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RESEARCH ARTICLE

Oil Displacement Behavior of Polymer Flooding in Horizontal Well Patterns: Experimental and Numerical Simulation Approaches

Shaohao Huang[1,3,*], **Zhibin Li**[1], **Xuefeng Song**[1], **Binshan Ju**[3], **Chen Zhang**[2] **and Bing Xu**[1]

[1] CNOOC EnerTech-Drilling & Production Co., Ltd., Tianjin 300452, China
[2] CNPC Xibu Drilling Engineering Company Limited, Urumqi 830011, Xinjiang, China
[3] China University of Geosciences, Beijing 100083, China

Abstract

Heavy oil reservoirs often retain substantial remaining oil after polymer flooding with vertical wells due to unfavorable oil-water mobility ratios and reservoir heterogeneity. Although horizontal wells can improve oil displacement efficiency by providing a larger contact area with the formation, systematic studies on the displacement behavior and key influencing factors of polymer flooding in opposed horizontal wells are still lacking. This study addresses this gap by combining two-dimensional physical simulation experiments with Eclipse numerical simulation to investigate the displacement dynamics and remaining oil distribution. The experimental results show that increasing well spacing prolongs the water-free oil production period and enhances final recovery. At the same time, the recovery at a crude oil viscosity of 50 mPa·s is 15.31% higher than that at a crude oil viscosity of 300 mPa·s at a well spacing of 14 cm, indicating that horizontal well polymer flooding is more effective in relatively low viscosity heavy oil reservoirs. Numerical simulation shows that the optimal distance is 390 m, beyond which the incremental recovery will become negligible. Both experimental and numerical simulation results confirm that polymer flooding in opposed horizontal wells can effectively alleviate water fingering and channeling, delay water breakthrough, and improve sweep efficiency. In the vertical direction, the remaining oil saturation of the middle layer increases from the inside out, with higher saturation in the upper part than in the lower part, and better recovery rates are observed at lower reservoir positions. By providing experimental validation, this study not only serves as a basis and verification for numerical simulations, but also offers scientific insight and engineering guidance for optimizing polymer flooding strategies in unconventional and mature horizontal-well reservoirs.

Keywords: horizontal well, polymer flooding, heavy oil reservoir, numerical simulation, recovery rates.

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***Corresponding author:**
Shaohao Huang
1602834900@qq.com

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1 Introduction

Despite polymer flooding being a common technique for heavy oil reservoirs, factors such as the oil-water mobility ratio and reservoir heterogeneity can still result in significant amounts of remaining oil after polymer flooding with vertical wells, leaving room for improvement in the recovery process. In this context, the use of horizontal wells for polymer flooding has emerged as a promising technology to enhance heavy oil recovery. When compared to vertical wells, the use of horizontal wells in combination with polymer flooding can lead to a significant increase in produced oil volumes for the same fluid injection volume [1, 23]. In flowable heavy oil reservoirs, polymer flooding with horizontal well patterns can effectively control the mobility of the fluid, reducing water flooding fingering phenomena to improved injection capabilities and significantly improving sweep efficiency [2–4, 24]. Recently, the research indicates that even very low concentrations of polymers yield relatively high recovery rates at adverse mobility ratios [5]. However, after long-term polymer flooding, it still leads to the formation of dominant seepage channels, resulting in severe ineffective circulation issues [6–8].

Therefore, it is crucial to design appropriate well locations, polymer concentrations, and injection parameters based on the characteristics of the reservoir. Scholars have shown that a well-designed injection strategy can significantly improve the recovery efficiency in horizontal well patterns [9]. Recently, similar multi-objective optimization strategies have been developed to maximize cumulative oil production while minimizing polymer injection volume. In addition, researchers have found that the distribution of remaining oil in the reservoir is influenced by the location and direction of the well, with lower recovery of crude oil observed in the low-permeability layer for highly heterogeneous reservoirs [10, 26]. To address this issue, researchers have proposed various strategies. For instance, heterogeneous composite flooding technology has been proven to effectively enhance the recovery rate of high water-cut reservoirs after polymer flooding, particularly in the presence of high-permeability channels [11]. The integration of nanomaterials with polymer flooding also demonstrates great potential, improving recovery rate through various mechanisms such as viscosity improvement, sweep efficiency enhancement, wettability alteration, interfacial tension reduction, the threshold pressure gradient, and adsorption control [12, 13, 18–22]. In addition, a recent combination of machine learning frameworks to screen suitable enhanced oil recovery methods has improved the accuracy and recovery rate of predictions [14]. Meanwhile, the optimization design and injection parameter selection of polymer solution are the key to the success of polymer flooding, especially in heavy oil reservoirs, where a balance between viscosity control effect and injection capacity is required [15, 27]. The viscosity of polymer solutions is closely related to factors such as temperature, salinity, and polymer concentration [16, 25]. A study has explored the optimization of polymer solution viscosity in heavy oil reservoirs through experiments and numerical simulations, and found that appropriate viscosity is crucial for improving oil recovery [15].

Although numerical simulation studies have explored the potential of polymer flooding in horizontal wells, systematic research on its displacement behavior and influencing factors remains lacking, and experimental verification is urgently needed to support the proposed technology. To address this issue, this paper established an experimental model that incorporates the geological characteristics, fluid properties, and well types of an actual reservoir, based on the physical mechanism of polymer transport in porous media. The research approach integrates two-dimensional physical simulation experiments with numerical simulation methods to quantitatively investigate the dynamic characteristics of oil displacement, enhanced oil recovery, and the key influencing factors. This integrated methodology allows for a detailed characterization of the spatiotemporal evolution of polymer-driven oil displacement fronts and the dynamic recovery efficiency under varying polymer concentrations, injection rates, and reservoir permeability contrasts [18]. The present work bridges this gap by providing an experimentally validated framework that underpins the numerical simulations and informs field-scale deployment strategies for horizontal-well polymer flooding.

2 Experimental Research

This study focuses on the development of conventional heavy oil in continental facies, using water flooding. To establish a mathematical model and design experiments, the similarity criterion and equation analysis method are utilized. The experiment is designed, according to the actual situation of the oilfield and the similarity theory, which reduces the oilfield to a flat plate model based on a certain

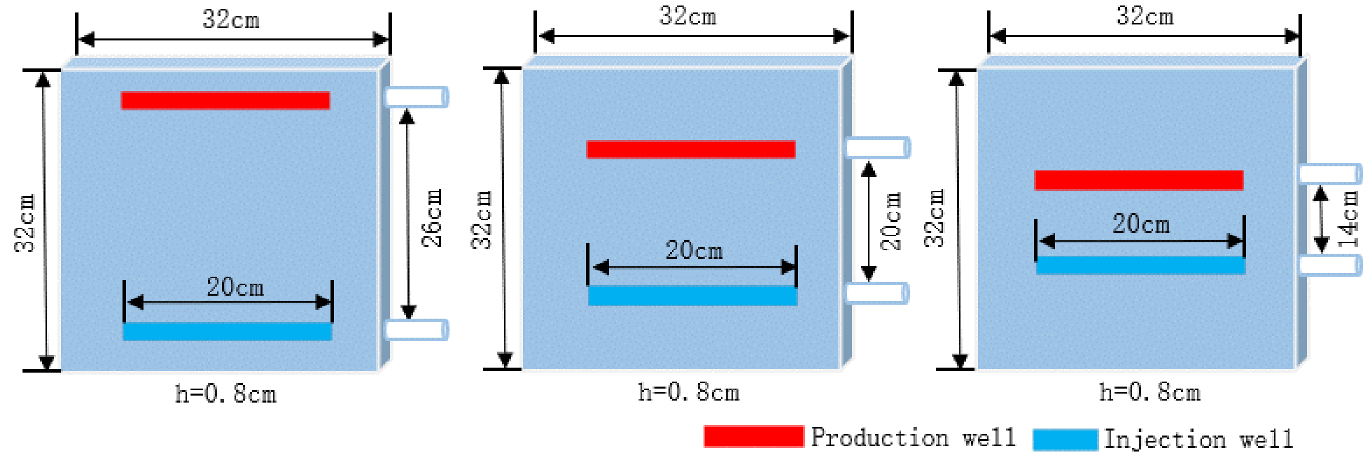

Figure 1. Experimental model diagram of opposed horizontal wells under different well spacings.

proportion. To ensure that the production indicators are scaled to a certain proportion [17], the similarity criterion is constrained by four parts, including geometric similarity, reservoir characteristics similarity, initial condition similarity, outer boundary condition similarity, motion, and dynamic similarity. In addition, the porosity of the sand-packed model was calculated using the water-measured volume method, and the permeability of the quartz sand after mixing different particle size ratios was determined by Darcy's law.

Geometric similarity criterion is determined based on the facing well, the length of the horizontal section, and the thickness of the sand body of the average horizontal well in the oilfield. The physical models are designed and fabricated for different oil viscosities and different well distances with 6 groups of physical models, and sand filling thickness of 0.8 cm. The two-dimensional experimental model's length and wellbore trajectory of the model horizontal wells are similar to the real horizontal wells in the target block. The experimental design is shown in Figure 1.

To ensure similar reservoir characteristics between the model and prototype, the physical simulation of two-phase flow requires the use of the same pore medium. This ensures that the phase permeability curve and capillary force curve reflecting the two-phase flow law in the model are the same as those in the prototype. To achieve this, the researchers collected of reservoir geological data and analyzed them to identify the physical and lithological parameters that can represent the core of the reservoir. These parameters were then used as the basis for making the models. For this experimental research, a geological model was designed with a permeability of 5000 md and crude oil viscosities of 50 cp and 300 cp in different experiments.

The initial conditions of the physical model are established to be similar to those of the prototype by fully saturating the model with water, and then flooding it with simulated oil. The irreducible water saturation in the model is measured, and the model is then saturated with oil to simulate the wettability of the original oil layer.

The outer boundary conditions of the model are also made similar to those of the prototype. The model has the same boundary properties at the boundary corresponding to the prototype, with a closed boundary, or constant pressure boundary. The pressure value at the constant pressure boundary is set to correspond proportionally to that of the prototype.

The similarity in motion and dynamics: To ensure dynamic similarity between the model and the prototype, the experimental parameters were carefully selected based on the injection and production data of the oilfield. The displacement speed in the experiment was set to 2 ml/min, following the enterprise standard of China National Offshore Oil Corporation (Q/HS 2032-2018). This parameter was chosen to ensure that the fluid flow in the model was representative of the actual oilfield conditions.

2.1 Experimental Materials

The experimental materials mainly include:

1) The experimental model used in this study has dimensions of 32 cm × 32 cm × 0.8 cm, with a horizontal well length of 20 cm, a porosity of $\Phi = 38.6\%$, and a permeability of 5000 mD. The fabrication of the model involved the use of various materials, which were assembled to create the experimental setup. The

Table 1. Oil field water ion composition table (salinity composition, mg/L).

water sample	K^{+}+Na^{+}	Mg^{2+}	Ca^{2+}	CO_3^{2-}	HCO_3^{-}	Cl^{-}	SO_4^{2-}	Degree of mineralization
QHD32-6	831.8	15.7	32.2	58.4	1062.7	705.8	11.4	2718.0

primary purpose of the model was to measure the permeability of the sand using Darcy's law.

2) In the experiment, the simulated water used was prepared to match the formation water salinity of the target oilfield Qinhuangdao 32-6, which is a sodium bicarbonate water type. The total salinity of the formation water is 2718 mg/L, and the total content of calcium and magnesium ions is 47.89 mg/L. The experimental data are presented in Table 1.

3) Two types of experimental oils were prepared by combining No. 10 white oil, No. 100 white oil, and No. 680 white oil. The resulting oils had viscosities of 50 mPa·s and 300 mPa·s at 25 °C, respectively.

4) In the experiment, polyacrylamide polymer 3640C was used. A 600 mg/L polymer solution was prepared at 25 °C through experiments, and its viscosity was measured to be 20 mPa·s after shearing.

2.2 Experimental Scheme and Steps

2.2.1 Experimental Scheme

The physical model was constructed by uniformly mixing artificial quartz sands with different mesh numbers. To simulate the geological characteristics of the target oilfield and the horizontal well in this experiment, a stainless steel tension spring was used to create a horizontal well in the model. The length and trajectory of the horizontal well in the model were designed to be similar to the real horizontal well in the target block. The horizontal wellbore was created in the experimental model using the buried pipe method. The experimental model is shown in Figures 2 and 3.

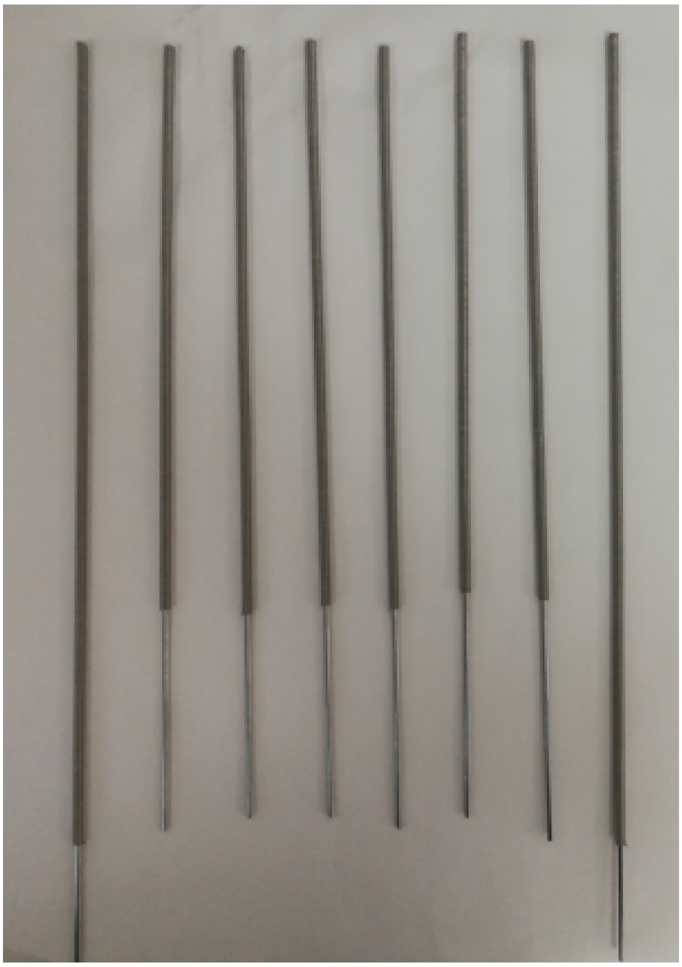

Figure 2. Horizontal well experimental model.

At a temperature of 25°C, the experimental model was initially saturated with simulated water, and then the prepared simulated oil was injected for displacement. The experiment was continued until there was no water at the outlet of the two-dimensional model, and the pressure difference between the two ends remained constant. The water output at the outlet was accurately measured to determine the original oil saturation. To reverse the wettability of the quartz sand and glass, the model saturated with crude oil was aged for 72

Table 2. Experiment scheme for oil displacement with positive well and fixed well spacing.

Test content	Well spacing	Permeability	Viscosity	Scheme number
Determination of polymer flooding effect with horizontal wells under different simulated oil viscosity and well spacing when setting the well	14 cm	5000 mD	50 mPa·s	SY1
			300 mPa·s	SY2
	20 cm		50 mPa·s	SY3
			300 mPa·s	SY4
			50 mPa·s	SY5
			300 mPa·s	SY6

Figure 3. Experimental sand-packed model.

hours to alter their wettability. The experimental results showed that the oil saturation of the model was S0=67.66%. The experimental displacement process is shown in Figures 4 and 5.

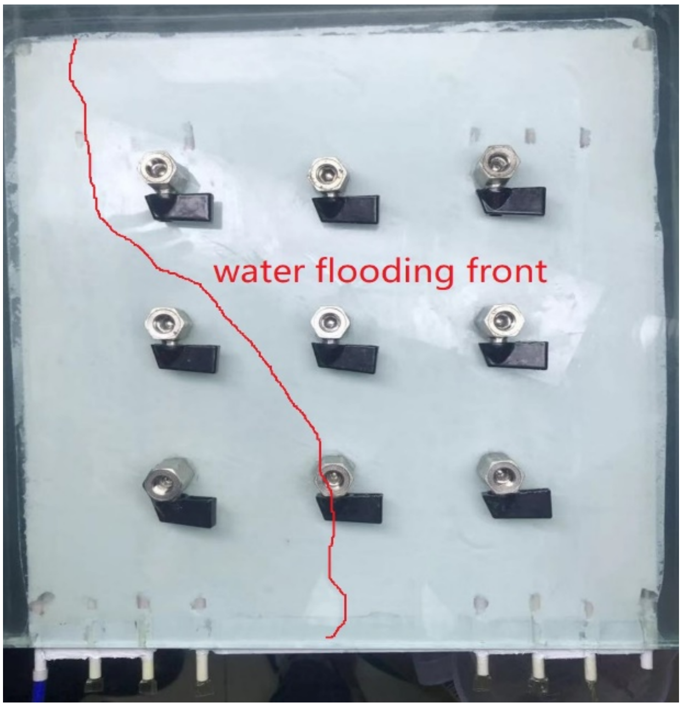

Figure 4. Water injection.

To investigate the impact of crude oil viscosity and well

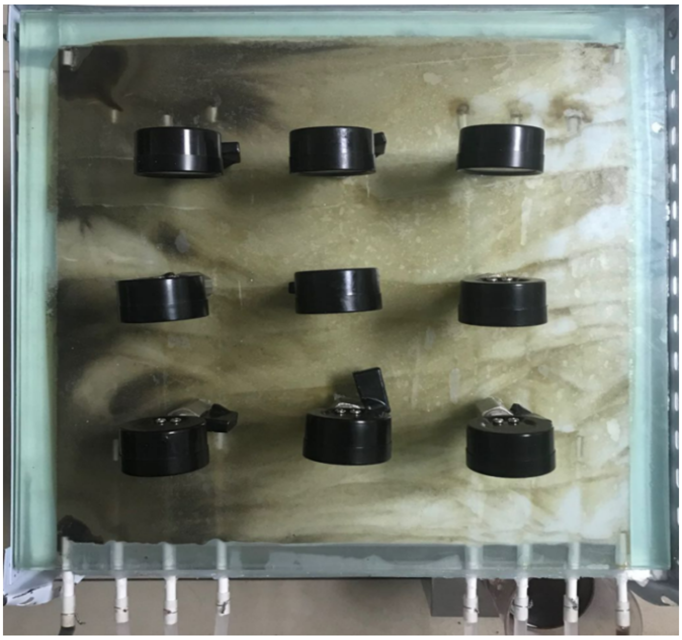

Figure 5. Oil injection.

spacing on the water flooding performance in heavy oil reservoirs, six physical models were constructed with horizontal wells. The experimental details and parameters are presented in Table 2 .

2.2.2 Experimental Steps

1)To ensure that the physical experimental model has a permeability of 5000 mD, a mixture of quartz sand and clay was used to fabricate the model, taking into account the required particle size distribution and compaction properties.

2)After saturating the experimental model with the prepared simulated formation water, the model was injected with simulated oil of two different prepared viscosities 50 mPa·s and 300 mPa·s at an initial speed of 2mL/min. The water output at the outlet was accurately measured to determine the original oil saturation based on the water output.

3)The experimental equipment was cleaned and reconnected. The model, which was saturated with simulated oil, was then left to age for 72 hours.

4)After the model is saturated with oil, it is replaced with simulated formation water, and the water flooding experiment is carried out. The water production, oil production, and water cut changes at the entrance of the two-dimensional model are accurately recorded, and the water flooding is stopped when the water cut reaches 90%. The oil recovery factor is calculated, and experimental data is recorded at different times to analyze the effect of well spacing and crude oil viscosity on the water flooding performance of heavy oil.

5)The experiment involved injecting a 20 mPa·s viscosity polymer into the two-dimensional model at a specified injection rate, with a slug volume of 0.4 PV. The model was then subjected to water flooding until the water cut of the produced liquid reached 98%, at which point the flooding was stopped and the experimental data was recorded.

6)Clean and replace the experimental equipment to finish the experiment.

The main experimental conditions are:

1)The experiment was conducted at a temperature of 25 ℃.

2)The displacement pressure used in the experiment was 12 kPa.

3)To enhance the visualization of test results, black heavy oil was added to the simulated oil.

2.3 Experimental Results and Analysis

2.3.1 Experimental Results

During the experiment, water flooding was conducted initially, and the relationship between oil and water production over time was recorded in this study. The water cut and recovery of the model were calculated using the oil and water production data. The experimental results are presented in Figure 6.

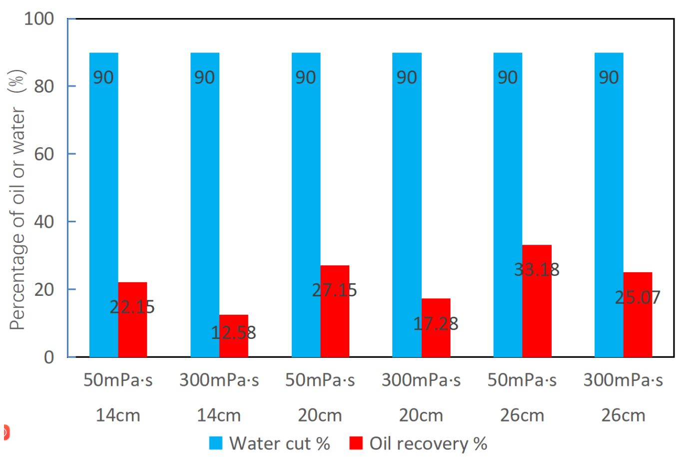

Figure 6. Comparison of water flooding performance using opposed horizontal wells.

During the experiment, water flooding was first carried out until the water cut reached 90%. At this point, polymer solution injection was initiated to study the characteristics of the driving state in aggregation. The experiment recorded the relationship between oil and water production over time, and the data was used to calculate the water cut and recovery of the model. The experimental data was presented in Figure 7.

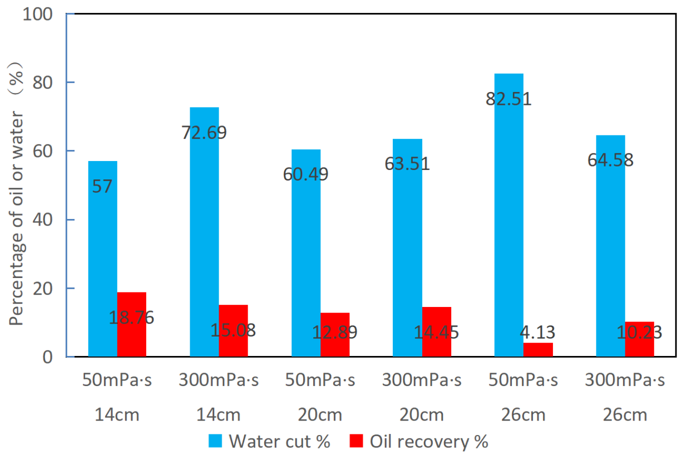

Figure 7. Comparison chart of polymer flooding under horizontal well in positive.

During the experiment, once the cumulative effluent of injected polymer solution reached 0.4 PV of the designed injection polymer volume, the water flooding process was immediately initiated. The experiment was stopped when the water cut reached more than 98%. To study the dynamic characteristics of displacement under different well spacing conditions during the displacement process, the researchers recorded the relationship between oil and water production with time. The water cut and recovery of the model were calculated using the data of the oil and water production in the process. The experimental data were plotted in Figure 8.

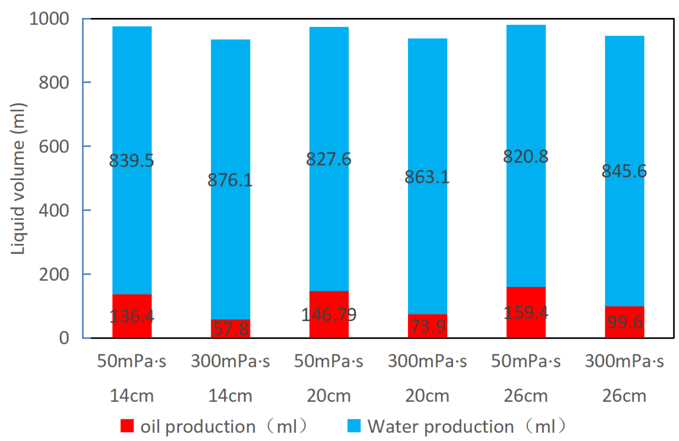

Figure 8. Comparison chart of subsequent water flooding under horizontal well in positive.

2.3.2 Experimental Analysis

The displacement process was conducted at an initial rate of 2 mL/min and measurements were taken every

8 minutes for a total duration of 320 minutes. Initially, the oil-producing well only produced oil without any water, resulting in a water cut of zero. After injecting a volume of 0.05 PV, the well started to produce water and the water cut gradually increased. The water cut continued to rise until the injection of polymer in the water flood. At the start of polymer injection, there was still a delay in the time for the injected polymer to reach the production well, hence the water cut continued to rise. After the total injection volume reached 0.5 PV, the water cut began to decrease gradually, and after decreasing to a certain extent, it started to increase again until the total injection volume reached 3 PV, at which point the experiment was terminated.

The liquid production during the displacement process with a well spacing of 14 cm is shown in Figure 9.

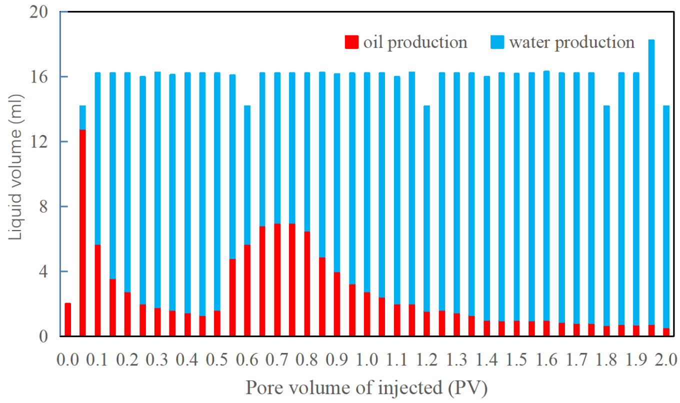

Figure 9. Comparison of oil and water production when the well spacing is 14 cm.

During the displacement process, the liquid production with a well spacing of 20 cm is shown in Figure 10.

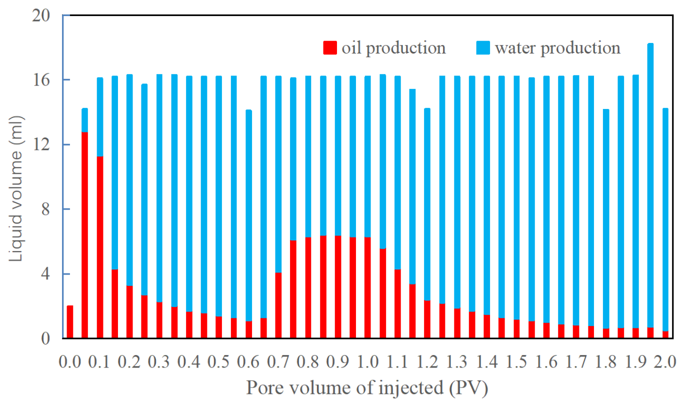

Figure 10. Comparison of oil and water production when the well spacing is 20 cm.

During the displacement process, the liquid production at a well spacing of 26 cm is shown in Figure 11.

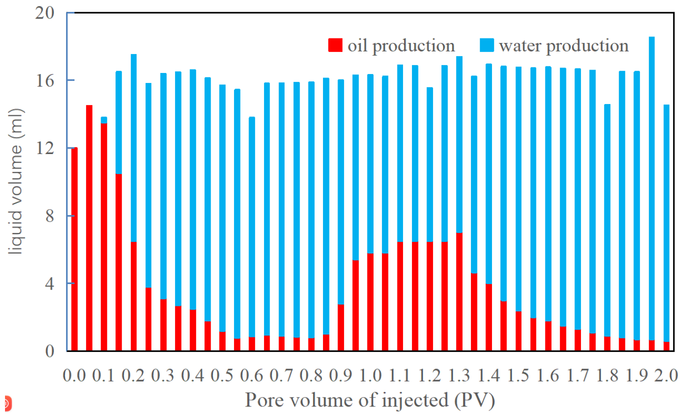

Figure 11. Comparison of oil and water production when the well spacing is 26cm.

A larger injection-production well spacing results in a larger area of control for the well, which is more favorable for increasing the swept volume of the oil layer, resulting in higher final recovery. As the well spacing decreases, the time taken to reach a water cut of 90% gradually increases during the water flooding process, and the recovery gradually decreases. This is shown in the following Figure 12.

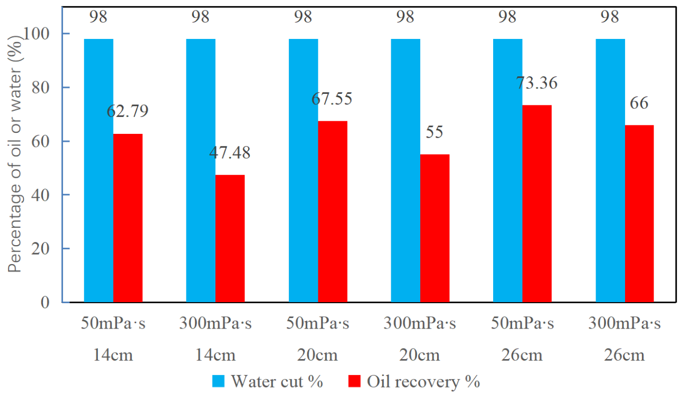

Figure 12. Comparison of displacement data under horizontal well in positive.

As the simulated oil viscosity increases, the water cut variation after water flooding to polymer flooding also changes. Figure 13 illustrates this trend. Even though the final water cut of the model for both simulated oil viscosities of 50 mPa·s and 300 mPa·s is approximately 98%, the change of water cut for the simulated oil viscosity of 300 mPa·s is ahead of that of the simulated oil viscosity of 50 mPa·s with the increase of injected fluid pore volume. The change process and trend are consistent after a certain period of advance. The specific change process is presented in Figure 13.

As the simulated oil viscosity increases, the recovery

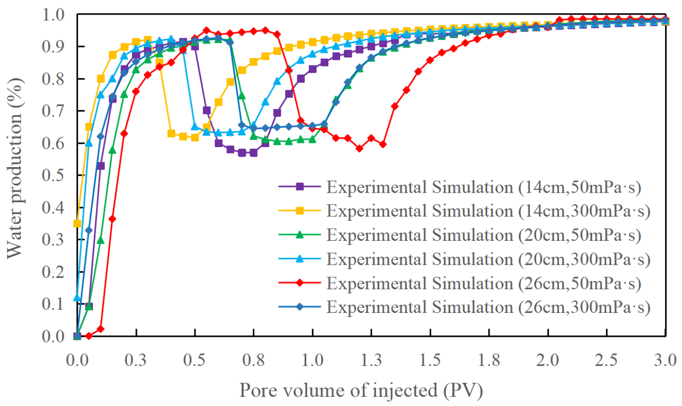

Figure 13. Water cut diagram under the condition of a well-aligned experiment.

rate gradually decreases, and the growth rate of the recovery rate becomes smaller. For example, at a well spacing of 14 cm, the recovery is 62.79% at 50 mPa·s and decreases to 47.48% at 300 mPa·s; at a well spacing of 26 cm, the recovery reaches 73.36% at 50 mPa·s. Figure 14 illustrates the comparison of the recovery rates under different simulated oil viscosity conditions.

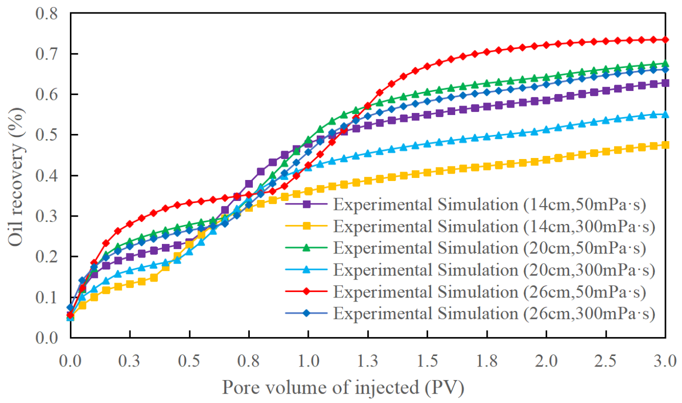

Figure 14. Recovery diagram under the experimental condition of well-aligned.

3 Numerical Simulation

In order to optimize the development plan of conventional water flooding heavy oil reservoirs, the Eclipse numerical modeling software is used for research. Firstly, simulations are performed based on previous experimental data, and the reservoir parameters and fluid properties are corrected and determined to ensure the reliability of the reservoir model. Secondly, the physical parameters of the numerical simulation scheme are modified, and numerical simulations and analyses are carried out to provide a basis for the design of the reservoir development plan.

3.1 Model Parameters

The numerical simulation study area covers an area of 0.25 km^2 and is discretized into a grid system. The grid size is set to 10 m in the x-axis and y-axis direction, and 2.5 m in the z-axis direction, resulting in the total number of grids is $50 \times 50 \times 5 = 12500$. The porosity of the model is 38%, and the initial oil saturation is 75%. The detailed reservoir and fluid property parameters are listed in Table 3.

Table 3. Model reservoir and fluid property parameters.

Parameter	Value
Oil layer thickness/m	12.5
Original formation pressure /MPa	30
Reservoir temperature/°C	60
Permeability/mD	5000
Porosity/%	38
Original oil saturation/%	75
Compressibility of water /bar^{-1}	1.5×10^4
Crude oil density/(kg/m^3)	880
Crude oil viscosity/(mPa·s)	300
Oil compression coefficient/bar^{-1}	1.1×10^5
Residual drag coefficient	1.5
Adsorption index	1
Rock density/($kg{\cdot}m^3$)	2852.58
The maximum adsorption value of the polymer	0.005

3.2 Numerical Simulation Scheme

According to the previous horizontal well polymer flooding experiment data and conventional heavy oil reservoir development experience, parameters were determined and numerically fitted using Eclipse simulation software. The basic well scheme was established based on the fitted water cut (FWCT) and recovery (FOE) values. Numerical simulations were conducted by adjusting parameters such as crude oil viscosity, horizontal well spacing, injection timing, and polymer slug. The water injection intensity was planned to be 250 t/d based on comprehensive consideration of numerical model and dynamics. The results of the simulation include optimization of parameters such as cumulative water production, cumulative oil production, oil production rate, pressure, and water cut under different conditions [29].

1)*Optimization of well-spacing*

The simulation scheme was evaluated under five different well spacing conditions. Initially, water flooding was performed, and once the water cut reached 70% within the simulation area, polymer solution was injected into the injection well until a volume of 0.4 PV was injected. Afterwards, water flooding was resumed until the produced liquid reached a water cut of 98%, at which point flooding was stopped. The comparison of oil recovery under the five different well spacing conditions shows that a a well spacing of 470 m achieves the highest absolute recovery among the five tested spacings; however, as shown in the results section, the marginal gain diminishes beyond 390 m. This is because the larger the horizontal well spacing, the larger the area controlled by the well, which in turn leads to a larger swept area and higher recovery. Figure 15 provides a visual representation of these findings.

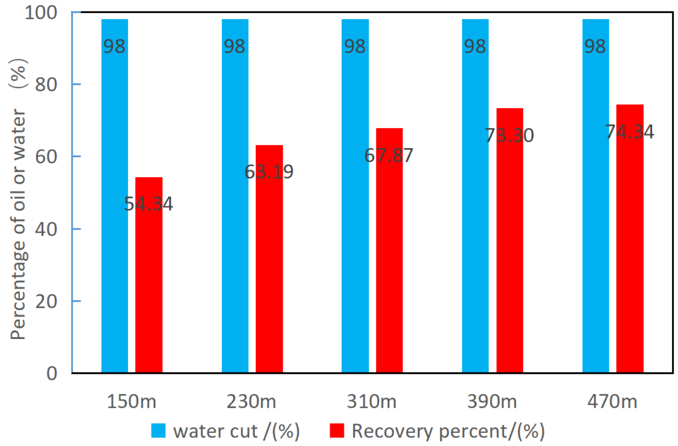

Figure 15. Comparison of displacement data under different well spacing conditions.

2)*Numerical simulation case optimization of different crude oil viscosities*

The numerical simulation of the scheme was conducted under 5 different levels of crude oil viscosity. Initially, water flooding was carried out until the water cut reached 70% in the numerical simulation area. The injection well then began to inject polymer solution until a volume of 0.4 PV was injected, after which water flooding was resumed. The simulation continued out flooding until the water cut of the produced liquid reached 98% and the flooding was stopped. By comparing the oil recovery under the different crude oil viscosity conditions, it was found that the oil displacement effect was better when the crude oil viscosity was 100 mPa·s, as shown in Figure 16.

3)*Optimization of polymer slug*

The selection of polymer slug size and injection method is an important consideration as they have a significant impact on the oil displacement effect [27]. During the simulation, water flooding was carried out initially, followed by the injection of polymer solution

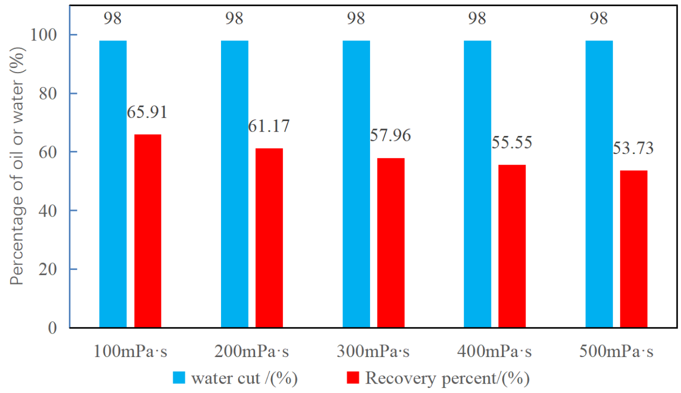

Figure 16. Comparison of displacement data under different crude oil viscosity conditions.

after the water cut reaches 70% in the numerical simulation area. The injection well then injects polymer solution until 0.4 PV is injected, and then the scheme carried out water flooding. The model simulation carried out flooding until the water cut of the produced liquid reaches 98% and stop the flooding. Figure 17 illustrates that the larger the injected slug volume, the more favorable it is to increase the swept volume of the oil layer, resulting in higher recovery.

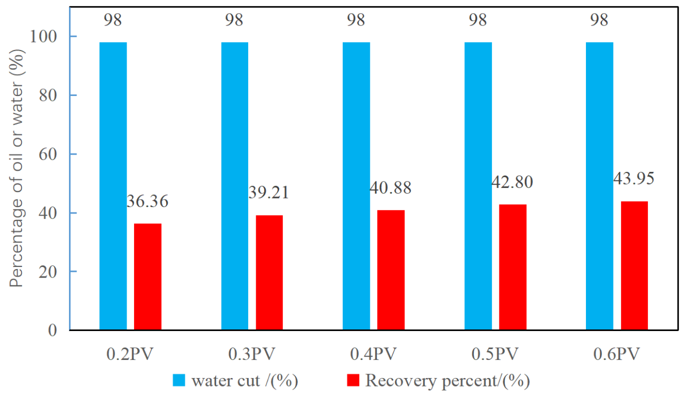

Figure 17. Comparison of displacement data under different polymer slug conditions.

4)*Optimization of time of injection polymer*

During the simulation, water flooding was carried out initially. When the water cut reaches 70% in the numerical simulation area, the injection well starts to inject polymer solution, until the injection of 0.4 PV volume and the scheme is followed by water flooding. The flooding is continued until the water content of the produced liquid reaches 98% and then stopped. Comparing the oil recovery under the conditions of five different injection times for polymer, Figure 18 indicates that the effect of polymer injection timing on recovery was investigated by comparing five scenarios where polymer injection commenced at different water-cut stages. Therefore, the earlier the injection time for polymer, the more it favors increasing the swept volume of the oil layer and achieving a higher cumulative recovery. This leads to a higher final water cut in the numerical simulation area and helps save the water injection volume.

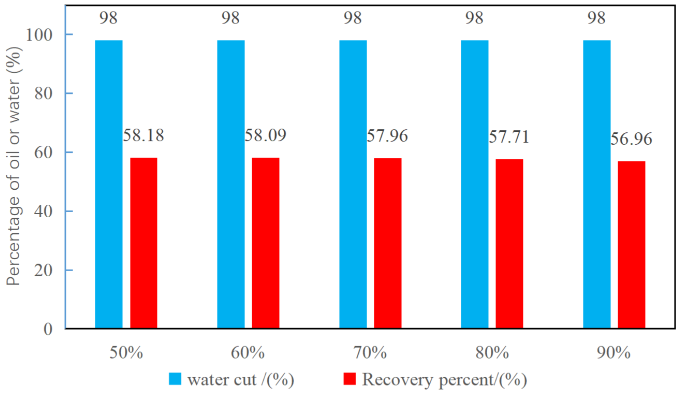

Figure 18. Comparison of displacement data under different injection time on polymers.

3.3 Numerical Simulation Results and Analysis

As the numerical simulation progresses, the pressure in the reservoir undergoes constant changes, reflecting the characteristics of reservoir development. To study this, the numerical simulation area is divided into five layers, each exhibiting different pressure distributions. Comparing the layers, it is found that the pressure drop rate is faster in the lower layer than in the upper layer. Furthermore, the pressure in the region close to the horizontal well is higher than that far away, indicating a higher rate of regional pressure drop. The distribution of remaining oil in each layer also varies. Comparing the layers, it is observed that the remaining oil outside the control area is enriched near the horizontal wells, while the reserves produced decrease vertically from bottom to top. Additionally, the residual oil saturation is higher in the upper position than in the lower position.

1)Comparison of numerical simulation schemes with different spacings of well

During the numerical simulation, it was observed that the recovery exhibits an "inflection point" when the horizontal well spacing is set at 390 m. This means that after increasing the well spacing beyond 390 m, there is not a significant increase in the recovery. Therefore, the optimum horizontal well spacing is considered to be 390 m. The corresponding dynamic characteristics of oil displacement are shown in Figures 19 and 20.

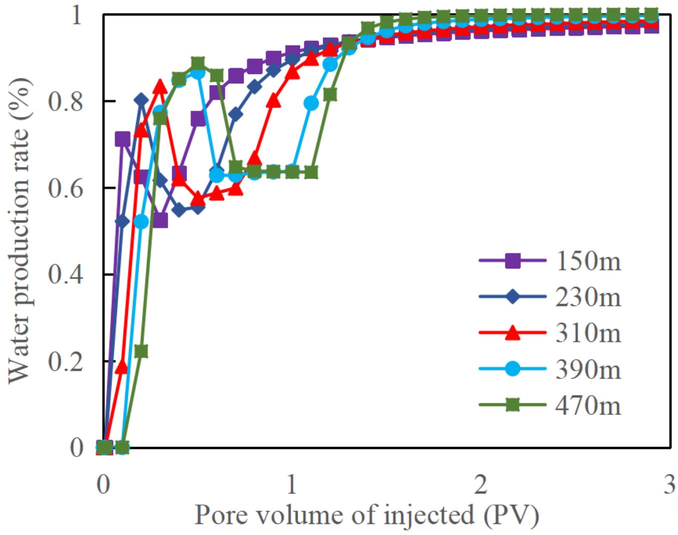

Figure 19. Spacing-Water Cut Curves.

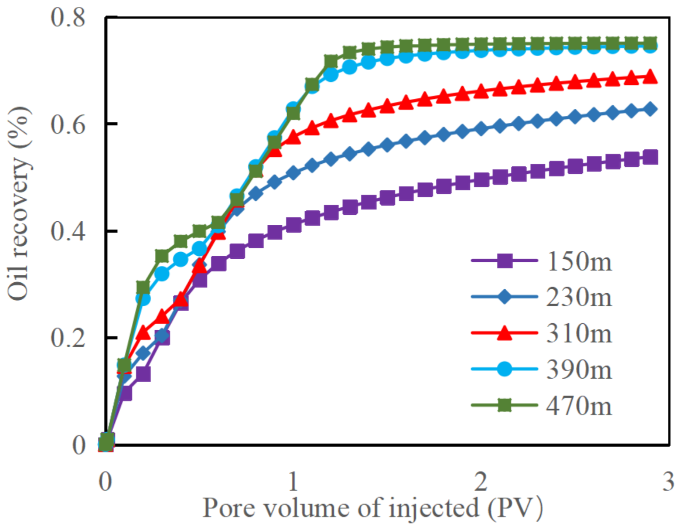

Figure 20. Spacing - Recovery Curves.

2)Comparison of numerical model schemes for different crude oil viscosities

It can be observed that the highest recovery is achieved when the crude oil viscosity is 100 mPa·s, whereas the recovery under other crude oil viscosities is not as significant. This is due to the fact that the smaller the viscosity of crude oil, the larger the swept volume of the oil layer, the easier the oil is to be displaced, and the higher the recovery. The relevant displacement dynamic characteristics are illustrated in Figures 21 and 22.

3)Comparison of digital-analog schemes for different slug sizes

It can be observed that the "inflection point" of the recovery occurs when the injected slug volume is 0.5 PV. After the injection of a 0.5 PV slug volume, the recovery does not increase significantly with the

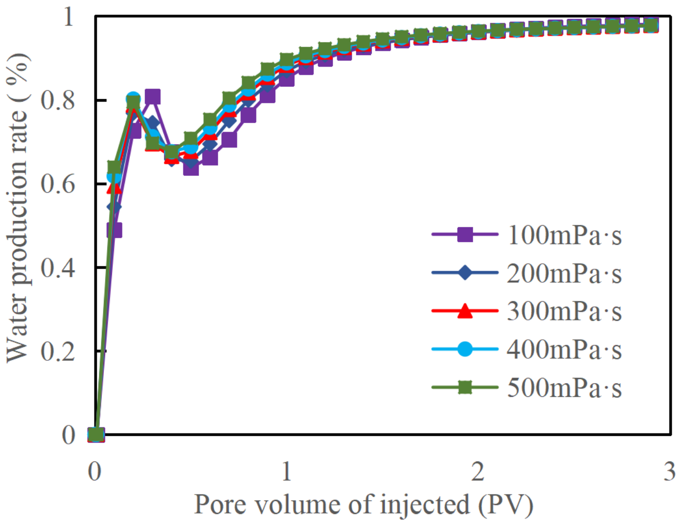

Figure 21. Viscosity-water cut curves.

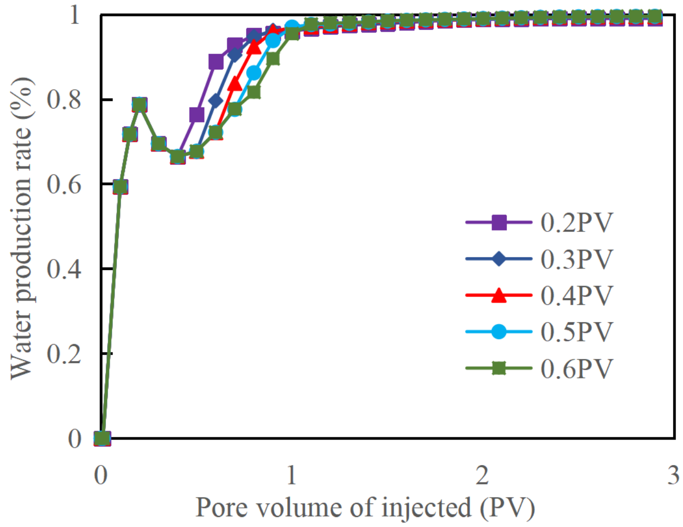

Figure 23. Slug size-water cut curves.

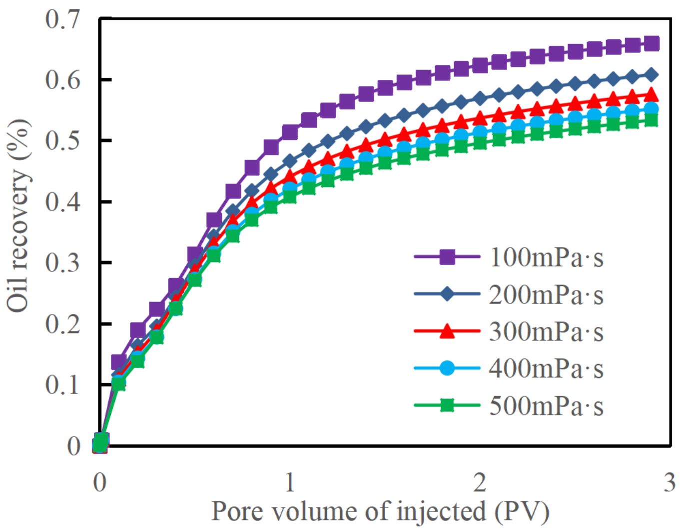

Figure 22. Viscosity-recovery curves.

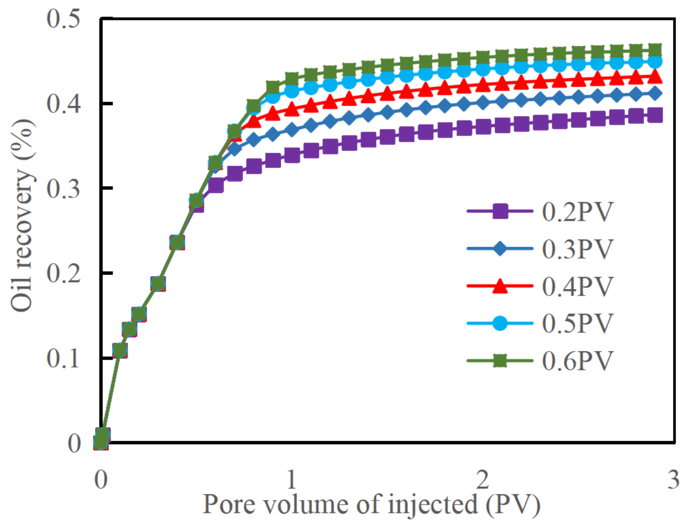

Figure 24. Slug size - recovery curves.

increase of the injected slug volume. With the increase of the slug volume, the utilization rate of the polymer decreases, and the recovery becomes stable. Therefore, injecting a 0.5 PV slug volume is considered the most optimal solution. The relevant displacement dynamic characteristics are shown in Figures 23 and 24.

4)Comparison of numerical simulation schemes for changing injection timing

It is observed that the largest recovery is achieved when the injection time on polymer is 50%, resulting in significant savings in water injection volume. The cumulative oil recovery values for different injection time on polymer conditions are: injection time on polymer 50% (58.17%) > injection time on polymer 60% (58.09%) > injection time on polymer 70% (57.96%) > injection time on polymer 80% (57.71%) > injection time on 90% (56.96%). The displacement dynamic characteristics relevant to this observation are depicted in Figures 25 and 26.

4 Conclusions

In this study, the displacement behavior and influencing factors of polymer flooding in horizontal well patterns were systematically investigated through two dimensional physical simulation experiments and Eclipse numerical simulation. The main conclusions are drawn as follows:

(1) Experimental results indicate that well spacing has a significant impact on polymer flooding performance in horizontal wells. A larger injection-production well spacing leads to a larger swept area, a longer water-free oil production period, and a higher ultimate recovery. Under the experimental conditions, the recovery at a well spacing of 26 cm reached 73.36%, which is notably

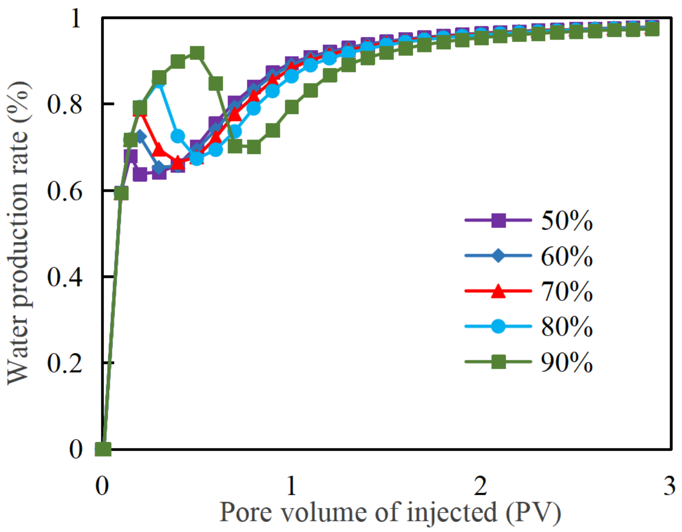

Figure 25. Injection time on polymer-water cut curve.

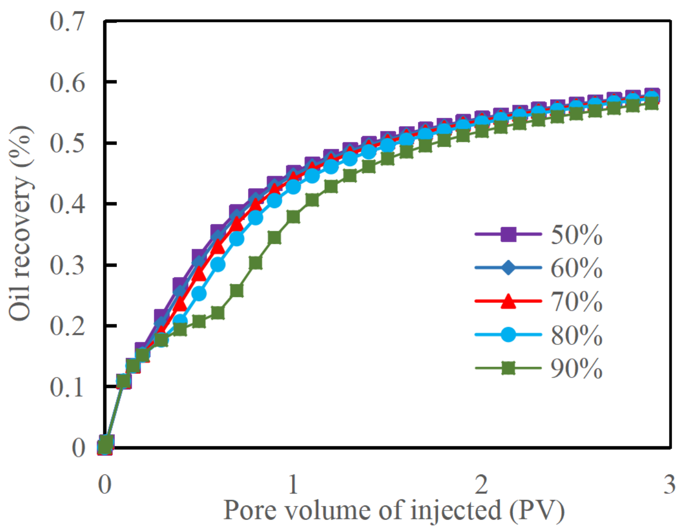

Figure 26. Injection time on polymer-recovery curve.

higher than that at 14 cm (62.79%).

(2) Crude oil viscosity strongly affects the displacement process. As the oil viscosity increases, the water cut rises earlier and the recovery factor decreases. When the experimental well spacing is 14cm, the simulated oil viscosity recovery rate at 50 mPa·s is 62.79%, while the recovery rate at 300 mPa·s decreases to 47.48%, indicating that horizontal well polymer flooding is more effective in relatively lower-viscosity heavy oil reservoirs.

(3) Numerical simulation optimized the key parameters for horizontal well polymer flooding. The optimal well spacing was determined to be 390 m, beyond which the increase in recovery becomes marginal. The optimal polymer slug size is 0.5 PV, as larger slug volumes do not yield a significant additional recovery improvement while reducing polymer utilization efficiency. The optimal injection timing is when the water cut reaches 50%, which provides the highest cumulative oil recovery (58.17%) and saves water injection volume.

(4) The combination of horizontal wells with polymer flooding can effectively mitigate water fingering and channeling, delay water breakthrough, and improve sweep efficiency. The residual oil saturation in the vertical direction gradually increases from the inside to the outside in the middle layer, and is higher in the upper part than in the lower part, with higher recovery observed in the lower positions of the reservoir.

(5) The integrated experimental and numerical simulation approach provides mutual validation and reliable guidance for field application. The results offer scientific insight and engineering recommendations for optimizing polymer flooding strategies in horizontal well patterns in heavy oil reservoirs.

Data Availability Statement

Data will be made available on request.

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Conflicts of Interest

Shaohao Huang, Zhibin Li, Xuefeng Song, and Bing Xu are affiliated with the CNOOC EnerTech-Drilling & Production Co., Ltd., Tianjin 300452, China; Chen Zhang is affiliated with the CNPC Xibu Drilling Engineering Company Limited, Urumqi 830011, Xinjiang, China. The authors declare that these affiliations had no influence on the study design, data collection, analysis, interpretation, or the decision to publish, and that no other competing interests exist.

AI Use Statement

The authors declare that no generative AI was used in the preparation of this manuscript.

Ethical Approval and Consent to Participate

Not applicable.

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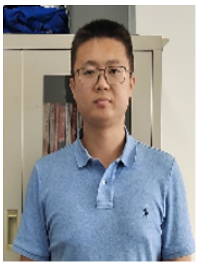
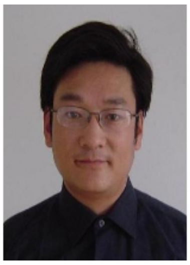
Shaohao Huang received the Master's degree in Petroleum and Gas Engineering from China University of Petroleum, in 2021. His research interests include offshore drilling, wellbore integrity, enhanced oil recovery, and drill string vibration. He is currently primarily engaged in research of drilling technology. (Email: 1602834900@qq.com)



Zhibin Li received the Master's degree in Oil and Gas Engineering from China University of Petroleum (East China), in 2014. He is currently primarily engaged in research and management of drilling technology. (Email: lizhb18@cnooc.com.cn)

Xuefeng Song received the Master's degree in Oil and Gas Well Engineering from China University of Petroleum(Beijing), in 2019. He is currently primarily engaged in research and management of drilling technology. (Email: songxf10@cnooc.com.cn)



Binshan Ju received the PhD. degree in Petroleum and Gas Engineering from China University of Petroleum(Beijing), in 2010. His research interests include improving oil recovery, polymer flooding, reservoir simulation, and multiphase flow in porous media. (Email: jubs2936@163.com)

Chen Zhang received the MEng degree in petroleum engineering from China University of petroleum, Qingdao 266000, China, in 2017. (Email: zc0610@email.edu)

Bing Xu received the Master's degree in Petroleum and Gas Engineering from China University of Petroleum(Beijing), in 2021.His research interests include offshore drilling, wellbore integrity, and drill string vibration. He is a drilling supervisor working at CNOOC (China National Offshore Oil Corporation). (Email: bingxu@cnooc.com.cn)