Objective of Water Shutoff Treatments

- Objective is to shut off water without seriously damaging hydrocarbon productive zones.
- Want to maximize blocking agent penetration into water-source pathways, while minimizing penetration into hydrocarbon zones.
- Want to maximize permeability reduction in water-source pathways, while minimizing permeability reduction in hydrocarbon zones.
GEL TREATMENTS ARE NOT POLYMER FLOODS

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

• Are not simply viscous polymer solutions.

• Do not flow through porous rock like polymer solutions.

• Do not enter and plug high-k strata first and progressively less-permeable strata later.

• Should not be modeled as polymer floods.
Distinction between a blocking agent and a mobility control agent.

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

For a blocking agent, penetration into low-k zones should be minimized.
KEY QUESTIONS DURING BULLHEAD INJECTION OF POLYMERS, GELANTS, OR GELS

• Why should the blocking agent NOT enter and damage hydrocarbon productive zones?

• How far will the blocking agent penetrate into each zones (both water AND hydrocarbon)?

• How much damage will the blocking agent cause to each zone (both water AND hydrocarbon zones)?
BASIC CALCULATIONS

Gelants can penetrate into all open zones.

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

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

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

<table>
<thead>
<tr>
<th></th>
<th>Water</th>
<th>Gel</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Injectivity Loss</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Linear</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Core 1:</td>
<td>90%</td>
<td>90%</td>
</tr>
<tr>
<td>Core 2:</td>
<td>47%</td>
<td>87%</td>
</tr>
</tbody>
</table>
Adsorbed polymers, “weak” gels, particle suspensions, and “dispersions” of gel particles reduce $k$ in low-$k$ rock more than in high-$k$ rock.

Vela et al. *SPEJ* (April 1976), 84

Adsorbed HPAM
$M_w = 5.5 \times 10^6$
20% hydrolysis.
Sandstone rock.
Contrary to some claims, adsorbed polymers, “weak” gels, and gel “dispersions” can harm flow profiles!!!

<table>
<thead>
<tr>
<th>Layer</th>
<th>$k_w @ S_{or}$, md</th>
<th>Gel radius, ft</th>
<th>Permeability reduction factor ($F_{rrw}$)</th>
<th>Layer flow capacity, final/initial</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>453</td>
<td>30</td>
<td>1.2</td>
<td>0.94</td>
</tr>
<tr>
<td>2</td>
<td>137</td>
<td>16.5</td>
<td>2.4</td>
<td>0.71</td>
</tr>
<tr>
<td>3</td>
<td>45</td>
<td>9.5</td>
<td>9.9</td>
<td>0.31</td>
</tr>
<tr>
<td>4</td>
<td>17</td>
<td>5.8</td>
<td>27</td>
<td>0.15</td>
</tr>
<tr>
<td>5</td>
<td>12</td>
<td>4.9</td>
<td>45</td>
<td>0.10</td>
</tr>
</tbody>
</table>
GEL PLACEMENT IS CRITICALLY DIFFERENT IN RADIAL FLOW THAN IN LINEAR FLOW!!!

This conclusion is not changed by:

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

See: http://baervan.nmt.edu/randy/gel_placement
SITUATION: Someone bullheads a conventional gel treatment into an “unfractured” well, without any special provision to protect oil zones. After the treatment, the flow profile “improved”.

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

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

- If fluids can cross flow out beyond the wellbore, does a flow profile mean anything?
COMMON PHILOSOPHY: “I don’t care whether my high-permeability streak is a fracture or not. I just want to fix it.”

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

- The appropriate composition for a fracture or void is different than for matrix.
- The optimum treatment volume for a fracture or void is different than for matrix.
- The proper placement method for treating a fracture or void is different than for matrix.
LOW-VISCOSITY
1. Acrylamide/acrylate monomer
2. Silicate solutions
3. Colloidal silica
4. Phenol-formaldehyde
5. Chromium-lignosulfonate
6. Dilute aluminum-citrate-HPAM/CPAM
7. Others

HIGH-VISCOSITY
1. Chromium-polyacrylamide
2. Chromium-xanthan
3. HPAM with organic crosslinkers
4. Others
LINEAR vs RADIAL FLOW

**DEGREE OF GELANT PENETRATION**

**Linear**
\[ \frac{L_{p2}}{L_{p1}} \]

**Radial**
\[ \frac{(r_{p2} - r_w)}{(r_{p1} - r_w)} \]
Degree of Penetration for Parallel Linear Corefloods with Newtonian Fluids

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

Fr is resistance factor (effective viscosity)

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

If \( F_r \) is large, then \( \frac{L_{p2}}{L_{p1}} = \left[\frac{k_2\phi_1}{k_1\phi_2}\right]^{0.5} \)
Degree of Penetration for Parallel Radial Corefloods with Newtonian Fluids (SPE 17332)

\[
\left(\frac{\phi_i}{k_i}\right) r_{pi}^2 \left[ F_r \ln\left(\frac{r_{pi}}{r_w}\right) + \ln\left(\frac{r_{p1}}{r_{pi}}\right) + \frac{(1-F_r)}{2}\right] = \\
= \left(\frac{\phi_1}{k_1}\right) r_{p1}^2 \left[ F_r \ln\left(\frac{r_{p1}}{r_w}\right) + \frac{(1-F_r)}{2}\right] \\
+ r_w^2 \left(\frac{\phi_i}{k_i} - \frac{\phi_1}{k_1}\right) \left[ \ln\left(\frac{r_{p1}}{r_w}\right) + \frac{(1-F_r)}{2}\right]
\]

If \( F_r = 1 \) and \( r_w \ll r_p \), then
\[\frac{r_{p2}}{r_{p1}} \approx \left[\frac{(k_2\phi_1)}{(k_1\phi_2)}\right]^{0.5}\]

If \( F_r \) is large and \( r_{p1} \approx 100 r_w \), then
\[\frac{r_{p2}}{r_{p1}} \approx \left[\frac{(k_2\phi_1)}{(k_1\phi_2)}\right]^{0.5} / \left[1 + 0.13 \ln\left[\frac{(k_2\phi_1)}{(k_1\phi_2)}\right]\right]^{0.5}\]
**EFFECT OF GELANT VISCOSITY (RESISTANCE FACTOR) ON PLACEMENT**

\[ k_1 = 10 \ k_2 \]
\[ \phi = 0.2. \ L_{p1} = r_{p1} = 50 \text{ ft.} \ r_w = 0.5 \text{ ft.} \]

<table>
<thead>
<tr>
<th>Resistance Factor</th>
<th>Linear flow</th>
<th>Radial flow</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>( L_{p2}/L_{p1} )</td>
<td>( (r_{p2}-r_w)/(r_{p1}-r_w) )</td>
</tr>
<tr>
<td>1</td>
<td>0.100</td>
<td>0.309</td>
</tr>
<tr>
<td>10</td>
<td>0.256</td>
<td>0.369</td>
</tr>
<tr>
<td>100</td>
<td>0.309</td>
<td>0.376</td>
</tr>
<tr>
<td>1000</td>
<td>0.316</td>
<td>0.376</td>
</tr>
</tbody>
</table>
Can rheology be exploited to optimize gel placement?

- Not with currently available fluids and technology.

See *SPERE* (May 1991) 212-218 and SPE 35450
Gelants Penetrate a Significant Distance into All Open Zones.

Radial flow, non-communicating layers

Distance of penetration in Layer 2 when gelant reaches 50 ft in Layer 1

Permeability ratio, $k_1/k_2$

$x$anthon $Fr=1$  $Fr=100$ HPAM
Will a water post flush reduce the need for zone isolation?

Layer 1

Layer 2

Yellow: Gelant  Blue: Water
For unit-mobility displacements, a water postflush will "thin" the gelant banks by about the same factor in all zones.

\[
\frac{k_1}{k_2} = 1, \quad \frac{k_1}{k_2} = 10, \quad \frac{k_1}{k_2} = 100, \quad \frac{k_1}{k_2} = 1,000
\]

SPERE (Aug. 1991) 343-352 and SPE 24192
In which layer will viscous fingers first break through the gelant bank?

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

SPERE (Aug. 1991) 343-352 and SPE 24192
DILUTION CAN PREVENT GELATION

Gelant Bank  Mixing Zone  Water Bank

FOR DIFFUSION:  \( L_m \approx 3.62 \sqrt{D_t} \)

FOR DISPERSION:  \( L_m \approx 3.62 \sqrt{\alpha L} \)

Gelant Concentration, \( C/Co \)

\( L \)

\( L_m \)

\( \sqrt{D_t} \)

\( \sqrt{\alpha L} \)

SPERE (Aug. 1991)

343-352
Can diffusion and dispersion be exploited to destroy gelant banks in low-k zones while plugging high-k zones?

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

*SPERE (Aug. 1991) 343-352*
Length of mixing zone due to diffusion

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

D = $10^{-5}$ cm$^2$/s

D = $10^{-8}$ cm$^2$/s

SPERE (Aug. 1991) 343-352

Time, days

$\frac{L^m}{2}$, ft
CAN CAPILLARY PRESSURE PREVENT GELANT FROM ENTERING ZONES WITH HIGH OIL SATURATIONS?

1. During laboratory experiments, capillary effects could inhibit an aqueous gelant from entering an oil-wet core. However, in field applications, the pressure drop between injection and production wells is usually so large that capillary effects will not prevent gelant from entering oil-productive zones.

2. Regardless of the wettability of the porous medium, the capillary-pressure gradient will increase the fractional flow of water. If pressure gradients are large enough so that flow occurs, then capillary effects will always increase the depth of gelant penetration into oil-productive zones.

3. Under field-scale conditions, the effects of capillary pressure on gelant fractional flow are negligible. In particular, capillary pressure will not impede gelant penetration into oil-productive zones.
Can be used for either vertical or horizontal wells.
Gel Placement in Heterogeneous Systems with Crossflow

Ideal Near-Wellbore Treatment

Ideal Far-Wellbore Treatment

Reality

Water  Oil  Gel

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

CROSSFLOW MAKES GEL PLACEMENT MORE DIFFICULT!!!

- 0-ppm xanthan, 1 cp
  Layer 1
  Layer 2

- 200-ppm xanthan, 3 cp
  Layer 1
  Layer 2

- 500-ppm xanthan, 8 cp
  Layer 1
  Layer 2

- 1000-ppm xanthan, 23 cp
  Layer 1
  Layer 2

- 2000-ppm xanthan, 75 cp
  Layer 1
  Layer 2

Xanthan

Water
DEMONSTRATION OF POLYMER FLOODING AND CROSSFLOW

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

Top layer is 11.2 times more permeable than bottom layer

75-cp polymer (red) displacing 1-cp water

1-cp water (blue) displacing 1-cp water
Vertical Sweep Efficiency with Crossflow

\[ v_2 \cong \frac{\Delta p \, k_2}{\mu \, \phi_2 \, L} \]

\[ v_1 \cong \frac{\Delta p \, k_1}{\mu \, F_{r1} \, \phi_1 \, L} \]

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

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

If \( F_r > \left[ \frac{k_2 \, \phi_1}{(k_1 \, \phi_2)} \right] \), the front moves at the same rate in both layers.
Crossflow with Power-Law Fluids: $F_r = C u^n$

Injection profiles are misleading!

**Fluid Rheology**
- **General**
  \[
  \frac{u_2}{u_1} = \left(\frac{k_2 C_1}{k_1 C_2}\right)^{-\frac{1}{n+1}}
  \]
- **Shear thinning**
  \[
  \frac{u_2}{u_1} < \frac{k_2}{k_1}
  \]
- **Newtonian**
  \[
  \frac{u_2}{u_1} = \frac{k_2}{k_1}
  \]
- **Shear thickening**
  \[
  \frac{u_2}{u_1} > \frac{k_2}{k_1}
  \]
Crossflow during polymer injection

Viscous fingering during water injection after polymer:
In which place will water fingers break through the polymer bank? IN THE HIGH-K PATH!

\[ \text{high } k \]
\[ \text{low } k \]

\[ \text{YES!} \]
\[ \text{No} \]
\[ \text{No} \]

\[ \text{high } k \]
\[ \text{low } k \]
EFFECT OF GRAVITY ON GELANT PLACEMENT

Gravity component of the darcy equation:

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

Dimensionless gravity number:

\[ G = \frac{k \Delta \rho \ g \sin \theta}{[1.0133 \times 10^6 \mu \ u]} \]
EFFECT OF GRAVITY ON GELANT PLACEMENT

Density difference
- 1 g/ml
- 0.3 g/ml
- 0.1 g/ml
- 0.01 g/ml

Vertical velocity, ft/d

k/µ, darcys/cp

SPEPF (Nov. 1996) 241-248
1. During gelant injection into fractured wells, viscous forces usually dominate over gravity forces, so gravity will have little effect on the position of the gelant front.

2. During shut-in after gelant injection, a gelant-oil interface can equilibrate very rapidly in a fracture.

3. In radial systems (e.g., unfractured wells) viscous forces dominate near the wellbore, but gravity becomes more important deeper in the formation. Long gelation times will be required to exploit gravity during gelant injection in unfractured wells.
Taking Advantage of Formation Damage

- If the hydrocarbon zones are damaged much more than water zones before a gel treatment, the formation damage may partially protect the hydrocarbon zones during gel placement.

- Stimulation fluids (e.g., acid) could be spotted to open the hydrocarbon zones after the gel treatment.

- This procedure will only work in special circumstances!
PLACEMENT OF PARTICULATES

To achieve placement superior to gels, particles must:

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

a. Original injection rate

b. Reduced injection rate

Water  Oil  Gelant

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

- If the average reservoir pressure in oil zones is much greater than that in water zones, fluids may crossflow in the wellbore in a certain range of wellbore pressures.

- To exploit this phenomenon during gelant placement, the proper wellbore pressure and duration of crossflow must be confirmed by measurement (e.g., flow log) before the gelant treatment.
GEL PLACEMENT IS CRITICALLY DIFFERENT IN RADIAL FLOW THAN IN LINEAR FLOW!!!

This conclusion is not changed by:
- Non-Newtonian rheology of gelants.
- Two-phase flow of oil and water.
- Fluid saturations, capillary pressure behavior.
- Anisotropic flow or pressure gradients.
- Pressure transient behavior.
- Well spacing, degree of crossflow.
- Chemical retention & inaccessible pore volume.
- Different resistance factors in different layers.
- Diffusion, dispersion, & viscous fingering.

See: http://baervan.nmt.edu/randy/gel_placement
Optimum Areal Placement Locations for Gel Plugs in Fractures

Randy Seright
Areal view of fracture connecting an injection well and a production well

Injector

Area = 1000 ft x 1000 ft

Δp = 1000 psi

$k_{matrix} = 100$ md

Producer
Pressure distribution when 1-mm fracture was fully open

1-mm open fracture

- psi
- ft
Pressure distribution with no fracture
A 25-ft Long Gel Plug Substantially Reduced Productivity in Moderate to Wide Fractures

- $w_f = 0.25\text{ mm}$
- $k_{matrix} = 100\text{ md}$
- $w_f = 0.5\text{ mm}$
- $w_f = 1\text{ mm}$
- $w_f = 2\text{ mm}$

Production rate relative to that for an open direct fracture.

Distance gel plug extends from producer, ft.
Gel Plugs Were Not Needed in Narrow Fractures (\(w_f \leq 0.25 \text{ mm if } k_{matrix} = 100 \text{ md}\))

\(w_f = 0.25 \text{ mm, } k_{matrix} = 100 \text{ md}\)
100-ft plug extending from producer into a 0.25-mm fracture
If $w_f > 0.5$ mm, Gel Plugs Filling > 10% of the Fracture Were Needed to Significantly Improve Sweep

$w_f = 0.5$ mm, $k_{matrix} = 100$ md
If \( w_f > 0.5 \) mm, Gel Plugs Filling > 10% of the Fracture Were Needed to Significantly Improve Sweep

\[ w_f = 1 \text{ mm}, \quad k_{matrix} = 100 \text{ md} \]
For Plugs Centered in the Fracture, Sweep Improvement Was Not Sensitive to Plug Size if the Plugs Were Longer than 20% of the Fracture Length.

\[ w_f = 1 \text{ mm}, \ k_{\text{matrix}} = 100 \text{ md} \]
Pressure distribution with a 10-ft plug centered in a 1-mm fracture
Pressure distribution with a 100-ft plug centered in a 1-mm fracture

Centered 100-ft plug
Pressure distribution with a 800-ft plug centered in a 1-mm fracture

Centered 800-ft plug

![3D graph showing pressure distribution with a 800-ft plug centered in a 1-mm fracture.](image-url)
Off-Centered Plugs Didn’t Affect Rates Much if the Plugs Were Not Close to a Well

Production rate relative to that for an open direct fracture

$k_{matrix} = 100$ md

$w_f = 0.25$ mm

$w_f = 0.5$ mm

$w_f = 1$ mm

$w_f = 2$ mm

Center of 100-ft-long gel plug, ft from producer
Sweep Decreased as Plugs Moved Off-Center

Fraction of fluid sweeping the outer:

- 95% of the pattern
- 90% of the pattern
- 80% of the pattern
- 50% of the pattern

$w_f = 1 \text{ mm}$, $k_{matrix} = 100 \text{ md}$
100-ft plug centered at 250 ft from producer
Summary for Optimum Plug Placement:
Direct fracture channel between two vertical wells.

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

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

3. Ideally, this plug should be placed near the center of the fracture.
When fractures cause severe channeling, restricting the middle part of the fracture provides the best possibility. (See our 2005 annual report).
When multiple fracture pathways are present, some benefit will result from plugging the middle part of the most conductive fracture. (E.g., a 90% water cut is better than a 99% water cut.)
MISCONCEPTION: Water-based polymers and gelants won’t enter oil zones.

If this is true, why does a waterflood work?

GEL PLACEMENT IN PRODUCTION WELLS

SPEPF (Nov. 1993) 276-284

Gelant Injection

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

Return to Production

To prevent damage to oil zones, gel must reduce $k_w$ much more than $k_o$.
• Some gels can reduce $k_w$ more than $k_o$ or $k_{gas}$.

• Some people call this “disproportionate permeability reduction” or “DPR”. Others call it “relative permeability modification” or “RPM”. It is the same thing!

• This property is only of value in production wells with distinct water and hydrocarbon zones. It has no special value in injection wells!!!

• NO KNOWN polymer or gel will RELIABLY reduce $k_w$ without causing some reduction in $k_o$ !!!
In the absence of fractures, casing leaks, and flow behind pipe, gel treatments are not expected to improve the WOR from a single zone.

\[ f_{W1} = f_{W2} \]
\[ f_{O1} = f_{O2} \]

before gel

after gel: \[ f_{W2} = f_{W1} \] and \[ f_{O2} = f_{O1} \]

SPEPF (Nov. 1993) 276-284
GEL TREATMENTS FOR RADIAL FLOW PROBLEMS

• Zones MUST be separated by impermeable barriers.
• Hydrocarbon-productive zones MUST be protected during gelant injection.
• Loss of water productivity or injectivity is not sensitive to radius of gelant penetration between 5 and 50 ft.
• Gel permeability reductions > 20 cause > 80% loss of water productivity.
Radial Flow Requires That $F_{rro} < 2$ and $F_{rrw} > 20$

In oil zone, $F_{rr}$ must be $< \sim 2$ to maintain oil productivity.

In water zone, $F_{rr}$ should be $> \sim 20$ to reduce water productivity.

40-acre 5-spot pattern, $r_w = 0.33$ ft

$r_{gel} = 5'$ ft

$r_{gel} = 50'$ ft
With present technology, hydrocarbon zones MUST be protected during gelant placement in unfractured production wells.

To avoid this requirement, we need a gel that RELIABLY reduces $k_w$ by $>20X$ but reduces $k_o$ by $<2X$. 
“DPR” or “RPM” is currently most useful in linear-flow problems (e.g., fractures)

Gel Restricting Water Flow into a Fracture

Equivalent resistance to flow added by the gel
• In oil zone: 0.2 ft x 50 = 10 ft.
• In water zone: 0.2 ft x 5,000 = 1,000 ft.

IN SITU 17(3), (1993) 243-272
\textbf{\textit{F}}_{\text{rrw}} \text{ and final } \textbf{\textit{F}}_{\text{rro}} \text{ values for pore-filling Cr(III)-acetate-HPAM gels in Berea sandstone.}

$$
\begin{array}{|c|c|c|c|c|c|}
\hline
\text{Pre-gel} & \text{HPAM in} & \text{Post-gel} & \text{Final} \\
\text{$k_w$, md} & \text{gel, \%} & \text{$k_w$, md} & \text{\textbf{\textit{F}}_{\text{rrw}}} & \text{\textbf{\textit{F}}_{\text{rro}}} \\
\hline
356 & 0.5 & 0.015 & 23,700 & 1.2 \\
389 & 0.5 & 0.005 & 77,800 & 1.2 \\
31 & 0.5 & 0.007 & 4,430 & 2.2 \\
40 & 0.4 & 0.019 & 2,110 & 2.0 \\
270 & 0.3 & 0.055 & 4,980 & 1.7 \\
\hline
\end{array}
$$
1. After gel placement, $k_o$ rose from 2 to 105 md in 100 PV ($F_{rro} = 4.8 @ 100$ PV).

2. $k_w$ stabilized at 0.17 md very quickly ($F_{rrw} = 706$).

0.5% HPAM, 0.0417% Cr(III) acetate, 746 md Berea core, $dp/dl = 40$ psi/ft
MOBILITY RATIO

\[ M = \frac{(k/\mu)_{\text{displacing phase}}}{(k/\mu)_{\text{displaced phase}}} \]

- **M \leq 1**: porous rock
- **M > 1**: unstable displacement

Displacing phase

Displaced phase

Recover efficiency, %

Pore volumes injected

*Stable displacement*

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

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

- Displacement is very UNFAVORABLE!

**Diagram:**
- **GEL**
- **OIL**
- **Water**
  - \( \mu = 0.93 \) cp
  - \( k_w \) at \( S_{or} = 0.17 \) md
- **Oil**
  - \( \mu = 3.34 \) cp
  - \( k_o \) at \( S_{wr} = 508 \) md
What happens in a water zone when a well is returned to production AFTER gel placement?

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

Producer

- $k_w$ at $S_{or} = 0.17$ md
- $k_w$ at $S_{or} = 120$ md

Water

- $\mu = 0.93$ cp
- $\mu = 0.93$ cp
KEY PLACEMENT POINTS

Gelants can penetrate into all open zones.

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

In radial flow (unfractured wells), oil-productive zones must be protected during gelant placement.
Distinction between a blocking agent and a mobility-control agent.

- For a mobility control agent, penetration into low-k zones should be maximized.
- For a blocking agent, penetration into low-k zones should be minimized.
GEL TREATMENTS ARE NOT POLYMER FLOODS

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

• Are not simply viscous polymer solutions.

• Do not flow through porous rock like polymer solutions.

• Do not enter and plug high-k strata first and progressively less-permeable strata later.

• Should not be modeled as polymer floods.
A COMPARISON OF POLYMER FLOODING WITH IN-DEPTH PROFILE MODIFICATION
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.
As the viscosity of the injected fluid increases, sweep efficiency in the less-permeable layer increases.

http://baervan.nmt.edu/randy/
After polymer or gel placement, injected water forms severe viscous fingers that channel exclusively through the high-permeability layer.

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

No
No
YES!
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.
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.
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).

MPB-03 Incremental Oil Associated with Treatment

- Treatment Injected June 2004
- Start of response March 2005
- Incremental Oil Associated with Treatment
- Oil Rate
- Pre-treatment decline forecast

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

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

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

1. Concern about injectivity losses has been a key motivation that was given for choosing in-depth profile modification over polymer flooding.

2. However, most waterflood and polymer flood injectors are thought to be fractured.

3. Fractures are especially likely to be present in hot reservoirs with cold-water injectors (Fletcher et al. 1991).

4. Even when injecting viscous polymer solutions (i.e., 200-300 cp), injectivity has not been a problem in field applications (Wang 146473) because fractures extend to accommodate the viscosity and rate of fluid injected.

5. Concerns when injecting above the parting pressure are to not allow fractures to (1) extend so far and in a direction that causes severe channeling and (2) extend out of zone.

6. Under the proper circumstances, injection above the parting pressure can significantly (1) increase injectivity and fluid throughput, (2) reduce the risk of mechanical degradation for HPAM, and (3) increase pattern sweep.
ADDITIONAL CONSIDERATIONS

1. For small banks of popping-agent, significant mixing and dispersion may occur as that bank is placed deep within the reservoir—thus, diluting the bank and potentially compromising the effectiveness of the blocking agent.

2. Since the popping material provides a limited permeability reduction (i.e., 11 to 350) and the popped-material has some mobility, the blocking bank eventually will be diluted and compromised by viscous fingering (confirmed by SPE 174672, Fabbri et al.). High retention (130 µg/g) is also an issue (SPE 174672).

3. If re-treatment is attempted for a in-depth profile-modification process, the presence of a block or partial block in the high-permeability layer will (1) divert new popping-agent into less-permeable zones during the placement process and (2) inhibit placement of a new block that is located deeper in the reservoir than the first block. These factors may compromise any re-treatment using in-depth profile
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)
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](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.
With one exception, aluminum from the CDG was never reported to be produced in a field application. In the exception, Chang reported producing 1 to 20% of the injected aluminum concentration.

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

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

Gelants can penetrate into all open zones.

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

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