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Polymer Gels Formulated with a Combination of High and Low Molecular-Weight Polymers Provide Improved Performance for Water-Shutoff Treatments of Fractured Production Wells

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Abstract

A laboratory study has shown improved performance for fracture-problem water-shutoff polymer gels that are formulated with a combination of high and low molecular-weight (Mw) polymers. These gels are intended for application to fractures or other high permeability anomalies that are in direct contact with petroleum production wells. More specifically, we focused on evaluating the mechanical strength and improved performance of these water-shutoff gels for use when exceptionally large fracture apertures or large drawdown pressures are encountered. During our study, the gels were injected into laboratory-scale fractures while the gel was in a *partially formed* state. The flooding-experiment study involved the placement of partially formed chromium(III)-carboxylate/acrylamide-polymer (CC/AP) gels in 1- to 4-mm (0.04- to 0.16-in.) aperture, by 2-ft-long, by 1.5-in.-height fractures where the fracture walls were 700 md unfired Berea sandstone.

During the injection of a 1.5% high Mw and 2.0% low Mw polymer gel formulation, the partially formed gel fluid exhibited an effective viscosity of roughly 500 cp during placement in a 1-mm (0.04-in.) aperture fracture, and the matured gel exhibited exceptionally good fracture-plugging characteristics. The gel withstood 52 psi total differential pressure across the fracture length (26 psi/ft pressure gradient) for 24 hrs, while permitting no detectable brine flow through the gel-filled fracture. Subsequently when the differential pressure was increased to 175 psi (88 psi/ft pressure gradient), the gel rendered a brine permeability reduction factor in the fracture of 30,000. When placed in a 4-mm (0.16-in.) aperture fracture, a 25 psi/ft critical pressure gradient was required to render first and limited brine flow through the fracture containing gel of the same composition. After exceeding the critical pressure gradient, the stabilized permeability reduction factor imparted by the gel to brine flow in the fracture was 260,000. When increasing the brine flow rate through a gel-containing 4-mm fracture from 500 to 8,000 cm^3/hr (superficial velocities of 260 to 4,100 ft/d in the open fracture), the stabilized permeability reduction factor decreased from 100,000 to 39,000.

The high and low Mw CC/AP gel exhibited significant disproportionate permeability reduction (DPR) effects during oil and brine flow through gel-filled fractures. The magnitude of the DPR effect decreased with increasing flow rate (and differential pressure). The effect also decreased with increasing number of flooding cycles with brine and oil.

Introduction

The objective of this investigation was to develop and characterize stronger and more durable polymer-gel formulations for water-shutoff applications in fractures or other multi-Darcy flow channels – especially for applications when large drawdown pressures or large aperture (>1.5 mm) fractures are encountered.

This study was part of an investigation[1] of water-shutoff polymer gels that are to be injected in the partially formed (partially mature) state into fractures or other high permeability anomalies that are connected to petroleum production wells.

Experimental

The experimental setup and procedures used in this study were described in more detail in Refs. 1 and 2. The flooding experiments were conducted in 1.5-in. by 1.5-in. by 2.0-ft-long rectangular, 700-md, 19% porosity, unfired Berea sandstone cores, where a 1- to 4-mm (0.04- to 0.16-in.) sawed-surface fracture ran down the middle of the length of the core.

Gel (and other fluids) exiting from the downstream end of the fracture flowed into a chamber in the core's acrylic end cap that was ~4-mm (~0.16-in.) deep and ~26x26-mm (~1.0x1.0-in.) square. The gel then flowed into a stainless-steel effluent port fitting having an inside diameter of 4.5 mm (0.18 in.) for the 1-mm aperture fracture and having 6.4-mm (0.25-in.) inside diameter for the 2- or 4-mm (0.08- or 0.16-in.) aperture fractures.

Two ports for collecting effluent from the matrix rock were placed at the downstream end of the core. The injected fluids were distributed over the majority of the injection face, including the fracture and the matrix sandstone. The matrix rock at the outlet end of the core was sealed so that fluids could only flow out of the fracture at this point. All effluent fluid flow out of the matrix rock occurred at the downstream matrix effluent ports. The Berea sandstone core was cast in epoxy. During each experiment, the rates of fluid production from the fracture and the matrix-rock effluent ports were recorded as a function of time.

Differential pressures were measured across four equally spaced intervals along the fracture length. A fifth pressure transducer continuously measured the differential pressure across the entire core and fracture length. There was always good agreement between the measured overall differential pressure and the sum of the differential pressures for the four intervals along the fracture length. The final differential-pressure readings during the flooding of any given fluid were corrected for pressure-transducer baseline drift. These differential-pressure values were used to calculate the stabilized and/or final permeability and residual resistance factors.

All flooding experimental work was conducted at 105°F (41°C). The brine and aqueous gel formulations contained 1.0 wt% NaCl and 0.1 wt% $CaCl_2$. The oil used was Soltrol 130™ (mixed C10-C13 isoparaffins).

The CC/AP [chromium(III)-carboxylate/acrylamide-polymer or Cr(III)-acetate-HPAM] gels[3,4] in this study used chromic triacetate as the chemical crosslinking agent. All gels were formulated in the brine that was described in the previous paragraph. No pH adjustment was made to any of the solutions. The crosslinking agent, chromic triacetate, was obtained from McGean as a 50 wt% active aqueous solution and was added to the polymer solutions in this form. The "high" molecular weight (Mw) polymer was Ciba Alcoflood 935™ commercial HPAM (hydrolyzed polyacrylamide). This acrylamide polymer has a nominal Mw of 5×10^6 daltons and is 5-10 mole% hydrolyzed. The concentration of active polymer in the as-supplied sample of Alcoflood 935 HPAM was analyzed to be 92%. The low Mw polymer was Ciba Alcoflood 254-S™ commercial HPAM. This latter acrylamide polymer has a nominal Mw of 500,000 daltons and is 5-10 mole% hydrolyzed. The concentration of active polymer in the as-supplied sample of Alcoflood 254-S HPAM was analyzed to be 93%. Pertinent information regarding the CC/AP gels employed in this study is provided in Table 1.

Table 1—H&LMW CC/AP gel used in this study.

Gel Designation	H&LMW	FSG-1	FSG-2
Concentration of the 92% active "high" MW HPAM, wt%	1.5	1.5	2.0
Concentration of the 93% active low MW HPAM, wt%	2.0	4.0	3.0
Concentration active Cr(III), ppm	601	960	873
Aging time prior to injection, min.	40	120	12
Viscosity of the polymer solution without crosslinking agent added (at 28 sec^{-1} and 41 °C), cp	860	650	1,000

Gel aging prior to first injection of the gel into the fractured core (time between crosslinker addition to the polymer solution and initiating injection of the gel fluid into the fractured core) was conducted at room temperature.

We were initially surprised that the measured viscosity for the polymer solution of the FSG-1 gel was somewhat less than the measured viscosity for the polymer solution of the H&LMW gel, where the H&LMW gel polymer solution has a lower concentration of the low Mw polymer. However, three separate determinations of these two viscosity values all showed the same viscosity trend. The polymer solution viscosities were measured using a Paar Physica USD 200 Universal Dynamic Spectrometer (rheometer). The viscosities were determined at 28 sec^{-1} shear rate and 41°C using a cup and bob configuration having a 1.06 mm gap.

Superficial velocities for brine or oil flow through gel-treated fractures will be reported in units of ft/d. These superficial velocities were calculated assuming that the fluid flow occurred through the original fracture without any gel present. The actual superficial velocity of brine or oil flow through the gel-treated fractures was probably more than ten times larger than stated because the fluid flow actually occurred through relatively small channels (wormholes) in the gel.[1]

Improved Water-Shutoff Performance for Polymer Gels

The goal of this study was to improve the performance (especially the strength) of polymer gels that are used to treat fractures and other high permeability anomalies which are in direct contact with production wells – especially when encountering large drawdown pressures and large apertures in high permeability channeling anomalies, such as fractures or solution channels.

Strategy of Incorporating High and Low Mw Polymers for Improved Performance. The strategy employed in this study was to formulate the gels with a combination of high and low Mw HPAM polymer. The overall performance improvements that we hope to achieve by this approach include improved 1) mechanical strength, 2) thermal and chemical stability, and 3) durability. However, the present study is limited to studying gels that will provide improved mechanical strength.

Although presently available water-shutoff polymer gels have sufficient strength for the successful treatment of many wells in numerous producing provinces (e.g., the Wyoming Big Horn Basin and the Texas Permian Basin), a need exists for stronger gels when encountering fractures with large apertures (>1.5 mm) and/or large drawdown pressures. For example, large drawdown pressures can be encountered when a horizontal well is drilled through a low permeability oil-bearing formation and the well intersects a single highly conductive vertical fracture that extends down into a prolific water aquifer.

The strategy of mixing high and low Mw HPAM polymer in gel formulations is based on the following premises.[5] First, there is an upper concentration limit for incorporating relatively high Mw HPAM into polymer-gel formulations. This upper concentration limit is set by the upper viscosity limit that can be tolerated during pumping and placement of the gel formulations.

The second premise is that any gel formulated for fracture water-shutoff purposes should contain as much high Mw polymer as possible (up to a limit discussed in the previous paragraph). More gel strength per unit weight or unit cost is attained at low polymer concentrations by incorporating high Mw polymer rather than low Mw polymer. However, as the concentration of high Mw polymer increases above a threshold value, addition of low Mw polymer imparts improved gel strength and stability that are comparable to addition of the same amount of high Mw polymer. When such a situation exists, both polymer chains are long enough to form effective crosslinks within the gel network.

The attractive feature of adding low Mw polymer to a base gel formulation that contains high Mw polymer is that the low Mw polymer imparts a minor increase in viscosity to the gelant solution, while substantially improving the gel strength and stability.

Gel Formulated with 1.5% High Mw and 2.0% Low Mw Polymer. The first high and low molecular weight (H&LMW) CC/AP gel employed in the study was formulated in a 1.0 wt% NaCl and 0.1 wt% $CaCl_2$ brine and contained 1.5 wt% high Mw Alcoflood 935 HPAM, 2.0 wt% low Mw Alcoflood 254-S HPAM, and 601 ppm Cr(III) as chromic triacetate.

H&LMW Gel in a 1-mm-Aperture Fracture. During the first evaluation phase of the H&LMW gel, 40 FV of partially formed gel were injected at 8,000 cm^3/hr (16,600 ft/d superficial velocity) into a 1-mm-aperture, 2-ft-long fracture. The gelant solution was aged at room temperature [~24°C (~75°F)] for 40 minutes before injection. During injection, the effective viscosity of the gel fluid in the fracture ranged from 470 to 510 cp. The gel was then allowed to age 48 hours before initiating brine injection. The following post-gel-placement results involved constant-pressure flooding.

During the first brine injection, we attempted to inject brine using a total injection pressure of 52 psi (differential pressure), which provided a pressure gradient of 26 psi/ft. During the 24 hours that we maintained this brine injection pressure, no brine flow through the fracture was detected.

Next, we raised the injection pressure to 75 psi (pressure gradient of 38 psi/ft) for 7.0 hrs. At this point, the average permeability of the fractured core was measured to be 700 md – yielding a residual resistance factor (permeability reduction factor) of 120,000. The similarity of this measurement to the 700-md permeability of the original matrix Berea rock is serendipitous.

Subsequently, we conducted six additional brine floods (in the same fractured core) where the injection pressure was increased incrementally and then decreased incrementally. The pressure responses of four floods of this series are shown in Fig. 1. In this figure, permeability of the gel-treated fractured core is plotted against the brine pressure gradient. The order of the sequence of floods was: Flood A, Flood B, Flood C, and Flood D. The data is based on the average pressure of the two internal pressure taps along the length of the fracture.

In general, the curves for these four floods were qualitatively similar, and all the pressure-cycle curves originated from the same abscissa point on the plot. That is, below roughly 12 psi/ft injection pressure gradient (or 24 psi injection differential pressure), there was no measurable brine flow through the gel-filled fracture for any of the flooding pressure cycles, and thus no measurable fracture permeability below this “critical” pressure gradient. With increasing number of flood cycles and/or increasing applied injection pressure, there is possibly a downward trend in the slopes of the curves.

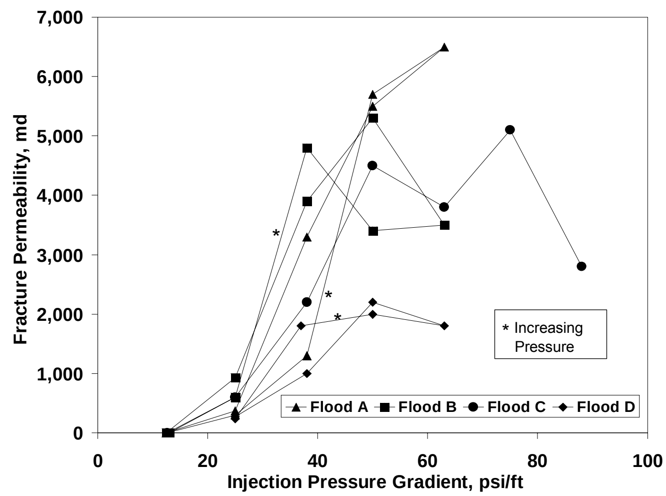

Fig. 1—Constant-pressure brine floods in a 1-mm fracture containing the H&LMW gel.

F_{rrw} (permeability reduction factor) was 13,000 for the maximum pressure gradient point (63 psi/ft) of Flood A in the above plot. F_{rrw} was 30,000 for the maximum pressure gradient point (88 psi/ft) of Flood C.

As the injection pressure was increased up to about 150 psi (75 psi/ft pressure gradient), proportionally more of the differential pressure occurred over the final downstream section of the fracture. In contrast, at significantly lower injection pressures, the differential pressures measured over all four fracture sections were quite comparable. This trend appeared to be reversible with increasing and decreasing pressure cycles and during multiple floods. At present, we don’t completely understand why this occurred. The phenomenon is shown in Table 2 for Flood A (involving injection pressures ranging from 25 to 125 psi).

Table 2—Injection pressure gradient cycle for Flood A.

Injection ΔP total, psi	25	50	75	100	125	100	75	50	25
Injection pressure gradient, psi/ft	13	25	38	50	63	50	38	25	13
Tap 1 Pressure gradient, psi/ft	10	12	12	17	23	16	11	8	13
Tap 2 pressure gradient, psi/ft	15	11	12	16	28	22	12	7	14
Tap 3 pressure gradient, psi/ft	12	14	30	12	13	13	10	7	4*
Tap 4 pressure gradient, psi/ft	14	68	97	157	189	150	120	78	20*

* Due to experimental problems, the exact values of these 2 data points are uncertain.

Perhaps the most significant finding of this experiment can be discerned from close inspection of the curve for Flood C in Fig. 1. That is, the gel successfully withstood 175 psi of total injection pressure (88 psi/ft pressure gradient) within the 1-mm-aperture fracture. Due to pressure limitations of the core/fracture system and safety considerations, we did not raise the injection pressure above 175 psi.

H&LMW Gel in a 2-mm-Aperture Fracture. As the next step in evaluating the H&LMW gel formulation, a series of experiments were conducted using the same procedures as in the previous section, except that the fracture aperture was 2 mm and all floods were conducted using constant-rate injection. During injection of 20 FV of the partially formed gel, the effective viscosity of the gel fluid in the fracture ranged from 550 to 630 cp.

Table 3 provides an overview of the results for the flooding experiment involving the H&LMW gel that was placed in the 2-mm fracture.

Table 3—Overview of flooding results for the H&LMW gel in a 2-mm fracture.

Gel fluid viscosity during injection, cp	550-630
First brine flood critical pressure gradient, psi/ft	37
First brine flood stabilized F_{rrw}	260,000
First oil flood stabilized F_{rro}	11,000
k_{of}/k_{wf} for first flood cycle	24
Second brine flood stabilized F_{rrw}	53,000
Second oil flood stabilized F_{rro}	11,000
k_{of}/k_{wf} for second flood cycle	4.8

During first brine flooding at 100 cm^3/hr (103 ft/d superficial velocity in fracture), the critical differential pressure gradient (averaged from the four pressure taps) required to first breach the gel was **37 psi/ft**, an encouraging value. The stabilized F_{rrw} for the first post-gel-placement brine flood was 260,000. After two cycles of flooding with 15 FV each of brine and oil [at 500 cm^3/hr (512 ft/d superficial velocity in fracture)], the stabilized F_{rrw} to brine was 53,000 and the stabilized F_{rro} to oil was 11,000. The permeability of the original 2-mm-aperture fracture was 340,000 darcies.

Next, a series of brine and oil floods were conducted to investigate the effectiveness of the H&LMW gel as flow rates and differential pressures were increased in the 2-mm fracture. During this series, all the brine floods were conducted first, and flooding proceeded from low to high flow rates. Next, the oil floods were conducted from low to high flow rates. The results of these experiments are summarized in Table 4.

The brine permeability reduction factor decreased from 52,000 to 14,000 as the superficial velocity in the fracture increased from 515 to 8,240 ft/d (Table 4). It is noteworthy that the residual resistance factor (F_{rrw}) was 14,000 for brine flow after injecting 21 FV of brine at 8,000 cm^3/hr and at a superficial velocity in the fracture of 8,240 ft/d. For any given flood, permeability to brine flow in the gel-filled fracture slowly increased with brine throughput volume at the 8,000 cm^3/hr injection rate.

Table 4—Effect of rate on oil and water F_{rr} values for the H&LMW gel in a 2-mm fracture.

Rate, cm^3/hr	Superficial velocity, ft/d	Brine F_{rrw}	Incremental FV of brine	Total FV brine	Oil F_{rro}	Incremental FV of Soltrol	Total FV Soltrol
500	**515**	**52,000**	2.7	2.7	**15,000**	3.4	3.4
1,000	**1,030**	**39,000**	5.5	8.2	**7,100**	5.5	8.9
2,000	**2,060**	**21,000**	10.9	19.1	**4,200**	11.0	19.9
4,000	**4,120**	**16,000**	21.1	40.2	**2,400**	21.2	41.1
8,000	**8,240**	**14,000**	21.4	61.6	**1,500**	21.4	62.5

Table 4 also shows that oil residual resistance factors decreased with increased flow rates and throughput. A summary of the results of Table 4 are depicted graphically in Fig. 2. The reader should be cautioned against making judgments concerning disproportionate permeability reduction based on this data (because the entire water rate sequence was completed before the oil rate sequence).

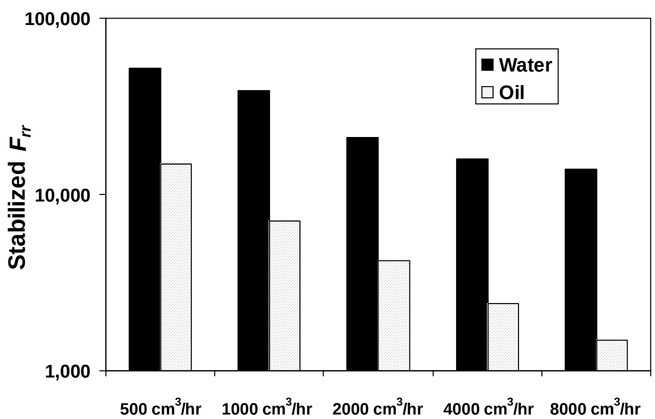

Fig. 2—Summary of variable-rate floods for a H&LMW gel in a 2-mm fracture.

In summary, concerning the H&LMW gel in a 2-mm-aperture fracture, possibly the most significant finding was that the gel was not breached by brine flow until a 37 psi/ft critical pressure gradient was exceeded.

H&LMW Gel in a 4-mm-Aperture Fracture. In the final studies of this series on the H&LMW gel in fractures, we used a 4-mm-aperture fracture. During this experiment, 10 FV of the partially formed gel were injected into the 2.0-ft-long fracture at 8,000 cm^3/hr (4,130 ft/d superficial velocity in the fracture), and then the core was shut in for 48 hours. During injection, the effective viscosity of the gel in the fracture ranged from 1,400 to 1,500 cp.

During first brine flooding at 100 cm^3/hr injection rate (52 ft/d superficial velocity in the fracture), the critical pressure gradient (average of the four pressure taps) required to first breach the gel was **25 psi/ft** – the highest pressure gradient that we have seen during any of our studies to date in 4-mm-aperture fractures.

Table 5 provides an overview of the results for the flooding experiment involving the H&LMW gel that was placed in a 4-mm fracture.

Table 5—Overview of flooding results for the H&LMW gel in a 4-mm fracture

Gel fluid viscosity during injection, cp	1,400-1,500
First brine flood critical pressure gradient, psi/ft	25
First brine flood stabilized F_{rrw}	260,000
First oil flood stabilized F_{rro}	42,000
k_{of}/k_{wf} for first flood cycle	6.2
Fourth brine flood stabilized F_{rrw}	84,000
Fourth oil flood stabilized F_{rro}	33,000
k_{of}/k_{ow} for fourth flood cycle	2.5

At the end of the first post-gel-placement brine flood (after 10 FV of brine had been injected), the stabilized permeability reduction factor for brine flow was again 260,000. The permeability of the original (untreated) 4-mm-aperture fracture was 1.4 million darcies.

Next, an oil flood was conducted, followed by three cycles of brine and oil flooding. During all of these floods, 10 FV of fluid were injected at a rate of 500 cm^3/hr (259 ft/d superficial velocity in the fracture). At the end of the fourth brine injection, the permeability reduction factor for brine flow was 84,000. As depicted in Fig. 3, the magnitude of the disproportionate permeability reduction (as measured by the ratio k_{of}/k_{wf}) decreased with increasing cycles of brine and oil.

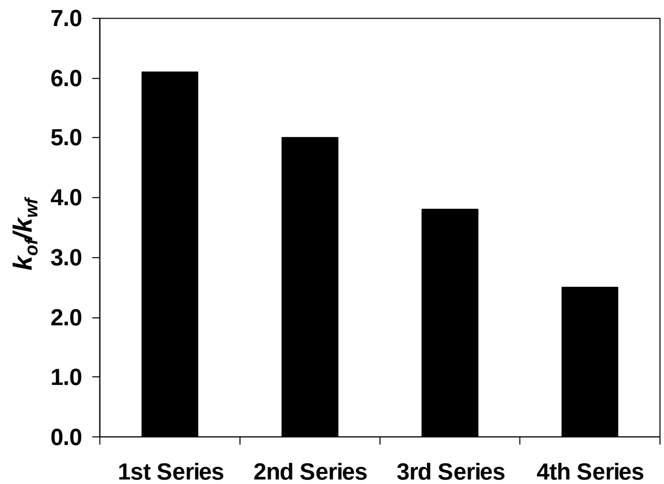

Fig. 3—Disproportionate permeability reduction as a function of brine/oil flooding series for a H&LMW gel in a 4-mm fracture.

Finally, using the same gel-treated 4-mm-aperture fracture, we carried out a series of brine floods that were conducted at increasing flow rates that was then followed by a single oil flood. During this flooding sequence, the five brine floods were completed first, followed by the oil flood. Results of this sequence of experiments are summarized in Table 6.

The final residual resistance factors imparted by the gel in the 4-mm fracture were substantial for both brine and oil flow (Table 6). The final brine and oil permeability reduction factors were 39,000 and 18,000, respectively. In total during all the flooding in this fractured core, more than 100 FV of water and 84 FV of oil were injected. Roughly 40 FV each of water and oil were injected during the studies associated with Fig. 3. In generating Table 6, an additional 64.6 FV of water and 44 FV of oil were injected. When conducting the brine injection at 8,000 cm^3/hr during any given flood, we noted a small but steady increase in brine fracture permeability with time and volume of brine injected.

Table 6—Effect of rate on water and oil F_{rr} values for the H&LMW gel in a 4-mm fracture.

Rate, cm^3/hr	Superficial velocity, ft/d	Brine final F_{rr}	Incremental FV brine	Total FV brine	Oil final F_{rr}	Total FV Soltrol
500	**259**	**100,000**	1.4	1.4	---	---
1,000	**518**	**67,000**	2.8	4.2	---	---
2,000	**1,040**	**53,000**	5.6	9.8	---	---
4,000	**2,070**	**45,000**	10.8	20.6	---	---
8,000	**4,140**	**39,000**	44.0	64.6	**18,000**	44.0

As expected, when the gel was subjected to higher brine flow rates and differential pressures, the water-blocking performance of the gel deteriorated somewhat. However, the gel exhibited substantial permeability reduction factors, even after experiencing high rates and large throughput volumes of brine and oil.

Effective Viscosity Versus Fracture Aperture. For the H&LMW gel, Table 7 lists effective gel fluid viscosities in 1- to 4-mm-aperture fractures – at a fixed injection rate of 8,000 cm^3/hr during injection. This viscosity trend probably resulted because the gel formulation is shear thinning. When injecting a shear-thinning fluid at a fixed rate into fractures having increasing apertures, the fluid will experience reduced shear rates.

Table 7—Effective viscosity of the H&LMW gel during placement.

Fracture aperture, mm	Effective viscosity range of gel formulation, cp
1.0	470-510
2.0	550-630
4.0	1,400-1,500

Fracture-Sealing Gel Formulations. The first "fracture-sealing" CC/AP gel (FSG-1) employed in the study was formulated in a 1.0 wt% NaCl and 0.1 wt% $CaCl_2$ brine and contained 1.5 wt% high Mw Alcoflood 935 HPAM, 4.0 wt% low Mw Alcoflood 254-S HPAM, and 960 ppm Cr(III) as chromic triacetate. The second "fracture-sealing" CC/AP gel (FSG-2) employed in the study was formulated in a 1.0 wt% NaCl and 0.1 wt% $CaCl_2$ brine and contained 2.0 wt% high Mw Alcoflood 935 HPAM, 3.0 wt% low Mw Alcoflood 254-S HPAM, and 873 ppm Cr(III) as chromic triacetate.

In an attempt to further improve the performance and strength of water-shutoff CC/AP gels for application in large aperture 4-mm fractures, we developed the "fracture-sealing-gel" formulations FSG-1 and FSG-2. The HPAM polymer concentration and the anticipated chemical costs of the CC/AP FSG-2 gel are comparable to that of the low Mw-polymer CC/AP gel formulation that is somewhat widely applied on a commercial scale and applied as relatively small volume (typically on the order of hundreds of barrels) and near-wellbore total-shutoff gel treatments which are applied to matrix rock reservoirs.

FSG-1 and FSG-2 Gels in 4-mm-Aperture Fractures. During the flooding experiments involving the two FSG CC/AP gels, 10 FV of partially formed gel were injected into 2-ft-long, 4-mm-aperture fractured cores at a rate of 8,000 cm^3/hr (4,140 ft/d superficial velocity within the fracture) and then shut in for 48 hours. The FSG-1 was injected as a *relatively mature* partially formed gel. The FSG-2 was injected as a *relatively immature* partially formed gel.

During first post-gel-placement brine flooding at an injection rate of 100 cm^3/hr (52 ft/d superficial velocity within the fracture), the critical pressure gradient (average of the four pressure taps) required to first breach the gel was **23 psi/ft** for the FSG-1 gel and **26 psi/ft** for the FSG-2 gel. If one is looking to obtain the largest critical pressure gradient for first brine breaching of a CC/AP gel in a 4-mm fracture and to do so for the least cost, that person would most likely choose the less expensive H&LMW gel formulation of this study (exhibiting a critical pressure gradient of 25 psi/ft at identical conditions).

Results are summarized in Table 8 for the two FSG CC/AP gel formulations that were placed in 4-mm-aperture fractures.

Table 8—Overview of flooding experiments involving FSG gels placed in 4-mm fractures.

Gel	FSG-1	FSG-2
Gel aging time prior to injection, min.	120	12
Effective viscosity in the fracture during gel injection, cp	1,300	1,300
Peak pressure gradient during first brine injection, psi/ft	23	26
Stabilized F_{rrw} during first brine flood	360,000	200,000
Stabilized F_{rro} during first oil flood	15,000	20,000
k_{of}/k_{wf}	24	10
Stabilized F_{rrw} during second brine flood	38,000	80,000
Stabilized F_{rro} during second oil flood	15,000	15,000
F_{rrw} after injection 33 FV of brine at 4,130 ft/d	14,000	25,000

During the first post-gel-placement brine flood, 10 FV of brine were injected. The stabilized F_{rrw} of the first brine flood for the FGS-1 and FGS-2 gels were 360,000 and 200,000, respectively. Next, 10 FV of Soltrol 130 was flooded at an injection rate of 500 cm^3/hr (259 ft/d superficial velocity within the fracture). The stabilized F_{rro} for the first oil flood were 15,000 and 20,000. The DPR ratio k_{of}/k_{ow} for the FGS-1 and FGS-2 gel formulations during the first cycle of post-gel-placement brine and oil flooding were 24 and 10, respectively. Thus, these two FSG gels did impart significant DPR effects for brine and oil flow in the gel-filled 4-mm-aperture fractures. Subsequently, another cycle of brine and oil flooding was conducted at the same injection rate. Stabilized F_{rr} results for these two floods are shown in Table 8.

Next we injected brine at the highest readily feasible rate with our flooding unit [8,000 cm^3/hr (133 cm^3/min) or 4,140 ft/d superficial velocity within the fracture]. A total of 4 liters (43 FV) of brine were injected during this flooding sequence. The final F_{rrw} measured during the brine floods (and measurements following all the previous post-gel-placement brine and oil flooding) were 14,000 and 25,000, respectively, for gels FSG-1 and FSG-2. These permeability-reduction-factor values in a 4-mm fracture, following such large-volume and high rate brine flooding, are considered to be substantial.

There was considerable variation in the elapsed time between the separate 1-liter brine floods during the injection of the last four 1-liter aliquots of brine at 8,000 cm^3/hr when conducting the flooding experiments series involving the FSG-1 and FSG-2 gels. The initial peak pressure observed during brine injection appeared to increase with increasing elapsed time.

In view of this observation, we conducted, at the end of the FSG-2 gel flooding-experiment series, a number of additional 8,000-cm^3/hr brine floods with significantly different elapsed times between the floods. The above-cited trend of increasing initial peak pressure with increasing elapsed time between the brine flooding experiments was quite repeatable, even during multi cycles of brine and oil injection.

For the FSG-2 gel during these 8,000-cm^3/hr brine floods, Fig. 4 shows how the initial peak pressure during brine injection increased with increasing elapsed time between the brine flooding experiments. In these two series of flooding experiments, a liter (10.8 FV) of brine was first injected at the shortest elapsed time, and then the core was shut in. Subsequently, another liter of brine was injected at the next longer elapsed time – and so on for the duration of that brine flooding series. Flooding series 1 was conducted immediately following the injection of 1 liter of oil at an injection rate of 500 cm^3/hr. Subsequent flooding series 2 was conducted immediately following the injection of 1 liter of oil at an injection rate of 8,000 cm^3/hr.

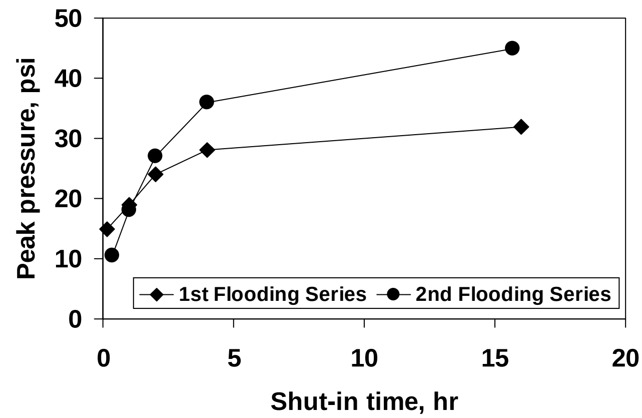

Fig. 4—Increasing peak pressure with increasing elapsed time between 8,000-cm^3/hr brine floods.

Since brine and oil flow through wormholes within the gel that resides in fractures for the type of fractures and gel studied in this work,[1] the above observations are consistent with the hypothesis that DPR effects observed during oil and water flow through gel-filled fractures (gel and fractures of the type studied) are an interrelated function of gel elasticity, fluid capillary forces, gel dehydration, and water imbibition into the gel (gel rehydration). That is, during oil flow through a wormhole within a gel-filled fracture, capillary forces cause the wormhole diameter to become relatively large. If the diameter of the wormhole is either being created or is being increased, some gel dehydration will occur. Subsequently when brine flows through the wormhole, capillary forces are not nearly as large (if they exist at all), and the gel's elasticity tends to reduce the diameter of the wormhole within the gel. Simultaneously, some water within the wormhole imbibes into the gel (rehydrates the gel). Apparently, if this hypothesis is correct, the water imbibition from the brine-filled wormhole into the gel (and the associated gel elastic constriction of the wormhole) is a relatively slow process. Hence, in the gel (as implied in Fig. 4), the wormhole diameter continues to constrict with time (on the order of hours) and the initial peak pressure observed during brine injection continues to increase as the elapsed time interval between successive brine flooding experiments increases.

This hypothesis is also consistent with the observation made in the work associated with Ref. 1 (but not explicitly reported). During this work, successive cycles of constant-rate brine and oil flooding were conducted through fractures that were filled with CC/AP gel. After the first cycle of brine and then oil flooding through the gel-filled fracture, there was always a substantial peak pressure observed during the oil floods. However, during the initial injection of the subsequent brine floods, there was usually very little, if no, initial peak pressure noted.

More work is required to investigate this hypothesis regarding the mechanism responsible for the DPR effects within the wormholes of gel-filled fractures.

Additional Discussion

Versatility and Optimization of High and Low Mw Polymer Gels. Formulating water-shutoff gels with a combination of high and low Mw polymers should prove to be a robust and powerful strategy. By varying the concentrations and Mw of the two polymers, gels with a broad range of costs and properties (especially gel strengths and gelant viscosities) can be readily formulated.

Use of gels formulated with high and low Mw polymers may be more expensive (on a unit volume basis) than conventional oilfield water-shutoff polymer gels. Field applications of high and low Mw polymer water-shutoff gels are envisioned to be most attractive if applied in one of the following two modes. First, these gels could be applied as relatively small volume (near-wellbore) water-shutoff jobs when large aperture fractures or large drawdown pressures are encountered. Second, these gels could be applied in conjunction with larger volume water-shutoff treatments (i.e., that employ weaker and less costly polymer gels) when large aperture fractures or large drawdown pressures are encountered. In this case, the gels formulated with high and low Mw polymers could be injected last (into the near-wellbore high-differential-pressure region) in order to prevent the conventional (weaker) water-shutoff gel from being back-produced.

A complementary strategy can be employed when the exact nature of highly conductive water-producing fractures is unknown at the onset of a water-shutoff gel treatment (often the case). First, a more conventional high Mw polymer gel is pumped. Depending on the pumping pressure response during this gel injection, the concentration of high Mw polymer in the gel is gradually increased to the maximum tolerable value. If warranted, near the end of the planned injection volume of the gel treatment, low Mw polymer is added in increasing concentrations to the high Mw gel, as dictated by the injection-pressure responses and good engineering judgment.

The high and low Mw polymer gel formulations used in this study may not be the optimum composition. On the other hand, there may not be a single optimum formulation when treating fractured production wells for water-shutoff purposes. The optimum composition may vary with 1) the exact nature of the excessive water-production problem to be treated and 2) the business objectives and cost constraints of the oilfield operator.

Pressure Gradient Along the Fracture Length. During the flooding experiments involving the H&LMW gel, we often observed that pressure gradients became progressively larger along the length of the fracture (from injection to effluent end) during post-gel-placement brine and oil flooding. At present, we do not completely understand this behavior. This phenomenon was not apparent for relatively weak CC/AP gels in fractures (gels of the type reported on in Ref. 1). This behavior became much more significant as gel strength increased and/or the overall differential pressure became larger. The larger downstream pressure gradients occurred despite 1) the inside diameter of the effluent port (from the fracture) was larger than the fracture aperture, 2) the effluent flow line from the fracture was cleared of gel before brine injection, and 3) all the other flow lines and pressure taps were maintained gel-free. Additional work will be required to fully understand this phenomenon.

Conclusions

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

1. The H&LMW CC/AP gel formulation of this study (which contained a combination of high and low Mw polymers) exhibited an effective viscosity of roughly 500 cp during placement at 16,600 ft/d superficial velocity in a 1-mm-aperture fracture. After placement, the gel provided exceptionally good fracture plugging characteristics. The gel withstood a 52 psi differential pressure (26 psi/ft pressure gradient) for 24 hrs while permitting no detectable brine flow through the fracture. Subsequently, when the differential pressure was increased to 175 psi (88 psi/ft pressure gradient), the gel imparted a brine residual resistance factor (permeability reduction factor) of 30,000.
2. When placed in a 2-mm-aperture fracture, the same gel required a 37 psi/ft pressure gradient for brine to first breach the gel. After exceeding this critical pressure gradient, the stabilized brine residual resistance factor in the fracture was 260,000.
3. When placed in a 4-mm-aperture fracture, the same gel required a 25 psi/ft pressure gradient for brine to first breach the gel. After exceeding this critical pressure gradient, the stabilized brine residual resistance factor in the fracture was again 260,000.
4. At a fixed injection rate during placement, the effective viscosity within the fracture of the injected H&LMW gel fluid increased with fracture aperture.
5. The H&LMW CC/AP gel exhibited disproportionate permeability reduction in fractures.
6. After placement of the H&LMW gel in a 4-mm-aperture fracture, stabilized residual resistance factors decreased by a factor of 2.6 when the brine superficial velocity was increased by a factor of 16 (i.e., from 259 to 4,140 ft/d in the fracture). Similar results were obtained during an analogous experiment in a 2-mm fracture.
7. After placement of the H&LMW gel in a fracture, the magnitude of the disproportionate permeability reduction decreased with increasing cycles of water and oil flooding.

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Nomenclature

CC/AP = chromium(III)-carboxylate/acrylamide-polymer
DPR = disproportionate permeability reduction
FSG-1 = fracture-sealing gel number 1
FSG-2 = fracture-sealing gel number 2
HPAM = hydrolyzed polyacrylamide polymer
H&LMW = high & low molecular-weight polymer gel

FV = fracture volume
F_{rr} = residual resistance factor
F_{rro} = oil residual resistance factor
F_{rrw} = water residual resistance factor
k = permeability, darcys [μm^2]
k_{of}/k_{wf} = ratio measuring degree of DPR
k_o = permeability to oil, darcys [μm^2]
k_w = permeability to water, darcys [μm^2]
Mw = molecular weight

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SI Metric Conversion Factors

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

*Conversion is exact.