

CORE FLOOD INVESTIGATION OF SURFACTANT- INDUCED EMULSION EFFECTS ON KAZAKHSTANI OIL RECOVERY

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ORIGINALITY STATEMENT

I, Muh Naim, hereby declare that this submission is my own work and to the best of my knowledge it contains no materials previously published or written by another person, or substantial proportions of material which have been accepted for the award of any other degree or diploma at Nazarbayev University or any other educational institution, except where due acknowledgement is made in the thesis.

Any contribution made to the research by others, with whom I have worked at NU or elsewhere is explicitly acknowledged in the thesis.

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ABSTRACT

An emulsion is defined as a system in which two immiscible liquids are mixed in which one phase is dispersed in the other as drops in micro-size. In porous media, emulsion plays a critical role through mechanisms such as partial areal blockage, viscosity modification, interfacial tension (IFT) reduction, and mobility control. In this study, a series of experiments was conducted to evaluate the influence of emulsion generation and the effective recovery scenario during core flooding. Preliminary experiments were conducted to assess the stability of the emulsion under varying types and concentrations of anionic surfactants for a specific Kazakhstani oil type. To generate an emulsion, alpha-olefin sulfonate (AOS) and sodium dodecyl sulfate (SDS) were used at concentrations ranging from 1000 to 3000 ppm, and 10,000 ppm NaCl brine was used as the base solution. Several experimental studies were carried out, including spontaneous emulsification, emulsion stability assessments, and core flooding tests using a couple of injection scenarios. Two scenarios of surfactant flooding were performed as primary and secondary injections following an initial water flooding stage on the Berea sandstone reservoir with permeability ~ 300 mD. The experimental results reveal that 2000 ppm AOS gives better stability performance in terms of droplet size distribution over time compared to other AOS and SDS concentrations. Conversely, in situ emulsification induced by surfactants as a secondary injection improved the cumulative oil recovery by 28.57% relative to the residual oil remaining after conventional secondary water flooding. Meanwhile, as a primary injection, surfactant gives promising in situ emulsion performance by stepwise oil production. These findings demonstrate that surfactant injections can substantially enhance oil recovery by promoting the formation of stable in situ emulsions within sandstone reservoirs.

Keywords: Core flooding, EOR, in situ emulsion, Sandstone reservoir, Stability, Surfactant

DEDICATION

In the last two years, I have written in English so much. It is in Bahasa Indonesia this time.

Tesis ini saya dedikasikan untuk kedua orang tua saya, **Ayah Amiruddin dan Ibu Harniati**. Dukungan, doa, dan kasih sayang yang kalian berikan sejak dahulu hingga saat ini tidak akan pernah mampu saya balaskan, bahkan hingga kapan pun. Ucapan terima kasih dalam bahasa Inggris, Indonesia, Kazakh, Rusia, Melayu, maupun Toraja tidak akan pernah cukup untuk menggambarkan betapa besar rasa syukur saya memiliki kalian sebagai orang tua.

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1. INTRODUCTION

1.1 Background

With an increase in the global population along with an increase in energy needs, which mainly comes from fossil fuels, the industry is facing a challenge in fulfilling the energy demand. Enhancing the recovery of trapped oil has reached great momentum in recent decades (Silva et al., 2014). Most of the world's oilfields have three stages of recovery: primary, secondary, and tertiary recovery. After the first and second stages of the recovery, at least half of the oil reserve usually remains in the reservoir. In tertiary recovery, usually called enhanced oil recovery (EOR), oil recovery could increase by 20% to 40% of the original oil in place (Li et al., 2020). Tertiary recovery is achieved by changing the physical or chemical properties of the reservoir and formation fluid. Among the other tertiary methods, chemical flooding is the most commonly used (Al-Sakkaf & Onaizi, 2024). Emulsification is one of the keys to the success of chemical flooding operations (Adil & Onaizi, 2022). Several studies have shown that the formation, migration, and stabilization of water in oil or oil in water emulsion could efficiently enhance oil recovery.

An emulsion is defined as a system in which two immiscible liquids are mixed, with one phase dispersed in the other as drops in microsize (Lim et al., 2015). Emulsion is defined into three main types: oil-in-water (O/W), water-in-oil (W/O), and multiple emulsions. The oil-in-water emulsion is a condition in which oil drops are dispersed throughout the water phase. In contrast, water in oil emulsion is the condition where water drops are dispersed throughout the oil phase (FigureFigure 1). Multiple emulsion is a more complex system in which O/W or W/O is dispersed into another immiscible phase. This type of emulsion includes water in oil in water (W/O/W) and oil in water in oil (O/W/O) emulsions (Agarwal & Kanwar, 2007). In porous media, emulsion plays a critical role through mechanisms such as partial areal blockage (Soot & Radke, 1984), viscosity modification (Arhuoma et al., 2009), reduction of interfacial tension (IFT), and mobility control (Guillen et al., 2012; J. Liu et al., 2023). Amphiphilic surface-active molecules or surfactants are usually used to create an emulsion to reduce the natural attractive forces between different phases of liquids, commonly called surface tension (Kale & Deore, 2016). According to Li et al. (2020), emulsions could efficiently enhance oil recovery by two mechanisms, which are improving displacement efficiency and sweep efficiency. However, the stabilization of the emulsion must be

considered to obtain the best result. The droplet size distribution, zeta potential, IFT, and rheological properties are some of the parameters used to evaluate the stability of an emulsion (Maaref & Ayatollahi, 2018; Wong et al., 2015).

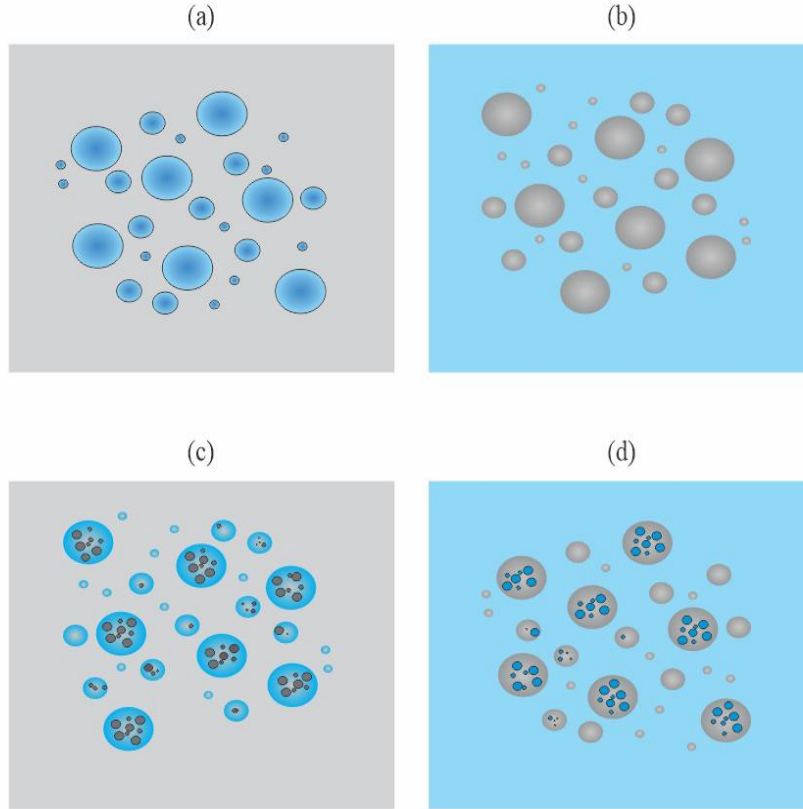


Figure 1. Schematic representation of different emulsion systems which blue represents water and grey represents oil; (a) water in oil (W/O), (b) oil in water (O/W), (c) oil in water in oil (O/W/O), and (d) water in oil in water (W/O/W)

In recent years, a number of studies based on experimental and field applications have been conducted to evaluate the stability of emulsions and their performance in enhancing oil recovery. (Pang et al., 2019) investigated the effect of in situ emulsion generation during water flooding and found that the total oil recovery was as low as 16.33% in the absence of in situ emulsion. In contrast, the total oil recovery increased from 16.33% to 33.98% in the presence of in situ emulsion. Sun et al. (2022) compared the ultimate oil recovery factor from water flooding and W/O emulsion flooding and found that emulsion flooding increased oil recovery from 30.2% to 48.7% after water flooding. Mandal et al. (2010) After investigating the efficiency of oil-water

emulsion for EOR through flooding experiments, researchers reported that an additional 20% of the original oil in place was recovered by emulsion flooding over conventional water flooding. (Karambeigi et al., 2015) found the same trend after flooding experiments, that is, emulsion flooding increased the total oil recovery by 28% compared with water flooding.

1.2 Problem Definition

Most existing studies on chemical EOR mainly focus on the performance of pregenerated emulsions during emulsion flooding. The mechanism of the in-situ generated emulsion within the porous media has received limited attention. However, in practical reservoir conditions, emulsions are often formed dynamically during chemical flooding, and their behavior can significantly influence the efficiency of oil recovery. Furthermore, emulsion generation and stability are strongly dependent on oil type and oil content, which vary across reservoirs. However, many studies rely on model oils rather than representative crude samples. Therefore, the effect of in situ emulsion generation during chemical flooding using crude oil from a local Kazakhstan oil field must be investigated to understand better its impact on emulsion behavior and overall recovery performance under realistic conditions.

1.3 Objectives of the Thesis

1.3.1 Main Objectives

The main objective of this study was to assess the stability of emulsions under varying surfactant concentrations for a specific Kazakhstani oil type. The novelty is attributed to the use of specific Kazakhstani oil types in this study. In this work, a series of experiments was conducted to evaluate the influence of emulsion generation and the effective recovery scenario during core flooding. Preliminary experiments were conducted to determine the optimal anionic surfactant concentration based on its influence on emulsion stability. Several experimental studies were carried out, including spontaneous emulsification, emulsion stability assessments, and core flooding tests using a couple of injection scenarios. Two scenarios of surfactant flooding were performed as primary and secondary injections following an initial water flooding stage on the Berea sandstone reservoir.

1.3.2 Specific Objectives

To achieve the main objective, the following specific objectives were determined:

- The effect of surfactant concentration on emulsion stability and droplet size distribution was analyzed.
- Screen the optimum concentration of the surfactant for further use in core flooding.
- The effect of emulsion generation during surfactant core flooding to increase the recovery of remaining oil after primary water flooding was studied.
- The effect of flooding scenarios on the volume of oil recovered from the reservoir is analyzed.

1.4 Scope of the Work

The scope of this work is to comprehensively study the factors affecting the stability of crude oil and water emulsions and their influence on the oil recovery factor. This will involve the following key chapters:

- **Methodology:** This section provides a detailed description of the study's materials, procedures, and equipment. It will also provide a precise design for the study, including the experimental sequences.
- **Results and Discussion:** This chapter provides a comprehensive analysis of the data obtained from the experiments detailed in the Methodology section. The results will be thoroughly discussed, and the emulsion performance will be evaluated.
- **Conclusion and Recommendations:** The thesis concludes with recommendations based on the experimental results.

2. LITERATURE REVIEW

2.1 Introduction of the emulsion

Crude oil and water emulsions are defined as a dispersion of two immiscible fluids in which one fluid is finely distributed as droplets within the other and behaves as a single fluid phase (Abed et al., 2019). Based on droplet size, emulsions are divided into three main types: microemulsion (0.01-0.1 μm), nanoemulsion (0.05-0.5 μm), and coarse macroemulsion ($>0.5 \mu\text{m}$) (Burguera & Burguera, 2012). Although they generally exhibit similar properties and all refer to emulsion, nanoemulsion, and coarse macroemulsion are thermodynamically unstable, whereas microemulsion is thermodynamically stable (Liet et al., 2024). In EOR, emulsions are commonly generated in situ during chemical flooding and interact with reservoir fluids under flow and shear in porous media (Zhou et al., 2019). Chemical agents such as acids, alkalis, surfactants, and polymers are injected into the oil reservoir. These chemicals interact with oil during formation and form different types of emulsions under reservoir conditions. Even though oil and water form emulsions, they behave as a single fluid phase with unique rheological properties that differ from oil or water. These properties could facilitate the mobilization of residual oil after secondary recovery, thereby improving total oil recovery.

Emulsions play a crucial role in EOR by improving mobility control within porous media. During chemical flooding, emulsion formation increases the apparent viscosity of the injected fluid, reducing the mobility ratio between the injected fluid and oil inside the reservoir (Sun et al., 2022b). This condition helps to reduce fingering, promotes a more uniform displacement front, and enhances the macroscopic sweep efficiency (Ding et al., 2022). Moreover, emulsion droplets could selectively block the large permeability channel, redirecting the injected fluid into previously unswept or low-permeability zones, and improving oil recovery (Liu et al., 2019). In the W/O system, water droplets and viscoelastic interfacial film increase the viscosity of the emulsion, delay water breakthrough, and enable piston-like displacement, which improves the total recovery in the heterogeneous reservoir. However, excessive dispersion of water could over-block the pores and result in high-pressure drops (Eslami & Malmir, 2025).

Another mechanism of emulsion in porous media to increase oil recovery is wettability alteration. Emulsion can alter the wettability of the reservoir rock from oil wet to water wet or from mixed wet to more water wet (Kumar & Mandal, 2020). In a surfactant-based emulsion, surfactant molecules adsorb into the oil-rock interface and change the surface charge and chemistry by displacing the cured oil components, such as asphaltene and resin (Tang et al., 2025). This replacement decreases the contact angle and changes the wettability from strongly oil-wet to favorable water-wet. The in-situ emulsion formed during surfactant flooding has the same mechanism as the in-situ emulsion, which absorbs the rock, shifts the contact angle, and allows the aqueous phase to penetrate and strip the residual oil films from the pore walls (Ray et al., 2024). Overall, wettability alteration, which is driven by emulsion, increases capillary force, improves relative permeability to oil, and leads to substantial incremental oil recovery.

Related to those, the effectiveness of emulsions mechanism in porous media to enhance oil recovery is strongly governed by its stability. Emulsion stability generally refers to the ability of dispersed droplets to resist coalescence, flocculation, and phase separation over time. Oil and water emulsion in petroleum systems in terms of stability is commonly classified into stable, meso-stable, and unstable (Fingas & Fieldhouse, 2009). Stable emulsion is generally characterized by small and uniform droplet distribution that remain dispersed due to strong interfacial film. Stable emulsion could last from separation for more than 30 days after emulsification (Fingas & Fieldhouse, 2003). Meanwhile, meso-stable emulsion represents an intermediate case in which emulsion remains stable for limited time, commonly up to 7 days, before coalescence occurs gradually. This is usually considered as optimum in reservoir conditions as it balances mobility control but avoids the total pore plugging. In the other hand, unstable emulsion rapidly breaks and separate in a very short period of time due to weak interfacial film. In the porous media, this level of stability is not favorable due to its limited and ineffective mechanism to enhance oil recovery.

To enhance oil recovery via pore blockage and flow diversion, emulsion must be stable long enough to partially block the high permeability zone but not strong enough to permanently block them. This behavior corresponds to quasi-stable emulsion which is not instantly breaking and not permanently blocking the pore (Zhou et al., 2019). Strongly stable emulsion, however, can move through pore throat without blockage problem when the droplet is highly smaller than pore size. In this regard, the ideal mechanism is wettability alteration and not the pore plugging (Pinto et al.,

2025). Meanwhile unstable emulsion coalesces and breaks quickly, losing its blocking effect and ineffective for flow diversion purposes(K. Li et al., 2024).

2.2 Factors characterizing the stability

2.2.1 Droplet size

The droplet size is an important parameter that affects the stability and behavior of emulsions in porous media. A smaller droplet size gives a more stable emulsion. The droplet size could be controlled by changing the emulsification parameters, such as the emulsifier concentration and applied shear. L'Estimé et al. (2024) studied the droplet size and distribution of oil in water emulsions generated by a high-shear rotor–stator mixer. Using 3 wt.% sodium dodecyl sulfate (SDS) surfactant to stabilize the oil-in-water emulsion, the effect of different mixer rotation speeds from 500 to 4000 rpm was studied. The experiment found that the droplet size can be controlled by the rotation speed, mixer geometry, and continuous phase viscosity. By increasing the rotation speed of the mixer, a smaller droplet size and a higher volume of the dispersed phase are obtained. Ghannam (2005) studied the effect of mixing speed on emulsion stability and found that increasing the rotation speed of the mixer from 500 rpm to 2000 rpm significantly increases emulsion stability by decreasing the diameter of the emulsion droplet. After studying the W/O emulsion, the same result was obtained by Ilia Anisa and Nour (2010). By increasing the stirring speed from 500 to 2000 rpm, the average droplet diameter decreased from 60.34 μm to 15.82 μm for oil water ratio of 50:50 (Figure 2). When the level of applied shear during emulsification reliably increases the emulsion stability by lowering the droplet size, the emulsifier concentration also plays an important role in obtaining the desired droplet size.

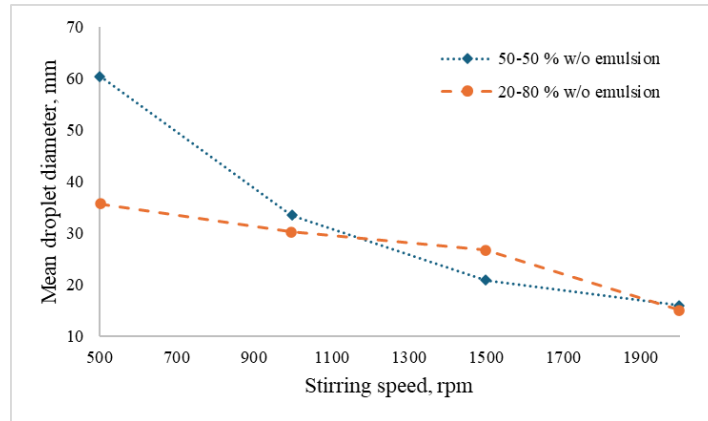


Figure 2. Effects of the mean droplet diameter at various phase ratios (Anisa& Nour, 2010)

The emulsifier concentration is a critical factor during the emulsification of the immiscible fluids. When the emulsifying agent is low, the ability to cover the interfacial film of the emulsion and protect from coalescence decreases, resulting in a larger droplet size and lower emulsion stability. Ghannam (2005) investigated the stability of water in crude oil emulsions using a range of different parameters. Those parameters include salt concentration of 0-5% NaCl, surfactant concentration of 0.1-1%, polymer concentration of 0-1000 ppm, mixing speed of 500-2000 rpm, temperature from 13°C to 40°C, and water concentration of 10-50%. The results show that emulsifiers are critical for obtaining stable emulsions. In line with this, L'Estimé et al. (2024) reported that higher surfactant concentrations can help prevent the coalescence of droplets, and fragmentation dominates the process. Eftekhardadkhahand Hashemabadi (2011) analyzed the effects of surfactant concentrations, salinity, and the power of an ultrasonic homogenizer on the size distribution of emulsion droplets. The study used crude oil from the Tehran refinery with a viscosity of 6 mPa · s at 25°C and a density of 850 kg/m³. Two different nonionic surfactants were used, namely, Triton X-100 and Tween 80, due to their availability and hydrophilic-lipophilic balance (HLB) value, which is more than 10, which is appropriate for a molecule made up of more hydrophilic components. In the preliminary experiments, the same concentrations of Triton X-100 and Tween 80 were used to generate emulsions. The results showed that Triton X-100 performed better with an emulsion droplet size of 2.56 µm compared to Tween80, which is 3.17 µm. The sensitivity of different Triton X-100 concentrations was then performed from 0.0001125 ml/100ml, 0.000225 ml/ml, and 0.001125 ml/ml solutions. As shown in Figure 3, increasing the concentration reduced the mean diameter of the emulsion droplets by 19% (3.05, 2.78, and 2.56 µm, respectively).

Moreover, another study tested the W/O emulsion with different water ratios of 55%, 65%, and 76%, and reported that as the droplet size decreased, the surfactant concentrations and layer thickness in the interfacial film increased (Pal, 1996).

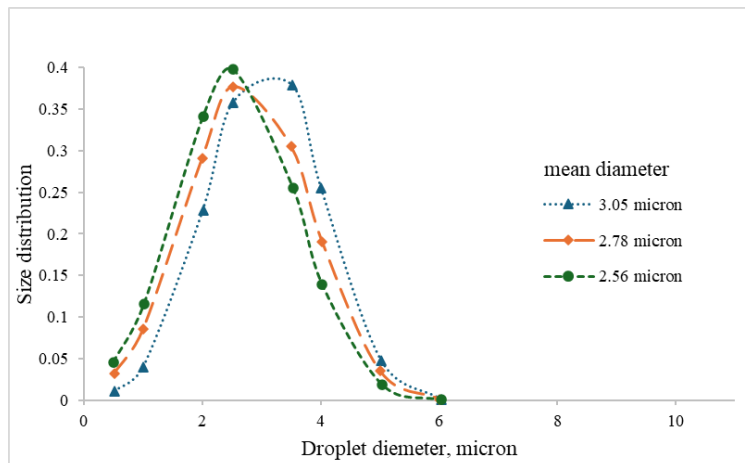


Figure 3. Effect of surfactant concentration on droplet size distribution (Eftekhardadkhah & Hashemabadi, 2011)

Regarding the Droplet size distribution of W-O emulsion influenced by the effect of salinity, (Maaref & Ayatollahi, 2018) conducted study to investigate the effect of different brine salinities on emulsion stability through Droplet size analysis. The study used synthetic brine to mimic the North Seawater, Red Seawater, Mediterranean Seawater, and Persian Gulf Seawater, as shown in Table 1. The W/O emulsions were prepared using a magnetic stirrer at 1000 rpm for 30 min with a water/oil ratio of 1:10. The investigation of emulsion stability was conducted several times after emulsion preparation (0, 6, 12, and 24 h) under a microscope. The stability assessment using droplet size distribution was then conducted, and the droplet size calculation was performed using ImageJ software. The results showed that the North Sea emulsion, which has the lowest NaCl and TDS contents of 24.12 g/L and 34.44 g/L, respectively, is still stable up to 24 h, as shown in Figure 4. On the other hand, the Red Sea emulsion, which has the highest contents of NaCl and TDS (32.39 and 41 g/L, respectively), became unstable after only 6 h. This study revealed that when the salinity increases, the droplet size also increases, thereby lowering the emulsion stability. On the other hand, Perles et al. (2012) revealed that the presence of salts in the water in oil emulsion system increases the emulsion stability up to a critical value of ionic strength, between 0.1 to 0.3 mol L⁻¹ depending on the system. Above this critical value, the stability of the emulsion decreases as the mean diameter and the range of size distribution increase.

Table 1. Composition and concentration of the synthesized brine (Maaref & Ayatollahi, 2018)

Brine identification	Salt concentration (g/L)						
	NaCl	Na ₂ SO ₄	MgCl ₂	CaCl ₂	KCl	NaHCO ₃	TDS
Synthesized seawater from the Persian Gulf	28.4	4.49	5.43	1.38	0.8	0.1	40.6
Synthesized red seawater	32.39	4.5	2.91	0.6	0.4	0.2	41
Synthesized Mediterranean seawater	26.44	4.32	5.5	1.16	0.88	-	38.3
Synthesized North Seawater	24.12	2.9	5.36	1.18	0.88	-	34.44

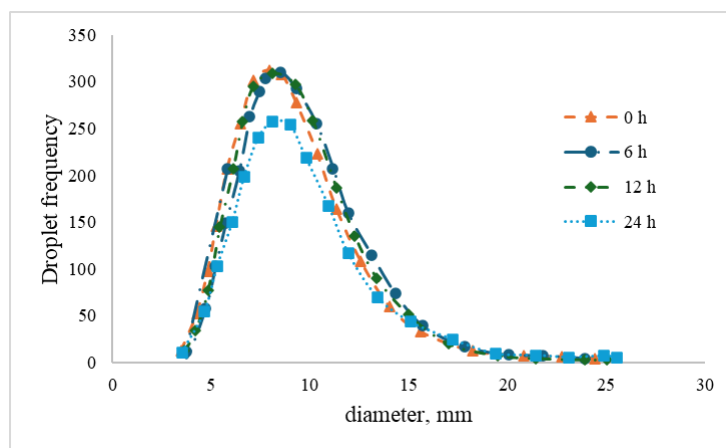


Figure 4. Emulsion droplet size distribution at 0, 6, 12, and 24 h after preparation for the North Sea without emulsion (Maaref & Ayatollahi, 2018)

Recent advances in emulsion science have demonstrated the effect of solid particles on droplet size distribution and long-term stability. Wanget al. (2021) studied the effect of highly hydrophilic pristine TiO₂ NPs on stabilizing oil and water emulsion. By controlling the emulsification experiments, we found that by increasing the nanoparticle concentration from 0.5 to 10 wt.%, the diameter of the oil droplets decreases, as shown in Figure 5. Singhet al. (2024) compared two oil-in-water emulsions stabilized by natural surfactant-polymer (SP) and silica nanoparticles-NSP. With the same condition of 1000 ppm polymer and 0.2 wt.% of polymer, with the same oil-water ratio of 40:60, the stability of emulsions was observed. The results revealed that emulsions stabilized by SP have higher phase separation than those stabilized by NSP. The higher phase

separation of the SP-stabilized emulsion is due to the larger droplet size. Meanwhile, the presence of Si enhanced the density of the NSP emulsion, thereby retarding droplet movement in the system. The same results were observed in other studies by Liu et al. (2022), Udoetok et al. (2024), and Tliba et al. (2025), which showed that increasing the concentration of hydrophilic nanoparticles on the Pickering oil in water (O/W) emulsion system enhanced the hydrophilic surface area, which resulted in higher stability and smaller droplet size distribution. Moreover, increasing the concentration of hydrophobic nanoparticles could increase the stability of the water-in-oil (W/O) emulsion system (Ramos et al., 2023).

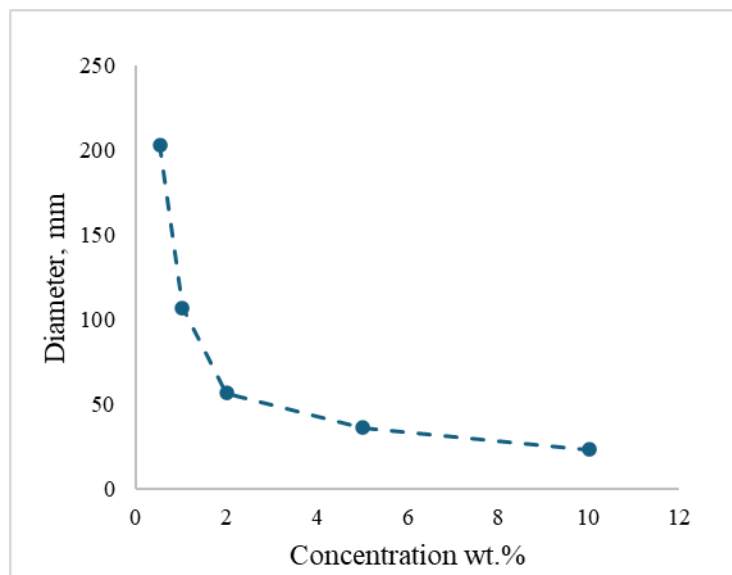


Figure 5. Droplet size of emulsions prepared at various TiO₂ particle concentrations (Wang et al., 2021)

The droplet size is a primary determinant of emulsion stability, governing both the droplet coalescence rate and the persistence of dispersed phases under reservoir-relevant conditions. Smaller droplets consistently yield more stable emulsions because of their larger interfacial area and reduced gravitational separation, and emulsification parameters strongly control these sizes. Increased shear rates, higher surfactant concentrations, and optimized mixing conditions reliably reduce droplet diameter, whereas insufficient surfactant loading or elevated salinity promote droplet growth and destabilization. Studies across diverse systems—from low-viscosity oil–water emulsions to heavy crude emulsions—show similar trends, confirming that enhanced interfacial

coverage and coalescence suppression primarily drive droplet size reduction. Conversely, excessive ionic strength can compress electrical double layers and weaken interfacial films, resulting in larger droplets and poorer emulsion stability. Collectively, existing evidence emphasizes that precise control of shear, surfactant chemistry, and salinity is essential for engineering emulsions with targeted droplet size distributions, particularly in applications such as enhanced oil recovery and flow assurance, where stability determines performance.

2.2.2 Zeta potential

Zeta potential is the electrokinetic potential at the interfacial film of the emulsion droplets. It gives the degree potential of either repulsion or attraction between the droplets of the dispersed fluid in the emulsion system (Hong et al., 2018). A greater gap between droplets and a higher chance of repulsion results in a higher zeta potential, resulting in a more stable emulsion (Jha et al., 2015). Onaizi (2022) investigated the effects of dispersed fluid volume on the characteristics of crude oil in water nanoemulsions. A fixed sodium dodecylbenzenesulfonate (SDBS) surfactant concentration of 2 wt.% was used to study the effect of increasing crude oil volume on the nanoemulsion characteristics, including zeta potential. This work was using 4 different crude oil fractions of 5, 10, 20, and 50 vol.%. The emulsion was prepared overnight using a magnetic stirrer at 600 rpm, and the zeta potential was measured immediately after the nanoemulsion preparation. Figure 6 showsFigure 6 that all formulated nanoemulsions have negative zeta potential of -42.1, -51.7, -57.3, and -62.6 mV from 5, 10, 20, and 50 vol.% crude oil, respectively. Hence, the absolute zeta potential increases with the volume of the crude oil phase.

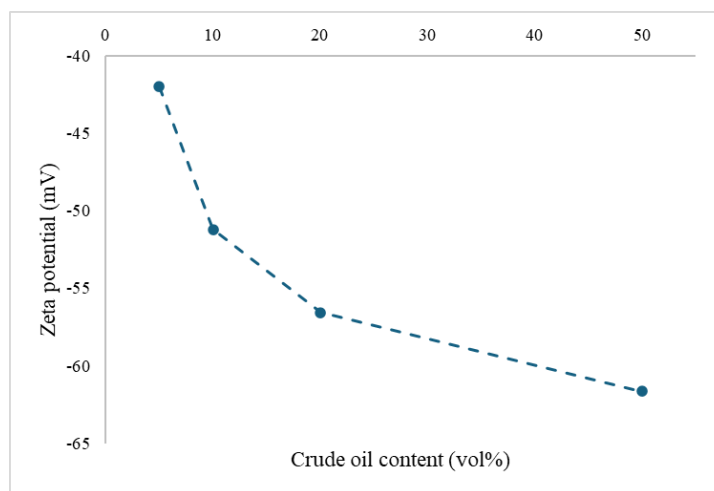


Figure 6. Effect of different oil volumes on the zeta potential of the formulated W/O nanoemulsion (Onaizi, 2022b).

Ashrafizadeh et al. (2012) studied an oil-in-water emulsion stabilized by a natural surfactant with various concentrations of sodium carbonate from 2,000 to 10,000 ppm in the aqueous phase. The results revealed that emulsions with Na_2CO_3 concentrations ranging from 2,000 to 6,000 were stabilized by double-layer repulsion interactions. Xin et al. (2013) investigated the properties of an O/W nano-emulsion with paraffin and span 20/tween 20 as an emulsifier. The emulsifier concentration ranges from 3 to 10 wt.% showed almost no difference in the droplet size after 35 days, indicating stability. However, there was a slight increase in the zeta potential from -35 mV to -32 mV along with an increase in the emulsifier concentration from 3 to 10 wt.%. In another study, Onaizi (2022a) formulated an emulsion with constant water and oil ratios of 80% and 20%, respectively, while the emulsifier content varied at 0.1, 0.5, 2, and 4 wt.%. The result revealed that increasing the anionic surfactant concentration, which is SDBS, from 0.1 to 4 wt.% gradually decreased the zeta potential from -16.3 to -62.2 mV gradually. Increasing the surfactant concentration made the zeta potential more negative due to the presence of more anions in the interfacial film. The same conclusion was obtained by other studies that showed that increasing the surfactant concentration increased the repulsion force of the emulsion, as demonstrated by the absolute zeta potential of the emulsion droplets (Dong et al., 2010; Irfan et al., 2023).

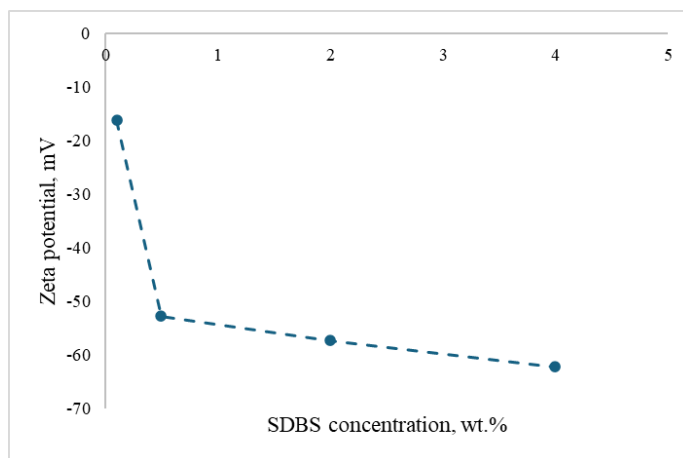


Figure 7. Zeta potential values of crude oil/water nanoemulsions formulated at different emulsifier concentrations (Onaizi, 2022a)

The water phase chemistry strongly influences the zeta potential of crude oil and water emulsions. Zeta potential determines the electrostatic stability of emulsion droplets by indicating the degree

of droplet repulsion. Higher absolute zeta potential values, which are typically more negative in systems dominated by anionic surfactants, correlate with stronger repulsive interactions and prolonged coalescence inhibition. Surfactant concentration is a decisive factor: increasing surfactant loading yields progressively more negative zeta potential due to enhanced interfacial charge density, while salinity and electrolyte type modulate this behavior by compressing the electrical double layer. Overall, engineering the interfacial charge environment through optimized surfactant chemistry and controlled salinity is central to maintaining stable emulsions.

2.2.3 Interfacial Tension

IFT is one of the critical parameters that affect the stability of an emulsion. Decreasing the IFT between crude oil and injected solutions would result in a more stable emulsion. Methods such as pendant drop tensiometry, spinning drop, and microfluidic devices were used to measure the IFT. The IFT could be reduced by adding an emulsifier to the interface between two immiscible fluids. Before the optimum number is reached, the more emulsifier absorbed, the lower the IFT, hence increasing the stability of O-W emulsion. Abdurahmanet al. (2012) investigated the effects of increasing the Triton X-100 concentration on the IFT of water and very viscous Malaysian crude oil samples. Using 0.25 wt.% of surfactant concentration gives an IFT of around 2.4 mN/m, and increasing the concentration to 2.5 wt.% lowers the IFT to 0.65 mN/m. Ahmed et al. (1999) reported that increasing the concentration of nonionic surfactant nonyl phenol ethoxylate (NPE) or anionic surfactant triethanolamine salt of dodecyl benzene sulfonic acid (TDS) surfactant lowered the IFT. The experiments used a surfactant concentration range of 0.0625–2.5 wt.% in different water salinities. The results showed a decrease in the IFT value from 2.1 to 0.6 mN/m, followed by an increase in the surfactant concentration of nonionic NPE in fresh water (Figure 8)Figure 8. On the other hand, anionic TDS also gave promising results by reducing the IFT from 1.75 to 0.21 mN/m. Both nonionic NPE and anionic TDS dissolved in formation water also gave promising results, as shown in Figure 8. This indicates the ability of different surfactant types to lower the IFT of immiscible fluids. It then revealed that combining those surfactants resulted in even better IFT reduction. Donget al. (2010) confirmed the same trends that a reduction in IFT along with an increase in surfactant concentrations.

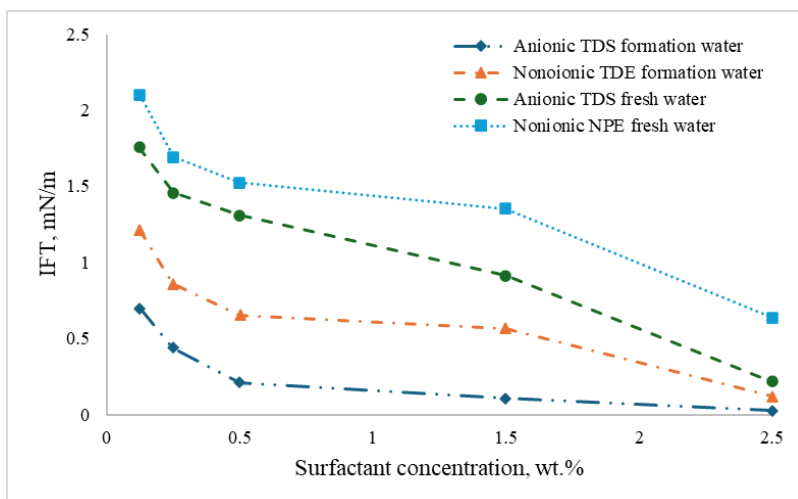


Figure 8. IFT of different surfactant concentrations and water salinity (Ahmed et al., 1999)

The effect of salinity on interfacial tension is then assessed in relation to the previous study. Salts directly impact the IFT and emulsion stability (Liu et al., 2018). Martínez-Palou et al. (2013) observed the effect of salt content on demulsifying an O/W emulsion and found that surfactant hydrophilicity tends to be decreased by water salinity, with a mechanism of reducing the interaction between water and the interfacial film. Ling et al. (2018) reported that emulsion stability increased with salinity, regardless of whether the salt was divalent (CaCl_2) or monovalent (NaCl). The emulsions were prepared using crude oil, paraffin oil, xylene, crude oil with reduced asphaltene content, and crude oil with reduced organic acid content. Various salt concentrations of 0, 0.01, 0.1, and 1 wt.% NaCl and CaCl_2 were used. The results revealed that two salts, CaCl_2 and NaCl , showed no significant difference. Both salts in the same concentration of 0.1 wt.% give the best results of a stable emulsion with unchanged droplet size for over 4 days, and adding a concentration above it did not give a significant benefit. The reduction of IFT, initial droplet size, dielectric permittivity, and density difference mechanisms is not relevant in this study's stability improvement.

The ease of droplet formation and the persistence of emulsified states are governed by interfacial tension, and its reduction is fundamental to achieving stable oil–water emulsions. Extensive experimental work demonstrates that surfactant type and concentration are the primary drivers of IFT reduction, with both ionic and nonionic surfactants lowering IFT to levels that suppress droplet coalescence. The influence of salinity is system-dependent: moderate salt concentrations may

enhance stability by reinforcing interfacial films, whereas excessive ionic strength disrupts surfactant hydration and increases droplet size. Collectively, these findings confirm that tailoring IFT through precise tuning of surfactant chemistry and salinity allows for effective modulation of emulsion stability, making it a key design criterion in enhanced oil recovery and flow assurance.

2.2.4 Rheology Properties

The rheological properties of emulsions are commonly used to characterize their ability. The rheological properties and emulsion stability are related to each other. A higher emulsion viscosity commonly indicates stability and favorable behavior in the reservoir during EOR. Kumar and Mahto (2017) prepared a pure heavy crude oil from the Cambay Basin in India and synthesized a surfactant to make an emulsion. PEG 4000 reacted with linoleic acid in the presence of 1 wt.% p-toluenesulfonic acid, which was used as the surfactant. To make an emulsion, a constant concentration of 1.5 wt.% of surfactant was used to react with a range of oil volumes from 40 to 60 vol.%. The results showed that increasing the volume of oil in the emulsion increases the viscosity from 5 mPa.s with 40 vol.% oil content to 681.8 mPa.s with 60 vol.% oil content. The maximum acceptable oil and water emulsion viscosity was 15.2 mPa.s with an oil content of 55%. This result indicates an increase in the emulsion viscosity along with an increase in the oil volume in the emulsion. Ahmed et al. (1999) also investigated the effect of surfactant type and concentration on emulsion rheology properties. The study found that after 3 days, the viscosity of the emulsion stabilized by the anionic surfactant TDS was much higher than that stabilized by the nonionic surfactant NPE. For both cases, an increase in the surfactant concentration resulted in a lower IFT, smaller droplet size, and hence an increase in the viscosity of the emulsion.

In the experiments carried out by Kolotova et al. (2018), the effect of temperature and water fraction in crude oil emulsion water was examined. The emulsion was prepared using different water concentrations of 1%, 5%, 10%, 20%, 30%, and 40% without any synthetic surfactant (relying on a natural emulsifier for stabilization). The results showed that the viscosity of w/o emulsion with water phases 1 and 5% is nearly independent of the shear rate and demonstrates the behavior of Newtonian behavior. When the water volume is above 20%, the viscosity significantly increases and behaves like a non-Newtonian fluid. Emulsions with water volumes of 10% and 20% at low shear rates exhibit shear thinning. Ariffinet al. (2016) reported that the viscosity of w/o emulsion increases with the addition of water phase in the system. With a shear range from 0.1 to

1000-1 and water content of 20%–40%, this study noticed that a higher water volume fraction will have more water droplets and hydrogen bonds. The interaction between droplets leads to an increase in the hydrodynamic forces. The emulsion viscosity increased slightly from 20% to 30% water volume fraction, and a sharp viscosity increase was observed when the water content was above 30%. Other rheology tests confirmed that emulsions exhibit Newtonian behavior at high shear rates and non-Newtonian behavior at lower shear rates (Pal, 2000; Zhai et al., 2023).

Li et al. (2020) study the effects of surfactant concentration, oil and water ratio, and kinetic conditions on rheological properties of oil in water (O/W) and water in oil (W/O) emulsions. In the room temperature, the effect of varying surfactant concentration from 0.01 to 2.0 wt.%, and oil-water ratio from 1:5 to 3:1, in the rheology of emulsion were assessed. The findings indicate that, while the surfactant concentration is lower than its CMC, smaller difference between dispersed and continuous phase volume fraction give greater O/W viscosity. In the constant surfactant concentration, the higher viscosity of continuous phase, the greater viscosity of the O/W emulsion. Trying to examine W/O emulsion, Bulgarelli et al. (2025) investigate the rheological behaviour of water in oil emulsion stabilized by SPAN 80 with varying water fraction. In the emulsion with water fraction from 30 to 60 vol.%, emulsion showed yield-stress behaviour which increasing from 2 to above 10 Pa along with the water fraction increase. At the water range 50-60 vol.%, storage modulus G' exceeded loss modulus G'' showing gel-like behaviour.

Rheological behavior offers critical insight into the structural integrity and flow characteristics of emulsions, with viscosity being strongly linked to droplet size, dispersed-phase concentration, and interfacial properties. Studies consistently show that increasing the volume fraction of oil or water, depending on the emulsion type, enhances viscosity due to intensified droplet–droplet interactions and the formation of structured networks. The surfactant concentration further modifies rheology by reducing IFT, facilitating finer droplets that increase the hydrodynamic resistance. Based on shear rate and dispersed-phase loading, emulsions often transition between Newtonian and non-Newtonian behavior, reflecting the dynamic rearrangement of droplet assemblies. Overall, rheological evidence underscores that viscosity is both an indicator and determinant of emulsion stability and must be carefully controlled to optimize the performance of reservoir transport and EOR processes.

3. METHODOLOGY

3.1 Materials

This section discusses the materials used for the research, including crude oil, brines, rock samples, and chemicals.

3.1.1 Oil characteristics

In this research, two different oil samples were used for preliminary experiments. These samples were obtained from different wells of an oil field in the Atyrau region, Kazakhstan, which is affiliated with KMG Engineering LLP. Based on the emulsion generation ability when mixed with 10,000 ppm NaCl brine, the name of the sample was determined. The first oil sample could generate an emulsion when mixed with brine, which is then called Sample 1. On the other hand, the second oil sample, later called Sample 2, was not able to generate any emulsion when mixed with brine. Since this study focuses on the surfactant-stabilized emulsion, we chose sample 2, which is believed to be non-asphaltenic oil due to its unavailability in generating emulsion without an additional emulsifier.

The viscosity, density, shear rate, shear stress, and API gravity of both oil samples were measured using an Anton Parr SVM 3001 and are presented in Table 2. Table 2

Table 2. Characteristics of oil at room temperature

Sample Name	Dyn. Viscosity	Kin. Viscosity	Shear Rate	Shear Stress	Density	API Gravity 15 °C	API Density 15 °C
	mPa·s	mm ² /s	1/s	Pa	g/cm		kg/m ³
Oil sample 2	401.75	441.99	26.52	10.66	0.909	23.45	912.3
Oil sample 1	280.41	310.77	37.64	10.55	0.902	24.59	905.7

3.1.2 Brines characteristics

This study used two different brines with different salinity and composition. Low-salinity water (LSW) with a composition of 10,000 ppm sodium chloride (NaCl) was used as the base for all surfactant solutions and as the injected fluid during LSW flooding. Synthetic brine was made

similar to Caspian Sea water composition and used to saturate the core at the first stage of core flooding as formation water to mimic the real reservoir conditions. This brine was categorized as high-salinity water (HSW) with a salinity of 50,000 ppm and was prepared using different salt compositions. The salt composition of LSW and HSW is presented in Table 3. Table 3

Table 3. Salt composition of the brines

Name	Molecular formula	Composition (g/1.5L)	
		LSW	HSW
Sodium chloride	NaCl	15	21.15
Calcium chloride	CaCl ₂	-	4.8
Magnesium chloride hexahydrate	MgCl ₂ *6H ₂ O	-	28.05
Sodium sulfate	Na ₂ SO ₄	-	21

The properties of brine samples were measured using Anton Parr SVM 3001. Owing to the high sensitivity of the equipment when measuring brine, the measurements were performed several times, and the average of the measurements is presented in Table 4.

Table 4 Characteristics of brine at room temperature

Sample Name	Dyn. Viscosity	Kin. Viscosity	Shear Rate	Shear Stress	Density	API Gravity 15 °C	API Density 15 °C
	mPa·s	mm ² /s	1/s	Pa	g/cm		kg/m ³
HSW	1.034	1.0280	986.16	1.017	1.0054	7.18	1008.02
LSW	1.031	1.0019	986.21	1.017	1.0293	5.49	1031.9

However, some precipitation was observed in the HSW solution during the preparation and resting time of both LSW and HSW. Minera precipitation can occur due to the mixing of chemically incompatible salts in the brine solution. After two days, no additional dissolved salts that crystalized were observed. Based on this condition, the brine is considered to have reached equilibrium and its maximum precipitation. The brine was then filtered to remove the generated crystals and dried in the oven (Figure 9). From the 1.5 L brine solution, the precipitated salt was measured to be 1.4 g, resulting in the salinity reduction of HSW by 2.8%, which is equivalent to 933 ppm from the initial 50,000 ppm.



Figure 9. Salt precipitated from the HSW after filtration

3.1.3 Chemical characteristics

In this study, salts and surfactant play a primary role as required chemicals. A previous study revealed the composition of the Caspian Sea formation water. Since this study is trying to mimic the real field conditions, different salts are required to make a synthetic brine that matches the Caspian Sea formation water. Apart from that, it is also required to make brine that is used for flooding with low salinity water. All of those salts were from one provider, SIGMA-ALDRICH, and are detailed in Table 5.

Table 5. Salt required for this study

Name	Molecular formula	Purity
Sodium chloride	NaCl	≥99.9
Calcium chloride	CaCl ₂	≥99.8
Magnesium chloride hexahydrate	MgCl ₂ *6H ₂ O	≥99.9
Sodium sulfate	Na ₂ SO ₄	≥99.9

Knowing that the main oil type used is a non-asphaltenic, a surfactant is needed to make the emulsifier. Two types of anionic surfactants were used in the preliminary test to determine the surfactant and its concentration, namely, alpha-olefin sulfonate (AOS) and sodium dodecyl sulfate (SDS). Anionic surfactant type was used because of its availability in the laboratory and to minimize its . Table 6 shows the details of the anionic surfactant used during the experimental stage of this study, which was obtained from the same company that provided the salts.

Table 6. Surfactant type used in this study

Name	Type	Purity
Alpha Olefin Sulfonate (AOS)	Anionic	≥ 99.9
Sodium Dodecyl Sulfate (SDS)	Anionic	≥ 99.9

3.1.4 Core characteristics

The Berea sandstone cores were used for core flooding. Sandstone was chosen because of its lower absorption capacity with anionic surfactant than carbonate rock. Before main core flooding, the cores were first saturated with HSW as formation water using a manual saturator. The details of HSW were discussed in Section 3.1.2. Table 7 shows the details of the core samples used during the study.

Table 7. Characteristics of core samples

Sample	Diameter	Length	Poro	Perm	PV	Area
	mm	mm	%	mD	cc	cm ²
Core 1	38.3	74.33	21.15	296	18.10	11.515
Core 2	38.3	75.87	21.53	301.5	18.81	11.515
Core 3	38.31	77.05	21.55	323.9	19.13	11.521



Figure 10. Helium Porosimeter to measure the core porosity



Figure 11. PoroPerm apparatus to measure the core permeability

3.2 Experiments and Methods

3.2.1 *Brine preparation*

Brine solutions were prepared to be used for most of the experiments. Two different brines with different compositions and purposes were prepared. However, most experiments used LSW as the main or base solution. The brine preparation required dissolving precise quantities of salts in the appropriate distilled water volume by stirring. The salts used were weighed to obtain an appropriate quantity for making 10,000 ppm LSW solution and 50,000 ppm HSW solution. Using a magnetic stirrer, the solution was stirred at a speed of 500 rpm until the salts completely dissolved. The same procedure was performed for both LSW and HSW making. The details of the brine solutions are provided in Section 3.1.2.



Figure 12. Magnetic stirrer used to mix solutions

3.2.2 Measurement of fluid properties

To have a better understanding of each fluid used in this experimental study, it is important to know their properties. For properties such as viscosity and density, Anton Parr SVM 3001 was employed. Not only to get an idea about fluid clear behavior but also the value is important during other tests such as IFT measurement and absolute permeability measurement. Since the core flood test was conducted at room temperature, the fluid properties were also measured at room temperature at 20 °C. Each fluid was measured several times, and the average value of the measurement results was used. For every measurement using the Anton Parr SVM 3001 equipment, it requires ~5 cc of sample. The sample used needs to be filtered first to remove any solids that could damage the equipment.

3.2.3 Evaluation of emulsion stability

Emulsion stability assessment was performed to better understand the effect of surfactant concentration on emulsion stability. Using 10,000 ppm NaCl as the base brine solution, several surfactant solutions were prepared, including AOS and SDS, with concentrations ranging from 1,000 to 3,000 ppm. The emulsion was made by mixing the solution and oil sample in the same 1:1 ratio. In beaker 50 cc capacity, mixing 20 cc surfactant solution and 20-cc oil were mixed using a magnetic stirrer at 500 rpm for 5 minutes. The sample was then stored in an airtight container and observed under a polarization microscope for 1, 24, and 72 h. 1 hour was chosen as the first timestep for observation to allow the sample to separate and provide a clear image of each phase. Since the study focuses on emulsion stability, a syringe with a needle was used to take samples from only the emulsion phase for microscope observation and to obtain a more precise sampling process. The same procedure was performed for all other samples with different concentrations. The microscopic images were assessed and droplet size distribution was calculated using software ImageJ.



Figure 13. Polarization microscope

3.2.4 IFT measurement

IFT measurements were conducted to evaluate the performance of the surfactant solution in reducing the interfacial tension between oil and water. IFT between brines and surfactant solutions with oil was measured using an IFT apparatus with high camera resolution and image analysis software, as shown in Figure 14. To have a picture of how the interfacial behavior is when an oil sample is contacted with different solutions, aqueous solutions were prepared, including LSW (NaCl 10,000 ppm), HSW sea water (50,000 ppm), LSW sea water (10,000 ppm), AOS 2,000 ppm, and AOS 500 ppm. A droplet of oil was carefully formed at the tip of a needle that was submerged in the aqueous phase. The droplet profile was then captured by a camera system and analyzed by the software. The IFT value was determined by fitting the shape of the droplet using the Young–Laplace equation. For each sample, the experiment was carried out multiple times to ensure consistency, and the average value was reported.

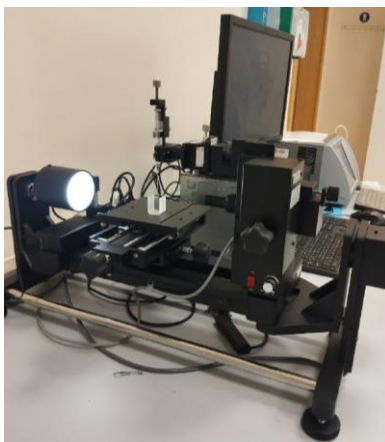


Figure 14. IFT apparatus

3.2.5 Measurements of emulsion resistivity

The resistivity measurement of the emulsion is mainly intended to evaluate the type of emulsion. The emulsion sample was prepared by stirring the oil and surfactant solution of 2,000 ppm AOS using a magnetic stirrer for 5 min at 500 rpm. The ratio of each phase is 1:1 for the oil and surfactant solutions. After the mixing process, the sample was left for 24 h to reach equilibrium and show a clear interface between the water, emulsion, and oil. The measurement was performed by compressing the rubber bulb to expel air from the measurement cell. The cell was then placed in the emulsion sample, and upon releasing the bulb, the sample was automatically drawn into the cell. The filled measurement cell was then placed into the resistivity meter, where it was connected to the electrodes for resistivity measurement. The resistivity measurements of the other sample solutions were performed to compare the resistivity differences in each solution.



Figure 15. Resistivity meter

3.2.6 Spontaneous emulsification

In this section, spontaneous emulsification is assessed. Spontaneous emulsification assessment was conducted to evaluate the ability of the surfactant-brine-oil system to generate emulsion naturally. This test provides an insight into the interfacial activity and the stability of the potential type of emulsion. The test started with brine preparation. The type of brine used was LSW, which is 10,000 ppm of NaCl. The brine was first mixed with a solid surfactant of different weights to make several solutions with different surfactant concentrations using a magnetic stirrer. Three solutions were made with AOS concentrations of 1000, 2000, and 3000 ppm. The test of spontaneous emulsification was performed by placing the surfactant solution and oil sample in airtight containers. The surfactant solution was first poured into the containers, followed by the oil, with the same ratio of 10 cc of surfactant and 10 cc of oil. During the process, all steps were performed very gently to ensure that no external energy was applied to the system. The container is then placed in a stable cabinet at room temperature, ensuring that there is no single shock. Observations were carried out every day for seven days to determine if any interfacial differences existed between water and oil.

3.2.7 Core flooding

After the preliminary tests, core flooding is the main experiment in this study. This test is important to give an idea of the emulsion performance in the porous media during flooding. The flooding test was performed using the core flooding system (CFS) 700 equipment (Figure 17). Before flooding, the cores were first saturated with HSW (details in section 3.1.2) as formation water using a manual saturator for at least 24 h at a pressure of 1,000 psi. After saturation, the cores were injected with the same brine using CFS 700 with injection rates varying from 1 to 10 cc per minute. HSW injection was conducted to ensure that the core was fully saturated with formation water. The corresponding pressure difference for each injection rate was used to calculate the absolute permeability (k).



Figure 16. Manual saturator



Figure 17. CFS 700 equipment

A main core flooding test was conducted on Berea sandstone cores under different scenarios. The first scenario uses surfactant as the primary injection. After being saturated with formation water, the core was injected with oil at a rate of 0.5 cc per minute until it reached 100% oil cut. This process was performed to mimic the drainage process inside the reservoir, and the saturation of the water connate, Sw_{ir} , was then calculated. Subsequently, surfactant flooding was conducted as secondary recovery with an injection rate of 0.5 cc per minute. This rate was determined after calculating the maximum possible rate to ensure that the mechanism remains in the capillary-dominated flow.

In the second scenario, surfactant injection was performed as a secondary injection, following an initial water flooding stage. The same procedure was performed as in the first scenario to obtain the Swir value. After oil injection, water flooding was conducted as the first recovery with a rate of 0.5 cc per minute until no more oil production was achieved. Subsequently, surfactant flooding was carried out as the next stage of recovery with the same rate of 0.5 cc per minute. The in situ-generated emulsion was then observed under a microscope to assess the droplet distribution.

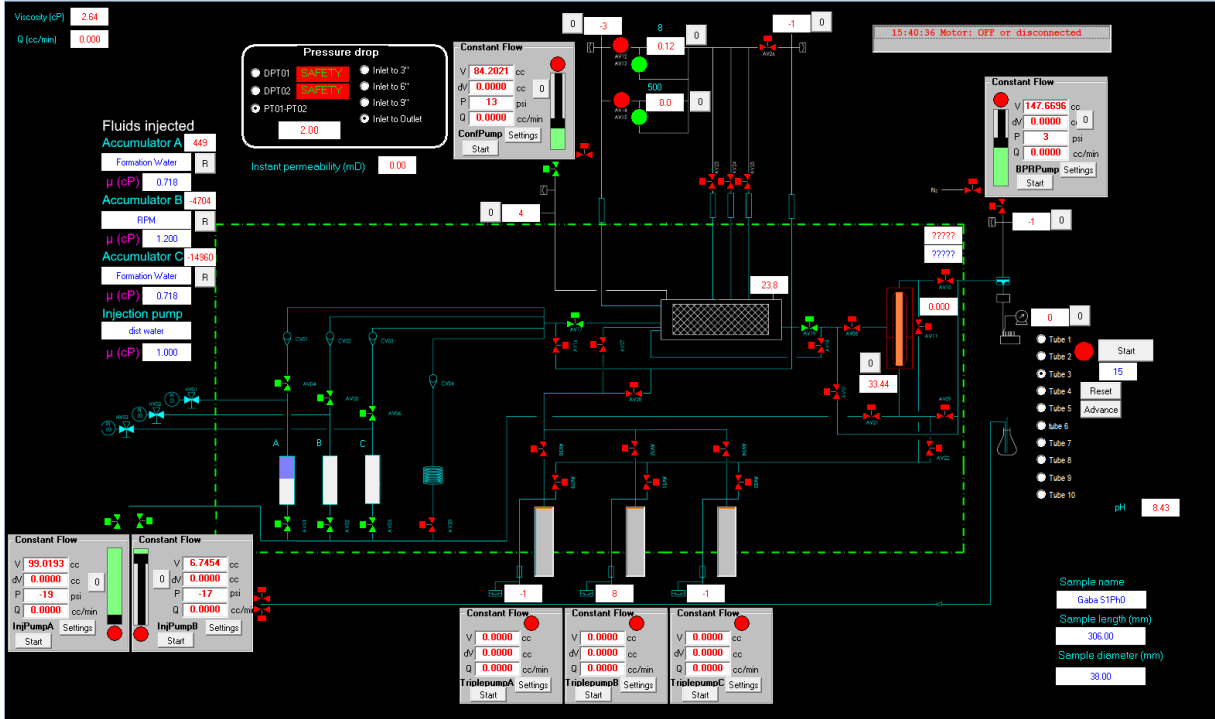


Figure 18. Schematic of the core flooding apparatus

4. RESULTS AND DISCUSSION

4.1 Spontaneous emulsification

The observation of spontaneous emulsification was mainly done to determine the ability of the surfactant-brine-oil system to generate an emulsion. As shown in Figure 19, no stable emulsion was generated after 10 minutes of observation. However, it still showed irregular oil and water interfaces, indicating the potential for emulsion generation. After seven days, the oil–water

interface became more uniform, and the irregularities disappeared. The results indicate that a stable emulsion cannot be generated without the addition of external energy to the system.



Figure 19. Spontaneous emulsification observation shows no difference; (left) after 10 min and (right) after 7 days

4.2 Stability assessment

4.2.1 Emulsion Stabilized by AOS Surfactant

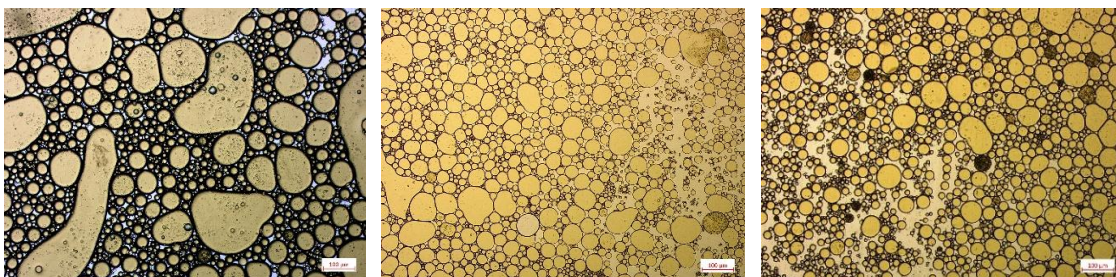
Figure 20 shows the system after 1 h of generating the emulsion. After 1 hour, the system shows partial phase separation with visible emulsion formation at the oil–water interface after 1 h. A distinct oil layer remained at the top, while the lower aqueous phase appeared turbid, indicating dispersed oil droplets within the water phase. The cloudy appearance of the aqueous phase suggests that emulsification has occurred, but the system has not yet reached equilibrium. The turbidity is caused by suspended oil droplets, which are stabilized by the AOS, preventing immediate coalescence and complete phase separation.

The interface appears irregular and diffuse at this early stage, indicating ongoing dynamic processes such as droplet breakup and coalescence. The presence of a transitional emulsion layer between the oil and water phases suggests incomplete separation, where some droplets remain trapped at the interface due to a reduction in interfacial tension and surfactant adsorption. Overall, the system represents a metastable emulsion in which surfactant molecules have initiated dispersion but have not yet fully stabilized the system.



Figure 20. Samples after 1 h of stirring

As shown in Figure 21, the emulsions observed after 1 h demonstrate a clear dependence of droplet characteristics on AOS concentration. Figure 21 At 1000 ppm AOS, the emulsion exhibits relatively larger droplets, indicating that weak electrostatic stabilization allows for partial coalescence, resulting in non-uniform droplet sizes. At 2000 ppm, the droplet size distribution becomes narrower, with a noticeable reduction in the average droplet diameter. This suggests improved surfactant adsorption at the oil–water interface, leading to enhanced IFT reduction and increased coalescence stabilization. At a final concentration of 3000 ppm, the emulsion is characterized by a significantly finer and more homogeneous dispersion with a high number density of small droplets. This indicates that the surfactant concentration approaches or exceeds the CMC, enabling rapid interfacial saturation. Consequently, the interfacial films become more rigid and stable, effectively suppressing droplet coalescence and promoting the formation of a stable oil-in-water (O/W) emulsion. Overall, increasing the concentration of surfactants leads to smaller droplet sizes and improves the potential for a more stable emulsion in 24 h. However, the difference in color in the overall figures is due to the inconsistency in the lighting of the microscope during the observation. In fact, the actual colors of the droplets and the systems are the same.



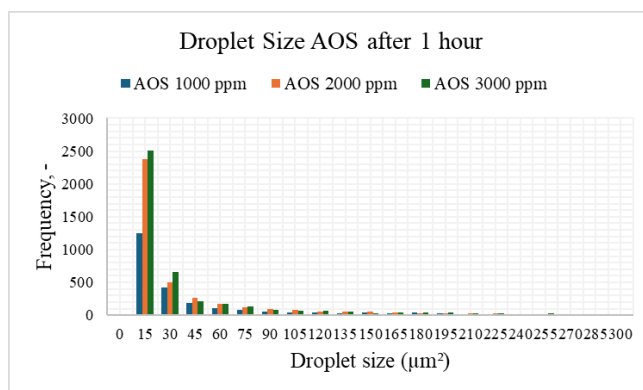


Figure 21. Emulsion observed after 1 h: (a) 1000, (b) 2000, and (c) 3000 ppm AOS. (d) Droplet size distribution

The emulsions observed after 24 h exhibited a clear evolution in droplet size distribution and stability as a function of the AOS concentration, indicating time-dependent stabilization mechanisms (Figure 22). At 1000 ppm, the emulsion is characterized by relatively large and irregular droplets, suggesting insufficient surfactant coverage at the oil–water interface. Over time, coalescence dominates, resulting in droplet growth and a broader size distribution. The limited interfacial film strength results in poor stability and a tendency toward phase separation. At 2000 ppm, the emulsion showed a more refined droplet structure with a wider range of intermediate and smaller droplets. This indicates improved interfacial adsorption of surfactant molecules, which enhances electrostatic repulsion and steric stabilization, thereby reducing coalescence. However, some degree of droplet aggregation is still evident, indicating that the system is moderately stable but not fully optimized. The emulsion exhibited a highly dispersed and dense population of fine droplets with a relatively uniform size distribution at a concentration of 3000 ppm. This reflects a well-stabilized emulsion system, where sufficient surfactant concentration ensures near-complete interfacial coverage. The resulting interfacial films are more rigid and rupture-resistant, effectively suppressing coalescence over time. Overall, after 24 h, the system demonstrated that increasing the surfactant concentration significantly improved the emulsion stability by reducing the droplet size, narrowing the size distribution, and inhibiting coalescence.

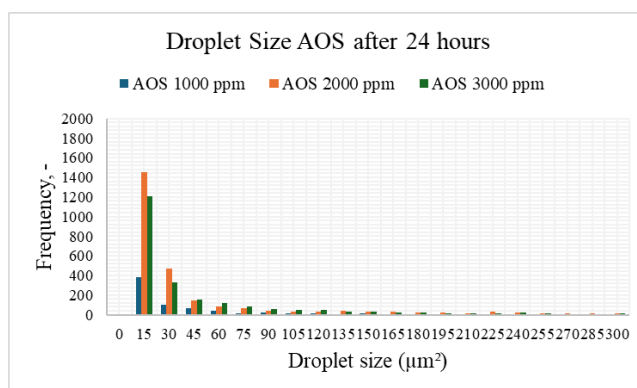
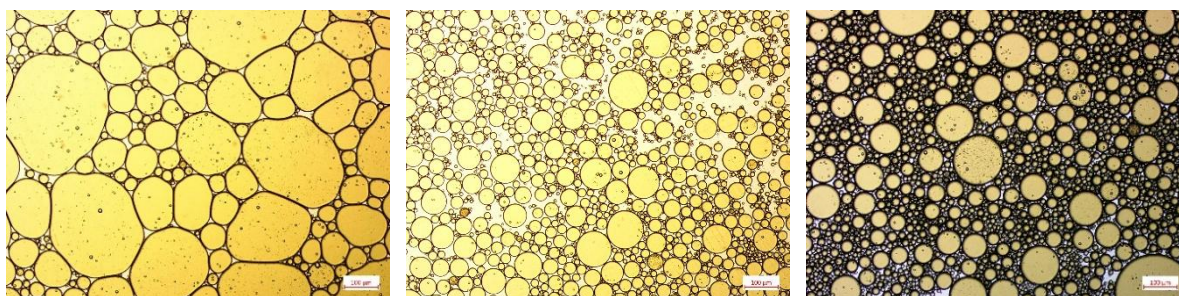


Figure 22. Emulsion observed after 24 h: (a) 1000, (b) 2000, and (c) 3000 ppm AOS. (d) Droplet size distribution

The emulsions observed after 72 h reveal the long-term stability behavior of the system as influenced by AOS concentration, highlighting the droplet size distribution. The 1000 ppm emulsion shows pronounced droplet growth with a wide and irregular size distribution. The presence of significantly larger droplets indicates that coalescence dominates the stabilization mechanisms. The limited surfactant concentration results in weak interfacial films, allowing droplets to merge over time, ultimately reducing emulsion stability and promoting phase separation. At 2000 ppm, the emulsion maintained a relatively fine and uniform droplet distribution even after 72 h. This result reveals that this concentration ensures a stronger interfacial film and effectively minimizes coalescence, thereby improving stability. Compared with the emulsion from 2000 ppm, the concentration of 3000 ppm gives more non-uniform droplets. The number of droplets was less than 24 h, especially smaller droplets, indicating coalescence and phase separation. Smaller droplets collided and formed larger droplets, while larger droplets separated from the emulsion phase.



Figure 23. Samples after 72 h of stirring

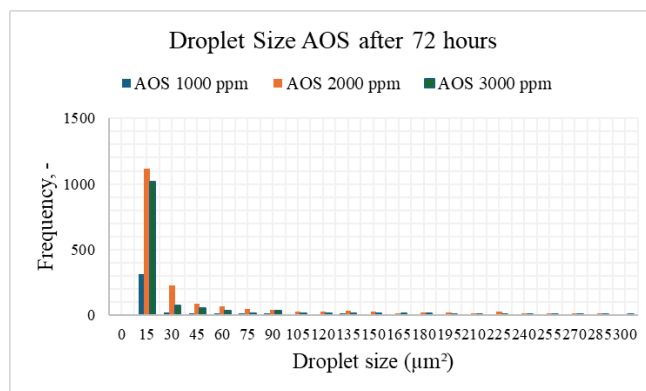
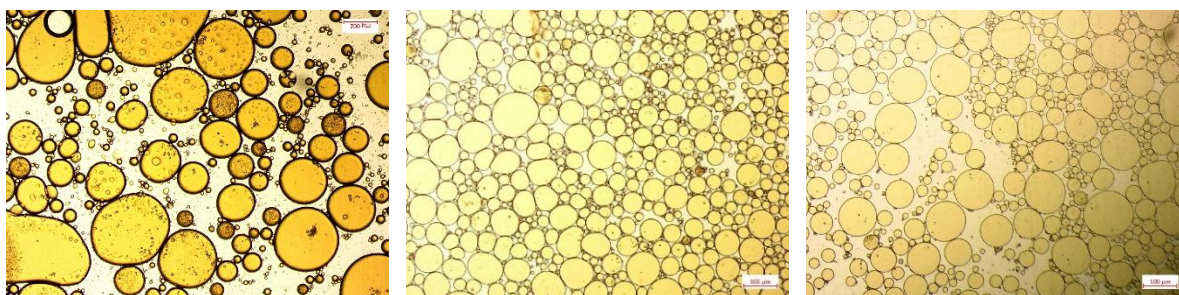


Figure 24. Emulsion observed after 72 h: (a) 1000, (b) 2000, and (c) 3000 ppm AOS. (d) Droplet size distribution

4.2.2 Emulsion Stabilized by SDS Surfactant

The emulsion generated by the SDS surfactant after 1 h is clearly shown in FigureFigure 26. The figure demonstrates the effect of SDS concentration increment on the emulsion droplet size distribution. At 1000 ppm, the emulsion exhibited relatively large and highly polydisperse droplets, indicating weak stabilization and early-stage coalescence. The emulsion generated at 2000 ppm yields more uniform droplets compared with the previous concentration. However, the

droplet size is quite large, and the polydispersity tendency remains high. In this early time observation, 3000 ppm SDS gives more promising results than the other concentrations in the same time range. The emulsion is characterized by a dense population of fine and relatively homogeneous droplets, indicating near-complete interfacial coverage and stronger interfacial film formation, which effectively suppresses coalescence. Increasing the concentration of surfactant SDS enhances the stability of the emulsion by promoting smaller droplet sizes, a narrower size distribution, and improved interfacial stabilization even at the early stage of emulsification.



Figure 25. Samples after 1 h of stirring

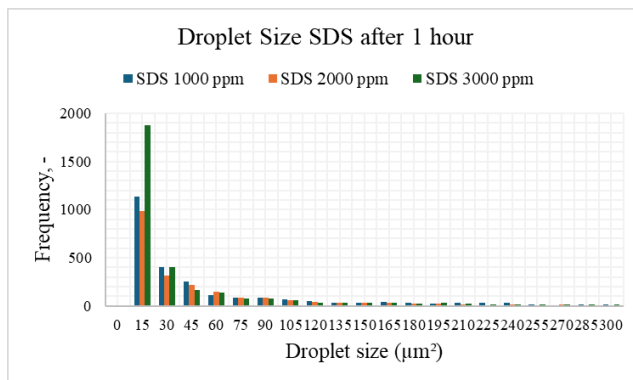
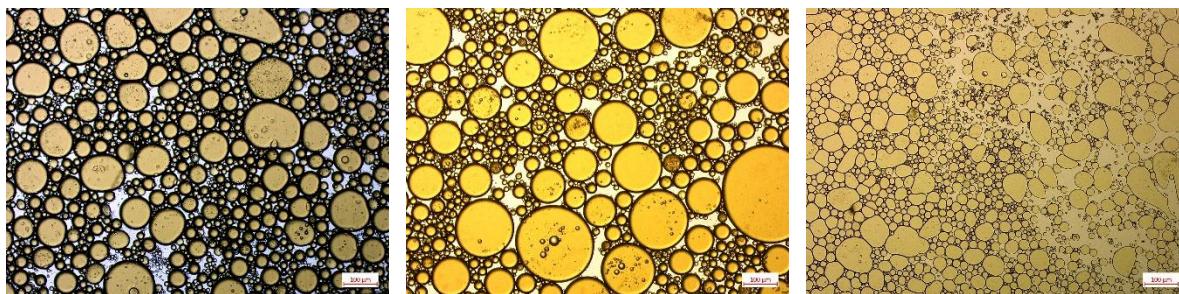


Figure 26. Emulsion observed after 1 h: (a) 1000, (b) 2000, and (c) 3000 ppm SDS. (d) Droplet size distribution

After 24 h, the stability of the emulsions changed over time. The system with different concentrations has the same trend, which is a reduction in the number of droplets and higher polydispersity. Figure 27 shows the microscopic images of the emulsion prepared with surfactant concentrations ranging from 1000 to 3000 ppm after 24 h. The larger droplets observed after 1 h have a weaker interfacial film and coalesce, resulting in a reduction in the number of droplets. The smaller droplets coalesce, recreating the larger droplets observed after 24 h. Conversely, Ostwald ripening was also observed, in which small droplets dissolved and their molecules diffused in the continuous phase. The molecules then precipitate and surround the larger droplets, forming a cloudy appearance around them. Overall, the system exhibits coalescence and Ostwald ripening, reducing droplet growth and stability.

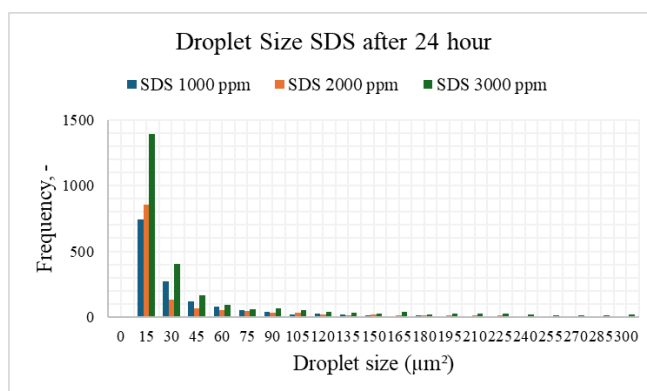
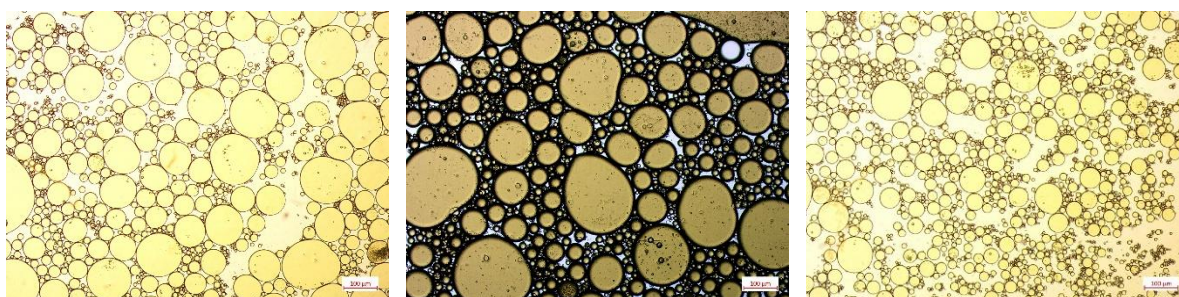


Figure 27. Emulsion observed after 24 h: (a) 1000, (b) 2000, and (c) 3000 ppm SDS. (d) Droplet size distribution

In Figure 29, the emulsion droplets become larger and exhibit a stability reduction after 72 h. The droplet coalescence became massive, resulting in higher polydispersity in the system. However, the system clearly shows the droplet size distribution differences, demonstrating that stability improved with an increase in SDS concentration.



Figure 28. Samples after 72 h of stirring

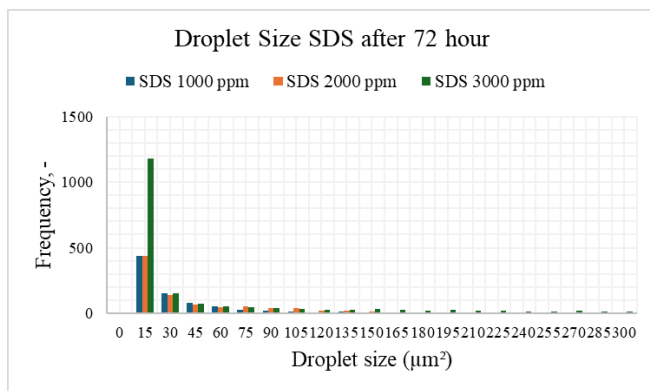
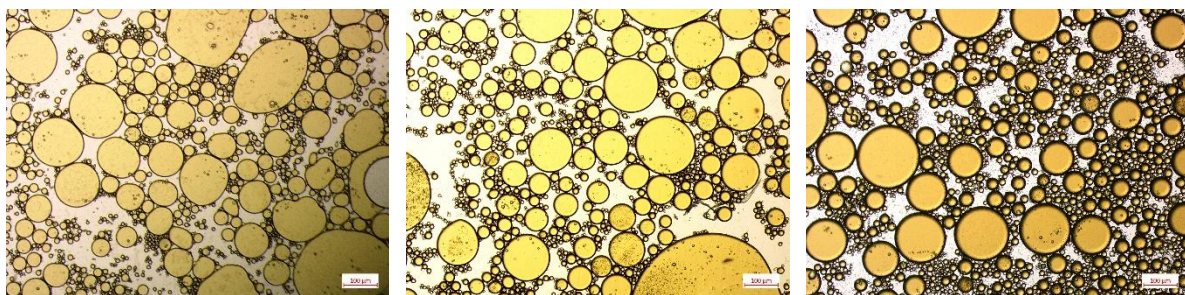


Figure 29. Emulsion observed after 72 h: (a) 1000, (b) 2000, and (c) 3000 ppm SDS. (d) Droplet size distribution

4.3 IFT Measurements

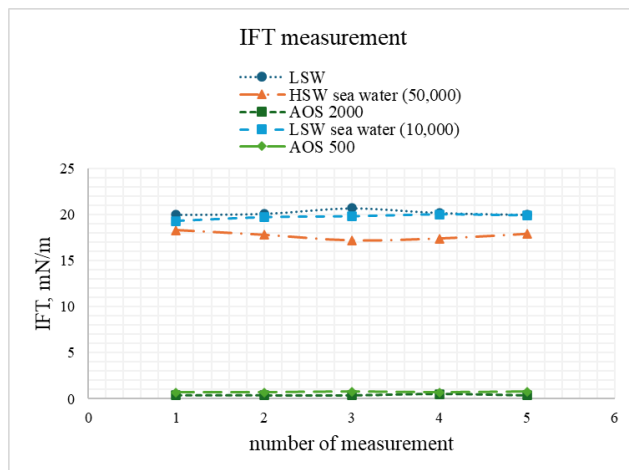


Figure 30. Result of the IFT measurements

The IFT measurement clearly distinguishes between the brine and surfactant systems. The baseline IFT values for low-salinity water (LSW) and high-salinity water (HSW) remain relatively high, ranging approximately 17–21 mN/m, indicating strong interfacial forces between oil and water in the absence of surfactants. Slight variations between LSW and HSW can be attributed to salinity and ion-type effects, where ionic strength influences interfacial properties.

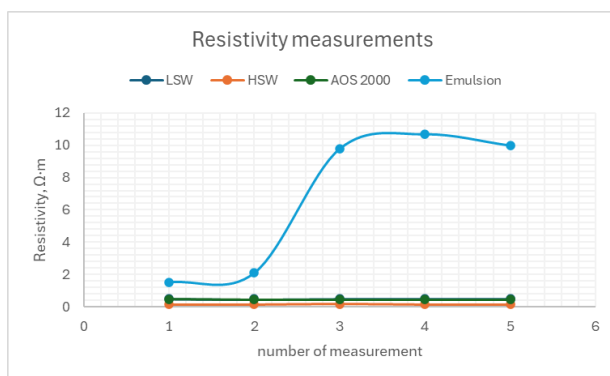
In contrast, the surfactant solutions give massive IFT reduction below 1 mN/m, demonstrating their strong effectiveness in reducing IFT. The increment of surfactant concentration from 500 ppm to 2,000 ppm of AOS reduced the IFT value from 0.7 to 0.4 mN/m. This significant decrease reveals the effectiveness of the surfactant in reducing IFT under CMC. Furthermore, the relatively stable IFT values across repeated measurements suggest good reproducibility and equilibrium conditions. Overall, the results confirm that the addition of surfactant is highly effective in lowering IFT.

Table 8. IFT measurement results

Measurement	LSW	HSW sea water (50,000)	LSW sea water (10,000)	AOS 2000	AOS 500
	mN/m	mN/m	mN/m	mN/m	mN/m
1	20	18.3	19.3	0.4	0.7
2	20.1	17.8	19.7	0.4	0.7
3	20.7	17.2	19.8	0.4	0.8
4	20.2	17.4	20	0.5	0.7
5	20	17.9	19.9	0.4	0.8

4.4 Resistivity measurement

Resistivity measurements indicate a significant difference between the emulsion and the individual fluid. The LSW, HSW, and surfactant solution exhibited consistently low resistivity values with minimal variation across measurements, reflecting their conductive nature due to dissolved ions. However, the emulsion shows substantially higher resistivity, indicating a balance of brine, surfactant, and oil in the system. In the first two emulsion measurements, the resistivity was low compared to the last three measurements. This is because the emulsion phase was taken near the water phase in the first two measurements. In contrast, in the last three measurements, the emulsion sample was taken closer to the oil phase, resulting in a higher oil content in the emulsion. When measuring the resistivity of a single oil phase, the equipment showed an error due to its extremely low electrical conductivity. Overall, the resistivity results provide a clear interpretation of the O/W emulsion system.



4.5 Core flooding

Core flooding was conducted to evaluate the in-situ emulsion generation performance during surfactant injection. Berea sandstone cores, which are derived from one main core that is divided into three, were employed. The surfactant solution and concentration used were 2,000 ppm AOS. This surfactant type and concentration were chosen after emulsion stability assessment, as described in Section 394.2, which showed that 2,000 ppm of AOS gave the best performance compared to the others.

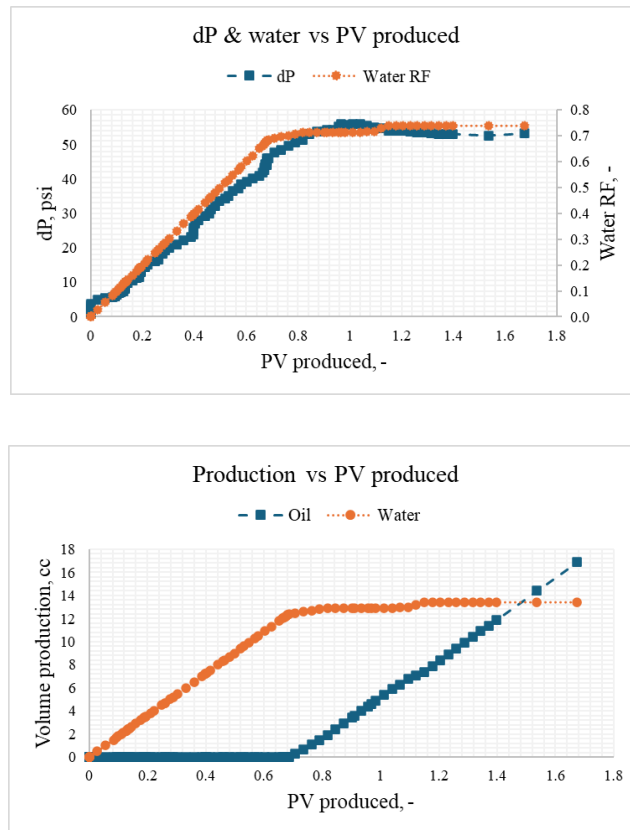
Experiments were conducted under capillary-dominated flow conditions during the chemical flooding. It is characterized by a low flow rate, such that capillary forces control the displacement in the porous media, allowing the surfactant to properly reduce the IFT and mobilize the trapped oil. To determine the optimum injection rate, the maximum capillary-dominated flow rate was calculated using the following formula:

$$q = \frac{Ca\sigma A\phi}{\mu}$$

The capillary number (Ca) used in this calculation is 5×10^{-6} which is the typical Ca of waterfloods in sandstone reservoirs (Guo et al., 2022). The maximum capillary-dominated flow region is $\sim 1.9 \text{ cm}^3/\text{mnt}$. Exceeding this value would lead to changes in the mechanism to viscous force-dominated flow. Maintaining capillary-dominated flow during core flooding is important to accurately represent the fluid behavior under reservoir conditions. At low capillary number, fluid is strongly influenced by capillary forces, which is crucial for preserving realistic pore-scale physics, accurately evaluating emulsion behavior, and validating the mechanisms responsible for incremental oil recovery. Meanwhile in high capillary number, the system would shift towards viscous dominated flow where fluids are forced through the pore network, leading to unrealistic displacement conditions.

4.5.1 Core 1: Surfactant flooding as a secondary recovery strategy

The first core flooding test was used to evaluate the performance of emulsion generation during core flooding of the surfactant. After being saturated with HSW as formation water, the core was first injected with oil, and the produced water was recorded. Oil injection was performed to mimic the drainage process in which the wetting phase was displaced by the non-wetting phase in the reservoir. The irreducible water saturation (S_{wir}) was 4.7 cm³ (25.96%) out of a total pore volume of 18.1 cm³. Figure 32 presents the production during oil flooding, which exhibits oil breakthrough after 0.71 PV production. The pore volume produced was chosen instead of PV injected because production gives a more reliable interpretation in the outlet. When the injection begins, the outlet does not immediately produce. Due to heterogeneity and small pores, the injection needs time for pressure to build up before the fluid is pushed to the outlet. Figure 32(c) shows the difference between the injected and produced fluid during the flooding.



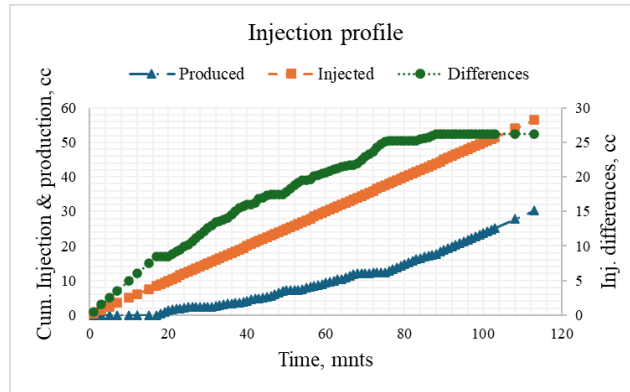


Figure 32. Oil injection profile (a) pressure drop, (b) fluid production, (c) inlet and outlet differences, and (d) effluent samples collected during oil injection

Surfactant flooding is closely related to the reduction of interfacial tension and wettability alteration. 0.5 cm³ and mnt was chosen as the injection rate which is below the maximum capillary-dominated flow conditions. This condition gives the surfactant molecules proper time to reduce IFT and change the wettability. Figure 33(a) shows how surfactant and emulsion performance in the porous media enhance oil recovery. During surfactant flooding, there were two steps of oil recovery. In the first step, the breakthrough occurred after 0.21 PV, as the pressure drop reached its peak and started to decrease after the breakthrough. During the first step, surfactant flooding recovered 56% of the oil from the total OOIP. A small amount of emulsion was observed at the end of the stage.

After the first step, the production will stop at the outlet even though the injection continues. The gap between the end of the first step and the time before the pressure increases again and production starts as the second step is called the relaxation time. During this period, in situ-generated emulsions agglomerate and block the large pores, allowing the injected fluid to reach the smaller pores or the core's edge. Even though the relaxation time causes a delay in oil

production, it allows the surfactant to reach the tiny pores, thereby improving the recovery of unrecovered oil from the first step. The total oil recovery from the chemical flooding was 74.63% (10 cm³) of the OOIP, of which 23% (2.3 cm³) was produced in the second step. Overall, in situ emulsion enhances oil recovery by stepwise oil production through IFT modification and partial areal blockage.

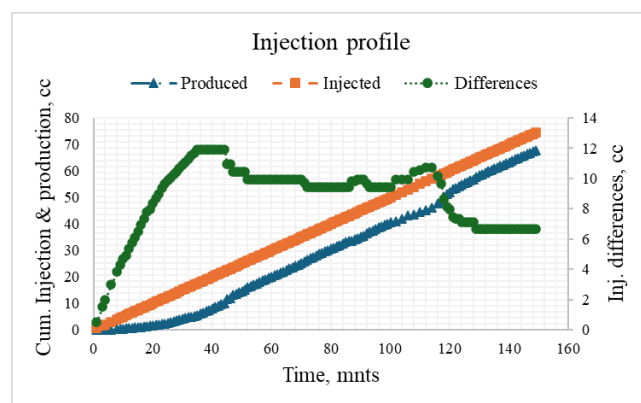
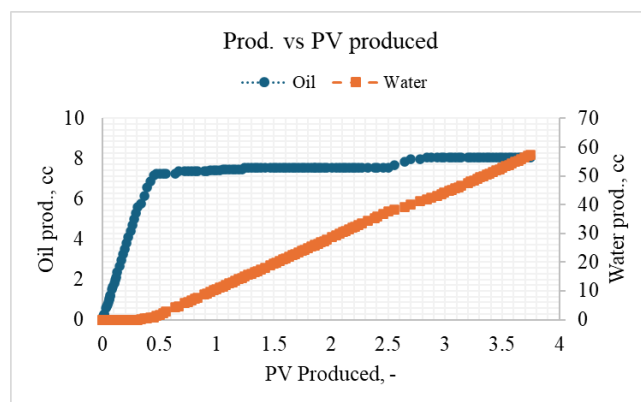
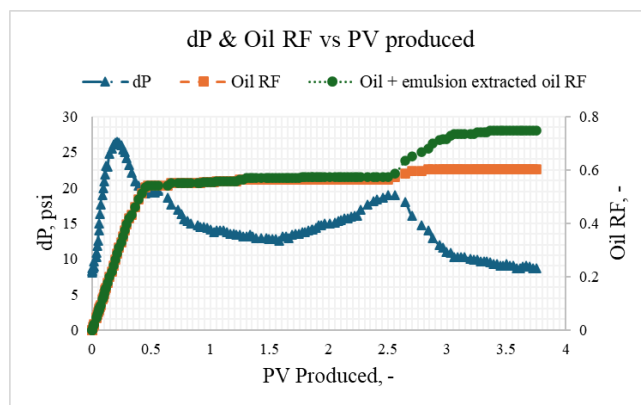




Figure 33. Surfactant flooding profile (a) pressure drops, (b) fluid production, (c) inlet and outlet differences, and (d) effluent samples collected during the flooding

During the core flooding experiments, in-situ emulsification cannot be observed visually and relies on effluent in the production outlet. However, the emulsion generation in porous media of this study, which classified as meso-stable formation, corresponds to one of mechanisms that already discussed from previous study such as snap-off mechanism (G. Li & Yao, 2023), Shear-induced breakup (Nazir & Vladisavljević, 2021), pore-scale fragmentation and ganglia breakdown (Anastasiou et al., 2024), capillary instability (Chen et al., 2019), and interfacial instabilities (Rayleigh–Plateau type) (Talon et al., 2023). Figure 34 shows the in situ-generated emulsion during surfactant core flooding, which was observed under a polarization microscope after an hour. The microscopic image shows a relatively homogeneous emulsion consisting of numerous spherical droplets dispersed within a continuous phase, likely indicating an oil-in-water system. The emulsion droplet is relatively fine, which often improves kinetic stability by minimizing creaming and sedimentation and limiting coalescence. Based on image observation, oil droplets exhibit around 80-90% of the total emulsion phase volume.

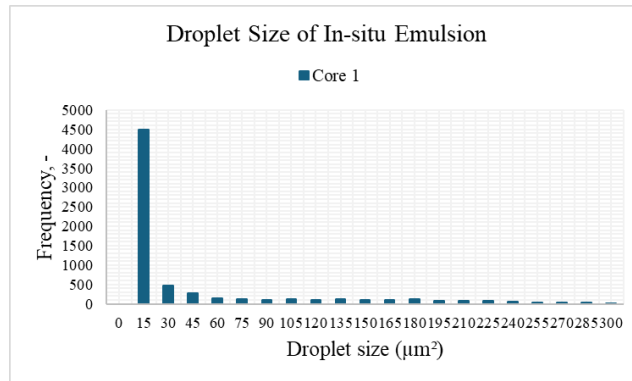
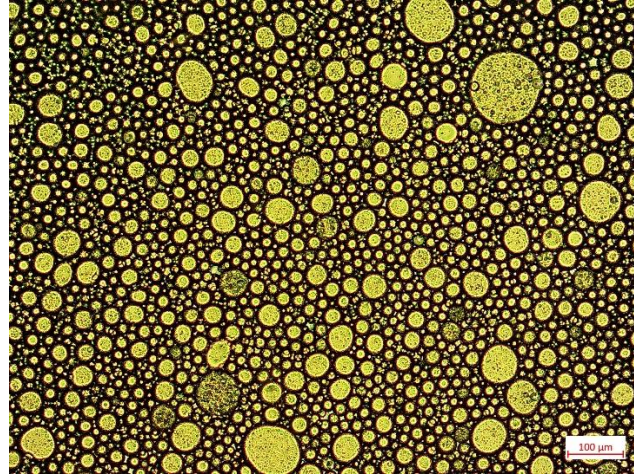


Figure 34. In situ O/W emulsion generated during surfactant core flooding

4.5.2 Core 2: Surfactant flooding as a tertiary recovery strategy

In the second core, the second scenario, which involves surfactant flooding as tertiary recovery after water flooding, was applied. Since the objective is to compare these two scenarios, we applied the same initial conditions. To maintain the capillary-dominated flow, the injection rate was 0.5 cm³/mnt for all stages. During the oil injection, Swir was found to be 4.11 cm³ (21.84%) of the total pore volume of 18.81 cm³. The observed oil breakthrough occurred after 0.77 PV was produced, as shown in FigureFigure 35.

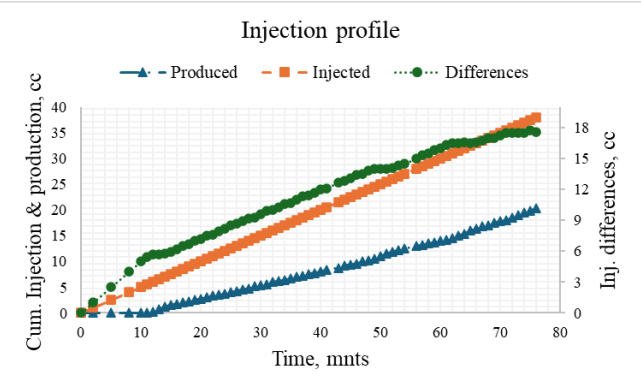
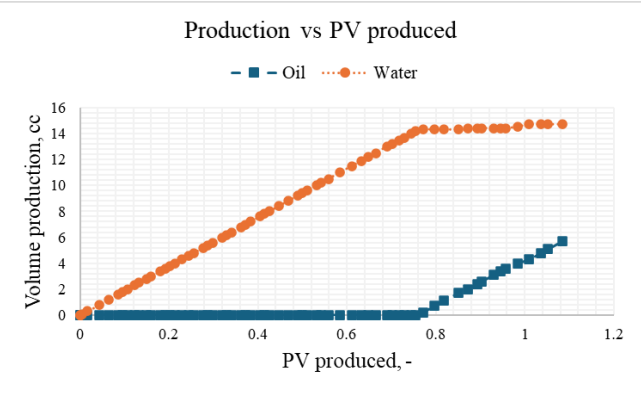
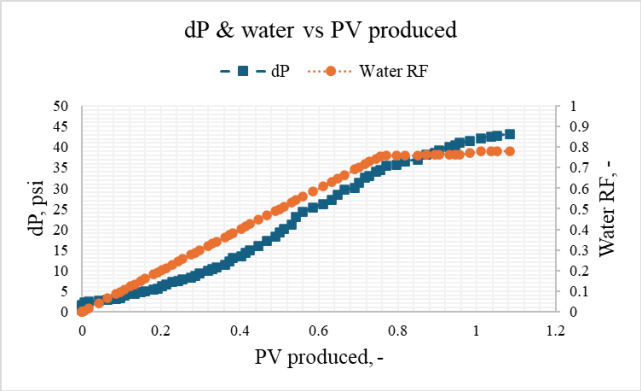
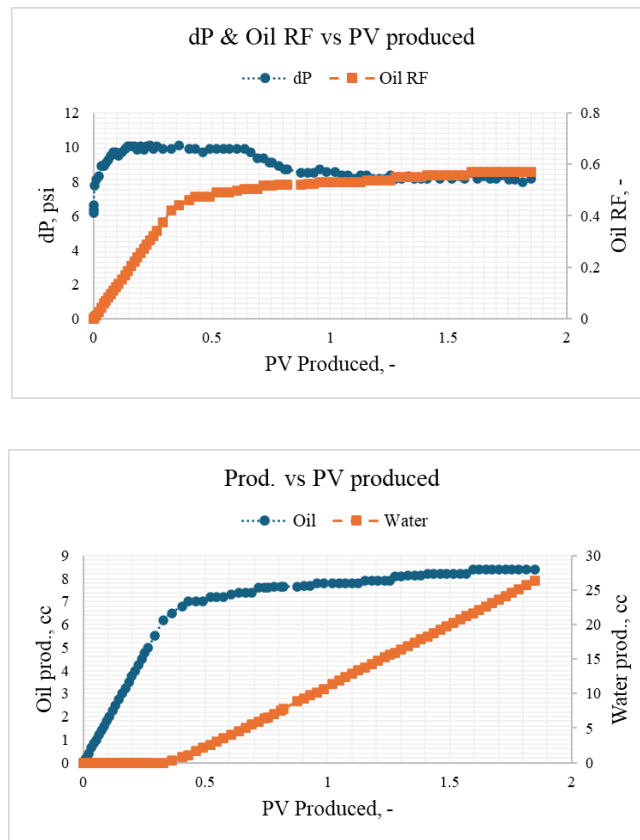


Figure 35. Oil injection profile (a) pressure drop, (b) fluid production, (c) inlet and outlet differences, and (d) effluent samples collected during oil injection

The first stage of the flooding was secondary recovery. LSW was injected into the core in this stage of the recovery. Figure 36 presents the waterflooding profile in which the pressure drop increases rapidly along with the sharp increase in the oil recovery factor. The breakthrough was reached at 0.4 PV injected, characterized by a slow recovery rate, a reduction in the pressure drop, and the initiation of water production in the outlet. The total oil recovery from the waterflooding stage was 8.4 cm³ and mnt or 57.14% of the OOIP.



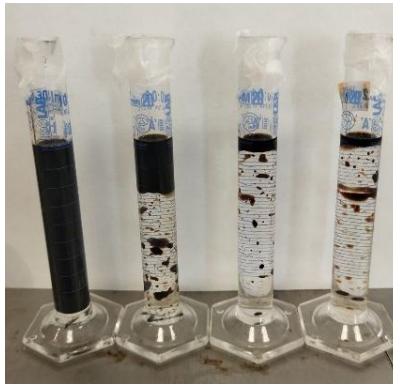
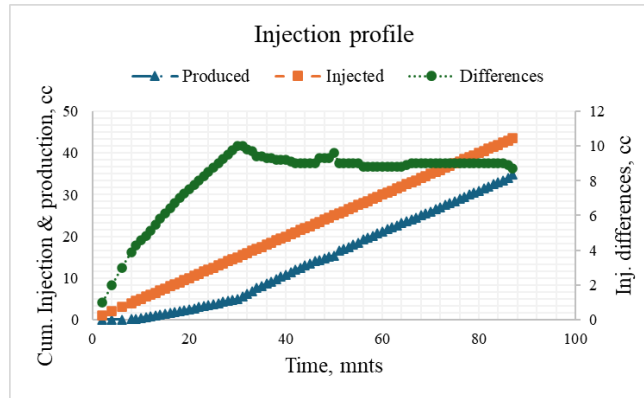


Figure 36. Water flooding profile (a) pressure drops, (b) fluid production, (c) inlet and outlet differences, and (d) effluent samples collected during the flooding

After water flooding, surfactant flooding was conducted as tertiary recovery. At the same flow rate of $0.5 \text{ cm}^3/\text{mnt}$, 2,000 ppm of AOS solution was injected to increase the oil recovery. The experimental results showed that surfactant flooding could increase the oil recovery by 28.64% or 4.21 cm^3 of the original oil in place. The production increment, along with the increase in pressure difference and emulsion production, reveals that in situ emulsification increases oil recovery through partial areal blockage. Overall, surfactant flooding could significantly increase oil recovery through in situ emulsification.

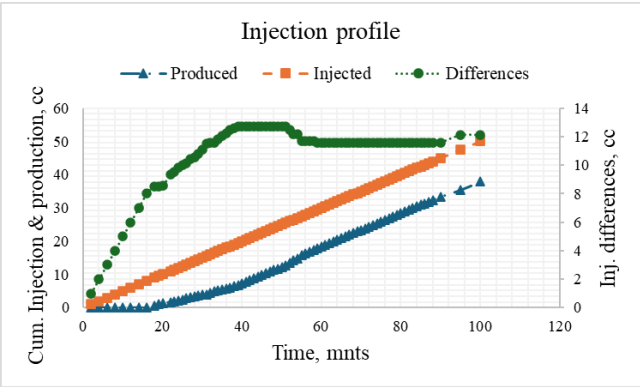
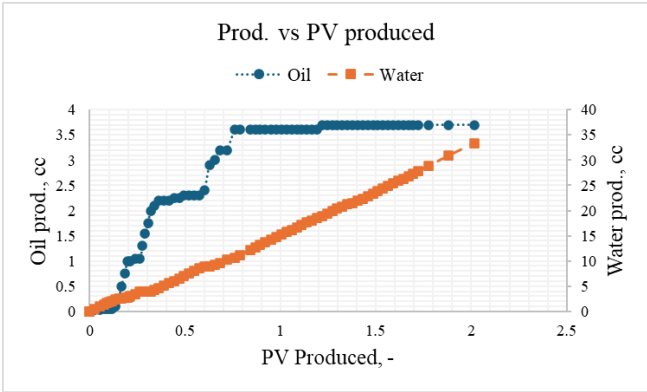
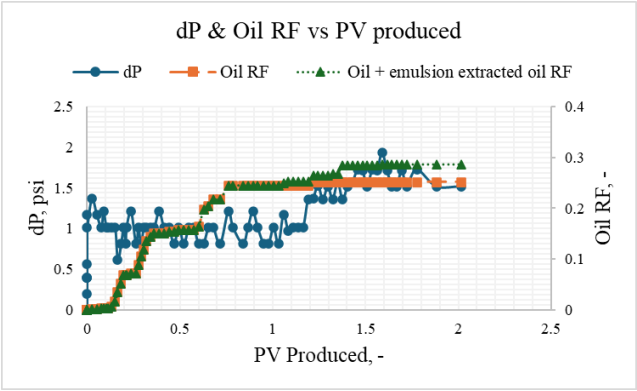


Figure 37. Surfactant flooding profile (a) pressure drops, (b) fluid production, (c) inlet and outlet differences, and (d) effluent samples collected during the flooding

Figure 38 shows the in situ-generated emulsion during core flooding, which was observed under a microscope. The microscopic image shows a highly polydisperse emulsion characterized by a wide distribution of droplet sizes, ranging from negligible to large droplets. The image observation reveals that oil droplets comprise approximately 60% of the total emulsion phase volume. However, high polydispersity could be an indication of lower stability, where larger droplets would lead to a weaker interfacial film and easier coalescing.

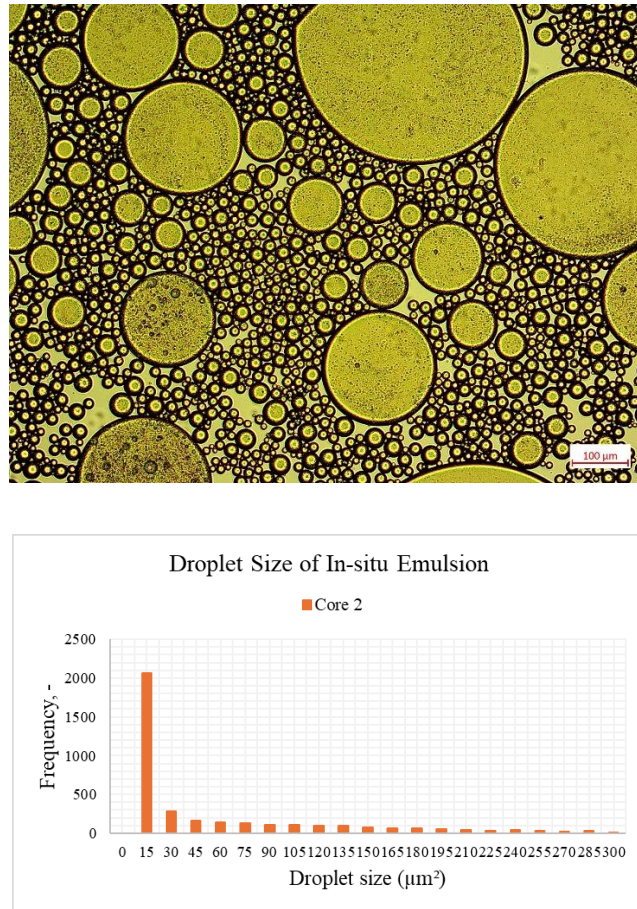
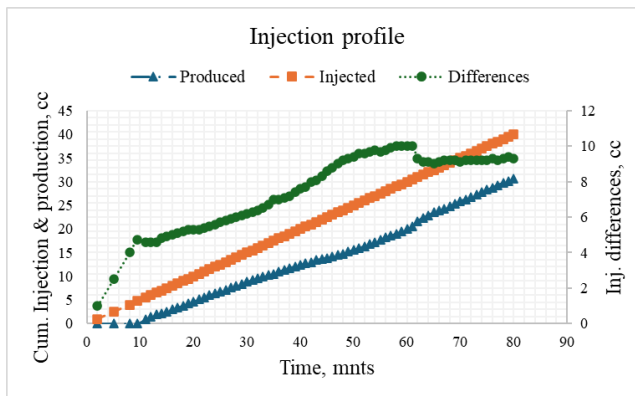
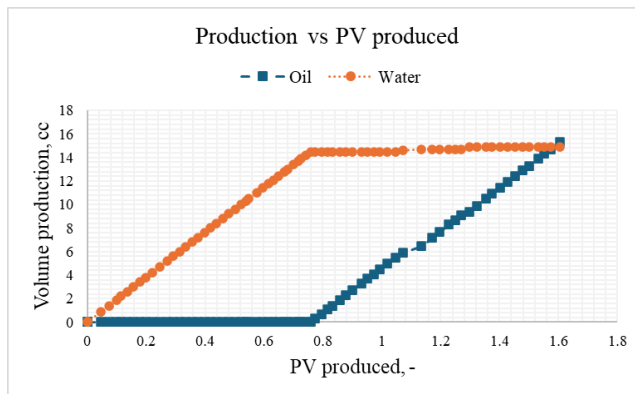
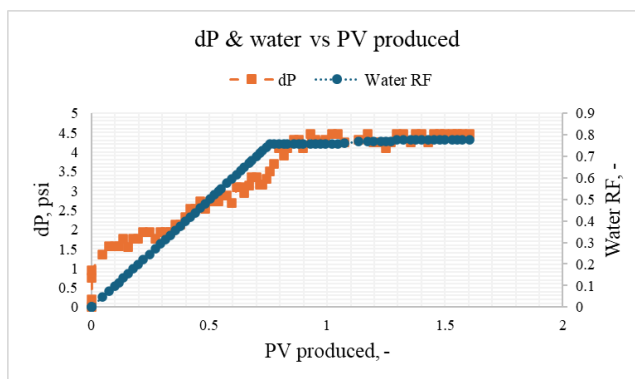


Figure 38. In situ O/W emulsion generated during surfactant core flooding

4.5.3 Core 3: Surfactant flooding as a secondary recovery strategy

To validate the results of the first scenario in which surfactant flooding was used as a secondary recovery, the same experiment was performed using core 3 and confirmed the reliability of the

results if the same trend was observed. Oil was injected under the same conditions to mimic the drainage process, and the irreducible water saturation was calculated. After this stage, Swir was 4.3 cm³, which is 22.11% of the total pore volume of 19.13 cm³. The first oil breakthrough was observed at 0.77 PV, characterized by a stabilized pressure drop, almost no water production increment, and oil production at the outlet.



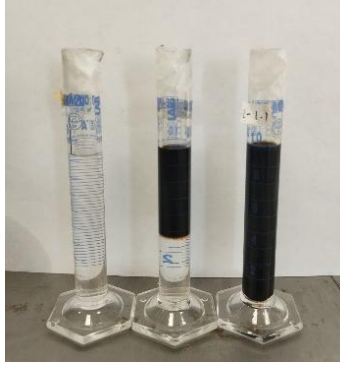
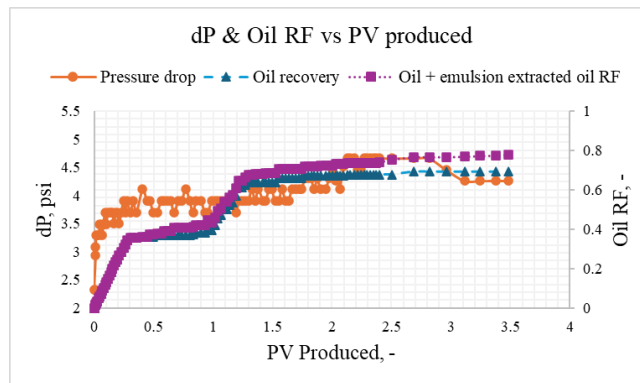


Figure 39. Oil injection profile (a) pressure drop, (b) fluid production, (c) inlet and outlet differences, and (d) effluent samples collected during oil injection

During surfactant flooding, stepwise oil production was observed. In the first step, sharp oil production was observed along with a massive increase in the pressure drops. The water breakthrough was first observed after 0.29 PV injection, and the oil recovery was 4.55 cm³ or 30% of OOIP. A small amount of emulsion was produced in the outlet, indicating that in-situ emulsification and the emulsion mechanism worked at the end of the first step. After the first step, the system exhibits a relaxation time before the pressure drop starts to increase again to the second step, and the oil production, along with emulsion production, as shown in Figure 40(a). During the relaxation time, the emulsion blocked the major pores and delayed oil production, allowing the injected fluid to reach the smaller pores and increasing the sweep efficiency. Overall, the total oil recovery at the end of surfactant flooding to core 3 was 77.72% of the original oil in place. Although the in-situ emulsion mechanism requires a longer time to work effectively, it significantly improved the oil recovery.



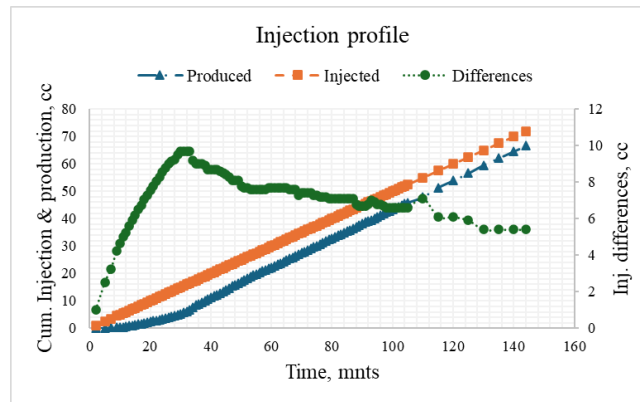
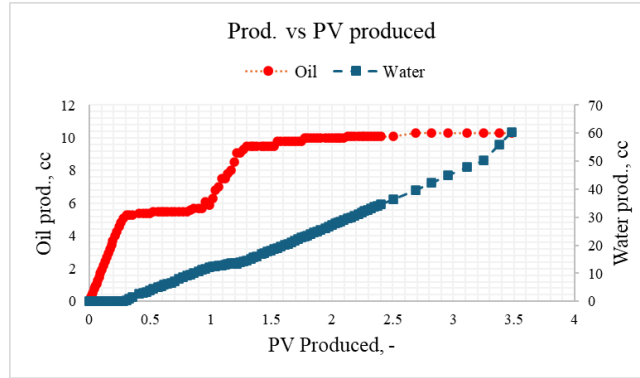


Figure 40. Surfactant flooding profile (a) pressure drops, (b) fluid production, (c) inlet and outlet differences, and (d) effluent samples collected during the flooding

Figure 41 shows a microscopic image of the emulsion generated during surfactant flooding. Figure 41 The emulsion exhibits homogeneity of the droplet size distribution. Based on the observation, the oil volume in the emulsion phase is around 80-90% and shows an O/W system in which water is the continuous phase. A relatively fine emulsion with a homogeneous droplet size distribution could be a sign of a stable emulsion by limiting coalescence.

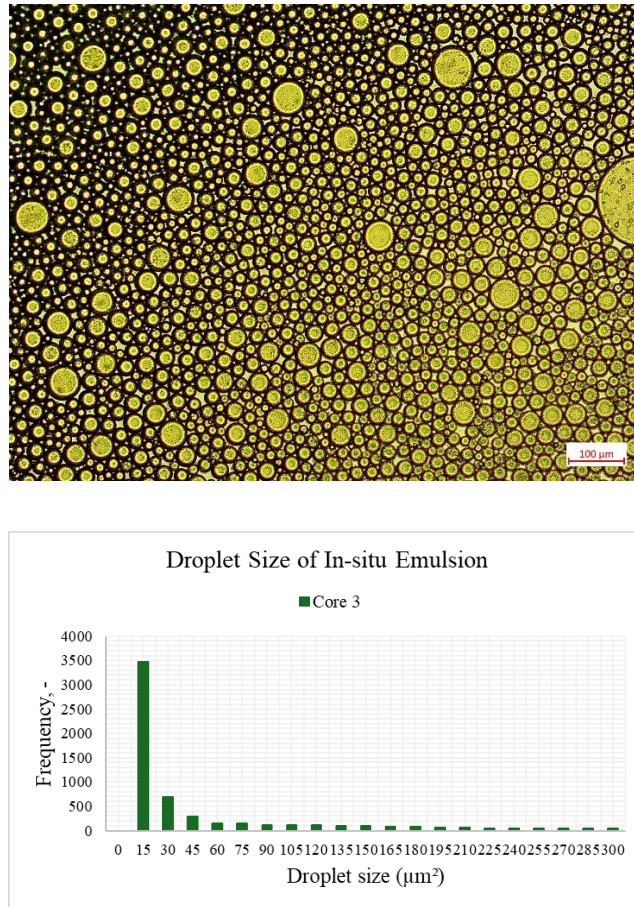


Figure 41. In situ O/W emulsion generated during surfactant core flooding

In the spontaneous emulsification test conducted in bulk volume, there was no emulsion generation observed. This is due to the absence of external energy input, as the system remained essentially static. In such conditions, physicochemical mechanisms such as surfactant concentration gradients is the main parameter of emulsification. However, this mechanism alone is not enough to generate emulsion in bulk system, particularly for the oil sample used in this study, which likely requires additional mechanical energy to overcome interfacial resistance. In contrast, there was in-situ emulsion generation observed during core flooding experiments even in a relatively low injection rate of $0.5 \text{ cm}^3/\text{mnt}$. Although the assigned flow rate corresponds to low macroscopic energy input, the heterogeneity of pore size creates localized velocity gradient and with very low IFT which leads to in-situ emulsification. Localized velocity gradient is a rapid changes of fluid velocity in the porous media that occurs when fluid passes through narrow pore throats. These effects generate

local shear forces that promote droplet deformation and oil breakup, leading to in-situ emulsion formation.

4.5.4 Recovery comparison

The comparison of both secondary recovery methods reveals the superior performance of surfactant flooding compared to conventional water flooding. Surfactant flooding was applied as a secondary recovery method in both core-1 and core-3. During early production, oil recovery rapidly increased and continued to improve after the relaxation time. Ultimately, the total oil recovery from surfactant flooding as a secondary method reached 74.63% and 77.72% of OOIP from core-1 and core-3, respectively. The results indicate the effectiveness of surfactant flooding to mobilize oil through the reduction of interfacial tension and the improvement of displacement efficiency. In contrast, core-2 used conventional water flooding as the secondary recovery method. The maximum oil recovery from conventional water flooding was observed at 57.14% of the OOIP. The recovery is significantly lower than that of the surfactant flooding method, reflecting the limitations of waterflooding in mobilizing oil under capillary-dominated conditions.

In the pressure profile of both scenario, there is a slight difference between pressure drop during water flooding and surfactant flooding. During water flooding, the peak pressure drop was observed ~10 psi, while the peak in surfactant flooding was ~25 psi. The difference in pressure drop profile could be attributed to emulsion generation during surfactant flooding which block the pore and results in higher pressure drop if compared with water flooding. This mechanism does not correspond to water flooding since there was no emulsion generation and partial pore blockage mechanism is not applicable in this stage.

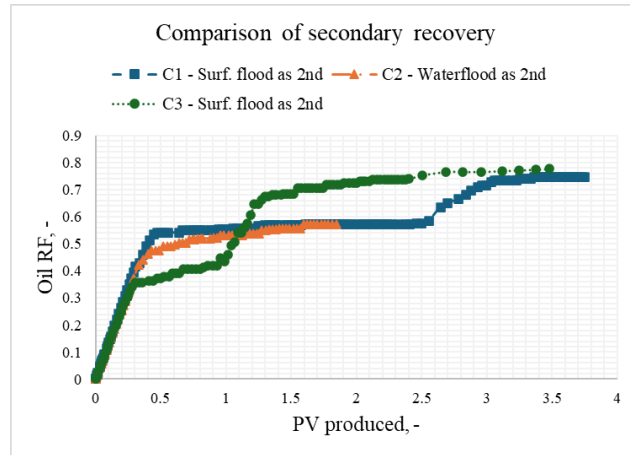


Figure 42. Comparison of oil recovery from the secondary recovery method

On the other hand, the comparison of surfactant flooding performance when different injection strategies are applied is presented in FigureFigure 43. Surfactant flooding applied as a secondary recovery method in core-1 and core-3 shows substantially higher oil recovery than its application as a tertiary process in core-2. Rapid production increment in early production of core-1 and core-3, indicating efficient oil mobilization when surfactant is introduced at an early stage. Conversely, C2, where surfactant flooding is implemented after waterflooding, shows a lower recovery trend, reaching only 28.64%. This indicates that prior waterflooding may have caused unfavorable flow paths or bypassing, limiting the effectiveness of subsequent surfactant injection. Overall, the results highlight that the early application of surfactant flooding is more effective in enhancing oil recovery, as it maximizes contact with residual oil and improves Displacement efficiency compared with delayed implementation.

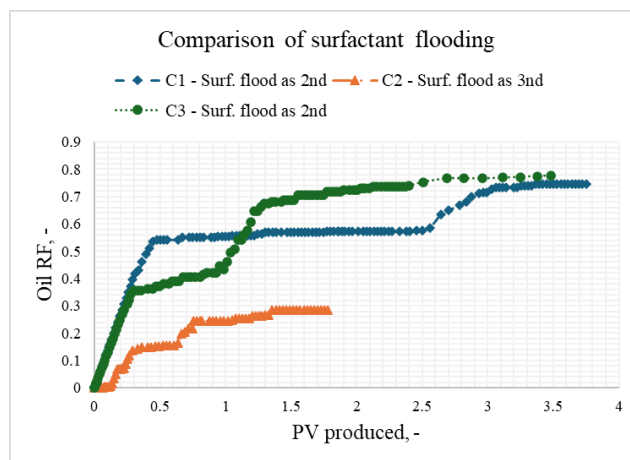


Figure 43. Comparison of oil recovery from surfactant flooding as secondary and tertiary recovery

Figure 44 presents the comparison of oil recovery from both secondary and tertiary recovery scenarios, highlighting the strong influence of the injection strategy on the overall performance. When applied as a secondary recovery method, surfactant flooding consistently achieves higher and earlier oil recovery than waterflooding. This higher early-stage recovery is attributed to the early reduction of interfacial tension, which enhances the efficiency of oil mobilization and displacement. Conversely, waterflooding operated under capillary-dominated conditions, leading to significant residual oil trapping and indicating limited mobilization efficiency. However, the application of surfactant flooding as a tertiary process after water flooding mobilizes the trapped oil, increasing the ultimate recovery from 57.63% to over 80%. These results demonstrate that while secondary surfactant flooding improves recovery efficiency, the combination of waterflooding followed by surfactant flooding can yield higher total recovery due to the additional mobilization of residual oil.

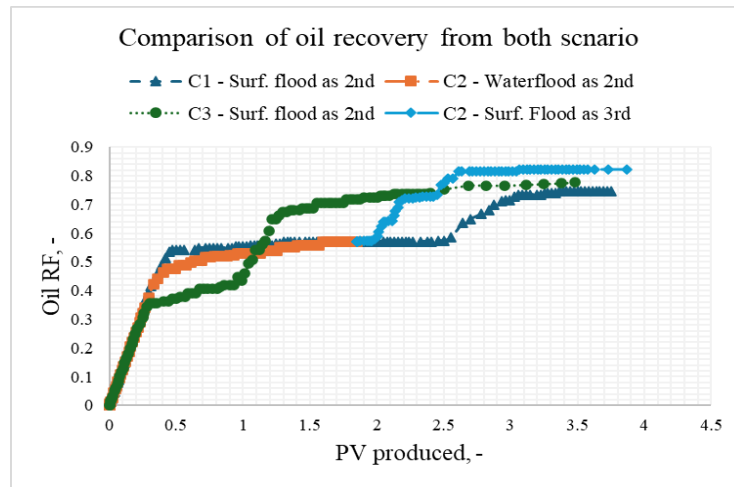


Figure 44. Comparison of the total oil recovery from both scenarios

Overall, the results of repeatable experiments showed a consistent trend based on the volume of recovered oil. This validates the result of this study and confirms the reliability and reproducibility of the experimental methodology. Furthermore, the results strengthen the interpretation of experimental data not based on random results variation but controlled physicochemical and pore-scale mechanisms.

4.5.5 Emulsion stability type

Based on the emulsion stability assessment and observation of in-situ emulsion produced during core flooding, the generated emulsion could be considered as meso-stable, since the droplet size distribution of emulsion was changed over time. In the emulsion stability assessment, a gradual increase of droplet sizes over time indicates ongoing coalescence. However, the fact that the droplets were not broken instantly even after 72 hours, indicating intermediate stability (meso-stable). During the core flooding, meso-stable emulsion is linked directly with flow behavior during the flooding. As droplets accumulate in the pore throats and partially block them, it reduces the effective permeability and diversify the flow path of injection fluid, characterized by an increase in pressure drop after breakthrough. Importantly, the pressure drop started to decrease again after sometimes and additional oil production was observed. This is a sign that the blockage is not permanent, as a sign of meso-stable nature of the emulsion.

For field applications, the emulsion generation during surfactant flooding observed in this study has significant implications for field scale EOR. The ability of in-situ emulsion generation during surfactant flooding to mobilize trapped oil through mechanisms such as wettability alteration, IFT reduction, and partial area blockage, is important into account. While meso-stable emulsion formation ensures operational safety by dynamic blockage rather than permanent, it minimizes the risk of severe formation damage or injectivity loss. The balance between mobility control and reversibility is particularly advantageous for field implementation, where sustained displacement efficiency and operational stability are critical. Therefore, the findings of this study suggest that controlled in-situ emulsion generation can be an effective and practical mechanism to enhance oil recovery in heterogeneous reservoirs.

5. Conclusions and Recommendations

5.1 Conclusion

Based on the laboratory results, the following conclusions can be drawn:

- Spontaneous emulsification confirmed that a stable emulsion cannot be generated without energy application to the system. Even though there are irregularities in the water–oil interface, a stable emulsion cannot be generated.
- Emulsion stability assessment showed stability variation with different surfactant types and concentrations over time. However, the experiments demonstrated that 2,000 ppm of AOS gives the best stability over time by reducing droplet size, narrowing size distribution, and inhibiting coalescence, compared to the other surfactant types and concentrations.
- The results of core flooding revealed that in situ emulsification induced by surfactant as a secondary injection improved the cumulative oil recovery by 28.57% relative to the residual oil remaining after conventional secondary water flooding.
- Comparing the results of the two scenarios, the results demonstrated that surfactant flooding is highly effective in enhancing oil recovery, especially when applied as a secondary recovery. The first test using core-1 recovered 75% of the original oil in place, whereas the second test using core-3 recovered 69.13%, indicating consistently strong performance when implemented early.
- Water flooding as a secondary recovery method resulted in a lower recovery of 57%, indicating a lower performance. However, subsequent surfactant flooding as a tertiary method could improve the overall recovery by 28.57%.
- In situ emulsification provides promising performance through partial areal blockage, allowing the injected fluid to reach the smaller pores and improving sweep efficiency.
- Based on emulsion stability assessment and core flooding observation, the generated emulsion is categorized as meso-stable.

5.2 Recommendation

Based on the findings of this study, several directions are recommended for better understanding and improvement of this study, including the following:

- Expand the study on the effect of water content on the stability of emulsions.
- Study the effect of pregenerated emulsion core flooding using the assigned surfactant concentration in this study.
- Study the effect of pressure and temperature on in-situ emulsion performance during core flooding.
- Assess the effect of salinity on emulsion stability.

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7. APPENDICES

(optional)

Diagrams, images, tables, software description, etc. may be presented here