Surfactant Based Oil Recovery Enhancement for Tight Oil: Mechanism, Field Application and Lessons Learned

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Abstract

Unconventional shale reservoirs have become a significant source of hydrocarbon production, yet their recovery factors remain low, typically ranging from 5-10% of the original-oil-in-place (OOIP), as these ultra-low permeability formations are dominated by capillary and surface forces. This review examines the potential of surfactant-induced wettability alteration as an enhanced oil recovery (EOR) technique for shale formations, providing a comprehensive overview of the role of surfactants in altering shale wettability to improve spontaneous imbibition and fluid flow in oil-wet or mixed-wet shales. The mechanisms of wettability alteration, such as ion-pair formation, surfactant adsorption, and micellar solubilization, are discussed in detail. Additionally, common experimental techniques, including contact angle measurements, interfacial tension (IFT) reduction, zeta potential analysis, and spontaneous imbibition experiments used to evaluate surfactant performance, are reviewed. The paper also explores various classes of surfactants tested in laboratory studies, along with field trials conducted in major U.S. shale formations, such as the Eagle Ford, Bakken, and Permian Basin. While challenges related to high salinity, temperature, and complex pore structures persist, significant advancements in surfactant formulations and experimental approaches suggest that surfactant-assisted EOR will play a key role in enhancing oil recovery from shale reservoirs in the future.

Introduction

Unconventional shale reservoirs have emerged as a significant source of hydrocarbon production in the United States over the past decade. The combination of horizontal drilling and multi-stage hydraulic fracturing has made it economically viable to extract oil and gas from these ultra-tight formations. Shale plays like the Eagle Ford, Bakken, and Permian Basin have contributed substantially to U.S. oil production, with shale oil accounting for 64% of total domestic production in 2023[1]. However, despite the success of hydraulic fracturing in unlocking these resources, recovery factors from shale reservoirs remain very low, typically in the range of 5-10% of original oil in place (OOIP). Production rates from shale wells tend to decline rapidly, often by 60-80% within the first year. This steep decline, coupled with the high costs of drilling and completing new wells, poses significant economic challenges for operators. Consequently, there is growing interest in enhanced oil recovery (EOR) methods to improve recovery and extend the productive life of existing shale wells.

The ultra-low permeability (typically in the nano Darcy range (9.87×10^{-22} m^2) and complex pore structure of shale formations make conventional EOR techniques ineffective. In these tight rocks, capillary and surface forces dominate fluid flow and distribution. Wettability, which describes the relative affinity of rock surfaces for oil versus water, plays a critical role in controlling fluid behavior and ultimate recovery. Many shale formations are naturally oil-wet or mixed-wet, which hinders water imbibition and oil displacement from the matrix[2].

Spontaneous imbibition, where a wetting fluid is drawn into the porous matrix by capillary forces, can be an important recovery mechanism in fractured reservoirs. However, in oil-wet shales, water does not spontaneously imbibe, limiting its effectiveness[3]. This has led researchers to explore surfactant-assisted spontaneous imbibition (SASI) as a promising EOR technique for shale reservoirs. By altering rock wettability from oil-wet to water-wet, surfactants can induce spontaneous imbibition of aqueous fluids, displacing oil from the matrix[4,5].

This review paper aims to provide a comprehensive overview of surfactant-induced wettability alteration in shales for enhanced oil recovery. The focus will be on several key aspects of this technology, including the mechanisms underlying surfactant-induced wettability alteration, experimental methods used to evaluate surfactant performance, and the various classes of surfactants employed for wettability alteration in the literature. Additionally, the review will examine field trials and case studies of surfactant EOR applications in shale formations.

Experimental Methods

Common laboratory techniques for screening and developing surfactant formulations for wettability alteration in shales include:

Contact Angle Measurements: Contact angle measurements are a well-established and widely used technique for quantitatively assessing the wettability of rock-fluid systems. This method is particularly suitable for evaluating wettability using pure fluids (single-phase) and clean core samples or minerals. Two main configurations are commonly employed for contact angle measurements in reservoir engineering applications - the sessile drop and captive bubble methods[6]. The sessile drop method involves dispensing a droplet of the denser fluid (typically brine) onto the rock surface in the presence of the less dense fluid (oil or gas) inside a high-pressure, high-temperature cell. As the droplet comes to rest on the surface, it forms a characteristic contact angle at the three-phase contact line where the rock, dense fluid, and less dense fluid meet (Figure 1a). In contrast, the captive bubble technique works in a quasi-opposite manner. Here, a droplet of the less dense fluid (usually oil or gas) is dispensed beneath the rock sample immersed in the denser fluid (brine) within the pressure cell. The bubble rises and attaches to the underside of the rock, forming the contact angle (Figure 1b).

Both methods allow measurement of static contact angles. However, advancing and receding contact angles, which provide insights into hysteresis effects[7], can also be measured using modifications like the tilted plate design or by adding/removing fluid volume (Figure 1c). Advancing angles correspond to the imbibition process; while receding angles relate to drainage. The contact angle is typically measured through the denser phase. Thus, in an oil-brine-rock system, angles less than 90° indicate water-wetness, while angles greater than 90° suggest oil-wetness. The transitions between strong water-wet, weakly water-wet, intermediate-wet, and oil-wet states occur at characteristic angle ranges.

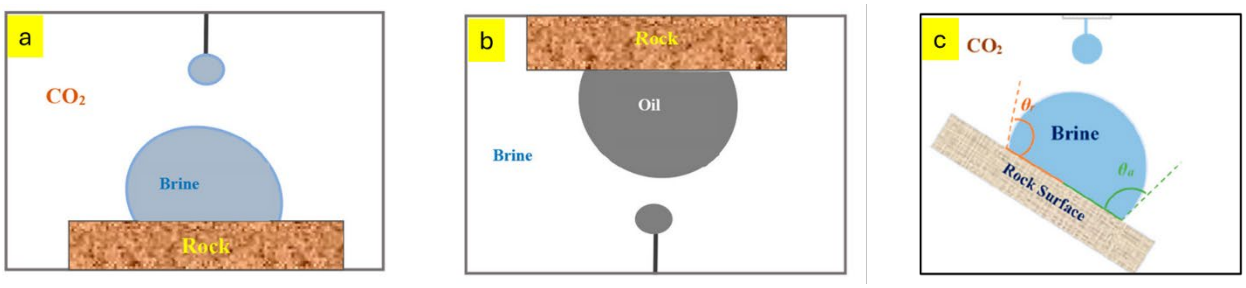

Figure 1: Schematic of different contact angle measurement methods: (a) sessile drop method, (b) captive bubble method, (c) sessile drop tilting plate method[6]

Key advantages of contact angle methods include their ability to provide rapid measurements across a wide range of pressures, temperatures, fluid compositions, and surface conditions. However, one must exercise caution, as surface contamination and cleaning procedures can significantly impact results. While traditional contact angle methods remain valuable, emerging techniques like microfluidic devices[8] and X-ray micro-CT imaging[9] are enabling in-situ contact angle measurements within porous media, providing insights at pore scale. These advanced approaches help bridge the gap between idealized flat surface measurements and complex pore network behaviors.

Interfacial Tension (IFT) Measurements: The interfacial tension between oil and the aqueous surfactant solution is measured to assess the surfactant's efficiency in reducing oil-water interfacial tension. The pendant drop method is commonly employed, where an oil droplet is suspended in the surfactant solution and its shape is captured using imaging techniques, often enhanced by backlighting for improved contrast[10]. Theoretical models based on the Young-Laplace equation are utilized to predict the expected shape of the pendant droplet under specific conditions. By comparing the observed droplet curvature with the theoretically predicted shape, the interfacial or surface tension can be accurately estimated.

Zeta Potential Measurements: Zeta potential measurements provide valuable insights into the surface charge and stability of surfactant solutions on shale surfaces. A common method used to measure zeta potential of shale samples is the streaming potential technique[11]. In this method, a crushed shale sample (typically <100 μm particle size) is packed into a glass column. An electrolyte solution is then forced through the packed bed under pressure, generating an electrical potential difference across the sample. This streaming potential is measured using electrodes at each end of the column. This method allows measurement of zeta potential as a function of pH, salinity, temperature, and other variables relevant to reservoir conditions. However, care must be taken in interpreting results for heterogeneous materials like shale.

Surfactant Adsorption Tests: These tests evaluate surfactant-shale interactions through a batch equilibrium method[12]. Crushed shale samples are hydrated in brine, mixed with surfactant solutions, and equilibrated at reservoir temperature. Surfactant concentration in the supernatant is analyzed before and after equilibration to calculate adsorption. This process is repeated at various surfactant concentrations to generate adsorption isotherms, which can be fitted to models like the Langmuir equation. Key considerations include particle size consistency, brine composition, equilibration time, and analytical methods. The resulting data provides insights into surfactant-rock interactions and can be used to develop predictive models based on shale mineralogy and organic content, crucial for designing effective enhanced oil recovery treatments in shale reservoirs.

Spontaneous Imbibition Experiments: These tests directly evaluate the effectiveness of surfactants in enhancing oil recovery through wettability alteration. Aged shale core samples are immersed in surfactant solutions, and oil recovery is monitored over time. Modified Amott cells are often used, allowing visual observation and measurement of produced oil[13].

CT-Assisted Core Flooding: Computed Tomography (CT) scanning is employed to visualize fluid movement within core samples during imbibition or flooding experiments. This non-destructive technique provides insights into fluid saturation changes and preferential flow paths[14].

Core-Scale Numerical Simulation: Experimental results, particularly from imbibition tests, are often history-matched using core-scale numerical simulations. This process helps derive important parameters like capillary pressure and relative permeability curves, which are crucial for upscaling to field-scale models.

Shale Wettability Characterization: Best Practices

Saputra et al. (2022) investigated the influence of oil composition, rock mineralogy, aging time, and brine pre-soak on shale wettability[15]. They conducted an extensive study utilizing over 1100 contact angle measurements on various shale oil/brine/rock systems. Their methodology incorporated samples from major U.S. shale formations, including seven reservoir rock samples, six crude oil samples, and seven brine compositions. The researchers employed the captive bubble method for contact angle measurements, with rock samples undergoing cleaning and aging in oil for periods ranging from 0 to 56 days. Some samples were subjected to a "brine pre-soak" process before oil aging to simulate reservoir conditions more closely.

The study revealed that oil composition plays a dominant role in determining shale wettability. Higher aromatic and resin content in the crude oil resulted in more oil-wet surfaces, while higher saturate content led to less oil-wet conditions. The authors proposed a mechanism where aromatics and resins act as a bridge between nonpolar oil components and the rock surface, facilitating oil adhesion. This bridging effect was particularly pronounced in quartz-rich samples, challenging the conventional understanding of wettability in carbonate versus siliceous rocks. The researchers attributed this phenomenon to the unique characteristics of shale oils, which typically contain minimal asphaltenes and organic acids compared to conventional crude oils.

Regarding rock mineralogy, the study found that higher quartz content correlated with stronger oil-wetness, while higher carbonate content resulted in less oil-wet surfaces. This observation contradicts some previous studies on conventional reservoirs, where carbonate surfaces are typically associated with stronger oil-wetness. The authors hypothesized that the absence of asphaltenes and organic acids in shale oils alters the interaction between oil components and mineral surfaces, leading to different wettability trends in shale systems (Figure 2).

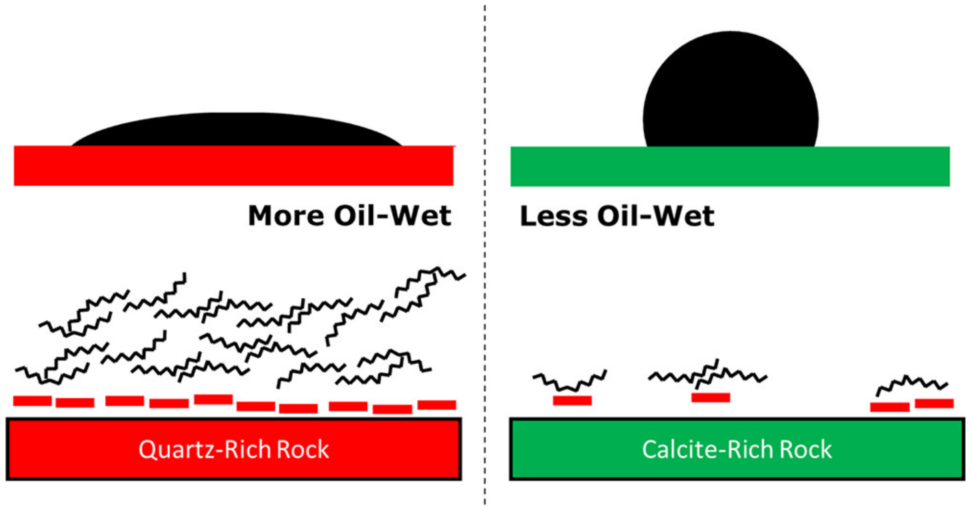

Figure 2: Oil-wetting mechanism of quartz-rich rock vs calcite-rich rock[15]

Aging time emerged as a critical factor in establishing stable wettability conditions. The researchers determined that 35 days was generally the optimum aging time for achieving stable wettability across the range of samples tested (Figure 3). However, they observed that oils with higher aromatic and resin content reached stable wettability faster, indicating that oil composition influences the kinetics of wettability alteration. Interestingly, higher brine salinity was found to increase the time needed to reach stable wettability, suggesting complex interactions between oil components, brine ions, and rock surfaces during the aging process.

The brine pre-soak experiments yielded intriguing results, showing that pre-soaking rock samples in brine before oil aging generally resulted in more oil-wet surfaces. Pre-soaked samples reached stable wettability faster (21 days compared to 35 days for non-pre-soaked samples), but this effect varied depending on the specific rock/oil/brine combination. The authors proposed that the presence of brine ions on the rock surface prior to oil contact may create additional adsorption sites for oil components, particularly aromatics and resins, thereby enhancing oil-wetness.

Throughout their analysis, Saputra et al. (2021) emphasized the importance of understanding the fundamental mechanisms driving wettability in shale systems. They proposed a mutual solubility theory to explain the observed wetting behavior, where the polarity contrast between oil components and rock surfaces, modulated by brine salinity, determines the ultimate wettability state. This comprehensive approach provides valuable insights into the complex interplay of factors influencing shale wettability, challenging some conventional wisdom, and highlighting the unique characteristics of unconventional reservoirs.

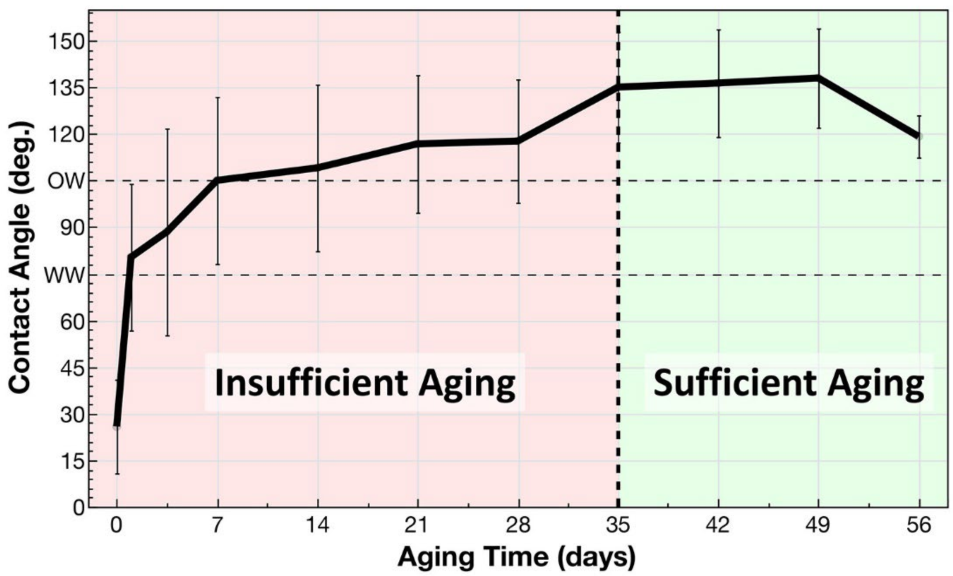

Figure 3: Wettability study of aging for all six crude oil samples and seven rock samples[15]

Surfactant-Induced Wettability Alteration

Unconventional liquid reservoirs (ULRs), particularly shale formations, present unique challenges in terms of wettability characterization and alteration due to their complex mineralogy and heterogeneous nature. Unlike conventional reservoirs, ULRs exhibit significant variations in mineral composition not only between different plays but also within the same reservoir at different depths. This heterogeneity can range from siliceous to carbonate-rich rocks even within a single well, making wettability characterization more complicated than in conventional reservoirs. Figure 4 shows the mineralogy of the major US shale plays. Adding to this complexity is the presence of organic matter in the form of kerogen, which creates a mixed wettability system. Odusina et al. (2011) observed that shale formations often contain water-wet inorganic pores alongside oil-wet organic pores[16]. This mixed wettability was further supported by their findings that shale rocks can imbibe both brine and oil, indicating the coexistence of different wetting preferences within the same formation.

Wang et al. (2012) conducted wettability studies on Bakken formation samples using a modified Amott-Harvey method. Their results indicated that shale cores generally exhibited oil-wet to intermediate-wet characteristics[17]. Similar findings were reported by Shuler et al. (2011), highlighting the prevalence of oil-wet tendencies in many ULRs[18]. However, it is important to note that the ultra-low permeability of these formations poses significant challenges in applying traditional wettability measurement techniques, necessitating the development of new methodologies tailored to ULRs.

The growing interest in improving oil recovery from ULRs has led to several studies investigating wettability alteration and imbibition processes in these tight formations. Shuler et al. (2011) evaluated the performance of various surfactants added to fracturing fluids in Middle Bakken Shale cores[18]. Their experiments demonstrated significant improvements in oil recovery, with surfactant-enhanced fluids recovering 15-60% of original oil in place (OOIP) compared to only 3% recovery with standard fracturing water. This study highlighted the potential of surfactants in altering wettability and enhancing oil recovery in ULRs.

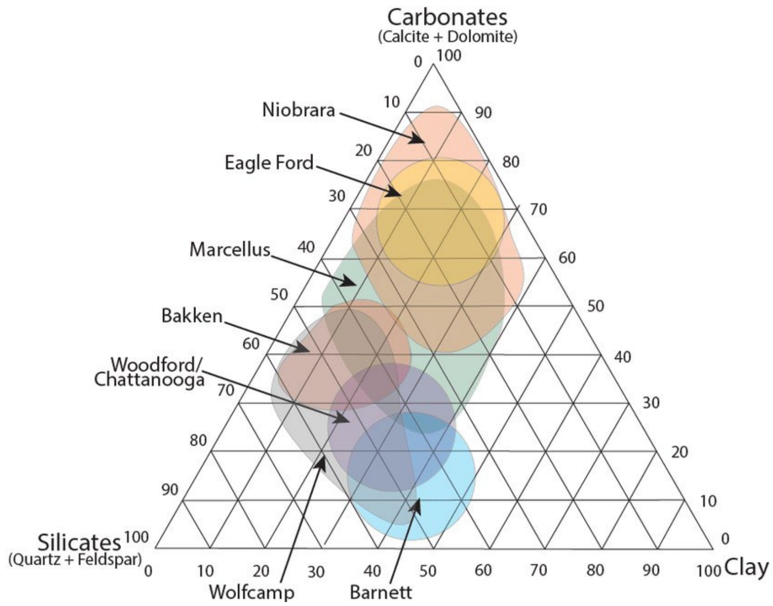

Figure 4: Mineralogy of US Shale Plays[19]

Xu and Fu (2012) investigated the impact of non-emulsifying and weakly emulsifying surfactants on oil recovery from crushed Eagle Ford samples[20]. Their laboratory experiments and field case studies showed that weakly emulsifying surfactants outperformed non-emulsifying ones, recovering more oil by reducing capillary pressure. The authors attributed this enhanced recovery to the ability of weak surfactant emulsions to solubilize oil droplets into their micelles and transport them out of the pores.

Wang et al. (2012) conducted a comprehensive study on wettability alteration in Bakken shale cores using various surfactant formulations[17]. Their experiments, carried out under reservoir conditions, demonstrated that surfactants could increase oil recovery by 6.8-10.2% of OOIP compared to brine alone. Notably, anionic surfactants showed superior performance in oil recovery compared to zwitterionic and nonionic surfactants.

Kathel and Mohanty (2013) evaluated wettability alteration and oil recovery in tight sandstone reservoirs using anionic and nonionic surfactants[21]. Their contact angle measurements on cristobalite plates showed that anionic surfactants were more effective in altering wettability from oil-wet to water-wet conditions. Subsequent spontaneous imbibition experiments in tight sandstone rocks yielded oil recoveries ranging from 42-68% of OOIP, with the authors proposing a countercurrent flow mechanism driven by capillary forces.

Nguyen et al. (2014) expanded the research to include both Eagle Ford and Bakken formations, testing a wide range of surfactant types[22]. Their spontaneous imbibition experiments revealed varying effectiveness of different surfactant types depending on the formation. In the Bakken, nonionic surfactants showed the highest oil recovery (up to 56% of OOIP), while in the Eagle Ford, anionic surfactants performed best (48% of OOIP).

Singh and Miller (2021) conducted a comprehensive study on surfactant-induced wettability alteration in Eagle Ford and Wolfcamp shale formations for improved oil recovery[13]. They screened various surfactant types (anionic, non-ionic, and zwitterionic) and developed synergistic surfactant blends that effectively altered wettability from oil-wet to water-wet conditions. Their contact angle experiments revealed that binary mixtures of anionic and zwitterionic surfactants outperformed individual surfactant systems in wettability alteration. The authors also performed spontaneous imbibition tests on tight carbonate and shale cores, demonstrating significant oil recovery improvements. For tight carbonate cores, they reported oil recoveries of up to 52% OOIP, while shale cores from Eagle Ford and Wolfcamp formations yielded recoveries ranging from 12.96% to 22.4% OOIP. Singh and Miller (2021) emphasized the importance of optimizing surfactant formulations for specific reservoir conditions and highlighted the potential of their synergistic surfactant blends for enhanced oil recovery in ULRs.

These studies collectively demonstrate the potential of wettability alteration as an EOR/IOR method in ULRs. However, they also highlight the complexity of the process and the need for tailored approaches based on the specific characteristics of each formation. The variability in results across different shale plays underscores the importance of continued research to better understand the mechanisms of wettability alteration and imbibition in these challenging reservoirs.

Mechanisms Of Surfactant-Induced Wettability Alteration

Wettability alteration mechanisms by surfactants have been extensively studied in conventional reservoirs, particularly in carbonate and sandstone formations. These mechanisms aim to shift the rock surface from oil-wet or intermediate-wet to water-wet conditions, thereby enhancing oil recovery. In unconventional liquid reservoirs (ULRs), the application of these mechanisms is still in its early stages due to the unique characteristics of these formations, such as ultralow permeability, low porosity, and the presence of organic matter. Nevertheless, understanding these mechanisms is crucial for developing effective improved oil recovery (IOR) strategies for ULRs.

Three main mechanisms have been proposed in literature to explain wettability alteration by surfactants: ion-pair formation, surfactant adsorption, and micellar solubilization.

The ***ion-pair formation mechanism*** was proposed by Standnes and Austad (2000) based on their observations of cationic surfactants irreversibly imbibing in oil-wet chalk cores and recovering more than 70% of the oil in place within 30 days[23]. This mechanism suggests that the positively charged heads of cationic surfactants form ion-pairs with negatively charged materials, primarily absorbed carboxylates from the oil, which are attached to the rock surface (Figure 5). The formation of these ion-pairs leads to the desorption of the oil layer from the surface, creating micelles that are transported to the oil phase due to their hydrophobicity. This process leaves behind a water-wet surface, allowing water to imbibe the rock through capillary forces. The effectiveness of this mechanism is influenced by factors such as the critical micelle concentration (CMC) and the hydrophobicity of the surfactant.

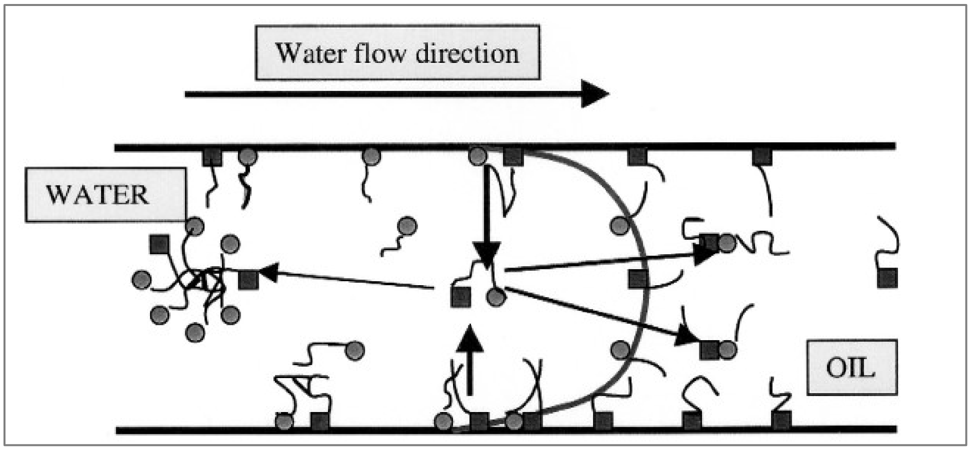

Figure 5: Illustrative model depicting the ion-pair formation mechanism by which cationic surfactants alter wettability within a pore. Circles represent cationic surfactants, while squares denote anionic surface-active organic materials found in the oil[23] .

The ***surfactant adsorption mechanism***, proposed by Austad and Milter (1997) and further developed by Standnes and Austad (2000), explains the behavior of anionic surfactants in altering wettability[23,24]. This mechanism is based on the observation that anionic surfactants create electrostatic repulsion between their negatively charged heads and the negatively charged compounds of oil on the rock surface. Instead of forming ion-pairs, the surfactants create a double layer through hydrophobic interactions with the oil layer adsorbed to the rock surface (Figure 6). The hydrophobic surfactant tails are adsorbed by the oil-wet surface, while their hydrophilic heads face the solution, altering the surface wettability to water-wet. This mechanism is considered reversible and occurs only when favorable electrostatic interactions are not present.

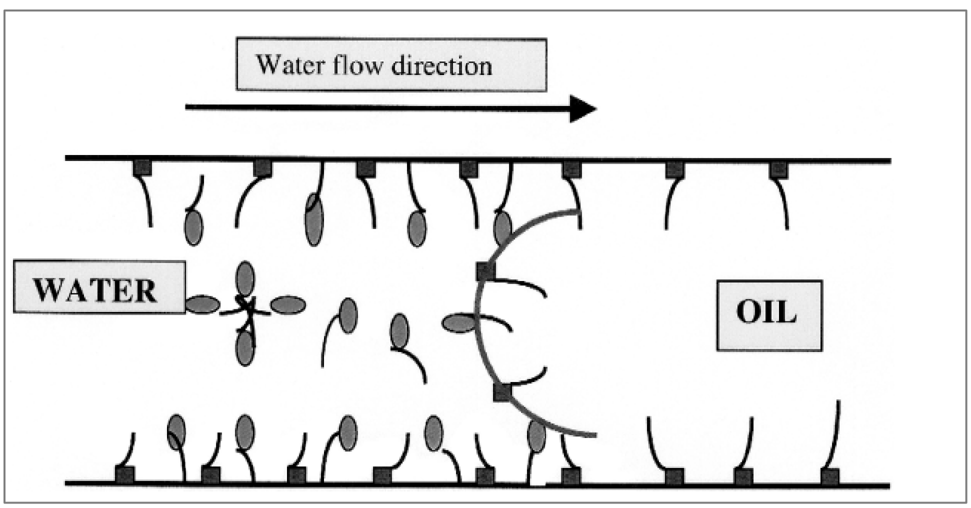

Figure 6: Illustrative model showing the surfactant adsorption mechanism of bi-layer formation within a pore using EO-sulfonates. The ellipses represent EO-sulfonates, while squares denote organic carboxylates present in the oil[23]

The ***micellar solubilization mechanism***, suggested by Kumar, Dao, and Mohanty (2008), was developed based on atomic force microscopy (AFM) studies on mineral surfaces representing carbonate and siliceous rocks[25]. They conducted parallel plate imbibition tests which involve visualizing the displacement of crude oil trapped in between oil-wet glass slides by different surfactant solutions. This mechanism suggests that surfactants, particularly anionic surfactants, reduce the oil-water interfacial tension (IFT), allowing the aqueous phase to imbibe the rock matrix and leave a thin oil layer attached to the surface. Subsequently, micellar solubilization of this oil film by the surfactants alters the wettability to water wet. This mechanism is considered to be faster and more effective for anionic surfactants compared to cationic surfactants, as the latter must first dissolve into the oil phase before forming ion-pairs and desorbing oil molecules from the surface.

While these mechanisms have been well-established for conventional reservoirs, their applicability to ULRs is still under investigation. The unique characteristics of ULRs, such as their mixed wettability due to the presence of organic matter and inorganic minerals, ultralow permeability, and complex pore structure, may influence the effectiveness of these mechanisms. Additionally, the absence or low content of asphaltenes and organic acids in many ULR crude oils may alter the interaction between surfactants and the rock surface, potentially leading to different wettability alteration behaviors compared to conventional reservoirs.

Field Trials In Us Shale Plays

Several companies have conducted field trials of surfactant EOR in shale reservoirs in recent years, with promising results demonstrating the potential of this technique to enhance oil recovery from tight formations. This section summarizes some key case studies from literature.

1) **Third Wave Production Trials in Eagle Ford**[26]

Third Wave Production LLC conducted surfactant huff-n-puff trials on two Eagle Ford wells, named EF-1 and EF-2. The wells were in the Upper Eagle Ford at depths of 7,000-7,300 ft (EF-1) and 6,700-7,000 ft (EF-2). Reservoir temperatures were 210°F and 200°F, respectively. Both wells had been producing for 7-8 years and were highly depleted. A proprietary surfactant formulation was injected at 0.22 wt% concentration in low salinity water (2.2 wt% TDS). The injection volume was about 5 times the estimated fracture void volume - 12,300 bbl for EF-1 and 11,300 bbl for EF-2. After injection, the wells were shut in for 30 days before returning to production. For EF-1, oil production increased 5-fold at peak and sustained a 2-fold increase after 2 years, resulting in 4,000 bbl of incremental oil over 2 years. EF-2 showed a more modest 2.4-fold peak increase and 1.5-fold sustained increase, yielding 2,200 bbl incremental oil. Key challenges included the high temperature and salinity, which required careful surfactant selection and lab testing to ensure stability. The low permeability also necessitated injection below fracture pressure to avoid creating new fractures.

2) **ULTRecovery Corporation Trials in Permian**[27]

ULTRecovery Corporation conducted surfactant huff-n-puff trials on a vertical well in the Spraberry/Wolfcamp formations and a horizontal well in the Wolfcamp formation of the Permian Basin. The vertical well targeted zones at around 9,000 ft depth with a temperature of 140°F. It had been producing for 3 years with an initial rate of 110 bbl/d declining to about 5 bbl/d. A proprietary microbial nutrient formulation was injected to stimulate indigenous microbes to produce biosurfactants. 500 bbl of treatment fluid was injected followed by 7 days of shut in. This resulted in a 113% increase in oil production rate after 8 months, yielding about 1,500 bbl of incremental oil. The horizontal well was at 9,900 ft depth with a temperature of 150°F. It had a 4,500 ft lateral with 20 frac stages and had been producing for 4 years. The same microbial treatment was applied in fractured horizontal well in Delaware, again with 500 bbl injected and 7 days shut in. This resulted in a 122% increase in oil rate after 6 months, providing about 12,000 bbl of incremental oil. A key challenge was the high salinity (60,000-150,000 ppm TDS) which required careful formulation of microbial nutrients. The low injection volume also meant only a portion of the fractures were likely contacted.

3) **Liberty Resources Trial in Bakken**[28]

Liberty Resources conducted a surfactant EOR field trial in the Bakken formation in Mountrail County, North Dakota. The pilot targeted the Middle Bakken and Three Forks formations at a depth of approximately 9,000-12,000 ft. The reservoir temperature was 240°F and initial pressure was around 7,500 psi. The formations had low permeability (0.001-0.1 mD) and porosity of 5-10%.
The trial used a huff-n-puff injection strategy in a single horizontal well with a 10,000 ft lateral and 30 hydraulic fracturing stages. A proprietary surfactant blend was co-injected with produced gas and water. The injection included 46 MMscf of gas, 40,000 bbls of freshwater, and 2,400 gallons of surfactant over a 31-day period.

A key technological innovation was the use of a "rapid-switched, stacked-slug" injection system developed by EOR ETC. This allowed co-injection of gas and water at low surface pressures (800-1300 psi) while achieving high bottomhole pressures. The system rapidly alternated between gas and water injection to create a stacked slug flow regime. The injection increased bottomhole pressure from around 1,000 psi initially to 4,500 psi, well above the estimated minimum miscibility pressure of 2,450 psi. This was achieved while keeping surface injection pressure below 1,300 psi.

Production results showed the oil rate increased from a baseline of 55 bpd to 68 bpd (30-day average) after treatment. Decline curve analysis predicted incremental oil recovery of about 7,000 bbls for the pilot over 1 year. The gas utilization factor was estimated at 6-10 Mcf/bbl, indicating an effective EOR process.
Key challenges included managing gas breakthrough in offset wells, which was mitigated by adjusting water-gas injection ratios. The trial also encountered issues with gas hydrate formation in surface lines due to cold ambient conditions, which was addressed through insulation.

Overall, the pilot demonstrated the feasibility of achieving miscible gas injection conditions in tight formations using water co-injection to boost bottomhole pressure. The surfactant addition showed promise for enhancing oil recovery, though longer-term production data would be needed to fully quantify the benefit. The rapid-switched injection technology enabled implementation at lower surface pressures compared to conventional gas injection.

4) **Chevron Trial in Permian**[4]

Chevron conducted a surfactant EOR field trial in the Permian Basin, targeting the Wolfcamp B formation in the Midland Basin. The trial involved two horizontal wells, each with a lateral length of approximately 2 miles. These wells had been producing for about two years and were yielding 100-200 bpd at the time of the trial. The formation was described as having low permeability and natural fractures. Chevron used a proprietary surfactant blend at a concentration of 0.1-0.2% in brackish water with 10,000 mg/L TDS. The injection strategy employed a huff-n-puff approach in both wells, with one well treated using only water as a reference and the other treated with the surfactant solution. Each well received 30-60 Mbbls of total fluid injected at rates of 6-12 bpm, followed by a 10–25-day shut-in period. Production results showed that the surfactant well achieved a 7.8% increase in oil EUR compared to 2.3% for the water-only well. The surfactant well maintained a higher productivity index for over 250 days and produced an incremental 31,720 bbls of oil over 365 days. Chevron implemented a comprehensive surveillance plan including tracers, rate transient analysis, and decline curve analysis. They also monitored offset wells for communication and developed a custom reservoir simulation approach using fracture swarm models. This trial demonstrated the potential for surfactant treatments to improve oil recovery in tight formations through wettability alteration, interfacial tension reduction, and fracture cleanup, while the use of a water-only reference well allowed for direct comparison of surfactant effects versus simple water injection.

These field trials consistently demonstrate the potential for surfactant EOR to enhance oil recovery from depleted shale wells. Key success factors include proper surfactant selection and formulation for specific reservoir conditions, adequate injection volumes to contact a large portion of the fracture network, and sufficient shut-in time to allow surfactant-rock interactions. Common challenges across the trials included ensuring surfactant compatibility with reservoir fluids and frac additives, managing high temperature and salinity conditions, and optimizing injection strategies to maximize reservoir contact while staying below fracture pressure. While challenges remain in optimizing treatments for individual well conditions, the positive results from multiple basins provide encouragement for wider application of this EOR technique in unconventional reservoirs.

Conclusions And Future Outlook

This review has examined the current state of surfactant-induced wettability alteration as an enhanced oil recovery (EOR) technique for unconventional liquid reservoirs (ULRs), particularly shale formations. The following key conclusions can be drawn:

Wettability Characterization: Shale formations exhibit complex, mixed-wettability systems due to their heterogeneous mineralogy and the presence of organic matter. Traditional wettability measurement techniques often require modification for application in ULRs. Recent studies have highlighted the importance of factors such as oil composition, rock mineralogy, aging time, and brine pre-soak in determining shale wettability.

Surfactant Types and Performance: Various surfactant types, including anionic, nonionic, cationic, and amphoteric, have shown potential for wettability alteration in shales. The effectiveness of different surfactant types varies depending on the specific shale play and reservoir conditions. Anionic and nonionic surfactants have generally demonstrated good performance across multiple studies.

Wettability Alteration Mechanisms: Three primary mechanisms have been proposed for surfactant-induced wettability alteration: ion-pair formation, surfactant adsorption, and micellar solubilization. While these mechanisms are well-established for conventional reservoirs, their applicability to ULRs requires further investigation due to the unique characteristics of shale formations.

Laboratory Evaluation Methods: Contact angle measurements, interfacial tension (IFT) measurements, zeta potential analysis, surfactant adsorption tests, and spontaneous imbibition experiments have emerged as key techniques for evaluating surfactant performance in shales. Advanced imaging methods, such as CT-assisted core flooding, are providing new insights into fluid behavior in tight formations.

Field Trial Results: Multiple field trials in major U.S. shale basins, including the Permian, Bakken, and Eagle Ford, have demonstrated the potential of surfactant EOR to enhance oil recovery from depleted shale wells. Huff-n-puff treatments have shown promising results, with some trials reporting 30-40% increases in cumulative oil production compared to offset wells.

Operational Challenges: Key challenges in implementing surfactant EOR in shales include:
- High temperature and salinity conditions affect surfactant stability.
- Ensuring compatibility between surfactants and reservoir fluids/frac additives
- Optimizing injection strategies to maximize reservoir contact while staying below fracture pressure.
- Designing effective well shut-in periods to allow sufficient time for surfactant-rock interactions.

Future Research Directions: Further research is needed to:

- Develop surfactant formulations tailored to specific shale play characteristics.
- Improve understanding of surfactant transport and retention in nanopore networks
- Optimize treatment designs for different well types (e.g., parent vs. child wells, different completion designs)
- Investigate the long-term effects of surfactant treatments on formation damage and well productivity.
- Develop predictive models to better estimate incremental recovery from surfactant EOR in shales.
- Continue active recurring engagement with operators on their KPIs and their criteria to see scalable implementations.

In conclusion, surfactant-induced wettability alteration shows significant potential as an EOR technique for unconventional shale reservoirs. While challenges remain in optimizing treatments for individual well conditions, positive results from laboratory studies and field trials provide encouragement for wider application. As the industry continues to seek ways to improve recovery factors from ULRs, surfactant EOR is likely to play an increasingly important role in maximizing the value of these resources.

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