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Numerical Simulation of Residual Oil Displacement in Offshore Strong Bottom Water Reservoir

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Abstract

C oilfield is located in Bohai Bay Basin, a typical strong bottom water reservoir. There is a large amount of remaining oil in the plane and vertical direction, which cannot be used. Therefore, it is urgent to explore the feasibility of changing the development mode of typical sand bodies and displacement mining. In this study, the residual distribution of the bottom water reservoir is studied through numerical simulation. According to the distribution of remaining oil in the middle of the two sand bodies and the local structure of the sand body, it is divided into top remaining oil, edge remaining oil, and inter well-remaining oil. The effects of different angular permeability laws and differential and injected medium on the development effect are simulated and analyzed. It is found that the effect of gas injection is affected by a high mobility ratio, which is easy to break through early, and the effect of gas channeling is limited. Using active water and air-water alternate (ammonia foam) can achieve relatively good results. This experimental study guides tapping the remaining oil potential in the offshore strong bottom water reservoir.

Keywords

Offshore Sandstone Reservoir, Nitrogen Foam, Different Viscosity, Displacement Experiment

1. Introduction

C oilfield is located in the Western Bohai Sea, and the regional structure is located in Shaleitian uplift. The primary development strata of the oilfield are Neogene Minghuazhen Formation and Guantao formation, which are high porosity and high permeability reservoirs. The central buried depth of the reservoir is 640 - 1750 m, the formation temperature gradient is 3.3˚C/100m, and the formation pressure gradient is 1.0 MPa/100m. It is an average temperature and pressure system. After nearly ten years of high-speed development, it has entered the high water cut period. Its primary development mode is to rely on natural energy exploitation driven by the strong edge and bottom water. Horizontal wells mainly develop it. The main production characteristics are high water cut of oil wells and large liquid production of single wells. For high efficiency and stable production of the oilfield, it is necessary to deeply study the oil stabilization and water control technology of bottom water reservoir and formulate the development strategy of bottom water reservoir (Myint & Firoozabadi, 2015; Liu et al., 2021a, 2021b; Tan et al., 2022; Jacquelin & Erik, 2020; Sharma et al., 2019; Cobos & Sogaard, 2020).

It is difficult for strong bottom water reservoirs in the middle and late stages of offshore development to implement technologies such as perfect injection production well pattern and steam displacement due to the limitation of offshore conditions. In order to better develop offshore bottom water oil fields, the feasibility of inter-well residual oil displacement is fully demonstrated (Cobos & Sogaard, 2020; Bhatia et al., 2014; Tan et al., 2021; Cai, 2000; Li et al., 2021). This time, the numerical simulation of residual oil displacement in the bottom water reservoir with different displacement media was carried out. We optimize the displacement medium and study the optimization of displacement parameters for the optimized displacement medium, select the medium suitable for the displacement of residual oil between wells and at the top of the C oilfield, and formulate a feasible scheme for the displacement of residual oil between wells and at the top of the C oilfield, and also guide tapping the potential of remaining oil in offshore strong bottom water reservoirs.

2. Types and Distribution Characteristics of Remaining Oil

2.1. Distribution Law of Remaining Oil in 943 Edge Water Reservoir

2.1.1. Block Digital Geological Model

The grid model adopts the corner grid system. Based on the existing acceptable three-dimensional geological model, the model grid is divided into 159 × 90 × 21. The grid step is 60 m × 60 m. The focus of this well group simulation is to select representative specific well groups for mechanism simulation and carry out targeted research on tapping potential remaining oil according to the distribution characteristics of the remaining oil. This time, the model has 21 layers longitudinally, with a vertical thickness of 0.867 - 4.011 m and an average of 1.23 m. There are 26 wells in the well cluster, with 300,510 grids.

2.1.2. PVT Properties of Fluids

The component model is established according to the PVT data of the fluid and the range of fluid physical properties. The PVT properties of the fluid are shown in **Table 1** below.

Table 1. 943 PVT attribute of formation water.

Project	Parameter value	Unit
Reference pressure	9.24	MPa
Formation water volume coefficient	1.001	sm^3/sm^3
Compressibility coefficient of formation of water	5×10^{-06}	bar^{-1}
Formation water viscosity	0.48	mPa·s
Formation water density	1020	kg/m^3

2.2. Screening of Typical Good Groups with Different Remaining Oil Types

Screening of Typical Good Groups in 943 Sand Body

Overall characteristics of remaining oil distribution in sand body 943:

1) From high to low 1 - 0 grid layer, the oil production gradually increases, and the remaining oil decreases.

2) There is residual oil between wells in layers 10 - 17 of the model grid.

3) The remaining oil mainly exists in the grid layer at the top of the reservoir.

Distribution characteristics of remaining local oil:

1) In the high part of the structure, due to the poor physical properties of the grid, the reserves of layers 1 - 10 of the model grid are undeveloped;

2) Residual oil between wells, bottom water along the water ridge and water cone, and there is a large amount of residual oil in the middle area of the two wells (layers 13 - 17 of the model grid);

3) In the area without production wells in the oil-bearing area, there is residual oil not controlled by the well pattern (grid layer 3 - 12);

4) A small, relatively low permeability area forms water drive uniform residual oil along the high permeability channel's water ridge and cone.

Based on the study of the plane and vertical distribution of residual oil in the body, three main types of residual oil wells are divided: edge residual oil, top residual oil, and inter-well residual oil. The remaining oil in sand body 943 is divided into three well groups: edge remaining oil group, top remaining oil well group, and inter well-remaining oil well group (Figure 1).

3. Study on Main Controlling Factors of Displacement Production

Based on the research on the remaining oil distribution of the large macro model and referring to the remaining oil distribution characteristics of the actual well group (physical conditions such as different dip angles, permeability rhythm, and differential), the mechanism model of the typical well group is established by splitting the small well group (the structural model is consistent with the actual well, and the machine model is established according to the parameter range of the actual well group for other physical parameters, dip angle between injection and production wells, etc.), Including top remaining oil well group, edge

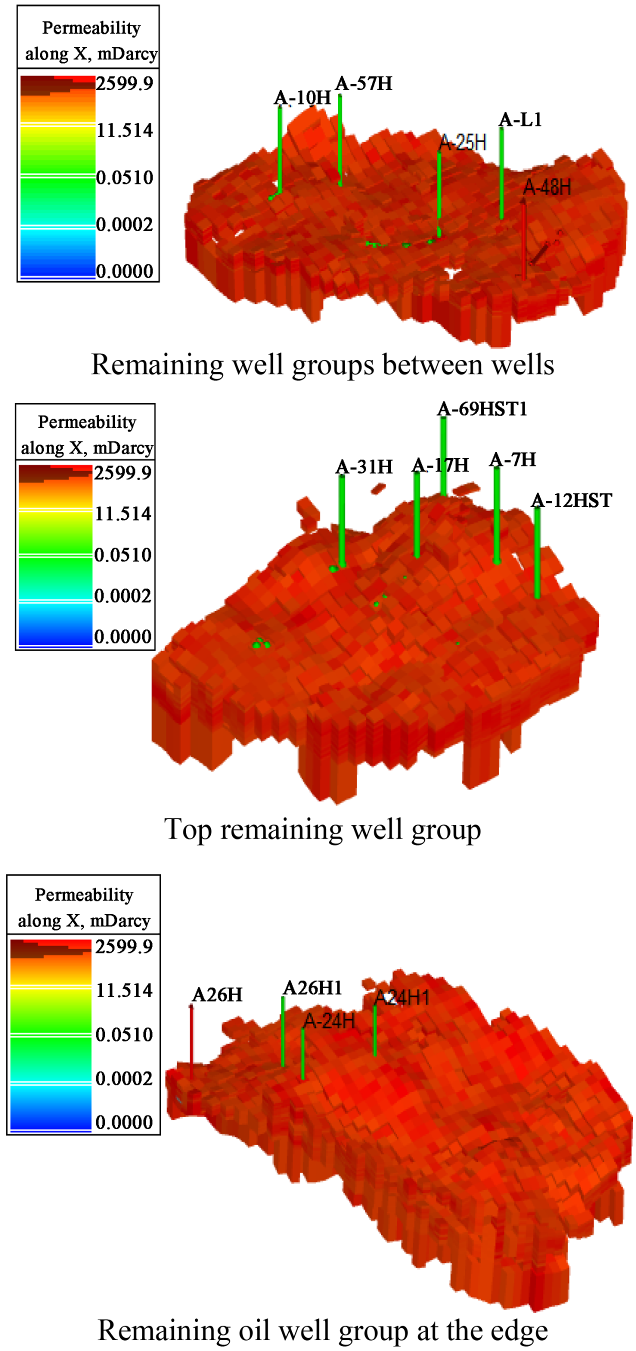


Figure 1. Typical well group of 943 sand body.

remaining oil well group and inter well-remaining oil well group: carry out mechanism simulation (structure, physical properties, injection medium, energy supplement mode, etc.), and analyze the main control factors affecting the production of remaining oil.

The Orthogonal Experiment of the Small Well Group on Influencing Factors of Remaining Oil in 943 Sand Body

According to the three types of remaining oil summarized and analyzed by the

943-second body, a typical well group is established, the mechanism simulation is carried out, the main factors affecting the distribution of remaining oil are analyzed, and the orthogonal experimental table of influencing factors of remaining oil of specific well group of 943 sand body is designed (Table 2). According to the distribution remaining oil, typical well groups are divided into top remaining well group, edge remaining well group and inter well-remaining well group.

Remaining Well Groups between Wells

The model is a three-dimensional fine geological model, and the grid is divided into 35 × 22 × 21. The grid step is 60 m × 60 m, and the grid system adopts a corner grid. The average porosity of the remaining oil well group model at the edge of sand body 943 is 0.283, and the average permeability in X and Y directions is 1261.5 mD. This time, the model adopts 32 layers longitudinally, 21 layers vertically; the vertical thickness is 0.896 - 16.136 m, with an average of 1.468 m. There are 5 production wells in the well group, no water transfer, and injection wells, and the total number of grids is 23,520.

The well cluster has been in production since 2004, and the cumulative recovery degree by January 2019 is 27.53%. The cumulative oil production is 1,048,500 m^3 and the cumulative water production is 18,526,200 m^3. The pressure retention

Table 2. Orthogonal experiment table for influencing factors of remaining oil in 943 sand body.

Remaining well groups between wells					Top remaining well group				Remaining oil well group at the edge			
factor	Dip angle	K rhythm	factor	Dip angle	K rhythm	factor	Dip angle	K rhythm	factor	Dip angle	K rhythm	factor
Experiment 1	1.5˚	Positive	7 times	Water injection	2.5˚	Positive	7 times	Water injection	0.5˚	Positive	7 times	Water injection
Experiment 2	1.5˚	Complex	3 times	gas injection	2.5˚	Complex	3 times	gas injection	0.5˚	Complex	3 times	gas injection
Experiment 3	1.5˚	Negative	1.5 times	Active water	2.5˚	Negative	1.5 times	Active water	0.5˚	Negative	1.5 times	Active water
Experiment 4	3.0˚	Positive	3 times	Active water	5.0˚	Positive	3 times	Active water	1.0˚	Positive	3 times	Active water
Experiment 5	3.0˚	Complex	1.5 times	Water injection	5.0˚	Complex	1.5 times	Water injection	1.0˚	Complex	1.5 times	Water injection
Experiment 6	3.0˚	Negative	7 times	gas injection	5.0˚	Negative	7 times	gas injection	1.0˚	Negative	7 times	gas injection
Experiment 7	4.5˚	Positive	1.5 times	gas injection	7.5˚	Positive	1.5 times	gas injection	1.5˚	Positive	1.5 times	gas injection
Experiment 8	4.5˚	Complex	7 times	Active water	7.5˚	Complex	7 times	Active water	1.5˚	Complex	7 times	Active water
Experiment 9	4.5˚	Negative	3 times	Water injection	7.5˚	Negative	3 times	Water injection	1.5˚	Negative	3 times	Water injection

rate is 76.47%, the current water cut is 99%, the change of remaining oil saturation is analyzed, and the main controlling factors of sand body displacement production are studied.

From the nine orthogonal experimental schemes, it can be seen that when the formation dip angle is 2.1˚C, the reverse permeability rhythm, the differential is low and the continuous water injection is 2941.5 m^3/d, the change trend of formation pressure is also gentle and the ability to maintain formation pressure is strong. The cumulative oil production of F3 scheme is the maximum among several schemes, and the cumulative recovery degree is the highest, which is 41.66%.

According to the above orthogonal experimental results (**Figure 2**), the scheme with the best effect is Experiment 3 and the worst is experiment 9. The comparison of oil saturation distribution is as follows. The active water is injected in the middle of the transfer well model in Experiment 3, and the oil displacement effect is obvious in the high part of the model compared with the water injection scheme in Experiment 9.

The injection of active water has a good displacement effect on the remaining oil between wells, with favorable mobility ratio and intermediate density, forming plane and vertical co displacement with bottom water.

In the physical simulation experiment, it was found that the nitrogen foam flooding and the active water displacement in the 943 sand bodies increased the recovery degree obviously. Therefore, on the basis of the orthogonal experiment, the simulation analysis of the comparison between nitrogen foam flooding and active water injection was supplemented.

943 the comparison of the effect between the active water and nitrogen foam flooding in the remaining wells between wells. The effect of the two is the same. The nitrogen foam flooding is slightly higher than that of the active water flooding scheme, and is higher than that of the pure water injection or gas injection scheme, and the recovery degree of the 15 years is 42.93%. The effect of chlorine foam on remaining oil between wells is good, favorable fluidity ratio and intermediate density are formed by plane and vertical displacement together with bottom water. Therefore, gas foam is selected as the displacing medium for the optimal scheme of remaining oil between wells in the subsequent 943 sand bodies.

Top Remaining Well Group

The model is a three-dimensional fine geological model, and the grid is divided into 33 × 25 × 21. The grid step is 60 m × 60 m, the grid system adopts corner grid. The average porosity of the remaining oil well group model at the edge of sand body 943 is 0.282, and the average permeability in X and Y directions is 3120 mD. Through the process of bottom water rising, the model level is adopted this time, with 25 layers vertically and 21 layers vertically. The vertical thickness is 0.753 - 13.054 m, with an average of 1.226 m. There are 5 production wells in the well group, no water transfer and injection wells, and the total number

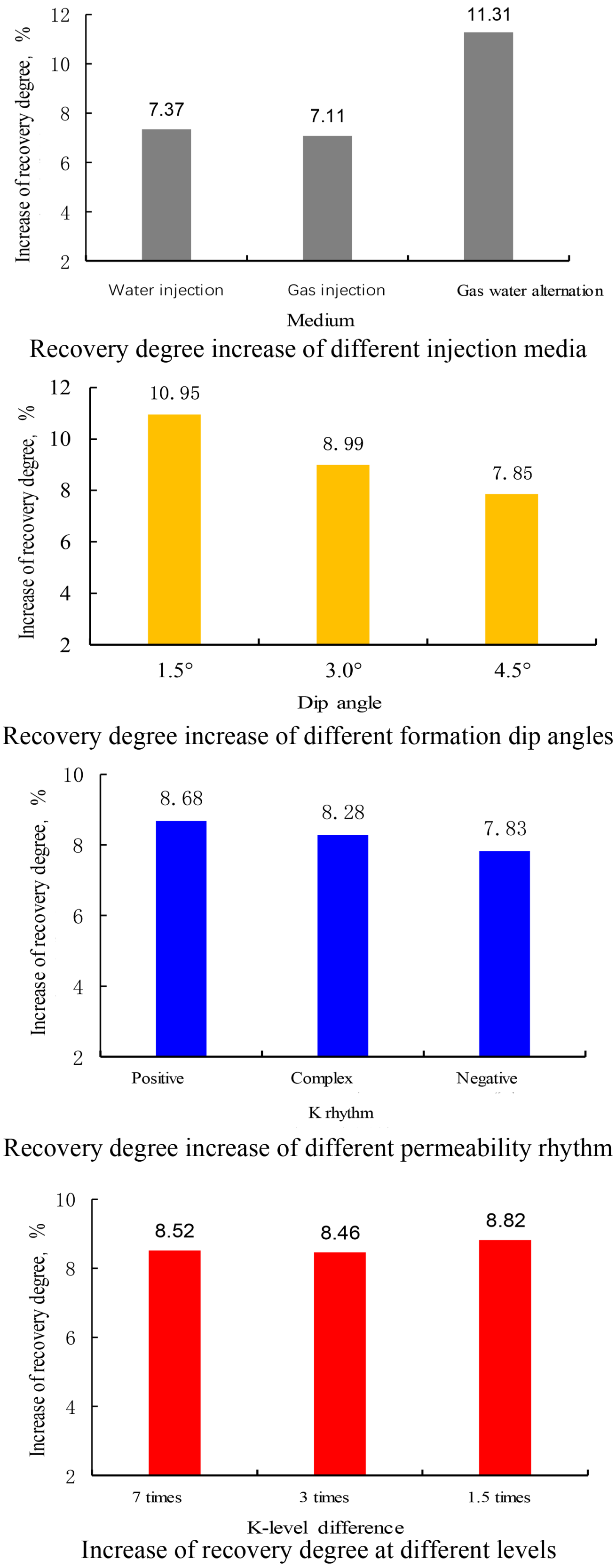


Figure 2. Orthogonal experimental results of recovery degree of remaining oil between wells in 943 sand body.

of grids is 17325.

The well cluster has been in production since 2004, and the cumulative recovery degree by January 2019 is 23.47%. The cumulative oil production is 825,000 m^3, the cumulative water production is 31,964,600 m^3, the pressure retention rate is 70.38%, and the current water content is 99.04%. Analyze the change of residual oil saturation on the plane and study the main controlling factors of sand body displacement production.

It can be seen from the nine orthogonal experimental schemes (**Figure 3**) that when the formation dip angle of 2.1˚C, the law of reverse permeability, low differential and continuous water injection diagram are 2941.5 m^3/d, the change trend of formation pressure is also gentle and the ability to maintain formation pressure is strong. The cumulative oil production of F3 scheme is the maximum among the three schemes, and the cumulative rice yield is the highest, which is 35.19%.

According to the above orthogonal experimental results, the best scheme is Experiment 3 and the worst is experiment 9. As shown in the comparison of oil saturation distribution, the top model transfer well injects active water to drive oil to the surrounding production wells, and the effect is obviously better than the water injection scheme.

Active water injection has a good displacement effect on the top residual oil, and forms plane and vertical co displacement with bottom water.

Remaining Oil Well Group at the Edge

The model is a three-dimensional acceptable geological model divided into 37 × 37 × 21. The grid step is 65 m × 65 m, and the grid system adopts a corner grid. The average porosity of the remaining oil well group model at the edge of the sand body 943 is 0.273, and the average permeability in X and Y directions is 1200 md. This time, 37 vertical layers of the model are adopted, including 21 vertical layers, with a vertical thickness of 0.666 - 13.552 m and an average of 1.419 m. There are 5 production wells in the well group, no transfer and water injection wells, and the total number of grids is 28,749.

The well cluster has been in production since 2004, and the cumulative recovery degree by January 2019 is 11.75%. The cumulative oil production is 517,900 m^3, the cumulative water production is 8,233,700 m^3, the pressure retention rate is 82.75%, and the current water content is 94.76%. The change of residual oil saturation on the plane is analyzed, and the main controlling factors of displacement production of 943 sand body are studied.

Based on the study of the top remaining oil well group, the remaining oil well group at the edge is corrected for the change of formation dip angle, and the other parameters remain unchanged. The component model is selected, the working system of constant liquid production is adopted, and the orthogonal experiment according to the above four factors to predict the future 15 years.

As can be seen from the nine orthogonal experimental schemes (**Figure 4**), when the formation dip angle of 2.1˚C, reverse permeability rhythm, low-level

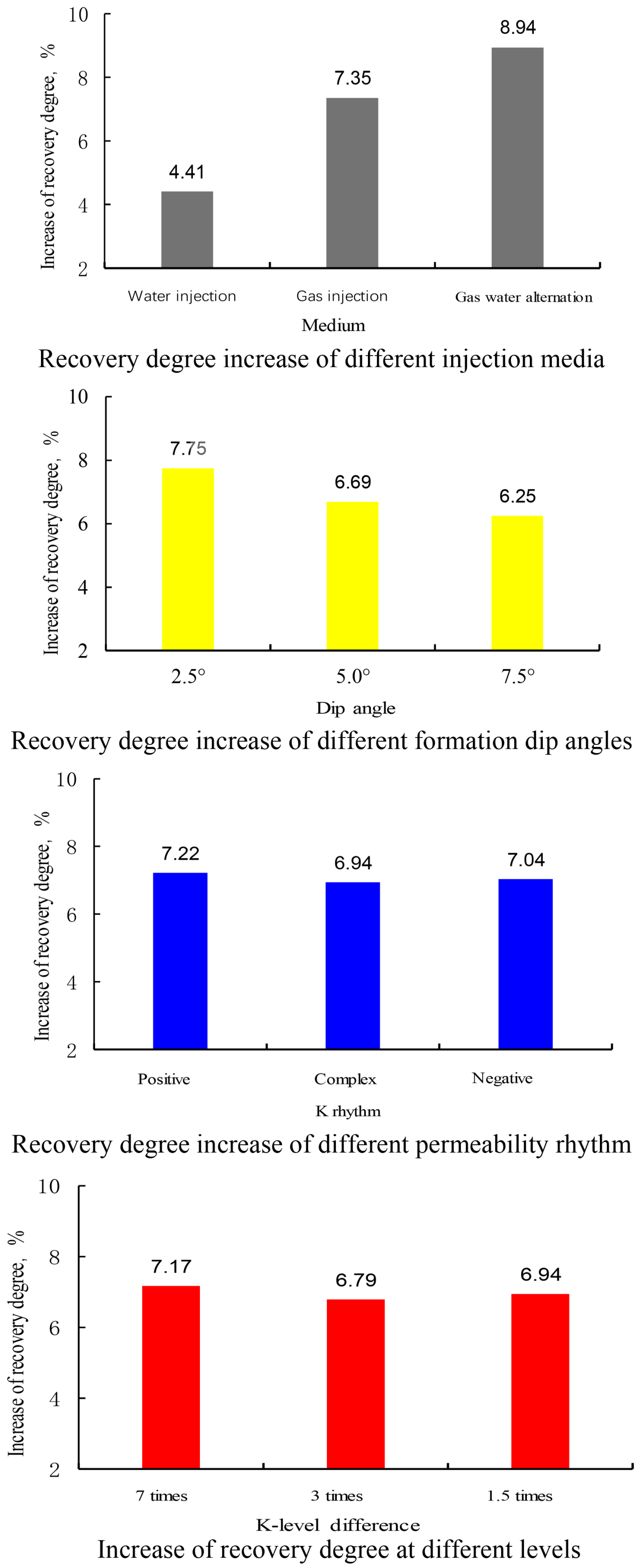
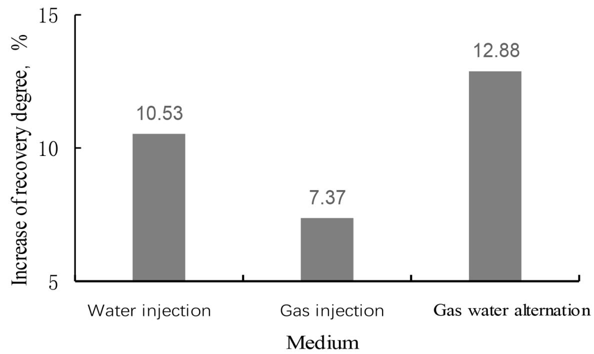
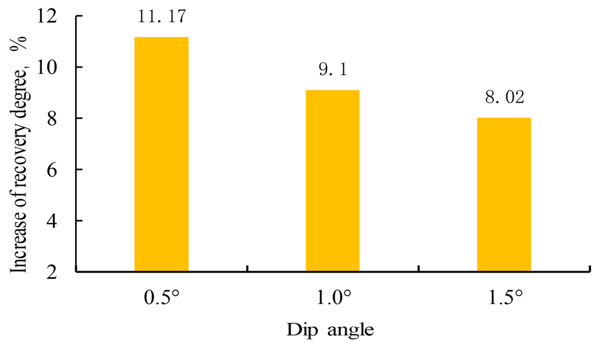


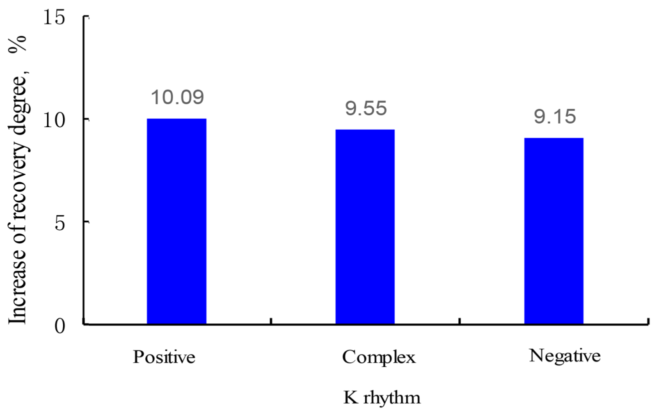
Figure 3. Orthogonal experimental results of recovery degree of remaining oil at the top of 943 sand body.



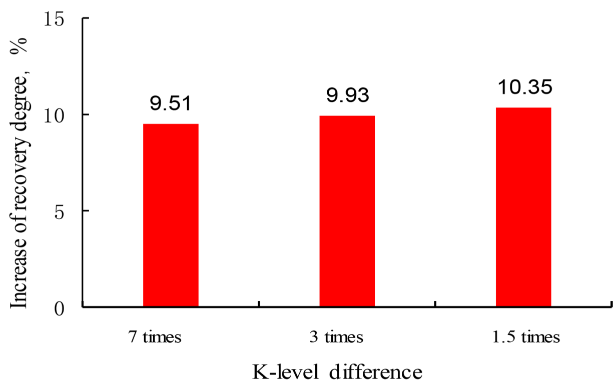
Recovery degree increase of different injection media



Recovery degree increase of different formation dip angles



Recovery degree increase of different permeability rhythm



Increase of recovery degree at different levels

Figure 4. Orthogonal experimental results of recovery degree of residual oil at the edge of 943 sand body.

difference, and continuous water injection volume are 3195.9 m^3/d, the changing trend of formation pressure is also gentle, and the ability to maintain formation pressure is strong. The cumulative oil production of F3 scheme is the maximum among several schemes, and the cumulative recovery degree is the highest, 32.61%.

According to the above orthogonal experimental results, the best scheme is Experiment 3, and the worst is experiment 9. The comparison of oil saturation distribution is shown as follows. The active water is injected in the middle of the transfer well model in Experiment 3, and the oil displacement effect is better than that in the high part of the model in Experiment 9.

The active water injection has a good displacement effect on the residual edge oil, and forms plane and vertical co displacement with the bottom water.

4. Conclusions

1) Remaining oil characteristics of sand body 943: due to the poor physical properties of the grid in the high part of the structure, the amount of layers 1 - 10 of the model grid is basically not used. There is a large amount of residual oil in the middle area of the two wells. There is residual oil not controlled by the well pattern in the area without production wells in the oil-bearing area. In the relatively low permeability area, the water direction forms water drive uniform residual oil along the water ridge and water cone of the high permeability channel.

2) Some horizontal displacement flow lines can be seen at the initial stage of the initial production of the two working areas. With the development, the number of flow lines moving vertically in the later stage gradually increases: the flow line is almost vertical in the reservoir section, and the flow line basically flows in a single aqueous phase. It enters the ultra-high water cut development stage, aiming at the distribution of remaining oil in the middle of the two sand bodies. According to the local structure of sand body, it is divided into top residual oil well group, edge residual oil well group and inter well residual oil well group.

3) The orthogonal experimental simulation of the 943 sand well group shows that the effect of high volume ratio on the 943 body injection of high viscosity oil is easy to break through earlier, and the gas channeling effect is limited. Using active water and gas water alternation (nitrogen foam) can achieve relatively good results. The low structure amplitude is conducive to enhancing the displacement of the plane and promoting the remaining oil utilization. The gas water alternating (hydrogen foam) is slightly higher than that of the active water flooding scheme, and is obviously higher than that of the pure water injection or gas injection scheme. The gas injection effect of top remaining oil is better than that of other types, but it is still lower than that of water-based scheme. Compared with other types of residual oil, the effect of edge residual oil and gas injection is worse, which is significantly lower than that of active water scheme

and water injection scheme.

Conflicts of Interest

The authors declare no conflicts of interest regarding the publication of this paper.

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