USING CHEMICALS TO OPTIMIZE CONFORMANCE CONTROL IN FRACTURED RESERVOIRS

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ABSTRACT

This technical progress report describes work performed from October 1, 1998 through March 31, 1999, for the project, "Using Chemicals to Optimize Conformance in Fractured Reservoirs." In our first task area, disproportionate permeability reduction, we are studying the ability of gels to reduce permeability to water more than that to oil. While examining the effects of pressure drawdown, the disproportionate permeability reduction was found to be four times greater after application of 90 psi/ft than that after 45 psi/ft.

In our second task area, we improved our software for sizing gelant treatments in hydraulically fractured production wells. The software now allows more convenient entry of reservoir and fluid properties.

In our third task area, we examined gel properties as they extruded through fractures. We developed and tested a simple model for predicting gel extrusion and dehydration in fractures. Predictions from the model matched experimental results reasonably well in fractures wider than 0.02 inches.

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PROJECT OBJECTIVES

This research project has three objectives. The first objective is to develop a capability to predict and optimize the ability of gels to reduce permeability to water more than that to oil or gas. The second objective is to develop procedures for optimizing blocking-agent placement in wells where hydraulic fractures cause channeling problems. The third objective is to develop procedures to optimize blocking-agent placement in naturally fractured reservoirs. This research project consists of three tasks, each of which addresses one of the above objectives. Our work is directed at both injection wells and production wells and at vertical, horizontal, and highly deviated wells.

RESULTS AND DISCUSSION

Task 1: Disproportionate Permeability Reduction

Effects of Pressure Drawdown on Disproportionate Permeability Reduction

In our previous annual report,[1] we performed oil-water experiments using a Cr(III)-acetate-HPAM gel in high-permeability Berea cores to study the effect of pressure drawdown on disproportionate permeability reduction. The gel contained 0.5% HPAM, 0.0417% Cr(III)-acetate, 1% NaCl, and 0.1% $CaCl_2 \bullet 2H_2O$. Soltrol-130 was the oil phase. Constant-pressure experiments were performed using different gradients (45, 90, 135, 180 psi/ft). For each pressure gradient, two similar oil-water experiments were performed; one with oil injected immediately after shut-in to measure oil residual resistance factor, F_{rro}, and the other with brine injected immediately after shut-in to measure water residual resistance factor, F_{rrw}. Results from the experiments were inconclusive due to gel breakdown. One possible way of increasing the gel strength is to lower the acetate content in the gelant. In this study, we lower the acetate content in the gelant by about 1/4 by mixing $CrCl_3 \bullet 6H_2O$ with Cr(III)-acetate while maintaining the same Cr(III) concentration. The new gelant used in this study consisted of 0.5% HPAM, 0.0313% Cr(III)-acetate, 0.0121% $CrCl_3 \bullet 6H_2O$, 1% NaCl, and 0.1% $CaCl_2 \bullet 2H_2O$.

Similar oil-water experiments are being performed in high-permeability Berea cores using the same pressure gradients. Preliminary results show that the disproportionate permeability reduction increases with increasing pressure gradient. In this study, we use the ratio, F_{rrw}/F_{rro}, to measure disproportionate permeability reduction. Higher F_{rrw}/F_{rro} values indicate more pronounced disproportionate permeability reduction. Table 1 shows that F_{rrw}/F_{rro} increased when the pressure gradient was increased from 45 psi/ft to 90 psi/ft. Preliminary results imply that as the pressure gradient increases, oil is more effective than water in breaking down the gel. This phenomenon may be useful in oil-zone cleanup after treatment. More experiments are being performed using higher gradients to study this phenomenon.

Table 1. Effect of Pressure Drawdown on Disproportionate Permeability Reduction
Gel: 0.5% HPAM, 0.0313% Cr(III)-acetate, 0.0121% $CrCl_3 \bullet 6H_2O$,
1% NaCl, and 0.1% $CaCl_2 \bullet 2H_2O$
Cores: ~750-md Berea sandstone

Pressure Gradient, psi/ft	F_{rrw}	F_{rro}	F_{rrw}/F_{rro}
45	47,000	202	233
90	30,000	35	857

Task 2: Gelant Treatments in Hydraulically Fractured Production Wells
In previous work, we developed a method for sizing gelant treatments in hydraulically fractured production wells.[2] The method was incorporated in user-friendly graphical-user-interface software (available at our web site at http://baervan.nmt.edu/ResSweepEffic/reservoir.htm). We updated the software to Version 1.06. After a candidate well was determined to be inappropriate for a gel treatment, the previous version (1.05) required the user to return to the beginning of the program if the user wished to examine a new case. In contrast, Version 1.06 allows the user to continue and modify previous data entries without re-entering all reservoir and fluid properties.

Task 3: Gels in Naturally Fractured Systems
Review of Recent Experiments. Many conformance control treatments rely on the ability of gels to extrude through fractures during the placement process. Recently, we performed an experimental investigation of the mechanism for propagation of a Cr(III)-acetate-HPAM gel through a 0.04-inch-wide, 4-ft-long fracture.[3] Pressure taps in the fracture and matrix divided the core into five sections of equal length. Our gel contained 0.5% Allied Colloids Alcoflood 935 HPAM, 0.0417% Cr(III) acetate, 1% NaCl, and 0.1% $CaCl_2$ at pH=6. The experiments were performed at 41°C (105°F). The gelant formulations were aged at 41°C for 24 hours (5 times the gelation time) before injection into the fractured core. When large volumes of gel were extruded through the fracture, progressive plugging (i.e., continuously increasing pressure gradients) was not observed (Fig. 1). The pressure behavior in Fig. 1 indicated the rate of gel propagation through the fracture. In particular, gel first entered Fracture Sections 2, 3, 4, and 5 after injecting 1.1, 2.7, 5.6, and 11 fracture volumes of gel, respectively.

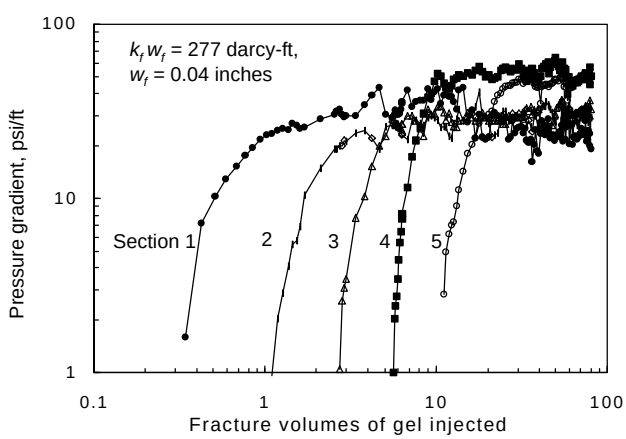

Fig. 1—Pressure behavior in the fracture taps during gel injection.

Effluent from the fracture had the same appearance and a similar composition as those for the injected gel, even though a concentrated, immobile gel formed in the fracture.[3] Concentrated gel formed when water leaked off from the gel along the length of the fracture. The driving force for gel dehydration (and water leakoff) was the pressure difference between the fracture and the adjacent porous rock. Fig. 2 plots the water leakoff rate per unit of fracture face versus the fracture volumes of gel injected for the various sections of the core. The leakoff rates were normalized relative to the largest leakoff rate observed during the experiment (i.e., 1.89 x 10^{-4} $ft^3/ft^2/min$ or 9.63 x 10^{-5} $cm^3/cm^2/s$).

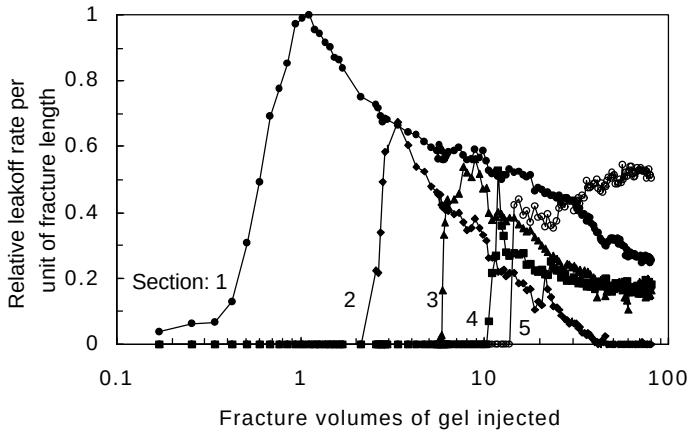

Fig. 2—Relative leakoff rates derived from the experiment.

For any given section, the leakoff rate rapidly rose to a maximum and then gradually diminished. The greatest leakoff rate was observed in the first core section after injecting about one fracture volume of gel. The peak leakoff rates in Sections 2, 3, 4, and 5 were 67%, 56%, 53%, and 54% of this value, respectively. After injecting 80 fracture volumes of gel, the relative leakoff rates varied from 0 (in Section 2) to 0.5 (in Section 5).

A special outlet fitting segregated the effluent from the fracture and that from the porous rock. The data points in Fig. 3 show the fraction of the effluent that was produced from the fracture versus from the porous rock. During the first 15 fracture volumes of gel injection, virtually 100% of the flow occurred in the fracture. This result was expected. Before gel injection, the calculated flow capacity of the fracture was 3,400 times greater than the flow capacity of the porous rock. Gel arrived at the fracture outlet after injecting 15 fracture volumes of gel. Coincident with gel arrival, flow from the fracture abruptly stopped for a period of about 2 fracture volumes of gel injection. (So, 100% of the effluent was produced from the matrix during this time.) Subsequently, the fraction of flow from the fracture increased, while flow from the porous rock decreased. After injecting 80 fracture volumes of gel, flow from the fracture accounted for 65% of the total flow, while flow from the matrix accounted for 35% of the total flow.

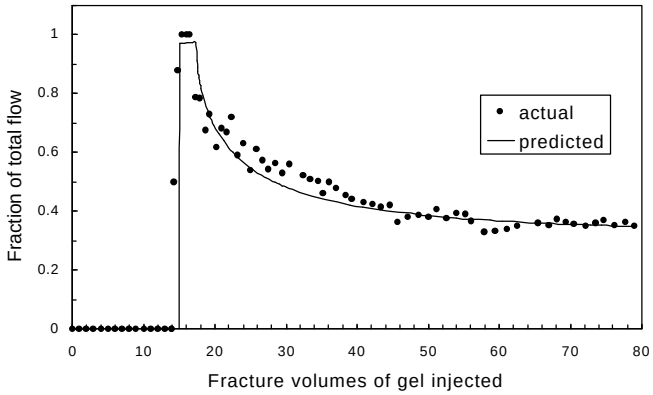

Fig. 3—Predicted versus actual fractional flow from the matrix at the core outlet.

Model for Gel Propagation and Dehydration During Extrusion Through Fractures. A simple model was developed that accounted for many of the experimental results. Our experimental results indicate that gel dehydration occurred because the pressure in the fracture was much greater than that in the porous rock next to the fracture. Since the gel had a finite permeability to water[4] and since the crosslinked polymer did not penetrate into the porous rock,[5] water flowed from the gel (in the fracture) into the porous rock. This action increased the average gel concentration in the fracture. For the most part, the concentrated gel was immobile.

At a given point along the fracture, the leakoff rate per unit area of fracture face, u_l, can be estimated from the Darcy equation.

$$u_l = 2k_{gel}\,\Delta p/(w_f \mu) \quad (1)$$

In Eq. 1, k_{gel} is gel permeability to water, μ is water viscosity, w_f is fracture width, and Δp is pressure drop between the fracture and the porous rock. Eq. 1 assumes that the average distance that water travels to reach the porous rock is $w_f/2$—i.e., from the center of the fracture to the fracture face. Consistent with our experimental observations, the gel composition at a given time and point along the fracture was assumed to be uniform across the width of the fracture. In our experiments, the pressure in the porous rock was small, so Δp in Eq. 1 was close to the actual pressure in the fracture.

As mentioned earlier, after the gel dehydrated, it generally became immobile in the fracture. The mobile gel basically had the same composition as the injected gel. Therefore, at any given time, t, and gel-contacted point along the fracture, the relative gel composition, C/C_o, was estimated using Eq. 2.

$$C/C_o = 1 + \int (2\,u_l/w_f)\,dt \quad (2)$$

A relation was not available between gel composition and gel permeability to water, k_{gel}. Therefore, a simple empirical equation was developed.

$$k_{gel} = 0.11 + (C/C_o)^{-3} \quad (3)$$

In Eq. 3, k_{gel} has units of md when the gel composition, C/C_o, is expressed relative to the composition of our original Cr(III)-acetate-HPAM gel. Of course, the validity of this empirical equation can be questioned. Eq. 3 was used simply because it allows a reasonable fit for the experimental results. In future studies, a sound relation between gel permeability and composition will be sought experimentally.

Eqs. 1, 2, and 3 were combined with a mass balance to form a simple model of gel propagation and dehydration in fractures. Based on Fig. 1, pressure gradients in the gel-contacted portions of the fracture were fixed at 28 psi/ft in the first three fracture sections and 50 psi/ft for the last two fracture sections.

Predictions Versus Experimental Results. Leakoff rates predicted by the model are shown in Fig. 4. The model accurately accounted for several experimental observations. First, the model predicted gel arrival at the ends of the first through fifth fracture sections after injecting 0.9, 2.8, 5.7, 10.7, and 16 fracture volumes, respectively. Experimentally, gel actually arrived after 1.1, 2.7, 5.6, 11, and 15 fracture volumes, respectively.

Second, the general shapes of the predicted water leakoff curves (Fig. 4) matched the experimental curves (Fig. 2) reasonably well. The predicted maximum leakoff rate occurred in the first section after injecting 0.9 fracture volumes of gel. For comparison, the experimental maximum in Section 1 was reached after injecting 1.1 fracture volumes. The predicted peak leakoff rates in Sections 2, 3, 4, and 5 were 68%, 54%, 43%, and 35%, respectively, of the predicted peak value in Section 1. The experimental peak leakoff rates in Sections 2, 3, 4, and 5 were 67%, 56%, 53%, and 54%, respectively, of the actual peak leakoff rate.

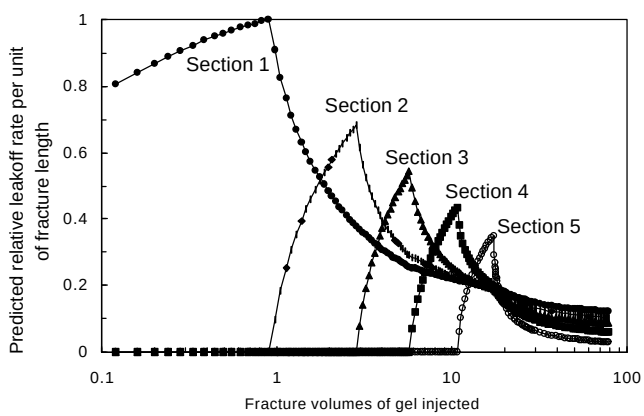

Fig. 4—Predicted leakoff rates.

Third, the model predictions matched the experimental results quite well with regard to the fraction of water flow from the matrix at the core outlet (see Fig. 3).

Fourth, the predicted profiles of final concentrations in the fracture matched the experimental values reasonably well. After 17 fracture volumes of gel injection, the predicted C/C_o values for gel in the fracture ranged from 25 near the fracture inlet to 12 in the fourth fracture section. The experimental values were 20 and 9, respectively.[3] After 80 fracture volumes of gel injection, the predicted C/C_o values for gel in the fracture ranged from 64 near the fracture inlet to 30 in the fourth fracture section. The experimental values were 36 and 25, respectively.[3] The model did not account for entry of any free chromium or uncrosslinked polymer into the porous rock. Therefore, the predicted concentrations in the fracture were expected to be somewhat higher than the experimental values.

Fracture with Varying Widths. To further test our model, an experiment was performed where our 1-day-old Cr(III)-acetate-HPAM gel was extruded through a 4-ft-long fracture with varying widths. The fracture width was 0.02 inches (0.05 cm) for the middle third of the fracture, while the remainder of the fracture was 0.08 inches (0.2 cm) wide. Internal fracture pressure taps were

located at 1/6, 1/3, 2/3, and 5/6 of the total fracture length. Fig. 5 shows the pressure behavior during gel injection. Typical stabilized pressure gradients were 15 psi/ft in the first and second fracture sections, 76 psi/ft in the third section, and 7.5 psi/ft in the fourth and fifth sections. From pressure and gel breakthrough data, gel arrival occurred at 0.55, 1.3, 8, 10.5, and 11.2 fracture volumes, respectively, for the ends of the first through fifth fracture sections.

After injecting 18.7 fracture volumes of gel (1,300 ml), the fracture was opened to determine the composition of gel in the fracture. Fig. 6 shows chromium and HPAM concentrations for gel in the fracture relative to the values for the original gel. We are uncertain why the HPAM concentrations were so much lower than the chromium concentrations in the first two-thirds of the fracture. This result was unexpected and will be re-examined in our future work.

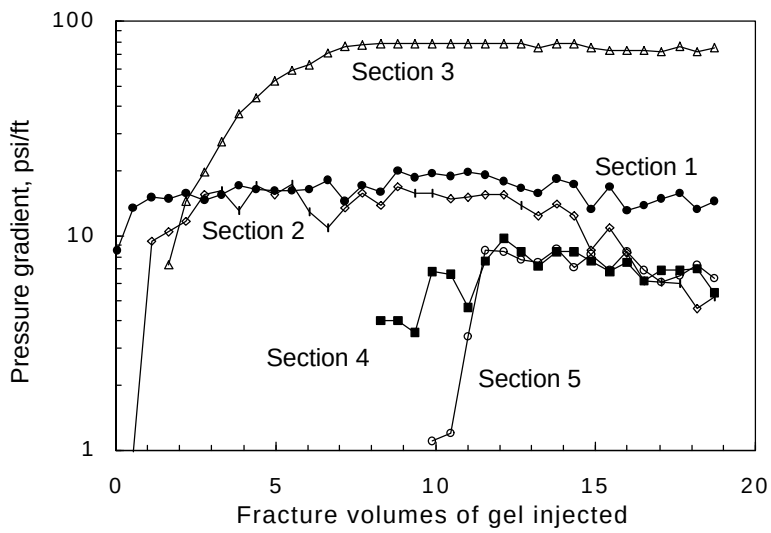

Fig. 5—Pressure gradients in a fracture with varying widths.

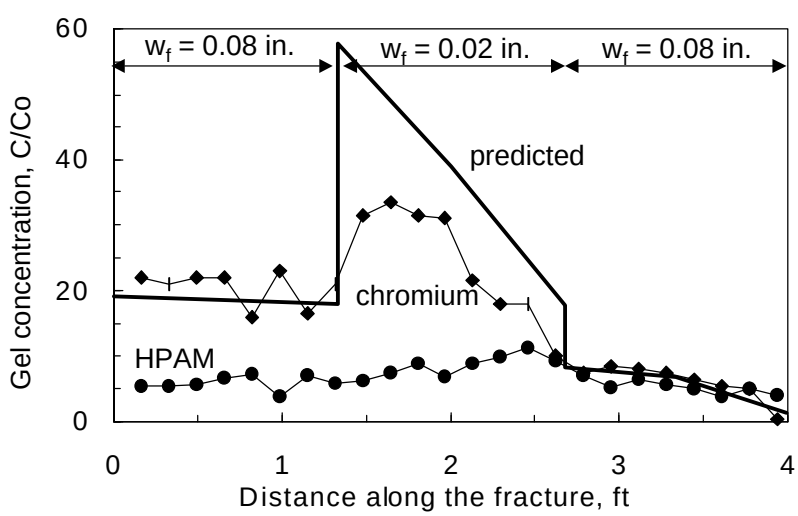

Fig. 6—Gel composition along the fracture.

Our predictive model was applied using the observed pressure gradients for the experiment and the new fracture widths and tap spacings. No other parameters were changed from the previous modeling effort. Our model predicted gel arrival at the ends of the first through fifth fracture sections at 0.59, 1.9, 7, 9.1, and 11.7 fracture volumes, respectively. These values were reasonably close to the experimental values of 0.55, 1.3, 8, 10.5, and 11.2, respectively.

The solid curve in Fig. 6 compares the predicted gel compositions along the fracture with the actual compositions. The model correctly predicted the chromium concentrations in the first and last third of the fracture. It also predicted increased chromium concentrations in the middle third of the fracture, although the model over-predicted the magnitude of the increase. As mentioned earlier, the relatively low HPAM concentrations in the first two-thirds of the model were unexpected.

Fractures with Other Widths. The data points in Fig. 7 show dehydration factors as a function of fracture width in 4-ft-long fractures. This figure shows the results from 38 separate experiments. Most of these data points were obtained shortly after gel arrival at the end of the fracture. The solid curve shows the predicted values based on our model. The predictions matched the experimental values fairly well for fracture widths greater than 0.02 inches. For more narrow fractures, our predictions were significantly greater than the actual values.

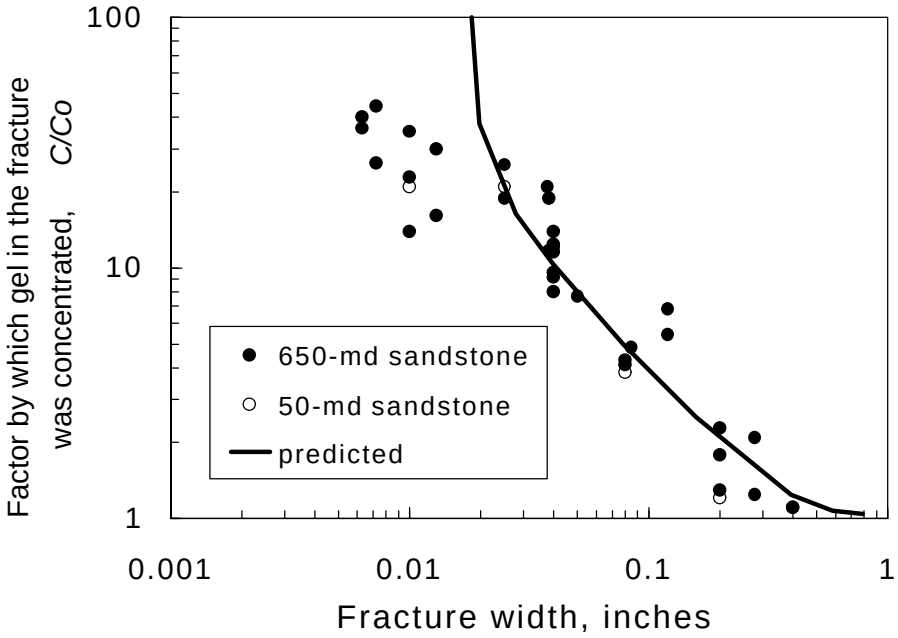

Fig. 7—Predicted versus actual dehydration factors as a function of fracture width.

Future Work. In future work, additional experiments will be performed to refine our model for gel extrusion and dehydration. Also, using our model and experimental findings, analyses will be performed to predict conditions, gel compositions, and gel volumes that provide the optimum gel placement in fractured reservoirs.

CONCLUSIONS

1. Experiments indicated that the disproportionate permeability reduction was four times greater after application of 90 psi/ft than that after 45 psi/ft.
2. To allow more convenient entry of reservoir and fluid properties, we updated our software for sizing gelant treatments in hydraulically fractured production wells.
3. We developed and tested a simple model for predicting gel extrusion and dehydration in fractures. Predictions from the model matched experimental results reasonably well in fractures wider than 0.02 inches.

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