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RESEARCH ARTICLE

Evaluating Chemical Stability Challenges in Surfactant Eor for High-Temperature, High-Salinity Reservoir: the Volve Field

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Abstract

This study evaluates the influence of surfactant concentration on oil recovery performance under high-temperature and high-salinity reservoir conditions in the volve field using numerical simulations. Several surfactant concentration scenarios were applied to analyze production response and recovery factor behavior. The result indicate that increasing surfactant concentration only slightly improves oil recovery, with recovery factor remaining within a narrow range from 19.82% to 19.93% across all scenarios. Limited performance is associated with thermal degradation, adsorption, salinity effects, and reduced interfacial tension efficiency under harsh reservoir conditions. This study is limited to numerical simulation and requires laboratory validation to confirm surfactant chemical behavior under actual reservoir conditions. Therefore, future research should prioritize laboratory evaluation of thermally stable surfactants before filed scale implementation.

Keywords: Surfactan, Recovery Factor, EOR, Volve Field, tNavigator

1. Introduction

Indonesia's upstream oil and gas industry has a lot of problems keeping up with oil production, especially from conventional fields that have reached maturity (Bukhtoyarov et al., 2023). The production rates of most reservoirs in sandstone formations drop a lot. The recovery factor is normally about 25% to 35% after water flooding, while the water cut keeps rising to more than 80%. This makes activities less profitable and puts the country's energy supply at risk of running out. More than 70% of Indonesia's oil and gas fields are becoming worse, and the average recovery factor is less than 35%.

Adding chemicals to enhanced oil recovery (EOR) technologies is one way to get more oil out of the ground (Bukhtoyarov et al., 2023). EOR changes how fluids behave in reservoirs through the application of chemical solutions. The main objective of this study involves reducing interfacial tension between oil and water (Xi et al., 2021). The process will increase the efficiency of oil transportation which results in easier production operations. The effectiveness of this method depends on different factors such as temperature and reservoir type and permeability level (Bukhtoyarov et al., 2023). The three primary categories of chemical EOR treatment methods include polymer injection and surfactant injection and alkali injection (Sarbast et al., 2022) (Podoprigora et al., 2022). Surfactant injection holds the greatest significance among treatments because it can decrease IFT to levels that enable oil trapped within rock pores to flow toward production wells (Xi et al., 2021).

The effectiveness of surfactant is highly dependent on reservoir conditions, where surfactant face significant chemical stability challenges. At temperature of 224.6°F, surfactant molecules may undergo thermal degradation, which weakens molecular stability and reduces micelle formation efficiency, thereby diminishing their ability to maintain low interfacial tension (Alli & Tobing, 2018) In addition, dissolved ions such as Na^{+}, Ca^{2+}, and Mg^{2+} in formation water may reduce surfactant effectiveness through precipitation, lower solubility, and increased adsorption onto rock surfaces. These combined mechanisms thermal degradation and ionic interactions explain why increasing surfactant concentration does not significantly improve oil recovery in this study. Surfactant performance under HTHS conditions is also influenced by critical micelle concentration (CMC) and interfacial tension (IFT) behavior, where elevated reservoir temperature may increase CMC, reducing micelle stability and limiting the surfactant's ability to lower oil–water interfacial tension effectively. In this study, CMC variation and dynamic IFT reduction were not explicitly modeled due to simulator limitations and unavailable laboratory data therefore, they are acknowledged as study limitations. The rock becomes more water-repellent which improves the sweep efficiency (Saw et al., 2023). he research demonstrates that different types of brine together with specific surfactant quantities determine the effectiveness of oil transportation. The proper dose must be achieved to obtain maximum oil extraction while minimizing adsorption (Sarbast et al., 2022).

To evaluate these chemical stability challenges under realistic field conditions, the Volve Field in the Norwegian North Sea was selected as a case study due to its high-temperature and high-salinity reservoir characteristics, which are representative of the conditions where surfactant stability becomes a critical factor in EOR success. The researchers used the Volve Field located in

Block 15/9 Norwegian North Sea as their field test site to determine how well surfactant injection performs in high-quality reservoirs. The Volve system operated successfully for eight years between 2008 and 2016. The reservoir contains 25-30% porosity and permeability that exceeds 1 Darcy together with light oil that has 38-42 °API and 1.5-2 cP properties which Equinor released to the public in 2018. Previous geophysical characterization of the Volve Field using 4D seismic analisys revealed that injected fluids preferentially migrate within the Middle Zone of the Hugin Formation due to increased shale content in the Lower Zone acting as a permeability barrier (Farania et al., 2026). We conducted compositional reservoir simulation tests with the tNavigator v.22.1 software using actual field data to assess the performance of surfactant injection at different chemical concentrations dissolved in 5,000 ppm brine.

However, limited studies specifically evaluate the effect of surfactant concentration under HTHS reservoir conditions using numerical simulation in the Volve Field, particularly considering chemical stability limitations that directly influence recovery performance. Additionally, laboratory validation of surfactant behavior under actual reservoir conditions remains scarce, creating a gap between simulation results and field-scale implementation. Therefore, this study aims to evaluate surfactant concentration performance under HTHS reservoir conditions using tNavigator simulation to identify its impact on oil recovery.

The study's findings are expected to provide valuable information which will aid in developing an effective surfactant-based Enhanced Oil Recovery EOR method for Indonesian mature oil assets (Podoprigora et al., 2022).

2. Metodhology

The study uses numerical reservoir simulation techniques to assess how surfactant injection improves oil recovery EOR in the Volve reservoir. The Navigator simulation software is used for the entire simulation workflow from history matching to forecasting scenarios.

Classification Surfactant Types

Table 1. Surfactant Type

Scenario	Surfactant Type	Consentration
1	Anionic Surfactant	0.1 %
2	Anionic Surfactant	0.3 %
3	Anionic Surfactant	0.5 %
4	Anionic Surfactant	1.0 %

Fluid Properties

Table 2. Fluid Properties

Parameter	Value	Unit
Viscosity	1.5 – 2	cP
Interfacial Tension	$10^{-2} - 10^{-3}$	dyne/cm
Adsorption	5.0	mg/g-rock
Injection Rate	4.400	STB/day

Previos simulation studies have demonstrated that chemical concentration significantly affects recovery factor and adsorption behavior, with higher concentrations leading to increased adsorpion on rock surfaces (Erfando et al., 2019).

Reservoir Data dan Model Setup

Data Source

Table 3. Parameters of the Volve Field

Parameter	Value	Unit
Reservoir Temperature	224.6 (107)	F (°C)
Porosity	0,001 – 0,29	%
Permeability x	0 – 20.000	mD
Permeability y	0 – 20.000	mD
Permeability z	0 – 2.000	mD
Water Saturation	0,03 - 1	
Oil Saturation	0 – 0,78	

Table 4. Compositional Model Data

Component	Mole Fraction	Molecular Weight
N2	0,00402	28,013
CO2	0,03801	44,01
C1	0,415959	16,043
C2 – C3	0,115699	36,6846337
IC4-NC4-IC5-NC5-C6	0,084629	69,3974423
C7+	0,340987	264,904807

Table 5. Reservoir Initialization Data

Parameter	Value	Unit
Original Oil In Place	76.9942	MMSTB
Original Water In Place	697.7655	MMSTB
Original Gas In Place	55.2871	MMSCF
Pore Volume	794.7169	Million RB

History Matching

This model calibrates the production data from August 2015 to March 2024 by matching the oil rate and liquid rate parameters.

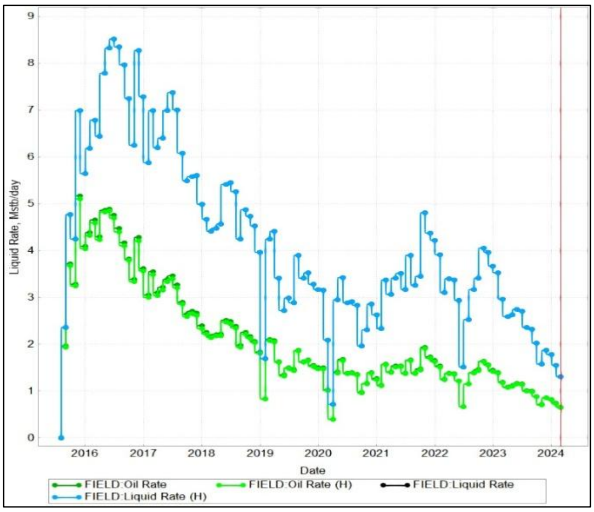

Fig 1. History matching results of oil and liquid roduction rates (2015–2024) with RMSE and MAPE Validation

The period between 2015 and 2024 saw a major decline in production levels. The oil and liquid production rate graphs demonstrate a significant decreasing pattern. The field operated at its best capacity during its first phase which lasted from 2015 to 2016 when it produced liquid at 8 to 8.5 Mstb per day and oil at 4.5 to 5 Mstb per day. The period experienced maximum production levels of both oil and liquid resources. The reservoir conditions maintained their high productivity because the system generated enough formation pressure and implemented effective oil recovery methods.

The time period between 2017 and 2020 saw both production characteristics experience their most significant decline. Liquid production dropped dramatically from around 8 Mstb/day to only 2–4 Mstb/day. Oil rates decreased from approximately 5 Mstb/day to 1–2 Mstb/day. The reservoir pressure decline caused both liquid and oil rate reductions while the water zone movement into production areas resulted in increased water cut (Alisheva et al., 2025).

Production levels experienced slight variations between 2020 and 2022 but later reached a stable state at reduced output levels. The graph displays a minimal increase, which maintenance activities and operational interventions use to maintain production levels, which results from actual production processes. But by 2023–2024, oil rate had dropped to 1.5 Mstb/day and the liquid rate had dropped to 1.5–3 Mstb/day. The situation keeps going the same way. (Luo & Su, 2022) demonstrate through their measurements that the field has entered its decline phase, which results in lower energy and water production from the reservoir until output reaches its final decline point.

The graph displays the standard decline pattern which mature oil fields experience through a continuous drop that extends beyond ten years (Yehia et al., 2023). The trend demonstrates the importance of developing reservoir management plans which use Enhanced Oil Recovery (EOR) methods to delay production decline and maximize extraction of existing reserves from the formation (Alisheva et al., 2025).

While the visual comparison between simulated and historical production data shows good agreement, quantitative validation is necessary to ensure the reliability of the model for forecasting purposes. Therefore, statistical error metrics such as RMSE and MAPE were considered to measure the deviation between simulation and historical production data (Mundu, 2026).

Based on table 6 the calculation with 35 data points, the Root Mean Square Error (RMSE) is 0.0352 Mstb/day and the Mean Absolute Percentage Error (MAPE) is 1.33%. These low error values indicate excellent agreement between simulated and historical production data (Geng et al., 2024), validating the reliability of the calibrated reservoir model for subsequent EOR scenario forecasting (Ahmed Al-Husseini, 2023).

Similar approaches using core modeling and sensitivity analysis have been successfully applied to validate reservoir simulation models (Jannoke & Syaifullah, 2025).

Table 6. History Matching Validation Results

Parameter	RMSE (Mstb/day)	MAPE (%)
Oil Rate	0.0352	1.33

Scenario Simulation

Base Case (0% Scenario)

1. Conventional water injection without surfactant
2. Injection rate: 4,400 STB/day
3. Injection wells: I-F-4, I-F-5
4. Production wells: P-F-11B, P-F-12, P-F-14

Surfactant Scenarios (0.1%, 0.3%, 0.5%, 1.0%)

1. Injection rate: 4,400 STB/day
2. Injection duration: 6 months
3. Brine salinity: 5,000 ppm
4. Chase water injection: surfactant injected during the first 6 months, followed by water injection until the end of the simulation periode
5. Injection wells: I-F-4, I-F-5
6. Production wells: P-F-11B, P-F-12, P-F-14

3. Result and Discussions

The manuscript must be organized in the following way, with all pages starting with the title page numbered in order. The study investigates how various surfactant concentrations that were tested at the Volve reservoir affect its performance, which the section describes through its detailed account of reservoir simulations that were executed for each injection test.

Reservoir Model Initialization and Validation

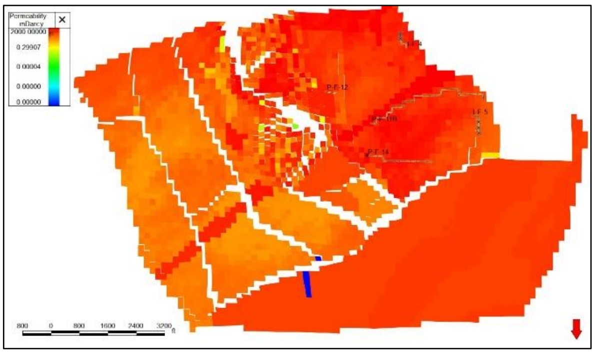

Fig 2. 2D Visualization of the permeability distribution in the volve field

The 2D model demonstrates the geological formation's permeability through its measurement of permeability which uses milliDarcy (mD) units. The blue areas have low permeability (about 0 mD), and the red areas have high permeability (up to about 2000 mD). The colors green, yellow, and orange mean that the permeability levels are in the middle. The model demonstrates how permeability changes throughout the entire formation. (Sheldon et al., 2023).

The middle to upper parts of the structure, especially around wells P-F-12, P-F-11B, P-F-11, and I-F-5, have areas with significant permeability (red-orange). The main pathways for fluid flow in this area are found within these specific sections (Zhang et al., 2021). The lower and western regions of the building, on the other hand, contain more orange to yellow areas, which suggests they are less porous. The two factors which lead to this result are the distance between pore gaps and the density of the rock (Lu et al., 2021). The light blue patches that are spread out also suggest that there are clay-rich areas or areas with strong binding, which can slow down the flow of fluids (Sheldon et al., 2023).

The uneven permeability distribution between different sections of the reservoir area shows that fluids will move through the reservoir mainly through sections that have higher permeability (Zhang et al., 2021). The information serves a crucial role in determining field development strategies and optimal locations for production and injection wells and in assessing the reservoir's operational behavior throughout its lifespan.

The graph below displays the total water injection amounts which were tested under various surfactant conditions from 2015 until 2034. The water injection pattern changes from 2015 to 2023, but it stays the same from 2024 to the end of the simulation period. Water injection atoperations start time shows a rapid increase which begins from 0 Mstb/day in 2015 and reaches 5.5 Mstb/day by 2017. The increased flow rate shows that the injection system works to reach needed reservoir pressure levels which will support maximum oil extraction efficiency.

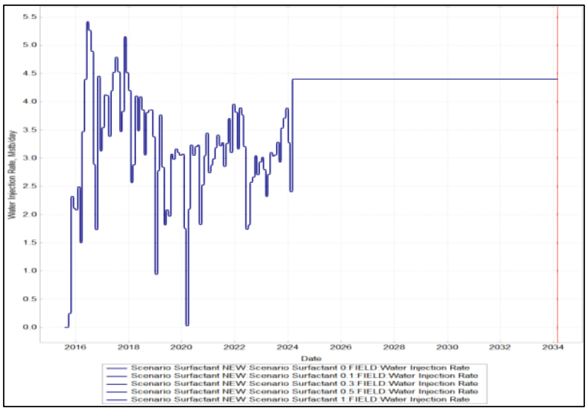

Fig 3. Water injection rate history (2015–2034) with stable phase from 2024 to 2034

The water injection rate drops from 2 to 5 Mstb/day between 2017 and 2023. The operational changes which include well injection distribution changes and reservoir pressure response shifts together with injection production pattern optimization efforts to maintain stable formation pressure created these variations (He et al., 2019).

The graph demonstrates that a significant transformation begins at the beginning of 2024. The injection rate maintains a constant value between 4.3 and 4.4 Mstb/day from 2024 until 2034. The injection system demonstrates stability because it operates in permanent conditions which maintain constant water injection and fluid production rates.

Surfactants also have less of an effect on macroscopic injection rates than they do on oil mobility and fluid-transfer efficiency in rock pores. As a result, all surfactant scenarios show nearly identical water injection patterns, that range from 0% to 1% concentration. These microscopic effects are important because surfactant injection enhances oil displacement and sweep efficiency by reducing entry pressure (Guo et al., 2019). Overall, the graph demonstrates a shift from an operational adjustment phase to a stable injection phase. This procedure is necessary to enable Enhanced Oil Recovery (EOR) processes that involve injecting surfactant and water at the same time, as well as to keep the reservoir pressure stable (Podoprigora et al., 2022)

The graph above displays three different stages of production. The graph demonstrates surfactants essential role in enhancing oil extraction from the ground. The primary production phase between 2015 and 2018 showed continuous high production rates across all operational scenarios. The maximum rate reached approximately 5.2 Mstb/day during the year 2016. The evidence demonstrates that natural reservoir conditions reached their optimal state until they were depleted. Production experienced a significant decline between 2018 and 2024 because it dropped from 0.4 to 0.8 Mstb/day by the year 2020. The natural reservoir pressure declined significantly, which forced EOR to take action. The current pattern of oil extraction supports previous research that establishes surfactants as essential for achieving maximum oil recovery after primary and secondary extraction processes. (Shaikhah et al., 2024).

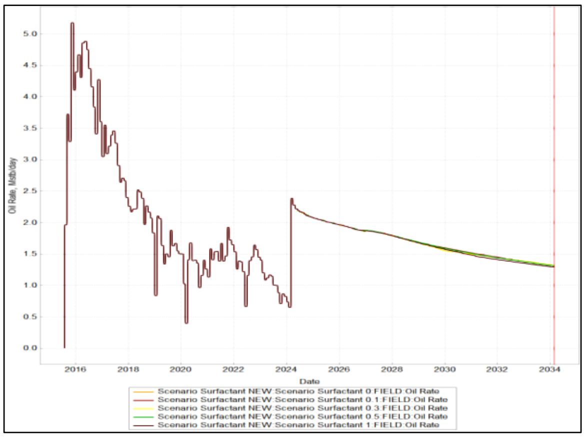

Fig 4. Oil rate decline profile for various surfactant concentrations from 2024 to 2034

The effectiveness of surfactant injection during the 2024 to 2034 period shows significant variability according to different concentration levels. Higher concentration scenarios do not consistently provide superior long-term performance, indicating that concentration increase alone does not guarantee improved recovery under HTHS conditions. The 1.0% surfactant scenario starts at approximately 2.4 Mstb/day and declines to 1.3 Mstb/day by 2034**.** The 0.5% surfactant scenario starts at 2.0 Mstb/day and shows the second-best performance. The 0.1% scenario maintains a constant output level close to its original value.

With the convergence of the mid-range concentration scenarios (0.3–0.5%) toward the end of the projection period, an ideal cost–benefit ratio is demonstrated without compromising long-term production sustainability. These results support previous research showing that surfactant solutions can alter rock wettability while effectively reducing interfacial tension between the oil and water phases (Xi et al., 2021). Therefore, maintaining production in a depleted reservoir becomes an economically viable option. The oil production increase is associated with interfacial tension reduction, which decreases capillary forces and improves oil mobility within porous media.

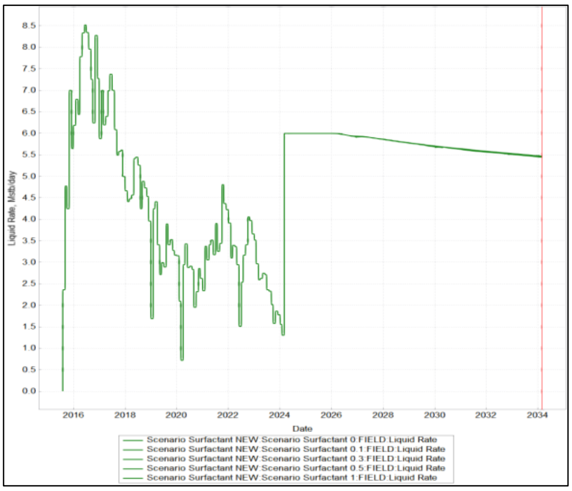

Fig 5. Liquid production rate history (2015-2034) with surfactant-induced stabilization from 2024 onward

The liquid production rate defines total liquid production which has shown different results for each surfactant scenario from 2015 until 2034 based on the data presented in the following graph. The field reached successful results during its initial year of production from 2015 until 2016. The maximum fluid output reached 8 to 8.5 Mstb per day which indicates that the reservoir maintained high pressure while its pore networks had effective connectivity for fluid movement. The period from 2017 until 2023 saw a significant decline in liquid production which dropped from approximately 8 Mstb per day to a range of 1.5 to 3 Mstb per day.

The introduction of surfactant scenarios in 2024 brought about a change to the existing trend. The production rates reached a steady state between 5.5 and 6 Mstb per day which continued until the simulation ended in 2034. The results show that surfactant injection maintains steady production levels through its ability to enhance fluid movement and increase oil extraction efficiency (Massarweh & Abushaikha, 2020). The surfactant concentration curve patterns show almost identical behavior for all concentrations between 0 and 1 percent (Bashir et al., 2022). The evidence demonstrates that surfactants do not create significant changes to the total fluid volume that they generate. The total produced fluid contains a greater oil volume than it contains water which results in increased water production (Druetta & Picchioni, 2020). Surfactants change production processes from a natural decline period into a stability phase, enabling extended field production that maintains high output rates even after the reservoir reaches its mature stage.

Surfactant mechanisms discussed in academic research maintain consistent production levels. Viscoelastic surfactants enable oil recovery increases of up to 10% while reducing water production by 47% in naturally fractured reservoirs. According to (Xi et al., 2021) surfactants lower the interfacial tension between oil and water which makes it easier for oil to flow. The surfactant solutions achieve 53% higher recovery rates than conventional methods through their ability to create thicker solutions and their effect of reducing interfacial tension (Curbelo et al., 2020). The field studies conducted by (Swadesi et al., 2015) demonstrate that using appropriate surfactant types enables the recovery of 86-90% of remaining oil. The liquid production trend shows minor differences among surfactant concentrations, indicating limited impact on total fluid mobility.

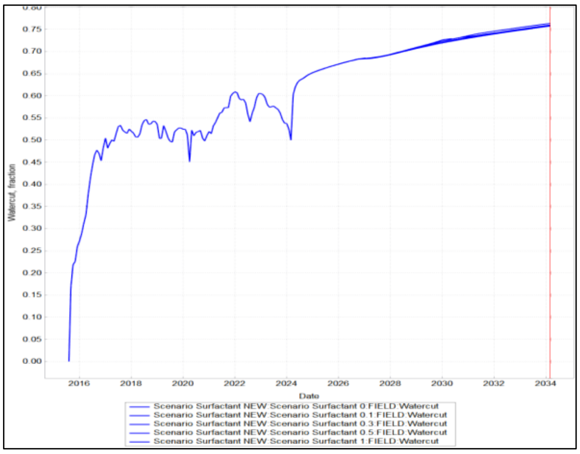

Fig 6. Water cut history (2015–2034) for five surfactant concentration scenarios (0–1.0%)

The graph shows how the water cutwhich measures water content in total fluid productionhas changed from 2015 to 2034 under different surfactant application situations. The water cut value remained below 0.1 (10%) during the first production year which lasted from 2015 to 2016. The fluid that was produced contained mostly oil with only a small amount of water. The water cut increased significantly over time until it reached approximately 0.5 (50%) between 2017 and 2018. This marked the beginning of water entering production wells through injection well systems. The reservoir pressure decline caused water to flow more freely throughout the entire system.

The study introduced surfactants into different scenarios with five different surfactant concentrations that included zero and 0.1 and 0.3 and 0.5 and 1 (Mousa et al., 2021). The graph demonstrates how water displacement increases at a gradual pace until it reaches a range between 0.65 and 0.7 before it continues to increase until it reaches a range between 0.75 and 0.78. The figure demonstrates that water production through time becomes a crucial element while surfactant injection maintains constant total fluid production rates. Mature fields commonly produce fluids which contain water as their main element during this production phase (Hu Yin, Gaorun Zhong, 2024). Surfactants reduce the oil-water tension which enables trapped oil in rock pores to flow more freely.

The trend demonstrates that water production keeps rising while surfactants display their capacity to improve oil recovery efficiency together with extending the field's operational timeframe. This indicates that sweep efficiency improvement remains limited under high-temperature and high-salinity conditions.

The graph below shows how overall oil production has changed over time for a number of surfactant scenarios from 2015 to 2034. Overall, oil production continues to increase from the start of field development to the end of the simulation period, and the scenarios show similar cumulative growth patterns. The period between 2015 and 2018 shows a major rise in total production. The initial phase of resource extraction starts when the reservoir maintains its high pressure which allows oil to flow smoothly into the production wells. The period from 2018 to 2023 shows an increase in oil accumulation that approaches a steady state. The production of oil has declined because the reservoir pressure has decreased while water production rates have increased.

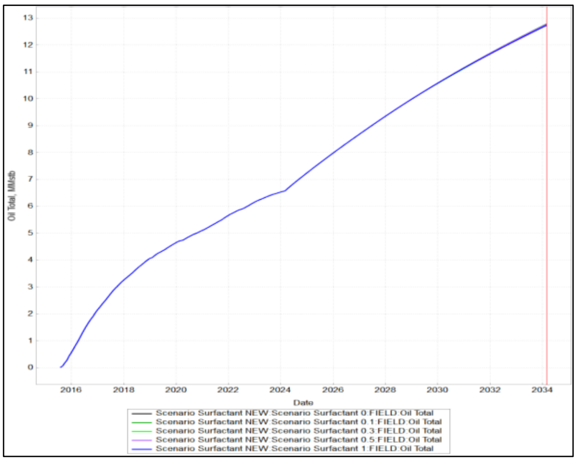

Fig 7. Cumulative oil production history 2015-2034

The rate of cumulative oil growth starts to increase after 2024 because surfactant-injection scenarios begin at that time. This demonstrates that surfactants enable better oil extraction by decreasing oil-water interfacial tension, thereby releasing oil trapped in rock pores. Haghighi, (2021) states that surfactants can decrease interfacial tension from 30 dynes/cm to 14 dynes/cm while increasing oil recovery from 40% to 59%. (Xi et al., 2021) demonstrate that surfactant injection decreases interfacial tension between oil and water phases which results in better oil recovery (EOR) efficiency through this method. Surfactant solutions achieve recovery factors that exceed traditional methods by 53% because they reduce interfacial tension and improve sweep efficiency (Curbelo et al., 2020)

By the end of the simulation period in 2034, it is expected that total oil production will be around 12–13 MMstb. This shows that scenarios with surfactants work better for long-term oil production than the standard scenario without surfactants. As illustrated in the graph, surfactant-based EOR can extend field life and enhance overall recovery from the reservoir.

Table 7. Surfactant Injection Scenario

Scenario	Oil Cummulative	RF %
Scenario 0 %	12,78	19,92
Scenario 0,1 %	12,79	19,93
Scenario 0,3 %	12,75	19,87
Scenario 0,5 %	12,77	19,90
Scenario 1,0 %	12,73	19,82

Table 7 shows different surfactant-injection scenarios. It shows that altering the surfactant content from 0% to 1.0% doesn't change Oil Cumulative or Recovery Factor (RF%) very much. The RF% values range from 19.82% to 19.93%, and the Oil Cumulative values range from 12.73 to 12.79 MMstb. When there is no surfactant (0%), the Oil Cumulative reaches 12.78 MMstb and the RF is 19.92%. Increasing the surfactant concentration to 0.1% just marginally improves the findings to 12.79 MMstb and 19.93%, which isn't really helpful in real life. When the concentration is between 0.3% and 0.5%, both Oil Cumulative and RF% change, but they don't show a clear upward trend. Even when the concentration is at its greatest (1.0%), both values decline to 12.73 MMstb and 19.82%, respectively. The highest concentration scenario (1.0%) does not produce the highest recovery factor, indicating reduced surfactant efficiency at elevated concentration under harsh reservoir conditions.

Overall, the data demonstrate that increasing the surfactant content to 1.0% does not really help recover oil. This indicates that increased surfactant levels do not provide substantial benefits Oil Cumulative or Recovery Factor. There are probably a few causes for this conclusion, but the most crucial ones are the high temperature of the reservoir (224.6°F) and the high salt of the formation water. Surfactants reach their breakdown point at 224.6°F because their molecular structures lose stability which prevents them from effectively reducing the surface tension between oil and water (Hou et al., 2024). The performance of surfactants decreases in water that contains high salt concentrations (Panthi & Mohanty, 2024). Saline water contains sodium ions, calcium ions, and magnesium ions which can bind with the surfactant's active sites. The surfactant will either form precipitate or experience decreased solubility (Alyousef et al., 2024). The surfactant shows reduced micelle formation capabilities which leads to decreased interfacial tension reduction. Oil recovery shows no improvement despite increasing the concentration.

In additional to these external factors, the inherent chemical structure of surfactants also plays a crucial role in determining interfacial stability. The ability of surfactants to lower interfacial tension is governed by their amphiphilic nature, where hydrophilic heads interact with water while hydrophobic tails interact with oil. As demonstrated by (Naibaho et al., 2025), the interface formation energy (IFE) for surfactant systems ranges from -48.53 kcal/mol for cationic surfactants to -178.33 kcal/mol for anionic surfactants, indicating that chemical structure significantly influences interfacial stability.

The surfactant fails to function correctly in the reservoir because both temperature and salinity levels exceed their normal operational range. The surfactant type requires reevaluation because its effectiveness against high temperature and salinity conditions needs testing. The use of surfactants which withstand extreme temperatures and high saline conditions shows potential to enhance Oil Cumulative and Recovery Factor in reservoirs that experience extreme heat and salinity levels. Although surfactant concentration increases from 0% to 1.0%, recovery factor only improves slightly, indicating limited surfactant effectiveness under the studied reservoir conditions (Alyousef et al., 2024).

These findings align with previous research. (Curbelo et al., 2020) demonstrated that surfactant effectiveness is highly dependent on chemical stability, with recovery improvements up to 53% achievable under optimal conditions through the addition of glycerol, which simultaneously increases viscosity and reduces interfacial tension. (Haghighi, 2021) reported that appropriate surfactant selection can increase RF from 40% to 59% by effectively reducing IFT from 30 dyne/cm to 14 dyne/cm and altering wettability from oil-wet to water-wet conditions. However, the marginal improvements observed in this study (RF ranging only from 19.82% to 19.93%) underscore that without addressing HT/HS stability including thermal degradation at 224.6°F (107°C) and ionic interactions with high-salinity formation water the full potential of surfactant EOR cannot be realized.

Beyond chemical stability, injection strategy also plays a critical role in determining EOR success. Optimization studies by (Oliveira et al., 2024) have shown that increasing slug size from 0.2 PV to 0.6 PV can improve recovery factor by up to 15% under optimal conditions, highlighting the importance of injection strategy design.

The findings have significant practical implications for field-scale implementation. The study demonstrates that investing in higher surfactant concentrations is economically and technically ineffective if the chemical is not stable under reservoir conditions. The core issue is not injection strategy, but the selection of the chemical agent itself. For the Volve Field or similar HTHS reservoir, the focus must shift toward the development and application of designer surfactants. Surfactants with proven thermal stability at temperatures exceeding 100°C, such as gemini surfactants known for enhanced thermal stability and lower critical micelle concentration values or zwitterionic surfactants exhibiting excellent salinity tolerance and reduced adsorption on rock surfaces, are recommended for future evaluation.

4. Conclusions

This study demonstrates that increasing surfactant concentration from 0% to 1.0% only slightly improves oil recovery in the Volve Field reservoir, with Recovery Factor ranging from 19.82% to 19.93%. This finding confirms that surfactant injection effectiveness is not solely determined by dosage, but rather by chemical stability under extreme reservoir conditions. The limited performance is primarily attributed to thermal degradation at 224.6°F(107°C), increased adsorption onto rock surfaces, high salinity effects, and reduced interfacial tension efficiency under harsh reservoir conditions.

From a practical perspective, successful surfactant EOR in high-temperature, high-salinity reservoirs requires shifting focus from increasing concentration to selecting or formulating surfactants specifically designed to withstand extreme conditions, such as gemini or zwitterionic types. This study is limited to numerical simulation and does not include laboratory validation of surfactant behavior under actual reservoir conditions. Therefore, future research should prioritize laboratory evaluation of thermally stable surfactants under temperature and salinity conditions representative of the Volve Field to confirm the findings before field-scale implementation.

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Glossary Of Terms And Symbols

Unit	Definition	Symbol
EOR	Enhanced Oil Recovery	
RF	Recovery Factor	%
IFT	Interfacial Tension	dyne/cm
OOIP	Original Oil In Place	Stb/day
STB	Stock Tank Barrel	
MMSTB	Million Stock Tank Barrels	
ppm	Parts per million	
mD	Millidarcy	
API	American Petroleum Institute	
cP	Centipoise	
Ca2+	Calcium ion	
Mg2+	Magnesium ion	
mN	Millinewton	

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