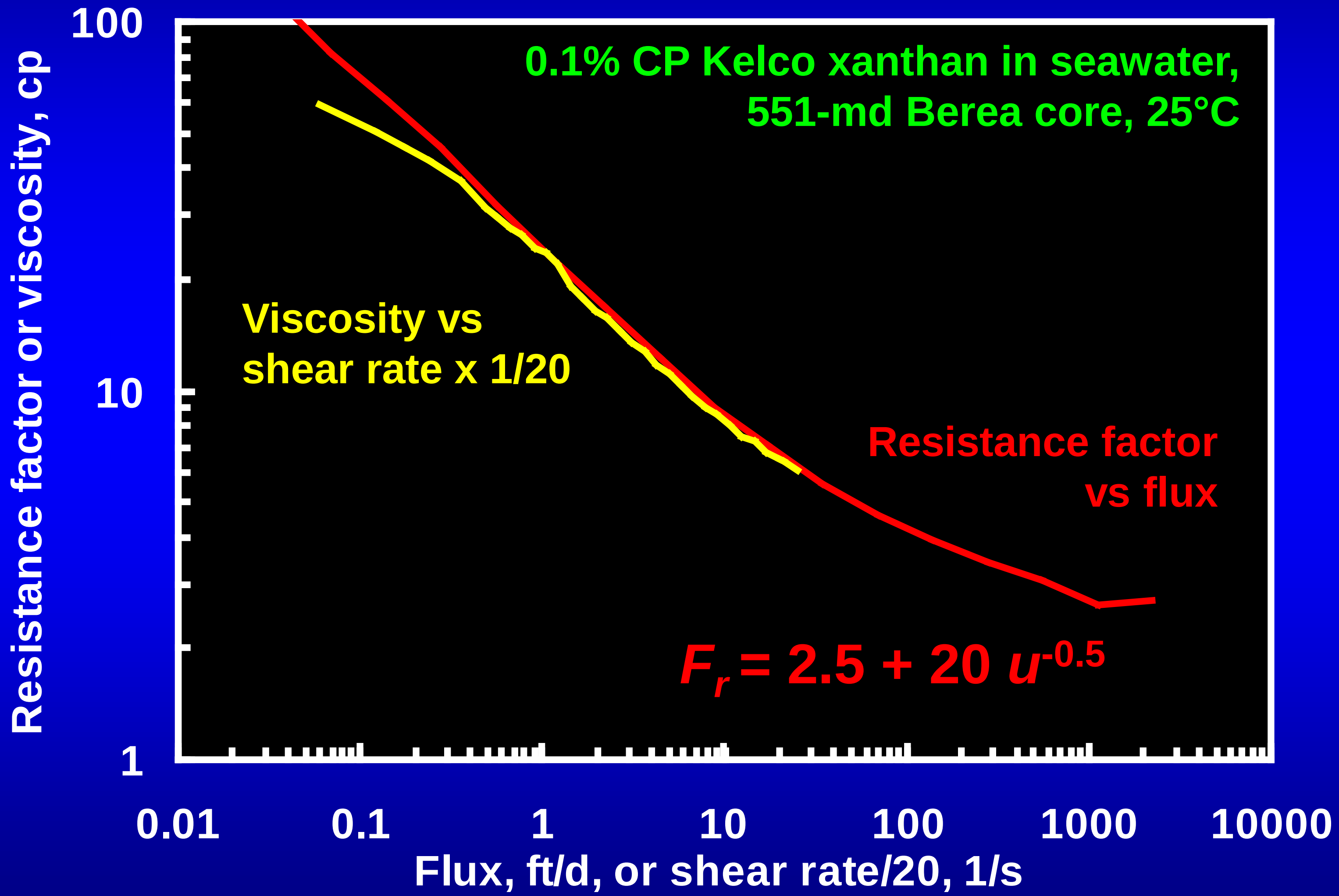
Even with the cleanest polymers, face plugging will exceed the capacity of unfractured wells during most chemical EOR projects.



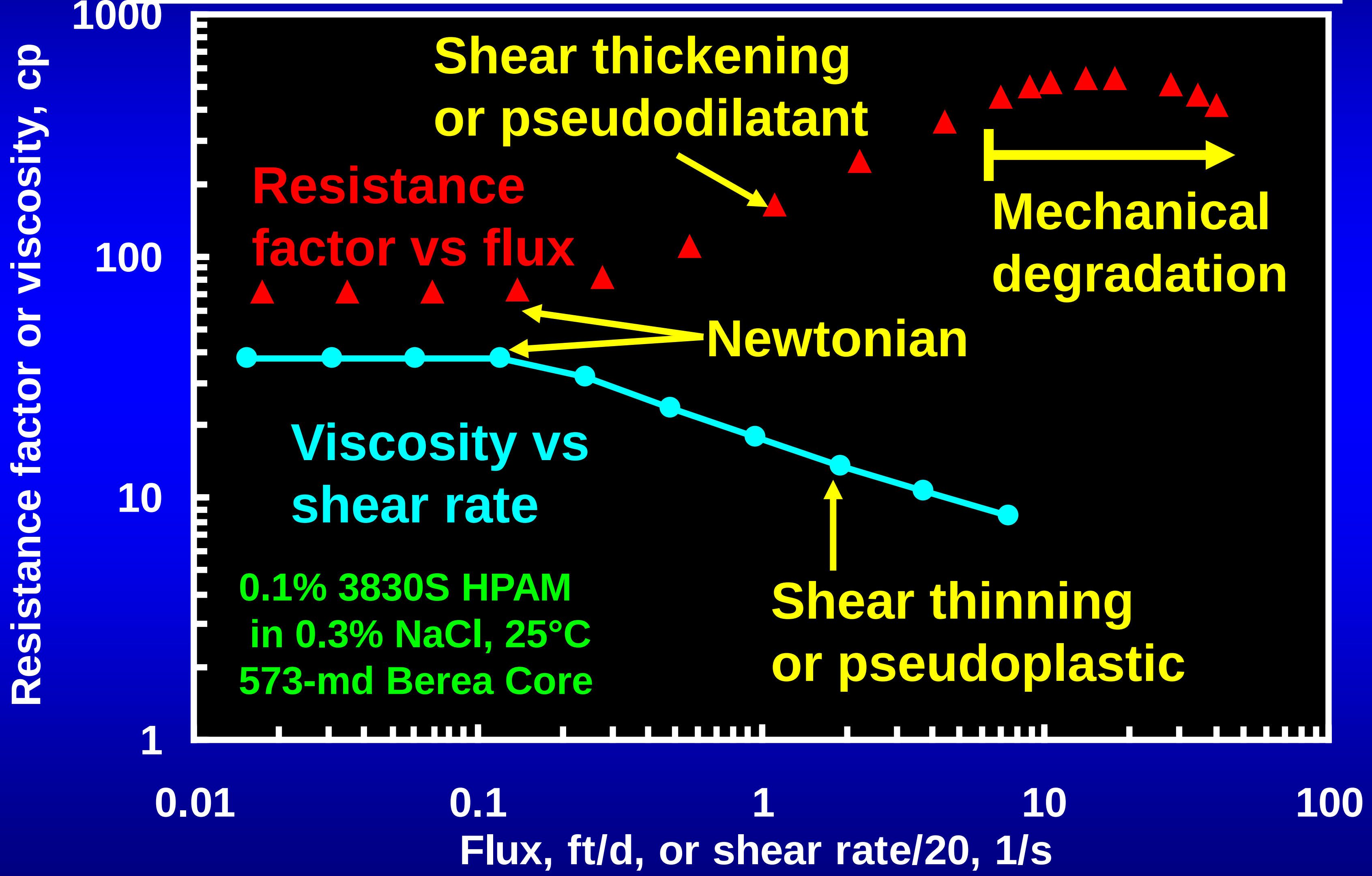
Fracture extension expectations for polymers that plug at a give throughput.



- Xanthan rheology in porous media correlates well with that in a viscometer.

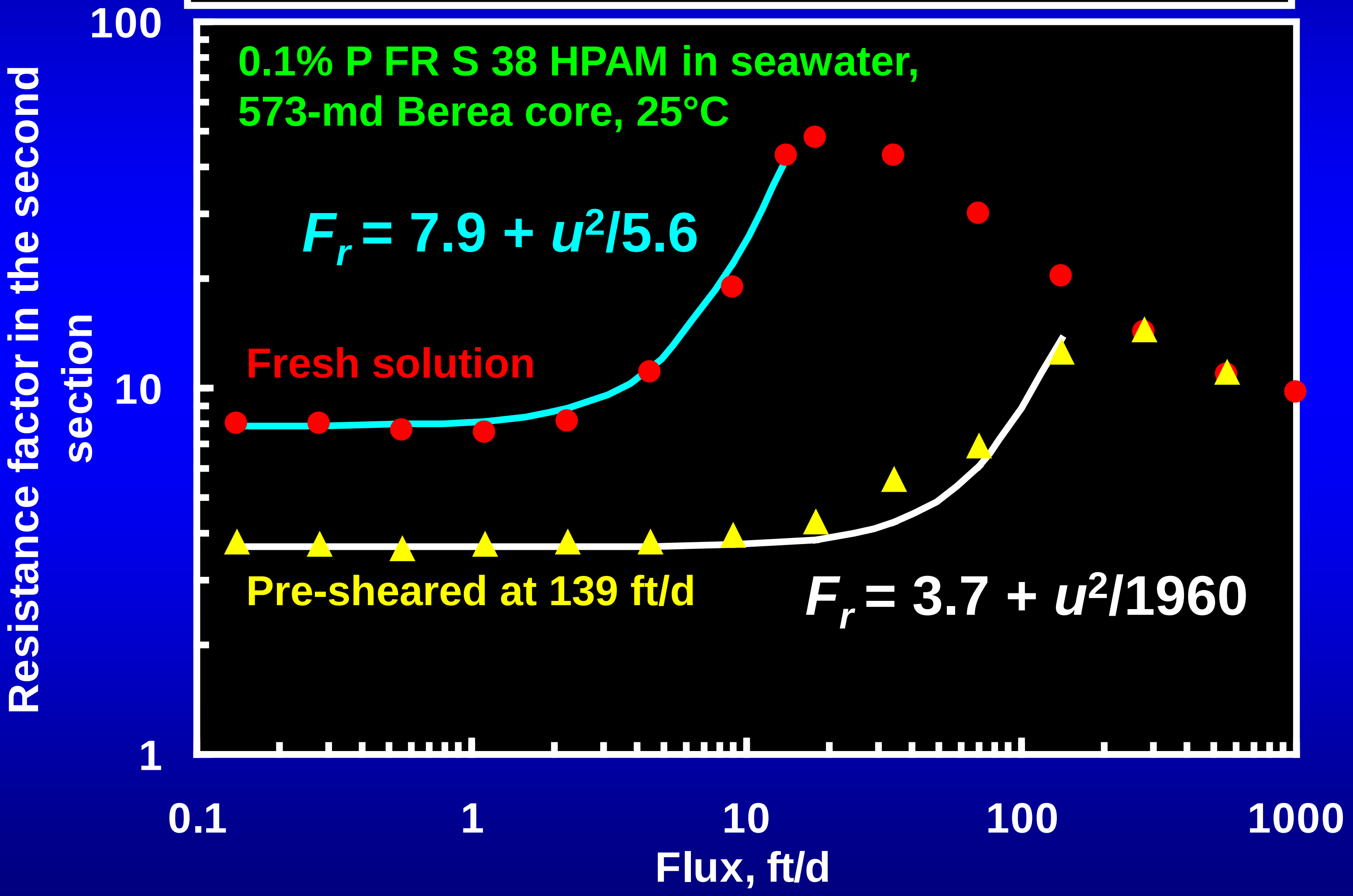


Although HPAM solutions show pseudoplastic behavior in a viscometer, they show Newtonian or shear-thickening behavior in porous rock.

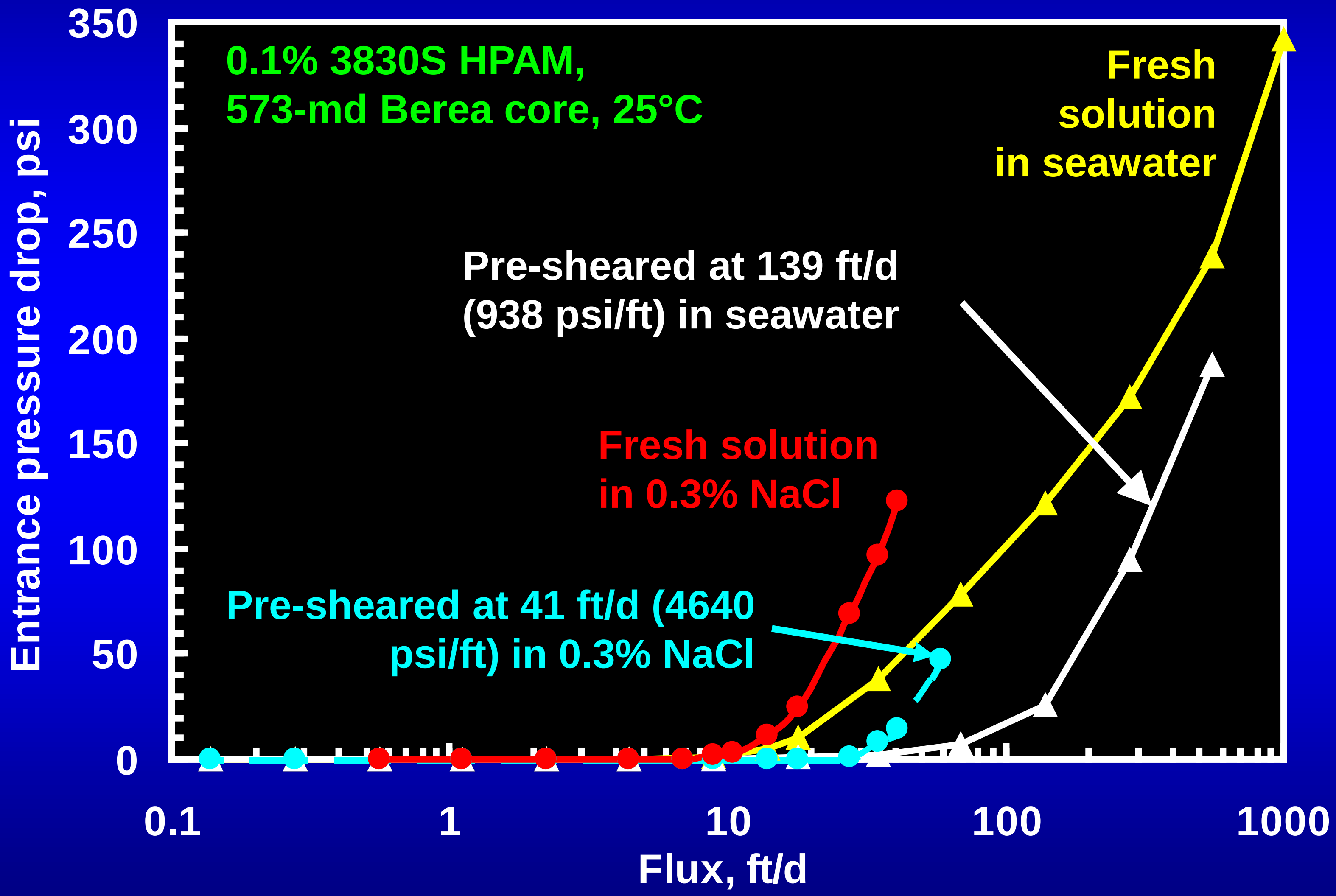


HPAM Rheology in Porous Rock:

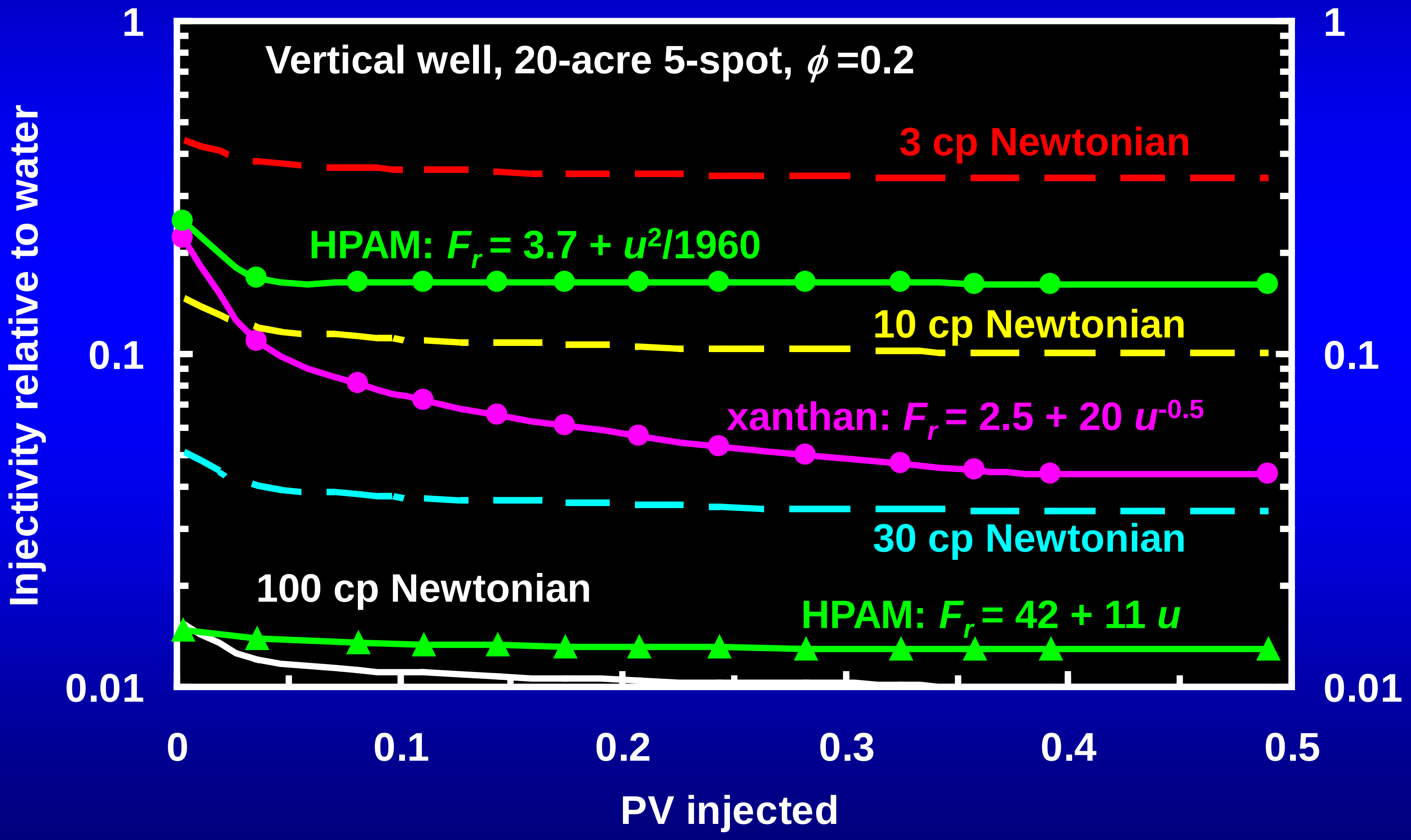
1) Newtonian at low flux,
2) pseudodilatant at intermediate flux,
3) mechanical degradation at high flux.



- HPAM can show an entrance pressure drop on entering porous rock. Xanthan does not.



Even without face plugging, the viscous nature of the solutions investigated requires that injectivity must be less than 20% that of water if formation parting is to be avoided (unless S_{or} is reduced).



SIMPLE MODELING OF INJECTIVITY

1. First, for vertical wells, you are looking for a “YES-NO” answer about whether fractures must be open during polymer injection.
2. Simple radial flow equation (polymer/water injectivity):

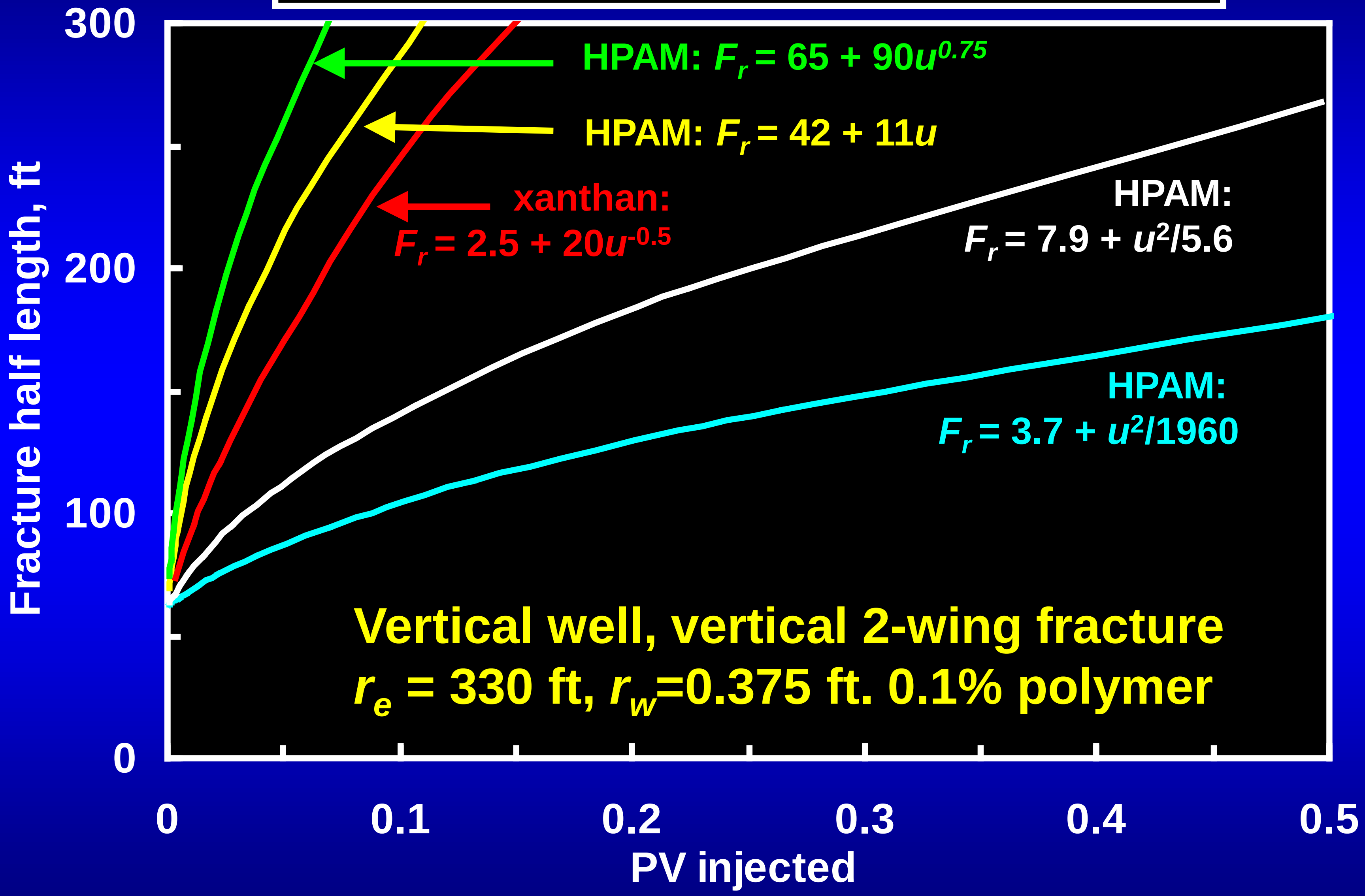
$$I / I_o = \mathrm{Ln}\,(r_e/r_w) \,/\, [F_r\, \mathrm{Ln}\,(r_p/r_w) + \mathrm{Ln}\,(r_e/r_p)]$$

Assume $r_e = 1000$ m, $r_w = 0.1$ m, $r_p = 100$ m.

F_r	I / I_o
3	0.40
10	0.13
20	0.07
50	0.03

3. If you inject above the formation parting pressure, the fracture(s) will extend to accommodate polymer injection.

Fracture extension expectations for polymers with different rheologies



Effect of Polymer Rhelogy and Induced Fracturing on Injectivity: Ma and McClure SPE 184389

1. Simulation effort confirms that fractures must be open when injecting HPAM into vertical wells under practical circumstances.

2. At practical rates, only shear thinning is seen in porous media because fractures are open and extend so velocities at the injection fracture face are low.

3. Only shear thinning is seen in the fracture—because if any porous media was present in the fracture (i.e., proppant), pressure gradients would rise until an open fracture was formed. Shear thickening is only seen in porous media. Only shear thinning is seen between parallel plates (e.g., an open fracture).

Don’t Forget About Productivity!

1. High pressures associated with high injectivity may push oil away from producers if the production wells don’t have sufficient flow capacity.

2. Pump off production wells as much as possible.

3. Make sure that production wells have minimum formation damage.

4. Stimulate production wells if that is viable.

5. Add more production wells if necessary.

6. Use horizontal production wells if that is viable.

INJECTIVITY: BOTTOM LINE

1. For most previous polymer floods, injection has occurred above the formation parting (fracture) pressure—even though the operators insisted that they did not.
2. This is not bad, so long as fracture extension is controlled so that fractures don’t (a) let fluids “flow out of zone” or (b) extend far enough to cause channeling.
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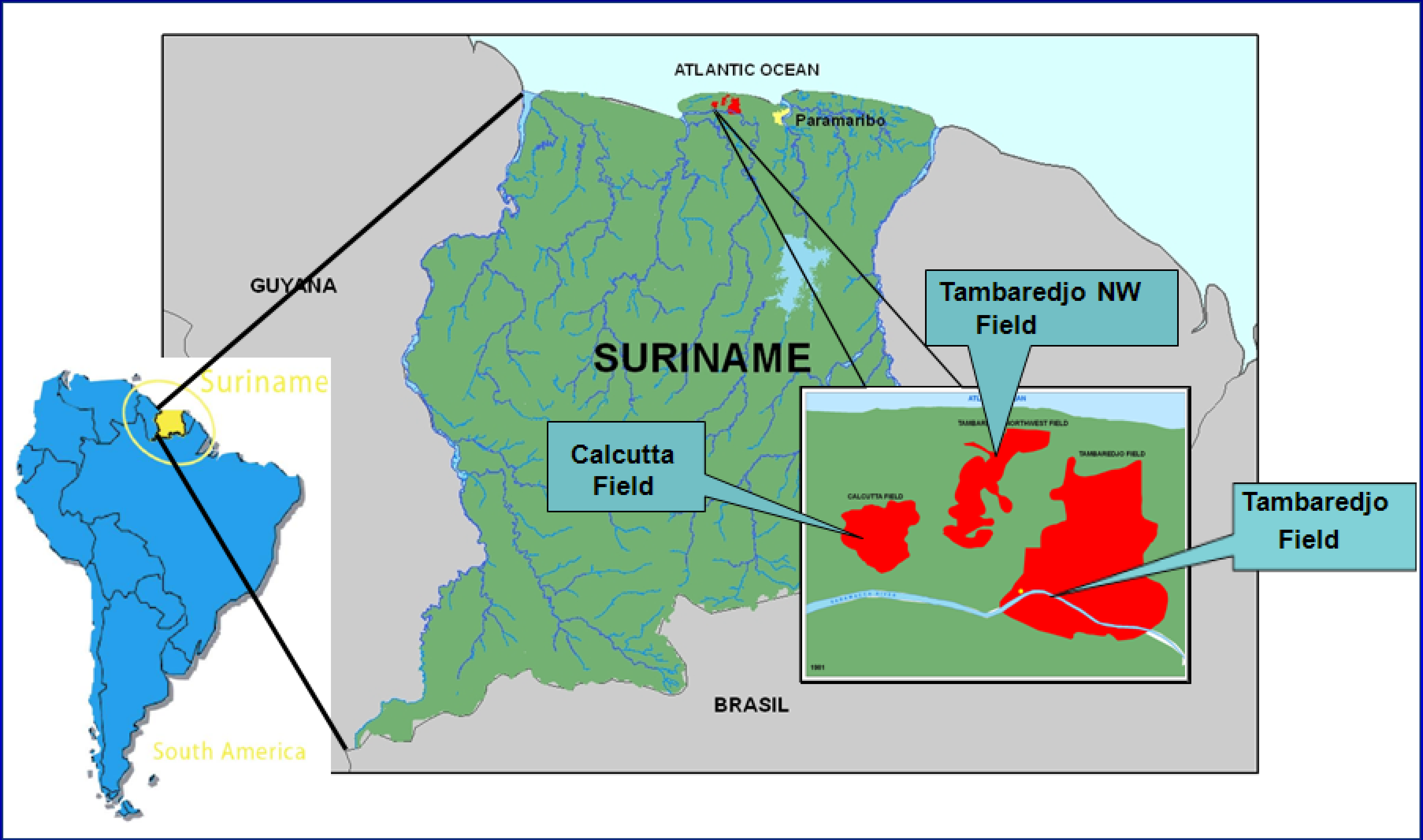
4. If you are willing to inject above the parting pressure, spend some time understand how the fractures will extend and the consequences.
5. Don’t forget about productivity for production wells!

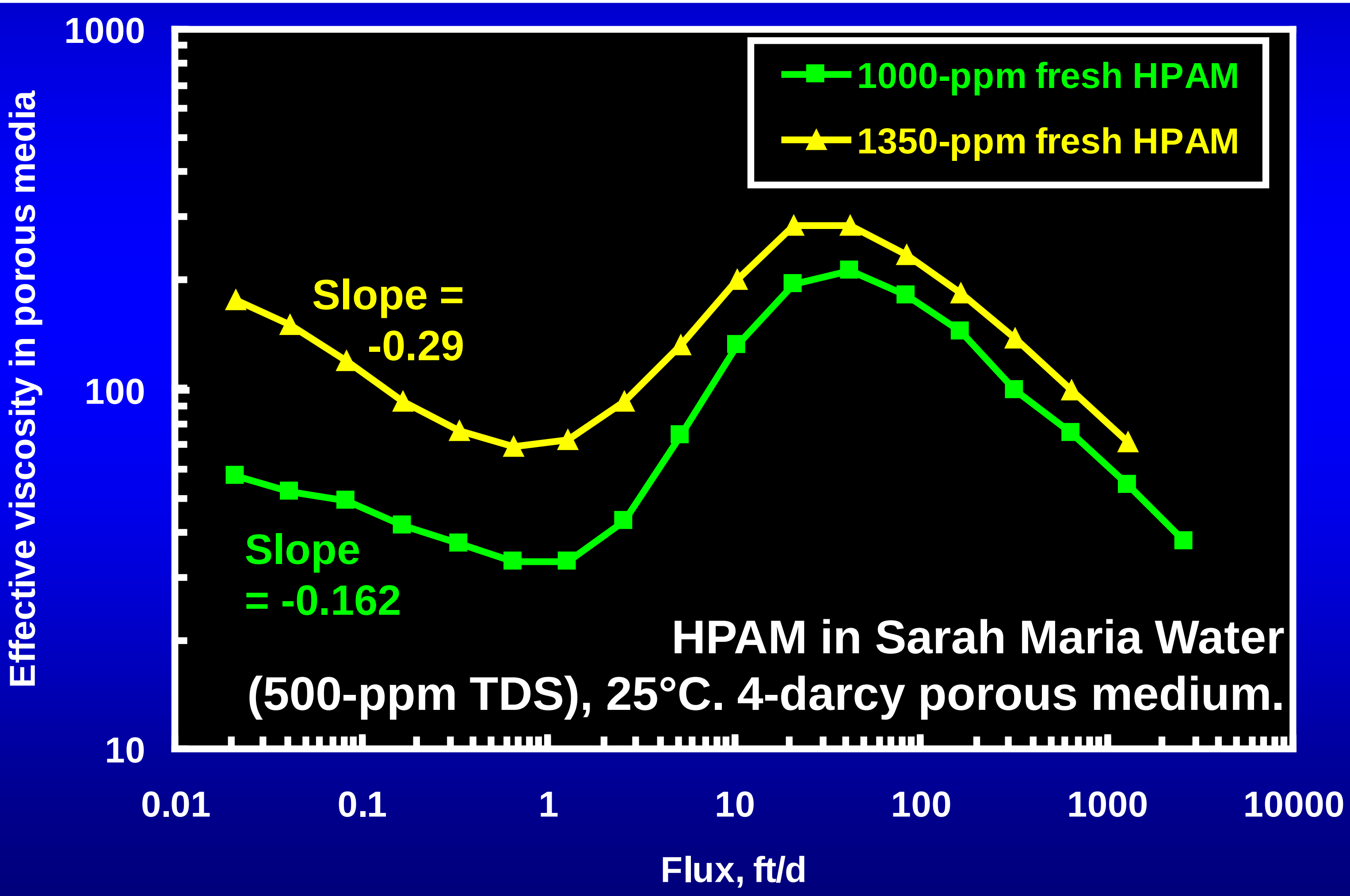
STAATSOLIE SURINAME (SPE 164121)



Oil viscosity ~1000 cp; Temperature 38°C;
Depth: 1000 ft; Thickness ~40 ft; Permeability 4-12 D.

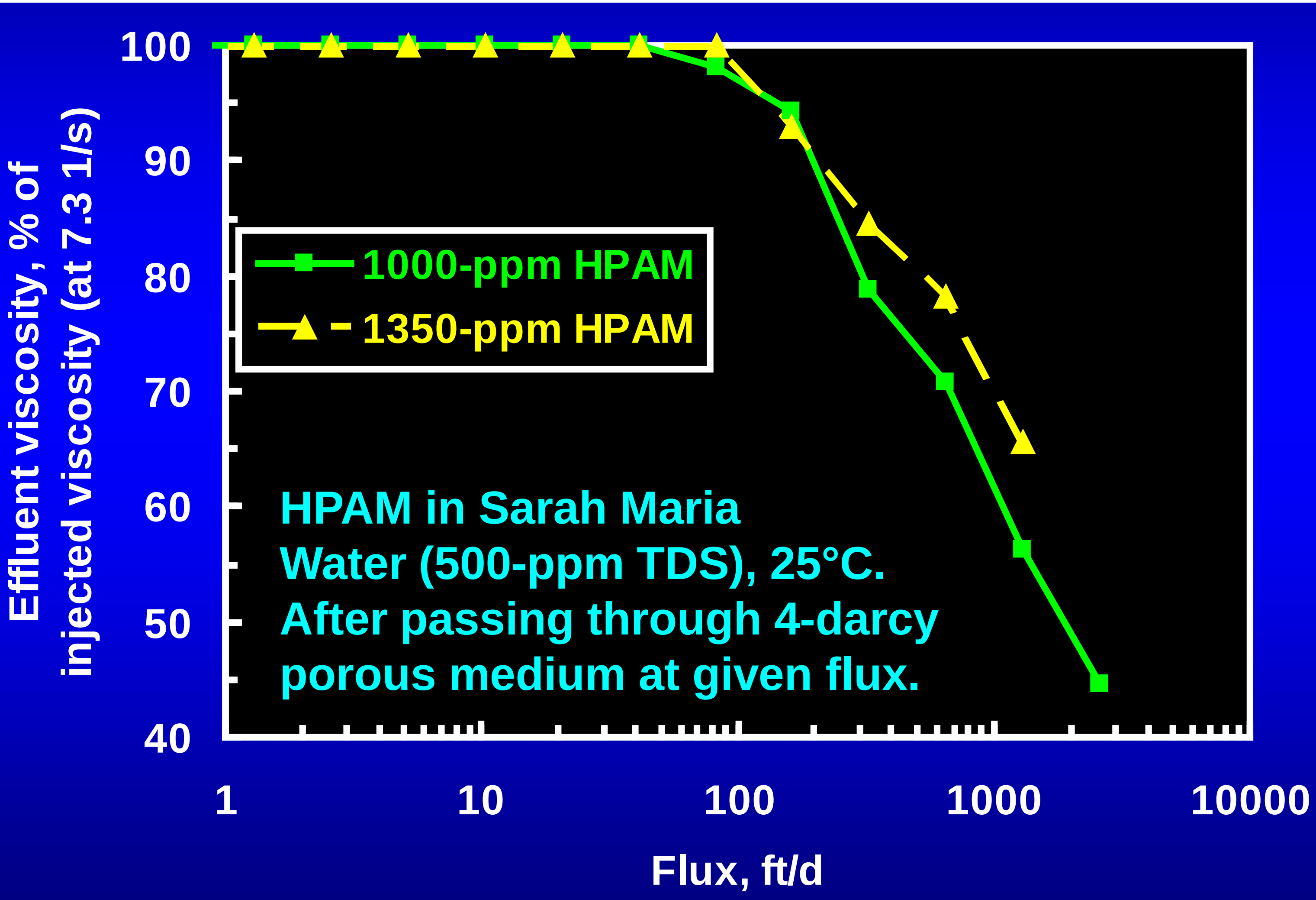
Rheology in Porous Media & Mechanical Degradation

- Shear thinning occurs below 1 ft/d.
- Shear thickening occurs between 1 and 40 ft/d.
- Mechanical degradation occurs above ~40 ft/d.



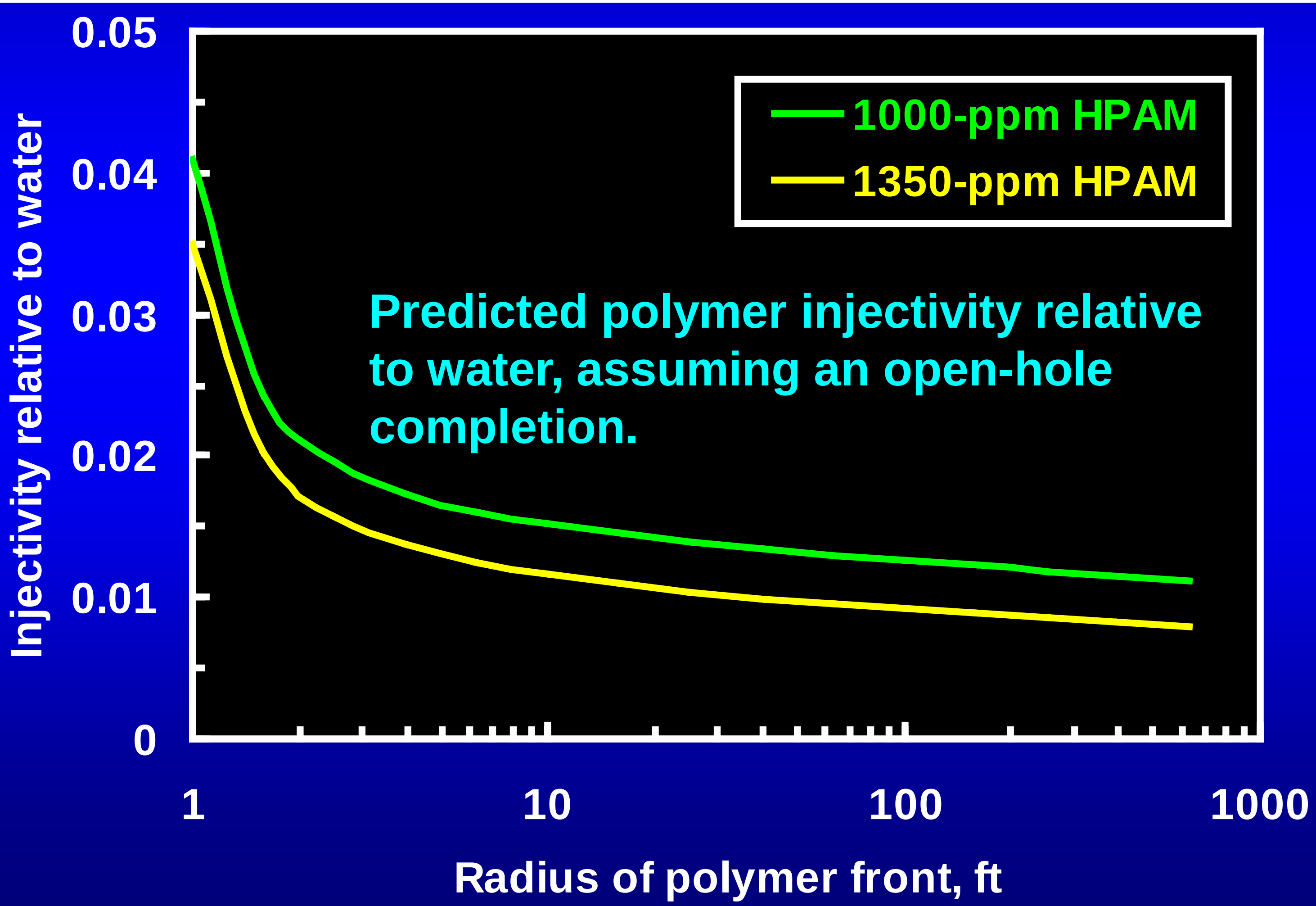
Rheology in Porous Media & Mechanical Degradation

- Mechanical degradation occurs above ~40 ft/d.



INJECTIVITY

- Assuming an open-hole completion, polymer injectivity should be 1-2% of water injectivity, with our HPAM rheology.
- Actual polymer injectivity was 27-62% that of water.
- Fractures were open during polymer injection.



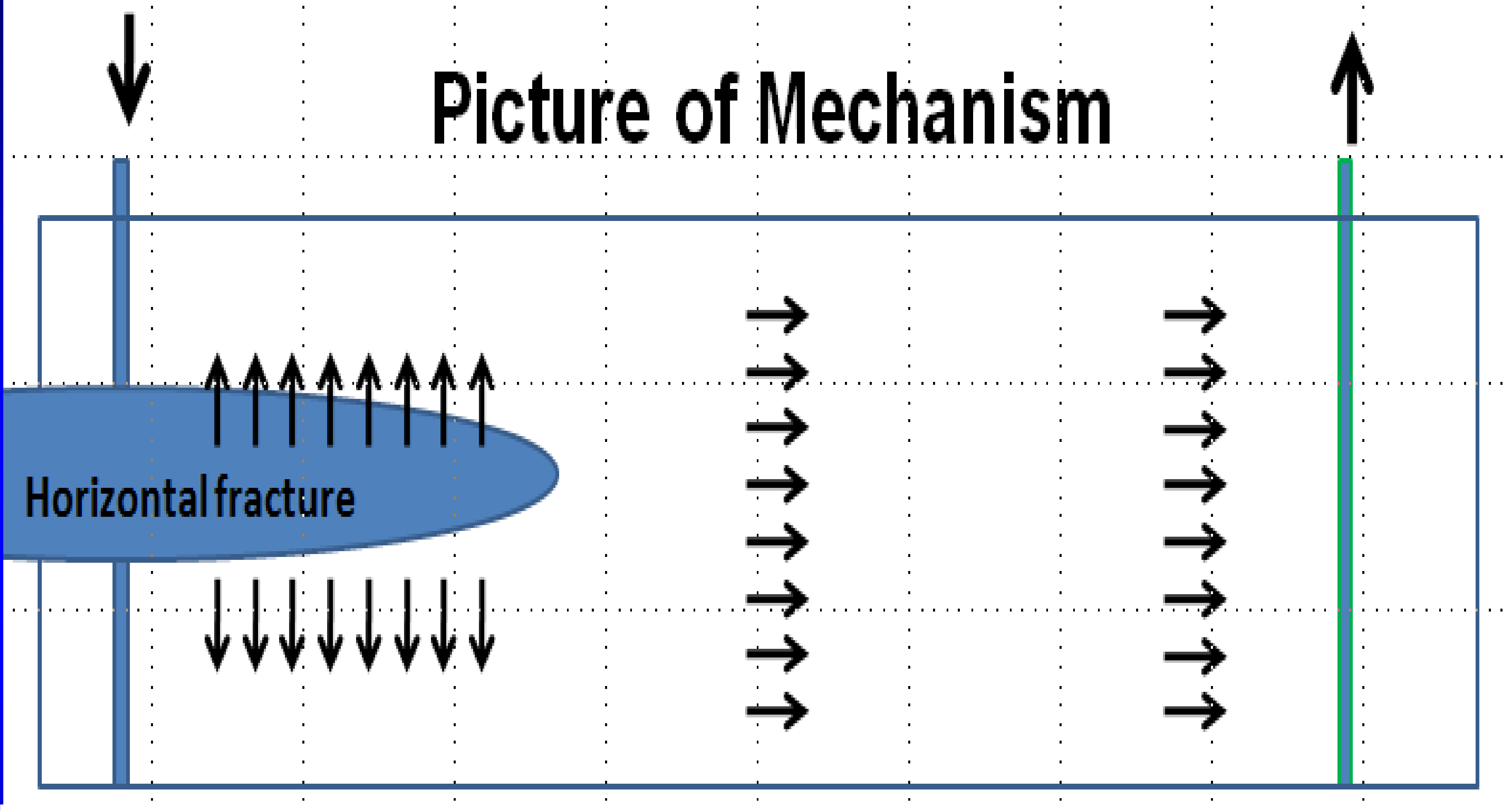
Predicted polymer injectivity relative to water, assuming an open-hole completion.

Injectivity Test of August, 2008, in Well 1M101

Injectant	Injection rate, BPD	BHP, psi	Injectivity, BPD/psi	Fracture status
water	100	553	0.28	closed
water	650	845	1.01	open
water	125	482	0.44	mostly closed
water	650	737	1.21	open
water	175	471	0.65	mostly closed
water	650	638	1.48	open
1000-ppm polymer	175	635	0.40	open

Fractures were open during polymer injection

- Radial horizontal fractures are expected at 1000-ft depth.
- Calculations indicate the maximum radial fracture extension to be ~20 ft. So polymer injectivity is substantially improved without compromising sweep efficiency.
- Polymer and salinity breakthroughs and production performance indicated no channeling through fractures.



- **Injectivity is enhanced without channeling, so long as the fracture does not extend to the producer.**

CONCLUSIONS (SPE 164121)

1. A strong shear-thickening rheology was observed for 1000-ppm and 1350-ppm HPAM solutions in porous media. Injectivity analysis revealed that these solutions were injected above the formation parting pressure in the Sarah Maria polymer injection wells.

2. Analysis suggested that the fractures extended only a short distance (~20 ft) from the injection wells and did not jeopardize sweep efficiency. In contrast, the short fractures greatly improved polymer injectivity and reduced concern about polymer mechanical degradation.

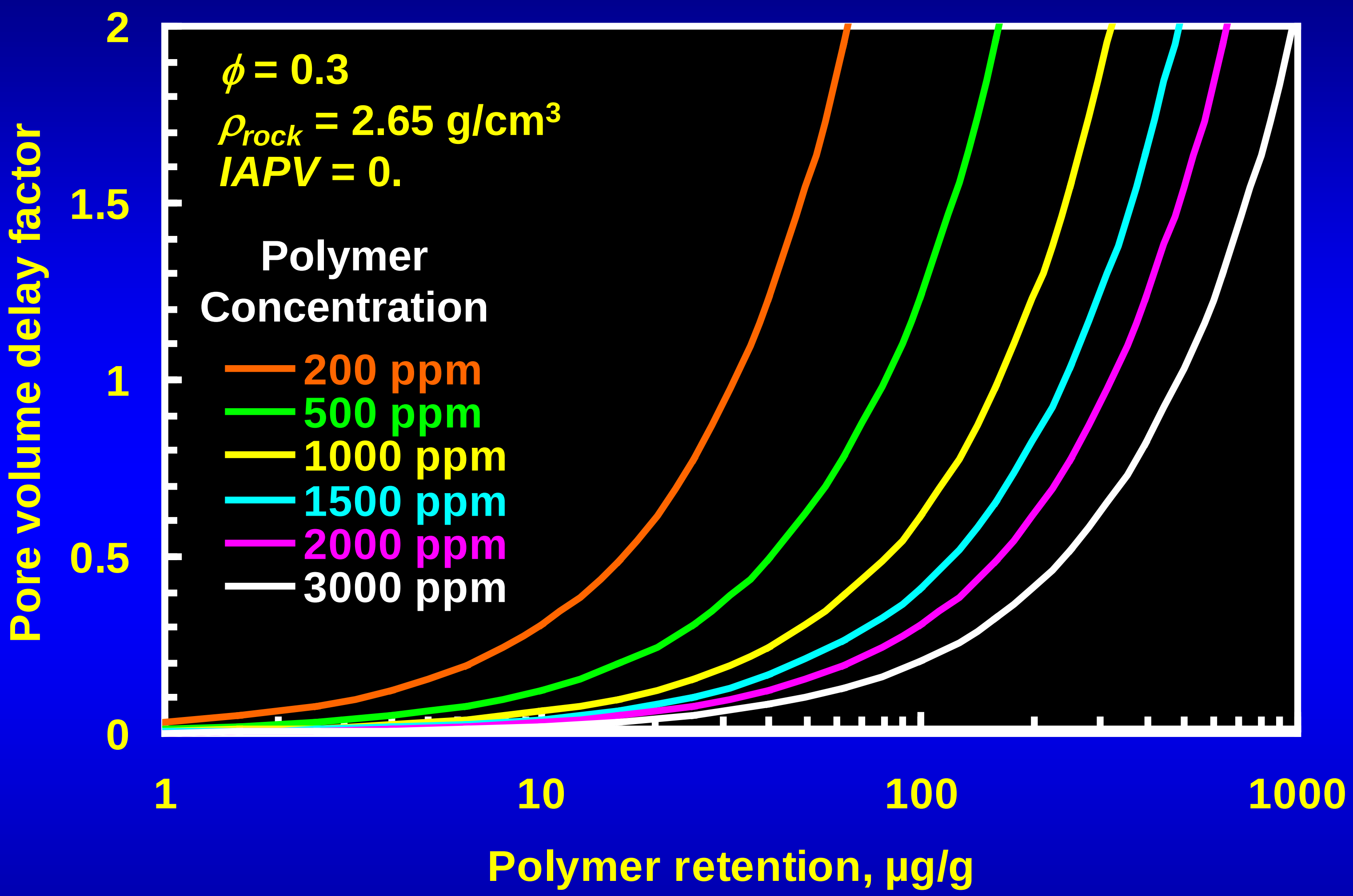
SPE 169027

Field vs Laboratory Polymer Retention Values for a Polymer Flood in the Tambaredjo Field

OUTLINE

1. Importance of polymer retention.
2. Literature review of polymer retention.
3. Literature review of inaccessible pore volume (IAPV).
4. Review of methods to assess polymer retention.
5. Laboratory polymer retention values In Tambarejo sand (associated with Sarah Maria polymer flood pilot).
6. Field polymer retention values associated with Sarah Maria polymer flood pilot in Suriname.

Polymer bank delay factors associated with polymer retention.



10 µg/g & 1500 ppm polymer: delay = 0.04 PV.
100 µg/g & 1500 ppm polymer: delay = 0.41 PV.
200 µg/g & 1500 ppm polymer: delay = 0.82 PV.

LITERATURE REVIEW OF POLYMER RETENTION

1. Clay (high-surface-area materials) and iron in the rock dominate polymer retention.
2. Polymer retention can increase dramatically with decreasing permeability, especially below 100 md. Most current polymer floods are applied in very permeable formations (> 500 md).
3. Most (but not all) polymer retention data suggests that use of the Langmuir isotherm is inappropriate. Ironically, most commercial simulators use the Langmuir isotherm.
4. Retention of xanthan is usually less than that of HPAM.
5. The most reliable current means to measure polymer retention is the double-polymer/tracer-bank method.
6. Retention in the presence of residual oil is ~1/2 half that without S_{or}. Wettability has not been established as a key factor in polymer retention.

LITERATURE REVIEW OF INACCESSIBLE PV (IAPV)

1. Reported IAPV values are VERY inconsistent, especially with respect to permeability dependence.

2. The available theories for the IAPV phenomenon cannot explain the magnitude and odd variations of IAPV with changes in permeability . Experimental limitations?

3. More work is needed to understand IAPV phenomenon.

4. Most current large polymer floods are in reservoirs with high-permeability sands or sandstones (Daqing: 800 md; Pelican Lake: 1-3 darcys; Mangala: 5 darcys; Marmul: 15 darcys; Dalia: >1 darcy; Tambaredjo: 4-12 darcys).

5. A conservative approach to design of a polymer flood would assume that inaccessible pore volume is zero, especially in multi-darcy sands

REVIEW OF POLYMER RETENTION METHODS

1. Mass balance on polymer: Polymer slug followed by water.
    - a. Unfavorable displacement during water injection after polymer –requiring MANY PV of water.
    - b. Significant errors accumulate from measuring low polymer concentrations.

2. Static method: Sand mixed with polymer solution.
    - a. Relies on only two measurements of polymer concentration.
    - b. Exposes extra mineral area for crushed rock.
    - c. Does not account for mechanically entrapped polymer.

PREFERRED POLYMER RETENTION METHOD

3. Double polymer/tracer bank method.

a. Two banks injected.

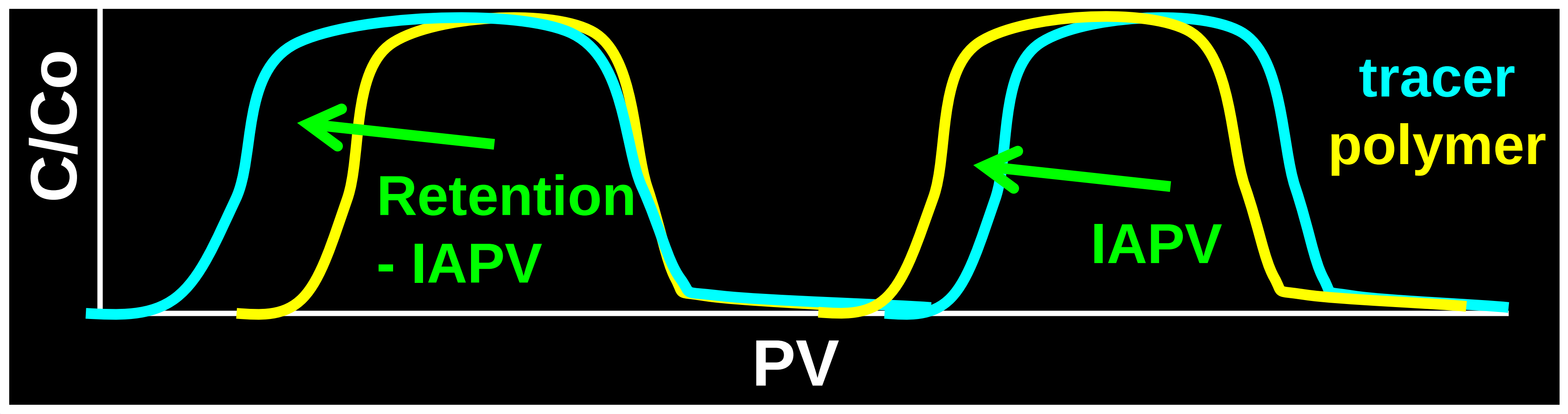
b. Each bank contains both polymer and tracer (KI).

c. ~100 PV of brine injected between the banks.

d. Only the front part of a given breakout curve is used—thus eliminating problems with unstable displacement.

e. **IAPV:** from area difference between the polymer and tracer breakout curves for the 2nd bank.

f. **Retention:** from the area difference between the polymer and tracer breakout for the 1st bank, after adding IAPV.



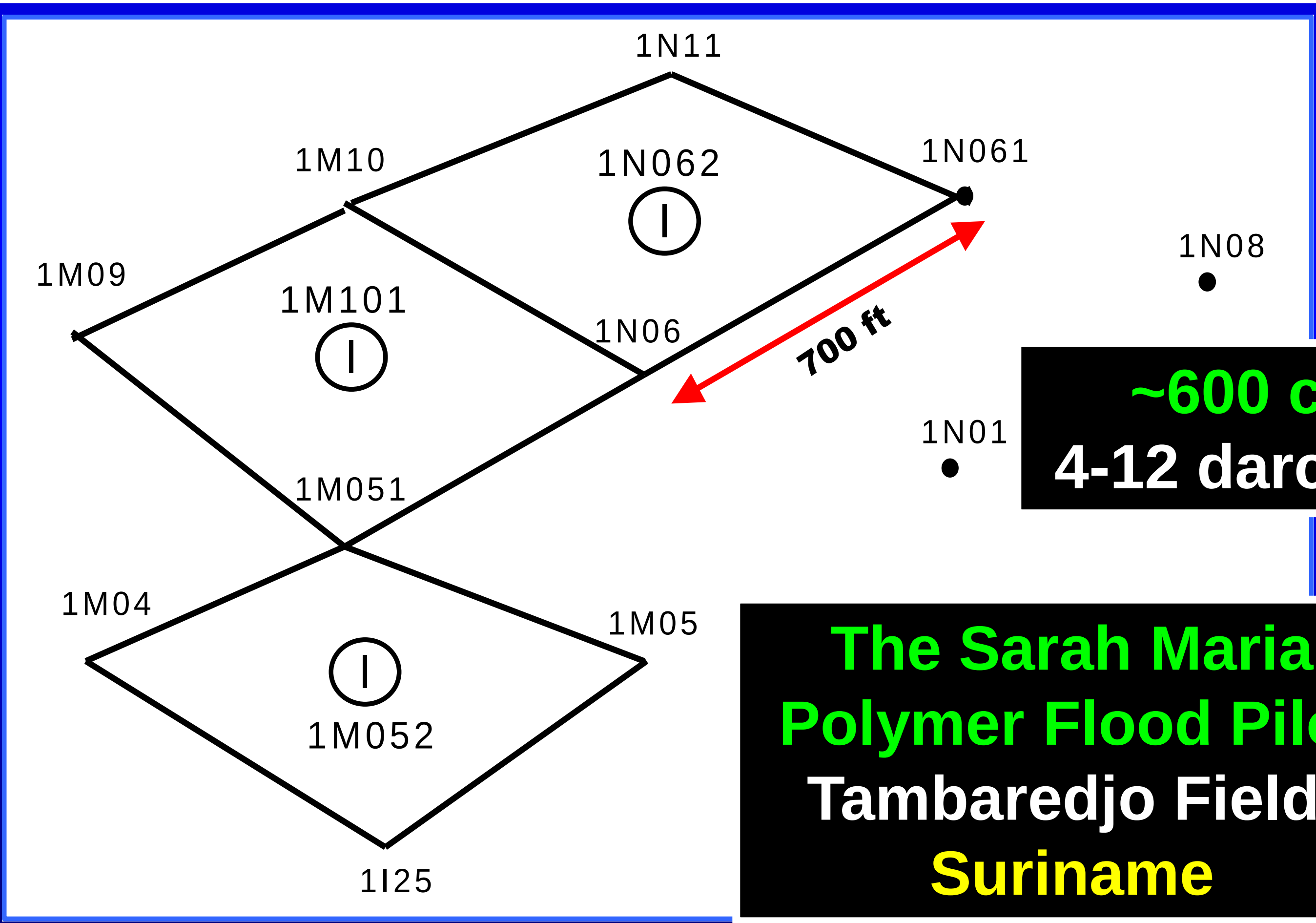
Polymer Retention and IAPV from Laboratory Studies

Tambaredjo Sands, Sarah Maria Polymer Flood, Suriname	Retention, µg/g	IAPV
T1 Sand	0 ± 20	0 ± 10%
T2 Sand	0 ± 20	0 ± 10%

What is the best source of reservoir sand?

a. Coring?
b. From the shale shaker during drilling?
c. Sand production from a production well?
d. Synthetic sand?

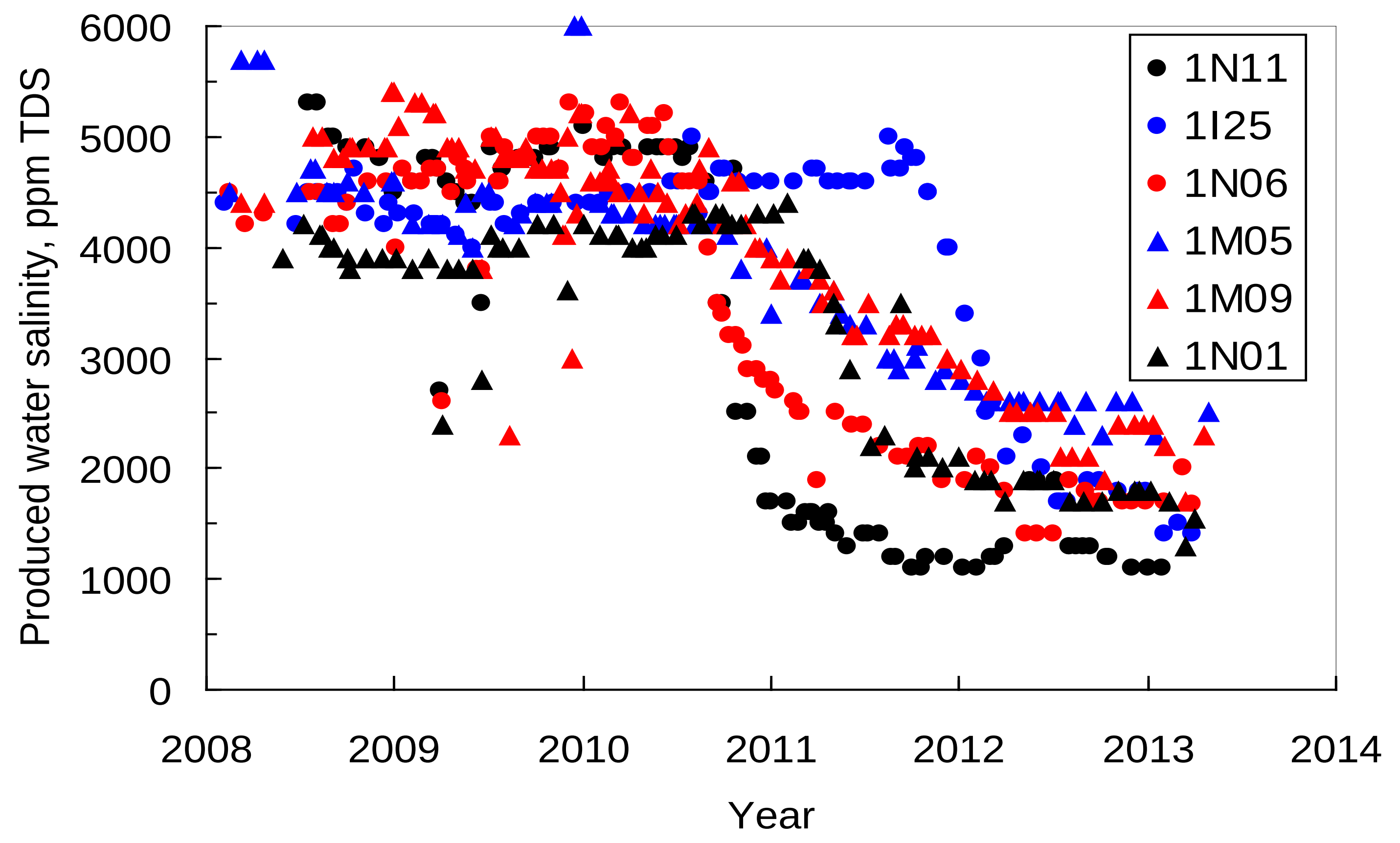
- Laboratory polymer retention measurements use/represent a VERY small part of the reservoir.
- Can field measurements be used to obtain more representative polymer retention values?
- Data would be helpful for scale up to a larger project.



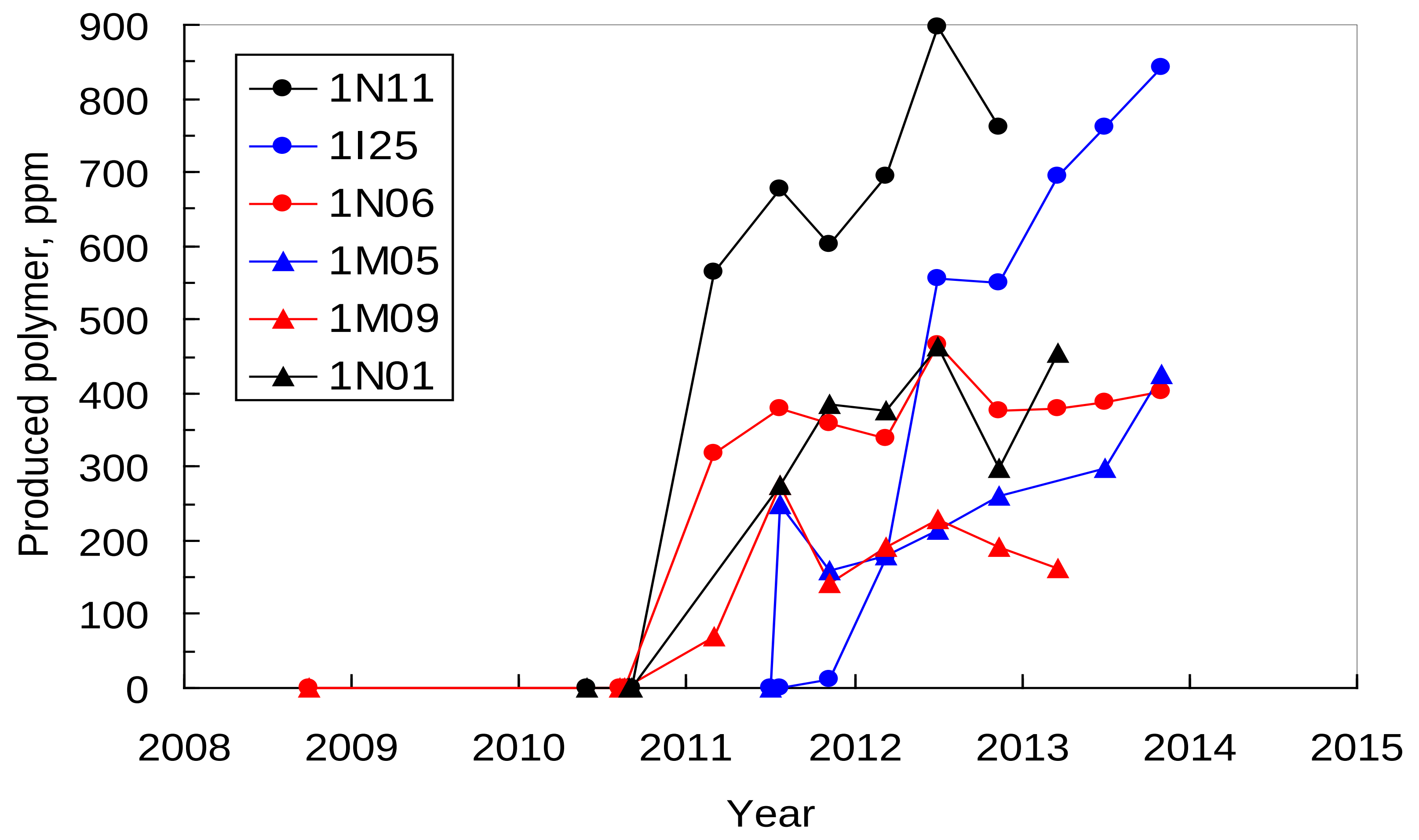
~600 cp oil
4-12 darcy sand

The Sarah Maria Polymer Flood Pilot
Tambaredjo Field, Suriname

- Injected salinity: 500-ppm TDS.
- Formation water salinity: 4700-ppm TDS.
- Polymer flood started right after primary production.
- Produced water salinity can act as a tracer.

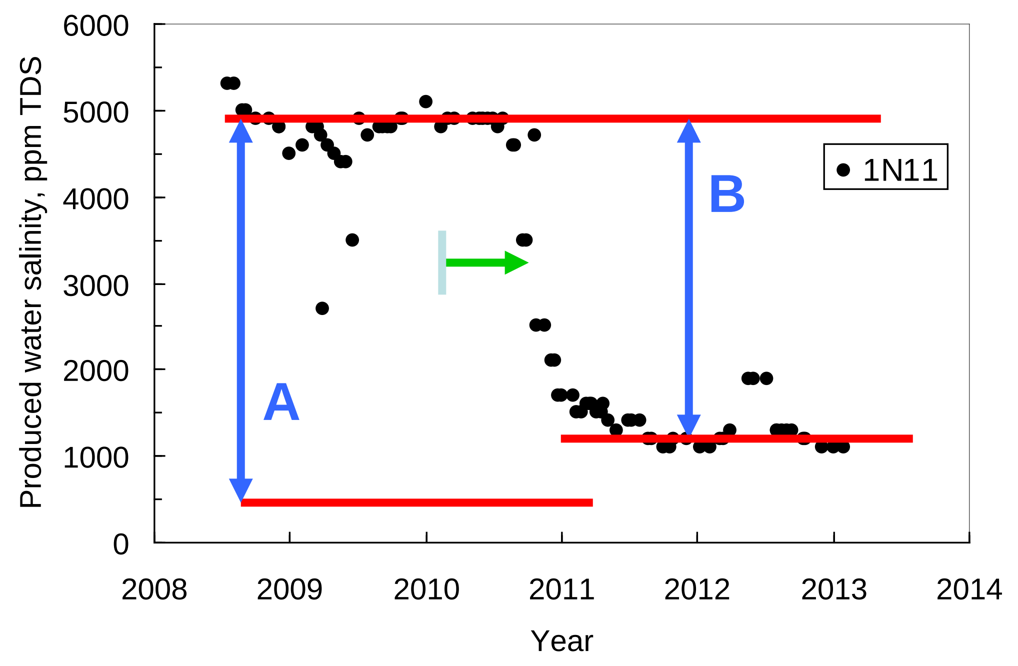


- **Injected 1000-ppm HPAM from 9/2008 – 11/2011.**
- **Inected 1350-ppm HPAM from 11/2011 – 2/2013.**
- **Recommend more frequent polymer sampling.**



Procedure to Estimate Polymer Retention from Field Data

1. Assume IAPV = 0.
2. For each producer, use the stabilized salinity data to establish the fraction of water flow coming from a nearby injector. (f_{wtrac} = B/A).
3. Use salinity to assign a swept volume between an injector producer pair. $V_{swept} = (f_{wtrac})\ \Sigma\ [\Delta V_{tracprod} * (1 - C_{trac}/C_{traco})]$



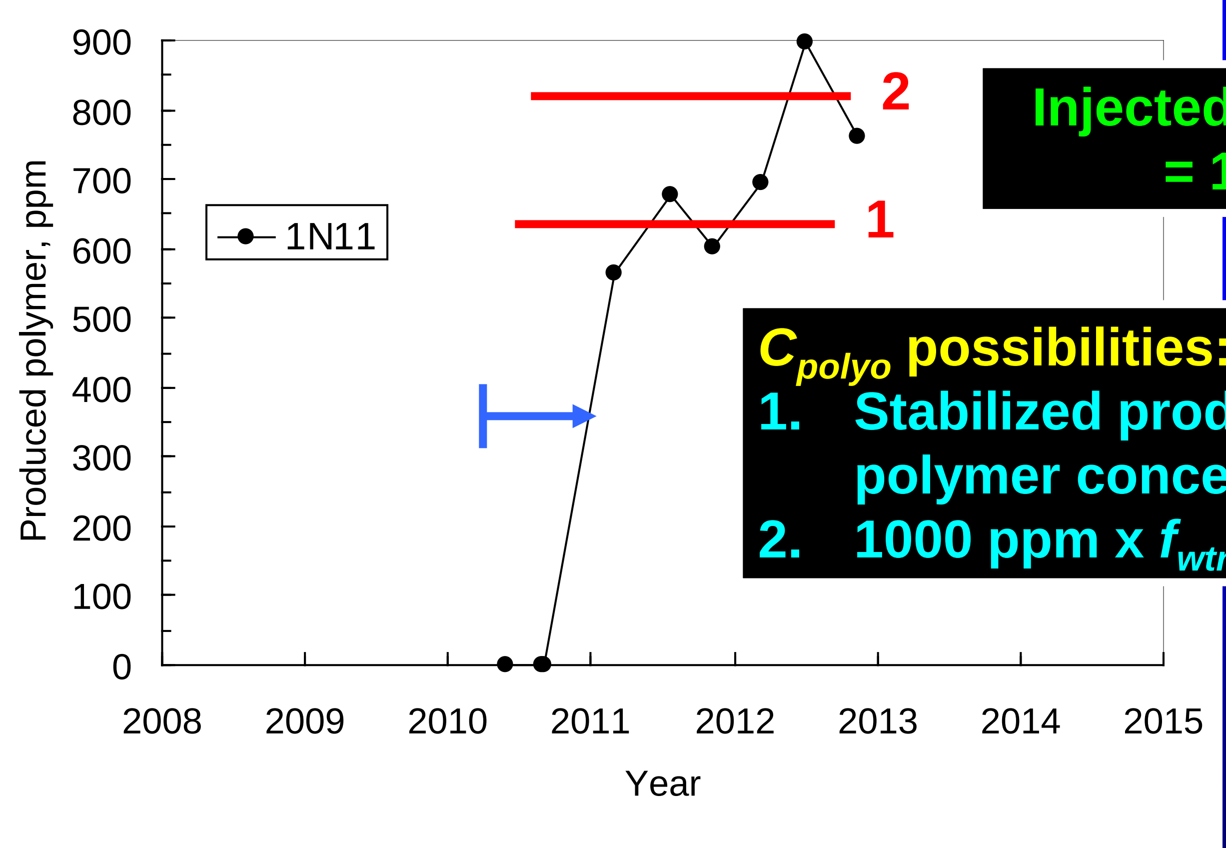
Procedure to Estimate Polymer Retention from Field Data

4. Estimate the rock mass in the swept area:

$$M_{rock} = V_{swept}\,[(1-\phi)/\phi]\,\rho_{rock}$$

5. Estimate polymer retention:

$$R_{pret} = \{C_{polyo}\,\Sigma\,[\Delta V_{polyprod} * (1-C_{poly}/C_{polyo})]\}/\,M_{rock}$$



Injected polymer = 1000 ppm

C_{polyo} possibilities:

1. **Stabilized produced polymer concentration**
2. **1000 ppm x f_{wtrac}**

Parameters for Estimation of Polymer Retention from Field Data

Production well	1N11	1I25	1N06	1M05	1M09	1N01
Starting salinity, ppm TDS	4737	4686	4657	4432	4707	3998
Ending salinity, ppm TDS	1291	1692	1684	2531	2281	1769
Ending polymer, ppm	634	550	375	226	216	395
f_{wtrac}	0.813	0.708	0.715	0.483	0.577	0.637
Range of retention values, µg/g	160-517	129-247	53-125	14-337	45-99	50-168

Most retention values fall between 50 and 250 µg/g

CONCLUSIONS (SPE 169027)

1. A review of the polymer-retention literature revealed that iron and high-surface-area minerals (e.g., clays) dominate polymer retention measurements in permeable rock and sand (>100 md).

2. A review of the literature on inaccessible pore volume revealed inconsistent and unexplained behavior. A conservative approach to design of a polymer flood in high-permeability (>1 darcy) sands would assume that inaccessible pore volume is zero.

3. Laboratory measurements using fluids and sands associated with the Sarah Maria polymer flood in Suriname suggested polymer retention and inaccessible pore volume values near zero.

CONCLUSIONS (SPE 169027)

4. A procedure was developed using salinity-tracer and polymer concentrations from production wells to estimate polymer retention during the Sarah Maria polymer flood in the Tambaredjo reservoir.

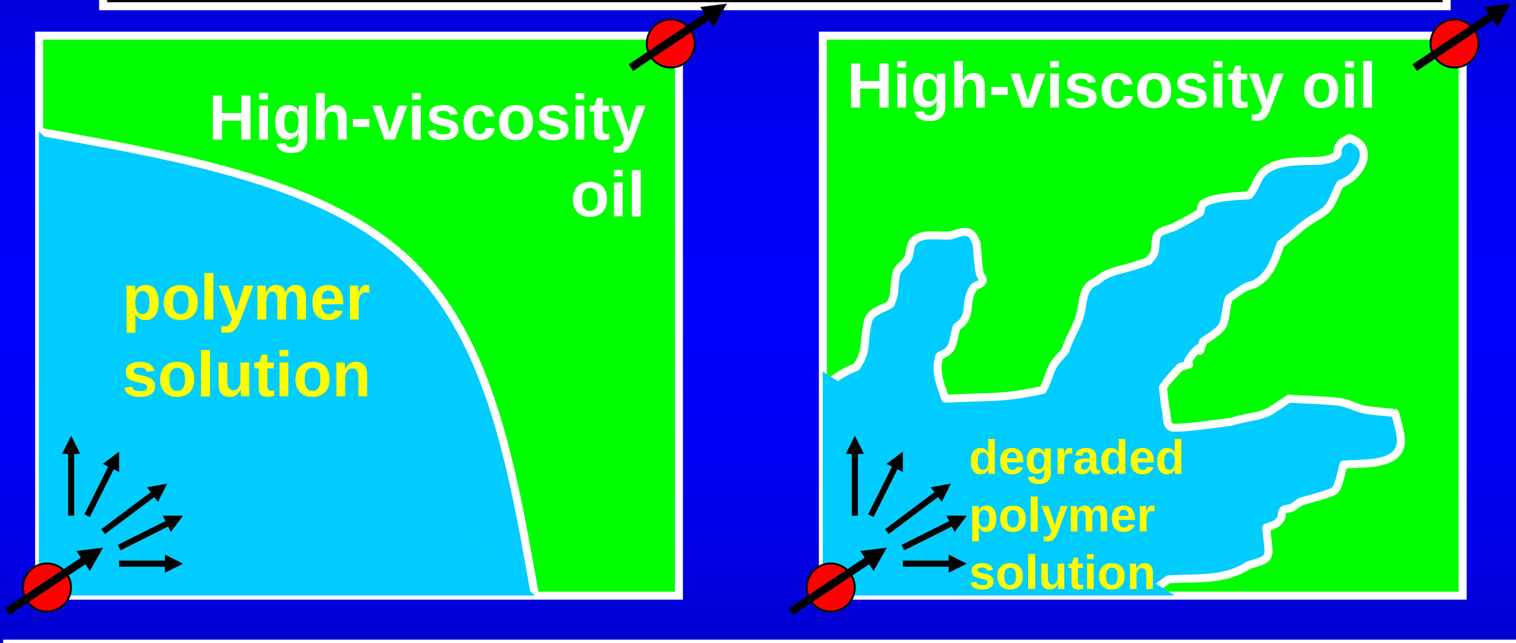
5. Field calculations indicated much higher polymer retention values than lab tests, typically ranging from ~50 to 250 µg/g.

6. Field cores necessarily represent an extremely small fraction of the reservoir. Because of the importance of polymer retention, there is considerable value in deriving polymer retention from field results, so that information can be used in the design of project expansions.

SPE 164121

Effective Propagation of HPAM Solutions through the Tambaredjo Reservoir during a Polymer Flood

When Displacing Viscous Oils, Viscous Polymer Solutions May Be Needed to Improve Sweep Efficiency



Polymer must remain stable during most of the transit through the reservoir.

In many polymer floods, the produced HPAM polymer was severely degraded, even in low-temperature applications:

Daqing, 45°C: 92% loss of Mw.
Shengli, 70°C: 77% loss of Mw.
Shuanghe (Henan) 70°C: 85% loss of Mw.
Courtenay, 30°C: 50% loss of Mw.
Tambaredjo, 38°C: 83% loss of Mw.

WHY?

Laboratory results indicate HPAM should be stable at low temperatures (Shupe 1981, Yang & Treiber 1985, Moradi & Doe 1987, Seright 2010).

Where does the degradation occur? If polymer degradation occurs during the first part of the flood, the polymer flood could be jeopardized.

Our hypothesis:

1. Iron minerals strip any dissolved oxygen from solution soon after injection (Seright 2010).
2. Fe^{2+} enters the polymer solution during transit through the reservoir.
3. Dissolved Fe^{2+} does not harm HPAM effectiveness if no dissolved O_2 is present.
4. Degradation occurs when HPAM solutions mix with air during sampling at the producer.
5. Better sampling methods are needed.

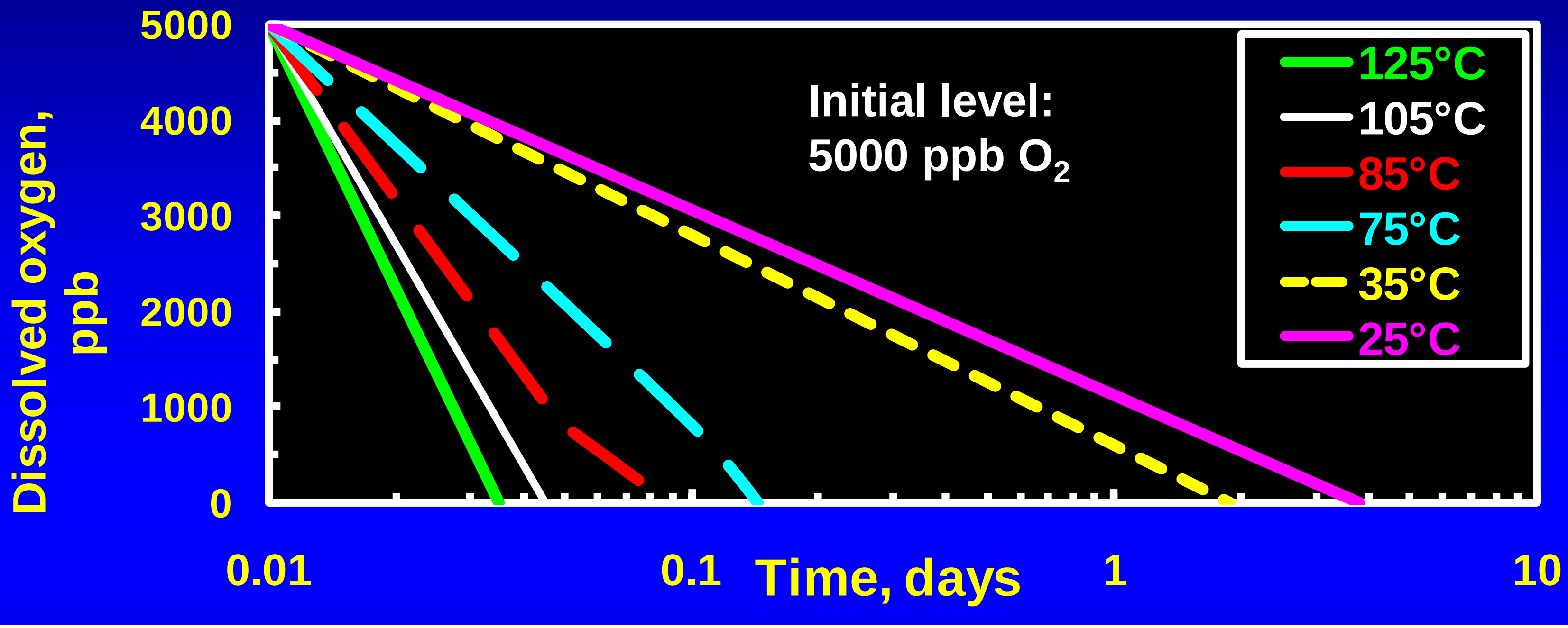
If both dissolved oxygen and iron are present, severe polymer degradation can occur.

$$Fe^{2+} + O_2 + \text{HPAM}$$

$$\downarrow$$

$$Fe^{3+} + H_2O + \text{degraded HPAM}$$

Depletion of dissolved oxygen by reaction with sand containing 1% pyrite



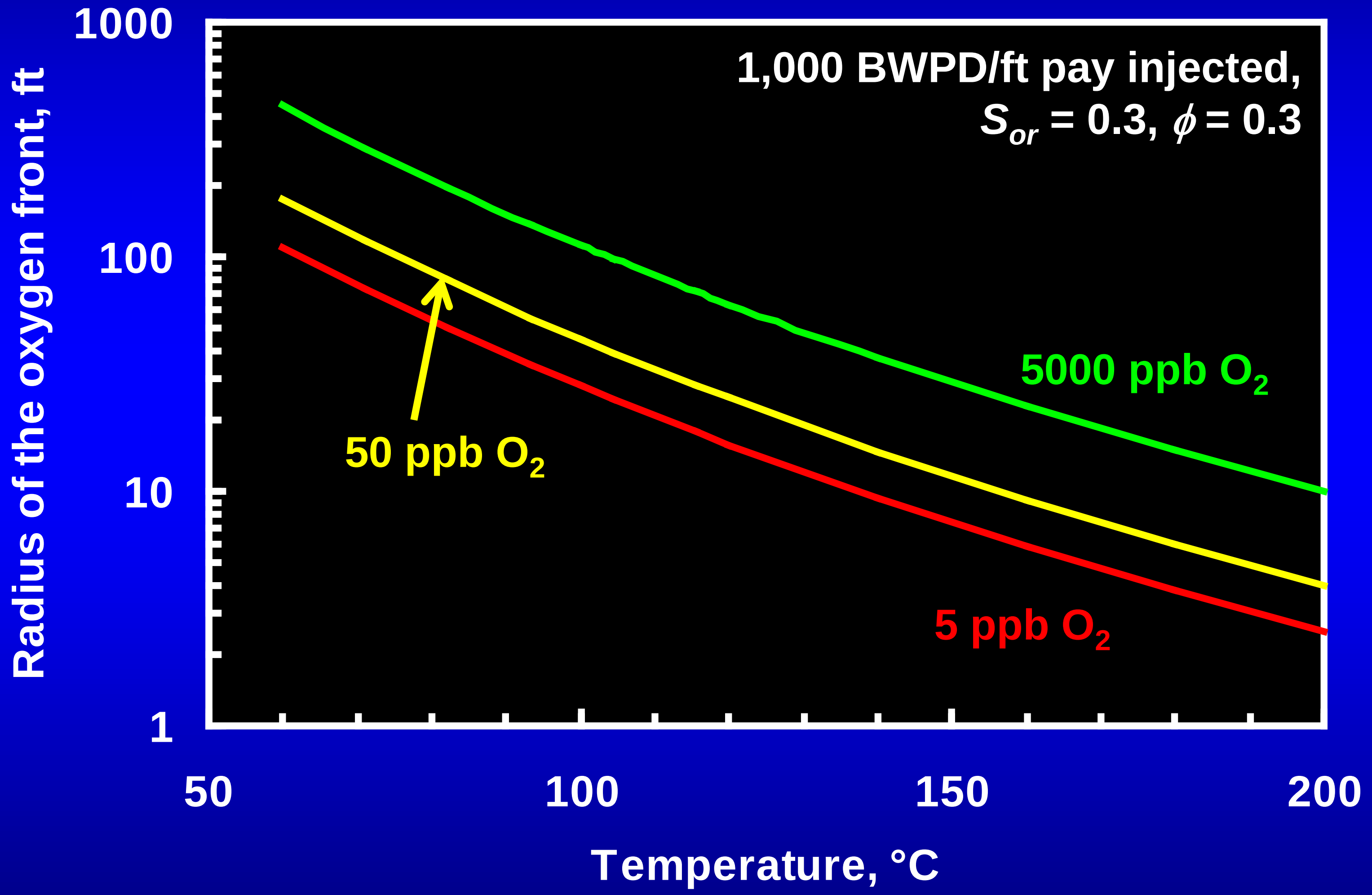
Dissolved O_2 that entered the reservoir prior to polymer injection will have been consumed and will not aggravate polymer degradation.

If an O_2 leak develops during the course of polymer injection, that O_2 will not compromise the stability of the polymer that was injected before the leak developed or after the leak is fixed.

Polymer that is injected while the leak is active will be susceptible to oxidative degradation. OXYGEN REMOVAL IS NECESSARY!

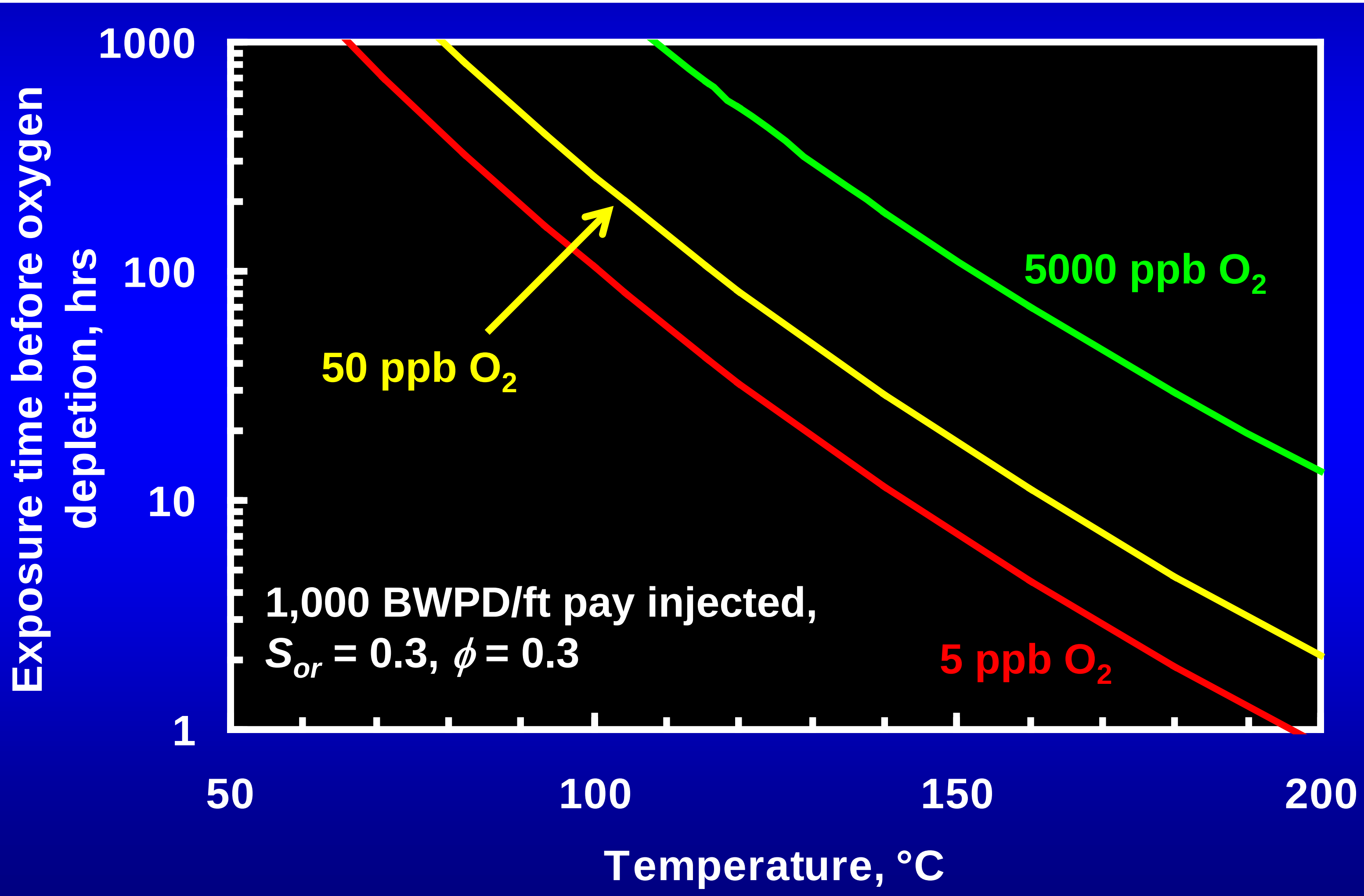
(But O_2 can be removed without use of expensive chemicals).

Radius at which dissolved oxygen is depleted by reaction with oil



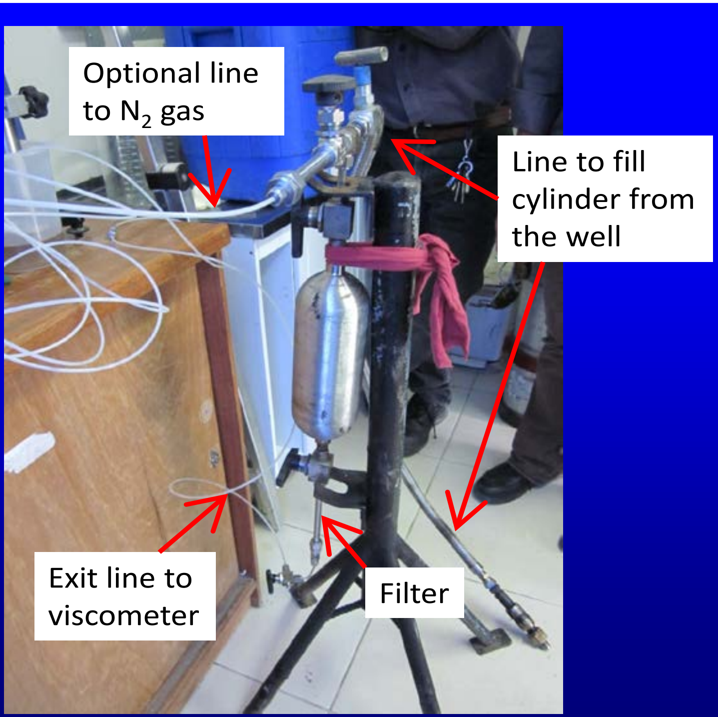
MODELING O_2 TRANSPORT THROUGH A RESERVOIR

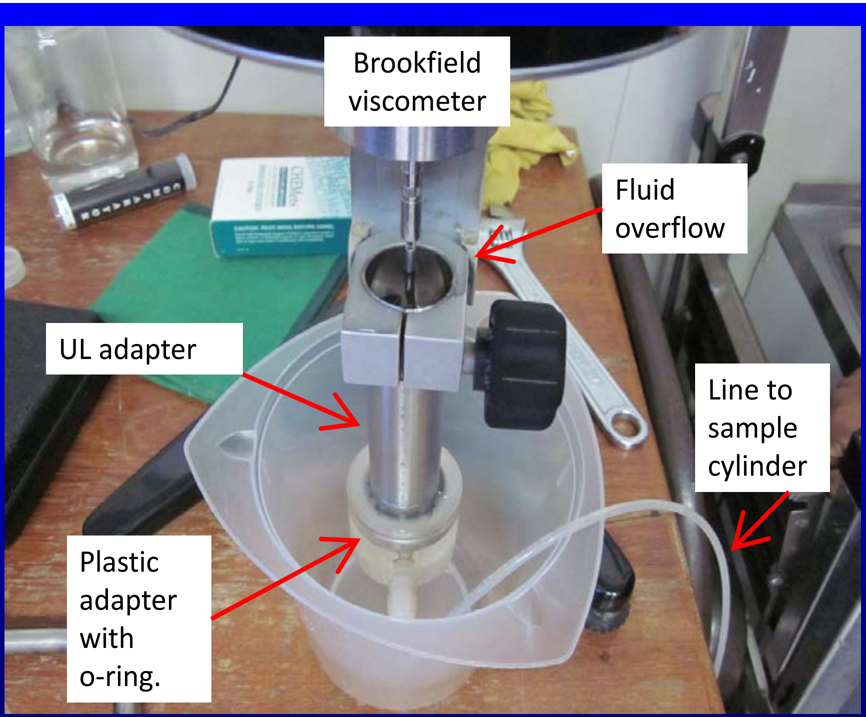
What if some O_2 is present? How long will it take for reaction with the oil to deplete the O_2?



New Anaerobic Sampling Method

1. Point the outlet end of the sample cylinder up during collection at the wellhead.
2. In the lab, if needed, pressurize the sample cylinder with N_2.
3. Flow anaerobic solution into the bottom of the viscometer cup (and overflow out the top).





Improved Sampling Method Results

Well	1N11	1N06
Polymer, ppm	896	465
	cp @ 7.3 s^{-1}	
Direct aerobic sampling	6	5
New method	32	14

KEY POINT: Minimum HPAM degradation after flowing >300 feet through the reservoir.

CONCLUSION (SPE 164121)

1. A new method was developed for anaerobically sampling polymer solutions from production wells in the Sarah Maria polymer flood pilot project in Suriname. Whereas previous methods indicated severe polymer degradation, the improved methods revealed that the polymer propagated intact over 300 ft through the Tambaredjo formation. This finding substantially reduces concerns about HPAM stability and propagation through low- and moderate-temperature reservoirs.

SPE 169030

Effect of Dissolved Iron and Oxygen on Stability of HPAM Polymers

Why bother worrying about degradation?

- **How much are you spending on polymer? $10 million? $100 million?**

- **In polymer flooding, viscosity is money. The volume of oil you get is directly related to the viscosity of your polymer in the reservoir.**

- **If you lose 50%-90% of your viscosity, you are wasting 50%-90% of your investment. Is it ok to throw away $5-90 million? Wouldn't it be better to spend a small fraction of that to remove O_2 from the make-up water or prevent O_2 from entering the flow stream?**

OXIDATIVE DEGRADATION OF HPAM

- **If O_2 is present, HPAM degradation depends on T, pH, E_H, and concentrations of Fe^{2+}, O_2 scavenger, polymerization impurities, and carbonate.**

- **If O_2 is not present (and divalent cations are not present), HPAM stability is good, regardless of the above impurities.**

- **If O_2 is re-introduced after a chemical oxygen scavenger is applied, a redox couple can form and degrade the polymer.**

APPROACHES TO MINIMIZE OXIDATIVE DEGRADATION IN FIELD APPLICATIONS

1. Do nothing if the temperature is low and no iron is present in the injection water.
2. Remove any existing O_2; don't let O_2 enter the flow stream.
3. Use an anti-oxidant package, including O_2 scavenger.
4. Intentionally oxygenate the water to precipitate iron. Then try to balance E_H, pH, and water composition to prevent formation of a redox couple.

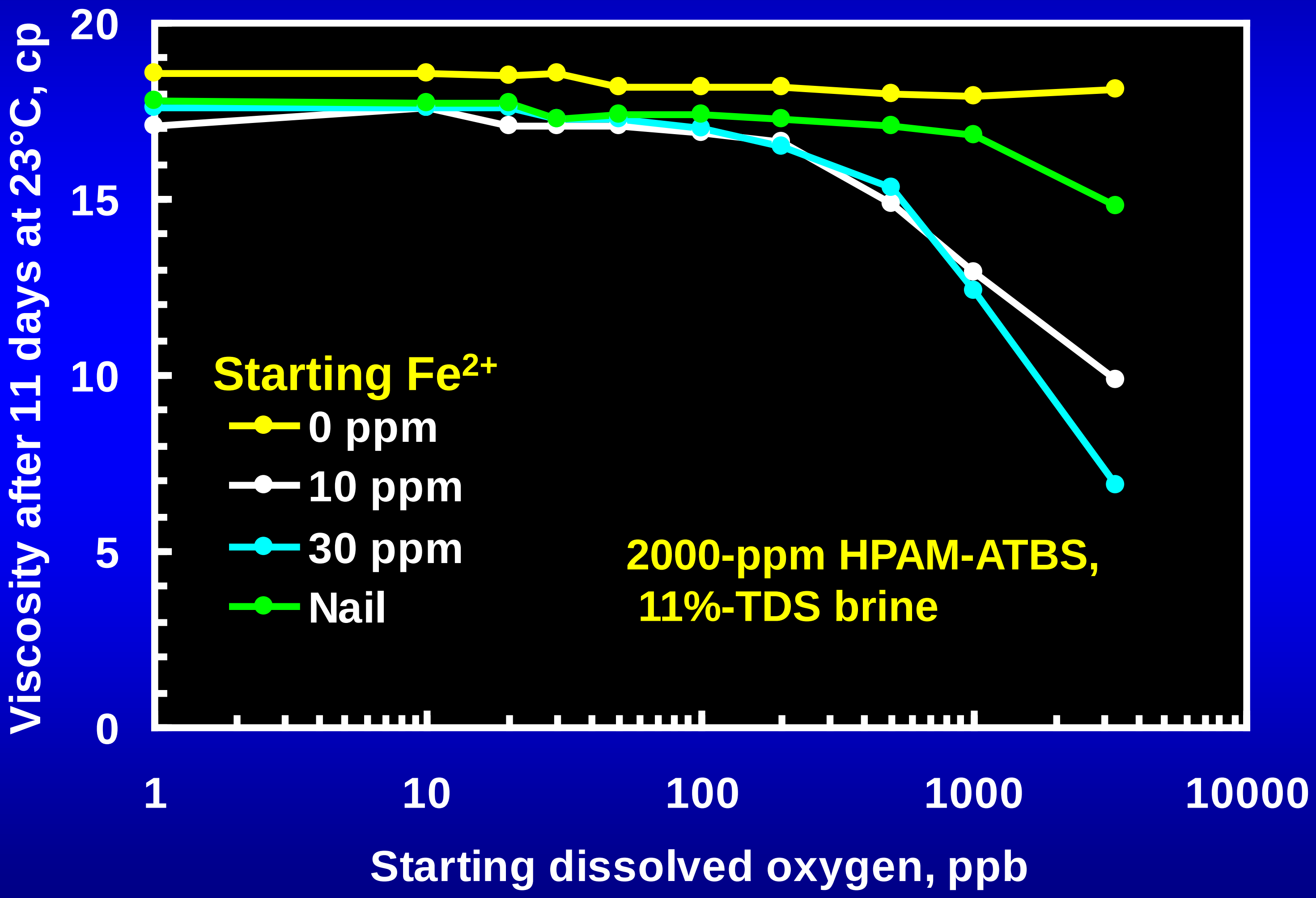
WHAT IS THE BEST APPROACH?

If iron is present, how much dissolved O_2 is acceptable?

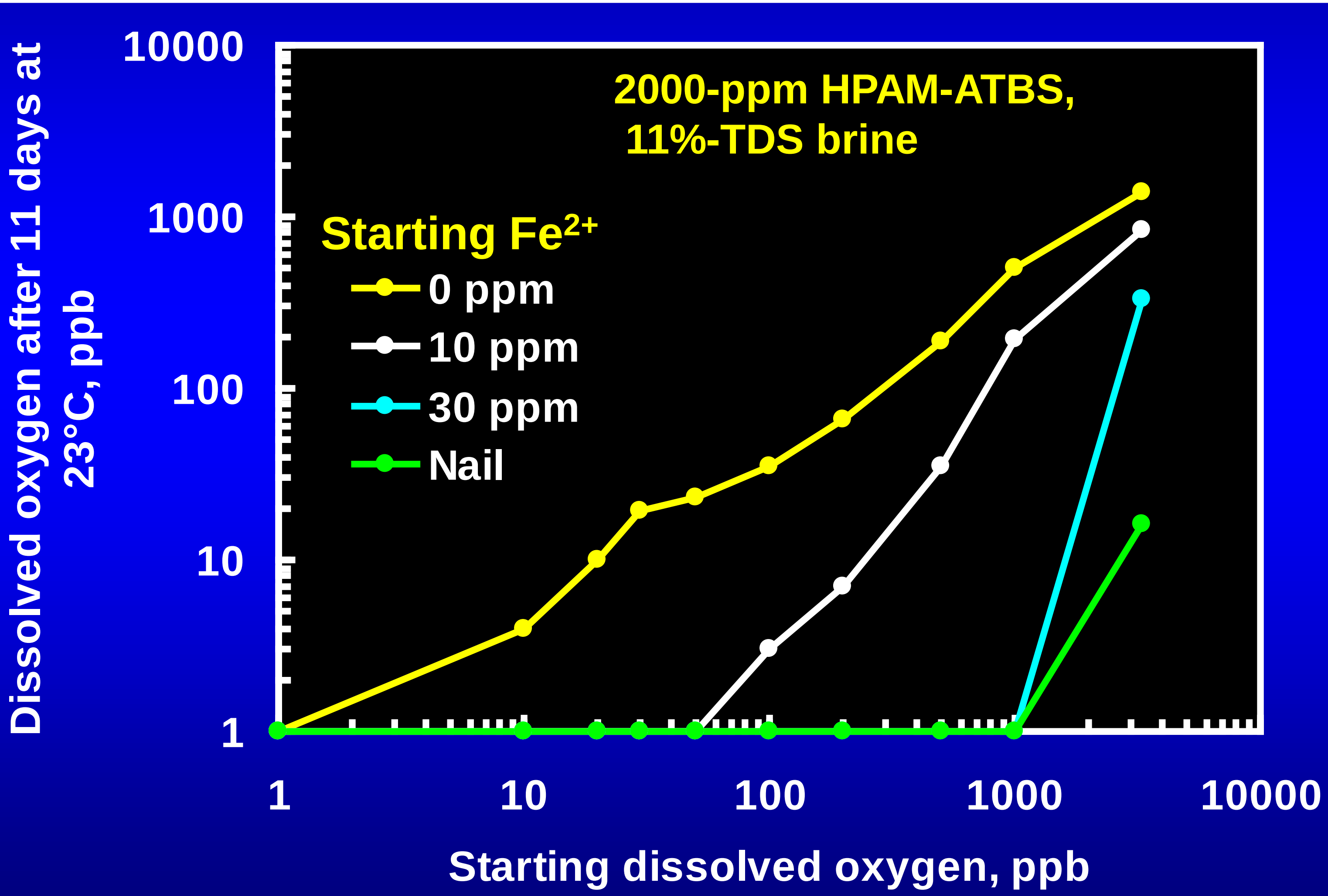
Polymers and Conditions Tested

1. Two polymers: HPAM and HPAM-ATBS.
2. Two salinities: 11%-TDS and 2.85%-TDS.
3. Two temperatures: 23°C and 90°C.
4. Dissolved O_2 concentrations from 0 to 8000 ppb.
5. Dissolved Fe^{2+} concentrations from 0 to 220 ppm.
6. Dissolved Fe^{3+} concentrations from 0 to 172 ppm.
7. Storage periods: 7-11 days.
    a. Iron minerals in the reservoir will remove any injected dissolved oxygen within days.
    b. Short storage period eliminates complications from hydrolysis/precipitation with Ca^{2+}.

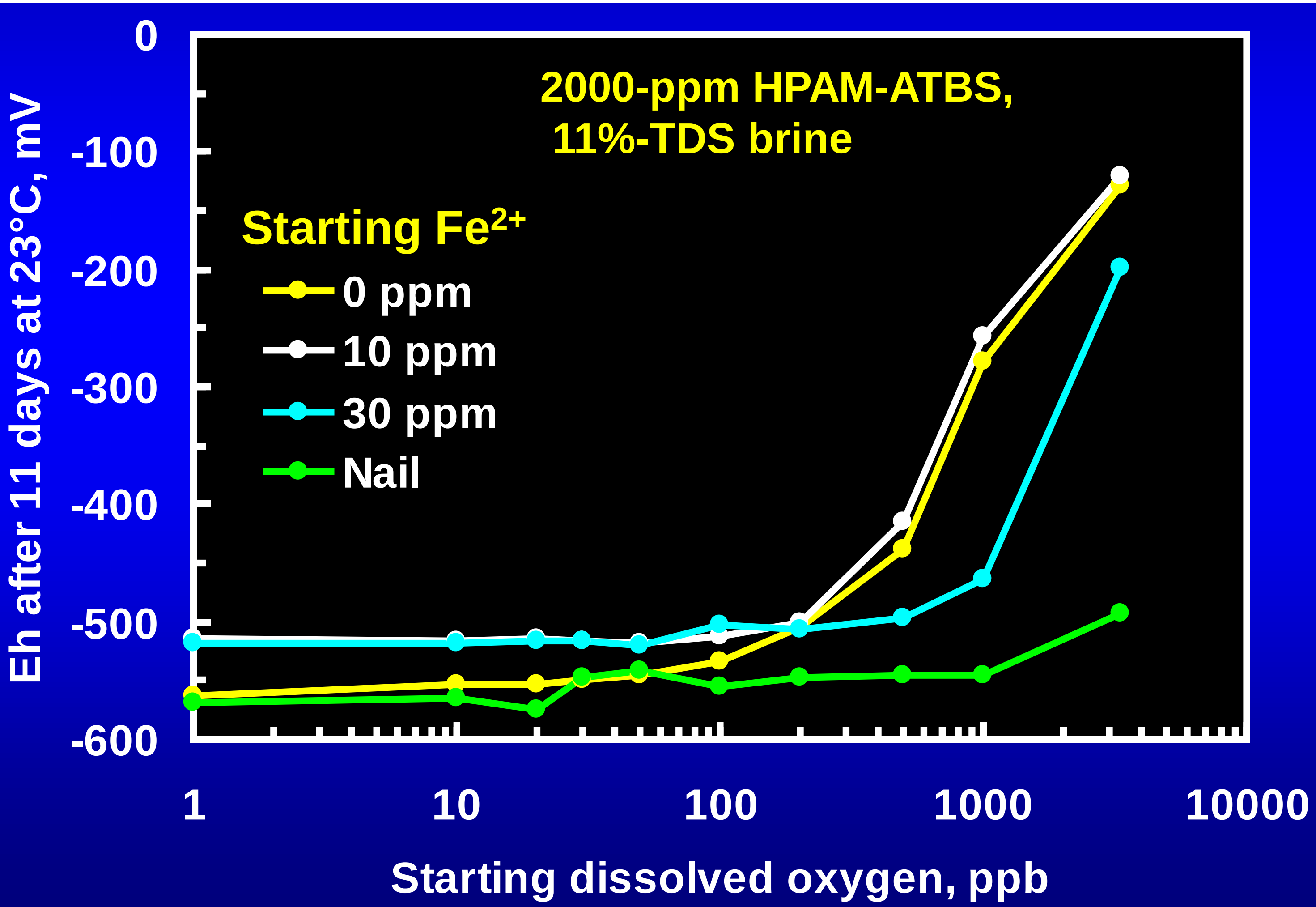
- Polymer degradation is low and not sensitive to Fe^{2+} if O_2 < 200 ppb and temperature is low.



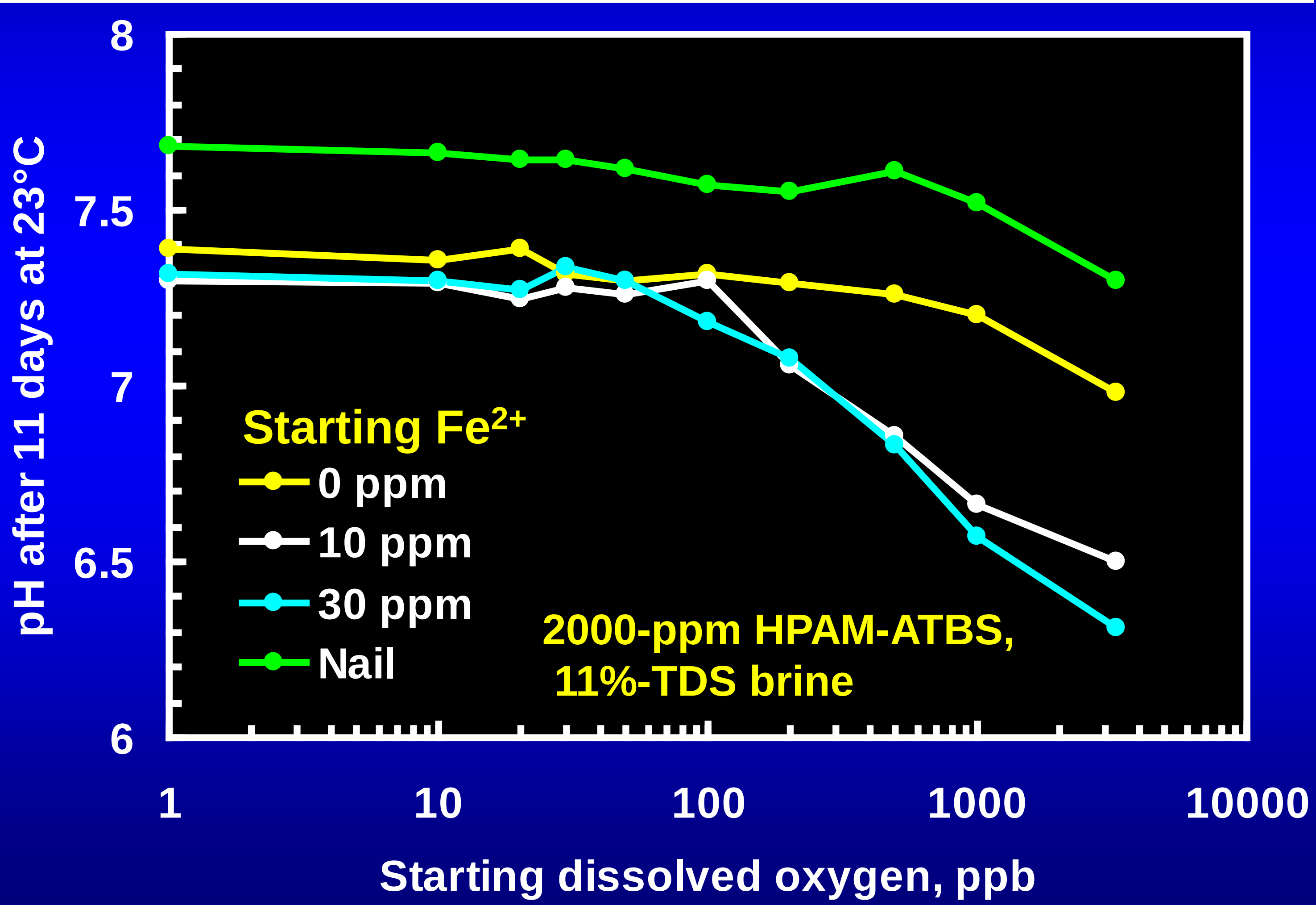
- O_2 depletion increases with higher Fe exposure.
- At the end, Fe^{2+} and O_2 appear to co-exist.
- Perhaps the polymer chelates Fe^{2+}?



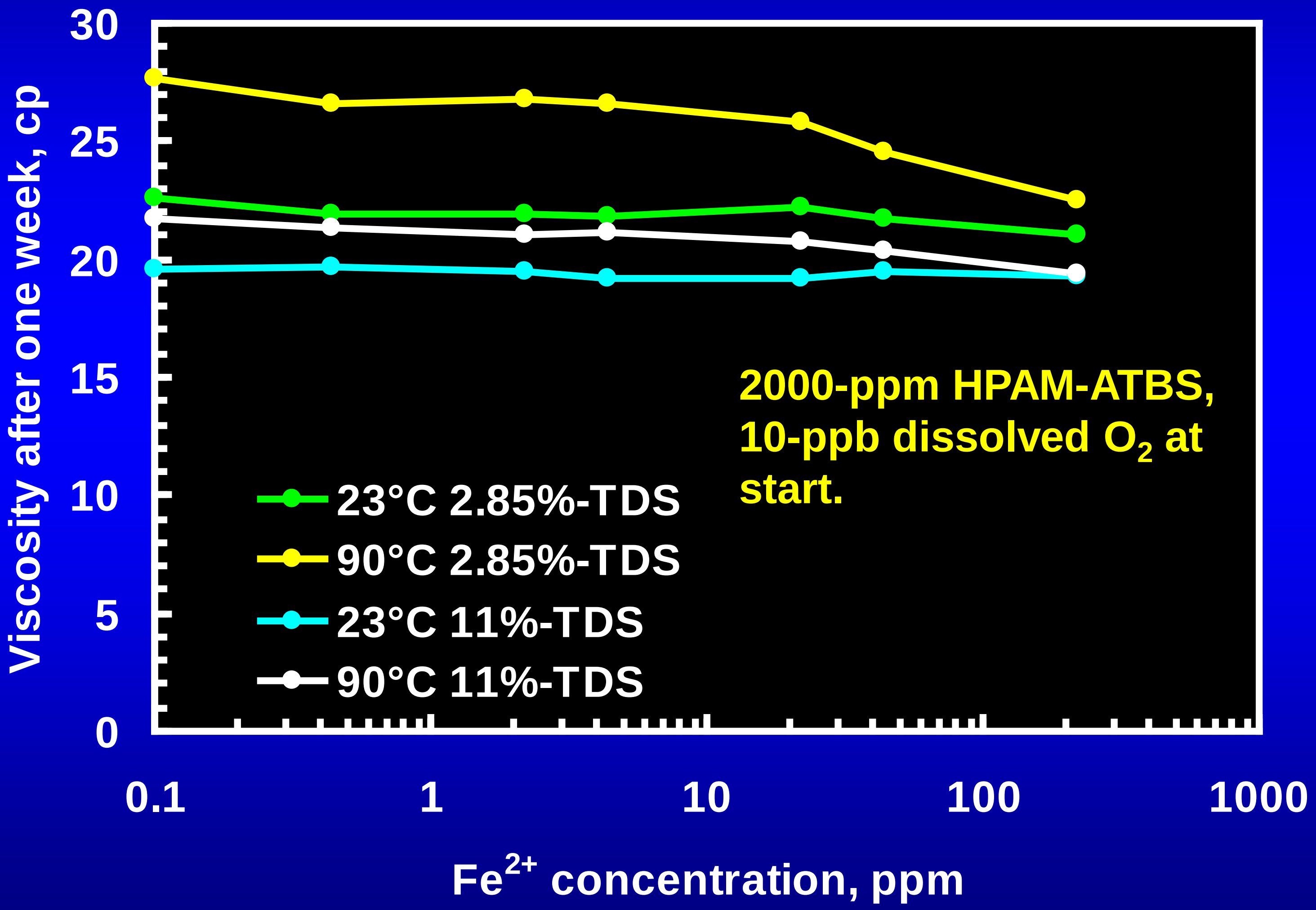
- The onset of polymer degradation coincided with the onset of a rise in Eh.
- However, the magnitude of degradation did not correlate with Eh.



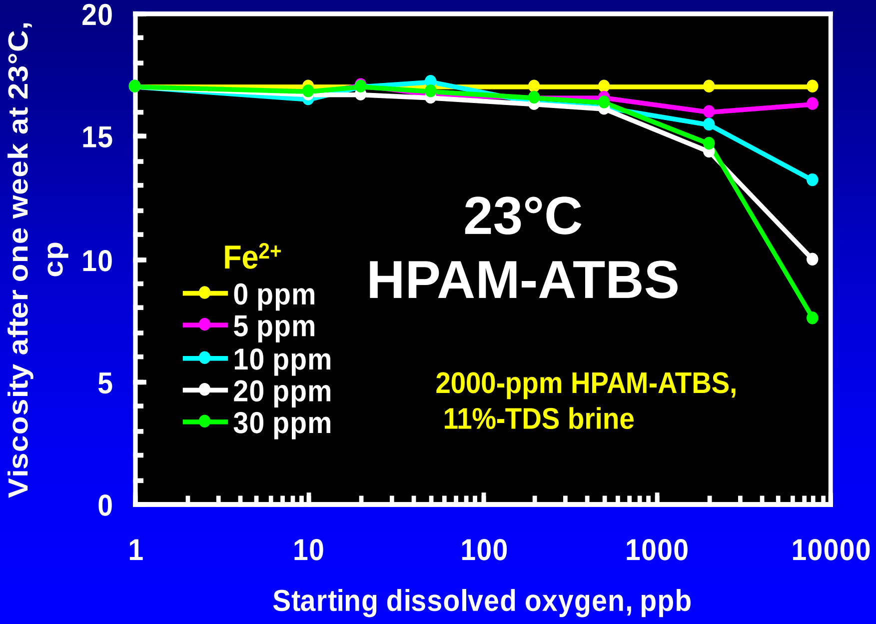
- The onset of polymer degradation coincided with the onset of a decrease in pH.
- This is consistent with Fe^{3+} complexation with OH^-.

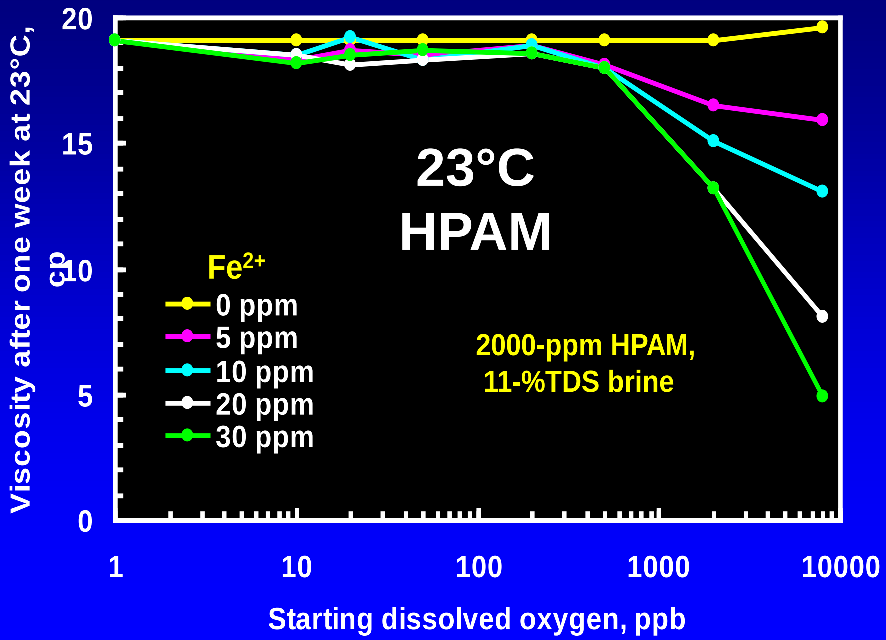


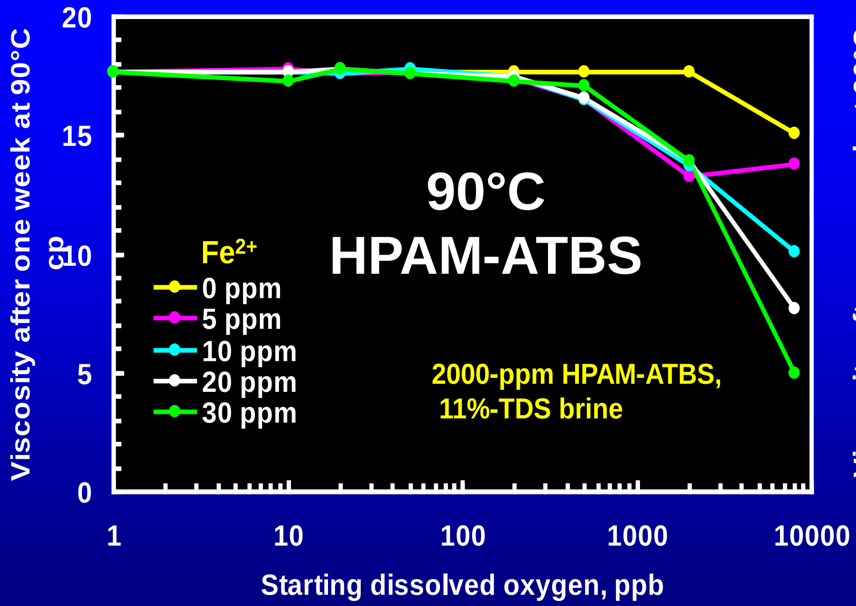
- With low O_2 content, polymer was stable and insensitive to Fe^{2+} concentration.

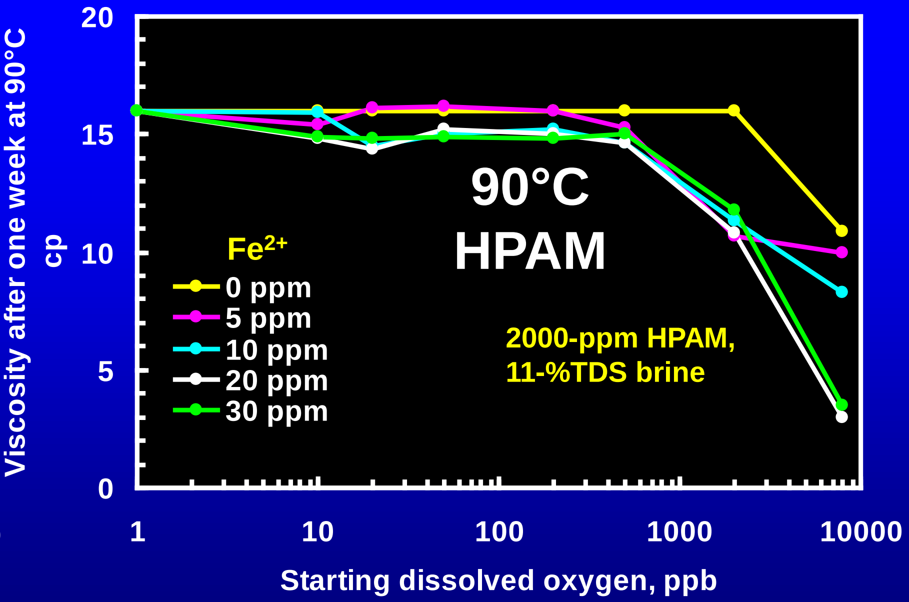


2000-ppm HPAM-ATBS, 10-ppb dissolved O_2 at start.

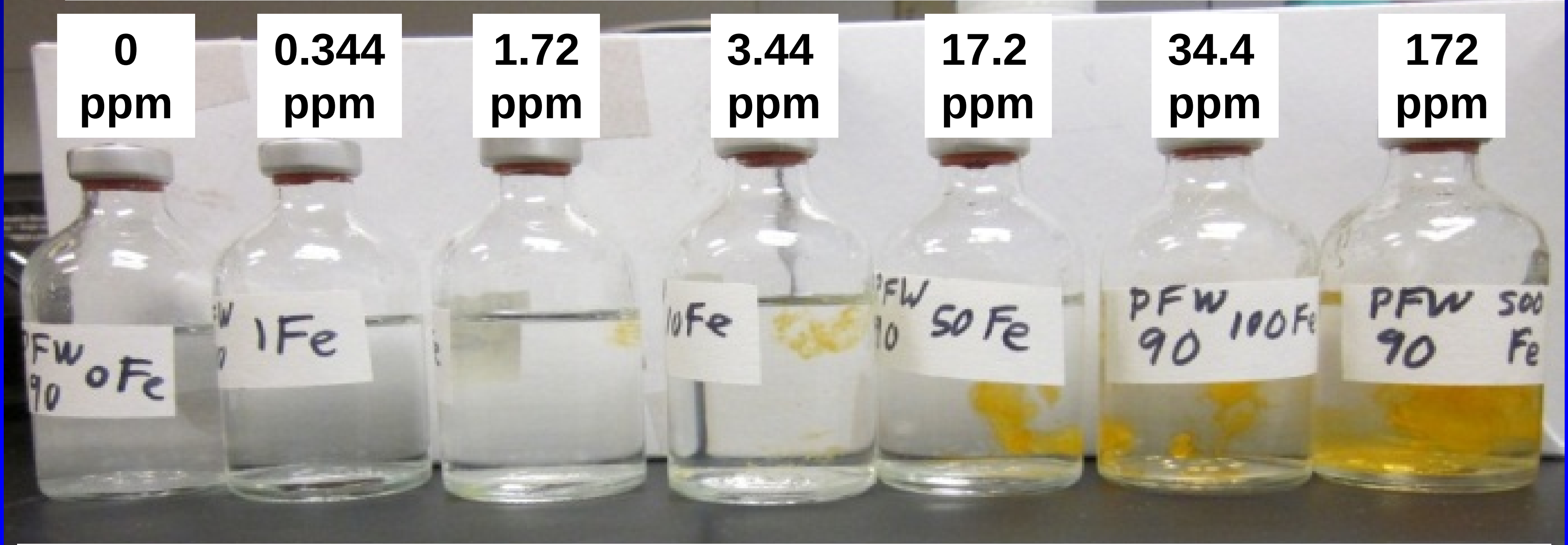

23°C
HPAM-ATBS
2000-ppm HPAM-ATBS,
11%-TDS brine
Fe^{2+}
0 ppm
5 ppm
10 ppm
20 ppm
30 ppm
Viscosity after one week at 23°C, cp
Starting dissolved oxygen, ppb
0
5
10
15
20
1
10
100
1000
10000


23°C
HPAM
2000-ppm HPAM,
11-%TDS brine
Fe^{2+}
0 ppm
5 ppm
10 ppm
20 ppm
30 ppm
Viscosity after one week at 23°C, cp
Starting dissolved oxygen, ppb
0
5
10
15
20
1
10
100
1000
10000


90°C
HPAM-ATBS
2000-ppm HPAM-ATBS,
11%-TDS brine
Fe^{2+}
0 ppm
5 ppm
10 ppm
20 ppm
30 ppm
Viscosity after one week at 90°C cp
Starting dissolved oxygen, ppb
0
5
10
15
20
1
10
100
1000
10000


90°C
HPAM
2000-ppm HPAM,
11-%TDS brine
Fe^{2+}
0 ppm
5 ppm
10 ppm
20 ppm
30 ppm
Viscosity after one week at 90°C cp
Starting dissolved oxygen, ppb
0
5
10
15
20
1
10
100
1000
10000

Concentration (in ppm) of Fe^{3+} added to 2000-ppm HPAM-ATBS in 11%-TDS brine, 10-ppb dissolved oxygen.



- Addition any concentration of Fe^{3+} to a polymer solution forms a gel.
- No gels formed during any of our studies with polymer and Fe^{2+}.
- Therefore, no Fe^{3+} formed during our studies with polymer and Fe^{2+}.

$$O_2 + 4e^- + 2H_2O \rightarrow 4OH^-$$

$$Fe \rightarrow Fe^{2+} + 2e^-$$

$$4Fe^{2+} + O_2 \rightarrow 4Fe^{3+} + 2O^{2-}$$

$$Fe^{2+} + 2H_2O = Fe(OH)_2 + 2H^+$$
$$Fe^{3+} + 3H_2O = Fe(OH)_3 + 3H^+$$

$$Fe(OH)_2 = FeO + H_2O$$
$$Fe(OH)_3 = FeO(OH) + H_2O$$
$$2FeO(OH) = Fe_2O_3 + H_2O$$

CONCLUSIONS (SPE 169030)

1. Between 0 and 30 ppm Fe^{2+}, viscosity losses were insignificant after one week (at either 23°C or 90°C) if initial $O_2 \leq 200$ ppb. If initial $O_2 > 200$-ppb, significant viscosity losses occurred.

2. For high O_2 content (>200 ppb), polymer degradation increased with increased iron exposure.

3. For HPAM-ATBS at 90°C with 10-ppb initial O_2, contact with steel caused viscosity losses of 34.4% in 2.85%-TDS brine and 31.5% in 11%-TDS brine. In contrast at 23°C, contact with steel caused no significant degradation if $O_2 \leq 1000$ ppb.

CONCLUSIONS (SPE 169030)

4. When anaerobic or low-oxygen solutions were exposed to atmospheric oxygen, polymer degradation increased substantially with increased Fe^{2+} concentration.

5. Orange gels formed when any concentration (down to 0.344 ppm) of Fe^{3+} was added. No gels formed during our studies with Fe^{2+}--suggesting that free Fe^{3+} did not form.

Implications for Field Applications

1. If temperature is low and the water contains no Fe^{2+}, no oxygen removal is needed. Iron minerals in the formation will quickly (days) remove the oxygen.

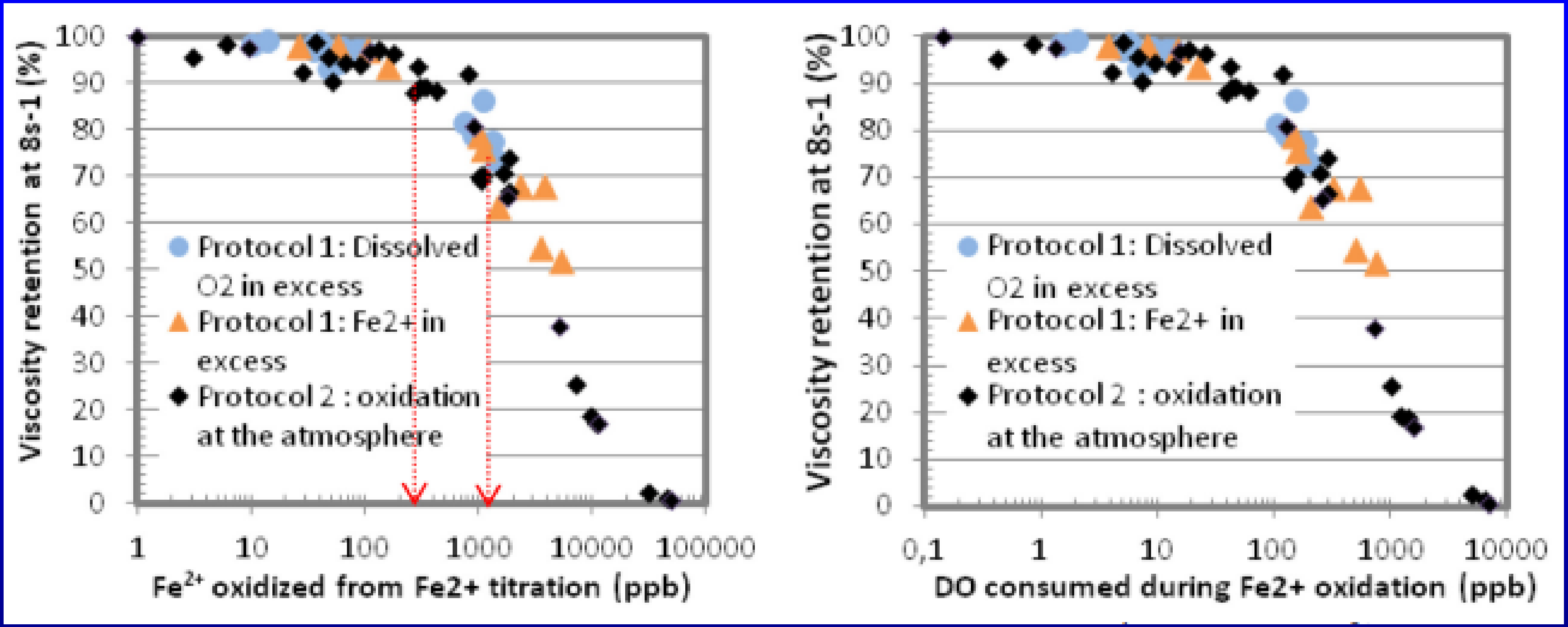
2. If Fe^{2+} is present in the polymer make-up water, the water is probably oxygen-free at its source. Keeping the water oxygen free is the recommended approach—by preventing O_2 leaks, better design of fluid transfer, gas blanketing, gas stripping.

Jouenne et al. (SPE 179614)

1. **For temperatures below 50°C and if iron is present, dissolved oxygen should be < 40 ppb.**
2. **Iron-oxygen stoichiometry is governed by:**

$$Fe^{2+} + \frac{1}{4} O_2 + H^+ \longrightarrow Fe^{3+} + \frac{1}{2} H_2O$$

$$[Fe^{2+} \text{ (in ppm)}] / [O_2 \text{ (in ppm)}] = 7.$$



How destructive are free radicals?

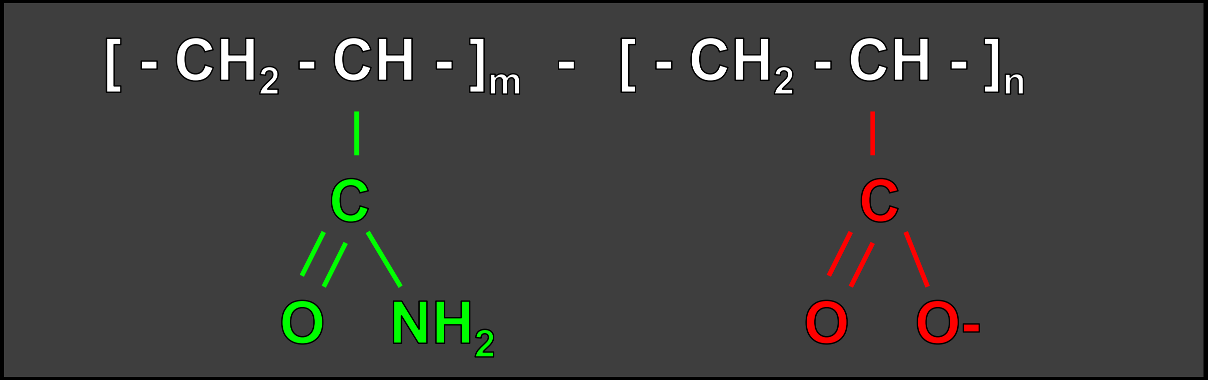
1. Wellington (SPE 9296) suggested that one free radical could degrade MANY HPAM molecules.

2. In contrast, data from Shupe (SPE 9299), Yang & Treiber (SPE 14232) and Seright et al. (SPE 121460, SPE 169030) reveals that once the O_2 is consumed, no more HPAM degradation occurs.

3. The data of Jouenne et al. (SPE 179614) indicates that over 400 free radicals are need to break the central bond in one HPAM molecule. 1 O_2 generates 1 free radical. 600 ppb O_2 halves the viscosity of 800 ppm $18x10^6$ Mw HPAM. $[(6x10^{-7})/32][(8x10^{-4})/(18x10^6)] = 422$.

UPPER LIMIT OF
TEMPERATURE STABILITY
FOR POLYMERS
(IF NO OXYGEN IS PRESENT)

What is the upper temperature limit for HPAM use in chemical EOR?



$$[-CH_2-CH-]_m - [-CH_2-CH-]_n$$

$$\underset{\overset{\parallel}{O}\ \ NH_2}{C} \qquad \underset{\overset{\parallel}{O}\ \ O^-}{C}$$

- Above 60°C, acrylamide groups hydrolyze to form acrylate groups.
- If the degree of hydrolysis is too high and too much Ca^{2+} or Mg^{2+} is present, HPAM polymers precipitate.

Temperature, °C:	75	88	96	204
Max Ca^{2+} + Mg^{2+}, mg/L:	2000	500	270	20

(from Moradi-Araghi and Doe, 1987)

You can’t stop hydrolysis of PAM or HPAM. At 80°C, hydrolysis will rise to ~60% after 100 days. (Moradi and Doe, Phillips, *SPERE* May 1987). Preventing >50% hydrolysis could be done by incorporating at least 50% AMPS or NVP (SPE 14233).

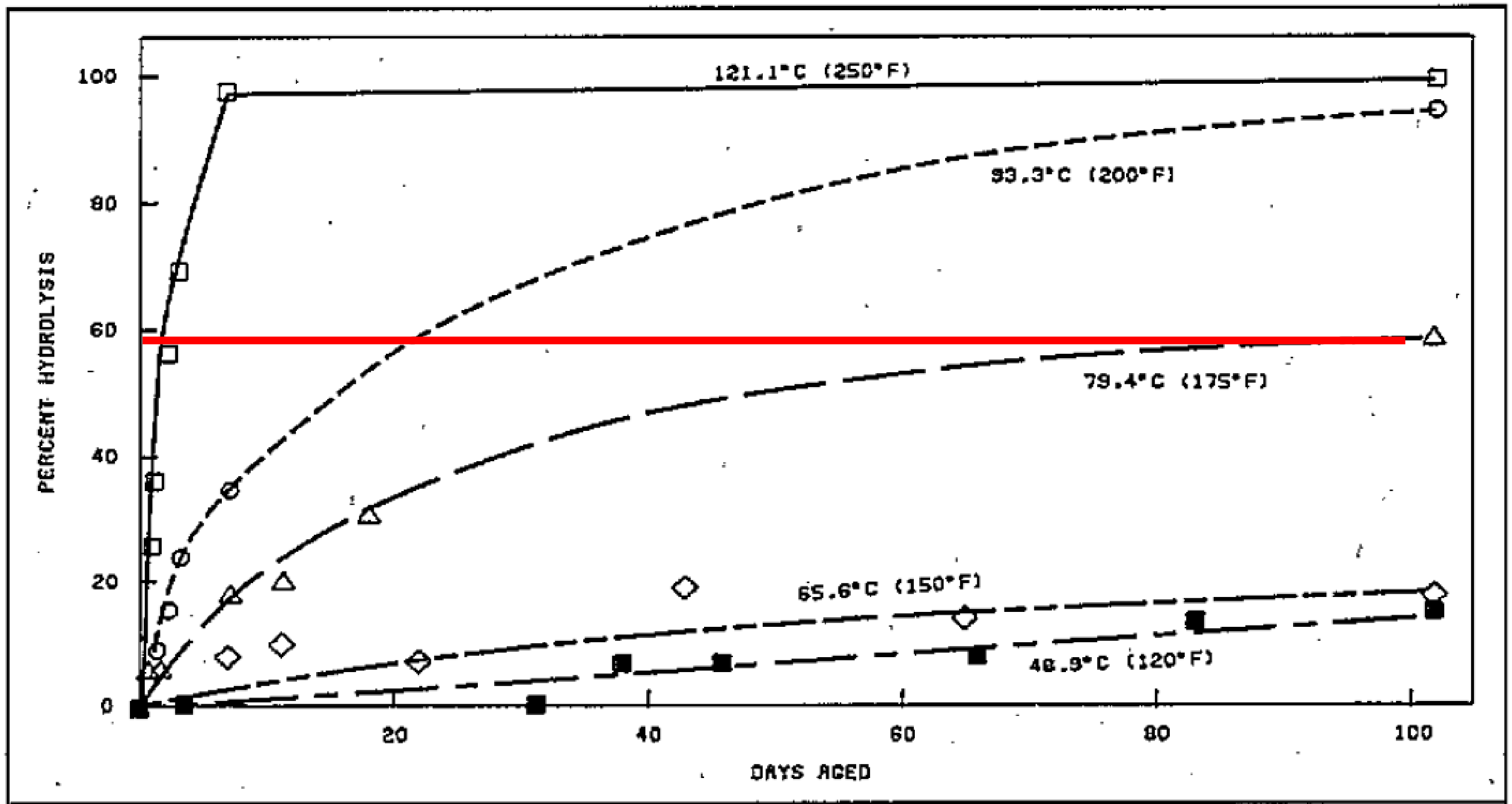


Fig. 13—The effect of temperature on the hydrolysis of 1,000-ppm originally unhydrolyzed Polyacrylamide A in 5% NaCl solution.

Recent paper on hydrolysis of HPAM: SPE 179558.

Approaches to mitigating HPAM precipitation:

1. A few hot reservoirs exist with low hardness.
2. Hydrolysis-resistant monomers (AMPS, NVP) can be incorporated into PAM polymers (Moradi-Araghi, Doe 1987). Need >50% NVP or AMPS. They tend to be expensive and less effective as viscosifiers.
3. Fresh water or low-hardness HPAM solutions can provide efficient sweep with minimum mixing with saline brines if polymer mobility is sufficiently low (Maitin 1992). Requires that mixing and cation exchange be understood and controlled.
4. Complex the hardness with chelating agents (Albonico and Lockhart, ENI, SPE 25220). Expensive. Must still prevent mixing with the formation water. May not provide any benefit over just using seawater.

WILL A CO/TER-POLYMER WITH AMPS OR NVP BE MORE STABLE THAN HPAM?

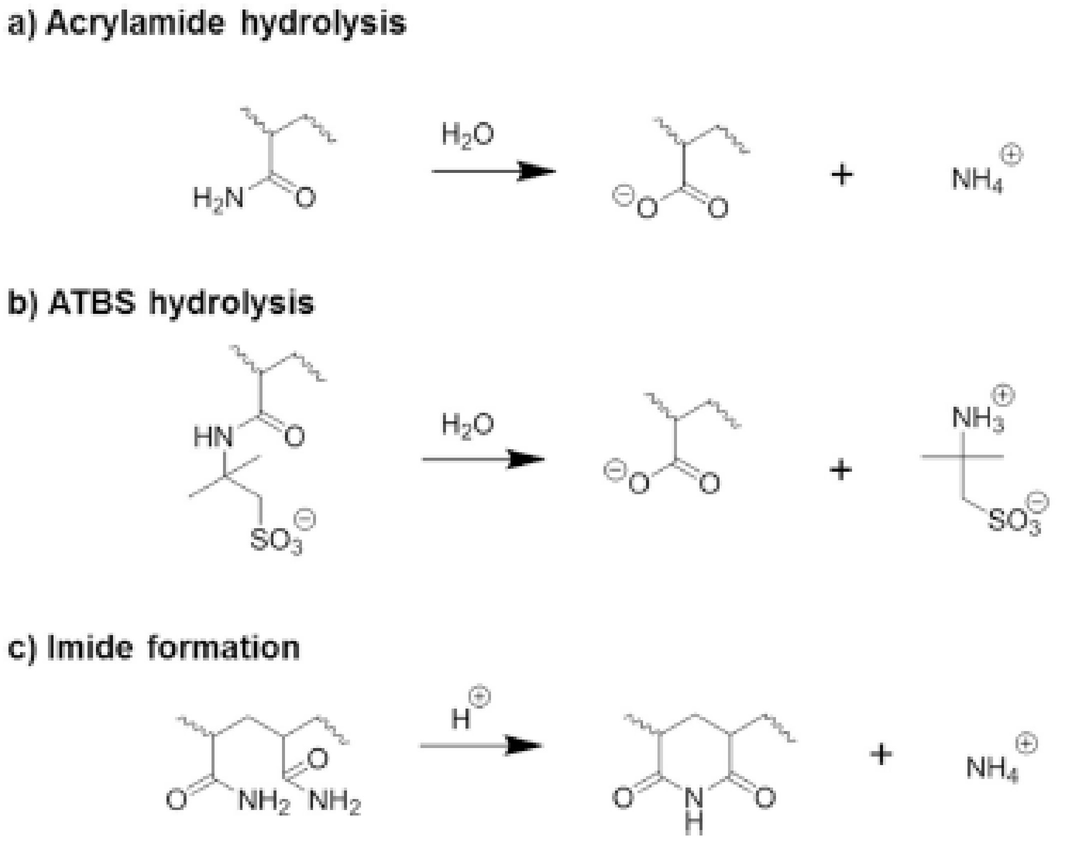
AMPS or NVP copolymers are more expensive, give lower Mw, and are less effective viscosifiers than HPAM.

However, some stability improvements can be expected, depending on composition: SPE 177073 (Gaillard et al.), SPE 141497 (Vermolen et al.).

AMPS or NVP copolymers with <45% AMPS/NVP will not be more stable (to O_2) than HPAM. [Doe, *SPERE* Nov. 1987; Parker and Lezzi, *Polymer* 34(23**) 1993; Seright *SPEJ* June 2010].**

Sandegen et al. *J. Petr. Sci. & Eng*. 158: 680-692.

1. Rise in pH seen during storage of HPAM/ATBS solutions is due to imide formation, not hydrolysis.
2. Hydrolysis reactions occur faster at lower pH values—so lab studies using unbuffered solutions may give overly optimistic estimates of hydrolysis rates in the field.


a) Acrylamide hydrolysis

b) ATBS hydrolysis

c) Imide formation

Fig. 1. Schematic of AM and ATBS conversion.

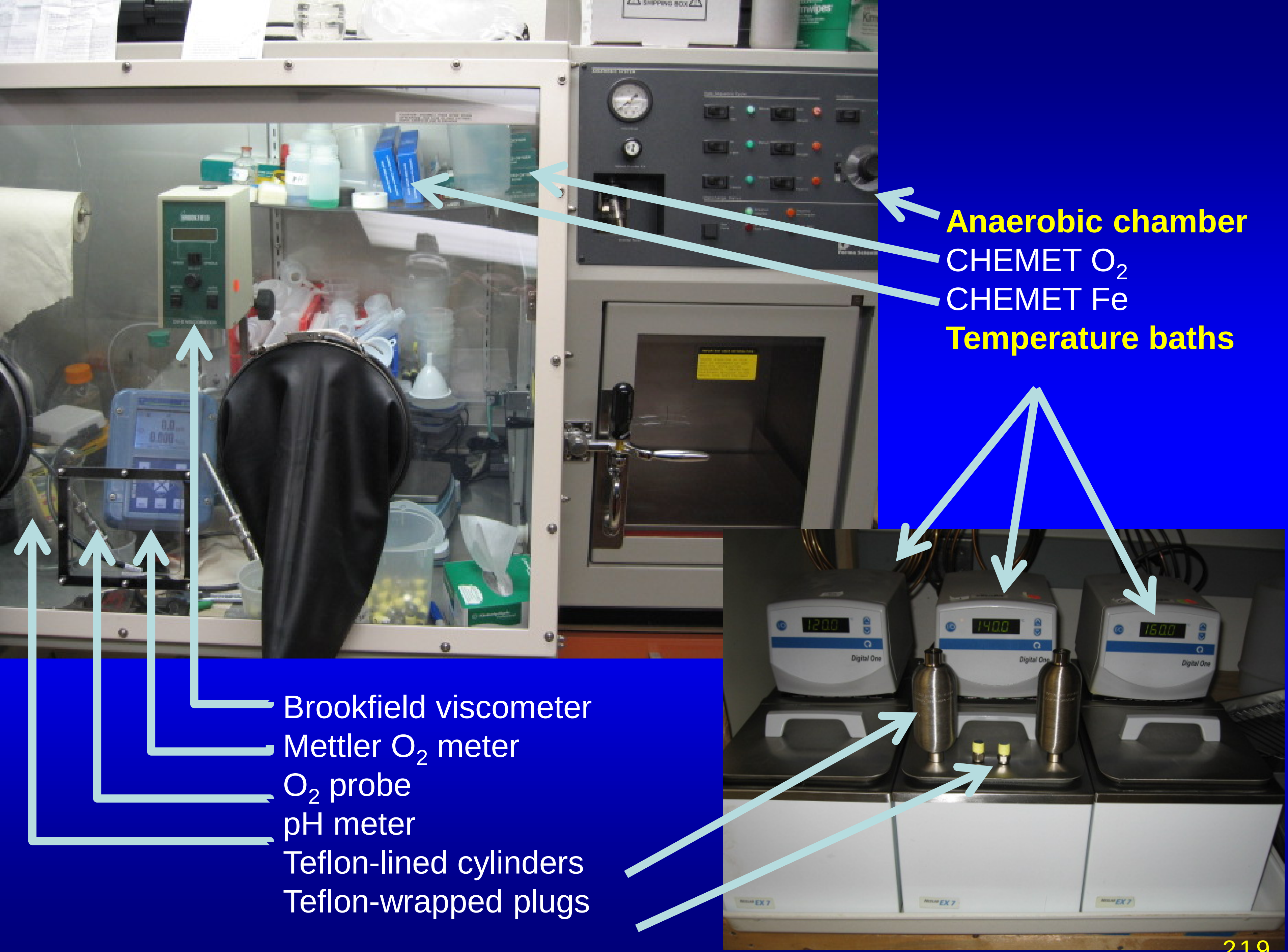
If divalent cations are not a problem, what is the upper temperature limit for HPAM use in EOR?

- Maximizing polymer stability requires minimizing oxygen contact.
- Most reservoirs produce water with no detectable dissolved oxygen.
- Oxygen-free EOR solutions can readily be prepared in the field by (1) preventing leaks, (2) gas blanketing tanks and mixing facilities, (3) gas stripping if necessary, (4) adding chemical oxygen scavengers if necessary.

Lab record to date: Shupe (1981) reported a 13% viscosity loss after 250 days at 105°C when a chemical oxygen scavenger was used.

Preparing, Storing, and Studying O_2-Free Polymer Solutions in the Laboratory. Our Method:

- Prepare solutions in an anaerobic chamber with 10% H_2 + 90% N_2 circulated through Pd catalyst.
- O_2 levels measured to <0.001% in the chamber atmosphere and to <0.1 ppb in solution.
- Brine reduced to <0.1 ppb O_2 by bubbling chamber gas into the brine (requires ~ 1 hour).
- Polymer stored and mixed in the chamber.
- Solutions sealed in 150 ml teflon-lined cylinders.
- Solutions stored in 120°C-180°C baths outside the anaerobic chamber.
- Viscosity at 7.3 s^{-1}, O_2, and pH measured inside the anaerobic chamber (at 25°C).



Anaerobic chamber

CHEMET O_2

CHEMET Fe

Temperature baths

Brookfield viscometer

Mettler O_2 meter

O_2 probe

pH meter

Teflon-lined cylinders

Teflon-wrapped plugs

New Features of Our Method:

- Uses a new oxygen meter that measures to 0.1 parts per billion (ppb) in solution.
- Confirmed that our solutions were prepared with <0.1 ppb O_2 and maintained at this level throughout the study.
- No need for chemical oxygen scavengers.

Advantage of our method over previous methods:

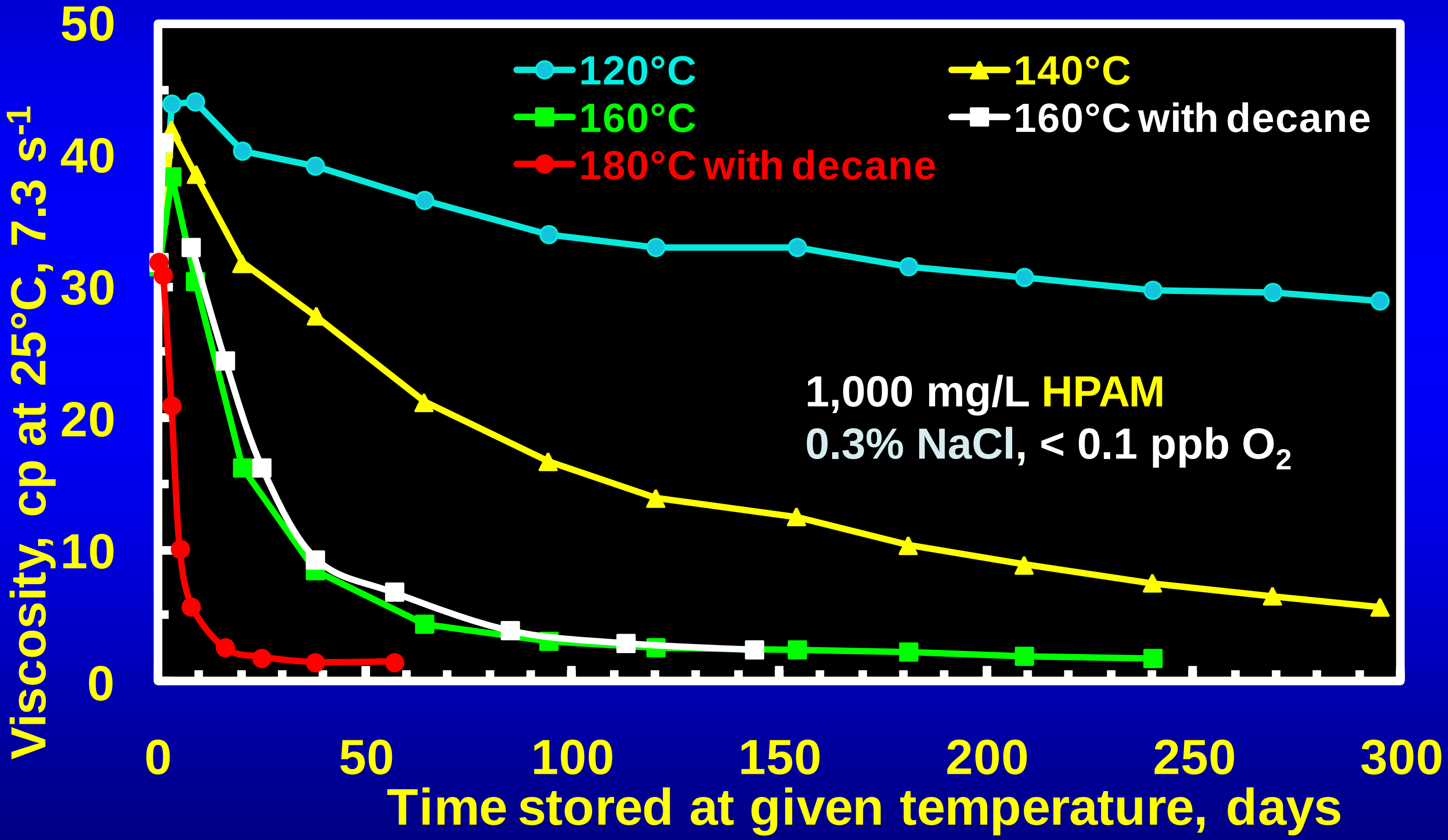
- Measure viscosity, dissolved O_2, and pH on the SAME sample throughout the study.

Disadvantage:

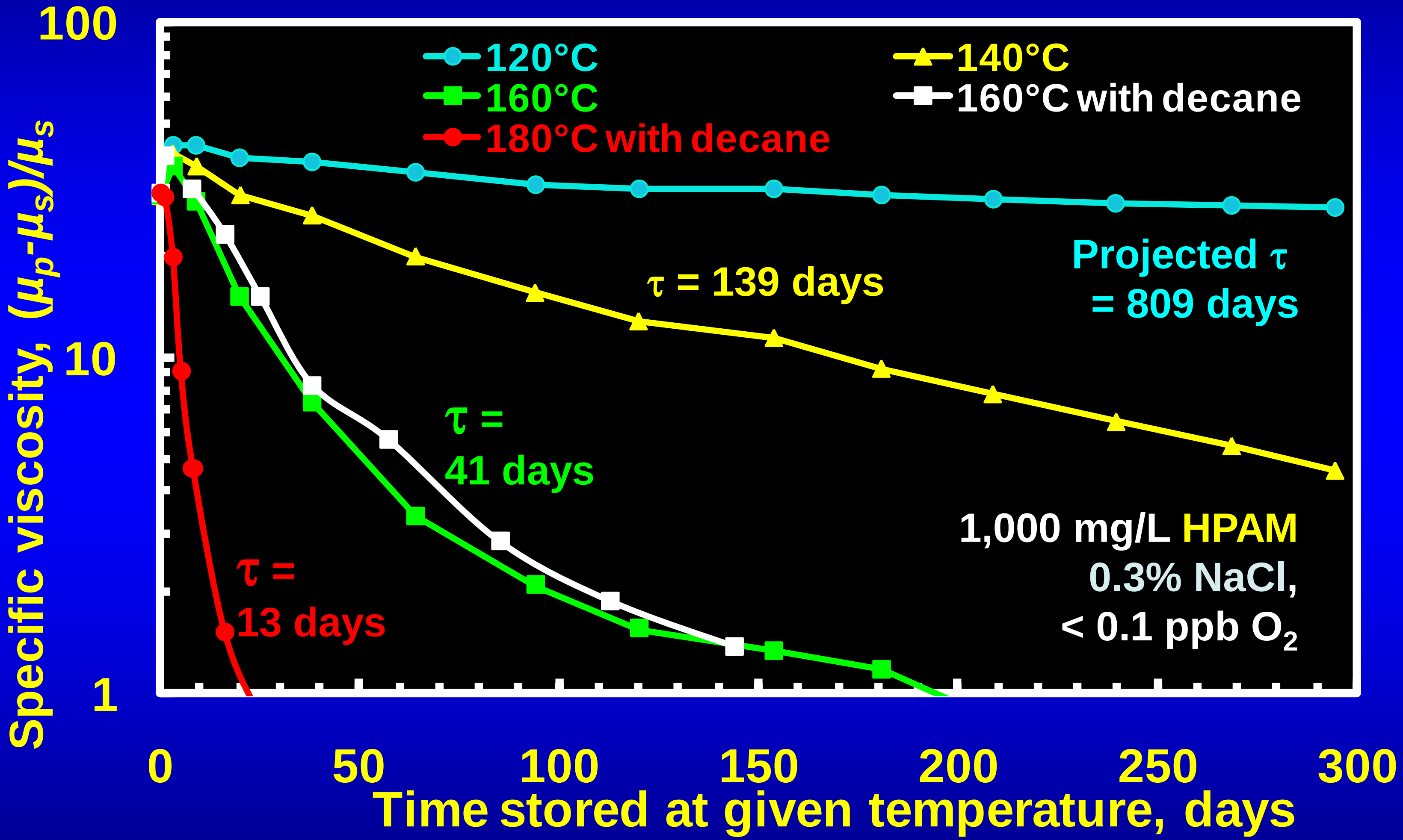
- If the storage cylinder leaks, the sample is lost.

Time/Temperature Behavior of Polymer Stability

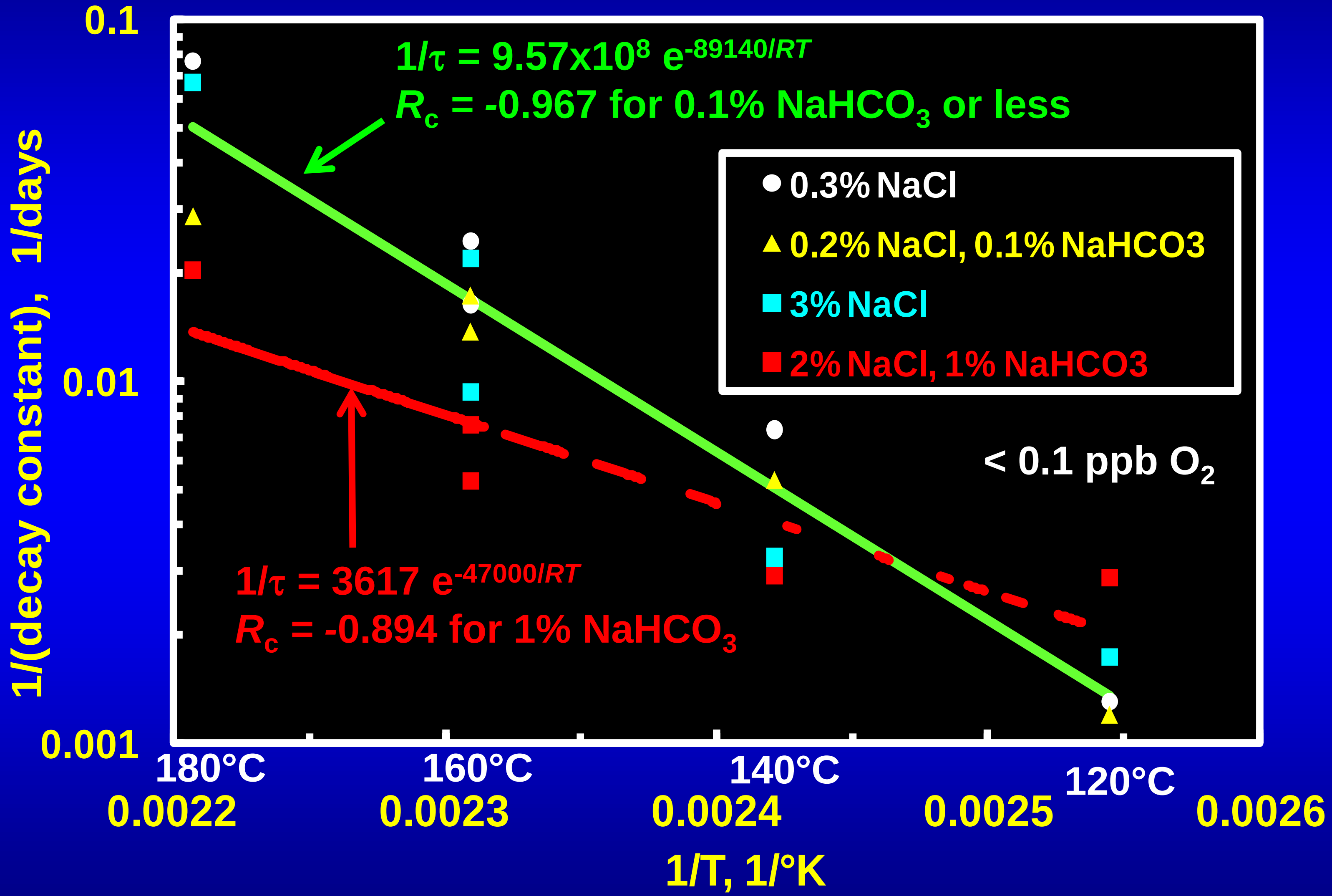
- Stability must be studied EITHER at reservoir temperature for MANY years OR at several temperatures and use an Arrhenius analysis.

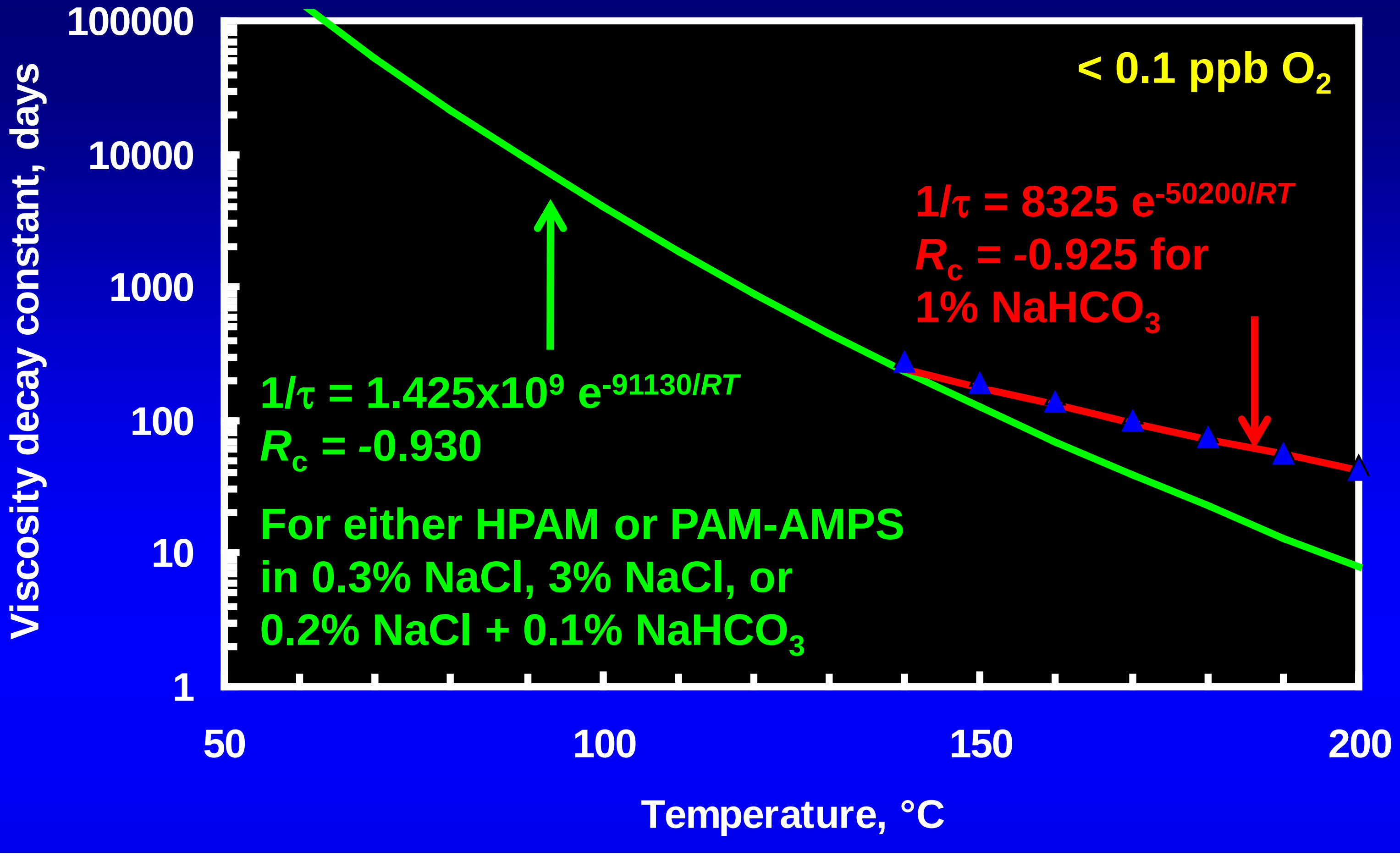


Viscosity decay constant, τ, is the time for the specific viscosity to fall to 1/*e* (0.368) times the original value.



Arrhenius Analysis for HPAM





- A given viscosity level can be predicted using: $\mu/\mu_o = e^{-t/\tau}$
- Viscosity half-lives for HPAM and PAM-AMPS solutions projected to be > 7 yrs at 100°C and ~2 yrs at 120°C.
- At 105°C after 250 days, we predict a 9% viscosity loss, while Shupe (1981) saw a 13% loss.

CONCLUSIONS (SPE 121460)

1. We developed a method to prepare, store, and test the stability of polymer solutions with <0.1 ppb O_2, without using oxygen scavengers.

2. In the absence of dissolved oxygen and divalent cations, HPAM solution viscosity half-lives could be over 7 years at 100°C and about 2 years at 120°C.

3. Within our experimental error, HPAM stability was the same with/without oil (decane).

CONCLUSIONS (SPE 121460)

4. A 25% AMPS copolymer showed similar stability to that for HPAM. Stability results were similar in brines with 0.3% NaCl, 3% NaCl, or 0.2% NaCl + 0.1% $NaHCO_3$.

5. At 160°C and above, the polymers were more stable in brine with 2% NaCl + 1% $NaHCO_3$ than in the other brines.

6. Even though no chemical oxygen scavengers or antioxidants were used in our study, we observed the highest level of thermal stability reported to date for these polymers.

CONCLUSIONS (SPE 121460)

7. By reaction with oil and pyrite, dissolved O_2 will be removed quickly from injected waters and will not propagate very far into the porous rock of a reservoir. Any dissolved O_2 that entered the reservoir prior to polymer injection will have been consumed and will not aggravate polymer degradation. If an O_2 leak develops during the course of polymer injection, that O_2 will not compromise the stability of the polymer that was injected before the leak developed or the polymer that is injected after the leak is fixed. Polymer that is injected while the leak is active will be susceptible to oxidative degradation. Maintaining dissolved oxygen at undetectable levels is necessary to maximize polymer stability. This can readily be accomplished without the use of chemical oxygen scavengers or antioxidants.

THERMAL, CHEMICAL, & BIO-DEGRADATION

- Both HPAM and xanthan are very susceptible to oxidative degradation. Fortunately, most reservoirs contain no free oxygen.
- HPAM's C-C main chain is very resistant to thermal breaking if O_2 or free radicals are absent.
- Xanthan's C-O main chain is susceptible to hydrolysis above 70°C.
- HPAM's amide groups are susceptible to hydrolysis above 60°C, leading to polymer precipitation if Ca^{2+} or Mg^{2+} are present.
- HPAM is much more resistant to bio-degradation than xanthan.

At 80°C, xanthan may have sufficient stability if the pH = 7-9, and O_2 = 0. (Seright & Henrici *SPERE* 1990).

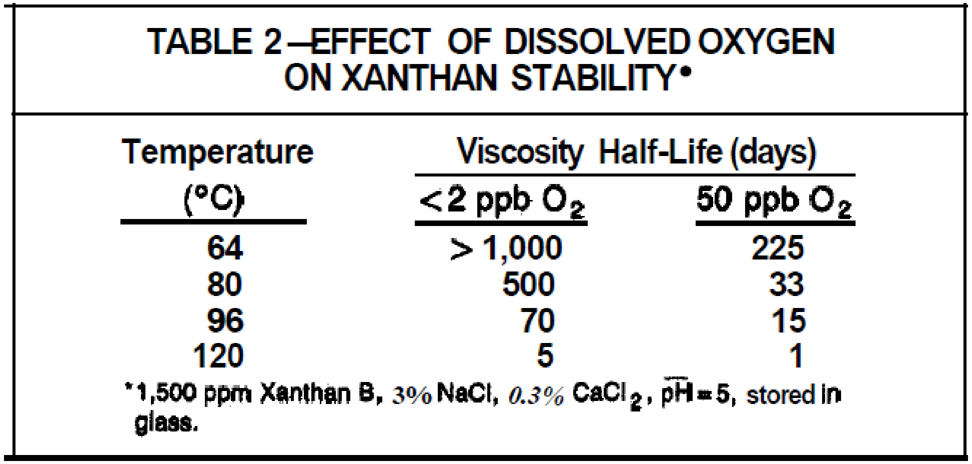


TABLE 2—EFFECT OF DISSOLVED OXYGEN ON XANTHAN STABILITY*

Temperature (°C)	Viscosity Half-Life (days) <2 ppb O_2	Viscosity Half-Life (days) 50 ppb O_2
64	>1,000	225
80	500	33
96	70	15
120	5	1

*1,500 ppm Xanthan B, 3% NaCl, 0.3% $CaCl_2$, $\overline{pH}=5$, stored in glass.

Xanthan stability at pH = 7-9 is much better than a pH=5.

Xanthan may be worth considering because you don't have to worry about mixing in the reservoir.

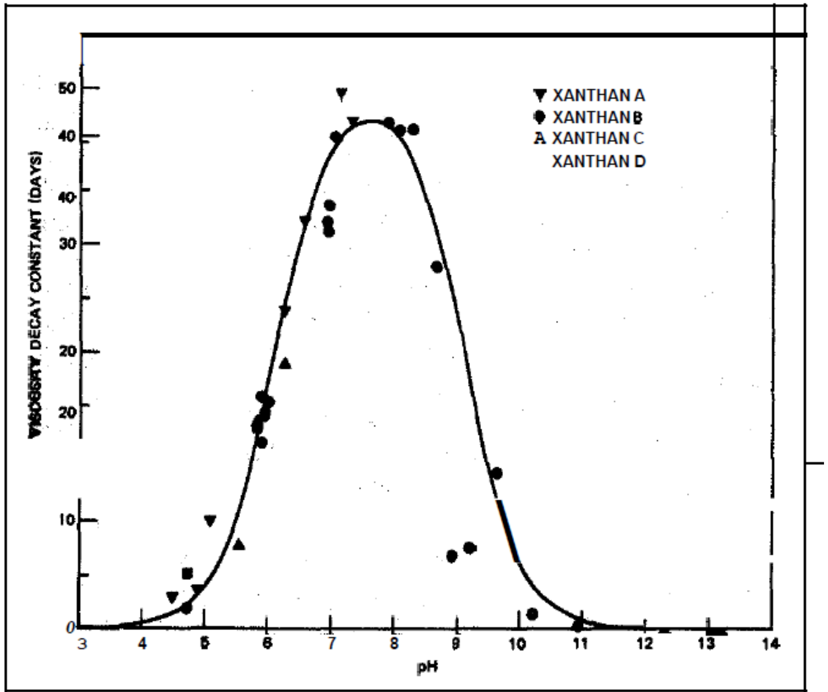


Fig. 4—Effect of pH on xanthan stability at 120°C: 1,500 ppm xanthan, 500 ppm $Na_2S_2O_4$, <2 ppb O_2, salt normality = 0.567 eq/L. Solid curve assumes that $\tau = 1/(0.02 + 25{,}000\,[H^+] + 1{,}500\,[OH^-])$.

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.

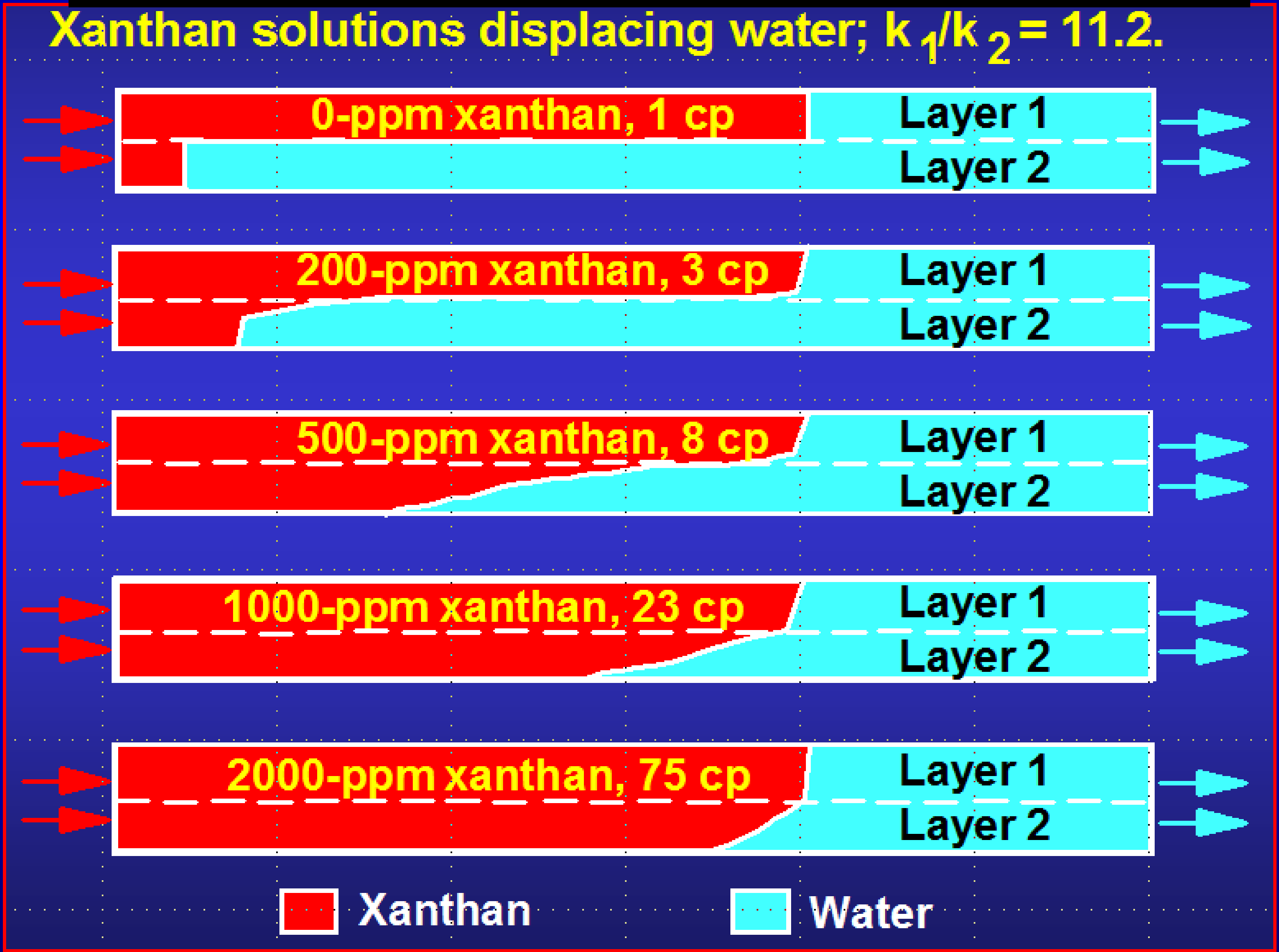
GEL TREATMENTS are best treating fractures and fracture-like features that cause channeling.

- 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.

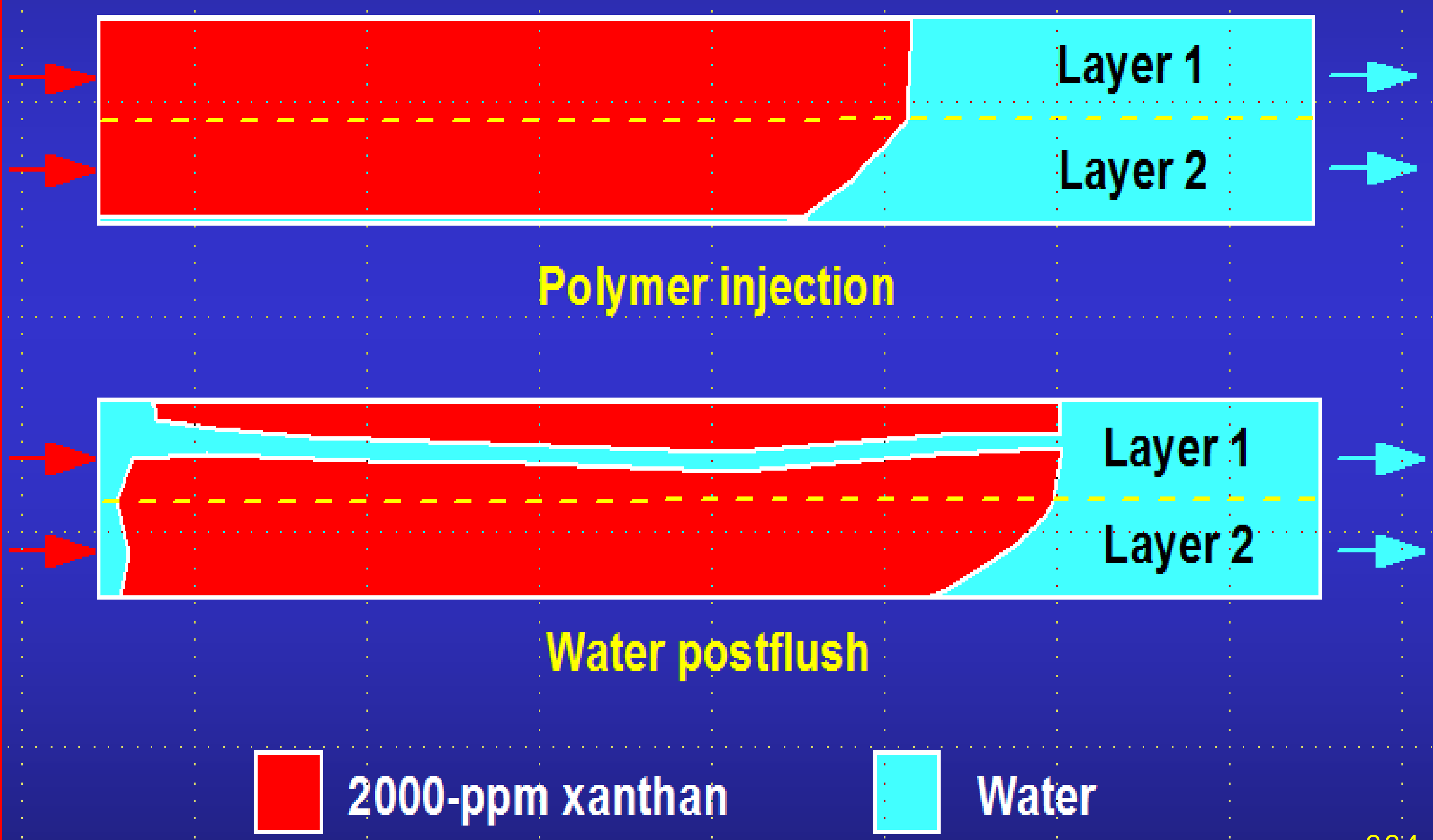
http://baervan.nmt.edu/randy/



Xanthan solutions displacing water; $k_1/k_2 = 11.2$.

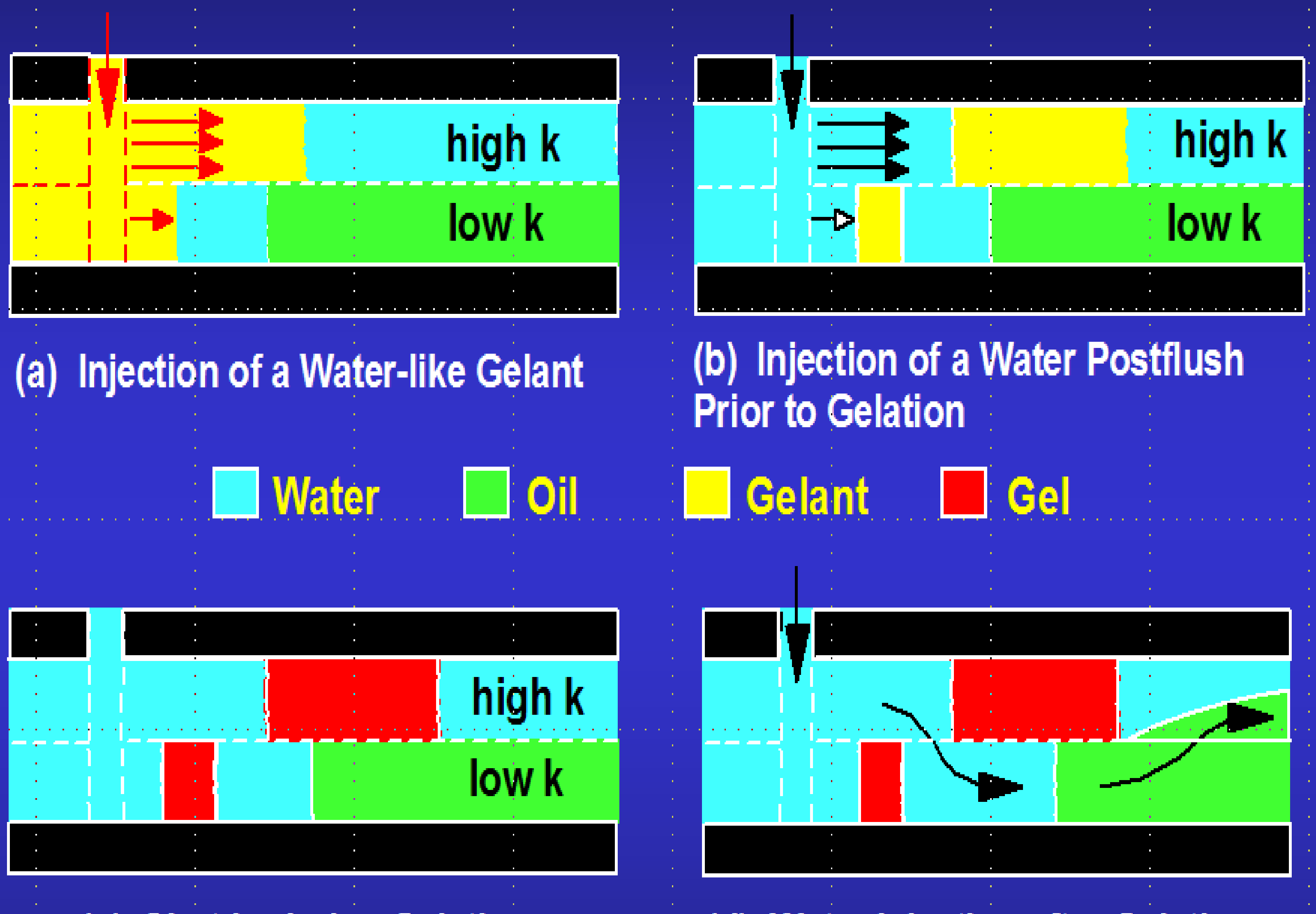
After polymer or gel placement, injected water forms severe viscous fingers that channel exclusively through the high-permeability layer.

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



IN-DEPTH PROFILE MODIFICATION

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



(a) Injection of a Water-like Gelant

(b) Injection of a Water Postflush Prior to Gelation

(c) Shut-in during Gelation

(d) Water Injection after Gelation

ADVANTAGES AND LIMITATIONS

ADVANTAGES:

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

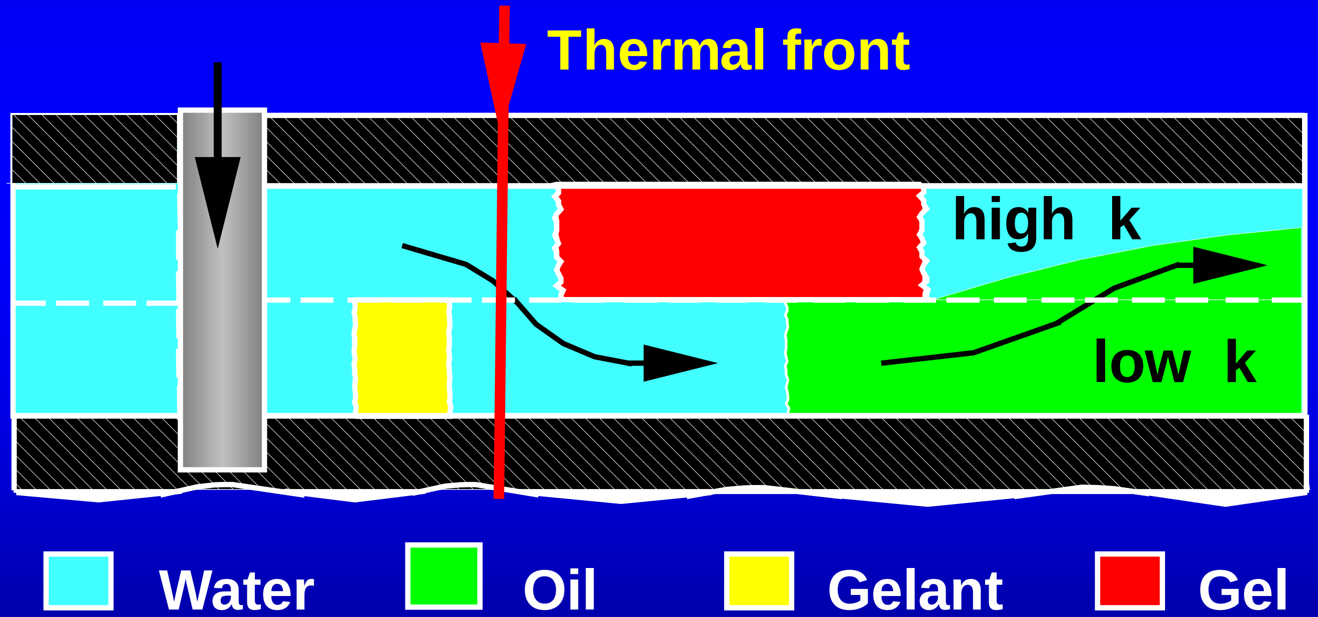
LIMITATIONS:

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.

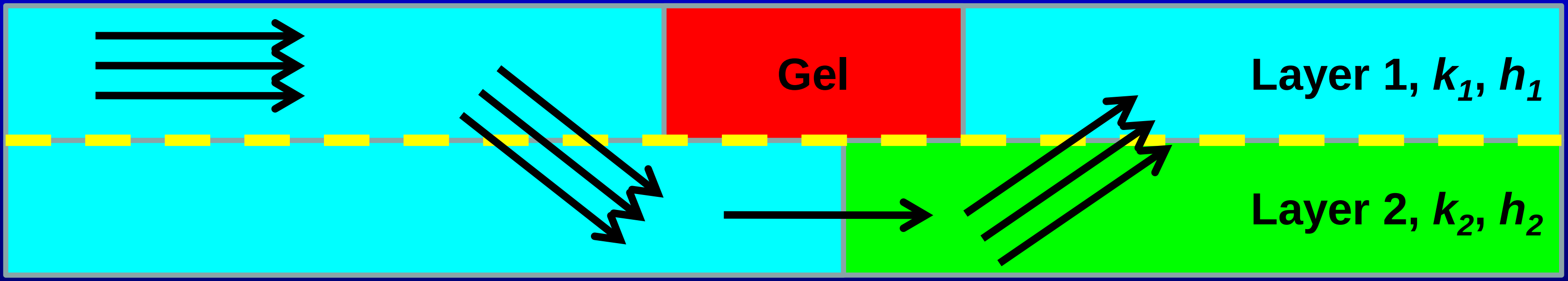
For reservoirs with free crossflow between strata, which is best to use: Polymer Flooding or In-Depth Profile Modification?

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

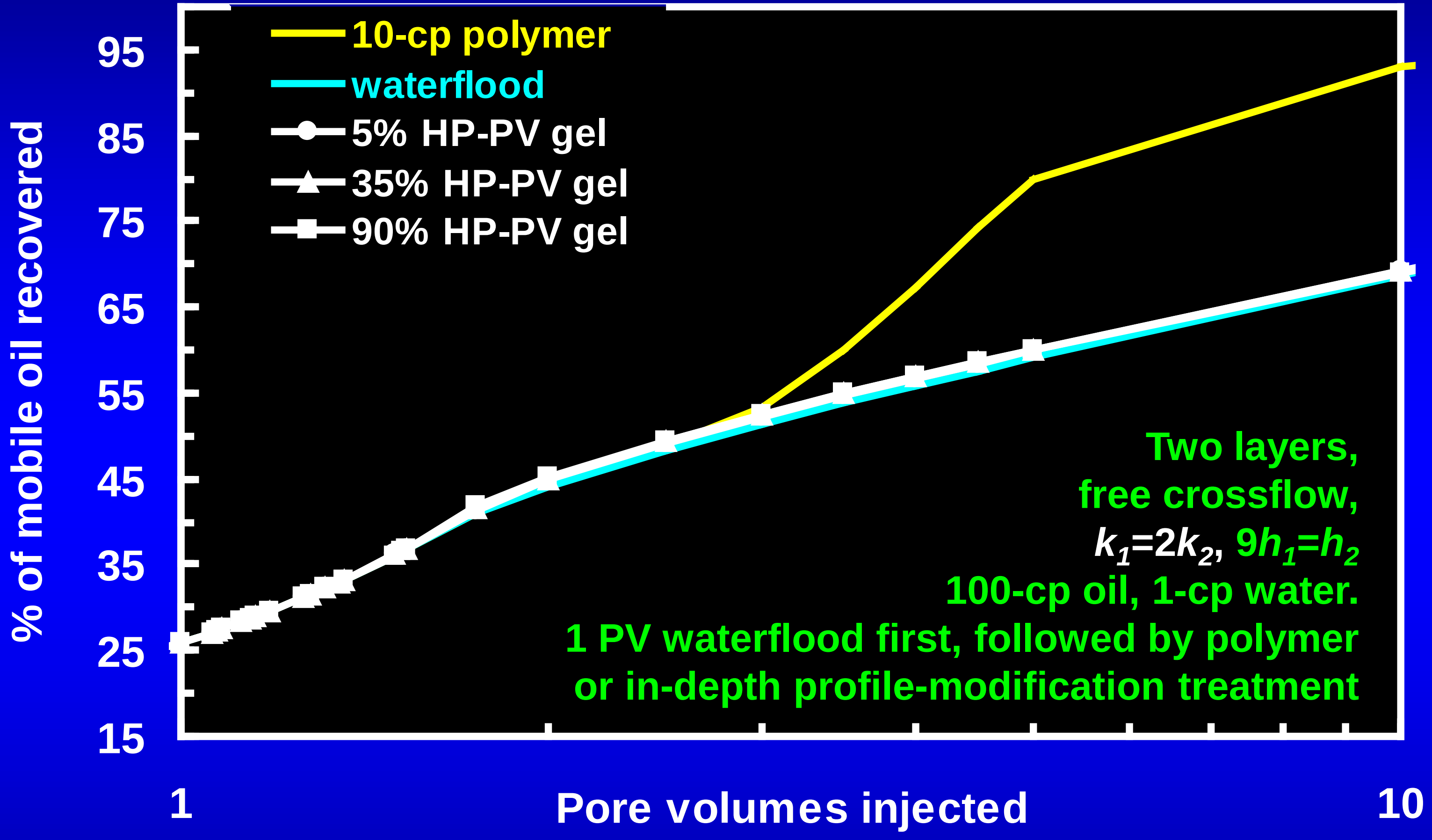
(1) permeability contrast (up to 10:1),
(2) relative zone thickness (up to 9:1),
(3) oil viscosity (up to 1,000 times more than water),
(4) polymer solution viscosity (up to 100 times more than water),
(5) polymer or blocking-agent bank size, and
(6) relative costs for polymer versus blocking agent.

ASSUMPTIONS

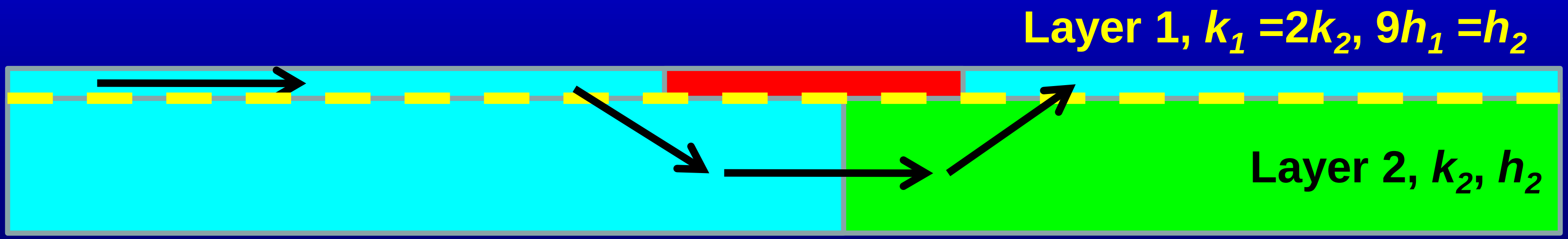
1. Two layers. Layer 1 has high permeability, k_1, h_1.
   Layer 2 has low permeability, k_2, h_2.
2. Free crossflow between layers.
3. No gravity forces.
4. No capillary forces.
5. Incompressible flow.
6. No dispersion of chemical banks.
7. Water viscosity is 1 cp.
8. 1 PV of water is injected prior to polymer or gelant.
9. Polymer solutions are Newtonian.
10. Retention balances inaccessible pore volume.
11. Gelation occurs instantaneously and reduces *k* to 0.



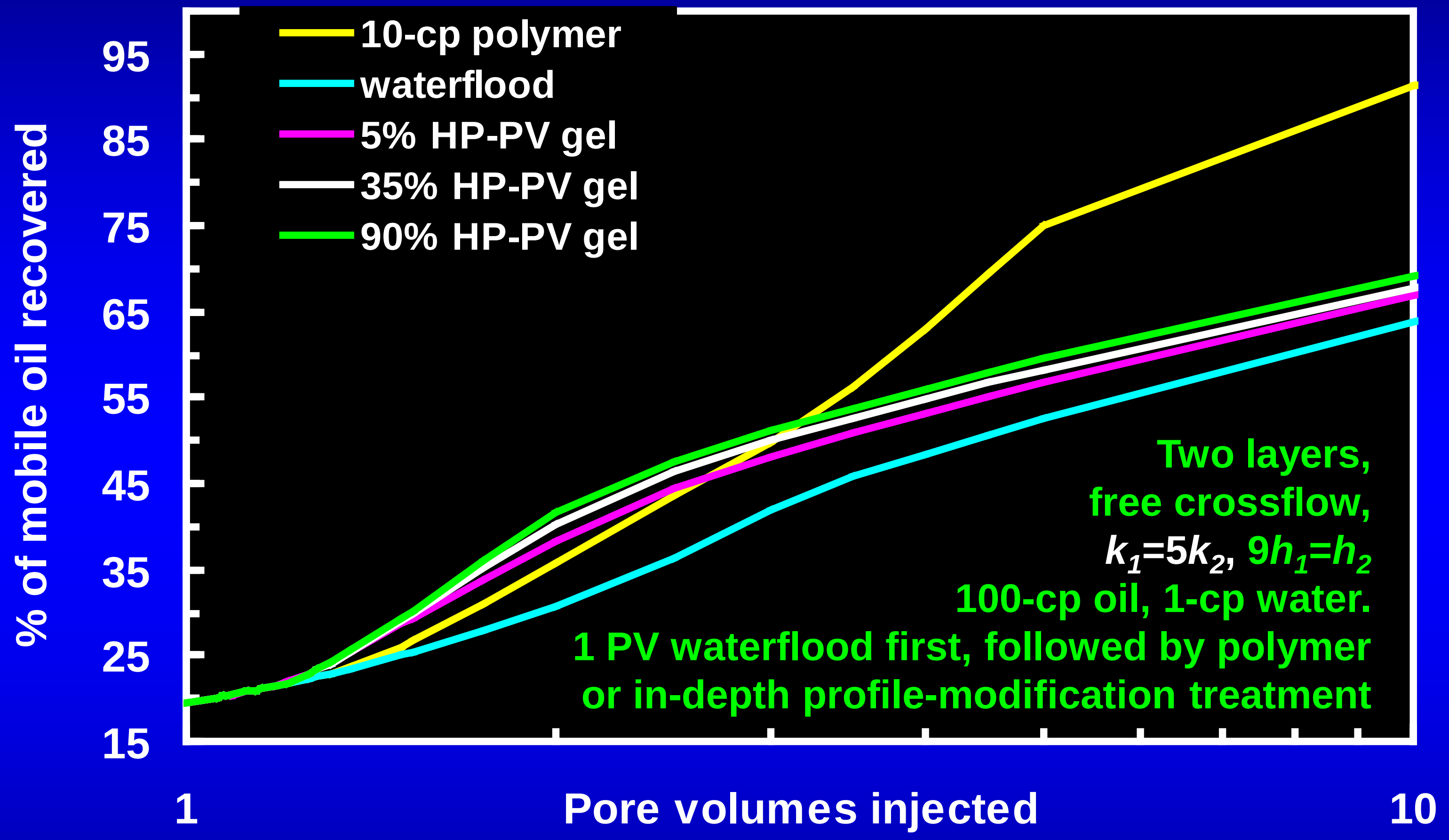
Polymer Flooding vs. In-Depth Profile Modification
2:1 permeability contrast and thin high-k layer ($9h_1=h_2$).
100-cp oil



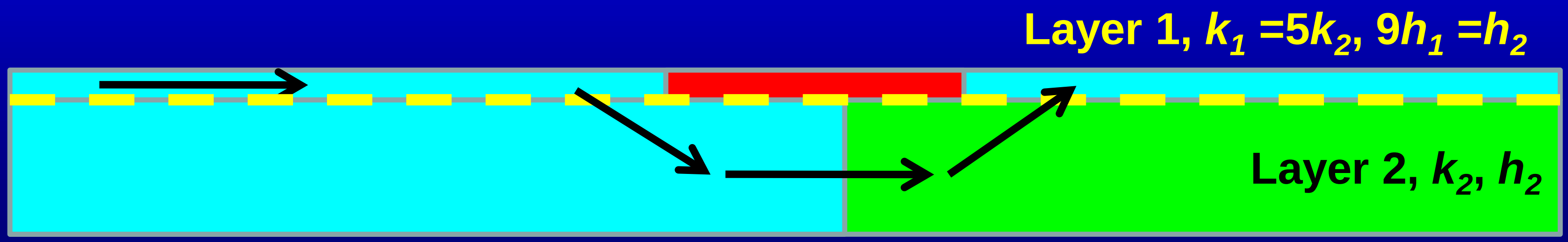
Two layers,
free crossflow,
$k_1=2k_2$, $9h_1=h_2$
100-cp oil, 1-cp water.
1 PV waterflood first, followed by polymer
or in-depth profile-modification treatment



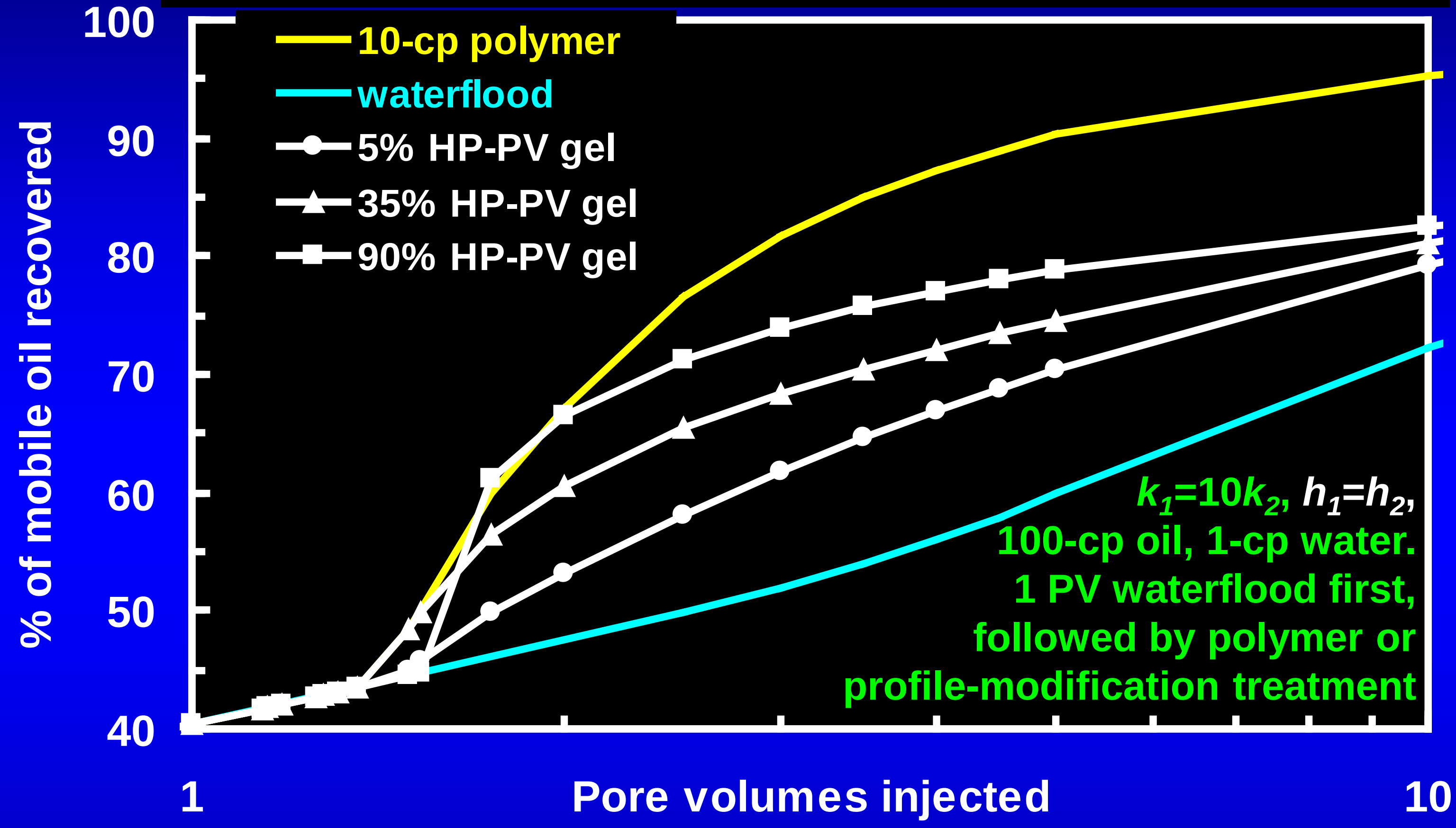
Polymer Flooding vs. In-Depth Profile Modification
5:1 permeability contrast and thin high-k layer ($9h_1=h_2$).
100-cp oil



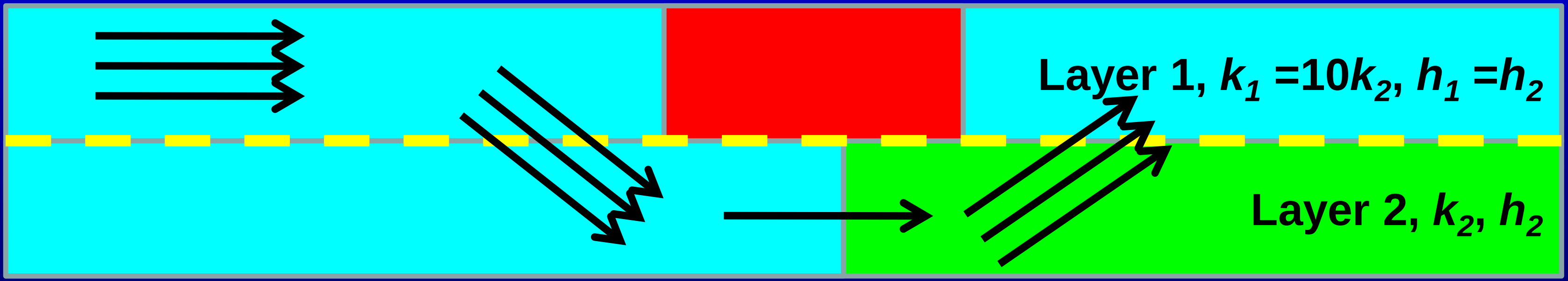
Two layers,
free crossflow,
$k_1=5k_2$, $9h_1=h_2$
100-cp oil, 1-cp water.
1 PV waterflood first, followed by polymer
or in-depth profile-modification treatment



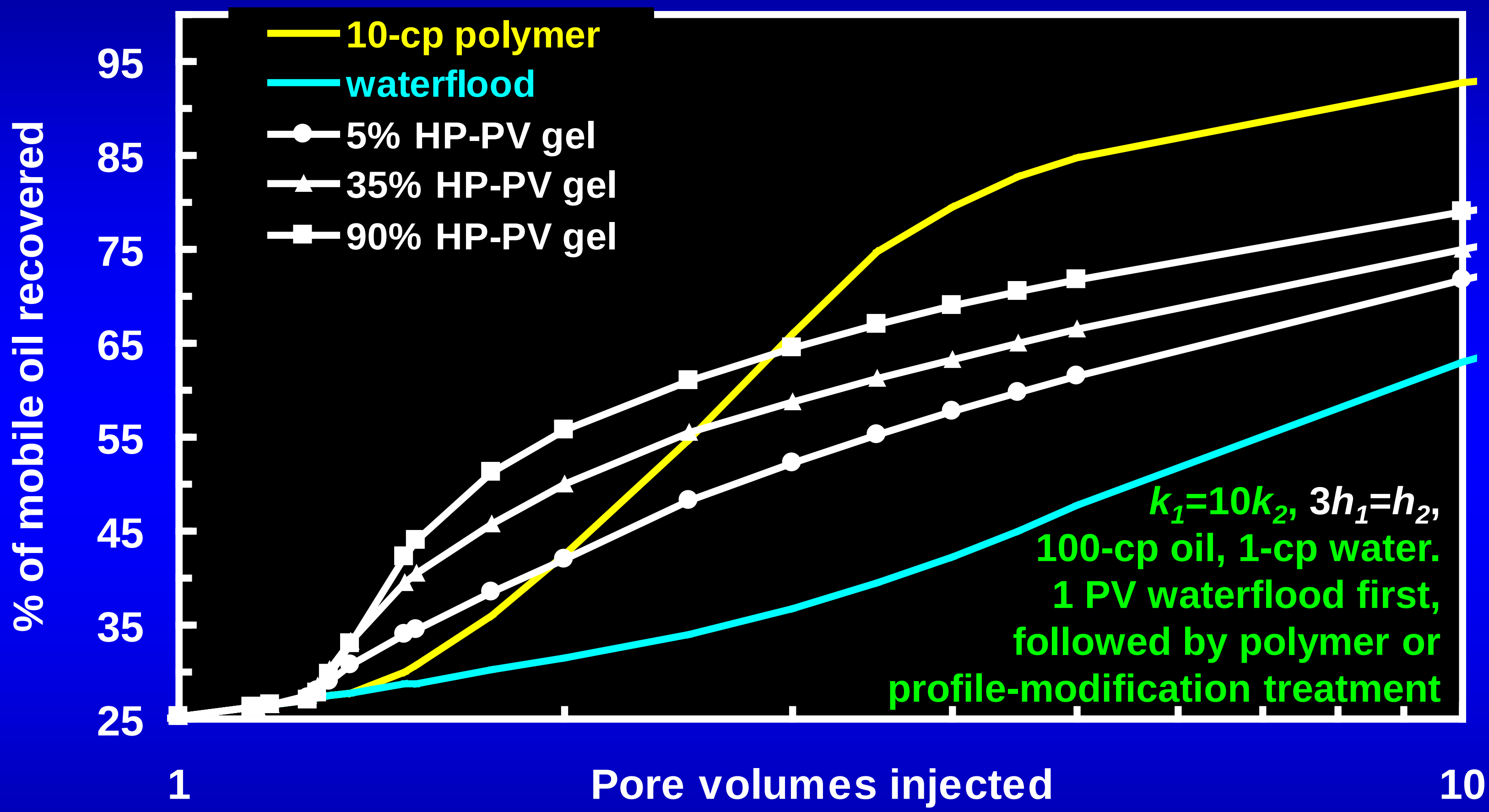
Polymer Flooding vs. In-Depth Profile Modification
10:1 permeability contrast and $h_1=h_2$.
100-cp oil



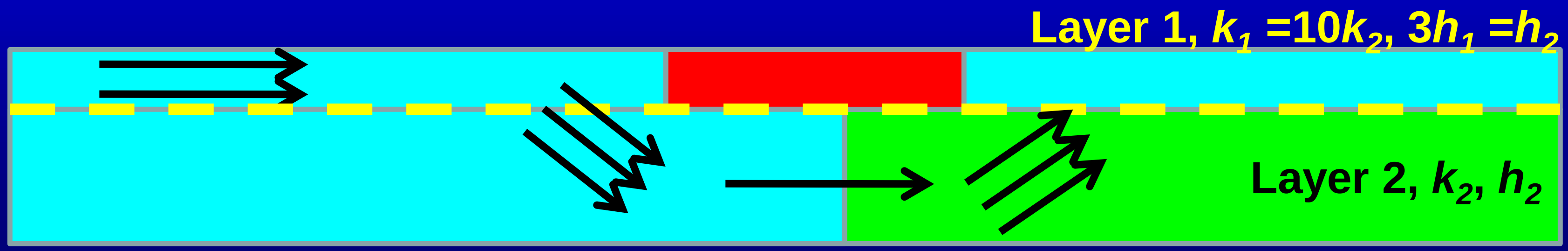
$k_1=10k_2$, $h_1=h_2$,
100-cp oil, 1-cp water.
1 PV waterflood first,
followed by polymer or
profile-modification treatment



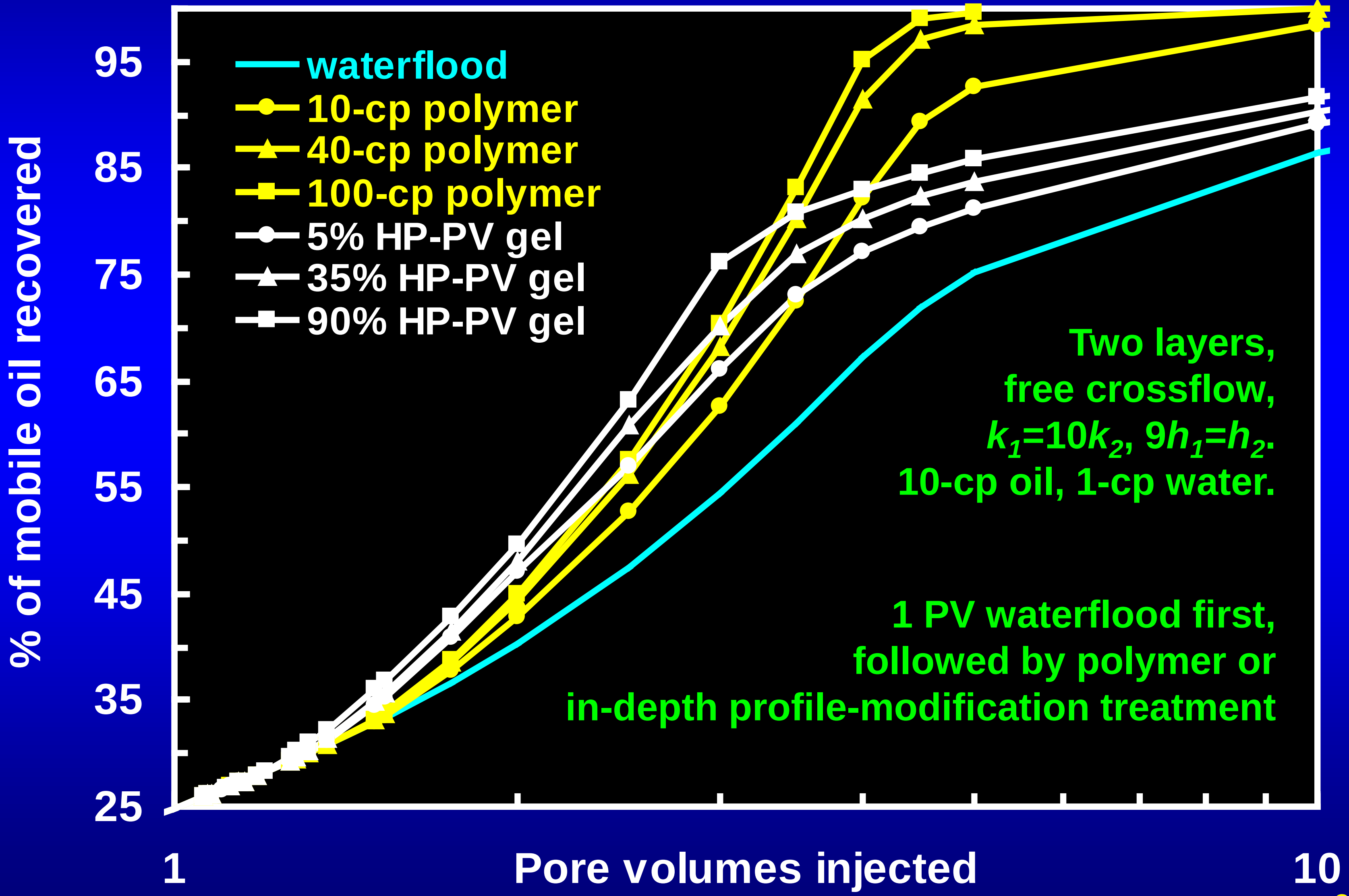
Polymer Flooding vs. In-Depth Profile Modification
10:1 permeability contrast and $3h_1=h_2$.
100-cp oil



$k_1=10k_2$, $3h_1=h_2$,
100-cp oil, 1-cp water.
1 PV waterflood first,
followed by polymer or
profile-modification treatment



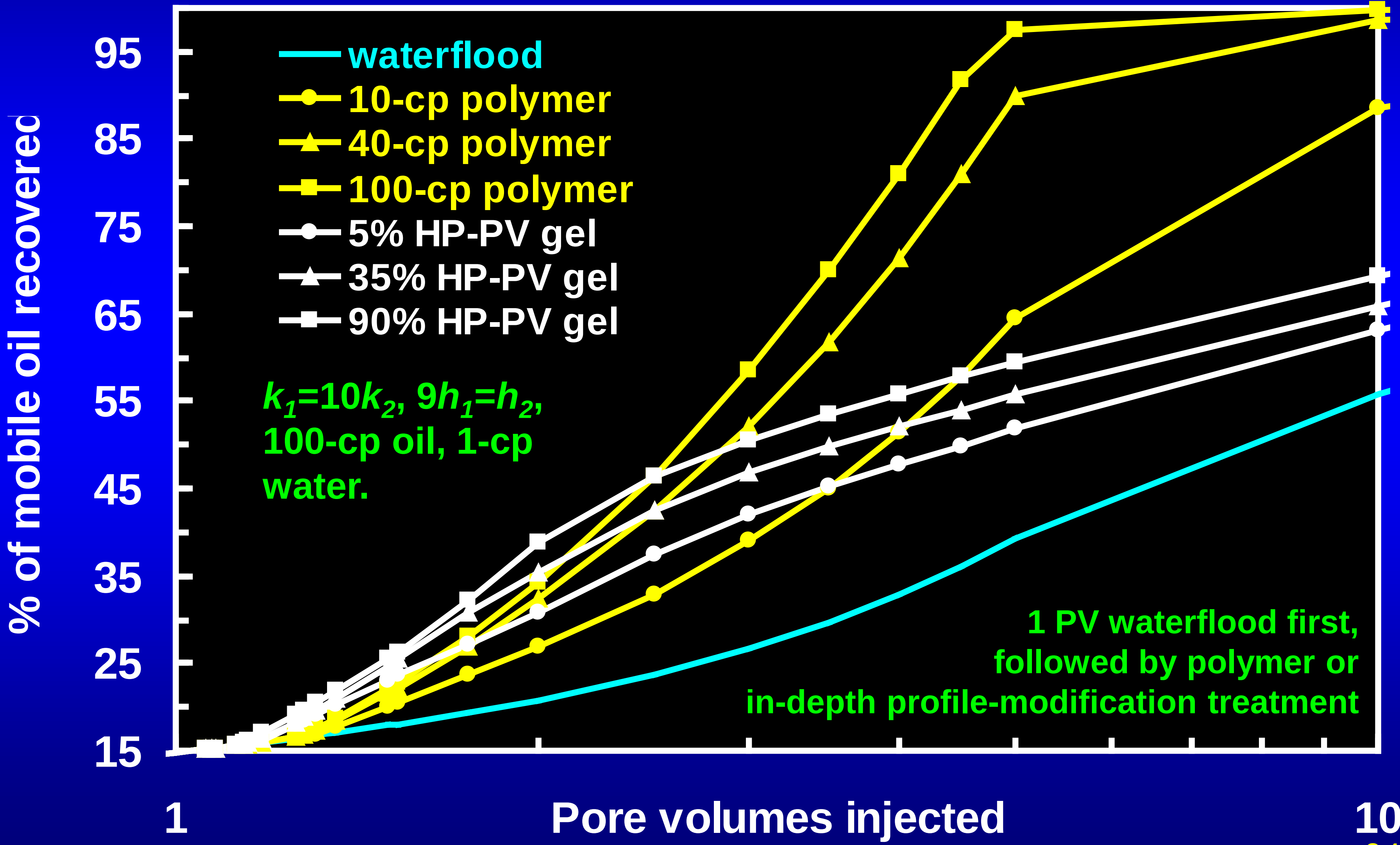
Polymer Flooding vs. In-Depth Profile Modification
10:1 permeability contrast and thin high-k layer ($9h_1=h_2$).
10-cp oil



Two layers,
free crossflow,
$k_1=10k_2$, $9h_1=h_2$.
10-cp oil, 1-cp water.

1 PV waterflood first,
followed by polymer or
in-depth profile-modification treatment

Polymer Flooding vs. In-Depth Profile Modification
10:1 permeability contrast and thin high-k layer ($9h_1=h_2$).
100-cp oil



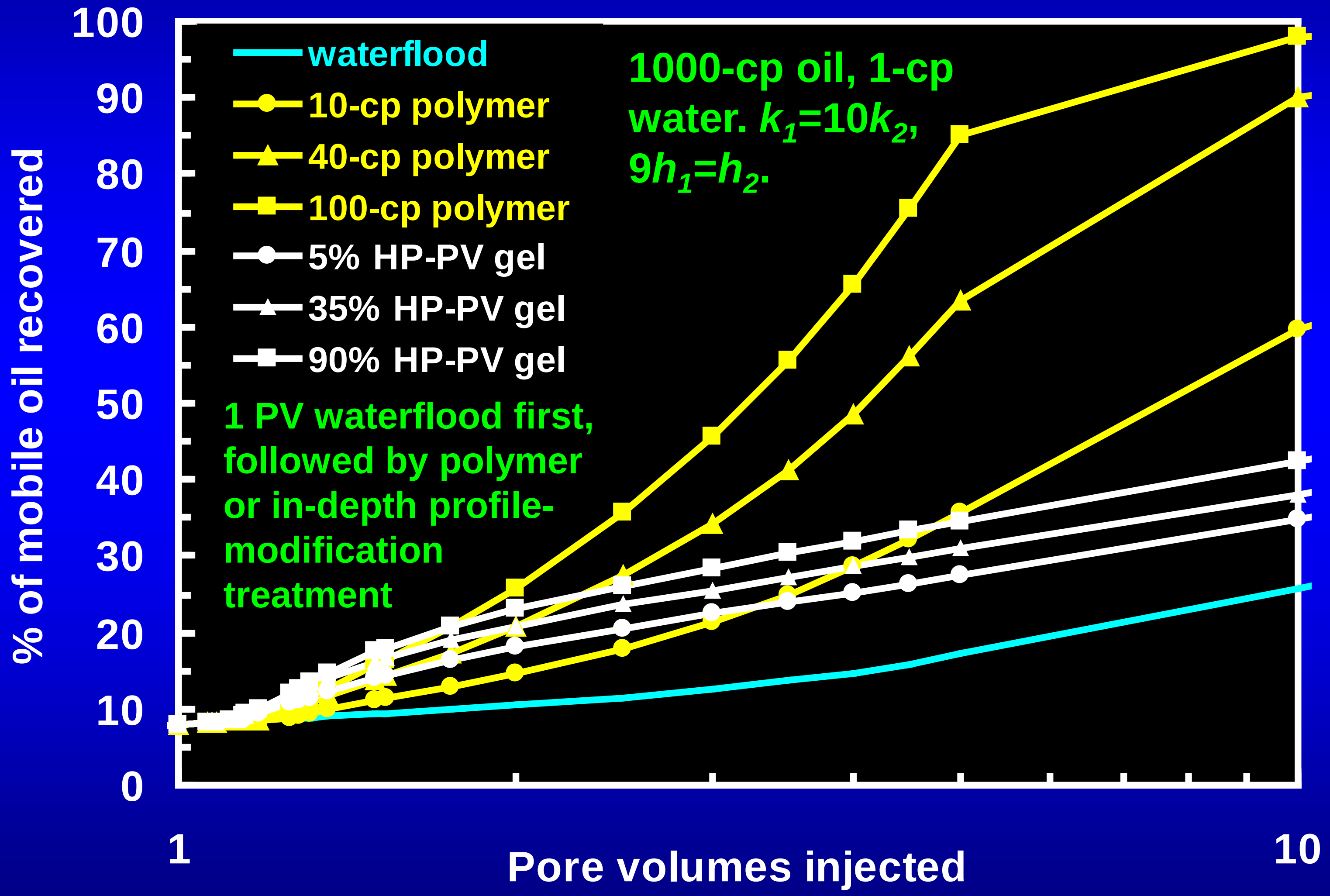
$k_1=10k_2$, $9h_1=h_2$, 100-cp oil, 1-cp water.

1 PV waterflood first, followed by polymer or in-depth profile-modification treatment

Polymer Flooding vs. In-Depth Profile Modification

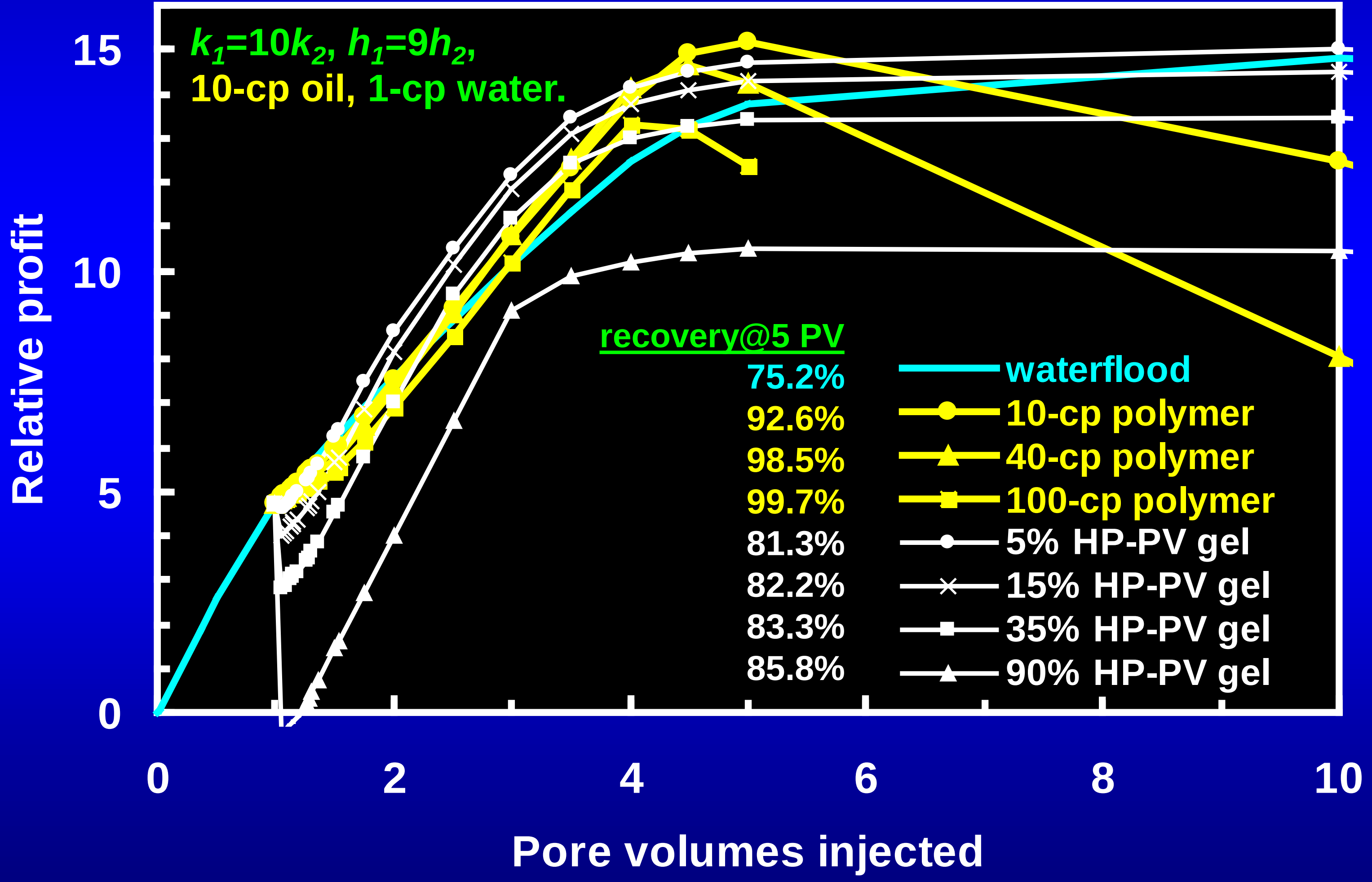
10:1 permeability contrast and thin high-k layer ($9h_1=h_2$).

1000-cp oil



Relative Profit = Oil value – Water Cost – Polymer/Gel Cost

HPAM cost = \$1.50/lb, BW cost = \$5.71/lb.
Water cost = \$0.25/bbl, Oil price = \$50/bbl.
0.1%, 0.2%, & 0.3% HPAM give 10, 40, & 100 cp, respectively.



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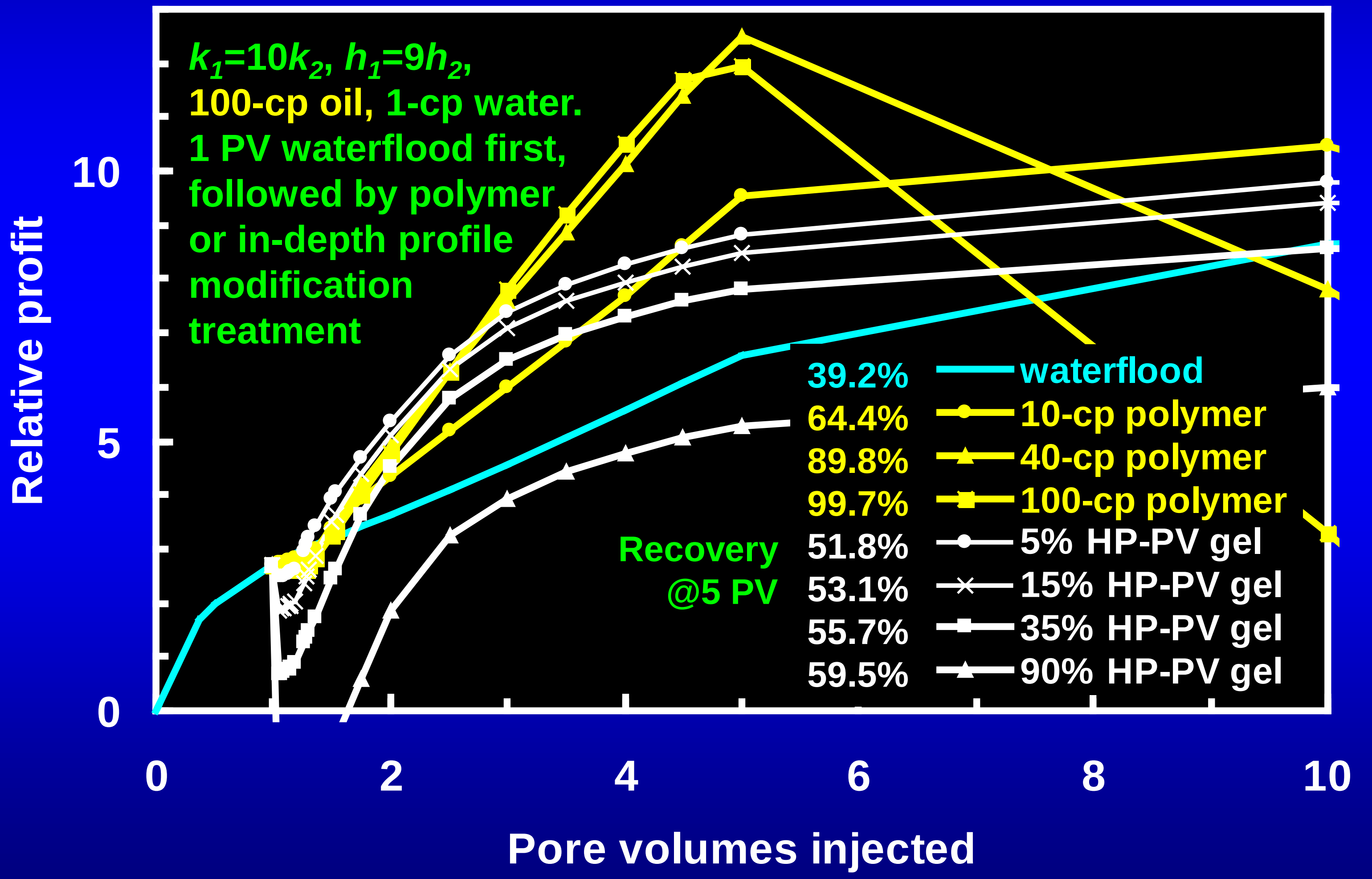

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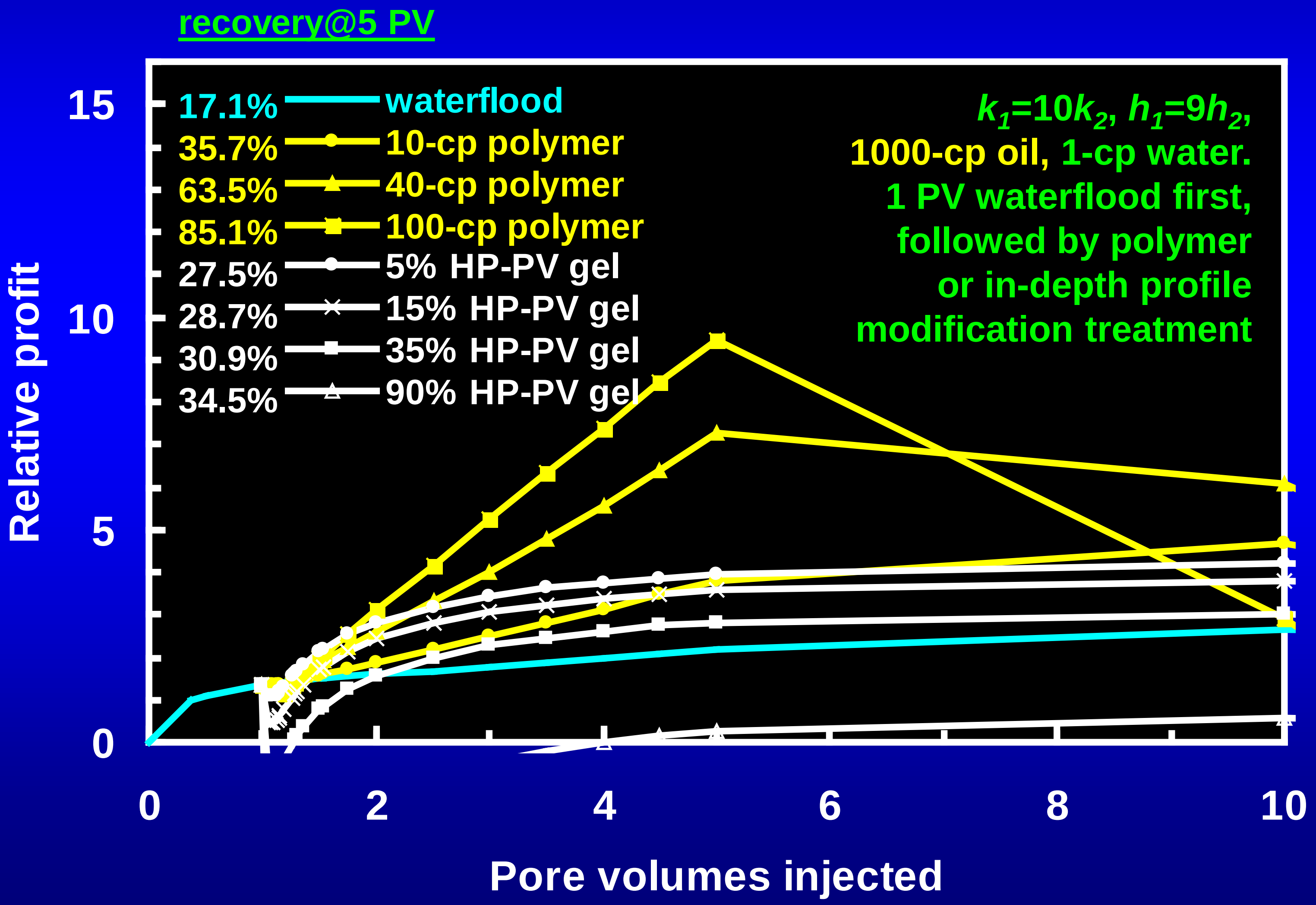
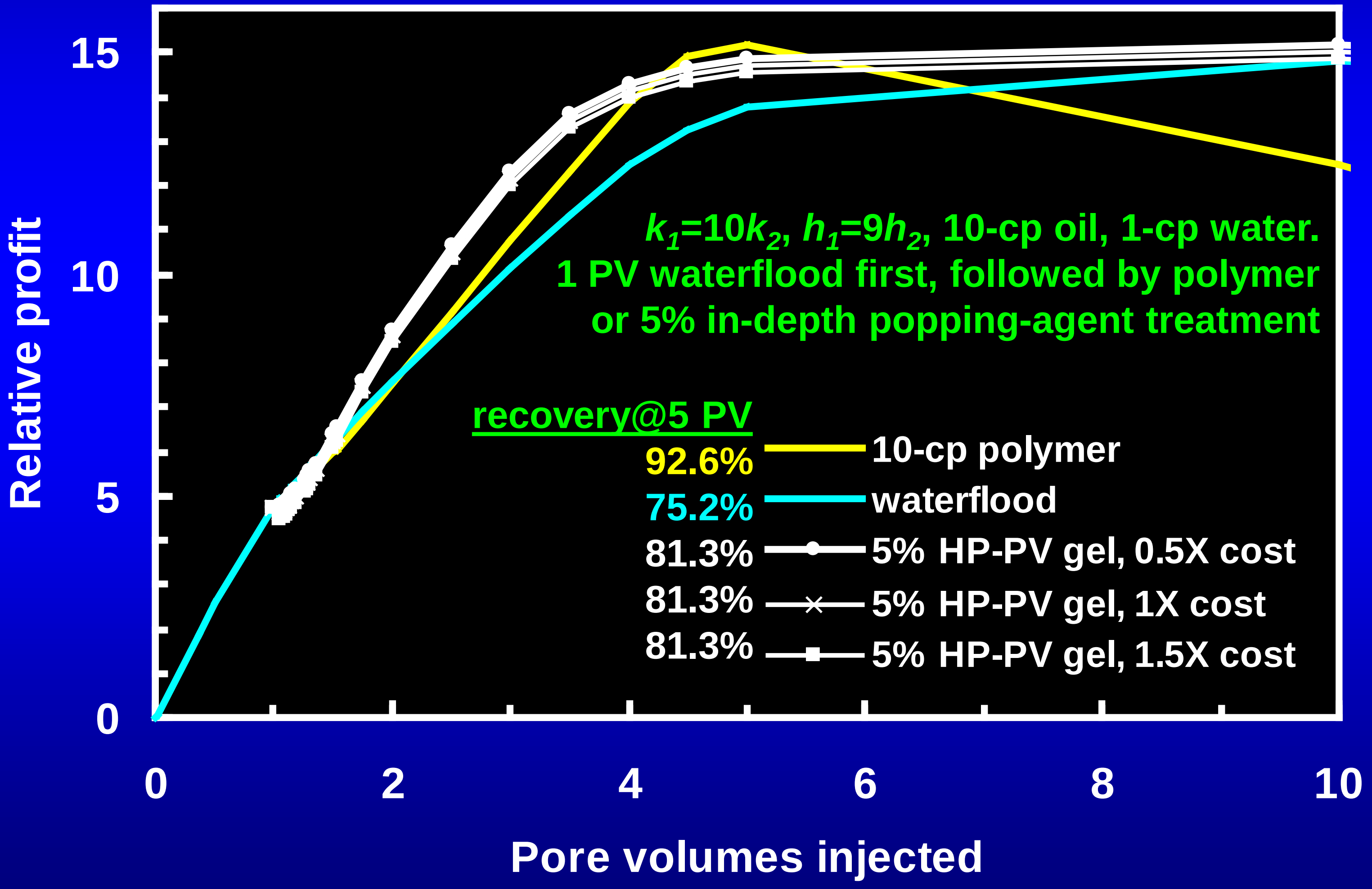
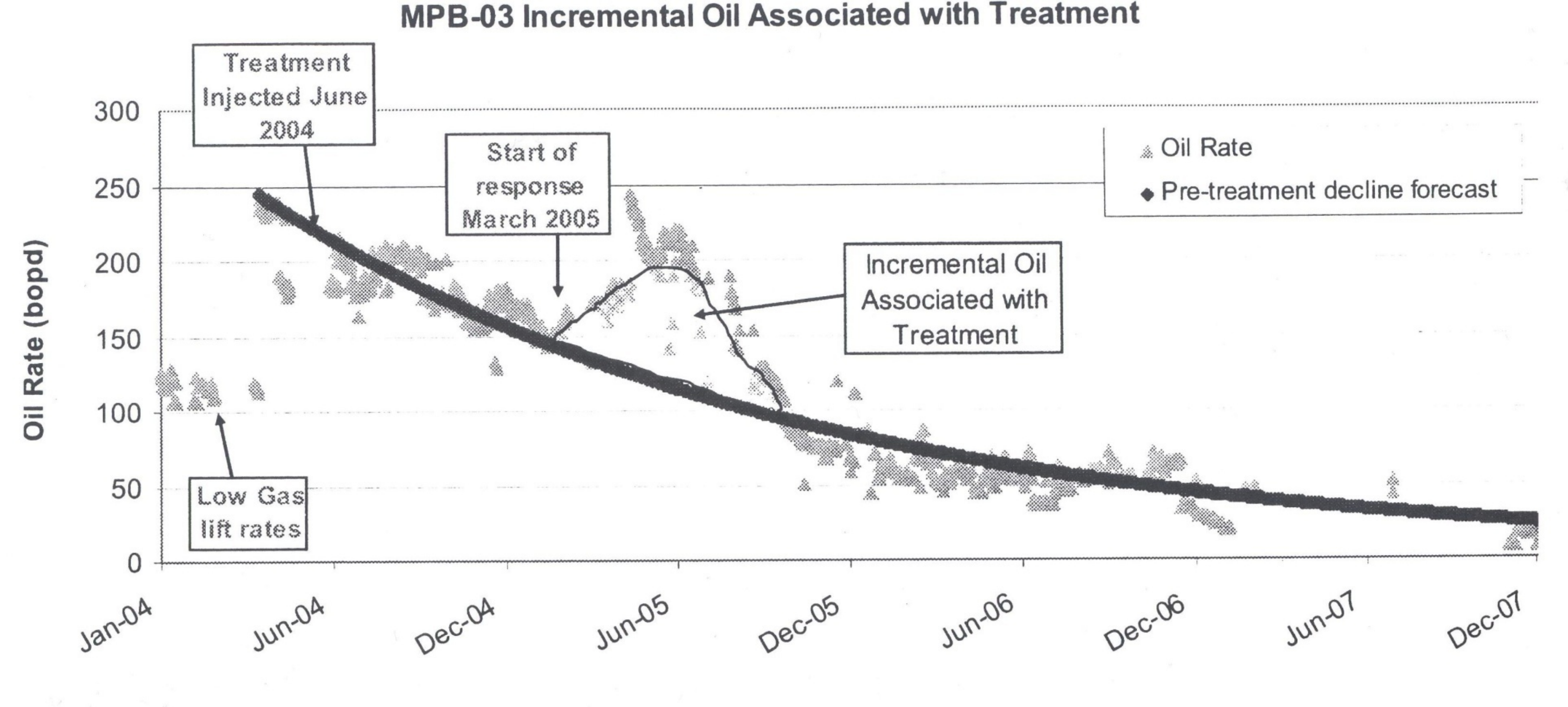


If the popping-agent bank size is small (e.g., 5% HP-PV), performance is not very sensitive to chemical cost.



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).



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.

Can Polymers Reduce S_{or} Below that for Waterflooding?

S_{or} Reduction by Polymers: Why Are We Talking About This? – DAQING!

Wu et al. SPE 109228, Wang et al. SPE 127453

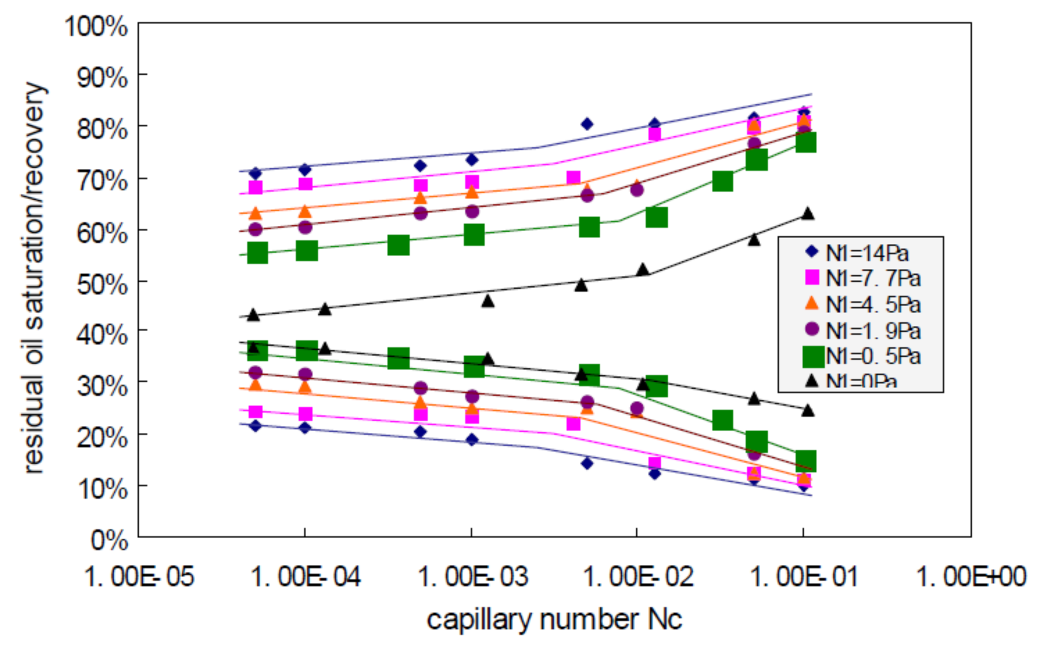


Fig.4 The relation curve of the recovery/residual oil saturation vs. the capillary number of the binary displacing system

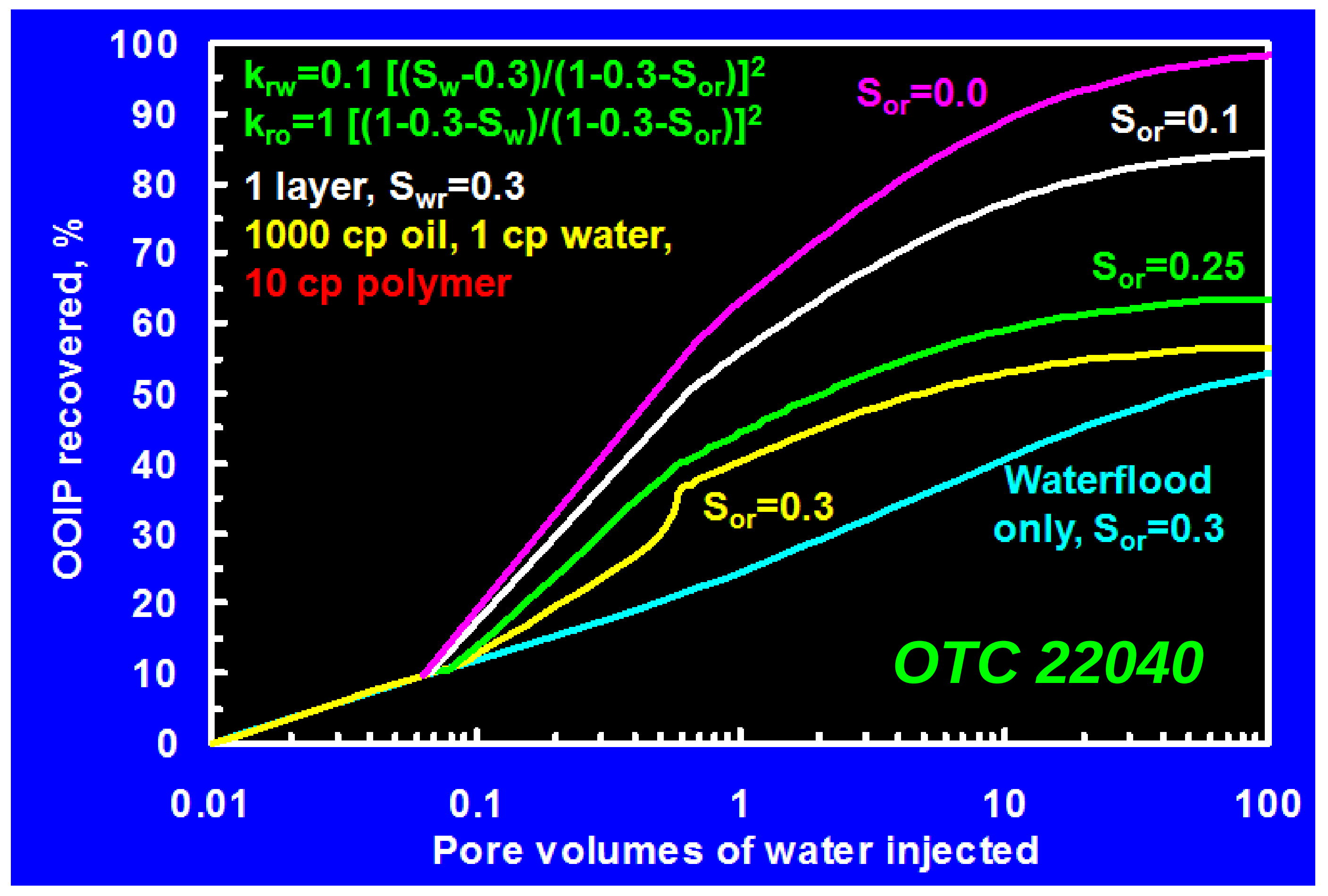
Wang et al. (SPE 144294) reported 20% OOIP EOR from injecting 150-300-cp HPAM into >5600 wells (10-cp oil) versus 12% OOIP EOR for 40-cp HPAM.

S_{or} Reduction by Polymers: Bottom Line

1. It does matter—even for viscous oils.
2. Primarily, true S_{or} reduction has been seen in non-water wet cores.
3. Most (but not all) seem to agree that the effect occurs mostly at higher velocities with high Mw HPAM.

Can viscoelastic polymer solutions reduce the S_{or} below that for waterflooding?.

1. Daqing says yes; UT Austin says maybe not.
2. Does it matter for viscous oils? (yes)



PREVIOUS LITERATURE: Water- Wet Cores

- Conventional wisdom within the petroleum industry is that the ultimate residual oil saturation (S_{or}) for a polymer flood is the same as that for a waterflood (Tabor 1969, Lake 1989).

- Polymers have a negligible effect on oil-water interfacial tension, so no reduction of S_{or} is expected, compared with waterflooding.

- Several previous literature reports are consistent with this view in water-wet cores, especially with Berea and Bentheim sandstone (Schneider and Owens 1982, Pusch et al. 1987, Wreath 1989).

LITERATURE:

Cores not water wet

- **Wang: Daqing HPAM solutions reduced S_{or} from 36.8% (with waterflooding) to 21.75% (for polymer flooding) using a constant capillary number under oil-wet, weakly oil-wet, and mixed-wet conditions.**
- **Schneider and Owens (1982): HPAM reduced S_{or} in oil-wet cores up to 8.4%.**

Water-wet cores

- **Zaitoun and Kohler (1987, 1988): PAM reduced S_{or} by 3% in water-wet Berea and Vosges sandstones. In Bentheim sandstone, Pusch et al. (1987) saw 1% to 4% reductions in S_{or} with xanthan and a sugar solution.**
- **Differences might not be significant.**

PREVIOUS LITERATURE: Water- Wet Cores

UT Austin View for Water-Wet cores

- During polymer flooding, Huh and Pope (2008) observed S_{or} reductions (relative to waterflooding) ranging from 2 to 22 saturation percentage points using heterogeneous Antolini cores. For heterogeneous cores, two effects could appear to make the S_{or} lower after a polymer flood than after a waterflood. First, if insufficient water is flushed through the core to displace mobile oil from less-permeable pathways, one could be misled by the high water cut to believe that the core was near S_{or}. Improved volumetric sweep during a subsequent polymer flood could rapidly produce a small spike of mobile oil from the less-permeable pathways. SPE 113417, 179683.

PREVIOUS LITERATURE: Water- Wet Cores

UT Austin View for Water-Wet cores

- For polymer flooding in a secondary mode (no prior waterflood), a lower S_{or} is reached because oil ganglia stay connected longer and drain pores of oil more effectively. SPE 113417

UT Austin, Bentheimer cores, 120-cp oil

- At low velocities, the endpoint residual oil satuation was the same for waterflooding and polymer flooding. SPE 179683 and SPE 179689.
- Reductions in S_{or} are seen when flooding with HPAM solutions at high velocities (Deborah numbers). SPE 179689

UT Austin SPE 187230 (Erincik et al. 2017)

- Unusually low S_{or} attained by injecting high-salinity polymer solutions after low-salinity polymer solutions.

- Explanation for the effect is currently unknown.
- Relevance to field applications is currently unknown.

- Experiments were performed at relatively high pressure gradients and rates.
- A controversial EDTA-hydrosulfite pre-treatment was used.
- The brine contained no divalent cations.

SPE 169681 (Vermolen et al. 2014)

- For 300-cp crude, no reduction in S_{or} occurred for HPAM rates up to 3 ft/d.
- For 9-cp crude, reduction of S_{or} can be seen, especially with viscous elastic HPAM solutions and higher rates.

SPE 174654 (Clarke et al. 2016)

- Argue that “elastic turbulence” is responsible for the apparent “flow-thickening” of HPAM solutions in porous media.

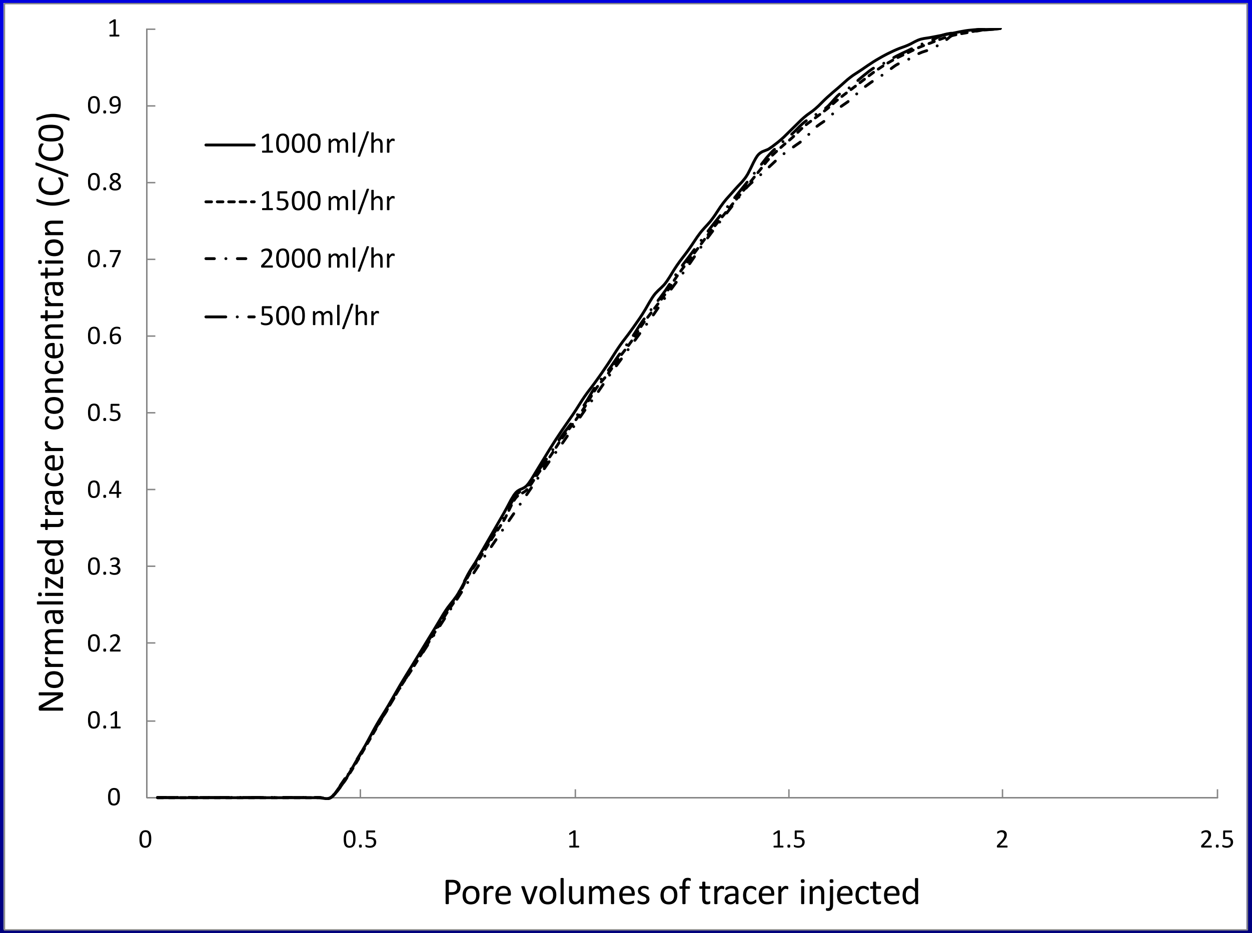
- Also argue this effect results in reduction of S_{or} because fluctuating flow field destabilizes trapped oil drops.

- Onset (flow velocity) of flow thickening
  - Decreases with increased polymer Mw.
  - Increases with increased rock permeability.
  - Is independent of polymer concentration.

Our experiments in homogeneous cores

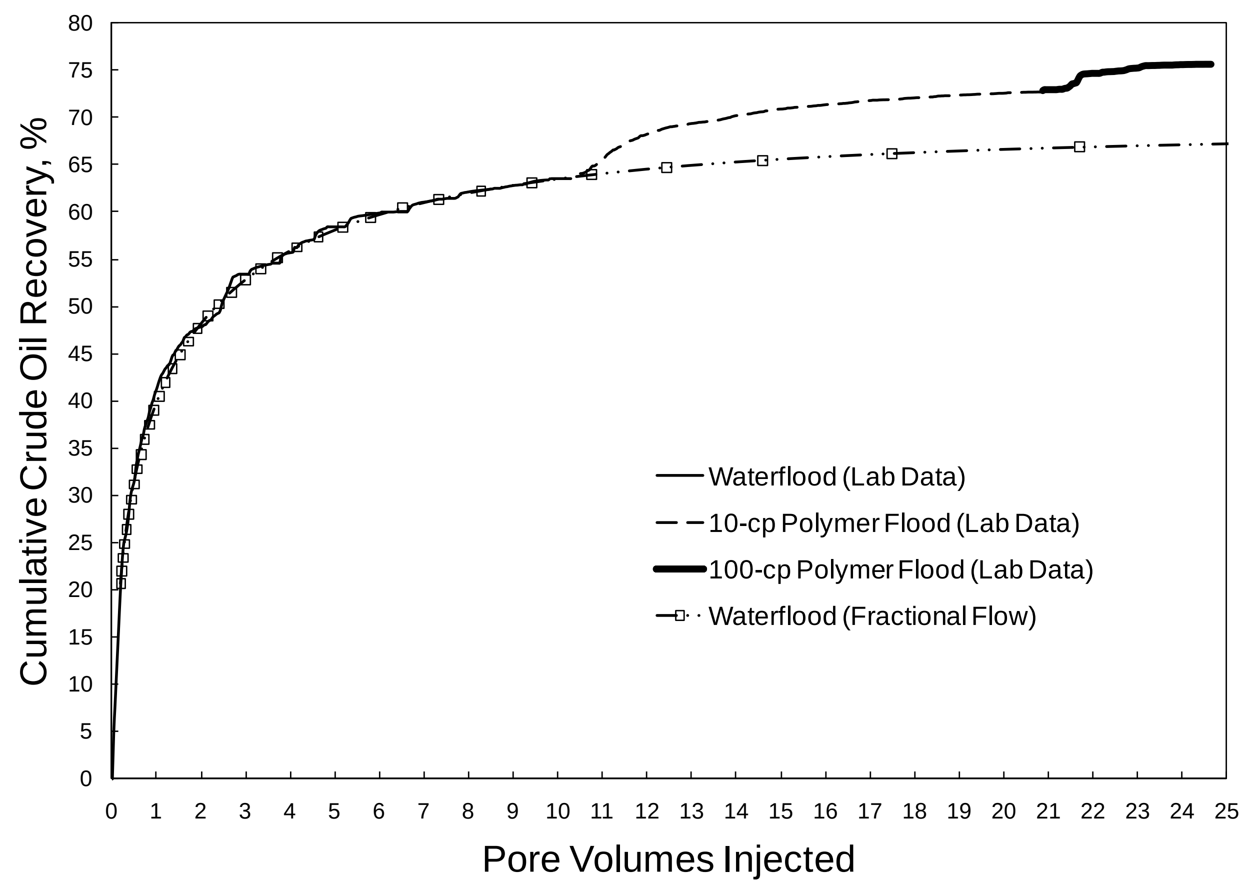
77-cm long, 10-darcy porous polyethylene

- Hydrophobic (oil wet)
- Homogeneous (based on tracer results).



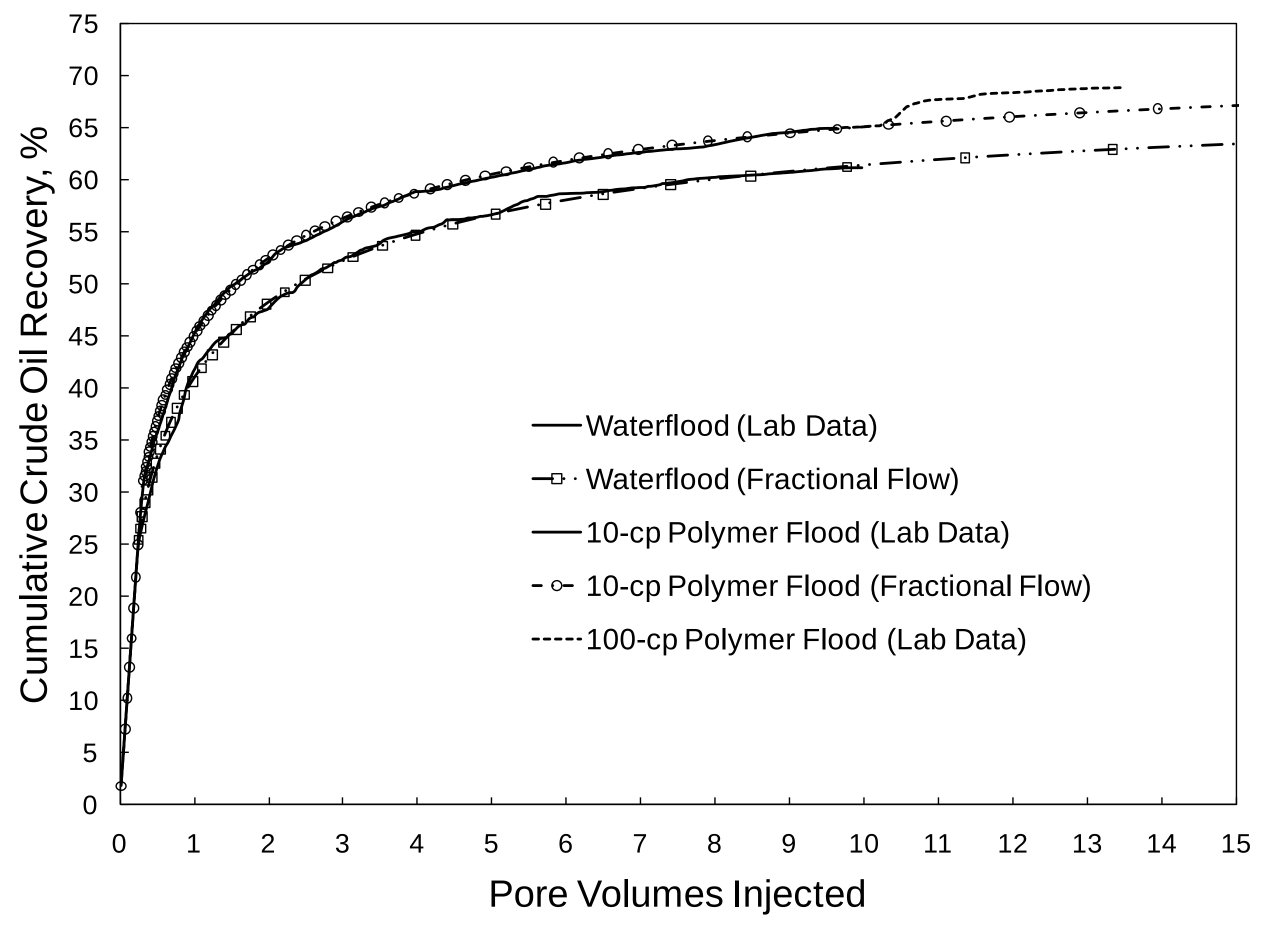
HPAM polymer as a tertiary flood:

- 190-cp North Slope crude. Polyethylene core.
- At S_{wr} initially. All floods at fixed capillary number.
- 10 PV brine, followed by 11 PV 10-cp HPAM.
- S_{or} reduced by at least 4 saturation percentage points.



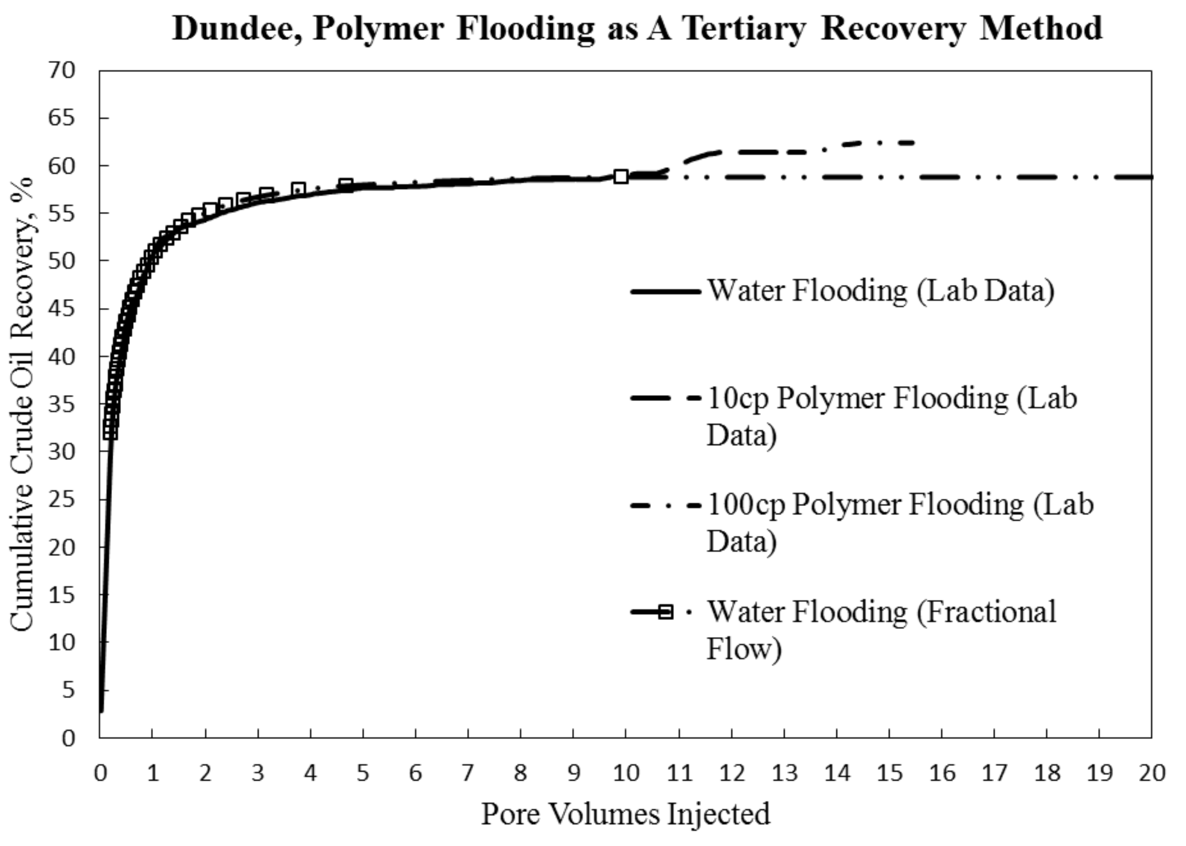
HPAM polymer as a secondary flood:

- 190-cp North Slope crude. Polyethylene core.
- At S_{wr} initially. All floods at fixed capillary number.
- Waterflood first. Re-saturate to S_{wr}. Then 10-cp HPAM.
- S_{or} reduced by at least 6 saturation percentage points.



HPAM polymer as a tertiary flood:

- 190-cp North Slope crude. Dundee sandstone core.
- At S_{wr} initially. All floods at fixed capillary number.
- 10 PV brine, followed by 10-cp HPAM.
- S_{or} reduced by ~2 saturation percentage points.



Papers on S_{or} Reduction Using Polymers

1. **Wang Demin et al. SPE 153070, 146473, 144294, 127453, 114335, 109228, 101950, 88456, 72123.**
2. **UT Austin. SPE 113417, 169037, 179683, 179689, 187230.**
3. **Cottin et al. SPE 169692.**
4. **Vermolen et al. SPE 169681, IPTC 17342.**
5. **Urbissionva et al. *JCPT* 49(12) 2010: 49-56.**
6. **Schneider and Owens. SPE 9408.**
7. **Kohler and Zaitoun. SPE 16274, 18085.**
8. **Clarke et al. SPE 174654.**

Bottom Line: Most (but not all) seem to agree that the effect occurs mostly at higher velocities with high Mw HPAM.

Summary of the Views on S_{or} Reduction Using Polymers

1. It is due to viscoelasticity of HPAM solutions.
   - A. Does not explain results where S_{or} reduction occurs at low capillary numbers.
   - B. If true, it means the phenomenon is largely irrelevant to oil recovery in field applications (because high velocities are needed to bring out the viscoelasticity).
2. It is an artifact of either having heterogeneous cores or unfavorable mobility ratio.
   - A. May not explain results where S_{or} reduction occurs at low capillary numbers in homogeneous cores.
   - B. May not explain the 20% OOIP EOR at Daqing field.
3. Could it be due to wettability alteration caused by the polymer?

S_{or} Reduction by Polymers: Why Are We Talking About This? – DAQING!

Wu et al.
SPE 109228,
Wang et al.
SPE 127453

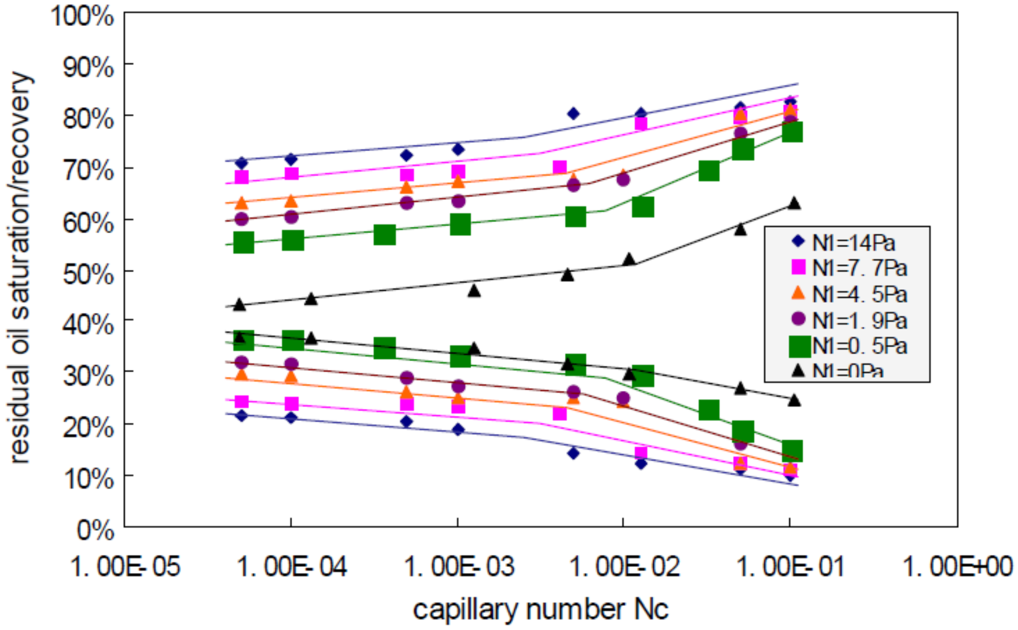


Fig.4 The relation curve of the recovery/residual oil saturation vs. the capillary number of the binary displacing system

Wang et al. (SPE 144294) reported 20% OOIP EOR from injecting 150-300-cp HPAM into >5600 wells (10-cp oil) versus 12% OOIP EOR for 40-cp HPAM.

S_{or} Reduction by Polymers: Bottom Line

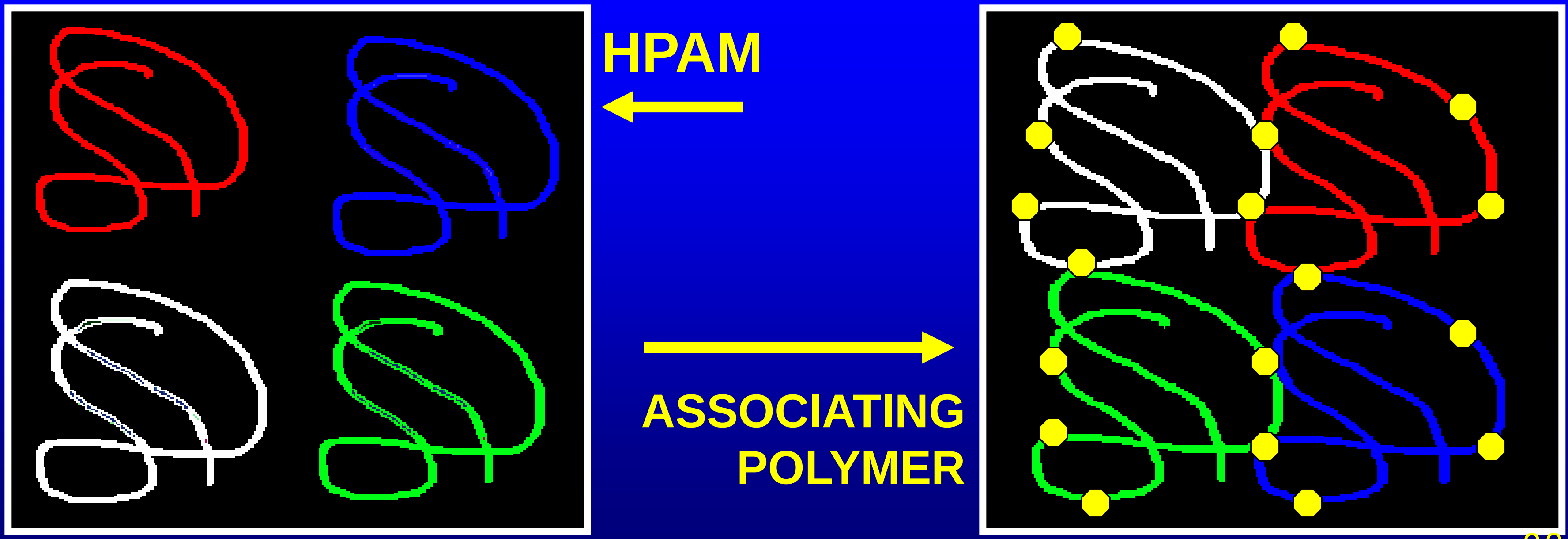
1. It does matter—even for viscous oils.
2. Primarily, true S_{or} reduction has been seen in non-water wet cores.
3. Most (but not all) seem to agree that the effect occurs mostly at higher velocities with high Mw HPAM.

SOME OTHER APPROACHES FOR IMPROVED MOBILITY CONTROL

- Associating polymers.
- Gel particulates (crosslinked polymers). (Could be emulsions or other particulates, also).
- Foams and other non-polymers.

ASSOCIATING POLYMERS -- Concepts

- Relatively small polymers with associating groups (e.g., hydrophobes) viscosify solutions like polymers with much higher molecular weights.
- Ideally, lower Mw polymers could improve stability.
- Ideally, associating polymers could be more cost-effective (i.e., if lower concentrations are needed to achieve high solution viscosities).

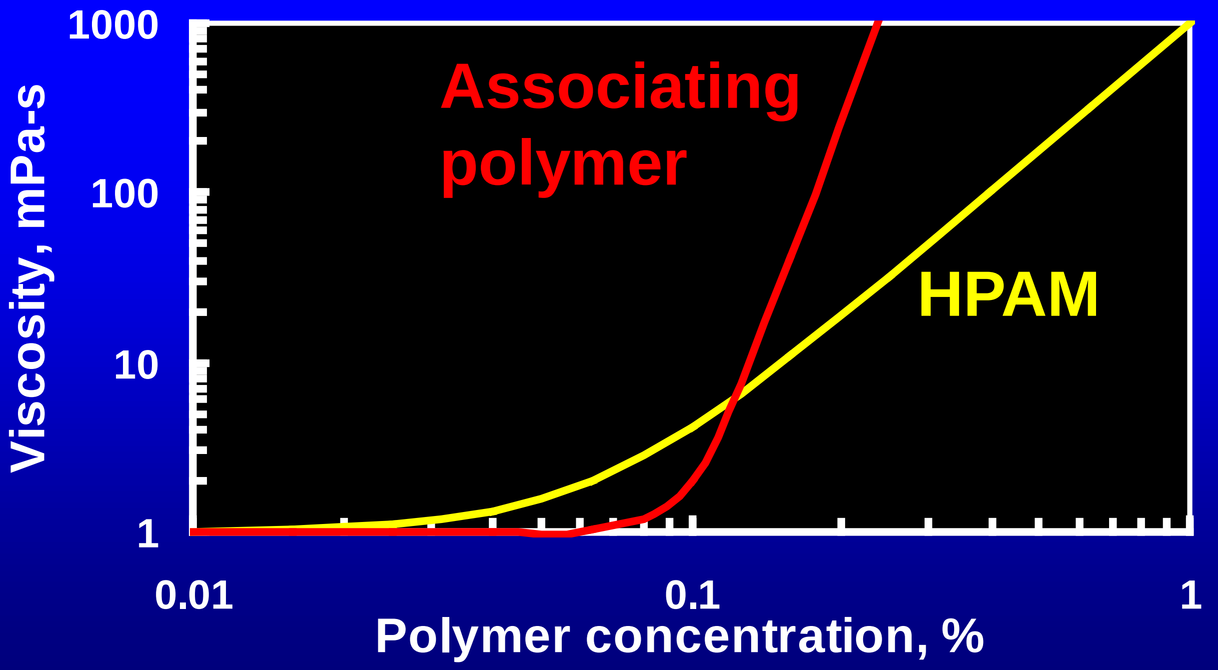


HPAM

ASSOCIATING POLYMER

ASSOCIATING POLYMERS -- Problems

- As concentration increases, viscosity of solutions of associating polymers increases much more quickly than for normal polymers.
- Achieving a PARTICULAR viscosity is more difficult.
- Small variations in concentration cause large variations in viscosity.
- Performance is sensitive to oil, salt, and temperature.



ASSOCIATING POLYMERS -- Problems

- At low flow rates, some associating groups bond within a given polymer, while others bond between separate polymer molecules.
- At high flow rates, the polymer stretches out, exposing more associating groups to other polymers.
- If too much bonding occurs between different polymer molecules, gelation occurs and flow stops.

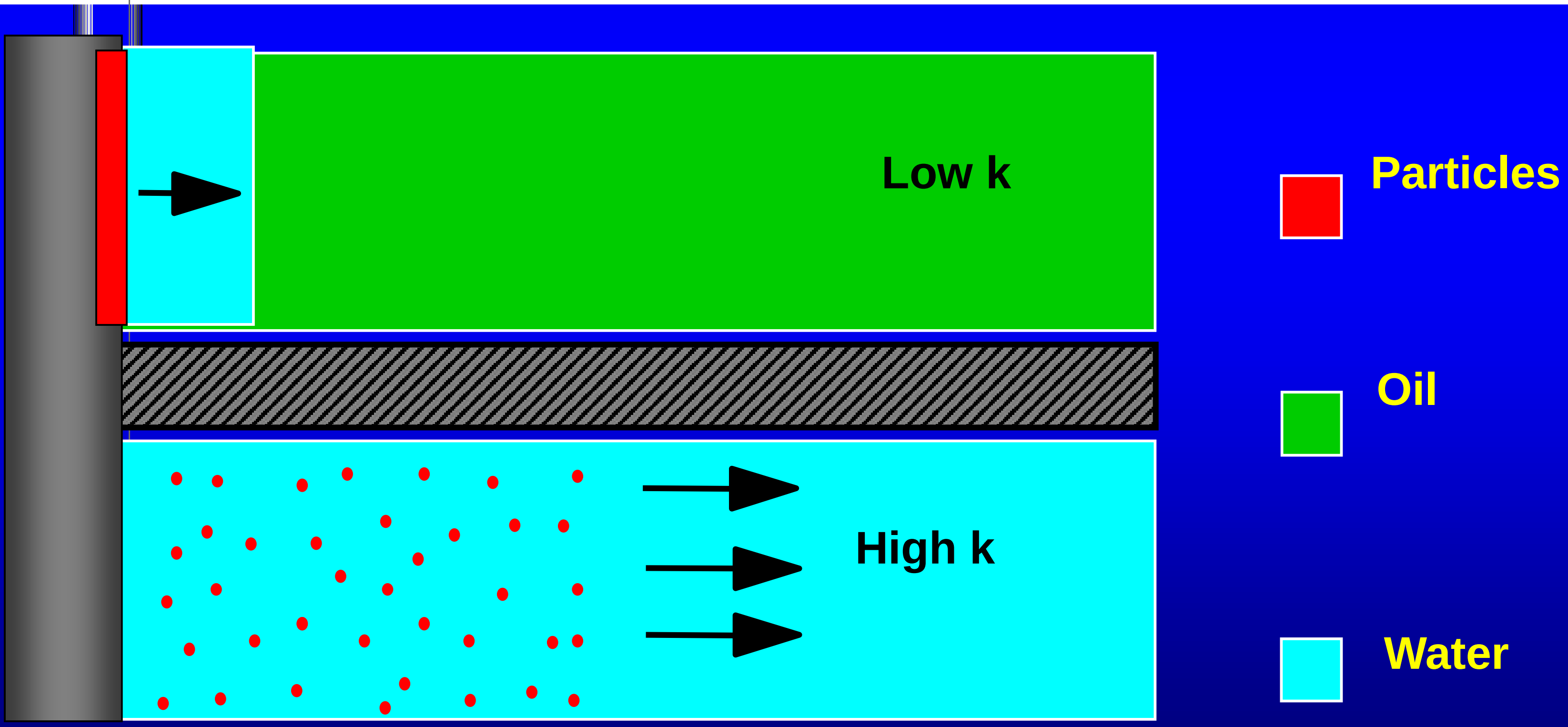
SO PERFORMANCE CAN BE SENSITIVE TO FLOW RATE AND PERMEABILITY (SPE 174553)

PROPAGATION ISSUE: Can these polymers propagate deep into a reservoir and provide acceptable, predictable performance? (SPE 129884, 141355,174553)

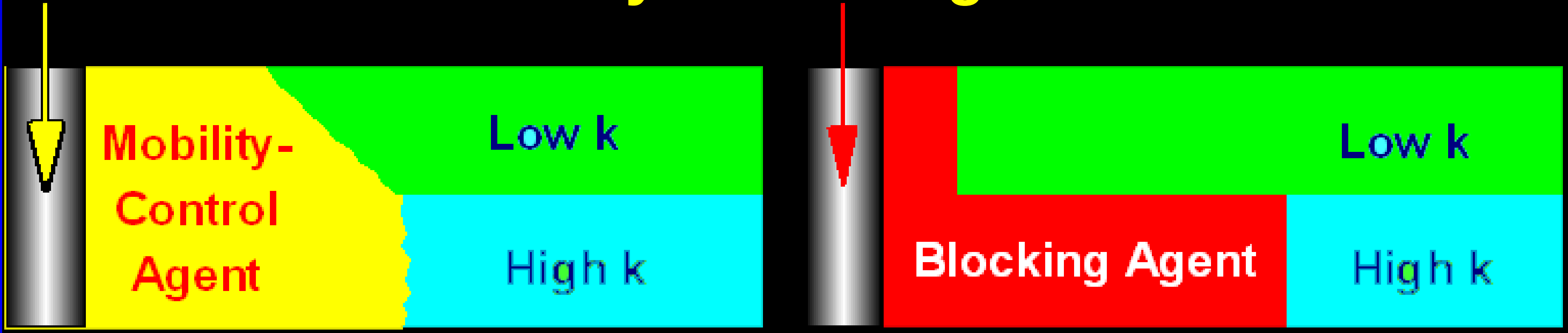
USE OF PARTICULATES (as a blocking agent)

One objective is to inject particles that are:

- small enough to flow freely into high-k zones,
- large enough not to enter low-k zones, and
- become immobile to divert water into oil zones.



Distinction between a blocking agent And a mobility control agent.

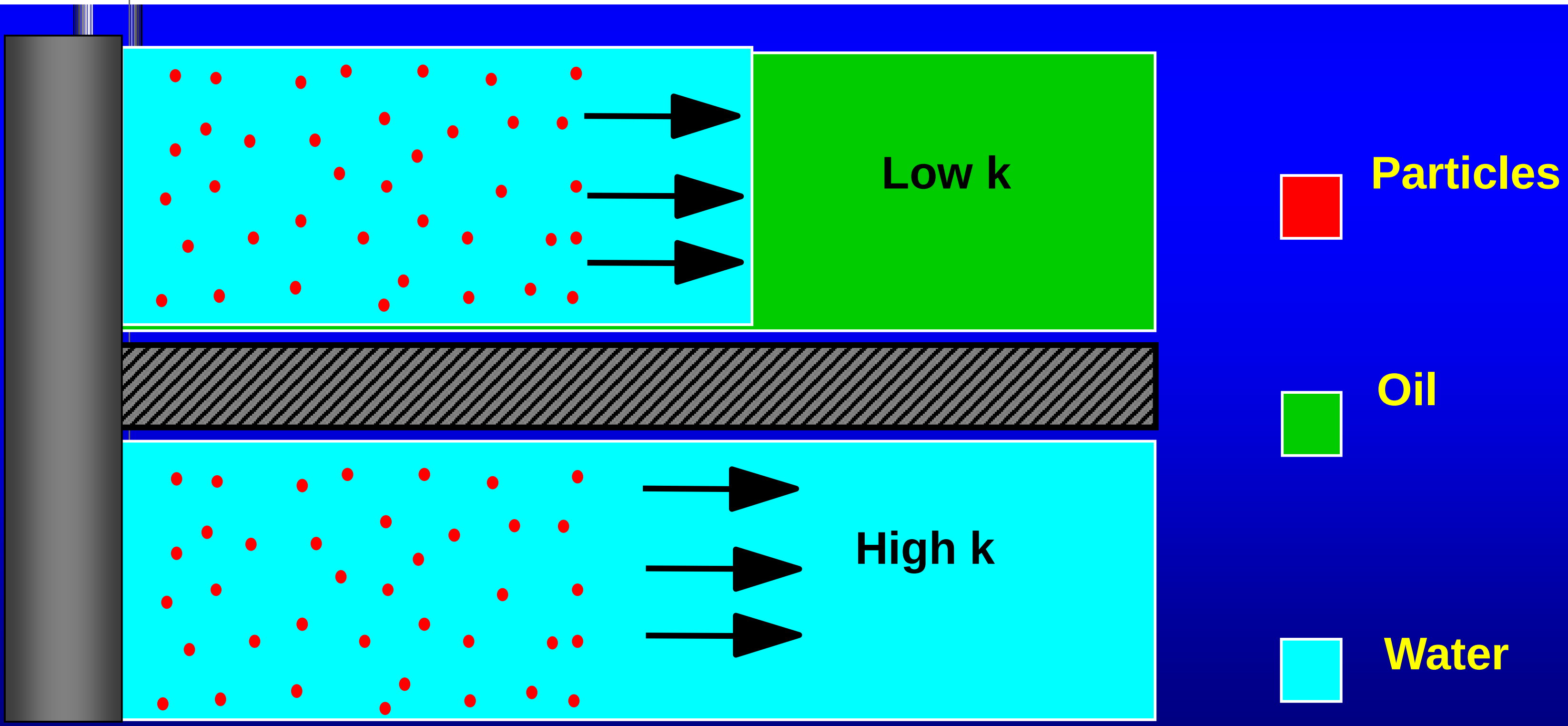


- For a mobility control agent, penetration into low-k zones should be maximized.
- For a blocking agent, penetration into low-k zones should be minimized.

USE OF PARTICULATES (for mobility control)

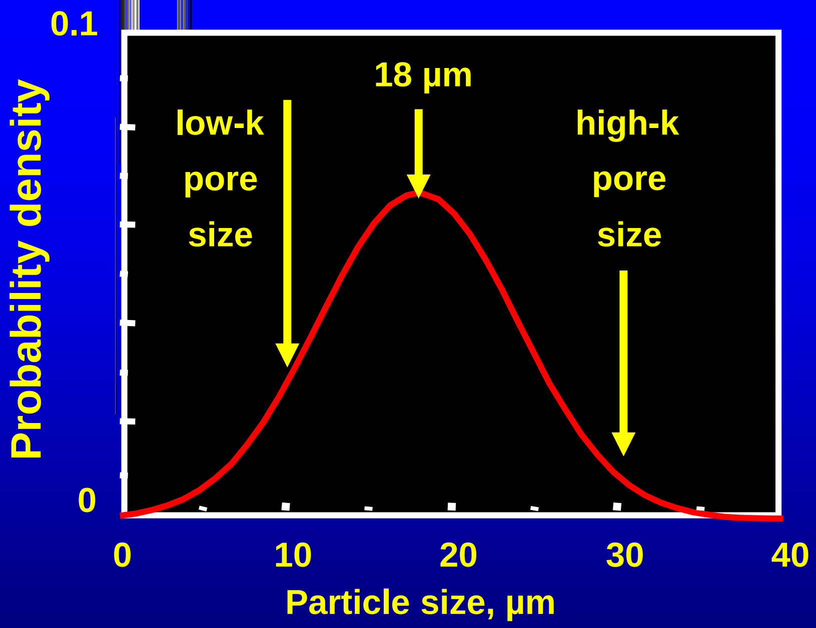
A different objective is to inject particles that:

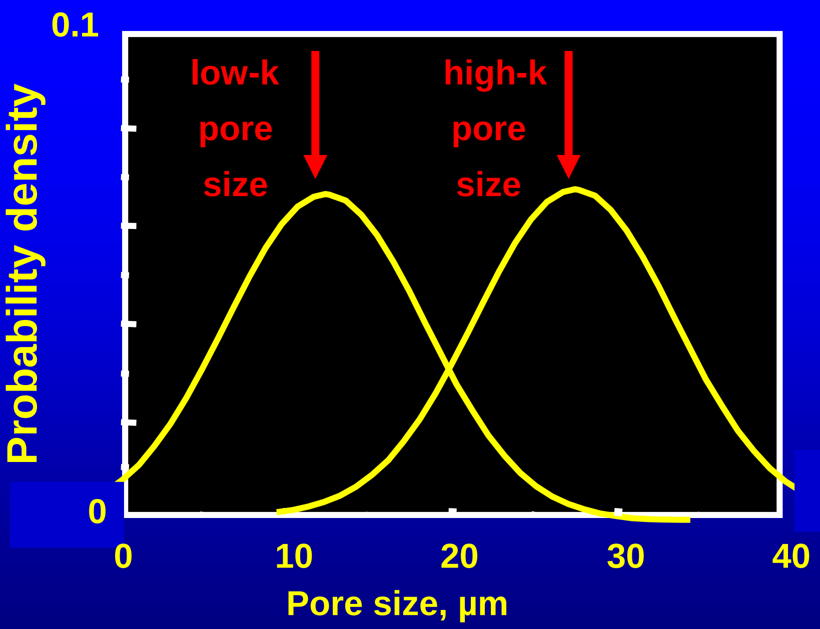
- deform as they extrude through pore throats,
- reduce water mobility, and
- Imitate a polymer flood.



USE OF PARTICULATES -- Problems

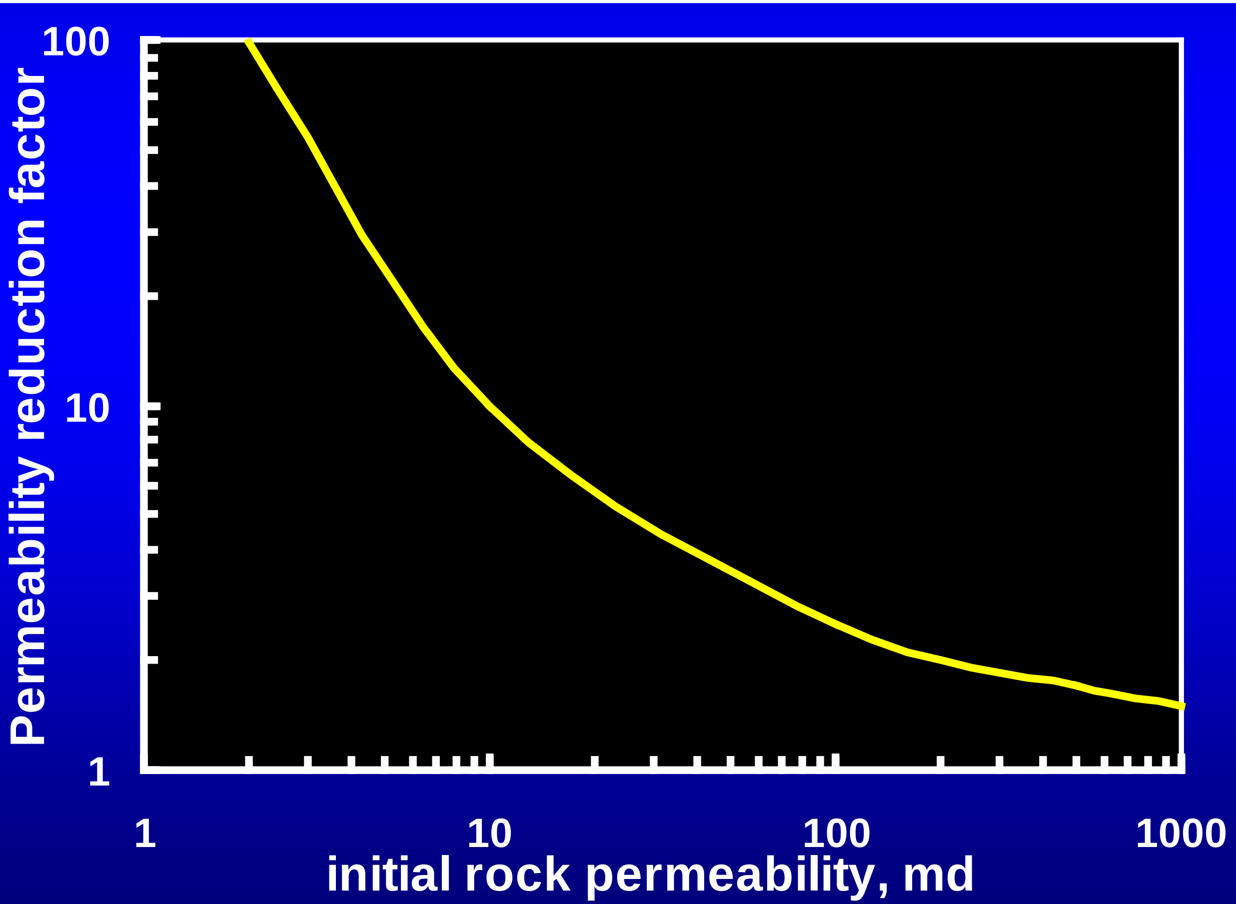
- Particles are not all the same size.
- Pores are not all the same size.
- Some particles will enter most or all pores.
- Permeability reduction may be greater in low-k pores than in high-k pores.



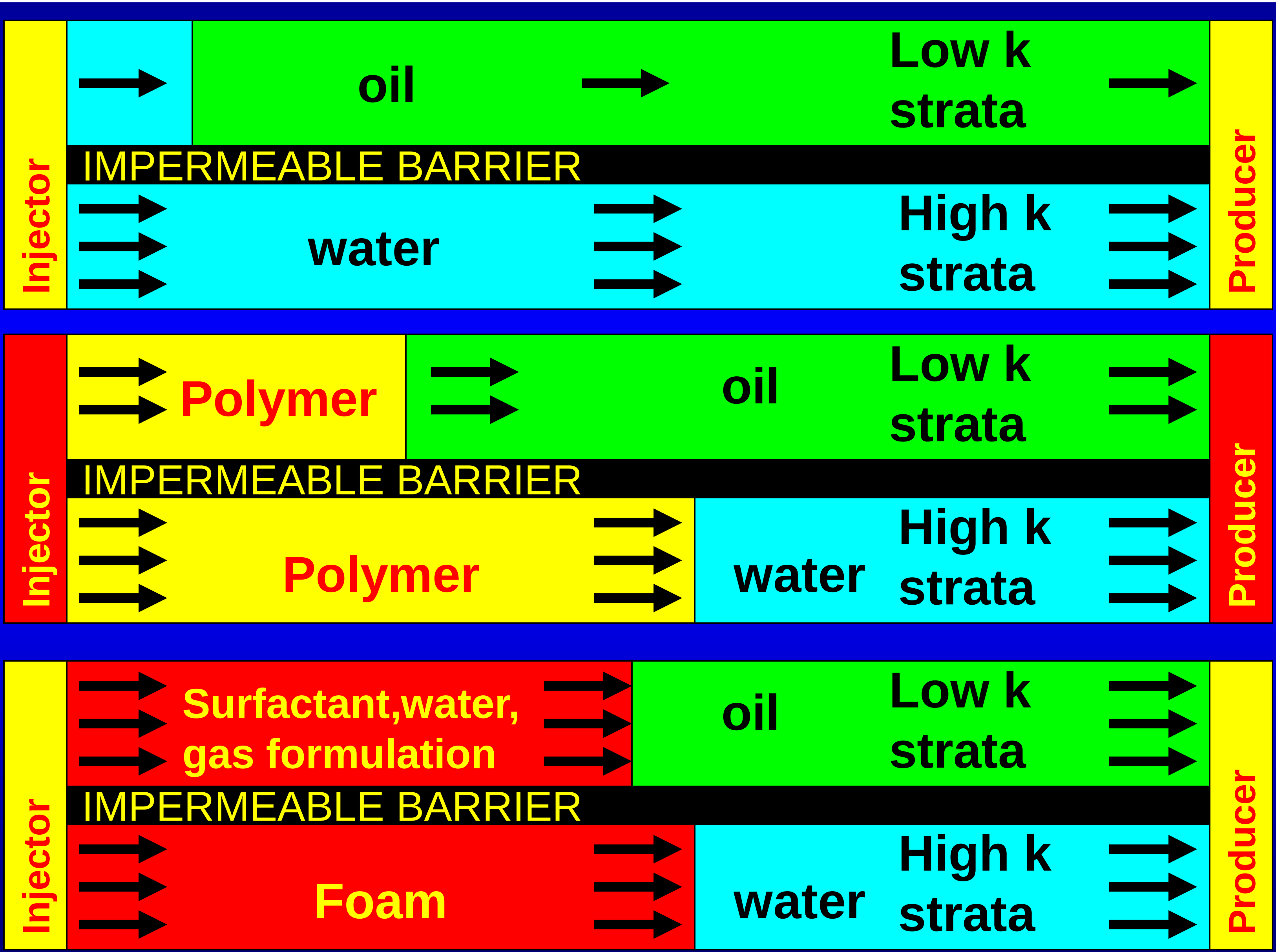


USE OF PARTICULATES -- Problems

- **Particles tend to block small pores more than large pores.**
- **This bad for both polymer floods and blocking agent treatments.**



If barriers prevent cross flow between strata, foams could provide better sweep efficiency than polymer solutions.



Injector

oil

Low k strata

IMPERMEABLE BARRIER

water

High k strata

Producer

Injector

Polymer

oil

Low k strata

IMPERMEABLE BARRIER

Polymer

water

High k strata

Producer

Injector

Surfactant,water, gas formulation

oil

Low k strata

IMPERMEABLE BARRIER

Foam

water

High k strata

Producer

PROBLEMS WITH FOAMS

For various reasons, foam stability may not be sufficient.

Foam may not propagate as desired.

The desired level of mobility reduction may be difficult to achieve. (If mobility is too high, sweep is bad. If mobility is too low, injectivity is bad).

SURFACE ISSUES

Water quality
Powder vs emulsion polymers
Fluid transfers & gas blanketing
Dissolution equipment
Distributing fluid to injectors
Issues in production wells
Oil/water separation

WATER QUALITY (mostly from SNF)

Salinity/Hardness: Economic issue. As TDS increases from 500 to 5000-ppm, HPAM viscosity drops 3.5X.

Particulates: < 20 ppm, size < 5 µm.

Oil content: < 100 ppm (often economic to achieve less).

Dissolved oxygen: < 20 ppb for T<50°C. Strive for 0 ppb at higher T. (Strive for 0 ppb at low T also.)

Fe^{2+}: Some people list an Fe^{2+} limit, but I advocate leaving the iron in solution and minimizing oxygen.

Microorganism content: Limit growth so it does not interfere with injectivity or operations.

Powder versus Emulsion Polymers

SPE 179631 (Total) and SPE 179657 (Chevron)

- **Emulsion polymers require less CAPEX and footprint and dissolve faster.**

BUT…

- **They cost more.**
- **Have higher transportation costs.**
- **Can show plugging/injectivity impairment associated with the oil phase.**

Fluid Transfers

Gas/oxygen entrainment can be minimized by piping fluid into tanks below the liquid surface.

Gas Blanketing

Gas blanketing tanks is reasonably economic for storage and transfer tanks. In contrast, blanketing the powder feed and storage hoppers can be expensive. Solution: introduce a nitrogen sparge line into the powder hopper cone just above the eductor or slicing unit.

Powder Polymer Dissolution Equipment

Eductors (high-energy water jets):

- Simple, low cost, easy to maintain.
- More difficult to exclude air/oxygen.

Polymer slicing units:

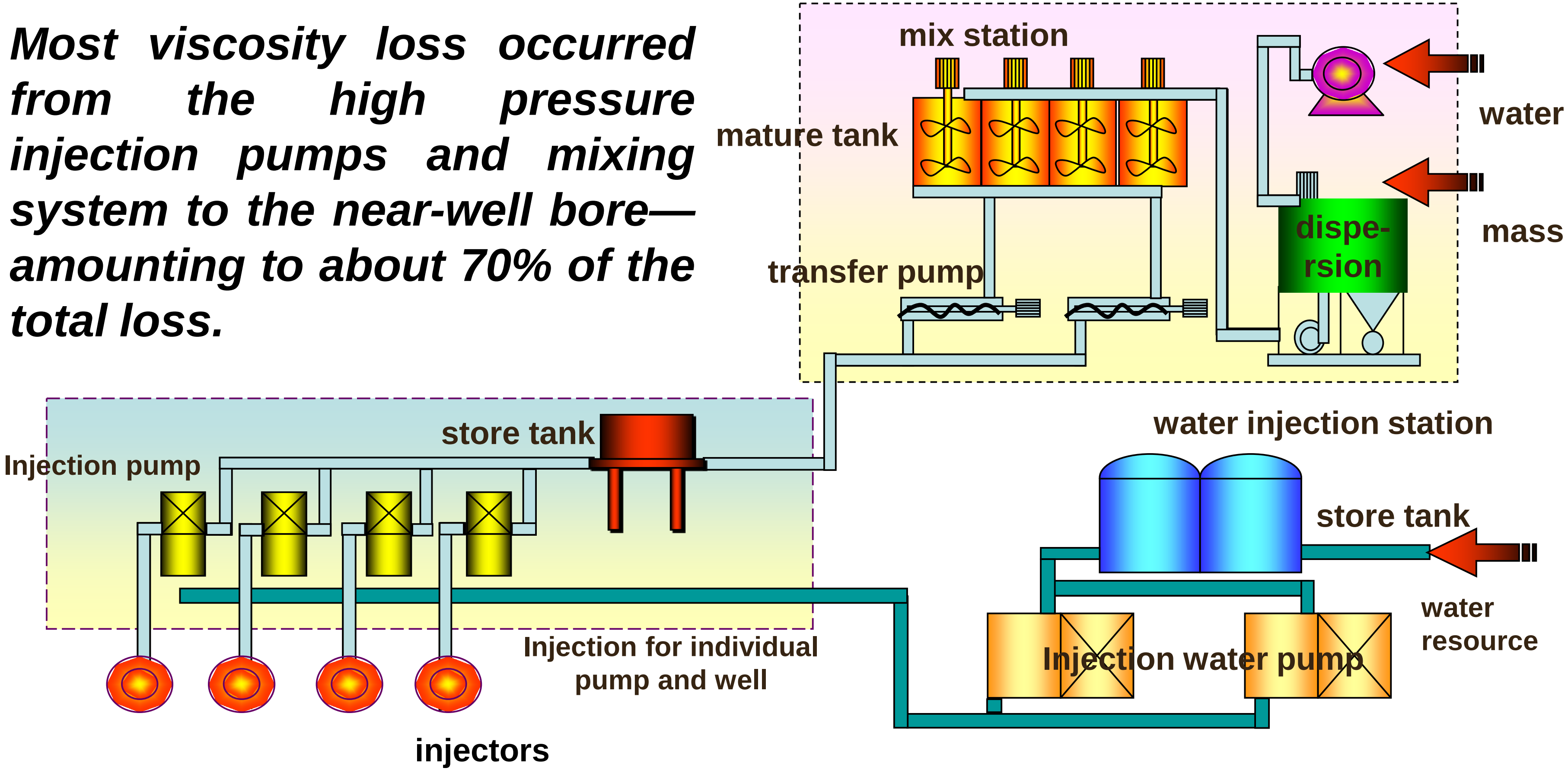
- Compact, more workable in controlled gas environments (H_2S or O_2-free).
- More expensive, higher maintenance costs?

Recent papers on startup & facility issues (pumps, tank mixers, filters, monitoring, logistics):

SPE 77496, 114342 (Daqing), 135735 (Total),165308 (Chang), 174350 (OMV), 174537 (IFP), 179807, 179820 (Cairn), 155116 (Shell).

Daqing Mixing and Injection (from D. Wang, *SPEREE* 2009, SPE 114342)

Most viscosity loss occurred from the high pressure injection pumps and mixing system to the near-well bore—amounting to about 70% of the total loss.



Flow illustration for polymer injection

SPE 135735

First Polymer Injection in Deep Offshore Field Angola: Recent Advances on Dalia/Camelia Field Case

Danielle Morel and Michel Vert, Total E&P; Stéphane Jouenne, Total Petrochemicals France; and
Renaud Gauchet and Yann Bouger, Total E&P Angola

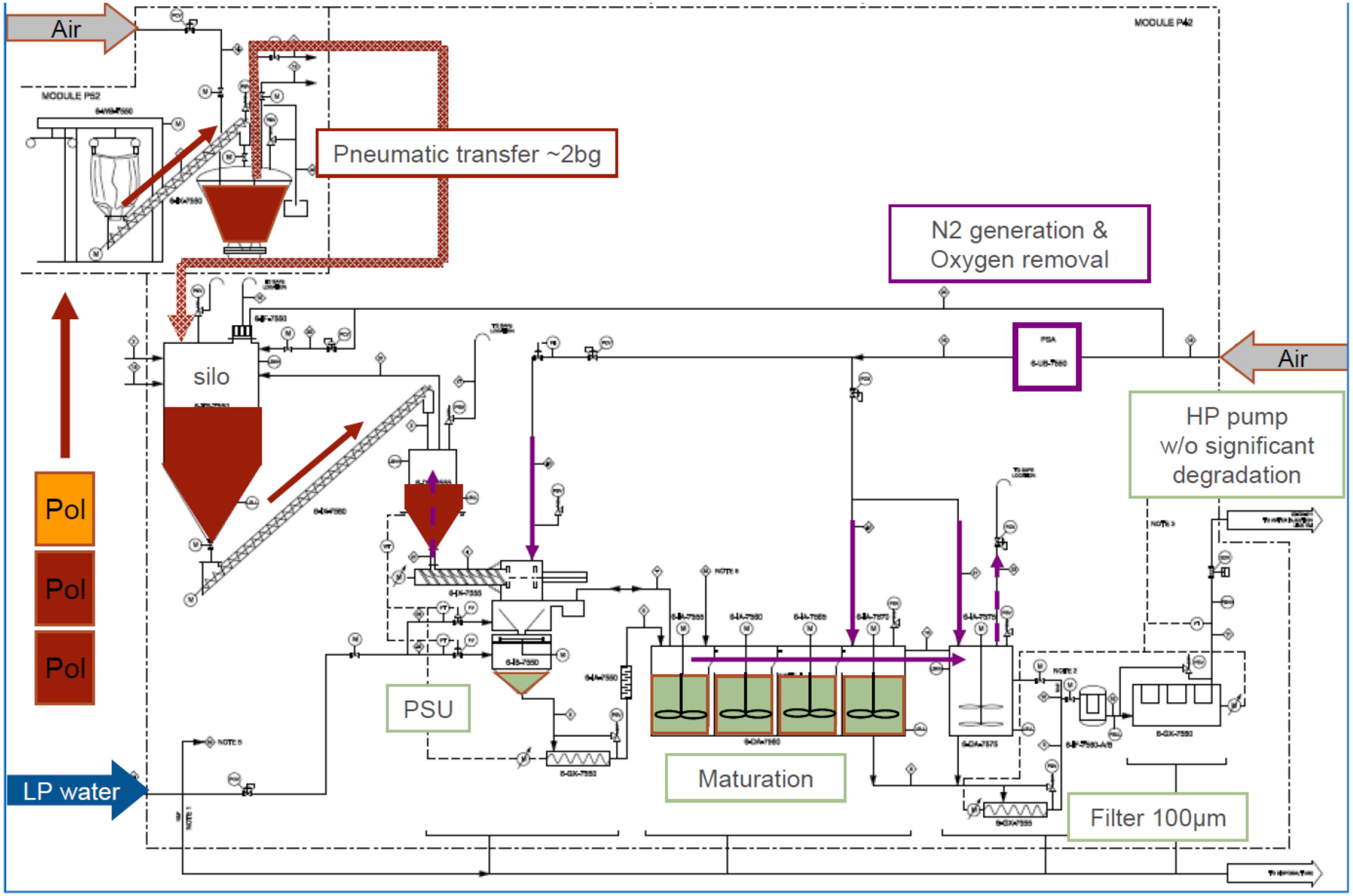


Figure 6 - Schematic of the powder polymer process

HPAM Mechanical Degradation in Pipes

SPE 169699: Jouenne et al. (Total)

HPAM mechanical degradation is low for velocities up to 3.7 m/s for pipes larger than 6-inch ID, for any length.

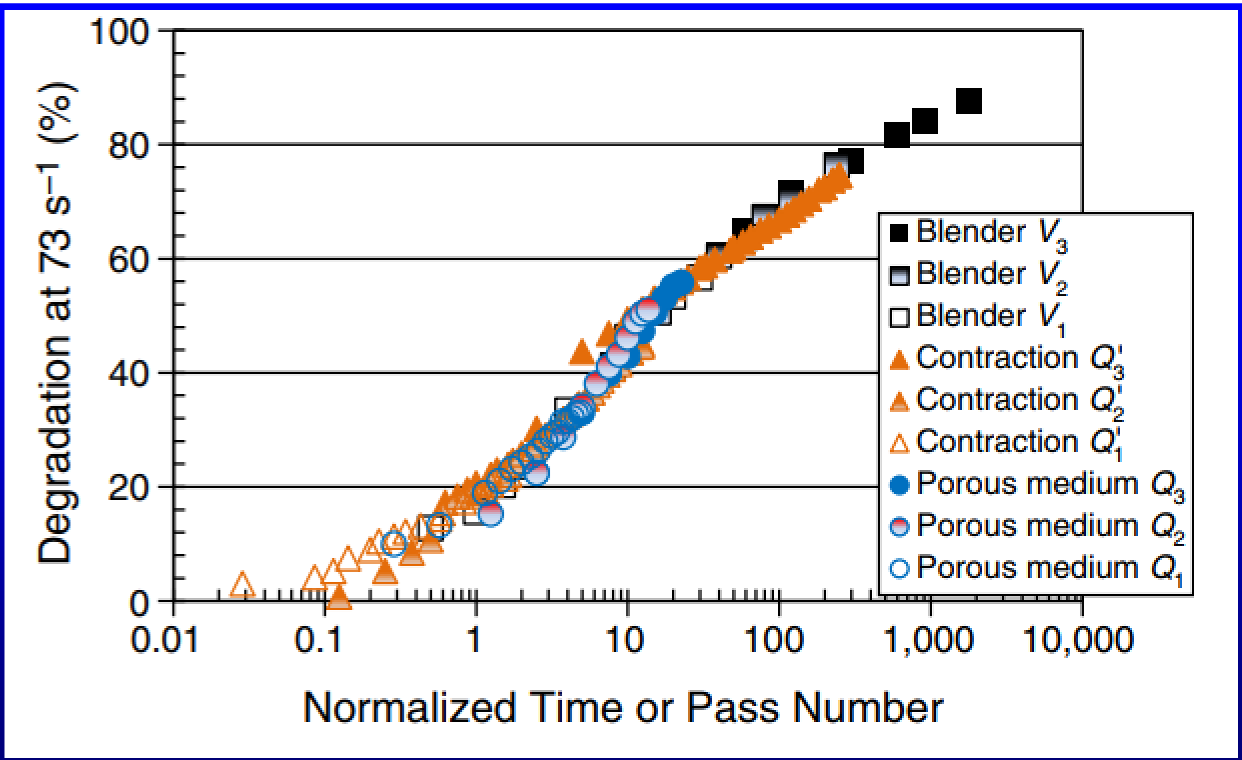
- 3630S HPAM concentrations from 300-2000 ppm.
- Distances up to 7500 meters.
- 50°C and 0.6%-TDS brine.

With 1200 ppm HPAM, mechanical degradation is:

- ~0 for up to 4 m/s in 0.98-inch-ID pipes.
- <10% for up to 7 m/s in 0.74-inch ID pipes.
- ~0 below 2 m/s in 0.49-inch ID pipes.

HPAM Mechanical Degradation after Sequential Exposures SPE 186103: Jouenne et al. (Total)

- Reviewed literature on mechanical degradation.
- Propose an empirical correlation between % loss of viscosity and (1) time in a blender, (2) flow through a contraction, and (3) flow in porous media.
- The correlation has potential but needs further testing.



SPECIAL ISSUES ASSOCIATED WITH USING VISCOELASTIC HPAM SOLUTIONS

Wang Demin et al. *SPEPF* (2004) SPE 77496

Problem: Inefficient polymer mixing in tanks.

Solution: Re-designed mixing blades reduced energy requirements 80% and reduced mixing time by 1.5-2 hours.

Problem: 10-30% shear degradation in static mixers.

Solution: Remove the static mixer.

SPECIAL ISSUES ASSOCIATED WITH USING VISCOELASTIC HPAM SOLUTIONS

Wang Demin et al. *SPEPF* (2004) SPE 77496

Problem: Pumping 0.5% HPAM solutions substantially increases vibration, especially upstream of pumps.

Solution: Use large diameter pipes, avoid T's.

SPECIAL ISSUES ASSOCIATED WITH USING VISCOELASTIC HPAM SOLUTIONS

Wang Demin et al. *SPEPF* (2004) SPE 77496

Problems with triplex pumps with HPAM:

- **High vibration.**
- **10-15% lower pump efficiency.**
- **15% viscosity loss from shear degradation.**

Solution: Re-design the pumps.

- **Decrease valve seat area.**
- **Adjust the angle of the valve seat.**
- **Increase inner cylinder diameter**
- **Decrease dead-end volume.**

Control of fluid distribution to injection wells

One pump per injection well.

Flow restriction devices:

- In-line sand packs (SPE 8202, W Yellow Creek)
- Coiled tubing (SNF and CAPSA, SPE 166255)
- Low-shear valve (Chang, SPE 165308).

PROBLEMS WITH PRODUCED POLYMER

- **Excessive wear for sucker rods (SPE 77496).**
- **Emulsions that are difficult to break.**
  - **Fouling of heat exchangers & fire tubes (SPE 14110, SPE 144322).**
  - **Efficiency reductions for hydrocyclones and gas floatation units (SPE 95343).**
- **Plugging filters (SPE 144277).**
- **Inability to reuse produced water for polymer flooding.**

POTENTIAL SOLUTION: Improve sweep to delay polymer breakthrough:

  - **Increase polymer concentration & viscosity.**
  - **Gel treatments to reduce severe channeling.**
  - **Separate layer injection.**

IDEAS TO TREAT PRODUCED POLYMER

- **Extended gravity separation (SPE 114342).**
- **Hydrocylone (SPE 95343).**
- **Modified heater treaters (170172).**
- **Oxidation (SPE 174683).**
- **Shearing through choke valves or centrifugal pumps.**
- **Flocculation with bentonite & pH changes (SPE 179525).**
- **Treatment with polyaluminum chloride or aluminum sulfate (SPE 172024) or iron chloride (SPE 174683).**
- **Addition of cationic polymers/surfactants (SPE 140860, SPE 169718, 177501).**
- **Removal using magnetic nanoparticles (SPE 179576).**

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.