Experimental Study on the Percolation Mechanism of Typical Sandstone Reservoirs and Analysis of Improving Water

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Abstract: In this study, the authors analyzed the pore structure characteristics and percolation mechanism of glutenite reservoirs using normalized permeability curves and NMR. They established a benchmark based on the displacement volume at 100% water production rate and introduced the concept of water flooding control degree. Based on this, they proposed a concise empirical formula that relates the water production rate to the recovery degree and water flooding volume coefficient. The application of this formula to two blocks in the Karamay oilfield yielded results consistent with production practice and provided clear guidance for future water flooding development work.

Keywords: two-phase flow; water flooding control degree; multi-model structures.

1. Introduction

Waterflooding is a widely used technique for enhancing oil recovery in reservoirs[1,2]. However, in glutenite reservoirs like those found in Karamay, China, the effectiveness of waterflooding can be limited due to the complex nature of the rock formations. Therefore, developing an improved method for analyzing and optimizing the waterflood effect in these reservoirs is crucial. The objective of this study is to propose a new method for analyzing the waterflood effect in Karamay glutenite reservoirs, with the aim of improving oil recovery and maximizing production efficiency.

The project for this article includes and uses the following analysis methods:

Data Collection: Gather geological, petrophysical, and production data from the Karamay glutenite reservoir.

Reservoir Characterization: Conduct a detailed reservoir characterization to understand the reservoir properties, such as porosity, permeability, and fluid saturation.

Numerical Simulation: Develop a numerical simulation model using advanced reservoir engineering software to simulate the waterflooding process in the glutenite reservoir.

Sensitivity Analysis: Perform sensitivity analysis by varying key parameters such as injection rate, water quality, and well placement to evaluate their impact on the waterflood effect.

Optimization: Utilize optimization algorithms to identify the optimal combination of injection parameters that maximize the waterflood effect and improve oil recovery.

The proposed method is expected to provide insights into the waterflood effect in Karamay glutenite reservoirs and optimize the injection parameters for enhanced oil recovery. The results will help operators make informed decisions regarding waterflooding strategies and improve production efficiency.

Due to the presence of threshold pressure gradient and low velocity non-Darcy percolation, an effective hydrodynamic system could not be established between injection and production wells. The evaluation process for glutenite reservoir water flooding development was complex and cumbersome, with limited relevant documentation and immature understanding of the main controlling factors affecting water flooding volume factor[3,4]. As a result, there was no accurate basis for determining the drive factor for water flooding volume.

In order to tackle this problem, we conducted a comparison between the relative permeability curves and nuclear magnetic resonance (NMR) results. This analysis aimed to understand the connection between the infiltration absorption effect and hydrophilic properties. Through this investigation, we successfully determined the water flooding volume factor and developed a standard chart using experimental data. This innovative approach allowed for a transparent and easily comprehensible evaluation of the impact scope and flow efficiency of the injected water in the glutenite reservoir, while considering production data. Furthermore, this novel method effectively showcased the efficacy of adjustment measures in oilfield development.

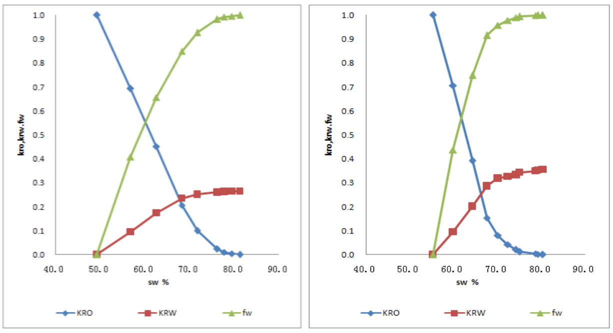
2. Material & Methods

2.1. Two Phase Flow Experiment

The experiments involving two-phase flow[1-4] played a crucial role in the development of oilfield water injection projects. These experiments served as fundamental groundwork for actual oil field development. In this study, we utilized the non-steady state method. The core data, which forms the basis of our analysis, is presented in Table 1.

Table 1. The basic core data table on the experiment of relative permeability

Well No	**Depth (m)**	**Layer**	**Length (cm)**	**D (cm)**	**Perm-plug (md)**	**Porosity (%)**
J001	2073.90	S42	5.83	2.52	1.52	12.33
J001	2027.67	S32	7.12	2.51	8.68	14.66
J001	2026.84	S32	6.10	3.80	14.00	14.61
J001	2079.11	S51	4.45	2.54	5.01	14.94
B002	6 23/30	S7	6.53	2.50	5.80	13.76
B002	6 23/30	S7	4.23	2.50	2.94	13.16
B002	6 28/30	S7	7.08	2.50	60.00	14.39
B002	7 2/38	S7	4.60	2.50	137.95	15.38
C003	2599.5-2601.3	S7	5.62	3.80	3.19	8.17



a Core test data of NO 3 b. Core test data of NO 9

Figure 1. Experimental curve of typical sandstone facies infiltration

Table 2. Core data table of relative permeability curve characteristics

Core no	**1**	**2**	**3**	**4**
Well no	J001	J001	J001	J001
Top depth m	2073	2027.17	2025.5	2077.4
Base depth m	2077.4	2031.08	2027.17	2082.2
Layer	S41	S32	S32	S51
Bound water daturation,%	58.81	52.34	49.35	50.46
Residual oil saturation,%	10.70	12.79	18.68	17.35
Two phase seepage zone width%	30.49	34.87	31.97	32.19
The highest water phase relative permeability	0.33	0.39	0.26	0.30
Oil displacement efficiency by 98% Water cut,%	72.05	68.14	60.65	62.31
Ultimate oil displacement efficiency,%	75.85	73.16	63.12	65.00

Table 2. displays the experimental data for core relative permeability. Meanwhile, Figure 1. illustrates the typical phase permeability experiment curve. It is evident from Figure 1. that there are substantial variations in the experimental data of the core within the same interval.

Currently, the project is utilizing the unsteady state method to measure the relative permeability curves of 9 rock cores located in the fifth and eighth zones of Xinjiang oilfield. The experimental procedure strictly follows the guidelines outlined in the "Oil-water Relative Permeability Determination Method (Unsteady State)" (SY5345-2007), a standard set by the People's Republic of China Oil and Gas Industry. In Table 3. and Table 4., we have compiled the core basic data for two distinct low permeability reservoirs. Additionally, Table 5. presents the mobile oil test data for four specific cores.

Table 3. Core basic data table of reservoir core relative permeability test in TTB Formation,

Well	**no**	**Depth m**	**Layer**	**Length cm**	**Dia cm**	**Perm-plug md**	**Porosity %**
	A0001	6 23/30	S7	6.53	2.50	5.80	13.76
	A0001	6 23/30	S7	4.23	2.50	2.94	13.16
	A0001	6 28/30	S7	7.08	2.50	60.00	14.39
	A0001	7 2/38	S7	4.60	2.50	137.95	15.38
	A0002	2599.5-2601.3	S7	5.62	3.80	3.19	8.17

Table 4. Characteristic data table of core relative permeability curve of lower TTB reservoir

Core no	**5**	**6**	**7**	**8**	**9**
Well no	A0001	A0001	A0001	A0001	A0002
Top depth m	6 23/30	6 23/30	6 28/30	7 2/38	2599.5
Base depth m	S7	S7	S7	S7	S7
Layer	59.76	50.74	53.46	50.44	55.31
Bound water daturation,%	9.77	21.12	14.86	13.63	19.69
Residual oil saturation,%	30.47	28.14	31.68	35.93	25.00
Two phase seepage zone width%	0.34	0.54	0.41	0.31	0.36
The highest water phase relative permeability	71.12	59.23	62.51	70.01	53.04
Oil displacement efficiency by 98% Water cut,%	75.73	61.18	68.07	72.49	55.90

2.2 Movable Oil Analysis Experiment.

Movable oil research[5-8] is an innovative experimental technique that investigates the two-phase percolation mechanism using a dehydrogenation-simulated oil as the medium. This approach combines macro water-oil displacement experiments with advanced technologies such as nuclear magnetic resonance (NMR) and mercury injection.

During oil saturation, the fluid primarily flows along large pore channels, forming complete connections (as shown in Figure 2.-3.). Consequently, some smaller connecting pores can also become saturated with crude oil. However, another pore system composed of clay minerals and clastic minerals remains unsaturated due to its lack of connection with the larger channels. Even if the pore space is significant, the fluid flows around this unsaturated pore system. As a result, the targeted reservoirs exhibit a characteristic multi-model structure typical of glutenite reservoirs[9-10].

The specific movable oil experiment capitalizes on the fact that dehydrogenated crude oil lacks a nuclear magnetic signal. By detecting water saturation at three specific time points - when saturated with water, after oil flooding water, and when saturated with oil - using nuclear magnetic resonance (NMR), we can gain insights into the distribution patterns of water within different pore types. This information serves as a guide for understanding the microscopic percolation mechanism.

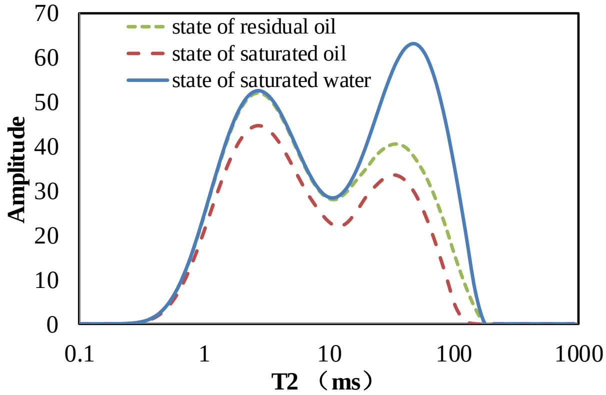


Figure 2. Movable oil test T2 spectrum of No 4 core

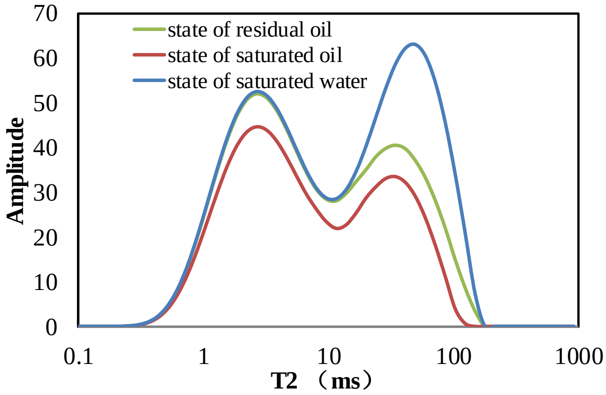


Figure 3. Movable oil test T2 spectrum of No 9

Table 5. Core basic data table of reservoir core movable oil

Well	no	Depth m	Layer	Length cm	Dia cm	Perm-plug md	Porosity %
	A0001	6 28/30	S7	6.53	2.50	5.80	13.76
	A0001	6 23/30	S7	4.23	2.50	2.94	13.16
	A0003	2027.72	S7	7.08	2.50	60.00	14.39
	A0003	2073.78	S7	4.60	2.50	137.95	15.38

3. Analysis and Discussion

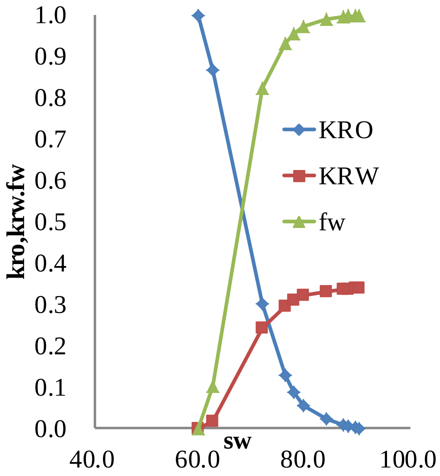


Figure 4. Standardized permeability curves

1). The oil saturation exhibited an island-like distribution, with small pores partially saturated with crude oil, reflecting the dual porosity characteristics of the formations. This can be observed in Figure 2. and Figure 3., which depict two sets of flowing channels.

2). Figure 4. and Figure 5. illustrates the water-phase relative permeability curves for the TTA formations and TTB formations, both showing a convex shape. This indicates a significant water breakthrough and a rapid increase in water production rate.

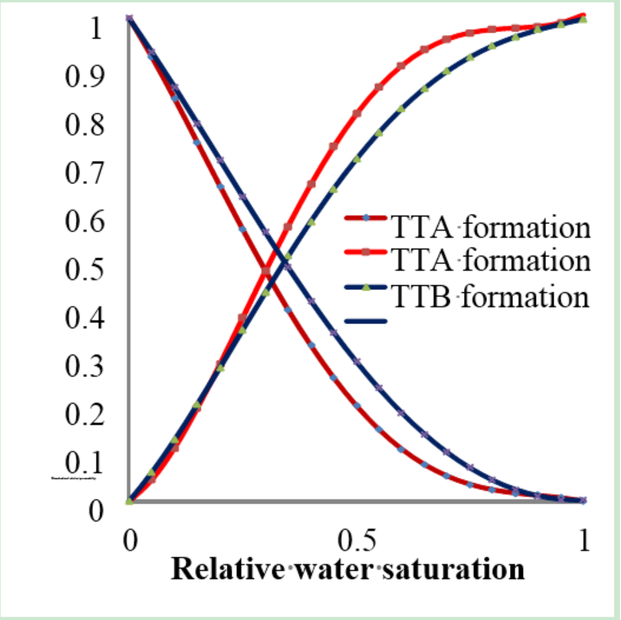


Figure 5. Typical relative permeability curves

3). To assess the effectiveness of water flood development, we introduced the concept of water drive volume factor and the concept of water control degree, as shown in Eq. 1. These concepts provide a distinct interpretation of the injection-production relationship compared to traditional literature.

4). If the water control degree approaches or exceeds 100%, it suggests that the development process has been executed according to the development program, resulting in satisfactory development outcomes. However, if the water control degree falls significantly below 100%, it indicates an unsatisfactory water flood effect, failing to meet the requirements set by the development plan (refer to Figure 6. and Figure 7.). The fitting formula for this concept is represented by Eq. 1:

$$f_W = 40.714\ln(100E_R) - 54.939\eta - 4.9898 \quad (1)$$

Where, f_W is water content,%, E_R is water drive volume factor,%, η is water flood control degree ,%.

To assess the effectiveness of water flood development[6], a concept known as waterflood control degree was introduced. This concept represents the ratio of the pore space actually involved in the reservoir, calibrated under the recovery degree at a specific time. Additionally, the concept of water drive volume factor was proposed as an estimation value, similar to recovery efficiency, to evaluate the efficacy of the water flood development.

If the water control degree approaches or exceeds 100%, it indicates that the development process has been executed in line with the development program, resulting in favorable development outcomes. Conversely, if the water control degree falls significantly below 100%, it suggests that the water flood effect is not satisfactory and does not meet the designed development requirements.

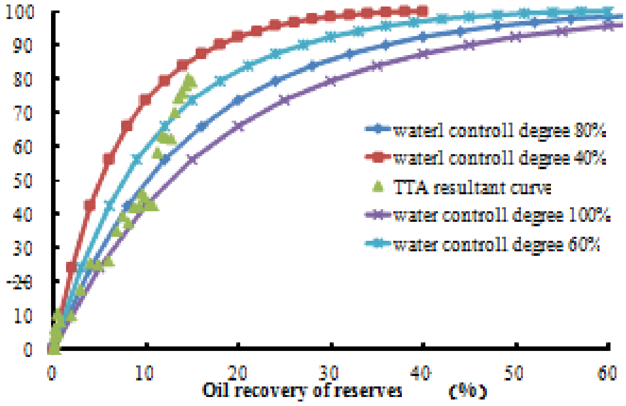


Figure 6. Water drive development evaluation chart of TTA

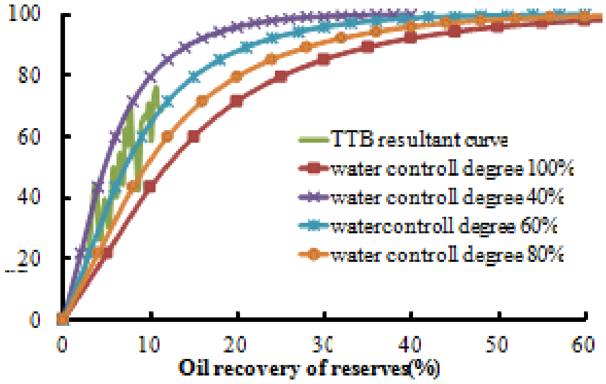


Figure 7. Water drive development evaluation chart of TTA

The evaluation of water flood effect is influenced by several factors, including:

1. Calibration of recovery efficiency: The choice of calibration value can significantly impact the evaluation results. A high calibration value may lead to deviation in the evaluation effect, while a low calibration value can introduce a preference bias.

2. Degree of well pattern control: The effectiveness of water flooding evaluation can be negatively affected if the degree of well pattern control is low.

3. Reservoir heterogeneity: Reservoirs with strong heterogeneity are prone to water breakthrough during the development process. This can reduce the degree of well pattern control and diminish the effectiveness of water injection in the reservoir.

In order to study the seepage characteristics[3,5], the relative permeability curves of TTB and TTA formations underwent normalization processing .From Figure 5., it can be observed that the oil phase relative permeability of TTA formations declines at a faster rate compared to that of TTB formations. This suggests that TTA formations are more challenging to develop than TTB formations.

6. For TTA formation (Figure 6.),in early of reservoir waterflood development, the water flooding volume factor is around 60%, the current value remains at around 60%, showing that the early pattern well spacing was too large, the lower level of well control requires encryption well pattern to improve the waterflood effect.

7. On erly of TTB reservoir water flooding (Figure 7.), the water flooding volume factor is around 80%, then to around 60%, the current value via an encrypted well pattern, waterflooding volume coefficient has returned to 80%.

4. Conclusions

1. Owing to the presence of dual porosity, a portion of crude oil flow through macropores remains unproduced, while imbibition occurs in some small pores.

2. By utilizing standardized relative permeability curves and combining them with oilfield production data, it becomes possible to accurately evaluate the decline in development and production performance.

3. A comprehensive comparison between two-phase permeability curves, nuclear magnetic resonance (NMR) results, and standard phase permeability curves reveals that the TTB formations are more amenable to development compared to the TTA formations.

4. The chart generated using Eq. 1, in conjunction with oilfield data, offers a clear depiction of the dynamic development process and the subsequent effects following adjustments.

Expanding on the points:

1. The existence of dual porosity within the reservoir poses challenges in optimizing crude oil production. While macropores facilitate the flow of crude oil, there are instances where this flow is not effectively produced. On the other hand, small pores contribute to oil production through imbibition. Understanding the dynamics of these different pore types is crucial in maximizing production efficiency.

2. Standardized relative permeability curves provide a valuable tool for evaluating the decline in development and production performance over time. By comparing these curves with actual oilfield production data, one can gain insights into the effectiveness of water flooding or other production enhancement techniques employed in the field.

3. Comparing various permeability curves, such as two-phase permeability curves, NMR results, and standard phase permeability curves, helps differentiate between formations that are easier or more challenging to develop. In this case, the comparison suggests that the TTB formations exhibit characteristics that make them more amenable to successful development compared to the TTA formations.

4. By incorporating oilfield data into the evaluation process and utilizing Eq. 1, a chart can be created to illustrate the dynamic development process and its subsequent effects. This chart provides a visual representation of the impact of adjustments made during the development phase and allows for better decision-making regarding future development strategies.

Shortcomings

- Evaluation of water flood effect is influenced by factors such as calibration of recovery efficiency (high or low calibration values can cause problems), degree of well pattern control (low degree can negatively affect evaluation), and reservoir heterogeneity (strong heterogeneity can lead to water breakthrough and reduce well pattern control and water injection effectiveness).

Future Development Prospects and Suggestions

- For formations like TTA where the oil phase relative permeability declines faster than in TTB formations, more attention should be paid to development challenges.
- In cases like the TTA formation where early water flooding volume factor remains low and well pattern control is low, encrypting the well pattern can be considered to improve the waterflood effect as seen in the TTB reservoir where this measure increased the waterflooding volume coefficient.

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