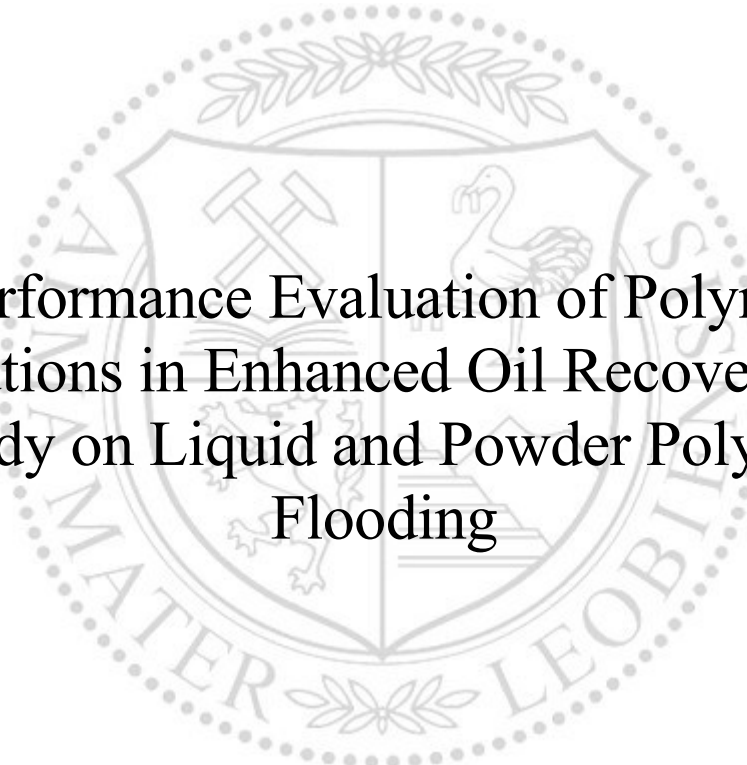




Chair of Reservoir Engineering

Master's Thesis



Performance Evaluation of Polymer
Solutions in Enhanced Oil Recovery: A
Study on Liquid and Powder Polymer
Flooding

Elham Ghodsi

November 2024



AFFIDAVIT

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A handwritten signature in blue ink, appearing to read 'Elham Ghodsi'.

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Master Thesis 2024

Petroleum Engineering/ Geoenergy Engineering

Performance Evaluation of Polymer Solutions in Enhanced Oil Recovery: A Study on Liquid and Powder Polymer Flooding

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Chair of Geoenergy Engineering

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Abstract

This study investigates the feasibility of liquid polymer flooding in Austrian oil reservoirs, focusing on the Hochleiten field with permeabilities ranging from 300 to 500 mD and extending to higher permeability (1300 mD) to assess the broader applicability of liquid polymers. The research compares the performance of liquid and powder polymers from two vendors, evaluating their potential as alternatives for EOR in challenging reservoir conditions. Four liquid polymer products (LP#1-4) and four powder polymer products (PP#1-4) with varying molecular weights were systematically tested. The target polymer concentration was set to achieve 20 cP viscosity at 20°C. Comprehensive experiments included stability tests, Interfacial Tension (IFT) measurements, phase behavior analyses, and core flooding tests at an interstitial velocity of 5 ft/day. Initial stability, IFT, and phase behavior tests showed promising results for liquid polymers. However, subsequent single-phase and two-phase core flooding experiments revealed significant injectivity challenges for liquid polymers across low permeable rocks. These challenges manifested as continuous pressure increases without stabilization, contrasting with the stable pressure profiles observed with powder polymers. In two-phase core floods, LP#4's concentration was reduced from 1800 ppm to 900 ppm to investigate whether a less viscous solution could resolve the observed injectivity issues. Despite this adjustment, injectivity problems persisted. For PP#3, the concentration was increased from 1400 ppm to 2000 ppm in two-phase core floods to examine the impact of a more viscous polymer solution on the recovery factor and differential pressure across the core plug. Adsorption tests showed comparable results for both liquid and powder polymers, with measurements around 250 µg/g of rock. Resistance and residual resistance factors were successfully determined for powder polymers but could not be accurately assessed for liquid polymers due to their unstable pressure profiles. The study concludes that while liquid polymers show potential in certain aspects, they face substantial injectivity challenges in the permeability range typical of the Hochleiten field. In contrast, powder polymers, particularly PP#4, demonstrated superior performance and stability across all tested permeabilities, making them more suitable candidates for EOR applications in these reservoirs. These findings provide critical insights for optimizing EOR strategies in mature Austrian oil fields and contribute to the broader understanding of polymer behavior in complex reservoir conditions across a range of permeabilities.

Zusammenfassung

Diese Studie untersucht die Durchführbarkeit der Flüssigpolymerflutung in österreichischen Ölfeldern, wobei der Schwerpunkt auf dem Hochleiten-Feld liegt, dessen Permeabilitäten von 300 bis 500 mD reichen und bis zu höheren Permeabilitäten (1300 mD) erweitert werden, um die breitere Anwendbarkeit von Flüssigpolymeren zu bewerten. Die Forschung vergleicht die Leistung von Flüssig- und Pulverpolymeren von zwei Anbietern und bewertet deren Potenzial als Alternativen für Enhanced Oil Recovery (EOR) unter herausfordernden Reservoirbedingungen. Vier Flüssigpolymerprodukte (LP#1-4) und vier Pulverpolymerprodukte (PP#1-4) mit unterschiedlichen Molekulargewichten wurden systematisch getestet. Die Zielpolymerkonzentration wurde so gewählt, dass eine Viskosität von 20 cP bei 20°C erreicht wurde. Umfassende Experimente umfassten Stabilitätstests, Interfacial Tension (IFT)-Messungen, Phasenverhaltensanalysen und Kernflutungstests bei einer interstitiellen Geschwindigkeit von 5 ft/Tag. Erste Stabilitäts-, IFT- und Phasenverhaltenstests zeigten vielversprechende Ergebnisse für Flüssigpolymere. Allerdings offenbarten nachfolgende Einphasen- und Zweiphasen-Kernflutungsexperimente signifikante Injektivitätsprobleme für Flüssigpolymere in gering permeablen Gesteinen. Diese Probleme äußerten sich in kontinuierlichen Druckerhöhungen ohne Stabilisierung, im Gegensatz zu den stabilen Druckprofilen, die bei Pulverpolymeren beobachtet wurden. In Zweiphasen-Kernflutungen wurde die Konzentration von LP#4 von 1800 ppm auf 900 ppm reduziert, um zu prüfen, ob eine weniger viskose Lösung die beobachteten Injektivitätsprobleme lösen könnte. Trotz dieser Anpassung blieben die Injektivitätsprobleme bestehen. Für PP#3 wurde die Konzentration in Zweiphasen-Kernflutungen von 1400 ppm auf 2000 ppm erhöht, um den Einfluss einer viskosereren Polymerlösung auf den Ertragsfaktor und den Differenzdruck über den Kernstecker zu untersuchen. Adsorptionstests zeigten vergleichbare Ergebnisse für Flüssig- und Pulverpolymere, mit Messwerten um 250 µg/g Gestein. Widerstands- und Residualwiderstands-Faktoren konnten für Pulverpolymere erfolgreich bestimmt werden, für Flüssigpolymere jedoch aufgrund ihrer instabilen Druckprofile nicht genau bewertet werden. Die Studie kommt zu dem Schluss, dass Flüssigpolymere in bestimmten Aspekten Potenzial zeigen, jedoch erhebliche Injektivitätsprobleme im für das Hochleiten-Feld typischen Permeabilitätsbereich aufweisen. Im Gegensatz dazu zeigten Pulverpolymere, insbesondere PP#4, eine überlegene Leistung und Stabilität über alle getesteten Permeabilitäten hinweg, was sie zu geeigneteren Kandidaten für EOR-Anwendungen in diesen Reservoirs macht. Diese

Ergebnisse liefern wichtige Erkenntnisse für die Optimierung von EOR-Strategien in reifen österreichischen Ölfeldern und tragen zum umfassenderen Verständnis des Polymerverhaltens in komplexen Reservoirbedingungen über einen breiten Permeabilitätsbereich bei.

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Chapter 1

Introduction

Enhanced oil recovery (EOR) techniques are becoming increasingly crucial in mature oil fields, particularly in the Austrian context. The Vienna Basin, with its low to medium permeability reservoirs, presents unique challenges for polymer flooding. Traditional powder polymers have been used successfully in these fields. Still, there's growing interest in liquid polymer flooding due to its potential advantages in terms of operational efficiency and environmental impact. The Hochleiten field and other similar reservoirs in Austria are the focal points for this research. As a chemical EOR technique, polymer flooding has shown promise in improving oil recovery from heterogeneous reservoirs. It works by modifying the mobility ratio and increasing sweep efficiency. While powder polymers have been widely used, liquid polymers offer potential benefits such as a smaller surface facility footprint and reduced environmental impact, making them particularly attractive for small onshore reservoirs and offshore applications.

1.1 Background and Context

Liquid polymers are a viable alternative to traditional powder polymers in EOR, especially for challenging environments like offshore operations. Two significant case studies have provided valuable insights into the application and performance of liquid polymers in various reservoir conditions. The first study, conducted in a North Sea field, assessed using liquid polymer products in a high-permeability, low-temperature reservoir with highly viscous crude oil. This research found that while the liquid polymers exhibited suitable viscosities for the reservoir brine, they encountered significant challenges related to polymer retention, high residual resistance factor (RRF), and injectivity issues due to the presence of a dispersed phase in the polymer solutions (Osterloh & Law, 1998). Another significant study focused on liquid polymers in a different type of rock sample, investigating their long-term effects on injectivity and developing remediation methods. This research emphasized the importance of particle size

in liquid polymer formulations. It demonstrated that first-generation liquid polymers caused significant permeability reduction after several pore volumes of injection. Developing second-generation liquid polymers with smaller particle sizes showed promise in addressing these plugging issues, highlighting the ongoing evolution and improvement of liquid polymer technology for EOR applications. Both studies underscored the complex interplay between liquid polymer properties and reservoir characteristics, providing valuable insights for future applications in various geological settings (Dwarakanath et al., 2016).

1.2 Scope and Objectives

This thesis assesses the feasibility of liquid polymer flooding in Austrian reservoirs, particularly on the Hochleiten field and similar formations with low to medium permeabilities ranging from 300 to 500 mD. The study thoroughly evaluates liquid polymers compared with their powder counterparts from the same two vendors. The study systematically approaches polymer evaluation, starting with a thorough rheological and stability analysis. This first phase step includes detailed characterization of the polymers, such as viscosity measurements, temperature scans, IFT tests, and phase behavior analyses. After these preliminary assessments, the investigation proceeds to core flooding experiments, starting with single-phase core floods to evaluate polymer behavior and injectivity in porous media, followed by two-phase core floods to assess injectivity in the presence of oil and displacement efficiency. The study then expands to testing these liquid polymers in higher permeability rocks to determine if injectivity issues persist across different geological settings. In parallel, powder polymers from the same two vendors are evaluated using identical methodologies, allowing for a direct comparison with their liquid counterparts. This research aims to thoroughly examine the rheological and stability characteristics of liquid polymers in conditions like those found in Austrian oil fields. It seeks to evaluate their injectivity and effectiveness in low to medium-permeability reservoirs and explore their behavior across various permeability levels to identify ongoing challenges. Additionally, the study intends to comprehensively compare liquid polymers and their powdered equivalents, focusing on rheological properties, stability, injectivity features, and overall performance.

The goal of this research is to generate detailed laboratory data that will support the technical qualification or disqualification of emulsion polymer products for use in Austrian oil fields. Through this comprehensive approach, the thesis aspires to offer valuable insights into the potential implementation of liquid polymer flooding in Austrian oil reservoirs, addressing both the obstacles and possibilities presented by this enhanced oil recovery method.

1.3 Achievements

This research has made notable advancements in assessing the viability of liquid polymer flooding. A comprehensive analysis uncovered significant injectivity issues with liquid polymers within the targeted permeability range. These results highlight the constraints of liquid polymers, which failed to perform adequately under the examined conditions. On the other hand, powder polymers from identical suppliers exhibited better injectivity and overall efficacy, emphasizing their appropriateness for these reservoir features. Furthermore, the investigation produced an extensive dataset detailing the rheological characteristics, stability, and behavior of liquid polymers in various scenarios. This information is vital for shaping enhanced oil recovery tactics in Austrian oil fields. Although the liquid polymers did not yield positive outcomes regarding injectivity, this finding is crucial, offering valuable insights that can steer upcoming research and development in polymer flooding methods. In summary, this study enhances the knowledge of polymer flooding within Austrian oil reservoirs and provides important perspectives for academic research and practical applications in the industry.

1.4 Overview of Dissertation

Chapter 2 presents a comprehensive literature review on polymer flooding as an enhanced oil recovery technique. It elucidates the fundamental principles of polymer flooding, encompassing the types of polymers utilized (such as HPAM and Xanthan), their molecular structures, and rheological behaviors. The chapter subsequently examines the factors influencing polymer performance in porous media, including salinity, temperature, and permeability. Furthermore, it investigates studies and advancements in liquid polymer flooding technology and its global applications in diverse field cases.

Chapter 3 focuses on liquid polymers and their possible applications in Austrian oilfields. This chapter describes the experimental techniques for assessing liquid polymers, such as rheological measures, stability tests, and core flooding studies. It covers the findings of these tests, focusing on the injectivity issues encountered in low to medium-permeability reservoirs. The chapter further investigates the behavior of liquid polymers in greater permeability rocks and examines how these discoveries may be applied in the field.

Chapter 4 presents a comparative analysis of powder polymers using the same experimental framework established for liquid polymers. This chapter examines the performance of powder polymers in terms of rheological properties, stability, and injectivity characteristics. It directly compares liquid and powder polymers, highlighting their strengths and limitations in Austrian oil field conditions.

Chapter 5 concludes the thesis by summarizing the key findings from liquid and powder polymer studies. It synthesizes the results to provide a comprehensive evaluation of the feasibility of polymer flooding in Austrian oil fields, focusing on the challenges and potential solutions for low to medium-permeability reservoirs. The chapter also offers recommendations for future research directions and potential field applications.

Chapter 2

State of the Art

Polymer flooding is a water-based enhanced oil recovery (EOR) method that injects a polymer solution into an oil reservoir to improve oil displacement and increase production rates. In Austrian oil fields, polymer flooding is gaining importance as a method to extract additional oil from mature reservoirs. The 8th Tortonian Horizon (8 TH) supermature reservoir in Austria's Matzen field underwent HPAM polymer flooding pilot tests 2014, revealing a highly heterogeneous reservoir with strong connections between injection and production wells. The tests demonstrated that polymer injection significantly modified flow patterns, leading to an incremental oil recovery of about 8% along the main flow path, with improved sweep efficiency accounting for 80% of the additional production, even at very high water cuts (Clemens et al., 2016).

Liquid polymer presents an economically attractive option for smaller or remote reservoirs, as it eliminates the need for large facilities and maintains a minimal footprint, making it a compelling alternative to powder polymer in such scenarios. However, their effectiveness in Austrian fields necessitates careful evaluation. Injectivity issues may arise, demanding thorough testing and experimentation. To optimize results, identifying the most suitable polymer is crucial. Collaborating with vendors to tailor the molecular weight of the polymer for specific reservoir conditions, such as the varying permeabilities found in two Austrian fields, is essential. By conducting comprehensive research and development, the potential of liquid polymer flooding can be fully realized in Austria's oil industry. This chapter provides a comprehensive overview of polymers, delving into their specifications and properties. This work focuses primarily on liquid and powder polymers and their feasibility for enhanced oil recovery in Austrian oil fields. These experiments serve as a foundation for understanding the challenges and potential of polymer-type flooding in the Austrian context.

2.1 Polymer Flood

Polymer flooding is a chemical Enhanced Oil Recovery (cEOR) technique that injects high-molecular-weight, polyelectric polymer solutions into an oil reservoir to enhance oil displacement (Gao, 2014). The efficacy of this method is primarily attributed to its ability to modify fluid mobility within the porous medium. As defined by Larson et al., the amount of oil trapped is determined by the force balance between viscous and capillary forces, as is already known, and is quantified using the capillary number. The capillary number, N_c , dimensionless, is the ratio of viscous to capillary forces:

$$N_c = \frac{v\mu}{\sigma} \quad 2.1$$

where σ is the interfacial tension and v and μ stand for fluid velocity (m/s) and viscosity (Pa*s), respectively (Larson et al., 1981). By raising the viscosity, the polymer flooding mechanism seeks to reduce the amount of trapped oil. This causes capillarity suppression due to viscous force and increases the number of mobilized hydrocarbons. By reducing capillary number, improving mobility control, and potentially altering rock-fluid interactions, polymers can contribute to more efficient oil recovery. However, this effectiveness depends on various factors, including polymer properties, reservoir characteristics, and oil type (Hirasaki & Pope, 1974). Nevertheless, the influence of polymers on microscopic displacement is quite small because the increase in capillary number is only one order of magnitude, and the characteristic that distinguishes polymer action is macroscopic displacement, which mainly targets the oil that is evaded by flooding with water and can be acquired by a crucial factor: mobility ratio. So, it is important to note that polymer flooding rarely reduces residual oil saturation or increases microscopic displacement efficiency (the proportion of oil displaced from the pores by the injected fluid). However, polymer flooding increases the macroscopic sweep efficiency (i.e., the fraction of the connected reservoir volume swept by the injected fluid) (Lake, 1989). As a result, the essential goal of adding polymers to injected water is to increase its viscosity to reduce its mobility and make it similar to the viscosity of oil, or even greater in some cases, reducing viscous fingering and increasing sweep efficiency. The result is a more equal displacement of oil, which is pushed into producing wells. Polymer flooding targets oil reservoirs with relatively high viscosities, ranging from 100 cp to 5000 cp and 12 API° to 22.3 API° (Saleh et al., 2014).

The mobility control induced by polymer flooding helps to overcome challenges encountered when injecting water into high-viscosity oil reservoirs, such as viscous fingering and bypassing of oil or early water breakthrough. In other words, polymer flooding can increase incremental recovery by improving the volumetric sweep efficiency (Seright, 2010). Heavy oil reserves, defined as liquid petroleum with an API gravity of less than 20° and a viscosity greater than

200 cP under reservoir conditions, account for 20-25% of global oil resources. According to the USGS, there are an estimated 355 billion barrels of recoverable viscous oil reserves, with a recovery factor ranging from 13-15% (Meyer and Attanasi, 2004). The above statistics show that recovery factors for heavy oilfields can be enhanced by using EOR techniques.

In addition to improving the sweep efficiency, polymer flooding has also been deployed in near-wellbore treatments to plug off watered-out high permeability zones and reduce water cuts or to improve the performance of injection wells to make the injection profile even. Furthermore, crosslinked polymers can be injected to plug off high permeability zones deep in the reservoir for fluid diversion (Sorbie, 1991). This thesis will focus on deploying polymer solutions for better mobility control and volumetric sweep in the entire reservoir.

The end-point mobility ratio M describes the stability of a displacement front and is given by:

$$M = \frac{k_{rw}/\mu_w}{k_{ro}/\mu_o} = \frac{k_{rw}\mu_o}{k_{ro}\mu_w} \quad 2.2$$

where k_{rw} is the relative permeability of water, k_{ro} is the relative permeability of oil, μ_w is the viscosity of water, μ_o is the viscosity of oil. For cases of $M \leq 1$, displacement piston-like, reaching 100% recovery of the displaced fluid at breakthrough (Chang, 1978). When $M > 1$, the displacing phase moves faster than the displaced phase, resulting in early breakthrough and bypassing the displaced phase. Inefficient displacement in unfavorable mobility circumstances is aggravated if the reservoir is heterogeneous and contains high-permeability streaks or fractures (Sorbie, 1991). Figure 2.1 depicts the irregular front and viscous fingering in water flooding and stable front in polymer flooding.

Polymers modify the viscosity of the displacing phase, causing the mobility ratio to improve. This, in turn, affects the recovery factor (Meyer & Attanasi), which is described as:

$$RF = ED \times EA \times EV \quad 2.3$$

The displacement efficiency (ED), areal sweep efficiency (EA), and vertical sweep efficiency (EV) are all taken into consideration. Polymer flooding increases volumetric sweep efficiency, which is calculated as the product of areal and vertical sweep efficiency (Larson et al.).

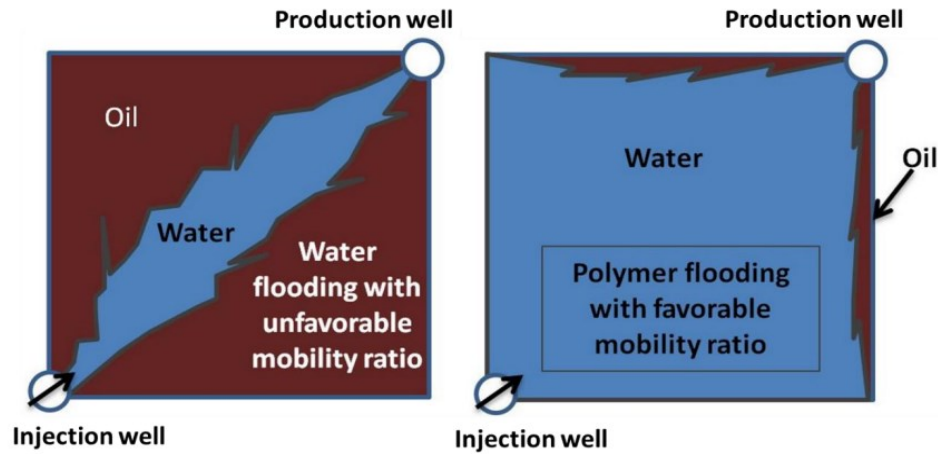


Figure 2.1 – Fingering impact with water flooding (left) and reduced effects of fingering with polymer flooding (right) (Zerkalov, 2015)

2.2 Polymer Types

Several types of polymers can be utilized for polymer injection. These can be broadly categorized into two types: synthetic and biopolymers. The most often used synthetic polymer is partially hydrolyzed polyacrylamide (HPAM), and Xanthan is the most widely utilized biopolymer. However, HPAM is the most popular polymer for polymer flooding (Sorbie, 1991).

Further details on the molecular structures and different behavior of HPAM and Xanthan are provided in sections 2.2.1 and 2.2.2.

2.2.1 Xanthan

Xanthan gum, a biopolymer commonly used as a thickening agent in industries like food production, has significant potential for application in EOR. Xanthan gum is a commercially accessible polymer derived from a microbial fermentation process employing the bacteria *Xanthomonas campestris* (Lake, 1989; Sorbie, 1991). Xanthan gum's core structure is a cellulose-like chain of bonded glucose units. The molecular weight and structural composition of xanthan generated by different strains of *Xanthomonas* bacteria result in polymers with slightly variable characteristics. The molecular structure of xanthan is commonly simplified as a rigid rod (Figure 2.2). This rod-like conformation stems from a linear polymer chain surrounded by 22 helical side groups, imparting a degree of stiffness to the molecule. According to rheological studies, xanthan gum has a structure that makes it resistant to water temperature variations, salinity, PH, and hardness. Xanthan gum, with a diameter of approximately 2 nanometers and a molecular weight ranging from 1 to 12 million grams per mole, can significantly impact its behavior in the reservoir due to its size. Higher molecular

weight xanthan molecules are prone to aggregation and gel formation, potentially leading to plugging issues. Filtering xanthan solutions can help mitigate this by removing gels and debris before injection. Xanthan polymers are sensitive to microbial deterioration when stored and injected into reservoirs. To overcome this, biocides like formaldehyde are frequently used to limit the development of bacteria that break down xanthan. However, using biocides increases operational expenses and causes environmental issues (Lake, 1989; Sorbie, 1991).

Biopolymers like xanthan and scleroglucan are very resistant to salt and shear stresses. However, the presence of cellular debris and proteins in the fermentation process frequently prevents their use in low-permeability reservoirs due to the possibility of pore blockage (Lipton, 1974).

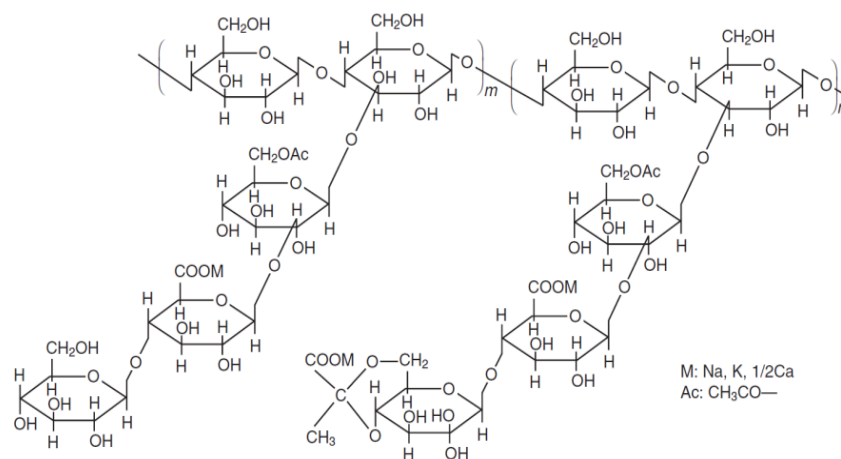


Figure 2.2 – The molecular structure of Xanthan (Dominguez & Willhite, 1977)

2.2.2 Polyacrylamides

Polyacrylamides (PAM) are synthetic polymers formed by polymerizing acrylamide monomers. PAM, especially its hydrolyzed form (HPAM), is extensively accessible due to its industrial uses. HPAM is a polymer comprising acrylamide and acrylic acid subunits organized linearly. HPAM can be produced by chemically modifying polyacrylamide through hydrolysis with a base such as sodium hydroxide or by synthesizing it directly from acrylamide and sodium acrylate. HPAM is preferred over xanthan in EOR because of its greater bacterial resistance, improved water solubility, excellent mobility control, and cheaper cost.

Additionally, HPAM has been shown to lower permeability permanently. However, HPAM's susceptibility to brine salinity and hardness is a disadvantage attributable to its hydrophilic nature. Unlike xanthan, HPAM lacks the stiff structural components that increase its mechanical resistance. Unlike PAM, which is neutral, HPAM is a polyelectrolyte with negative charges across its molecular chain. Prior to its use in improved oil recovery, the effect of these charges on the viscosity of polyelectrolyte solutions was well understood (Lake, 1989;

Ranganathan et al., 1998; Sorbie, 1991). The electrostatic repulsion between charged groups within a polyelectrolyte molecule significantly expands its size in dilute solutions, substantially increasing intrinsic viscosity. This phenomenon accounts for the distinct rheological properties of HPAM compared to PAM. The distribution of charges along the HPAM chain, represented by the degree of hydrolysis (typically 15% to 35% in commercial EOR products), impacts the polymer's characteristics (Flory, 1953). The molecular structure of HPAM is shown in Figure 2.3.

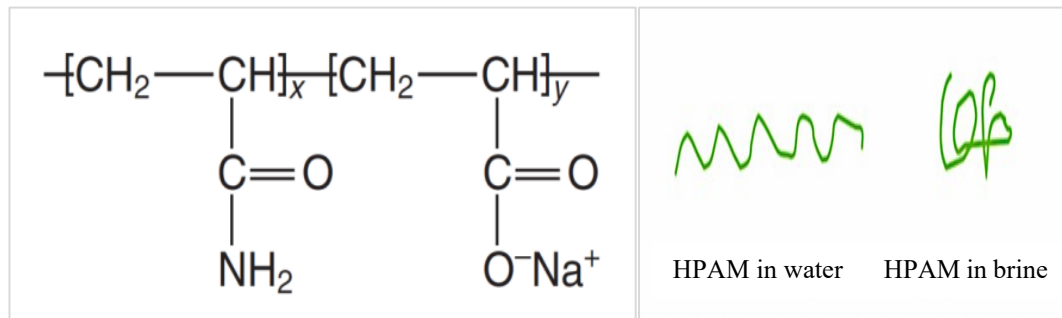


Figure 2.3 – The molecular structure of HPAM (Sheng, 2011)

A polymer's conformation, or the three-dimensional arrangement of its component monomers, significantly impacts its characteristics. HPAM's large molecular weight and linear structure punctuated by charged groups give it a distinct rheological character. HPAM's efficiency as a thickening agent is inextricably linked to its spatial arrangement, often represented as a random coil in solution. The ionic content of the fluid around it dynamically modifies this conformation. The electrostatic repulsion between charged groups inside the HPAM molecule is counteracted by brine solutions, which are made up of ions that function as a shield for the polymer charges. The shielding phenomena cause the polymer coil to compress, reducing its hydrodynamic volume. Divalent cations, such as Mg^{2+} and Ca^{2+} , have a stronger shielding effect than monovalent cations like Na^+ . As a result, larger salt concentrations considerably diminish HPAM's inherent viscosity, which measures its hydrodynamic volume in solution (Hirasaki & Pope, 1974). While there is a general preference for larger molecular weight polymers to improve oil recovery efficiency in reservoirs with moderate to high permeability, selecting the correct molecular weight and distribution becomes critical in lower permeability formations. The polymerization process automatically produces a variety of molecule sizes, known as polydispersity, as seen in Figure 2.4. In low permeability reservoirs, the shape of the molecular size distribution is crucial, as specific low permeability conditions may impose an upper limit on the molecular weight or size. If the size distribution is unclear or excessively broad, it may confound the assessment of the relationship between molecular weight and permeability (Herr & Routson, 1974).

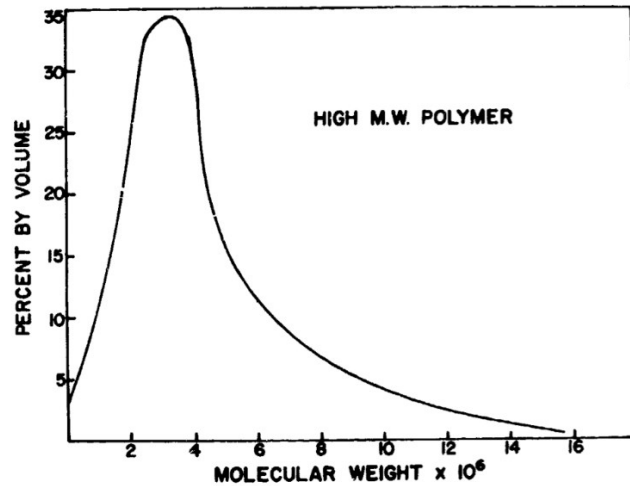


Figure 2.4 – Molecular weight distribution of a polymer (Herr & Routson, 1974)

The rheological behavior of a polymer solution is determined by interactions between polymer molecules and within them. Because of their huge size, polymers distributed in water can form colloidal systems. As the polymer content increases, the solution moves from a dilute to an overlapped state and finally to a semi-dilute state (Teraoka, 2002). The overlap concentration is reached when the total hydrodynamic volume of polymer molecules equals the volume of the solution. Below the overlap concentration, the solution's viscosity increases nearly proportionately to the polymer concentration. However, viscosity increases significantly quicker at the overlap concentration owing to macromolecular entanglements. The Flory-Huggins equation describes the link between viscosity and concentration (Flory, 1941; Huggins, 1942).

$$\mu = \mu_1 [1 + K_1 c + K_2 c^2 + \dots] \quad 2.4$$

Where K_i is Huggins coefficients, μ_1 is solvent viscosity, μ is solution viscosity, and c is concentration. For ultra-high molecular weight, the overlap concentration tends to be relatively low: A small increase in polymer concentration over the overlap point significantly increases solution viscosity. HPAM solutions display more complicated behavior than other viscous fluids, such as those made of tiny molecules or non-ionic polymers, due to the presence of charge, high molecular weight polymers, and the possibility of ion interactions. This intricacy is heightened in low-permeability situations. As a result, using HPAM under difficult environments such as high salinity, limited permeability, and high temperatures necessitates carefully considering various parameters (Al-Hamairi & AlAmeri, 2020).

2.3 Flow characteristics of polymer solutions

The flow behavior of polymer solutions becomes increasingly complex as the environment changes from bulk liquid to capillary tubes and porous media. The following sections will explore the properties of polymer solutions in these different settings.

2.3.1 Rheology of bulk polymer solution

In Newtonian fluid flow, shear stress and shear rate are proportional.

$$\tau = \mu \left(\frac{du}{dy} \right) = \mu \dot{\gamma} \quad 2.5$$

Shear stress (τ) is related to shear rate ($\dot{\gamma}$) through dynamic viscosity (μ). Rheology and behavior of polymer solutions Fluids are divided into Newtonian and non-Newtonian fluids. The viscosity of Newtonian fluids is defined as the constant of proportionality between shear stress and shear rate, implying that viscosity is independent of shear rate. A non-Newtonian polymer solution can behave in two ways: shear thinning (pseudoplastic) or shear thickening (dilatants). Polymer solutions display shear-thinning behavior, where the viscosity decreases with increasing shear rate. This is an important property for injecting polymer as high shear rates experienced by polymer solutions within wellbores facilitate their injection, which is crucial for maintaining consistent fluid injection. As the polymer solution moves from the high-shear environment of the well into the reservoir, it undergoes a reduction in shear rate. This decrease in shear rate increases the fluid's viscosity, resulting in improved overall oil displacement efficiency (Zeynalli et al., 2022). This relationship can be modeled using the power law equation:

$$\tau = -K \left(\frac{du}{dy} \right)^n = K(\dot{\gamma})^n \quad 2.6$$

K denotes the consistency index, and n represents the power law index. Alternatively, it may be written as equation 2.7.

$$\tau = \mu_a \dot{\gamma} \quad 2.7$$

$$\mu_a = K(\dot{\gamma})^{n-1} \quad 2.8$$

Which μ_a is apparent viscosity.

The power law model effectively captures the shear-thinning behavior of polymer solutions within a specific shear rate range. However, as illustrated in Figure 2.5, polymer solutions exhibit a more complex rheological profile across a wider range of shear rates. The solution acts as a Newtonian fluid at low shear rates with moderately constant viscosity. As the shear rate increases, polymer chains align with the flow, decreasing viscosity (shear thinning). At extremely high shear rates, the solution again approaches Newtonian behavior, primarily influenced by the solvent's properties. To accurately describe this complete rheological behavior, the Carreau model is often employed. The Carreau model is a mathematical equation that describes the non-Newtonian behavior of fluids, particularly those exhibiting shear-thinning characteristics. Unlike the power law model, which is limited to describing shear-

thinning behavior, the Carreau model can capture a wider range of fluid behaviors, including Newtonian plateaus at both low and high shear rates (Bird & Carreau, 1968). The Carreau model is a rheological model commonly employed in polymer flooding to characterize the shear-thinning behavior of polymer solutions. This model effectively captures the non-Newtonian fluid properties of these solutions, which is essential for predicting flow behavior and optimizing injection strategies in enhanced oil recovery processes. By accurately describing the relationship between viscosity and shear rate, the Carreau model enables more precise simulation and prediction of polymer flood performance (Zeynalli et al., 2022).

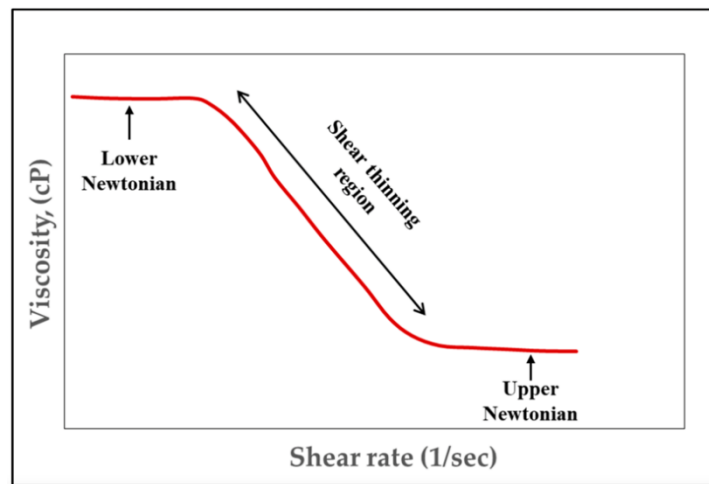


Figure 2.5 – Rheology of a shear-thinning fluid (log-log plot)(Muhammed et al., 2020)

The Carreau model is the most comprehensive model for describing the rheology of polymers (Zhu et al., 2022):

$$\mu = \left((\mu_0 - \mu_{inf}) [1 + (\lambda r)^a]^{\frac{n-1}{a}} + \mu_{inf} \right) \quad 2.9$$

μ is the apparent viscosity (mPa·s)

r is the shear rate (s^{-1})

μ_0 is the zero-shear viscosity (mPa·s)

μ_{inf} is the limit shear viscosity (mPa·s)

λ is the characteristic relaxation time (s)

a is the Carreau constant

n is the Carreau exponent.

2.3.2 Polymer solution flow in a capillary tube

The study of polymer solution flow via a capillary tube begins with examining Newtonian fluid behavior. The fundamental equations that regulate this flow are shown in equations 2.10 to 2.15.

The Hagen-Poiseuille equation describes the continuous, laminar flow of an incompressible Newtonian fluid under a pressure differential (Δp) in a cylindrical capillary of diameter D and length L (Mohtadi et al., 1984).

$$q = \frac{\pi D^4 \Delta p}{128L\mu} \quad 2.10$$

The wall shear rate $\dot{\gamma}_w$ of a Newtonian fluid is:

$$\dot{\gamma}_w = \frac{32q}{\pi D^4} \quad 2.11$$

For a shear thinning fluid described by the power law model, the average velocity u and the wall shear rate $\dot{\gamma}_p$ of a non-Newtonian fluid are (Holland & Bragg, 1995):

$$\dot{\gamma}_p = \frac{3n+1}{4n} \frac{8u}{D} \quad 2.12$$

And

$$\frac{\Delta p D}{4L} = K \left[\left(\frac{3n+1}{4n} \right) \frac{8u}{D} \right]^n \quad 2.13$$

The above equations will determine viscosity with the steel capillary viscometer for polymer solutions described in the subsequent experiment section. Taking the logarithm of both sides of Equation 2.13 yields:

$$\ln \left(\frac{\Delta p D}{4L} \right) = \ln K + n \ln \frac{8u}{D} \quad 2.14$$

$$\dot{K} = K \left(\frac{3n+1}{4n} \right)^n \quad 2.15$$

After measuring flow rates at different pressure drops, a graph of $\Delta p D / 4L$ vs. $8u/D$ can be plotted on a log-log scale. The slope of the curve represents the power law index n , while the intercept corresponds to the new consistency index K (Holland and Bragg, 1995).

2.3.3 Polymer flow in low-permeability porous medium

Unlike the simplistic geometry of a capillary tube, reservoir rock pore systems are complex three-dimensional networks with varied pore and throat size, connectivity, surface roughness, and chemical characteristics. Even under single-phase aqueous flow conditions, introducing a polymer solution of flexible macromolecules of various sizes into such a complex porous media results in very complicated interactions.

2.3.3.1 Power-law fluid flow through a packed bed

Polymer solutions cannot be correctly modeled using Darcy's Law, which is valid for Newtonian fluids with constant viscosity. The Blake-Kozeny model was adapted to describe polymer flow in porous media (Christopher & Middlemen, 1965). This improved model allows for determining average shear rates inside a porous material at a given flow velocity. Researchers can study the link between bulk and in-situ polymer solution viscosities by comparing calculated shear rates to apparent viscosities obtained with viscometers.

Similarly, the Blake-Kozeny equation, originally developed for Newtonian fluids, is extended to packed bed flow by including the hydraulic radius model (Bird & Carreau, 1968):

$$\frac{\Delta p}{L} = 150 \left(\frac{\mu u}{D^2} \right) \frac{(1 - \phi)^2}{\phi^3} \quad 2.16$$

In this equation, the variables u (m/s) denote surface velocity, D (m) the diameter of uniform packing spheres, ϕ porosity, Δp (Pa) pressure drop, and L (m) the packing bed's length. 150 is the experimental constant.

Comparing the preceding equation to Darcy's law yields the following expression for permeability k :

$$k = \frac{D^2 \phi^3}{150(1-\phi)^2} \quad 2.17$$

Building on the equation for non-Newtonian flow in a capillary tube and the previously mentioned hydraulic radius model, a new model for non-Newtonian fluids is proposed. This model modifies the Blake-Kozeny equation, assuming that the permeability remains constant for non-Newtonian flow in a packed bed (Christopher and Middlemen, 1965):

$$u = \frac{n\phi}{3n+1} \left(\frac{D\phi}{3(1-\phi)} \right)^{1+\frac{1}{n}} \left(\frac{6\Delta p}{25KL} \right)^{\frac{1}{n}} \quad 2.18$$

The average shear rate is:

$$\dot{\gamma}_{av} = \frac{3n+1}{4n} \frac{12u}{120k\phi} \quad 2.19$$

where n and K are determined by the relationship between shear stress and shear rate for a power-law fluid, and k denotes the permeability (m^2).

2.3.3.2 Polymer Stability

The preservation of polymer integrity is critical for effective polymer flooding. To do this, avoiding polymer degradation induced by chemical, biological, or mechanical forces is critical. The polymer can be chemically degraded when exposed to oxygen or iron, whereas bacterial activity causes biological breakdown. Furthermore, high-pressure circumstances near wellbore perforations can cause severe mechanical stress on the polymer, breaking it down and

decreasing its viscosity. Laboratory testing is essential for determining the stability of a polymer solution under varying circumstances (Lake, 1989). Laboratory experiments can be used to assess the stability of a polymer solution.

2.3.3.3 Polymer Retention in Porous Media

As a polymer solution flows through porous rock, polymer molecules interact with the rock's surface, leading to their retention on the rock surface. The loss of polymer can significantly impede oil recovery by slowing the movement of the polymer solution through the reservoir. The amount of polymer retained can vary greatly and directly impact the efficiency and economic viability of polymer flooding. Excessive polymer retention can drastically reduce oil displacement and make the process economically impractical (Lake, 1989).

To illustrate the impact of polymer retention, a delaying factor ranging from a minimal 10 μg to a substantial 200 μg is introduced, as shown in Figure 2.6. For instance, moderate retention of 100 μg in a 1000 ppm polymer solution necessitates approximately 51% more polymer to reach the desired formation depth compared to a scenario without retention. Conversely, a moderate retention of only 10 μg in a 2000 ppm solution results in a negligible delay of about 3%. Retention levels exceeding 200 μg can severely compromise oil displacement and the economic viability of polymer flooding (Ranganathan et al., 1998).

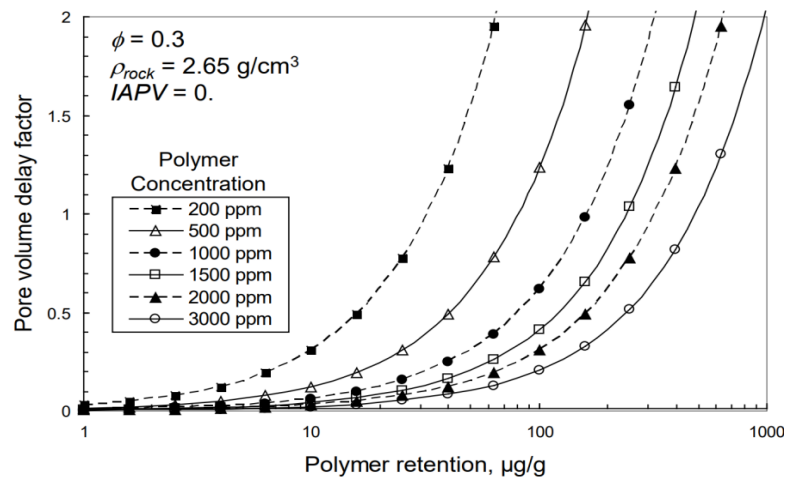


Figure 2.6 – Polymer bank delay caused by retention (Ranganathan et al., 1998)

Polymer retention in porous media is achieved by three mechanisms: mechanical entrapment, hydrodynamic retention, and adsorption, which are shown in Figure 2.7 (Dominguez & Willhite, 1977). Mechanical entrapment happens when large polymer molecules become trapped in small pores within porous media. Unlike smaller water and salt molecules, polymers cannot pass through these pores and accumulate there. Hydrodynamic retention occurs when polymers are temporarily held in stagnant areas of the reservoir by osmotic forces. Polymer adsorption is the primary cause of polymer retention and will be discussed subsequently.

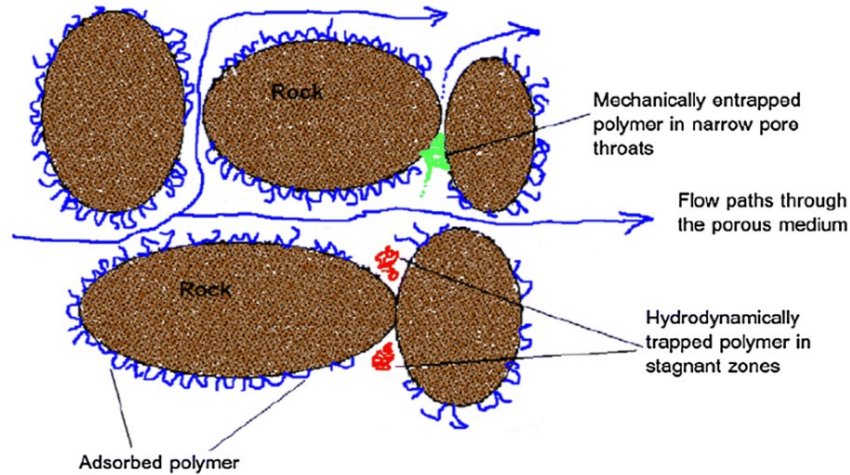


Figure 2.7 – Polymer retention in porous media (Huh et al., 1990)

Adsorption is the process by which polymer molecules bind to the rock surface. This interaction reduces the polymer concentration in the solution, impacting its viscosity and propagation. Although widely studied and often assumed to be instantaneous, adsorption is primarily a physical process—excluding chemical bonding (chemisorption)—that occurs over longer periods between the polymer and the rock surface (Seright, 2010; Sorbie, 1991). Generally considered irreversible, adsorption can be modeled using isotherms like Langmuir and Freundlich (Zhang & Seright, 2014). The Langmuir isotherm, commonly used for polymer adsorption, is expressed as:

$$\hat{C}_p = \min \left(C_p \frac{ap(C_p - \hat{C}_p)}{1 + bp(C_p - \hat{C}_p)} \right) \quad 2.20$$

C_p represents the injected polymer concentration while \hat{C}_p denotes the adsorbed polymer concentration. The equilibrium concentration within the rock-polymer solution system is represented by $(C_p - \hat{C}_p)$. The empirical constants ap and bp are used in the model (Sheng, 2010). Based on equilibrium conditions, the Langmuir model presupposes instantaneous and reversible polymer adsorption in relation to concentration. When polymer concentration decreases, and adsorption becomes irreversible, direct application of the Langmuir model is inappropriate. Consequently, an additional parameter is required to monitor adsorption history (Liu et al., 2007).

2.3.3.4 Resistance and residual resistance factor

Polymer adsorption can partially or fully block pore spaces, lowering permeability. There are several approaches for estimating this decrease. The resistance factor (RF), which compares water and polymer mobility before and after injection, may distinguish between adsorption effects and viscosity changes. However, it is not always accurate due to viscosity's

counteracting influence. The residual resistance factor is more prevalent. RRF is used in reservoir simulations to calculate permeability decline, directly related to adsorption. The RRF measures the water mobility before and after the flood, eliminating the influence of viscosity changes in the polymer (Jennings Jr & Newman, 1971). Under these conditions, Darcy's law applies to water and polymer flows.

Initial water flow:

$$q_w = \frac{k_w \Delta p_w A}{L \mu_w} \quad 2.21$$

Polymer solution flow:

$$q_p = \frac{k_p \Delta p_p A}{L \mu_p} \quad 2.22$$

Water flow after polymer solution flow:

$$q_{wp} = \frac{k_{wp} \Delta p_{wp} A}{L \mu_w} \quad 2.23$$

k_{wp} , q_{wp} and Δp_{wp} are permeability, rate, and differential pressure of water after polymer flood.

Then, the resistance factor RF is expressed as:

$$RF = \frac{\lambda_w}{\lambda_p} = \frac{\frac{k_w}{\mu_w}}{\frac{k_p}{\mu_p}} = \frac{\frac{q_w}{\Delta p_w}}{\frac{q_p}{\Delta p_p}} \quad 2.24$$

If the same flow rate is used for water and polymer, RF can be simplified as:

$$RF = \frac{\Delta p_p}{\Delta p_w} \quad 2.25$$

The residual resistance factor is given by:

$$RRF = \frac{\Delta p_{wp}}{\Delta p_w} \quad 2.26$$

The concepts and equations presented above will be used to analyze single-phase polymer solution flow through core samples. The residual resistance factor, also known as permeability decrease, measures the change in permeability before and after polymer flooding. Figure 2.8 depicts the relationship between permeability and permeability decrease as modeled by the UTCHEM chemical flood simulator. While permeability decrease is minor in high-permeability reservoirs where viscosity increase is the major goal, it has a greater influence in low-permeability formations. Polymer molecular weight, brine salinity, core permeability, and lithology all affect the reduction in permeability. Polymer flow instability or full core clogging may occur (Gao, 2014).

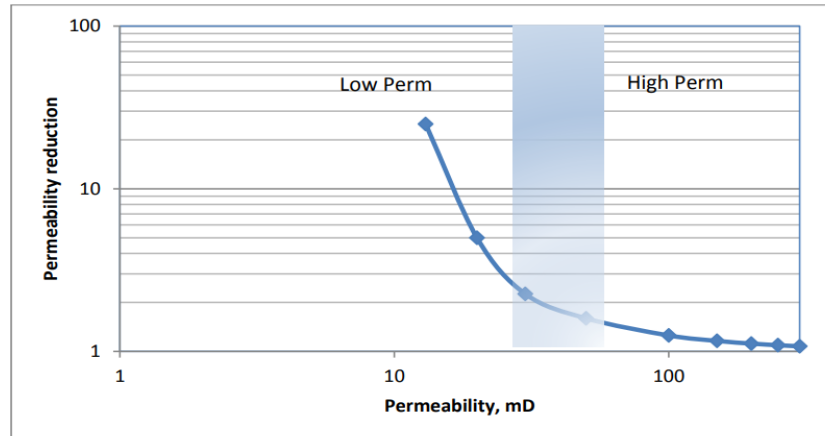


Figure 2.8 – Illustrative plot of the relation between permeability reduction and permeability (Gao, 2014)

The reduction factor R_k , expressed as:

$$R_k(c_p) = 1 + (RRF - 1) \frac{c_a(c_p)}{c_{a,max}} \quad 2.27$$

When RRF is greater than or equal to one, it indicates that the adsorbed polymer (c_a) has reached its maximum capacity ($c_{a,max}$). Estimating permeability reduction is crucial during polymer flood design and planning as it affects injection rates and fluid flow patterns. However, this approach is primarily suitable for conventional, highly permeable reservoirs where adsorption is the main cause of permeability decline. In contrast, tight reservoirs primarily experience permeability reduction due to polymer entrapment (Huh et al., 1990).

The inaccessible pore volume occurs when pore throats are too narrow for a polymer molecule of a certain molecular weight. IPV prevents polymer solutions from reaching certain reservoir areas because polymer molecules only flow via bigger holes. Polymer solution will thus flow quicker via the bigger pores than any accompanying tracer, which will have complete access to the whole reservoir. IPV may cause viscous fingering and bypassing the oil (Sorbie, 1991). Wall exclusion is a second mechanism contributing to the accelerated travel speed of polymer solutions due to IPV. This phenomenon arises when polymer molecules proximate to the pore wall are repelled towards the pore center, increasing polymer concentration within this region. Given the typically higher velocity of fluid streamlines at the pore center than those near the wall, the concentrated polymer solution experiences faster transport relative to tracers, which tend to disperse more uniformly throughout the reservoir (Lake, 1989). It should be noted that polymer adsorption can impede the flow of a polymer solution, which can have a similar effect to IPV (Sorbie, 1991).

2.3.3.5 Influence of polymer molecular weight on polymer flooding in low-permeable rocks

Various investigations are undertaken on applying polymer flooding to reservoirs with limited permeability. Early studies revealed polymer solutions' high resistance and unsteady-state flow through low-permeability rock materials. These difficulties become more obvious when employing high molecular weight polymers or extremely low permeability rocks (Jennings Jr & Newman, 1971; Martin, 1974; Pye, 1964). Later experiments with different rock samples revealed that large polymer molecules can become stuck in the rock's entry, resulting in significant resistance. However, smaller molecules can flow through with little resistance (Fletcher & Morrison, 2008). A correlation was established between polymer molecular weight and permeability (Figure 2.9) when polymer blockage occurs in low-permeability reservoirs (Wang et al., 2009). However, the specific conditions leading to this blockage were not detailed.

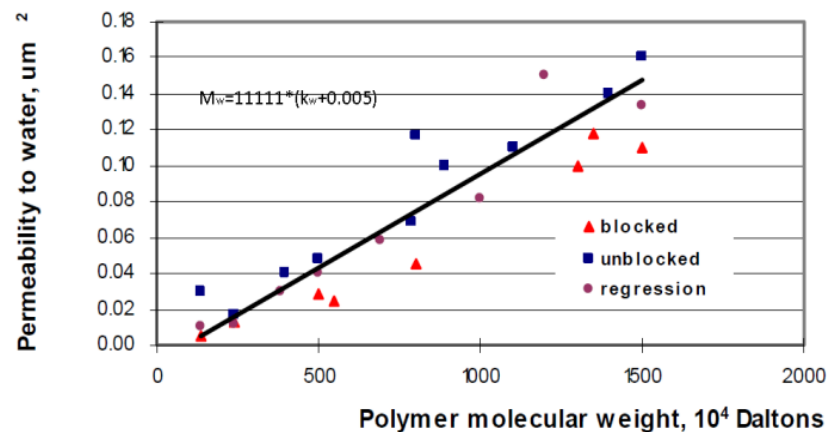


Figure 2.9 – Blocking correlation between molecular weight and permeability (Wang et al., 2009)

The correlation which is established is:

$$Mw = 11111 * (k_w + 0,005) \quad 2.28$$

Here, Mw denotes the molecular weight in units of 10,000 Daltons, and k_w signifies water permeability in terms of square micrometers.

For example, in the Daqing oil field, polymers with a molecular weight of 12 to 16 million Daltons are commonly permitted in rocks with a permeability of 100 millidarcies. However, given the existing reservoir's average permeability of just 10 millidarcy, the appropriate polymer molecular weight would be substantially lower, estimated at 1 to 2 million Daltons based on this association. It is important to note that this is only a preliminary estimate, as the original correlation was derived for a reservoir with a different salinity and pore structure than the current one. Consequently, using lower molecular weight polymers in formations with

lower permeability is generally recommended. The optimal molecular weight can only be accurately determined through flooding tests (Wang et al., 2009).

2.4 Liquid polymer

Liquid polymers are versatile materials composed of polymeric substances dissolved or dispersed in a liquid medium. They offer unique properties and applications across various industries. The following subsections explore liquid polymers' fundamental components, characteristics, and applications.

2.4.1 Components of Liquid Polymer Formulations

The creation of liquid polymers involves several crucial elements, each playing a distinct role in boosting the polymer's efficacy and longevity. The foundation of these mixtures is the base polymer, which imparts the desired characteristics such as viscosity and flow patterns. Typical base polymers range from synthetic varieties like Partially Hydrolyzed Polyacrylamide (HPAM) to natural biopolymers such as Xanthan Gum (Ryles & Cicchiello, 1986)

Unlike powder polymers, liquid polymers are typically prepared as inverse water-in-oil emulsions. This structure consists of oil, which forms the continuous phase of the emulsion, and water, which is present as the dispersed phase, containing the dissolved polymer. This emulsion structure allows for easier handling and rapid deployment, especially in offshore or remote locations (Dwarakanath et al., 2016).

A critical component in liquid polymer formulations is the inversion surfactant. This surfactant is essential for the emulsion to invert when mixed with water, releasing the polymer for hydration. The surfactant emulsifies the carrier oil effectively, facilitating the transition from the inverse emulsion to a polymer solution (Dwarakanath et al., 2016).

Stabilizers are introduced to ensure the polymer's durability over time. These compounds help prevent breakdown, separation of components, or growth of microorganisms and may include preservatives and surface-active agents (Ambrogi et al., 2017).

Thickening agents are incorporated to modify the viscosity of the liquid polymer, facilitating the achievement of the required flow properties for various applications. Sometimes, these thickeners are polymers or additives that alter the polymer's behavior in solution. Substances that adjust pH are also vital in the formulation process; they maintain the appropriate acidity level, ensuring the polymer remains effective throughout its storage period. Depending on the formulation requirements, these pH modifiers can be acidic or basic (Zeyghami et al., 2014).

For certain preparations, crosslinking agents enhance the polymer's properties by establishing chemical connections between polymer strands, which can improve stability and performance,

particularly in gel-like applications. Furthermore, various additives may be included to further modify the polymer's behavior under different conditions, such as agents sensitive to temperature changes or those that enhance interactions with other materials. Antimicrobial agents are crucial for preventing contamination by microorganisms and extending the usable life of the liquid polymer, especially in water-based solutions (Ambrogi et al., 2017).

Liquid polymer activation entails changing the molecular structure of the polymers to improve oil displacement properties. Usually, chemical or physical procedures like hydrolysis, oxidation, crosslinking, or physical treatments are used to accomplish this. Improved oil recovery results from highly activated polymers' prolonged conformations, higher viscosity, and charge density. Figure 2.10 depicts the activation of liquid polymer in the hydrolysis process.

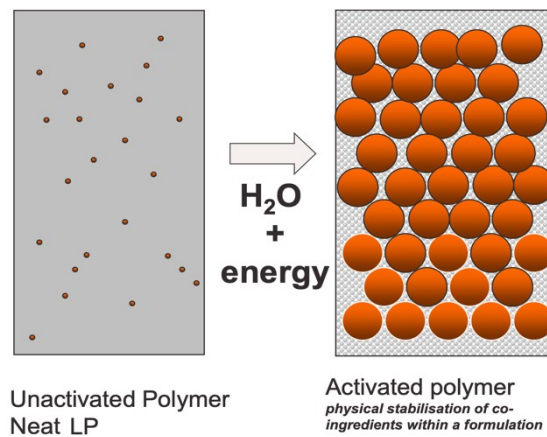


Figure 2.10 – Activation process of liquid polymer

2.4.2 Liquid vs. Powder Polymers in Enhanced Oil Recovery

Liquid and powder polymers are two distinct forms employed in various industries, including EOR. The choice between these forms depends on specific application requirements, handling preferences, and logistical factors.

- Characteristics and Preparation:** Liquid polymers are typically supplied as aqueous solutions or emulsions, with the polymer dissolved or dispersed in a liquid medium. They are manufactured through a water-in-oil emulsion process and subsequent water removal. Liquid polymers require an inversion surfactant to emulsify the oil and allow for HPAM hydration. Powder polymers, in contrast, come in a dry, granular, or powdered state, requiring dissolution or hydration before use. Recent polymer flooding projects have primarily relied on powdered HPAM polymers, especially in onshore operations, due to the space available for storing, mixing, and creating the viscous

solutions necessary for injection. Preparing these polymers involves creating a dilute solution and further diluting (Ryles & Cicchiello, 1986).

- **Handling and Application:** Liquid polymers offer greater convenience in preparation and handling, as they can be directly incorporated into processes without additional mixing or dissolution steps. They don't require specialized handling or dispensing equipment, making them ideal for offshore operations where space is restricted and adapting old platforms is not feasible. Powder polymers require an initial dissolution or mixing phase with water, which can be time-consuming and demands appropriate equipment to ensure complete dissolution and prevent clumping. Precise handling and measurement of the powder during the initial mixing phase are crucial for producing high-quality polymer solutions. The success of the Marmul polymer pilot, which employed a 30% liquid HPAM solution, has demonstrated the viability of liquid polymers for enhanced oil recovery (Teeuw et al., 1983).
- **Storage and Stability:** Liquid polymers often have a shorter shelf life due to potential chemical degradation, such as hydrolysis or microbial growth, especially in aqueous solutions. They might require specific storage conditions, such as temperature control, to maintain stability. Powdered polymers typically have a longer shelf life greater stability, are less prone to degradation, and support less microbial growth. Shelf time, or shelf life, is crucial in EOR when a polymer remains effective and stable under specified storage conditions. This ensures the polymer maintains its intended performance characteristics, such as viscosity enhancement and mobility control. Factors influencing shelf life include chemical and physical stability, environmental conditions (temperature, humidity, light exposure), and packaging type. Determining shelf life involves stability testing under controlled conditions. Effective management requires optimal storage conditions and proper inventory practices (Ryles & Cicchiello, 1986).
- **Transportation and Logistics:** Liquid polymers, being bulkier and heavier, incur higher transportation costs and pose more complex handling challenges. However, they can be easily shipped to remote and offshore locations without the complexities associated with powder handling. Powder polymers, being more compact and lightweight, are easier and more economical to transport and store, making them suitable for onshore operations with available space (Dwarakanath et al., 2016).
- **Performance and Cost Considerations:** Despite their distinct manufacturing techniques, Liquid polymers show lower retention during core floods when compared to powder polymers with similar molecular weights (Osterloh & Law, 1998). The success of the Marmul polymer pilot, which employed a 30% liquid HPAM solution,

has demonstrated the viability of liquid polymers for enhanced oil recovery. Cost-wise, liquid polymers tend to be more expensive per unit of active polymer, partly due to solvents, stabilizers, and higher transportation costs. Powder polymers are generally less expensive per unit of active polymer but may incur additional costs for mixing or dissolution equipment (Teeuw et al., 1983).

- Injectivity:** Effective polymer flooding hinges on maintaining high injection rates by preventing polymer buildup near the wellbore. While powdered polymers generally exhibit good long-term injectivity when mixed with treated water and allow sufficient hydration, liquid polymers pose a higher risk of wellbore plugging. This is partly due to suspended oil droplets in liquid polymer formulations, which can reduce permeability through straining or interception (Schmidt & Binder, 1985). Straining occurs when oil droplets from the emulsion become trapped within the pore spaces, blocking fluid flow. Interception refers to the adhesion of oil droplets to the rock surface, reducing the available pore space and hindering fluid movement. Figure 2.11 visually depicts both these processes during stable emulsion flow through porous rock. Liquid polymers are more costly than powdered polymers due to inactive carrier oil and require specific chemical additives for emulsification. These additives may interact negatively with surface equipment. Traditional polymer selection methods primarily focus on polymer rheology and oil recovery efficiency. This emphasis arises from plugging issues like interception and straining, commonly associated with liquid polymers, which are generally not observed when using powdered polymers (Dwarakanath et al., 2016).

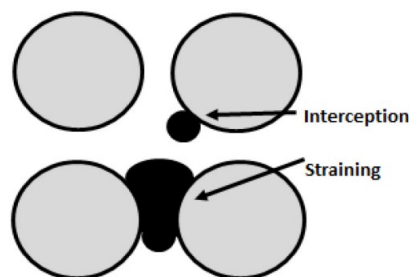


Figure 2.11 – Plugging phenomena: interception or straining of oil in porous media (Dwarakanath et al., 2016).

- Recent Advancements:** Current polymer flooding research focuses on enhancing polymer stability and effectiveness, understanding polymer-reservoir rock interactions, and developing polymers for harsh reservoir conditions. Emerging areas include incorporating nanoparticles into polymer solutions and exploring "smart" polymers that respond to specific reservoir conditions, such as pH or temperature changes, to optimize performance.

2.4.3 Advantages and Disadvantages of Powder and Liquid Polymers

This section reviews the advantages and disadvantages of powder and liquid polymers that should be considered.

Advantages of Powder Polymers:

- **Higher Polymer Concentration:** Powder polymers typically offer higher active polymer content than liquid forms, leading to greater efficiency in EOR applications (Teeuw et al., 1983).
- **Longer Shelf Life:** Powders have better stability and are less prone to degradation over time, especially when stored properly (Ryles and Cicchiello, 1986).
- **Lower Transportation Costs:** Powders are more cost-efficient to transport without added water or solvents due to their lower weight and volume (Teeuw et al., 1983).
- **Flexibility in Preparation:** Powder polymers can be mixed on-site, allowing greater control over concentration and solution quality, which is particularly useful in different reservoir conditions (Dwarakanath et al., 2016).
- **Better Control over Viscosity:** Powders allow precise viscosity control, ensuring better sweep efficiency and oil displacement (Ryles & Cicchiello, 1986).
- **Reduced Risk of Microbial Growth:** Powders are less susceptible to contamination by microbes during storage (Ryles & Cicchiello, 1986).

Disadvantages of Powder Polymers:

- **More Complex Handling:** Powders require careful mixing on-site, which can introduce logistical challenges (Dwarakanath et al., 2016).
- **Potential for Dust Formation:** Handling powder polymers can result in dust, which poses safety and environmental risks (Dwarakanath et al., 2016).
- **Mixing Time:** Dissolving powders properly in water or brine requires time, which may delay operational schedules (Dwarakanath et al., 2016).

Advantages of Liquid Polymers:

- **Easy to Handle and Mix:** Liquid polymers come pre-mixed and can be injected directly, simplifying field operations and saving time during preparation (Dwarakanath et al., 2016).
- **Consistent Polymer Solution:** Since they are pre-mixed, liquid polymers provide a uniform solution ready for immediate use, reducing the potential for preparation errors (Dwarakanath et al., 2016).

Disadvantages of Liquid Polymers:

- Lower Active Polymer Content: Liquid polymers are often diluted, leading to less efficient performance than powder polymers (Dwarakanath et al., 2016).
- Shorter Shelf Life: Liquid polymers can degrade over time due to microbial growth, oxidation, or exposure to light (Ryles & Cicchiello, 1986).
- High Transportation and Storage Costs: Due to solvents or water, liquid polymers are heavier and bulkier, leading to higher logistical costs (Ryles & Cicchiello, 1986).
- Susceptibility to Shear Degradation: Liquid polymers are prone to breaking down under mechanical stress during pumping and handling, which can reduce their effectiveness (Teeuw et al., 1983).
- Incompatibility with High-Salinity Brines: Liquid polymers, especially in emulsion form, may become unstable in brine containing high concentrations of divalent ions like calcium and magnesium. This instability can lead to precipitation, reduced viscosity, or emulsion breaking (Teeuw et al., 1983).

2.5 Liquid Polymer Case Studies

The Captain field in the North Sea UKCS is a high-viscosity crude accumulation with exceptional reservoir quality, making it an ideal candidate for polymer flooding to enhance oil recovery. The field's characteristics include Lower Cretaceous turbiditic sandstones, shallow unconsolidated formation, average reservoir permeability of 7,000 md, low clay content, low temperature (Ambrogi et al.), oil viscosity ranging from 48-200 cp at reservoir conditions, and high oil-water mobility ratios of 18-75. Two liquid HPAM products, HPAM-1 and HPAM-2, 30% hydrolyzed with up to 50% active concentration, were primarily tested due to offshore logistical constraints. The experiments used synthetic brines with 13,000 ppm and 18,000 ppm total dissolved solids (TDS) to represent Captain field brine. The brine composition included NaCl (11.02 g/kg), KCl (0.10 g/kg), CaCl₂·2H₂O (1.042 g/kg), MgCl₂·6H₂O (1.35 g/kg), BaCl₂·2H₂O (0.05 g/kg), and SrCl₂·6H₂O (0.25 g/kg). Crude oil from the lower Captain sand was dried, filtered, and thinned with tetralin to match live oil viscosity (88 cp at 87°F) (Osterloh & Law, 1998).

Key experiments included phase stability and viscosity, polymer flood, and membrane filtration tests. The polymer flood experiments were conducted in composite Captain core stacks at a Darcy velocity of 1 ft/day and 87°F. These tests measured polymer retention, RRF, and in-situ viscosity. The process involved sequentially injecting a 500ppm polymer solution containing a tracer followed by brine into a core sample initially saturated with residual oil from waterflooding. Each experiment consisted of two steps: 1) continuous injection of the polymer-

tracer solution until the polymer concentration in the produced fluid stabilized or increased gradually, and 2) subsequent injection of brine until the polymer concentration in the effluent became negligible. The produced fluids were analyzed for both polymer and tracer content. HPAM-1 and HPAM-2 exhibited suitable viscosities for Captain brine, suggesting potential applicability. Apparent viscosities vs shear rates for these two liquid HPAMs are shown in Figure 2.12 and Figure 2.13 (Osterloh & Law, 1998).

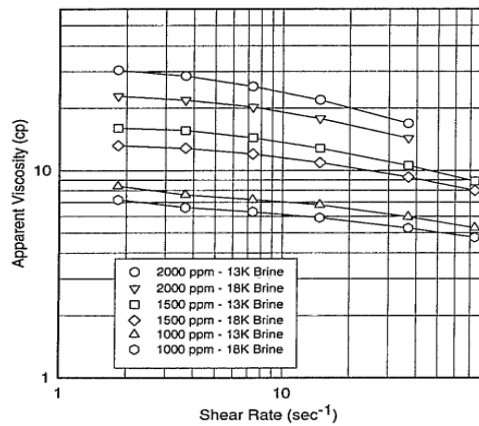


Figure 2.12- Viscosity of HPAM-1 in Captain brine at 87°F (Osterloh & Law, 1998)

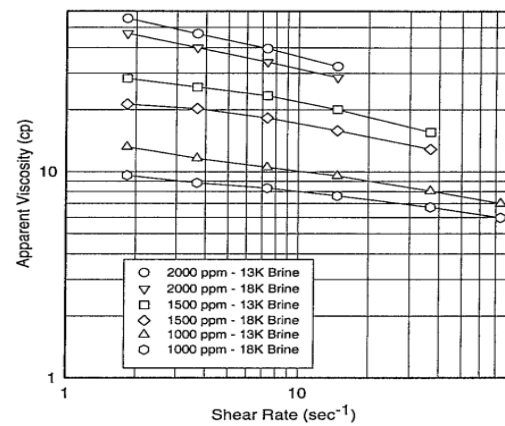


Figure 2.13 - Viscosity of HPAM-2 in Captain brine at 87°F (Osterloh & Law, 1998)

Both polymers were retained within the core through adsorption and Mechanical entrapment. The effluent polymer concentration failed to match the injected concentration, and there was a persistent increase in pressure gradient. Polymer retention in the core was primarily due to adsorption and mechanical entrapment. While adsorption occurred throughout the core, mechanical entrapment was more pronounced near the sand face, significantly impacting polymer propagation. The Captain formation's low clay content and high permeability resulted in lower-than-expected polymer retention. However, the RRF was unacceptably high, primarily due to mechanical entrapment caused by a dispersed phase within the polymer solution. This issue, which could lead to wellbore plugging if not addressed, was persistent despite filtration attempts. To isolate the impact of a dispersed phase in the liquid polymer solutions, identified as a water-in-mineral oil emulsion, on polymer propagation and pressure build-up, flow experiments are conducted using polymer/tracer solutions free of mineral oil created from solid-form HPAM. Figure 2.14 and Figure 2.15 illustrate the effluent profiles of these experiments using 500 ppm solid-form HPAM solutions in Captain brine. Unlike in prior tests, the pressure gradient remained stable, and the polymer concentration in the generated fluid matched the injected concentration. This result shows that the poor polymer propagation seen with liquid HPAM solutions was due to a dispersed phase.

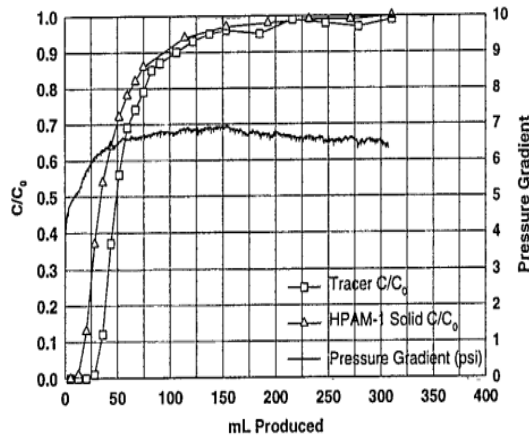


Figure 2.14 – Elution curves and pressure gradient of HPAM-1 solid (Osterloh & Law, 1998)

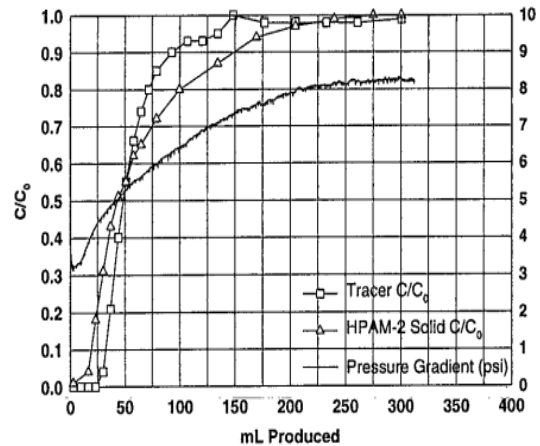


Figure 2.15 - Elution curves and pressure gradient of HPAM-2 solid (Osterloh & Law, 1998)

Membrane filtration experiments supported the core flood observations by demonstrating significantly higher pressure build-up with liquid HPAM solutions compared to stable pressures with solid HPAM solutions. Analysis revealed the dispersed phase in liquid HPAMs to be a mineral oil-water-polymer emulsion. This emulsion was responsible for the increased pressure and impeded polymer flow, as confirmed by filtration tests. The clear initial filtrate, followed by a cloudy filtrate with higher polymer concentration under increased pressure, indicated the emulsion's deformation and passage through the filter. Given the correlation between filtration and core flood results, this method proved effective for rapidly screening potential polymer solutions for Captain field suitability. By employing the Millipore membrane filtration technique, HPAM-4 was selected for further tests. These new polymers maintained the desired bulk concentration for offshore operations, exhibited enhanced viscosity and injectivity compared to their predecessors, and demonstrated excellent filterability when a 1500 ppm solution of HPAM-4 was injected into a one ft long x 1.5 in. diameter, 6,000 md sand pack at S_{orw} . HPAM-4 viscosity and injectivity are shown in Figure 2.16 and Figure 2.17 (Osterloh & Law, 1998).

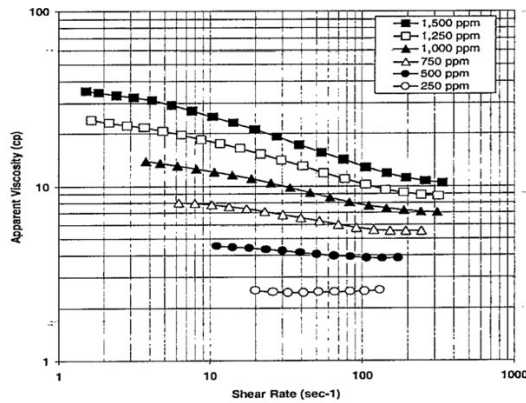


Figure 2.16- Viscosity of HPAM-4 in 13,000ppm Captain brine at 87°F (Osterloh & Law, 1998)

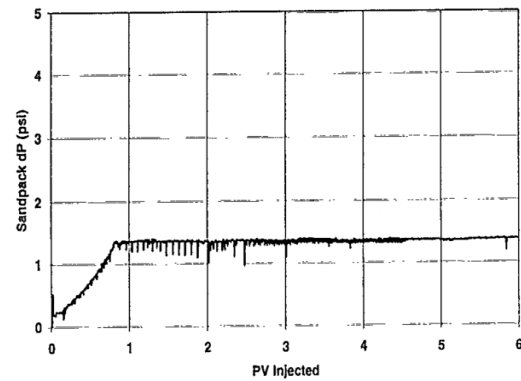


Figure 2.17 – Pressure gradient of 1500ppm HPAM-4 injection in a 6000md sand pack at S_{orw} (Osterloh & Law, 1998)

However, during the development process, a critical observation was made regarding the impact of pH on HPAM stability. A slightly acidic HPAM solution displayed rapid viscosity loss in a stainless steel rheometer at a low shear rate and room temperature, highlighting the importance of pH control and potential material interactions for polymer stability (Osterloh & Law, 1998).

Despite promising results, the implementation of polymer flooding at Captain faced several challenges. These included substantial costs, complex offshore logistics, compatibility issues with horizontal wells, potentially increased corrosion rates, microbial contamination risks, and difficulties separating oil and water (Osterloh & Law, 1998).

In another study, valuable insights into applying liquid polymers for EOR conducted under specific experimental conditions are studied. The research used Bentheimer rock as the porous medium, with brine of 16,000 TDS at a temperature of 31°C. The liquid polymers tested had molecular weights ranging from 18 to 21 million Daltons, and the oil used in the experiments had a viscosity of 80 cP. The permeability of the rock samples varied between 1.3 and 2 Darcies. This study investigated the long-term effects of liquid polymer use on injectivity and developing remediation methods. One of the study's key findings was the varying effects of different liquid polymers on permeability over time. Some first-generation liquid polymers showed significant permeability reduction in core samples after 3-4 pore volumes of injection, confirming the concerns raised by earlier studies about interception and straining mechanisms (Dwarakanath et al., 2016). Figure 2.18 depicts the pressure drop and relative permeability reduction of one of the first-generation liquid polymer solutions.

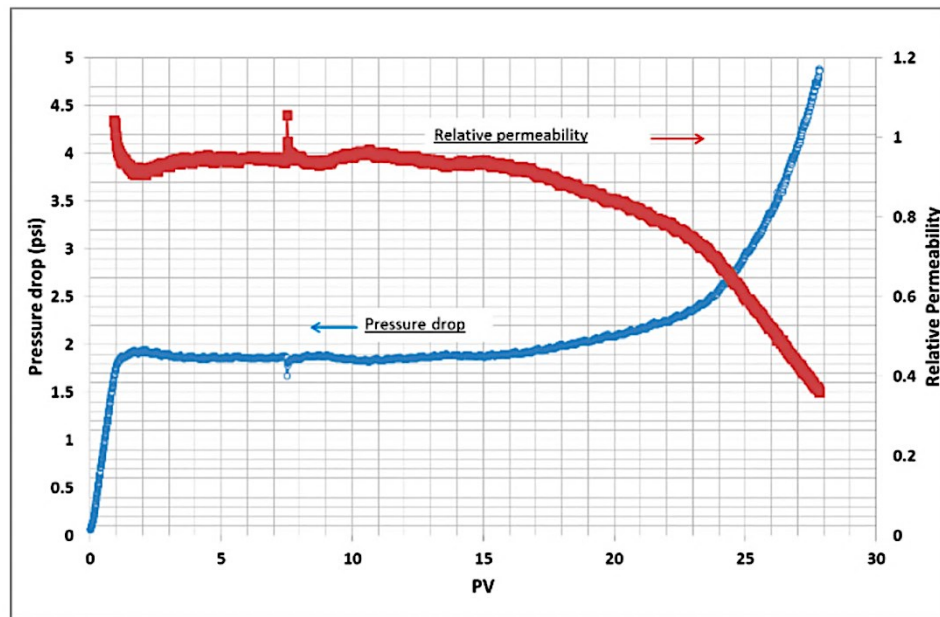


Figure 2.18- Pressure drop and relative permeability for injectivity test in Bentheimer sandstone cores (Dwarakanath et al., 2016)

The initial attempt to prevent permeability reduction involved testing second-generation liquid polymers, as the first-generation liquid polymers were found to plug the Bentheimer sandstone due to their large particle sizes. To avoid plugging, the particle size of liquid polymers should be 10% smaller than the pore throats. The second-generation liquid polymers successfully addressed this issue by having smaller particle sizes that allowed them to pass through the pores without causing blockages (Dwarakanath et al., 2016).

The researchers developed surfactant-polymer formulations to address the permeability reduction issue as remediation solutions. These formulations were injected after the initial polymer flood to improve injectivity by solubilizing trapped oil, a novel approach to addressing liquid polymer-induced damage. This remediation technique improved relative permeability, demonstrating the potential for maintaining long-term injectivity in liquid polymer EOR operations. The study found that plugging tends to be more severe near the injection face of the core. This near-wellbore effect is particularly important as it suggests that periodic treatments could alleviate the problem without making the process prohibitively expensive. Incorporating surfactants into the liquid polymers reduces the number of suspended particles, as some of the oil would be incorporated into the surfactant micelles. The oil trapped due to straining and interception would also be solubilized, increasing relative permeability (Dwarakanath et al., 2016).

Another significant finding was the effect of iron on polymer performance. The presence of iron was found to exacerbate plugging issues and affect polymer stability (Seright & Skjevrak, 2015). The study demonstrated that using chelating agents like Ethylenediaminetetraacetic acid

(EDTA) could mitigate the negative effects of iron, providing a practical solution for field applications where iron content in formation water is a concern (Dwarakanath et al., 2016).

Chapter 3

Liquid Polymers: Experimental Investigation

EOR techniques are increasingly employed to improve hydrocarbon recovery from mature reservoirs. Among these methods, polymer flooding has emerged as a promising approach for enhancing oil displacement efficiency. This study evaluates the potential of polymer flooding for improving oil recovery from the Hochleiten field in Austria. Both liquid and powder polymer formulations will be investigated and compared to achieve this objective.

The research encompasses several key areas. The reservoir's characteristics, including crude oil and brine properties and interfacial tension, will be comprehensively assessed. Subsequently, suitable liquid polymers will be selected and characterized. The rheological behavior of the chosen polymers under varying conditions will be investigated to understand their flow properties. Finally, the stability and compatibility of the polymers will be evaluated to determine their suitability for field application.

Core flood experiments will further assess the selected polymers' performance under reservoir conditions. Single-phase and two-phase flow experiments will be performed to evaluate polymer injectivity and recovery factors. The results of these experiments will provide valuable insights into the potential effectiveness of polymer flooding in the Hochleiten reservoir.

This study aims to contribute to the understanding of polymer flooding in the context of the Hochleiten reservoir and to provide recommendations for future development and implementation of EOR projects in similar reservoir settings.

3.1 Hochleiten field description

The field Hochleithen consists of stacked reservoirs. The field's hydrocarbon production is derived from two key Sarmatian reservoirs with significant oil accumulations and production performance. The 11th Sarmatian reservoir comprises an Original Oil in Place (OOIP) range from 895,000 to 1,340,000 cubic meters, of which 442,000 cubic meters have been successfully produced, resulting in an outstanding recovery factor of 33%-49%. Similarly, the 12th Sarmatian reservoir has an OOIP of 863,000 to 1,409,000 cubic meters and a cumulative production of 359,000 cubic meters, with a recovery factor ranging from 25% to 42%.

Production started in 1974, and water injection started in 2019 in the 11th Sarmatian, the target formation for viscous saltwater injection. The oil's viscosity ranges from 50 cP to 130 cP at 36°C, and the reservoir pressure is depleted to approximately 25 bar. As water flooding has occurred in this reservoir, the temperature around the injecting well is 25°C. Reservoir permeability is expected to vary significantly from 20 mD to 4000 mD, and the average reservoir permeability is 500 millidarcy. In 2020, a tracer study established connections between the injection well and the producers.

Due to the remote location of the Hochleithen field underneath a forest, there are limitations regarding surface installations. To ensure a relatively small footprint, injecting liquid polymers is an interesting alternative to powder polymers.

The southwest-northeast trending Vorstaffel Fault structurally defines the Hochleithen Field, which lies northwest of the Matzen Field on the southern boundary of Mistelbach High (Figure 3.1). The field is distinguished by a highly compartmentalized structure with stacked reservoirs, with the primary hydrocarbon accumulations located in the Tiefscholle region, notably within the Sarmatian and Tortonian layers. The depositional environment represents a transition from alluvial to coastal plain settings, with principal reservoir rocks comprising alluvial and crevasse channel sandstones. These reservoir units are inextricably linked to floodplain and levee deposits, revealing a dynamic depositional mechanism that created the field's complex stratigraphic architecture.

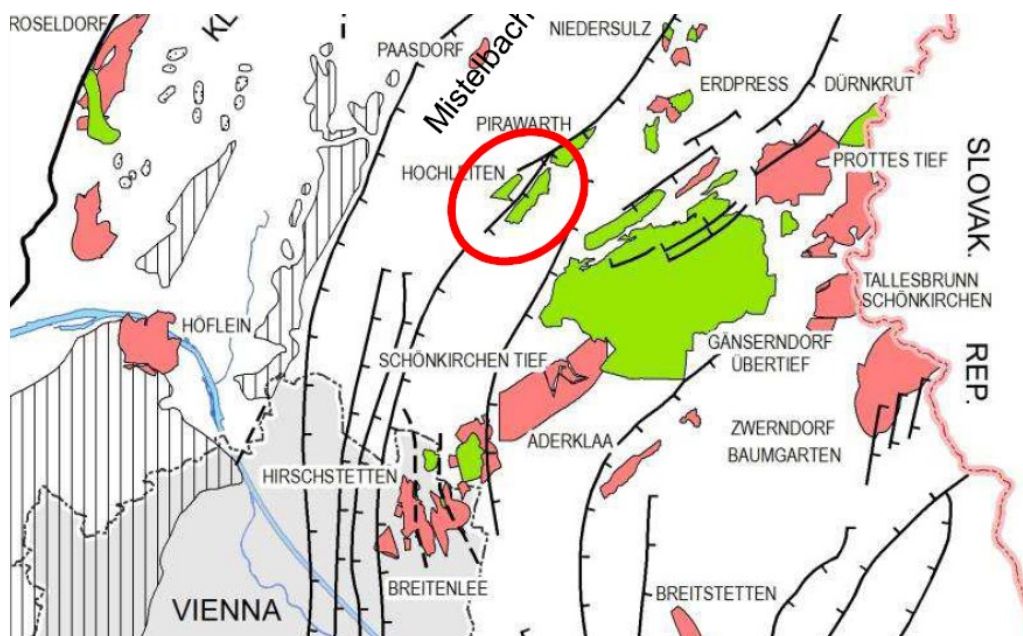


Figure 3.1 – Hochleithen Field location

3.1.1 Oil Properties

The oil composition and properties of the studied field are summarized in Table 3.1.

Table 3.1 – Hochleiten field oil properties

Hochleiten Oil Properties	
Density @20°C (g/cm ³)	0.93
API (°)	19.97
Viscosity at current reservoir pressure (at 25 bar and 36 °C)	84
TAN (mg KOH/g)	1.56
Saturates (%)	36.3
Aromatics (%)	53.2
Resins (%)	9.2
Asphaltene (%)	1.4

3.1.2 Brine Properties

Brine sourced from the 8TH Water Treatment Plant is used in polymer preparation and flooding. This brine exhibits a viscosity of 0.997 centipoise at 25 degrees Celsius. The specific chemical composition and properties of the brine are detailed in Table 3.2.

Table 3.2 – 8 TH brine properties

Base Brine 8TH WTP	
NaCl (mg/L)	22,470
KCl (mg/L)	160
MgCl ₂ *6H ₂ O (mg/L)	630
CaCl ₂ *6H ₂ O (mg/L)	940
pH-value	7.24
Density @20°C (g/cm ³)	1.014
TDS calc. (mg/l)	21,360
Total hardness (°dH)	36.8

3.2 Polymer Solutions

This section will delve into the preparation and properties of the polymer solutions employed in this study. The following experiments use four liquid polymer products, each with a unique formulation. All polymers contain a combination of HPAM, likely water as a solvent, surfactants, and oil-based components.

3.2.1 Polymer Selection and Preparation

The research introduces two polymer products: LP#1 and LP#2. These products undergo a series of evaluations, including product specifications, flow behavior analysis, and single-

phase testing. Further liquid polymers, LP#3 and LP#4, modified versions of LP#1, are then added for analysis. Detailed specifications for all polymers involved are summarized in Table 3.3. The milky appearance of the polymer when mixed with 8TH brine is shown in Figure 3.2, approving the existence of emulsions in polymer solutions.

A target viscosity of 20 cP at 20°C was established as the desired rheological property for effective polymer flooding, resulting in a mobility ratio 4.9 at the reservoir temperature of 36°C. This value was selected based on experience, as propagating a fluid through an entire reservoir, especially one with high viscosity, is challenging due to substantial pressure drops. Near-wellbore viscoelastic effects can occur, combined with potential fracturing and plugging of high-permeability pores.

Table 3.3 – liquid polymer specification

Product	Molecular weight (million Daltons)	Used Polymer concentration (ppm)
LP#1	18-22	1,200
LP#2	22-25	2,250
LP#3	< 18-22	1,300
LP#4	<< 18-22	1,800

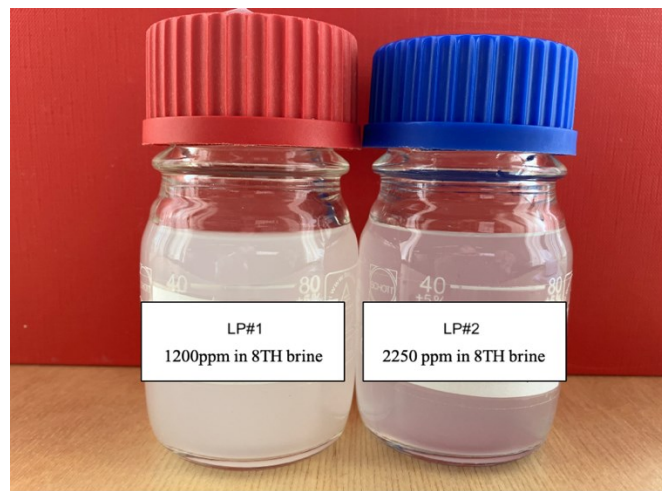


Figure 3.2 - Liquid polymers appearance

The mother solution is first prepared to make the polymer solutions. The active polymers are shaken and mixed because, as shown in Figure 3.3, primary active polymers are not homogenous before shaking. The objective is to prepare the mother solution from inverse emulsion. It is recommended to inverse the emulsion at a concentration of 10,000 ppm for LP#1 and 20,000 ppm for LP#2. The needed polymer is calculated using the equation 3.1 provided by vendors.

$$\text{Needed polymer amount (g)} = \frac{\text{Target concentration(ppm)} * \text{Total weight(g)}}{\text{active polymer concentration (ppm)}} \tag{3.1}$$

The active polymer concentration is 500,000 ppm for LP#1 and 1,000,000 ppm for LP#2, and the target concentration of the mother solution (stock solution) is 10,000 ppm and 20,000 ppm, respectively. After weighing the active polymer and 8TH brine amount, the solution is stirred at 500 rpm for 2 hours. This mother solution is then further diluted using the following equation given by vendors to attain the desired concentration:

$$\text{Needed stock solution amount (g)} = \frac{\text{Total weight(g)} * \text{target concentration(ppm)}}{\text{stock solution concentration (ppm)}} \quad 3.2$$



Figure 3.3 – 500,000 ppm active polymers before shaking

3.3 Rheological and Stability Assessment

A comprehensive study of their rheological and stability properties will be conducted to evaluate the suitability of polymer solutions for enhanced oil recovery. This research will determine the relationship between shear viscosity and shear rate, concentration, and temperature. Additionally, the polymer solutions' thermal stability over time and their interfacial tension behavior will be assessed. Understanding these properties can effectively evaluate the potential of polymer solutions to improve oil recovery.

3.3.1 Viscosity measurements

Kinexus device measures the viscosity in different shear rates and concentrations. The Kinexus is a sophisticated rheometer manufactured by NETZSCH Analyzing and Testing. It's designed to accurately measure the flow properties of a wide range of materials. When using a cylindrical measuring setup to analyze fluids that become thinner under stress (shear thinning), advanced calculations are necessary to compensate for factors like equipment precision, the specific shape of the measuring tools, and data refinement.

Figure 3.4 and Figure 3.5 show shear viscosity vs. shear rate at 20°C for LP#2 and LP#1, respectively. Both products have the proper shear viscosity and depict shear thinning behavior, which is important for polymer flooding.

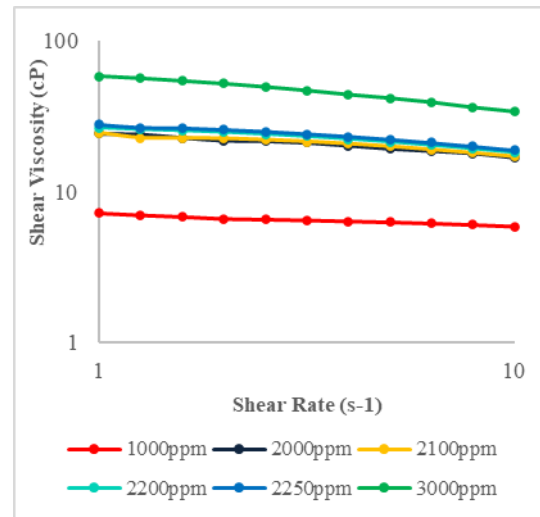
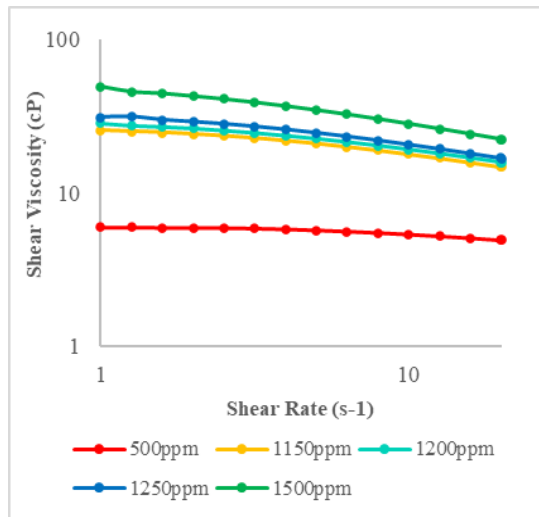


Figure 3.4 - LP#1 shear viscosity vs. shear rate Figure 3.5 - LP#2 shear viscosity vs. shear rate

Shear viscosity in different concentrations at 20°C is measured and shown in Figure 3.6. To compare the first two polymer products, each concentration value in ppm is divided by two target concentrations: 1200 ppm and 2250 ppm, representing the planned polymer solution concentrations for LP#1 and LP#2, respectively.

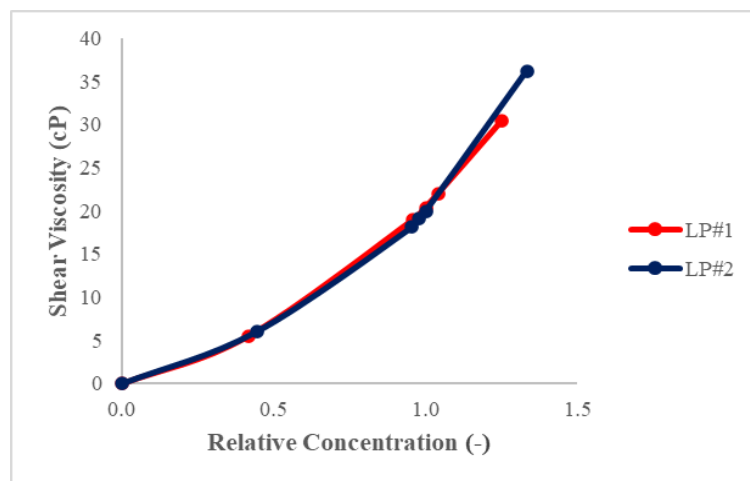


Figure 3.6 - Shear viscosity vs. relative concentration for LP#1 and LP#2

3.3.2 Temperature Scan

Polymers are susceptible to degradation, which breaks down the polymer chains, altering its properties. While 36°C might seem mild, it can significantly impact the polymer's stability. The polymer's viscosity was determined under a shear rate of 7.944 s⁻¹ at a constant temperature of 36°C (reservoir temperature) over 20 days. Employing the following equation, the extent of thermal degradation was calculated:

$$\text{Thermal Degradation Rate (\%)} = \left(\frac{\eta_{\text{Fresh solution}} - \eta_{\text{Effluent}}}{\eta_{\text{Fresh solution}}} \right) * 100 \tag{3.3}$$

Which $\eta_{\text{Fresh solution}}$ is the viscosity of the polymer solution in the beginning and η_{Effluent} is the viscosity of the solution over time. As depicted in Figure 3.7, LP#2 is more temperature-resistant.

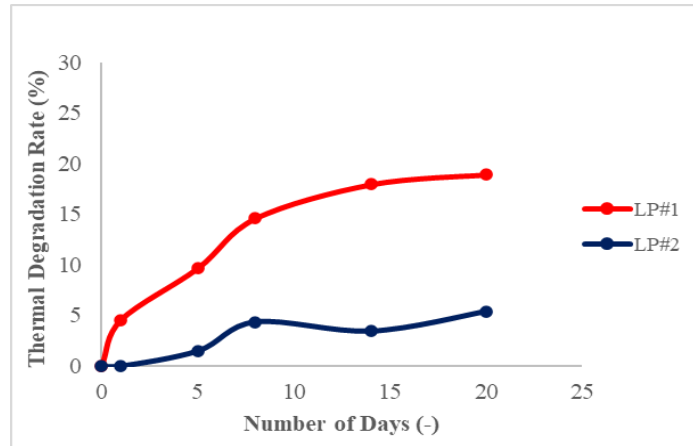


Figure 3.7 - Thermal degradation of polymer solution over time

The shear viscosity versus temperature test was performed to understand how viscosity changes with temperature. Figure 3.8 demonstrates how both products' relative shear viscosity decreases as temperature increases. Relative viscosity is the viscosity of each polymer divided by target viscosity (20cP). The curves are nearly identical, with LP#1 showing slightly lower viscosity at higher temperatures.

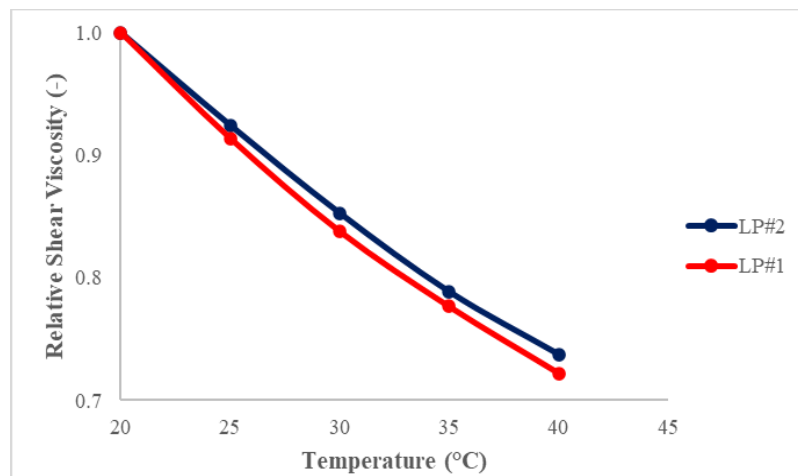


Figure 3.8 - Relative shear viscosity vs. temperature for LP#1 and LP#2

3.3.3 Interfacial Tension Measurement

IFT measurements were conducted using a spinning drop tensiometer to assess the compatibility of the polymer solutions with the crude oil. Figure 3.9 depicts the interfacial tension between Hochleiten oil and 8TH brine and Hochleiten oil and two polymer products in mN/m versus time (in the square root of seconds). All three show a general decrease in IFT

over time, with the most rapid decrease occurring in the initial stages. The 8TH Brine maintains the highest IFT throughout the experiment. LP#1 and LP#2 have lower IFT values, suggesting they are more effective at reducing interfacial tension. The LP#2 polymer exhibits a lower interfacial tension with oil compared to LP#1, indicating enhanced surfactant properties. This reduced IFT suggests a greater capacity for the polymer to decrease surface tension at the oil-water interface, potentially improving its effectiveness in applications requiring strong surfactant behavior.

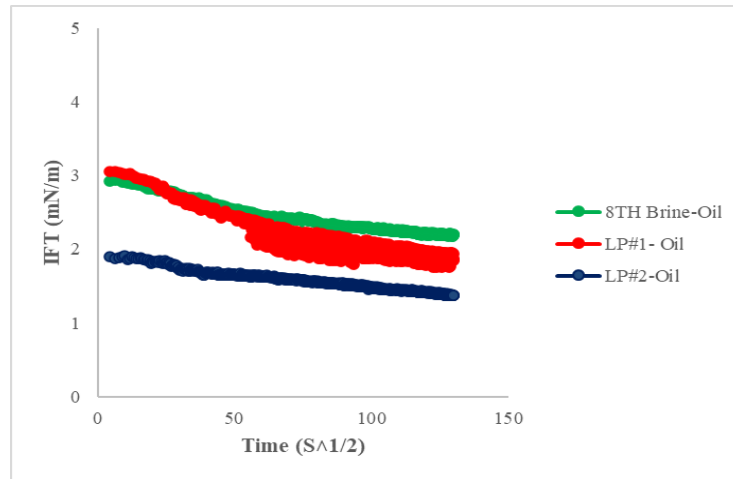


Figure 3.9 - IFT vs. square time between 8TH brine, LP#1, LP#2, and Hochleiten oil

3.3.4 Phase Behavior Test

The samples were prepared in 10 ml pipettes for the phase behavior experiments. The pipettes were sealed from the bottom using an open flame of methane-oxygen. The samples were filled with 5 ml of aqueous solutions containing 8TH brine and another 5 ml of dead oil. The pipettes were closed from the top, ensuring a closed system. Proper mixing was achieved by rotating the closed pipettes at 50 rpm for 48 hours using a rotating shaker. Finally, the samples were stored in an oven at a reservoir temperature of 36°C, and the volume of the different phases in each sample was monitored. Multiple trials for each solution were prepared to increase the reliability of the results. It can be seen in Figure 3.10 that no emulsions were produced in pipettes after shaking the fluids with a volume ratio of 1:1. There was a clear separation of oilic and aqueous phases after a couple of hours, hence concluded that there was no evidence of fluid-fluid interactions.



Figure 3.10 - Phase behavior test using pipettes to produce the emulsions resulting from fluid-fluid interaction. The left side of the four pipettes is for LP#1, and the right side of the four pipettes is for LP#2

3.4 Core Flooding Setup

Core flood experiments are essential techniques in reservoir characterization and enhanced oil recovery studies. These experiments typically begin with single-phase core floods with a sequential injection of polymer solution followed by brine in a brine-saturated core to evaluate basic properties such as permeability and fluid injectivity. In polymer flooding applications, single-phase experiments are crucial for assessing the injectivity and potential mechanical entrapment of polymer molecules within the porous media. This process helps identify any formation damage or permeability reduction caused by polymer retention or pore-blocking. Two-phase core floods follow single-phase tests to simulate more realistic reservoir conditions. Two-phase core flooding experiments are conducted by sequentially injecting polymer and brine solutions into an oil-saturated core containing irreducible water to study residual oil saturation, fluid displacement efficiency, and the effectiveness of the polymer in improving oil recovery. Two-phase core floods provide valuable insights into the complex interactions between the reservoir rock, resident fluids, and injected polymer solutions, helping researchers and engineers optimize EOR strategies for field applications.

The polymer flooding enhanced oil recovery experiment utilizes a setup to simulate reservoir conditions and evaluate the effectiveness of polymer flooding. The process begins with a prepared core sample, an outcrop of real reservoir rock cleaned and characterized for absolute permeability, porosity, bulk volume, and pore volume.

Brine is injected at 20 and 40 ft/day rates in single-phase core floods to calculate water absolute permeability. After brine injection, a polymer solution is injected at different rates to study the injectivity problems, followed by water injection.

Oil is introduced at 5 and 2.5 ft/day in two-phase core floods to establish a two-phase condition and calculate the oil's effective permeability. The amount of brine produced provides information about the remaining oil in the core. Overall, the experiment involves a brine flood, followed by polymer flooding at a 5 ft/day rate, and then post-polymer brine injection at the same rate. Oil production is carefully measured during the polymer flooding phase. It is important to clarify that all velocities referenced in this study are interstitial.

As shown in Figure 3.11, the setup's components play crucial roles throughout the experiment. The oven controls temperature, while pressure gauges monitor differential and confining pressures. Valves throughout the system manage flow control, and the confining pressure pump ensures proper pressure around the core holder. The sampling point allows for the collection and analysis of effluent, providing valuable data on the flooding process.

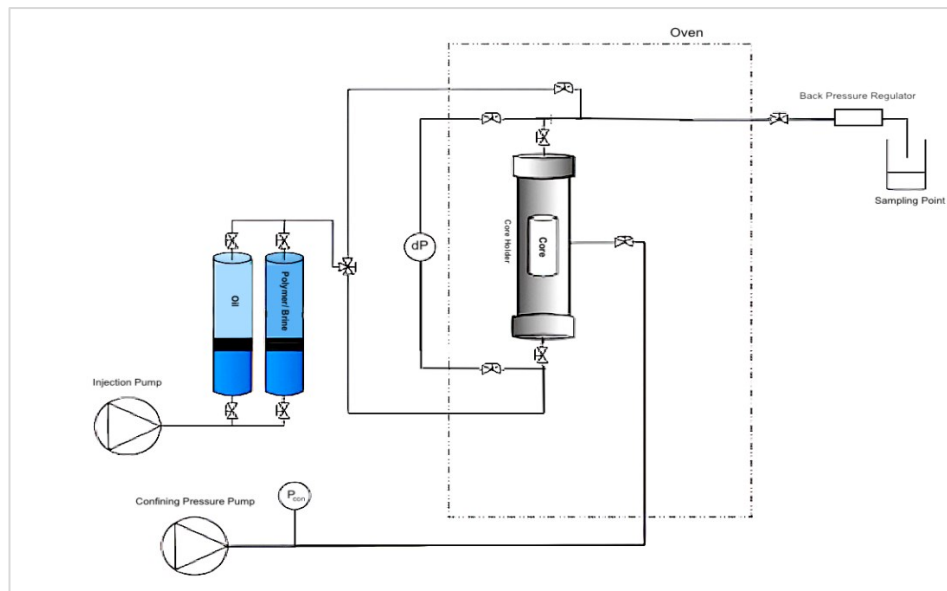


Figure 3.11 – Core flooding setup

3.4.1 Single-phase Core Flood

A set of core samples with a porosity of 22%, characterized by the properties outlined in Table 3.4, were used to assess the injectivity of polymer solutions.

Table 3.4 – Single-phase test core specification

Core Type	Pore Volume (mL)	Permeability (md)
Berea SS	15	300
Silvergray SS	15	500
Bentheimer SS	15	1300

In a single-phase core flood, the polymer was injected at varying flow rates (1 ft/day, 5 ft/day, and 10 ft/day), with pressure profiles monitored to identify potential injectivity issues. As seen in Figure 3.12, the pressure stabilized at a flow rate of 10 ft/day, suggesting effective polymer propagation without further significant permeability reduction. In contrast, injections at lower rates (1 ft/day and 5 ft/day) exhibited a continuous increase in pressure, indicative of injectivity impairment. Higher injection rates result in reduced viscosity due to the increased shear rate, enabling the polymer molecules to align in the flow direction and making it easier to pass through the pores. A steadier pressure profile is the outcome of this.

Moreover, a further increase in pressure was observed during the subsequent brine injection following polymer flooding. This could be attributed to the residual polymer within the pore spaces, which reduces the effective permeability and thus hinders brine flow.

A photo was taken of the core after it was removed from the core holder. Figure 3.13 clearly shows a polymer filtration problem at the core's entry point, which likely caused the increase in pressure.

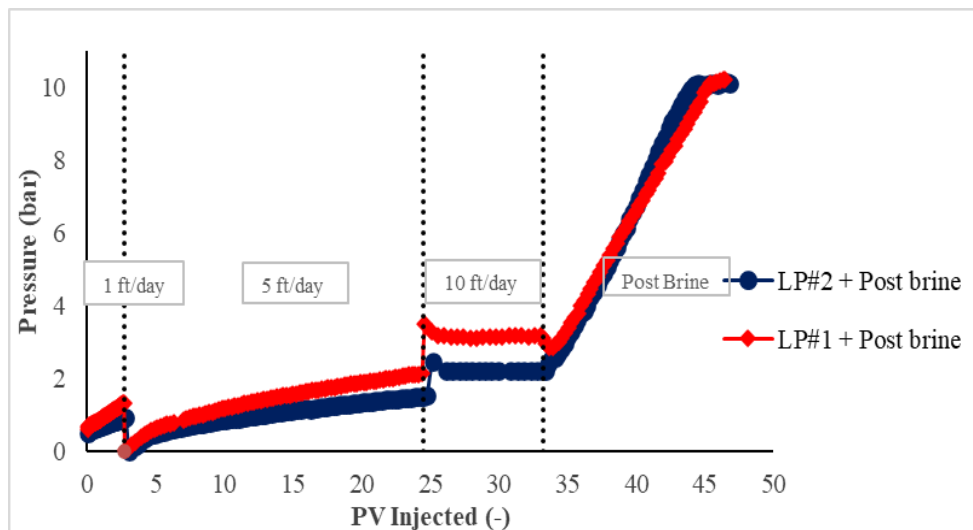


Figure 3.12 – Pressure gradient in single-phase 300mD core flood



Figure 3.13- Filtration issue in 300mD core

The experiment was replicated using a Bentheimer sandstone core with permeability of 1300mD. The purpose of testing higher permeability is to determine if the polymer's performance is affected by higher permeability reservoirs. If the polymer proves effective in these conditions, it could be applied to other reservoirs with similar or higher permeability characteristics.

Pressure gradient measurements were obtained during this test, which exclusively focused on the LP#1 polymer. As depicted in Figure 3.14, a consistent pressure increase is observed across all injection rates. However, a post-brine flood in the 1300mD core resulted in a pressure decrease, indicating a positive outcome.

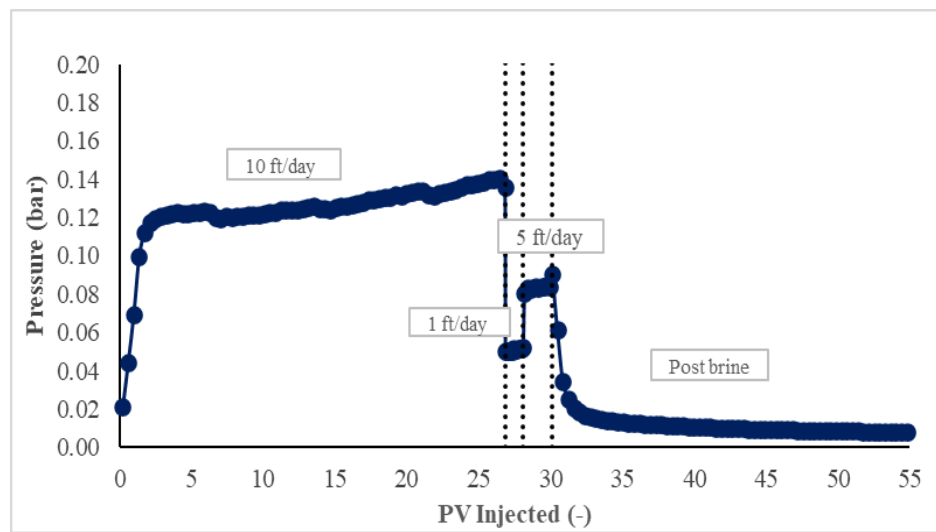


Figure 3.14 – LP#2 and post-brine pressure gradient in single-phase 1.3D core flood

3.4.1.1 Effect of polymer type and permeability on Mechanical Degradation in single-phase core floods

Mechanical degradation in polymer flooding occurs when intense shear forces break down polymer molecules as they are injected into a reservoir. This breakdown reduces the polymer's molecular weight, leading to decreased viscosity. Consequently, the polymer's ability to displace oil is compromised, resulting in lower oil recovery efficiency and increased water breakthrough. While reduced viscosity can improve injectivity, excessive degradation can cause premature polymer breakthrough and hinder sweep efficiency. The overall impact is a reduction in the profitability of the polymer flooding operation. Mitigating mechanical degradation involves using higher molecular weight polymers, optimizing injection rates, and incorporating stabilizers.

In this experiment, polymers are injected with different velocities. The viscosity of the effluent polymer is compared to that of the fresh polymer, and the percentage of difference is considered mechanical degradation.

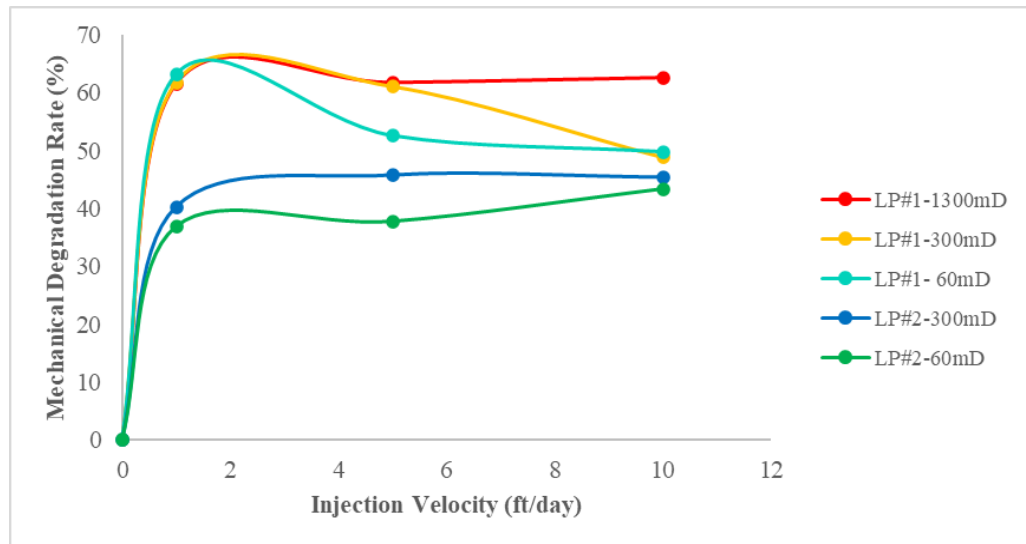


Figure 3.15 - Effect of liquid Polymer type and permeability on mechanical degradation in single-phase core flood

Figure 3.15 illustrates that mechanical degradation is more pronounced in high-permeability cores. This observation is contrary to expectations, as increased permeability is typically associated with minimal changes in molecular structure, which should result in lower mechanical degradation. One possible explanation for this discrepancy is that the pressure did not stabilize, and the mechanical degradation was assessed while retention and mechanical entrapments were still occurring. Additional Field-Flow Fractionation (FFF) tests are necessary to separate molecules and particles and study the molecular changes of polymer in different core floods. A key observation to highlight is that at a flow rate of 1 ft/day (the rate used in further experiments), each LP exhibits comparable mechanical degradation, regardless of permeability variations.

3.4.1.2 Adsorption Measurement

An adsorption test was performed on a 300mD core for LP#4. The core was initially saturated with 8TH brine and flooded with LP#4 at 1800 ppm. A brine flood was then conducted. The core was subsequently removed from the core holder and subjected to vacuum drying in an oven for two days. The weight difference between the initial and final states determined the amount of polymer adsorbed onto the pore surface, measured to be 192 micrograms per gram of rock.

3.4.2 Two-phase Core Flood

In section 3.4.1, LP#1 and LP#2 and their unfavorable injectivity characteristics were addressed. Table 3.3 lists additional products with lower molecular weights than a reference polymer, LP#1. It is hypothesized that the observed poor injectivity might be attributed to

single-phase testing without oil presence. LP#1 and the new polymers in different concentrations will undergo two-phase core flooding experiments in different permeabilities to investigate this matter. The results will be compared to those obtained from the previous single-phase tests.

In 3.4.1, the pressure gradient in LP#1 flooding through a 300mD core is studied. The single-phase and two-phase core flood results are shown in Figure 3.16. Single-phase_rep is the repetition of the single-phase core flood, but it is continued for more pore volumes to be sure that pressure doesn't stabilize. A two-phase core flood is then applied in the presence of Hochleiten oil. The presence of oil altered the pressure behavior, resulting in a more stable pressure trend. However, a gradual pressure increase was still observed.

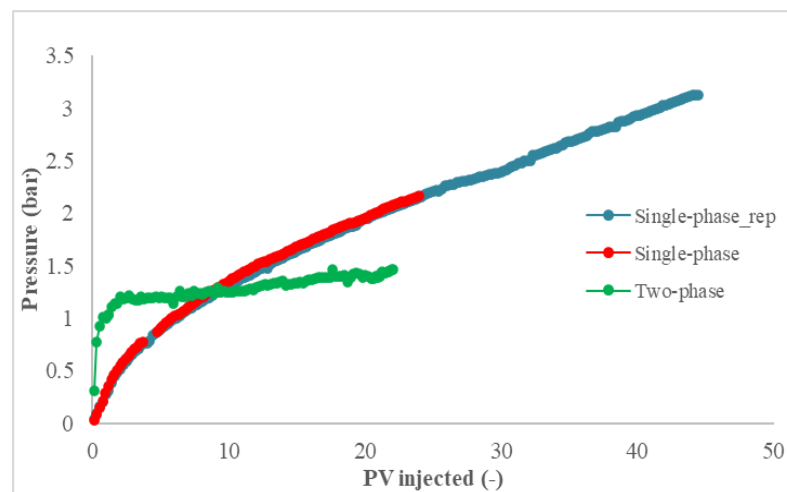


Figure 3.16 - LP#1 pressure gradient in single-phase and two-phase 300mD core flood

Three polymers, LP#1, LP#3, and LP#4, were subjected at 5 ft/day to two-phase core flood experiments in a 300mD core. Pressure profiles, depicted in Figure 3.17, indicate that LP#4 consistently exhibited the lowest pressure compared to the other two polymers because it is the lightest polymer. However, all three polymers gradually increased pressure throughout the core flood process.

Pressure data in a post 8TH brine injection were collected at a 5 ft/day flow rate (Figure 3.18).

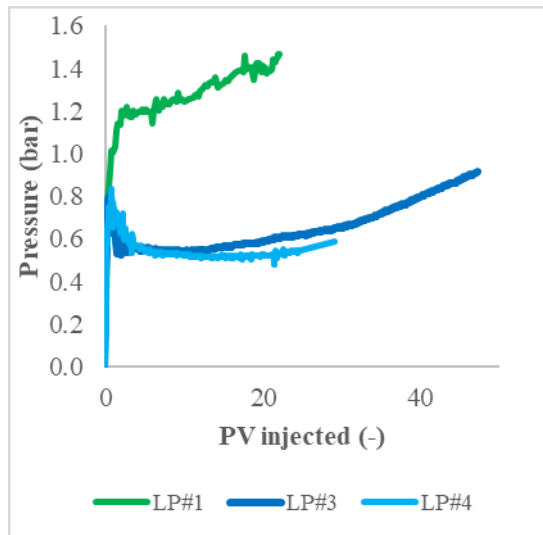


Figure 3.17 - Polymer pressure gradient in two-phase 300mD core flood

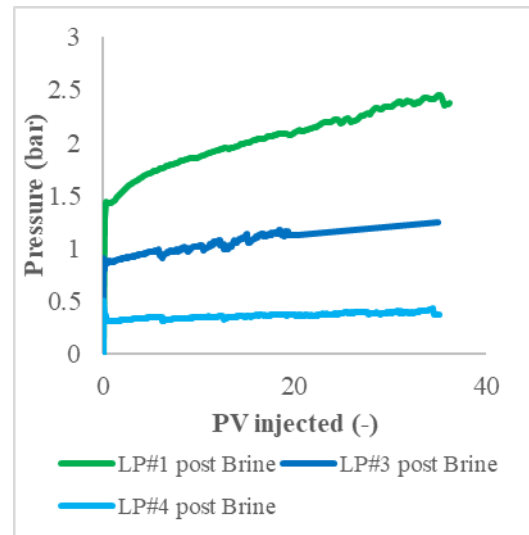


Figure 3.18 - Post brine pressure gradient in two-phase 300mD core flood

Despite the constant increase in pressure during both polymer flooding and subsequent brine injection phases for LP#1, LP#2, and LP#3, which indicates the inefficiency of polymers, the recovery factor was still determined and is presented graphically in Figure 3.19. It is expected that the recovery factor during a brine flood prior to polymer injection should be consistent across different cores. However, a lower recovery factor was observed due to slightly lower permeability in the core used for testing LP#1. Oil recovery factors for LP#1, LP#3, and LP#4 are 15%, 18%, and 12% respectively. The post-brine flood did not yield significant additional oil production and was not included in the data.

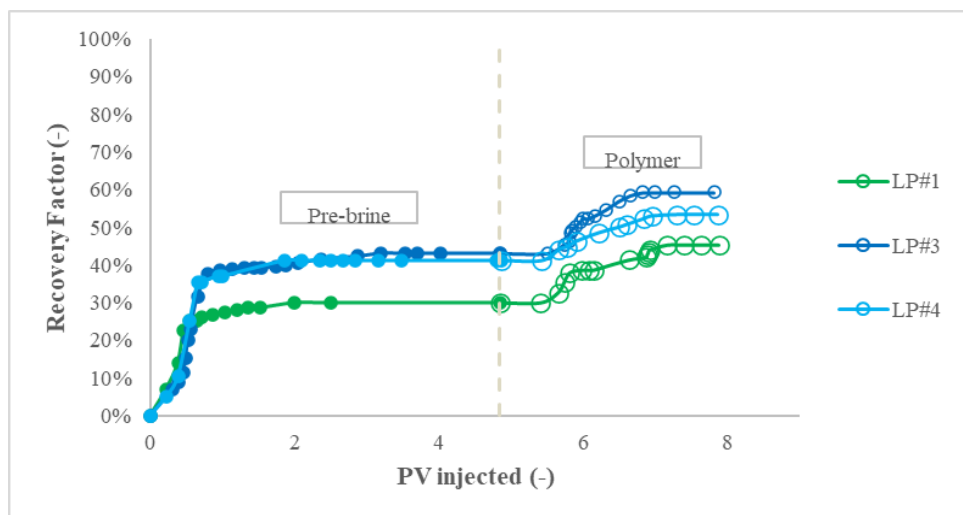


Figure 3.19 - Recovery factor in Brine and polymer flood

The subsequent experiment involved injecting the lowest molecular weight polymer, LP#4, at a reduced concentration of 900 ppm. Viscosity measurements of the freshly prepared polymer solution yielded a value of 6 mPa.s. For comparative purposes, the viscosity of the original

1800 ppm polymer solution was determined to be 20 mPa.s. Figure 3.20 presents a comparative pressure profile of core floods conducted with LP#4 at 1800 ppm and 900 ppm concentrations. The subsequent post-brine flood pressure profiles for each polymer concentration are depicted in Figure 3.21. The elevated pressure observed during the post-brine flood of the 900ppm polymer is attributed to the extended polymer flooding phase, which resulted in greater pore blockage within the core. Neither the polymer flooding nor the subsequent brine flooding phases exhibited favorable pressure profiles.

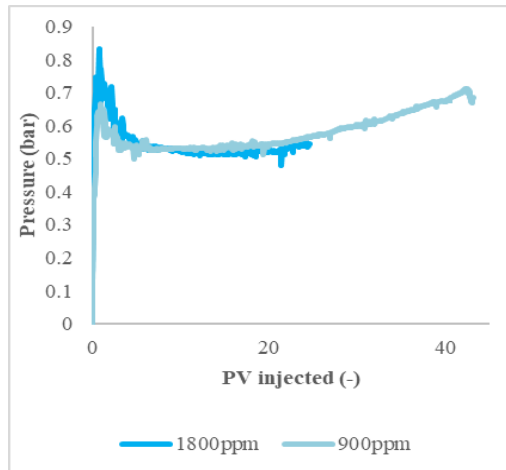


Figure 3.20 - Effect of LP#4 concentration on pressure profile during polymer flood in two-phase 300mD core flood

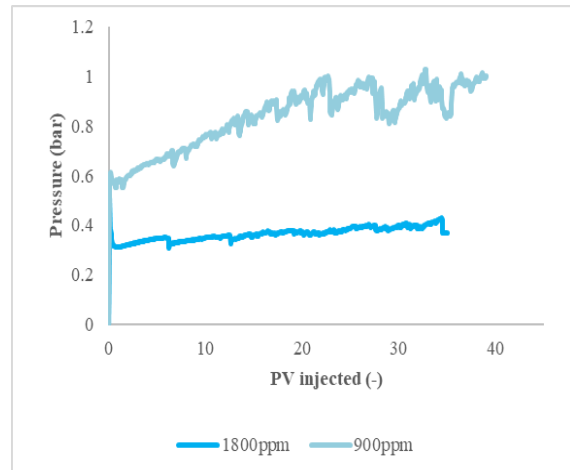


Figure 3.21 – Pressure gradient during brine flood after LP#4 injection in two-phase experiment 300mD core

While supplementary recovery factor data was collected during the experimental process, the pressure data yielded from the study proved to be inadequate for extrapolation to a full-scale field operation. The inconsistencies and unfavorable trends observed within the pressure data render it unsuitable for informing the design and execution of a large-scale polymer flood project. Due to the low viscosity of the 900ppm polymer solution, further testing with lower concentrations was considered unnecessary. Compared to the lower concentration, the 1900 ppm LP#4 solution's higher viscosity increased oil recovery (Figure 3.22).

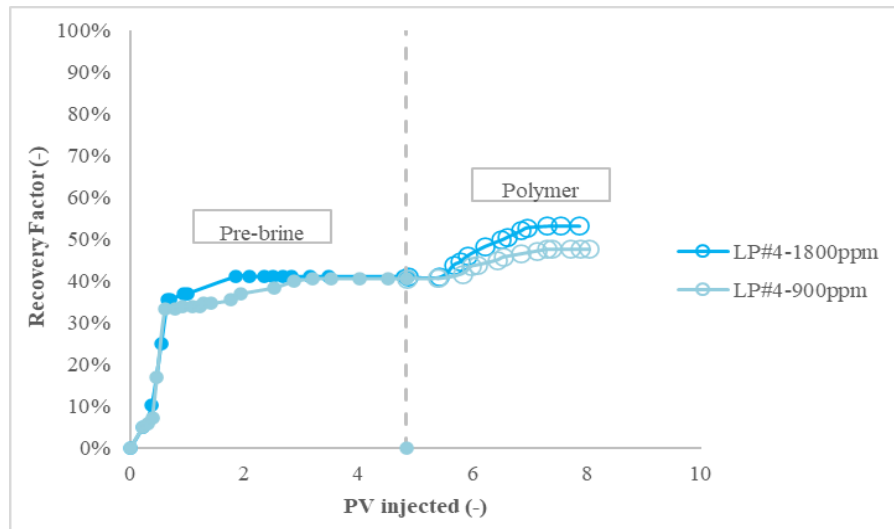


Figure 3.22 - Recovery factor in brine and polymer flood for 900ppm and 1800ppm LP#4 polymer in 300mD core flood

Two additional core floods were conducted to assess the influence of permeability on liquid polymer injectivity. The results of LP#4 flooding with 1800ppm concentration and post-brine flood in core samples with permeabilities of 600mD and 1300mD are compared with what was observed in 300mD core (Figure 3.23, Figure 3.24, and Figure 3.25).

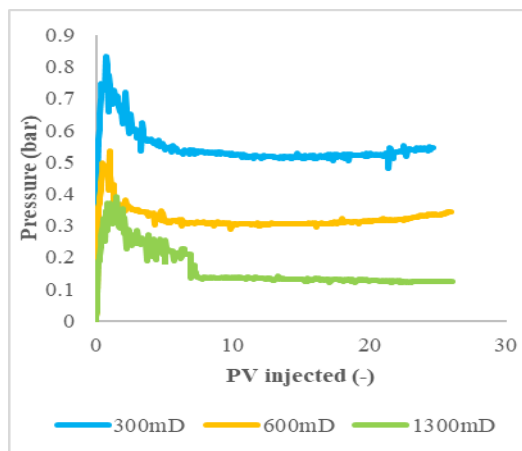


Figure 3.23 - Effect of permeability on pressure profile during LP#4 flooding in two-phase experiment

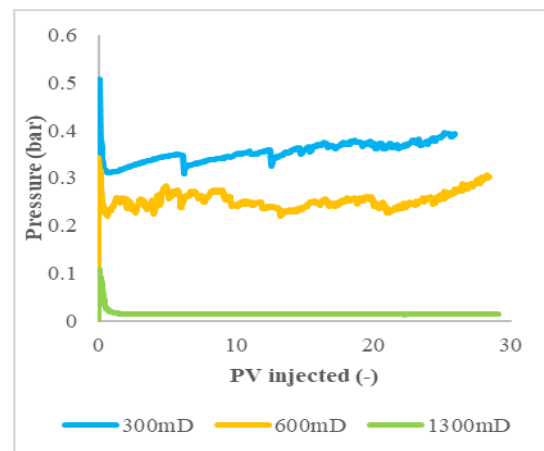


Figure 3.24 - Pressure gradient during brine flood after LP#4 injection in a two-phase experiment in different permeabilities

Pressure gradient profiles indicate that while injectivity issues persisted in the 600mD core, the 1300mD core successfully maintained stable pressure during polymer injection. Additionally, a significant reduction in pressure was observed during post-brine injection, highlighting the positive impact of LP#4 flooding in the 1300mD rock.

According to the recovery factor data in Figure 3.25, LP#4 improved oil production and enhanced efficacy as permeability increased (55% in 1300mD core and 52% in 300mD core).

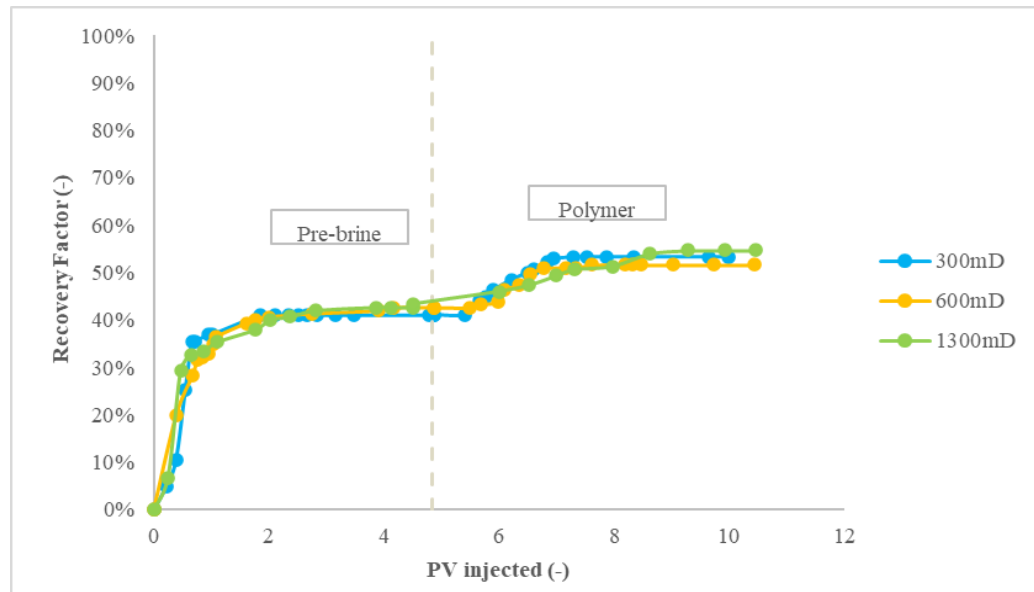


Figure 3.25 - Effect of Permeability on Recovery Factor in brine and polymer (LP#4 polymer) flood

3.4.2.1 Effect of presence of oil, permeability, and concentration on mechanical degradation in single-phase and two-phase core floods

To assess the extent of mechanical degradation, the polymer solution's viscosity was measured before and after the polymer flooding process, which was conducted at a 5 ft/day flow rate. The percentage change in viscosity served as a quantitative indicator of the polymer's degradation during its passage through the core. Mechanical degradation is crucial for selecting the appropriate polymer type for specific reservoir conditions in enhanced oil recovery applications.

Figure 3.26 proves that mechanical degradation of polymers is higher in single-phase (SP) compared to two-phase (TP) systems primarily due to the absence of protective effects provided by oil in two-phase systems. In single-phase, polymer molecules are fully exposed to shear forces and surface interactions, leading to more stretching and breaking. Two-phase systems benefit from oil, creating slip effects, lubricating pore surfaces, altering flow patterns, and reducing mechanical stress on polymer molecules.

A clear correlation between polymer molecular weight and mechanical degradation is observed in the two-phase system. The heaviest polymer, LP#1 (1200 ppm), shows the highest degradation rate at 54%. Moving to lighter variants, the degradation rate decreases significantly. LP#3 (1300 ppm) exhibits 32% degradation, while the lightest variant, LP#4 (1800 ppm), shows only 18% degradation. This trend can be explained by the fact that longer polymer chains (higher molecular weight) are more susceptible to mechanical stresses and breaking under flow conditions. They present larger targets for shear forces and are more likely to become entangled or stretched in porous media. Conversely, shorter polymer chains (lower

molecular weight) are more resistant to these mechanical stresses, resulting in lower degradation rates.

Polymer concentration also influenced mechanical degradation, with the 900ppm solution exhibiting less degradation compared to the 1800ppm solution (18% vs. 15% for 1800ppm and 900ppm polymer solutions, respectively).

Increasing formation permeability can mitigate polymer degradation. The polymer solution experiences reduced shear forces in higher permeability formations due to lower flow velocities and turbulence within the pores. Moreover, the smoother flow path through larger pores minimizes contact between the polymer and the pore walls, further reducing mechanical degradation. Consequently, the polymer can maintain its molecular weight and viscosity for a longer duration, enhancing the efficiency of the flooding process.

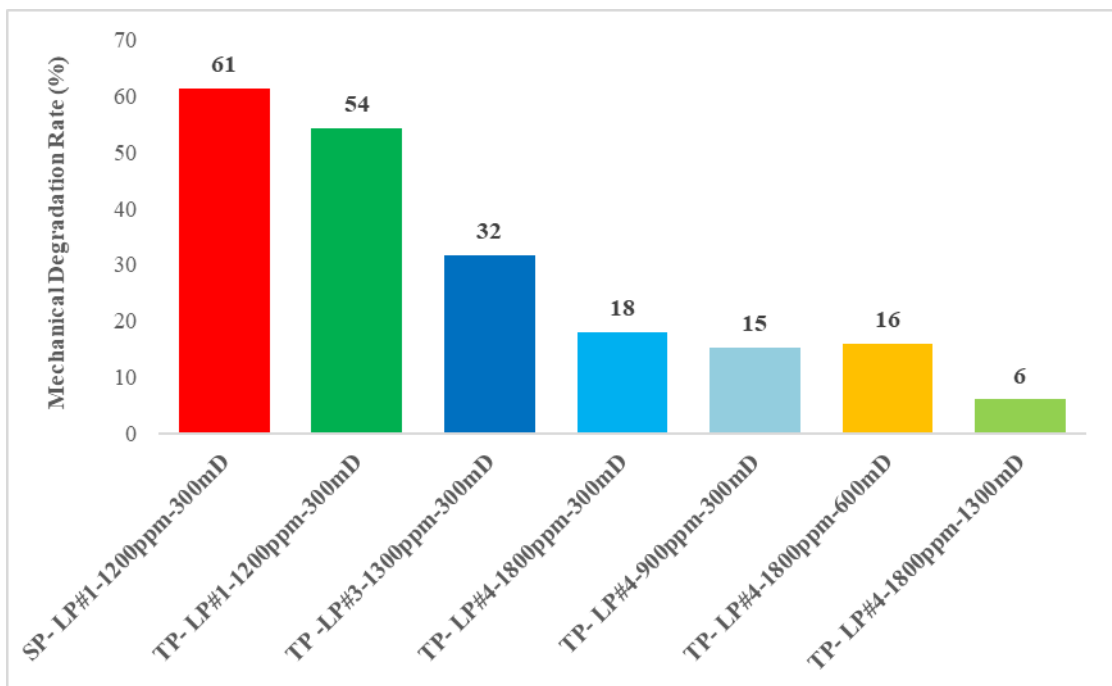


Figure 3.26 – Effect of the presence of oil, permeability, and concentration on mechanical degradation

Chapter 4

Powder Polymers: Experimental Investigation

In the previous chapter, the effectiveness of liquid polymer solutions was evaluated for enhanced oil recovery in the Hochleiten field and the other two fields with higher permeabilities. Despite varying the permeability, concentration, and polymer formula, consistent pressure stability during polymer injection and post-brine flooding was not achieved. The primary goal of this project was to identify an optimal polymer solution for EOR in Hochleiten or other fields with limited surface area and similar characteristics. Unfortunately, the liquid polymer trials yield satisfactory results in 1300mD or higher permeability rocks.

To continue the investigation, the current focus has shifted to powder polymers. These polymers are being tested in the Hochleiten field at permeabilities of 300mD and 500mD. The aim is to assess whether the powder form of these polymers can overcome the challenges encountered with the liquid formulations and provide a more promising solution for EOR in this specific field.

4.1 Polymer Selection and preparation

Four polymer solutions were prepared by dissolving powdered polymer in 8TH brine. The mixtures were stirred at different speeds (650 rpm for 15 minutes and 335 rpm for 2 hours). The mother solutions were diluted with brine to achieve a target viscosity of 20 cP centipoise at 20°C. The polymer product's molecular weights and concentrations are listed in Table 4.1.

Table 4.1 – Powder polymer specification

Product	Molecular Weight (million Daltons)	Used Polymer Concentration (ppm)
PP#1	20-25	1,200
PP#2	20-24	1,300
PP#3	18-22	1,400
PP#4	18-20	1,400

OMV has approved PP#4, so the remaining three products will be evaluated further.

4.2 Single-phase Core Flood

As mentioned in the previous chapter, the Hochleiten reservoir's average permeability is 500mD. To be cautious and account for the potential decrease in permeability due to past water flooding, the initial tests used a core with a permeability of 300mD. Pressure data in single-phase 300mD core flood for PP#1, PP#2, and PP#3 are depicted in Figure 4.1. Lower pressure in polymer and post-brine flood made PP#3 more favorable.

As described in section 2.3.3.4, the resistance factor is determined by dividing the stabilized pressure during polymer flooding by the stabilized pressure in pre-brine flood. The residual resistance factor is the ratio of stabilized pressure in post-brine flood to the stabilized pressure in pre-brine flood.

The RF and RFF data for the 300mD core is depicted in Figure 4.2. Despite having similar viscosities, PP#2 and PP#3 demonstrate better injectivity than PP#1 due to their lower RF and RFF values.

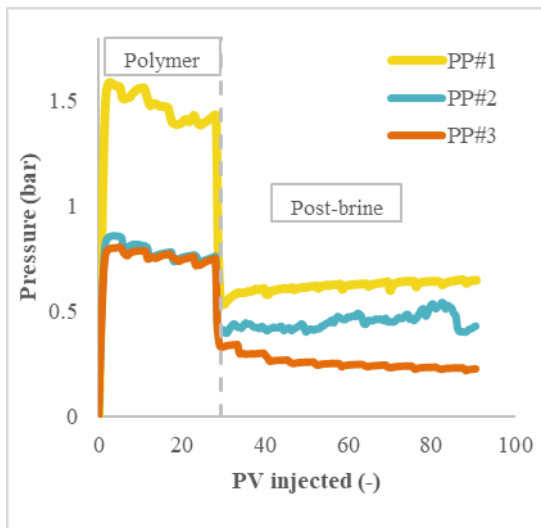


Figure 4.1 - Pressure gradient in single-phase polymer and post-brine flood in 300mD core

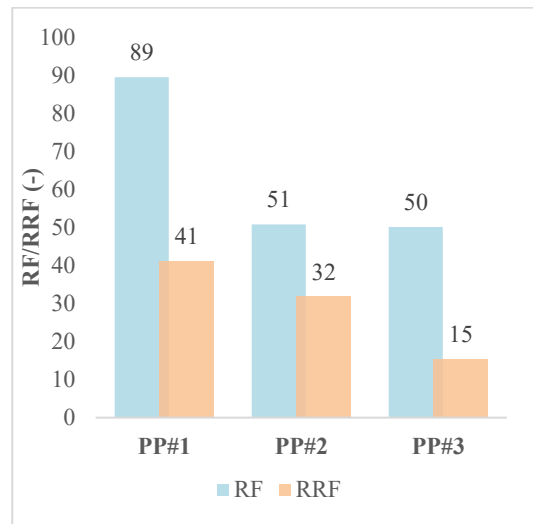


Figure 4.2 - Resistance and residual resistance factor in single-phase 300mD core flood

Given its superior injectivity and RF/RRF performance, PP#3 was selected for the next experiment. It will be compared to PP#4, which has already been approved for use in a 500 mD core, representing the typical permeability of the reservoir.

The pressure profile and RF/RRF values are shown in Figures 4.3 and 4.4, indicating that both products have similar injectivity and RF/RRF values.

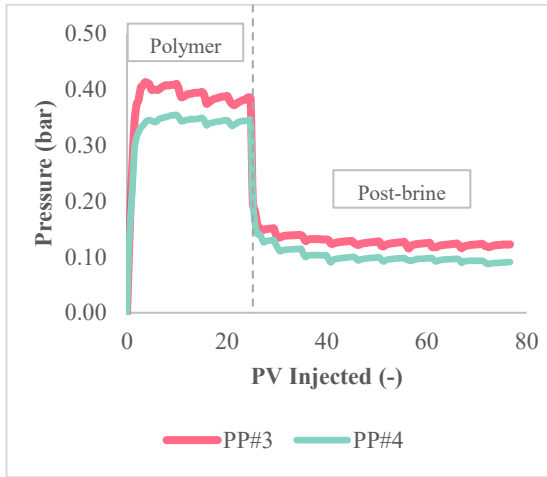


Figure 4.3 - Pressure gradient in single-phase polymer and post-brine flood in 500mD core

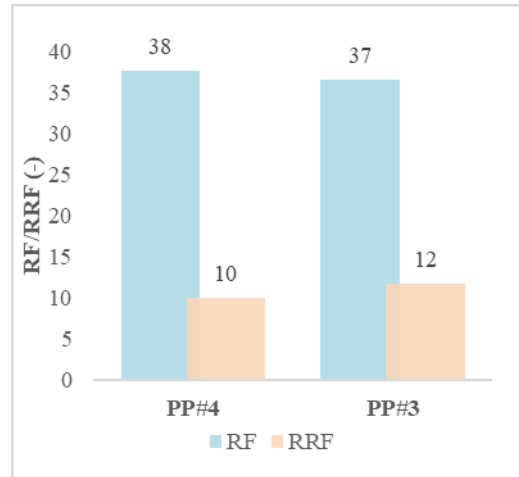


Figure 4.4 - Resistance and residual resistance factor in single-phase 500mD core flood

The resistance factor was measured at various injection velocities to understand these polymer products better. Figure 4.5 and Figure 4.6 show the RF and MD values in different injection velocities, respectively.

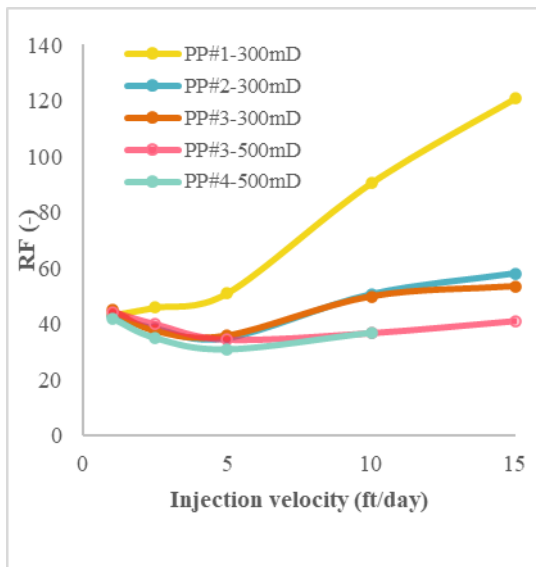


Figure 4.5 – Effect of permeability and velocity on Resistance Factor in single-phase powder polymer flood

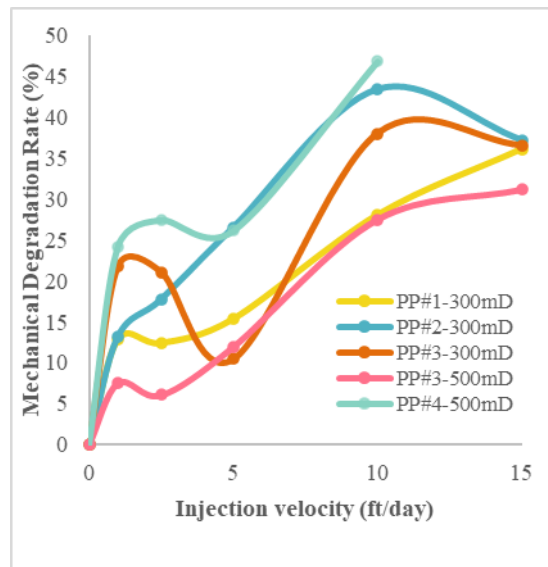


Figure 4.6 - Effect of permeability and velocity on Mechanical Degradation rate in single-phase powder polymer flood

These figures can be helpful when selecting between PP#3 and PP#4. While both products have similar RF values in a 500mD core, PP#3 was chosen due to its lower mechanical degradation, particularly at higher velocities near the wellbore. This ensures that the polymer maintains adequate viscosity in deeper reservoir areas and has a suitable mobility ratio. The same RF values of all polymers at 1 ft/day denote that the polymer acts as a Newtonian fluid at this velocity.

The adsorption of each polymer candidate was measured in all five experiments. After removing the cores from the core holder following the polymer flood and post-brine flood, they were heated in an oven to evaporate the remaining water. The weight change is the amount of polymer stuck in the core, considered the adsorption (Table 4.2). This contradicts the typical tendency, which states that lower permeability rocks have higher adsorption due to smaller pore sizes and a larger surface area. This arises because minerals in 500mD rock may have a stronger affinity to polymer molecules. Certain clay minerals and metal oxides, for example, may provide better adsorption sites.

Adsorption of powdered polymer is comparable to the quantity of adsorption seen with liquid polymer in section 3.4.1.2.

Table 4.2 - Adsorption amounts in all polymer products' core floods

Experiment	Exp.1	Exp.2	Exp.3	Exp.4	Exp.5
Polymer Slug	PP#1	PP#2	PP#3	PP#3	PP#4
Initial Concentration (ppm)	1,200	1,300	1,400	1,400	1,400
Core Permeability (mD)	300			500	
Adsorption (µg/g)	213	267	215	281	296
Adsorption (ppm)	89.2	111.6	90	117.6	124

4.3 Two-phase Core Flood

A two-phase core flood was conducted using PP#3 at a 5 ft/day flow rate. Two concentrations of 1400 ppm and 2000 ppm (corresponding to viscosities of 20 cP and 37 cP) were selected to investigate the performance of this polymer. The data in Table 4.3 presents key reservoir rock properties and polymer transport characteristics. The polymer was chosen based on previous experiments, and the goal was to study its behavior in the presence of oil and determine its potential to enhance oil recovery. The pressure profile and recovery factor in the two-phase core flood for PP#3 are shown in Figure 4.7 and Figure 4.8, respectively.

Table 4.3 – Rock and polymer properties in PP#3 flood experiments

ID	Porosity (%)	PV (mL)	Brine Perm. (mD)	$k_{ro}@S_{wi}$	$k_{rw}@S_{or}$	$k_{rp}@S_{or}$	Slug (ppm)	Soi (%)
CF1	20.4	69	384	0.81	0.047	0.029	1400	70
CF2	20.3	69	411	0.79	0.050	0.045	2000	70

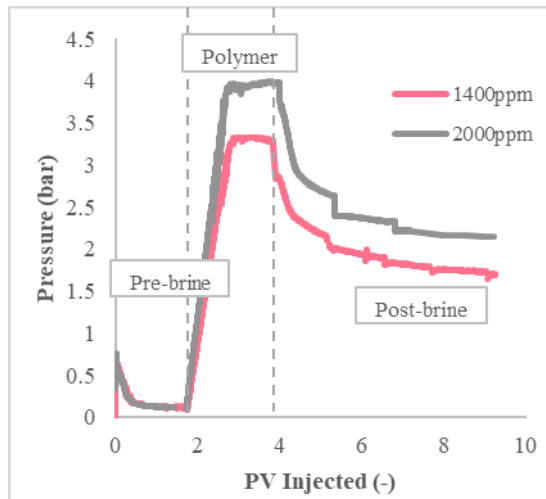


Figure 4.7 – Effect of PP#3 concentration on pressure gradient in the two-phase core flood in 500mD core

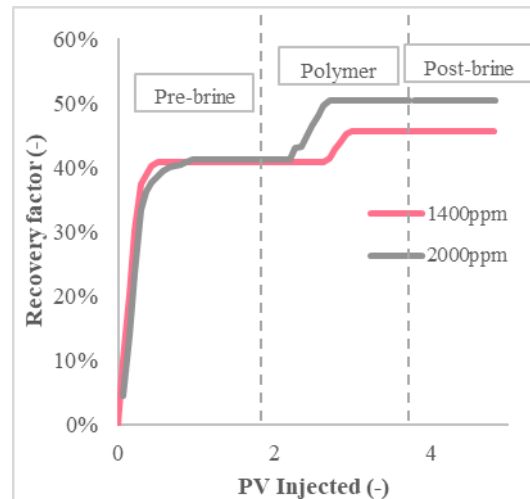


Figure 4.8 - Effect of PP#3 concentration on recovery factor in 500mD core

4.3.1 Polymer adsorption for PP#3 in two-phase core flood

In single-phase core floods, polymer adsorption can be determined by weighing the core before and after polymer injection. However, in two-phase core floods, oil particles or molecules remain trapped within the core, making direct measurement of polymer adsorption impossible. To overcome this limitation, the concentrations of the injected polymer solution and the effluent polymer can be measured using Size Exclusion Chromatography (SEC). SEC device is a powerful technique for determining polymers' molecular weight and size distribution. It can also be used to estimate polymer concentration indirectly by creating a calibration curve and comparing the detector response of the unknown sample to the curve. Alternatively, direct concentration determination can be performed using a concentration detector, such as a differential refractive index detector. However, the accuracy of concentration measurements depends on factors like calibration curve accuracy, detector sensitivity, sample purity, and column interactions. By carefully considering these factors, SEC can provide reliable estimates of polymer concentration.

To get the amount of polymer adsorbed on the rock surface, the effluent polymer concentration (C) was measured after a specific injected pore volume and was compared to the concentration of the fresh polymer solution (C_0). The ratio of C to C_0 was calculated. The polymer injection was continued until this ratio reached unity.

Figure 4.9 illustrates the normalized concentration value (C/C_0) of PP#3 polymer (for two concentrations 1400ppm and 2000ppm) during a flood through a 500mD core. The figure also depicts the normalized polymer concentration of brine injected after the polymer flood. The

dotted lines in Figure 4.9 represent extrapolated values based on the observed trends. In the case of a polymer flood using PP#3 at a concentration of 1400 ppm, it was observed that the polymer continued to adsorb onto the rock. The injection should have been prolonged until adsorption ceased and the effluent concentration was equivalent to the fresh polymer solution concentration.

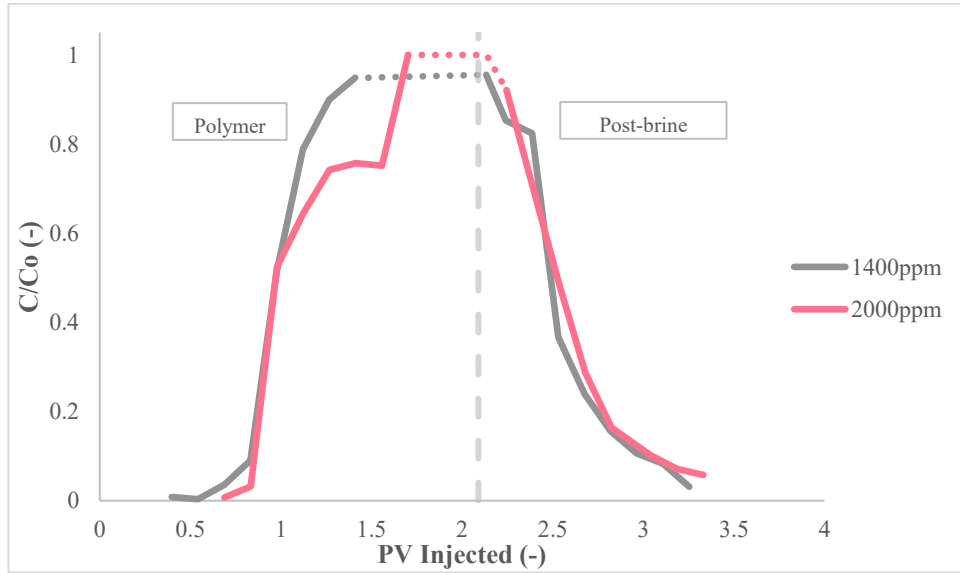


Figure 4.9 – Normalized PP#3 concentration in a polymer and post-brine 500mD core flood

Chapter 5

Conclusion

The conclusion chapter summarizes the key findings of the research, offering a comprehensive overview of the conducted experiments and their implications for enhanced oil recovery. The following sections provide a more detailed analysis of the results, their significance, and potential avenues for further research.

5.1 Summary

A comprehensive series of experiments evaluated and compared various liquid and powder polymers for enhanced oil recovery applications. Four liquid polymers were initially tested (LP#1, LP#2, LP#3, and LP#4).

LP#1 and LP#2 demonstrated good viscosity measurements and shear thinning behavior. LP#2 exhibited superior thermal stability, maintaining viscosity over 20 days with only a 5% thermal degradation rate compared to 19% for LP#1. Both polymers showed decreased viscosity with increased temperature, though LP#2 exhibited less reduction.

IFT tests were performed for LP#1, LP#2, and brine with oil. The liquid polymers demonstrated lower IFT with oil than brine, which was attributed to surfactant in the polymer solutions. However, phase behavior tests indicated no stable emulsions formed between oil and polymer fluids.

Single-phase core flood tests at 25°C, simulating injection well temperature, were conducted at interstitial velocities of 1, 5, and 10 ft/day. In a 300 mD core, the pressure difference between the inlet and outlet increased constantly during polymer injection and subsequent brine injection. Similar behavior was observed in a 1300 mD core.

LP#3 and LP#4, introduced by the vendor with lower molecular weights than LP#1, were tested in two-phase core floods alongside LP#1 in a 300 mD core. The presence of oil in the core in

LP#1 flood reduced the pressure difference from 2 bar to 1.4 bar and stabilized pressure, though an increasing trend persisted.

LP#4 was further tested in 300 mD, 600 mD, and 1300 mD cores. Pressure increased constantly in 300 mD and 600 mD cores but remained constant in the 1300 mD core, with a decrease during subsequent brine injection.

Concentration tests for LP#4 showed that halving the concentration reduced viscosity threefold but maintained similar pressure increases.

Mechanical degradation tests revealed reduced degradation in two-phase core floods compared to single-phase (54% vs. 61% for LP#1), with degradation decreasing as permeability increased (18% in 300 mD vs 6% in 1300 mD).

Powder polymers PP#1, PP#2, PP#3, and PP#4 were also evaluated. PP#2 and PP#3 demonstrated better injectivity and lower resistance factors (RF of 50) than PP#1 (RF of 89). PP#4, previously approved by OMV, showed lower pressure and RRF than PP#3 in a 500 mD core.

Further testing of PP#3 in two-phase core floods at increased concentrations (1400 ppm to 2000 ppm) resulted in a viscosity increase from 20 to 37 cp, pressure increase from 3.3 to 3.9 bar, and a 4% increase in recovery factor.

Adsorption tests for liquid and powder polymers yielded similar results, with liquid polymers showing 192 $\mu\text{g/g}$ of rock and powder polymers ranging from 213 to 267 $\mu\text{g/g}$ in 300 mD cores.

5.2 Evaluation

The results indicate that the liquid polymers tested are ineffective in 300 mD and 500 mD cores, exhibiting significant injectivity issues and unfavorable pressure responses. In contrast, a more favorable behavior was observed in the 1300 mD rock, where the polymer demonstrated improved performance during both the polymer injection and the subsequent brine injection phases. However, the increase in pressure during the post-brine injection stage necessitates further investigation to understand the underlying reasons for this behavior. Injectivity problems in liquid polymer flooding are often attributed to oil particles in the polymer solution. Previous studies have demonstrated that separating the oil from the polymer solution effectively mitigates these issues (Osterloh & Law, 1998). In higher-permeability rocks, however, no injectivity problems were observed with liquid polymers, likely due to the larger pore throats allowing oil particles to pass without causing significant obstruction.

Powder polymers PP#3 and PP#4 showed promising results, with PP#3 exhibiting less mechanical degradation than PP#4. Given this advantage, continuing PP#3 at a concentration

of 1400 ppm may be more beneficial. However, further economic evaluation is necessary to assess the implications of increasing concentration, as tests indicated that raising the concentration to 2000 ppm resulted in a 4% increase in recovery factor. This economic analysis should consider whether the additional recovery justifies the increased costs associated with higher polymer usage. While liquid polymers faced challenges in lower permeability cores, powder polymers demonstrated better injectivity and effectiveness. The findings highlight the importance of selecting appropriate polymer types and concentrations tailored to specific reservoir conditions, emphasizing the need for continued research and development in polymer flooding technologies to optimize enhanced oil recovery strategies.

5.3 Future Work

The observed increase in pressure during the polymer injection and post-brine injection phases for liquid polymers requires further investigation. Filtration experiments on the liquid polymer emulsions are essential to determine the root cause of this phenomenon. These experiments would separate the oil component from the emulsion, allowing for a more precise evaluation of whether the pressure increase is due to the oil content or the molecular size of the polymer itself. This separation will help ascertain if the oil contributes to the injectivity issues or if the polymer molecules are too large to pass through the pore spaces effectively.

LP#4 has shown potential for application in 1300 mD rocks, suggesting that further testing in this permeability range could provide valuable insights. More extensive evaluations are necessary to monitor pressure behavior in higher permeability formations and understand the reasons behind the pressure jump observed during brine injection following polymer flooding. These tests should focus on replicating the conditions that led to the favorable pressure response and investigating the factors contributing to the sudden pressure increase during the post-polymer brine injection.

Additionally, long-term core flooding experiments should be conducted to assess the stability of the pressure behavior over extended periods. This would help determine if the observed pressure increases are temporary or persist, potentially affecting long-term injectivity and reservoir performance.

These investigations will be crucial for optimizing liquid polymer formulations and enhancing their effectiveness in various reservoir conditions. The results could lead to improved liquid polymer products tailored for specific permeability ranges, ultimately contributing to more efficient enhanced oil recovery strategies in Austrian oil fields and similar reservoirs worldwide.

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Nomenclature

C	Concentration	ppm
D	Diameter	m
EA	Areal sweep efficiency	Percentage
ED	Displacement efficiency	Percentage
EV	Vertical sweep efficiency	Percentage
k	Permeability	millidarcy
k_{ro}	Relative permeability of oil	Dimensionless
k_{rw}	Relative permeability of water	Dimensionless
L	Length	m
M	Mobility ratio	Dimensionless
Mw	Molecular weight	Daltons
N_c	Capillary number	Dimensionless
PH	Potential of Hydrogen	dimensionless
T	Temperature	°C (Celsius) or °F(Fahrenheit)
T	Shear stress	Pa (Bird et al.)
TH	Total hardness	°dH
Δp	Differential Pressure	bar
q	Fluid interstitial velocity	(ft/day)
R_k	Reduction factor	Dimensionless
v	Fluid velocity	(m/s)
σ	Interfacial tension	mN/m
ϕ	Porosity	Percentage
$\dot{\gamma}$	shear rate	s^{-1}
λ	Mobility	mD/cP
μ	Viscosity	mPa·s (cP)

Abbreviations

API	American Petroleum Institute (used in oil gravity measurement)
cEOR	chemical Enhanced Oil Recovery
cP	Centipoise (unit of dynamic viscosity)
EOR	Enhanced Oil Recovery
FFF	Field-Flow Fractionation
HPAM	Partially Hydrolyzed Polyacrylamide
IFT	Interfacial Tension
IPV	Inaccessible Pore Volume
OOIP	Original Oil in Place
PAM	Polyacrylamides
PH	Potential of Hydrogen (measure of acidity or basicity)
ppm	Parts per million (used for concentration measurements)
RF	Resistance Factor
RRF	Resistance Resistance Factor
TAN	Total Acid Number
TDS	Total Dissolved Solids
UKCS	UK Continental Shelf
USGS	United States Geological Survey