Microscopic characteristics of water invasion and residual gas distribution in carbonate gas reservoirs

Pengyu Chen1,2 | Huiqing Liu1 | Hailong Zhao3 | Chunqiu Guo2 | Yuzhong Xing2 | Muwei Cheng2 | Haidong Shi2 | Liangjie Zhang2 | Yunzhu Li4 | Penghui Su2

1China University of Petroleum, Beijing, China
2CNPC Research Institute of Petroleum Exploration & Development, Beijing, China
3Key Laboratory of Unconventional Oil & Gas Development (China University of Petroleum (East China)), Ministry of Education, Qingdao, China
4Research Institute of Geological Exploration and Development, Chuanqing Drilling Engineering Company, PetroChina, Chengdu, China

Correspondence
Pengyu Chen, CNPC Research Institute of Petroleum Exploration & Development, Beijing 100083, China.
Email: chenpengyu@petrochina.com.cn
Huiqing Liu, China University of Petroleum, Beijing 102249, China.
Email: liuhq@cup.edu.cn
Hailong Zhao, Key Laboratory of Unconventional Oil & Gas Development (China University of Petroleum (East China)), Ministry of Education, Qingdao 266580, China.
Email: zhhl@upc.edu.cn

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Abstract
We used the nuclear magnetic resonance online detection method to analyze the water invasion mechanism and residual gas distribution of a carbonate rock gas reservoir. The T2 spectra obtained by using the Carr-Purcell-Meiboom-Gill (CPMG) pulse sequence were applied to characterize the invasion water and residual gas distribution. The results showed that (a) in the pore-type gas reservoir, the water first invades the meso–macropores and then the small pores as the pressure decreases further. The fracture distribution in a fracture-pore-type gas reservoir has an effect on the water invasion mode. The water can enter the pores through the fracture wall after the water invades the fracture. (b) In the pore-type gas reservoir, 37.7% of the residual gas resides in the small pores, while the rest resides in the macropores. While in the fracture-pore-type gas reservoir, 4.8% ~ 26.8% of the residual gas is in the smaller pores and 69.2% ~ 95.7% in the macropores. Barely, any residual gas resides in the fractures. The residual gas in the small pores is difficult to produce. (c) The residual gas is controlled by the fracture penetration, amount of bottom water, fracture width, and production rate. It is suggested the production rate decreased to induce the water to invade the meso–macropores after the gas well begins to produce water to reduce the amount of residual gas in the meso–macropores.

KEYWORDS
carbonate gas reservoir, displacement experiment, meso-macropores, nuclear magnetic resonance, residual gas distribution, water invasion mechanism
1 INTRODUCTION

Fracture-pore gas reservoirs are the most common type of carbonate gas reservoir. For a fracture-pore gas reservoir with edge and bottom water, the water can easily flow into the production well through the fractures, causing water channeling, lower production, and even a cessation of production, leading to a lower recovery.1-11 Researchers have conducted a great deal of work on the water invasion mode and invasion mechanism. The water invasion mode includes the water cone mode, vertical channeling mode, lateral invasion mode, and vertical channeling-lateral invasion mode.1-11

The water invasion mechanism has mainly been studied through physical simulations, numerical simulations, and field statistics. The etched glass model and the core model are the two main types of physical simulation models.12-20 The etched glass model can simulate the water invasion mechanism and flow characteristics at the pore throat scale. Based on the results of the etched glass model, researchers proposed a water invasion mechanism involving water channeling, bypassing, and snapping off. Because of the complex pore structure of the actual core, the etched glass model is merely an approximation of the real pore structure, which causes the experiment results to contain limitations. The core water invasion experiment is conducted using natural or artificial cores. The experiment can be used to investigate the influences of the porosity, permeability, and fractures on the water invasion on the macroscopic scale rather than the pore scale. However, it cannot monitor the progress of the water invasion and provides only the final results. The numerical simulation method can be used to study the factors influencing water invasion by constructing a mathematical model and fitting the field production data or experiment results.21-28 This method has the advantages of convenience and a wide range of research applications. However, for the convenience of calculation, the model usually simplifies the actual situation to a certain extent and cannot truly reflect the actual situation. The field statistical method is mainly used to analyze the characteristics and mechanism of water invasion based on the geological and production characteristics of the gas reservoir.29-31 This method is closely combined with field investigations, but it cannot analyze the mechanism of water invasion on the pore throat scale, and it is a macroscopic scale study.

Aimed at the existing problems in this research on the water invasion mechanism, we proposed that the nuclear magnetic resonance (NMR) online analysis system could be used to continuously monitor the water invasion process on the pore throat scale using natural cores under high temperature and pressure conditions. Because the experimental conditions were similar to the formation conditions, the experimental results were more representative of actual conditions. Taking the right bank of the Amu River in Turkmenistan as an example, in this study, we conducted water invasion experiments on a core from a fracture-pore carbonate gas reservoir using the online NMR analysis system. We studied the water invasion characteristics and residual gas distribution law to provide a theoretical basis for the efficient development of fracture-pore carbonate gas reservoirs.

2 MATERIALS AND METHODS

2.1 Principle of the online NMR analysis system

NMR is an important means of studying fluid distribution in porous media. When a core sample is placed in a static magnetic field, the hydrogen nuclei of the fluid in the core are polarized by the magnetic field. Then, the sample is subjected to a radio-frequency (RF) field with a certain frequency and hydrogen NMR occurs. When the RF field is turned off, the signal decays exponentially with time. In core analysis, the Carr-Purcell-Meiboom-Gill (CPMG) pulse sequence test is usually used to obtain the attenuation signals, and the transverse relaxation time $T_2$ map of the NMR can be obtained after the inversion of the signal data.32,33

In a uniform magnetic field, the transverse relaxation time $T_2$ can be expressed as follows:

$$\frac{1}{T_2} = \frac{1}{T_{2B}} + \rho_2 \left( \frac{S}{V} \right)$$  \hspace{1cm} (1)

where $T_{2B}$ is the volumetric relaxation time of the fluid (ms); $\rho_2$ is relaxation law ($\mu$m/ms); and $S/V$ is the specific surface of the pore. Because $T_{2B}$ (usually $>3000$ ms) is much larger than $T_2$, the first term on the right side of Equation (1) can be ignored and the equation becomes,

$$\frac{1}{T_2} = \rho_2 \left( \frac{S}{V} \right)$$  \hspace{1cm} (2)

After simplification, the relaxation time $T_2$ is related to the specific surfaces of the pores, which is determined by the sizes and shapes of the pores. Therefore, the $T_2$ spectra obtained from the inversion reflect the distribution of the pore size of the core and the distribution of the fluid in the different pores.

The model of the online NMR analysis system used is MacroMR12-150H-VTHP and is manufactured by the NIUMAG analytical instrument corporation, Suzhou, China. The magnetic field intensity is $0.3 \pm 0.05$T. The
system has the following four units: a displacement unit, an NMR detection unit, a metering unit, and a radio-frequency emission unit (Figure 1). The displacement unit uses gas to saturate the core and supply the water. The radio-frequency emission unit is used to generate an external magnetic field. The NMR detection unit detects the distribution of the fluid in the core at different times. The metering unit is used to measure the amounts of water and gas produced. The NMR online analysis system can realize the real-time detection and analysis of the displacement process by combining the NMR principle with the displacement system, and it can be used to obtain the distribution of the fluid in the core at different times throughout the experimental process. The maximum working pressure of the system is 40 MPa, and the maximum working temperature is 80 °C, which simulates the formation temperature and pressure conditions of a reservoir and can realize real-time monitoring of the fluid distribution in the core's pore throats under formation conditions. Therefore, the experimental results are more accurate.

2.2 | Experiment subject

To study the water invasion characteristics of pore and fracture-pore gas reservoirs, we selected pore cores and fracture-pore cores from bottom water carbonate gas reservoirs in the Right Bank of the Amu River for the experiments. The core parameters are presented in Table 1, and Figure 2 presents photographs of the cores used in the experiments. Core 1 is a pore core, and core 2 is a fracture core. The fractures in the core are artificial fractures. The fractures in the core are artificial fractures and are obtained by cutting the core into two parts using the cutting machine. We used a layer of quartz sand with different particle sizes (45-60 mesh, 70-80 mesh, and 120-140 mesh) to evenly fill in the fractures to control the fracture opening. The larger the mesh number, the smaller the fracture opening. The corresponding fracture openings of these three sizes of quartz sand were designated as A, B, and C. Core 1 and core 2 were cut into two parts, the lengths of which were 1/3 and 2/3 of the original core length. We simulated cores with 1/3 and 2/3 degrees of fracture penetration using the different parts (Figure 3). To avoid the impact of the current generated by the ions in the water on the NMR results, deionized water and nitrogen gas with a purity of 99.99% were used in the experiments. Nitrogen does not contain hydrogen atoms, and therefore, it can be used in NMR experiments to distinguish between gas and water.

To study the influence of the degree of fracture penetration, the fracture opening, pressure drop rate, and amount of bottom water on the water invasion, we considered four factors and three levels. We used the orthogonal experimental design method to design the experimental

![Flowchart of online NMR analysis system, which consists of a displacement unit, an NMR detection unit, a metering unit, and a radio frequency emission unit](image)

| TABLE 1 | Core parameters of the experiments |
|----------|-----------------------------------|
| Core number | Length (cm) | Diameter (cm) | Permeability (mD) | Porosity (%) |
| 1          | 6.05       | 2.50          | 0.92              | 9.87         |
| 2          | 6.00       | 2.50          | 0.87              | 9.37         |

Note: The cores were selected from bottom water carbonate gas reservoirs in the Right Bank of the Amu River.
schemes shown in Table 2. Because of the small pore volume of the core, to reduce the experimental error, the amount of water in Table 2 is the ratio of the water volume to the core volume. In addition, we carried out a comparative experiment on the water invasion characteristics of the pore cores using core 1 to compare the water invasion characteristics of pore cores and fracture-pore cores. In total, we conducted 10 groups of experiments.

2.3 | Experiment procedure

The experiments were carried out using the following experimental steps.

1. The core was cleaned, dried, and weighed according to the "core analysis method" (national standard GB/T 29172-2012), and the permeability and porosity were measured using nitrogen gas.
2. After the core was dried again, it was placed in the NMR core gripper, the temperature was increased to 80°C, and the core was pressurized to 30 MPa (the maximum pressure of the nuclear magnetic equipment was 38 MPa and the maximum temperature was 100°C) using nitrogen gas (did not have an NMR signal, so it could be distinguished from the water).
3. The outlet pressure was gradually decreased by controlling the backpressure regulator. The T 2 spectra of the core were measured with a certain pressure interval (each pressure was maintained for half an hour), and the water production and gas production at each pressure were measured simultaneously until the pressure in the core decreased to 2 MPa. To eliminate the influence of the stress sensitivity, the pressure tracking pump was used to maintain the confining pressure at 2 MPa higher than the pressure in the core by pressurizing the fluoride solution surrounding the core. The fluoride solution has no NMR signal, therefore, can be used to supply confining pressure.
4. Change the experimental conditions and repeat steps (1-3).

![Core photographs. Core 1 is a pore core, and core 2 is a fractured core. The fractures in the core are artificial fractures.](image1)

![Diagrams of the cores with different degrees of fracture penetration. Core 1 and core 2 were cut into two parts, the lengths of which were 1/3 and 2/3 of the original core length. We simulated cores with 1/3 and 2/3 degrees of fracture penetration using the different parts.](image2)

| No. | Penetration degree | Fracture width No. | Pressure drop speed (MPa/h) | Aquifer size |
|-----|--------------------|--------------------|------------------------------|--------------|
| 1   | 1/3                | C                  | 3                            | 10           |
| 2   | 1/3                | B                  | 4                            | 20           |
| 3   | 1/3                | A                  | 5                            | 30           |
| 4   | 2/3                | C                  | 4                            | 30           |
| 5   | 2/3                | B                  | 5                            | 10           |
| 6   | 2/3                | A                  | 3                            | 20           |
| 7   | 1                  | C                  | 5                            | 20           |
| 8   | 1                  | B                  | 3                            | 30           |
| 9   | 1                  | A                  | 4                            | 10           |

Note: The orthogonal experimental design method was used to design the experimental schemes. To reduce the experimental error, the amount of water in Table 2 is the ratio of the water volume to the core volume.
3 | RESULTS AND DISCUSSION

3.1 | Water invasion mechanism of pore-type core

The water invasion experiments conducted on the pore-type core were carried out on core 1. The NMR test parameters are as follows: TE=0.2 ms, TW=3000 ms, and NS=64. In these experiments, the aquifer size was 30, and the pressure drop rate was 3 MPa/h. The experimental results are shown in Figures 4-6. The dimensionless pressure in the figure is defined as the ratio of the current pressure to the initial pressure. As can be seen from Figure 4, the gas production was relatively stable before the water was produced. When the pressure was reduced to 16 MPa, water appeared in the core outlet. As the pressure decreased further, the water production gradually increased, the gas production gradually decreased, and the water–gas ratio increased. When gas pressure in the core decreased, the aquifer expanded and entered the core due to the compressibility. The lower the pressure, the more water entered the core, which led to an increase in the water saturation of the core, a decrease in the gas flow space, and a decrease in the relative gas permeability. In addition, because of the presence of water, the fluid flow in the core changed from single phase gas flow to two phase water gas flow.

Due to the capillary force and the surface tension, the flow resistance of the gas in the core increased and the gas production decreased.

FIGURE 4 Production curve for pore-type reservoirs. The red line, purple line, blue line, and green line refer to the gas production, recovery factor, water production, and water to gas ratio, respectively. The X-axis is dimensionless pressure, which is defined as the ratio of the current pressure in the core to the original pressure in the core at the beginning of the experiment. The left Y-axis denotes the gas production, the calculated water–gas ratio is multiplied by 10.

FIGURE 5 $T_2$ spectra at different pressures. The Y-axis denotes the signal intensity, which represents the hydrogen atom content and is proportional to the water content in the core. The signal intensity is a relative magnitude with an arbitrary unit (a.u.). The X-axis denotes the relaxation time with an unit of millisecond (ms). It gives the distribution of the invasion water in the pore scale. A larger horizontal ordinate value refers to a larger pore in the core.

FIGURE 6 Proportion of the water influx to the total water influx at different pressures and the distribution of the invasion water. The X-axis is dimensionless pressure, which is defined as the ratio of the current pressure in the core to the original pressure in the core at the beginning of the experiment. The blue line and the red line give the distribution of the invasion water in the small and macropores at a certain pressure, respectively. They can be obtained by dividing the water content in the small and macropores with the invasion water content at a certain pressure. The green line refers to the invasion water percentage at different pressures. It can be calculated by dividing the invasion water content at a certain pressure with the total invasion water content at the end of the experiment.
According to the water–gas ratio curve shown in Figure 4, the water invasion process can be divided into a water-free period, a water–gas ratio increase period, and a stable water–gas ratio period. Figure 5 shows the $T_2$ spectra curves at different pressures. The $T_2$ spectra named “fully water saturated” is obtained with NMR test after the core is fully saturated with water. The total signal intensity is proportional to the amount of water in the core, so the amounts of water invasion at different pressures can be compared using the signal intensity. Figure 6 shows the proportion of the water influx to the total water influx at different pressures. In the water-free period, all of the invasion water enters the core, so the amount of invasion water remains relatively stable. In the water–gas ratio increase period and the stable water–gas ratio period, the amount of water invasion decreased, which was mainly caused by the partial production of the water.

For the convenience of analysis, according to the characteristics of the relaxation time distribution, the core’s pores were divided into small pores (relaxation time <10 ms) and macropores (relaxation time >10 ms). As shown in the $T_2$ spectra curve in Figure 5, as the pressure initially decreased, 98.22% of the initial invasion water entered the macropores in the core (relaxation time >10 ms), and only 1.78% of the invasion water entered the small pores (relaxation time <10 ms). When the pressure decreased, the gas flow resistance in the macropores was small and the water easily invaded them. As the pressure decreased further, the gas in the small pores was produced and more water entered them. According to the $T_2$ spectra, the proportion of the invasion water in the small pores increased from 1.78% to 13.3%. When the pressure finally decreased to 2 MPa, 22.07% of the small pores and 52.79% of the macropores were invaded by water. 37.7% of the residual gas resided in the small pores, and 62.3% of the residual gas resided in the macropores. As shown in the $T_2$ curve of the water-saturated core, the macropores accounted for a large proportion, so the residual gas mostly existed in the macropores. The final recovery factor of the pore-type core was 76.2% (Figure 4).

3.2 Mechanism of water invasion in fracture-pore cores

To study the water invasion characteristics and residual gas distribution of the fracture-pore cores, we conducted water invasion experiments on fracture-pore cores with different degrees of fracture penetration, aquifer sizes, pressure drop rate and fracture widths, and achieved the real-time detection of the experimental process using the NMR method.

3.2.1 Water production characteristics

The experimental results for the fracture-pore-type cores are shown in the Figure A1. According to the gas production curve in the figure, in the presence of fractures, compared with the pore-type cores, the gas production curve decreased rapidly rather than slowly after the water was produced, indicating a faster rate of decrease in the gas production. Because of the high permeability of the fractures, as a high-speed channel for edge and bottom water invasion, the water was produced from the fracture-pore cores earlier. As shown in Table 3, the minimum pressure at which water was produced in the nine groups of experiments on the fracture-pore cores was 17 MPa, which was significantly higher than that of the pore cores (16 MPa). The gas recovery factor ranged from 61.58% to –69.35%, much lower than that of the pore-type core, which was 76.2%. The recovery factor without water production ranged from 40.17% to 49.60%, and the maximum water–gas ratio ranged from 0.010 to 0.058.

| No. | Water production pressure (MPa) | RF without water (%) | Max. WGR (m³/m³) | RF (%) |
|-----|--------------------------------|----------------------|------------------|-------|
| 1   | 17.5                           | 46.81                | 0.010            | 66.21 |
| 2   | 17                             | 49.60                | 0.019            | 69.35 |
| 3   | 19                             | 42.18                | 0.053            | 62.14 |
| 4   | 19.5                           | 42.34                | 0.054            | 62.57 |
| 5   | 18                             | 45.66                | 0.025            | 66.42 |
| 6   | 19                             | 43.94                | 0.023            | 67.94 |
| 7   | 18.5                           | 40.32                | 0.027            | 64.39 |
| 8   | 20                             | 40.17                | 0.058            | 61.58 |
| 9   | 19                             | 42.34                | 0.019            | 63.54 |

Note: The minimum pressure at which water was produced in the nine groups of experiments on the fracture-pore cores was 17 MPa, which was significantly higher than that of the pore cores (16 MPa). The gas recovery factor ranged from 61.58% to –69.35%, much lower than that of the pore-type core, which was 76.2%. The recovery factor without water production ranged from 40.17% to 49.60%, and the maximum water–gas ratio ranged from 0.010 to 0.058.
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3.2.2 | Water invasion mechanism

The water invasion mechanism in the cores with fracture penetrations of 1/3, 2/3, and 1 was studied with the following parameters: TE=0.2 ms, TW=3000 ms, and NS=16. The obtained NMR T$_2$ spectra were shown in Figure 7. The abscissa relaxation time represents the pores of different scales. According to the principle of NMR, the vertical signal intensity of the NMR T$_2$ spectra was proportional to the water content, so the stronger the signal intensity under different relaxation times, the more water there was in the pores corresponding to the relaxation time. Because the larger the pore was, the larger the relaxation time was, the peak with the largest relaxation time corresponded to the fractures. For the convenience of analysis, we categorized the pores into three types: small pores (relaxation time 1-10 ms), meso-macropores (relaxation time 10-400 ms), and fractures (relaxation time >400 ms) based on the characteristics of the relaxation time distribution.

The experimental results showed that when the matrix was in contact with the aquifer and the fracture was not (Figure 7A-B), the signal intensity in the meso-macropores increased as the pressure decreased, indicating that the water mainly flowed into the meso—macropores of the matrix. As the pressure decreased further, the signal intensity of the fractures increased, implying that the water

**FIGURE 7** T$_2$ spectra with fracture penetration degrees of (A) 1/3, (B) 2/3, and (C) 1. The Y-axis denotes the signal intensity, which represents the hydrogen atom content and is proportional to the water content in the core. The signal intensity is a relative magnitude with an arbitrary unit (a.u.). The X-axis denotes the relaxation time with an unit of millisecond (ms). It gives the distribution of the invasion water in the pore scale. A larger horizontal ordinate value refers to a larger pore in the core. Based on the characteristics of the relaxation time distribution, the pores were categorized into three types: small pores (relaxation time 1-10 ms), meso-macropores (relaxation time 10-400 ms), and fractures (relaxation time >400 ms).
flowed into the fractures through the meso–macropores. As the pressure continued to decrease, the fracture signal intensity did not change significantly, whereas the T2 spectra shifted to the left and the intensity increased. According to this result, we speculated that the water fully filled the fractures and entered the smaller pores in the core through the fracture walls. However, there was no signal in the small pores, indicating that it was difficult for the water to enter the small pores.

When the fractures fully penetrated the core (Figure 7C), the signal intensity in the fractures strengthened quickly in the early pressure reduction process, implying that the water mainly flowed into the fractures. Because of their higher permeability, the gas in the fractures was produced first, causing the pressure in the fractures to decrease. The water quickly invaded the fractures due to the pressure difference between water aquifer and the core. As the pressure continued to decrease, the water fully filled the fractures (the signal intensity remained the same), while the water in the fractures passed through the fracture walls into smaller pores in the core, causing the overall T2 spectra to shift to the left and the signal intensity to increase.

The invasion water distribution is the ratio of signal intensity in different pores or fractures to the total signal intensity. Table 4 shows the distribution of the invasion water at different pressures. It is evident that as the degree of fracture penetration increased, the proportion of the invasion water in the meso–macropores decreased, while the invasion water in the fractures increased. For example, at 2 MPa, the proportion in the meso–macropores decreased from 93.65% to 64.88%, whereas the proportion in the fractures increased from 6.35% to 35.11%.

The proportion of the water invasion to the total water invasion at different pressures in Experiment 7 was calculated, as shown in Figure 8. It is evident that similar to the pore-type core, in the water-free period, all of the invasion water entered the core, so the invasion water remained relatively stable. In the water/gas ratio increase stage and the stable water/gas ratio stage, because of the existence of the fractures, the invasion water flowed along the fractures and was produced in the outlet, resulting in a much faster rate of decrease in the invasion water than that for the pore-type core.

These experimental results indicated that the fracture distribution had an influence on the water invasion pattern in fracture-pore gas reservoirs. Under the conditions that the fractures did not communicate with the aquifer, the water first entered the meso–macropores in the matrix (relaxation time 10-400 ms) and then entered the fractures (relaxation time >400 ms). If the fractures communicated with the aquifer, the water first entered the fractures, and after the fractures were filled with water, the water

| Pressure (MPa) | Fracture penetration degree 1/3 | Fracture penetration degree 2/3 | Fracture penetration degree 1 |
|---------------|-------------------------------|-------------------------------|-----------------------------|
|               | Small pores (%)                | Meso–macropores (%)           | Fractures (%)               |
| 26            | 0                              | 62.30                         | 0                           |
| 22            | 0                              | 65.04                         | 0                           |
| 18            | 0                              | 62.30                         | 0                           |
| 14            | 0                              | 65.04                         | 0                           |
| 10            | 0                              | 62.30                         | 0                           |
| 6             | 0                              | 65.04                         | 0                           |
| 2             | 0                              | 65.04                         | 0                           |

Note: As the degree of fracture penetration increased, the proportion of the invasion water in the meso–macropores decreased, whereas the proportion of invasion water in the fractures increased.
invaded the meso–macropores in the matrix. Compared with pore-type gas reservoirs, the water could not enter the small pores (relaxation time <10 ms) due to the high capillary force in the small pores, which made it difficult for water to enter them. Because of the small flow resistance in the fractures and meso–macropores, the invasion water preferably entered these spaces and formed a dominant flow channel. The invasion water flowed out along the dominant channel, so the small pores could not be invaded. In the gas field in the right bank of the Amu River, the proportion of small pores in the matrix is relatively large and fractures abound. Therefore, waterproofing of the gas wells should be considered as soon as possible to improve the gas recovery factor.

3.2.3 | Distribution of residual gas

By comparing the $T_2$ spectra of a core that was fully saturated with water and one at waste pressure, we found that the residual gas in the fracture-pore gas reservoir was distributed mainly in the small and meso–macropores, and the residual gas in the fractures was much less (Table 5). As shown in the $T_2$ spectra, however, there was basically no water invasion in the small pores, which indicated that it was difficult to produce the residual gas in the small pores. Therefore, the main purpose of improving the development effect of a gas reservoir was to reduce the residual gas saturation in the meso–macropores.

We used the meso–macropores water invasion percentage (invasion water content/fully saturated water content $\times 100\%$, termed as “WIP”) as the evaluation index to evaluate the factors influencing the residual gas distribution in the meso–macropores. We analyzed the influences of the degree of fracture penetration, the fracture width, the pressure drop rate, and the aquifer size using the orthogonal test analysis method to determine the main factors controlling the residual gas. The variable $m$ in Table 6 refers to the meso–macropore invasion percentage under different parameters. As the degree of fracture penetration increased, the invasion percentage of the meso–macropores decreased and the residual gas increased. As the fracture width increased, the invasion percentage initially increased and then decreased. When the fracture width was medium (B), the invasion percentage was the largest. When the fracture width was small, the gas flow resistance in the fracture was large, and it was difficult for the gas in the meso–macropores to enter the fracture, causing the pressure in the meso–macropores to be high and making it hard for water to enter them. The water would quickly invade when the fracture width was larger, causing water channeling and less water invasion into the meso–macropores, so the invasion percentage was highest when the fracture width was medium. As the aquifer size increased, the invasion percentage initially increased and then decreased. When the aquifer size was 20, the meso–macropore invasion percentage was larger and there was less residual gas. When the aquifer size was small, the energy of the aquifer decayed rapidly, making it difficult for the water to enter the meso–macropores. The higher the gas production rate, the smaller the invasion percentage of the meso–macropores. Higher production rate caused greater pressure drop rate and higher water flow rate, leaving less time for water to invade the meso–macropores.

In the production process of a fracture-pore gas reservoir, proper control of the gas production rate can promote the invasion of water into the meso–macropores.

**FIGURE 8** Proportion of the water invasion at different pressures to the total water invasion. The X-axis is dimensionless pressure, which is defined as the ratio of the current pressure in the core to the original pressure in the core at the beginning of the experiment. The Y-axis refers to the invasion water percentage at different pressures. It can be calculated by dividing the invasion water content at a certain pressure with the total invasion water content at the end of the experiment.

**TABLE 5** Distribution of the residual gas in the pores

| No. | 1   | 2   | 3   | 4   | 5   | 6   | 7   | 8   | 9          |
|-----|-----|-----|-----|-----|-----|-----|-----|-----|------------|
| Small pores (%) | 4.8 | 3.4 | 2.9 | 6.4 | 6.0 | 5.4 | 23.4| 24.1| 26.8       |
| Meso–macro pores (%) | 94.7| 95.5| 95.7| 93.0| 91.4| 93.7| 76.2| 75.3| 69.2  |
| Fractures (%)     | 0.5 | 1.1 | 1.4 | 0.6 | 2.6 | 0.9 | 0.4 | 0.6 | 4.0        |
Table 6: Effects of the different parameters on the residual gas

| Parameters     | Fracture penetration degree | Fracture width | Pressure drop rate | Aquifer size |
|---------------|-----------------------------|----------------|-------------------|--------------|
|               | value | WIP m | value | WIP m | value | WIP m | value | WIP m |
| m1            | 1/3   | 22.24 | 22.22 | 0.1   | 13.94 | 18.46 | 3     | 19.32 | 18.32 |
| m2            | 2/3   | 19.19 | 17.64 | 0.2   | 17.89 | 19.02 | 4     | 18.31 | 19.33 |
| m3            | 1     | 13.94 | 14.77 | 0.3   | 12.48 | 17.16 | 5     | 17.00 | 17.61 |
| R             | 7.45  | 1.86  | 1.01  | 2.47  |        |        |        |        |        |

Note: WIP refers to the meso-macropore water invasion percentage. The R value (extreme difference) is the difference between the maximum and minimum values of the average index value at each level of each factor. The greater the difference, the greater the influence of this factor.

delay water breakthrough, and increase the life of the gas wells. The R value (extreme difference) in Table 6 is the difference between the maximum and minimum values of the average index value at each level of each factor. The greater the difference, the greater the influence of this factor. As can be seen, in order to decreasing influence, the factors influencing the residual gas were the degree of fracture penetration, the aquifer size, the fracture width, and the pressure drop rate.

4 | FIELD APPLICATION AND ANALYSIS

The fractures in the gas reservoir in the right bank of the Amu River in Turkmenistan are well developed with severe reservoir heterogeneity, and the aquifers are active in some regions, which leads to water production from the gas wells. During the J2k–J3o period, carbonate rocks were deposited on a gentle slope and biological shoals were mainly developed.

The types of reservoir rocks in the study area are diverse and consist of bioclastic and bioclastic microcrystalline limestone. The reservoir space consists of pores and fractures but mainly pores. The primary pores are intergranular pores, intercrystalline pores, intragranular pores, and biological cavity pores, and the secondary pores are intergranular dissolved pores, intragranular dissolved pores, and mold pores. The fracture types are structural fractures, with pressure dissolution fractures visible, which increase the risk of water channeling. The reservoirs’ physical properties vary widely. The porosity ranges from 0.14% to 13.33%, with an average of 4.94%. The permeability is 0.0003-10 574.75 × 10⁻³μm², with an average of 0.076 × 10⁻²μm² and strong heterogeneity.

The gas field displayed the following complex development contradictions: (a) Differences in the degree of fracture development, the aquifer size, and the gas column height resulted in changes in the absolute open flow rates of the gas wells (0.1-229.6 × 10⁴), leading to different gas well productivities and difficulties of gas well deployment. (b) In some regions, the water-free period was short because of the aquifer and fractures. In some of the gas fields, it was only three months, which worsened the development effect (Figure 9).

On the basis of these experimental results, we propose the following development strategies for the development of fractured gas reservoirs with bottom aquifers:

1. Optimize the development well location: The well development location should be far away from the fracture development area or an area with a low degree of fracture penetration should be selected, and the reasonable water avoidance height should be determined to delay the occurrence of water invasion as much as possible.
2. Optimize the production scheme: In the early stage of production, while ensuring the gas production, a lower gas production rate can cause the water invasion front to advance in a more uniform manner, delay water breakthrough, and increase the waterless recovery

Figure 9: In the production curve of gas field with bottom water, when decreases the gas production, achieve the purpose of controlling water–gas ratio simultaneously
factor. After water is produced from the gas well, the gas recovery rate should be further appropriately reduced to make the invasion water enter the meso–macropores as much as possible to reduce the residual gas in them and to improve the recovery factor.

5 | CONCLUSIONS

Using a high temperature and high-pressure online NMR detection system to simulate formation conditions, we carried out water invasion simulation experiments on different types of reservoirs, and the following conclusions were drawn:

1. Regarding the pore-type gas reservoir, the water invasion path was from the meso–macropores to the small pores, and the gas reservoir recovery factor was the highest.
2. Regarding the fracture-pore-type gas reservoir, when the fracture was not connected with the bottom aquifer and only the matrix was connected with the aquifer, the water invasion path was in the meso–macropores, the fractures, and the small pores, and the recovery factor was higher. When the fractures were connected with the aquifer, however, the water invasion path was in the fractures, the meso–macropores, and the small pores, and the gas recovery factor was low. It was difficult for the water to enter the small pores in fracture-pore-type gas reservoirs. Compared with pore-type gas reservoirs, in fracture-pore-type gas reservoirs, the water influx decreased rapidly and the gas–water ratio increased rapidly after water breakthrough. As the degree of fracture penetration increased, the proportion of invasion water in the meso–macropores decreased from 93.65% to 64.88%, whereas the proportion of invasion water in the fractures increased from 6.35% to 35.11%.
3. The residual gas in pore-type gas reservoirs was distributed mainly in the meso–macropores, whereas the residual gas in fracture-pore-type gas reservoirs was distributed mainly in the small and meso–macropores, but the residual gas in the small pores was difficult to produce.
4. The main factors controlling the distribution of the residual gas in fracture-pore-type gas reservoirs were the degree of fracture penetration, the aquifer size, the fracture width, and the pressure drop rate.
5. To efficiently develop fractured gas reservoirs with bottom aquifers, the well location should be selected reasonably and the production scheme should be optimized to delay water breakthrough. The gas production rate should be appropriately reduced after water breakthrough to recover the residual gas in the meso–macropores and to improve the ultimate recovery factor.

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CONFLICT OF INTEREST
The authors declare no conflict of interest.

AUTHOR CONTRIBUTIONS
PC and HZ involved in conceptualization. HL, CG, and QL involved in methodology and investigation. PC and H.Z involved in writing—original draft preparation. YX, MC, HS PS, and YL involved in writing—review and editing. CG involved in project administration. HS involved in funding acquisition. All authors have read and agreed to the published version of the manuscript.

ORCID
Hailong Zhao https://orcid.org/0000-0001-8760-3944

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APPENDIX

FIGURE A1 (Continued)
FIGURE A1  Experimental results for fracture-pore-type gas reservoirs. For each experiment, the curves in the left graph show the gas and water production, and the curves in the right one give the recovery factor and water to gas ratio.