

## Article

# Further Investigation of CO<sub>2</sub> Quasi-Dry Fracturing in Shale Reservoirs—An Experimental Study

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**Abstract:** The physical properties of shale reservoirs are typically poor, necessitating the use of fracturing technology for effective development. However, the high clay content prevalent in shale formations poses significant challenges for conventional hydraulic fracturing methods. To address this issue, CO<sub>2</sub>-based fracturing fluid has been proposed as an alternative to mitigate the damage caused by water-based fracturing fluids. In this paper, the applicability of quasi-dry CO<sub>2</sub> fracturing in shale reservoirs is examined from three key perspectives: the viscosity of CO<sub>2</sub> fracturing fluid, the fracture characteristics induced by the CO<sub>2</sub> fracture fluid, and the potential reservoir damage caused by the fracturing fluid. Firstly, the viscosity of CO<sub>2</sub> fracturing fluid was determined by a rheological experiment. Rheological tests revealed that the viscosity of CO<sub>2</sub> fracturing fluid was significantly influenced by the water–carbon ratio. Specifically, when the water–carbon ratio was 30:70, the maximum viscosity observed could reach 104 mPa·s. Moreover, increasing reservoir temperature resulted in decreased fracturing fluid viscosity, with a 40 °C temperature rise causing a 20% viscosity reduction. Secondly, matrix permeability tests were conducted to investigate permeability alteration during CO<sub>2</sub> fracturing fluid invasion. Due to the weak acidity of CO<sub>2</sub>-based fracturing fluid, the permeability reduction induced by clay hydration was inhibited, and an increase in permeability was observed after a 3-day duration. However, the matrix permeability tends to decrease as the interaction time is prolonged, which means prolonged soaking time can still cause formation damage. Finally, triaxial fracturing experiments facilitated by a three-axis servo pressure device were conducted. The fracture properties were characterized using computed tomography (CT), and 3D reconstruction of fractured samples was conducted based on the CT data. The results demonstrate that CO<sub>2</sub> fracturing fluid effectively activates weak cementation surfaces in the rock, promoting the formation of larger and more complex fractures. Hence, CO<sub>2</sub> quasi-dry fracturing technology emerges as a method with significant potential, capable of efficiently stimulating shale reservoirs, although a reasonable soaking time is necessary to maximize hydrocarbon production.

**Keywords:** shale; CO<sub>2</sub> quasi-dry fracturing; carbon dioxide–water–shale interaction; permeability



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## 1. Introduction

CO<sub>2</sub> fracturing technology has emerged as a promising method for enhancing hydrocarbon recovery while mitigating environmental impacts associated with conventional hydraulic fracturing. Unlike traditional hydraulic fracturing that relies on water-based fluids, CO<sub>2</sub> fracturing utilizes supercritical or liquid CO<sub>2</sub> as the fracturing fluid [1]. This approach offers several advantages, including reduced water usage, a reduced environmental footprint, and the potential for enhanced reservoir stimulation [2–5]. Hence, CO<sub>2</sub>-based fracturing methods have steadily garnered attention within the oil industry.

Supercritical CO<sub>2</sub> fluid boasts a plethora of unique physical and chemical properties, setting it apart in various applications [6–9]. Its low viscosity, high diffusion coefficient, and near-zero surface tension make it a standout choice [10–12]. Since its introduction into the oil industry, CO<sub>2</sub> fracturing has showcased numerous advantages. Notably, it readily forms intricate fracture networks within reservoirs [13]. Moreover, its low water content mitigates the risk of reservoir clay expansion. One of its standout benefits lies in the rapid flowback after fracturing, significantly reducing non-production periods for oil and gas, thereby enhancing economic returns [14]. Furthermore, the robust absorption capabilities enable CO<sub>2</sub> to displace methane molecules adsorbed in shale, thereby amplifying production and recovery efficiency while facilitating permanent CO<sub>2</sub> storage [12,15–17]. Consequently, CO<sub>2</sub>-based fracturing technology is lauded as a promising new approach with expansive potential. The effectiveness of CO<sub>2</sub>-induced fracture propagation hinges on several key mechanisms [18]. Firstly, thermal stress coupled with pore pressure alleviates effective stress, instigating shear failure. Secondly, the absence of surface tension diminishes the net pressure necessary for crack propagation. Thirdly, adsorption phenomena decrease the critical stress required for crack growth. Lastly, localized phase transformations drive dynamic fracture growth. These mechanisms collectively underscore the multifaceted nature of CO<sub>2</sub>-induced fracture propagation, shedding light on its efficacy and versatility in various engineering contexts. However, liquid CO<sub>2</sub> encounters challenges due to its significant friction resistance, which hinders its ability to meet the demands of high-displacement injection during field application [19]. Moreover, its low viscosity exacerbates issues such as rapid settling of proppants, resulting in limited sand-carrying ability and increased filtration loss [1,20].

To tackle these challenges, a thickening agent is introduced into the liquid CO<sub>2</sub> [21,22]. This additive serves to enhance the suspended sand capacity, effectively slowing down the settling process and reducing filtration loss. By incorporating a thickening agent, the performance of liquid CO<sub>2</sub> is improved, making it better suited for high-displacement injection tasks while mitigating issues associated with proppant settling and filtration loss. In theory, the molecular structure of carbon dioxide thickeners typically comprises two components: it is a polymer of a CO<sub>2</sub>-philic group, which can fully dissolve in carbon dioxide, and a CO<sub>2</sub>-phobic group, which enhances the viscosity of carbon dioxide. CO<sub>2</sub> exhibits physical properties compatible with organic agents. In this mixed system, water molecules attract CO<sub>2</sub> to form hydrophilic groups of rod-like or worm-like micelles, while CO<sub>2</sub>-philic molecules attract CO<sub>2</sub> groups. Through a series of interactions, the intermolecular forces strengthen, consequently elevating the viscosity of CO<sub>2</sub>. Many scholars have dedicated efforts to studying the factors influencing the viscosity of gelled CO<sub>2</sub> and have established criteria for evaluating its rheological properties. Through systematic experimentation and theoretical analysis, researchers have identified key parameters that impact the viscosity of gelled CO<sub>2</sub>. These parameters include the concentration and type of thickening agent, the temperature, the pressure, the shear rate, and the presence of additives such as surfactants or polymers. Luo et al. [23] investigate the rheological properties and friction performance of thickened CO<sub>2</sub> fracturing fluid. They establish correlations for rheological parameters, noting a significant decrease in effective viscosity with increasing shear rate and temperature, albeit with a modest increase linked to thickener concentration. Frictional resistance decreases with flow velocity, temperature, and pressure, but exhibits a smaller change range concerning pressure and thickener concentration. Zhao et al. [21] investigate a novel supercritical CO<sub>2</sub> fracturing fluid system composed of 5% polydimethylsiloxane, 5% kerosene, and 90% supercritical CO<sub>2</sub>. Through systematic evaluation experiments, it demonstrates significantly enhanced rheological properties, an improvement in the sand-carrying capacity by 38.17%, and a reduction in the filtration loss coefficient by up to 71.71%. Zhao et al. [24] propose that a siloxane-based polymer significantly enhances CO<sub>2</sub> viscosity while minimizing damage and chemical residue in the stratum after fracturing.

In addition to viscosity, the formation damage caused by fracturing-fluid intrusion is another crucial parameter for evaluating the suitability of fracturing fluid. The potential for

reservoir damage is a significant concern in hydraulic fracturing operations, as it can affect well productivity and reservoir performance in the long term. The intrusion of fracturing fluid into the reservoir rock can lead to various forms of damage, including formation matrix swelling, clay dispersion, fines migration, and pore plugging. Researchers have developed various methods to assess reservoir damage induced by fracturing-fluid intrusion. These methods often involve laboratory experiments, core analysis, and numerical simulations to quantify the extent of damage and its impact on reservoir properties such as permeability, porosity, and fluid flow behavior. Lu et al. [25] investigate the impact of supercritical CO<sub>2</sub>-slickwater hybrid fracturing on shale pore structures using various analytical techniques. The treatment leads to an increase in micropores (<2 nm) and mesopores (2–50 nm), expanding total specific surface area (TSSA) and total pore volume (TPV) while reducing average pore size. Tian et al. [26] investigate the impact of exposure to supercritical CO<sub>2</sub> on the porosity and permeability evolution of both dry and wet shale samples over varying periods. Results indicate an initial increase followed by a decrease in porosity and permeability, with a distinct inflection point observed. Therefore, evaluating the reservoir damage resulting from fracturing-fluid intrusion is crucial for optimizing fracturing fluid formulations and designing effective fracture treatments.

Pure CO<sub>2</sub> fluid suffers from low viscosity, resulting in poor sand-carrying capacity and inadequate reduction of filtration loss, which hampers its effectiveness in fracturing operations. In this paper, a novel CO<sub>2</sub> thickener system (VIC-2, VIC-6) was proposed to enhance CO<sub>2</sub> viscosity, and the following research was carried out. Firstly, high-temperature and high-pressure rheological experiments are conducted to evaluate the viscosity of CO<sub>2</sub> fracturing fluid across varying water-carbon ratios. Secondly, the impact of CO<sub>2</sub>-water-rock reactions on shale matrix permeability during fracturing remains ambiguous despite the presence of a small amount of water and polymer in the CO<sub>2</sub> fracturing fluid system. Hence, permeability tests are conducted on shale samples subjected to different soaking times to elucidate this influence. Finally, CO<sub>2</sub> triaxial fracturing experiments are conducted using downhole cores, and fracture reconstruction is facilitated through CT imaging. These experiments provide a theoretical foundation for the further application of CO<sub>2</sub> quasi-dry fracturing in shale reservoirs. By systematically investigating these aspects, the research aims to enhance the understanding of CO<sub>2</sub> fracturing fluid behavior and optimize its performance in shale reservoir stimulation, paving the way for more efficient and effective fracturing operations.

## 2. Methodology

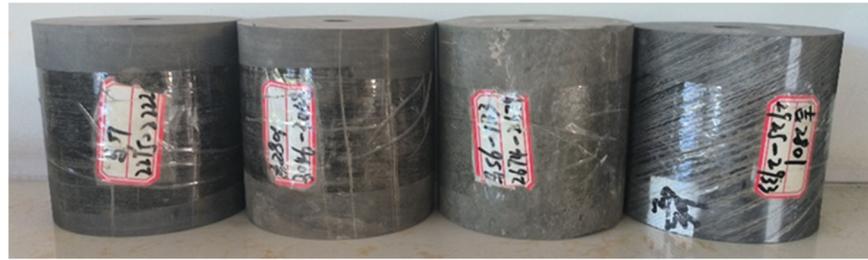
In this paper, the experimental section primarily encompasses 3 key components:

1. **Shale damage test:** This aspect aimed to assess the permeability reduction induced by water-based fracturing fluid and CO<sub>2</sub> quasi-dry fracturing fluid. In this part, the PDP instrument was used to determine the shale permeability. By subjecting cores to both types of fluids, we evaluated the extent of damage inflicted on the cores. This evaluation provides insights into the comparative performance of the two types of fracturing fluids in terms of core preservation and permeability retention.
2. **Rheological experiment:** This involved studying the rheological behavior of CO<sub>2</sub> quasi-dry fracturing fluid under varying water-carbon ratios and temperatures.
3. **True triaxial fracturing experiment:** Quasi-dry CO<sub>2</sub> fracturing fluid and slickwater were applied to conduct the fracturing experiment. By subjecting shale rock samples to different hydraulic fracturing, the fracture characteristics were further evaluated.

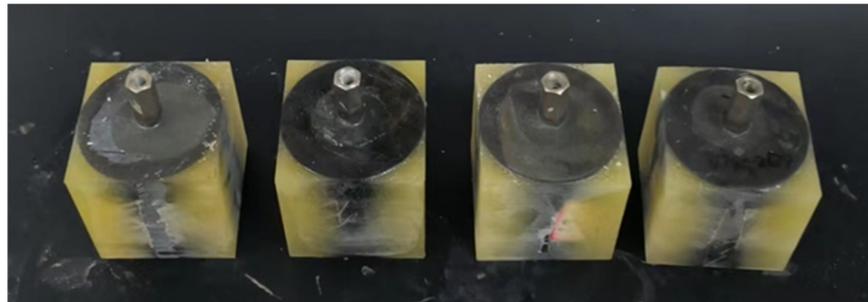
### 2.1. Rock Sample Preparation

The experimental setup involved rock samples sourced from the Jimsar Block in Xinjiang, extracted from depths ranging from 3045 to 3172 m underground (Figure 1). To conduct the shale damage test, cylindrical samples with a diameter of 25.4 mm and a height of 30 mm were prepared for permeability testing. Meanwhile, the cylinder samples were

encapsulated in epoxy resin and molded into cube-shaped samples measuring 100 mm × 100 mm × 100 mm (Figure 2) to facilitate fracturing tests.



**Figure 1.** Full-diameter shale cores.



**Figure 2.** Cemented core with stainless steel wellbore.

The CO<sub>2</sub> fracturing fluid used in the experiments comprised formation water, the CO<sub>2</sub> thickeners VIC-6 and VIC-2 (Xian Victory Co., Ltd., Xi'an, China), and 99.9% pure CO<sub>2</sub> (Beijing Huatong Jingke Co., Ltd., Beijing, China). For shale damage tests and tri-axial fracturing tests, water-based fracturing fluids containing a 0.1% concentration of polyacrylamide were employed.

## 2.2. Experimental Setup and Procedures

### 2.2.1. Rheological Test of CO<sub>2</sub> Fracturing Fluid

Liquid viscosity is the main factor affecting fracturing effects, which has a direct influence on fracture morphology and proppant-carrying effects. In this part, the rheology of CO<sub>2</sub> fracturing fluid was studied. The CO<sub>2</sub> fracturing fluid preparation device consists of a heating system, a CO<sub>2</sub> pumping system, a pressurization system, a stirring system, a viscosity testing system, a control system, and a reaction kettle with a sapphire window (Figure 3). The equipment was provided by Tochuang Co., Ltd., Ningbo, China. The characteristics and main parameters were as follows:

- Maximum torque: 200 mN·m;
- Volume: 400 mL;
- Minimum rotation speed CR: 10 rpm;
- Maximum rotation speed: 1500 rpm;
- Temperature range: high-temperature electric heating system: 20 degrees to 400 degrees; able to withstand pressure of 40 MPa;
- Maximum lateral loading capacity: 6 Kn.



**Figure 3.** CO<sub>2</sub> fracturing fluid preparation and rheological testing device.

The experimental setup for configuring and testing the CO<sub>2</sub> fracturing fluid involved the following steps:

1. **Base fluid preparation:** The experimental water was prepared with NaCl at a salinity of 600 ppm. The base fluid was then configured with various water–carbon ratios. For instance, if the ratio was 30/70 (water/CO<sub>2</sub>), 132 mL of water and 268 mL of CO<sub>2</sub> were combined. The thickeners, VIC-6 and VIC-2, were added in appropriate proportions. Specifically, the VIC-6 volume was 1.2% of the water volume (1.584 mL), while the VIC-2 volume was 1.5% of the CO<sub>2</sub> volume (4.02 mL). After adding the thickeners, the mixture was stirred thoroughly to ensure uniform distribution before transferring it to the miscible device.
2. **CO<sub>2</sub> fracturing fluid configuration:** CO<sub>2</sub> was introduced into the miscible device using a gas booster pump to increase the pressure inside the device. Once the pressure stabilized, mechanical stirring was employed to disperse and mix the miscible system. The stirring was performed in both the forward and reverse directions for 15 min at a speed of 2500 rpm to ensure thorough dispersion and homogeneity of the fracturing fluid.
3. **Rheological testing:** The prepared CO<sub>2</sub> fracturing fluid is then subjected to rheological testing using a Harkar rheometer (Thermo Fisher, Waltham, MA, USA) to evaluate its rheological characteristics at different temperatures.

#### 2.2.2. Shale Permeability Damage Test

When the shale matrix is exposed to CO<sub>2</sub> fracturing fluid, a series of chemical reactions will occur, resulting in changes in the physical properties of the shale matrix. In this part, the shale permeability alteration induced by CO<sub>2</sub>-based fracturing fluid is studied, and a PDP instrument was applied to conduct the permeability determination. The experimental process was as follows:

1. The column samples were dried, and the permeability of the untreated shale was measured to establish a baseline.
2. The core sample comprising both the core plug and fragments was placed in the high-temperature and high-pressure reactor. The reactor was then evacuated and subsequently immersed in a water bath device set to a constant temperature of 60 °C.
3. CO<sub>2</sub>-based fracturing fluid was pumped into the high-temperature and high-pressure reactor until the pressure within the reactor increased by 10 MPa. The core sample was allowed to react with the fracturing fluid for designated durations of 3, 5, and 7 days, respectively.

- After the specified reaction periods, the core plug and fragments were removed from the reactor. The core plug was dried and subjected to permeability testing to assess any changes in permeability resulting from the interaction with the fracturing fluid. Meanwhile, the fragments underwent further treatment to meet the requirement of the XRD test, and the alterations in mineral composition were evaluated.

In an experimental setup similar to the one described above, a control group utilizing slickwater was employed to conduct shale hydration experiments. This control was included to provide a comparative baseline and further elucidate the changes in shale permeability under the influence of CO<sub>2</sub>-based fracturing fluid. The experimental procedure closely resembled that of the CO<sub>2</sub> fracturing fluid experiments, with the main difference lying in the choice of fluid used. In this case, slickwater was utilized instead of CO<sub>2</sub> fracturing fluid.

### 2.2.3. True Triaxial Fracturing Experiment

The experimental instruments were provided by Tochuang Co., Ltd., Ningbo, China. The experimental equipment are shown in Figure 4, including a stress servo control system, a rock high-temperature heating system, and an injection pump. After fracturing, a Computed Tomography (CT) device was applied to reconstruct the fracture distribution in rock samples. In this study, a GE Brivo CT385 (General Electric Company, Shanghai, China) was used (Figure 5). The experimental process was as follows:

- A stainless steel shaft was drilled into the center of the rock sample, and the well was cemented using high-strength cement to ensure stability.
- The prepared sample was placed in the triaxial loading chamber, ensuring the device's airtightness. CO<sub>2</sub> fracturing fluid was prepared in an intermediate container, and the pipeline was connected. Triaxial stress is gradually applied until it reaches stability. Fluid is injected into the sample at a set flow rate, and fracturing tests are conducted. Pressure changes are recorded during the test, and injection ceases when a significant pressure drop occurs, indicating completion of fracturing.
- After fracturing, the sample is placed in a high-precision CT device. Cracks in the rock are reconstructed using the CT device and post-processing software. This step allows for detailed visualization and analysis of fracture distribution within the rock sample, providing valuable insights into the fracturing process and fracture characteristics.

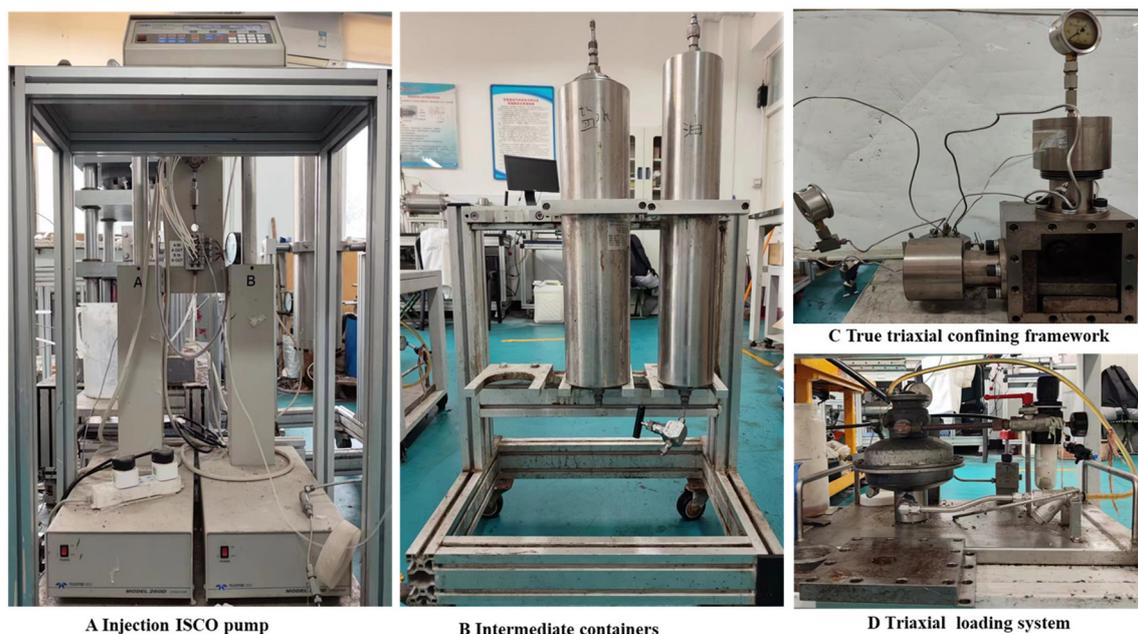


Figure 4. True triaxial fracturing device.

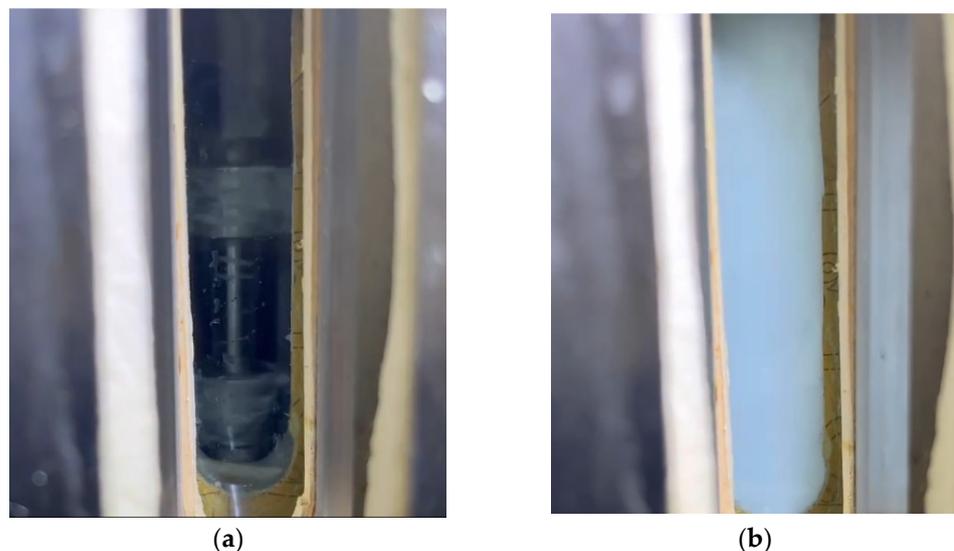


**Figure 5.** CT equipment.

### 3. Results and Discussion

#### 3.1. High-Pressure and High-Temperature Rheological Experiment

Conventional CO<sub>2</sub> fluid exhibits low viscosity, posing challenges in meeting sand-carrying requirements during fracturing operations. To address this issue, viscosity enhancement of CO<sub>2</sub> was achieved herein through the use of thickeners, specifically the water-based thickener VIC-6 and the CO<sub>2</sub> thickener VIC-2 (Figure 6). These two thickeners are miscible and, when mixed, undergo copolymerization of monomers such as ethyl propenyl ether, methyl methacrylate, octadecyl methacrylate, and allyl carbonate in a CO<sub>2</sub>-philic solvent. This process leads to increased structural viscosity through molecular chain stretching and an enhanced probability of entanglement with neighboring molecules.

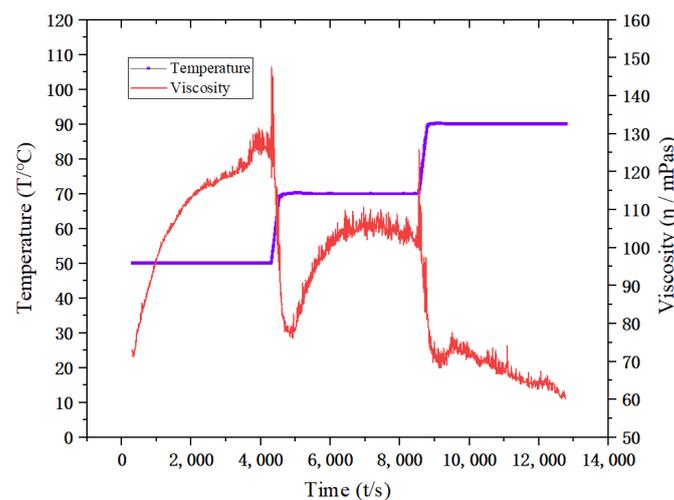


**Figure 6.** Mixture of CO<sub>2</sub> and water-based thickener (a) before stirring and (b) after stirring.

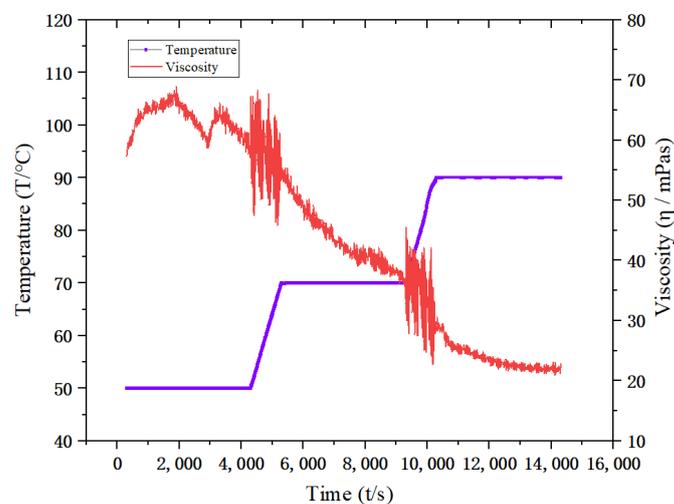
However, as liquid CO<sub>2</sub> is a weak solvent and almost immiscible with water, a small amount of water-based fracturing fluid is necessary for sand carrying in CO<sub>2</sub> quasi-dry fracturing. Optimizing the water–carbon ratio of the liquid CO<sub>2</sub> and water base is essential to minimize damage while ensuring stable fracturing fluid performance. CO<sub>2</sub> fracturing fluid comprises a thickener base fluid and CO<sub>2</sub>, with varying rheological properties at different water–carbon ratios. Rheological experiments were conducted for different water–carbon ratios (30:70, 40:60, and 35:65). The viscosity of CO<sub>2</sub> fracturing fluid is summarized in Table 1. The results indicate that the fluid viscosity is sensitivity to the temperature. Specifically, the liquid viscosity decreases with increasing temperature, with a maximum drop of approximately 50 mPa·s observed. Moreover, the viscosity of the fracturing fluid initially increases and then decreases with increasing water content. The viscosity is 104 mPa·s at a water–carbon ratio of 30:70, and further increases in water content result in a rapid viscosity decrease (Figures 7–9). This phenomenon suggests that 30:70 is the optimal ratio.

**Table 1.** Viscosity of CO<sub>2</sub> fracturing fluid.

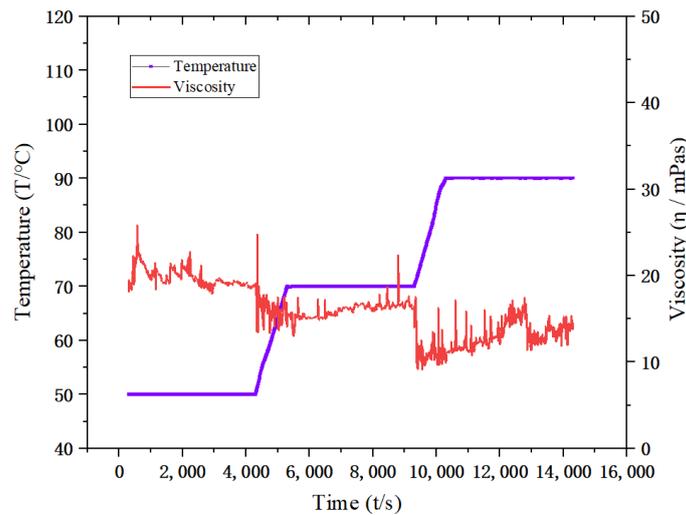
| Water–Carbon Ratio | Temperature, °C |       |       |
|--------------------|-----------------|-------|-------|
|                    | 50              | 70    | 90    |
| 30:70              | 104.25          | 93.37 | 78.70 |
| 35:65              | 63.50           | 45.63 | 22.56 |
| 40:60              | 19.43           | 16.77 | 15.62 |



**Figure 7.** Viscosity–temperature relationship at a water–carbon ratio of 30:70.



**Figure 8.** Viscosity–temperature relationship at a water–carbon ratio of 35:65.

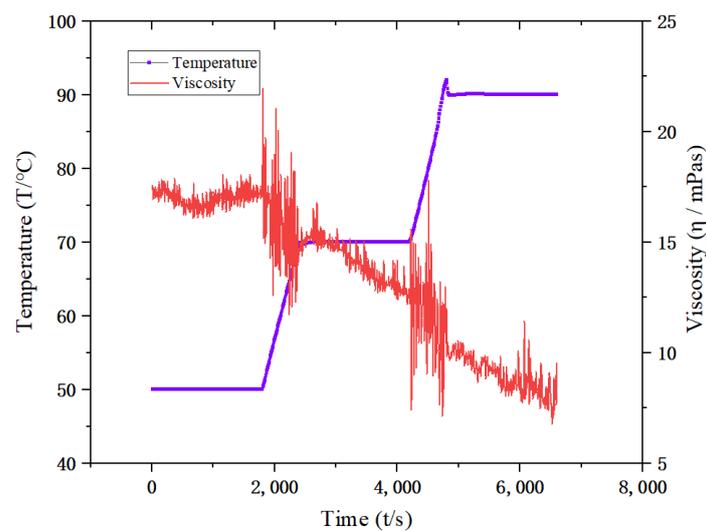


**Figure 9.** Viscosity–temperature relationship at a water–carbon ratio of 40:60.

On the basis of the optimal water–carbon ratio, the viscosity of CO<sub>2</sub> fracturing fluid at different concentrations of water-based thickener was studied. Testing was conducted using different concentrations (0.5%, 0.6%, 0.8%, and 1.2%) of an aqueous-phase viscosifier at temperatures of 50 °C, 70 °C, and 90 °C through the quasi-dry method. As the concentration of liquid thickener decreases, the viscosity of the miscible liquid experiences a rapid decline. This reduction in viscosity poses challenges in achieving the requisite viscosity for sand-carrying purposes (Figures 10–12).

### 3.2. Mineral Composition and Permeability Variation

Shale is a type of sedimentary rock primarily composed of fine-grained mineral particles, with a composition that typically includes clay minerals, quartz, and a variety of accessory minerals. XRD results revealed that the shale samples primarily consisted of quartz and clay minerals, constituting approximately 30% and 25% of the composition, respectively. Additionally, carbonate minerals such as dolomite and calcite made up around 20% of the composition (Figure 13).



**Figure 10.** Viscosity–temperature relationship at a VIC-6 concentration of 0.5%.

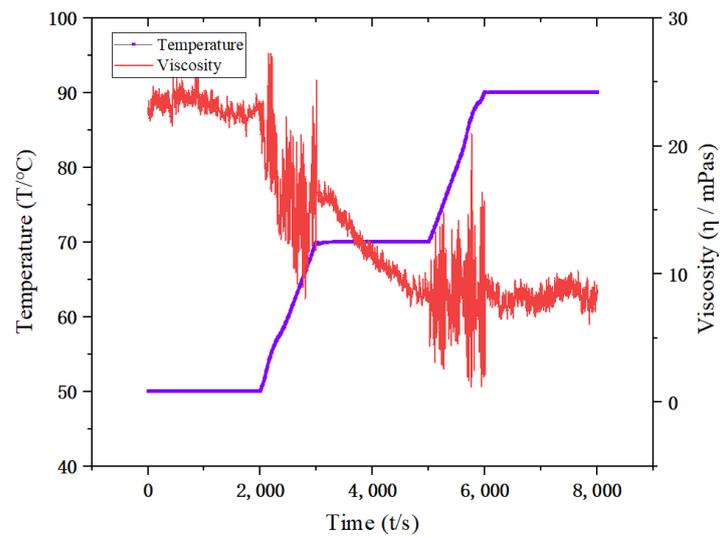


Figure 11. Viscosity–temperature relationship at a VIC-6 concentration of 0.6%.

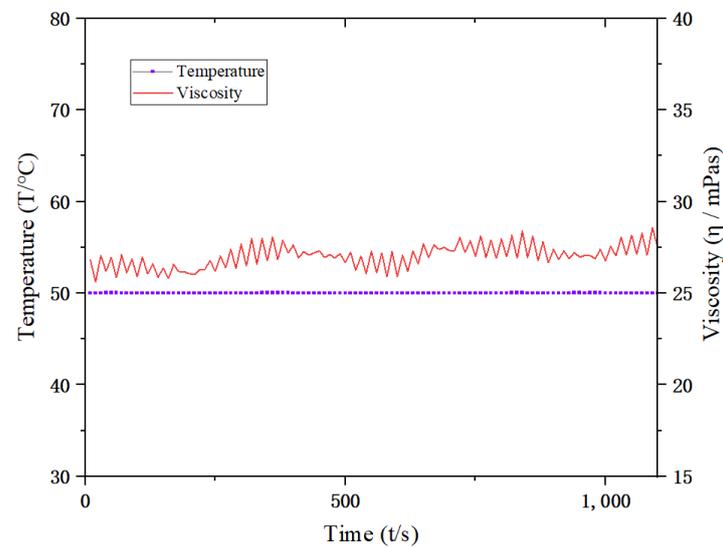


Figure 12. Viscosity–temperature relationship at a VIC-6 concentration of 0.7%.

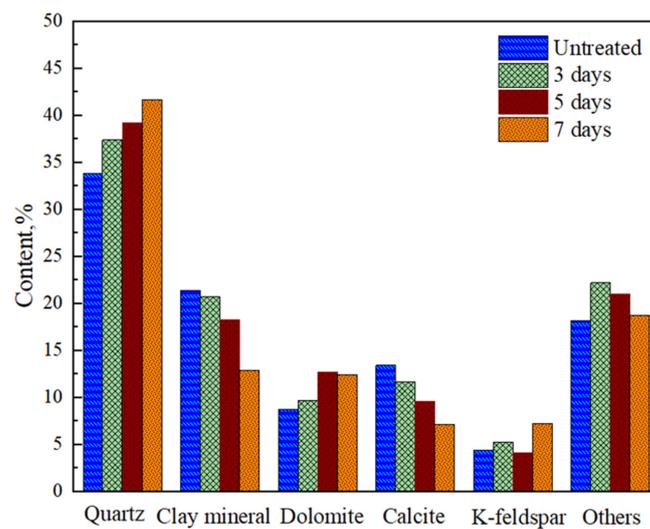
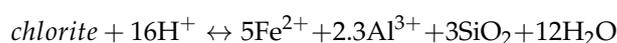
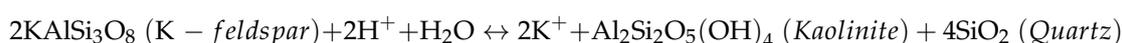
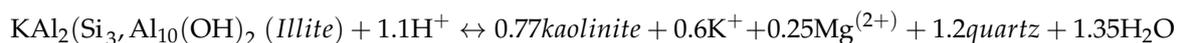


Figure 13. Mineral composition of shale under CO<sub>2</sub> fracturing fluid treatment.

In this section, a CO<sub>2</sub> fracturing fluid was prepared with a water–carbon ratio of 30:70. When the fracturing–fluid base is not fully mixed with CO<sub>2</sub>, its pH remains neutral at 7. However, upon complete mixing with CO<sub>2</sub>, the fracturing fluid becomes acidic, initiating a series of chemical reactions with the mineral composition of the rock [27]. These reactions involve mineral dissolution and the formation of new minerals, which are the primary factors influencing the change in shale permeability. In an acidic environment, feldspar, illite, and chlorite undergo partial dissolution, leading to the formation of more stable minerals such as quartz and kaolinite. This transformation process results in an increase in quartz content as the reaction progresses. Additionally, calcite, being a typical carbonate mineral, is consumed in this acidic environment, leading to a decrease in its content over time.



The permeability testing results are depicted in Figure 14. The permeability of the untreated shale was 474 nD. The permeability of shale in a slickwater environment exhibited a clear decreasing trend over time. After 3 days, 5 days, and 7 days of hydration reaction, the shale permeability values were recorded as 313 nD, 249 nD, and 217 nD, respectively. The absorption of water may induce swelling and expansion of clay minerals [28]. Water absorption causes shrinkage of pore spaces and reduces pore connectivity, ultimately resulting in decreased permeability. In contrast, the variation of shale permeability is more complicated when it is exposed to a CO<sub>2</sub>-based fracturing fluid environment. After 3 days of reaction, the permeability of the shale matrix increased to 541 nD, indicating an enlargement effect due to chemical reactions, leading to improved pore connectivity and increased permeability. Subsequently, after 5 days of reaction, the matrix permeability exhibited a downward trend, dropping to 314 nD. This suggested that the chemical reaction was nearing completion, and while a small amount of water in the fracturing fluid might cause hydration expansion leading to core damage, the permeability changes were relatively minor with further extension of the reaction time. Finally, after 7 days of reaction, the permeability stabilized, indicating that CO<sub>2</sub>–water–rock interaction had minimal influence on permeability at this stage. This stability suggested that the chemical reactions had reached equilibrium, resulting in a relatively stable permeability state in the shale matrix. Indeed, while CO<sub>2</sub> fracturing fluid can still cause some damage to the reservoir, the extent of damage is generally less severe than that induced by water-based fracturing fluids. This is primarily due to the chemical properties of CO<sub>2</sub> and its interaction with the reservoir rock. One advantage of CO<sub>2</sub> fracturing fluid is its ability to undergo a phase change, transitioning from a supercritical state to a gaseous state upon depressurization. This phase change facilitates the rapid flowback of the fracturing fluid from the reservoir, minimizing the duration of fluid–rock interaction and reducing potential damage to the formation. Efficient flowback of the CO<sub>2</sub> fracturing fluid is key to further reducing reservoir damage and enabling efficient reservoir development.

### 3.3. True Triaxial Fracturing Experiment Results

In this section, fracture morphology and propagation characteristics with different fracturing media were studied. To ensure experimental consistency, all rock samples were subjected to the same stress state, and both fracturing fluids were injected into the core at the same rate through the wellbore.

The shale samples exhibited prominent bedding development and typical layered stacking characteristics, indicative of their sedimentary origin. The presence of distinct bedding planes is essential for understanding fracture propagation behavior, as these planes can influence the path and orientation of fractures within the rock matrix (Figures 15 and 16).

1. Fractures induced by slickwater

The injection of water into the core resulted in the formation of a single symmetrical two-winged slit fracture. This fracture initiated along the borehole and propagated radially outward, creating a distinct fracture pattern. Analysis of CT results revealed that the average crack width generated by water injection measured 0.27 mm, with the resulting crack volume calculated at 1296 mm<sup>3</sup>.

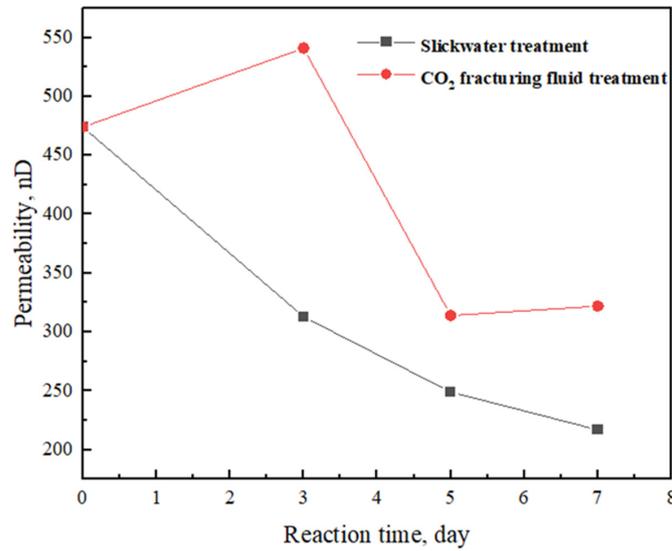


Figure 14. Permeability variation with different fracturing fluid treatments.

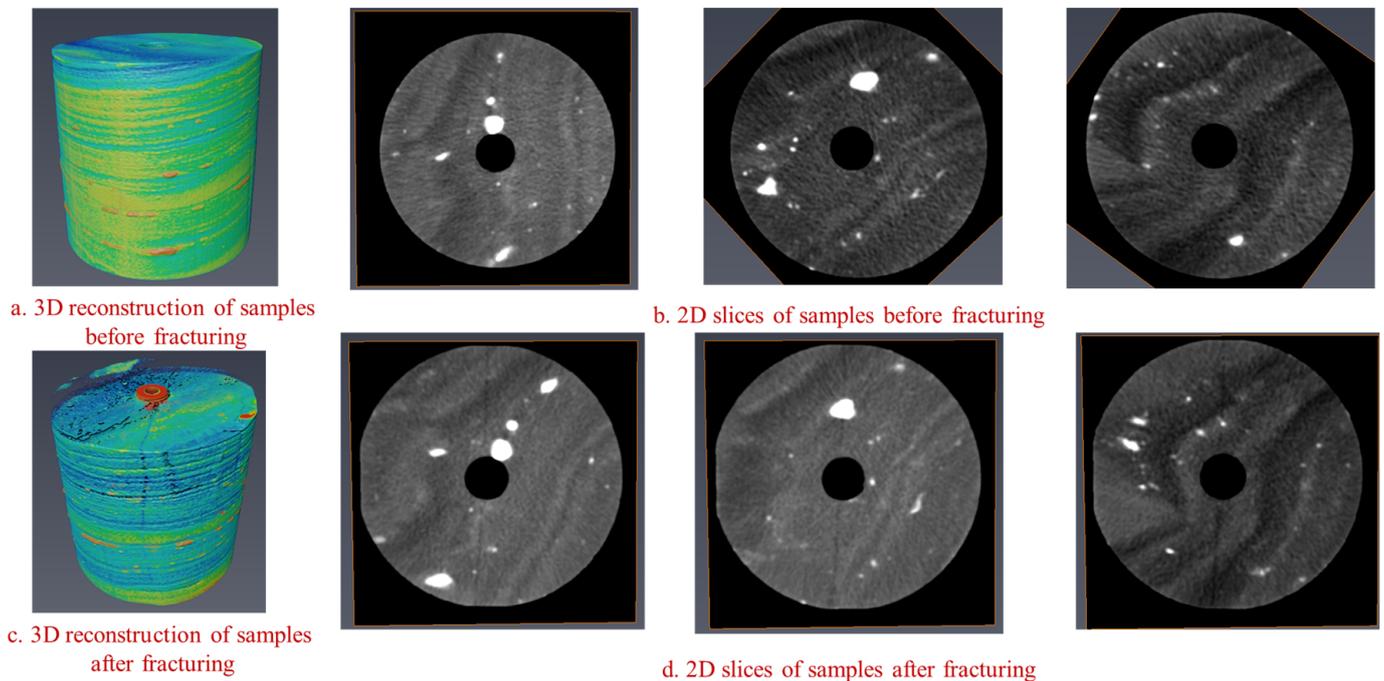
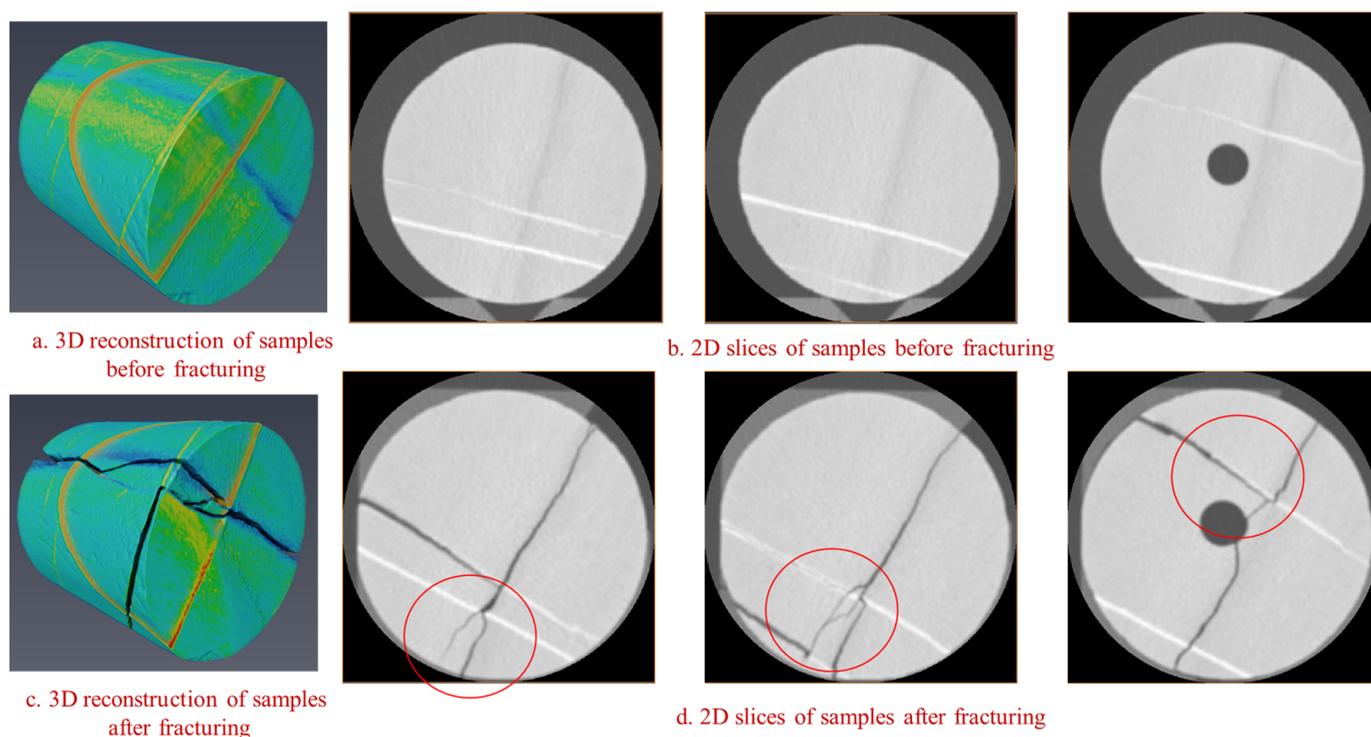


Figure 15. Reconstruction image of hydraulically fractured shale sample.



**Figure 16.** Reconstruction image of CO<sub>2</sub> quasi-dry fractured shale sample.

## 2. Fractures induced by CO<sub>2</sub> fracturing fluid

As depicted in Figure 16, fractures formed by CO<sub>2</sub> injection exhibited greater complexity than those induced by water. The CO<sub>2</sub>-induced fractures displayed a variety of characteristics, including fractures along bedding planes and fractures cutting through the bedding. Some fractures expanded rapidly along weak surfaces such as filling joints within the core, while others extended vertically through original veins and weak surfaces. Additionally, some fractures changed direction upon encountering weak surfaces, leading to the complete opening of these weak surfaces and resulting in the complete fracturing of the core. This multifaceted behavior culminated in the formation of a more intricate fracture network.

CT results revealed that although the fractures induced by CO<sub>2</sub> fracturing fluid were narrower than water-induced fractures, with an average width of 0.14 mm, the resulting fracture volume was significantly higher. Specifically, the fracture volume generated by CO<sub>2</sub> hydraulic fracturing was approximately 7.6 times that induced by water, totaling about 9873 mm<sup>3</sup>.

## 4. Conclusions

In this paper, a comprehensive investigation of CO<sub>2</sub> quasi-dry fracturing in shale reservoirs was conducted. The rheological characteristics of CO<sub>2</sub> fracturing fluid under high temperature and pressure were determined through laboratory experiments, and the fracture distribution characteristics and matrix permeability changes under CO<sub>2</sub> fracturing fluid treatment were evaluated. Several key findings were obtained:

1. Compared to conventional water-based fracturing fluids, quasi-dry CO<sub>2</sub> fracturing fluid causes less damage to the reservoir. Under the influence of CO<sub>2</sub> fracturing fluid, core permeability initially increases before decreasing. Short-term exposure to the fracturing fluid enhances reservoir permeability, but prolonged exposure is detrimental.
2. The acidic environment of CO<sub>2</sub> quasi-dry fracturing fluid promotes the dissolution of feldspar, illite, and chlorite minerals, which initially compensates for the decrease in permeability caused by shale expansion. However, as soaking time increases, the

- weakening effect of chemical reactions allows shale hydration expansion to regain dominance, leading to a decrease in shale permeability.
3. The viscosity of conventional CO<sub>2</sub> is insufficient for proppant transport into fractures, and water-based thickeners are necessary to improve CO<sub>2</sub> viscosity. Rheological tests demonstrate that a water–carbon ratio of 3:7 yields a maximum viscosity of 104 mPa·s for CO<sub>2</sub> fracturing fluid. Adjusting the water proportion affects viscosity, with higher proportions leading to decreased viscosity. Additionally, temperature significantly influences fracturing fluid viscosity.
  4. Fractures formed by conventional water-based fracturing fluids tend to be relatively singular, with small volumes but larger widths (approximately 0.27 mm). In contrast, fractures induced by CO<sub>2</sub> fracturing fluid exhibit larger volumes, with an average width of only 0.14 mm.
  5. CO<sub>2</sub> fracturing fluid exhibits a high rock-breaking ability. Particularly, in cores with numerous weak surfaces, the fluid tends to rapidly open along these weak surfaces, leading to the formation of a complex fracture network.

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