

# Laboratory Experimental Optimization of Gel Flooding Parameters to Enhance Oil Recovery during Field Applications

Jianguang Wei, Xiaofeng Zhou,\* Dong Zhang, and Jiangtao Li



Cite This: *ACS Omega* 2021, 6, 14968–14976

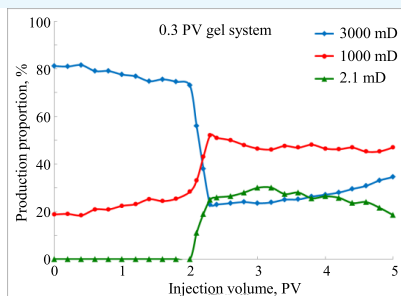
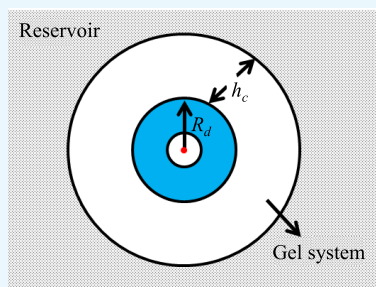


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**ABSTRACT:** The profile-control technique is one of the most important enhanced oil recovery (EOR) methods to maintain oil production in the medium and late stages of water flooding. It is necessary to conduct laboratory experiments based on the reservoir parameters from specific oil reservoirs to optimize the operation parameters during the profile-control process. In this work, based on the reservoir properties from Daqing Oil Field (China), we employed three parallel core holders and a square core with one injection well and four production wells to conduct profile-control experiments, and the operational parameters in the field scale were obtained using the similarity principle. The results show that the selected gel system has a good plugging performance and the best injection volume and profile-control radius are 0.3 PV and 6 m, respectively. Additionally, we show the optimized injection speed under different injection pressures when the profile-control radius is in the range of 6–9 m. The optimized displacing radius of the field is in the range of 3–6 m. When the radius is 6 m, the pressure decreases 90% and the corresponding plugging ratio is 81%. The optimized plugging proportion of the fracture length is 50%, and further increase of the proportion has a negligible effect on the production performance. Good field response has been achieved after the implementation of the optimized parameters in the target reservoir. This work, for the first time, systematically studies the operational parameters for the profile-control technique using experimental methods, and it provides the fundamental understandings and implications for enhancing oil recovery in similar types of high-water-cut reservoirs.

## INTRODUCTION

In the petroleum industry, unwanted water is always inevitably produced along with crude oil after long-term water flooding.<sup>1</sup> Due to the heterogeneity of the oil reservoirs, the injected water preferentially flows through the high-permeability channels, which leads the oil in low-permeability zones hardly to be further recovered.<sup>2–4</sup> The unwanted produced water in the production wells not only reduces the profitability of the oil field but also causes operational problems (equipment corrosion, salts deposition, etc.) and raises environmental concerns (water disposal).<sup>5</sup>

During the past decades, the profile-control technique was proposed to reduce water production and improve oil sweeping efficiency.<sup>6–10</sup> In profile-control methods, many types of chemicals/fluids (gel, polymer, foam, etc.) have been injected in the subsurface to mitigate the effect of reservoir heterogeneity and thus enhance oil recovery.<sup>11–15</sup> Among them, both theories and applications have proved that injection of a gel system,

synthesis of polymers and cross-linking agents, is one of the most cost-effective chemicals to be served as a profile-control material.<sup>16–18</sup> The gel system can (1) increase the fluid viscosity that converts the fingerlike displacement into pistonlike displacement<sup>19–21</sup> and (2) accumulate at the large pores/fractures or directly plug the small pore throats, thus compelling the fluid behind flow into the unswept low-permeability region.<sup>22–26</sup> Although the chemical/physical interactions between the gel system and reservoir rocks such as adsorption, dilution, or shearing effect can decrease the profile-control

Received: February 25, 2021

Accepted: May 21, 2021

Published: June 4, 2021



performance, it is still one of the most widely applied profile-control techniques in the oil field.<sup>27,28</sup>

The current studies on the profile-control technique can be classified into the following three types: (1) Development of new types of profile-control agents with the characteristics of temperature/salt resistance, high stability, and in-depth plugging performance.<sup>29–37</sup> For example, Shi and Yue<sup>29</sup> proposed new self-aggregated divinylbenzene-*co*-acrylamide microspheres. They adopted scanning electron microscopy (SEM) equipment to detect the migration position of the new microspheres in porous media, and the results showed that the microspheres can migrate a long distance and achieve in-depth profile control. Liu et al.<sup>30</sup> proposed a novel chemical system composed of dispersed particle gel and dodecyl dimethyl sulfo-propyl betaine. They indicated that the system has good wettability alteration ability and emulsifying capacity and the synergistic mechanisms achieve both high oil displacing efficiency and in-depth profile control. (2) Development of new types of profile-control agents for application in low-permeability and ultralow-permeability reservoirs.<sup>38–40</sup> Zhao et al.<sup>38</sup> adopted a mechanical shearing method to prepare phenolic resin-dispersed particle gel, which has nano- to micrometer particle size distribution, and the gel system has been successfully injected into the low-permeability reservoir (Changqing Oil Field, China) and good field responses have been reported. (3) Improve the accuracy for the numerical simulation of profile control.<sup>41–43</sup> Goudarzi et al.<sup>42</sup> performed particle gel experiments on a sandpack to describe the gel rheology, swelling ratio, and adsorption in the sandpack model, and the phenomenological models were further implemented in a reservoir simulator. The validation showed that the calibrated simulation model is consistent with the laboratory experimental results. Liu et al.<sup>43</sup> introduced a concept named critical pressure gradient to capture the deformation and migration of preformed particle gel based on the size exclusion theory, and their numerical model agreed well with physical experiments. As the examples listed above, studies related to the optimization of profile-control parameters during field application are limited. However, the operation parameters directly determine the performance of the profile-control technique, which should be investigated systematically.

In this work, a series of gel flooding experiments were conducted to optimize the operational parameters of an oil field located in Daqing, Songliao basin (China), one of the earliest and most successful fields to apply chemical flooding in the world.<sup>44,45</sup> First, we introduced the components of the gel system. Then, we set up the following two experimental apparatus: three parallel cores to represent three layers with different permeabilities (apparatus 1) and a square core with one injection well and four production wells (apparatus 2). The detailed experimental procedures of the two apparatuses were introduced. After that, the static properties (viscosity, gelling stability, and elastic properties) and the dynamic parameters (breakthrough pressure gradient, fracture plugging ratio, and flushing resistance) of the gel system used in the gel flooding experiments were evaluated. In addition, the operation parameters including the profile-control radius, injection speed, displacing radius, and fracture plugging length were discussed and optimized through the laboratory experiments, and these parameters were converted into field scale based on the similarity principle. Finally, main conclusions were summarized.

## RESULTS AND DISCUSSION

**Properties of the Gel System.** As an in-depth profile control agent, the gel system should have good static and dynamic parameters. The static properties of the gel system include gelling viscosity, gelling stability, and elastic properties, and the dynamic parameters include breakthrough pressure gradient, fracture plugging ratio, and flushing resistance. A series of measurements were made to evaluate the properties of the selected gel system.

**Static Parameters.** The time-dependent viscosity of the gel system was measured at 78 °C (temperature of the target reservoir) by an RS6000 rheometer (HAAKE, German), and the results are shown in Figure 1. As we can see, the gelling viscosity

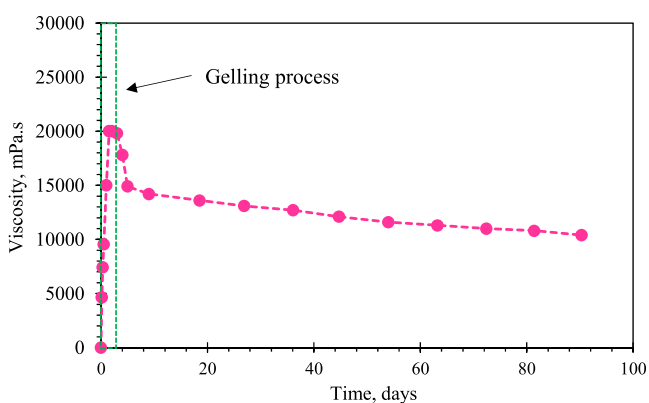


Figure 1. Gelling viscosity and its stability of the selected gel system.

of the system measured on the fifth day is 15 364 mPa·s, which is far more than the general requirement of 10 000 mPa·s. In addition, the selected formula also has good stability, and its viscosity is still larger than 10 000 mPa·s after 90 days. Because mechanical phenomena such as shearing or stretching occur during the gel injection process in the reservoir, it is necessary to evaluate the elastic properties (shear or tensile resistance) of the gel system. The measured results of the selected gel system at different gelling times (5–90 days) are shown in Figure 2. The system exhibits obvious stress relaxation, and the reduction of stress decreases with an increase of aging time. After five days of aging time, the storage modulus and loss modulus at 0.1 Hz are 4.25 and 0.89 Pa, respectively.

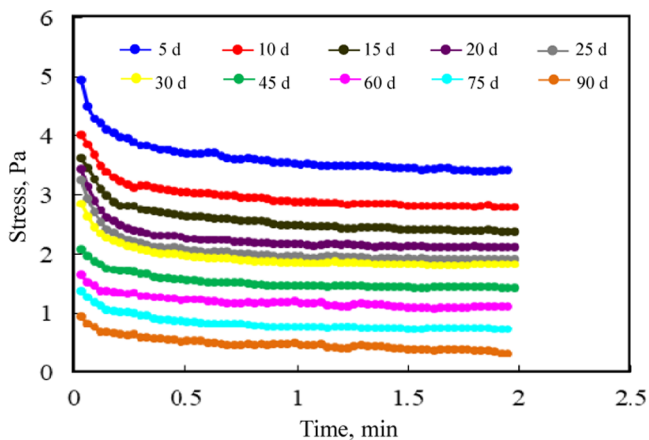
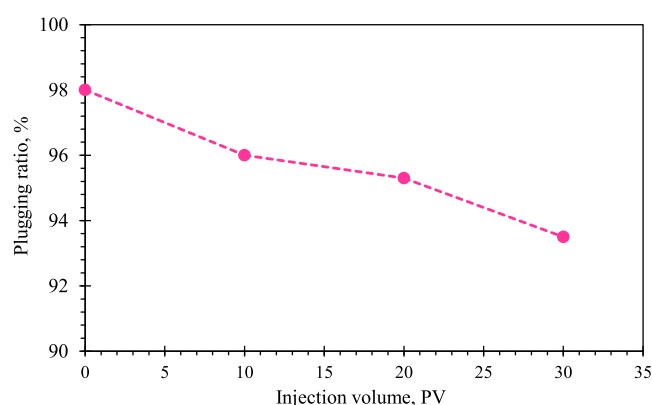


Figure 2. Measured stress of the selected gel system at different gelling times.

**Dynamic Parameters.** The above-measured parameters are the static parameters, and the profile-control performance of the gel system in the porous media needs to be evaluated by core dynamic experiments. We employed the experimental apparatus (one core holder in apparatus 1) and procedures shown in [Experimental Section](#) to evaluate the dynamic parameters. The matrix permeability and porosity of the prepared core sample are 2.1 mD and 15.3%, respectively. A fracture is created at the center of the core sample, which has a permeability of 1000 mD to represent the reservoir condition.

The breakthrough pressure/pressure gradient can reflect the dynamic gelation strength after gel injection. Higher breakthrough pressure/pressure gradient indicates stronger gelation in the porous media. The test result shows that the breakthrough pressure/pressure gradient of the gel system is 3.89 MPa/m. The plugging ratio after the gel injection operation can directly reflect the profile-control performance, and the plugging ratio of the selected system can reach up to 98.0%. After sealing the fractures in the reservoir, the gel system injected into the reservoir would undergo long-term water flooding in the late stage. Therefore, not only the initial plugging ratio but also the plugging ratio after long-term water flooding, termed as flushing resistance, of the gel system should also be evaluated during the core flooding experiment. As shown in [Figure 3](#), the plugging ratio can still maintain the value of 93.5% after 30 PV of water flooding, showing good flushing resistance of the gel system.



**Figure 3.** Plugging ratio of the selected gel system after different volumes of water flooding.

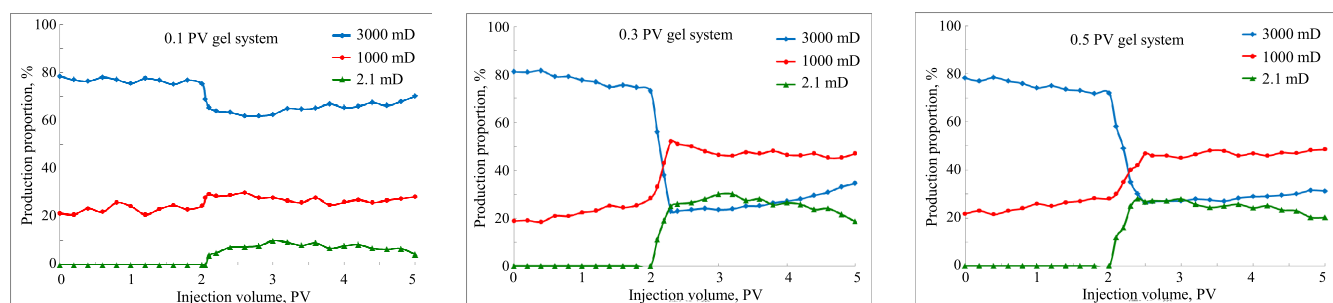
**Optimization of the Operational Parameters. Profile-Control Radius.** [Figure 4](#) shows the production contributed by each core of the three parallel samples under different gel injection volumes (0.1, 0.3, 0.5 PV). As we can see, the gel system plays an important role in plugging the highly permeable

flow pathway (300 mD sample). Once the gel system is injected into the cores (at the point of 2 PV), the production contribution of each layer changes. When the injection volume of the gel system is 0.1 PV ([Figure 4a](#)), the production contribution of the high-permeability layer decreases from 77 to 66%. However, if the gel injection volume increases to 0.3 PV ([Figure 4b](#)), the production of the 300 mD layer decreases significantly from 75 to 23%, and the production of the layer with the lowest permeability (2.1 mD) increases from 0 to 26%. If we further increase the gel injection volume to 0.5 PV ([Figure 4c](#)), the profile-control performance cannot be increased noticeably. Therefore, the optimized injection volume of the gel system at the laboratory model is 0.3 PV.

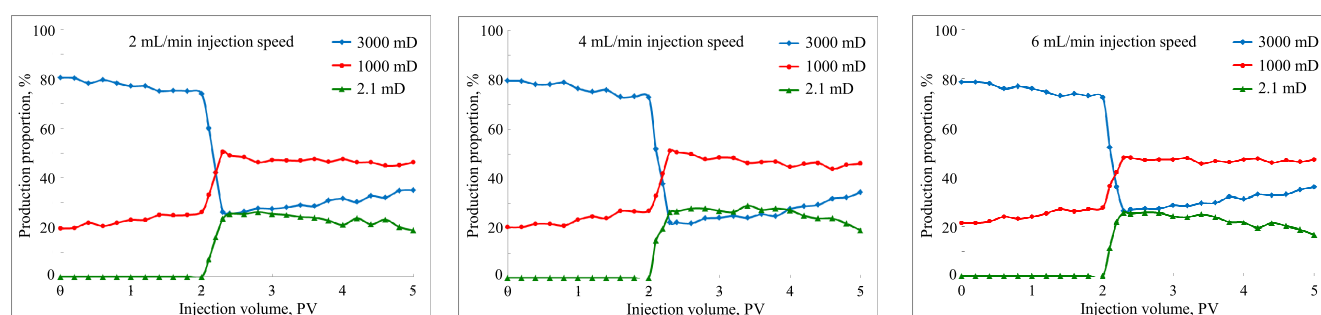
In the field situation, the injected gel system can transport from the bottom hole to the surrounding reservoir to form a profile-control region, and the length from the well is called the profile-control radius. Based on the field and laboratory parameters, we can obtain the profile-control radius in the target field application according to the similarity principle. The calculation data include the following: the viscosity of the gel system decreases 31.5% after 90 days of aging time, the maximum injection pressure in the field is 20.5 MPa, the injection pressure in the laboratory experiments is in the range of 0.34–0.77 MPa, and the invasion length of the gel system in the core is adopted from the layer with medium permeability as 0.06 m. Therefore, the optimized profile control radius in the field application can be calculated as follows: maximum injection pressure (field)  $\times$  Invasion length (lab)  $\times$  (1 – viscosity reduction)/maximum injection pressure (lab) = 5.2 m. It should be noted that the effects of dilution and diffusion in the field injection process are higher than those in the laboratory experiments. Therefore, the optimized profile control radius during the field application is adjusted as 6 m.

**Injection Speed.** Before we conduct the optimization experiments of injection speed, it is necessary to estimate the laboratory injection speed from the parameters in the field application. The gel flooding experiments are conducted using the three parallel core samples, and the best injection speed is obtained when the production of the three layers is nearly equivalent. At this condition, the vertical heterogeneity can be avoided maximally and the best profile-control performance can be achieved. Note that the gel system should be injected into the reservoir before its viscosity increases to 10 000 mPa·s (about 16 h). Therefore, the injection speed in the field that guarantees the gel system is not gelled before injection can be calculated as follows:

$$v_f = \frac{q_f}{T_g \times h \times \Delta p_f} = \frac{\pi R_f^2 \varphi}{T_g \times \Delta p_f} \quad (1)$$



**Figure 4.** Production contributed by each core of the three parallel samples under different injection PVs of the gel system.



**Figure 5.** Production contributed by each core of the three parallel samples under different injection speeds of the gel system.

where  $q_f$  is the injection volume in the field;  $R_f$  is the profile-control radius in the field;  $\phi$  is the porosity of the reservoir,  $\phi = 17\%$ ;  $h$  is the thickness of the production layer;  $T_g$  is the gelling duration time of the selected gel system,  $T_g = 16$  h; and  $\Delta P_f$  is the maximum injection pressure in the field,  $\Delta P_f = 20.5$  MPa. According to the equation, the injection speeds in the field can be predicted as 0.06, 0.135, and 0.24  $\text{m}^3/\text{MPa}/\text{m}/\text{h}$  when the profile-control radii are 6, 9, and 12 m, respectively. Therefore, the corresponding injection speeds in the laboratory experiments are 2, 3, and 4 mL/min, which are used in the experimental procedures as we mentioned in [Experimental Section](#).

The production of each layer under the three different injection speeds is shown in [Figure 5](#). As we can see, the three curves in the three figures look similar, which indicates that the injection speed in this range has negligible effects on the profile-control performance. Specifically, the production contribution of the high-permeability layer decreases from 74 to 26% when the injection speed of the gel system is 2 mL/min ([Figure 5a](#)). Even the injection speed increases to 6 mL/min, the production contribution of the high-permeability layer only decreases from 73 to 27% ([Figure 5c](#)). Thus, we may safely conclude that the injection speed of the gel system in the target reservoir has minimal effects on its profile-control performance. Based on this, the injection speed in the field only needs to consider the gelling duration time of the gel system. The optimized injection speed in the field application under different injection pressure can thus be obtained and is listed in [Table 1](#).

**Table 1.** Optimized Injection Speed of Gel System in the Field Application

profile-control radius (m)	injection strength ( $\text{m}^3/\text{MPa}/\text{m}/\text{h}$ )	injection speed ( $\text{m}^3/\text{m}/\text{h}$ )		
		15 MPa injection pressure	20 MPa injection pressure	25 MPa injection pressure
6	0.06	$\geq 0.9$	$\geq 1.2$	$\geq 1.5$
9	0.14	$\geq 2.0$	$\geq 2.7$	$\geq 3.4$
12	0.24	$\geq 6.6$	$\geq 4.8$	$\geq 6.0$

**Displacing Radius.** After the injection of the gel system, subsequent water is injected into the subsurface to displace the gel system into a deep reservoir, and a circular region occupied by the gel system is formed, as shown in [Figure 6](#). According to the material balance of the gel injection volume, the relationship between the displacing radius  $R_d$  and profile-control radius  $R_f$  can be obtained by  $q_f = \pi R_f^2 h \phi = \pi (R_d + h_c)^2 h \phi - \pi R_d^2 h \phi$ . In section [Profile-Control Radius](#), the profile-control radius without considering the displacing radius is recommended to be larger than 6 m during the field application. Thus, we

guarantee that the circular gel thickness is 6 m after considering the displacing radius. Based on this, the profile-control radii can be calculated as 8.5, 9.5, and 10.4 m if the displacing radii are assumed as 3, 4, and 6 m, respectively. Correspondingly, the profile-control radii in this experimental model are 3, 4, and 6 mm, and the water injection volumes are 0.005, 0.01, and 0.015 PV, respectively. To better represent the fluid displacement process in the reservoir, we use apparatus 2 and follow the procedures shown in [Experimental Section](#) to conduct the optimization experiments of displacing radius.

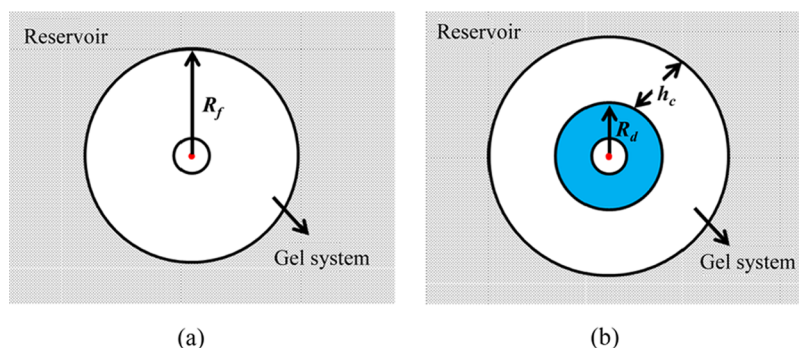
[Figure 7](#) shows the experimental results of pressure curves under different water injection volumes (displacing radius). When the gel system is injected into the porous medium, the pressure increases sharply to nearly 95 MPa, the pressure decreases to a stable value, and the value is determined by different water injection volumes (displacing radius). Because the mobility ratio of water is lower, the migration of water in the near-well region has lower flow resistance in comparison with the gel fluid. As a result, with an increase of displacing radius, the pressure decreases to a lower value. At the same time, the plugging ratio decreases due to longer migration distance. Specifically, when the displacing radius is 3 m, the pressure decreases 30% and the plugging ratio is 95%; when the displacing radius is 6 m, the pressure decreases 90% and the plugging ratio decreases to 81%.

**Fracture Plugging Length.** To investigate the gel flooding performance in the presence of fractures, we create a 15 cm length and 2 mm width fracture in the 30 cm long core samples, as shown in [Figure 8](#). Different fracture plugging lengths are achieved by injection of gel solution into the sample with different injection volumes at the outlet. Then, the cores are placed within the core holder in apparatus 1 to conduct drainage experiments to investigate the effects of fracture plugging length on production performance.

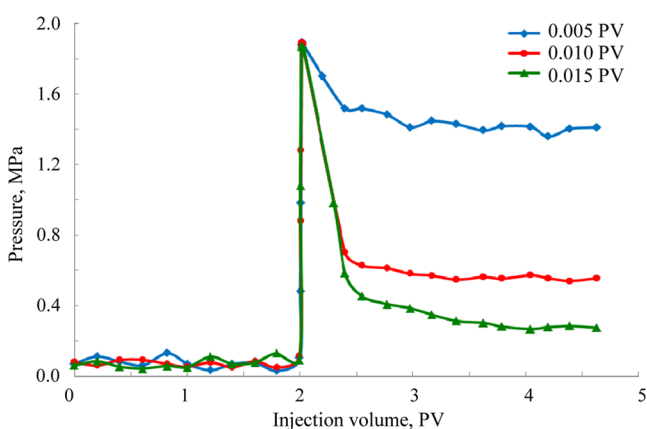
[Figure 9](#) shows the experimental results of recovery factor and water cut under different injection volumes and fracture plugging lengths. When the water cut reaches 80%, the injection water volume is smaller than 1 PV, reflecting that the existence of fractures results in quick water breakthrough. The effect of fracture plugging length can be observed when the fluid injection volume is larger than 1.5 PV. When the fracture plugging lengths are 0, 30, 50, and 70%, the water cut values are 99.56, 98.21, 97.70, and 97.93% and the recovery factors are 31, 35, 37, and 38%. The recovery factor increases with an increase of fracture plugging length, while the effect is negligible when the plugging length increases from 50 to 70%. That is, 50% fracture plugging length is an appropriate value in the practical application.

**Field Response.** We created a pioneering test area ([Figure 10a](#)) in the target oil reservoir to apply the optimized operation

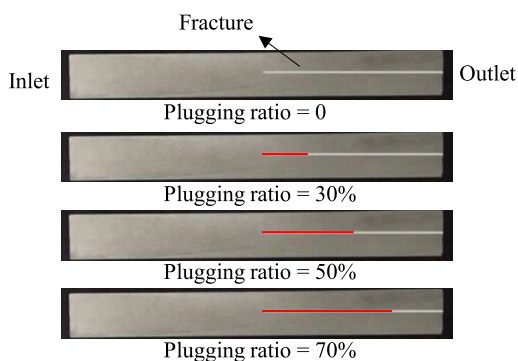




**Figure 6.** Before (a) and after (b) the injection of the displacement fluid during gel flooding operation.



**Figure 7.** Production contributed by each layer of the square core sample under different water injection volumes (displacing radius).



**Figure 8.** Prepared samples with different fracture plugging lengths.

parameters. There are a total of 34 wells including 12 injection wells and 22 production wells in this area, and the average well spacing between each well is in the range of 100–300 m. Due to good connectivity between each well and the short well spacing, the average water cut of these production wells reaches up to 81%, giving the challenge to further enhance oil recovery for this area.

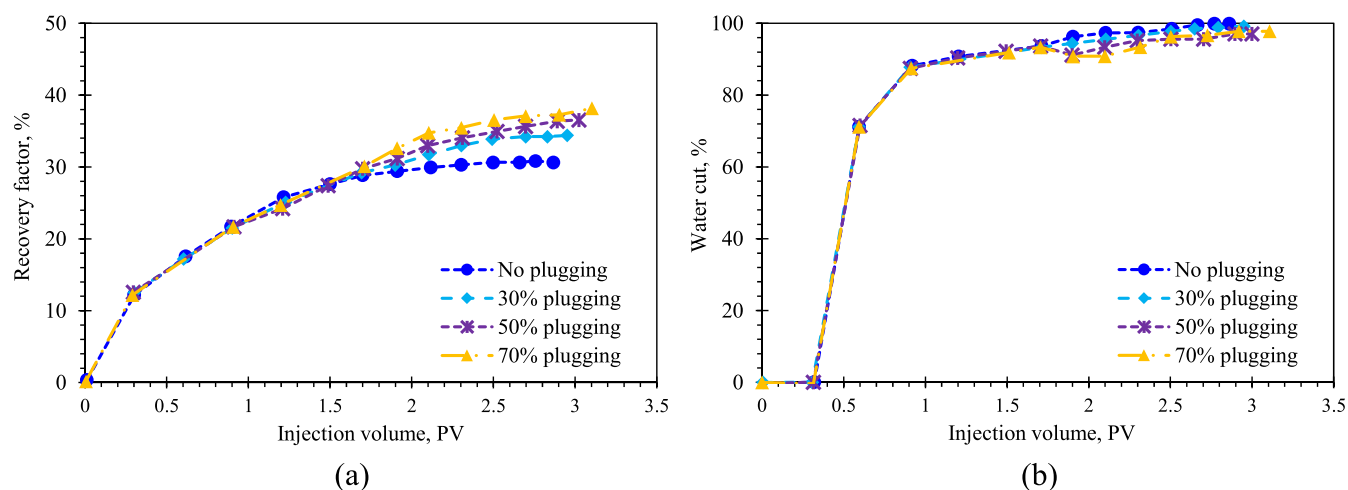
The profile-control technique was started in January 2020, trying to control the water cut and extend the production life of these wells. We take the injection performance of well T71313 as an example to show the effectiveness of our operational parameters (Figure 10b). Before the profile-control technique, the injection testing shows that layer S732 is the main water injection layer, and the water uptake for this layer occupies more than 90% of the total injection water due to its good permeability and lateral connectivity. Therefore, the injection water for the

injection well can easily reach the production well, causing earlier water breakthrough. After implementation of the profile-control technique, the water uptake volume for this layer significantly decreases and other layers (e.g., S722, S741) also start to soak water, resulting in a uniform injectivity profile. We list the oil/water production before and after the application of the profile-control technique for the production wells in the area, as shown in Table 2. Before the profile-control technique, the average daily oil production and daily water cut for each well are 2.84 m<sup>3</sup>/day and 81%, respectively. After the profile-control technique, the two parameters change to 6.23 m<sup>3</sup>/day and 65%, respectively, which indicates that the optimized profile-control operation parameters have good adaptability for the target oil reservoirs.

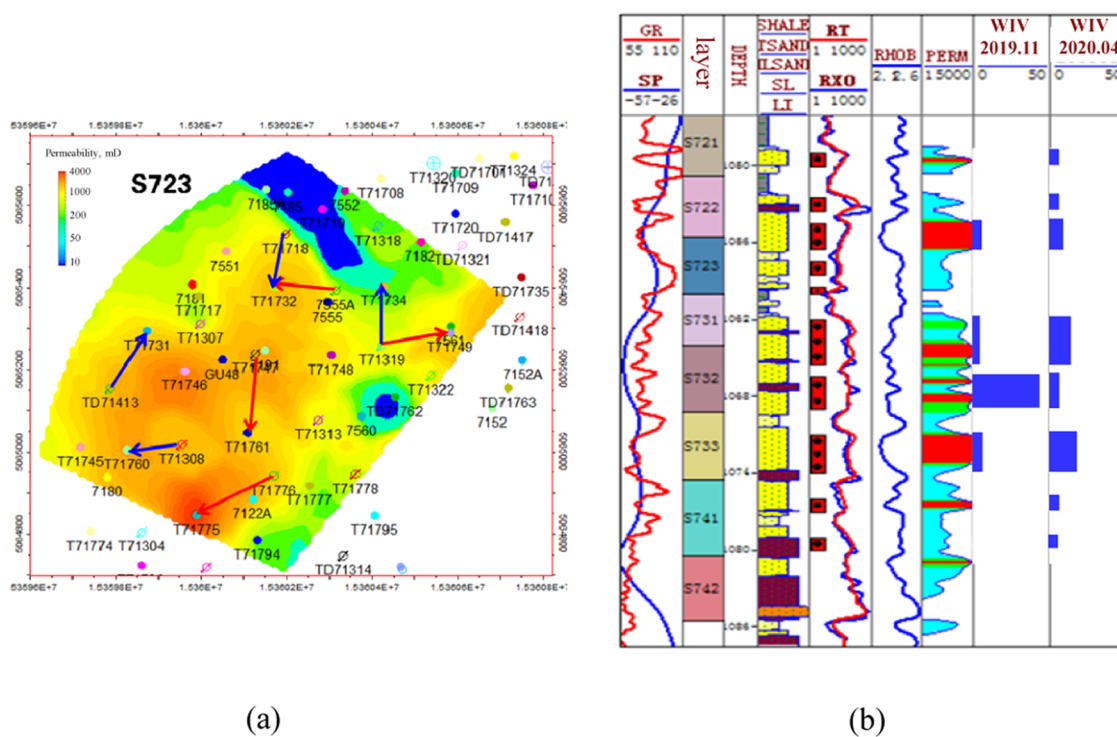
## CONCLUSIONS

In this work, a series of gel flooding experiments by using two laboratory apparatuses were conducted to optimize the operational parameters of an oil field located in Daqing, Songliao Basin (China). The static properties and dynamic parameters of the gel system used in the gel flooding experiments were characterized in detail. The operation parameters in the field scale including the profile-control radius, injection speed, displacing radius, and fracture plugging length were discussed and optimized based on the experiments and the similarity principle. Good field response has been achieved after the implementation of the optimized parameters. The main conclusions are summarized as follows:

- (1) The selected gel system can effectively plug the highly permeable layer, and the optimized injection volume of the gel fluid is 0.3 PV. After gel injection, the production contribution from the high permeable layer decreases significantly from 75 to 23%. Based on the indoor experimental results and possible errors, the profile-control radius in the field application is safely optimized as 6 m.
- (2) Experiments conducted on the three parallel core samples show that the injection speed of the gel system in the target reservoir has minimal effects on its profile-control performance. Based on this, the injection speed in the field only needs to consider the gelling duration time of the gel system (before the viscosity increased to 10000 mPa·s). The optimized injection speed in the field application under different injection pressures is obtained in this work.
- (3) The optimized displacing radius during field application is in the range of 3–6 m. When the radius is 6 m, the pressure decreases 90% and the corresponding plugging



**Figure 9.** Recovery factor (a) and water cut (b) under different injection volumes and fracture plugging lengths.



**Figure 10.** (a) Production and injection wells in the pioneering test area. The arrow indicates the direction of water channels. (b) Logging section and injectivity profile before and after the profile-control operation for well T71313.

ratio is 81%. The optimized plugging proportion of the fracture length is 50%, and further increase of the proportion has a negligible effect on the production performance.

## EXPERIMENTAL SECTION

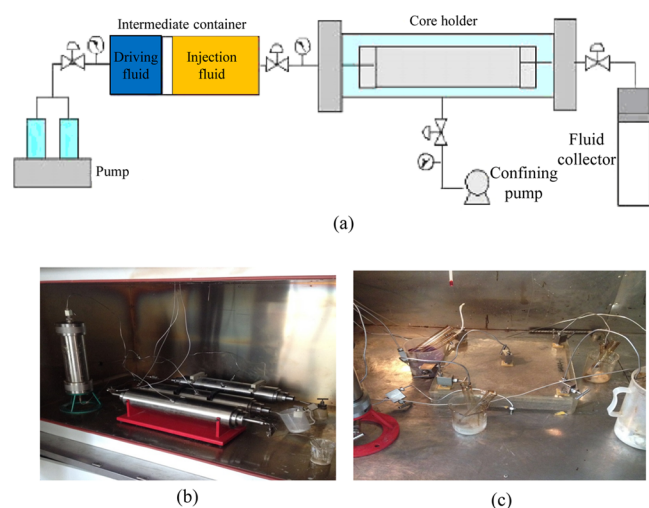
**Gel System.** Before we conduct the gel flooding experiments, it is necessary to select the composition of the gel system, which has a good adaption to the target reservoir. The gel system used in the experiments is the synthesis of polymers, cross-linking agents, and stabilizers. Based on different concentrations of these components, a total of 20 possible mixtures have been formed during the process. Then, we carried out a series of tests to select the gel system with the best static and dynamic performance from the 20 mixtures. The final selected formula is

composed of 0.5% polymers, 1.34% cross-linking agents, 0.01% stabilizer A, and 0.015% stabilizer B. The properties of the selected formula are shown in section [Results and Discussion](#).

**Experimental Apparatus.** Figure 11 shows the experimental system for the profile-control fluid injection experiments. The system mainly consists of five parts including fluid injection, a percolation part, fluid collection, data acquisition, and a constant-temperature air bath. The fluid injection part is composed of an injection pump (accuracy of 0.01 mL/min) and an intermediate container (maximum working pressure 60 MPa). The percolation part is placed within an air bath to maintain a constant-temperature environment during the experiments (Figure 11a). We have two percolation apparatuses: apparatus 1 (Figure 11b) has three parallel core holders, and the dimension of each core in the holders is  $30 \times 4.5 \times 4.5$

**Table 2. Oil and Water Production Performance Before and After Profile-Control (PC) Operation for the Pioneering Test Area**

well	average oil production before PC (m <sup>3</sup> /day)	average oil production after PC (m <sup>3</sup> /day)	average water cut before PC	average water cut after PC
T185A	0.60	7.87	0.79	0.77
T71717	1.80	6.36	0.92	0.76
T71719	6.60	7.44	0.63	0.56
T71731	4.00	3.82	0.71	0.73
T71732	3.00	8.67	0.88	0.71
T71734	1.80	4.66	0.93	0.85
T71745	2.40	1.92	0.85	0.86
T71746	2.60	5.75	0.76	0.55
T71749	2.60	6.99	0.81	0.60
T71760	3.60	7.57	0.81	0.65
T71761	2.80	3.43	0.95	0.59
T71775	2.40	9.37	0.84	0.59
T71794	2.80	4.18	0.81	0.73
TD71762	0.60	6.98	0.94	0.61
7555A	2.58	5.27	0.83	0.68
T71307	2.34	4.74	0.79	0.61
T71308	1.92	3.32	0.84	0.76
T71313	4.02	8.33	0.72	0.55
T71319	6.72	6.76	0.55	0.52
T71747	1.98	9.24	0.79	0.44
T71776	1.20	6.60	0.92	0.67
TD71413	4.14	7.74	0.66	0.49
Total	2.84	6.23	0.81	0.65



**Figure 11.** (a) Schematic diagram of the gel system injection experiments, (b) three parallel core holders for experiment apparatus 1, (c) square core with one injection and four production wells for experimental apparatus 2.

cm<sup>3</sup>. The permeabilities of the cores in the three holders are 3000, 1000, and 2.1 mD, respectively. Apparatus 1 is used to optimize the profile-control radius, injection speed, and fracture plugging length. Apparatus 2 (Figure 11c) is a square core sample sealed with epoxy resin. One injection well at the center and four production wells at the corners are drilled in the samples to conduct flooding experiments. The permeabilities of the three layers of the square sample are consistent with the samples in parallel core holders. Apparatus 2 is used to optimize the displacing radius. In the fluid collection part, the production

fluid is separated into oil and another fluid, and the component concentration of the fluid is measured with an ultraviolet spectrophotometer. The core holders are manufactured by Hanan Oil Scientific Instrument Col., Ltd. (China). The core samples are manufactured by Artificial Core Preparation Laboratory in Northeast Petroleum University.

**Experimental Procedure.** Using the two experimental apparatuses, we designed three gel injection experiments to optimize the operation parameters.

- (1) For the optimization of the profile-control radius and injection speed, we used experimental apparatus 1 by following the procedures: (i) set the temperature of the environment to 78 °C, vacuum the core samples for at least 24 h, and then inject the formation brine into the cores with a total injection volume of 2.0 PV (pore volume) at a speed of 5 mL/min to determine the porosity. (ii) Inject crude oil into the cores until there is no water produced to achieve initial oil saturation. After that, the system is allowed to sit with an aging time of 24 h. (iii) Conduct water flooding with a total injection volume of 2.0 PV at a speed of 5 mL/min. Inject gel solution into the sample with different injection volumes (0.1, 0.3, and 0.5 PV) at different speeds (1.0, 2, 3, and 4 mL/min). Wait for the gelling process for at least five days. (iv) Conduct subsequent water flooding until the water cut reaches up to 98%. At the same time, record the plugging ratio and water production of each core.
- (2) For the optimization of the fracture plugging length, we only use one core holder of apparatus 1, and most of the experimental procedures are consistent with the above procedures except procedure (iii). Procedure (iii) in here follows: conduct water flooding at a speed of 5 mL/min until the water cut reaches 80%. Inject gel solution into the sample with different injection volumes (0, 3.5, 5.8, and 8.2 mL) at 0.1 mL/min injection speed to seal different lengths of the fracture. Wait for the gelling process for at least five days.
- (3) For the optimization of the displacing radius, we use apparatus 2, and the experimental procedures are also consistent with experiment (1) except procedure (iii). Procedure (iii) in here follows: conduct water flooding with a total injection volume of 2.0 PV at a speed of 5 mL/min. Inject gel solution into the sample with 0.02 PV injection volume at 1 mL/min injection speed. Then, inject different volumes of water as the displacing fluid (0.005, 0.01, and 0.015 PV). Wait for the gelling process for at least 10 days.

## ■ AUTHOR INFORMATION

### Corresponding Author

Xiaofeng Zhou – Key Laboratory of Continental Shale Hydrocarbon Accumulation and Efficient Development (Northeast Petroleum University), Ministry of Education, Northeast Petroleum University, Daqing, Heilongjiang 163318, China; Institute of Unconventional Oil & Gas, Northeast Petroleum University, Daqing 163318, China; [orcid.org/0000-0002-4555-1450](https://orcid.org/0000-0002-4555-1450); Email: [zhouxiaofeng\\_cup@126.com](mailto:zhouxiaofeng_cup@126.com)

### Authors

Jianguang Wei – Key Laboratory of Continental Shale Hydrocarbon Accumulation and Efficient Development (Northeast Petroleum University), Ministry of Education,



Northeast Petroleum University, Daqing, Heilongjiang 163318, China; Institute of Unconventional Oil & Gas, Northeast Petroleum University, Daqing 163318, China

**Dong Zhang** – Key Laboratory of Continental Shale Hydrocarbon Accumulation and Efficient Development (Northeast Petroleum University), Ministry of Education, Northeast Petroleum University, Daqing, Heilongjiang 163318, China; Institute of Unconventional Oil & Gas, Northeast Petroleum University, Daqing 163318, China

**Jiangtao Li** – Key Laboratory of Continental Shale Hydrocarbon Accumulation and Efficient Development (Northeast Petroleum University), Ministry of Education, Northeast Petroleum University, Daqing, Heilongjiang 163318, China; Institute of Unconventional Oil & Gas, Northeast Petroleum University, Daqing 163318, China

Complete contact information is available at:

<https://pubs.acs.org/10.1021/acsoomega.1c01004>

## Notes

The authors declare no competing financial interest.

## ACKNOWLEDGMENTS

We acknowledge the National Science and Technology Major Projects of China (2016ZX05023-005-001-003) and the National Natural Science Foundation Projects of China (51474070).

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