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Compatibility assessment of rhamnolipid biosurfactant with reservoir fluids and minerals of sandstone

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Abstract

As Indonesia's mature oil fields decline, biosurfactant-based Enhanced Oil Recovery (EOR) offers a sustainable alternative. This study evaluates the compatibility of rhamnolipid biosurfactant with reservoir fluids and mineralogy of sandstone using Buff Berea Sandstone Sample. Tests were conducted at 0–7.5% rhamnolipid concentrations in brines with salinities of 5000–30,000 ppm NaCl. Rhamnolipid remained stable at high salinities and 60 °C. Mineralogical analysis confirmed quartz dominance (>70%) with reactive silicates influencing biosurfactant retention. IFT decreased significantly with increasing rhamnolipid concentration, most notably between 0% and 1.5%, with greater reduction in light oils. Viscosity increases were prominent in medium oil at medium–high salinity, reaching 18–20 cP, indicating improved mobility control. pH remained stable (5–6), safe for reservoir applications. Contact angle tests showed light oil had higher wettability (15.07°) than medium oil (25.05°), with medium oil offering higher mobilization potential under surfactant-assisted recovery. Results demonstrate rhamnolipid's strong potential as an efficient, environmentally friendly EOR agent, with chemical and mineralogical compatibility supporting its application in Indonesian oil fields. This integrated evaluation provides insights into biosurfactant behavior in realistic geological conditions.

Keywords: Berea sandstone, Enhanced oil recovery (EOR), Interfacial tension (IFT), Rhamnolipid biosurfactant, Wettability alteration.

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1. Introduction

Many oil fields in Indonesia are currently quite old and experiencing declining production, so to meet the increasing demand for oil and natural gas domestically [1] efforts are needed to discover new reserves through increasing exploration activities and drilling new wells to increase production and increase reserves with the success ratio of new reserve discoveries from exploration activities that are increasingly declining [2] coupled with the uncertainty of affecting oil prices, making reserve search activities from exploration activities full of risk [3]. An alternative to increasing reserves and increasing oil production in another way is through Enhanced Oil Recovery (EOR) technology, which is currently very strategic for Indonesia and has quite significant potential [4]. Several advanced oil recovery (EOR) enhancement processes have been developed for draining oil and gas reservoirs. This EOR process includes four categories of chemical injection (chemical flood), miscible gas injection, thermal methods, and other processes such as with the help of microbes [5].

Among EOR methods, chemical flooding using surfactants is particularly valuable due to its ability to reduce interfacial tension (IFT) and alter rock wettability [6]. The primary purpose of chemical injection is to improve sweep efficiency by reducing displacement fluid mobility and residual oil saturation by lowering the IFT between displacement fluid and displaced fluid. The chemicals used are specific to each reservoir [7]. This is a massive opportunity for the chemical industry to develop polymers, surfactants, and alkalines that suit the characteristics of reservoirs in Indonesia. Surfactants reduce the interfacial tension of oil, water, and oil wit, and by reducing the interfacial tension, oil trapped in the pores of the rock will be easily released [8]. Typical surfactants consist of nonpolar (lipophile) and polar (hydrophile) parts. The properties of surfactants are greatly influenced by their polar and nonpolar characteristics [9]. A slight change in this structure will drastically affect the properties of the surfactant. Because of this sensitivity, EOR surfactants are particular to each reservoir. However, conventional petroleum-based surfactants are costly, non-renewable, and environmentally burdensome, prompting research into alternative, sustainable agents such as biosurfactants [10]. One such candidate, rhamnolipid, offers biodegradable and environmentally friendly properties while retaining the capacity to lower IFT and enhance oil mobilization [11, 12].

Despite these advantages, biosurfactants are highly sensitive to reservoir-specific conditions, particularly the nature of the oil, brine salinity, and the mineralogical composition of the rock [13]. Recent research on surfactants has developed surfactants from microorganism sources, known as biosurfactants. Biosurfactants have biodegradable properties or can be broken down naturally so that in their application, they are more environmentally friendly, especially in reservoirs where petroleum is located [14]. The application of biosurfactants to increase advanced oil recovery on a laboratory scale shows satisfactory results. Al-Ghamdi, et al. [15] and Hosseini and Tahmasebi [16] studied biosurfactant injection in sandstone reservoirs with medium oil characteristics. This study produced a biosurfactant formulation that can reduce oil viscosity and interfacial tension (IFT) in the field studied and significantly increase oil recovery.

This study addresses key research questions: How compatible is rhamnolipid biosurfactant with crude oil and water at various concentrations? To what extent do these concentrations affect interfacial tension, viscosity, and rock wettability? And how do specific minerals such as kaolinite, calcite cement, and clays influence the adsorption and behavior of biosurfactants in sandstone cores?

The objective of this research is to understand how rhamnolipid biosurfactant can be compatible with reservoir fluids and mineralogy from the berea sandstone, which basically includes the characteristics of fluid properties, measurements of IFT and viscosity, and studies on adsorpting and wettability changes using laboratory techniques such as XRD, SEM, and EDS. The significance behind the study is that it provides empirical evidence with respect to biosurfactant performance against specific processes of reservoirs and provides a scientific framework for designing EOR strategies, specific reservoirs, using environment-friendly materials.

Berea sandstone was selected as the study's core sample because of its previous benchmarking as a reference rock in laboratory-based enhanced oil recovery (EOR) research. Because of its homogenous and continuous mineralogical and petrophysical features, this sandstone from the Appalachian Basin in the United States is recommended in core flooding and chemical compatibility tests. Berea sandstone mainly comprises quartz with trace amounts of reactive minerals such as kaolinite, muscovite, and feldspars. It typically has moderate to high porosity and permeability. Research on surfactant-rock interactions, namely biosurfactant adsorption behavior and wettability alteration, is facilitated by this composition. The predictable structure and mineral solid composition of Berea sandstone provide a non-variable environment in assessing rhamnolipid biosurfactant performance and its potential as a precursor to field-scale application.

The underlying hypothesis is that an optimal concentration of rhamnolipid biosurfactant will achieve IFT values below 10^{-2} dyne/cm, reduce oil viscosity, and shift wettability toward more water-wet conditions. The hypothesis that underpins the above might be as follows: optimum concentration of rhamnolipid biosurfactant is expected to attain IFT below 10^{-2} dyne/cm, add depletion in oil viscosity and alter wettability to water-wetted condition maximum. Furthermore, it will be presumed that mineral constituents- kaolinite and calcite, in particular, would yield a relative contribution towards varied extent of biosurfactant adsorption, thus affecting the overall efficiency. The originality of this study is to be comprehensive in examining all rock–fluid and fluid–fluid interaction that involves biosurfactants within the berea sandstone.

2. Materials and Methods

This study was conducted over 12 months, comprising five stages: (1) preparation, (2) biosurfactant testing, (3) rock mineralogy analysis, (4) core flooding, and (5) results evaluation. Preparations included literature review, procurement of tools and materials, and rhamnolipid biosurfactant preparation. The material used in this study was berea sandstone cores (1-inch diameter, 5 cm length) from the EOR Laboratory, Institut Teknologi Bandung, were used due to their homogeneity, high quartz content, and suitable porosity–permeability characteristics (80–150 mD). Oil samples included light and medium oil; brines had salinities of 5000–30,000 ppm NaCl. Commercial rhamnolipid was obtained from Shanghai Yuchuang Chemical Technology Co., Ltd.

2.1. Procedure

2.1.1. Crude Oil and Rock Characterization

Crude oil properties were analyzed for SARA fractions, Total Acid Number (TAN), viscosity, and API gravity. Rock characterization involved X-ray diffraction (XRD), scanning electron microscopy with energy-dispersive X-ray spectroscopy (SEM-EDS), gas porosity, and gas permeability tests. Porosity was measured using the PORG-200 system (Boyle's Law, nitrogen gas), and permeability using the PERG-200 system (Darcy's Law, Klinkenberg correction).

2.1.2. Fluid-to-Fluid Compatibility

Interfacial tension (IFT) between oil and brine/rhamnolipid solutions was measured with a spinning drop tensiometer (ASTM D1331) at 60 °C and 6000 rpm for 30 minutes. Rhamnolipid concentrations tested were 0–7.5% in brines of varying salinity. Phase behavior tests assessed microemulsion stability (Winsor type III) over 7 days at 60 °C with daily agitation. pH was measured using ASTM E1172 standards. Viscosity was determined using a Brookfield DV3T viscometer (ASTM D2270).

2.1.3. Rock-to-Fluid Compatibility

Static and dynamic adsorption tests evaluated biosurfactant retention on Berea sandstone cores. Wettability alteration was measured using contact angle analysis in a two-phase system (oil/brine and oil/surfactant) on rock thin sections. Fluids tested were brine (10,000 ppm NaCl), light oil, medium oil, and rhamnolipid solutions (0.5%, 1%, 2%). Smaller contact angles indicated greater water-wetness.

2.1.4. Mineralogical Analysis

XRD identified quartz as the dominant phase (>70%), with reactive minerals including kaolinite (~5.6 wt%), muscovite (~6.6 wt%), and anorthite (~14.9 wt% in some samples). SEM-EDS provided morphological and compositional details:

- Quartz: large angular grains, smooth surfaces, minor clay coatings.
- Kaolinite: platy aggregates with high surface area, enhancing adsorption.
- Muscovite: thin layered flakes (2:1 phyllosilicate) influencing wettability.
- Anorthite: blocky crystals with moderate chemical reactivity for ion exchange.

These mineralogical characteristics were assessed for their influence on biosurfactant adsorption and EOR efficiency.

2.1.5. Biosurfactant Properties

The rhamnolipid had a concentration of 298.76 g/L and pH 7.67 (10% solution), meeting quality standards. Its glycolipid structure, low toxicity, and biodegradability make it suitable for harsh reservoir conditions.

2.2. Data Analysis

IFT, viscosity, pH, and contact angle data were analyzed across biosurfactant concentrations and salinity levels to determine optimal operating conditions. Adsorption behavior was interpreted alongside mineralogical data to assess compatibility and predict performance in EOR applications.

3. Results and Discussions

3.1. Reservoir Characteristics

Berea sandstone is widely used in petroleum studies, especially for chemical injection and Enhanced Oil Recovery (EOR), due to its moderate–high porosity (18–24%) and permeability (50–200+ mD). Based on Table 1, the mineralogical analysis of Buff Berea samples 1–7 shows quartz dominance (>70%), classifying it as quartz arenite with stable mechanical properties, good porosity, and high permeability. Kaolinite occurs in low–moderate amounts, minimally affecting permeability, while muscovite appears only in trace levels. Anorthite is absent in most samples, present only in Buff Berea 7 (14.9%). This mineralogy supports excellent reservoir characteristics, optimal fluid flow, and low pore-clogging risk, making Buff Berea ideal for EOR testing.

Table 1.
Mineralogical Composition of Buff Berea Cores 1–7.

Mineralogy	Buff Berea Core (% mass)						
	1	2	3	4	5	6	7
Quartz	93.66	93	91.63	88	92	82.5	72.9
Kaolinite	4.11	3.74	4.72	4.9	4.38	2.66	5.6
Muscovite	n/a	n/a	n/a	3.99	0.9	n/a	6.6
Anorthite	n/a	n/a	n/a	n/a	n/a	n/a	14.9

Berea sandstone's uniform pore structure and low organic content enable controlled biosurfactant compatibility testing. This study evaluates rhamnolipid interactions with Berea's rock matrix and fluids through IFT, viscosity, wettability, and

SEM-EDS analyses, integrating mineralogical and reservoir properties to provide a comprehensive assessment of biosurfactant performance for EOR applications.

3.1.1. Crude Oil

This study evaluates Berea sandstone's light and medium oils using SARA fractions, viscosity, TAN, and API gravity (Table 2). Both are saturated-rich, aromatic-balanced, and low in resins/asphaltenes, indicating good stability. Light oil shows lower viscosity, higher TAN, and higher API gravity, offering better flow and mobilization potential during biosurfactant-assisted EOR.

Table 2.
Oil Characteristics.

Oil Characteristics	Characteristics of Light Oil	Medium Oil
Saturated	71.60%	74.67%
Aromatics	25.49%	24.07%
Resins	2.14%	1.15%
Asphaltene	0.78%	0.106%
TAN (Total Acid Number)	1.23 mg KOH/g	0.178 mg KOH/g
Viscosity	0.9 cP (66^0 C)	4.38 cP (60^0C)
Gravity API	43.45°API	33.1°API

Table 2 shows that both oils have characteristics that support the biosurfactant injection process, mainly because of the low asphaltene and resin content. So, the risk of asphaltene precipitation when in contact with biosurfactants is minimal.

3.1.2. Berea Buff Rock and Field

Gas porosity and permeability of seven Berea Buff cores were measured using PORG-200 and PERG-200 with nitrogen gas, applying Boyle's and Darcy's laws. Table 3 presents the results of physical measurements and laboratory tests on seven Berea Buff rock core samples used in the reservoir characterization study. Cores had uniform dimensions, P1/P2 ratios of 3.94–4.10, and corrected grain volumes of 15.07–15.82 cc, supporting consistent reservoir characterization for EOR studies.

Table 3.
Physical Characteristics and Results of Porosity and Gas Permeability Tests on Berea Buff Rock Core Samples.

Core	1	2	3	4	5	6	7
Length (cm)	3.98	3.94	3.93	4.09	3.99	3.9	3.92
Diameter (cm)	2.53	2.52	2.53	2.52	2.52	2.53	2.53
r (cm)	1.265	1.26	1.265	1.26	1.26	1.265	1.26
Bulk Volume (cm^3)	19.998	19.641	19.747	20.389	19.890	19.596	19.541
Disc Number	4+3+1	4+3+1	4+3+1	4+3+1	4+3+1	4+3+1	4+3+1
P1(psig)	100	100	100	100	100	100	100
P2 (psig)	24.9	24.8	24.7	25.4	25	24.5	24.4
P1/P2	4.016	4.032	4.049	3.937	4.000	4.082	4.098
Vgrain (cc)	33.134	33.059	32.982	33.503	33.209	32.828	32.750
Vgrain addition (cc)	17.683	17.683	17.683	17.683	17.683	17.683	17.683
Final Vgrain	15.451	15.376	15.299	15.820	15.526	15.145	15.067
Gas Porosity (%)	22.738	21.717	22.523	22.408	21.941	22.715	22.897
Gas Permeability (mD)	81.051	75.436	80.879	141.658	79.587	98.490	85.220

Porosity and gas permeability tests on seven Berea sandstone cores showed high suitability for EOR. Porosity ranged from 21.717% to 22.897%, indicating ample pore space for fluid storage. Permeability values ranged from 75.436 to 141.568 mD, enabling efficient fluid flow, with Core 4 highest and Core 2 lowest. XRD analysis of Core 7 revealed quartz dominance (72.90%), with anorthite (14.90%), muscovite (6.60%), and kaolinite (5.60%). Quartz provides structural stability, while reactive minerals influence ion exchange and biosurfactant adsorption.

The mineralogical composition of the berea sandstone is determined by X-ray diffraction (XRD) analysis of core 7. The diffractogram presented in Figure 1 shows a significant incidence of Quartz (SiO_2), represented by a weight ratio of 72.90%, which therefore suggests a highly siliceous sandstone.

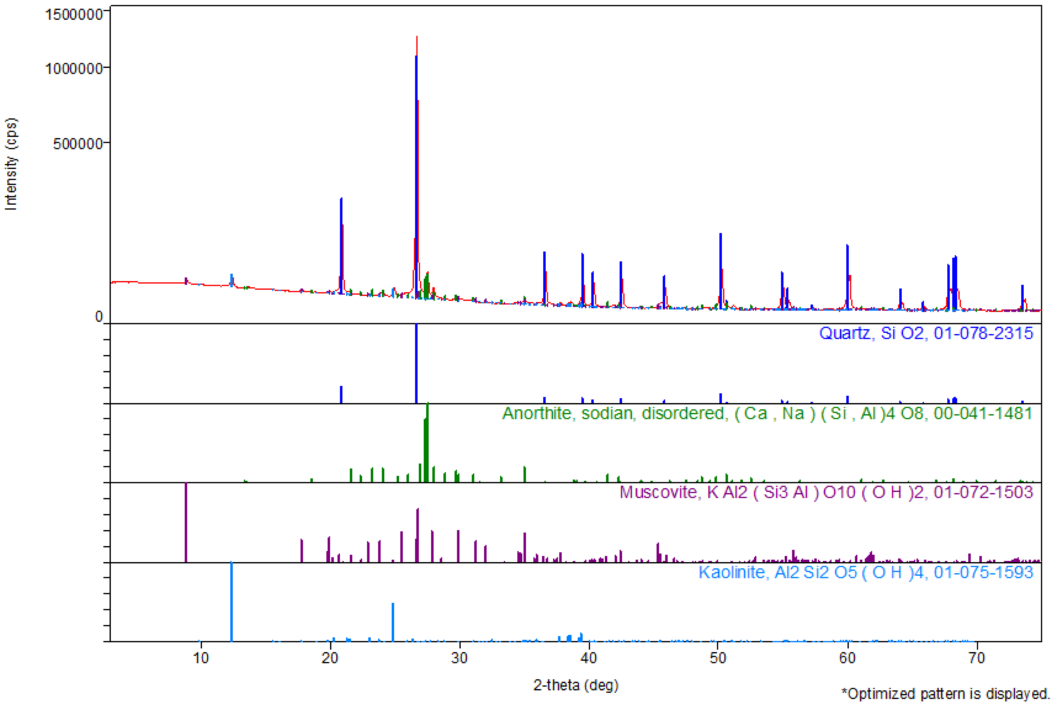


Figure 1.
Phase data pattern of X-ray diffraction (XRD) analysis.

Based on Figure 1, quartz is chemically inert and structurally rigid, and its presence affects fluid movement and interaction with biosurfactants in the reservoir rock. Besides Quartz, Anorthite, sodian-disordered [$(Ca,Na)(Si,Al)_4O_8$], a feldspar group mineral, takes 14.90% of the mineral content. Feldspar minerals are much more reactive as compared to quartz and hence can also serve in ion exchange and surface interaction processes which are crucial for biosurfactant compatibility evaluation. Muscovite ($KAl_2(AlSi_3O_{10})(OH)_2$), belonging to mica, constitutes 6.60% of the sample. In addition, Muscovite can be relevant in influencing by its layered silicate structure, adsorption mechanisms of biosurfactant molecules due to its platy morphology and surface charge characteristics. Finally, Kaolinite ($Al_2Si_2O_5(OH)_4$), belonging to the group of clay minerals, can be detected at around 5.60% but it is in a minimally small amount. Despite its relatively low abundance, kaolinite can have a significant impact on biosurfactant performance due to its high surface area, cation exchange capacity, and potential to adsorb active biosurfactant components. Figure 2 shows the results of scanning electron microscope (SEM) observations of four main types of minerals identified in the berea sandstone, each with different magnifications according to the characteristics of the mineral morphology.

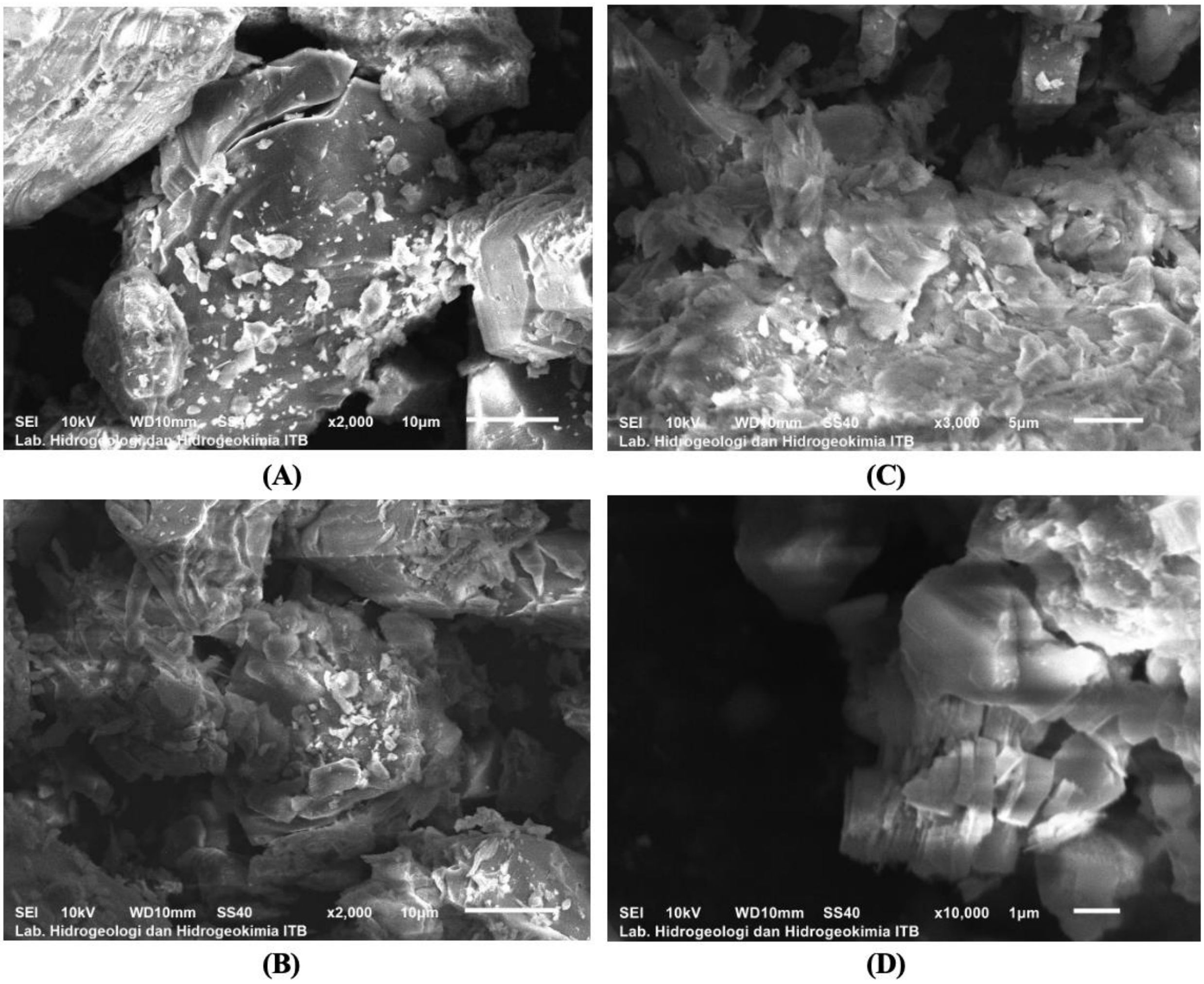
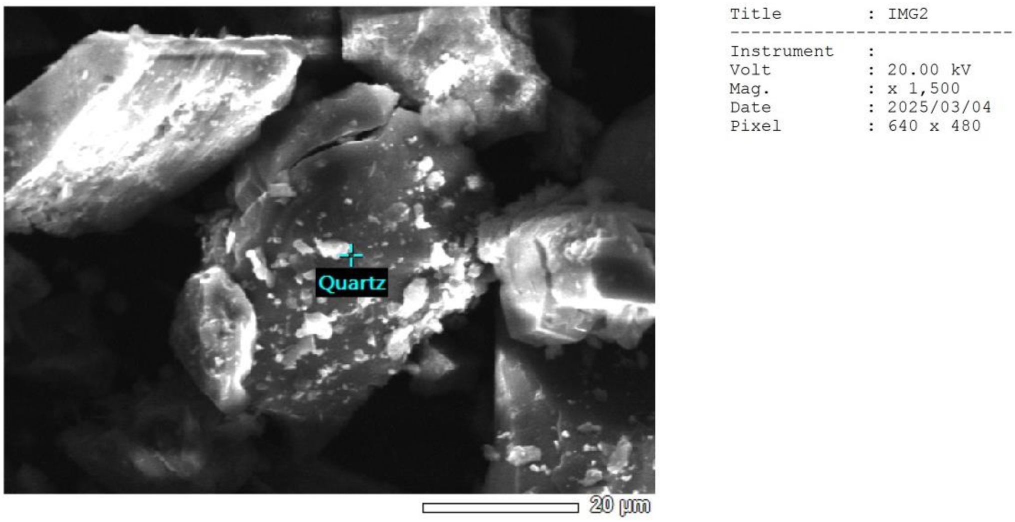
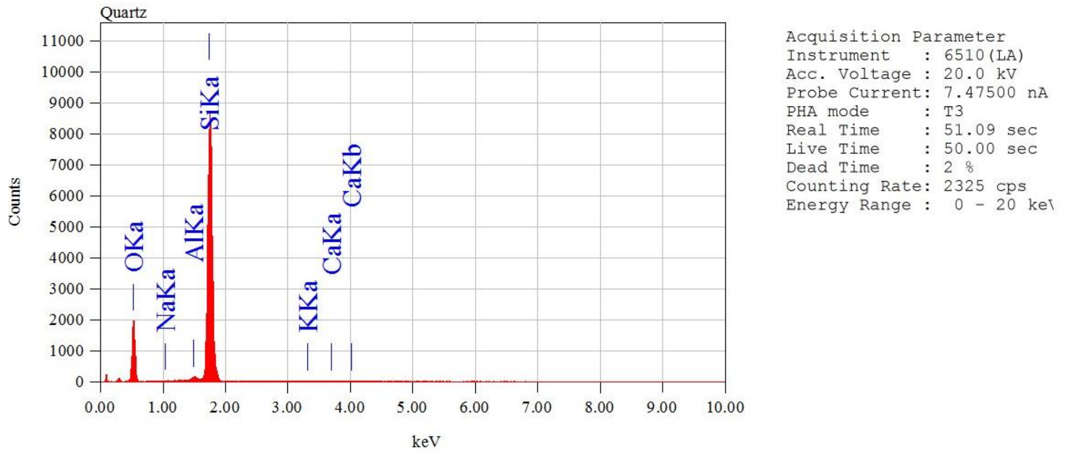


Figure 2.
SEM Test Results: Quartz with 2000x magnification (A), Kaolinite with 2000x magnification (B), Muscovite with 3000x magnification (C), and Anorthite with 10,000x magnification (D).

Berea sandstone is dominated by quartz with notable reactive silicate and clay minerals, influencing biosurfactant compatibility for EOR. SEM analysis shows quartz (2000x) as large, angular grains with fine clay coatings, providing strength and stability (2A). Kaolinite (2000x) appears as thin plates in aggregates, offering high surface area and adsorption capacity (2B). Muscovite (3000x) forms thin flakes with layered structures, affecting fluid interactions (2C). Anorthite (10,000x) displays blocky crystals with angular edges, exhibiting moderate reactivity for ion exchange and chemical weathering (2D). These mineralogical features highlight the rock's mechanical stability while indicating potential chemical interactions that must be considered in biosurfactant-assisted recovery processes.

Figure 3 show the result of SEM-EDS analysis of Berea sandstone quartz (1500×) shows sub-angular to angular grains with smooth surfaces and minor adhered particles, likely clay or precipitates. These images reveal mineral morphology and texture, aiding understanding of biosurfactant–mineral interactions and their impact on fluid movement efficiency in Enhanced Oil Recovery (EOR) processes.





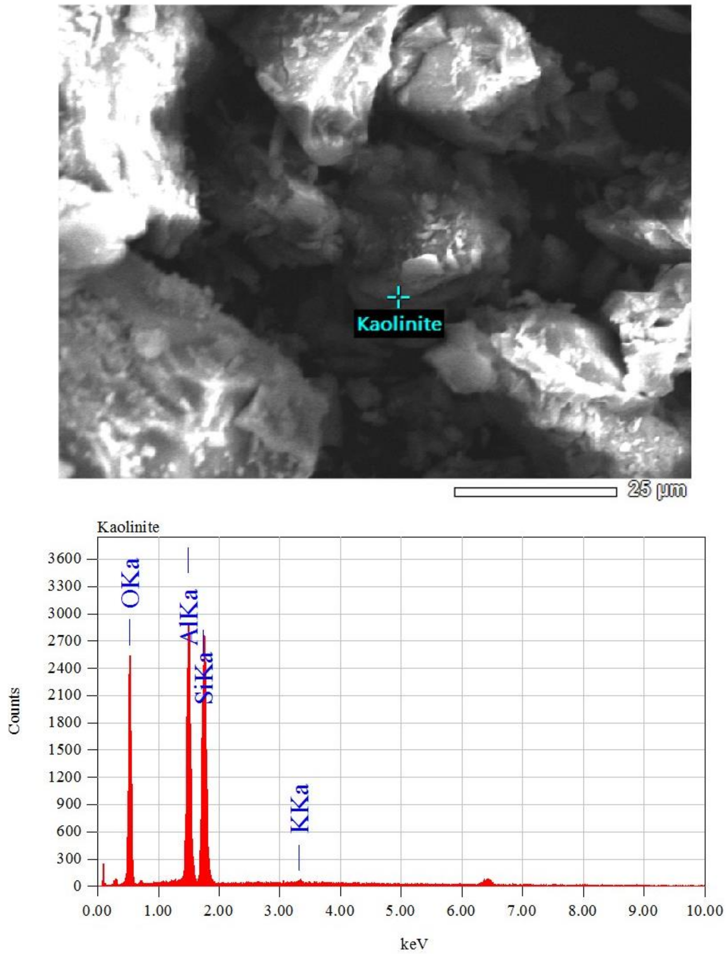
ZAF Method Standardless Quantitative Analysis
Fitting Coefficient : 0.2129

Element	(keV)	Mass%	Sigma	Atom%	Compound	Mass%	Cation	K
O K	0.525	53.93	0.55	67.28				59.2307
Na K	1.041	0.02	0.03	0.01				0.0108
Al K	1.486	0.39	0.04	0.29				0.2936
Si K	1.739	45.53	0.29	32.35				40.3451
K K	3.312	0.12	0.03	0.06				0.1033
Ca K	3.690	0.02	0.03	0.01				0.0165
Total		100.00		100.00				

Figure 3.
SEM-EDS Analysis of Quartz Grain in Berea Sandstone.

SEM-EDS of quartz in Berea sandstone shows O (53.93 wt%) and Si (40.35 wt%), matching SiO_2 stoichiometry. Trace Ca, Na, K, and Al likely reflect mineral inclusions. High purity and crystalline texture suggest minimal alteration, with surface properties influencing biosurfactant interaction and adsorption in EOR applications. The kaolinite is starting from the SEM image shown at 1300× magnification and, therefore, appears as aggregates of fine platy particles with a layered texture.

Figure 4 show the result of SEM-EDS analysis identified kaolinite in Berea sandstone, showing flake-like morphology with high surface area, enhancing fluid–rock interactions in biosurfactant EOR. Elemental composition was O (61.58 wt%), Si (20.79 wt%), and Al (17.28 wt%), matching $Al_2Si_2O_5(OH)_4$, with trace K from impurities.

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Live Time     : 50.00 sec
Dead Time     : 2 %
Counting Rate: 1861 cps
Energy Range :  0 - 20 ke\
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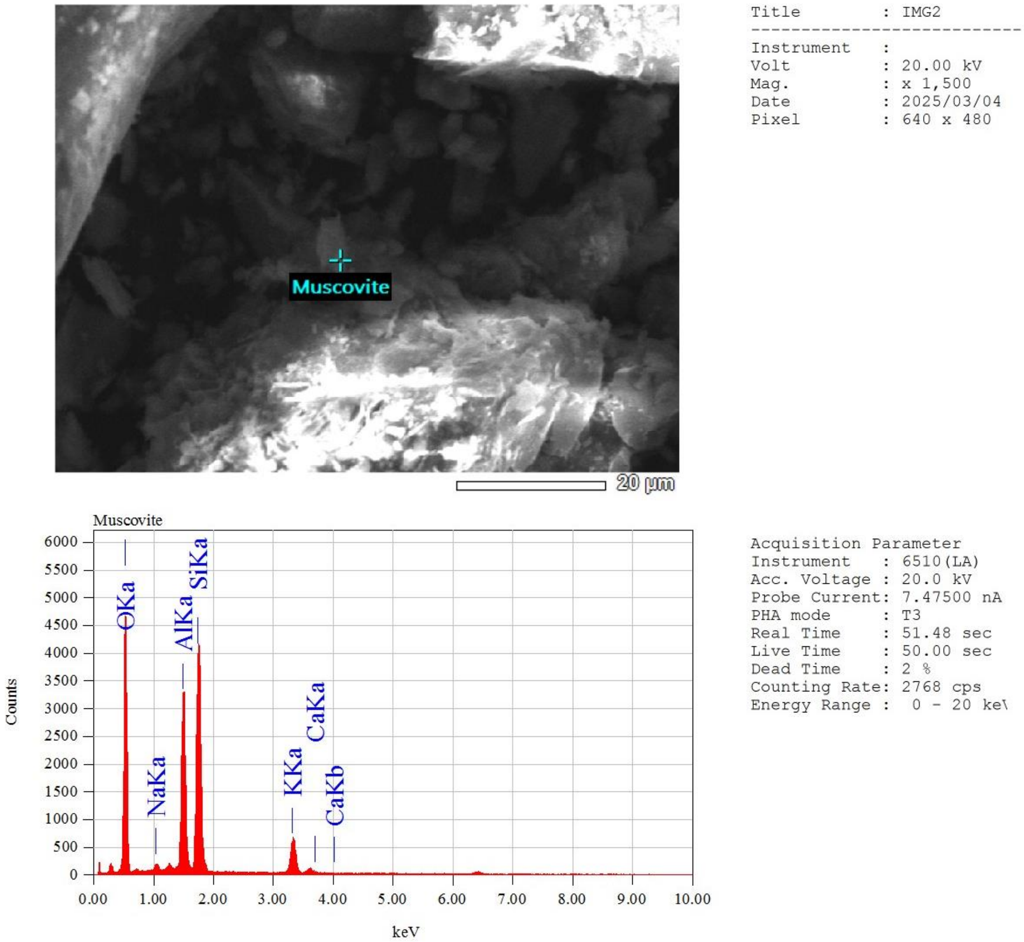
ZAF Method Standardless Quantitative Analysis
Fitting Coefficient : 0.1878

Element	(keV)	Mass%	Sigma	Atom%	Compound	Mass%	Cation	K
O K	0.525	61.58	0.55	73.48				75.0065
Al K	1.486	17.28	0.19	12.23				11.5641
Si K	1.739	20.79	0.23	14.13				13.1552
K K	3.312	0.34	0.04	0.16				0.2742
Total		100.00		100.00				

Figure 4.
SEM-EDS Analysis of Kaolinite Grain in Berea Sandstone.

Muscovite was also observed, displaying thin, layered flakes typical of 2:1 phyllosilicate, whose high surface area influences mineral–fluid interactions and biosurfactant adsorption in reservoir conditions (Figure 5).



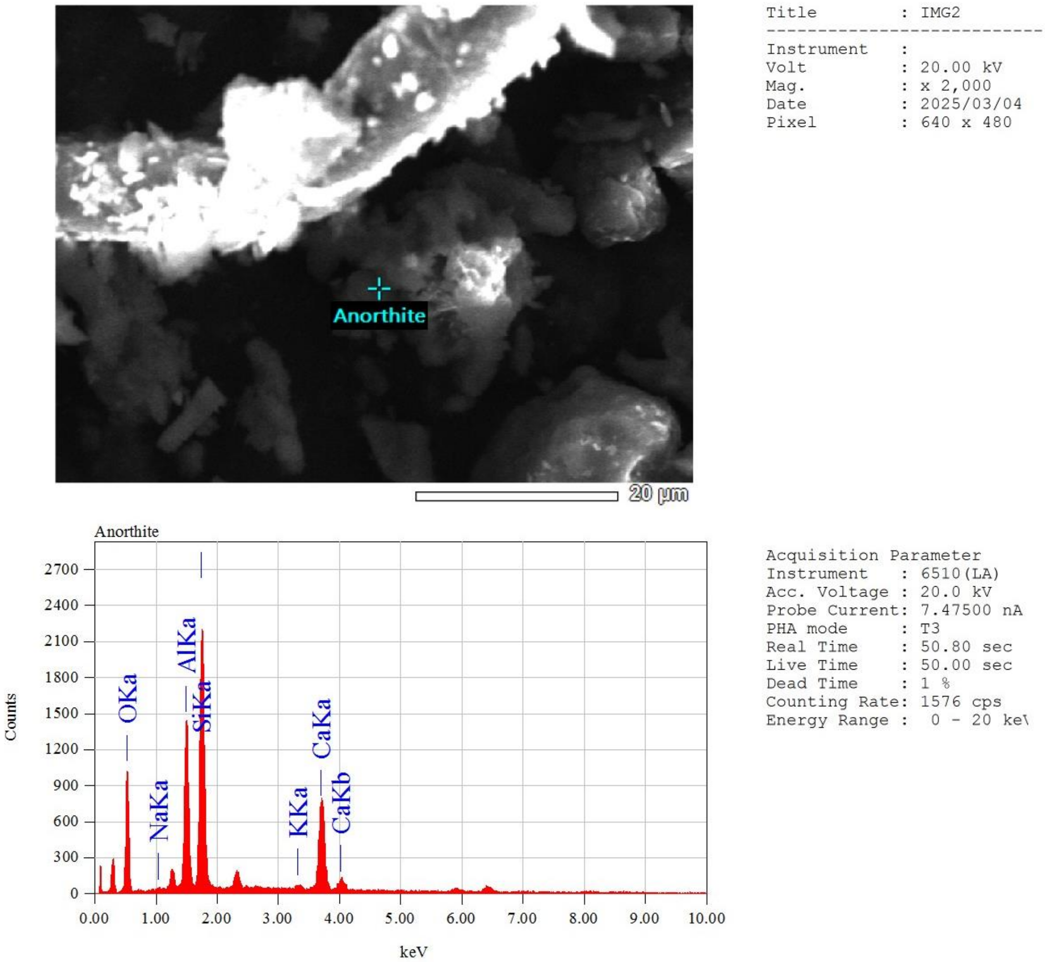
ZAF Method Standardless Quantitative Analysis
Fitting Coefficient : 0.1622

Element	(keV)	Mass%	Sigma	Atom%	Compound	Mass%	Cation	K
O K	0.525	66.44	0.44	77.91				77.5416
Na K	1.041	0.79	0.05	0.64				0.4535
Al K	1.486	11.68	0.12	8.12				7.4268
Si K	1.739	17.04	0.15	11.38				11.1973
K K	3.312	3.99	0.08	1.91				3.3252
Ca K	3.690	0.06	0.02	0.03				0.0556
Total		100.00		100.00				

Figure 5.
SEM-EDS Analysis of Muscovite Grain in Berea Sandstone.

EDS analysis of muscovite in Berea sandstone shows O (66.44 wt%), Si (17.04 wt%), Al (6.18 wt%), and K (5.02 wt%), with minor Na and Ca (<1 wt%). Results match the formula $KAl_2(AlSi_3O_{10})(OH)_2$. Muscovite's platy structure and surface chemistry can influence wettability, reactivity, and biosurfactant adsorption in porous media, making its presence relevant for EOR performance. SEM-EDS also identified anorthite in the sample.

A grain of anorthite is found in the berea sandstone, according to the SEM-EDS investigation shown in Figure 6. SEM (2000×) and EDS analysis identified anorthite in Berea sandstone, showing Ca, Si, Al, O as major elements, with minor Na and K. Quantitative analysis shows that oxygen is the most abundant element (69.48 atom%), followed by silicon (15.18 atom%), aluminium (6.96 atom%), and calcium (7.36 atom%), in agreement with the chemical formula of anorthite ($CaAl_2Si_2O_8$). The trace levels of sodium and potassium may be a sign of mild contamination or the presence of other feldspar minerals. Overall, the elemental composition of the investigated grain indicates its mineralogical role in the sandstone matrix, confirming that it is anorthite, a calcium-rich plagioclase feldspar.



ZAF Method Standardless Quantitative Analysis
Fitting Coefficient : 0.2935

Element	(keV)	Mass%	Sigma	Atom%	Compound	Mass%	Cation	K
O K	0.525	54.73	0.77	69.48				55.6297
Na K	1.041	0.21	0.05	0.18				0.1670
Al K	1.486	11.96	0.19	9.00				10.6538
Si K	1.739	20.98	0.26	15.18				19.1291
K K	3.312	0.54	0.06	0.28				0.6145
Ca K	3.690	11.59	0.20	5.87				13.8059
Total		100.00		100.00				

Figure 6.
SEM-EDS Analysis of Anorthite Grain in Berea Sandstone.

Quartz (~72.90 wt%) dominates the matrix, contributing little to biosurfactant retention due to low reactivity. Reactive silicates—muscovite (~6.60 wt%), anorthite (~14.90 wt%)—and kaolinite (~5.60 wt%) provide surface sites for ion exchange and adsorption. Kaolinite's high surface area and charge promote rhamnolipid attachment via electrostatic, hydrogen bonding, and van der Waals forces. These mineral–surfactant interactions, confirmed in adsorption tests, may reduce mobile biosurfactant concentrations, highlighting the need for dose optimization in EOR applications to maintain efficiency and recovery.

3.1.3. Rhamnolipid Biosurfactant

Figure 7 characterizes the biosurfactant Rhamnolipid for use in reservoir applications as corroborated by the Certificate of Analysis (COA) from Shanghai Yuchuang Chemical Technology Co., Ltd. The Rhamnolipid looks like a dark brown liquid as seen from the beaker containing approximately 50 mL of sample. This product was made on August 15, 2022, with batch number 20220815, according to the COA. The Rhamnolipid satisfies the required quality criteria, according to the test results. The product is extremely pure and concentrated because its Rhamnolipid concentration of 298.76 g/L is greater than the minimal requirement of 250 g/L. The product won't corrode the subsurface environment in reservoirs since its pH of 7.67 in a 10% water solution is neutral, falling between 6.0 and 8.0. Its practical application in enhanced oil recovery (EOR) and other subsurface processes also depends on its water solubility.

Figure 7.
Rhamnolipid Biosurfactant and Rhamnolipids at various concentrations.

Rhamnolipids, glycolipid biosurfactants produced by Pseudomonas aeruginosa via microbial fermentation, consist of one or two hydroxy fatty acid chains linked to rhamnose sugars. Their unique structure imparts strong surface activity, enabling significant reduction of surface and interfacial tension. Environmentally friendly, biodegradable, and effective under harsh conditions, rhamnolipids are produced from renewable substrates through controlled fermentation, followed by extraction and purification. This study tested concentrations of 0–7.5% to evaluate effects on oil recovery efficiency, emulsification, and interfacial tension. The concentration range supports determining the optimal dosage for reservoir treatment, maximizing EOR performance while minimizing chemical use and ensuring practical field applicability.

3.2. Fluid-to-Fluid

3.2.1. IFT (Interfacial Tension)

Using Rhamnolipid biosurfactant, Figure 8 shows the interfacial tension (IFT) behavior between the oil and water phases at different salinity levels of sodium chloride (NaCl): 5000 ppm (A), 10000 ppm (B), 15000 ppm (C), 20000 ppm (D), 25000 ppm (E), and 30000 ppm (F). To determine how well the biosurfactant reduced IFT for medium and light oil, it was tested at doses ranging from 0% (no biosurfactant) to 7.5%. When Rhamnolipid is added, IFT significantly decreases, especially in the concentration range of 0–1.5%. The sharpest reduction occurs between 0% and 1%, indicating vigorous surface activity at low concentrations. Beyond 1.5%, increased concentrations of biosurfactant show only negligible improvement when added to the solution. In this, it appears, the critical micelle concentration has been reached beyond which increments yield diminishing returns.

Light oils invariably demonstrate lower IFT values than medium oils at all concentrations and salinity levels, indicating that rhamnolipid interacts better with light oil than with medium oil, possibly due to its less complicated molecular structure and lower viscosity. The biosurfactant is also active, even at very high saline levels of up to 30,000 parts per million. Since such high salinities are generally found in reservoir brines, this capability to function under saline conditions becomes very important with respect to EOR methodologies. The study results reveal that Rhamnolipid biosurfactant remains stable and effective under a very wide range of salinities and even demonstrates decent interfacial activity, especially at low concentrations. These factors make it very compatible for application under chemical EOR techniques, particularly within high-salinity formation water and light oil reservoirs.

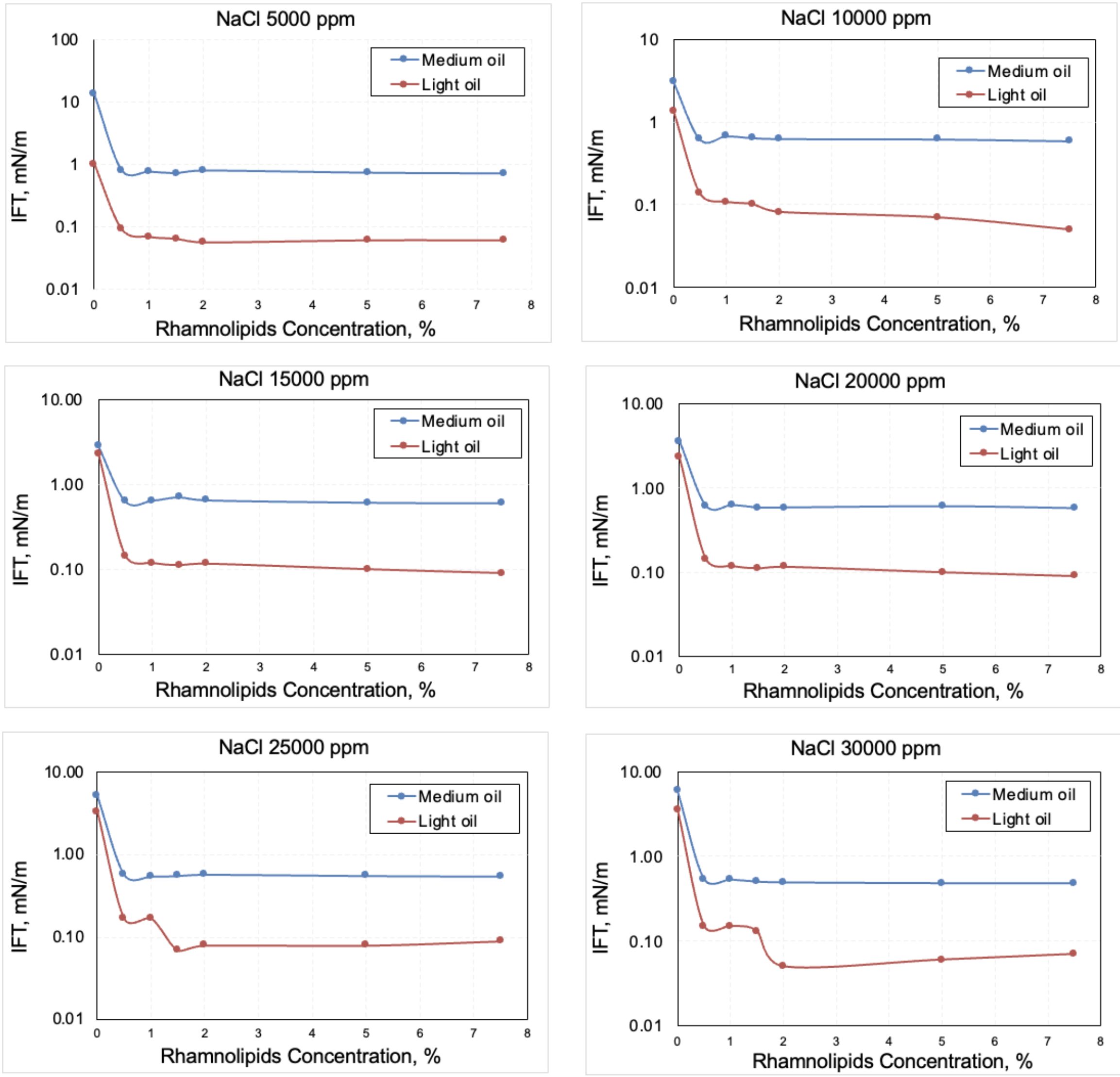


Figure 8.
Rhamnolipid Interfacial Tension at various concentrations of NaCl: 5000 ppm (A), 10000 ppm (B), 15000 ppm (C), 20000 ppm (D), 25000 ppm (E), and 30000 ppm (F).

3.2.2. pH and Viscosity

Table 4 shows Rhamnolipid's effect on pH at 5000–30000 ppm salinity. Without Rhamnolipid, pH was ~6, except 5000 ppm (pH 5). At 0.5–2%, pH rose to 6 at 5000 ppm but dropped to 5 at ≥10000 ppm. At 5–7.5%, pH stayed at 5 across salinities, likely due to acidic groups. Overall, Rhamnolipid maintains stable pH (5–6), indicating good salinity tolerance for EOR applications.

Table 4.
Rhamnolipid Concentration on pH at Various NaCl Salinity Levels.

Rhamnolipid Concentration (%)	Brine (ppm)					
	NaCl 5000	NaCl 10000	NaCl 15000	NaCl 20000	NaCl 25000	NaCl 30000
0	5	6	6	6	6	6
0.5	6	5	5	5	5	5
1	6	5	5	5	5	5
1.5	6	5	5	5	5	5
2	6	5	5	5	5	5
5	5	5	5	5	5	5
7.5	5	5	5	5	5	5

Figure 9 shows rhamnolipid's effect on medium and light oil viscosity across NaCl salinities (5000–30000 ppm). Medium oil viscosity increased notably at 1.5–2% rhamnolipid, especially at moderate salinity, reaching ~18–20 cP at high salinity. Light oil viscosity remained largely unchanged (2–5 cP). Results suggest rhamnolipid interacts more with medium oil, enhancing viscosity and mobility control for EOR, while its effect on light oil is minimal.

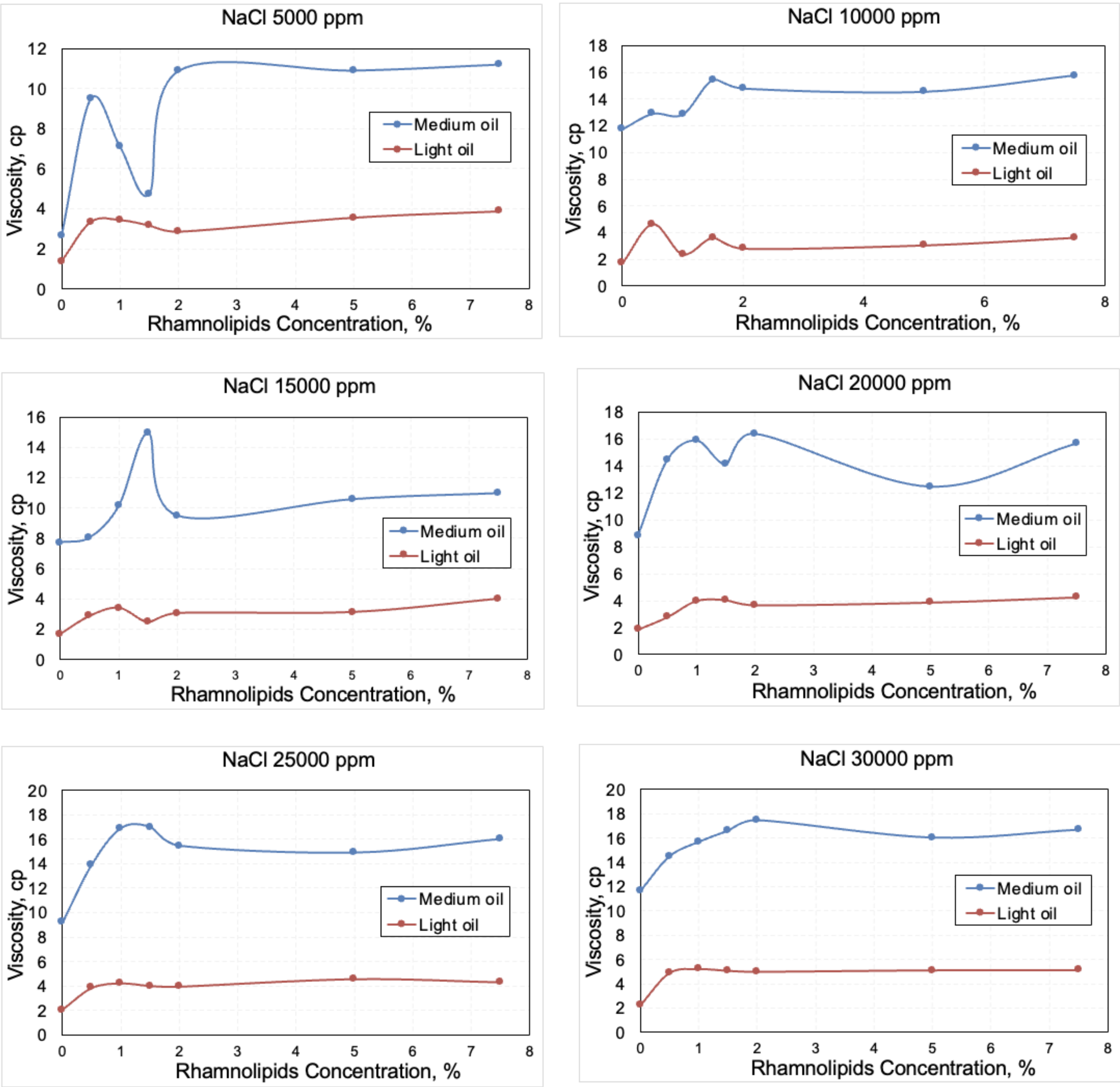


Figure 9.
Viscosity at various concentrations of NaCl: 5000 ppm (A), 10000 ppm (B), 15000 ppm (C), 20000 ppm (D), 25000 ppm (E), and 30000 ppm (F).

3.3. Rock-to-Fluid

3.3.1. Wettability Test

The objective of the wettability test is to evaluate the effectiveness of the rhamnolipid surfactant in altering the wettability of reservoir rocks. The test used a two-phase method by comparing the contact angles formed between rock surfaces and three different fluids: crude oil, brine, and surfactant solution. A smaller contact angle indicates stronger wettability toward the rock surface, desirable in enhanced oil recovery applications. A good surfactant can reduce the contact angle of the brine significantly. In contrast, an excellent surfactant is characterized by its ability to reduce the contact angle of crude oil. Figure 10 show the wettability test of light oil.

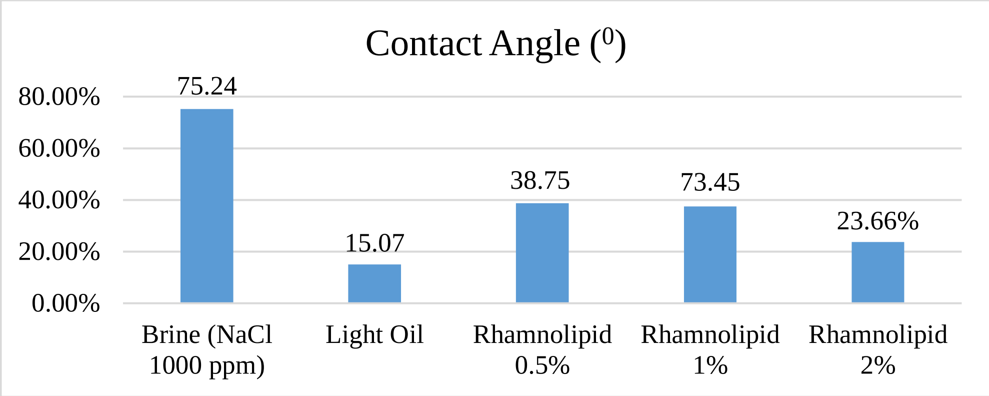
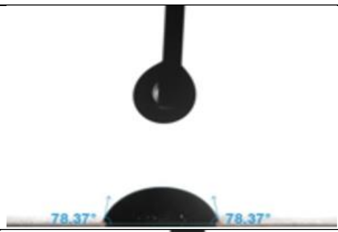
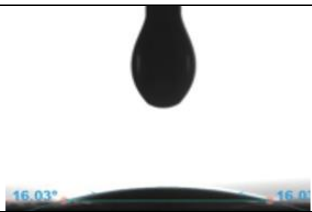
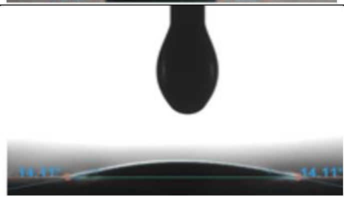
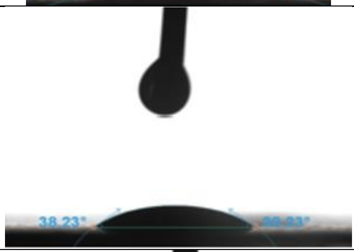
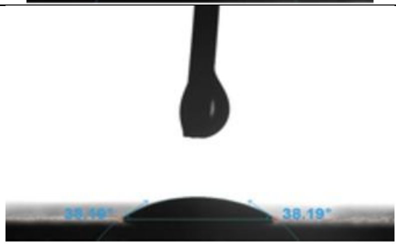
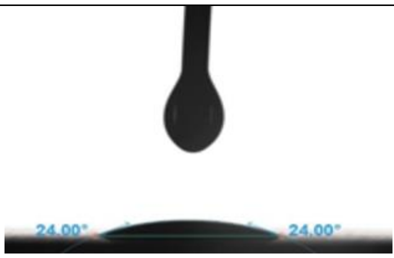
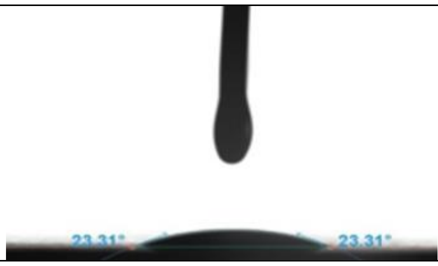


Figure 10.
Wettability Test of Light Oil and Rhamnolipid Solutions on Berea Sandstone.

Rhamnolipid surfactant reduced Buff Berea rock's contact angle from 75.24° (brine) to 23.66°–38.75°, with higher concentrations yielding greater water-wetness. Performance surpassed crude oil (15.07°) in altering wettability. These results confirm rhamnolipid's strong potential as a wetting agent for Enhanced Oil Recovery, facilitating oil release from rock pores. Table 5 shows the results of wettability tests conducted to evaluate the effectiveness of the Rhamnolipid biosurfactant in altering the wettability of Berea Buff rock.

Table 5.
Contact Angle of Brine, Light Oil, and Rhamnolipid Solutions on Berea Sandstone.

No.	**Samples**	**Photo**	
		1	**2**
1.	Brine (NaCl 10000 ppm)		
2.	Light oil		
3.	Rhamnolipid 0.5%		
4.	Rhamnolipid 1%		

5.	Rhamnolipid 2%		

Wettability tests show brine had the highest contact angle (75.24°), indicating partial oil-wetness. Medium oil reduced it to 25.05°. Rhamnolipid lowered angles further with increasing concentration, reaching 23.66% at 2%, shifting rocks from intermediate- to water-wet. This highlights rhamnolipid's strong potential for EOR in non-water-wet reservoirs (Figure 11).

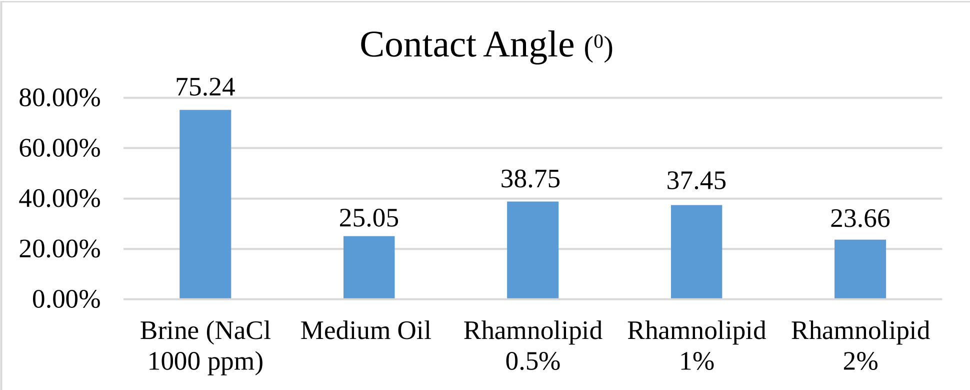
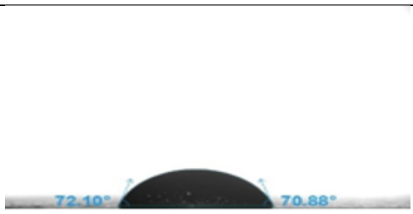
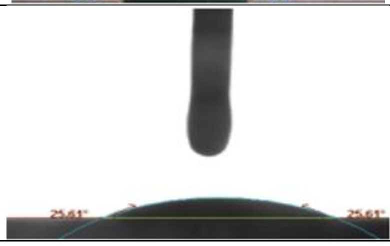
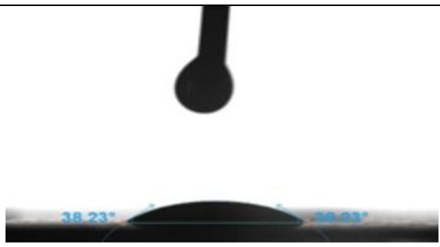
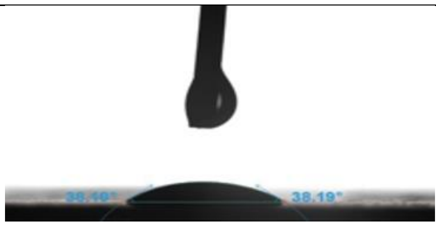
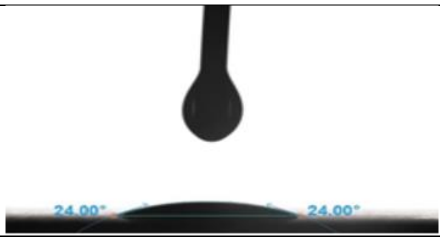


Figure 11.
Wettability Test of Medium Oil and Rhamnolipid Solutions on Berea Sandstone.

Table 6 shows the contact angles of various brine (10,000 ppm NaCl), medium oil, and rhamnolipid solutions at concentrations of 0.5%, 1%, and 2% on the Berea Sandstone limestone surface. The ability of liquid to reside on a surface is indicated by contact angle: a smaller contact angle indicates better wettability (more hydrophilic) while greater angle indicates hydrophobicity. That indicates, brine has a comparatively larger contact angle, averaging at 75.24°, meaning that the surface of the rock is somewhat hydrophobic toward this salt solution and does not wet readily. Medium oil displayed a very low contact angle, averaging at 25.05°, suggesting that oil has more affinity to wet the surface of the rock given that it is more oleophilic. These results indicate that rhamnolipid can significantly reduce the contact angle, especially at a concentration of 2%, and make the rock surface more wettable. This is particularly important in enhanced oil recovery (EOR) applications, as increased wettability can help mobilize oil trapped in the rock pores.

Table 6.
Contact Angle of Brine, Medium Oil, and Rhamnolipid Solutions on Berea Sandstone.

No.	**Samples**	**Photo**	
		1	**2**
1.	Brine (NaCl 10000 ppm)		
2.	Medium oil		

3.	Rhamnolipid 0.5%		
4.	Rhamnolipid 1%		
5.	Rhamnolipid 2%		

The wettability test showed a contact angle of 15.07° for light oil and 25.05° for medium oil on Berea sandstone. Smaller contact angles indicate higher wettability, meaning light oil wets rock surfaces more easily, while medium oil—with lower wettability—has greater mobilization potential when surfactants are applied. The rhamnolipid biosurfactant demonstrated good compatibility with reservoir properties, aided by high porosity, permeability, and quartz-dominated mineralogy. SEM-EDS confirmed possible interactions between mineral grains and biosurfactant molecules. Fluid tests revealed that rhamnolipid reduced interfacial tension (IFT) and shifted wettability toward water-wet conditions. Stability was maintained at salinity up to 30,000 ppm and 60°C, with optimal IFT reduction at 5,000 ppm, aligning with prior findings on medium salinity effectiveness. Rhamnolipid was more effective in mobilizing light oils due to their lower viscosity and simpler molecular structure, while still improving medium oil mobilization. The observed 25.05° contact angle for crude oil further supports enhanced water wettability. These results confirm literature reports and extend prior work by incorporating crude oil compatibility, mineralogy, and SEM-EDS analysis. Overall, rhamnolipid biosurfactant shows strong potential for Enhanced Oil Recovery (EOR) in challenging reservoir conditions, offering improved efficiency and supporting its practical application in sustainable field operations.

4. Conclusion

The findings indicate that rhamnolipid biosurfactant exhibits strong potential for application in chemically enhanced oil recovery (EOR). Berea cores exhibited high quartz content with minor reactive minerals, uniform porosity (21.717–22.897%) and permeability (75.436–141.658 mD), providing a stable matrix for fluid–rock interactions. The interface tension (IFT) was shown to decrease as the concentration of rhamnolipid increased, particularly between 0 and 1.5%. After that, the drop stabilized at concentrations over 1.5%. At a salinity of 5000 ppm NaCl, where the IFT dropped to its lowest value, the maximum efficacy was noted. Rhamnolipid was more effective with light oil due to its simpler molecular structure and lower viscosity, although viscosity enhancement was more prominent in medium oil systems, especially at moderate to high salinities (15,000–30,000 ppm). This implies favorable mobility control and emulsion formation, both of which are critical for increasing sweep efficiency in porous media. The pH of the solution was quite stable at a range between 5 and 6, a range considered to be clear for reservoir applications in which there will be no severe corrosion risk. The viscosity of rhamnolipid solutions increased slightly with increasing concentration and salinity in medium oils, especially at medium to high salinities (15,000-30,000 ppm), reaching values up to approximately 18-20 cP. This viscosity increase can improve mobility control and sweep efficiency in EOR applications. Meanwhile, the effect on light oils was negligible, indicating minimal interaction between the biosurfactant and the lighter oil phase. The average contact angle in brine (10,000 ppm NaCl) was 75.24°, indicating relatively neutral wettability or moderately wet conditions. However, upon exposure to rhamnolipid biosurfactant, the contact angle decreased drastically. The wettability test results showed that the contact angle between light oil and the Berea sandstone surface was 15.07°, while the contact angle for medium oil was 25.05°. Therefore, light oil has higher wettability than medium oil because it spreads more easily across the rock surface and is retained within small pores, which are important characteristics in enhanced oil recovery (EOR) processes. However, from an oil recovery efficiency perspective, this also indicates that medium oil, with its larger contact angle, has a higher potential for mobilization when surfactants are added. Rhamnolipid is an effective and eco-friendly EOR agent, according to the comprehensive assessment of fluid, rock, and chemical interactions. This provides a scientific foundation for developing long-term recovery plans in sandstone reservoirs.

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