

Article

The Temporal and Spatial Evolution of Flow Heterogeneity During Water Flooding for an Artificial Core Plate Model

Chen Jiang ^{1,2,3}, Qingjie Liu ^{2,3,*}, Kaiqi Leng ^{1,2}, Zubo Zhang ³, Xu Chen ³ and Tong Wu ^{1,2,3}

¹ College of Engineering Sciences, University of Chinese Academy of Sciences, Beijing 100049, China; jiangchen201@mails.ucas.ac.cn (C.J.); lengkaiqi20@mails.ucas.ac.cn (K.L.); wutong23@mails.ucas.ac.cn (T.W.)

² Institute of Porous Flow and Fluid Mechanics, Chinese Academy of Sciences, Langfang 065007, China

³ State Key Laboratory of Enhanced Oil Recovery, Research Institute of Petroleum Exploration and Development, PetroChina, Beijing 100083, China; zzbb@petrochina.com.cn (Z.Z.); chx9500@petrochina.com.cn (X.C.)

* Correspondence: lqj@petrochina.com.cn

Abstract: In the process of reservoir water flooding development, the characteristics of underground seepage field have changed, resulting in increasingly complex oil–water distribution. The original understanding of reservoir physical property parameters based on the initial stage of development is insufficient to guide reservoir development efforts in the extra-high water cut stage. To deeply investigate the spatio-temporal evolution of heterogeneity in the internal seepage field of layered reservoirs during water flooding development, water–oil displacement experimental simulations were conducted based on layered, normally graded models. By combining CT scanning technology and two-phase seepage theory, the variation patterns of heterogeneity in the seepage field of medium-to-high permeability, normally graded reservoirs were analyzed. The results indicate that the effectiveness of water flooding development is doubly constrained by differences in oil–water seepage capacities and the heterogeneity of the seepage field. During the development process, both the reservoir’s flow capacity and the heterogeneity of the seepage field are in a state of continuous change. Influenced by the extra resistance brought about by multiphase flow, the reservoir’s flow capacity drops to 41.6% of the absolute permeability in the extra-high water cut stage. Based on differences in the variation amplitudes of oil–water-phase permeabilities, changes in the heterogeneity of the internal seepage field of the reservoir can be broadly divided into periods of drastic change and relative stability. During the drastic change stage, the fluctuation amplitude of the water-phase permeability variation coefficient is 114.5 times that of the relative stable phase, while the fluctuation amplitude of the oil-phase permeability variation coefficient is 5.2 times that of the stable stage. This study reveals the dynamic changes in reservoir seepage characteristics during the water injection process, providing guidance for water injection development in layered reservoirs.

Keywords: positive rhythm reservoir; seepage field; heterogeneity; comprehensive flow capacity; variation coefficient



Academic Editor: Reza Rezaee

Received: 24 November 2024

Revised: 22 December 2024

Accepted: 8 January 2025

Published: 12 January 2025

Citation: Jiang, C.; Liu, Q.; Leng, K.; Zhang, Z.; Chen, X.; Wu, T. The Temporal and Spatial Evolution of Flow Heterogeneity During Water Flooding for an Artificial Core Plate Model. *Energies* **2025**, *18*, 309. <https://doi.org/10.3390/en18020309>

Copyright: © 2025 by the authors.

Licensee MDPI, Basel, Switzerland.

This article is an open access article

distributed under the terms and

conditions of the Creative Commons

Attribution (CC BY) license

(<https://creativecommons.org/licenses/by/4.0/>).

1. Introduction

Reservoir heterogeneity refers to the significant differences in spatial distribution and the internal properties of oil and gas reservoirs, resulting from the complex impacts of deposition, diagenesis, and subsequent tectonic processes during prolonged geological evolution [1,2]. This variability not only profoundly influences the distribution and flow of oil,

gas, and water within the reservoir, but also directly relates to the ultimate success of reservoir development [3–6]. For water injection oilfield development, the core manifestation of reservoir heterogeneity lies in the heterogeneity of permeability [7]. The heterogeneity of reservoirs is usually quantitatively characterized by calculating the permeability variation coefficient [8–11].

The reservoir serves as the medium for fluid seepage, and the heterogeneity of the seepage field is directly influenced by changes in reservoir physical properties [12]. Especially for reservoirs in the late stage of extra-high water saturation, due to the long-term erosion effect of injected water, the physicochemical characteristics of the porous media in the reservoir undergo significant changes. For instance, the clay mineral content of the reservoir eroded by injected water will change, thereby affecting the wetting angle and changing the wettability of the reservoir [13]. Understanding the underground seepage field based on initial reservoir physical property parameters can no longer effectively guide work at the later stages of development [14]. Yuan Qingfeng et al. [15] summarized the development patterns of sandstone oilfields during the extra-high water cut stage and found that during water flooding development, reservoir heterogeneity significantly increases. Additionally, the increase in water saturation within the reservoir and the reduction in water-phase flow resistance jointly form preferential flow channels, thereby affecting development effectiveness. Du Qinglong et al. [16] conducted in-depth research on the impact of long-term water flushing on the reservoir, defining the changes in physical properties such as pore structure and mineral composition resulting from this process as static heterogeneity changes in the reservoir. As the development duration of the oilfield extends, the water cut continues to rise, and the water-phase permeability within the reservoir also exhibits significant growth, leading to increasingly prominent differences in seepage capacity between the oil and water phases. This difference in seepage is defined as dynamic heterogeneity changes in the reservoir. Under the dual influence of static heterogeneity (controlled by physical property differences) and dynamic heterogeneity (induced by differences in two-phase seepage), the contradictions faced in oilfield development at the plane, interlayer, and intra-layer levels become increasingly acute, posing new challenges and tests for water drive development [17–23].

Previous researchers have conducted exhaustive and systematic studies on the changes in reservoir static heterogeneity during long-term water injection development. They generally agree [24–29] that after prolonged water injection flushing, the pore throat radius of the reservoir expands, permeability increases, and reservoir physical properties improve. However, the degree of heterogeneity intensifies, which is detrimental to the overall development of the oilfield. Despite significant progress in the study of static heterogeneity, research on reservoir dynamic heterogeneity is currently inadequate, lacking effective research methods, and the understanding of its evolution patterns remains vague. Therefore, in-depth exploration of the evolution patterns of reservoir dynamic heterogeneity is of great significance for achieving the efficient development of water injection reservoirs during the extra-high water cut stage.

This paper conducts indoor experiments on the entire process of water drive development in layered, normally graded reservoir models, combined with precise monitoring using CT scanning technology. Based on two-phase seepage theory, it quantitatively calculates oil- and water-phase permeabilities and the coefficient of variation of phase permeabilities, in order to deeply explore the changes in oil–water flow capacity and heterogeneity characteristics within the reservoir during the water injection development process.

2. Experimental Materials and Methods

2.1. Experimental Materials

In the experiment, a 10% NaI (from Shanghai Kanglang Biotechnology Co., Ltd. China Shanghai) saline solution was used to simulate formation water and act as an enhancer for CT scanning, while 5# white oil (from Shandong Guoxuan Chemical Technology Co., Ltd. China Zaozhuang) was used to simulate formation crude oil. Under the set experimental conditions (23 °C), the viscosity of the white oil was 11.1 mPa·s, with a specific gravity of 0.83, while the specific gravity of the brine was 1.003. To precisely control the parameters of the core model, sand gravel was selected as the filling material for preparing artificial cores. To enhance the accuracy and clarity of CT scanning, the artificial cores were encapsulated with epoxy resin, effectively avoiding potential interferences during the scanning process. The artificial core plate model used in the experiment consisted of two layers of cores with different permeabilities, as illustrated in Figure 1, with detailed basic parameters listed in Table 1. The model's gas-measured permeability was 711 mD, and the permeability variation coefficient was 0.84.

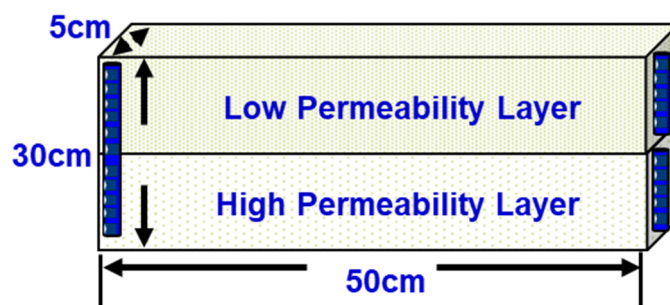


Figure 1. Schematic diagram of positive rhythm model.

Table 1. Model-related parameters.

Model Sample	Permeability Layer	Length (cm)	Width (cm)	Height (cm)	Porosity (%)	Air Permeability (mD)
ZYL1	High	50	5	15	16.2	1308
	Low	50	5	15	14.7	113.3

2.2. Experimental Methodology

To investigate the dynamic change law of heterogeneous characteristics during water flooding, core experiments combined with visualized CT scanning were conducted on a positive rhythm model throughout the entire process of water flooding development. The injection rate was 0.18 L/h. Due to the small amount of water injected during the experiment [30] and the fact that this study was not aimed at investigating the impact of long-term injections on reservoir pore structures, the influence of the injected water on the internal structure of the model was not considered. CT technology, which stands for X-ray-based Computed Tomography, scans the cross-sections of the object being tested using a radiation source, to obtain a series of CT values for its two-dimensional cross-sections. These values are then processed into grayscale image information by the supporting software [31,32]. By scanning the cross-sections in dry rock, water-saturated, and oil–water coexistence states, CT values can be obtained for different conditions [33,34]:

$$CT_{dry} = (1 - \phi)CT_{grain} + \phi CT_{air} \quad (1)$$

$$CT_{waterwet} = (1 - \phi)CT_{grain} + \phi CT_{water} \quad (2)$$

$$CT_t = (1 - \varnothing)CT_{\text{grain}} + \varnothing(S_o CT_{\text{oil}} + S_w CT_{\text{water}}) \quad (3)$$

where CT_{dry} is the CT value of the dry rock cross-section; $\varnothing$ is the core porosity; CT_{grain} is the CT value of the core skeleton particles; CT_{air} is the CT value of air; CT_{waterwet} is the CT value of the cross-section after the rock is 100% water-saturated; CT_{water} is the CT value of water; CT_t is the CT value of the rock cross-section at a specific time t during water flooding; S_o is the oil saturation of the core; S_w is the water saturation of the core; CT_{oil} is the CT value of oil; and CT_{water} is the CT value of water.

Based on the above formulas, the oil saturation (S_o) and water saturation (S_w) within the core can be derived [31,32]:

$$S_o = \frac{CT_{\text{water}} - CT_t}{CT_{\text{water}} - CT_{\text{dry}}} * \frac{CT_{\text{water}} - CT_{\text{air}}}{CT_{\text{water}} - CT_{\text{oil}}} \quad (4)$$

$$S_w = 1 - \frac{CT_{\text{water}} - CT_t}{CT_{\text{water}} - CT_{\text{dry}}} * \frac{CT_{\text{water}} - CT_{\text{air}}}{CT_{\text{water}} - CT_{\text{oil}}} \quad (5)$$

By conducting online scanning throughout the water drive process of the model, original scan data of rock cross-sections under different water saturation conditions were successfully acquired. These data were processed into slices using specialized software, leading to the construction of a 96X10X2 grid model, where the CT value of each grid cell was precisely calculated. Based on these CT values, combined with Formulas (4) and (5), the oil and water saturation values for each grid were accurately determined, enabling the creation of saturation distribution maps during the water drive process of the model. Furthermore, the oil–water relative permeability curves for cores from different permeable layers were measured, as shown in Figure 2. Combining the oil–water two-phase flow theory, the obtained saturation data, the oil–water relative permeability curves, the absolute permeability of the model, and the oil- and water-phase permeabilities were calculated. This indicator truly reflects the flow capacity of oil and water within the reservoir. Since the water injection development process involves the oil–water two-phase flow, to more accurately assess the actual flow capacity of the reservoir, the innovative concept of “reservoir comprehensive flow capacity” was proposed, which comprehensively reflects the sum of the flow capacities of the oil and water phases. The calculation method for this comprehensive capacity is shown in Formula (6).

$$K_r = K_w + K_o \quad (6)$$

where K_w is the water-phase permeability (mD); K_o is the oil-phase permeability (mD); and K_r is the reservoir comprehensive flow capacity (mD).

To accurately quantify and describe the degree of heterogeneity within the reservoir’s internal seepage field, standard quantitative indicators for reservoir heterogeneity were referenced, and ultimately, the coefficient of variation V_k was selected as the key indicator to measure the intensity of heterogeneity in the reservoir’s heterogeneous field. By observing and analyzing the numerical changes in the coefficient of variation, we can intuitively judge the fluctuations in the intensity of heterogeneity within the reservoir’s internal seepage field. The calculation formula for the coefficient of variation V_k is as follows:

$$V_k = \frac{\sqrt{\frac{\sum_{i=1}^n (K_i - \bar{K})^2}{N}}}{\bar{K}} \quad (7)$$

where V_k —coefficient of variation of permeability, K_i —permeability value of a sample within the region (mD), $\bar{K}$ —average permeability value of all samples within the region (mD), and N —number of samples within the region.

By adjusting the variables in Formula (7), replacing the permeability with phase permeability, and substituting N with the number of grid cells, the coefficient of variation of phase permeability can be calculated.

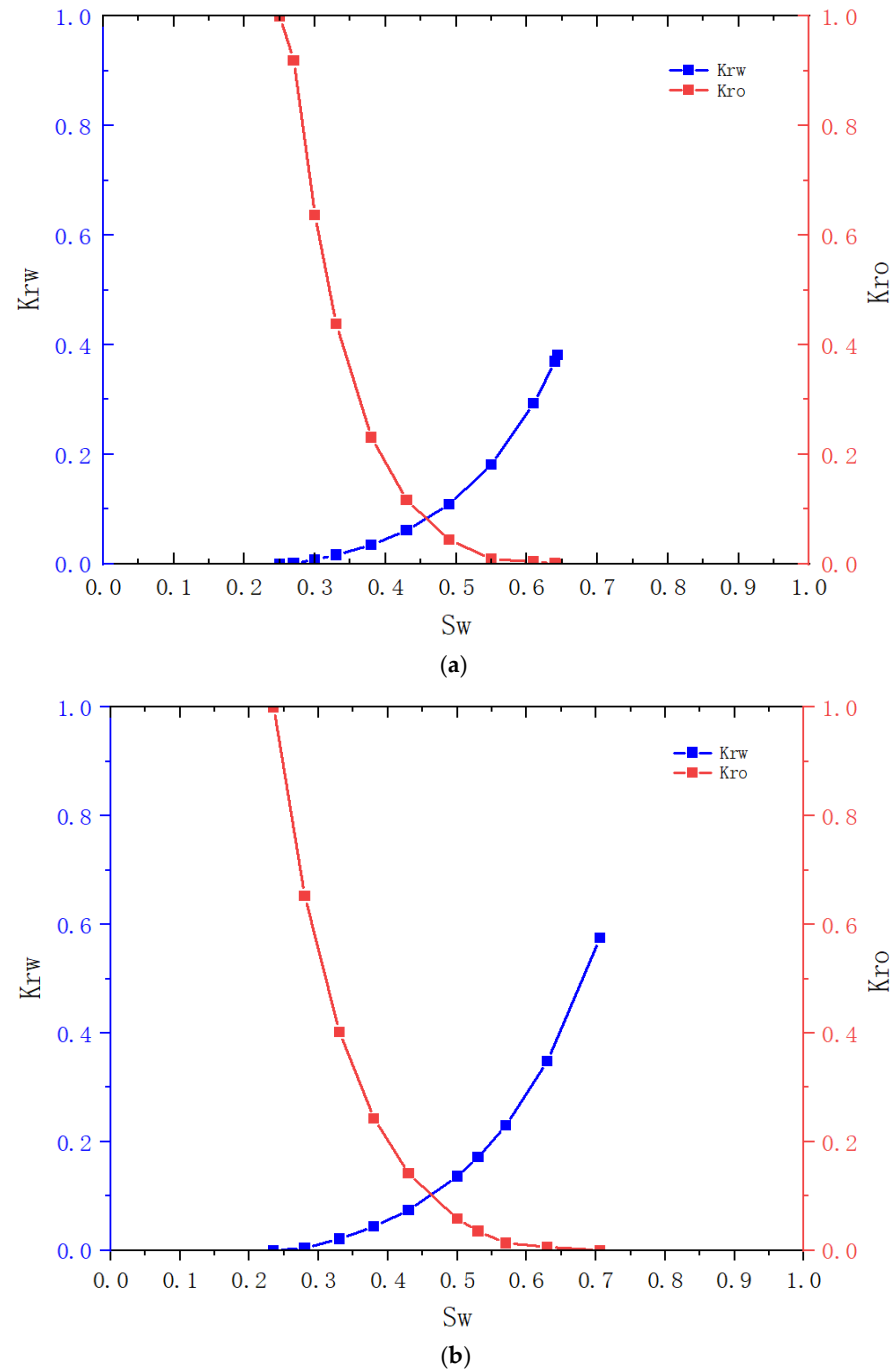


Figure 2. Oil–water relative permeability curve of the model. (a) Oil–water relative permeability curve for low-permeability layers. (b) Oil–water relative permeability curve for high-permeability layers.

3. Results and Discussion

3.1. Variation Characteristics of Seepage Capacity in Water Flooding Process

By conducting online scanning of the water drive process in heterogeneous models and applying Formulas (4) and (5) to calculate the scanning results, oil saturation profiles at various pore volume multiples (PV) of displacement can be obtained. Additionally, based on the amount of water produced at the outlet, the relationship between water cut and injected water volume can be calculated. Subsequently, oil saturation distribution profiles at specific water injection volumes of 0.103 PV, 0.207 PV, 0.491 PV, 0.926 PV, and 1.605 PV were extracted and presented in Figure 3. The water cut variation of the model during water flooding with the change in injected PV number is shown in Table 2.

Table 2. Water cut variation with PV number during water flooding.

Injection Volume (PV)	Water Cut (%)	Injection Volume (PV)	Water Cut (%)
0.026	0	0.246	0
0.052	0	0.268	71.4
0.078	0	0.371	83.9
0.103	0	0.491	89
0.129	0	0.706	90.2
0.155	0	0.926	91.2
0.181	0	1.156	92.6
0.207	0	1.605	94.6
0.233	0	1.778	94.7

Before the water is seen at the production end, with the gradual increase in water injection the front edge of water flooding begins to move forward gradually, the affected area of injected water gradually expands, and the oil saturation of the affected area gradually decreases. The advancing speed of the water flooding front of the high-permeability layer and the low-permeability layer shows a significant difference. The water flooding front of the high-permeability layer has moved forward to the position of 350 mm, while the water flooding front of the low-permeability layer is relatively slow, only reaching 25 mm (Figure 3a,b). There is no significant change in oil saturation in the high-permeability layer after the water is seen in the model. In the low-permeability layer, the water drive front continues to advance deep, extending from the initial 25 mm to 250 mm. The remaining oil is mainly concentrated in the deep area of the low-permeability layer, that is, the low-permeability layer exceeding the model length of 200 mm (Figure 3c–e).

As illustrated in Figure 3, it is clearly observed that during the water injection development process, the oil and water saturations in different regions within the reservoir undergo a dynamic evolution. Since the oil–water relative permeability is a function of saturation, the dynamic changes in saturation directly affect the seepage capacity of oil and water, causing them to exhibit corresponding dynamic characteristics. In order to obtain the overall oil–water seepage capacity and comprehensive flow capacity of the model, an averaging process is applied to all grid data. Based on this, the variation laws of the oil–water two-phase seepage capacity and comprehensive flow capacity of the model are studied.

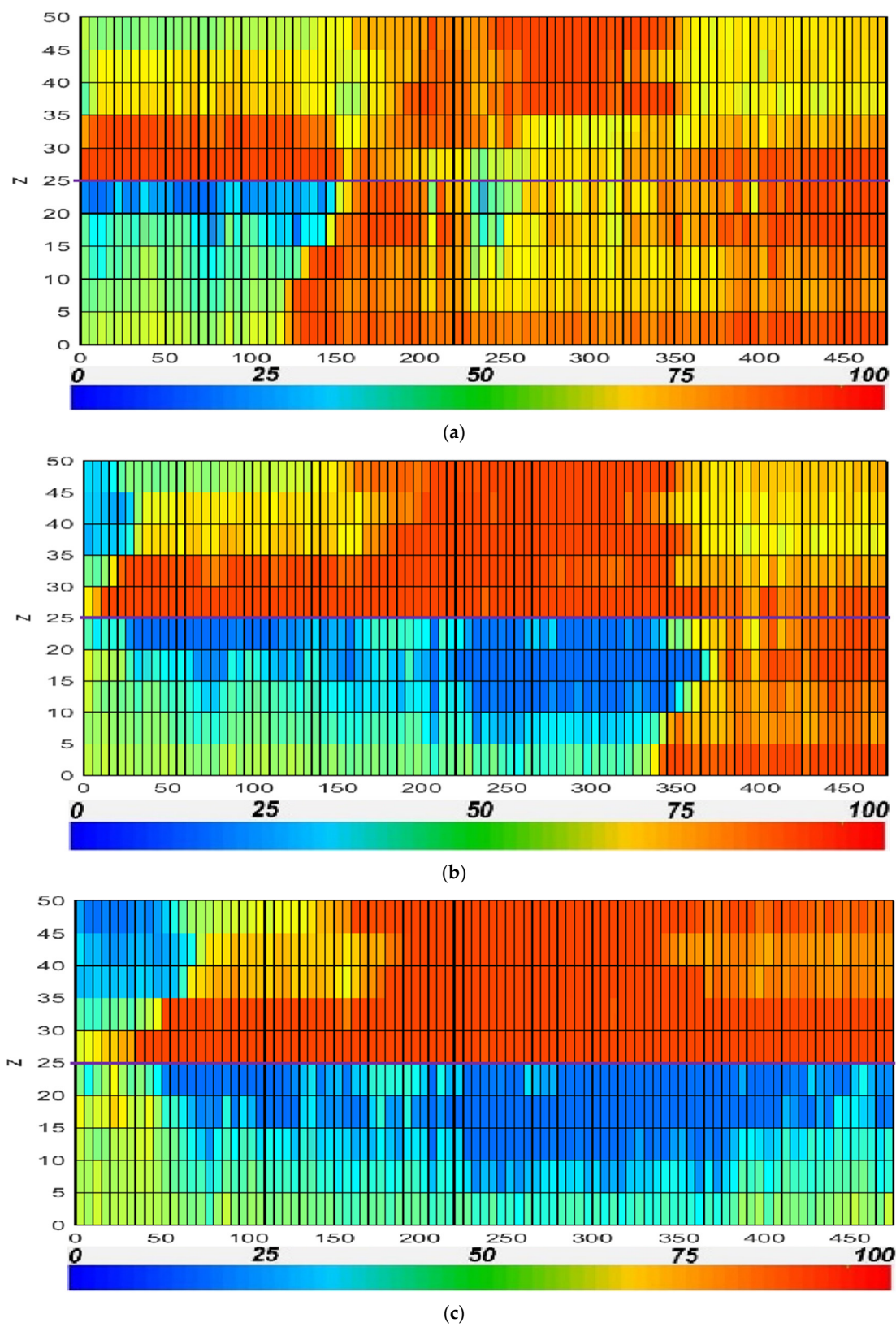


Figure 3. Cont.

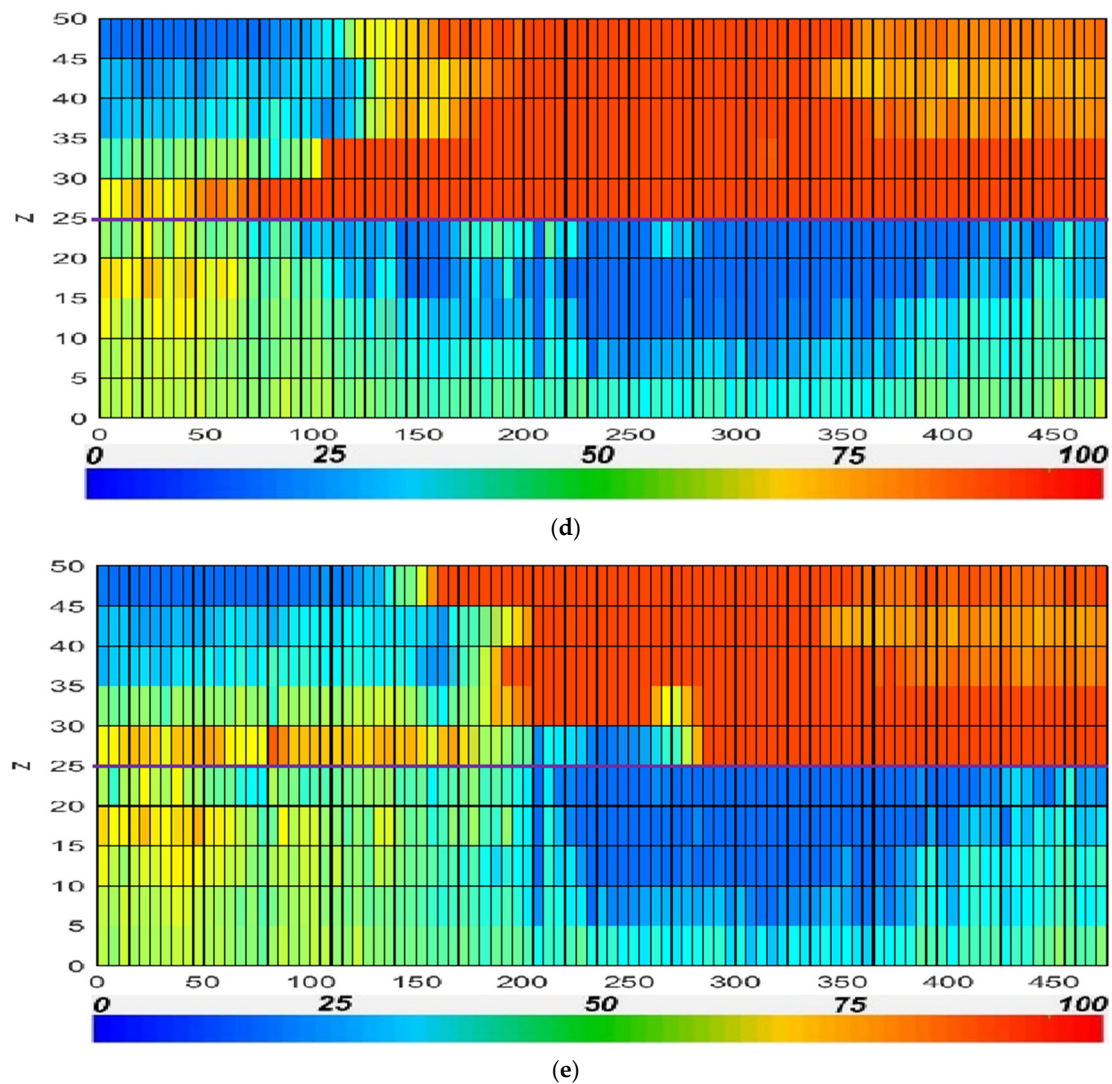


Figure 3. Oil saturation distribution maps at different water injection volumes for the model. (a) With an injection of 0.103 PV, the water cut is 0.0%. (b) With an injection of 0.207 PV, the water cut is 0.0%. (c) With an injection of 0.491 PV, the water cut is 89%. (d) With an injection of 0.926 PV, the water cut is 91%. (e) With an injection of 1.605 PV, the water cut is 95%.

The calculation results of oil–water-phase permeability and comprehensive flow capacity of the model show that during the water flooding experiment, the oil–water-phase permeability and comprehensive flow capacity of the model change significantly with the increase in water injection (Figure 4). In the initial low water cut stage, with the gradual increase in water injection, the comprehensive flow capacity decreased from 463 mD to 332 mD, with a decrease of up to 28.3%. At the same time, the oil-phase permeability experienced a greater decline, from 453 mD to 73.4 mD, a decrease of 83.8%. However, the water-phase permeability showed an opposite trend, from 10.6 mD to 259 mD, an increase of 23.4 times. After entering the high water cut and extra-high water cut stage, as the water injection volume continues to increase, the decline rate of the comprehensive flow capacity slows down, from 332 mD to 296 mD, a decrease of only 12.2%. The oil-phase permeability also showed a slow downward trend, from 73.4 mD to 56.8 mD, a decrease of 22.9%. However, the water-phase permeability decreased slightly at this stage, from 264 mD to 239 mD, a decrease of 9.46%.

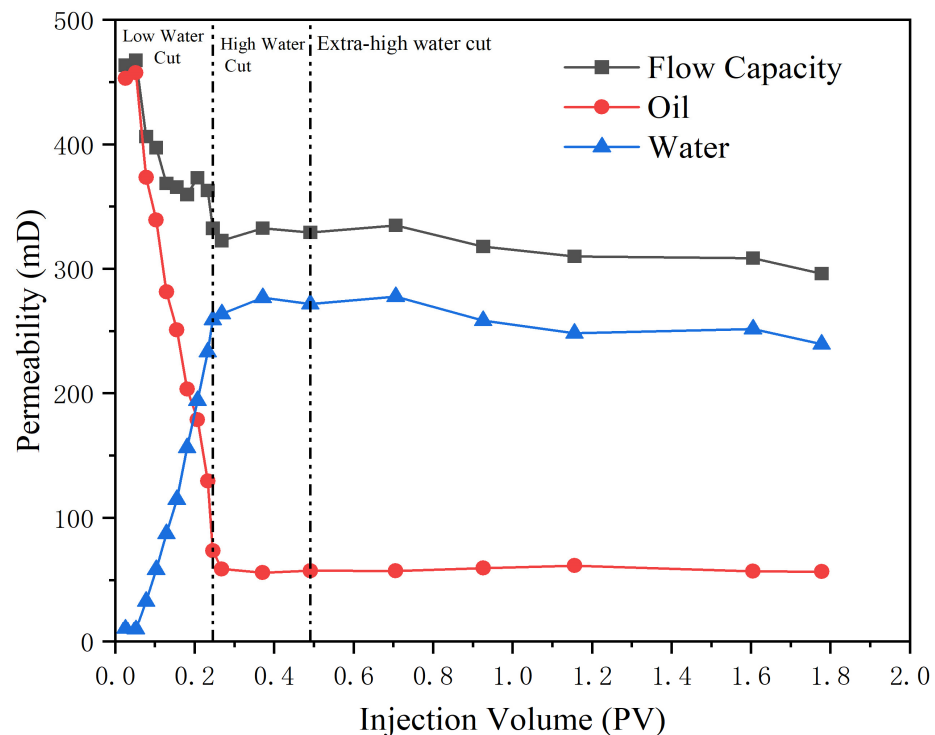


Figure 4. Flow capacity model during water flooding process.

By comparing the data analysis results of different water cut stages, it can be observed that during the low water cut stage, when the water injection volume reaches 0.246 PV, the magnitudes of change in overall fluidity, oil-phase permeability, and water-phase permeability are as high as 28.3%, 83.8%, and 2340%, respectively. However, as the development progresses to the high water cut stage, despite the water injection volume increasing to 1.53 PV, which is 6.22 times that of the low water cut stage, the magnitudes of change in these parameters significantly narrow: the magnitude of change in overall fluidity decreases to 12.2%, the magnitude of change in oil-phase permeability drops to 22.9%, and the magnitude of change in water-phase permeability drops to 9.46%. These magnitudes of change are only 43.1%, 27.3%, and 0.404% of the corresponding magnitudes of change during the low water cut stage, respectively. This phenomenon profoundly reflects the significant impact of injected water on the internal seepage field of the reservoir during the initial low water cut stage of oilfield development. As the process enters the high water cut stage, due to the gradual formation of preferential seepage pathways within the reservoir, the injected water mainly flows along these pathways, resulting in the remaining oil in areas outside the preferential pathways, especially in low-permeability layers, being difficult to effectively sweep.

By comparing the absolute permeability of the model with its comprehensive flow capacity in the water flooding process, the results show that the absolute permeability of the model is 711 mD, while the comprehensive flow capacity of the model is always in a state of dynamic change, and is less than the absolute permeability in value. This indicates that in the process of water injection development, due to the common flow of multiphase fluids, the flow resistance of multiphase flow is significantly increased compared with that of single-phase flow, especially in the extra-high water cut stage, when it is reduced to 296 mD, accounting for only 41.6% of the absolute permeability. This significant difference fully shows that after entering the extra-high water cut stage, the oil–water distribution and comprehensive flow capacity in the reservoir have changed significantly compared with the initial stage of development. Therefore, the reservoir development work at the extra-high

water cut stage cannot be fully guided based on the physical property understanding at the initial stage of development, and the accurate measurement and real-time grasp of the actual flow capacity of the reservoir has become an indispensable scientific basis for formulating and adjusting the development plan.

3.2. Dynamic Heterogeneity Variation Characteristics of Water Flooding Process

In order to more fully explore the dynamic change law of the heterogeneity of the seepage field in each region of the reservoir during the water flooding process based on the oil–water-phase permeability data of the model, the coefficient of variation of the high- and low-permeability layers and the model as a whole in the oil–water-phase permeability is calculated. Subsequently, the trend maps of the variation coefficient of the oil–water-phase with the increase in water injection volume were drawn (Figures 5 and 6) to visually display their relationship.

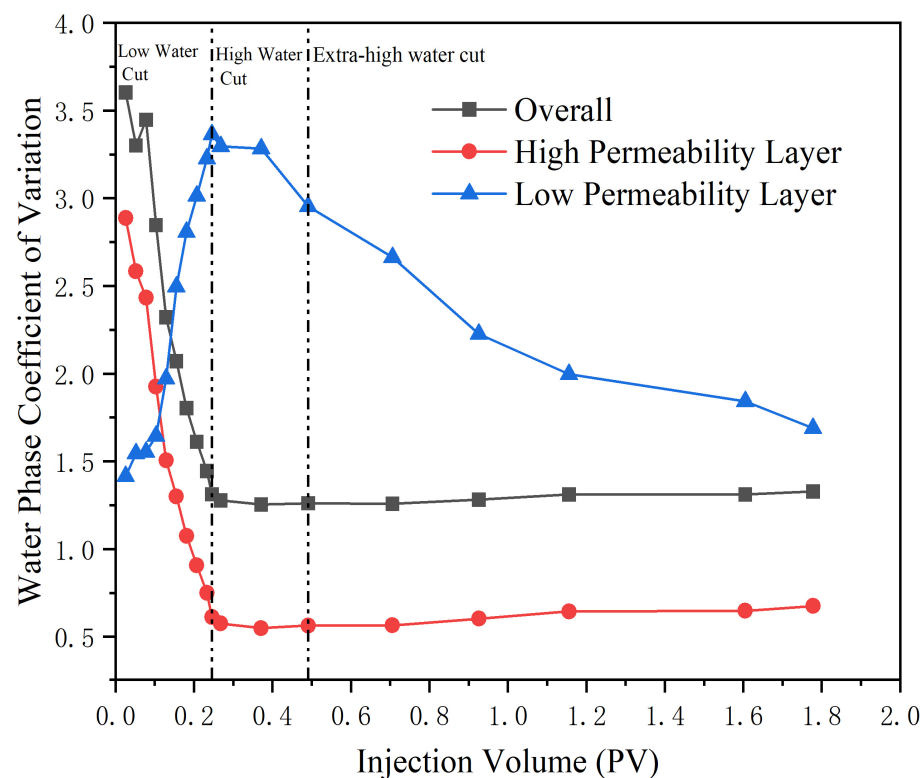


Figure 5. Coefficient of variation of water phase during water flooding process model.

The trend of the coefficient of variation (CoV) of water-phase permeability in various regions of the model with changing water injection volume during the water flooding process is illustrated in Figure 5. In the low water saturation stage, as the water injection volume increases, the CoV of water-phase permeability for both the overall model and the high-permeability layer exhibits a noticeable decreasing trend. Specifically, the overall CoV decreases from 3.60 to 1.31, while the CoV for the high-permeability layer drops from 2.89 to 0.613. This trend reveals that, during the low water saturation stage, as the water injection volume increases, the heterogeneity of the water-phase seepage field decreases in both the high-permeability layer and the overall model. In contrast, the CoV of water-phase permeability in the low-permeability layer shows a marked increasing trend, rising from 1.42 to 3.36, indicating a significant enhancement in the heterogeneity of the water-phase seepage field in the low-permeability layer.

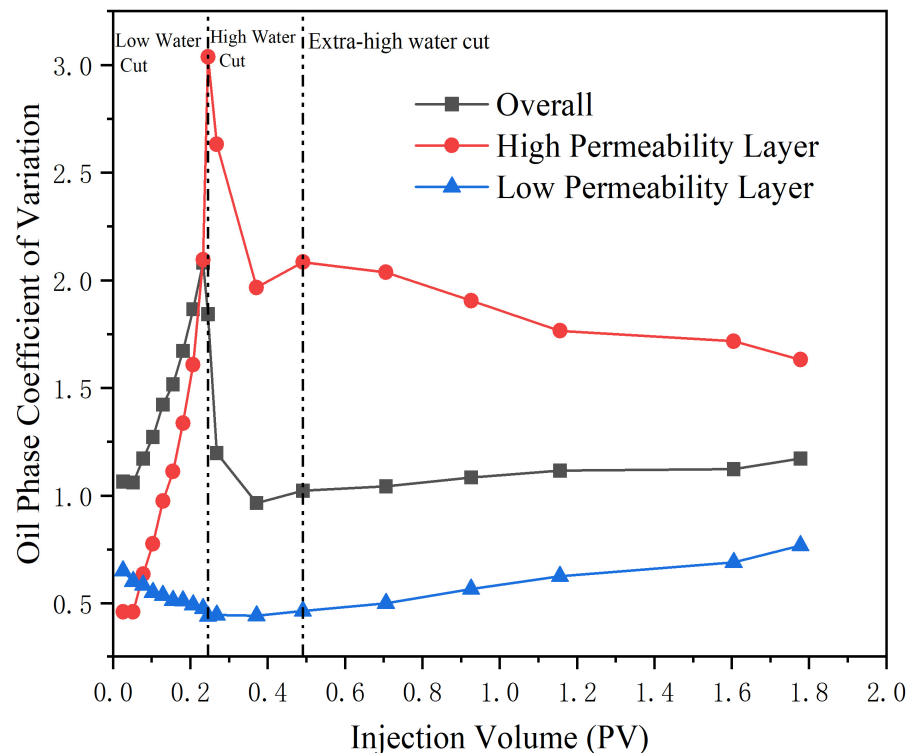


Figure 6. Coefficient of variation of oil phase during water flooding process model.

Upon entering the high water saturation stage, with further increases in water injection volume, a slight rebound is observed in the CoV of water-phase permeability for both the overall model and the high-permeability layer. The overall CoV increases slightly to 1.33, with a growth rate of only 1.53%, while the CoV for the high-permeability layer rises to 0.676, representing a 10.3% increase. This phenomenon indicates that, in the high water saturation stage, the impact of injected water on the overall model and the high-permeability layer is relatively limited, with minimal changes in the degree of heterogeneity of the water-phase seepage field, and a high level of stability maintained. Notably, the CoV of water-phase permeability in the low-permeability layer experiences a significant decrease, falling from 3.36 to 1.69, with a reduction rate of 49.7%. This change suggests that injected water significantly improves the heterogeneity of the water-phase seepage field within the low-permeability layer.

The CoV of oil-phase permeability in different regions of the model with changing water injection volume during the water flooding is shown in Figure 6. In the low water cut stage, the CoV of oil-phase permeability undergoes significant changes as the water injection volume increases. The overall CoV of the model rises from 1.06 to 1.84, and the CoV of the high-permeability layer jumps from 0.459 to 3.04. These figures indicate that injected water significantly increases the heterogeneity of the oil-phase seepage field in both the high-permeability layer and the overall model, resulting in greater differences in oil-phase seepage capacity among various regions within these areas. Conversely, the CoV of the low-permeability layer decreases from 0.650 to 0.446, suggesting that injected water reduces the heterogeneity of the oil-phase seepage field in the low-permeability layer, albeit with limited effectiveness.

In the high water cut stage, the CoV of oil-phase permeability in both the overall model and the high-permeability regions exhibits a complex evolutionary trend, first decreasing and then increasing. The overall CoV experiences a 47.5% decline, followed by a 5.59% rebound. Similarly, the CoV of the high-permeability regions first drops by 35.2% and then increases by 5.58%. During this stage, the CoV of the low-permeability regions begins to

rise, increasing from 0.441 to 0.464, with a growth rate of 5.21%. This signifies that the low-permeability regions start to be affected by the water displacement action, thereby exacerbating the heterogeneity of the oil-phase seepage field.

After entering the extra-high water cut stage, the heterogeneity of the oil-phase flow field continues to evolve and exhibits new characteristics. The CoV in the high-permeability regions decreases from 2.08 to 1.63, representing a 21.6% reduction. Despite the high-permeability regions continuing to be influenced by injected water, the heterogeneity adjustment within their oil-phase flow field gradually stabilized, and its impact weakened compared to the initial stage of development. Meanwhile, the CoV in the low-permeability regions increases significantly from 0.464 to 0.768, with a growth rate of 65.5% and the overall CoV of the model also rises from 1.02 to 1.17, an increase of 14.7%. These changes may be related to the enhanced contribution of low-permeability regions to the flow field, highlighting the central role of low-permeability regions in regulating the heterogeneity of the overall oil-phase flow field during the later stages of development.

Based on the information presented in Figures 5 and 6, the heterogeneity changes in the internal seepage field of the reservoir can be divided into two stages, according to the difference in the variation amplitude of the coefficient of variation (CoV) of oil- and water-phase permeabilities within the reservoir as the water injection volume gradually increases: a stage of drastic changes and a stage of relative stability. The stage of drastic changes in the CoV of water-phase permeability corresponds to the low water saturation stage, while the CoV of water-phase permeability transitions to a stage of relative stability upon entering the high water cut stage. Correspondingly, the stage of drastic changes in the CoV of oil-phase permeability spans both the low and high water cut stages, and the CoV of oil-phase permeability also enters a stage of relative stability after entering the extra-high water cut stage. Specific data analysis of the CoV variations reveals that the variation amplitude of the overall CoV of water-phase permeability in the model during the stage of drastic changes is 114.5 times that during the stage of relative stability. Similarly, the variation amplitude of the overall CoV of oil-phase permeability in the model during the stage of drastic changes is 5.2 times that during the stage of relative stability. This phenomenon indicates that during the stage of drastic changes in the CoVs of both oil and water phases, the reservoir interior is significantly affected by injected water, resulting in drastic fluctuations in the heterogeneity of the oil- and water-phase seepage fields. Upon entering the stage of relative stability, due to the formation of preferred seepage pathways within the reservoir, injected water mainly flows along these pathways. The impact of injected water on the internal seepage field of the reservoir is significantly reduced compared to in the stage of drastic changes, leading to a decrease in the variation amplitude of the CoVs of oil- and water-phase permeabilities.

To comprehensively elucidate the impact of heterogeneity changes in the internal flow field of the reservoir during the water injection development process, the CoV of oil- and water-phase permeabilities, oil- and water-phase permeabilities, and comprehensive flow capacity of the reservoir at different development stages were selected as analysis objects for a comprehensive analysis. The specific values of each parameter are provided in Tables 3 and 4. Additionally, based on these tabular data, corresponding schematic diagrams were plotted, as shown in Figures 7 and 8, respectively.

Based on the data in Table 2 and taking the CoV of oil-phase permeability at different stages as an example, a schematic diagram of the oil-phase flow channels within the reservoir is plotted, as shown in Figure 7. The area of the graphics in the figure represents the relative size of the oil-phase permeability within the same permeable layer.

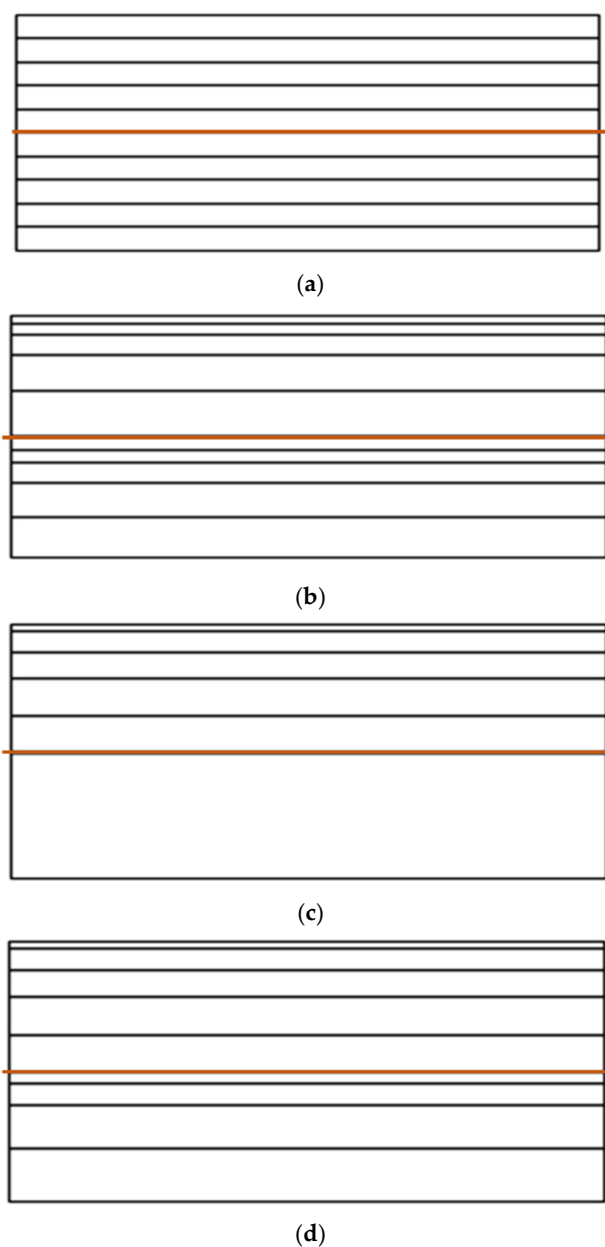


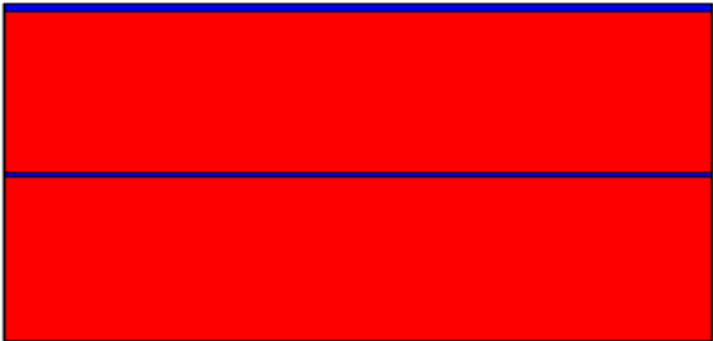
Figure 7. Schematic diagram of oil phase permeability variation coefficient at different development stages. (a) CoV for high-permeability layer: 0, CoV for low-permeability layer: 0. (b) CoV for high-permeability layer at low water cut stage: 0.46, CoV for low-permeability layer at low water cut stage: 0.60. (c) CoV for high-permeability layer at high water cut stage: 1.97, CoV for low-permeability layer at high water cut stage: 0.44. (d) CoV for high-permeability layer at extra-high water cut stage: 1.63, CoV for low-permeability layer at extra-high water cut stage: 0.77.

Table 3. CoV of oil–water phase permeability at different development stages.

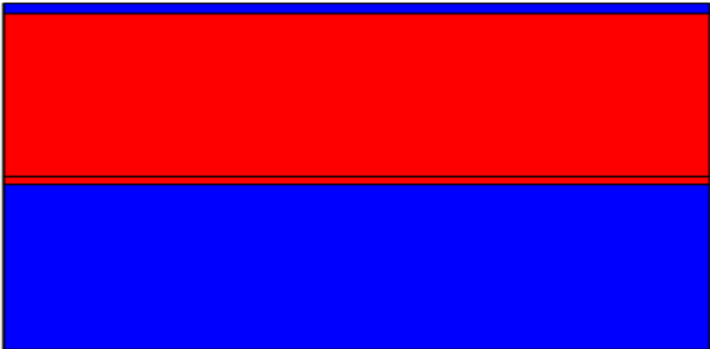
Water Cut Stage	Permeability Layer	CoV of Oil-Phase permeability	CoV of Water-Phase Permeability
Low Water Cut	High	0.46	2.58
	Low	0.60	1.54
High Water Cut	High	1.97	0.55
	Low	0.44	2.95
Extra-High Water Cut	High	1.63	1.69
	Low	0.77	0.68

Table 4. Oil–water-phase permeability and comprehensive flow capacity at different development stages.

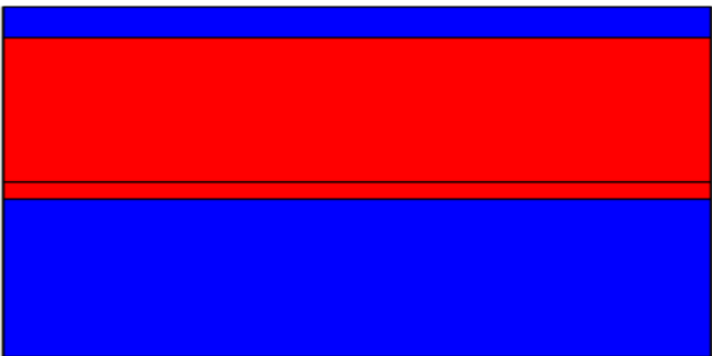
Water Cut Stage	Permeability Layer	Oil-Phase Permeability (mD)	Water-Phase Permeability (mD)	Comprehensive Flow Capacity (mD)
Low Water Cut	High	854	17.7	871.7
	Low	60.6	2.5	63.1
High Water Cut	High	25.8	549.8	575.6
	Low	86.1	4.92	91.02
Extra-High Water Cut	High	48.2	465.8	514
	Low	62.3	13	75.3



(a)



(b)



(c)

Figure 8. Schematic diagram of oil and water flow capacity at different development stages. (a) Low water cut stage. (b) High water cut stage. (c) Extra-high water cut stage. Blue represents water and red represents oil.

As clearly shown in Figure 7, at different water cut stages, the CoV for oil-phase permeability within each permeable layer of the model exhibits significant differences,

and the magnitude of this coefficient of variation positively correlates with the difference in seepage capacity among the internal seepage channels. In this context, channels with a stronger seepage capacity tend to produce significant interference effects on weaker channels, resulting in an obvious shielding phenomenon, which can be intuitively observed in the schematic diagram of Figure 7c. This shielding effect poses considerable challenges and unfavorable factors for subsequent development work.

Based on the data in Table 3, a schematic diagram of the oil and water flow capacity within the reservoir at different development stages is depicted in Figure 8. The relative size of the areas in the diagram represents the relative magnitude of the oil and water flow capacity within the same permeability layer.

The differences in oil–water seepage capacity within the reservoir can be seen as a result of the seepage channels being occupied by oil and water phases in different proportions. By observing Figure 8, it can be found that as the development stage progresses, the oil–water seepage capacity within the reservoir exhibits dynamic characteristics, with the proportion of oil and water phases in the seepage channels fluctuating accordingly. Specifically, in the early low water saturation stage of development, both the high-permeability and low-permeability layers within the reservoir have oil as the main seepage medium, with the flow capacity of the oil phase being significantly advantageous compared to the water phase. However, as the development process enters the high water saturation stage, a significant shift occurs: in the high-permeability layers, the water phase gradually becomes dominant, occupying the main seepage channels and significantly enhancing its seepage capacity, while the seepage capacity of the oil phase weakens noticeably, making it difficult for subsequently injected water to effectively reach the remaining oil. In contrast, within the low-permeability layers, the oil phase still controls the main seepage channels, and the seepage capacity of the water phase gradually increases at this stage. Due to the difference in water-phase seepage capacity between the high- and low-permeability layers, the injected water mainly flows along the main seepage channels of the high-permeability layers, making it difficult to penetrate into the low-permeability layers and thus effectively reach the remaining oil within them.

Based on a comprehensive analysis of Figures 5–8, the following conclusions can be drawn: During the development process, the oil–water seepage characteristics within the reservoir and the heterogeneity of the seepage field exhibit dynamic changes. During the low water saturation period, the oil phase demonstrates strong seepage capability, dominating the seepage pathways, and the heterogeneity of the oil-phase seepage field is relatively low, with minimal differences in seepage capability among various regions within the reservoir. This stage is considered favorable for resource exploitation. However, as the water saturation increases and the reservoir enters the high water saturation stage, the situation significantly changes. The oil phase permeability of the high-permeability layers drops substantially, while the heterogeneity of the oil-phase seepage field intensifies, leading to notable differences in seepage capability among various regions within the oil-phase seepage field. Meanwhile, the water-phase permeability significantly increases, becoming the controller of the main seepage pathways, and the heterogeneity of the water-phase seepage field is relatively low, with minimal differences in seepage capability among internal regions. This results in subsequent injected water tending to flow along the main seepage pathways, making it difficult to effectively mobilize the remaining oil within the reservoir. The differences in oil–water seepage capabilities and among internal regions within the oil-phase seepage field pose significant challenges for the subsequent development of high-permeability layers. Therefore, in subsequent development planning, it may be necessary to consider implementing appropriate strategies to enhance oil-phase seepage capability and reduce the heterogeneity of the oil-phase seepage field. Regarding

low-permeability layers, their oil phase permeability and the heterogeneity of the oil-phase seepage field do not show significant changes compared to the low water saturation stage. The oil phase permeability is much higher than the water-phase permeability, and the heterogeneity of the oil-phase seepage field is relatively small. From the perspectives of flow capability and flow capability differences, low-permeability layers have certain advantages in subsequent development. However, it is also necessary to comprehensively assess the water-phase seepage capability of high-permeability layers and the potential impact of the water-phase seepage field on low-permeability layers.

4. Conclusions

- (1) During the process of water injection development, the comprehensive flow capacity of the layered cores and the flow capacity of the oil–water phases are always in a state of dynamic change. Due to the additional resistance present when multiple phases of fluid flow together, the comprehensive flow capacity of the reservoir is always lower than its absolute permeability. After entering the extremely high water saturation stage, the comprehensive flow capacity of the layered cores is only 41.6% of its absolute permeability. The internal seepage field and oil–water distribution of the reservoir have undergone significant changes compared to the initial stage of development. Therefore, the understanding of physical properties based on the initial stage of development can no longer fully guide the development work at the extremely high water saturation stage.
- (2) Based on the differences in the variation ranges of the CoV of oil- and water-phase permeabilities within the layered cores during the development process, the heterogeneity changes in the seepage field, and the layered cores of the seepage field within the layered cores are divided into two stages: a stage of drastic changes and a stage of relative stability. During the stage of drastic changes, the seepage field within the reservoir is significantly affected by the injected water, leading to notable changes in its degree of heterogeneity. The variation range of the CoV of water-phase permeability during the stage of drastic changes is 114.5 times that of the stable stage, while for the oil phase, it is 5.2 times that of the stable stage. There are also notable differences in the change stages of the seepage fields for the oil and water phases.
- (3) During the process of water flooding development, the oil–water distribution and flow state within the layered cores are jointly constrained by the differences in oil–water seepage capacity and the heterogeneity of the oil–water seepage field. When there is significant imbalance in the oil–water seepage capacity across different regions within the reservoir, or when the heterogeneity of the oil-phase seepage field is excessively strong, it will adversely affect the development process.

Author Contributions: Conceptualization, Q.L.; Methodology, C.J.; Validation, C.J. and X.C.; Formal analysis, X.C.; Investigation, X.C.; Resources, Q.L., K.L. and Z.Z.; Data curation, C.J., K.L. and T.W.; Writing—original draft, C.J.; Writing—review & editing, C.J., Q.L., K.L., Z.Z. and T.W.; Supervision, Z.Z.; Funding acquisition, Q.L. All authors have read and agreed to the published version of the manuscript.

Funding: This research was funded by PetroChina grant number 2023ZZ04-08. And the APC was funded by PetroChina grant number 2023ZZ04-08.

Data Availability Statement: The original contributions presented in this study are included in the article. Further inquiries can be directed to the corresponding author.

Conflicts of Interest: Authors Chen Jiang, Qingjie Liu, Kaiqi Leng and Tong Wu were employed by the PetroChina. The remaining authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

References

1. Yang, S.C.; Wang, R.L. Characteristics of three-dimensional models of reservoir heterogeneity in sandstone oil reservoirs during different development periods. *Pet. Nat. Gas Geol.* **2006**, *27*, 8.
2. Chen, H.Q.; Wang, J.; Du, Y.J. Advances in research methods for reservoir heterogeneity. *J. Geol. Higher Educ.* **2017**, *23*, 13.
3. Yin, Z.J.; Lu, G.Y.; Zou, X.; Yang, Z.P. Heterogeneity of terrestrial reservoirs and its impact on oil recovery rate: A case study of Jidong Gaoshangbao and Shengli Yong'an Town oil reservoirs. *Pet. Nat. Gas Geol.* **2006**, *27*, 6.
4. Li, M.; Qu, Z.; Wang, M.; Ran, W. The Influence of Micro-Heterogeneity on Water Injection Development in Low-Permeability Sandstone Oil Reservoirs. *Minerals* **2023**, *13*, 1533. [\[CrossRef\]](#)
5. Cai, Z. Study on the relationship between reservoir pore structure and oil displacement efficiency. *Pet. Explor. Dev.* **2000**, *27*, 3.
6. Yazynina, I.V.; Shelyago, E.V.; Abrosimov, A.A.; Yakushev, V.S. New method of oil reservoir rock heterogeneity quantitative estimation from x-ray mct data. *Energies* **2021**, *14*, 5103. [\[CrossRef\]](#)
7. Lü, X.G.; Tian, D.H.; Li, B.H. Discussion on the plane macro-heterogeneity of thick oil layers and potential tapping methods. *Pet. Explor. Dev.* **1993**, *20*, 7.
8. Fitch, P.J.R.; Lovell, M.A.; Davies, S.J.; Pritchard, T.; Harvey, P.K. An integrated and quantitative approach to petrophysical heterogeneity. *Mar. Pet. Geol.* **2015**, *63*, 82–96. [\[CrossRef\]](#)
9. Tavoosi, I.P.; Mehrabi, H.; Rahimpour Bonab, H.; Ranjbar Karami, R. Quantitative analysis of geological attributes for reservoir heterogeneity assessment in carbonate sequences; a case from Permian–Triassic reservoirs of the Persian Gulf. *J. Pet. Sci. Eng.* **2021**, *200*, 108356. [\[CrossRef\]](#)
10. Luo, J.; Hou, Z.; Feng, G.; Liao, J.; Haris, M.; Xiong, Y. Effect of reservoir heterogeneity on CO₂ flooding in tight oil reservoirs. *Energies* **2022**, *15*, 3015. [\[CrossRef\]](#)
11. Shao, X. A new characterized parameter for the permeability heterogeneity of the reservoir: Calculation method of permeability diversity coefficient and its significance. *Pet. Geol. Exp.* **2010**, *32*, 397–399.
12. Dong, F.J.; Sun, Z.Y.; Gao, Z.W.; Lu, X.F.; Chen, Y.; Huang, H.; Ren, D.Z. Quantitative characterization of micro-scale pore-throat heterogeneity in tight sandstone reservoir. *Appl. Sci.* **2022**, *12*, 6758. [\[CrossRef\]](#)
13. Cortes-Cano, J.M.; Suarez-Dominguez, E.; Perez-Sanchez, J.; Lozano-Navarro, J.; Palacio-Perez, A. Clay-Sand Wettability Evaluation for Heavy Crude Oil Mobility. *Chem. Chem. Technol.* **2022**, *16*, 448–453. [\[CrossRef\]](#)
14. Sun, Z.; Li, Y.; Ma, K.; Xu, J.; Pan, S. A Novel Method to Characterise Time-Variation of Reservoir Properties: Experimental Study, Simulator Development and its Application in Bohai Bay Oilfield. In Proceedings of the SPE Asia Pacific Oil and Gas Conference and Exhibition, Bali, Indonesia, 29–31 October 2019.
15. Yuan, Q.F.; Pang, Y.M.; Du, Q.L.; Fang, Y.J.; Zhao, Y.F.; Lu, H.M. Development laws during the ultra-high water-cut period in sandstone oilfields. *Daqing Pet. Geol. Dev.* **2017**, *49*–55. [\[CrossRef\]](#)
16. Du, Q.L.; Song, B.Q.; Zhu, L.H.; Jiang, Y.; Zhao, G.Z. Challenges and countermeasures in waterflooding development during the ultra-high water-cut stage in the La, Sa, and Xing oilfields. *Daqing Pet. Geol. Dev.* **2019**, *38*, 6.
17. Zhang, H.; Shan, G.J.; Du, Q.L.; Wang, C.X. Technical challenges and countermeasures for waterflooding development in the late stage of ultra-high water cut in Daqing Changyuan Oilfield. *Daqing Pet. Geol. Dev.* **2022**. [\[CrossRef\]](#)
18. Sun, K.; Liu, H.; Wang, Y.; Ge, L.; Du, W. Novel method for inverted five-spot reservoir simulation at high water-cut stage based on time-varying relative permeability curves. *ACS Omega* **2020**, *5*, 13312–13323. [\[CrossRef\]](#)
19. Xu, J.; Guo, C.; Wei, M.; Jiang, R. Impact of parameters time variation on waterflooding reservoir performance. *J. Pet. Sci. Eng.* **2015**, *126*, 181–189. [\[CrossRef\]](#)
20. Sun, H.Q.; Yang, Y.; Wang, H.T. Distribution characteristics of remaining oil in ultra-high water-cut reservoirs and new technologies for enhancing oil recovery. *J. China Univ. Pet. (Nat. Sci. Ed.)* **2023**, *47*, 90–102.
21. Sun, H.Q.; Yang, Y.; Fang, J.C.; Fan, Z.Y.; Wu, G.H.; Yuan, F.Q.; Yang, Y.L.; Wu, Y.C. Collaborative methods and applications for enhancing oil and gas recovery. *Pet. Nat. Gas Geol.* **2024**, *45*, 600–608.
22. Du, Q.L.; Guo, J.H.; Zhu, L.H.; Jiang, X.Y.; Zheng, X.B.; Wang, Z.G. Philosophy thinking in the practice of water injection development in Daqing Oilfield. *Daqing Pet. Geol. Dev.* **2024**, *43*, 145–151.
23. Shu, N.K.; Liu, L.J.; Yao, X.T.; Huang, Y.S.; Lai, F.P.; Cui, W.F. Formation mechanism of extreme water-consuming layer zone and flow field control and efficiency enhancement mode—A case study of continental sandstone ultra-high water-cut late integrated oilfield. *Reserv. Eval. Dev.* **2024**, *14*, 237–246.
24. Wang, C.Y.; Yang, P.H.; Ma, Y.H.; Qin, Z.Z.; Guo, M.C. Changes in wettability and pore structure of oil layer rocks during the water injection development process in Daqing Oilfield. *Pet. Explor. Dev.* **1981**, *54*–67.
25. Liu, C.; Zhang, X.F.; Tian, B.; Zhang, R.; Wang, Z.; Wang, Y.C. Reservoir physical property change laws during waterflooding development in Z Oilfield, Bohai Sea area. *Mar. Geol. Front.* **2021**, *37*, 7.
26. Deng, Y.Z.; Wu, S.Y. Study on the change laws of reservoir physical characteristics during water injection development. *Oil Gas Recov. Technol.* **1996**, *3*, 44–52.

27. Zhu, L.H.; Du, Q.L.; Li, Z.J.; Yu, H.; Song, X.C. Study on the change laws of reservoir physical properties and wettability during the high water cut period. *Pet. Explor. Dev.* **2004**, *31*, 3.
28. Jiang, R.Z.; Qiao, X.; Teng, W.C.; Xu, J.C.; Sun, Z.B.; Xie, L.S. The impact of reservoir physical property time variation on oil reservoir waterflooding development. *Fault Block Oil Gas Fields* **2016**, *23*, 4.
29. Du, Q.L. The variation laws and microscopic mechanism of reservoir permeability in sandstone oilfields under long-term water injection development. *Acta Pet. Sin.* **2016**, *37*, 6.
30. Deng, S.G.; Lü, W.F.; Liu, Q.J.; Leng, Z.P.; Li, T.; Liu, H.X. Study on the oil displacement mechanism of conglomerate using CT technology. *Pet. Explor. Dev.* **2014**, *41*, 330–335. [[CrossRef](#)]
31. David, C.; Nabawy, B.S. X-ray CT scanning imaging for the Nubia sandstone as a tool for characterizing its capillary properties. *Geosci. J.* **2016**, *20*, 691–704.
32. Leng, Z.P.; Yang, S.J.; Lü, W.F.; Ma, D.S.; Liu, Q.J.; Jia, N.H. Characterization methods of tight oil pore structure: A case study of the tight oil reservoir core in the central Sichuan Basin. *Fault Block Oil Gas Fields* **2016**, *23*, 161–165. [[CrossRef](#)]
33. Lv, J.; Liu, Y.Z.; Gao, J.; Wang, J.L.; Li, Y.K. Study on the mechanism of deep fluid flow redirection in horizontal well gel placement dam using CT technology. *Pet. Explor. Dev.* **2011**, *38*, 733–737.
34. Kang, H.; Gao, J.; Song, X.M. Method for evaluating water-flooded core storage and seepage characteristics based on CT technology. *Sci. Technol. Eng.* **2016**, *16*, 169–173.

Disclaimer/Publisher’s Note: The statements, opinions and data contained in all publications are solely those of the individual author(s) and contributor(s) and not of MDPI and/or the editor(s). MDPI and/or the editor(s) disclaim responsibility for any injury to people or property resulting from any ideas, methods, instructions or products referred to in the content.