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A Comparative Experimental Study of Sweep Efficiency in Naturally Fractured Reservoirs

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Abstract

In this paper the performance of gel and polymer in fractured core plugs in laboratory is compared. The experimental results show that in a naturally fractured reservoir, the best solution to improve oil recovery should be such that the gel particle sizes are larger than the pore sizes, and the solution viscosity becomes very high after the particles contact with water. If the fracture is wide, the improvement of sweep efficiency by a polymer solution is limited because the polymer solution could flow through the fracture channel. The results in this paper provide us with guidelines to select proper polymers to improve sweep efficiency.

Key words: Sweep efficiency; Naturally fractured reservoirs; Polymer solution; Oil recovery

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INTRODUCTION

To improve sweep efficiency in naturally fractured reservoirs, different types of polymers are used. In this paper, we compared the performance of two kinds of polymers in fractured core plugs in laboratory. One is a crystallized super-absorbent copolymer. The particles of this co-polymer swell after hydration and the solution has a very high viscosity like a gel. We call it gel in this paper. The other one is a polymer like partially hydrolyzed polyacrylamide whose viscosity is much lower than that of a gel. We simply call it polymer.

There is some debate regarding which kind of polymer is better in improving sweep efficiency. Some argue that using conventional polymer flooding is a better option, whereas some field results suggest using cross-linked gels is a better option[1,2]. There has been limited laboratory work done to address this issue. Some experiments have been done using dual-layer sand packs where the permeability of one layer is significantly higher than that of the other one[3]. The high-permeability layer represented fractures. Shi *et al.* [3] found that cross-linked polymer outperformed uncross-linked polymer HPAM (partially hydrolyzed polyacrylamide). The recovery from the former was 13% higher than that from the latter.

In this paper, we present our laboratory study using fractured cores to compare the performance of a conventional polymer and a gel in naturally fractured reservoirs.

1. EXPERIMENTAL

This section describes the materials and experimental setup used in the study.

1.1 Cores

The cores used in the experiments were all commercially made sandstone Berea cores. All of them came from the same batch and were expected to be similar in all aspects. The diameters were 1.5 inches and the lengths varied from 1.5 to 3 inches. The average porosity of these cores were about 20% measured using a helium porosimeter.

To prevent possible clay swelling, all the cores were “fired” by being heated in four stages in order to avoid the risk of thermal cracking. The cores were first heated to 250 °F for three hours, followed by being heated to 400 °F for two hours and to 575 °F for two hours. Finally, the cores were heated to 825 °F for three hours before being allowed to cool down inside the furnace.

1.2 Fracturing

Next we need to create artificial fractures in the core plugs that would simulate the natural fractures of a reservoir. Different approaches were tried to create fractures. Fathi-Najafabadi *et al*.[4] simply placed small rectangle cores together to form a composite block and the middle axial channels (about 0.5 mm space) between these small cores represented fractures. We tried drilling a small hole through a core so that the hole in the middle represents a fracture. After experimenting with different drill bits, this idea was discarded in favor of using a compressive strength testing machine to create a fracture. This approach was similar to the Brazilian disc test used in geomechanics. A cylindrical core was positioned beneath the blocks as shown in Figure 1.

Figure 1
A Compressive Strength Testing Machine Used to Create a Fracture

Then the core was subjected to compressive loading until failure, where the loading rate was kept at a minimum. This proved to be a sort of a trial and error method as described in the guidelines for such a test given by the ASTM standard C39/C39M-09a[5]. The aim of our experiments was to create a fracture in the core plug. Many times, the cores would just shatter into pieces and had to be discarded. Nonetheless, with careful repetition of the procedure, enough cores were fractured so as to enable us to conduct our experiments. Later on, it was found that these small fractures closed when the confining pressure was applied, and therefore their openings had to be enlarged manually. An example of the original fracture, as created using the compressive strength testing machine, is shown in Figure 2.

Figure 2
An Example of a Crack Core

1.3 Oil

Two different oils were used in the experiments: synthetic oil (Soltrol 130) and a crude oil. Soltrol 130 was a colorless light oil with a density of 0.764 g/cc and a viscosity of 2.37 cp. In the beginning, we used this oil, but later we stopped using it because the viscosity is too low and it is more difficult to see the polymer effect. The crude oil had a density of about 0.872 g/cc and its viscosity was about 8 cp.

1.4 Water

In all the experiments, distilled water was used for injection. To prepare polymer solutions, brine was prepared using this distilled water and 1 wt.% NaCl by weight.

1.5 Polymer

The polymer we used in this experimental study is a polymer derived from polyacrylamide.

Figure 3 shows the viscosity of a prepared 0.1 wt.% polymer solution at different shear rates. We used this solution in the experiments.

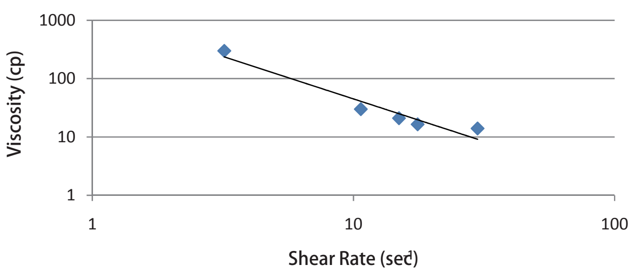

Figure 3
Polymer Solution Viscosity Versus Shear Rate

1.6 Super-Absorbent Copolymer (Gel)

The gel used in this study is a water swellable material capable of absorbing 30 to 400 times its own weight of water. The gel particles have different grain sizes: 1 mm, 2 mm and 4 mm. Because of its large sizes compared with pore throat diameters, the gel particles do not invade the matrix, but will enter fractures carried by injection water. When the particles contact water, they swell by hydration (absorbing water). Figure 4 shows the volumes of gel particles before and after hydration. The swelling rate and volume depend upon particle size, carrying fluid and formation water and salinity, temperature, etc. The smaller sizes show an increased rate owing to the increased surface area of the particles. Temperature does not have a significant effect on either the swelling rate or the resultant swelling volume.

Figure 4
Volumes of Gel Particles Before (left) and After (right) Contacting Water

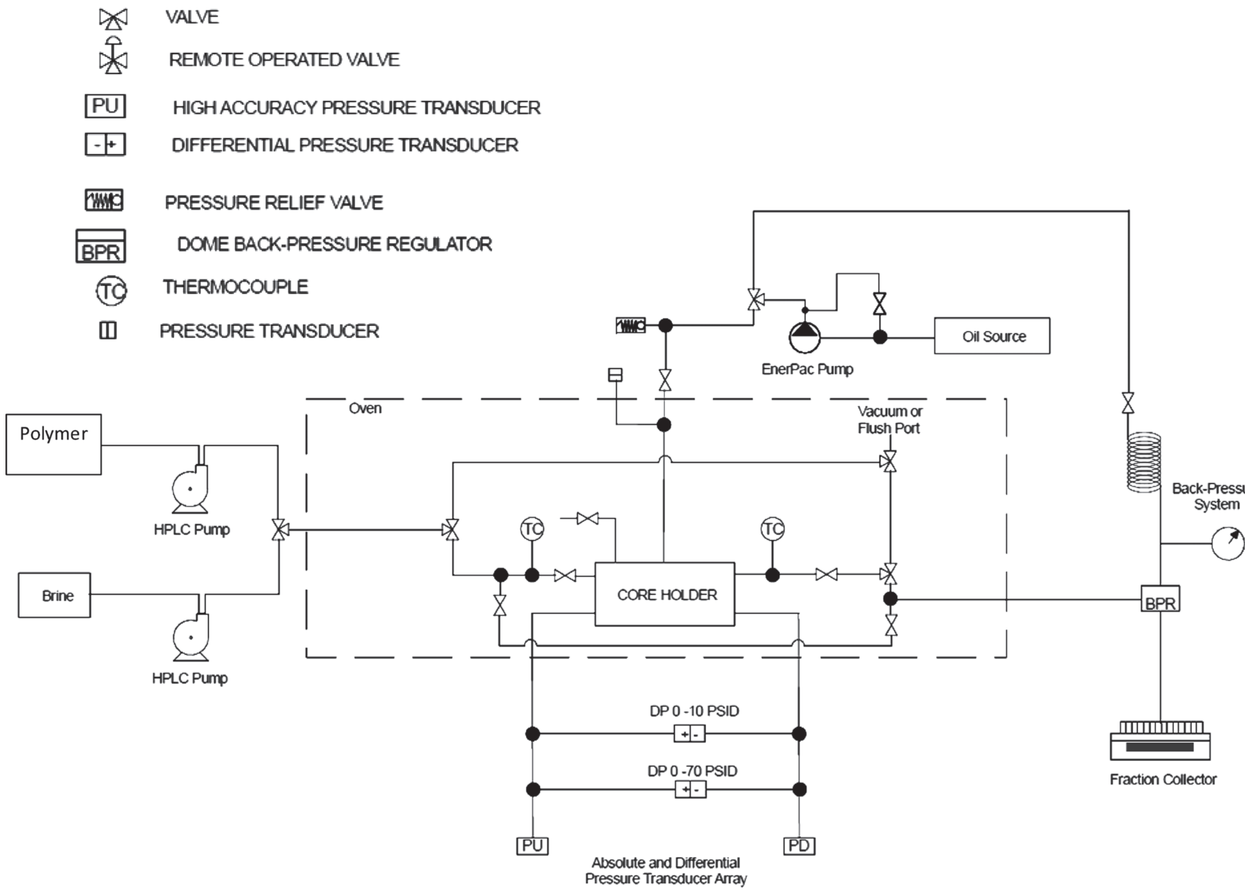

Figure 5
Schematic of Experimental Setup

1.7 Experimental Setup

Figure 5 shows the schematic of experimental setup. Basically, it had pumps for polymer solution or brine (water), a core holder, a back pressure regulator, a fractional collector, control valves and pressure transducers. The pumps and all the automatic valves could be directly controlled using software. All the pressure data, weight of produced fluid, and pump rate or pump pressure could be automatically recorded.

2. RESULTS AND DISCUSSIONS

A typical experimental procedure was as follows. A core plug was initially saturated with oil. The core plug was flooded by about 5 pore volumes (PV) of water, and then by one PV of gel particle or polymer solution followed by several PV of water injection again. Many experiments were done, but only representative experiments are presented and discussed next.

2.1 Experiments Using the Super-Absorbent Copolymer

2.1.1 Experiment G1

From earlier attempted tests, we observed that the gel particles tended to settle down very quickly when added in brine. Although it took more than twenty minutes for the particles to fully swell, the particles started hydrating almost immediately when added in water and started showing an appreciable increase in volume. When we used a high concentration, although some particles settled down to the bottom of an accumulator in the experiment, we still had a reasonable concentration of particle solution in the top of the accumulator because not all the particles had swollen. Therefore, when we prepared a solution, we used a concentration higher than a target concentration to inject. In this test, we prepared 3.6 wt.% (weight percent) solution which is the highest manufacture-recommended concentration. The high concentration ensured that the volume of pure brine at the top was minimized.

The core used for this experiment had a pore volume of approximately 9.5 cc. For the initial water slug, about 4 pore volumes were injected at a rate of 5 cc/min. Almost immediately, the water broke through, showing a differential pressure reading of about 0.1 psi. The produced fluid was mainly just water with a few specks of oil. This shows that waterflooding in such fractured core could not displace oil out.

Then we shifted to injection of the particle solution. After it was estimated that an appropriate amount of particle solution had been pumped in, the flow was stopped for about 45 minutes to let the particles swell up within the fracture.

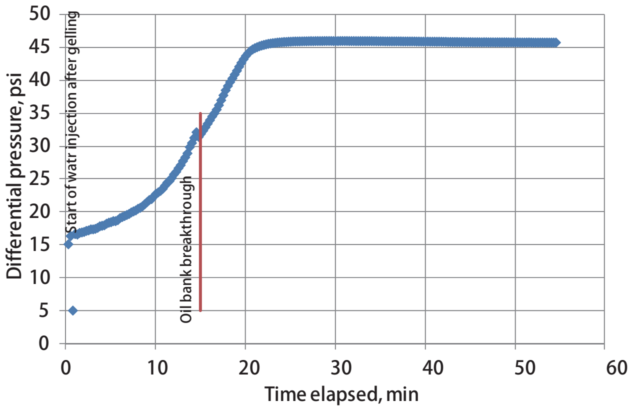

Figure 6
Pressure Changes During Waterflooding After Particles Swollen

Finally, having waited for a sufficient amount of time, water flooding was resumed. No flow was observed at the outlet as water was being pumped in. As the pump rate was remained unchanged (5 cc/min), the pump pressure increased, as shown in Figure 6. When the pressure differential was slightly above 30 psi, the pump pressure was sufficient to break through the blockage created by the swollen particles. Very soon after this, breakthrough was observed at the outlet end. A clear oil bank was seen coming out. Oil flowed out for a short time. Then a mixture of oil and water started coming out. During this time, the differential pressure kept showing a rising trend. Eventually, the differential pressure stabilized at about 46 psi as the water flooding was continued.

During the initial water slug, a cumulative oil volume of only about 0.2 cc was observed. During the pumping of particle solution, almost no fluid was produced. In the final water slug, a total oil volume of about 6 cc was produced. In other words, almost 97% of the total oil produced was due to the improved sweep efficiency by swollen particles blocking the fracture opening. In this experiment, about 65% of the total oil in place was produced.

Figure 7 compares the core faces before (left) and after (right) the experiment. The fracture was open before the experiment. After the experiment, the fracture opening was completely filled up with gel. But gel particles did not travelled deep inside the fracture, as shown in Figure 8. No gel could be seen in the exit end. Such experiment was repeated several times, and the observations were similar. Therefore, they are not presented here. For details, see Nasir[6].

Figure 7
Core Faces Before (left) and After (right) the Experiment

Figure 8
Opened Fracture Showing the Gel Distribution Within the Fracture

2.1.2 Experiment G2

In this experiment, an unfractured core was used. The objective of this experiment was to see whether small particles could enter the matrix causing permeability reduction (formation damage). In the experiment, 1.2 wt.% of 1 mm particles were carried by 0.1% NaCl brine. As shown in Figure 9, during the initial water injection, the differential pressure leveled out at a value of about 26 psi. Then the pressure rose dramatically when gel particles were injected until the pumping was stopped. At this point, the core-holder was depressurized and the gel accumulated on the entrance face of the core was washed off. After that, the core was pressurized again and water injection was re-initiated. As shown in the figure, the pressure started to build up steadily and eventually leveled off at a value of about 40 psi. It should be noted that this was the differential pressure during water injection after the core was injected with gel particles. This differential pressure was higher than 26 psi during water injection before injection of gel particles. The results of this experiment show that some small particles could enter some pores of the matrix causing permeability reduction.

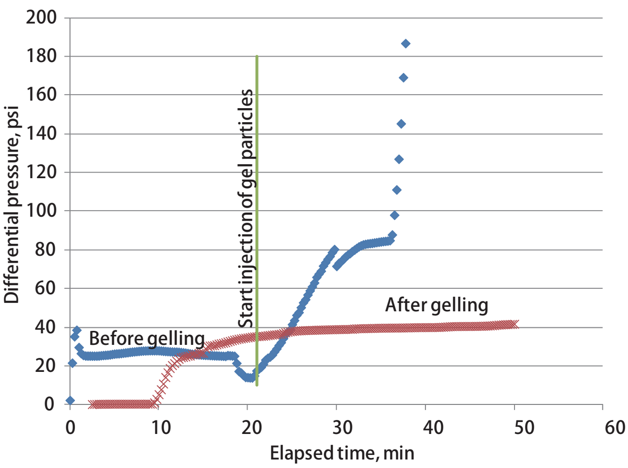

Figure 9
Pressure Histories During Water Injection Before Gelling and During Particle Injection, and After Gelling

2.2 Experiments Using Polymer

Many experiments were done using a polymer with different polymer concentrations and using two different oils: synthetic oil Soltrol 130 and a crude oil. Many of the experiments were just repetitive so only four experiments are discussed here. Because only crude oil was used in the gel experiments, for the purpose of comparison, the experiments conducted with the crude oil are discussed. The injection scheme used in these experiments was to flow 5 pore volumes of water before 1 pore volume of polymer was injected, followed by water injection again. All of the following experiments were performed at a temperature of 35 °C.

2.2.1 Experiment P1

An unfractured core was used in this experiment which served as the reference case for the subsequent experiments. The crude oil was used, and the concentration of polymer used was 0.5wt.%. A total of about 70% of the oil in the core was recovered by the end of the experiment, with the incremental oil recovered being about 10% over waterflooding. Figure 10 shows that initially with the water injection, the differential pressure rose steadily before leveling at about 10 psi. As the polymer injection began, the differential pressure rose sharply, until it began to drop again as water injection was re-started. The pressure kept decreasing until it leveled out again at about 60 psi. This behavior clearly showed the permeability was decreased after the polymer injection.

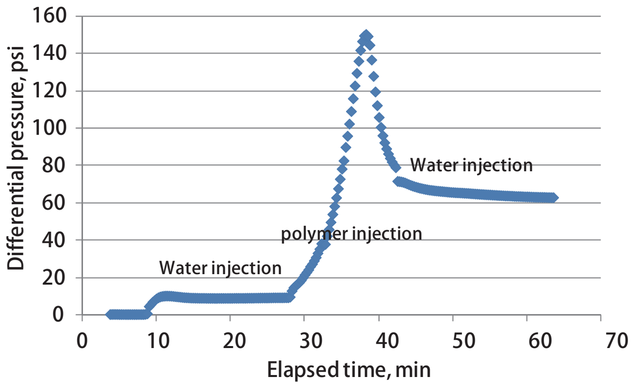

Figure 10
Different Pressure During Water-Polymer-Water Injection for Experiment P1

2.2.2 Experiment P2

For this experiment, a fractured core was used with 0.1% concentration polymer. The core was saturated with the crude oil. This fracture opening at the inlet side was big but at the outlet side, it was not as wide, as shown in Figure 11.

Figure 11
Fractures in the Inlet Side (left) and the Outlet Side (right) for Experiment P2

As per the injection scheme, about 5 pore volumes of water was injected before 1 pore volume of polymer, followed by water injection again. A total oil produced was about 60% of the oil in the core, with the incremental oil due to polymer flooding being about 40%. The differential pressure response recorded for the experiment is shown in Figure 12. From this figure, we can see that the differential pressure leveled out at 0.5 psi during the initial water-flooding. The pressure rose until it reached a peak during polymer injection, and then dropped steadily during the second water injection. The pressure leveled out to a value of about 2.8 psi, showing that the permeability was reduced by polymer. This experiment proved that if the fracture is not too big, polymer flooding can have really good oil recovery.

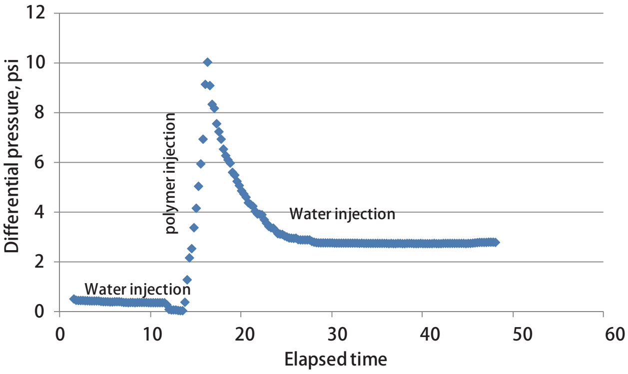

Figure 12
Different Pressure During Water-Polymer-Water Injection for Experiment P2

Figure 13
Fractures in the Inlet Side (left) and the Outlet Side (right) for Experiment P2

2.2.3 Experiment P3

This experiment provides a sharp contrast to the previous one where polymer flooding proved to be extremely successful. In this experiment, again a fractured core saturated with crude oil was flooded by water, polymer with 0.1 wt.% and water. Unlike the previous experiment, the fracture opening was wide at both the inlet and outlet end of the core, thus the fracture provided a direct connection between the two ends. Figure 13 shows the two faces of the core. The injection scheme was kept the same as in the previous experiment. First, about 5 pore volumes of water were injected, followed by 1 pore volume of polymer and then water injection. During the initial stage of water-flooding, absolutely no oil was produced. As polymer flooding was started, small specks of oil were seen at the outlet. Approximately 0.17 % of the original oil in the core was produced. The pressure transducers did not record any differential pressure for this experiment. In other words, the fracture was just too big and there was no restriction to flow. This experiment clearly showed that polymer flooding might not work if the fractures were widely open.

2.2.4 Experiment P4

In this experiment, a fractured core saturated with the crude oil was flooded with a 0.5 wt.% concentration polymer. The fracture itself was big, and provided a direct channel between the inlet and outlet ends. In this experiment, the usual 5 pore volumes of water were injected before 1 pore volume of polymer. In addition, after about 3.5 pore volumes of water, another pore volume of polymer was injected, followed by water injection.

A total of about 30% of the original oil in the core were produced. The incremental oil was 19.5%. It is important to note that although the incremental percentage is high, a high concentration (0.5 wt.%) and two pore volumes of polymer were injected to produce this amount of oil. This would be inefficient and uneconomical.

CONCLUDING REMARKS

Both polymer and gel have been successfully used in mature fields to improve oil recovery. Our experiment study aimed to ascertain which one is better in naturally fractured reservoirs. Our experimental results show that the improvement of sweep efficiency in a fractured core plug by a polymer solution is limited because the polymer solution could flow through the fracture channel from the inlet to outlet of the core, if the fracture width is large enough. And a limited polymer solution flowed through the matrix. The incremental oil recovery was limited mainly depending on the fracture width. In some cases with wide fractures, no incremental oil can be recovered using the polymer.

The results from our experiments suggest that overall particle type of super-absorbent copolymer is better than conventional polymers in fractured reservoirs, especially when the fractures are widely open. However, for the particle type of super-absorbent copolymers, an important issue is the gelation time. If the gelation time is too short, then particles cannot be carried deep into fractured formation. Another issue is the particle size. The particle size must be proper for a specific formation. If it is too large, it cannot enter the formation. If it is too small, it will enter small pores in the matrix and thus would damage formation once contacting with water.

Ideally, the super-absorbent copolymer is only supposed to fill and block the fractures and render the core as if it were an unfractured one. This would give us an oil recovery similar to that in unfractured cores under waterflooding. In some of our experiments, the actual oil recovered was even higher than that from unfractured cores. This seems to suggest that in addition to blocking the fracture, some of the super-absorbent copolymer solution did invade the matrix and improved the sweep efficiency in the same way as conventional polymers, thereby leading to a higher recovery.

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