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Gel Dehydration During Extrusion Through Fractures

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Abstract

Some of the most successful water shutoff treatments in fractured reservoirs used relatively large volumes of gel that extruded through fractures during the gel placement process. Laboratory experiments show that gel extrusion through fractures occurs at an unexpectedly low rate if the fracture conductivity or width is sufficiently small. This paper demonstrates that this low rate of gel propagation occurs because the gel dehydrates as it extrudes through fractures. Our experiments used a Cr(III)-acetate-HPAM gel that is commonly injected during field applications. In fractures with conductivities between 1 and 242 darcy-ft (effective average widths between 0.006 and 0.04 in.), the gel was concentrated (or dehydrated) and gel propagation was delayed by factors typically between 20 and 40 during the extrusion process. The gel dehydration effect became less pronounced as the fracture width increased. However, a fracture width around 0.4 in. was required to completely eliminate the effect.

For a given fracture conductivity, a minimum pressure gradient (i.e., a yield stress) was necessary to extrude gel through the fracture. A correlation was developed that provides a good estimate of the required pressure gradient for gel extrusion for a wide range of fracture conductivity and width values. For example, to extrude the gel with a pressure gradient less than 1 psi/ft, the fracture width should be at least 0.1 in. During gel extrusion through fractures of a given width, the pressure gradient and degree of gel dehydration were nearly independent of position and velocity during both radial and linear flow. During brine injection after gel placement, no significant gel washout occurred for fracture widths up to 0.4 in.

Introduction

When reducing channeling through naturally 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.[1-4] In these applications, gel injection times were substantially longer than gelation times (e.g., by factors ranging from 10 to 100). Since these gels (after gelation) do not flow through porous rock,[5] they must extrude through fractures during the placement process. Therefore, we are investigating the properties of gels during flow in fractures.

In previous work,[6] we reported that gel extrusion through fractures can occur at an unexpectedly low rate if the fracture conductivity is sufficiently small. We suggested that this low rate of gel propagation occurred because the gel dehydrated as it extruded through the fracture. Water left the gel and leaked off into the porous rock or flowed through the fracture ahead of the gel, while the crosslinked polymer remained behind in the fracture to propagate at a much slower rate.

We note that other oilfield gels experience dehydration when exposed to pressure against a porous medium. In particular, cements lose water and gain additional strength when "squeezed." Also, polymeric gels used to reduce fluid loss during hydraulic fracturing concentrate when forming a filter cake against a fracture face.

Recently, we performed several additional experiments to characterize the gel dehydration effect for gels used in conformance control. The questions that we addressed in these experiments were:

1. What concentrations of polymer and crosslinker are found in the core effluent as a function of gel throughput?
2. How much are the polymer and crosslinker concentrated in the dehydrated gel?
3. Will gel extrude through fractures when low pressure gradients are applied?
4. How does gel extrusion in radial flow (e.g., vertical fractures that cut through horizontal wells) compare with that for linear flow (e.g., vertical fractures that cut through vertical wells)?

Experimental

Our experiments used an aqueous gel that contained 0.5% Allied Colloids Alcoflood 935 HPAM, 0.0417% Cr(III) acetate, 1% NaCl, and 0.1% $CaCl_2$ at pH=6. All experiments were performed at 41°C (105°F). The gelant formulations were aged at 41°C for 24 hours (5 times the gelation time) before injection into a fractured core. Preparation of the fractured cores was described earlier.[5-7] The fractured cores (Berea sandstone) were 2.7 to 4 ft

(81 to 122 cm) in length and 1.5 in. (3.8 cm) in height and width. Each core had four internal pressure taps that were spaced equidistant along the fracture—thus dividing the core into five equal sections. **Table 1** lists the properties of these fractured cores. Before gel injection, all fractured cores were completely saturated with brine. All linear fractures were oriented vertically during our experiments.

TABLE 1—PROPERTIES OF LONG FRACTURED CORES

Core No.	Length, ft	Fracture volume, in^3	w_f, in.	$k_f w_f$, darcy-ft
15	4.0	0.62*	0.013♦	9.5
16	4.0	1.07*	0.014♦	12.6
17	4.0	1.14*	0.011♦	5.8
18	2.7	1.06*	0.0063♦	1.14
19	4.0	2.71*	0.038♦	242
20	2.7	0.74*	0.0073♦	1.75
21	4.0	6.10**	0.084	2,730**
22	2.7	0.79*	0.0072♦	1.72
23	4.0	14.0**	0.20	34,700**
24	4.0	28.4**	0.4	277,000**
25	4.0	8.48**	0.12	7,500**
27	4.0	1.02*	0.023♦	58.4
28	4.0	5.67**	0.078	2,220**

* Estimated from tracer studies.
** Calculated from fracture width. (Eq. 1 in Ref. 6.)
♦ Calculated from fracture conductivity. (Eq. 1 in Ref. 6.)

Demonstration of Gel Dehydration

In Fractured Core 15, we injected 43 fracture volumes (26.9 in^3 or 440 cm^3) of gel using a fixed injection rate of 0.122 in^3/hr (2 cm^3/hr). Considering the dimensions of this fracture (average width of 0.013 in.), the average fluid velocity in the fracture would be 13 ft/d if all injected fluid stayed in the fracture. Even though 43 fracture volumes of gel were injected, no significant polymer or chromium were produced (see **Fig. 1**). The pressure gradient in the first section (i.e., the first 20%) of the core was fairly stable at 160 psi/ft during the last 40 fracture volumes of gel injection (see **Fig. 2**). In contrast, the pressure gradients in the last three sections (the last 60%) of the core were very low. After gel injection, the core was disassembled to determine how far gel had propagated through the fracture. A rubbery gel was found in the first 25% (1 ft or 30 cm) of the fracture length. These findings all suggest that the gel only propagated one-quarter of the distance through the 4-ft-long fracture.

The gel in the fracture was analyzed for HPAM and chromium as a function of distance along the fracture. The results are shown in **Fig. 3**. Note that gel at the inlet sandface contained 22 times the HPAM concentration and 39 times the chromium concentration of the original gel. To a distance of 0.82 ft (25 cm) within the fracture, the gel contained between 8 and 28 times the HPAM concentration and between 18 and 45 times the chromium concentration of the original gel. In summary, our results demonstrate that the gel was concentrated (or dehydrated) substantially during the extrusion process.

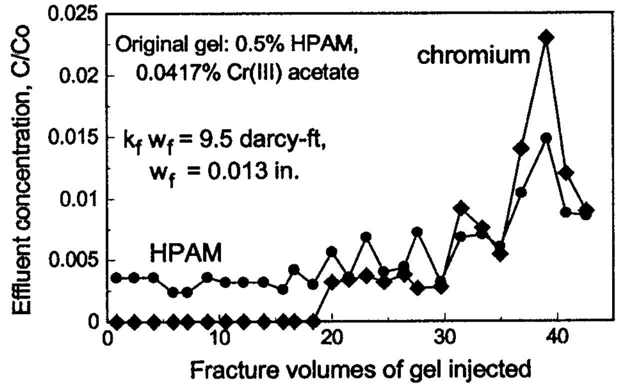


Fig. 1—Chromium and HPAM effluent concentrations during gel injection into Core 15 (relative to injected concentrations).

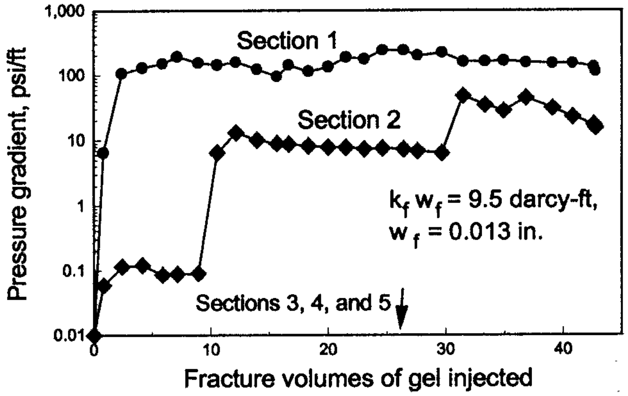


Fig. 2—Pressure gradients during gel injection into Core 15.

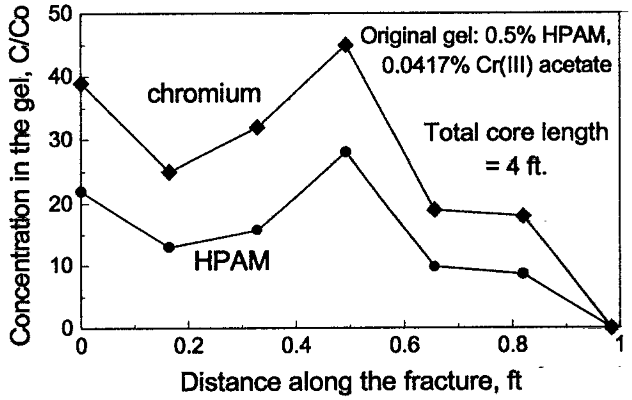


Fig. 3—Chromium and HPAM concentrations for gel in the fracture of Core 15 (relative to injected concentrations).

Gel Extrusion at Low Pressure Gradients

Our results using Core 15 suggested that a pressure gradient of 160 psi/ft was required to propagate gel through a 9.5-darcy-ft fracture when injecting at a fixed rate of 0.122 in^3/hr (2 cm^3/hr). For comparison, in earlier work,[6] we noted that a pressure gradient of 10.8 psi/ft was required to extrude this gel through a 568 darcy-ft fracture. These pressure gradients were quite high compared to values expected in many field applications. Typically, we expect pressure gradients around 1 psi/ft in reservoirs. In a previous paper,[6] we demonstrated that low-pressure gradients can be attained (during constant-rate injection tests) if the fracture conductivity is very high. However, will gel propagate through low-to-medium-conductivity fractures if a fixed, low-pressure gradient is applied?

To answer this question, constant-pressure experiments were performed using Cores 16 and 17. In Core 16, a pressure drop of 35 psi was applied across the 4-ft-long core. As with our other experiments, the Cr(III)-acetate-HPAM gel was aged for 24 hours before attempting injection. **Fig. 4** shows that after 10 days exposure to a 35-psi pressure drop, less than 4 fracture volumes of gel were injected (apparently) and flow had effectively stopped. The HPAM and chromium concentrations in the core effluent were insignificant during this time. After the experiment, the core was disassembled and concentrations were determined along the fracture length. No sign of gel was found in the fracture. Gel was found on the inlet sandface. This gel contained 30 times the HPAM concentration and 47 times the chromium concentration of the original gel. Thus, a pressure drop of 35 psi was insufficient to extrude gel into this 12.6-darcy-ft (0.014 in. average width) fracture.

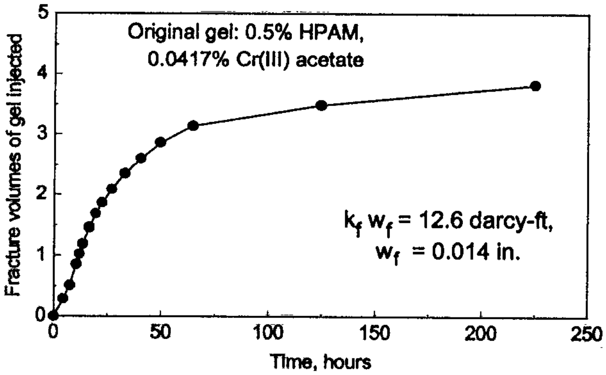


Fig. 4—Apparent gel extrusion with a constant pressure drop of 35 psi across a 4-ft-long core (Core 16).

A similar experiment was performed using Core 17. However, a constant pressure drop of 1 psi was applied across the 4-ft-long core (5.8 darcy-ft fracture conductivity and 0.011 in. average fracture width). After 19 days, less than one fracture volume was injected. Upon disassembly of the core, no evidence of gel was found in the fracture. Fluid samples at the core inlet contained 1.36 times the HPAM concentration and 3.0 times the chromium concentration of the original gel.

In summary, the Cr(III)-acetate-HPAM gel did not extrude through low-to-medium-conductivity fractures when low pressure gradients were applied. Some gel dehydration occurred even when relatively low pressure gradients were applied.

Effluent Compositions After Gel Breakthrough

In the above experiments, the gel did not propagate completely through the fractured core. Therefore, we performed several experiments to examine the effluent when gel was produced. One experiment was performed using Core 20, which was 2.7 ft in length. The average conductivity was 1.75 darcy-ft, and the effective average fracture width was 0.0073 in. We injected 110 fracture volumes of 24-hr-old Cr(III)-acetate-HPAM gel using an injection rate of 12.2 in³/hr (200 cm³/hr). **Fig. 5** indicates that HPAM and chromium fronts arrived at the core outlet after injecting 30 fracture volumes of gel. The final effluent concentrations (relative to the original concentrations in the gel) were 0.82 for HPAM and 1.38 for chromium. Gel taken from the core inlet contained 26 times the original HPAM concentration and 44 times the original chromium concentration. Unfortunately, because of the method used for constructing Core 20 (it was cast in a metal alloy), we could not determine gel compositions along the length of the fracture.

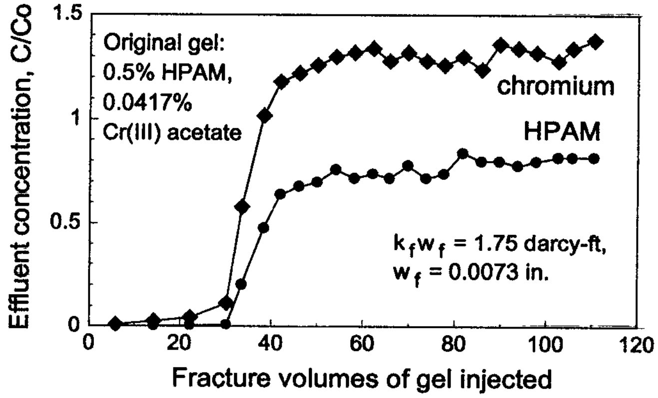


Fig. 5—Chromium and HPAM effluent concentrations during gel injection into Core 20 (relative to injected concentrations).

In Fig. 5, one might have expected the effluent chromium and HPAM concentrations to be much higher than the injected concentrations, since we indicated that the gel was concentrated by roughly a factor of 30 when extruding through the fracture. However, remember that the effluent stream consists of the fluid that flows through the porous rock as well as the gel that extrudes through the fracture. When a steady state is reached, the chromium and HPAM concentrations in the effluent should equal the injected concentrations. To a rough approximation, Fig. 5 supports this expectation—the effluent relative concentrations for both polymer and chromium are much closer to a value of 1 than to 30. However, upon closer examination, we were somewhat surprised that after injecting 110 fracture volumes of gel, the stabilized relative chromium concentration was significantly more than the relative HPAM concentration (1.38 versus 0.82).

This experiment was performed in triplicate (Cores 18, 20, and 22) with the same results obtained in each case. To explain why the effluent relative chromium concentrations were higher than the relative HPAM concentrations, a number of possibilities come to mind. For example, perhaps HPAM was retained in the concentrated gel more than chromium. This explanation was contradicted by the analysis of the retained gel. Analysis of the gel taken from the inlet of Core 20 (after gel injection) revealed 44 times the original chromium concentration and 26 times the original HPAM concentration. In agreement with our other observations (e.g., Fig. 3), the dehydration process consistently concentrated chromium by a greater factor than HPAM.

As a second possible explanation, perhaps the differences were caused by experimental errors associated with our determinations of chromium and HPAM concentrations. However, this explanation was contradicted by detailed examination of the error bars and interferences associated with our analytical procedures. Our error bars were typically ±5% for both the HPAM and chromium concentrations. These uncertainty levels were too low to explain the deviations from the expected steady state values in Fig. 5.

A third explanation was that some of the chromium and HPAM leached from the gel and propagated slowly through the porous rock. If HPAM was retained in porous rock by a greater factor than chromium, one might be able to rationalize the results in Fig. 5. More work is needed to test these ideas.

Gel Behavior in Wider Fractures

The fractures examined to this point were fairly narrow—i.e., 0.014 in. or less in width. Will the dehydration effect be less pronounced if wider fractures are used? To answer this question, additional experiments were performed using long fractured cores. The core properties, core dimensions, gel composition, gel age, and experimental procedures were similar in all cases. With these experiments, we extended our range of fracture widths examined from 0.0063 to 0.4 in. The corresponding range of fracture conductivities extended from 1.14 to 277,000 darcy-ft. During these experiments, we noted (1) the average pressure gradients, (2) the gel breakthrough volumes, (3) chromium and HPAM concentrations in the effluent, and (4) chromium and HPAM concentrations in gel along the fracture (after disassembling the core at the end of an experiment). The results from these experiments are summarized in **Table 2** and **Fig. 6**. (Details are provided in Ref. 7.)

TABLE 2—EFFECT OF FRACTURE CONDUCTIVITY ON GEL PROPAGATION

$k_f w_f$, darcy-ft	w_f, in.	dp/dl, psi/ft	Gel breakthrough, fracture volumes
1.14	0.0063	750	40
4.5	0.010	65	35
242	0.038	20	21
586	0.051	10.8	7.7
2,730	0.084	6.5	4.8
7,500	0.12	2.0	5.4
34,700	0.2	0.28	1.8
277,000	0.4	0.14	1.1

Several important conclusions become evident after examining Table 2 and Fig. 6. First, the pressure gradient required to extrude the gel through a fracture decreased with increased fracture conductivity and width. Fig. 6 quantifies this point by plotting the results from 34 separate experiments. The solid line in Fig. 6 shows a least squares fit, suggesting that the average pressure gradient during extrusion of this gel was proportional to fracture conductivity raised to the -0.58 power.

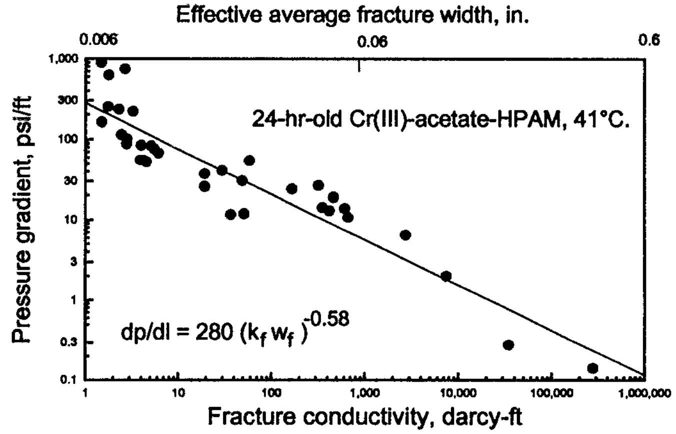


Fig. 6—Pressure gradient versus fracture conductivity for a fixed volumetric injection rate.

A second point is that relatively wide fractures (> 0.1 in.) were needed for this gel to propagate using typical reservoir pressure gradients (e.g., ~1 psi/ft). Thus, the gel simply may not enter fractures with widths less than 0.1 in. In naturally fractured reservoirs with a range of fracture conductivities, the gel may selectively be confined to the wider fractures.

A third point (from Table 2) is that the degree of gel dehydration (as judged by gel breakthrough) decreases with increased fracture width and with decreased extrusion pressure gradient. At pressure gradients around 1 psi/ft, this gel may concentrate (dehydrate) by a factor less than 6. However, since near-wellbore pressure gradients could be much greater than 1 psi/ft, much greater degrees of gel dehydration could be observed near the well.

Water Flow After Gel Placement

How effectively does the gel reduce fracture conductivity after gel placement? This question is addressed in **Fig. 7** for fractures with conductivities ranging from 1 to 277,000 darcy-ft (corresponding to fracture widths ranging from 0.006 to 0.4 in.). The brine injection rates during these experiments were generally the same as those used during gel placement (typically 12.2 in^3/hr or 200 cm^3/hr). These studies were routinely performed after the gel injection experiments described above.

For reference, the horizontal line (at 0.081 darcy-ft) in Fig. 7 gives the conductivity associated with a fresh, unfractured 650-mD Berea sandstone core. (In other words, if the gel perfectly healed the fracture without damaging the porous rock, the final effective conductivity of the core should be 0.081 darcy-ft.) For fractures with initial conductivities (before gel placement) below 5,000 darcy-ft, the conductivities after gel placement were less than or equal to 0.081 darcy-ft. This result indicates that the gels effectively healed the fractures when the initial conductivities were less than 5,000 darcy-ft (i.e., fracture widths less than about 0.1 in.). We noted (Table 2) that the gel placement process concentrated gel in the fracture generally by a factor of 5 or more when the initial conductivities were less than 5,000 darcy-ft. Incidentally, final core conductivity values less than 0.081 darcy-ft indicated that the permeability of the porous rock was reduced along with the conductivity losses experienced by the fracture. Much of this damage to the porous rock was simply gel that was not completely removed from the injection sand face before beginning brine injection.

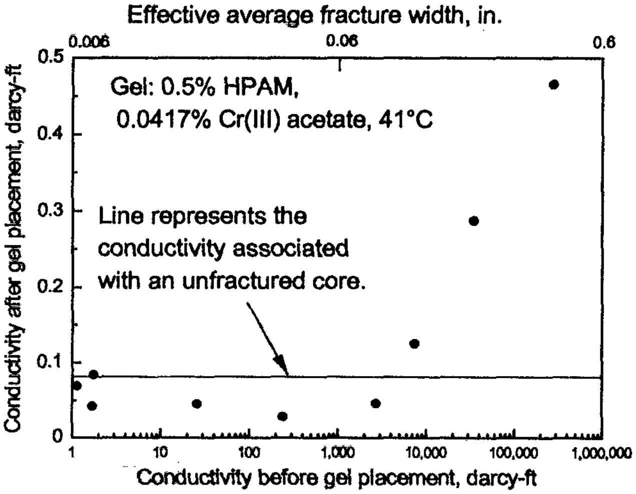


Fig. 7—Core conductivity during brine injection after gel placement versus fracture conductivity before gel placement.

For fractures with initial conductivities greater than 5,000 darcy-ft, Fig. 7 shows that the gel did not completely heal the fracture (because the final conductivities were greater than 0.081 darcy-ft). For these cases, the final conductivity after gel placement increased with increased initial fracture conductivity. Even so, the gel substantially reduced the fracture conductivities for all cases. For the 277,000-darcy-ft fracture, the gel reduced fracture conductivity by a factor of 600,000.

For all tests that we performed to date, virtually no gel, polymer, or chromium was produced from the fractured cores during brine injection after gel placement. This result is demonstrated in **Fig. 8** for our three most conductive fractures (Cores 23, 24, and 25 with conductivities of 34,700, 277,000, and 7,500 darcy-ft, respectively). Within about 0.2 fracture volumes of brine throughput, the HPAM and chromium concentrations in the effluent were reduced below two percent of the concentrations in the original gel. Thus, we observed virtually no gel washout under the conditions that we tested.

Modeling Gel Behavior in Fractures

In earlier work,[6] we showed that gels show an extremely strong apparent shear-thinning behavior when extruding through fractures and tubes (see **Fig. 9**).

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. 1,

$$F_r = 2 \times 10^6 u^{-0.83} \text{ if } w_f < 0.035 \text{ in.,} \qquad (1)$$

where u was the superficial velocity in ft/d. The solid line in Fig. 9 illustrates Eq. 1.

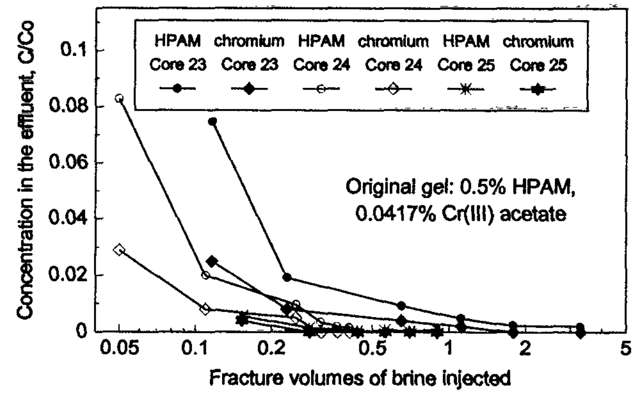


Fig. 8—Chromium and HPAM concentrations produced from Cores 23, 24, and 25 during brine injection after gel placement.

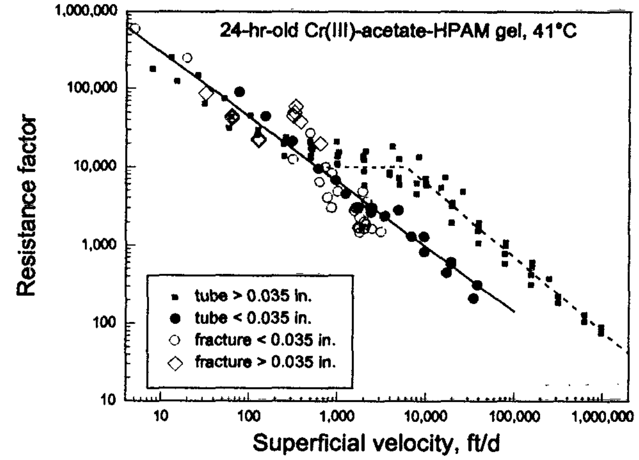


Fig. 9—Correlating behavior in short tubes (3 to 15 ft) and short fractures (0.5 to 4 ft). (After Ref. 6.)

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. 2.

$$\begin{aligned} F_r &= 2 \times 10^6 u^{-0.83} \text{ if } u \le 600 \text{ ft/d} \\ F_r &= 10{,}000 \text{ if } 600 < u < 6{,}200 \text{ ft/d} \qquad (2) \\ F_r &= 4 \times 10^7 u^{-0.95} \text{ if } u \ge 6{,}200 \text{ ft/d} \end{aligned}$$

The dashed curve in Fig. 9 illustrates Eq. 2 for velocities above 600 ft/d. Below 600 ft/d, Eq. 2 predicts the same values as Eq. 1.

The steep slopes of the curves in Fig. 9 indicate that the pressure gradient is fairly insensitive to fluid velocity over much of the velocity range. In other words, a minimum pressure gradient appears necessary to extrude the gel through a given fracture (or tube). This suggestion is consistent with our observations associated with Figs. 1 through 4—gel will not enter a fracture if the pressure gradient is not sufficiently high.

This behavior suggests that a Bingham model might be appropriate when describing extrusion of gels through fractures. In the Bingham rheological model,[8] the fluid will not move until a minimum shear stress or "yield" stress, τ_o, is exceeded. (For the Cr(III)-acetate-HPAM gel, Fig. 6 provides a good indication of the magnitude of this yield stress for a wide range of fracture conductivities and fracture widths.) Above this minimum shear stress, the model assumes that flow is basically Newtonian. In the Bingham model, the fluid velocity profile is flat (the velocity gradient is zero) between the center of the fracture and some distance, x_o, from the fracture center. In other words, the gel flows like a solid plug in this region. Between x_o and the fracture wall, the Bingham model assumes Newtonian flow. In effect, the Bingham model assumes that a Newtonian fluid flowing near the fracture wall lubricates the flow of the plug through the fracture. In our experiments, since the gel dehydrates as it extrudes through fractures, we suspect that the water leaving the gel during the dehydration process may be the key component of the lubricating layer.

In Appendix F of Ref. 7, an analysis was performed using the Bingham model to determine x_o as a function of gel resistance factor. Eq. 3 provides this relation.

$$F_r = 1/[1 - 3(x_o/w_f) + 4(x_o/w_f)^3] \quad \text{.......................................(3)}$$

This relation can be coupled with Eq. 2 to provide an estimate of the thickness of the lubricating layer relative to the fracture width. (Appendix F of Ref. 7 shows details of this determination.) **Fig. 10** shows the results.

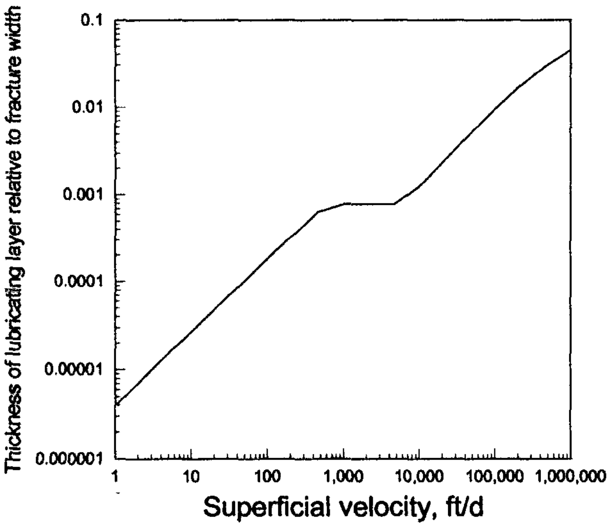


Fig. 10—Use of the Bingham model to predict the thickness of the lubricating layer based on Fig. 9, Eq. 2, and Eq. 3.

Fig. 10 suggests, first, that the relative thickness of the lubricating layer is very small for the range of velocities shown. Second, the thickness of the lubricating layer increases with increased superficial velocity. If a means could be devised to physically measure the thickness of the lubricating layer (perhaps using interferometry), one could test whether the thickness of the lubricating layer actually does increase with increased velocity.

Gel Extrusion in Radial Flow

Most of the previous discussion is relevant to gel extrusion in linear flow—for example, in vertical fractures that cut through vertical wells. However, in vertical fractures that cut through horizontal wells, the flow geometry is radial (at least, near the well). How does gel extrusion in radial flow compare with that in linear flow?

Eq. 4 gives the Darcy equation for radial flow.

$$dp/dr = u\mu/k_f = u\mu_w F_r / k_f \quad \text{..(4)}$$

In the proper velocity range, Eqs. 2 and 4 combine to give Eq. 5.

$$dp/dr = c_a u^{n+1} \mu_w / k_f \quad \text{...(5)}$$

In Eq. 5, c_a is a constant and n is the velocity exponent that varies from -0.83 to -0.95 (from Eq. 2). Since n is close to a value of -1, Eq. 5 suggests that the pressure gradient should be almost constant (i.e., independent of velocity or radial position) during gel extrusion in radial flow. If the pressure gradient is independent of radial position, we expect the degree of gel dehydration also to be independent of radial position.

To test these ideas, we performed gel extrusion experiments in a horizontal fracture. The fracture was formed by placing two 650-mD Berea sandstone slabs (each with dimensions, 12 x 12 x 3 in.) together and casting in epoxy. From tracer and conductivity experiments, we estimated that the fracture width was about 0.01 in. Thus, the fracture dimensions were 12 x 12 x 0.01 in. An injection port and a production port were positioned at opposite corners of the fracture, and four internal pressure taps were located along the connecting diagonal.

We injected 114 in^3 (1,870 cm^3) of 24-hr-old Cr(III)-acetate-HPAM gel (0.5% HPAM, 0.0417% Cr(III) acetate, 1% NaCl, 0.1% $CaCl_2$) at a rate of 12.2 in^3/hr (200 cm^3/hr). No chromium or polymer was produced during the gel injection process. Near the end of gel injection, **Fig. 11** shows the pressure behavior observed across the horizontal fracture. For comparison, Fig. 11 also plots the pressure behavior expected for Newtonian radial flow and for Newtonian linear flow. In agreement with the prediction of Eq. 5, Fig. 11 shows that the behavior during gel extrusion in radial flow was more similar to that for Newtonian linear flow than for Newtonian radial flow. In other words, during gel extrusion through fractures, the pressure gradient was nearly independent of position in both linear and radial flow.

After gel injection, the core was opened to expose the gel in the fracture. **Fig. 12** shows the extent of gel propagation in this horizontal fracture. The fracture area was divided into 36 equal 2 x 2-inch squares, and the composition of each square was determined. The numbers in the squares in Fig. 12 indicate the chromium concentrations relative to the chromium concentration in the originally injected gel. Fig. 12 reveals that on average, the gel was concentrated by a factor of 21 (standard deviation: ± 6) during the extrusion process. The gel was often slightly less concentrated near the gel-water front. However, in general, the degree of dehydration was independent of radial position from the injection point.

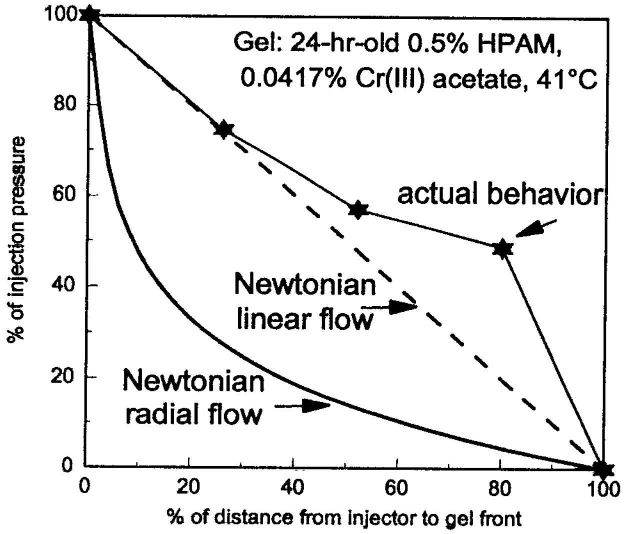
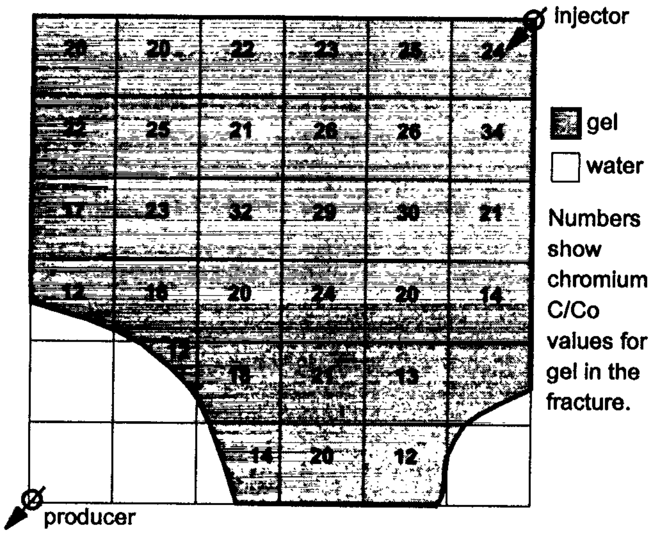


Fig. 11—Pressure behavior observed during gel injection into Horizontal Fracture 1.



Numbers show chromium C/Co values for gel in the fracture.

Fig. 12—Relative chromium concentrations in Horizontal Fracture 1 (12 in. x 12 in. x ~0.01 in.) after gel placement.

Gels with Other Concentrations

In all experiments to this point, we injected gels that contained 0.5% HPAM and 0.0417% Cr(III) acetate. (Refer to this composition as our 1X gel.) What would happen if different concentrations were used? In Core 27 (average $k_f w_f$=58.4 darcy-ft), we injected a gel (named our 0.5X gel) that contained one-half the HPAM and Cr(III)-acetate concentrations of our earlier experiments. All other conditions were the same. Gel arrived at the end of the 4-ft-long fracture after injecting roughly twice the volume associated with breakthrough for the 1X gel in earlier, similar experiments. During injection of the 0.5X gel, the pressure gradient along the gel-filled fracture averaged 55 psi/ft. This value is consistent with the trend shown in Fig. 6. Furthermore, chemical analysis of gel in the fracture (determined after the fracture was opened) revealed that the gel was concentrated by a factor of 32. The final concentrations in the dehydrated gel were about the same as those seen in our previous experiments with our 1X gel (in fractures with similar conductivities). These results suggest that for a given fracture conductivity and gel system, the gel may concentrate to a fixed level, regardless of the initial gel composition.

To further test this idea, we performed another experiment using a gel that initially contained 3% HPAM and 0.25% Cr(III) acetate (named our 6X gel). We noted that our 1X gel experienced a pressure gradient of 6.5 psi/ft and concentrated by a factor of 4.8 when extruded through a 2,730 darcy-ft fracture (see Table 2). Thus, based on the above results, we speculated that our 6X gel might extrude through a similar fracture, exhibiting a low pressure gradient and without dehydrating.

We extruded our 6X gel through a 4-ft-long, 2,200 darcy-ft fractured core (Core 28) using the same conditions as those in our other experiments. Analysis of pressure behavior (during gel injection) and gel in the fracture (after disassembly of the core) revealed that the gel was concentrated by a factor of 5.5. The average pressure gradient was 233 psi/ft during gel extrusion. Obviously, more work is needed to understand gel dehydration and propagation through fractures for the concentrated gels.

Conclusions

During experiments where one-day-old Cr(III)-acetate-HPAM gels were extruded through 2.7- to 4-ft-long fractures, we observed the following results:

1. In fractures with conductivities between 1 and 242 darcy-ft (effective average widths between 0.006 and 0.04 in.), the gel was concentrated (or dehydrated) and gel propagation was delayed by a factor typically between 20 and 40 during the extrusion process.
2. The gel dehydration effect became less pronounced as the fracture width increased. However, a fracture width around 0.4 in. was required to completely eliminate the effect.
3. For a given fracture conductivity and width, a minimum pressure gradient (i.e., a yield stress) was required to extrude gel through the fracture. For fractures with conductivities ($k_f w_f$, in darcy-ft) between 1 and 277,000 darcy-ft (widths between 0.006 and 0.4 in.), the required pressure gradient (dp/dl, in psi/ft) can be estimated using the relation: $dp/dl=280(k_f w_f)^{-0.58}$. To extrude this gel with a pressure gradient of only 1 psi/ft, the fracture width should be at least 0.1 in.
4. During gel extrusion through fractures of a given width, the pressure gradient and degree of gel dehydration were nearly independent of position and velocity during both radial and linear flow.
5. During brine injection after gel placement, we saw no evidence of significant gel washout for fractures with widths up to 0.4 in. For fractures with widths greater than 0.1 in., the gel did not completely heal the fracture (i.e., reduce its flow capacity to near zero). However, the fracture conductivities were reduced substantially.

Nomenclature

C = produced tracer concentration, g/m^3
C_o = injected tracer concentration, g/m^3
c_a = constant in Eq. 5
F_r = resistance factor (brine mobility before gel placement divided by gel mobility)
k_f = fracture permeability, darcys [μm^2]
l = length, ft [m]
n = exponent in Eq. 5
p = pressure, psi [Pa]
u = flux or superficial velocity, ft/d [m/s]
w_f = fracture width, ft [m]
x_o = thickness of a lubricating layer, ft [m]
μ = viscosity, cp [Pa-s]
μ_w = viscosity of water, cp [Pa-s]
τ_o = yield stress, psi [Pa]

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