



ARTICLE

# Visualization of Water Plugging Displacement with Foam/Gel Flooding in Internally Heterogeneous Reservoirs

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## ABSTRACT

During the displacement of water plugging with binary flooding in internally heterogeneous reservoirs, it is essential to understand the distributions of remaining oil as well as the oil displacement mechanisms at different stages. In this study, two types of internally heterogeneous systems, i.e., vertical and horizontal wells are investigated experimentally through a microscopic approach. The results show that plugging agent types have a greater impact on oil recovery than well types, and foam injection can enhance oil recovery more effectively than gel injection. Additionally, the injection sequence of plugging agents significantly affects oil displacement efficiency. Injecting gel after foam is more beneficial. According to the present results, the main formation mechanisms of remaining oil in each displacement stage are influenced by: capillary force, viscous force, inertial force, shear force, microscopic fingering & channeling.

## KEYWORDS

Microscopic visualization experiment; internally heterogeneous reservoir; remaining oil; foam; gel

## 1 Introduction

The amount and location of the remaining oil in reservoirs are the key factors to be considered during the design and adjustment for the Enhanced Oil Recovery (EOR) operations. The remaining oil distribution in reservoir can be classified into two types including macroscopic and microscopic according to the size of the research scale [1,2]. Research methods of remaining oil can be classified as follows [3–9]: development geology, sequence stratigraphy, reservoir engineering, well logging, numerical simulation, physical simulation, and microscopic experiment. The internal relationship between the two classification methods is that the first six research methods belong to macroscopic analysis while the microscopic experiment method concentrates on microscopic analysis. Recently, with the combination of nuclear magnetic resonance (NMR) technology and core displacement experiment [10–19], the visualization technology from macroscopic displacement to micro imaging has been realized. However, this visualization technology has not yet reached the level of microscopic scale.

The microscopic scale research is the study on the scale of the pore structure from a few microns to a few millimeters, which can be considered as the smallest scale for studying oil displacement mechanisms and the



remaining oil distribution at present. The microscopic visualization method and equipment are required to realize the microscopic scale research. The existing microscopic visualization method is to etch the micro two-dimensional pore structure on the optical glass plate by laser etching technology to imitate the porous structure of the reservoir. The microscopic image of the displacement process can be amplified by the microscope and then captured during the microscopic flooding processes. The captured image can be transferred to the computer simultaneously for the following analysis. Efforts have been done to investigate the remaining oil for the homogeneous reservoir by the microscopic visualization method. So far, few attempts have been made to analyze the remaining oil distribution during complex water shutoff operations for a heterogeneous reservoir by this visualization method.

Due to the difficulty of making heterogeneous optical glass plates and the complexity of displacement process for water plugging with binary systems in internally heterogeneous reservoirs, the numerical simulation method, core displacement method, and macroscopic visualization method are usually chosen to investigate the water shutoff operations with binary systems in internally heterogeneous reservoirs. Few attempts have been made with the microscopic scale visualization method. Besides, the types and distribution characteristics of the remaining oil, as well as the displacement mechanisms during each displacement stage of water shutoff operations with binary systems in internally heterogeneous reservoirs, are still unclear. Therefore, this study carried out a series of microscopic visualization experiments in the internally heterogeneous models with vertical and horizontal well patterns, to investigate the remaining oil types, distribution characteristics, and generation mechanisms based on the analysis of microscopic visualization images.

## 2 Microscopic Visualization Experiments

### 2.1 Experimental Materials

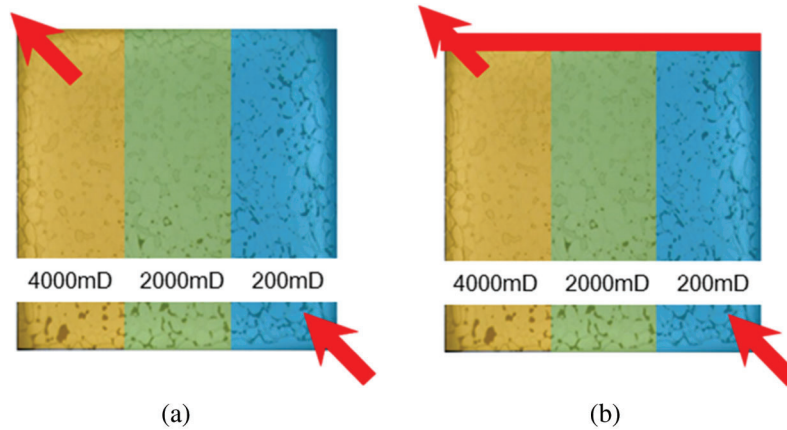
- (1) Brine preparation. Formation water with a total salinity of  $0.7 \times 10^4$  mg/L, and the content of calcium and magnesium ions was  $0.02 \times 10^4$  mg/L in this study.
- (2) Foam system preparation. Because the target reservoir is in the conditions of high temperature and high salinity, the properties of the foam system should be screened and optimized before the experiments. THS-1 was selected as a foaming agent with an optimal concentration of 0.25%. The interfacial tension between the surfactant and crude oil was 1.94 mN/m. The foam system was injected by mixing  $N_2$  with foaming agent of THS-1, and the injection rate was 1 ml/min with the gas-liquid ratio of 1:1.
- (3) Polymer solution preparation. LF polymer was selected in this study since it has a strong temperature and salt resistance. The optimal concentration was 0.6 wt%, and the viscosity of LF polymer solution was 275 mPa·s at room conditions.
- (4) Crude oil preparation. Crude oil with a viscosity of 1.73 mPa·s at reservoir conditions was used.

### 2.2 Experimental Models

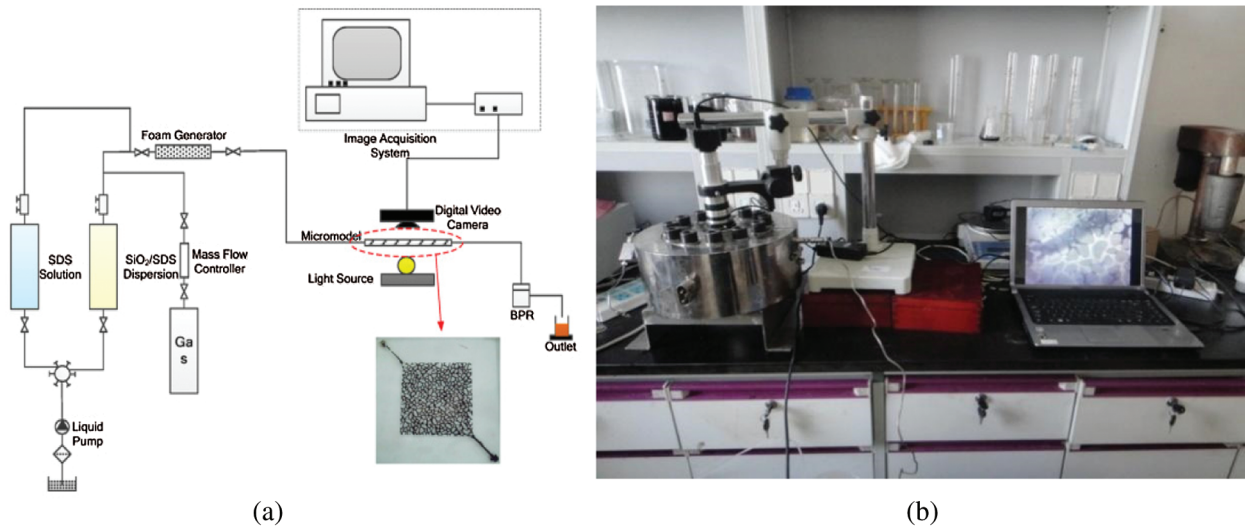
The micro two-dimensional pore structure was etched on optical glass plates with laser etching technology. The pore size of the model was between 0.01-0.1 mm. Therefore, the model could represent internally heterogeneous reservoirs with high-medium-low permeability zones precisely. This study applied a vertical well model (the point export as a vertical well, as shown in Fig. 1a) and a horizontal well model (the horizontal export as a horizontal well, as shown in Fig. 1b). The simulated permeability of three different permeability zones was 4000 mD, 2000 mD, and 200 mD, respectively.

### 2.3 Experimental Methods

The schematic and equipment of the microscopic visualization experiment are shown in Fig. 2.



**Figure 1:** Experimental models (a) Vertical well model (b) Horizontal well model



**Figure 2:** Microscopic visualization experiment setup (a) Schematic (b) Equipment

Experimental procedures were detailed as follows:

- (1) Water was injected into the micro model within the core holder, and the confining pressure was added to 9 MPa.
- (2) The temperature was heated to 80°C and maintained for 90 min.
- (3) Backpressure was added to 8 MPa.
- (4) Water was injected into the micro model at a specific flow rate. Turned on the micro camera and adjusted the focal length till the image was clear. After the flow was stable, the pressure detection system was applied to measure the pressure difference between the input point and the output point of the model.
- (5) Foam system was injected into the micro model continuously with different rates and patterns to reach steady flow condition. Meanwhile, the generation of the foam in the micro porous media was videoed and captured. The pressure difference between the input and the output point of the model was measured when the foam system flowed steadily.

## 2.4 Experimental Scheme Designs

Two types of comparative experiments were implemented in this work: (1) the effect of injected plugging agents on oil recovery in both vertical and horizontal well models, (2) the influence of injection sequence of the plugging agents on oil recovery in the horizontal well models. The experimental scheme designs were detailed in [Tab. 1](#).

**Table 1:** Experimental scheme designs

Well models	Scheme designs
Vertical well model + horizontal well model	<p>Scheme 1 (Foam injection). Water was injected till the water cut at the export reaches 98%, and then foam was reversely injected (gas-liquid co-injected). The injected volume of the foam should be within 0.5 PV, and the gas-liquid ratio was 1:1 with the injection rate of 1 ml/min. After that, water was forwardly injected till the water cut reached 98%.</p> <p>Scheme 2 (Gel injection). Water was injected till the water cut at the export reaches 98%, and then 0.5 PV of LF gel solution was reversely injected at a concentration of 0.6 wt%. After that, water was forwardly injected till the water cut reached 98% or the injected volume reached 2 PV.</p>
Horizontal well model	<p>Scheme A (Injecting gel after foam). Firstly, water was injected till the water cut at the export reached 98%, and then 0.25 PV solution of foam followed by gel were reversely injected into the model. After that, water was injected forwardly till the water cut at the export reached 98% or the injected volume of water reached 2 PV.</p> <p>Scheme B (Injecting foam after gel). Firstly, water was injected till the water cut at the export reached 98%, and then 0.25 PV solution of gel followed by foam were reversely injected into the model. After that, water was injected forwardly till the water cut at the export reached 98% or the injected volume of water reached 2 PV.</p>

## 3 Microscopic Visualization Experiment Results

### 3.1 Injection of Different Plugging Agents in the Vertical Well Model

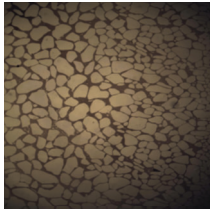
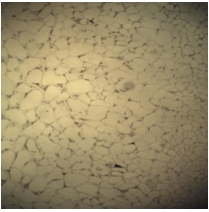
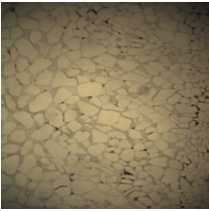
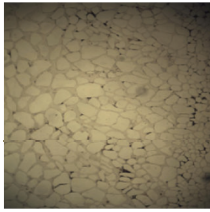
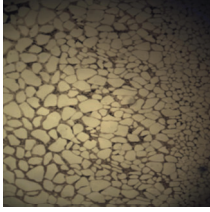
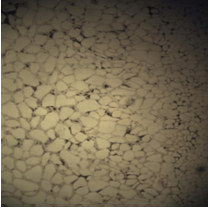
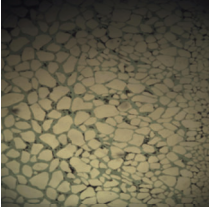
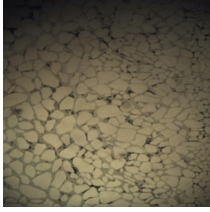
The distributions of remaining oil, the injected foam, and the injected gel in porous media at different displacement stages were observed and captured by conducting Schemes 1 and 2. [Tab. 2](#) showed the remaining oil distributions at different displacement stages with different operation schemes. Recovery factors at different displacement stages in internally heterogeneous vertical well model with different operation schemes were summarized in [Tab. 3](#).

Experimental results showed that the oil recovery of Scheme 1 was similar to that of Scheme 2 at a water cut of 98% in the first water flooding stage. Then, after the plugging agent injection stage, the oil recovery factor of Scheme 1 was slightly higher than that of Scheme 2. After the subsequent water flooding stage, the oil recovery of Scheme 1 was 7.7% higher than that of Scheme 2. Overall, the final oil recovery of Scheme 1 was 8.4% higher than that of Scheme 2 which means the foam injection could be more effective to enhance oil recovery than gel injection.

As shown in [Fig. 3](#), the distribution characteristics of remaining oil in the zones with different permeability were significantly different after the first water flooding stage. The remaining oil mainly existed in the un-swept area in medium and low permeability zones. The oil displacement efficiency in

the high permeability zone was the highest among others, and the remaining oil can be trapped on the edge of large pores in the high permeability zone. The oil displacement efficiency in medium-low permeability zones was worse than that in the high permeability zone due to the poor sweep efficiency.

**Table 2:** Remaining oil distributions in internally heterogeneous vertical well model

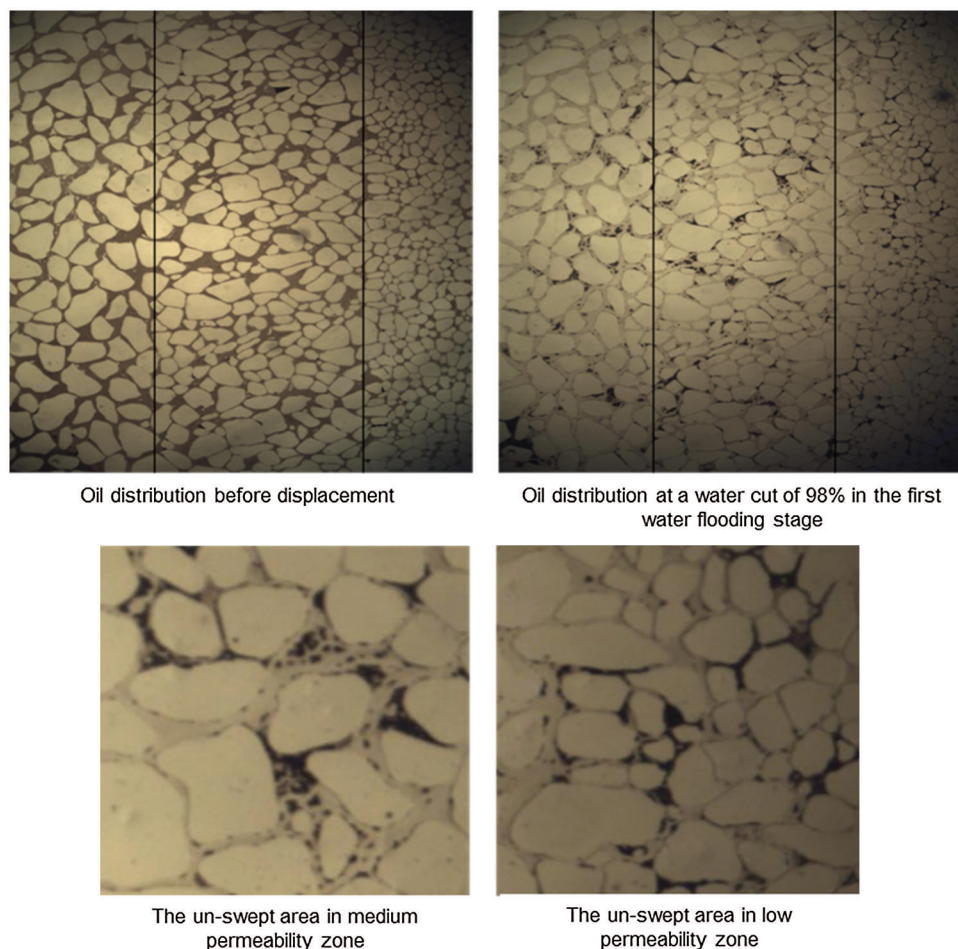
Experimental schemes	Remaining oil distribution			
	Original state	After water flooding	After injecting plugging agent	After subsequent water flooding
Scheme 1: foam injection				
Scheme 2: gel injection				

**Table 3:** Recovery factors in internally heterogeneous vertical well model

Experimental schemes	Recovery factor/%				
	Water flooding stage	Plugging agent injection stage	Subsequent water flooding stage	Incremental oil recovery	Final recovery factor
Scheme 1: foam injection	38.3	12.3	18.7	31.0	69.3
Scheme 2: gel injection	39.7	10.2	11.0	21.2	60.9

As illustrated in Fig. 4, the oil displacement efficiency in the zones with different permeability were drastically different after injecting foam system, and the remaining oil mainly existed in un-swept areas in the low permeability zone. In medium and high permeability zones, oil was displaced effectively owing to the Jamin effect and the compressed effect caused by the foam. In addition, after the injection of the gel solution, the oil displacement efficiencies in different permeability zones were similar. The remaining oil in the large pores of the high/medium permeability zones was displaced. Meanwhile, gel occupied those large pores. The remaining oil in the high/medium permeability zones, mainly distributed in the edge of large pores, while the remaining oil in the low permeability zone, mainly distributed in un-swept areas.

As shown in Fig. 5, after the subsequent water flooding, the oil displacement efficiency of Scheme 1 (foam injection) was significantly higher than that of Scheme 2 (gel injection). The remaining oil of Scheme 1 appeared in un-swept areas (i.e., the edge of the model). Remaining oil saturation of Scheme 2 (gel injection) remained high in the medium-low permeability zones.



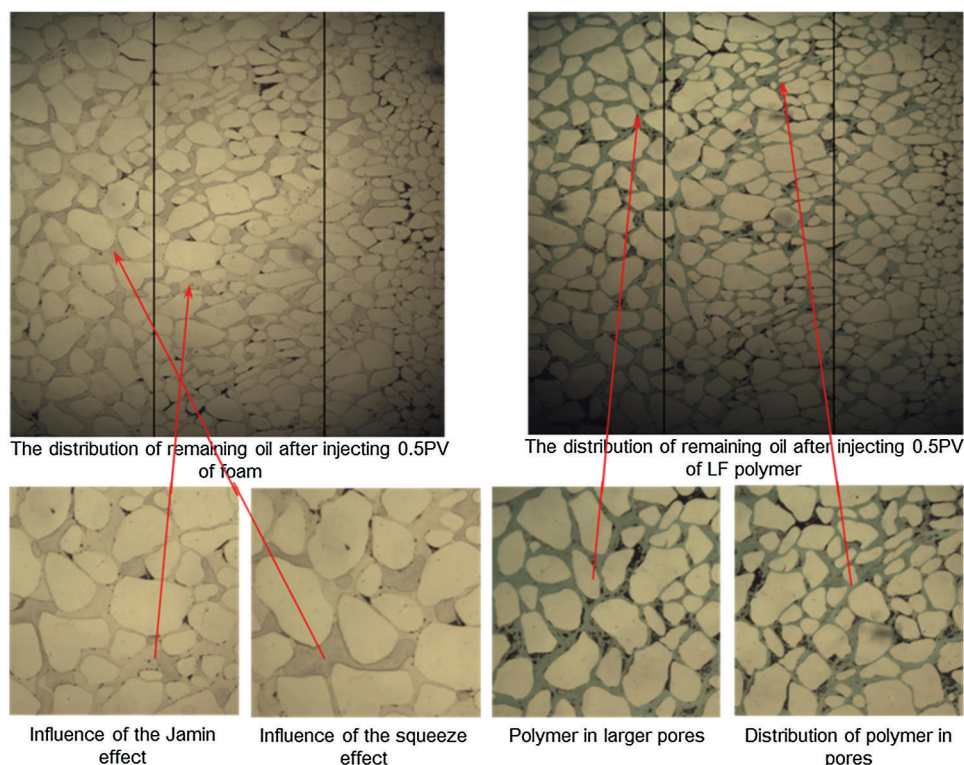
**Figure 3:** Distribution of remaining oil after water flooding stage in the vertical well model

### 3.2 Injection of Different Plugging Agents in the Horizontal Well Model

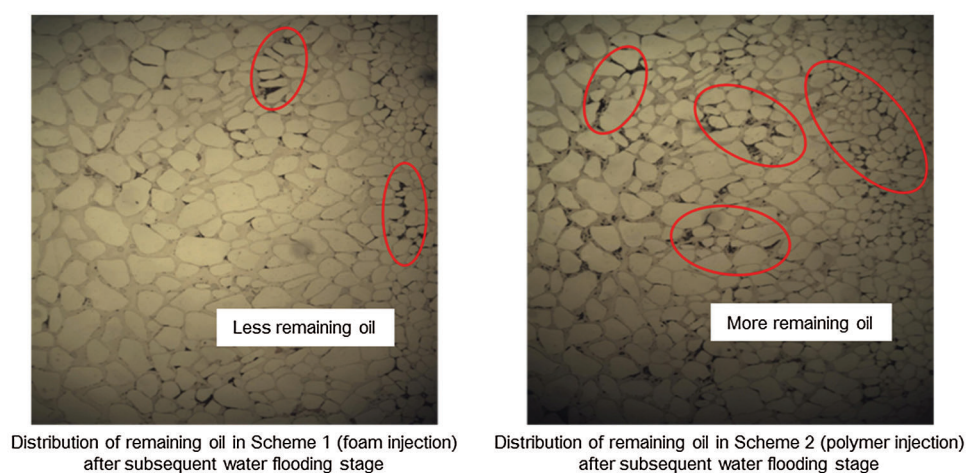
The distributions of remaining oil, foam and gel in porous media at different stages were observed captured by implementing Schemes 1 and 2. [Tab. 4](#) showed the remaining oil distributions at different displacement stages with different operation schemes. Recovery factors at different displacement stages in internally heterogeneous horizontal well model with different operation schemes were summarized in [Tab. 5](#).

Experimental results showed that the oil recovery of Scheme 1 was similar to that of Scheme 2 after water flooding stage. Then, after the plugging agent injection stage, the oil recovery factor of Scheme 1 (foam injection) was slightly higher than that of Scheme 2 (gel injection). After the subsequent water flooding stage, the oil recovery of Schemes 1 was 3 times higher than that of Scheme 2. Overall, the final oil recovery of Scheme 1 was 10.6% higher than that of Scheme 2 which means that the foam injection could be more effective to enhance oil recovery than gel injection.

As shown in [Fig. 6](#), the distributions of remaining oil in different permeability zones were markedly different, and the remaining oil mainly distributed in medium and low permeability zones. The oil displacement efficiency in the high permeability zone was the highest among others. The remaining oil saturation in medium-low permeability zones remained high due to poor sweep efficiency.



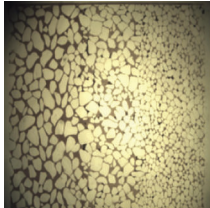

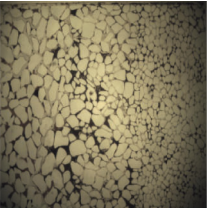
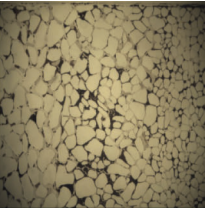
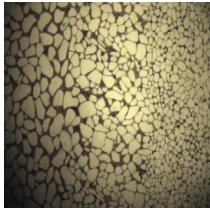
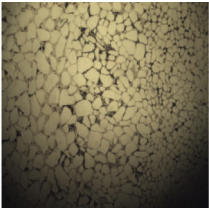
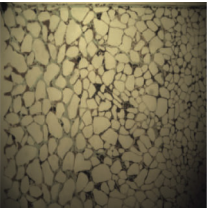
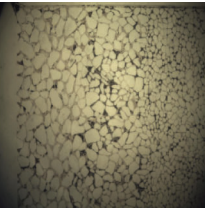
**Figure 4:** Distribution of remaining oil after plugging agent injection stage in the vertical well model



**Figure 5:** Distribution of remaining oil after subsequent water flooding in vertical well model

As shown in Fig. 7, after the foam injection, the oil displacement efficiency in three zones were not changed greatly compared with the first water flooding stage. The remaining oil saturation reduced near the export but remained high far from the export. The oil displacement efficiency of Scheme 2 (gel injection) was higher than that of Scheme 1 (foam injection). In high permeability zone, remaining oil in large pores was displaced, and these large pores were occupied by the injected gel. Remaining oil in the high permeability zone, mainly distributed on the edge of large pores; the remaining oil saturation in medium-low permeability zones remained high after the gel injection.

**Table 4:** Remaining oil distributions in internally heterogeneous horizontal well model

Experimental schemes	Remaining oil distribution			
	Original state	After water flooding	After injecting plugging agent	After subsequent water flooding
Scheme 1: foam injection				
				

**Table 5:** Recovery factor in internally heterogeneous horizontal well model

Experimental schemes	Recovery factor/%				
	Water flooding stage	Plugging agent injection stage	Subsequent water flooding stage	Incremental oil recovery	Final recovery factor
Scheme 1: foam injection	36.7	9.7	14.0	23.7	60.4
Scheme 2: gel injection	35.4	9.2	5.2	14.4	49.8

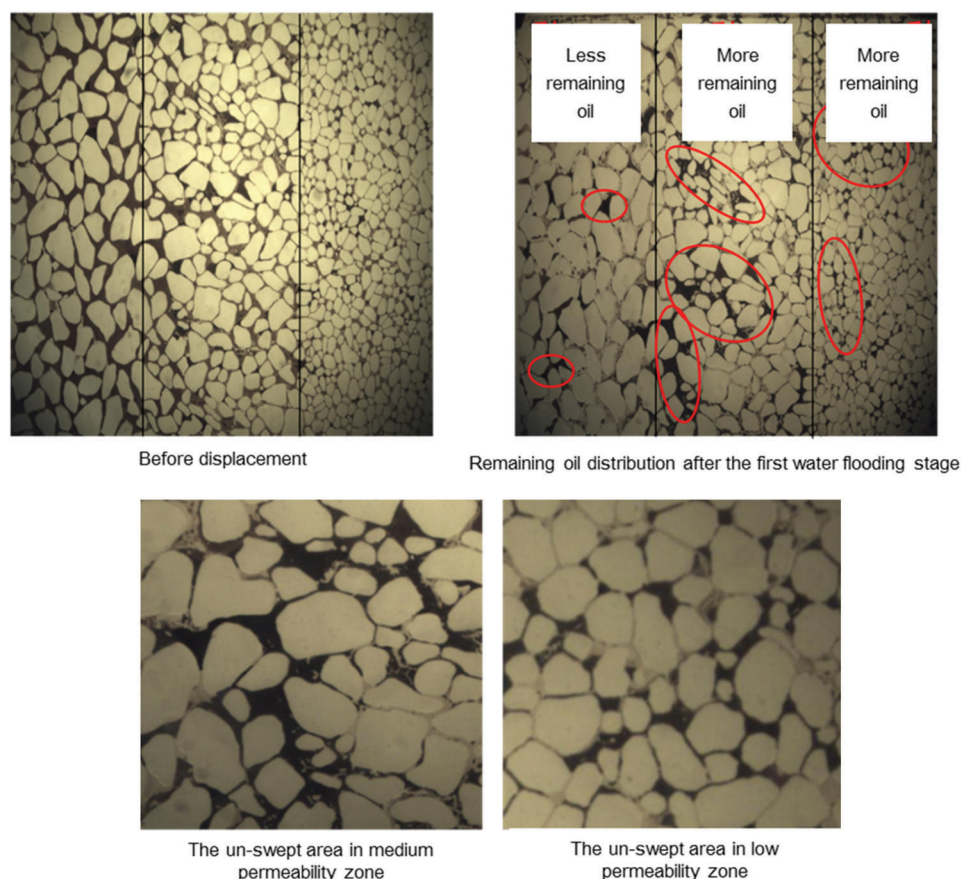
Fig. 8 showed the remaining oil distribution after the subsequent water flooding. The oil displacement efficiency of Scheme 1 (foam injection) was higher than that of Scheme 2 (gel injection) in medium and low permeability zones. In addition, in medium and low permeability zones, remaining oil of Scheme 1 (foam injection) mainly distributed at the edge of large pores and in the dead pore volume; remaining oil saturation of Scheme 2 (gel injection) remained high.

### 3.3 Different Injection Sequence of Plugging Agents in the Horizontal Well Model

The distributions of remaining oil, foam and gel in the horizontal well model at different displacement stages were observed and captured by implementing Schemes A and Schemes B. Tab. 6 showed the remaining oil distributions at different displacement stages in internally heterogeneous horizontal well model with different injection sequences. Recovery factors at different displacement stages were obtained and summarized in Tab. 7.

From the experimental results shown in Tab. 7, the oil recovery of Scheme A is similar to that of Scheme B at a water cut of 98% in the first water flooding stage. Then, after the plugging agent injection stage, the oil recovery factor of Scheme A is slightly higher than that of Scheme B. After the subsequent water flooding stage, the oil recovery of Scheme A is twice that of Scheme B. Overall, the final oil

recovery of Scheme A is 11.5% higher than that of Scheme B. Therefore, the injection sequence of plugging agents can affect incremental oil recovery significantly, and the oil displacement efficiency of Scheme A is markedly higher than that of Scheme B.



**Figure 6:** Distribution of remaining oil after the first water flooding stage

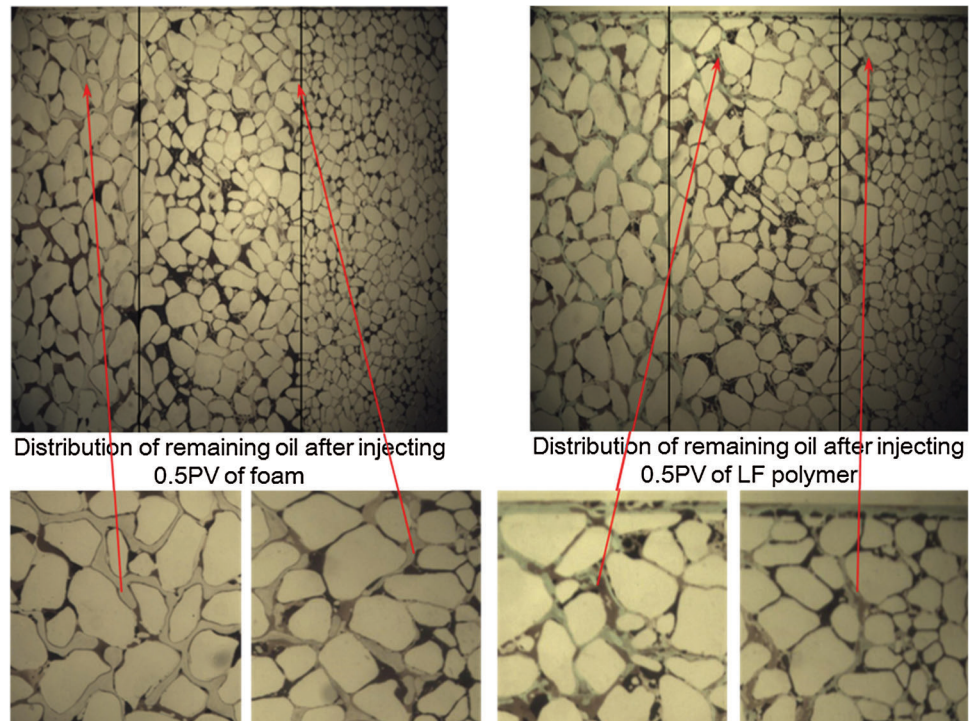
As shown in Fig. 9, remaining oil in medium and low permeability zones was displaced more effectively by implementing Scheme A, where the remaining oil only existed in un-swept areas. The remaining oil saturation of Scheme B in medium-low permeability zones remained high after the subsequent water flooding.

#### 4 Characteristics and Mechanisms of Microscopic Remaining Oil

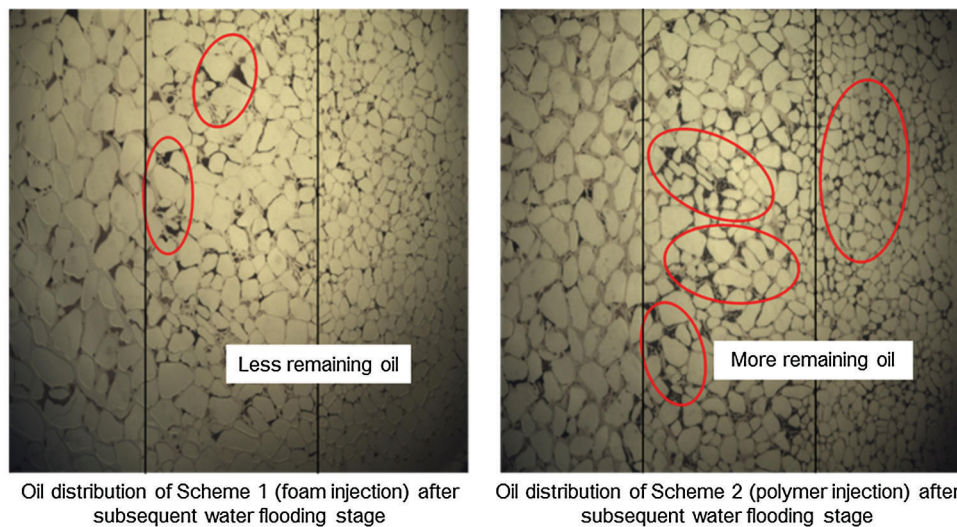
As shown in Fig. 10, remaining oil can be classified into two types based on the pore space volume occupied by them, block-type and dispersed type. The former one, including the block-type remaining oil in the un-swept area and the cluster-like remaining oil in the swept area, occupied more pore spaces and mainly appeared in the primary recovery stage. The latter, including pole remaining oil, corner remaining oil and isolated remaining oil, occupied fewer pore spaces and mainly appeared in the secondary and tertiary recovery stages.

Flow in porous media can be affected by capillary force, viscous force, inertial force, shear force and so on [20–23]. In addition, experiment results showed that the following parameters affected the types and distribution characteristics of remaining oil during the water plugging operation: (1) capillary force, viscous force, inertial force, and shear force; (2) microscopic viscous fingering; (3) adhesion of the

porous media (oil-wet); (4) microscopic water channeling due to heterogeneity; (5) the snap-off of oil flow caused by the high pore-throat aspect ratio. Tab. 8 detailed the effect of the factors on remaining oil distribution characteristics.

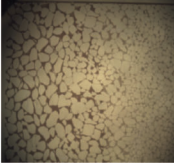
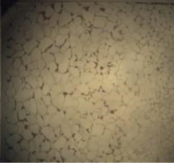
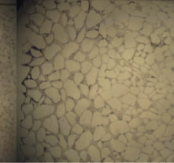
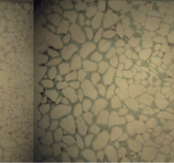
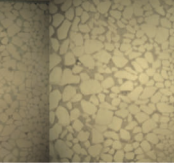
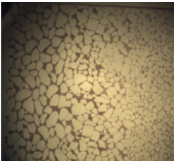
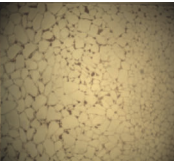
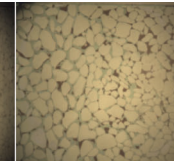
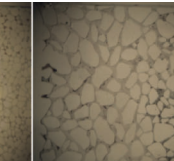
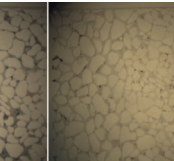


**Figure 7:** Distribution of remaining oil after plugging agent injection in the horizontal well model



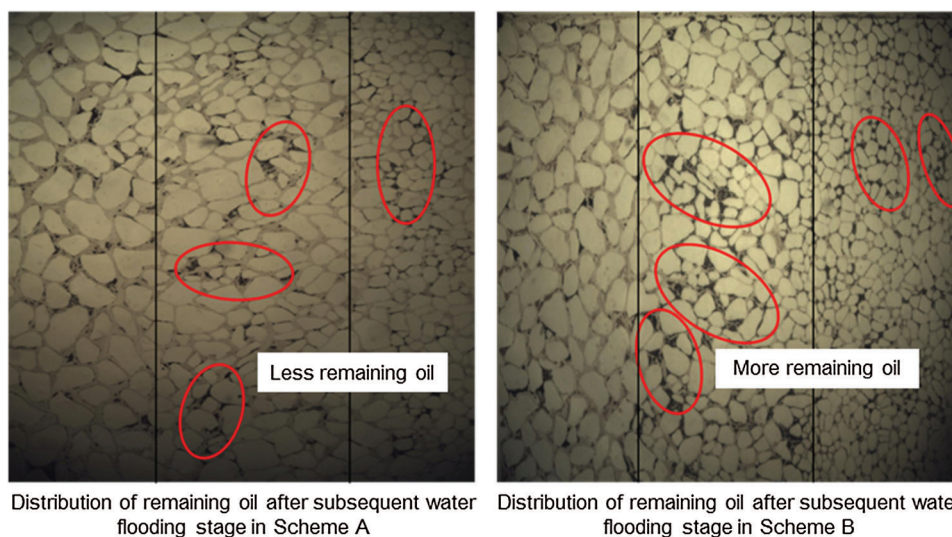
**Figure 8:** Distribution of remaining oil after subsequent water flooding in horizontal well model

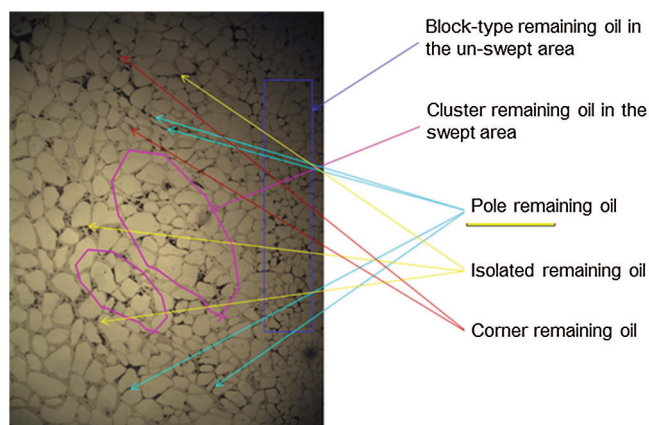
**Table 6:** Remaining oil distributions in internally heterogeneous horizontal well model with different injection sequences

Experimental schemes	Remaining oil distribution				
	Original state	After water flooding	After injecting 1st plugging agent	After injecting 2nd plugging agent	After subsequent water flooding
Scheme A (foam + gel)					
Scheme B (gel + foam)					

**Table 7:** Recovery factor in internally heterogeneous horizontal well model with different injection sequences

Experimental schemes	Recovery factor/%				
	Water flooding stage	Plugging agent injection stage	Subsequent water flooding stage	Incremental oil recovery	Final recovery factor
Scheme A (foam + gel)	37.6	5.2 + 5.7	15.2	26.1	63.7
Scheme B (gel + foam)	36.4	4.9 + 3.2	7.7	15.8	52.2

**Figure 9:** Distribution of remaining oil of Schemes A and B



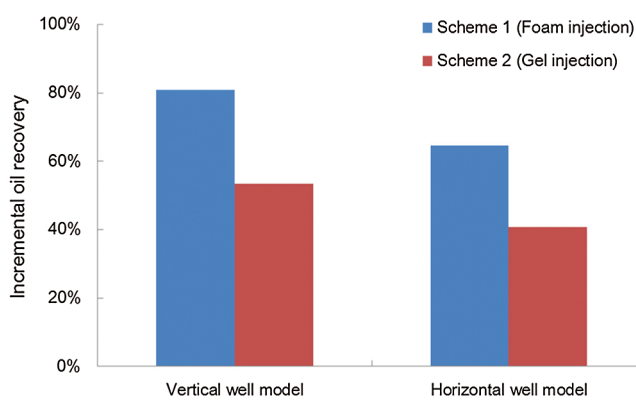
**Figure 10:** Types of remaining oil

**Table 8:** Distribution characteristics and mechanisms of microscopic remaining oil

Types of remaining oil		Hydrodynamics (microscopic mechanism)	Distribution characteristics	Formation stage
Block-type remaining oil	Block-type in un-swept area	Resistance force: viscous force Oil displacement force: inertia force and shear force Displacing fluid cannot flow into the pore-throat area. Inertia force and shear force can't displace remaining oil effectively.	Remaining oil distributes in the un-swept area, i.e., the edge of the model.	Block-type remaining oil mainly appears in the primary recovery stage.
	Cluster in water swept area	Resistance force: viscous force Oil displacement force: inertia force and capillary force Oil displacement forces in water-wet reservoirs are limited and cannot overcome the viscous force.	Remaining oil distributes in narrow pores near the swept areas. It is caused by water fingering and channeling.	
Dispersed remaining oil	Pole	Resistance force: viscous force and capillary force Oil displacement force: inertial force Inertial force cannot overcome the viscous force and capillary force during displacement process.	Remaining oil mainly appears in throats especially in narrow throats.	Dispersed remaining oil mainly appears in the secondary and the ternary recovery stages.
	Corner	Resistance force: viscous force Oil displacement force: shear force Shear force cannot overcome the viscous force during displacement process.	Remaining oil mainly appears in un-swept areas.	
	Isolated-type	Resistance force: viscous force and capillary force Oil displacement force: inertial force and shear force Oil displacement force cannot overcome resistance the force during displacement process.	Remaining oil mainly appears in large pores and water-wet porous media.	

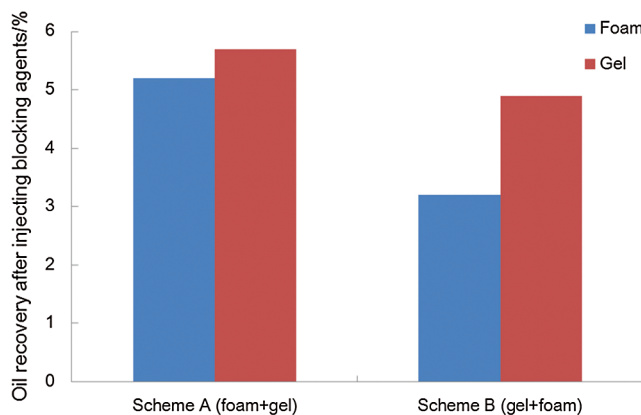
## 5 Analysis and Discussion of Oil Displacement Efficiency of Different Schemes

Based on the experimental results, in terms of the incremental oil recovery, the vertical well model outperformed the horizontal well model. The oil recovery difference between the two models was caused by the permeability distribution characteristics of the heterogeneous models and the well locations. For the vertical well model, the vertical well was located in the high permeability zone. For the horizontal well model, the horizontal well was located through the high-medium-low permeability zones. Therefore, the displacement efficiency of the vertical well was higher than that of the horizontal well, which caused a higher recovery for the vertical well model than for the horizontal well model. In addition, as shown in Fig. 11, Scheme 1 (foam injection) outperformed Scheme 2 (gel injection), and plugging agent types had a greater impact on the incremental oil recovery compared with well types.



**Figure 11:** Comparison of incremental oil recovery between Schemes 1 and 2

Furthermore, for the horizontal well model, the oil recovery of Scheme A (foam + gel) was higher than that of Scheme B (gel + foam). As illustrated in Fig. 12, oil recovery during the foam injection period was lower than that during the gel injection period, which indicated that injecting foam before injecting gel strengthened the gel's performance in oil displacement, whereas injecting gel before foam weakened the foam's performance in displacing oil.



**Figure 12:** Comparison of oil recovery between Schemes A and B

In Scheme A, the injected foam selectively blocked high permeability and high water saturation zones, and the subsequently injected gel strengthened the foam's blocking effectiveness. In Scheme B, the injected gel blocked some large pores, which could weaken the blocking effect of the foam.

Given the microscopic oil displacement mechanisms, foam injection has the following advantages compared with gel injection:

- (1) The injected surfactant can alter the wettability of porous media, which is conducive to desorption of the crude oil from rock surfaces.
- (2) Foam can change the rheology of crude oil, the viscosity and the limiting shear stress can be reduced.
- (3) Interfacial tension can be reduced by the injected foam, oil droplets flow more easily through the throat and the oil flow rate can be increased as well.
- (4) O/W (oil in water) emulsion can be formed after the addition of surfactant because of the emulsification and entrainment effect, so oil droplets in O/W emulsion can flow towards the area with lower pressure.
- (5) Foam system has higher sweep efficiency compared with gel solution due to inherent properties of the foam (compressible non-Newtonian fluid).
- (6) Due to Jamin effect, the injected foam can form resistance zones in both high permeability and high water saturation regions, thus it can block high permeability zone and activate low permeability zone.

## 6 Conclusions

- (1) Based on the experimental results of different plugging agent types, it can be found that: 1) foam injection outperforms gel injection in terms of oil recovery and oil displacement efficiency; 2) plugging agent types have a greater impact on oil recovery compared with well types.
- (2) Based on the experimental results of different injection sequence, we can find that: 1) the injection sequence of plugging agents significantly affects the oil displacement efficiency; 2) injecting foam system followed by gel solution can strengthen the oil displacement efficiency of the gel solution, while injecting gel first cannot strengthen the subsequent foam's performance in improving oil displacement efficiency.
- (3) During the displacement process of water plugging with binary systems, the remaining oil can be classified into two types: the block-type remaining oil (incl. block-type remaining oil in un-swept area and cluster remaining oil in swept area) and dispersed remaining oil (incl. pole remaining oil, corner remaining oil, and isolated remaining oil). The former one mainly appears at the primary displacement stage, while the latter mainly appears at the secondary and tertiary displacement stages.
- (4) During the displacement process of water plugging with binary systems, the main formation mechanism of remaining oil can be summarized as follows: 1) capillary force, viscous force, inertial force and shear force; 2) microscopic fingering due to viscosity difference; 3) adhesion in porous media; 4) water channeling due to heterogeneity; 5) oil truncation due to pore-throat resistance mutation.

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