

Article

From NMR Signals to Fracture Size: Capillary-Controlled Conversion for Shale

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Abstract

Fracture size governs fluid mobility in shale, yet its direct quantification remains challenging. Nuclear Magnetic Resonance (NMR) transverse relaxation time (T_2) offers a unique, non-destructive probe of fracture size distributions; however, a physically grounded conversion from transverse relaxation time to pore radius r (T_2-r) is essential to translate NMR signals into quantitative geometric constraints on fluid mobility. This study introduces a capillary-constrained experimental method for T_2-r transformation into shale fractures. The workflow uses computed tomography (CT) scanning to extract fracture geometry. The gas-displacing-water process is precisely controlled by integrating the pore capillary pressure and back-pressure feedback algorithm. The NMR-CT conversion method performed in this study differs significantly from the T_2-r transformation based on conventional MICP. Differential spectral analysis isolates fracture-specific T_2 responses, and least-squares fitting derives the T_2-r conversion. Constraining displacement pressure and controlling segmental pressure are effective methods for ensuring the accuracy of fracture displacement. By emphasizing the governing role of capillary pressure during displacement, this method achieves accurate fracture-targeted displacement and reliable T_2-r mapping. The results significantly advance the use of NMR for quantifying fracture size and evaluating fluid transport in shale.

Keywords: shale; fracture; transverse relaxation time; capillary; NMR



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1. Introduction

Shale plays a significant role in global oil and gas development, with fractures serving as the primary spaces for hydrocarbon storage and migration. Understanding fracture distribution characteristics is a critical issue in shale reservoir evaluation [1,2]. Nuclear Magnetic Resonance (NMR) is an advanced technology for the non-destructive quantitative evaluation of rock pore structure and is currently the only method capable of continuous downhole characterization (NMR well logging) [3,4]. There is a clear positive correlation between NMR response time T_2 and pore radius r (denoted T_2-r), but accurately achieving the T_2-r transformation remains a technical challenge that researchers are eager to solve. This transformation is crucial for the study of NMR characterization methods for shale reservoir fractures [5,6].

Currently, fracture evaluation methods can be categorized into two types. (1) The direct observation of fractures using core photos, such as thin sections and scanning electron microscopy (SEM). The main advantage is direct detail identification, but there are limitations in terms of scale and three-dimensional information representation [7,8]. (2) Indirect inversion of fracture parameters using algorithms, where seismic and electrical imaging logs (FMI) have a characterization scale ranging from millimeters to meters, suitable for formation-scale analysis [9]. CT (computed tomography), NMR, and MICP (mercury injection capillary pressure) are the main techniques for the quantitative analysis of fractures at the core scale, but only the first two belong to non-destructive testing [10,11]. CT can intuitively provide fracture size information, but it cannot achieve full formation scanning [12]. NMR can quickly perform pore-throat analysis from the laboratory to entire wells, but the results provided are time values T_2 rather than size values r [13,14]. Assigning empirical values and coupling characteristic points are currently the most commonly used T_2-r conversion methods [15]. Sondergeld et al. assigned a value of 50 nm/ms to shales, with the converted pore lower limit ranging from 5 to 150 nm, but the accuracy of this method significantly depends on the researcher's experience [16]. The method of extracting coupled points through spectrum superposition can better reflect target-zone information, but the calculation results are relatively rough [17,18].

Combining CT and NMR is an ideal method to achieve T_2 -to- r conversion, but the prerequisite is to clarify the nuclear magnetic distribution of fractures [19]. Methods for extracting fracture nuclear magnetic distribution primarily include spectral analysis and fluid injection [20]. Golsanami (2016) reviewed methods for studying open fractures using NMR well logging [21,22], among which the use of fractal dimensions is the most widespread [23,24]. Dong (2022) conducted NMR experiments for pore-throat division using a solution of guar gum formulated with heavy water, which is a meticulous but expensive process [25]. Similar studies often control fracture displacement pressure based on empirical formulas without an explicit theoretical basis [26,27].

In this study, we leverage the advantages of CT and NMR in characterizing shale pores and throats to conduct experimental research on the T_2-r transformation method for fractures. First, we performed CT scans to clearly determine fracture size information and then calculated the capillary force characteristic parameters to constrain the displacement experiment pressure, obtain accurate fracture nuclear magnetic distribution through the differential spectrum method, and finally elucidate the T_2-r relationship through the least-squares fitting method, realizing the transformation from nuclear magnetic time to size. This study significantly enriches the application of NMR technology in evaluating shale fractures.

2. Materials and Methods

2.1. Sample and Principle

The sample is an organic-rich shale selected from a certain formation (named Liang-gao-shan) in the Sichuan Basin, Zi Gong, China, with a TOC content of 2.0% [28]. The lithology is dark gray feldspathic shale, containing 54.2% feldspar, 1.8% carbonate minerals, and 37.4% clay minerals. The rock sample has a porosity of 3.62%, a permeability of 2.48 mD, and a matrix density of 2.66 g/cm³. Figure 1 shows the incandescent light photograph and thin section image of the selected sample, with obvious microfractures visible in the images.

CT scanning utilizes differential attenuation characteristics of X-ray as they penetrate different components to measure the internal structure of rocks [29,30]. The attenuated X-ray are received by a detector located behind the rock sample, forming projections. In rock CT scanning, the X-ray source and detector are placed on either side of a rotating stage. High-speed electrons from the source bombard a metal target, generating X-ray [31,32]. By

rotating the sample around its central axis, two-dimensional slice images at various angles can be obtained. Using mathematical methods to reconstruct these two-dimensional slices results in three-dimensional structural images of the rock, which can clearly display fine internal structures, such as fractures and pore distribution [33,34].

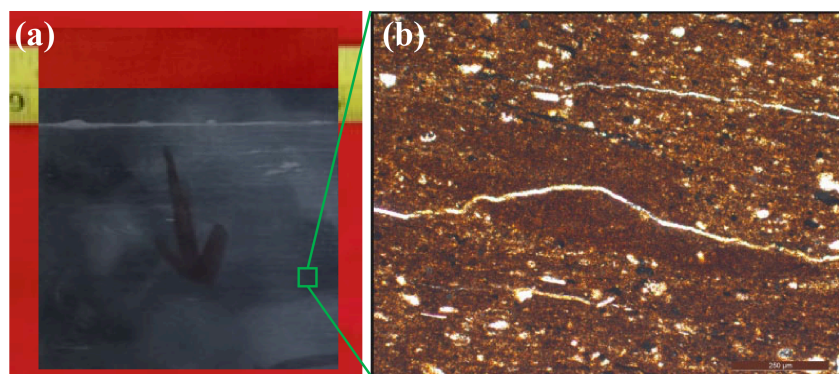


Figure 1. Core photo (a) and thin section image (b) of the selected sample. Green lines show the imaged area.

NMR T_2 is an advanced technology for analyzing the pore structure and fluid characteristics of rock cores [18,35]. When a rock sample is placed in a uniform magnetic field, the hydrogen nuclei (^1H protons) within the rock exhibit different magnetization states in the magnetic field and undergo magnetic resonance phenomena as the field changes [31,36]. Different pore structures and sizes have distinct T_2 response patterns, but the positive correlation between T_2 and r remains consistent [15,37]. Therefore, T_2 spectra are commonly used to analyze core pore structures, identify fluids (such as water, oil, and gas), and calculate permeability. The CPMG (Carr–Purcell–Meiboom–Gill) sequence is often used in laboratories to measure the NMR T_2 spectra [3,38].

2.2. Methods

The experimental procedure shown in Figure 2 consists of five parts: (1) pre-treatment, (2) CT scanning to extract fracture size r_f and calculate capillary force P_f , (3) a fracture fluid displacement experiment, (4) an NMR differential spectrum method to extract fracture time T_{2f} , and (5) the transformation of T_{2f} to r_f .

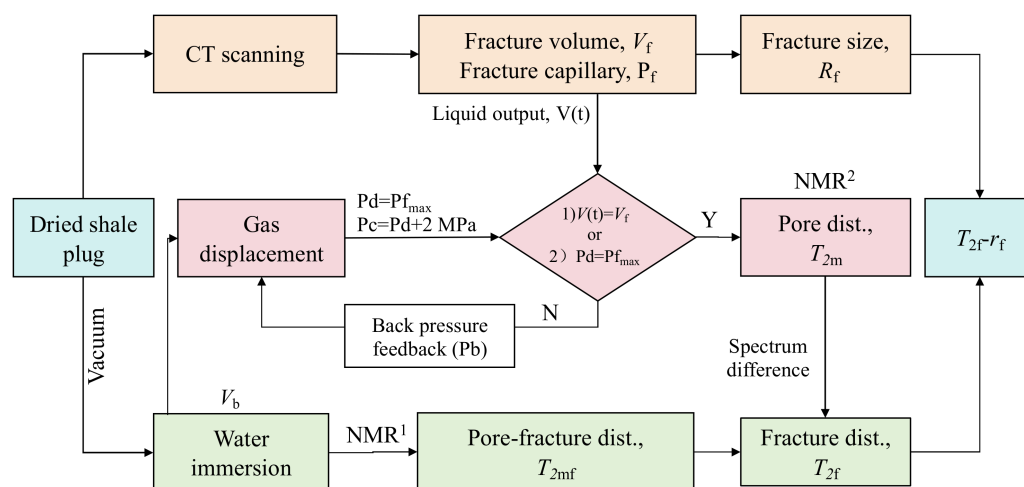


Figure 2. Procedures for transformation of T_{2f} - r_f .

Step 1. Pre-treatment.

- (1) Sample preparation and drying. Shale samples were prepared into standard plugs with a length of 50 mm and a diameter of 25.4 mm using wire cutting technology. They were then placed in an oven for dehydration at 200 °C for 24 h, as Sondron's experiment showed that drying at 200 °C can remove residual fluids without destroying the clay structure [39]. After drying, the samples were stored in a desiccator containing silica gel particles to prevent moisture absorption [40].
- (2) Vacuum pressure saturation. The rock sample was placed in a water-filled pressure tank and vacuumed to 130 Pa, followed by pressure saturation at 32 MPa for 24 h.
- (3) Archimedes' displacement method was used to measure the total volume, V_b .

Step 2. CT scanning to extract fracture size r_f and calculate capillary force P_f .

- (1) CT, combined with digital image processing technology, is used to distinguish pores from fractures and extract the fracture aperture distribution r_f . Define the fracture size boundary values as r_{fmax} and r_{fmin} , which will be used as reference values for subsequent T_2-r conversion.
- (2) Calculate the total volume of fractures V_f , which will be used to monitor the progress of the fracture displacement experiment.
- (3) Calculate the capillary force parameter P_f to constrain the displacement experiment pressure. Based on the inverse relationship between capillary pressure and size, the capillary force boundary values P_{fmin} and P_{fmax} are estimated using the Washburn equation.

$$r_f = 0.735/P_f \quad (1)$$

Step 3. Fracture Fluid Displacement Experiment under Capillary Force Constraint.

- (1) Set displacement pressure $P_d = P_{fmax}$, with a confining pressure $P_c = P_d + 2$ MPa. A differential pressure of 2 MPa is used to ensure that the gas does not leak from the sides. The initial value of backpressure is $P_b = P_{fmin}$, with a minimum value of 0.1 MPa.
- (2) Segmented Pressure Control Function for Fracture Displacement. After placing the rock sample in the holder and applying confining pressure to fix it, we placed a graduated cylinder at the outlet end to collect the expelled water and calculate the cumulative fluid volume $V(t)$. Next, we installed a pneumatic tube near the core side of the outlet end to allow periodic air release, preventing the liquid from sticking to the pipe wall and affecting the measurement of $V(t)$. The pressure adjustment function was set to two segments. The first segment was a buffer stage, the duration of which was related to the amount of fluid in fractures with capillary forces below 0.1 MPa; the second segment was used to displace fluids in smaller-sized fractures, with the completion time of displacement related to the total volume of fractures, V_f .

$$V(t) = \begin{cases} P_{fmin} \cdot \frac{S}{L} & (0 < t \leq \Delta t_a) \\ K_p \cdot \left[e(t) + \frac{1}{Tl} \cdot \int_0^t e(t) dt \right] + V(t_a) & (t > t_a) \end{cases} \quad (2)$$

$$t_a = \frac{\int_{r_{fmax}}^{r_{fp}} r_f dr_f}{\int_{r_{fmax}}^{r_{fmin}} r_f dr_f} \quad (3)$$

$$e(t) = V_f - V(t) \quad (4)$$

$$K_p = \frac{L}{S} \cdot V_f = \frac{L}{\pi \cdot r^2} \cdot V_f \quad (5)$$

where L is the length of the core; S is the cross-sectional area; $e(t)$ is the deviation from the target value; $t(a)$ is the buffer time for core displacement, corresponding to the content in the low capillary force interval of fractures; K_p is the proportional adjustment function used for high capillary force fracture displacement, which is a manually entered value before system operation; and $r_{fp} = 7.35 \mu\text{m}$ represents the radius of the fracture at the point where the capillary force is 0.1 MPa.

- (3) The displacement process is considered complete when the cumulative fluid volume expelled from the fractures equals the total volume of the fractures ($V(t) = V_f$), or when the displacement pressure (P_d) and backpressure (P_b) both reach the maximum capillary force value (P_{fmax}). These conditions ensure that all fluids within the fractures have been effectively displaced, providing accurate data for subsequent analysis.

Step 4. Extraction of fracture time T_{2f} using the NMR differential spectrum method.

- (1) Set parameters: $TE = 70 \mu\text{s}$, $T_w = 10 \text{ s}$, $NECH = 8000$, and $SCAN = 32$. Distribute points in T_2 from 0.01 to 10,000, with a BRD algorithm compensation factor $\alpha = 0.1$.
- (2) Measure the T_2 spectra in the dry state (T_{dry}) and saturated state (T_{sat}). Use the differential spectrum method to calculate the overall distribution of pores and fractures, T_{2mf} .

$$T_{2mf} = T_{sat} - T_{dry} \quad (6)$$

- (3) After the gas drive experiment, test the matrix pore T_2 spectrum T_{2m} . Use the differential spectrum method to calculate the NMR distribution of fractures T_{2f} .

$$T_{2f} = T_{2mf} - T_{2m} \quad (7)$$

Step 5. Calculation of the T_{2f} – r_f quantitative transformation relationship using the least-squares method with cumulative curves.

Plot the cumulative distribution frequency curves for both NMR and CT data of fractures, and read the data points (x, r_{fi}, T_{fi}). Based on the principle of the least-squares method, perform an $r_{f(i)} - T_{f(i)}$ fitting to obtain the coefficients that yield the smallest error. Substitute the NMR data into the transformation equation to obtain the corresponding size measurements [41–43].

3. Results

3.1. CT Results

Figure 3 presents the results of CT scanning (upper image) and reconstruction (lower image). The first row displays 2D grayscale images of both horizontal and vertical slices, along with a 3D grayscale image of the entire sample. In these images, prominent fractures are clearly visible. The second row shows reconstructed three-dimensional volume images that include integrated pore-fracture distribution, pore distribution, and fracture distribution. Here, red represents the matrix, blue denotes the matrix pores, and green indicates the fractures. The reconstructed structure reveals the distribution characteristics of fractures within the core's three-dimensional structure. Fractures exhibit non-uniform distribution in the vertical direction, while they generally show a through-going pattern in the horizontal direction. Fractures from upper and lower layers connect via small crack surfaces to form larger crack faces.

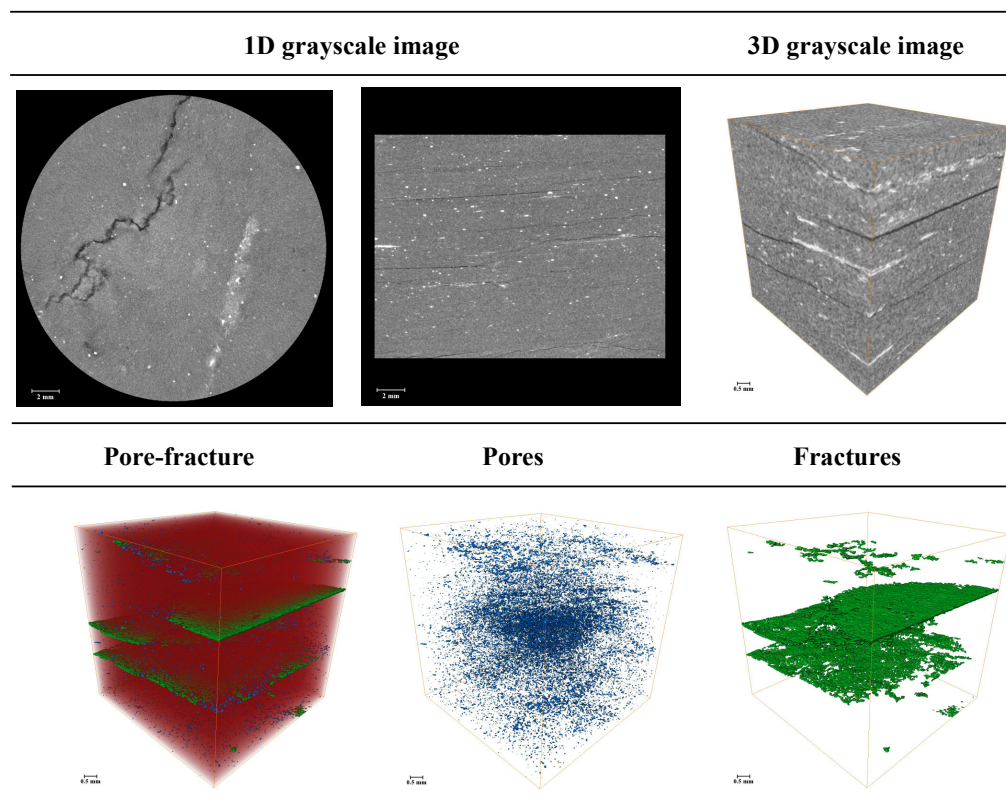


Figure 3. CT scanning and 3D reconstructed images. Red, blue and green represent the distributions of matrix, pores and fractures.

Figure 4 presents the results of crack size distribution based on calculations from CT images. The x -axis represents crack size, while the y -axis shows the frequency of pixel occurrence. The label value denotes ‘size/capillary force’. Cracks are mainly distributed between 1 and 52 μm , with a peak at 22.7 μm . Using the spectral area integration method, it is calculated that cracks larger than 10 μm accounts for 94% of the total, and those greater than 1 micrometer exceed 98%. According to the Washburn equation, capillary forces for cracks larger than 1 micrometer range between 0.014 and 0.735 MPa, with a peak pressure point at 0.032 MPa.

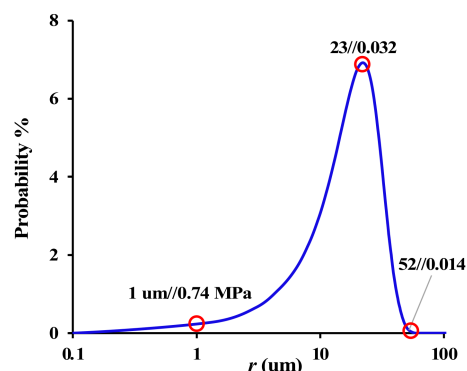


Figure 4. CT-calculated fracture size and capillary pressure for special points.

3.2. NMR Results

Figure 5a presents T_2 spectra measured under various conditions. ‘Sat’ (saturated) and ‘Dry’ represent the upper and lower boundaries of pore characterization, respectively. The difference between these two spectra reveals a pore-fracture distribution ranging from 1 to 300 ms, characterized by a low left peak and a high right peak (Figure 5b). ‘Disp-1’

is a spectrum obtained during displacement, while ‘Disp-2’ represents the spectrum after complete fluid displacement in fractures. The difference between ‘Sat’ and ‘Disp-2’ yields the fracture distribution. Figure 5c (blue line) shows that the fracture T_2 spectrum exhibits a single peak, with values predominantly greater than 30 ms, and the main peak at 100 ms. The difference between ‘Disp-2’ and ‘Dry’ represents the pore fluids that were not expelled (Figure 5c, green line). The pore T_2 spectrum displays multiple peaks, generally within the range of 1 to 100 ms. The left peak at 1 ms has a small amplitude and narrow width, whereas the right peak at 10 ms has a larger amplitude and broader distribution. Overall, both the size and amplitude of the pore signals are smaller than those of the fractures. Figure 5d–f shows the two-dimensional NMR spectra corresponding to the dry, saturated, and displaced states, respectively. Specifically, Figure 5d illustrates the distribution of residual hydrogen signals in the skeleton under dry conditions.

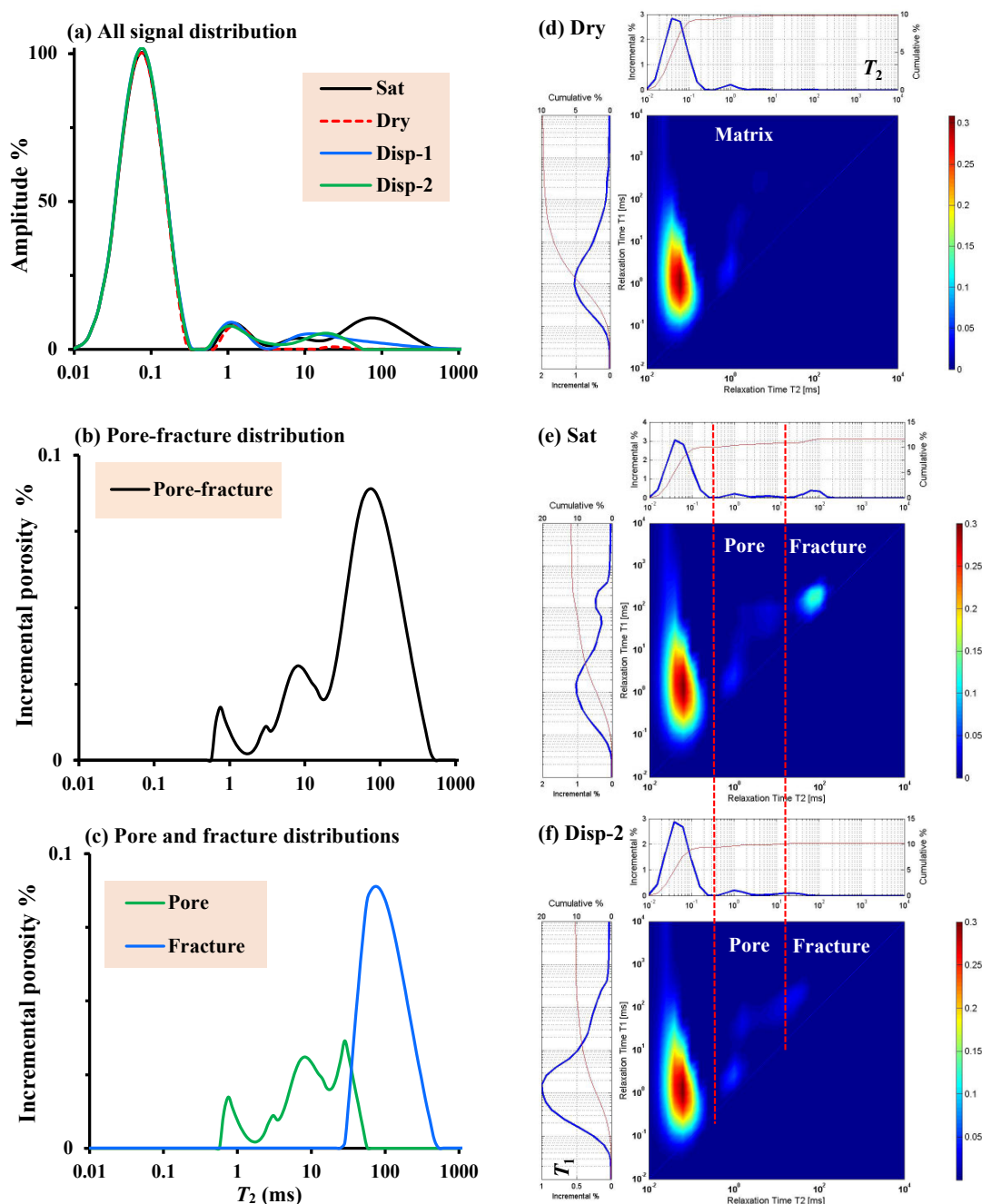


Figure 5. T_2 (a–c) and T_1 – T_2 (d–f) for pore-fracture distribution.

3.3. T_2 – r Transformation Results

Figure 6a displays the cumulative distribution curves for fractures obtained from NMR (red dashed line) and CT (blue solid line), with the x -axis representing the cumulative signal. After interpolating points on the cumulative curve and performing data fitting, the least-squares method yields a T_{2f} – r_f conversion relationship that follows an exponential rule (Equation (8)). In Figure 6b, the red line represents the original fracture CT distribution (same as Figure 4), while the blue line shows the fracture NMR size distribution calculated using Equation (8). After the conversion, the main peaks of fractures derived from both CT and NMR are relatively close, exhibiting a unimodal pattern.

$$r = 10^{-3} \times 120.18 \times T_2^{1.03} \mu\text{m/ms} \quad (8)$$

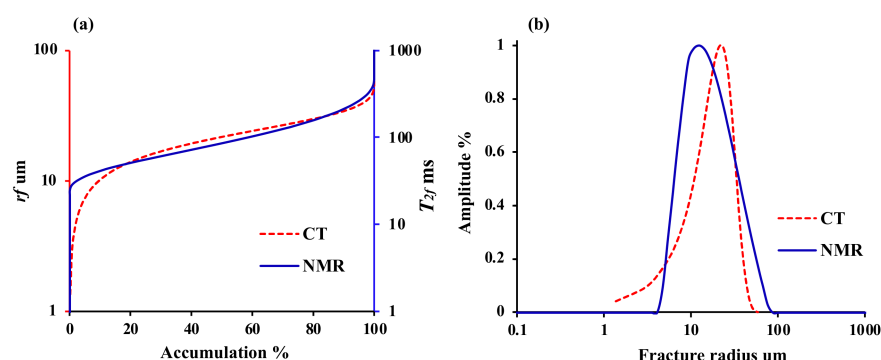


Figure 6. Fitting results of T_2 (a) and width (b) for fractures derived with CT (red dash-line) and NMR (blue solid-line).

4. Discussion

4.1. Constraint Boundaries to Prevent Over-Displacement

The disparity in pore-fracture sizes influences capillary flow efficiency, with permeability following the pattern ‘fractures > matrix-pores’. Although fracture fluid dehydration is more efficient than that of matrix pores, over-displacement (expulsion of matrix pore fluids) can still lead to an increase in the identified fracture NMR signal, making the avoidance of over-displacement a primary concern for extracting fracture NMR signals. Ideally, only when the cumulative liquid output volume $V(t)$ equals the fracture volume V_f does the rock pore-fracture system reach a state where fractures are dry and only matrix pores contain liquids, marking the completion of the fracture displacement experiment. Quantifying the boundary between pore and fracture displacement pressures is crucial to prevent over-displacement. In this study, we calculated the capillary pressure range of CT-determined fractures using the Washburn equation, which falls between 0.014 and 0.735 MPa. We set the P_d to the maximum capillary force value ($P_d = 0.74$ MPa). While there will inevitably be some overlap between large pores and small fractures, this selected P_d ensures the integrity of fractures as much as possible. The confining pressure P_c on the rock sample is approximately 2.74 MPa. At this confining pressure, significant stress changes in the pore-fracture structure are unlikely, contributing to the accuracy of the T_2 – r conversion.

4.2. Staged Pressure Control to Prevent Inadequate Displacement

Inadequate displacement is the second issue to consider. Due to the variability in fracture permeability, once gas penetrates larger fractures and forms preferential flow channels, it will directly discharge from the rock along these large fractures without diffusing further to displace fluids in smaller fractures. This can lead to inadequate displacement, which directly reduces the total NMR signal identified by the difference spectrum method. To

address this, backpressure is often set in laboratory settings to obstruct gas flow, forcing smaller intervals that achieve a more thorough displacement. For the studied samples, the capillary pressure between the peak point of fractures and the maximum size ($r = 52 \mu\text{m}$) is within the range of 0.014–0.03 MPa. This interval's capillary force is only slightly greater than atmospheric pressure, making it easy for fluid to escape from fractures under actual production conditions. Considering the practical performance of the displacement equipment, we recommend setting the minimum backpressure at 0.1 MPa. At this pressure, the fracture radius is $7.35 \mu\text{m}$. We leveraged differences in fracture permeability by modeling fractures as a series of pipes with varying sizes and conducted staged displacement experiments on fracture fluids using $7.35 \mu\text{m}$ as a boundary. By employing the capillary force feedback algorithm shown in Equation (4) for intelligent staged pressure control, we can gradually expel fracture fluids, effectively avoiding the problem of inadequate displacement that often results from fixed backpressures or manual pressure increases. Therefore, the completion criteria for the experiment should include two parts: (1) the cumulative liquid output volume equals the fracture volume V_f , and (2) the adjusted backpressure value is less than both the displacement pressure and the maximum capillary force of the fractures.

4.3. Multi-State Tests for Extracting NMR Pore Boundaries

Determining the boundary conditions of pores (T_{sat} and T_{dry}) and eliminating the influence of matrix signals is fundamental to studying the pore-fracture structure in shale using NMR. Unlike reservoir rocks, such as sandstone, that do not contain organic matter and thus cannot generate hydrocarbons, where the oil present is a product of migration and has a $T_{2d} = 0$, there is no need for additional testing of the dry state nuclear magnetic spectrum. In contrast, source rocks have the capacity for self-generation and storage of hydrocarbons, and their dried samples contain residual organic matter (such as kerogen or solid bitumen) within the rock skeleton. Therefore, it is necessary to remove the hydrogen signal from the rock skeleton in the T_2 spectrum to accurately extract the distribution of nuclear magnetic pores. Figure 5(d–f) shows that the left peak ($T_2 < 0.3 \text{ ms}$) remains relatively unchanged throughout the process, mainly located at the top-left corner, indicating short T_2 and long T_1 characteristics typical of solid components. This suggests that these signals originate from some kerogens or solid bitumens, which are part of the rock skeleton. Thus, T_{dry} represents the background signal of nuclear magnetism (i.e., the lower boundary). The difference between T_{sat} and T_{dry} represents the actual PSD of shale, which exhibits a bimodal shape with the right peak significantly higher than the left, suggesting a higher content of large pores compared to small ones. This contrasts with the feature shown by T_{sat} , which indicates a high content of small pores. After the gas drive experiment, the differences in the two-dimensional distribution of NMR signals in fractures are also very noticeable.

In this study, we performed an NMR-CT conversion, which differs significantly from the T_2-r transformation based on MICP. MICP primarily focuses on matrix pores, and due to the limitations of detecting smaller pores, there can be discrepancies in total pore volume between NMR and MICP methods, making conversions based on cumulative signal volume less reliable. Our research specifically targeted fractures, with the effective separation of fractures as the basis. The total quantity and distribution of fractures were clear, and no issues related to insufficient signal detection were detected. Therefore, performing a $T_{2f}-r_f$ transformation for fractures' transverse relaxation time and the physical size based on cumulative signal volume is credible.

5. Conclusions

In this study, we leveraged the advantages of CT scanning for extracting fracture information and made full use of the control effect of capillary forces on flow capacity. We provided a robust methodology for accurately converting T_2 signals into corresponding radius values. This is of great significance for evaluating the nuclear magnetic properties of fractures. The main conclusions are as follows. Multi-state NMR scanning is fundamental for quantifying the true NMR distribution of fractures. Constraining displacement pressure and segmental pressure control are effective methods for ensuring the accuracy of fracture displacement. Clearly defining the content of fractures is crucial for achieving accurate T_2-r conversion using the least-squares method. A limitation of this study is that it does not consider the influence of fluid viscosity on the displacement process or the impact of stress on pore structure.

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Conflicts of Interest: The authors declare no conflict of interest.

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