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## CONFORMANCE IMPROVEMENT USING GELS

### ABSTRACT

This technical progress report describes work performed from September 1, 2003, through February 29, 2004, for the project, "Conformance Improvement Using Gels." We examined the properties of several "partially formed" gels that were formulated with a combination of high and low molecular weight HPAM polymers. After placement in 4-mm-wide fractures, these gels required about 25 psi/ft for brine to breach the gel (the best performance to date in fractures this wide). After this breach, stabilized residual resistance factors decreased significantly with increased flow rate. Also, residual resistance factors were up to 9 times greater for water than for oil. Nevertheless, permeability reduction factors were substantial for both water and oil flow. Gel with 2.5% chopped fiberglass effectively plugged 4-mm-wide fractures if a 0.5-mm-wide constriction was present. The ability to screen-out at a constriction appears crucial for particulate incorporation to be useful in plugging fractures.

In addition to fiberglass, we examined incorporation of polypropylene fibers into gels. Once dispersed in brine or gelant, the polypropylene fibers exhibited the least gravity segregation of any particulate that we have tested to date. In fractures with widths of at least 2 mm, 24-hr-old gels (0.5% high molecular weight HPAM) with 0.5% fiber did not exhibit progressive plugging during placement and showed extrusion pressure gradients similar to those of gels without the fiber. The presence of the fiber roughly doubled the gel's resistance to first breach by brine flow. The breaching pressure gradients were not as large as for gels made with high and low molecular weight polymers (mentioned above). However, their material requirements and costs (i.e., polymer and/or particulate concentrations) were substantially lower than for those gels.

A partially formed gel made with 0.5% HPAM did not enter a 0.052-mm-wide fracture when applying a pressure gradient of 65 psi/ft. This result suggests a lower limit of fracture width for entry of formed or partially formed gels (when reasonable pressure gradients are applied).

In unfractured porous rock, we investigated the time dependence of oil and water permeabilities during various cycles of oil and water injection after placement of a Cr(III)-acetate-HPAM gel. Permeability to water stabilized rapidly (within 1 pore volume, PV), while permeability to oil stabilized gradually over the course of 100 PV. The behavior was surprisingly insensitive to core material (strongly water-wet Berea sandstone and strongly oil-wet porous polyethylene), core permeability (740 to 10,000 md), and applied pressure gradient (10 to 100 psi/ft).

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## PROJECT OBJECTIVES

This research project has two objectives. The first objective is to identify gel compositions and conditions that substantially reduce flow through fractures that allow direct channeling between wells, while leaving secondary fractures open so that high fluid injection and production rates can be maintained. This goal will be reached by (1) characterizing gel propagation through fractures as a function of fracture width, length, and height, injection rate, gel composition, and temperature, (2) correlating rheology in fractures with that in a viscometer, and (3) using the experimental results to develop an appropriate model for gel placement and treatment sizing.

The second objective is to optimize treatments in fractured production wells, where the gel must reduce permeability to water much more than that to oil. Within this objective, the specific goals are to (1) determine the correct mechanism(s) for the disproportionate permeability reduction, (2) identify conditions that maximize the phenomenon, (3) find materials and methods that make the phenomenon predictable and controllable, and (4) establish a methodology to determine how much gelant should be injected in a given fractured production well.

## GELS IN FRACTURES

**Partially Formed Gels with High and Low Mw Polymers.** We continued our studies using “partially formed” Cr(III)-acetate-HPAM gels to reduce the flow capacity of fractures (at 41°C). (Bob Sydansk provided the lead direction during these studies.) The specific objective of these experiments was to identify formulations that will flow readily into fractures and then effectively plug the fractures during brine flow after placement—especially in wider fractures (2- to 4-mm widths). Table 1 shows the compositions investigated. The gels contained both high and low molecular weight polymers. The high molecular weight (Mw) polymer was Ciba Alcoflood 935<sup>TM</sup> HPAM (hydrolyzed polyacrylamide), with a nominal Mw of  $5 \times 10^6$  daltons. The low Mw polymer was Ciba Alcoflood 254-S<sup>TM</sup> HPAM, with a nominal Mw of 500,000 daltons. Both polymers were 5-10 mole% hydrolyzed. The gelant compositions listed in Table 1 were 30 to 50 times more viscous than our base-case “1X” gelant [0.5% high Mw HPAM, 0.0417% Cr(III) acetate]. Even so, because they were injected in a “partially formed” state (i.e., shortly after the first sign of gel structure was detected), they exhibited low pressure gradients during placement in 2- and 4-mm-wide fractures.

Table 1—Gel compositions with high and low Mw polymers.

| Gel designation  | H&LMW  | FSG-1 | FSG-2  |
|--|--------|-------|--------|
| Concentration of high Mw HPAM, wt%   | 1.5    | 1.5   | 2.0    |
| Concentration of low Mw HPAM, wt%  | 2.0    | 4.0   | 3.0    |
| Concentration active Cr(III), wt%  | 0.0601 | 0.096 | 0.0873 |
| Aging time prior to injection, min.  | 40     | 120   | 12     |
| Viscosity of the polymer solution without crosslinking agent added (at 28 sec <sup>-1</sup> and 41 °C), cp | 860    | 650   | 1,000  |

During first brine injection after gel placement (for the H&LMW gel), the pressure gradient required to first breach the gel was 37 psi/ft in a 2-mm-wide fracture and 25 psi/ft in a 4-mm-wide fracture. For these fracture widths, these breaching pressure gradients were the highest

values observed to date. Fig. 1 plots stabilized water ( $F_{rrw}$ ) and oil ( $F_{rro}$ ) residual resistance factors during several cycles of water and oil injection at various rates in a 2-mm-wide fracture. As superficial velocity in the fracture increased from 515 to 8,240 ft/d,  $F_{rrw}$  values decreased 3 to 4 times and  $F_{rro}$  values decreased by a factor of ten. Nevertheless, the final water residual resistance factor was still 14,000—indicating a substantial reduction in the flow capacity of the fracture. The gel exhibited a noticeable disproportionate permeability reduction, since  $F_{rrw}$  values were 3 to 9 times greater than  $F_{rro}$  values (at a given rate). However, the value of this effect is debatable, since the gel also reduced the flow capacity toward oil by at least a factor of 1,500.

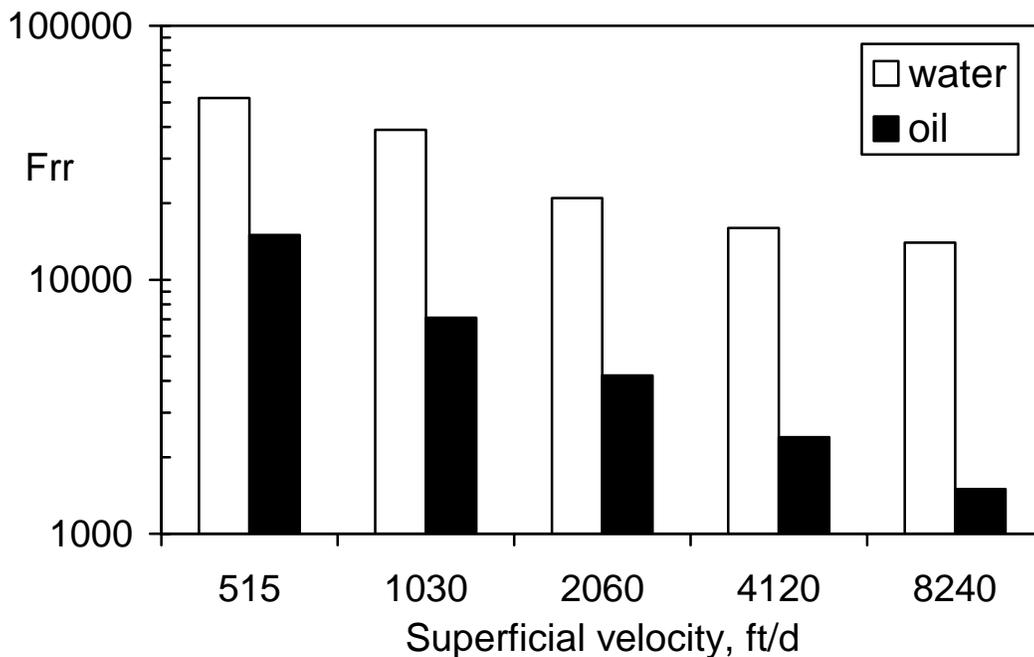


Fig. 1—Effect of rate on  $F_{rr}$  in a 2-mm-wide fracture.

Similar behavior was observed for the same H&LMW gel in a 4-mm-wide fracture. After gel placement, as brine superficial velocity increased from 259 to 4,140 ft/d, the  $F_{rrw}$  values decreased from 100,000 to 39,000. Thus, the gel provided effective permeability reductions in both 2- and 4-mm-wide fractures.

Experiments were also performed for the FSG-1 and FSG-2 formulations described in Table 1. During first brine injection after placement in 4-mm-wide fractures, the pressure gradient required to breach the gels were 23 and 26 psi/ft, respectively. Stabilized  $F_{rrw}$  values were 360,000 and 200,000, respectively. However, after a few cycles of oil and water injection, the values dropped to 14,000 and 25,000, respectively. Although these were substantial permeability reductions, the H&LMW gel provided equivalent performance with lower polymer loading (and therefore lower gel cost).

**Partially Formed Gels with Particulates.** We also investigated the effect of incorporating 2.5% chopped fiberglass strands (each typically 3-mm long) into the H&LMW gel described in Table 1. During placement in a 4-mm-wide fracture (with smooth faces), the effective viscosity of this partially formed gel formulation was 1,100 to 1,300 cp—similar to values for partially formed gel without the fiberglass strands. Pressure gradients were fairly stable during gel placement, and no screen-out behavior was observed. During first brine injection after gel placement, the pressure gradient required to first breach the gel was 38 psi/ft. The stabilized  $F_{rrw}$  value was 310,000. These values were somewhat greater than those for the H&LMW formulation without fiberglass, but they were not as high as we had hoped. Upon opening the fracture at the end of the experiment, the fiberglass strands were evenly distributed along the fracture.

The above experiment was performed using a 4-mm-wide fracture with smooth-sawed faces. The real value of adding the fiberglass stands became evident in fractures with variable widths (i.e., constrictions). Two experiments were performed using fractures that were 4-mm wide for the first 15 inches of the fracture but narrowed to 0.5-mm for the last 9 inches. In these cases, the partially formed gel contained 1.5% Alcoflood 935 [crosslinked with Cr(III) acetate] and 2.5% fiberglass. Problems with gravity segregation of the fiberglass were noted in both experiments. Nevertheless, the small fraction of fiberglass that remained suspended screened out at the entrance to the 0.5-mm portion of the fracture and effectively plugged the fracture. During brine injection after gel placement, all fluid flowed through the porous rock, with little flow through the fracture. The gel/fiberglass plug withstood pressure gradients of at least 75 psi/ft.

**Gels with Polypropylene Fibers.** Another set of experiments was performed incorporating 0.5% Forta Super Sweep™ polypropylene fibers into our standard 1X gelant. The fibers were roughly 13-mm long. Once dispersed in brine or gelant, these fibers exhibited the least gravity segregation of any particulate that we have tested to date. After incorporation of the fiber, the formulations were aged for 24 hours at 41°C, and then extruded (3,700 cm<sup>3</sup> total gelant volume) through one of three fractured cores using an injection rate of 2,000 cm<sup>3</sup>/hr. These Berea cores were 4-ft (122-cm) long and had smooth-face fracture widths of 1 mm, 2 mm, or 4 mm. During placement in the 1-mm-wide fracture, moderate plugging behavior (i.e., steady increase in pressure) was noted at the fracture inlet, but stable pressure gradients were observed throughout the remainder of the fracture—averaging about 10 psi/ft. This stabilized pressure gradient was similar to that for gel without the fibers.<sup>1</sup> When extruding the fiber formulation into 2-mm-wide and 4-mm-wide fractures, pressure gradients at the fracture entrance were greater than in the remainder of the fracture, but these entrance pressures did not increase with throughput. For the remainder of the fracture, placement pressure gradients were consistent with gel formulations that did not contain fibers (3 psi/ft and 1.6 psi/ft, respectively).

During brine injection after gel placement, the pressure gradients required to first breach the gel were 28.9, 10, and 5.1 psi/ft, for fracture widths of 1, 2, and 4 mm, respectively. These values were roughly twice those for formulations that were placed without the fiber. After first breach of the gel, the flow capacity of the fracture was significantly greater than that through the porous rock. However, the flow capacity of the fracture after gel placement was still substantially less than that before gel placement. This behavior (after the first gel breach) was similar to most gel formulations that we investigated to date.

In summary, the main advantage associated with use of the polypropylene fibers is their resistance to gravity segregation after dispersion in brine or gelant. In fractures with widths of at least 2 mm, they did not exhibit progressive plugging during placement and showed extrusion pressure gradients similar to gel formulations without the fiber. The presence of the fiber roughly doubled the gel's resistance to first breach by brine flow. The breaching pressure gradients were not as large as for the H&LMW gels (described above). However, their material requirements and costs (i.e., polymer and/or particulate concentrations) were substantially lower than those for the H&LMW gels.

**Gel Placement in Tight Fractures.** Although much of our current work investigates how to effectively plug moderate to wide fractures, we also wondered how narrow a fracture could be plugged with a partially formed gel. Using a closed, sawed-surface fracture, brine injection data was used to calculate a fracture width of 0.052 mm. (For a fixed flow rate and fluid viscosity, pressure drop is inversely proportional to the third power of the effective average fracture width.) This is the tightest fracture that we have investigated to date. Interestingly, we found that a 5-hr-old partially formed gel [containing 0.5% Alcoflood 935 and 0.0417% Cr(III) acetate at 41°C] could not be forced into the fracture, even with pressure gradients up to 65 psi/ft.

**Cement in Fractures.** Cement is the most common water-shutoff material. Qualitatively, gels can propagate much more effectively into fractures, but cement withstands much higher pressure gradients after placement. We have begun an effort to quantify when use of gels should be preferred over cement. Our first experiments revealed that Class B and H cements were incapable of propagating more than a few inches into fractures that were 2-mm-wide or less unless very high pressure gradients were used. In our first experiment using a 4-mm-wide fracture (in a Berea core), Class B cement readily propagated to the end of the 4-ft-long smooth-face fracture—exhibiting a pressure gradient of only 2-3 psi/ft. Upon reaching the end of the fracture, the pressure gradient immediately shot up to about 40 psi/ft and flow was stopped. The sudden pressure increase may have occurred because the flow area decreased from 152 mm<sup>2</sup> in the fracture (i.e., 4 mm x 38 mm) to 32 mm<sup>2</sup> in the outlet fitting (6.35-mm diameter tube). This possibility will be examined in future work. After letting the cement cure for five days, brine was injected. With pressure gradients up to 317 psi/ft, the cement showed no sign of breakdown, and the fracture remained effectively plugged. All brine flow was diverted through the porous rock. Additional comparisons of the capabilities and limitations of cements and gels are planned for our future work.

## **DISPROPORTIONATE PERMEABILITY REDUCTION IN POROUS MEDIA**

**Time Dependence of Oil and Water Permeabilities.** We investigated the time dependence of oil and water permeabilities during various cycles of oil and water injection after gel placement in unfractured porous media. We used our standard “1X” gel that contained 0.5% Alcoflood 935 HPAM, 0.0417% Cr(III) acetate, 1% NaCl, 0.1% CaCl<sub>2</sub> at 25°C. The first Berea sandstone core was 3 inches long, with an absolute permeability of 746 md. After gel placement (6 PV) and shut-in, hexadecane was injected using a fixed pressure gradient of 40 psi/ft. The solid circles in Fig. 2 demonstrate that permeability to oil increased gradually from 2 md to 105 md during the course of 100 PV. One might expect a gradual increase in oil permeability during this injection stage since the oil must force pathways through gel that occupies most of the aqueous pore space.

The open circles in Fig. 2 show the permeability when water was injected after the above oil-injection stage. In contrast to the oil behavior, permeability to water stabilized at 0.17 md within a few tenths of one PV of injection.

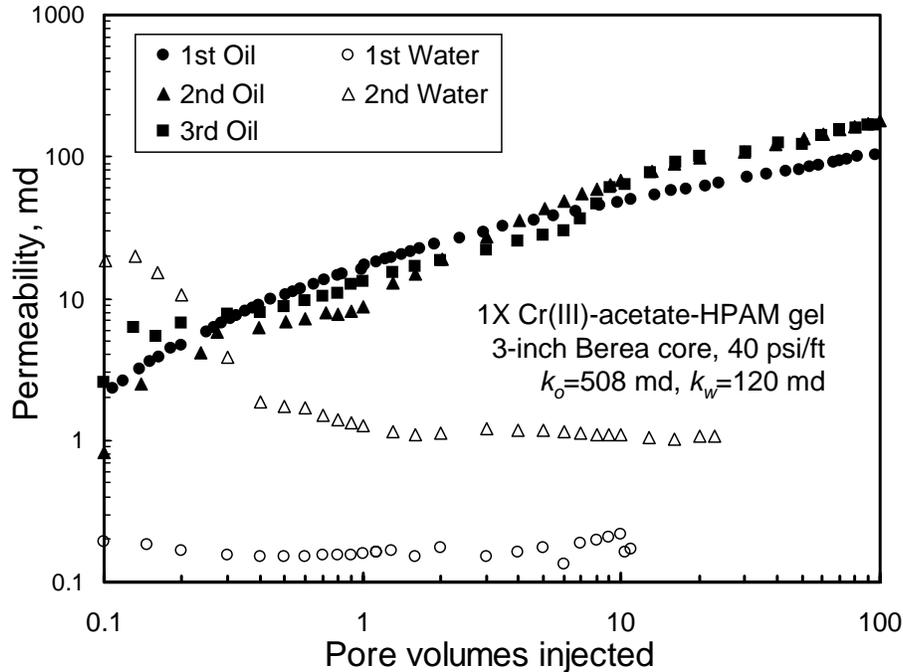


Fig. 2—Permeabilities to oil and water after gel placement in a Berea core.

During the second and third cycles of oil injection (solid triangles and squares in Fig. 2), permeability again gradually increased over the course of injecting 100 PV. The permeability to oil followed the same trend for all three cycles (although the final permeability was 60% greater for the second and third cycles than for the first cycle). During the second cycle of water injection (open triangles in Fig. 2), the permeability stabilized at 1.1 md within 1 PV.

Since the final oil and water permeabilities were higher during the second injection cycle than the first, some gel degradation or dehydration is implied. However, we were surprised by the similarity in the three oil curves. Why should stabilization of permeabilities occur so quickly during water injection, yet take so long during oil injection? This question will be the focus of our research for the near term. As mentioned earlier, gradual stabilization of permeability might be expected during the first oil injection because of the creation of new oil paths through the gel. However, for the second and third cycles of oil injection, these paths should already be established. One might argue that gels re-hydrate during the water injection cycles, so that oil pathways must be re-established during subsequent oil injection. However, we see no evidence that gel re-hydration occurs to the extent required by this suggestion. Also, stabilization of permeability during water injection occurs *much* more rapidly than during oil injection. We see no reason why gel re-hydration should occur significantly more rapidly than dehydration.

Analogous experiments were performed in a 3-inch long porous polyethylene core (10 darcys) using a pressure gradient of 30 psi/ft. Fig. 3 shows that the behavior was similar to that observed in Berea (Fig. 2). The similarity is somewhat surprising, considering that the polyethylene was oil-wet, the Berea was water-wet, and the polyethylene core was originally 13.5 times more permeable than the Berea core.

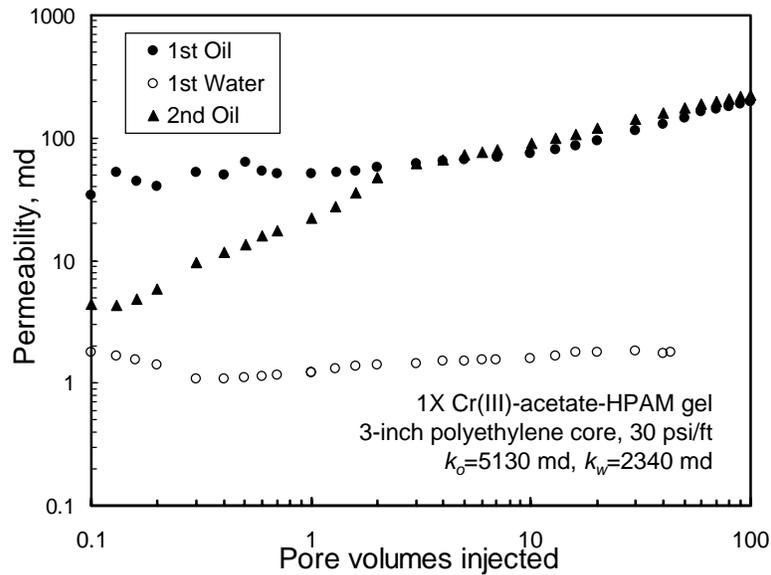


Fig. 3—Permeabilities to oil and water after gel placement in a polyethylene core.

Several additional experiments were performed using different core materials, core lengths, pressure gradients, and order of first water or oil injection after gel placement. Table 2 summarizes the stabilized permeabilities during water injection (after gel placement) for experiments in fused silica when water was the first fluid injected after gel placement. (The entries labeled “2<sup>nd</sup> water” apply to cases where water was injected first after gel placement, then oil was injected, and finally water was injected again. The permeability was measured during the second cycle of water injection.) Except for the case of 100 psi/ft pressure gradient, the permeabilities were quite similar, averaging 0.23 md. The larger  $k_w$  value during exposure to 100 psi/ft suggests a significant degree of gel failure at high pressure gradients.

Table 2— $k_w$  when water was injected first after gel placement.

| Core material   | Core length, in | Initial core permeability, md | Pressure gradient, psi/ft | Condition | Final permeability, md |
|---|-----------------|-------------------------------|---------------------------|-----------|------------------------|
| fused silica  | 3               | 2,390                         | 10                        | water 1st | 0.12                   |
| fused silica  | 3               | 2,390                         | 10                        | 2nd water | 0.35                   |
| fused silica  | 3               | 1,820                         | 30                        | water 1st | 0.23                   |
| fused silica  | 3               | 1,820                         | 30                        | 2nd water | 0.22                   |
| fused silica  | 3               | 850                           | 100                       | water 1st | 131                    |
| Average $k_w$ for the top 4 listings: 0.23 md ( $\pm 0.1$ md) |                 |                               |                           |           |                        |

Table 3 summarizes stabilized permeabilities during water injection for many experiments when oil was the first fluid injected after gel placement. Again, except for the cases with 100 psi/ft pressure gradients in fused silica, the permeabilities were quite similar, averaging 1.65 md. As in Table 2, the larger  $k_w$  values in fused silica during exposure to 100 psi/ft suggest a significant degree of gel failure at high pressure gradients. Interestingly, the gel resisted failure (at 100 psi/ft) more effectively in 7,410-md polyethylene than in 1,330-md fused silica.

Table 3— $k_w$  when oil was injected first after gel placement.

| Core material   | Core length, in | Initial core permeability, md | Pressure gradient, psi/ft | Condition           | Final permeability, md |
|---|-----------------|-------------------------------|---------------------------|---------------------|------------------------|
| Berea   | 3               | 746                           | 40                        | water after oil     | 0.17                   |
| Berea   | 3               | 746                           | 40                        | 2nd water after oil | 1.11                   |
| Berea   | 6               | 738                           | 40                        | water after oil     | 1.93                   |
| Berea   | 6               | 738                           | 40                        | 2nd water after oil | 2.25                   |
| polyethylene  | 3               | 8,400                         | 10                        | water after oil     | 1.56                   |
| polyethylene  | 3               | 10,000                        | 30                        | water after oil     | 1.49                   |
| polyethylene  | 3               | 7,410                         | 100                       | water after oil     | 2.83                   |
| fused silica  | 3               | 1,970                         | 10                        | water after oil     | 0.45                   |
| fused silica  | 3               | 2,110                         | 30                        | water after oil     | 3.1                    |
| fused silica  | 3               | 1,330                         | 100                       | water after oil     | 13.6                   |
| fused silica  | 3               | 1,330                         | 100                       | 2nd water after oil | 211                    |
| Average $k_w$ for the top 9 listings: 1.65 md ( $\pm$ 1 md) |                 |                               |                           |                     |                        |

For moderate pressure gradients, the results in Tables 2 and 3 are consistent with earlier findings. The gel appears to reduce the permeability of all aqueous pore space to roughly the same low value, regardless of the initial permeability of the rock. These final permeability values were near the inherent permeability of the gel to water. Thus, permeability reductions tend to be fairly predictable for strong gels. If the gel sets up properly and the inherent permeability to water is known for the gel, the final permeability (to water) after gel placement can be readily estimated, regardless of the initial rock permeability.

After gel placement, trends in oil permeability versus pore volume of oil injected were surprisingly similar for most floods. Fig. 4 plots these trends for all oil floods in Berea and polyethylene. It also plots results for an oil flood in fused silica at 10 psi/ft. (As with the permeability to water, permeability to oil in fused silica increased significantly with increased pressure gradient. This behavior was much less noticeable in Berea and polyethylene.) For a given PV of oil injected, the  $k_o$  values typically varied (minimum to maximum) by a factor of 3. This range is not large, considering that core permeabilities differed by a factor of 13.5 (740 md in Berea to 10,000 md in polyethylene), pressure gradients differed by a factor of 10 (10 to 100 psi/ft in polyethylene), and wettability varied from strongly water-wet (in Berea) to strongly oil-wet (in polyethylene). Future work will focus on why these similarities occur. The ultimate objective of these studies is to reliably predict oil and water permeability reductions that are caused by gels.

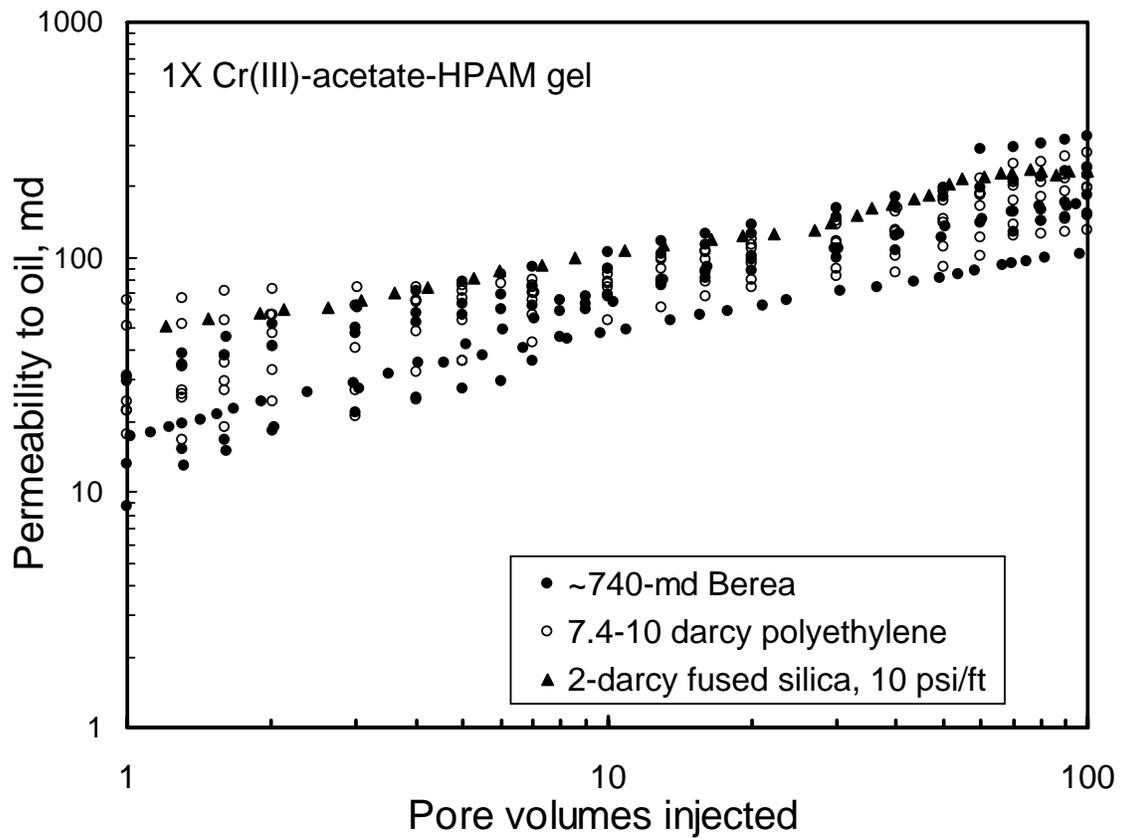


Fig. 4—Permeability to oil after gel placement in various cores.

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1. Seright, R.S.: "Washout of Cr(III)-Acetate-HPAM Gels from Fractures," paper SPE 80200 presented at the 2003 SPE International Symposium on Oilfield Chemistry, Houston, Feb. 5-7.