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Evaluation of Ultra-high Temperature Resistant Hydrogels for the Preferential Fluid Flow Control

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ABSTRACT

Enhanced geothermal systems (EGS) are emerging technologies that can recover clean energy from the Earth's crust. However, the existence of short-circulation in some geothermal reservoirs can significantly deteriorate their long-term viability as sustainable energy because injected cold fluids could quickly flow through the fractures with large apertures or the fractures directly communicating from injection well to production well without acquiring enough heat from the rock matrix. Therefore, controlling flow regimes outside the wellbore and within the reservoir is vital to mitigate undesirable flow. Polymer gels which have been successfully applied to control the preferential flow in oil and gas reservoirs, could also be adapted to control the preferential flow in geothermal reservoirs. However, no hydrogel products are available to be stable in the harsh conditions of geothermal reservoirs (>150 ^{o}C) for more than a few months. Recently, we have developed several novel high-temperature resistant preformed particle gels (HT-PPG) for this purpose. This work reported the swelling, rheology behavior and thermal stability of one novel HT-PPG that can be stable at 200 ^{o}C. We assessed the effect of variables including temperature and salinity on swelling behavior, gel strength and long-term thermal stability of this novel HT-PPG. The dried gel particle can swell to over 30 times its original volume, and the elastic modulus of the fully swelled gel can reach over 700 Pa. Additionally, the HT-PPG showed excellent long-term hydrolytic thermal stability for more than six months. HT-PPG described in this work is a promising product for controlling the preferential fluid flow in geothermal reservoirs.

1. INTRODUCTION

Fossil fuels—namely, coal, oil and natural gas are cheap and plentiful and have been applied to power society for centuries. However, since the industrial revolution, more than 2,000 gigatons of carbon dioxide have been released into the atmosphere, significantly threatening the climate (2022). Enhanced geothermal systems (EGS) as emerging technologies could provide new methods to recover energy generated by the radioactive decay within the crust. Geothermal energy has a lot of advantages over traditional fossil fuels, such as being renewable and pollution-free. Economically extracting the energy from the geothermal reservoir requires the reservoirs to be hot, porous and permeable. The conductivity of the low permeability rock could be enhanced through hydraulic fracturing, creating a connected fracture network through which the injected fluid could flow readily.

However, the natural and unwanted fractures generated during the drilling and hydraulic fracturing could cause excessive water production, reducing the heat-exchanging efficiency. The rapid communication/channeling problem not only reduces thermal production temperatures but also significantly reduces production efficiency. The oil and gas industry has developed several methods to solve this problem, such as cement squeeze and gel treatment (Kabir, 2001). The low fluid loss, excellent mechanical strength, and good thermal stability (up to 450 °C) make cement squeeze a viable way to remedy tubing leaks caused by flowing behind the pipe. However, cement treatment is costly and usually requires a rig to re-drill and perforate to maintain the well productivity. In addition, it cannot be applied for the far wellbore conformance control due to the relatively short setting time and irreversible plug. Due to the controllable gelation time, adjustable gel strength, and high injectivity, gel treatment can be deployed to near and far wellbore water management. Moreover, the gel treatment is less costly than the cement squeeze. Currently, two kinds of polymer gel systems have been developed for water management, and they are in-situ gels and particle gels. In-situ gel involves the simultaneous or sequential injection of polymer and crosslinker solution, and the mixture could form gels in the reservoir conditions. Preformed particle gels (PPG) are pre-crosslinked hydrogel synthesized on the surface facilities, which can swell but not dissolve in brine. PPG has excellent plugging performance in treating tiny fractures, and the gel slurry selectively penetrates into the fractures because of the large particle size compared with rock pore size. Compared to cement squeeze, gel treatment is more efficient in treating near/far-wellbore conformance problems such as conduits, fractures and high permeability matrix. However, the most challenging issue for ultra-high temperature geothermal reservoirs is the extremely high temperature, and most commercially available polymer gel systems are unstable under such high-temperature conditions. For example, the acrylamide-based polymer gels crosslinked by Cr (III), phenol/formaldehyde, and polyethyleneimine cannot be applied to temperatures higher than 150 ^{o}C in the presence of high salinity. Due to the weak crosslinking points, the acrylamide-based preformed particle gels are also unstable at high temperatures (Xiong, 2018). The heat-triggered chain depolymerization/degradation and syneresis due to the interaction between polymer chains and brines could significantly deteriorate the plugging efficiency. Therefore, the polymer gel composition should be modified to satisfy the harsh geothermal reservoir conditions. Monomers with extraordinary hydrolytic thermal stability should be deployed to synthesize the polymer gels.

Our group has developed a novel high-temperature resistant preformed particle gel that can be stable for over one year at 150 ºC (Schuman, 2022, Salunkhe, 2021). Based on the previous product, we further modified the recipe to endow the polymer gel with excellent stability at 200 ºC. In this work, we evaluated the modified HT-PPG in terms of its swelling behavior, thermal stability, gel strength and plugging performance.

2. MRTHODS

2.1 Synthesis of Hydrogel

The modified HT-PPG was synthesized in our lab. The precise synthesis method can be found in our previous publication (Salunkhe et al. 2021).

2.2 Swelling Kinetics

The swelling kinetics was evaluated by swelling the dried gel particles in brine solutions and recording the volume changes. The precise evaluation method can be found in the previous work (Song, 2022, Song and Ahdaya, 2022). To be convenient in industry application, the swelling ratio (SR) was defined and calculated using equation (1), where V_t is the volume of the swelled particle, and W_0 is the initial weight of the dried gel particles.

$$SR=V_t/W_0 \tag{1}$$

2.3 Rheology Test

The rheological properties of HT-PPG were performed using a Haake MARS III rheometer (Thermo Scientific Inc.). The spindle used in this process was P35Ti L, and the gap was set at 1 mm. The linear strain region was determined through strain-sweep experiments. The elastic modulus of the polymer gels was obtained through time-dependent oscillation experiments with a fixed frequency of 1 Hz and a controlled strain of 1%. The gel strength test was repeated three times for each sample.

2.4 Thermal Stability Test

High pressure/temperature resistant glass tubes with thermally stable O-ring (Ultra-Chemical-Resistant High-Purity Kalrez 6230 O-Ring, McMASTER-CARR) and stainless steel sample cylinders (Swagelok, 304L-HDF2-40) were used to evaluate the hydrolytic thermal stability of the polymer gels. Oxygen was removed before the aging test.

2.5 Core Flooding Test

The core flooding experiment was performed to examine the HT-PPG efficiency in plugging open fracture/ void space conduits (VSC). A sandstone core was used for the test. Initially, the core was oven dried to remove any residual water in the core. Then the core was vacuumed for 24 h, and saturated with 2% KCl. Figure 1 shows the schematic diagram of the core flooding test, where the core was placed inside the core holder and a confining pressure of 700 psi was applied to the core. Then, the core was flooded with 2% KCl at different injection flow rates, the resulted stabilized pressure gradients were recorded, and the matrix permeability was calculated based on Darcy's law. Thereafter, the core was removed from the core holder and cut uniformly into two halves where stainless steel strips with a thickness of 0.5 mm were glued on the surface of the core, and the fractured core was wrapped with Teflon sheet. The fractured core was flooded with 2% KCl at a constant injection flow rate of 1.0 cm^3/min until a stabilized pressure gradient was reached. Then, the HT-PPG with a swelling ratio of 10 in 2% KCl was placed inside the accumulator and injected through the fracture using 0.5 cm^3/min provided by the Isco pump. After the gel placement pressure gradient was stable, post-water injection at different injection flow rates was carried out in order to determine the plugging performance of HT-PPG.

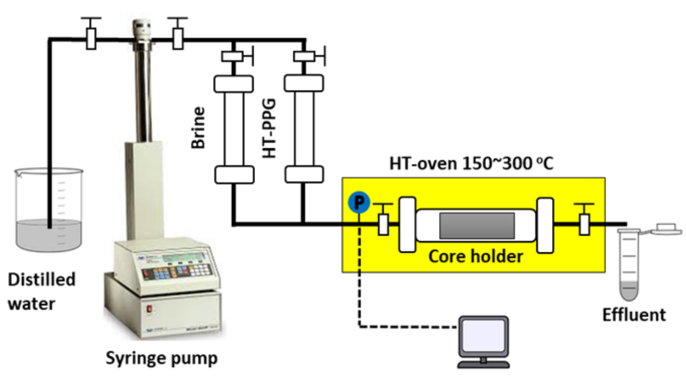

Figure 1 Core flooding setup

3. RESULTS AND DISCUSSION

3.1 Swelling Kinetics

Figure 2 shows the effect of salinity on the swelling kinetics. The HT-PPG has an equilibrium swelling ratio/maximum swelling ratio of 30 and 32 in 2% KCl and 1% $CaCl_2$ solution. In addition, the dried particles need around 2 hours to reach the maximum swelling ratio. The swelling speed is fast at the beginning and gradually decreases as the concentration gradient difference between the gel matrix and solvent decreases (Lin, 2010). Salinity/ionic strength can alter the swelling ratio because the divalent ions have a more substantial charge shielding effect than the monovalent ions (Flory, 1953).

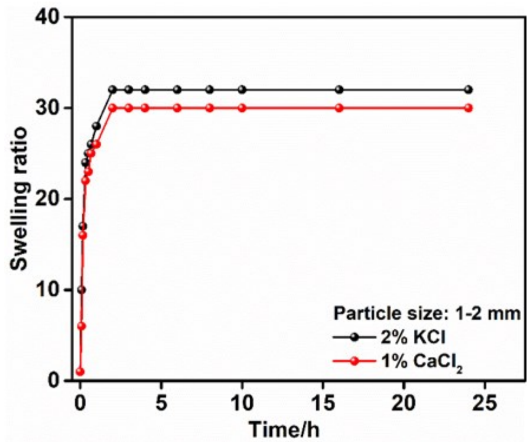

Figure 2 Effect of salinity on the swelling kinetics

3.2 Gel Strength

The shear/elastic modulus was deployed to represent the gel strength, and all the tests were carried out in the linear viscoelastic region. Figure 3 shows the effect of swelling ratio and salinity on the gel strength. The gel strength decreases with the increasing swelling ratio. Besides, the salinity has a negligible impact on the gel strength. The elastic modulus of the polymer gel in 1% NaCl, 2% KCl, and 1% $CaCl_2$ were 3580, 3601 and 3504 Pa, respectively.

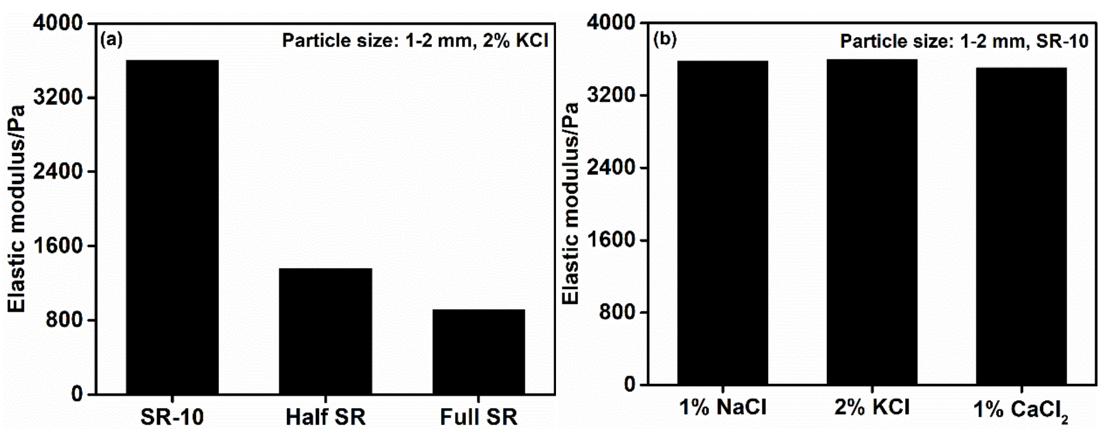

Figure 3 Effect of (a) swelling ratio, (b) salinity on the gel strength

3.3 Thermal Stability

The thermal stability of the polymer gel significantly affects the treatment efficiency. Therefore, we studied the hydrolytic thermal stability of the polymer gel at 200 °C, and the testing lasted for 180 days. As shown in Figure 4, the polymer gel maintained its integrity and the volume loss was less than 20%. The thermal stability test confirmed that this novel polymer gel could be stable at 200 °C for over 180 days.

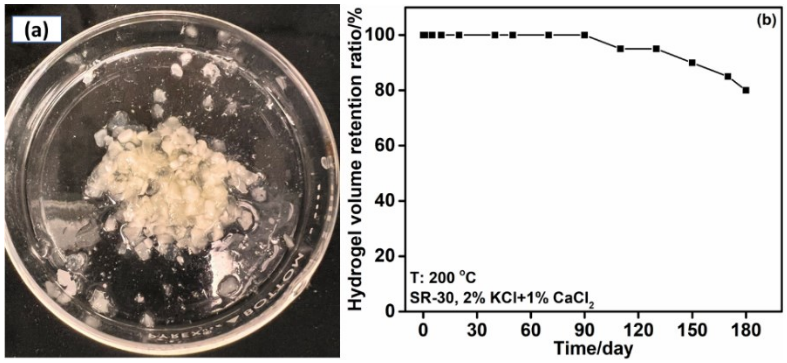

Figure 4 (a) Gel appearance after 180 days of aging at 200 °C, (b) gel volume changes at 200 °C

3.4 Core Flooding Test

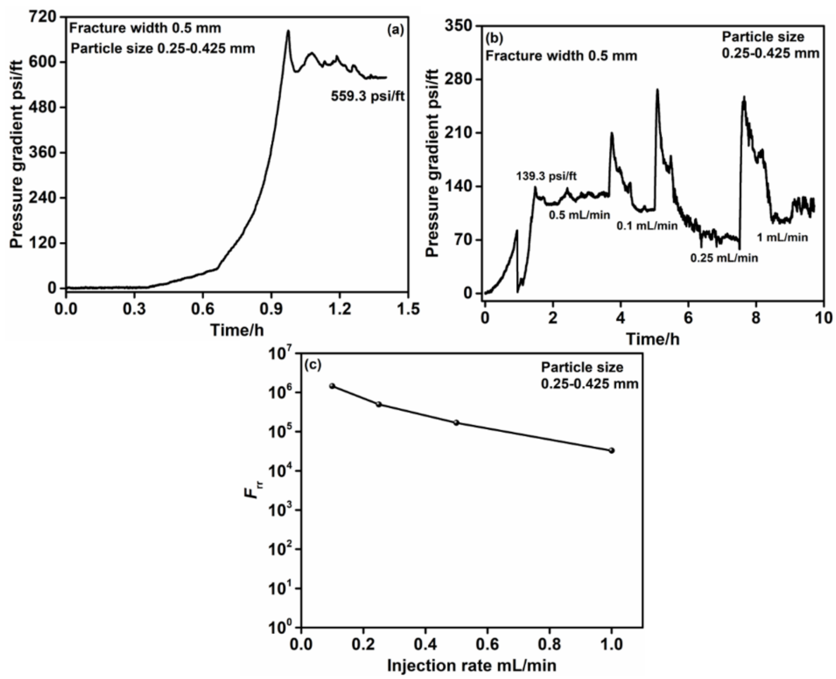

Figure 5 (a) Gel injection, (b) Water breakthrough test, (c) F_{rr}

Figure 5 shows the gel injection pressure gradient and water breakthrough pressure. The stable gel placement pressure was around 560 psi/ft, and the water breakthrough pressure gradient was 139.3 psi/ft/. The gel placement pressure gradient can be optimized by changing the ratio of particle size to the fracture width. After the water breakthrough, the water injection rate was changed to 0.1, 0.25, 0.5 and 1 mL/min to evaluate PPG's packing and plugging efficiency in fractures. The stable injection pressure gradient at flow rates of 0.1, 0.25, 0.5 and 1 mL/min are 109, 72.5, 128.9 and 96.6 psi/ft, respectively. After gel placement, the fracture permeability could be reduced to millidarcy level. In addition, it should be noted that during the post-water flooding process, we did not observe any gel particles in the effluent. The residual resistance factor (F_{rr}) is a ratio of water mobility before and after the gel placement. It is an important parameter that demonstrates the plugging performance/permeability reduction. High F_{rr} represents excellent plugging efficiency, and the plugging efficiency was over 99.99%.

4. CONCLUSIONS

The swelling kinetics, rheology behavior, thermal stability and plugging performance of this novel HT-PPG were studied in this work. This novel HT-PPG has a maximum swelling ratio of 32 in 2% KCl at room temperature. The elastic modulus of the polymer gel with a swelling ratio of 10 could reach over 3000 Pa. The thermal stability test confirmed that the polymer gel could be stable for over 180 days at 200 °C. In addition, core flooding test showed HT-PPG can reduce the permeability of open fractures to millidarcy level, and the plugging performance is higher than 99.99%.

ACKNOWLEDGMENTS

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