Hindawi
Geofluids
Volume 2022, Article ID 2147200, 21 pages
https://doi.org/10.1155/2022/2147200

Research Article

Residual Oil Distribution Pattern in a Fault-Solution Carbonate Reservoir and Countermeasures to Improve Oil Development Effectiveness

Peiliang Liu, Lin Jiang, Bochao Tang, Ke Ren, Mina Huang, and Chunying Geng

Sinopec Northwest Oilfield Company, Xinjiang Urumqi 830011, China

Correspondence should be addressed to Bochao Tang; tangbochao1008@163.com

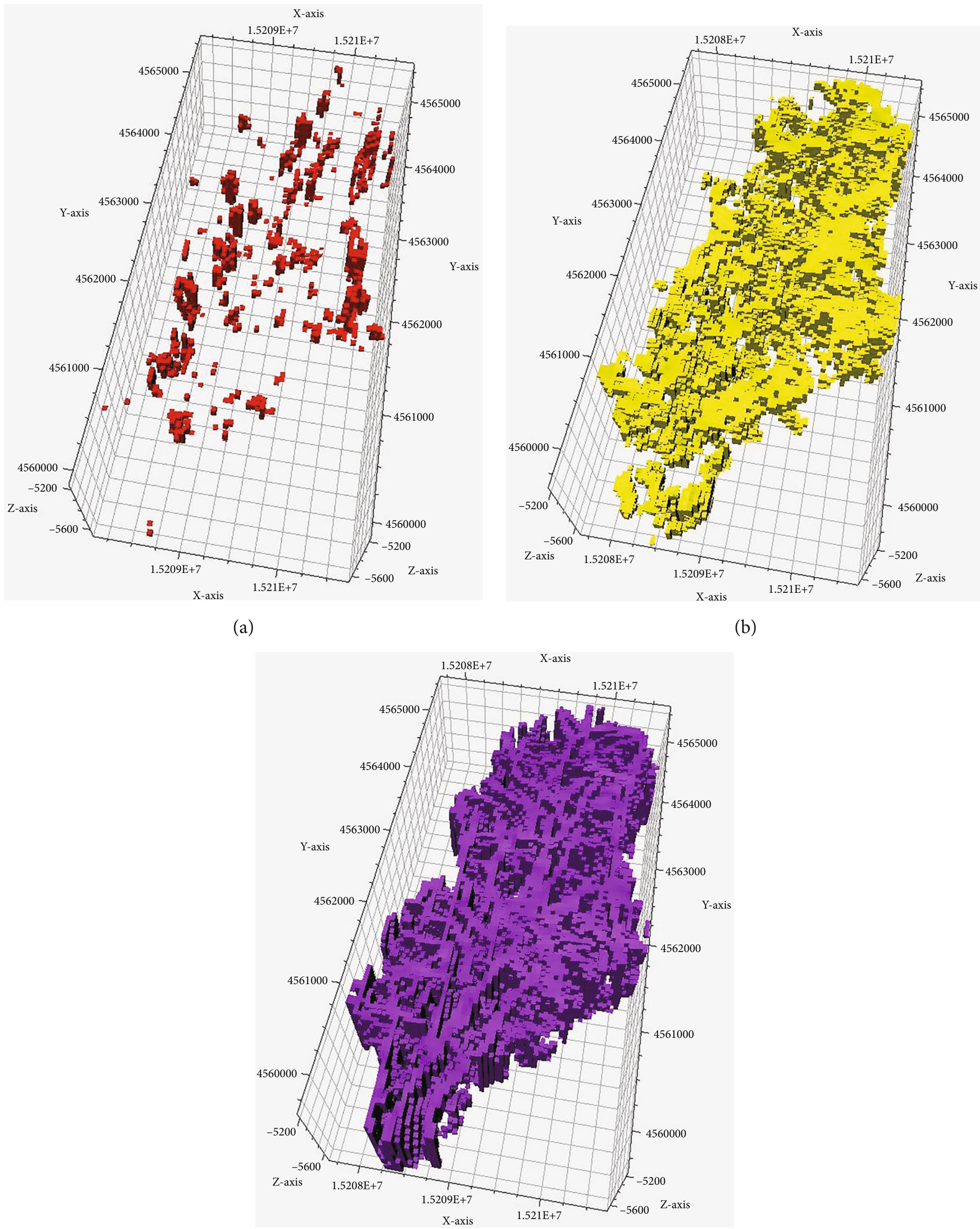
Received 5 November 2021; Revised 8 February 2022; Accepted 17 February 2022; Published 15 April 2022

Academic Editor: Xiang Zhou

Because of the strong random distribution of fractures and caves, fault-solution carbonate reservoirs exhibit significantly different flow mechanisms and development methods from conventional carbonate reservoirs. Natural elastic and edge-bottom water flooding are the main processes for developing fault-solution reservoirs. The rapid decline in production and the complex residual oil distribution are major challenges for oil production. This study is aimed at (1) assessing the residual oil migration law, (2) determining the residual oil distribution characteristics, and (3) identifying the main controlling factors using numerical simulation, to provide suggestions for enhancing oil recovery. The results showed that fractures are the main channel for oil flow and the main path of bottom water coning in the fault-solution reservoirs. The channeling of bottom water along high-angle fractures is the main reason for the decline in oil production. In addition, bottom water coning and gas/water injection are the key factors affecting the distribution of residual oil, while the irregular development of fractures and caves is the main factor causing diversified distribution patterns of the residual oil. The residual oil distribution patterns of fault-solution reservoirs include 4 types, namely, attic, bottom water rising and blocking, separated fracture-cavity, and pores near high-conductivity channel types. For tapping the potential of residual oil, several approaches can be used, namely, deploying new wells or using sidetracking of old wells in the loft and the separated fracture-cavity reservoirs. In addition, the attic residual oil type can also be developed using drainage oil recovery or gas injection for oil replacement. Liquid lift pump, water shutoff, and water cone restrain can also be used to tap residual oil from rising bottom water. Optimizing profile control and water shutoff measures and adjusting the injection and production relationship can be effective approaches for developing residual oil in the pores and cracks beside the high diversion channel.

1. Introduction

Fault-solution reservoirs are important components of deep carbonate oil and gas resources in China. They are mainly controlled by dissolution and strike-slip fault zones at different levels. These reservoirs are characterized by segmented accumulation along the fault zone, vertical penetration, and intermittent spatial distribution [1, 2]. Fault-solution oil reservoirs are independent of the regional unconformity levels and structural locations. Hydrocarbon is filled vertically along the Tongyuan fault zone to form reservoirs and migrates in a "T" shape along with the fracture network system related to the fault zone, which are the characteristics of vertical transportation and accumulation, segmented accumulation, and differential accumulation [3, 4]. The main zones of fault-solution reservoirs are characterized by high oil and gas resources, with high productivity of oil wells. Indeed, they are characterized by large and small faults with large and small reservoirs, respectively, while the absence of faults results in the lack of oil accumulation. The controlled reserves and development characteristics of different wells in the same fault-solution reservoir are different. The size of caves in the well-controlled and the degree of interwell connectivity can determine the single well productivity and

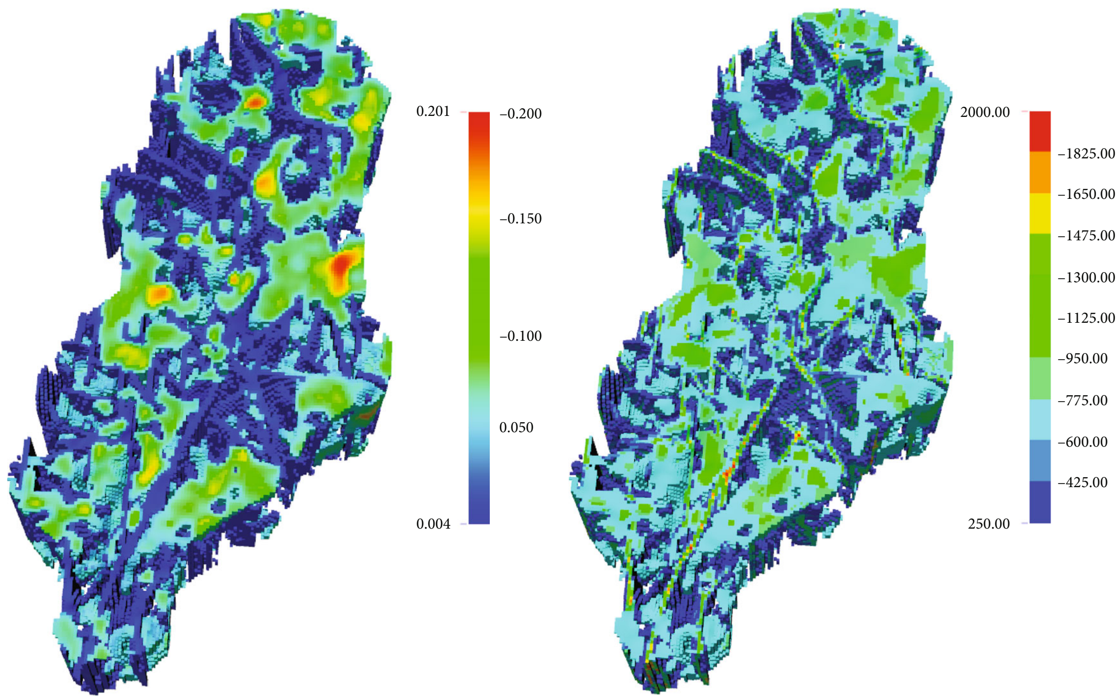


(c)

Figure 1: Distribution characteristics of L11 unit reservoirs.

residual oil distribution.

The Middle-Lower Ordovician carbonate strata in the Tahe Oilfield have experienced multiphase tectonic movements, forming a series of fault systems of different levels and multiphase superimposition and developing abundant fault-solution reservoirs [5]. Oil reservoirs are mainly composed of fractures caused by tectonic deformation, pore structures, caves, and fractures, formed by the karstification process. Indeed, large caves are the most important storage space, while fractures constitute not only the storage spaces but also the main seepage channels. The carbonate has no significant storage and permeability matrix. The reservoir spaces are diverse in shape, large in size, uneven in distribution, and highly heterogeneous, resulting in a complex distribution of residual oil in oilfield development. Therefore, it is important to improve the development effect by further investigating the distribution pattern of the residual oil in the reservoir and improving the comprehensive management of the reservoir to exploit the potential of the residual oil. Indeed, numerous researchers have investigated the



(a) (b)

Figure 2: Porosity and permeability fields of L11 unit.

Table 1: Physical parameters of the numerical simulation model of the L11 unit.

Model parameter	Value	Model parameter	Value
Reservoir temperature	140°C	Reservoir pressure	67 MPa
Rock compressibility	4.93×10^{-5} 1/MPa	Fluid compressibility	13.2×10^{-4} 1/MPa
Porosity	0.01-0.28%	Permeability	0-2000 mD
Water multiple	10	Oil volume factor	1.167

residual oil in clastic and carbonate fractured reservoirs. For carbonate fractured-cavity reservoirs, many scholars have used indoor mechanism model experiments and numerical simulation methods. The distribution characteristics of residual oil have been explored and studied, and some distribution laws of residual oil have been preliminarily summarized [6].

Wang et al. [7] studied the distribution characteristics and laws of remaining oil in fractured-cavity carbonate reservoirs through experiments and numerical simulations. Rong et al. [8] divided the remaining oil into 4 categories and 5 subcategories based on the distribution characteristics of the residual oil through the detailed description of the reservoir and the analysis of the production performance test data. Ameri et al. [9] suggested that the residual oil can be extracted by water, surfactant, and gas flooding in the buried hill fractured reservoir matrix. Zheng et al. [10] used various data, such as cores, logging, seismic, and production performance, to determine the multiscale characteristics, reservoir types, spatial morphology, and distribution laws of fracture-cavity carbonate reservoirs. The model and the configuration relationship with production wells were studied, the influence of various factors on the distribution of residual oil was analyzed, and the main controlling factor model on the residual oil distribution after the water flooding was established. Liu et al. [11] proposed a method for building fractured porous media models for macroscopic experimental simulation of reservoirs and presented an application example of simulation of the development process of fractured porous media reservoirs. Due to the different physical properties of the reservoirs, problems such as water intrusion and unclear distribution of residual oil arise, compromising the successful development of the waterflooding process in carbonate reservoirs. Li et al. [12] used an interlayer heterogeneous and anisotropic physical model to conduct a three-dimensional water flooding experiment and to quantitatively characterize the water-conducting states, water flooding mechanisms, and residual oil distribution of the bottom water-bearing carbonate porous reservoir. In recent years, studies on residual oil distribution and enhanced oil recovery in carbonate reservoirs worldwide have mainly focused on fractured reservoirs, while studies on fractured-cavity reservoirs in my country have focused on bottom water flooding, based on laboratory experiments and numerical simulations. There is a lack of systematic studies on the distribution pattern of residual oil in fault-

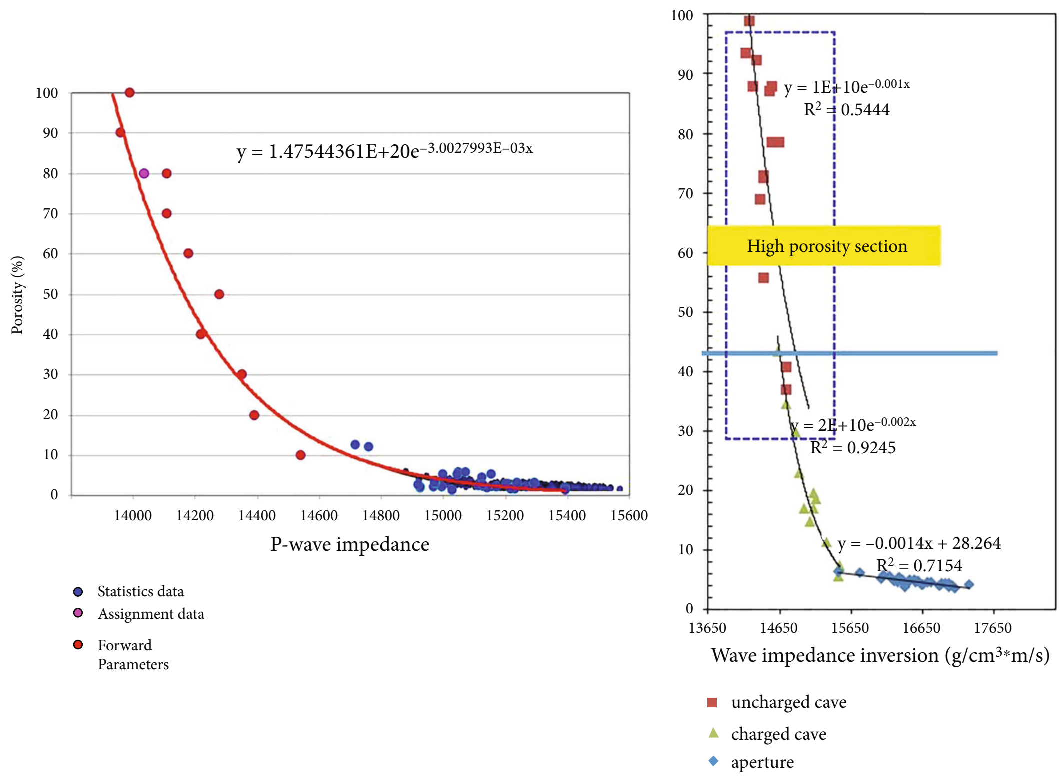


Figure 3: Reserve fitting porosity correction.

karst carbonate reservoirs and on enhanced oil recovery methods in the later stage of the water flooding development process.

Unit L11 is a typical fault-solution fracture-cavity carbonate reservoir. Since its development in 2009, it has been experiencing several phases of natural energy and water/gas injection development. The current production and comprehensive water cut rates are 10.2 and 70%, respectively. However, there are several development challenges, including high water cut, low recovery rate, and low recovery degree [13]. Several researchers have used numerical simulation to study the typical unit of L11 and to reveal the residual oil distribution characteristics of fault-solution reservoirs, in order to provide suggestions for further improving the recovery factor, forming and stimulating potential residual oil stimulation of the fault-solution fracture-cavity reservoir in the Tahe Oilfield, and providing technical support for the efficient production of residual oil in fault-solution reservoirs [14].

2. Implementation of a Numerical Simulation Model for Fault Solution

Based on the geological data of the L11 unit, the model was divided according to the type of reservoir, while the corresponding porosity and permeability parameters, as well as phase permeability curves, were used to implement the numerical model of the typical unit of fault-solution reservoir [15, 16].

Table 2: L11 unit reserve fitting parameters.

Type	Geological reserves ($\times 10^4$ rm^3)	Numerical simulation reserves ($\times 10^4$ rm^3)	Relative error (%)
Caves	1100	1113	0.3
Cavities	900	902	0.2
Fractures	89	91.4	2.7
Total	2099	2106.4	0.4

2.1. Geological Characteristics of L11 Unit. The L11 unit is located in the tension zone of the L12CX main fault, with a large communication depth. The NW-oriented secondary faults form a compression and transformation on the main fault. The surface layer developed NEE- and NW-oriented secondary faults. In addition, the primary and secondary faults are superimposed, the degree of fragmentation is large, and the dissolution foundation and the filling conditions are good. The L11 unit is a typical fault-solution fracture-cavity reservoir. The L11 reservoir is developed in segments along the primary and secondary faults, with a large scale and vertical depth. The reservoirs developed along the faults and converge with the primary faults.

There are 14 wells in the well-block pressure and can be divided into 4 well groups based on the previous understanding of connectivity: (1) group L1: L10X, L11X, and L1X; (2) group L110: L18 and L110X; (3) group L11: L11, L18X, L12X, and L16CH; and (4) group L13: L19, L18H, and L13CH. L14 and L15X wells have not been established Unicom.

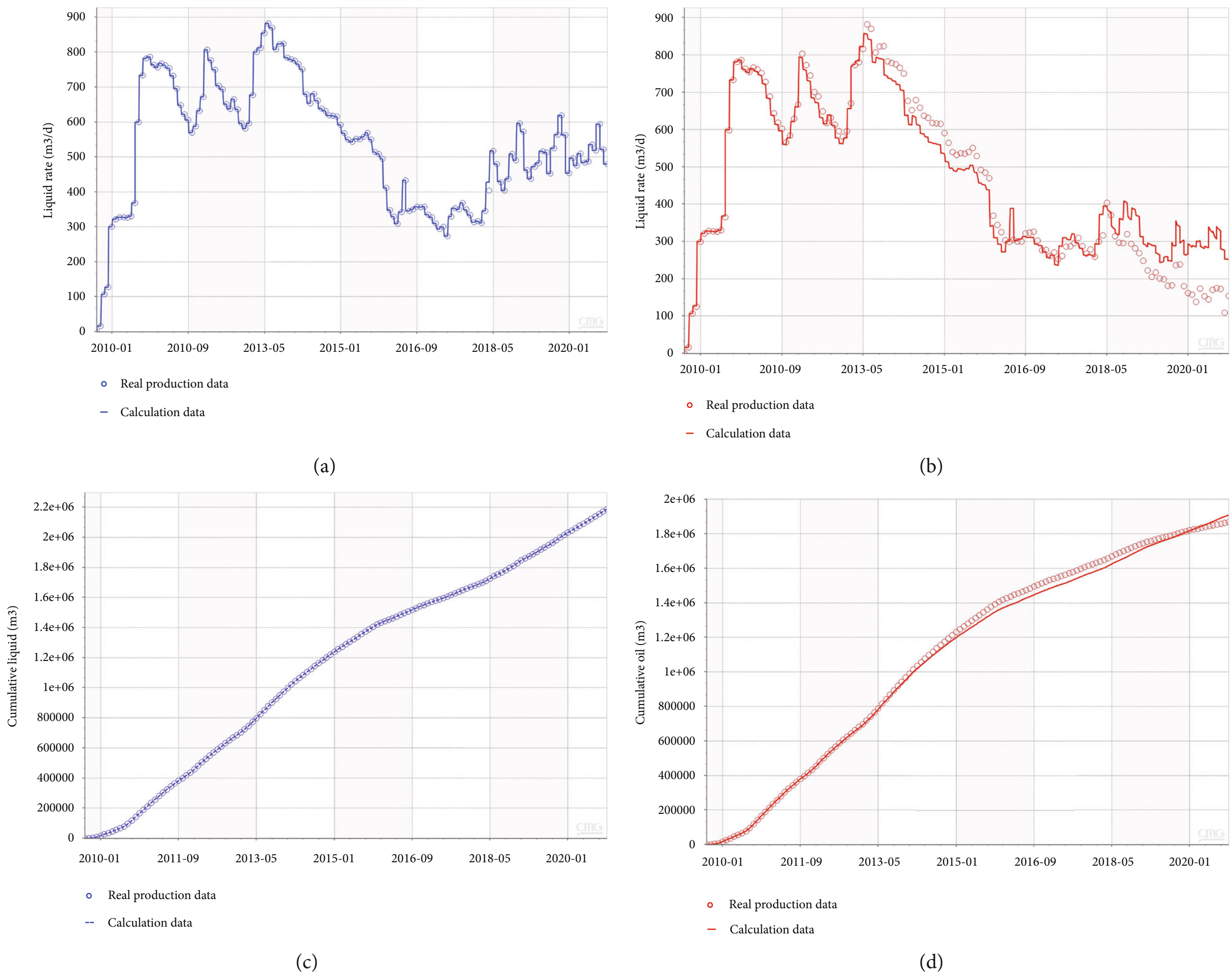


Figure 4: Fluid production and oil production fitting curves of the L11 unit.

2.2. Implementation of the Numerical Simulation Model. Based on the development characteristics, porosity, and permeability of the L11 unit, three types of reservoirs were first distinguished: caves, cavities, and fractures; then, a numerical model of the L11 unit was implemented [17, 18]. The distribution characteristics of reservoir types are shown in Figure 1. The size and number of the model grid were 25 m × 25 m × 3 m and 4561216 (124 × 242 × 152), respectively.

Grid reservoir definition principle: loyal to the well point reservoir type, caves and fractures are given priority, cavities second, and the reservoir type of each grid is unique.

Part of the grid in the model is a superposition of multiple reservoirs. The porosity and permeability characteristics of these grids were processed. The permeability is determined by the dominant channel method. The maximum value of the superimposed reservoir permeability was considered the permeability of the grid, while the pore degree was determined using the direct summation method [19]. The porosity and permeability distribution of the model is shown in Figure 2.

The reservoir and oil-water physical parameters of the digital simulation model are shown in Table 1. The positions and trajectories of the wells, as well as the perforation horizons in the model, were obtained using the actual data of the L11 unit. Taking into account the different flow laws of pores and fractures, as well as the characteristics of the numerical simulation model, the permeability curve was used to reflect the flow characteristics of different reservoirs. The bottom water energy was stimulated using the water-oil volume ratio method.

2.3. History Fitting and Model Verification. The history matching process is based on historical data production and adjusting reservoir parameters to establish a model that represents as much as possible the true behavior of the reservoir. The L11 unit reservoir showed significant differences in porosity and permeability [20]. The porosity values can be adjusted using the inversion relationship of the parameters and statistical methods, and they can be corrected during reserve fitting. On the other hand, there is currently no unified theory for adjusting permeability, and it needs to be carried out correction during production dynamic fitting.

The established mathematical model was used to calculate the unit geological reserves. In addition, the porosity, net-to-gross ratio, and oil-water saturation were adjusted based on the characteristics of the reservoir type and the

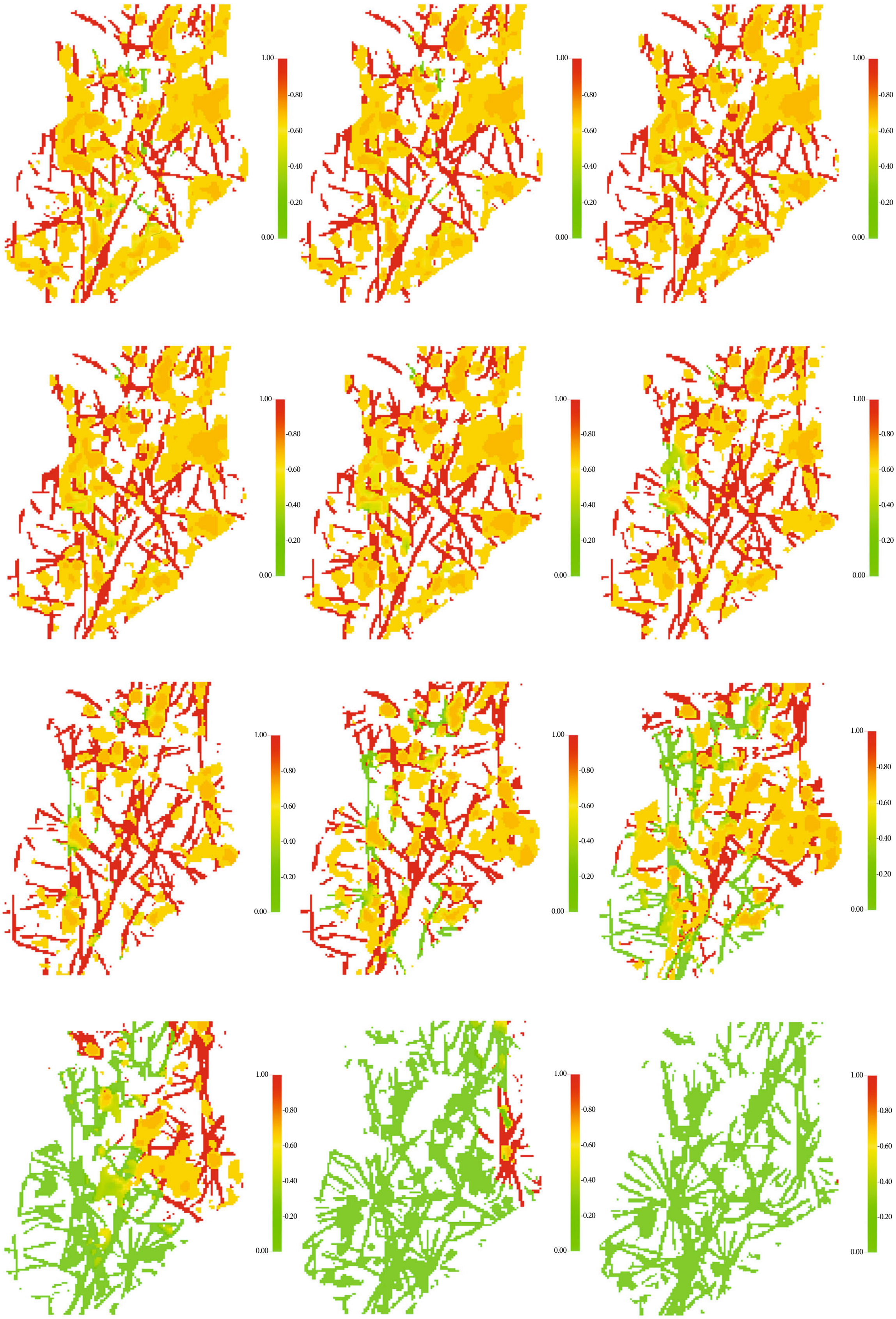


Figure 5: Residual oil distribution in different depth planes of the L11 unit (k from 1 to 40).

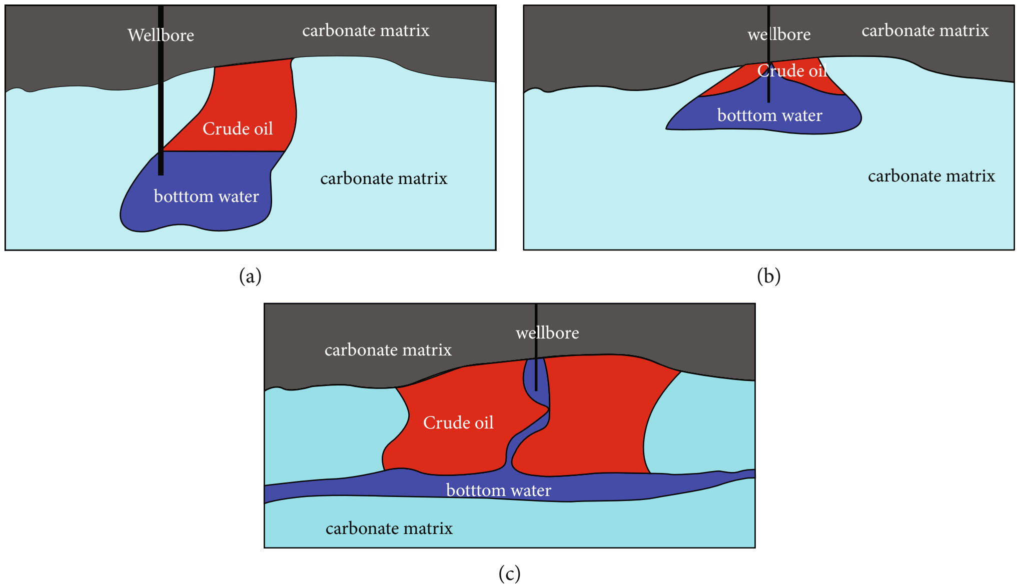


Figure 6: Well point residual oil mode.

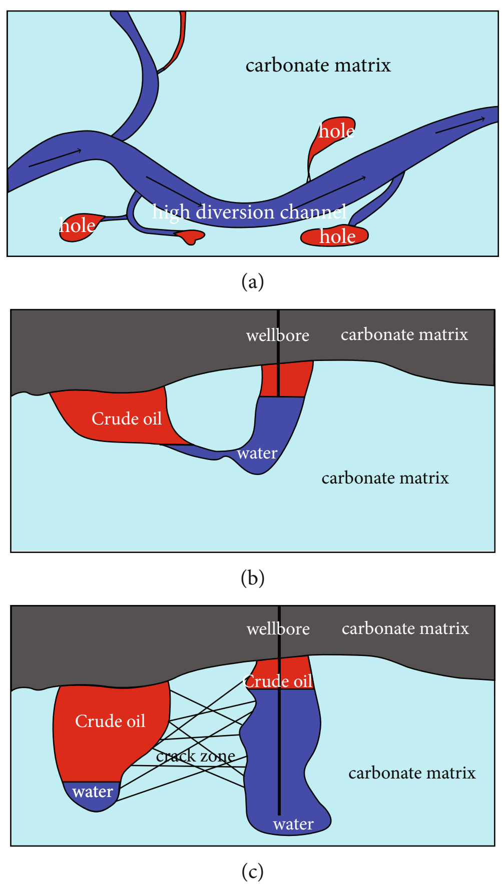


Figure 7: Residual oil pattern between wells.

seismic logging combined with statistical methods, while the actual geological reserves were used as the basis for reserve fitting. After matching the production history data, the constant liquid production was used for fitting the oil production index. By modifying the relative permeability, the production history of the whole district was fitted. Then, based on seismic logging data and stimulation measures, single-well production fitting was performed. In addition, the original digital model was revised to establish a more consistent model by adjusting the near-well permeability,

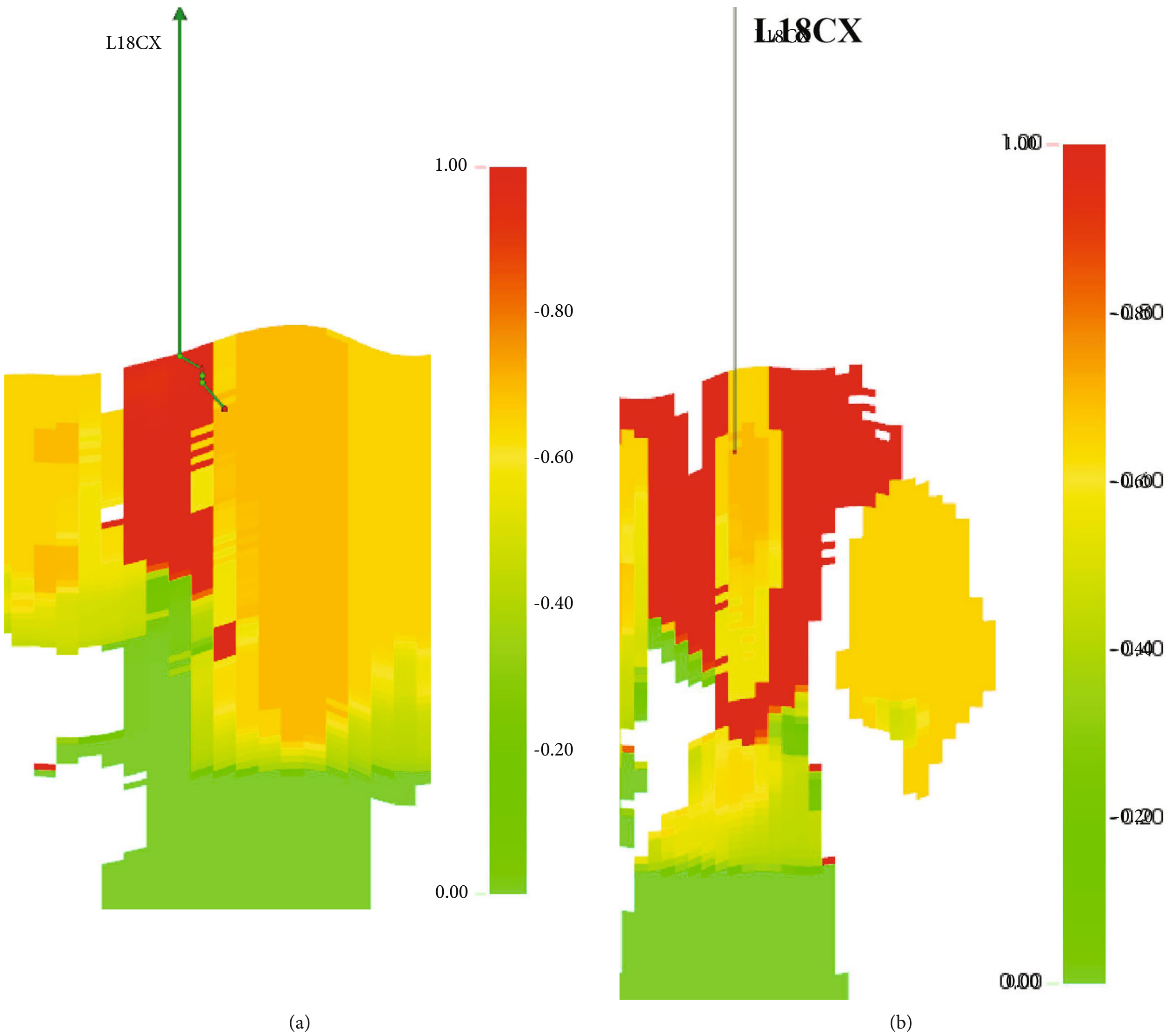


Figure 8: Residual oil distribution characteristics of the well L18CX.

the connection relationship, and the degree of connection between the well, surrounding reservoirs, and water bodies [21, 22]. The digital simulation model of production dynamics provides a reliable basis for the analysis of residual oil distribution and the study of countermeasures to improve the development effect.

2.3.1. Reserve Fitting. The unit geological reserve, the actual geological reserve, and the relative error were 2106.4×10^4, 2099×10^4 rm^3, and 0.4%, respectively. The results showed good reserve fitting. The calibration basis for porosity in the fitting process is shown in Figure 3. Table 2 reports the reserve fitting situation of reservoir types in the L11 unit.

2.3.2. Production History Matching. Figure 4 shows the fitted temporal production rates of fluid and oil in the L11 unit block. The liquid and oil production rates were consistent with the actual production data. Moreover, the cumulative liquid and oil production rates were in line with the actual production rates. The results revealed that the single-well production fitting rate reached more than 90%. The adjusted digital model based on geological data and stimulation operations can reflect the characteristics and current situation of the L11 unit and serve as the basis for assessing the residual oil distribution characteristics and adjustment countermeasures.

3. Analysis of Residual Oil Distribution Mode

Study the produced reserves under different injection-production conditions during the development process of the L11 fault-dissolution fracture-cavity unit, analyze the residual oil migration rules, and summarize the main controlling factors of residual oil distribution under different development methods. Study the residual oil distribution at different development stages in the water-drive gas reservoir, summarize the main concentration positions of the residual oil after the development effect deteriorates, determine the

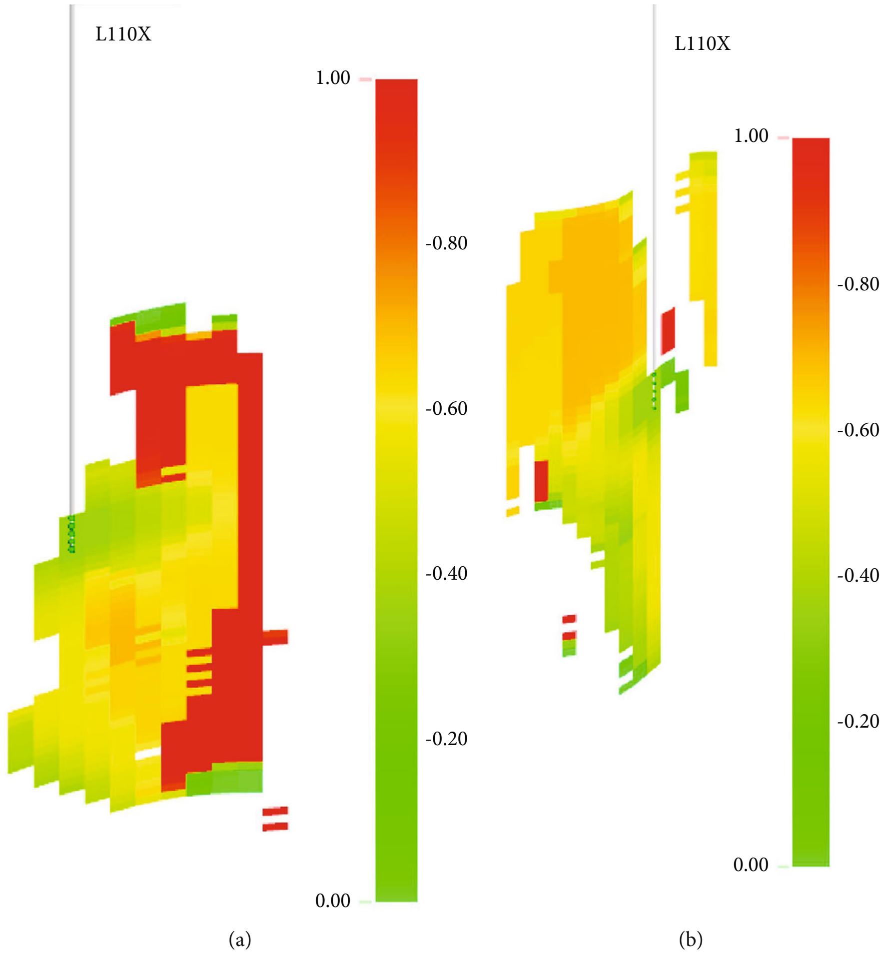


Figure 9: Residual oil distribution characteristics in the L110X well.

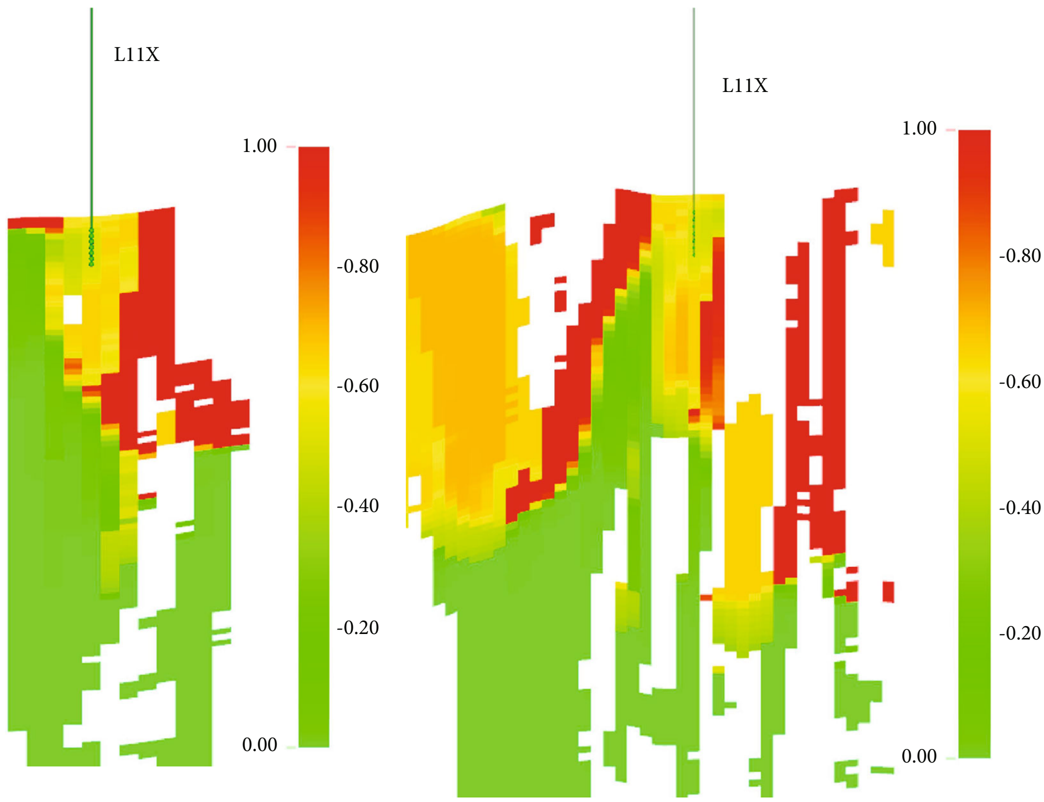
residual oil distribution and main control factor analysis methods, and provide a research base for the formulation of countermeasures to improve the development effect [23].

3.1. Residual Oil Distribution Characteristics of the L11 Unit. The L11 unit has abundant residual oil reserves and great potential for subsequent adjustment and development. The residual oil distribution at different depths of the L11 unit, from production to May 2021, is shown in Figure 5. In the upper part of the unit, wells L18, L110X, TP157, L19, TP188, L18H, and L13CH formed clear gas caps, and the crude oil corresponding to the upper of the reservoir was produced to a certain extent. However, as the depth of the reservoir increases, the influence of the gas cap weakens rapidly. Moreover, it was observed disappearance of the gas cap influence at $k = 5$. With increasing depth, the high-angle fractures communicate with the bottom water, leading to bottom water coning in the wells L11X, L11, and L18X ($k = 7\sim10$). At $k = 15$, clear bottom water cones appeared in wells L11 and L14. In the process, a mixed distribution of oil and water was formed, leading to dispersing and distribution of the residual oil. In the interval $k = 20$-30, the wells L1X, L12X, L16CH, L18H, and L13CH showed obvious bottom water coning. Since then, as the depth increases, the degree of water flooding of the production well became increasingly severe until it was completely flooded ($k = 80$).

Fractures in fault-solution fracture-cavity reservoirs are the main channel for oil and gas flow and the main path of bottom water coning. The bottom water channeling along high-angle fractures is the main reason for the decline in the L11 unit production, while bottom water coning and gas/water injection development are the key factors affecting the residual oil distribution in the L11 unit. In addition, the irregular development of fractures and caves represents the main factors that cause the diversified residual oil distribution patterns. To assess the main controlling factors of residual oil in the L11 unit, the residual oil distribution pattern of each production well was analyzed and classified [24].

3.2. Residual Oil Distribution Pattern and the Main Controlling Factors

3.2.1. Residual Oil Distribution Pattern. According to the distribution location and formation mechanism, the residual oil distribution pattern of the L11 unit includes 4 types (Figures 6 and 7). There are two types of residual oil at the well points, namely, loft-type and bottom water rising blocking type (including bottom water cone ingress blocking and



(a) (b)

Figure 10: Residual oil distribution characteristics of the L11X well.

bottom water intrusion blocking types). In addition, two types of residual oil between wells are distinguished, namely, separated fracture-cavity type (including oil-separation and near-fracture cave types) and pore/slit type near high diversion channels [25].

(1) Loft-Type. Loft-type residual oil refers to the residual oil that cannot be directly produced from the fractured-vuggy reservoir above the top of the production interval of the oil well. In the production well, above the oil-water interface of the fractured-vuggy in the production interval, with the production of crude oil, the oil-water interface in the lower part of the reservoir continues to rise [26]. As the oil-water interface rises to the production interval, flooding occurs in the production interval of the oil well, resulting in the presence of attic-type residual oil in the upper fissures that were difficult to recover, as revealed in L18CX, L14, and L13CH wells. As shown in Figure 8, well L18CX is a side-drilling well of well L18, designed to develop cavern reservoirs shielded by the bottom water channel. The well was successfully sidetracked to the upper edge of the cavernous reservoir, showing a good production rate. At present, the residual oil is mainly karst cave residual oil. Indeed, fractures were developed near the well; thus, restraining and delaying the penetration of bottom water along the fractures is the key to ensuring stable production of the well [27].

(2) Bottom Water Rising and Blocking Type. Bottom water rising and blocking residual oil refers to the residual oil that cannot be directly produced around the flooded oil well due to bottom water rising, blocking the residual oil [28]. The formation of two types of residual oil with bottom water rising and blocking type is summarized:

(1) The bottom water cone enters the residual oil of the sealing type. In reservoirs with pores and fractures, the bottom water rises in a cone-shaped distribution at the bottom of the well, and crude oil around the well cannot be produced, forming a water cone that blocks the residual oil, as revealed in well L110X.

As shown in Figure 9, well L110X is located in the north-central part of the L11 unit. The area where this well is located is controlled with caves and fractures. During the development process, the bottom water coning causes a decline in production, resulting in the dispersion of the residual oil on the upper part of the cave [29, 30].

(2) The bottom water flees into the residual oil of the blocking type. There are cracks near the bottom of the well that communicates with the deep bottom water. During the production process, the deep water quickly penetrates the bottom of the well along the cracks, with a pressure difference, causing flooding of the oil well. Because the water in the cracks enters linearly, after the oil well is flooded, wells mainly produce water, with the presence of significant residual oil amount blocked by the bottom

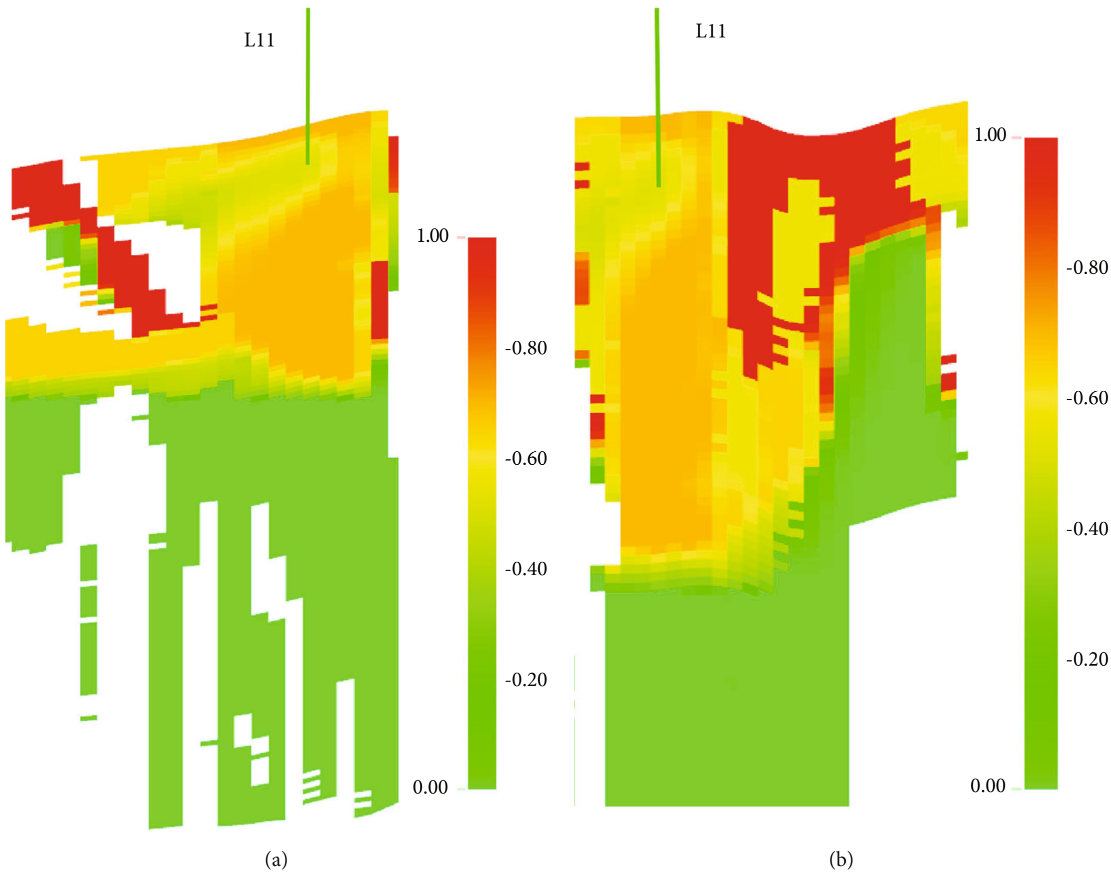


Figure 11: Distribution characteristics of residual oil in the L11 well.

water that cannot be directly produced around the oil well, as observed in L11X, L1X, L11, L18X, L12X, L16CH, L19, and L18H wells. The distribution characteristics of this type of residual oil were analyzed, using L11X and L11 wells as examples. As shown in Figure 10, well L11X is located in the northern part of the L11 unit. The area where the well is located is characterized by the presence of fractures and karst caves. Indeed, the well connects the karst cave reservoirs through the fractures. During the production process, the bottom water penetrates along the fractures, causing partial water flooding in the production well section and protecting the crude oil in the karst caves, resulting in dispersed and lumpy residual oils.

As shown in Figure 11, well L11 is located in the west of the unit, where karst caves and abundant crude oil reserves were developed. The well is connected to the top of the cave, and the cracks between the cave and the bottom water body are developed. Before 2017, L11 was the main production well in the block. During the production process, the bottom water flowed into the wellbore through high-angle fractures, shielding the crude oil in the middle and lower parts of the caves, thus resulting in a substantially lower output. Indeed, the residual oil is mainly shielded block-shaped residual oil.

(3) Hole Type Near High Diversion Channel. The residual oil of pores and fractures near the high conductivity channel refers to the residual oil in low-developed pores and fractures near the water channel along the fault. The large-scale fractures are high-conductivity channels allowing the bottom water to flow into carbonate fracture-cavity reservoirs. In fact, these parts are easily flooded by water. Porous and fractured reservoirs, which are associated with high-conductivity channels and have a low degree of development, are located on nonflowing channels, resulting in a high retention rate of residual oil. As illustrated in Figure 12, there are clear channels between L18 and L110X wells.

(4) Separated Fracture-Cavity Type. Separated fracture-vuggy residual oil refers to the residual oil in the fracture-vuggy assembly that is not directly connected to the strong water-flooded fracture-vuggy in the transverse direction. Fracture-cavity bodies in carbonate fracture-vuggy reservoirs are mostly geometrically complexes. Inside the fracture-cavity, there are connected channels with different degrees of connectivity. Indeed, this fracture-cavity is the main storage space of crude oil and may have a certain degree of separation in the horizontal direction. According to the type of fracture-cavity separation, it can be divided into separated and near-fracture-cavity residual oils.

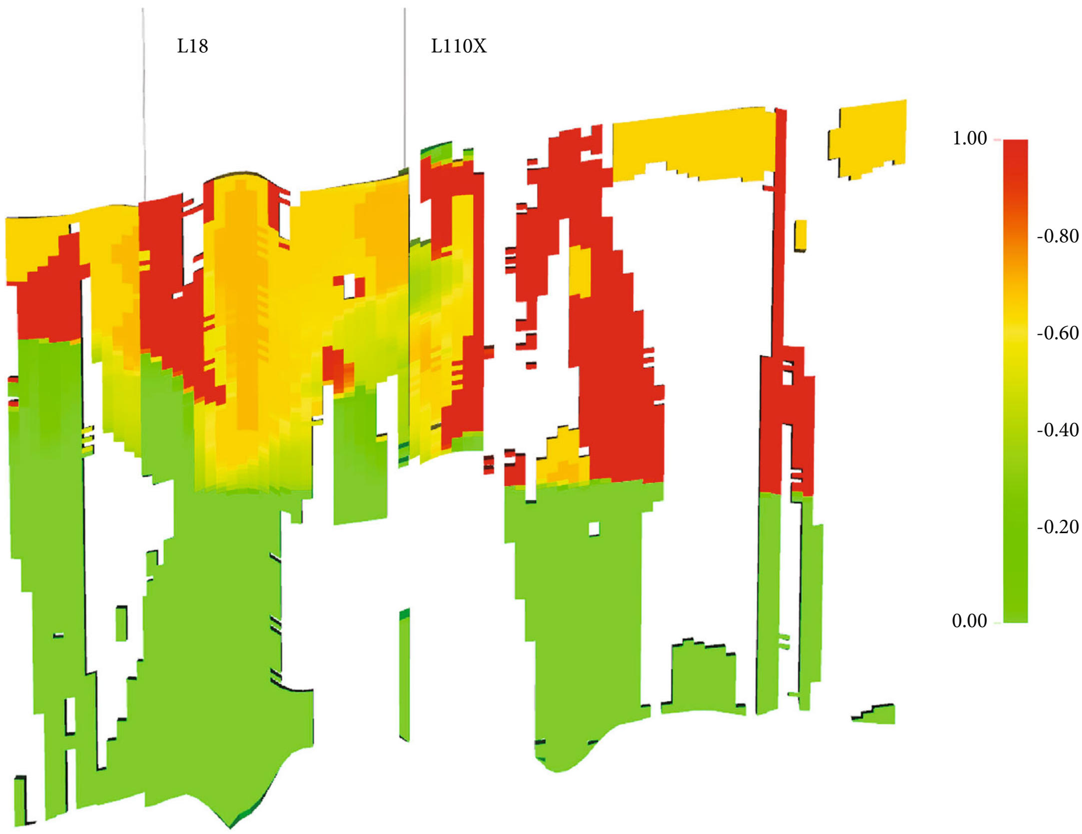


Figure 12: Distribution characteristics of residual oil in the L110X well.

The separated residual oil refers to the fractured "U"-shaped cave, where one side is exploited with high water flooding, and the other side is not well controlled. Because each fractured-vuggy is laterally separated by nonpermeable matrix rock blocks or low-developed reservoirs, the deep reservoirs are connected, forming a separate "U"-shaped connected fractured-vuggy. In this type of fractured caverns, when drilling on one side of the "U"-shaped fractured-vuggy is put into production, the oil-water interface may gradually rise and flood along with the production, while the other side of the fractured "U"-shaped fractured-vuggy cannot be flooded. The oil-water interface in the well-controlled fracture-cavity may remain at the overflow point, where the two fracture cavities are connected; thus, the upper crude oil cannot be produced, forming a separated fracture-type residual oil. Indeed, L10X and L11X wells present some evidence of the separated residual, as shown in Figure 13.

The near fractured-vuggy type refers to the residual oil in uncontrolled and low-connected fractures and caves. Each fractured-vuggy is laterally separated by nonpermeable matrix rock blocks or connected by small fractures or pore-type reservoirs; thus, the degree of connectivity is considered relatively low and fluids cannot directly flow through, forming a near-fracture-type separated fractured-vuggy. In this type of separated fracture-cavity, the fluid cannot flow directly after producing the crude oil in one fracture cavity. The other fracture-cavity cannot be produced by conventional methods, and the separated fracture-cavity type residual oil is formed, as illustrated in Figure 14 between wells L11 and L12X and between wells L12X and L16CH.

3.2.2. Main Controlling Factors of Residual Oil. A numerical simulation was performed on the L11 unit. According to the analysis of static and residual oil simulation results, the distribution of residual oil in the reservoir is related to the development degree of the reservoir, the position of the structure, the positional relationship between the fracture and the reservoir, and the oil well-operating conditions. The connectivity between karst caves and reservoirs is poor, and the fractures communicate with the water body, causing a rapid tapering of the bottom water into the well section, thus shielding the cave area by the upper part of the oil well and the bottom water to enrich the residual oil [29]. The main controlling factors of the residual oil are summarized as follows:

(1) Vertical Reservoir Connectivity. L11 fractured-vuggy reservoirs have vertical fractures of different sizes. The development of fractures may improve the permeability of the reservoir near the well. In addition, the fractures that communicate with the bottom water are crucial for the coning of the bottom water. During the production process, the cracks that have good communication with the bottom water are opened, forming a water cone and advantageous water channels between the production section of the oil well and the bottom water. For reservoirs with good vertical

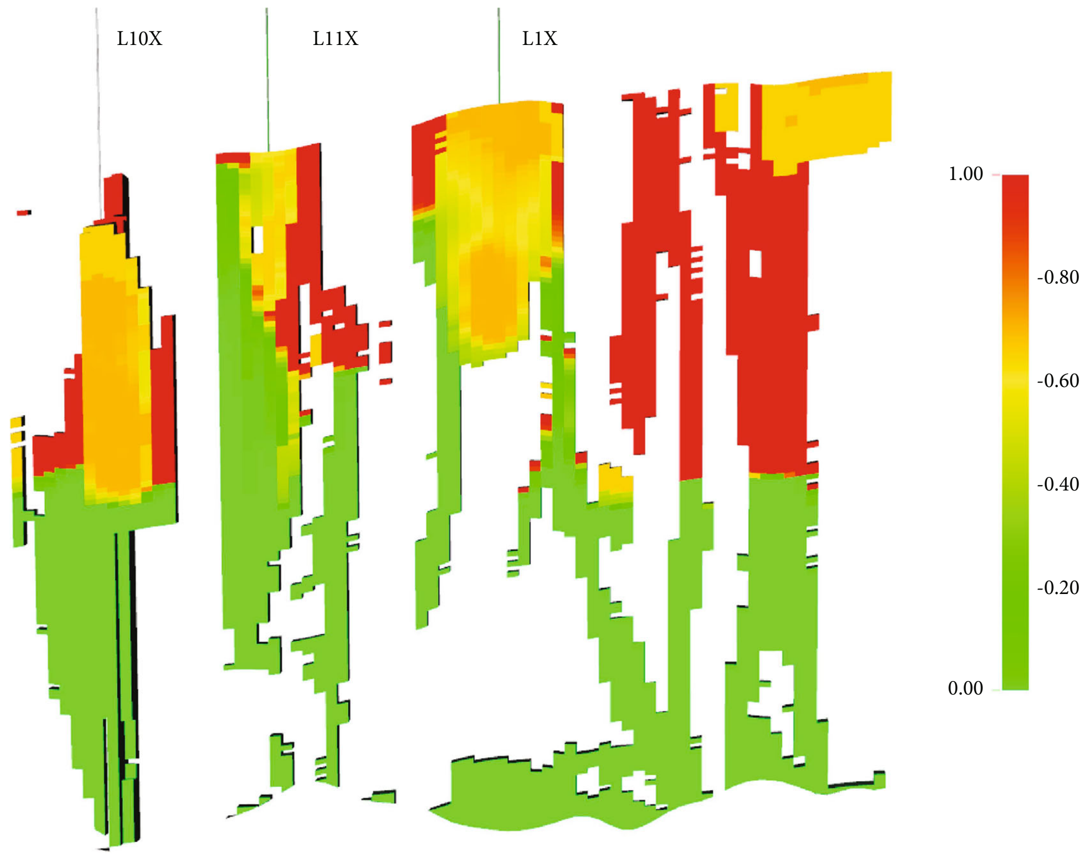


Figure 13: Residual oil distribution between L10X and L11X wells.

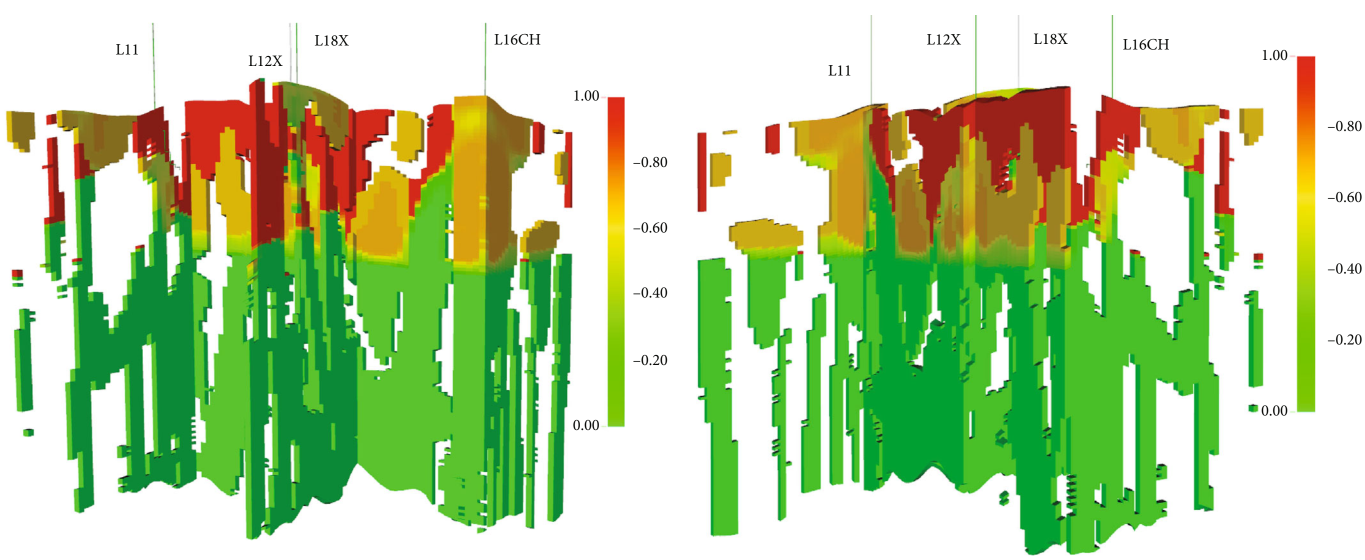


Figure 14: Residual oil distribution between L11, L12X, and L16CH wells.

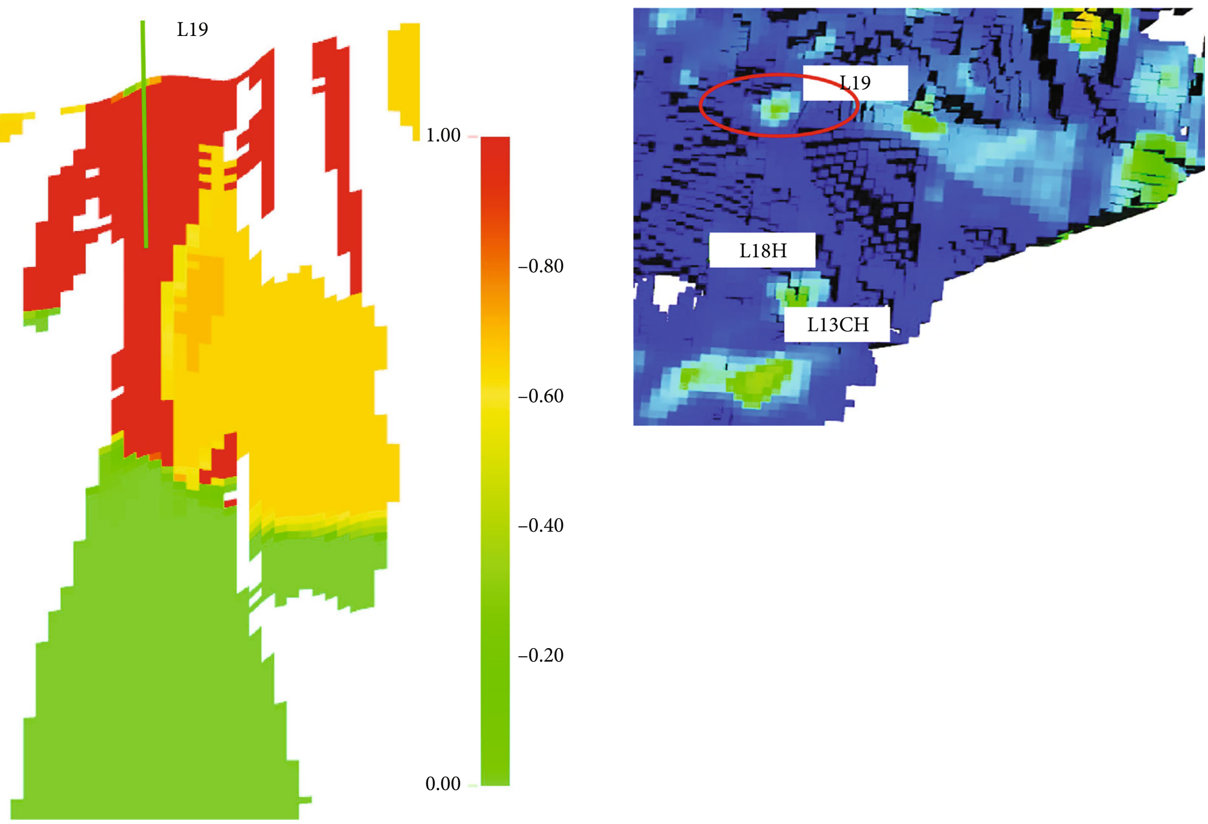


Figure 15: Residual oil near the L19 well.

connectivity, the development of fractures becomes the main influencing factor controlling the distribution of residual oil. Indeed, the residual oil is mainly distributed in dissolved caves that are not connected to the fractures or shielded caves by bottom water channeling.

(2) Single Well Working System. Fractured-vuggy reservoirs can form dispersed residual oil following injection of bottom water, artificial water, or gas due to the heterogeneity of the reservoir. This type of residual oil is characterized by a large dispersion range and low oil saturation, making development difficult.

4. Countermeasures and Schemes for Enhancing Oil Recovery

In the middle and late stages of the development of fracture-cavity reservoirs in fault solution, as the water cut increases, the development effect may gradually deteriorate, and the oil-water relationship becomes more complicated. To improve the development effect, it is necessary to formulate countermeasures to tap the potential of the residual oil between the control well and the well according to the residual oil distribution pattern. In general, the potential of various types of residual oil in uncontrolled fractured caverns between wells and large well spacing can be exploited by deploying new wells or using sidetracking in old wells. Conventional measures are mainly used to exploit the potential of remaining oil distribution at wells, taking into account the distribution characteristics of the residual oil. These measures can be summarized as follows:

4.1. Deploying New Wells or Using Sidetracking in Old Wells Allowing for Effective Control of the Residual Oil of the Loft-Type and the Separated Fracture-Cavity Type with a Large Well Spacing. Well L19 is located in the central and southern parts of the L11 unit. The well-controlled area is characterized by fractures, connecting the cave reservoir and the bottom water body. During the production process, the bottom water channeled through the fractures, causing rapid flooding in the production well section and distribution of the residual oil in the bottom water channeling (Figure 15).

The sidetracking development of this well was carried out inside the shielded cave, and the new sidetracking well was produced with a fixed rate of 60 m^3/day. The results of the 3-year production simulation, as well as comparison and analysis of the effect of increasing production of the measured wells, are reported in Figure 16.

After the sidetracking of the well L19, the upward trend of bottom water was better delayed, while the possibility of shielding the residual oil from the bottom water was improved. When the new well allocates 60 m^3/day, the oil production rate can be stabilized above 40 m^3/day, corresponding to a cumulative oil of 26480 m^3 for 1.5 years (validity period). During the production process, a bottom water ridge gradually occurred at the heel of the sidetracked horizontal well, leading to a significant decrease in the oil production rate. Therefore, when developing sidetracking in

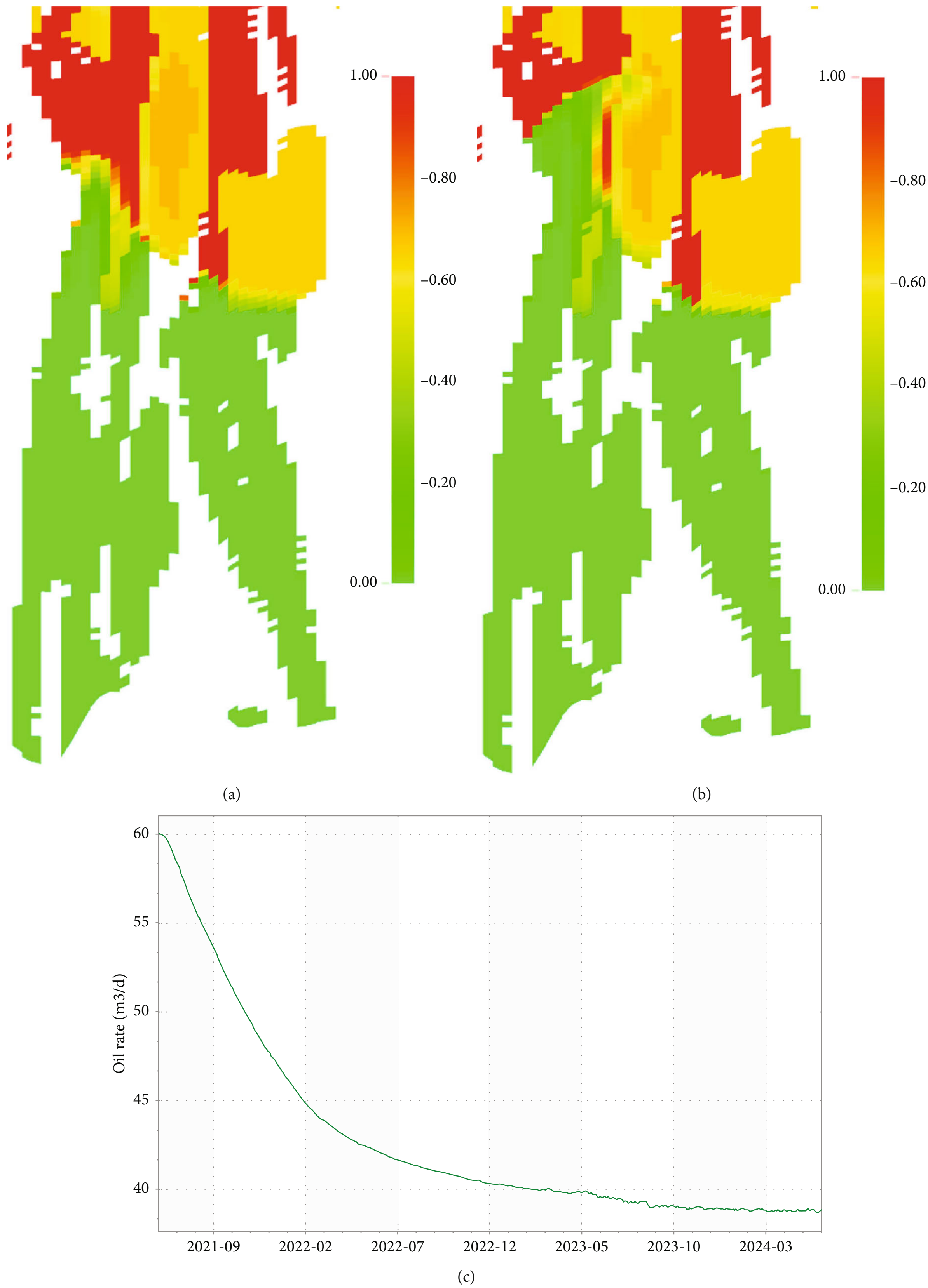


FIGURE 16: Sidetracking effect on the residual oil near the L19 well.

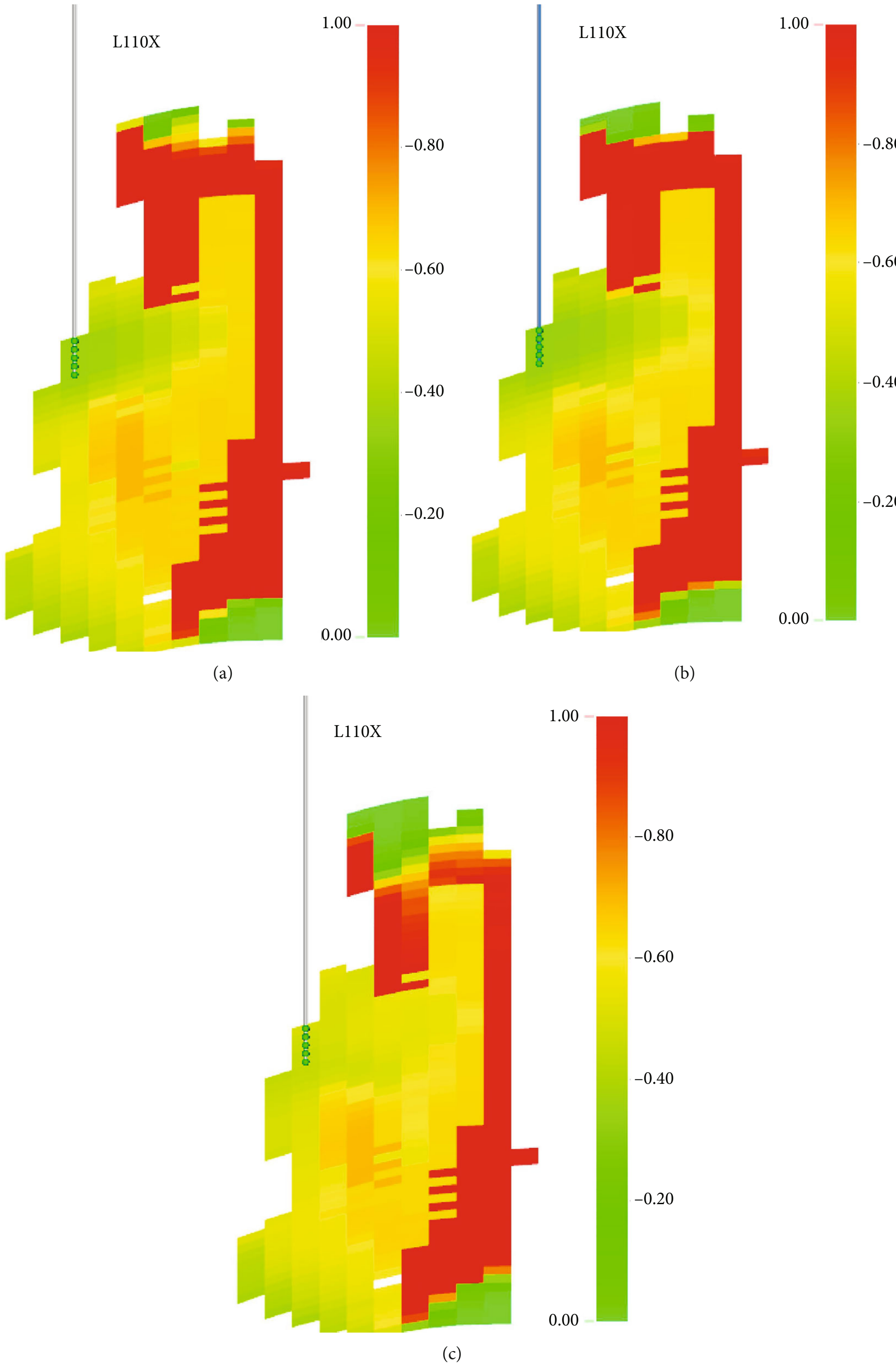


FIGURE 17: Influence of gas injection development on oil-water distribution characteristics of the L110X well.

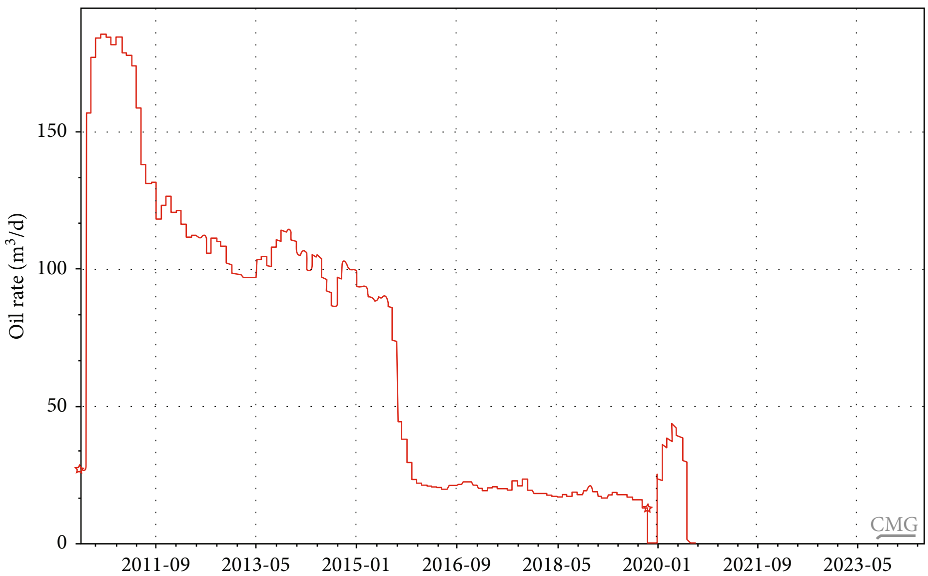


Figure 18: L110X well gas injection development increasing effect.

the fracture-developed area, it is recommended to compound corresponding plugging measures to extend the high and stable production period of sidetracking.

4.2. Exploiting of Attic Residual Oil Using Drainage Oil Extraction and Gas Injection. For the attic-type residual oil formed in the upper part of the generation interval, where the oil-water interface rises at the late stage of production in nonconstant volume fractures, conventional drainage cannot lower the oil-water interface, but it can be exploited by gas injection in oil. In addition, by injecting nitrogen into the suffocating well, the nitrogen may rise to the top of the attic under the action of gravity and accumulate to fill the attic space, causing a decrease in the gas-oil and oil-water interfaces. In addition, the well may become open when the oil-water interface sinks to the bottom of the production well, resulting in continuous crude oil production (Figure 17).

The well-controlled area of the L110X well consists of controlled caves and fractures. During the development process, the bottom water coning caused a decline in production, thus resulting in dispersion of the residual oil on the top of the cave. The well was developed by gas injection to produce the crude oil from the top of the cave. In addition, the oil-water interface was adjusted by the gas injection process, and the bottom water was used to shield the residual oil. From August 2020 to April 2021, several rounds of gas injection with water and drilling were carried out. The numerical simulation results showed that the gas injection and water rates were 42000 and 40 m^3/day, respectively, in June 2021. After the well was simmered in January, the liquid production rate was fixed at 80 m^3/day. After multiple rounds of gas injection with water in the well L110X, a clear gas cap was forme shows the temporal evolution of the residual oil production.

After multiple rounds of gas injection with water in the well L110X, a clear gas cap was formed, as shown in Figure 18. After the well is braised, the oil-water interface was redistributed and the bottom water cone was effectively removed. After the well is opened for production, the effect of increasing production is obvious. The oil production rate can reach 40 m^3/d, and the oil production rate before the measures is 20 m^3/d. After the well is opened for production within 2 months, the increase in production can reach more than 1000 t.

4.3. Use of Pumps to Lift Liquid, Jam Water, Pressure Cone, Unit Water Injection Drive, and Other Measures to Tap the Bottom Water to Rise and Block the Residual Oil. Due to the differences in the mechanism of bottom water rise and the distribution of residual oil, there are various methods for tapping the potential of bottom water ascending and blocking residual oil. For the residual oil of the cone-in-blocking type, the conventional shut-in cone pressure or deep water plugging measures are mainly used to collapse the water cone and restore the production capacity of the oil well. The conventional water plugging method is not effective for bottom water penetration and residual oil blocking due to the linear characteristics of bottom water rise and the similar oil and water paths. By considering foam and other selective water plugging agents or using connected adjacent wells, water injection can laterally drive residual oil near the oil well and be blocked as a result of the good effect of the bottom water.

In the design of the numerical simulation scheme, the conductivity between the grids at the bottom of the production well was modified to simulate the injection of gel in actual production to establish an artificial partition to delay the rise of the bottom water, increase the extent of the bottom water, and reduce the residual oil distribution. On the other hand, in the L11 unit model, an artificial partition was established for the high water cut production in well L15X (the partition was 6 m from the bottom of the well, while the diameter of the partition was 60 m); then, the

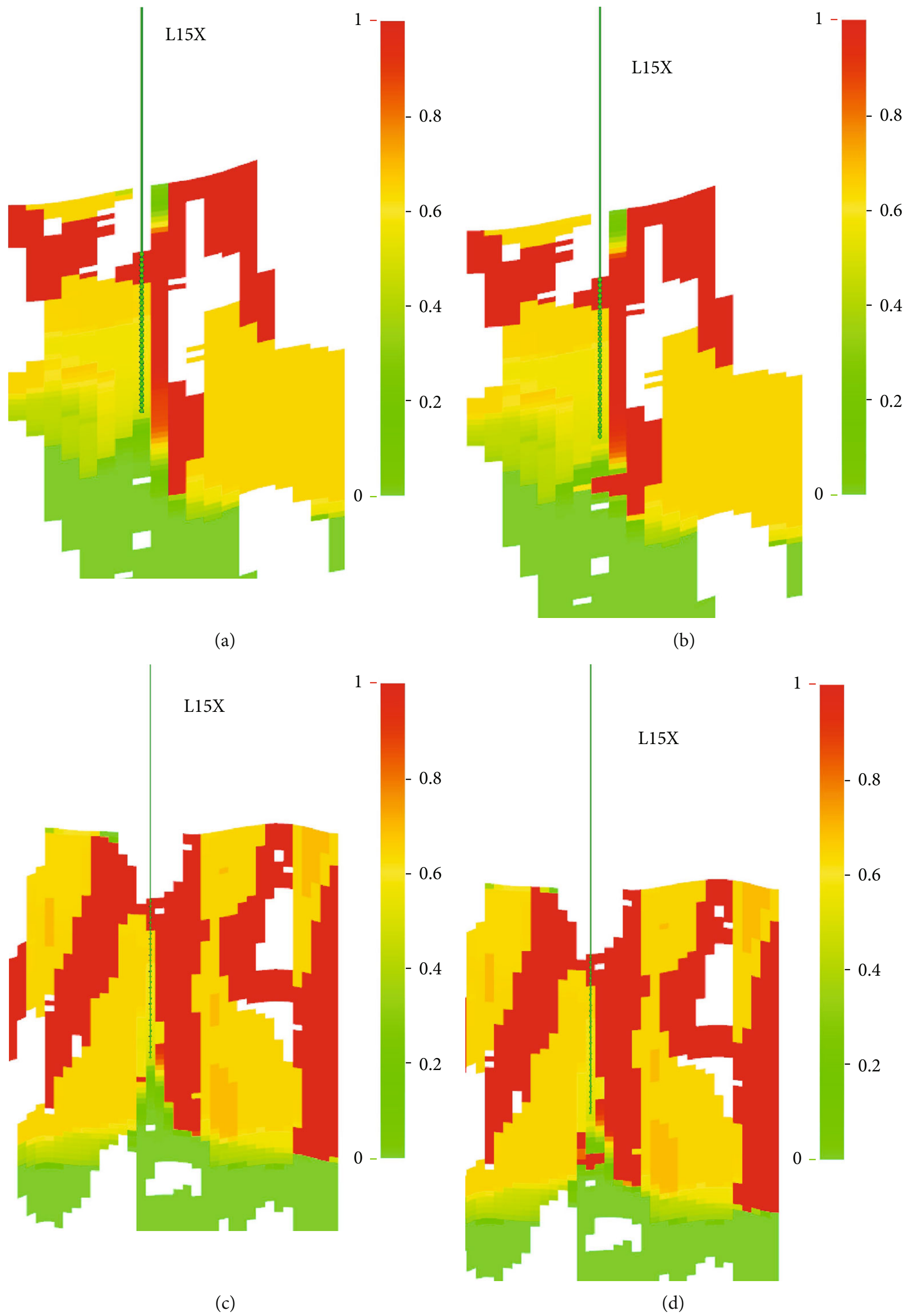


Figure 19: The influence of bottom hole artificial baffle on residual oil distribution.

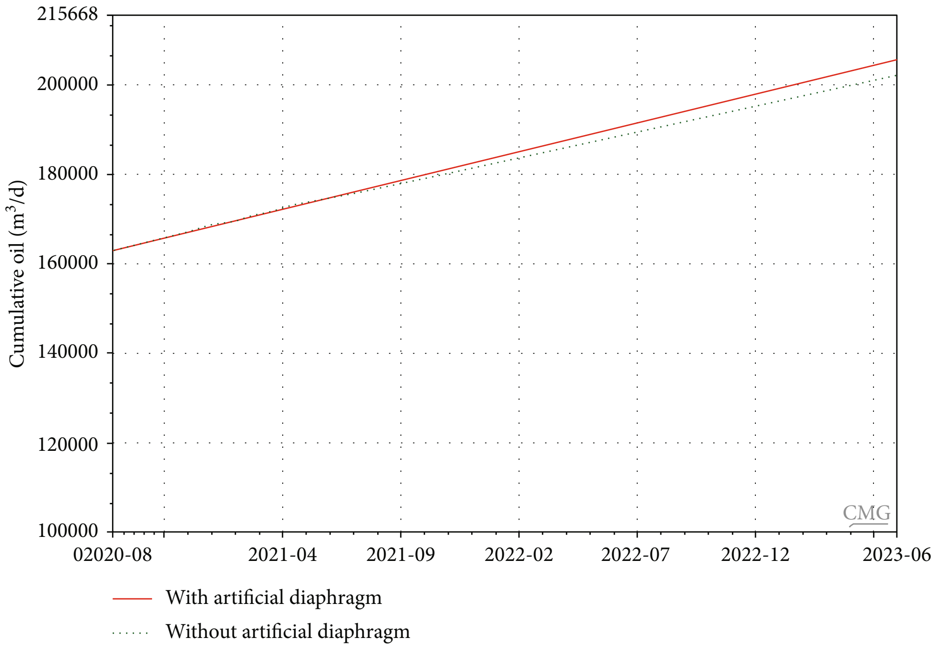


Figure 20: Effect of artificial diaphragm on increasing production in the well L15X.

production was started at a constant liquid production rate. The liquid production rate was determined based on the average liquid production rate of the well during 1 year ($50\,m^3/d$). Figure 19 shows the simulation results of 2 years of production before and after the implementation of the measures.

After adding the artificial partition, the rising trend of the bottom water of the L15X well was more delayed, and the extent of the bottom water's impact on the residual oil in the near-well reservoir was increased (Figure 20). At a production rate of $50\,m^3$/day, the rate of oil production after the measures was increased by $5\,m^3$/day compared to that of no measures, corresponding to a cumulative oil amount of $1696\,m^3$/year. Therefore, an artificial bottom hole barrier can be an effective measure to remove bottom water coning and improve the residual oil production degree.

5. Conclusions

(1) Fractures are the main channel for oil and gas flow in fault-solution reservoirs, as well as the main path of bottom water coning. The channeling of bottom water along high-angle fractures is the main reason for the decline in the oil production of typical units. Bottom water coning and gas/water injection development are the key factors affecting the distribution of residual oil. In addition, the irregular development of fractures and caves are the main factors causing the diverse distribution patterns of residual oil

(2) The residual oil distribution patterns of fault-solution reservoirs include 4 types of residual oil, namely, attic and bottom water upblocking types at well point (including bottom water cone-inlet blocking and bottom-water channeling blocking types) and separated fracture-cavity (including oil-separating and near-fracture-cavity types), and pore-fracture types near the high conductivity channel between wells

(3) According to the residual oil distribution pattern, approaches to exploiting the potential residual oil were formulated. By deploying new wells or using sidetracking of old wells, it is possible to effectively control the residual oil of the loft and fracture-cavity separated oil types with a large well spacing. Drainage oil extraction or gas injection can be used to replace and exploit the potential attic residual oil. In addition, a liquid lift pump, jam water, press cones, and other measures can be used to tap the bottom water to rise and block the residual oil. By optimizing oil and water well-plugging measures, adjusting the injection and production structure, changing the direction of liquid flow, and tapping the potential residual oil in the pores and cracks beside the high diversion channel, residual oil can be further exploited

Data Availability

Data used in this study will be available upon reasonable request.

Conflicts of Interest

The authors declare that they have no conflicts of interest.

Acknowledgments

This research was funded by the National Science and Technology Major Project of China (2016ZX05053) and the

Science and Technology Department Project of Sinopec-China Petroleum (P11089).

References

[1] F. Tian, Q. Jin, X. B. Lu et al., "Multi-layered Ordovician paleokarst reservoir detection and spatial delineation: a case study in the Tahe Oilfield, Tarim Basin, Western China," *Marine and Petroleum Geology*, vol. 69, pp. 53–73, 2016.

[2] X. M. Zhou and M. H. Shahzad Kamal, "Experimental study on the relationship between carbonate reservoir quality index and dynamic parameters of chemical solutions for oil recovery practice," *Energy & Fuels*, vol. 33, no. 10, pp. 9747–9758, 2019.

[3] E. Artun, T. Ertekin, R. Watson, and B. Miller, "Performance evaluation of cyclic pressure pulsing in a depleted, naturally fractured reservoir with stripper-well production," *Liquid Fuels Technology*, vol. 29, no. 9, pp. 953–965, 2011.

[4] C. F. Guo, H. B. Li, Y. Tao, L. Y. Lang, and Z. X. Niu, "Water invasion and remaining gas distribution in carbonate gas reservoirs using core displacement and NMR," *Journal of Central South University*, vol. 27, no. 2, pp. 531–541, 2020.

[5] A. Goudarzi, M. Delshad, K. K. Mohanty, and K. Sepehrnoori, "Surfactant oil recovery in fractured carbonates: experiments and modeling of different matrix dimensions," *Journal of Petroleum Science & Engineering*, vol. 125, pp. 136–145, 2015.

[6] Y. Li, D. P. Wan, and J. M. Liu, "Remaining oil enrichment areas in continental waterflooding reservoirs," *Petroleum Exploration and Development*, vol. 32, no. 3, pp. 91–96, 2005.

[7] J. Wang, H. Q. Liu, J. Xu, and H. F. Zhang, "Formation mechanism and distribution law of remaining oil in fracture-cavity reservoir," *Petroleum Exploration and Development*, vol. 39, no. 5, pp. 624–629, 2012.

[8] Y. S. Rong, J. Z. Zhao, X. B. Lu, X. H. Li, and X. B. Li, "Remaining oil distribution patterns and potential-tapping countermeasures in carbonate fracture-cavity reservoir," *Acta Petrolei Sinica*, vol. 35, no. 6, pp. 1138–1146, 2014.

[9] A. Ameri, R. Farajzadeh, V. S. Suicmez, M. Verlaan, and J. Bruining, "Effect of non-equilibrium gas injection on the performance of (immiscible and miscible) gas–oil gravity drainage in naturally fractured reservoirs," *Energy & Fuels*, vol. 27, no. 10, pp. 6055–6067, 2013.

[10] S. Q. Zheng, M. Yang, Z. J. Kang et al., "Controlling factors of remaining oil distribution after water flooding and enhanced oil recovery methods for fracture-cavity carbonate reservoirs in Tahe Oilfield," *Petroleum Exploration and Development*, vol. 46, no. 4, pp. 786–795, 2019.

[11] T. Bochao, C. Geng, M. Huang, H. Lu, and K. Ren, "Research on the Depletion and Recovery Characteristics of Fault-Karst Reservoirs," *Geofluids*, Article ID 1105335, 12 pages, 2022.

[12] S. Q. Li, Y. T. Liu, X. Liang, Y. Li, Z. W. Yuan, and C. S. Jian, "An investigation on water flooding performance and pattern of porous carbonate reservoirs with bottom water," *Journal of Petroleum Science & Engineering*, vol. 200, article 108353, 2021.

[13] K. D. Pennell, G. A. Pope, and L. M. Abriola, "Influence of viscous and buoyancy forces on the mobilization of residual tetrachloroethylene during surfactant flushing," *Environmental Science and Technology*, vol. 30, no. 4, pp. 1328–1335, 1996.

[14] K. Qian, S. L. Yang, H. E. Dou, Q. Wang, L. Wang, and Y. Huang, "Experimental investigation on microscopic residual oil distribution during CO_2 huff-and-puff process in tight oil reservoirs," *Energies*, vol. 11, no. 10, p. 2843, 2018.

[15] S. Ayatolahi, F. H. Boukadi, A. S. Al-Bemani, R. S. Al-Maamari, and M. A. Al-Wadhahi, "Investigation of thermal gas-oil gravity drainage (GOGD) in fractured carbonate reservoirs," in *SPE Middle East Oil and Gas Show and Conference*, Kingdom of Bahrain, 2005.

[16] D. Y. Yuan, J. R. Hou, Z. J. Song, Y. Wang, M. Luo, and Z. Y. Zheng, "Residual oil distribution characteristic of fractured-cavity carbonate reservoir after water flooding and enhanced oil recovery by N_2 flooding of fractured-cavity carbonate reservoir," *Journal of Petroleum Science and Engineering*, vol. 129, pp. 15–22, 2015.

[17] G. J. Wang, J. C. Zhang, S. Kou, and Q. Zhang, "Models for residual oil distribution of carbonate reservoir in Yanling Oilfield," *Journal of the University of Petroleum, China*, vol. 23, no. 4, pp. 26–28, 1999.

[18] P. H. Nelson, "Pore-throat sizes in sandstones, tight sandstones, and shales," *AAPG Bulletin*, vol. 93, no. 3, pp. 329–340, 2009.

[19] J. Wang, H. Q. Liu, J. Zhang et al., "Experimental investigation on water flooding and continued EOR techniques in buried-hill metamorphic fractured reservoirs," *Journal of Petroleum Science and Engineering*, vol. 171, no. 12, pp. 529–541, 2018.

[20] L. Yang, "The theory and method for development of carbonate fractured-cavity reservoirs in Tahe Oilfield," *Acta Petrolei Sinica*, vol. 34, no. 1, pp. 115–121, 2013.

[21] L. Yang, Z. J. Kang, Z. J. Xue, and S. Q. Zheng, "Theories and practices of carbonate reservoirs development in China," *Petroleum Exploration and Development*, vol. 45, no. 4, pp. 712–722, 2018.

[22] Z. C. Liu, "Analyses of the remained oil and EOR methods for Tahe paleokarst reservoirs," *Petroleum Geology & Oilfield Development in Daqing*, vol. 34, no. 2, pp. 62–68, 2015.

[23] Y. S. Liu, Y. T. Liu, Q. C. Zhang et al., "Large-scale physical simulation experimental study on thick carbonate reservoirs," *Petroleum Geology and Recovery Efficiency (in Chinese)*, vol. 27, no. 4, pp. 117–125, 2020.

[24] Y. F. Yang, S. B. Cai, J. Yao et al., "Pore-scale simulation of remaining oil distribution in 3D porous media affected by wettability and capillarity based on volume of fluid method," *International Journal of Multiphase Flow*, vol. 143, article 103746, 2021.

[25] T. Akai, A. M. Alhammadi, M. J. Blunt, and B. Bijeljic, "Modeling oil recovery in mixed-wet rocks: pore-scale comparison between experiment and simulation," *Transport in Porous Media*, vol. 127, no. 2, pp. 393–414, 2019.

[26] S. W. Mao, Z. D. Bao, X. X. Wang et al., "Origin of carbonate cements and reservoir evolution of tight sandstone in the Upper Triassic Yanchang Formation, Ordos Basin, China," *Australian Journal of Earth Sciences*, vol. 66, no. 8, pp. 1175–1194, 2019.

[27] R. Marathe, M. L. Turner, and A. Fogden, "Pore-scale distribution of crude oil wettability in carbonate rocks," *Energy & Fuels*, vol. 26, no. 10, pp. 6268–6281, 2012.

[28] M. Y. Cai, Y. L. Su, L. Li, Y. M. Hao, and X. G. Gao, “CO_2-fluid-rock interactions and the coupled geomechanical response during CCUS processes in unconventional reservoirs,” *Geofluids*, vol. 2021, Article ID 6671871, 22 pages, 2021.

[29] H. I. Petersen, B. Holland, H. P. Nytoft et al., “Geochemistry of crude oils, seepage oils and source rocks from Belize and Guatemala: indications of carbonate-sourced petroleum systems,” *Journal of Petroleum Geology*, vol. 35, no. 2, pp. 127–163, 2012.

[30] V. Anand, R. Freedman, S. Crary, C. C. C. Minh, and R. L. L. Terry, “Predicting effective permeability to oil in sandstone and carbonate reservoirs from well-logging data,” *SPE Reservoir Evaluation and Engineering*, vol. 14, no. 6, pp. 750–762, 2011.