Petroleum Science 21 (2024) 4100–4118

Contents lists available at ScienceDirect

Petroleum Science

journal homepage: www.keaipublishing.com/en/journals/petroleum-science

Review Paper

Review of carbonated water injection as a promising technology to enhance oil recovery in the petroleum industry: Challenges and prospects

Ke Chen [a], Jing-Ru Zhang [a], Si-Yu Xu [a], Mu-Zi Yin [a], Yi Zhang [a,*], Yue-Chao Zhao [b], Yong-Chen Song [a,**]

[a] *Key Laboratory of Ocean Energy Utilization and Energy Conservation of Ministry of Education, School of Energy and Power Engineering, Dalian University of Technology, Dalian, 116024, Liaoning, China*

[b] *NEPU Sanya Offshore Oil & Gas Research Institute, Northeast Petroleum University, Sanya, 572025, Hainan, China*

A R T I C L E I N F O

Article history:
Received 17 January 2024
Received in revised form
30 June 2024
Accepted 4 July 2024
Available online 6 July 2024

Edited by Yan-Hua Sun

Keywords:
Carbonated water injection
Enhanced oil recovery
Recovery mechanism
Geological carbon sequestration
Interaction

A B S T R A C T

Carbonated water injection (CWI) is a promising enhanced oil recovery (EOR) technology that has received much attention in co-optimizing CO_2 storage and oil recovery. This study provides a comprehensive review of the fluid system properties and the underlying changes in rock–fluid interactions that drive the CWI-EOR mechanisms. Previous research has indicated that CWI can enhance oil recovery by shifting reservoir wettability towards a more water-wet state and reducing interfacial tension (IFT). However, this study reveals that there is still room for discussion in this area. Notably, the potential of CWI to alter reservoir permeability has not yet been explored. The varying operational conditions of the CWI process, namely temperature, pressure, injection rate, salinity, and ionic composition, lead to different levels of oil recovery factors. Herein, we aim to meticulously analyze their impact on oil recovery performance and outline the optimal operational conditions. Pressure, for instance, positively influences oil recovery rate and CWI efficiency. On one hand, higher operating pressures enhance the effectiveness of CW due to increased CO_2 solubility. On the other hand, gas exsolution events in depleted reservoirs provide additional energy for oil movement along gas growth pathways. However, CWI at high carbonation levels does not offer significant benefits over lower carbonation levels. Additionally, lower temperatures and injection rates correlate with higher recovery rates. Further optimization of solution chemistry is necessary to determine the maximum recovery rates under optimal conditions. Moreover, this review comprehensively covers laboratory experiments, numerical simulations, and field applications involving the CWI process. However, challenges such as pipeline corrosion, potential reservoir damage, and produced water treatment impact the further application of CWI in EOR technologies. These issues can affect the expected oil recovery rates, thereby reducing the economic returns of EOR projects. Finally, this review introduces current research trends and future development prospects based on recently published studies in the field of CWI. The conclusions of this study aid readers in better understanding the latest advancements in CWI technology and the strengths and limitations of the techniques used, providing directions for further development and application of CWI.

1. Introduction

Despite the rapid advancement in the utilization of renewable energy sources, fossil fuels are projected to remain the predominant source for the coming decades (Ahmed et al., 2023). The International Energy Agency (IEA) forecasts that the global oil consumption will surge from 90 mb/d in 2020 to 104 mb/d by 2030 (Ritchie et al., 2024). However, anthropogenic CO_2 emissions are

* Corresponding author.
** Corresponding author.
E-mail addresses: zhangyi80@dlut.edu.cn (Y. Zhang), songyc@dlut.edu.cn (Y.-C. Song).

https://doi.org/10.1016/j.petsci.2024.07.009

recognized as a major contributor to global warming and climate change (Zhang and Li, 2023). Consequently, the global petroleum industry faces the dual challenge of expanding oil production while ensuring long-term environmental stability. Primary energy consumption and CO_2 emissions from energy production for the period 2012 to 2022 are shown in Fig. 1.

Historically, CO_2-enhanced oil recovery (EOR) programs have not only boosted oil production but also reduced CO_2 emission (Zhang et al., 2015). Over the past few decades, CO_2-EOR projects have successfully improved the oil recovery factors (RFs) by approximately 20%–40% (Yu et al., 2015; Tan et al., 2022; Ren et al., 2023). The common mechanisms by which CO_2-EOR include oil expansion, wettability alteration, and light component vaporization/extraction (Kumar et al., 2022). However, challenges such as severe viscous fingering, low sweep efficiency, and premature CO_2 breakthrough can arise during CO_2 flooding. Therefore, gravity override, mobility control, and channeling are three critical issues that must be addressed for the successful implementation CO_2-EOR project. To address these issues, several CO_2-based EOR technologies have been proposed, including water-alternating-gas (WAG) injection, carbonated water injection (CWI), and CO_2 foam injection.

The CWI is an EOR technique that involves dissolving CO_2 in water under reservoir conditions to form a single-phase fluid, which is then transported and injected into oilfields (Hasanvand et al., 2013). Compared to conventional CO_2 injection, CWI offers several advantages: (1) It significantly reduces the volume of CO_2 required for CWI, thereby lowering the costs associated with CO_2 purchase and transportation; (2) CWI is particularly practical for offshore environments where the only available gas supply might be CO_2 separated from gas storage facilities (An et al., 2021); (3) CO_2-saturated brine has a higher density than formation brine, mitigating the risk of CO_2 buoyancy-driven leakage; (4) The injected CW readily mixes with resident water, alleviating the adverse effects of high-water saturation and water shielding (Shu et al., 2014); (5) The CW can dissolve inorganic minerals, reducing harmful particle migration and clay swelling in the reservoir; (6) The injection of CW creates a low pH environment and enhances the dissolution of carbonate minerals, improving the effective permeability of the reservoir; (7) The displacement efficiency of CWI is governed by the mass transfer between water and hydrocarbon phases, not by the minimum miscibility pressure (Peksa et al., 2013). In summary, this technique effectively addresses the

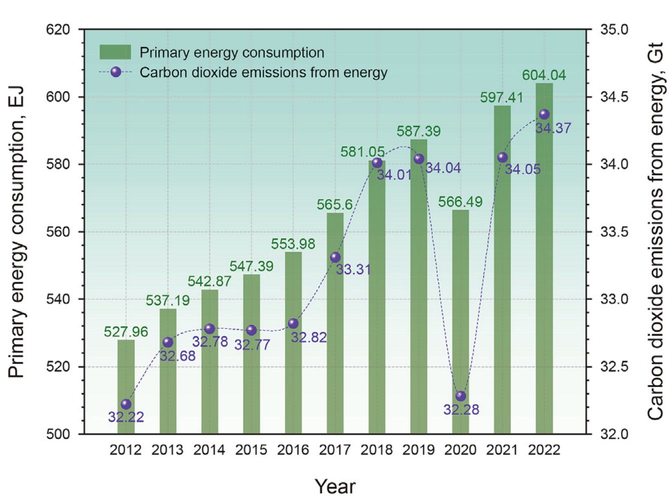

Fig. 1. Primary energy consumption and CO_2 emissions from energy in 2012–2022 (modified after Raimi et al., 2023).

issue of gas fingering, reduces the oil–water mobility ratio, and thereby improves the sweep efficiency and oil production. Despite the advantages of CWI, there are also some drawbacks to consider: Firstly, the acidic environment created by carbonic water can accelerate the corrosion of well equipment and pipelines. Secondly, reactions between CO_2 and reservoir minerals can cause mineral precipitation and plugging of pore throats, which can decrease the effectiveness of the CWI process. Lastly, the cost of CWI and the potential safety risks associated with handling and storing large volumes of CO_2 may be significant.

The CWI technique was first theorized in the 1930s and later implemented by the oil industry by the 1940s. Field experience of CWI in Texas and Oklahoma demonstrated oil recovery rate improvements exceeding 40%. Additional economic benefits, such as increased water injectivity and shortened waterflood lifespans, have been associated with CWI implementations. Numerous research indicate that CWI is a promising water-based CO_2-EOR technology (Bergmo and Holt, 2024; Dastjerdi et al., 2024) and a feasible approach for global warming mitigation strategies (Marotto and Pires, 2019; Motie and Assareh, 2020; Ji et al., 2023). The incremental RFs reported in the literature are 6.74% and 9.0%–40.54% for secondary and tertiary CWI, respectively (Shakiba et al., 2016; Zou et al., 2019; Salehpour et al., 2020). Moreover, the corresponding potential for CO_2 storage is generally in the range of 40%–54% (Kechut et al., 2011; Sohrabi et al., 2011a). Progress of current research directions in CWI is illustrated in Fig. 2.

In recent years, a number of review articles have been published (Esene et al., 2019a; Bisweswar et al., 2020; Talebi et al., 2022), Fig. 3 presents a historical overview of review papers published from 2019 to 2024. This paper analyzes in detail the mechanism of CWI to improve oil recovery and establishes a database. In addition, it elucidates the influence of the operating parameters of CWI technology on oil recovery performance, which provides a reference for parameter design in practical applications. An important contribution of this paper is to help readers understand the latest development of CWI technology as well as the advantages and limitations of the techniques used, and to provide new research directions for future technological advancements. CWI is an advanced EOR technology with the potential to harmonize oil recovery and environmental management. Despite the challenges, incorporating this approach into oilfield practice can contribute to global efforts to mitigate climate change and extend reservoir production life.

The overall structure of this study is organized as follows: Section 2 begins with an introduction to the background knowledge of EOR in the petroleum sector, elucidating the relevant mechanisms of EOR during the CWI process. Section 3 then explores the impact of operational parameters on the performance of CWI. Sections 4 and 5 present the findings from numerical/mathematical modeling studies and field application results related to practical issues in CWI. Section 6 discusses the current challenges and emerging research directions in the application of CWI. Finally, Section 7 concludes with the main highlights and significant recommendations of this report.

2. CWI-EOR technology process description: Theory and mechanisms

2.1. Theory of EOR

Globally, the development of conventional oil fields is categorized into three distinct phases: primary, secondary, and tertiary oil recovery. During the primary oil recovery stage, crude oil naturally flows out of the reservoir due to the natural underground pressure. When the reservoir pressure is insufficient to maintain this flow,

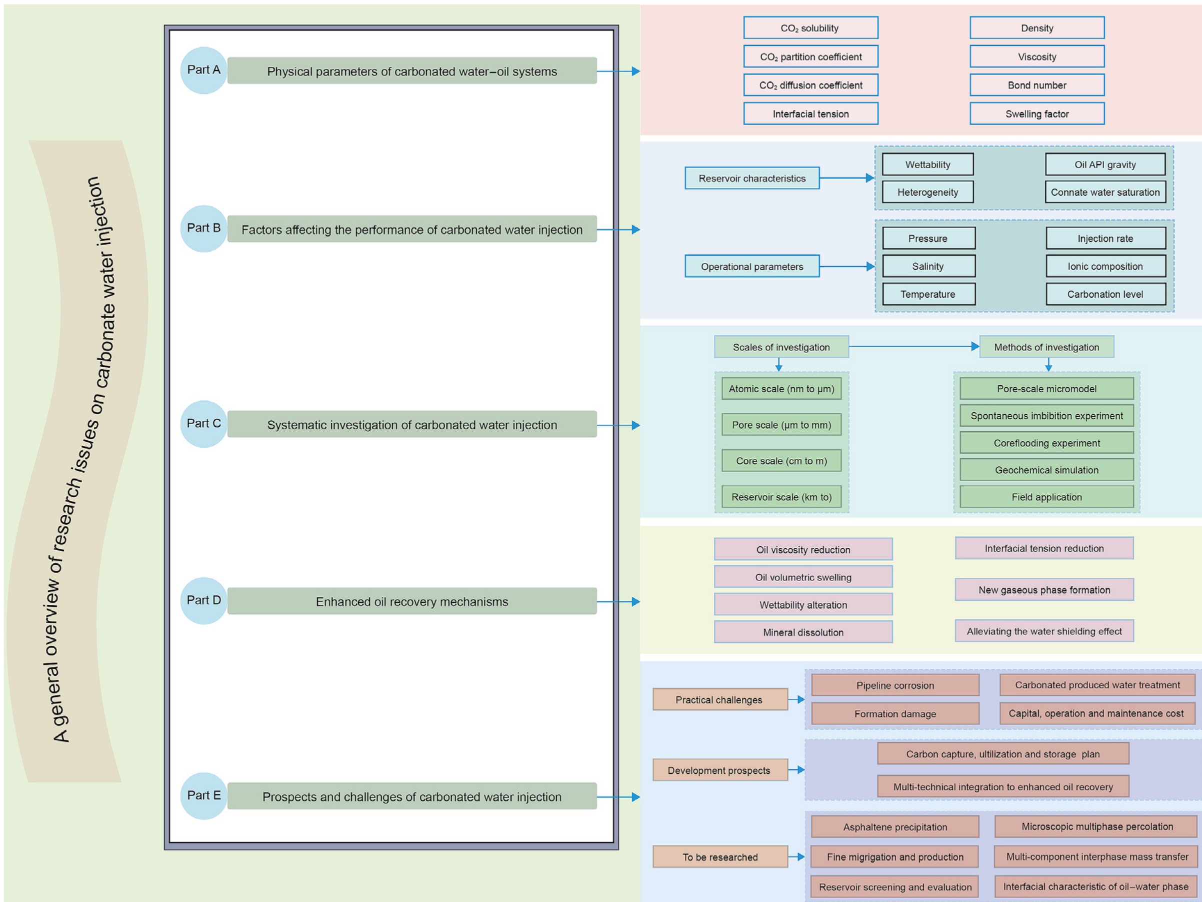

Fig. 2. A general overview of research topics on CWI.

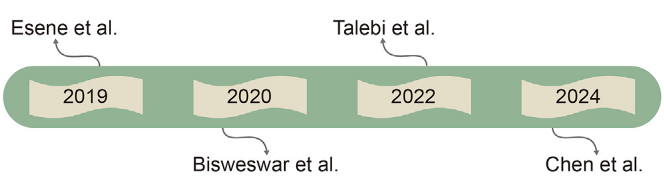

Fig. 3. A timeline of review papers on EOR using CWI technology.

water is injected into the reservoir to sustain pressure and drive out additional oil, a process known as secondary oil recovery. However, this process can be impeded by heterogeneous reservoir characteristics, leading to channeling through high-permeability zones and underutilization of certain reservoir areas. Additionally, the surface tension between oil and water contributes to the entrapment of oil within the rock matrix, hindering efficient recovery (Blunt et al., 1993). The schematic diagram of residual oil distribution following waterflooding is shown in Fig. 4.

Consequently, several classic EOR technologies have been proposed, which are categorized into gas injection methods, chemical flooding (including polymers, surfactants, nanoparticles, etc.), thermal methods, and microbial processes (Fig. 5) (Lake et al., 2014). These approaches aim to further liberate residual oil from the reservoir. The primary objective of all EOR processes is to achieve optimal results in terms of economic viability and oil recovery rates, that is, to simultaneously enhance both microscopic displacement efficiency and volumetric sweep efficiency.

Typically, an increase in the capillary number by three orders of magnitude can result in a 50% reduction in residual oil saturation. It has been posited that the residual oil saturation is inversely proportional to the capillary number, as depicted by the desaturation curve (Fig. 6). This implies that increasing the capillary number is a key objective when attempting to enhance the displacement process. The capillary number is defined as the ratio of viscous forces to capillary forces:

$$N_{\mathrm{Ca}} = \frac{F_{\mathrm{v}}}{F_{\mathrm{c}}} = \frac{\mu u}{\gamma \cos\theta} \tag{1}$$

where N_{Ca} is the capillary number; μ and u are the viscosity and velocity of the injected fluid, respectively; γ is the interfacial tension (IFT); and θ is the contact angle.

The mobility ratio (M) is defined as the ratio of the mobility of the displacing fluid to the mobility of the displaced fluid:

$$M = \frac{\lambda_{\mathrm{w}}}{\lambda_{\mathrm{o}}} = \frac{k_{\mathrm{rw}}/\mu_{\mathrm{o}}}{k_{\mathrm{ro}}/\mu_{\mathrm{w}}} = \frac{k_{\mathrm{rw}}\mu_{\mathrm{o}}}{k_{\mathrm{ro}}\mu_{\mathrm{w}}} \tag{2}$$

where k_{rw} and k_{ro} denote the relative permeability of water and oil, respectively; λ_{o} and λ_{w} are the mobility of oil and water, respectively; μ_{o} and μ_{w} refer to oil and water viscosity, respectively. The effect of M on fluid displacement is illustrated in Fig. 7.

2.1.1. Mechanisms of enhanced oil recovery by CWI

The interaction between CW, oil, and rock is a critical issue in studying the mechanisms and feasibility of CWI application, which serves as the foundation for effectively extracting hydrocarbons

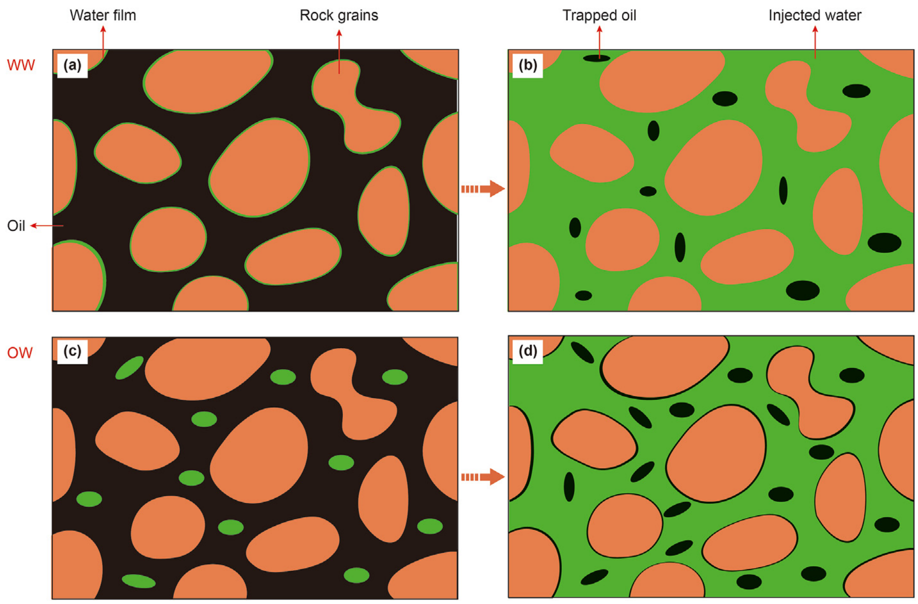

Fig. 4. Trapped oil droplets due to capillary effect after WF at different initial reservoir condition.

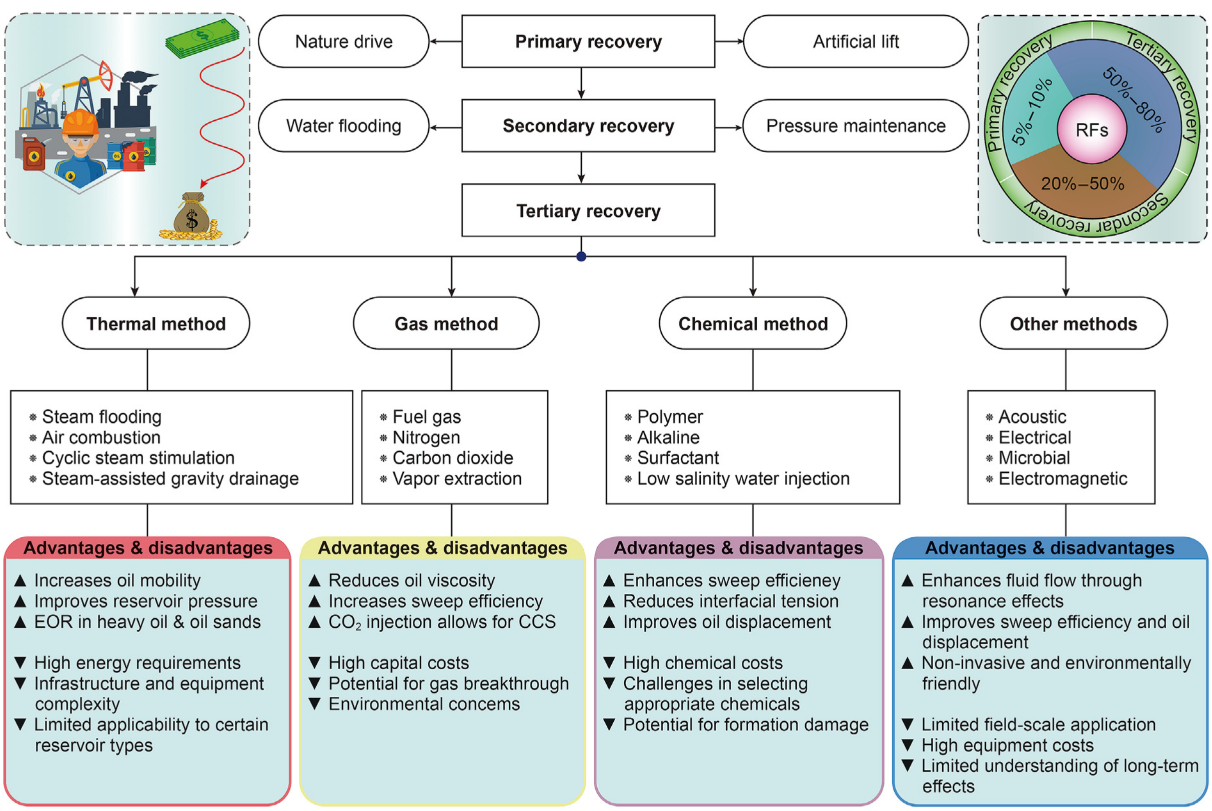

Fig. 5. EOR methods, advantages, and disadvantages.

from reservoirs. Fig. 8 illustrates a schematic of the multiscale investigation approach used for CWI.

2.1.2. Oil swelling and viscosity reduction

The volumetric expansion of oil is influenced by the CO_2 dissolution, dispersion, and diffusion (Shu et al., 2017). This expansion allows isolated oil droplets to reconnect, overcoming the water shielding effect. The formula for calculating the swelling factor (SF) is as follows:

$$SF = \frac{V_f - V_i}{V_i} \times 100\% \tag{3}$$

where V_i and V_f are the initial and final volumes of the oil drop, respectively.

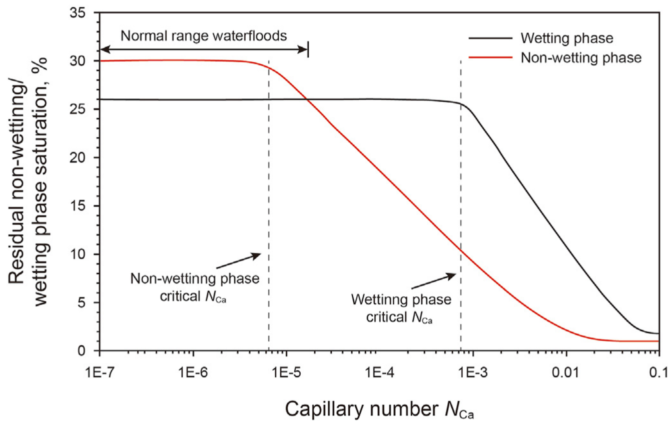

Fig. 6. Schematic capillary desaturation curve for wetting and non-wetting phases (modified after Lake, 1989).

The effect of temperature, pressure, and ion type on the dynamic swelling behavior of crude oil was investigated. A critical crossover pressure was observed (Fig. 9), where the swelling factor decreases with increasing temperature at low pressures, while the opposite is true at high pressures. This phenomenon suggests that CO_2 solubility in the aqueous phase controls the initial region, while the mobility of CO_2 molecules and the disruption of hydrogen bonding between water molecules dominate the latter region. In addition, it was found that the presence of monovalent cations (i.e., Na^+ and K^+) increases the cross-pressure, while divalent cations (i.e., Ca^{2+} and Mg^{2+}) tend to decrease the crossover pressure (Lashkarbolooki et al., 2019). Researchers have consistently reported that oil swelling is dependent on parameters that affect CO_2 dissolution, with pressure and salinity considered to be the main factors affecting the extent of oil swelling (Nowrouzi et al., 2020). Furthermore, some investigators have explored the influence of oil type on this process. Oil expansion (for viscous oils) and viscosity reduction (for heavy oils) represent distinct mechanisms through which oil production can be improved (Mosavat et al., 2020). Compared to dead oil, live oil is larger at equilibrium due to higher CO_2 solubility (Golkari and Riazi, 2018). A summary of relevant studies is provided in Table 1.

2.1.3. New gaseous phase formation

Extensive pore-scale observations (Seyyedi et al., 2017a, 2017b; Seyyedi and Sohrabi, 2017) have consistently demonstrated the significant role of new gaseous phase formation and growth in CWI under live oil conditions. The enhancement of oil recovery rates can be attributed to three primary mechanisms: (I) the reconnection and redistribution of trapped oil clusters, (II) the creation of favorable three-phase flow regimes, and (III) the restriction of CW flow pathways, steering them towards un-swept areas (Fig. 10).

A study conducted by Seyyedi et al. (2019) investigated the effect of two key parameters—associated gas concentration and oil composition—on the generation and growth of the new gas phase. The results of the study showed that the concentration of dissolved gas had a direct effect on the saturation and growth rate of the new gaseous phase. In addition, it was found that the presence of heavy hydrocarbon components initiates the formation of the new gaseous phase, while light and medium hydrocarbon components promote the subsequent growth of the new gaseous phase (Seyyedi et al., 2019). Another study utilized a fluid modeling software tool to characterize the development of a new gaseous phase. The simulation results confirmed that the amount of dissolved gas affects the generation of new gaseous phase. Furthermore, the new gaseous phase exhibits a clear tendency to enlarge the oleic phase compared to conventional oil expansion (Al Mesmari et al., 2016). It was also found that the formation of the new gaseous phase resulted in a significant increase in the differential pressure response due to the unidirectional mass transfer of CO_2 during the CWI process (Castañeda et al., 2022). Current studies of the visualization of the new gaseous phase are mainly focused on micro-scale models. It is worth noting that the precipitation of asphaltenes during the interaction of CW with crude oil has not been documented under real reservoir conditions.

2.1.4. IFT reduction

IFT is a key parameter that determines the behavior and distribution of multiphase reservoir fluids in porous media, and is critical to oil recovery and carbon sequestration strategies. Yang et al. (2005) firstly investigated the variation of IFT in the CO_2–brine–oil system under reservoir conditions by using the pendant drop method. Their results showed that the presence of CO_2 in brine is favorable to reduce the IFT. On the one hand, the

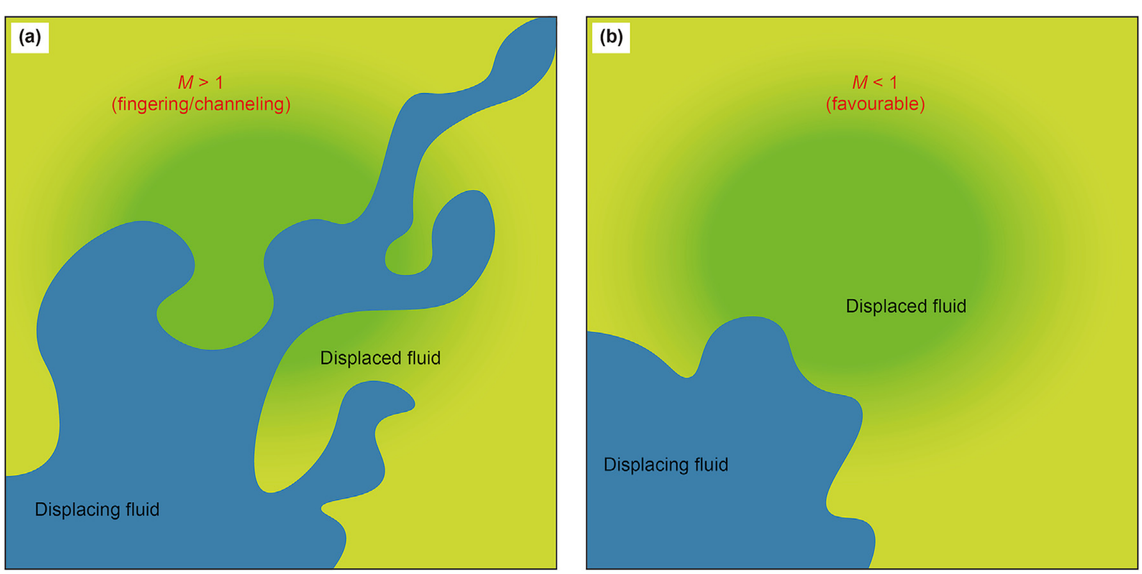

Fig. 7. (**a**) High M yields a poor areal sweep; (**b**) Piston-like displacement due to a favorable M (modified after Solling et al., 2021).

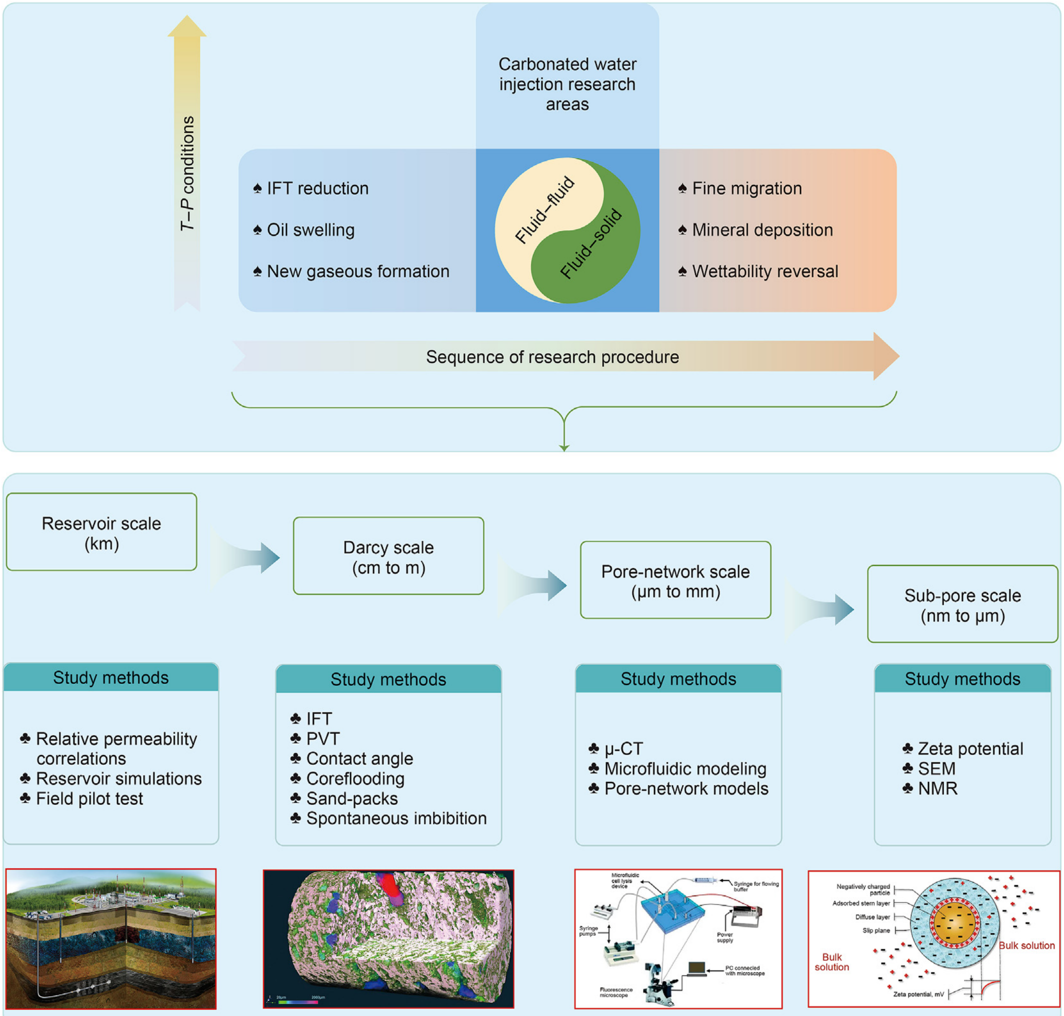

Fig. 8. Illustration of systematic investigation of CWI at different length scales.

increased solubility of CO_2 in brine and oil is responsible for the reduction of IFT values. On the other hand, the migration of CO_2 molecules towards the oil–water interface reduces the space for water molecules to move, thus weakening the hydrogen bonding in the water and leading to a decrease in the IFT value (Dreybrodt et al., 1996). Another study found that increased temperature and pressure had a favorable effect on reducing IFT (Honarvar et al., 2017). IFT is affected by the solubility of CO_2, with higher solubility resulting in lower IFT values. Another mechanism controlling IFT involves the total entropy at the interface between the two phases. When temperature affects IFT, the primary mechanism is the change in entropy rather than the solubility of CO_2. As the kinetic energy and mobility of molecules increase with increasing temperature, the total entropy at the two-phase interface increases, which decreases the free energy, leading to a decrease in IFT with increasing temperature (Riazi and Golkari, 2016).

Ionization and component activity of natural surfactants are the two main factors affecting IFT in CW–oil systems. Lashkarbolooki et al. (2017) described the potential reduction of interfacial affinity by surfactants (i.e., asphaltenes and resins). Furthermore, it has been observed that CO_2 diffusion not only destroys natural surfactants, but also accelerates/slows down their orientation and accumulation at the interface (Lashkarbolooki et al., 2018a), as shown in Fig. 11.

In a recent study, Rahimi et al. (2020) investigated the effects of CO_2 and salinity on dynamic IFT at 80 °C and 6.89 MPa. The presence of CO_2 was reported to reduce the IFT of FB, SW, NaCl and $CaCl_2$ solutions by 48.6%, 34.6%, 24.4%, and 19.9%, respectively. The results showed that the IFT decreased as the salinity of the solutions decreased. The proposed mechanism is the migration of organic matter into the aqueous phase, thus increasing the boiling point of water and the solubility of CO_2 in the aqueous phase. Fig. 12 depicts the dynamic IFT versus time for oil–CB solutions. In addition, pH may have an antagonistic/synergistic effect on the IFT values of binary solutions such as acidic or non-acidic crude oils (Zaker et al., 2021). The studies are summarized in Table 2.

2.1.5. *Wettability alteration*

Wettability is the affinity of a fluid to spread on a solid surface against another fluid (Yang and Zhou, 2020). Oil and gas reservoirs are classified as water-wet, oil-wet, or mixed-wet (Christensen and Tanino, 2017).

The fluid–solid phase interaction is closely related to the wettability of the solid reservoir rock surface (Bera et al., 2012). This is a key parameter in determining oil recovery efficiency. Numerous experimental and modeling studies have shown that the addition of CO_2 to water leads to wettability reversal (Lee and Lee, 2017; Alqam et al., 2019; Chen et al., 2019b). To quantify the extent to

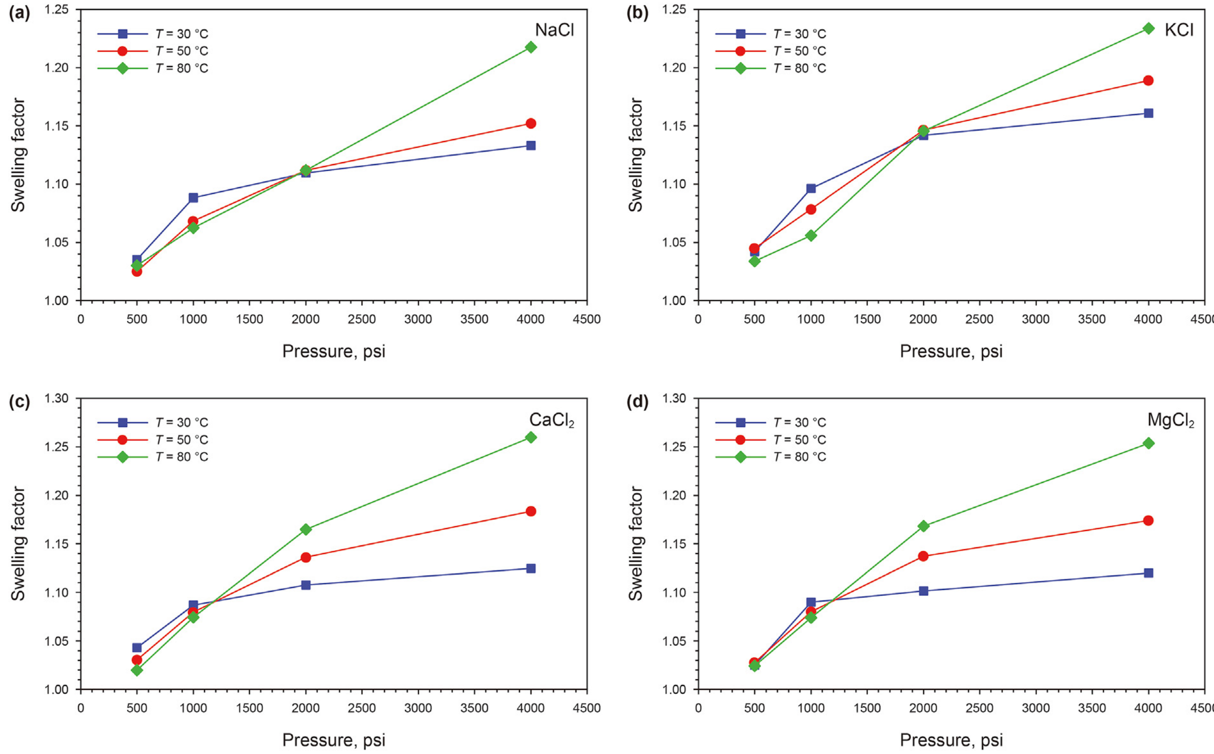

Fig. 9. Swelling factor of heavy-acidic crude oil in the presence of CB containing monovalent/divalent cation (modified after Lashkarbolooki et al., 2019).

Table 1
Summary of works related to volumetric expansion in CW-crude oil system.

Ref.	*T*, °C	*p*, MPa	Aqueous phase	Oleic phase	*SF*, %
Golkari and Riazi (2018)	40	4.83–13.79	CB (5000 ppm)	Dead oil (24.46 °API); live oil (dead oil + CH_4)	8.3–24.7
Golkari et al. (2022)	40–50	3.45–13.79	CW	Dead oil (24.46 °API)	7–23
Riazi et al. (2011b)	38	13.79	CW	*n*-decane (0.83 mPa s)	8.23–30.6
Lashkarbolooki et al. (2018b)	30–80	3.45–27.59	CW	Dead oil (21.5 °API)	3.6–30.8
Lashkarbolooki et al. (2019)	30–80	3.45–27.59	CW, CB (15,000 ppm)	Dead oil (21.5 °API)	NA
Nowrouzi et al. (2020)	40–80	3.45–10.34	CFW (74,000 ppm)	Dead oil (87 mPa s)	4–14
Mosavat et al. (2020)	25	3.45	CB (20,000 ppm)	Viscous oil (13.01 mPa s, 21.31 mPa s); heavy oil (1471 mPa s)	14.2–16.4
Samara et al. (2022)	60	8–15	CW, CB	Model oil	18.8–49.9
Seyyedi et al. (2017a, 2018)	38	17.24	CSW (54,540 ppm)	Dead oil (20.87 °API); live oil	4–20
Sohrabi et al. (2011b)	38	13.79	CW	Mineral oil (16.5 mPa s; *n*-decane (0.83 mPa s)	8.29–30.61
Bagalkot and Hamouda (2017)	25–45	1–10	CW	*n*-decane	3–21.34
Zaker et al. (2020a)	30–80	3.45–27.59	CB (15,000 ppm)	Dead oil (21.49 °API)	17–32
Zaker et al. (2020b)	30–80	3.45–27.59	CB (15,000 ppm)	Heavy-acidic crude oil (21.5 °API)	1.03–1.24

Note: NA indicates not available.

which CW changes wettability, Seyyedi et al. (2015) measured the contact angle of three different minerals (quartz, mica, and calcite) using the captured bubble method. They studied both unaged and aged rock systems with pressures ranging from 0.69 to 24.18 MPa and 38 °C, as shown in Fig. 13. The results show that the measured contact angle is directly related to the pressure (CO_2 concentration). The effect of the aged material on the change in wettability is more significant compared to the unaged substrate. In addition, the change in wettability of aged calcite is greater than that of aged mica and quartz due to dissolution of calcite and desorption of adsorbed oil layers at low-pH CW.

Geochemical modeling suggests that additional H^+ significantly displaces exchangeable cations present in muscovite, thereby attenuating electrostatic bridging between oil, brine, and muscovite (Chen et al., 2019a). Xie et al. (2017) proposed that excess H^+ from dissolved CO_2 in formation brines competes for ion adsorption, stripping the polarized ends of the connection from the pore surface in crude oil. In addition, they measured the contact angles of two oils with different acid number (AN) and base numbers (BN) (oil A: AN = 4.0 mg KOH/g and BN = 1.3 mg KOH/g; oil B: AN = 1.7 mg KOH/g and BN = 1.2 mg KOH/g) using the captured drop method in the presence of 1 M Na_2SO_4 at pH = 3 or 8. Their study showed that pH and oil content had a significant effect on the contact angle of these two oils. In addition, the CO_2-assisted EOR method adsorbs H at the interface formed by CO_2 dissolution, making the system more hydrophilic, as shown in Fig. 14. Table 3 lists the available rock/oil/CB measurement data sets.

3. Factors affecting CWI performance during EOR

Before using CWI for EOR, it is important to have a thorough understanding of the parameters that affect CWI performance. Subsequent sections will provide an in-depth look at operational factors that are critical to CWI efficiency, including temperature,

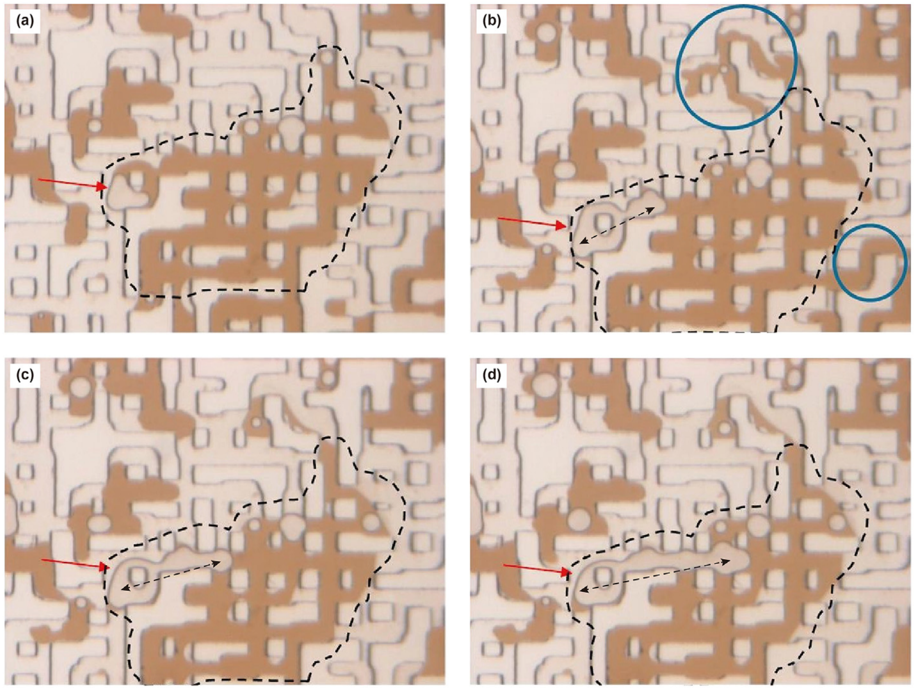

Fig. 10. The link between residual oil saturation and the creation of the third phase. (**a**) Early stage of CWI; (**b**) Oil began to swell (blue circles) and reconnect (black arrow); (**c**) Oil saturation became similar to the original residual oil; (**d**) Further growth of the third phase within the original oil (modified after Mahzari et al., 2018).

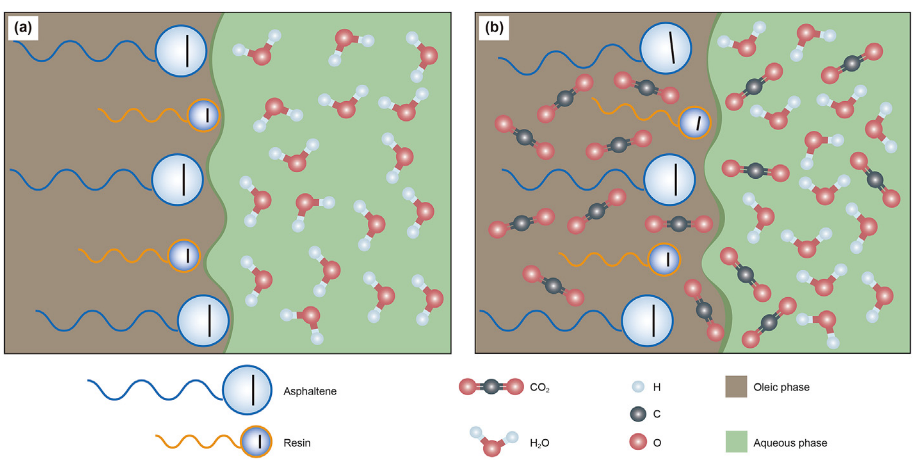

Fig. 11. The effect of CO_2 on IFT of CW/oil system.

pressure, injection rate, and solution chemistry (salinity and ionic composition).

3.1. Temperature

Current research on the effect of temperature on CWI performance is limited, and as a result, a comprehensive reservoir-specific database has not yet been developed. In Mosavat and Torabi's study (Mosavat and Torabi, 2014a, 2014b), sand-pack flooding experiments were conducted at two different temperatures, 25 and 40 °C, at a constant pressure of 4.1 MPa. Based on the results of recovery factor (RF) results, it was found that the RF of secondary carbonated water injection (SCWI) was 68.8% at 25 °C, which decreased by 1.8% with increased temperature. The RF of tertiary carbonated water injection (TCWI) was 66.5% at 40 °C. This reduction is attributed to the fact that the solubility of CO_2 decreases with increasing temperature at constant pressure, i.e., from 0.9775 mol/kg (25 °C) to 0.7303 mol/kg (40 °C), resulting in a relatively lower transfer of CO_2 to the oleic phase. In another study, Esene et al. (2020) modeled CWI using the COMSOL® simulator with a cylindrical porous medium and performed a parameter sensitivity analysis in order to investigate the effect of temperature on the performance of CWI. As shown in Fig. 15, SCWI exhibits the highest RF at 38 °C compared to other higher temperatures. Considering that the solubility of CO_2 in water decreases with increasing temperature, the performance of CWI in high temperature reservoirs will be significantly lower than in typical reservoirs.

3.2. Pressure

Pressure has a significant impact on the performance of CWI, and research has focused on two main areas: operating pressure

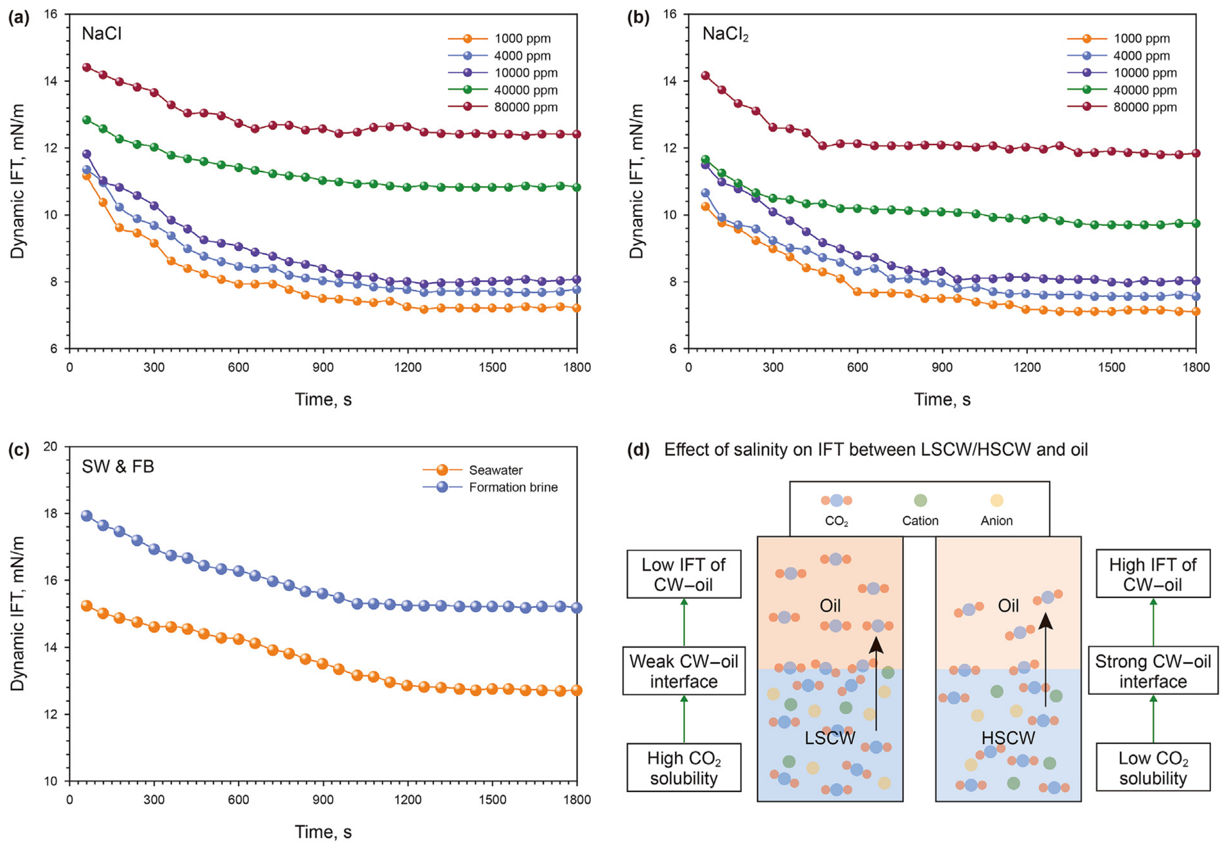

Fig. 12. Dynamic IFT of oil–CB solution versus time. (**a**) Carbonated NaCl solution; (**b**) Carbonated $CaCl_2$ solution; (**c**) CSW and CFB; (**d**) representative schematic of salinity effect (modified after Rahimi et al., 2020).

Table 2
Summary of works related to IFT in CW–crude oil system.

Ref.	*T*, °C	*p*, MPa	Aqueous phase	Oleic phase	Research topics
Honarvar et al. (2017)	40 −100	6.89 −17.24	CFB (97,645 ppm), CSW (35,079 ppm)	Crude oil (24.94 mPa s at 20 °C)	Temperature, pressure, aging time
Yang et al. (2005)	27, 58	0.23 −31.442	CFB (4270 ppm)	Crude oil (6.83 mPa s at 25 °C)	Pressure
Riazi and Golkari (2016)	40, 50	2.76 −13.79	CB (10,000 ppm)	Stock tank crude oil (24.46 °API)	Pressure
Golkari and Riazi (2018)	40, 50	3.45 −13.79	CB (5000 ppm)	Stock tank crude oil (24.46 °API), live oil (CH_4)	Oil type, pressure,
Golkari et al. (2022)	40, 50	2.76 −13.79	CW	Asphaltenic crude oil (24.46 °API)	Temperature, pressure
Manshad et al. (2016)	35 −75	0.1 −13.79	CB (500–80,000 ppm), CW	Crude oil	Ion type, salinity, temperature, pressure
Nowrouzi et al. (2018)	75	0.1 −13.79	CB, CSW (33,194 ppm)	Crude oil	Salinity
Nowrouzi et al. (2019)	75	13.79	CB (500–80,000 ppm), CW	Crude oil (32.02 °API)	Ion type
Nowrouzi et al. (2020)	40 −80	3.45 −10.34	CFB (74,000 ppm, 10-times dilution, 20-times dilution)	Crude oil (87 mPa s at 15.5 °C)	Temperature, pressure, salinity
Lashkarbolooki et al. (2017)	30	3.44 −27.58	CW	Acidic and basic crude oil	Pressure, oil type
Lashkarbolooki et al. (2018a)	30 −80	3.45 −27.59	CW	Heavy acidic crude oil (21.5 °API), light basic crude oil (35.0 °API)	Temperature, pressure, crude oil type
Zaker et al. (2020a)	30 −80	3.45 −27.59	CB (15,000 ppm)	Heavy acidic crude oil (21.5 °API)	pH, salt, pressure, temperature
Zaker et al. (2021)	30 −80	3.45 −27.59	CB (15,000 ppm)	Dead crude oil (21 °API)	pH, salt, pressure, temperature,
Rahimi et al. (2020)	80	6.89	CB (1000–80,000 ppm), CFB (97,600 ppm), CSW (35,009 ppm)	Crude oil (31.56 °API)	Salinity, ion type, aging time
Samara et al. (2022)	60	8	CB (30,000 ppm, 100,000 ppm) CW	Model oil	Salinity
Akindipe et al. (2022)	40	8.97	CB (5000 ppm), CSW (5000 ppm)	Crude oil (34.3 °API at 15 °C)	Salinity

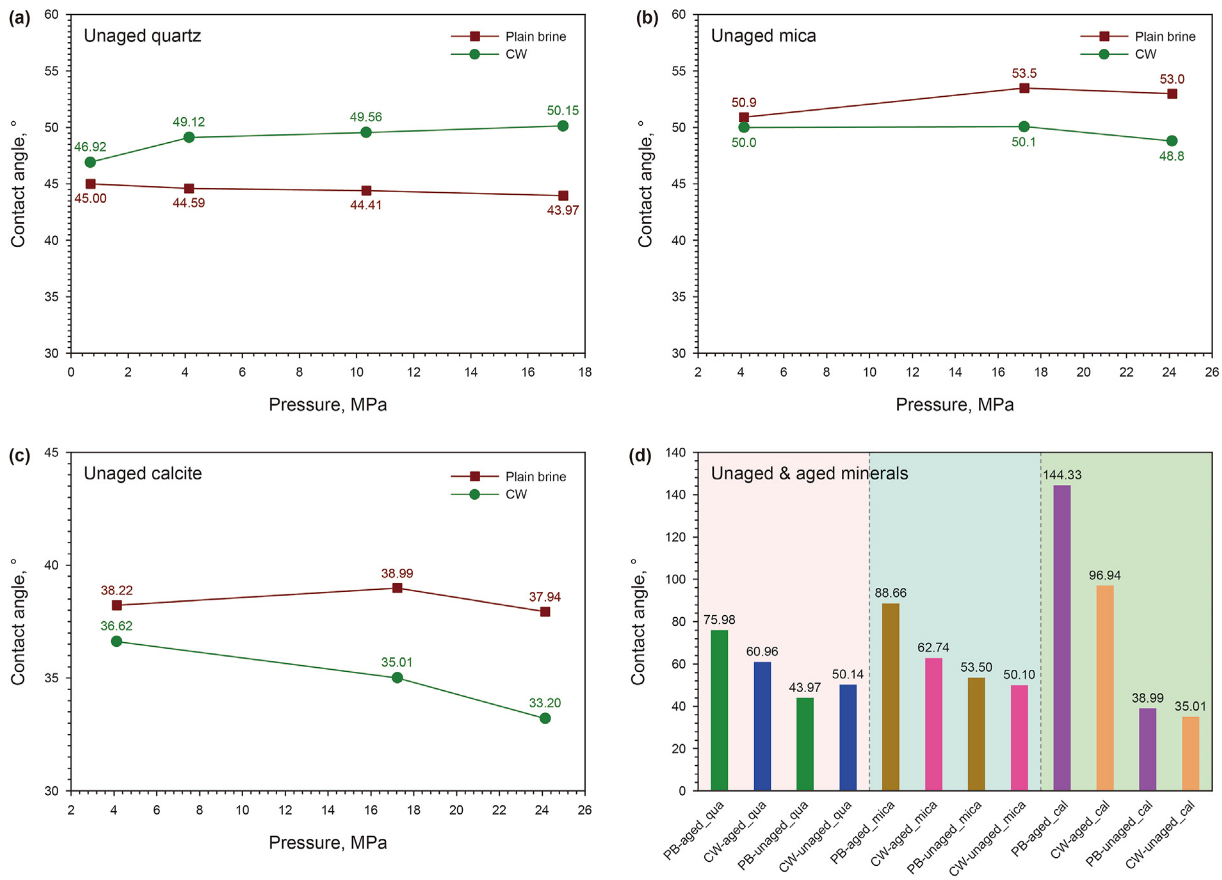

Fig. 13. Contact angle measurements on aged and unaged minerals (modified after Seyyedi et al., 2015).

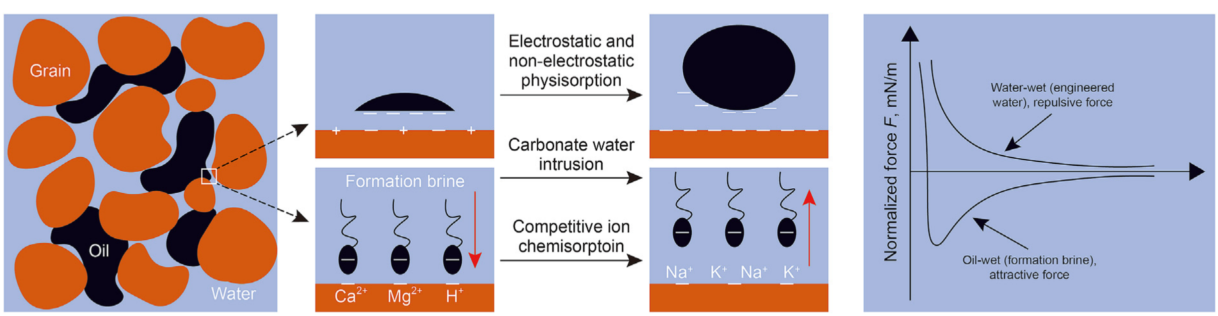

Fig. 14. Cartoon that explains the physics of CO_2-assisted EOR approaches (competitive ion chemisorption, none/electrostatic physisorption) (modified after Xie et al., 2017).

Table 3
For the CW–oil–rock system, experimental contact angles have been reported.

Ref.	Rock	Operating conditions			Method
		Temperature, °C	Pressure, MPa	Salinity, ppm	
Yang et al. (2008)	Limestone	27, 58	0.1–33	30,000	Sessile drop
Jaeger et al. (2010)	Calcite, limestone, sandstone, dolomite	50	0.1–21.2	32,000	Captive bubble
Ameri et al. (2013)	Water-wet sandstone, oil-wet sandstone	45	0.2–14	35,000	Captive bubble
Al-Mutairi et al. (2014)	Carbonate	70	7.0	20,000	Captive bubble
Seyyedi et al. (2015)	Quartz, calcite	38	0.7–17	54,597	Captive bubble

and depressurization. Mosavat and Torabi (2014b) conducted a series of sand-pack flooding experiments to measure the RFs at different operating pressures. The results of SCWI and TCWI, as shown in Fig. 16, clearly demonstrate the critical role of operating pressure in the oil recovery process of CWI. The ultimate RF of CWI increased by 14.21% and 8.03% when the pressure was increased from 1.4 to 10.3 MPa, respectively. It was also observed that the cumulative RF increased significantly at pressures up to 5.6 MPa

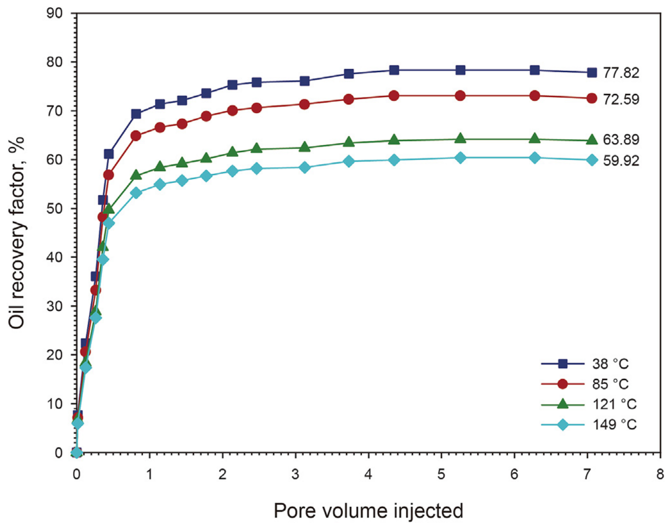

Fig. 15. Effect of temperature on RF at 20.69 MPa and 4 mL^3/min (modified after Esene et al., 2020).

and only slightly at pressures above 5.6 MPa. This is due to the fact that the solubility of CO_2 in brine increases significantly at a certain level of pressure and remains almost constant thereafter.

In a study, Perez (1992) proposed a cyclic recovery method that combines CWI with depressurization to increase oil production by utilizing the localized gas drive observed after depressurization. Another study conducted by Shakiba et al. (2020) confirms their findings, where depressurization tests increased oil recovery by 25.22%, and 18% for SCWI and TCWI tests respectively compared to 5% for original oil in place (OOIP). Subsequently, Riazi et al. (2011b) investigated the potential advantages of post-CWI pressure release for oil recovery. The results showed that the dissolution of in-situ CO_2 during depressurization led to significant fluid redistribution and additional oil production. Furthermore, Alizadeh et al. (2014) investigated the effects of CO_2 dissolution and in-situ free gas growth during CWI on oil ganglia activity in the Berea sandstone. As shown in Fig. 17, the gradual increase in pressure drop resulted in gas release from the aqueous phase, internal gas drive, oil ganglia activation, and reduced residual oil saturation. Recently, Qin et al. (2021) further found that in-situ CO_2 dissolution during TCWI significantly reduced the residual oil saturation to 21% at the end of the subsequent depressurization phase. During in-situ CO_2 dissolution, gas bubbles grew, expanded, and resided in larger pore units, which led to the coalescence of isolated oil droplets, increased the local connectivity of the oil phase, and facilitated oil flow.

3.3. Injection rate

The effect of injection rate on CWI performance is largely dependent on the contact time between the CW and the residual oil. Holm (1959) and Dong et al. (2011) explored the effect of flow rate on the performance of CWI using packaged sand cores, and showed that increasing the flow rate can improve oil recovery. However, there exists a critical injection rate that ensures optimal contact time between CWI and oil, thus promoting effective interphase mass transfer (Esene et al., 2020). In addition, due to the relatively high permeability of the porous medium, the injection rate has a negligible effect on the efficiency of CW conversion, and lowering the CW injection rate is inefficient in prolonging the contact time between CO_2 and oil. In a study, Mahdavi (2016) investigated the dispersion pattern of CW in a micromodel at two production rates (0.0008 and 0.004 mL/min). The results of the study showed that the dispersion of CW in porous media is a function of the production rate. The higher the productivity, the faster the initial displacement and the earlier the breakthrough. However, the oil sweeping effect of CW in porous media is poor and the distribution in different pore throat directions is not uniform. Finally, as shown in Fig. 18, RF reduction is less likely when the production rate is low. In order to assess the effect of injection flow rate on CWI efficiency, Ahmadi et al. (2016) conducted CWI experiments on water-wet carbonate cores using the ECLIPSE 300 (E300) compositional simulator and field-scale numerical simulations. It was observed that when the injection rate increased from 2 to 4 cm^3/h, the ultimate RF increased from 48.75% to 60%. However, at the field scale, the ultimate RF decreases from 40.6% to 25.9% when two different injection rates of 3×10^6 and 6×10^6 are used. This phenomenon explains the water-cone effect in field-scale production wells, where higher injection rates increase the number of abandoned wells in a shorter period of time, thus decreasing the ultimate RF.

3.4. Carbonation level (CL)

CW is an aqueous solution enriched with CO_2 at a specific temperature and pressure, and depending on whether or not dissolution equilibrium has been reached, which can be either undersaturated or fully saturated with CO_2. In a study, Mosavat and Torabi (2014a) reported that reducing CL from 100% to 50% resulted

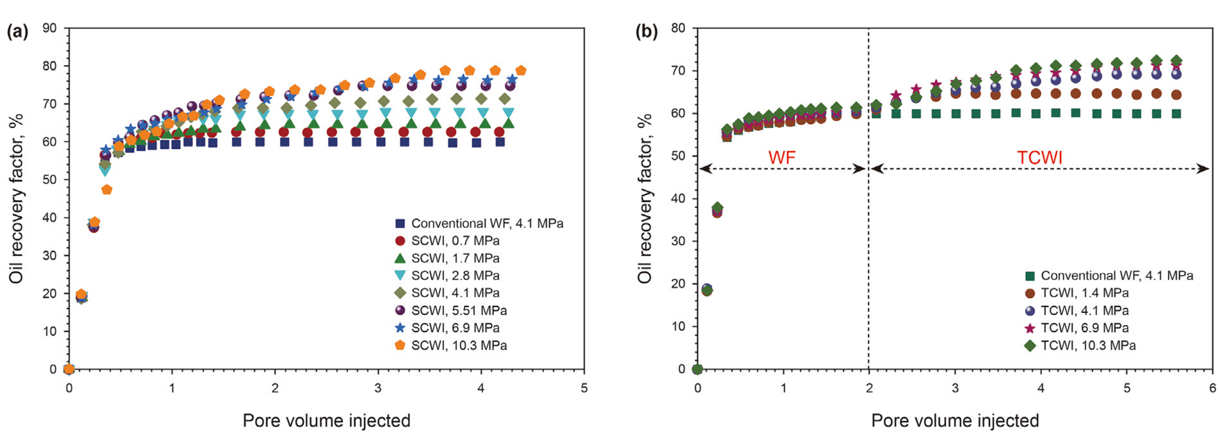

Fig. 16. Cumulative oil RFs for seven SCWI tests (**a**) and four TCWI tests (**b**) at constant temperature of 25 °C (modified after Mosavat and Torabi, 2014b).

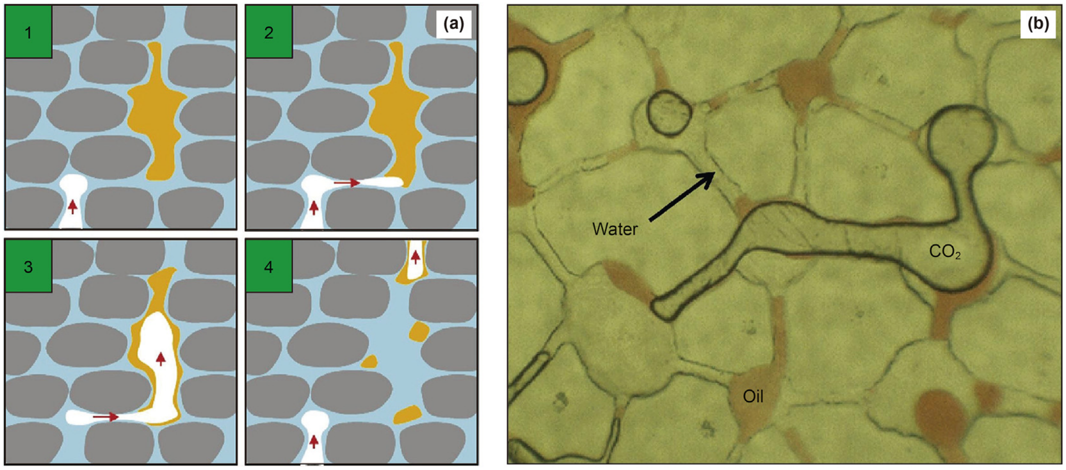

Fig. 17. (**a**) Schematic representation of three-phase ganglion dynamics. Water, oil, and gas are represented by blue, orange, and white, respectively; (**b**) An image of a displacement step taken during clear glass micromodel studies (modified after Alizadeh et al., 2014).

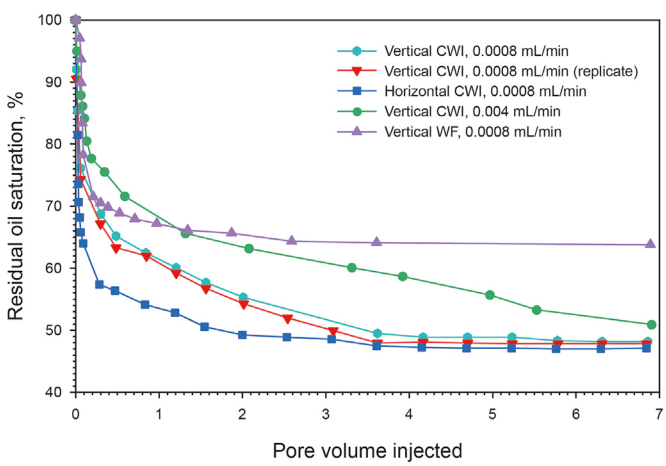

Fig. 18. ROS in different scenarios as a function of PVI (modified after Mahdavi, 2016).

in a decrease in the ultimate RF from 68.8% to 66.8% in the TCWI test, which was mainly attributed to the decrease in CO_2 delivery. In another study, Zou et al. (2019) conducted a series of core flooding experiments to examine the impact of CLs (partial and full saturation) on the performance of CWI under actual reservoir conditions (16.00 MPa, 80 °C). The results show that at full saturation, the RF is improved by 7.42% and 4.21% for SCWI and TCWI modes, respectively, compared with 50% CL, as shown in Fig. 19. The lower CL indicates that there is less dissolved CO_2 in the injected water, which leads to oil swelling and lower viscosity, which in turn makes the injection process more water-driven and reduces the ultimate RF.

3.5. Salinity and ionic composition

In recent years, optimizing the mineralization and ionic composition of injected water has emerged as a novel EOR technique, known as low salinity water injection (LSWI) (Rostami et al., 2019). Several scholars have conducted studies in conjunction with CWI. In a study, Sohrabi et al. (2012) investigated the effect of the injected CW salinity (1% and 3%) on RFs from water-wet rock cores under realistic reservoir conditions (17.24 MPa and 38 °C). They found that the RF of LSCW in SCWI was slightly higher compared to high salinity CW in TCWI. On the contrary, HSCW produced higher RF in TCWI. Nowrouzi et al. (2020) investigated the effect of LSCWI on the RF at 10.34 MPa and 80 °C. As shown in Fig. 20, which shows the results of spontaneous imbibition of CW at three different salinities. The highest RF was obtained at 20 times dilution of the initial formation brine, yielding RF of 55.68%, 62.95%, and 68.52% for the undiluted, 10 times diluted, and 20 times diluted conditions, respectively. In another study, Akindipe et al. (2022) conducted pore-scale oil displacement experiments on oil-wet carbonate rock cores under actual reservoir conditions (8.97 MPa and 40 °C) to investigate the potential mechanisms of different brine ionic compositions and salinities in the CWI process. They found that low-salinity carbonated seawater was significantly more recoverable with a substantial 79% increase in RF compared to non-carbonated brines and LSCW. Clearly, low salinity carbonate seawater is more selective. Supporting this is the hypothesis that the lower threshold pressure requirement allows the injected brine to penetrate more extensively into the oil-filled pores (especially the small and medium-sized pores), thereby displacing the oil more efficiently. This explains why carbonated low-salinity seawater performs better in all pore sizes.

4. Numerical simulation and mathematical modeling investigations of CWI

The published literature on numerical and mathematical studies of the CWI process focuses primarily on numerical simulations using commercial simulators such as compositional simulators like the E300, as well as mathematical studies through theoretical models. The black oil model and the compositional model are the two approaches used for the mathematical simulation of CWI. The black oil model characterizes a two-phase (CW and oil) system and assumes that free CO_2 is not present even if there is mass transfer from CWI to oil. The compositional model considers the case where CO_2 dissolves from solution and appears as free gas at a specific pressure reduction. Both models capture the complexity of the CWI conversion process well, although the compositional model appears to be more successful based on numerical and experimental studies (Esene et al., 2019b). Nevers (1964) developed the first 1D mathematical model for predicting CWI results in 1964, in which CO_2 inputs for both injected water and reservoir solubility in the injected water and oil as a function of CO_2 pressure at reservoir temperature. The model was based on Buckley–Leverett type linear flow and Welge's method. It was concluded that the main reason

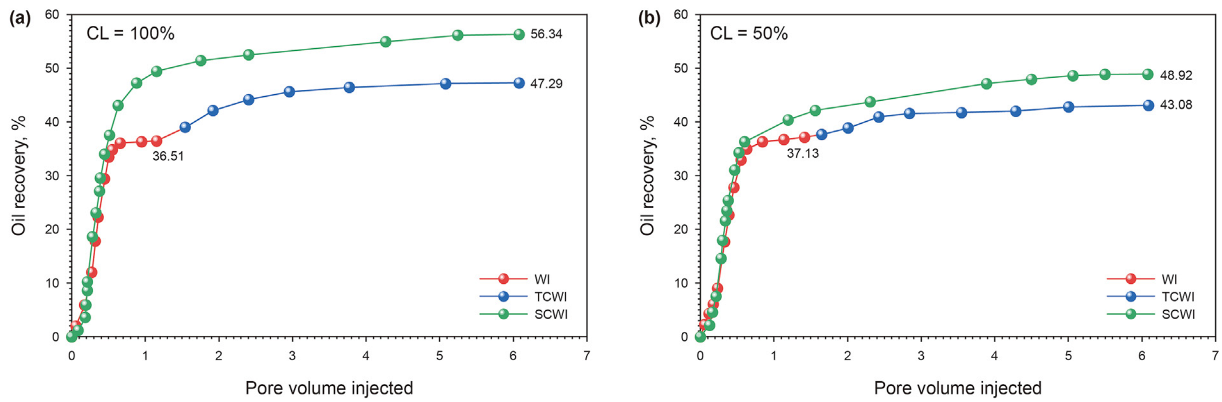

Fig. 19. RF for SCWI, WI and TCWI at different CLs (modified after Zou et al., 2019).

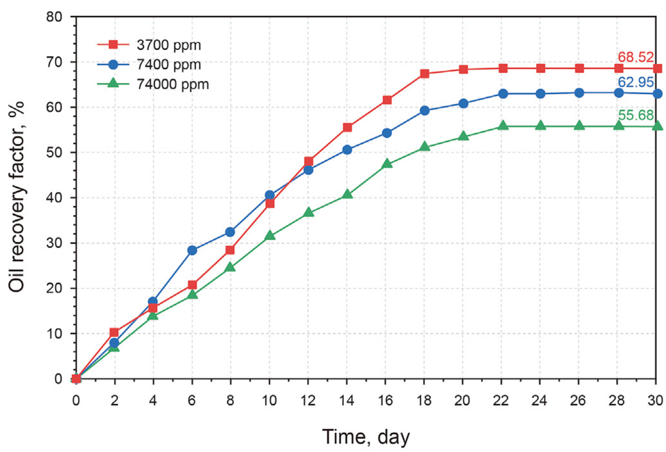

Fig. 20. Variation of RF versus time (modified after Nowrouzi et al., 2020).

for the increase in RF was the decrease in viscosity. Subsequently, Ramesh and Dixon (1973) developed a three-phase black oil mathematical model for CWI to simulate simultaneous two-dimensional flow of oil, water, and CO_2 in porous space.

In addition, Riazi et al. (2011a) recently developed a mathematical model to simulate the dynamic expansion of oil ganglia under direct (oil/water) and indirect (oil/water/CO_2 source) contact scenarios, which was solved using the finite-element method in the COMSOL® multi-physics mathematical modeling software. It was found that water has a detrimental effect on the rate of diffusion of carbon dioxide from the CO_2 source to the oil, a phenomenon known as the water blocking effect. Subsequently, Kechut et al. (2011) conducted CWI displacement tests in a one-dimensional compositional model using the commercial numerical simulator E300. The results show that the instantaneous equilibrium and complete mixing assumptions in the commercial simulators are not sufficient to accurately model the local non-equilibrium processes in CWI. The inability of the compositional simulator to account for molecular diffusion and convective mixing of CO_2 from CWI to oil resulted in a poor match between experimental and simulated recoveries.

It is worth noting that the instantaneous equilibrium assumption may lead to significant errors when the contact time of the mass transfer process is short (laboratory scale), the diffusion paths for component diffusion are large (field scale), and the high viscosity of the resident fluid results in slower diffusion rates. Therefore, Foroozesh et al. (2016) constructed a new non-equilibrium-based component mathematical model to replicate the CWI experiment, relaxing the instantaneous equilibrium assumption by incorporating a mass transfer term. Simulated CWI trials captured by the simulator indicate that equilibrium has not been achieved. In addition, a new dimensionless number called the equilibrium number was introduced (Foroozesh and Jamiolahmady, 2018) Meanwhile, Sanaei et al. (2019) integrated the compositional reservoir simulator UTCOMP with the geochemical program IPHREEQC to study the CWI process, culminating in the development of the reactive migration simulator UTCOMP-IPHREEQC. The study examined the effect of CO_2 mass transfer between the aqueous and hydrocarbon phases, constrained by thermodynamic conditions at reservoir state. It was demonstrated that the underlying mechanism of CWI is oil swelling and consequent viscosity reduction. In addition, at low pH, calcite undergoes extensive dissolution, which leads to wormhole formation rather than a change in wettability.

5. Field applications and practical issues associated with CWI projects

5.1. Pilot tests of CWI projects

Martin (1950) conducted pioneering CWI injection tests in the late 1940s aimed at increasing oil productivity. It was documented that replacing conventional waterflooding with CWI could increase recovery of residual oil saturated by 12%. Field tests of CWI applications showed increased oil production rates. From the early 1950s to the late 1970s, large sums of money were invested in CWI programs in Oklahoma and Texas in the U.S., reflecting the positive results of these operations (Christensen, 1961; Scott and Forrester, 1965). The K&S project in Oklahoma during the early 1960s marked the first commercial field application of CWI (Hickok et al., 1960), where all injection wells exhibited a significant enhancement in water injectivity and mobility ratio throughout the CWI operations (Ramsay and Small, 1964). The Slaughter Field in Hockley County, Texas, witnessed the most recent documented use of CWI, spanning from July 1985 to March 1986 (Blackford, 1987). Table 4 lists CWI's field experience with enhanced reservoir recovery, and Fig. 21 depicts CWI's program workflow.

5.2. Practical issues related to CWI

5.2.1. Corrosion, scale formation and asphaltene precipitation

A major operational challenge associated with CW leaks is extensive corrosion of facilities such as steel pipes, casing, and ground equipment. This corrosion is often exacerbated by the

Table 4
Reported field applications where CWI projects have been used in EOR (Gao, 2015).

Project name	Country	Reservoir depth, m	Reservoir permeability, mD	Reservoir porosity, %	Oil gravity, °API	Production year	Oil production rate before CWI, bbl/d	Oil production rate after CWI, bbl/d
K&S	USA	396.24	56	17.6	33	1958	30	2300
Wirt	USA	NA	44	16.0	33	1959	15	420
Post oak	USA	NA	43	17.0	35	1960	300	870
White and Baker	USA	533.4	24	21.0	31	1960	NA	NA
Dome	USA	563.88	22	14.5	32	1960	7–10	448

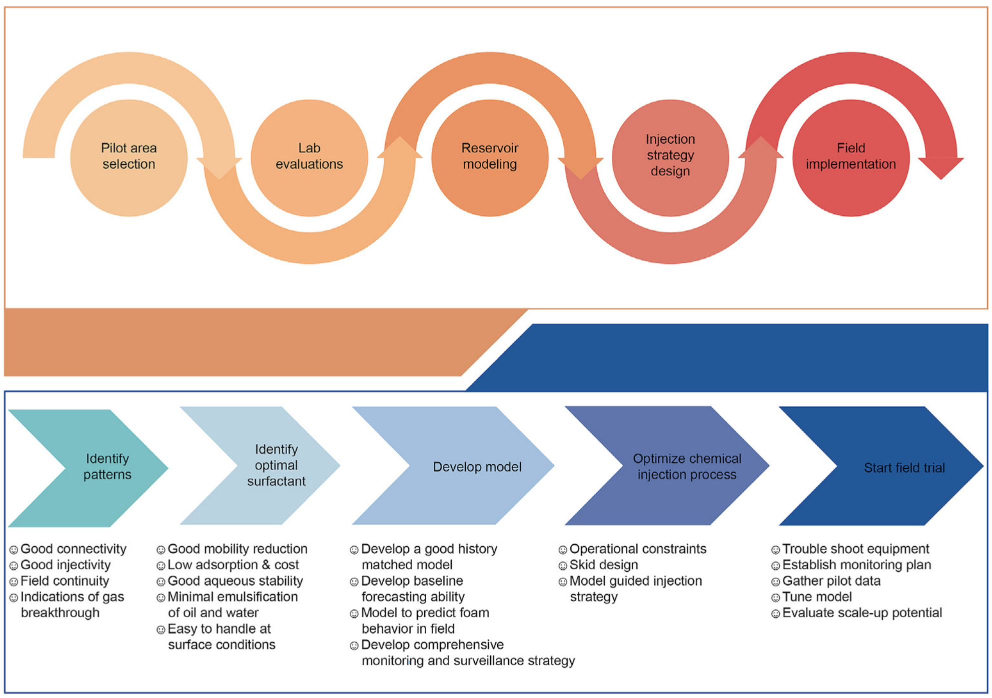

Fig. 21. Illustration of the project workflow for piloting CWI technology.

formation of carbonic acid from CO_2 dissolved in water, which contributes significantly to the corrosion of carbon steel. In addition, solid particle precipitation from the reaction of carbonate minerals with carbonic acid can lead to clogging of reservoir pores, causing infiltration problems. Therefore, corrosion-resistant materials such as stainless steel must be used to ensure safe operation.

In addition, another challenge associated with CWI in secondary and tertiary recovery operations is the potential for damage to the reservoir. High molecular weight aromatic solid deposits known as asphaltenes, which typically contain heavy metals, nitrogen, sulfur, and oxygen, are the primary cause of the formation of paraffin, asphalt, and asphaltene-like deposits in reservoirs and during oil production. Changes in the thermodynamic state of the system are the main cause of these deposits, which can lead to an increase in pore joints and pressure differentials in the reservoir. This, in turn, reduces the oil production rate and ultimate RF.

When the operating pressure during CWI is lower than the minimum miscible pressure, CO_2 can be present as a free phase, leading to an increased tendency for asphaltene deposition (Zendehboudi et al., 2014; Doryani et al., 2016). During CWI operation, asphaltene aggregation can affect oil production by plugging pores driven by compositional and temperature changes, altering reservoir wettability, and reducing formation permeability due to asphaltene particles adsorbed on rock surfaces (Fig. 22). In addition, deposition or precipitation of asphaltenes in downstream equipment can present significant operational challenges, such as plugging of flow facilities and accumulation of solids in storage tanks.

5.2.2. Carbonated produced water treatment

Produced water is a by-product of fossil fuel extraction and includes both formation water and injected water. It contains a complex mixture of dissolved and particulate organic and inorganic impurities that must be removed for proper management of this effluent. Typically, the resulting water contains organic pollutants (e.g., oil and grease, hydrocarbons, natural organics, surfactants), suspended particles, heavy metals, hardness, and dissolved solids, resulting in salinities that are much higher than those of seawater (Coha et al., 2021). Initially, large quantities of low total dissolved solids (TDS) wastewater are generated, and the TDS content of these wastewaters gradually increases, typically tens to thousands of times the agricultural irrigation limit, until the chemistry of the solution matches that of in-situ stratified brines (Zhu et al., 2022).

In addition, the oil production process generates a large amount of wastewater on a daily basis, which contains organic and inorganic constituents that can cause potentially harmful impacts on ecosystems, and this is one of the major challenges facing the energy industry. Extracted water has always been treated by gas–liquid–oil separation, sedimentation or cyclone separators,

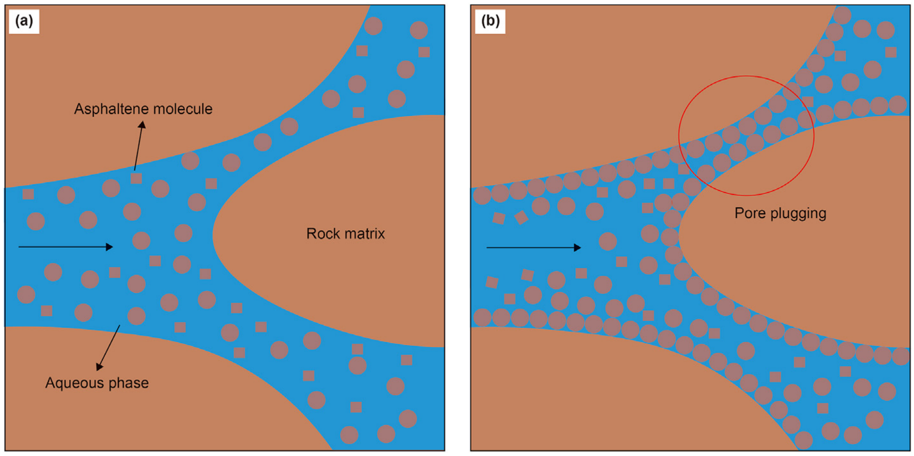

Fig. 22. Schematic image of asphaltene precipitation in an oil reservoir.

followed by coarse depth filtration, and finally discharged from offshore platforms into the ocean or re-injected into onshore soils. However, due to the high solubility of CO_2 in carbonated produced water, a suite of corrosion protection equipment and treatment technologies are required to address the potential for groundwater contamination and soil acidification if not managed properly. While reuse and dilution through discharge to large water bodies may help to mitigate this problem, proper treatment prior to disposal remains critical (Ganiyu et al., 2022).

6. Recommendations for future research directions

Based on the review, we have identified and highlighted a number of knowledge gaps and prospects for future research in the area of CWI, as detailed in the following sections.

6.1. *Enhancement of CO_2 absorption*

Essentially, the solubility of CO_2 in the aqueous phase depends on temperature, pressure and ionic strength, which in turn determines the amount of CO_2 that the CW can carry into the reservoir (Ahmadi and Chapoy, 2018). It also ensures that CO_2 is transported to the reservoir through the CW at the displacement front. Therefore, it is crucial to use CO_2 dissolution enhancers prior to injection to increase the CO_2 loading capacity in the water phase. Nanomaterials can significantly enhance CO_2 uptake compared to conventional sorbents. Therefore, there is a great potential to utilize nanomaterials to enhance the solubility of CO_2 in CW, thereby improving oil recovery and CO_2 sequestration.

In recent decades, there has been a strong interest in the unique ways in which nanomaterials enhance CO_2 uptake capacity. Several studies have shown that the addition of nanomaterials to water can significantly enhance CO_2 solubility (Sun et al., 2023; Halari et al., 2024). Brownian motion, shuttle effect mechanisms and hydrodynamic effect are the mechanisms that regulate and influence the transportation and diffusion of CO_2 within the solution, which leads to an increase in the rate of CO_2 uptake (Shayan et al., 2021). In addition to the enhancement of CO_2 uptake, various studies have shown that the use of nanoparticles for enhanced oil recovery is also effective (Olayiwola and Dejam, 2019; Davoodi et al., 2022; Liang et al., 2022). Given the promising performance of nanomaterials in enhancing CO_2 uptake and EOR, nanomaterial-enhanced CW emerges as a new type of injectant with great potential for enhanced oil recovery and CO_2 sequestration.

6.2. *Co-optimization strategy*

In recent years, there has been a surge in research on injecting CWs and combining this approach with other EOR processes. Laboratory experiments have shown that combining CW with polymers, surfactants, or a combination of the two can contribute to enhanced oil recovery (Chaturvedi et al., 2019). Polymers increase the viscosity of the aqueous phase and reduce the permeability of water due to due to mechanical retention, resulting in more favorable flow ratios. The most commonly used polymers include synthetic and partially hydrolyzed polyacrylamides, modified natural polymers, and xanthan gum (Wever et al., 2011).

Furthermore, the residual oil can be mobilized through the significant reduction in IFT caused by the injection of surfactant solutions. Surfactant molecules are typically amphiphilic organic compounds, meaning they possess two functional groups: a hydrophilic (water-loving) head and a hydrophobic (water-repelling) tail. Surfactants are categorized based on the charge of their polar head groups into anionic, cationic, nonionic, or zwitterionic (amphoteric) surfactants (Madani et al., 2019). The use of CW and surfactants as EOR additives is widespread in the petroleum industry for the addition of chemical and altered WF into reservoirs. The reduction of IFT facilitates the mobilization and recovery of trapped oil clusters and can modify flow paths by plugging pore spaces with oil-in-water (O/W) emulsions.

Additionally, LSWF has been demonstrated to be a useful method for further improving recovery rates, both in laboratory observations and field applications (Katende and Sagala, 2019). The low salinity effect is primarily attributed to rock-fluid interactions, but can also be explained by fluid-fluid interactions (Tetteh et al., 2020). In light of the impact of low salinity, the combination of CW and LSWF yields more oil than LSWF alone or CWI alone.

The enhancement of chemical-based oil recovery methods is commonly achieved by combining two or more additives, thereby harnessing their synergistic mechanisms of action within the EOR process. Consequently, there is a burgeoning interest in research aimed at improving oil recovery rates through the integration of diverse polymers and surfactants with low-salinity CWI, stimulating further inquiry and innovation among researchers in the field.

6.3. *Microfluidic visualization*

Research on pore-level phenomena and oil recovery mechanisms associated with CWI is scarce. Consequently, a comprehensive understanding of the pore-scale interactions and processes occurring during CWI in reservoirs, and the practical methods that may recover additional oil, remains elusive. To date, micromodel studies of CWI have primarily focused on aspects such as in-situ CO_2 exsolution during depressurization, gravity effects, fracture impacts, and new gaseous phase formation.

Microfluidic devices, also known as micromodels, are particularly effective laboratory apparatuses used for direct observation of fluid flow behavior and the study of oil recovery mechanisms at microscales relevant to reservoirs. These are simulated porous media made from transparent materials such as glass, polydimethylsiloxane, polymethyl methacrylate, quartz, and silicon (Karadimitriou and Hassanizadeh, 2012). As fluids propagate, several multiphase flow phenomena can be observed, revealing the pore-scale mechanisms that drive flow and transport phenomena in natural porous media. Additionally, digital image processing techniques, employing cameras with or without fluorescence microscopy, allow for the determination of key parameters such as fluid saturation, size distribution of captured oil droplets, and interfacial curvature, leading to a better understanding of the physical displacement processes at the microscale (Mahmoodi et al., 2018).

In summary, micromodels are applicable for qualitative observation, quantitative analysis, and simulation studies, which are also utilized to investigate the fundamental and critical aspects of fluid-fluid and rock-fluid interactions in porous media, such as wettability alteration, capillary pressure, interfacial phenomenon, and asphaltene deposition.

6.4. Reservoir simulation

Numerical and mathematical research on the CWI process in subsurface oil and gas reservoirs, as documented in the published literature, predominantly relies on numerical simulations utilizing commercial simulators and mathematical models (Alvarez et al., 2018). Due to the complex oil recovery mechanisms associated with CWI, capturing the physics of accurate CWI through numerical simulations and mathematical models has been a challenging endeavor. Most models are constructed with impractical and uncertain assumptions (Derakhshanfar et al., 2012), which has led to skepticism towards the existing models and a lack of confidence in their application at larger scales, such as pilot plants. Moreover, due to the intricate multi-physics involving fluid–fluid and fluid–rock interactions in the CWI process, the majority of studies have been conducted at the laboratory scale. There is a dearth of adequately comprehensive modeling studies on CWI operations in open-source platforms.

Reservoir simulation is an economical and time-efficient method for reservoir evaluation. This simulator allows for the examination of numerous EOR scenarios within the reservoir and the selection of the optimal approach. It is crucial during the simulation process that the model created by the simulator is history matched with the actual reservoir historical data before generating any predictions. Therefore, there is a need for broader CWI modeling studies to assess the performance of this EOR technique. Additionally, the development of accurate and reliable commercial reservoir simulators that can thoroughly reflect the actual physics and complex displacement mechanisms in the CWI process is warranted.

7. Summary and conclusions

This review synthesizes the latest advancements in CWI research, with the key findings summarized as follows.

(1) Multiple significant operational parameters have been investigated, including (a) operational characteristics such as pressure, temperature, injection rate, and carbonation level, and (b) ionic composition with monovalent and divalent cations, as well as salinity. Among these, pressure has a favorable impact on oil recovery rates and CWI performance. On one hand, higher operating pressures enhance the effectiveness of CW due to increased CO_2 solubility. On the other hand, gas exsolution events in depleted reservoirs provide additional energy for oil movement along gas growth pathways. However, CWI at high carbonation level does not offer significant benefits over lower carbonation level. Additionally, lower temperatures and injection rates correlate with higher recovery rates. Further optimization of solution chemistry is necessary to determine the maximum recovery rates under optimal conditions.

(2) A variety of processes, including oil swelling, viscosity modification, IFT reduction, wettability change, new gaseous phase generation, and rock wettability reversal, are considered to be involved in the application of CWI for enhancing oil recovery. Nevertheless, there is still much to learn about the interactions between different systems and how to characterize these effects experimentally.

(3) Discrepancies exist between laboratory-scale data and numerical simulation results. Moreover, fluid–reservoir rock interactions may reveal differences across multiple scales, from core to nanoscale. Therefore, understanding these interactions across various scales using a range of relevant experimental techniques is crucial. Different experimental methods may be required to characterize the impact of CW–oil–rock interactions.

(4) In general, reservoir damage, pipeline corrosion, asphaltene precipitation, and carbonated water treatment are categorized as the main practical technical challenges in most field applications of CWI. To achieve better performance benefits, a comprehensive assessment of the technical and economic viability of CWI is necessary.

(5) Accurate reservoir screening criteria, including temperature, depth, rock type, crude oil viscosity, connate water saturation, porosity, permeability, and effective thickness, need to be established as the selection criteria for CWI programs in matrix reservoirs have not yet been established.

(6) Considering the relevance of CO_2 concentration in enhancing oil recovery rate and CO_2 storage, the idea of using chemical additives and co-solvents to improve CO_2 solubility in brine should be discussed and thoroughly evaluated in future work.

(7) To optimize oil production and CO_2 sequestration in reservoirs, CWI projects can be synergized with other water-based EOR processes, such as nanoparticles, surfactants, polymers, and LSWF. However, there is a lack of research on this topic both domestically and internationally, and further studies of injection strategies are recommended.

(8) Static analysis combined with visible pore-scale measurements using microfluidic devices can help to comprehensively understand the CWI process. Additionally,

computational fluid dynamics methods offer advantages in cost and computational efficiency compared to experimental studies for numerical investigations of multiphase flow in porous media.

CRediT authorship contribution statement

Ke Chen: Writing – original draft, Conceptualization. **Jing-Ru Zhang:** Data curation. **Si-Yu Xu:** Formal analysis. **Mu-Zi Yin:** Investigation. **Yi Zhang:** Supervision, Funding acquisition. **Yue-Chao Zhao:** Funding acquisition. **Yong-Chen Song:** Writing – review & editing, Supervision.

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.

Acknowledgements

This work was supported by National Key Research and Development Program of China (Grant No. 2023YFB4104200), Liaoning Foundation Research Projects for Application (Grant No. 2023JH2/101300005), and National Natural Science Foundation of China (Grant No. 51976024, 52076030).

References

Ahmadi, M.A., Hasanvand, M.z., Behbahani, S.S., Nourmohammad, A., Vahidi, A., Amiri, M., Ahmadi, G., 2016. Effect of operational parameters on the performance of carbonated water injection: experimental and numerical modeling study. J. Supercrit. Fluids 107, 542–548. https://doi.org/10.1016/j.supflu.2015.07.012.

Ahmadi, P., Chapoy, A., 2018. CO_2 solubility in formation water under sequestration conditions. Fluid Phase Equil. 463, 80–90. https://doi.org/10.1016/j.fluid.2018.02.002.

Ahmed, A.A., Alsharif, A., Yasser, N., 2023. Recent advances in energy storage technologies. International Journal of Electrical Engineering and Sustainability 9–17.

Akindipe, D., Saraji, S., Piri, M., 2022. Carbonated water injection in oil-wet carbonate rock samples: a pore-scale experimental investigation of the effect of brine composition. Energy Fuels 36 (9), 4847–4870. https://doi.org/10.1021/acs.energyfuels.2c00326.

Al-Mutairi, S.M., Abu-Khamsin, S.A., Okasha, T.M., Aramco, S., Hossain, M.E., 2014. An experimental investigation of wettability alteration during CO_2 immiscible flooding. J. Petrol. Sci. Eng. 120, 73–77. https://doi.org/10.1016/j.petrol.2014.05.008.

Al Mesmari, A., Mahzari, P., Sohrabi, M., 2016. An improved methodology for simulating oil recovery by carbonated water injection: impact of compositional changes. In: SPE Annual Technical Conference and Exhibition. https://doi.org/10.2118/181630-MS.

Alizadeh, A.H., Khishvand, M., Ioannidis, M.A., Piri, M., 2014. Multi-scale experimental study of carbonated water injection: an effective process for mobilization and recovery of trapped oil. Fuel 132, 219–235. https://doi.org/10.1016/j.fuel.2014.04.080.

Alqam, M.H., Abu-Khamsin, S.A., Sultan, A.S., Okasha, T.M., Yildiz, H.O., 2019. Effect of rock mineralogy and oil composition on wettability alteration and interfacial tension by brine and carbonated water. Energy Fuels 33 (3), 1983–1989. https://doi.org/10.1021/acs.energyfuels.8b04143.

Alvarez, A.C., Blom, T., Lambert, W.J., Bruining, J., Marchesin, D., 2018. Analytical and numerical validation of a model for flooding by saline carbonated water. J. Petrol. Sci. Eng. 167, 900–917. https://doi.org/10.1016/j.petrol.2017.09.012.

Ameri, A., Kaveh, N.S., Rudolph, E.S.J., Wolf, K., Farajzadeh, R., Bruining, J., 2013. Investigation on Interfacial Interactions among crude oil–brine–sandstone rock–CO_2 by contact angle measurements. Energy Fuels 27 (2), 1015–1025. https://doi.org/10.1021/ef3017915.

An, S., Erfani, H., Hellevang, H., Niasar, V., 2021. Lattice-Boltzmann simulation of dissolution of carbonate rock during CO_2-saturated brine injection. Chem. Eng. J. 408, 127235. https://doi.org/10.1016/j.cej.2020.127235.

Bagalkot, N., Hamouda, A.A., 2017. Experimental and numerical method for estimating diffusion coefficient of the carbon dioxide into light components. Ind. Eng. Chem. Res. 56 (9), 2359–2374. https://doi.org/10.1021/acs.iecr.6b04318.

Bera, A., S, K., Ojha, K., Kumar, T., Mandal, A., 2012. Mechanistic study of wettability alteration of quartz surface induced by nonionic surfactants and interaction between crude oil and quartz in the presence of sodium chloride salt. Energy Fuels 26 (6), 3634–3643. https://doi.org/10.1021/ef300472k.

Bergmo, P.E.S., Holt, T., 2024. CO_2 capture from offshore oil installations: an evaluation of alternative methods for deposition with emphasis on carbonated water injection. Carbon Capture Science & Technology 11, 100184. https://doi.org/10.1016/j.ccst.2023.100184.

Bisweswar, G., Al-Hamairi, A., Jin, S., 2020. Carbonated water injection: an efficient EOR approach. A review of fundamentals and prospects. J. Pet. Explor. Prod. Technol. 10 (2), 673–685. https://doi.org/10.1007/s13202-019-0738-2.

Blackford, T.A., 1987. Carbonated waterflood implementation and its impact on material performance in a pilot project. In: SPE Annual Technical Conference and Exhibition. https://doi.org/10.2118/16831-MS.

Blunt, M., Fayers, F., Orr, F.M., 1993. Carbon dioxide in enhanced oil recovery. Energy Convers. Manag. 34 (9–11), 1197–1204. https://doi.org/10.1016/0196-8904(93)90069-M.

Castañeda, J.O., Alhashboul, A., Farzaneh, A., Sohrabi, M., 2022. A novel insight into the effect on the differential pressure of the formation of the new gas phase in carbonated water injection and its comparison with conventional CO_2 injection. In: International Petroleum Technology Conference. https://doi.org/10.2523/IPTC-22516-MS.

Chaturvedi, K.R., Trivedi, J., Sharma, T., 2019. Evaluation of polymer-assisted carbonated water injection in sandstone reservoir: absorption kinetics, rheology, and oil recovery results. Energy Fuels 33 (6), 5438–5451. https://doi.org/10.1021/acs.energyfuels.9b00894.

Chen, Y., Sari, A., Xie, Q., Saeedi, A., 2019a. Excess H^+ increases hydrophilicity during CO_2-assisted enhanced oil recovery in sandstone reservoirs. Energy Fuels 33 (2), 814–821. https://doi.org/10.1021/acs.energyfuels.8b03573.

Chen, Y., Sari, A., Xie, Q., Saeedi, A., 2019b. Insights into the wettability alteration of CO_2-assisted EOR in carbonate reservoirs. J. Mol. Liq. 279, 420–426. https://doi.org/10.1016/j.molliq.2019.01.112.

Christensen, R.J., 1961. Carbonated waterflood results - Texas and Oklahoma. In: Annual Meeting of Rocky Mountain Petroleum Engineers of AIME. https://doi.org/10.2118/66-MS.

Christensen, M., Tanino, Y., 2017. Waterflood oil recovery from mixed-wet limestone: dependence upon the contact angle. Energy Fuels 31 (2), 1529–1535. https://doi.org/10.1021/acs.energyfuels.6b03249.

Coha, M., Farinelli, G., Tiraferri, A., Minella, M., Vione, D., 2021. Advanced oxidation processes in the removal of organic substances from produced water: potential, configurations, and research needs. Chem. Eng. J. 414, 128668. https://doi.org/10.1016/j.cej.2021.128668.

Dastjerdi, A.M., Kharrat, R., Niasar, V., Ott, H., 2024. Salinity-driven structural and viscosity modulation of confined polar oil phases by carbonated brine films: novel insights from molecular dynamics. J. Phys. Chem. B 128 (7), 1780–1795. https://doi.org/10.1021/acs.jpcb.3c07300.

Davoodi, S., Al-Shargabi, M., Wood, D.A., Rukavishnikov, V.S., Minaev, K.M., 2022. Experimental and field applications of nanotechnology for enhanced oil recovery purposes: a review. Fuel 324, 124669. https://doi.org/10.1016/j.fuel.2022.124669.

Derakhshanfar, M., Nasehi, M., Asghari, K., 2012. Simulation study of CO_2-assisted waterflooding for enhanced heavy oil recovery and geological storage. In: Carbon Management Technology Conference. https://doi.org/10.7122/151183-MS.

Dong, Y., Dindoruk, B., Ishizawa, C., Lewis, E., Kubicek, T., 2011. An experimental investigation of carbonated water flooding. In: SPE Annual Technical Conference and Exhibition. https://doi.org/10.2118/145380-MS.

Doryani, H., Malayeri, M.R., Riazi, M., 2016. Visualization of asphaltene precipitation and deposition in a uniformly patterned glass micromodel. Fuel 182, 613–622. https://doi.org/10.1016/j.fuel.2016.06.004.

Dreybrodt, W., Lauckner, J., Zaihua, L., Svensson, U., Buhmann, D., 1996. The kinetics of the reaction $CO_2 + H_2O \rightarrow H^+ + HCO_3^-$ as one of the rate limiting steps for the dissolution of calcite in the system H_2O-CO_2-$CaCO_3$. Geochem. Cosmochim. Acta 60 (18), 3375–3381. https://doi.org/10.1016/0016-7037(96)00181-0.

Esene, C., Rezaei, N., Aborig, A., Zendehboudi, S., 2019a. Comprehensive review of carbonated water injection for enhanced oil recovery. Fuel 237, 1086–1107. https://doi.org/10.1016/j.fuel.2018.08.106.

Esene, C., Zendehboudi, S., Aborig, A., Shiri, H., 2019b. A modeling strategy to investigate carbonated water injection for EOR and CO_2 sequestration. Fuel 252, 710–721. https://doi.org/10.1016/j.fuel.2019.04.058.

Esene, C., Zendehboudi, S., Shiri, H., Aborig, A., 2020. Systematic sensitivity analysis to investigate performance of carbonated water injection based on computational dynamic modeling. Fuel 274, 117318. https://doi.org/10.1016/j.fuel.2020.117318.

Foroozesh, J., Jamiolahmady, M., 2018. The physics of CO_2 transfer during carbonated water injection into oil reservoirs: from non-equilibrium core-scale physics to field-scale implication. J. Petrol. Sci. Eng. 166, 798–805. https://doi.org/10.1016/j.petrol.2018.03.089.

Foroozesh, J., Jamiolahmady, M., Sohrabi, M., 2016. Mathematical modeling of carbonated water injection for EOR and CO_2 storage with a focus on mass transfer kinetics. Fuel 174, 325–332. https://doi.org/10.1016/j.fuel.2016.02.009.

Ganiyu, S.O., Sable, S., Gamal El-Din, M., 2022. Advanced oxidation processes for the degradation of dissolved organics in produced water: a review of process performance, degradation kinetics and pathway. Chem. Eng. J. 429, 132492. https://doi.org/10.1016/j.cej.2021.132492.

Gao, C.H., 2015. Carbonated water injection revisited. International Journal of Petroleum Engineering 1 (3), 164. https://doi.org/10.1504/IJPE.2015.071058.

Golkari, A., Riazi, M., 2018. Comparative study of oil spreading characteristics for water and carbonated water systems using live and dead oils. J. Petrol. Sci. Eng. 171, 242–252. https://doi.org/10.1016/j.petrol.2018.07.034.
Golkari, A., Riazi, M., Cortés, F.B., Franco, C.A., 2022. Experimental investigation of interfacial tension and oil swelling for asphaltenic crude oil/carbonated water system. Egyptian Journal of Petroleum 31 (2), 51–58. https://doi.org/10.1016/j.ejpe.2022.04.001.
Halari, D., Yadav, S., Kesarwani, H., Saxena, A., Sharma, S., 2024. Nanoparticle and surfactant stabilized carbonated water induced in-situ CO_2 foam: an improved oil recovery approach. Energy Fuels 38 (5), 3622–3634. https://doi.org/10.1021/acs.energyfuels.3c04232.
Hasanvand, M.Z., Ahmadi, M.A., Shadizadeh, S.R., Behbahani, R., Feyzi, F., 2013. Geological storage of carbon dioxide by injection of carbonated water in an Iranian oil reservoir: a case study. J. Petrol. Sci. Eng. 111, 170–177. https://doi.org/10.1016/j.petrol.2013.09.008.
Hickok, C.W., Christensen, R.J., Ramsay, H.J., 1960. Progress review of the K&S carbonated waterflood project. J. Petrol. Technol. 12 (12), 20–24. https://doi.org/10.2118/1474-G.
Holm, L.W., 1959. Carbon dioxide solvent flooding for increased oil recovery. Transactions of the AIME 216 (1), 225–231. https://doi.org/10.2118/1250-G.
Honarvar, B., Azdarpour, A., Karimi, M., Rahimi, A., Afkhami Karaei, M., Hamidi, H., Ing, J., Mohammadian, E., 2017. Experimental investigation of interfacial tension measurement and oil recovery by carbonated water injection: a case study using core samples from an Iranian carbonate oil reservoir. Energy Fuels 31 (3), 2740–2748. https://doi.org/10.1021/acs.energyfuels.6b03365.
Jaeger, P.T., Alotaibi, M.B., Nasr-El-Din, H.A., 2010. Influence of compressed carbon dioxide on the capillarity of the gas–crude oil–reservoir water system. J. Chem. Eng. Data 55 (11), 5246–5251. https://doi.org/10.1021/je100825b.
Ji, M., Kwon, S., Choi, S., Kim, M., Choi, B., Min, B., 2023. Numerical investigation of CO_2-carbonated water-alternating-gas on enhanced oil recovery and geological carbon storage. J. CO_2 Util. 74, 102544. https://doi.org/10.1016/j.jcou.2023.102544.
Karadimitriou, N.K., Hassanizadeh, S.M., 2012. A review of micromodels and their use in two-phase flow studies. Vadose Zone J. 11 (3). https://doi.org/10.2136/vzj2011.0072 vzj2011.0072.
Katende, A., Sagala, F., 2019. A critical review of low salinity water flooding: mechanism, laboratory and field application. J. Mol. Liq. 278, 627–649. https://doi.org/10.1016/j.molliq.2019.01.037.
Kechut, N.I., Jamiolahmady, M., Sohrabi, M., 2011. Numerical simulation of experimental carbonated water injection (CWI) for improved oil recovery and CO_2 storage. J. Petrol. Sci. Eng. 77 (1), 111–120. https://doi.org/10.1016/j.petrol.2011.02.012.
Kumar, N., Augusto Sampaio, M., Ojha, K., Hoteit, H., Mandal, A., 2022. Fundamental aspects, mechanisms and emerging possibilities of CO_2 miscible flooding in enhanced oil recovery: a review. Fuel 330, 125633. https://doi.org/10.1016/j.fuel.2022.125633.
Lake, L.W., 1989. Enhanced Oil Recovery.
Lake, L.W., Johns, R., Rossen, B., Pope, G.A., 2014. Fundamentals of Enhanced Oil Recovery. Society of Petroleum Engineers, Richardson, TX.
Lashkarbolooki, M., Riazi, M., Ayatollahi, S., 2017. Effect of CO_2 and natural surfactant of crude oil on the dynamic interfacial tensions during carbonated water flooding: experimental and modeling investigation. J. Petrol. Sci. Eng. 159, 58–67. https://doi.org/10.1016/j.petrol.2017.09.023.
Lashkarbolooki, M., Riazi, M., Ayatollahi, S., 2018a. Effect of CO_2 and crude oil type on the dynamic interfacial tension of crude oil/carbonated water at different operational conditions. J. Petrol. Sci. Eng. 170, 576–581. https://doi.org/10.1016/j.petrol.2018.07.002.
Lashkarbolooki, M., Riazi, M., Ayatollahi, S., 2018b. Experimental investigation of dynamic swelling and Bond number of crude oil during carbonated water flooding: Effect of temperature and pressure. Fuel 214, 135–143. https://doi.org/10.1016/j.fuel.2017.11.003.
Lashkarbolooki, M., Hezave, A.Z., Ayatollahi, S., 2019. Swelling behavior of heavy crude oil during injection of carbonated brine containing chloride anion. J. Mol. Liq. 276, 7–14. https://doi.org/10.1016/j.molliq.2018.11.112.
Lee, J.H., Lee, K.S., 2017. Enhanced wettability modification and CO_2 solubility effect by carbonated low salinity water injection in carbonate reservoirs. J. Chem. 2017, 1–10. https://doi.org/10.1155/2017/8142032.
Liang, T., Hou, J.-R., Qu, M., Xi, J.-X., Raj, I., 2022. Application of nanomaterial for enhanced oil recovery. Petrol. Sci. 19 (2), 882–899. https://doi.org/10.1016/j.petsci.2021.11.011.
Madani, M., Zargar, G., Takassi, M.A., Daryasafar, A., Wood, D.A., Zhang, Z., 2019. Fundamental investigation of an environmentally-friendly surfactant agent for chemical enhanced oil recovery. Fuel 238, 186–197. https://doi.org/10.1016/j.fuel.2018.10.105.
Mahdavi, S., 2016. Pore scale investigation of carbonated water injection with and without gravity. International Symposium of the Society of Core Analysts.
Mahmoodi, M., James, L.A., Johansen, T., 2018. Automated advanced image processing for micromodel flow experiments; an application using labVIEW. J. Petrol. Sci. Eng. 167, 829–843. https://doi.org/10.1016/j.petrol.2018.02.031.
Mahzari, P., Tsolis, P., Sohrabi, M., Enezi, S., Yousef, A.A., Eidan, A.A., 2018. Carbonated water injection under reservoir conditions; in-situ WAG-type EOR. Fuel 217, 285–296. https://doi.org/10.1016/j.fuel.2017.12.096.
Manshad, A.K., Olad, M., Taghipour, S.A., Nowrouzi, I., Mohammadi, A.H., 2016. Effects of water soluble ions on interfacial tension (IFT) between oil and brine in smart and carbonated smart water injection process in oil reservoirs. J. Mol. Liq. 223, 987–993. https://doi.org/10.1016/j.molliq.2016.08.089.
Marotto, T.A., Pires, A.P., 2019. Mathematical modeling of hot carbonated waterflooding as an enhanced oil recovery technique. Int. J. Multiphas. Flow 115, 181–195. https://doi.org/10.1016/j.ijmultiphaseflow.2019.03.024.
Martin, 1950. The Use of Carbon Dioxide for Increasing the Recovery of Oil.
Mosavat, N., Torabi, F., 2014a. Experimental evaluation of the performance of carbonated water injection (CWI) under various operating conditions in light oil systems. Fuel 123, 274–284. https://doi.org/10.1016/j.fuel.2014.01.077.
Mosavat, N., Torabi, F., 2014b. Performance of secondary carbonated water injection in light oil systems. Ind. Eng. Chem. Res. 53 (3), 1262–1273. https://doi.org/10.1021/ie402381z.
Mosavat, N., Al-Riyami, S., Pourafshary, P., Al-Wahaibi, Y., Rudyk, S., 2020. Recovery of viscous and heavy oil by CO_2-saturated brine. Energy and Climate Change 1, 100009. https://doi.org/10.1016/j.egycc.2020.100009.
Motie, M., Assareh, M., 2020. CO_2 sequestration using carbonated water injection in depleted naturally fractured reservoirs: a simulation study. Int. J. Greenh. Gas Control 93, 102893. https://doi.org/10.1016/j.ijggc.2019.102893.
Nevers, N.D., 1964. A calculation method for carbonated water flooding. Soc. Petrol. Eng. J. 4 (1), 9–20. https://doi.org/10.2118/569-PA.
Nowrouzi, I., Manshad, A.K., Mohammadi, A.H., 2018. Effects of dissolved binary ionic compounds and different densities of brine on interfacial tension (IFT), wettability alteration, and contact angle in smart water and carbonated smart water injection processes in carbonate oil reservoirs. J. Mol. Liq. 254, 83–92. https://doi.org/10.1016/j.molliq.2017.12.144.
Nowrouzi, I., Manshad, A.K., Mohammadi, A.H., 2019. Effects of dissolved carbon dioxide and ions in water on the dynamic interfacial tension of water and oil in the process of carbonated smart water injection into oil reservoirs. Fuel 243, 569–578. https://doi.org/10.1016/j.fuel.2019.01.069.
Nowrouzi, I., Manshad, A.K., Mohammadi, A.H., 2020. Evaluation of interfacial tension (IFT), oil swelling and oil production under imbibition of carbonated water in carbonate oil reservoirs. J. Mol. Liq. 312, 113455. https://doi.org/10.1016/j.molliq.2020.113455.
Olayiwola, S.O., Dejam, M., 2019. A comprehensive review on interaction of nanoparticles with low salinity water and surfactant for enhanced oil recovery in sandstone and carbonate reservoirs. Fuel 241, 1045–1057. https://doi.org/10.1016/j.fuel.2018.12.122.
Peksa, A.E., Wolf, K.-H.A., Zitha, P.L., 2013. Molecular diffusion of CO_2 from carbonated water (CW) into the oil–Experimental observations. In: SPE Asia Pacific Oil and Gas Conference and Exhibition. https://doi.org/10.2118/165902-MS.
Perez, J.M., 1992. Carbonated water imbibition flooding: an enhanced oil recovery process for fractured reservoirs. In: SPE/DOE Enhanced Oil Recovery Symposium. https://doi.org/10.2118/24164-MS.
Qin, Z., Arshadi, M., Piri, M., 2021. Carbonated water injection and in situ CO_2 exsolution in oil-wet carbonate: a micro-scale experimental investigation. Energy Fuels 35 (8), 6615–6632. https://doi.org/10.1021/acs.energyfuels.1c00230.
Rahimi, A., Safari, M., Honarvar, B., Chabook, H., Gholami, R., 2020. On time dependency of interfacial tension through low salinity carbonated water injection. Fuel 280, 118492. https://doi.org/10.1016/j.fuel.2020.118492.
Raimi, D., Zhu, Y., Newell, R.G., Prest, B.C., Bergman, A., 2023. Global energy outlook 2023: sowing the seeds of an energy transition. Resources for the Future.
Ramesh, A.B., Dixon, T.N., 1973. Numerical simulation of carbonated waterflooding in a heterogeneous reservoir. In: SPE Symposium on Numerical Simulation of Reservoir Performance. https://doi.org/10.2118/4075-MS.
Ramsay, H.J., Small, F.R., 1964. Use of carbon dioxide for water injectivity improvement. J. Petrol. Technol. 16 (1), 25–31. https://doi.org/10.2118/595-PA.
Ren, D., Wang, X., Kou, Z., Wang, S., Wang, H., Wang, X., Tang, Y., Jiao, Z., Zhou, D., Zhang, R., 2023. Feasibility evaluation of CO_2 EOR and storage in tight oil reservoirs: a demonstration project in the Ordos Basin. Fuel 331, 125652. https://doi.org/10.1016/j.fuel.2022.125652.
Riazi, M., Golkari, A., 2016. The influence of spreading coefficient on carbonated water alternating gas injection in a heavy crude oil. Fuel 178, 1–9. https://doi.org/10.1016/j.fuel.2016.03.021.
Riazi, M., Jamiolahmady, M., Sohrabi, M., 2011a. Theoretical investigation of pore-scale mechanisms of carbonated water injection. J. Petrol. Sci. Eng. 75 (3–4), 312–326. https://doi.org/10.1016/j.petrol.2010.11.027.
Riazi, M., Sohrabi, M., Jamiolahmady, M., 2011b. Experimental study of pore-scale mechanisms of carbonated water injection. Transport Porous Media 86 (1), 73–86. https://doi.org/10.1007/s11242-010-9606-8.
Ritchie, H., Rosado, P., Roser, M., 2024. Access to energy. Our World in Data.
Rostami, P., Mehraban, M.F., Sharifi, M., Dejam, M., Ayatollahi, S., 2019. Effect of water salinity on oil/brine interfacial behaviour during low salinity waterflooding: a mechanistic study. Petroleum 5 (4), 367–374. https://doi.org/10.1016/j.petlm.2019.03.005.
Salehpour, M., Riazi, M., Malayeri, M.R., Seyyedi, M., 2020. CO_2-saturated brine injection into heavy oil carbonate reservoirs: investigation of enhanced oil recovery and carbon storage. J. Petrol. Sci. Eng. 195, 107663. https://doi.org/10.1016/j.petrol.2020.107663.
Samara, H., Al-Eryani, M., Jaeger, P., 2022. The role of supercritical carbon dioxide in modifying the phase and interfacial properties of multiphase systems relevant to combined EOR-CCS. Fuel 323, 124271. https://doi.org/10.1016/j.fuel.2022.124271.
Sanaei, A., Varavei, A., Sepehrnoori, K., 2019. Mechanistic modeling of carbonated waterflooding. J. Petrol. Sci. Eng. 178, 863–877. https://doi.org/10.1016/j.petrol.2019.04.001.

Scott, J.O., Forrester, C.E., 1965. Performance of domes unit carbonated waterflood-first stage. J. Petrol. Technol. 17 (12), 1379–1384. https://doi.org/10.2118/1126-PA.
Seyyedi, M., Sohrabi, M., 2017. Pore-scale investigation of crude oil/CO_2 compositional effects on oil recovery by carbonated water injection. Ind. Eng. Chem. Res. 56 (6), 1671–1681. https://doi.org/10.1021/acs.iecr.6b04743.
Seyyedi, M., Sohrabi, M., Farzaneh, A., 2015. Investigation of rock wettability alteration by carbonated water through contact angle measurements. Energy Fuels 29 (9), 5544–5553. https://doi.org/10.1021/acs.energyfuels.5b01069.
Seyyedi, M., Mahzari, P., Sohrabi, M., 2017a. An integrated study of the dominant mechanism leading to improved oil recovery by carbonated water injection. J. Ind. Eng. Chem. 45, 22–32. https://doi.org/10.1016/j.jiec.2016.08.027.
Seyyedi, M., Sohrabi, M., Sisson, A., 2017b. Experimental investigation of the coupling impacts of new gaseous phase formation and wettability alteration on improved oil recovery by CWI. J. Petrol. Sci. Eng. 150, 99–107. https://doi.org/10.1016/j.petrol.2016.11.016.
Seyyedi, M., Mahzari, P., Sohrabi, M., 2018. A comparative study of oil compositional variations during CO_2 and carbonated water injection scenarios for EOR. J. Petrol. Sci. Eng. 164, 685–695. https://doi.org/10.1016/j.petrol.2018.01.029.
Seyyedi, M., Mahzari, P., Sohrabi, M., 2019. A fundamental micro scale study of the roles of associated gas content and different classes of hydrocarbons on the dominant oil recovery mechanism by CWI. Sci. Rep. 9 (1), 5996. https://doi.org/10.1038/s41598-019-42226-6.
Shakiba, M., Ayatollahi, S., Riazi, M., 2016. Investigation of oil recovery and CO_2 storage during secondary and tertiary injection of carbonated water in an Iranian carbonate oil reservoir. J. Petrol. Sci. Eng. 137, 134–143. https://doi.org/10.1016/j.petrol.2015.11.020.
Shakiba, M., Ayatollahi, S., Riazi, M., 2020. Activating solution gas drive as an extra oil production mechanism after carbonated water injection. Chin. J. Chem. Eng. 28 (11), 2938–2945. https://doi.org/10.1016/j.cjche.2020.07.026.
Shayan, N.M., Esmaeilnezhad, E., Choi, H.J., 2021. Effect of silicon-based nanoparticles on enhanced oil recovery: review. J. Taiwan Inst. Chem. Eng. 122, 241–259. https://doi.org/10.1016/j.jtice.2021.04.047.
Shu, G., Dong, M., Chen, S., Luo, P., 2014. Improvement of CO_2 EOR performance in water-wet reservoirs by adding active carbonated water. J. Petrol. Sci. Eng. 121, 142–148. https://doi.org/10.1016/j.petrol.2014.07.001.
Shu, G., Dong, M., Chen, S., Hassanzadeh, H., 2017. Mass transfer of CO_2 in a carbonated water–oil system at high pressures. Ind. Eng. Chem. Res. 56 (1), 404–416. https://doi.org/10.1021/acs.iecr.6b03729.
Sohrabi, M., Kechut, N.I., Riazi, M., Jamiolahmady, M., Ireland, S., Robertson, G., 2011a. Safe storage of CO_2 together with improved oil recovery by CO_2-enriched water injection. Chem. Eng. Res. Des. 89 (9), 1865–1872. https://doi.org/10.1016/j.cherd.2011.01.027.
Sohrabi, M., Riazi, M., Jamiolahmady, M., Idah Kechut, N., Ireland, S., Robertson, G., 2011b. Carbonated water injection (CWI)–A productive way of using CO_2 for oil recovery and CO_2 storage. Energy Proc. 4, 2192–2199. https://doi.org/10.1016/j.egypro.2011.02.106.
Sohrabi, M., Kechut, N.I., Riazi, M., Jamiolahmady, M., Ireland, S., Robertson, G., 2012. Coreflooding studies to investigate the potential of carbonated water injection as an injection strategy for improved oil recovery and CO_2 storage. Transport Porous Media 91 (1), 101–121. https://doi.org/10.1007/s11242-011-9835-5.
Solling, T., Shahzad Kamal, M., Shakil Hussain, S.M., 2021. Surfactants in Upstream E&P. Springer International Publishing, Cham. https://doi.org/10.1007/978-3-030-70026-3.
Sun, X., Ning, H., Shi, Y., Yu, G., Jia, Z., Han, M., Zhang, Y., 2023. Study of CO_2 solubility enhancement by nanomaterials in carbonated water: implications for enhanced oil recovery and CO_2 storage. J. Clean. Prod. 396, 136562. https://doi.org/10.1016/j.jclepro.2023.136562.
Talebi, A., Hasan-Zadeh, A., Kazemzadeh, Y., Riazi, M., 2022. A review on the application of carbonated water injection for EOR purposes: opportunities and challenges. J. Petrol. Sci. Eng. 214, 110481. https://doi.org/10.1016/j.petrol.2022.110481.
Tan, Y., Li, Q., Xu, L., Ghaffar, A., Zhou, X., Li, P., 2022. A critical review of carbon dioxide enhanced oil recovery in carbonate reservoirs. Fuel 328, 125256. https://doi.org/10.1016/j.fuel.2022.125256.
Tetteh, J.T., Brady, P.V., Barati Ghahfarokhi, R., 2020. Review of low salinity waterflooding in carbonate rocks: mechanisms, investigation techniques, and future directions. Adv. Colloid Interface Sci. 284, 102253. https://doi.org/10.1016/j.cis.2020.102253.
Wever, D., Picchioni, F., Broekhuis, A.A., 2011. Polymers for enhanced oil recovery: a paradigm for structure–property relationship in aqueous solution. Prog. Polym. Sci. 36 (11), 1558–1628. https://doi.org/10.1016/j.progpolymsci.2011.05.006.
Xie, Q., Chen, Y., Sari, A., Pu, W., Saeedi, A., Liao, X., 2017. A pH-resolved wettability alteration: implications for CO_2-assisted EOR in carbonate reservoirs. Energy Fuels 31 (12), 13593–13599. https://doi.org/10.1021/acs.energyfuels.7b03071.
Yang, D., Tontiwachwuthikul, P., Gu, Y., 2005. Interfacial tensions of the crude oil + reservoir brine + CO_2 systems at pressures up to 31 MPa and temperatures of 27 °C and 58 °C. J. Chem. Eng. Data 50 (4), 1242–1249. https://doi.org/10.1021/je0500227.
Yang, D., Gu, Y., Tontiwachwuthikul, P., 2008. Wettability determination of the crude oil–reservoir brine–reservoir rock system with dissolution of CO_2 at high pressures and elevated temperatures. Energy Fuels 22 (4), 2362–2371. https://doi.org/10.1021/ef800012w.
Yang, J., Zhou, Y., 2020. An automatic in situ contact angle determination based on level set method. Water Resour. Res. 56 (7). https://doi.org/10.1029/2020WR027107.
Yu, W., Lashgari, H.R., Wu, K., Sepehrnoori, K., 2015. CO_2 injection for enhanced oil recovery in Bakken tight oil reservoirs. Fuel 159, 354–363. https://doi.org/10.1016/j.fuel.2015.06.092.
Zaker, S., Parvizi, R., Hosseini, S., Ghaseminejad, E., 2020a. Crude oil behavior during injection of solutions containing $MgSO_4$ in the presence and absence of CO_2. Energy Sources, Part A Recovery, Util. Environ. Eff. 1–18. https://doi.org/10.1080/15567036.2020.1783397.
Zaker, S., Sharafi, A., Parvizi, R., Esmaeili-Faraj, S.H., Ghaseminejad, E., 2020b. Swelling behavior of heavy crude oil in carbonated water at the presence of Na_2SO_4 and $MgSO_4$. J. Pet. Explor. Prod. Technol. 10 (7), 2759–2769. https://doi.org/10.1007/s13202-020-00927-z.
Zaker, S., Parvizi, R., Ghaseminejad, E., Moradi, A., 2021. Effect of brine type and pH on the interfacial tension behavior of carbonated brine/crude oil. J. Dispersion Sci. Technol. 42 (8), 1184–1195. https://doi.org/10.1080/01932691.2020.1735409.
Zendehboudi, S., Shafiei, A., Bahadori, A., James, L.A., Elkamel, A., Lohi, A., 2014. Asphaltene precipitation and deposition in oil reservoirs–Technical aspects, experimental and hybrid neural network predictive tools. Chem. Eng. Res. Des. 92 (5), 857–875. https://doi.org/10.1016/j.cherd.2013.08.001.
Zhang, L., Ren, B., Huang, H., Li, Y., Ren, S., Chen, G., Zhang, H., 2015. CO_2 EOR and storage in Jilin oilfield China: monitoring program and preliminary results. J. Petrol. Sci. Eng. 125, 1–12. https://doi.org/10.1016/j.petrol.2014.11.005.
Zhang, X., Li, J.-R., 2023. Recovery of greenhouse gas as cleaner fossil fuel contributes to carbon neutrality. Green Energy Environ. 8 (2), 351–353. https://doi.org/10.1016/j.gee.2022.06.002.
Zhu, B., Wilson, S., Zeyen, N., Raudsepp, M.J., Zolfaghari, A., Wang, B., Rostron, B.J., Snihur, K.N., Gunten, K. von, Harrison, A.L., Alessi, D.S., 2022. Unlocking the potential of hydraulic fracturing flowback and produced water for CO_2 removal via mineral carbonation. Appl. Geochem. 142, 105345. https://doi.org/10.1016/j.apgeochem.2022.105345.
Zou, J., Liao, X., Chen, Z., Zhao, X., Mu, L., Chu, H., Dong, P., Guan, C., 2019. Integrated PVT and coreflooding studies of carbonated water injection in tight oil reservoirs: a case study. Energy Fuels 33 (9), 8852–8863. https://doi.org/10.1021/acs.energyfuels.9b01243.