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Experimental Study on the Diversion Characteristic of a Viscous Fluid in a Heterogeneous Reservoir

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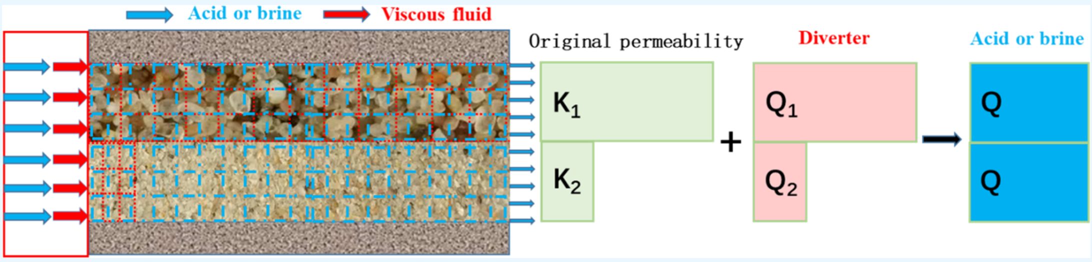

ABSTRACT: As a typical feature of a reservoir, heterogeneity is the main reason for low oil recovery and the poor effect of acidizing measures. Diversion is the main measure to improve the acidizing effect. Over the years, technological progress has mainly focused on the material development of diverting agents. In this study, the diverting effect and influencing factors for a viscous fluid were systematically studied by the heterogeneous dual-core flooding experiment. The results are as follows: First, increasing the displacement pressure in heterogeneous reservoirs can improve the diverting effect, which is consistent with maximum differential pressure and injection rate (MADPIR) theory, but the diverting effect is weak. The injection pressure difference is increased by 50 times, and the diverting effect is improved by 16.27% at most. Second, taking a viscous fluid as the stimulation fluid can partially realize the diversion for heterogeneous reservoir and further improve the acidizing effect, and the breaking through PV can be improved by 78% at most. Using a viscous fluid as a diverting agent can achieve 100% balanced acid injection. Third, compared with a viscoelastic surfactant, a relatively uniform and stable polymer solution as the diverting agent has the possibility to completely block the low-permeability layer. So, a 5% viscoelastic surfactant as the diverting agent is more suitable for acidizing. Finally, any diverter injected into the formation will enter all layers. The conclusion that the diverting agent only enters the high-permeability layer but not the low-permeability layer is not tenable. Diverting acidizing is only effective for near-well zones, which is difficult to fundamentally solve the seepage problem of heterogeneous reservoirs.

1. INTRODUCTION

In recent years, with the increasing demand for energy around the world, the development of oil and gas wells has also been increasing.[1] However, it is less likely to discover new large oil and gas fields every year. Therefore, to effectively utilize limited resources, especially to improve the recovery more effectively for existing oil and gas fields, acidizing is a frequent and routine measure for oil and gas field plug removal and stimulation.[2−5] As a typical or basic feature of oil and gas reservoirs, heterogeneity brings about a poor acidizing effect or even failure.[6] Especially for a water flooding reservoir, with long-term high-intensity water injection, the heterogeneity of the reservoir will be further aggravated.[7−11] To improve the acidizing effect, not only should the type and volume of acid be optimized but diverting technology should also be used to ensure that the acid is injected into the whole interval or more into the low-permeability (seriously damaged) interval.[12]

At present, diverting technology mainly includes mechanical and chemical diverting.[6] Mechanical diverting includes down-hole tools and maximum differential pressure and injection rate (MADPIR) technology. Downhole tools, such as packers, plugging balls, etc., block a certain operation interval or fixed-point perforation to make the fluid in the wellbore diverted. The MADPIR technique means to maximize the injection rate under the allowable injection pressure.[12] Chemical diverting technology acts in the reservoir through a diverting agent, which is mainly injected before or during the acid stage. At present, there are four kinds of diverting agents widely used in acidizing. They are solid particles,[13] viscous fluids (polymers[14,15] or viscoelastic surfactants[16,17] (VESs)), and foams.[18] The apparent viscosity is the key factor that affects the acid

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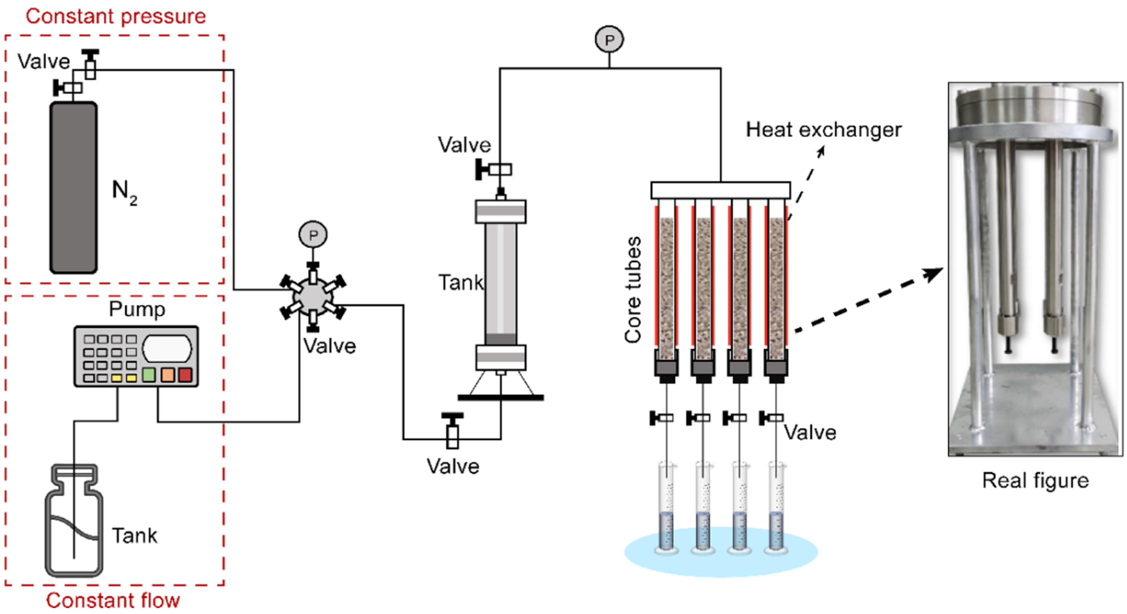

Figure 1. Schematic of the flow experimental setup.

injection and diversion during acidizing operations. Low-viscosity acids are beneficial to inject into sandstone reservoirs, while high-viscosity acids can ensure the distribution of acids throughout the whole interval.[19] Therefore, due to their convenient operation and modification to improve their physical and chemical properties, viscous fluids or gels are the most widely used.

At present, viscous fluids for diverting widely used in acidizing include polymers and viscoelastic surfactants (VESs). Polymers are characterized by excellent stability and low dosage, while VESs are characterized by green and large dosage.[16,17] The relevant research on these two kinds of chemical materials has never stopped, and the research focuses on improving the temperature and salt resistance of materials through chemical modification and synthetic routes.[20] For acidizing in heterogeneous reservoirs, the relevant research on how to use a viscous fluid to effectively place acid has not been reported. For this purpose, the diverting effect and influencing factors of the viscous fluid (hydrophobically associated polyacrylamide (HAPM) solution, viscoelastic surfactants (VESs)) were systematically studied by the heterogeneous dual-core flooding experiment. The results can provide guidance for the application of viscous fluids in the acidizing design for heterogeneous sandstone reservoirs and provide a theoretical basis for uniform acid placement in heterogeneous reservoirs.

2. EXPERIMENTAL SECTION

2.1. Materials. HCl and NH_4Cl were analytical reagent grade, and 40 mesh to 200 mesh quartz sand was purchased from Chengdu Klong Chemical Co., Ltd. (Chengdu, China). The HPAM was 1800 w cationic polyacrylamide. The VES contained *N,N*-bis(2-hydroxyethyl)oleylamine with a purity of 97% and the corrosion inhibitor oleic-based imidazoline (OIM). Since the acid solution can cause equipment corrosion, 1% OIM was added to all samples to prevent equipment corrosion during the test. The HPAM, VES, and OIM were purchased from Chengdu Acidizing Petroleum Technology Development Co., Ltd.

2.2. Methods. According to the Darcy formula of porous media (1), when a heterogeneous reservoir is stimulated by an acid, the amount of acid in each small area is proportional to its permeability.[21] After the acid is injected into the reservoir, a large amount of acid enters high-permeability areas and increases reservoir heterogeneity. As shown in Formula 1, the fluid viscosity can be improved so that the acid reaches each layer.

$$Q_i = \frac{K_i \Delta P A}{\mu L} \quad (1)$$

A parallel long-core flooding model for simulating heterogeneous reservoirs was established (Figure 1). It consisted of a flow field with two, three, and four layers with different permeabilities without crossflow. Each layer with an inner diameter of 2.54 cm and a length of 40 cm had an independent heating sleeve, which can be heated to 150 °C. Before the experiment, a certain proportion of quartz sand with different mesh numbers was used to prepare core tubes with different permeabilities. Two layers represented by two core tubes with different permeabilities were used in this experiment. All experiments were carried out at 65 °C. This research was funded by the China Bohai oil field, and the average reservoir temperature in the Bohai oil field was 65 °C. Due to the limited working space, offshore oil fields mainly focused on chemical diversion and the MADPIR principle for acid stimulation.

2.2.1. Impact of the Injection Pressure Difference on Diversion. Four core tubes with different permeabilities were prepared by mixing quartz sand with different mesh numbers in a certain proportion. The permeabilities of the four core tubes were tested with 2% NH_4Cl at injection pressure differences of 0.2, 0.6, and 1 MPa. The permeabilities K_1, K_2, K_3, and K_4 were 170, 368, 736, and 1473 mD, respectively. Then, the core tubes were combined into three groups (G_1: 170−368 mD; G_2: 170−736 mD; G_3: 170−1473 mD), and the diversion results of heterogeneous core tubes under different injection pressure differences (0.2, 0.4, 0.6, 0.8, 1, 2, 5, and 10 MPa) were tested. During the experiment, the stable flow rates

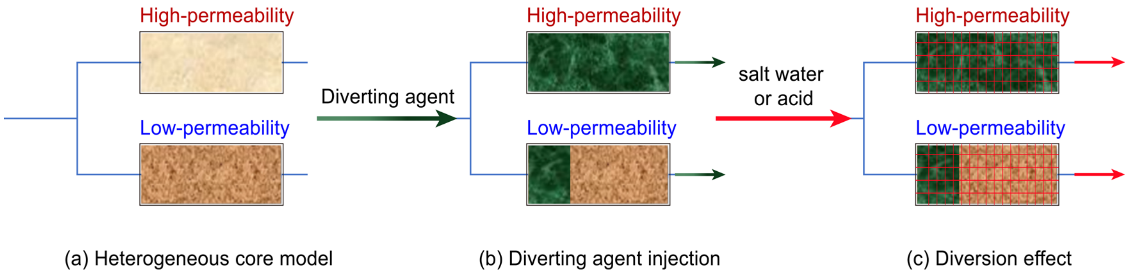

Figure 2. Schematic diagram of the experimental process for placing salt water evenly in heterogeneous cores.

(q_i^1 and q_i^2) of the two core tubes under different injection pressure differences were recorded. The flow rate ratio of the two core tubes was defined as R and calculated as follows:

$$R_i = q_i^{\,2}/q_i^{\,1} \tag{2}$$

where R_i is the flow rate ratio of the two core tubes under injection pressure differences i MPa and q_i^1 and q_i^2 are the stable flow rates of the two core tubes.

The improvement effect of the injection pressure difference on diversion was defined as S and calculated as follows

$$S_i = (R_{0.2\mathrm{MPa}} - R_i)/R_{0.2\mathrm{MPa}} \tag{3}$$

where S_i is the improvement effect of the injection pressure difference i MPa on diversion and $R_{0.2\mathrm{MPa}}$ is the flow rate ratio of the two core tubes under an injection pressure difference of 0.2 MPa.

2.2.2. Diversion Effect of Viscous Fluids on Heterogeneous Cores. The effect of the viscous fluid with different concentrations on the diversion of heterogeneous cores was studied. The G_3: 170−1473 mD core group was used for the experiment, and the displacement flow was constant at 10 mL/min. First, 2% NH_4Cl was displaced, and the flow velocities of the two cores were recorded when the flow was stable. Then, the viscous fluid with different concentrations was displaced, and the flow velocities of the two cores were recorded when the flow was stable. Two groups of experiments (HPAM and VES) were carried out, and the concentrations of the viscous fluid included 0.1% HPAM, 0.2% HPAM, 0.3% HPAM, 0.4% HPAM, 1% VES, 3% VES, and 5% VES.

The influence of the viscous fluid on breakthrough pore volume (PV) was studied. The G_3: 170−1473 mD core group was used for the experiment. First, the core was dried at 80 °C for 12 h, and then the time t (min) of each core tube from liquid injection to liquid outflow at a flow rate of 2 mL/min was tested, and the outlet liquid volume was calculated as follows

$$V = t \times v \tag{4}$$

where V is the outlet liquid volume in mL, and t is the time of each core tube from liquid injection to liquid outflow, and v is the flow rate in mL/min.

The core group PV was defined as follows[16]

$$\mathrm{PV_{total}} = V_{\mathrm{high}} + V_{\mathrm{low}} \tag{5}$$

where $\mathrm{PV_{total}}$ is the core group breakthrough PV, V_{high} is the outlet liquid volume of the high-permeability core, and V_{low} is the outlet liquid volume of the low-permeability core.

The two parallel core tubes at a flow rate of 2 mL/min were displaced, and the liquid production times of the high-permeability and low-permeability cores as T_1 and T_2, respectively, were recorded.

The outlet liquid volume of the high-permeability layer was calculated as follows

$$V_1 = T_1 \times 2 \tag{6}$$

The outlet liquid volume of the low-permeability layer was calculated as follows

$$V_2 = T_2 \times 2 \tag{7}$$

The PV number breaking through the high-permeability core was $V_1/\mathrm{PV_{total}}$, and the total PV number breaking through the two cores was $V_2/\mathrm{PV_{total}}$. The breakthrough PVs of 2% NH_4Cl, 0.1% HPAM, 0.3% HPAM, 3% VES, and 5% VES were tested.

2.2.3. Uniform Placement of Viscous Fluids on Brine in the Heterogeneous Core. The G_1: 170−368 mD, G_2: 170−736 mD, and G_3: 170−1473 mD core groups were used for the experiment. First, 2% NH_4Cl was injected to test the initial permeability of the core. Then, the HPAM solution was injected until the solution completely swept the high-permeability core, and finally, a 2% NH_4Cl solution was injected to test the uniform placement of the HPAM solution at an injection pressure difference of 1 MPa. Each group of cores was tested for the uniform placement of 0.05% HPAM, 0.1% HPAM, and 0.2% HPAM. The experimental process model is shown in Figure 2.

2.2.4. Effect of the Injection Pressure Difference on the Diversion Breakthrough of Viscous Fluids. The G_3: 170−1473 mD core group was used for the experiment. First, the permeability of the two cores was tested by 2% NH_4Cl at 0.2 MPa. Then, the viscous fluids (0.3% HPAM and 5% VES) were displaced at 0.2 MPa until the high-permeability core was completely swept. Finally, the permeability of the cores was tested by 2% NH_4Cl at higher pressure.

2.2.5. Uniform Placement of Viscous Fluids on Acid. The G_3: 170−1473 mD core group was used for the experiment. Two groups of experiments were carried out, and the displacement sequences were 2% NH_4Cl → 0.3% HPAM → 8% HCl + 6% HBF_4 + 1% OIM; 2% NaCl → 5% VES → 8% HCl + 6% HBF_4 + 1% OIM. The first step was to test the diversion effect of two cores by displacing 2% NH_4Cl at a flow rate of 10 mL/min. In the second step, the viscous fluids (0.3% HPAM and 5% VES) were displaced at 0.2 MPa until they completely swept through the high-permeability core, during which the low-permeability core was partially swept. In the third step, the acid 8% HCl + 6% HBF_4 + 1% OIM was displaced at a flow rate of 10 mL/min, and the diversion of the two groups of cores was recorded.

2.2.6. Shear Resistance and Microstructure Test. The apparent viscosity of the viscous fluids (0.3% HPAM and 5% VES) was tested using a HAAKE Mars III rheometer (Thermo Scientific, Germany). A P39 rotor was used for the apparent

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viscosity test under 65 °C continuous shear for 70 min at 170 s^{-1}.

Cryo-scanning electron microscopy (Cryo-SEM) was used to investigate the microstructure of the viscous fluids (0.3% HPAM and 5% VES). SEM measurements were performed using a Quanta 450 microscope (FEI, America), where the fluid samples were frozen at −165°C before scanning.

3. RESULTS AND DISCUSSION

3.1. Impact of the Injection Pressure Difference on Diversion. The MADPIR technique is a routine measure that has been used for acidizing. Therefore, different injection pressure (IP) difference experiments were used to analyze the diversion effect of the MADPIR technique. The experimental results of the three groups (G_1: 170−368 mD; G_2: 170−736 mD; G_3: 170−1473 mD) are shown in Table 1, plotted in Figures 3 and 4. Figure 3 shows the ratio (R) of the high-permeability core flow rate to the low-permeability core flow rate under different IP differences. Figure 4 shows the diversion improvement effect vs IP for the heterogeneous parallel core (S is the change ratio of R). The results are as follows: (1) With the increase of IP, the flow rate ratio R of the two cores gradually decreases, and the diversion improvement effect S gradually increases. This shows that with the increase of IP, the diversion effect of the 2% NH_4Cl solution can be effectively enhanced, which is consistent with MADPIR theory. (2) When IP was increased by 50 times (0.2 to 10 MPa), the S values of the three experiments increased by 13, 16.27, and 12.98%, respectively. S increased slowly with the increase of IP. (3) When the fluid was injected into the heterogeneous reservoir, the fluid partial flow was mainly determined by the permeability, which was mainly controlled by Darcy's law. (4) The effect of increasing the IP to achieve fluid diversion was poor, that is, it is difficult to achieve effective diversion for acidizing operation in heterogeneous reservoirs following the MADPIR principle. The diverting agent is the key to improving the effective placement of acid in the acidizing process.

Table 1. Flow Rate Ratios and the Diversion Effect of Heterogeneous Core Tubes under Different Injection Pressure (IP) Differences

	G_1(170−368 mD)		G_2(170−736 mD)		G_3 (170−1473 mD)	
IP (MPa)	R	S (%)	R	S (%)	R	S (%)
0.2	2.207	0.00	4.615	0.00	8.867	0.00
0.4	2.200	0.32	4.535	1.73	8.636	2.60
0.6	2.143	2.90	4.400	4.66	8.525	3.86
0.8	2.134	3.31	4.341	5.94	8.454	4.66
1.0	2.129	3.53	4.324	6.30	8.398	5.29
2.0	2.049	7.16	4.179	9.45	8.185	7.69
5.0	1.960	11.19	3.999	13.35	7.918	10.70
10.0	1.920	13.00	3.864	16.27	7.716	12.98

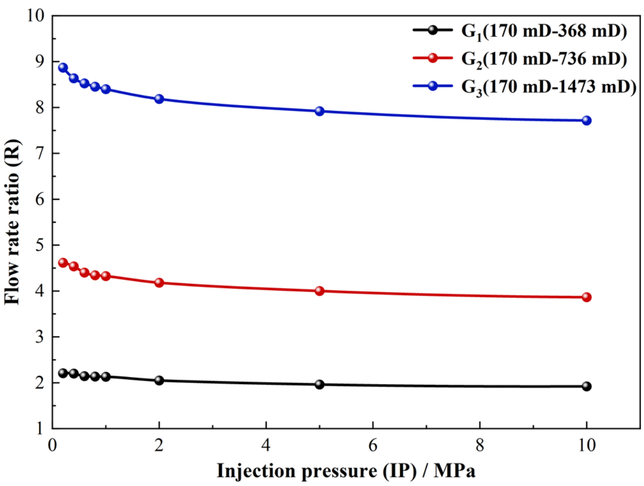

Figure 3. Flow rate ratio ($R_i = q_{\text{high-permeability}}/q_{\text{low-permeability}}$) under different injection pressure differences.

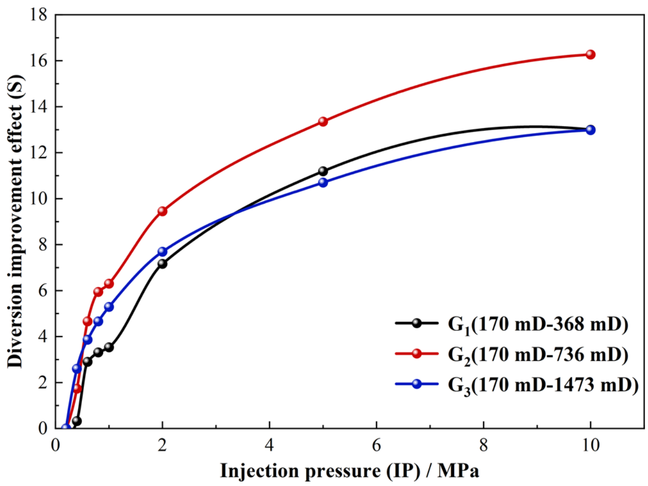

Figure 4. Diversion improvement effect ($S_i = (R_{0.2\text{MPa}} - R_i)/R_{0.2\text{MPa}}$) under different injection pressure differences.

3.2. Diversion Effect of Viscous Fluids on Heterogeneous Cores. Hydrophobically associated polyacrylamide (HAPM) is a kind of water-soluble polymer widely used and studied in oil fields.[22] Viscoelastic surfactants (VESs) are a new kind of material developed in recent years for fracturing and acidizing. The surfactants can self-assemble to form gels with complex micelle structures, to achieve diversion, filtration reduction, and other functions. The diversion effect of the HPAM solution on heterogeneous cores is shown in Figure 5, and that of the VES solution on heterogeneous cores is shown in Figure 6. The influences of HPAM and VES solutions on the breakthrough PV in heterogeneous cores are shown in Figure 7. The experiment results are as follows: (1) The flow trends of HPAM and VES diversion experiments were completely similar. With the increase of the viscosity of the injected fluids, the diversion curves for the two groups of heterogeneous cores gradually approached the middle, and the distance between the two curves became larger and larger when they continued to be increased to a certain concentration (0.4% HPAM, 5% VES). This showed that increasing the viscosity of the injected fluid can increase the proportion of the fluid flowing to the low-permeability layer, which is similar to the polymer flooding mechanism in EOR (enhanced oil recovery). However, when the fluid viscosity exceeded a certain value, it would cause the opposite effect that the low-permeability layer was completely blocked. Therefore, when the viscous fluid is used for diverting, the viscosity should be optimized. (2) The experimental curve of HPAM was smooth, and the experimental curve of VES fluctuated. This indicated that the

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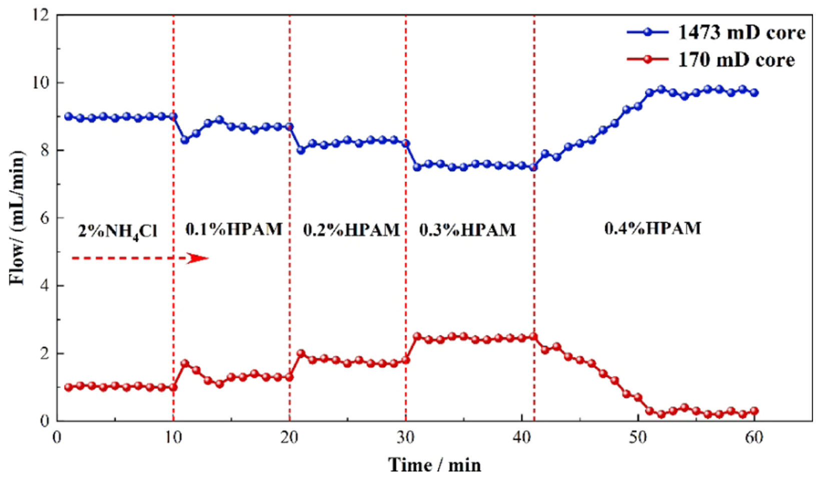

Figure 5. Seepage process of the core with the permeability range of 170−1473 mD displaced by the HPAM solution with different concentrations.

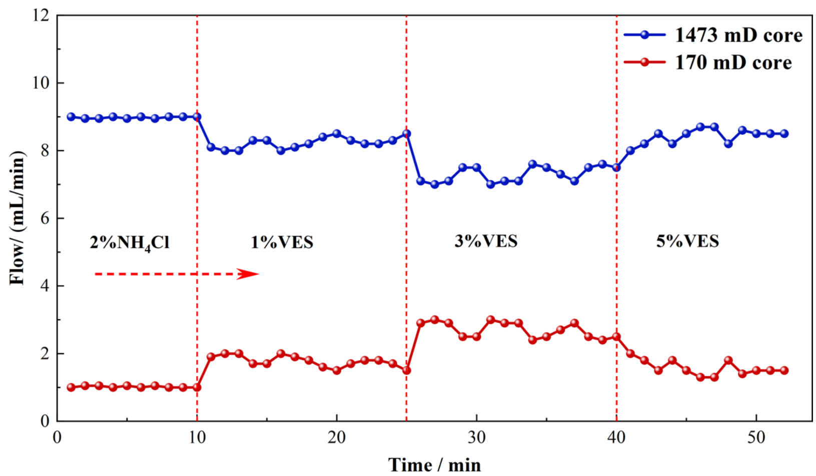

Figure 6. Seepage process of the core with the permeability range of 170−1473 mD displaced by the VES solution with different concentrations.

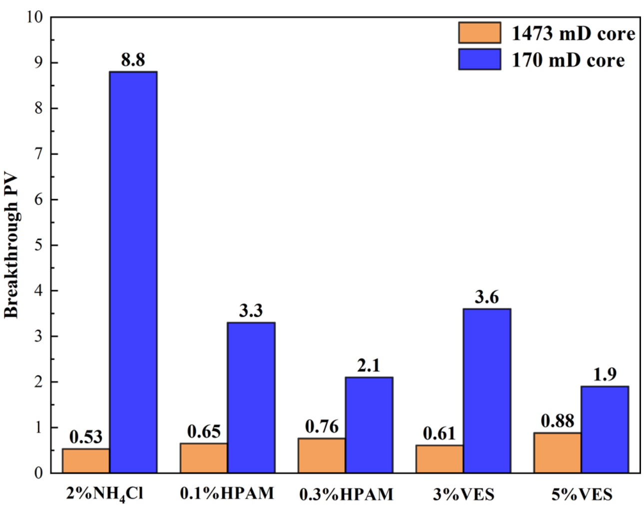

Figure 7. Experimental results of the viscous fluid breaking through heterogeneous cores.

physical properties of the polymer solution were relatively uniform and stable, while the micelles formed by VES were discontinuous. So, 0.3% HPAM and 5% VES were selected for the follow-up experiments. (3) When the 2% NH_4Cl solution was injected, about 8.8PV of liquid can completely sweep two cores. 0.1% HPAM, 0.3% HPAM, 3% VES, and 5% VES swept two cores under 3.3PV, 2.1PV, 3.6PV, and 1.9PV respectively, indicating that viscous resistance can effectively realize fluid diversion. However, the PV numbers of the four experiments were all greater than 1, showing that there was still a large amount of fluid diverted into the high-permeability core. It was consistent with the previous experimental results that the viscous fluids cannot completely achieve uniform seepage. (4) The experiment showed that the viscous fluid can be used to realize the uniform placement of acid in heterogeneous reservoirs, such as thickened acid, VES acid, etc. However, the two curves of the experiment did not intersect or coincide in the end, which shows that Darcy's law is always followed in the process of fluid injection. The viscous fluid can partially realize the diversion, but it is difficult to achieve complete diversion (i.e., the high-permeability layer is temporarily plugged to stimulate the low-permeability layer).

3.3. Uniform Placement of Viscous Fluids on Brine or Acid in the Heterogeneous Core.

The injected HPAM solution was controlled by Darcy's law, as vividly illustrated in Figure 2. The high-permeability core was completely saturated with the HPAM solution, and a small amount of the HPAM solution flowed into the low-permeability core. In the process of further injecting the salt water, the high-permeability core has great resistance, so it can effectively force the salt water into the low-permeability core, making the salt water placed

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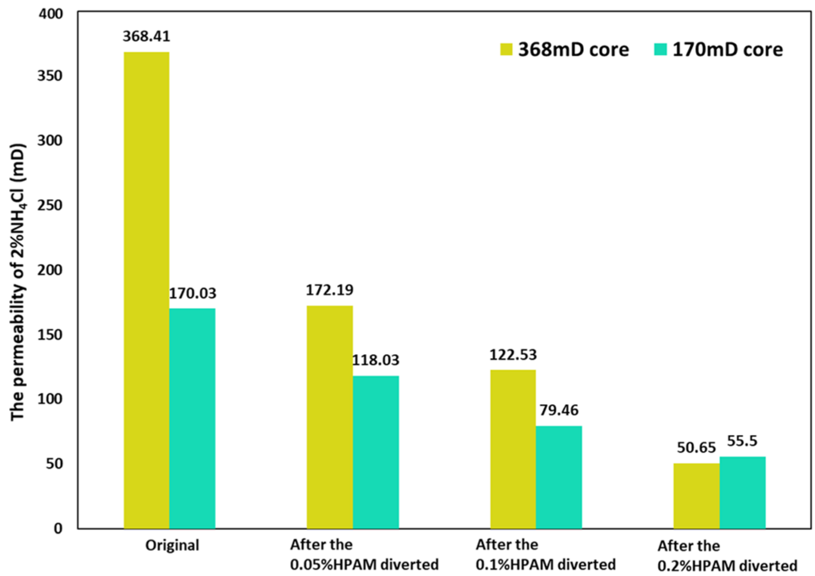

Figure 8. Effect of placing the NH_4Cl solution evenly using the HPAM solution (170−368 mD).

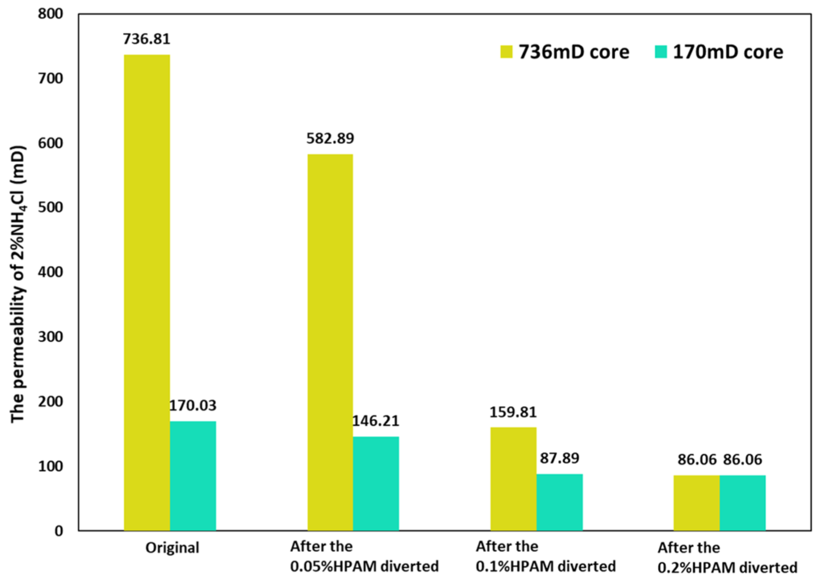

Figure 9. Effect of placing the NH_4Cl solution evenly using the HPAM solution (170−736 mD).

evenly into two cores. The experimental results are shown in Figures 8−10. (1) With the increase of HPAM solution concentration, the plugging strength of the high-permeability core increases, contributing to the effect of uniform placement for NH_4Cl. Salt water can be placed evenly in the experimental rock core under the condition of 0.2% HPAM. (2) After injecting the HPAM solution, the permeability of all cores was reduced. This indicates that they are blocked at the same time, similar to the experiment results given in Section 3.2. During the injection of the HPAM solution, Darcy's law must be followed, and the diversion cannot be realized. Using HPAM as a diverting agent to assist in the uniform placement of salt water can promote the effective diversion of salt water. (3) It is further explained that to realize the uniform placement of acid (for acidizing) or salt water (for water flooding), the effect of the one-step injection method is very small. The two-step injection method is also needed. First, the diverting agent is injected, and then the acid or salt water is injected. Furthermore, the physical properties of the fluid change after being injected into the formation, such as delayed cross-linking or reaction in the formation to generate a solid phase. The IP impact experiment shows that the injected fluid is mainly controlled by Darcy's rule. Therefore, a large amount of fluid is injected into the high-permeability layer by the one-step injection method. In the two-step injection process, in the first step, a large amount of the diverting agent is injected into the high-permeability layer to prevent the brine or acid in the second step from entering the high-permeability layer so as to realize diversion.

3.4. Effect of the Injection Pressure Difference on the Diversion Breakthrough of Viscous Fluids. Through the experiment results given in Sections 3.2 and 3.3, it is clear that the viscous fluid can be used as a diverting agent to place salt water or acid evenly. However, all diverting effects decrease or even fail with the increase of pressure. The influences of the injection pressure difference on the diverting effect for 0.3% HPAM and 5% VES are shown in Figures 11 and 12. The experimental results are as follows: (1) HPAM and VES can

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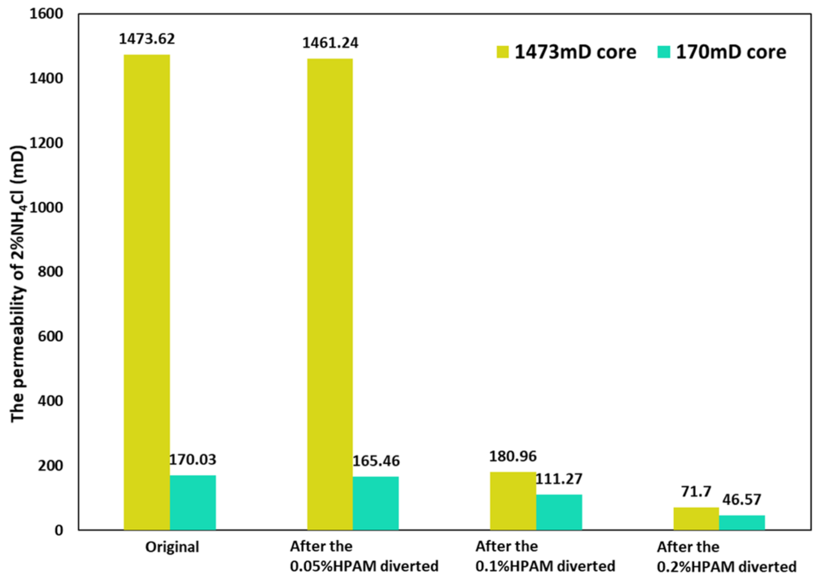

Figure 10. Effect of placing the NH_4Cl solution evenly using the HPAM solution (170−1473 mD).

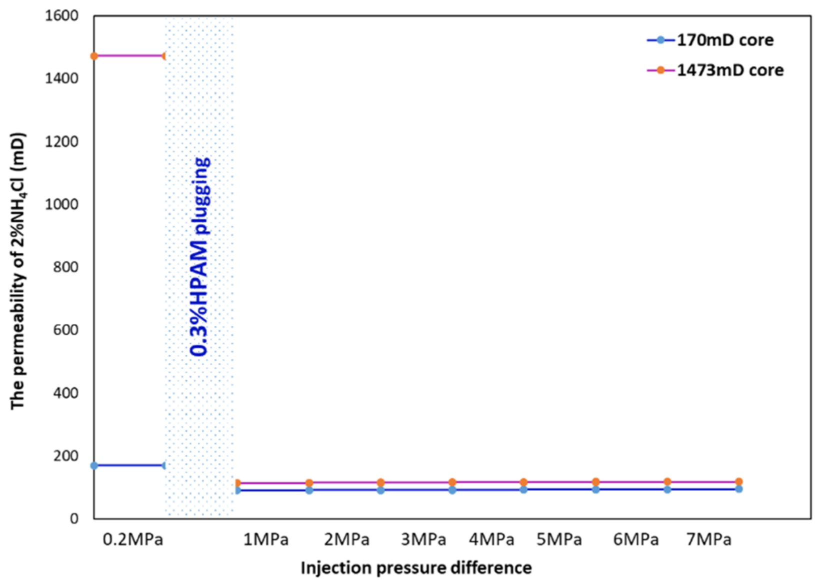

Figure 11. Impact of the injection pressure difference on 170−1473 mD of 0.3% HPAM diverting breakthrough.

block the low-permeability and high-permeability cores at the same time. The two cores can maintain a consistent flow state when passing through salt water after HPAM plugging, while the VES plugging section will be broken after increasing pressure, and the diverting effect is stable after breaking through. (2) HPAM, as a polymer, will be entangled in porous media during injection, so it is not easy to be driven out of the core by salt water to maintain a stable diverting effect. HPAM with stable performance for acidizing may cause secondary damage to the formation, while VES, as a small-molecule surfactant, becomes a viscous fluid through micelle action, which can be considered a discontinuous weak gel system. So, increasing pressure can easily break through the discontinuous system. (3) The diverting agent can make the injection area reach a relatively stable flow state, and the formation beyond the diverting range will continue to follow Darcy's law. It further shows that diverting acidizing is only effective for near-well zones, that is, near-well plug removal. It is difficult to fundamentally solve the seepage problem of heterogeneous reservoirs.

3.5. Uniform Placement of Viscous Fluids on Acid.

The purpose of viscous fluids used for acidizing is to assist the acid to flow evenly into all layers or block the high-permeability layer to make the acid completely flow into the low-permeability layer. HPAM and VES are used as diverting agents for acidizing, and the effects of diverting acid are shown in Figures 13 and 14. At the initial stage of acid injection, that is, at the initial stage of plugging, the seepage capacity of the two cores is close. This shows that HPAM and VES can effectively realize the uniform placement of acid to improve the effect of acidizing for plug removal and enable the use of low-permeability layers. In terms of displacement, the two curves eventually move away from each other, that is, the diverting effect becomes weaker and weaker because the viscosity stability of the HPAM and VES fluids reduces due to the acid. The change in the amplitude of the VES curve is slower than

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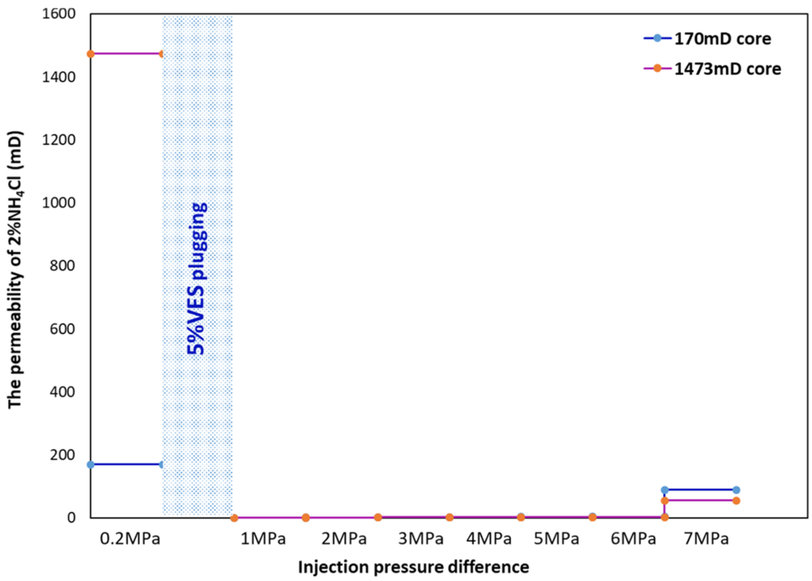

Figure 12. Impact of injection pressure difference on 170−1473 mD of 5% VES diverting breakthrough.

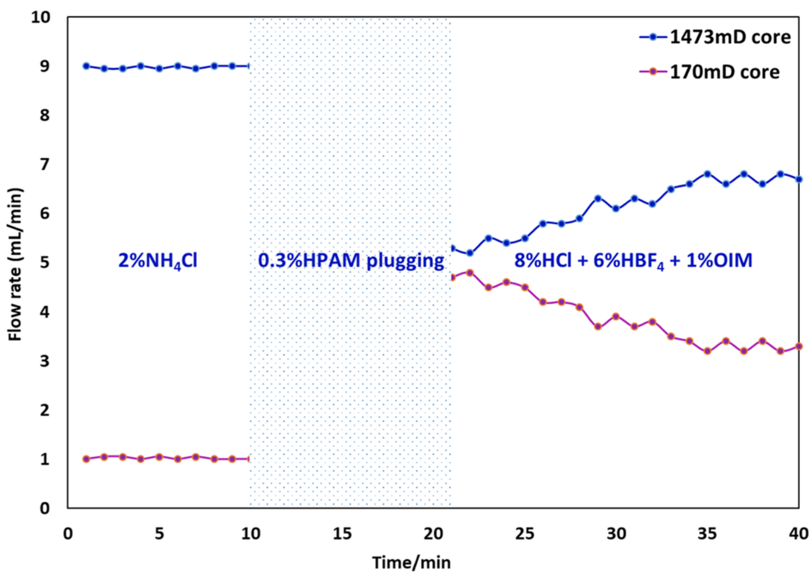

Figure 13. Stimulation effect of placing the acid evenly using a 0.3% HPAM solution.

that of the HAPM curve, which may be caused by the discontinuous effect of micelles in the VES system. Therefore, it is recommended to choose 5%VES as the diverting agent to make acid placement uniform.

3.6. Shear Resistance and Microstructure Test. Rheological measurement results can be used to determine the stability of the viscous fluid system in the engineering operation. The rheological property measurements of the 0.3% HPAM and 5% VES solutions are shown in Figures 15 and 16, respectively. The viscosity of the 0.3% HPAM solution decreases gradually with the increase of shear time, and the changing trend is gentle. The reason is the gradual reduction of the entanglement between molecular chains with the increase of shear time, causing the decrease of viscosity. The viscosity of the 5% VES solution fluctuates continuously with the increase of shear time, which may be because the micelles formed by viscoelastic surfactants through physical action will build up quickly after shear, and the viscosity remains good without reduction during the shear process of 70 min. The viscoelastic surfactant is recommended as the diverting agent for acidizing. The SEM images of HPAM and VES solutions are shown in Figure 17a,b, respectively. The microstructure differences between the two systems are clearly seen in SEM images. The network structure of HPAM in the solution is spatially continuous, while VES in the solution has a regular and tight micelle structure. The advantage of the network structure is high strength, but the disadvantage is that it can easily cause residue damage to the formation. The advantage of the viscoelastic surfactant is low damage, but the disadvantage is that it is not suitable for high-temperature reservoirs. Therefore, the diverting agent should be selected according to the needs of reservoir stimulation, such as the collaborative application of different types of diverting agents (particles).

4. CONCLUSIONS

As a typical feature of a reservoir, heterogeneity is the main reason for low oil recovery and the poor effect of acidizing

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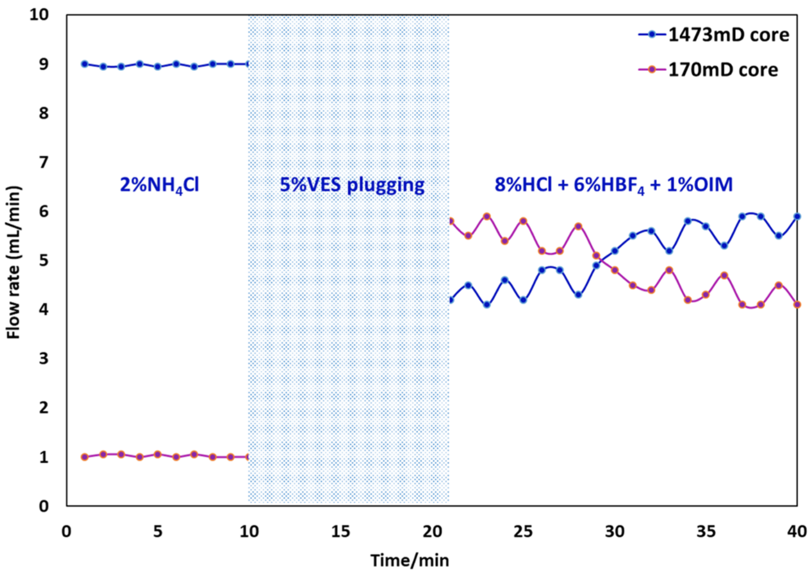

Figure 14. Stimulation effect of placing the acid evenly using a 5% VES solution.

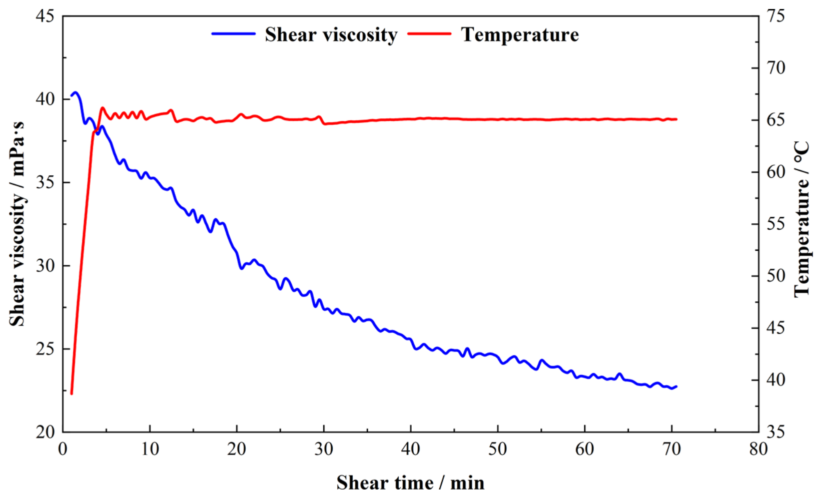

Figure 15. Shear viscosity of 0.3% HPAM at 65 °C, 170 s^{-1}.

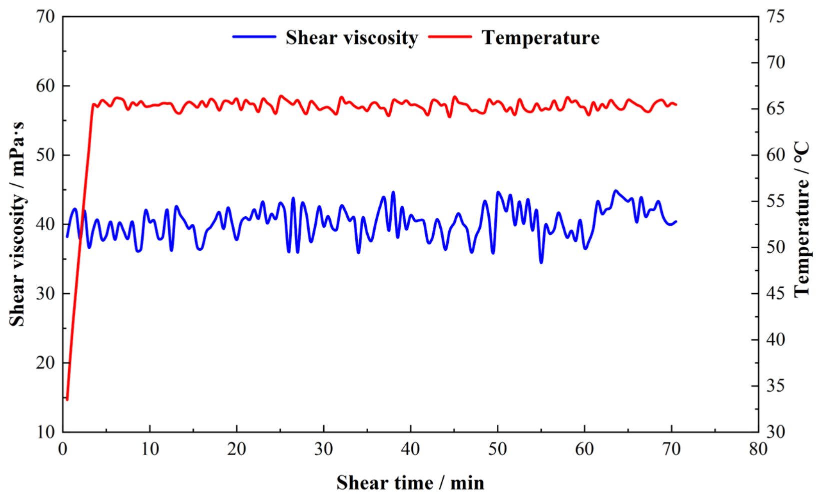

Figure 16. Shear viscosity of 5% VES at 65 °C, 170 s^{-1}.

measures. To improve the effect of acidizing measures, chemical diverting agents are widely used, among which viscous fluids are the most widely used. To further understand the diverting effect and influencing factors of viscous fluids and

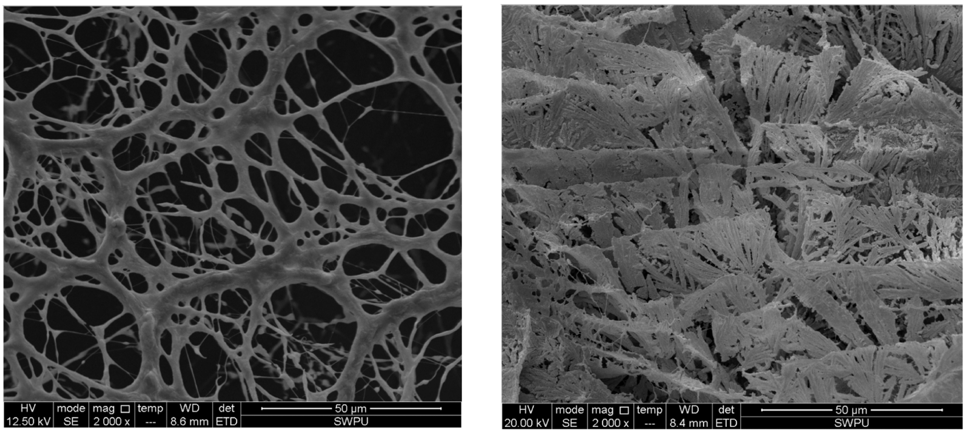
(a) (b)

Figure 17. SEM images of the (a) HPAM solution and (b) VES solution.

provide theoretical guidance for engineering design, a series of experiments were carried out with a heterogeneous dual-core flooding device, and the following conclusions were drawn:

(1) With the increase of the injection pressure difference, the diversion effect of salt water can be effectively improved, which is consistent with MADPIR theory. The injection pressure difference is increased by 50 times, and the diverting effect is improved by 16.27% at most. This shows that the fluid partial flow of heterogeneous reservoirs mainly follows Darcy's rule. Under the maximum allowable injection pressure difference, maximizing the injection rate can not achieve good diverting effect. To improve the effective placement of acid, it is necessary to use a diverting agent.

(2) Increasing the viscosity of the injected fluid can increase the proportion of fluid flowing into the low-permeability layer, which is similar to the polymer flooding mechanism in EOR. However, when the fluid viscosity exceeds a certain value, it will cause the opposite effect that the low-permeability layer is completely blocked. Therefore, when the viscous fluid is used for diverting, the viscosity should be optimized.

(3) Diversion is blocking the low-permeability and high-permeability cores at the same time. Viscous fluids can be used to realize the uniform placement of acids in heterogeneous reservoirs, such as thickened acid, VES acid, etc. However, a one-step injection method has little effect. A two-step injection method needs to be adopted. First, the diverting agent is injected, and then the acid or salt water is injected. Furthermore, the physical properties of the fluid change after being injected into the formation, such as delayed cross-linking or reaction in the formation to generate a solid phase.

(4) The diverting effect of the HPAM solution is more stable than that of the VES solution. The network structure of HPAM in the solution is spatially continuous, while VES in the solution has a regular and tight micelle structure. The advantage of HPAM is high strength, but the disadvantage is that it can easily cause residue damage to the formation. The advantage of the viscoelastic surfactant is low damage, but the disadvantage is that it is not suitable for high-temperature reservoirs. The HPAM and VES solutions can divert brine stably, but the effect of the diverting acid fluid gradually weakens because the viscosity stability of the fluid reduces due to the acid. It is recommended to select the 5% viscoelastic surfactant with an appropriate concentration for acid distribution in the wellbore.

(5) The diverting agent can make the injection area reach a relatively stable flow state, that is, diverting acidizing is only effective for near-well zones and is also effective for near-well plug removal. It is difficult to fundamentally solve the seepage problem of heterogeneous reservoirs.

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Notes

The authors declare no competing financial interest.

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