

How Much Polymer Should Be Injected During a Polymer Flood? Review of Previous and Current Practices

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Summary

This paper provides an extensive review of the polymer concentrations, viscosities, and bank sizes used during existing and previous polymer floods. On average, these values have been substantially greater during the past 25 years than during the first 30 years of polymer-flooding field activity. Reasons for the changes are discussed. Even with current floods, a broad range of polymer viscosities are injected, with substantial variations from a base-case design procedure. Extensive discussions with operators and designers of current polymer floods revealed substantial differences of opinion for the optimum design of polymer floods. This paper examines the validity of arguments that are commonly given to justify deviations from the base-case design. For applications involving viscous oils (e.g., 1,000 cp), the designed polymer viscosities have sometimes been underestimated because of insufficient water injection while determining relative permeabilities; reliance on mobility ratios at a calculated shock front; and overestimation of polymer resistance factors and residual resistance factors. In homogeneous reservoirs, the ratio of produced-oil value to injected-fluid cost is fairly insensitive to injected-polymer viscosity (up to the viscosity predicted by the base-case method), especially at low oil prices. However, reservoir heterogeneity and economics of scale associated with the polymer-dissolution equipment favor high polymer viscosities over low polymer viscosities, if injectivity is not limiting.

Injection above the formation-parting pressure and fracture extension are crucial to achieving acceptable injectivity for many polymer floods, especially those using vertical injectors. Under the proper circumstances, this process can increase fluid injectivity, oil productivity, and reservoir-sweep efficiency, and also reduce the risk of mechanical degradation for polyacrylamide solutions. The key is to understand the degree of fracture extension for a given set of injection conditions so that fractures do not extend out of the target zone or cause severe channeling. Many field cases exist with no evidence that fractures caused severe polymer channeling or breaching of the reservoir seals, in spite of injection above the formation-parting pressure.

Although at least one case exists (Daqing, China) where injection of very-viscous polymer solutions (i.e., more viscous than the base-case design) reduced S_{or} to less than that for waterflooding, our understanding of when and how this occurs is in its infancy. At this point, use of polymers to reduce S_{or} must be investigated experimentally on a case-by-case basis.

A “one-size-fits-all” formula cannot be expected for the optimum bank size. However, experience and technical considerations favor use of the largest practical polymer bank. 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.

Introduction

This paper addresses two questions for polymer flooding. First, what polymer-solution viscosity should be injected? A base-case

reservoir-engineering method has been available for making that decision, which focuses on waterflood-mobility ratios and the permeability contrast in the reservoir (Sorbie and Seright 1992; Wang et al. 2008a). However, some current field applications use injected-polymer viscosities that deviate substantially from this methodology. At one end of the range, Canadian projects inject only 30-cp polymer solutions to displace 1,000- to 3,000-cp oil (Delamaide et al. 2014). At the other end of the range, a project in Daqing, China, injected 150–300 cp polymer solutions to displace 10-cp oil (Wang et al. 2011).

The second question is: When should polymer injection be stopped or reduced? For existing polymer floods, this question is particularly relevant in the current low-oil-price environment. Should these projects be switched to water injection immediately? Should the polymer concentration be reduced or graded? Should the polymer concentration stay the same but reduce the injection rate?

Discussions with many operators of polymer floods, service companies, and polymer suppliers (mentioned in the Acknowledgments section) revealed substantial differences of opinion for the appropriate way to design a polymer flood. Resolving these differences provides the main motivation for this paper. In the following presentation, a historical perspective of polymer concentrations, viscosities, and bank sizes is first provided. Second, an existing base-case-design method is detailed for estimating the appropriate injection viscosity for a polymer flood. Projections from that method are compared with viscosities of recent polymer floods. Third, relative permeability effects are considered to determine the extent that they will allow use of lower-than-expected polymer viscosities for efficient oil displacement. Fourth, the relation between polymer viscosity and project economics is examined. Next, realistic choices of resistance factors and residual resistance factors are discussed. The role of polymer-solution rheology during unfavorable displacements is covered. Then, the importance of fractures is analyzed with respect to polymer injectivity, sweep efficiency, and breaching reservoir seals. Next, evidence is considered for polymer floods reducing the residual oil saturation (to less than that for extended waterflooding). Then, the decision to reduce or stop polymer injection is considered. The final section contemplates strategies to follow in the current environment of low oil prices.

What Polymer Concentrations/Viscosities and Bank Sizes Have Been Used in the Past?

1960–1980. The history of field applications for polymer flooding can be divided into three periods. The first period extends from the first implementation of polymer flooding, approximately 1960, through 1980. For 92 projects (both field and pilot), Manning et al. (1983) reported a median injected-polymer concentration of 250–260 ppm. The vast majority of these projects used hydrolyzed polyacrylamide (HPAM) or acrylamide-acrylate copolymer. Before polymer flooding, the median water/oil mobility ratio was approximately five. (In this case, mobility ratio is defined as water mobility divided by oil mobility. Mobility for a given phase is defined as effective permeability divided by viscosity.) The median polymer-bank size was quite small, only 17% pore volume (PV) for fieldwide projects and 5% PV for pilot projects. During this historical period, the choice of low polymer

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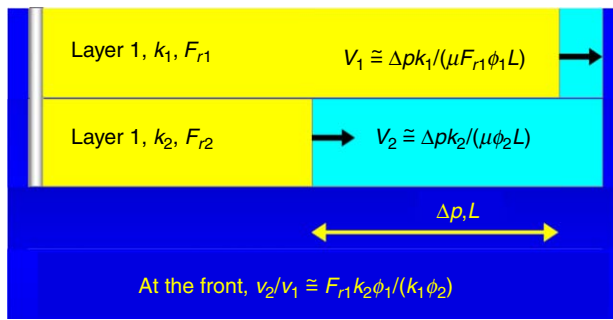


Fig. 1—Simple basis for the method.

concentrations and small polymer banks was predicated on two beliefs, which are now known to be misleading or incorrect. The first belief was that HPAM polymer provided a substantial permeability reduction (residual resistance factor) that would benefit the floods by providing much-more mobility reduction than expected from viscosity measurements and by improving the mobility ratio during post-polymer waterflooding (Pye 1964; Knight and Rhudy 1977). (Note that resistance factor is defined as water mobility divided by polymer-solution mobility. Residual resistance factor is defined as water mobility before the rock was exposed to polymer divided by water mobility after exposure to polymer.) Unfortunately, the very-high-molecular-weight (M_w) polymer species that caused this effect in short laboratory cores is unlikely to propagate very far into a reservoir (Seright 2010; Seright et al. 2011). The second belief was that small polymer banks would preferentially enter high-permeability strata, allowing subsequently injected water to be diverted to displace oil from less-permeable strata (Needham and Doe 1987; Chang et al. 2006). Unfortunately, injected water preferentially fingers first through polymer banks in the most-permeable pathways (Cyr et al. 1988; Sorbie and Seright 1992; Seright et al. 2012). This realization has led to larger polymer-bank sizes over time, as demonstrated by Fig. 1 of Sheng et al. (2015).

1980–1990. Up to 1990, a number of well-documented field projects were performed that advanced our knowledge of polymer flooding. These included Coalinga (Duane and Dauben 1983), Courtenay/Chateauguay (Putz et al. 1994), Daqing (Wang et al. 1995), Marmul (Koning et al. 1988), North Burbank (Zornes et al. 1986), North Stanley (DuBois and Burch 1978), Oerrel and Hankensbuettel (Maitin and Volz 1981), Oregon Basin and Byron (DeHekker et al. 1986), Eliasville Caddo (Weiss and Baldwin 1985), Rapdan (Pitts et al. 1995), Storms Pool (Craig 1984; Norton and Dauben 1986), and West Yellow Creek (Holstein 1981). Unfortunately, the Windfall Profits Tax Act of 1980 stimulated a large number of polymer projects in the US between 1980 and 1986 that were motivated solely to achieve tax reductions. During this time period, the median polymer concentration for 171 projects was 460 ppm (primarily HPAM) and the median volume of polymer solution injected was 10% PV (Seright 1993). In contrast, polymer concentrations for the well-documented projects listed previously were typically 1,000–1,500 ppm, and polymer-bank sizes usually ranged from 25 to 100% PV. The large number of tax-driven projects in the 1980s strongly skews statistical analyses of polymer floods, and can lead to the erroneous conclusion that polymer flooding is applicable in virtually all conventional reservoirs (Saleh et al. 2014).

1990–Present. For the most-recent historical period, polymer-flooding field projects have generally used 1,000-ppm HPAM or greater and relatively large bank sizes. The world’s largest polymer flood was implemented at Daqing, China, in 1996 to displace 9- to 10-cp oil (Wang et al. 1995, 2008a, 2008b, 2009, 2011). Polymer-flooding pilot tests were performed at Daqing since 1972 (Wang et al. 2009). The first 12 years of the large-scale Daqing project typically used 1,000–1,300 ppm of HPAM (15–18 million g/mol), providing 40–50 cp of surface viscosity. Typically, approximately 1

PV of polymer solution was injected for a given pattern, although a significant amount of variation and experimentation occurred to optimize performance.* Since 2002, Daqing increasingly tested and implemented injection of 2,000–2,500 ppm of HPAM (20–35 million g/mol), providing 150- to 300-cp polymer solutions to displace the same 9- to 10-cp oil (Wang et al. 2011). Bank sizes reported for this high-concentration process ranged from 0.4 to 1.2 PV. Table 1 lists information for other recent polymer floods. Polymer concentrations and bank sizes for recent projects have been considerably greater than for projects before 1990. Note the wide range of ratios of oil viscosity to injected-polymer viscosity in Table 1, apparently reflecting a wide range of beliefs regarding the mobility ratio needed for an effective polymer flood.

In Table 1, C_{poly} is the polymer concentration injected during the specified project, μ_{poly} is the viscosity of the injected-polymer solution, μ_{oil} is the oil viscosity at reservoir temperature (T), endpoint M is the endpoint-mobility ratio, and k_{cont} is the average permeability contrast between reservoir layers. Grading (last column of Table 1) indicates whether polymer viscosities were gradually lowered near the end of the polymer bank (rather than abruptly changing from polymer to water injection).

Floods involving “colloidal dispersion gels” (CDGs) are sometimes labeled as polymer floods or substitutes for polymer flooding (Chang et al. 2006). In contrast to recent polymer floods, these floods by use of CDGs still follow the philosophy of low polymer concentrations and small bank sizes (Manrique et al. 2014). A detailed analysis and review of CDGs is available (Seright 2015). This review reveals that that CDGs cannot propagate deep into the porous rock of a reservoir, and at the same time provide resistance factors or residual resistance factors that are greater than those for the same polymer formulation without the crosslinker. As with most particulate materials, gel particles that approach the size of pore throats are quickly filtered from the solution during flow through porous media (Ranganathan et al. 1998). Gel particles that are too small have no significant effect on liquid mobility.

Base-Case Method for Estimating the Required Polymer Viscosity

Crossflow Between Layers. A simple method is available to estimate a base-case viscosity for injection during a polymer flood (Sorbie and Seright 1992; Wang et al. 2008a). This method estimates the desired polymer viscosity (relative to water viscosity) as the product of mobility ratio (M , mobility of the displacing phase relative to the displaced phase) and the permeability contrast (k_{cont} , between adjacent layers in the reservoir; high permeability divided by low permeability). In this method, an important issue is: What value should be assigned for the mobility contrast? This question will be addressed in the next section. However, for simplicity in illustrating the method, the first focus is on cases where polymer solutions are injected to miscibly displace water. Fig. 1 provides a basis for the method in a two-layer porous medium with free crossflow between the layers. Assume that a polymer solution (yellow in Fig. 1) is injected to displace water (light blue, with viscosity μ). Layer 1 has permeability k_1 and porosity ϕ_1 , whereas Layer 2 has permeability k_2 and porosity ϕ_2 . The polymer resistance factor is F_{r1} in Layer 1 (meaning that effective viscosity of the polymer solution is F_{r1} times greater than water) and F_{r2} in Layer 2. (F_{r1} may be different from F_{r2} because of non-Newtonian rheology of the polymer solution or because of pore-plugging effects if one or both layers have permeability less than 100 md.) If vertical equilibrium (Coats et al. 1971; Zapata and Lake 1981) can be assumed (and gravity and capillary forces can be neglected), at any given horizontal position along Fig. 1, the pressure in Layer 1 is the same as that in Layer 2. This condition is generally true in reservoirs with no barriers to vertical flow if the length/width ratio is 10 or greater (i.e., the injector/producer distance is more than 10 times greater than the formation thickness) (Zapata and Lake 1981). For simplicity of visualization, the

* Personal communication with P. Han. 2015. PetroChina Daqing Oilfield Company Limited, 8–17 July.

Field	C_{poly} (ppm)	μ_{poly} (cp)	μ_o at Reservoir Temperature (cp)	Endpoint (M)	k_{cont}	$\mu_{\text{poly}} (M \times k_{\text{cont}})$	Bank Size (PV)	Graded?
Daqing, China (1996–2008) ¹	1,000–1,300	40–50	9–10	9–10	4:1	~1	~1	Mixed
Daqing, China (2008–2016) ²	2,000–2,500	150–300	9–10	9–10	4:1	3–8	0.4–1.2	Mixed
Gudao/Shengli, China ³	2,000	25–35	50–150	–	–	–	0.4–0.6	–
Shengtiao/Shengli, China ³	1,800	30–50	10–40	–	–	–	0.4–0.6	–
ShuangHe, China ⁴	1,090	93	7.8	–	4:1	–	0.4	Yes
Bohai Bai, China ⁵	1,200–2,500	98	30–450	–	4:1	–	0.11–0.3	–
Pelican Lake, Canada ⁶	600–3,000	13–200	~1,650	~165	4:1	0.02–0.3	0.5–2	–
East Bodo, Canada ⁷	1,500	50–60	417–2,000	~42	–	–	–	–
Mooney, Canada ⁸	1,500	20–30	100–250	–	–	–	–	–
Seal, Canada ⁸	1,000–1,500	25–45	3,000–7,000	–	–	–	–	–
Suffield Caen, Canada ⁹	1,300	32	69–99	44–64	4:1	~0.2	0.6	–
Wainwright, Canada ¹⁰	2,100–3,000	25	100–200	–	–	–	0.5	Yes
Dalia, Angola ¹¹	900	3	1–11	–	10:1	–	0.5	Yes
Diadema, Argentina ¹²	1,500–3,000	15–40	100	80	9:1	~0.06	0.8	–
El Corcobo, Argentina ¹³	1,000	20–25	160–300	–	–	–	–	–
Matzen, Austria ¹⁴	900	10	19	17	–	–	–	Yes
Canto do Amaro, Brazil ¹⁵	1,000	30	50	12	–	–	0.1	–
Carmopolis, Brazil ¹⁵	500	40	10.5	3	–	–	0.16	–
Buracica, Brazil ¹⁵	500	10	7–20	2–5	–	–	1.1	–
Bockstedt, Germany ¹⁶	300 (biopoly)	25	11–29	–	3:1	–	–	–
Mangala, India ¹⁷	2,000–2,500	20	9–22	36	10:1	~0.06	0.8	Yes
Marmul, Oman ^{18,19}	1,000	15	80–90	~40	10:1	~0.04	1	–
Tambaredjo, Suriname ²⁰	1,000–2,500	45–140	325–2,209	40–50	12:1	~0.4	–	–

¹Wang et al. 2008b

²Wang et al. 2011

³Gao 2014

⁴He et al. 1998

⁵Kang et al. 2011

⁶Delaplace et al. 2013

⁷Wassmuth et al. 2009

⁸Saboorian-Jooybari et al. 2015

⁹Liu et al. 2012

¹⁰Irving et al. 2012

¹¹Morel et al. 2012

¹²Buciak et al. 2015

¹³Hryc et al. 2013

¹⁴Zechner et al. 2015

¹⁵de Melo et al. 2005

¹⁶Sheng et al. 2015

¹⁷Prasad et al. 2014

¹⁸Al-saadi et al. 2012

¹⁹Thakuria et al. 2013

²⁰Manichand et al. 2013

Table 1—Polymer injected during recent polymer floods.

vertical interfaces between the light blue and the yellow in Fig. 1 show the polymer-front positions in Layers 1 and 2. Because of vertical equilibrium, the pressure difference Δp over the horizontal distance L is the same in both layers. Consequently, the

Darcy equations listed in Fig. 1 show approximations for the velocities of the polymer fronts in the two layers, whereas the bottom equation in Fig. 1 shows the approximate ratio of the two front velocities:

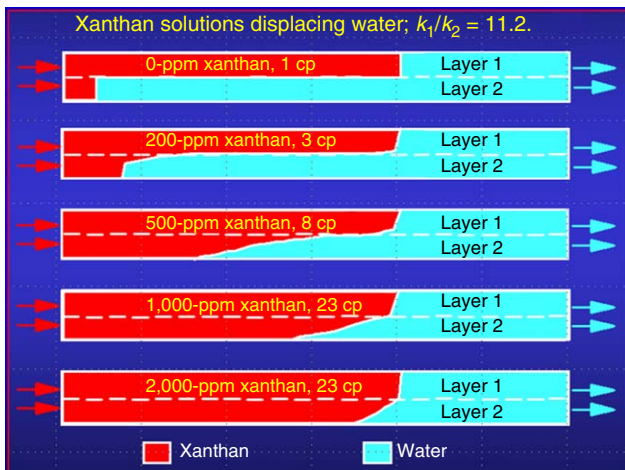


Fig. 2—Polymer solutions displacing water in two-layer bead-packs with crossflow.

$$v_2/v_1 \approx (F_{r1}k_2\phi_1)/(k_1\phi_2) \dots \dots \dots (1)$$

In Eq. 1 and Fig. 1, L is the horizontal distance between the front end of the polymer bank in Layer 2 and the point in Layer 2 that is adjacent to the front end of the polymer bank in Layer 1. F_{r2} does not appear in Eq. 1 because only brine flows over this distance in Layer 2.

When F_{r1} = unity (i.e., water displaces water), the ratio of front velocities, v_2/v_1 , is given by the permeability/porosity ratio, $(k_2\phi_1)/k_1\phi_2$, as expected from the simplest form of Darcy's law. Eq. 1 predicts that the ratio of front velocities increases in direct proportion to the resistance factor, F_{r1} , until F_{r1} reaches the permeability/porosity ratio, $(k_2\phi_1)/k_1\phi_2$. Above this value, the equation predicts that the polymer front in the low-permeability layer will outrun that in the high-permeability layer, which of course will not happen.

In reality, the polymer front in Layer 2 will not be vertical because of local pressure gradients and crossflow in the region between the polymer front in Layer 2 and that in Layer 1. Fig. 2 shows actual polymer-front profiles from experiments where polymer solutions (with viscosities ranging from 1 to 75 cp) displaced water in two-layer bead-packs (Sorbie and Seright 1992). For each of five cases shown in Fig. 2, Layer 1 was 11.2 times more permeable than Layer 2. (Layers 1 and 2 have the same porosity.) Red-dyed xanthan solutions (with viscosities at 7.3 seconds⁻¹ ranging from 1 to 75 cp) were injected to displace blue 1-cp water. (The shear rate, 7.3 seconds⁻¹, is simply a standard that has been accepted within the oil industry to allow direct comparison of solutions in chemical flooding.) Videos of these displacements are available at <http://baervan.nmt.edu/groups/res-sweep/> (Seright 2000) and <https://www.youtube.com/watch?v=98PZkqBhqdw> (Seright 2014). Watching these videos reveals that for the cases of 23-cp- and 75-cp-polymer solutions, the polymer fronts in Layers 1 and 2 move at the same velocity, as predicted by Eq. 1 because F_{r1} (i.e., 23 and 75) is greater than the permeability/porosity contrast, $(k_1\phi_2)/(k_2\phi_1)$ (i.e., 11.2:1). The fronts in Layer 2 are angled and lag behind those in Layer 1 because the local pressure gradients cause extensive polymer crossflow (from Layer 1 into Layer 2) in the angled region. In other words, in an attempt to achieve vertical equilibrium, polymer is forced from Layer 1 to Layer 2 in the angled region. If Layer 2 were thicker, the polymer front in Layer 2 would follow a fixed angle (for a given viscosity case) as the thickness of Layer 2 increased. Also, the angle of inclination for the front in Layer 2 for the 75-cp-polymer case is steeper than that for the 23-cp-polymer case. This occurs because the local pressure gradients that push polymer into Layer 2 (in the angled region) are greater for the 75-cp-polymer case than for the 23-cp-polymer case. In other words, achieving vertical equilibrium at a given horizontal position in the angled region requires

that polymer penetrates farther vertically into Layer 2 as polymer viscosity increases.

For the case of 1-cp water (i.e., 0-ppm polymer) displacing water in Fig. 2, the videos reveal that the front in Layer 2 moves 11.2 times slower than that in Layer 1, just as is predicted by Eq. 1.

For the cases of 3 and 8 cp polymer-displacing water, the front movements are a bit more complex and are intermediate between the 1-cp and 23-cp cases. However, Eq. 1 is not a bad approximation for the average front movements.

The base-case method (mobility contrast multiplied by permeability contrast) is consistent with the original polymer-flood design for the Daqing polymer flood (Wang et al. 2008a). The endpoint-waterflood-mobility ratio (mobility contrast) at Daqing was given as 9.4. A number of different layers can be identified at Daqing, with a range of permeability contrasts between layers and with different circumstances of crossflow vs. no crossflow. However, a permeability contrast of 4:1 (high permeability over low permeability) approximates much of the reservoir associated with the original polymer flood (Wang et al. 2008a). Then, raising the injection-water viscosity by a factor of 10 should reduce the mobility ratio to unity, thereby eliminating the tendency for viscous fingers to form. Raising the polymer-solution viscosity by an additional factor of four (i.e., to 40 total) overcomes the permeability contrast to provide the maximum vertical-sweep efficiency (i.e., more like the bottom illustrations in Fig. 2 than the top illustration).

No Crossflow. If barriers to fluid crossflow exist, the distance of polymer penetration into less-permeable layers is substantially limited compared with the case with crossflow. By use of the distance of polymer penetration into a high-permeability layer (with permeability k_1) as a reference, the relative distance of polymer penetration into a less-permeable layer (with permeability k_2) is approximately given by the square root of the permeability/porosity ratio, $[(k_2\phi_1)/k_1\phi_2]^{0.5}$ (Seright 1988, 2010). Consequently, polymer flooding has considerably more potential in improving oil recovery in layered reservoirs with crossflow than in those without crossflow. Seright (2010) provided an example showing diminished incentive to inject more than 10 cp polymer to displace 1,000 cp polymer in a layered reservoir with no crossflow. If no crossflow occurs, a satisfactory design involves simply decreasing the mobility ratio to unity in a given layer.

Comparison With Field Designs. The seventh column of Table 1 lists a measure of how the injected-polymer concentration for some recent polymer floods compares with the base-case-design method. The parameter listed in this column is the injected-polymer viscosity divided by the product of endpoint-mobility ratio and permeability contrast. When this parameter is unity, our base-case design is achieved. Examination of Table 1 reveals one case (early Daqing) where the base-case design was achieved, one case (later Daqing) that substantially overshot the base-case design, and numerous cases that significantly underachieved the base-case design. For cases that underachieved the base-case design, note that some engineers are overly aggressive when characterizing the heterogeneity of their reservoirs. This action will result in overpredicting the polymer viscosity needed by use of the base-case design. If the reservoir has no clear delineation of layers that have distinctly different permeability, it should be treated as basically one layer in our base-case method. That consideration moves some of the "underachieving" designs in Table 1 closer to the base-case design. This point is most valid for cases where the injected-polymer viscosity was close to the oil viscosity. Cases that were most likely to be true "underachieving" designs were those where polymer viscosity was substantially less than oil viscosity.

In the sixth column of Table 1, the permeability contrast is listed for several cases. Those values were derived from literature reports where either Dykstra-Parsons coefficients of permeability variation or a range of permeabilities were provided. Given a Dykstra-Parsons coefficient (D_v), an effective permeability contrast (k_{cont}) can be calculated; i.e., $k_{cont} = 2$ if $D_v = 0.4$, $k_{cont} = 2.5$

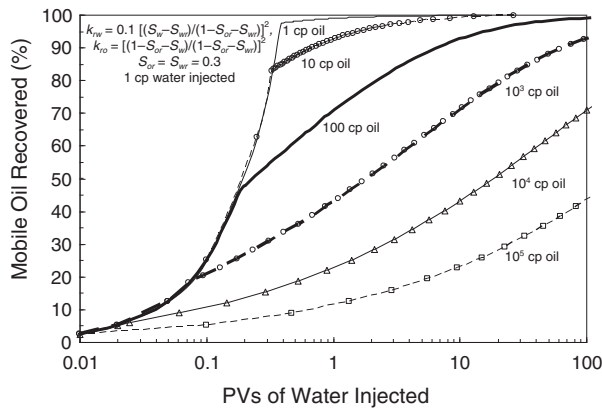


Fig. 3—Fractional-flow calculations for water displacing oil, one layer. Initial case, $k_{rwo} = 0.1$.

if $D_v = 0.5$, $k_{cont} = 3.5$ if $D_v = 0.6$, $k_{cont} = 5.1$ if $D_v = 0.7$, $k_{cont} = 8.8$ if $D_v = 0.8$, and $k_{cont} = 23$ if $D_v = 0.9$. As mentioned previously, if engineers assign a high Dykstra-Parsons coefficient to a relatively thin stratum with uncorrelated permeability variations, the base-case design overestimates the required polymer viscosity.

Will Relative Permeability Effects Favor Use of Low Polymer Viscosities?

In the preceding section, an issue was left hanging for our base-case method for determining the appropriate polymer viscosity to use. Specifically, what value should be used for the mobility contrast? Mobility is defined as permeability (k) to a given phase divided by the viscosity (μ) of that phase. An accepted part of reservoir engineering is that the efficiency of a displacement depends on the mobility ratio, which is the mobility of the displacing phase divided by the mobility of the displaced phase. (Craig 1971). **Fig. 3** illustrates oil recovery for water displacing oil by use of a wide range of assumed oil viscosities (from 1 to 100,000 cp). These curves were generated by use of fractional-flow calculations assuming one homogeneous layer, incompressible flow, and no density or capillary pressure differences between phases. The initial water saturation was 0.3. The relative permeability characteristics were given by Eqs. 2 and 3. The conditions given in Eq. 4 will be labeled our “initial case.”

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

$$k_{ro} = k_{roo} [(1 - S_{or} - S_w) / (1 - S_{or} - S_{wr})]^{no}, \dots \dots \dots (3)$$

$$k_{rwo} = 0.1, k_{roo} = 1, S_{or} = 0.3, S_{wr} = 0.3, nw = 2, no = 2. \dots \dots \dots (4)$$

The y-axis in Fig. 3 plots the percentage of the mobile oil that was recovered for a given PV of water injected. (The total mobile oil is given by the difference between the original oil saturation at the con-

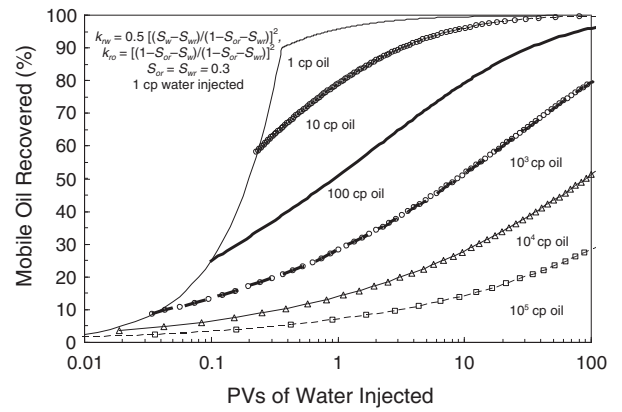


Fig. 4—Fractional-flow calculations for water displacing oil, one layer. Initial case, but $k_{rwo} = 0.5$.

nate-water saturation S_{wr} and the residual oil saturation S_{or} .) At 1 PV of water injected, note that oil recovery increases substantially each time the mobility ratio is decreased by a factor of 10. Specifically, oil recoveries at 1 PV are 11.3, 22.7, 42.8, 70.4, 92.7, and 99.2% for oil viscosities of 100,000, 10,000, 1,000, 100, 10, and 1 cp, respectively.

Fig. 4 presents similar fraction-flow calculations with the same parameters, except the endpoint permeability to water is 0.5 instead of 0.1. This plot shows qualitatively the same behavior as Fig. 3. Oil recoveries at 1 PV are 6.7, 14.0, 27.9, 50.7, 78.5, and 95.7% for oil viscosities of 100,000, 10,000, 1,000, 100, 10, and 1 cp, respectively.

A convenient and conservative choice for the mobility contrast in our base-case polymer-viscosity-selection method discussed previously is to use the endpoint-water/oil-mobility ratio. However, two relative permeability arguments have been used to rationalize injection of either water or relatively low (compared with the base-case method) polymer viscosities to displace viscous oils. One argument contends that the specific relative permeability curves associated with a particular field could allow a surprisingly efficient displacement. **Table 2** illustrates this point. Note for the case where the water-saturation exponent (nw) was 20, 86% of the mobile oil was recovered after injecting only 1 PV of water to displace 1,000 cp oil. In contrast, only 43% of the mobile oil was recovered when $nw = 2$ (with all other parameters remaining fixed). Unfortunately, relative permeability curves are notoriously difficult to determine for viscous oils. Maini (1998) discussed the many challenges associated with their determination and use. If the water-saturation exponent is assigned incorrectly high or the endpoint water relative permeability is measured too low (perhaps by insufficient waterflooding during core floods), the polymer requirements could be substantially underestimated.

In a number of cases where relative permeability curves were obtained during water injection to displace oil with viscosity of 1,000 cp or more, only 5 PV of water was injected. The laboratories performing the work assumed that because little or “no” additional oil was produced at 5 PV, they had reached the endpoint. Not surprisingly, they concluded that the endpoint k_{rw} (labeled

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%

Table 2—Effect of water relative permeability parameters: $\mu_o = 1,000$ cp, $\mu_w = 1$ cp, $k_{roo} = 1$, $no = 2$.

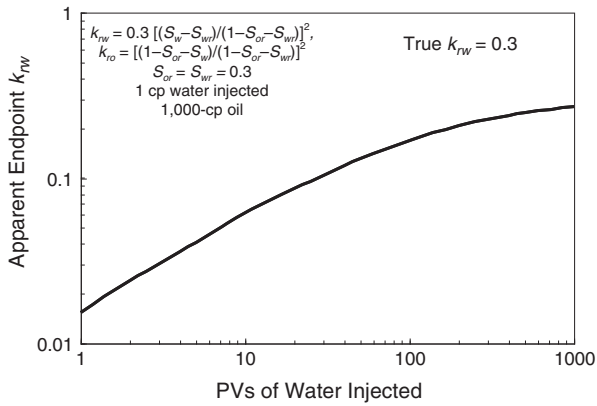


Fig. 5—Insufficient throughput yields misleadingly low k_{rw} values.

k_{rwo}) was 0.05 or less, and consequently, they deemed only 25–30 cp was needed for an efficient polymer flood. **Fig. 5** (derived from fractional-flow calculations by use of the parameters shown) demonstrates how the apparent endpoint value increases with water throughput, up to 1,000 PV injected. In **Fig. 5**, the k_{rwo} is 0.0407 after 5 PV. The blue curve in **Fig. 6** shows predicted recovery for a polymer flood (displacing 1,000-cp oil) by use of 25-cp polymer, assuming that k_{rwo} is 0.0407. In contrast, the green circles in **Fig. 6** demonstrate that 200 cp polymer is required to produce the same effect if the true k_{rwo} is 0.3. Consequently, assignment of a low k_{rwo} value after insufficient water throughput leads to under-designing the polymer flood.

Another argument is that the mobility ratio at the shock front should be used instead of the endpoint-mobility ratio to judge the efficiency of a displacement. The mobility ratio at the shock front (from fractional-flow calculations) can be surprisingly favorable (low) when injecting aqueous fluids to displace viscous oils. Beliveau (2009) noted a case for the Mangala field where the endpoint-mobility ratio during water injection was 14 but the mobility ratio at the shock front was only 0.94. Table 2 lists cases where the endpoint-mobility ratios ranged from seven to 260 times greater than mobility ratios at the shock front. The table lists a wide range of recovery efficiencies (at 1 PV injection) that did not correlate well with the mobility ratio at the shock front.

Viscous fingering is another phenomenon that should be considered before committing to a low-concentration polymer flood to displace viscous oil. Without consideration of viscous fingering, the PV throughput (averaged over all pore space) might seem quite low, and the associated relative permeability to water might be estimated to be quite low, suggesting a modest mobility ratio. However, if the viscous finger is narrow (as would be expected with a high mobility contrast), only a small fraction of a layer thickness might be contacted. Consequently, the actual water throughput in a given section of a viscous finger and the associ-

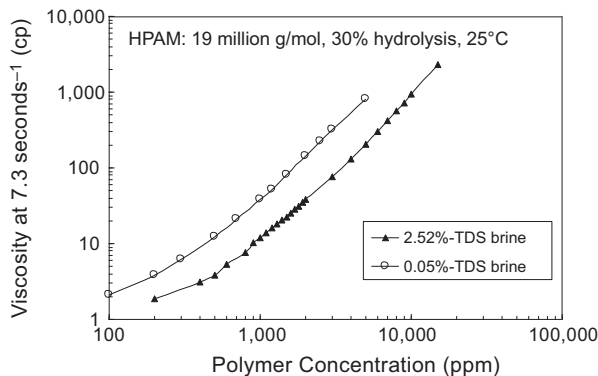


Fig. 7—HPAM viscosity vs. polymer concentration.

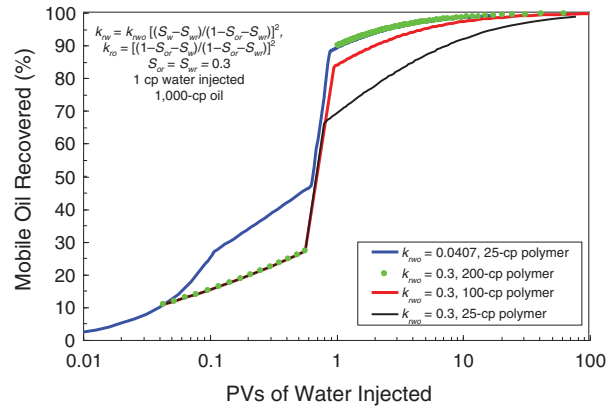


Fig. 6—Fractional-flow calculations of polymer flooding in a homogeneous system.

ated water relative permeability might be radically higher than assumed by use of the calculated shock-front mobility ratio.

In summary, relative permeability curves can be identified that allow efficient displacement of viscous oil by use of water or low-viscosity polymer solutions. However, incorrect assumption of overly optimistic relative permeability and the consequent selection of low injected-polymer-solution viscosity can lead to early polymer breakthrough and its associated inconveniences. A low mobility ratio at the shock front does not guarantee an efficient displacement of a viscous oil. Viscous fingering may make displacements much less efficient than expectations derived from shock-front mobility ratios.

Do Economics Favor Use of Low Polymer Viscosities?

When displacing viscous oils (e.g., 1,000 cp), relatively high polymer viscosities (e.g., > 100 cp) are normally required to achieve a favorable or piston-like displacement. However, in notable Canadian polymer floods (Delamaide et al. 2014) with 1,000-cp oil, injected viscosities were 30 cp or fewer. Do economics favor use of low polymer viscosities over high polymer viscosities? For this part of the analysis, assume that injectivity and pressure limitations do not exist in the reservoir; therefore, focus is explicitly on the economic issue. (Injectivity and pressure limitations will be covered later.) **Fig. 7** plots viscosity of an HPAM (that is commonly used commercially) vs. polymer concentration in two waters with different salinities. [The brine with 2.52% of total dissolved solids (TDS) is characteristic of that in a Canadian polymer flood, whereas the brine with 0.05% of TDS is characteristic of that in a Suriname polymer flood.] For both water salinities, if polymer concentration is greater than 1,000 ppm, viscosity (at 7.3 seconds⁻¹) varies with the 1.9 power of polymer concentration. This behavior economically favors use of high polymer concentrations. For example, if one wished to double the polymer-solution viscosity, only 44% more polymer is required; i.e., $2^{(1/1.9)} = 1.44$.

Because a finite amount of oil exists in a reservoir, injection of polymer solutions will eventually reach a point where the value of the produced oil becomes less than the costs associated with polymer injection. Does this reality favor use of low polymer viscosities and concentrations? To address this question, a simple benefit analysis was performed that focused on oil price and polymer viscosity/concentration. To determine oil recovery vs. volume of polymer solution injected, fractional-flow calculations were performed assuming the conditions indicated at the top of **Fig. 8**. (The reservoir was assumed to be at $S_{wi} = 0.3$ at the start of polymer injection. Polymer retention and inaccessible PV were assumed to be zero.) For any given volume of polymer solution injected, the “benefit” was calculated as the value of the oil produced up to that time minus the cost of the polymer injected. Oil prices between USD 20/bbl and 100/bbl were considered, and polymer cost was fixed at USD 1.50/lbm (USD 3.30/kg). The relation between polymer concentration and viscosity was taken from

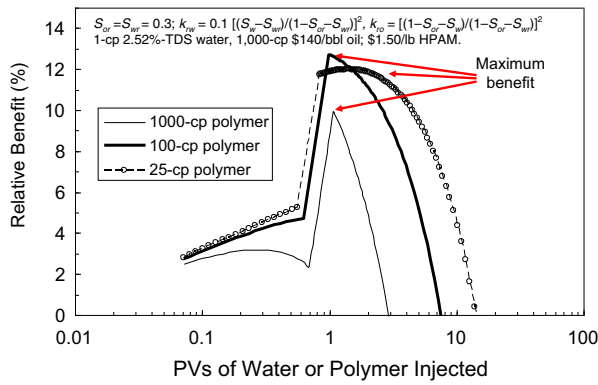


Fig. 8—Benefit vs. PV injected: one homogeneous layer, 2.52%-TDS brine, USD 40/bbl oil.

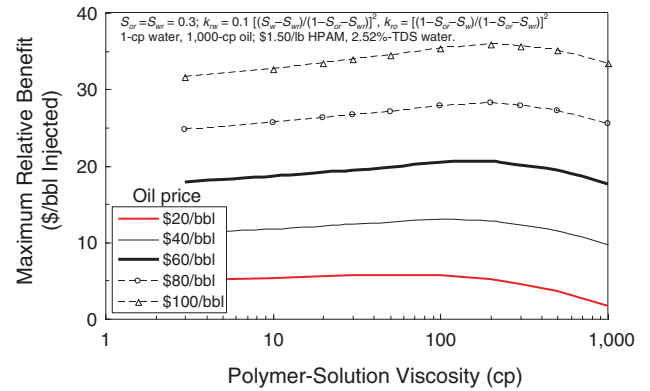


Fig. 9—Benefit vs. polymer viscosity: one homogeneous layer, 2.52%-TDS brine.

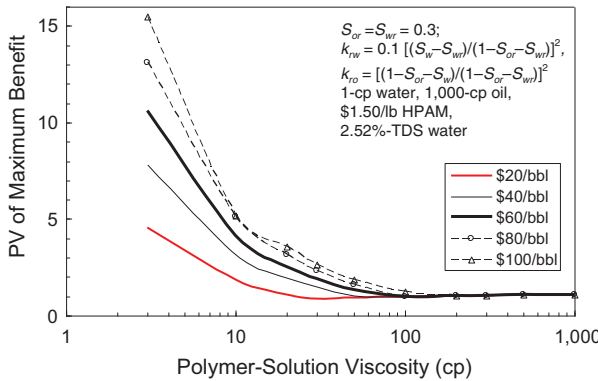


Fig. 10—PV injected for maximum benefit, associated with Fig. 9.

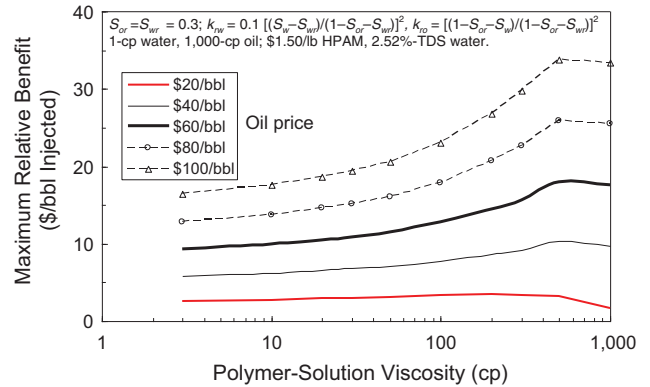


Fig. 11—Benefit vs. polymer viscosity: two layers, free cross-flow, $k_1 = 10k_2$, $h_1 = h_2$.

the higher-salinity case in Fig. 7. Of course, detailed economic analyses will normally consider many factors when planning a polymer flood, including oil price, polymer costs, labor, drilling and well-preparation costs, polymer-preparation facilities, water-source costs, flow lines to/from wells and instrumentation, produced-fluid separation and treatment costs, surveillance costs, and other costs (Wang et al. 2008b). For simplicity of illustration of our point, assume these other costs can be reflected as a lower-than-actual oil price.

When injecting polymer solutions, profitability increases with time and volume injected up to some maximum value and then declines (Fig. 8). Fig. 9 plots this point of maximum benefit as a function of injected-polymer viscosity and oil price for a polymer flood in a homogeneous one-layer reservoir with 1,000-cp oil. Two points can be taken from Fig. 9. First, in a homogeneous system with the particular relative permeability characteristics listed in Fig. 9, the greatest benefit is associated with injection of 100- to 200-cp polymer solutions. Second, for a given oil price, the relative benefit was not very sensitive to injected-polymer viscosity, especially at low oil prices. Fig. 10 plots the PV of polymer injected to achieve a given maximum relative benefit provided in Fig. 9. When using low polymer viscosities, large volumes of polymer solution must be injected to achieve the maximum benefit. In contrast, for polymer viscosities of 100 cp and greater, the polymer volume associated with the peak or maximum benefit is approximately 1 PV, regardless of oil price.

Fig. 11 (analogous to Fig. 9) considers the case where two layers (of equal thickness) are present, and fluids can freely cross-flow. Layer 1 is 10 times more permeable than Layer 2. Comparing Figs. 9 and 11 confirms higher financial benefits at higher polymer viscosities (up to 500 cp in this case) and that the maximum benefit becomes less sensitive to polymer-solution viscosity as oil price decreases. The main point of this analysis is that “economics” do not favor injection of low-viscosity-polymer solutions when displacing viscous oils. Justifying a preference for

the use of low-viscosity-polymer solutions requires some other factor, such as injectivity considerations or imposed pressure constraints. These other factors will be considered shortly.

Some Improvement in Mobility Ratio Is Better Than None

Given caveats, this argument is difficult to dispute. Examination of Figs. 3 and 4 reveals that decreasing the mobility ratio by a factor of 10–30 will substantially increase sweep efficiency even for very-viscous oils. However, that observation must be tempered with two other facts. First, a significant capital outlay must be made for water-treatment and polymer-preparation facilities when upgrading from waterflooding to polymer flooding, regardless of the polymer concentration chosen. The costs of facilities for a high-polymer-concentration flood are not greatly different from those for a low-concentration polymer flood (Wang et al. 2011).** Second, when displacing viscous oils, low-viscosity polymer floods will experience viscous fingering and earlier polymer breakthrough than high-viscosity polymer floods. Consequently, low-viscosity polymer floods must deal with the problems of produced polymer earlier than high-viscosity polymer floods. (This statement assumes that fractures do not cause severe interwell channeling. The fracture-channeling issue will be considered shortly.)

Do High Resistance Factors and Residual Resistance Factors Reduce the Need for High Polymer Viscosities and Volumes?

Resistance Factors. Resistance factor is defined as brine mobility (λ or k/μ) divided by polymer mobility in porous media. Early researchers (Pye 1964; Smith 1970; Jennings et al. 1971; Hirasaki

** Personal communication with Antoine Thomas, Cedrick Favero, Nicolas Gaillard, and C. Rivas. 2015. France: SNF at Andrezleux Cedex (11 June).

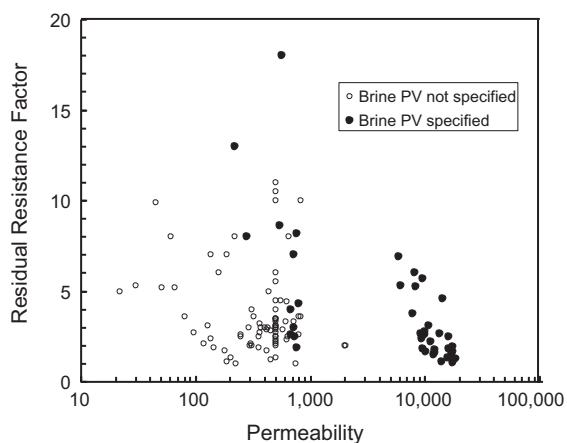


Fig. 12—Literature residual resistance factors vs. permeability.

and Pope 1974) recognized that high- M_w HPAM sometimes reduced the mobility of aqueous solutions during laboratory experiments in porous media by a greater factor than can be rationalized by use of the viscosity (μ) of the solution. The incremental reduction in mobility was attributed to reduction in permeability (k), caused by adsorption or mechanical entrapment of the high- M_w polymers, especially from the largest polymers in the M_w distribution for a given polymer. This effect was touted to be of great benefit (Pye 1964; Jennings et al. 1971) for polymer flooding because the polymer appeared to provide significantly more apparent viscosity (i.e., resistance factor) in porous media than expected from normal viscosity measurements. This effect was normally achieved by use of short cores and gently handled HPAM solutions. Unfortunately, these benefits were often not achievable in field applications because normal field handling and flow through an injection sandface at high velocities mechanically degraded the large molecules that were responsible for the permeability reduction (Seright et al. 1981; Seright 1983; Seright et al. 2011). Also, the largest molecules were preferentially retained (i.e., by mechanical entrapment in pores) and stripped from the polymer solution before penetrating deep into the formation (Seright et al. 2011). Consequently, in rock with moderate to high permeability (> 200 md), one cannot expect low-velocity resistance factors of conventional polymers (i.e., HPAM or xanthan) to be substantially greater than (i.e., > 2 times) the value expected from viscosity measurements (Seright et al. 2011). A conservative approach to polymer-flood design would assume that low-velocity resistance factors track low-shear-rate viscosities.

Residual Resistance Factors. Residual resistance factor is defined as water mobility before polymer injection divided by water mobility during water injection after a polymer flood. This parameter can be thought of as the permeability reduction provided by the polymer. If the residual resistance factor is unity, no permeability reduction is caused by the polymer. In that case, the mobility ratio can be high during water injection after polymer, and severe viscous fingering can occur. Consequently, a large polymer bank must be injected. As the residual resistance factor increases, the mobility contrast decreases when water follows polymer injection, and greater sweep efficiency can be maintained. At the extreme, if the residual resistance factor has approximately the same value as the resistance factor, a relatively small polymer bank can be injected (i.e., just enough to satisfy polymer retention).

Displacements with high mobility ratios require many PVs of throughput to reach the final saturation state. If insufficient water is injected, residual resistance factors will be artificially high. Oddly, literature reports rarely specify how many PVs of water were flushed to reach the stated residual resistance factor. Fig. 12 plots residual resistance factors (vs. initial permeability of the porous medium) that were reported in the literature. Many authors reported residual resistance factors without specifying brine

throughput: Jennings et al. (1971) (24 HPAM values ranging from 2 to 11), Szabo (1972) (five HPAM values ranging from 1.2 to 2.4), Hirasaki and Pope (1974) (eight Pusher 700 HPAM values ranging from 1.3 to 5), Vela et al. (1976) (seven Pusher 700 HPAM values ranging from 1.2 to 48), Duda et al. (1983) (more than 60 HPAM and xanthan values ranging from 1.1 to 7), Chauveteau (1981) (two HPAM values from 1.2 to 2), Zaitoun and Kohler (1987) (four xanthan-solution values from 1 to 2.5), Ramazani et al. (2010) (24 HPAM values from 1.2 to 8.7), and Stavland et al. (2010) (28 HPAM values from 1.0 to 7).

Dabbous (1977) reported 10 Pusher 500 and 700 HPAM residual resistance factors (ranging from 1.0 to 18) in which he did not specify brine-throughput values. As expected, residual resistance factor generally decreased with increased throughput, although some odd exceptions were noted. Chauveteau and Kohler (1974) observed a residual resistance factor of 2.5 after 8 PV of brine, after a 5.3-cp Pusher 500 HPAM bank. Dey and Baijal (1978) reported residual resistance factors from 1.06 to 13 after “several PV” of brine after HPAM banks.

Large variations in residual resistance factors were seen in literature data. Several factors may be responsible for these large variations. First, core-to-core mineralogy variations may cause part of the scatter because permeability reduction may depend on polymer adsorption and polymer adsorption depends strongly on mineralogy (especially clay and iron content). A second, major reason for the scatter is probably that insufficient brine was injected to drive the core to a true residual resistance factor. Only two cases in the literature reported flushing the core with more than 10 PV of brine. Exactly how much brine should be injected for a given core remains to be established.

For adsorbed polymers, resistance factors (F_r , apparent viscosities in porous media relative to brine) and residual resistance factors (F_{rr} , permeability-reduction values) can increase with decreasing permeability, especially less than 100 md (Pye 1964; Jewett and Schurz 1970; Jennings et al. 1971; Hirasaki and Pope 1974; Vela et al. 1976; Duda et al. 1983; Zaitoun and Kohler 1987; Rousseau et al. 2005). In other words, these polymers can reduce the flow capacity of low-permeability rock by a greater factor than high-permeability rock. Depending on the magnitude of this effect, vertical-flow profiles can be harmed, even though the polymer penetrates significantly farther into the high-permeability rock (Seright 1988, 2010; Liang et al. 1993; Zhang and Seright 2007).

How Much Brine Must Be Flushed To Reach a Stabilized Residual Resistance Factor?

A core experiment was performed to monitor residual resistance factors as a function of PV throughput. The Dundee sandstone core was 122 cm long and 3.81×3.81 cm² in cross section, with a porosity of 0.203 and PV of 358.8 cm³. The core had four internal-pressure taps that divided the core into five 24.4-cm-long sections. After saturating the core with brine (2.52% TDS), 10 PV (3.6L) of 1,000-ppm SNF Flopaam 3830S in 2.52% TDS brine was injected at a velocity of 2.1 ft/D. This solution had a viscosity of 10.1 cp at 7.3 seconds⁻¹ and 25 °C. Subsequently, 100 PV of brine (2.52% TDS) was injected and the residual resistance factor in the middle three core sections (73 cm in length) was monitored. The results are shown in Fig. 13. Fig. 13 reveals that residual resistance factors were still decreasing after injecting 100 PV of brine. The final value after 100 PV was 2.2.

Summary. An important point from our videos at <http://baervan.nmt.edu/groups/res-sweep/> (Seright 2000) and from polymer-flooding experience over the past 50 years is that the polymer bank should be as large as is practical (Sheng et al. 2015). Once brine injection begins, viscous fingering and heterogeneities will quickly lead to severe channeling (Cyr et al. 1988; Sorbie and Seright 1992). Many residual resistance factors that have been reported in the literature (for permeability greater than 200 md) are probably too high because not enough brine was injected to displace the mobile polymer or because nonpropagating high- M_w -

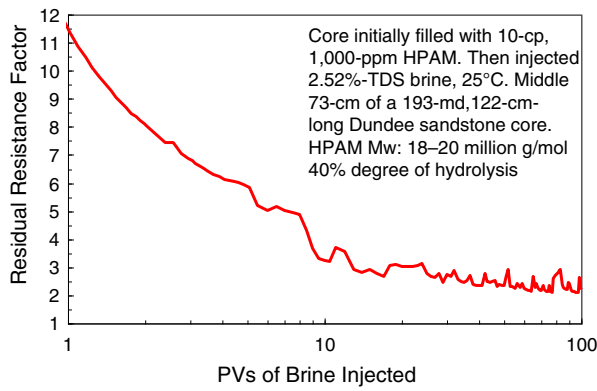


Fig. 13—Residual resistance factor vs. brine throughput.

polymer species caused artificially high resistance to flow during short core experiments. Thus, accepting high experimental residual resistance factors without caution may lead to not injecting a large-enough polymer bank or a high-enough polymer concentration in the polymer bank. To be conservative during the design of a polymer flood, residual resistance factors should be assumed to be unity, unless reservoir permeability is low (< 200 md).

A Rheological Effect During Unfavorable Displacements

If the base-case-design method is used to select the polymer-solution viscosity, oil displacement will be efficient and the rheology of the polymer solution will have virtually no effect on sweep efficiency (Seright 1991a, 2010). However, rheology of the polymer solutions can affect sweep efficiency if polymer-solution viscosity is less than optimum. To explain, first consider the rheology in porous media of HPAM solutions, as shown in Fig. 14. Depending on HPAM concentration, M_w , and salinity (Seright et al. 2011), these solutions show Newtonian (flow rate independent) or flow-thinning (shear thinning, where resistance factors decrease reversibly with increasing fluid velocity) behavior at low velocities, flow-thickening (shear thickening or pseudodilatant, where resistance factors increase reversibly with increasing velocity) behavior at intermediate velocities, and mechanical degradation at high velocities (where resistance factors decrease irreversibly with increased velocity). (The later behavior is not shown in Fig. 14.) Velocities greater than 10 ft/D are confined to the near-wellbore region. The vast majority of oil will be displaced far away from the wellbore, where flux values are low (1 ft/D or less).

In Fig. 1, consider the region where polymer exists in both layers. If the mobility ratio is low, little mobile oil will remain in this region after the polymer front passes. However, if the mobility ratio is greater than unity, considerable mobile oil may remain in the polymer-contacted region depending on exactly how high the mobility ratio is. If fluids can freely crossflow between the two layers, the ratio of velocities for the two layers in the polymer-filled region will be given by Eq. 5:

$$v_2/v_1 = (k_2/k_1)(\phi_1/\phi_2)(Fr_2/Fr_1). \dots\dots\dots (5)$$

(n-1)	$k_1/k_2 = 2$	$k_1/k_2 = 4$	$k_1/k_2 = 10$	$k_1/k_2 = 20$
0	0.500	0.250	0.100	0.050
-0.110	0.479	0.229	0.087	0.042
-0.137	0.473	0.224	0.083	0.039
-0.236	0.449	0.202	0.070	0.031
-0.249	0.446	0.199	0.068	0.030
-0.5	0.354	0.125	0.032	0.011
-0.7	0.223	0.050	0.007	0.002

Table 3— v_2/v_1 values in the polymer-contacted region.

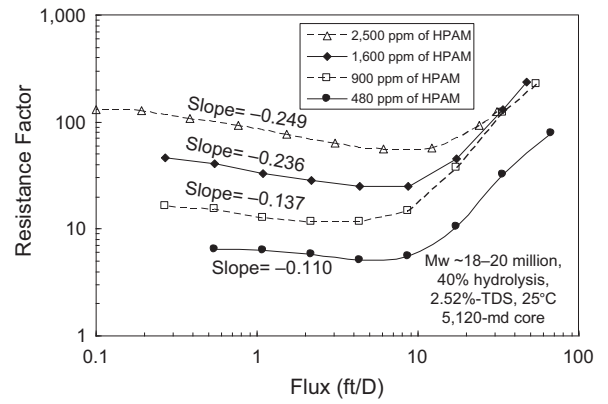


Fig. 14—Rheology in porous media for a commercial HPAM.

If the resistance factors in the two layers can be described by the power-law equation and the Blake-Kozeny equation applies, Eq. 6 describes resistance factor vs. velocity, permeability, and porosity:

$$Fr \approx (v\phi)^{(n-1)}(k/\phi)^{(n-1)/2}, \dots\dots\dots (6)$$

where (n-1) is the slope of the flow-thinning region in Fig. 14. Eqs. 5 and 6 can be combined to form Eq. 7:

$$v_2/v_1 \approx [(k_2\phi_2/(k_1\phi_1))^{(1+n)/(2n)}]. \dots\dots\dots (7)$$

Table 3 provides velocity ratios (v_2/v_1) in the polymer-contacted region for various permeability ratios (assuming porosity is fixed). Table 3 reveals that flow thinning (shear thinning) slows the velocity in the less-permeable layer. This effect is modest if the permeability contrast is low and the slope of flow-thinning region is low (as in Fig. 14). However, the effect is quite significant for high slopes and high-permeability contrasts. By slowing the velocity in the less-permeable layer, the aqueous throughput is reduced through that layer. If the polymer/oil-mobility ratio was favorable (less than unity), this phenomenon is of little consequence because most mobile oil was displaced when the polymer front passed through. However, if the mobility ratio was greater than unity, oil displacement may be slowed considerably for the mobile oil that remains in the less-permeable layer behind the polymer front. This observation argues in favor of polymer viscosities that are high enough to provide a favorable mobility ratio, especially when high permeability contrasts exist.

Is Injectivity Impaired by Viscous Polymer Solutions?

In wells that are not fractured, injection of viscous polymer solutions will necessarily decrease injectivity, roughly in proportion to the viscosity of the fluid injected (Wang et al. 2008; Seright et al. 2009; Manichand et al. 2013). If injectors are horizontal, economic polymer-injection rates can be attained without injection to greater than the formation-parting pressure (Taber and Seright 1992; Delamaide et al. 2014). However, if wells are

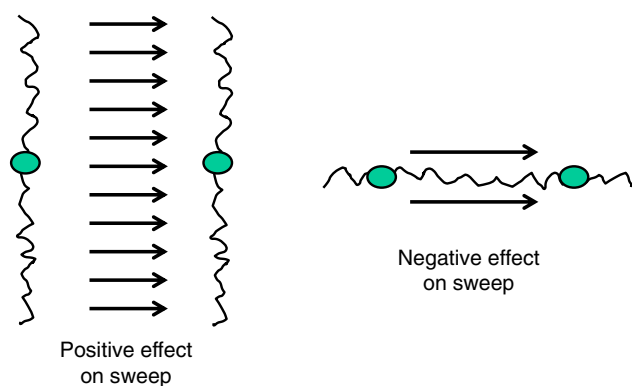


Fig. 15—Effect of fracture orientation on sweep.

vertical, injectivity losses (relative to water injectivity) are usually prohibitive during polymer injection unless fractures or fracture-like features are open (Khodaverdian et al. 2009; van den Hoek et al. 2009; Manichand et al. 2013).

Injections at pressures greater than the formation-parting pressure and fracture extension are not necessarily detrimental. Under the proper circumstances, they can increase fluid injectivity, oil productivity, and reservoir-sweep efficiency (Crawford and Collins 1954; Dyes et al. 1958; Wang et al. 2008a). Fractures can also reduce the risk of mechanical degradation for polyacrylamide solutions (Trantham et al. 1980; Wang et al. 2008a; Seright et al. 2009; Zechner et al. 2015). The key is to understand the degree of fracture extension for a given set of injection conditions so that fractures do not extend out of the target zone or cause severe channeling.

Previous work (Gadde and Sharma 2001; Seright et al. 2009) indicates that once fractures are opened, the fracture area increases to accommodate the increased injection rate or increased injectant viscosity, with small increases in downhole pressure. Saripalli et al. (1999) and Gadde and Sharma (2001) considered fracture growth as a function of particle plugging and other effects. Their work demonstrated that particle plugging during injection at a fixed rate leads to fracture extension. As a portion of the fracture face becomes impaired by plugging, pressure at the fracture tip forces the fracture to extend until enough fracture area is available to accommodate the existing injection rate. Consequently, injectivity observed for a well—i.e., injection rate divided by flowing pressure minus static pressure—may not appear to be sensitive to volume of particles injected (Schmidt et al. 1999). Similarly, when injecting viscous polymer solutions, fracture extension explains why injectivity often appears to be not greatly different from that during water injection (Wang et al. 2008; Manichand et al. 2013).

Manichand et al. (2013) performed calculations to estimate the fracture area open to flow during polymer injection into a vertical well in the Tambaredjo field (Suriname). Given the depth of the Tambaredgo formation (1,000 ft) and the local stress field, induced fractures are horizontal. In their case, polymer-solution injectivity was 61 times greater than expected for injection into an openhole completion, and the fracture area was roughly 61 times greater than that associated with the open hole. This area equated to a fracture that extended radially 20 ft from the well. This short fracture did not jeopardize sweep (i.e., create severe channeling) because the nearest production well was more than 300 ft away (Moe Soe Let et al. 2012). However, the fracture tremendously increases injectivity for the polymer solution. The fracture also reduced the possibility of HPAM mechanical degradation. By increasing the sandface area by a factor of 61, the velocity when the polymer enters the formation is reduced in proportion.

Will Injection To Greater Than the Formation-Parting Pressure Compromise Reservoir Containment?

If injection of viscous polymer solutions opens fractures that cut through the upper or lower formations, that would provide a good reason not to inject by use of high polymer concentrations or

rates. De Pater (2015) recently reviewed issues associated with reservoir containment during fracture growth. He noted that growth of fracture height is complex and not entirely understood. However, in general, growth of fracture height has been less than predicted during simulations. The rate and extent of fracture-height growth is specific to the formation. Some of the greatest ratios of fracture length to fracture height have been observed in soft formations such as those in western Canada (80:1 in some cases). These are the same types of formations where polymer flooding has been applied to displace viscous oils, thus providing hope that the caprock will not be breached during injection of viscous polymer solutions. Even so, the actual pressure that these formations can withstand must be determined experimentally. Consequently, the most-appropriate time to assess the maximum polymer viscosity and injection rate for a formation is during a polymer-flood pilot project in a given field.

Zhou et al. (2010) experimentally examined shear dilation and fracture growth during polymer injection in unconsolidated sands. They concluded that injection pressure should exceed the minimum stress by a factor of 2.5 to induce fracture propagation. They also concluded that fracture creation was only a function of pressure, irrespective of the injection-fluid viscosity. Also, induced fractures were dominantly planar, although they were tortuous. Matrix-permeability enhancements up to 40% were observed caused by shear dilation.

In the Daqing oilfield in China (approximately 5,600 injection wells, 500–800-md rock, and 9 cp oil), injectivities were only 10% lower by use of 150- to 300-cp-polymer solutions compared with 40- to 50-cp-polymer solutions (Wang et al. 2011). This observation is consistent with fracture extension when injecting viscous polymer solutions. Interestingly, no problems were reported of fractures compromising the reservoir seals or causing severe channeling during this large-scale project.*

Will a Fracture Extend Too Far and Compromise Sweep Efficiency?

Parallel Vertical Fractures. The existence of a fracture near an injection well can dramatically increase polymer injectivity and reduce mechanical degradation (Trantham et al. 1980; Seright 1983; Seright et al. 2009; Zechner et al. 2015). Of course, if fractures extend too far in the wrong direction, they can compromise sweep efficiency (Crawford and Collins 1954; Dyes et al. 1958; Bargas and Yanosik 1988). The key questions are how far is too far and what degree of injectivity improvement will be realized as a function of fracture length? Some simple concepts help appreciate the effect of fractures. First, if vertical fractures in vertical injection wells run parallel to fractures that intersect offset vertical production wells, a line drive is formed, which is ideal for sweep efficiency—effectively making parallel horizontal wells. This fact argues strongly for understanding the direction and orientation of fractures before beginning a polymer flood (or any other injection process). Most of the concerns about fracture extension could be mitigated if the field is drilled to take advantage of fracture direction and orientation (Fig. 15). Even if the fractures connect from injector to injector, sweep toward the production wells should not be compromised. However, keeping vertical fractures open in injection wells is easier than in production wells. If fractures are open in injection wells but closed in production wells, oil could be driven past or away from the production wells if pressures in the pattern are not balanced well.

Horizontal Fracture in a Vertical Well. The Sarah Maria polymer pilot project in Suriname is believed to have horizontal fractures that are open during polymer injection into their vertical wells (Moe Soe Let et al. 2012; Manichand et al. 2013; Manichand and Seright 2014). For this type of case, some simple calculations can be made to estimate polymer injectivity and fracture extension. From one viewpoint, injectivity should be proportional

* Personal communication with P. Han. 2015. PetroChina Daqing Oilfield Company Limited, 8–17 July.

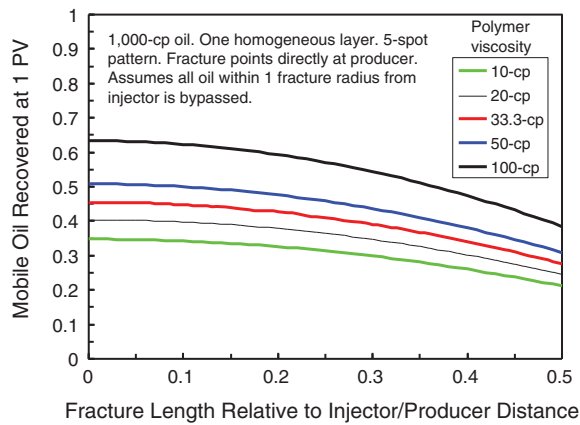


Fig. 16—Effect of fracture length on sweep: one homogeneous layer.

to or closely related to the area available. For an openhole completion, the area open to flow is $2\pi r_w h$, where r_w is wellbore radius and h is formation height. If a horizontal fracture opens radially from the well, the added fracture area is $2\pi(r_f)^2$, where r_f is the radius of the horizontal fracture. (Recall that there are upper and lower faces associated with a horizontal fracture.) If formation height is 30 ft and wellbore radius is 0.5 ft, the area for an open hole is 94 ft². If a horizontal fracture extends 30 ft radially from the wellbore, the added fracture area is 5,655 ft², or 60 times greater than the openhole area. In this particular case, this area of 5,655 ft² also corresponds to the area associated with an openhole wellbore that was 30 ft in radius. In the general case, the increase in effective flow area will be less than the smaller of $2\pi(r_f)^2$ and $2\pi(r_f)h$. Increasing the flow area to 100 and 200 times the original openhole area will require fracture extension at least to 50 and 100 ft, respectively. Thinner formations will result in risk of longer fracture extension. For the Suriname project (which typically has injector/producer distances of approximately 300 ft), efforts are being conducted to assess whether fracture extension compromises sweep efficiency when injecting viscous-polymer solutions (up to 165 cp) and at various rates.

Vertical Fracture (In a Vertical Injector) Pointed at a Production Well. This subsection considers the case where vertical fractures are pointed directly at a production well. Dyes et al. (1958) argued that even with mobility ratios as high as three, these fractures would have little effect on sweep efficiency if they extended halfway (or less) to the offset production well. Bargas and Yanosik (1988) examined cases where a fracture extended one-quarter of the pattern distance from an injection well and one-quarter of the pattern distance from a production well. When the injector fractures point at the producer fractures, they found little effect on sweep efficiency if the mobility ratio was unity. However, as the mobility ratio increased to 10, sweep efficiency was significantly compromised. This finding re-emphasizes that the well pattern should be chosen so that fractures are oriented to form a line drive (as much as possible). The finding also means that if fractures are not oriented favorably, there will be a balance between improving mobility ratio through increasing injected-polymer-solution viscosity and harming sweep by extending fractures too far (when injecting very-viscous-polymer solutions).

In considering the fracture area as a function of fracture length, assume that a vertical fracture has two wings, with two fracture faces for each wing. Then the fracture area open to flow would be $4L_f h$, where L_f is the length of one fracture wing. Figs. 16 and 17 illustrate the tradeoff between fracture length (to improve polymer injectivity) and improved mobility ratio. Fig. 16 applies to a single homogeneous layer. Fig. 17 applies to a two-layer reservoir with free crossflow between layers. (Both layers have the same thickness, but one layer is 10 times more permeable than the other. The fracture extends the same distance in both layers.) Figs. 16 and 17 assume 1,000-cp oil, a five-spot pattern, that the

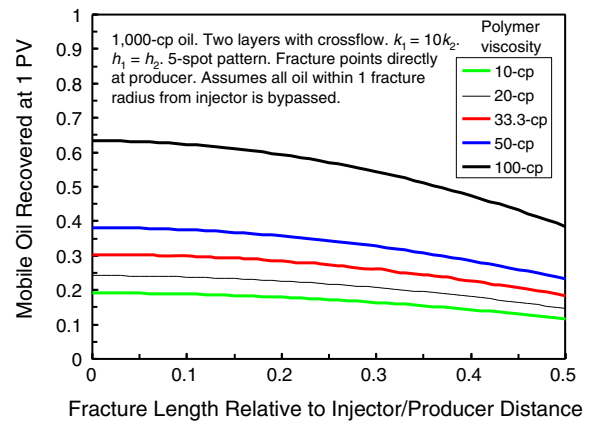


Fig. 17—Effect of fracture length on sweep: two layers, free crossflow.

fracture in the injection well points directly at the production well, and that all oil within one fracture radius of the injector is bypassed. The pattern is initially at connate-water saturation (i.e., $S_{wr} = 0.3$), and the relative permeability parameters are given by Eqs. 2 through 4. The x -axis plots the fracture length relative to the total direct-line distance between the injector and producer. The y -axis plots fraction of the original mobile oil in the pattern that is recovered after 1 PV of polymer injection. This fraction is given by the macroscopic displacement efficiency times the areal-sweep efficiency times the volumetric-sweep efficiency. Macroscopic-sweep efficiency at 1 PV was determined from fractional-flow calculations (like those in Fig. 3). Areal-sweep efficiency was determined by use of the Craig-Geffen-Morse equation (Craig 1971). Vertical-sweep efficiency for Fig. 17 was determined by use of Eq. 1. (Vertical sweep was unity for Fig. 16, because there is one homogeneous layer.)

Consistent with the work of Dyes et al. (1958), fractures do not have a major effect on sweep efficiency until the fracture extends beyond one-third of the interwell distance. The key point from Figs. 16 and 17 is that the benefit from an improved mobility ratio outweighs the sweep-efficiency loss from the fracture, so long as the fracture is not too long. For example, in Fig. 16, note that increasing the fracture length from 0 to 30% (of the total distance) decreased oil recovery from 0.63 to 0.53 (with 100 cp polymer), whereas increasing the injected-polymer viscosity from 10 to 100 cp increased oil recovery from 0.30 to 0.54 (for fractional fracture length of 0.3). The benefit from increasing polymer viscosity is greater for Fig. 17: Increasing the fracture length from 0 to 30% (of the total distance) decreased oil recovery from 0.63 to 0.53 (with 100 cp polymer), whereas increasing the injected-polymer viscosity from 10 to 100 cp increased oil recovery from 0.16 to 0.54 (for fractional fracture length of 0.3).

For a polymer flood in the Matzen field in Austria, Zechner et al. (2015) simulated that vertical fractures only extended 43 ft from the injection well, whereas well spacing was 650–1,000 ft.

Note the findings of Lee et al. (2011), which stated that sweep could be compromised if a fracture grows in one layer but not in adjacent oil-bearing layers. However, one must question how often this situation actually occurs for polymer floods in high-permeability unconsolidated formations.

Distinguishing Between Channeling Through a Fracture vs. Viscous Fingering. An important dilemma exists. If excessive fracture extension causes severe channeling, injected-polymer viscosities and/or rates should be reduced. In contrast, if channeling through fractures is not a problem but viscous fingering compromises sweep efficiency, injected-polymer viscosities should be increased. When early polymer breakthrough occurs, how can we distinguish whether fractures or viscous fingers are primarily responsible? Kurina (2014) examined this issue and found that fluid-transit time through fractures is typically at least one order of magnitude faster than transit through a viscous finger. To

appreciate this fact, consider a 1-mm-wide, 30-ft-high vertical fracture that leads between an injector and a producer that are 500 ft apart. With a 50-cp tracer and 500-psi pressure drop, the tracer should transit the fracture in approximately 1 hour [see spreadsheet at <http://baervan.mmt.edu/groups/res-sweep> (Seright 2008)]. The volume of this fracture is only 8.8 bbl. In contrast, consider a “viscous finger” that is effectively a pipe-shaped sand body that is 1 ft in diameter and 500 ft long, with a permeability of 10 darcies, a porosity of 0.3, and an S_{or} of 0.3. This “viscous finger” has an aqueous PV of 14.7 bbl. With the same imposed pressure drop of 500 psi, the 50-cp tracer-transit time would be 83 days. In other words, flow through fractures happens much faster than flow through porous sand (as in the viscous finger). If a fracture extends partway from an injector toward a producer, a tracer will transit rapidly through the fracture and transit through the porous sand or rock in proportion to its length. Therefore, in the example discussed previously, if a fracture extended 250 ft, followed by a 250-ft-long “viscous finger,” the tracer-transit time would still be 41.5 days (i.e., substantially longer than if the fracture extended the entire distance from the injector to the producer).

If an interwell-tracer study is performed before polymer injection has started, fractures may not be open or may not extend very far. The length of a fracture may depend on how long polymer has been injected. Consequently, a diagnostic interwell tracer study may be desirable at one or more intermediate times during a polymer flood. During these studies, the tracer formulation must have the same viscosity as the most recently injected polymer solution. If a low-viscosity tracer solution is injected, it may finger unreasonably rapidly through high-permeability paths.

Should Polymer Solutions Be More Viscous Than the Base-Case Design?

To this point, consideration was given primarily to arguments advocating use of polymer solutions that are less viscous than our base-case design. Now, consider arguments advocating use of more-viscous polymer solutions than the base-case design. These arguments stem from a belief that viscous solutions of very-high- M_w HPAMs will drive the residual oil saturation to less than the level that can be achieved during a waterflood or a conventional polymer flood. Views differ on what causes this phenomenon and whether it truly occurs.

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 (Taber 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).

However, for conditions associated with the Daqing reservoir, researchers (Wang et al. 2000, 2001a, 2001b; Xia et al. 2004; Wu et al. 2007; Wang et al. 2010, 2011) argued that HPAM solutions reduced S_{or} by 6–15% in saturation, even with waterfloods and polymer floods conducted at the same constant capillary number. Notably, Wu et al. (2007) observed that HPAM polymers reduced the waterflood S_{or} by up to 15% in saturation (i.e., a S_{or} of 36.8% with waterflooding vs. 21.75% for polymer flooding) by use of a constant capillary number of 5×10^{-5} . The Daqing researchers observed reductions in S_{or} under oil-wet, weakly oil-wet, and mixed-wet conditions. They attributed the reduction in oil saturation to the viscoelasticity of high- M_w HPAM solutions—particularly associated with a polymer solution’s normal stress difference. They did not observe the effect with Newtonian glycerin solutions. Ironically, the Daqing researchers reported reductions in S_{or} to approximately the same extent at low velocities in porous media as at high velocities (Wu et al. 2007; Wang et al. 2010). This result seems inconsistent with their proposed explanation, because viscoelasticity and normal stress differences vanish at low velocities. Conceivably, wettability alteration by HPAM may be partly responsible for this effect.

Wang et al. (2011) reported injecting 150- to 300-cp HPAM solutions (HPAM M_w : 20–35 million g/mol) into more than 5,600

wells to displace 9-cp oil from 500- to 800-md rock. They report incremental oil recoveries of approximately 20% original oil in place, double that for their conventional polymer flood (by use of 40- to 50-cp polymer) and approximately the same recovery as for alkaline/surfactant/polymer flooding.

Others have reported reductions in S_{or} during polymer flooding in cores that were not water-wet. Schneider and Owens (1982) found that HPAM floods resulted in 1–6% reductions in S_{or} in Berea that was treated with diesel oil to make the core oil-wet. They found that HPAM floods caused 6.5–8.4% reductions in S_{or} in Tensleep and Berea cores that were treated with Surfasil to induce oil-wettability.

Interestingly, reports also exist where polymer floods reportedly reduced S_{or} in water-wet cores. Zaitoun and Kohler (1987, 1988) observed that a nonionic polyacrylamide reduced S_{or} by 3% in water-wet Berea and Vosges sandstones. In Bentheim sandstone, Pusch et al. (1987) reported 1–4% reductions in S_{or} with xanthan and a Newtonian viscous sugar solution. These observations may have been within experimental error of the S_{or} determinations.

Huh and Pope (2008) performed studies in water-wet Berea and Antolini sandstone cores. Their work indicated that HPAM solutions would not significantly reduce S_{or} in a homogeneous water-wet core that had previously been waterflooded to residual oil saturation. However, they also noted that when polymer flooding was in a secondary-recovery mode (i.e., when the core had a high oil saturation at the start of the polymer flood), the S_{or} reached was notably less than for a waterflood. This effect was attributed to the ability of the polymer to maintain longer oil ganglia and more effective pore drainage before snapoff and trapping of residual oil.

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. Huh and Pope (2008) envisioned a second means by which a polymer flood could reduce S_{or} from a heterogeneous core: a case where high-permeability pathways have been effectively flushed with water at the start of polymer injection, but the mobile oil saturation remains high in less-permeable pathways. In the high-permeability pathways, the final S_{or} from polymer flooding would be no different from that for the waterflood. However, in the less-permeable pathways, polymer flooding could drive the S_{or} to a lower value by means of the same mechanism mentioned at the end of the preceding paragraph. During polymer flooding, Huh and Pope (2008) observed S_{or} reductions (relative to waterflooding) ranging from 2 to 22% in saturation by use of heterogeneous Antolini cores and a constant capillary number of 4×10^{-6} .

Seright (2011) observed that injection of a 10-cp HPAM solution (at a fixed capillary number of 1.77×10^{-5}) to displace 190-cp crude from a hydrophobic core reduced S_{or} by 4–6% in saturation, compared with waterflooding. In contrast, Vermolen et al. (2014) observed no significant reduction in S_{or} when polymer flooding a 300-cp oil, but saw noticeable S_{or} reductions when polymer flooding with high- M_w HPAMs to displace a 9-cp oil.

Clarke et al. (2015) presented evidence that reductions in S_{or} by polymer flooding are associated with “elastic turbulence” exhibited by high- M_w HPAM polymers. These phenomena occur during the shear thickening or flow thickening observed by HPAM polymer solutions at moderate-to-high velocities in porous media (where resistance factor increases with increased fluid velocity).

Most investigators (Urbissinova et al. 2010; Wang et al. 2010; Vermolen et al. 2014; Clarke et al. 2015) tie reductions in S_{or} to the viscoelastic character of high- M_w polymer solutions. If this view is accepted, polymer reduction of S_{or} should only occur at relatively high velocities. Note in Fig. 14 that the viscoelastic behavior only becomes evident at greater than 10 ft/D for 18- to 20-million-g/mol HPAM in a 5,120-md core. The onset of viscoelastic behavior occurs at lower velocities for less-permeable cores and higher- M_w polymers (Seright et al. 2011; Vermolen

et al. 2014; Clarke et al. 2015). Concern is raised whether significant reductions in S_{or} can be expected at the very-low velocities present deep in the reservoir where the majority of the oil exists. As an unexplained exception, significant reductions in S_{or} were reported at low velocities associated with the Daqing field (Fig. 21 of Wang et al. 2010, 2011). In view of the state of the art for this area, extensive experimentation is needed to demonstrate whether viscous- and high- M_w -polymer solutions can provide a significant reduction in S_{or} for a given field application.

When Should Polymer Injection Be Reduced or Stopped?

This question is predominantly an economic issue. However, before addressing economics, some technical misconceptions and issues should be discussed.

Technical Considerations. As mentioned previously, some authors reported that polymers exhibit substantial residual resistance factors (permeability reduction values). If these values were valid, they could significantly reduce the polymer concentration and volume needed for a flood. Unfortunately, these high residual resistance factors were often an experimental artifact that resulted either from not injecting sufficient water to displace the polymer during corefloods and/or from the use of short cores with no internal pressure taps. The reader should be suspicious of residual resistance factors greater than two unless the rock permeability is less than 200 md or the polymer M_w is extraordinarily high. A conservative approach to polymer-flood design would assume that the residual resistance factor is one (Seright 2010).

Another invalid concept is that a small bank of viscous-polymer solution can be pushed intact through a reservoir by a water post-flush. Some have advocated that as the viscous-polymer solution propagates intact through a high-permeability layer, the water post-flush will be forced into adjacent low-permeability layers, where it will displace oil (Needham and Doe 1987; Chang et al. 2006). This concept is not correct. In cases where fluids can cross-flow between layers, a water post-flush will preferentially finger through the polymer bank in the most-permeable layer (Cyr et al. 1988; Sorbie and Seright 1992; Seright et al. 2012). This fact can be appreciated by viewing the videos mentioned in the discussion between Figs. 1 and 2. These videos clearly show that water will break through the polymer bank in the high-permeability layer before water has a chance to displace much fluid from less-permeable layers. For cases where fluids cannot crossflow between layers, Seright (1991b) demonstrated (both theoretically and experimentally) that a water post-flush breaks through the polymer bank in all open layers at approximately the same time. Consequently, sweep efficiency cannot be expected to be maintained or improved during water injection after a polymer bank.

Polymer retention plays a critical role in deciding the size of the polymer bank. The viscous-polymer solution must penetrate deep into the reservoir to displace the oil. If polymer retention is less than 30 $\mu\text{g/g}$ and polymer concentration is moderate to high (>1,000 ppm), polymer retention does not greatly delay movement of the polymer bank. However, if polymer retention is greater than 100 $\mu\text{g/g}$ and especially if polymer concentrations are low, multiple PVs of polymer solution may be needed to flood the reservoir (Manichand and Seright 2014).

Economic Considerations. If the previously discussed technical considerations are incorporated properly, the decision when to stop polymer flooding is largely an economic issue. Most field-case histories of polymer flooding report the overall economic aspects of their project. In this paper, our concern with economics is focused on whether it limits either the polymer concentration used or the volume of the polymer bank. When the cost of injecting the polymer solution exceeds the value of the produced oil, polymer injection is stopped. Of course, this time will depend greatly on oil price, polymer cost, and many individual factors associated with a given field. Therefore, a “one-size-fits-all” formula cannot be expected for the optimum bank size.

Many authors pointed out that well spacing can greatly affect the timing and economics of a polymer flood. The increased rate of recovery and improved sweep efficiency gained from smaller well spacing must be balanced against the cost of infill wells (Wassmuth et al. 2007; Wang et al. 2008b, 2009). At Daqing, Wang et al. (2008b) reported optimum polymer-injection rates of 0.14–0.16 PV/yr for 250-m spacing and 0.16–0.20 PV/yr for 150- to 175-m well spacing.

The few papers that focus on when to stop polymer injection are associated with the Daqing polymer flood. Wang et al. (2008b, 2009) may provide the most-extensive discussion, reporting that polymer injection was switched to water cut when the water cut reached 92–94%. For many of the newer polymer floods, operators are just now faced with the decision of when to stop polymer injection, especially in view of low oil prices.

If the achievable injection rate is governed dominantly by polymer viscosity, the total fluid-production rate will be slowed by polymer injection (given a fixed pressure drop across the system). An economic optimum will occur if the increased fractional flow of oil from polymer flooding must be balanced against a reduced total fluid-production rate (Seright 2010). However, as mentioned earlier, fracture extension can mitigate or eliminate injectivity losses under the proper circumstances. If fractures are not taken into consideration during simulations of polymer flooding, a substantial pressure drop is typically predicted in the injection gridblock, which predicts a false (low) “economic optimum” polymer concentration (Moe Soe Let et al. 2012). Care must be exercised during simulations to avoid this effect if polymer solutions are injected at greater than the formation-parting pressure.

Should Polymer Banks Be Graded at the End of Polymer Injection? During water injection after polymer in the experiments with 11.2:1 permeability contrast (i.e., those shown in Fig. 2), injected water formed viscous fingers that broke through in the high-permeability layer after advancing the polymer front by 70% when the polymer-bank viscosity was 8 cp, by 40% when the polymer-bank viscosity was 23 cp, and by 25% when the polymer-bank viscosity was 75 cp.

In contrast to the laboratory experiments, water breakthrough appears more rapidly in field applications. At Daqing, after injecting approximately 1 PV of 40-cp polymer solution (well spacing of 250 m), water cuts typically stabilized at approximately 90%.^{*} When injection was switched from polymer to water at Daqing, water breakthrough was first noted after approximately 0.02 PV (by the first increase in water cut). During continued water injection, the water cut rose and stabilized at 96–98% after 0.23 PV of water.^{*}

At the Mangala polymer-flood pilot in India, the main polymer-bank concentration was 2,000–2,500 ppm of HPAM. After the polymer concentration was reduced to 1,700–1,800 ppm of HPAM, injection profiles gradually deteriorated (Prasad et al. 2014).

To mitigate viscous fingering near the end of a polymer flood, Claridge (1978) and Stoneberger and Claridge (1988) developed methods for grading polymer viscosities. They recognized that their grading method was most appropriate for application in homogeneous reservoirs, and that viscous fingering is most severe when heterogeneity exists. Cyr et al. (1988) argued that grading schemes would not be of practical benefit for polymer flooding and that once polymer concentrations were reduced or polymer injection was stopped, the polymer flood would effectively be finished. Several of the field polymer floods used (or plan) graded polymer banks (Table 1). 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.

Strategies When Oil Prices Fall

In view of the precipitous drop in oil prices from 2014 to 2015, operators of existing polymer floods wonder how they

^{*} Personal communication with P. Han. 2015. PetroChina Daqing Oilfield Company Limited, 8–17 July.

should proceed. Should these projects be switched to water injection immediately? Should the polymer concentration be reduced or graded? Should the polymer concentration stay the same but reduce the injection rate? Of course, the answer will depend partly on whether the flood is profitable at the current oil price.

Consider the Daqing case mentioned previously, where injection of 1,000–1,300 ppm of HPAM resulted in a stabilized water cut of approximately 90%, whereas subsequent water injection resulted in a stabilized water cut of approximately 97%. Assuming USD 1.50/lbm for HPAM cost, the chemical cost of polymer injection was USD 0.52–USD 0.68/bbl. Assuming USD 100/bbl for oil price, the value of the produced fluid was USD 10/bbl when the water cut was 90% (i.e., during polymer injection) vs. USD 3/bbl when the water cut was 97%. Assuming USD 40/bbl for oil price, the value of the produced fluid was USD 4/bbl when the water cut was 90% (i.e., during polymer injection) vs. USD 1.20/bbl when the water cut was 97%. With either oil price, continued polymer injection is preferred over water injection (assuming other operational costs associated with polymer injection are not prohibitive).

If the voidage replacement ratio is unity, reducing the injection rate is not likely to improve the economics for the scenarios mentioned previously. However, the voidage replacement ratio for several recent polymer floods was noticeably greater than unity, and values of two have been observed. In searching for the reason why these projects had high voidage replacement ratios, dilation of the reservoir was suggested during polymer injection. Compaction and dilation are uncommon phenomena in the experience of most reservoir engineers. However, recent polymer floods in unconsolidated reservoirs appear to have an unusually compressible nature. For example, for the Tambaredjo field in Suriname, 20% of original oil in place was produced during primary production, dominantly by means of compaction (Moe Soe Let et al. 2012). During polymer injection after primary production, compaction is reversed; i.e., the reservoir is actually dilated, average porosity increases, and the voidage replacement ratio can be significantly greater than unity. During times of low oil prices, there may be value in reducing or stopping injection and allowing compaction to again become the dominant drive mechanism.

As noted previously (Seright 2010), polymer flooding is probably the most-forgiving enhanced-oil-recovery process. So many actions that may be taken during times of low oil price do not have a permanent detrimental effect that cannot be reversed when the economic outlook improves.

Conclusions

1. For applications involving viscous oils (e.g., 1,000 cp), the designed polymer viscosities have sometimes been underestimated because of insufficient water injection while determining relative permeabilities; reliance on mobility ratios at a calculated shock front; and overestimation of polymer resistance factors and residual resistance factors.
2. In homogeneous reservoirs, the ratio of produced-oil value to injected-fluid cost is fairly insensitive to injected-polymer viscosity (up to the viscosity predicted by a base-case method), especially at low oil prices. However, reservoir heterogeneity and economics of scale associated with the polymer-dissolution equipment favor high polymer viscosities over low polymer viscosities, if injectivity is not limiting.
3. Injection greater than the formation-parting pressure and fracture extension are crucial to achieving acceptable injectivity for many polymer floods, especially those by use of vertical injectors. Under the proper circumstances, this process can increase fluid injectivity, oil productivity, and reservoir-sweep efficiency, and also reduce the risk of mechanical degradation for polyacrylamide solutions. The key is to understand the degree of fracture extension for a given set of injection conditions so that fractures do not extend out of the target zone or cause severe channeling.

4. Many field cases exist with no evidence that fractures caused severe polymer channeling or breaching of the reservoir seals, in spite of injection greater than the formation-parting pressure.
5. Although at least one case exists (Daqing) where injection of very-viscous-polymer solutions (i.e., more viscous than the base-case design) reduced S_{or} to less than that for waterflooding, our understanding of when and how this occurs is in its infancy. At this point, use of polymers to reduce S_{or} must be investigated experimentally on a case-by-case basis.
6. A “one-size-fits-all” formula cannot be expected for the optimum bank size. However, experience and technical considerations favor the use of the largest practical polymer bank. 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.

Nomenclature

- C_{poly} = polymer concentration, ppm, g/cm³
 F_r = resistance factor (water mobility/polymer solution mobility)
 F_{rr} = residual resistance factor (water mobility before polymer/water mobility after polymer)
 F_{r1} = resistance factor in Layer 1 (high-permeability layer)
 F_{r2} = resistance factor in Layer 2 (low-permeability layer)
 h = formation height, ft, m
 h_1 = height of Layer 1, ft, m
 h_2 = height of Layer 2, ft, m
 $IAPV$ = inaccessible PV
 k = permeability, darcies, μm^2
 k_{cont} = permeability contrast (high-permeability/low-permeability)
 k_{ro} = relative permeability to oil
 k_{roo} = endpoint relative permeability to oil
 k_{rw} = relative permeability to water
 k_{rwo} = endpoint relative permeability to water
 k_1 = permeability of Layer 1, darcies, μm^2
 k_2 = permeability of Layer 2, darcies, μm^2
 L = linear distance, ft, m
 L_{p1} = linear distance of polymer penetration into the high-permeability layer, ft, m
 L_{p2} = linear distance of polymer penetration into the low-permeability layer, ft, m
 M = mobility ratio (water mobility/oil mobility)
 M_w = molecular weight, daltons, g/mol
 n = power-law exponent
 no = oil-saturation exponent
 nw = water-saturation exponent
 PV = PVs of fluid injected
 PV_{ret} = PV delay per PV injected
 S_{or} = residual oil saturation
 S_w = water saturation
 S_{wr} = residual water saturation
 u = flux, ft/D, m/d
 v_1 = front velocity in Layer 1, ft/D, m/d
 v_2 = front velocity in Layer 2, ft/D, m/d
 Δp = pressure difference, psi, Pa
 ΔPV = PVs difference
 μ = viscosity, cp, mPa·s
 μ_o = oil viscosity, cp, mPa·s
 μ_{poly} = polymer-solution viscosity, cp, mPa·s
 ϕ = porosity
 ϕ_1 = porosity in Layer 1
 ϕ_2 = porosity in Layer 2

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SI Metric-Conversion Factors

cp × 1.0*	E–03 = Pa·s
ft × 3.048*	E–01 = m
in. × 2.54*	E+00 = cm
md × 9.869 233	E–04 = μm ²
psi × 6.894 757	E+00 = kPa

*Conversion factor is exact.

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