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High Thermal Stability Silica Nanofluids For EOR in Sandstone Reservoir

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ABSTRACT The development of silica nanofluids for enhanced oil recovery (EOR) has gained significant attention. However, their application is limited bypoor stability under high temperature, and high salinity conditions. Our previous studies demonstrated that using the anionic surfactant alpha olefin sulfonate (AOS) combined with the co surfactant disodium laurent sulfosuccinate (DLS) at consentrations of 0.3% AOS and 0.3% DLS significantly enhanced thermal stabilility, reduced IFT, decreased wettability, and increased incremental oil recovery. This study reports a one step synthesis method for preparing silica nanofluids using hydrophilic colloidal nano silica (CNS) stabilized with the AOS and DLS at surfactant concentrations above 0.3%. Nanofluids were formulated with formation water from a reservoir in Sumatra, Indonesia. We systematically evaluated the effects of AOS-DLS concentrations on the thermal stability, turbidity, interfacial tension (IFT), wettability, filtration test, and core flooding performance. The optimized formulation of stable silica nanofluids for EOR applications under reservoir relevant conditions was also systematically evaluated. The silica nanofluid (0.3% AOS + 0.3% DLS) exhibited more than 3 months of stability at 60 °C. It also had a low contact angle of 13.88° and a reduced IFT of 6.3×10^{-1} mN/m. The filtration ratio was 1.2. Spontaneous imbibition resulted in a recovery factor (RF) of 59%. Core flooding analysis yielded an incremental RF of 12.9% of the OOIP. These results demonstrate the synergistic role of silica nanoparticles and surfactants in improving nanofluid stability, reducing IFT, and enhancing oil recovery. This supports their potential application in chemical flooding for sandstone reservoirs.

Keywords: silica nanofluids; enhanced oil recovery; thermal stability; surfactant

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INTRODUCTION

Global energy demand continues to rise. To meet this demand, new oil reservoirs must be explored. Production from existing reservoirs must also be maximised (Sharma et al., 2024). The application of the EOR method is considered a key solution to the increasing global demand for crude oil (Rezaei et al., 2022). EOR serves as a tertiary recovery method, helping recover the remaining 60 -70% of oil left after primary and secondary recovery. Several EOR techniques, have been developed to improve overall oil production, including chemical flooding, gas injection, and thermal flooding (Samanta et al., 2012; Wang et al., 2016; Gbadamosi et al., 2019; Mansour et al., 2019; Seidy et al., 2024). In chemical EOR, the main approaches are polymer flooding, surfactant flooding, and alkaline flooding. Integrated methods that combine chemical and thermal processes are also used (Zhengbin et al., 2018; Mansouri et al, 2024). Nevertheless, conventional chemical EOR techniques face several limitations, such as unexpected chemical losses within porous formations and reduced economic efficiency (Gazem & Krisna, 2025).

Nanoparticles (NPs) have emerged as one of the most promising solutions for EOR. With their small size, 1-100 nm, NPs can flow through reservoir formations without becoming trapped in microscopic pore spaces, thereby improving fluid transport and sweep efficiency. Reservoir pore spaces are commonly categorized by size into micro pores (<2 nm), meso pores (2–50 nm), macro pores (50 nm–2 μm), and micro-fractures (>2 μm) (Gou et al., 2019). The presence of narrow pore networks underscores the importance of using nanoparticles with sufficiently small aggregates to ensure smooth migration through the formation. Beyond transport advantages, nanoparticles can influence critical reservoir properties, including wettability, interfacial tension (IFT), and fluid viscosity. A wide range of nanoparticles has been investigated for EOR applications, including metal oxides of aluminium, iron, magnesium, zinc , zirconium, nickel, silicon and tin (Sharma et al., 2024; Han et all., 2025). Among them, iron oxide (Fe_2O_3/Fe_3O_4) is widely used due to its magnetic properties and high surface area, which generate disjoining pressure and enable targeted oil mobilisation. Al_2O_3 NPs are valued for their thermal stability under harsh reservoir conditions, while Magnesium Oxide (MgO) nanoparticles exhibit high adsorption capacity, improving viscoelasticity and sweep efficiency. Zirconium Oxide (ZrO_2) nanoparticles are chemically stable and can adsorb asphaltenes, mitigating their negative effect on flow properties.

Titanium Oxide (TiO_2) nanoparticles are notable for their photocatalytic activity and are particularly effective in altering wettability in sandstone reservoirs. Zinc Oxide (ZnO) nanoparticles offer antimicrobial properties that can enhance microbial EOR processes. Finally, SiO_2 nanoparticles are widely used due to their high surface area, tunable surface chemistry, and excellent compatibility with both sandstone and carbonate reservoirs (Kandiel et al., 2025).

Silica nanoparticles are particularly attractive for EOR applications due to their sustainability, relative chemical inertness, eco friendliness, cost-effectiveness, stability in brines, and tunable surface chemistry (Zhou et al., 2019; Kandiel et al., 2025). Furthermore, the nanoparticles act as sacrificial materials, limitting surfactant retention and consumption, thereby improving thermal stability and extending the performance of nanofluids (Gazem & Krishna, 2025). In EOR, silica nanoparticles are typically applied as nanofluids, colloidal suspensions with particle sizes of 1 - 100 nm (El-Diasty et al., 2021). Although silica nanoparticles have been widely reported as effective EOR agents, their application in hydrophilic form is limited because they tend to aggregate easily due to their highly energetic hydrophilic surfaces. Moreover, high temperatures and high salinity (ionic strength) reservoir conditions further promote nanofluid instability. Therefore, achieving long-term nanoparticle stability under harsh reservoir conditions remains a critical challenge for their successful application in chemical EOR (Hutin et al., 2022).

Maintaining long term nanofluid stability under reservoir conditions requires proper physical or chemical treatments. One common approach is pH control. Nanofluid stability is closely related to electrokinetic behavior. Adjusting the pH can shift the zeta potential away from the isoelectric point. This increases electrostatic repulsion between particles, which prevents aggregation. Another key technique is adding a surfactant. Surfactant addition is widely used to improve nanoparticle stability in aqueous media. Surfactants adsorb nanoparticles' surface, converting hydrophobic surfaces into hydrophilic ones. This increases electrostatic repulsion and the absolute value of zeta potential. Surface modification, known as steric stabilization, is another stabilization technique. Surfactants or polymers are attached to nanoparticle surfaces to prevent aggregation. The steric barrier and osmotic repulsion that result enhance nanofluid stability (Li et al., 2020). Studies on polymer and surfactant selection provide technical context for the design of surfactant assisted nanofluids (Auni et al., 2023).

In recent years, several authors have proposed combining nanoparticles with surfactants to prepare nanofluids for EOR applications. .However, conventional surfactant flooding has certain limitations, including insufficient IFT reduction, high operational costs, and significant surfactant adsorption on rock surfaces, thereby reducing overall efficiency (Paternina 2022). To mitigate these challenges, new approaches have been introduced to optimize surfactant injection, and the use of nanoparticles has shown strong potential to enhance performance. Nanoparticles can be added to nanofluids to enhance their physicochemical properties and synergistically improve EOR efficiency (Schneider et al., 2023). Nanoparticles combined with surfactants have been extensively explored due to their ability to alter rock wettability and adsorb at the oil–water interface, thereby enhancing interfacial activity (Almahfood et al., 2018).

These formulations can achieve ultra-low IFT and form highly stable emulsions, an effect not typically observed when using either component alone (Shamsijazeyi et al., 2014). Furthermore, the presence of nanoparticles can reduce surfactant losses by decreasing adsorption onto reservoir rock surfaces (Wu et al., 2017). The surfactant to nanoparticle concentration ratio is critical: insufficient ratios result in incomplete surface coverage, whereas excessively high ratios may lead to bilayer formation on nanoparticle surfaces, thereby reducing overall efficiency (Gbadamosi et al., 2019). Recent laboratory studies have shown the synergistic benefits of combining silica nanoparticles with anionic surfactants for EOR, reporting improved thermal stability and alterations in wettability.

Local investigations additionally demonstrate that metal oxide nanoparticles (e.g., TiO_2) and optimized surfactant types (including tween and methyl ester sulfonates) can significantly improve displacement efficiency under reservoir relevant conditions (Fathaddin et al., 2025; Pauhesti et al., 2025; Rowi et al., 2025). Comparative work on alternative nanoparticle sources such as coal fly ash further supports the potential of silica based approaches for mobility control and foam stability (DN & Szafdarian, 2023), Zhao et al (2022) investigated the use of silica nanoparticles combined with alpha olefin sulfonate (AOS) surfactant in low permeability rock (<1 mD).

Their results showed that the nanofluids exhibited excellent stability when stored at 80°C for 3 weeks, with IFT reduced by 99.98% and contact angles decreasing to 20°C, significantly improving wettability. Moreover, spontaneous imbibition tests revealed a substantial increase in oil recovery: from 8.9% with high salinity brine (30,000 mg/L) and 14.33% with surfactant alone to 29%-with nanofluids. According to Hadia et al

(2021), a silica nanofluid with high thermal stability under high temperature, and high salinity conditions was successfully synthesised by surface modifying nano-silica with SBS and GLYMO as surfactant modifiers. Turbiscan analysis indicated that the resulting nanofluids remained stable for up to 6 months at 60 °C and 3.5 wt% NaCl salinity. Similarly, Worthen et al (2016) reported that silica nanoparticles (7–20 nm) were stabilized with nonionic ligands such as (PEG), GLYMO, and zwitterionic sulfobetaine (SB) in seawater and API brine (pH 3.5). GLYMO and SB modified nanoparticles exhibited excellent colloidal stability, remaining stable for over 30 days at 80 °C.

In addition, the raw material for silica nanoparticles plays a critical role in producing stable silica nanofluids. Two primary methods are commonly employed for nanofluid preparation. In the two step method, nanoparticles are first produced as dry powders and then dispersed into a base fluid. Due to their high surface energy, this process often leads to particle aggregation. To address this issue, additional dispersion methods, such as high-shear homogenization, ultrasonication, and dispersant use, are typically employed. Alternatively, the single-step method integrates nanoparticle synthesis and nanofluid preparation into a single step, thereby eliminating the need for drying, storage, transportation, and post-synthesis dispersion.

This approach significantly minimizes nanoparticle aggregation, leading to superior longterm stability and improved homogeneity of the resulting nanofluid (Li et al., 2020). Consequently, the single step method is generally preferred for applications that require highly stable nanofluids, such as EOR under harsh reservoir conditions.

In previous studies, silica nanoparticles powders were commonly used as raw materials for silica nanofluids (Ahmed et al., 2020; Daneshmand et al., 2021; Bijani et al., 2022). However, improving nanofluid stability solely through surfactant addition has been reported to be less than optimal due to complex, time-consuming synthesis procedures, the need to surface modify the nanosilica, and the associated increase in production costs (Ahmed et al., 2020; Hadia et al., 2021).

The application of higher surfactant concentrations combined with the use of formation water as the dispersion medium significantly enhances nanofluid performance under reservoir relevant conditions. Unlike synthetic brine, formation water contains complex ionic compositions and salinity levels that more accurately represent actual reservoir environments, thereby influencing surfactant behavior, nanoparticle surfactant interactions, and overall nanofluid stability. (Rowi et al., 2025), investigated the effect of AOS: DLS surfactants addition in synthetic brine on the thermal stability and oil recovery performance of silica nanofluids. The results showed that a concentration of 0.3% AOS and 0.3% DLS effectively improved thermal stability, reduced interfacial tension, altered wettability, and enhanced oil recovery.

However, the impact of higher AOS: DLS with concentrations under formation water conditions has not yet been explored. In this study, a single step nanofluid synthesis approach was employed to overcome these challenges. Hydrophilic colloidal nanosilica (CNS) was synthesized using a modified sol gel method. Subsequently, different concentrations of AOS surfactants (more than 0.3%) and DLS co-surfactants (more than 0.3%) were introduced as stabilizers to enhance the dispersion stability of silica nanofluids and improve oil recovery performance. Notably, this method does not require additional surface modification of silica nanoparticles, allowing for a simpler, more efficient, and potentially cost-effective synthesis process.

METHODOLOGGY

Material

This study utilized colloidal nano-silica with an average particle diameter of approximately 3 nm, synthesized at the Nanotechnology Laboratory, Diponegoro University, following the method reported by Qomariyah et al (2018). To enhance and maintain the stability of the silica nanofluid, commercial anionic surfactants were employed: alpha olefin sulfonate (AOS) with specification yellow color, density of 0.97 g/ml, and pH 8.0 purchased from PT. Rachara Chemical Technology and disodium laureth sulfosuccinate (DLS) used in this study (Evonik) had a clear appearance, and a pH range of 6.0-7, which helped maintain the stability of nanosilica dispersion. Formation water was collected from a reservoir operated by PT Pertamina in Sumatra (chemical composition shown in Table 1), while crude oil was obtained from the same reservoir (characteristics provided in Table 2). Synthetic sandstone cores used in the flooding experiments were upper grey Berea cores, commonly used as standard core materials for laboratory scale EOR evaluations.

Table 1. Specification of the formation water from the reservoir in Sumatra.

No	Parameter	Unit	Result	Method
1	Salinity	ppm	11,000	SM 2520 B, 23rd Edition:2017
2	Sodium total (Na)	ppm	17.22	SM 3500-Na, 23rd Edition:2017
3	Calcium total (Ca)	ppm	0.074	SM 3500-Ca, 23rd Edition:2017
4	Magnesium total (Mg)	ppm	0.151	SM 3500-Mg, 23rd Edition:2017
5	Chloride (Cl)	ppm	5,102	MU 2.06 (Discrete Photometry)
6	Sulphate (SO_4)	ppm	3.22	SM 4500-SO4, 23rd Edition:2017
7	Carbonic acid (H_2CO_3)	ppm	2,692	SM 2320. Alkalinity, 23rd Edition:2017
8	pH		7.58	

Table 2. Specification of the crude oil from a reservoir in Sumatra.

No	Parameter	Unit	Result	Method
1	Specific gravity at 60 °F	-	0.8595	ASTM D 1298
2	°API Gravity	-	23.65	ASTM D 1298
3	Density 15 °C	g/ml	0.9111	ASTM D 5002
4	Kinematic viscosity at 40 °C	mm^2/s	5,700	ASTM D 445
5	Pour point	°C	12	ASTM D 97
6	Total acid number	mg KOH/g	0.28	ASTM D 664-18e2
7	Asphaltenes	%wt	0.22	ASTM D 664-18e2

Methods

Silica nanofluids preparation

Silica nanofluids were synthesized by mixing 0.1% (v/v) colloidal nano silica with anionic surfactant AOS-DLS at varying concentrations, as shown in Table 3. The mixture was stirred at room temperature for 30 minutes. Subsequently, formation water from the reservoir was added and homogenized using a high-speed mixer at 20,000 rpm for 10 minutes. Preliminary studies have demonstrated that a minimum concentration of 0.3 wt% AOS and 0.3 wt% DLS provides the highest thermal stability of silica nanofluids under reservoir relevant conditions. Therefore, in this study, the AOS-DLS system was used at a 0.3 wt% concentration for each component to ensure maximum stability.

Table 3. Variation of AOS-DLS surfactant concentration.

Sample	Concentration of AOS-DLS (w/v %)	Ratio AOS:DLS
Nanofluid 1	0.3%-0.3%	1:1
Nanofluid 2	0.6%-0.3%	2:1
Nanofluid 3	0.9%-0.3%	3:1
Nanofluid 4	0.3%-0.6%	1:2
Nanofluid 5	0.6%-0.6%	2:2
Nanofluid 6	0.9%-0.6%	3:2

Characterization of silica nanofluid

Thermal stability

The synthesized silica nanofluids were evaluated for thermal stability by placing them in an oven at 60 °C and visually monitoring their appearance over 3 months.

Diameter aggregate

The aggregate diameter of nanoparticles was determined using a particle size analyzer (PSA) equipped with an automatic multi-angle dynamic light scattering (DLS) system of Anton Paar Litesizer 700.

Wettability

The wettability alteration of the porous medium was assessed using the sessile drop method. Thin slices of clean core plugs were prepared and immersed in silica nanofluid solution within a sessile drop apparatus at 60 °C. Crude oil was subsequently injected beneath the core section, and the core surface was measured and analyzed to quantify wettability changes.

Interface tension (IFT)

IFT (interfacial tension) measurements were conducted using a spinning drop interfacial tensiometer TX-500D model. The IFT values were determined using the Vonnegut approach, which calculates IFT based on the curvature of the elongated drop shape. All measurements were performed at 60°C, with a rotation speed of 3000 rpm under atmospheric pressure (1 atm).

Filtration test

Filtration tests were conducted using a filtration apparatus connected to a nitrogen gas source. The nanofluid samples were passed through a (0.45 μm) filter paper under a constant pressure (20 psig). The filtration time was recorded for each milliliter (mL) of filtrate that passed through the membrane. The collected data were plotted as filtrate volume versus time, and the filtration ratio (FR) was calculated. A linear volume time relationship indicates the absence of clogging particles, which is desirable to prevent potential formation damage during the core flooding test. For nanofluids to be considered injection ready, the FR value is generally recommended to be less than 1.2.

Core flood

The upper gray Berea sandstone core plug, with a length of 3.1 inches and a diameter of 1.5 inches, was initially characterized for porosity and permeability. The core was thoroughly cleaned and subsequently saturated with synthetic brine by immersion for 5 hours to ensure complete pore saturation. The brine saturated core was then mounted in the core holder and further injected with crude oil until irreducible water saturation was achieved. The core was aged for 48 hours at 60 ° C to restore wettability to reservoir like conditions. Core flooding experiments were conducted using a core flooding apparatus at 60°C with a constant injection rate of 0.3 cc/min, following a 3 steps sequence: formation water injection, then silica nanofluid injection, and finally, post flush using formation water to displace remaining nanofluid. The eluent was collected and analyzed to calculate the oil recovery factor.

RESULTS AND DISCUSSION

Synthesis of silica nanofluids

Figure 1 shows the results of silica nanofluid synthesis at various concentrations of AOS-DLS surfactant. The synthesized nanofluids were formulated using 0.1% (v/v) CNS combined with different concentrations of AOS-DLS surfactant in formation water from reservoir. No phase separation or precipitation was observed in any of the formulations, indicating excellent compatibility of silica nanofluid with the reservoir brine and suggesting its suitability for application in sandstone reservoirs.

The synthesized nanofluids were analyzed at room temperature using a PSA to determine the aggregate diameter and evaluate the effect of surfactant concentration on aggregates size (Table 4). PSA results indicated that increasing surfactant

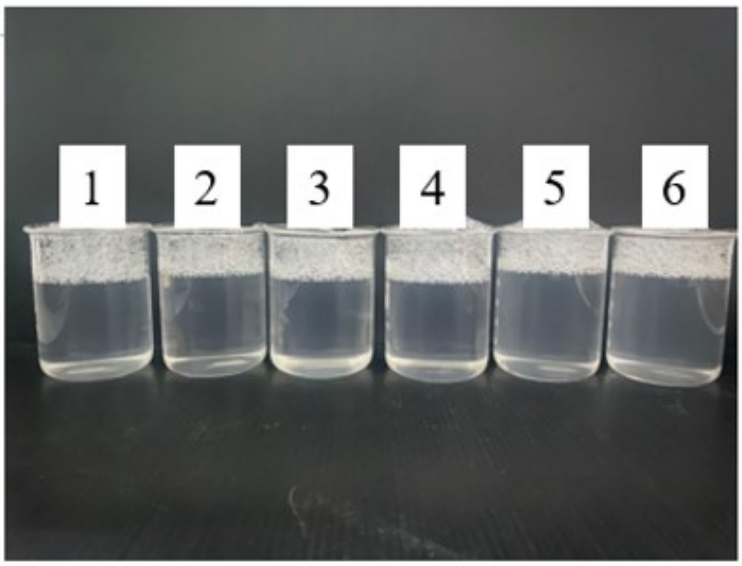

Figure 1. Silica nanofluids at various concentrations of AOS-DLS surfactants: 1) nanofluid 1 (AOS 0.3%-DLS 0.3%), 2) nanofluid 2 (AOS 0.6%-DLS 0.3%), 3) nanofluid 3 (AOS 0.9%-DLS 0.3%), 4) nanofluid 4 (AOS 0.3%-DLS 0.6%), 5) nanofluid 5 (AOS 0.6%-DLS 0.6%), and 6) nanofluid 6 (AOS 0.9%-DLS 0.6%)

concentration influenced the aggregate diameters, which remained relatively small, significantly below the average pore size of sandstone (5-50 µm), suggesting that the nanofluids are suitable for transport through reservoir rock without pore plugging (Zhong, 2020).

Table 4. Diameter of silica nanofluid aggregates

Sample Fluid	Z-Avg (nm)	Z-Intensity (nm)	Z-Number (nm)	Z-Volume (nm)
Nanofluid 1	172.1	386.5	6.32	23.41
Nanofluid 2	177.6	484.6	6.69	7.84
Nanofluid 3	225.1	681.2	15.51	20.37
Nanofluid 4	238.9	438.2	23.62	27,66
Nanofluid 5	280.3	509.8	7.74	8.72
Nanofluid 6	392.6	588.0	32.53	38.31

Figure 2 shows the Transmission Electron Microscopy (TEM) image of silica nanoparticles before their formulation into silica nanofluids. TEM analysis confirms that the primary silica nanoparticles have an average diameter of approximately 3 nm, a near spherical morphology, and a relatively uniform distribution prior to formulation. Figure 3 shows that, after mixing with the AOS- DLS surfactant system, large structures form, indicating the formation of nanoparticle surfactants aggregates rather than irreversible precipitation. The hydrodynamic characteristics obatained from DLS further clarify this behaviour. The Z average represents the intensity weighted mean aggregate diameter in suspension, while Z intensity emphasises the contribution of larger particles due to their stronger light scattering. In contrast, Z number reflects the population based size distribution and is more sensitive to smaller particles, whereas Z volume indicates the volumetric fraction of aggregates. The divergence among these values suggests dynamic, reversible clustering rather than severe agglomeration. Therefore, TEM primarily represents the size of individual silica nanoparticles, whereas PSA/DLS reflects the hydrodynamic diameter of nanoparticle aggregates in the formulated silica nanofluid (Ahmadi et al., 2016; Gbadamosi et al., 2019; Kesarwani et al., 2021; Nafisifar et al., 2022).

Characterization of thermal stability of silica nanofluid

Thermal stability testing was conducted to evaluate the heat resistance of the synthesized silica nanofluids. The test temperature was set to 60 °C, simulating the reservoir temperature of a sandstone reservoir in Sumatra. Thermal stability was observed over 3 months, and the results are summarized in Table 5.

Based on the thermal stability analysis presented in Table 5, the nanofluid remained stable under the tested conditions. The finding confirms that silica nanofluids containing AOS-DLS surfactants at all tested concentrations remained stable at 60°C for 3 months. These results indicate

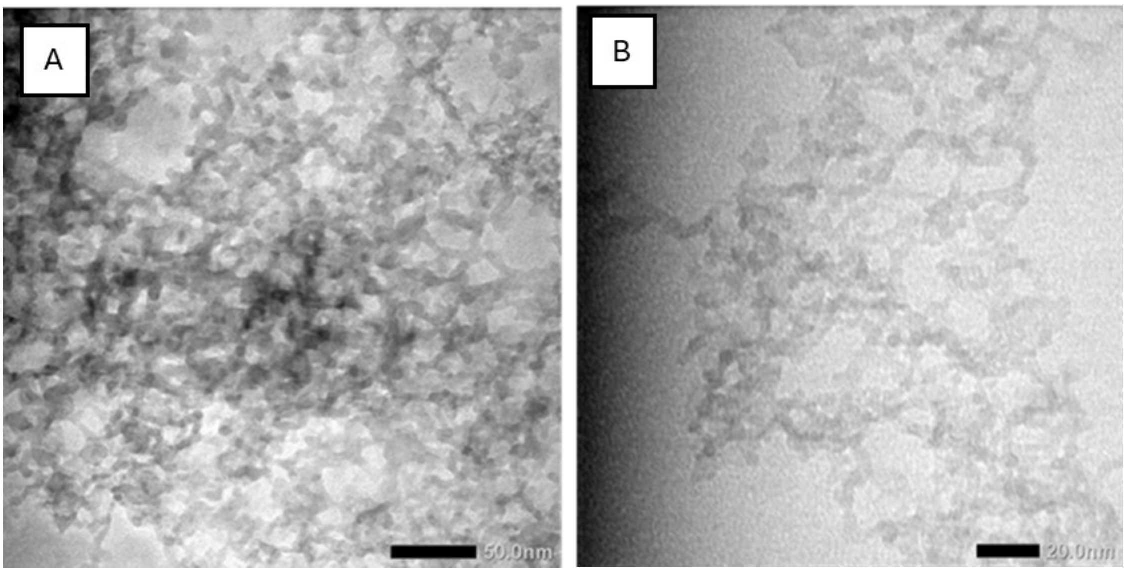

Figure 2.TEM image of silica nanoparticles

Table 5. Visualization of thermal stability of silica nanofluids.

Times	Figure	Information
1st day		Silica nanofluids were stable at 60 °C at all variations of AOS-DLS surfactant concentration on the first day.
1st month		Silica nanofluids were stable at 60 °C at all variations of AOS-DLS surfactant concentrations in the first month.
2nd month		Silica nanofluids were stable at 60 °C at all variations of AOS-DLS surfactant concentrations in the second month.
3rd month		Silica nanofluids were stable at 60 °C at all variations of AOS-DLS surfactant concentrations in the third month.

that the formulated silica nanofluids exhibit excellent thermal stability, making them suitable as fluid agents for EOR in sandstone reservoirs with salinity <1% and a temperature around 60 °C.

The stabilization mechanism of silica nanoparticles by anionic surfactants is illustrated in Figure 4. Silica nanoparticles exhibit surface siloxane (Si-O) and silanol (Si-OH) functional groups. The polar Si-OH groups enable the specific interactions with the polar head groups of anionic surfactants, particularly the oxygen atoms (:O) in sulfonate and sulfosuccinate groups via hydrogen bonding. The polarity of the Si-OH functional group originates from the electronegativity difference between silicon and oxygen atoms, which results in a partial positive charge (ä+) on hydrogen and a partial negative charge (ä-) on oxygen. The polar head groups of anionic surfactants also possess a partial negative charge (ä-). Although both silica surfaces and anionic surfactant head groups are negatively charged, hydrogen bonding can still occur due to the polar nature of the interface, resulting in improved steric and electrostatic stabilization of nanoparticles.

Vatanparast et al (2019) investigated the interaction mechanism between surfactant molecules and silica nanoparticles, confirming that hydrogen bonding plays a key role in stabilizing nanofluids, particularly under low dielectric conditions.

Jia et al (2020) reported that electrostatic repulsion between the negatively charged silica surface and surfactant head groups can enhance interfacial adsorption, ultimately increase dispersion stability, and reduce the IFT value.

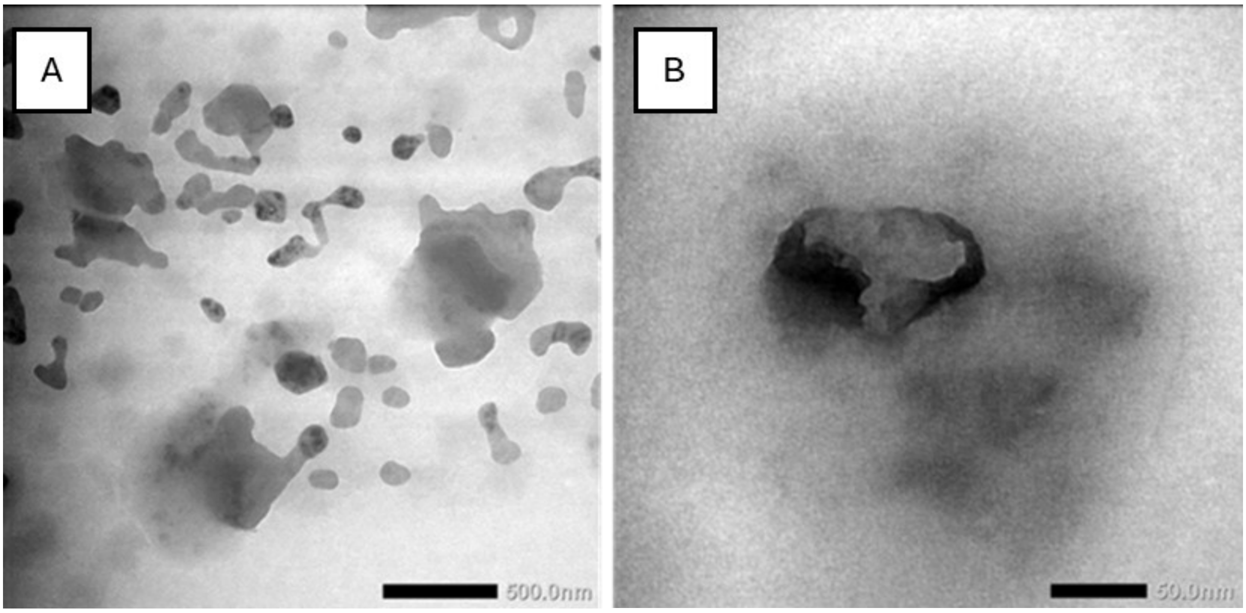

Figure 3. TEM image of silica nanofluids.

IFT characterization of silica nanofluids

Formulating silica nanofluids with surfactants as nanoparticle stabilizers also significantly reduces IFT between oil and water. IFT is a critical parameter that influences wettability alteration and capillary forces, both of which directly affect EOR performance. Lowering IFT increases the capillary number, thereby improving the displacement efficiency of residual oil and reducing trapped oil saturation (Abdi et al., 2024). IFT measurements (Figure 5) demonstrated that the addition of surfactants alone markedly reduced the IFT value. However, consistent with the findings of Hendraningrat et al, (2013), the combined use of silica nanoparticles with surfactants in the nanofluid formulation further enhanced IFT reduction compared to surfactants alone. This synergistic effect arises because nanoparticles adsorb at the oil water interface, lowering interfacial free energy and providing additional steric stabilization to surfactant molecules. Consequently, the frictional force between the oil and aqueous phase is minimized, leading to a significant increase in capillary number and EOR.

In general, the surfactants in this study act primarily as stabilizing agents to maintaining silica nanoparticles dispersed at 60^{o} C. The reduction in IFT is considered an additional benefit that can further improve the performance of silica nanofluid in enhancing oil recovery. The use of surfactants as stabilizers is therefore expected to maximize the development potential of nanofluids for EOR applications. Silica nanoparticles at very low concentrations are known to effectively improve the recovery factor (RF); however, their main limitation is poor thermal stability. Consequently, combining silica nanoparticles with other chemical EOR agents, such as surfactants or polymer, offers strong potential to achieve higher oil recovery while maintaining economic feasibility in future applications (Ahmadi et al., 2016; Gbadamosi et al., 2019; Kesarwani et al., 2021; Nafisifar et al., 2022).

Characterization of wettability of silica nanofluid

Contact angle analysis was conducted to evaluate the effect of surfactant concentration in nanofluid formulation on rock wettability. Wettability is a key reservoir parameter that strongly influences capillary pressure and, consequently, fluid flow behavior and recovery efficiency. A liquid is considered to wet a solid surface if the adhesion stress is positive ($\theta < 90°$), indicating a water-wet system. Conversely, a negative adhesion stress ($\theta > 90°$) indicates an oil-wet system (Ivanova et al., 2023). The results of the wettability analysis (Figure 6) demonstrate that

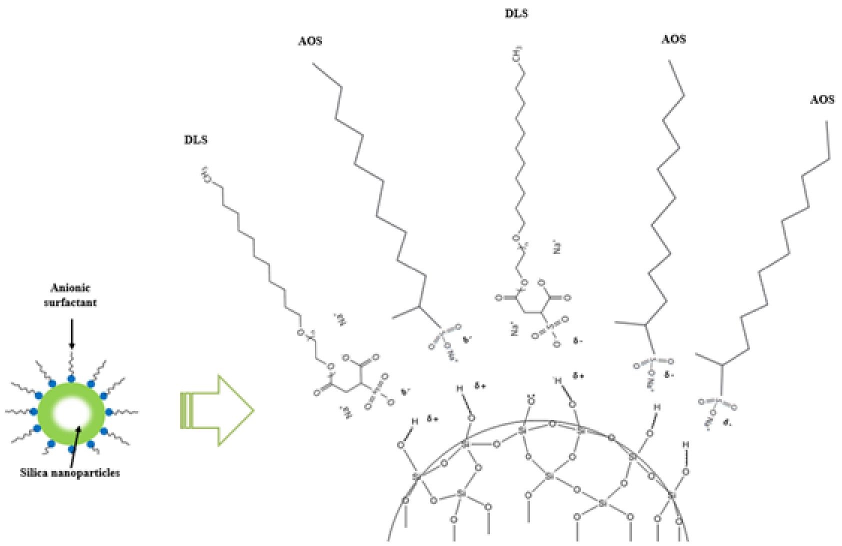

Figure 4. Mechanism of reaction of silica nanoparticles with anionic surfactant AOS-DLS

the use of AOS-DLS surfactant 0.3%-0.3% slightly reduced the contact angle from 75.21° (pure formation water) to 61.79° (pure surfactant AOS-DLS). In contrast, the application of silica nanofluids significantly reduced the contact angle value from 75.21° (pure formation water) to 10.81° (pure silica nanoparticles), indicating a transition toward strongly water wet conditions. The combination of 0.1% silica nanoparticles 0.3% - 0.3% AOS-DLS surfactant (nanofluid 1) yielded the most favorable wettability alteration, producing a contact angle of 13.88º, which is lower compared to other surfactant concentration variations. The improvement can be attributed to the synergistic interaction between surfactant molecules; and when crude oil is injected into a surfactant solution, most surfactant molecules preferentially adsorb at the oil water interface through their hydrophobic tails, with only a limited fraction adsorbing onto the rock surface. This results in a modest reduction in contact angle. However, the presence of hydrophilic silica nanoparticles allows them to deposit on the rock surface, increasing surface hydrophilicity and facilitating a more pronounced wettability alteration toward water wet conditions.

Characterization of filtration test of silica nanofluid

The filtration test was conducted to evaluate the presence of precipitates or suspended solids in the nanofluid, as they can cause pore plugging and negatively affect the injectivity during the EOR process. The test was performed using a filtration apparatus connected to a nitrogen gas supply. The nanofluid solution was passed through a (0.45 µm) filter paper under a pressure of (20 psig), and the time required for each milliliter (mL) of filtrate to pass through the filter was recorded. The recorded data were then used to calculate the FR value (Table 6) and to construct a plot of filtration time versus effluent volume (Figure 7). A linear plot with an FR value below 1.2 indicates that the nanofluid does not contain particle that could block pore throats, suggesting good injectivity and minimal risk of formation damage.

Table 6. Data analysis of filtration test.

Vol (ml)	Cumulative time on nanofluid (s)					
	1	2	3	4	5	6
10	59.98	8.05	11.86	32.16	10.19	7.49
20	319.04	17.63	50.75	321.26	109.2	13
30	501.18	42.83	195.05	722.48	582.19	77.58
40	484.99	112.75	423.21	1174.28	1127.59	210.4
50	526.64	222.57	710.48	1657.2	1754.83	419.77
60	534.61	363.13	1043.44	2182.18	2486.65	838.49
70	536.22	534.01	1396.47	2759.46	3367.36	1356.26
80	593.57	715.83	1741.47	3420.62	4404.39	1988.78
90	683.10	924.71	2116.52	4258.92	5554.94	2731.65
100	783.29	1148.32	2526.55	5190.76	6898.16	3669.09
FR	**1.14**	**4.55**	**2.11**	**2.08**	**2.45**	**8.51**

The filtration curve is expected to be straight and linear, indicating the absence of clogging particles that could potentially interfere with rock pore networks during nanofluid injection. An FR value below 1.2 is considered acceptable for field application, as it reflects good injectivity and minimal formation damage risk. The filtration test analysis (Figure 7 and Table 6) demonstrated that nanofluid sample 1 (CSN 0.1%, AOS 0.3%, DLS 0.3%, and formation water) achieved the best performance. This sample exhibited an FR value below 1.2 and produced a straight, linear filtration curve, confirming its suitability for EOR injection operations.

Characterization of core flooding of silica nanofluid

Core flooding experiments were performed to evaluate the ability of the synthesized nanofluids to EOR in sandstone formations. The experiments used synthetic Berea sandstone cores with properties adjusted to match the target reservoir, exhibiting an average porosity of approximately 20% and permeability of about 200 mD. The crude oil used was obtained from a sandstone reservoir, and the injected fluid included: base surfactant solution (AOS 0.3%, DLS 0.3% and formation water) and nanofluid 1 (CSN 0.1%, AOS 0.3%, DLS 0.3% and formation water).

The flooding sequence followed a standard three stage protocol consisting of initial water flooding, followed by nanofluid flooding, and finally post flush flooding. All experiments were conducted at a reservoir simulated temperature of 60 °C, with a constant injection rate of 0.3 cc/min. The results of the core flooding test are summarized in Table 7.

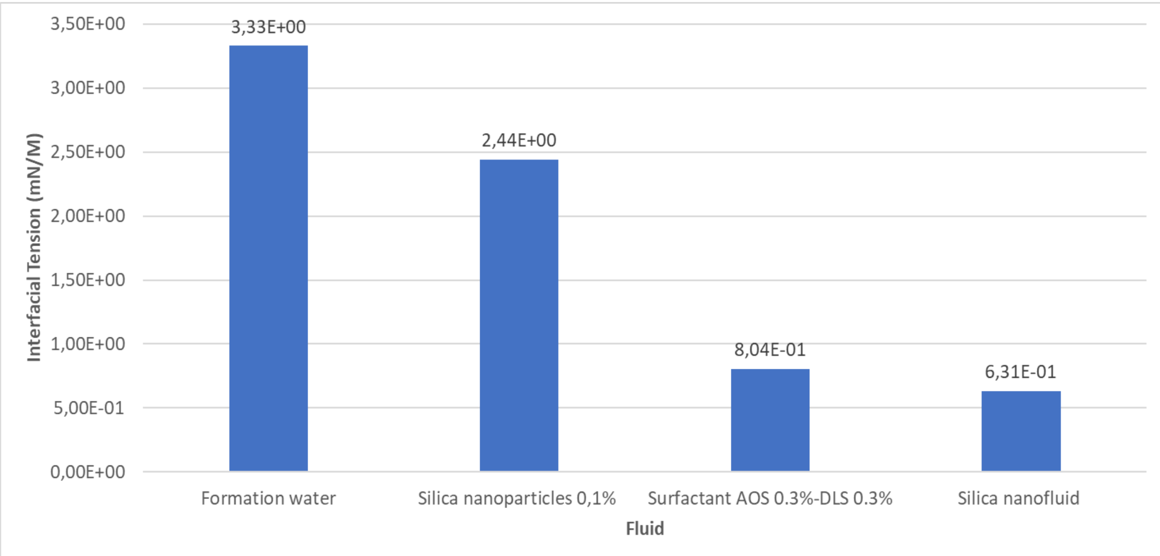

Figure 5. IFT measurement of fluids

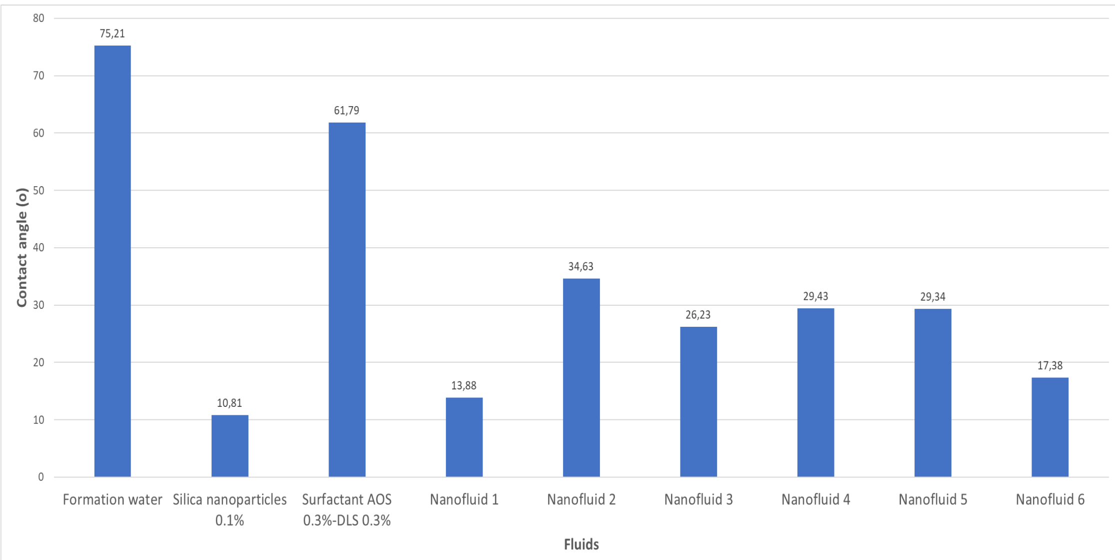

Figure 6. Contact angle measurement of fluids.

Table 7. Data core flooding.

Parameters	Nanofluid 1	Surfactant AOS-DLS 0,3%-0,3%
Porosity Φ	0.21	0.21
Permeability k (mD)	184	179
Oil saturated as OOIP (cc)	6.6	6.7
Oil saturated as OOIP (%)	56.8	58.2
RF Water flood (% OOIP)	25.0	27.6
RF Chem flood (% OOIP)	**12.9**	**7.5**
RF Chem flood (% ROIP)	17.2	10.3
RF Post-flush (% OOIP)	0	0
Total RF (% OOIP)	37.9	35.1

Figure 8 presents the results of the core flooding analysis using nanofluid 1. The data indicate a significant increase in differential pressure (dP) at the end of the nanofluid flooding stage, followed by a decrease during the post-flush stage. This pressure rise is likely attributed to the mobilization and displacement of crude oil from the core, as evidenced by the subsequent pressure decline after nanofluid injection.

In contrast, the results of surfactant core flooding (Figure 9) showed a more stable pressure profile than those of nanofluid flooding. The marked difference in incremental oil recovery between nanofluid and surfactant flooding suggests that the observed variation may be directly linked to enhanced oil displacement mechanisms during nanofluid injection, albeit with a potential risk of partial pore plugging. As illustrated in Figure 8, water-cut initially decreases slightly around 0.5 PV during waterflooding, indicating early-stage oil production. During nano flooding, water cut trends show a gradual decline starting at 2.0 PV, followed by a sharp drop at 2.7 PV, and fluctuations between 3.2 and 3.6 PV, before stabilization in the post-flush phase, which signals effective oil displacement, particularly in the 2.7-3.2 PV interval. Conversely, Figure 9 shows that surfactant flooding results in fluctuating water-cut value during the early injection stages, with less pronounced reductions and a relatively flat trend during the post flush.

Quantitatively, waterflooding in Figure 8 recovers approximately 25% OOIP, while nanofluid injection contributed an additional 12.9% OOIP. In Figure 9, waterflooding achieved 27.6% OOIP, with surfactant flooding adding an additional 7.5% OOIP. In both cases, post flush injection did not yield additional recovery.

These findings indicate that silica nanofluid exhibits superior oil displacement efficiency compared to surfactants alone. Specifically, surfactant flooding produced an incremental RF of 7.5% OOIP (10.3% ROIP), whereas nanofluid flooding achieved an incremental RF of 12.9% OOIP (17.2% ROIP). This confirms that incorporating silica nanoparticles into the nanofluid formulation significantly enhances incremental oil recovery.

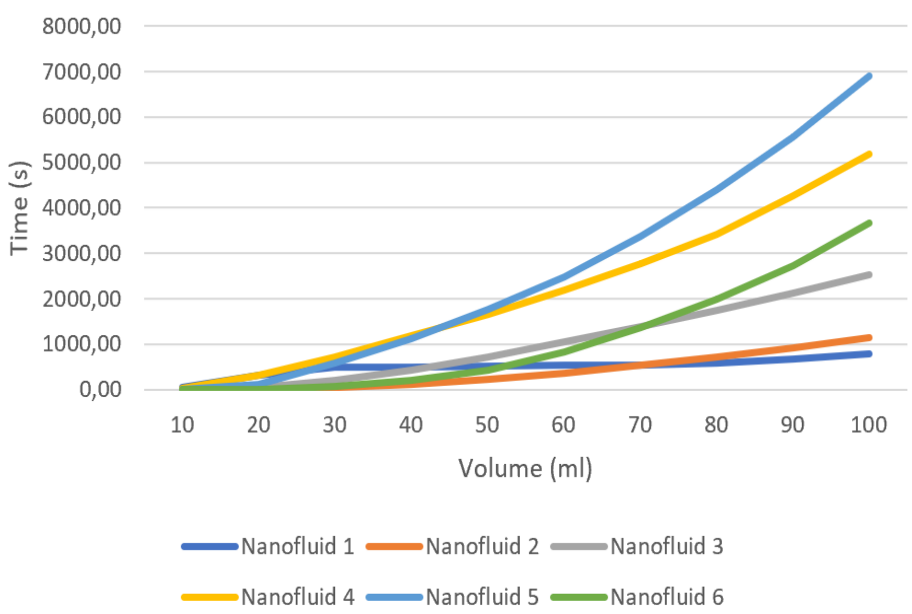

Figure 7. Analysis graph of the filtration test.

CONCLUSION

The preparation and stability of a novel silica based nanofluid were investigated using the synergistic effect of negatively charged silica nanoparticles and an AOS-DLS anionic surfactant system, with wettability and EOR performance evaluated by core flooding experiments. The following conclusions can be drawn:

- The silica nanofluid formulation, containing silica nanoparticles and AOS-DLS surfactants at various concentrations, was fully compatible with sandstone reservoir fluids. The addition of AOS-DLS increased the aggregate diameter of the silica nanofluid. Consistent with previous studies, surfactant adsorption around nanoparticles can lead to aggregation.
- The incorporation of AOS and DLS at various concentrations enhanced the thermal stability of the silica nanofluid under reservoir representative conditions (temperature ≤ 60°C and salinity ≤ 1%) for 3 months. This finding supports earlier reports that anionic surfactants improve nanoparticle dispersion and long-term colloidal stability under reservoir conditions.
- The addition of AOS-DLS significantly reduced the IFT between crude oil and brine. The formulated silica nanofluid archieved an IFT value of approximately $6.3x10^{-1}$ mN/m, indicating its

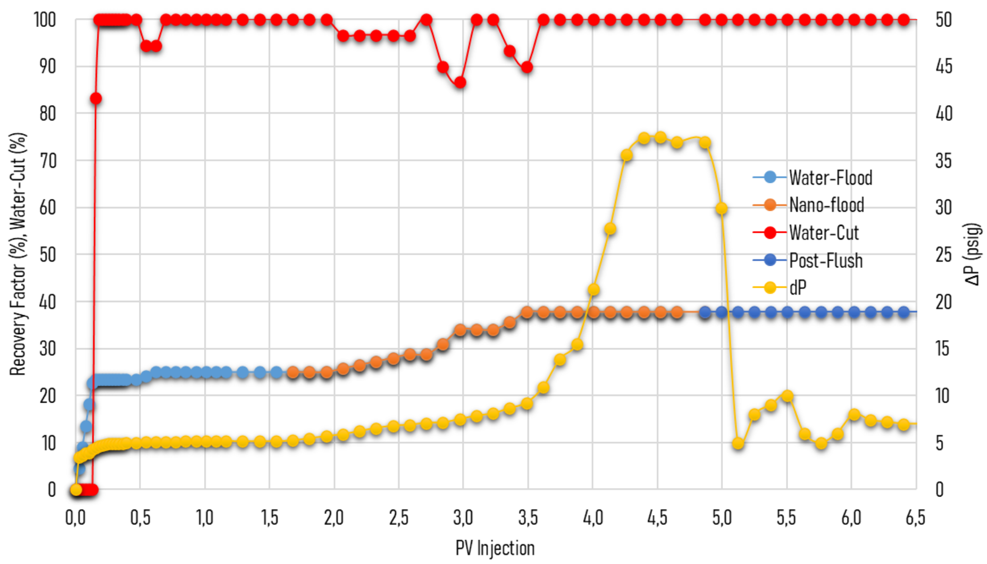

Figure 8. Results of nanofluid core flooding analysis.

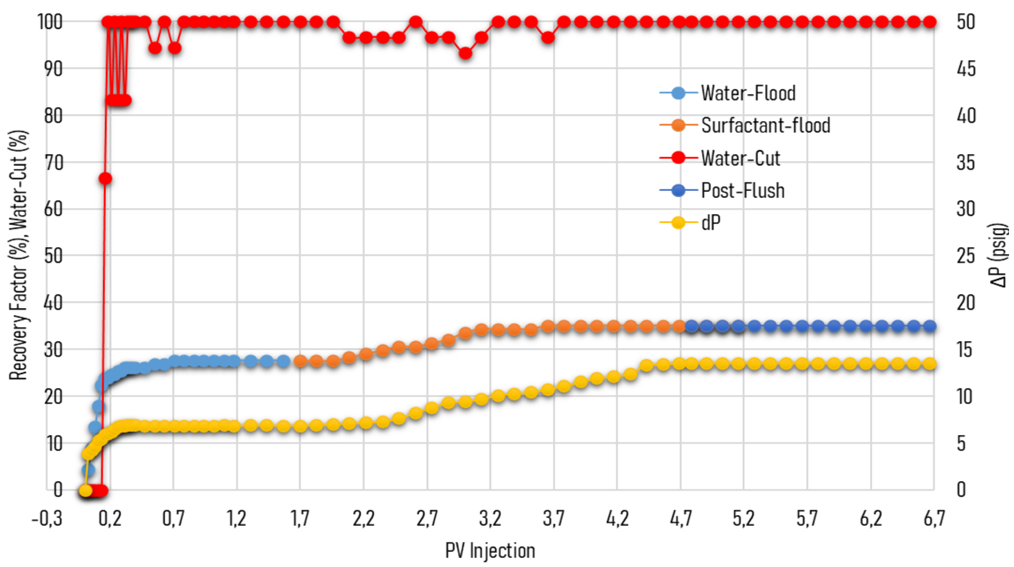

Figure 9. Results of core flooding analysis of AOS 0.3%-DLS 0.3% surfactant.

potential to improve microscopic sweep efficiency and mobilize trapped oil.

- The addition of nano-silica significantly altered rock wettability toward more water wet conditions. In contrast, the addition of anionic surfactant AOS-DLS surfactant alone at various concentrations produced only minor changes in wettability. Nanofluid 1, containing AOS 0.3%- and DLS 0.3%, achieved the lowest contact angle of 13.88°, indicating improved rock wettability and enhanced oil displacement.
- The filtration test results demonstrated that the AOS 0.3%-DLS 0.3% nanofluid formulation exhibited excellent injectivity, with a filtration ratio (FR) of 1.2 and a linear filtration curve, suggesting the absence of clogging particles and good compatibility with the porous medium.
- Core flooding experiments revealed that the silica nanofluid (0.1% silica nanoparticle, 0.3% AOS, 0.3% DLS) achieved an incremental oil recovery of 12.9% of OOIP, which was significantly higher than the 7.5% OOIP obtained using the pure surfactant solution. These results confirm that the synergistic combination of silica nanoparticles and surfactant enhances oil displacement efficiency and provides superior EOR performance.

GLOSSARY OF TERMS AND SYMBOLS

Terms & Symbols	Definition	Unit
API Gravity	American Petroleum Institute gravity	degree
ASTM	American Society for Testing and Materials	-
IFT	Interfacial tension	mN/m
PV	Pore volume	Cm^3
Si-OH	Silanol group	-
Si-O	Siloxane group	-
Soi	Intial oil saturation	Fraction / %

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