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Optimizing Disproportionate Permeability Reduction

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Abstract

An idealistic goal of water shutoff technology is identifying materials that can be injected into any production well (without zone isolation) and will substantially reduce the water productivity without significantly impairing hydrocarbon productivity. Although many polymers and gels reduce permeability to water more than to oil or gas, several factors currently limit widespread field applications of this disproportionate permeability reduction property. First, adsorbed polymers and weak gels (suspensions of gel particles) show large variations in performance. Second, in unfractured wells (i.e., radial flow into porous sand or rock), the oil residual resistance factor, F_{rro}, (permeability reduction factor) must be reliably less than 2. Third, adsorbed polymers and weak gels reduce permeability by greater factors in low-permeability rock than high-permeability rock.

Strong pore-filling gels were investigated to overcome these limitations. For porous media with pre-gel k_w (at S_{or}) ranging from 120 to 6,500 md, one Cr(III)-acetate-HPAM gel (with 0.5% HPAM) consistently reduced k_w to about 0.24 md (ranging from 0.12 to 0.37 md). In contrast, in Berea sandstone with k_w (at S_{or}) ranging from 222 to 363 md, a weak gel (with 0.18% polymer) exhibited a much wider range of post-polymer k_w values—from 0.75 to 202 md. Thus, strong pore-filling gels can provide greater reliability and behavior that is insensitive to the initial rock permeability.

With sufficient oil throughput, pore-filling gels dehydrate, thus increasing permeability to oil. Several gel formulations provided water residual resistance factors greater than 2,000 and ultimate F_{rro} values of 2 or less. These results provide hope that our current approach will identify gels that can successfully and reliably treat either fractured or unfractured production wells without zone isolation. Significant oil throughput was required to achieve low F_{rro} values, suggesting that gelant penetration into porous rock must be small (a few feet or less) for existing pore-filling gels to provide effective disproportionate permeability reduction.

Introduction

Many polymers and gels can reduce permeability to water more than that to oil or gas.[1-5] This disproportionate permeability reduction (or "relative permeability modification") is essential if polymers or gelants are placed in production wells without protecting hydrocarbon-productive zones.[6] With existing polymers, gels, and technology, disproportionate permeability reduction may have its greatest value when treating production wells that intersect a fracture or fracture-like features.[7-9] Nonetheless, many people are very interested in exploiting this property to reduce excess water production from unfractured wells (i.e., radial flow into porous rock or sand). The idealistic goal of this technology is to develop a material that can be injected into any production well (without zone isolation) and will substantially reduce water productivity index without significantly impairing hydrocarbon productivity. Several obstacles must be overcome before this ideal can be achieved.

Challenges for Applications of Disproportionate Permeability Reduction

Variable Performance. Field applications of polymer and gel treatments have shown substantial variations in performance from one application to the next. In part, these variations arise from differences in reservoir conditions, well conditions, and mixing and injection procedures. However, significant performance variations appear inherent for some polymers and gels.[10,11] During replicate experiments (in Berea sandstone) with a commercially available weak gel, oil residual resistance factors (F_{rro}, permeability reduction factors) ranged from 2.7 to 59 (median of 5.9, average of 9.7, and standard deviation of 13.5), while water residual resistance factors (F_{rrw}) ranged from 1.5 to 317 (median of 6.6, average of 32, and standard deviation of 78).[10]

Uncontrolled variability of residual resistance factors may be an inherent flaw for adsorbed polymers and weak gels. Permeability reduction by adsorbed polymers can be strongly influenced by mineralogy of the rock. In turn, rock mineralogy typically exhibits significant variations locally within a porous medium. Consequently, these mineralogical variations could lead to wide differences in performance for adsorbing polymers.

Weak gels are typically suspensions of gel particles—not a continuous three-dimensional gel structiure.[12-15] These suspensions have a particle size distribution—they are not monodisperse. Pores within a rock also have a size distribution. Since the particles reduce permeability by lodging in pore throats, the ratio of particle size to pore throat size is important in determining residual resistance factors for these suspensions. Variations in particle size distribution (especially resulting from unknown or uncontrolled particle generation) and variations in throat size distribution (resulting from normal geologic processes) may cause wide variations in performance for particle suspensions. An extensive effort is underway at Institut Francais du Petrole (IFP) to address this issue. IFP is developing suspensions of "microgels" that are manufactured with very narrow particle size distributions.[16]

F_{rro} Must Be < 2 for Radial Flow. A second challenge is presented by the requirements for successful application of disproportionate permeability reduction for different types of problems. For example, consider an unfractured (i.e., radial flow) production well with one water zone, one oil zone, and a separating impermeable shale barrier. **Fig. 1** illustrates that productivity losses in radial flow are much more sensitive to residual resistance factors than to radius of gel penetration (r_{gel}) To avoid excessive losses in oil productivity when gelant is placed using unrestricted injection (i.e., no zone isolation), the gel *must* provide a residual resistance factor less than 2 in the oil zone.[6,13,17] Preferably, the gel should provide a residual resistance factor greater than 20 in the water zone (Fig. 1). The variations in residual resistance factors mentioned above point to the difficulties in reliably attaining permeability reductions to oil that are less than two.

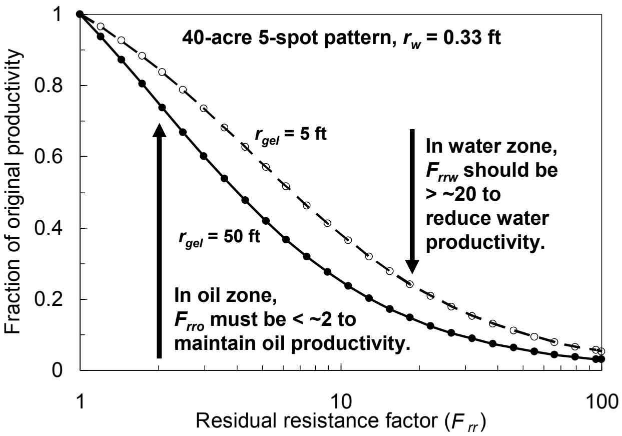


Fig. 1—Losses of zone flow capacity for radial flow.

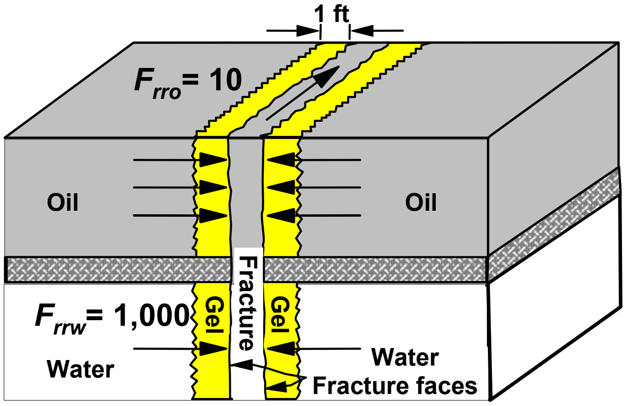
Permeability Dependence of F_{rr}. A third challenge comes from the dependence of residual resistance factors on the permeability of the porous media. For adsorbing polymers and weak gels, resistance factors and residual resistance factors increased with decreased permeability (**Fig. 2**).[14,15,18-21] In other words, these materials damage low-permeability rock more than high-permeability rock. Depending on the magnitude of this effect, these polymers and gels can harm injection or production flow profiles in wells, even though the polymer or gelant penetrates significantly farther into the high-permeability rock.[6,13,17]

Overcoming the Obstacles

Variability. Variability of residual resistance factors was the first challenge mentioned above. This variability can be attributed to uncontrolled particle size distributions for suspensions of gel particles and to mineralogical variations for both adsorbed polymers and suspensions of gel particles. Perhaps this variability in performance can be mitigated by using a permeability reduction mechanism with better control. In particular, if all aqueous pore space was filled with a uniform gel, the permeability reduction (at least for water flow) would be controlled by flow through the gel itself. If the inherent permeability of the gel to water was much less than the permeability of the original porous media, the permeability reduction would not be sensitive to variations in mineralogy, pore size, or pore size distribution.

Concerning variability of oil residual resistance factors, our recent work[22] suggested that re-establishing oil permeability in a gel-filled porous media can be predicted using concepts of mobility ratios and stable-versus-unstable displacements.

Linear versus Radial Flow. The second hurdle mentioned depended on the type of problem to be treated. Our work suggests that disproportionate permeability reduction currently has its greatest utility in treating fractures and fracture-like features.[7,8,9] If gelant is allowed to leakoff a short, controlled distance from the fracture faces and if the gel provides predictable residual resistance factors, water entry into the fracture can be greatly impeded while causing minimal reduction in hydrocarbon productivity. This process does not require that the gel provide very low oil residual resistance factors—only that the gel provides water residual resistance factors that are reliably much greater than oil residual resistance factors (see Fig. 2 for an example).



Equivalent resistance (expressed as distance through untreated rock) that fluid must flow to traverse the gel bank and enter the fracture:
In oil zone: 1 ft x 10 = 10 ft.
In water zone: 1 ft x 1,000 = 1,000 ft.

Fig. 2—Gel restricting water entry into a fracture.

In contrast, for radial flow from wells into porous rock (i.e., unfractured production wells), the oil residual resistance factor (F_{rro}) must generally have a value below 2[6,13] (see Fig. 1). Normally, we might not expect this to be achievable using a pore-filling gel, such as Cr(III)-acetate-HPAM. We typically expect pore-filling gels to provide high residual resistance factors for both oil and water. However, our recent work provides hope that low F_{rro} values may be attained.[22] For example, in one case before gel placement, a Berea core showed an endpoint permeability to oil of 508 md (i.e., at S_{wr}) and an endpoint permeability to water of 120 md (i.e., at S_{or}). After placement of a Cr(III)-acetate-HPAM gel [with 0.5% HPAM and 0.0417% Cr(III) acetate], the permeability during brine injection quickly stabilized at 0.17 md (open circles in **Fig. 3**)—indicating a water residual resistance factor of 706 (i.e., 120/0.17). In contrast, during oil (hexadecane) injection after gel placement (solid circles in Fig. 3), the permeability rose gradually to 105 md over the course of 100 pore volumes (*PV*)—indicating an oil residual resistance factor of only 4.8 (i.e., 508/105). Since the permeability to oil was still rising at 100 *PV* (Fig. 3), hope exists that even lower oil residual resistance factors could be achieved.

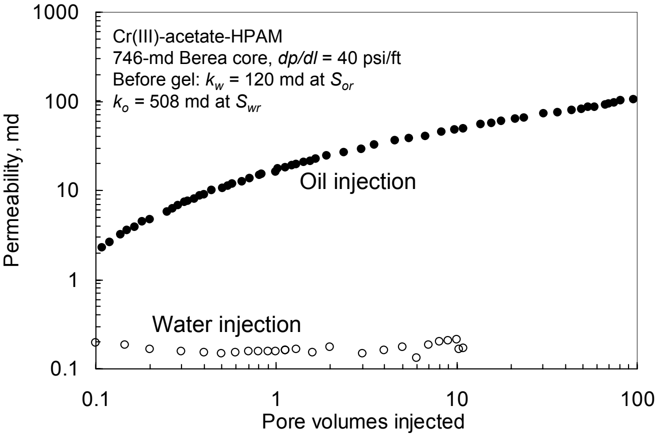


Fig. 3—Permeabilities to oil and water after gel placement.

Permeability Dependence. The third challenge mentioned above was the permeability dependence of residual resistance factors. For adsorbing polymers and suspensions of gel particles, residual resistance factors increased with decreased permeability. In contrast, pore-filling gels reduced the permeability to water of all porous media to the same low value—a value that approximates the inherent permeability of the gel to water.[12-15] Consequently, use of pore-filling gels may provide a means to overcome some of the important challenges that have limited applications of disproportionate permeability reduction.

Permeability to Water after Gel Placement

k_w versus Initial Core Permeability and Core Material. With the above considerations in mind, we performed several experiments in an effort to use pore-filling Cr(III)-acetate-HPAM gels to optimize disproportionate permeability reduction. One goal was to ensure that water residual resistance factors (F_{rrw}) are reliably high. For radial flow, Fig. 1 suggests that F_{rrw} values should be greater than 20. For linear flow applications (e.g., fractured wells), much larger F_{rrw} values are desirable (see Fig. 2). Thus, we performed experiments to establish whether a pore-filling gel can provide reliable k_w and F_{rrw} values. In particular, for the first set of experiments (all at 41°C), we wished to confirm that a pore-filling gel reduces the permeability (k_w) of all porous media to the same low value—that reflects the inherent permeability of the gel to water. In **Table 1**, the first six entries describe experiments where cores at residual oil (hexadecane) saturation (S_{or}) were flooded with a Cr(III)-acetate-HPAM gelant [with 0.5% Ciba Alcoflood 935™ HPAM, 0.0417% Cr(III) acetate, 1% NaCl, 0.1% $CaCl_2$], shut in for 3 days to allow gelation, followed by brine injection (1% NaCl, 0.1% $CaCl_2$) at a fixed pressure gradient. Initial core permeabilities ranged from 746 to 15,270 md in core materials including Berea sandstone, fused silica, and porous polyethylene. At S_{or}, k_w values before gel placement ranged from 120 to 6,500 md. For the first six post-gel cases, k_w at S_{or} averaged 0.24 md (± 0.084 md), and no trend was evident when correlating with material type or initial core permeability (solid circles in **Fig. 4**). These results support our previous finding that pore-filling gels reduce permeability of all porous media to a value that reflects the inherent permeability of the gel to water.[12,14,15] In contrast, in Berea sandstone with k_w (at S_{or}) ranging from 222 to 363 md, a weak gel (with 0.18% polymer) exhibited a much wider range of post-polymer k_w values—from 0.75 to 202 md (open circles in Fig. 4, data from Ref. 10). Thus, pore-filling gels can provide greater reliability and behavior that is insensitive to the initial rock permeability.

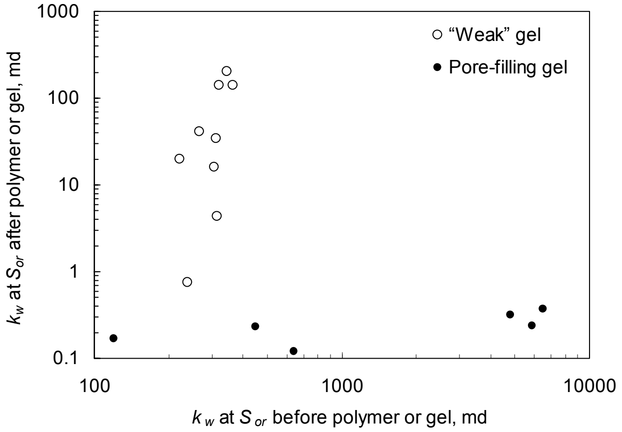


Fig. 4—Variations in k_w for pore-filling gels versus weak gels.

k_w with/without S_{or}. Entries 7-9 and 14-16 in Table 1 list results for the same gel (0.5% HPAM) but in porous media with no initial oil saturation (i.e., the cores were completely saturated with gel before brine was injected). For these six cases, a larger degree of variation was seen (average post-gel k_w was 0.043 md ± 0.047 md) compared to that for the first six entries. Even so, most measured post-gel k_w values with no S_{or} were noticeably lower than those cases with a residual oil saturation. Why should permeability to water be higher when residual oil is present? Several possibilities come to mind. First, brine could breach or fracture through the gel. With residual oil drops dispersed throughout the porous medium, breaking pathways through gel films (that separate oil drops) might be easier than breaking a path through one continuous block of gel. However, such a breaking mechanism should depend on the pore size: gel breaching should be easier in large pores and very permeable media than in small pores and low-permeability rock. Generally, we did not see a significant trend for post-gel k_w values as initial core permeability increased (Entries 1-6 in Table 1). However, Entry 12

Table 1—k_w during brine flow after gel placement.

Entry	Core material	Initial k, md	ϕ, %	k_w at S_{or}, md	HPAM in gel, %	S_{or} present?	dp/dl, psi/ft	Post- gel k_w, md	F_{rrw}
1	Berea	746	21	120	0.5	yes	40	0.17	706
2	fused silica	1,820	27	447	0.5	yes	30	0.23	1,940
3	fused silica	2,390	27	640	0.5	yes	10	0.12	5,330
4	polyethylene	6,400	40	4,810	0.5	yes	100	0.32	15,000
5	polyethylene	9,530	40	5,860	0.5	yes	30	0.24	24,400
6	polyethylene	15,270	40	6,500	0.5	yes	10	0.37	17,600
7	Berea	356	21	*	0.5	no	13.7	0.015	23,700
8	Berea	389	21	*	0.5	no	30	0.005	77,800
9	Berea	100	21	*	0.5	no	58	0.01	10,000
10	Berea	40	21	*	0.4	no	58	0.019	2,110
11	Berea	274	21	*	0.3	no	58	0.055	4,980
12	Berea	98	21	31	0.5	yes	58	0.007	4,430
13	Berea	69	21	14.4	0.3	yes	58	0.092	157
14	polyethylene	8,100	40	*	0.5	no	30	0.06	135,000
15	sand pack	8,100	35	*	0.5	no	1.5	0.029	279,000
16	polyethylene	2,000	40	*	0.5	no	24.5	0.14	14,300
17	polyethylene	3,200	40	*	0.125†	no	24.5	0.23	13,900

* Since no residual oil was present, F_{rrw} was calculated using the initial core permeability. † xanthan instead of HPAM.

(with initial k of 98 md and k_w = 31 md at S_{or}) showed a post-gel k_w value (0.007 md) that was much less than those for Entries 1-6. Interestingly, post-gel k_w values for Entries 9 and 12 (0.01 versus 0.007 md) suggest no significant effect of an initial residual oil saturation for this set of cases.

A second conceivable mechanism is that brine could force a pathway between the gel and the walls of the porous media. However, for this mechanism, the ability to form a pathway (i.e., higher k_w values) should be enhanced with (1) increased initial permeability (i.e., decreased rock-gel surface area) and (2) increased hydrophobic nature of the rock surface. In support of this mechanism, the post-gel k_w values for the polyethylene cores (Entries 14 and 16) were noticeably greater than those for the Berea cores (Entries 7 to 9).

The remaining mechanism is that water dominantly forces a pathway between the gel and the residual oil. Additional work is needed to clarify the importance of these mechanisms.

k_w versus Polymer Content. In previous work with Cr(III)-acetate-HPAM gels,[23,24] results suggested that the inherent permeability of the gel to water (k_{gel} in md) varied inversely with the third power of polymer concentration (C in %).

$$k_{gel} = 0.125 / C^3 \quad \text{.......} \quad (1)$$

Part of our approach to optimizing disproportionate permeability reduction involves controlling the inherent permeability of the gel to water. So, we examined the performance of gels as a function of polymer content.

Entries 9 through 11 examines three Berea cores that were saturated with three different compositions of Cr(III)-acetate-HPAM gel, with HPAM concentrations of 0.5%, 0.4%, and 0.3%, respectively. The cores had the same dimensions and were cut from the same slab of Berea sandstone, but interestingly, the initial rock permeabilities (before gel placement) varied from 40 to 274 md. We should mention one "trick" to ensure that pore-filling Cr(III)-acetate-HPAM gels form in Berea sandstone. That trick involved flushing the cores with a few pore volumes of brine containing 0.12% Cr(III) acetate before injecting the gelant. This process saturates chromium adsorption sites and minimizes depletion of chromium from the gelant during placement. Prior to using this procedure, we often had problems with incomplete gel formation in Berea sandstone.

During brine flow (at 58 psi/ft) after gelation, post-gel k_w values were 0.01 md, 0.019 md, and 0.055 md, respectively. For the gel with 0.5% HPAM, the 0.01-md value (Entry 9) was similar to the 0.015-md and 0.005-md values associated with Entries 7 and 8—indicating a reasonable degree of reproducibility for the results. However, these values were substantially lower than the 1-md value predicted from Eq. 1. This discrepancy may be tied to differences in porosity of the porous media. In particular, Eq. 1 was based on flow through solid pieces of gel—i.e., 100% porosity with no rock.[23,24]

On the other hand, if we accept the 0.01-md value for the gel with 0.5% HPAM, the post-gel k_w values for Entries 10 and 11 were consistent with the cubic relation of Eq. 1 between polymer concentration and inherent gel permeability. In particular, for Entries 9-11, post-gel k_w values of 0.01 md, 0.019 md, and 0.055 md were observed, while Eq. 1 predicted values of 0.01 md, 0.019 md, and 0.046 md (if 0.01 md was accepted as correct for the 0.5%-HPAM case).

Entries 12 and 13 in Table 1 provide another set for comparison, using low-permeability Berea sandstone cores with residual oil present before gelant placement. Here, the gel with 0.3% HPAM (Entry 13) exhibited a post-gel k_w value that was 13 times that for the gel with 0.5% HPAM (Entry 12).

For yet another comparison, Entry 17 in Table 1 lists results for a gel that contained 0.125% xanthan (Kelco Kelzan XCD™), 0.0125% Cr(III) acetate, 1% NaCl, and 0.1% $CaCl_2$.

Before adding crosslinker, the xanthan polymer solution was clarified by filtration to remove cellular debris. Use of xanthan allowed formation of a pore-filling gel with a considerably lower polymer concentration than when using HPAM. Presumably, the semi-rigid-rod structure of xanthan allows the critical overlap concentration to be much lower than that for the random-coil structure of HPAM in solution.

The Cr(III)-acetate-xanthan gelant was placed in a 3.2-darcy polyethylene core (no residual oil present), and a brine pressure gradient of 24.5 psi/ft was applied (41°C). During brine injection, the post-gel k_w quickly stabilized at 0.23 md. This value can be compared with 0.06 md for Entry 14 or with 0.14 for Entry 16 (which used gels with 0.5% HPAM in porous polyethylene). Since the polymer concentration for Entry 17 was four times less than those for Entries 14 and 16, the post-gel k_w for Entry 17 might be expected to be 64 times (i.e., 4^3) greater than those for Entries 14 or 16—i.e., 3.8 md (0.06 md x 64) or 9.0 md (0.14 md x 64) instead of 0.23 md. Alternatively, Entry 17 can be compared with Entry 11, where the post-gel k_w was 0.055 md for a gel with 0.3% HPAM in Berea sandstone. For this case, since the polymer concentration for Entry 17 was 2.4 times less than that for Entry 11, the post-gel k_w for Entry 17 might be expected to be 13.8 times (i.e., 2.4^3) greater than that for Entry 11—i.e., a value of 0.76 md (0.055 md x 13.8) instead of 0.23 md. Thus, for both comparisons, the post-gel k_w for the Cr(III)-acetate-xanthan gel was significantly less than expected from the behavior of Cr(III)-acetate-HPAM gels. This result reveals limitations in using Eq. 1 for estimating post-gel k_w values. Nevertheless, the post-gel k_w value for Entry 17 was the highest for any pore-filling gel examined to date for cases where residual oil was not present during gelant placement.

Stability of Post-Gel k_w. In the next section, we show that permeability to oil (k_o) after gel placement was a strong function of time and throughput. In contrast, if the gel was not compromised (e.g., by exposure to high pressure gradients), **Fig. 5** demonstrates that the post-gel k_w was stable for a substantial period. In particular, for the gel associated with Entry 14 in Table 1, k_w held a value of about 60 µd (0.06 md) for over 500 days during continuous exposure to a pressure gradient of 30 psi/ft at 41°C. At 530 days, the permeability jumped from 60 to 80 µd, for unexplained reasons. Since then, the permeability has been stable.

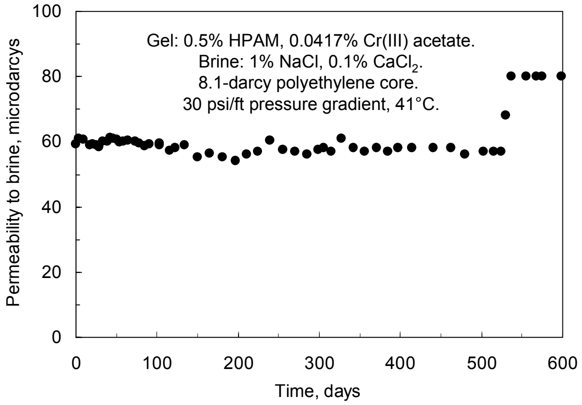


Fig. 5—k_w versus time after gel placement.

Are F_{rrw} Values High Enough? For radial flow, the residual resistance factor in the water zone should be at least 20 (Fig. 1). Will the results from Table 1 meet this requirement? The highest post-gel k_w value listed was 0.37 md. Given the definition of water residual resistance factor (i.e., permeability to water before gel placement divided by permeability to water after gel placement), F_{rrw} will be ≥20 if the permeability to water before gel placement is greater than 7.4 md (i.e., 20x0.37). Many engineers and geologists (including the author) believe that if a productive oil reservoir has a matrix permeability below 20 md, fractures or fracture-like features probably play a major role in allowing fluid to flow to the wells. Consequently, these gels would provide acceptable F_{rrw} values for radial flow applications.

When treating fractures using the concept illustrated in Fig. 2, will the post-gel k_w values from Table 1 be satisfactory? The degree of productivity impairment (q/q_o) for flow into a fracture can be estimated using Eq. 2:

$$q/q_o \approx L_e \,/\, (F_{rr}\, L_p + L_e), \qquad (2)$$

where L_p is the distance of polymer or gelant leakoff from the fracture face and L_e is the effective external drainage distance. From Eq. 2, reducing water productivity index by at least 50% requires that $F_{rrw}\, L_p \geq L_e$. If L_e is 100 ft, F_{rrw} must be at least 10 if L_p is 10 ft and at least 100 if L_p is 1 ft. If k_w after gel placement is 0.37 md (Table 1), a F_{rrw} value of at least 10 can be achieved if k_w before gel placement is at least 3.7 md (i.e., 10x0.37 md). A F_{rrw} value of at least 100 can be attained if k_w before gel placement is at least 37 md (i.e., 100x0.37 md).

These calculations reveal that gels can achieve beneficial reductions in water productivity for both linear and radial flow problems. However, they will not be effective in all situations. Effective applications require attention to ensure that the distance of gelant penetration is adequate for rock of a given permeability. For example, many West Texas fractured dolomite reservoirs have rock permeability around 10 md. If a gel provides a k_w after gel placement of 0.24 md (average of Entries 1-6 in Table 1), a fairly large gelant leakoff distance may be needed (i.e., > 2.4 ft) to reduce water productivity by more than 50%. Alternatively, if a gel provides a k_w after gel placement of 0.007 md (Entry 12 in Table 1), a much smaller gelant leakoff distance (i.e., 0.07 ft) may provide the same effect. Large gelant leakoff distances present challenges—especially with respect to penetration of high molecular weight polymers into tight rock. Different gel formulations—e.g., using higher concentrations of lower molecular weight polymers—may require consideration for these applications. Additional work is needed to determine k_w values after gel placement in low-permeability rock.

Permeability to Oil after Gel Placement

Of course, the key to utilizing disproportionate permeability reduction is to identify conditions where a polymer or gel will reduce permeability to water much more than that to hydrocarbon. The previous section was concerned with whether water residual resistance factors were sufficiently high. This section will examine whether oil residual resistance factors can be sufficiently low. We also investigate how fast oil zones regain oil productivity after gel placement.

Concepts from Previous Work. Previous work[5,25,26] revealed that gels can dehydrate during oil injection, thus causing disproportionate permeability reduction. Although oil cannot enter or flow through the gel matrix, pressure applied by the oil forces water to flow through and out from the gel. In locations where the gel has been compressed and dehydrated, oil forms “fingers” or “wormhole” pathways. These oil wormholes grow with time (and the entire gel structure continues to dehydrate with time under pressure), gradually increasing permeability to oil (note the solid circles in Fig. 3).

This time- and throughput-dependent behavior during oil flow through gel-filled cores has important consequences for the time required for wells to “clean up” or regain oil productivity after a gel treatment.[22] For applications in production wells where hydrocarbon zones are not protected during placement, polymers and gelants necessarily penetrate some distance into the hydrocarbon zones. After the well is returned to production, oil can force its way through the gel to reach the well, but this process takes time. Our previous analysis suggested that the clean up time varies (1) with the cube of the distance of polymer or gelant penetration from the well, (2) inversely with pressure drawdown, and (3) inversely with k_w in the gel-treated region.[22]

This last finding (i.e., that clean up time varies inversely with k_w in the gel-treated region) inspired our current approach to optimizing disproportionate permeability reduction. A high k_w value is desired to allow rapid dehydration and clean up of gel-treated areas during hydrocarbon flow. In contrast, a low k_w value is desired to restrict flow from the water zones. Thus, an optimum k_w value may be needed to maximize disproportionate permeability reduction.

For many of the experiments described in Table 1, oil (hexadecane for Entries 1-6 and Soltrol 130™ for Entries 7-17) was injected after gel placement and determination of k_w. The apparent permeability to oil (k_o) for these experiments are summarized in **Table 2** and are detailed in **Figs**. **6** through **13**.

Table 2—Ultimate k_o and F_{rro} during oil flow after gel placement.

Entry	Core material	Initial *k*, md	k_o at S_{wr} before gel, md	HPAM in gel, %	*dp/dl*, psi/ft	Final k_o, md	Final F_{rro}	Final F_{rrw}/F_{rro}
1	Berea	746	508	0.5	40	105	4.8	147
2	fused silica	1,820	1,240	0.5	30	307	4.0	485
3	fused silica	2,390	1,632	0.5	10	208	7.8	683
4	polyethylene	6,400	6,400	0.5	100	515	12.4	1,210
5	polyethylene	9,530	9,530	0.5	30	531	17.9	1,363
6	polyethylene	15,270	11,410	0.5	10	637	17.9	983
7	Berea	356	242*	0.5	2.7	209	1.2	19,800
8	Berea	389	389	0.5	4.9	330	1.2	64,800
9	Berea	100	68*	0.5	12	16.8	4.0	2,500
10	Berea	40	27.2*	0.4	12	13.4	2.0	1,050
11	Berea	274	186*	0.3	12	110	1.7	2,930
12	Berea	98	132	0.5	21.6	60.1	2.2	2,010
15	sand pack	8,100	8,100**	0.5	1.5	1,840	4.4	63,400
16	polyethylene	2,000	2,000**	0.5	9.8	1,450	1.4	10,200
17	polyethylene	3,200	3,200**	0.125†	9.2	1,052	3.0	4,630

* Estimate based on Entry 1. ** Estimate based on Entries 4 and 5. † xanthan instead of HPAM.

Effect of Pressure Gradient. The effects of pressure gradient on the k_o-versus-PV curves are shown for gel in polyethylene cores in **Fig. 6**, in Berea sandstone cores in **Fig. 7**, and in fused silica cores in **Fig. 8**. For a given porous medium, the curves generally had similar shapes. However, in polyethylene and Berea, the curves shifted to greater PV throughput values as the pressure gradients were increased. If pressure gradient had no effect on the gel structure, the curves should have overlapped. If the gel structure was compromised by applications of higher pressure gradients, the curves should have shifted to the left (i.e., higher permeabilities achieved with smaller throughput values.). Instead, the curves in Figs. 6 and 7 shifted right. It is possible that the differences are inherent variations associated with the gel and porous media. In fused silica (Fig. 8), the curves shifted left with increased pressure gradient.

Interestingly, k jumped from ~0.2 md to ~2 md between 0 and 0.1 PV in the polyethylene and silica cores. In Berea, k_o at 0.1 PV was more similar to k_w before oil flow. As a possible explanation, a rapid increase in k_o may have been facilitated by imbibition of oil along the oil-wet surfaces of the porous polyethylene. Upon first consideration, this explanation is not very satisfying for the same behavior in fused silica (Fig. 8), which we assumed was water-wet. However, since we did not measure the wetting characteristics of the fused silica cores, they may have been more oil-wet than we expected.

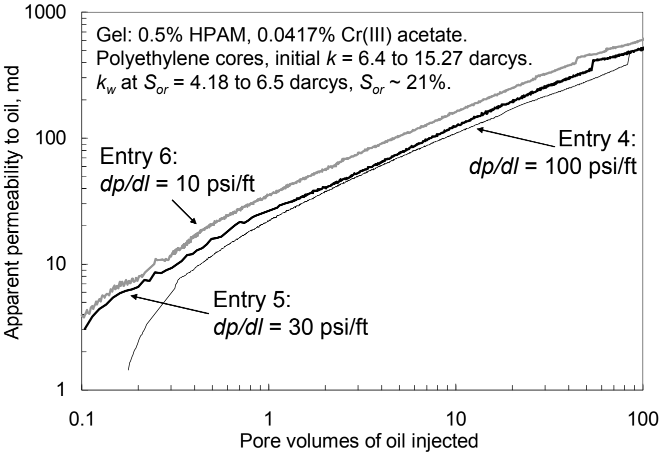


Fig. 6—k_o versus *PV* and pressure gradient in polyethylene.

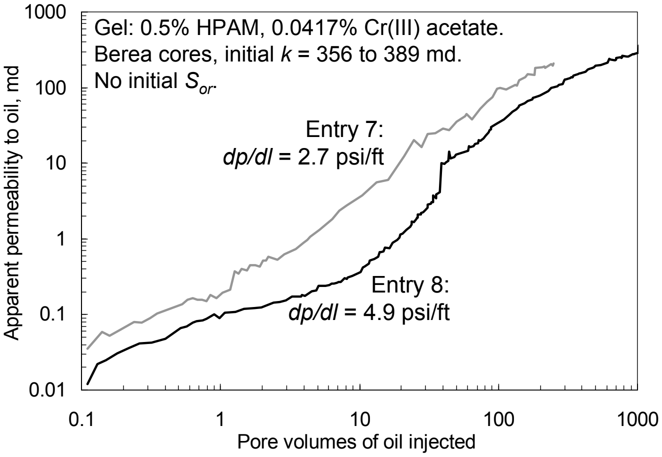


Fig. 7—k_o versus *PV* and pressure gradient in Berea sandstone.

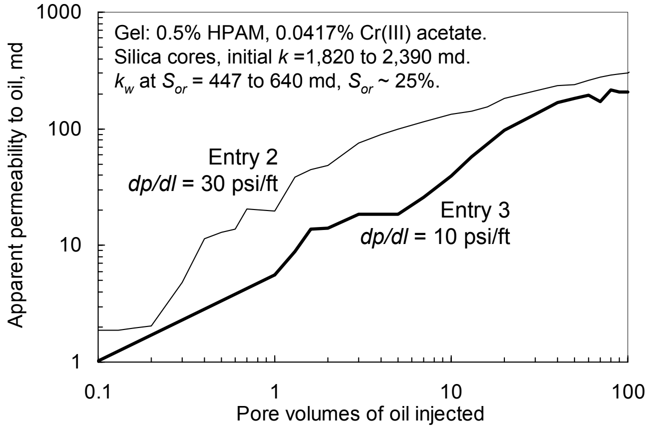


Fig. 8—k_o versus *PV* and pressure gradient in fused silica.

Effect of HPAM Content in the Gel. In Table 1, post-gel k_w values increased with decreased polymer content in the gel—from 0.01 md for the gel with 0.5% HPAM (Entry 9) to 0.055 md for the gel with 0.3% HPAM (Entry 11). Fig. 9 reveals that for early oil throughput values, the k_o values were qualitatively consistent with the post-gel k_w trends. However, at higher throughput values, the separation of the curves became less evident. Fortunately, because the clean up behavior is dominated by the post-gel k_w values and the early k_o values,[22] an advantage in clean up time can be realized by using gels with low polymer concentrations. However, this suggestion must be moderated by a realization that if the polymer content is too low, a pore-filling gel will not form. Instead, a weak gel or suspension of gel particles will form.

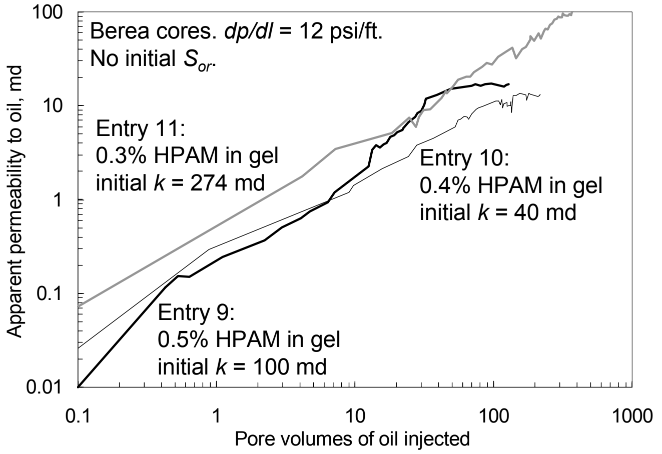


Fig. 9—k_o versus *PV* for different HPAM concentrations.

Effect of Initial S_{or}. Figs. 10 and 11 show k_o versus *PV* for cases with and without an initial residual oil saturation. In Fig. 10, Berea sandstone cores were used with an initial (absolute) permeability (to water) of about 100 md. Both Berea cores had the same dimensions, and both were flooded with the same gel (0.5% HPAM, 0.0417%, 1% NaCl, 0.1% $CaCl_2$). One core had no residual oil saturation before gelant placement (Entry 9). The other core (Entry 12) had a S_{or} of 31% before gelant placement and a k_w value (at S_{or}) of 31 md. Table 1 reveals that the k_w values during brine injection (at *dp/dl*=58 psi/ft) immediately after gel placement were similar for the two cases (0.01 versus 0.007 md). Fig. 10 shows that the development of k_o versus *PV* was also similar for the two cases.

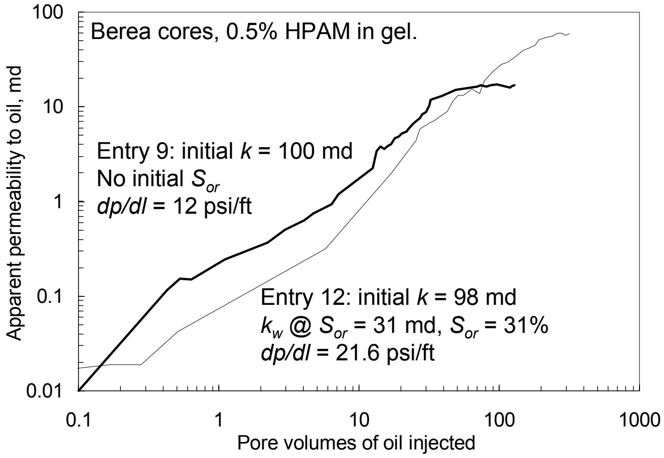


Fig. 10—k_o with/without an intial S_{or} in Berea.

In contrast to the Berea cases, the presence of initial oil saturation had a significant effect in porous polyethylene. When S_{or} was present before gel placement (Entry 6 in Fig. 11), *k* jumped from 0.37 md to 4 md between 0 and 0.1 *PV*. Thus, in oil-wet porous polyethylene, the residual oil promoted a rapid initial increase in k_o. A similar jump did not happen for Entry 16 (where no residual oil was present before gelant placement) until about 10 *PV* of oil injection, when the k_o curve increased to match the curve for Entry 6. The large initial jump in k_o was noted for the three polyethylene cores with S_{or} before gel (Fig. 6 and Entries 4, 5, and 6 in Table 1). It was also noted for the two fused silica cores (Fig. 8 and Entries 2 and 3 in Table 1), which we assumed (perhaps incorrectly) were strongly water-wet. In water-wet Berea, this rapid initial increase in k_o was not observed, with or without the presence of residual oil before gelant placement (Fig. 10).

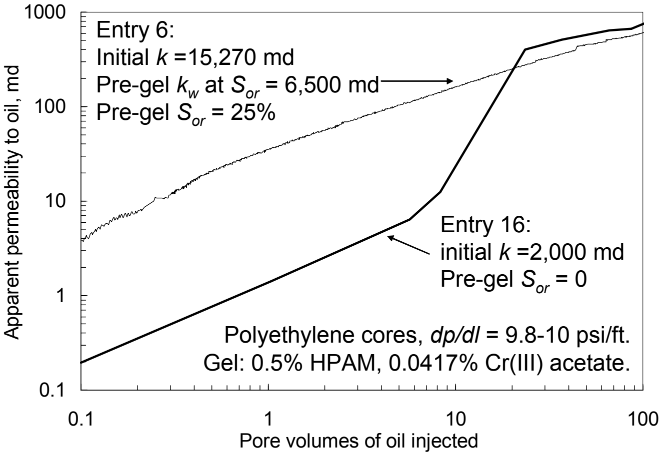


Fig. 11—k_o with/without an intial S_{or} in polyethylene.

Effect of Porous Medium. Fig. 12 shows k_o versus pore volume for different porous media (with no residual oil before gel placement). The three porous media, Berea sandstone, quartz sandpack, and porous polyethylene, show significantly different curves for k_o versus pore volume. However, for Entries 8, 9, and 15 in Table 1 and Fig. 12 (i.e., the cases with strongly water-wet porous media) the early-throughput k_o values were fairly similar.

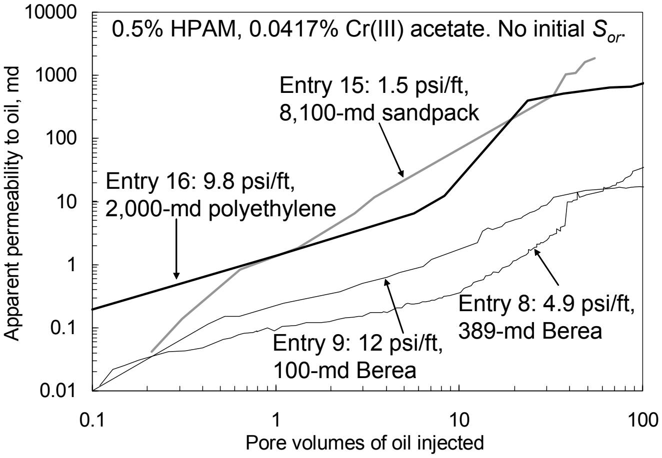


Fig. 12—k_o versus *PV* for different porous media.

Effect of Polymer Type in the Gel. For Entry 17, the gel contained 0.125% xanthan. During oil injection for Entry 17, k_o increased steadily with throughput, as shown in Fig. 13. For comparison, results from a similar experiment (Entry 16) using a Cr(III)-acetate-HPAM gel (with 0.5% HPAM) are also shown. The low-concentration, pore-filling Cr(III)-acetate-xanthan gel showed behavior similar to the Cr(III)-acetate-HPAM gel during the first 10 *PV* of oil flow. Beyond 10 *PV*, the curves deviated markedly, as the curve for Entry 16 experienced a sharp jump. Perhaps the xanthan gel adhered more tenaciously to the polyethylene pore walls than did the HPAM gel.

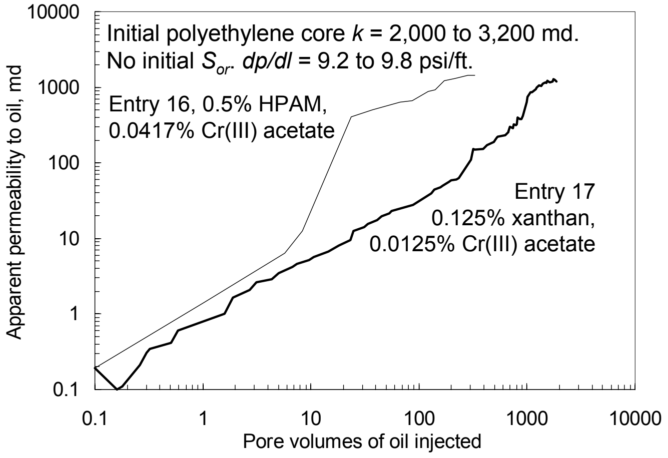


Fig. 13—Xanthan versus HPAM gels.

Are F_{rro} Values Low Enough? With radial flow, oil residual resistance factors must be less than 2 to mitigate damage caused by polymer or gel to oil productive zones. Can F_{rro} values this low be attained using pore-filling gels? The seventh and eigth columns in Table 2 list the final k_o and F_{rro} values for each case. Typically, these values were measured after over 100 *PV* of oil were injected. The lowest F_{rro} value was 1.2. We found five cases where gels provided water residual resistance factors greater than 2,100 and ultimate F_{rro} values of 2 or less (see Entries 7, 8, 10, 11, and 16 in Tables 1 and 2). These cases used gels with 0.3% to 0.5% HPAM. As noted above, F_{rro} must be less than 2 for radial flow treatments where hydrocarbon zones are not protected during gel placement. So, our recent results provide hope that our current approach will identify a gel that can successfully and reliably treat either fractured or unfractured production wells without zone isolation.

For linear flow applications (wells that intersect fractures), our main requirement was that the gel reduce permeability to water much more than that to oil. The last column in Table 2 lists the ratio, F_{rrw} / F_{rro}. These ratios range from 147 to 64,800. These values would be very acceptable for applications in very permeable media. Unfortunately, fractures and fracture-like features are less likely to present channeling problems as the permeability of the media increases. The greatest need for high F_{rrw} / F_{rro} ratios exists in tight rock. As mentioned earlier, if the F_{rrw} value is too low when treating a fracture, the gelant must leakoff a substantial distance from the fracture faces. In addition to the expense of requiring large gelant volumes, this situation may be limiting because many polymer-based gelants cannot penetrate into tight rock.[18] On a positive note, the case for Entry 10 (using gel with 0.4% HPAM in 40-md Berea) exhibited F_{rrw} = 2,110, F_{rro} = 2.0, and

F_{rrw} / F_{rro} = 1,050. These values would be quite acceptable for applications in either fractured or unfractured wells. Since they were measured in 40-md rock, we see hope that our approach will identify a gel that can successfully and reliably treat either fractured or unfractured production wells without zone isolation.

How Fast Will Oil Zones Clean Up?

Previous Approach. In Ref. 22, a means was described to estimate how rapidly productivity can be restored in an oil zone that was invaded by a polymer or gel. A simple mobility-ratio model was used to predict clean up times for both fractured and unfractured wells after a gel treatment. Conventional relative permeability equations were used (Eqs. 3 and 4).

$$k_{rw} = k_{rw}^o((S_w - S_{wr})/(1 - S_{or} - S_{wr}))^{nw} \qquad (3)$$

$$k_{ro} = k_{ro}^o((1 - S_{or} - S_w)/(1 - S_{or} - S_{wr}))^{no} \qquad (4)$$

The time to restore productivity to a gel-treated oil zone (1) was similar for radial versus linear flow, (2) varied roughly with the cube of distance of gel penetration, (3) varied inversely with pressure drawdown, (4) varied inversely with the k_w at S_{or} in the gel-treated region, and (5) was not sensitive to the final k_o at S_{wr}. Although k_o at S_{wr} (after gel placement) had no effect on the clean up time, it strongly affected how much of the original oil productivity was ultimately regained. The results from this model were described quite well using an empirical equation (Eq. 5), so long as the distance of gelant penetration was not too small. Eq. 5 predicts the level of oil productivity that may be regained (q_{oil} / q_{end}) as a function of time (t in days), distance of gelant penetration into the porous rock (L_p in ft), permeability to water in the gel-treated region (k_w in md), pressure drawdown (Δp in psi), and fluid viscosities (μ_o and μ_w).

$$q_{oil} / q_{end} = (2/\pi) \arctan[(64\, t\, \Delta p\, k_w\, \mu_w / (\mu_o L_p^3))^{\pi/4}] \qquad (5)$$

New Approach. The approach taken in Ref. 22 and Eq. 5 assumed that recovery of oil productivity was dominated by the inherent permeability of the gel to water. It neglected the detailed shapes of the k_o-versus-PV curves in Figs. 6-13. Consequently, an effort was made to consider how clean up time was influenced by these curves. A power regression worked reasonably well in fitting the curves in Figs. 6-13. Columns 8-10 in Table 3 list regression parameters associated with fitting the data with the equation,

$$k_o = k_w + B\,(PV)^n \qquad (6)$$

Table 3—Actual versus predicted times to recover 50% of ultimate k_o.

Core properties							Parameters from power regression, (Eq. 6)			Time to reach 50% of ultimate k_o, days		
Entry	Core material	Initial k, md	S_{or} present?	dp/dl, psi/ft	Core length, ft	Post-gel k_w, md	B	n	R^2	Actual	Old model	New model
1	Berea	746	yes	40	0.256	0.17	13	0.52	0.956	0.37	0.14	0.40
2	fused silica	1,820	yes	30	0.231	0.23	17.2	0.73	0.923	0.08	0.13	0.6
3	fused silica	2,390	yes	10	0.244	0.12	8.9	0.72	0.972	0.9	0.8	3.5
4	polyethylene	6,400	yes	100	0.238	0.32	19.8	0.72	0.971	0.84	0.03	0.24
5	polyethylene	9,530	yes	30	0.245	0.24	25	0.68	0.997	1.2	0.14	0.68
6	polyethylene	15,270	yes	10	0.256	0.37	31	0.69	0.991	2.1	0.28	1.6
7	Berea	356	no	2.7	0.438	0.015	0.244	0.86	0.941	162	45	330
8	Berea	389	no	4.9	0.462	0.005	0.05	1.26	0.955	255	81	363
9	Berea	100	no	12	0.104	0.01	0.183	1.1	0.978	7.2	3.9	10.2
10	Berea	40	no	12	0.104	0.019	0.22	0.86	0.985	8.4	2.2	10.2
11	Berea	274	no	12	0.104	0.055	0.45	0.91	0.991	4.4	0.73	5.9
12	Berea	98	yes	21.6	0.104	0.007	0.10	1.17	0.988	9.5	1.8	10.8
15	sand pack	8,100	no	1.5	0.405	0.029	1.13	1.84	0.996	94	42	129
16	polyethylene	2,000	no	9.8	0.229	0.14	2.2	1.2	0.947	2.5	0.4	4.5
17	polyethylene	3,200	no	9.2	0.245	0.23	0.743	0.88	0.992	25	0.54	20.6

This equation was used as the basis for our new model. The last column in Table 3 lists the calculated time (i.e., the estimated clean up time) for k_o to reach 50% of its final value. For comparison, the second to last column in Table 3 lists clean up times using our previous model.[22] Calculated clean up times from the new method were consistently greater than those from the old method and were generally closer to the actual laboratory values (third to last column in Table 3), except for the cases using fused silica cores.

Using parameters associated with Entry 1 in Tables 1-3, Fig. 14 was generated to compare predictions from the two models as a function of distance of gelant penetration into porous rock. For the old model, the saturation exponents, *nw* and *no* were 2, S_{wr} was 0.3, S_{or} was 0.3, k_w (at S_{or} after gel placement) was 0.17 md, k_o (ultimate value after gel placement and 100 *PV* of oil injection) was 104 md, oil viscosity, μ_o, was 3.34 cp, and water viscosity was 1 cp. For the new model, k_w was 0.17 md, *B* was 13 and *n* was 0.52.

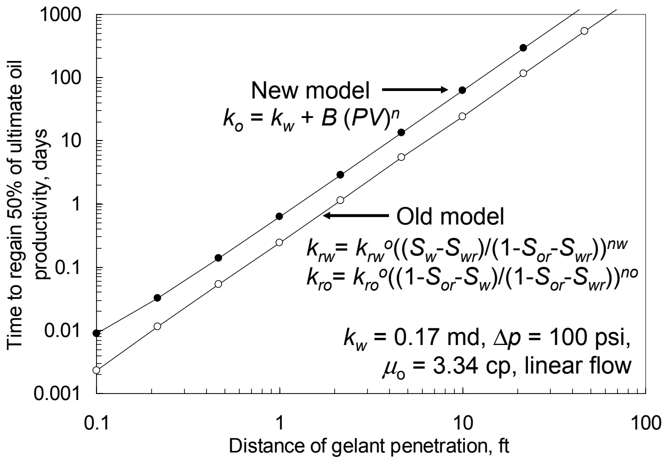


Fig. 14—Predicted clean up times: old versus new models.

For a given distance of gelant penetration, predicted clean up times from the new model were consistently about 2.5 times longer than those from the old model. For the conditions in Fig. 14, the new model indicates that the distance of gelant penetration must be less than 4 ft in order to keep the clean up time less than 10 days. For both models, the clean up time increased with the square of the distance of gelant penetration. In contrast in Ref. 22, we reported that the clean up time should increase with the cube of the distance of gelant penetration. A detailed reconsideration of the old analysis revealed that the apparent dependence of clean up time on length was influenced by the saturation exponents used and the range of lengths examined.

Laboratory results and the predictions from both models suggest that clean up time is strongly influenced by the magnitute of k_w immediately after gel formation. Consequently, there are three main choices to speed clean up time after a gel treatment: (1) limit gelant penetration into porous rock to small distances (i.e., no more than a few feet with current gels), (2) maximize pressure drawdown for the well, and (3) attempt to increase k_w in the gel-treated rock. The first two options should be employed as much as practical, but limits exist on how much they can be exploited. Our future work will focus on the third option: identifying a gel that provides higher, stable k_w values in the gel-treated rock.

Reliability. Reliability and reproducibility of performance are central issues for field applications of polymers and gels. Fig. 4 and Column 9 of Table 1 indicate that pore-filling gels can consistently reduce k_w to low values, regardless of the nature of the porous medium. Figs. 6-13 and Column 8 of Table 2 reveals that given enough oil throughput, pore-filling gels consistently provide low F_{rro} values—although not necessarily values below two. The main area of variability is the time or throughput dependence of achieving low F_{rro} values. If the distance of gelant penetration into porous rock is small, this variability will not matter, since all clean up times will be fast. However for intermediate distances of penetration (i.e., multiple feet), the variability may be of concern. For a given type of porous medium, the curves for k_o versus *PV* were fairly similar (see Figs. 6-10). Consequently, variability of clean up times may be manageable for wells within a given field. Since the greatest differences amoung the curves for k_o versus *PV* were seen when comparing different porous media (Fig. 12), significant variations in clean up times might be expected after gel treatments in wells from different fields.

Second Water Flow after Oil Flow

Water was injected again after the oil-flow experiments described in Table 2 and in Figs. 6-13. In all cases, the permeability to water stabilized quite quickly. Column 7 in Table 4 lists k_w values for these experiments. The last column in Table 4 converts the k_w values to water residual resistance factors. (For Entries 7-11 and 15-17, the initial core permeability to water was used when calculating F_{rrw} values, because k_w values were not measured at S_{or} before gel placement.) For Entries 1-5 in Table 4, the second k_w values were quite low—0.22 to 1.17 md. In most cases, these values were higher than the first k_w values after gel placement (Table 1), but were still very low relative to the k_o values (Table 2). An explanation was provided in Refs. 25 and 26. (The explanation involves trapping of high residual oil saturations.)

For Entries 6-17 in Table 4, the second F_{rrw} values were between 126 and 29,400 times less than the values before oil injection (compare the last columns of Tables 1 and 4). Thus, extended oil injection caused substantial damage to the gel for these cases. Interestingly, this damage was much less severe for the cases associated with Entries 1-5, where residual oil was present during gel placement. For Entries 1-5, the second F_{rrw} values were between one and seven times less than the values measured before oil injection.

The results in this section (i.e., for water flow following both gel placement and subsequent oil flow) are generally more of academic interest than of practical interest. After a polymer or gel treatment has been applied, brine is the first flowing fluid to contact the polymer or gel in the water zones, so the results from our "Permeability to Water after Gel Placement" section are of direct practical interest. Similarly, oil is the first flowing fluid to contact the polymer or gel in the oil zones, so the results from our "Permeability to Oil after Gel Placement" section are also of direct practical interest. The results from this current section could have practical application mainly if an oil zone becomes watered out after being treated by a polymer or gel.

Conclusions

We investigated the merits of pore-filling gels in providing disproportionate permeability reduction.

1. For porous media with pre-gel k_w (at S_{or}) ranging from 120 to 6,500 md, one strong pore-filling Cr(III)-acetate-HPAM gel (with 0.5% HPAM) consistently reduced k_w to about

0.24 md (ranging from 0.12 to 0.37 md). In contrast, in Berea sandstone with k_w (at S_{or}) ranging from 222 to 363 md, a weak gel (with 0.18% polymer) exhibited a much wider range of post-polymer k_w values—from 0.75 to 202 md. Thus, strong pore-filling gels can provide greater reliability and behavior that is insensitive to the initial rock permeability.

2. With sufficient oil throughput, pore-filling gels can be dehydrated, thus increasing permeability to oil. We found several formulations where gels provided water residual resistance factors greater than 2,000 and ultimate F_{rro} values of 2 or less. These results provide hope that our current approach will identify gels that can successfully and reliably treat either fractured or unfractured production wells without zone isolation.
3. Significant oil throughput was required to achieve low F_{rro} values, suggesting that gelant penetration into porous rock must be small (a few feet or less) for existing pore-filling gels to provide effective disproportionate permeability reduction.

Table 4—Ultimate k_w and F_{rrw} during the second water flow after gel placement.

Entry	Core material	Initial k, md	k_w at S_{or} before gel, md	HPAM in gel, %	*dp/dl*, psi/ft	2nd k_w, md	2nd F_{rrw}
1	Berea	746	120	0.5	40	1.11	108
2	fused silica	1,820	447	0.5	30	0.22	2,030
3	fused silica	2,390	640	0.5	10	0.35	1,830
4	polyethylene	6,400	4,810	0.5	100	0.74	6,500
5	polyethylene	9,530	5,860	0.5	30	1.17	5,008
6	polyethylene	15,270	6,500	0.5	10	106	61.3
7	Berea	356	*	0.5	13.7	42	8.5
8	Berea	389	*	0.5	30	26	15
9	Berea	100	*	0.5	58	2.5	40
10	Berea	40	*	0.4	58	2.4	16.7
11	Berea	274	*	0.3	58	18.5	14.8
12	Berea	98	31	0.5	58	2.2	14.1
15	sand pack	8,100	*	0.5	14.8	850	9.5
16	polyethylene	2,000	*	0.5	24.5	860	2.3
17	polyethylene	3,200	*	0.125†	24.5	210	15.2

* Since no residual oil was present, F_{rrw} was calculated using the initial core permeability. † xanthan instead of HPAM.

Acknowledgments

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Nomenclature

B = parameter in Eq. 6
C = polymer concentration, %
F_{rr} = residual resistance factor (permeability before/after gel placement)
F_{rro} = residual resistance factor for oil
F_{rrw} = residual resistance factor for water
k_{gel} = inherent permeability of gel to water, darcys [μm^2]
k_o = permeability to oil, darcys [μm^2]
k_{ro} = relative permeability to oil
k_{ro}^o = endpoint relative permeability to oil
k_{rw} = relative permeability to water
k_{rw}^o = endpoint relative permeability to water
k_w = permeability to water, darcys [μm^2]
L_e = external drainage distance, ft [m]
L_p = distance of polymer or gelant leakoff, ft [m]
n = pore volume exponent in Eq. 6
no = oil saturation exponent in Eq. 4
nw = water saturation exponent in Eq. 3
Δp = pressure drop, psi [Pa]
dp/dl = pressure gradient, psi/ft [Pa/m]
PV = pore volumes of fluid injected
q = flow rate, BPD [m^3/d]
q_{end} = final oil rate after large throughput, BPD [m^3/d]
q_o = flow rate before polymer/gel placement, BPD [m^3/d]
q_{oil} = instantaneous oil rate after gel treatment, BPD [m^3/d]
r_{gel} = radius of gelant penetration, ft [m]
S_{or} = residual oil saturation
S_{wr} = residual water saturation
t = time, d
μ_o = oil viscosity, cp [mPa-s]
μ_w = water viscosity, cp [mPa-s]
ϕ = porosity

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SI Metric Conversion Factors

cp x 1.0*	E-03	= Pa·s
ft x 3.048*	E-01	= m
in. x 2.54*	E+00	= cm
md x 9.869 233	E-04	= μm^2
psi x 6.894 757	E+00	= kPa

*Conversion is exact.