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Review Paper

A technical review of CO_2 flooding sweep-characteristics research advance and sweep-extend technology

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ABSTRACT

The utilization and storage of CO_2 emissions from oil production and consumption in the upstream oil industry will contribute to sustainable development. CO_2 flooding is the key technology for the upstream oil industry to transition to sustainable development. However, there is a significant challenge in achieving high recovery and storage efficiency in unconventional reservoirs, particularly in underdeveloped countries. Numerous studies have indicated that the limited sweep range caused by premature gas channeling of CO_2 is a crucial bottleneck that hinders the enhancement of recovery, storage efficiency and safety. This review provides a comprehensive summary of the research and technical advancements regarding the front sweep characteristics of CO_2 during migration. It particularly focuses on the characteristics, applicable stages, and research progress of different technologies used for regulating CO_2 flooding sweep. Finally, based on the current application status and development trends, the review offers insights into the future research direction for these technologies. It is concluded that the front migration characteristics of CO_2 play a crucial role in determining the macroscopic sweep range. The focus of future research lies in achieving cross-scale correlation and information coupling of CO_2 migration processes. Currently, the influence weight of permeability, injection speed, pressure and other parameters on the characteristics of 'fingering-gas channeling' is still not well clear. There is an urgent need to establish prediction model and early warning mechanism that considers multi-parameters and cross-scale gas channeling degrees, in order to create effective strategies for prevention and control. There are currently three technologies available for sweep regulation: flow field intervention, mobility reduction, and gas channeling plugging. To expand the sweep effectively, it is important to systematically integrate these technologies based on their regulation characteristics and applicable stages. This can be achieved by constructing an intelligent synergistic hierarchical segmented regulation technology known as 'flow field intervention + mobility regulation + channel plugging chemically'. This work is expected to provide valuable insights for achieving conformance control of CO_2-EOR and safe storage of CO_2.

1. Introduction

CO_2 as the main greenhouse gas emission, has become one of the main driving factors of climate change (Tyne et al., 2021; Pradhan et al., 2024). In the process of oil production and use, a large amount of CO_2 will be released (Farajzadeh et al., 2022). The application of CO_2 in the upstream oil industry can realize the economic utilization of CO_2 while the underground storage, this approach offers dual environmental and economic benefits, and has promising market prospects (Saravanan et al., 2020; Liu and Rui, 2022; Yuan et al., 2022). Since the birth of the world's first CO_2 flooding patent in the mid-20th century, CO_2-EOR has garnered significant attention in scientific research and engineering applications. This is primarily due to its remarkable interphase mass transfer characteristics, its ability to achieve oil and gas miscibility, and its capacity to expand and reduce viscosity upon contact with oil (Whorton et al., 1952; Lang et al., 2021; Mahdaviara et al., 2021;

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Yu et al., 2021; Zuo et al., 2023). The research on CO_2 flooding technology in European and American countries has a longer history. The first CO_2 flooding field test in the United States took place in 1958, and since then, there has been significant development in the theory and technology of CO_2 flooding. By the end of 2021, the United States has successfully implemented over 142 CO_2-EOR projects, as shown in Fig. 1, resulting in an annual increase of 16 million tons of oil, representing a 30% annual growth rate (Qin et al., 2015; Advanced Resources International, Inc, 2021; Warwick et al., 2022; Rui et al., 2023). In the 1960s, China initiated a pilot test of CO_2-EOR in Daqing Oilfield. However, the development of CO_2 flooding technology has been slow and has not been widely implemented due to limitations in gas source, pipeline, and injection–production technology (Li S., Tang Y. et al., 2019). Since the 21st century, China has been actively focusing on reducing CO_2 emissions and has made significant progress in the theory and development technology of CO_2 flooding. Large-scale application demonstrations of carbon capture, utilization and storage (CCUS) projects have been successfully carried out in Jilin Oilfield, Shengli Oilfield, Changqing Oilfield, and Yanchang Oilfield, leading to positive development outcomes (Hu et al., 2019; Li, 2020; Wang, 2023; Gao et al., 2024).

However, many unconventional reservoirs are predominantly composed of continental deposits, resulting in a complex and challenging formation environment characterized by low permeability and significant heterogeneity. These reservoirs are subjected to high formation temperatures and higher miscible pressures. Additionally, the oil stored in these reservoirs is deeply buried and contains a high concentration of heavy components such as resin and asphaltene (Chen et al., 2020; Jia et al., 2023; Sambo et al., 2023). These practical difficulties hinder the miscibility of CO_2 in the process of underground oil displacement, leading to the premature occurrence of ‘fingering-breakthrough-gas channeling’ behavior. This significantly restricts the spread range during CO_2 flooding, ultimately resulting in low oil recovery efficiency of CO_2 flooding in practical applications (Chen et al., 2019). Yamabe et al. (2015) conducted a simulation of the migration process of CO_2 in porous media using the lattice Boltzmann method. Their findings revealed that the fingering phenomenon has a significant impact on the efficiency of CO_2 replacement and storage. Similarly, Mahabadi et al. (2020) and Zhao et al. (2020) observed a serious uneven spread of CO_2 in porous media, as evidenced by the uneven saturation and fluid distribution during CO_2 migration in rock. Sanchez-Rivera et al. (2015) analyzed production data and numerical simulation results from the Bakken oilfield, and discovered that the uneven sweep caused by gas channeling leads to a substantial reduction in oil production. Therefore, achieving a balanced sweep has become a crucial technical challenge that hinders the further enhancement of CO_2-EOR. Based on statistical data, there is a noticeable disparity in oil production between regions with unfavorable geological conditions or underdeveloped gas flooding technology and the United States. For instance, in China, the annual oil production through gas flooding is projected to be less than 1 million tons by 2023. Consequently, it is crucial to urgently explore suitable methods to enhance the oil recovery effect of CO_2 flooding.

To enhance oil recovery, it is essential to implement appropriate engineering technology and chemical sweep regulation methods that can effectively inhibit or delay the occurrence of CO_2 fingering-gas channeling. In general, sweep regulation is often considered from the following aspects: (1) Intervention of CO_2 flow field and front migration is achieved by regulating CO_2 injection–production parameters or water-alternating-gas (Haro et al., 2018; Chen and Pawar, 2019; Mirzaei-Paiaman et al., 2023); (2) Reducing the mobility of CO_2 by increasing the viscosity of CO_2 (Føyen et al., 2021; Pal et al., 2022; Shah et al., 2024); (3) Plugging the CO_2 channeling channel is achieved by chemical plugging agents or foams (Bal et al., 2015; Liu et al., 2022; Nguele et al., 2021; Wu et al., 2023). Although there are obvious differences in the technical principles and regulatory ideas of different control methods, they complement each other in terms of timing and scenarios: The flow field intervention method based on regulating the controlled injection and production regimes can effectively delay the development of fingering, and is inexpensive and simple to operate, so it is often used as an early control method before gas breakthrough. The

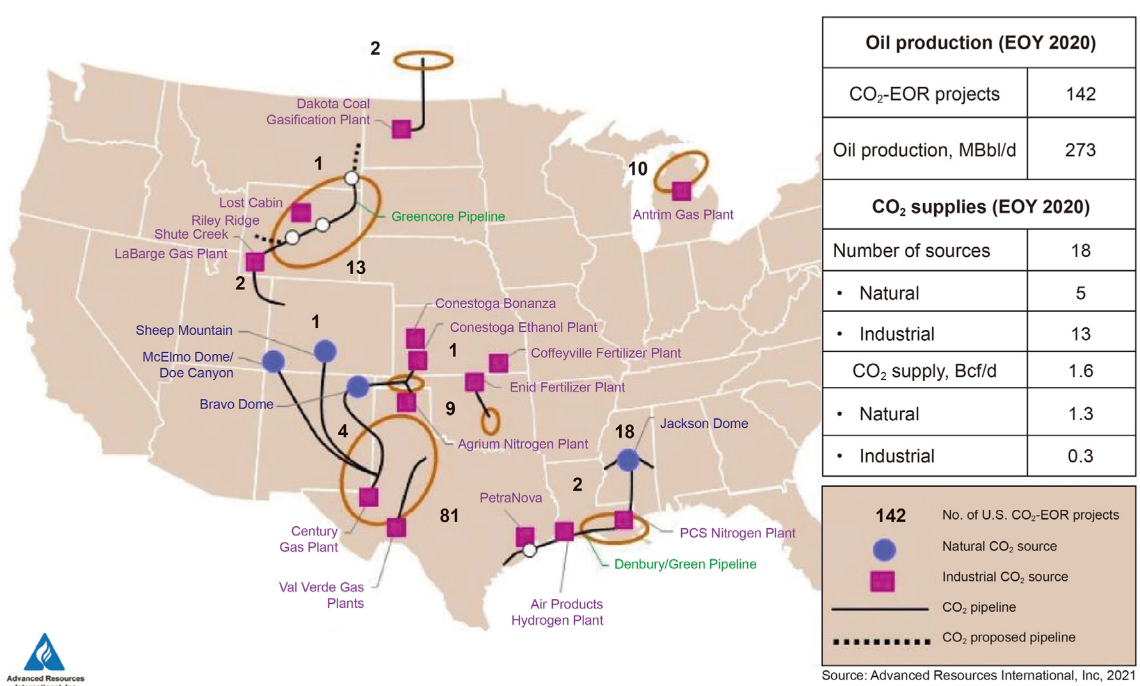

Fig. 1. Summary of CO_2-EOR project in the United States in 2021 (Image courtesy Advanced Resources International, Inc., 2021).

method of enhancing CO_2 viscosity requires the introduction of exotic chemical systems, and is often used as a control means after gas breakthrough for cost and applicability reasons. The method of plugging is often used to block the gas channeling channel after gas channeling. Therefore, there is a prospect of systematic integration of applications.

However, existing research mostly focuses on in-depth studies of specific methods, with limited reports on the successive combination of all three methods. Moreover, although scholars have comprehensively reviewed 'flow field intervention' (Kumar and Mandal, 2017; Afzali et al., 2018; Mariyate and Bera, 2023), 'CO_2 mobility regulation' (Sun and Sun, 2015; Liu et al., 2021; Massarweh and Abushaikha, 2022; Ricky et al., 2023) and 'channel plugging chemically' (Enick et al., 2012; Liu and Liu, 2022; Bai et al., 2022; Jansen-van Vuuren et al., 2023) in recent years, they are only limited to investigating and commenting on the research progress of a single method. There is no idea or argument for an integrated application based on the characteristics of multiple technologies.

This review aims to summarize the research advance of the whole CO_2 sweep process from research methods to regulation technologies. The paper extensively investigates the recent research progress on CO_2 front sweep characteristics. It discusses the key control technologies to expand the sweep range of CO_2 and provides a research direction for further expanding CO_2 sweep. The findings of this review are expected to serve as a reference for the development of an integrated CO_2 flooding equilibrium sweep theory system and engineering regulation technology, ultimately facilitating the efficient utilization and safe storage of CO_2. The introduction overview is shown in Fig. 2, and the integration technique proposed is shown in Fig. 3

2. Advances in research methods of CO_2 front

The relationship between the front and sweep range is similar to the relationship between 'line and surface' or 'surface and volume'. Therefore, the migration characteristics of CO_2 with multi-fronts play a crucial role in determining the macroscopic sweep range. In water flooding, the immiscible flooding of water and oil does not result in significant interphase mass transfer and phase change, making the front characteristics evident. However, the front characteristics of CO_2 are more complex and variable due to its dissolution, extraction, and miscible properties (Elias and Trevisan, 2016; Li R. et al., 2021). In general, CO_2 multi-fronts are differentiated in the actual formation, displacement front, CO_2 component front, phase front, and pressure front, each exhibiting different migration characteristics. Scholars primarily employ mathematical modeling simulation and advanced visualization experiments to study the characteristics of the front (Chen et al., 2020).

2.1. Mathematical and simulation methods

Mathematical methods play a crucial role in determining the characteristics of CO_2 migration. In the initial stages, the concept of the 'front' was not clearly defined, and the analysis of migration relied on the saturation field and phase field. Young and Stephenson (1983) established a multi-phase and multi-component model by introducing the material balance and phase equilibrium constraint equations of multiple components and simulated the saturation change and multi-contact miscible process in CO_2 migration based on Newton–Rahpson iteration method. Cheng et al. (1998) investigated the impact of water solubility on the migration of CO_2. They developed a mathematical model that incorporated the dissolution equilibrium and water phase physical property equations, taking into account temperature, pressure, and salinity. The model simulated and analyzed the distribution of CO_2 saturation and the occurrence of overlap phenomena. Hou et al. (2008) opted for the streamline method over the finite difference method to address the problem. They employed the saturation weighting method to calculate the changes in viscosity and the relative permeability of oil and gas, aiming to simulate the miscible process. Additionally, they utilized the boundary element method to solve the streamlined migration law and determine the potential distribution of the flow field during CO_2 migration. Shen and Huang (2009) established a multi-phase multi-component seepage model considering interphase mass transfer earlier and explored the influence of multi-component on the expansion of gas flooding and the miscibility in the contact area. These initial studies did not explicitly define the concept of the front and the considered influencing factors were relatively simple. However, they provided a valuable research direction. Notably, Shen and Huang's study in 2009 shed light on the relationship between the phase front and the displacement front, prompting scholars to explore the specific effects of multi-phase multi-component dissolution and miscible front migration.

After the concept of the front was proposed, scholars have

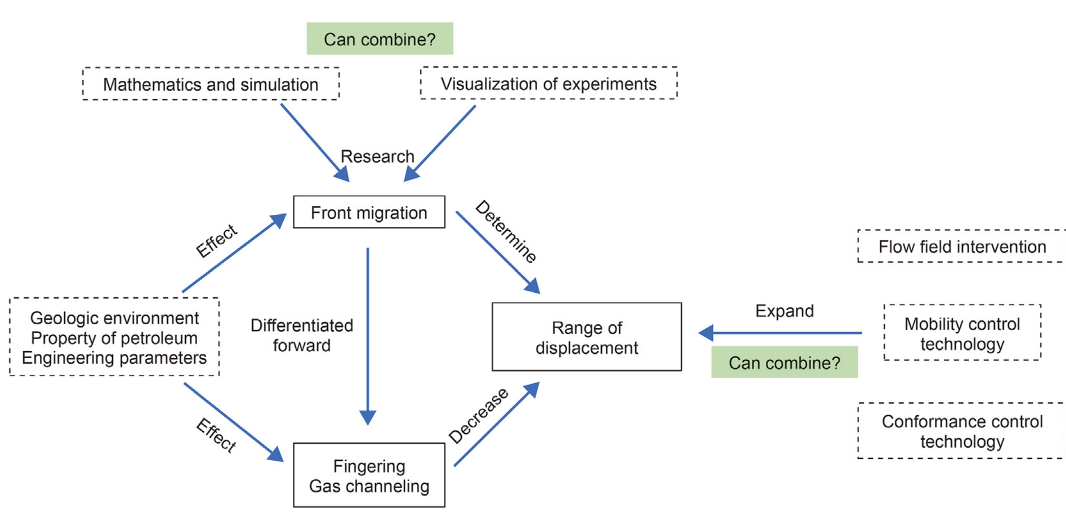

Fig. 2. Research mind maps for this view.

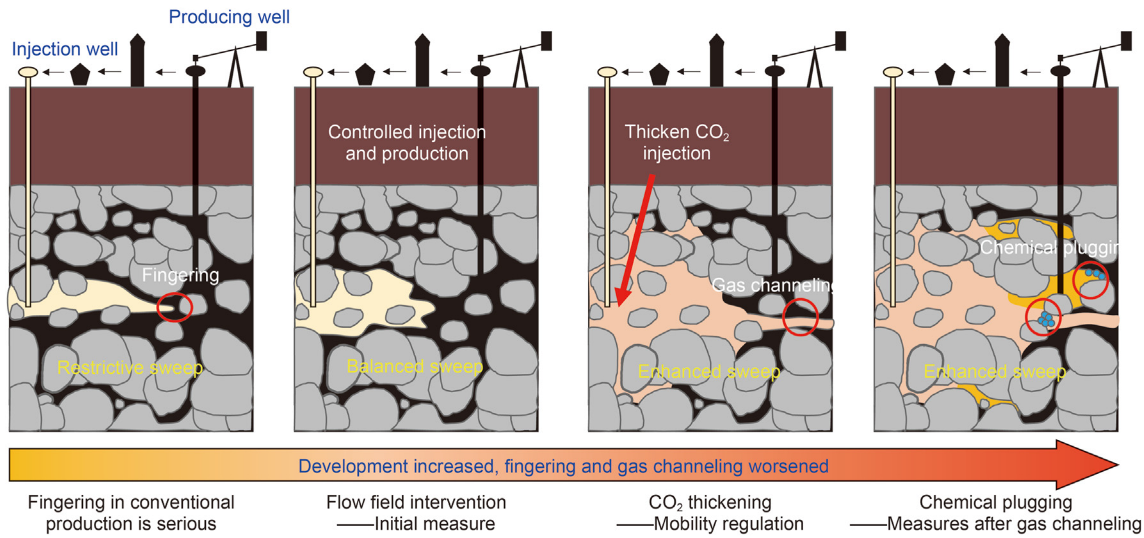

Fig. 3. 'Flow field intervention + mobility regulation + channel plugging chemically' integrated sweep-extend technology.

increasingly focused on the expansion of the boundary and studying the miscible mass transfer. They have conducted comprehensive analyses on the multi-factors influencing the sweep range. Su et al. (2011) developed a mathematical model that takes into account CO_2 adsorption. They utilized the Barakat–Clark finite difference scheme to calculate the profile shape of the component front, and used it instead of the phase front to analyze the impact of the Peclet number, porosity, and injection pressure on migration and miscibility. Li S. et al. (2018) developed a highly applicable mathematical model by incorporating Fick's diffusion law and the Peng–Robinson equation of state (PR-EOS) equation. They investigated the synergistic effect of temperature, pressure, and permeability on front diffusion. In a separate study, Mu and Liao (2020) utilized the Whitson method to redefine the standard for reservoir fluid recombination and splitting. They constructed a multi-phase multi-component model and effectively characterized the difference between the component front and phase front in migration based on the dimensionless distance. Li J. et al. (2022) and Sun et al. (2023) established a flow control equation that incorporates CO_2 adsorption, diffusion, and concentration changes, using Fick's diffusion law and Langmuir adsorption equation as the basis. They quantitatively characterized the migration characteristics of the CO_2 phase front and component front. By employing iterative solution methods, they analyzed the impacts of key parameters such as injection concentration and injection rate on the sweep and gas channeling. Chen et al. (2022a, 2022b) established the mathematical models of CO_2 component front and pressure front end diffusion. The front diffusion process is divided into three stages, as shown in Fig. 4, while the migration miscible process is divided into four phase regions. By combining laboratory experiments and numerical simulations, the study determines the specific effects of pore pressure and overburden pressure on the sweep coefficient and sweep distance of CO_2.

In recent years, the development of computer computing power has led to the booming and widespread use of computational fluid dynamics (CFD) technology. This technology is often coupled with the discrete element method (DEM) in the oil industry to simulate the flow behavior of fluid in porous media using the Navier–Stokes (N–S) equation and Boltzmann equation (Wang X. et al., 2023). Yamabe et al. (2015) and Zacharoudiou et al. (2018) utilized the lattice Boltzmann method (LBM) to simulate the migration process of CO_2 in porous media. They analyzed the internal relationship between Heines jump and front migration, as well as the fingering characteristics, and clarified the influence of fluid behavior on sweep efficiency (see Fig. 5). Based on the actual rock characteristics observed in X-ray computed tomography (CT) scanning experiments, Fazeli et al. (2019) developed a 3D pore-scale reaction transport model using the LBM. Xie Q. et al. (2023) presented the governing equation for simulating calcite dissolution and assessed the impact of dissolution-induced changes in porosity and permeability on CO_2 migration through a normalization method. Several typical mathematical models mentioned above are shown in Table 1, and these diversified methods for constructing and solving models have laid the foundation for CO_2 sweep theory research. However, most of the physical experiments conducted during the construction process of the mathematical model are only conventional measurements for certain parameters in the equation. These experiments, such as core-scale gas flooding or slim tube experiments, can only be used to study the impact of important parameters on injection–production efficiency or miscibility. However, due to technological and methodological limitations, it is challenging to accurately characterize the migration process at the front of the core and visualize it. In recent years, there has been a notable increase in combining theoretical models with visualization experiments. These conventional core-scale experiments can only study the influence of some important parameters on injection–production efficiency or miscibility. And due to the limitations of techniques and methods, it is difficult to clearly characterize the migration process of the front in the core interior, and it is impossible to realize visualization. In recent years, there has been a notable increase in combining theoretical models with visualization experiments.

2.2. Methods of visualization experiments

Microfluidic technology enables the visualization of fluid migration behavior on the pore-scale in a more intuitive manner. In the 1980s, Lenormand et al. (1983, 1988) utilized etched glass plates to study the migration process of water flooding. However, early microfluidic technology only employed simplified pore grids for basic research, which deviated significantly from the actual pore space and yielded limited results. Based on the actual characteristics of the core obtained through CT scanning, scanning electron microscopy (SEM), nuclear magnetic resonance (NMR), or

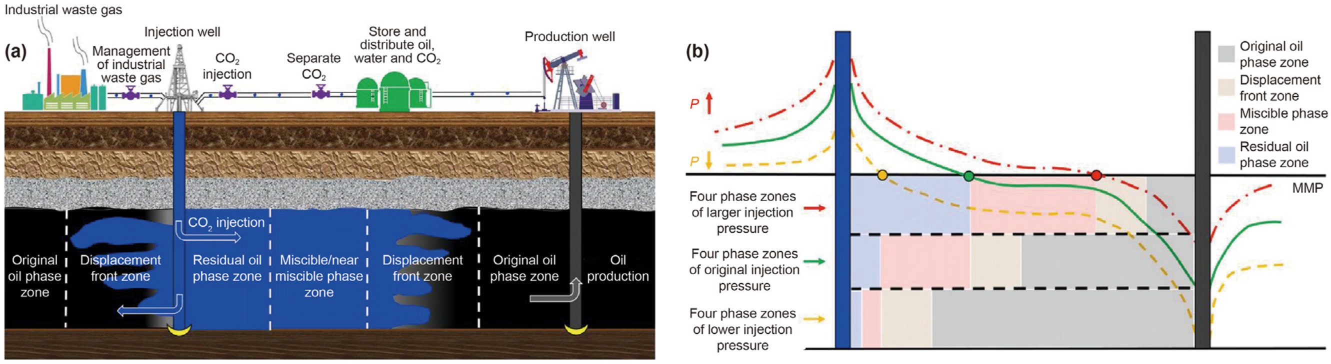

Fig. 4. (**a**) Migration process after CO_2 injection; (**b**) The four-phase regions divided according to the CO_2 miscible process. Adapted from Chen et al. (2022a).

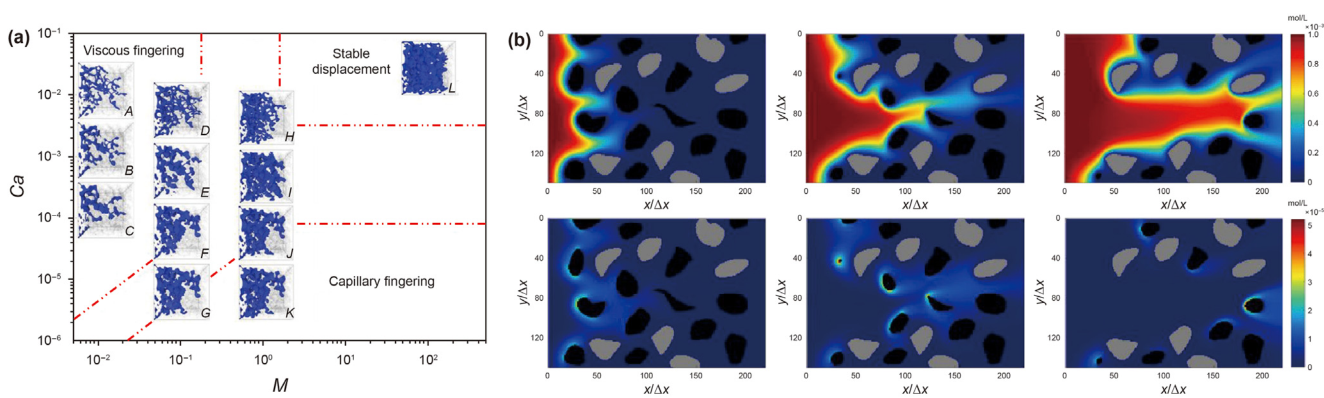

Fig. 5. (**a**) Displacement patterns in the (Ca, M) phase diagram, the blue represents the injection phase. The three typical fluid displacement patterns are observed, including viscous fingering (high Ca, $\log M < 0$), capillary fingering (low Ca), and stable displacement (high Ca, $\log M > 0$). Adapted from Zacharoudiou et al. (2018). (**b**) The CO_2 fingering (top) and calcite dissolution process (bottom) in LBM simulation of CO_2 migration. Adapted from Xie Q. et al. (2023).

Table 1
Summary of the existing correlations.

Source	Key mathematical models or improvement strategies
Young and Stephenson (1983)	$\phi\frac{\partial Fz_i}{\partial i} = \nabla\cdot(\lambda_o x_i + \lambda_g y_i)\nabla p + q_i$ $V_j'\left[(Fz_i)_j^{m+1} - (Fz_i)_j^m\right] + \sum_{k=1}^{N} T_{ijk}p_k^{m+1} = Q_{ij}$ $\sum_{i=1}^{n}(y_i - x_i) = \sum_{i=1}^{n}\frac{(K_i-1)z_i}{1+(K_i-1)v} = 0$ $\sum_{i=1}^{n-1}c_{yij}\Delta y_{ij} + c_{vj}\Delta v_j + \sum_{i=1}^{n-1}c_{ij}\Delta z_{ij} + c_{fj}\Delta F_j + c_{wj}\Delta W_j + c_{pj}\Delta p_j = r_{pj}$
Hou et al. (2008)	$\Phi(V) = \sum_{k=1}^{n_x}q_kG_k + \int_s\frac{\partial\Phi(R_0)}{\partial n}G(R_0,V)\mathrm{d}S(R_0) - \int_S\Phi(R_0)\frac{\partial G(R_0,V)}{\partial n}\mathrm{d}S(R_0)$ $K_{\mathrm{rm}} = \frac{S_o - S_{\mathrm{orm}}}{1-S_w-S_{\mathrm{orm}}}K_{\mathrm{row}} + \frac{S_s}{1-S_w-S_{\mathrm{orm}}}K_{\mathrm{rs}}$ $\frac{1}{\mu_m^{0.25}} = \frac{1}{1-S_w}\left(\frac{S_o}{\mu_o^{0.25}} + \frac{S_s}{\mu_s^{0.25}}\right)$
Su et al. (2011)	$\left[1 + \frac{1-\phi}{\phi}\rho_r\frac{a}{\left(1+bC_0C_{\mathrm{D}i}^j\right)^2}\right]\frac{C_{\mathrm{D}i}^{j+1} - C_{\mathrm{D}i}^j}{\Delta t_{\mathrm{D}}} = \frac{1}{Pe}\frac{C_{\mathrm{D}i+1}^j - C_{\mathrm{D}i}^j - C_{\mathrm{D}i}^{j+1} + C_{\mathrm{D}i-1}^{j+1}}{\Delta x_{\mathrm{D}}^2} - \frac{1}{\Delta x_{\mathrm{D}}}\left(\frac{C_{\mathrm{D}i}^{j+1} - C_{\mathrm{D}i-1}^{j+1}}{2} + \frac{C_{\mathrm{D}i+1}^j - C_{\mathrm{D}i}^j}{2}\right)$
Sun et al. (2023)	$\frac{\partial}{\partial x}\left[\rho_{\mathrm{mix}}\frac{k}{\mu_{\mathrm{mix}}}\left(\frac{\partial p}{\partial x} - G\right)\right] + \rho_g q_{\mathrm{in}} - \rho_{\mathrm{mix}}q_{\mathrm{out}} = \rho_{\mathrm{mix}}(\phi C_{\mathrm{mix}} + C_s)\frac{\partial p}{\partial t}$
Xie et al. (2023)	$I_m = -k_{cc}(1-\Omega) = -\left(k_1 a_{H^+} + k_2 a_{H_2CO_3} + k_3\right)\left(1 - \frac{a_{Ca^{2+}}a_{{CO_3}^{2-}}}{K_{sp}}\right)$ $f_i(x + e_i\Delta t, t + \Delta t) - f_i(x,t) = -\frac{1}{\tau_\sigma}[f_i(x,t) - f_i^{\mathrm{eq}}(x,t)]$ $g_{k,i}(\mathbf{x} + \mathbf{e}_i\Delta t, t+\Delta t) - g_{k,i}(\mathbf{x},t) = -\frac{1}{\tau_{k,g}}[g_{k,i}(\mathbf{x},t) - g_{k,i}^{\mathrm{eq}}(\mathbf{x},t)]$

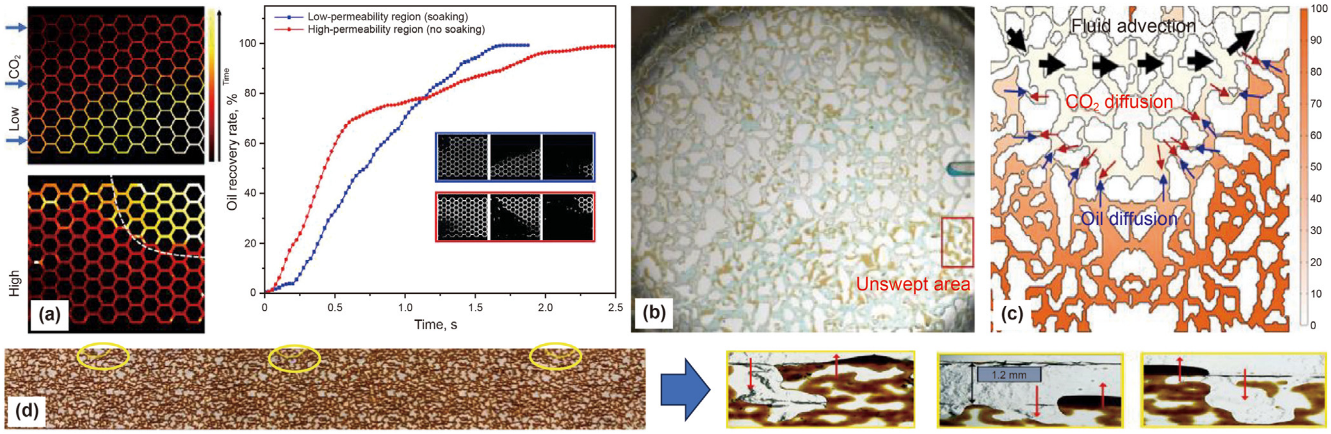

Fig. 6. Several typical microfluidic experimental phenomena. (**a**) Visualized immiscible flooding process and cumulative oil recovery versus time. Adapted from Guo et al. (2022). (**b**) Distribution of oil, gas, and water. Adapted from Hao et al. (2022). (**c**) Analysis of CO_2 injection considering diffusion. Adapted from Li Z. et al. (2023). (**d**) Oil distribution at the end of injection. Adapted from Mahmoudzadeh et al. (2022).

ultrasonic equipment, a microfluidic model is constructed using temperature-resistant and pressure-resistant materials, and supplemented by computer software for real-time monitoring. This is the current development trend in microfluidic technology (Kumar Gunda et al., 2011). Hao et al. (2022) and Li Z. et al. (2023) conducted a study using a high-fidelity microfluidic device to observe and analyze the change characteristics of the phase front and the migration law of the displacement front in microscopic pore–throat structures, as shown in Fig. 6. They also performed a driving analysis and clarified the impact of sweep efficiency on oil displacement. Nguyen et al. (2018) and Guo et al. (2023) investigated the CO_2 migration process between heterogeneous layers and fractures using a microfluidic model. They examined the impact of heterogeneous layers and injection pressure on the sweep efficiency. Wang C. et al. (2021) and Qiu et al. (2023) constructed a microfluidic unit with a precise control structure. They clarified the capillary balance of CO_2 bubbles during the flow process and the influence of porous media roughness on both microphysics and macroscopic displacement patterns. While the development and application of microfluidic technology have enabled the visualization of the CO_2 displacement front, it is important to note that this technology is currently limited to studying the migration process in two-dimensions. To investigate the migration of the front at a three-dimensional core-scale, it is necessary to rely on penetrable technology.

In recent years, non-invasive detection technology has been increasingly used in the study of fluid flow in porous media. Among the preferred technologies used by scholars are CT and NMR. CT technology allows for the visualization of pore–throat structure and fluid distribution inside the core without causing any damage (Su et al., 2022; Zhang Y. et al., 2024). Shi et al. (2009, 2011) conducted a study using CT technology on the relationship between the law of component front and sweep efficiency of CO_2 in sandstone cores with varying porosity and heterogeneity (see Fig. 7(a)). Gunde et al. (2010) utilized micro-focus CT to extract the pore geometry of sandstone cores. They then established a digital core model and mathematical control equation, which was solved through finite element simulation. This enabled them to elucidate the migration law of CO_2–water–oil during immiscible displacement. Andrew et al. (2014) and Øren et al. (2019) quantitatively measured the in-situ contact angle by CT technology, and characterized the effects of wettability and capillary number on the CO_2 sweep range. Xie J. et al. (2023) studied the migration path of supercritical CO_2 in sandstone based on the results of CT scanning, and determined the effect of fluid velocity and pressure. The limitations of noise, resolution, lack of micro-holes in the reconstruction process, and the limitation of X-ray absorption by gaseous fluids contribute to errors in pore determination and make it difficult to distinguish characteristic differences caused by gas differences in CT technology (Wu et al., 2019).

NMR technology has been utilized for core analysis since the 1960s. Its primary advantage lies in its ability to quantify fluid information within porous media, enabling real-time visualization of fluid diffusion and sweep. Additionally, it accurately determines the distribution characteristics of the fluid in pore size (Seevers, 1966; Timur, 1968; Luo et al., 2022). Liu et al. (2011, 2017) and Song et al. (2013) conducted an analysis of NMR images to describe various aspects of the CO_2 displacement front in a simulated core filled with glass beads and artificial sandstone. They focused on the displacement velocity, geometric shape, displacement mechanism, and the degree of differentiation with the phase front. They also evaluated the impact of dispersion force and viscous force on the displacement process, as shown in Fig. 7(b). The research group of Jiang utilized NMR technology to monitor the CO_2 flooding process under variable temperature and pressure conditions (Wang S. et al., 2021, 2023). They observed the distribution characteristics of the CO_2 plume and the phase front in high permeability reservoirs, and investigated the effects of injection rate, gravity, and phase state. Li B. et al. (2023) conducted a study on the impact of matrix permeability and fractures on the sweep efficiency of CO_2 in low-permeability blocks. In a separate study, Wang Q. et al. (2021) analyzed NMR images in conjunction with fractal theory to assess the specific effects of wettability and pore size distribution on the sweep under similar permeability. However, due to limitations of the temperature and pressure requirements of the core holder, the paramagnetism of the observed sample, the resolution, and the field strength of the equipment, it is still difficult to accurately observe the CO_2 flow rate and analyze the hysteresis effect at the pore scale in the process of nuclear magnetic application. Analysis of some paramagnetic cores may result in noticeable image distortion (Xu et al., 2019).

2.3. *The brief summary of CO_2 front*

The multi-front migration law of CO_2 is the current hot topic, and they present the characteristics of differential migration, as shown in Fig. 8. Within the CO_2-phase-front region, CO_2 saturation is high and almost exclusively CO_2 and residual oil are present.

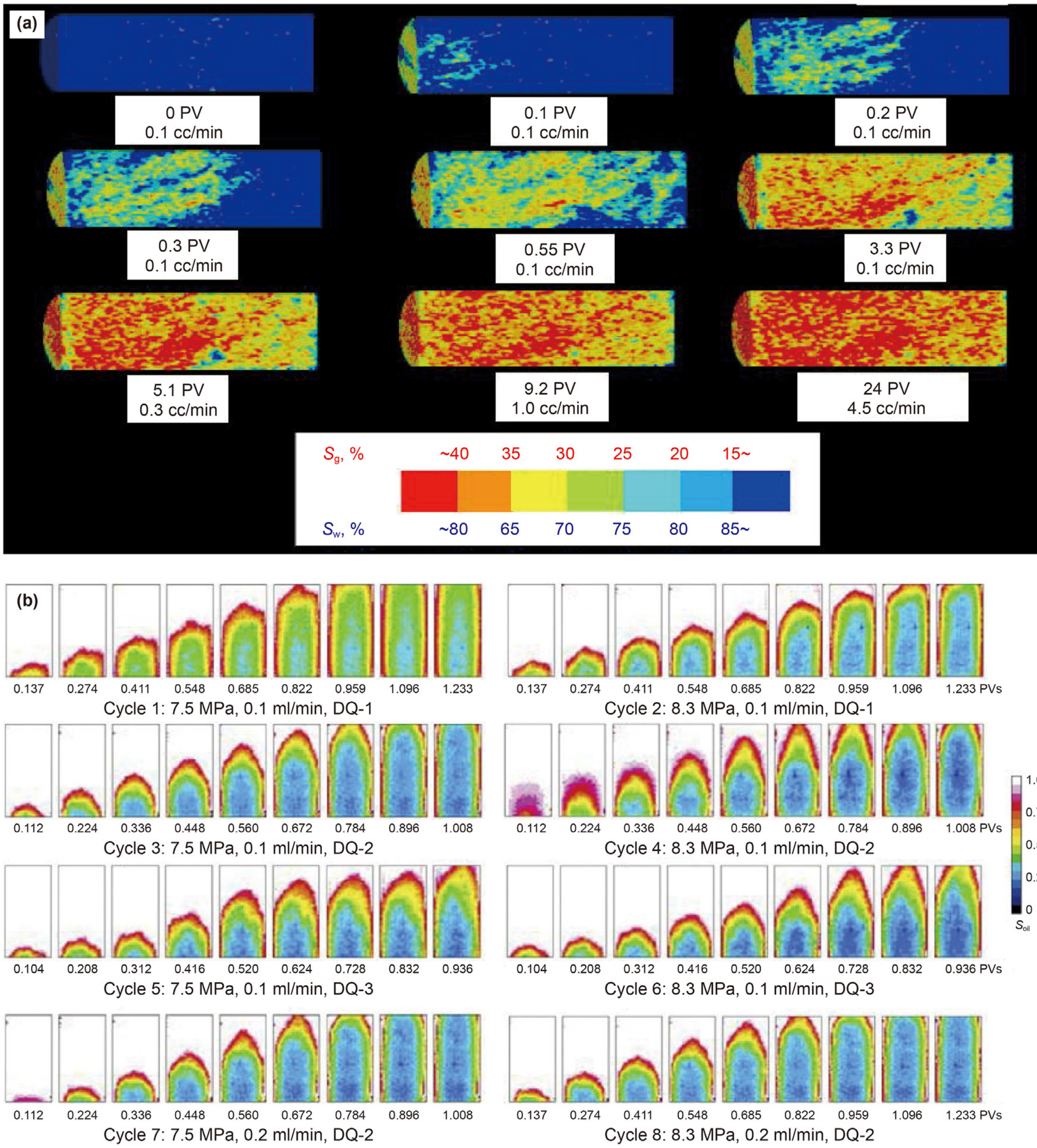

Fig. 7. (**a**) CT images of phase saturation distribution showing the migration of CO_2 at different stages of CO_2 flooding. Adapted from Shi et al. (2009). (**b**) MRI images of CO_2 flooding for cycles. Adapted from Liu et al. (2017).

Within the displacement-front region, CO_2 displaces the oil in the pores, and complex mutual mass transfer behavior such as extraction and miscibility occurs. Within the CO_2-component-front region, CO_2 enters the oil by dissolution and diffusion, but no displacement effect occurs. The pressure-front is at the forefront, driving oil production due to its rapid transfer along the formation at the time of CO_2 injection.

The sweep and diffusion characteristics of the front are closely related to the composition and injection parameters. The advantage of the simulation method is that the pattern of influence of a single or small number of parameters on the front can be clarified, and with software upgrades, the flow behavior can be characterized by video. However, the results are ideal, and there are limitations in modeling and solving for multi-field and multi-parameter coupling. The advantage of visual physics experiments is that they enable the visualization of fluid transport behavior at the core scale, especially since the online monitoring experiments have been proposed. However, the measurement is based on the difference in fluid saturation in the core and the measurement takes time, which results in its accuracy being limited by core aperture, noise, and flow rate, and it is not able to distinguish the difference in gas during non-pure gas replacement, and there is an unavoidable hysteresis effect. Currently, the collaborative application of fine simulation and advanced physical experiments, such as microfluidic + image recognition, LBM + CT, etc., has become a popular method for scholars. Therefore, realizing the cross-scale correlation of the study, systematically exploring the influence weights of multiple factors of front migration and diffusion from multi-scale perspectives, and characterizing the CO_2 migration process and features in the actual field will be the direction of future research.

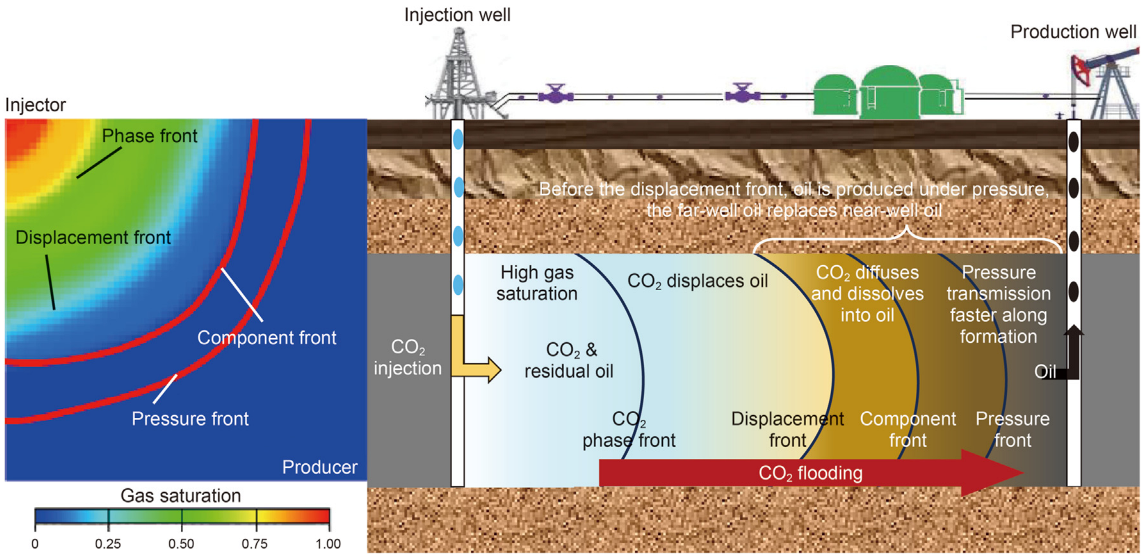

Fig. 8. Multi-front migration characteristics.

3. Fluid dynamics method based on flow field intervention

According to the characteristics of reservoir and CO_2 migration, the expansion of CO_2 flow field can be interfered without introducing foreign chemical system by adjusting the working system of injection–production well group, such as injection rate, pressure, injection time, and injected gas composition. By adjusting the working system of injection–production well group and key parameters such as injection rate, pressure, injection time, production system, and injection gas composition, the expansion of CO_2 flow field can be intervened. This intervention helps inhibit the development of CO_2 fingering and gas channeling, thereby prolonging the gas-free oil production period. Ultimately, this approach achieves balanced sweep and improves the effectiveness of gas flooding (Zheng et al., 2013; Ding et al., 2022).

3.1. Injection–production process regulation

The purpose of the injection process design is to minimize the CO_2 consumption per ton of oil produced. Conventional CO_2 flooding typically involves continuous injection of CO_2 into injection wells and continuous production from production wells. This method has several advantages, including strong injection capacity, simple process principle, and rapid replenishment of reservoir pressure. However, it also has some drawbacks such as high CO_2 consumption and cost, low vertical displacement efficiency, and the potential for gas breakthrough and channeling, resulting in less than ideal recovery (Wei et al., 2020; Tang and Sheng, 2022). In addition to continuous gas injection, there are two other methods: pulse gas injection and periodic (intermittent) gas injection. Pulse gas injection involves injecting gas at a constant pressure. Once the reservoir reaches a certain pressure, the gas injection is stopped and the process converts to depletion, which is then repeated. This creates a fluctuating pressure field in the formation, creating an unstable dynamic environment that hinders the expansion of the CO_2 front and delays the development of fingering, as shown in Fig. 9. Periodic gas injection involves stopping injection and production after a certain amount of gas has been injected, a specific injection time, or a certain pressure. This allows for soaking during the intermittent period. This injection method helps attenuate the power of the finger quickly, slows down the advancement of the front, and delays the occurrence of gas channeling. It also prolongs the diffusion and dissolution time of CO_2, maximizing its EOR role and increasing the efficiency of oil washing (Feng et al., 2020; Niu et al., 2021).

The primary challenge in regulating the injection process is determining how to scientifically manage key parameters such as injection rate (pressure) and gas injection cycle. To address this, researchers typically conduct experiments and numerical simulations that consider field conditions. These studies aim to assess the impact of key parameters on the sweep range and oil production, enabling the identification of suitable parameter combinations and ranges. Wen et al. (2015) utilized the orthogonal experiment method to investigate the impact of gas injection rate and period on sweep efficiency. They developed a combination scheme of injection and production parameters for periodic gas injection, which yielded significant improvements in production. Wang X. et al. (2018) examined the effects of injection rate and path on CO_2 breakthrough and oil recovery. They determined the optimal parameter range considering the economic aspects of CO_2 storage–oil recovery. In a field test conducted by Peng (2013) in Shengli Oilfield, it was observed that pulse gas injection and periodic gas injection effectively mitigated gas channeling and reduced production decline, when implemented with appropriate parameters. Notably, regulating the gas injection rate had the most pronounced impact on performance enhancement, as shown in Fig. 10.

In addition to continuous oil recovery at the production end, there are also methods such as synchronous injection–production, asynchronous injection–production, and intermittent oil recovery. The main challenge in regulating the production end is determining the optimal start–stop timing for the production well. In their study, Kovscek and Cakici (2005) compared the production characteristics and recovery of different gas injection schemes. They proposed a well control strategy that involves the continuous injection of injection wells and real-time control of start–stop of production wells based on the dynamic changes of two core parameters: production gas–oil ratio and reservoir pressure. The findings indicated that this injection–production mode enables flow field intervention before CO_2 breakthrough, facilitating the separation and migration of oil and gas components, and effectively improving the sweep displacement efficiency of CO_2 within the pore space. However, in practical production processes, accurately

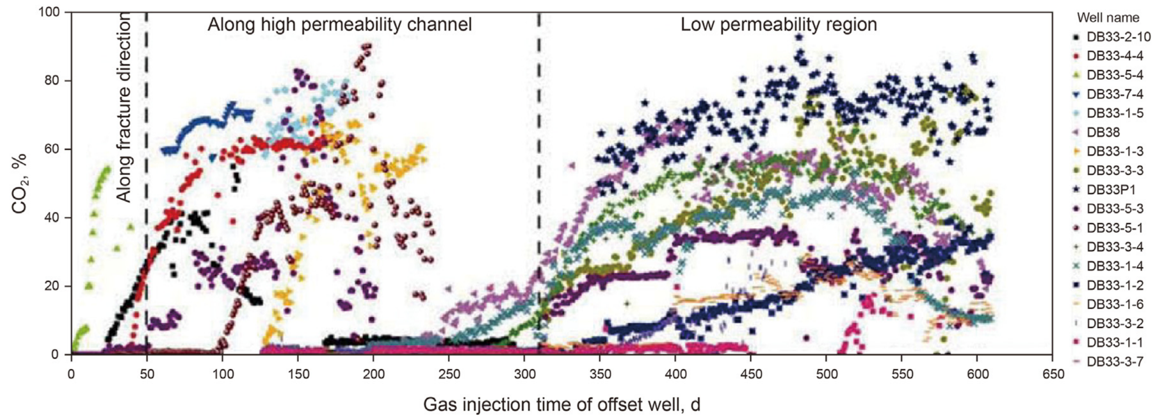

Fig. 9. Change of CO_2 concentration with gas injection time of offset injection well. Adapted from Gao et al. (2014).

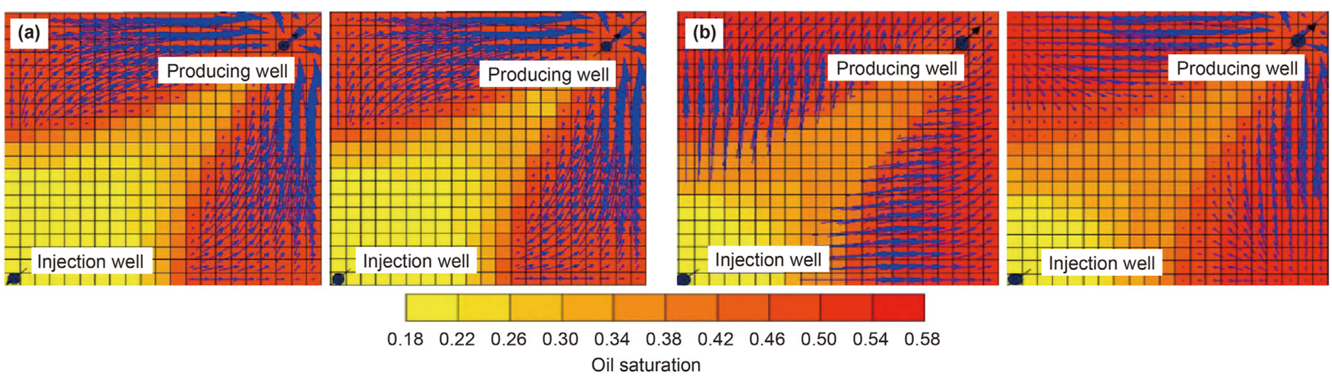

Fig. 10. The distribution of oil saturation in the horizontal profile of oil flow rate with different injection and production methods and the same production time. (**a**) Continuous injection and production, left is 30 d, right is 60 d. (**b**) Controlled injection and production, left is injection for 30 d, right is production for 60 d. Adapted from Cui et al. (2022).

obtaining changes in reservoir pressure is challenging, and frequent switching of wells is not feasible. Therefore, the production of wells is often simplified to intermittent production, and the timing and duration of the stopover are relatively fixed. While it may be difficult to achieve the ideal economic limit, it can still yield certain improvement results (Yang and Li, 2017). Building upon this, Li et al. (2010) proposed using the average static pressure, measured after shutting down the production well, as the monitoring index for well control instead of the formation pressure. Simulation results demonstrate that this approach can lead to better sweep and recovery benefits.

3.2. Water-alternating-gas technology

Water-alternating-gas (WAG) is a significant technology for controlling the flow field and expanding the sweep of CO_2 based on fluid dynamics. Field tests were conducted in Alberta as early as 1957 (Christensen et al., 1998). Through WAG technology, water injected into the reservoir will preferentially occupy the high permeability layer or large pore channels. Consequently, CO_2 entering the reservoir will face difficulties in flowing through the large pore channels due to the high seepage resistance caused by water plugging and the high capillary resistance caused by the change of oil–water interface and rock wettability. However, due to its high fluidity, CO_2 can enter the low permeability layer and small pore throats, effectively expanding the sweep range and curbing the fingering and gas channeling of CO_2 in the dominant high permeability channel (Christie et al., 1993; Christensen et al., 1998). Additionally, the alternating injection of water and CO_2 results in CO_2 being blocked by water and dispersed in the reservoir's pores, making it difficult to form a continuous phase. This phenomenon plays a role in reducing CO_2 mobility and delaying the development of fingering (Wang L. et al., 2020).

The focus of WAG technology research is to determine elemental parameters such as injection parameters and period, slug ratio, well pattern and well spacing based on reservoir characteristics. Changlin et al. (2013) conducted numerical simulations to study different regulation technologies, including allocation of injection rates (AOIR), tapered water-gas alternation (T-WAG), and AOIR-TWAG. They also investigated the influence of injection pressure and displacement rate, highlighting the significant impact of injection rate and pressure on sweep and recovery. Laboratory studies by Al-Shuraiqi et al. (2003), Kulkarni and Rao (2005), and Zhao et al. (2019) preferred a 1:1 slug ratio for injection. However, Carpenter (2019), Pancholi et al. (2020), and Wang Y. et al., 2020 found that longer water slugs can better reduce oil production fluctuations, expand the CO_2 sweep range, and achieve higher recovery in laboratory research and field feedback. Conversely, Nasser et al. (2023) argued that excessively long water slugs could reduce the contact between CO_2 and oil, making it difficult for them to mix or utilize oil. Based on previous studies, the selection of slug ratio is closely linked to the characteristics of formation and early development mode. Longer water slugs may have a better-balanced sweep effect when there are more high permeability channels or during the CO_2 gas channeling period. On the other hand, shorter water slugs should be chosen when the CO_2 production capacity needs to be

Table 2
Summary of studies of the flow field intervention methods discussed in this review.

Development mode	Operation method	Working principle	Advantage	limitation	Application
Continuous injection and production	Continuous CO_2 injection and production	Continuous CO_2 injection to replenish formation energy and drive oil production	High injection capacity, simple process principle, rapid replenishment of formation pressure	High gas consumption and high cost, the gas is easy to break through prematurely to form gas channeling.	Nahorkatiya Main, India (Chen P. et al., 2023) Petra Nova, America (Olalotiti-Lawal et al., 2019)
Periodic (intermittent) gas injection	Continuously injecting gas to a certain injection volume, time or pressure and then stopping the injection	The pressure disturbance and interaction flow are formed between the high and low permeability zones. Creates an unstable dynamical environment, so that the formation of continuous fluid redistribution.	Disturbing the expansion of CO_2 front and delaying the development of fingering/gas channeling. Activate the oil in the low permeability area, increase the degree of oil mobilization, and expand the sweep volume.	Injection parameters such as gas injection slug size and speed need to be optimized. The disturbance law of mine scale migration under different control data is not clear.	Bakken Shale, America (Sanchez-Rivera et al., 2015) Jingbian Oilfield, China (Wang et al., 2016)
Pulse gas injection	Constant pressure injection, stop injection when the reservoir reaches a certain pressure, repeat injection when the pressure drops to a certain pressure	Same as periodic gas injection	Can control the miscible degree of CO_2 in the displacement process. Others are same to periodic gas injection.	Difficult to realize pressure control in the reservoir of fracture-cavity or with potential escape channel. There are certain requirements for the pressure sensitivity of the reservoir.	Song-fang-tun Oilfield, China (Huo et al., 2012) Daqing Oilfield, China (Wu, 2015)
Asynchronous injection and production	Stop production during CO_2 injection, start production after reaching the preset bogging time, stop CO_2 injection during production	Replenishing formation energy, increasing formation pressure, and establishing a new pressure equilibrium by closing wells and alternating driving mode	Reduce the plane contradiction, change the direction of CO_2 migration, expand the sweep volume, delaying the development of fingering. Closure of production wells can effectively improve oil repulsion and seepage effect.	Fractures and potential escape channels can affect the effectiveness of development. Often necessary to cooperate with the injection control to achieve better development results. Parameters need to be optimized.	Bakken Oilfield, America (Luo G. et al., 2021) Shengli Oilfield (Chen et al., 2024)
WAG	Alternate injection of water and CO_2 into the reservoir	Water enters the high permeability layer or large pore channel, increasing the seepage resistance and capillary resistance. Water blocks the CO_2, so that the CO_2 disperses in the pores, forming a discontinuous phase.	Make CO_2 accessible to the low-permeability layer and small pore throats, expand the sweep volume, delaying the development of fingering and gas channeling in the dominant hypertonic channels. Reduce CO_2 mobility and delay fingering development.	Difficult to inject water in tight/extra-low seepage blocks, due to excessive seepage resistance. The water shield effect may affect the utilization of the remaining oil at the blind end. Low-temperature water injection may cause reservoir temperature drop. Parameters need to be optimized.	Al Shaheen Oilfield, Qatar (Denney, 2010) Sumatera Light Oilfield, Indonesia. (Abdurrahman et al., 2021)

maximized (Wang G. et al., 2017). Furthermore, Jiang et al. (2010), Salehi et al. (2014), and Ahmadi et al. (2015) analyzed the impact of WAG from the perspective of optimizing the composition of injected gas and water (salinity or addition of surfactant), and made significant progress. In addition to the challenge of optimizing parameters, another significant issue with WAG technology is the formation of water shield effect, where the remaining oil after water injection is mostly surrounded by a water film. This water film hinders the penetration of CO_2 and its contact with oil, making it more difficult to achieve miscibility and reducing the efficiency of oil washing. As a result, WAG technology still faces significant limitations in its practical application process (Lu et al., 2017; Chen et al., 2020).

3.3. The brief summary of fluid dynamics method

The characteristics of main flow field intervention methods were shown in Table 2. These methods based on flow field intervention have the advantages of low cost, wide applicability and simple technology. The disadvantage is that it is necessary to access the behavior of formation fluids in order to carry out timely and effective regulation. Moreover, these methods are effective during the fingering developmental period, but difficult to control during the gas channeling period. Therefore, it is suggested to adopt this method to regulate ‘fingering-gas channeling’ in the early stage of development.

Multi-parameter optimization and decision processing are the biggest technical challenges in the application of this methodology. In the case of multi-condition coupling, the weighting of the influence of numerous parameters on the degree of fingering and recovery at the laboratory and mine scale is still not clear. Consequently, there is a growing interest in utilizing artificial intelligence and machine learning technology to analyze experimental or underground data, predict fluid flow behavior in porous media, and assist in making informed decisions regarding parameter regulation (Shen et al., 2023; Zhuang et al., 2024). Chen et al. (2010) incorporated orthogonal array and topology technology into the genetic algorithm, while Nait Amar et al. (2021) utilized the Levenberg–Marquardt algorithm, ant colony optimization, and gray wolf optimization to optimize two machine learning models. Similarly, Ding et al. (2022) combined an artificial neural network with non-dominated sorting genetic algorithm. Using their respective approaches, they investigated the impact of each parameter on the recovery factor and identified the optimal injection-production parameters. Despite significant advancements in intelligent oil and gas development technology in recent years, there is a lack of consensus on the key control parameters, and research in this area remains fragmented. Therefore, it is necessary to clarify the influence weights of multiple factors on gas channeling, formulate prevention and control countermeasures according to the development degree of fingering, and then establish a hierarchical control mechanism of gas channeling.

4. Chemical thickeners based on mobility regulation

Gas channeling in CO_2 flooding is primarily caused by the gravity overlap and mobility difference resulting from the density and viscosity disparity between CO_2 and oil. To mitigate this issue, CO_2 tackifiers are employed to enhance the viscosity of CO_2, thereby reducing its mobility and improving its distribution within layered formations. This leads to a decrease in gas channeling and an expansion of the sweep efficiency (Enick et al., 2012; Bai et al., 2022). The most commonly used CO_2 chemical thickener currently include polymers and surfactants.

4.1. Polymeric for thickening of CO_2

Polymers have been widely used in various scenarios to increase the viscosity of liquids. Scholars began exploring the application of polymers to control the mobility of CO_2 in the 1980s. However, due to the short orbital hybrid bond length and only one weak electric dipole moment of the carbon-oxygen double bond in CO_2, it is challenging to dissolve high molecular weight polymers. Early studies did not yield satisfactory results. Therefore, increasing the solubility and tackifying ability of polymers in CO_2 has become a crucial focus for subsequent research (Lundberg and Sikorski, 1983; Heller et al., 1985; Huang et al., 2019). To enhance solubility in CO_2, the researchers considered incorporating specific functional groups onto the polymer, researchers specifically focused on fluorine due to its quadrupole interaction with CO_2. DeSimone et al. (1992) took the lead in developing a high molecular weight polyfluorinated acrylates PFOA (poly (1H, 1H-perfluoro-*n*-octyl acrylate), which can increase the viscosity of CO_2 to 2.5-fold. Huang et al. (2000) earlier used fluorinated acrylate and styrene to make the copolymer PolyFAST, which increased the viscosity of CO_2 by more than 10-fold, showing good viscosity increase and temperature resistance. In a separate study, Sun et al. (2019) utilized molecular simulation technology to analyze the interaction between CO_2 and copolymer systems of perfluorodecyl acrylate (HFDA) with different configurations at the microstructure and molecular level. They elucidated the adhesive and dissolving performance of different configurations at various temperatures and pressures. Another study by Zaberi et al. (2020) involved the synthesis of high molecular weight polyfluoroacrylate (PFA) and examined the thickening and channeling inhibition performance of the PFA-CO_2 system in porous media. Dai et al. (2022) introduced the benzene ring into HFDA as a thickening group, which significantly improved the viscosification effect. And the whole atomic molecular dynamics simulation method was used to investigate the microscopic behavior of fluoro group, benzene ring, and their copolymer in SC-CO_2.

Fluorine-containing polymers exhibit favorable tackifying properties; however, their high cost and environmental impact hinder their widespread application. On the other hand, hydrocarbon polymers offer cost and environmental advantages, but their tackifying effect is limited at low dosage levels (Kar and Firoozabadi, 2022; Du et al., 2024). In comparison, silicon-oxygen polymers containing silicon and carbon, which belong to the same group of elements, possess similar polarity and characteristics. As a result, they exhibit certain CO_2 solubility and low mixed cohesive energy, while also being cost-effective, making them a subject of significant interest (Sun and Sun, 2015; Liu et al., 2021). The viscosity increase is particularly noticeable under high pressure. The research group of Wang sequentially designed and evaluated silicone thickeners using the response surface method and extended finite element numerical simulation method (Li Q. et al., 2018b, 2019). They synthesized triethoxysilane-based silicone terpolymer and epoxy ether-based Polydimethylsiloxane (EEPDMS), and analyzed the relationship between structure, viscosity, and phase behavior. Gandomkar et al. (2021) investigated the viscosifying properties of PDMS while also evaluating the effect on MMP and the performance of EOR at core scale. Sui et al. (2023) introduced a short CO_2-philic chain into the main chain of the polymer through ring-opening polymerization and hydrosilylation reaction. This resulted in the formation of a spatial network structure that enhances solubility and solubilization effects in CO_2. Overall, the solubility and tackifying ability of silicon-oxygen polymers are still inferior to those of fluorine-containing polymers. In order to enhance their performance, additional solubilizers or CO_2-philic groups may be required, although this can increase the cost. However, silicon-oxygen polymers are generally more cost-effective and environmentally friendly compared to fluorine-containing polymers. Therefore, further research is focused on optimizing and improving the properties of silicon-oxygen polymers.

In addition, the solubility of polymers can be enhanced by utilizing appropriate cosolvents. These cosolvents typically consist of small molecule polar chemical agents that rely on specific functional groups or form hydrogen bonds with CO_2 Lewis acid-base to improve polymer solubility in CO_2. Examples of commonly used cosolvents include ethanol and toluene. Williams et al. (2004) and O'Brien et al. (2016) separately used toluene and ethane as cosolvents with thickeners, and discovered that these low-polarity cosolvents can significantly enhance the solubility of thickeners in CO_2. They supplemented this with tackifiers to achieve a tackifying effect several times greater. Li Q. et al. (2018a) assessed the solubilization performance of cosolvents based on absorbance and observed that solubilization performance increased with the length of the carbon chain. They also found that low-polarity alcohols exhibited better solubilization performance for siloxane polymers due to similar miscibility principles. Gong et al. (2019) conducted a molecular simulation study on the effect of different cosolvents on the dissolution of poly (vinyl acetate) (PVAc) and determined that the interaction between Lewis acid and Lewis base and the hydrogen bond between carbon and oxygen atoms were the main factors influencing solubility. Zhu and Dong (2018) primarily evaluated the phase behavior and rheological changes of the ternary system under high pressure after introducing the cosolvent. They discovered that changes in cohesive energy density and mixing entropy were the key reasons for solubilization, and they established a predictive model for viscosity correlation. Although the cosolvent can effectively enhance the solubility of the thickener in CO_2, it typically requires a significantly larger amount of the thickener to achieve a satisfactory solubilization effect. This economic limitation hinders its practical application in actual fields. Consequently, cosolvent mostly used in the laboratory to aid in the evaluation of the tackifying effect of specific structures or functional groups at the present stage.

4.2. Surfactant for thickening of CO_2

The surfactant exhibits cementation properties when its concentration exceeds the critical micelle concentration (CMC). The surfactant forms micelle structures that cause the substances connected to its two ends to cross-wrap, resulting in a significant increase in system viscosity. Based on this principle, the surfactant is designed with one end being solvent-philic and the other end being CO_2-philic. This CO_2-surfactant system can self-assemble and form a viscoelastic reverse micelle system, with the CO_2 phase wrapping around the solvent phase. At a specific surfactant concentration, the reverse micelle system becomes entangled, forming a worm-like structure that greatly enhances the viscosity of CO_2 (Wang J. et al., 2018; Yang et al., 2021). However, due to the nonpolar characteristics of CO_2, the solubility of common surfactants in CO_2 is almost negligible. The solubility and self-assembly properties of surfactants have emerged as major challenges in research. In order to address the solubility issue, Hoefling et al. (1991) and Eastoe et al. (1996) focused on the principle of similarity dissolution and explored the use of fluorine, which has a similar structure to CO_2, in surfactant research. Their studies revealed that the presence of a fluorine-containing group at the end carbon atom of the surfactant, after fluorination, is crucial for enhancing its dissolution. Eastoe et al. (2006) conducted a study of the interfacial behavior of fluorine-containing surfactants using molecular simulation. They discovered that fluorinated surfactants have a better ability to maintain the steady state of the phase interface. They also proposed the theory of free volume fraction. In a separate study, Ren and Yin (2020) utilized advanced molecular simulation technology to investigate the dynamic self-assembly process of water-soluble alcohols with varying hydrocarbon chain lengths at the atomic level. Their research shed light on the impact of different carbon chain structures on assembly arrangement, skeleton stability, and interaction energy. Similar to fluorine-containing polymer tackifiers, surfactants are also being developed with a focus on low or non-fluorinated options, driven by concerns over environmental pollution and the high cost of fluorine-containing surfactants.

In order to scientifically reduce the fluorine content in surfactants, it is important to determine the minimum fluorine content required for the conversion of surfactants to CO_2-philic. Mohamed et al. (2011) conducted a study where they measured the formation of reverse micelles in CO_2 using high-pressure small-angle neutron scattering technology. They clarified the optimization ability of fluorine content on interfacial tension, CMC value, dew point pressure, etc., and proposed a structural benchmark, di-CF2, for dual-chain surfactants with lower fluorine content. Subsequently, the team (Mohamed et al., 2015, 2016) selected fluorocarbons with the same hydrophilic head group to bond with hydrocarbons, and synthesized a variety of CO_2 affinity hybrid surfactants with low fluorine content while ensuring solubility. As a result, the fluorine content of CF2/SIS1 surfactant was reduced to 15.01 wt%. Bao et al. (2019) proposed a novel approach by combining hydrocarbon surfactants and fluorinated surfactants to reduce the amount of fluorinated surfactants while still achieving the desired dissolution and tackifying effect. Using molecular simulation technology, they investigated the key factors influencing the formation and stability of self-assembled microemulsions. Additionally, they developed two surfactants that can partially replace fluorinated surfactants, thereby reducing the fluorine content in the system. Wang M. et al. (2017) also employed molecular simulation technology to explore the relationship between the surfactants middle group and the self-assembly morphology. They enhanced the fusion ability of reverse micelles by improving the middle group. Furthermore, they designed a fluorine-free hydrocarbon surfactant capable of self-assembling into wormlike micelles. However, its drawback is the dependence on the co-surfactant (C8Benz) for effective wormlike micelle generation. Xiong et al. (2023) conducted a study where they selected the tertiary amine group as the response unit. They designed and synthesized a self-assembled intelligent response gemini surfactant using a frozen transmission electron microscope. This surfactant formed a high-viscosity aggregate in response to CO_2, resulting in a thickening effect of over 200 times. Moreover, it did not show thickening properties in response to oil. Instead, it reduced the interfacial tension to approximately 10^{-2} mN/m. The advancements in molecular simulation and microscopic visualization technology have greatly contributed to understanding the influence of functional groups on phase interfaces and energy conversion angles, as well as the research on self-assembly theory. The characteristics of several typical CO_2 thickeners mentioned above are shown in Table 3. Despite these developments, fluorocarbon surfactants still demonstrate superior performance in CO_2 tackifying. To address this issue, the key lies in transforming theoretical research into more efficient low-fluorine and fluorine-free surfactant products.

In addition to its tackifying effect, surfactant is also used as a foaming agent to produce CO_2 foam. In this foam system, the liquid acts as the continuous phase while the gas is dispersed, resulting in a higher apparent viscosity and flow resistance compared to pure gas. This effectively reduces the flow energy of CO_2 and its mobility (Talebian et al., 2013; Chen et al., 2018; Yang et al., 2019; Zhang L. et al., 2020). At the same time, due to the larger volume of foam, it can effectively plug the formation and contribute to its plugging effect. Further details on the research of foam systems will be discussed in the next section.

4.3. The brief summary of chemical thickeners

The low density and low viscosity of CO_2 are the essential causes of viscous fingering, so CO_2 thickener can fundamentally inhibit gas channeling. However, due to the introduction of exotic chemical systems, the CO_2 tackifying technology will inevitably face problems such as cost, applicability, and formation damage. Therefore, CO_2 tackifying can be used as a means to regulate CO_2 mobility and reduce gas channeling after the failure of the flow field intervention method. However, there is still a lack of thickeners that can be realized for large-scale use in mines.

CO_2 thickeners need to meet the requirements of high CO_2 solubility, low price, non-toxic and resistant to high temperature and salt, which is extremely challenging. Although fluoride has shown good solubility thickening properties in the laboratory, low- or no-fluorine thickeners have become the focus of research nowadays, considering the price and environmental factors. At present, the advantages of non-fluorinated functionalities such as acetate, carbonate, ether, and carbonyl functionalities, which have certain CO_2-affinity, have become more and more obvious, but how to realize effective solubilization and thickening at low concentrations is still a bottleneck that is difficult to break through. Meanwhile, small molecule thickeners, 'nanoparticle + polymer/surfactant' systems, specially designed thickener structures,

Table 3
Summary of studies of the polymeric CO_2 thickeners discussed in this review.

Classification	Polymer composition	Polymer concentration, wt%	Co-solvent	Experimental condition	CO_2 thickening ability	References
Fluorinated	PFOA	3.4	No co-solvent	323 K, 30 MPa	2.5 folds	DeSimone et al. (1992)
	PolyFAST	1–5		295 K, 48.28 MPa	5–400 folds	Huang et al. (2000)
	HFDA	5.0		308 K, 30 MPa	About 80 folds	Sun et al. (2019)
	PFA	1.0		298 K, 20.7 MPa	4 folds	Zaberi et al. (2020)
	$HFDA_{0.70}$-co-$STY_{0.30}$	5.0		320 K, 30 MPa	297 folds	Dai et al. (2022)
Hydrocarbons	P-1-D	1.8	Ethanol, acetic acid	308 K, 31 MPa	6.5 folds	Kar and Firoozabadi (2022)
	PVEE	11.48	or ethyl acetate	308 K, 8 MPa	2.25 folds	Du et al. (2024)
Siloxanes	EEPDM	3	Toluene or hexane	308 K, 12 MPa	7.2 folds	Li Q. et al. (2018b, 2019)
	PDMS	4	Toluene	353 K, 21 MPa	4.7 folds	Gandomkar et al. (2021)
	PSAGEGPEAc	Less than 0.8	Phenyl	308 K, 15–35 MPa	4–5 folds	Zhang et al. (2021)
	Modified silicone polymers*	1.5	Toluene	323 K, 15 MPa	7–10 folds	Sui et al. (2023)

Note: *Polymerization of octamethylcyclotetrasiloxane, tetramethylcyclodisiloxane and diethylene glycol dimethylpropenyl acetate.

biopolymers, etc. May also be an effective way to realize the thickening of CO_2, but further research is still needed. In conclusion, despite many years of in-depth research on CO_2 thickeners, the product economics and solubility of associated molecules in CO_2 are still the biggest problems that hinder the promotion of thickeners from laboratory experiments to field applications. Nowadays, the scientific research system of laboratory and simulation has been relatively complete. The focus of future research needs to anchor the actual situation of the field, conduct research and field testing according to the real needs, so as to realize the field application at an early date.

5. Chemical system based on CO_2-channeling plugging

The occurrence of fingering-gas channeling is closely related to the heterogeneity of the reservoir. When the reservoir heterogeneity is significant or gas channeling has already taken place, it becomes challenging to effectively control gas channeling through dynamic regulation of the flow field or chemical regulation of mobility. In such cases, it becomes necessary to employ certain methods to block the high permeability area or the dominant seepage channel. Currently, the primary technologies used for channeling plugging are the gels and foam.

5.1. Gels for CO_2-channeling plugging

The channeling plugging gel system is primarily used to inject a specific chemical agent into the reservoir, gel, and block the high permeability layer or dominant channel. This process changes the displacement direction of CO_2 and expands the sweep range (Zhao et al., 2021). The gel system generally takes two forms: delayed cross-linking and pre-crosslinking. The delayed cross-linking gel of underground gelation achieves the plugging effect by delaying the cross-linking reaction after injecting macromolecular polymers and cross-linking agents underground. Among these, the most widely used gel is polyacrylamide (PAM) gel, which contains numerous hydrophilic groups like amide groups and carboxyl groups. Through hydration expansion and electrostatic repulsion, it can significantly increase in volume after gelation. The resulting three-dimensional network structure, formed through crosslinking, gives the gel higher viscosity and strength, effectively achieving plugging (Lantz and Muniz, 2014; Zhao et al., 2021; Chen L. et al., 2023). The characteristics of several typical gels mentioned below are shown in Table 4.

Due to the strong corrosion of CO_2, the gel system requires higher standards. In a previous study by Martin and Kovarik (1987), they evaluated the effectiveness of a gel system formed by polyacrylamide and Cr^{3+} ion cross-linking, which is commonly used in water flooding profile control, for CO_2 plugging. They found that the gel initially had higher strength and plugging ability, but it exhibited poor stability in high-temperature CO_2 environments and experienced significant viscosity loss over time. They suggested that better performance could be achieved by changing the type of crosslinking agent or altering the path or concentration of chromium ion acquisition (limited by technology, Cr^{3+} is obtained through the reaction of sodium dichromate and sodium thiosulfate). Sydansk (1988) previously evaluated the gelling properties of chromium acetate and polyacrylamide, and this system was quickly applied to the Wertz oilfield, resulting in a successful plugging effect and subsequent widespread use and study (Borling, 1994). Al-Ali et al. (2013) conducted a detailed study on the effect of this system on CO_2 flow in the core using CT technology. Cheng et al. (2023) further investigated the diffusion process of gas in the gel during CO_2 plugging using scanning electron microscopy and energy dispersive spectroscopy, providing a clearer understanding of the system's plugging mechanism and proposing new ideas for improvement.

Scholars are continuously working towards optimizing the performance of gel systems. To enhance the plugging strength and stability of the gel system in high-temperature environments, the research group of Dai conducted a study using atomic force microscopy and cold field electron microscopy (Dai et al., 2018, 2021; Wang et al., 2022; Ji et al., 2023; Zhao et al., 2023). The objective was to understand the matching law and regulation mechanism of gel dispersion and pore throat at the micro-nano scale. As a result, a new method called nano-graphite hybridization and cascade hybridization was developed to improve the temperature and salt resistance of polymer gel. This advancement led to an improvement in temperature resistance up to 160 °C and salt resistance up to 250,000 mg/L. Shao et al. (2020) employed the interfacial precipitation method to prepare microcapsules with ammonium persulfate as the active core. Their study focused on controlling the initiator to enhance stability and effectively regulate the gelation time. The gel system achieved a gelation time of over 30 h, leading to successful plugging in the core with a permeability as low as 50 mD. In a separate study, Cao et al. (2018) utilized self-made modified cellulose to graft acrylamide and cross-linking agent, resulting in the development of a strong gel channeling agent with a viscosity of 18×10^4 mPa s. This agent demonstrated a robust skeleton that could withstand high-pressure CO_2 environments for up to 120 days. Furthermore, Zhao et al. (2022) conducted numerical simulations to investigate the gel regulation of the H-95 block in Jilin Oilfield. Their research evaluated the impact of gel size and plugging strength on reservoir permeability and CO_2 flooding after plugging. They determined that the optimal permeability adjustment ratio for the gel was 30.

With the development of intelligent response materials, the CO_2-responsive gel system formed by introducing CO_2-responsive

Table 4
Summary of studies of the gels discussed in this review.

Gel composition	Gel concentration	Initiator (response group)	Temperature resistance	pH/salinity resistance	Gelation time	Performance	Reference
PA/PHPA	At least 1.5 wt%	$(CH_3COO)_3Cr$	Maximum 397 K	pH = 4–10.6 Salinity >29,200 mg/L	At least 12 h	Work hour >2400 h at pH = 8.6, 295 K	Sydansk (1988)
EAPD	2.5–3.0 wt%	NaSal	More than 353 K	/	150 s at 298 K	Plugging efficiency for 100 mD core >95% at 353 K and 4 MPa	Zhao et al. (2023)
CR-DPG	0.15 wt%	$Zr(CH_3COO)_4$	More than 363 K	Salinity >5000 mg/L	2.5 h at 303 K	Work hours >60 d at 363 K and 20 MPa	Zhao et al. (2013); Ji et al. (2023)
AM + MBA	AM 5 wt% MBA 0.05 wt%	$(NH_4)_2S_2O_8$ (capsule type for longer gelation time)	Maximum 363 K	/	30 h	Work hour >90 d	Shao et al. (2020)
Modified cellulose[a] + AM + MBA	Modified cellulose 2 wt% AM 2 wt% MBA 0.1 wt%	$K_2S_2O_8$	More than 338 K	pH = 5.8 Salinity >50,000 mg/L	6–24 h	Work hour >120 d at 10 MPa	Cao et al. (2018)
DOAPA + SPTS	DOAPA 4.4 wt% SPTS 2.0 wt%	CO_2	More than 323 K	Salinity >10,985 mg/L	10 min	Plugging efficiency for the fractured core is 99.2%, EOR = 20%	Zhang et al. (2019)
DMTA-NADS	200 mmol/L	CO_2	More than 343 K	/	10 min	Plugging efficiency of high permeability core >90%, EOR >25%	Dai et al. (2020)
VFMES/TMPDA-MNPs	VFMES 3 wt% TMPDA 0.03 wt% MNPs 1.2 wt%	CO_2 (tertiary amine)	More than 353 K	Salinity >20,000 mg/L	80 min	Environmental friendliness, plugging efficiency reaches 97%, EOR = 22.2%	Zhang L. et al. (2024)
PEO_{100}-PPO_{65}-PEO_{100}	0.7–2 wt%	CO_2 (tertiary amine) Temperature response, $T > 313$ K (pluronic F127)	More than 358 K	pH = 5.1	20 min	Increase pressure drop about 15 times, EOR = 21%–22%	Luo X. et al. (2021)
IPN-PAASP	5.0 wt%	CO_2 (tertiary amine)	More than 341 K	pH = 4.2	30 min	Plugging efficiency reaches 99%, pressure drop increased from 5 kPa to 0.342 MPa, EOR = 6.0%	Pu et al. (2021)
MRPG	5.0 wt%	CrAc	501 K[b]	Salinity> 1000 mg/L	0.8 –16.5 d[c]	Work hour >220 d at 353 K	Pu et al. (2023)

Note: [a] Unnamed, structural formula can be found in Ref.; [b] *N*-vinylpyrrolidone had high thermal-stability; [c] Underground secondary crosslinking time.

groups into polymers or surfactants has attracted attention due to its low initial viscosity and strong selective plugging. Commonly used response functional groups include amines, guanidines, and amides. The reaction principles are summarized in Fig. 11(b) (Alshamrani et al., 2016; Jansen-van Vuuren et al., 2023; Cunningham and Jessop, 2023). Based on these principles, Zhang et al. (2019) conducted a study in which they developed a low-cost CO_2-responsive composite surfactant system through compounding and screening. They investigated the transformation characteristics of the system from spherical micelles to wormlike micelles using freeze-transmission electron microscopy. In a similar vein, Dai et al. (2020) prepared a CO_2-responsive gel system by utilizing small-molecule amine compounds and modified long-chain alkyl anionic surfactants. Through electron microscopy images and nuclear magnetic resonance results, they observed that the system protonated upon contact with CO_2, transitioning from small molecule amine compounds to pseudo gemini surfactants and subsequently self-assembled into worm-like micelles. This transition resulted in a significant increase in the resistance coefficient by 75 times, and a plugging rate of over 90%. Zhang Z. et al. (2024) synthesized a green anionic surfactant VFMES using tung oil and formed an environmentally friendly intelligent gel system with

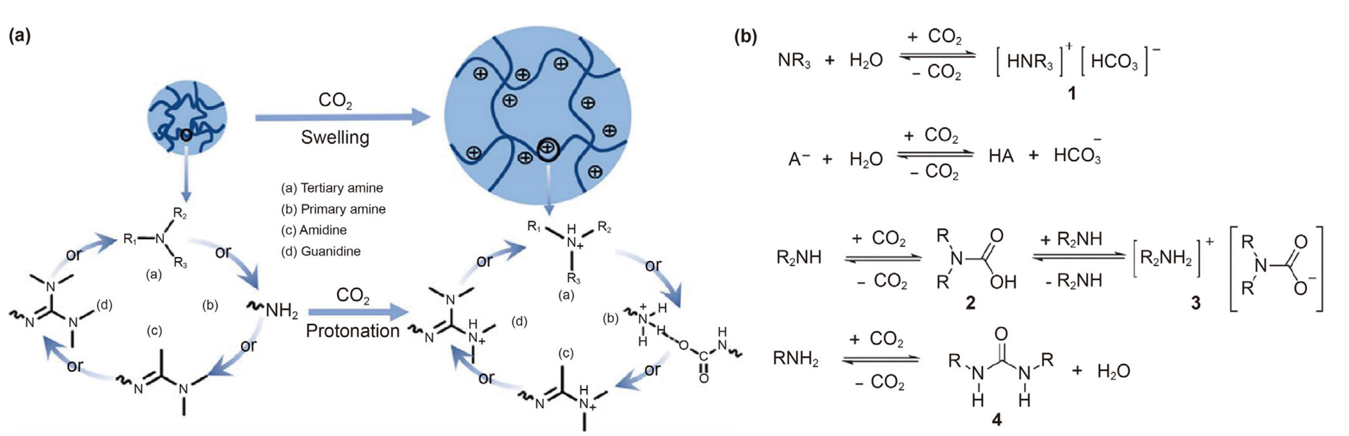

Fig. 11. (**a**) Scheme of the swelling mechanism of CO_2 responsive gel. Adapted from Liu and Liu (2022). (**b**) The four general scenarios involving the use of CO_2 as stimulus. Adapted from Alshamrani et al. (2016) and Jansen-van Vuuren et al. (2023).

the response agent TMPDA and the fortifying agent MNPs particles, which showed high plugging properties, stability and environmental friendliness. The research group of Feng conducted a study on the thermal response characteristics of polymers (Wang M. et al., 2018; Luo X. et al., 2021). In their recent work Luo X. et al. (2021) synthesized a copolymer, PEO_{100}-PPO_{65}-PEO_{100}, by using a triblock copolymer, pluronic F127, as a skeleton and poly (2-(dimethylamino)ethyl methacrylate) (PDMAEMA) as a branch. This copolymer exhibits dual response characteristics to heat and CO_2. The product was comprehensively analyzed in terms of its structure, rheology, and core recovery, providing valuable insights for the development of multi-stimulus thickening polymers.

The use of the delayed cross-linking gel for underground gelation has been widely adopted due to its strong injectivity and simple principle. However, there are challenges in effectively controlling the gelation time, process, and quality. Preformed particle gels (PPGs) are synthesized on the ground, which ensures relatively stable and controllable size, performance, and quality. Additionally, the injection process for a single component is relatively simple, making PPGs an area of interest among scholars (Bai et al., 2015; Goudarzi et al., 2015). The research group of Hou conducted visual microscopic experiments to quantitatively analyze the microscopic seepage characteristics of the fluid after PPGs system plugging (Zhou et al., 2017, 2019; Hou et al., 2019; An et al., 2023). They proposed the lattice Boltzmann method-discrete element method-immersed moving boundary (LBM-DEM-IMB) method to analyze the elastic deformation characteristics and flow resistance of PPGs. Bai et al. (2002, 2007a, 2007b) previously studied the PPGs for water flooding profile control, examining the impact of composition and structure on gel properties and flow. In more recent years, the research conducted by Bai and his coworkers (Sun et al., 2018; Bai and Sun, 2020) focused on PPGs for CO_2 flooding. They evaluated the performance of polyacrylamide-based super-absorbent polymers (PASP) for supercritical CO_2 plugging and synthesized gel particles ranging in size from nanometers to millimeters, which can be utilized in various CO_2 flooding scenarios. Notably, 2-Acrylamido-2-methylpropane sulfonic acid sodium salt-acrylamide (AMPS-AM) synthesized by dispersion polymerization and the double cross-linking response copolymer nanoparticles based on AMPS exhibited rapid and effective plugging of CO_2 in the core matrix, along with enhanced stability. Pu et al. (2021) synthesized responsive PPGs (IPN-PAASP) with interpenetrating networks using acrylamide as the core. They evaluated the changes in particle size and strength of the gel after contact with CO_2 and studied its plugging characteristics in the core, resulting in a 23.1% increase in recovery. Despite the numerous advantages of PPGs, there are still challenges that need to be addressed, such as particle-channel matching, injection capacity, adsorption loss during injection, seepage mechanism of particles in the flow process, and economic considerations. To tackle these issues, the development of recrosslinkable-PPG (RPPG) that can be re-crosslinked underground may offer a promising solution (Pu et al., 2019, 2023).

5.2. Foam system for CO_2-channeling plugging

The previous section highlighted that the foam system is effective in reducing mobility and plugging. CO_2 foam, in particular, has advantages such as easy foaming, large volume, and high density due to its stronger solubility and lower surface tension compared to gases like N_2 and CH_4. As a result, CO_2 foam has been extensively studied (Ren et al., 2022). During migration, CO_2 foam tends to enter the larger throat flow due to the Jamin's effect, resulting in accumulation and plugging due to its large volume and flow resistance (Mukherjee et al., 2016). However, due to its thermodynamic instability, foam naturally tends to develop in the direction of reducing free energy. Additionally, the solubility of CO_2 and the acidic environment after dissolution make CO_2 foam slightly less stable at high temperatures compared to foam systems with N_2, air, and other gases. Therefore, scholars are focused on researching how to enhance the stability of the CO_2 foam system in high temperature, high salt, and low pH environments (Aarra et al., 2014; Siddiqui and Gajbhiye, 2017; Solbakken and Aarra, 2021).

The earlier conventional CO_2 foam system was prepared using a surfactant with foaming properties. Zhang et al. (2013, 2014) conducted performance tests and evaluated the plugging of foams prepared using nonylphenol polyoxyethylene ether series of nonionic surfactants under high temperature and high-pressure conditions. The study clarified the strengthening effect of the degree of polymerization of polyoxyethylene (EO) on temperature resistance, resistance factor, and stability. Furthermore, an anionic-nonionic surfactant was synthesized by combining the EO group and anionic sulfonic acid group. The generated CO_2 foam exhibited a temperature resistance of 125 °C and a half-life of 295.2 min. Wang J. et al. (2018) developed a novel kind of CO_2-switchable foam using a long-chain cationic surfactant $UC_{22}AMPM \cdot H^+$ (*N*-erucamidopropyl-*N*,*N*-dimethylammonium bicarbonate), which achieves responsiveness with excellent foam strength and stability, and the schematic illustration of self-assembled process was shown in Fig. 12. Alzobaidi et al. (2017), Niu et al. (2022), and Li et al. (2024) investigated the performance of betaine surfactant in generating CO_2 foam using microfluidics, frozen transmission electron microscopy, and molecular simulation. The characterization of microscopic foam structure and kinetic process revealed that this surfactant's aggregation behavior effectively increased and maintained the thickness of the liquid film, resulting in high stability.

To enhance the stability of CO_2 foam system, Zhang C. et al. (2020) proposed an anionic surfactant system using ethanol as a solubilizer. They conducted molecular simulation and oil displacement experiments to investigate the positive effect of ethanol on dissolution, foaming, and stability (see Fig. 13). Li S., Yang K. et al. (2019) suggested a synergistic approach by combining non-ionic surfactant (lauryl alcohol polyoxyethylene ether ($C_{12}E_{23}$)) with modified hydrophilic nanoparticles. This method effectively increased the interfacial elastic modulus and improved the mechanical strength of the foam. The half-life of the foam generated by this approach was extended 30 times compared to that of foam generated by a single surfactant. Building on their previous research, the team (Li S. et al., 2022, 2023) recently proposed combining the CO_2-responsive surfactant *N*,*N*-dimethyldodecylamine ($C_{12}A$) with the modified nanoparticle N20. They analyzed the evolution of the foam structure using a three-dimensional microscope with ultra-depth of field. Experimental results demonstrated further improvement in the selective plugging and stability of the foam system, providing a novel approach for enhancing foam stability. In addition to optimization from the perspective of foaming agent, Li et al. (2024), Ren (2020), Li S. et al. (2021) and Hassanzadeh et al. (2023) have also investigated the multi-scale flow and plugging characteristics of CO_2 foam. They approached the topic from different angles, including molecular simulation, numerical simulation, and field tests. These studies comprehensively examined the effects of injection-production strategies, such as pressure, slug ratio, and injection position, on foam stability and plugging effect. They proposed engineering parameters that can help improve foam stability. Furthermore, some scholars (Etemad et al., 2022) have proposed a combined plugging method that utilizes the advantages of different plugging techniques. Chen S. et al. (2023) analyzed the performance of conventional polymer gel, CO_2-responsive polymer, and CO_2 foam under separate and combined conditions. Parallel long-core experiments revealed that the synergy of multiple systems can enhance pore

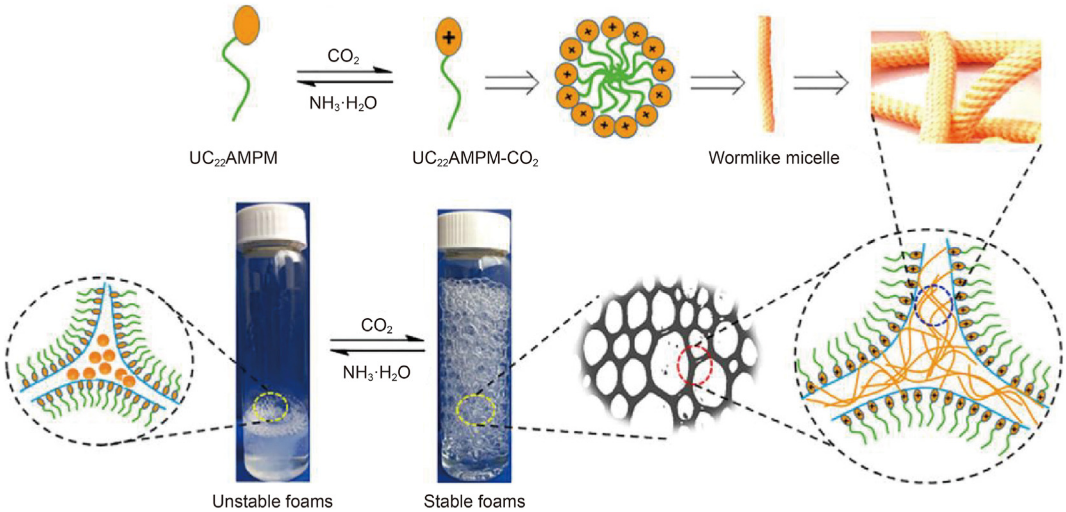

Fig. 12. Schematic illustration of $UC_{22}AMPM \cdot H^+$ self-assembled into wormlike micelles forming stable CO_2 foam. Adapted from Wang J. et al. (2018).

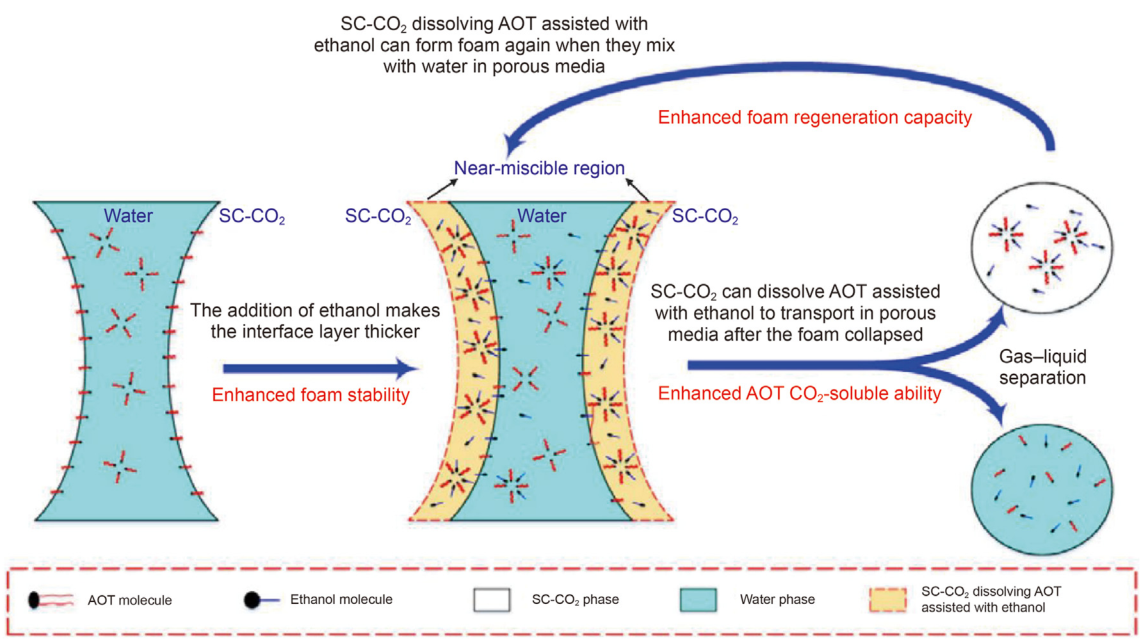

Fig. 13. Schematic illustration of synergistic enhancement of CO_2 foam stability by AOT surfactant and ethanol. Adapted from Zhang C. et al. (2020).

plugging ability, with a plugging efficiency of up to 78.37%. Although the stability of CO_2 foam as a plugging agent is weaker compared to the gel system, it offers advantages such as oil displacement, thickening, and plugging. Consequently, the application scheme of CO_2 foam is more flexible, leading to improved recovery results.

5.3. The brief summary of CO_2-channeling plugging

Channel plugging chemically can achieve significant CO_2 channeling control effect in CO_2 channeling stage or strong heterogeneous layer. This method also has the significant advantage of mature technology and more complete theory, since it has been successfully applied to water flooding. Currently, CO_2 channeling plugging agents have been successfully applied in Bati Raman in Turkey and East Seminole in Texas, USA (Karaoguz et al., 2007; Alcorn et al., 2020). However, channel plugging still faces the problems of easy deactivation under high temperature and high salt environment, difficulty in predicting the gelation time and strength, difficulty in injecting into the tight reservoir, and economic and environmental issues. Therefore, future research should further improve the plugging system according to the actual complex environment, and the temperature-resistant and environment-friendly CO_2-responsive in-situ crosslinked gel may be an effective solution.

6. Conclusions and prospect

Achieving a balanced sweep has emerged as a significant technical challenge that hinders the further enhancement of CO_2 flooding and storage effectiveness. To shed light on future research directions for expanding the sweep range of CO_2 and sustainable development of the upstream oil industry, this review conducted a comprehensive investigation encompassing: the advances in research methods of CO_2 front, and the technical methods for sweep regulation. The study yielded the following conclusions and insights.

(1) The front migration characteristics of CO_2 play a crucial role in determining the macroscopic sweep range. Previous studies have revealed that the front of CO_2 demonstrates various migration patterns during the actual migration process. However, mathematical research on CO_2 migration and diffusion has mostly been conducted separately from advanced visualization experimental techniques such as microfluidics and CT. In the future, it is important to focus on achieving cross-scale correlation and information coupling of the CO_2 migration process.
(2) The phenomenon of fingering-gas channeling of CO_2 during the migration process is a significant factor that limits the sweep range and oil displacement effect, particularly in the field. The state and characteristics of fingering-gas channeling are influenced by various parameters; however, the impact weight of multi-parameter coupling is ambiguous. Therefore, it is essential to develop a multi-parameter and cross-scale artificial intelligence prediction model for gas channeling degree. Additionally, an early warning mechanism for gas channeling classification should be established to effectively formulate prevention and control measures.
(3) The key premise to achieve balanced sweep is the development of reasonable and effective CO_2 sweep regulation technology. Currently, sweep regulation is primarily focused on three aspects: flow field intervention, mobility reduction, and gas channeling plugging. Research in these areas indicates a trend towards intelligence and micromation. However, the research on CO_2 sweep regulation technology remains fragmented. To address this, a systematic integrated application should be implemented, taking into account the control characteristics and applicable scenarios of different technologies, according to the prediction model of gas channeling degree, and making auxiliary decisions on regulation means by artificial intelligence technology. This calls for the construction of an intelligent synergistic hierarchical segmented regulation technology, realizing by 'flow field intervention + mobility regulation + channel plugging chemically' of artificial intelligence early warning and assisted decision-making, covering the whole life cycle of CO_2 flooding.

CRediT authorship contribution statement

Yi-Qi Zhang: Writing – original draft, Methodology, Investigation. **Sheng-Lai Yang:** Writing – review & editing, Funding acquisition. **Lu-Fei Bi:** Writing – original draft. **Xin-Yuan Gao:** Methodology, Conceptualization. **Bin Shen:** Formal analysis. **Jiang-Tao Hu:** Investigation. **Yun Luo:** Investigation. **Yang Zhao:** Writing – review & editing. **Hao Chen:** Writing – review & editing. **Jing Li:** Writing – review & editing, Funding acquisition.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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