

# Gel Systems for Controlling CO<sub>2</sub> Mobility in Carbon Dioxide Miscible Flooding

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## Summary

Conformance control for carbon dioxide miscible flooding using gel has not been widely attempted. Laboratory research efforts at the University of Kansas have produced promising in-situ gelation techniques aimed at this application. Three in-situ gel systems were developed and tested in laboratory cores. Two systems are based on a new biopolymer, termed KUSP1, and the third gel system uses the reaction of sulfomethylated resorcinol and formaldehyde to form a gel.

KUSP1 gel systems were studied using two different methods of inducing in-situ gelation. In the first method, gelation was accomplished by injecting CO<sub>2</sub> at low pressure into the Berea sandstone core saturated by alkaline polymer solution. Permeability reduction to the brine and CO<sub>2</sub> in the range of 80% was achieved. Stability of the gel was tested in the presence of supercritical CO<sub>2</sub>. When supercritical CO<sub>2</sub> was used to induce in-situ gelation, the same degree of permeability reduction was achieved. The gel remained stable after the injection of many pore volumes of supercritical CO<sub>2</sub>. The second method of initiating in-situ gelation involved the use of an ester. Hydrolysis of the ester, monoethylphthalate, in the alkaline polymer solution caused the pH to drop to levels where in-situ gelation occurred. The permeability of the treated core to supercritical carbon dioxide was about 1 md which was equivalent to a permeability reduction of 95%–97% of the initial brine permeability.

The third gel system, based on the reaction of sulfomethylated resorcinol and formaldehyde (SMRF), was gelled in situ and contacted with both brine and supercritical CO<sub>2</sub>. Permeabilities to carbon dioxide on the order of 1 md or less were observed. This permeability is equivalent to a reduction of about 99% in the initial brine permeability. Reduced permeabilities were maintained after injecting many pore volumes of supercritical CO<sub>2</sub> and brine.

## Introduction

Carbon dioxide miscible flooding is one of the most important tertiary oil recovery techniques employed in the United States. However, the process experiences major difficulties in field application because of reservoir heterogeneity due to high permeability contrast. CO<sub>2</sub> tends to finger through the high permeability zones and bypass the oil. Early CO<sub>2</sub> production occurs with increased recycling and other operating costs.

Different methods have been investigated for improving the overall efficiency of the CO<sub>2</sub> flooding process. In almost all these methods, attempts have been made to achieve a favorable mobility ratio by affecting the CO<sub>2</sub> relative permeability. Examples of these methods are: (1) water alternating gas (WAG) process,<sup>1</sup> (2) carbon dioxide-foam process,<sup>2</sup> and (3) viscosified carbon dioxide process.<sup>3</sup>

Another technology which is under study is permeability reduction by in-depth placement of polymer gels. The objective of this

research is to reduce the permeability in permeable zones of the reservoir. Reduction of matrix permeability in the CO<sub>2</sub> process has been studied by other investigators.<sup>4,5</sup> No systems were found that gave satisfactory permeability reduction when exposed to prolonged injection of CO<sub>2</sub>.

Three new in-situ gel systems developed and tested in our laboratory are described in this paper. Two of these systems are based on a biopolymer termed KUSP1.<sup>6,7</sup> The third system is based on a modification of a previously reported organic crosslinking system.

## Experiment

The experimental program consisted of gelling each polymer system in a 1 ft Berea core which was mounted in a core holder and determining the permeability of the treated rock to brine and carbon dioxide at supercritical conditions. Five separate tests were conducted. Dispersion tests were run in some tests to estimate the pore volume contacted by the injected fluids after treatment with a gelled polymer system.

## Equipment and Materials

**Experimental Apparatus.** Fig. 1 is a schematic presentation of the experimental apparatus used in this work. An ISCO syringe pump was used for injecting CO<sub>2</sub>, brine, and gel solutions into the core. All the experiments were conducted at constant rate. The effluent of the core was collected by a fraction sample collector for further analysis. A TEMCO high-pressure core holder equipped with pressure ports was used. The rubber sleeve was filled with water and the injection pressure was kept at 500 psi below the sleeve pressure because higher sleeve pressures caused the rubber sleeve around the pressure taps to deform and seal off the pressure ports.

One ft Berea cores, 2 in. in diameter, were used in all experiments. Pressure ports were located such that the core was divided into four sections. The first and fourth sections were 5 cm in length and sections two and three were 10 cm long. The pressure difference for each section and the overall pressure difference were measured by pressure transducers and recorded via a computer-based data gathering system. The apparatus was placed in an air bath in which the temperature of the core and the injected fluids was kept constant. The pressure of the core was maintained by a TEMCO back-pressure regulator connected to a cylinder containing nitrogen at high pressure. The back pressure was maintained at 1200 psi. Details of the experimental setup are presented elsewhere.<sup>8</sup>

**Gels Produced from KUSP1.** KUSP1 is an acronym for a biopolymer developed at the University of Kansas. The polymer is a  $\beta$ -1,3-polyglucan and is produced by fermentation of a bacterium known as *Alcaligenes faecalis* and certain species of *Agrobacterium*.<sup>6</sup> The polymer grows on the surface of the bacteria. During the fermentation process, the polymer laden bacteria aggregate and settle out from the growth medium. Polymer is extracted from the bacteria by suspension in dilute alkali. Neutralization of the alkaline polymer solution produces a hydrogel. The gelation process is reversible and the hydrogels are stable at high temperatures in neutral solutions. The polymer degrades in alkaline solution with time and at elevated temperatures.

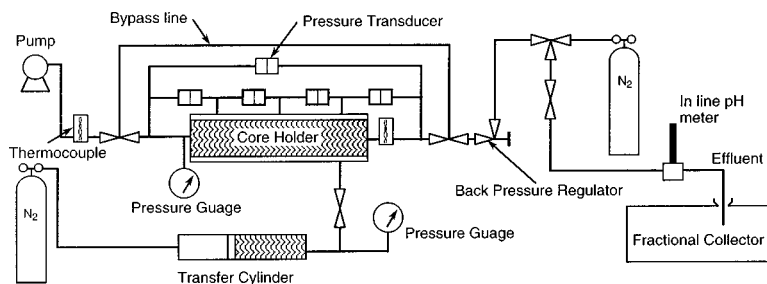


Fig. 1—Schematic presentation of experimental equipment.

Earlier investigations<sup>9,10</sup> revealed the potential of this biopolymer for permeability reduction in sand packs as well as Berea sandstones. In-situ gelation was achieved by injecting acid to reduce the pH of the alkaline polymer solution to the level below the gelation point, i.e., pH=10.8. It was also established<sup>11</sup> that the fluid-rock interaction is not sufficient to lower the pH of the alkaline solution to the gelation point. Two methods of gelling the biopolymer solution were studied: (1) in-situ gelation by injection of carbon dioxide and (2) neutralization of the alkaline polymer solution using an ester.

**KUSPI-CO<sub>2</sub> System.** This system is based on neutralization of the alkaline polymer solution by controlled injection of CO<sub>2</sub>. Initial experiments<sup>8</sup> were conducted in sand packs under atmospheric conditions to investigate the possibility of in-situ gelation by CO<sub>2</sub> injection in porous media saturated with the KUSPI. In the first experiment, early gas breakthrough occurred with no permeability reduction. This was attributed to a high CO<sub>2</sub> injection rate (1 mL/min), which caused CO<sub>2</sub> to finger through the sand pack without sufficient reaction with the polymer solution. A second experiment, conducted at lower CO<sub>2</sub> injection rates, led to permeability reduction on the order of 98%. It was not possible to restore the permeability to its original state by injection of concentrated NaOH. This may be because of the inability of NaOH to contact all the gels formed.

The second set of experiments was performed in Berea sandstone cores. The core was mounted in the coreholder; the air in the core was displaced by CO<sub>2</sub> under atmospheric conditions at room temperatures (~25°C). Brine was injected to saturate the core with a 2% solution. Porosity was determined by material balance. A dispersion run was carried out by displacing 2% brine with a 2.2% brine and vice versa to check the pore volume as well as the heterogeneity of the core. The core was then saturated with 1 N NaOH solution. This ensured that the system pH was above 11 to avoid possible gelation at the interface between the injected polymer and the fluid inside the core. In experiments on Berea Core No. 3, CO<sub>2</sub> was injected into the core saturated with NaOH to determine the permeability to CO<sub>2</sub> in the presence of a trapped liquid saturation. The core was resaturated with NaOH before injection of alkaline polymer solution.

The alkaline polymer solution was prepared in distilled water with a concentration of 1% KUSPI, 1% NaCl and 3.73% NaOH. The solution was stirred continuously using a magnetic stirrer for about 2 hr until a clear and consistent solution was obtained.

KUSPI contains some proteinaceous impurities such as cell debris.<sup>12</sup> Biopolymers are known to form microgels in the presence of salt and free proteins. The polymer solution was filtered through a 5 μm nylon filter using a vacuum filtration apparatus to remove the impurities. Approximately 2 g of carbon black and 2 g of diatomaceous earth were added to the solution to help the filtration process. The carbon black absorbed proteins in the polymer. Care was taken to ensure that the filter cake formed was not disturbed or cracked while pouring the solution into the beaker. The final pH of the solution was 13.6.

Polymer solution was injected into the core under atmospheric conditions. The pressure data were recorded continuously while injecting the polymer solution into the core. After injecting about two pore volumes of the polymer solution, the core was pressurized to 1300 psi. This was done by increasing the injection pressure gradually in three steps. First the pressure was increased to 500 psi then to 900 psi and finally to 1300 psi and the system was maintained at that pressure. The inlet and the outlet valves were closed in preparation for CO<sub>2</sub> injection.

The experiment was carried out under constant flow rate conditions at 90°F. At the effluent end, an in-line pH electrode was used to record the variation in effluent pH and to determine the gas breakthrough time. Pressure data were collected continuously. The effluent was observed continuously for the presence of gas bubbles which would indicate gas breakthrough. Effluent was collected at a predetermined frequency in glass tubes mounted on a fraction collector. Gas breakthrough could also be detected by a sharp change in effluent pH from about 13.5 to 8. After gas breakthrough occurred, injection of CO<sub>2</sub> continued until the pressure drops across all the sections remained constant. Other experimental details are given in Reference 8.

Brine (10,000 ppm NaCl) under supercritical CO<sub>2</sub> conditions was injected to determine the liquid permeability after gelation and the persistence of the permeability reduction. Trapped and dissolved CO<sub>2</sub> were displaced from the core before permeability measurements to eliminate relative permeability effects due to trapped gas saturation. A dispersion run was carried out before disassembling the core.

Four Berea cores were used to investigate CO<sub>2</sub>-induced gelation of KUSPI. **Table 1** presents the initial permeabilities of the cores as measured by injecting brine and measuring pressure drop for each section and for the entire core. Permeabilities of the cores varied from 72 to 384 md. Three CO<sub>2</sub> injection rates of 0.5, 0.1, and 0.005 mL/min were studied with one replication (cores 1 and 2). Brine permeabilities after CO<sub>2</sub>-induced gelation are given in **Table 2**. Permeability reductions on the order of 78%–93% were observed after CO<sub>2</sub> was injected into the core saturated with KUSPI in alkaline solution. The highest permeability reduction

TABLE 1—PROPERTIES OF BEREA SANDSTONE CORES

	Initial Brine Permeabilities (md)			
	Berea Core No.			
	1	2	3	4
Overall	384	163	72	93
Section 1	331	154	68	72
Section 2	423	174	70	97
Section 3	384	163	73	106
Section 4	332	161	53	101
Porosity (%)	21.4	26.3	17.5	—

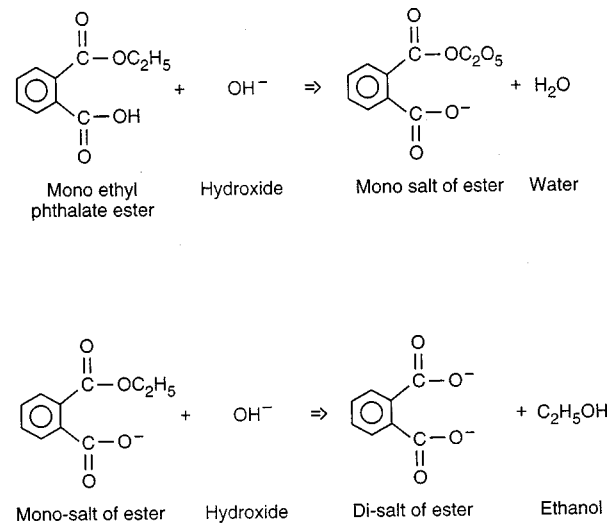
**TABLE 2—BRINE PERMEABILITIES AFTER CO<sub>2</sub>-INDUCED GELATION**

	Brine Permeabilities (md)			
	Berea Core No.			
	1	2	3	4
Overall	86	34	9	6
Section 1	88	30	7	4
Section 2	92	38	11	5
Section 3	78	41	11	10
Section 4	90	43	7	13
CO <sub>2</sub> injection rate (mL/min)	0.5	0.5	0.1	0.005
Permeability reduction (%)	78	79	88	93

occurred for the lowest CO<sub>2</sub> injection rate. A total of 12 pore volumes was injected into the core to investigate the gel stability under brine injection and the permeability was evaluated after every 2 pore volumes injected. Results for Berea core No. 1 are presented in **Table 3**. Data clearly support the fact that the gel was stable under the operating conditions.

The effective permeability for carbon dioxide in the presence of a trapped liquid saturation was determined in Berea Core No. 3 by displacing the initial alkaline solution with carbon dioxide. Effective permeabilities to CO<sub>2</sub> for the CO<sub>2</sub>-NaOH system are presented in **Table 4**. These are effective permeabilities to CO<sub>2</sub> at CO<sub>2</sub> breakthrough (around 15% CO<sub>2</sub> saturation) in the absence of polymer. The effective permeabilities to CO<sub>2</sub> at residual liquid saturation would be significantly higher than these values. Also presented in Table 4 are the effective permeabilities for the KUSPI-CO<sub>2</sub> system after the pressure stabilized. Inspection of Table 3 shows that in-situ gelation of KUSPI caused a reduction of 85% in the effective permeability to CO<sub>2</sub> at CO<sub>2</sub> breakthrough. The reduction in overall CO<sub>2</sub> effective permeability is much greater than 85% compared to the 88% reduction in overall brine permeability reported in Table 2 for Berea core No. 3.

The reduction in effective permeability of CO<sub>2</sub> is close to that of brine in contrast to the observation reported by Seright.<sup>13</sup> The difference in our observation is attributed to the nature of the gel system which is different from gel systems studied by Seright.<sup>13</sup>



**Fig. 2—Chemical structure for mono ethyl phthalate and the hydrolysis reactions leading to production of hydrogen ion and reduction of pH.**

**KUSPI—Ester System.** The second system uses the hydrolysis of an ester to control the rate of neutralization. The ester is slowly hydrolyzed and causes the pH to decrease to the level where the KUSPI alkaline solution gels. The ester used in this study was monoethylphthalate. **Fig. 2** shows the structure of monoethylphthalate ester and the reaction which produces ethanol and hydrogen ion.<sup>12</sup> The rate of hydrolysis is controlled by the concentration of the ester and the initial pH of the solution. There are two mechanisms contributing to the reduction of pH. A rapid, irreversible neutralization reaction takes place as soon as the ester is added to the alkaline solution. This reaction releases H<sup>+</sup> ions resulting in a fast, initial pH drop. The second reaction is the hydrolysis reaction that is rate determining.

**Fig. 3** shows pH versus time data for the KUSPI—monoethylphthalate system used in this research.<sup>12</sup> The pH drops with time, causing the polymer solution to gel at about pH 10.8. It is possible to control the gel time of a KUSPI system injected into a porous medium through control of the hydrolysis reaction. The

**TABLE 3—GEL STABILITY STUDY FOR BEREA CORE 1**

	Brine Permeability (md) after Injecting Indicated Pore Volumes				
	4 PV	6 PV	8 PV	10 PV	12 PV
Overall	90	90	93	85	86
Section 1	89	91	94	91	88
Section 2	89	92	93	93	92
Section 3	85	84	85	72	78
Section 4	103	103	103	98	90

**TABLE 4—COMPARISON OF CO<sub>2</sub> EFFECTIVE PERMEABILITY FOR BEREA CORE 3**

	CO <sub>2</sub> Effective Permeability (md)		
	CO <sub>2</sub> -NaOH System	CO <sub>2</sub> -KUSPI System	Reduction (%)
Overall	3.65	0.56	85
Section 1	4.83	1.20	75
Section 2	6.05	0.95	84
Section 3	4.84	0.32	93
Section 4	1.21	0.48	60

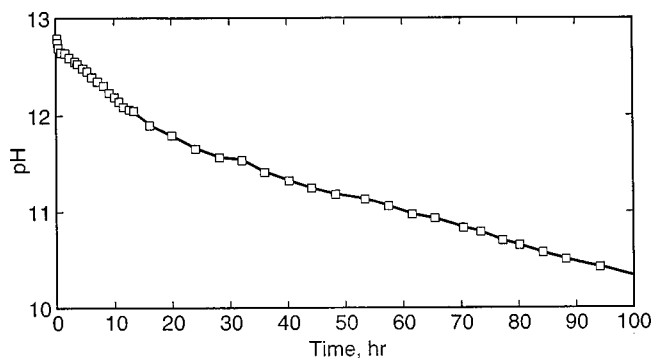


Fig. 3—A representative pH versus time plot for the gelation of KUSP1-ester system.

gelation system has been studied and results are reported in detail elsewhere.<sup>14</sup>

The KUSP1 polymer solution was prepared as described before. An ester solution was added to the filtered polymer solution. The ratio of the number of moles of monoethylphthalate to sodium hydroxide was 1:0.6. Special care was taken while adding ester solution to prevent gel globules from forming in the region where the ester came in contact with the polymer solution.<sup>12</sup> The ester solution was added drop by drop, giving each drop sufficient time to dissolve into the polymer solution before the next drop was added. Gelation time was adjusted by adding concentrated hydrochloric acid to reduce the pH to the required value. This was done just before injecting the solution into the core to ensure a reasonable gelation time for the experiment to be carried out.

The core was prepared using the same procedures as for the KUSP1-CO<sub>2</sub> system. Before injecting the polymer-ester solution, the core was saturated with 0.1 N NaOH. The polymer-ester solution was injected into the core at 5 mL/min. A small sample of the solution was kept in a bottle under the same temperature as the core to verify the time of gelation. The polymer solution gelled after 114.5 hr. The polymer-ester solution was allowed to gel in situ at atmospheric pressure before injecting CO<sub>2</sub>. Liquid permeability was measured after the completion of in-situ gelation. This was followed by permeability measurement with CO<sub>2</sub> under supercritical conditions. Five pore volumes of CO<sub>2</sub> were injected before initiating brine injection. Brine injection was resumed after CO<sub>2</sub> injection to determine the effect of CO<sub>2</sub> on gel structure. Temperature was maintained at 93°F for all runs.

After confirming that gelation had occurred, brine was injected into the core at 0.1 mL/min under atmospheric conditions to determine the reduced permeability of the core. The core was then pressurized to 1200 psi and brine injection was resumed. Permeabilities to brine are presented in Table 5. Missing values in the table are due to plugging of pressure ports. An overall permeability reduction on the order of 99% was obtained. Permeabilities

Porosity=0.23	Brine Permeability (md)		
	Initial	After Gelation (Low Pressure)	After Gelation (High Pressure)
Overall	144	1.08	2.64
Section 1	167	0.56	0.40
Section 2	186	0.63	—
Section 3	164	0.31	—
Section 4	76	1.44	—

Back Pressure Applied:	Brine Permeability (md)			
	0 psi	400 psi	800 psi	1200 psi
Overall	5.58	5.70	6.05	7.64
Section 1	0.97	0.99	1.00	1.05
Section 2	—	—	—	—
Section 3	—	—	—	—
Section 4	—	—	—	—

after gelation under high pressure are slightly higher than those under atmospheric condition. This suggests that gel dehydration might have occurred as a result of pressurizing the system. This was further substantiated by measuring brine permeabilities under different back pressures as reported in Table 6.

The effective permeability of the core, treated by KUSP1-ester gel, to CO<sub>2</sub> under supercritical conditions of 1200 psi was 4.15 md which is 3% of the initial permeability to brine. The permeability was evaluated after injecting about five pore volumes of CO<sub>2</sub> into the core after gas breakthrough. Brine injection was resumed after injecting about five pore volumes of CO<sub>2</sub> under supercritical conditions. Brine permeabilities were evaluated under different back pressure values. No significant changes were observed. For example, the overall brine permeability at 1200 psi back pressure was 7.64 md before the gel was exposed to supercritical CO<sub>2</sub> and its value changed to 7.9 md (5% of the initial brine permeability) after injecting about five pore volumes of CO<sub>2</sub> under supercritical conditions. Thus, the gel is quite stable under the conditions studied in these experiments.

**SMRF System.** The third gel system developed and studied in this work for application to CO<sub>2</sub> flooding is the SMRF system. This is an organic gel system based on modification of the resorcinol formaldehyde system which was used commercially for a limited period of time and abandoned due to sensitivity to salinity and solution pH.<sup>15</sup> Tolerance for both pH and a broad range of salinity was obtained by sulfomethylating the resorcinol.<sup>16</sup> The resulting gel system tolerates a high salinity environment, temperatures up to about 45°C, and the range of solution pH anticipated in carbonate reservoirs. Gel time is controlled by the composition of the reactants. The injected solution has a low viscosity (1.1 cp at 41°C) and is easily injected into porous rocks. Fig. 4 shows the chemistry of the SMRF and Fig. 5 is a typical viscosity time plot for a SMRF gel system which has a nominal gel time of 27 hr.

Sulfomethylation was carried out by initially reacting sodium sulfite with formaldehyde and subsequently reacting it with resorcinol at 60°C.<sup>16</sup> The composition of the SMR was maintained at a mole ratio of F/S/R=0.75/0.5/1; where, F is formaldehyde, S, is sodium sulfite, and R is resorcinol. The pH of the final solution was adjusted to 9.8 by adding 50% NaOH solution at the initiation of the reaction.

A 40 mL sample of SMRF gelling solution was prepared by adding 20 g brine (10% NaCl to 0.072% CaCl<sub>2</sub>) and 1.032 g of 37% aqueous solution of formaldehyde to 4.6 g of SMR solution. Water was added to the above solution until the total solution was

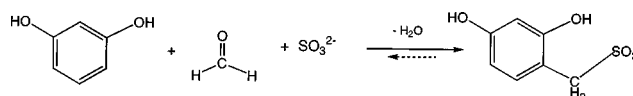


Fig. 4—Chemistry of the SMRF.

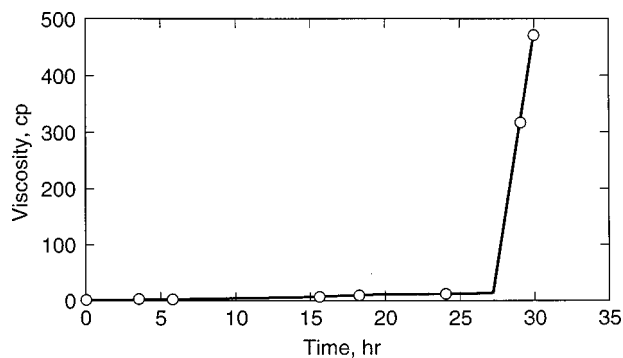


Fig. 5—Viscosity time graph for the gelation of SMRF at 41°C.

40 g. The pH of the solution was adjusted to approximately 7 by adding 20% acetic acid. Thus, the brine concentrations of the gelant were 5% NaCl and 0.035% CaCl<sub>2</sub>.

The core preparation procedure was identical to the KUSP1-ester experiments except the core was saturated with brine having the same composition as the gelling solution (i.e., 5% NaCl and 0.035% CaCl<sub>2</sub>) and the temperature was maintained at 41°C (105.8°F). SMRF solution was injected in place of KUSP1-ester. Around three pore volumes of SMRF solution at pH=7 were injected into the core. A small sample of effluent was collected before injection stopped and kept in a bottle under the same temperature as the core to verify gelation time. After the sample gelled in the bottle, the core was left for another 48 hr to make sure that the gelation process was complete in the core. In-situ gelation was done at atmospheric pressure and the permeability to brine was determined. Because of our earlier experience with the system, a permeability in the range of microdarcies was expected after gelation was complete. Therefore, the injection rate of brine was reduced to 0.007 mL/min in order to remain in the pressure measuring range of the transducers. The core was pressurized to 1200 psi and permeability to brine was determined. Then, CO<sub>2</sub> was injected at a constant rate to determine the permeability of the gelled core to CO<sub>2</sub> and the persistence of the permeability reduction under continued injection.

The initial brine permeabilities measured at two different brine flow rates are given in Table 7. The average permeability of the core was 700 md. Permeabilities after in-situ gelation are presented in the last column of Table 7. The effective permeability to brine after in-situ gelation was 0.049 md, a reduction of over 99% in the initial brine permeability. It is clear from Table 7 that the SMRF gel effectively shuts off the flow of brine and reduces the effective brine permeability of the core to almost zero.

The core was pressurized to 1200 psi and its permeability to brine was determined again. The permeability to brine increased due to pressurizing the core, but still remained below 1 md. For example, the overall permeability increased from 0.049 to 0.9 md.

TABLE 7—PERMEABILITY MODIFICATION FOR SMRF GEL SYSTEM

Porosity=0.23	Brine Permeability (md)		
	Initial (2 mL/min)	Initial (5 mL/min)	After Gelation (0.007 mL/min)
Overall	705	695	0.049
Section 1	531	567	0.060
Section 2	776	744	0.085
Section 3	638	622	0.034
Section 4	716	707	0.042

Nine pore volumes of CO<sub>2</sub> under supercritical conditions, i.e., 1200 psi and 41°C, were injected following brine injection at 1200 psi. Permeability of the core to the CO<sub>2</sub> was determined when the pressure reading became stable. This produced an overall effective permeability to CO<sub>2</sub> of 0.56 md. The injection rate of CO<sub>2</sub> was raised to 0.4 mL/min and 12 more pore volumes of CO<sub>2</sub> were injected. The effective permeability to CO<sub>2</sub> was 0.64 md and did not change significantly. This is a reduction of over 99% of the initial brine permeability. The CO<sub>2</sub> injection rate was reduced to 0.2 mL/min and three more pore volumes of CO<sub>2</sub> were injected. The effective permeability to CO<sub>2</sub> was 0.61 md. Thus, the gel treatment remained intact after 24 pore volumes of supercritical CO<sub>2</sub> were injected. At the end of the CO<sub>2</sub> injection, the overall brine permeability was 1.7 md which is 0.2% of the initial overall brine permeability of 700 md.

Seright<sup>13</sup> studied a similar gel system and reported lower permeability reduction to the gas flow than that to the flow of brine. In contrast, data generated for the SMRF gel show that permeability to supercritical CO<sub>2</sub> was lower than the permeability to brine after several pore volumes of carbon dioxide were injected. This may be due to the improved characteristics of the SMRF gel system.

## Conclusions

The following conclusions apply to the three gel systems studied to control CO<sub>2</sub> mobility in Berea sandstone cores:

(1) Injection of supercritical CO<sub>2</sub> into Berea cores saturated with KUSP1 solution causes in-situ gelation. The amount of permeability reduction was about 85% of the original permeability. The reduction in effective permeability of CO<sub>2</sub> (86%) was very close to that of brine (84%) and the permeability reduction was uniform throughout the length of the cores.

(2) The KUSP1-CO<sub>2</sub> induced gel was stable under prolonged brine injection at supercritical conditions.

(3) KUSP1 was gelled in porous media by hydrolysis of monoethylphthalate ester with a gelation time of over 100 hr at 90°F. Permeabilities to brine and CO<sub>2</sub> were reduced to 95%–97% of the initial brine permeability. The permeability reduction was stable after injecting several pore volumes of CO<sub>2</sub> under supercritical conditions.

(4) The SMRF system effectively shuts off the flow of brine in Berea sandstone and is equally effective in reducing the mobility of the CO<sub>2</sub> under atmospheric and under supercritical conditions. Effective permeability to supercritical CO<sub>2</sub> was less than 1 md for a Berea core with an initial brine permeability of 700 md. The permeability reduction did not deteriorate with the flow of supercritical CO<sub>2</sub> through the treated core.

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