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Identification of Water-Flooded Layers and Evaluation of Flooded Levels in Fractured Tight Sand Oil Reservoir

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Abstract: Owing to the heterogeneity of tight reservoirs, the development of fractures, and the unreasonable water injection development method, the logging response characteristics of water-flooded layers in fractured tight sandstone reservoirs in the H oilfield in the Junggar Basin are complex, making it difficult to identify and evaluate them quantitatively. This has severely restricted the treatment of water-flooded layers and the optimization of development methods. This study calibrates logging data with dynamic production data and experimental analysis data. Based on clarifying the logging response characteristics of the water-flooded layers, these layers were qualitatively identified through radial resistivity differences and original resistivity recovery methods. By constructing models for the water cut and extraction index, which reflect water flooding characteristics, quantitative evaluations of water flooding levels can be conducted on the basis of consistency principles. Furthermore, the impacts of structural location, sedimentary environment, and fracture development on the water-flooded layers were analyzed. The results suggest that the radial resistivity difference method, along with the original resistivity recovery approach, can effectively identify water-flooded layers. By integrating the water cut, the extraction index, and the radial resistivity difference chart, the influence of reservoir heterogeneity is mitigated, resulting in improved quantitative characterization accuracy and efficiency for water-flooded layers in fractured tight sandstone reservoirs. There are two primary mechanisms for the formation of water-flooded layers in the H oilfield: matrix pore infiltration and differential water drive through fractures. The lower parts of the structure and areas with developed channel sedimentary microfacies are more susceptible to the formation of water-flooded layers, and the remaining oil potential in the matrix pores of the fracture development zone in the northeast of the oilfield is objective.



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Keywords: water-flooded layers; fractured tight sand reservoir; heterogeneity; logging evaluation

1. Introduction

As oil and gas reservoirs advance to the mid-to-late phases of development, the capacity to depend on natural reservoir energy for extraction progressively diminishes. In the 1920s, an innovative enhanced oil recovery technique known as water flooding was introduced [1,2]. This method involves the injection of water into the formation through designated injection wells to maintain reservoir pressure and facilitate efficient oil and gas extraction. Currently, water flooding is employed in more than 85% of China's oilfields [3,4].

Water flooding offers significant advantages in reservoir management, including pressure maintenance, enhanced crude oil production, and improved recovery rates. Nonetheless, this technique also presents challenges, such as substantial initial capital investments, complexities in the formation and management of water-flooded layers, and potential environmental concerns associated with wastewater reinjection. The impact of water-flooded layers, a direct consequence of water flooding, is particularly noteworthy [5,6]. During the water flooding process, various factors, including incomplete reservoir characterization, suboptimal injection-production well patterns, and excessive water injection, can lead to significant damage in low-permeability reservoirs. These challenges result in increased

vertical heterogeneity, higher permeability variation coefficients, greater interlayer discrepancies, and reduced water-driven recovery efficiency, which directly affect the overall development efficacy and economic viability of oilfields [7]. The formation of water-flooded layers alters the petrophysical properties and fluid saturation of the formation, leading to a nonuniform distribution of residual oil [8]. Moreover, these layers are influenced by multiple parameters, including saturation, injected water properties, oil-water distribution relationships, and wettability [9,10], resulting in complex electrical characteristics [11]. Consequently, this complexity poses substantial challenges for well logging identification and quantitative evaluation [12].

Research into the well logging evaluation of water-flooded layers has focused primarily on three principal areas: rock–electric response mechanisms, qualitative identification, and quantitative assessment. For example, Zhang et al. employed theoretical derivation and numerical simulation techniques to analyze the relationship between water-driven oil resistivity and water saturation [13]. Tian et al. investigated the impact of injected water properties on the resistivity–water saturation relationship [14]. Katika et al. (2018) conducted an experimental analysis of the effects of injected water ions on the resistivity and rock structure of water-flooded layers [15]. The qualitative identification of water-flooded layers hinges on a comprehensive understanding of rock–electric response mechanisms, primarily through the analysis of curve shapes and their characteristic features. The established methods include spontaneous potential baseline shift analysis [16], resistivity comparison techniques [17], cross-plot analysis, and curve reconstruction [18]. Moreover, advanced computational approaches using big data, machine learning, and AI algorithms, such as decision trees, BP neural networks, gray correlation analysis [19], and fuzzy comprehensive discrimination [20,21], have been widely adopted in the qualitative identification of water-flooded layers. The quantitative evaluation of water-flooded layers involves the calculation of critical parameters, notably residual oil saturation [22] and water cut [23], to assess the extent of water flooding. An accurate determination of residual oil saturation relies on precise calculation of the mixed resistivity in water-flooded layers [24,25]. In open-hole wells, this can be achieved through water chemistry analysis and apparent formation water resistivity methods [26,27]. In cased-hole wells, techniques such as carbon/oxygen ratio spectral logging [28] and through-casing resistivity logging [29] are commonly employed. The water cut, which directly classifies water flooding levels, can be obtained via relative permeability calculation methods [30] and regional empirical formulas.

While existing research methodologies have demonstrated their efficacy in evaluating water-flooded layers within homogeneous sandstone reservoirs, their applicability to unconventional reservoirs characterized by significant heterogeneity and complex geological environments remains limited. Discrepancies between well logging interpretation results and actual production data persist. The H oilfield [31] in the Junggar Basin, Northwestern China exemplifies these challenges. This fractured tight sandstone reservoir, which has been subjected to water flooding development since the late 1980s, has exhibited pronounced heterogeneity due to the influence of both matrix pores and fracture storage spaces. Consequently, severe water flooding issues have emerged, compounded by an inadequate understanding of water flooding patterns and a lack of effective methods for identifying and quantitatively evaluating water-flooded layers. To address these challenges, this research initiative employs a multifaceted approach. Starting with the reservoir's geological characteristics, the water flooding parameters are calibrated via production data. It then focuses on developing and refining techniques for the qualitative identification and quantitative evaluation of water-flooded layers in fractured tight sandstone reservoirs. Furthermore, research has endeavored to explore water flooding patterns from structural, sedimentary, and fracture development perspectives. This holistic approach aims to provide valuable insights for advancing both research and the application of well logging evaluation methods for water-flooded layers.

2. Geological and Development Overview

The H oilfield is situated at the southern base of the Kelameili Mountains in the eastern Junggar Basin, within Jimsar County, approximately 190 km southwest of Urumqi (Figure 1). The topography of the oilfield is characterized by higher elevations in the northeast and lower in the southwest, with an average elevation of 620 m. The structural form is an asymmetrical anticline oriented north-south, steeper on the eastern side, and more gradual on the western side. It is classified as a structural–lithological reservoir [32] with an oil-bearing area of approximately 35.2 km². The oil-bearing strata are part of the Permian Pingdiquan Formation (P), which is stratigraphically divided from bottom to top into four oil reservoir groups: H1, H2, H3, and H4. These groups are separated by stable dolomitic mudstone layers. The predominant reservoir rock is fine sandstone, accompanied by siltstone, medium sandstone, and occasionally pebbly sandstone [33]. Owing to postdiagenetic effects, pore types change from primarily intergranular pores in H4 to mainly dissolution pores in H1, with the porosity increasing with depth. The focus of this study, the H3 oil group, has an average porosity of 10.52% and a permeability of 0.59 mD.

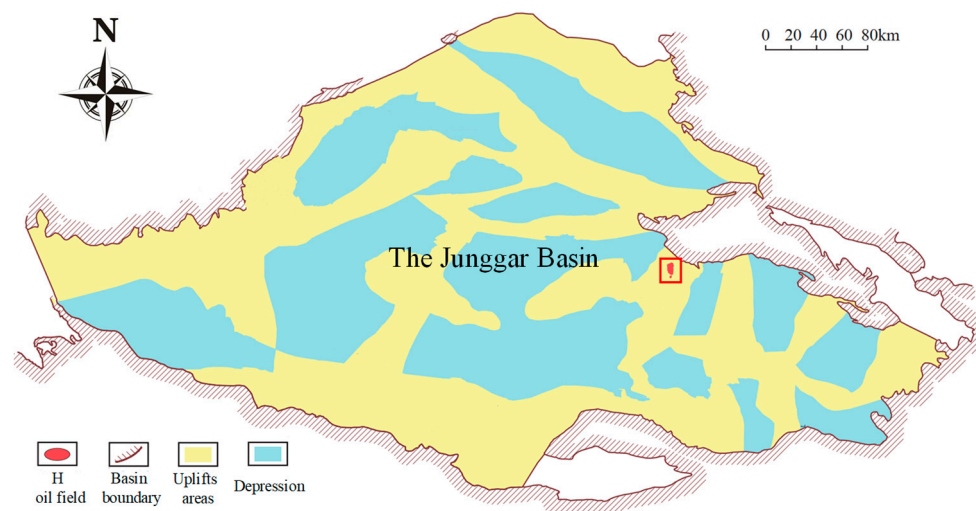


Figure 1. Geographical location H oilfield.

The H oilfield was the first to reach a million-ton level in the eastern Junggar Basin and was also the earliest to undergo development. Since the adoption of water flooding in the 1990s, numerous high-angle tensile fractures have emerged in rigid rock formations due to anticlinal folding, serving as channels for oil and water seepage upon opening [34]. Since the 2000s, injected water has predominantly migrated along these fractures, causing extensive water flooding. Consequently, the comprehensive water cut rapidly rose from less than 10% to 63.4%, which led to a significant decline in production and a continuous deterioration of development conditions [35]. The reservoir is characterized by strong heterogeneity and severe water flooding challenges. Thus, the H oilfield is recognized as a “world-class problematic oilfield” that is difficult to develop and manage.

3. Methodology

This study focuses on the H3 oil reservoir group in the oilfield and collects core observation, mercury injection, oil–water relative permeability, and logging data such as resistivity, natural potential before and after water flooding, and cased-hole formation resistivity. By utilizing dynamic production data and experimental analysis data to calibrate logging data, the logging response characteristics of reservoirs with varying degrees of waterflooding were analyzed, followed by extracting logging parameters sensitive to waterflooding to conduct a qualitative identification of water-flooded layers. In order to reduce the impact of fracture development and reservoir heterogeneity on the quantitative

evaluation of water flooding level solely based on water cut, a comprehensive approach including the water productivity, recovery index, and radial resistivity difference chart are used to determine the waterflooding level. On the basis of qualitative identification and quantitative evaluation of water-flooded layers, the impact of structural location, sedimentary environment, and fracture development on the formation of water-flooded zones is analyzed further (Figure 2).

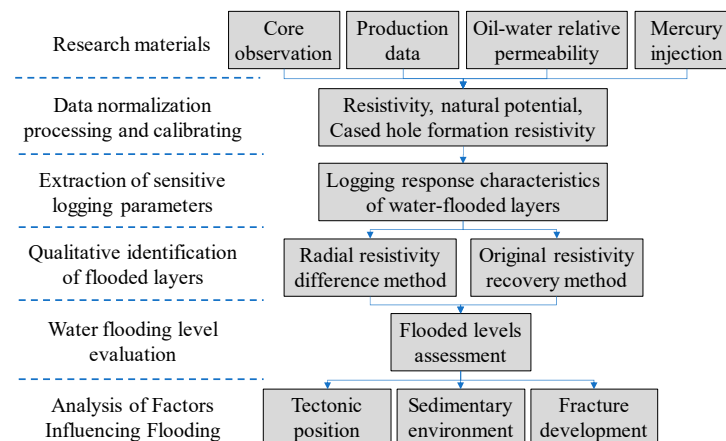


Figure 2. Research flowchart.

Owing to the nearly 40-year development time span of the oilfield, the calibrations of logging instruments in different periods and series are inconsistent, and there are systematic errors between logging curves. Therefore, the 15–21 m mudstone layer between H3 and H4 was selected as the standard layer, and the frequency histogram method was used to standardize the same type of logging data.

4. Results and Discussion

4.1. Logging Response of Flooded Layers

(1) Spontaneous potential

Spontaneous potential (SP) logging is a commonly utilized technique for identifying water-flooded layers. When there is a disparity between the formation pressure and the drilling fluid pressure, filtration occurs within the formation pores. Owing to the ion concentration difference between the formation water and the drilling fluid, an electrochemical process near the borehole wall establishes an electric field [36]. Theoretically, when an oil layer is infiltrated by low-mineralization surface-injected water, the mineralization of the formation water in the flooded area decreases, causing a change in the SP amplitude and a shift in the SP baseline. The observations indicate that the SP curves in most infill wells and adjustment wells within high water cut intervals exhibit flat characteristics. The analysis suggests that the H3 oil reservoir group has poor matrix pore properties and a weak seepage capacity ($K_{ave} = 0.59$ mD). The injected water mainly flows into the wellbore through fractures and cannot generate diffusion-adsorption electromotive forces in the matrix pores [37]. Therefore, the SP response to water-flooded layers in the study area is suboptimal.

(2) Resistivity logging

Fluid resistivity measurements indicate that the drilling mud resistivity in the study area ranges between 1.0 and 3.0 $\Omega \cdot m$, whereas the formation water resistivity is less than 0.5 $\Omega \cdot m$, suggesting an invasion by freshwater mud. According to the nonwater-flooded formation model and induction logging theory (Figure 3a), oil layers should display a pattern of decreased resistance invasion characterized by the following hierarchy: deep induction resistivity (R_t) reflecting the original formation > medium induction resistivity

(R_i) representing the invaded zone > shallow resistivity (R_{xo}) indicative of the flushed zone. Conversely, water layers demonstrate an increased resistivity invasion pattern.

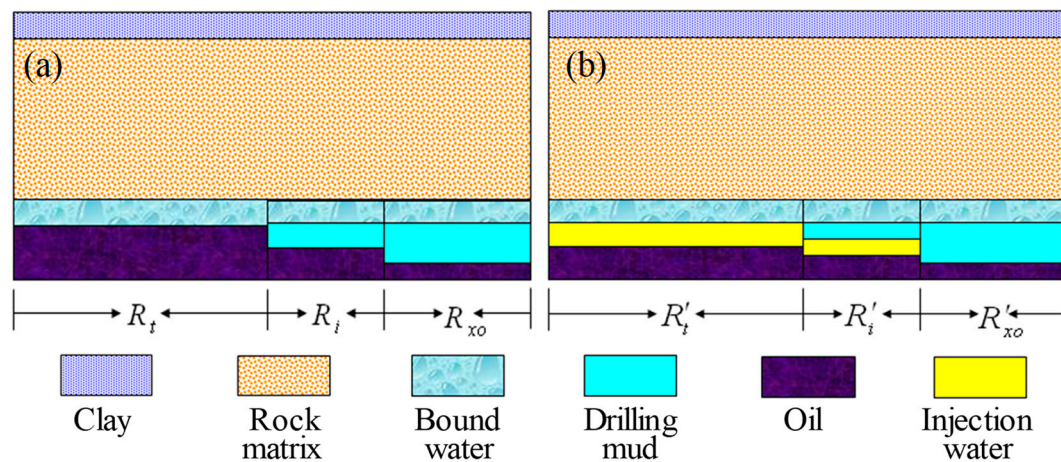


Figure 3. Formation model of the nonwater-flooded layer (a) and water-flooded layer (b).

Water-flooded formations contain large amounts of injected water (Figure 3b). Given that its resistivity is lower than that of the mud, it diminishes the decreased resistance invasion characteristics initially caused by mud invasion in oil layers. The differences between deep, medium, and shallow resistivities diminish and continue to weaken as the volume of injected water entering the reservoir increases (i.e., as the water flooding level increases). On the basis of the analysis of the production data and resistivity response characteristics of the water-flood intervals, when $C_w > C_{in} > C_{mf}$, the oil layers exhibit significant positive amplitude differences in deep, medium, and shallow resistivities. Weakly water-flooded layers display some positive amplitude differences, whereas medium to strongly water-flooded layers show insignificant or even pronounced negative amplitude differences in resistivity. The statistical results of the average radial resistivity differences for intervals with varying water cuts indicate that as the water cut progressively increases, the deep, medium, and shallow resistivities gradually decrease, eventually becoming negative.

(3) Cased-hole formation resistivity logging

During the exploration phase, the resistivity measured after open well drilling represents the original formation resistivity (R_T). Once the development phase begins and casings are installed in the wellbore, conventional resistivity logging can no longer measure the formation resistivity outside the casing. In such situations, cased-hole formation resistivity logging (CHFR) is employed to obtain the actual formation resistivity (R_{CHFR}) [38] during the development phase. By comparing the original formation resistivity with the current resistivity and applying Archie's formula alongside the formation porosity, the initial formation fluid saturation (S_{wo}) and the current formation fluid saturation (S_w) can be calculated. Analyzing the changes in saturation offers a comprehensive reflection of the water flooding status. For instance, in well H2414, within the H3 oil reservoir group, the 1572.5–1574.5 m and 1575–1577 m intervals exhibit a water cut of 68.3%. Compared with R_T , R_{CHFR} has decreased by approximately 80 $\Omega \cdot m$, and the saturation has decreased by approximately 20%. In contrast, for the 1597–1599 m and 1600–1602 m intervals, the water cut is 45.6%, the resistivity decreases by approximately 50 $\Omega \cdot m$, and the saturation decreases by 14%. These results indicate varying degrees of water flooding in the abovementioned intervals (Figure 4).

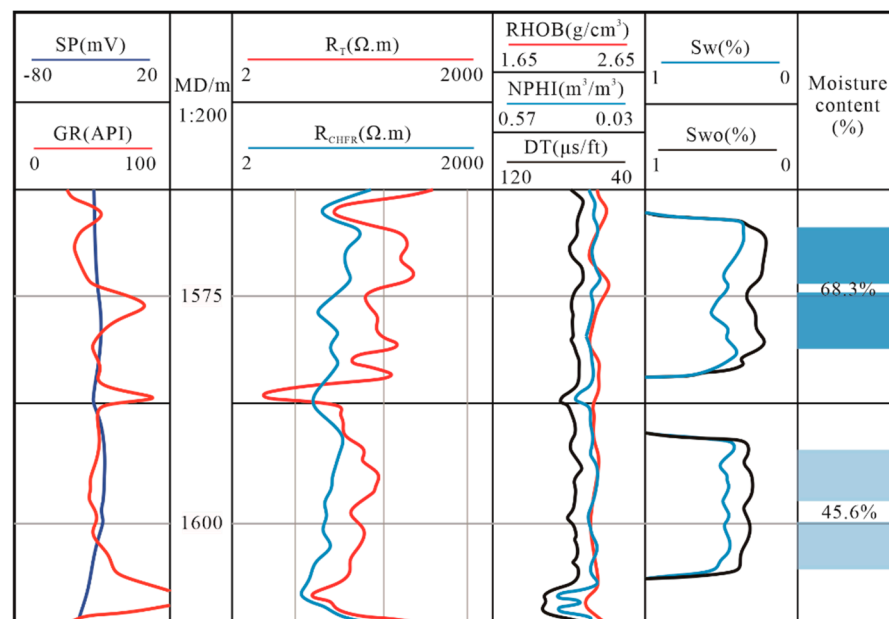


Figure 4. Response of cased-hole formation resistivity logging (Well H2414).

4.2. Qualitative Identification of Flooded Layers

(1) Radial resistivity difference method

The influx of substantial amounts of injected water leads to changes in the radial resistivity of water-flooded layers. The tight sand bodies in the H oilfield exhibit extensive lateral distributions, allowing for the comparison of radial resistivity amplitude differences between wells at the same stratigraphic level to qualitatively identify water-flooded layers. To this end, a cross-plot of R_{ILD} versus $\Delta(R_{ILD}-R_{ILM})$ was developed using production data as a benchmark (Figure 5). The figure shows that the R_{ILD} and $\Delta(R_{ILD}-R_{ILM})$ values of the oil layers are the highest, exceeding $150 \Omega \cdot m$ and $35 \Omega \cdot m$, and as the degree of water flooding intensifies, the deep induction resistivity decreases from over $150 \Omega \cdot m$ to below $70 \Omega \cdot m$, and the difference between the deep and medium induction resistivities decreases from 29 to 13 progressively diminishes (Table 1).

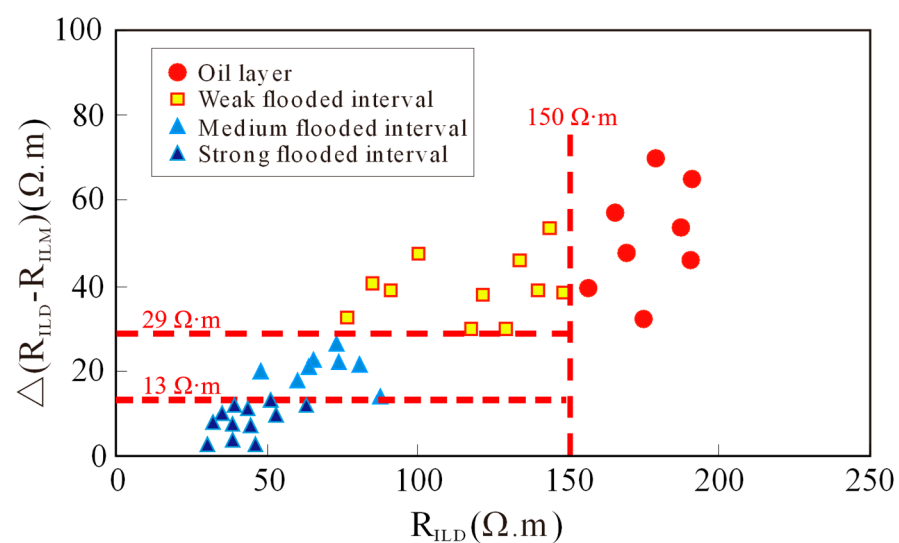


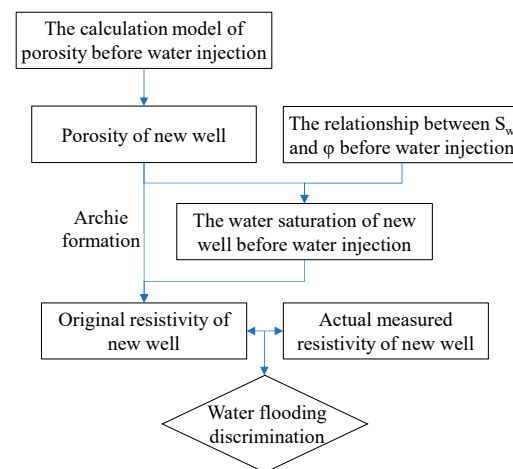
Figure 5. Cross-plot between R_{ILD} and $\Delta(R_{ILD}-R_{ILM})$.

Table 1. Differences in the radial resistivity at different degrees of flooding.

Water Flooding Levels	R_{ILD} ($\Omega \cdot m$)	$R_{ILD}-R_{ILM}$ ($\Omega \cdot m$)
Oil layer	>150	≥ 35
Weak	$75 \sim 150$	≥ 29
Medium	≤ 80	$13 \sim 29$
Severe	≤ 70	≤ 13

(2) Original resistivity recovery method

As oil reservoirs progress into the middle and late stages of development, some production wells become water-flooded, complicating the acquisition of reliable original formation resistivity. Alternative methods must be employed to indirectly obtain this resistivity and assess the degree of water flooding. The H3 tight reservoir comprises both matrix pores and fractures as storage spaces, leading to differences in the mechanism of water-flooded layer formation. Injected water advances slowly through matrix pores, whereas fractures serve as the primary flow channels. Since the clay content in the H3 layer is less than 6%, the scouring effect of the injected water on the matrix pores is minimal, leading to negligible changes in the matrix porosity before and after water flooding. Therefore, for matrix pore reservoirs, the porosity model from before water injection development can be used to calculate the porosity of new wells. Using Archie's formula, the original formation resistivity can then be deduced and compared with the current formation resistivity to evaluate the water flooding conditions of the reservoir (Figure 6).

**Figure 6.** Process of original resistivity recovery.

Based on core analysis data available prior to water injection development and after abnormal data points such as lithological transition layers and thin interlayers were excluded, linear relationships were identified between core porosity and acoustic transit time, and between water saturation and core porosity (Figure 7). This analysis led to the development of a statistical regression formula for the porosity of the H3 layer:

$$Por_{core} = 0.523 \times AC - 24.863 \quad (R = 0.91) \quad (1)$$

$$S_w = -3.871 \times Por_{core} + 97.429 \quad (R = 0.83) \quad (2)$$

Por_{core} —Core analysis porosity, %; AC —acoustic time difference, $\mu s/ft$; S_w —water saturation, %.

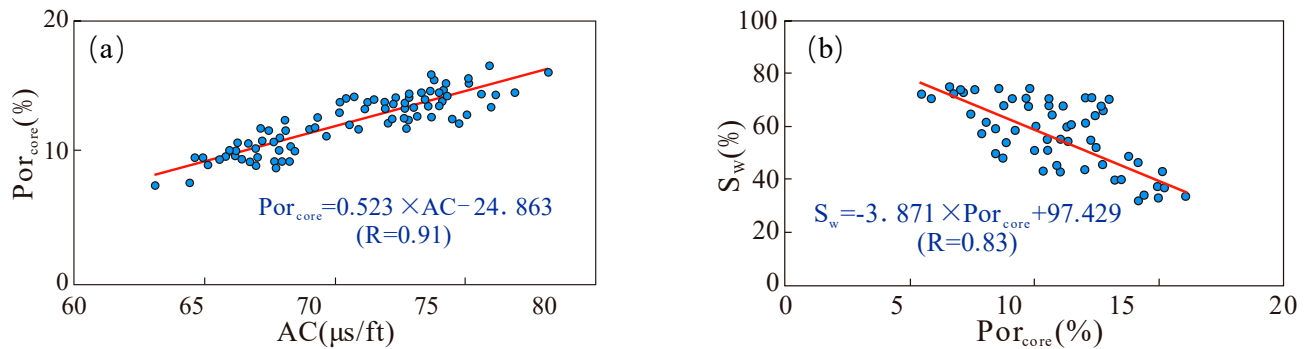


Figure 7. Cross-plots between core porosity and acoustics (a) and between core water saturation and core porosity (b) in layer H3.

Transforming Archie's formula [26], the following equation can be obtained:

$$Rt = \frac{abRw}{S_w^n \cdot \phi^m} \quad (3)$$

By incorporating rock–electric parameters from experiments ($a = 3.2519$, $b = 1.0697$, $m = 1.3402$, $n = 1.5654$) alongside porosity values, the original formation resistivity prior to water flooding can be determined. A comparison of this resistivity with the current formation resistivity allows for the identification of water-flooded intervals. For example, in well H2821, within the 1460–1470 m interval, the original formation resistivity (R_{Ti}) calculated via the original resistivity recovery method closely matches the measured resistivity (R_{CHFR}), indicating a nonwater-flooded layer. However, in the 1510–1519 m interval, the original formation resistivity is significantly higher than the measured resistivity, suggesting that reduced formation resistivity due to water flooding is present, thus indicating a water-flooded layer (Figure 8).

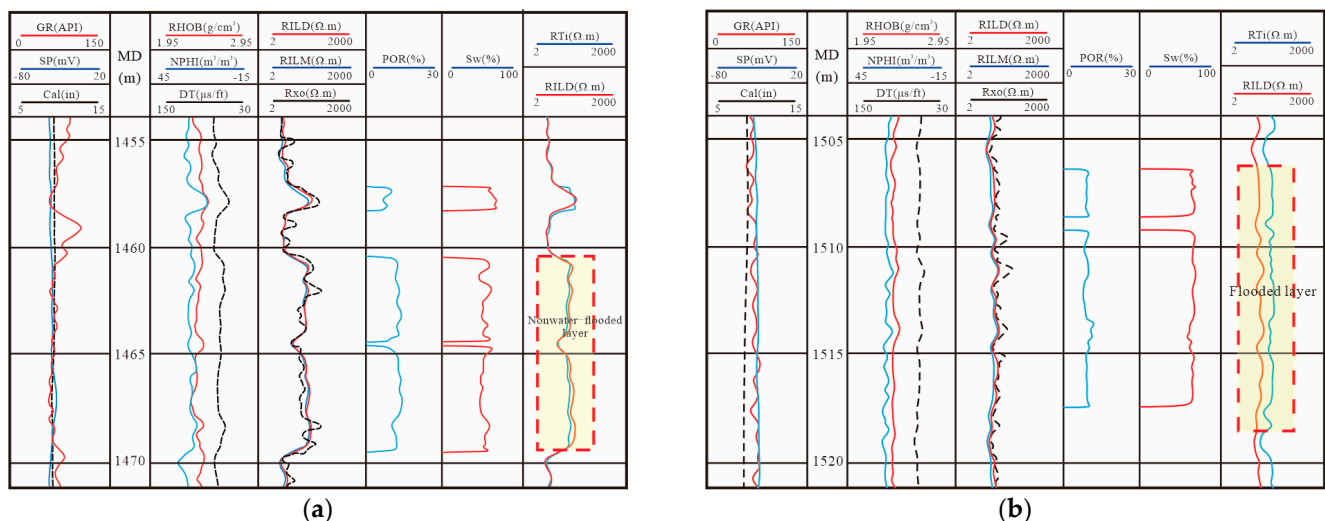


Figure 8. Identification of flooded layers through the original resistivity recovery method. (a) Nonwater-flooded layer; (b) water-flooded layer.

4.3. Quantitative Evaluation of the Flooding Level

For homogeneous sandstone reservoirs with consistent lithologies, the use of a water cut to quantitatively assess the degree of water flooding is highly effective. However, in fractured tight sandstone reservoirs, the water cut may be affected by fracture development and heterogeneity, potentially leading to inaccuracies. Therefore, this study employs the

extraction index (F_o), calibrated by the actual production water cut (F_w), to comprehensively evaluate the water flooding level.

(1) Water cut (F_w)

The water cut is defined as the ratio of water production to total liquid production during periods of simultaneous oil and water production. On the basis of the principles of fluid mechanics and seepage, the water cut formula is outlined as follows:

$$F_w = \frac{Q_w}{Q_o + Q_w} = \frac{1}{1 + B \cdot \frac{K_{ro}\mu_w}{K_{rw}\mu_o}} \quad (4)$$

K_{ro} , K_{rw} —Relative permeability of oil and water, $10^{-3} \mu\text{m}^2$; μ_w , μ_o —Viscosity of oil and water, $\text{mPa}\cdot\text{s}$; B —Parameters related to lithology and physical properties; the better the lithology and physical properties are, the smaller the B value.

By utilizing fluid analysis data, μ_w and μ_o are determined to be 0.39 $\text{mPa}\cdot\text{s}$ and 7.98 $\text{mPa}\cdot\text{s}$, respectively, yielding a μ_w/μ_o ratio of 0.05. The lithology parameter B is derived through regression by correlating water saturation from sealed core wells and fractured wells with actual water cut data. Through relative permeability experiments, a normalized relative permeability curve was developed (Figure 9), and a statistical regression relationship between the oil–water relative permeability ratio (K_{ro}/K_{rw}) and water saturation (S_w) was established (Figure 10).

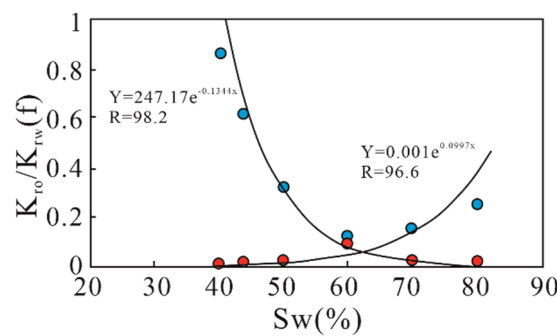


Figure 9. Normalized relative permeability curve of H3 layer.

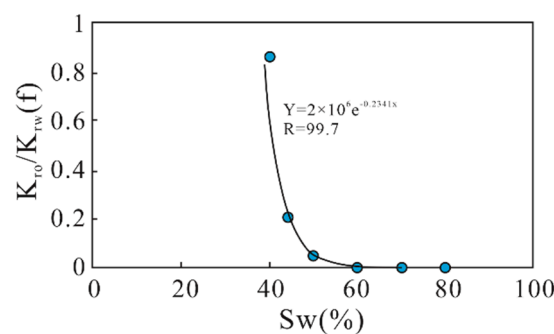


Figure 10. Cross-plot between oil–water relative permeability ratio and water saturation of H3 layer.

Substituting the aforementioned parameters into Formula (1), we derive the water cut calculation model as follows:

$$F_w = \frac{1}{1 + 1100000 * e^{-0.2341S_w}} \quad (5)$$

According to the CNPC classification standards for water flooding levels, the categories are as follows: oil layer: $F_w < 10\%$; level I water flooding: $10\% \leq F_w \leq 40\%$; level II water flooding: $40\% \leq F_w \leq 60\%$; level III water flooding: $60\% \leq F_w \leq 80\%$; and level IV water flooding: $F_w > 80\%$.

(2) Extraction index (F_{ow})

To mitigate the influence of heterogeneity, we define the extraction index (F_{ow}) as the ratio of the difference between the original oil saturation and the current oil saturation to the original oil saturation:

$$F_{ow} = \frac{S_{oi} - S_o}{S_{oi}} \quad (6)$$

F_{ow} —Extraction index, %; S_{oi} —Original oil saturation, %; S_o —Current oil saturation of the reservoir, %.

The extraction index is based on the principle of relative values. This approach avoids the limitations of using only the current oil saturation to quantitatively assess the water flooding level. Moreover, determining the water cut involves calculating the relative permeability of oil and water as well as their viscosities within the reservoir. In practice, core analysis data for these parameters are often insufficient, hindering the model's efficiency and accuracy. The extraction index circumvents these challenges, allowing for a dynamic characterization of the degree of reservoir water flooding. A higher extraction index indicates a more significant degree of water flooding, and vice versa.

Using core analysis data from old wells collected before water injection, we derived a calculation formula for the original water saturation of the H3 layer (Figure 7b). Since the matrix porosity minimally changes before and after water flooding, we can apply this model to calculate the original oil saturation of new wells. By utilizing the original and current oil saturations, we compute the extraction index and establish a cross-plot of the extraction index versus the water cut (Figure 11) to define the quantitative evaluation criteria for water flooding levels (Table 2). In practical applications, quantitative evaluations of water flooding levels are conducted through logging, with the consistency of the extraction index and water cut as a guiding principle. In cases where there are inconsistencies between the extraction index and water cut in determining the level, we refer to the radial resistivity difference chart to ascertain the water flooding level.

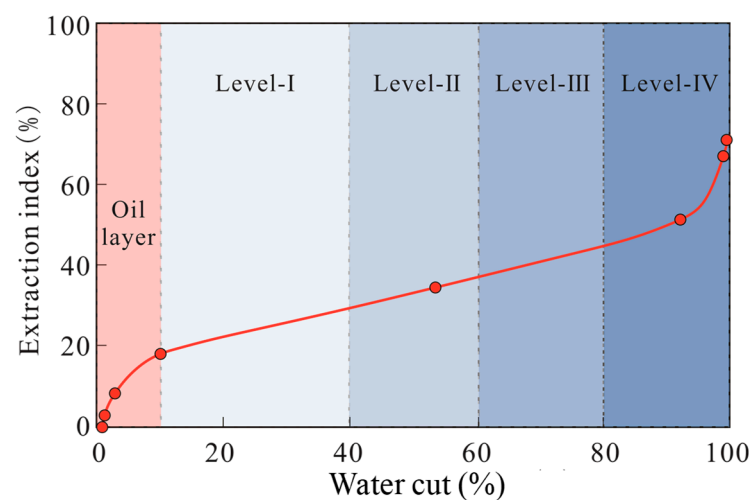


Figure 11. Cross-plot between the extraction index and water cut of layer H3.

Table 2. Relationships between the extraction index and water flooding levels.

F_w (%)	F_{ow} (%)	Water-Flooded Level
≤ 10	≤ 18	Oil layer
10~40	18~30	I
40~60	30~38	II
60~80	38~43	III
≥ 80	≥ 43	IV

4.4. Factors Affecting Flooding

(1) Tectonic position

The H oilfield is characterized by an anticline with a long axis oriented roughly north-south. The eastern and western flanks of the structure are asymmetrical, with the eastern flank being steeper and the western flank being more gradual. Two wells (H2445 and H2449), located in high and low structural positions, respectively, were selected for comparison of their water flooding conditions across three stages: early development, initial water breakthrough, and current production.

During the early development stage in 1997, both wells experienced weak water flooding, with water cuts of 23% and 27%, respectively. As water injection development progressed by 2003, well H2445, located at the higher structural position, continued to experience weak water flooding ($F_w = 28.7\%$), whereas H2449 transitioned to moderate water flooding ($F_w = 49.6\%$). By 2014, H2445 had progressed to a moderate water flooding state ($F_w = 55.2\%$), whereas H2449 had reached a state of strong water flooding ($F_w = 71.3\%$). These findings indicate that in the absence of fault and fracture communication, oil wells positioned structurally higher are subject to slower water flooding development and enjoy longer periods of stable production. In contrast, oil wells located in lower structural positions are more prone to water flooding because of their structural setting and oil–water density differentiation. They experience faster increases in water cuts, shorter stable production periods, and greater water flooding intensity.

(2) Sedimentary environment

The H3 oil reservoir group is part of a lacustrine–delta depositional system characterized by the development of three sedimentary microfacies: channel, shoal back, and shallow lacustrine top. Three wells with similar structural heights, representing these microfacies, namely, H84, H83, and H81, were chosen for analysis to assess the impact of sedimentary microfacies on water flooding.

During the initial production stage, all the wells produced oil with no water production. By 2015, well H84, situated in the channel, experienced a water cut of 82.5%, indicating significant water flooding. Well H83, located in the shoal back, had a water cut of 68.2%, reflecting relatively strong water flooding. In contrast, well H81, positioned at the shallow lacustrine top, displayed a water cut of 51.4%, representing moderate water flooding (Table 3). A comparison of the reservoir properties of the H3 interval in these three wells reveals that sedimentary microfacies significantly influence reservoir characteristics. As one transitions from a channel to shoal back, and then to shallow lacustrine top, the hydrodynamic conditions of deposition weaken, resulting in a decline in reservoir quality, the porosity decreased from 21.2% to 18.6% and 16.8%, while the permeability decreased from 5.45 mD to 3.22 mD and 1.65 mD. As development progresses from natural pressure depletion to water injection, reservoirs with superior properties are more prone to water flooding. Moreover, continued water injection accelerated the intensification of water flooding in these areas.

Table 3. Parameter table of flooded water layers with different sedimentary microfacies.

Well	Sedimentary Microfacies	Por (%)	Perm (mD)	Water Cut (%)	Water Flooding Level
H84	channel	21.2	5.45	82.5	IV
H83	shoal back	18.6	3.22	68.2	III
H81	shallow lacustrine top	16.8	1.65	51.4	II

(3) Fracture development

The tight sandstone reservoir of the H oilfield, characterized by a matrix with low porosity and permeability, features natural fractures oriented in the north-south, north-west, and north-east directions. The eastern and northern regions exhibit a high degree of fracture

development, with the H3 layer showing the most extensive vertical fracture development. These variations in fracture development significantly influence the formation of water-flooded layers. A comparison between wells H1455 and H1456, which are located in the southwest and northeast areas under the same development pattern, involved analyzing their physical properties, oil content, and dynamic production data (Table 4). Despite having similar physical properties, oil contents, and water injection techniques, well H1455 demonstrated a gradual decrease in daily oil production accompanied by an initially low water content that gradually increased. Conversely, well H1456 exhibited extremely low daily oil production and high-water content from the onset of production, with suboptimal water flooding effects.

Table 4. Comparison of the physical properties and oil contents of H1455 and H1456.

Well	Perforation Interva	Por (%)	Perm (mD)	S _O (%)
H1455	1602–1605	20.18	11.44	76.59
	1612–1615	19.87	7.23	67.98
H1456	1575–1579	20.90	12.91	76.57
	1586–1589.5	20.38	5.76	84.38

The development characteristics of fractures in various directions within the H3 layer significantly impact the seepage patterns of the injected water, which is a key factor in the differing production performances of these two wells. In the northeast area, where fractures are extensively developed, reservoir fluid flow mainly occurs through these fractures. The fluid seepage ability of fractures greatly surpasses that of matrix pores, positioning fractures as the primary channels for water-driven oil recovery. Owing to the unsatisfactory properties of matrix pores, fluid exchange between the matrix and fractures is limited, resulting in very low displacement efficiency of injected water on the oil within these matrix pores. Consequently, intense water flooding occurs in proximity to the fracture system, with newly drilled wells typically showing low production, high water cuts, and suboptimal water flooding effects, leaving large amounts of residual oil in the matrix system. For example, well H2340 initially produced 0.9 tons of oil per day with a water cut of 81.3%, categorizing it as a Level IV water flood interval. Nonetheless, an examination of core cross-sections revealed oil seepage from nonfractured core surfaces with extensive oil-bearing areas, suggesting high residual oil saturation in the reservoir matrix (Figure 12a,b). The areas near fracture surfaces experienced significant water washing, whereas the matrix regions distant from fractures still contained considerable residual oil (Figure 12c,d).

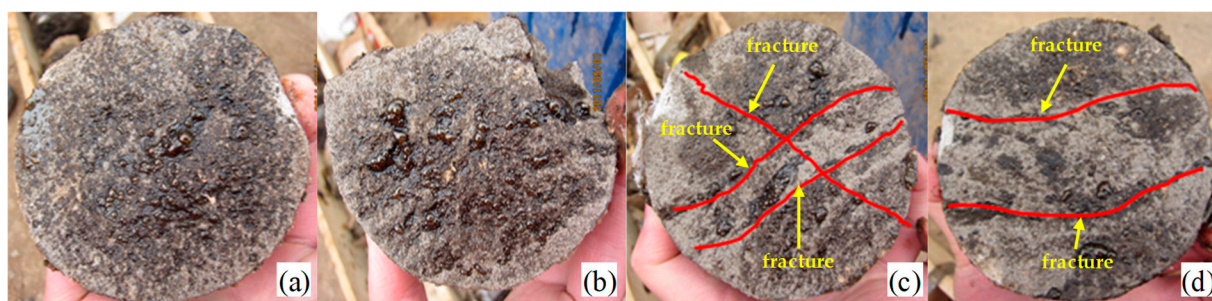


Figure 12. Matrix (a,b) and fracture (c,d) core sections of well H2340.

The southwest area predominantly features microfine fractures with limited connectivity, characterized by a fracture-pore dual-medium seepage system. Injected water enters both the pore media and fractures simultaneously to displace oil, facilitating relatively active fluid exchange between the matrix and fractures, which results in improved water flooding effects. Oil wells in this region seldom experience rapid water flooding, with the

water cut gradually increasing after production starts, and oil well exploitation generally aligns with the development patterns of conventional sandstone reservoirs.

These analyses suggest that the complex storage space of fractured tight sandstone reservoirs dictates the coexistence of two water-driven oil mechanisms during development: imbibition displacement in the bedrock system and differential pressure displacement in the fracture system. The fracture system, which serves as an important fluid migration channel, controls the seepage patterns in tight sandstone reservoirs and represents a geological factor of significant importance in the water injection development of such reservoirs.

5. Conclusions

- (1) The radial resistivity difference method is an effective approach for identifying water-flooded layers characterized by extensive lateral distribution and significant contrast within tight sand bodies. For reservoir sections with a prolonged production history, pronounced water flooding, and absent original formation resistivity data, the original resistivity recovery method can be employed to accurately identify these water-flooded layers.
- (2) The evaluation of water flooding levels can be quantitatively assessed by integrating the water cut, extraction index, and radial resistivity difference chart. This methodology circumvents the limitations associated with current quantitative evaluations that rely solely on oil saturation metrics. It mitigates the influence of reservoir heterogeneity while significantly enhancing both evaluation efficiency and accuracy.
- (3) In the northeastern region of the oilfield, fracture development has led to severe water flooding in reservoirs adjacent to fractures; however, the displacement efficiency remains low in matrix pore, indicating substantial remaining oil potential. Consequently, it is advisable to consider adjustments in water injection strategies and development methods aimed at improving matrix pore oil recovery rates.
- (4) Beyond larger-scale factors such as structural positioning, sedimentary environments, and types of reservoir space discussed herein, microscopic elements including fluid properties, rock–fluid interactions, dip angles, and pressure also directly impact the formation and evolution of water-flooded layers. Future research should focus on developing a more comprehensive logging evaluation method for assessing water flooding by elucidating how these factors influence outcomes through experimental studies and numerical simulations. This will enhance the precision of identifying water-flooded layers in heterogeneous oil and gas reservoirs while providing guidance for effective development strategies.

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