Brief Introduction to Polymer Flooding and Gel Treatments

and

Injectivity Characteristics Of EOR Polymers

(SPE 115142)

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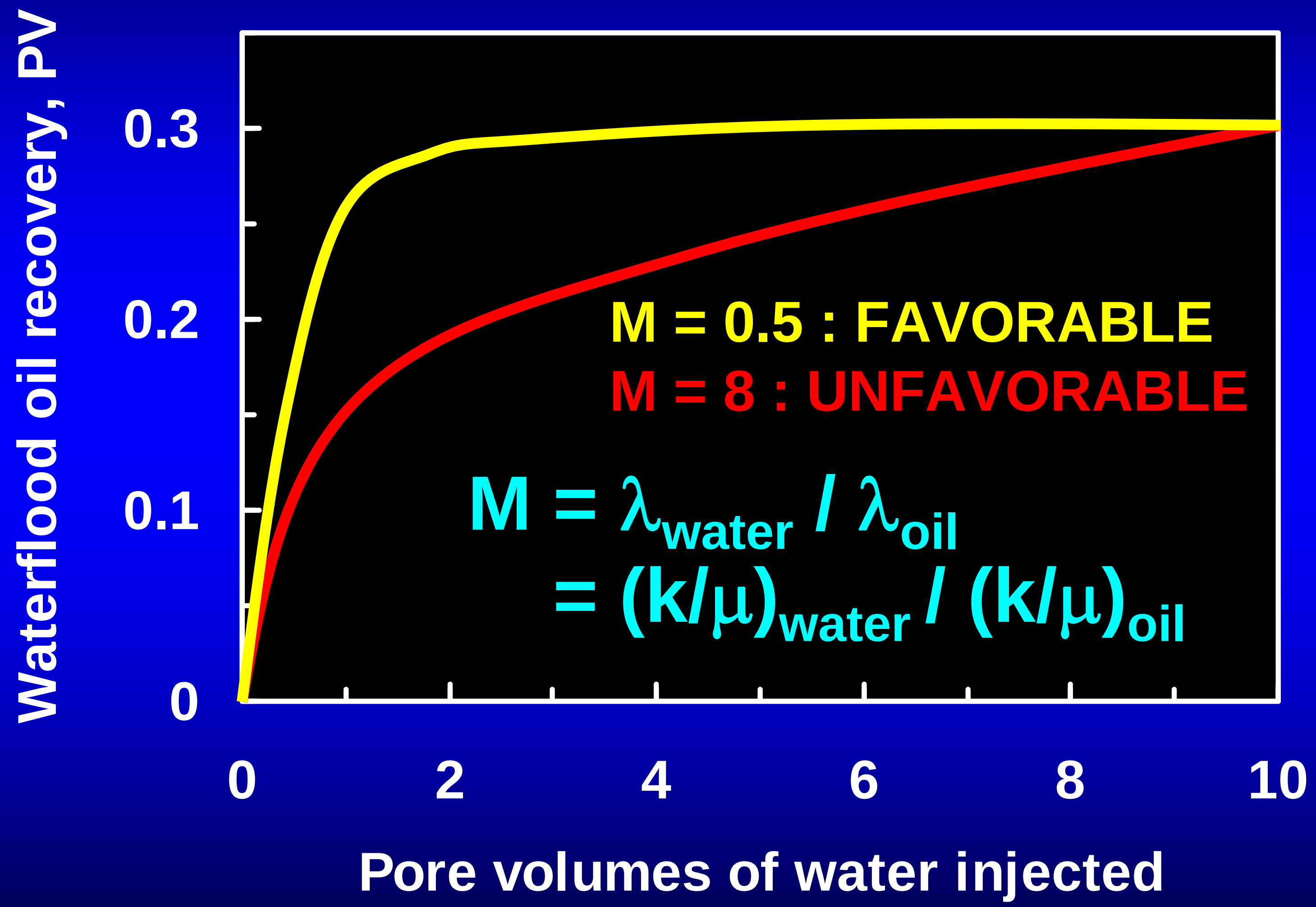
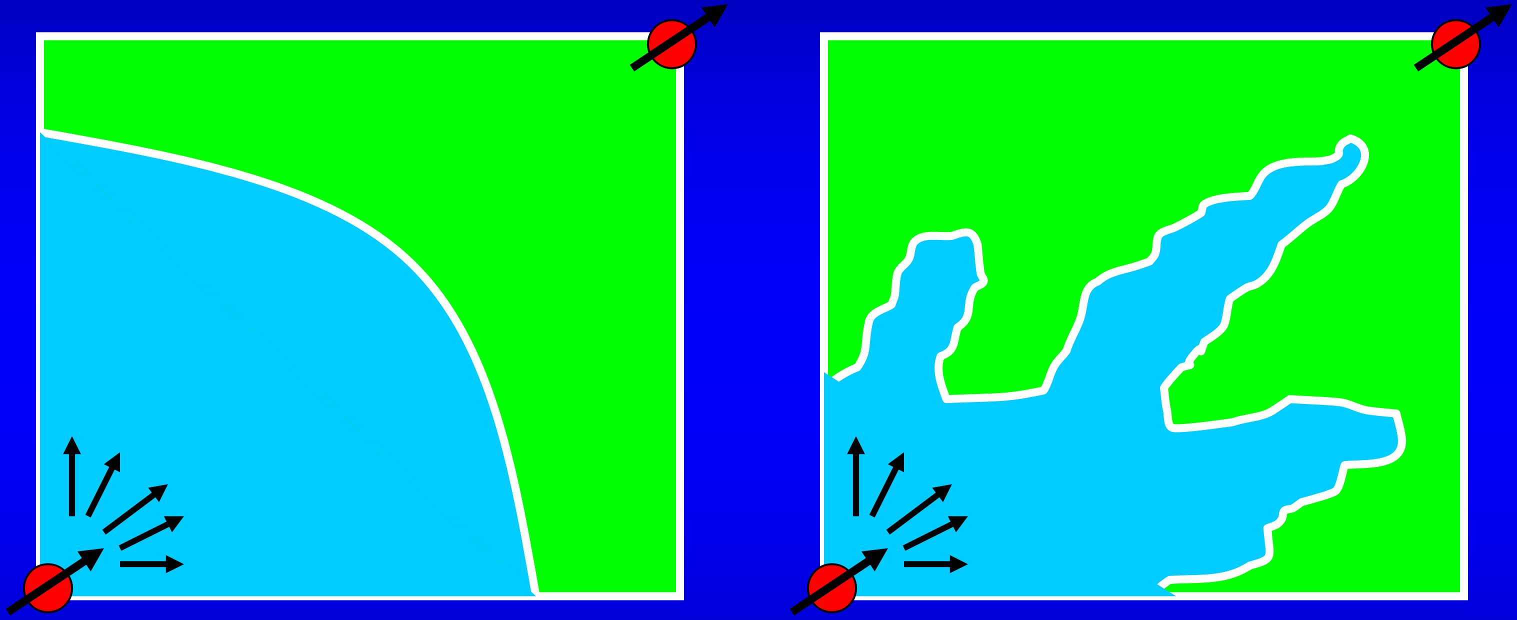
EFFECT OF MOBILITY RATIO ON WATERFLOOD OIL RECOVERY



EFFECT OF MOBILITY RATIO ON AERIAL SWEEP EFFICIENCY

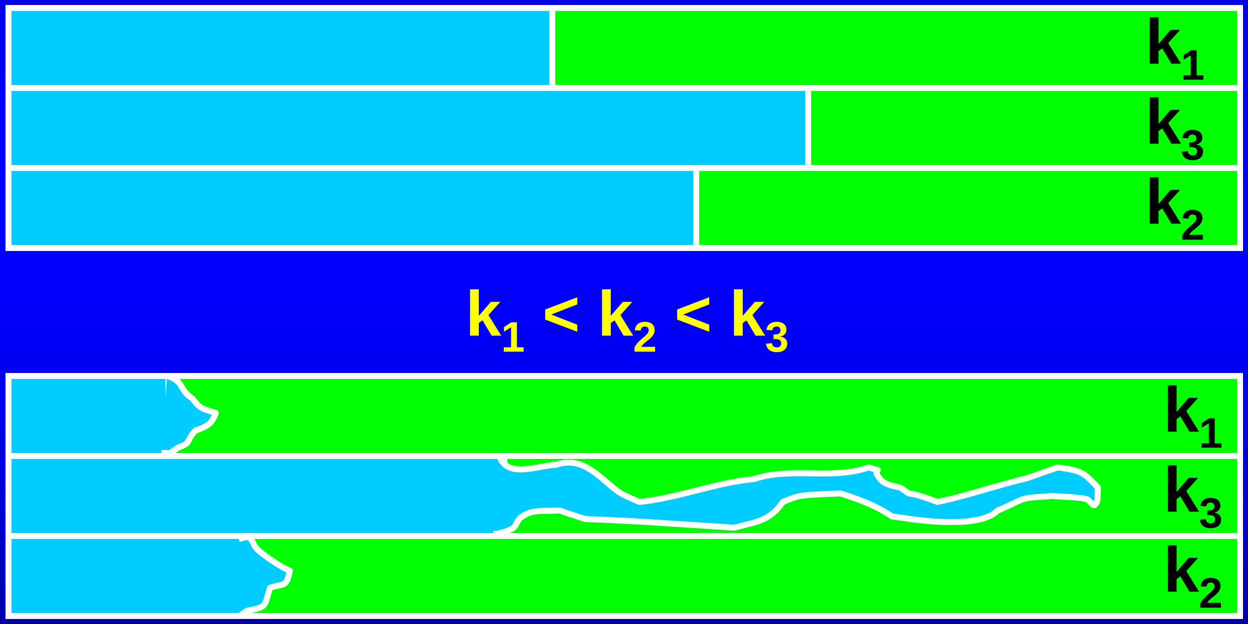


M < 1: FAVORABLE **M > 1: UNFAVORABLE**

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

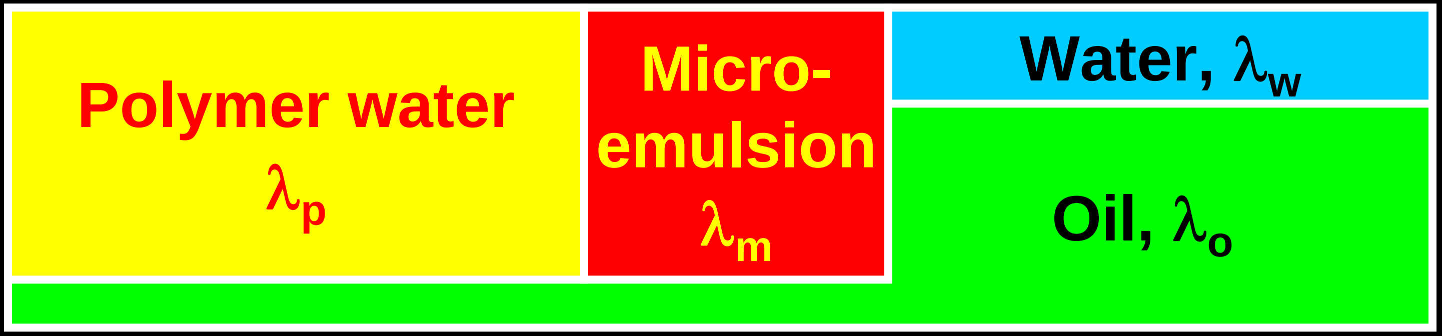
EFFECT OF MOBILITY RATIO ON VERTICAL SWEEP EFFICIENCY

M < 1: FAVORABLE



M > 1: UNFAVORABLE

MOBILITY CONTROL



Favorable displacement at microemulsion front requires:

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

Favorable displacement at microemulsion rear requires:

$$\lambda_p \leq \lambda_m$$

IDEAL PROPERTIES FOR MOBILITY CONTROL AGENTS

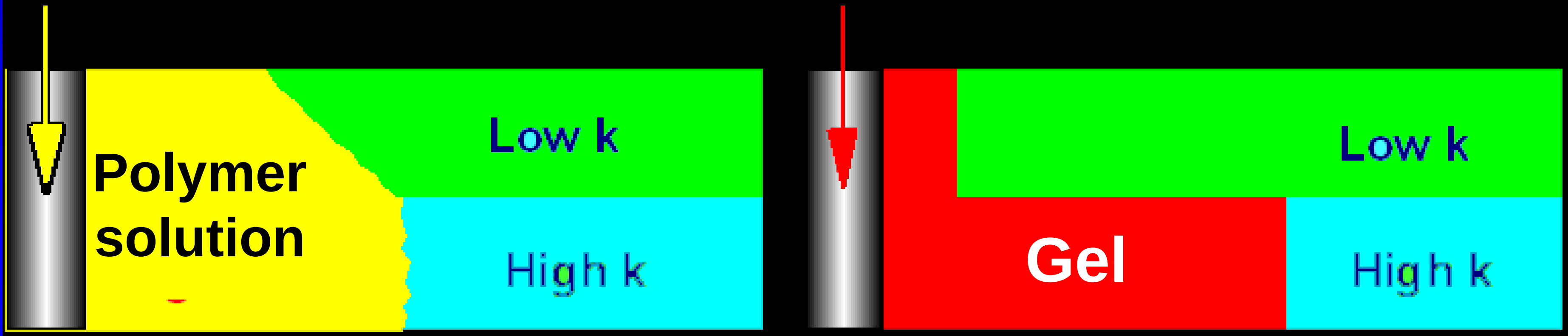
- Low cost or high cost-effectiveness.
- Allows high injectivity.
- Effective when mixed with reservoir brines (up to 20% total dissolved solids).
- Resistant to mechanical degradation (up to 1000 $m^3/m^2/d$ flux when entering porous rock).
- 5 to 10 year stability at reservoir temperature (up to 150°C).
- 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.

GEL TREATMENTS ARE NOT POLYMER FLOODS

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

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

Distinction between a gel treatment and a polymer flood.



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

POLYMER FLOODING is best for improving sweep in reservoirs where fractures are not important.

- 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.

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We perform research and development to improve reservoir sweep efficiency and reduce saltwater production during oil and gas recovery operations.

Search

Use of Gels for Water Shutoff
An introduction

A strategy for attacking excess water production
Identifying the problem is critical before attempting a solution. But I have limited resources for diagnosis. How do I start?

Gel Placement Concepts
How do I place gel to stop water production without damaging oil or gas production?

Designing Gel Treatments
Spreadsheets of important calculations

Videos of Polymer Flooding and Crossflow Concepts

Why do pore-filling gels reduce k_w much more than k_o?

Are Colloidal Dispersion Gels Really a Viable Technology?

"Clean Up" of Oil Zones after a Gel Treatment

New Filter Cake Model

Physical Realities For In Depth Profile Modification

Annual Reports
2006 2005, 2004, 2003, 2002, 2001, 2000, 1999, 1998, 1997, 1996, 1995, 1994, 1993, 1992, 1991, 1990

Water Shutoff Consortium (Members Only)

Publications

SPE 115142

INJECTIVITY CHARACTERISTICS OF EOR POLYMERS

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.

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)**

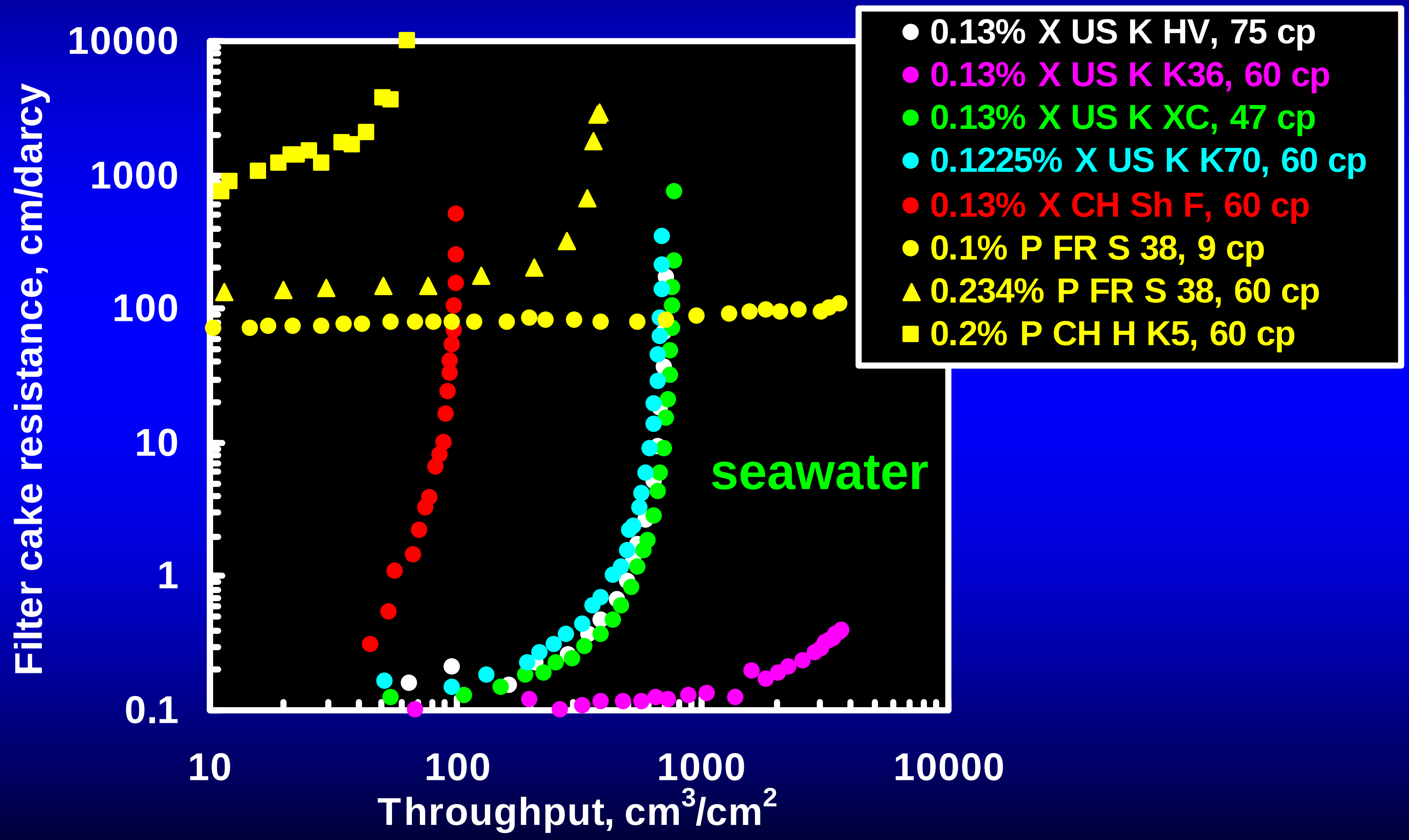
Plugging of Rock Face During Polymer Injection

- **Throughput for field EOR projects:**
  - ~ 100,000 cm^3/cm^2 for unfractured vertical wells.
  - ~ 1,000-10,000 cm^3/cm^2 for fractured vertical wells.

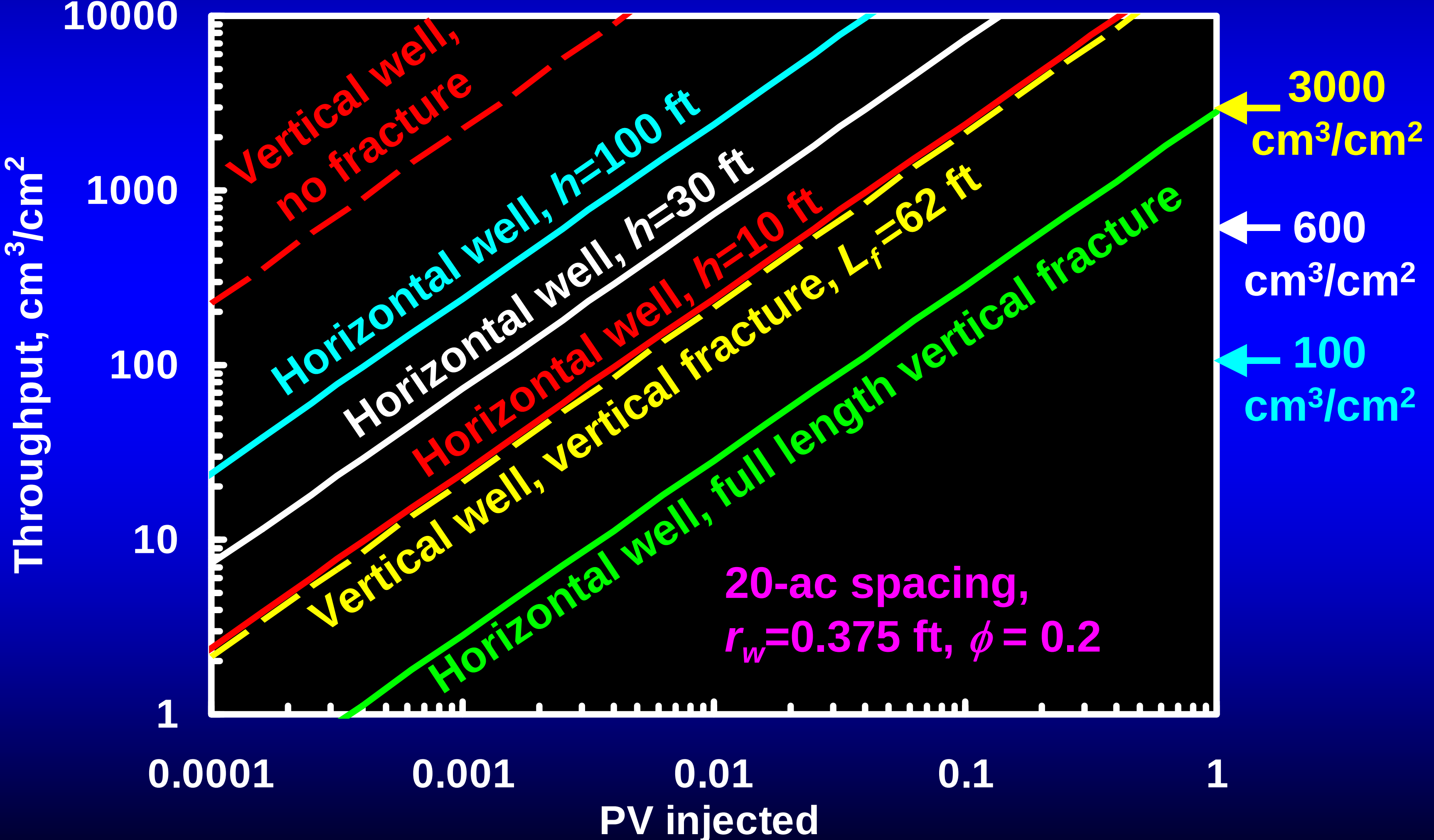
- **Previous lab filter tests**
  - Used less than 40 cm^3/cm^2 throughput.
  - Typically use "filter ratios". $[(t_{500}-t_{400})/ t_{200}-t_{100})]$
  - Do not correlate with injection into rock.

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

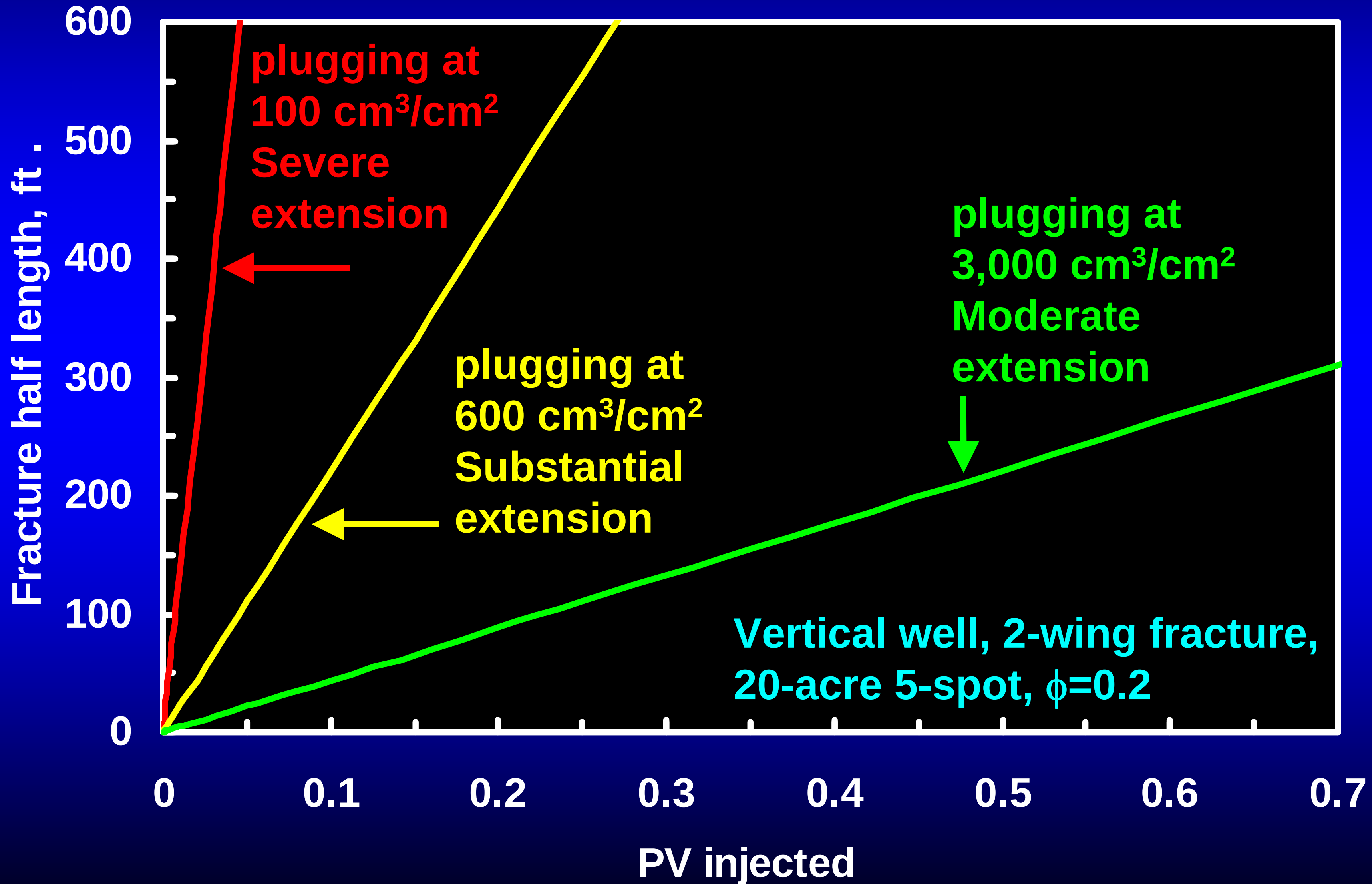
- For both xanthan and HPAM solutions, filterability varies a lot, depending on polymer source.



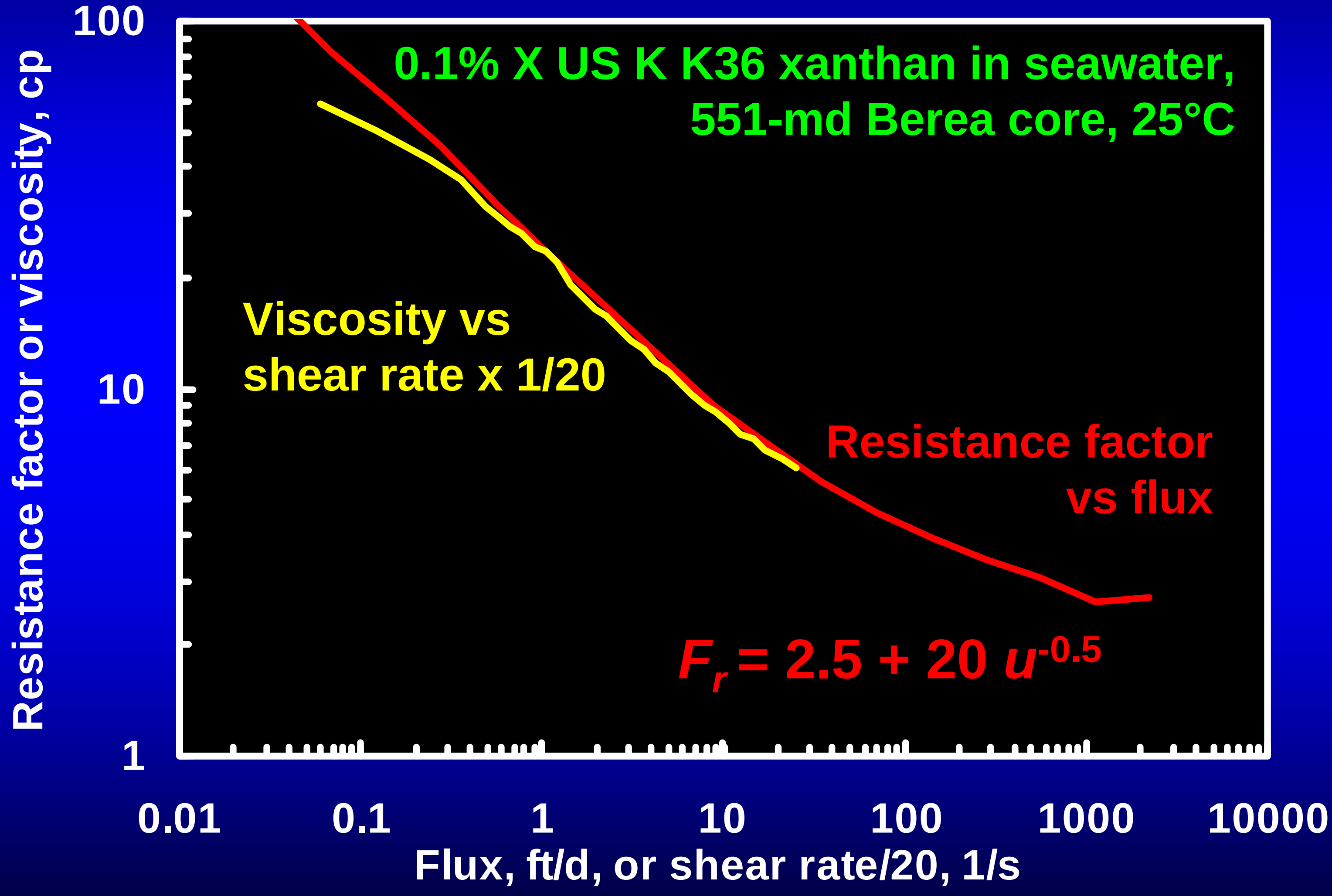
Even with the cleanest polymers, face plugging will exceed the capacity of unfractured wells during most chemical EOR projects.



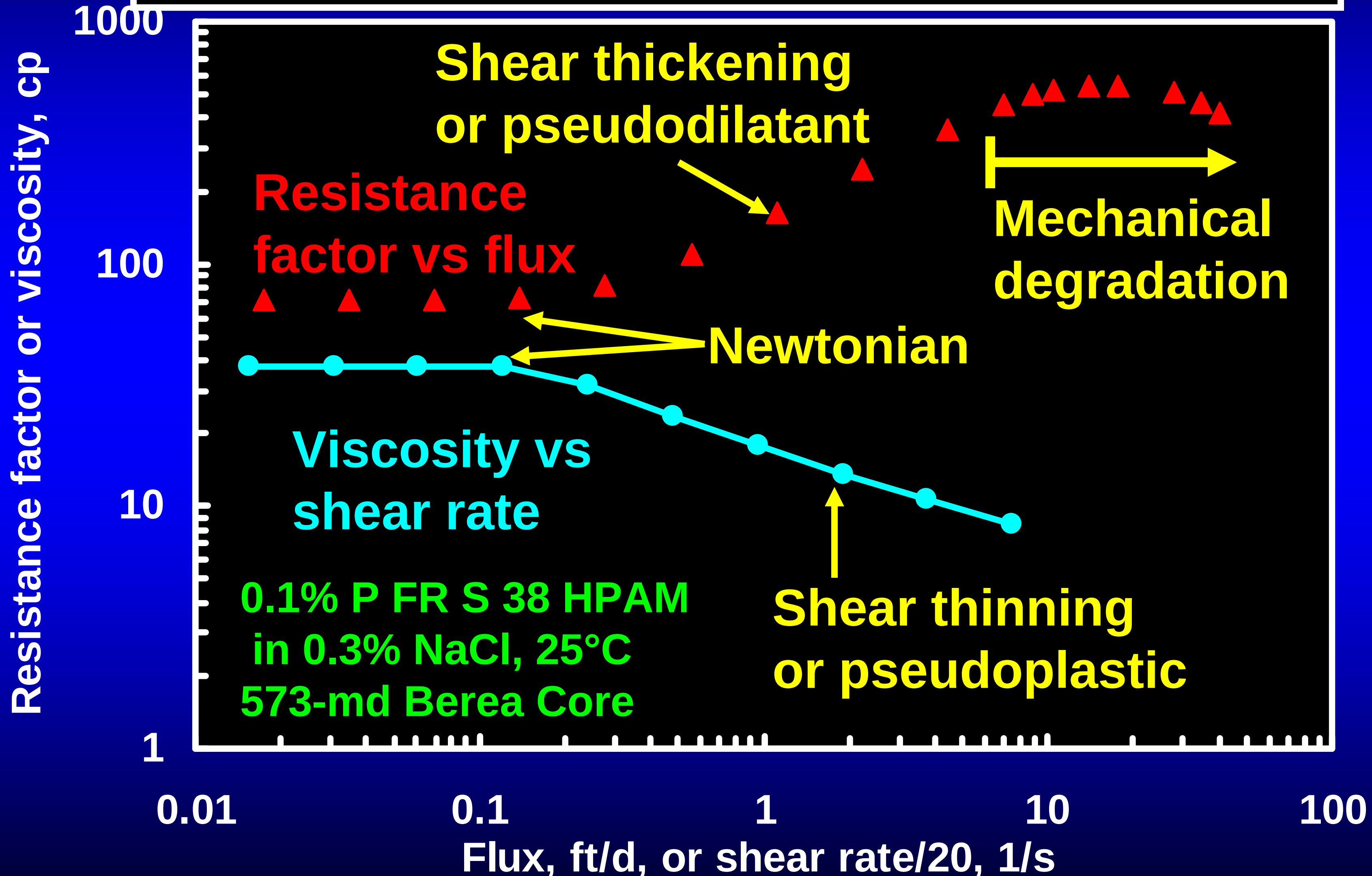
Fracture extension expectations for polymers that plug at a give throughput.



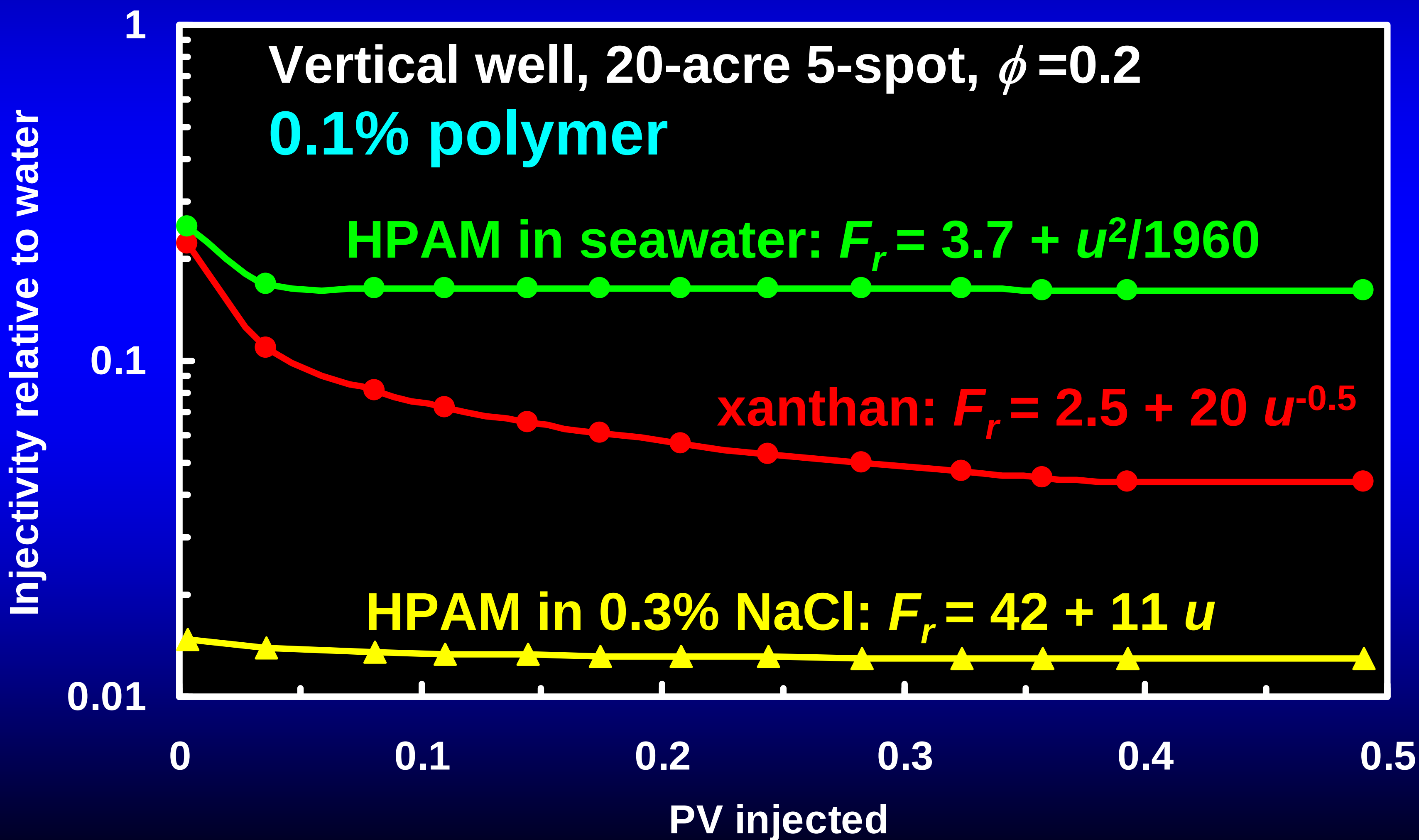
- Xanthan rheology in porous media correlates well with that in a viscometer.



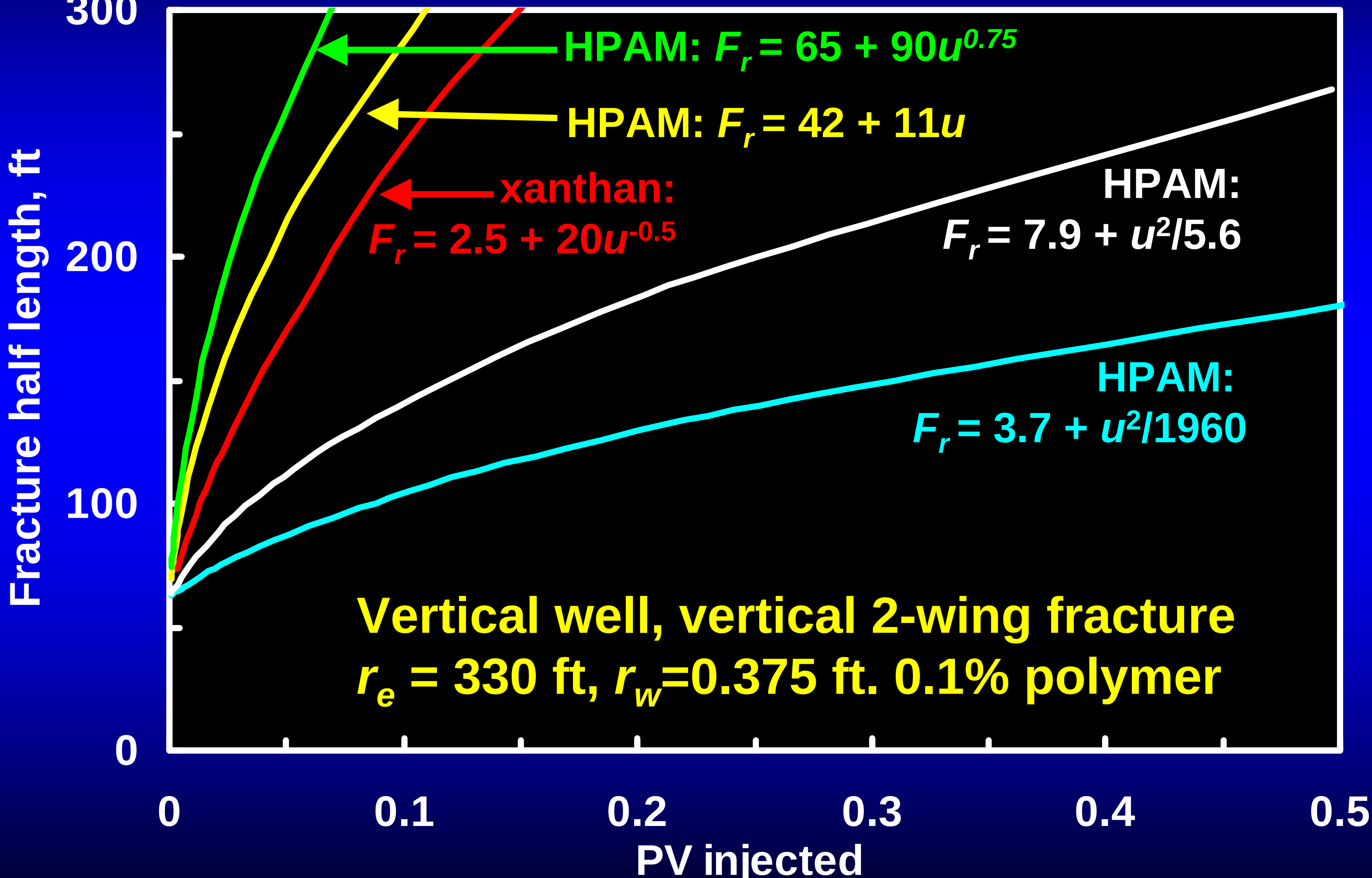
Although HPAM solutions show pseudoplastic behavior in a viscometer, they show Newtonian or pseudodilatant behavior in porous rock.



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).



Fracture extension expectations for polymers with different rheologies



CONCLUSIONS

1. We developed an improved test of the tendency for EOR polymers to plug porous media. The new test is more sensitive to differences in polymer plugging than the old 1970s test. The new test demonstrated that plugging tendencies varied considerably among both partially hydrolyzed polyacrylamide (HPAM) and xanthan polymers.

2. Consistent with previous work, we confirmed that xanthan solutions show pseudoplastic behavior in porous rock that closely parallels that in a viscometer. Xanthan was remarkably resistant to mechanical degradation, with a 0.1% xanthan solution (in seawater) experiencing only a 19% viscosity loss after flow through 102-md Berea sandstone at a pressure gradient of 24,600 psi/ft.

CONCLUSIONS

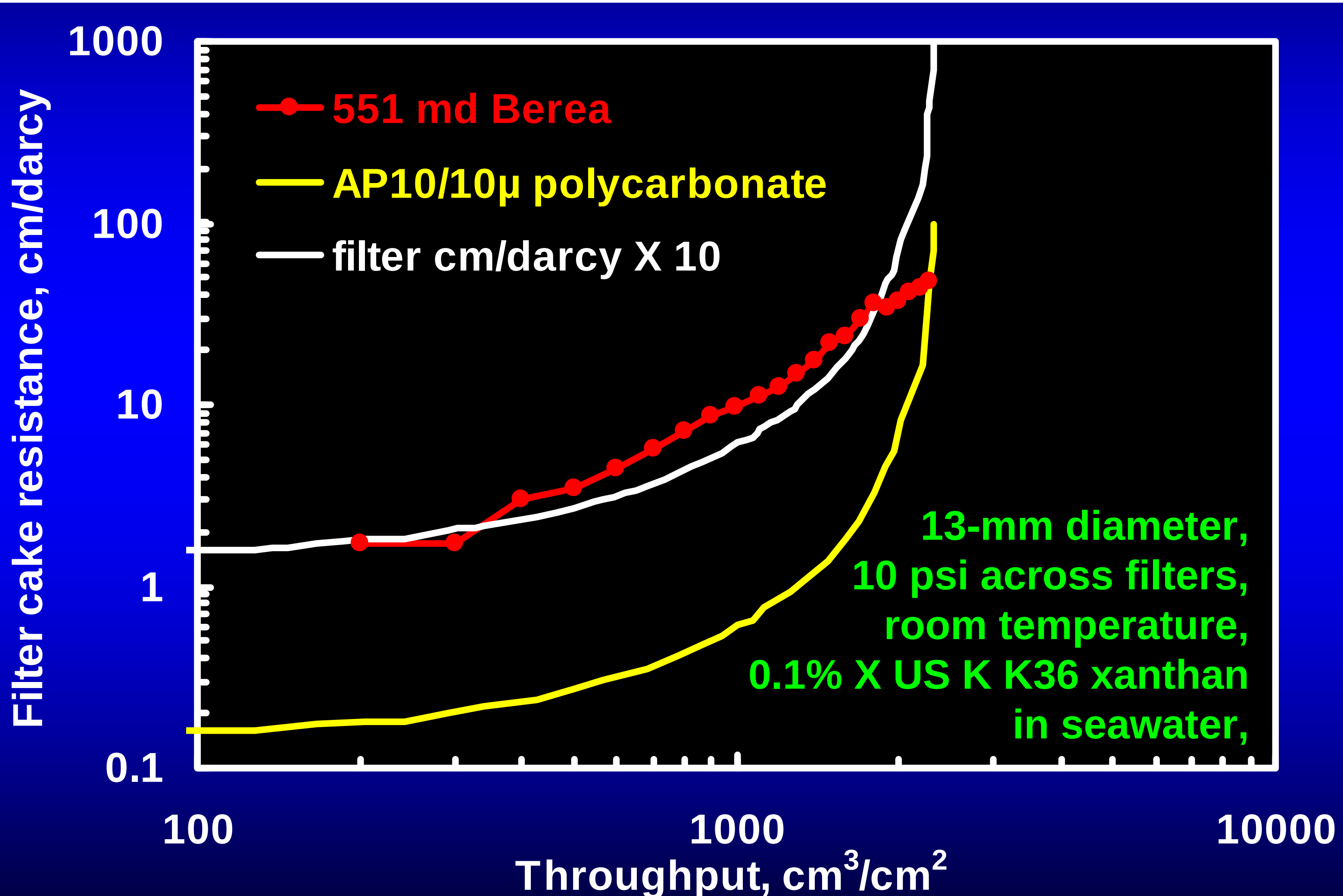
3. For 0.1% HPAM in both 0.3% NaCl brine and seawater in 573-md Berea sandstone, Newtonian behavior was observed at low to moderate fluid fluxes, while pseudodilatant behavior was seen at moderate to high fluxes. No evidence of pseudoplastic behavior was seen in the porous rock, even though one solution exhibited a power-law index of 0.64 in a viscometer. For this HPAM in both brines, the onset of mechanical degradation occurred at a flux of 14 ft/d in 573-md Berea sandstone.

CONCLUSIONS

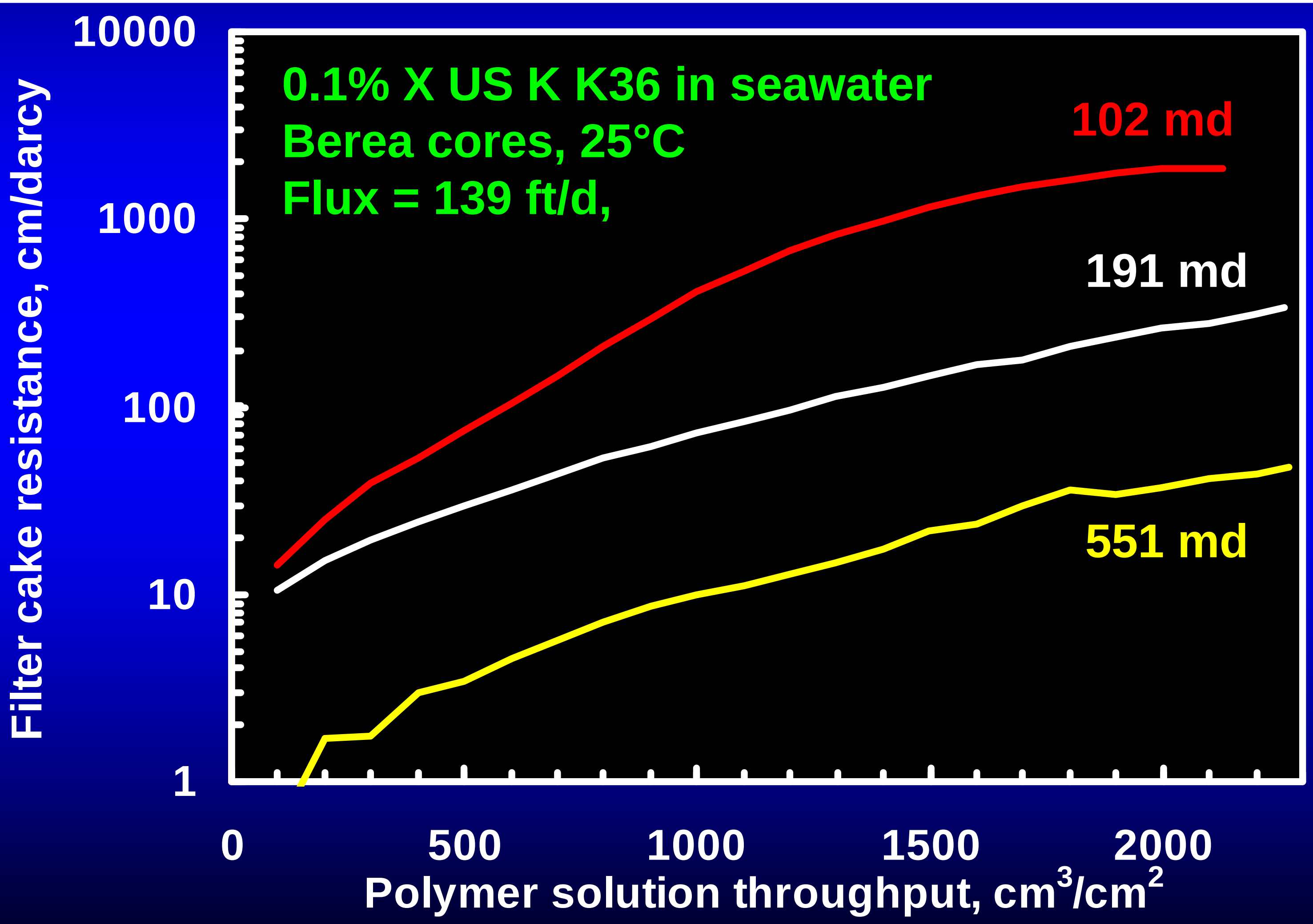
4. Considering the polymer solutions investigated, satisfactory injection of more than 0.1 PV in field applications could only be expected for the cleanest polymers (i.e., that do not plug before 1,000 cm^3/cm^2 throughput), without inducing fractures (or formation parts for unconsolidated sands).

5. Even in the absence of face plugging, the viscous nature of the solutions investigated requires that injectivity must be less than one-fifth that of water if formation parting is to be avoided. Since injectivity reductions of this magnitude are often economically unacceptable, fractures or fracture-like features are expected to open and extend significantly during the course of most polymer floods. Thus, an understanding of the orientation and growth of fractures appears crucial for most EOR projects where polymer solutions are injected.

- Correlating core face plugging with a filter test.
- Time scale of plugging is similar for core vs. filter.



- The magnitude of face plugging is more severe as permeability decreases, but it occurs over roughly the same time scale.



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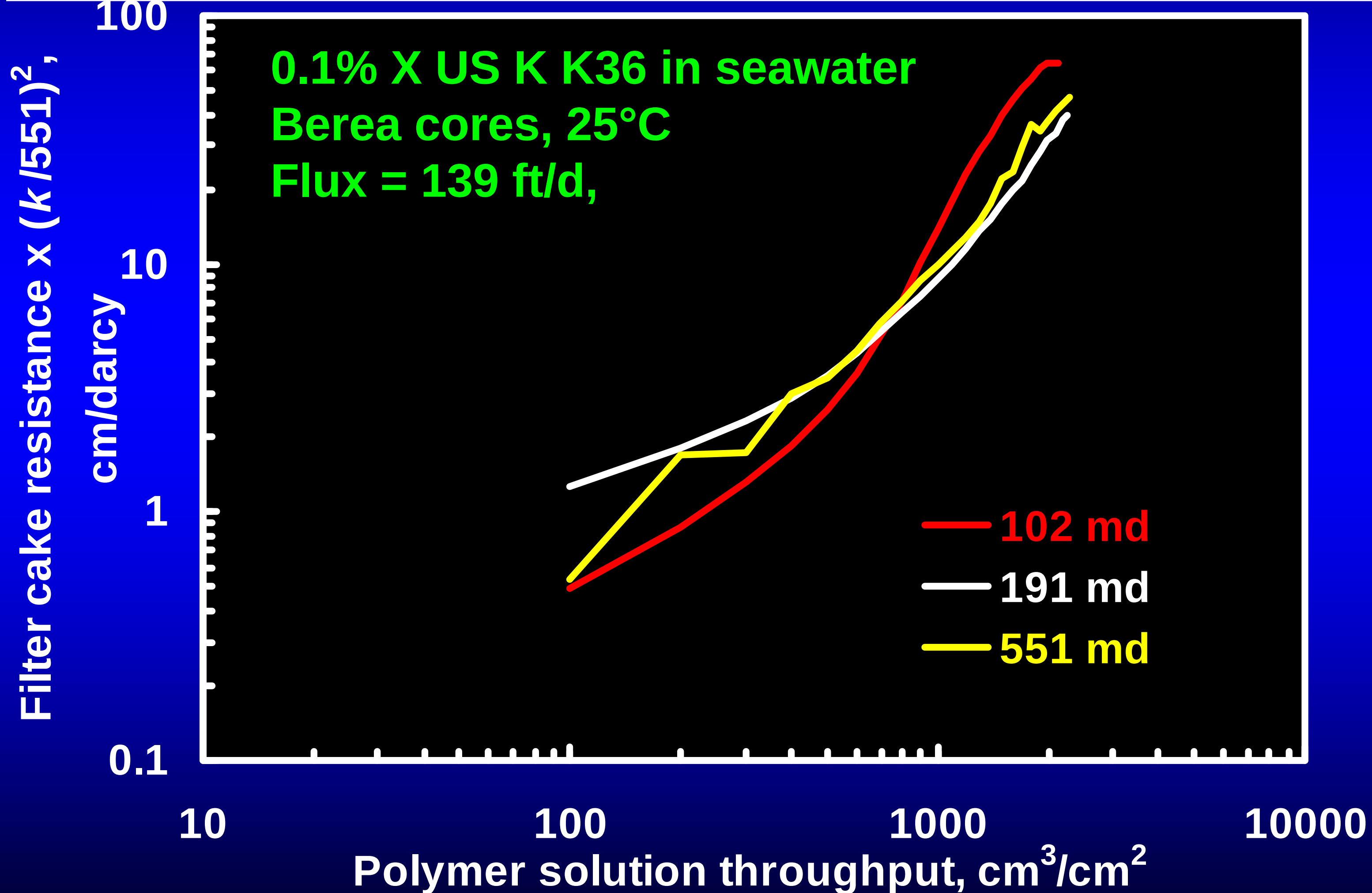
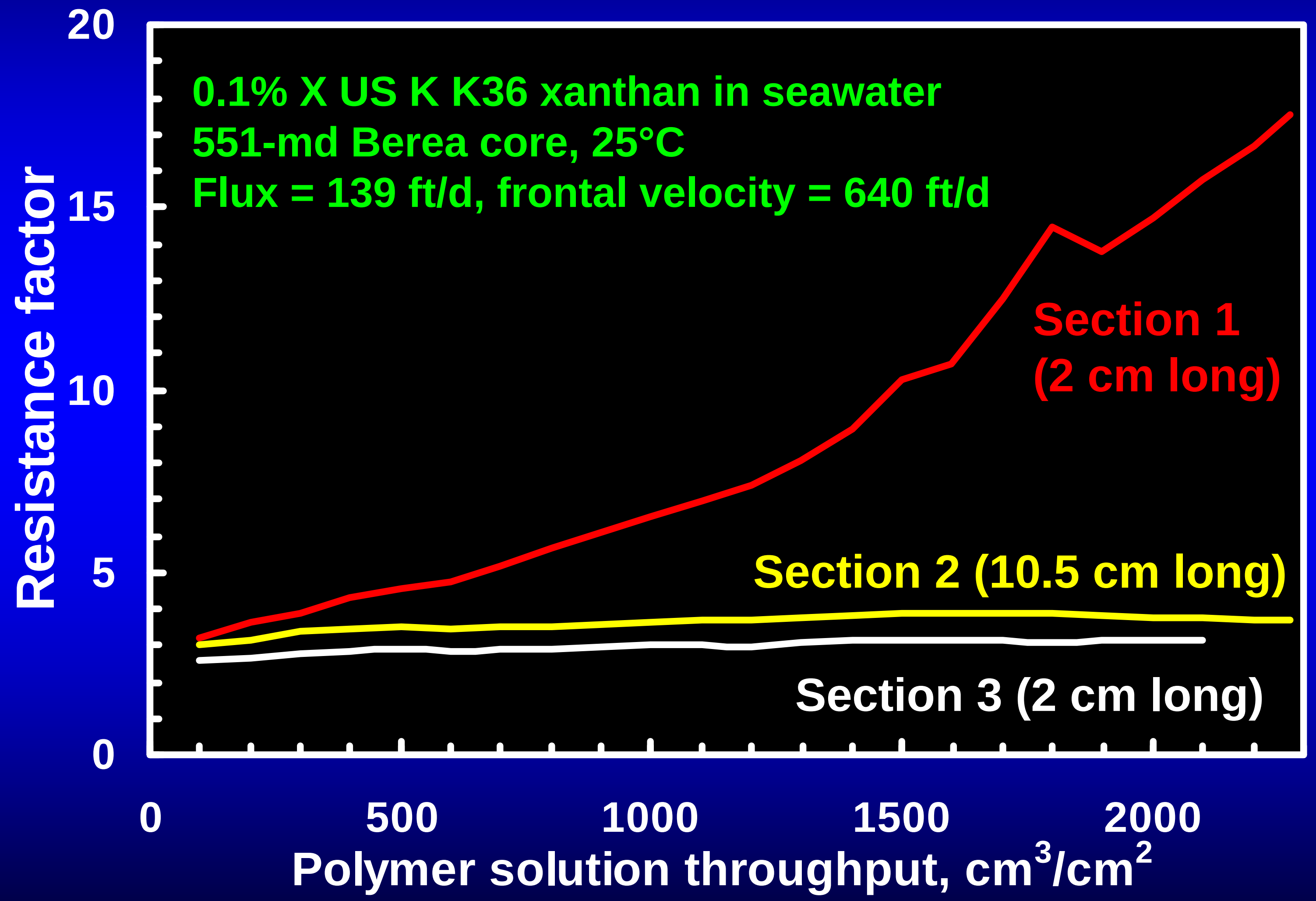
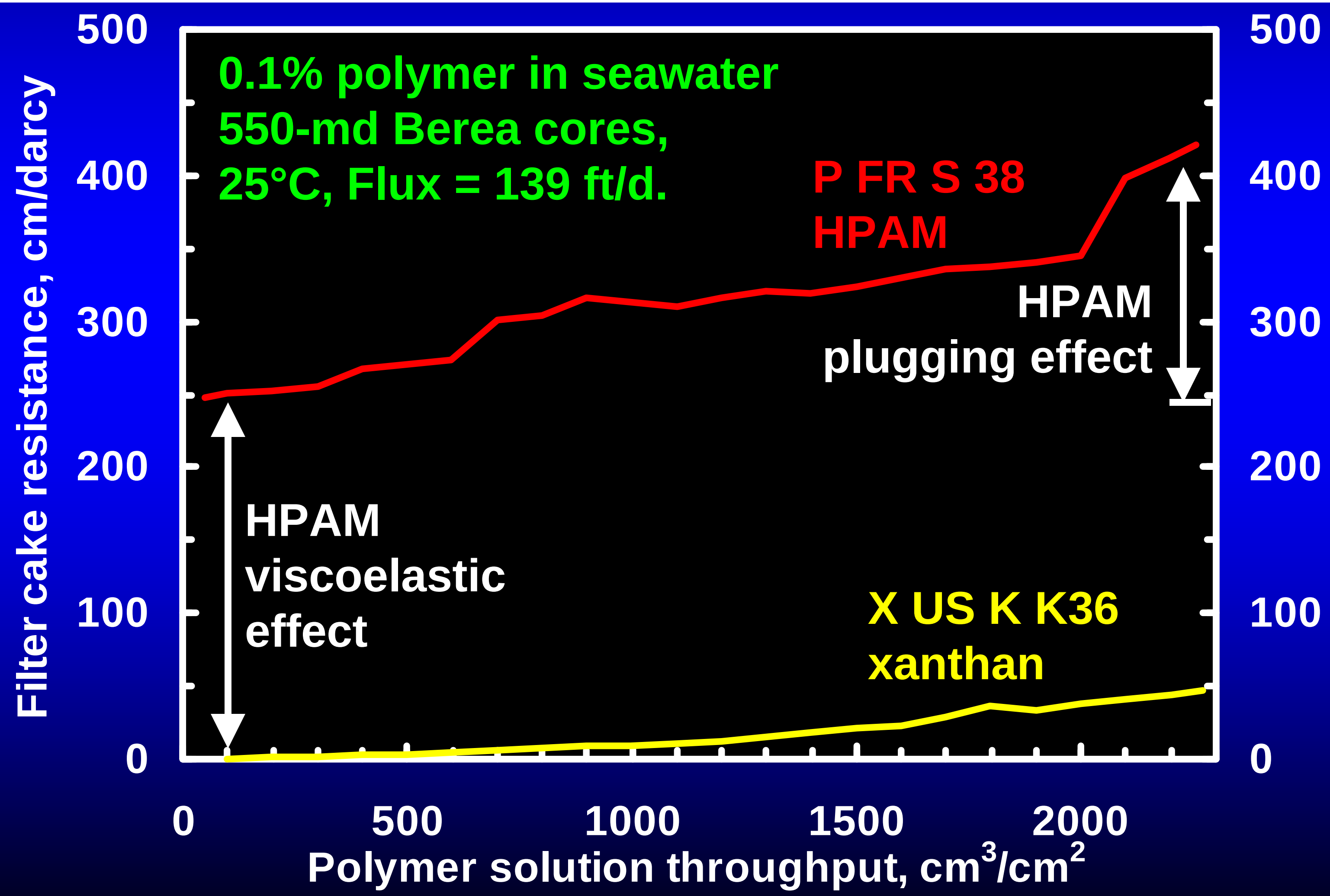


Core tests: Flowed ~27 liters through 11.3 cm^2 core face.

Plugging occurred primarily on the face, not internal.



- Face plugging by X US K K36 xanthan and P FR S 38 HPAM was mild.
- Viscoelasticity makes HPAM flow resistance much greater than for xanthan.



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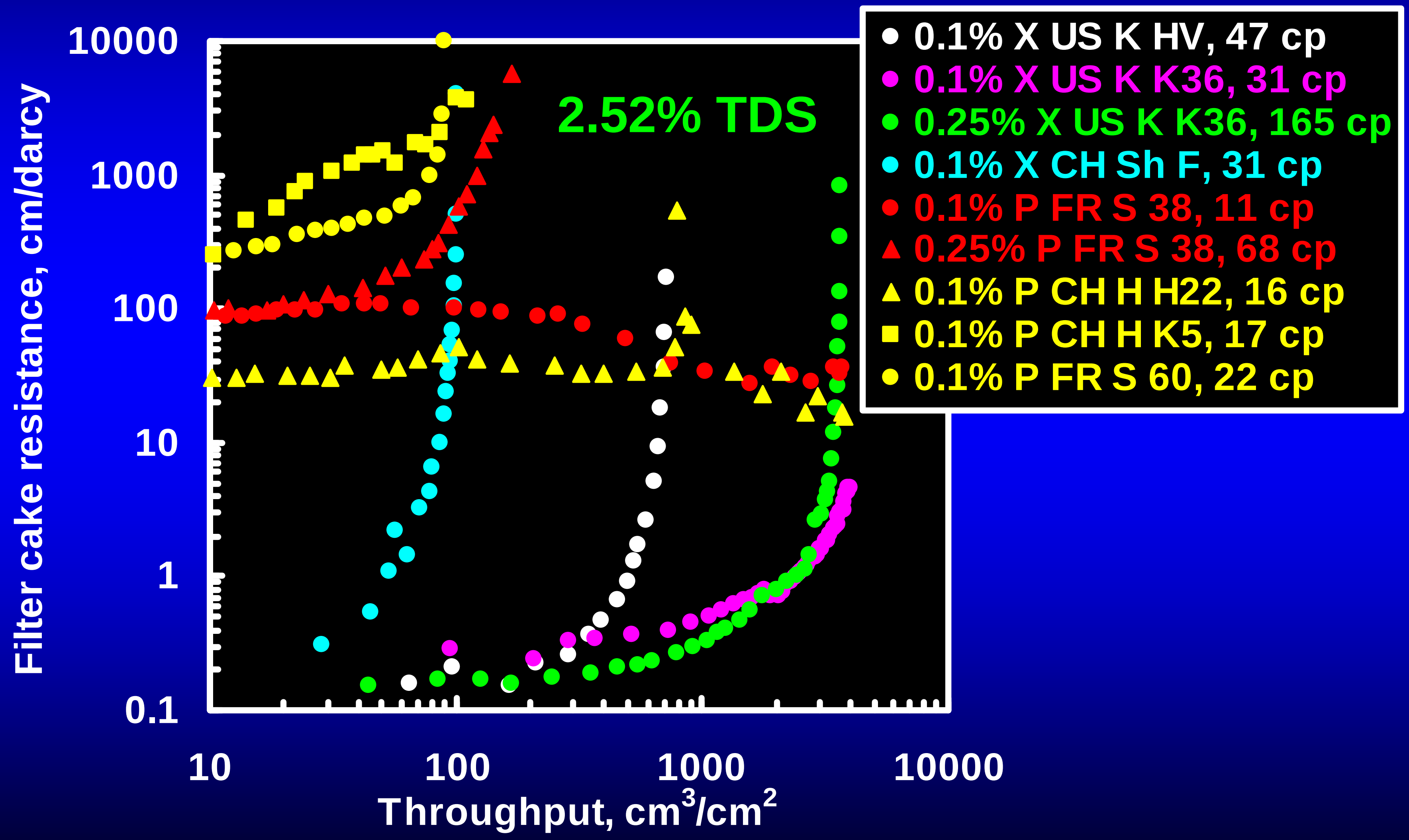
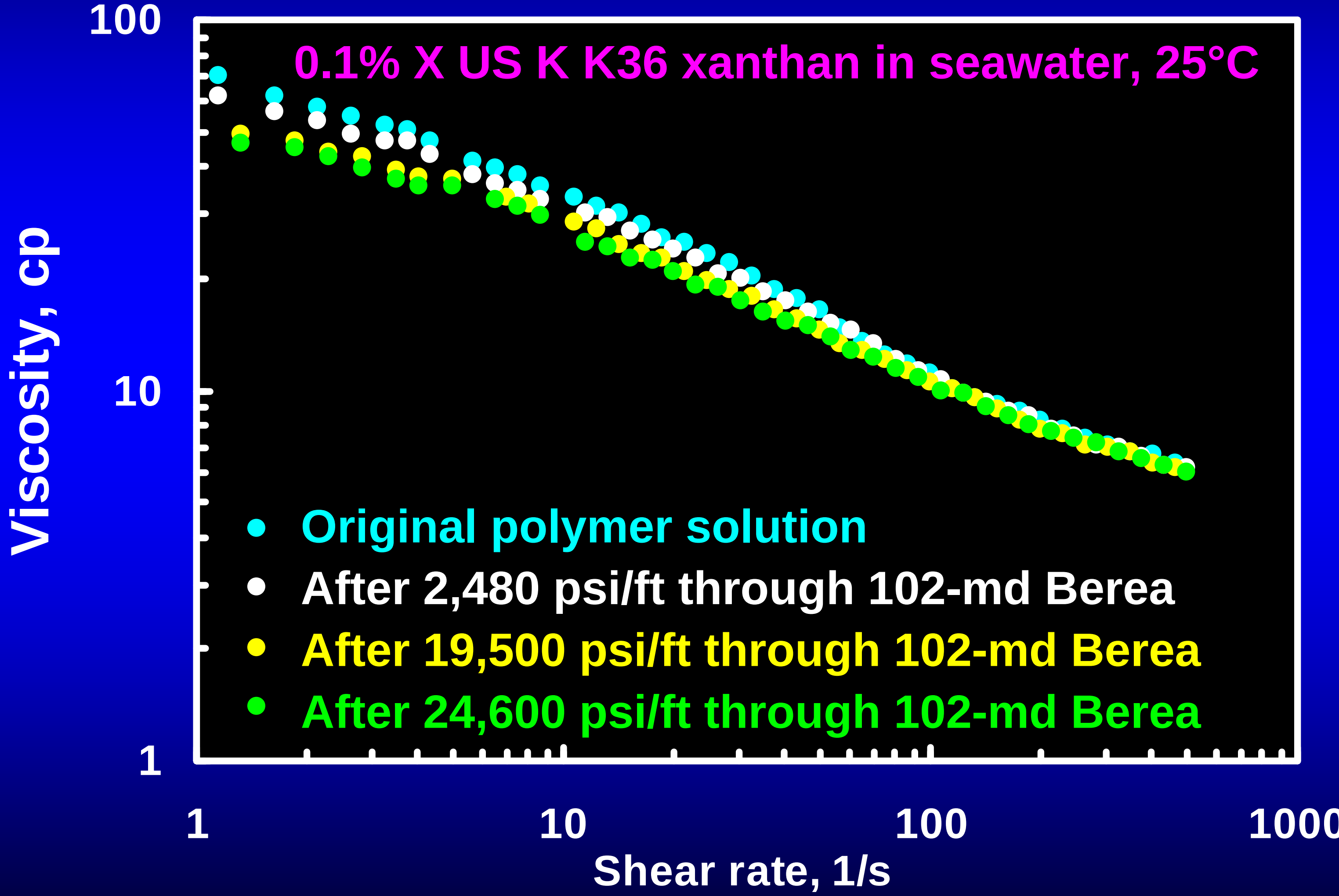


• Xanthan is remarkably resistant to mechanical (shear) degradation.



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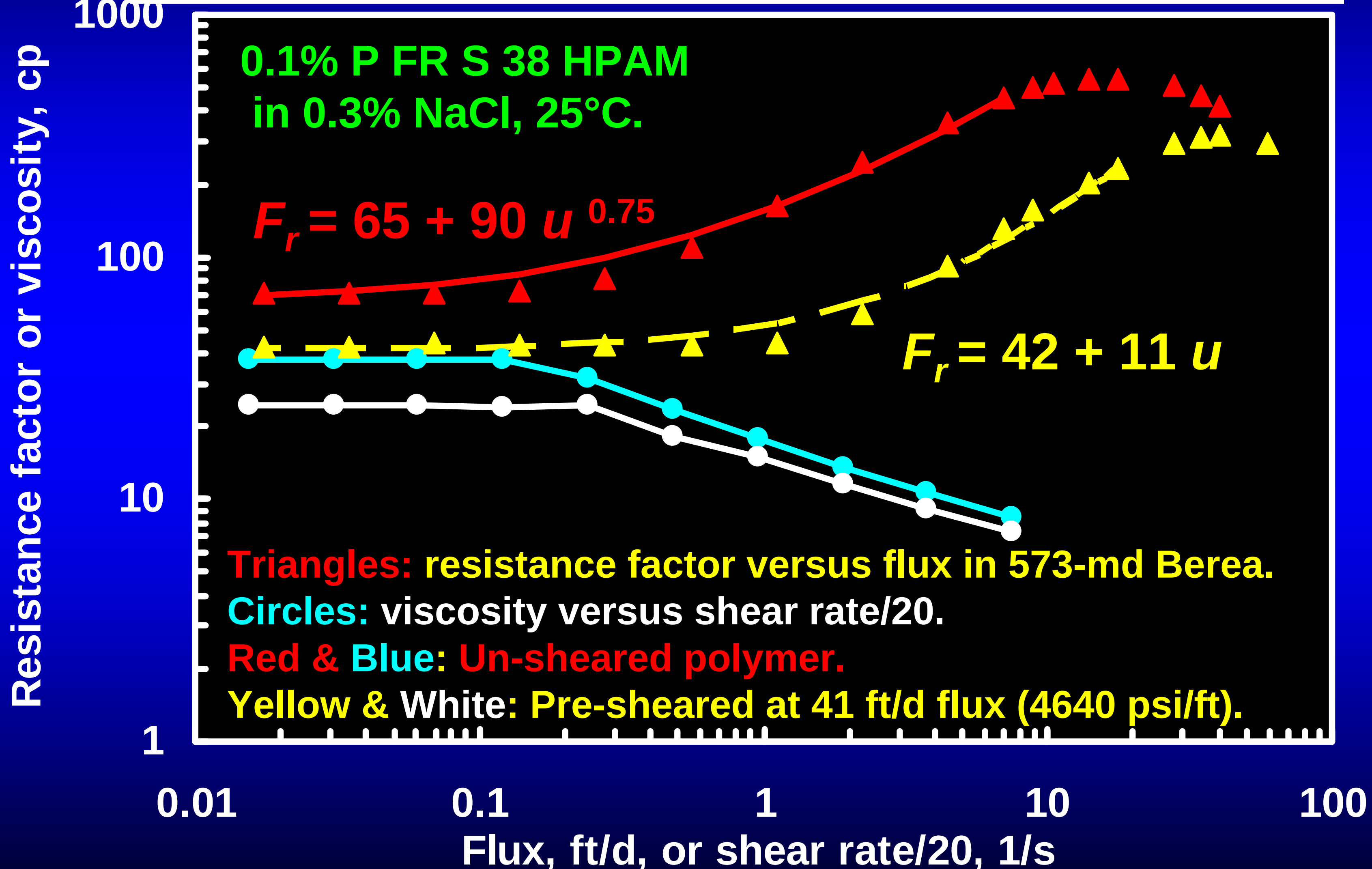
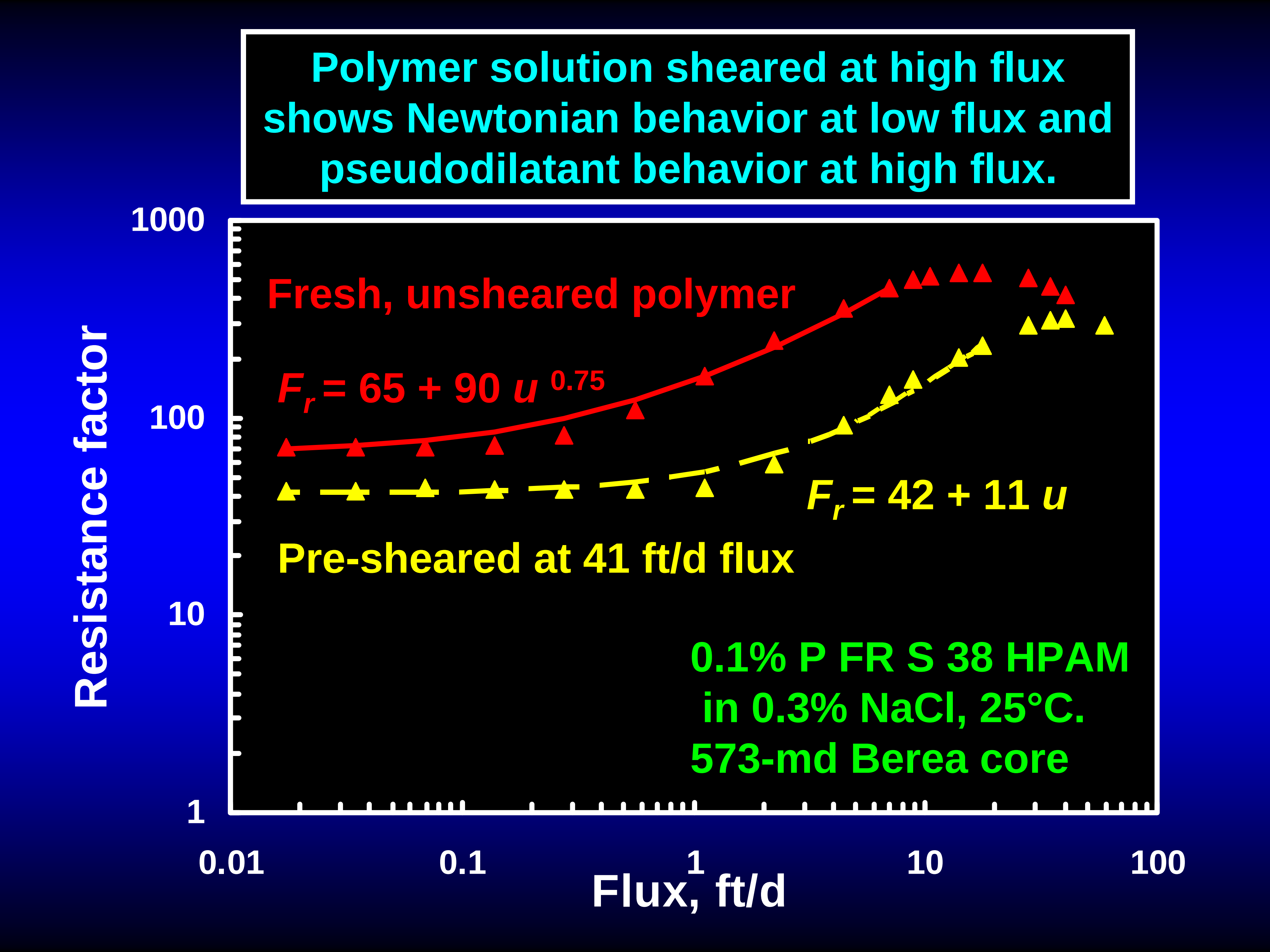
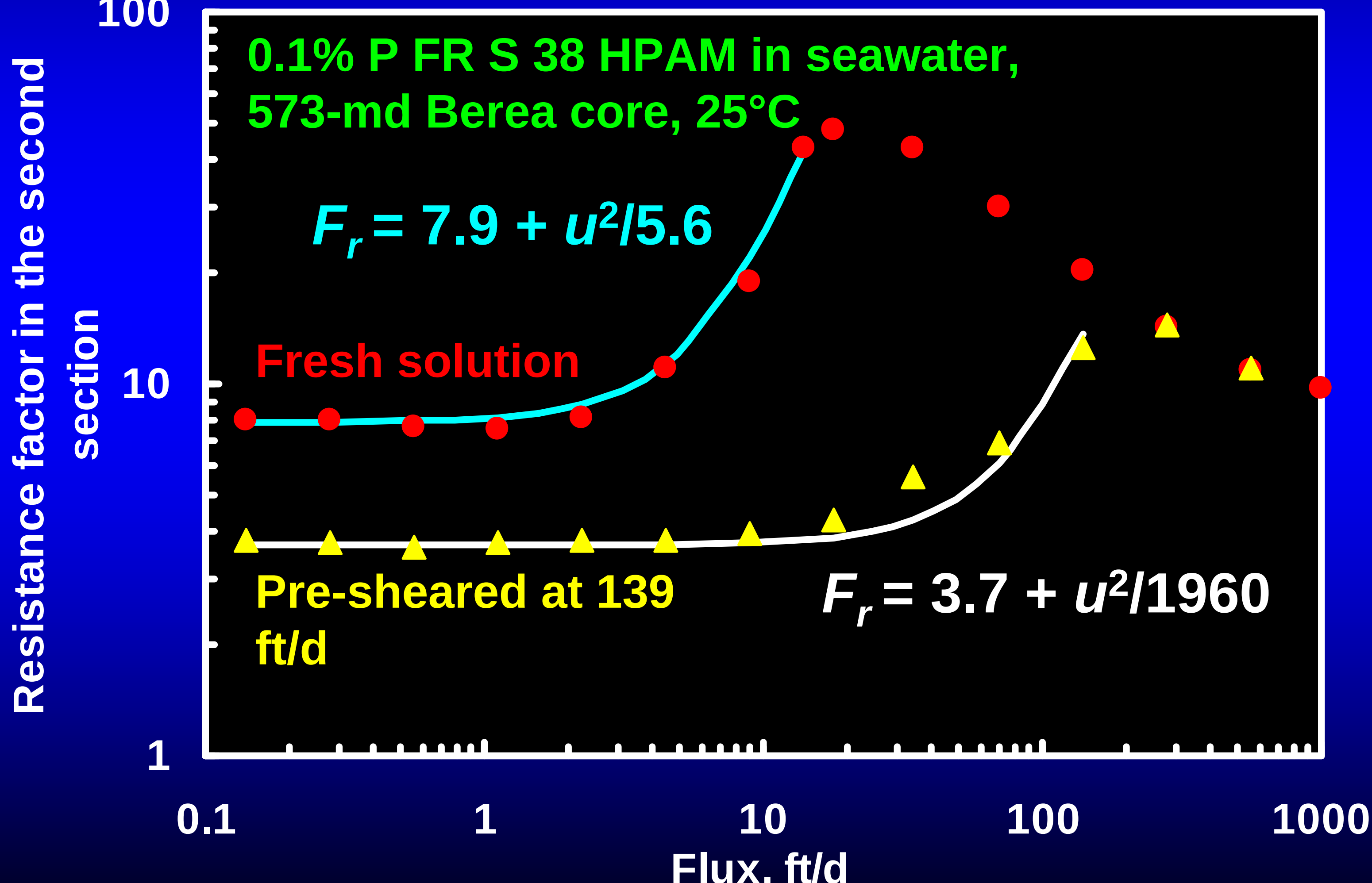



Polymer solution sheared at high flux shows Newtonian behavior at low flux and pseudodilatant behavior at high flux.
Fresh, unsheared polymer
$F_r = 65 + 90\ u^{0.75}$
$F_r = 42 + 11\ u$
Pre-sheared at 41 ft/d flux
0.1% P FR S 38 HPAM
in 0.3% NaCl, 25°C.
573-md Berea core
Resistance factor
1000
100
10
1
0.01
0.1
1
10
100
Flux, ft/d

HPAM Rheology in Porous Rock:

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



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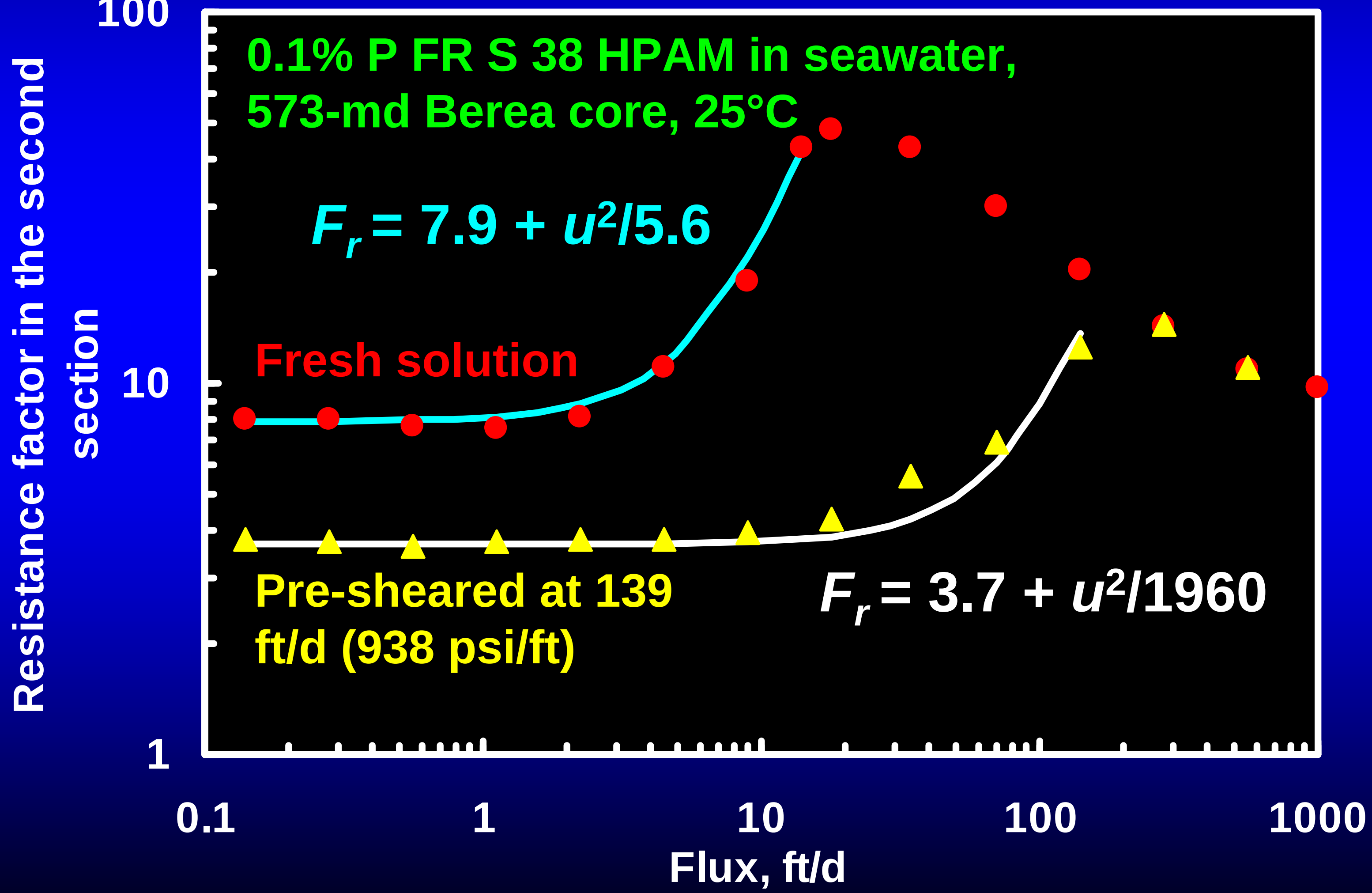
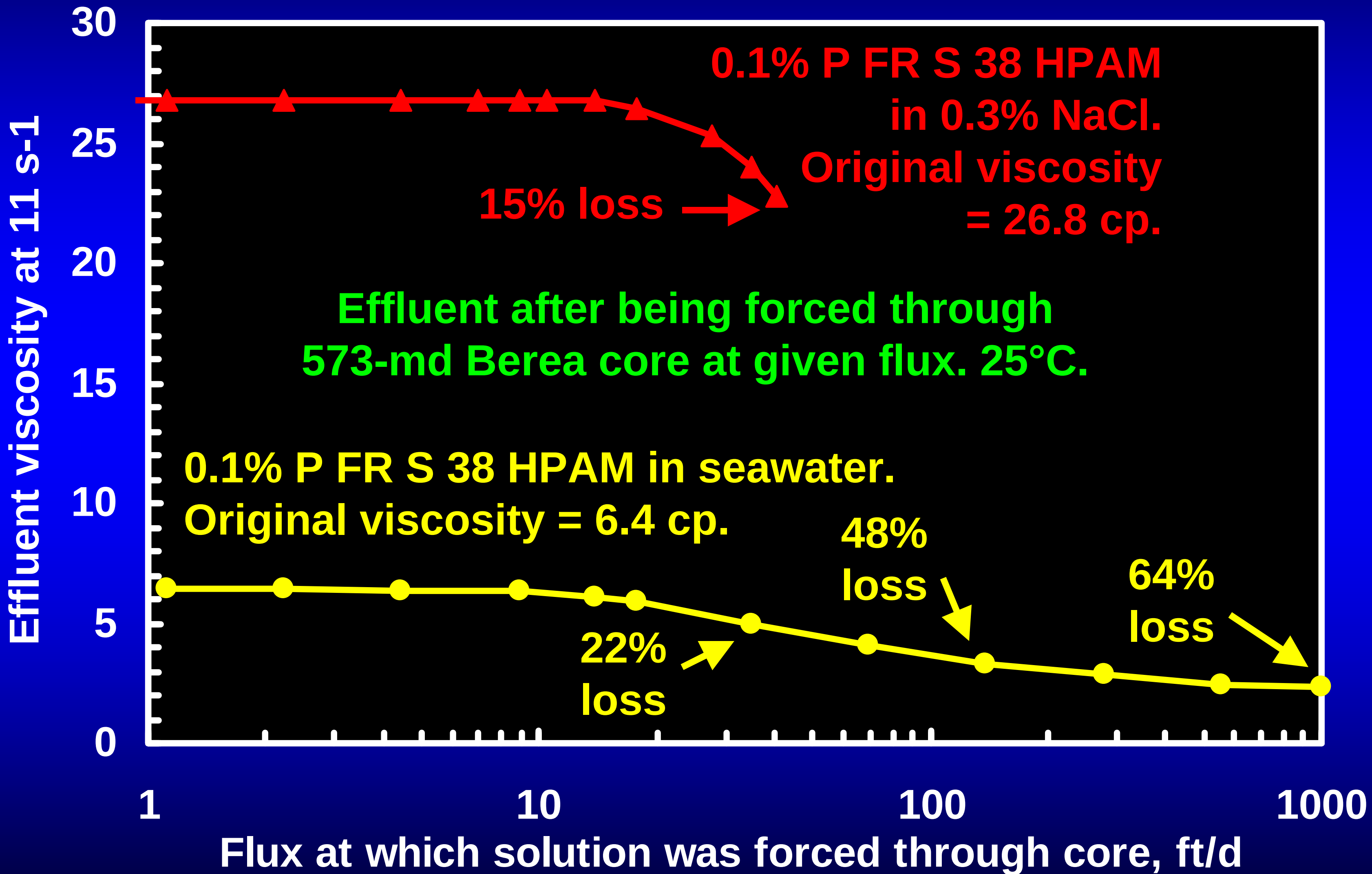
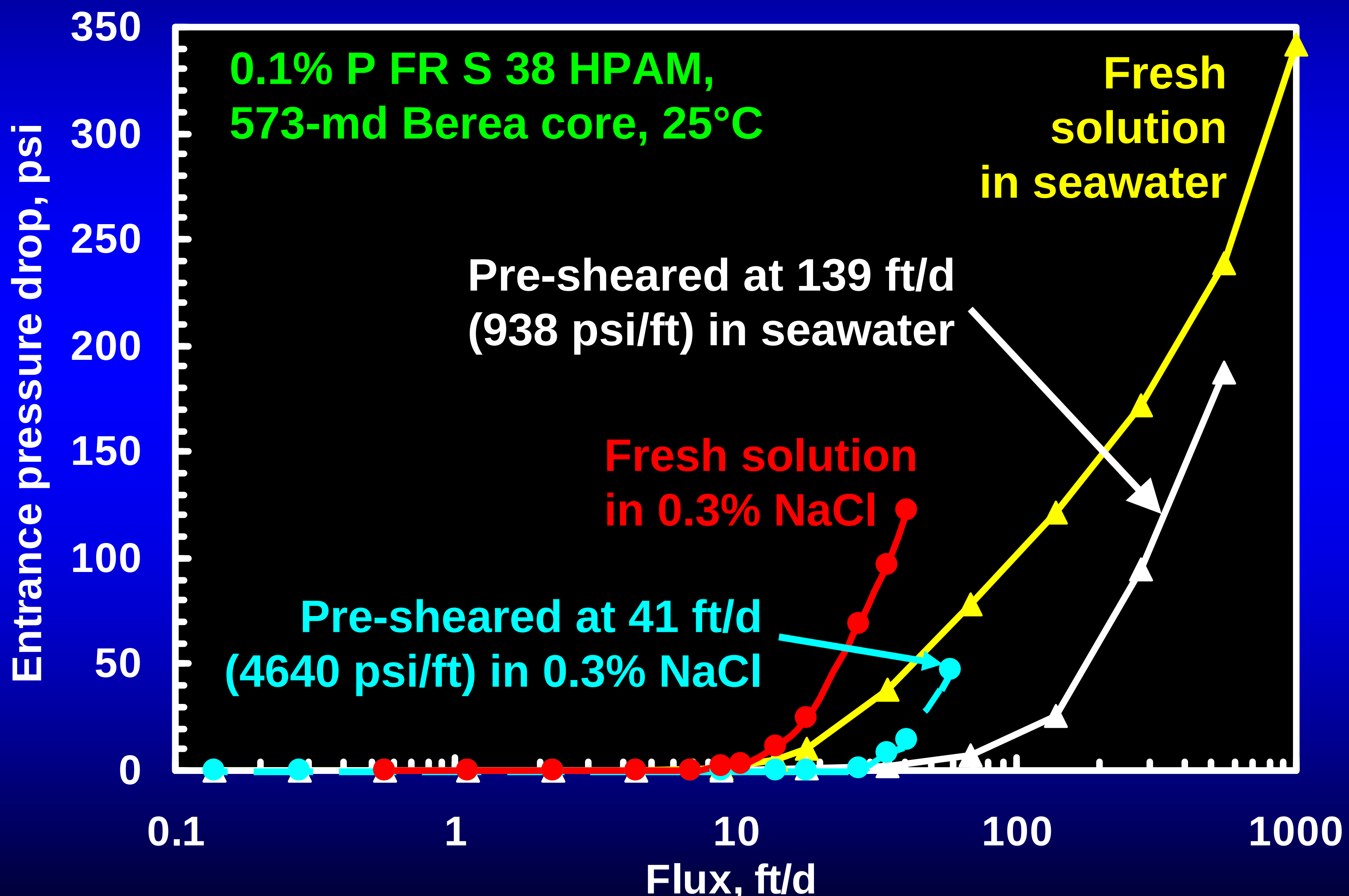


HPAM is susceptible to mechanical degradation



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



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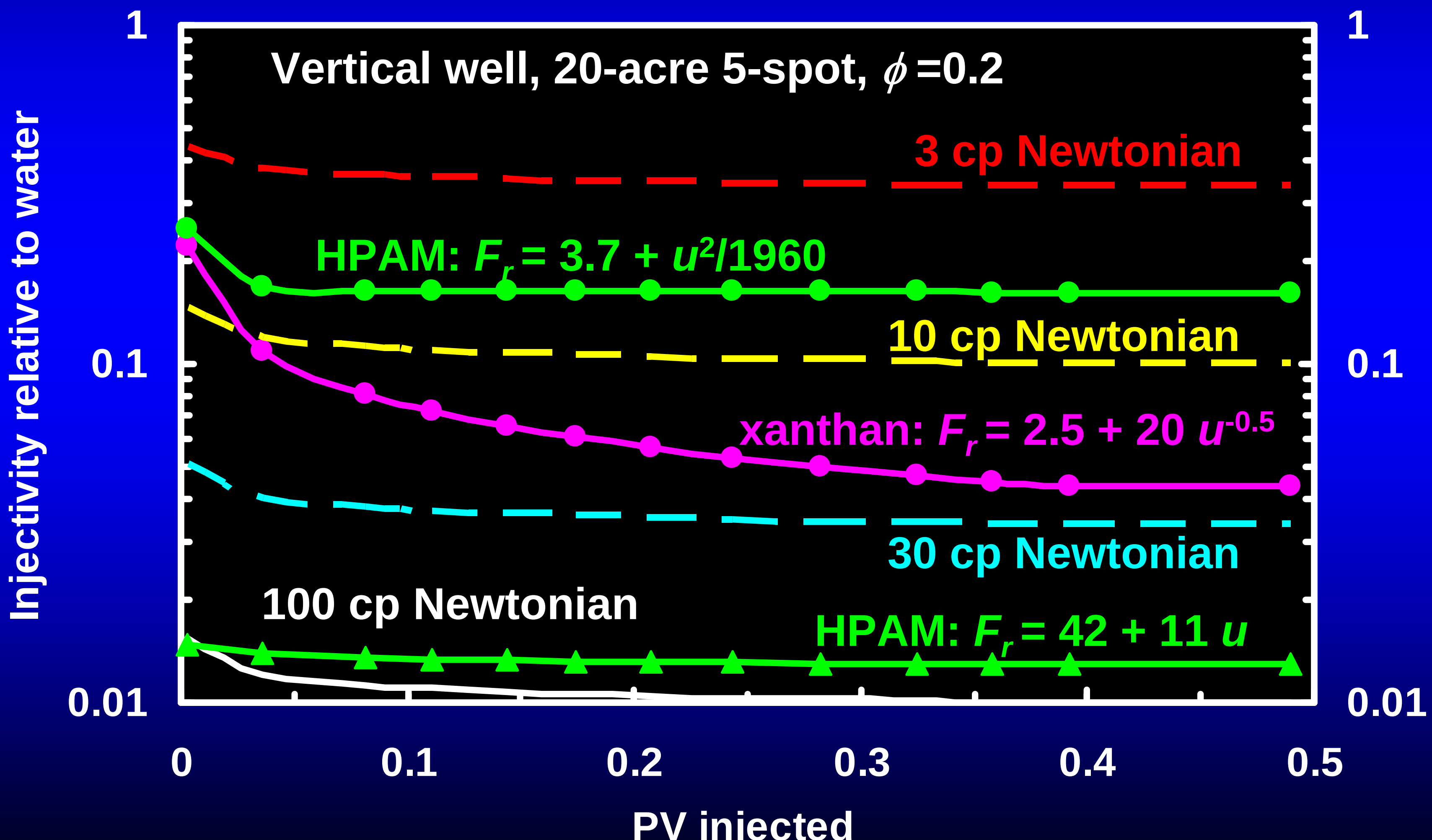

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