Study on Fluid-Rock Interaction and Reuse of Flowback Fluid for Gel Fracturing in Desert Area

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Hydraulic fracturing requires a large volume of fresh water, which is difficult and expensive to obtain in the desert area such as Tarim Basin. Currently, flowback fluid is typically transported to the sewage treatment plant and then discharged after reaching environmental requirements; however, this is not only costly, but also a waste of water resource. Therefore, it is imperative to understand the potential interactions between fracturing fluid and reservoir rock and then find solutions to reuse the flowback water for subsequent fracturing. In this study, once flowback fluid was directly collected from the field, its chemical compositions were analyzed; then, filtering, decoloring, and chelating methods were chosen to effectively remove or shield the unfavorable reintroduced components. Moreover, pH value was further tuned during different stages of the recycling process to ensure good gelation and cross-linking properties of guar. Cross-linked guar synthesized with the flowback fluid was evaluated in the lab through shear resistance tests and coreflood tests under the reservoir conditions; results indicated the recycled gel behaved similarly as the original gel, or even better. From this work, a cheap and effective treatment process was proposed to reuse the flowback fluid in the desert area.

1. Introduction

Hydraulic fracturing enables hydrocarbon production from low-permeability or low-productive reservoirs to be economical. In the US, 51% of crude oil production and 67% of natural gas production came from the hydraulically fractured wells in 2015 [1–3]. To fracture the formation, a large volume of water is injected to create a fracture network that provides pathways for hydrocarbon to flow [4–8]. In recent years, fracturing experience from various fields indicates that the larger the volume of water used per well, the more complex the created fracture network, and thus the higher the initial hydrocarbon production rate [9–13]. However, in desert area where water resource is scarce, it is neither economic nor sustainable to fracture the formation with a large volume of fresh water. Therefore, it is imperative to understand the potential interactions between fracturing fluid and reservoir rock and then find solutions to recycle and reuse the flowback water for subsequent fracturing.

During hydraulic fracturing, a large volume of proppants is pumped along with fracturing fluid to prevent fractures being closed. To maximize the proppant-carrying capacity of the fracturing fluid, cross-linked gel is typically used [4, 14–16]; this is attributed to its excellent viscosity and elasticity that can prevent proppants settling [17–19]. However, fracturing fluid can interact with formation minerals and the connate water therein, resulting in high contents of suspended and dissolved solids in the flowback fluid [20, 21]. When this flowback fluid is reused, the proppant-carrying capacity of the gel can be seriously weakened. Studies have shown that the dissolved solids can affect the gelation and cross-linking of the gel and thus reduce its viscosity and elasticity [22–25]. Therefore, when flowback fluid is recycled and reused to prepare the cross-linked gel for fracturing, all components
that are unfavorable to its gelation and cross-linking must be removed or shielded. Depending on properties of reservoir and fracturing fluid, these reintroduced components in the flowback fluid may include suspended solids, dissolved solids (i.e., anions and cations), and residual gel breakers. Besides, the pH value and the density of the fracturing fluid may also need to be tuned to fit the requirements of reservoir stimulation design.

In the US, advanced integrated systems have been reported that can collect and recyle the flowback fluid through oxidation and precipitation methods \cite{26, 27}; however, they are expensive to be used in the Tarim Basin, and similar technology is not yet available in China. Therefore, a simple and effective method is expected to be developed to fill the blank. To remove the suspended solids, sand filtration, flocculation, coagulation, and sedimentation methods are typically used in the field \cite{28–30}. In the field, cost is one of the key factors that determines which technique is the best to be used; therefore, this step was not the focus of this study, and the filtration and adsorption were chosen to remove the suspended solids. To remove the dissolved solids, membrane filtration \cite{31, 32}, reverse osmosis \cite{33, 34}, and oxidation treatments \cite{28, 35–37} have been developed; however, they are either energy-intensive or difficult to be equipped in Tarim Basin. Therefore, an easier and cheaper chemical shielding method needs to be proposed and evaluated in the lab.

In this study, after the flowback fluid was directly collected from the field, its components were evaluated in the lab to understand the interaction between the fracturing fluid and the reservoir rock; thus, effective treatments could be wisely chosen for reusing the flowback fluid. The formulation for synthesizing the fracturing fluid with the recycled flowback fluid was optimized by evaluating (1) the gelation and cross-linking properties of gel, (2) the shear resistance of gel under the reservoir temperature, and (3) permeability damage due to gel residuals through coreflood tests.

2. Materials

2.1. Flowback Fluid. The target reservoir locates in the piedmont region of Tarim Basin, which is characteristic of desert environment, great reservoir depth (over 3000 m), and high reservoir temperature (approximately 140°C) \cite{38–40}. To hydraulically fracture this reservoir, cross-linked guar was used as the fracturing fluid. Flowback fluid was directly collected from the field and then tested in this study to explore its recycling and reuse. Key properties of the flowback fluid that may affect the gelation of guar were firstly analyzed in the lab to design the corresponding treatments for recycling and reusing the fluid. These key properties include the pH value, the density, contents of the residual breakers, the suspended solids, and the dissolved solids of the fluid. The analysis results are shown in Results and Discussion.

2.2. Original Formulation of the Fracturing Fluid. The fracturing fluid applied in the field contained approximately 0.35 wt.% high-molecular-weight guar, 0.36 wt.% cross-linking agent (i.e., organic borate), 0.7 wt.% cross-linking regulator (i.e., alkalai), 1 wt.% temperature stabilizing agent (i.e., antioxidant), 1 wt.% flowback surfactant, 1 wt.% demulsifier, and traces of other additives. To compare the properties of the original gel with the gel synthesized with the recycled flowback fluid, the original fracturing fluid was synthesized in the lab using the same formulation as used in the field.

2.3. Mimicked Formation Brine. In the lab, the mimicked formation brine was prepared with 2 wt.% potassium chloride, 5.5 wt.% sodium chloride, 0.45 wt.% magnesium chloride, and 0.55 wt.% calcium chloride.

3. Laboratory Evaluation Methods

3.1. Cross-Linking Evaluation. Before gel cross-linking, the base fluid was prepared by mixing high-molecular-weight guar with all additives as introduced in the formulation section except the cross-linking agent. As described above, these additives included cross-linking regulator, temperature stabilizing agent, flowback surfactant, demulsifier, and citric acid for tuning the pH value. The base fluid was stirred for 30 min and left to rest for another 2 hr for hydrating and swelling. Then, 100 g base fluid was mixed with 0.15 g cross-linking agent at a slow stirring speed. The cross-linking time and the morphology of the cross-linked guar were recorded for evaluation.

3.2. Temperature and Shear Resistance Test. HAAKE Mars-III rheometer was applied to measure the change of viscosity of the cross-linked guar at a fixed shear rate of 170 s\(^{-1}\) under the reservoir temperature (i.e., 140°C). Guar synthesized from the flowback fluid was compared with the one originally applied in the field. Results can tell if the unfavorable components were removed, and thus if the recycling was effective.

3.3. Coreflood Test. To further evaluate the permeability damage due to different broken/degraded guar systems, coreflood experiments were applied to determine the reduction of rock permeability to the formation brine before and after the gel breaking. Before conducting the coreflood experiment, the reservoir rock sample was cut into smaller cylindrical cores with diameters of 2.5 cm and lengths of 3.5 cm. For each core sample, its porosity was determined by saturating the dry core with the mimicked formation brine (i.e., material balance), and it was found to be approximately 9%. Detailed information about the porosity of each core sample tested in this work refers to Results and Discussion.

Figure 1 shows the coreflood setup applied in this study. Once a brine-saturated core sample was loaded vertically in the core holder with a confining pressure of 10 MPa, an insulation jacket was used to wrap the core holder for controlling the temperature (center in Figure 1). Due to the limitation of this setup, all corefloods were conducted under 90°C instead of 140°C; further testing might be needed to fill this gap. After the system was stabilized, a 3-step coreflood sequence was conducted on this core sample. The broken/degraded guar system has a higher density than the formation brine; to improve the stability of the displacement front during the coreflood, the mimicked fracturing fluid after gel breaking was injected from the bottom to the top of
the core sample while the mimicked brine was injected in the opposite direction [41–43]. Details are as follows.

**Step 1** (measure rock permeability to brine before gel damage (i.e., $K_0$)). The mimicked formation brine was injected into the core sample at a constant flow rate from the top to the bottom through a piston accumulator by an ISCO pump (not shown in Figure 1); meanwhile, the pressure drop across the core sample was recorded with time by a ROSEMOUNT pressure transducer (left in Figure 1), and the effluent was measured by an electronic balance (right in Figure 1). When the pressure drop and the effluent were stabilized, rock permeability was calculated from Darcy’s Law.

**Step 2** (simulate rock damage due to the fracturing fluid after gel breaking). To mimic the gel breaking process under the reservoir condition, the cross-linked guar was mixed with 100 ppm (0.01 wt.%) ammonium persulfate as the gel breaker. This mixture was then placed in 140°C water-bath till the cross-linked gel was completely broken and degraded. After the residual gel was filtered out, it was degassed under vacuum for 1 hr. The final product was the mimicked fracturing fluid after gel breaking at the reservoir condition, and it was defined as Fluid-X in this paper. To mimic the rock damage due to Fluid-X, it was injected into the core sample at a constant flow rate from the bottom to the top through another piston accumulator by the ISCO pump. After 3–5 PVs of Fluid-X was injected through the core, the pump was stopped and the setup was left to rest for another 2 hr at 90°C.

**Step 3** (measure rock permeability to brine after gel damage (i.e., $K_1$)). The mimicked formation brine was injected again into the core sample from the top to the bottom as in Step 1. After the pressure drop across the core sample and the effluent were stabilized, rock permeability was calculated from Darcy’s Law.

### 4. Results and Discussion

#### 4.1. Analysis of Flowback Fluid from the Field

**4.1.1. PH Value and Density.** Table 1 shows the change of pH value and density of the flowback fluid with time from one well in the piedmont region of Tarim Basin. Since this well was previously acidized, the flowback fluid was weakly acidic as shown in this table. The acidic environment is helpful to the hydration of the guar powder; therefore, no additional operation is required to tune the pH value for reusing the flowback fluid. In fact, the usage of citric acid in the original formulation can be saved.

For the fluid density, it was above the fresh water since sodium nitrate was used as the weighting agent during hydraulic fracturing. Comparing to the original fracturing fluid whose density was 1.30 g/cc, the density of the flowback fluid decreased with time, indicating the loss of weighting agent into the formation. When the flowback fluid is reused, additional weighting agent might be needed depending on the fracturing job; however, the dosage can be less than the case using the fresh water.

**4.1.2. Total Suspended Solids.** The suspended solids can affect the synthesis of cross-linked guar using the flowback fluid, and it may further cause the formation damage once the fluid is used again for fracturing. The flowback fluid was collected at the early time (<1 week, Sample 1#), the mid time (2-3 weeks, Sample 2#), and the late time (4 weeks, Sample 3#) for testing in this study, and their pictures are shown in Figure 2. To examine the concentration of the suspended solids in each sample, 10 mL of sample fluid was centrifuged and dried, and the mass of the total suspended solids was then measured by an electronic balance. The results are shown in Table 2.

**4.1.3. Residual Gel Breakers.** Since the residual gel breaker can also seriously impact the gelation and cross-linking of guar, its amount in the flowback fluid needs to be examined. In this case, the gel breaker was ammonium persulfate, and potassium iodide was used to detect its existence because their product iodine can turn the starch blue. The chemical reaction equation is shown as follows.

$$\left(\text{NH}_4\right)_2\text{S}_2\text{O}_8 + 2\text{KI} = \left(\text{NH}_4\right)_2\text{SO}_4 + \text{K}_2\text{SO}_4 + \text{I}_2 \quad (1)$$
Table 2: Analysis of total suspended solids and residual gel breakers in the flowback fluid in Tarim Oilfield.

<table>
<thead>
<tr>
<th>Sample Name</th>
<th>5 ppm Ammonium persulfate</th>
<th>10 ppm Ammonium persulfate</th>
<th>50 ppm Ammonium persulfate</th>
<th>Sample 1# (Early time)</th>
<th>Sample 2# (Mid time)</th>
<th>Sample 3# (Late time)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total suspended solid (mg/L)</td>
<td>/</td>
<td>/</td>
<td>/</td>
<td>530</td>
<td>260</td>
<td>360</td>
</tr>
<tr>
<td>Color change</td>
<td>Blue</td>
<td>Blue</td>
<td>Blue</td>
<td>No change</td>
<td>No change</td>
<td>No change</td>
</tr>
</tbody>
</table>

Table 3: Change of chloride ion content in flowback fluid in different flowback periods.

<table>
<thead>
<tr>
<th>Flowback time</th>
<th>Chloride ion content (ppm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Day 1</td>
<td>32000</td>
</tr>
<tr>
<td>Day 2</td>
<td>45000</td>
</tr>
<tr>
<td>Day 3</td>
<td>57000</td>
</tr>
<tr>
<td>Day 4</td>
<td>57000</td>
</tr>
<tr>
<td>Day 5</td>
<td>62000</td>
</tr>
<tr>
<td>Day 6</td>
<td>64000</td>
</tr>
<tr>
<td>Day 7</td>
<td>62000</td>
</tr>
<tr>
<td>Day 8</td>
<td>58000</td>
</tr>
<tr>
<td>Day 9</td>
<td>58000</td>
</tr>
<tr>
<td>Day 10</td>
<td>58000</td>
</tr>
</tbody>
</table>

Ammonium persulfate solution was diluted into 5 ppm, 10 ppm, and 50 ppm as the control groups; they were compared with the filtered samples 1#–3# to estimate the amount of gel breaker therein. Specifically, 2 g of potassium iodide was added to 20 mL of each fluid sample; then, 1 wt.% of starch solution was added to the mixture for observation. Figure 3 shows the comparison of flowback fluid Sample 2# with two ammonium persulfate control samples (5 ppm and 10 ppm) after both potassium iodide and starch were added; Table 2 also lists the color test results of all six fluid samples.

Results indicate that this examination method can detect as low as 5 ppm ammonium persulfate in the solution. Since all three flowback fluid samples did not turn blue, the amount of residual gel breaker could be negligible and thus it is unlikely to affect the following recycling process.

4.1.4. Dissolved Solids/Ions from the Formation. Flowback fluid also contains dissolved ions from the formation as well as the formation water. Table 3 lists the change of chloride ion content in the flowback fluid during different flowback periods. The content increased from 30000 ppm and plateaued at 58000 ppm after 8 days. Since the original fracturing fluid contained only trace amounts of chloride ions, high chloride ion content in the flowback fluid was attributed to the dissolved solids from the formation. Although not measured here, high cation contents were expected along with the chloride ions, which can be sodium, calcium, magnesium, iron, and other metal ions. These metal ions can seriously affect properties of the cross-linked gel; thus corresponding treatments are necessary for recycling the flowback fluid.

4.2. Removal of Suspended Solids. In the field, sand filtering was typically applied to remove the suspended solid from the flowback fluid; in the lab, this was mimicked by using the filter papers. After flowback fluid samples 1#–3# were filtered, they were heated up to 90°C with 5 wt.% activated carbon and stirred for 30–60 min for decoloring.

Figure 4 shows the concentrations of total suspended solids in different flowback samples after filtering and decoloring treatments in the lab, and Figure 5 shows the appearances of these treated fluid samples. Results indicate that filtering can effectively remove the suspended solid, and the decoloring by activated carbon can further remove the suspended solids, achieving similar values as the tap water used in the lab.

4.3. Shielding of Dissolved Solids. The impact of different dissolved ions on the gelation and cross-linking of guar was firstly studied for choosing the target ions to be shielded. To do so, the original formulation as depicted in the section of Materials was mixed with the following chemicals, respectively: 20000 ppm NaCl (Sample TI-1), 20000 ppm NaNO₃ (Sample TI-2), 500 ppm CaCl₂ (Sample TI-3), 500 ppm MgCl₂ (Sample TI-4), and 400 ppm FeCl₂ (Sample TI-5).

As shown in Figures 6–10, Na⁺, Cl⁻, and NO₃⁻ had negligible effect on the cross-linking of guar, while Ca²⁺, Mg²⁺, and Fe²⁺
Figure 4: Concentrations of total suspended solids in different flowback samples (1#–3#) after filtering and decoloring treatments in the lab.

Figure 5: Flowback fluid samples (1#–3#) after filtering and decoloring treatments.

Figure 6: Cross-linking of guar with 20000 ppm NaCl (Sample TI-1).

Figure 7: Cross-linking of guar with 20000 ppm NaNO₃ (Sample TI-2).

and Fe²⁺ all dramatically reduced the elasticity of the cross-linked guar. Since the elasticity of fracturing fluid may enhance its ability to transport proppants [18, 44, 45], these divalent metal ions need to be shielded when the flowback fluid is recycled and reused.

To shield these divalent metal ions, two types of chelating agents with different concentrations were chosen and compared, and they are EDTA and Gl-47S. As compared in Table 4, when sufficient EDTA or Gl-47S was added, the gelation and cross-linking of guar became normal, and the cross-linked gel showed excellent elasticity; for every additional 500 ppm of Ca²⁺, Mg²⁺, or Fe²⁺, an additional 1000 ppm of EDTA or Gl-47S was needed. For the collected flowback fluid in this study, adding 0.1 wt.% Gl-47S was sufficient to shield the dissolved divalent metal ions brought from the formation. The cross-linking time was slightly different for two chelating agents; the best pH value for gel cross-linking was found to be 8 for EDTA, and 9 for Gl-47S.

Combining all analysis results, the optimized formulation for recycling and reusing the flowback fluid from this well/oilfield was found to be filtered flowback fluid + 0.1 wt.% Gl-47S + 0.03 wt.% citric acid (tune pH value to 5) + 0.35 wt.% high-molecular-weight guar + 0.3 wt.% cross-linking regulator (tune pH value back to 9) + 0.36 wt.% cross-linking agent + 1 wt.% temperature stabilizing agent + 1 wt.% flowback surfactant + 1 wt.% demulsifier + traces of other additives as in the original formulation.

4.4. Evaluation of Temperature and Shear Resistance. Figure 11 compares the shear resistance of the cross-linked guar synthesized using the original formulation (a) or using the recycling formulation (b) under the reservoir temperature (140°C). It can be noticed that peaks showed at the early time of both measurements, and this is likely because the guar and cross-linkers were not sufficiently mixed yet. Nevertheless, the late-time viscosity when temperature reached 140°C was the key of this shear resistance test. As shown in this figure, the late-time viscosity of the original fracturing fluid was approximately 200 mPa·s, while the late-time viscosity of the recycled fracturing fluid was approximately 250 mPa·s. The recycled guar instead showed a better temperature and shear resistance comparing to the original guar; this indicates the success of the recycling treatment proposed in this study.

4.5. Evaluation of Permeability Damage due to Gel Residuals. Coreflood test can evaluate the comprehensive impact of fracturing fluid on the reservoir rock, from including clay swelling, fine migration, water blockage, and clogging of residuals. Using the coreflood method introduced in the
### Table 4: Gelation and cross-linking tests for removing different divalent metal ions.

<table>
<thead>
<tr>
<th>Formulations</th>
<th>Concentrations of divalent metal ions (ppm)</th>
<th>Concentrations of EDTA or GL-47S (ppm)</th>
<th>Results (PH)</th>
</tr>
</thead>
<tbody>
<tr>
<td>IT-6</td>
<td>200</td>
<td>1000</td>
<td>Normal cross-linking (8)</td>
</tr>
<tr>
<td>(CaCl₂ with EDTA)</td>
<td>500</td>
<td>2000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>1000</td>
<td>4000</td>
<td></td>
</tr>
<tr>
<td>IT-7</td>
<td>200</td>
<td>1000</td>
<td>Normal cross-linking (9)</td>
</tr>
<tr>
<td>(CaCl₂ with GL-47S)</td>
<td>500</td>
<td>2000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>1000</td>
<td>4000</td>
<td></td>
</tr>
<tr>
<td>IT-8</td>
<td>200</td>
<td>1000</td>
<td>Normal cross-linking (8)</td>
</tr>
<tr>
<td>(MgCl₂ with EDTA)</td>
<td>500</td>
<td>2000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>1000</td>
<td>4000</td>
<td></td>
</tr>
<tr>
<td>IT-9</td>
<td>200</td>
<td>1000</td>
<td>Normal cross-linking (9)</td>
</tr>
<tr>
<td>(MgCl₂ with GL-47S)</td>
<td>500</td>
<td>2000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>1000</td>
<td>4000</td>
<td></td>
</tr>
<tr>
<td>IT-10</td>
<td>40</td>
<td>1000</td>
<td>Normal cross-linking (8)</td>
</tr>
<tr>
<td>(FeCl₂ with EDTA)</td>
<td>400</td>
<td>&gt;2000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>600</td>
<td></td>
<td></td>
</tr>
<tr>
<td>IT-11</td>
<td>40</td>
<td>1000</td>
<td>Normal cross-linking (9)</td>
</tr>
<tr>
<td>(FeCl₂ with GL-47S)</td>
<td>400</td>
<td>&gt;2000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>600</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Table 5: Comparison of rock permeability damage due to different fracturing fluids.

<table>
<thead>
<tr>
<th>Formulations</th>
<th>Rock sample</th>
<th>Porosity (%)</th>
<th>Permeability before damage $K_0$ (mD)</th>
<th>Permeability after damage $K_1$ (mD)</th>
<th>Damage ratio $\eta$ (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Broken/degraded recycled guar</td>
<td>SH11#</td>
<td>9.63</td>
<td>0.0121</td>
<td>0.0087</td>
<td>28.10</td>
</tr>
<tr>
<td></td>
<td>SH7#</td>
<td>9.10</td>
<td>0.0331</td>
<td>0.0231</td>
<td>30.21</td>
</tr>
<tr>
<td>Broken/degraded original guar</td>
<td>Or1#</td>
<td>5.17</td>
<td>0.7609</td>
<td>0.6860</td>
<td>9.85</td>
</tr>
<tr>
<td></td>
<td>Or6#</td>
<td>8.66</td>
<td>1.0188</td>
<td>0.8188</td>
<td>19.63</td>
</tr>
</tbody>
</table>

**Figure 8:** Cross-linking of guar with 500 ppm CaCl₂ (Sample TI-3).

**Figure 9:** Cross-linking of guar with 500 ppm MgCl₂ (Sample TI-4).

Section of Laboratory Evaluation Methods, four rock samples were tested to compare the permeability damage due to the degraded original guar and the degraded recycled guar, as shown in Table 5. The damage ratios were all higher in the cases when the recycled guar was used; gel residuals and other fluid additives are likely more sensitive to smaller pores/pore throats in rocks with lower permeabilities, where blockage can happen and aggravates the permeability damage. However, considering that the permeability damage was only doubled when rock permeability was reduced by about 45 times, the recycled formulation may still meet the field requirements. Nevertheless, further tests are needed to fully understand the damage resulting from the usage of recycled flowback water.
Figure 10: Cross-linking of guar with 400 ppm FeCl₂ (Sample TI-5).

Figure 11: Comparison of shear resistance of the cross-linked guar synthesized using the original formulation (a) or using the recycling formulation (b) under 140°C.

5. Conclusions

Effective oil/gas recovery from low-permeability reservoirs requires huge amounts of water to create complex fracture networks; in the remote desert area, water resource is scarce, and thus the recycling and reusing the flowback fluid collected from the fractured wells is crucial to ensure the sustainable development. Fracturing fluid interacts with the reservoir rock and the formation water, resulting in high contents of suspend solids and dissolved solids in the flowback fluid; this can seriously affect the gelation and cross-linking of the gel during the recycling and reusing process.

After the flowback fluid is collected from the well, its key properties and main components are firstly analyzed for designing the recyle scheme; they may include the pH value, the density, contents of the residual breakers, the suspended solids, and the dissolved solids of the fluid. To effectively remove the unfavorable components and reuse the favorable components for subsequent fracturing, this study established the following procedures: (1) filtering and decoloring the collected fluid to remove the suspend solids; (2) optimizing the chelating agents to shield the dissolved divalent metal ions from the formation; (3) supplementing with citric acid and cross-linking regulators to tune the pH value in sequence for gel cross-linking. By following this procedure, the recycled guar synthesized from the collected flowback fluid shows excellent gelation and cross-linking properties, and a better shear resistance under the reservoir temperature comparing to the original guar used for the previous fracturing. However, its residuals can still cause formation damage, and more studies are needed to fully understand this damage as well as its mitigation methods.

Conflicts of Interest

The authors declare no financial conflicts of interest regarding the publication of this paper.

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