



Permeability Damage Induced by Low and High Molecular Weight Polymer Gels in Porous Media

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Abstract

The current challenge in oil fields is high water cuts and low oil production due to high permeability layers causing water breakthrough. Polymer gels are commonly used to treat wells and reduce water permeability. However, polymers infiltrating oil-saturated zones may reduce oil permeability. Thus, a comprehensive study on polymer behaviour in porous media is imperative. 0.3% low molecular weight gelant caused inlet plugging in 0.258 mD core, while 0.5% in 3.4 mD core did not. Acceptable permeability reduction to hydrocarbon fluid was observed only when the medium-high permeability short core was treated with low molecular weight gelant. However, the reduction of resistance and residual resistance factors along the length of the cores indicates polymer retention, suggesting the need for experimenting with longer cores. Residual resistance factors to 3.15 cp oil provided by the low and high molecular weight gels were not significantly different and equalled to 70-79. Polymer gels can cause severe oil production loss in a radial flow pattern. Additionally, the relatively low difference between residual resistance factors for water and oil disqualifies the tested gels for the treatment of linear flow problems in production wells. The tested gels may find a better application for the treatment of injection wells.

Keywords: Crude oil; Brine; Sandstone; Core; Polymer; Gelant; Gel; Permeability.

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1. Introduction

The water co-produced with hydrocarbons represents a major wastewater source, sometimes reaching volumes up to 30 times larger than the oil output.^[1] In the previous ten years, there has been a substantial rise in oil and natural gas extraction and production, leading to the generation of 20 to 25 billion barrels (3.2 to 4.0 billion m³) of produced water (PW) annually in the United States.^[2] The existence of harmful substances within produced water presents a significant environmental hazard.^[3] Besides that, as the water cut rises, there is a subsequent increase in both development investments and production expenses. This situation compels oil-producing companies to cease operations in wells that fall beyond their economic viability.^[4]

High water cut levels in oil formations arise due to the presence of high permeability layers. Injected water has a

tendency to breakthrough these layers, migrating towards production wells. Consequently, water production rates increase, while oil production experiences a decline.^[5]

Current solutions for this issue involve the use of packers, bridge plugs, and patches. However, these conventional methods prove effective only when the elevated water cut is attributed to casing leaks or flow behind the pipe.^[6] In situations where high water cut levels result from the existence of high permeability channels, it may be necessary to deploy a permeability-reducing agent within the formation. This can be achieved by introducing various chemicals into the reservoir.^[7] In fact, gels can be employed to seal high-permeability channels.^[8] Hydrolyzed polyacrylamide (HPAM) is widely utilized not only for polymer flooding^[9,10] but also to decrease permeability in fractures.^[11] The efficacy of polymer gels in reducing water production is evident in the Arbuckle field, where 300 gel treatments resulted in a reduction of water production by 110 million barrels.^[12] Another instance is the treatment of 274 production wells, which increased oil production in three times and reduced water cut from 98.7 to 87.5%.^[13] Furthermore, a notable example involves the injection of 768 m³ of HPAM gel into a horizontal well. As a result, oil flow rate increased from 0 to 16.3-27.4 tons/day and a moderate decrease in water cut was observed.^[14]

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When polymers are introduced into oil-producing zones, it is crucial for the polymers to possess specific properties that reduce friction, lubricate the core wall, and maintain fluid smoothness and viscosity.^[15] Besides that, polymer hydrogels have a unique property of reducing water permeability to a greater extent than that of oil (disproportional permeability reduction or DPR)^[12,16,17] This is important because the oil/water flow rate of a well is proportional to the oil/water phase permeability. As demonstrated in a radial flow pattern, if the gel penetration distance is 5 ft, it is crucial for RRF in the oil zone to be less than 2. On the other hand, in water zones, RRF must be more than 20 to achieve a substantial reduction in water cut.^[17]

Unfortunately, the magnitude of the favourable DPR effect is unpredictable from one application to another. For example, in some studies RRF to oil much higher than 2 was reported.^[17] A number of experiments have been conducted to study the effect of various parameters, such as gelant composition, pressure gradient, and oil properties, on the magnitude of DPR. For instance, RRF decreased from 69 to 1.3 for oil and from 17,000 to 7.1 for water as the polymer concentration decreased from 4,000 to 2,100 ppm.^[18] In another work using a higher concentration of polymer (7,500 ppm) resulted in a much greater RRFs - 254,762 and 1,279 to brine and oil, respectively.^[19] The authors of^[20] demonstrated that in cores saturated and post-flushed with oils of higher viscosity, lower RRFs to oil were observed. At the same time, it is noteworthy that RRF to oil was not affected by pressure gradient, which varied from 1 to 50 psi/ft.^[18] However, the current work involves applying much higher-pressure gradients.

This study delves into examining the impact of high and low molecular weight (MW) HPAM gels on sandstone core permeability to oil and brine. The findings from this investigation hold relevance for oil production companies operating in mature oil fields experiencing elevated water cut levels.

2. Materials and methods

HPAM with low (~6-7 mln Da) or high (~20 mln Da) MW were used in this study. Polymer samples were obtained from SNF (France). Hydrolysis degree of both polymers was equal to 5%. Fig. 1 shows the viscosities of the polymer solutions measured by Ofite 900 viscometer.

The gels were obtained by adding Cr(III)-acetate to the polymer solutions at the ratio of 10:1 polymer:Cr(III)-acetate. The gel strength obtained by the high MW HPAM is notably higher than that obtained by the low MW HPAM (Fig. 2).

The core flooding experiments were conducted by using epoxy type core holder (Fig. 3a). The core was covered with 5-minute epoxy and inserted into a metallic sleeve. The area between the core and the metal sleeve was filled with a mixture of 24-hour epoxy and clay. After the curing of the casting material, the core underwent machining in a conventional lathe at a machine shop, and pressure ports were created by drilling through holes in the metal sleeve. During

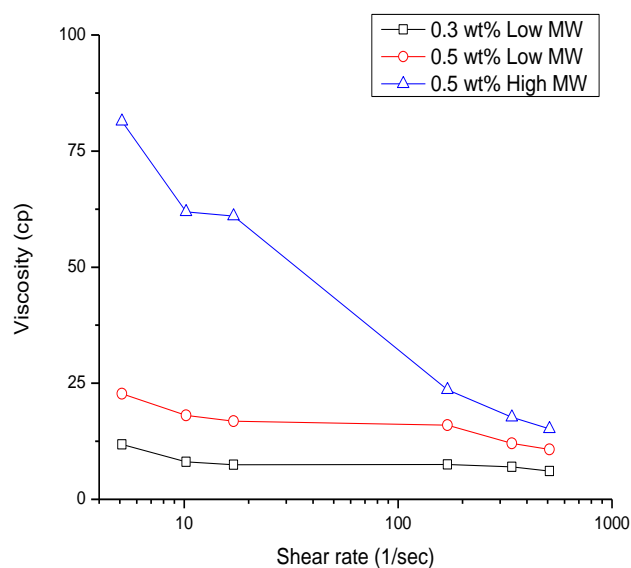


Fig. 1 Viscosity of the polymer solutions, prepared in 75 g/L NaCl brine, measured at 40 °C.

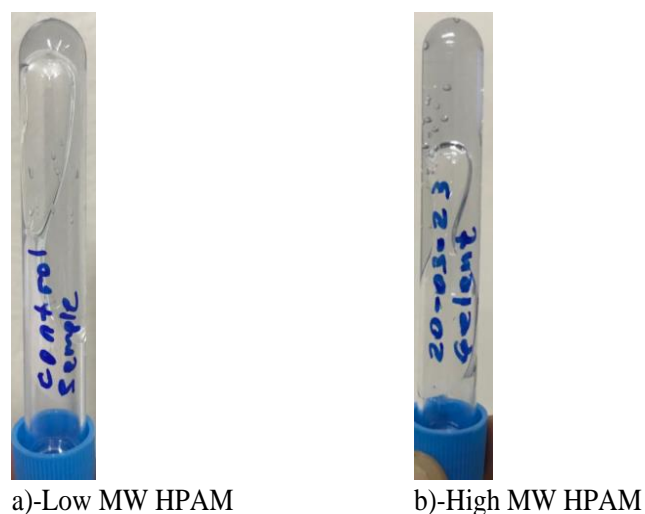


Fig. 2 0.5 wt% HPAM / 0.05 wt% Cr(III)-acetate in 75 g/L NaCl brine aged for 24 hr at 40 °C.

the core flooding experiment fluids were injected at a constant flow rate by piston pump. The permeability change of the cores was assessed by measuring pressure values at the inlet and inside of the cores by using pressure transducers (Fig. 3b).

Figure 4 illustrates a schematic representation of the core flooding set-up. It shows that pressure transducers were linked not only to the injection tube but also to the core sample, enabling the measurement of permeability changes within the sample. In experiments involving 8-cm-length cores, two pressure transducers were employed to measure the pressure gradient within the sample. However, in experiments with shorter cores, only two transducers were utilized, positioned to measure pressure at the inlet and the core center. This setup allowed the calculation of pressure gradients for various core sections by dividing the pressure drop across a particular segment by its length.

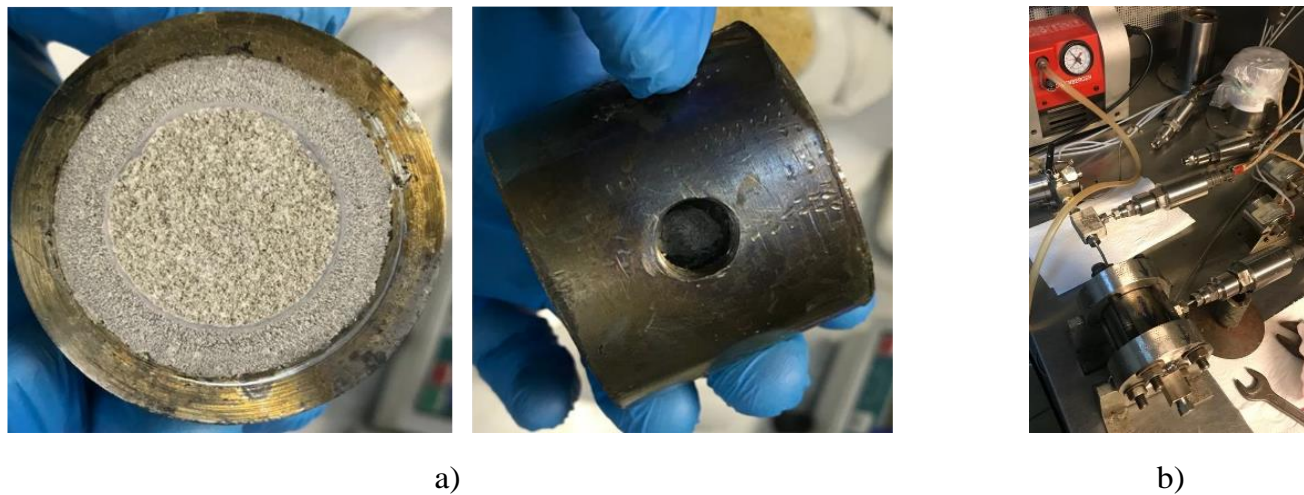


Fig. 3 Epoxy core holder used in this study.

Table 1. Lists the details of the core flooding experiments.

#	Polymer type	Rock type	Core length (cm)	Pore volume, cm ³	Permeability to brine at 100% water saturation, mD	Polymer gel recipe	Crude oil/ Kerosene	PVs of polymer solution or gelant injected	Flow rate, cm ³ /min	Aging time after treating the core with polymer solution/gelant, days	Temperature, °C	
1	Low MW HPAM	1,720.64 m sandstone reservoir core	4.5	7.6	2.5	0.5 % HPAM / 75 g/L NaCl	Kerosene	7	0.1	1	25	
2		Sandstone from Sarybulak field 1,636-1,643.1 m	3.5	5.44	0.295	0.3 % HPAM / 0.03 % Cr(III)-acetate / 75 g/L NaCl	Kerosene	1	0.02	2	25	
3		1,280.25 m sandstone reservoir core	4.6	12	665	0.5 % HPAM / 0.05 % chromium acetate / 75 g/L NaCl	Kerosene	5	5	1	40	
4		Artificially made sandstone core	8	17.36	1,980 (measured for the central part of the core)	0.5 % HPAM / 0.05 % chromium acetate / 75 g/L NaCl	3.15 cp Crude oil	5	5	1	40	
5		High MW HPAM	1,280.49 m	4.6	11.94	135.8	0.5 % HPAM / 0.05 % chromium acetate / 75 g/L NaCl	Kerosene	5	5	1	40
6			Artificially made sandstone core	8	17.36	2,460 (measured for the central part of the core)	0.5 % HPAM / 0.05 % chromium acetate / 75 g/L NaCl	3.15 cp Crude oil	5	5	1	40

Table 1 provides the details of the core flooding experiments. As is seen the length of the samples varied from 3 to 8 cm, whereas permeability of the samples varied from 0.295 mD to 2,460 mD. Throughout most experiments, kerosene was utilized to replicate crude oil conditions. Nevertheless, real low-viscosity crude oil was employed in experiments involving relatively long cores (8 cm in length).

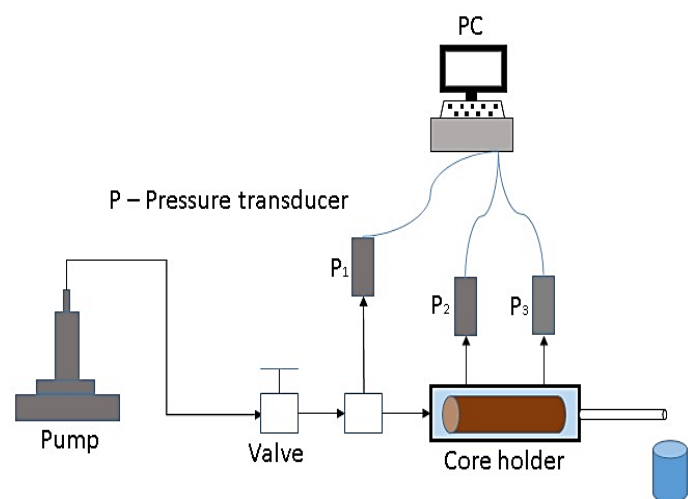


Fig. 4 Schematic illustration of the core flooding set-up. The distance between P_2 and P_3 is 4 cm.

In general, the following step by step procedure was followed to conduct the core flooding tests:

1. Vacuuming the core.
2. Saturating the core with 75 g/L NaCl brine. Measuring pore volume and permeability to brine.
3. Brine displacement with kerosene/oil. Measuring permeability to oil at residual water saturation.
4. Kerosene/oil displacement with brine. Measuring permeability to brine at residual oil saturation.
5. Injecting polymer solution (experiment # 1) or gelant.
6. Aging the core to allow the gelation of the polymer.
7. Repeat brine and kerosene/oil injection to measure permeability reduction.

Specifically outlined in the text, certain tests involved injecting alkali solutions, prepared in distilled water, into the cores to restore oil permeability. Following the injection of alkali solutions, repeated injections of kerosene/oil were conducted to assess the recovery of permeability. Experiments #3-6 (Table 1) were carried out at 40 °C. This temperature was determined based on bottle tests with polymer gels, indicating it as the minimum threshold necessary for nearly complete gelation of the polymer solution within a 24-hour timeframe.

Table 2 presents the properties of the kerosene and crude oil measured by Stabinger SVM 3000 viscometer.

Table 2. Properties of kerosene and crude oil.

Fluid	Density, g/cm ³	Viscosity, cp	Temperature, °C
Kerosene	0.78	1.09	25
	0.77	0.89	40
Crude oil	0.82	3.15	40

It is worth noting that nearly all the tests conducted in this study utilized a 0.5% polymer/0.05% crosslinker formulation. This specific composition was selected based on its recurrent application in various works for the purpose of permeability

reduction in cores,^[21] and our laboratory observations confirmed its ability to produce moderately strong gels.

3. Results and discussion

This section delves into the outcomes of core flooding experiments, which are crucial for understanding permeability reduction to oil and water. Through simulated reservoir conditions in a controlled laboratory environment, the impact of polymer gels on the permeability of core samples was quantitatively assess. The findings not only elucidate changes in permeability but also provide valuable insights for optimizing treatment strategies.

3.1 Permeability reduction after low MW polymer solution injection into the low permeability core

Figure 5 demonstrates dp/dl required to inject 0.5 wt% low MW polymer solution into a 4.5-cm-length sandstone core. Due to the non-uniform permeability, dp/dl in the first half is 1.46 times lower than that registered for the second half. Despite the high dp/dl, no progressive plugging of the core inlet was detected. However, the reduction in RF from 51 to 35 along the length of the core (Fig. 5) indicates that some polymer molecules propagate at a slow rate and are not expected to penetrate deep.

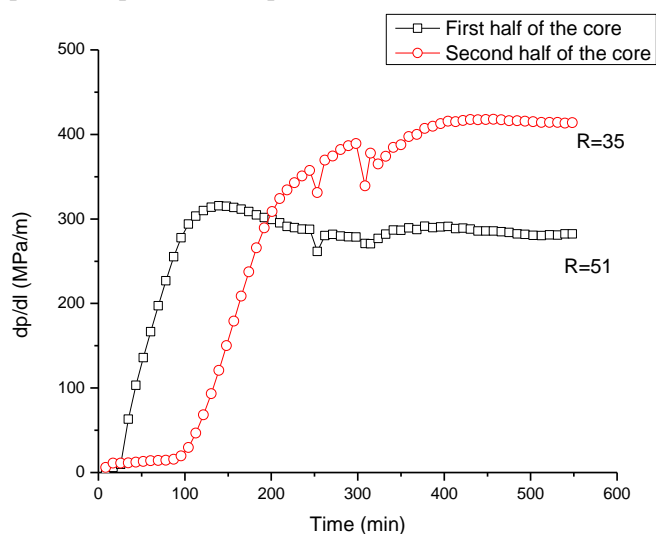


Fig. 5 Pressure gradients required to inject 0.5 wt% low MW polymer solution at 0.1 cm³/min and 25 °C into 4.5-cm-length sandstone core having permeability of 3.4 mD and 2 mD for the first and second halves, respectively, if measured at 100% water saturation.

Around 7 PVs of brine injection were required for dp/dl to stabilize at 79 and 116 MPa/m for the first and second halves, respectively (Fig. 6). With regards to kerosene injection after the polymer, dp/dl stabilized at 9 and 24 MPa/m for the first and second halves, respectively, after around 11 PVs were injected.

Table 3 indicates greater permeability reduction for brine and kerosene in the first half of the core, despite its higher initial permeability (3.4 mD vs. 2 mD) compared to the second

Table 3. The results of polymer solution injection into 4.5-cm-length sandstone core.

Brine/Kerosene	dp/dl for the first half, MPa/m		dp/dl for the second half, MPa/m		dp/dl for the total length, MPa/m		RRF		
	Before	After	Before	After	Before	After	First half	Second half	Total core
Brine	5.5	79	11.8	116	8.68	97.4	14.36	9.8	11.2
Kerosene	0.93	9	2.75	24	1.84	16.46	9.67	8.72	8.9

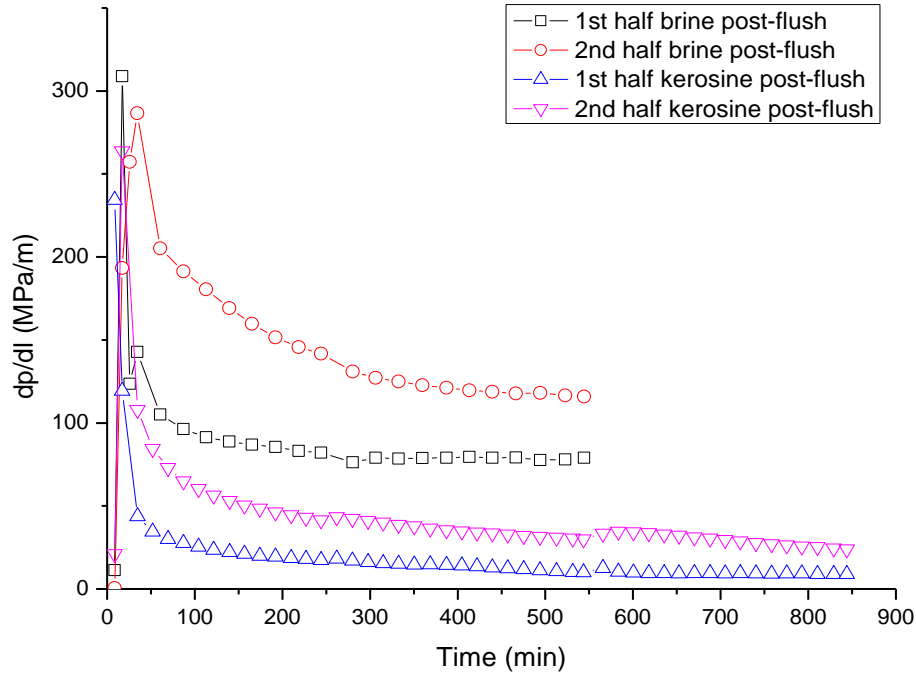


Fig. 6 Pressure gradients during brine or kerosene post-flush at 0.1 cm³/min and 25 °C in 4.5-cm-length sandstone core having permeability of 3.4 and 2 mD for the first and second halves, respectively, if measured at 100% water saturation.

half. This suggests polymer retention in the first half of the core. For both halves of the core brine permeability was reduced to a higher degree than that of kerosene. However, kerosene RRFs are still too high and cannot be allowed for radial flow, whereas brine RRFs are not enough to substantially reduce water cuts.^[17]

3.2 Permeability reduction after the low MW polymer gelant injection into the low permeability core

Figure 7 demonstrates that the dp/dl required for gelant injection into the first part of the core, which has a permeability of 0.258 mD, progressively increases and reaches 127 MPa/m. In contrast, dp/dl for the second part of the core stabilized at 14.85 MPa/m, which is similar to the values that would have been observed if water had been injected into the model at the same flow rate (0.02 cm³/min). This indicates that the inlet part of the core is gradually being plugged by the retained polymer. The progressive pressure increase is less likely to be associated with viscosity increase due to gelation, as gelation at this temperature (25 °C) takes much longer than 350 minutes (Fig. 8). Fig. 9 shows the formation of a filter cake on the face of the core from the

injection direction.

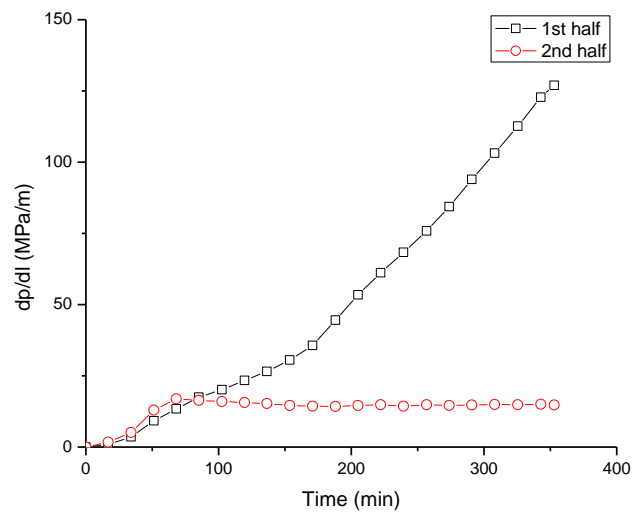


Fig. 7 Pressure gradients required to inject 0.3 wt% low MW polymer / 0.03 wt% Cr(III)-acetate gelant at 0.02 cm³/min and 25 °C into 3.5-cm-length sandstone core having permeability of 0.258 and 0.347 mD for the first and second halves, respectively, if measured at 100% water saturation.

After the injection of gelant the model was aged for 2 days. The brine post-flush showed that permeability to brine decreased in almost 10 times, if calculated for the first half of the core. Kerosene post-flush was conducted three days after the addition of the crosslinker to the polymer solution. The permeability of kerosene decreased from 0.32 to 0.0022 mD (a reduction of 145 times) for the first part of the core. Permeability to kerosene for the second part of the core, unlike that to brine, was reduced from 0.35 to 0.124 mD. This can be attributed to a longer aging time, which allowed for the gelation of a limited number of polymer molecules that were able to penetrate deeper into the core (Table 4).

Table 4 Comparison between RRFs to brine and kerosene after gelant injection into 3.5-cm-length sandstone core.

*-higher RRFs for kerosene are explained by longer aging time.

Brine/Kerosene	Aging time, days	RRF		
		First half	Second half	Total core
Brine	2	10	1	5.1
Kerosene	3	145*	2.8	75

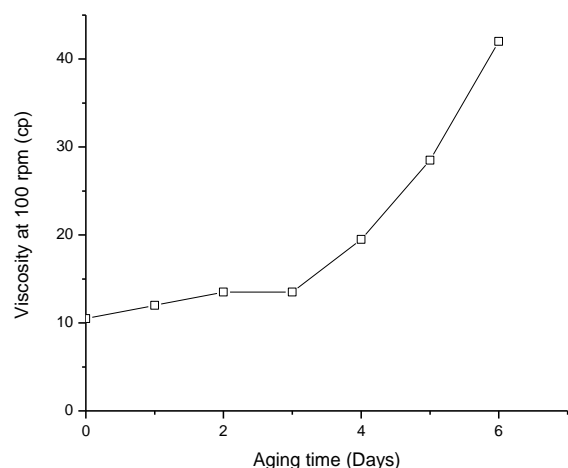


Fig. 8 The viscosity of 0.3 wt% low MW polymer / 0.03 wt% Cr(III)-acetate gelant versus time. All measurements were taken at 100 rpm and room temperature by using an electric viscometer model RC-35D.

It was concluded that at 25 °C, permeability reduction increased with aging time due to the slow gelation process at this temperature (Fig. 8). To address this, the subsequent experiments were conducted at higher temperatures and using cores with higher permeability.

3.3 Permeability reduction by low MW polymer gelant in high permeability 4.6-cm-length core

0.5 wt% low MW polymer / 0.05 wt% Cr(III)-acetate gelant was injected into a 4.6-cm-length core with permeability values of 832 mD and 555 mD for the first and second halves, respectively, if measured at 100 % water saturation. The final RFs of 31 and 18 for the first and second halves of the core, respectively, were observed (Fig. 10). Therefore, in the high permeability core, RF decreases along the core length, similar to what was observed in the low permeability core (Fig. 5).

As can be seen from Table 5, RRF for brine depends on the direction of brine injection. If brine is injected in the same direction as the gelant was injected, the RRF for the first half is 9.5 times higher than that for the second half (Table 5, line 6). This can be explained by the retention or screening out of polymer at the injection point.

The injection of kerosene from the side of 555 mD (production direction) resulted in an increase in RRF from 1.11 to 10 along the length of the core. This can be explained by the presence of a larger number of polymer molecules in the first half of the core (831 mD side).

Steps #7 and #8 are taken into consideration to analyse DPR effect provided by the gel. No positive DPR effect can be seen for the first part of the core, which is most likely due to the severe polymer retention. However, for the second part of the core, the RRFs to brine and kerosene were equal to 9.6 and 1.1, respectively.

In real conditions, the formation of a gel filter cake and polymer retention are also expected to take place. However, in this experiment, the negative effect of these phenomena is limited to around 2.3 cm or less.

Steps #10 and #12 (Table 5) show that aging the core for more than 24 hr at 40 °C does not increase the RRF to brine.

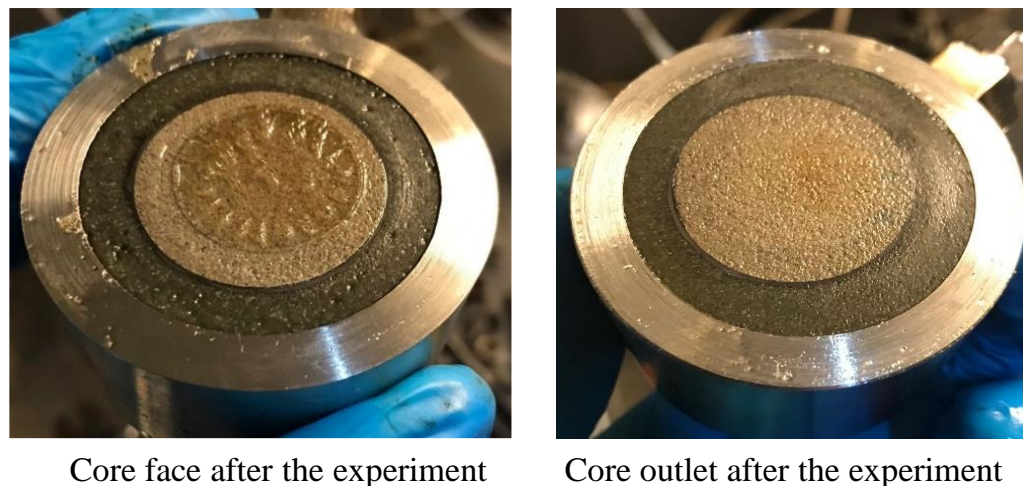


Fig. 9 Core faces from inlet and outlet sides.

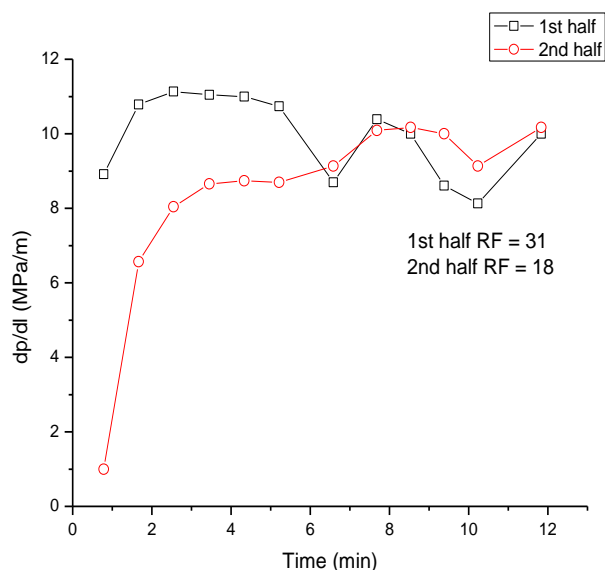


Fig. 10 0.5 wt% low MW polymer / 0.05 wt% Cr(III)-acetate gelant injection into 4.6-cm-length core having permeability of 832 mD and 555 mD for the first and the second halves, respectively. Flow rate – 5 cm³/min, temperature – 40 °C.

As shown in Table 5, the injection of NaOH into the core resulted in only partial permeability recovery to brine. However, the decrease in RRF to kerosene from 1.11 to 0.56 indicates an increase in permeability to kerosene above the baseline value. This can be explained by the reduction of residual kerosene saturation during the NaOH injection due to the change in interfacial tension.

3.4 Permeability reduction by low MW polymer gelant in high permeability 8-cm-length core

Figure 11 illustrates dp/dl versus time during the injection of gelant into an 8-cm-length core. The core is divided into three sections: the first 2 cm - 2.36 D, the next 4 cm - 1.98 D, and the final 2 cm - 0.79 D, all measured at 100 % water saturation. It is evident that dp/dl increases along the length of the core, and the final RF value registered for the first section is lower than those registered for the other parts of the core. This difference in RF values can be attributed to the uneven distribution of permeability to the water phase in the core at residual oil saturation (Table 6, step 3).

Table 5. Results of brine and kerosene injection before and after treating the core with low MW gelant.

#	Phase - volume injected	dp/dl, MPa/m		RF		RRF	
		1st - 831 mD	2nd - 555 mD	1st - 831 mD	2nd - 555 mD	1st - 831 mD	2nd - 555 mD
1	Kerosene – 60 cm ³	0.13	0.39	-	-	-	-
2	Brine – 60 cm ³	0.33	0.54	-	-	-	-
3	Gelant – 60 cm ³	10.00	10.17	→30.67	18.72	-	-
4	Shut-in 24 hr						
5	Brine in production direction* – 60 cm ³	1.74	2.87	-	-	5.33	5.28←
6	Brine in injection direction** – 60 cm ³	11.43	2.00	-	-	→ 35.07	3.68
7	Brine in production direction – 60 cm ³	3.04	5.22	-	-	9.33	9.60←
8	Kerosene in production direction – 90 cm ³	1.30	0.43	-	-	10.00	1.11←
9	Shut-in over night						
10	Brine in production direction – 60 cm ³	3.04	4.39	-	-	9.33	8.08←
11	Shut-in 24 hr						
12	Brine in production direction – 60 cm ³	2.96	4.87	-	-	9.07	8.96←
13	1 M NaOH – 90 cm ³	1.87	1.17	-	-	-	-
14	Shut-in 24 hr						
15	Brine in production direction – 90 cm ³	1.61	2.78	-	-	4.93	5.12←
16	Kerosene in production direction – 120 cm ³	0.43	0.22	-	-	3.33	0.56←

*-injected from the side of 555 mD.

**-injected from the side of 831 mD.

Pore volume – 12 cm³.

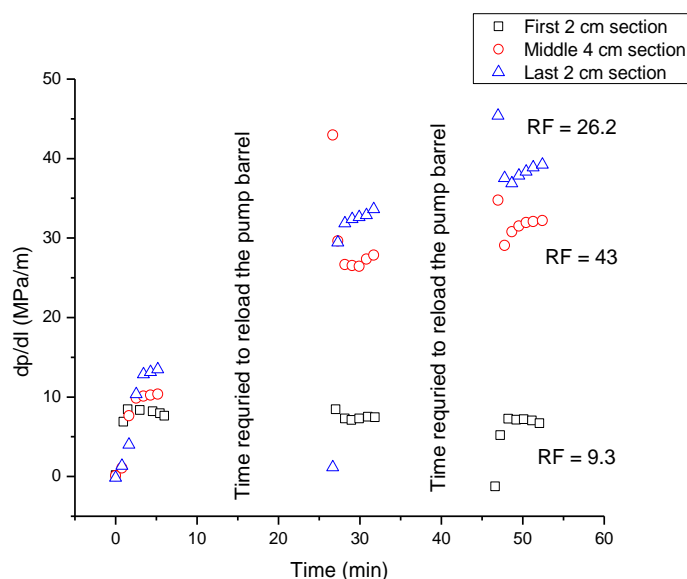


Fig. 11 0.5 wt% low MW polymer / 0.05 wt% Cr(III)-acetate gelant injection into 8-cm-length core. Flow rate – 5 cm³/min, temperature – 40 °C.

Table 6 demonstrates a decrease in RRF to brine when injected in the same direction as the gelant along the core length. The highest value (314.75) was observed for the first 2 cm of the core (step 7). This could be attributed to the retention of polymer molecules at the core face, impacting brine permeability.

The repeated injection of brine in the production direction resulted in RRF values of 57, 151, and 39 for the first, second, and third parts of the core, respectively. Similarly, the injection of oil in the production direction exhibited RRF values of 27.4, 79, and 20.2 for the first, second, and third parts of the core, respectively. It is evident that in steps 8 and 9, the highest RRF values were recorded for the centre (4-cm-length section) of the core. The lowest RRFs were registered for the third 2-cm-length part of the core, while the medium RRFs were observed for the first 2-cm-length part of the core. This can be explained through the following reasoning:

1-The lowest RRFs for the third section of the core are due to significant polymer retention in the first two sections (6 cm). A large number of polymer molecules were retained before reaching beyond 6 cm from the inlet.

2-The highest RRFs for the 4-cm-length central part of the core may be attributed to the highest polymer retention in this section, as indicated by the highest RF value observed (Fig. 11).

3-The medium value of RRFs registered for the first 2-cm-length section can be attributed to the brine permeability of this section, which was measured at residual oil saturation and found to be 92 % higher than that registered for the central 4-cm-length part of the core (Table 6, step 3). This higher brine permeability to some degree results in lower polymer retention in this part of the core compared to the central 4-cm-length section.

Table 6. Results of brine and oil injection before and after treating the 8-cm-length core with low MW gelant.

#	Phase	dp/dl MPa/m			RF/RRF		
		1st 2 cm	2nd 4 cm	3rd 2 cm	1st 2 cm	2nd 4 cm	3rd 2 cm
		2.36 D	1.98 D	0.79 D	2.36 D	1.98 D	0.79 D
1	Oil – 120 cm ³	1.00	0.50	2.00 ←	-	-	-
2	Brine in production direction* - 180 cm ³	1.10	0.78	1.05 ←	-	-	-
3	Brine in injection direction** - 30 cm ³	→ 0.4 (192 mD)	0.75 (100 mD)	1.50 (50 mD)	-	-	-
4	Gelant – 90 cm ³	6.50	32.13	39.25	→16.25	42.83	26.17
5	Shut-in 24 hr						
6	Brine in production direction – 180 cm ³	64.55	151.30	42.85	58.68	195.23	40.81←
7	Brine in injection direction – 180 cm ³	125.90	116.28	34.55	→314.75	155.03	23.03
8	Brine in production direction – 180 cm ³	62.65	116.98	40.75	56.95	150.94	38.81←
9	Oil – 180 cm ³	27.40	39.55	40.50	27.40	79.10	20.25←
10	1 M NaOH injection direction – 130 cm ³	96.90	81.70	27.70	-	-	-
11	Shut-in 24 hr						
12	Brine in production direction – 180 cm ³	27.75	43.80	50.35	25.23	56.52	47.95←
13	Oil – 180 cm ³	16.80	26.98	53.00	16.80	53.95	26.50←

*production direction 0.79 Darcy → 1.98 Darcy → 2.36 Darcy.

**injection direction 2.36 Darcy → 1.98 Darcy → 0.79 Darcy.

Despite RRFs to oil being 1.9-2 times lower for all parts of the core compared to those for brine (Table 6, steps 8 and 9), the obtained values (20-80) are still unacceptably high. Additionally, Table 6 shows that the injection of 1 M NaOH solution did not succeed in reducing RRF values to an acceptable level (around 2) for oil.

3.5. Permeability reduction by using high MW polymer gelant in 4.6-cm-length core

High MW gelant was injected into 4.6-cm-length core having permeability of 92 and 259 mD for the first and the second halves, respectively. Fig. 12 shows that dp/dl and RF were sufficiently higher for the first half of the core. This is explained by its lower permeability.

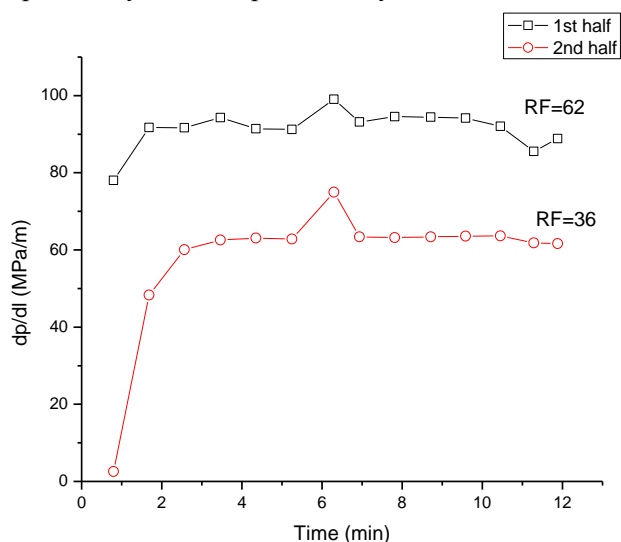


Fig. 12 0.5 wt% high MW polymer / 0.05 wt% Cr(III)-acetate gelant injection into 4.6-cm-length core having permeability of 92 and 259 mD for the first and the second halves, respectively. Flow rate – 5 cm³/min, temperature – 40 °C.

As can be seen from Table 7, when post-flush was injected in the production or injection directions, high RRFs were observed for the parts of the core that faced the injection point – 92 mD for the injection direction and 259 mD for the production direction. Fig. 13 shows that at the beginning of the post-flush, very high pressure values were observed, followed by a sudden decrease in pressure accompanied by gel displacement from the core holder. Additionally, the pressure values registered at the centre of the core were 9-18 times lower than the inlet pressure values. Fig. 14 provides some explanation for the obtained results.

Figure 14 suggests that a gel polymer filter cake formed on the faces of the core from both sides. The assumption of a filter cake on the face of the 92 mD part of the core is supported by the high (42) and low (3.28) RRFs registered for the 92 mD and 259 mD parts of the core, respectively, when the post-flush was injected in the injection direction from 92 mD towards 259 mD (Table 7, step 7). Similarly, the assumption of a filter cake on the face of the 259 mD part of the core is supported by the high (39) and low (2.8) RRFs registered for the 259 mD and 92 mD parts of the core, respectively, when the post-flush was injected in the production direction from 259 mD towards 92 mD (Table 7, step 8).

This demonstration proves that the high MW polymer gelant primarily reduced the permeability of the core by forming a filter cake on its face.

To assess the changes in water and kerosene permeability within the porous media, the observed RRFs for the 92 mD part of the core during brine and kerosene post-flush in the production direction (from 259 mD towards 92 mD) can be used (highlighted in bold in Table 7). As seen, the permeability to kerosene and water reduced by a factor of 4.33 and 2.79, respectively. Treatment with 1 M NaHCO₃ solution led to a reduction in the RRF to kerosene from 4.33 to 1.83.

Table 7. Results of brine and kerosene injection before and after treating the 4.6-cm-length core with high MW gelant.

#	Phase	dp/dl, Mpa/m		RF/RRF	
		1st - 92 mD	2nd - 259 mD	1st - 92 mD	2nd - 259 mD
1	Kerosene in production direction – 60 cm ³	0.78	0.13←	-	-
2	Brine in production direction – 60 cm ³	2.30	1.39←	-	-
3	Brine in injection direction – 60 cm ³	→1.43	1.74	-	-
4	Gelant – 60 cm ³	88.87	61.65	→61.94	35.45
5	Shut-in 24 hr				
6	Brine in production direction – 60 cm ³	4.83	85.87	2.09	61.72←
7	Brine in injection direction – 60 cm ³	60.35	5.70	→42.06	3.28
8	Brine in production direction – 60 cm ³	6.43	54.43	2.79	39.13←
9	Kerosene in production direction – 90 cm ³	3.39	8.83	4.33	67.67←
10	Shut-in for 1 week				
11	1 M NaHCO ₃ – 90 cm ³	35.87	6.57	-	-
12	Shut-in 24 hr				
13	Brine in production direction – 90 cm ³	5.26	48.22	2.28	34.66←
14	Kerosene in production direction – 120 cm ³	1.43	5.57	1.83	42.67←

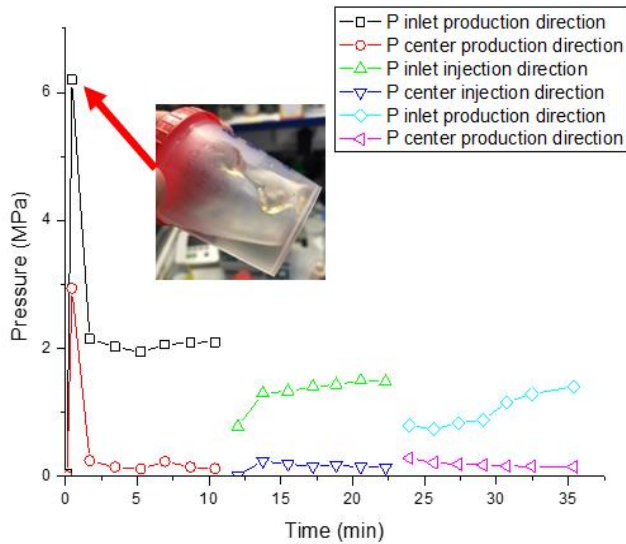


Fig. 13 Post-flush with brine in different directions after treating 4.6-cm-length core with high MW gelant.

3.6. Permeability reduction by using high MW polymer gelant in 8-cm-length core

In the next experiment, a high MW gelant was injected into an 8-cm-length core having permeability of the central 4-cm-length section equal to 2,460 mD (Fig. 15). The much lower dp/dl values registered for the first 2-cm-length section of the core can be explained by the higher permeability of that part of the core to the gelant. However, the main focus of this test

is on the central part of the core. The increase of pressure during the third cycle of gelant injection is related to its crosslinking over time.

In general, the decreasing RRF to brine when injected in the same direction as the gelant (step 7, Table 8) indicates the presence of sufficient polymer retention within the first 6 cm of the core.

As shown in Table 8, during the brine post-flush in different directions (6-8), the RRFs observed at the inlet (injection point) were consistently higher than those observed at the outlet. This can be attributed to the inlet and outlet effects, which are visually represented in Fig. 14. By using a longer core compared to the previous experiment (Table 7), it was possible to place the measurement points further away from the sample ends.

The comparison of Tables 6 and 8 reveals that RRFs to oil provided by low and high MW gelants are not significantly different. Despite both gelants resulting in lower RRFs to oil compared to water, the permeability damage to the oil phase remained unacceptable for the radial flow pattern, even after treating the cores with NaOH.

Another important observation is that RRFs to water were not considerably greater than those to oil (Tables 6 and 8, lines 8 and 9). For example, the low MW polymer gelant provided RRFs of 151 for water and 79 for oil, respectively, for the central part of the core. This renders the application of these gelants ineffective even for the treatment of linear flow problems in a production well. To address this issue, RRF to

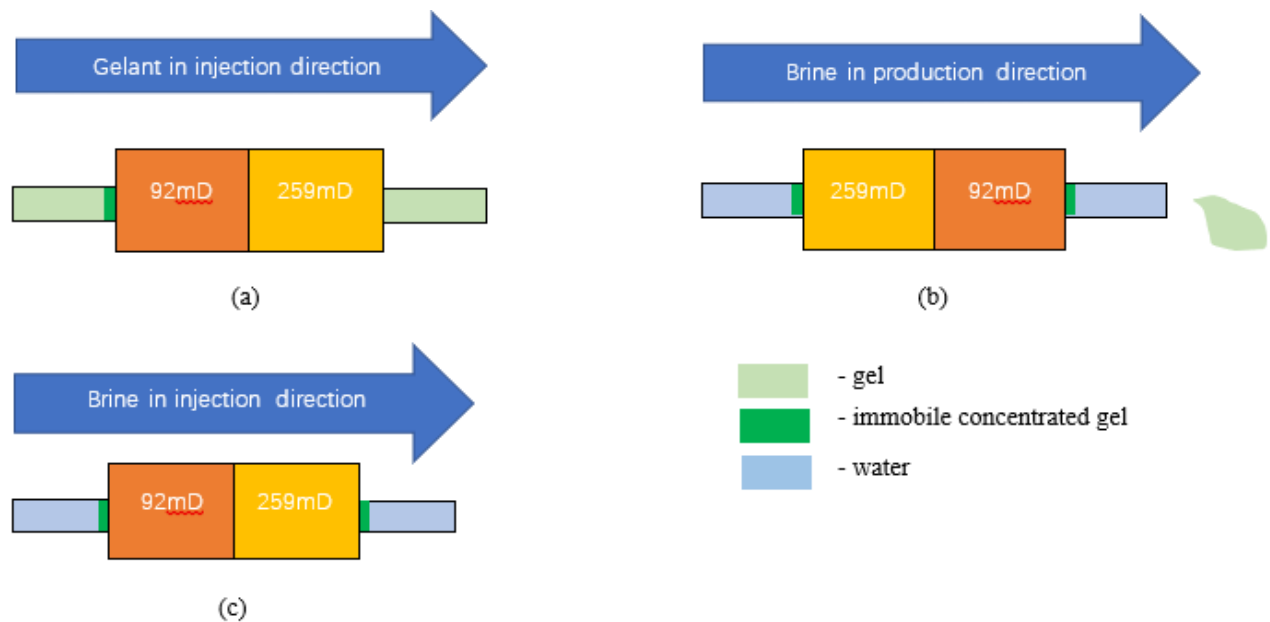


Fig. 14 Visual explanation of the results presented by Table 7 and Fig. 13. a) During the gelant injection into the core holder the gel accumulated in the core holder injection and production lines. Polymer filter cake formed on 92 mD face side. b) Brine injection in the production direction resulted in the expulsion of the gel from the line located at the 92 mD part of the core outlet. This is evident from the sudden increase in pressure at the beginning of the post-flush (Fig. 13) and the presence of gel in the effluent. Additionally, during this step, the post-flush may have pushed the gel from the 259 mD side into the rock face. The high pressure dehydrated the gel and formed a gel filter cake on the 259 mD face side. c) Effluent samples showed that the gel in the production line was not displaced during the brine injection in the injection direction. This is most likely because the gel on the 259 mD side face became immobile due to dehydration.

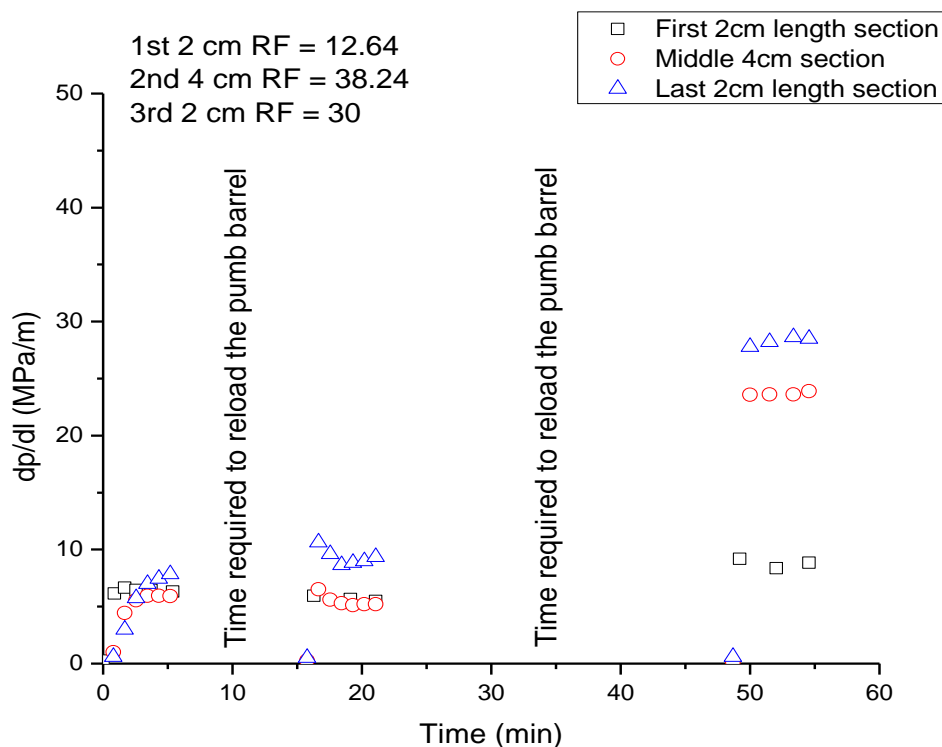


Fig. 15 0.5 wt% high MW polymer / 0.05 wt% Cr(III)-acetate gelant injection into 8-cm-length core. Flow rate – 5 cm³/min, temperature – 40 °C.

Table 8. Results of brine and oil injection before and after treating 8-cm-length core with high MW gelant.

#	Phase	dp/dl, MPa/m			RF/RRF		
		1st 2cm	2nd 4cm	3rd 2cm	1st 2cm	2nd 4cm	3rd 2cm
1	Oil – 120 cm ³	1.45	0.35←	2.55	-	-	-
2	Brine in production direction – 180 cm ³	1.30	0.63←	0.95	-	-	-
3	Brine in injection direction – 30 cm ³	→0.70	0.63	0.95	-	-	-
4	Gelant – 90 cm ³	8.85	23.90	28.50	→12.64	38.24	30.00
5	Shut-in 24 hr						
6	Brine in production direction – 180 cm ³	81.30	128.65	91.40	62.54	205.84	96.21←
7	Brine in injection direction – 180 cm ³	109.70	89.73	63.85	→156.71	143.56	67.21
8	Brine in production direction – 180 cm ³	84.45	80.03	82.50	64.96	128.04	86.84←
9	Oil – 180 cm ³	29.95	24.58	32.90	20.66	70.21	12.90←
10	1 M NaOH injection direction – 120 cm ³	102.75	68.73	76.80	-	-	-
11	Shut-in 24 hr						
12	Brine in production direction – 180 cm ³	34.55	44.55	131.55	26.58	71.28	138.47←
13	Oil – 180 cm ³	18.05	19.40	28.15	12.45	55.43	11.04←

water should be significantly higher than that to oil ($RRF_w = 1,000$; $RRF_o = 10$).^[17] Of note is that these results are significantly different from the results obtained by other authors. For example, in laboratory experiments conducted by

Liang *et al.* (1992),^[22] the treatment of Berea sand cores with bulk gels, specifically HPAM/Cr⁺³, led to a reduction in water permeability by a factor of 2–100 and oil permeability by a factor of just 2–15. Seright *et al.* (2004) demonstrated that,

irrespective of rock wettability, HPAM/Cr³⁺ gels resulted in a water permeability reduction of 80–90 times more than that of oil.^[23] Willhite *et al.* (2002) reported a range of 100 to 1000 for this value in their study.^[24] This indicates that the process of permeability reduction to both oil and water using polymer gels is an intricate phenomenon, necessitating further investigations to establish a correlation between experimental conditions and the ultimate outcomes.

Nevertheless, the injection of polymer gels into production wells has the potential to substantially reduce water cut without significantly impacting oil flow rates. For instance, consider a fractured production well where fractures contribute significantly to water influx. Effectively placing gel within these fractures, maintaining a partially formed state that ensures acceptable injectivity while restricting its penetration into the oil-saturated matrix, is a crucial element for a successful production well treatment.^[25] Achieving this balance can be attained by customizing the concentrations of the polymer and crosslinker.

4. Conclusion

1. The core flooding results show that even in cores with permeability higher than 1 Darcy some polymer molecules propagate at a very slow rate and are not expected to penetrate deep into the reservoir. Experiments with cores longer than 8 cm are needed in order to determine the profile of RRF change versus length away from the wellbore.
2. The injection of 0.3 wt% low MW polymer gelant into a core with permeability of 0.258 mD for the first half caused progressive inlet plugging. In contrast, the injection of 0.5 wt% low MW polymer solution into a core with permeability of 3.4 mD for the first half did not cause a notable inlet plugging. This is a valuable observation that can be used to formulate screening criteria for the choice of polymer-based methods in low permeability rocks.
3. Experimenting with low or high MW gelants in high permeability 8-cm-length cores demonstrated that RRFs to a real crude oil, measured for the central 4-cm-length part of the core, were not significantly different and equalled to 70-79.
4. Although both gelants resulted in lower RRFs to oil compared to water, the permeability damage to the oil phase remained unacceptable for radial flow even after treating the cores with NaOH.
5. The fact that the difference between RRF values for water and oil is not significant disqualifies these gelants for the treatment of linear flow problems in production wells. However, these gelants can find better applications in conformance control operations in injection wells.

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Conflict of Interest

There is no conflict of interest.

Supporting Information

Not applicable.

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