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-TITLE-

Experimental and modeling Investigation of polymers Flooding for EOR Application in a Micromodel System

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To my lovely sisters.

To my two brothers,

To all my big family, **SAHED et REBBOU BENBERBER**

To my best friends, each in his own name, and to everyone I love.

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YACINE

الخلاصة

بعد الحقن المائي، يظل 65٪ من النفط عالقًا في مكانه. لقد عمل المهندسون لعقود من الزمن لتطوير حلول فنية لاسترجاعه. إحدى هذه التقنيات تتكون من حقن الماء المُعَقَّد في التكوين لتحريك النفط. يخلق تباين اللزوجة بين الماء المحقون والنفط اللزج عدم استقرار ويعزز اختراق الماء عبر النفط أو تجاوز النفط بشكل كامل.

الهدف من هذا العمل هو دراسة وتحليل أداء استعادة النفط المعززة عن طريق حقن البوليمرات القابلة للذوبان في الماء في نموذج glass micro model الزجاجي ودراسة المحاكاة في برنامج CMG. تشمل هذه الدراسة حقن البوليمرات التي لها تأثيرات قوى لزجة، نقارن بين الحقن المائي وحقن البوليمرات، وتظهر النتائج أن كفاءة الحقن المائي الإجمالية حوالي 40٪ قبل عمليات استعادة النفط المعززة، وتقفز الكفاءة إلى 70٪ بعد عمليات استرجاع النفط المعززة.

الكلمات المفتاحية: – الاسترجاع المعزز للنفط – حقن البوليمر –اللزوجة – النموذج الزجاجي.

RESUME

Après l’inondation d’eau, 65% du pétrole reste piégé en place. Les ingénieurs ont travaillé pendant des décennies pour développer des solutions techniques afin de le récupérer. Une telle technique consiste à injecter de l’eau viscosifiée dans la formation pour déplacer le pétrole. Le contraste de viscosité entre l’eau injectée et le pétrole visqueux crée une instabilité et favorise la pénétration de l’eau à travers le pétrole ou le contournement complet du pétrole.

L’objectif de ce travail est d’étudier l’analyse et la performance de la récupération assistée du pétrole par injection de polymères solubles dans l’eau dans un micromodèle en verre et de simuler l’étude dans le logiciel CMG. Cette étude implique l’injection de polymères qui ont des effets sur les forces visqueuses, nous comparons entre l’inondation d’eau et l’inondation de polymères, les résultats montrent que l’efficacité globale de l’injection d’eau est d’environ 40 % avant la RAH, l’efficacité passe à 70 % après la RAH.

Mots-clés : - Récupération tertiaire de l’huile – Injection de polymère – Viscosité – Micromodèle de verre.

ABSTRACT

After the water flooding, 65% of oil is stranded in place. engineers have worked for decades to develop technical solutions to recover it. One such technique consists of injecting viscous water into the formation to displace the oil. The viscosity contrast between the injected water and the viscous oil creates instability and promotes water penetration through the oil or complete bypass of the oil.

The objective of this work is to study Analysis and Performance of Enhanced Oil Recovery by Injection of Water-Soluble Polymers in glass micromodel and study simulate in CMG software. This study involves injecting polymers that have effects viscous forces, we compare between Water flooding and Polymers flooding, the results show that the overall water injection efficiency is around 40 % before the EOR, the efficiency jump to 70 % after the EOR.

Keywords: - Enhanced oil recovery – Polymer injection – Viscosity – Glass micromodel.

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List of symbols and abbreviations:

K The absolute permeability in md.

Q flow of fluids from the reservoir in m3/s.

µ the dynamic viscosity in cp.

P The pressure (kg/cm2).

Δ The gradient modulus.

ρ The density of the fluid in kg/m3 .

g The acceleration of gravity in m/s2 .

Krw The relative permeability of water in md.

µw The viscosity of water (displacement fluid) in cp.

µo Viscosity of the oil in cp.

Kro The relative permeability of oil in md.

Sw The saturation of water.

So the saturation of the oil.

Sg Gas saturation.

M The mobility report.

Swi The irreducible water saturation.

Sor Residual oil saturation.

θ The wetting angle in degrees.

Pc Capillary pressure.

r The radius of the capillary tube in mm.

γ(o,w) the water/oil interfacial tension in N/m or J/m2 .

Nca the capillary number.

CS Convenient system.

IS International System.

EOR Enhanced Oil Recovery.

OOIP Original Oil in place.

HMD Hassi Messaoud.

IOR Improved Oil Recovery.

MP porous media.

IFT Interfacial Tension.

H2S hydrogen sulfide.

CMG computing modeling group.

Oil extraction is a critical component of the global energy industry, providing the fuel that powers economies, transportation, and industries. Worldwide, the process of extracting oil from underground reservoirs has evolved significantly since its inception in the mid-19th century. Advanced technologies and methods, such as seismic surveys, horizontal drilling, and enhanced oil recovery techniques, have greatly increased the efficiency and yield of oil extraction operations. Major oil-producing regions, including the Middle East, North America, and Russia, dominate global production, shaping international markets and geopolitics.

In Algeria, oil extraction plays a pivotal role in the national economy, being one of the primary sources of revenue and foreign exchange. The country boasts significant oil reserves, primarily located in the Sahara Desert, with key fields like Hassi Messaoud and Hassi R'Mel driving production. Algeria's oil industry is characterized by a combination of mature fields and newer exploration efforts, with state-owned company Sonatrach leading the sector. The country has also been integrating modern extraction techniques to maximize output and efficiency, addressing both technical challenges and environmental considerations. As Algeria continues to develop its oil resources, it remains a vital player in the global energy landscape.

The production stage of petroleum extraction is a complex and vital process that ensures a steady supply of crude oil to meet the world's energy demands. This stage encompasses various methods to efficiently bring oil from underground reservoirs to the surface, involving both mechanical and chemical techniques to maximize recovery. From the initial extraction using natural and artificial lifts to advanced secondary were using water and gas injection to maintain the reservoir pressure and EOR (enhanced oil recovery) methods that include chemical methods, The present research is dedicated to the exploration of polymer flooding one of the chemical methods.

The work will be presented as follows:

Chapter I:

Chapter II: Multiphase flows in a porous medium.

Chapter III: Experimental study.

Chapter IV: Analysis and modeling.

Chapter Ⅰ:

Polymer flooding

The process of recovering hydrocarbons involves two key stages: primary and secondary recovery. While secondary hydrocarbon extraction of hydrocarbons is done at the cost of energy injected into the reservoir from the outside by injecting gas and/or fluids to maintain or increase the initial energy in the reservoir, primary extraction uses the reservoir's natural energy.

I.1. Drainage mechanism

Drainage is the set of methods and techniques that cause the movement of fluids from the reservoir rock to the production wells. There are two types of drainage:

- Natural drainage (primary recovery).
- Assisted drainage. [1]

I.2. Primary Recovery

Gravity forces, expanding rock and liquid, releasing, and expanding gas dissolved in oil while reducing reservoir pressure (depletion drive), expanding the gas cap or active aquifer, or a combination of these factors are the methods used to obtain the energy needed to move oil through the reservoir and into the production well during primary extraction. [2]

I.3. Secondary recovery

Oil and gas are extracted from extraction wells and external energy is introduced into the reservoir through injection wells as part of the secondary recovery of hydrocarbons. Injection wells are typically used for the immiscible displacement of water, gas, or water-gas mixtures in the secondary recovery of hydrocarbons. However, because it is readily available and reasonably priced, water is the fluid that the reservoir introduces most frequently to maintain its energy. [2]

I.3.1. Waterflooding

One of the main methods used to produce oil is flooding. Waterflooding is projected to produce about half of all oil produced. Pumping water into a sequence of injection wells allows for water flooding, and the production wells are used to produce hydrocarbons. Generally speaking, flooding is done to accomplish any of the following objectives, or any combination of them:

- reservoir pressure maintenance
- water-pressure regime's establishment in order to transfer hydrocarbons from injection wells to producing wells.
- Connate the elimination of water during hydrocarbon separation

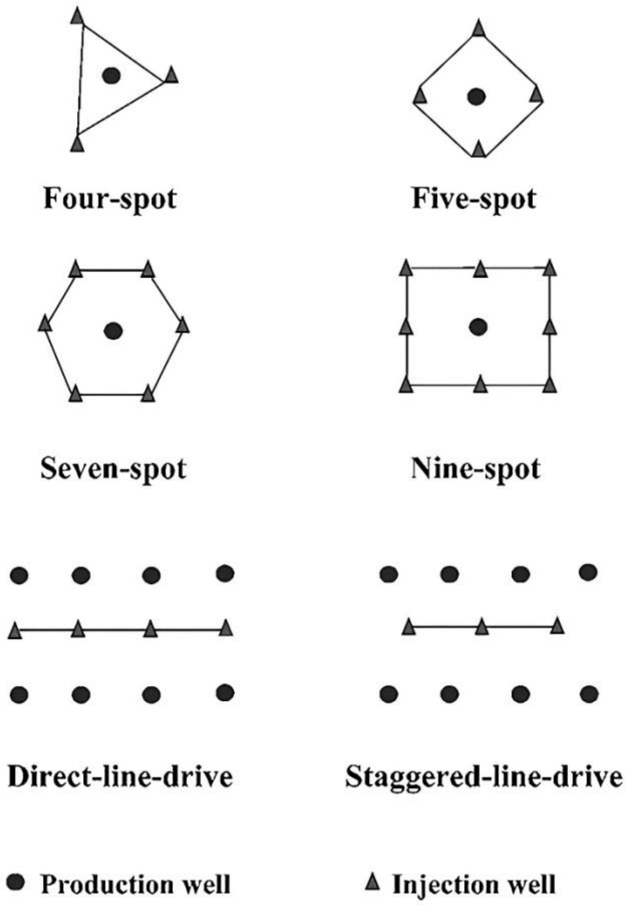


Figure I.3.1: Some schemes for areal waterflooding.

I.3.2. Gas injection

Immiscible gas injection is used to keep reservoir pressure stable, delay the pace of production drop in the reservoir's natural regimes, and, in some cases, to support the gravity regime. An immiscible gas is typically injected in cyclical patterns with water. Immiscible displacement uses related petroleum gas, nitrogen, or flue gases. The gas injected into the well reacts similarly to the gas in gas cap drive mode: it expands and acts like a compressed spring, displacing oil into the producing wells. Gas injection involves the use of high-pressure compressors. Although injecting immiscible gases is less efficient than water flooding.

I.4. enhanced oil recovery (EOR)

Generally, tertiary, or enhanced oil recovery involves the extraction of residual oil after primary and secondary production stages. At this stage, modern and technologically advanced methods are used to modify the properties of the reservoir fluids or reservoir rocks. The aim is to a higher recovery yield than that achieved by these methods in the recovery process (primary and secondary recovery phases). [2]

There are three primary techniques of EOR:

I.4.1. Miscible Gas Flooding

This technique uses gases such as natural gas, nitrogen, or carbon dioxide (CO_2) that dissolve in the oil to lower its viscosity and improve its flow rate. Miscible gas flooding is presently the most-commonly used approach in enhanced oil recovery. A miscible displacement process maintains reservoir pressure and improves oil displacement because the interfacial tension between oil and gas is reduced.

I.4.2. Thermal Injection

This involves the introduction of heat, such as the injection of steam, to lower the viscosity, or thin, the heavy viscous oil, and improve its ability to flow through the reservoir. Thermal EOR usually involves burning natural gas to produce steam which is injected into the reservoir to heat heavy oil to reduce its viscosity. [3]

I.4.3. Chemical Injection

This method involves injecting specific chemicals into an underground oil reservoir to increase oil recovery by enhancing the effectiveness of water injected into the reservoir, thereby displacing the oil more efficiently. We use in this method (Polymers - Surfactant - Alkaline) flooding. Chemical EOR can result in 30-60 per cent or more of the reservoir's original oil being extracted, compared to just 20-40 per cent using primary or secondary recovery methods.

I.4.3.1. alkaline flooding

Alkaline flooding is a tertiary enhanced oil recovery (EOR) technique that involves injecting an alkaline solution into a crude oil reservoir. This method can be used as a standalone process or in combination with surfactant-polymer injection. The alkaline solution, typically consisting of chemicals like sodium hydroxide, sodium orthosilicate, or sodium carbonate, reacts with the oil, particularly those containing organic acids, to form in-situ surfactants. [4]

I.4.3.2. Surfactant flooding

Surfactant flooding, also known as detergent or microemulsion flooding, is an Enhanced Oil Recovery (EOR) technique that involves the injection of surfactants into a reservoir.

The surfactants are special chemicals that lower the Interfacial Tension (IFT) between the oil and water, which can help to mobilize trapped oil, making it easier to displace and recover. This method can also alter the wettability of the reservoir rock, potentially changing it from oil-wet to water-wet, creating more favorable conditions for oil displacement. [5]

I.4.3.3. Polymer flooding

In polymer flooding (PF) water augmented with polymers is injected, resulting in increased fluid viscosity. This enhancement improves the sweep efficiency of reservoir floods by providing effective mobility control between water and resident hydrocarbons. [6]

Figure I.4.3.3: Polymer flooding.

I.4.3.4. Polymer Flooding Applicability

In a waterflood, oil is either bypassed or retained by the capillary forces, resulting in discontinuous residual oil left behind. This bypassing effect is reduced by using polymers to increase the mobility ratio. Typically, polymer flooding is used in two cases:

- When faced with an unfavorable mobility ratio during waterflooding, enhancing water viscosity through the addition of polymers can lead to improved sweep efficiency and enhanced oil recovery.

- Even in cases where the mobility ratio is favorable, if the reservoir exhibits heterogeneity, polymer injection can effectively decrease water mobility within the high-permeability layers, thereby facilitating the displacement of oil from the low-permeability layers. [7]

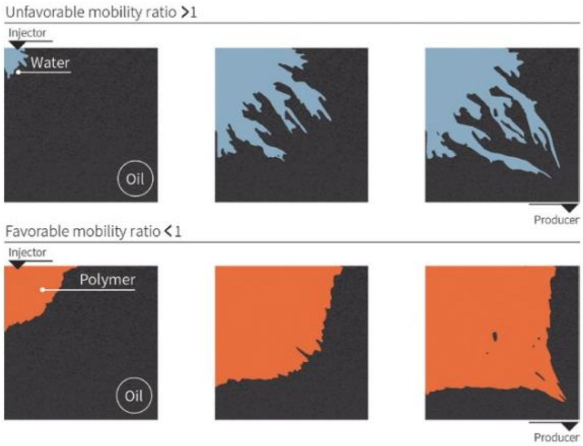


Figure I.4.3.4: The impact of mobility in displacement of oil. *[6]*

I.4.3.5. Reservoir Screening

Given the current recovery factors, which average 35% of oil initially in place (OOIP) after waterflood, there exists significant potential for EOR. Leveraging existing infrastructure can facilitate the implementation of EOR techniques. Specifically, polymer injection is a promising approach. Here are the general guidelines to assess the feasibility of polymer flooding in a field, The two principal screening rules for polymer flooding are:

- Pointing out reservoirs that have poor sweep efficiency due to high oil viscosity and/or large-scale heterogeneity.
- Determining whether the overall conditions are suitable (compatible brine, mobile oil saturation, retention) for polymer flooding implementation to fix the problem.

We can narrow the primary parameters needed to check whether polymer flooding is a viable option, by order of importance:

Parameter	Preferred condition
Lithology	Sandstones preferred
Wettability	Water-wet
Current oil saturation	Above residual oil saturation
Porosity type (matrix/ fractures)	Matrix preferred
Aquifer	Edge aquifer tolerated
Salinity	See comments
Dykstra-Parsons and facies variations	0.1<DP<0.8
Clays	Low
Flooding pattern and spacing	Confined – small spacing

Table I.4.3.5: Parameters to consider when screening candidates for polymer flooding.

High Salinity:

- While high salinity in the injection water isn't a showstopper, it does affect the choice of polymer chemistry and dosage.
- High salinity can lead to increased polymer degradation, affecting viscosity and overall performance.

I.4.3.6. Definition of polymers:

Polymers are typically polydisperse, indicating that micro-molecules with identical chemical compositions but varying chain lengths exist together in a sample. Within the oil and gas sector, to enhance water viscosity for better reservoir sweep efficiency, two primary polymer families are considered: **biopolymers**[1], such as polysaccharides, and **synthetic polymers**[2]**.** [8]

[1] Natural polymers, also commonly referred to as biopolymers, are polymers synthesized from natural plants or bioproducts.
[2] The synthetic polymers are commonly categorized into polyacrylamide (PAM), hydrolyzed polyacrylamide (HPAM), and hydrophobically associating polyacrylamide (HAPAM).

I.4.3.7. The polymerization process of biopolymers

The polymerization process of biopolymers involves linking monomers, which are small, repeating chemical units, to form large chain-like molecules. Here's a general overview of the process:

- **Initiation:** Start the polymerization reaction by adding an initiator or catalyst (water) that triggers the bonding of monomers.
- **Propagation:** Continue the growth of the polymer chain as monomers add to the chain one by one.
- **Termination:** the reaction Stopped when the polymer reaches the desired length or when the monomer supply is exhausted. [6]

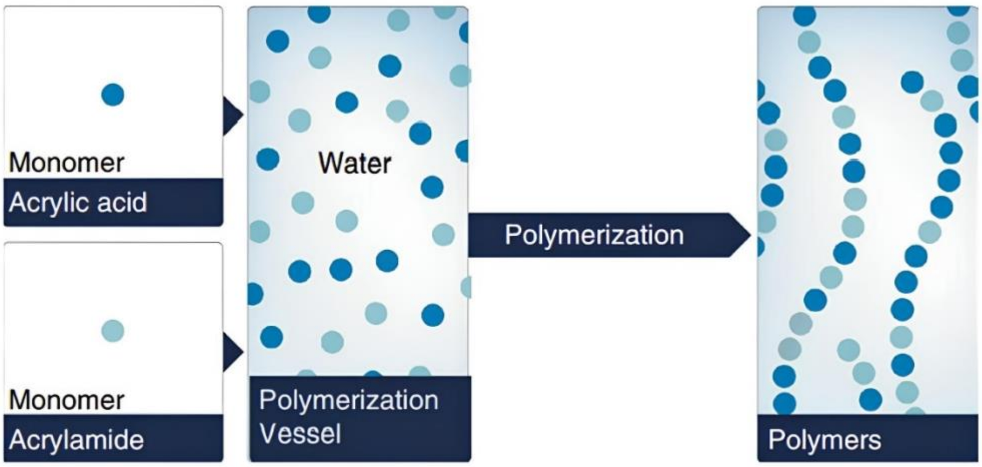


Figure I.4.3.7: Polymerization process.

I.4.3.8. Type of monomer Biopolymers

A. Xanthan gum

Xanthan gum is a nontoxic biodegradable polysaccharide. The high molecular weight of xanthan gum polymer accounts for its thickening ability. Furthermore, polymer chains are rigid, which makes them resistant to mechanical shear, high salinity, and/or divalent ion concentration, xanthan gum is relatively more stable in harsh reservoir conditions. [5]

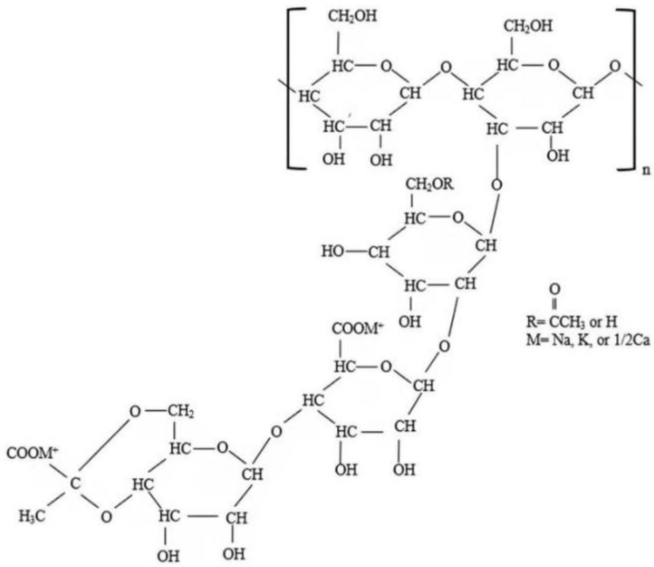


Figure I.4.3.8.1: Xanthan gum.

B. Cellulose

Cellulose is usually derived from the tissue of plant cell walls and eukaryotic cells and is widely regarded as the most abundant biopolymer in the world. Cellulose can withstand high mechanical shearing and temperature due to its network structure. Several types of cellulose have been exploited for EOR. These include hydroxyethyl cellulose, carboxymethylcellulose, and nanocellulose. [9]

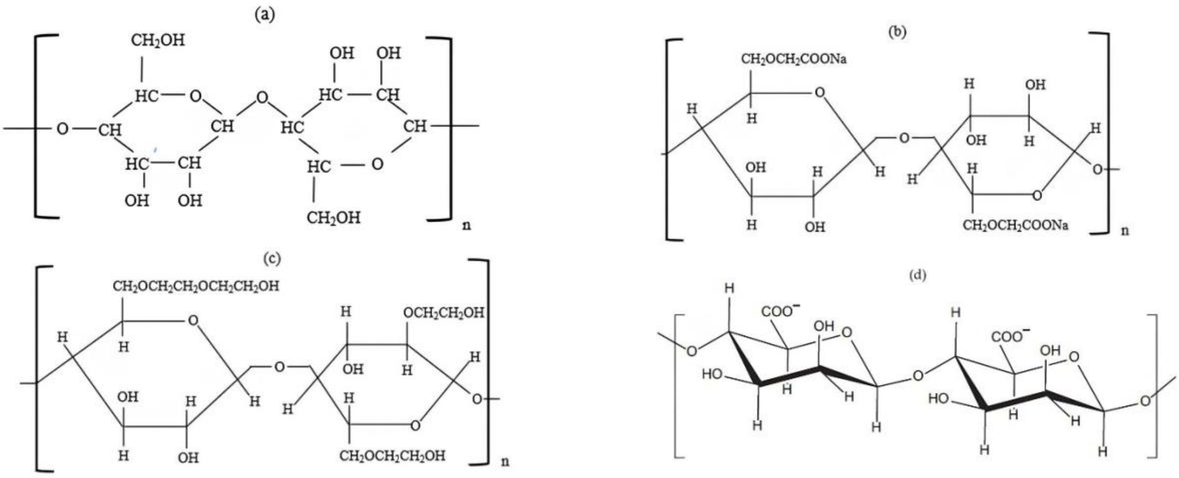


Figure I.4.3.8.2: (a) Cellulose, (b) carboxymethylcellulose, (c) hydroxyethylcellulose, and (d) nanocellulose *[5] [8]*

I.4.3.9. Polymers Choice

The choice of the optimal polymer shape and chemical composition hinges on several factors. To shortlist potential polymer candidates, it's crucial to be aware of the temperature of the reservoir, the average permeability, and the salinity and molecular weight. [6]

Average molecular weight (million Da)	Minimum permeability (mD)
>20	>1000
18–20	>750
15–18	>500
12–15	>350
8–12	>200
5–8	>100
1–5	>10

Table I.4.3.9: Correlation Between Average Molecular Weight and Absolute Rock Permeability.

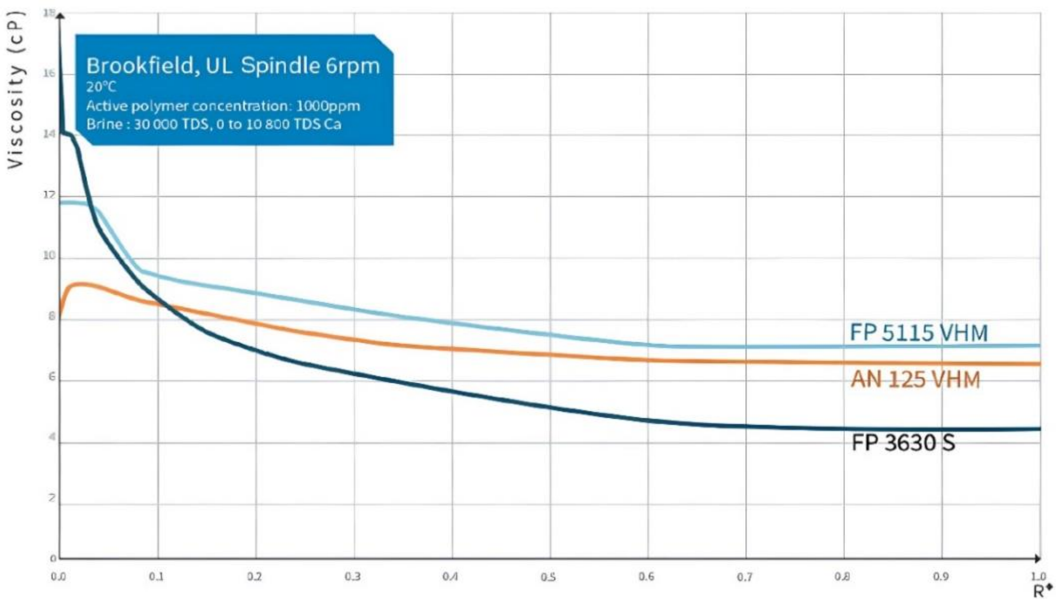


Figure I.4.3.9.1: The Impact of Salt Content on Viscosity.

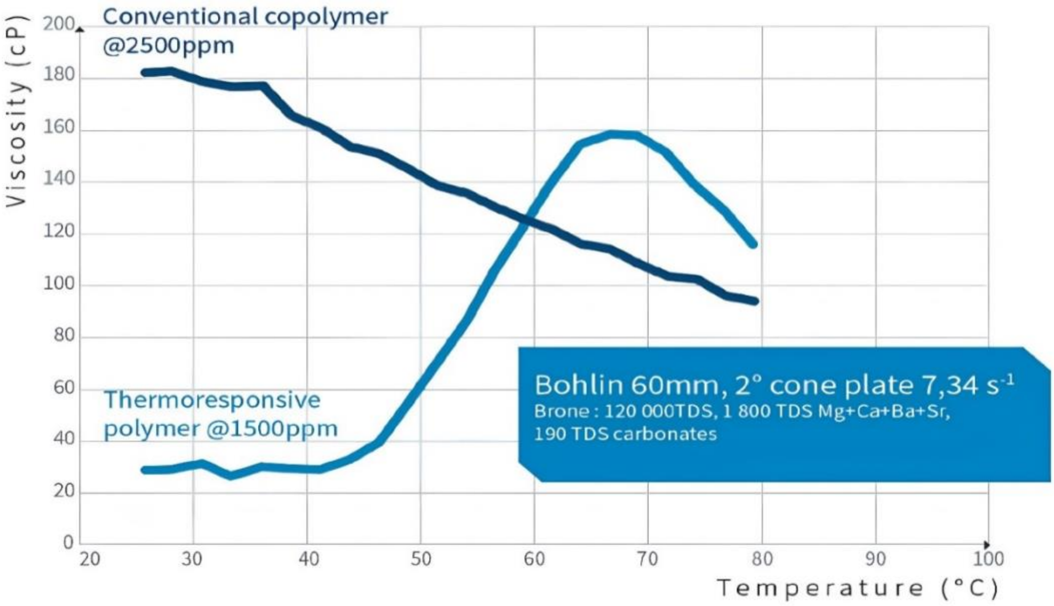


Figure I.4.3.9.2: The Impact of Temperature on Viscosity.

I.4.3.10. Degradation

A significant challenge in polymer injection is the rapid degradation of polymers. This degradation process involves the disintegration of long-chain polymer molecules in the solution. Consequently, the polymers' molecular weight reduces, leading to a substantial loss in the solution's viscosity. Several factors influence the degradation of a polymer solution. The most critical factors are: [10]

A. Chemical Degradation

In Enhanced Oil Recovery (EOR) processes, free radicals are typically produced by oxidation-reduction reactions between dissolved oxygen in water and either iron (II) or hydrogen sulfide (H2S). Chain scission results in a decrease in the hydrodynamic volume of the polymer, leading to a reduction in viscosity. Numerous studies have provided guidelines to minimize polymer degradation, setting limits for oxygen and iron content.

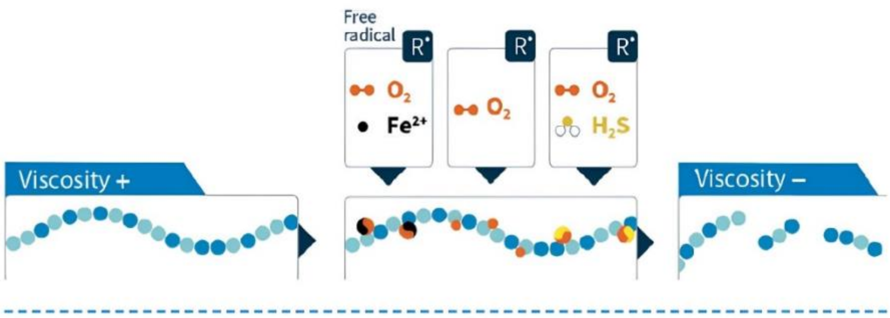


Figure I.4.3.10.1: Chemical Degradation by Free Radical Generated by the Red/Ox Reaction Between Oxygen and Iron or Hydrogen Sulfide. *[6]*

B. Mechanical Degradation

Polymer mechanical degradation happens when the molecule undergoes high shear rates or distinct pressure reductions in a pipe, a choke, an orifice, or a pump. This leads to chain scission and ultimately a decrease in viscosity. The susceptibility to mechanical degradation increases with the molecular weight and chain length of the polymer.

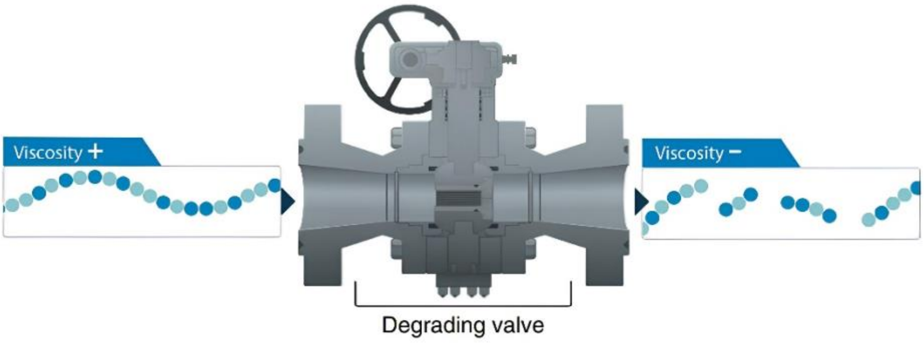


Figure I.4.3.10.2: Mechanical Degradation Due to a Valve *[6]*

The choice of equipment is paramount to ensure that little degradation will occur in the system. Here are a few examples:

- Centrifugal pumps should not be used for polymer solution. Progressive cavity or triplex pumps are preferred.
- Manifolds should not be used to control flow. Chutes should be fully opened, avoided, or replaced with non-shear devices.
- Turbine flow meters should be avoided.

I.4.3.11. Retention

The reduction in permeability during polymer injection is due to several interactions of the fluid and the porous medium. Reduced permeability has a critical effect on flood productivity, especially in initially low permeability reservoirs.

This reduction always results, to some extent, in irreparable damage to the reservoir, a decrease in production efficiency, and higher costs. Usually, a small percentage of the injected polymer liquid is lost due to retention. This includes three mechanisms: [11]

- **Adsorption:** The polymer "sticks" to the rock via van der Waals forces or ionic or hydroelectric bonds. Given the ability of the molecule to attach to the rock at many points, adsorption is generally considered irreversible.
- **Mechanical trapping:** Very large molecules can be physically trapped at the entrance to the pore throats.

- **Hydrodynamic retention:** Molecules may be temporarily trapped in regions where flow is stagnant.

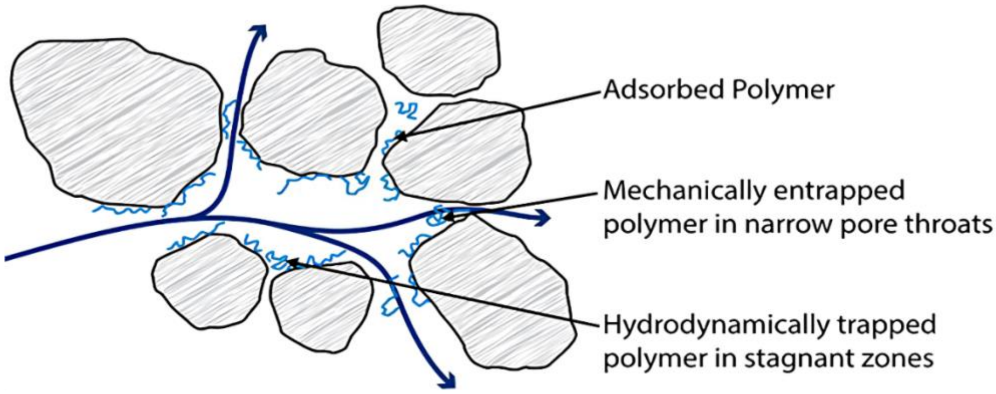


Figure I.4.3.11: Retention Mechanisms

Chapter II:

Multiphase flows in a porous medium

II.1. Introduction

Monophasic flow refers to the flow of a single fluid phase in the rock. Other phases may be present, but they are immobile. For example, monophasic oil flows in undersaturated oil reservoirs even if water is present at an interstitial water saturation. Multiphase flow refers to the simultaneous flow of two or more phases in the rock. The presence of two or more flowing phases in a porous space affects the flow of each phase and also the interaction between the fluid and the rock.

In this chapter we will discuss the properties that represent the interaction and the rock-fluid properties and their application in multiphase flows in the porous medium.

II.2. Porosity

Porosity is a measure of the empty space within a rock, which is expressed as a fraction (or percentage) of the overall volume of that rock.

The general expression for Ø porosity is:

$$\emptyset = \frac{v_p}{v_b} = \frac{v_b - v_s}{v_b} \qquad \textbf{Equation II.2}$$

Where:

- v_b is the apparent volume of the rock,
- v_s is the volume occupied by solids (also known as grain volume),
- v_p is the volume of the pores.

From an engineering perspective, porosity is classified as follows:

- **Absolute porosity**: total porosity of a rock, regardless of whether the individual voids are connected.
- **Effective porosity** only the porosity due to voids that are interconnected.

It is the effective porosity that is of interest. Any further discussion of porosity will focus on effective porosity.

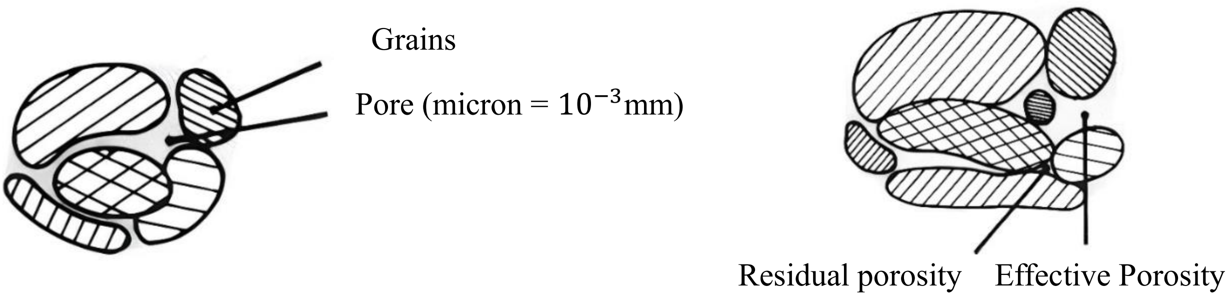


Figure II.2: A Porous Medium

II.3. Permeability

Permeability is a property of the porous medium that measures the ability and suitability of the formation to transmit fluids. The permeability of the rock, k, is a very important property of the rock because it controls the directional movement and flow of fluids from the reservoir in the formation Q. This characterization of the rock was first defined mathematically by Henry Darcy in 1856.

If a horizontal linear flow of an incompressible fluid is established through a core sample of length X and a surface cross-section A, the pressure difference (dP) and the fluid viscosity μ, the fluid flow equation is defined as follows:

- International System (IS)

$$\boldsymbol{Q}_{(\frac{m^3}{s})} = \boldsymbol{K}_{(m^2)} \cdot \frac{\boldsymbol{A}_{(m^2)}}{\boldsymbol{\mu}_{(Pa.s)}} \cdot \frac{\boldsymbol{dP}_{(pa)}}{\boldsymbol{dX}_{(m)}} \qquad \textbf{Equation II.3.1}$$

(IS)

- Convenient system (CS)

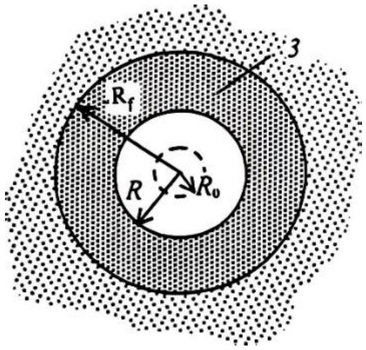
$$\boldsymbol{Q}_{(\frac{m^3}{s})} = \boldsymbol{K}_{(Darcy)} \cdot \frac{\boldsymbol{A}_{(cm^2)}}{\boldsymbol{\mu}_{(cp)}} \cdot \frac{\boldsymbol{dP}_{(atm)}}{\boldsymbol{dX}_{(m)}} \qquad \textbf{Equation II.3.2}$$

(CS)

- Circular Radial Flow

$$\mathbf{Q} = \frac{\mathbf{2\pi hk}}{\boldsymbol{\mu}} \cdot \frac{\mathbf{P_1 - P_2}}{\mathbf{ln\frac{r_1}{r_2}}}$$

Where h is the thickness of the rock assumed to be constant in which the fluid flows, and r_1 and r, are the distances to the axis of the cylinder where P_1, and P_2 prevail.



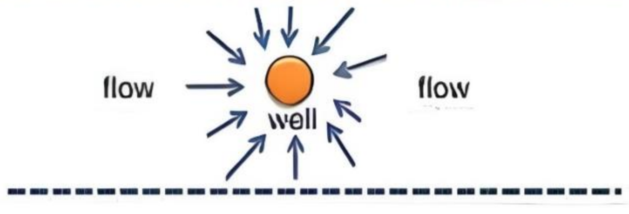


Figure II.3: Circular Radial Flow System.

II.4. The Saturation

Saturation is defined as the fraction, or percentage, of the pore volume occupied by a particular fluid (oil, gas, or water). It can be expressed by the following relationship:

$$\boldsymbol{Saturation} = \frac{\textbf{the total volume of a fluid (oil,gas,or water)}}{\textbf{pore volume}}$$ **Equation II.4.1**

❖ By applying the concept to each fluid in the reservoir:

- $\mathbf{S_o = \frac{V_o}{V_p}}$ **Equation II.4.2**
- $\mathbf{S_g = \frac{V_g}{V_p}}$ **Equation II.4.3**
- $\mathbf{S_w = \frac{V_w}{V_p}}$ **Equation II.4.4**

Such as:

S_o is Oil saturation.

S_g is Gas saturation.

S_w is Water saturation.

The saturation of each individual phase varies between zero and 100%. By definition, the sum of the saturations is therefore equal to 100%:

$$\mathbf{S_O + S_G + S_W = 100\ \%}$$

II.5. Displacement of fluids in the reservoir

II.5.1. The concept of relative permeability

In hydrocarbon reservoirs, there are generally two fluids competing for the same pore space (for example, O/W). Darcy's law allows to determine an effective permeability for each of the fluids.

$$Q_1 = \frac{k_1}{\mu_1}.A.\frac{\Delta P_1}{L} \qquad And \qquad Q_2 = \frac{k_1}{\mu_1}.A.\frac{\Delta P_2}{L}$$

The permeability of one of the fluids is then described by its relative permeability (Kr), which is a function of the fluid saturation. Relative permeabilities are measured in the laboratory on reservoir rock samples using reservoir fluids.

$$\text{Permeabilité Relative} = \frac{\text{Permeabilité effective}}{\text{Permeabilité absoule}}$$

We generally introduce the relative permeabilities of each fluid in place:

Water:

$$k_{rw} = \frac{k_w}{k}$$

Oil:

$$k_{ro} = \frac{k_o}{k}$$

Gas:

$$k_{rg} = \frac{k_g}{k}$$

- The relative permeability varies between 0 and 1.

II.5.2. The Mobility

The mobility of a fluid is defined as the ratio between its permeability (k) and its viscosity (µ). In mathematical terms, it can be represented as:

$$Mobility\ \lambda = \frac{Permeability}{Viscosity}$$ **Equation II.5.2**

When there are two fluids in place, the mobility ratio is defined as the ratio of the mobility of one fluid to the mobility of the other fluid. If we denote the mobilities of the two fluids as $\lambda_1\ And\ \lambda_2$

The mobility ratio can be expressed as:

$$\boldsymbol{M_1} = \frac{\lambda_1}{\lambda_2}$$

Where:

λ_1 is the mobility of the first fluid.

λ_2 is the mobility of the second fluid.

This ratio is important in the study of multiphase flow in porous media, such as in oil reservoirs, where it can influence the efficiency of oil recovery. A lower mobility ratio is generally more favorable for efficient displacement of oil.

If the mobility ratio is greater than 1.0, water will tend to move preferentially in the reservoir, resulting in an unfavorable displacement front, described as viscous fingering. If the mobility ratio is less than one, stable displacement can be expected. This is a key concept in the study of fluid dynamics within reservoirs. It's crucial for optimizing the extraction of resources.

The mobility ratio can be influenced by changing the viscosities of the fluids.

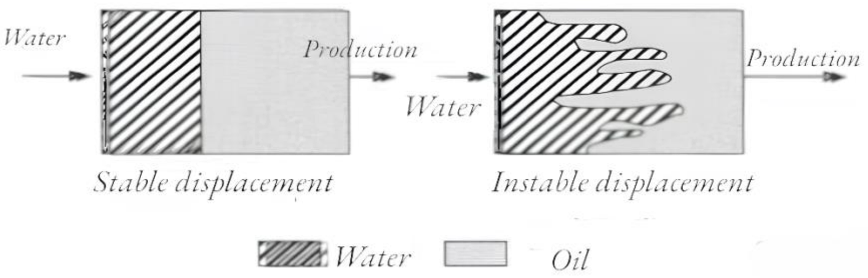


Figure II.5.2: Stable and Instable displacement example in the horizontal plane.

II.6. Capillary Mechanism

Two surface properties affect the distribution of fluid phases in a reservoir: interfacial tension (IFT) and wettability.

II.6.1. Interfacial Tension (IFT)

Interfacial tension is a measure of the force that exists at the interface between two fluids. It's a result of the difference in the attractive forces of molecules in the two phases. This property plays a significant role in the displacement of one fluid by another in various applications, including oil recovery processes in reservoirs. High interfacial tension can hinder the displacement process, while low interfacial tension can enhance it. Therefore, understanding and controlling IFT is crucial in optimizing fluid displacement and recovery operations.

$$\sigma_{ow} = \frac{rgh(\rho_w - \rho_o)}{2\cos\theta}$$ **Equation II.6.1**

Where:

σ_{ow} is the interfacial tension (IFT) between oil and water is typically measured in dynes/cm.

ρ_o is the volumetric mass density oil.

ρ_w is the volumetric mass density water.

II.6.2. Wettability

Wettability is the result of interactions between a solid surface and two adjacent fluid phases, as the figure would illustrate. The contact angle is the most fundamental measure of wettability. The surface is said to be wetted by water because the contact angle is less than 90°. In this competition for contact with the solid, water spreads over the solid. Water is the wetting phase and oil is the non-wetting phase.

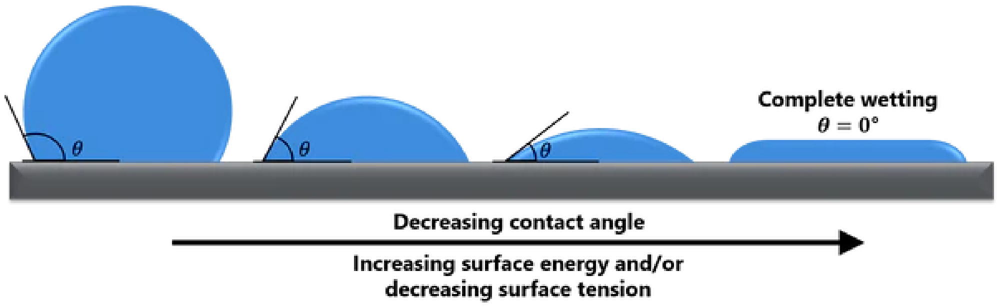


Figure *II.6.2*: Angle of contact between a surface with two fluids.

- Wettability can be altered by several factors, including contact with drilling fluids, fluids present on the platform floor, and the core's contact with oxygen or atmospheric water.
- Drilling fluids, for instance, can alter the wettability of the reservoir rock, potentially affecting the distribution and flow of oil and water within the reservoir. Similarly, exposure to oxygen or atmospheric water can also change the wettability characteristics of the rock.

These changes can have significant implications for oil recovery processes, as wettability plays a crucial role in determining the efficiency of oil displacement in the reservoir. Therefore, understanding and controlling these factors is an important aspect of reservoir management and engineering.

Wet condition	Contact angle (°)
Strongly Wetted	0-30
Moderately Wetted	30-75
Neutrally Wetted	75-105
Moderately Oil-Wetted	105-150
Strongly Oil-Wetted	150-180

Table II.6.2: Engle impact on wettability

II.6.3. Capillary Pressure

Capillary forces in an oil reservoir are the result of the combined effect of the surface and interfacial tensions of the rock and fluids, the size and geometry of the pores, and the wetting characteristics of the system. When two immiscible fluids are in contact, there is a pressure discontinuity between the two fluids, which depends on the curvature of the interface separating the fluids. This pressure difference is called capillary pressure and is denoted by P_c.

if we denote the pressure in the wetting fluid as P_w and the pressure in the non-wetting fluid as P_{nw}, the capillary pressure (P_c) can be expressed as follows:

$$P_c = P_{nw} - P_w$$ **Equation II.6.3.1**

The three types of capillary pressure can be written as follows:

$$P_{cwo} = P_o - P_w \quad ; \quad P_{cgo} = P_g - P_o \quad ; \quad P_{cgw} = P_g - P_w$$

Where:

P_{cwo} is the water-oil capillary pressure.

P_{cgo} is the gas-oil capillary pressure.

P_{cgw} is the gas-water capillary pressure.

The equation of capillary pressure can be expressed in terms of surface and interfacial tension as follows:

$$P_C = \frac{2\sigma_{wo}(\cos\theta)}{r} \quad ; \quad h = \frac{2\sigma_{wo}(\cos\theta)}{rg(\rho_w - \rho_o)}$$ **Equation II.6.3.2**

II.7. Drainage and imbibition

The drainage process involves moving a non-wetting fluid (like gas or oil) through a medium, displacing the wetting fluid (like water). This process is used to generate a curve that represents the capillary pressure in the medium.

This drainage process establishes the fluid saturations found at the time of reservoir discovery. The other main flow process involves reversing the drainage process by displacing the non-wetting phase (such as oil) with the wetting phase (for example, water). This displacement process is called the imbibition process, and the resulting curve is called the capillary pressure imbibition curve. The process of saturating and desaturating a core with the non-wetting phase is called capillary hysteresis. The figure shows typical capillary pressure, drainage, and imbibition curves. The two capillary pressure-saturation curves are not the same.

This difference in the saturation and desaturation of capillary pressure curves is closely related to the fact that the advancing and receding contact angles of fluid interfaces on solids are different.

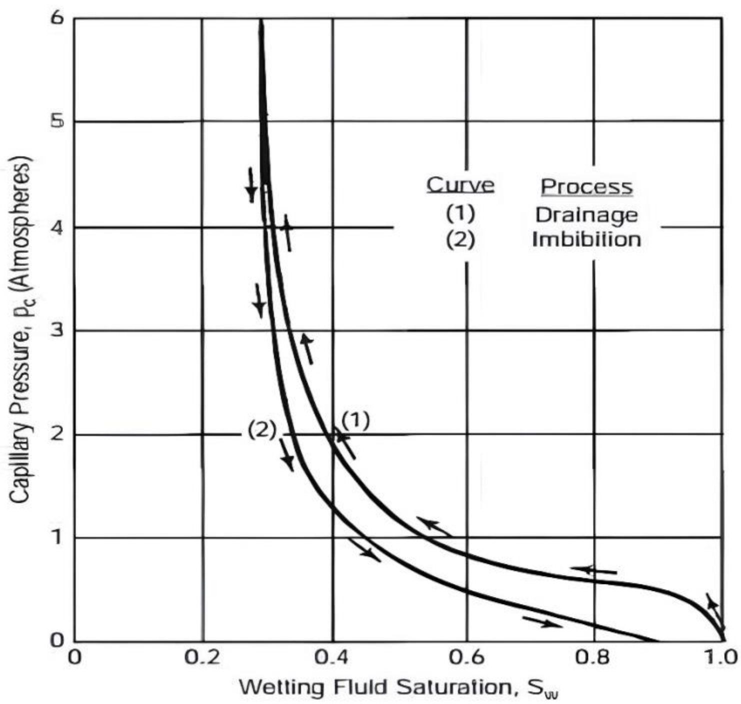


Figure II.7: Capillary hysteresis.

II.8. Capillary Number

The recovery of oil in the reservoir after the completion of the water injection process is governed by the ratio of two forces. These forces are the viscous forces, which attempt to mobilize the oil, and the capillary forces that keep the oil trapped in the pores. The relationship between these two forces is very important and is defined by the capillary number (NC). It is a dimensionless quantity, defined by:

$$N_c = \frac{v\mu_w}{\sigma_{ow}} \qquad \textbf{Equation II.8}$$

μ_w is the viscosity of water (which is the displacement fluid).

σ_{ow} is the oil-water IFT.

v is the velocity.

II.9. Mechanism of oil trapping in porous media

Oil can be trapped in fine capillaries in the form of disconnected droplets. Capillary trapping can be of two types, namely the snap-off process and the bypass process.

- In the snap-off process, oil is trapped in the widest parts of a pore, which has a larger ratio between the body of the pore and the throat of the pore. When the wetting phase is water, it forms a layer around the non-wetting phase, the oil. The thin layer of water gradually thickens in the throat and forces the oil filaments to break near the throats of the pores, causing the oil droplets to be separated from the other droplets, with water surrounding the oil droplets.
- The bypass process (water bypass) is caused by the relative competition between the flow of oil and water in pores of different sizes. The flow is faster in the larger channels. Capillary forces draw the displacement phase (water) into the smaller and narrower pores due to the stronger interaction of water with the capillaries than oil.

Therefore, water is pushed into the smaller pores and, at low injection rates, due to a viscosity lower than that of oil, water lodges in the smaller pores by capillary action. The oil, on the other hand, is trapped in the larger pores, and water continues to bypass the oil by flowing through the smaller capillaries.

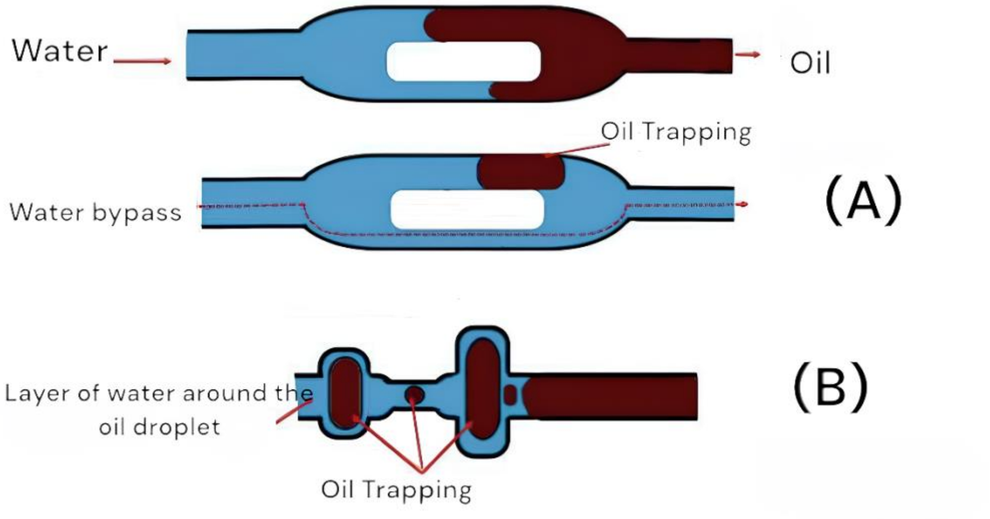


Figure II.9: Mechanism of Oil Trapping by (A) Bypass and (B) Snap off.

Chapter III:

Experimental study

In this chapter, we describe the materials and fluids chosen for carrying out the experiments, as well as the experimental procedures used during the study.

In this work, experiments were performed in a micromodel and then the results were modeled using CMG software.

III.1. CMG software for study modeling:

CMG's primary focus is on developing simulation software for reservoir recovery methods, helping to overcome technological barriers and optimize the extraction of oil and gas from underground reservoirs.

CMG offers a range of software products for various applications in the oil and gas industry, including:

- ❖ **STARS**: A thermal and advanced processes reservoir simulator that models stress-induced phenomena, such as elastic and plastic deformation and fracturing of reservoir rock and is coupled with surface network modelling software for simultaneous modelling of the reservoir and the surface network.
- ❖ **GEM**: A compositional reservoir simulator that models' recovery processes where the fluid composition affects recovery, and includes advanced features for modelling asphaltenes, coal bed methane, and the geochemistry of the sequestration of various gases including acid gases and CO2.
- ❖ **IMEX**: A full-featured three-phase, four-component black oil reservoir simulator for modelling primary depletion and secondary recovery processes in conventional oil and gas reservoirs.
- ❖ **CMOST**: A software tool for history matching, optimization, sensitivity, and uncertainty analysis.
- ❖ **COFLOW**: An integrated production and reservoir simulation software that models the interaction between the reservoir and the surface network.
- ❖ **WINPROP**: A software tool for PVT phase behavior characterization.
- ❖ **LAUNCHER**: A software component for file management and job scheduling.

In our study, we needed to use three products of the CMG software, which are **Builder** and **STARS**.

- **Builder:**

  1. **Description:** *Builder* is an interactive interface designed by CMG for creating and preparing simulation models across all CMG simulators.
  2. **Functionality:**
     - Defines and edits reservoir properties for specific sectors or regions.
     - Provides intuitive well planning and field development tools.
     - Supports pattern-based or horizontal well drilling.
     - Allows defining group and cyclic well controls.
  3. **Use Case:**

Engineers and reservoir modelers use *Builder* to design and prepare simulation models efficiently, ensuring accurate representation of reservoir properties and well configurations.

- **STARS:**

  1. **Description:** *STARS* is CMG's flagship reservoir simulator, widely recognized as the industry standard for thermal, chemical EOR, and other advanced processes.
  2. **Functionality**:
     - Simulates complex thermal recovery processes (e.g., SAGD, SA-SAGD, CSS, In-situ Combustion, Solvent Co-Injection).
     - Models' geothermal effects, wellbore physics, and chemical EOR processes (e.g., ASP flooding, LSW injection, foam flooding).
     - Optimizes steam allocation and solvent injection in full-field multi-pad simulations.
  3. **Use Case:**

Engineers use *STARS* to analyze heavy oil recovery, evaluate recovery processes, and design optimal well and field development plans.

III.2. Characteristics and preparation of the porous medium

in this study we choose to use glass micromodel as our porous medium

III.2.1 Glass micromodel

A glass micromodel is a small-scale, transparent replica of a porous medium or geological formation, typically used in laboratory settings to study fluid flow and transport processes. These micromodels are constructed by etching or engraving microscopic channels and structures into glass plates, which are then sealed together. The transparency of the glass allows researchers to directly observe and analyze the movement and interaction of fluids, such as water, oil, or gas, within the porous network. This capability makes glass micromodels valuable tools in fields like petroleum engineering, hydrogeology, and environmental science for investigating complex subsurface phenomena under controlled conditions. Our glass micromodel are parallelepiped in shape (125mm X 3mm X 205mm) with two pressure taps which allow us to characterize our porous environment (permeability K , Porosity Ø , …) and monitor polymer injections, during the drainage and imbibition phases. Glass micromodels play a crucial role in enhancing oil recovery for several reasons:

- **Direct Visualization:** Glass micromodels provide a transparent medium that allows researchers to directly observe and analyze the behavior of fluids in porous media. This capability is critical for understanding the mechanisms of oil displacement, the formation of emulsions, and the dynamics of multiphase flow.
- **Controlled Experimentation:** These micromodels enable precise control over experimental conditions, such as pore structure, flow rates, and fluid properties. This control allows for systematic investigation of various enhanced oil recovery (EOR) techniques and their effectiveness under different scenarios.
- **Mechanism Understanding:** By mimicking the complex pore structures of natural reservoirs, glass micromodels help researchers understand key processes like capillary forces, wettability alteration, and interfacial tension reduction. This understanding is essential for optimizing EOR methods such as chemical flooding, microbial EOR, and pulsing water injection.
- **Innovation and Testing:** Glass micromodels are used to test new EOR strategies and materials, such as novel surfactants, nanoparticles, and biosurfactants. This testing is crucial for developing more efficient and environmentally friendly oil recovery methods.
- **Model Validation:** Experimental data from glass micromodel studies are used to validate and refine computational models of fluid flow in porous media. This validation improves the accuracy of simulations and predictions, aiding in the design and implementation of effective EOR projects.

Here are some research articles that utilize glass micromodels in their studies:

- **A 2.5-D Glass Micromodel for Investigation of Multi-phase Flow in Porous Media:**

This article discusses the development of a novel 2.5-D glass micromodel that better simulates 3-D multi-phase flow in porous media compared to traditional 2-D models. The study demonstrates the model's ability to replicate capillary snap-off and the formation of residual oil droplets, offering insights into emulsion flooding and light oil displacement with surfactants.

- **Experimental Microemulsion Flooding Study to Increase Low Viscosity Oil Recovery Using Glass Micromodel:**

This research focuses on using glass micromodels to study the efficiency of microemulsion flooding for enhancing oil recovery. The study compares different microemulsions and their effectiveness in reducing interfacial tension and increasing oil recovery rates.

- **Rhamnolipids Produced by Indigenous Acinetobacter junii from Petroleum Reservoir and its Potential in Enhanced Oil Recovery:**

This article explores the use of a glass micromodel to test the effectiveness of biosurfactants produced by bacteria isolated from oil reservoirs. The study highlights the role of these biosurfactants in reducing interfacial tension and altering wettability, thereby enhancing oil recovery.

III.3. characteristics and preparations of fluids

In this part we present the characteristics of the fluids used for the experiments: brine, polymer solution and oil.

III.3.1. Crude oil

In the conducted experiments, gasoline was utilized as a surrogate for formation fluids. The primary objective is to elucidate the migration patterns of gasoline spills or leaks through geological substrates such as soil or rock formations. Employing gasoline within a micromodel, the observation of its interaction with the pore network, thereby simulating its propagation in natural settings. This approach aids in visualizing and understanding the behavior of hydrocarbons as they traverse porous media.

III.2.1. Brine

Brine salinity is a critical parameter in glass micromodel studies because it allows researchers to investigate how it impacts wettability, interfacial tension, and multiphase flow behavior at the pore level. This knowledge is valuable for understanding oil recovery mechanisms and optimizing techniques for improved oil production. We used brine with salinity of 300 g/l based on the salinity of water formation of Hassi Masoud.

Steps to Prepare the brine Solution:

Materials Needed

1. Sale (NaCl).
2. distilled water.
3. Measuring equipment.
4. Mixing equipment.

Determine the Concentration:

- based on reservoir conditions, we seek to make brine of 300 g/l.

Measurements:

- Fill 500 ml of distilled water in the beaker.
- Weigh 150g of salt NaCl.

Mixing:

- We put the water on the magnetic mixer and raise the temperature to 50 C°
- Slowly add NaCl.
- Continue stirring the solution until the NaCl is completely dissolved.
- Ensure the solution is homogeneous. adjust the stirring speed and duration based on observations.
- Filter the solution to remove any undissolved particles.

III.3.2. Polymers

The polymer used is a Xanthene gum (XCD-POLYMER). is a modified Bio degradable high viscosity Polymer It used to viscosify and improve the rheological properties of fluids. The characteristics are given in the table below.

Physical and chemical properties	
Appearance	Creamish White free Flowing Powder
Bulk density (kg/m3)	0.67 -0.89
pH (1% solution)	6.0-7.5
Temperature Stability	Stable up to 150 Deg C
Moisture Content	12% max
Toxicity	Non-Toxic

Table III.3.2: Properties of the polymer used.

Steps to Prepare the brine Solution:

Materials Needed

5. Biopolymer (Xanthene gum) powder
6. distilled water
7. Mixing equipment
8. Measuring equipment
9. Optional additives

Steps to Prepare the biopolymer Solution:

1. **Determine the Concentration**:

    - Typical concentrations for EOR range from 500 to 3000 ppm (parts per million), depending on reservoir conditions and desired viscosity.
    - For example, if you need a 1000 ppm solution in 1 liter of brine:

Mass of XCD = 1000 ppm ×1 liter = 1000 mg = 1 g

2. **Measurements**

    - Fill 500 ml of distilled water in the beaker.
    - Weigh 0.5 g of polymer XCD.

3. **Slowly add biopolymer**:
    - Gradually add the biopolymer powder to the distilled water while continuously stirring. This helps prevent clumping.
    - Use the magnetic mixer at a moderate speed to avoid introducing air bubbles, which can affect the solution's properties.
4. **Mixing**:
    - Continue stirring the solution until the biopolymer is completely dissolved. This can take several hours, depending on the type and concentration of biopolymer.
    - Ensure the solution is homogeneous and free of lumps. You might need to adjust the stirring speed and duration based on observations.
5. **Check for Viscosity and Stability**:
    - Measure the viscosity of the prepared solution using a viscometer to ensure it meets the desired specifications. Adjust the concentration if necessary.
    - Monitor the stability of the solution over time to ensure it remains effective under reservoir conditions.
6. **Filter the Solution**:
    - To prevent plugging of the porous media, filter the solution through a fine mesh or filter to remove any undissolved particles.

Important Considerations

- **Temperature and pH**: These factors can influence the dissolution rate and viscosity of the biopolymer solution. Ensure these parameters are within the recommended range for your specific biopolymer product.
- **Mixing Time**: Adequate mixing time is crucial to ensure complete dissolution and achieve the desired solution properties.
- **Storage and Handling**: Store the prepared solution in clean, covered containers to prevent contamination. Use the solution within a reasonable timeframe to avoid degradation.

We repeat the same steps, but in different concentrations:

- 1g per 0.5l (2000ppm)
- 2g per 0.5l (3000ppm)

III.4. Experimental assembly

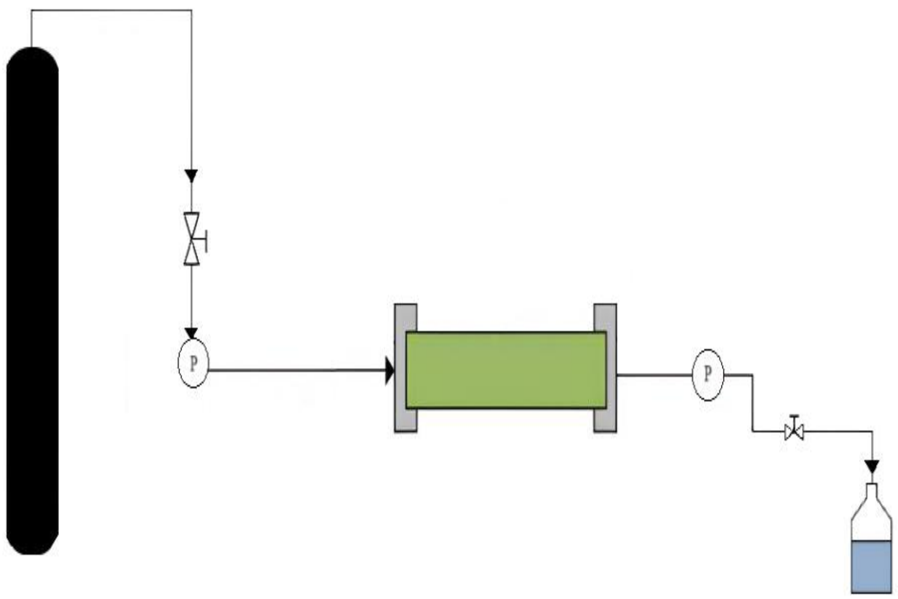


Figure III.4: Schematic of the experimental setup.

Elements	
Injection tank	

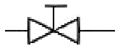
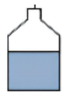
Valve	
Pressure-gauge	
Porous medium	
Beaker	

Table III.4: The components of the experimental setup.

III.5. Experimental procedures

III.5.1 Micromodel characterization

To conduct experiments, we need to know a set of data, the most important of which is the petrophysical property of micromodel.

We saturate our micromodel with the prepared brine 300g/l and we measured both of the ΔP and flow rate Q and to be able to conclude the permeability, then we retrieve the brine that inside the MP and measured its volume V_p to determine the porosity Ø.

III.5.2 Drainage

We saturated the micromodel with brine of 300 g/l, followed by gasoline injection in low flow rate to simulate the migration of oil in real case. It is an initial reservoir drainage until reaching the initial oil saturation 75%. There we get a reservoir model in its initial state ready to produce.

1. **Waterflooding imbibition**

For saturated porous media with oil, water is injected at a constant flow rate and inlet pressure initially until the residual oil saturation is obtained. We determined the Recovery factor by measuring volume of recovered oil. all the tests performed in fixed time (3 min) to be able of comparing the results with polymer flooding.

2. polymer imbibition

For saturated porous media with oil, the polymer solution is injected at a constant inlet pressure initially until the residual oil saturation is obtained. We measure Recovery factor by measuring recovered oil volume. We repeat this process for all the 3 concentrations. All the tests performed in fixed time (3 min) to be able of comparing the results and conclude the optimal value of concentration.

Chapter IV:

Analysis and modeling

In this chapter, we will highlight the results of the experiments we have carried out in the laboratory. We will follow it up by trying to interpret these results.

IV.1. Micromodel characterization:

- **Porosity**

To saturate the entire micromodel, we needed a fluid volume equal to $V_p = 34$ ml and the total volume of the micromodel is $V_t = 0.3 \times 12.5 \times 20.5 = 76.875$ ml

We can determine the porosity of the micromodel by measuring the pore volume over the total volume.

$$Ø = \frac{V_p}{V_t} = \frac{34}{76.875} = 44.22\%$$

- **permeability:**

We can determine the permeability of the micromodel based on the application of the Darcy law. By injecting distilled water from a vessel into the micromodel and retrieving it in a graduated burette.

$Q = 0.4545\ m^3/s$

$A = 12.5 \times 20.5 = 256.25\ cm^2$

$\Delta P = (6.5 - 5.1) \times 10^2 \times 9.81 \times 10^3 = 147.15\ Pa = 0.0015\ atm$

We compensate in Darcy law:

$$K = \frac{Q.A.\Delta P}{\mu.\Delta L}$$ **Equation IV.1**

The permeability $K = 17$

IV.2. Waterflooding imbibition

	test 01	test 02	
volume of extracted oil	13	13.5	
Total volume	28	29	Moy
Recovery Factor	0.464	0.465	0.4649

Table IV.2: The results of the water flooding imbibition.

During the injection process, we noticed that the water circulates with very low differential pressure and very high flow rate, the micromodel let us to see how the water follows preferential path. The recovery factor was a little bit low.

IV.3. polymer imbibition

- **Concentration of 1000 ppm**

	test 01	test 02	
volume of extracted oil	18	17	
Total volume	26	25	Moy
Recovery Factor	0.692	0.68	0.6861

Table IV.3.1: The results of the polymer imbibition at 1000 ppm.

During the injection process, we noticed that the polymer solution circulates with medium differential pressure and medium flow rate, the micromodel let us to see how the polymer solution sweeps more than the water. The recovery factor was a little bit higher than water.

- **Concentration of 2000 ppm**

	test 01	test 02	
volume of extracted oil	21	20	
Total volume	30	27	Moy
Recovery Factor	0.7	0.74	0.72

Table IV.3.2: The results of the polymer imbibition at 2000 ppm.

During the injection process, we noticed that the water circulates with high differential pressure and low flow rate, the micromodel let us to see how the polymer solution more efficient to sweep. The recovery factor was high.

- **Concentration of 3000 ppm**

	test 01	test 02	
volume of extracted oil	10	9	
Total volume	30	29	Moy
Recovery Factor	0.33	0.31	0.3218

Table IV.3.3: The results of the polymer imbibition at 3000 ppm.

During the injection process, we noticed that the polymer solution circulates with very high differential pressure and very low flow rate, the micromodel let us to see how the polymer solution was struggling to flow and take too much energy and time. The recovery factor was very low.

IV.4. Modelling

- **water injection model**

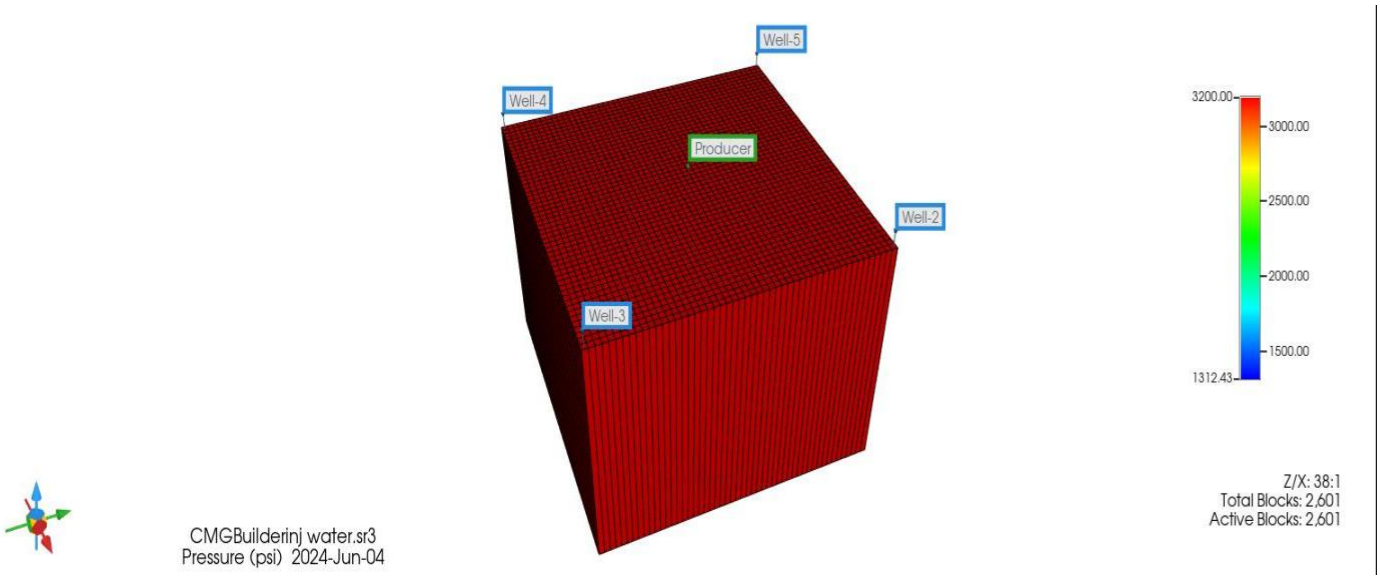


Figure IV.4.1: Water injection model.

❖ **Polymer injection model**

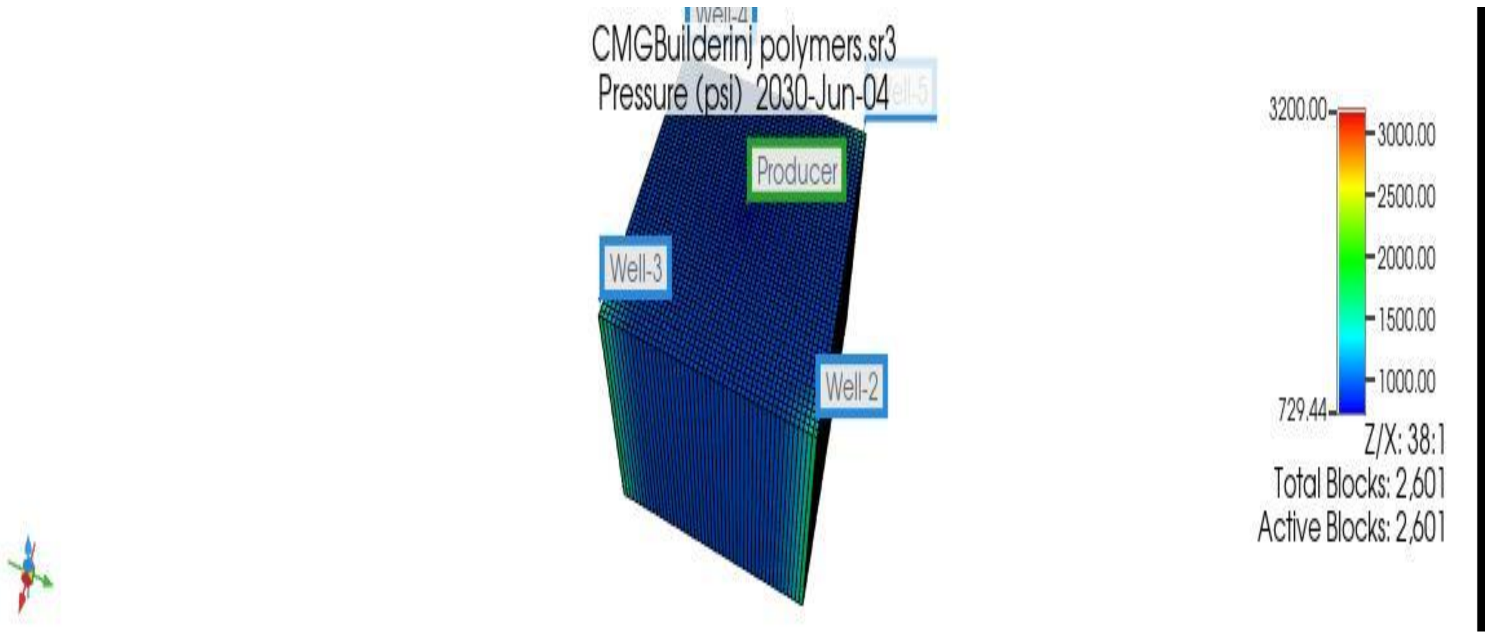


Figure IV.4.2: polymer injection model.

IV.5. Analysis of the results

The previous results show the following:

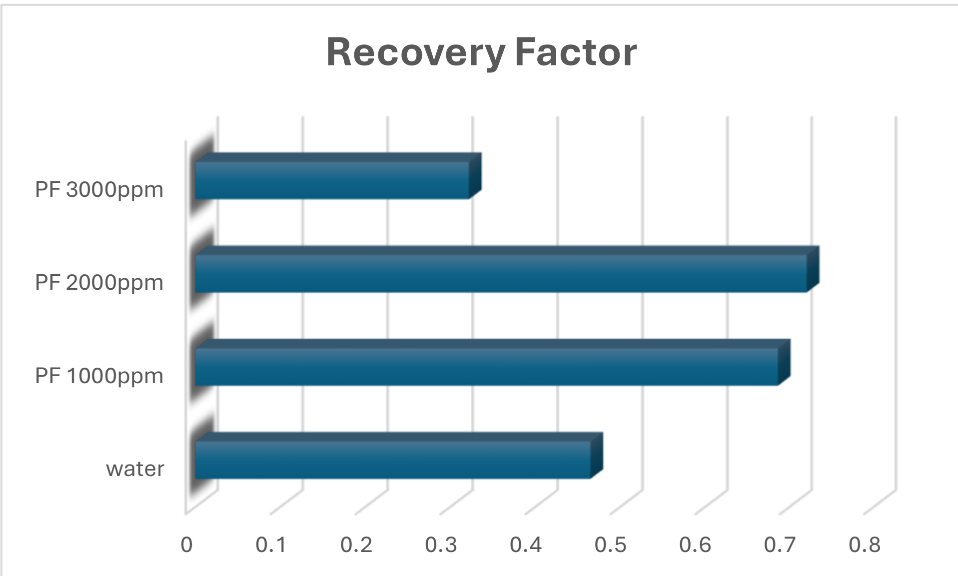


Figure IV.5.1: Bar chart representing the change in recovery factor for the injected fluid.

The water follows preferential path and leading to bypassing a big amount of oil staying trapped in the pores. This can be explained through the mobility ratio. Where we have the mobility of water higher than the oil, so the mobility ratio is M <1 which causes the viscous fingering effect.

Adding the polymer led to increase the viscosity so the mobility ratio decreases which improves the recovery factor as it is clear in the figure 18.

The polymer concentration 1000 ppm performs in rising viscosity so the recovery factor, The polymer concentration 2000 ppm rise more the viscosity, so the recovery factor is higher than 1000ppm.

But at 3000 ppm the viscosity is much too high until reaching a certain value where it is blocking the displacing process due to flow resistance which returns with negativity on the recovery factor as it is shown.

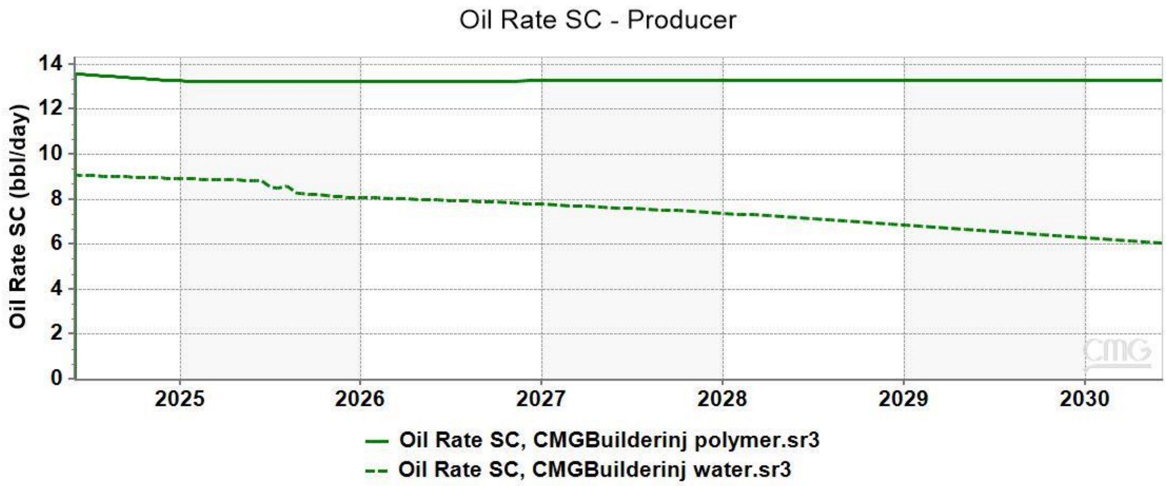


Figure IV.5.2: Oil rate forecast for both polymer and water injection.

This curve was derived from the simulation program and through it showed the quality of production by polymer injection compared to water injection. The reason of the drop of the recovery production in water injection is phenomena of bypass.

Chapter V:

General conclusion

V.1. General conclusion

Currently, about 60% of hydrocarbon recovery from reservoirs is achieved through primary and secondary recovery techniques, while the remaining 40% is left in reservoirs. The remaining trapped hydrocarbons have been very difficult to recover using the secondary recovery techniques with current completion technologies. The waterflooding method is commonly used by many oil companies to enhance oil recovery, and the gas injection method has been used to some degree. Polymer flooding has also been proven to be an effective oil recovery enhancement method for reservoirs and has the most efficient recovery. Through this experience, we see that enhanced oil recovery is the future, especially polymer injection, as the experience shows a clear difference in production between water and polymer, but focus must be placed on the viscosity value, as the viscosity must be suitable for the process.

V.2. Recommendation

Experimental modeling helps assess the economic viability of polymer flooding by analyzing the costs associated with polymer injection against the expected increase in oil recovery, the client company should select the optimum Polymer.

Selection of Optimum Polymer Characteristics through these recommended Formation Tests

1. Molecular Weight:

High molecular weight polymers generally provide better viscosity and stability, enhancing oil mobility control. Formation tests can help identify the best molecular weight ranges that yield the desired flow characteristics in the reservoir.

2. Shear Stability:

Optimal polymers must maintain their viscosity under shear conditions encountered in the reservoir. Testing different polymers for shear stability helps in selecting those that will perform well during injection.

3. Salinity Tolerance:

The presence of salts in formation water can affect polymer performance. Conducting formation tests allows for the selection of polymers that are resistant to salinity changes and retain their effectiveness in such environments.

4. Temperature Stability:

Reservoirs often exhibit varying temperatures that can affect polymer properties. Experimental characterization of polymer stability at different temperatures ensures reliable performance during the entire EOR process.

5. Compatibility with Other Chemicals:

Formation tests can evaluate the interactions between the selected polymers and other injected fluids (like surfactants or alkaline solutions). This is crucial for ensuring that the overall flooding strategy does not lead to unforeseen complications.

6. Environmental and Economic Considerations:

Selecting polymers which are environmentally safe and cost-effective is essential. Experimental modeling aids in comparing available options to make informed decisions that meet regulatory requirements and economic constraints.

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