Use of Preformed Gels for Conformance Control in Fractured Systems

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Summary

Using wide ranges of gel age, gel velocity, and fracture conductivity or tube diameter, Cr(III)-acetate-HPAM gels were studied as they extruded through fractures and tubes. Gels exhibited shear-thinning behavior in fractures and tubes that correlated with the gel superficial velocity and the fracture width or tube diameter. In fractures with sufficiently small widths, gels dehydrated during extrusion, thus reducing the rate of gel propagation. This effect was more pronounced as the fracture width decreased. Using the experimental results, a numerical study was conducted to compare placement of preformed gels and water-like gelants.

Introduction

Gels often have been used to reduce fluid channeling in reservoirs.[1] The objective of these gel treatments is to reduce flow substantially through high-permeability channels without damaging hydrocarbon-productive zones. The most successful applications for this purpose have occurred when treating linear flow problems—either fractures[2-4] or flow behind pipe.[5,6] In fractured reservoirs, some of the most successful treatments used relatively large volumes (e.g., 10,000 to 37,000 bbl/well) of Cr(III)-acetate-HPAM gel.[2,4] In these applications, the gel injection times were substantially longer than the gelation time (e.g., by factors ranging from 10 to 100). Because these gels (after gelation) do not flow through porous rock,[7] they must extrude through fractures during the placement process. Therefore, we wonder how the properties of preformed gels compare with those of gelants during placement in fractured reservoirs.

The term "preformed gel" refers to any gel state that does not flow into or through porous rock—whether it is a rigid gel, a "weak" elastic gel, or a dispersion of gel aggregates. For example, a freshly prepared polymer solution with a crosslinker may flow readily through porous rock until gel aggregates grow to become trapped in pore throats. Thereafter, the crosslinked polymer (the preformed gel) does not flow through porous rock at a significant rate. (Of course, preformed gels may extrude through fractures.)

In this paper, we first discuss idealized placement locations for gels in fractures. Second, we review the properties of gels in fractures. Third, results of new experiments are reported that characterize how gel extrusion through fractures and tubes is affected by gel age, gel velocity, and fracture or tube conductivity. Finally, results from our experiments are used during a modeling study to compare the placement of preformed gels with that of gelants with a water-like viscosity.

Desired Placement Locations

Fig. 1 shows idealized placement locations for gels in fractures. First, consider a production well where water channels through a fracture. In the ideal gel placement, the fracture is plugged far from the wellbore, but the fracture remains open near the well (upper left part of Fig. 1). Then, water channeling can be reduced while maintaining a high productivity for the well. If the gel plugs the near-wellbore portion of the fracture (lower left part of Fig. 1), water channeling may be reduced, but the well productivity could be lowered to an unacceptable value.

In vertical fractures that cut through multiple zones, we might want to exploit gravity and density differences to place gel in the lower part of a fracture, thereby reducing water influx from the lower zones while leaving the upper part of the fracture open to oil flow (center part of Fig. 1). In contrast, gel placement in the upper part of the fracture could be detrimental.

The amount of gelant that leaks off from a fracture face is also important (right side of Fig. 1). Ideally, the distance of gelant leakoff from the fracture face should be very small. If the leakoff distance is too great, the near-wellbore region could be plugged, and the gel treatment could do more harm than good. A basic principle of fluid displacement in porous media is that the efficiency of the displacement increases with increasing viscosity of the injected fluid.[8] This principle suggests that, other factors being equal in a fractured system, the distance of gelant leakoff will be greater for a high-viscosity gelant than for a low-viscosity gelant. For gel treatments, this principle presents a potential problem for viscous gelants—too much gelant may leak off from the fracture into the formation rock. Leakoff associated with the use of viscous gelants could compromise the effectiveness of a treatment unless it is controlled.

Review of Gel Behavior in Fractures

In concept, leakoff could be minimized by injecting preformed gels instead of gelants. In our previous work,[7,9] we investigated the properties in fractures for several 1-day-old gels, including Cr(III)-acetate-HPAM, Cr(III)-xanthan, resorcinol-formaldehyde, Cr(VI)-HPAM/AMPS, Cr(III)-acetate-HPAM/AMPS, Al-citrate-HPAM, and hydroquinone-hexamethylenetetramine-HPAM. We focused on the Cr(III)-acetate-HPAM gel. Tracer studies performed before and after gel placement revealed that this gel can heal fractures effectively with minimum damage to the porous rock. During brine injection after gel placement, preformed gels were more resistant to washout than gels formed in situ from gelants. However, high-resistance factors (apparent viscosities) and pressure gradients often were observed during injection of preformed gels. For fractures with conductivities ranging from 0.33 to 6.4 darcy-ft (average fracture widths ranging from 0.0042 to 0.011 in.), pressure gradients ranged from 40 to 300 psi/ft during gel injection.[7] (Incidentally, fracture conductivity is the product of fracture width and fracture "permeability.") These high-pressure gradients raised concern about our ability to place preformed gels deep in fractured systems. However, the fractures used in our experiments had relatively low conductivities, so perhaps pressure gradients would not be prohibitively high during gel extrusion through more conductive fractures.

Preformed gels showed an apparent shear-thinning behavior during extrusion through fractures—gel resistance factors decreased with increased flow rate.[7] At high flow rates, the pressure gradient was almost independent of gel injection rate.[7] For example, in a fracture with a conductivity of 6.2 darcy-ft, the pressure gradient increased from 60 to 75 psi/ft as the injection rate increased from 2.4 to 24 in.^{3}/hr. This behavior suggests that the gel experienced "slip" when extruding through fractures at high rates.

In contrast to the shear-thinning behavior observed during gel extrusion through fractures, flow-rate-independent behavior was usually seen during brine or oil injection after placement of preformed gels in fractures.[7,10] This behavior was expected. If the gel effectively plugs the fracture without damaging the porous rock, then normal Newtonian flow of oil and water occurs in the porous rock.

Most of our previous experiments used 1-day-old gels in 6-in. fractured cores that had low fracture conductivities. Therefore, a number of important questions remain to be answered for flow of preformed gels in fractures. First, how do gel resistance factors and pressure gradients vary with fracture conductivity or width? Second, how do gel properties vary with fracture length? Third, how does the age of the gel (i.e., gel curing time) affect the flow of pre-

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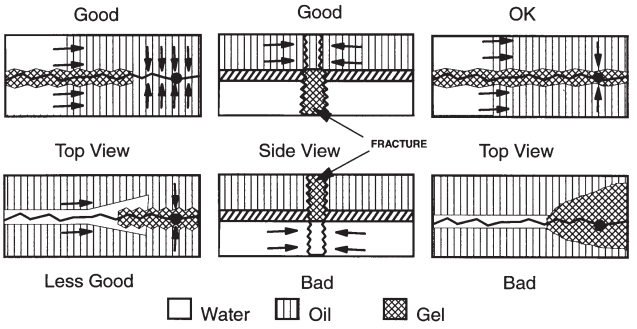

Fig. 1—Idealized placement locations for gels in fractures.

formed gels in fractures? Finally, given the flow properties of preformed gels in fractures, how do their placement characteristics compare to those for gelants that form gels in situ? These questions are addressed in this paper.

Experimental Procedure and Results

Cores Used. To answer the previous questions, we performed experiments using fractured Berea sandstone cores. Before fracturing, the cores had a nominal permeability to brine of 650 md. Two core lengths were used. One set of cores was about 6 in. in length and 1.4 in. in diameter. These cores were fractured lengthwise, and the two halves of the core were repositioned and cast in epoxy. Two internal pressure taps were drilled 1 in. from the inlet sandface. One tap was located 90° from the fracture to measure pressure in the porous rock, while the other tap was drilled to measure pressure in the fracture. The second set of cores was 3.8 to 4.0 ft in length and 1.5 in. in height and width. Again, these cores were fractured lengthwise, and the two halves of the core were repositioned and cast in epoxy. Four internal pressure taps were spaced equally along the length of the fracture (i.e., to measure pressure in the fracture). During our corefloods, the fractures were always oriented vertically. All experiments described in this paper were performed at 105°F (41°C).

Gel Used. All experiments described in this paper used a Cr(III)-acetate-HPAM gel. This gel contained 0.5% HPAM (Allied Colloids Alcoflood 935®, Mw $\approx 5 \times 10^6$ daltons, degree of hydrolysis: 5-10%), 0.0417% chromium triacetate, and 1% NaCl at pH 6. The gelation time for this formulation was about 5 hours at 105°F.

Effect of Fracture Conductivity and Width. How does the ability of a given gel to extrude through a fracture vary with fracture conductivity or width? For a Cr(III)-acetate-HPAM gel (composition given above) that was aged 24 hours before injection, **Fig. 2** plots pressure gradient in the fracture vs. fracture conductivity and width for 23 experiments where preformed gels were forced through fractures that were typically 6 in. in length. Fracture conductivities ranged from 1.5 to 700 darcy-ft. Estimated fracture "permeabilities" ranged from 2,600 to 152,000 darcys.[10] Effective average fracture widths ranged from 0.0067 to 0.054 in. Fracture widths were estimated using Eq. 1, which was based on Refs. 10 and 12.

$$w_f = 5.03 \times 10^{-4} (k_f w_f)^{1/3}, \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (1)$$

where w_f is fracture width in feet and fracture conductivity ($k_f w_f$) is in darcy-ft. In these experiments, the injection rate was constant at 12.2 in.^{3}/hr (200 mL/hr), and at least 50 fracture volumes of gel were injected during the pressure measurements. Pressure gradients were inversely proportional to fracture conductivity, varying from 11 to 250 psi/ft for the range of fracture conductivities and widths shown in Fig. 2.

Effect of Superficial Velocity. As already mentioned, the data shown in Fig. 2 were collected using a single volumetric injection rate. **Fig. 3** plots gel resistance factor vs. superficial velocity in fractures and tubes for a large number of experiments. Fig. 3 includes all data shown in Fig. 2 plus results from other experiments where

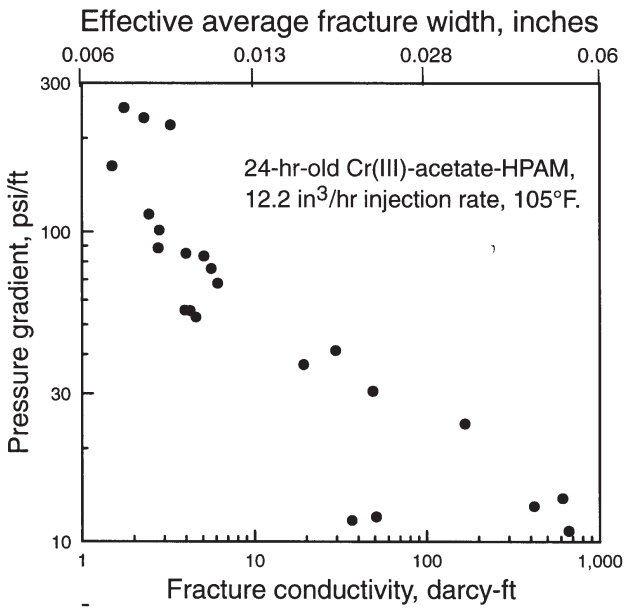

Fig. 2—Pressure gradient vs. fracture conductivity and width.

velocity was varied during gel extrusion through fractures.[7,9,10] The open circles apply to fractures with effective average widths less than 0.035 in., while the open diamonds represent fractures that were wider than 0.035 in.

We also forced preformed gels (same composition and age as that mentioned above) through tubes of various diameters. The inside diameters of these tubes were 0.009, 0.03, 0.04, 0.079, 0.245, and 0.325 in. Except for the 0.03- and 0.325-in. tubes (which were 15 ft in length), our tubes were 3 ft long. Details from these extrusion experiments can be found in Refs. 11 and 13. The solid circles in Fig. 3 show the data for the 0.009- and 0.03-in. tubes, while the small squares apply for tube diameters ranging from 0.04 to 0.325 in.

Fig. 3 shows that the fracture data were in reasonable agreement with the tube data. For tubes with diameters less than 0.035 in. or fractures with estimated widths less than 0.035 in., the resistance factors, F_r, were described fairly well using Eq. 2,

$$F_r = 2 \times 10^6 \, u^{-0.83} \text{ if } w_f < 0.035 \text{ in.}, \quad \ldots\ldots\ldots\ldots\ldots\ldots (2)$$

where u is the superficial velocity in ft/d. The solid line in Fig. 3 illustrates Eq. 2.

For tubes with diameters greater than 0.035 in. (and presumably, for fractures with widths greater than 0.035 in.), the resistance factors were described using Eq. 3.

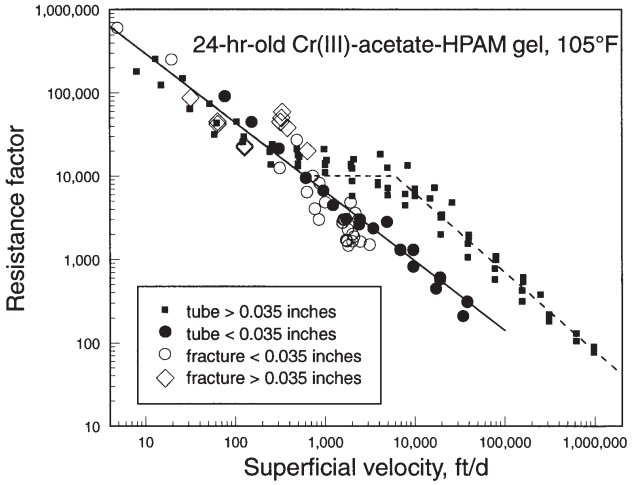

Fig. 3—Comparison of resistance factors in fractures vs. in tubes.

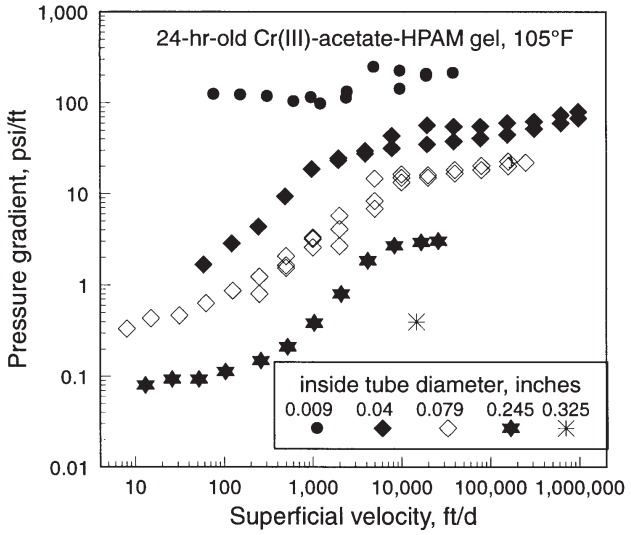

Fig. 4—Pressure gradient vs. velocity for gel in tubes.

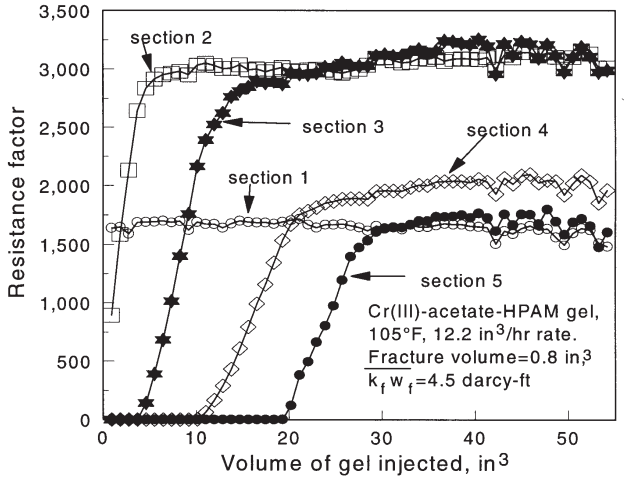

Fig. 5—Resistance factor vs. volume of gel injected in a fractured core (3.8-ft long).

$$F_r = 2 \times 10^6\, u^{-0.83} \text{ if } u \le 600 \text{ ft/d},$$

$$F_r = 10{,}000 \text{ if } 600 < u < 6{,}200 \text{ ft/d},$$

$$F_r = 4 \times 10^7\, u^{-0.95} \text{ if } u \ge 6{,}200 \text{ ft/d}. \quad \ldots\ldots\ldots\ldots\ldots\ldots (3)$$

The dashed curve in Fig. 3 illustrates Eq. 3 for velocities above 600 ft/d. Below 600 ft/d, Eq. 3 predicts the same values as Eq. 2. Fig. 3 and Eqs. 2 and 3 provide a useful means to estimate gel extrusion behavior over a broad range of superficial velocities and opening sizes. When coupled with the Darcy equation, Eqs. 2 and 3 can show the relationship between resistance factors, pressure gradients, superficial velocities, and fracture width. Thus, these equations were used in our modeling study (described later).

Using some of the tube data from Fig. 3, **Fig. 4** plots pressure gradients vs. superficial velocities. For most of the tubes, the pressure gradient increased noticeably with increased superficial velocity until reaching a velocity of about 6,000 ft/d. Above 6,000 ft/d, increased velocity had a much less significant effect on the pressure gradient. This behavior suggests that gel "slip" became important above 6,000 ft/d (i.e., instead of laminar flow, the gel extruded through the tube as a plug, while an apparent discontinuity occurred in the velocity profile at or near the gel-tube interface). Our observations at high flow rates were consistent with our previous results for gel extrusion through fractures. As mentioned earlier, at high flow rates in fractures, the pressure gradient was almost independent of gel injection rate.[7]

At a given velocity in the tubes, the pressure gradient decreased significantly with increased tube diameter. For example, around 20,000 ft/d, the pressure gradients were 208, 57, 16, 3, and 0.4 psi/ft for tube diameters of 0.009, 0.04, 0.079, 0.245, and 0.325 in., respectively. Except for the 0.009-in. tube, pressure gradients appeared to stabilize at lower values when low superficial velocities were applied. In fact, Fig. 4 suggests that some threshold pressure gradient may be needed before the gel will move through a given opening size. This point could be quite important during field applications because pressure gradients in reservoirs are usually quite low—e.g., less than 1 psi/ft. If a 1-psi/ft pressure-gradient constraint is applied, Fig. 4 suggests that the gel may not be extrudable through opening sizes of 0.009-in. or less. For other opening sizes, the minimum allowable pressure gradient can be estimated using Eqs. 2 and 3. We will continue to examine this point during ongoing experimental studies.

Gel Resistance Factors in Longer Fractures. Most of our previous experiments used fractured cores that were fairly short (6 in.). Of course, we are interested in assessing gel propagation through longer fractures. We performed an experiment using a fractured Berea sandstone core that was 3.8 ft in length and 2.25 in.^{2} in cross-section (square). Four internal pressure taps were spaced equally along the length of the fracture. The conductivities of the five 9-in. fracture sections of the core were 4.2, 5.1, 5.6, 2.8, and 4.6 darcy-ft. A tracer study performed before gel injection indicated that the volume associated with the fracture was about 0.8 in.^{3} (13 cm^3). For comparison, the total core pore volume was 22.9 in.^{3} (375 cm^3).

Using a 24-hour-old Cr(III)-acetate-HPAM gel with the same composition as that mentioned earlier, we forced 53.7 in.^{3} (67 fracture volumes) of gel through the fractured core at a rate of 12.2 in.^{3}/hr. **Fig. 5** shows resistance factors in the five core sections as a function of the volume of gel injected. Resistance factors in all core sections were more or less stable after injecting 30 in.^{3} of gel. The magnitude of the stabilized values varied from section to section. In the first and last sections ($k_f w_f = 4.2$ and 4.6 darcy-ft), the stabilized resistance factors averaged 1,700. In the second and third sections ($k_f w_f = 5.1$ and 5.6 darcy-ft), values averaged 3,100. In the fourth section ($k_f w_f = 2.8$ darcy-ft), the stabilized value averaged 2,000. End effects may have been at least partly responsible for the relatively low values observed in the first and last sections.

Interestingly, about 28 in.^{3} (35 fracture volumes) of gel were injected before gel was produced from the core. The relatively slow propagation of the gel through the fracture can be seen from the resistance factor data in Fig. 5. This slow rate of gel propagation suggests that the gel was dehydrated as it extruded through the core—i.e., water from the gel leaked off into the porous rock while the polymer and chromium were left behind in the fracture. This suggestion is consistent with an observation made during a previous experiment[9]—the gel found in a fracture (upon disassembly of the core after the experiment) was significantly more rigid (Sydansk gel code[14] = I) than the gel was before injection (Sydansk gel code = D). Thus, the gel appeared to be concentrated by the extrusion process.

The slow rate of gel propagation through the fracture is consistent with field observations that were reported earlier.[9] In some injection-well treatments, tracer studies were first performed to determine interwell transit times for water. Very rapid transit times were observed, confirming fractures as the cause of the channeling. When a Cr(III)-acetate-HPAM gel was injected, no gel was detected at the offset producers, even though the gel volume was ten times greater than the volume associated with transit of the water tracer between the wells. We note that other factors could also account for the delayed propagation of gels through fractures in field applications.[9] These factors include leakoff of the viscous gelant before gelation, and extrusion of gel into alternate fracture pathways (in naturally fractured systems).

We performed two similar experiments using long fractured cores. These cores were also 3.8 to 4.0 ft in length and 2.25 in.^{2} in cross-section. Four internal pressure taps were spaced equally along the length of the fracture. The average conductivities of these fractures were 568 darcy-ft and 1,860 darcy-ft. Estimated fracture

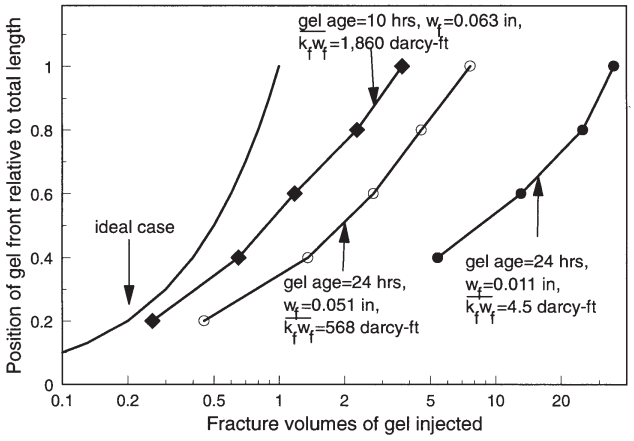

Fig. 6—Gel propagation through fractures (3.8-4.0 ft long).

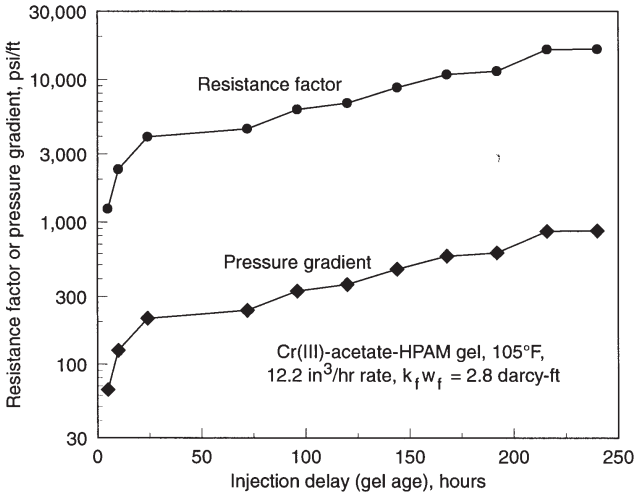

Fig. 7—Effect of gel age on resistance factors and pressure gradients in a fracture.

widths were 0.051 in. and 0.063 in., respectively, and the estimated fracture permeabilities were 133,000 darcys and 360,000 darcys, respectively. Fracture volumes, determined from tracer studies, were 3.5 in.^{3} and 4.5 in.^{3}, respectively. Again, we forced preformed Cr(III)-acetate-HPAM gels through these fractures using a rate of 12.2 in.^{3}/hr. Rates were determined both from ISCO pump settings and by volumetric effluent measurement. The gels were aged at 105°F for either 10 or 24 hours before injection. By observing the effluent from a given core and the pressures along the core, we monitored the gel front in the fracture during gel injection. **Fig. 6** shows the results for experiments in the long fractured cores. The positions of the gel fronts were plotted vs. the fracture volumes of gel injected.

To test our hypothesis that the gels dehydrated during extrusion through the fractures, we monitored the chromium concentration, viscosity, and appearance of the effluent during the above experiments in the 568 and 1,860 darcy-ft fractures. For the 568 darcy-ft fracture, between 7.7 and 8.0 fracture volumes of gel injection, (1) gel was noted in the effluent, (2) the effluent viscosity jumped from 0.7 cp (the viscosity of brine) to a high value, (3) the effluent chromium concentration jumped from 0 to 53% of the injected concentration, and (4) the pressure drop stabilized across the last core section. Similarly, for the 1,860 darcy-ft fracture, between 3.2 and 3.7 fracture volumes of gel injection, (1) gel was noted in the effluent, (2) the effluent viscosity jumped from 0.7 cp to a high value, (3) the effluent chromium concentration jumped from 0 to 120% of the injected concentration, and (4) the pressure drop stabilized across the last core section. Thus, none of the gel components arrived at the core outlets until much more than one fracture volume was injected. These observations are consistent with our contention that the gels dehydrated as they extruded through the fractured cores. We are currently conducting other experiments to understand how and why this phenomenon occurs.[13]

The curve without data points in Fig. 6 shows the ideal case expected if gel propagation was not retarded by gel dehydration or other factors. In other words, the fracture would be completely filled with gel after injecting one fracture volume of gel. For the three corefloods, gel transport was retarded to varying degrees, depending on the fracture conductivity and the age of the gel. The greatest retardation occurred for the 24-hour-old gel in the least conductive fracture (average $k_f w_f = 4.5$ darcy-ft). In that case, 35 fracture volumes were required for the gel to reach the end of the core (solid circles in Fig. 6). An average pressure gradient of 65.4 psi/ft was required to extrude the gel through this fracture. For comparison, a 24-hour-old gel in a fracture with $k_f w_f = 568$ darcy-ft reached the end of the fracture after injecting 7.7 fracture volumes of gel (open circles in Fig. 6). In this case, the average pressure gradient was 10.8 psi/ft during gel injection. For the third coreflood (solid diamonds in Fig. 6), a 10-hour-old gel was extruded through a fracture with $k_f w_f = 1{,}860$ darcy-ft. In this experiment, the gel reached the core outlet after injecting 3.7 fracture volumes of gel, and the average pressure gradient was 9.9 psi/ft.

The results in Fig. 6 indicate that the rate of gel propagation decreased as fracture conductivity decreased. We are actively studying factors that may affect the rate of gel propagation (and, presumably, gel dehydration), including the effects of pressure gradient, velocity, opening size, gel age, and gel composition.[13]

Incidentally, because the previous section revealed that gel rheology in fractures was quite similar to that in tubes, we are investigating the importance of the apparent gel dehydration phenomenon during gel extrusion through tubes.[13] Results to date suggest that in short tubes (less than 15-ft long), the water that separates from the gel can flow more rapidly than the concentrated gel while having a relatively small impact on the resistance to flow. However, in longer tubes, the gel and free water make a dispersion that has substantially less resistance to flow.[13]

Effect of Gel Age on Gel Extrusion. Most of our previous experiments used gels that were aged for 24 hours before injection. Therefore, we were interested in how gel performance varies with the age of the gel (or the gel "curing" time). We performed an experiment where a fractured core (6 in. long) and a single batch of gel were used. The conductivity of the fracture in this core (Core 32) was 2.8 darcy-ft. A large volume of Cr(III)-acetate-HPAM gel (same composition as that used previously) was prepared and placed in a transfer vessel between an ISCO pump and the fractured core. At predetermined times, 3.7 in.^{3} (60 fracture volumes) of this gel were injected into the fractured core using a constant rate of 12.2 in.^{3}/hr. The injection delays (time since the gelant was prepared) ranged from 5 to 240 hours. **Fig. 7** shows the resistance factors and pressure gradients that were observed during the experiment. Resistance factors increased rapidly between 5 and 24 hours after gelant preparation. Thereafter, the resistance factors increased more gradually until a value of 16,240 was reached 240 hours (10 days) after gelant preparation.

Placement of Preformed Gels Vs. Water-Like Gelants

Fracture Model. We now wish to use our experimental results to assess whether preformed gels have placement advantages over gels formed in situ from gelants. We focused on a simple model of a fractured reservoir. Consider an injector-producer pair where Fracture 1 allows injected water to channel directly from the injection well to the production well. For Fracture 1, L_{f1} is the effective length, and the effective permeability is k_1. (Conversions between fracture conductivities, widths, and permeabilities can be made using Eq. 1.) This reservoir also contains a second fracture, Fracture 2, that has a beneficial role in oil recovery. Specifically, Fracture 2 meanders from the injection well to the production well in a way that is much less direct than Fracture 1. Because of its length and orientation, Fracture 2 allows the injected water to be well distributed in the reservoir and allows a high water injectivity (relative to the case where

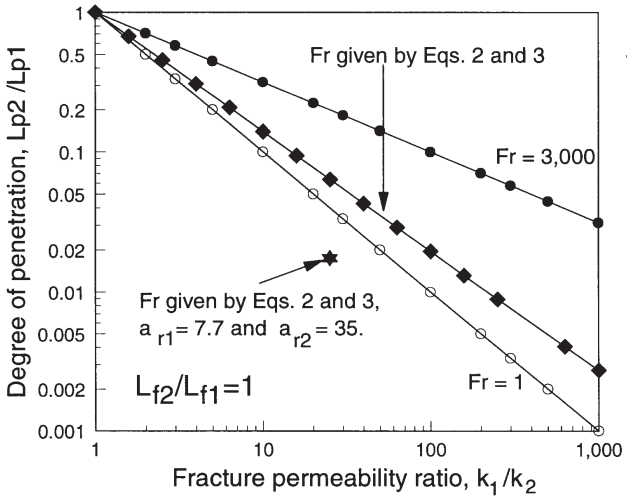

Fig. 8—Degree of penetration vs. fracture permeability ratio.

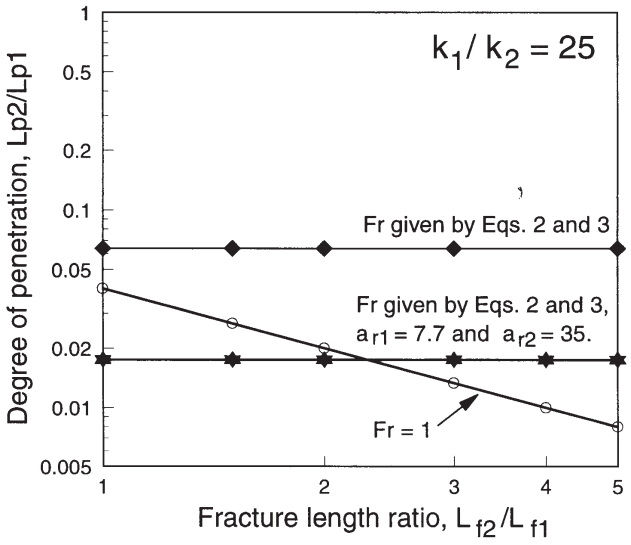

Fig. 9—Degree of penetration vs. fracture length ratio.

no fractures exist). (Of course, Fracture 1 also allows a high water injectivity, but most of that water channels directly to the production well.) Fracture 2 also acts as a conduit for oil flowing to the production well so that a relatively high oil productivity can be maintained. Fracture 2 has an effective length, L_{f2}, and an effective permeability, k_2. Generally, Fracture 2 will be longer and have a lower conductivity (and lower effective fracture permeability) than Fracture 1.

Ideally, a gel treatment will substantially reduce the flow capacity of Fracture 1 while having little or no effect on the flow capacity of Fracture 2. Thus, we wish to maximize penetration of gel into Fracture 1 and minimize gel penetration into Fracture 2. The question is then raised, for a given distance (L_{p1}) of gel penetration into Fracture 1, how far (L_{p2}) will the gel penetrate into Fracture 2? We used the analytical and numerical methods described in Refs. 13 and 15 to answer this question. In these analyses, we assumed that (1) fluids were incompressible, (2) the fractures were initially filled with fluids with water-like viscosities, (3) displacement was miscible and piston-like, (4) dispersion, capillary effects, and gravity effects were negligible, (5) flow of gel in a given fracture was effectively linear, and (6) all factors that can retard gel propagation (such as dehydration, leakoff, adsorption, and mechanical entrapment) were included in a propagation delay factor, a_r. In the base case for our numerical studies, Fracture 1 had an effective length of 500 ft, and a pressure drop of 1,000 psi was applied between the injector and the producer. During sensitivity studies, the following results were insensitive to the length of Fracture 1 (between 50 and 5,000 ft) and to the pressure drop (between 100 and 3,000 psi).

Effects of Differences in Fracture Permeability. In most circumstances, Fracture 1 will be more permeable than Fracture 2. So, how does the degree of gel penetration, L_{p2}/L_{p1}, vary with the fracture permeability ratio? **Fig. 8** answers this question for several cases of gel resistance factor. (In this figure, both fractures were assumed to have the same length.) The curve with the solid circles illustrates the case where the gel resistance factor was fixed at a value of 3,000. In this case, when Fracture 1 was 10 times more permeable than Fracture 2, the gel penetrated 31.6% as far in Fracture 2 as it did in Fracture 1 ($L_{p2}/L_{p1} = 0.316$).

The curve with the solid diamonds in Fig. 6 illustrates a second case, where the gel resistance factors followed the behavior shown in Fig. 3 (described by Eqs. 2 and 3). For these gel resistance factors, Fig. 8 shows significantly lower degrees of penetration than when $F_r = 3{,}000$. When Fracture 1 was 10 times more permeable than Fracture 2, the degree of penetration was 0.140.

The third case illustrated in Fig. 8 involved the use of a gelant with a water-like viscosity, where $F_r = 1$. In that case, when Fracture 1 was 10 times more permeable than Fracture 2, the gel penetrated 10.0% as far in Fracture 2 as it did in Fracture 1 ($L_{p2}/L_{p1} = 0.100$).

In the three cases considered here, the gel propagation delay factor (a_r) was assumed to be the same in Fractures 1 and 2. However, for a given preformed gel, Fig. 6 indicates that the a_r value should decrease with increasing fracture conductivity. In particular, Fig. 6 suggests that the a_r values are 35 and 7.7 when $k_f w_f$ values are 4.5 darcy-ft and 568 darcy-ft, respectively. (In other words, 35 fracture volumes of gel must be injected to fill the 4.5-darcy-ft fracture, while 7.7 fracture volumes of gel must be injected to fill the 568-darcy-ft fracture.) Using Eq. 1, one can determine that a conductivity ratio of 568 to 4.5 translates to a fracture permeability ratio of 25.

We calculated the degree of penetration assuming that (1) gel resistance factors were given by Eqs. 2 and 3, (2) $a_{r1} = 7.7$ in Fracture 1, (3) $a_{r2} = 35$ in Fracture 2, and (4) the fracture permeability ratio was 25. As indicated by the star in Fig. 8, the calculated degree of penetration was 0.0175. For comparison, if the gel propagation delay factor was the same in both fractures, the degree of penetration was 0.064 for a permeability ratio of 25. For a water-like gelant with the same permeability ratio, the degree of penetration was 0.040. Therefore, in this particular case, the "real" preformed gel (i.e., showing resistance factors given by Eqs. 2 and 3 and gel propagation delay factors of 7.7 and 35 in Fractures 1 and 2, respectively) provided a degree of gel penetration that was less than half that for a water-like gelant.

Effect of Differences in Fracture Length. In the above discussion, we assumed that Fractures 1 and 2 had the same length. In reality, Fracture 1 (the most direct channel between the wells) will probably be significantly shorter than Fracture 2. How will the degree of gel penetration, L_{p2}/L_{p1}, be affected by the fracture length ratio, L_{f2}/L_{f1}? This question is addressed in **Fig. 9** for a fixed fracture permeability ratio, $k_1/k_2 = 25$. The curve with the solid diamonds applies for the case where gel resistance factors were described by Eqs. 2 and 3, but the gel propagation delay factors were equal in both fractures ($a_{r1} = a_{r2}$). For this case, the degree of penetration was 0.064, independent of the fracture length ratio.

The curve with the stars in Fig. 9 applies for the case where gel resistance factors were described by Eqs. 2 and 3, but the gel propagation delay factors were 7.7 and 35 in Fractures 1 and 2, respectively. For this case, the degree of penetration was 0.0175, independent of the fracture length ratio. Of course, because the dehydration effect was significantly greater in Fracture 2 than in Fracture 1 (i.e., $35 > 7.7$), the gel front moved more slowly in Fracture 2. Consequently, the degree of penetration for this case (0.0175) was significantly less than that for the previous case, where the gel propagation delay factor was assumed to be the same in both fractures.

The curve with the open circles plots the degree of penetration vs. the fracture length ratio for a water-like gelant ($F_r = 1$). In contrast to the two cases above where preformed gels were considered, the

degree of penetration for the water-like gelant decreased significantly with increased fracture length ratio. When Fracture 2 was more than twice the length of Fracture 1 in Fig. 9, the water-like gelant provided degrees of penetration that were less than those for the performed gels.

Implications for Field Applications

The results presented in Figs. 8 and 9 suggest that the placement characteristics of preformed gels may be as good as or better than those of water-like gelants if the fracture length ratio has a value of 2 or less. An analysis[13] has revealed that fracture length ratios will be less than 3 in most field applications. Therefore, preformed gels will frequently have placement properties that are at least as desirable as those of water-like gelants. Admittedly, this conclusion relies on the limited experimental data that we have collected to date. Much work remains to determine how gel dehydration and propagation in fractures are affected by pressure gradient, velocity, fracture width, gel age, and gel composition.

Of course, several other factors can influence the relative merits of using preformed gels vs. gelants. First, water-like gelants are usually more expensive than polymer-based gels. Water-like gelants typically require from 5 to 30% concentrations of active chemicals, whereas polymer-based gels typically require 0.3 to 2% concentrations. Second, gelation chemistry for gelants is often quite sensitive to contact with reservoir rocks and fluids. In contrast, the effect of gelation chemistry is minimized with preformed gels because the gelation reactions are largely finished before reservoir contact occurs. Third, gravity effects are much more important for gelants than for preformed gels. During gelant injection, viscous forces in fractures usually dominate over gravity forces, so the shape of the gelant front is not greatly distorted by gravity.[7] However, after gelant injection stops, gravity segregation (of gelant and reservoir fluids) can occur very rapidly in a fracture.[7] If minimum gravity segregation is desired, the gelation time must be carefully controlled to coincide with the gelant injection time. In contrast, gravity segregation usually is not important for preformed gels because they have high-resistance factors.

On the other hand, water-like gelants have at least two advantages over preformed gels. First, because of their low viscosities, water-like gelants exhibit relatively high injectivities, regardless of the conductivities of the fractures in the reservoir. In contrast, preformed gels may experience significant injectivity problems if the fractures are not sufficiently conductive. Because one often does not know the conductivities of the fractures near a well, preformed gels have a greater risk of plugging the well before the desired volume of gel is injected.

A second advantage of water-like gelants is that they easily can be displaced away from the wellbore before gelation using a water or oil postflush. This allows placement of the gel deep in the fracture while leaving the near-wellbore part of the fracture open (upper left of Fig. 1). As mentioned earlier, this placement process allows sweep efficiency to be improved while maintaining a high injectivity or productivity for the well. (As illustrated in the lower right part of Fig. 1, viscous gelants *do not* share this advantage with water-like gelants.[10]) In contrast, preformed gels are more difficult to displace from the near-wellbore part of the fracture. To achieve a placement like that in the upper left of Fig. 1 using preformed gels, perhaps one could incorporate a gel-degrading chemical (e.g., an oxidizer, enzyme, hydrolysis agent, or delayed complexing agent) into the last volume of gel injected. Gel without the degrading chemical is injected first to penetrate into and plug the far-wellbore portions of the fracture. This gel is then followed by gel that contains the degrading agent that destroys the gel (after an appropriate delay) in the near-wellbore portion of the fracture. Of course, this idea remains to be tested experimentally.

Conclusions

Conclusions From Experimental Study of Preformed Cr(III)-Acetate-HPAM Gels in Fractures. The following conclusions were reached using a gel that contained 0.5% HPAM (Allied Colloids Alcoflood 935), 0.0417% Cr(III)-acetate, and 1% NaCl and 105°F:

1. During gel extrusion through fractures and tubes at high velocities, pressure gradients were insensitive to flow rate.
2. Gels exhibited shear-thinning behavior in fractures and tubes that correlated with the gel superficial velocity and the fracture width or tube diameter.
3. In fractures with sufficiently small opening sizes, gels dehydrated during extrusion, thus reducing the rate of gel propagation. This effect was more pronounced as the opening size decreased.
4. Gel resistance factors in fractures increased rapidly with increased gel age during the first 24 hours but increased more gradually during the next 200 hours.

Conclusions From Numerical Study. During a numerical study comparing the placement properties of preformed gels and water-like gelants in a simple two-fracture reservoir, the following conclusions were reached:

1. The gel-dehydration effect can aid gel placement by minimizing the degree of gel penetration (i.e., the distance of gel penetration into a given fracture pathway divided by that for the most-conductive fracture pathway between an injector-producer pair).
2. For preformed gels, the degree of penetration was insensitive to the fracture length ratio (i.e., the length of a less-conductive fracture divided by the length of the most-conductive fracture in the system).
3. In contrast, for gelants with a water-like viscosity, the degree of penetration decreased dramatically with increased fracture length ratio.
4. For fracture length ratios below 2, preformed gels may have a placement advantage over water-like gelants.

Nomenclature

a_r = gel propagation delay factor, PV
F_r = gel resistance factor in a fracture
k_f = effective fracture permeability, darcys
L = length, ft
L_f = effective fracture length, ft
L_p = distance of blocking-agent penetration, ft
u = superficial velocity, ft/d
w_f = average fracture width, inches

Subscripts

1 = most-permeability fracture (Fracture 1)
2 = less-permeability fracture (Fracture 2)

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SI Metric Conversion Factors

cp × 1.0*	E − 03	= Pa · s
in. × 2.54*	E + 00	= cm
ft × 3.048*	E − 01	= m
°F (°F–32)/1.8		= °C
$in.^3$ × 1.638 706	E + 01	= cm^3
psi × 6.894 757	E + 00	= kPa

*Conversion factor is exact.

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