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

R.D. Sydansk, SPE, **A.M. Al-Dhafeeri**, SPE, **Y. Xiong**, SPE, and **R.S. Seright**, SPE,
New Mexico Petroleum Recovery Research Center

Summary

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.) apertures, by 2-ft-long × 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 approximately 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 hours, 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 gels exhibited disproportionate permeability-reduction (DPR) effects during oil and brine flow through gel-filled fractures. However, the gels of this study are probably better characterized as total-shutoff or sealing agents (not DPR agents) because of the large permeability reduction imparted to oil flow through the gel-filled fractures.

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 multiple-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. × 1.5-in. × 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 endcap 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 a 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 flow only 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 permeabilities 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 C_{10}–C_{13} 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%

This paper (SPE 89402) was first presented at the 2004 SPE/DOE Symposium on Improved Oil Recovery, Tulsa, 17–21 April, and revised for publication. Original manuscript received for review 9 July 2004. Revised manuscript received 6 August 2004. Paper peer approved 17 September 2004.

active aqueous solution and was added to the polymer solutions in this form. The "high"-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 to 10 mol% 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 to 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.**

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 fracture-sealing Gel Number 1 (FSG-1) gel was somewhat less than the measured viscosity for the polymer solution of the high- and low-molecular weight (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 that 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 mechanical strength, thermal and chemical stability, and durability. However, the present study is limited to studying gels that will provide improved mechanical strength.

Although currently 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 aquifer.

The strategy of mixing H&LMW 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.

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 (28 sec^{-1} and 41°C), cp	860	650	1,000

Gel Formulated With 1.5% High MW and 2.0% Low MW Polymer. The first high- and low-MW CC/AP gel (H&LMW) 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 fracture volumes (FV) of partially formed gel was injected at 8,000 cm^3/h (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 hours. 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 200,000 (average for data obtained from all four intervals along the fracture length and at a brine flow rate through the fracture of 63 cm^3/hr). The similarity of the 700-md post-gel-treatment average core permeability to the 700-md permeability of the original matrix Berea rock is serendipitous.

Subsequently, we conducted six additional brine floods (in the same gel-filled 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 are 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

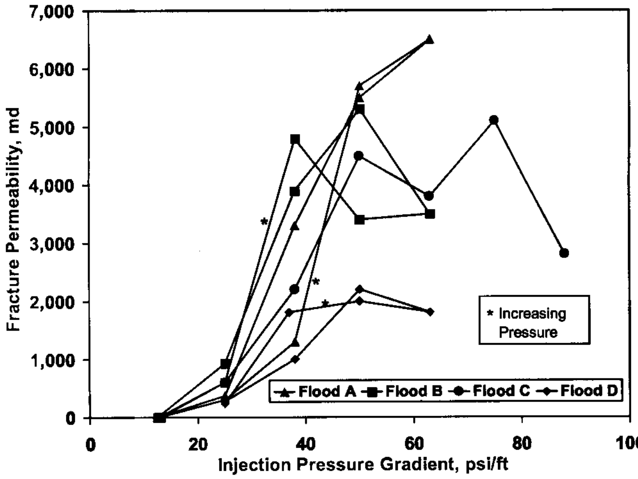

Fig. 1—Constant-pressure brinefloods in a 1-mm fracture containing the H&LMW gel.

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 an increasing number of flood cycles and/or increasing applied injection pressure, there is possibly a downward trend in the slopes of the curves.

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 approximately 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 do not completely understand why this occurred. The phenomenon is shown in **Table 2** for Flood A (involving injection pressures ranging from 25 to 125 psi).

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. Because of 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 was 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.

During first brineflooding 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 brineflood 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 oilfloods was 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 brinefloods were conducted first, and flooding proceeded from low to high flow rates. Next, the oilfloods 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. 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 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).

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 brineflooding at 100-cm^3/hr injection rate (52 ft/d superficial velocity in the fracture), the critical pressure gradient

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*

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

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 brineflood critical pressure gradient, psi/ft	37
First brineflood stabilized F_{rrw}	260,000
First oilflood stabilized F_{rro}	11,000
k_{of}/k_{wf} for first flood cycle	24
Second brineflood stabilized F_{rrw}	53,000
Second oilflood stabilized F_{rro}	11,000
k_{of}/k_{wf} for second flood cycle	4.8

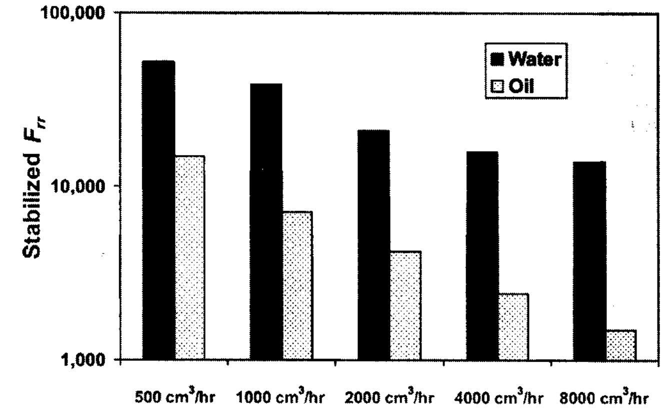

Fig. 2—Summary of variable-rate floods for the H&LMW gel in a 2-mm fracture.

(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.

At the end of the first post-gel-placement brineflood (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 oilflood was conducted, followed by three cycles of brine- and oilflooding. During all of these floods, 10 FV of fluid was 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 oilflooding. See the Disproportionate Permeability Reduction subsection of the Additional Discussion section at the end of the paper for a discussion of how the gels of this study are better characterized as being total-shutoff or sealing agents than DPR agents.

Finally, using the same gel-treated 4-mm-aperture fracture, we carried out a series of brinefloods that were conducted at increasing flow rates that was then followed by a single oilflood. During this flooding sequence, the five brinefloods were completed first, followed by the oilflood. 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 was injected. Roughly 40 FV each of water and oil was injected during the studies associated with Fig. 3. While generating the data of Table 6, an additional 64.6 FV of water and 44 FV of oil was 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.

As expected, when the gel was subjected to higher brine flow rates and differential pressures, the waterblocking 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 Vs. 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.

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 4-mm-aperture 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 those 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 that 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 was 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.

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 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 brineflood critical pressure gradient, psi/ft	25
First brineflood stabilized F_{rrw}	260,000
First oilflood stabilized F_{rro}	42,000
k_{of}/k_{wf} for first flood cycle	6.2
Fourth brineflood stabilized F_{rrw}	84,000
Fourth oilflood stabilized F_{rro}	33,000
k_{of}/k_{wf} for fourth flood cycle	2.5

During first post-gel-placement brineflooding 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 under identical conditions).

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

During the first post-gel-placement brineflood, 10 FV of brine was injected. The stabilized F_{rrw} of the first brineflood 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 oilflood for the FGS-1 and FGS-2 gels were, respectively, 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 oilflooding 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 oilflooding 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 4L (43 FV) of brine was injected during this flooding sequence. The final F_{rrw} measured during the brinefloods (and measurements following all the previous post-gel-placement brine- and oilflooding) 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 brineflooding, are considered to be substantial.

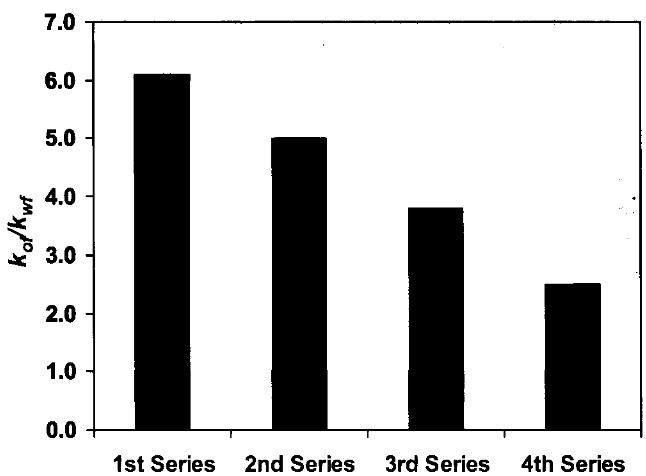

Fig. 3—Disproportionate permeability reduction as a function of brine-oilflooding series for the H&LMW gel in a 4-mm fracture.

There was considerable variation in the elapsed time between the separate 1L brinefloods during the injection of the last four 1L aliquots of brine at 8,000 cm^3/hr when conducting this flooding experiment 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 brinefloods with significantly different elapsed times between the floods. The above-cited trend of increasing initial peak pressure with increasing elapsed time between the brineflooding experiments was verified and was quite repeatable, even during multicycles 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 brineflooding experiments. In these two series of flooding experiments, 1L (10.8 FV) of brine was first injected at the shortest elapsed time, and then the core was shut in. Subsequently, 1L of brine was injected at the next longer elapsed time—and so on, for the duration of that brineflooding series. Flooding Series 1 was conducted immediately following the injection of 1L of oil at an injection rate of 500 cm^3/hr. Subsequent Flooding Series 2 was conducted immediately following the injection of 1L of oil at an injection rate of 8,000 cm^3/hr.

Because 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 previous 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. Therefore, 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 brineflooding 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 oilflooding were conducted through fractures that were filled with CC/AP gel. After the first cycle of brine- and then oilflooding through the gel-filled fracture, there was always a substantial peak pressure observed during the oilfloods. However, during the initial injection of the subsequent brinefloods, there was usually very little, if any, 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 H&LMW 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-solution viscosities) can be readily formulated.

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

Use of gels formulated with high- and low-MW polymers are likely to 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 backproduced.

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-polymer 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 the exact nature of the excessive water-production problem to be treated, and 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 oilflooding. 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 the fact that (1) the inside diameter of the effluent port (from the fracture) was larger than the fracture aperture, (2) the effluent flowline from the fracture was cleared of gel before brine injection, and (3) all the other flowlines and pressure taps were maintained gel-free. Additional work will be required to fully understand this phenomenon.

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

Disproportionate Permeability Reduction. Although DPR occurred for water and oil flow through the gel-filled fractures of this study, it is doubtful that this effect can be effectively exploited during most field applications of fracture-problem water-shutoff treatments. This is because the permeability reduction to oil is so large that all flow is effectively shut off.

Nevertheless, the DPR that we observed for gels in fractures is significant because it might be usefully exploited under limited circumstances, and could lead to an improved understanding of the mechanism for disproportionate permeability reduction in matrix rock, as well as in fractures.

Improved Performance. This discussion is intended to justify the contention made in our paper that water-shutoff polymer gels, formulated with a combination of high- and low-MW polymers, provide improved performance (as compared to more conventional water-shutoff polymer-gel formulations) when used to treat fractures having exceptionally large apertures (e.g., 4-mm apertures) or when encountering unusually large drawdown pressures.

The critical pressure gradient, which was required to first breach a 3X CC/AP gel (that contained 1.5 wt% of the high-MW polymer) in a 1-mm-aperture fracture, was determined to be 99 psi/ft.[1] After breaching the 3X gel, the stabilized residual resistance factor was measured to be 22,000 for brine flow within the fracture (at 81 cm^3/hr). In all other respects (except for constant-rate vs. constant-pressure flooding), the gel formulations, fracture configuration, and experimental conditions of the flooding experiments in Ref. 1 were identical to those reported in the present paper. The 3X CC/AP gel, containing solely 1.5 wt% of the high-MW polymer, can be considered to be the base gel for the present study's H&LMW gel (containing 1.5 wt% of the high-MW polymer plus 2.0 wt% of the low-MW polymer).

Because of gelant-solution viscosity and associated pumping constraints during field applications, it is generally accepted that the maximum concentration of high-MW polymer that fracture-problem water-shutoff gelants can contain is 1.5 wt%. Thus, the increased functionality resulting from the addition of any amount of low-MW polymer to the base 3X gel formulation (containing 1.5 wt% of the high-MW polymer) should improve performance for the resultant water-shutoff gel by increasing its resistance to breaching or washout and still allow for reasonable injection pressures during gel-solution placement.

The stabilized permeability-reduction factor to brine flow (after the gel in the 1-mm fracture had been first breached) was 200,000 for the H&LMW CC/AP gel (at a brine flow rate of 63 cm^3/hr through the gel-filled fracture and at a pressure gradient of 38 psi/ft). For comparison, the stabilized permeability-reduction factor was 22,000 for the base 3X gel (at a brine injection rate of 81 cm^3/hr into the gel-filled fractured and at a pressure gradient of 5.0 psi/ft). This demonstrates improved water-shutoff performance for the H&LMW (1.5% high-MW and 2.0% low-MW polymer) gel over the 3X (1.5% high-MW polymer) gel.

TABLE 8—OVERVIEW OF FLOODING EXPERIMENTS INVOLVING FSG GELS PLACED IN 4-mm FRACTURE

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 brineflood	360,000	200,000
Stabilized F_{rro} during first oilflood	15,000	20,000
k_{of}/k_{wf}	24	10
Stabilized F_{rrw} during second brineflood	38,000	80,000
Stabilized F_{rro} during second oilflood	15,000	15,000
F_{rrw} after injecting 33 FV of brine at 4,130 ft/d	14,000	25,000

As previously pointed out, the maximum concentration of high-MW polymer that a fracture-problem water-shutoff gel can normally contain, because of viscosity constraints, is 1.5%. As discussed previously, addition of low-MW polymer to the base 1.5%-high-MW-polymer gelant solution can be tolerated because it increases the viscosity of the resulting gelant solution only slightly. Consequently, addition of the low-MW polymer to the H&LMW gel formulation greatly improved performance, without compromising placement characteristics.

In Fig. 1, the H&LMW gel exhibited a critical pressure gradient of ≈12.5 psi/ft (for brine flow after having first breached the gel in a 1-mm fracture). Below this pressure gradient after brine flow had previously breached the gel, no measurable brine flow occurred through the gel-filled fracture. In contrast, for the base 1.5%-high-MW-polymer 3X gel (in a similar experiment),[1] brine was able to flow through the previously breached gel at a pressure gradient of 5.0 psi/ft (flow rate of 81 cm^3/hr). In fact during studies conducted in Ref. 1, it was noted that following initial brine breaching of the gel, brine flow could occur through gel-filled 1-mm fractures, containing the 3X gel, at pressure gradients of much less than 5.0 psi/ft. This again demonstrates improved performance for a fracture-problem water-shutoff gel that was formulated with a combination of high- and low-MW polymers.

Injection of Partially Formed Gels. CC/AP-gel water-shutoff treatments that are applied to fracture problems are normally injected in the partially formed state. The objective is to ensure that the gel solution has relatively low viscosity (and good injectivity) as it exits the wellbore and enters the fracture(s), yet has developed enough crosslinked gel structure (developed microgel structure) so the gel cannot appreciably enter and damage the matrix rock adjacent to the fracture. Subsequent to when gelation has been first detected visually for CC/AP gels, sufficient gel structure has occurred to prevent substantial penetration of the gel into matrix reservoir rock of normal permeabilities (<1,000 md).[1]

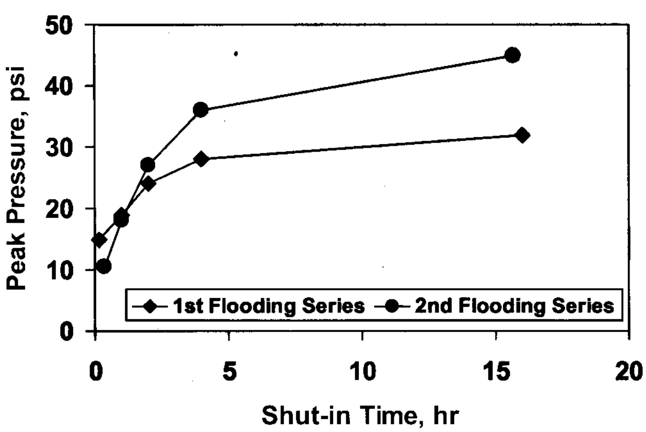

Fig. 4—Increasing peak pressure with increasing elapsed time between 8,000-cm^3/hr brinefloods.

Typically during field application of CC/AP-gel water-shutoff treatments, the gelant solution resides in the injection tubing for 10 to 45 minutes prior to exiting the wellbore into the petroleum formation. However, situations can be easily envisioned in which the gel residence time in the injection tubing could fall outside of the 10 to 45-minute range. Two of three of the gel formulations that were discussed in this paper were aged within the 10 to 45-minute range prior to being injected into the fractured cores of this study.

Ideally for any given fracture-problem CC/AP-gel water-shutoff treatment that is to be injected at a given rate, the gel formulations should be designed such that initial gelation has already occurred as the gel solution exits the wellbore and enters the fracture(s). The rate of gelation can be controlled, in most instances, by the appropriate addition to the CC/AP-gel formulation of a chemical gelation-rate accelerator (e.g., $CrCl_3$) or chemical gelation-rate retarder (e.g., sodium lactate).

The placement and propagation of partially and fully formed CC/AP gels in fractures are discussed in Refs. 1, 2, and 6.

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 a 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 hours 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 gel-filled 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 gel-filled 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. However, the gels of this study are probably better characterized as total-shutoff or sealing agents

(not DPR agents) because of the large permeability reduction imparted to oil flow through the gel-filled 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 oilflooding.

Nomenclature

F_{rr} = residual resistance factor
F_{rro} = oil residual resistance factor
F_{rrw} = water residual resistance factor (permeability-reduction factor)
H&LMW = high- and low-molecular-weight polymer gel
k_{of}/k_{wf} = ratio measuring degree of DPR
MW = molecular weight

Acknowledgments

Financial support for this work is gratefully acknowledged from the U.S. Dept. of Energy (NETL/Natl. Petroleum Technology Office), the State of New Mexico, ConocoPhillips, Marathon, PDVSA/Intevep, Shell, and the Ufa branch of YuganskNIPIneft. Ying Wang, Merrie Michelle Huskey, and Kate Wavrik contributed to the laboratory study.

References

1. Sydansk, R.D. *et al.*: "Characterization of Partially Formed Polymer Gels for Application to Fractured Production Wells for Water-Shutoff Purposes," paper SPE 89401 presented at the 2004 SPE/DOE Symposium on Improved Oil Recovery, Tulsa, 17–21 April.
2. Seright, R.S.: "Mechanism for Gel Propagation Through Fractures," paper SPE 55628 presented at the 1999 SPE Rocky Mountain Regional Meeting, Gillette, Wyoming, 15–18 May.
3. Sydansk, R.D.: "A Newly Developed Chromium(III) Gel Technology," *SPERE* (August 1990) 346.
4. Sydansk, R.D. and Southwell, G.P.: "More Than 12 Years' Experience With a Successful Conformance-Control Polymer-Gel Technology," *SPEPF* (November 2000) 270.
5. Southwell, G.P. and Sydansk, R.D.: "Permeability or Fluid Mobility Reduction Treatment for a Hydrocarbon-Bearing Formation Using a Dual Molecular Weight Polymer Gel," U.S. Patent 6,025,304 (2000).
6. Seright, R.S.: "Gel Propagation Through Fractures," *SPEPF* (November 2001) 225.

SI Metric Conversion Factors

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

*Conversion factors are exact.

Robert D. Sydansk has headed Sydansk Consulting Services in Centennial, Colorado, since 2000. e-mail: RDSydansk@msn.com. Previously, he conducted R&D for 33 years for Marathon Oil Co. in almost all areas of chemical IOR, with his most recent focus there being on conformance improvement and polymer gels. He is the inventor or coinventor of 60 U.S. patents and has authored or coauthored 38 technical papers. Sydansk holds a BS degree in chemistry from the U. of Colorado. He is an SPE Distinguished Member and was an SPE Distinguished Lecturer. **Abdullah M. Al-Dhafeeri** is a research scientist with the Saudi Aramco R&D Center in Dhahran, Saudi Arabia. e-mail: abdullah.dhafeeri@aramco.com. His current research interests include water shutoff, well stimulation, IOR processes, and rheology. He has published and presented several papers. Al-Dhafeeri holds a BSc degree from King Saud U. and MSc and PhD degrees from the New Mexico Inst. of Mining and Technology. **Yin Xiong** worked as a research assistant in the Reservoir Sweep Improvement Group of the Petroleum Recovery Research Center of New Mexico Tech. e-mail: kikixy@yahoo.com. Xiong holds a BS degree in storage and transportation of oil and gas from the Southwest Petroleum Inst. (China) and an MS degree in petroleum engineering from New Mexico Tech. **Randall S. Seright** is a senior engineer at the New Mexico Petroleum Recovery Research Center at New Mexico Tech in Socorro. e-mail: randy@prrc.nmt.edu. Seright holds a PhD degree in chemical engineering from the U. of Wisconsin at Madison. He was an SPE Distinguished Lecturer for 1993–1994.