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Research Article

Evaluation of High-Temperature Recrosslinkable Preformed Particle Gel for Fluid Loss Control during Drilling

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Lost circulation has become one of the biggest challenges that drilling engineering faces during drilling, especially at high-temperature reservoirs. The consequences of lost circulation can vary from an economic aspect as well as a safety aspect. In this paper, the capability of a novel high-temperature recrosslinkable preformed particle gel (HT-RPPG) is evaluated to see whether it can be better used to control severe and total losses. The HT-RPPG is injected in the form of dispersed swellable gel particles, but it can self-crosslink to form a strong bulk gel after being placed in target zones. The sealing pressure and plugging efficiency of the HT-RPPG were evaluated utilizing a core flooding test. Various impacting factors were investigated, including the swelling ratios, fracture widths, and bentonite concentrations. Results indicated that HT-RPPG is an excellent material that can be used to control the severe loss of drilling fluids in fractured reservoirs with temperatures up to 130°C. The recrosslinked RPPG could withstand pressure up to 1,077 psi/ft for fractures up to 2 mm, and permeability was reduced more than 10^7 times.

1. Introduction

Lost circulation is a phenomenon that occurs while drilling in fractured formations. This could begin with seepage loss lower than 10 bbl/hr and could increase until none returns to the surface [1]. The lost circulation problems are not limited to one area. These problems can be encountered at any depth when the pressure applied to the formation exceeds the formation breakdown pressure. The outcomes of these issues can result in a significant increase in operational costs since it will greatly increase the nonproductive time. Based on the literature, the annual estimated cost worldwide of lost circulation is 1–4 billion dollars [2, 3]. According to the US Department of Energy, approximately 10%–20% of the total expenses of drilling at high-temperature and high-pressure wells are due to lost circulation issues [4]. Moreover, these issues can result in well control issues that can lead to loss of the well or blowouts. Lost circulation treatment is classified into two categories, based on the period at which they were introduced: preventive treatment, also known as wellbore strengthening and corrective treatment [5]. Corrective treatments are usually added to the drilling fluid after the lost circulation has occurred [6]. Usually, conventional lost circulation materials (LCMs) are used to cure seepage and partial losses, as their function is to plug permeable formations or minor fractures to prevent losses. Depending on their appearance or physical properties, LCMs are classified into fibrous, flaky, or granular materials or a blend of the three. Alsaba et al. [7] reclassified LCMs into seven categories, including granular, flaky, fibrous, a mixture of LCMs, acid-soluble/water-soluble, high-fluid loss LCMs squeeze, swellable/hydratable LCM combinations, and nanoparticles.

The performance of LCMs has been evaluated utilizing two methods: a high-pressure high-temperature (HPHT) filter press or particle plugging apparatus using slotted discs to measure the volume of the fluid loss and core flooding experiments to measure sealing efficiency [5, 8]. Hinkebein et al. [9] studied different conventional LCMs at different temperatures. They found that the LCM could seal fractures of 1.52 mm at room temperature, but it failed at high temperatures (204.5°C). Lécolier et al. [10] evaluated a nanocomposite gel as a LCM for high-temperature 120°C reservoirs.

They claim that the nanocomposite gel effectively reduced the permeability of high-permeable formations. The gelation time at high-temperature reservoirs is one of the challenges. Gamage et al. [11] investigated an LCM pill that consists of a water-soluble polymer and a metal-based crosslinker for high-temperature applications up to 176°C. The minimum gelling time ranged from one to 5 hr, depending on the temperature. Kulkarni et al. [12] studied LCM pills for high-temperature applications. They used various particulate components with different carrier fluids and studied them at 121 and 162.7°C. They found that the plugging performance is highly dependent on carrier fluids at high temperatures. Ettehadi and Altun [13] investigated the stability of using calcium carbonate in sepiolite drilling fluid for high-temperature applications. They found that using sepiolite-based mud with calcium carbonate plugged the pores at temperatures up to 193°C. Mansour et al. [14] studied a shape memory polymer (SMP) that was activated at the temperature of 70°C, and they found that it can plug fractures of 2.54 mm. Deng et al. [15] studied a crosslinked polyacrylamide gel. They used a microencapsulated initiator to control the gelation time. The temperature limitation for this gel was 90°C. Lah et al. [16] studied eggshells at 49°C as LCM utilizing an HPHT filter press. Their results indicated that the coarse size of eggshells obtained the best performance for plugging applications. Jiang et al. [17] studied crosslinked polyacrylamide gel for lost circulation at high temperatures, 80–150°C. They mentioned that it could hold 1,000 psi at 150°C when using a fracture width of 3.00 mm. Xie et al. [18] evaluated crosslinked polyacrylamide gel (HMP gel) to cure lost circulations in a high-temperature environment utilizing a customized bridging material apparatus. They found that this gel withstood a pressure of 600 psi at 140°C when a fracture width of 3.0 mm was used. Cui et al. [19] studied an SMP for high-temperature applications. They found that when it was activated at a temperature of 95°C, it withstood a pressure of 800.6 psi. Wang et al. [20] studied a supramolecular gel (GP-A) at high temperature, and they found that the GP-A gel has good thermal stability under 200°C, and it could be used in fractured formations to reduce fluid losses. Wang et al. [21] conducted studies to investigate polymer gel plugging efficiency, and they found that plugging can reach up to 154.2 kpa (22.36 psi) when the fracture width is 1.2 mm. Sonmez et al. [22] studied calcium carbonate as a lost circulation additive at 148°C. The highest plugging performance was obtained when adding 50 lb/bbl of $CaCO_3$. Bai et al. [23] studied a polymer gel for high-temperature applications up to 160°C. Their results showed a sealing pressure of 613.5 psi for a fracture width of 1.00 mm and 601.9 psi for a fracture width of 3.00 mm.

The lost circulation has been addressed by many researchers, yet it is still a major challenge, especially in high-temperature reservoirs [24]. In our previous research [25], a low-temperature recrosslinkable preformed particle gel (RPPG) was evaluated and proved its success at plugging fractures at low temperatures, up to 80°C. This paper will introduce the high-temperature RPPG (HT-RPPG) to be evaluated as an LCM for high-temperature applications, 130°C.

2. Experimental Materials Description

2.1. HT-RPPG. The HT-RPPG used in this study is yellow granular dry particles consisting of crosslinked poly (acrylamide-*co*-*N*-vinyl-2-pyrrolidone) [26]. Swelling RPPG with predetermined swelling ratios was prepared by gradually adding the HT-RPPG particles to the brine to avoid flocculation. The particle size range was 1–4 mm. More details regarding the swelling kinetics, recrosslinking behavior, rheology, and thermal stability can be found in the previous publication [26].

2.2. Brine. A solution composed of 2% potassium chloride (KCl) was utilized in this study.

2.3. Drilling Fluid. Water-based mud with 7% bentonite was used in this study. The drilling fluid was prepared using a Hamilton Beach mixer, mixed for at least 10 min, and left overnight for bentonite prehydration to ensure that the bentonite was fully swelled [27].

2.4. Fractured Cement Cores. Several fracture widths were prepared, including 1.5, 2.0, and 3.0 mm. The preparation of these cores was conducted by initially fixing a steel bar to the center of the cylinder mold to initiate the fracture within the cement core. Then, the cement paste was poured into the mold, and before the cement was fully set, the steel bar was removed to create a fracture.

2.5. HAAKE Rheometer. The elastic modulus (G') and viscous modulus (G'') of each sample were measured using a HAAKE rheometer. The spindle used in this process was P35Ti L, and the gap was set at 1 mm. The test was selected as the oscillation time-dependent experiments model with a fixed frequency of 1 Hz and a controlled strain of 1% to obtain elastic modulus (G') and viscous modulus (G''). G' was used to evaluate the strength of the gel.

2.6. Scanning Electron Microscopy (SEM). The microstructure of the HT-RPPG was characterized with HELIOS NANO LAB 600. A recrosslinked bulky gel was used for the test. The sample was prepared by freeze–drying in a nonhydrated state and coated with a thin gold layer before scanning.

3. Experimental Setup Description

The experimental setup design is shown in Figure 1. The setup is composed of two accumulators for sample and mud injection, a core holder to retain the fractured core, a pressure transducer to record the pressure response during the trial, and a syringe pump.

4. Experimental Procedure Description

The evaluation of sealing pressure, which is the highest pressure the material can withstand before it fails, and the residual resistance factor (Frr) were obtained through core flooding experiments conducted using fractured cement cores. Initially, the fractured core was placed inside the core holder, and confining pressure was applied. Then, the first accumulator was

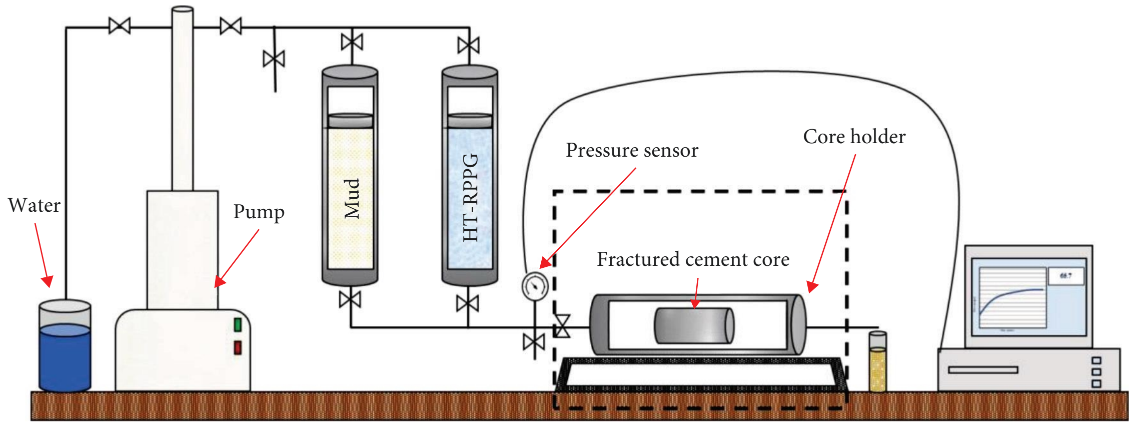


Figure 1: Core flooding setup design.

used to inject the pretreatment drilling fluid injection into the fractured core to simulate the actual scenario. After that, the second accumulator was used to inject the sample into the fractured core, utilizing a flow rate of 1 cc/min until the pressure was stabilized. The gel particles are hydrated to the designed swelling ratio before injection. Next, the setup was disassembled to collect the core. Then, the fractured core was isolated and placed in a high-temperature vessel and placed at 130°C for 24 hr to allow the HT-RPPG to recrosslink. Subsequently, the core was placed again inside the core holder, and postinjection using drilling fluid was injected through until a breakthrough was obtained.

After obtaining the sealing pressure, a postinjection was performed using 2% KCl brine. The objective of this postinjection was to measure the Frr, which indicates the effectiveness of HT-RPPG in reducing the permeability. Various flow rates were used, including 0.10, 0.25, 0.50, 1.00, and 2.00 cc/min. The permeability was calculated using the Darcy equation:

$$k = \frac{q\mu L}{A\Delta P}, \tag{1}$$

where K is permeability (md), Q is flow rate (cc/s), μ is viscosity (cp), L is core length (cm), A is cross-section area (cm^2), and ΔP is differential pressure (atm).

Then, Frr was calculated using the following equation:

$$\mathrm{Frr} = \frac{K_{\mathrm{before}}}{K_{\mathrm{after}}}, \tag{2}$$

where K_{before} is the permeability before HT-RPPG the treatment, and K_{after} is the permeability after the treatment.

5. Results and Discussion

5.1. Effect of Swelling Ratio on Gel Strength. In this research, different HT-RPPG swelling ratios were used, including 5, 8, 10, 16, and 20. The swelling ratios were prepared using the following equation:

Table 1: HT-RPPG samples.

#	RPPG ratio	Brine
Sample 1	1 : 20	
Sample 2	1 : 16	
Sample 3	1 : 10	2% KCl
Sample 4	1 : 8	
Sample 5	1 : 5	

$$W_{\mathrm{brine}} = (\mathrm{SR} - 1) \times Wt_{\mathrm{RPPG}}, \tag{3}$$

where SR is the swelling ratio, W_{brine} is the mass of water in grams, and Wt_{RPPG} is the RPPG mass in grams.

Table 1 shows the samples used in this study. Figure 2 shows the HT-RPPG dry particles (a), the initial slurry (dry HT-RPPG particles immersed in 2% KCl brine) (b), and fully swelled particles (c) separately. The sample was mixed using a magnetic stirrer at low speed. The duration of mixing depends on the swelling ratios; it can range from 30 to 120 min.

Figure 3 shows the G' and G'' for samples 1, 2, 3, 4, and 5 after absorbing all the free water. The results showed that decreasing the swelling ratio will result in a more robust material since the G' was 78.01 Pa for a swelling ratio of 20 and 2452.15 Pa for a swelling ratio of 5. Figure 4 illustrates pictures of sample 3 at different times at 130°C. After the brine was absorbed, the sample was placed in a high-temperature oven at 130°C, and pictures were taken every 30 min for visualization purposes. From these pictures, the particles of the HT-RPPG started to recrosslink from each other after approximately an hour at 130°C. The particles gain more strength as they stay longer in the oven. Figure 5 illustrates an image for sample 3. The SEM image shows the pore structure for sample 3 after fully recrosslinked. The pores were strongly interconnected and bonded with the thick walls in between.

5.2. Core Flooding Experiments Results. The evaluation of the plugging efficiency for the HT-RPPG was conducted utilizing a series of experiments using different samples and

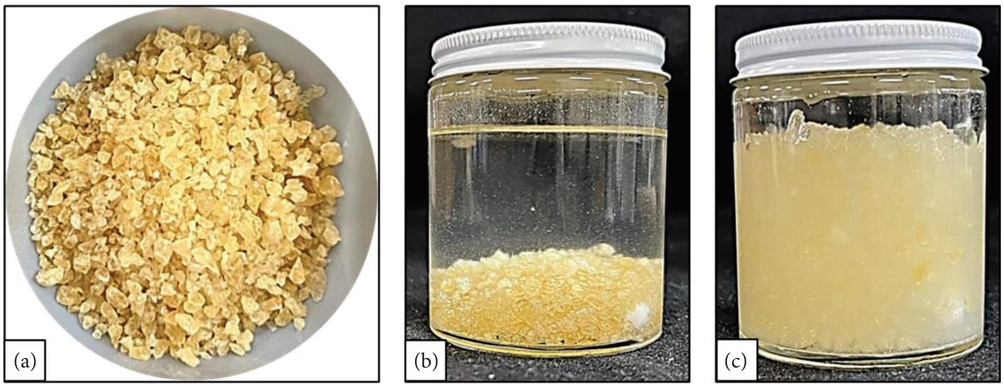


Figure 2: (a) HT-RPPG dry particles, (b) initial slurry, and (c) fully swelled (maximum swelling ratio).

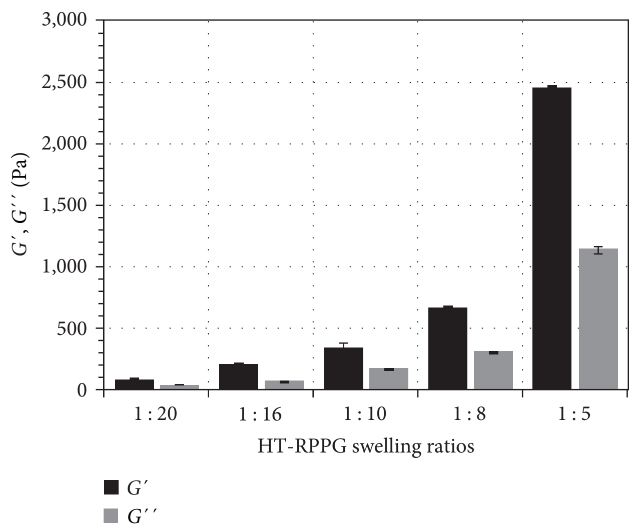


Figure 3: The G' and G'' for different samples.

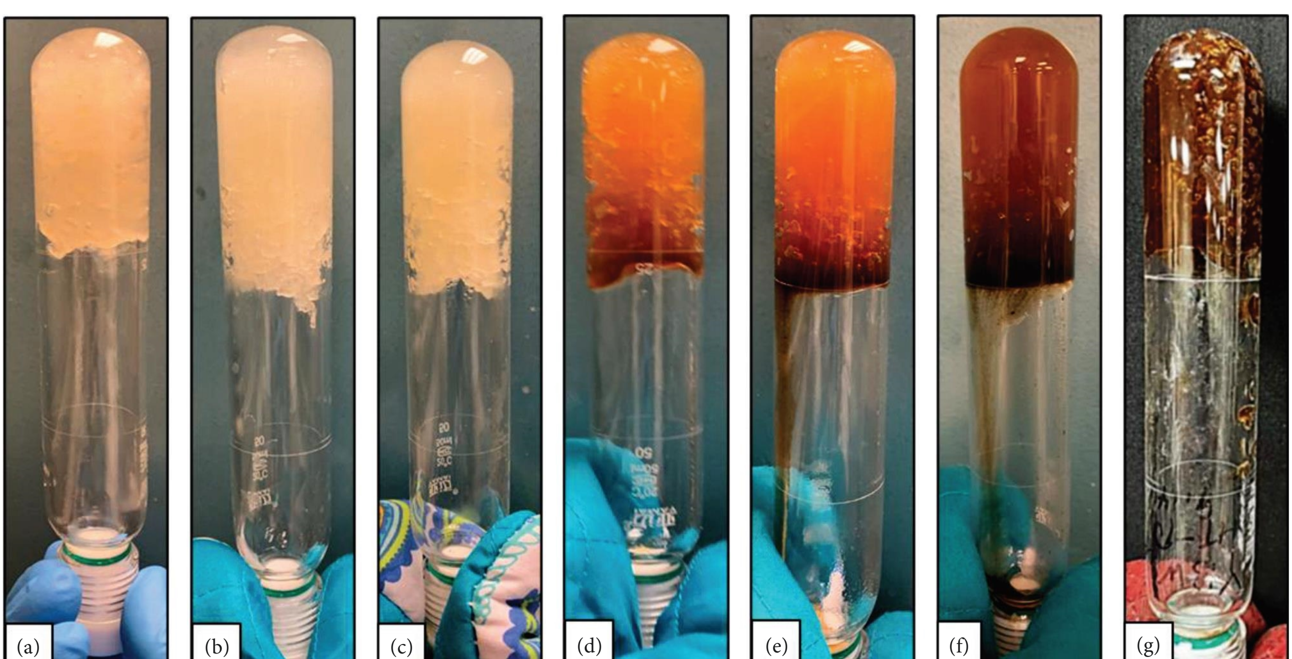
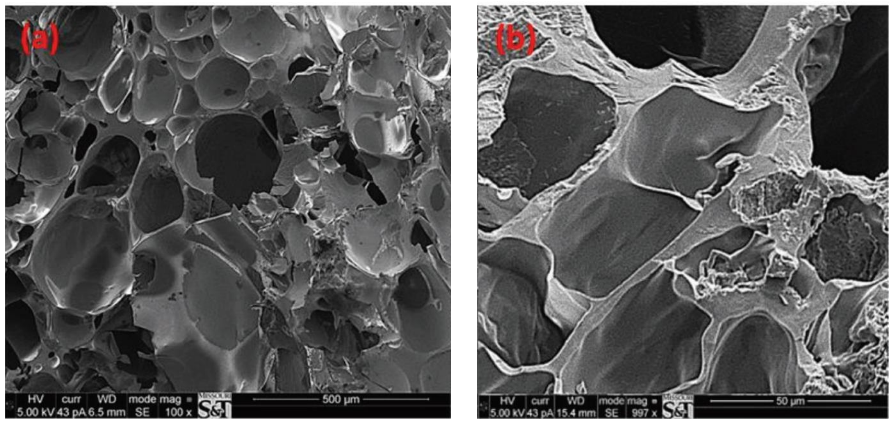


Figure 4: Pictures of sample 3 after aging for different times at 130 °C: (a) after absorbed all the brine; (b) after 30 min; (c) after 1 hr; (d) after 6 hr; (e) after 1 day; (f) after 3 days; (g) after 1 month.



(a) (b)

Figure 5: SEM image for sample 3 after fully recrosslinked (a) without drilling fluid and (b) with 7% of drilling fluid.

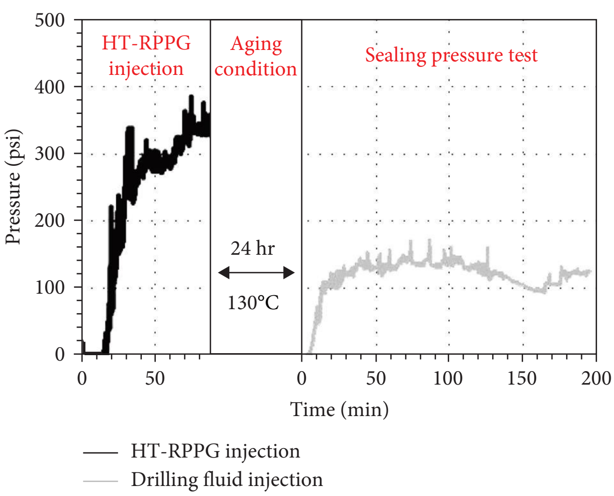


Figure 6: Core flooding results.

different fracture widths. In this section, details regarding the sample 3 outcomes, including the sealing pressure along with the Frr determination, will be discussed.

Figure 6 shows the core flooding test results for sample 3 utilizing a fracture width of 2.0 mm. As the graph illustrates, the HT-RPPG injection stabilized at around 350 psi/ft after approximately 60 min. The entire HT-RPPG injection process lasted about 80 min. Then, the core was aged at 130°C for 24 hr to facilitate the recrosslinking process. Subsequently, a sealing pressure test was performed, where the aged sample was subjected to the drilling fluid at 1.0 cc/min injection rate. The results showed that the HT-RPPG at 10 swelling ratio (SR10) could resist a pressure up to 126.66 psi/ft.

Figure 7 shows the fractured cement core after the experiment. These pictures illustrate that even after the breakthrough has occurred, the gel is still inside the fracture, which reduced the volume of the fracture, leading to a significant reduction in permeability. Figure 8 shows the inside part of the fracture after the experiment. The fractured cement core was broken into two identical pieces to observe the surface of the fracture after the experiment. The HT-RPPG has clearly remained with a significant amount within the fracture which contributed enormously to decreasing the permeability within the fracture. Based on the obtained results, the permeability reduction was more than 99.99%. The permeability was decreased from 3.4E + 08 to 6.82 md after treatment. Figure 9 shows the Frr results for sample 3 at different flow rates. The Frr drops from 10E + 09 to 10E + 07 as the injection rate increases from 0.1 to 2 mL/min. Therefore, the recrosslinked HT-RPPG is a potent gel product that can efficiently decrease the fracture permeability by 10E + 07 times, even under a relatively high flow rate.

5.3. Fracture Width Effect. As it is known, the lost circulation mainly occurs in fractured formations; while drilling through these formations, most or all of the drilling fluid will invade these fractures and result in severe or total loss. The fracture sizes play an essential role in this process; thus, investigating the HT-RPPG plugging efficiency at different fracture widths is a must as the fracture width and size in unknown in real situations, so it is necessary to have a robust product that can handle different fractures. Three different fracture widths were prepared for this study, including 1.50, 2.00, and 3.00 mm. The formulation used in these experiments was composed of brine and HT-RPPG with a swelling ratio of 10. Figure 10 shows sealing pressure results for different fracture widths. As expected, the results indicated that minuscule fractures would have the highest sealing pressure, but the exciting part is that the sealing pressure increased more than eight times when a fracture width of 1.50 was used compared to 2.00 mm. This indicates that the HT-RPPG is more likely to permanently close minor fractures. On the other hand, the sealing pressure was 88.29 psi/ft when a fracture width of 3.00 mm was used. Figure 11 shows the Frr results for different fracture widths at different flow rates. The permeability results showed a reduction of more than 99.99% after the treatment. Bai et al. [23] claimed that their gel withstood a pressure of 623.3 psi/ft when a fracture of 1.00 mm was used at 160°C while our HT-RPPG could withstand the pressure of 1,077 psi/ft when a fracture width of 1.50 mm was used.

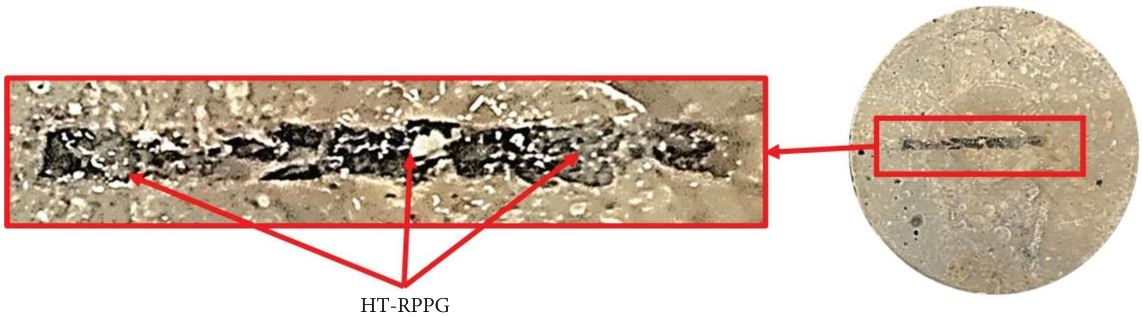


FIGURE 7: Fractured cement after the experiment.

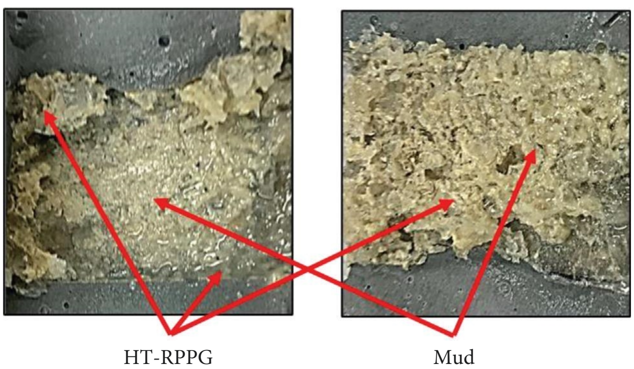


FIGURE 8: Inside image of the fracture for the fractured cement core after the experiment.

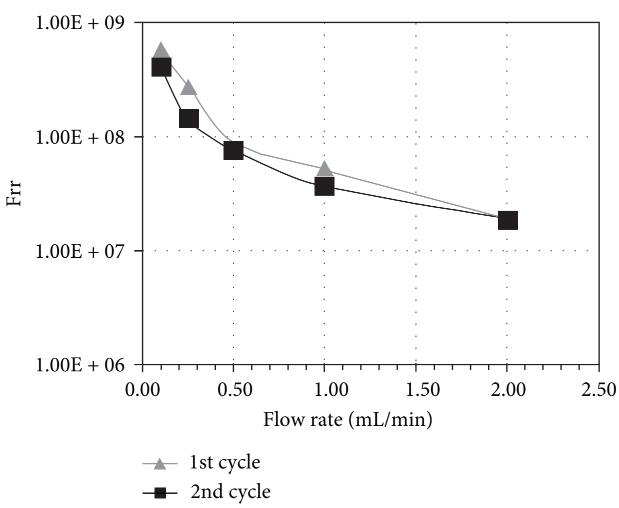


FIGURE 9: Frr results for sample 3.

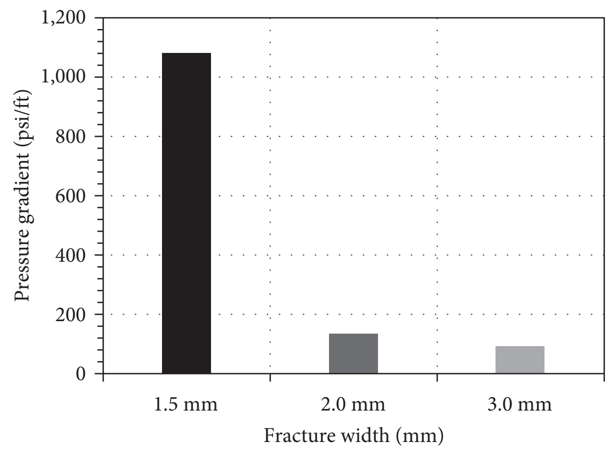


FIGURE 10: Sealing pressure at different fracture widths.

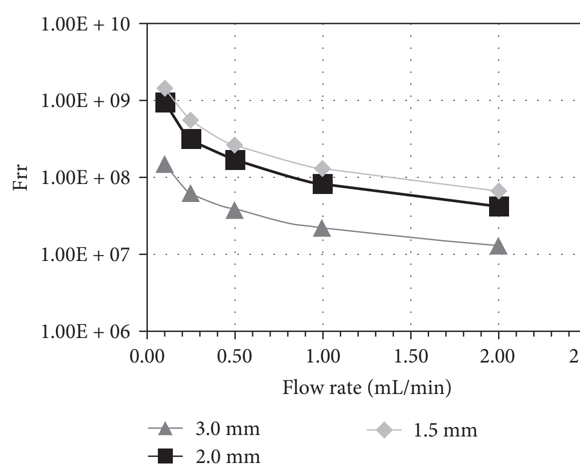


FIGURE 11: Frr results for different fracture widths.

5.4. Swelling Ratio Effect. The strength of the HT-RPPG mainly depends on its concentrations within the brine. Adding more HT-RPPG particles into the solution will undoubtedly increase its strength. However, this could affect the injection processes. Different ratios were prepared to evaluate the sealing pressure, including 1 : 5, 1 : 8, 1 : 10, and 1 : 16. The experiments were conducted using a 2.00 mm fracture, and the waiting time was 24 hr at 130°C. For an HT-RPPG swelling ratio of 5, the sample could not be injected into the fracture since after its particles absorbed the brine, they aggregated, as shown in Figure 12. The particles did not recrosslink but bonded, which prevented them from entering the fracture. However, this issue could be avoided when smaller particles are used.

The obtained results illustrate that reducing swelling ratios will facilitate gaining higher sealing pressure. Figure 13 shows the results of sealing pressure for 1 : 8, 1 : 10, and 1 : 16 swelling ratios. The sealing pressure was 44.42 psi/ft for the

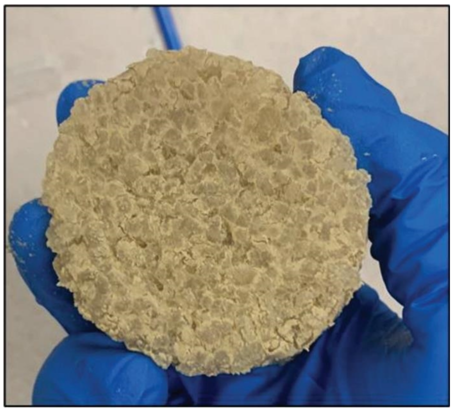


Figure 12: HT-RPPG sample after injection failure.

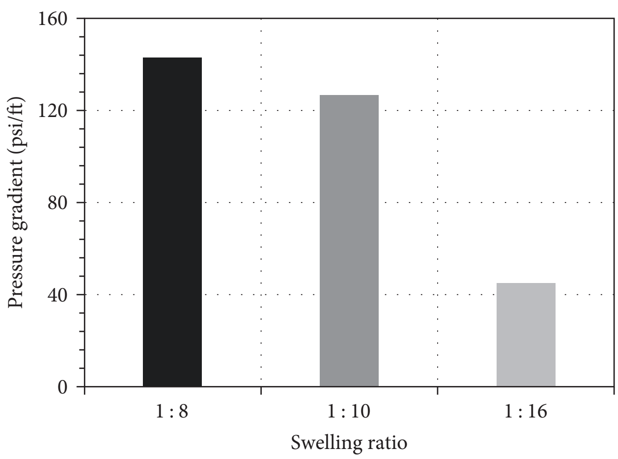


Figure 13: Sealing pressure at different swelling ratios.

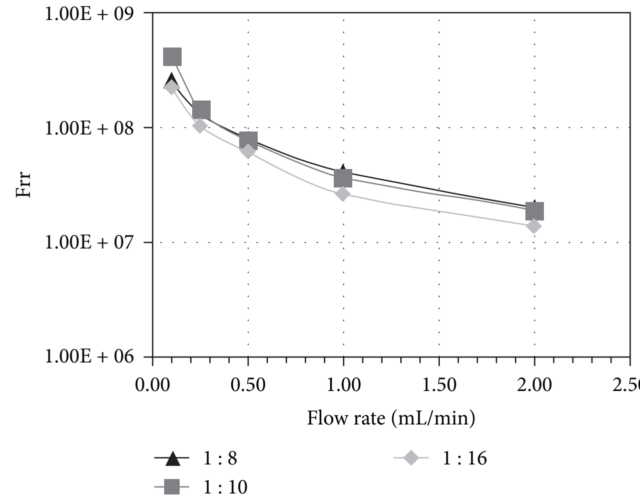


Figure 14: Frr results for different HT-RPPG swelling ratios.

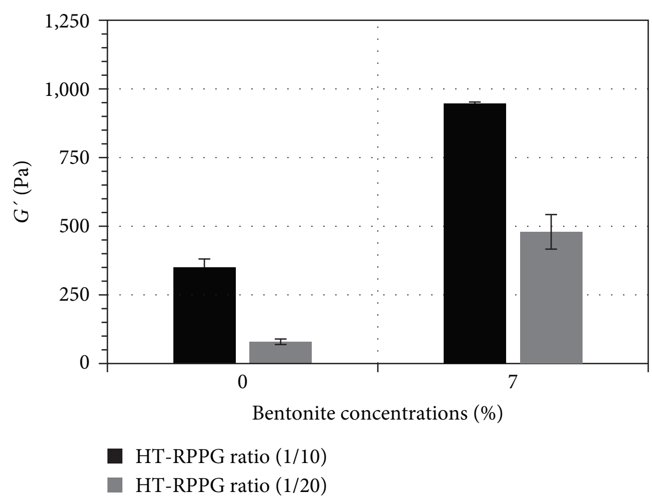


Figure 15: The G' results of HT-RPPG in the presence and absence of drilling fluid.

1 : 16 swelling ratio and increased to 142.63 when the 1 : 8 swelling ratio was used. This coincides with what we mentioned earlier that increasing the concentration of the HT-RPPG forms a more durable material that can withstand higher pressure before it cracks. The permeability results showed an enormous decrease as it became 6.59, 6.82, and 9.38 md for swelling ratios 8, 10, and 16, respectively, after treatment. Figure 14 shows the Frr results for each swelling ratio at different flow rates.

5.5. Drilling Fluid Effect. The effect of adding drilling fluid to the mixture on the material strength was evaluated. Four samples were prepared, including two samples with swelling ratios of 20 and two samples with swelling ratios of 10 in the presence and absence of drilling fluid. Figure 15 shows the G' results for all the samples. As illustrated by Figure 15, the G' significantly increased drilling fluid in both swelling ratios when it was introduced, as it increased from 78.01 to 478.83 Pa for swelling ratios of 20 and from 341.87 to 944.38 Pa for swelling ratios of 10. This indicates that bentonite enhanced the strength of the material and formed a more robust material.

Moreover, core flooding experiments were conducted to investigate the impact of drilling fluid on the plugging efficiency of the HT-RPPG. The first sample was composed of brine and HT-RPPG with a swelling ratio of 10. The second sample was prepared by adding the HT-RPPG particles with a swelling ratio of 10 to the drilling fluid, which was prepared using 7% bentonite. The experiments were performed utilizing a 3.00 mm fracture width and waiting time of 24 hr at 130°C. Figure 16 shows the sealing pressure for both samples. The results showed that mixing the HT-RPPG with drilling fluid increased its ability to withstand higher pressure. The sealing pressure increased to 238.61 psi/ft when drilling fluid was introduced compared to 88.29 psi/ft when no bentonite was used. Figure 17 illustrates the Frr results for different bentonite concentrations using different flow rates. The permeability for each sample was reduced by more than 10^7 times as it became 25.56 and 18.33 md for 0% and 7% bentonite, respectively, after the treatment. Figure 5(b) shows the SEM image for the sample

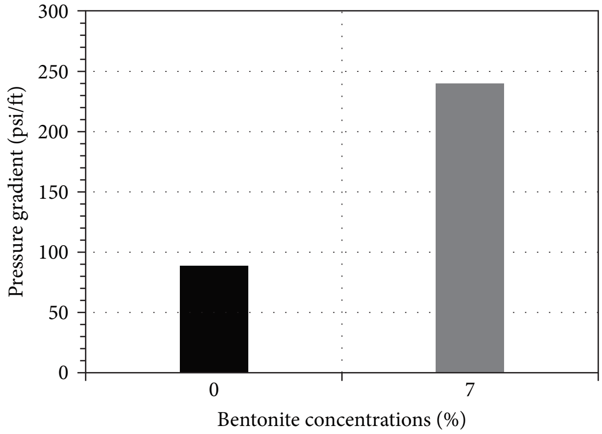


Figure 16: Sealing pressure results for different bentonite concentrations.

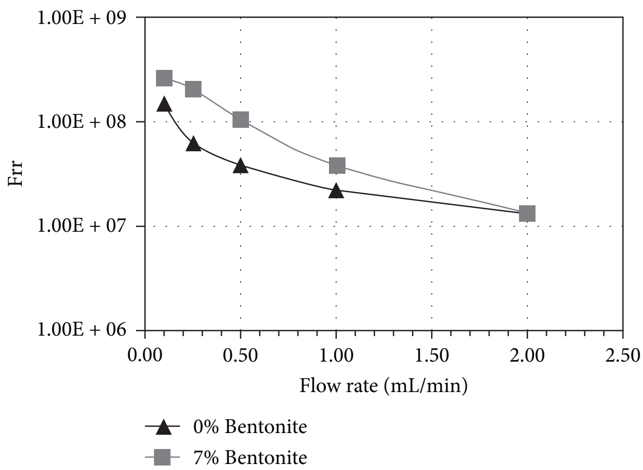


Figure 17: Frr results for different bentonite concentrations.

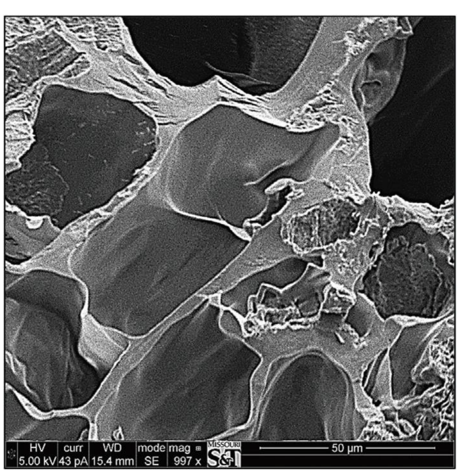


Figure 18: SEM image for HT-RPPG with a swelling ratio of 10 mixed with drilling fluid.

prepared using an HT-RPPG swelling ratio of 10 with drilling fluid. As shown in the image, the drilling fluid did not affect the bonding between the pores, as they still have a thick wall between them (Figure 18).

6. Conclusion

As high-temperature reservoirs have recently received attention, it is critical to have better materials available for the lost circulation application in those reservoirs. In this research, the capability of HT-RPPG to mitigate drilling fluid losses during drilling operations was investigated. It is approved that HT-RPPG has excellent plugging efficiency to fractures at 130°C. The HT-RPPG can be modified and used with different concentrations based on the fracture size and targeted formation.

The following conclusions were obtained from this research:

(1) Swelling ratios play a critical role in the material's strength. Reducing swelling ratios leads to a stronger material that can withstand a harsh environment.
(2) HT-RPPG is a promising candidate to seal fractures at high-temperature reservoirs, 130°C, since it can hold up to 1,077 psi/ft for a fracture width of 1.50 mm.
(3) Introducing drilling fluid to the mixture created a more robust material as it doubled its capability to withstand the pressure, as the sealing pressure increased from 88.29 to 238.61 psi when drilling fluid was introduced.
(4) The HT-RPPG remained in the fracture even after cracking, which significantly decreased the permeability, as the permeability decreased more than 10^7 times in all the experiments. This could play an essential role in reducing losses even if the pressure exceeds its capability.

Nomenclature

HT-RPPG: High temperature reassembling preformed particle gel
KCl: Potassium chloride
SEM: Scanning electron microscopy
Frr: Residual resistance factor
SMP: Shape memory polymer
HMP Gel: Crosslinked modified polyacrylamide gel
SR: Swelling ratio
LCMs: Lost circulation materials.

Data Availability

Data will be available on request.

Disclosure

This paper was published in the paper-format dissertation written by Ahdaya [28] and supervised by the first author of the paper (https://scholarsmine.mst.edu/doctoral_dissertations/3164).

Conflicts of Interest

The authors declare no conflicts of interest.

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