



Surfactant Content Influence On Formation Water Compatibility

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Abstract

In the pursuit of resolving surfactant non-solubility issues for enhanced oil recovery, this study identifies surfactants that are soluble and compatible with the formation brine of the Langgak field. Over the course of 21 days, the solubility and compatibility of 12 various surfactants were evaluated in synthetic brine with a salinity of 100 ppm and a reservoir temperature of 58°C. The results indicated that surfactants S3 to S11 were compatible, exhibiting no signs of cloudiness or precipitation, thus making them suitable for further testing. These surfactants are recommended to proceed to phase behavior and interfacial tension (IFT) tests to evaluate their performance and impact on brine formation under reservoir conditions. Conversely, surfactants S1, S2, and S12 demonstrated incompatibility with the Langgak field's brine, as evidenced by cloudiness and precipitation. This incompatibility highlighted specific surfactant compositions that do not align well with the brine composition, providing crucial insights for future surfactant formulation. Understanding these interactions aids in improving the process of choosing surfactants that work well in comparable conditions. Overall, this study establishes a foundational understanding of surfactant-brine interactions, guiding the selection of suitable surfactants for enhanced oil recovery in the Langgak field.

Introduction

Continuous extraction of oil from a reservoir leads to a gradual decline in its internal pressure (Bundang, 2023), ultimately resulting in a state known as a depleted reservoir. As a result of the reservoir's diminished capacity to force remaining oil toward the production wells due to fluid withdrawal, pressure depletion is an inevitable byproduct of continuous oil production. An approach called Enhanced oil recovery (EOR) is used to counteract this decline and increase in oil production (Wicaksono et al., 2015; Olajire, 2014; Dooley et al., 2010).

EOR methods, which include thermal recovery, gas injection, and chemical flooding (Putra & Kiono, 2021), work by introducing external substances or energy into the reservoir. By applying more pressure and decreasing the oil's viscosity, these techniques enhance flow and optimize the extraction efficiency of the residual hydrocarbons, thus extending the productive life of the reservoir. EOR is usually applied upon the completion of primary and secondary recovery, the first phases of oil extraction (Yuan & Wood, 2018; Liu et al., 2020). Only a portion of the oil in place is recovered during primary recovery when oil is produced to the surface by natural reservoir pressure. Secondary recovery follows, which uses methods like gas injection or water flooding to maintain the reservoir pressure and displace additional oil (Inaloo et al., 2014; Kumar et al., 2022). Yet, even with these techniques, a sizable amount of

oil is still trapped in the reservoir. Therefore, the use of EOR is necessary to extend the lifespan of a field.

The research focus of this study is chemical injection (CEOR), particularly surfactant flooding. CEOR involves adding chemical substances to the injection water to increase oil recovery, thereby improving sweep efficiency, and reducing oil saturation in the reservoir (Gbadamosi et al., 2019; Kumar & Mandal, 2017; Hamza et al., 2017). By optimizing efficiency, the chemical injection technique helps build microemulsions and produce residual oil. There are three common types of chemicals commonly used in the CEOR method: alkalis, surfactants, and polymers.

Before implementing a CEOR process, it is necessary to conduct a compatibility test between the chemical, in this case, surfactant and the formation water (Chowdhury et al., 2022; Hirasaki et al., 2011). The test ensures that the selected surfactant performs effectively under the specific conditions of the reservoir. The compatibility test involves mixing the surfactant with samples of formation water and observing for any adverse reactions, such as precipitation, phase separation, or changes in viscosity. These reactions hinder the effectiveness of the surfactant and potentially damage the reservoir or production equipment. By carefully analyzing the interactions between the surfactant and formation water, the optimal chemical formulation could be selected, ensuring maximum recovery efficiency, and maintaining the integrity of the reservoir (Wang et al., 2017; Jia et al., 2024; Lebouachera et al., 2024).

The compatibility test mimics the reservoir conditions by maintaining the reservoir temperature and mixing the surfactant solution with formation water. Observations are made to detect any adverse reactions, such as precipitation, gel formation, or phase separation, which would indicate incompatibility. The formation of a stable, homogeneous solution without any negative reactions confirms that the surfactant is suitable for the reservoir. If the surfactant is incompatible, it can lead to reduced efficiency in oil recovery and potential damage to the reservoir or production equipment. Thus, selecting a compatible surfactant is essential for the success of the EOR process in enhancing oil recovery from the reservoir. If this compatibility test fails or an incompatibility is found, the surfactant is deemed unsuitable for the reservoir, see Figure 1.

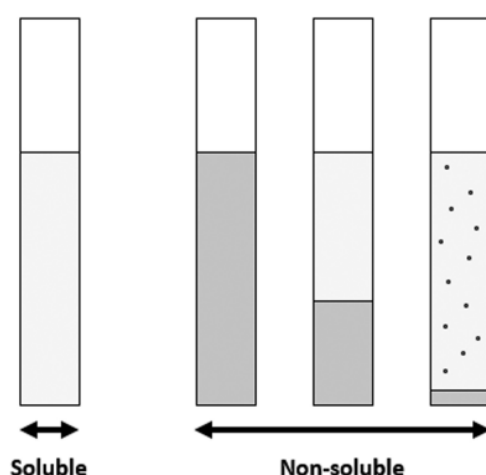


Figure 1. Schematic of solubility evaluation of surfactants and brine (Nadir et al., 2022).

The indication is observed as: 1) Well-mixed solution: Formation of a clear mixture or a single phase; 2) Colloid (cloudy): Formation of a mixture that is not clear, or the solution appears cloudy, indicating a single phase; 3) Suspension (precipitation): Liquid and solid particles form visible grains or clumps, indicating the formation of a two-phase mixture.

This study aims to provide the suitability of surfactant from compatibility test to determine the eligibility of surfactant in Langgak field.

Formation water

Formation water samples were collected from one of the Langgak fields. These samples were preserved in sealed containers to prevent contamination and evaporation, ensuring that the water's chemical composition remained unchanged. The samples were then analyzed for their salinity, pH, and ionic composition to provide a baseline for compatibility testing, see Table 1.

Table 1. Formation water properties.

Properties	Value
Ca^{2+}	3.537 ppm
Fe^{2+}	0.077 ppm
K^{2+}	2.283 ppm
Mg^{2+}	0.615 ppm
Mn^{2+}	0.192 ppm
CO^{2-}	<1 ppm
Cl^{-}	13.2 ppm
SO_4^{2-}	4 ppm
pH	7.44
Salinity	100 ppm
Total dissolved solid (TDS)	121 ppm
Specific gravity (SG)	1.002
Electro conductivity (EC)	241 $\mu S/cm$
Oxidation reduction potential (ORP)	215 mV

Surfactant

Surfactants play a key role in the oil and gas industry, particularly in EOR processes. These substances are divided into four main types based on the nature of their hydrophilic head groups: anionic, cationic, non-ionic, and zwitterionic, each offering unique benefits for specific applications in the industry.

Anionic surfactants, these surfactants carry a negative charge and are commonly used in EOR due to their ability to reduce the interfacial tension (IFT) between oil and water (Sheng, 2010). This reduction helps mobilize trapped oil, making it easier to extract. Anionic surfactants are effective in alkaline-surfactant-polymer (ASP) flooding, a widely used EOR technique that combines the benefits of alkali, surfactants, and polymers to improve oil displacement efficiency.

Cationic surfactants, with their positively charged head groups, cationic surfactants are primarily used in applications where interaction with negatively charged surfaces is beneficial. In the oil and gas industry, they are often employed in the treatment of oilfield equipment and pipelines to prevent corrosion and scale formation. Additionally, cationic surfactants can enhance the stability of emulsions, which is important in various drilling and production processes.

Non-ionic surfactants, these surfactants do not carry any charge, making them highly stable and less sensitive to changes in salinity and pH. Non-ionic surfactants are used in EOR to enhance oil recovery. Their stability in harsh reservoir conditions makes them suitable for use in various EOR formulations, including surfactant-polymer (SP) flooding and chemical flooding.

Zwitterionic surfactants, containing both positive and negative charges within the same molecule, zwitterionic surfactants offer unique properties such as low toxicity and high biocompatibility. In the oil and gas industry, they are used in EOR processes to create microemulsions that can mobilize residual oil. Their ability to function effectively in a wide range of pH and salinity conditions makes them versatile and valuable in challenging reservoir environments (Sheng, 2010).

This study uses a number of surfactant samples, which are identified as S1, S2, S3, S4, S5, S6, S7, S8, S9, S10, S11, and S12. Table 2 gives a summary of each surfactant's properties, from the surfactant base, composition, color, and their solubility in water.

Methods

The purpose of this compatibility test is to determine the solubility of the surfactant in the formation water. The criteria for a compatible solution include being completely soluble, clear, not hazy, and free from any precipitation.

The methodology for compatibility testing involves assessing the suitability between the surfactant and the formation water present in the reservoir. This testing serves as an initial screening to identify surfactants that are commonly used for further EOR testing. The surfactant is mixed with formation water at specified concentrations with predetermined salinity levels.

The equipment and materials used include chemical glassware, funnels, a magnetic stirrer, a magic hot stirrer, an oven, and a micropipette. The formation water from field X is utilized, along with several surfactant samples: S1, S2, S3, S4, S5, S6, S7, S8, S9, S10, S11, and S12. The surfactants non-ionic surfactants (S1 - S12) were selected for this study due to the sandstone nature of the reservoir in this field, as they are known to be effective in such formations.

The first step involved cleaning the formation water from any contaminants (filtration of the formation water), ensuring that it is contaminant-free from other particles which may interfere with the testing. The formation water was then mixed with surfactants at itemized concentrations and stirred using a magnetic stirrer until the solution became homogeneous. Subsequently, the solution was transferred into tightly sealed bottles, and left to stand at reservoir temperature (60 °C) for 21 days (estimated soaking time), which was adjusted from the drainage period of the Langgak field. Figure 2 explains the further step-by-step of the conducted study.

In order to test the compatibility of surfactant, the test was conducted with the basic salinity of the formation water of 100 ppm.

Table 2. Properties of the studied surfactant

Surfactant	Base	Composition	Color	Solubility
Surf 1	Oil base	Glycol ether, sulfonate, ethylenediamine-tetra-acid 4 – sodium, and hydrocarbon.	Light yellow	Dispersed in water
Surf 2	Water base	Glycol ether, nonylphenol polyethylene glycol ether, and ethylenediamine tetra acid 4 – sodium	Colorless	Soluble in water

Surf 3	Water base	Alcohols, C9 - 11, and ethoxylated	Colorless	Soluble in water
Surf 4	Water base	Alcohol alkoxyate sulfate, alcohol alkoxyate, internal olefin sulfonate, internal olefin, glycol ethers, and water	Light yellow	Soluble in water
Surf 5	Oil base	Alkaryl hydrocarbon, proprietary surfactant, and proprietary catalyst	Colorless	Soluble in water
Surf 6	N/A	Proprietary surfactant, and proprietary solvent	Yellowish	N/A
Surf 7	N/A	Proprietary blend of surfactants	Dark amber	N/A
Surf 8	N/A	Proprietary blend of surfactants, and hexylene glycol	Dark amber	N/A
Surf 9	Water base	Sulfonic acids, C15-20- alkane hydroxy and C15-20-alkene sodium salts, alcohols, C6 – C12, and ethoxylated	Amber	N/A
Surf 10	Water base	Sulfonated anionic surfactant, 2 – butoxyethanol, lauryl dimethyl betaine, sulfonate, myristyl dimethyl betaine, oxyalkylated polymer, sodium chloride, and ethoxylated alcohol	Light yellow	N/A
Surf 11	N/A	Proprietary surfactant	Colorless	N/A
Surf 12	Oil base	Palm olein methyl ester sulfonic and water	Black liquor	N/A

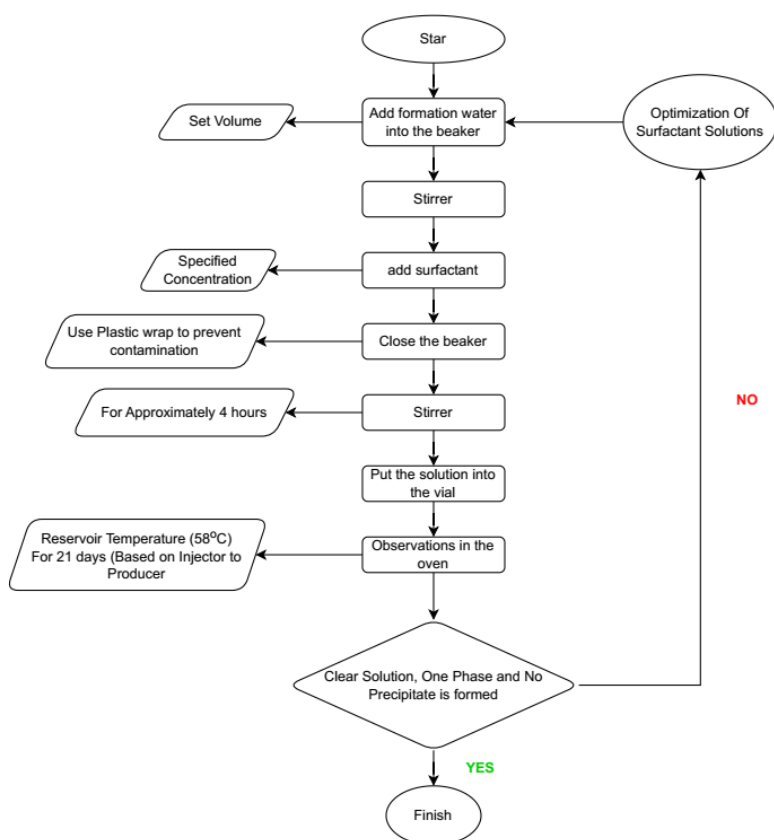


Figure 2. Flowchart of the surfactant compatibility study.

Results and Discussion

In order to resolve the surfactant non-solubility issue, the aim of this test is to determine if the surfactant is soluble and compatible with the formation water. In addition, the surfactant was assessed in brine of 100 ppm salinity and reservoir temperature of 58° C in order to replicate the reservoir conditions for 21 days. During the screening process, the solubility and compatibility of twelve different surfactants were assessed in synthetic brine at the specified reservoir temperature. The results of this assessment are presented in Figure 3 and Table 3.

From the solubility and compatibility results, it was observed that only three of the twelve surfactants tested were incompatible with the reservoir brine conditions. This incompatibility is evidenced by the appearance of a cloudy color in samples S1 and S2, and the occurrence of precipitation in sample S12. Other surfactants S3 to S11 were found to be compatible with the formation brine, as indicated by their clear colors in the test solutions.



Figure 3. Solubility and compatibility after 21 days.

Table 3. Summary Of Surfactants' Solubility and Compatibility After 21 Days.

Surfactant	Indication
Surf 1	Cloudy
Surf 2	Cloudy
Surf 3	Clear
Surf 4	Clear
Surf 5	Clear
Surf 6	Clear
Surf 7	Clear
Surf 8	Clear
Surf 9	Clear
Surf 10	Clear
Surf 11	Clear
Surf 12	Cloudy & phase separation

In the preliminary screening to identify suitable and compatible surfactants for use in the Langgak field, surfactants S3 through S11 have been identified as promising candidates. This recommendation is based on the solubility and compatibility tests conducted under conditions mimicking those of the Langgak field's formation brine.

The tests demonstrated that surfactants S3 to S11 exhibit solubility and compatibility with the formation brine, which is crucial for their effective performance in EOR operations. These surfactants did not show any signs of cloudiness or precipitation, indicating their stable behavior in the reservoir conditions of the Langgak field.

Given these positive results, it is suggested to implement surfactants S3 to S11 in the field. Their use is expected to improve oil recovery by reducing interfacial tension and improving the wettability of the reservoir rocks, without causing issues related to chemical incompatibility or solubility problems. The selection of these surfactants follows a rigorous testing process, ensuring that they are well-suited to the specific environmental and chemical conditions of the Langgak field.

To further understand the incompatibility issues observed with surfactants S1, S2, and S12, Table 4 provides a detailed analysis of the reactions between the formation brine and the compositions of these surfactants. This table profiles the specific interactions and reactions that occur when these surfactants are introduced to the formation brine, offering insights into why these particular surfactants are not suitable for use under the given reservoir conditions.

By examining the data in Table 4, it becomes evident how the chemical compositions of S1, S2, and S12 lead to cloudiness and precipitation, indicating their incompatibility. This detailed assessment helps in identifying the components or conditions that contribute to their adverse reactions, providing a basis for modifying or avoiding these surfactants in future applications.

S1, for instance, has a composition of glycol ether, sulfonate, ethylenediamine-tetra-acid 4 – sodium, and hydrocarbon. Glycol ether when reacts with Ca^{2+} , Fe^{2+} and Mg^{2+} can dissolve (Cui et al., 2022; Ryu et al., 2009), and glycol ether when reacts with Mn^{2+} , CO_3^{2-} , and SO_4^{2-} form precipitation. The sulfonate does not completely dissolve in Ca^{2+} (Ádám et al., 2023) and forms precipitation when reacting with Mg^{2+} and CO_3^{2-} . Ethylenediaminetetra acid 4 – sodium is not dissolved in Fe^{2+} and form precipitation in K^+ , Mg^{2+} , Mn^{2+} , and CO_3^{2-} . The hydrocarbons containment in the S1 has difficulty dissolving in Fe^{2+} , K^+ , Mg^{2+} , and Mn^{2+} (Silver, 1993).

S2, on the other hand, consists of glycol ether, nonylphenol polyethylene glycol ether, and ethylenediamine-tetra-acid 4 – sodium. The glycol ether and ethylenediamine-tetra-acid 4 – sodium in S2 react similarly to the same brine composition as in S1. The nonylphenol polyethylene glycol ether is not dissolved in Ca^{2+} and CO_3^{2-} , and forms precipitation in Fe^{2+} , Mg^{2+} , and Mn^{2+} .

S12 is made up of palm olein methyl ester sulfonic and water. The palm olein methyl ester sulfonic forms precipitation when reacting with Ca^{2+} , Fe^{2+} , and Mg^{2+} (Barnes et al., 2010), and not completely dissolved in K^+ and Mn^{2+} . The water of S12 is not dissolved in Ca^{2+} , Fe^{2+} , and Mn^{2+} , and soluble in Mg^{2+} (Libretexts, 2015) and (Libretexts, 2013).

Table 4. Summary of Brine Composition Reaction with Surfactant Composition of Incompatible Surfactants S1, S2, And S12.

Brine composition	Surfactant composition	Indication
Ca^{2+}	Glycol ether	Soluble
	Sulfonate	Not completely dissolved
	Ethylenediaminetetra acid 4 – sodium	Did not react
	Hydrocarbon	Did not react
	Nonylphenol Polyethylene Glycol Ether	Difficult to dissolve

	Palm Olein Methyl Ester Sulfonic	Forms precipitation
	Water	Difficult to dissolve and forms precipitation
Fe ²⁺	Glycol ether	Soluble
	Sulfonate	Did not react
	Ethylenediaminetetra acid 4 – sodium	Not dissolved
	Hydrocarbon	Difficult to dissolve
	Nonylphenol Polyethylene Glycol Ether	Forms precipitation
	Palm Olein Methyl Ester Sulfonic	Difficult to dissolve and forms precipitation
	Water	Difficult to dissolve
K ⁺	Glycol ether	Did not react
	Sulfonate	Soluble
	Ethylenediaminetetra acid 4 – sodium	Forms precipitation
	Hydrocarbon	Difficult to dissolve
	Nonylphenol Polyethylene Glycol Ether	Did not react
	Palm Olein Methyl Ester Sulfonic	Not completely dissolved
	Water	Soluble
Mg ²⁺	Glycol ether	Soluble
	Sulfonate	Forms precipitation
	Ethylenediaminetetra acid 4 – sodium	Forms precipitation
	Hydrocarbon	Not dissolved
	Nonylphenol Polyethylene Glycol Ether	Forms precipitation
	Palm Olein Methyl Ester Sulfonic	Forms precipitation
	Water	Soluble in hot water
Mn ²⁺	Glycol ether	Forms precipitation
	Sulfonate	Soluble
	Ethylenediaminetetra acid 4 – sodium	Forms precipitation
	Hydrocarbon	Not dissolved
	Nonylphenol Polyethylene Glycol Ether	Forms precipitation
	Palm Olein Methyl Ester Sulfonic	Not dissolved
	Water	Not dissolved
CO ₃ ²⁻	Glycol ether	Forms precipitation
	Sulfonate	Did not react
	Ethylenediaminetetra acid 4 – sodium	Did not react
	Hydrocarbon	Did not react

	Nonylphenol Polyethylene Glycol Ether	Did not react
	Palm Olein Methyl Ester Sulfonic	Did not react
	Water	Did not react
Cl ⁻	Glycol ether	Did not react
	Sulfonate	Did not react
	Ethylenediaminetetra acid 4 – sodium	Did not react
	Hydrocarbon	Did not react
	Nonylphenol Polyethylene Glycol Ether	Did not react
	Palm Olein Methyl Ester Sulfonic	Did not react
	Water	Did not react
SO ₄ ²⁻	Glycol ether	Forms precipitation
	Sulfonate	Did not react
	Ethylenediaminetetra acid 4 – sodium	Did not react
	Hydrocarbon	Did not react
	Nonylphenol Polyethylene Glycol Ether	Did not react
	Palm Olein Methyl Ester Sulfonic	Did not react
	Water	Did not react
CO ₂ ⁺	Glycol ether	Did not react
	Sulfonate	Forms precipitation
	Ethylenediaminetetra acid 4 – sodium	Forms precipitation
	Hydrocarbon	Did not react
	Nonylphenol Polyethylene Glycol Ether	Not completely dissolved
	Palm Olein Methyl Ester Sulfonic	Did not react
	Water	Did not react

Conclusion

The solubility and compatibility of twelve surfactants were assessed in the previous section. Based on the results, surfactants S3 to S11 are considered compatible with the formation brine of the Langgak field. Consequently, these surfactants are recommended for further testing, specifically the phase behavior and interfacial tension (IFT) tests, to evaluate their impact on the brine formation. These additional tests provide deeper insights into the performance of these surfactants under reservoir conditions, ensuring their effectiveness in enhanced oil recovery. Surfactants S1, S2, and S12 were found to be incompatible with the Langgak field's brine. The test provided valuable insights into the specific surfactant compositions that are not suitable for use with this brine composition. Understanding these incompatibilities helps in identifying the chemical interactions that lead to issues such as cloudiness and precipitation, guiding future formulations and selections of surfactants for enhanced oil recovery in similar brine conditions.

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