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Study on Distribution Patterns of Displacement Pressure Gradients and Regulation Effectiveness of Chemical Flooding in Strong Heterogeneity Reservoir#

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ABSTRACT

Compared with onshore oil fields, offshore oil fields have lower well pattern completeness, larger well spacing, and stronger heterogeneity, necessitating a profile control and flooding system as well as corresponding laboratory evaluation methods to achieve deep reservoir regulation and efficient development. This study compared the performance of different chemical agents, simulated the heterogeneous development process of offshore oil reservoirs in both vertical and planar planes, and conducted multi-point pressure measurements. By analyzing the profile control and flooding effects under different reservoir conditions and the differences in pressure gradient distribution during the displacement process, the regulation mechanisms under different reservoir conditions were revealed. The results showed that during the development of vertically heterogeneous reservoirs, the pressure gradient difference along the high-permeability layer was less than 0.01 MPa/m, indicating a relatively uniform distribution. This indicates that the selected chemical system can achieve deep regulation of the high-permeability layer, increasing the recovery factor by 50.4%. During the development of planar heterogeneous reservoirs, the pressure gradient in the near-well zone was significantly greater than that in the far-well zone, resulting in an increase in the pressure at the core boundary. This indicates that the selected chemical system can achieve the development effect of subsequent fluid bypassing and further expansion of the swept area, increasing the recovery factor by 31.1%. This study provides theoretical guidance and technical support for field implementation.

Keywords: strong heterogeneity, physical experiment, displacement pressure gradient, regulation effect

1. INTRODUCTION

Offshore oil and gas are an indispensable and significant part of Chinese oil and gas industry, characterized by complex reservoir types, large thickness, and severe heterogeneity[1-4]. Waterflooding is the primary technology for offshore oilfield development. Due to the property of the reservoir, the conflicts between layers and within layers intensify during long-term waterflooding, leading to the development of preferential flow channels and severe water channeling, which seriously constrains the effectiveness of oilfield development[1,3-5]. Practice has proven that chemical profile control and flooding technology has become an important technical means to improve the waterflooding effect in offshore oilfields, laying a solid foundation for stable and increased production in offshore oilfields using waterflooding[1,2].

Currently, the commonly used profile control system is polyacrylamide (HPAM) chromium cross-linked gel system. Due to its inherent properties and environmental factors, this gel system has the characteristics of high initial viscosity and short gelation time, resulting in high and rapidly increasing injection pressure during the injection process, easy contamination of low- and medium-permeability layers, difficulty in migrating to the deep part of the oil layer, and inability to seal only high-permeability layers[6-9]. Rock core simulation experiments by Sorbie et al[10]. have shown that when the initial viscosity of the polymer profile control agent is greater than 20 mPa·s, the amount of polymer entering the medium- and low-permeability layers is approximately 84% of that entering the high-permeability layers, making it impossible to achieve deep part profile control. Therefore, new chemical system and corresponding laboratory evaluation methods suitable for offshore oil reservoirs are needed to achieve deep regulation and reveal its regulation mechanism.

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In response to this, this study designs rock cores based on the characteristics of strong heterogeneity in offshore oil reservoirs, conducts vertical and planar heterogeneous rock core flooding experiments to simulate the effect of chemical flooding regulation in oil reservoirs, and reveals its regulation mechanism through the law of displacement pressure gradient.

2. MATERIAL AND METHODS

2.1 Experimental Materials

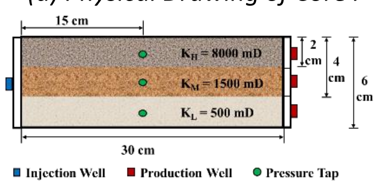
2.1.1 Design of Core Models

Based on the characteristics of Block B, a heterogeneous core with a permeability combination of 8000/1500/500 mD is designed. Among them, Core II is a planar heterogeneous model scaled down from the mine model under laboratory conditions through similarity criteria. The physical and design drawings of the cores are shown in Fig. 1.

2.1.2 Physical Properties of Experimental Fluids

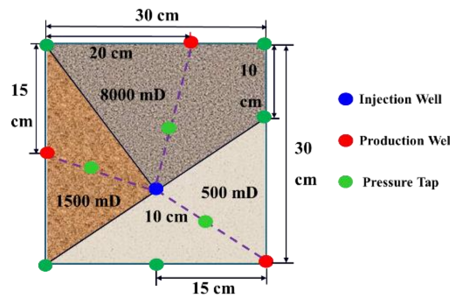
The experimental oil is a simulated oil with a viscosity of 20 mPa·s (at 65℃). The experimental water is the injection water of the block with a salinity of 7052.73 mg/L. The experimental agents are Gel A, Gel B, two types of profile control agents, and emulsion microsphere flooding system. The effective concentration of the agents is 35%.

(a) Physical Drawing of Core I



(b) Design Drawing of Core I

(c) Physical Drawing of Core II



(d) Design Drawing of Core II

Fig. 1 Physical and Design Drawings of Cores

2.1.3 Experimental Instruments

The experimental equipment mainly includes a viscometer, a vacuum pump, a displacement pump, a pressure sensor, an intermediate container, etc.

2.2 Experimental Methods

2.2.1 Testing of Gel Gelation Performance

Prepare a mother liquor of the profile control agent with an effective concentration of 10000mg/L, add a cross-linking agent in a ratio of profile control agent: cross-linking agent = 2:1, and then dilute it to different target concentrations. Test the change in viscosity over time under different concentrations of agents.

2.2.2 Core Displacement Experiment

Evacuate and saturate the core with water to calculate the pore volume of the core. Place the core in a 65℃ thermostat to simulate the formation environment and saturate it with oil, calculating the original oil saturation. In the 65℃ thermostat, conduct water flooding at 0.5mL/min until the water cut reaches 90%, then switch to chemical flooding according to the slug design, and finally switch to subsequent water flooding until the water cut reaches 98% and the experiment ends. Record parameters such as pressure and oil-water production during the experiment, calculate the recovery factor, and see Table 1 for the experimental scheme design.

Table 1 Experimental scheme design

No.	*Core Type*	*Slug Design*
1	*Core I*	*4000mg/L Gel(0.1PV, Waiting for 15 days for gelation)+ 4000mg/L emulsion microspheres(0.2PV)*
2	*Core II*	

3. RESULTS

3.1 Evaluation of Gel Performance

Within the effective concentration range of 3000-6000 mg/L, the initial viscosity of Gel A increases gradually, but stabilizes at around 6 mPa·s. While the effective concentration of Gel B also ranges from 3000 to 6000 mg/L, its initial viscosity gradually increases, and the growth trend is significant. The effective concentration of emulsion microsphere flooding system ranges from 3000 to 6000 mg/L, and the initial viscosity fluctuates within 0.08 mPa·s with the concentration of the agent, always stabilizing at around 1 mPa·s.

The gelation performance of profile control agents is shown in Fig. 2. It can be seen from the Fig. 2 that within the concentration range of 3000-6000 mg/L, the gelation strength of both profile control agents gradually increases, while the increasing trend of gelation strength slows down. By analyzing the gelation strength of the gels, we can find that the gelation strength of Gel A is above 15000 mPa·s, with a maximum of 27253 mPa·s. The gelation strength of Gel B ranges from 10000 to 15000 mPa·s. Comparing the gelation strength of the two profile control agents at the same concentration, the gelation strength of Gel A is about twice that of Gel B.

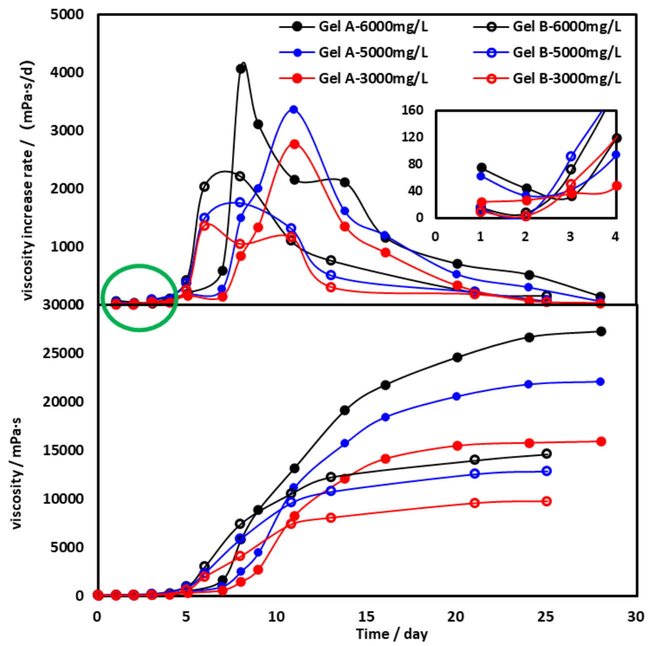


Fig. 2 Gelation Time of Profile Control Agents

By analyzing the viscosity increase rate during the gelation process of the gels, it can be seen that the gelation process can be divided into three stages: slow viscosity increase stage, rapid gelation stage, and stable viscosity stage. For Gel A, the slow viscosity increase stage lasts from day 0 to day 7, with a viscosity increase rate below 500 mPa·s/d, and the initial viscosity increase rate reaches about 80 mPa·s/d. The rapid gelation stage lasts from day 7 to day 20, with a viscosity rise rate above 1000 mPa·s/d, reaching a maximum of 4000 mPa·s/d. After day 20, it enters the stable viscosity stage, with a viscosity rise rate below 500 mPa·s/d and gradually decreasing. For Gel B, the slow viscosity increase stage lasts from day 0 to day 3, with a viscosity increase rate below 10 mPa·s/d. The rapid gelation stage lasts from day 3 to day 13, with a viscosity increase rate above 500 mPa·s/d, reaching a maximum of only 2213 mPa·s/d. After day 13, it enters the stable viscosity stage, with a viscosity increase rate below 200 mPa·s/d and gradually decreasing. Comparing the viscosity increase rates of the two profile control agents, it can be seen that the slow increase stage of Gel A is about twice as long as that of Gel B, but the viscosity increase rate is 50 times higher than that of Gel B. Gel B enters the rapid gelation stage earlier, with a shorter rapid gelation stage time compared to Gel A, and its viscosity increase rate is only half of that of Gel A. Similarly, Gel B also enters the viscosity stability stage earlier, and its viscosity increase rate is lower than that of Gel A.

By comparing and analyzing the gelation performance of the two profile control agents, it can be found that Gel A has the characteristics of low initial viscosity, strong injectability, high gelation strength, and long gelation time. Therefore, Gel A is selected for subsequent experimental research.

3.2 Simulation of Reservoir Development Effect

3.2.1 Simulation of Vertical Heterogeneous Reservoir Development Effect

It can be seen from *Fig. 3* that the water flooding recovery factor in the three-layer vertical heterogeneous core is only 23.82%, with 11.7% recovered from the high permeability layer, 11% from the medium permeability layer, and only 1% from the low permeability layer, indicating ineffective utilization. Chemical flooding improves the recovery factor by 31.79%, with an increase of 5.9% in the high permeability layer, 17.3% in the medium permeability layer, and 8.6% in the low permeability layer. The utilization of the medium permeability layer is the highest during the chemical flooding stage, and the recovery factor of the low permeability layer is significantly increased compared to the water flooding process. In the subsequent water flooding stage, the recovery factor is increased by 18.7%, with an increase of 0.7% in the high permeability layer, 5.9% in the medium permeability layer, and 12.2% in the low permeability layer.

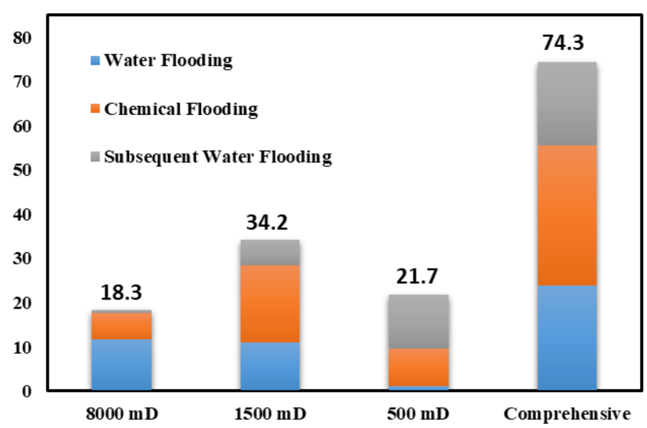


Fig. 3 Recovery Factor

Combined with the analysis of the diversion rate curve as shown in the Fig. 4, during the water flooding process, the diversion rate of the high permeability layer reaches 80% when only 0.17PV of injection water is injected, indicating that the high permeability layer enters the high water cut stage and the water flooding channel is formed, and the water flooding process mainly develops the high permeability layer. The diversion rate of the medium permeability layer is only about 15%, with a later onset of water breakthrough and a higher recovery factor.

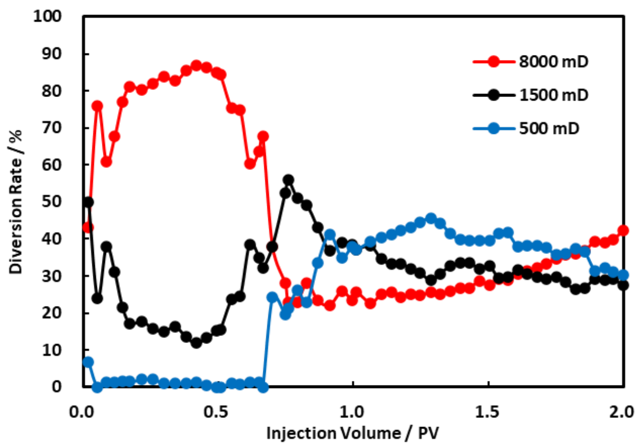


Fig. 4 Diversion Rate Curve

The diversion rate of the low permeability layer remains below 3%, indicating ineffective utilization. During the chemical flooding process, due to the low initial viscosity of Gel A, its reservoir diversion rate during injection is not significantly different from that of the water flooding process, which helps Gel A migrate to the deep layer and achieve deep profile control of the reservoir. The injection of the emulsion microsphere can block and adjust the medium permeability layer, resulting in a decrease in the diversion rate of the medium permeability layer and the reactivation of the low permeability layer. In the subsequent water flooding stage, the diversion rate of the high permeability layer gradually recovers, stabilizing at around 30%. The diversion rates of the medium and low permeability layers show an overall downward trend, but the decline is not significant, stabilizing between 30% and 40%, indicating that the chemical flooding regulation measures are effective.

The pressure curves at injection well and pressure tap are shown in the Fig. 5. During the water flooding process, the injection pressure because of the existence of high permeability layer is small, only 0.001 MPa, and the pressure at the pressure tap of the high, medium, and low permeability layers is 0 due to the precision of the instrument. During the chemical flooding process, the pressure distribution pattern during Gel A injection process is similar to that of the water flooding process due to the influence of the initial viscosity. During the injection of the emulsion microsphere, the injection pressure suddenly rises to 0.027 MPa, and the pressures at the high, medium, and low permeability measurement points also rise to 0.012 MPa. Subsequently, with the injection of the emulsion microsphere, the injection pressure gradually decreases, and the pressures in the high, medium, and low permeability layers begin to fluctuate. In the subsequent water flooding process, the injection pressure suddenly drops to 0.016 MPa and then stabilizes at 0.014 MPa. The pressures at the pressure taps of the high, medium, and low permeability layers fluctuate and finally stabilize at 0.007 MPa, 0.008 MPa, and 0.01 MPa, with differences in the pressures at the pressure taps, with the high permeability layer having the lowest pressure, followed by the medium permeability layer, and the low permeability layer having the highest pressure.

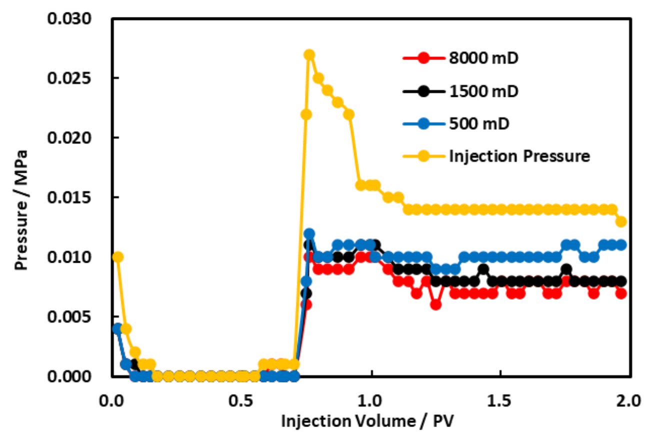


Fig. 5 Pressure at Injection Well and Pressure Tap

The analysis suggests that Gel A, after being injected along the water drive channel of the high permeability layer, blocks the high permeability layer, leading to a sudden pressure rise during subsequent fluid injection. The injection of the emulsion microsphere again improves the diversion rate of the medium and low permeability layers, resulting in an increase in diversion rate in the low permeability layer, which leads to a higher pressure at the pressure tap in the low permeability layer. Moreover, as the emulsion microsphere migrates in the formation, it can also lead to an increase in pressure at the pressure tap in the low permeability layer. Combined with the analysis of the pressure gradient in the high permeability layer, the pressure gradient difference before and after the pressure tap in the high permeability layer is only within 0.01 MPa/m (Fig. 6), indicating that Gel A can uniformly block the entire section of the high permeability layer, achieving effective regulation of chemical flooding in vertical heterogeneous reservoirs.

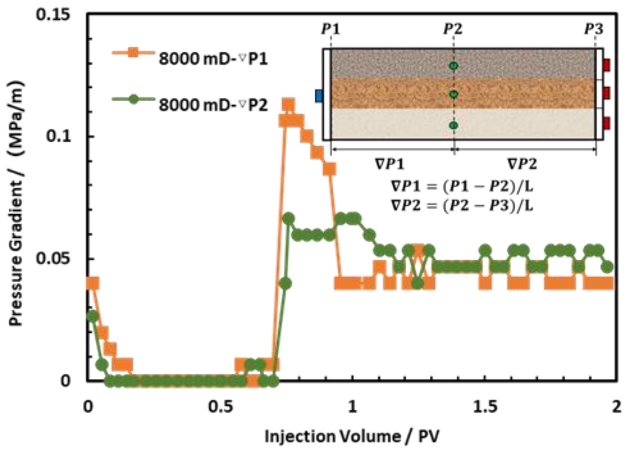


Fig. 6 Pressure Gradient in High Permeability Layer

3.2.2 Simulation of Planar Heterogeneous Reservoir Development Effect

In planar heterogeneous cores, the recovery factor of water flooding is only 8.4%. After chemical flooding, the recovery factor is increased by 17.9%, and after water flooding, the recovery factor is increased by 13.2%.

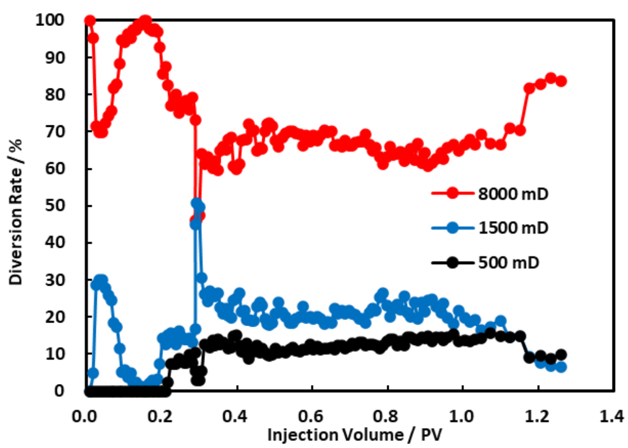


Fig. 7 Diversion Rate Curve

As Fig. 7 shows, the diversion rate of the high permeability layer in the water drive process quickly reaches 100%, so the water drive process mainly utilizes the high permeability layer; During the chemical flooding injection process, the viscosity of Gel A gradually increases, showing some ability of profile control and flooding, which can improve diversion rate; During the subsequent water drive process, the diversion rates of high, medium, and low permeability layer remain stable at around 70%, 20%, and 10%. The high permeability layer quickly reaches the high water cut stage, while the medium and low permeability layers remain in the low water cut or oil recovery stage without water, which can effectively exploit the medium and low permeability layers.

Upon analyzing pressure curves at injection well and pressure tap shown in the Fig. 8, it can be seen that the stable pressure at the injection end during the water drive process is only 0.001 MPa.

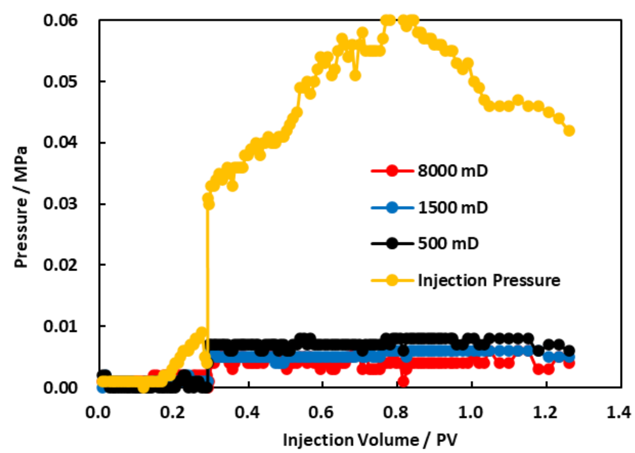
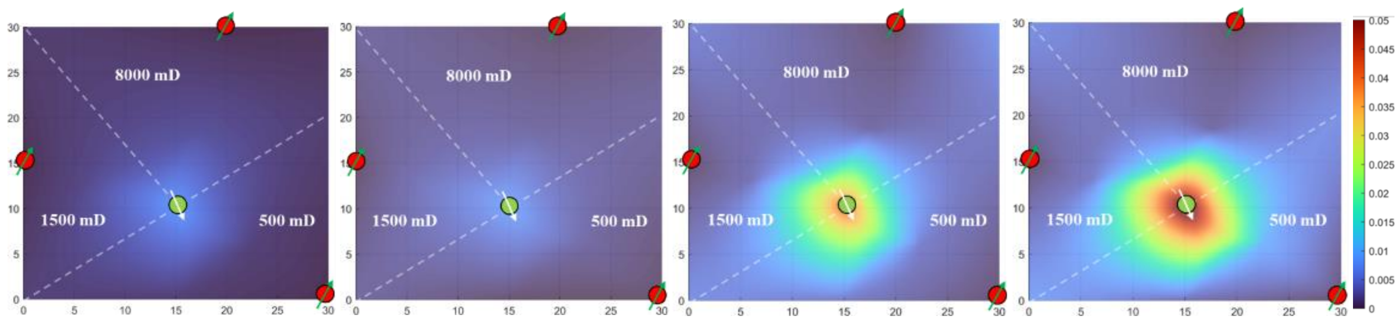


Fig. 8 Pressure at Injection Well and Pressure Tap



(a) After Water Flooding (b) After Profile Control (c) After Chemical Flooding (d) After Subsequent Water

Fig. 9 Displacement Pressure Field Diagram

Combined with the analysis of the pressure field diagram after water flooding, a water channel is formed in the high permeability layer. During the injection process of Gel A, due to the influence of temperature and time, there is a slow increase in pressure and improvement in diversion rate during the injection process because of the increase of viscosity. Fig. 9(b) shows that the pressure at the core boundary increases, and the fluid flow towards the surrounding areas. This process has a certain chemical profile control effect. After the subsequent injection of emulsion microsphere, the pressure suddenly rises, and the injection pressure is much higher than the pressure at the pressure tap. Fig. 9(c) shows that there is an ultra-high pressure difference near the wellbore, and the pressure at the pressure tap is lower than that at the core boundary point, indicating that Gel A has gelled and blocked the near-wellbore area with a bypass flow phenomenon. The injection pressure during the subsequent water flooding process has a trend of first rising and then falling, which corresponds to a rebound in the diversion rate of the high permeability layer. It is believed that this is caused by the production of chemical agents.

By comparing the pressure gradient distribution during the production process of two types of reservoirs, it can be seen that in core displacement, $\nabla P1 > \nabla P2$ indicates that Gel A can effectively block the near-well zone. In vertical heterogeneous cores, $|\nabla P1-\nabla P2|$ is much smaller than $|\nabla P1-\nabla P2|$ in planar heterogeneous cores. It is speculated that in planar heterogeneous cores, after chemical flooding to block the near-well zone, the injected fluid breaks through the weak blocking zone during subsequent displacement, expanding the swept area in the formation and further improving the recovery factor. In the pressure field diagram simulating the production process on a plane, the increase in pressure at the core boundary also indirectly proves the existence of bypass flow during subsequent fluid injection.

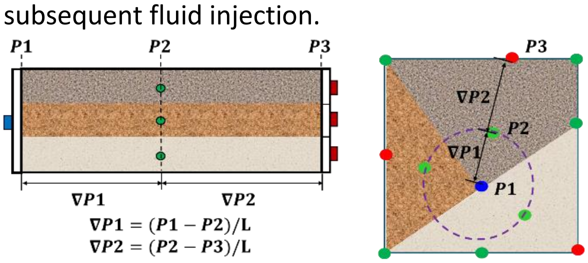


Fig. 10 Schematic diagram of displacement pressure gradient

4. CONCLUSIONS

Based on the screening of profile control and flooding systems, this study conducted simulations of vertical and planar heterogeneity in oil reservoirs, analyzed the regulation effects during chemical flooding, and reached the following conclusions:

1 Gel A was selected as profile control agent for subsequent experiments. Gel A has the characteristics of low initial viscosity, strong injectivity, high gel strength and long gelation time.

2. In vertical heterogeneous cores, chemical flooding can achieve plugging and regulation of the entire section of the high-permeability layer, with a pressure gradient difference of only 0.01 MPa/m before and after the pressure measurement point, and a final recovery factor of up to 74.3%.

3. After chemical flooding in a planar heterogeneous core, the pressure gradient $\nabla P1$ near the wellbore is much higher than the pressure gradient $\nabla P2$ in the far wellbore, achieving the development effect of subsequent fluid flow and expanding the swept area, ultimately increasing the recovery factor by 31.1% compared to water flooding.

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