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## **Further Insights into the Mechanism of Disproportionate Permeability Reduction**

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### **Abstract**

Disproportionate permeability reduction (DPR) is a phenomenon whereby many water-soluble polymer solution and polymer gels reduce the permeability to water flow more than to oil or gas flow. DPR is important for some gels that are applied to production wells in water-shutoff treatments. The mechanisms of DPR need more investigation and clarification. In this study, experiments on two different scales, core- and micro-model-scale, were conducted to study the mechanism of DPR in flow through permeable medium treated with Cr(III)-acetate-HPAM gels. The procedures for the two experiments can be similarly divided into five phases: gelant injection and gelation, oil flooding, gel rehydration with no oil phase pressure difference, oil re-flooding, and water flooding.

In the core-scale experiments, we used nuclear magnetic resonance (NMR) to monitor the T2 signal change during fluorine-tagged oil and water flooding after the gel treatment. NMR can detect the signal change of trapped and free water inside the gel in different pore sizes in porous medium. In the micro-model-scale experiments, a microscopic glass-etched model is subject to red oil and blue water flooding alternately after the gel treatment. Oil extrusion under an oil phase pressure gradient and the evolution of oil flow channel are recorded by a video sensor. The subsequent water flooding is also investigated.

Results show that a gel-displacement mechanism is a primary reason for the development of the oil flow path initially. As the displacement proceeds, the gel dehydration occurs induced by the oil phase pressure and therefore the flow channel continues forming, but no gel is produced during this phase. During gel rehydration, the flow channel is blocked, which can be inferred from the T2 spectrum and visual microscope image. However, the rehydrated gel can only partially reduce permeability and oil pathways re-establish easily with the subsequent oil flooding. In water flooding, water permeability decreases abruptly. The mechanisms for the disproportionate permeability reduction involve channel segregation, gel rehydration, residual oil effects, and the low permeability of gel relative to water.

## Introduction

Many polymers and gels can reduce permeability to water more than to oil or gas (Liang et al. 1995; Seright 1995; Zaitoun et al. 1988; Al-Sharji et al. 1999; Willhite et al. 2002). This phenomenon is usually referred to as disproportionate permeability reduction (DPR). An ideal goal of water shut-off technology is that of identifying materials that can be injected into any production well (with no zone isolation) and that will substantially reduce water productivity without significantly impairing hydrocarbon productivity (Seright 2009). The DPR property is important to the success of gel treatments in production wells located in hydrocarbon zones that are not effectively protected during gelant placement (Seright et al. 1993; Liang et al. 1993). However, two technical impediments prevent gel with a DPR property from being successfully applied in unfractured reservoirs without zone isolation. First, the oil residual resistance factors must be less than 2, while the water residual resistance factors must be greater than 10 (Seright et al. 2001). Second, oil residual resistance factors ( $F_{rro}$ ) less than 2 are difficult to achieve because small  $F_{rro}$  values often result from incomplete gelation because of gelation sensitivity to pH, salinity, temperature and other factors. Thus, it is difficult to predict and control the gelation stage to achieve a desired  $F_{rro}$  because of complex reservoir conditions (Seright 1993).

The utility of the DPR property in fractured reservoirs is different from that in an unfractured matrix. DPR conformance improvement treatments, which involve relatively strong gels, can be successfully applied in hydraulically or naturally fractured reservoirs. Basic engineering calculations reveal that gel treatments with the DPR are currently far more useful when treating linear flow problems (e.g., fractures) than when treating radial flow problems (e.g., wells without fractures). For the former problem, the successful application of gel treatment has two requirements. First, the reduction of permeability to water must be greater than that to oil. That is, the residual resistance factor of oil must be smaller than that of water. Second, the distances of gelant leak-off from the fracture surface should be controlled. Since the gel is placed and functions within the rock matrix adjacent to the fractures (Seright et al. 1998; Marin et al. 2002), the ability of the gel to reduce water entry into the fracture is determined by the product of gel leak-off distance and the water residual resistance factors provided by the gel (Seright et al. 2003). Similarly, the extra resistance provided by the gel in oil zones is the product of oil residual resistance factors and gelant leak-off distance. If gelant penetration distances are too large, the pressure gradient may be too small to allow oil to flow through the gel (Seright et al. 2006a).

For both linear and radial flow, the residual resistance factors of gel to water and oil are critical issues for DPR application. Therefore, it is necessary to understand the mechanism of DPR. Knowledge of the mechanism will aid in controlling and improving gel-treatment performance and allow full exploitation of DPR. Several extensive investigations were performed of the mechanisms for the oil permeability development and DPR after gel treatment (Zaitoun et al. 1988; Liang et al. 1992; Dawe et al. 1994; Liang et al. 1995; Liang et al. 1997; Thompson et al. 1997). In the following, we discuss the possible mechanisms for the oil permeability development and DPR separately.

## Mechanisms of Oil Permeability Development

After treating a permeable medium with cross-linked polymers, the permeability to oil and to water will simultaneously decrease. Afterward, the oil permeability will recover as oil penetrates into the gel-filled pore space. There are several possible mechanisms for oil permeability development. Dawe and Zhang's visual micro-model-scale studies revealed that oil passes through a gel by fingering through the center of the pores and widens the pathway by removing water from inside the gel and dehydrating the gel (Dawe and Zhang, 1994). Willhite et al. (2000) argued that the oil permeability develops as oil penetrates into the gel-filled pore spaces, dehydrates the gel by displacing brine from gel structure and creates flow channels within or around the gel. Nguyen et al. (2000) studied DPR in sand packs treated with Cr(III)-acetate-HPAM gels. They advocated that the oil restores permeability by dehydrating and displacing gels and by reconnecting residual

oil ganglia. Seright et al. (2004) studied the mechanism of DPR using X-ray computed microtomography. They proposed that dehydration is the primary reason for oil permeability increasing. Seright defines gel "dehydration" as a process of removing water from the gel by imposing a pressure gradient on the gel. The gel becomes more concentrated, and its volume is reduced because of the dehydration (Seright et al. 2006b).

With respect to oil permeability development, researchers focus mainly on the displacement mechanism (Zaitoun et al. 1998; Al-Sharji et al. 1999; Seright et al. 2002), dehydration mechanism (Willhite et al. 2000; Seright et al. 2006b), and both mechanisms (Nguyen et al. 2006). Based on a detailed analysis of Nguyen's data, Seright indicates that the ripping or gel-displacement mechanism dominates over gel dehydration mechanism in their work. The removal of polymer from the core plays a key role in establishing oil pathways by a process that is not directly tied to dehydration (Seright et al. 2004). However, Seright's experimental results show that no noticeable gel production was observed in a Berea core with a permeability of 0.47 Darcy. A possible deduction provided by Seright is that ripping or gel displacement becomes more important as permeability increases for water-wet porous media (Seright et al. 2006b). In view of inconsistent conclusions in Seright's and Nguyen's work, more work should be done to investigate the mechanism for oil permeability development.

## Mechanisms of Disproportionate Permeability Reduction (DPR)

There are several explanations about why some gels can reduce the permeability to oil more than to water. Dawe and Zhang (1994) held that oil and water pass through the gels by different mechanisms. Water passes a gel by diffusing into and swelling the gel, while oil fingers through the gel (i.e., channel segregation). Liang et al. (1995) examined several possible explanations about DPR. Their work indicates that gel shrinking and swelling is unlikely to be responsible for DPR. Rather, wettability plays a limited role in DPR. They ultimately suggest that the segregation of oil and water pathways may play a dominant role in the DPR with an oil-based gel. Nillson et al. (1998) supported a mechanism with segregated pathways for oil and water, the preferred pathways for oil and water being controlled by wettability and partially by pore size. Willhite et al. (2000) and Nguyen et al. (2006) advocated that the subsequent (post-gel-placement) brine flows primarily in the flow channels created by oil. The trapping of residual oil causes a disproportionate permeability to brine. Seright's work concurred that gel and oil primarily flow in the same path—suggesting that the extremely small permeability to water is caused either by trapping of residual oil or gel rehydration which will partially close the existing pathways. Thus the water must flow through the gel itself (Seright et al. 2004; Seright et al. 2006b).

In summary, there are two probable mechanisms for DPR. The first one is pathway segregation, where water mainly flows through the gel films or gel itself. The second mechanism says that the water flows in the same pathways created by the oil phase, and gel rehydration or the trapping of residual oil is responsible for the blocking of water flow channels. Neither explanation is fully accepted. Therefore, more investigations on the mechanism of DPR are necessary to elucidate the primary mechanism.

Polyacrylamide polymers have been routinely used for years to reduce water production in oil wells and for mobility control in injection wells. White et al. (1973) first reported the ability of polyacrylamides to reduce the permeability to water more than to oil. However, if the permeability of the flow path is too large, even such polymers will not be effective. Trivalent cations added to the polymer solution can serve as ionic bridges with the negative sites on polymer molecules causing the mixture to form a solid-like gel structure. Hence, the cross-linked polymer provides greater reductions in permeability than uncross-linked polymers (Lake et al. 2014). Sydansk (1990) developed aqueous gels by crosslinking a polyacrylamide polymer with a Cr(III)-carboxylate-complex crosslinking agent. This gel technology has been tested in many oilfields and often provides effective conformance control (Sydansk and Smith 1988). Field cases show that these cross-linked gels were widely applied and quite successful in oil-field conformance control (Sydansk and Southwell 1998). Our work will be based on this kind of cross-linked polyacrylamide gels.

In this study, experiments on two different scales, the core- and micro-model-scales, were conducted to comprehensively study the mechanisms of oil permeability development and DPR in porous medium treated with Cr(III)-acetate-hydrolyzed polyacrylamide polymer gel. In the core-scale experiments, NMR scanning was used to detect the changes of trapped and free water inside the gel in different ranges of pore size. Thus, NMR can provide insights into the mechanisms of oil flow channel development and DPR. In the micro-model-scale experiments, a microscopic glass-etched model is subject to red oil and blue water flooding alternately after the gel treatment. The entire process is recorded by a video sensor, which can visualize the oil saturation development and DPR mechanism directly.

## Experimental Procedures

### Core-Scale Experiments

In our experiments, the gel is comprised of 0.3% HPAM, 0.4% Cr(III) acetate, and 0.3% NaCl in deionized water. The HPAM has a molecular weight of approximately 12 million daltons, a degree of hydrolysis of about 25%, and a purity of over 98 wt %. The sandstone cores used were 7.1cm long and 2.51cm in diameter. The water-wetted core sample had an absolute permeability of 2.3 Darcy. Before gelant injection, the cores were fully saturated with DI water. Then, 6 pore volumes (PV) of Cr(III)-acetate-HPAM gelant were injected with a fixed pressure gradient of 48.6 psi/ft, and the cores were shut in at 50°C for 24 hours to allow gelation.

In the Nuclear Magnetic Resonance (NMR) T2 test, *nuclear* refers to hydrogen nuclei (1H), which has a magnetic moment (a tiny bar magnet). *Magnetic* means the instrument provides a magnetic field. Under certain conditions, a strong resonance interaction between the hydrogen atom and magnetic field will be generated. This characteristic is *nuclear magnetic resonance*. The magnetic moment synthesis of each hydrogen nucleus is presented as a macroscopic magnetization vector. The magnitude of the magnetization vector is proportional to the number of the hydrogen nuclei, which is proportional to the volume of the fluid. In the NMR T2 spectrum, the signal amplitude is representative of the macroscopic magnetization vector. Therefore, the larger the signal amplitude, the larger the fluid volume. The magnitude of relaxation time reflects the force that the fluid is subjected to. Under the condition that the properties of rock surface and fluid are the same, the magnitude of relaxation time is a measure of the pore size. See the NMR T2 curves in Fig. 1.

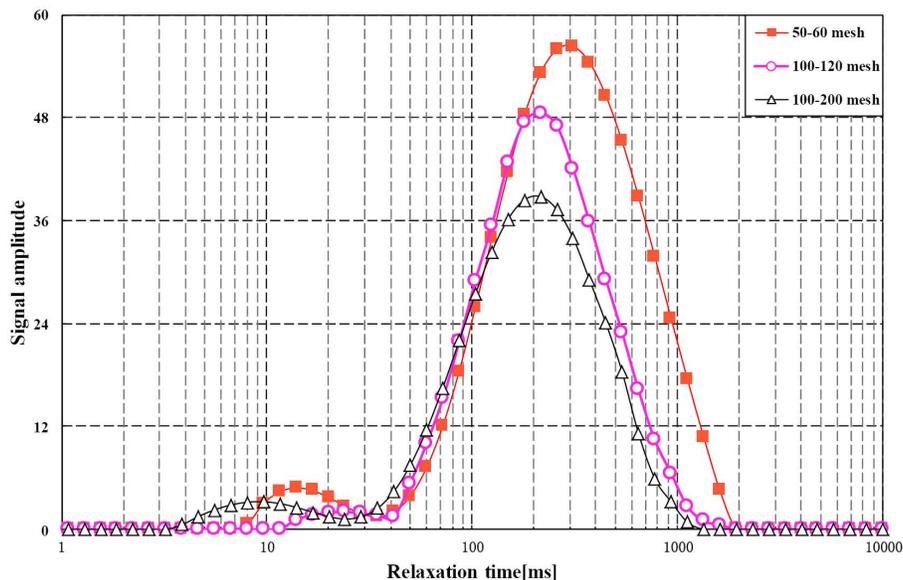


Figure 1—Schematic diagram of nuclear magnetic resonance relaxation time in different size sand grains (Liang et al. 2017).

Figure 1 contains NMR T2 curves of three unconsolidated sand packs saturated with kerosene. The diagram shows that the signal amplitude of 50-60-mesh quartz sand is the greatest; accordingly, the free fluid volumes of the pores are the largest for this grain size. In the case of 100-120 mesh sand when the relaxation time exceeds 100, the signal amplitude becomes smaller than that of 50-60 mesh sand. This phenomenon is consistent with our general understanding that the 50-60-mesh quartz sand possesses larger pores.

Since both oil and water contain hydrogen nuclei, it is difficult to separate them in the magnetic signal directly. Two approaches can be adopted to solve this. The first is to block the water signal by adding paramagnetic  $MnCl_2$  to the water with a concentration more than 50g/L. The second is to block the oil signal by replacing oil with fluorine-tagged oil, in which the hydrogen nuclei has been replaced by fluorine (Liang et al. 2017). In this study, we use the second method to block the oil signal because the Cr(III)-acetate-HPAM gelant is sensitive to  $MnCl_2$ . Gelation will be stopped by  $MnCl_2$  concentrations more than 50g/L.

To comprehensively study the mechanisms, we divided the experiment procedures into five phases: 1. gelant injection and gelation, 2. oil flooding, 3. gel rehydration without an oil phase pressure gradient, 4. oil re-flooding, and 5. water flooding. Each procedure was subjected to a set of NMR scans to catch all the signal changes during these processes. Flooding was stopped for T2 scanning after every 10 or 20 PV of liquid injection. A pressure sensor at the inlet detected the pressure gradient. During the NMR scanning, the core sample was inserted into the NMR probe for T2 scanning and then reset in a holder for subsequent flooding. The experimental procedures of the NMR T2 scanning for DPR experiments are divided into following stages:

- a. Injecting fluorine-tagged oil with a constant speed of 0.5 cm<sup>3</sup>/min (4.8 ft/d flux).
- b. Stopping oil injection for T2 scanning for every 10 PV injection.
- c. Stopping oil injection, T2 scanning at a different time.
- d. Injecting formation brine after 110 PV oil is injected.
- e. Stopping water injection for T2 scanning for every 20 PV injection.

### Micro-Model-Scale Experiments

In this stage of the experiments, a microscopic glass-etched model was alternately flooded with red kerosene oil and blue water after the gel treatment. The gel in this experiment was the same as that in the core-scale experiments. The gel was colorless, the kerosene was dyed red with oil-soluble Sudan Red, and the water was dyed blue with water-soluble methylene blue. This color combination enabled us to distinguish the gel, oil, and water phases. The entire process was recorded by a video sensor.

The procedures of the micro-model experiments were similarly divided into five phases as core-scale experiments. Before gelant injection, the micro-model was fully saturated with water. Then, after about 6 PV of Cr(III)-acetate-HPAM gelant were injected, the micro-model was shut in at 50°C for 24 hours to allow gelation. During the subsequent procedures, the pressure gradient was recorded as flooding proceeded. A video sensor recorded the entire process.

Figure 2 shows an example of the microscope image after oil injection. The green circles indicate grains in the porous medium. There is a distinct boundary between the grains and pore pathways, which were filled with red oil and gel. Red arrows point from oil flow channels created by the oil phase. The colorless space pointed by the blue arrows in the pore pathways is the gel that remained in the pore space. The subsequently injected water is dyed blue, which will be easy to distinguish.

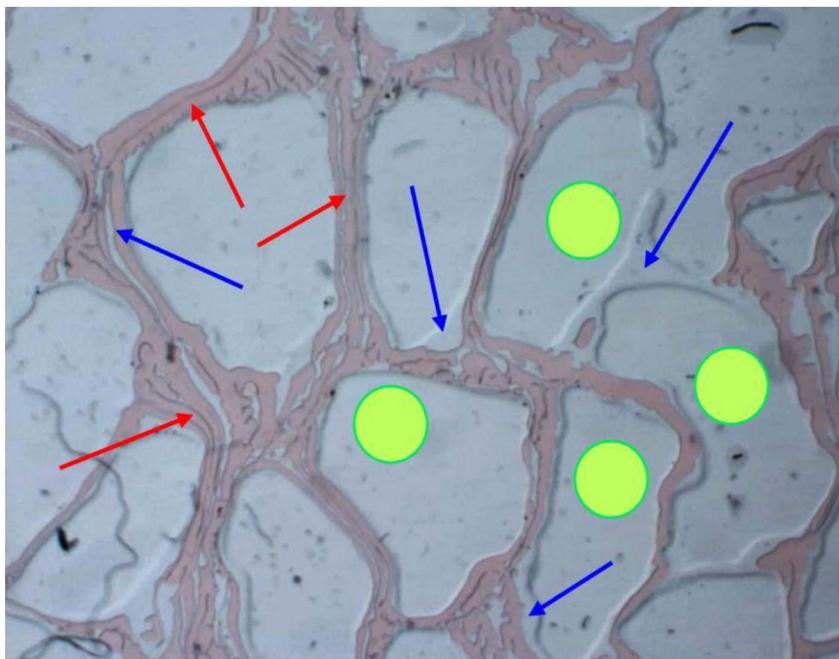


Figure 2—An example of the microscope image after oil injection. The size of this region is about 0.6cmx0.5cm.

## Results and Discussions

Figure 3 shows the organization of the work. It is divided into two objectives: 1. mechanisms of oil permeability development, and 2. mechanisms of DPR. After gel treatment, the oil flooding is to study Objective 1, during which we stop oil injection to study the behavior of gel rehydration. Afterward, subsequent water flooding is to study Objective 2. For each objective, experiments on two different scales, core- and micro-model-scales, were conducted to comprehensively study the mechanisms. NMR scanning in Method 1 can reflect the signal change of trapped and free water inside the gel in different ranges of pore size, while microscope image in Method 2 can visualize the oil pathway development and DPR directly. Method 2 can verify the conclusions in Method 1 and further provide insights of oil, water, and gel distributions.

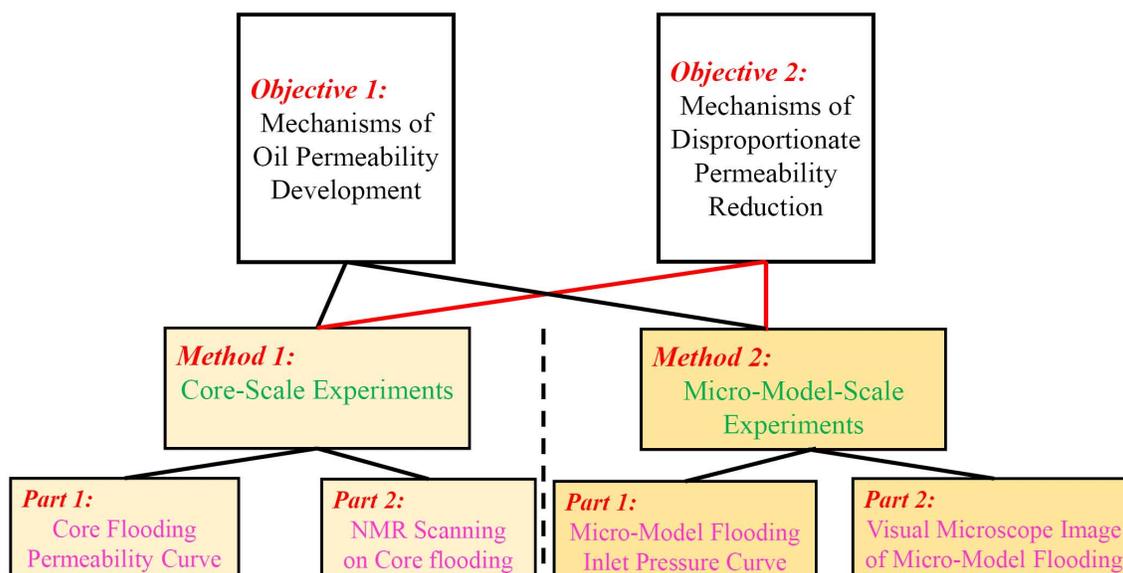


Figure 3—Generalized framework of the organization of the work.

This section studies the underlying mechanisms of DPR by discussing the two different scales of experiments. We discuss the results in three steps: 1. disproportionate permeability/pressure reduction behaviors, 2. mechanisms of oil permeability development, and 3. mechanisms of DPR. For each step, we first discuss the core-scale experimental results after which we discuss the micro-model-scale experiments to verify and enrich the conclusions.

### Disproportionate Permeability Reduction Behaviors

**Core-scale experiments.** The red curve in Fig. 4 demonstrates that the permeability to oil increased gradually from 90 mD to 505 mD during the 110 PV of oil injection. Meanwhile, the oil permeability gradient (i.e., the rate of change of oil permeability) decreased as oil injection proceeded. The first decrease of permeability gradient happened at 7 PV. Then, the oil permeability climbed more slowly after this point. In the literature review, the oil pathways evolution is recognized as resulting from either a gel displacement mechanism or a gel dehydration mechanism (Seright et al. 2006b). If this is true, why would permeability gradient (i.e., the slope of the permeability curve) variation occur? During oil injection, we observed that some gel was produced at the outlet at first but very little gel was produced after this. This implies that the gel-displacement mechanism was dominant at the initial stage of oil flow pathway development. Later, induced by the oil phase pressure increase, gel dehydration occurred and then the flow channel continued to open. However, more evidence is required to support this assumption.

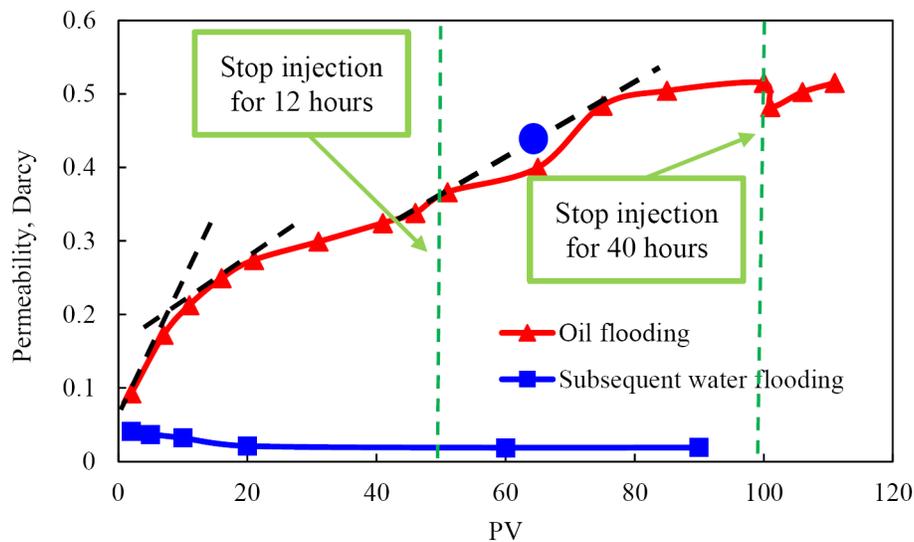


Figure 4—Permeability to oil and water after gel placement in a core with a permeability of 2.3 Darcy.

When 65 PV oil was injected, the permeability was expected to be at the level shown by the blue solid circle in Fig. 4, whereas the actual permeability was smaller. Why did this happen? An issue should be mentioned that when the injected volume reached 51 PV, we stopped oil injection for 12 hours. The permeability reduction means there is an increase of flow resistance. Seright et al. (2006b) mentioned that dehydrated gel will rehydrate when it contacts free water. Therefore, we assumed that gel rehydration causes a slight reduction of oil phase permeability. If our assumption is correct, some free water should remain in the pore space.

When the injected volume reached 100 PV, we stopped injection for 40 hours and observed a noticeable permeability reduction within another 1 PV of oil injection—indicating gel rehydration and its influence on oil permeability. However, more work should be performed to prove this conjecture. The permeability to oil increased significantly during the next 10 PV.

The blue line in Fig. 4 shows the permeability when water was injected after the previous oil-injection stage. The permeability to water decreased sharply from 500 to about 40 mD. In contrast to the oil behavior, the permeability of water maintained at 30mD during the 90 PV water injection.

**Micro-model-scale experiments.** Figure 5 plots the pressure performance during oil and subsequent water injection in the glass-etched model. The behavior is similar to that in the core-scale experiments as the oil and water flooding proceeded. During the oil flooding, as the kerosene was injected into the glass-etched model, the inlet pressure decreased—indicating a continuous opening of the oil flow pathways. After two hours of oil injection, we stopped pumping for 14 hours to leave the glass-etched model with no pressure difference. This step was taken to test whether gel rehydration would occur during the shut-in. When we re-injected oil into the model, a slight pressure increase was observed. However, the permeability reduction only lasted for a short period, which was analogous to the permeability behavior after the 100 PV oil injection in the core-scale experiments. The results are consistent with gel rehydration. During the subsequent water injection, the pressure gradient increased rapidly to a large value (i.e., the permeability to water decreased rapidly as water injection proceeded).

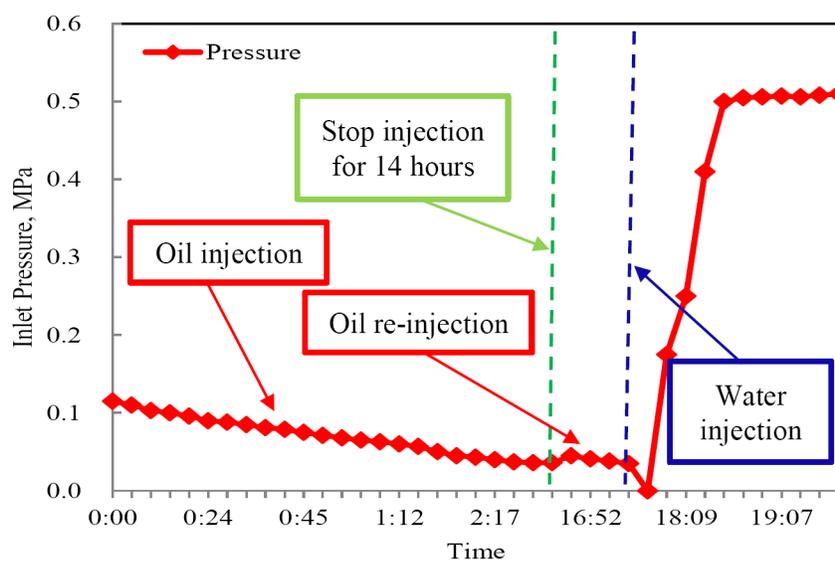


Figure 5—Pressure performance with an injection rate of 0.005 cm<sup>3</sup>/min.

### Mechanisms of Oil Permeability Development

In this section, we study the mechanism of oil saturation development using NMR T2 scanning and visual microscope images.

**Core-scale experiments.** The red curve in Fig. 6 represents the initial status of the core sample that was fully saturated with water. The pink curve shows the signal saturation of the core sample after being flooded with Cr (III)-acetate-HPAM gelant. As described above, a longer relaxation indicates a larger average pore size, and a larger signal amplitude indicates larger free liquid volume. An obvious decrease in signal amplitude occurred in both large and small pores after gelant flooding. As 99% of the Cr (III)-acetate-HPAM gelant is water, the signal change should not be the consequence of a liquid component change in the porous medium.

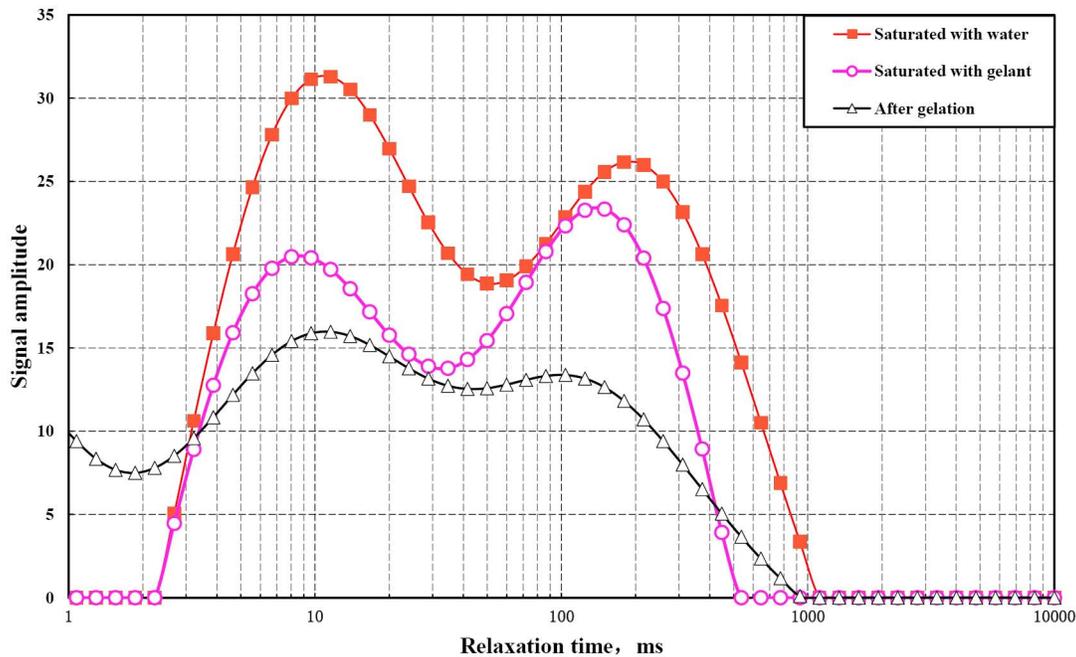


Figure 6—NMR T2 scanning curves for different initial states.

The large difference between the T2 of gelant and pure water is because of the large molecular weight HPAM. The HPAM polymer chain is like a net that can limit the resonance activity between the hydrogen atom and magnetic field. This leads to the decrease of signal amplitude. Some of the large pores are effectively divided into small pores by the polymer chain, which leads to a further decrease of relaxation time. The black curve in Fig. 6 shows the T2 response of the core after gel gelation. A further decline of signal amplitude occurs compared to the situation after gelant injection. This phenomenon can be explained in this way: the gel converts into 3D cross-linked structures that tightly holds the water molecules like a net (<http://baervan.nmt.edu/groups/res-sweep/>). Thus, the resonance activity of the hydrogen atom in water molecules would be further weakened and the signal amplitude would decline as a result. The signal amplitude of the free water is greater than that for the same amount of gel.

Figure 7 shows the NMR T2 scanning curves at different oil injection volumes. A sharp decrease in signal amplitude occurred in the large pores during 2-7 PV oil injection. As the signal amplitude is proportional to the fluid volume, this signal amplitude decreasing in large pores means the replacement of gel by fluorine-tagged oil, which has no signal appearance in NMR T2 scanning. Thus, we can conclude that a gel displacement mechanism in large pores is the primary reason for oil pathway development. The production of some gel and water at the outlet further supports this conclusion. No significant additional signal amplitude decrease in large pores was detected during further oil injection after 7. Gel can dehydrate during this process, but it is difficult for the free water dehydrated from the gel to stay in these large pores. However, with the oil flooding proceeding, there is an upward trend in signal amplitude in small pores. As the signal amplitude is proportional to the volume of free fluid, the rise of signal amplitude indicates an increase of gel or free water. The gel volume could not rise because it is difficult for more gel to be pushed into small pores. As the signal amplitude of free water is higher than the same amount of gel, the only possible explanation is an increase of free water. The Cr(III)-acetate-HPAM gel can dehydrate under an oil phase pressure gradient (Seright et al. 2006b), so the gradual increase of signal amplitude in the small pores results from the increase of free water because of gel dehydration. As for the relatively constant signal amplitude in large pores, a possible explanation is that most of the large pores are saturated with fluorine-tagged oil, and the dehydrated gel in large pores cannot dehydrate further because of its large concentration.

It is possible that a small portion of free water dehydrated from the gel was displaced through the large pores, but this effect is too small to result in a noticeable increase in signal amplitude.

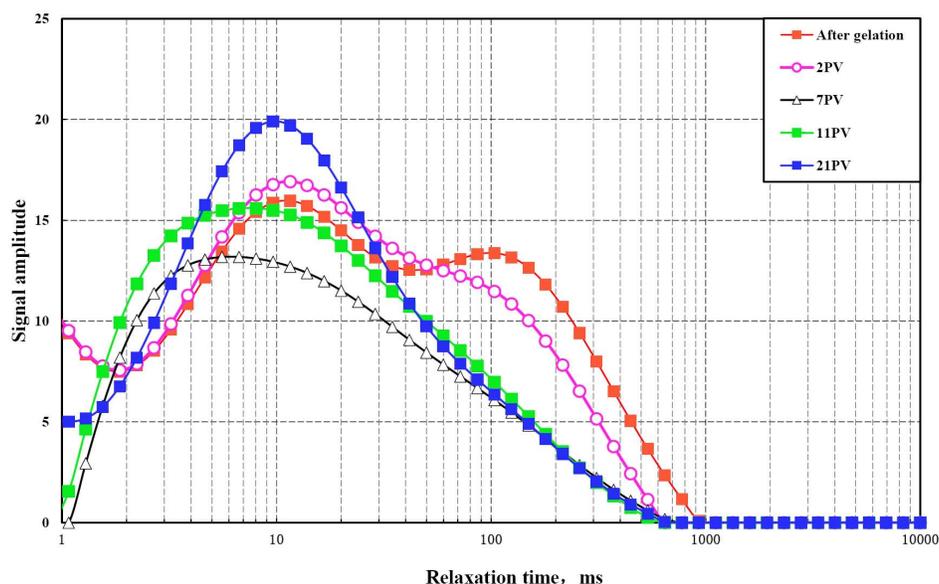


Figure 7—NMR T2 scanning curves at different PV of oil injected.

Figure 8 shows a set of NMR T2 curves at different PV of oil injected to study the mechanism for the further development of oil permeability. We obtained the NMR T2 at 51 PV of oil injection (pink curve) and then stopped flooding for 12 hours. Next, we acquired the second NMR T2 curve (black curve). There was a sharp decline in signal amplitude after the 12-hour shut-in, which indicated a decrease of free water or gel volume. As there was no flooding during this period, the phenomenon might be attributed to the decrease of free water. As mentioned above, the gel can rehydrate when there is possible free water and no oil phase pressure. Thus we can infer that a portion of the free water remained in the flow channels enables the rehydration. The rehydrated gel shows a smaller signal amplitude than the residual free water, which explains the decline of signal amplitude. Thus, after oil flooding, the gel can rehydrate and a smaller portion of residual free water remains in the small pores. When there is no oil phase pressure, the dehydrated gel will rehydrate. This rehydration inevitably reduces permeability to some extent. This explains why the permeability measured at 65 PV is smaller than the point indicated by the blue inference circle in Fig. 4. Later, we continued oil flooding and scanned the corresponding core sample. As expected, the signal amplitude in small pores gradually increased because of gel dehydration while no noticeable change occurred in the large pores. The oil phase permeability kept increasing because of gel dehydration. Thus, gel dehydration mainly occurs in small pores, and the gel dehydrates only under oil-phase pressure.

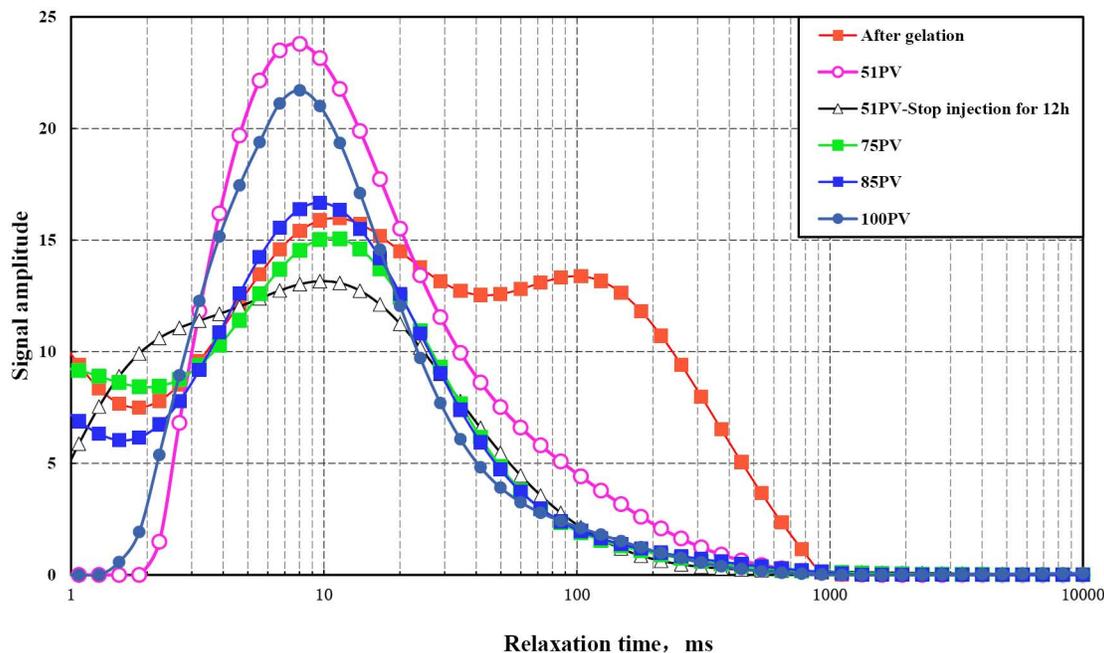


Figure 8—NMR T2 scanning curves at different PV of oil injected.

**Micro-model-scale experiments.** At the beginning of the oil flooding, some gel was produced at the outlet after which it ceased. In this section, we consider the oil pathway development in detail using microscope images.

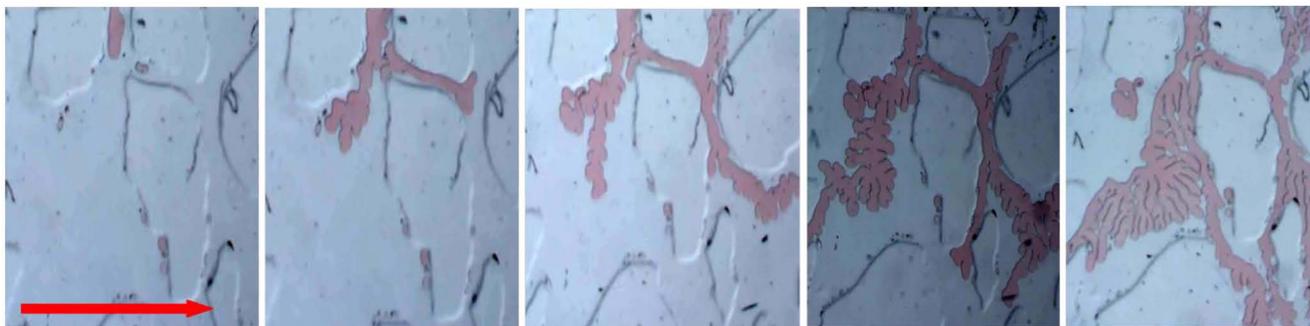


Figure 9—Gel rupture in large pores. From the left to the right, the figure shows the development of the flow channel. The size of this region is about 0.25cmx0.25cm.

At the initial stage of the oil flooding (dyed red), the oil phase extruded slowly through the large pores, and mainly through the middle of them. Later, the oil evolved into multi-directional fingers and displayed a cluster-like shape.

Figure 10 indicates that the oil primarily extruded through the middle of the pores. Two points are worth mentioning. First, there is a break (or breach) in the red flow channel. With continued oil flooding, the break progressed forward and other breaks occurred in the flow channel. However, the oil flowed through the same route even though some breaks developed between oil drops. This indicates that once the flow channel took shape, its connectivity was robust. Second, the oil follows the same route even though there were breaks in the middle of the oil drops. The breaks were strong enough to push the oil drops forward, proving the break is not imbibed. As the gel displacement mechanism is the primary mechanism for the oil pathway development, the colorless breaks must be mainly comprised of gel, and the gel displaced by the oil phase was mainly from the middle of the pores.

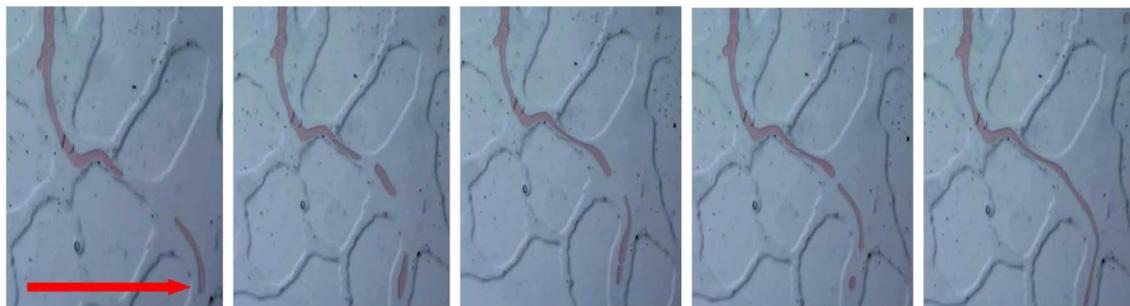


Figure 10—The continuity of oil flow channel in pore throats. From the left to the right, the figure shows the development of the flow channel. The size of this region is about 0.4cmx0.4cm.

Figure 11 indicates that as the oil flooding continued, several pathways developed within one pore pathway. As the blue arrows point out in image (a) and (b), an oil drop extruded near an oil pathway. The oil drops combined with the existing pathway in image (c) at the location where the arrow points. However, the subsequent oil followed flowed in a pathway that is the same as the route of the oil drop, as image (c) and (d) show. A flow channel parallel to the existing pathway was created by subsequent oil. There is a boundary between the two flow channels, which must be comprised of gel. As oil flooding proceeded, the oil channels broadened through the middle of the pores and the flow boundary becomes more distinct. The gel phase was more exposed to the oil phase, promoting gel dehydration and oil pathway development because of the oil phase pressure. The oil permeability further developed because of gel dehydration in these pores.

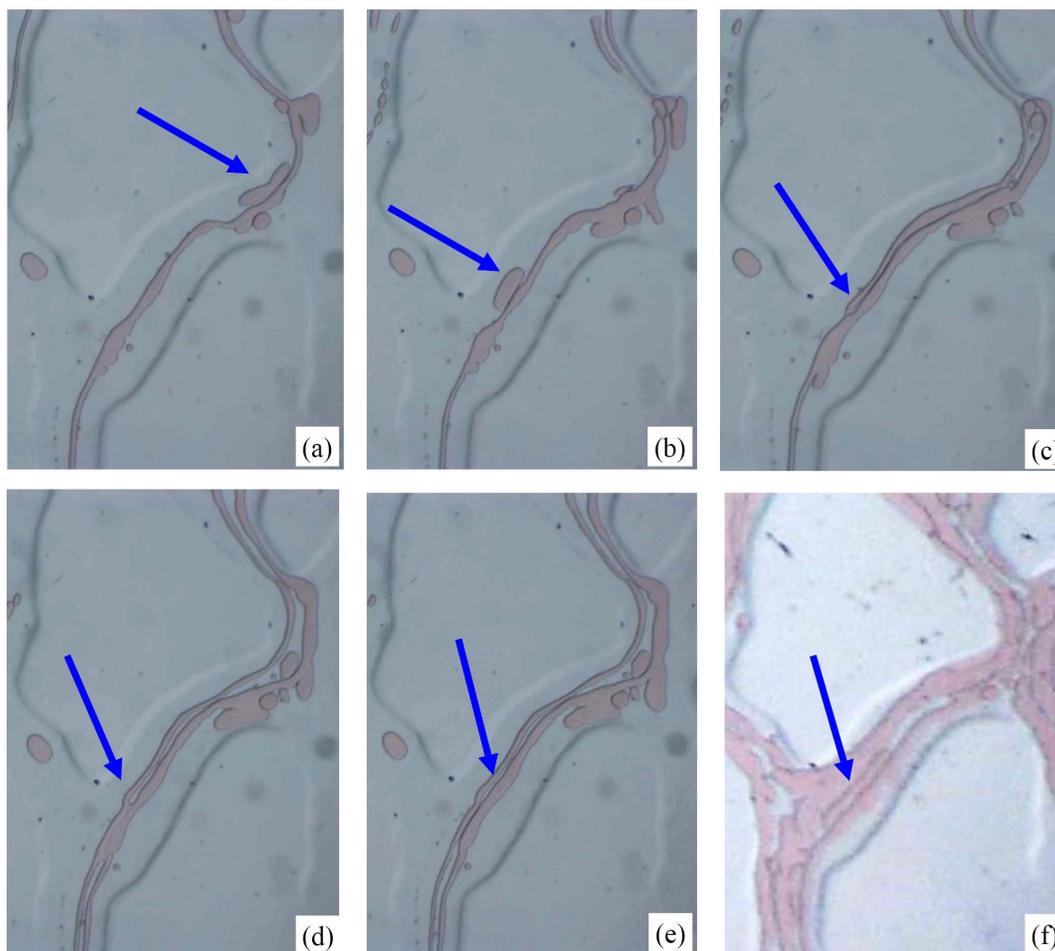


Figure 11—The multiplicity of flow pathways in pore throats. From (a) to (e), the figure shows the development of a flow channel. The size of this region is about 0.15cmx0.1cm.

The blue arrows in Fig. 12 show that different flow channels may have a distinct boundary. Whereas the blue arrows point out that two flow channels may merge. However, the merging was fleeting, which was frequently displaced by colorless drops (white arrows). The colorless break must be free water because dehydration is the main mechanism at this stage and the volume of free water grows subsequently. A small portion of free water drops will be produced at the outlet because of the oil-phase pressure.

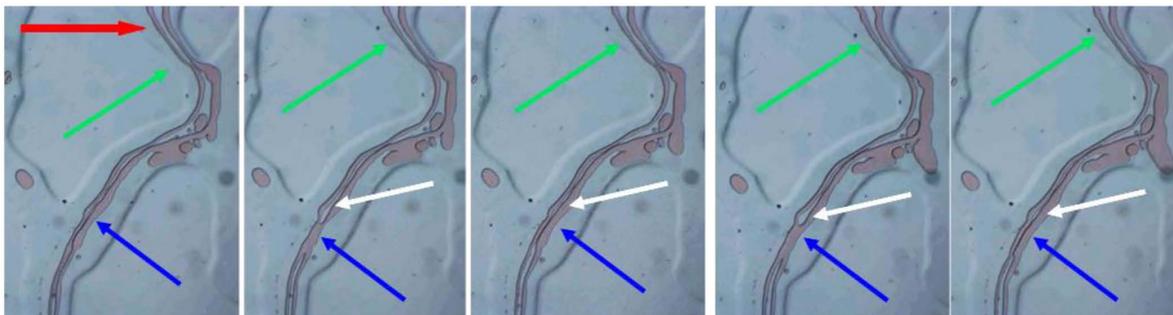


Figure 12—The boundary between flow pathways. From the left to the right, the figure shows the development of the flow channel. The size of this region is about 0.15cmx0.1cm.

### Gel Rehydration with No Oil Phase Pressure Difference and Oil Re-flooding

**Core-scale experiments.** Figure 13 plots a series of NMR T2 curves that demonstrate gel rehydration versus shut-time. When the oil injection reached 100 PV, we stopped flooding and performed the NMR T2 scanning at different times after the start of shut-in. The signal amplitude in small pores decreased gradually as time progressed while signal amplitude in large pores remained unchanged. As discussed earlier, the decrease of signal amplitude is related to the decrease of free water, and the gel rehydrates to diminish permeability to some extent. However, the oil permeability showed only a slight decrease and quickly recovered after an additional 10 PV injection (Fig. 4). When oil injection reached 110 PV, the signal amplitude increased because of gel dehydration. So gel rehydration can only reduce permeability by a limited amount.

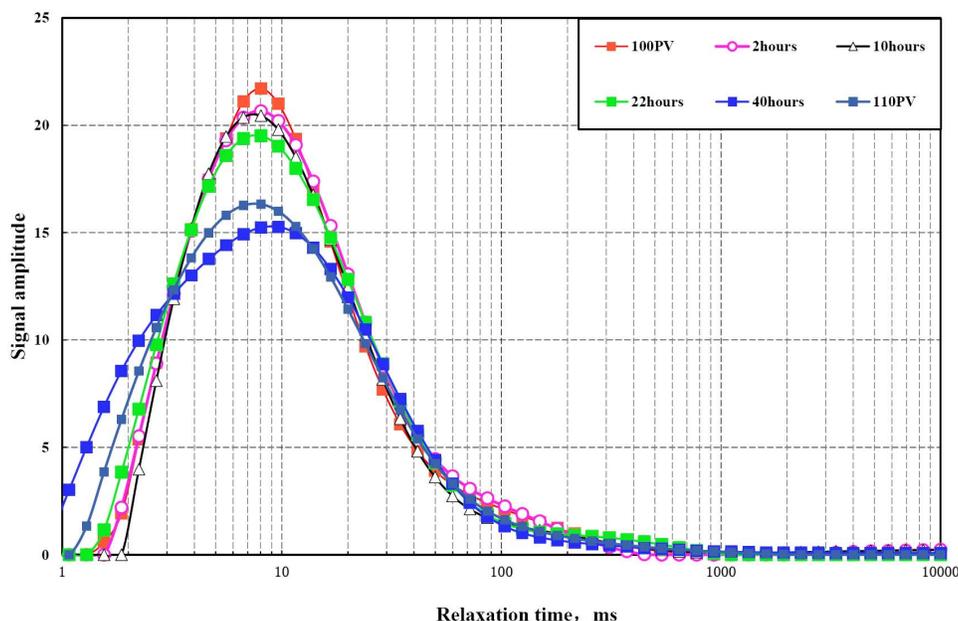


Figure 13—NMR T2 scanning curves at different shut-in time duration.

**Micro-model-scale experiments.** Figure 14 shows that when the oil injection is paused, the gel rehydrated and swelled. A small portion of the oil flow channels was partially constricted (red circles). However, the third picture suggested that the rehydrated gel could be easily extruded or removed by the subsequent oil flooding. The flow channels in pores re-established shortly after the oil flooding restarted. Therefore, the oil permeability easily recovered after the subsequent oil flooding, just as the quick oil permeability recovery in Fig. 4 and Fig. 5. As shown in Fig. 14, only part of oil flow channels are narrowed, so permeability was only temporarily reduced.

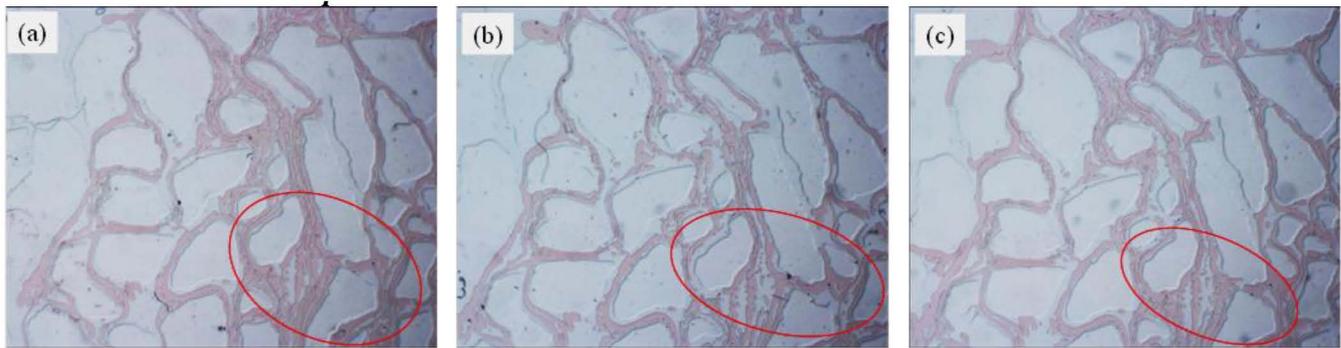


Figure 14—Gel rehydration and oil re-injection. Picture (a) is the oil and gel distribution when the oil injection is paused. Picture (b) is the oil and gel distribution after rehydration for 14 hours. Picture (c) is the oil and gel distribution after oil re-injection for 15mins. The size of this region is about 0.9cmx0.9cm.

## Mechanism of DPR

**Core-scale experiments.** After oil flooding, DI water was subsequently injected into the core sample after 110 PV oil was injected. The corresponding NMR T2 curves are in Fig. 15.

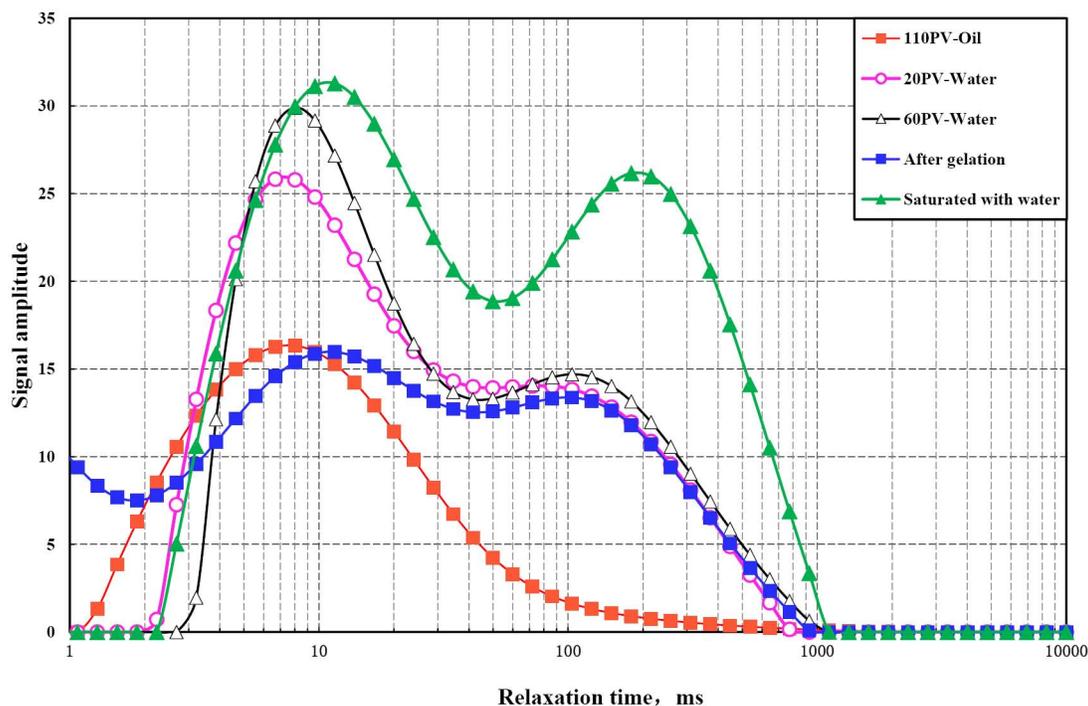


Figure 15—NMR T2 scanning curves at different PV of water injected.

Compared to the NMR T2 curve when oil injection reached 110 PV, the signal amplitude of water flooding in both large and small pores displayed an obvious increase, especially in large pores. Compared to the NMR

T2 curve just after gelation, the signal amplitude at 20 PV in the large pores immediately recovered to a value that is close to the signal amplitude after gel gelation. The signal amplitude in the large pores increased because the dehydrated gel rehydrated and part of the pore space previously occupied by the fluorine-tagged oil was partially replaced by free water. As discussed above, some gel in the large pores would be flushed out and some would dehydrate, so the dehydrated gel absorbed free water and led to the displacement of some fluorine-tagged oil and the increase of signal amplitude. Also, during water flooding, a small part of residual oil was replaced by free water, which also resulted in the increase of signal amplitude.

The rehydrated gel swelled and blocked the existing pathways, so the water must inevitably flow through the gel. As the permeability to water through the gel is extremely small (Seright et al, 2006b), gel rehydration in large pores is one possible reason causing DPR. This assumption will be further demonstrated in the next section.

The large pores, which were previously occupied by the gel, are now occupied by residual oil and free water, and its signal amplitude is roughly the same as the signal amplitude after gelation, As described in Fig. 6, for a given equal volume, the signal amplitude of free water is much larger than matured gel, so we can infer that a large portion of non-signal oil remains in the large pores. Before water flooding, the permeability to oil reached 500 mD (Fig. 4), whereas, the permeability to water immediately dropped to a small value of 40 mD during water flooding. Since a large residual oil saturation is an important phenomenon during this process, it must be one contributor for DPR.

With subsequent water injection, the signal amplitude in large pores was almost unchanged, while the signal amplitude in small pores increased. However, the permeability to water was relatively constant. The growth of the signal amplitude in the small pores indicates extended gel rehydration and the trapping of very little free water in small pores.

**Micro-model-scale experiments.** In this section, we verify the mechanisms for DPR based on microscope images.

Image (a) in Fig. 16 shows that after oil flooding, various large oil saturation flow channels existed in the porous medium. Image (b) in Fig. 16 demonstrates that after subsequent oil flooding, there was still a lot of residual oil trapped in the glass-etched model. This observation is consistent with the deduction from Fig. 15 that there is a large portion of residual oil left in the large pores. In view of the complex distribution of residual oil, a large residual oil saturation provides an important factor that prevents the water from flowing through the pathways created by the oil. Only a portion of oil flow pathways is available for water flow.

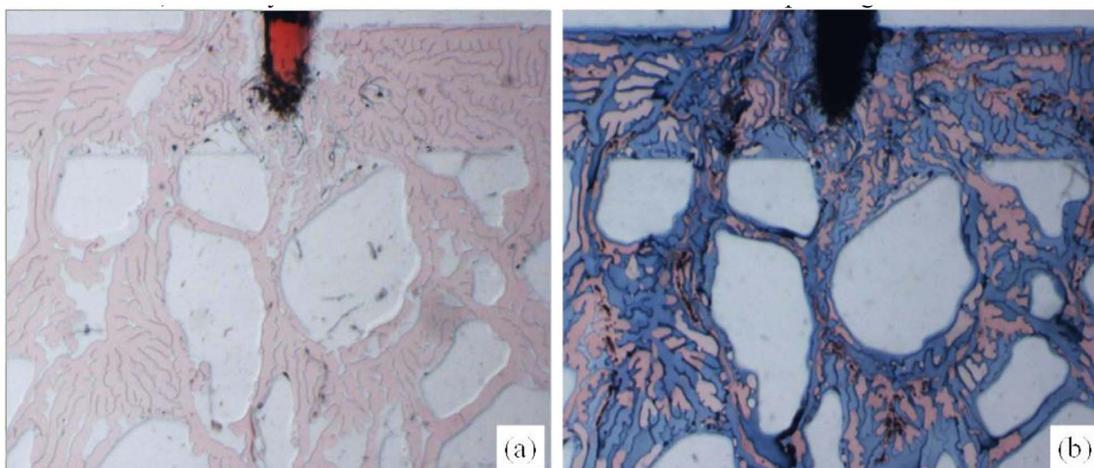


Figure 16—A general view of highly trapped residual oil saturation. Image (a) is the gel and water distribution just after oil flooding. Image (b) is the gel, oil and water phase distribution after subsequent water flooding. The size of this region is about 0.4cmx0.4cm.

The gel dehydrated after oil flooding. When contacted with blue water, the gel immediately rehydrated and swelled. The red circles in the two pictures in Fig. 17 indicate that the residual oil and flow channels became deformed because of the expansion of rehydrated gel. As the red arrows show, a large portion of the water flows through the gel itself and the thin gel films near the grain surfaces. Since the permeability to water through the gel is extremely small (Seright et al. 2006b), flow through gel and gel films is one contributor for DPR.

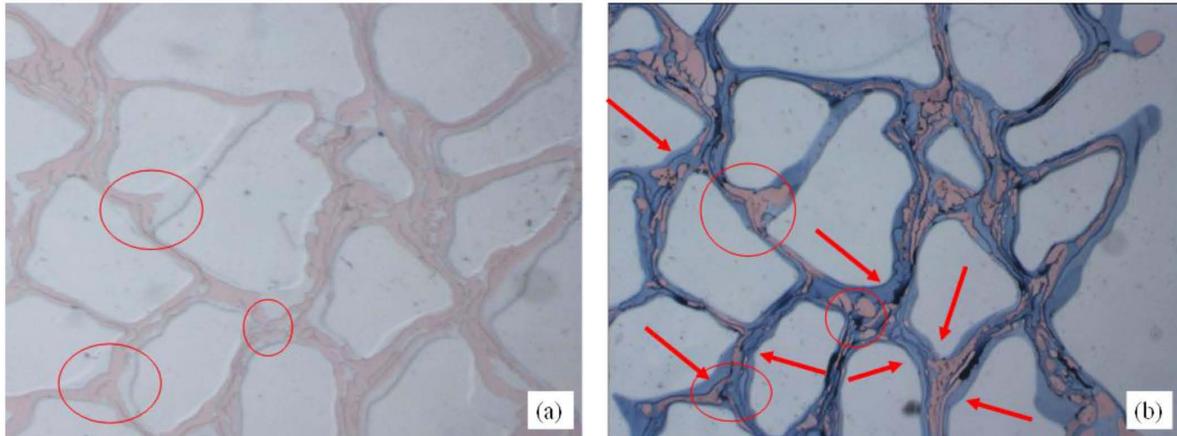


Figure 17—Evidence of water flow through gel films and the gel itself. Image (a) is the picture after oil flooding, image (b) is the picture after water flooding. The size of this region is about 0.6cmx0.5cm.

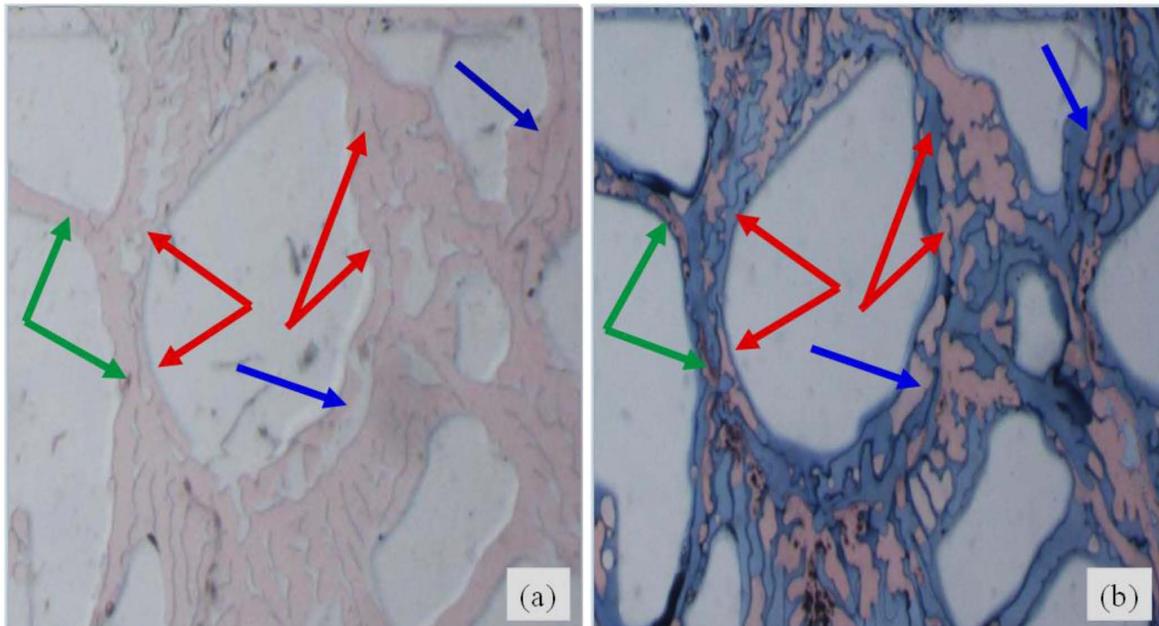


Figure 18—Evidence of swelled gel constricting oil pathways. Image (a) is after oil flooding, image (b) is after water flooding. The size of this region is about 0.2cmx0.2cm.

The red arrows indicate that water does flow through part of the flow pathways created by the oil phase. However, the residual oil drops severely block the pathway. Therefore, it is difficult for water to effectively flow through pathways created by oil. The green arrows in the picture (a) point to an oil flow pathway with a certain width, whereas, the flow channel is severely squeezed into a line by the rehydrated gel. The blue arrows show that the expansion of the dehydrated gel can push and reshape the residual oil, which would

reduce the connectivity of the flow channels. Therefore, it can be concluded that the gel rehydration and expansion is also one contributor to DPR.

Figure 19 is a summary of the mechanisms causing DPR.

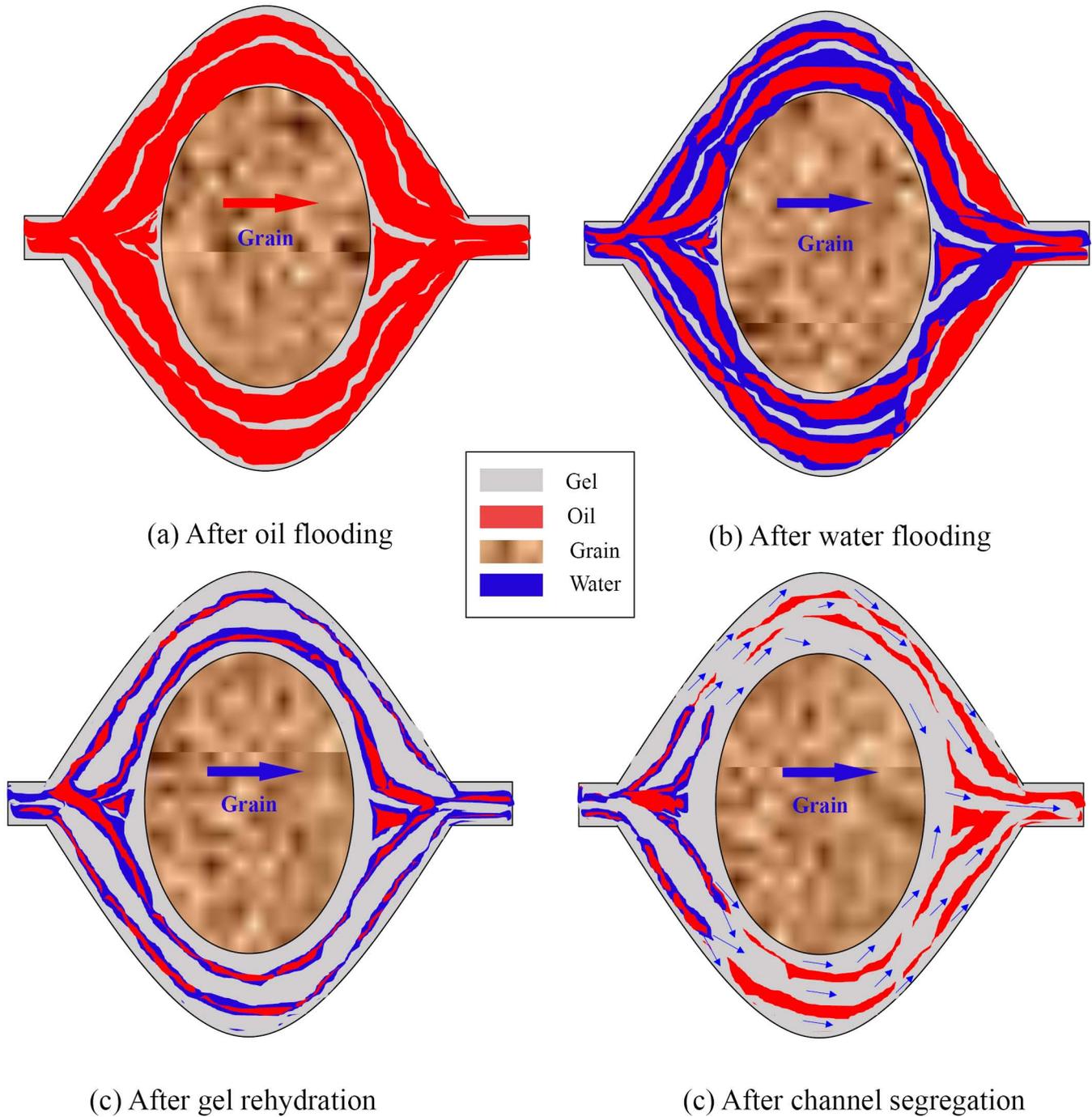


Figure 19—Schematic diagram of the mechanisms causing DPR. Image (a) shows the oil flow channel after oil flooding in the gel-treated porous medium. Image (b) on the upper right shows the blocking effect of the residual oil. Image (c) on the bottom left shows the effect of gel rehydration and expansion, which causes shrinking of flow pathways and deformation of residual oil drop. Image (d) on the bottom right shows channel segregation, which is caused by gel rehydration and trapping of residual oil. Water can only flow through gel body and gel films with extremely small permeability.

## Conclusions

1. Oil initially extrudes through the middle of pores and causes the production of some gel, which is the primary mechanism for oil permeability development. As the oil flooding proceeds, the oil pathways widen and multi-pathways develop in pores. The gel then dehydrates because of the oil phase pressure. The dehydration is the main mechanism in this stage.
2. A portion of free water dehydrated from gel will remain in the medium, and gel can rehydrate when there is no oil-phase pressure gradient. However, the permeability can only be reduced to a limited extent.
3. Water only flows in a small fraction of the oil flow pathways that are created by oil flooding. Residual oil significantly restricts the existing flow channels relative to water. The dehydrated gel immediately rehydrates during water flooding and the expansion of the gel greatly reduces the flow capacity of the available flow channels. Water mainly flows through both the thin gel films and the gel body.

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