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Characterization of Partially Formed Polymer Gels for Application to Fractured Production Wells for Water-Shutoff Purposes

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Abstract

A laboratory study was conducted to characterize water-shutoff polymer gels that are injected in the partially formed (partially matured) state into fractures (or other high permeability anomalies) that are in direct contact with production wells. Partially formed (<8-hr-old) 1X (0.5% polymer) chromium(III)-carboxylate/acrylamide-polymer (CC/AP) gels showed much lower (as much as 100 times less) effective viscosities (17 to 30 cp) during placement in a 1-mm-wide fracture than "fully formed" (>15-hr-old) gels with the same chemical composition. Thus, partially formed gels exhibit substantially higher injectivities and lower placement pressures. This feature is of major importance during field applications where pressure constraints limit rates and volumes during gel injection. For gelants and partially formed gels that were 5 hours old or less, the rates of gelant leakoff through fracture faces were very low [about 0.013 $ft^3/ft^2/d$ (ft/d)]. Thus, field applications that inject relatively small volumes of gelant or partially formed gels will generally experience small gelant leakoff distances, and the leakoff substance will not significantly inhibit oil from entering the fractures.

During first brine injection after gel placement and maturation in 1-mm-wide fractures, the pressure gradient required to first breach the gel increased significantly with increasing polymer concentration in the gel — ranging from roughly 5 psi/ft for 1X (0.5% polymer) partially formed gels to 99 psi/ft for 3X (1.5% polymer) partially formed gels. For 1X gels, the breaching pressure gradient was greatest (~9 psi/ft) when the gel was aged from 12 to 24 hours before injection. Prior to exceeding the breaching pressure gradient, no detectable brine flowed through the fracture. During the limited brine flow after gel placement, most (>90%) of the gel remained in the fracture and did not "washout." The stabilized residual resistance factors (permeability reduction factors) for the first brine flood through the fracture (following gel placement and maturation) ranged from 750 to 22,000 – increasing with increasing polymer concentration and gel strength. The large stabilized (final and equilibrium) residual resistance factors for brine flow through the gel-filled fracture resulted from the brine flow occurring through relatively small channels (wormholes) residing in the gel. For the 1X gel, the stabilized permeability reduction factors (for brine flow in a gel-treated fracture) were comparable for formulations injected in the gelant state, the partially formed state, and the "fully formed" state.

The CC/AP gels exhibited disproportionate permeability reduction during brine and oil flow through gel-filled fractures. During one experiment with the 1X gel, brine permeability in the fracture was reduced 166 times more than that for oil. In this case, brine was flooded first, followed by oil. For the 1X and 3X gels, the permeability reduction factor for oil flow remained constant (within experimental error) during four cycles of brine and oil injection. In contrast, the permeability reduction factor for brine decreased more than a factor of 10 during these cycles.

Introduction

During this laboratory study, we characterized water-shutoff polymer gels of the type that are to be injected in the *partially formed* state into fractures which are connected to production wells. Findings of this study should also be relevant to other high-permeability anomalies that are connected to petroleum production wells. Other than fractures, these high-permeability anomalies could include solution channels, interconnected vugs, karsted features, joints, faults, rubblized zones, and ultra-high matrix rock permeability. These features generally have permeabilities greater than two darcies.

For water-shutoff applications in fractured production wells (i.e., during field applications), injected polymer gels are usually in the partially formed state during transit from the wellbore into the formation. For classical bulk gel treatments applied to reservoir fractures, the injected polymer-gel solution should develop enough gel structure (including microgel structure) to minimize detrimental gel solution leakoff into the matrix reservoir rock that is adjacent to the fractures. On the other hand, the gel should not be fully formed during placement because excessive injection pressures may be encountered. Use of partially formed gels

permit manageable injectivities during placement, will cause minimum damage to matrix rock when properly formulated, and yet ultimately yield strong gels that will function as required to shut off water production. Gels must be in the partially formed state when injecting strong gels that will ultimately be "rigid and rubbery" in nature.

The objective of this paper is to characterize the performance of polymer gels that are injected into fractures in the partially formed state. This study was intended to investigate the properties of gel that resides in the near- and intermediate-wellbore region and gel that is part of relatively small-volume gel treatments (treatment pumped in less than a day) that are applied to fractured production wells. During the flooding experiments of this study that were conducted in 2-ft-long fractured cores, 40 fracture volumes (FV) of gel fluid were injected as rapidly as possible (injected within about seven minutes using a superficial velocity within the fracture of 16,600 ft/d). An explicit goal during this gel injection was to minimize time-dependent gel dehydration.[1] For these particular experiments, the resultant mature gels residing in the fractures were 1.2 to 2.5 times more concentrated than the injected gel formulation (as will be noted later in this paper). During the experiments conducted in 4-ft-long fractured cores, 80 FV of gel formulation were injected at a superficial velocity of 4,130 ft/d within the fracture.

Experiments in this paper addressed five objectives:

1) Determination of the effective viscosity of partially formed gel formulations in fractures during gel injection,
2) Estimation of damage to fracture-wall porous rock from gel solution leakoff,
3) Determination of the peak or critical pressure gradient where the gel is first breached during brine injection after gel placement in a fracture,
4) Determination of the stabilized (equilibrium or "final") residual resistance factor (F_{rr}) for water or oil flow through a gel-filled fracture, and
5) Characterization of disproportionate permeability reduction (DPR) during oil and water flow through gel-filled fractures.

Experimental

Our flooding experiments were conducted in 1.5-in. by 1.5-in. by either 2.0- or 4.0-ft-long rectangular, 700-md, 19% porosity, unfired Berea sandstone cores, where a 1.0-mm-wide (0.04-in.-wide) clean-sawed fracture ran down the middle of the length of the core. An earlier study[2] showed that it makes little difference for this type of flooding experiment whether the fracture surface is "rough" (as occurs during core splitting) or the fracture surface is "smooth" (as occurs with a cleaned-sawed rock surface). During all floods, the fracture was oriented vertically. In all cases, gel (and other fluids), exiting from the downstream end of the fracture, flowed into a chamber in the core's acrylic end cap that was ~4-mm (~0.16-in.) deep and ~26x26-mm (~1.0x1.0-in.) square. The gel then flowed into a stainless steel effluent port fitting having an inside diameter of 4.5 mm (0.18 in).

Two ports for the flow of fluids from the matrix rock were placed at the downstream end of the core material. The injected fluids, including gel fluids, were distributed over the majority of the injection face, which included both the fracture and the matrix sandstone rock. The matrix-rock effluent end of the core slab was sealed such that fluids could only flow out of the fracture at this point, and could not flow out of the matrix rock. All effluent fluid flow out of the matrix rock occurred by exiting the downstream matrix-rock effluent ports. The fractured Berea sandstone slab was cast in epoxy. During each flooding experiment, the rates of fluid production from both the fracture and the matrix-rock effluent ports were recorded versus time. Differential pressures along the fracture length were continuously monitored during all flooding experiments using Honeywell Series 100e quartz differential-pressure transducers. Several equally spaced pressure taps allowed measurement of pressures along the fracture. The 2-ft-long cores had three internal pressure taps placed along the fracture, dividing the fractured core into four 6-in.-long sections. The 4-ft-long cores had four internal pressure taps, dividing the fractured core into five 9.6-in.-long sections. Fig. 1 shows a 2-ft-long fractured core prior to casting it in sand-filled epoxy resin. The core and flooding equipment and the procedures were similar to those discussed in Ref. 2.

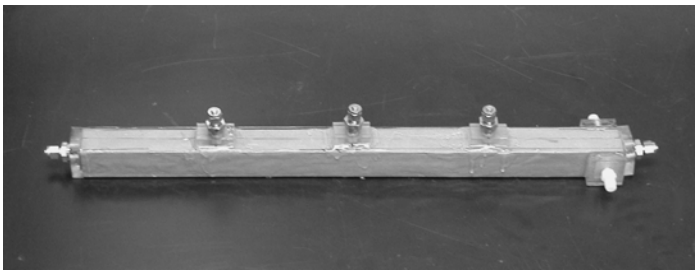

Fig. 1—Fractured core used during the gel/fracture floods.

All flooding experimental work was conducted at 105°F (41°C). The brine and gel formulations contained 1.0 wt% NaCl and 0.1 wt% $CaCl_2$. The oil used was Soltrol 130™ (mixed C10-C13 isoparaffins). The CC/AP [or Cr(III)-acetate-HPAM] gels[3,4] in this study employed chromic triacetate as the chemical crosslinking agent. No pH adjustment was made to any of the solutions. The crosslinking agent, chromic triacetate, was obtained from McGean as a 50 wt% active aqueous solution and was added to the polymer solutions in this form. The polymer was Ciba Alcoflood 935™ commercial HPAM (hydrolyzed polyacrylamide). This acrylamide polymer has a nominal Mw of $5x10^6$ daltons and is 5-10 mole% hydrolyzed. The concentration of active polymer was 91-92%. Pertinent information regarding the three CC/AP gel formulations employed in this study is provided in Table 1.

Table 1—CC/AP gels used in this study.

Gel designation	1X	2X	3X
Concentration of the 91-92% active HPAM, wt%	0.5	1.0	1.5
Concentration active Cr(III), wt%	0.0095	0.015	0.020
Aging time prior to injection, hr	0.2 to 240	2.5	1.0
Viscosity of the polymer solution without crosslinker added (at 28 sec^{-1} shear rate and 41°C), cp	15	63	180

In the 2-ft-long cores, 40 fracture volumes (~1,000 cm^3) of gel formulation were injected at a rate of 8,000 cm^3/hr (16,600 ft/d superficial velocity within the fracture). In the 4-ft-long fractures, 80 fracture volumes (~4,000 cm^3) of gel formulation were injected at 2,000 cm^3/hr (4,130 ft/d superficial velocity within the fracture). In this paper, superficial velocities for brine or oil flow through gel-treated fractures will be reported in units of ft/d. These superficial velocities were calculated assuming that all fluid flow occurred through the original fracture without any gel present. As will become evident later in this paper, the actual velocities of brine or oil flow through the gel-treated fractures were probably more than ten times larger than the stated superficial velocity because the fluid flow actually occurred through relatively small channels in the gel.

For the flooding experiments involving the injection of the gel solution at a superficial velocity of 16,600 ft/d within the fracture, the gel injection delay time (i.e., time from crosslinker addition to the polymer solution to initiating gel fluid injection) was selected using the bottle-testing procedure that was described in Ref. 5. These included the 2X and 3X gels described in Table 1 and one 7-hr-old 1X gel. Utilizing the gel-strength-code assignment as a function of gel aging time at 41°C (105°F), the injection delay time was determined when the first visually detectable gel formation occurred. At this aging time, we estimated very roughly that 10% of full gel maturation and gel strength was attained. At a minimum, substantial microgel formation occurred by this time. For quality control, a sample (in a bottle) of the gel to be injected was set in the air bath along side the core to verify that the newly prepared gel formulation matured (crosslinked) at the proper rate and that the final gel attained the expected ultimate strength.

Additional details of the core preparation and flooding experiments can be found in Refs. 2 and 6.

Effective Viscosity of Partially Formed Gels During Injection

In all experiments during placement of the gel fluid, pressure gradients rapidly stabilized after brine was displaced from the fracture. As reported earlier,[1] no screen-out or progressive plugging behavior was ever observed during injection of the gel fluid.

Fig. 2 plots the effective viscosities in the studied fractures for 1X gels in the "partially formed" and the "fully formed" states. The fully formed gel was aged 24 hrs prior to injection into the fracture. The partially formed gel was aged 7 hrs. The gel solutions were injected at 16,600 ft/d superficial velocity within the fracture. Note that the effective viscosities were fairly stable during the course of injecting 27 to 29 fracture volumes of gel fluid.

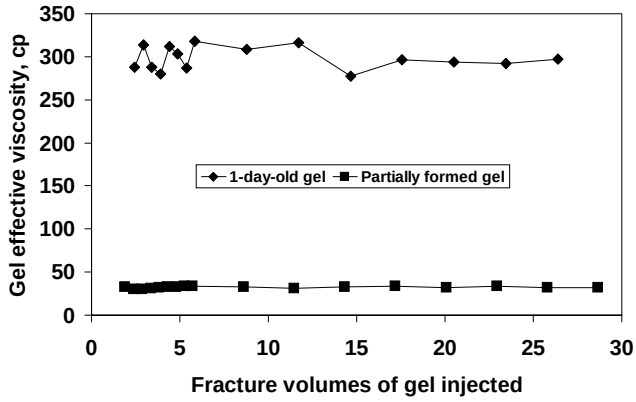

Fig. 2—Effective viscosity during injection of "fully" and "partially" formed 1X gels.

The effective viscosities of all of the studied gel formulations (in the fracture) are plotted in Fig. 3 as a function of the gel aging or the injection delay time (i.e., the time between chromium addition to the polymer solution and the start of gel injection into the fracture).

From viscosity measurements and bottle testing, the gelation onset time for our 1X gel was estimated to be about 5 hours at 41°C. Note in Fig. 3 that for injection delays of 4 hours or less, the apparent viscosities (17 to 30 cp) of the 1X gels in the fractures were only moderately greater than the viscosity of the uncrosslinked polymer solution (15 cp). For the 7-hr-old 1X gel (injected at 16,600 ft/d), the apparent viscosity was also relatively low — about 32 cp. This should be a manageable solution viscosity during gel placement. For longer times, Fig. 3 demonstrates that the apparent viscosity increased rather abruptly to more than 1,300 cp for injection delays of 16 hours or more. *The effective viscosities of partially formed gels can be up to 100 times less than those for "fully formed" gels. Thus, partially formed gels (i.e., gels entering the fractures shortly after their gelation onset times) exhibit substantially higher injectivities and lower placement pressures. This better-injectivity feature is of major importance during field applications where injection pressure constraints limit rates and volumes during gel treatments.* In addition, when a conformance-improvement treatment involves the placement of a strong rigid gel, it is mandatory to inject the gel in a partially formed state.

In Fig. 3, the solid triangle and square show apparent viscosities for the substantially-stouter 2X (with 1% polymer) and 3X (with 1.5% polymer) gels. Again, these gels were formulated and injected so that placement occurred while the gels were partially formed. The effective viscosities in the fractures were about 70 cp and 110 cp for the 2X and 3X gels, respectively. For comparison, the viscosities of the uncrosslinked polymer solutions for the 2X and 3X gels were 63 and 180 cp, respectively (Table 1). Note that the apparent viscosities of the partially formed 2X and 3X gels were more than 10 times less than the values for the fully formed 1X gels. The effective viscosity of 110 cp for the partially formed 3X

(1.5 wt% polymer) gel should not substantially adversely impact the ability to inject this gel solution into most fractures during water-shutoff treatments.

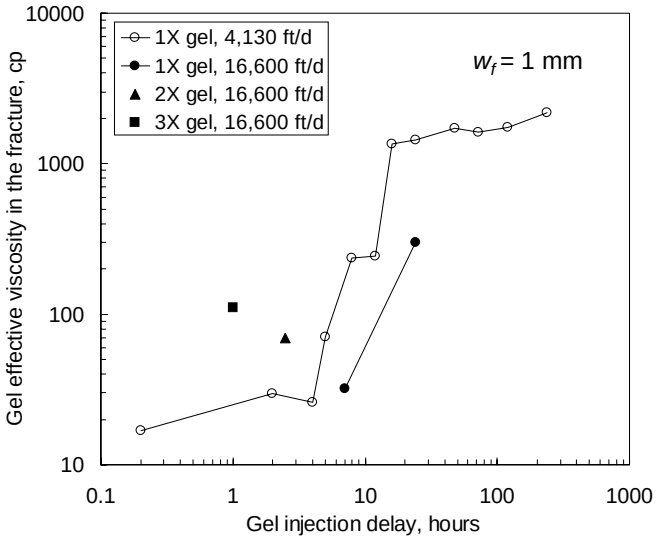

Fig. 3—Effective viscosity versus gel injection delay for 1X CC/AP gels.

Damage to Porous Rock from Gelant Leakoff

One concern with injecting either gelants or partially formed gels is that leakoff conceivably could damage the porous rock adjacent to the fracture. Could this damage significantly impede hydrocarbon flow into the fracture when the well is returned to production? This question is best addressed by answering two related questions: (1) How far does the gelant or partially formed gel formulation leakoff from the fracture faces? and (2) How much does the gel reduce permeability to water versus hydrocarbon?

The distance of gelant leakoff can be estimated using results from our experiments. In particular, by monitoring fluids produced from our matrix ports, we determine leakoff rates during the course of gelant or gel fluid injection. Fig. 4 shows these leakoff rates as a function of gel aging or injection delay time for 12 separate experiments where our 1X gel was forced through 1-mm-wide fractures at 4,130 ft/d (superficial velocity in the fracture). The *y*-axis plots the leakoff rate (in units of ft/d or ft^3 of fluid leakoff per ft^2 of fracture surface per day) averaged during the 2-hr course of injecting ~4,000 cm^3 of gel formulation. Notice that the highest leakoff rates (~0.5 ft/d) occurred for gel injection delays of 12 hours and longer. In previous work,[1,2,7] we demonstrated that this leakoff is strictly brine with no crosslinked polymer. Thus, this water leakoff causes no significant damage to the porous rock. (Of course, dehydrated gel that accumulates on the fracture faces can impede flow.)

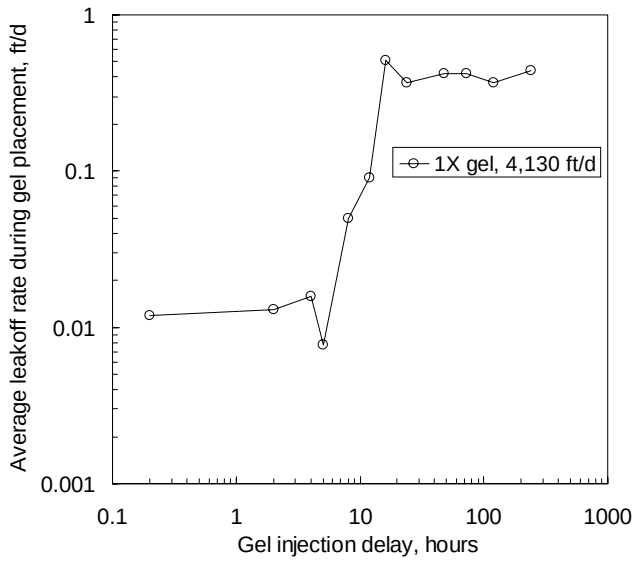

Fig. 4—Leakoff rates during gelant/gel placement.

In contrast, for injection delays of 5 hours or less, the leakoff that occurs presumably is gelant and might be of concern. Fortunately, Fig. 4 indicates that leakoff rates are low for the 1X gel when the gelant is less than 5 hours old. Given an average leakoff rate of 0.013 ft/d, the average distance of gelant penetration from the fracture face was about 20 μm for the 2-ft-long fractures (where ~1,000 cm^3 of partially formed gel was injected at 8,000 cm^3/hr) and about 0.3 mm for the 4-ft-long fractures (where ~4,000 cm^3 of gel formulation was injected at 2,000 cm^3/hr). With this same leakoff rate, the estimated gelant leakoff distance is less than 4 mm if injection continued for 24 hours. The 4-mm estimate may be high, since most polymer should be sufficiently crosslinked by the gelation time so that gel penetration into porous rock is severely limited.[2] Since the gelation time of the 1X gel is 5 hours at 41°C, 1 mm might be a better estimate of the maximum distance of gelant leakoff for this gel (under our laboratory conditions). These small distances of gelant leakoff and damage in the porous rock provide encouragement for the use of partially formed gels in field applications where gel placement lasts less than one day.

For gel injection that exceeds one day and gels that have a gel onset time of less than one day, there should be little gel leakoff after the first day of injection. After one day of gel injection, freshly injected gel will see only fracture rock face surfaces that have been "sealed" by previously injected gel (provided the gel is flowing down one single fracture flow channel or flow channel set).

To assess the damage from any possible gelant leakoff, the permeability reduction (residual resistance factors) must be considered after gel placement. For 700-md Berea, we typically observed water residual resistance factors around 10,000 and oil residual resistance factors of 200 or less.[8,9] For a 1-mm distance of gel penetration into the rock, these permeability reductions provide resistances equivalent to flowing through an additional 30 ft of rock for the water and 8 in. of rock for the oil. This disproportionate permeability reduction is favorable, but would probably not have a large

impact on either oil or water productivity in this particular case.

The primary conclusion from this section is that damage to oil flow caused by gelant leakoff is generally relatively small. With lessened concern about damage from gelant leakoff, we increase confidence in the use of gelants and partially formed gels for treating fractures.

Peak Pressure Gradient for First Gel Breaching

After gel placement and a one-day shut-in, brine was injected at a fixed rate of 100 cm^3/hr (206 ft/d superficial velocity within the fracture). In each experiment, the pressure gradient rose to a peak, followed by a pressure gradient decline to a more or less stabilized value. (Greater detail on this behavior can be found in Ref. 6) The peak pressure gradient indicates the point when brine first breached the gel in the fracture. (As will be discussed shortly, breaching the gel does not constitute total washout. The flow capacity of the fracture remains dramatically less than before gel placement.)

As shown in Fig. 5, the peak pressure gradient was greatest (99 psi/ft) for the 3X gel. This high pressure gradient should be sufficient to resist gel failure for most common fractured-well production rates and pressure drawdowns. Of course, this conclusion applies to 3X gels in 1-mm-wide fractures. Presumably in wider fractures, the peak or critical pressure gradient for breaching the gel would be lower for the 3X gel. On the other hand, for fractures with widths below 1 mm, less concentrated (and therefore less expensive) gels would usually be more appropriate. After placement in 1-mm-wide fractures, Fig. 5 indicates peak pressure gradients of 32 psi/ft for the 2X gel and up to 9 psi/ft for the 1X gels. These values should be sufficient to prevent gel breaching under many circumstances.

Until the peak pressure gradient was exceeded, no measurable brine flow occurred through the gel-filled fracture. The pressure gradient for brine flow in fractures in the intermediate and far wellbore region of many naturally fractured reservoirs is quite small (<10 psi/ft). Thus, if these polymer gels completely filled the fracture volume, water flow through the fracture should be completely blocked.

Interestingly for the 1X gel, Fig. 5 indicates a maximum of ~9 psi/ft in the peak pressure gradient occurred for gels that were aged about 24 hours before placement. For gels placed as gelants, the peak pressure gradient was as low as 1.3 psi/ft. After placing partially formed 1X gels (i.e., injection delays of 4 to 8 hours), 3 to 5 psi/ft was required for brine to first breach the gel. Although the latter pressure gradients were one-third to one-half those for the 24-hr-old gels, the lower pressure gradients during placement will often favor use of the partially formed gels (Fig. 3).

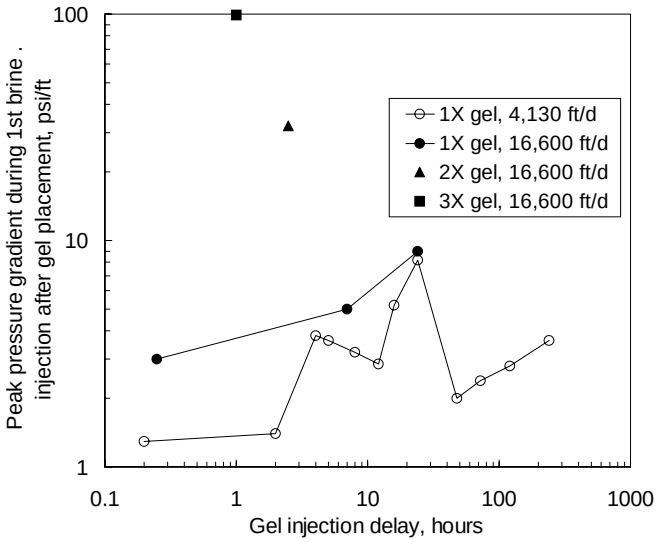

Fig. 5—Peak or critical pressure gradients during first brine flow after gel placement.

The maximum shown for the 1X gel in Fig. 5 may result from the combined influence of gel dehydration and mechanical degradation. When crosslinked polymers are forced through fractures, gel can dehydrate (lose water). The free water leaves the fracture by leaking off through the rock faces. However, the crosslinked polymer remains in the fracture to become increasingly concentrated as more dehydration occurs.[1,2] This concentrated gel is stronger (more resistant to being breached) than the original gel.[10] Also, during deposition of the concentrated gel, the original gel flows through small wormhole pathways (through the dehydrated gel).[5] For most practical circumstances, the dehydrated gel is not mobile. The only mobile gel is that with the original gel composition in the wormhole pathways.[1,2,7] These pathways do not form during flow of uncrosslinked polymer (i.e., fresh gelant). These wormholes become smaller as the age of the injected gel increases (because of an increasingly unfavorable mobility ratio).[7] Since these wormholes were filled with the original gel (i.e., not dehydrated), they probably provide the pathway for first breaching of the gel by brine.[10] With smaller diameter wormholes as the gel injection delay increases, the breaching pressure should increase.

On the other hand, this dehydration effect may be countered by mechanical degradation. Crosslinked polymer can experience mechanical degradation (bond rupture) during flow. For gels placed with small injection delays, additional crosslinking can occur after gel placement to heal any mechanical damage. With long injection delays, mechanical degradation may be more severe during the extrusion process (because many more crosslinks have formed) and less free crosslinker remains to heal the mechanical damage. Consequently, the mechanically damaged gel is more susceptible to breach during brine flow. These arguments could explain the maximum for the 1X gel (around 24-hr injection delay) in Fig. 5.

Stabilized Residual Resistance Factors

In each experiment, after establishing the peak pressure gradient for brine to first breach the gel, we determined the stabilized (equilibrium or "final') residual resistance factor (F_{rrw} or permeability reduction factor) for brine flow through the gel-filled fracture.

Table 2 shows the stabilized residual resistance factors for the experiments involving the 1-mm-wide, 2-ft-long fractured cores (where partially formed gel fluids were placed at 16,600 ft/d superficial velocity in the fractures). For this set of flooding experiments, the stabilized F_{rr} values for brine flow were 1) comparable for the 1X gel injected in the gelant, the partially formed, and the fully formed states and 2) increased with increasing polymer concentration within the gel formulation. The brine was injected at a superficial velocity of 206 ft/d within the fracture (100 cm^3/hr).

Table 2—Stabilized F_{rr} values during the first brine flood through 2-ft-long gel-filled fractures.

Gel state when injected	"Fully formed"	"Gelant"	Partially formed	Partially formed	Partially formed
Time gel aged prior to injection, hr	24	~0.25	7.0	2.5	1.0
Polymer concentration in the gel, wt%	0.5	0.5	0.5	1.0	1.5
Final F_{rr} value	**7,000**	**6,500**	**6,400**	**9,300**	**22,000**

The complete set of the stabilized F_{rr} values for the first post-gel-placement brine floods in both the 2- and 4-ft-long fractured cores are plotted in Fig. 6. Qualitatively, these stabilized residual resistance factors followed the same trends observed in Fig. 5. The values for the 2X and 3X gels were generally greater than those for the 1X gel. One series of experiments with the 1X gel (open circles in Fig. 6) showed maximum stabilized F_{rrw} values for injection delays from 8 to 24 hours. However, it is interesting that the stabilized F_{rrw} values for the 1X and 2X gels were somewhat similar.

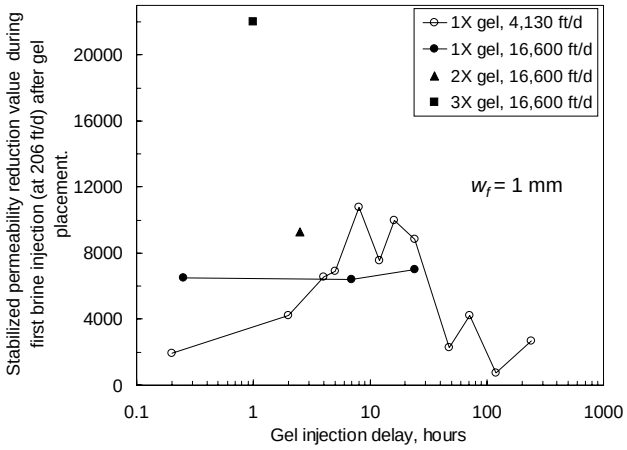

Fig. 6—Stabilized residual resistance factors after first brine injection at 206 ft/d.

Using an equation from Ref. 11, the permeability of the original unobstructed 1-mm fracture was calculated to be 84,000 darcies. A fracture aperture of 1 mm is fairly typical of the average fracture aperture that is found in many naturally fractured oil reservoirs in the Big Horn Basin of Wyoming and the Permian Basin of Texas. In wells with moderate or narrow fractures, the residual resistance factors shown in Fig. 6 should be sufficient to greatly reduce water production. However, for wide fractures, larger residual resistance factors may be needed to reduce the fracture flow capacity to an acceptable level.

The results in Figs. 5 and 6 differ from results reported in Ref. 12, which reported that similar gels did not form in fractures when leakoff was not permitted. However, gel-mixing procedures and a number of experimental factors differed between the experimental studies of Ref. 12 and those of the present study.

As an aside, we briefly mention an experiment involving 16,600 ft/d superficial velocity placement of the 1X gel in a 1.0-ft-long fractured core where no effluent ports were present in the matrix sandstone. In all other respects, this flood was comparable to the experiment for the 1X 7-hr-old gel that is cited in Figs. 3 and 4. (Details of this experiment can be found in Ref. 6) For the 1.0-ft-long core (with no matrix effluent ports), both the peak (breaching) pressure gradient and the stabilized F_{rr} for the post-gel brine were comparable to those values for the 1X partially formed gel experiments of Figs. 3 and 4 where matrix effluent ports were present.

Very Little Gel Was Displaced from the Fractures

The relatively large stabilized F_{rr} values shown in Fig. 6 suggest that 1) only a small portion of the gel residing in the fracture was displaced (washed out) and 2) the brine formed relatively small flow channels or "fingers" through (or around) the gel in the fracture.

Several additional observations suggest that the brine flow channels through the gel are relatively small (likely <10% FV). First, no gel was visually observed in the produced brine, no blue color was visually noted in the produced brine [qualitatively indicating, little or, no dissolved chromium(III)], and there was no slippery feeling to the produced brine (a qualitative indication that little, or no, polymer or gel was present). During first brine flow after gel placement, four of the five analyzed effluent brine samples contained less than 5% of the injected gel's chromium or polymer concentration (the exception contained 7% polymer concentration). In fact, the majority of effluent samples contained less than 1% of the chromium or polymer concentration in the injected gel. Thus, very little gel was produced from the fracture during the first post-gel-placement brine flood.

Second, brine breakthrough occurred substantially before one fracture volume was injected. During all experiments, brine breakthrough indicated that the brine flow channel was a small fraction of the fracture volume. The brine breakthrough volume was determined from the volume of fluid that had been injected when the peak differential pressure for brine injection passed through the furthest downstream of the pressure taps.

Third, the large stabilized (final and equilibrium) residual resistance factors (Fig. 6) could only occur if the final

flow channels were small. Assuming a single cylindrical brine pathway through the gel, standard calculations[13] indicated effective tube diameters typically between 0.06 and 0.11 mm. These values suggest that more than 99% of the gel remained in the fracture after brine injection.

Fourth, upon termination of the experiment, the fracture was opened and visually inspected. For the gels that were aged less than 12 hours before injection, the fracture was filled with gel having qualitatively the same consistency and strength as the mature form of the gel. Little of the gel was displaced from the fracture during brine flow. In fact, chromium analysis of gel samples taken from the fracture after termination of the experiments (specifically those involving gel injection at 16,600 ft/d superficial velocity through the fracture) indicated that the gel was concentrated by 1.2 to 2.5 times. Several small flow channels through the gel were noted (as will be discussed in the next paragraph).

Fifth, at the end of the experiments, several "wormhole" channels were observed through the gel. The wormhole flow channels within the gel were easy to observe because the last fluid injected was Soltrol 130 oil that was dyed red. The relatively small wormhole channels (<10% FV) appeared similar to the wormhole channels that were reported for "fully formed" gels in similar fractures.[7,10]

The photograph in Fig. 7 shows the wormhole channels after the fracture was split open. In this instance, the experiment involved the 2X CC/AP gel and the photo was taken after four cycles of brine and oil flooding. During the final flood of the experiment, red-dyed oil was injected into the gel-filled fracture. Flow occurred from left to right in the photograph. In this photo, the core material resides in roughly the middle half of the photo, with the remaining outer material (top and bottom) being core-holder materials.

Fig. 7—Post-gel-treatment "wormhole" channels in the gel.

In Fig. 7, immediately adjacent to the oil-flow channels, a series of short dead-end "flow channels" appear to emanate perpendicular to the direction of the main oil-flow channels. These "railroad track" features may be an artifact. When a fracture and associate gel were split open, the resulting gel surface was not perfectly smooth. The freshly opened gel surface had alternating series of inward and outward protruding dimples. After splitting open the fracture and gel, a portion of the oil from within the wormhole may have accumulated in the inwardly protruding gel dimples (that were immediately adjacent to the wormhole channels) — thus forming the "railroad tracks".

Pressure Gradients for Other Brine Rates

For many experiments with the 1X gel, after brine injection at 100 cm^3/hr (206 ft/d), the injection rate was doubled, and the measurements were repeated. This process was repeated in stages up to a final brine flow rate of 16,000 cm^3/hr (33,000 ft/d). The final stabilized pressure gradients at other brine rates are shown in Fig. 8. In this figure, the heavy solid line indicates the behavior expected if the core contained no fracture, while the dashed line shows the behavior if the fracture was open and unaffected by the gel. In all experiments, the pressure gradients were substantially larger (by factors ranging from 65 to 8,600) than the values expected for an open fracture. Consequently, all gels caused significant conductivity reductions in the fracture. In particular, residual resistance factors ranged from 2,000 to 8,600 at 100 cm^3/hr and from 65 to 337 at 16,000 cm^3/hr.

For most of the data curves, the pressure gradient varied with rate raised to the 0.3 power. This variation indicates that some incremental erosion or compaction of the gel occurred with each increase in brine injection rate. If no gel erosion or compaction occurred, the slopes of the curves should have been unity.

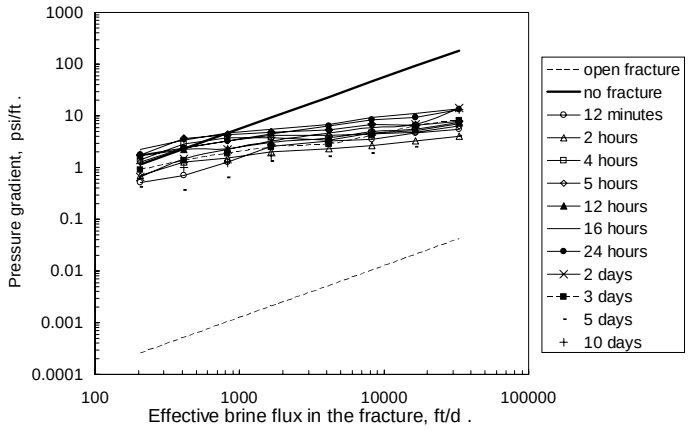

Fig. 8—Final stabilized pressure gradients at various brine rates.

For a given brine injection rate, the pressure gradients generally increased with increasing injection delay up to 24 hours. For injection delays beyond 24 hours, the pressure gradients were lower.

For a given brine injection rate, the largest pressure gradient (typically associated with the 16-hour delay) was 5 to 6 times greater than the lowest pressure gradient. Presumably, brine forced at least one pathway through the gel for each experiment shown in Fig. 8. Although the exact shapes of these pathways are not known, we note that flow capacity varies with the third power of width for slit openings and with the fourth power of diameter for circular openings. The data in Fig. 8 represent a relatively narrow range of brine pathways sizes. For example, assuming tube-shaped brine pathways, the diameters ranged from 0.07 to 0.11 cm for the experiments at 16,000 cm^3/hr (33,000 ft/d) in Fig. 8.

"Healing" a Fracture

An important point from the above discussions was that the gel caused substantial reductions in the fracture conductivities (i.e., residual resistance factors were between 750 and 22,000). These reductions occurred because very little gel washed out when brine was injected after gel placement. Ideally, a gel treatment should "heal" the fracture without damaging the porous rock. In that case, the final composite permeability of the core plus the fracture would revert to the permeability of the unfractured core. The last row of Table 3 lists composite permeabilities (after injecting 30 FV of brine) for the five cases considered (experiments involving gel injection at 16,600 ft/d superficial velocity). Interestingly, these overall permeabilities were insensitive to the gel state when injected (aged 0.25-24 hr) and polymer concentration in the gel formulation. In all cases, the overall fractured-core permeabilities were somewhat less than the 700-md permeability of the Berea sandstone. It is not surprising that the gel reduced the permeability of the matrix rock somewhat because most of the inlet core face was exposed during gel injection. Thus, the core inlet face was damaged to some extent by the injected gel.

Table 3—Composite stabilized fracture-core permeability for the first brine flood.

Gel state when injected	"Fully formed"	"Gelant"	Partially formed	Partially formed	Partially formed
Gel designation	1X	1X	1X	2X	2X
Aging time prior to injection, hr	24	~0.25	7.0	2.5	1.0
Polymer concentration in gel, wt%	0.5	0.5	0.5	1.0	1.5
Composite stabilized permeability, md	**330**	**380**	**380**	**300**	**440**

It should be noted that reduction of the composite fracture-core permeability below 700 md does not necessarily insure that the fracture was "healed" (i.e., that the fracture conductivity was reduced to near zero). In theory, it is possible that the fracture may still be open to some extent and the rock matrix is damaged enough so that the composite permeability falls below 700 md.

Flow Diversion

The extent to which brine is diverted away from the fracture and into the matrix can be assessed by examining the ratio of brine produced from the fracture versus from the matrix. For the experiments of Table 3, the final rate of brine production from the matrix effluent ports ranged from 14% to 21% of the total flow rate. In contrast, at the time of the peak pressure, 21% to 92% of the total flow rate was produced from the matrix ports. Before gel placement, no measurable amount of fluid was produced from the matrix ports. Thus, the gel diverted brine flow away from the fracture and into the matrix sandstone rock. Of course, in the ideal case, all flow would be produced from the matrix port after the gel treatment.

Fig. 9 plots the percent of the brine that was produced from the matrix during the various experiments with the 1X gels in the 4-ft-long fractures (gel injection at 4,130 ft/d superficial velocity).

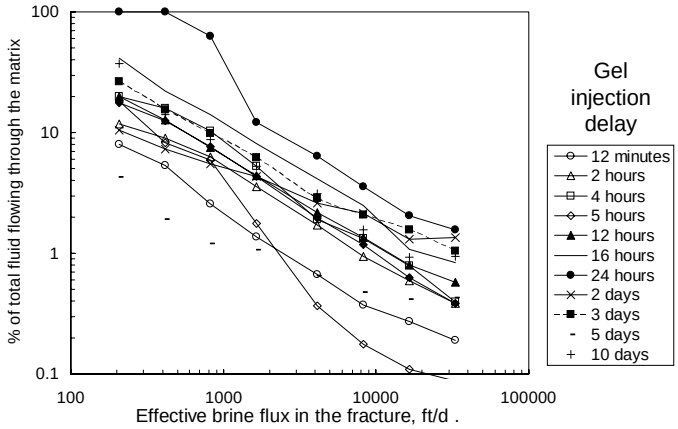

Fig. 9—Percent of brine flowing through the matrix.

The 24-hour experiment showed the best behavior, with 100% of the brine being forced to flow through the matrix (i.e., no flow occurred in the fracture) at rates of 413 ft/d and lower. In general, longer gel injection delays (up to 24 hours) lead to better fluid diversion. For all injection delays, the favorable diversion properties deteriorated substantially upon exposure to successively greater brine injection rates.

However, on a more positive note, we routinely observed that very little, if any, brine was produced from the fracture during the first brine injection after gel placement — so long as the gel in the fracture had not been breached (i.e., the peak pressure described in Fig. 5 had not yet been exceeded). Thus, prevention of the first gel breach (i.e., the data from Fig. 5) may be an extremely important factor for many gel water-shutoff applications in fractures and fracture systems. If this peak pressure is not exceeded and the gel completely fills the target fracture volume, then no significant water flow should occur.

Gel-Treated Fractures Exhibit Disproportionate Permeability Reduction

In previous literature, disproportionate permeability reduction (DPR) and its synonym, relative permeability modification (RPM), refer to polymers or gels that reduce the permeability to water more than that to oil or gas *in porous rock.*[8,9]

A series of experiments were conducted during this study to determine if partially formed CC/AP polymer gels promote disproportionate permeability reduction within a fracture. During six experiments involving three gel formulations (gel injection at 16,600 ft/d superficial velocity), the CC/AP gels that were placed in a partially formed state exhibited varying degrees of disproportionate permeability reduction in the fractures (k_{of}/k_{wf} ranged from 22 to 88). Details can be found in Ref. 6.

1X and 3X Gels Exhibit DPR. For two additional flooding experiments (one involving a 1X gel aged for 7 hours before placement and the other involving the 3X gel that was aged for 1 hour before placement), we examined the gel's ability to reduce permeability to water more than that to oil *in fractures*. In each case, after the first brine flood following gel placement in 1-mm-wide fractures, we performed an oil flood at a rate of 500 cm^3/hr. Results of these experiments are summarized in Table 4. "Final permeability" in this table refers to the permeability after injection of 30 FV of brine or oil.

In Table 4, the ratio of oil permeability to water permeability (k_{of}/k_{wf}) was 166 for the 1X gel and 77 for the 3X gel. Thus, *CC/AP gel placed in the partially formed state reduced the permeability to water in the fracture to a much greater extent than the permeability to oil*. As expected, the F_{rr} values for brine and oil for the 3X gel were significantly larger than the F_{rr} values for the 1X gel.

Table 4—Disproportionate permeability reduction by 1X and 3X gels.

Gel designation	1X	3X
Polymer concentration in gel, wt%	0.5	1.5
Final brine permeability, md	**12,000**	**3,900**
Final oil permeability, md	**2,000,000**	**300,000**
Ratio, k_{of}/k_{wf}	**166**	**77**
Brine F_{rrw}	7,000	22,000
Oil F_{rro}	42	280

As a cautionary note, the above k_{of}/k_{wf} value (166) is one of the largest that we observed to date for gel placed in a fracture. Shortly, we will discuss examples and conditions where the disproportionate permeability reduction was substantially less. The value of 166 was determined during experiments that were conducted at relatively low flow rates and where the brine was flooded before oil.

We repeated the water/oil flooding sequence three more times for each experiment. Figs. 10 and 11 plot the brine and oil residual resistance factors (F_{rr}) for the four series of post-gel-placement brine and oil floods. During each cycle, 30 FV of brine and oil were injected into the gel-filled fracture. All these floods were conducted at an injection rate of 500 cm^3/hr.

At the end of the first oil flood for the 1X gel, the final fracture permeability to oil was 2,000,000 md, yielding a permeability reduction factor of only 42. *During the next three flooding series, the final permeability to oil remained constant, within experimental error. However, brine F_{rr} values progressively declined from 7,000 to 180 (i.e., by a factor of 38). The final fracture permeability to brine flow progressively increased from 12,000 to 460,000 md.* The same general type of DPR behavior as depicted in Fig. 10 has been previously reported for a CC/AP gel residing in porous media.[8]

As was observed with the 1X gel, the oil F_{rr} values and the permeabilities for the 3X gel remained fairly constant during the four series of oil floods. However, final brine F_{rr} values progressively declined from 22,000 to 1,000.

A final brine permeability reduction factor of 1,000 should be adequate for many water-shutoff applications in 1-mm fractures. In wider fractures, larger residual resistance factors may be needed.

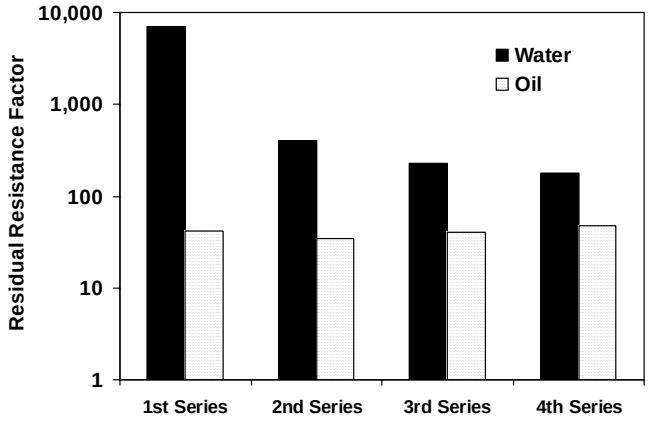

Fig. 10—Four post-gel-placement water and oil floods for the 1X gel.

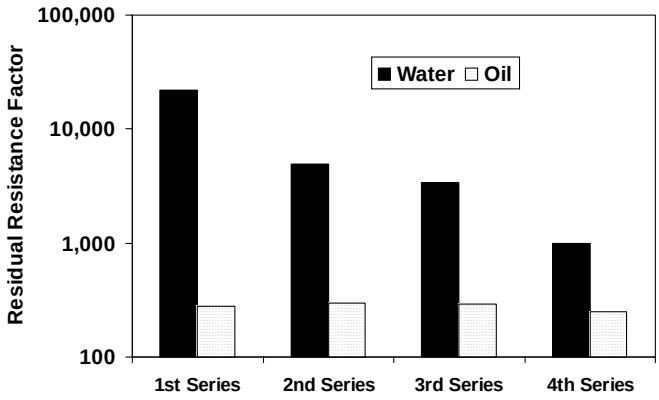

Fig. 11—Four post-gel-placement water and oil floods for the 3X gel.

Additional Discussion Relating to Water-Shutoff Gel Characterization

Gel Washout? Terms such as "gel washout" and "gel failure" have often been invoked to describe brine breaching gel in fractures. In a sense, these terms can be misleading (as demonstrated in this study) because the vast majority of the fracture volume remains filled with gel that can substantially reduce water flow through the fracture.

Inferior Field Performance and What Is Needed. Considering our laboratory findings, why don't we see near complete reduction in brine production during field applications of polymer-gel water-shutoff treatments in fractured reservoirs? There are a number of possible

explanations. First, if a well is not pumped off (even if the water is being produced from a single fracture), the reduction in the water production rate will probably be less than the permeability reduction factor that the gel imparted to the treated fracture. For example, consider a well that can produce 10,000 BPD of water though a single fracture when fully drawn down, and the well's pump can only produce 1,000 BPD of fluid. Thus, the well produces 1,000 BPD of fluid. For the sake of simplicity in this example, we assume no oil production and all the fluid production occurs from the single fracture. Now, we successfully apply a polymer-gel treatment that reduces the permeability and fluid flow capacity of the fracture by 80%. If the well is put back on production with the same pumping unit, the water production rate will not be reduced by 80%. Instead, the well will still produce 1,000 BPD of water.

Second, the reservoir fractures may have sufficiently large apertures such that the applied gel does not have enough mechanical strength to withstand the prevailing pressure gradients and/or is not appropriate for application to such wide fractures.

Third, complete filling of the fracture volume with gel can be more difficult in the field than in our laboratory experiments. For example in large aperture vertical fractures, the gel formulation may gravity-segregate to the bottom of the fracture during placement on the field scale (especially if there is oil in the fracture). Since the top part of the fracture remains open, water flow to the well may not be retarded sufficiently. In the field setting, this fourth explanation is probably a *major contributor* to less than optimum performance of polymer-gel water-shutoff treatments in fractured production wells.

This paper demonstrated that polymer gels can impart large permeability reduction factors for water flow in gel-treated fractures. Our results and discussion imply that ineffective and/or incomplete filling of the fracture volume during gel placement is often responsible for attaining smaller water-shutoff values in the field than in the laboratory. Mastering how to more completely fill fractures with a gel may be the key to improving the success rate and the effectiveness on the field scale of water-shutoff polymer gels in fractures and fracture systems.

Brine Flow Rates and Fracture Apertures. The post-gel-placement flow rates investigated during this study were often relatively low. At higher brine flow rates, and associated higher pressure drops, gel erosion or compaction (dehydration) can occur — increasing fracture flow capacity and reducing gel effectiveness. However, as will be shown in Ref. 14, polymer gels can be formulated to help mitigate these concerns.

The 1-mm fracture aperture, which was utilized in this experimental study, is not exceptionally large.

Wormholing. This study found that brine and oil usually "wormhole" through water-shutoff gels that reside in fractures. This finding is not surprising, since the brine and oil are tremendously more mobile than the gels. "Fingers" (for the case of liquids displacing liquids) and "wormholes" (for the case of fluids destructively penetrating into solids) are well known to occur for displacements involving unfavorable mobility ratios. In previous work,[7,10] we reported a special type of wormholing when a 1-day-old gel was extruded into fractures. During the extrusion process, the gel dehydrated or concentrated, forming an immobile gel within the fracture that became increasingly concentrated with time. Gel of the original concentration was forced to wormhole through the concentrated immobile gel in order to continue propagating through the fracture. Consequently, at the end of the gel placement process, most of the fracture was filled with a strong, concentrated gel, but the wormholes were filled with less concentrated and less rigid gel. During brine or oil flow after gel placement, the first breach of the gel occurred in these pre-established wormholes.

In contrast, when a gel formulation was placed as a gelant or partially formed gel, these pre-established wormholes were not necessarily present. Thus, during brine or oil flow, *different breach points* occurred within the gels. Nonetheless, for all the experiments to date, the wormhole pathways had a similar appearance, regardless of whether the gels were placed as gelants, partially formed gels, or "fully formed" gels.

The "wormhole" fluid-flow pathways within the gel residing in the fractures of this study are not too unlike, in concept, the "finger" fluid-flow channels, observed by University of Kansas researchers, for CC/AP gel residing in tubes.[15,16]

Conclusions

The following conclusions are limited to the polymer gels and the experimental conditions of this study.

1. Partially formed (<8-hr-old) 1X (0.5% polymer) CC/AP gels showed much lower (as much as 100 times less) effective viscosities (17 to 35 cp) during flow through a 1-mm-wide fracture than "fully formed" (>15-hr-old) gels with the same chemical composition. Thus, partially formed gels exhibit substantially higher injectivities and lower placement pressures. This feature is of major importance during field applications where pressure constraints limit rates and volumes during gel treatments.
2. For gelants and partially formed gels that were 5 hours old or less, the rates of gelant leakoff through fracture faces were very low (about 0.013 $ft^3/ft^2/d$). Thus, field applications that inject relatively small volumes of gelant or partially formed gels will generally experience small gelant leakoff distances and will not significantly inhibit oil from entering the fractures.
3. During first brine injection after gel placement in 1-mm-wide fractures, the pressure gradient required to first breach the gel increased significantly with increased polymer concentration in the gel — ranging from roughly 5 psi/ft for 1X (0.5% polymer) partially formed gels to 99 psi/ft for 3X (1.5% polymer) partially formed gels. For 1X gels, the breaching pressure gradient was greatest (~9 psi/ft) when the gel was aged from 12 to 24 hours before injection. Prior to exceeding the breaching pressure gradient, no detectable brine flowed through the fracture.
4. During the limited brine flow after gel placement, most (>90%) of the gel remained in the fracture and did not "washout."

5. The stabilized residual resistance factors (permeability reduction factors) for the first brine flow through the fracture (following gel placement and maturation) ranged from 750 to 22,000 – increasing with increased polymer concentration and gel strength.
6. For the 1X gel, the stabilized permeability reduction factors (for brine flow in a gel-treated fracture) were comparable for formulations injected in the gelant state, the partially formed state, and the "fully formed" state.
7. The large stabilized (final and equilibrium) residual resistance factors for brine flow through the gel-filled fractures resulted from the brine flowing through relatively small channels (wormholes) residing within the gel.
8. The CC/AP gels exhibited disproportionate permeability reduction during brine and oil flow through the gel-filled fractures.
9. During one experiment with the 1X gel, brine permeability in the fracture was reduced 166 times more than that for oil. In this case, brine was flooded first, followed by oil.
10. For the studied 1X and 3X gels, the permeability reduction factor for oil flow remained constant (within experimental error) during four cycles of brine and oil injection. In contrast, the permeability reduction factor for brine decreased more than a factor of 10 during these cycles.

Acknowledgements

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Nomenclature

CC/AP = chromium(III)-carboxylate/acrylamide-polymer
DPR = disproportionate permeability reduction
HPAM = hydrolyzed polyacrylamide polymer
FV = fracture volume
F_{rr} = residual resistance factor
F_{rro} = oil residual resistance factor
F_{rrw} = water residual resistance factor
k = permeability, darcys [μm^2]
k_{of}/k_{wf} = ratio measuring degree of DPR
k_o = permeability to oil, darcys [μm^2]
k_w = permeability to water, darcys [μm^2]
Mw = molecular weight
Δp = pressure drop, psi [Pa]
w_f = fracture width, in. [m]
μ = viscosity, cp [mPa-s]
1X = gel containing 0.5 wt% polymer
2X = gel containing 1.0 wt% polymer
3X = gel containing 1.5wt% polymer

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SI Metric Conversion Factors

cp x 1.0*	E-03	= Pa·s
ft x 3.048*	E-01	= m
ft/d x 3.528	E-06	= m/s
°F x (°F-32)/1.8		= °C
in. x 2.54*	E+00	= cm
$in.^3$/hr x 6.102374	E-02	= cm^3/hr
md x 9.869233	E-04	= μm^2
psi x 6.894757	E+00	= kPa
psi/ft x 2.262059	E+01	= kPa/m

*Conversion is exact.