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Pore-Scale Flow Mechanisms of CO₂ Fracturing Fluid in a Pore-Fracture Microfluidic Model

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Abstract

CO₂ is a promising fracturing fluid for tight reservoirs because it avoids water-phase damage and offers low viscosity, high diffusivity, and strong penetration into fine pore throats, but its pore-scale flow in pore-fracture systems remains difficult to evaluate because thermodynamic state, fractures, and mass transfer act together. In this study, a radial microfluidic model containing randomly distributed microfractures was used with a temperature- and pressure-controlled visualization platform to compare CO₂–oil and water–oil flow. Image segmentation and areal-fraction statistics quantified swept area and final fluid distribution. Gaseous CO₂ at ambient pressure and compressed-liquid CO₂ below the critical temperature differ substantially in density and viscosity, but both retain a discernible CO₂–oil interface and exhibit pressure-driven preferential-path flow. The gaseous case shows strong fracture guidance and fingering, whereas the compressed-liquid velocity series demonstrates increasingly rapid advancement and stronger channeling at excessive velocity. Under near-critical supercritical conditions (35 °C, 8 MPa), progressive oil-color fading ahead of the displacement front shows that dissolution participates while flow expands through matrix pores. Under higher-temperature supercritical conditions, disappearance of the sharp interface and continuous color attenuation identify dissolution-assisted diffusion as a significant transport mechanism and produce diffuse redistribution across the pore space. Water undergoes immiscible channelized displacement and remains capillary-trapped in small throats and low-permeability regions. The results identify three flow regimes: distinct-interface pressure-driven displacement, near-critical convection–dissolution coupling, and higher-temperature supercritical dissolution-assisted diffuse redistribution.

Keywords: CO₂ fracturing; tight reservoir; microfluidics; pore-scale flow; pore-fracture system; supercritical CO₂



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1. Introduction

Tight oil and gas resources are a key target for unconventional reserve growth and production replacement. These reservoirs commonly have low porosity, low permeability, small pore throats, and strong heterogeneity [1–4]. Their low natural productivity makes hydraulic fracturing central to economic development [5,6]. Conventional water-based fracturing can build effective fracture networks, but water-based fluids entering tight formations are readily trapped by capillary forces and can cause water blocking, low flowback efficiency, reservoir damage, and a reduction in effective conductivity [6–8]. As

unconventional development moves toward tighter and more heterogeneous reservoirs, reducing fracturing-fluid damage while improving matrix utilization has become a key direction for fracturing design.

CO₂ fracturing has received increasing attention because it avoids water-phase damage, has low viscosity and strong diffusivity, and can be recycled or partly stored underground [9–12]. Above its critical conditions, CO₂ becomes supercritical and combines liquid-like density with gas-like viscosity; its high diffusivity further promotes transport into fine pore structures [13,14]. Experimental comparisons among water, liquid CO₂, and supercritical CO₂ also show that fluid state changes the fracturing response [15]. In addition to entering fractures and pore space as a working fluid, CO₂ dissolves and transfers into crude oil, promoting oil replacement and fluid redistribution [16]. CO₂ fracturing has the potential to couple reservoir stimulation, enhanced oil recovery, and partial CO₂ storage.

Although field application and production evaluation of CO₂ fracturing have progressed, the pore-scale transport and fracture-matrix partitioning of CO₂ require further investigation. Recent microfluidic and nanofluidic studies have begun to resolve post-fracturing interface dynamics, microscale displacement and mass-transfer behavior, and confined CO₂-hydrocarbon miscibility [17–19]. At the pore scale, pore-throat microstructure influences CO₂ flow and associated formation damage [20], while fracture connectivity creates preferential pathways [21,22]. CO₂ diffusion under reservoir conditions [14] and mass transfer into oil [16] introduce phase-exchange mechanisms beyond immiscible displacement. Because CO₂ density, viscosity, solubility, and interfacial tension vary strongly with temperature and pressure, its partitioning between fractures and matrix pores can change substantially under different reservoir conditions.

Microfluidic visualization provides a useful way to examine multiphase flow at the pore scale [17–19]. By building controlled pore structures and recording interface evolution in real time, path selection, swept area, and residual-fluid distribution can be observed after a fracturing fluid enters a pore-fracture system. Many existing microfluidic studies, however, are performed at ambient conditions and use planar pore-network chips with a single inlet and outlet or an end-face displacement configuration. Such designs mainly represent linear or quasi-one-dimensional flow along a fixed pressure gradient. They are less suited to capturing the phase-state changes in CO₂ under temperature- and pressure-controlled conditions and the radial flow of fracturing fluid from fractures toward matrix pores. A temperature- and pressure-controlled microfluidic visualization method suitable for CO₂ fracturing conditions is needed, together with quantitative image analysis to identify the controlling mechanisms.

This work focuses on tight-reservoir pore-fracture systems. A radial microfluidic model containing randomly distributed microfractures was constructed on a temperature- and pressure-controlled microscopic flow visualization platform. Pore-scale flow experiments were carried out under gaseous, compressed-liquid, near-critical supercritical, and higher-temperature supercritical CO₂ conditions, together with water–oil comparisons and injection-velocity tests. Image recognition and areal-fraction statistics were used to quantify fluid migration and the secondary distribution of resident fluids. The four thermodynamic states were retained separately in the experimental scheme and synthesized into three observed flow regimes. Gaseous and compressed-liquid CO₂ exhibited distinct-interface, pressure-driven preferential-path flow; near-critical CO₂ showed convection–dissolution coupling and greater matrix participation; and higher-temperature supercritical CO₂ produced dissolution-assisted diffuse redistribution without a sharp front. Excessive injection velocity intensified preferential channeling and reduced matrix sweep. These findings reveal how thermodynamic state, fracture guidance, and injection velocity jointly control CO₂ distribution in the tested pore-fracture system.

2. Materials and Methods

2.1. Temperature- and Pressure-Controlled Microscopic Visualization Platform

The CO₂ fracturing-fluid flow experiments were performed using a self-designed temperature- and pressure-controlled microscopic flow visualization system. The system consists of four parts: a fluid injection unit, a temperature and pressure control unit, a microfluidic model, and an image acquisition unit, as shown in Figure 1a,b. The injection unit includes a high-pressure pump, a vacuum pump, and four intermediate vessels for CO₂, oil, water, and cleaning fluid. The temperature and pressure control unit includes a temperature- and pressure-controlled chamber, a model holder, a temperature controller, and a pressure transmitter, allowing the chamber temperature and the confining and internal model pressures to be controlled during the experiment. The acquisition unit includes a stereomicroscope, a high-speed CMOS camera, an image-processing workstation, and supporting software. The microscope has a magnification range of 6.1–55 $\times$, a field-of-view diameter of 37.7 mm, and a camera resolution of 2048 $\times$ 1536, which is sufficient to record dynamic two-phase distributions in the chip. The internal fluid pressure was monitored using a KELLER Series 33X piezoresistive pressure transmitter (KELLER Pressure AG, Winterthur, Switzerland), with a measurement range of 0–100 MPa. During testing, the holder was filled with confining fluid, and the confining pressure was kept 1–2 MPa higher than the fluid pressure inside the microfluidic model to protect the chip and reduce pressure-fluctuation effects on image observation [23].

2.2. Microfluidic Chip Design

To represent a coupled pore-fracture structure in a tight reservoir while keeping the flow process visible, a circular radial microfluidic model was designed, as shown in Figure 2a. A central inlet (1) was used to simulate fracturing fluid moving from the wellbore toward the surrounding reservoir matrix. The fluid entered the microscopic flow cell (3) through an injection channel (2), where the flow process was observed. Four equal-length and symmetric outlet channels (4/5/6/7) were connected to two outlets (8 and 9) to maintain pressure balance in the flow cell. Compared with a conventional linear-displacement model, this radial model better represents the flow of fracturing fluid from a local high-pressure source into the surrounding matrix. As shown in Figure 2b,c, the circular porous domain had a diameter of 10 mm and a uniform channel depth of 5 μ m. The central inlet had a diameter of 1 mm and was connected to an injection channel with a width of 1 mm. The four symmetric outlet branches each had a width of 0.5 mm. The matrix region consisted of cylindrical micropillars with a diameter of 200 μ m and a center-to-center spacing of 210 μ m, corresponding to a minimum pore-throat width of 10 μ m. Eight predefined microfractures were incorporated into the model, with fracture apertures ranging from 50 to 216 μ m.

Both the substrate and cover plate of the microfluidic chip were fabricated from soda–lime–silica glass. The pore-fracture geometry was first designed using AutoCAD (version 2021) and subsequently converted into a photomask. The designed pattern was transferred to the glass substrate by mask photolithography followed by isotropic wet chemical etching. After patterning, the substrate and cover plate were cleaned, aligned in a clean and particle-free environment, and sealed by glass-to-glass thermal fusion bonding.

Before use, each chip was examined under an optical microscope to identify blocked pore throats, residual particles, bonding voids, local delamination, and obvious dimensional defects. The chip was then completely placed in a water-filled high-pressure chamber, with water serving as the external pressure-transmitting medium. The chamber pressure was increased stepwise to 100 MPa. After the pressure had stabilized, the integrity of the glass structure and bonding interface was examined.

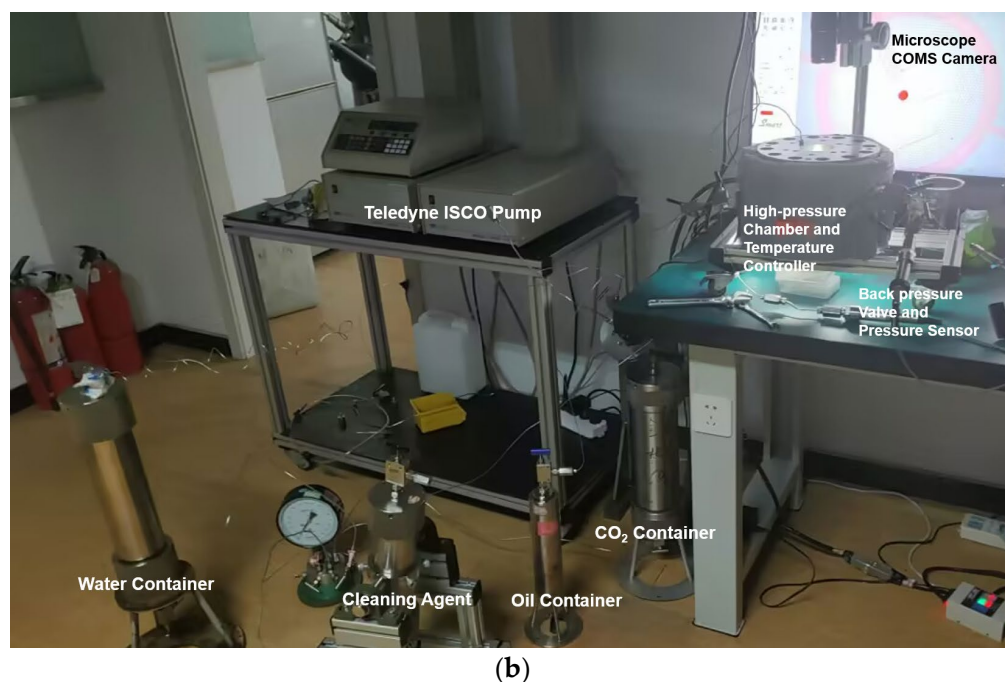
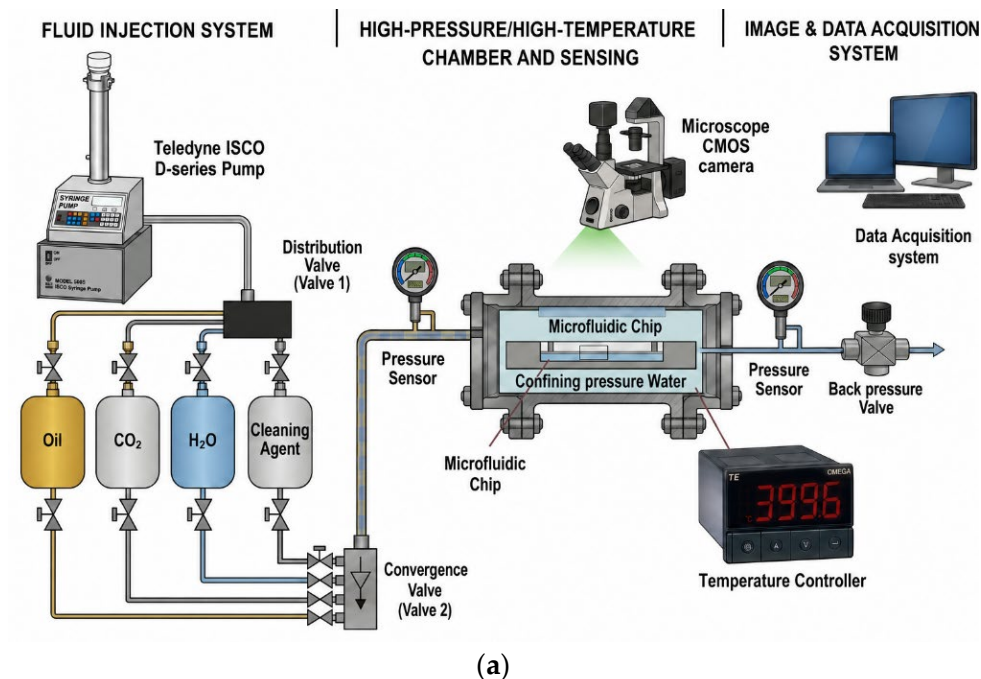


Figure 1. Schematic diagram and physical image of the temperature- and pressure-controlled microscopic flow visualization platform. (a) Schematic diagram; (b) physical object image.

The microfluidic model was simplified as follows: all matrix pillars were set as cylinders; pore-throat wall roughness and wall compressibility were neglected; the model height was fixed at 5 μm ; and nanoscale pores and throats, which contribute less to the observed flow in this model, were not explicitly included. The model mainly retained micron-scale pore structures. Randomly distributed microfractures were added to the uniform-pillar-based porous medium to represent the influence of natural fractures on fracturing-fluid flow paths.

2.3. Experimental Materials and Test Scheme

Industrial-grade CO₂ with a purity of 99.9% was used as the test gas. The experimental liquids were light kerosene and deionized water. Light kerosene was used as the substitute oil phase, with a density of 0.82 g/cm³ and a viscosity of 1.29 mPa s; 1 wt.% Sudan Red was added as a dye. Deionized water had a density of 1.01 g/cm³ and a viscosity of 1.055 mPa s; 1 wt.% methylene blue was added as a dye. With this coloring scheme, colorless CO₂ and red oil could be distinguished in the CO₂–oil experiments, while blue water and red oil could be distinguished in the water–oil experiments.

Light kerosene was selected as a transparent, low-viscosity model oil to support direct visualization of interface migration and color attenuation. Its viscosity (1.29 mPa s) is representative of the low-viscosity end of light hydrocarbon liquids and provides a comparable order of viscous contrast for qualitative pore-scale flow analysis. Tight oil can span a broader viscosity range and contains a wider molecular-weight distribution, including variable resin and asphaltene fractions that can contribute to CO₂-induced deposition and formation damage [26]. Consequently, the magnitude of CO₂ solubility, oil swelling, viscosity reduction, and interfacial-property changes depends on crude-oil composition and thermodynamic conditions [13]. Deionized water provides a stable water-phase baseline, whereas field water-based fracturing fluids can contain dissolved salts, polymers, surfactants, and suspended solids. Because each controlled-variable series used identical model-fluid compositions, these compositional differences are expected to have a limited influence on the comparative flow-path and phase-distribution trends, while absolute interfacial and mass-transfer values remain fluid-specific.

Sudan Red and methylene blue were used as phase-selective optical tracers. Under the tested conditions, both dyes behaved as chemically nonreactive tracers: no visible precipitation, cross-phase color transfer, or persistent residue was observed during repeated experiments and cleaning checks. After sequence-specific image normalization, sustained fading of the Sudan-Red-dyed oil served as the optical marker of CO₂ entry, dissolution, and subsequent redistribution within the oil phase. Small changes in interfacial tension or surface affinity may arise from dissolved colorants, but the dye type and concentration were held constant within each fluid system. Their contribution remained secondary to the controlled changes in CO₂ state, injection velocity, temperature, and pressure.

A controlled-variable experimental design was used to examine the effects of fracturing-fluid type, fluid temperature, injection pressure, and injection velocity on two-phase pore-scale flow. Under each condition, interface advance, oil-color attenuation, channel selection, and final fluid distribution were recorded after CO₂ or water entered the pore-fracture system. The experimental scheme is listed in Table 1.

Table 1. Complete experimental conditions for each test case.

Case	Temperature (°C)	Pressure (MPa)	CO ₂ Phase State	Injection Velocity (m/s)	Injected Fluid (s)	Experimental Series
1	25	8	Compressed liquid	0.0005	CO ₂ /Water	Temperature
2	35	8	Supercritical (near-critical)	0.0005	CO ₂ /Water	Temperature
3	45	8	Supercritical	0.0005	CO ₂ /Water	Temperature
4	55	8	Supercritical	0.0005	CO ₂ /Water	Temperature
5	25	0.1 (atmospheric)	Gaseous	0.0005	CO ₂ /Water	Pressure
6	25	20	Compressed liquid	0.0005	CO ₂ /Water	Pressure
7	25	30	Compressed liquid	0.0005	CO ₂ /Water	Pressure
8	25	50	Compressed liquid	0.0005	CO ₂ /Water	Pressure
9	25	8	Compressed liquid	0.005	CO ₂ /Water	Injection velocity
10	25	8	Compressed liquid	0.001	CO ₂ /Water	Injection velocity
11	25	8	Compressed liquid	0.0005	CO ₂ /Water	Injection velocity
12	25	8	Compressed liquid	0.0001	CO ₂ /Water	Injection velocity

To provide a quantitative physical basis for interpreting the observed flow patterns, the fluid properties corresponding to the experimental conditions in Table 1 were compiled, as summarized in Table 2. The density and dynamic viscosity of CO₂ were obtained from reference thermodynamic and transport-property correlations, whereas the CO₂–oil interfacial tension, solubility, and diffusion coefficient were estimated from published data for representative CO₂–hydrocarbon systems.

Table 2. Physical properties and estimated CO₂–oil interaction parameters corresponding to the experimental conditions in Table 1.

Case (s)	ρ_{CO_2} (kg·m ^{−3})	μ_{CO_2} (mPa·s)	$\sigma_{\text{CO}_2\text{--o}}$ (mN·m ^{−1})	S_{CO_2} (mol·kg ^{−1})	D (10 ^{−9} m ² ·s ^{−1})	T_D (s)
1, 9–12	776.6	0.0674	N.C.	N.C.	4.5	5556
2	419.1	0.0292	0.43	32.7	5.0	5000
3	241.0	0.0208	3.99	14.6	5.7	4386
4	203.6	0.0201	7.06	8.44	6.4	3906
5	1.81	0.0149	25.0	N.C.	7.5	3333
6	914.2	0.0963	N.C.	N.C.	3.8	6579
7	966.5	0.1113	N.C.	N.C.	3.3	7576
8	1034.2	0.1358	N.C.	N.C.	2.8	8929

Notes: Temperature, pressure, injection velocity, and CO₂ phase state are listed in Table 1. ρ_{CO_2} and μ_{CO_2} denote CO₂ density and viscosity; $\sigma_{\text{CO}_2\text{--o}}$ is the estimated CO₂–oil interfacial tension; S_{CO_2} is the estimated CO₂ solubility in the surrogate hydrocarbon; D is the estimated diffusion coefficient; and $T_D = R^2/D$, where $R = 5$ mm. N.C. denotes not calculated.

Based on the physical properties in Table 2 and the characteristic dimensions of the microfluidic model, the viscosity ratio, capillary number, pore-scale Péclet number, and Reynolds number were calculated for the experimental cases, as listed in Table 3. These dimensionless parameters were used to relate the observed flow-path development and swept-area evolution to the relative effects of viscous force, capillary force, convective transport, molecular diffusion, and fluid inertia. To avoid repeating the temperature, pressure, injection velocity, and CO₂ phase-state information already provided in Tables 1–3 are indexed by experimental case number.

Table 3. Characteristic dimensionless parameters for the CO₂ experimental cases in Table 1.

Case (s)	M_μ	Ca	Pe_p	Re
1, 11	0.0523	N.C.	1.11	0.0573
2	0.0226	3.36×10^{-5}	1.00	0.0715
3	0.0161	2.60×10^{-6}	0.88	0.0577
4	0.0156	1.42×10^{-6}	0.78	0.0505
5	0.0116	2.98×10^{-7}	0.67	6.03×10^{-4}
6	0.0746	N.C.	1.32	0.0472
7	0.0863	N.C.	1.52	0.0432
8	0.1053	N.C.	1.79	0.0379
9	0.0523	N.C.	11.11	0.573
10	0.0523	N.C.	2.22	0.115
12	0.0523	N.C.	0.22	0.0115

Notes: The corresponding temperature, pressure, injection velocity, and CO₂ phase state are listed in Table 1. The dimensionless parameters were defined as $M_\mu = \mu_{\text{CO}_2}/\mu_{\text{oil}}$, $Ca = \mu_{\text{CO}_2}U/\sigma_{\text{CO}_2\text{--o}}$, $Pe_p = Uw_t/D$, and $Re = \rho_{\text{CO}_2}Ud_h/\mu_{\text{CO}_2}$. The characteristic lengths were $w_t = 10$ μm and $d_h = 9.95$ μm . N.C. indicates that the capillary number was not calculated because a reliable finite interfacial tension was unavailable.

2.4. Experimental Procedure and Image-Based Quantification

The experimental procedure included system connection and evacuation, temperature and pressure setting, adjustment of image-acquisition parameters, oil saturation,

fracturing-fluid injection, image recording, and chip cleaning. The microfluidic model was first installed in the holder, and the connectivity and sealing of the system were checked. Residual air was then removed using the vacuum pump. After the experimental temperature and confining pressure were set and stabilized, dyed kerosene was injected from an intermediate vessel to saturate the model. CO₂ or water was then introduced from the inlet, while the pressure difference was stabilized using the outlet back-pressure valve. Each key experimental condition was repeated three times using the same chip after cleaning. Between repeated runs, the chip was cleaned with ethanol and then inspected under an optical microscope to confirm that no residual dye, residual oil, or blocked pore throats remained. The quantitative results are presented as mean $\pm$ standard deviation. The standard deviation reflects run-to-run variability associated with initial saturation, pressure control, and flow-path selection.

Image processing was performed using ImageJ (version 1.54P). All image sequences were first registered using stationary features of the microfluidic structure to correct small frame-to-frame displacements. Each frame was then cropped to the same circular porous-domain region of interest. The inlet channel, outlet channels, regions outside the circular observation domain, image annotations, and solid micropillars were excluded using a fixed pore-space mask derived from microfluidic geometry.

Because the absolute image intensity could vary among experiments as a result of differences in the optical path, temperature and pressure condition, and illumination, each image sequence was normalized against its own initial oil-saturated frame. The normalized images were converted into 32-bit grayscale images. Threshold segmentation was then performed to distinguish the CO₂-affected or water-occupied region from the initially oil-saturated region.

The same image-processing procedure and threshold-selection rule were applied to all comparable experimental sequences. However, a single numerical threshold was not imposed on all experiments because their initial optical intensities were not identical. For each experimental sequence, the reference threshold (T_0) was determined from the normalized grayscale image using the Otsu algorithm and was then kept unchanged for all frames within that sequence. The binary segmentation result was overlaid on the corresponding original image and checked visually to ensure that solid pillars, illumination gradients, and regions outside the pore space were not incorrectly classified as fluid-affected areas. The image-processing workflow is illustrated in Figure 4.

To quantitatively evaluate the influence of threshold selection on the image-derived areal fraction, four representative experimental conditions were selected for threshold-sensitivity analysis, including gaseous CO₂, near-critical supercritical CO₂, higher-temperature supercritical CO₂, and water–oil displacement. For each representative image, the areal fraction was recalculated using ($0.95T_0$), (T_0), and ($1.05T_0$), and the results are summarized in Table 4.

Table 4. Sensitivity of the image-derived areal fraction to the segmentation threshold.

Representative Case	Image Time (s)	A ($0.95T_0$) (%)	A (T_0) (%)	A ($1.05T_0$) (%)	Maximum Absolute Deviation (%)	Maximum Relative Deviation (%)
Gaseous CO ₂ , 25 °C, atmospheric pressure	40	49.2	48.1	46.9	1.2	2.49
Near-critical supercritical CO ₂ , 35 °C, 8 MPa	30	83.4	81.2	78.9	2.3	2.83
Higher-temperature supercritical CO ₂ , 55 °C, 8 MPa	20	92.5	89.1	85.4	3.7	4.15
Water–oil, 25 °C, 8 MPa	50	46.8	45.9	44.7	1.2	2.61

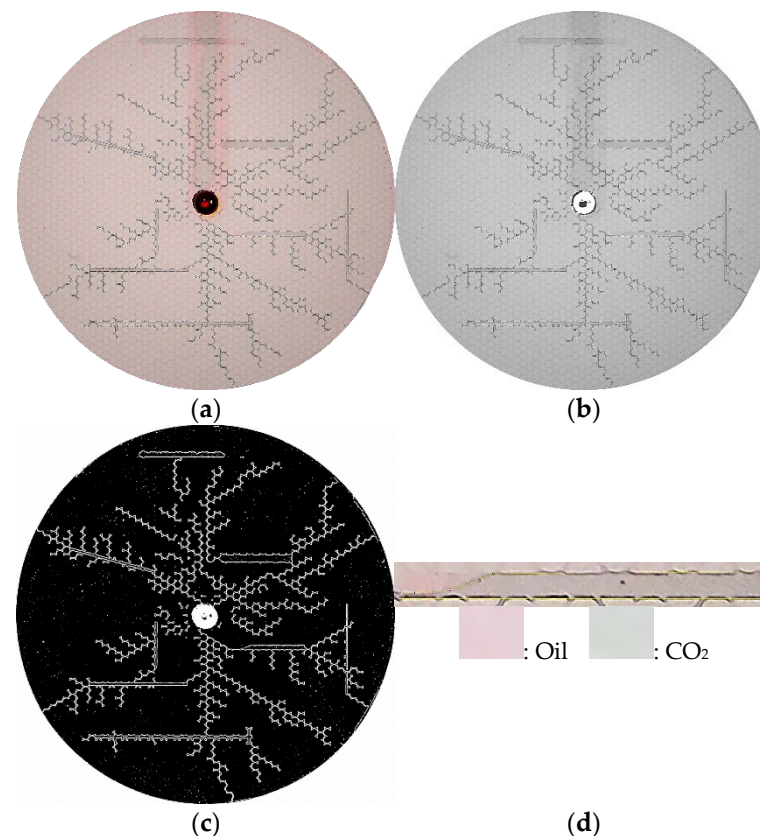


Figure 4. Example of image post-processing. (a) The original image excluding the areas outside the circular observation field (such as entrance and exit channels, etc.); (b) 32-bit grayscale image; (c) Binary image; (d) extracted fracturing-fluid area in a single fracture.

The threshold-sensitivity analysis showed that a $\pm 5\%$ variation in the reference threshold resulted in maximum relative deviations of 2.49–4.15% in the calculated areal fractions. The supercritical CO₂ case exhibited the greatest sensitivity because of its gradual and spatially diffuse color attenuation, whereas the gaseous CO₂ and water–oil cases, which retained comparatively distinct interfaces, were less sensitive to threshold variation. Nevertheless, the maximum relative deviation remained below 5% for all representative cases, indicating that the principal image-derived trends were not substantially affected by small variations in threshold selection.

Because the microfluidic model is two-dimensional with a uniform depth, the volume fraction of the fracturing fluid can be approximated by its areal fraction:

$$R_L = \frac{V_L}{PV} \times 100\% \approx \frac{S_L}{S_p} \times 100\% \quad (3)$$

where R_L is the percentage of pore volume occupied by the fracturing fluid, V_L is the volume of fracturing fluid in the pores, PV is the total pore volume, S_L is the area occupied by the fracturing fluid, and S_p is the total flow-channel area. For fluid distribution in an individual fracture, the area occupied by CO₂ or water in that fracture was extracted separately and divided by the total fracture area.

3. Results and Discussion

3.1. CO₂ Thermodynamic States and Flow-Regime Transition

The experimental results show that the CO₂ state causes markedly different two-phase migration and secondary fluid distribution. Under gaseous conditions, the CO₂–oil system maintains a clear immiscible interface, but the front advances nonuniformly through the

pore network. Preferential entry into low-resistance branches produces fracture-guided channelized displacement accompanied by fingering. When the advancing CO₂ front reaches a fracture, the fracture rapidly becomes the main conduit, and CO₂ extends along it with limited lateral replenishment into the adjacent matrix. These preferential pathways create a nonuniform flow pattern and restrict matrix-pore coverage (Figure 5).

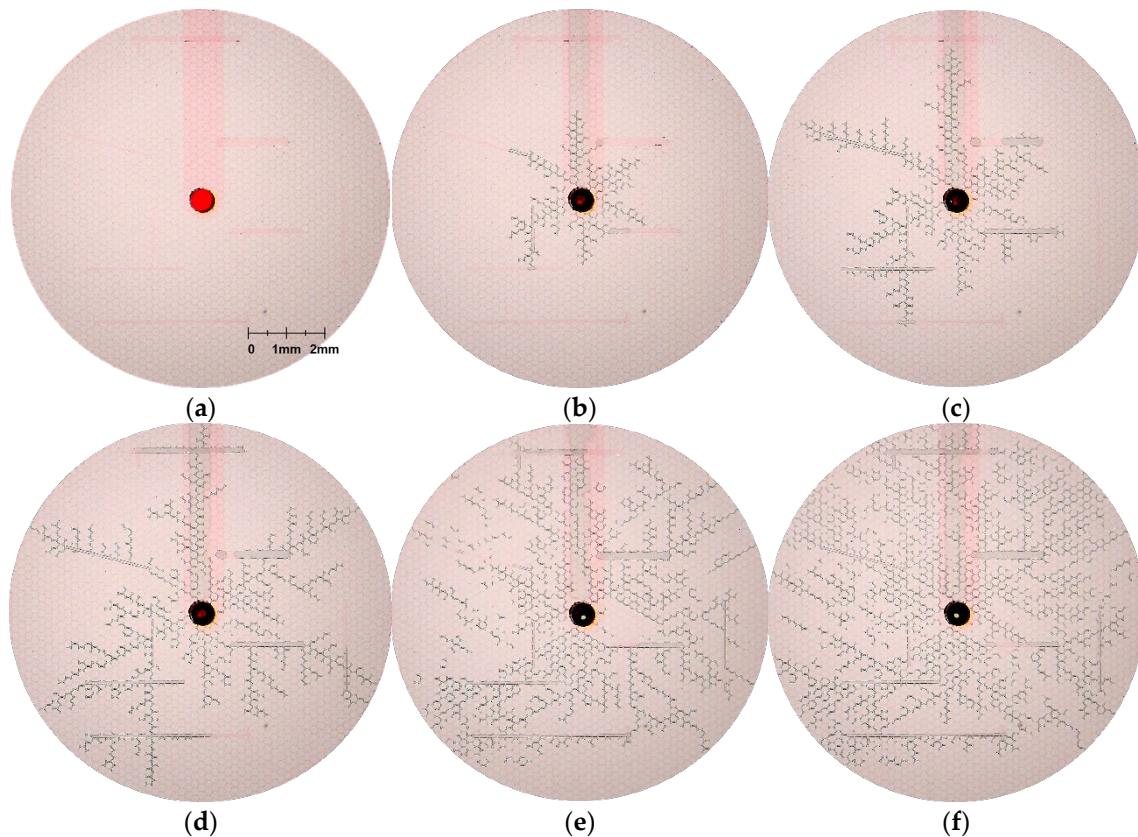


Figure 5. Fracture-guided channelized displacement accompanied by fingering during gaseous CO₂ injection. (a) $t = 0$; (b) $t = 5$ s; (c) $t = 10$ s; (d) $t = 15$ s; (e) $t = 20$ s; (f) $t = 40$ s.

At 25 °C, increasing pressure above the saturation pressure places CO₂ in the compressed-liquid state. The density and viscosity rise from 776.6 kg/m³ and 0.0674 mPa s at 8 MPa to 1034.2 kg/m³ and 0.1358 mPa s at 50 MPa (Table 2). The 25 °C, 8 MPa velocity series retains a discernible CO₂–oil boundary and preferential-path advancement, although the propagation rate and swept area vary with velocity. Gaseous and compressed-liquid CO₂ are kept as separate thermodynamic states in Table 1 and grouped at the mechanism level as distinct-interface pressure-driven displacement. This framework captures their shared flow morphology while Tables 1 and 2 retain the state-specific density, viscosity, and phase behavior.

Under near-critical supercritical conditions (35 °C, 8 MPa), the normalized red intensity of the Sudan-Red-dyed oil decreases progressively, showing that colorless CO₂ enters and dissolves in the resident oil. Color attenuation begins before a stable displacement front develops (Figure 6), demonstrating that CO₂ transfer extends ahead of bulk-interface advance and that diffusion participates in the early redistribution. As injection continues, the CO₂–oil interface develops while the flow expands in multiple directions through matrix pores instead of being diverted predominantly into fractures (Figure 7). The close-packed matrix arrangement (Figure 8) produces the observed hexagonal-star front. The reduced deflection into fractures and the multidirectional matrix propagation reflect a

reduced effective flow-resistance contrast between fractures and matrix pores, allowing matrix geometry to exert stronger control on the overall distribution.

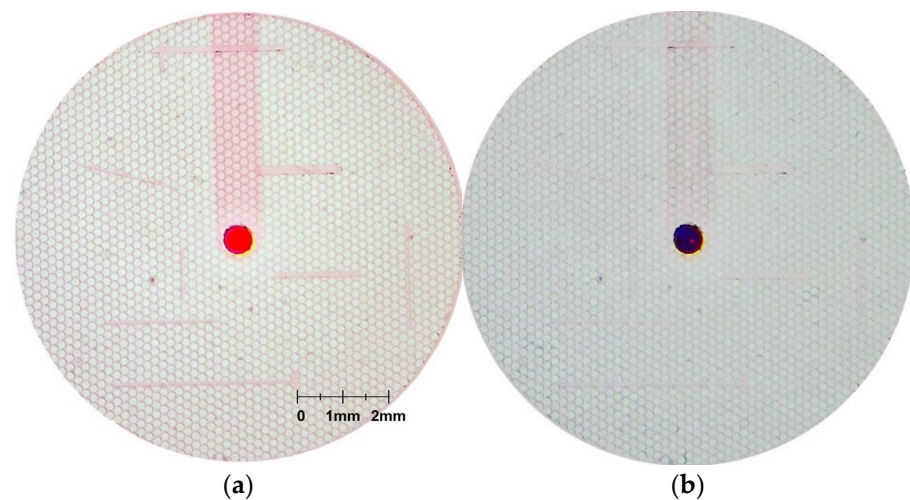


Figure 6. Early-stage fluid distribution during CO₂ injection under near-critical conditions. (a) $t = 0$; (b) $t = 42$ s—oil color becomes much lighter, consistent with CO₂ transfer into the oil phase.

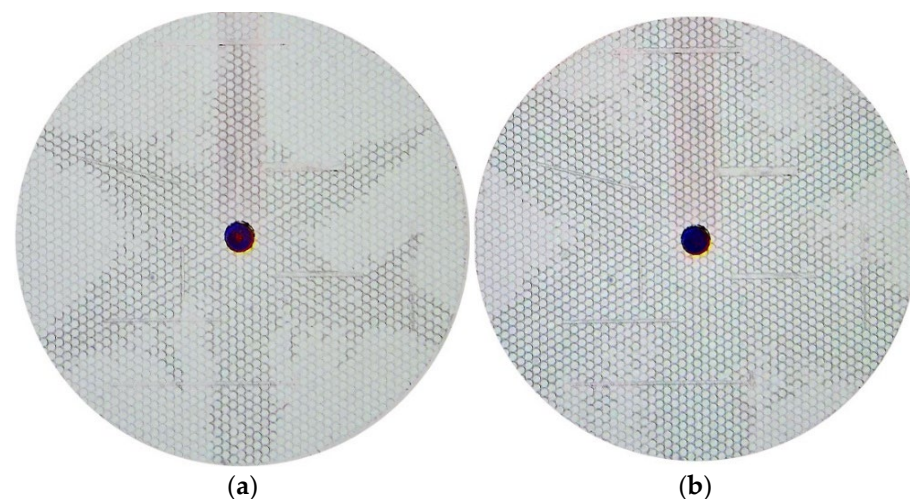


Figure 7. Mid-stage fluid distribution during CO₂ injection under near-critical conditions. (a) $t = 43$ s; (b) $t = 44$ s.



Figure 8. Close-packed pore arrangement in the microfluidic model.

Under higher-temperature supercritical conditions, the CO₂–oil system no longer shows a distinct two-phase displacement front. As injection continues, the Sudan-Red-dyed oil fades progressively from the inlet toward surrounding pores and eventually becomes nearly transparent. With illumination normalized to the initial oil-saturated frame and Sudan Red remaining confined to the oil phase, this continuous attenuation records CO₂ entry and dissolution in the resident oil. Propagation of the color-change region

beyond a discernible interface reveals diffusion-mediated redistribution after dissolution. Dissolution–diffusion contributes significantly to the supercritical flow pattern and expands the CO₂-affected region through both fractures and matrix pores. The coordinated loss of a sharp interface, continuous oil-color attenuation, and matrix-wide expansion of the affected region establish the transition from sharp-front channelized displacement to dissolution-assisted diffuse redistribution under supercritical conditions. The corresponding spatial evolution is shown in Figure 9.

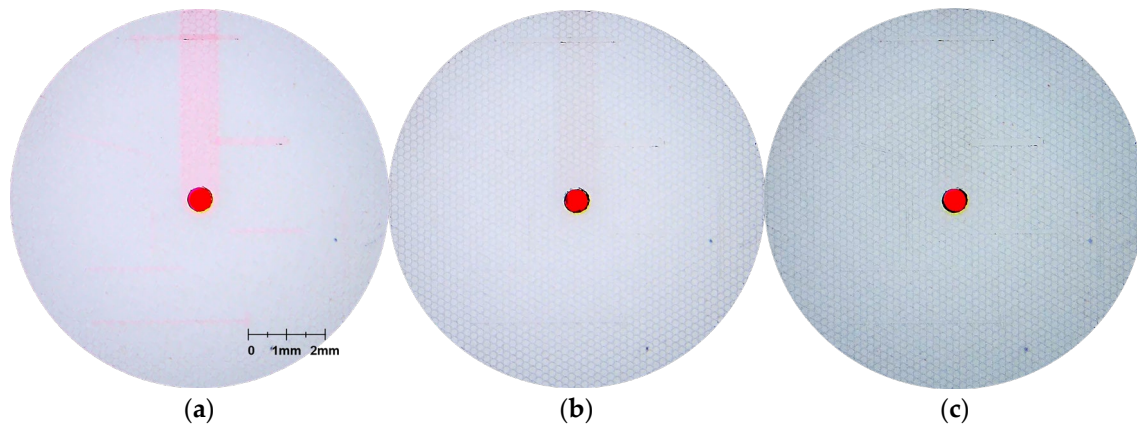


Figure 9. Evolution of fluid distribution in the supercritical CO₂–oil system. (a) $t = 0$, initial state; (b) $t = 600$ s—no clear displacement front or two-phase interface; oil color gradually fades; (c) $t = 1800$ s—Sudan-Red-dyed oil is fully decolorized; no two-phase interface is observed.

Temperature and pressure change the CO₂ phase state and its density, viscosity, and estimated CO₂–oil interaction properties (Table 2). The thermodynamic states remain distinct in Table 1, while the observations are synthesized into three flow regimes. Gaseous and compressed-liquid CO₂ retain a discernible interface and exhibit pressure-driven preferential-path displacement. At the near-critical supercritical condition, progressive oil-color attenuation and multidirectional matrix propagation identify convection–dissolution coupling. Under higher-temperature supercritical conditions, loss of the sharp interface and matrix-wide color attenuation mark dissolution-assisted diffuse redistribution. Figure 10 presents representative images of these three regimes, with the gaseous case representing the distinct-interface regime; compressed-liquid behavior is quantified separately in the injection-velocity analysis.

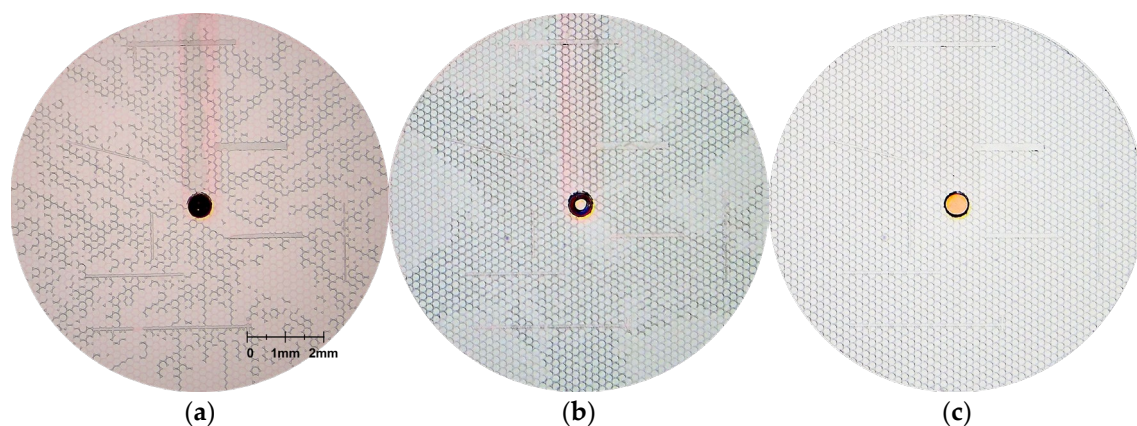


Figure 10. Representative pore-scale distributions for distinct-interface gaseous displacement, near-critical coupling, and higher-temperature supercritical redistribution. (a) Gaseous CO₂ (25 °C, At-mospheric pressure); (b) near-critical supercritical CO₂ (35 °C, 8 MPa); (c) supercritical CO₂ (55 °C, 8 MPa).

The affected-area curves compare the near-critical and higher-temperature supercritical regimes under elevated-pressure conditions (Figure 11). Under higher-temperature supercritical conditions, the affected area rises rapidly and oil-color attenuation expands through the pore space over a shorter period, revealing faster dissolution-assisted access to the oil-filled region. At the near-critical condition, the gradual increase records slower CO₂ transfer and matrix expansion while a developing interface remains discernible. Together, Figures 10 and 11 show the transition from near-critical convection-dissolution coupling to higher-temperature supercritical diffuse redistribution.

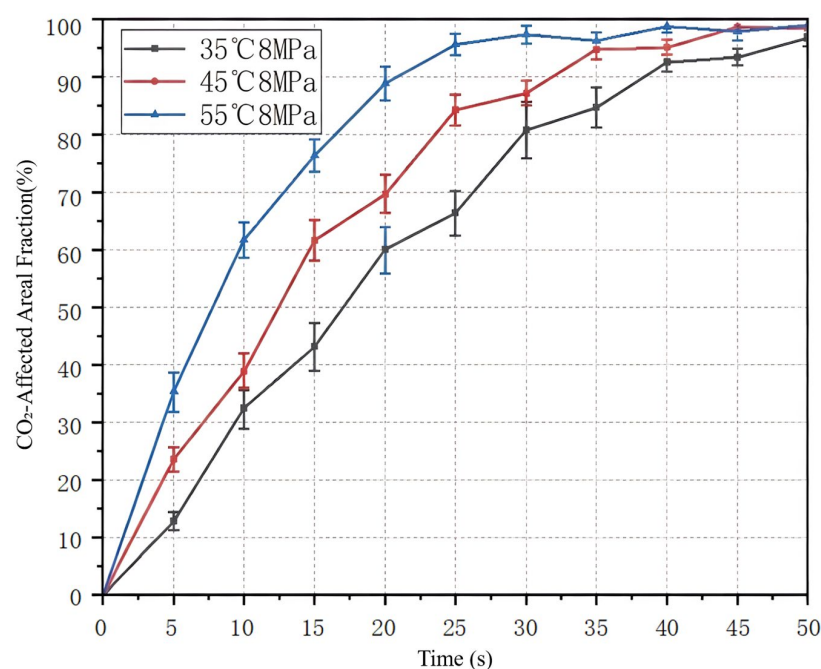


Figure 11. CO₂-affected areal fraction versus time under near-critical and higher-temperature supercritical conditions.

3.2. Comparison Between CO₂ and Water

The water-phase experiment shows incompressible and immiscible displacement with a continuous water–oil interface (Figure 12; pink denotes oil and blue denotes water). Water first advances through fractures and high-permeability channels, which rapidly develop into dominant flow paths. After front passage, water remains immobilized in small pore throats, pore corners, blind ends, and low-permeability regions. These residual aqueous patches are produced by capillary trapping under the comparatively high water–oil interfacial tension and constitute the pore-scale fluid-retention morphology responsible for water blocking.

Compared with water, CO₂ produces a fundamentally different phase-distribution pattern. Water transport is dominated by immiscible channelized displacement and capillary trapping, leaving residual aqueous patches in small throats and low-permeability zones. Under near-critical and higher-temperature supercritical conditions, sustained fading of the oil phase demonstrates CO₂ dissolution into the resident oil, and the color-change region extends through a broader portion of the matrix pore space. This comparison identifies two distinct transport pathways: capillary-controlled aqueous displacement and retention for water and increasingly dissolution-assisted matrix redistribution for CO₂ as its state changes.

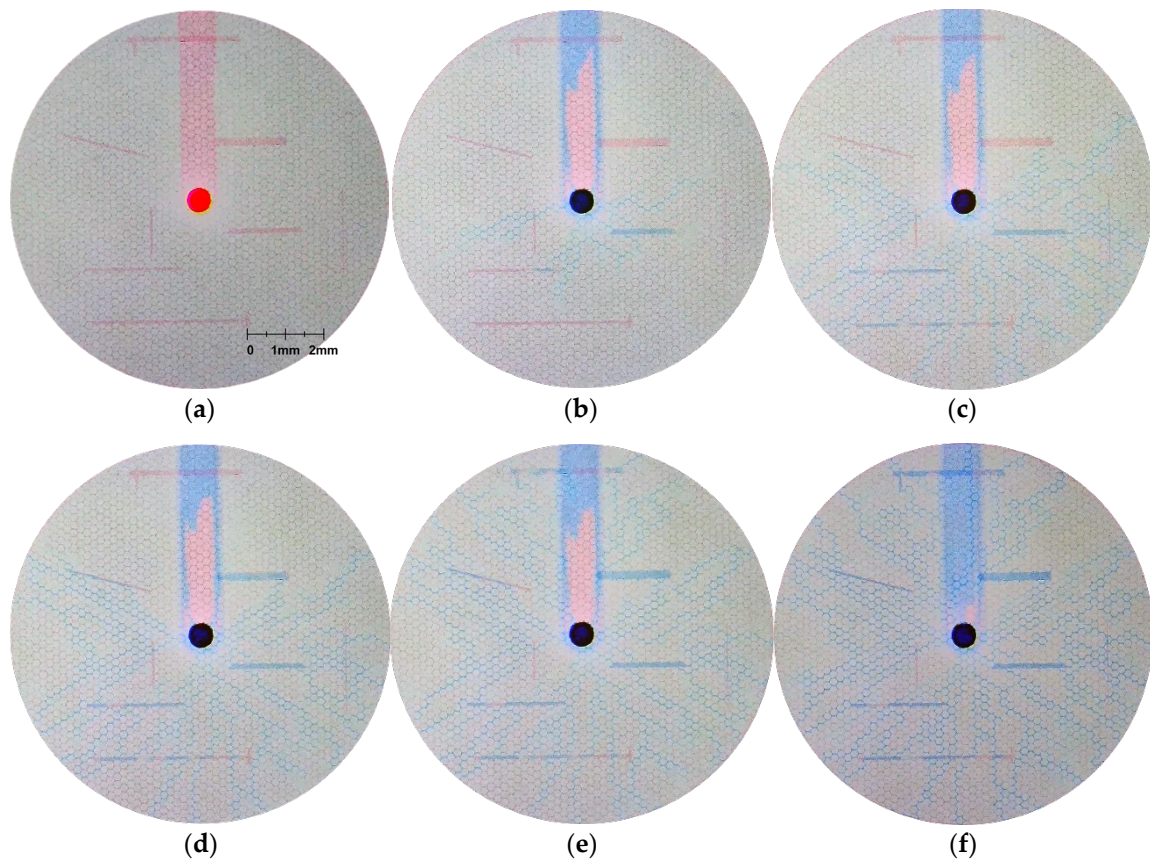


Figure 12. Time-dependent distribution of the water phase in the water–oil system. (a) $t = 0$; (b) $t = 5$ s; (c) $t = 10$ s; (d) $t = 20$ s; (e) $t = 50$ s; (f) $t = 100$ s.

3.3. Effects of Injection Velocity and Injected PV

All injection-velocity experiments were conducted at 25 °C and 8 MPa, where CO₂ was in the compressed-liquid state. Injection velocity controls the rate at which CO₂ enters the pore-fracture system. As velocity increases from a low to an intermediate level, CO₂ advances more rapidly and the swept area increases. At low velocity, CO₂ mainly follows larger pores and low-resistance channels, while entry into smaller pores remains delayed (Figure 13). This selective advance shows capillary-limited access to small pore throats at low injection rates.

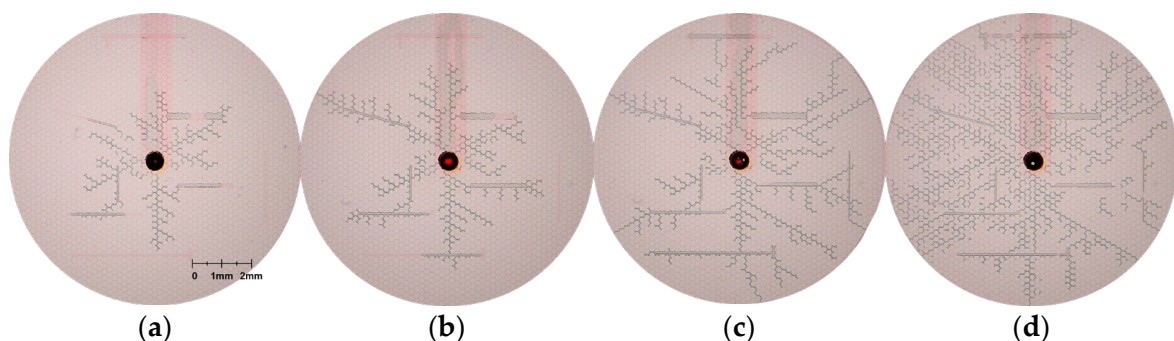


Figure 13. Flow-path distribution of compressed-liquid CO₂ at different injection velocities (25 °C, 8 MPa; $t = 30$ s). (a) $v = 0.0001$ m/s; (b) $v = 0.0005$ m/s; (c) $v = 0.001$ m/s; (d) $v = 0.005$ m/s.

CO₂ saturation was used to quantify the affected area at different injection velocities (Figure 14). Higher velocity accelerates early advancement, but swept area does not increase linearly with velocity. At the highest velocity, the saturation curve reaches an inflection

point earlier, subsequent growth weakens, and the final affected area remains below that obtained at the intermediate velocity. The early inflection and reduced final coverage reveal preferential channeling through fractures and large pores, which bypasses part of the surrounding matrix.

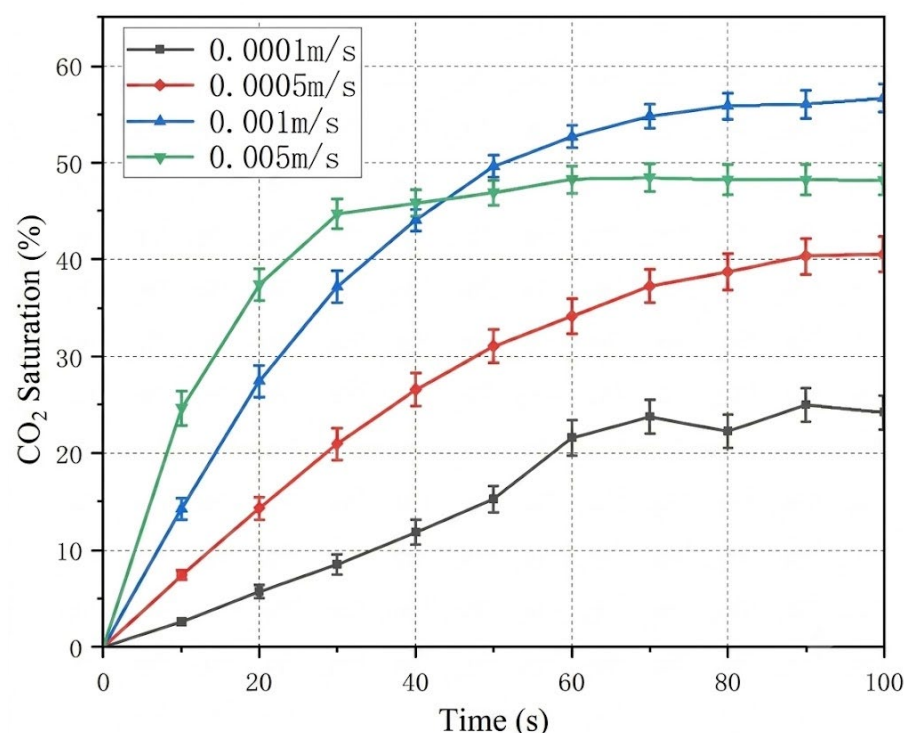


Figure 14. CO₂ saturation versus time at different injection velocities under compressed-liquid conditions (25 °C, 8 MPa).

The velocity results indicate a nonmonotonic operating range. Low velocity produces slow advancement, intermediate velocity balances propagation and swept-area growth, and high velocity accelerates breakthrough along preferential pathways while reducing late-stage growth. Injection velocity should be selected by considering pore-throat size, preferential fracture pathways, and the CO₂ state.

To distinguish the effect of injection velocity from that of cumulative injected volume, CO₂ saturation was further plotted against cumulative injected pore volume (PV), as shown in Figure 15. The results show that sweep efficiency does not vary monotonically with injection velocity. At a low velocity, the longer residence time allows CO₂ to redistribute more fully into the matrix pores, resulting in relatively high matrix utilization per unit injected PV. However, fluid advancement is slow, and a longer injection time is required to reach the same injected volume. At 0.001 m/s, a better balance is achieved between pressure-driven advancement and matrix-pore utilization. At a cumulative injection of 3.5868 PV, the CO₂ saturation reaches 49.64% at 0.001 m/s, compared with 40.61% and 24.57% at 0.0005 and 0.005 m/s, respectively. At 7.1736 PV, the saturation is 56.65% at 0.001 m/s but only 37.36% at 0.005 m/s. Although an excessively high velocity accelerates early CO₂ advancement, it also promotes rapid migration through low-resistance pathways, such as fractures and large pores. Consequently, the additional swept area gained per injected PV decreases substantially, indicating stronger preferential channeling and bypassing of the surrounding matrix. Injection design should consider both propagation rate and sweep efficiency per unit injected volume. Within the experimental range investigated, an intermediate injection velocity provides a more favorable balance between rapid advancement and effective matrix utilization.

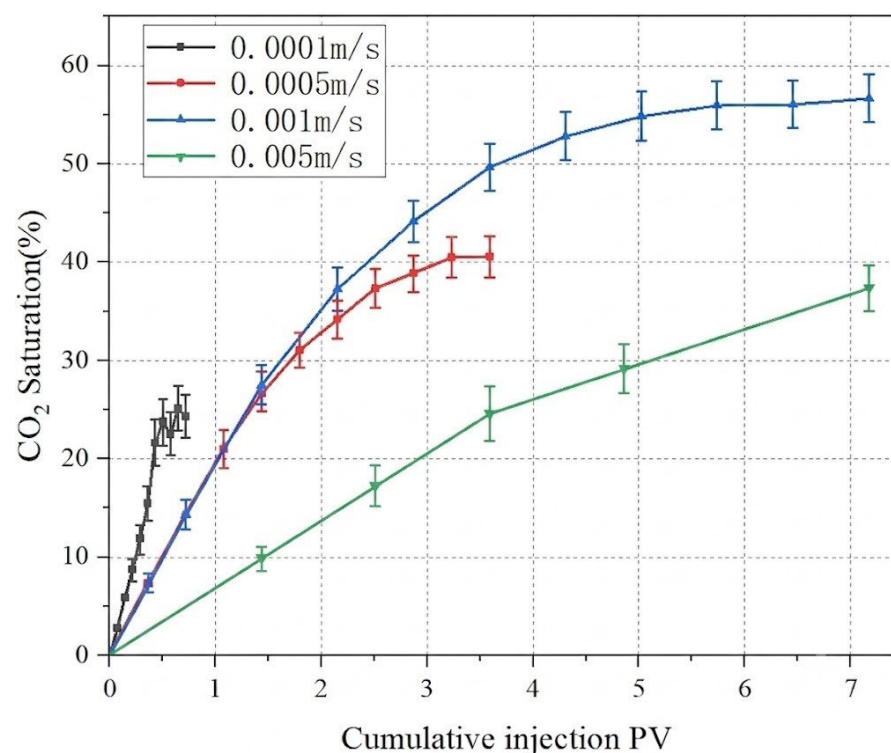


Figure 15. CO₂ saturation versus cumulative injected PV under compressed-liquid conditions (25 °C, 8 MPa).

3.4. Role of Microfractures Across Representative CO₂ States

Microfractures act as low-resistance pathways for fracturing-fluid migration, and the strength of their flow-guiding role varies with the CO₂ state. Under gaseous conditions, microfractures strongly guide migration. Once CO₂ enters a connected microfracture, it spreads rapidly along the fracture; the fracture fills before the adjacent matrix and develops into a preferential flow path. This preferential filling sequence is shown in Figure 16.



- CO₂ front reaches the fracture
- CO₂ flows along and fills the fracture
- The fracture is filled before the surrounding matrix

Figure 16. Preferential microfracture filling under gaseous CO₂ conditions.

At the near-critical condition, fracture guidance weakens while the matrix pore arrangement exerts greater control over CO₂ migration. When the front reaches a fracture, only part of it enters and propagates along that pathway; the remaining front continues through matrix pores. This reduced deflection into fractures indicates a narrower effective flow-resistance contrast between fractures and matrix pores. Microfractures still act as local

low-resistance regions, but matrix geometry determines the system-scale distribution more strongly. The associated fracture-matrix partitioning is shown in Figure 17.

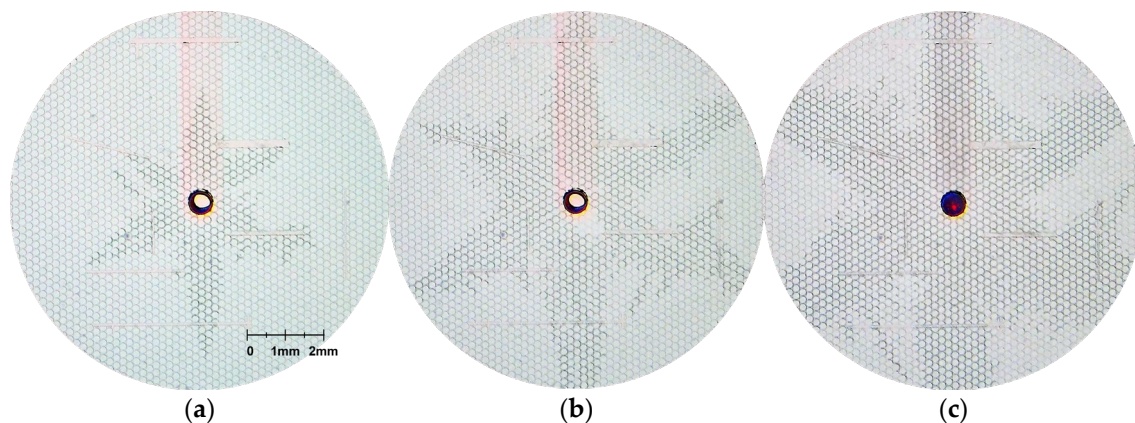


Figure 17. Reduced fracture guidance and continued matrix propagation under near-critical CO₂ conditions: (a) CO₂ front reaches the fracture; (b) CO₂ continues through the matrix with limited fracture entry; (c) CO₂ distribution in the model.

Under higher-temperature supercritical conditions, preferential fracture filling is limited. The oil-fading region expands through fracture and matrix space without concentrating along the fracture pathways, and no continuous fracture-dominated path develops in the observed field (Figure 18). The matrix-wide color attenuation shows that fracture guidance becomes secondary to dissolution-assisted redistribution across the pore space, establishing the phase-state dependence of fracture-matrix partitioning.

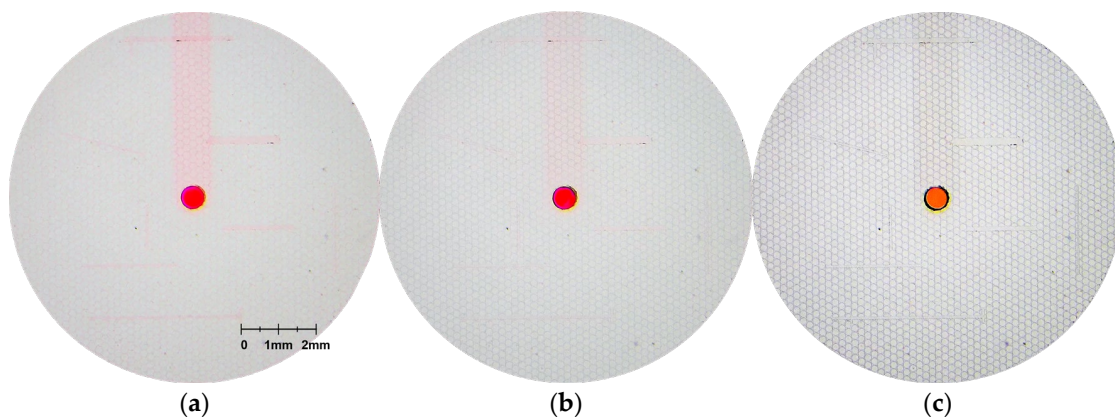


Figure 18. Diffuse spatial redistribution under supercritical CO₂ conditions. (a) Initial state; (b) progressive oil-color attenuation after CO₂ enters the model; (c) no conventional two-phase front is observed during the process.

3.5. Integrated Mechanism, Engineering Implications, and Model Applicability

The four thermodynamic states listed in Table 1 map onto three observed flow regimes. Gaseous and compressed-liquid CO₂ form the distinct-interface pressure-driven regime, in which preferential paths and injection velocity control advancement. Near-critical supercritical CO₂ forms a convection–dissolution coupled regime, in which oil-color attenuation extends ahead of bulk-interface movement and matrix geometry exerts greater control. Higher-temperature supercritical CO₂ forms a dissolution-assisted diffuse-redistribution regime, in which the sharp interface disappears and fracture guidance becomes secondary. Injection velocity determines the balance between early propagation and sustained swept-area growth within the compressed-liquid regime, while microfractures govern pathway

selection most strongly when a channelized front is maintained. Figure 19 summarizes this three-regime framework, and Figures 10–15 provide the corresponding state, time, velocity, and injected-PV evidence.

For engineering interpretation, thermodynamic condition, injection velocity, cumulative injected PV, and preferential fracture pathways should be considered together. The velocity results favor an operating range that balances rapid propagation with sustained swept-area growth, while the water–CO₂ comparison highlights distinct residual and re-distribution patterns. The low viscosity of CO₂ may promote early channeling and limit proppant-carrying capacity, so foam, viscosity enhancement, or staged injection may be considered when broader matrix distribution is desired.

The engineering implications of these observations should be interpreted within the applicability of the microfluidic model. The transparent two-dimensional chip directly resolves interface evolution and fracture-matrix partitioning under controlled temperature and pressure, making it suitable for comparing the effects of CO₂ state, injection velocity, and microfracture guidance. Its cylindrical pillars, uniform depth of 5 μm , and smooth glass surfaces simplify the three-dimensional connectivity, nanoscale pores, mineral-dependent wettability, surface roughness, and reactive mineral interfaces of tight reservoirs. During prolonged CO₂ exposure, asphaltene deposition can obstruct flow pathways [26], mineral dissolution and precipitation and CO₂–brine–rock reactions can alter pore structure [27,28], and the resulting changes in pore structure and microscopic flow capacity can further modify transport [29,30]. The present results are applicable to relative comparisons of pore-scale mechanisms and parameter-dependent trends, while quantitative reservoir-scale prediction requires models incorporating representative mineral surfaces, wettability heterogeneity, nanoscale porosity, rough pore walls, and three-dimensional multiscale fracture networks.

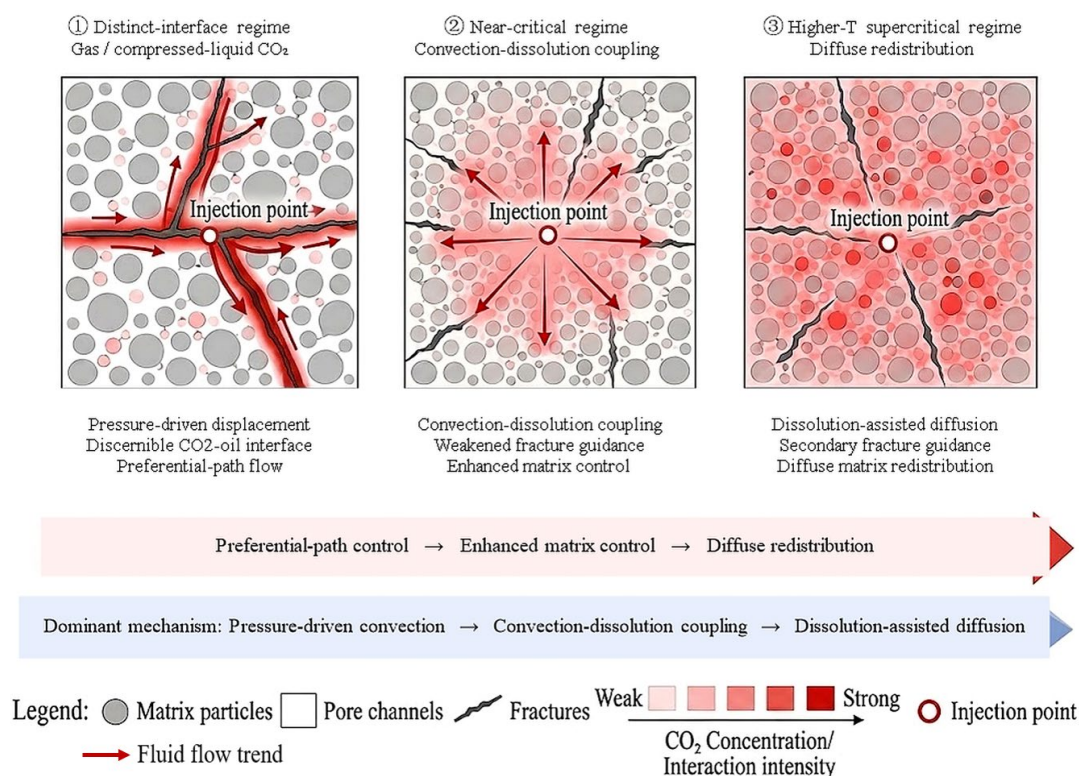


Figure 19. Integrated evolution of CO₂ flow mechanisms from distinct-interface displacement to near-critical coupling and higher-temperature supercritical redistribution.

4. Conclusions

- (1) Four CO₂ thermodynamic states produce three characteristic pore-scale flow regimes. Gaseous and compressed-liquid CO₂ retain a discernible CO₂–oil interface and exhibit pressure-driven preferential-path displacement, although their density and viscosity differ substantially. The gaseous case shows fracture-guided fingering, whereas compressed-liquid CO₂ exhibits velocity-dependent channeling. At the near-critical supercritical condition, oil-color fading ahead of the developing front and multidirectional matrix propagation identify convection–dissolution coupling. Under higher-temperature supercritical conditions, disappearance of the sharp interface and continuous color attenuation across the pore space identify dissolution-assisted diffusion as a significant transport mechanism and produce diffuse fracture-matrix redistribution.
- (2) CO₂ and water follow different pore-scale transport pathways. Water preferentially occupies fractures and high-permeability channels, and the residual aqueous patches retained in small throats, corners, blind ends, and low-permeability regions constitute capillary trapping and the microscopic basis of water blocking. Under near-critical and higher-temperature supercritical conditions, oil-color fading demonstrates CO₂ dissolution into the resident oil, and the affected region extends through a broader portion of the matrix. CO₂ injection changes the post-injection distribution from immiscible aqueous retention to dissolution-assisted redistribution within the oil-filled pore space under the tested conditions.
- (3) Compressed-liquid CO₂ flow at 25 °C and 8 MPa has a favorable injection-velocity range. Low velocity restricts pore-throat entry and slows advancement. Intermediate velocity provides the best balance between propagation and matrix utilization within the tested range. Excessive velocity strengthens preferential channeling through fractures and large pores, reducing the incremental swept area per injected PV.
- (4) The flow-guiding strength of microfractures decreases as the CO₂ state changes from gaseous to near-critical and higher-temperature supercritical conditions. Gaseous CO₂ rapidly fills connected microfractures and forms preferential pathways. At the near-critical condition, reduced deflection into fractures allows matrix geometry to exert stronger control on the distribution. Under higher-temperature supercritical conditions, no continuous fracture-dominated pathway develops; continuous oil-color attenuation across fracture and matrix space shows that dissolution–diffusion extends redistribution beyond the preferential fracture network.

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