Advances in
Geo-Energy Research
Vol. 20, No. 2, p. 163-179, 2026

Invited review

CO_2 injection for enhanced oil recovery: A review of existing methods, challenges and promising solutions

Valentin A. Morenov, Kirill V. Shchigolev*

Petroleum Department, Empress Catherine II Saint Petersburg Mining University, Saint Petersburg 199106, Russia

---

Keywords:
CO_2 enhanced oil recovery
CO_2 injection
reservoir engineering
advanced CO_2 mobility control
surfactant-stabilized CO_2 foam
nanoparticles

Cited as:
Morenov, V. A., Shchigolev, K. V. CO_2 injection for enhanced oil recovery: A review of existing methods, challenges and promising solutions. Advances in Geo-Energy Research, 2026, 20(2): 163-179.
https://doi.org/10.46690/ager.2026.05.05

Abstract:
Carbon dioxide injection for enhanced oil recovery is a key technology that combines increased hydrocarbon extraction with CO_2 storage. However, existing literature mostly describes isolated solutions and rarely offers a comparative systematization of methods considering their practical limitations and industrial results. The purpose of this review is to systematize CO_2 enhanced oil recovery methods and summarize the experience of the world largest projects to develop a comprehensive approach to selecting injection schemes under various geological and technological conditions. Based on an analysis of more than 100 studies, carbon dioxide enhanced oil recovery methods in this work are classified by injection type and additives used. For each method, the main recovery mechanisms are summarized, including fluid mobility control, wettability modification, and asphaltene deposition inhibition. An analysis of major industrial projects in North America, China, and Europe, conducted in the paper, showed up to 25% increase in oil recovery with optimized water-alternating-gas schemes. Pore-scale visualization studies show that CO_2 flow involves unsteady effects like snap-off and cyclic bubble dilation. These phenomena explain channel formation and early gas breakthrough, justifying the need for mobility control methods. Synthesis of the results identified three prioritized technological limitations: First, the reliability of CO_2 infrastructure and supply; second, control of the displacement profile in heterogeneous reservoirs; and third, long-term well integrity and CO_2 balance management. These findings support the selection of optimal carbon dioxide enhanced oil recovery schemes and future research priorities.

---

1. Introduction

With the ever-growing demand for energy resources and the immediate depletion of easily accessible oil reserves, the global energy community is faced with the need to develop hard-to-recover hydrocarbon reserves (Litvinenko et al., 2022; Petrakov et al., 2024). According to the reports of the International Energy Agency, the share of hard-to-recover oil reserves in global energy balance is increasing every year, which calls into question the sustainability of traditional approaches to production (Cozzi et al., 2021). This, in turn, requires oil producing companies and countries to pay increased attention to the development and application of new technologies to increase the recovery factor of hydrocarbons (Bratskikh and Romasheva, 2025). Global strategic agendas in the field of energy and environment, such as the Paris Agreement (Zharikova et al., 2025), stimulate not only the search for alternative energy sources, but also the development of more efficient and environmentally friendly technologies in conventional energy (Taber et al., 1997; Metz et al., 2005; Kovyazin et al., 2026). In this regard, enhanced oil recovery (EOR) methods are of particular relevance, as they allow maximizing production from already explored fields, whereas reducing environmental impact.

Among the various EOR techniques, gas methods are the

---

*Corresponding author.
E-mail address: morenov@spmi.ru (V. A. Morenov); shchigolev.kv@gmail.com (K. V. Shchigolev).

Yandy Scientific Press

Received March 21, 2026; revised April 19, 2026; accepted May 6, 2026; available online May 10, 2026.

Table 1. Comparison of the cost of CO_2-EOR with other EOR methods.

Method	Original oil in place (OOIP)	Costs ($/BBL) (Liu and Wei, 2017)
Waterflood	5%-20%	2-8
CO_2-EOR	7%-25%	10-30
Chemical	10%-20%	11-50
Thermal	20%-50%	9-25
Microbial	5%-15%	3-9

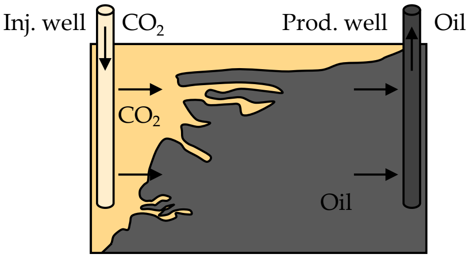

Fig. 1. CCI.

leading ones due to their cost- efficiency and high performance. The use of natural gas, nitrogen and, in particular, carbon dioxide for injection into formations allows not only to increase the pressure in the reservoir, but also significantly improve the physical and chemical properties of oil, facilitating its recovery (Taber et al., 1997). The method of carbon dioxide enhanced oil recovery (CO_2-EOR) has gained considerable attention in recent years because of its potential to improve oil recovery (a comparison of CO_2-EOR with other EOR methods is presented in Table 1) and its ability to capture and store carbon dioxide, which helps reducing the concentration of greenhouse gases in the atmosphere (Cherepovitsyn and Ilinova, 2016). Historically, the CO_2-EOR method started to be actively developed in the second half of the twentieth century in the United States, and since then the technology has undergone a long path of modernization and optimization, adapting to different operating conditions and field types (Metz et al., 2005).

This review article is intended to provide an in-depth analysis of existing CO_2-EOR methods, drawing on the experience from worldwide projects, assess their efficiency, explore new opportunities and challenges, and discuss the prospects and limitations of their application in various conditions.

2. CO_2-EOR methods

There are many ways to use carbon dioxide for injection into the reservoir to increase oil recovery (Bai et al., 2019). In global enhanced oil recovery practice, carbon dioxide injection methods are traditionally classified into two fundamental approaches: Continuous injection mode and cyclic injection mode. This division reflects not only differences in the organization of injecting the working agent into the reservoir, but also a fundamental difference in hydrodynamics, mass transfer, the mechanism of interaction between CO_2, oil, and rock, as well as in the requirements for the composition of the injected fluid. This classification, based on the nature of the flow (continuous or cyclic), is widely accepted in the works of Society of Petroleum Engineers, International Energy Agency Enhanced Oil Recovery, and the DOE Carbon Storage Program.

2.1 Continuous CO_2 injection methods

Carbon dioxide can be present in different phase states when it is injected into the formation, depending on pressure and temperature: Liquid, gaseous or supercritical. At temperatures below 31.1 °C and pressures below 73.8 bar, CO_2 is in gaseous form. CO_2 becomes liquid when the temperature is below the critical point with the pressure above it. At the supercritical state, when the temperature exceeds 31.1 °C and the pressure exceeds 73.8 bar, CO_2 combines the properties of both a liquid and a gas. In this state it has a high density similar to a liquid and a low viscosity similar to gas. These properties allow CO_2 to effectively penetrate porous media, reduce oil viscosity and improve oil displacement. A recent study showed that pulsed supercritical CO_2 jets with adjustable frequency can induce microcracks and enhance permeability, accelerating and stabilizing gas flow between wells (Shen et al., 2023).

2.1.1 Continuous CO_2 injection

Continuous CO_2 injection (CCI) (Fig. 1) involves the sustained delivery of carbon dioxide into the reservoir, either in liquid (liquid injection) or gaseous (gas injection) form, depending on temperature and pressure conditions. This method is operationally simple and relatively easy to control compared to alternating or chemical injection schemes, which makes it economically attractive at the early stage of field implementation. In homogeneous reservoirs, continuous injection can achieve stable displacement and high incremental oil production. Although it typically requires a larger total CO_2 volume, long-term results may surpass other CO_2-based flooding strategies in terms of flow rate and cumulative recovery. In heterogeneous formations, CCI performance is often constrained by an unfavorable mobility ratio between CO_2 and oil. The resulting viscous fingering, gravity segregation, and early gas breakthrough lead to poor sweep efficiency. The dependence on reservoir architecture and pressure-temperature regime makes this process highly site-specific and limits its large-scale applicability.

Recent micro-scale visualization studies have revealed that even under immiscible conditions, continuous CO_2 flow in porous media is governed by transient phenomena (such as jumping displacement, gas-to-oil-to-gas multiple displacement, and cyclic compression-release of CO_2 bubbles in narrow throats). These pore-scale instabilities, identified by Wang et al. (2020), explain the formation of irregular channels and early CO_2 breakthrough observed in field practice, emphasizing the need for mobility control during prolonged injection. Field experience confirms these observations. Laboratory work on Jilin sandstone cores (China) showed that once gas chan-

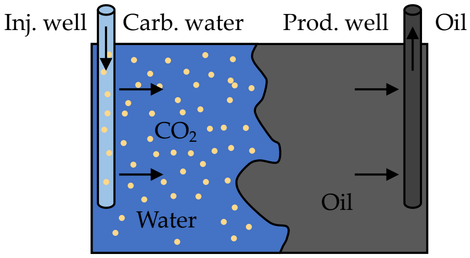

Fig. 2. CWI.

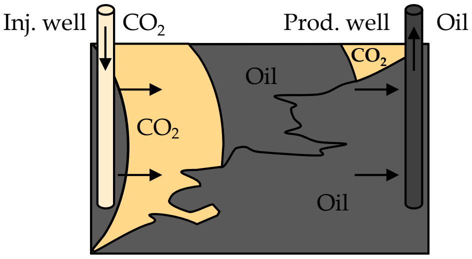

Fig. 3. Cyclic Injection into injection wells (Pure CO_2).

neling occurs during CCI, subsequent transition to miscible CO_2-water alternate gas (WAG) can increase final oil recovery from 51.97% to 73.15%. Similarly, at the Reinecke field (USA, Chevron), continuous injection delivered strong initial productivity but soon suffered from excessive gas recirculation due to vertical high-permeability streaks. Simulation studies indicated that CO_2 flux exceeded the gravity-stable threshold; converting the scheme to tapered WAG (TWAG) restored conformance and stabilized injectivity. Overall, CCI remains an effective yet unstable displacement process. Its success depends on controlling channel growth and integrating it with alternating or tapered injection cycles that mitigate gravity override and viscous fingering.

2.1.2 *Carbonated water injection*

The method is an EOR technique that uses carbon dioxide-saturated water for injection into the reservoir (Fig. 2). Carbonated water injection (CWI) has a higher efficiency in enhancing oil recovery compared to conventional waterflooding (with optimal application, oil recovery can be increased by 7%-15%). According to a recent study conducted on glass micromodels, CWI was found to EOR for a longer period of time than water flooding (WF), even after water breakthrough to the production well. The main mechanism is the continuous dissolution of CO_2 in the oil phase and subsequent oil swelling and viscosity reduction, resulting in improved mobility of residual oil in the micromodel. Moreover, the water cut of the final product is lower with CWI than with conventional WF.

Investigations on wettability established that pH level of the injected water affects the efficiency of the process. Lower pH level of carbonated water changes the wettability state of the “formation water-oil-rock” system and thus improves oil recovery. The process of displacement by carbonated water also depends on the properties of the oil itself. For example, if the oil is light and has ultra-low viscosity, it is possible to achieve miscible displacement at the first contact with carbonated water, whereas wettability at CWI in heavy oils also has a positive effect, but with a lesser intensity.

The efficiency of the CWI process, as previously stated, is affected by CO_2 solubility in the oil. In this case, the CWI rate has minimal effect on the process efficiency. With respect to sequestration, the amount of CO_2 that can be stored at the end of CWI for different operating pressures ranges from 22% to 42% of the total CO_2 injected (Mosavat and Torabi, 2014; Salehpour et al., 2020). The most important advantage of the CWI method is the low risks of free phase migration of carbon dioxide to the ground surface, which are due to low chance of carbon dioxide leaks (Mosavat and Torabi, 2014). A key limitation of the CWI method is that the CO_2 concentration front lags behind the oil displacement front, resulting in a time delay in obtaining the expected results from the technology implementation. Thus, CWI has great potential to permanently store injected CO_2 and simultaneously significantly improve oil recovery.

Recent investigations on crude oil samples from a field in southeastern Iran confirmed the results of earlier research (Lashkarbolooki and Ayatollahi, 2016) that the decrease in the interfacial tension (IFT) of the oil-water system is caused by adsorption of natural surfactants (components of asphaltenes and resins) at the interface between the two phases (Golkari et al., 2022). Experimental results also show higher IFT values at 50 °C than at 40 °C. This is due to the lower dissolution of CO_2 in the oil phase at higher temperatures.

2.2 *Cyclic CO_2 injection methods*

This class of technologies is based on regular alternation of slugs of different fluids: CO_2, water, polymers, surfactants, nanoparticles, small self-interacting molecules. Each slug interacts with the zone modified by the previous one, forming a multilayer displacement front. All the methods discussed in this section are cyclic, since they are based on phase or chemical alternation, without which their movement mechanisms cannot function.

2.2.1 *Cyclic injection into injection wells (Pure CO_2)*

This method represents the injection of alternating cycles of carbon dioxide in gaseous, liquid, or supercritical form with varying intervals Cyclic CO_2 injection (Fig. 3) is carried out through the injection well to develop low-permeability zones when CCI is inefficient and uneconomical (Raupov et al., 2025). The basic concept of the method is to select a productive zone with permeability from 0.001 to 2 mD and to apply cyclic CO_2 injection into the injection well when the reservoir pressure drops to 50%. CO_2 injection should be stopped after the reservoir pressure level is restored to the initial state. Application of cyclic carbon dioxide injection in an injection well in a carbonate reservoir section with low permeability and porosity increased oil recovery by 11.6% (Pavlova et al., 2022). A specific case of cyclic injection is also the injection of a single slug of liquid or gaseous carbon dioxide, followed by its subsequent displacement through the reservoir by continuous WF.

In 1960-1980 a series of field experiments on the ef-

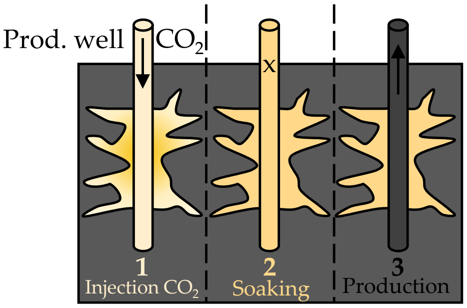

Fig. 4. Huff-n-Puff process.

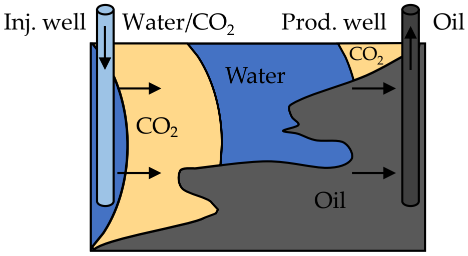

Fig. 5. WAG.

fect of CO_2 on the formations of the Romashkinskoye, Chashkinskoye, Olkhovskoye, Radaevskoye, Kozlovskoye and Sergeevskoye fields of the USSR were carried out. It was found that CO_2 injection followed by water or CWI resulted in higher hydrocarbon recovery than conventional CWI (Ryazantsev and Lozin, 2020). However, the implementation of CO_2 injection faced significant challenges: Frequent pipeline ruptures caused by carbonic acid corrosion and unstable gas supplies rendered the technology economically unviable, leading to the termination of trials in 1988. Additional constraints included the high costs of corrosion-resistant materials, extended payback periods, and the lack of reliable equipment for continuous injection in such an aggressive environment. In 1964, a similar field test project was conducted in the Mead Strawn field, involving the injection of a large volume of CO_2 (25% of pore volume) followed by the injection of carbonated water under formation conditions. The results showed that the CO_2 flooding produced between 53% and 82% more oil than was produced from the best Mead Strawn sections with conventional WF.

As mentioned above, when pure CO_2 is injected into a reservoir, its concentration lags behind the oil displacement front. However, by injecting pure CO_2 in volumes up to 30% of the pore volume and then continuing the process with carbonated water or conventional water, this lag can be eliminated. Thus, the method using liquid CO_2 becomes limited only by the critical temperature. The intensive dependence of oil displacement process by CO_2 gaseous front on gravity segregation limits the application of this method in formations with high vertical permeability (Kalinin and Morozyuk, 2019).

2.2.2 Huff-n-Puff

Carbon dioxide gas cycling (CO_2 Huff-n-Puff) is an EOR technique that involves three main steps (Fig. 4): CO_2 injection into the production well, a soak period for CO_2 diffusion into meso-, micro- and nanopores, which helps swell the oil and reduce its viscosity, and subsequent operation of the well to produce a mixture of CO_2 and oil (Shi et al., 2024). The Huff-n-Puff cycles are usually repeated several times. CO_2 can be injected into the production well either in a liquid or supercritical state.

Investigations have shown that Huff-n-Puff method can significantly increase the oil recovery factor by 20%-80% (Ding et al., 2021; Liu et al., 2022). Experiments have confirmed that CO_2 can improve oil recovery by reducing viscosity, increasing volume by dissolving CO_2, and cleaning the bottomhole zone from asphaltene-resin-paraffin deposits (Ipatov et al., 2023). Molecular dynamic modelling has indicated the formation of stable aggregate structures of asphaltenes, which have a positive effect on oil recovery efficiency in the presence of CO_2 (Zhang et al., 2023; Korobov et al., 2024).

Nuclear magnetic resonance (NMR) is often used to experimentally quantify changes in fluid saturation during shale oil production. The results of NMR spectrometry on tight shale oil reservoirs using Huff-n-Puff showed an increase in oil recovery of more than 40% (Zeng et al., 2020). NMR experiments of CO_2 injection into rock samples from Shengli oil field (China) at a constant pressure of 25 MPa, well soaking for three hours, and five injection and production cycles resulted in a cumulative recovery efficiency of 45.9%.

Research has been conducted on the efficiency of using the CO_2 "Huff-n-Puff" process in tight oil reservoirs of the Lukaogou field (China) after hydraulic fracturing. For this purpose, historical fractured wells were simulated in rock samples using a mixture of fracturing fluid and CO_2. After soaking, the rock samples with fracturing fluid and implementing CO_2 Huff-n-Puff the oil recovery factor improved with increasing soaking time and number of cycles. However, due to the complex pore structure, the ultimate oil recovery factor for the samples averaged 25%. After injection, the carbon dioxide reacted first with the fracturing fluid and afterwards with the oil in the shallower pores. Therefore, it is necessary to exclude fracturing fluid or formation water from the zones of influence before carbon dioxide injection into the formation (Blinov et al., 2025; Dvoynikov and Kutuzov, 2025).

2.2.3 WAG

The CO_2-WAG (Fig. 5) method involves alternate injection of carbon dioxide and water into oil reservoirs. In the CO_2-WAG method carbon dioxide is injected first, which, with its high mobility and ability to dissolve in oil, reduces its viscosity and increases its volume that helps to displace hydrocarbons from the rock more efficiently. CO_2 injection is followed by the introduction of water, which displaces both dissolved carbon dioxide and oil to the production wells. The water acts as a buffer, reducing segregation of CO_2, which is a frequent problem when CO_2 is injected alone. The alternation of the two fluids favours uniform pressure distribution in the reservoir and improves oil displacement efficiency compared to WF or CCI, as well as providing mobility control.

The CO_2-WAG method contributes to efficient use of carbon dioxide, minimizing its loss and improving the overall economic efficiency of CO_2-EOR projects. However, the successful application of this technology requires careful injection planning, including optimization of injection modes, calculation of the volume and quantity of water and gas slugs, and adaptation to the specific conditions of the oil reservoir with further control and monitoring of the flood process (Wang et al., 2017). Chen and Reynolds (2016), based on net present value (NPV) analysis, optimized the target gas and water injection rates and target bottomhole pressure of production wells with different numbers of WAG cycles and concluded that the maximum NPV is achieved by increasing the injection cycles, whereas fixing the injection cycles for the whole period of technology application is not reasonable (dos Santos et al., 2023).

The increase in recovery efficiency is particularly evident under conditions of miscibility. In this regard, fields with light oil are often favoured because miscibility can be achieved at relatively low pressure (Orujov et al., 2023). Tests of the method in carbonate subsalt reservoirs of the Brazilian field also showed that the use of CO_2-WAG promoted multi-contact miscibility between CO_2 and oil in the reservoir. It was found that due to the better mobility coefficient, the formation of viscous fingers was reduced. At the same time, recovered oil fraction increased as more fluid was injected. However, the increase in oil recovery is not always proportional to the increase in injected fluid, which also highlights the importance of proper injection organization and selection of the volume and number of slugs.

A specific case of the WAG method is the simultaneous water alternate gas (SWAG) method. In the SWAG process, water and CO_2 are injected through the same well simultaneously. There are two different SWAG schemes: Water over gas and co-injection. In the first case, water is injected from the upper perforations and gas is injected from deeper perforations. In this way, the rapid upward movement of the gas is reduced by the water phase injected from above. Dual completion can be used for such injection in an injection well. In co-injection, the two phases are mixed and injected together. For layered reservoirs, this injection scheme is the most suitable (Karimaie et al., 2017).

The results of CO_2-WAG and CO_2-SWAG implementation in the Tight Bakken formation, USA, showed that the WAG method with a water-gas ratio (WGR) of 1:3 showed a slightly higher oil recovery ratio relative to CO_2-SWAG. However, several investigations determined that the CO_2-SWAG method with a WGR of 1:3 showed the best results with the highest oil flow rate, oil recovery factor, controlled gas production and low water consumption (Han and Gu, 2014; Gong and Gu, 2015). The results of CO_2-WAG implementation in terrigenous reservoirs of sandstone and carbonate reservoirs of dolomites and limestones at Iranian fields showed optimal WGR of 1:1 (optimal conditions - maximum oil production with minimum amount of formation water). It is noted that in carbonate rocks under CO_2-SWAG conditions with high WGR, increasing the volume of injected gas does not lead to a significant increase in the oil recovery factor, but this observation is not confirmed in the case of CO_2-WAG.

CO_2 and water co-injection methods are also possible in the presence of the chemical reagents: Chemical water alternate gas (SAG (Active water alternate gas), foam-assisted WAG (FAWAG), PAG) and Chemical carbonated water injection (ACWI), which will be discussed in the following sections (Kumar and Mandal, 2017; Chen et al., 2021; Yu et al., 2021). Another key modification of the conventional WAG technique is the TWAG process. Tapered WAG method is a variation of WAG technique, in which the duration of gas injection cycles is varied: Longer cycles are used at the beginning of the process, which are shortened over time. The method is applicable to both homogeneous and heterogeneous reservoirs. This technology proved its superiority over conventional WAG in heterogeneous low-permeability reservoirs of Xinjiang field (China) both in terms of final oil recovery and NPV. Reservoir modelling of a real field in the Middle East under conventional WAG and TWAG using the same WGR (4:1) in homogeneous and heterogeneous areas shows that 4-year water injection followed by 1-year CO_2 injection shows the highest oil recovery. Due to existing disadvantages CO_2-EOR (early breakthrough of carbon dioxide to production wells because of its high mobility, formation of viscous fingers and others), in recent years there have been numerous investigations on the application of disperse systems using thickeners, foam-forming surfactants, polymers, nanoparticles and low molecular weight compounds capable of eliminating these drawbacks.

2.2.4 Surfactant assisted WAG

Surfactant-assisted WAG (Fig. 6) is an EOR method based on the cyclic injection of a surfactant solution and gas without implying foam generation as a governing displacement mechanism. In this approach, surfactants are primarily used to reduce oil-water IFT, thereby mobilizing residual oil, while the injected gas serves as an energy carrier that improves macroscopic displacement efficiency and supports reservoir pressure. The alternation of surfactant and gas slugs enables the combination of capillary desaturation and improved sweep without the need for surfactant-induced gas mobility control. Unlike foam-assisted processes, Surfactant-assisted WAG does not require the use of foaming surfactants or stable gas-liquid lamellae formation in the reservoir, making it applicable in formations where foam stability is limited by oil composition, salinity, or reservoir temperature.

Surfactant-assisted WAG aims to reduce gas mobility at the displacement front. In the front, the low water saturation causes the foam to collapse (partially or completely); thus, gas mobility is gradually increased to the original mobility in the injection well. Potentially, this could result in high-mobility gas entering an area with low-mobility gas in the form of foam. The alternate injection of gas and surfactants on tight rock samples from the Pazanan oil field (southern Iran) showed better oil recovery factors compared to WAG (54% vs. 46%).

The FAWAG method can be considered a specific implementation of the Surfactant-assisted WAG concept, in which the injected surfactant is intentionally selected for its foam-forming capability. In contrast to conventional Surfactant-assisted WAG, FAWAG employs foaming surfactants that promote the generation of stable gas-liquid lamellae in the porous medium, thereby enabling effective gas mobility con-

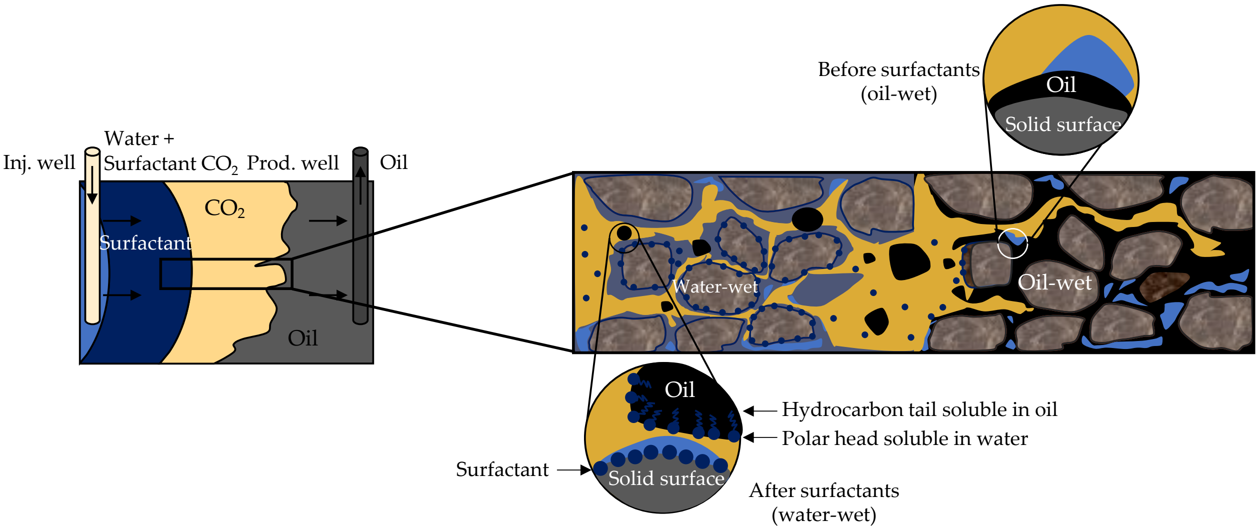

Fig. 6. Surfactant assisted WAG.

trol and improved sweep efficiency. Foam stability is typically enhanced through the use of surfactants formulated with foam-boosting additives, such as co-surfactants (e.g., alcohol ethoxylates or betaines), stabilizing polymers, or inorganic salts, which increase lamella elasticity and resistance to coalescence under reservoir conditions.

Foam can be injected into the formation using two methods: The first one is Co-Injection of foam, in which the foam is formed before entering the formation, and the second one is the gas and surfactant-assisted WAG, in which gas and surfactant solutions are injected sequentially (Afsharpoor et al., 2010; Podoprigora et al., 2025). Parameters such as flow velocity, foam structure, surfactant concentration, capillary pressure, temperature, wettability, IFT, ion exchange and degree of saturation influence foam spreading and stability.

Conventional foam flooding methods have been studied since the middle of the twentieth century and have been widely used around the world. Later investigations revealed a direct correlation between foam stability and the initial wettability of reservoir rocks. For example, mixed or hydrophilic environments produce much less stable foam, which slows down the foaming process. The surfactant-assisted WAG foam test in the Norwegian Snorre field went without significant complications, whereas co-injection of foam was complicated by operational difficulties resulting in unstable injectivity. From an operational point of view, the surfactant-assisted WAG process is similar to the water-gas alternation method and requires minimal additional effort.

Further research has revealed the prospects of improving the process of conventional foaming through the use of CO$_2$-philic additives in the composition of surfactants. The use of CO$_2$-philic surfactants can reduce their adsorption on the rock, decrease the redistribution of surfactants between water and oil, and increase foam stability (Adkins et al., 2010). Experiments on rock samples from the Malaysian field confirmed that CO$_2$-philic surfactant, which is more active at the gas/water interface, is more stable in the presence of oil compared to other hydrocarbon surfactants such as alpha-olefin sulfonate (Talebian et al., 2015).

CO$_2$-philic surfactants interact with CO$_2$ at the molecular level due to the presence of CO$_2$-affine fragments in their structure, such as fluorinated chains, silicone segments, and polyether groups. These functional groups exhibit high solubility in CO$_2$ or the ability to engage in specific interactions with CO$_2$ molecules (e.g., via dispersion forces and dipole-induced interactions). Under elevated pressure conditions typical of oil reservoirs, such surfactants are capable of forming stable supramolecular structures (namely micelles and interfacial layers at the gas-liquid boundary) in which CO$_2$ molecules can become partially incorporated into the molecular shell. This results in a significant reduction of IFT, enhanced surfactant adsorption at the gas-liquid interface, and the formation of more stable and elastic foam films. In the presence of crude oil, these films exhibit increased resistance to rupture, which is critical for maintaining foam integrity within the porous medium. Foam stability directly influences mobility control: Stable foams mitigate gas breakthrough, reduce filtration heterogeneities, and promote uniform oil displacement. Thus, the molecular interactions between CO$_2$-philic surfactants and CO$_2$ underlie both the physicochemical stability of foam and its effectiveness in EOR applications.

Another study considered the use of resistivimetry method for monitoring the distribution of foam solutions in sandstone reservoirs. The analysis of data obtained from modelling and practical experiments allowed establishing a correlation between the duration of foam injection and the specific electrical resistivity, as well as the degree of saturation of the reservoir with water and gas. It is emphasized that an increase in the content of surfactants in the foam is accompanied by an increase in the resistivity. The use of foam with surfactant content of 0.5% mass demonstrates excellent results, reducing residual oil saturation to 11.37% and increasing oil recovery factor to 66.99%, which distinguishes it among other experimental concentrations (Khan et al., 2024).

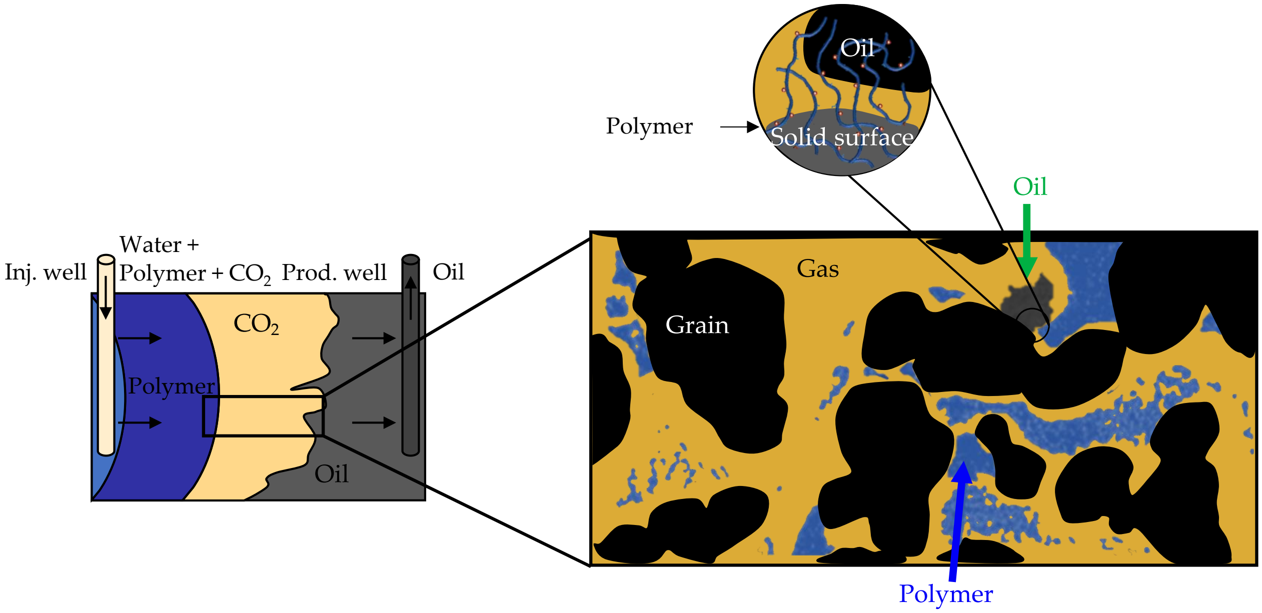

Fig. 7. Polymer-assisted WAG.

2.2.5 Polymer assisted WAG

The use of polymer thickeners is a key method to increase the CO_2 viscosity (Fig. 7). Research on thickening CO_2 with polymers has been ongoing since the 1970s. Many investigations have been carried out to find suitable polymer thickeners. Research shows that polymeric thickeners are more potent due to their stability under reservoir conditions. Polymers containing heteroatoms (O, N, Si, F) are considered to be more efficient as they are more compatible with CO_2 compared to polymers consisting of only carbon and hydrogen. There are also polymers based on hydrocarbons. The solubility and thickening properties of polymers in CO_2 are largely determined by the interactions between the polymer and CO_2. The stronger the polymer- CO_2 interaction and the weaker the polymer-polymer interaction, the higher the probability of polymer dissolution and thickening of the CO_2 solution. Polymers usually contribute to CO_2 thickening through polymer tangle expansion, intermolecular interactions, entanglement, aggregation, and structuring (Fig. 7).

Polymer injection experiments with CO_2 on rock samples from the Alaska North Slope viscous oil field have concluded that polymer injection using solvents (e.g., low-salinity water) can simultaneously improve both displacement and recovery. However, the interaction of CO_2 with clay minerals in the formation can produce large amounts of cations that cause polymer precipitation. To prevent polymer precipitation, it is recommended to introduce a layer of low salinity water between the CO_2 and the polymer plug. All the solvent EOR methods in this study showed remarkable performance with the lowest recovery factor of 78.44% and maximum recovery factor of 92.23% (Cheng et al., 2023).

Polymer-enriched CO_2 and gel-forming systems are a promising approach to improve the efficiency of CO_2-EOR and ensure reliable CO_2 storage in oil reservoirs. In one study, the use of a CO_2-responsive, temperature-resistant polymer surfactant in low-permeability cores (5-20 mD) increased oil recovery by 8.2% compared to the traditional WAG (water-alternating-gas) method, due to enhanced viscosity and reduced gas channeling (Chen et al., 2023). A recent review highlighted various gel systems (including polymer-based, silicate, and CO_2-sensitive gels) used for fracture sealing, leakage control, and improved sweep efficiency in both EOR and CO_2 storage operations (Bai et al., 2007). Another field-scale study showed that polymer gels effectively reduce CO_2 mobility and improve bath oil recovery and long-term CO_2 containment (Brattekås and Seright, 2023).

2.2.6 Small self-interacting molecules

Low molecular weight compounds form macromolecular networks through intermolecular associations, which increases the viscosity of the solution (Carpenter, 2014; Pal et al., 2022). The use of small self-acting molecules is considered as an alternative to polymers for CO_2 thickening. These compounds include CO_2-philic and CO_2-phobic groups that facilitate their dissolution in CO_2 and interaction with adjacent molecules (Pal et al., 2022). Their advantages include a significant increase in the viscosity of CO_2 at low concentrations and ease of gel formation in bulk liquids, resulting in a more viscous solution (Ricky et al., 2023).

However, there are disadvantages: Some low molecular weight compounds require heating and co-solvent to dissolve in CO_2, and their ability to increase viscosity decreases at elevated temperatures. Low- CO_2 gels become more viscous and difficult to pass, and fluorinated molecules are expensive and environmentally harmful. Overly strong associating groups can make the thickener insoluble in CO_2, while excessively weak groups can increase viscosity only slightly. Special attention should be paid to temperature conditions. Elevated temperatures lead to the breakdown of intermolecular attractions.

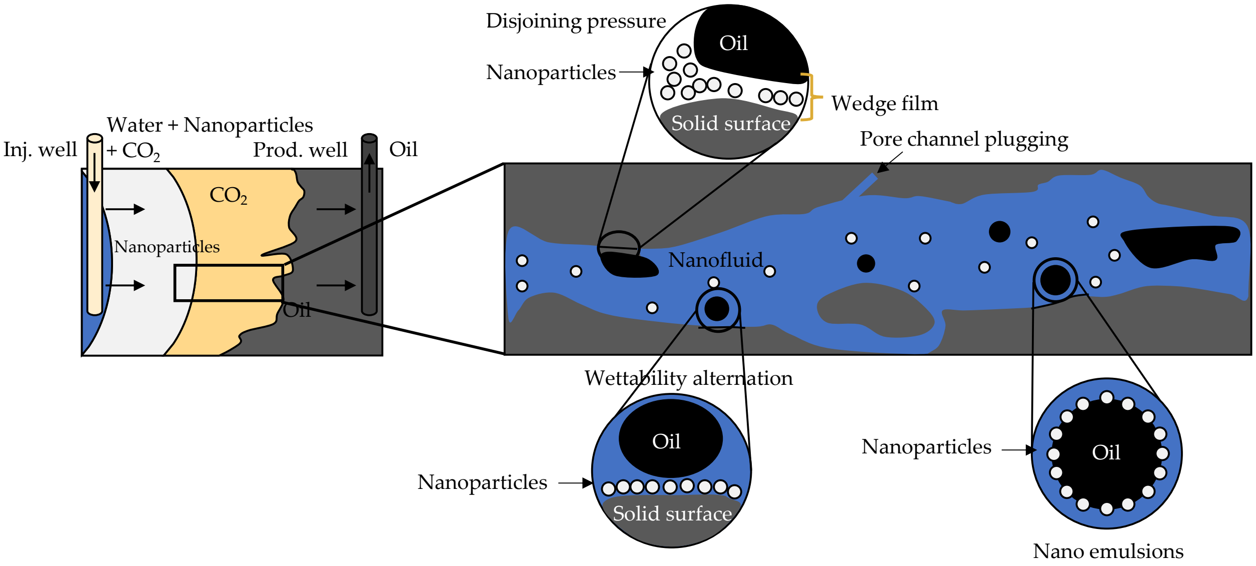

Fig. 8. Waterflooding mechanism using nanoparticles.

Optimal CO_2 thickener should be soluble under formation conditions without the use of co-solvents and increase CO_2 viscosity by a factor of 2-100 at concentrations less than 1% mass (Jangda et al., 2014; Lee et al., 2014; Ricky et al., 2023).

2.2.7 Nanoparticle-assisted WAG

Nanotechnology offers innovative solutions to overcome challenges associated with EOR methods due to the unique properties of nanoparticles, such as a high surface-to-volume ratio, nanoscale dimensions, and significant adsorption capacity. Nanoparticles are tiny particles of matter with diameters ranging from 1 to 100 nm. Various types of nanoparticles, including silver (Ag), silicon dioxide (SiO_2), palladium (Pd), copper oxide (CuO), iron oxide (Fe_3O_4), titanium dioxide (TiO_2), nickel oxide (NiO), aluminum oxide (Al_2O_3), cobalt oxide (Co_3O_4), boron nitride (BN), graphene oxide (GO), and magnesium oxide (MgO), have been investigated under laboratory conditions. The main mechanisms of EOR during WF with nanofluids (nanoparticles dispersed in the aqueous phase) include creation of wedging pressure, reduction of IFT and changes in rock wettability (Fig. 8) (Koca et al., 2018; Korobov et al., 2026). Nanoparticles enhance the hydrophobicity of CO_2 dispersions, which, in turn, promotes viscosity enhancement (Pal et al., 2022). In this scenario, the size, shape, and surface functionalization of the nanoparticles influence the thickening ability of CO_2.

In brief, nanofluids enhance CO_2-EOR via three primary levers: (i) Interfacial-tension reduction, (ii) wettability alteration toward more water- or gas-wet states, and (iii) mobility control through foam stabilization and, in some systems, effective CO_2 viscosification. Silica (SiO_2) mitigates the IFT penalties of elevated temperature and salinity and strengthens foams (up to 2-18× higher flow resistance), although foam stability decreases with temperature; Fe_3O_4 (PVA/HAp) shifts carbonates toward gas-wet behavior; and surface-modified TiO2 (AEAPTMS) remains colloidally stable up to 90 °C and 30 wt% salinity while markedly reducing contact angles. γ-Al_2O_3 at 0.06 wt% inhibits asphaltene precipitation (onset 6.8 MPa), and GO-based modifiers at 0.05 wt% lower contact angle (from approximately 161° to approximately 35°) and IFT (from approximately 18.45 mN/m to approximately 8.8 mN/m), improving displacement. Effective dosage typically lies near 0.05-0.1 wt%; higher loadings increase aggregation and pore-blocking risks, especially for particles > 100 nm in brines. Synergistic blends (NP+surfactant/polymer) and emerging nanofluid + CO_2 microbubble schemes further enhance sweep and delay breakthrough, but most results remain laboratory-scale, underscoring the need for core- and pilot-level validation.

Nanoparticles have shown promising results under laboratory conditions, particularly in their ability to thicken carbon dioxide. However, current research remains largely confined to laboratory-scale experiments. Moreover, nanoparticles such as silver (Ag), palladium (Pd), nickel oxide (NiO), cobalt (III) oxide (Co_3O_4), boron nitride (BN), and magnesium oxide (MgO) are either underrepresented or entirely absent in studies focused on CO_2 flooding modeling and core-scale displacement experiments, with their use being limited to adjacent fields (Li et al., 2023; Medina et al., 2023; González et al., 2024). To validate their potential as CO_2 thickeners, broader and more comprehensive investigations are required.

To conclude the review, we provide a comparative table that systematically organizes the fundamental characteristics of different CO_2-EOR technologies. This comparative analysis, drawn from extensive evaluation of both laboratory experiments and field applications, offers a holistic perspective on the capabilities and constraints of each method for reservoir oil recovery enhancement (Table 2). The described CO_2-EOR mechanisms have been tested at varying scales (from laboratory experiments to full-field deployments). To evaluate their real-world effectiveness and identify operational best practices, the following section reviews large-scale case studies across major producing regions.

Table 2. Comparative analysis of CO_2-EOR methods.

Method	Advantages	Disadvantages
CCI	Simple design; effective in homogeneous reservoirs	High gas recirculation; early breakthrough in heterogeneities
CWI	Lower CO_2 loss; safe storage; effective in light oils; pH effect improves wettability	Lag of CO_2 front behind oil front; efficiency depends on oil properties
Cyclic injection into injection wells	Boosts pressure in low-perm zones; cost-effective in late-stage recovery; applicable at low reservoir pressure	Limited to 0.001-2 mD permeability; requires pressure control; lower sweep than WAG
Single-slug CO_2	Higher recovery with combined CO_2+H_2O; simple injection design	Corrosion; unstable CO_2 supply; high material cost
Huff-n-Puff	Bottomhole cleanup; viscosity reduction; repeatable cycles	Efficiency drops in complex pore structures; requires shut-in time
WAG	Mobility control; better sweep efficiency; improved economics	Complex design; risk of early breakthrough; optimized cycles needed
SWAG	Simplified injection; controlled mobility; dual perforation possible	Less efficient than WAG in some fields; gas/water separation complex
TWAG	Better gravity stability; adaptable for heterogeneities	Longer gas cycles needed early; complex modeling
Surfactant- assisted WAG	Operationally simple; good for unstable injectivity	Foam collapse risk at displacement front
FAWAG	Improved mobility control; stable foam; reduced gas bypassing	Foam stability sensitive to salinity and surfactant
Polymer-assisted WAG	Increases CO_2 viscosity; good thermal stability	Precipitation risk; clay interaction; cost of solvents
Small self-interacting molecules	Effective at low concentrations	Temp sensitivity; solubility issues; high cost of fluorinated compounds
Nanoparticle-assisted WAG	Wettability alteration; asphaltene inhibition; IFT reduction	Agglomeration; sensitivity to salinity/temp; lab-scale only

3. Large-scale world experience in CO_2-EOR

This section reviews only the largest and best-documented CO_2-EOR case studies for which high-quality, traceable information is publicly available (Table 3). The article examines three major regional projects for each of the key basins, selected based on the availability of the most reliable and extensive operational data. For each project, we synthesize the most reliable data from peer-reviewed articles, operator and regulator reports (including monitoring, reporting and verification (MRV) plans), and national laboratory/agency technical documents, and we present a consistent set of metrics (OOIP and stage-wise recovery, injection regime, monitoring and integrity/corrosion controls, and operational lessons). Emphasis is placed on parameters and outcomes that can be directly referenced to primary sources, with units normalized and uncertainties noted where the literature diverges.

3.1 North America

3.1.1 Weyburn-Midale

The Weyburn-Midale Project (Canada) is one of the most thoroughly documented industrial demonstrations of CO_2 injection for EOR coupled with geological storage. Between 2000 and 2004, a coordinated research program (combining laboratory experiments, pressure-volume-temperature/equation of state modeling, and field surveillance) was executed to resolve the physicochemical behavior of the coupled CO_2-oil-brine-rock system (Whittaker et al., 2004). Under reservoir conditions ($T \approx 61$-63 °C, P = 15-18 MPa), CO_2 is in the supercritical state (high density, low viscosity). The minimum miscibility pressure (MMP) for the Weyburn crude is 14-17 MPa, indicating that multicontact miscibility is attainable at *in-situ* conditions. Multicontact phase-equilibrium experiments showed that the CO_2 content in the oil phase can reach 70 mol%, while the CO_2-enriched phase contains up to ~80-90 mol%. For overall CO_2 concentrations below 60 mol%, single-phase (miscible) behavior was observed; above this threshold a separate CO_2-rich phase appeared. Pressure-volume-temperature analysis also recorded an increase in oil density attributable to extraction of light ends by supercritical CO_2.

Eight coreflood experiments on Berea sandstone core plugs saturated with Weyburn crude were conducted to quantify process efficiency. The sequences comprised an initial water-

Table 3. Large-scale world CO_2-EOR projects.

Project	Depth (m)	Conditions	Type of CO_2-EOR	Increase RF (CO_2, %)	Reservoir type
Weyburn-Midale (Canada)	1,450	63 °C, 12.5-18 MPa	WAG	34	Carbonate
SACROC Unit (USA)	2,040	56-71 °C, 19-21.5 MPa	CO_2 +WAG	10	Carbonate
West Ranch (USA)	1,525-1,920	69 °C, 14.7 MPa	WAG	/	Sandstone
Jilin (China)	2,300-2,600	66 °C, 16-23 MPa	WAG + Foam	20-25	Sandstone
Xinjiang (China)	2,400-2,671	64 °C, 24 MPa	WAG	5-8	Sandstone
Yanchang (China)	2,000	44 °C, 12 MPa	WAG	12	Sandstone
Ivanic and Zatica (Croatia)	1,500-2,000	18-21 MPa	WAG	15-20	Sandstone
Szank (Hungary)	2,000	17-21 MPa	WAG	1.5-2	Carbonate/Sandstone
Rusanda (Serbia)	1,000-2,200	/	CCI	/	Sandstone

flood, followed by CO_2 injection and a subsequent water drive. The incremental oil recoveries spanned 2.3%-46.2% of OOIP, underscoring strong sensitivity to rock heterogeneity and permeability. These measurements were used to calibrate field-scale flow simulators, which, for the first development phase, predicted an incremental recovery of 16% OOIP (Whittaker et al., 2004).

Geochemical surveillance of produced formation waters over the first 930 days of CO_2 injection revealed pronounced shifts: Alkalinity increased by +155% (from 429 to 1,094 mg/L), Ca^{2+} and Mg^{2+} concentrations rose by 39% and 60%, respectively, specific resistivity decreased by 43%, and pH dropped from 6.7 to 6.6. The trends are consistent with dissolution of CO_2 in brine, formation of carbonic acid, and subsequent reactions with carbonate minerals ($CaCO_3$, $CaMg(CO_3)_2$), which elevate total dissolved solids and mobilize divalent cations (Whittaker et al., 2004).

Alongside the confirmed EOR effectiveness, several operational challenges were documented. Case studies published in International Journal of Greenhouse Gas Control report casing corrosion in CO_2 injectors (ranging from localized pitting to full perforation of the lower casing string within a few years in CO_2-saturated aqueous environments) as well as packer replacements due to CO_2-induced elastomer degradation. Experimental and review studies show that corrosion rates depend strongly on the phase state of CO_2, water availability and salinity, and the presence of H_2S; for carbon steel exposed to "water-saturated supercritical CO_2 + H_2S," peak laboratory rates up to ~ 0.2 mm/yr have been measured, although *in-situ* film formation can reduce effective rates. Systematic reviews also support the efficacy of Cr-bearing alloys, corrosion inhibitors, and high-quality cementing; the cement-steel-rock triad ultimately governs long-term well integrity given the roles of microannuli, interfacial sealing, and secondary mineralization (Laumb et al., 2017). Operational practice at Weyburn included periodic integrity logging (Cement bond log / Ultra sonic imaging tool), management of the aqueous phase to minimize "wet" corrosion, inhibitor programs, material/-coating selection for packers and tubing, and "dry" operating modes with periodic blowdowns.

Although no critical injectivity failures were reported for the carbonate reservoir, the literature emphasizes the need to control near-wellbore salt precipitation (dry-out) under high-salinity conditions, which can impair permeability and damage completions; risk-based injection/wetting schedules and appropriately designed WAG are standard mitigations. Collectively, Weyburn-Midale demonstrates that CO_2-EOR can deliver substantial incremental recovery while simultaneously storing CO_2 geologically, provided that long-term success is underpinned by robust corrosion control and well integrity management, proactive injectivity management, and explicit control of geochemical processes in the near-wellbore region.

3.1.2 SACROC Unit

SACROC Unit (Scurry Area Canyon Reef Operators Committee), commissioned in January 1972, is the first large-scale commercial CO_2-EOR project in the Permian Basin. The producing reservoir is the carbonate Canyon Reef, discovered in 1948, with an estimated OOIP of 2,8 billion barrels (Reeves, 2008). Waterflooding began in 1954; however, the step change in oil production occurred after the implementation of CO_2-EOR. CO_2 supply initially came from gas-processing plants and was later augmented by pipelines delivering natural CO_2 (e.g., from the Bravo Dome field) (Duda et al., 2010; Melzer, 2012).

According to the simulation report, black-oil models yielded an ultimate recovery of up to 46% of OOIP (whereas the literature had cited a maximum of 39%) (Schepers et al., 2007). This supports a substantial CO_2-EOR contribution, amounting to approximately 10 to 20 percentage points of incremental recovery factor above primary and waterflood baselines (Reeves, 2008). Geologically, SACROC is a complex fractured carbonate reef with numerous intra-reservoir flow barriers that partition the accumulation into blocks with lateral communication. CO_2 injection has been implemented both as continuous gas injection and as WAG, mitigating gas breakthrough and improving displacement efficiency.

The enabling infrastructure comprises CO_2 pipelines spanning hundreds of kilometers (e.g., 270 km) with capacities up to 6.8 million m^3/d (Taber, 2000). As reported in the public domain, SACROC has utilized more than 600 Mt of CO_2, and ongoing CO_2-EOR production amounts to thousands of barrels per day (Meyer, 2010). Overall, SACROC has become a technical and economic benchmark, demonstrating that CO_2-EOR in complex carbonate reservoirs can deliver roughly 10%-20% of OOIP in incremental recovery, albeit requiring large-scale infrastructure, rigorous engineering management, and carefully optimized injection strategies.

3.1.3 West Ranch

The Petra Nova/West Ranch (Texas) project implements CO_2-EOR in Frio Formation reservoirs at depths of approximately 1.5-1.9 km, the Anahuac Formation provides regional seal capacity, and the development area is a simple anticlinal trap with no significant internal faulting, as documented in BEG appendices to the NEPA/EIS record and Department of Energy materials. In the BEG engineering basis, the operating constraints adopted for design and surveillance were: An average current reservoir pressure of 16.6 MPa, a maximum allowable bottom-hole injection pressure of 24.1 MPa, a minimum allowable bottom-hole flowing pressure in producers of 13.8 MPa, and a total CO_2 supply on the order of 1.7 Mt/yr (54 kg/s).

Railroad commission orders specify authorized Frio injection intervals across injector groups at 1.54-1.93 km and establish maximum surface injection pressures on the order of 17.4-19.8 MPa (by injector subgroup). According to the Railroad Commission of Texas for the West Ranch 41-A/98-A Consolidated Unit, as of March 2015 cumulative production amounted to approximately 13.39×10^6 m^3 from the 41-A horizon and approximately 7.15×10^6 m^3 from the 98-A horizon (total approximately 20.54×10^6 m^3), and the operator's expected incremental recovery from CO_2-EOR was approximately 9.54×10^6 m^3 of oil.

The project has demonstrated the technical feasibility of large-scale post-combustion CO_2 capture integrated with CO_2-EOR in a Frio sandstone oilfield. The capture facility reaches its nameplate rate at nominal operation (approximately 54 kg/s), and approximately 3.54 Mt of CO_2 were captured over the three-year demonstration. Year-to-year outcomes were limited not by capture chemistry per se but by the aggregate availability of the following chain: Power unit, CCS, compression, approximately 130-km pipeline, and field. This provides a key lesson on integration reliability and planned downtime management (Nakatsuka, 2023).

In terms of storage monitoring, the approved Monitoring, reporting and verification plan and the 2023 annual report indicate no pressure anomalies, compliance with planned WAG cycling, and use of scheduled blowdowns to restore injectivity (with emissions accounting for those operations). Operationally, the suspension of new CO_2 delivery on 1 May 2020 and resumption on 7 September 2023 highlight the sensitivity of long-term performance to base-plant availability and external market/infrastructure factors, consequently, economic robustness requires priority on power-unit reliability, compression/transport serviceability, and pre-planned injectivity maintenance procedures.

3.2 China

China's CO_2-EOR practice has been developed on several low- and ultra-low-permeability clastic targets (Jilin (Songliao Basin), Yanchang (Ordos Basin), and Xinjiang (Junggar Basin)).

3.2.1 Jilin

At Jilin (Qing-1 reservoir, depths 2.0-2.6 km, $T \approx 100$ °C, reservoir pressure 28-32 MPa), in addition to conventional WAG the operator implemented tapered-WAG sequences and CO_2-foam treatments to improve conformance; typical single-well injection rates were 20-50 t/d at bottom-hole pressures of 16-23 MPa. On the upscaled Hei-79 North sector, 10 injectors and 27 producers were placed on stream with a total design CO_2 supply of 600 t/d; relative to baseline waterflood, average oil recovery was 20% higher (central area 25%), cumulative recovery increased by 15.6%, and CO_2 retention reached up to 95% (Wang, 2023).

3.2.2 Yanchang

At Yanchang (Chang-6, Qiaojiawa/Jingbian area), by July 2015 mobile surface facilities had been deployed for five well groups and pilots of WAG and cyclic CO_2 injection were executed; in aggregate, on the order of several-tens-of-thousands of tonnes of CO_2 were injected (the report cites 48 kt), and the expected incremental recovery from the pilot was 5%-8%.

3.2.3 Xinjiang

In Xinjiang (Cainan/Di-2), single-well field tests indicated that after one week of CO_2 injection the average daily oil rate remained 3.1 t/d higher for roughly four months; the incremental oil produced was 372 t, corresponding to an 12% gain in oil recovery (Shi, 2017). With respect to integrity and corrosion control, Jilin is the most comprehensively documented: A combined program of materials selection (stainless steels for wellheads/packers/valves, carbon steels with inhibitors in the wellbore, seamless pipelines with corrosion-resistant spools), continuously dosed inhibitor/biocide formulations, and multi-tier monitoring (autoclave tests, mass-loss coupons, ultrasonic thickness gauging, electrochemical probes in completions) is described. Under routine operation the target annual corrosion rate is maintained below 0.076 mm/yr, as verified by field surveillance (Cai and Li, 2019).

3.3 Europe

3.3.1 Ivanic and Zutica

Since October 2014, INA, Oil Industry Ltd. has run a large-scale CO_2-EOR scheme on the mature Ivanic and Zutica fields using alternating CO_2 and water (WAG). CO_2 captured at the Molve Gas Processing Plant is dehydrated, compressed to 30 bar and moved via a DN500 (20-inch), 88-km onshore pipeline to the Fractionation Facilities Ivanic-Grad (compression and liquefaction unit (CLU Etan)), where it is recompressed to 90 bar, liquefied, and then pumped/injected at approximately 200 bar; nameplate injection capacity is 600,000 Sm^3/d (0.41 Mtpa) (Blecich et al., 2024). Over the planned 25-year life, about 5×10^9 Sm^3 of CO_2 are scheduled for injection, targeting 3.4×10^6 t of incremental oil and 5.99×10^8 Sm^3 of gas; due to reservoir conditions, roughly 50% of injected CO_2 is expected to remain permanently trapped and 50% to be produced with associated gas and recycled (Novak Mavar et al., 2021). Early field performance (2014-2019) included 1×10^9 Sm^3 injected, 1,579,429 boe from Ivanic (approximately 35% uplift attributable to CO_2-EOR) and 390,136 boe from Zutica-North (approximately 77% EOR share); MMP was 200 bar, versus initial reservoir pressure of 190 bar at Zutica-North and 120 bar at Ivanic, so WAG was adopted promptly to control mobility and mitigate early gas channeling as the CO_2 cut rose faster than expected (Blecich et al., 2024). In 2019 the surface system was upgraded with membrane separation and methyldiethanolamine units at Fractionation Facilities Ivanic-Grad to capture CO_2 from associated gas and return it to the injection system (total separation capacity 500,000 Sm^3/d; recompression of recycled CO_2 360,000 Sm^3/d), effectively phasing out routine venting and closing the loop. By 2024, cumulative injected CO_2 had surpassed approximately 3.3 Mt, with about 78% estimated as permanently retained in the subsurface. A new compressor station at the Fractionation Facilities Ivanic-Grad (FFIG) has been built to route captured CO_2 back into the EOR grid. Due to technical issues, start-up is expected in 2025. Overall, the project demonstrates material incremental recovery while building a high-recycle, WAG-managed CO_2 flood; key operational lessons include maintaining injection above MMP where feasible, conformance control to limit viscous fingering and channeling, and high-reliability compression/cooling trains for both primary and recycled CO_2 streams (Blecich et al., 2024).

3.3.2 Szank

Hungary reports more than four decades of CO_2-EOR practice spanning multiple injection strategies (continuous CO_2, WAG, and deliberate gas-cap creation) implemented on sandstone and karstified carbonate reservoirs. Two well-documented projects at Budafa and Lovasi (1972-1996) applied non-miscible CO_2-WAG in several sandstone compartments; the CO_2 source was the Budafa-Deep natural CO_2 reservoir directly underlying the oil and gas pays, which enabled technically and economically robust operations. Cumulative CO_2 injected reached 2.1 billion m^3 (Budafa) and 1.2 billion m^3 (Lovasi); incremental oil totaled 893,000 m^3 and 442,000 m^3, corresponding to +6-14 percentage points in recovery factor across different reservoirs. At Nagylengyel (blocky, karstified limestone with an active aquifer), early water breakthrough was addressed by engineering a CO_2 gas cap delivered via a 30 km pipeline from Budafa-Deep; the project yielded 2.5 million m^3 of additional oil (an additional 7.5 percentage points recovery, ultimate RF $> 55\%$). Pustaföldvár (SE Hungary) leveraged a local high- CO_2 associated gas stream (70% CO_2) for pressure maintenance (1973-1984), transitioned to CO_2-WAG (1989-1997) and then to continuous waterflood (to 2004), delivering 109,000 m^3 of incremental oil and lifting RF by 11.1 percentage points to 38.7%.

At Szank (Szank-SE and Szank-NE; Miocene breccia and limestone), production had declined to 1/8 of peak by 1990; nearby gas fields contained 20%-30% CO_2. In 1992, an acid-gas removal (amine treating) unit was commissioned to separate CO_2 from the hydrocarbon gas stream and feed it for injection, first at Szank-SE and then Szank-NE. The combined incremental oil reached 115,000 m^3, with RF increases of 2.0 percentage points (SE) and 1.5 percentage points (NE). Collectively, the Hungarian casebook shows: (i) Local CO_2 sourcing (natural CO_2 pools or acid-gas removal at gas-processing plants) can obviate long-haul CO_2 pipelines; (ii) matching injection mode to rock type is critical, specifically water-alternating-gas (WAG) for mobility control in heterogeneous sandstones and gas-cap creation in fractured/karstic carbonates; and (iii) success hinges on conformance management (WAG/tapered WAG), integrity/corrosion control, and adaptation to active water drive conditions.

3.3.3 Rusanda

The industrial-scale CO_2-EOR project at the Rusanda field (Vojvodina, Serbia) has been operational since 2015. CO_2 is separated at the Elemir Gas Processing Plant using a HiPACT amine unit and delivered by pipeline as a 99% CO_2 stream. Plant design figures indicate 880,000 Sm^3/d inlet gas, up to 220,000 Sm^3/d separable CO_2, and discharge pressures up to 90 bar; the Rusanda scheme injects 140,000 Sm^3/d of fresh CO_2 with 80,000 Sm^3/d recycled from produced gas. Injection is CCI into the field's gas cap of the Pg-1, naturally fractured oil-gas reservoir (associated gas contains up to 52% CO_2) to provide pressure support and CO_2 displacement; wells are equipped with dehydration and corrosion-control hardware due to the high-CO_2 environment. Cumulative injected volumes reached 51.14 million Sm^3 by end-2019 and 70.18 million Sm^3 by 2024, with injection ongoing in 2025. The operator reports production uplift on the Rusanda-2 block after start-up; the project's EOR mechanism is pressure maintenance with miscible/near-miscible displacement locally, rather than WAG, with closed-loop recycle to improve conformance.

This section reviews only the largest and best-documented cases; in practice there are at least 150 CO_2-EOR projects worldwide (i.e., projects explicitly targeting EOR), and in the United States alone 139 were operating by late 2022. Taken together, the cases considered indicate that when operated above the minimum miscibility pressure and under disciplined conformance management (water-alternating-gas with tapered slugs, selective layered injection, and, where appropriate, CO_2-foam treatments), miscible CO_2-EOR consistently yields a material increase in oil recovery on the order of 10%-20%

of OOIP, with higher local gains where pattern design and reservoir heterogeneity are carefully managed. However, practical performance is governed not only by reservoir physics: The rate-limiting step is often the reliability of the entire capture/supply-compression-transport-injection-recycle chain, and sustained injectivity requires explicit control of near-wellbore processes (including prevention of dry-out and salt precipitation in saline systems). Equally critical is long-term integrity (materials and cement design, inhibitor/biocide programs, and regular verification of well integrity), without which corrosion and loss of containment can rapidly erode EOR gains.

4. Conclusions

This review synthesized results from more than 100 laboratory, pilot, and field studies to evaluate the effectiveness, mechanisms, and operational constraints of major CO_2-EOR technologies. Application of various CO_2-EOR methods represents a significant intersection of economic, environmental, and technological considerations in the modern energy production. CO_2-EOR is not just a method to enhance oil recovery from depleted reservoirs, but also a significant component of a world strategy to mitigate carbon emissions and counter climate change.

Global field experience with CO_2-EOR demonstrates several consistent technological and operational patterns across different geological settings. The highest recovery gains are typically achieved under miscible conditions, when reservoir pressure exceeds the MMP. Most documented projects report incremental oil recovery of approximately 10%-20% of OOIP, although higher local values are possible when injection patterns and reservoir heterogeneity are effectively managed. At the same time, WAG injection remains the dominant field strategy, as it improves sweep efficiency and mitigates early CO_2 breakthrough caused by the unfavorable mobility ratio of gas. Field implementations increasingly employ modified WAG schemes (e.g., tapered WAG, selective layered injection, or foam-assisted treatments) to control gas channeling and improve conformance in heterogeneous reservoirs, which could be complicated by near-wellbore processes. Such processes as salt precipitation and injectivity decline must be actively managed through injection scheduling, water management and periodic well maintenance to ensure efficient operation. Furthermore, long-term well integrity and CO_2 balance management are reinforced by the susceptibility of carbon steel components to corrosion in water-saturated CO_2 environments, necessitating the use of corrosion-resistant alloys, inhibitor programs, and regular integrity monitoring.

Another important trend in the CO_2-EOR approach is the critical role of infrastructure and supply chain reliability. Large-scale projects in North America demonstrate that the long-term success of CO_2-EOR depends not only on reservoir performance but also on the stability of the entire capture-compression-transport-injection-recycling system. Interruptions in CO_2 supply, compressor performance, or pipeline constraints directly impact injectivity, reservoir pressure maintenance, and overall sweep efficiency. Building on these infrastructure considerations, operational experience further refines the understanding of the prioritized technological limitations identified in this study.

Although all considered methods showed high efficiency under laboratory conditions, their successful application in the field requires additional research. Future development of CO_2-EOR technologies should focus on integrated mobility-control strategies and reservoir-specific process design that combine optimized injection schemes (e.g., WAG, cyclic injection, and tapered schedules) with advanced chemical or dispersed systems such as surfactants, polymers, nanoparticles, and CO_2 thickeners. Particular attention should be given to scaling laboratory findings to pilot and field applications, improving the stability and transport of functional additives under reservoir conditions, and developing adaptive injection strategies capable of managing heterogeneity, gravity segregation, and early gas breakthrough. Such integrated approaches are expected to simultaneously enhance oil recovery efficiency, CO_2 utilization and long-term geological storage performance, thereby strengthening the role of CO_2-EOR in the transition toward lower-carbon hydrocarbon production.

Acknowledgements

The authors appreciate Empress Catherine II Saint Petersburg Mining University and the Research Center “Arctic” for providing the necessary facilities and support to conduct this research.

Supplementary file

https://doi.org/10.46690/ager.2026.05.05

Conflicts of interest

The authors declare no competing interest.

References

Adkins, S. S., Chen, X., Nguyen, Q. P., et al. Effect of branching on the interfacial properties of nonionic hydrocarbon surfactants at the air-water and carbon dioxide-water interfaces. Journal of Colloid and Interface Science, 2010, 346(2): 455-463.

Afsharpoor, A., Lee, G. S., Kam, S. I. Mechanistic simulation of continuous gas injection period during surfactant-alternating-gas (SAG) processes using foam catastrophe theory. Chemical Engineering Science, 2010, 65(11): 3615-3631.

Alizadeh, A., Ghazanfari, M. H., Taghikhani, V., et al. Experimental investigation of water alternating CH_4-CO_2 mixture gas injection in light oil reservoirs. International Journal of Oil, Gas and Coal Technology, 2014, 8(1): 31-40.

Amraeiniya, A., Rahimi, A., Nikpour, N., et al. Inhibition of asphaltene deposition by Al_2O_3 nanoparticles during CO_2 injection. Petroleum Research, 2023, 8(4): 499-504.

Bai, B., Li, L., Liu, Y., et al. Preformed particle gel for conformance control: Factors affecting its properties and applications. SPE Reservoir Evaluation & Engineering, 2007, 10(4): 415-422.

Bai, H., Zhang, Q., Li, Z., et al. Effect of fracture on production characteristics and oil distribution during CO_2 huff-n-puff under tight and low-permeability conditions. Fuel, 2019, 246: 117-125.

Blaker, T., Aarra, M. G., Skauge, A., et al. Foam for gas mobility control in the Snorre Field: The FAWAG project. SPE Reservoir Evaluation & Engineering, 2002, 5(4): 317-323.

Blecich, P., Wolf, I., Senčić, T., et al. Current status of enhanced oil recovery projects using carbon dioxide (EOR CO_2) in Croatia. Paper Presented at the 3rd International Electronic Conference on Processes - Green and Sustainable Process Engineering and Process Systems Engineering (ECP 2024), Basel, Switzerland, 29-31 May, 2024.

Blinov, P. A., Silichev, N. M., Nikishin, V. V., et al. Substantiation and development of a methodology for calculating the bending of the drive shaft of a continuous deflector for drilling with coring. SOCAR Proceedings, 2025, 3: 39-48.

Bratskikh, D. S., Romasheva, N. V. A comprehensive approach to assessing the efficiency and sustainability of oil supply chains under digital transformation. SOCAR Proceedings, 2025, 4: 214-225.

Brattekås, B., Seright, R. A review of polymer gel utilization in carbon dioxide flow control at the core and field scale. SPE Journal, 2023, 28(6): 3291-3307.

Cai, B., Li, Q. China status of CO_2 Capture, Utilization and Storage (CCUS) 2019, Beijing, Chinese Academy for Environmental Planning, 2019.

Carpenter, C. Development of small-molecule CO_2 thickeners. Journal of Petroleum Technology, 2014, 66(7): 145-147.

Chen, B., Reynolds, A. C. Ensemble-based optimization of the water-alternating-gas-injection process. SPE Journal, 2016, 21(3): 786-798.

Cheng, Y., Chang, H., Du, Z., et al. A laboratory investigation of CO_2 influence on solvent-assisted polymer flooding for improving viscous oil recovery on Alaska North Slope. Geoenergy Science and Engineering, 2023, 229: 212053.

Chen, X., Li, Y., Sun, X., et al. Investigation of polymer-assisted CO_2 flooding to enhance oil recovery in low-permeability reservoirs. Polymers, 2023, 15(19): 3886.

Chen, X., Paprouschi, A., Elveny, M., et al. A laboratory approach to enhance oil recovery factor in a low permeable reservoir by active carbonated water injection. Energy Reports, 2021, 7: 3149-3155.

Cherepovitsyn, A., Ilinova, A. Ecological, economic and social issues of implementing carbon dioxide sequestration technologies in the oil and gas industry in Russia. Journal of Ecological Engineering, 2016, 17(2): 19-23.

Cong, Z., Li, Y., Pan, Y., et al. Study on CO_2 foam fracturing model and fracture propagation simulation. Energy, 2022, 238: 121778.

Cozzi, L., Gould, T., Bouckaert S., et al. World Energy Outlook 2021. Paris, International Energy Agency, 2021.

Ding, M., Wang, Y., Liu, D., et al. Enhancing tight oil recovery using CO_2 huff and puff injection: An experimental study of the influencing factors. Journal of Natural Gas Science and Engineering, 2021, 90: 103931.

dos Santos, D. R., Fioravanti, A. R., Botechia, V. E., et al. Accelerated optimization of CO_2-miscible water-alternating-gas injection in carbonate reservoirs using production data-based parameterization. Journal of Petroleum Exploration and Production Technology, 2023, 13(8): 1833-1846.

Duda, J. R., Yost, A. B., Long, R., et al. Untapped domestic energy supply and long term carbon storage solution, National Energy Technology Laboratory, 2010.

Dvoynikov, M., Kutuzov, P. Identification of critical and post-critical states of a drill string under dynamic conditions during the deepening of directional wells. Eng, 2025, 6(11): 306.

Golkari, A., Riazi, M., Cortés, F. B., et al. Experimental investigation of interfacial tension and oil swelling for asphaltenic crude oil/carbonated water system. Egyptian Journal of Petroleum, 2022, 31(2): 51-58.

Gong, Y., Gu, Y. Miscible CO_2 Simultaneous water-and-gas (CO_2-SWAG) injection in the Bakken Formation. Energy & Fuels, 2015, 29(9): 5655-5665.

González, A., Martínez-Cruz, M. A., Alcántar-Vázquez, B., et al. Influence of NiO into the CO_2 capture of Li_4SiO_4 and its catalytic performance on dry reforming of methane. Heliyon, 2024, 10(2): e24645.

Graue, D. J., Blevins, T. R. Sacroc Tertiary CO_2 pilot project. Paper SPE 7090 Presented at the SPE Symposium on Improved Methods of Oil Recovery, Tulsa, Oklahoma, 16-17 April, 1978.

Han, L., Gu, Y. Optimization of miscible CO_2 water-alternating-gas injection in the Bakken Formation. Energy & Fuels, 2014, 28(11): 6811-6819.

Hao, Y., Wu, Z., Chen, Z., et al. The characteristics and effects of Huff-n-Puff in shale with brine, aqueous surfactant solutions and CO_2. Journal of CO_2 Utilization, 2024, 79: 102655.

Heidari, P., Kharrat, R., Alizadeh, N., et al. A comparison of WAG and SWAG processes: Laboratory and simulation studies. Energy Sources, Part A: Recovery, Utilization, and Environmental Effects, 2013, 35(23): 2225-2232.

Holm, W. L. Evolution of the carbon dioxide flooding processes. Journal of Petroleum Technology, 1987, 39(11): 1337-1342.

Hosseini, M. S., Khazaei, M., Misaghi, M., et al. Improving the stability of nanofluids via surface-modified titanium dioxide nanoparticles for wettability alteration of oil-wet carbonate reservoirs. Materials Research Express, 2022, 9(3): 035005.

Hosseininoosheri, P., Hosseini, S. A., Nuñez-López, V., et al. Impact of field development strategies on CO_2 trapping mechanisms in a CO_2-EOR field: A case study in the permian basin (SACROC unit). International Journal of Greenhouse Gas Control, 2018, 72: 92-104.

Ipatov, A. I., Kremenetsky, M. I., Khudiev, E. R., et al. The effectiveness of downhole distributed fiber-optic monitoring of ESP horizontal wells production in the Gazprom Neft. Neftyanoe Khozyaystvo-Oil Industry, 2023, (12): 58-63.

Jafarbeigi, E., Salimi, F., Kamari, E., et al. Effects of modified graphene oxide (GO) nanofluid on wettability and IFT changes: Experimental study for EOR applications. Petroleum Science, 2022, 19(4): 1779-1792.

Jamshidi, T., Zeng, F., Tontiwachwuthikul, P., et al. Viability of carbonated water injection (CWI) as a means of secondary oil recovery in heavy oil systems in presence and absence of wormholes: Microfluidic experiments. Fuel, 2019, 249: 286-293.

Jangda, Z. Z., Sultan, A. S., Gajbhiye, R. N., et al. Evaluation of fluorosurfactant performance with super-critical CO_2 flooding for high salinity carbonate reservoirs. Paper SPE 169725 Presented at the SPE EOR Conference at Oil and Gas West Asia, Muscat, Oman, 31 March-2 April, 2014.

Jia, H., Zhang, R., Luo, X., et al. Nuclear magnetic resonance experiments on the time-varying law of oil viscosity and wettability in high-multiple waterflooding sandstone cores. Petroleum Exploration and Development, 2024, 51(2): 394-402.

Kalinin, S., Morozyuk, O. Using carbon dioxide to develop highly viscous oil fields in carbonate reservoirs. Global experience analysis. Perm Journal of Petroleum and Mining Engineering, 2019, 19(4): 373-387.

Kar, T., Firoozabadi, A. Effective viscosification of supercritical carbon dioxide by oligomers of 1-decene. iScience, 2022, 25(5): 104266.

Karimaie, H., Nazarian, B., Aurdal, T., et al. Simulation study of CO_2 EOR and storage potential in a North Sea Reservoir. Energy Procedia, 2017, 114: 7018-7032.

Khan, J. A., Kim, J., Irawan, S., et al. Application of foam assisted water-alternating-gas flooding and quantification of resistivity and water saturation by experiment and simulation to determine foam propagation in sandstone. Heliyon, 2024, 10(3): e25435.

Khan, M. Y., Kohata, A., Patel, H., et al. Water Alternating gas WAG optimization using tapered WAG technique for a Giant Offshore Middle East Oil Field. Paper SPE 183181 Presented at the Abu Dhabi International Petroleum Exhibition & Conference, Abu Dhabi, UAE, 7-10 November, 2016.

Koca, H. D., Doganay, S., Turgut, A., et al. Effect of particle size on the viscosity of nanofluids: A review. Renewable and Sustainable Energy Reviews, 2018, 82: 1664-1674.

Korobov, G., Rogachev, M., Krylov, V. Mechanisms of asphaltene-resin-paraffin deposit formation and prevention in oil production: From physicochemical processes to inhibition and delivery strategies. Eng, 2026, 7(3): 116.

Korobov, G., Vorontsov, A., Buslaev, G., et al. Analysis of nucleation time of gas hydrates in presence of paraffin during mechanized oil production. International Journal of Engineering, 2024, 37(7): 1343-1356.

Kovyazin, V., Bogdanova, E., Volkova, J., et al. Environmental assessment of economic activity based on analysis of types of permitted use of land plots in the Russian Federation. Land, 2026, 15(5): 786.

Kumar, S., Mandal, A. A comprehensive review on chemically enhanced water alternating gas/CO_2 (CEWAG) injection for enhanced oil recovery. Journal of Petroleum Science and Engineering, 2017, 157: 696-715.

Lashkarbolooki, M., Ayatollahi, S. Effect of asphaltene and resin on interfacial tension of acidic crude oil/ sulfate aqueous solution: Experimental study. Fluid Phase Equilibria, 2016, 414: 149-155.

Laumb, J. D., Glazewski, K. A., Hamling, J. A., et al. Corrosion and failure assessment for CO_2 EOR and associated storage in the Weyburn Field. Energy Procedia, 2017, 114: 5173-5181.

Lee, J. J., Cummings, S., Dhuwe, A., et al. Development of small molecule CO_2 thickeners for EOR and fracturing. SPE-DOE Improved Oil Recovery Symposium Proceedings, 2014, 1: 145-162.

Li, K., Li, X., Li, L., et al. Nature of catalytic behavior of cobalt oxides for CO_2 hydrogenation. JACS Au, 2023, 3(2): 508-515.

Lima, R. O., de L. Cunha, A., Santos, J. A. O., et al. Assessment of continuous and alternating CO_2 injection under Brazilian-pre-salt-like conditions. Journal of Petroleum Exploration and Production Technology, 2020, 10(7): 2947-2956.

Litvinenko, V., Petrov, E., Vasilevskaya, D., et al. Assessment of the role of the state in the management of mineral resources. Journal of Mining Institute, 2022, 259: 95-111.

Liu, J., Li, H., Tan, Q., et al. Quantitative study of CO_2 huff-n-puff enhanced oil recovery in tight formation using online NMR technology. Journal of Petroleum Science and Engineering, 2022, 216: 110688.

Liu, K., Wei, X. Oil recovery: Experiences and economics of microbially enhanced oil recovery (MEOR), in Consequences of Microbial Interactions with Hydrocarbons, Oils, and Lipids: Production of Fuels and Chemicals, edited by Lee S., Springer, Cham, pp. 671-678, 2017.

Medina, O. E., Galeano-Caro, D., Brattekås, B., et al. Simultaneous CO_2 adsorption and conversion over Ni-Pd supported CeO_2 nanoparticles during catalytic n-C7 asphaltene gasification. Fuel, 2023, 342: 127733.

Melzer, L. S. Carbon dioxide enhanced oil recovery (CO_2 EOR): Factors involved in adding Carbon Capture, Utilization and Storage (CCUS) to Enhanced Oil Recovery. Texas, Melzer consulting, 2012.

Metz, B., Davidson, O., de Coninck, H., et al. Carbon dioxide capture and storage. Cambridge, Intergovernmental Panel on Climate Change, 2005.

Meyer, J. P. Summary of carbon dioxide enhanced oil recovery (CO_2-EOR) injection well technology. Texas, American Petroleum Institute, 2010.

Mosavat, N., Torabi, F. Performance of secondary carbonated water injection in light oil systems. Industrial & Engineering Chemistry Research, 2014, 53(3): 1262-1273.

Mosavat, N., Torabi, F. Micro-optical analysis of carbonated water injection in irregular and heterogeneous pore geometry. Fuel, 2016, 175: 191-201.

Mustafaev, A. S., Grabovskiy, A. Y., Sukhomlinov, V. S., et al.

A universal triode-based plasma device with controllable electrokinetic characteristics. Journal of Applied Physics, 2026, 139(15): 153302.

Nakatsuka S. Annual report: 40 C. F. R. 98.446 (Subpart RR). Houston, Petra Nova Parish Holdings LLC, 2023.

Novak Mavar, K., Gaurina-Međimurec, N., Hrnčević, L. Significance of enhanced oil recovery in carbon dioxide emission reduction. Sustainability, 2021, 13(4): 1800.

Omar, S., Jaafar, M. Z., Ismail, A. R., et al. Monitoring foam stability in foam assisted water alternate gas (FAWAG) processes using electrokinetic signals. Paper SPE 165312 Presented at the SPE Enhanced Oil Recovery Conference, Kuala Lumpur, Malaysia, 2-4 July, 2013.

Orujov, A., Coddington, K., Aryana, S. A. A Review of CCUS in the context of foams, regulatory frameworks and monitoring. Energies, 2023, 16(7): 3284.

Pal, N., Mandal, A. Enhanced oil recovery performance of gemini surfactant-stabilized nanoemulsions functionalized with partially hydrolyzed polymer/silica nanoparticles. Chemical Engineering Science, 2020, 226: 115887.

Pal, N., Zhang, X., Ali, M., et al. Carbon dioxide thickening: A review of technological aspects, advances and challenges for oilfield application. Fuel, 2022, 315: 122947.

Pal, R., Ghara, M., Chattaraj, P. K. Activation of small molecules and hydrogenation of CO_2 catalyzed by frustrated Lewis Pairs. Catalysts, 2022, 12(2): 201.

Panjalizadeh, H., Alizadeh, A., Ghazanfari, M., et al. Optimization of the WAG injection process. Petroleum Science and Technology, 2015, 33(3): 294-301.

Pavlova, P. L., Bashmur, K. A., Bukhtoyarov, V. V. Analysis and development of proposals to improve the equipment and technologies of capture and injection of carbon dioxide at the oil fields. SOCAR Proceedings, 2022, SI1: 116-126.

Petrakov, D. G., Loseva, A. V., Jafarpour, H., et al. Experimental evaluation of effective chemical composition on reservoir quality of bottomhole zone of low permeability terrigenous reservoirs. International Journal of Engineering, 2024, 37(8): 1547-1555.

Podoprigora, D., Rogachev, M., Byazrov, R. Surfactant-polymer formulation for chemical flooding in oil reservoirs. Energies, 2025, 18(7): 1814.

Raupov, I., Rogachev, M., Shevaldin, E. Review of formation mechanisms, localization methods, and enhanced oil recovery technologies for residual oil in terrigenous reservoirs. Energies, 2025, 18(21): 5649.

Reeves, S. R. Demonstration of a novel, integrated, multiscale procedure for high-resolution 3D reservoir characterization and improved CO_2-EOR/Sequestration management, SACROC Unit. Houston, National Energy Technology Laboratory, 2008.

Ricky, E. X., Mwakipunda, G. C., Nyakilla, E. E., et al. A comprehensive review on CO_2 thickeners for CO_2 mobility control in enhanced oil recovery: Recent advances and future outlook. Journal of Industrial and Engineering Chemistry, 2023, 126: 69-91.

Ryazantsev, M. V., Lozin, E. V. Carbon dioxide flooding: History of world and local investigations. Neftyanoe khozyaystvo-Oil Industry, 2020, 7: 100-103.

Safaei, A., Esmaeilzadeh, F., Sardarian, A., et al. Experimental investigation of wettability alteration of carbonate gas-condensate reservoirs from oil-wetting to gas-wetting using Fe_3O_4 nanoparticles coated with Poly (vinyl alcohol), (PVA) or Hydroxyapatite (HAp). Journal of Petroleum Science and Engineering, 2020, 184: 106530.

Salehpour, M., Riazi, M., Malayeri, M. R., et al. CO_2-saturated brine injection into heavy oil carbonate reservoirs: Investigation of enhanced oil recovery and carbon storage. Journal of Petroleum Science and Engineering, 2020, 195: 107663.

Schepers, K., Gonzalez, R. J., Reeves, S. R. Optimized reservoir history matching simulation of canyon formation, SACROC Unit, Permian Basin. Huston, U.S. Department of Energy, 2007.

Seyyedi, M., Sohrabi, M., Sisson, A., et al. Quantification of oil recovery efficiency, CO_2 storage potential, and fluid-rock interactions by CWI in heterogeneous sandstone oil reservoirs. Journal of Molecular Liquids, 2018, 249: 779-788.

Sha, X., Yu, K., Cao, H., et al. Shear thickening behavior of nanoparticle suspensions with carbon nanofillers. Journal of Nanoparticle Research, 2013, 15(7): 1816.

Shafiei, M., Kazemzadeh, Y., Escrochi, M., et al. A comprehensive review direct methods to overcome the limitations of gas injection during the EOR process. Scientific Reports, 2024, 14(1): 7468.

Shen, H., Liu, Y., Wei, J., et al. Impact frequency variation of self-excited oscillation pulsed supercritical carbon dioxide jets. Petroleum Exploration and Development, 2023, 50(5): 1261-1268.

Shi, Q. Xinjiang Guanghui coal-to-gas CCUS pilot project prefeasibility study. Xinjiang, Xinjiang University, 2017. (in Chinese)

Shi, Y., Wu, B., Wang, H., et al. Insights into CO_2 huff-n-puff mechanisms from laboratory experiment and single-well pilot test in the Lucaogou tight oil reservoir, Jimsar sag, China. Geoenergy Science and Engineering, 2024, 232: 212456.

Sun, W., Sun, B., Li, Y., et al. Thickening supercritical CO_2 with π-stacked co-polymers: Molecular insights into the role of Intermolecular Interaction. Polymers, 2018, 10(3): 268.

Sun, X., Liu, J., Dai, X., et al. On the application of surfactant and water alternating gas (SAG/WAG) injection to improve oil recovery in tight reservoirs. Energy Reports, 2021, 7: 2452-2459.

Taber, J. Programme Barriers to overcome in implementation of CO_2 Capture and Storage. Cheltenham, International Energy Agency Greenhouse Gas R&D, 2000.

Taber, J. J., Martin, F. D., Seright, R. S. EOR Screening criteria revisited – Part 1: Introduction to screening criteria and enhanced recovery field projects. SPE Reservoir Engineering, 1997, 12(3): 189-198.

Tadepalli, K. M., Chakrabarty, S., Patil, P., et al. Design of CO_2 thickeners and role of aromatic rings in enhanced oil recovery using molecular dynamics. Langmuir, 2022, 39(3): 989-996.

Talebian, S. H., Mohd Tan, I., Sagir, M., et al. Static and dynamic foam/oil interactions: Potential of CO_2-philic surfactants as mobility control agents. Journal of Petroleum Science and Engineering, 2015, 135: 118-126.

Tananykhin, D. S. Scientific and methodological support of sand management during operation of horizontal wells. International Journal of Engineering, 2024, 37(7): 1395-1407.

Verma, M. Fundamentals of carbon dioxide-enhanced oil recovery (CO_2-EOR): A supporting document of the assessment methodology for hydrocarbon recovery using CO_2-EOR associated with carbon sequestration. Reston, U.S. Geological Survey, 2015.

Wang, G. Carbon dioxide capture, enhanced-oil recovery and storage technology and engineering practice in Jilin Oilfield, NE China. Petroleum Exploration and Development, 2023, 50(1): 245-254.

Wang, L., He, Y., Wang, Q., et al. Multiphase flow characteristics and EOR mechanism of immiscible CO_2 water-alternating-gas injection after continuous CO_2 injection: A micro-scale visual investigation. Fuel, 2020, 282: 118689.

Wang, X., Luo, P., Er, V., et al. Assessment of CO_2 flooding potential for Bakken Formation, Saskatchewan. Paper SPE 137728 Presented at the Canadian Unconventional Resources and International Petroleum Conference, Calgary, Alberta, Canada, 19-21 October, 2010.

Wang, Z., Yang, S., Lei, H., et al. Oil recovery performance and permeability reduction mechanisms in miscible CO_2 water-alternative-gas (WAG) injection after continuous CO_2 injection: An experimental investigation and modeling approach. Journal of Petroleum Science and Engineering, 2017, 150: 376-385.

Whittaker, S., White, D., Law, D., et al. IEA GHG Weyburn CO_2 monitoring & storage project summary Report 2000-2004. Vancouver, Petroleum Technology Research Centre, 2004.

Yu, H., Fu, W., Zhang, Y., et al. Experimental study on EOR performance of CO_2-based flooding methods on tight oil. Fuel, 2021, 290: 119988.

Zeng, T., Miller, C. S., Mohanty, K. K. Combination of a chemical blend with CO_2 huff-n-puff for enhanced oil recovery in oil shales. Journal of Petroleum Science and Engineering, 2020, 194: 107546.

Zhang, L., Ren, B., Huang, H., et al. CO_2 EOR and storage in Jilin oilfield China: Monitoring program and preliminary results. Journal of Petroleum Science and Engineering, 2015, 125: 1-12.

Zhang, Y., Yuan, L., Liu, S., et al. Molecular dynamics simulation of bubble nucleation and growth during CO_2 Huff-n-Puff process in a CO_2-heavy oil system. Geoenergy Science and Engineering, 2023, 227: 211852.

Zharikova, N. Kh., Savenok, O. V., Korolev, M. I., et al. Increase of condensate recovery factor by reservoir pressure maintenance injecting hydrocarbon and non-hydrocarbon gases. Bulletin of the Tomsk Polytechnic University Geo Assets Engineering, 2025, 336(12): 243-255.

Zhou, D., Yan, M., Calvin, W. M. Optimization of a mature CO_2 flood – From continuous injection to WAG. Paper SPE 154181 Presented at the SPE Improved Oil Recovery Symposium, Tulsa, Oklahoma, USA, 14-18 April, 2012.

Zuloaga, P., Yu, W., Miao, J., et al. Performance evaluation of CO_2 Huff-n-Puff and continuous CO_2 injection in tight oil reservoirs. Energy, 2017, 134: 181-192.