Gel Treatments for Reducing Channeling in Naturally Fractured Reservoirs

R.S. Seright, SPE, and **R.L. Lee,** SPE, New Mexico Petroleum Recovery Research Center

Summary

This paper considers some of the reservoir variables that affect the severity of channeling and the potential of gel treatments for reducing channeling through naturally fractured reservoirs. We performed extensive tracer and gel placement studies using two different simulators. We show that gel treatments have the greatest potential when the conductivities of fractures that are aligned with direct flow between an injector-producer pair are at least 10 times the conductivity of off-trend fractures. Gel treatments also have their greatest potential in reservoirs with moderate to large fracture spacing. Produced tracer concentrations from interwell tracer studies can help identify reservoirs that are predisposed to successful gel applications. Our simulation studies also show how tracer transit times can be used to estimate the conductivity of the most direct fracture. The effectiveness of gel treatments should be insensitive to fracture spacing for fractures that are aligned with the direct flow direction. The effectiveness of gel treatments increases with increased fracture spacing for fractures that are not aligned with the direct flow direction.

Introduction

Some of the most successful gel treatments have been applied to reduce channeling in naturally fractured reservoirs.[1-5] Therefore, a need exists to identify which characteristics of naturally fractured reservoirs indicate good candidates for gel applications. This paper considers some of the reservoir variables that affect the severity of channeling and the potential of gel treatments for reducing channeling through naturally fractured reservoirs.

Available Characterization Methods

At least three books describe reservoir engineering in naturally fractured reservoirs.[6-8] These books concentrate on oil and gas recovery during primary production. In contrast, this paper focuses on correcting channeling problems during secondary recovery operations.

Various logging methods have been used to detect and characterize fractures (Chap. 3 of Ref. 6, Chap. 2 of Ref. 7, and Chap. 5 of Ref. 8). These methods must be used with caution since they usually measure properties at or very near the wellbore. The value of these methods can be increased if the wellbore is deviated to cross the different fracture systems (i.e., fractures with different orientations).

Pressure transient analyses have often been used to characterize fractured reservoirs (Chap. 4 of Ref. 6, Chap. 4 of Ref. 7, Chaps. 6 through 8 of Ref. 8, and Ref. 9). Reportedly, these methods can estimate the fracture volume, the fracture permeability, and, possibly under some circumstances, the minimum spacing between fractures. Pressure interference tests can also indicate fracture orientation. In addition to unsteady-state methods, steady-state productivity indexes were also suggested as a means to estimate fracture permeability.

Interwell tracer studies provide valuable characterizations of fractured reservoirs, especially in judging the applicability of gel treatments to reduce channeling.[10-13] Interwell tracer data provide much better resolution of reservoir heterogeneities than pressure transient analysis.[14] Tracer results can indicate (1) whether fractures are present and if those fractures are the cause of a channeling problem, (2) the location and direction of fracture channels, (3) the fracture volume, (4) the fracture conductivity, and (5) the effectiveness of a remedial treatment (e.g., a gel treatment) in reducing channeling. Several models are available to analyze tracer results.[13-19]

In this paper, we present some simple concepts to assess the applicability of gel treatments in naturally fractured reservoirs—in particular, when channeling occurs between injector-producer pairs.

Representation of a Naturally Fractured Reservoir

When modeling naturally fractured reservoirs, the fracture systems generally have been envisioned as slabs (i.e., one set of parallel fractures), columns (i.e., two intersecting sets of parallel vertical fractures), or cubes (i.e., three intersecting sets of parallel fractures—two vertical and one horizontal). Geostatistics have also been used to describe fracture distributions. In this paper, we focus on the column model. For simplicity, assume that a naturally fractured reservoir consists of a regular pattern of north-south fractures intersected by east-west fractures (see **Fig. 1**). For a given number, n, of fractures that are oriented in the north-south direction (the y direction), $2n-1$ fractures are oriented in the east-west direction (the x direction). Fig. 1 illustrates a numbering scheme for the fractures (specifically for the case where $n=11$). For our base case, one injection well and one production well were located at either end of the central east-west fracture. Also, the distance between fractures was the same in both the x and y directions. (Later, we will consider wells where the producer is not on the central east-west fracture. Also, fracture spacing will be varied in different directions.) We assumed that flow through the rock is negligible compared with that through the fractures and that the system is incompressible. Furthermore, fractures in the y direction are assumed to have a conductivity, $(k_f w_f)_y$, and fractures in the x direction are assumed to have a different conductivity, $(k_f w_f)_x$. A conductivity ratio, R, is defined using Eq. 1.

$$R=(k_f w_f)_x/(k_f w_f)_y . \qquad (1)$$

In Ref. 20 two simulators were described (denoted C and E) that were used to determine pressures, flow rates, and front positions when a water tracer, a gelant, or a gel was injected into a fracture pattern. Simulator C assumed that gelant or tracer was injected continuously with a unit-mobility displacement without dispersion. In contrast, Simulator E was more sophisticated—allowing injection of banks of gelant, gel, or tracer and also accounting for dispersion of the banks. Simulator E was most useful for systems with relatively few fractures (i.e., with n values of 21 or less). Simulator C was useful for obtaining relatively rapid results for systems with large numbers of fractures (i.e., with n values up to 101).

Tracer Transit Times in a Single Fracture

During a unit-mobility displacement, the time required for a tracer to travel between an injector-producer pair often provides a useful characterization of a fractured reservoir.[10-13] Of course, the tracer transit time depends on a number of variables, including the pressure drop between the wells (Δp), the distance between wells (L), the number, orientation, and conductivity ($k_f w_f$) of the connecting fractures, and the viscosity of the fluid in the fractures (μ).

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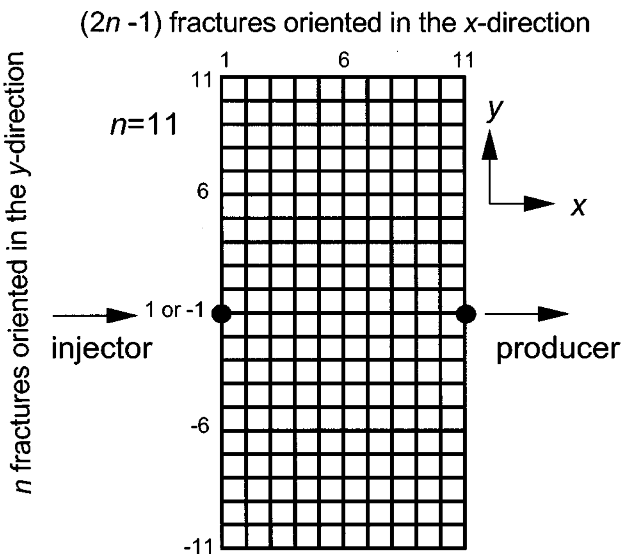

Fig. 1–Plan view of an injector-producer pair in a simple naturally fractured reservoir.

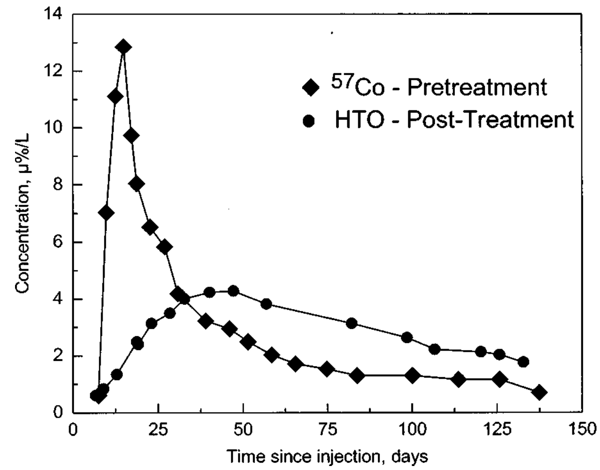

Fig. 3–Interwell tracer results before and after a gel treatment (after Ref. 13). Injection: 250 BWPD; production: 550 BWPD.

We use the transit time associated with a single direct fracture as a means to normalize transit times for our fracture systems. If a reservoir contains only one fracture (with fracture height, h_f) that leads directly from the injector to the producer and flow through the rock matrix can be neglected, the Darcy equation determines the volumetric flow rate (q):

$$q = \Delta p k_f w_f h_f / (L \mu). \tag{2}$$

The transit time (t) for a tracer is estimated from the fracture volume ($h_f w_f L \phi_f$) divided by q:

$$t = h_f w_f L \phi_f / q = w_f L^2 \mu \phi_f / [\Delta p (k_f w_f)]. \tag{3}$$

Given the fracture conductivity, the effective average fracture width, w_f, can be estimated using Eq. 4 if w_f is expressed in feet and $k_f w_f$ is expressed in darcy-ft:[21]

$$w_f = 5.03 \times 10^{-4} (k_f w_f)^{1/3}. \tag{4}$$

Fig. 2 plots expected tracer transit times from Eq. 3 versus fracture conductivity and pressure drop when $L = 1{,}000$ ft, $\mu = 1$ cp, and $\phi_f = 1$. As an example, for a pressure drop of 80 psi, Fig. 2 predicts a transit time of one day for a 1,000-ft-long fracture with a conductivity of 1 darcy-ft.

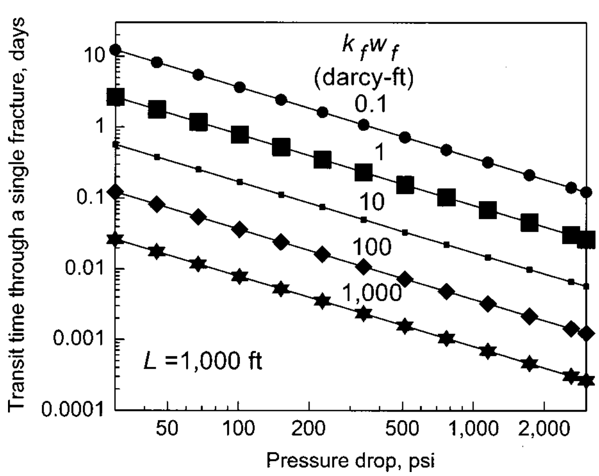

Fig. 2–Transit times through a single 1,000-ft-long fracture.

Although the above analysis provides a simple and useful means to roughly estimate tracer transit times, one should recognize that dispersion affects the profile of produced tracer concentrations versus time or volume throughput. For example, **Fig. 3** (from Ref. 13) shows field results from two interwell tracer tests that were performed before and after application of a gel treatment in a limestone reservoir. For both tests, a slug of radioactive tracer was injected over a short time period, but the tracer was produced over the course of 140 days. In both cases, the first tracer was produced only four days after tracer injection into a well that was 450 ft from the producer. The peak concentration was observed after 10 days for the tracer study before the gel treatment and after 37 days for the study after the gel treatment.

Using tracer results, Tester *et al.*[11] considered several methods to estimate the volume associated with a fracture channel. They suggested that the best estimate of the volume of a fracture path is provided by the modal volume (i.e., the volume associated with the peak concentration in the produced tracer distribution). For example, in Fig. 3, the peak concentration during a tracer study before the gel treatment was noted about 10 days after tracer injection. Based on other information provided in Ref. 13, about 20% of the production rate of 550 BWPD was attributed to the well where tracer was injected. Thus, the estimated volume of the dominant fracture path was $0.2 \times 550 \times 10$ or 1,100 bbl.

Tester *et al.*[11] noted that other volume measures could be determined from the tracer curves. However, they observed that these volumes are weighted to overestimate the fracture volume in most circumstances.

If dispersion during flow through a single fracture (with no leakoff) was caused only by laminar mixing, a tracer would first arrive at the end of a fracture after injecting two-thirds of one fracture volume.[22,23] In the examples shown in Fig. 3, tracer breakthrough occurred at 40% and 11% of the times (and volumes) associated with the peak concentrations. These results suggest that considerable dispersion occurred in the field examples. Also, the tracer bank should completely pass after injection of a few fracture volumes (i.e., a few thousand barrels). Instead the tracer profile was dispersed over 140 days ($\approx$70 fracture volumes). This dispersion reflects the range of pathways from the injection well to the production well.[11,13] Early tracer production reflects the most rapid pathways, while late tracer production indicates long or circuitous pathways, dead ends, or possibly chemical exchange in the reservoir.[11,13] As will be evident in the next section, a wide range of pathways are available in naturally fractured reservoirs.

Transit Times in a Fracture System

Simulator C was used to determine times required for a tracer to travel from an injection well to a production well in a naturally

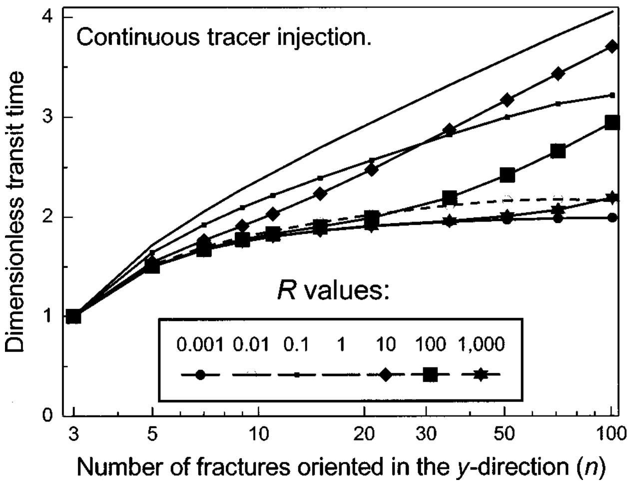

Fig. 4–Injector-producer tracer transit times in naturally fractured systems relative to that for a single direct fracture (unit-mobility displacement, fixed pressure drop, continuous injection, no dispersion); (Simulator C).

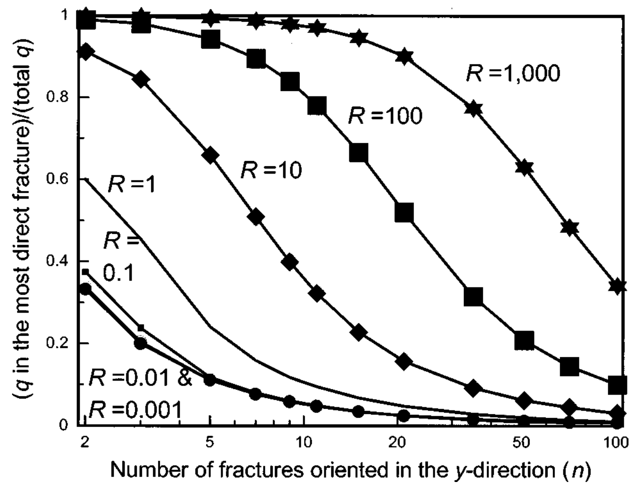

Fig. 5–Severity of channeling through the most direct *x*-direction fracture; (Simulator C).

fractured system. These calculated transit times reflect the most rapid pathways between the wells. In all cases, the ''reservoir'' looked like Fig. 1. Also, a unit-mobility displacement was used, and a fixed pressure drop was applied between the wells. The transit times from this program were normalized by dividing by the time calculated using Eq. 3. (The time calculated using Eq. 3 represents the transit time when the system contains a single fracture.) These dimensionless transit times are plotted in **Fig. 4** for fracture conductivity ratios, R, ranging from 0.001 to 1,000. The number of fractures oriented in the y direction, n, ranged from 3 to 101.

Simulator E was used to confirm the results shown in Fig. 4. Similar conditions were applied for both sets of simulations. Details of these simulations can be found in Ref. 20. As mentioned earlier, Simulator E considered injection of a tracer bank that can experience dispersion, while the Simulator C only considered continuous tracer injection with no dispersion. For runs made with Simulator E, the volume of the injected tracer bank was 10% of the total fracture volume of the system.

For the range of conditions examined, Fig. 4 suggests that the transit time is not greatly sensitive to the R or n values. In particular, we see, at most, a four-fold variation in dimensionless transit times. These results indicate that tracer transit times will not help much in determining R or n values in field applications. With increasing n values, the greatest variations occur when $R=1$ (fractures in the x direction have the same conductivity as those in the y direction). The smallest variations occur when R is very large or when R is near zero.

Incidentally, under our conditions, the dimensionless transit time is unity when $n \leqslant 3$. When n has a value of 1 or 2, the y-direction fractures only exist at the injection and/or production wells. Since no intermediate y-direction fractures are present between the wells to divert the tracer from the central x-direction fracture, the transit time is the same when $n=1$ or 2. For the case when $n=3$, one y-direction fracture exists exactly half way between the two wells. However, because the pressure is the same all along this y-direction fracture (because of its central location), tracer flowing through the central x-direction fracture has no potential to be diverted into the central y-direction fracture. Consequently, the transit time when $n=3$ is the same as when $n=1$ or 2.

The fact that tracer transit times are not sensitive to R or n values suggests that transit times can be very useful when estimating the permeability or conductivity of the most direct fracture. To explain, Fig. 4 indicates that the tracer transit time in a naturally fractured reservoir is usually between one and four times the value for a single direct fracture (if $n \leqslant 101$). Therefore, if the tracer transit time is measured, that value can be used in Eq. 5 (obtained by rearranging Eq. 3) to estimate the effective fracture permeability (within a factor of four):

$$k_f = L^2 \mu \phi_f / (t \Delta p). \tag{5}$$

If k_f is known in darcy units, Eq. 6 (obtained by rearranging Eq. 4) can be used to convert fracture permeability to fracture conductivity (in darcy-ft):

$$k_f w_f = 1.13 \times 10^{-5} (k_f)^{1.5}. \tag{6}$$

Sweep Efficiency

The sweep efficiency in our model systems can be assessed by comparing flow rates through specific fractures. For example, an effective method to judge the severity of channeling is to compare the flow rate in the most direct fracture with the total injection rate. This comparison is made in **Fig. 5** for R values ranging from 0.001 to 1,000 and for n-values ranging from 2 to 101. The y axis in Fig. 5 shows the flow rate in the most direct x-direction fracture (i.e., the central east-west fracture in Fig. 1) divided by the total injection rate. More specifically, the flow rate in the most direct fracture was determined at the midpoint between the two wells.

As expected, Fig. 5 shows that the most severe channeling occurs with the largest R values (i.e., when fracture conductivity in the x direction is much greater than that in the y direction). When the R values are 0.1 or less, the fraction of flow in the most direct fracture is low and nearly independent of the R value—indicating that sweep efficiency is quite good. Fig. 5 suggests that channeling is generally not severe unless the R value is 10 or greater.

Fig. 5 also indicates that the severity of channeling through the most direct fracture decreases with increasing n value. Recall from Fig. 1 that n is the number of fractures oriented in the y direction, while $2n-1$ fractures are oriented in the x direction. In all figures in this paper, the distance between the two wells is fixed. So, as the n value increases, the distance between fractures decreases. For example, if $n=11$, the distance between fractures will be 10 times greater than when $n=101$.

Fig. 5 suggests a method to make interwell tracer studies useful when assessing the R and n values in field applications. When R is large and n is low to intermediate, the production rate is dominated by flow through the most direct fracture. Thus, if a tracer is injected continuously, the tracer concentration in the production well should stabilize at a high value under these conditions. Fig. 5 suggests that if the produced tracer concentration was 90% of the injected value, the R value must be at least 10. However, this suggestion assumes that our production well is fed only by the fracture system to the left of the producer in Fig. 1. In a naturally fractured system, we expect a similar fluid supply from a fracture pattern to the right of the producer in Fig. 1. Thus, the expected tracer concentrations would be half of the values suggested by Fig. 5. Then, in the example above, if the produced tracer concentration was 45% of the injected value, the R value must be at least 10.

Similar reasoning suggests that a produced tracer concentration of 30% indicates that the R value is at least 1 and is probably at least 10. To explain, in Fig. 5, flow through the most direct fracture amounts to 60% of the total when $R=1$ and $n=2$ or when $R=10$ and $n=5$. Thus, the produced tracer concentration would be 30% in a well fed by two identical patterns (i.e., 60%/2). Actually, this reasoning is conservative. In naturally fractured reservoirs, fracture intensities are frequently greater than those associated with $n=5$ (corresponding to an average distance of 125 ft between fractures if the wells are separated by 500 ft). From Fig. 5, for a given value on the y axis, the R value increases with increasing n value. Furthermore, as mentioned earlier, dispersion during laminar flow in a single fracture is expected to result in a 33% dilution.[22,23] Therefore, a produced tracer concentration of 20% [i.e., $(1-0.33)\times 30\%$] generally indicates an R value of at least 10.

As will be shown shortly, gel treatments in naturally fractured reservoirs have the greatest potential when R values are high and n values are low to intermediate. In searching for a guideline to distinguish when a reservoir meets these conditions, a potentially useful indicator is a peak produced tracer concentration of at least 20% of the injected value. Of course, the potential for a gel treatment becomes greater as the peak produced tracer concentration increases above 20% of the injected value. When produced tracer concentrations are low, gel treatments are unlikely to be effective.

The above recommendation assumes that a sufficient tracer bank is injected. If the tracer bank is too small, dispersion will reduce the produced concentrations well below those suggested here. Of course, retention, degradation, or leakoff of the tracer can also have this effect. Thus, the tracer study must be designed properly in order for our recommendation to be of value.

When $R\leqslant 0.1$, we found that the flow rate is basically the same through all x-direction fractures, regardless of the n value.[20] The sweep efficiency is very high when the conductivity of the x-direction fractures is much less than that of the y-direction fractures. Obviously, no gel treatment is needed in this type of reservoir, since no significant channeling exists.

In contrast, when $R\geqslant 10$, our simulations indicated that virtually no flow occurs through most of the x-direction fractures.[20] In these cases, most flow occurs through the most direct fracture or through fractures close to the most direct fracture.[20] Of course, these are the conditions where a gel treatment is expected to work best.

When $R=1$ (all fractures have the same conductivity), our studies revealed that the flow rate in the least direct fracture is about 20% of that in the most direct fracture.[20] [The least direct fracture is defined as the fracture pathway(s) that follows the outer boundary of the fracture pattern.] Thus, the sweep efficiency is still reasonably good, and we suspect that a gel treatment may not provide much benefit.

Fig. 5 was generated using Simulator C. As a check for these results, simulations were also performed using Simulator E. This program calculated the tracer concentrations that were produced after injecting a tracer bank equivalent to 10% of the total fracture volume.

Fig. 6 was generated using Simulator E. This figure plots the produced tracer concentration when $n=11$ for R values ranging from 0.001 to 1,000. In agreement with the previous results and conclusions, Fig. 6 demonstrates that (1) the tracer transit time (as determined by tracer breakthrough) was not sensitive to R value, (2) produced tracer concentrations were low (less than 10% of the injected values) when $R\leqslant 1$, and (3) peak produced tracer concentrations were relatively high when $R\geqslant 10$. These conclusions were supported by results using both simulators.[20]

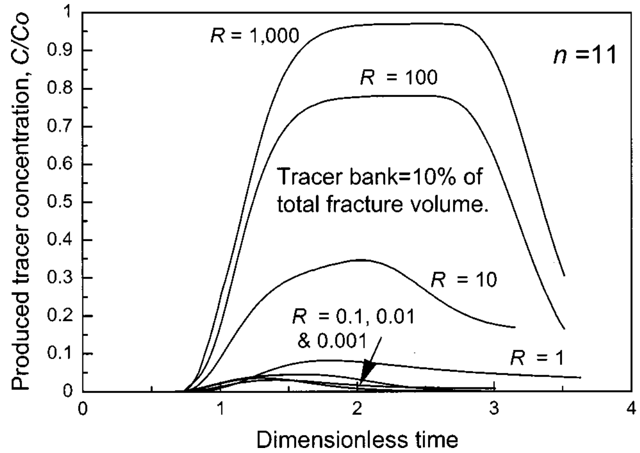

Fig. 6–Produced tracer concentrations when injecting a tracer bank with $n=11$; (Simulator E).

Effect of Plugging the Most Direct Fracture

Ideally, a gel treatment should plug the most direct fracture without entering or damaging the secondary fractures. If this gel placement could be achieved, how would sweep efficiency be affected? More specifically, how rapidly would a water tracer travel between an injector and a producer after versus before a gel treatment? This question is addressed in **Fig. 7** for R values ranging from 1 to 1,000 and for n values ranging from 3 to 101. (Fig. 7 was generated using Simulator C.) The y axis plots the ratio of breakthrough times, i.e., the transit time for a tracer after the most direct fracture was plugged divided by the tracer transit time before the most direct fracture was plugged.

Fig. 7 indicates that gel treatments have the greatest potential for reservoirs with high R values and low to intermediate n values. Gel treatments are not expected to provide much sweep improvement when $R\leqslant 1$.

Diagonally Oriented Fractures

We have focused on fractured systems where one central x-direction fracture directly connects the injector-producer pair. How would our results be affected if the fractures were oriented diagonally relative to the wells [e.g., if the production well was located at position (11,11) in Fig. 1]? In Ref. 20, we demonstrate that diagonally oriented fractures act like direct-fracture systems

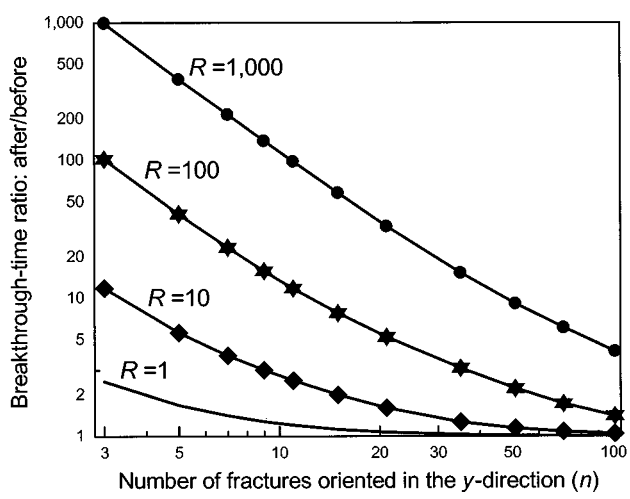

Fig. 7–Effect of plugging the most direct fracture; (Simulator C).

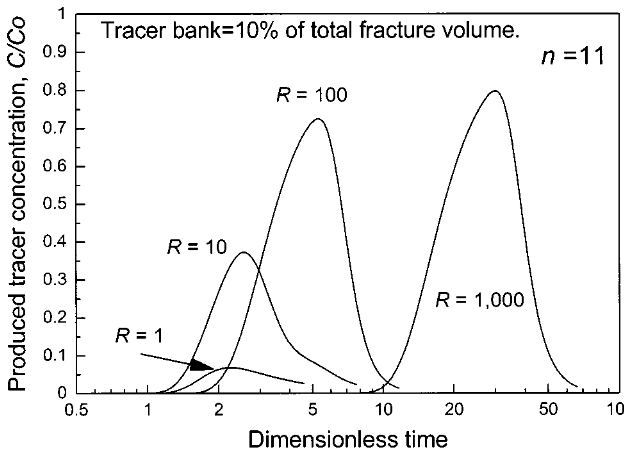

Fig. 8–Tracer curves when injector and producer were located at (1,1) and (11,2), respectively; (Simulator E).

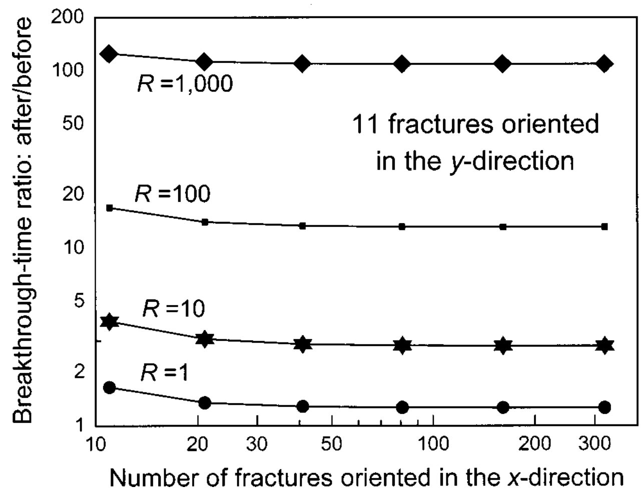

Fig. 9–Effect of plugging the most direct fracture when spacing for *y*-direction fractures is greater than for *x*-direction fractures.

with low R values. Careful consideration reveals that diagonally oriented fractures should provide acceptable sweep efficiencies, and they are poor candidates for gel treatments.

Fig. 8 shows the effects of injecting a 0.1 fracture-volume tracer bank when $n=11$ and the producer was slightly off the direct east–west path. In this case, the injection well was located on the central x-direction fracture, and the production well was located one fracture north of the central x-direction fracture. In other words, using Fig. 1, the production well was located at coordinates (11,2), while the injection well was located at (1,1). Fig. 8 plots the relative produced tracer concentration (C/C_0) versus dimensionless time for R values ranging from 1 to 1,000. The denominator used to determine the dimensionless time was the same for all four curves. Specifically, the denominator was the same transit time used when determining dimensionless times for Figs. 4 and 6.

For cases where the injector-producer pairs were located at opposite ends of the central x-direction fracture, Fig. 6 shows that breakthrough times all occurred at dimensionless times around 0.8 and the peak-concentration times occurred at dimensionless times roughly around 2, regardless of the R value. In contrast, when the producer was located one fracture off center, at (11,2), Fig. 8 shows that the breakthrough times and peak-concentration times increased with increased R value. (The conductivities of x-direction fractures were fixed in this study.)

The behavior in Fig. 6 can be readily understood by remembering that in all cases, the central x-direction fracture had the same conductivity. Also, all injector-producer pairs represented in Fig. 6 were effectively separated by the same distance and experienced the same pressure drop. Therefore, we expected the interwell tracer transit time to be fairly insensitive to R value. Recall that the results in Fig. 4 were consistent with this idea. As mentioned earlier, the tracer transit times provide an excellent means to estimate the permeability and conductivity of the most direct fracture (i.e., using Eqs. 5 and 6).

The behavior in Fig. 8 can be understood by recognizing that the most direct injector-producer pathways were slightly longer (specifically, 10% longer) than those associated with Fig. 6. Depending on the R value, the resistance to flow added by the additional 10% of fracture pathway could significantly increase the transit time.

Interestingly, the tracer curves in Fig. 8 appear more peaked than those in Fig. 6, but the peak concentration values are fairly similar for the two figures. The $R=1{,}000$ case appears to be a slight exception, with the peak value in Fig. 8 being about 16% lower than that in Fig. 6. Simulations using larger tracer banks revealed that this was a dispersion effect—the peak values for the $R=1{,}000$ cases would have been much closer if a 0.5-fracture-volume tracer bank had been injected.[20]

Uneven Fracture Spacing

In the work described so far, the distance between adjacent x-direction fractures was the same as that for y-direction fractures. How would our results change if fracture spacing was different in the x and y directions? This question is addressed in **Figs. 9 and 10**. (Both figures were generated using Simulator C.) In Fig. 9, the reservoir contained eleven fractures oriented in the y direction. The number of fractures oriented in the x direction varied from 11 to 321. As a reminder, the case with eleven y-direction fractures and 21 x-direction fractures has the same fracture spacing in both directions (see Fig. 1). Also recall that the dimensions of the reservoir are fixed, so we simply change the fracture spacing or intensity when the number of fractures are varied. The case with 321 x-direction fractures has 16 times greater distance between y-direction fractures than between x-direction fractures.

Figs. 9 and 10 show the effect of fracture-spacing anisotropy on the breakthrough-time ratio. In both figures, the y-axis plots the tracer transit time after an ideal gel treatment divided by that before the gel treatment. The gel treatment was ideal because we assumed that the gel plugged the most direct fracture without damaging secondary fracture pathways. In Fig. 9, where the number of y-direction fractures was fixed at 11, note that the breakthrough-time ratio was remarkably insensitive to the number of fractures oriented in the x direction.

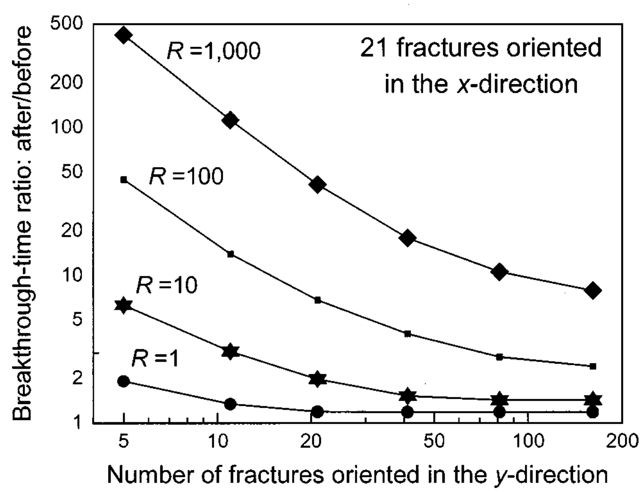

Fig. 10–Effect of plugging the most direct fracture when spacing for *x*-direction fractures is greater than for *y*-direction fractures.

In contrast, in Fig. 10, the number of x-direction fractures was fixed at 21, while the y-direction fractures varied from 5 to 161. The breakthrough-time ratio was sensitive to y-direction fracture spacing, especially for high R values. The trends in Fig. 10 were similar to those in Fig. 7. This similarity suggests that variation in the spacing of y-direction fractures was responsible for the sensitivity to n values seen in Fig. 7. Both Figs. 9 and 10 confirm that gel treatments have their greatest potential in reservoirs with high R values (i.e., $R \geqslant 10$).

Why should the breakthrough-time ratio be sensitive to the spacing of y-direction fractures but not x-direction fractures? The y-direction fractures provide pathways for an injected tracer to be drained away from the central x-direction fracture. Thus, as the spacing between y-direction fractures decreases, more opportunities exist for tracer diversion from the central x-direction fracture, and the transit time increases.

In contrast, the tracer breakthrough time is insensitive to the spacing between x-direction fractures. At high R values, flow in the x direction is dominant through the central x-direction fracture. Since this fracture provides the most conductive pathway through the pattern, it determines the fastest transit time. The other x-direction fractures play a much less significant role.

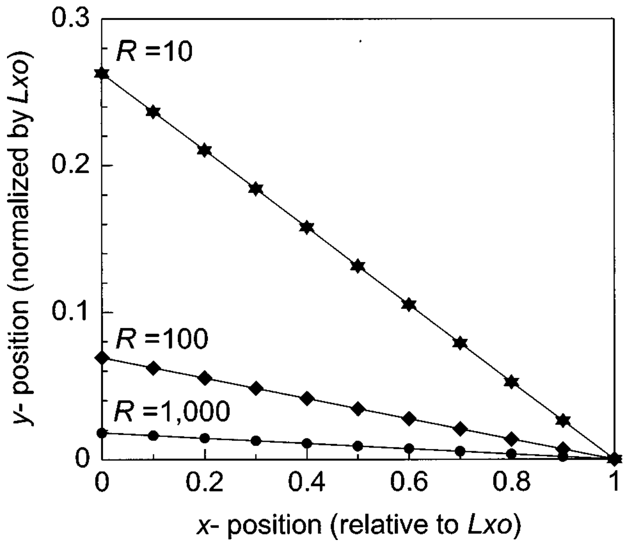

Fig. 11–Generalized outlines of areal gel front profiles.

Areal Gel Front Profiles

How will a gel distribute in a fracture system during a gel treatment? In addressing this question, we note that during gel injection, the pressure drop in the fracture system is greatest across the viscous gel bank. For the field applications discussed in Refs. 1, 3, and 4, a formed gel (rather than a fluid gelant solution) was extruded through the fractures during most of the placement process. This gel was typically 1,000 to 100,000 times more viscous than water.[24,25] Therefore, in the vicinity of the gel bank, the pressure differences in parts of the fracture system that do not contain gel (i.e., where only water or hydrocarbon flows) are negligible compared to the pressure drops in the fractures that contain gel. Thus, we assume that the pressure drop is the same from the injection well to any point at the gel front.

In our analysis, we assume that gel only flows through the fracture network. This assumption is consistent with experimental observations—after gelation, gel does not flow through porous rock.[21,24-26] We also neglect the effects of gravity during the displacement of fracture fluids (i.e., water) by gel. This assumption is reasonable in view of the large viscosity contrast between gel and water. Ref. 25 demonstrated that viscous forces usually dominate over gravity forces during gel placement in fractures. We also neglect dispersion of the gel bank. This assumption also seems reasonable in view of the large mobility contrast between the gel bank and the displaced water in the fractures.

We note that a minimum pressure gradient is required to extrude the gel through a fracture with a given conductivity.[21,24-26] Also, once that pressure gradient is achieved, the pressure gradient required for extrusion is effectively independent of gel velocity.[21,24,25] These observations considerably simplify the flow behavior of gels in fractures. If the pressure gradient is below the minimum or critical value, no flow occurs. If the minimum pressure gradient is met, gel flow occurs at that pressure gradient.

The minimum or critical pressure gradient required for gel extrusion decreases with increased fracture conductivity or width.[21,24,26] This relation is quantified by Eq. 7 for a Cr(III)-acetate-HPAM gel:[20]

$$dp/dl = 280(k_f w_f)^{-0.58}. \tag{7}$$

Using the above concepts and observations, we developed a model to determine positions of gel fronts in naturally fractured systems. In these analyses, the injection and production wells were located at opposite ends of the central x-direction fracture in Fig. 1. Front profiles were determined when gel first arrived at the production well. Details of the model and the analyses can be found in Ref. 27.

Based on this model, **Fig. 11** plots generalized outlines of areal gel front profiles as a function of the fracture conductivity ratio, R. Interestingly, Fig. 11 should be relevant to a wide variety of conditions. Fig. 11 can provide gel front positions independent of fracture spacing between adjacent x- or y-direction fractures.[27] In real reservoirs, we acknowledge that fracture spacings, conductivities, and orientations will not be as uniform as those considered here. These factors could have an important influence on gel placement, so these considerations will be addressed in our future work.

To obtain the results shown in Fig. 11, we assumed that gel propagation was only affected by rheological effects (Eq. 7) during the extrusion process. However, gels can dehydrate or concentrate during extrusion if the fractures are sufficiently narrow.[24,26] In fractures with widths less than 0.04 in., gel dehydration can retard gel propagation by factors up to 40. Since this dehydration becomes more pronounced as fracture conductivity and width decrease,[24] gel penetration into secondary fracture pathways could be much lower than otherwise expected.

Gels also require a minimum pressure gradient (i.e., a yield stress) to enter a fracture with a given conductivity.[24] This property could also help to optimize gel placement in naturally fractured reservoirs. For moderate to large fracture spacing and relatively high R values, gel placement may approach the ideal case where only the central x-direction fracture is plugged by gel. In that case, Fig. 7 can be used to estimate the effectiveness of a gel treatment for a given set of R and n values.

Practical Use of Findings

For the practicing engineer, several concepts from this work may be of value. First, the average width or conductivity of the most direct fracture between an injector-producer pair can be estimated from the breakthrough time from an interwell tracer study using Eqs. 3–6. Since the ability of a gel to extrude through a fracture depends critically on the fracture width or conductivity,[24,26] this knowledge is important when selecting a gel for the treatment.

Second, produced tracer concentrations from a properly designed interwell tracer test can indicate the potential effectiveness for applying a gel treatment. We propose that the potential for a gel treatment becomes greater as the peak produced tracer concentration increases above 20% of the injected value. When produced tracer concentrations are low, gel treatments are unlikely to be effective. However, results from a poorly designed tracer test can mislead one to believe that a gel treatment has little potential. For example, if the tracer bank is too small, dispersion can reduce produced tracer concentrations to very low values in a fracture system even though a gel treatment has excellent potential.

In addition to interwell tracer studies, other methods, such as pressure-transient testing, core and log analysis from deviated wells, and seismic methods, can be used to assess the spacing, conductivity, and orientation of fractures.[6-8,28] If these methods are used, our work indicates the best candidate reservoirs for gel treatment have moderate to large spacings between y-direction fractures, and the conductivity of x-direction fractures should be at least 10 times greater than those of the y-direction fractures.

In our future work, we hope to develop a methodology for sizing gel treatments in naturally fractured reservoirs. Results from our initial efforts in this area can be found in Ref. 27.

Conclusions

In a naturally fractured reservoir, we define an R value as the conductivity of fractures that are aligned with direct flow between an injector-producer pair divided by the conductivity of fractures that are not aligned with direct flow between wells. We also define an n value as the number of fractures between an injector-producer pair, where these fractures are not aligned with the direct flow direction.

1. Gel treatments in naturally fractured reservoirs have the greatest potential when R values are high (greater than 10).

2. Produced tracer concentrations from interwell tracer studies can be useful in identifying reservoirs with high R values.

3. We propose that the potential for a gel treatment becomes greater as the peak produced tracer concentration increases above 20% of the injected value (for a properly designed tracer study). When produced tracer concentrations are low, gel treatments are unlikely to be effective.

4. Because tracer transit times are not sensitive to R or n values, they can be very useful when estimating the permeability or conductivity of the most direct fracture.

5. The effectiveness of gel treatments should be insensitive to fracture spacing for fractures that are aligned with the direct flow direction.

6. The effectiveness of gel treatments increases with increased fracture spacing for fractures that are not aligned with the direct flow direction.

Nomenclature

C = produced tracer concentration, g/m^3
C_0 = injected tracer concentration, g/m^3
h_f = fracture height, ft (m)
k_f = fracture permeability, darcy (μm^2)
L = distance between wells, ft (m)
L_{xo} = distance of gel penetration along the central x-direction fracture, ft (m)
n = number of fractures oriented in the y direction
Δp = pressure drop, psi (Pa)
dp/dl = pressure gradient, psi/ft (Pa/m)
q = flow rate, B/D (m^3/s)
R = fracture conductivity ratio defined by Eq. 1
t = time, days (s)
u = flux, ft/D (m/s)
w_f = fracture width, ft (m)
x = abscissa
y = ordinate
μ = viscosity, cp (mPa·s)
ϕ_f = effective porosity in a fracture

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SI Metric Conversion Factors

cp	×	1.0*	E−03	=	Pa·s
ft	×	3.048*	E−01	=	m
in.	×	2.54*	E+00	=	cm
bbl	×	1.589 873	E−01	=	m^3
md	×	9.869 233	E−04	=	μm^2
psi	×	6.894 757	E+00	=	kPa

*Conversion factors are exact.

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Randy Seright is a senior engineer at the New Mexico Petroleum Recovery Research Center in Socorro, New Mexico. e-mail: randy@prrc.nmt.edu. He holds a BS degree in chemical engineering from Montana State U. and a PhD degree in chemical engineering from the U. of Wisconsin. Seright, a recipient of a 1999 Regional Service Award, represents the Southwest North America region as a 2000–02 member of the SPE Board of Directors. He has served on several SPE committees and was the 1997–98 program chairman of the SPE/DOE Improved Oil Recovery Symposium. **Robert Lee** is Director of the New Mexico Petroleum Recovery Research Center and a professor of petroleum and chemical engineering at New Mexico Inst. of Mining and Technology. He holds a BS degree in chemistry from Chung-Yuan Christian College, an MS degree in chemical engineering from Oregon State U., and a PhD degree from the U. of Michigan.