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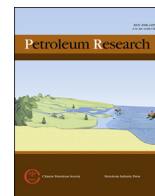
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Review Article

A review on the mechanisms of low salinity water/surfactant/nanoparticles and the potential synergistic application for c-EOR

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ABSTRACT

Chemical enhanced oil recovery (c-EOR) is a conventional and promising strategy to recover oil from reservoir techniques such as low salinity water flooding (LSWF), surfactant flooding, alkaline flooding, polymers flooding, and nanofluid flooding. The use of various types of chemical materials for c-EOR method has recently attracted the attention of the oil and gas industry. The primary objective of this review work is to explore the synergy of low salinity water/surfactant/nanoparticle flooding for effective c-EOR method and investigate the mechanism behind these methods. The advantages of combining these chemical materials for c-EOR methods is also reviewed. Challenges and limitations of this synergy and their economic feasibility for additional oil recovery and potential return on investment are reviewed. Nanoparticles have been successfully used in various applications in several industries and have also shown good application for EOR in terms of wettability alteration. LSWF contributes to wettability alteration, while surfactant contributes to wettability alteration and interfacial tension (IFT) reduction. However, fines migration caused by LSWF and nanoparticle agglomeration can cause formation damage, while excessive surfactant adsorption can lead to cost overrun on surfactant use. Understanding the characteristics of reservoir formation mineralogy and appropriate nanoparticle type, size, and concentration can be used to resolve this challenges. The synergy of LSWF and nanoparticles in alkaline medium can serve as sacrificial agent to reduce excessive surfactant loss. Therefore, the appropriate synergistic formulation of LSWF/surfactant/nanoparticle can improve additional oil recovery and support return on investment for c-EOR projects.

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1. Introduction

With rapid industrial growth, global energy demand continues to increase and it is anticipated to rise 30% by the year 2040 (Karatayev et al., 2019). The Organization of Petroleum Exporting Countries (OPEC) report projects crude oil demand to reach 109.4 mbbbl/d by the year 2040 (Li et al., 2021). Crude oil is one of the most important primary energy resources and has the highest consumption of all the major primary energy resources (Massarweh and Abushaikha, 2020). Production of crude oil must be increased to fulfil global energy demand; this can be achieved through efficient recovery from existing reservoirs. Conventional techniques are unable to maximize crude oil extraction from reservoirs, leaving

a large amount of oil in the reservoir. Therefore, it is crucial for the oil and gas industry to seek appropriate, efficient, and economical techniques to recover the remaining crude oil from reservoirs.

Oil recovery processes are classified into three main categories: primary, secondary, and tertiary phases. The primary oil recovery process can be via natural flow, artificial lift, pump jack, or through other devices (Alagorni et al., 2015). The key driving mechanisms during the primary oil recovery process with natural flow are solution gas drive, gas cap drive, water drive, rock and liquid expansion drives, combination drives, and gravity drainage (Davaranpanah and Mirshekari, 2018). The production of oil depends on the reservoir pressure during natural flow (Agi et al., 2018); however, primary oil recovery can only achieve approximately 5%–30% of original oil in place (El-Hoshoudy et al., 2017). Therefore, secondary oil recovery processes are applied to the reservoir at the stage when primary oil recovery processes are not capable of

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increasing or maintaining oil production within economic considerations.

Secondary oil recovery involves the injection of water or gas into the reservoir through injection wells. The main purpose of the water or gas injection is to maintain reservoir pressure and displace the hydrocarbon that remains in the reservoir. Primary and secondary oil recovery processes are able to recover 10%–20% of original oil in place (Wang et al., 2017; Geetha et al., 2018; Zaeri et al., 2018; Yun et al., 2020). Secondary oil recovery reaches its maximum point when a considerable volume of injected fluid is produced, and the production of oil is insufficient and not economical. After completing primary and secondary recovery processes, 50% or more of the oil remains in the reservoir (Shedid, 2006; Madani et al., 2019). Therefore, tertiary or enhanced oil recovery (EOR) methods are implemented to obtain additional oil recovery from the existing reservoir with a large amount of the original oil in place.

The implementation of tertiary EOR in existing reservoirs improves production of the remaining original oil in place and defers the abandonment of depleted oilfield. Tertiary EOR methods can be chemical, thermal, microbial, electromagnetic, miscible gas, water-alternating-gas processes, or combinations of any of these (Kögler et al., 2021; Moradpour et al., 2021; Hasani and Jafari, 2022). The chemical EOR (c-EOR) method is one of the most promising tertiary EOR techniques, and has gained attention because of its outstanding technical capability, efficiency, economic sustainability, and acceptable capital expenditure that could achieve an extra 5%–20% of residual oil (Liu et al., 2021a,b).

The c-EOR method drives oil recovery by improving one or several essential mechanisms: wettability alteration, interfacial tension reduction, sweep efficiency and oil mobility enhancement, viscosity improvement, or fines migration control (Hasannejad et al., 2017; Aghaeifar et al., 2018; Torrijos et al., 2018; Huang et al., 2019; Eslahati et al., 2020). Numerous laboratory studies have been carried out to show the driving mechanisms of specific chemical materials on c-EOR methods (Lager et al., 2008; Xie et al., 2019; Bhicajee and Romero-Zerón, 2021; Han et al., 2022). Different chemical agents were repeatedly tested and applied in the c-EOR method, including the injection of brines, alkaline solutions, polymers, surfactants, and synthetic chemical solutions (Mejía et al., 2021). However, the driving mechanism behind these chemical agents needs to be understood to discover their best formulations and most suitable application conditions. The influencing factors of specific chemical agents on the c-EOR method should be considered. Harsh reservoir conditions might affect the function of the injected fluid; therefore, comprehensive research needs to be carried out to confirm the feasibility of specific chemical agents.

Many literature reviews discuss c-EOR methods and their particular demerits and merits. However, few reviews discuss the synergy of c-EOR methods and consider their advantages, limitations, efficiency, and recovery. The objective of this work is to review the key methods of c-EOR recovery and to discuss individual mechanisms, factors affecting the methods, and highlight the advantages of a combination of two or more c-EOR methods. Furthermore, the scope of this work considers three c-EOR methods: LSWF, surfactant flooding, and nanotechnology application for c-EOR.

2. Chemical EOR methods

2.1. Low salinity water flooding

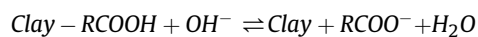
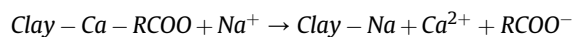
Low salinity water is a specifically adjusted brine solution with a salt concentration less than 2000 mg/L (Katende and Sagala, 2019). This EOR technique has gained high attention from the oil and gas

industry because of its benefits such as low cost, ease of adjusting water chemistry, and environmentally friendly characteristics (Chen et al., 2021a,b). Many researchers state that low salinity water could significantly reverse the wettability of rock surfaces from an oil-wet state to the preferential water-wet state (Al-Saedi and Flori, 2018; J. Wang et al., 2020; Bhicajee and Romero-Zerón, 2021). Experimental works and field application carried out with low salinity water flooding indicated that LSWF applied for c-EOR was feasible (Lager et al., 2008; Skrettingland et al., 2011; Robbana et al., 2012). Many researchers stated that different driving mechanisms are responsible for recovery by LSWF; therefore, further investigation on the driving mechanisms behind LSWF and the interactions between oil-brine-rock is needed to clarify the main mechanism of LSWF for EOR.

2.1.1. Multi-component ionic exchange

Multi-component ionic exchange (MIE) was proposed by Lager et al. (2008), and refers to various ionic interactions, including anion exchange, cation exchange, ligand exchange, water bridging, cation bridging, protonation, hydrogen bonding, and van der Waals interactions. These mechanisms could occur through interactions between different organic functional groups and rock minerals in the hydrocarbon reservoir. Table 1 shows the various MIE mechanisms with their related functional groups.

Further experimental works on LSWF highlighted that the presence of divalent ions in the injected saline water such as magnesium (Mg^{2+}) and calcium (Ca^{2+}) ions are crucial because they were significantly adsorbed to the rock matrix (Gandomkar and Rahimpour, 2017; Al-Saedi and Flori, 2019; Seetharaman et al., 2021). Mg^{2+} showed a higher affinity to clay surfaces than Ca^{2+} because of the higher charge density and smaller ionic radius (Alagic et al., 2011). Therefore, Mg^{2+} is expected to adhere more strongly to clay surfaces than Ca^{2+} . Generally, direct bonding occurs between positively charged organic compounds and the rock surfaces, while negatively charged organic compounds are attracted to divalent cations that exist on the clay surfaces, leading to the formation of organometallic complexes (Collins et al., 2018). The formula of organometallic complexes can be written as $RCOO-M$, where the term M is a multivalent cation (Khishvand et al., 2019). MIE causes the desorption of negatively and positively charged organic compounds during LSWF, and organometallic complexes and organic polar compounds are removed from the rock surfaces through ionic exchanges and substitution with un-complexed cations (i.e., Na^+ and H^+) present in the low salinity water. The chemical reactions for proton exchange and cation exchange (Khishvand et al., 2019) are shown below:



These reactions show the detachment of the divalent cation from the rock surface, which will lead to additional oil recovery because the oil adhered on the rock surface is also removed and the wettability changes to a water-wet condition.

Experimental work by Lager et al. (2008) indicates that the presence of divalent ions in injected saline water is crucial to increase additional oil recovery from the reservoir. Proton exchange will result in excessive OH^- release in the aqueous phase, leading to a higher pH level. Higher pH, especially at the area close to the mineral surface, can also contribute to wettability alteration. Among the eight proposed mechanisms, ligand exchange, cation

Table 1
MIE mechanisms with corresponding involved functional groups.

Multi-ion Exchange Mechanism	Functional Group	References
Cation exchange	Amino, ring NH, heterocyclic N (aromatic ring)	Khishvand et al. (2019)
Anion exchange	Carboxylate	Purswani et al. (2017)
Ligand exchange	Carboxylate	Chen et al. (2021)
Cation bridging	Amines, Alcoholic OH, Carboxylate, Carbonyl	Katende and Sagala (2019)
Water bridging	Amines, Alcoholic OH, Carboxylate, Carbonyl	Katende and Sagala (2019)
Protonation	Amino, Carboxylate, Carbonyl, heterocyclic N	Yue et al. (2020)
Hydrogen bonding	Amino, Carbonyl, Carboxyl	Ding and Rahman (2017)
Van der Waals	Non-polar molecules	Yue et al. (2020)

bridging, and van der Waals interactions are the predominant adsorption mechanisms (Katende and Sagala, 2019). On the basis of Deryaguin–Landau–Verwey–Overbeek theory, van der Waals attractive forces are deemed significant under the high ionic strength condition. Therefore, a higher ionic strength results in lower electrostatic repulsive force. Ligand bonding is the formation of direct bonds between carboxylate groups and divalent cations. Ligand bonding is stronger than cation bridging and cation exchange, and can cause desorption of organometallic complexes from the rock surfaces. Cation bridging is the connection between the negatively charged rock surface and the functional group of the organic material (i.e., negatively charged molecules in oil). Although the divalent cation acts as a bridge, it is a weak adsorption mechanism. When low salinity water is injected, organometallic complexes can be released from the mineral surface through weak cation bridging and stronger ligand bonding, leading to wettability alteration towards the water-wet state.

2.1.2. Expansion of electrical double layer

The electric double layer (EDL) phenomenon was first discovered by von Helmholtz, where it was described as a structure that exists on rock minerals when fluid is in contact with the rock. EDL occurs at the fluid–fluid interface and also at the rock–fluid interface. Experimental work conducted by P. Ahmadi et al. (2019), Amiri and Gandomkar (2019) and Duffy et al. (2019), revealed that expansion of the EDL is the main mechanism to alter the wettability towards a water-wet state. Literature studies demonstrated the relationship between the zeta potential and EDL, illustrated by (Park and Seo, 2011) where parallel layers of charges are shown (Nasralla and Nasr-El-Din, 2014; Xie et al., 2019).

Experiments conducted by Farhadi et al. (2021) indicated that reducing the salinity of water from normal seawater to 40 times diluted seawater resulted in more negative zeta potential, which decreased from -2.9 mV to -5.4 mV. The reduction of salinity also reduced the zeta potential of both oil–brine and rock–brine interfaces. Therefore, this phenomenon leads to a larger repulsive force and a thickening of the water film, which directly alters the wettability of rock surfaces towards the water-wet state. Other studies have indicated that injection of low salinity water containing divalent cations and monovalent cations could significantly increase the oil recovery factor because of the contribution of EDL expansion (Pooryousefy et al., 2018; Y. Chen et al., 2019; Mehraban et al., 2021).

2.1.3. Fines migration

The initial state of the reservoir is in high salinity condition, and this causes the ionic equilibrium to be stable and the clay particles immobile and in an oil-wet condition. However, this also results in poor sweep efficiency and lower oil recovery from the reservoir. When low salinity water is injected into the reservoir, it contacts the high salinity water and the clay particles on the rock surface, causing an unbalanced ionic condition because of the salinity

difference. This condition causes multi-ion exchange to occur continuously until ionic equilibrium is achieved. This process will result in the detachment of clay particles from the mineral surface and lead to fines migration, and it is vital because the detachment of clay particles during LSWF will accompany the detachment of oil molecules (Tang and Morrow, 1999; Yuan et al., 2018; Al-Saedi and Flori, 2018; Yu et al., 2019). The presence of a high concentration of divalent cations tends to reduce the repulsive forces; therefore, clay particles on the mineral surfaces are more stable under a high salinity condition. Tang and Morrow (1999) state that injection of low salinity water established a different salinity condition, mobilized fines such as kaolinite, and resulted in higher oil recovery. According to Bernard (1967), fines migration will result in a pressure difference and higher oil recovery. Experiments conducted by Alhuraishawy et al. (2018) showed that fines migration led to an increase in oil recovery because detachment of clay particles occurred during LSWF and simultaneously released the attached oil molecules. Experimental work from Yu et al. (2019) revealed that an additional 3% oil recovery was observed as a result of fines migration during LSWF. Most of the clay particles produced during LSWF are kaolinite (Tang and Morrow, 1999).

Although numerous studies indicate that fines migration could lead to additional oil recovery, other studies have highlighted that fines migration causes a negative impact on fluid flow and reduces additional oil recovery (Yang et al., 2019; Tangparitkul et al., 2020; Y. Wang et al., 2020). Furthermore, researchers have also revealed that fines migration could lead to permeability reduction and declined oil production (Mansour et al., 2021). Zhang et al. (2015) determined that fine particles that are one-fifth the size of the pore throat are produced out of the reservoir, but fine particles with a larger radius are more likely to cause permeability reduction. Therefore, the issue of fines migration requires more attention to confirm whether this phenomenon is detrimental or beneficial for oil recovery.

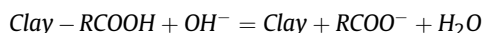
2.1.4. Salting-in effect

The salting-in effect is one of the driving mechanisms on wettability alteration proposed by Austad et al. (2010). The clay particles present in sandstone rock behave as cation exchangers. In the initial situation, acidic and basic components are naturally attached to the rock surfaces. Clay particles are exposed to the high salinity environment where the polar components are attracted to the rock surface. Meanwhile, chemical equilibrium is achieved between the divalent ions present on the rock surface and the surrounding formation water with a high salinity level. The chemical equilibrium is broken once the low salinity water is injected. At the same time, the divalent ions present on the mineral surface are released to re-establish chemical equilibrium. Water molecules in the solution can facilitate the process of re-establishing chemical equilibrium by segregating into hydroxide (OH^-) and hydrogen (H^+) ions. The hydrogen ions tend to attach to clay surfaces because hydrogen ions have the largest affinity for the

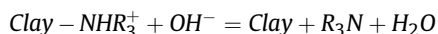
clay particles. In contrast, the hydroxide ions are retained in the solution, increasing the pH especially in the area close to the clay surface. The chemical reaction that describes the salting-in effect was presented by Purswani et al. (2017):



As the acidic components attach to the rock surface, the equation is as follows:



As the basic components attach to the rock surface, the equation is as follows:



The presence of clay particles thus encourages the salting-in effect. Mokhtari et al. (2019) highlighted that the salting-in effect induced more Na^+ ions to undergo segregation and detachment in the system during LSWF. Integration of surfactant with low salinity water showed a distinct impact on the reduced IFT caused by the salting-in effect. A study by Rock et al. (2018) concluded that the salting-in effect has a lower impact on the LSWF EOR method. Nevertheless, literature studies supporting the salting-in effect mechanism with LSWF are limited. Therefore, additional studies are needed to validate the mechanism of the salting-in effect during the LSWF EOR process.

2.1.5. Effect of pH on low salinity water flooding

LSWF causes an increase in pH mainly through two types of reactions: cation exchange and mineral dissolution (Alhuraishawy et al., 2018; Khishvand et al., 2019; Mehraban et al., 2022). Clay particles in the rock play an important role by acting as cation exchangers. Initially, the polar components in the crude oil adsorb onto the clay surface together with divalent cations from the formation water. The injection of low salinity water causes the destabilization of the oil-brine-rock equilibrium, leading to the detachment of divalent ions such as Ca^{2+} and Mg^{2+} . Compensation for the loss of divalent cations can be achieved by substituting H^+ from water molecules, which adsorbs onto the clay surfaces. Consequently, an increase in the local pH occurs in the area close to the clay surfaces. The rising local pH causes a typical acid-base proton transfer reaction to occur between the previously adsorbed polar components (acidic and basic materials). The desorption of the polar components from the mineral surfaces results in alteration of the wettability towards the water-wet phase. This mechanism was also observed by the experimental work of Mohammadi et al. (2021).

Empirical information was provided by the work of (Khishvand et al., 2019), where effluent from LSWF were collected and geochemical analyses were performed for ions concentrations and pH level. Results showed an initial increase in divalent ions concentration and as pore volume increased. At higher pore volume, reduction in divalent ions concentration was observed, which were below the low salinity baseline. In addition, high pH level was observed for effluents collected after the low salinity flooding compared to the initial pH of low salinity water prior to the start of the flooding. This results validates the mechanisms of MIE and proton exchange as core mechanism of LWSF discussed in previous section.

Dissolution of clay particles results in the release of OH^- , which increases the pH. However, this reaction depends on the amount of clay particles existing on the rock surface, and the process is relatively slow if the dissolution occurs on a silicate surface (Aminian and ZareNezhad, 2019). Laboratory work from Farhadi et al.

(2021) indicated that a reduction in the salinity level could lead to higher pH and mineral dissolution, resulting in a more negatively charged calcite rock surface. Electrostatic repulsive forces between oil molecules and rock surfaces increase because of the higher negatively charged rock surface, resulting in the desorption of oil molecules (Al-Saedi and Flori, 2019). Other studies also support the increase in pH as a result of mineral dissolution (Torrijos et al., 2018; Al-Saedi and Flori, 2019; Abbasi and Khamehchi, 2021).

2.1.6. Summary of low salinity water experimental work and core findings

For sandstone reservoir rock under consideration at an ambient reservoir with a temperature of 75 °C and pressure of 2500 psi, with a low salinity condition of 100–5000 ppm. The core findings show that the main driving mechanisms are either MIE or EDL expansion, altering the wettability to a favourable water-wet state, fines migration, interfacial tension reduction, and higher pH levels. These effects were observed to be favourable to additional oil recovery of 5%–15% (Tang and Morrow, 1997; Chen et al., 2020; Costa et al., 2020; Kim et al., 2020; Okoro et al., 2021; Costa et al., 2021). Rotondi et al. (2014) presented a field application of LSWF by ENI S.P.A on a shore field in West Africa and North Africa. The candidate reservoir was a sandstone reservoir with high clay content. The outcomes from this field trial showed 7%–8% additional oil recovery, which was facilitated by the mechanisms previously discussed. This field result validates the efficiency and effectiveness of LSWF as c-EOR method. Experimental work of LSWF was performed in a carbonate reservoir rock at reservoir conditions of 80 °C and 1500 psi pressure, with salinity from 0 to 5000 ppm. MIE was identified as one of the core driving mechanisms. In addition, the effect of electrostatic repulsion, fines migration, and rock dissolution contributed to wettability alteration and IFT reduction. This resulted in up to 20% additional oil recovery (Farhadi et al., 2021; Mokhtari et al., 2022).

2.2. Surfactant flooding

Surfactants are surface-active agents that act as a wetting agent to reduce interfacial tension between two different phases in a system. Molecules of surfactant are usually organic compounds comprising a hydrophobic tail and a hydrophilic head. Surfactants can be classified into different groups: anionic, cationic, zwitterionic, and non-ionic (Khayati et al., 2020). Anionic and cationic surfactants are usually used in c-EOR to reduce the interfacial tension between oil and water in sandstone and carbonate reservoir rocks (Shirazi et al., 2019; Koparal et al., 2021). Cationic surfactants are usually used in carbonate reservoirs and not sandstone reservoirs because the adsorption on sandstone rock is relatively high. Because of the constraint of cost, zwitterionic surfactants receive less attention for use in c-EOR (Mohamad-Aziz et al., 2019; Atta et al., 2020). Non-ionic surfactants are commonly applied together with cationic or anionic surfactants to improve their performance (Esfandyari et al., 2020). Table 2 shows the different types of surfactants commonly used in c-EOR.

2.2.1. Effect of concentration of surfactant

The critical micelle concentration (CMC) is the lowest concentration where aggregation of a surfactant monomer occurs and results in the formation of micelles. CMC is usually measured by plotting a graph of interfacial tension versus different concentrations of surfactant (Manshad et al., 2017). The surfactant molecule is present as a single monomer when the concentration of surfactant is below the CMC, and this monomer state is essential to achieve wettability alteration and interfacial tension reduction. The interaction between surfactant monomers and adsorbed

Table 2
Different types of surfactants and c-EOR usage.

Surfactants	Preferable Usage	Example of Surfactants	References
Anionic	Typically applied for sandstone rock because of the minimum adsorption.	Sodium dodecyl sulfate (SDS), Sodium Ethyl Ester Sulfonate, Alpha-Olefin Sulfonate (AOS)	Negin et al. (2017); Nowrouzi et al. (2019)
Cationic	Typically used for carbonate rock and not suitable for sandstone rock because of its high adsorption.	Cetylmethylammonium bromide(CTAB), Dodecyltrimethylammonium bromide (DTAB)	Derikvand et al. (2020); Karimi et al. (2016)
Non-Ionic	Usually applied for carbonate rock. High tolerance for high pressure, temperature and salinity conditions.	Zizyphus Spina Christi, Alkyl polyglucoside	Atta et al. (2020); Esfandiyari et al., 2020; C. Sun et al., 2021
Zwitterionic	Typically used for sandstone rocks. However, it can also be used with carbonate rocks under specific conditions. High tolerance for high salinity and high temperature conditions. Rarely use due to constraint of cost (high cost).	N-Hexadecyl-N, N-dimethyl-2-amm onio-1-ethanecarbonate, N, N-Dimethyl-N-[2-hydroxy-3-sulfo-propyl]-N'-phenyloctadecanoyl-1, 3-diaminopropane (SPODP)	Abbas et al. (2020); Z.-Z. Chen et al., 2019; Kumar and Mandal, 2019

components on the mineral surface can cause wettability alteration towards the water-wet state (Yao et al., 2021). The interfacial tension remains constant as the surfactant monomer concentration reaches a maximum until it is above the CMC. Several studies suggested that the surfactant concentration should be slightly above or at the CMC to achieve the lowest IFT and wettability alteration (Nafisifar et al., 2021; Prince et al., 2021). Hirasaki et al. (2011) mentioned that higher surfactant concentration could cause more water and oil to solubilize and form a type III Winsor aqueous phase, leading to additional oil recovery. In addition, a low concentration of surfactant is not capable of achieving favourable wettability and IFT reduction. Experimental work from Apaydin and Kovscek (2001) indicated that a relatively high surfactant concentration might establish a pressure gradient with the end effect, resulting in flow in the opposite direction. However, laboratory work from Y.-P. Sun et al. (2021) revealed that IFT reduction and oil recovery increased gradually with increasing concentration of surfactant below the CMC point. Once the concentration of surfactant is beyond the CMC point, the oil recovery decreased as the concentration of surfactant increased. Part of the surfactant might also be lost through adsorption on the mineral surface, which would affect the efficiency of the surfactant to achieve wettability alteration and IFT reduction, and also would result in economic losses (Saxena et al., 2019; Bashir et al., 2019; Kalam et al., 2021).

2.2.2. Effect of divalent ions

Negin et al. (2017) recommended that the concentration of divalent cations such as Mg^{2+} and Ca^{2+} should be low. Divalent cations promote a bridging effect between negatively charged rock surfaces and the surfactant, which causes higher surfactant adsorption. Lower or optimum divalent cation concentrations are needed to decrease the surfactant adsorption and also promote the bridging between oil molecules and clay particles (Aminian and ZareNezhad, 2019; Paternina et al., 2020). According to Nelson (1981), divalent ions are more sensitive than monovalent ions during anionic surfactant flooding, especially at low surfactant concentration. However, the presence of divalent ions is inevitable, and researchers suggested using a surfactant with higher resistance to divalent cations, such as surfactants with carboxylate, sulfonate, or ethoxy units in their structure (Negin et al., 2017; Massarweh and Abushaikha, 2020).

2.2.3. Effect of presence of carboxylate/sulfonate/sulfate

Atta et al. (2020) revealed that sulfonate-type surfactants are the most widely used. Sulfonate surfactant can originate from fatty acids in natural oils. The main reactions to produce bio-based sulfonate surfactants are transesterification or esterification and sulfonation (Cohen et al., 2008). Bio-based sulfonate surfactants contain a hydrophilic part with a sulfonate group and an ethyl or methyl ester. Hirasaki et al. (2011) highlighted that the presence of

carboxylate or sulfonate units in the surfactant improved and prolonged the stability under high temperature reservoir conditions. Literature studies also mentioned that sulfonate-type surfactants are more stable under high salinity (Tai et al., 2018). According to Sheng (2015), carboxylate surfactants had excellent performance and a stable result under high salinity and high temperature in the presence of divalent cations. Researchers also found that sulfonate-type surfactants could result in a higher oil recovery with lower adsorption in harsh condition formations and at the same time achieve a lower CMC (Li et al., 2020; Lin et al., 2020).

Sulfate surfactants can be applied under high salinity conditions, but they are not temperature tolerant. According to Negin et al. (2017), alcohol propoxy sulfate is one of the commonly used surfactants for core-flooding, which sustains high salinity but low temperature conditions. Sodium dodecyl sulfate (SDS) is a kind of anionic surfactant that has been widely used. Recent studies have indicated that SDS could significantly reduce the contact angle and interfacial tension under ambient conditions in light crude oil and sandstone rock samples (Yekeen et al., 2020). However, the molecules become thermally insensitive and unstable at high temperature because of the sulfate linkages in the molecular structure of the surfactant (Negin et al., 2017). Therefore, further investigation is needed to validate the feasibility of a sulfate group in a surfactant to be used under harsh conditions.

2.2.4. Effect of pH value

The pH of the reservoir and the injected solution can affect the efficiency of the surfactant, especially on adsorption. According to Saxena et al. (2019), increasing the alkalinity of the surfactant solution could reduce excessive adsorption of the surfactant on the rock surface because a higher electrostatic repulsion is formed. Southwick et al. (2016) also mentioned that increasing the pH to a particular range could efficiently reduce anionic surfactant adsorption on the sandstone rock surface. However, experimental work conducted by Liu et al. (2020) revealed that a decrease in pH of the injected surfactant solution resulted in a lower density charge on the silica surface and lower surfactant adsorption to the rock surface. Although the majority of researchers proposed that a higher pH of the injected surfactant solution can reduce excessive surfactant adsorption, further investigation of the effect of pH on the interaction between surfactant and mineral surfaces is needed.

2.2.5. Summary of surfactant flooding experimental work and core findings

Anionic surfactant is predominantly used in sandstone reservoirs. Varying types of anionic surfactant used in sandstone reservoirs have a retention mechanism dominated by adsorption on the sandstone rock surface. Anionic surfactants contributed immensely to IFT reduction and wettability, resulting in more additional oil

recovery (Hanamertani et al., 2018; Liu et al., 2020; Koparal et al., 2021; Zhong et al., 2021), while cationic surfactants are suitable for carbonate reservoir rock and their retention mechanism is by adsorption. The presence of cationic surfactant in carbonate reservoir rock mainly supported IFT reduction and wettability alteration, and overall contributed to additional oil recovery (Jia et al., 2019; Derikvand et al., 2020; Nowrouzi et al., 2020; Deng et al., 2021). Because both anionic and cationic surfactants have limited performance when subjected to harsh reservoir conditions such as high temperature, pressure, and salinity, non-ionic and zwitterionic surfactants can be used in these situations. Both surfactants have a main retention mechanism of adsorption, and also contribute to IFT reduction, wettability alteration, and support additional oil recovery (Liu et al., 2020; Q. Sun et al., 2021).

2.3. Nanoparticles

Nanotechnology has been extensively applied in various sectors, including medical, engineering, science, space, electrical and electronics, and oil and gas (Olayiwola and Dejam, 2019). With technological advancements, nanoparticles (NPs) can be produced easily and cost effectively (Chen et al., 2021a,b; Yu et al., 2010). The size of NPs is within the range of 1–100 nm and, because of their size, they demonstrate distinctive chemical and physical properties. In the oil and gas industry, NPs have been used for drilling, completion, cementing, and the EOR method. NPs are usually dispersed and suspended in a colloidal solution (nanofluid), with a water or surfactant solution as the base solution. Research has revealed that nanofluids can alter the wettability of rock surface towards a water-wet state, which is beneficial to EOR (Kanj et al., 2020; Alnarabiji and Husein, 2020; Ahmadi and Mansouri, 2021). Currently, c-EOR methods can involve a combination of chemical agents such as low salinity water with surfactant, low salinity water with NPs, surfactant with NPs, and other types of chemical materials in synergy (Almahfood and Bai, 2018; Hashemi and Saien, 2020; Yekeen et al., 2020). These combinations could further improve the efficiency of the c-EOR method compared with a single chemical EOR injection. However, the effectiveness of combining various chemical materials with NPs will be affected by the concentration of chemical materials in the solution. The selection of the appropriate chemical materials and NPs is vital to achieve several key mechanisms to maximize oil recovery. Olayiwola and Dejam (2020) demonstrated that the use of NPs in the reservoir together with low salinity water could control fines migration and further improve the wettability alteration of the rock surface towards a water-wet state. Studies have also revealed that NPs can increase the macroscopic sweep efficiency and mitigate the viscous fingering issue, illustrated in Fig. 1 (Alnarabiji et al., 2018).

2.3.1. Size of nanoparticles (NPs)

The size of the NPs can affect the wettability alteration and IFT reduction, especially when at a low concentration of applied nanofluid (Minakov et al., 2021). Numerous studies have shown

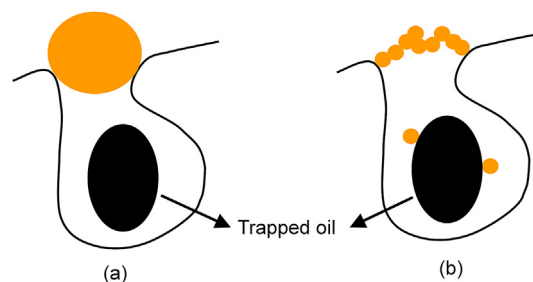


Fig. 2. (a) Chemical materials with larger size; (b) size of nanoparticles.

that smaller NPs result in a lower IFT (Adil et al., 2020; Kim et al., 2016; Udoh, 2021). A study by Nasr et al. (2021a) revealed that the performance of metal-based NPs on wettability alteration and IFT reduction was better than with carbon-based NPs because the smaller size and higher specific surface area of metal-based NPs resulted in larger disjoining pressure and improved interaction between NPs and oil. Panchal et al. (2021) stated that smaller NPs could provide better wettability alteration because their larger charge density results in a larger electrostatic repulsive force and will increase the strength of the disjoining pressure. In addition, smaller NPs can easily penetrate through the small pore throat and prevent trapping (Kazemzadeh et al., 2019), as shown in Fig. 2.

The size of NPs should be within an ideal range so that they can perform well at a minimum size without causing log-jamming (Panchal et al., 2021; Sofla et al., 2018; Youssif et al., 2018). Log-jamming is the phenomenon where NPs accumulate at the entrance of the pore throats and block the potential flow paths, and results from constant differential pressure and smaller pore throat size (Youssif et al., 2018). This issue might further cause pore blockage, reduction of oil recovery, and formation damage (Feroozesh and Kumar, 2020; Nasr et al., 2021a; Yakasai et al., 2022). Therefore, further investigation of the optimal NP size to apply at specific conditions is needed.

2.3.2. Concentration of nanoparticles

Varying concentration of NPs may be detrimental to the overall recovery because a high NP concentration might cause pore blockage while a low NP concentration may have little or no effect on oil recovery. Panchal et al. (2021) found that increasing the NP concentration leads to higher Brownian motion and disjoining pressure, which could aid wettability alteration and increase oil recovery. Experimental work by Afekare et al. (2021) indicated that increasing the hydrophilic silica NP concentration from 500 ppm to 5000 ppm significantly reduced adhesive forces between mica and alkane, which led to wettability alteration towards a more water-wet state. However, they also highlighted that a concentration of NPs above 5000 ppm might increase the adhesive force and even reverse the wettability effect. An experiment conducted by Sagala et al. (2020) demonstrated that hydroxyl-functionalized silicate-

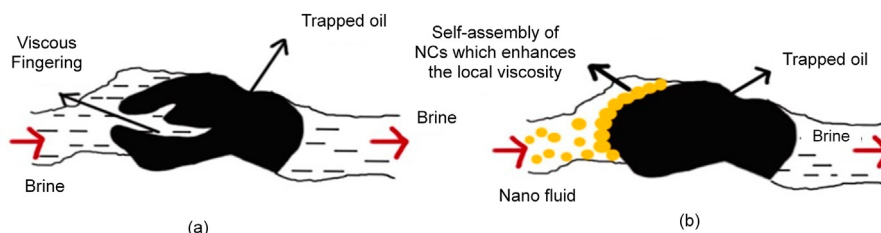


Fig. 1. (a) Brine injection induced viscous fingering issues; (b) Nanoparticles mitigate the viscous fingering issues by self-assembly.

based NPs tested at different concentrations (25 ppm, 50 ppm, 75 ppm, 100 ppm) achieved the lowest contact angle measurement on sandstone rock at 25 ppm NP. Other researchers have found that a higher concentration of NPs can cause aggregation of NPs and pore blockage, further reducing fluid mobility (Nasr et al., 2021b; Wu et al., 2017; Yakasai et al., 2022). In addition, increasing the NP concentration beyond the optimum concentration does not significantly reduce IFT, but will lead to economic loss (Sagala et al., 2020). Therefore, an optimum concentration should be considered to achieve favourable wettability alteration, oil recovery, and economic viability.

2.3.3. Salinity

The salinity in the reservoir is significantly high; therefore, an understanding of the interactions between NPs-oil-rock and the influence of different concentrations of salinity is needed to verify whether NPs can withstand the high salinity condition. According to the literature, increasing salinity will reduce the stability of NPs and affect the efficiency of NP injection to improve oil recovery (Panchal et al., 2021; Yakasai et al., 2022). The electrostatic repulsion force between the NPs-oil-rock is the main mechanism affecting the stability of dispersed NPs in aqueous solution (Rezvani et al., 2018; Udoh, 2021). In a high salinity environment, the ionic strength will be high, and will cause the compression of the EDL and lead to lower zeta potential. Consequently, the electrostatic repulsion between the NPs will be drastically reduced, and surface neutralization with NPs might occur because of the large number of ions in solution. Meanwhile, van der Waals attractive forces become significant in high salinity conditions, where attraction forces occur between the regions of molecules with high and low electrons (Alnarabiji and Husein, 2020).

Few studies have investigated if injection of NPs into high salinity reservoirs could cause the NPs to aggregate and be retained in the porous media (Kim et al., 2015.; Aziz and Tunio, 2019; Foroozesh and Kumar, 2020). Rasid et al. (2022) found that retention of NPs can adversely affect the wettability alteration, flow capacity, reservoir permeability, and porosity. An experiment conducted by Agi et al. (2020) revealed that the viscosity of rice husk silica NPs decreased as the salinity level increased because of the reduction in electrostatic repulsion force. In addition, Yang et al. (2021) found that the interfacial tension increased as the salinity increased. Experimental work by Kumar et al. (2020) indicated that oil recovery was reduced by approximately 10% when the salinity level increased from 0 to 3 wt% NaCl. However, experimental work from Liu et al. (2021a,b) showed that the introduction of high salinity water with Janus-silica NPs did not lead to any significant effect; in particular, the effect on IFT reduction was not changed.

2.3.4. pH effect

The pH in the reservoir varies between different reservoirs and is usually not neutral (Alnarabiji and Husein, 2020). The stability of NPs dispersed in a solution is strongly affected by pH (Kumar and Mandal, 2016) and the surface charge of NPs also depends on the pH environment (Yakasai et al., 2022). The magnitude of the surface charge on NPs and the surrounding aqueous medium becomes higher as the pH deviates from the isoelectric point (IEP). In contrast, aggregation of NPs might occur when the pH approaches the IEP or becomes zero, leading to favourable van der Waals attractive forces. Afekare et al. (2021) found that the IEP of quartz and mica are in the range of pH 2–3; therefore, the surface of these minerals becomes positively charged in solution with pH below 3 and becomes negatively charged in solution with pH above 3. Experimental work by Kumar et al. (2020) indicated that introducing NaCl into the nanofluid reduced the pH and shifted the solution towards the acidic region, thereby affecting the stability of

NPs dispersed in the solution.

Experimental work by Behera and Sangwai (2021) demonstrated that reducing the pH of the base solution with dispersed NPs leads to a reduced zeta potential. The reduction of zeta potential until the IEP showed that net migration has not occurred within the electric field, indicating that retention of NPs might occur. An experiment conducted by Rezvani et al. (2018) indicated that dispersion of NPs in alkaline fluid could achieve a higher NP stability and higher wettability alteration than with the dispersion of NPs in acidic fluid; this is because of the higher electrostatic repulsion forces occurring between the oil-brine-NPs and the rock surface. Experimental work by Sagala et al. (2020) revealed that increasing the pH of the nanofluid can reduce the distribution of the hydrodynamic size of hydroxylated nanopyroxene NPs (HPNP) from 300 nm to 10 nm. The researchers also agreed that increasing the pH of the HPNP can alter the wettability towards a water-wet state and increase the oil recovery by an additional 4.37%. However, Nowrouzi et al. (2019) mentioned that the key factor in reducing the IFT was introducing dissolved carbon dioxide into the nanofluid, which reduces the pH. They obtained the lowest IFT with a carbonated γ -Al₂O₃ nanofluid. Therefore, the optimum pH value, where the NP dispersion in the solution is stable and functions efficiently to alter wettability towards a water-wet state and increase additional oil recovery, should be obtained.

2.3.5. Effect of temperature

Generally, the temperature in the reservoir is higher than the surface. Therefore, an investigation on the sustainability and reliability of specific NPs for EOR is needed to confirm that NPs are resistant to thermal degradation at high temperature. Experiments carried out by Taborda et al. (2021) revealed that silica NPs and modified silica NPs with NaOH could minimize thermal degradation at a reservoir temperature of 70 °C. They also found that reducing the acidity of the nanofluid reduced the thermal degradation of silica NPs. Experiments by Bila et al. (2020) demonstrated that different types of silica NPs have different temperature sensitivities.

Investigation of the tolerance of different NPs at higher temperature is thus required to determine the appropriate types of NPs for the c-EOR process. Nasr et al. (2021a) and Sharma et al. (2014) found that increasing temperature affects the stability of NPs, which could directly reduce the efficiency of NP injection. Nasr et al. (2021b) also found that the Brownian motion of NPs increased with temperature, which could reduce their stability and efficiency. In contrast, Panchal et al. (2021) proposed that increasing the temperature leads to higher displacement efficiency, which could directly increase oil recovery. The effects of temperature on NPs are complicated and under dispute; therefore, further investigation is needed to understand this mechanism comprehensively.

2.3.6. Wettability of nanoparticles(NPs)

The majority of existing nanoparticles (NPs) are synthetic and they can be classified into several groups according to their wettability: neutral-wet polysilicon, hydrophobic and lipophilic polysilicon, and lipophobic and hydrophilic polysilicon (Udoh, 2021). Hydrophilic NPs tend to be attracted to the water phase, while hydrophobic NPs are attracted to the oil phase (Panchal et al., 2021). The wettability of NPs defines their position at the water and oil interface. The adsorption of NPs onto the rock surface prompts the alteration of wettability towards a water-wet state where the oil molecules on the rock surface are removed, leading to higher oil recovery from the reservoir. Some studies have reported the positive effects of using hydrophilic NPs to enhance oil recovery (Afekare et al., 2020; Hendraningrat et al., 2013a,b; Negi et al., 2021; Youssif et al., 2018). Experimental work conducted by Izadi et al.

(2019) demonstrated that polymer-citrate-coated Fe_3O_4 , a type of hydrophilic NP, successfully altered wettability, and reduced the IFT between the aqueous system and the oil. They also achieved an additional 28% oil recovery with the use of hydrophilic NPs. [Yakasai et al. \(2020\)](#) suggested that hydrophilic NPs are more appropriate for enhancing viscosity and altering wettability, and they recommended that partially hydrophilic and hydrophobic NPs are more suitable for IFT reduction. However, the researchers mentioned that iron oxide NPs (IONPs) cause retention and deposition because of the hydrophilic nature of IONPs when applied in a saline environment that lacks functional groups ([Yakasai et al., 2022](#)).

In contrast, [R. Ahmadi et al. \(2019\)](#), [Singh and Mohanty \(2020\)](#) found that hydrophilic NPs were also important in selective pore channel plugging to increase pressure drop and enhance oil recovery; however, pore plugging could also lead to a reduction of additional oil recovery ([Omidi et al., 2020](#)). Literature studies indicated that hydrophilic NPs could improve the stability of the foam and do not deteriorate the foamability when used in c- EOR ([Rasid et al., 2022](#); [Bashir et al., 2019](#); [Yang et al., 2021](#)).

2.3.7. Mineralogy of reservoir rock

Several researchers inferred that the pore structure and mineralogy of the rock might affect the efficiency of nanofluid flooding ([Afekare et al., 2021](#); [Wang et al., 2021](#)). [Panchal et al. \(2021\)](#) anticipated that the grain size of the rock could affect the retention of NPs in the porous media. The surface area per unit bulk volume decreased when the grain size of the mineral rock was larger than the surface area. Meanwhile, retention of NPs on the mineral rock surface increases as the reduction of surface area per unit bulk volume increases. [Khaliil et al. \(2017\)](#) found that the clay content in the mineral rocks could lead to retention of NPs on the rock surface because the free spaces between the mineral rock grains are occupied by clay particles, reducing the porosity of the reservoir. In addition, retention of NPs on the clay surface increases when the surface area per unit bulk volume of clay particles increases. The surface charge of the reservoir rock is variable because of the various mineral compositions, including micas (illite and muscovite), carbonate rocks (dolomite and calcite), clay (chlorite and kaolinite), and feldspars ([Feroozesh and Kumar, 2020](#)).

2.3.8. Summary of nanoparticle experimental work and core findings

The use of NPs in c-EOR has been successful in sandstone and carbonate reservoirs with harsh reservoir environments up to 120 °C and 3000 psi ([Gbadamosi et al., 2019](#); [Agi et al., 2020](#); [Olayiwola and Dejam, 2020](#)). The important function of NPs is their ability to act as a sacrificial agent when used in synergy with surfactants ([Zargartalebi et al., 2014](#); [Wu et al., 2017](#); [Kumar et al., 2020](#); [Rashidi et al., 2021](#); [Yekeen et al., 2021](#)). The core driving mechanism behind the contribution of NPs towards oil displacement are electrostatic interaction and the effect of structural disjoining pressure, supporting IFT reduction and wettability alteration ([Rezvani et al., 2018](#); [Mansouri et al., 2019](#); [Shakiba et al., 2020](#); [Behera and Sangwai, 2021](#); [Fan et al., 2021](#); [Manshad et al., 2022](#)).

3. Combination of low salinity water/surfactant/nanoparticle

3.1. Efficient performance on wettability alteration and interfacial tension reduction

Recent studies indicated that the combination of chemicals such as surfactant, saline water, and NPs could relatively enhance the oil recovery ([Pal and Mandal, 2020](#); [Kumar and Mandal, 2020](#); [Yang et al., 2021](#)). This is because the combination of these chemicals

could further improve the mechanisms of wettability alteration, IFT reduction, and sweep efficiency enhancement, ultimately leading to higher oil recovery. Laboratory studies conducted by [Rezaei et al. \(2020\)](#) demonstrated that the IFT and contact angle were significantly reduced when synthesizing the surfactant with NPs. The reduction in IFT for cocamido propyl betaine surfactant flooding under alkaline conditions achieved a wettability alteration index (WAI) up to 0.55, while the WAI was up to 0.9 with the combination of surfactant and NPs. NPs provided a higher disjoining pressure when dispersed onto the rock surface, which significantly detached the oil molecules from the mineral rock surface. A wedge-like film was formed at the edge between the oil and mineral rock surface, resulting in a significant disjoining pressure and detachment of the oil from the rock surface, as illustrated in [Fig. 3](#).

[Behera and Sangwai \(2021\)](#) studied the combination of nanofluid with surfactant and polymer in low salinity water (Smart Lowsal) to enhance oil recovery from sandstone reservoirs. They showed that IFT was reduced from 0.53 mN/m to 0.27 mN/m, and total oil recovery increased to 55.38%. They highlighted that NPs could alter the wettability towards a water-wet state by rupturing the oil film on the rock surface. In addition, experimental work by [Omidi et al. \(2020\)](#) indicated that nanocomposites of Fe_3O_4 /eggshell in a CTAB surfactant solution reduced the IFT and contact angle to 0.18 mN/m and 60.7°, respectively, which were much lower than with the surfactant alone. Meanwhile, a combination of NPs with low salinity water and surfactant resulted in higher oil recovery during tertiary EOR and better reduction of IFT and contact angle. Other studies found a positive impact with the combination of NPs with other chemicals in the c-EOR process ([Wu et al., 2017](#); [El-Hoshoudy et al., 2020](#); [Rafiei and Khamehchi, 2021](#); [Yekeen et al., 2021](#); [Rayeni et al., 2022](#)).

3.2. Advantages of low salinity water flooding/surfactant/nanoparticles synergy

3.2.1. Surfactant adsorption reduction

Although increasing the concentration of surfactant could still achieve larger IFT reduction and higher oil recovery, it is costly ([Ali et al., 2018](#)). Literature studies have shown that excessive surfactant loss through adsorption onto the mineral rock surface can be mitigated or resolved by synthesizing the surfactant with chemicals such as NPs, or by controlling the salinity level ([Liu et al., 2021a,b](#); [Negi et al., 2021](#); [Yakasai et al., 2022](#); [Zhang et al., 2015](#)). Surfactant adsorption onto the mineral rock surface might also reduce oil recovery ([Adila et al., 2022](#)). [Paternina et al. \(2020\)](#) revealed that higher salinity leads to higher surfactant adsorption because the

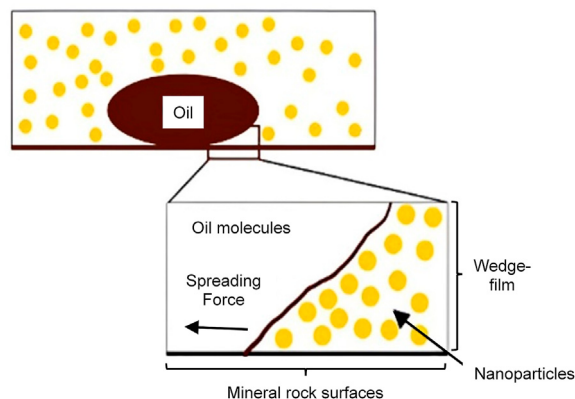


Fig. 3. Formation of nanoparticles in wedge-film region.

EDL between the molecules is compressed and reduces the electrostatic repulsive force between the surfactant and negatively charged substrate. Therefore, the surfactant more easily adsorbs onto the rock surface. Experimental work by Abbas et al. (2020) showed an increasing trend of Aerosol-OT adsorbed onto the rock surface with increasing salinity. This trend also applied to mineral surfaces, including kaolinite, montmorillonite, illite, and quartz-sand. A study by Liu et al. (2020) demonstrated that a reduction in calcium ion concentration reduced surfactant adsorption onto the silica surface because the cation bridging between surfactant and silica surface was reduced. In addition, applying 50 ppm of polystyrene sulfonate with 0.05 wt% alcohol alkoxy sulfate significantly reduced the surfactant adsorption up to 85%. Similarly, a laboratory study by Musa et al. (2020) showed that surfactant adsorption onto the rock surface increases with salinity, and henna extract reduced surfactant adsorption by 53%. Several literature studies have shown that a combination of low salinity water with surfactant could reduce surfactant adsorption onto the rock surface (Saxena et al., 2019; Yekeen et al., 2019; Paternina et al., 2020; Quezada et al., 2022).

3.2.2. Nanoparticles as sacrificial agent

NPs play an important role by acting as a sacrificial agent, where adsorption of specific NPs onto the rock surface is favoured over the surfactant because of their smaller size and higher surface area. This could reduce the surfactant adsorbed onto the rock surface because the rock surfaces are occupied with NPs. Adsorption tests conducted by Rezaei et al. (2020) indicated that NPs, including silica NPs and sodium carbonate NPs, efficiently reduced the adsorption of surfactant onto dolomite rock surfaces by 35.7% and 59.7%, respectively. Rezaei et al. (2020) also mentioned that adsorption of linear alkyl benzene sulfonic acid onto carbonate rock surface could be reduced by up to 75% with the presence of 0.1% of silica NPs. Experiments by Kumar et al. (2020) used a combination of chemical flooding (surfactant with NPs) in a moderately saline environment (4 wt% NaCl) and found that this treatment efficiently reduced surfactant adsorption onto the rock surface and recovered more oil than with surfactant flooding.

Rattanaudom et al. (2021) studied the interaction between carboxylate-based extended surfactant-silica NPs-Ottawa sand and found that surfactant adsorption on the rock surface was significantly reduced compared with the absorption in the absence of NPs. Foroozesh and Kumar (2020) highlighted that hydrophilic NPs reduce surfactant adsorption onto the rock surface more than hydrophobic NPs; hydrophilic NPs contain more hydroxyl ions than hydrophobic NPs, which influences the NPs coverage. Selecting a suitable NP (hydrophobic or hydrophilic) and the corresponding surfactant type for different types of reservoir rocks is the key factor in achieving the lowest surfactant adsorption and highest oil recovery. A combination of IONPs with non-ionic surfactants for c-EOR will influence the efficiency of the surfactant and have a negative impact on IFT reduction (Yakasai et al., 2022). This is because the displacement of IONPs and non-ionic surfactant at the oil-water interface will occur simultaneously instead of reducing the surfactant adsorption onto the rock surface. Meanwhile, an appropriate combination of surfactant with specific NPs and low salinity water is a novel method to reduce excessive surfactant loss.

3.2.3. Fines migration control

LSWF induces fines migration because of electrostatic interaction between the brine-oil-rock surface; here, attractive and repulsive forces occur between different ions and cause the release of clay particles and oil molecules attached to the mineral surface. Fines migration occurs during LSWF, which could lead to pore blockage and formation damage. A higher pH of the chemical

material injection and higher flow rate will also cause fines migration (Mansouri et al., 2019), reducing the permeability of the reservoir and the oil recovery. Literature studies have found that the fines migration issue can be controlled or prevented by applying NPs (Hasannejad et al., 2017; Mansouri et al., 2019; Moghadasi et al., 2019). Olayiwola and Dejam (2020) concluded that the capability of NPs to mitigate fines migration depends on three main factors: resultant electric surface charge of NPs, fines particles, and the ions present in the ionic solution. For instance, dispersion of alumina NPs on a silica surface achieved a larger positive zeta potential and a higher retention of NPs, while dispersion of zinc oxide NPs on the silica surface achieved a larger negative zeta potential and a lower retention of NPs. Therefore, appropriate NPs with specific conditions (reservoir types) should be selected to balance the repulsive and attractive forces between NPs and fines particles.

Laboratory work by Mansour et al. (2021) indicated that injection of 500 ppm of magnesium oxide NPs could mitigate fines migration and increase permeability (from 236.62 mD to 390.62 mD) in sandstone cores. MgO NPs and silica NPs were sufficient to adsorb with the rock surface and reduce the repulsive forces between the mineral surface and the fines particles. Jha et al. (2020) revealed that a combination of zirconium dioxide NPs with low salinity water and surfactant could mitigate fines migration through the adsorption of nanoaggregate complexes occurring along the pore walls. Adsorption of nanoaggregate complexes increases the disjoining pressure and increases the detachment of oil molecules from the pore walls, achieving an additional 8.6% oil recovery. Yuan et al. (2018) suggested that nanofluid injection prior to LSWF could minimize fines migration and enhance the sweep efficiency. Several studies have investigated the control and prevention of fines migration using nanotechnology (Arab and Pourafshary, 2013; Mansouri et al., 2019; Moghadasi et al., 2019; Giraldo et al., 2021; Mansour et al., 2021). Table 3 shows the additional oil recovery that can be achieved through the implementation of LSWF/surfactant/nanoparticles and polymer in alkaline medium.

4. Technical challenges and limitations

- (1) Implementation of LSWF/surfactant/NP is without its own unique challenges. These challenges are particular with NPs, as its field-wide application is limited because only laboratory experimental data is available. Again, due to the different types of nanoparticles: metallic oxide and non-metallic oxide nanoparticles. It is difficult to conclude which type will be efficient for c-EOR. As more data is required on metallic oxide and magnetic type nanoparticles to ascertain its potential application as c-EOR chemical agent (Almahfood and Bai, 2018).
- (2) Maintaining nanofluid at a colloidal state of dispersion to prevent nanoparticle agglomeration has limited discussion in literatures. This phenomenon is important because nanofluid needs to maintain its state of colloidal suspension to effectively and efficiently perform its mechanism for oil displacement such as structural disjoining pressure, density difference effect, wettability alteration and interfacial tension reduction (Khalil et al., 2017; Kazemzadeh et al., 2019).
- (3) The associated problems of low salinity water and surfactant flooding due to large fines migration and excessive surfactant adsorption may pose difficulties as a result of formation damage and cost of surfactant use.
- (4) Finally, LSWF support environmental sustainability due to its low toxicity. However, chemical agents such as surfactants and nanoparticles are deemed hazardous materials. Thus,

Table 3
List of additional oil recovery of the synergy from selected literatures.

References	Surfactant/Alkaline/Low Salinity Water/NPs/Polymer	Additional oil recovery
Raffa and Picchioni (2021)	Low salinity water/polymer	9%
El-Hoshoudy et al. (2020)	Silica NPs/polyacrylates	32.4–40.4%
Hamdi et al. (2021)	Gum Arabic natural polymer/dispersed and grafted Graphene nanoplatelets	5–17%
Rayeni et al. (2022)	Silica NPs/sea water	45.55%
Izadi et al. (2019)	Polyelectrolyte polymer coated Fe ₃ O ₄ NPs	28%
Saha et al. (2018)	Alkali/Sodium Dodecyl Sulfate/Sodium Dodecyl Benzene Sulfonate/Cetyl Trimethylammonium bromide/Triton X-100	12.79–14.46%
Yahya et al. (2022)	Sulfonated Alkyl Esters/Fatty Esters/aluminosilicate NPs	2–5%
Zhou et al. (2020)	Synthetic PolyNPs/Betain-type zwitterionic surfactant	9.32%
Zhao et al. (2021)	Silica NPs/AOS surfactant (anionic surfactant)	29%

implementation of the synergy of LWSF/surfactants/nanoparticles will score low on Environment, Social and Governance (ESG) scale.

Overcoming the challenges of the synergy is key to its overall success. Shirmeheni et al. (2021) proposed green nanoparticle from natural sources which are non-metallic or eco-friendly but possess comparable unique properties as the metallic, metallic oxide and magnetic nanoparticles (Pereira et al., 2022). This is the base argument for green nanotechnology application for oil and gas industry towards its contribution to environmental sustainability. Issues of surfactant loss and fines migration can be reduced by appropriate use of nanoparticles, as nanoparticles acts as sacrificial agent to reduce surfactant loss and controls fines migration (Mansour et al., 2021; Yakasai et al., 2022). The challenge of nanofluid synergy is its ability for the colloidal solution to remain stable for the required duration. This can be achieved by sonification, maintaining high pH level and appropriate concentration of surfactant at its critical micelle concentration (Zamani et al., 2020; Sajid and Bicer, 2022).

5. Economic implication of low salinity water/surfactant/nanoparticle synergy

Although numerous studies have investigated synergistic chemical materials for c-EOR, the implementation of the entire c-EOR process must be economically viable. Synthesizing the chemical materials at low to moderate concentrations could minimize the investment cost (Rayeni et al., 2022). However, the capability of the synthesized chemical materials to produce hydrocarbon from the reservoirs must be considered. Druetta and Picchioni (2019) found that the synergy of NPs with surfactant could significantly reduce implementation cost. In contrast, Deljooei et al. (2021) suggested that the combination of green surfactant with low salinity water could lead to favourable oil production with economic and environmental considerations. Excessive surfactant adsorbed onto the rock surface could cause considerable financial loss (Phukan et al., 2020), and reducing surfactant adsorption onto the rock surface and re-using the surfactant produced from the reservoirs could make the c-EOR process more economically viable. Reduction of surfactant adsorption can be achieved by synthesizing the surfactant with other chemical materials that substitute the adsorption onto the rock surface (Bautkinová et al., 2020; Chong et al., 2020; Liu et al., 2021a,b; Koparal et al., 2021).

The cost of chemical materials used as sacrificial agents also needs to be considered. The implementation cost for c-EOR is lower than the gas-EOR method, which can be applied in particular during low oil price periods because it could be economically feasible (Liang et al., 2021). Furthermore, fines migration could lead to formation damage, reduction of injection rate, and can cause economic loss (Yuan and Moghanloo, 2018). Fines migration requires

higher reservoir pressure to produce the hydrocarbon from the reservoirs; therefore, fines migration issues should be mitigated to maintain high injectivity and crude oil production rates. Furthermore, controlling fines migration could lengthen the life span of surface treatment facilities (Belcher et al., 2010; Jiang et al., 2021), and energy consumption can be reduced because pressure pumps require less when the synergy fluid reduces capillary pressure (Bashir et al., 2019). Therefore, mitigation of fines migration during the c-EOR method could further reduce unnecessary cost.

The synergy of the chemical materials, such as low salinity water, surfactant, and NPs, not only increases crude oil production but also extends the life span of the reservoirs (Druetta et al., 2019; Nikolova and Gutierrez, 2020). Implementing synergistic chemical solutions could increase additional oil production, which directly increases the ROI. A study by Henthorne et al. (2013) indicated that the injection of chemical materials, including low salinity water and surfactants under alkaline conditions, could provide significant returns estimated at USD40/bbl. Another study by Al-Ghnemi et al. (2019) investigated flooding with different chemical materials in the North Kuwait Sabriyah Lower Burgan Reservoir. They found that the c-EOR method was a promising and economically viable investment because it could prolong the reservoir lifespan and increase the crude oil production rate. Hassan et al. (2019) found that although the initial capital cost was higher than water injection, the ROI was substantially higher.

On the basis of the available literature, the implementation of c-EOR clearly yields significant returns. Therefore, extensively investigating c-EOR methods, especially to find c-EOR synergies, is worthwhile as energy demands continue to increase.

6. Conclusions

This work presented a literature review on the synergy of low salinity water, surfactant, and NP application in c-EOR. The review highlighted the mechanism, factors affecting the efficiency, and additional recovery that can be achieved. As a result, the following conclusions can be reached.

- (1) Divalent ions (Ca²⁺ and Mg²⁺) are more effective than monovalent ions, as shown by MIE and expansion of the EDL. However, fines migration poses a risk of formation damage as a result of mobilization of the clay particles present in the formation. In addition, LSWF has a good environmental profile and can effectively support wettability alteration to the favourable water-wet state to aid additional oil recovery.
- (2) Surfactants support wettability alteration and IFT reduction; however, excessive adsorption of surfactants on the reservoir rock surface may impede the success of surfactant flooding. Therefore, a synergy with other chemical materials acting as sacrificial agents to reduce excess surfactant loss is crucial for surfactant flooding.

- (3) Nanoparticles application has limited EOR field-wide application, but experimental laboratory data overwhelmingly suggest that it has potential for field application. The mechanism of disjoining pressure forming a wedge-like structure supports the ability of to displace oil from the rock surface.
- (4) A synergy of LSWF/surfactant/in an alkaline medium may complement each other; LSWF and nanoparticles can act to reduce excessive surfactant loss, contribute to wettability alteration, and reduce interfacial tension, leading to overall additional recovery.
- (5) The key findings from the review can be applied to a field case scenario because laboratory experimental studies have demonstrated significant efficacy for the nanofluid synergy.

Declaration of competing interest

Authors declares no conflict of interest whatsoever to undertake this project.

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