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# Numerical and Experimental Study about Chemical Flooding by Polymer Towards Enhanced Oil Recovery (EOR): A review

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**Abstract**

Chemical EOR processes had gained popularity in recent years as a result of breakthroughs in chemical formulations and injection procedures. Polymer injection (P) is a technique for enhancing oil production in secondary and tertiary floods by boosting sweep and displacement efficiency. There had recently been a lot of interest in chemical flooding for a variety of problematic scenarios. Reservoirs with high temperatures, formations with severe salinity and hardness, naturally cracked carbonates, and sandstone reservoirs with heavyweight and viscous crude oil are among the challenges. The first section of this paper reviews recent principles of polymer flooding, including mechanisms of polymer solution. Polymer types used in (EOR), rheology of polymer solutions in porous media, polymer degradation, polymer flooding experiments, and wettability measurement. The second section is about polymer simulation.

*Keyword: EOR*, Principles of Polymer Flooding, Rheology in Porous Media, Polymer Simulation.

## 1. Introduction

Global energy demand is rising as a result of industrial and social developments. In comparison to other energy production methods such as solar, wind, and so on, the use of fossil fuels, particularly petroleum and natural gas, now plays a significant role in the provision of energy [1]. It is required to expand petroleum funds and capacity for production in order to meet global energy demand. As illustrated in Figure 1, annual demand for oil is increasing, implying that oil-producing countries should increase production [2]. Increased oil and gas production can be accomplished by developing mature reservoirs or discovering new reservoirs [3]. The oil is drawn toward the production well by the differential pressure between the reservoir and the production well, which is known as primary recovery [4]. Following this stage, gas or water is injected into the reservoir to keep the reservoir pressure constant. Secondary recovery is the term used to describe this stage. Due to economic considerations, it is not possible to continue oil production after the primary and secondary stages [5].

Increasing the water cut and gas oil ratio (GOR) results in more expensive fluid production from the reservoir due to the need for more surface facilities to separate oil from gas and water. As a result, the production schedule must be altered. Following these stages, there are two options: well abandonment or the use of new production methods. After secondary oil recovery, there is a significant amount of residual oil left in reservoirs. As a result, abandoning a well is not always the best option. Some techniques can aid in the recovery of residual oil from reservoirs following secondary stages [6]. Although these tertiary methods are costly and not always operationally viable, researchers are particularly interested in increasing oil production

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through these techniques. However, tertiary recovery can still be economically viable if oil prices and demand are sufficiently high. These techniques are known as (EOR). This is known as tertiary recovery [7]. In general, EOR processes fall into four groups: chemical flooding, thermal flooding, miscible flooding, and microbial [9].

These four groups are:"Chemical enhancing oil recovery (CEOR) is a key EOR technique that has been used in some oil fields." According to EOR research, "11 percent of EOR projects worldwide are compelled to use CEOR." More than 77% of these methods are polymer floods, and 23% are polymers combined with surfactants [10]. This technique might include a polymer, deep-formation profile modification using polymer, surfactant, alkaline, emulsion, and a mixture of them [11]. One of the first choices to increase oil recovery is water flooding, where water is injected into the injection well to push the oil toward a production well [12].

Oil and water, on the other hand, are immiscible fluids, which mean they do not mix. This means that, within an oil reservoir, oil and water cannot displace one another. It happens because the reservoir has a lot of different types of water and low water viscosity [13]. Fingering happens, and water is injected into the well, but there is still a lot of oil in the reservoir.

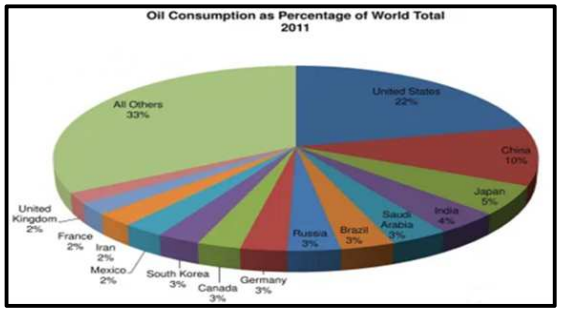



**Figure1**: Global Crude Oil Production [8]

Polymer flooding has been used in industry for over 50 years."Adding water-soluble polymers increases the viscosity of the water, improving mobility control while potentially decreasing water relative permeability compared to oil [14]. Water-soluble polymers are commonly divided into two categories: synthetic and biopolymer [15]. Hydrolyzed polyacrylamide (HPAM) is the best common commonly used synthetic polymer in most polymer flooding processes on a large and small scale [16]. Xanthan is a non-ionic biopolymer that has been used in the oil industry for a variety of purposes, including polymer flooding and drilling mud [17]. Polymer flooding has several advantages, including improved injected fluid mobility, low price, friendly to environment, durable, increase water viscosity and etc.

Another widely A rather significant viscous force perpendicular to the oil–water contact is the acknowledged mechanism for mobile leftover oil following water flooding It is necessary to pump the leftover oil. This force should be sufficient to overcome the capillary forces that keep the leftover oil in position in order to move, mobilize, and recover it [18]. Increasing vertical and areal sweep efficiencies, using less water than water flooding, and being less expensive than other EOR techniques [19]. During the core test, oil recovery reached 95% at 2500 ppm of PAM/brine water solution. At this ratio, the high stability and less viscous finger effect produced in the touching region between polymer solution and crude oil clearly appear as a qualitative contour in numerical simulation, as shown in Figure 2.

80.32 percent oil is produced By adding 1000ppm PAM to 0.005% ZnO/brine water, the interfacial tension is low, and the oil volume fraction interaction between the injected solution and the displacement fluid from Core is uniform "" Ansys. Figure 3 depicts those results. Due to the breadth of polymers researched and studied during the last two decades at the academic and industry levels, "Polymer flooding continues to be a thought-provoking topic [22]. Hydrophobically associating polymers continue to be a fundamental paradigmatic polymer product developed during this time period. The sustained thickening ability of hydrophobically associating polymers under conditions such as temperature, salinity, and ion concentration has been the focus of scientific studies linking hydrophobically associating polymers to chemical flooding.

These associative polymers are synthesized or produced with the incorporation of hydrophobic comonomers along the polymer backbone. Accordingly, these hydrophobic monomers contribute to the overall molecular weight of the polymers. In addition, HAPAM polymers are characterized by a CAC (Figure 4). The enhanced rheological properties of HAPAM are obvious above the CAC, which can be traced to the intermolecular association between polymer chains. However, these

interactions between polymer chains above the CAC are dependent on the distribution of the hydrophobic comonomers along the polymer chain. These distributions can be random or block-like and it is determined by the conditions of the synthesis procedure [23].

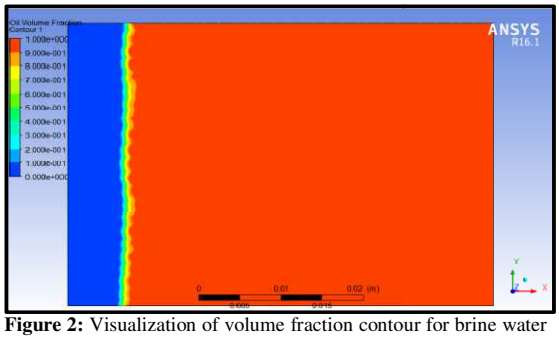



**Figure 2:** Visualization of volume fraction contour for brine water / 2500 ppm PAM with crude oil [20]

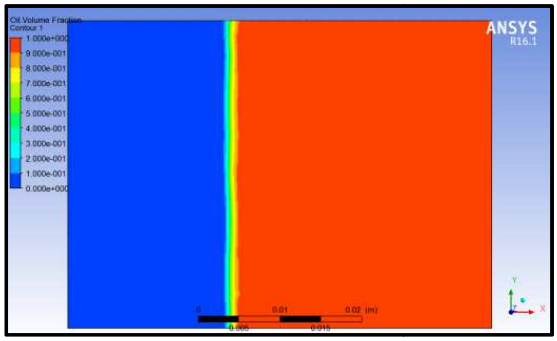



**Figure 3:** Visualization of Oil Volume Fraction Contour for Core Injected by 1000 ppm PAM with 0.005% ZnO NPs /Brine Water [21]

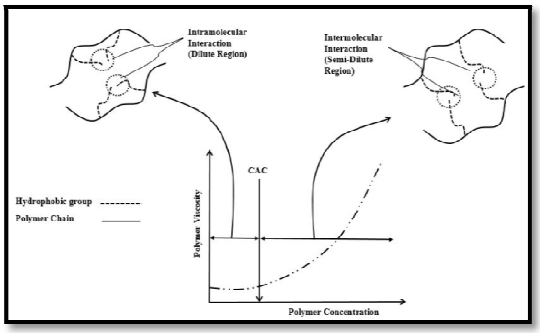



**Figure4**: Viscosity behavior of hydrophobically associating polymers (HAPAM) before and after the critical aggregation concentration [24]

## 2. Principle of Polymer Flooding

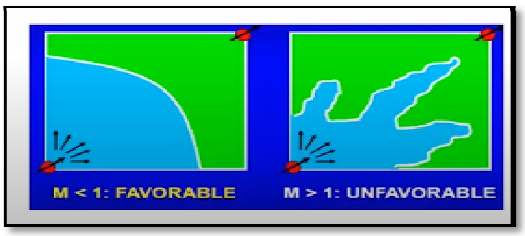
### 2.1 Mechanisms of Polymer Solution

Flooding by polymer is used to improve sweep efficiency by increasing fluid injectivity [25]. Fingering phenomena will occur as a result of the porous media's high permeable layers, and injected fluid will travel much faster than oil through the porous media areas of the reservoir are not contacted by water. Water mobility can be reduced by adding small amounts of a water-soluble polymer. Water's mobility is reduced in this case compared to oil, and water sweeps the oil like a piston [27]. The Buckly-Leverett equation principle demonstrates the effect of the mobility ratio (M). According to equation (1), when the amount of this parameter is reduced to less than M1, the fractional flow curve exhibits piston-like flow and the average water saturation has a higher value. As a result, the amount of residual oil will be reduced [28]. kw is the effective permeability of water, ko is the effective permeability of oil, o is the oil's viscosity, and w is the water's viscosity. As illustrated in Figure 5, the formation of a viscous finger in water indicates that the residual oil saturation is greater than at the end of polymer flooding. It's because of changes in wetting that make it less likely that the injected polymer solution will be able to get through. This is shown in Figure 6.

$$f_w = \frac{\frac{k_w}{\mu_w}}{\frac{k_w}{\mu_w} + \frac{k_o}{\mu_o}} = \frac{M}{1+M} = \frac{1}{1+\frac{1}{M}} \quad (1)$$

where M is the mobility ratio and defined:

$$M = \frac{\frac{k_w}{\mu_w}}{\frac{k_o}{\mu_o}} \quad (2)$$



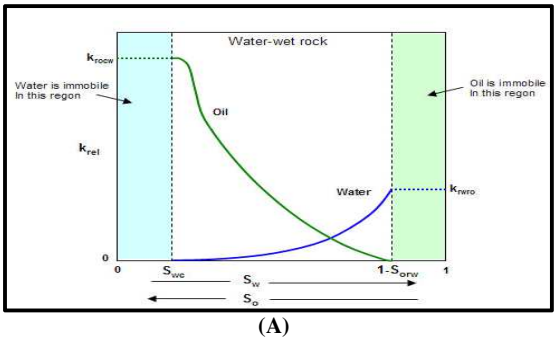

(a) (b)

**Figure5:** (a) polymer flooding and (b) water flooding [29]

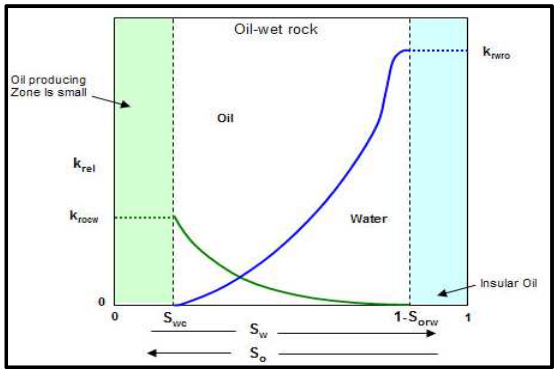
When two curves meet at a 50% cross point, the injected solution is water-wet and can get a lot of oil out of porous media. When the cross point is less than 50%, the injected solution is oil-wet and can't get a lot of oil out of porous media [30].

Increased polymer elasticity results in high flow resistance. Increased polymer elasticity leads to increased contact zone stability and displacement efficiency from porous media, as shown in Figure 7, and the ability of polymer aqueous solution to pull oil from a dead end. Because of the transformation of normal stress between polymer solution and oil and shear stress caused by long polymer chains, This is in contrast to Newtonian solutions, which are incapable of doing so [32]. Figure 8 shows that the velocity profiles of Newtonian and non-Newtonian fluids are

different. The latter has a bigger velocity profile at the capillary wall, which allows it to remove oil film from porous media [34].




**(A)**




**(B)**

**Figure 6:** (A) Water wet and (B) oil wet system [31].

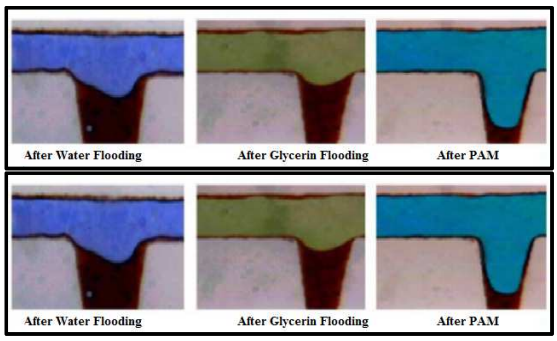



**Figure7**: Release Oil from Dead Ends [33].

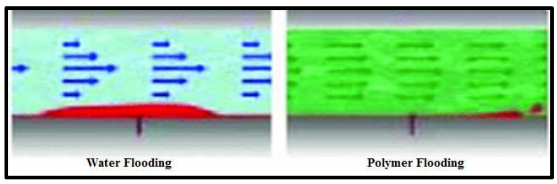



**Figure8:** Stripping oil film on rock surface [35].

When HPAM flows through converging-diverging (C-D) flow channels in porous media, it experiences shear and elongational deformations [37]. Once one result is achieved, as it passes through porous surfaces, the polymer conformation undergoes sequential expansion and contraction (E-C). Figure 9 displays a schematic illustration of typical HPAM flow zones with respect to shear rate. Polymer molecules begin to disentangle with an increasing shear rate during shear thinning until they meet yet another Newtonian plateau with a really high degree of disentanglement. However, as illustrated above (. c2), when polymer chains do not have enough time to recoil and align with the flow, the coil-stretch (C-S) transition occurs, resulting in a gradual increase in apparent viscosity with shear rate. The normal stresses that cause chain stretch raise the extensional viscosity, resulting in pressure buildup and high apparent viscosity (shear thickening behavior). Chain stretch may evolve into chain fragmentation if the stretch rates associated with shear thickening behaviors are high enough. Chain scissions caused by mechanical degradation result in viscosity loss, as shown in Figure 9 at high shear rates. This flow phenomenon is discussed in more detail elsewhere [38]. Large molecules shear preferentially as a result of the high strain forces.

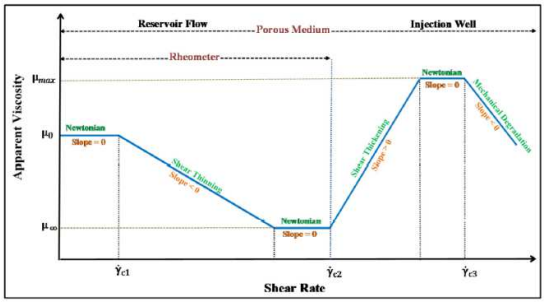
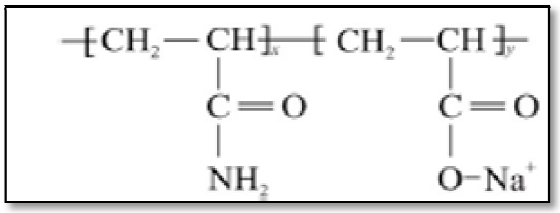



**Figure9**: HPAM apparent viscosity vs shear rate data sheet [36]

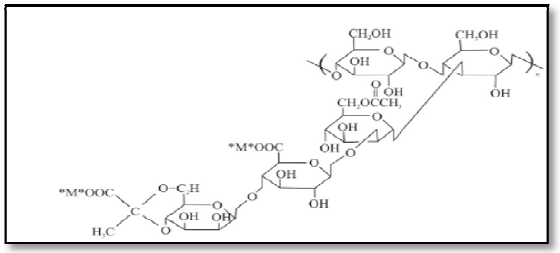
## 2.2 Types of Polymers used in EOR

There are two types of polymers used in conventional polymer flooding: synthetic and biopolymer [39]. One of the most common synthetic polymers is partially hydrolyzed polyacrylamide (HPAM) [40]. The structure of this polymer is depicted in Figure 10 (a). Xanthan is a well-known biopolymer. It is a bio polysaccharide with a large molecular weight that is typically produced by the fermentation process of the bacterium Xanthomas [41]. The structure of Xanthan [42] is depicted in Figure 7 (b).



(a)

Traditional polymers used in EOR operations, such as polyacrylamide (PAM), hydrolyzed polyacrylamide (HPAM), and Xanthan Gum, present a number of challenges. Under extreme reservoir conditions, PAM and HPAM polymers are prone to viscosity loss. While Xanthan Gum can withstand high salinity conditions, its biodegradability has limited its long-term use in EOR operations. Table 1 shows how these strengths and weaknesses are reflected in their field applications. Table 1 shows that Xanthan Gum and hydroxyethyl cellulose (HEC) outperform HPAM and PAM in the field under high salinity conditions. Above all, increased study into the chemical derivatives markets of polyacrylamide has been required by the need to alleviate the problems associated with the usage of PAM/HPAM and biodegradable polymers for EOR [43].



(b)

**Figure10:** Show the structure of (a) HPAM and (b) xanthane

**Table1**
Example of oil field applications of different conditions [44]

| Country | Field | Polymer Type | T(°C) | Formation Salinity (mg/L) | Reference |
|---|---|---|---|---|---|
| China | Daqing | HPAM | 45.0 | 9000 | Pu and Xu (2009) |
| | Gudong | HPAM | 68.0 | 3022 | Zhijian et al. (1998) |
| | Bohai Bay | HPAM | 65.0 | 6070 | Mogollon and Lokhandwala (2013) |
| | Xing Long Tai | HPAM | 56.6 | 3112 | Zhang et al. (1999) |
| | Bohai oil field | HPAM | 65.0 | 32423 | Han et al. (2006) |
| | Henan oil field | HPAM | 75.0 | 5060 | Chen et al. (1998) |
| | Shengli | HPAM | 70.0 | 10000 | Gao (2014) |
| USA | Cambridge Minnelusa | PAM | 55.6 | Not specified | Vargo et al. (2000) |
| | Tambaredjo | HPAM | 36.0 | Not specified | Mogollon and Lokhandwala (2013) |
| | West Khiel | HPAM | 80.0 | 66800 (P)[a] | Pitts et al. (2006) |
| | Tanner | PAM | 57.0 | 46,480 (P)[a] | Meyers et al. (1992) |
| Canada | Pelican | HPAM | 23.0 | 6800 | Mogollon and Lokhandwala (2013) |
| | David pool | PAM | 31.0 | 6660 (I)[b] | Pitts et al. (2004) |
| Germany | Eddesse-Nord | Xanthan Gum | 22.0 | 120,000 | Abbas et al. (2013) |
| | Vorhop-Knesebeck | Xanthan Gum | 56.0 | 210,000 | Abbas et al. (2013) |
| Austria | Matzen | HPAM | 50.0 | 20,000 | Kornberger et al. (2013) |
| India | Viraj | HPAM | 81.0 | 13,250 | Pratap and Gauma (2004) |
| | Sanand | PAM | 85.0 | Not specified | Tiwari et al. (2008) |
| Russia | Romashkino (Tatarstan) | HEC | 36.0 | 250,000 | Abbas et al. (2013) |

Hydrophobically associating polyacrylamide is an important derivative (HAPAM). The basic purpose of these compounds was to increase polyacrylamide thickening capabilities in difficult reservoir conditions such as high temperature, high salinity (HTHS) [45]. Associative polymers have a higher mobility reduction than HPAM polymers due to their improved thickening capability. Associative polymers' high mobility reduction translates to higher incremental oil recovery when compared to HPAM polymers. Recently, it was demonstrated that for viscoelastic polymers, a transition from steady laminar flow to a strongly fluctuating flow consistent

with elastic turbulence exists [46]. The onset of this elastic turbulence (or flow fluctuations) has been identified as the mechanism underlying the additional mobilization of trapped oil (capillary desaturation through destabilization of trapped oil).

When the capillary number (Ca) is less than the threshold (Ca 1), extensional viscosity cannot be used to justify additional oil recovery at flow rates greater than the onset of shear thickening. As a result, the degree of trapped oil mobilization is proportional to the amount of elastic turbulence generated. As a result, the incremental recovery of associating polymers may be due to the additional effect of intermolecular association (hydrophobic interaction) on elastic turbulence in porous media. The laboratory studies on HAPAM shown in Table 2 are numerous, but when compared to Table 1, they indicate limited field application. More importantly, the level of scientific research on HAPAM suggests that it will eventually replace HPAM for polymer flooding operations.

These associative polymers are created by introducing hydrophobic comonomers along the backbone of the polymer. As a result, these hydrophobic monomers add to the total molecular weight of the polymers. In addition, HAPAM polymers are differentiated by a CAC (see Figure 4). The increased rheological capabilities of HAPAM over CAC can be due to polymer chain intermolecular interaction [47]. The location of hydrophobic commoners mostly along the polymer chain, on the other hand, determines the interaction within polymer chains well above CAC. The synthesis living conditions decide whether these distributions are random or block-like. As previously stated, the method of synthesizing HAPAM polymers has a significant influence on the hydrophobic distribution on the polymer chain. HAPAM polymers can be made in a number of ways, including homogeneous, heterogeneous, and micellar copolymerization [48].

**Table 2**
Core flooding on the same polymers [49]

| Polymer Type | Polymer Concentration (ppm) | T (◦ C) | Salinity (mg/L) | Core Type | Recovery (%) | Reference |
|---|---|---|---|---|---|---|
| Xanthan Gum | 500 | 50 | - | Sandstone | 66 T | Austad et al. (1997) |
| HAPAM | 1000 | 50 | - | Sandstone | 53.6 T | Austad et al. (1997) |
| HAPAM | 5000 | 60 | 5000 | Sandstone | 8.5 | Liu et al. (2012) |
| HPAM | 2000 | 60 | 5000 | Sandstone | 11 | Sabhapondit et al. (2003) |
| HAPAM | 2000 | 70 | 10000 | Sandstone | 34 | Gong et al. (2008) |
| HPAM | 7000 | 60 | 5000 | Sandstone | 10.6 | Ye et al. (2013) |
| HPAM | 1100 | 75 | 12000 | Sandstone | 9.8 | Chen et al. (1998) |
| HPAM | 2500 | 45 | 508–6778 | Sandstone | 16.7 | (Yang et al., 2006; Liu et al., 2007) |
| HAPAM | 4500 | 38 | 30700 | Carbonate | 45 | Panthi et al. (2013) |
| HAPAM | 2000 | 60 | - | Not specified | 12 | Lai et al. (2013) |
| HAPAM | 2000 | 60 | - | Not specified | 18 | Lai et al. (2013) |
| HAPAM | 2000 | 65 | 5000 | Sandstone | 5.7 | Lai et al. (2013) |

In particular, associative polymers have been investigated as a potential alternative to HPAM polymers [50]. In particular, they conducted a thorough review of the literature on the synthesis and performance of associative polymers. These polymers (with 0.1–7 percent hydrophobic monomer) can produce much higher viscosities at low concentrations (e.g., 0.05 percent to 0.5 percent) than equivalent-molecular-weight polymers without hydrophobic groups (e.g., 0.05 percent to 0.5 percent) [51].Several difficulties have prevented the widespread use of associative polymers in EOR. The rise in viscosity with increasing polymer concentration can be rapid in some situations, generating questions regarding how to regulate the polymer's performance during flooding operations.

Small operational mistakes might increase injectivity issues if polymer concentrations are greater than desired or offer insufficient mobility control if polymer concentrations are low. Another source of worry is the capacity of associative polymers to penetrate deep into a reservoir. Compositions with a maximum in viscosity vs shear rate graphs [52] have been discovered. The polymer appears to become sufficiently stretched within a given shear rate range to favour intermolecular interactions above intramolecular interactions. Associative polymer combinations surely enhance viscosity and can give substantial resistance to flow in porous media for a short distance. However, a key unsolved problem with many associative polymers is whether the improved viscosity properties can be spread deep into a reservoir. [53].

**2.3 Polymer Solution Rheology in Porous Media**

Water's rheological behavior changes when polymers are added to it. The flow movement property of a fluid is described by its rheology. The viscosity of the polymer solution is an important rheological property [54]. A polymer solution is not a Newtonian fluid. The Newtonian fluid is depicted in Equation (1). Shear stress and shear rate have a linear relationship with the slope of fluid viscosity in this type of fluid [55].

$$\tau = \mu * \gamma = \mu * \frac{du}{dy} \quad (3)$$

Where τ is shear stress, γ is shear rate, and μ is dynamic viscosity. However, because solution of polymers is a shear thinning fluid, the relation among shear stress and shear rate may be specified using a power law equation [56].

$$\tau = K(\gamma)^n \quad (4)$$

Where K is the consistency index, Pa. γ n, and n is the power law index. Figure 11, depicts the connection between a polymer solution's viscosity and shear rate. The solution behaves like a homogeneous solution or Newtonian flow at low shear rates. As the shear rate increases, the apparent viscosity decreases and the solution behavior shift to power law. When the shear rate is raised higher, the polymer molecules have no influence on the solution's viscosity and the solution returns to Newtonian behavior. [57].

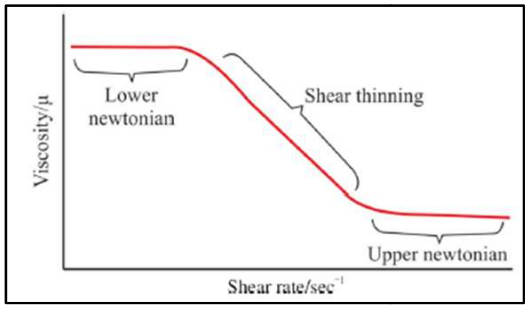



**Figure 11**: Log-log plot for shear-thinning fluid rheology [58]

The polymer solution's greater viscosity, in contrast to water, assists in the sweeping of oil in porous media and promotes oil recovery. To improve oil recovery in the polymer flooding process, the viscosity of polymer slugs can be increased using one of two methods: increasing polymer concentration in brine, decreasing solvent salinity, or employing polymers with a high molecular weight [59]. There are two significant difficulties that arise when polymer concentration increases: high costs to provide the high concentration and injectivity issues such as high-pressure injection into the well bore [60].

As a result, increasing polymer concentration to achieve greater viscosity is not always a good option. Otherwise, using polymers with a high molecular weight can provide higher viscosity at lower polymer concentrations than using polymers with a high polymer concentration. As a result, using a polymer with a high molecular weight can help to achieve higher viscosity at a lower concentration [61]. Increasing the molecular weight of a polymer can cause additional issues. Because increasing molecular weight causes the size of the polymer molecule to be larger than the pore size, causing injectivity issues or increasing inaccessible pore volume (IPV), IPV refers to the volume of pore space that cannot be accessed by polymer. When the particle size is greater than the pore size, polymer molecules cannot flow through the pore [62]. For example, look into the IPV during a polymer flood in sandstone. They reported that polymer solutions were unable to reach 30% of the connected PV in the rock samples. Polymer molecules can be stuck to the surface of a pore or mechanically trapped by a small hole.

The interactions between the porous medium and the polymer molecules that cause the polymer to be retained by the rock are referred to as polymer retention. After polymer flooding, the permeability of rock may be reduced [63]. Figure 12 depicts the interaction of a polymer molecule with a rock grain.

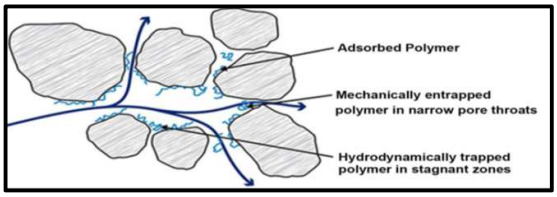



**Figure12**: Show adsorbed polymer [64]

In this regard, there are two parameters: resistant factor (RF) and residual resistant factor (RRF). The RF, as shown in equation (3), is a term that is commonly used to describe the resistance to flow of a polymer solution in comparison to the flow of water [65]. For example, a resistance factor of 10 indicates that the polymer solution is 10 times more difficult to flow through the system than water or that the

polymer solution requires 10 times the pressure to inject when compared to water. Because water has an apparent viscosity of about 1 cp at room temperature and pressure, a polymer solution would flow through the porous medium as if it had an apparent viscosity of 10 cp.

$$RF = \frac{\left(\frac{K}{\mu}\right)water\ flooding}{\left(\frac{K}{\mu}\right)polymer\ flooding} = \frac{\Delta P\ polymer}{\Delta P\ water} \quad (5)$$

The RRF is the ratio of the initial injected water mobility to the water injection movement behind the polymer solution. The definition of RRF [66] is shown in Equation (4). For example, if RRF = 5 is obtained after polymer flooding, it means that the rock permeability after polymer flooding is close to 25% of the initial permeability. This shows how much permeability has been reduced in rock after polymer flooding due to polymer molecule adsorption.

$$RRF = \frac{\left(\frac{K}{\mu}\right)before\ polymer\ flooding}{\left(\frac{K}{\mu}\right)after\ polymer\ flooding} = \frac{\Delta P\ water\ after\ polymer\ flooding}{\Delta P\ water\ befor\ polymer\ flooding} \quad (6)$$

## 2.4 Degradation of Polymers

Polymer degradation includes thermal, chemical, mechanical, and biological degradation [67], and the magnitude of degradation is affected by temperature, oxygen content, shear rate, and other factors [68]. As a consequence, polymer degradation can reduce the viscosity of a polymer solution, as a consequence of which the water-oil mobility ratio rises [69]. This ratio is one of the most important factors in successful polymer flooding. Many researchers investigated polymer degradation under non-reservoir or static conditions [70].

These experimental findings do not accurately describe polymer degradation during polymer flooding, particularly when a polymer solution flows in reservoirs. This constraint is unlikely to produce accurate results. As a result, more detailed and precise polymer degradation experiments must be devised. It is critical to use special equipment in the field to prevent polymer degradation and viscosity loss. Thermal degradation, salinity degradation, and microbial activity all influence the rheology of polymer solutions in porous media [71]. The temperature of the polymer solution has a direct effect on its hydrolysis. In most cases of polymer flooding, HAPM begins to hydrolyze between 25 and 90 degrees Celsius [72].

A polymer solution's viscosity decreases as a result of this phenomenon. Figure 13 depicts the effect of temperature on HPAM viscosity. Acrylamide-based polymers are hydrolyzed and become negatively charged in a high-temperature environment [73].

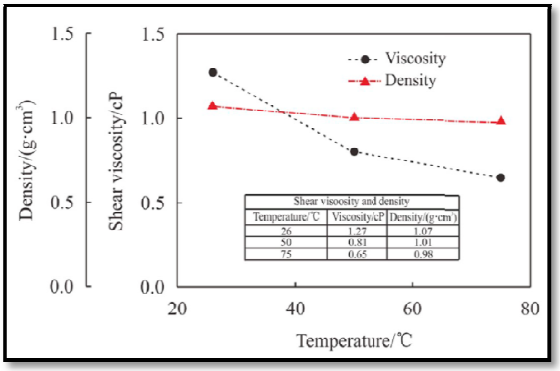



**Figure 13**: The effect of temperature on the viscosity of an aqueous solution of HPAM

On the other hand, the reservoir rock (formation water) contains high concentrations of divalent ions ($Ca^{2+}$, $Mg^{2+}$) [74]. As shown in Figure 14, divalent ions trap acrylamide molecules. This process reduces the viscosity of the polymer solution and prevents real-time polymer injection. Additionally, polymer adsorption on the surface of the rock reduces reservoir permeability and causes problems when injected. In high temperature and high salinity (HTHS) reservoirs, HPAM has limitations. High temperatures and salinity degrade added biopolymers like Xanthan. At low temperatures, Xanthan gum molecules have a double helix structure, but as temperatures rise, the double helix structure changes to a disordered coil [75].

The temperature limit for xanthan gum is 70 °C, and when a small amount of salt is added, the viscosity of the xanthan solution decreases due to the charge shielding effect [76]. Xanthan gum is more sensitive to high salinity than polyacrylamide-based polymers. At higher salinity and temperatures, xanthan gums are generally more stable than acrylamide at higher salinity and temperatures. However, at high temperature and high salinity (HTHS) conditions, all of them deteriorate. As a result, this type of synthetic and biopolymer cannot be used in reservoirs with high salinity and

temperatures [77].

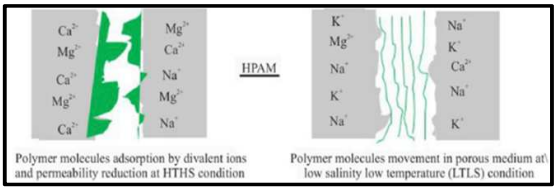



**Figure 14**: Polymer molecule adsorption on the surface of porous media

Today, some polymers are designed to help maintain the viscosity of the solution phase in high temperature and high salinity reservoirs. New smart Thermoviscosifying polymers (TVPs) were defined, and both apparent viscosity and elastic modulus increased for TVPs aqueous solution as temperature increased, but the same parameters decreased for HPAM solution. The findings indicated that TVPs have some potential for use in EOR in HTHS reservoirs. Sulfating polyacrylamide can make the polymer more resistant to high temperatures [78]. Using micellar polymerization in water, a new terpolymer was created by combining the hydrophobic monomer N-dodecyl acrylamide, acrylamide, and the polar monomer 2-acrylamido-2-methylpropanesulfonic acid. The terpolymer solution viscosity at 1500 ppm was 18.7 mPas1, and the viscosity was stable for 30 days at 85 °C and 32000 mg/L water salinity [79]. The elastic modulus and apparent viscosity of HPAM are increased by the addition of silica nanoparticles to a polyacrylamide solution mixed with hybrids of silica nanoparticles under HTHS oil reservoir conditions with total divalent salinity 32868 mg/l and 85 °C of temperature. They also discovered that HPAM silica had greater long-term thermal stability than HPAM in synthetic brine [80]. The success of polymer flooding at ultra-high temperatures and salinity in one of China's oilfields [81]. The less significant development of biopolymer for polymer flooding is due to issues such as biomaterial debris at the wellbore wall and injection issues, biological degradation by bacterial and microorganisms, and high production costs when compared to synthetic polymers such as HPAM. When biopolymer and synthetic polymer are in liquid form during field injection, biological degradation occurs, but it is more pronounced for biopolymer. Biological degradation can cause formation damage by pore plugging. In many cases, it has been discovered that bio-plugging increased oil recovery by preventing flow in high permeable porous structures such as fractures [82].

### 2.5 Polymer flooding experimentation

Because anionic polymers such as HPAM adsorb significantly on the surface of carbonate rocks, the majority of polymer flooding in the world has been applied to sandstone rock. However, polymer flooding is not restricted to this type of rock [83]. Many projects in carbonate rock are currently underway [84].Other limitations of polymer flooding include crude oil viscosity (200cp), temperature (120°C), salinity (20000 ppm), and permeability (> 30 md). Table 3 displays the polymer flooding screening criteria [85]. The initial investigation into polymer flooding was restricted to laboratory work only. Many researchers [86] did, however, report some field applications of polymer flooding.HPAMwas used in a sandstone reservoir in the Marmul field in southern Oman. In this field, after polymer flooding, the water cut (WC) was reduced from 50% to 20% [87].

Reduced WC can help to extend the life of wells and reduce the cost of surface facilities such as separators. It will also extend the life of surface facilities by lowering the rate of corrosion. The polymer was then used extensively in the Daqing oilfield in China. In this field, polymer flooding began in 1996. The incremental oil recovery factor from this field was reported to be 13% higher than that of water flooding [88].The polymer flooding process was studied by HPAM in the CantodoAmaro oil field in Brazil. The reservoir type was sandstone with an oil viscosity of 50 cp oil viscosity at 50 °C, and this result shows that polymer flooding can be applied in reservoirs with high viscosity [89]. Because the application of polymer flooding was limited to high salinity and high temperature reservoirs in the years 2000 and later, many types of new HPAM polymers were synthesized. [90] Investigated polymer flooding in the Sanand oil field in the United States. In this study, HPAM was used as a water-soluble polymer, and the reservoir contained 20 cp of oil at an 85℃ temperature.

**Table 3**
Polymer flooding screening criteria

| Factor | Polymer Flooding |
|---|---|
| Oil viscosity, Cp | <1000 |
| Residual oil saturation, % | >30 |

| | |
|---|---|
| Formation salinity, ppm | <250000 |
| Temperature, F | <250 |
| Thickness, ft | >10 |
| Porosity, % | >10 |
| Permeability, mD | >10 |

## 2.6 Wettability Testing

(A) Quantitative Evaluation

Wettability was calculated by measuring the contact angle of an oil droplet with the rock surface under simulated reservoir conditions (90oC and 40,000ppm salt) and a polymer content of 2g L-1. Contact angles for a cylindrical sandstone core plate were determined at different stages of the wettability test. Figure 15 shows photos of the drop adhered to the plate throughout the course of two days. After aging with crude oil for a day at higher temperatures, the plate was revealed to be oil-wet. The plate is then submerged in a copolymer-brine solution at reservoir conditions for 48 hours before being shot with an oil droplet hanging on the plate's lower surface. Images are analyzed to determine the contact angle. The advancing contact angle is found to decrease with time and stabilize at roughly 74°. Changes in wettability caused by polymer addition may be described using [91]; a) Adsorption of polymer molecules on the rock surface changes the physicochemical characteristics of the rock, causing a thin wetting water layer at the interface to become unstable and break, resulting in a continuous oil channel for oil displacement and increased oil recovery. b) Because silica surfaces (sandstone rock) are negatively charged above (PH=2), positively charged nitrogen bases can adsorb on the rock surface and change the wettability from oil to water. This is confirmed by a contact angle of nearly 74º.

In addition of, the wettabilities were confirmed through contact angle measurements using a goniometer developed at the ICMT. The goniometer consisted of a main stainless steel chamber, a specimen holder, two flat, glass windows to allow for visualization, an image capturing system composed of a digital camera and computer interface, and a backlight to illuminate the specimen and droplet. The goniometer can be seen in Figure 17 (note: top cover of chamber with probes not used in tests). Each specimen was prepped and cleansed before being submerged in the hydrocarbon phase the goniometer. 0.5 L of the hydrocarbon phase was poured into the main chamber of the goniometer. An 8µL droplet of the water phase was deposited on the immersed specimen's surface. Using the ImageJ software, the contact angle is measured using the truncated sphere method, as previously mentioned [92].

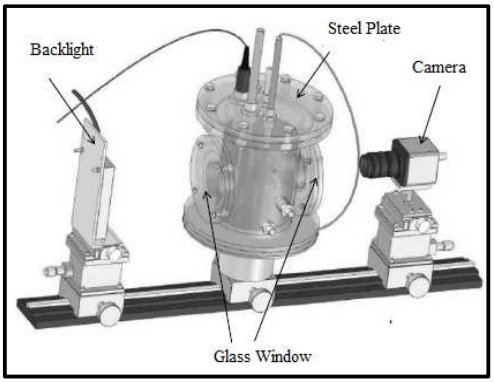



**Figure 17:** Image of goniometer, camera, and light source used to measure contact angle on a steel plate. Figure courtesy of ICMT

(B) Qualitative Evaluation

Figure 16, depicts a qualitative assessment of wettability performed using a two-phase separation test, which shows that grinded sandstone grains are dispersed in the oil phase in the case of an oil and brine solution (16,A). This indicates that the sandstone is oil-soaked. In the case of HAPAM Figure (16,B), the sandstone grains sink into the aqueous phase of the polymer solution. This means that the sandstone grains have been moist with water [93]. All of the foregoing findings support HAPAM copolymer's potential to shift the wettability of the rock from oil-wet to water-wet, increasing oil recovery by enhancing displacement efficiency

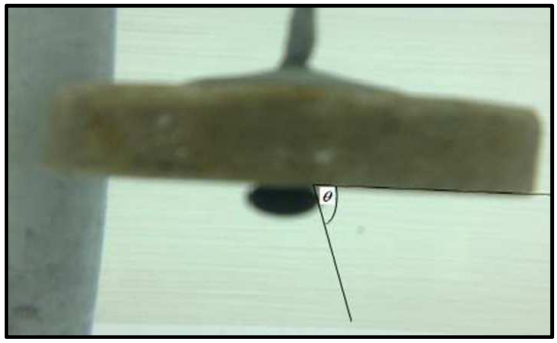



**Figure 15:-** Picture of contact angle after 48 hours

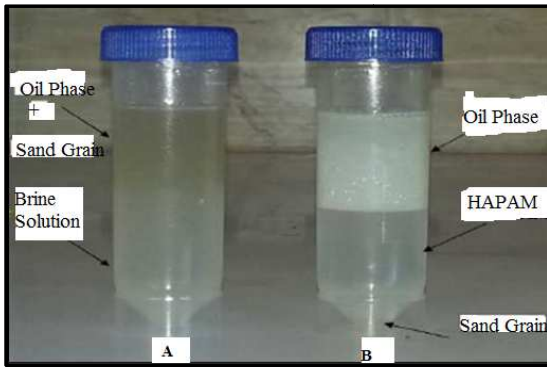



**Figure16:** Two – phase separation test

Two fluids were used for both measurements of surface wettability and phase wetting characterization. The oil phase used was Isopar V, a clear saturated paraffinic hydrocarbon. It was an ideal hydrocarbon for testing since it allowed for visualization of the water phase when immersed in the oil phase during wettability testing. The water phase used was 1 wt% NaCl solution prepared from deionized water. The oil was reused between each trial by letting the tested oil-water mixture settle for at least 24 hours, allowing separation of the two fluids. The oil was then siphoned from the top into a clean container. The oil-water inversion point is the volumetric percent ratio of the water phase to the oil phase that signals the point where entrainment of water into oil is highly improbable. Due to this inversion point, flow experiments were performed in horizontal condition near room temperature (25°C25) using mixture velocities from 0.2 to 1.5 m/s and water cuts from 2.5 % to 20 %. The interfacial tension is measured using a KRUSS K20 Force Tensiometer using the ring method (Figure 18)[94].

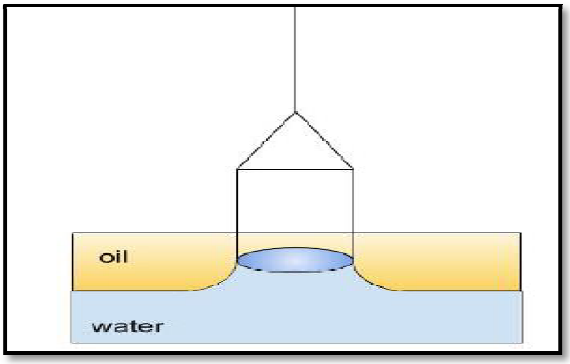



**Figure 18**: Diagram of measuring the interfacial tension between oil and water using the Ring Method

The effectiveness of polymer flooding simulation in forecasting, estimating, and analysing the factors that influence polymer flooding was chosen. Most polymer physicochemical properties are observable.

However, despite continuous advancements in numerical simulation research, one major issue remains unresolved: how to describe polymer degradation in a simulation in a reasonable and accurate manner. Previous polymer flooding models even ignored polymer degradation [95]. Furthermore, commercial simulation software, such as ECLIPSE and the Computer Modeling Group (CMG) GEM, has not adequately addressed polymer degradation [96].

Some methods have been proposed to improve polymer flooding simulation. The first-order concentration attenuation model was used to characterise polymer concentration reduction during polymer flooding, and it could be embedded in simulation with the polymer mass conservation equations [97]. However, the model does not adequately describe the process of polymer degradation in which concentration remains constant while viscosity decreases, which contradicts polymer theory. Under static conditions, a viscosity reduction model could describe the variation in polymer viscosity with time [98], but the model was difficult to apply in polymer flooding simulations because it could not accurately obtain the polymer degradation time in each grid when a polymer solution flowed. Although the concept of "time flux" was proposed to calculate an equivalent polymer degradation time [99], it has no practical physical meaning and cannot be validated by experiments.

As a result, the calculation's accuracy cannot be verified. Furthermore, in these proposed methods, polymer static and dynamic degradations were not distinguished during simulation processes. As a result, it is unlikely that an accurate simulation result for polymer flooding will be obtained. As a result, developing a simulator capable of reasonably and accurately describing polymer degradation and identifying polymer static and dynamic degradations is required.

CMG's STARS simulator was the last simulation tool investigated and chosen to simulate the experimental data. This simulator, which is utilised by various businesses in the petroleum sector, is notable for its capacity to represent both laboratory and field-scale models, as well as sophisticated chemical behavior. The option to enter the polymer apparent viscosity in a tabular style was one of the

simulator's most enticing features. Although it was never assured, the intention was that the tabular input could manage all four flow regimes if necessary. [100] To the best of our abilityCMG-STARS is a reservoir simulator for advanced processes, including polymer flooding, surfactant flooding, steam flooding, and in situ combustion. CMG-STARS are capable of operating in both completely implicit and adaptive implicit modes. We'll talk about the distinctions between polymer flooding and surfactant flooding later.

Polymer flooding characteristics, such as viscosity, permeability decrease, adsorption, and rheology, will be compared to UTCHEM. The surfactant model, which is based on Type I, does not include a ME phase (water and oil). The IFT decrease as a function of surfactant concentration can be defined using tables [101].HPAM investigated the polymer flooding technique at the CantodoAmaro oil field in Brazil, where the reservoir type was sandstone with an oil viscosity of 50 cp oil viscosity at 50 °C, and the results demonstrated that polymer flooding may be used in reservoirs with high viscosity [102].

Because the usage of polymer flooding for high salinity and high temperature reservoirs was limited in the years 2000 and after, numerous novel HPAM polymers were produced. Polymer flooding was investigated in the Sanand oil field in the United States [103 ,104]. HPAM was employed as a water-soluble polymer, and the reservoir held 20 cp of oil at 85 ºC.

## 4. Conclusions

The following are the main findings and suggestions for the future of polymer flooding based on this study:

(1) Polymer flooding is a low-cost CEOR method with a high success rate. One good thing about this process is that it can help get more oil out of the ground. For example, it can cut down on how much water comes out of oil wells, and it takes less water than flooding with water.

While most of the time, the polymer flooding method has been used to flood sandstone rocks, there have been reports of it working well in carbonate rocks as well.

(3) Temperature, salinity, and biological activity all break down the polymer molecule during the process of making it. This causes viscosity loss and polymer adsorption.

(4) HPAM and Xanthan are water-soluble polymers that can be used in low salinity and low temperature reservoirs. However, they are inapplicable to the HTHS condition. Some polymers, such as TVP, sulfonate (AMPS, n-VP) polymers, SMG from acrylamide base polymer, or Schizophyllan from biopolymer, are now designed for HTHS conditions.

(5) In the EOR industry, numerical simulators such as STARS from CMG, UTCHEM, and ECLIPSE are used to predict polymer flooding in lab and field scale cases.

(6) To achieve optimal polymer flooding, laboratory and field-scale studies are required. Optimum polymer flooding entails a low cost, a high viscosity at a low polymer concentration, a high molecular weight in a small particle size of polymer, and the ability to be used in any rock type under any harsh conditions (HTHS).

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