

**STUDY OF VISCOELASTICITY AND IFT AS A
MICROSCOPIC OIL RECOVERY MECHANISM IN
SANDSTONE FORMATION**

BY

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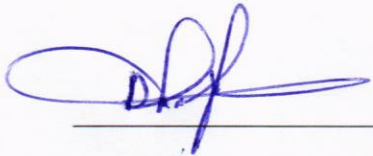
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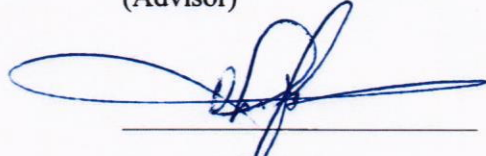
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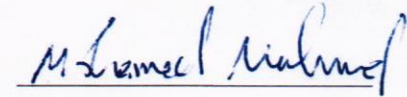
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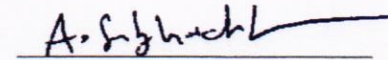
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*This thesis is dedicated to my parents and family for their continuous support, prayers,
and motivation throughout my life.*

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LIST OF ABBREVIATIONS

ASP	:	Alkaline-Surfactant-Polymer
CaCl₂	:	Calcium Chloride
CDC	:	Capillary Desaturation Curve
cP	:	Centipoise
CTAB	:	Hexacetyltrimethylammonium bromide
DI	:	Deionized
ΔP	:	Pressure Drop
EOR	:	Enhanced Oil Recovery
EU	:	European Brine
ft/D	:	Feet per Day (Flux Rate)
HPAM	:	Hydrolyzed Polyacrylamide
IFT	:	Interfacial Tension
K	:	Permeability
KCl	:	Potassium Chloride
kDa	:	Kilo-Dalton
MEOR	:	Microbial Enhanced Oil Recovery

MgCl₂	:	Magnesium Chloride
NaCl	:	Sodium Chloride
NaHCO₃	:	Sodium Bicarbonate
Na₂SO₄	:	Sodium Sulfate
Nc	:	Capillary Number
N_{crit}	:	Critical Capillary Number
NMR	:	Nuclear Magnetic Resonance
OOIP	:	Original Oil in Place
P.U.	:	Pore Unit
Ppm	:	Parts Per Million
ROIC	:	Remaining Oil in Core
RPM	:	Rotations Per Minute
SAGD	:	Steam-Assisted Gravity Drainage
Sor	:	Residual Oil Saturation
SP	:	Surfactant Polymer
Φ	:	Porosity
<i>E</i>	:	Total Recovery Factor

E_D	:	Microscopic Displacement Efficiency
E_s	:	Macroscopic Sweep Efficiency
θ	:	Contact Angle
σ	:	Interfacial Tension

|

ABSTRACT

Full Name : Mohammed Farhan Jameel

Thesis Title : Study of Viscoelasticity and IFT as a Microscopic Oil Recovery Mechanism in Sandstone Formation

Major Field : Petroleum Engineering

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The study focused on comparing the relative roles of interfacial tension (IFT) reduction and polymer viscoelasticity on residual oil recovery in water-wet sandstone formation. Enhanced oil recovery (EOR) methods are generally classified into thermal, miscible, and chemical techniques based on the injectant's nature. However, based on operational mechanisms, EOR methods can be divided into mobilization and mobility control approaches. While mobility control between the injection EOR solution and oil improves sweep efficiency, mobilizing well-swept capillary-trapped residual oil through enhanced microscopic displacement is critical for maximizing the overall recovery factor during EOR processes.

Historically, IFT reduction has been regarded as the key microscopic recovery mechanism for improving residual oil recovery, particularly in permeable water-wet formations. Recent studies, however, have highlighted the potential of a polymer's viscoelasticity to positively influence residual oil recovery. Viscoelasticity, a rheological phenomenon with a dependency on time and flux rate, contrasts with IFT reduction, which is an interfacial phenomenon less influenced by flux rate. These contrasting concepts required thorough examination to determine if polymer flooding, a mobility control method, could serve as a viable replacement for surfactant-based mobilization techniques that rely on IFT reduction.

To address this, two solutions with similar viscosities but distinct IFT and viscoelastic properties were systematically studied. A surfactant-glycerol solution, designed to reduce IFT without exhibiting viscoelasticity, was compared against a synthetic polymer solution with comparable viscosity but no IFT reduction capability. Initial IFT and rheology experiments were conducted to formulate the solutions, ensuring appropriate properties for studying their effects on microscopic oil recovery.

Core flooding experiments were then performed using water-flooded cores at varying flux rates, ranging from low to high (e.g., low, intermediate, and high flow rates). These experiments aimed to generate capillary desaturation curves, which enabled the interpretation of the dominant microscopic recovery mechanisms in water-wet conditions.

In this study, the results are obtained for the following system- polymer used was HPAM 3630 with a concentration of 2000 ppm, surfactant used CTAB (Hexacetyltrimethylammonium bromide), for water-wet Bentheimer core having high permeability. The results demonstrated that viscoelastic polymer flooding provided higher incremental oil recovery, particularly at low flux rates. The onset of rapid oil mobilization (desaturation) occurred earlier during polymer flooding, with a flux rate of 2 ft/day, compared to 3 ft/day in the surfactant-glycerol flood. This earlier desaturation highlights the superior performance of viscoelastic polymers in mobilizing residual oil, especially under low flux conditions, marking a significant advancement in understanding the potential of viscoelastic polymer flooding for enhanced oil recovery.

ملخص الرسالة

الاسم الكامل: محمد فرحان جميل

عنوان الرسالة: دراسة للزوجة المرنة والتوتر السطحي كآلية لاسترداد النفط المجهري في تكوين الحجر الرملي

التخصص: هندسة البترول

تاريخ الدرجة العلمية: ديسمبر ٢٠٢٤

ولزوجة البوليمر المرنة على استرداد النفط المتبقي (IFT) ركزت الدراسة على مقارنة الأدوار النسبية لتقليل التوتر السطحي عمومًا إلى تقنيات حرارية وقابلة للمزج (EOR) في التكوينات ذات البلل المائي. يتم تصنيف طرق تحسين استرداد النفط إلى نهج التعبئة EOR وكيميائية بناءً على طبيعة المادة المحقونة. ومع ذلك، بناءً على الآليات التشغيلية، يمكن تقسيم طرق المحقون والنفط كفاءة الاجتياح، فإن تعبئة النفط المتبقي EOR والتحكم في الحركة. بينما يعزز التحكم في الحركة بين محلول المحاصر شعريًا بشكل جيد من خلال تحسين الإزاحة المجهرية بعد أمرًا حاسمًا لتعظيم عامل الاسترداد الإجمالي أثناء عمليات EOR.

الآلية الرئيسية للاسترداد المجهري لتحسين استرداد النفط المتبقي، خاصة في (IFT) تاريخيًا، تم اعتبار تقليل التوتر السطحي التكوينات ذات النفاذية العالية والبلل المائي. ومع ذلك، سلطت الدراسات الحديثة الضوء على إمكانات لزوجة البوليمر المرنة في التأثير الإيجابي على استرداد النفط المتبقي. تتميز اللزوجة المرنة بأنها ظاهرة انسيابية تعتمد على الزمن ومعدل التدفق، بينما يعتبر تقليل التوتر السطحي ظاهرة بين السطوح تتأثر بشكل أقل بمعدل التدفق. تطلبت هذه المفاهيم المتناقضة دراسة متأنية لتحديد ما إذا كان حقن البوليمر، كطريقة للتحكم في الحركة، يمكن أن يكون بديلاً صالحاً لتقنيات التعبئة القائمة على تقليل التوتر السطحي التي تعتمد على استخدام المواد الخافضة للتوتر السطحي.

للتعامل مع هذه القضية، تم دراسة محلولين ذوي لزوجة مماثلة ولكن بخصائص مختلفة من حيث التوتر السطحي واللزوجة المرنة بشكل منهجي. تم تصميم محلول مكون من مادة خافضة للتوتر السطحي والجلسرين لتقليل التوتر السطحي دون إظهار اللزوجة المرنة، وتمت مقارنته بمحلول بوليمر صناعي له لزوجة مماثلة ولكنه لا يمتلك قدرة على تقليل التوتر السطحي. تم إجراء تجارب أولية على التوتر السطحي والريولوجيا لتشكيل المحاليل، مما يضمن وجود الخصائص المناسبة لدراسة تأثيراتها على استرداد النفط المجهري.

تم إجراء تجارب فيضان النوى باستخدام نوى مشبعة بالماء عند معدلات تدفق مختلفة تتراوح بين منخفضة وعالية (مثل التدفقات المنخفضة والمتوسطة والعالية). هدفت هذه التجارب إلى إنشاء منحنيات إزالة التشبع الشعري، والتي مكنت من تفسير الآليات الرئيسية للاسترداد المجهري في الظروف ذات التبلل المائي.

بتركيز ٢٠٠٠ جزء في المليون، HPAM ٣٦٣٠ في هذه الدراسة، تم الحصول على النتائج للنظام التالي: البوليمر المستخدم هو (سداسي سيتيل ثلاثي أمونيوم بروميد)، وذلك لعينة من لب CTAB والمادة الخافضة للتوتر السطحي المستخدمة هي بنثايمر ذات تبلل مائي ونفاذية عالية. أظهرت النتائج أن عملية حقن البوليمر اللزج المرن قدّمت زيادة أكبر في استرداد النفط، خاصة عند معدلات تدفق منخفضة. وقد حدثت بداية التحرك السريع للنفط (إزالة التشبع) في وقت مبكر أثناء حقن البوليمر، عند معدل تدفق قدره ٢ قدم/يوم، مقارنة بـ ٣ أقدام/يوم في عملية حقن الجلسرين مع المادة الخافضة للتوتر السطحي. هذه الإزالة المبكرة للتشبع تسلط الضوء على الأداء المتفوق للبوليمرات اللزجة المرنة في تحريك النفط المتبقي، خاصة في ظل ظروف تدفق منخفضة، مما يمثل تقدمًا كبيرًا في فهم إمكانات حقن البوليمر اللزج المرن لاسترداد النفط المحسن.

CHAPTER 1

INTRODUCTION

Enhanced Oil Recovery (EOR) methods are vital for optimizing the extraction of hydrocarbons from reservoirs. Primary recovery methods, which depend on the natural pressure within the reservoir, typically only retrieve a small portion of the oil initially present. Secondary recovery techniques, such as water flooding, are used to sustain reservoir pressure and improve the movement of oil towards production wells. However, even with these methods, there is a significant amount of original oil in place (OOIP) that remains unrecovered due to incomplete sweep efficiency and the trapping of oil by capillary forces. To address challenges like these, EOR strategies have focused on two primary operational mechanisms—mobilization and mobility control. Mobilization techniques aim to reduce the forces trapping oil within the reservoir, primarily by decreasing interfacial tension (IFT), while mobility control methods enhance the displacement efficiency of injected fluids, often by increasing viscosity with polymers. The effectiveness of these mechanisms varies depending on reservoir conditions and the properties of the injected fluids.

The reduction of interfacial tension (IFT) between oil and water is a fundamental aspect of chemical EOR methods. Lowering the IFT diminishes the capillary forces that trap oil within pore spaces, making it easier to mobilize and recover. Early work by Holm and Csaszar (1962) demonstrated the significant impact of IFT reduction on oil recovery during

waterflooding. Surfactant flooding, which utilizes the IFT-lowering capabilities of surfactants, has been extensively studied and applied in the field, with Stegemeier (1977) providing comprehensive insights into its mechanisms. Although effective, IFT reduction alone may not be sufficient to maximize oil recovery, particularly in heterogeneous reservoirs where capillary forces can vary widely. This limitation has led to the exploration of additional mechanisms, such as polymer viscoelasticity, to further enhance oil recovery.

Polymer flooding has emerged as an EOR method designed to improve the sweep efficiency of displacing fluids by increasing the viscosity of injected water. This improvement in viscosity helps achieve a more favorable mobility ratio, reducing the occurrence of fingering and enhancing overall displacement efficiency. Early studies by Gogarty (1967) and Pye (1964) established the effectiveness of polymer flooding in increasing oil recovery. More recently, research has focused on the viscoelastic properties of polymers and their influence on oil recovery. Polymers exhibiting viscoelasticity, which combines both viscous and elastic behaviors, can generate normal stresses that assist in mobilizing trapped oil droplets. Studies by Wang et al. (2011) and Seright (2017) highlighted the potential of polymer viscoelasticity to improve oil recovery, particularly through the elastic properties that can help displace oil droplets from pore throats. Study done by Azad et al. (2019, 2020, 2021) further demonstrated that polymers with viscoelastic characteristics have achieved higher oil recovery factors compared to solutions that are purely viscous.

Comparative studies have been conducted to evaluate the relative effectiveness of IFT reduction and polymer viscoelasticity in EOR. Research by Sheng (2015) and Levitt and Pope (2008) compared surfactant-polymer (SP) flooding with polymer flooding, finding

that while IFT reduction is crucial for mobilizing oil trapped by capillary forces. Investigation by Azad et al. (2020) into the effects of shear rate on polymer viscoelasticity revealed that optimizing shear rate has enhanced polymer viscoelastic properties, leading to improved oil recovery across different flow rates. This suggests that viscoelasticity might complement or even replace traditional IFT reduction methods in specific EOR applications.

The findings presented by Azad and Seright (2024) are highly relevant to this study, as the experiments will be conducted at low flux rates starting from 0.05 ft/day—conditions that closely align with realistic field scenarios. Their analysis highlights that, while laboratory studies often operate at flux rates exceeding 1 ft/day to observe shear-thickening and viscoelastic effects, such conditions rarely occur in the field. By conducting experiments at low flux rates, this study aims to bridge the gap between laboratory results and practical field conditions, ensuring that the observed microscopic recovery mechanisms, such as viscoelasticity and interfacial tension (IFT) reduction, are representative of actual reservoir behavior in sandstone formations. At flux rates as low as 0.05–0.2 ft/day, shear thickening is less likely to occur across the entire reservoir volume. However, localized effects near the wellbore or within pressure gradient zones may still contribute to incremental oil recovery. The experiments are focused on evaluating the viscoelastic effects or IFT reduction, serving as a mechanism to mobilize residual oil under low-flux conditions. This approach is particularly critical for sandstone reservoirs, where reservoir heterogeneity and permeability variations influence fluid flow and recovery mechanisms. By systematically investigating these effects, the study will provide insights into how low flux rates impact Sor reduction, thereby enhancing the understanding of microscopic oil recovery

mechanisms. By operating within the realistic flux range (starting at 0.05 ft/day), this study addresses a key recommendation from Azad and Seright (2024) to simulate field-relevant conditions. The results will contribute to validating whether viscoelastic effects are significant at low flux rates and whether alternative mechanisms, such as wettability alteration or localized pressure gradients, play a more dominant role. This experimental design ensures that the findings are directly applicable to field-scale polymer flooding projects, offering a more accurate assessment of the potential for microscopic oil recovery enhancement in sandstone formations.

Despite the advancements in understanding IFT reduction and polymer viscoelasticity, there has been a need for systematic comparative studies to determine the dominant microscopic recovery mechanism under varying reservoir conditions. This research has critically compared the roles of IFT reduction and polymer viscoelasticity in enhancing oil recovery by conducting experiments that screen two EOR solutions with similar viscosity but differing IFT and viscoelastic properties. The Surfactant solution has been formulated to reduce IFT without viscoelasticity, while a synthetic polymer solution has exhibited viscoelasticity without reducing IFT.

To effectively study the influence of viscoelasticity and IFT on microscopic oil recovery, viscosity has been controlled in the EOR solutions. The Surfactant solution has been combined with IFT-reducing surfactants, and a synthetic polymer with comparable viscosity has been selected. A series of IFT and rheology experiments have been conducted to formulate these solutions, followed by core flooding experiments at varying flux rates to generate capillary desaturation curves. The interpretation of these curves has identified the dominant microscopic recovery mechanism in water-wet conditions.

The results of this research have provided valuable insights into the dominant microscopic recovery mechanisms in EOR, aiding in the optimization of EOR strategies, particularly in water-wet sandstone formations. These findings could lead to the development of more effective EOR techniques that leverage both IFT reduction and polymer viscoelasticity.

1.1 Residual Oil Saturation

It is the remaining oil in the core (ROIC) after waterflooding (secondary). (Rathmell et al, 1973)

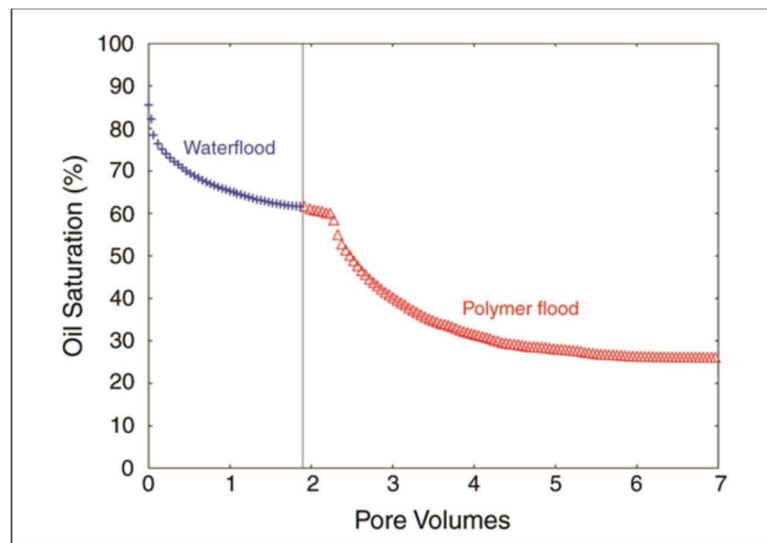


Figure 1: Oil Saturation for a polymer flood experiment [Koh et al, 2017]

The figure shows reduction in Oil Saturation % with injection of several Pore-volumes of Water followed by an additional drop of Oil Saturation by Polymer injection.

The total recovery factor (E) during Enhanced Oil Recovery (EOR) is an essential concept in reservoir engineering, emphasizing the efficiency of extracting hydrocarbons. It is

defined as the product of microscopic displacement efficiency (E_D) and macroscopic sweep efficiency (E_S) (Green & Willhite, 1998):

$$E = E_D \times E_S \quad (1.1)$$

1.1.1 Microscopic Displacement Efficiency (E_D)

It refers to the fraction of oil displaced at the pore level within the swept zone. It is influenced by factors such as interfacial tension, wettability alteration, and capillary forces. Techniques like surfactant flooding and gas injection are often employed to improve E_D (Lake, 1989).

The microscopic displacement refers to the effectiveness of the surfactant in mobilizing trapped oil at the pore level. When the IFT is reduced to ultra-low levels, it allows the oil droplets trapped in the rock pores to overcome capillary forces and become mobilized. This process significantly enhances the microscopic displacement efficiency, meaning more of the trapped oil can be displaced and subsequently recovered. (Azad, 2021)

1.1.2 Macroscopic Sweep Efficiency (E_S)

It represents the effectiveness of the injected fluid in contacting hydrocarbon-bearing zones on a reservoir-wide scale. Factors such as reservoir heterogeneity, mobility ratio, and injection patterns significantly impact E_S . Optimization of injection schemes and fluid properties is critical for improving this efficiency (Thomas, 2008). On the macroscopic scale, the sweep efficiency refers to the ability of the injected fluids (in this case, surfactant solutions) to uniformly displace oil across the entire reservoir. While lowering IFT improves microscopic displacement, it must be combined with effective macroscopic sweep to ensure that the entire reservoir is efficiently swept by the injected fluids. Azad,

2021, highlights that the combination of reduced IFT and improved sweep efficiency is essential for maximizing overall oil recovery during surfactant-based EOR methods. (Azad, 2021)

1.2 Different EOR Methods

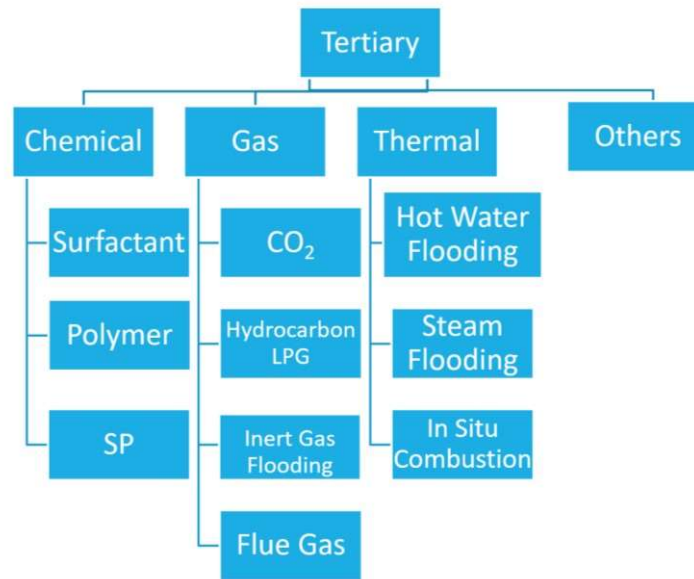


Figure 2: Different EOR Methods

Enhanced Oil Recovery (EOR) encompasses advanced techniques aimed at maximizing hydrocarbon recovery from reservoirs after primary and secondary recovery methods become less effective. EOR is broadly classified into three main categories: chemical, gas, and thermal methods, along with other emerging techniques. These approaches are designed to alter reservoir conditions or fluid properties to enhance oil displacement efficiency. Chemical methods involve the injection of surfactants, polymers, or a combination of these agents to improve fluid mobility and reduce interfacial tension. Gas-based EOR utilizes CO₂, hydrocarbon gases, or inert gases to maintain reservoir pressure

and improve miscibility. Thermal methods, including steam injection and in-situ combustion, leverage heat to reduce oil viscosity and facilitate its flow. Each type of EOR is tailored to specific reservoir characteristics, ensuring effective recovery in different rock and fluid environment/properties.

1.2.1 Chemical EOR

Surfactant Flooding- Surfactants are used to lower the interfacial tension between oil and water, making it easier to displace the trapped oil.

Polymer Flooding- Introduced in the late 1950s and early 1960s, polymer flooding involves adding polymers to the injection water to increase its viscosity and improve the sweep efficiency

Alkaline-Surfactant-Polymer (SP) Flooding- Combining surfactants, polymers, and alkali to enhance oil recovery. The method was extensively studied in the late 1970s and 1980s.

1.2.2 Gas EOR

CO₂ Flooding- One of the most studied gas injection methods, CO₂ flooding was first proposed in the 1950s, with substantial research and field application beginning in the 1970s. The SACROC (Scurry Area Canyon Reef Operators Committee) Unit project in Texas is one of the earliest and most famous examples.

Hydrocarbon Gas Flooding- Introduced around the same time as CO₂ flooding, this method involves injecting light hydrocarbons (like propane or LPG) to mix with the oil and reduce its viscosity. The 1950s and 1960s saw initial development and applications.

Inert Gas Flooding- This method involves injecting non-reactive gases such as nitrogen or flue gas. While not as commonly applied as CO₂ or hydrocarbon gases, inert gas flooding gained attention in the late 1970s and early 1980s as a potential alternative in specific reservoirs.

1.2.3 Thermal EOR

Hot Water Flooding- This technique involves injecting hot water into the reservoir to reduce oil viscosity. Early research in the 1960s explored this method, although steam flooding became more prominent.

Steam Flooding- Also known as steam injection, this is one of the most widely used thermal recovery methods. It was developed in the 1960s, with significant contributions from Butler in 1969, who proposed the concept of steam-assisted gravity drainage (SAGD).

In Situ Combustion- This method involves burning a portion of the oil in the reservoir to generate heat, reducing the viscosity of the remaining oil. The technique has been studied since the 1960s.

1.2.4 Others

These could include a variety of methods such as microbial EOR (MEOR), where microbes are injected to produce gases or chemicals that can improve oil recovery. MEOR has roots in research from the 1940s and 1950s, but it gained more attention in the 1980s with advancements in biotechnology.

1.3 Interfacial Tension (IFT) Reduction

Interfacial tension (IFT) reduction is a fundamental principle in chemical enhanced oil recovery (EOR) methods. By lowering the IFT between oil and water, the capillary forces that trap oil within the reservoir's pore spaces are diminished, facilitating the mobilization and subsequent recovery of the trapped oil. This concept has been extensively researched and documented, proving to be a critical factor in improving oil recovery efficiency, especially in water-wet formations.

The significance of IFT reduction in oil recovery was first recognized in the early 1960s. Lowering IFT could significantly enhance oil recovery during waterflooding operations. Research laid the foundation for subsequent studies exploring the role of surfactants in EOR. Holm and Csaszar (1962) advanced this application by showing that surfactants could effectively reduce the IFT between oil and water, leading to improved oil mobilization. Their work provided essential insights into the mechanisms by which surfactants enhance oil recovery and identified the conditions under which these mechanisms are most effective. These early studies established the foundation for the widespread use of surfactants in chemical EOR methods.

The mechanisms by which IFT reduction enhances oil recovery are well-documented in the literature. Surfactants, which are amphiphilic molecules, adsorb at the oil-water interface, reducing the interfacial tension and altering the wettability of the reservoir rock. This adsorption process reduces the capillary forces that trap oil within the pores, thus facilitating its mobilization (Stegemeier, 1977; Hirasaki, Morrow 1991). Stegemeier (1977) provided a comprehensive review of these mechanisms, emphasizing the role of

capillary pressure and wettability in oil recovery. His research demonstrated that reducing IFT not only enhances oil mobilization but also improves the overall displacement efficiency of the displacing fluid, which is particularly important in heterogeneous reservoirs where capillary forces can vary significantly across different sections.

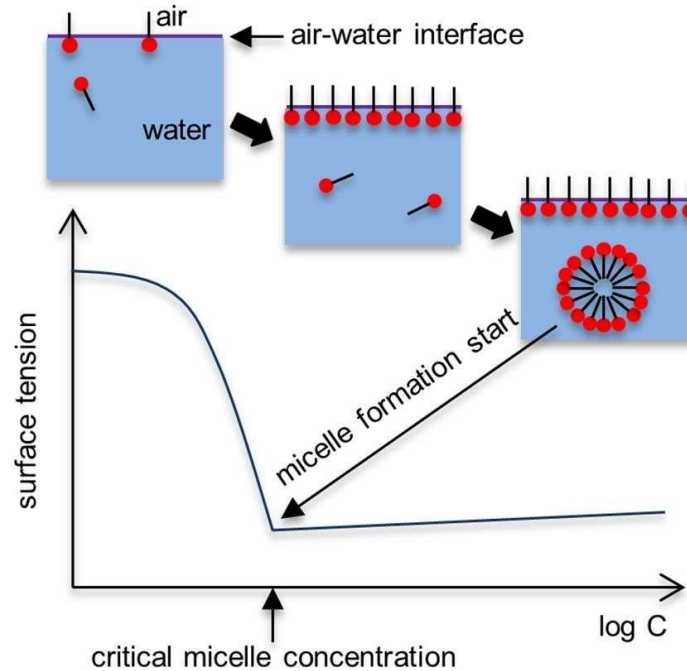


Figure 3: Surface tension and surfactant concentration [Ueno et al. 2016]

Ueno et al. (2016) discussed the mechanism of interfacial tension (IFT) reduction by surfactants in the context of enhanced oil recovery (EOR). They explained that surfactants, which are surface active agents, reduce the IFT between oil and water by adsorbing at the oil-water interface. This adsorption alters the balance of forces at the interface, significantly lowering the IFT. The reduction in IFT leads to a decrease in capillary forces that trap oil in the pore spaces of the reservoir rock, thereby facilitating the mobilization of the trapped oil.

The study by Ueno et al. (2016) highlighted the importance of surfactant selection and formulation in achieving effective IFT reduction. They emphasized that the effectiveness of IFT reduction depends on factors such as the concentration of surfactants, the type of surfactants used, and the specific characteristics of the reservoir fluids and rocks. The research also pointed out that the optimization of these factors is crucial for maximizing oil recovery in EOR processes.

Understanding the role of the capillary number, which is the ratio of viscous forces to capillary forces, is crucial in the context of IFT reduction. As the capillary number increases, the effectiveness of IFT reduction in mobilizing trapped oil improves, underscoring the importance of optimizing surfactant concentration and formulation to achieve the desired IFT reduction (Hirasaki and Morrow, 1991).

Numerous experimental studies have validated the effectiveness of IFT reduction in enhancing oil recovery. McAuliffe (1973) investigated the behavior of oil-in-water emulsions, highlighting the role of surfactants in stabilizing emulsions and improving flow properties in porous media. His experiments showed that surfactants could significantly reduce IFT, leading to the formation of stable emulsions that enhance oil displacement. This work provided critical insights into the practical application of surfactants in EOR. Field applications of surfactant flooding have also demonstrated significant improvements in oil recovery. Willhite (1986) reviewed several case studies where surfactant flooding was successfully implemented, showcasing the practical benefits of IFT reduction in real-world EOR operations. These case studies demonstrated that surfactant flooding could substantially increase oil recovery rates compared to conventional waterflooding.

For instance, in the Daqing oil field in China, surfactant flooding led to a significant increase in oil recovery, attributed to effective IFT reduction and improved displacement efficiency (Green & Willhite, 1986). Similarly, other field trials in the North Sea and the United States reported positive outcomes, further validating the effectiveness of IFT reduction in enhancing oil recovery. In addition to surfactant flooding, combined methods such as Alkaline-Surfactant-Polymer (ASP) flooding have shown promise in improving oil recovery. ASP flooding leverages the combined benefits of alkalines, surfactants, and polymers to enhance both mobilization and mobility control (Olajire, 2014). The alkali reduces IFT and alters wettability, the surfactant further reduces IFT and stabilizes emulsions, and the polymer improves sweep efficiency by increasing the viscosity of the displacing fluid. This integrated approach has been particularly effective in complex reservoirs where multiple recovery mechanisms are required.

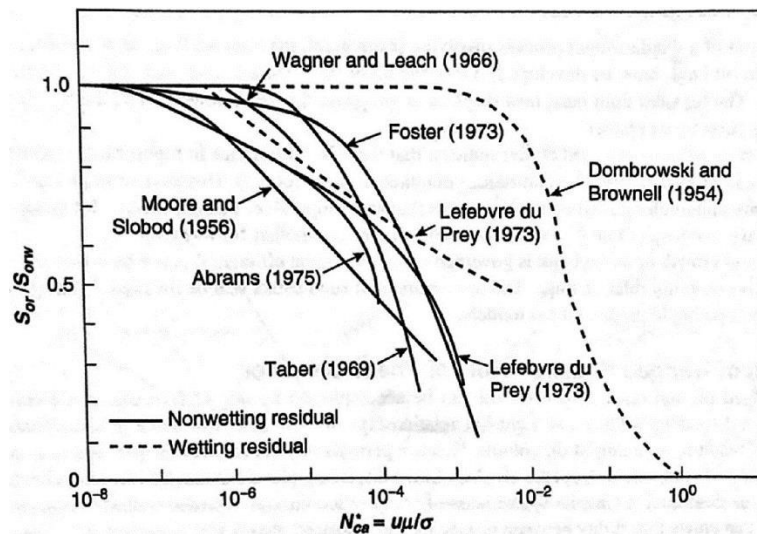


Figure 4: CDC curve generated by different EOR researchers (From -Green and Willhite, 2018)
[Azad, M.S, 2021]

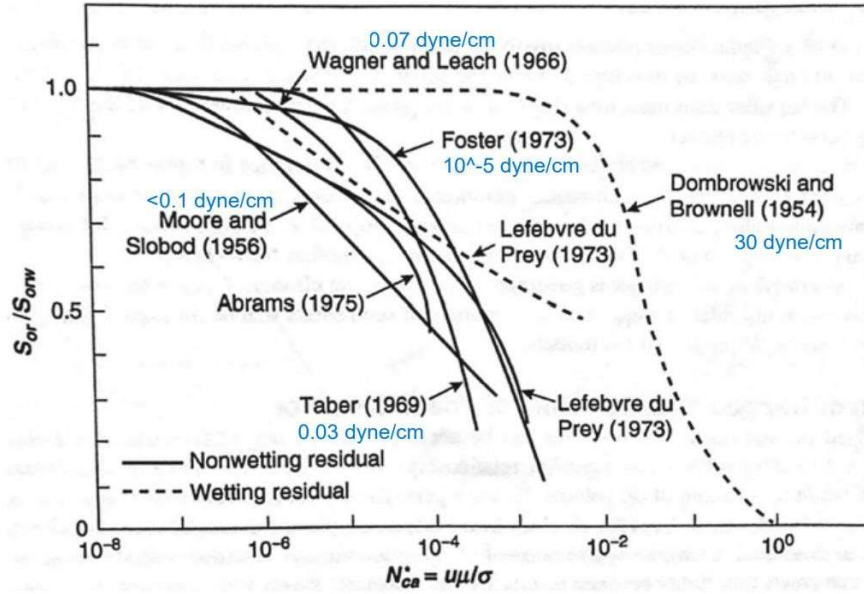


Figure 5: CDC with IFT values- Historically Ultralow IFT is a strong microscopic recovery mechanism. Graph modified from [Green and Willhite, 2018]

Advances in surfactant technology have further enhanced the effectiveness of IFT reduction in EOR. The development of new surfactant formulations tailored to specific reservoir conditions has enabled more efficient and cost-effective EOR operations. Researchers have focused on optimizing surfactant properties, such as adsorption, desorption, and thermal stability, to ensure their performance under reservoir conditions (Sheng, 2015). Modern surfactant formulations often include a combination of anionic, nonionic, and amphoteric surfactants to achieve the desired reduction in IFT and improve the overall efficiency of the EOR process. These formulations are designed to be compatible with the reservoir brine and crude oil, ensuring their effectiveness throughout the injection and production phases (Levitt & Pope, 2008).

1.4 Polymer Flooding and Viscoelasticity |

While interfacial tension (IFT) reduction has long been recognized as an effective method for enhancing oil recovery, the viscoelastic properties of polymers have recently emerged as a promising alternative. Polymer flooding, first introduced in the late 1960s, initially focused on improving mobility control by increasing the viscosity of the displacing water (Pye, 1964; Gogarty, 1967). However, recent research has illuminated the potential of polymer viscoelasticity to enhance microscopic displacement efficiency, adding a new dimension to EOR strategies (Seright, 2017; Wang et al., 2011).

Polymer flooding as an EOR method was pioneered in the late 1960s in response to the need for more efficient waterflooding processes. Early studies by Gogarty (1967) and Pye (1964) were instrumental in demonstrating the effectiveness of this approach. Their research revealed that adding polymers to the injection water increased its viscosity, which in turn improved sweep efficiency and reduced the fingering effect—the uneven advance of the displacing fluid through the reservoir. The fundamental principle behind polymer flooding is to enhance the mobility ratio, defined as the ratio of the mobility of the displacing fluid to that of the displaced fluid (oil). Achieving a favorable mobility ratio (close to or less than one) ensures that the displacing fluid sweeps the reservoir uniformly, thereby displacing more oil. Early field applications, such as the successful trials in the Wilmington Field in California, provided compelling evidence of polymer flooding's potential to enhance oil recovery (Lake, 1989).

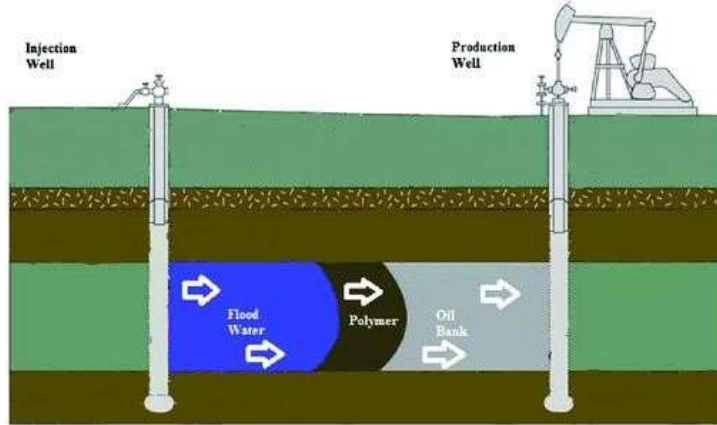


Figure 6: Polymer flood process representation [Cheraghian, et.al, 2013]

The viscoelastic properties of polymers have increasingly been recognized as critical to enhancing oil recovery. Polymers exhibit both viscous and elastic behavior, significantly influencing displacement efficiency in porous media. The viscous component of polymers helps to improve sweep efficiency by increasing the viscosity of the displacing fluid, while the elastic component generates normal stresses that can mobilize trapped oil droplets. Wang et al. (2011) and Seright (2017) emphasized the importance of polymer viscoelasticity in EOR. The elastic properties of polymers enable them to generate normal stresses as they flow through porous media, which can deform oil droplets trapped in pore throats, thereby reducing the capillary forces that hold the oil in place and facilitating its mobilization. This mechanism is particularly effective in mobilizing residual oil that remains after conventional waterflooding. The concept of the Deborah number, which is the ratio of the relaxation time of the polymer to the characteristic time of the flow, is crucial for understanding polymer viscoelasticity. A higher Deborah number indicates more pronounced elastic behavior of the polymer under flow conditions, and experimental

studies have shown that polymers with higher Deborah numbers are more effective in mobilizing residual oil (Wang et al., 2011).

The viscoelastic properties of polymers have increasingly been recognized as critical to enhancing oil recovery, as these polymers exhibit both viscous and elastic behavior, significantly influencing displacement efficiency in porous media (Azad and Trivedi, 2019). This dual behavior, known as viscoelasticity, allows polymers to adjust their flow characteristics under different shear rates and stresses within the reservoir, leading to more effective displacement of oil. Extensive experimental studies have been conducted to explore the impact of polymer viscoelasticity on oil recovery, reflecting the growing interest in this mechanism as a critical component of Enhanced Oil Recovery (EOR) strategies (Azad et al., 2019, 2020, 2021).

Viscoelasticity is particularly important in the context of EOR techniques like polymer flooding. When viscoelastic polymers are injected into a reservoir, they experience various shear rates as they move through the porous media. At low shear rates, polymers typically exhibit a Newtonian flow, where their viscosity remains constant. However, as the shear rate increases, viscoelastic polymers often demonstrate shear-thinning behavior, where their viscosity decreases. Beyond a certain critical shear rate, they can enter a shear-thickening regime, where viscosity increases due to the elastic stretching of polymer chains (Azad and Trivedi, 2019). This behavior is advantageous in EOR as it enhances sweep efficiency by improving the uniformity of the displacement front. Azad et al. (2020) further explored the influence of shear rate on polymer viscoelasticity and its implications for oil recovery, revealing that optimizing the shear rate could enhance the viscoelastic properties of polymers, thereby improving oil recovery across a range of flux rates.

The ability of viscoelastic polymers to reduce residual oil saturation (S_{or}) has been a subject of significant interest. Traditional capillary number theories, which relate the balance between viscous and capillary forces to S_{or} , suggest that polymers with higher viscosities can enhance oil recovery by improving displacement efficiency. However, viscoelastic polymers go beyond this by potentially mobilizing residual oil trapped in smaller pore spaces, thanks to the normal stresses generated by their elastic properties. These normal stresses can induce mechanisms such as the pulling effect, stripping effect, and oil-thread stabilization, which contribute to additional oil recovery (Azad and Trivedi, 2019). The viscoelastic polymers were particularly effective in mobilizing trapped oil droplets, leading to a substantial reduction in residual oil saturation.

Despite the recognized benefits, quantifying the viscoelastic effects of polymers in porous media remains challenging. Many models rely on parameters such as the Deborah number, which compares the polymer relaxation time to its residence time in the porous media. However, these models often fail to fully capture the complex interplay between shear and extensional flows within the reservoir (Azad and Trivedi, 2019). For instance, the Deborah number calculated using shear-based relaxation times may not accurately reflect the viscoelastic behavior during extensional flows, where polymers experience significant stretching at pore throats (Azad and Trivedi, 2019). Study by Levitt and Pope (2008) compared the performance of viscoelastic polymers with conventional surfactant-polymer flooding, finding that viscoelastic polymers could achieve similar or even superior recovery efficiencies under certain reservoir conditions, underscoring the potential of viscoelasticity as a key mechanism in EOR.

Building on these findings, recent work has continued to refine our understanding of polymer viscoelasticity and its role in EOR. Sheng (2017) explored the application of viscoelastic polymers in challenging reservoir conditions, demonstrating that the elasticity of these polymers can significantly improve sweep efficiency and reduce oil trapping in heterogeneous formations.

In field applications, the importance of adopting low-flux rate polymer flooding for field-realistic conditions has gained attention. Low-flux rate operations ensure that the viscoelastic effects are maximized, as polymers have sufficient time to exhibit their elastic behavior, which is crucial for mobilizing residual oil. Additionally, low-flux conditions help mitigate shear degradation of polymers, maintaining their effectiveness over longer injection periods. It is important to note that, the flux rate of polymer flood at distances away from the injection well, decreases with increase in distance. A thorough investigation and interpretation of the effects of flux with respect to distance from the injection well has been studied for various field cases around the globe (Azad and Seirght, 2024). This has been discussed in greater detail, along with its significant importance to the objectives of this study, in the literature review.

Field applications of polymer flooding have also demonstrated the practical benefits of incorporating viscoelastic polymers in EOR operations. Several field trials have been conducted to evaluate the performance of viscoelastic polymers under real reservoir conditions, providing valuable insights into the challenges and opportunities associated with implementing viscoelastic polymers in large-scale EOR projects. One significant field application involved using viscoelastic polymers in the Daqing oil field in China, where polymer flooding resulted in a substantial increase in oil recovery. The success of this

project highlighted the effectiveness of viscoelastic polymers in improving sweep efficiency and mobilizing trapped oil, leading to enhanced recovery rates (Sheng, 2010). In another field trial in the North Sea, polymer flooding demonstrated improved oil displacement and reduced residual oil saturation compared to conventional polymer flooding. This trial underscored the importance of tailoring polymer formulations to specific reservoir conditions to achieve optimal results (Sorbie, 1991).

Despite the promising results of polymer viscoelasticity in EOR, several challenges remain. One of the primary challenges is the cost associated with producing and injecting high-performance viscoelastic polymers. Developing cost-effective formulations that maintain their viscoelastic properties under reservoir conditions is critical for the widespread adoption of this technology. Additionally, the environmental impact of polymer flooding must be carefully managed. Research is ongoing to develop biodegradable and environmentally friendly polymers for use in EOR operations without causing long-term environmental harm (Olajire, 2014). Future research should focus on further understanding the mechanisms of polymer viscoelasticity at the pore scale and developing advanced modeling techniques to predict the behavior of viscoelastic polymers in complex reservoirs. Additionally, integrating polymer viscoelasticity with other EOR methods, such as IFT reduction and CO₂ injection, could create synergistic effects that enhance overall recovery efficiency.

It is crucial to emphasize the need for a more comprehensive investigation into interfacial tension (IFT) reduction and viscoelasticity for low-flux polymer flooding. These factors play a vital role in optimizing oil recovery, particularly under field-realistic conditions.

Future research must address the interplay between IFT and viscoelastic properties to fully exploit their combined potential for enhanced oil recovery.

1.5 Capillary Number (N_c)

The capillary number (N_c) is a dimensionless quantity that describes the relative importance of viscous forces to capillary forces in fluid flow within porous media. It plays a critical role in understanding the mobilization of trapped fluids, such as residual oil, during enhanced oil recovery (EOR) processes.

$$N_c = \frac{k \times \left(\frac{\Delta P}{L}\right)}{\sigma \times \cos \theta} \quad (1.2)$$

Where k represents the permeability of the medium, measured in square meters (m^2), ΔP is the pressure drop across the medium, expressed in Pascals (Pa), L denotes the length of the medium in meters (m), and σ refers to the interfacial tension between the fluids, measured in Newtons per meter (N/m), and $\cos \theta$ accounts for the wettability of the medium, where θ is the contact angle between the fluid interface and the solid surface.

The capillary number quantifies the competition between viscous forces (that promote fluid movement) and capillary forces (that resist fluid flow due to surface tension and wettability effects). A low capillary number indicates that capillary forces dominate, leading to fluid trapping in the pores. A high capillary number suggests that viscous forces are significant enough to overcome capillary forces, mobilizing trapped fluids.

1.5.1 Critical Capillary Number

The critical capillary number ($N_{c_{crit}}$), defines the point at which residual oil saturation (S_{or}) starts to decrease significantly. Beyond $N_{c_{crit}}$, viscous forces dominate, leading to effective oil recovery. The critical capillary number is defined as the point at which a significant reduction in residual oil saturation (S_{or}) occurs with an increase in the capillary number (N_c). This phenomenon is observed as a sudden drop in S_{or} beyond a specific N_c , indicating the point where viscous forces become sufficient to overcome capillary forces, thereby mobilizing the trapped oil. At the critical capillary number, S_{or} transitions from being relatively stable to decreasing rapidly, which is an important parameter for enhanced oil recovery processes.

1.5.2 Capillary Desaturation Curve (CDC)

The Capillary Desaturation Curve (CDC) establishes the relationship between the capillary number (N_c) and the residual oil saturation (S_{or}). It is a plot between N_c and S_{or} , which indicates the reduction in S_{or} with increase in N_c , with the point at which the desaturation starts (Critical Capillary Number).

A Capillary Desaturation Curve (CDC) is a key tool in oil recovery, as it highlights the flow conditions necessary for effective oil displacement within porous media.

CHAPTER 2

LITERATURE REVIEW

Among various EOR methods, interfacial tension (IFT) reduction and polymer flooding stand out as significant strategies for improving oil recovery efficiency. These techniques focus on mobilizing residual oil trapped in pore spaces through distinct yet complementary mechanisms. IFT reduction primarily addresses capillary forces by lowering the interfacial tension between oil and water, facilitating oil displacement. Meanwhile, polymer flooding leverages the viscoelastic properties of polymers to enhance sweep efficiency and displace trapped oil. Understanding the interplay between these mechanisms is vital for optimizing EOR strategies across varying reservoir conditions.

The role of viscoelasticity in polymer flooding has garnered significant attention, particularly for its potential to mobilize residual oil beyond what conventional polymers achieve. The viscoelastic behavior, characterized by the generation of normal stresses during flow through porous media, enhances microscopic displacement efficiency. Recent studies have underscored the importance of factors such as polymer molecular weight, concentration, and injection rates in influencing the extent of viscoelastic effects. Moreover, the interplay between viscoelasticity and flux rates in field-relevant scenarios has raised important questions about the scalability of laboratory observations to practical applications. This has prompted a comparative analysis of IFT reduction and polymer viscoelasticity, seeking to identify their relative effectiveness and optimal conditions for deployment.

Flux rates play a pivotal role in determining the manifestation of viscoelastic effects in polymer flooding. Laboratory studies often operate at higher flux rates, which facilitate shear thickening and enhance viscoelastic responses. However, field conditions typically involve significantly lower flux rates, challenging the relevance of laboratory findings to practical reservoir scenarios. Recent literature has highlighted this gap, emphasizing the need for experiments that simulate realistic field conditions. Comparative studies have demonstrated that while IFT reduction is effective in reducing capillary-trapped oil, viscoelastic polymers can achieve incremental oil recovery under specific conditions, particularly in low-permeability or heterogeneous reservoirs. The following given studies and literature aims to bridge the gap between laboratory and field-scale insights, providing an insightful understanding of how these mechanisms contribute to EOR under varying flux rates and reservoir characteristics.

2.1 Comparative Studies of IFT Reduction and Polymer Viscoelasticity

Comparative studies have been conducted to evaluate the relative effectiveness of interfacial tension (IFT) reduction and polymer viscoelasticity in enhancing oil recovery. These studies aim to identify the most effective strategies for maximizing oil recovery under different reservoir conditions by understanding the unique contributions of each mechanism to reducing residual oil saturation. Both IFT reduction and polymer viscoelasticity are crucial for enhancing oil recovery, but they operate through different mechanisms. IFT reduction lowers the capillary forces that trap oil in the pore spaces, facilitating its mobilization (Holm & Csaszar, 1962), while polymer viscoelasticity helps in mobilizing trapped oil by generating normal stresses that deform and displace the oil

droplets (Wang et al., 2011; Seright, 2017). Understanding how these mechanisms individually contribute to oil recovery is essential for optimizing Enhanced Oil Recovery (EOR) strategies.

IFT reduction has been a well-established method for enhancing oil recovery. Surfactants, commonly used for IFT reduction, lower the interfacial tension between oil and water, thereby reducing the capillary forces that trap oil. This process enhances the mobilization of residual oil, particularly in water-wet formations where capillary forces are significant. Holm and Csaszar (1962) demonstrated that surfactants could effectively reduce IFT and improve oil mobilization, laying the foundation for understanding the role of IFT reduction in EOR. These early studies established the critical role of IFT reduction in enhancing oil displacement efficiency in various reservoir conditions (Stegemeier, 1978; Hirasaki & Morrow, 1991).

The mechanistic understanding of how IFT reduction and polymer viscoelasticity contribute to enhanced oil recovery has been advanced by numerous studies. These studies provide valuable insights into the individual contributions of each mechanism and their comparative effectiveness under various reservoir conditions. The primary mechanism by which IFT reduction enhances oil recovery is through the reduction of capillary forces that trap oil in the pore spaces (Stegemeier, 1978; Hirasaki, Morrow, 1991). Surfactants, which are amphiphilic molecules, adsorb at the oilwater interface, reducing the interfacial tension and altering the wettability of the reservoir rock, thereby facilitating the mobilization of trapped oil. Stegemeier (1978) provided a comprehensive review of IFT reduction mechanisms, emphasizing the role of capillary pressure and wettability in oil recovery,

which is critical for designing effective surfactant formulations and optimizing IFT reduction strategies in EOR.

Numerous experimental studies have been conducted to compare the effectiveness of IFT reduction and polymer viscoelasticity in enhancing oil recovery. These studies aim to identify the most effective strategies for different reservoir conditions by evaluating the individual contributions of each mechanism. McAuliffe (1973) explored the behavior of oil-in-water emulsions, highlighting the role of surfactants in stabilizing emulsions and improving flow properties in porous media. His experiments showed that surfactants could significantly reduce IFT, leading to the formation of stable emulsions that facilitate improved oil displacement. These findings provided critical insights into the practical application of surfactants in EOR. Willhite (1986) reviewed several case studies where surfactant flooding was successfully implemented in the field, highlighting the practical benefits of IFT reduction in real-world EOR operations, demonstrating that surfactant flooding could substantially increase oil recovery rates compared to conventional waterflooding.

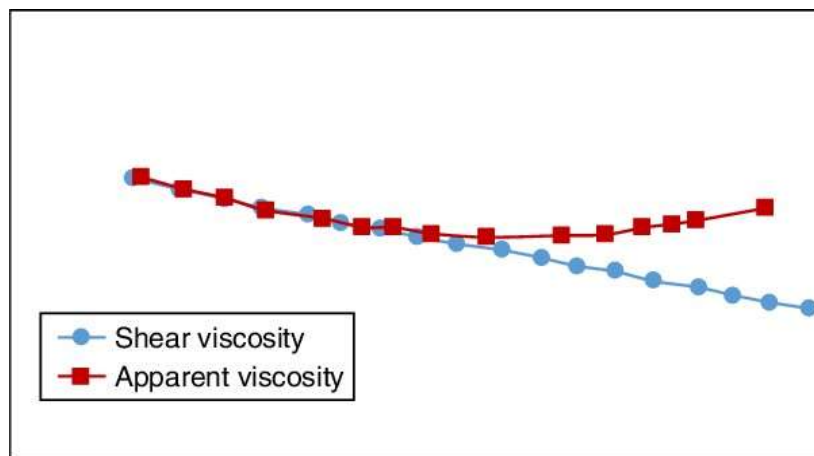


Figure 7: Porous-media behavior of the viscoelastic polymer. (reproduced from Han et al. 1995)
[Azad and Trivedi, 2019]

In the work by Azad and Trivedi (2019), they referenced the study by Han et al. (1995) to describe the behavior of viscoelastic polymers in porous media. They discussed how viscoelastic polymers, when injected into porous media, exhibit complex flow behaviors that are distinct from those of Newtonian fluids. Specifically, the viscoelastic properties of these polymers—such as their ability to generate normal stresses—can significantly influence the flow dynamics within the porous structure.

Han et al. (1995) observed that the viscoelastic nature of polymers allows them to exhibit both viscous and elastic responses when flowing through the interconnected pore spaces of the reservoir rock. This behavior can lead to enhanced oil recovery by improving the sweep efficiency and by mobilizing oil that is trapped in pore spaces due to capillary forces. The elastic component of the polymer flow can generate additional stresses on the trapped oil droplets, deforming them and reducing the capillary forces, which facilitates the displacement and recovery of the trapped oil.

Azad and Trivedi (2019) expressed the potential of viscoelastic polymers to improve oil recovery, emphasizing the importance of understanding these unique flow characteristics in optimizing the application of polymers in Enhanced Oil Recovery (EOR) processes.

While the conventional polymer flood has higher sweep efficiency (attributed to Mobility Control) but does not give higher reduction in well swept residual oil saturation, Viscoelastic polymer flood provides a greater reduction in residual oil saturation which is attributed to both- mobility control and Mobilizing Residual Oil via Enhanced Microscopic Displacement (Clarke et al. 2015; Qi et al. 2017; Azad and Trivedi 2020)

2.2 Considerations for Viscoelastic Effect

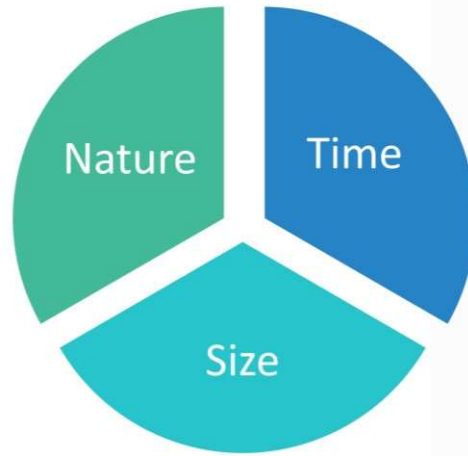


Figure 8: Factors to be considered for Viscoelastic effect

Nature of the polymer- whether the polymer is a synthetic polymer having the properties of viscoelastic stretching, or a polymer which does not show viscoelastic properties.

Time effect which can be attributed to the injection/flow rate to indicate the time the polymer is allowed to flow in porous media . For viscoelastic effect to undergo, the polymer must be studied for the relaxation time and observation time. This gives an understanding of the ability to stretch and exhibit the viscoelastic phenomena for a particular flux rate.

The size effect can be related to the flow path through which the polymer flows. When we talk about flow in tighter rock having low permeability, it provides more constriction to flow and thereby increasing the pressure drop. The non-linear viscoelasticity in the pore-scale level is higher for flow of polymer in lower permeability. This is supported by research by Azad et al 2019 ,indicating that the normal (extensional) stresses of viscoelastic polymer solutions become higher as these solutions approach the pore throat, particularly in low-permeability environments. This increase in extensional stresses is more

pronounced due to the restricted flow paths and the higher deformation of polymer chains in these narrower pores, which leads to enhanced viscoelastic effects.

Azad et al. (2019, 2020, 2021) made significant contributions to understanding the influence of polymer viscoelasticity on oil recovery, focusing on hydrolyzed polyacrylamide (HPAM) and associative polymers. Their studies highlighted the importance of extensional rheology in characterizing polymer behavior in porous media. The authors demonstrated that viscoelastic polymers with strain-hardening properties in extensional fields enhanced oil recovery compared to purely viscous polymers. Experimental results revealed that these polymers reduced residual oil saturation (S_{or}) significantly, even at capillary numbers below the critical threshold necessary for traditional oil mobilization mechanisms. The studies underscored the limitations of oscillatory rheology and the Deborah number in explaining viscoelastic effects, advocating for extensional rheology as a robust tool for predicting polymer performance in enhanced oil recovery (EOR). Incorporating extensional properties into EOR polymer selection provides a more accurate prediction of in-situ behavior and potential recovery outcomes

Comparative analysis of experimental results from studies on IFT reduction and polymer viscoelasticity provides valuable insights into the relative effectiveness of each mechanism. Sheng (2015) and Levitt and Pope (2008) conducted studies comparing the efficiency of surfactant polymer (SP) flooding to polymer flooding. Their findings indicated that while IFT reduction is crucial for mobilizing capillary-trapped oil, the viscoelastic properties of polymers play a significant role in enhancing oil recovery, especially under certain reservoir conditions. Azad et al. (2020) further investigated the impact of shear rate on polymer viscoelasticity and its implications for oil recovery. They

found that optimizing the shear rate could enhance the viscoelastic properties of polymers, leading to improved oil recovery at different flux rates, underscoring the importance of tailoring EOR strategies to specific reservoir conditions to maximize the effectiveness of each mechanism.

Understanding the individual contributions of IFT reduction and polymer viscoelasticity is crucial for optimizing EOR strategies. The practical implications of these findings are significant for EOR operations, allowing operators to design tailored strategies that maximize oil recovery. For instance, in reservoirs where capillary forces are a major barrier to oil recovery, surfactant flooding with a focus on IFT reduction may be more effective. Conversely, in heterogeneous reservoirs with significant variations in capillary forces, polymer flooding with viscoelastic polymers may provide superior results. Future research should focus on further elucidating the mechanisms of IFT reduction and polymer viscoelasticity at the pore scale, developing advanced modeling techniques and experimental studies to understand the complex interactions between these mechanisms and reservoir conditions. Comparative studies should continue to explore the relative effectiveness of IFT reduction and polymer viscoelasticity under a wide range of reservoir conditions, providing valuable insights for optimizing EOR strategies and advancing the field of enhanced oil recovery. The viscoelastic effect proven for its ability to increase the viscous forces, thereby reducing residual oil saturation, is strongly dependent on the physiochemical properties and the considerations as discussed in the previous studies.

2.3 Observations reported by different researchers regarding the effect of polymer viscoelasticity on oil recovery

The table summarizes various experimental studies that analyze polymer flooding techniques for enhanced oil recovery, focusing on polymer properties, core characteristics, and observed outcomes (Azad and Trivedi, 2020).

Table 1: Observations reported by different researchers regarding the effect of polymer viscoelasticity on oil recovery

Authors	Conditions for Polymer Comparisons	Polymer Properties	Core Details and Oil Viscosity	Flux/Shear Rate	Observations
Xia et al.(2004)	Similar shear viscosities	Polymer: HPAM(17 MDa, 500-2,500 ppm) and glycerin(0.000092 MDa 800.000-960,000 ppm) Salinity: 508 ppm	Formation: Artificial core k: 1062 ± 52 $\Phi: 0.235 \pm 0.001$ μ_o : 15 cp	4.52 (ft/D)	Additional incremental oil (7%) was recovered by HPAM compared with glycerin. HPAM corresponds to higher first-normal-stress difference
Wu et al. (2007)	Same capillary numbers	Polymer: HPAM (18 MDa,500-2,500 ppm)Salinity: 508 ppm	Formation: Artificial core k: - Φ : - μ_o : 9.8 cp	3.28 (ft/D)	High-concentration HPAM solutions characterized by higher first-normal-stress difference and higher IT contributed to higher Sor reduction during surfactant polymer flooding than low-concentration HAM characterized by lower first-normal-stress difference and lower IFT.
Urbissinova et al. (2010)	Similar shear viscosities	Polymer: Blended Sample A(9 MDa, 12,500 ppm) and Blended Sample B(10 MDa, 10,000 ppm) Salinity: 0	Formation: Spherical glass beads k: 150 md Φ : 0.4285 μ_o : 33.5 cp	15-100 seconds ⁻¹ (shear rate)	Higher oil-recovery factor was shown by Blended Sample A that corresponded to higher polydispersity index and elastic modulus than did Blended Sample B.

Veerabhadrapa et al.(2013)	Similar shear viscosity	Polymer: Four blended polymeric samples(20 MDa, 1,000 ppm)Salinity: 0	Formation: Sandpack k: 2900 ± 20 md Φ : 0.3585 ± 0.001 μo : 27.8 cp	10 ft/D	The combination with higher elastic modulus contributed to stable displacement, higher breakthrough recovery, and ultimate recovery factor
Vermolen et al. (2014)	Varying oscillatory relaxation time and shear viscosity	Polymer: HPAM 3230(3.6 MDa, 6,140 ppm) and HPAM 3530 (16 MDa, 1,300-4,230 ppm) Salinity: 623-6,230 ppm	Formation: Bentheimer core k: 859 md Φ : 0.22 μo : 9 cp	1-3 (ft/D)	Polymer characterized by higher oscillatory relaxation time contributed to higher Sor reduction at 1 ft/D during 9-cp light-oil recovery. Flux rate of 3 ft/D contributed to higher Sor reduction than did 1 ft/D during light-oil recovery.
Vermolen et al. (2014)	Varying oscillatory relaxation time and shear viscosity	Polymer: HPAM 3230(3.6 MDa, 6, 140 ppm) and HPAM 3530 (16 MDa, 1,300-4.230 ppm) Salinity: 623-6,230 ppm	Formation: Bentheimer core k: 581 md Φ : 0.22 μo : 300 cp	3.28 (ft/D)	No Sor reduction was observed because of the increased polymer elasticity and flux rate during 300cp heavy-oil recovery.
Clarke et al.(2015)	Varying shear and apparent viscosity	Polymer: HPAM 3130(3.6 MDa, 6,000 ppm) and HPAM 6040 (30-36 MDa, 640 ppm) Salinity: 4,800 pm	Formation: Sandstone cores k: 450 ± 15 md Φ : 0.23 μo : 34 cp	1 ft/D	HPAM 6040 characterized by higher elastic turbulence contributed to higher Sor reduction than HAM 3130 despite possessing lower shear and apparent viscosity.
Qi et al.(2017)	Similar shear viscosity	Polymer: HPAM 3630(18-20 MDa, 2,100 ppm) and glycerin(0.000092 MDa, ~860,000-890,000 ppm) Salinity: 11.000 pm	Formation: Bentheimer core k: 2,220md Φ : 0.22 μo : 120 cp	0.96 ft/D	HAM 3630 corresponding to higher Deborah number contributed to higher Sor reduction compared with preceding glycerin flood in the same core.
Erincik et al.(2018)	Similar shear viscosity, varying Deborah number	Polymer: HAM 3630(18-20 MDa, 2,000-3,548 ppm) Salinity: 1,400-24.300 ppm	Formation: Bentheimer core k: 1480 md Φ : 0.25 μo : 114 cp	1 ft/D	High-saline solutions characterized by lower oscillatory Deborah number contributed to higher Sor reduction than low-saline HAM solutions characterized by higher oscillatory Deborah number in same core

Seright et al. (2018)	Varying shear viscosity	Polymer: HPAM 3630(18-20 MDa, 725-5,250 ppm) Salinity: 19,000 ppm	Formation: CactusLake sandstone coreko: 1,217 $\pm$ 418 md b: 0.3387 $\div$ 0.0043 Ho: 1,610 cp k: 1217 $\pm$ 418 md Φ : 0.3387 $\pm$ 0.0043	1 ft/D (Darcy Velocity)	No Sor reduction was observed by high-concentrated(5,250 ppm) polymer solutions, compared with 2,690 pm polymer solutions during the recovery of 1,610-cp heavy oil.
			μ o: 1610 cp		
Azad et al.(2018a)	Similar shear viscosity	Polymer: HPAM 3630(18-20 MDa, 2,000 pm) and associative polymer(18-20 MDa, 2,000 pm) Salinity: 0	Formation: Sandpack k: 1550 $\pm$ 1560 md Φ : 0.4 μ o: 540 cp	4.6 ft/D	Associative polymer characterized by the presence of hydrophobic group contributed to higher pressure drop, higher permeability reduction, and marginal increment in oil recovery. Extensional rheological properties of associative polymer were higher than HAM 3630.

2.4 Field-Relevant Observations on Low Flux Rates and Polymer Flooding- Insights from Azad and Seright (2024)

2.4.1 Importance of Low Flux in Polymer Flooding

Azad and Seright (2024), explored the role of flux rate in the effectiveness of polymer flooding for reducing residual oil saturation (Sor). The study meticulously highlights how laboratory experiments often exaggerate the benefits of polymer viscoelasticity because they are conducted at flux rates far exceeding those realistically achieved in field conditions.

2.4.2 Viscoelasticity and Shear Thickening: Laboratory vs. Field Observations

Viscoelasticity is a rheological property wherein the polymer solution exhibits time-dependent behavior under shear stress. This effect becomes pronounced at high flux rates due to shear thickening, a phenomenon where the apparent viscosity of the polymer solution increases with shear rate. The onset of shear thickening marks the point at which viscoelastic forces can potentially mobilize capillary-trapped oil, reducing Sor (Hirasaki and Pope, 1974; Seright, 1983).

While several laboratory studies (e.g., Ehrenfred, 2013; Koh et al., 2017; Qi et al., 2018) have observed Sor reduction attributed to shear-thickening-induced viscoelastic effects, Azad and Seright (2024) argue that the Darcy velocity (flux rate) achieved in these experiments often surpasses realistic reservoir conditions. For instance:

- Laboratory experiments commonly operate at flux rates >1 ft/day, facilitating shear thickening behavior and leading to Sor reduction.
- In contrast, field polymer floods typically operate at flux rates as low as 0.01–0.2 ft/day, which are insufficient to trigger shear thickening.

2.4.3 Field-Relevant Flux Rates: A Critical Comparison

Azad and Seright (2024) provide a comprehensive analysis of polymer flooding projects across nine countries (USA, Canada, China, Oman, etc.), comparing field flux rates with the onset velocity for viscoelasticity. Using well-documented cases such as Milne Point (USA), Pelican Lake (Canada), and Matzen (Austria), the authors illustrate the following:

a) **Low Flux Rates in Horizontal Wells:**

- In most field cases, horizontal wells exhibit extremely low Darcy velocities (0.01–0.2 ft/day) due to the extended well lengths and significant reservoir thickness. For example:
- At Milne Point, with horizontal well lengths of 5000–5400 ft, the average Darcy velocity was 0.05–0.12 ft/day—well below the onset shear thickening velocity of 0.43 ft/day (Manichand et al., 2013).
- At Pelican Lake, even with a reduced well spacing of 100 ft, the maximum Darcy velocity achieved was 2.05 ft/day, still insufficient to conclusively induce viscoelasticity across the reservoir.

b) **Vertical Wells and Limited Velocity Regions:**

- Vertical injectors achieve slightly higher velocities near the wellbore, but this effect diminishes rapidly with radial distance. For instance:
- In low-permeability reservoirs (<200 mD), onset shear thickening can occur at flux rates as low as 0.17 ft/day. However, Azad and Seright (2024) estimate that only 2–3% of the reservoir volume experiences velocities high enough for viscoelastic effects to manifest.

The rest of the reservoir remains at flux rates insufficient for Sor reduction.

2.4.4 Alternative Mechanisms Influencing Sor Reduction

While shear thickening remains improbable in most field conditions, Azad and Seright (2024) acknowledge that other mechanisms may contribute to incremental oil recovery:

- Wettability Alteration: Polymer-induced changes in rock wettability have been shown to enhance oil recovery (AlSofi et al., 2019; Li et al., 2021). However, this effect is more pronounced in low-viscosity oils and carbonate formations.
- Secondary vs. Tertiary Flooding: Higher recovery factors have been observed during secondary polymer flooding compared to tertiary flooding due to improved sweep efficiency and reduced snap-off effects (Huh and Pope, 2008; Ehrenfred, 2013).
- Pressure Gradients: Even at low flux rates, regions with significant pressure gradients can experience localized mobilization of trapped oil.

2.4.5 Case Study: Matzen Field—A Unique Scenario

The Matzen Field in Austria represents an extreme case where the combination of short horizontal wells (1210 ft) and low reservoir thickness (10 ft) resulted in an average Darcy velocity of 1.16 ft/day. This value is close to the predicted onset velocity for viscoelasticity in low-permeability reservoirs (~1.18 ft/day for 100 mD). However, Azad and Seright (2024) caution that while this may appear promising, the overall reservoir conditions—such as permeability heterogeneity and limited well spacing—still limit the macroscopic manifestation of viscoelastic effects.

2.4.6 Relevance to the Study

The findings presented by Azad and Seright (2024) are highly relevant to this study, as the experiments will be conducted at low flux rates starting from 0.05 ft/day—conditions that closely align with realistic field scenarios. Their analysis highlights that, while laboratory studies often operate at flux rates exceeding 1 ft/day to observe shear-thickening and

viscoelastic effects, such conditions rarely occur in the field. By conducting experiments at low flux rates, this study aims to bridge the gap between laboratory results and practical field conditions, ensuring that the observed microscopic recovery mechanisms, such as viscoelasticity and interfacial tension (IFT) reduction, are representative of actual reservoir behavior in sandstone formations.

At flux rates as low as 0.05–0.2 ft/day, shear thickening is less likely to occur across the entire reservoir volume. However, localized effects near the wellbore or within pressure gradient zones may still contribute to incremental oil recovery. The experiments will focus on evaluating whether subtle viscoelastic effects, in conjunction with wettability alteration and IFT reduction, can mobilize residual oil under low-flux conditions. This approach is particularly critical for sandstone reservoirs, where reservoir heterogeneity and permeability variations influence fluid flow and recovery mechanisms. By systematically investigating these effects, the study will provide insights into how low flux rates impact Sor reduction, thereby enhancing the understanding of microscopic oil recovery mechanisms.

By operating within the realistic flux range (starting at 0.05 ft/day), this study addresses a key recommendation from Azad and Seright (2024) to simulate field-relevant conditions. The results will contribute to validating whether viscoelastic effects are significant at low flux rates and whether alternative mechanisms, such as wettability alteration or localized pressure gradients, play a more dominant role. This experimental design ensures that the findings are directly applicable to field-scale polymer flooding projects, offering a more accurate assessment of the potential for microscopic oil recovery enhancement in sandstone formations.

2.5 Comparative Perspective from Other Studies

Azad and Trivedi (2018) reinforce the positive role of viscoelastic polymers, particularly in improving sweep efficiency and mobilizing oil under low flux conditions (~ 1 ft/day). Their experiments demonstrate that polymers with higher shear viscosity contribute to faster and more effective sweep efficiency, leading to better oil recovery. Barri et al. (2023) further demonstrated that low molecular weight (MW) polymers, when used in low-permeability formations at a Darcy velocity as low as 0.2 ft/day, can achieve incremental oil recovery through viscoelastic effects. These findings challenge the conventional belief that viscoelastic effects are only significant at high flux rates, showcasing their applicability in realistic field scenarios. Both studies highlight the untapped potential of polymer flooding at field-relevant conditions, where viscoelasticity, even at reduced magnitudes, can still contribute to incremental oil recovery.

By incorporating these insights, the current study is well-positioned to build upon the support and results and interpretations made in the aforementioned literature. These findings ensure that the evaluation of viscoelastic and interfacial tension (IFT) effects in sandstone formations remains grounded in proven, field-applicable principles.

2.6 Problem Statement

Despite significant advancements in understanding the mechanisms of interfacial tension (IFT) reduction and polymer viscoelasticity, there remains a critical need for systematic comparative studies to determine the dominant microscopic recovery mechanism in

sandstone formation. This research is essential for optimizing Enhanced Oil Recovery (EOR) strategies and maximizing oil recovery in water-wet sandstone formations.

The primary objective of this research is to compare the relative effectiveness of IFT reduction and polymer viscoelasticity in enhancing oil recovery in water-wet sandstone formations. The research involves conducting a series of controlled experiments designed to systematically evaluate two EOR solutions with similar viscosity but distinct IFT and viscoelastic properties. Specifically, a surfactant-glycerol solution was needed to be formulated to possess IFT reduction capabilities without any viscoelastic properties, while a synthetic polymer solution was to be designed to exhibit viscoelastic characteristics without reducing IFT. This approach will help to identify and address the dominant mechanism responsible for mobilizing residual oil trapped by capillary forces in these reservoirs. The hypothesis guiding this research is that, while IFT reduction decreases capillary forces at the oil-water interface, polymer viscoelasticity – non-linear viscoelasticity in especially, induces elastic stresses that effectively mobilize trapped oil. The study systematically investigates which of these mechanisms proves more effective for water-wet sandstone formation.

To study the relative effects of viscoelasticity and IFT on microscopic oil recovery, viscosity had to be ruled out as a variable from the EOR solutions. The Surfactant-glycerol solution having IFT-reducing surfactants is needed to be considered to achieve significant IFT reduction without introducing viscoelasticity. Conversely, selection of a synthetic polymer with similar viscosity for its viscoelastic properties but without any IFT reduction capability is required to assess the same. This controlled experimental setup will address the differences in oil recovery that attributed solely to the targeted mechanisms.

CHAPTER 3

METHODOLOGY

The research involves the following key experimental steps:

3.1 Formulation of EOR Solutions

The Surfactant-glycerol solution was formulated using a combination of surfactants that effectively reduce IFT. The synthetic polymer solution is chosen for its viscoelastic properties, ensuring both solutions have matched viscosities to isolate the effects of IFT reduction and viscoelasticity.

3.1.1 Preparation of Brine

The brine was prepared by dissolving salts in deionized water in the specified composition, followed by filtration to remove any impurities.

Table 2: Composition of Brine

Salts	European Brine EU (mg/L)	10 times European Brine 10xEU (mg/L)
NaCl	3,115	31,150
NaHCO ₃	1,310	13,100
Na ₂ SO ₄	239	2,390
KCl	54	540
CaCl ₂	96	960
MgCl ₂	93	930

3.1.2 IFT Measurements for Brine and Surfactant Concentration Screening

The interfacial tension (IFT) measurements were conducted using a KRÜSS spinning drop tensiometer equipped with a high-resolution camera to accurately observe the behavior of the oil droplet within the brine solution. Prior to starting the experiment, the fluids were prepared, including the major fluid (brine) and the dispersed fluid (oil), ensuring they were free from air bubbles and contaminants by degassing if necessary. A clean, dry glass capillary tube was mounted onto the tensiometer, and the major fluid (brine) was carefully injected into the tube using a syringe to avoid air entrapment. The capillary tube was filled to approximately 80–90% of its length to allow for proper fluid dynamics during rotation.



Figure 9: KRÜSS Spinning Drop Tensiometer



Figure 10: Anton Paar Density Meter

The Anton Paar Density Meter was used to accurately determine the density of the solutions employed in the IFT measurements using the spinning drop tensiometer. Prior to measurement, the instrument was calibrated with standard fluids to ensure precision. The prepared brine solutions, polymer solutions, and oil samples were carefully loaded into the density meter to measure their densities at the ambient experimental temperature. The densities obtained were critical for calculating the interfacial tension (IFT) using the Vonnegut equation, which requires the density difference between the two fluids (oil and brine).

Once the major fluid was in place, a small oil droplet was introduced at one end of the capillary tube using a fine-tipped syringe. The droplet was carefully positioned so that it remained suspended within the brine and did not contact the capillary walls. The capillary tube was then securely mounted in the tensiometer's rotation system, and the integrated camera was focused to ensure a clear and undistorted image of the oil droplet. The rotational speed of the capillary was gradually increased, inducing centrifugal forces that

caused the oil droplet to elongate along the axis of rotation. The rotational speed was adjusted in steps, typically ranging from 500 to 6000 RPM, until the droplet reached a stable, steady shape at equilibrium.

At this point, the dimensions of the oil droplet were captured using the tensiometer's camera system. The length and diameter of the droplet were measured using the tensiometer's software, ensuring precision by taking measurements at the widest part of the droplet. The interfacial tension was then calculated using the Vonnegut equation, which relates the droplet dimensions, rotational speed, and density difference between the brine (major fluid) and oil (dispersed fluid). To ensure accuracy, multiple measurements were taken at varying rotational speeds, and the consistency of the IFT values was verified.

After completing the measurements, the capillary tube was carefully removed and cleaned to remove any residual fluids. The cleaning process involved rinsing with a suitable solvent followed by deionized water to prevent contamination during subsequent experiments. The capillary tube was then dried thoroughly before reuse. Throughout the procedure, precautions were taken to maintain a constant temperature, optimize lighting and focus for precise image capture, and avoid introducing bubbles that could distort the droplet shape. This systematic approach ensured reliable and repeatable IFT measurements with the oil droplet initially placed at one end of the capillary tube within the brine solution.

3.1.3 Preparation of Polymer

The polymer solution was prepared by adding the required amount of HPAM 3630 (Hydrolyzed Polyacrylamide polymer with a molecular weight of 3,630 kilodaltons (kDa)) to achieve a concentration of 2000 ppm. A vortex was created in the brine solution

(10xEU), and the polymer was added slowly to avoid clumping. The solution was then stirred at 250 RPM for 24 hours using a magnetic stirrer to ensure complete dissolution and homogeneity.

Rheological tests was done to determine the viscoelastic properties of the synthetic polymer solution, focusing on parameters such as the zero-shear viscosity, shear-thinning and shear thickening to characterize its linear and non-linear viscoelastic behavior.

3.1.4 Preparation of Surfactant- Glycerol Solution

The surfactant used in this study to prepare the solution is Hexacetyltrimethylammonium bromide (known as CTAB). Viscous Glycerol was added to Surfactant solution to match the viscosity of the polymer solution. A series of IFT measurements was conducted to quantify the reduction achieved by the Surfactant-Glycerol solution. This is done by a screening of different concentrations and combinations of surfactant and salinity at the same viscosity of that achieved by the polymer solution of comparison.

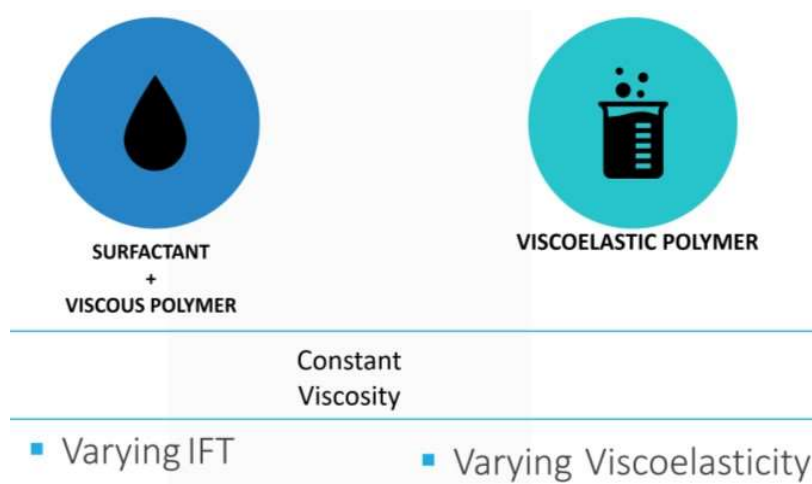


Figure 11: Condition set and mechanisms to be compared for the prepared solutions

3.2 Wettability

The wettability of Bentheimer sandstone chips was measured using a KRÜSS contact angle goniometer and the sessile drop method. Small chips were cut from a Bentheimer sandstone sample, ensuring consistency in size and surface roughness. These chips were then thoroughly saturated with brine. Three solutions were prepared for the experiment: deionized (DI) water, a viscoelastic polymer solution, and a surfactant-glycerol solution. The density of each solution was measured and recorded prior to the wettability measurements.

For the measurements, each chip was immersed in the corresponding solution to create a uniform wetting environment. A controlled oil drop was then released onto the surface of the immersed chip using a precision needle, maintaining consistency in drop volume across all samples. The contact angle of the oil drop was measured using the KRÜSS goniometer software.

3.3 Coreflooding

3.3.1 Core Preparation

The cores were prepared by cutting them to dimensions of 4 inches in length and 1.5 inches in diameter. The cores were then placed in an oven to ensure complete drying. Once dry, the porosity of the cores was determined using VINCI helium porosimetry, which provides an accurate measurement of pore volume. Following the porosity measurement, the dry weight of each core was recorded.

The dried cores were then subjected to vacuuming in a pressure cell to remove any residual air and ensure proper fluid saturation. After vacuuming, the cores were saturated in the same pressure cell at 2000 psi for 24 hours to achieve complete brine saturation. This process ensured that the cores were fully prepared for subsequent flooding experiments.

The permeability of the core was determined using Darcy's law by injecting brine at various flow rates and recording the corresponding pressure differentials across the core.

The two cores selected for the polymer flood and surfactant flood, had similar permeability.

3.3.2 Coreflood Setup



Figure 12: Coreflood Setup

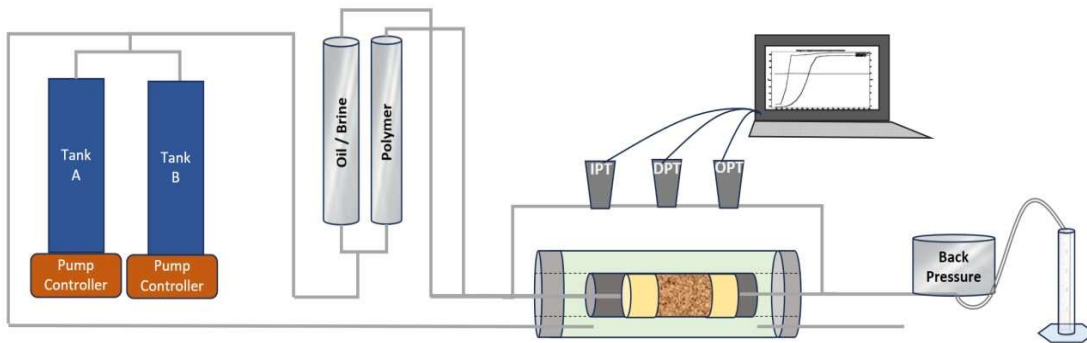


Figure 13: Schematic of the coredflood setup

The coreflood apparatus was prepared by loading the accumulators with oil, brine, and polymer solutions, which were used for oil saturation, waterflooding, and polymer flooding stages. The confinement pressure was maintained at 1500 psi, and the backpressure was set to 1000 psi. To ensure system integrity, the backpressure line was pressurized and observed for 24 hours to check for any potential leakage.

The experimental setup involved accumulator units controlled by two Teledyne Pump Controllers to manage the fluid flow and pressures. The accumulator lines for oil, brine, and polymer were connected to the core holder via various valves to facilitate controlled flooding of each fluid and to maintain confinement pressure.

The coreflood apparatus utilized Tank A of the pump controller to regulate the confinement pressure. Tank A was connected to the confinement pressure line of the core holder. The confinement pressure was achieved incrementally by inputting constant pressure values via the pump controller. The pressure was gradually increased in steps of 10, 50, 100, 200, 500, up to 1500 psi.

Tank B of the pump controller was utilized for initiating fluid injection under constant flow rate conditions. This tank was connected to the accumulator units containing oil, brine, or polymer solutions. The accumulator output was, in turn, connected to the input line of the core holder, enabling flow rate-driven fluid injection during coreflood experiments.

3.4 Recording Oil Recovery for increasing flux rates

The methodology followed for both cores was similar, with the only difference being the type of flooding conducted. In the first core, polymer flooding was performed, while in the second core, surfactant-glycerol flooding was carried out.

3.4.1 Brine Saturation

- The core was initially saturated with brine to ensure complete pore filling.
- Pressurization was applied to confirm uniform brine saturation throughout the core.
- Brine saturation was verified by comparing the dry and wet weights of the core.

3.4.2 Oil Injection

- After brine saturation, oil was injected into the core to displace brine and establish initial oil saturation.
- Oil injection was carried out for at least 3-4 pore volumes to achieve uniform oil saturation.
- The volume of water displaced during oil injection was measured to calculate the oil in place (OIP).
- NMR measurements were used to support the determination of oil and water saturations.

3.4.3 Water Flooding

- Water flooding was initiated to displace oil from the core.
- Water was injected at increasing Darcy velocities (2, 4, 8, and 12 ft/day) and the amount of oil recovered at each rate was recorded.

- Flooding continued until no further oil could be recovered (For 3-4 PVs-Pore volumes), ensuring the presence of well-swept residual oil saturation.

3.4.4 Polymer Flooding/Surfactant Flood

Polymer flooding was conducted for the first core and Surfactant flooding for the second core, after water flooding to target residual oil.

They were injected at different rates ranging from lower to high flux rates (0.05, 0.07, 0.1, 0.2, 0.5, 1, 2, 3, 4, 8, 16, 32 ft/day Darcy Velocities) and the additional oil recovered during each rate was recorded.

The process was monitored to assess the efficiency of polymer flooding and surfactant flooding at different rates, in enhancing oil recovery.

3.5 NMR (T_2 and Saturation Profile)

The NMR (Nuclear Magnetic Resonance) measurements, including T_2 relaxation times and the saturation profile, were conducted using an Oxford Instruments NMR system. The procedure was carried out in multiple stages: waterflooding, oil saturation, and post-polymer flood to evaluate fluid distribution and pore-scale behavior throughout the experiment.

Before starting the core measurements, the T_2 of the bulk fluids (brine and oil) was first measured to establish a reference. The fluids were placed in sealed containers, and the T_2 relaxation times were recorded using the Oxford Instruments system. This step provided the baseline values necessary for subsequent core analysis.

Next, the core sample preparation process was initiated. The core dimensions (length and diameter) were precisely measured using Vernier calipers to ensure accurate data input for NMR calculations. The core surface was carefully examined, and any droplets of fluid on the surface were removed to prevent overestimation of saturation. Once the core surface was clean, it was loaded into the NMR instrument for analysis.

The T_2 relaxation time measurements were performed under controlled conditions. The T_2 signal distribution provides insights into the pore-size distribution and fluid saturation within the core. To determine the T_2 max values, the H index value of the instrument was input into the analysis software. This index corresponds to the specific NMR instrument calibration parameters, allowing accurate estimation of the T_2 cutoff and maximum values.

The NMR measurements were repeated at different stages of the experiment, including after waterflooding, oil saturation, and post-polymer flood. These results were subsequently analyzed to generate the saturation profile and T_2 relaxation distributions at each stage.

The analyzed NMR results is presented to provide an evaluation of fluid distribution in pores, saturation changes, and the effectiveness of the flooding processes.

3.6 Capillary Desaturation Curve Generation

The Capillary Desaturation Curve (CDC) is generated by plotting the Residual Oil Saturation with respect to the Capillary Number (N_c).

The dimensionless and normalized Capillary number (N_c) is calculated with the experimental data obtained. It is crucial to estimate the same using compatible units, preferably S.I units.

CHAPTER 4

RESULTS AND CONCLUSION

4.1 Interfacial Tension (IFT) Measurements

4.1.1 Brine

The interfacial tension (IFT) measurements were conducted using a KRÜSS spinning drop tensiometer to determine which salinity condition, between European Brine (EU) and 10 times the salinity of European Brine (10xEU), provided the lowest IFT when mixed with varying surfactant concentrations. The results showed that the 10x European Brine (10xEU) provided significantly lower IFT values compared to the standard European Brine (EU) for all surfactant concentrations tested. At a surfactant concentration of 10 ppm, the IFT in 10xEU was 0.005707 mN/m, while for the same concentration in European Brine (EU), the IFT was much higher at 0.053892 mN/m. This highlights the superior performance of the surfactant in the high salinity 10xEU solution.

4.1.2 Surfactant Solutions

Surfactant solutions of varying concentrations were tested to determine their interfacial tension (IFT) with oil in both European Brine (EU) and 10x European Brine (10xEU) using a spinning drop tensiometer. The experiments aimed to evaluate the efficiency of the surfactant in reducing IFT under standard and high-salinity conditions.

The results, as presented in the table below, demonstrate the impact of surfactant concentration on IFT reduction. A significant reduction in IFT was observed at low surfactant concentrations, with further variations based on the salinity of the brine solution. The 10x European Brine generally showed lower IFT values compared to the standard European Brine, highlighting the enhanced performance of the surfactant in high-salinity environments.

Table 3: IFT Measurements for different concentrations of surfactant for both brines

	IFT Measurements in mN/m for different brines	
Surfactant Conc.	EU	10xEU
Base	10.78	8.764
10ppm	0.053892	0.005707
50ppm	0.131855	0.02
100ppm	0.1235	0.084
250ppm	0.36	0.11
500ppm	0.532	-
1000ppm	0.342	-
2000 ppm	0.432	-
3000 ppm	0.446	-



Figure 14: IFT Measurement and Observation for EU Brine at 10ppm Surfactant

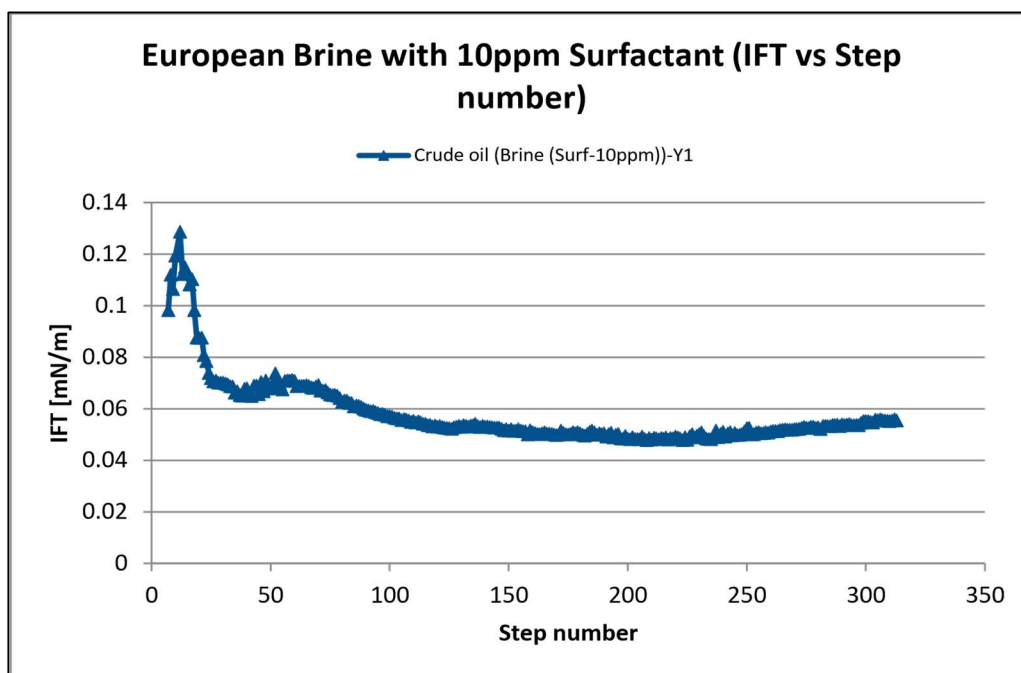


Figure 15: IFT of EU brine with 10 ppm surfactant vs. step number

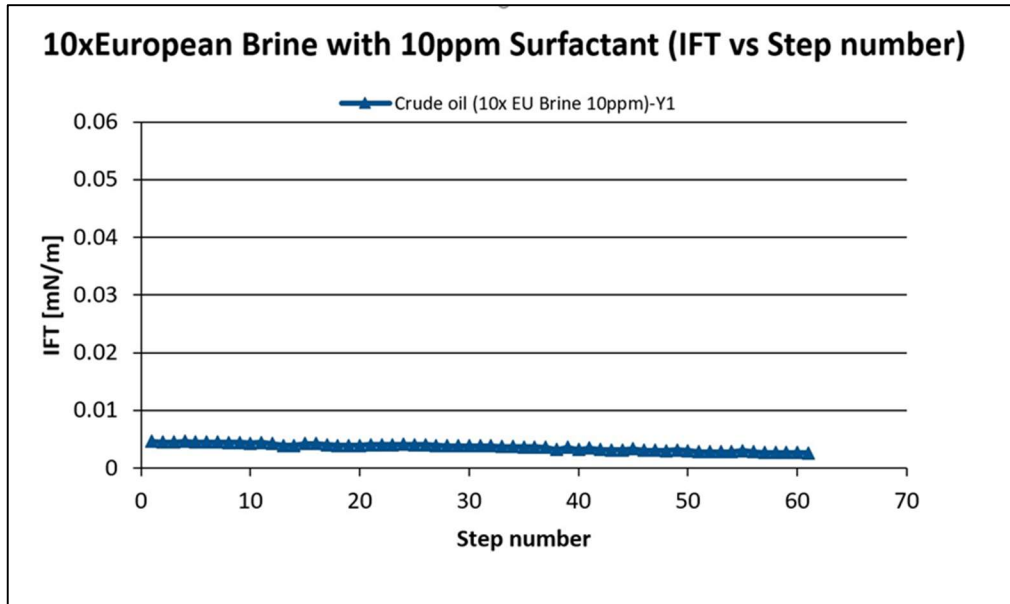


Figure 16: IFT of 10xEU brine with 10 ppm surfactant vs. step number

Based on these findings, 10xEU brine was selected as the base solution to prepare two solutions for further comparison under controlled viscosity conditions. The first solution was prepared by mixing 10xEU with HPAM 3630 polymer at a concentration of 2000 ppm, and the IFT for this system was measured as 16.4 mN/m at a rotational speed of 6000 RPM. The second solution was prepared by adding glycerol to the 10xEU brine with 10 ppm surfactant to match the viscosity of the first solution. Glycerol, being purely viscous and non-viscoelastic, ensured that the viscosity of the system was comparable without introducing viscoelastic effects. The addition of glycerol was done in batches, and the process continued until the viscosity of the glycerol-surfactant-brine solution matched the Newtonian viscosity of the viscoelastic polymer solution. This ensured a proper comparison between the two systems under similar viscosity conditions. This match of viscosity was done using the Antor Paar Rheometer.

The IFT for the second system, containing glycerol and surfactant-brine, was measured as 8.15 mN/m, which is significantly lower than the polymer-based system's IFT of 16.4 mN/m. This comparison demonstrates that the glycerol-brine-surfactant system was far more effective in reducing interfacial tension despite both systems having comparable viscosities. The addition of surfactant in the glycerol-brine system played a dominant role in achieving this low IFT value, whereas the polymer solution, while contributing to viscosity, did not reduce the interfacial tension as efficiently.



Figure 17: IFT Measurement and Observation for Surfactant Glycerol solution

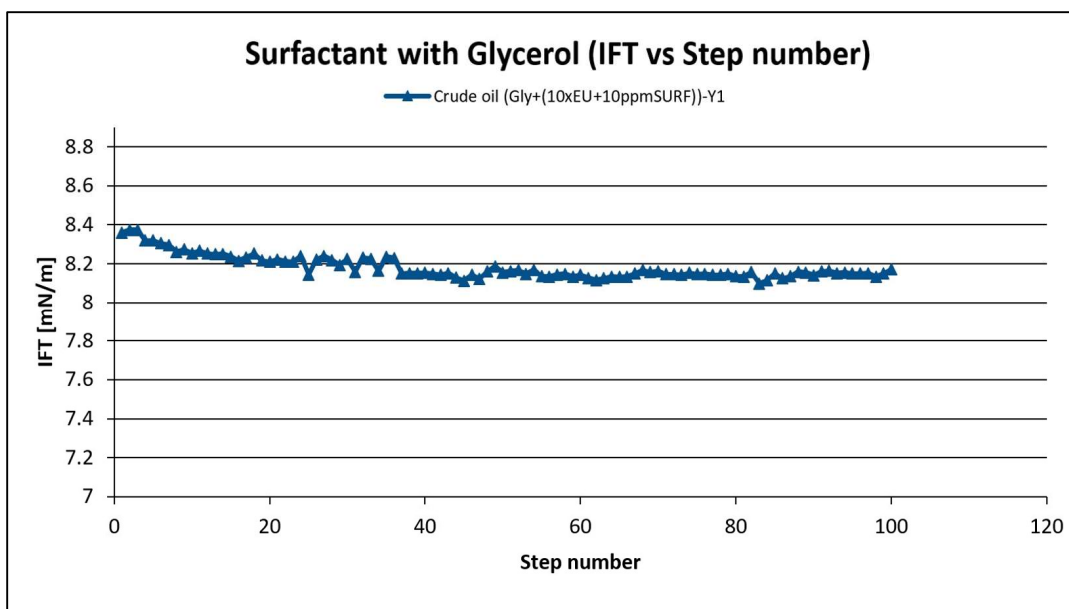


Figure 18: IFT of Surfactant Glycerol solution vs. step number

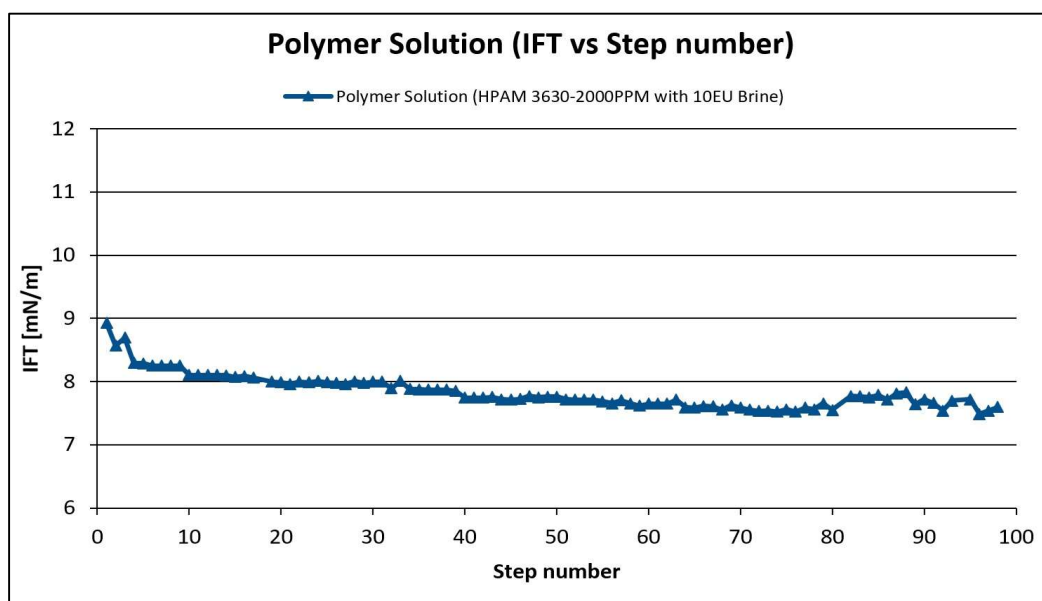


Figure 19: IFT Polymer solution vs. step number

The results emphasize that viscosity alone does not dictate interfacial tension reduction, and the presence of surfactants is critical for achieving ultra-low IFT values. Furthermore, the superior performance of the glycerol-brine-surfactant system highlights the importance

of 10x salinity in enhancing surfactant efficiency, as well as the careful preparation and adjustment of the system to match viscosity for reliable comparisons.

4.2 Rheology

Rheometer used- **Anton Paar MCR 702e**

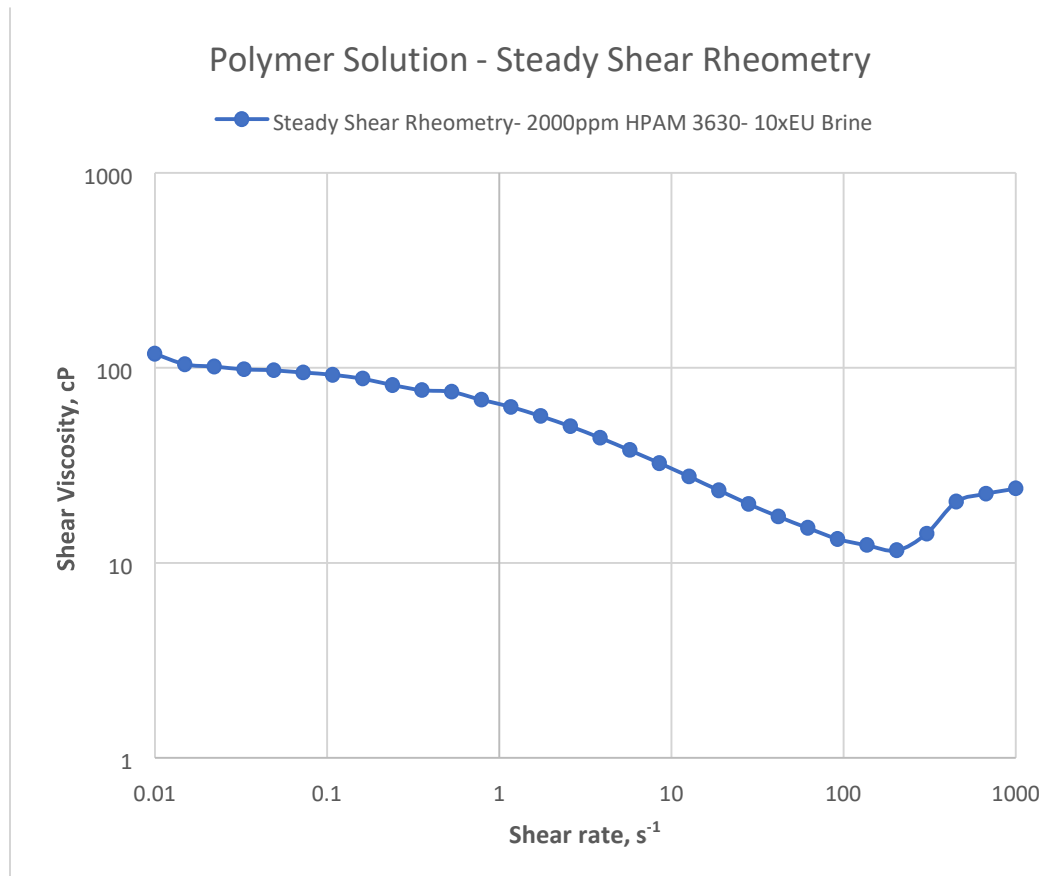


Figure 20: Steady Shear Rheology of the Polymer Solution

The Newtonian viscosity of the polymer solution was found to be 100cP. Viscous glycerol was added to Surfactant solution to match the viscosity of the polymer solution of 100cP.

4.3 Porosity and Permeability Measurements

Porosity and permeability are critical rock properties that significantly influence fluid flow and oil recovery during core flooding experiments. Porosity refers to the fraction of the total volume of the rock that is occupied by void spaces or pores, and it determines the storage capacity of the rock for fluids. Permeability refers to the ability of the rock to transmit fluids through its pore spaces and is directly related to the ease of fluid flow during flooding experiments.

For the Bentheimer cores used in these experiments, porosity and permeability were measured as follows:

Table 4: Porosity and Permeability measurements of the Bentheimer cores used

Core	Permeability (k)	Porosity (ϕ)
Polymer Flood Core (P.F.)	1758 mD	22.46%
Surfactant Flood Core (S.F.)	1747 mD	22.69%

These measurements indicate that both cores have similar porosity and permeability, ensuring comparable conditions for the experiments. This allows the differences in oil recovery to be attributed primarily to the flooding mechanisms (polymer or surfactant) rather than variations in the rock properties.

Porosity and permeability were determined using helium porosimetry and liquid permeability measurements.

4.4 Wettability

The volumetric recovery analysis assesses oil recovery and saturation profiles under varying conditions to evaluate overall recovery efficiency and fluid flow behavior. Tests with viscoelastic polymer solutions and surfactant solutions provides insights into the contributions of polymer viscoelasticity and interfacial tension (IFT) reduction in mobilizing residual oil.

Additional analyses, including imbibition tests and contact angle measurements, further clarify wettability alteration and capillary interactions.

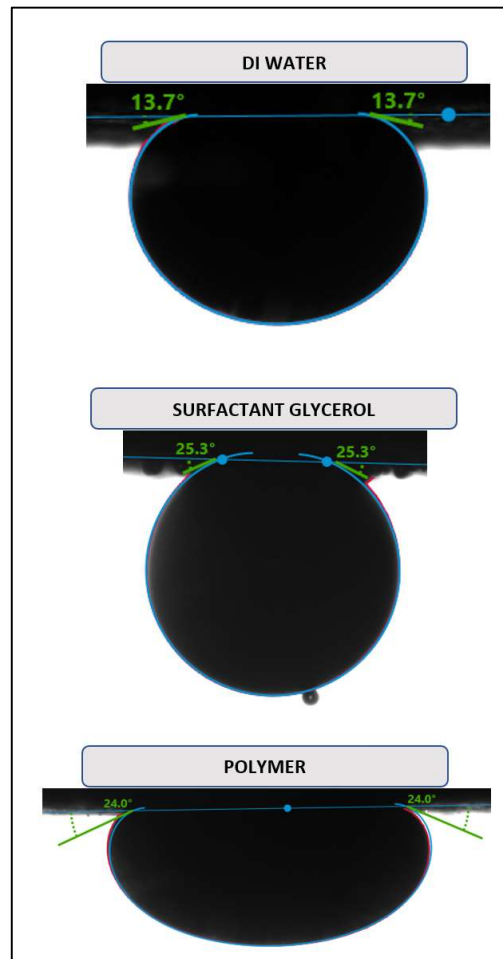


Figure 21: Contact Angle Measurements of Bentheimer in DI, Surfactant and Polymer Solutions

The results of the contact angle measurements provide valuable insights into the wettability of the Bentheimer sandstone under different fluid conditions. Deionized (DI) water, with a contact angle of 13.7° , indicates a strong water-wet condition. In this scenario, water strongly adheres to the sandstone surface, making oil less likely to stick to the rock. While this is favorable for water flooding, it may limit oil recovery in reservoirs where significant amounts of oil remain trapped due to strong capillary forces.

In contrast, the surfactant-glycerol solution, with a contact angle of 25.3° , demonstrates a shift toward intermediate wettability. This change is attributed to the surfactant's ability to reduce interfacial tension and alter surface energy, facilitating greater oil mobilization. Intermediate wettability enhances oil displacement efficiency in enhanced oil recovery (EOR) processes by reducing the capillary forces that trap oil in the pores. Similarly, the viscoelastic polymer solution, with a contact angle of 24° , exhibits behavior comparable to the surfactant-glycerol solution, reflecting intermediate wettability. The polymer's viscoelastic properties further contribute to improved sweep efficiency and the mobilization of residual oil from pore spaces.

These findings have significant implications for oil recovery. While DI water, with its water-wet state, is effective for initial water flooding, it may leave substantial residual oil due to strong capillary forces, especially in small pores. On the other hand, the surfactant-glycerol solution and polymer solution, with their ability to shift wettability toward intermediate conditions, reduce the adhesion between oil and rock, thereby improving oil displacement and recovery efficiency.

The variation in contact angles highlights the ability of different fluids to modify the wettability of the rock surface. Both the surfactant-glycerol solution and the viscoelastic polymer solution demonstrate superior wettability alteration compared to DI water, making them more effective agents for enhanced oil recovery.

4.5 Coreflood Results

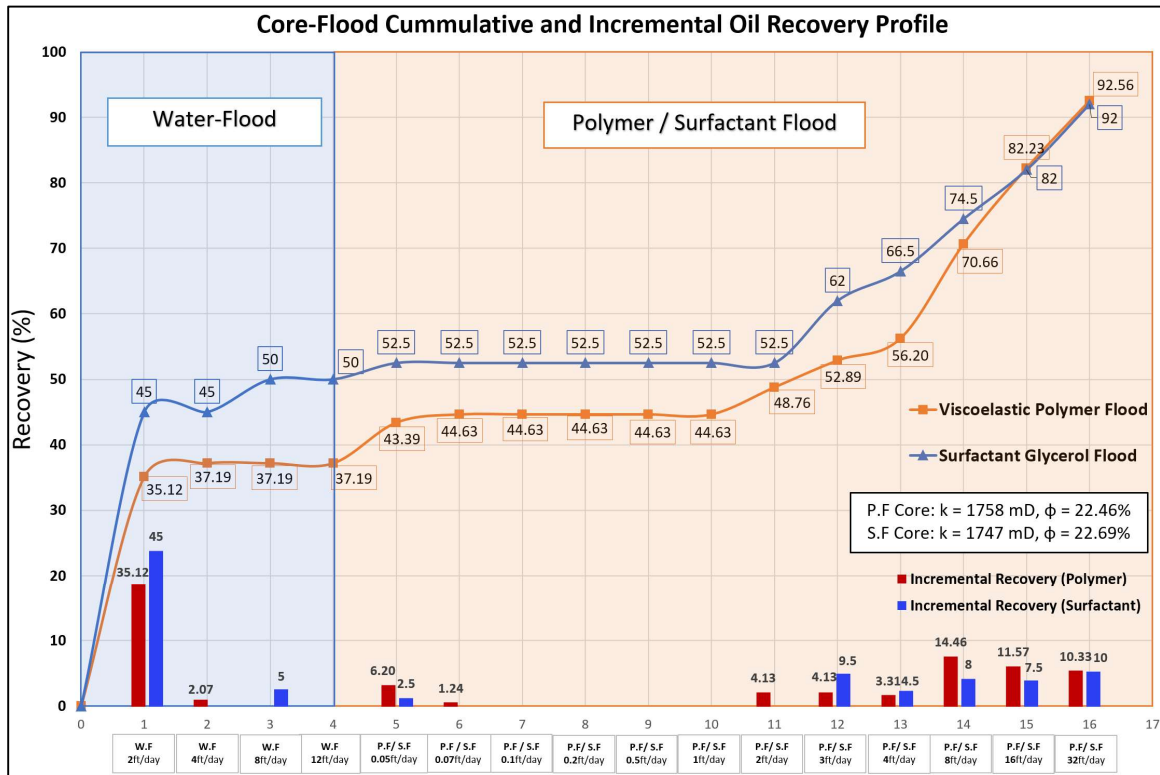


Figure 22: Coreflood Cumulative and Incremental Oil Recovery Profile for Polymer and Surfactant Floods

The graph demonstrates the cumulative and incremental oil recovery profiles during core flooding experiments conducted on Bentheimer cores with similar porosity and permeability. The core properties are: permeability (k) of 1758 mD for polymer flood and 1747 mD for surfactant flood, and porosity of 22.46% and 22.69%, respectively. The graph

shows the performance of viscoelastic polymer flooding and surfactant glycerol flooding, following an initial water flood phase.

After the water flood, the polymer flood at the initial low flux rate of 0.05 ft/day achieved a higher incremental oil recovery of 6.2% compared to 2.5% for the surfactant flood at the same rate. The polymer flood also provided an additional recovery of 1.24% at 0.07 ft/day, whereas no recovery was observed for the surfactant flood at 0.07 ft/day. While recovery at these flux rates could be attributed to the change in viscosity (which is common for both as they exhibit similar Newtonian viscosity of 100 cP) post-water flood, the polymer's ability to achieve higher recovery at 0.05 ft/day and also provide recovery at 0.07 ft/day demonstrates its superior performance at low flux rates. The polymer likely exhibits higher apparent viscosity due to size effects while flowing through the tortuous paths of porous media and its viscoelastic nature (HPAM), despite the low contribution of the time effect at such low flux rates.

The oil recovery observed with surfactant flooding at low rates cannot solely be attributed to the viscosity increase but also to the interfacial tension (IFT) reduction, which enhances oil mobilization. The surfactant glycerol solution does not exhibit an increase in viscosity as it remains a Newtonian fluid.

With an increase in flux rate, no recovery was observed for the following few rates.

At 2 ft/day, polymer flooding showed oil recovery, achieving an incremental recovery of 4.13%, marking the onset of desaturation. This can be attributed to reaching the critical capillary number, which will be discussed later in the context of the capillary desaturation curve (CDC). However, at 2 ft/day, no recovery was observed during the surfactant flood.

At 3 ft/day, the surfactant-flood initiated oil recovery, marking the beginning of desaturation.

It is important to note that for subsequent flux rates in both polymer and surfactant flooding, the slope of cumulative recovery differed. The surfactant flood exhibited a slightly linear and stable increase in oil recovery with higher flux rates. In contrast, the polymer flood showed a gradually low slope of cumulative recovery at flux rates of 2, 3, and 4 ft/day but exhibited a steep increase at higher flux rates of 8, 16, and 32 ft/day. This steep increase in recovery at higher flux rates can be attributed to the significant shear-thickening behavior of the viscoelastic polymer.

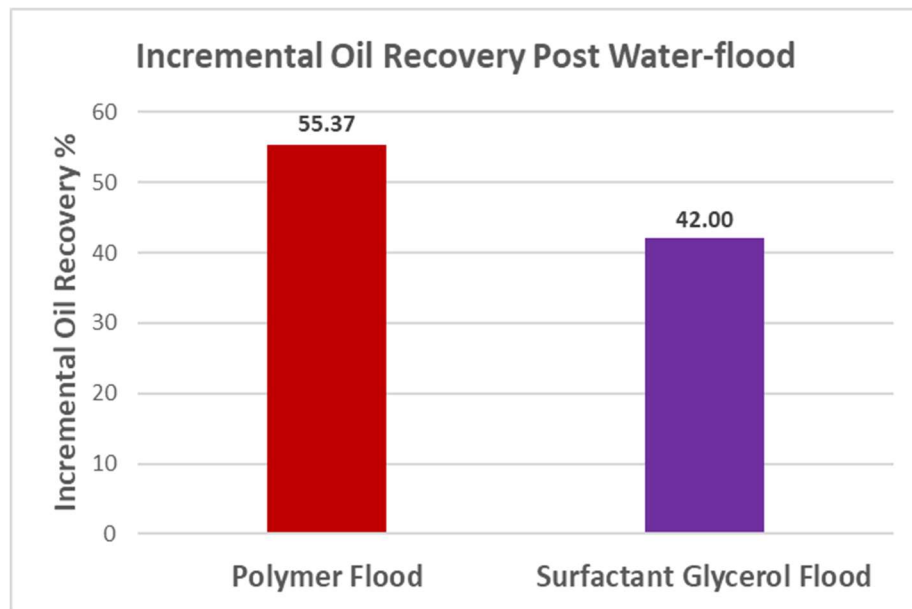


Figure 23: Total Incremental Oil Recovery for each flooding process post waterflood

After injection of several pore volumes during water flood at increasing rates, when it was ensured that there was no recovery till 12 ft/day, the percentage of oil recovered by water

flood for the core utilized for polymer flood was found to be 37.19%, and 50% for the second core which was used for surfactant flood.

The incremental oil recovery from the first rate of polymer/surfactant flood (0.05 ft/day) to the final rate (32 ft/day), was recorded.

After injecting polymer into the first core and surfactant into the second core at various flux rates ranging from low rates of 0.05 ft/day to high rates of 32 ft/day, the total oil recovery achieved at the end of each flooding process was 92% and 92.56%, respectively. This corresponds to total incremental oil recoveries (from post-water flooding to the final injection rate) of 55.37% for the polymer flood and 42% for the surfactant flood, as indicated in the graph above.

Therefore, the oil recovery profile, when compared for viscoelastic polymer flood and surfactant glycerol flood, suggests that the polymer flood was more effective at low flux rates. This is evident as the incremental oil recovery at the initial rate of 0.05 ft/day, post-water flood, showed a higher percentage of recovery compared to the surfactant flood.

This effectiveness is further supported by the earlier onset of recovery at 2 ft/day for the polymer flood, compared to the onset of recovery at 3 ft/day for the surfactant flood. At higher flux rates, the greater magnitude of shear-thickening behavior of the polymer primarily contributed to the observed recovery, resulting in higher oil recovery at these rates.

Towards the end of the core flooding experiments, it was observed that both flooding methods resulted in similar cumulative oil recovery. However, the polymer flood showed a slight advantage in cumulative oil recovery by the end of the experiment.

4.6 NMR (T_2 and Saturation Profile)

The NMR T_2 relaxation data after brine saturation, oil injection, and polymer flooding provide key insights into reservoir characterization and enhanced oil recovery (EOR) processes.

4.6.1 Characterization

a) Initial Brine Saturation (100% S_w)

T_2 relaxation primarily reflects the pore size distribution and brine mobility.

Longer relaxation times correspond to larger pores with free brine, while shorter times indicate smaller, less mobile pore spaces.

The cumulative distribution here serves as a baseline for comparison.

b) After Oil Injection

Oil infiltration shifts the relaxation time distribution due to changes in fluid saturations and wetting conditions.

Shorter T_2 components may dominate, indicating residual brine in smaller pores, while the oil occupies larger pore spaces.

Changes in cumulative T_2 highlight the displacement efficiency of brine by oil.

c) Post-Polymer Flood (EOR)

The polymer flood further alters T_2 relaxation by reducing residual oil saturation and potentially improving mobility in trapped zones.

Increments in longer T_2 relaxation components suggest enhanced oil mobilization from larger pores, while changes in shorter T_2 values reflect improved fluid displacement from smaller pores.

The cumulative shift demonstrates the effectiveness of polymer flooding in altering fluid distribution.

4.6.2 How is it related to EOR?

a) Viscoelastic Polymer Impact:

Viscoelastic properties of the polymer enhance sweep efficiency by mobilizing trapped oil. The T_2 distribution post-polymer flood shows improved connectivity in previously isolated pore spaces.

b) Improved Displacement Efficiency:

The shift in cumulative T_2 highlights incremental oil recovery after polymer injection, demonstrating the success of the EOR technique in reducing residual oil saturation.

c) Pore-Level Dynamics:

Changes in relaxation times reveal the polymer's ability to alter wettability and reduce interfacial tension, making oil mobilization more effective, even in smaller or poorly connected pores.

4.6.3 NMR of Polymer Flood Core

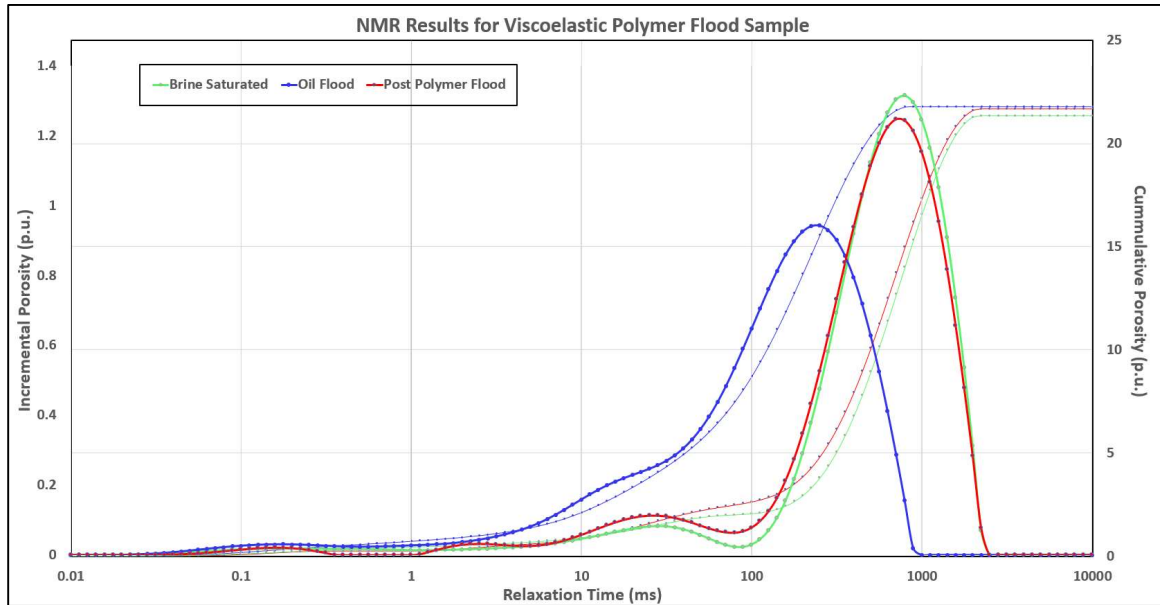


Figure 24: NMR Results for Viscoelastic Polymer Flood Core showing Incremental Porosity and Cumulative Porosity as a function of T_2 Relaxation Time

This graph illustrates the T_2 NMR relaxation times for a core sample across three stages: 100% brine saturation (green), after oil injection (blue), and post-polymer flooding (red). The green curve, representing the baseline, highlights the T_2 relaxation times when the core was saturated with brine, with a peak at shorter relaxation times indicating smaller pores dominated by brine. Following oil injection, the blue curve reveals a shift in the T_2 distribution, showing reduced cumulative porosity in smaller pores as oil displaced brine from larger pores while trapping residual brine in smaller pores. The red curve, representing post-polymer flooding, demonstrates a significant recovery in cumulative porosity across both smaller and larger relaxation times. This indicates that the viscoelastic polymer effectively mobilized residual oil, improving connectivity within the pore network. The cumulative porosity axis emphasizes the substantial increase after polymer flooding, signifying and indicating its enhanced efficiency in mobilizing residual oil. The

T_2 relaxation distribution thus offers valuable insights into pore size distribution and fluid mobility, confirming the effectiveness of viscoelastic polymers in reducing residual oil saturation and improving sweep efficiency, even in smaller pores. This graph validates the ability of viscoelastic polymer flooding to enhance oil recovery by targeting residual oil across a range of pore sizes. These NMR measurements provide a detailed understanding of fluid distribution changes across recovery stages, aiding in reservoir evaluation.

The NMR result confirms that viscoelastic polymer flooding enhances recovery by targeting both macropores and micropores, improving overall displacement efficiency.

4.6.4 NMR of Surfactant Flood Core

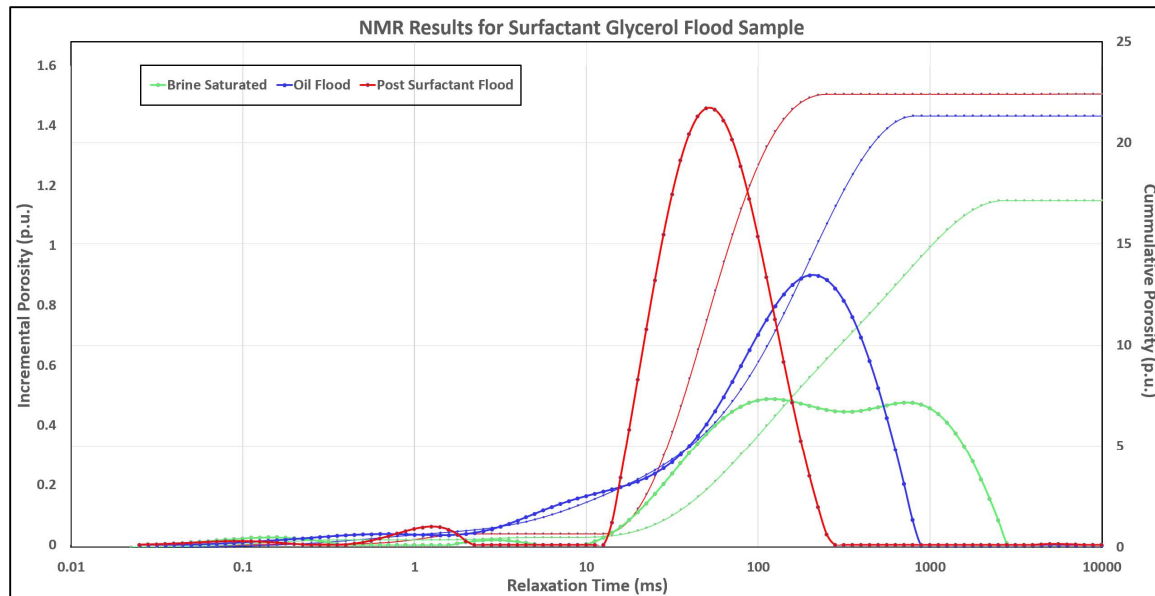


Figure 25: NMR Results for Surfactant Glycerol Flood Core showing Incremental Porosity and Cumulative Porosity as a function of T_2 Relaxation Time

For the surfactant flood core, the initial brine saturation (green line) demonstrates a cumulative porosity of 17.14 porosity units (p.u.) at the end of the process, reflecting the total pore volume accessible to brine during complete saturation. Incremental porosity analysis reveals that the highest values are concentrated at shorter T_2 times (<1 ms),

peaking around 0.1 ms, which indicates that brine predominantly resides in micropores and mesopores corresponding to smaller pore sizes. In contrast, lower incremental porosity at longer T_2 times (>100 ms) signifies reduced brine occupancy in macropores. These findings, coupled with the system's water-wet nature, suggest that brine preferentially occupies smaller pore spaces due to capillary forces. The T_2 relaxation distribution further confirms brine presence in both bound water regions (short T_2) and free fluid regions (long T_2), with most porosity associated with smaller pores.

After oil flooding, represented by the blue curve and data, cumulative porosity decreases significantly to 21.32 p.u., indicating that oil has displaced brine from macropores and connected mesopores. A noticeable T_2 shift occurs, with a marked reduction in incremental porosity at shorter T_2 times (<10 ms), suggesting that brine is pushed into tighter pore spaces while oil occupies larger pores. Incremental porosity values show a distinct increase around 100 ms and beyond, reflecting oil's preference for occupying macropores and the displacement of brine into residual pockets. This behavior implies that residual brine becomes trapped in smaller pores due to capillary forces, while oil preferentially fills larger, more connected pores. The observed increase in incremental porosity at longer T_2 times confirms fluid redistribution within the pore network as brine is displaced by oil.

Cumulative porosity recovery after post-surfactant glycerol flooding is highly significant, reaching 22.4 p.u., surpassing the initial porosity observed during brine saturation. This result suggests that the surfactant glycerol solution not only mobilized residual oil but also reconnected isolated pore spaces. Incremental porosity recovery is particularly pronounced at shorter T_2 times (0.1 to 10 ms), highlighting the mobilization of residual oil and brine from micropores and mesopores. Additionally, incremental porosity recovers at longer T_2

times (>100 ms), demonstrating effective oil displacement from macropores. The surfactant's ability to reduce interfacial tension facilitated the mobilization of oil trapped in micropores, while glycerol likely altered wettability, enhancing fluid flow and displacement in smaller pore spaces. Recovery across all T_2 ranges underscores substantial improvements in both microscopic displacement efficiency and macroscopic sweep efficiency.

During the brine saturation stage, high incremental porosity confirms brine occupancy in micropores. The oil flooding stage causes a sharp reduction in incremental porosity, reflecting residual brine entrapment within smaller pores. However, post-surfactant glycerol flooding demonstrates significant recovery, indicating effective mobilization of residual oil and brine from these tight spaces. At intermediate T_2 times (10–100 ms), a slight reduction in incremental porosity occurs after oil flooding as oil invades intermediate pores. Surfactant glycerol flooding restores incremental porosity in this range, confirming the mobilization of oil from mesopores. At longer T_2 times (>100 ms), incremental porosity values increase significantly after oil flooding, highlighting oil's preference for occupying macropores. Post-surfactant flooding further enhances recovery in this range, demonstrating successful oil displacement from macropores.

The efficiency of surfactant glycerol flooding is evident from the recovery of cumulative porosity to 22.4 p.u., exceeding the initial porosity at brine saturation. This indicates enhanced pore connectivity driven by the combined effects of surfactant and glycerol. Mobilization of residual oil from micropores, as reflected by porosity recovery at shorter T_2 times, underscores the microscopic displacement efficiency of the process. Incremental porosity recovery at longer T_2 times highlights improved macroscopic sweep efficiency in

macropores. Glycerol's potential to alter wettability likely shifted the system to a more favorable condition for brine displacement of oil, particularly in smaller pores. The surfactant's ability to reduce interfacial tension played a critical role in detaching residual oil from pore walls, enabling brine flow and enhancing pore volume recovery. This dynamic effectively overcame capillary forces in smaller pores, as evidenced by the porosity recovery observed at shorter T_2 times.

4.6.5 Inference from NMR results

The viscoelastic polymer flood exhibits a unique ability to stretch within tighter pores, which plays a significant role in its displacement mechanism as reflected in the NMR T_2 results. This stretching behavior leads to an increase in the microscopic pressure gradient at the pore throat due to a localized increase in viscosity. The NMR incremental porosity curve after polymer flooding highlights this phenomenon, showing a gradual increase in porosity contributions from smaller relaxation times, indicating oil mobilization in tighter pores. The viscoelastic nature of the polymer allows it to deform non-linearly, adapting to the complex geometry of pore spaces, which enhances its ability to exert higher displacing forces in regions where capillary forces dominate.

In comparison to the surfactant flood, the increase in viscosity of viscoelastic polymer within narrow pore throats improves the displacement of residual oil. The increase in viscosity near the pore throat translates to a higher pressure drop across the pore, effectively reducing oil trapping and mobilizing hydrocarbons that would otherwise remain untouched by fluids with a Newtonian viscosity profile. This behavior is particularly evident in the broader distribution of incremental porosity in the polymer flood NMR curve, as the

polymer effectively bridges the gap between mobilizing oil in both macropores and micropores.

While the surfactant flood primarily relies on wettability alteration and interfacial tension reduction (forms emulsions) to displace oil, the polymer flood complements this with its non-linear elastic behavior. This allows it to exert greater viscous forces in tighter pores, where the resistance to flow is highest. The cumulative porosity curves for the polymer flood reflect this steady mobilization, showing a gradual increase as the polymer adapts to the pore geometry, maintaining a stable displacement front and ensuring microscopic sweep efficiency.

4.7 Capillary Desaturation Curve (CDC)

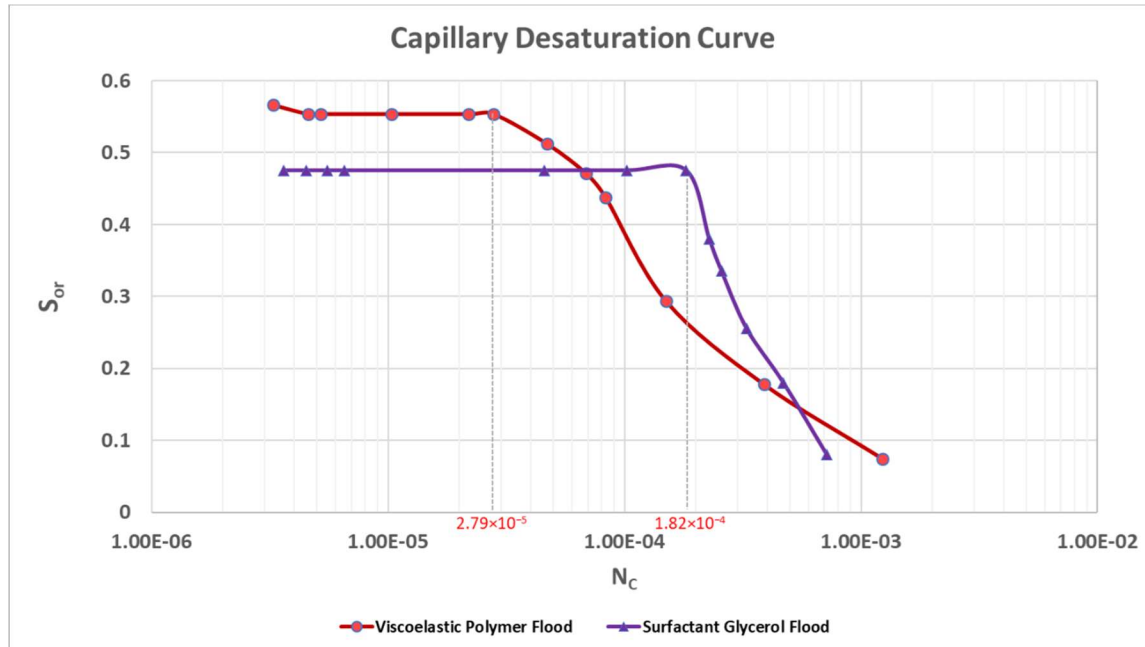


Figure 26: Capillary Desaturation Curves for Viscoelastic Polymer Flood and Surfactant Glycerol Flood

The Capillary Desaturation Curve (CDC) illustrates the relationship between residual oil saturation (S_{or}) and the capillary number (N_C) for two flooding techniques: Viscoelastic Polymer Flood and Surfactant Glycerol Flood. Observations reveal that the critical capillary number for the viscoelastic polymer flood is significantly lower (2.79×10^{-5}) compared to the surfactant glycerol flood (1.82×10^{-4}). For the viscoelastic polymer flood, oil recovery starts gradually at low flux rates of 0.05 ft/day and 0.07 ft/day after waterflooding, with no further recovery observed until a rate of 2 ft/day is reached. At this point, rapid oil mobilization begins, corresponding to the critical capillary number. The desaturation curve for the polymer flood exhibits a gradual reduction in S_{or} , indicating steady and continuous oil mobilization as the capillary number increases. In contrast, for the surfactant glycerol flood, some oil production occurs at an initial flux rate of 0.05 ft/day, followed by no further recovery until a higher rate of 3 ft/day is reached. At this point, rapid oil mobilization begins at the critical capillary number of 1.82×10^{-4} . Unlike the polymer flood, the desaturation curve for the surfactant flood demonstrates a sharper transition, indicating a threshold effect where oil recovery occurs abruptly once the critical capillary number is exceeded.

Both solutions exhibit the same viscosity, suggesting that the observed differences arise from their distinct mechanisms of action. The viscoelastic polymer flood relies on its viscoelastic properties, which enhance sweep efficiency and mobilize oil at lower capillary numbers, while the surfactant glycerol flood depends on interfacial tension (IFT) reduction to achieve oil recovery. At the low flux rate of 0.05 ft/day, both flooding techniques achieved some oil recovery, indicating that the flow conditions were sufficient to initiate slight mobilization of residual oil. However, at a slightly higher flux rate of 0.07 ft/day,

only the viscoelastic polymer flood exhibited additional recovery, while the surfactant glycerol flood did not.

This difference can be attributed to the distinct mechanisms of the two flooding techniques. The viscoelastic polymer flood benefits from its viscoelastic properties, which enhance elongational flow and improve pore-scale displacement efficiency even at relatively low capillary numbers. These properties likely contribute to a better redistribution of forces within the pore spaces, pore-scale stretching, enabling the mobilization of trapped oil as the flow rate slightly increases. In contrast, the surfactant glycerol flood relies primarily on IFT reduction, which may not be effective enough at this flux rate to overcome capillary forces and further mobilize the residual oil.

The lower critical capillary number of the viscoelastic polymer flood highlights its efficiency in mobilizing residual oil under lower flow conditions. This is attributed to the elongational flow and viscoelastic forces that improve sweep efficiency and reduce capillary trapping. On the other hand, the surfactant glycerol flood requires higher flow conditions to reach its critical capillary number and trigger significant oil mobilization. The gradual desaturation observed in the polymer flood indicates continuous oil recovery over a range of capillary numbers, while the abrupt desaturation in the surfactant flood suggests a dependency on reaching a specific threshold before significant oil mobilization occurs.

The results obtained in this study corresponded to the system comprising HPAM 3630 polymer at a concentration of 2000 ppm and CTAB (Hexadecyltrimethylammonium Bromide) as the surfactant, applied to a water-wet Bentheimer core with high permeability. The implication of these observations is that viscoelastic effects in the polymer flood

provide an advantage at lower flux rates, allowing for incremental recovery with small increases in flow rate. This highlights the greater efficiency and adaptability of viscoelastic polymer flooding under conditions of low to moderate flow rates compared to IFT reduction technique. Overall, the CDC curve underscores the superior performance of viscoelastic polymer flood in achieving oil recovery at lower critical capillary numbers, making it a more effective option under low flux conditions.

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