Gel Placement in Fractured Systems

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Summary

This paper examines several factors that can have an important effect on gel placement in fractured systems, including gelant viscosity, degree of gelation, and gravity. For an effective gel treatment, the conductivity of the fracture must be reduced and a viable flow path must remain open between the wellbore and mobile oil in the reservoir. During placement, the gelant that "leaks off" from the fracture into the rock plays an important role in determining how well a gel treatment will reduce channeling. For a given volume of gelant injected, the distance of gelant leakoff is greater for a viscous gelant than for a low-viscosity gelant (other factors being equal).

In one method to minimize gelant leakoff, sufficient gelation is designed to occur before the gelant leaves the wellbore. We investigated this approach in numerous experiments with both fractured and unfractured cores. We studied Cr(III)/acetate/hydrolyzed polyacrylamide (HPAM), resorcinol/formaldehyde, Cr(III)/xanthan, aluminum/citrate/HPAM, and other gelants and gels with various delay times between gelant preparation and injection. Our results suggest both hope and caution concerning the injection of gels (rather than gelants) into fractured systems. Tracer studies indicate that some gels can effectively heal fractures under the right circumstances. However, high resistance factors exhibited during placement could limit the ability to propagate certain gels deep into a fractured system unless the fractures are very conductive.

Introduction

More than 1 million wells have been intentionally fractured to stimulate oil and gas production.[1] Currently, 35% to 40% of newly drilled wells are hydraulically fractured. Many other wells have been fractured unintentionally during waterflooding operations. Naturally fractured reservoirs also are common.[2]

With the proper length and orientation, fractures can enhance productivity and/or injectivity without adversely affecting sweep efficiency.[3,4] Unfortunately, in many circumstances fractures impair oil recovery. In reservoirs with waterdrive or gasdrive recovery mechanisms, fractures may aggravate the production of water or gas. In waterfloods or enhanced recovery projects, fractures can allow injected fluids to channel through the reservoir.

Theoretical developments[5–7] and many field results[8–10] indicate that gel treatments are most effective in reservoirs where fractures constitute the source of a severe fluid channeling problem. An important factor responsible for this result is that an effective gel placement is easier to achieve in fractured wells than in unfractured wells.[5] The "permeability" of a fracture is typically 10^3 to 10^6 times greater than that of the porous rock.[11,12] Thus, a gelant can propagate a substantial distance along the length of the fracture while penetrating a small distance into the adjacent rock. However, the gelant that "leaks off" into the rock plays an important role in determining how effectively the gel treatment will reduce channeling. If the distance of gelant leakoff is too great, then both productivity and oil-recovery efficiency could be damaged. For an effective gel treatment, the conductivity of the fracture must be reduced, and a viable flow path must remain open between the wellbore and mobile oil in the reservoir.

This paper investigates several factors that have an important effect on gelant placement in fractured systems. First, we suggest idealized placement locations. Second, we discuss the influence of gelant viscosity on leakoff into the porous rock. Then, we describe experiments that probe how gelled and partially gelled materials affect leakoff. We also investigate the ability of gels to propagate through fractures. Finally, we explore the effects of gravity on gel placement.

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Desired Placement Locations

Where should a gel be placed in a fractured system? Consider a fractured injection well, as shown in **Fig. 1.** The fracture may extend part of or all the way between the injection well and a nearby production well. Because of its orientation and conductivity, this fracture significantly reduces sweep efficiency. To improve sweep efficiency in one idealized scenario, a gel would completely fill the fracture and effectively negate the existence of the fracture. This scenario would increase sweep efficiency but significantly reduce injectivity. The injectivity loss associated with the complete healing of the fracture may not be acceptable.

Hypothetically, a high injectivity could be maintained and sweep efficiency could be improved if the gel could be placed at the proper locations in the fracture. In fractured injection wells, we would prefer to plug the fracture far from the wellbore rather than near the wellbore. The part of the fracture farthest from the wellbore is most likely to allow injected fluid (e.g., water) to bypass oil (see Fig. 1). Thus, plugging this part is most likely to improve sweep efficiency. Also, if the near-wellbore part of the fracture remains open to flow, then injectivity could remain relatively high. Similar arguments apply to fractured production wells.

In stratified reservoirs where the fracture cuts multiple strata, we prefer the gel to plug or restrict flow in the water-saturated zones more than in the oil zones. However, for injection wells, one could argue that reducing the conductivity of the fracture is more important than selectively plugging the matrix of different strata adjacent to the matrix.[13] Vertical placement of gels in fractures will be discussed later.

Effects of Gelant Viscosity on Leakoff

A basic principle of fluid displacement in porous media is that the efficiency of the displacement increases with increasing ratios of displacing fluid viscosity to displaced fluid viscosity.[14,15] This principle suggests that for a given volume of gelant injected into a fractured system, the distance of gelant leakoff will be greater for a viscous gelant than for a low-viscosity gelant (other factors being equal). For fractured systems, this principle was demonstrated with flow visualization studies in Chap. 9 of Ref. 16. For gel treatments, this principle presents a potential problem for viscous gelants—too much gelant may leak off from the fracture into the formation rock.

This principle helps to explain some recent field experiences. In some injection-well treatments, tracer studies were first performed to determine interwell transit times for water.[16] Very rapid transit times were observed, confirming that fractures were the cause of the channeling. When a viscous gelant was injected, no gelant was detected at the offset producers even though the gelant volume was 10 times greater than the volume associated with transit of the water tracer between the wells. A possible explanation is that leakoff was substantially greater for the viscous gelant than for the low-viscosity tracer solution. Thus, the volume of injected water tracer required for transit from an injector to a producer is much less than that for a viscous injectant.

How could the idealized placement shown in Fig. 1 be obtained? Could this placement be achieved by injecting a postflush (e.g., water, polymer solution, or oil) to displace the gelant or gel away from the wellbore? Theoretical work and flow visualization studies suggest that a postflush could aid placement if the gelant viscosity was not greater than that for the postflush fluid (or more generally, if a favorable mobility ratio exists during the displacement) and the postflush was injected before significant gelation occurred.[14,16–18]

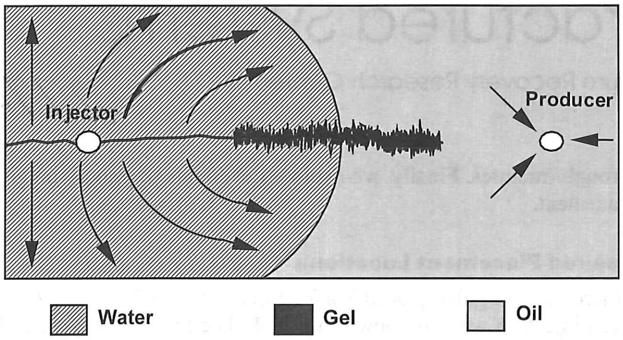

Fig. 1--Idealized gel placement in fractured wells.

However, these studies indicate that a low-viscosity postflush may not help placement for viscous gelants. Specifically, a water postflush (before gelation) will form viscous fingers that remain almost exclusively in the fracture.[16–18] Thus, leakoff associated with the use of viscous gelants could compromise the effectiveness of a treatment unless it is controlled.

Gelant/Gel Penetration Into Porous Rock

Use of suspended particulate matter is one of the most common and effective methods to reduce leakoff during hydraulic fracturing.[19,20] Logically, suspended particulate matter might be effective in minimizing gelant leakoff during gel treatments.[13,17] One experimental investigation suggests that crosslinked polymers can effectively minimize gelant leakoff into porous rock.[21] Thus, we are interested in exploiting gelled or partially gelled material to reduce gelant leakoff.

A number of studies that discuss the flow of gelants and gels in porous media have been reported.[22–27] Early in the gelation process, many gelants behave like clean fluids that do not contain suspended particulate matter.[23–26] For example, early in the gelation process, the rheology in porous media is the same for a Cr(III)/xanthan gelant as for a xanthan solution without a crosslinker.[24] However, after gel aggregates form and grow to the size of pore throats, gel filtration can radically increase the resistance to flow.[26–27] The literature indicates that gelants can penetrate a significant distance into porous rock before gelation, but after gelation, gel propagation is extremely slow or negligible.[23–27]

We performed several experiments to confirm these concepts for a Cr(III)/acetate/HPAM gelant. The gelant contained 0.5% HPAM (Allied Colloids Alcoflood 935, $M \approx 5\times10^6$ daltons; degree of hydrolysis is 5% to 10%), 0.0417% chromium triacetate, and 1% NaCl (pH = 6). All experiments were performed at 105°F. The viscosity was 18 cp (at 1.3 seconds^{-1}, 105°F) for a freshly prepared gelant. **Fig. 2** plots viscosity vs. time for the gelant. From 0 to 4 hours after gel preparation, the viscosity gradually increased. Thereafter, the viscosity rapidly rose to very high values. Fig. 2 suggests that the gelation time was from 4 to 6 hours at 105°F.

The Cr(III)/acetate/HPAM gelant was examined during several corefloods with various delays between gelant preparation and gelant injection into the core. We used high-permeability Berea sandstone cores (brine permeability averaged 650 md and porosity averaged 0.21). With one exception, the cores were 5.5 in. long with a cross-sectional area of 1.6 in.^{2}. Each of these cores had one internal pressure tap located approximately 0.8 in. from the inlet rock face. The first core segment was treated as a filter, while the second core segment (4.7-in. length) was used to measure mobilities and resistance factors. As an exception, one core was only 1.1 in. in length and had no internal pressure tap. All cores were cast in epoxy and were not fired.

One coreflood was conducted with the minimum delay (0.1 hour) between gelant preparation and gelant injection. Slightly more than 2 hours were required to inject 14 PV of gelant with a Darcy velocity of 15.7 ft/D. The bottom curve in **Fig. 3** (solid stars) shows the gelant resistance factor in the first core segment as a function of gelant throughput. The resistance factor increased gradually from 20 at 1 PV to 76 at 14 PV. For comparison, the resistance factor in the second segment (not shown) rose to 43 after 14 PV of gelant throughput. Although some face plugging was observed, most of the gelant passed readily through the core. After the first few PV, the effluent from the core had about the same properties (viscosity, appearance, and gelation time) as the original gelant. During this experiment, the maximum pressure drop across the core was 78 psi.

A second coreflood was conducted with a 3.5-hour delay between gelant preparation and gelant injection. In this experiment, the pump was set to maintain a constant pressure drop of 100 psi across the core. In Fig. 3, the solid diamonds represent resistance factors in the first core segment as a function of gelant throughput. During the first 0.5 hour of injection, about 1 PV of gelant was injected. The viscosity and appearance of the effluent indicated that the gelant had propagated through the 5.5-in. core. After injecting the first PV of gelant, the resistance factor increased sharply. With the application of a 100-psi pressure drop, less than 2 PV had been injected after 24 hours. Also, after the first 3 hours of gelant injection, the viscosity of the effluent was near that for water. Thus, 6.5 hours after gelant preparation (3.5 hours of delay plus 3 hours of injection), no more gelant appeared to propagate through the core.

A third coreflood was performed with a 24-hour delay between gelant preparation and gel injection. After 24 hours, the gelant had formed a highly deformable, nonflowing gel (i.e., the Sydansk gel code[21] was F). In this experiment, the pump again was set to maintain a constant pressure drop of 100 psi across the core. In Fig. 3, the solid circles represent resistance factors in the first core segment as a function of gelant throughput. Severe face plugging was observed immediately. Over the course of 24 hours, about 0.5 PV of gel appeared to be injected. We say "appeared" because of the possibility that the polymer may have been largely filtered out at the sandface, with only water propagating through the core. We noted that all ef-

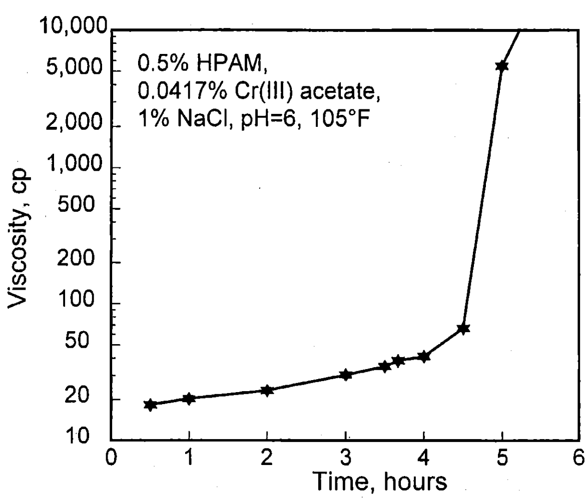

Fig. 2—Viscosity vs. time during gelation.

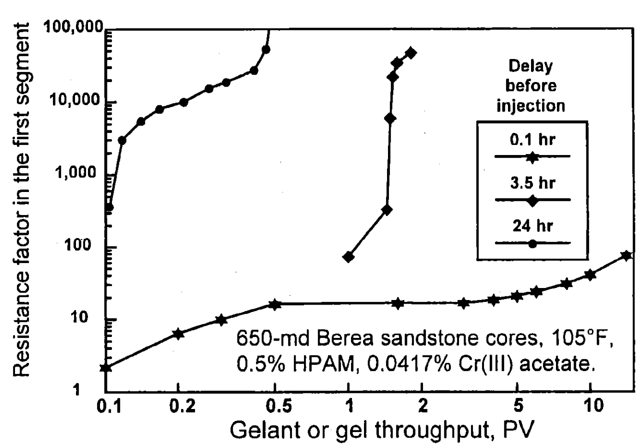

Fig. 3—Plugging in the first core segment for different delay times between gelant mixing and gelant injection.

fluent from the core had the same viscosity as water. The injected gel contained a blue dye (food coloring). After the experiment, the core was cut in half to estimate how far the dye (and possibly the gel) propagated through the core. The dye was visible up to one-third of the distance through the core.

To determine whether the gel actually propagated through the sandstone during the third coreflood, a fourth coreflood was conducted with a Berea core whose length was 1.1 in. rather than 5.5 in. Again, a 24-hour delay occurred between gelant preparation and gel injection. This gel also contained a blue dye that acted as a tracer. The pump was set to maintain a constant pressure drop of 100 psi across the core. As was noted in the third coreflood, resistance factors immediately rose to very high values (up to 200,000) when the gel was injected. The blue dye was first detected in the effluent after injecting 1.5 PV. However, the viscosity of the effluent remained near that for water throughout injection of 6.5 PV of dyed gel. Also, no chromium was detected in the effluent. Thus, although the dye propagated through the core, the gel did not.

In summary, our experiments confirmed that the Cr(III)/acetate/HPAM formulations performed in a similar manner to that for other gelants and gels that were described in the literature. Specifically, before significant gelation (or before gel aggregates become large relative to the size of pore throats), gelants can penetrate readily into porous rock, but after gelation, gel propagation is extremely slow or negligible. These observations suggest two possible methods to minimize gelant leakoff in fractured systems. One method is to cause sufficient gelation to occur before the gelant leaves the wellbore so that the gelant will not penetrate into the rock. For this approach to succeed, the gel must remain pumpable for some period after gelation. The second method involves adding gel or particulate matter to the gelant. Both methods deserve further investigation.

Gelants and Gels In Fractured Cores

Several experiments were conducted with fractured Berea sandstone cores. The nominal permeability for most of these cores was 650 md. However, the brine permeability of one core was 66 md. Core porosities were typically 0.21. All experiments were performed at 105°F. Before fracturing, the cores were identical to those described in the previous section. The cylindrical cores were 5.5 in. long with a cross-sectional area of 1.6 in.^{2}. These cores were fractured lengthwise with a core splitter (Park Industries Hydrasplit). The two halves of the core were repositioned as shown in **Fig. 4** and cast in epoxy. Two internal pressure taps were drilled 0.8 in. from the inlet sandface. One tap was located 90° from the fracture to measure pressure in the rock matrix, while the other tap was drilled to measure pressure in the fracture. During our corefloods, the fracture was always oriented vertically.

After casting the core in epoxy and saturating with brine, we determined the permeability to brine. The third column in **Table 1** lists brine permeabilities, $\bar{k}$, for several fractured cores. These permeabilities average the effects of flow through the fracture and the porous rock. The fourth column in Table 1 lists calculated fracture conductivities, $k_f b_f$. The flow capacity of the fracture relative to that of the porous rock is given by the ratio, $k_f b_f h_f / A k_m$ (fifth column in Table 1). The fracture flow capacities ranged from 5 to 256 times greater than the flow capacities of the porous rock. For two cores

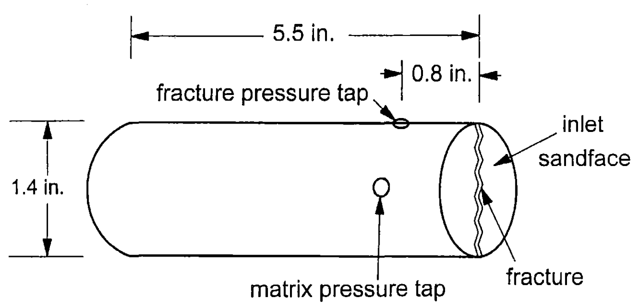

Fig. 4—Schematic of a fractured core.

TABLE 1—CORE AND FRACTURE PERMEABILITIES

Core	k_m, (darcies)	$\bar{k}$, (darcies)	$k_f b_f$, (darcy-cm)	$\frac{k_f b_f h_f}{A k_m}$	outlet sealed
1	0.65	4.1	9.6	5.3	no
2	0.65	6.0	14.9	8.3	yes
3	0.65	31.0	84	46.5	no
4	0.65	7.4	18.8	10.4	yes
5	0.65	18.4	49.7	27.3	no
6	0.066	17.0	47.2	256	no
7	0.65	19.9	53.8	29.6	no
8	0.65	67.7	187	103	no
9	0.65	70.6	196	108	no
10	0.65	13.6	36.2	13.0	no
11	0.65	16.5	44.4	15.9	no
12	0.65	24.1	65.5	36.1	no
13	0.65	18.3	49.2	27.1	no
14	0.65	28.8	78.5	43.2	no

listed in Table 1 (Cores 2 and 4), the outlet end of the fracture was blocked with epoxy. This block was placed to prevent gel from washing out of the fracture during some experiments.

We routinely performed water-tracer studies before and after gel placement during our experiments. These tracer studies were used to characterize PV and dispersivities of the cores. The studies involved injecting a brine bank that contained potassium iodide as a tracer. The tracer concentration in the effluent was monitored at a wavelength of 2,300 Å. In **Fig. 5,** the curve with the open circles illustrates the results from a tracer study for an unfractured Berea core that was saturated with brine. Dispersivities of unfractured Berea sandstone cores were typically 0.04 in., and the effluent tracer concentration reached 50% of the injected concentration after injecting 1 PV of tracer solution.

The solid circles in Fig. 5 show the tracer results from a fractured Berea core (Core 1 from Table 1). For this fractured core, the first tracer was detected in the effluent after injecting 0.04 PV of tracer solution. In contrast, for the unfractured core, the first tracer was detected after injecting 0.8 PV.

Tracer Experiments With Cr(III)/Acetate/HPAM. Several experiments were performed in fractured cores with Cr(III)/acetate/HPAM gelants and gels. These formulations had the same composition as that mentioned earlier (0.5% HPAM, 0.0417% chromium triacetate, and 1% NaCl at pH = 6). In each experiment, a volume

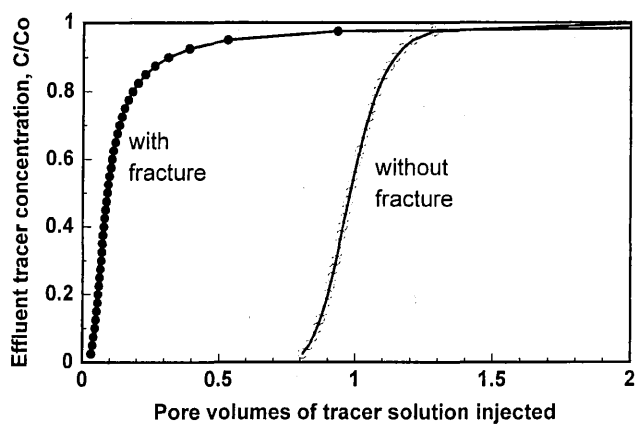

Fig. 5—Tracer results in fractured vs. unfractured Berea sandstones cores.

of gelant or gel (usually 0.3 PV or 10 mL) was injected into a new fractured Berea core with an injection rate of 200 mL/h. Only one of these cores (Core 4) had an epoxy blockage at the outlet of the fracture. After injecting the gelant or gel, we shut in the core for several days. After the shut-in period, brine was injected to determine permeability reduction values (residual resistance factors), and tracer studies were conducted to assess whether the gel treatment resulted in fluid diversion.

To assess improvements in sweep efficiency, we compared the tracer curves shown in Fig. 5 with those obtained before and after placing gel in a fractured core. Presumably, the best sweep improvement would be obtained if a gel treatment could effectively heal the fracture without gel penetrating into the porous rock. In this case, the final tracer curve should resemble the open-circle curve in Fig. 5.

Fig. 6 illustrates the tracer results for four sets of gel experiments. The curve with the open circles shows the results from a tracer study for a fractured core (Core 3) before any gelant was injected. One of these curves was obtained for each set of core experiments. Because these curves were very similar before gelant or gel was injected, only one of the pregel curves is shown in Fig. 6.

In the first experiment, 0.3 PV of fresh gelant was injected into Core 3 immediately after the formulation was prepared. Because the fracture volume was less than 0.05 PV, we expected that 0.3 PV of gelant should completely fill the fracture. However, after the shut-in period, tracer results (open diamonds in Fig. 6) indicated that the gel treatment did not improve sweep efficiency. In fact, the gel treatment actually impaired sweep efficiency slightly (because the open diamonds in Fig. 6 are consistently to the left of the open circles).

For this case, we suspected that the gel may have washed out of the fracture. Therefore, for the second experiment, we used a core (Core 4) with an epoxy block at the fracture outlet. Again, 0.3 PV of fresh gelant was injected. After shut-in, tracer results (solid circles in Fig. 6) showed that sweep efficiency was improved.

In the third and fourth experiments (with Cores 5 and 7, respectively), a 24-hour delay occurred between gelant preparation and gel injection. We injected 0.3 PV and 17 PV of gel, respectively. After placement, tracer results (the solid diamonds and stars in Fig. 6) showed significant sweep improvements, especially after injecting 17 PV of gel.

Behavior During Injection of Cr(III)/Acetate/HPAM Gels. These results suggest that in fractured systems, superior diversion may be obtained by injecting gels rather than gelants. However, before accepting this suggestion, we had to determine whether gels can be injected into fractures without "screening out" or developing excessive pressure gradients. Therefore, we conducted several experiments where large volumes of gels were injected into fractured Berea cores.

With fractured Core 7, we injected 17 PV of brine, followed by 17 PV of Cr(III)/acetate/HPAM gel (24 hours after preparation), followed by 17 PV of brine (see **Fig. 7**). During these steps, the injection rate was 200 mL/h. During the first brine injection, the apparent brine mobility was 30 darcies/cp. During the subsequent injection of gel, the apparent gel mobility stabilized at 0.01 darcies/cp. Thus, the gel was injected without plugging or "screening out" in the fracture. Because the apparent brine and gel mobilities were known (30 and 0.01 darcies/cp, respectively) and because these values were associated almost exclusively with flow in the fracture, we can calculate a resistance factor for gel in the fracture. This value was 3,000. Thus, the effective viscosity of gel in the fracture was 3,000 times greater than that of water.

After injecting the gel, we shut in the core for several days, and gel was removed from the flow lines and the inlet and outlet core faces. Then, 17 PV of brine was injected (Fig. 7). The apparent brine mobility was stable at 0.85 darcies/cp. This value was close to that expected for an unfractured core. Tracer results confirmed that the gel effectively healed the fracture (solid stars in Fig. 6).

With fractured Core 8, we examined the apparent rheology of the Cr(III)/acetate/HPAM gel in a fracture. One day after the gelant was prepared, gel was injected into the fractured core at a rate of 400 mL/h. During gel injection at this rate, the pressure gradient stabilized at about 75 psi/ft, and the resistance factor in the fracture was 1,500. After obtaining this data, we decreased the injection rate in stages. The results are shown by the solid stars in **Figs. 8 and 9.** At each successively lower rate down to 40 mL/h, stabilized pressure drops were achieved and the resistance factors increased with decreasing flow rate (Fig. 8). Also, the pressure gradient remained fairly constant between 60 and 75 psi/ft (Fig. 9). This result suggests that some minimum pressure gradient was needed to keep the gel mobilized.

When the gel injection rate was reduced to 10 mL/h (2 hours after gel injection started and 26 hours after the gelant was prepared), the resistance factor increased to 200,000, and the pressure gradient increased to 250 psi/ft (Figs. 8 and 9). This deviation from the previous trend may have resulted from an increased degree of gelation, from the decreased injection rate, or from a combination of both effects. At lower injection rates, the average pressure gradients were lower, and the resistance factors were erratic. The low-injection-rate data points in Figs. 8 and 9 show averages of these erratic values.

After reaching a low gel-injection rate of 0.64 mL/h, the injection rate was increased in stages. Results from this portion of the experiment are illustrated by the solid diamonds in Figs. 8 and 9. When the gel injection rate was increased to 10 mL/h (6 hours after gel injection started and 30 hours after the gelant was prepared), the resistance factor was 222,000, and the pressure gradient was 280 psi/ft. These values are similar to those mentioned in the previous paragraph (associated with an injection rate of 10 mL/h).

At higher injection rates, the resistance factors quickly stabilized at each new rate, and the pressure gradients were fairly constant around 300 psi/ft (Fig. 9). Again, this behavior suggests that some minimum pressure gradient was needed to keep the gel mobilized.

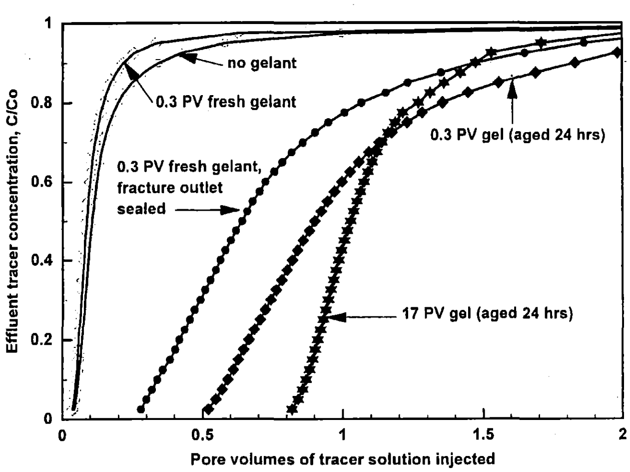

Fig. 6—Tracer results during brine injection after placement of Cr(III)/acetate/HPAM gelants or gels in fractured Berea sandstone cores.

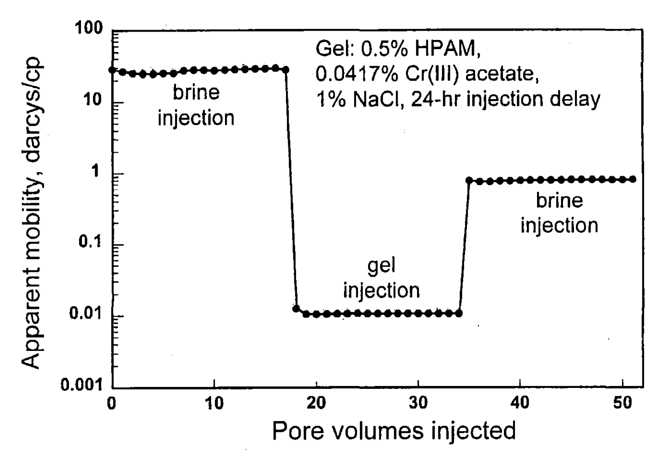

Fig. 7—Effect of brine and gel throughput on apparent mobility in fractured Core 7.

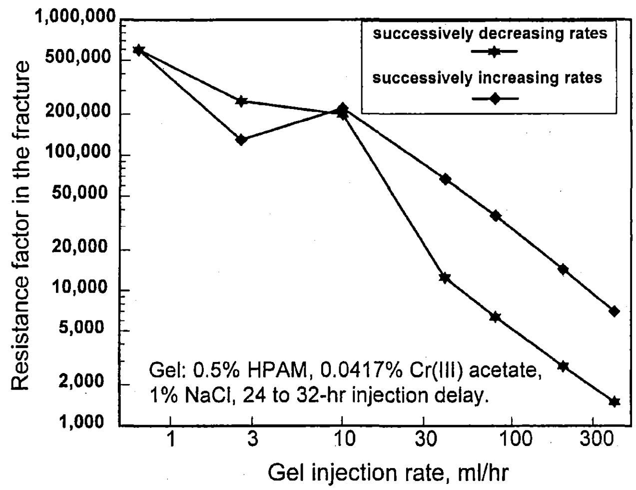

Fig. 8—Resistance factor in the fracture during placement of a Cr(III)/acetate/HPAM gel.

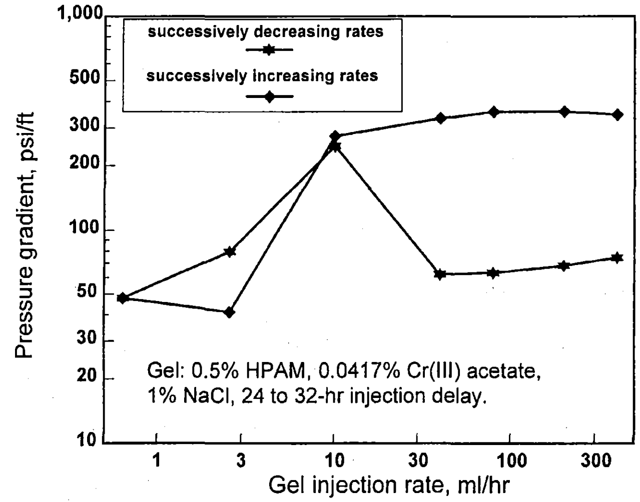

Fig. 9—Pressure gradient during placement of a Cr(III)/acetate/HPAM gel.

However, at this point, the pressure gradient was 4 to 6 times greater than that noted earlier in the experiment. This experiment was completed 8 hours after gel injection started and 32 hours after the gelant was prepared.

A concern raised by the data in Fig. 9 is that pressure gradients between 40 and 300 psi/ft were necessary to force the gel through the fracture. This requirement may limit the ability of this particular gel to propagate through a fracture system unless the fractures are very conductive. Perhaps these high pressure gradients may widen fractures in some cases so that gels could propagate more readily. Further work is needed to examine this possibility (i.e., with a fracture simulator).

Permeability Reduction With Cr(III)/Acetate/HPAM Gels. Several experiments were performed to assess the permeability reduction provided by the gel during brine injection after gel placement. The cores were shut in for 4 days after gel injection. Then, the inlet and outlet endcaps were removed, and gel was scraped from flow lines and the inlet and outlet rock faces. The endcaps were then repositioned, and brine injection commenced. For the experiments where gelants were injected instead of gels (Cores 3 and 4), the residual resistance factors decreased significantly after injecting a few PV of brine, especially when no epoxy blocked the fracture outlet. The behavior suggests that gel washed out from the fracture. Residual resistance factors were more stable when gels were injected instead of gelants (Fig. 7).

Two additional experiments were performed (with Cores 5 and 6) to test the permeability reduction properties of Cr(III)/acetate/HPAM gels. Core 6 had a brine permeability of 66 rather than 650 md before fracturing. The fracture outlets for these cores were not sealed. In both experiments, a 24-hour delay occurred between gelant preparation and gel injection into the fractured cores. Between 0.3 and 0.6 PV of gel (10 to 16 mL) was injected.

Fig. 10 shows residual resistance factors vs. brine throughput for Cores 5 and 6. For both cores, the residual resistance factors were stable during injection of 35 PV of brine. Thus, the gel did not appear to wash out easily.

For Cores 5 and 6, the gels provided residual resistance factors that averaged 30 and 180, respectively (see Fig. 10). Before the gels were injected, we noted that the flow capacities of the fracture relative to those of the rock matrix were 27.3 and 256 for Cores 5 and 6, respectively (Table 1). The similarity of these values to the corresponding residual resistance factors is consistent with the idea that the gels, in effect, healed the fractures.

The effect of pressure gradient on the residual resistance factors during brine injection is shown in **Fig. 11.** In both the 650-md core (Core 5) and the 66-md core (Core 6), the residual resistance factors were insensitive to pressure gradient over the ranges examined. In contrast, our previous work demonstrated that Cr(III)/acetate/HPAM gels in unfractured cores (i.e., in porous rock) exhibited a strong apparent shear-thinning behavior during brine injection.[25]

Experiments With Resorcinol/Formaldehyde. We performed three experiments in fractured cores with gels and gelants that contained 3% resorcinol, 3% formaldehyde, 0.5% KCl, and 0.42% $NaHCO_3$ at pH = 9. Before gelation, the viscosity of this gelant was almost the same as that for water. The gelation time for this gelant was 4 to 6 hours at 105°F, and a clear, rigid gel was formed. Details

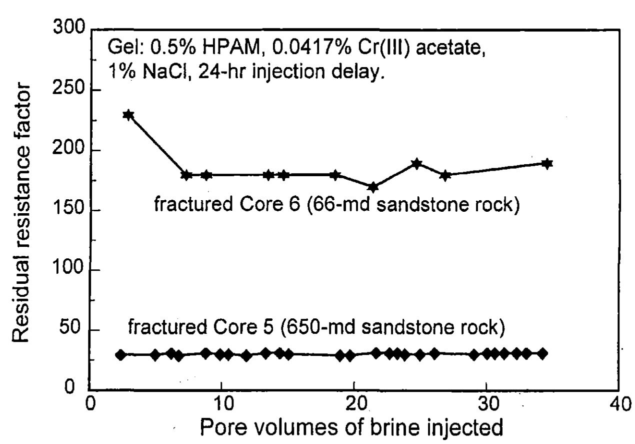

Fig. 10—Residual resistance factor vs. throughput after gel placement.

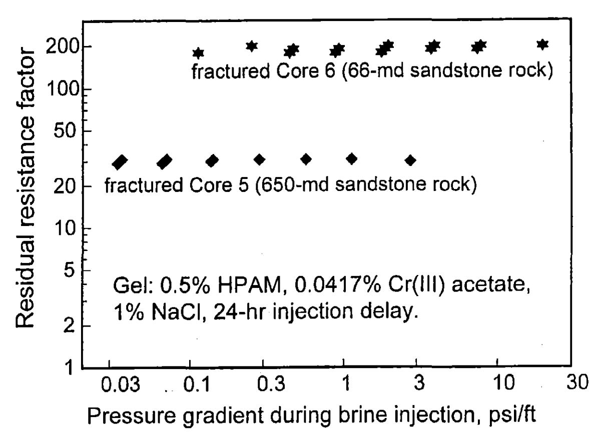

Fig. 11—Residual resistance factor vs. pressure gradient after gel placement.

of these experiments can be found in Chap. 9 of Ref. 16. The results can be summarized by the following observations. First, when gelant was injected into a core with no epoxy block in the fracture outlet (Core 1), tracer studies and permeability reduction measurements revealed that the gel treatment did not improve sweep efficiency. Second, when gelant was injected into a core with an epoxy block in the fracture outlet (Core 2), the gel treatment improved sweep efficiency only slightly. These findings are similar to those obtained for the Cr(III)/acetate/HPAM gelant treatments (Cores 3 and 4). When the fractured cores were disassembled, we noted that the red resorcinol/formaldehyde gelant had settled to the lower part of the core. Apparently, density differences allowed this settling during the shut-in period before gelation. Although the gelant was only 1% more dense than the brine, this difference was enough to allow the gelant to drain from the upper part of the fracture. Thus, gravity can play a very important role during gelant placement.

With fractured Core 9, a set of experiments were performed with a resorcinol/formaldehyde gel (aged 24 hours before injection). During the first brine injection, the apparent brine mobility was stable at 105 darcies/cp. During the subsequent injection of gel (at a rate of 200 mL/h), the apparent gel mobility dropped sharply to 0.003 darcies/cp after injecting less than 1 PV of gel. No stabilization was evident. Thus, severe plugging was apparent during gel injection. After a shut-in period, 17 PV of brine was injected. The apparent brine mobility was stable at 1.5 darcies/cp. After completion of the experiment, the core was disassembled to reveal that the gel had only penetrated 2.8 in. into the fracture (total length was 5.5 in.). This observation confirmed that the gel was "screening out" during injection into the fracture.

Experiments With Other Gels. Table 2 summarizes the results from experiments that we performed where various gels were injected into fractured cores. In all cases, 1 day elapsed between gelant preparation and gel injection into the cores. Compositions of the Cr(III)/acetate/HPAM gel and the resorcinol/formaldehyde gel were given previously. The Cr(III)/xanthan gel contained 0.4% xanthan (Pfizer Flocon 4800), 0.047% $CrCl_3$, and 0.5% KCl at pH = 4. The Cr(III)/acetate/polyacrylamide (PAM)/poly (2-acrylamido-2-methylpropanesulfonate) (AMPS) gel contained 0.3% PAM/AMPS (Drilling Specialties HE-100), 0.044% chromium triacetate, and 2% KCl at pH = 5. The Cr(VI)/redox/PAM/AMPS gel contained 0.3% PAM/AMPS (HE-100), 0.15% $Na_2S_2O_4$, 0.05% $Na_2Cr_2O_7$, and 2% KCl. The aluminum/citrate/HPAM gel contained 0.03% HPAM (Tiorco HiVis 350), 0.0015% aluminum (as citrate, Tiorco 677) and 0.5% KCl at pH = 8. Typically, 10 to 17 PV of gel was injected into a fractured core at a rate of 200 mL/h. (Note that the fracture volume was less than 0.05 PV.) After gel injection, the cores were shut in for several days, followed by brine injection.

The first two listings in Table 2 provide data for unfractured and fractured cores without gel. The ideal gel treatment would heal the fracture so that tracer results matched those associated with the unfractured core. The ideal gel would also exhibit low resistance factors so that the gel could be placed without developing excessive pressure gradients. It would also provide a residual resistance factor that was approximately equal to the corresponding relative flow capacity value given in Table 1. (The latter property would indicate that the gel had plugged the fracture but not the porous rock.)

The tracer results and residual resistance factors suggest that for the gels examined, the Cr(III)/acetate/HPAM and Cr(VI)/redox/PAM/AMPS gels most effectively healed the fractures. In both cases, the tracer results after gel placement approached those seen for the unfractured core. Also, the residual resistance factors were similar to the corresponding relative flow capacities for the cores, as listed in Table 1. However, the high resistance factors (3,000 to 5,000) raise concern about our ability to propagate these gels deep into fractured systems. This concern also applies to most of the other gels. As mentioned earlier, severe plugging was apparent during injection of the resorcinol/formaldehyde gel (resistance factors exceeded 35,000 after injecting less than 1 PV of gel).

For the Cr(III)/xanthan gel, the resistance factor averaged 8,600 after injecting 13.5 PV of gel. However, the resistance factors were erratic during gel injection—possibly a result of intermittent screenouts of gel aggregates in the fracture. In contrast, very stable residual resistance factors were observed during subsequent brine injection (values averaging 19). Tracer studies revealed that this Cr(III)/xanthan treatment provided a moderate improvement in sweep efficiency.[28]

The Cr(III)/acetate/PAM/AMPS formulation exhibited a low resistance factor in the fracture during placement. However, the tracer results did not indicate much improvement in sweep efficiency for the core.[28] Also, because the residual resistance factor (130) was much greater than the corresponding relative flow capacity (36.1) in Table 1, we suspect that the gel was not sufficiently formed before injection to prevent substantial leakoff into the porous rock.

For aluminum/citrate/HPAM, resistance factors steadily increased throughout injection of 10 PV of formulation, suggesting a slow but continuous plugging effect.[28] During brine injection after gel placement, the residual resistance factor was very low (1.7), and the tracer results indicated no improvement in sweep. As was the case for the Cr(III)/acetate/PAM/AMPS formulation, gel formation was not evident when viewing the aluminum/citrate/HPAM composition in a bottle.

For most gels listed in Table 2, residual resistance factors in the fractured cores were stable and independent of injection rate. As an exception, residual resistance factors for the aluminum/citrate/HPAM gel decreased with increased injection rate. Also, washout of gel from the fractures appeared to be significant only for the aluminum/citrate/HPAM gel. More detailed results from these experiments can be found in Chap. 9 of Ref. 16 and Chap. 6 of Ref. 28.

TABLE 2—PROPERTIES IN FRACTURED CORES WITH 1-DAY-OLD GELS

Core	Gel	Resistance Factor	Residual Resistance Factor	Tracer Results, PV	
				Breakthrough	$C/C_o = 0.5$
no fracture	none	—	—	0.81	1.00
7	none	1	1	0.05	0.12
7	Cr(III)/acetate/HPAM	3,000	35	0.82	1.03
9	resorcinol/formaldehyde	plugged	70	0.36	0.54
10	Cr(III)/xanthan	8,600*	19	0.46	0.88
12	Cr(III)/acetate/PAM/AMPS	12.5	130	0.25	0.35
13	aluminum/citrate/HPAM	865†	1.7	0.02	0.08
14	Cr(VI)/redox/PAM/AMPS	5,000	50	0.65	1.00

*erratic † still increasing after 10 PV

Review

Our data indicate both hope and caution concerning the injection of gels into fractured systems. Our tracer studies indicate that some gels can effectively heal fractures under the right circumstances. However, the high resistance factors and pressure gradients exhibited during placement raise concern about our ability to propagate these gels deep into a fracture system unless the fractures are very conductive. We suspect that the ability of a given gel to propagate effectively through a fracture depends on the composition of the gelant, the degree of gelation or gel "curing," the fluid velocity (or pressure gradient) in the fracture, and the width, conductivity, and tortuosity of the fracture. Thus, at this point, we are not suggesting that one gel is necessarily better than other gels for fracture applications. More work will be needed to establish the best circumstances for propagation of gels in fractures.

Exploiting Gravity During Placement

For most commercial gel treatments, the process of gel placement consists of two stages. First, the gelant is injected in a fluid form. Second, the well is shut in to allow gelation to take place. During the first stage in fractured wells, viscous forces virtually always dominate over gravity forces—that is, the gravity number is much less than one. To demonstrate this fact, first consider a fracture with an effective permeability of 100 darcies, fluids with a density difference of 12.5 lbm/ft^3, a viscosity of 1 cp, and $\sin\theta = 1$. The dimensionless gravity number, G, provides a way to compare the importance of gravity forces relative to viscous forces during a displacement of oil by water.[15]

$$G = -\frac{k\Delta\rho \;\; g\sin\theta}{1.0133 \times 10^6 \; v \; \mu}. \qquad (1)$$

For gel treatments in fractured production wells, gelant injection rates are typically very high—e.g., 50 to 500 bbl-D/ft of pay (based on discussions with operators and venders[10]). Thus, for a fracture with a width of 0.01 ft, the velocity in the fracture during gelant injection typically ranges from 28,000 to 280,000 ft/D. With these velocities, the G values range from 0.000193 to 0.00193. Note that the gravity number is substantially less than one. Even if the fracture was 100 times more permeable, the G values would still be much less than one. Thus, viscous forces dominate over gravity forces during gelant or gel injection into fractures. This fact means that the position of the gelant or gel front will not be affected significantly by gravity during injection.

When the well is shut in after gelant injection, how rapidly will gravity equilibrate the level of the gelant/oil interface in the fracture? If gravity alone acts as the driving force, then the vertical superficial velocity, v_z, is given by Eq. 2.[15]

$$v_z = -\frac{k\Delta\rho \;\; g}{1.0133 \times 10^6 \mu}. \qquad (2)$$

Fig. 12 illustrates v_z as a function of k/μ and $\Delta\rho$. Assume that oil has ready access to the fracture, either from the porous rock or from portions of the fracture beyond the gelant front. (This assumption will generally be valid for applications in production wells but not in injection wells unless oil also is injected.) Also assume that fluid displacements are piston-like (i.e., that capillary-pressure and relative permeability effects are negligible). Given a fracture permeability of 100 darcies, a density difference of 12.5 lbm/ft^3, and a 1-cp fluid viscosity, then v_z is –55 ft/D. Thus, the rate of interface equilibration in a fracture can be quite rapid. For example, a fracture 55-ft high could be drained of gelant in 1 day if the gelation time is long enough.

Exploiting gravity to clear a fracture of gelant before gelation could be useful, especially for applications in production wells. By clearing the upper portion of a fracture, a high-permeability conduit remains open for oil to flow to the well. Without this conduit, oil productivity could be severely impaired.

After placement, the gel must effectively restrict water flow. If the source of the excess water is an underlying aquifer, then gravity would cause gelant to drain into and plug that part of the fracture located in the aquifer. If the gelant density is not greater than that for the aquifer water, then gravity should prevent the final gelant/oil interface from falling below the pretreatment (static) water/oil interface.

If the gelant/oil interface does fall to the level of the pretreatment static water/oil interface, then some way must be found to prevent water from cusping into the fracture. One plausible method could be realized if the gel extends some distance into the rock matrix and the gel reduces permeability to water much more than to oil. If the product of the oil residual resistance factor and the distance of gel penetration from the fracture face (into the rock) is relatively small, then the gel will not significantly impede oil from entering the fracture and flowing to the well. If at the same time the product of water residual resistance factor and the distance of gel penetration from the fracture face is large, then water entry into the fracture can be restricted considerably. This mechanism is discussed in detail in Ref. 16.

Future Work

Ultimately, the practicing field engineer needs a tool to determine the best means to place gels in fractured systems. Our work to date will be useful in some circumstances, but much more work is needed to cover more general applications. In particular, several important experimental questions must be answered: How does gel mobility in fractures depend on fracture length, width, conductivity, and tortuosity? How are gel properties affected by continued gel curing reactions and shear degradation as gels are extruded down fractures? How much water is lost from the gels as they extrude through fractures? Once these and other experimental questions are answered, these gel properties should be used during simulation to determine optimum placement strategies and treatment volumes for specific cases (both in hydraulically fractured and naturally fractured reservoirs). We are actively pursuing these issues with laboratory, numerical, and field studies.[28]

Conclusions

1. Coreflood experiments confirmed that a Cr(III)/acetate/HPAM gelant and gel performed in a similar manner to that for other gelants and gels that were described in the literature. Specifically, before gelation, gelants can penetrate readily into the rock matrix, but after gelation, gel propagation is extremely slow or negligible.

2. With tracer studies and permeability reduction measurements, injection of preformed gels was shown to improve sweep efficiency (in effect, by healing the fractures) much more effectively than injection of gelants that formed gels in situ.

3. One day after gelant preparation, several gels were found to propagate through fractured cores without "screening out." However, high resistance factors and pressure gradients were observed, raising concern about the ability to propagate these gels deep into a fracture system unless the fractures are very conductive.

4. During brine injection, gel washout from fractured cores was much less for gels that were formed before injection than for gels

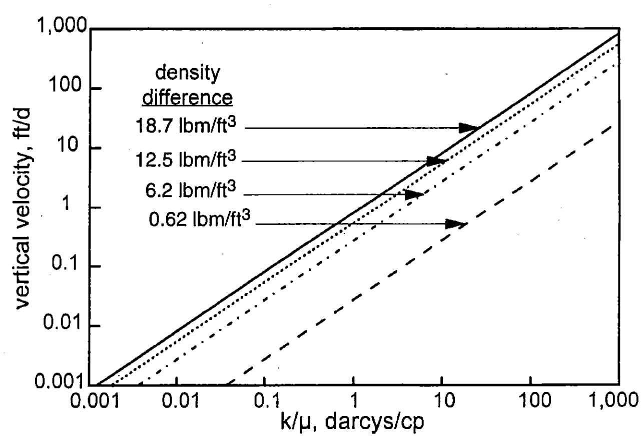

Fig. 12—Vertical velocity vs. k/μ and density difference.

that were formed in situ from gelants. For all but one of the gels tested, residual resistance factors were independent of brine injection rate.

5. More work is needed to establish the best circumstances for propagation of the various gels in fractures.

6. During injection of aqueous gelants into fractured wells, viscous forces usually dominate over gravity forces. Thus, the position of the gelant front will not be significantly altered by gravity during gelant injection.

7. When a well is shut in after gelant injection, equilibration of a gelant/oil interface in a fracture can occur very rapidly. This fact can be exploited during gel placement.

Nomenclature

A = core cross-sectional area, L^2, in.^{2}
b_f = fracture width, L, in.
C = tracer concentration in effluent, m/L^3, lbm/ft^3
C_o = injected tracer concentration, m/L^3, lbm/ft^3
g = acceleration of gravity, L/t^2, ft/s^2
G = dimensionless gravity number defined by Eq. 1
h_f = fracture height, L, ft
k = permeability, L^2, md
$\bar{k}$ = average permeability of fractured core, L^2, md
k_f = effective fracture permeability, L^2, md
k_m = effective rock permeability, L^2, md
v = superficial or Darcy velocity or flux, L/t, ft/D
v_z = vertical component of superficial velocity, L/t, ft/D
θ = angle of inclination, degrees
μ = viscosity, m/Lt, cp
$\Delta\rho$ = water density minus oil density, m/ L^3, lbm/ft^3

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SI Metric Conversion Factors

Å	× 1.0*	E − 10	= m
bbl	× 1.589 873	E − 01	= m^3
cp	× 1.0*	E − 03	= Pa·s
ft	× 3.048*	E − 01	= m
°F	(°F − 32)/1.8		= °C
in.	× 2.54*	E + 00	= cm
lbm/ft^3	× 1.601 846	E + 01	= kg/m^3
md	× 9.869 233	E − 04	= μm^2
psi	× 6.894 757	E + 00	= kPa

*Conversion factor is exact.

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