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Review Article

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Polymer Applications in Enhanced Oil Recovery: A Review

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ABSTRACT

Enhanced Oil Recovery (EOR) is an essential technique for increasing oil production from mature reservoirs, extending the life of existing fields. Among various EOR methods, polymer flooding stands out due to its ability to improve sweep efficiency and control the mobility of injected fluids, leading to enhanced oil displacement. This review delves into the role of polymers in EOR, examining the underlying mechanisms, types of polymers used, and the latest advancements in the field. The discussion emphasizes the importance of polymer properties, such as viscosity, thermal stability, and salt resistance, and explores formulation considerations for optimizing performance in different reservoir conditions. Additionally, emerging trends like smart polymers, which are responsive to environmental stimuli, and nanocomposite-enhanced polymers, which improve stability and retention in harsh reservoir conditions, are highlighted as key innovations that could significantly enhance oil recovery efficiency. The review also addresses the challenges in polymer flooding, including polymer degradation, adsorption on reservoir rock surfaces, and environmental concerns, while suggesting potential solutions and future research directions to further optimize the method.

Keywords: Polymers, Polymer Flooding, EOR, Oil Recovery, Oil Reservoirs

Introduction

The global energy demand has driven the need for advanced technologies to maximize hydrocarbon recovery. Conventional oil production methods, such as primary and secondary recovery, typically extract only 30–50% of the original oil in place (OOIP), leaving a substantial amount of hydrocarbons trapped in the reservoir [1-5]. To address this issue, Enhanced Oil Recovery (EOR) techniques have been developed to improve the efficiency of oil displacement and extraction. Among the various EOR methods, polymer flooding has emerged as a widely adopted chemical technique due to its effectiveness in increasing the viscosity of injected water. This, in turn, helps reduce the mobility ratio between water and oil, leading to improved sweep efficiency and enhanced oil recovery. By modifying the flow characteristics of water in the reservoir, polymer flooding mitigates the challenges associated with water channeling, fingering, and bypassing of oil-rich zones [6-9].

Polymers used in EOR applications vary in composition, molecular weight, and rheological properties, allowing for their customization based on reservoir conditions such as temperature, salinity, and permeability. Advances in polymer technology, including the development of temperature-resistant, salt-tolerant, and nanocomposite-based polymers, have further expanded the applicability of polymer flooding to harsh reservoir environments. In addition to polymer flooding, polymers are also used in other EOR processes such as conformance control, surfactant-polymer flooding, and foam-polymer flooding, making them a versatile tool for improving oil recovery [10-14]. This review provides an in-depth analysis of the role of polymers in EOR, their mechanisms, applications, and the latest advancements aimed at overcoming existing challenges. A comprehensive understanding of polymer-based EOR strategies

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will aid in optimizing oil recovery operations and ensuring the sustainability of hydrocarbon production.

Mechanism of Polymer Flooding

Increasing Water Viscosity to Improve Mobility Control

Mobility describes the ease with which a fluid phase flows through a porous medium and is given by the ratio of its effective permeability to its viscosity as shown in eq 1:

$$M_i = \frac{K_{ri}}{\mu_i} \tag{1}$$

Where:
M_i is the mobility of phase i
K_{ri} is the relative permeability of phase i,
μ_i is the viscosity of phase i

A fluid with higher mobility will generally flow more rapidly through the reservoir. However, when the displacing fluid has much greater mobility than the displaced fluid, it may lead to instability in the displacement front, resulting in poor sweep efficiency and early breakthrough. One of the primary functions of polymers in EOR is to increase the viscosity of injected water. By adding water-soluble polymers, such as partially hydrolyzed polyacrylamide (HPAM) or biopolymers like xanthan gum, the viscosity of the injection fluid is significantly enhanced. This leads to a better mobility ratio between the displacing water and the displaced oil, reducing the tendency of water to bypass oil-rich zones and improving the overall sweep efficiency. The increased viscosity slows down the movement of injected water, preventing the formation of viscous fingers and channeling, which commonly occur in heterogeneous reservoirs. As a result, oil trapped in less permeable zones can be effectively mobilized and recovered. The efficiency of viscosity enhancement depends on factors such as polymer concentration, molecular weight, reservoir salinity, and temperature stability [15-18]. Mariam Shakeel and his colleagues, explored how combining engineered water (EW) with chemical enhanced oil recovery (CEOR) methods can improve oil recovery in challenging carbonate reservoirs. We carefully selected the best combinations of alkali, surfactant, and polymer after conducting tests on phase behavior, surfactant adsorption, and polymer rheology. The results showed that using 1 wt% Soloterra 113-H surfactant, 1 wt% $Na2CO3$ alkali, and 1500 ppm Flopaam 5115 polymer provided the best performance. Notably, the hybrid EWASP flooding in slug-wise injection mode achieved a 36% increase in oil recovery, outperforming other combinations like EWSPF and continuous EWASP flooding. This method worked so well because it reduced surfactant adsorption, improved mobility control, and modified the wettability of the reservoir, which helped reduce capillary forces and improved the efficiency of oil displacement [19]. Additionally, advanced polymer formulations, such as hydrophobically modified polymers and nanocomposite-based polymers, exhibit improved thickening abilities under harsh reservoir conditions. These developments have further optimized the use of polymer flooding in high-temperature and high-salinity environments, expanding its applicability to a broader range of reservoirs [20-22].

Reducing Water Channeling and Fingering

Fingering refers to the unstable and irregular patterns formed when one fluid displaces another in porous media, particularly during immiscible flow. It occurs due to imbalances between viscous, capillary, and gravitational forces. There are two main types:

- Viscous fingering, which happens when a less viscous fluid displaces a more viscous one, leading to narrow, fast-moving fingers [23].
- Capillary fingering, which occurs due to pore-scale randomness and surface tension effects, often resulting in branching or irregular paths [24]. An illustration of fingering phenomena and the relationship between mobility and oil recovery in EOR is shown in Figure 1.

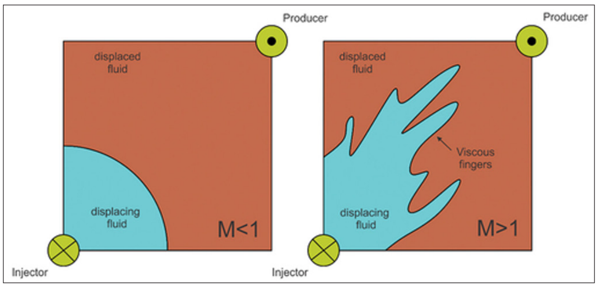

Figure 1: Fingering phenomena and the relationship between mobility and oil recovery in EOR [25]

Fingering reduces sweep efficiency, leaving behind trapped fluids and lowering the effectiveness of processes like enhanced oil recovery (EOR), Understanding and controlling fingering is essential for improving fluid displacement in heterogeneous subsurface environments. Water channeling and viscous fingering are major challenges in conventional water flooding operations, leading to inefficient oil displacement and early water breakthrough. These phenomena occur when the injected water follows high-permeability pathways or preferential flow paths, bypassing oil-rich zones and leaving significant amounts of oil unrecovered. The addition of polymers to the injection water increases its viscosity, reducing the water's ability to flow through high-permeability streaks while promoting a more uniform displacement front. By decreasing the mobility ratio between water and oil, polymers ensure that the injected fluid moves more uniformly through the reservoir, reducing the tendency for water to create narrow channels or fingers that bypass the oil. A study by [24]. Investigates the impact of porous media heterogeneity on immiscible fluid displacement, focusing on the transition between capillary and viscous fingering. By incorporating liquid compressibility into a pore network model, the research quantifies the characteristics of fingering patterns and defines a new parameter - *the characteristic waterfront flow rate* - based on invading fluid saturation and media heterogeneity. Results show that increased heterogeneity expands the crossover zone, shifts it toward lower capillary numbers, raises the flow rate, reduces displacement efficiency, and promotes the invasion of larger pores. These findings highlight the critical role of heterogeneity in influencing the efficiency and dynamics of fluid injection processes such as enhanced oil recovery and geological CO_2 sequestration.

Enhancing Sweep Efficiency and Displacement of Residual Oil

Sweep efficiency refers to the ability of the injected fluid to effectively contact and displace oil over a large reservoir volume. Volumetric sweep efficiency basically tells us how well the injected fluid-like water, gas, or chemicals-spreads through the reservoir to push out oil. It's not just about how much fluid you inject, but how effectively that fluid reaches the oil. A lot of things can influence this, like how the wells are arranged, whether there are natural fractures, and how thick or varied the reservoir rock is. Even the difference in density between the fluids and how easily they move through the rock (mobility ratio) matter. The flow rate you choose also plays a big role. A combination of these factors that determines how much of the oil you can actually recover. In conventional water flooding, poor sweep efficiency occurs due to reservoir heterogeneity, high permeability contrast, and unfavorable mobility ratios between water and oil. This results in oil bypassing and incomplete displacement of residual oil. Polymers play a critical role in improving sweep efficiency by modifying the flow dynamics of the injected fluid. By increasing water viscosity, polymers promote a more uniform displacement front, reducing the formation of unswept zones and bypassed oil pockets. This improved volumetric sweep leads to higher oil recovery rates. Furthermore, polymers enhance microscopic displacement efficiency by reducing the interfacial tension between water and oil. This allows for better mobilization of residual oil trapped in pore spaces. Advanced polymer formulations, such as viscoelastic and associative polymers, exhibit superior displacement capabilities by improving fluid rheology and promoting better oil-phase connectivity [30-32].

A study by Huiying Zhong and his coworkers, explores how the combined effects of polymer elasticity and reservoir wettability influence the displacement of residual oil during enhanced oil recovery (EOR). Using a simplified oil droplet model and advanced simulations via a modified interFoam solver in OpenFOAM, the interaction between these two factors was analyzed. The findings revealed that while viscous forces primarily control the initial deformation of oil droplets, elasticity significantly improves oil displacement in strongly water-wet conditions. Specifically, displacement efficiency increased from 65.61% to 69.06% as elasticity rose. Conversely, in weakly oil-wet environments, greater elasticity reduced displacement efficiency, indicating an inhibitory effect. The study also found that the direction of normal stresses varied with wettability, influencing the overall flow behavior [33]. These insights offer a deeper understanding of how elasticity and wettability interact at the microscale, helping to refine polymer flooding strategies for more efficient oil recovery in different reservoir conditions.

To enhance sweeping efficiency some researchers developed a smart two-step approach: first, they use a special foam (AOS-DYG) to block the high-permeability zones that usually steal the flow. Then, they follow up with a custom-made active polymer (AM/AMPS/DMCA) that can push oil out from the tighter, less accessible areas. This combo proved to be very effective. In lab tests, it boosted oil recovery by over 44% in some cases, and even in highly varied rock formations, it achieved up to 36% more oil recovery. The foam helps redirect the flow, while the polymer improves how deeply the fluid can penetrate the reservoir [26]. This method not only works well but could be a real game-changer for challenging, heterogeneous oil fields. Selective polymer placement techniques, such as gel blocking and profile modification treatments, further optimize sweep efficiency by redirecting injected fluids to less-permeable zones. These techniques help overcome the challenge of reservoir heterogeneity and ensure a more even distribution of displacement forces throughout the reservoir. The effectiveness of polymer-enhanced sweep efficiency depends on reservoir characteristics, polymer properties, and injection strategies. Proper design and optimization of polymer flooding campaigns are essential for maximizing oil recovery while minimizing operational costs and polymer degradation. Some researchers tested a deep profile control strategy using two different gels: modified starch gel and traditional polymer gel. They conducted a series of lab experiments, including rheology tests, injection and plugging capacity assessments, and core flooding tests, combined with CT imaging to understand how each gel behaves inside the reservoir. The results indicated that the modified starch gel outperformed the polymer gel in several key areas. It was easier to inject and showed stronger plugging ability. During gel flooding, the starch gel held its shape and effectively blocked high-permeability zones, while the polymer gel appeared looser and less effective. When water flooding followed, the starch gel stayed in place, redirecting the flow toward lower-permeability regions, increasing sweep efficiency in those hard-to-reach zones by 60%. Notably, before turning into a gel, the starch behaves like a regular viscous fluid, whereas the polymer gel is viscoelastic. But once they gel, the starch version becomes a much more effective barrier. In comparison, the polymer gel increased sweep efficiency by about 37%. Moreover, while high-permeability zones are usually swept clean with ease, getting oil out of tighter areas remains a challenge. CT scans confirmed that the modified starch gel did a better job overall, making it a promising tool for enhancing oil recovery in complex sandstone reservoirs [27].

Decreasing Permeability in High-Permeability Zones to Ensure Uniform Injection

One of the challenges in polymer flooding is the preferential flow of injected fluids into high-permeability zones, leaving low-permeability regions underutilized. This phenomenon results in inefficient sweep efficiency and premature water breakthrough. Polymers, especially cross-linked polymer gels, are used to selectively reduce permeability in high-permeability zones, ensuring a more uniform fluid distribution. These gels act as blocking agents, diverting injected fluids into less permeable zones where residual oil remains trapped. By selectively modifying permeability, polymers improve overall displacement efficiency and maximize oil recovery. In addition to gel-based systems, associative and viscoelastic polymers can form network structures within porous media, restricting fluid flow through high-permeability channels. This controlled permeability reduction prevents excessive water production and enhances the effectiveness of polymer flooding operations. The success of permeability control depends on polymer properties, injection strategies, and reservoir characteristics. Advances in smart polymers, which respond to reservoir conditions such as temperature and salinity, have further improved the efficiency of permeability modification in heterogeneous reservoirs [34]. Polymer-Induced Permeability Reduction (PIPR) is a phenomenon where polymers clog or damage the rock's pore structure, reducing permeability. Several factors contribute to

PIPR, including rock type, oil saturation, temperature, salinity, polymer properties, shear rate, and injection water quality. Poor polymer preparation or fluid incompatibility can further worsen injectivity problems. A study reviews corefl ooding experiments as a practical technique to evaluate PIPR and introduces a new interpretation method that links polymer retention and reservoir rock quality to the observed permeability reduction. The researchers were able to better predict and match PIPR behavior in both sandstone and carbonate cores, using literature data. The findings emphasize the importance of including PIPR evaluation in the polymer selection workflow. Proper assessment can help anticipate injectivity challenges, guide polymer formulation, and improve the overall success of EOR projects [35]. Another study explores a faster, smarter way to predict how cross-linked polymer gels reduce permeability in porous rocks—something crucial for controlling water production in oil and gas wells. Because simulating gel flow through rock is slow and computationally intense, the researchers developed an Artificial Neural Network (ANN) model to do the job in seconds. They ran over 20,000 simulations using the Lattice Boltzmann Method (LBM) to model how gel flows through a 2D rock sample. This created a massive, but imbalanced dataset. To tackle this, they introduced a new technique for balancing data in regression models, which helped improve prediction accuracy. This work presents a novel and efficient method to estimate permeability changes caused by polymer gel injection [36].

A study conducted by Reza Askarinezhad and his colleagues investigated the effectiveness of a low-molecular-weight associative polymer for Disproportionate Permeability Reduction (DPR) in Berea sandstone cores under water-wet and chemically treated oil-wet conditions at 60 °C. Coreflood experiments with real-time electrical resistivity monitoring were used to track fluid saturation and flow behavior. The founding of this study indicated that the mobility reduction during polymer injection was strongly shear-dependent, with water flow showing a power-law response and oil flow being slightly shear-thinning in water-wet cores and weakly shear-thickening in oil-wet cores as shown in Figure 2. The study confirms that associative polymer DPR treatments can reduce water cut effectively, especially in oil-wet formations, but the trade-off in reduced oil production rate must be carefully weighed when considering field applications [37]. Therefore, it is very important to select the right polymer treatment strategy based on reservoir conditions, especially in the context of permeability variations, potential injectivity issues, and wettability. Modified starch gel has shown superior performance over traditional polymer gels in deep profile control, offering better plugging, ease of injection, and improved sweep efficiency in low-permeability zones. Meanwhile, artificial intelligence tools like ANN, trained using Lattice Boltzmann simulations, offer promising predictive capabilities for permeability reduction, streamlining the polymer selection process.

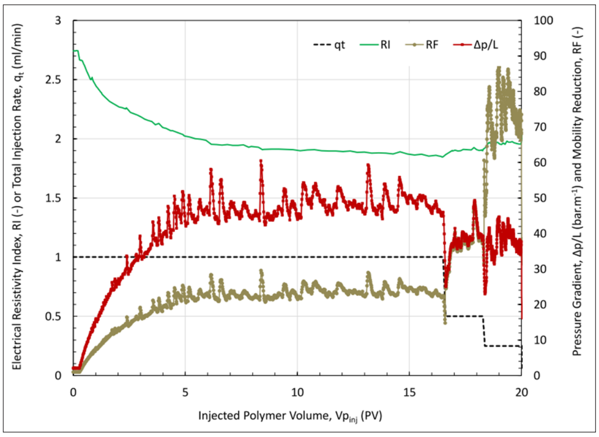

Figure 2: Mobility reduction, pressure gradient, and electrical resistivity index variations as a function of polymer volume injected [37]

Uses of Polymers in EOR

Polymer Flooding

Polymer flooding, a widely used enhanced oil recovery (EOR) technique, is most effective in reservoirs with moderate to high permeability (50-5000 mD), temperatures below 90°C, and low salinity, where polymers like HPAM can improve oil recovery by 5–30% over water flooding. This method enhances oil displacement by increasing water viscosity and reducing the water-to-oil mobility ratio, making it particularly effective when oil viscosity is between 10–150 cP. However, its application is limited by factors such as polymer degradation under high temperature, salinity, or shear stress, economic constraints related to polymer costs, and potential formation damage from poorly dissolved polymers. Solutions include using temperature-resistant co-polymers, optimizing injection rates, and conducting cost-benefit analyses. Despite these challenges, polymer flooding has been successfully implemented in fields like Daqing (China), Marmul (Oman), and Pelican Lake (Canada), leading to increased production and extended field life. Future trends focus on developing smart polymers with self-healing properties, nanoparticle-enhanced formulations for improved stability, and hybrid EOR methods combining polymer flooding with surfactants or alkaline flooding for enhanced oil recovery. The most widely used polymer-based EOR method is improving displacement efficiency by increasing water viscosity and reducing the mobility ratio. Polymer flooding is an Enhanced Oil Recovery (EOR) technique used to increase oil production in mature fields where conventional water flooding is ineffective. It involves adding polymers to injected water to increase its viscosity, thereby improving oil displacement and reducing water mobility. This method enhances sweep efficiency, meaning more oil is pushed toward production wells instead of being bypassed by water. The fundamental principle behind polymer flooding is to improve the water-to-oil mobility ratio by:

- Increasing water viscosity (thicker water moves more uniformly).
- Decreasing oil-water mobility ratio, preventing water from bypassing oil-rich zones.
- Reducing reservoir heterogeneity effects, allowing better oil displacement from low-permeability zones.

Water-soluble polymers are mixed with water to form a solution. The concentration is carefully controlled to optimize viscosity.

The polymer solution is pumped into the reservoir through injection wells. The most widely used polymers in polymer flooding application are:

Partially Hydrolyzed Polyacrylamide (HPAM)

HPAM is the most widely used polymer in polymer flooding, valued for its cost-effectiveness and ability to significantly enhance water viscosity at low concentrations. Derived from polyacrylamide (PAM) through partial hydrolysis, it incorporates carboxyl (-COO^-) groups, improving its ability to control water mobility in reservoirs. By increasing the viscosity of injected water, HPAM enhances oil displacement, reduces the water-to-oil mobility ratio, and minimizes premature water breakthrough, making it highly efficient even at low concentrations (0.1–1.0 wt%). Compared to biopolymers like xanthan gum, HPAM is a more economical choice; however, its performance can be compromised in high-salinity or high-temperature environments, necessitating modifications to maintain stability and effectiveness in challenging reservoir conditions [38,39]. A summary of HPAM properties that make it suitable for polymer flooding operation is shown in Table 1.

Table 1: Properties of HPAM in EOR Applications

Property Details	Property Details
Molecular Weight	1–20 million Daltons (higher MW increases viscosity).
Solubility	Highly soluble in fresh and low-salinity water.
Viscosity Enhancement	Can increase water viscosity by 10-100 times.
Shear Sensitivity	Can degrade under high shear conditions (e.g., high injection rates).
Thermal Stability	Stable up to 60–90°C, but degrades at higher temperatures.
Salinity Tolerance	Sensitive to high salinity and hardness (Ca^{2+}, Mg^{2+} ions cause precipitation).

HPAM (Hydrolyzed Polyacrylamide) has been extensively studied as a polymer flooding agent for enhanced oil recovery (EOR), with numerous research findings highlighting its promising potential. These studies consistently demonstrate HPAM's effectiveness in improving sweep efficiency, reducing the mobility ratio, and enhancing oil recovery, especially in heterogeneous and high-viscosity reservoirs. Its favorable properties, such as good water solubility, thickening ability, and compatibility with a variety of reservoir conditions, make it a widely recommended candidate for polymer flooding applications [40,41].

The advantages of HPAM include affordability compared to natural polymers and a high molecular weight that enhances water viscosity, improving oil displacement efficiency. However, its application is limited by challenges such as precipitation in high-salinity reservoirs containing divalent cations (Ca^{2+}, Mg^{2+}), thermal degradation at temperatures above 90°C, and shear sensitivity, which can lead to polymer chain breakage under high flow rates. To address these limitations, recent advancements have focused on developing crosslinked HPAM for improved thermal and salt resistance, HPAM-nanoparticle composites to enhance viscosity and stability, and HPAM-surfactant blends to optimize oil displacement in challenging reservoir conditions. A study by Najeebullah Lashari and his coworkers suggested a method for the incorporation of graphene oxide (GO) nanoparticles with HPAM to produce GO-SiO_2/HPAM composite as shown in Figure 3 [42,43].

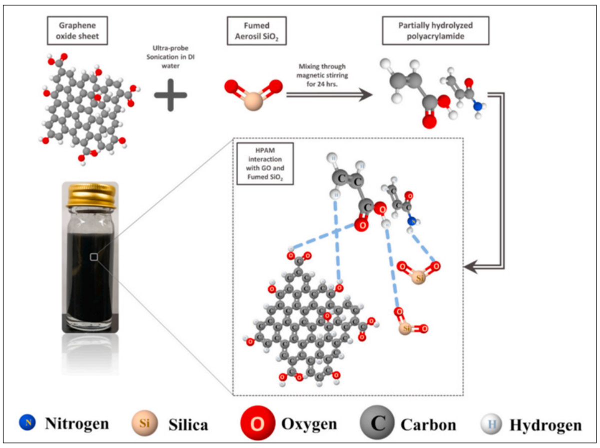

Figure 3: The HPAM polymer molecular interaction with graphene oxide and fumed Aerosil 380 SiO2 nanoparticles

Another study focusses on enhancing the thermal stability and rheological behavior of hydrolyzed polyacrylamide (HPAM) solutions using SiO_2 nanoparticles. The thermal degradation tests of this study showed that the presence of SiO_2 nanoparticles significantly improved HPAM stability, especially in the absence of oxygen, indicating that SiO_2 not only enhances viscosity behavior but also acts as a stabilizer against thermal breakdown as can be seen in Figure 4 and 5 [41]. Despite these challenges, HPAM continues to be a preferred choice for polymer flooding, with ongoing modifications aimed at extending its applicability in high-temperature, high-salinity, and high-shear environments to ensure sustained efficiency and enhanced oil recovery.

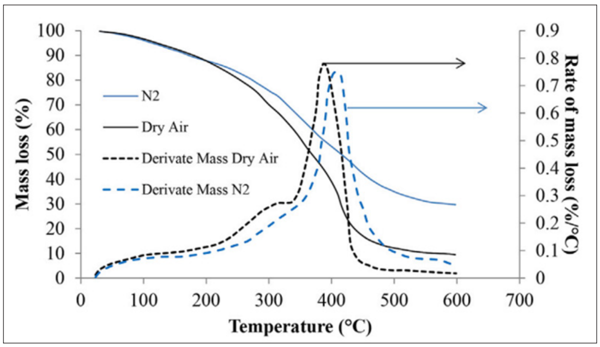

Figure 4: Polymer decomposition under oxidative and inert atmospheres. Heating rate of 10 oC/min from 30 oC to 600 oC and flow rate of 100 cm3 /min [41]

In addition, the exploration of acrylamide-based copolymers has shown promise for polymer flooding techniques. Co-polymerizing acrylamide with monomers like 2-acrylamido-2-methylpropane sulfonic acid (AMPS) results in polymers that exhibit improved thermal and salinity resistance. These properties are essential for maintaining polymer performance in the diverse and often harsh conditions of oil reservoirs. The enhanced stability and viscosity of these copolymers contribute to more effective oil displacement and increased recovery rates [44]. Furthermore, the development of novel copolymers, such as Zetag 8187G, has been evaluated for EOR applications in high-temperature and high-salinity environments. Studies have demonstrated that Zetag 8187G maintains its viscosity and structural integrity under such conditions, leading to improved oil recovery rates compared to traditional polymers. This advancement underscores the importance of tailoring polymer structures to meet specific reservoir challenges [45].

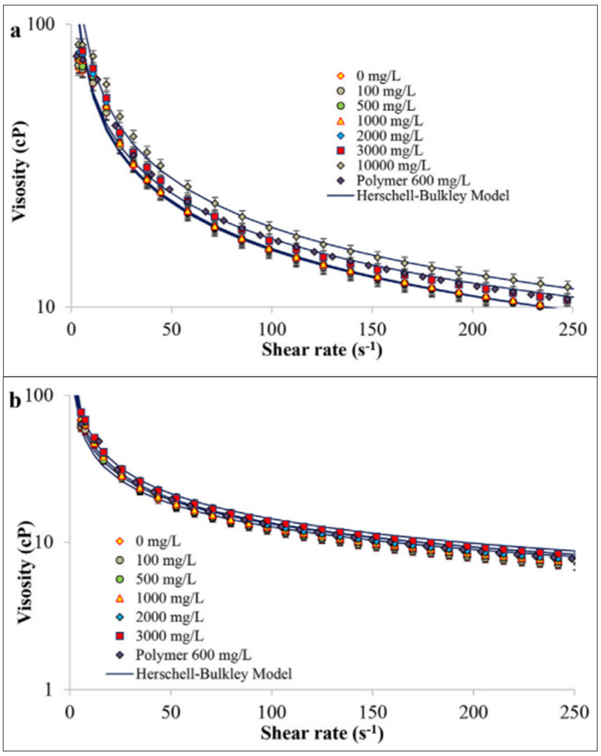

Figure 5: Rheological behavior of a 500 mg/L polymer solution in the presence of different dosages of SiO2 nanoparticles at a) 25 and b) 70 oC [41]

Xanthan Gum

Xanthan gum is composed of a cellulose-like backbone of β-D-glucose units linked by (1→4) glycosidic bonds. Every second glucose residue is substituted with a trisaccharide side chain consisting of β-D-mannose-(1→4)-β-D-glucuronic acid-(1→2)-α-D-mannose. The terminal mannose may carry a pyruvate group, and the inner mannose often has an acetyl group at the C6 position as can be seen in Figure 6 [46]. This structure imparts xanthan gum with its characteristic viscosity and stability properties. The properties of Xanthan Gum are summarized in Table 2.

In EOR, xanthan gum is utilized to increase the viscosity of the displacing water, thereby improving the mobility ratio between water and oil. This leads to a more efficient displacement of oil from the reservoir. Studies have shown that xanthan gum solutions can maintain their viscosity under high salinity and temperature conditions, making them suitable for challenging reservoir environments. For instance, hydrophobically modified xanthan gum has demonstrated enhanced viscosity and stability, resulting in improved oil recovery rates compared to unmodified xanthan gum. Additionally, xanthan gum's biodegradability and non-toxic nature make it an environmentally friendly option for EOR processes. Its resistance to shear degradation ensures that it maintains its viscosity during the injection process, further enhancing its effectiveness in oil recovery applications [47-49].

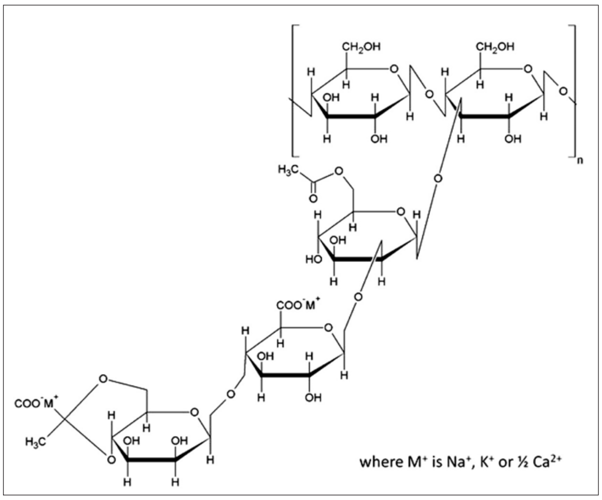

Figure 6: Chemical structure of Xanthan Gum [46]

Table 2: Properties of Xanthan Gum

Molecular Weight	High (several million Daltons)
Solubility	Soluble in both hot and cold water
Viscosity Behavior	Exhibits shear-thinning (pseudoplastic) behavior
Thermal Stability	Maintains viscosity across a wide temperature range
Salt Tolerance	Stable in the presence of various salts, including divalent cations
pH Stability	Stable across a broad pH range
Biodegradability	Biodegradable and environmentally friendly
Applications in EOR	Enhances oil recovery by improving sweep efficiency and mobility control

Scleroglucan

Scleroglucan is a naturally derived extracellular polysaccharide produced by fungi, particularly Sclerotium rolfsii. It has attracted significant attention in enhanced oil recovery (EOR) applications due to its excellent thermal and salt stability, high thickening efficiency, and eco-friendly profile. Structurally, scleroglucan is composed of a linear β-(1→3)-D-glucan backbone, with every third glucose unit substituted at the C6 position with a β-(1→6)-linked glucose side chain. The molecular structure of Scleroglucan is shown in Figure 7 [50, 51]. This specific arrangement promotes a stable triple-helix conformation in aqueous environments, making it resistant to extreme reservoir conditions and maintaining its viscosity over long periods. One of the key advantages of scleroglucan over conventional synthetic polymers like hydrolyzed polyacrylamide (HPAM) is its remarkable resistance to thermal degradation and divalent ions, such as calcium and magnesium. The properties of scleroglucan are summarized in Table 3.

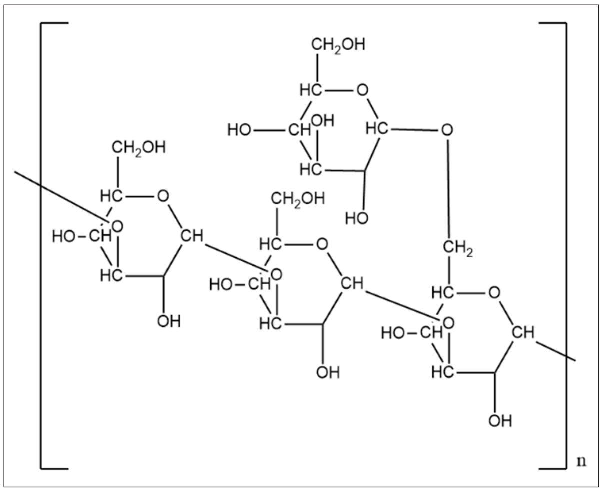

Figure 7: The molecular structure of Scleroglucan [51]

Table 3: Properties of Scleroglucan

Molecular weight	~1–10 million Da
Solubility	Water-soluble
Rheology	Shear-thinning (non-Newtonian) behavior
Thermal stability	Stable up to ~120°C
Salinity tolerance	High; stable in brines with Ca^{2+}, Mg^{2+}, and Na^{+}
Biodegradability	Biodegradable and environmentally friendly
Compatibility	Compatible with most surfactants and reservoir conditions
Triple-helix structure	Increases viscosity and stability in aqueous solution

Studies have shown that scleroglucan retains its viscosity and flow behavior in high-salinity brines and temperatures above 100 °C, making it a promising candidate for high-temperature and high-salinity (HTHS) reservoir applications. Its rheological properties exhibit non-Newtonian, shear-thinning behavior, which is crucial for minimizing pressure loss during injection while maintaining high viscosity in the reservoir to improve oil displacement efficiency. Furthermore, scleroglucan is biodegradable and environmentally safe, aligning well with the oil industry's increasing shift toward sustainable practices [so. Core flooding experiments and simulation studies further support the viability of scleroglucan in EOR. For instance, a comparative analysis demonstrated that scleroglucan outperformed many synthetic and natural polymers in both viscosity retention and oil displacement efficiency under harsh conditions [51,52].

A capsule polymer flooding emerges as a promising next-generation technique for enhanced oil recovery, addressing the limitations of conventional polymer flooding such as shear degradation and poor injectability. This innovative approach leverages the benefits of easy injection, shear resistance, and temperature-sensitive controlled release, enabling deeper and more effective reservoir penetration. Its ability to delay viscosity buildup allows better mobility control, reduces viscous fingering, and significantly expands sweep efficiency particularly in high-water-cut, offshore, or low-permeability reservoirs. Success in field applications relies on tailoring capsule properties like particle size, release timing, and shear resistance to specific reservoir conditions. Ultimately, capsule polymer flooding represents a strategic shift from surface-based thickening to deep-reservoir mobility regulation, offering a highly adaptable and efficient solution for improving oil recovery [53,54].

Polymer-Gel Treatment for Conformance Control

Polymer-gel treatment for conformance control is a highly effective technique in enhanced oil recovery (EOR) used to reduce excessive water production and improve sweep efficiency by selectively blocking high-permeability zones within a reservoir. This method is particularly beneficial in reservoirs where high-permeability zones tend to allow water to break through prematurely, reducing the overall effectiveness of water flooding. By injecting cross-linked polymer gels, such as polyacrylamide-based gels, into these high-permeability zones, the flow of water is reduced, and the injected fluids are directed towards oil-rich areas, improving the distribution of fluids and increasing oil recovery. The polymer gel helps to maintain better conformance control by reducing water breakthrough and enhancing the overall sweep efficiency of the injected water or gas, thereby prolonging the productive life of the field [55-57].

Polymer gels, especially polyacrylamide-based gels, are commonly used for conformance control due to their excellent water solubility and ability to modify viscosity. Cross-linking the polymer increases the gel's strength, ensuring it remains stable and effective over time under reservoir conditions such as temperature, salinity, and pressure. Other biopolymers, such as xanthan gum, are also used for specific applications, particularly in reservoirs with high salinity or more demanding conditions. These gels work by selectively blocking water flow in high-permeability zones and allowing for more uniform displacement of oil, leading to improved oil recovery. Polymer gels are especially effective in improving sweep efficiency, reducing premature water breakthrough, and ensuring better distribution of injected fluids [57-59].

One of the primary advantages of polymer-gel treatments is their ability to provide selective blocking of high-permeability zones, improving oil recovery efficiency by reducing water production. The technique is also cost-effective compared to other EOR methods, such as gas injection or thermal recovery, especially in reservoirs with high-permeability challenges. Additionally, polymer gels have proven to be stable and durable, providing long-lasting results with minimal maintenance [60]. However, challenges such as ensuring adequate gel strength, ensuring compatibility with varying reservoir conditions (e.g., temperature, salinity), and avoiding premature gelation during injection must be addressed for successful implementation. Moreover, the formulation and injection processes must be carefully controlled to avoid issues with dissolution, filtration, or formation damage [61-63]. The mechanism of action of the blocking gels is illustrated in Figure 8 [61].

Recent advancements in polymer-gel treatment have focused on improving the gels' performance under extreme reservoir conditions. Smart polymer gels, which respond to changes in reservoir pressure or temperature, are being developed to provide more adaptive conformance control. Additionally, incorporating nanoparticles, such as silica or clay particles, into polymer gels has shown promise in enhancing gel strength, improving thermal stability, and better controlling gelation. Researchers are also exploring hybrid systems that combine polymer gels with other EOR techniques, such as surfactant or alkaline flooding, to improve overall oil recovery in complex reservoirs [64-66]. Field applications of polymer-gel treatments have been successfully implemented in various oil fields worldwide, particularly in mature fields or waterflooded reservoirs that are experiencing high water-cut issues. These treatments have been instrumental in improving oil recovery and reducing water production, making them a key tool for reservoir management and long-term field productivity [67,68].

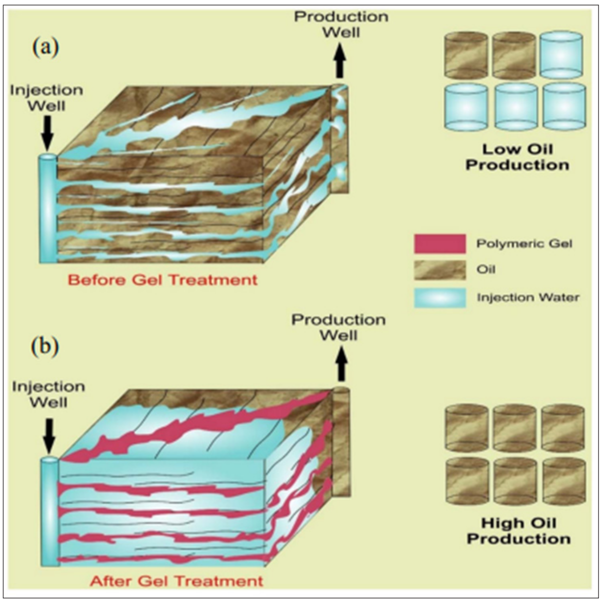

Figure 8: Mechanism of action of the blocking gels, where: (a) the injected fluid flows preferentially through zones of greater permeability, reducing oil production and (b) formation of polymer gel preferentially in the thief zones of the reservoir, displacing the injected water to regions with lower permeability and increasing oil production [61]

Polymer-Enhanced Surfactant Flooding

Polymer-Enhanced Surfactant Flooding (PESF) is an enhanced oil recovery (EOR) technique that combines surfactants and polymers to improve oil recovery in reservoirs. This method works by reducing the interfacial tension between oil and water, which enhances the displacement of oil from the reservoir rock. The combination of surfactants and polymers helps in improving the mobility ratio, which refers to the relative ease with which the injected fluids (such as water or gas) move through the reservoir compared to the oil. By reducing the interfacial tension and optimizing the flow of fluids, PESF leads to better oil displacement and higher recovery factors compared to traditional water flooding methods as shown in Figure 9 [46,69-71].

A study by M. Elmuzafar Ahmed indicated the effectiveness of surfactant-polymer (SP) flooding in high-temperature (90 °C), high-salinity (57,000 ppm) carbonate reservoirs. It evaluated a thermo-viscosifying polymer and an ATBS/acrylamide copolymer combined with various carboxybetaine surfactants. Among the tested formulations, the best result was achieved using 0.05 wt% carboxybetaine with 0.25 wt% ATBS/AM polymer, which recovered 31.29% of residual oil saturation (ROS), equal to 11.63% of the original oil in place (OOIP). Increasing the slug size to 3.5 pore volumes improved the recovery to 34.21% ROS (17.05% OOIP). The co-injection method (SW-SP-SW) was the most efficient injection sequence [70].

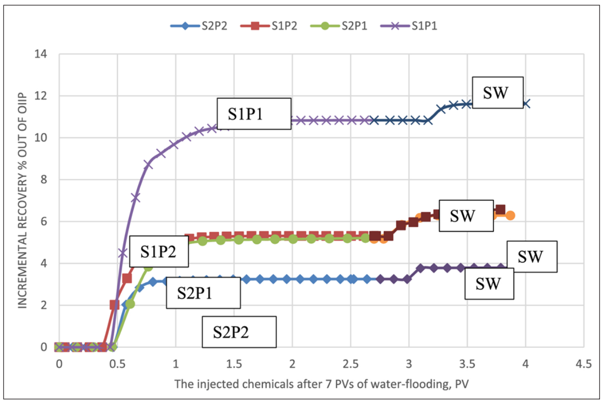

Figure 9: The effect of PESF on oil recovery [70]

The role of the surfactant is to lower the interfacial tension (IFT) between oil and water, allowing the oil to be more easily mobilized and displaced as illustrated in Figure 10 [72]. However, surfactants alone can have limitations, such as poor stability in harsh reservoir conditions like high salinity or temperature. The polymers are added to stabilize the emulsions formed during the process and to prevent excessive surfactant loss. The polymer acts as a viscosity modifier, which helps to reduce the rapid dilution of the surfactant in the injected water, allowing the surfactant to remain effective over a longer period of time and across larger portions of the reservoir. This enhancement is particularly useful in high-salinity or high-temperature environments, where surfactants alone might degrade or become less effective [73-77].

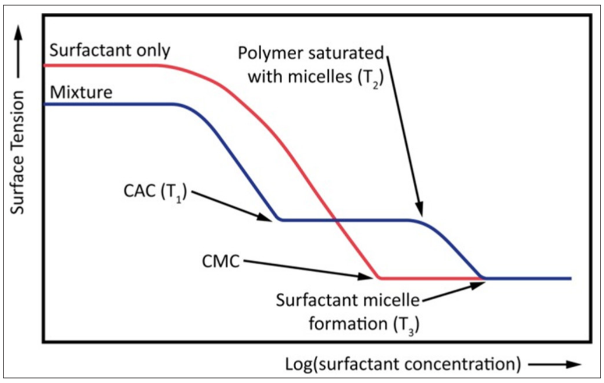

Figure 10: Effect of the polymer on the IFT [72]

The key benefits of polymer-enhanced surfactant flooding include improved surfactant effectiveness, as the polymer helps to stabilize emulsions and maintain a longer-lasting surfactant presence in the reservoir. By enhancing the stability of the surfactant-polymer mixture, this method improves oil recovery efficiency by reducing surfactant losses, which otherwise occur due to adsorption onto reservoir rock or dilution with the injection water. Additionally, polymer-enhanced surfactant flooding can be used to improve mobility control, ensuring that injected fluids flow more efficiently through the reservoir, displacing more oil and reducing water production [46,69,78]. However, there are challenges associated with polymer-enhanced surfactant flooding, such as the complexity of formulation and the need for careful control over the injection rates to ensure that both the surfactant and polymer are evenly distributed throughout the reservoir. The cost of both surfactants and polymers can be significant, especially when applied in large-scale field projects. Furthermore, the compatibility of the surfactant-polymer mixture with reservoir conditions (e.g., salinity, temperature, and rock type) must be thoroughly tested and optimized for each individual reservoir to ensure the highest possible recovery [78,79].

Foam-Polymer Flooding

Foam-Polymer Flooding is an enhanced oil recovery (EOR) technique that involves the use of polymer-stabilized foams to improve the effectiveness of gas-based EOR methods, such as CO_2 or nitrogen injection. This method is particularly effective in controlling gas mobility and enhancing sweep efficiency by reducing the gas fingering phenomenon. Gas fingering occurs when gas injection bypasses oil-rich areas due to high permeability zones, leading to inefficient displacement of oil. By introducing foam, the gas is stabilized and distributed more evenly throughout the reservoir, ensuring that the injected gas has better contact with the oil and leads to more efficient recovery [80-83]. Figure 11 illustrated the effect of foam assisted technique on cumulative oil production [84].

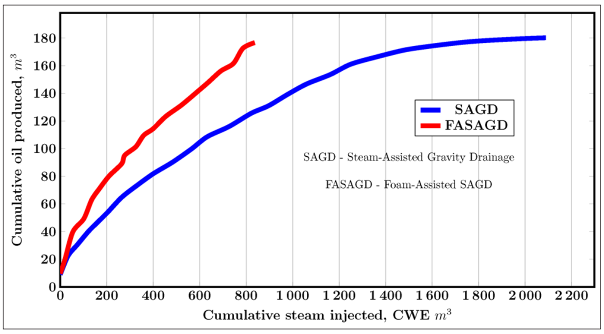

Figure 11: Comparison of the recovery efficiency between steam-assisted gravity drainage (SAGD) and foam-assisted FA-SAGD [84]

The foam in foam-polymer flooding is typically a mixture of gas, water, and a surfactant, which forms a stable foam when combined with a polymer that enhances its viscosity. The polymer acts as a stabilizer, preventing the foam from collapsing too quickly and ensuring it maintains its integrity throughout the reservoir. The foam helps in dividing the gas flow and reducing its mobility, which improves sweep efficiency by ensuring a more uniform displacement of oil from the reservoir rock. This is particularly beneficial in reservoirs with heterogeneous permeability, where foam can help ensure that gas injection is more evenly distributed, thereby reducing the risk of gas bypassing the oil zones [80, 83, 85, 86]. In combination with gases like CO_2 or nitrogen, foam-polymer flooding can increase reservoir contact by ensuring that the injected gas reaches more of the oil-bearing zones. The foam serves to minimize the risk of gas channeling through high-permeability areas, ensuring that the gas can contact a larger portion of the reservoir and displace oil more effectively. This can significantly improve oil recovery, especially in reservoirs where conventional gas flooding might otherwise be less efficient due to gas fingering [87-89]. The advantages of foam-polymer flooding include improved mobility control, as the foam reduces the tendency of gas to flow too quickly through certain zones of the reservoir. This method also helps to enhance sweep efficiency, allowing the injected gas to cover a larger area of the reservoir and displace more oil. Additionally, the use of foam-polymer systems can increase the residence time of the gas in the reservoir, improving overall oil displacement. However, challenges exist in implementing foam-polymer flooding, such as the stability of the foam over time, particularly under high-pressure and high-temperature conditions. Ensuring that the foam remains stable and does not degrade too quickly is crucial for maintaining the efficiency of the flooding process. Moreover, the cost of the surfactants, polymers, and gas injection can be high, which must be considered when evaluating the overall economic viability of this EOR method. Additionally, careful formulation is required to ensure that the polymer-stabilized foam is compatible with the specific conditions of the reservoir.

Polymers Nanocomposite for EOR

Nanocomposite Polymers for Enhanced Oil Recovery (EOR) represent an advanced approach that incorporates nanoparticles into polymer formulations to significantly improve their performance in challenging reservoir conditions. The addition of nanoparticles, such as silica, clay, or metal oxides, enhances the thermal stability, salt resistance, and shear resistance of the polymer. These properties are crucial in high-temperature and high-salinity environments, where traditional polymers, like partially hydrolyzed polyacrylamide (HPAM), often degrade or lose their effectiveness. Nanoparticles act as stabilizers that strengthen the polymer matrix, allowing it to maintain its functionality over a broader range of reservoir conditions, thus improving the overall efficiency of the EOR process [90-92]. Figure 12 illustrate the effect of different nanoparticle concentrations on polymer viscosity. Figure 13 illustrate a comparison between different injectivity scenarios on oil recovery factor [93].

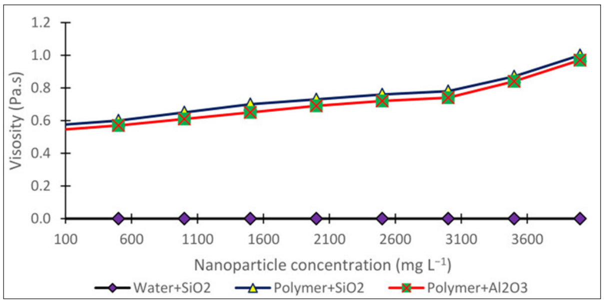

Figure 12: Viscosity measurement in the presence of different nanoparticle concentrations [93]

One of the key advantages of nanocomposite polymers is their ability to improve polymer retention and reduce adsorption losses. In many reservoirs, polymers are prone to adsorption onto the reservoir rock, which diminishes their effectiveness and increases operational costs. The incorporation of nanoparticles into the polymer helps to reduce these adsorption losses, ensuring that more polymer remains in the reservoir, leading to more efficient displacement of oil. This also enhances the mobility control and viscosity of the injected fluid, ensuring that the polymer works effectively to modify the flow behavior of the injected water or gas and improve oil recovery [90, 94]. The mechanism of increasing fluid viscosity by combining silica nanoparticles with amphiphilic polymers is illustrated in Figure 14 [90].

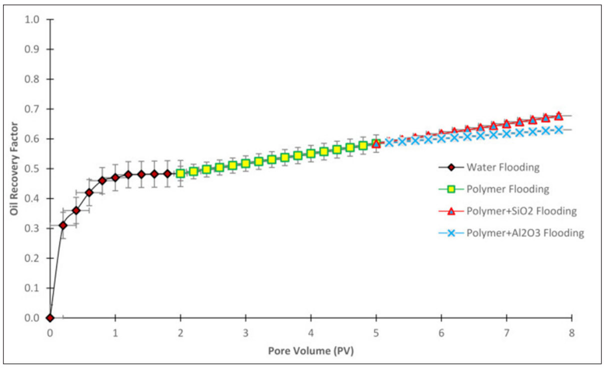

Figure 13: A comparison between different injectivity scenarios on oil recovery factor

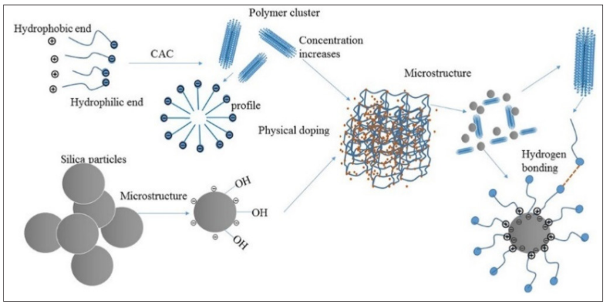

Figure 14: The mechanism of increasing fluid viscosity by combining silica nanoparticles with amphiphilic polymers [95]

Additionally, the shear resistance of nanocomposite polymers is improved, which means that the polymers can withstand high shear forces without degrading. This is particularly important in reservoirs where high flow rates or turbulent conditions are common, as the polymer needs to retain its structure to maintain its viscosity and mobility control. The enhanced shear stability ensures that the polymer's effectiveness in displacing oil is sustained over the course of the injection process [96]. Nanocomposite polymers also offer improved thermal stability, allowing them to perform effectively in reservoirs with high temperatures, where conventional polymers may degrade and lose viscosity. The presence of nanoparticles helps to stabilize the polymer chains, making them more resistant to thermal breakdown, which is essential in maintaining the overall efficiency of the EOR operation in high-temperature conditions. The effect of nanoparticle on thermal resistance of polymers is shown in Figure 15 [5].

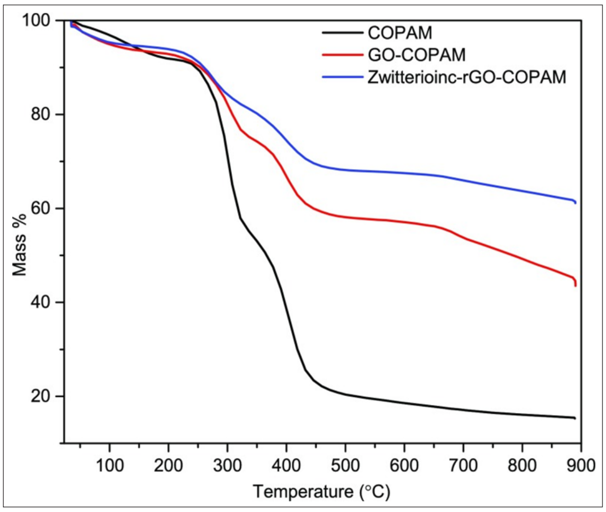

Figure 15: The effect of nanoparticle on thermal resistance of polymers [5]

Smart and Stimuli-Responsive Polymers

Smart and Stimuli-Responsive Polymers represent an innovative class of materials designed to respond to specific environmental changes within a reservoir, such as temperature, pH, or salinity, and adjust their viscosity or other properties accordingly. These polymers are engineered to undergo physical or chemical changes when exposed to varying conditions, enabling them to adapt in real time to the dynamic environment of the reservoir. For example, a polymer may become more viscous at higher temperatures or in response to a change in pH, which allows it to enhance oil displacement or improve mobility control. This ability to adjust based on environmental stimuli makes smart polymers highly valuable in enhanced oil recovery (EOR) applications, where they can optimize fluid flow and enhance oil recovery efficiency [97]. These polymers are particularly useful in situations where controlled gelation or delayed polymer activation is required. In deeper reservoir sections, where pressure, temperature, and other factors can vary significantly, smart polymers can be programmed to activate only when they reach certain conditions. For example, in deeper reservoir zones, these polymers might remain in a low-viscosity state during injection, allowing them to flow easily through the reservoir. However, once they reach the target section with the desired temperature or salinity conditions, they gel or increase in viscosity, thereby improving the sweep efficiency and reducing water production by selectively blocking high-permeability zones. This controlled activation ensures that the polymer provides the desired effect only when it is needed, making the process more efficient and cost-effective [76,98,99]. Figure 16 shows the different between oil recovery by smart thermoviscosifying polymers (TVPs) and hydrolyzed polyacrylamide (HPAM) [76].

The stimuli-responsive behavior of these polymers allows them to tailor their performance to specific reservoir conditions, enhancing both oil recovery and cost efficiency. They are especially valuable in reservoirs with heterogeneous or complex geological structures, where traditional methods might fail due to variations in temperature, salinity, or pressure. By ensuring that the polymer only activates in the areas where it is needed, smart polymers help to optimize displacement efficiency and extend the productive life of the field. In addition to controlled gelation and delayed activation, smart polymers can also be designed to respond to other stimuli, such as pressure or ionic strength, providing even greater versatility in EOR processes. Their adaptability enables them to perform well under a wide range of conditions, making them highly effective for challenging reservoirs, such as those with high temperatures, high salinity, or variable pH levels. Smart and stimuli-responsive polymers represent an advanced, highly adaptive approach to enhanced oil recovery, offering the ability to optimize fluid flow, improve sweep efficiency, and increase oil recovery in challenging reservoirs. Their ability to respond to specific environmental changes and provide controlled activation is revolutionizing EOR processes, offering significant potential for improving recovery rates and reservoir management strategies [97,100-102].

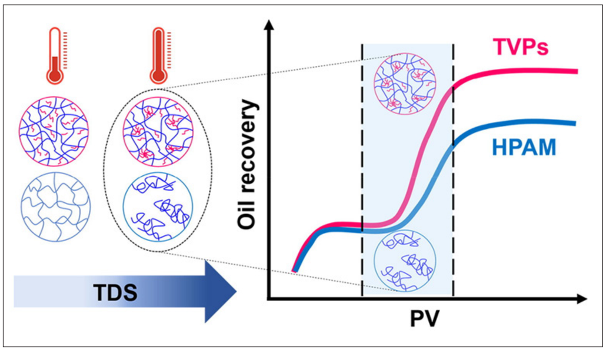

Figure 16: shows the different between oil recovery by smart thermoviscosifying polymers (TVPs) and hydrolyzed polyacrylamide (HPAM) [76]

Biopolymer-Based in EOR

Biopolymer-Based Enhanced Oil Recovery (EOR) Methods utilize natural polymers, such as xanthan gum and scleroglucan, to enhance oil recovery while offering environmental benefits. These biopolymers are derived from natural sources and are known for their biodegradability, making them an environmentally friendly alternative to synthetic polymers. Unlike traditional synthetic polymers, which can sometimes be harmful to the environment, biopolymers offer a more sustainable approach to enhanced oil recovery while still providing high performance in improving oil displacement and increasing recovery factors [51,103-105].One of the key advantages of biopolymer-based EOR methods is their ability to perform effectively under challenging reservoir conditions, such as high temperature and high salinity environments. Biopolymers like xanthan gum and scleroglucan are naturally more resistant to the effects of elevated temperatures and saline conditions, which can degrade synthetic polymers. This makes them particularly useful in harsh reservoir environments, where conventional synthetic polymers might fail or lose their viscosity over time. In such environments, biopolymers maintain their viscosity and mobility control properties, making them highly effective for increasing oil recovery [103,106,107].

Xanthan gum, for example, is a widely used biopolymer in EOR due to its high viscosity and salt tolerance. It helps to modify the flow behavior of injected water or gas, improving the sweep efficiency and reducing water production. A research study by Hee Yeon Jang and his coworkers compares the performance of xanthan gum and hydrolyzed polyacrylamide (HPAM) as polymer flooding agents for heavy oil recovery under varying salinity conditions. The findings indicated that xanthan gum exhibited greater stability in shear viscosity compared to HPAM, particularly under conditions of elevated temperature and salinity. This enhanced stability makes xanthan gum a more effective option for polymer flooding in high-salinity reservoirs, where HPAM tends to show decreased viscosity and performance [106].

Scleroglucan is another biopolymer known for its thermal stability and resistance to shear degradation, which is crucial for ensuring that the polymer maintains its effectiveness in high-shear environments, such as those found in deep reservoir sections or when injected through production wells. Unlike traditional polymers, scleroglucan maintains viscosity even in the presence of high concentrations of divalent ions, making it suitable for produced water re-injection without additional treatment. Laboratory tests showed less than 25% viscosity loss after exposure to 115 °C for six months, and no viscosity loss at 95 °Cover a one-year period. Shear degradation tests revealed that scleroglucan retained over 95% of its initial viscosity after 100 passes through a centrifugal pump, while synthetic polymers lost up to 50% of viscosity after just 10 passes. Capillary shear tests (API RP 63 method) at >150,000 s^{-1} confirmed its robustness under high shear. Core flooding experiments conducted in both sandstone and carbonate cores showed consistent resistance factors (RF) and residual resistance factors (RRF) in the optimal range, indicating strong injectivity and mobility control. Adsorption values and oil recovery results also aligned with expectations for polymer flooding performance. Additionally, scleroglucan demonstrated compatibility with biocides, including glutaraldehyde and TTPC, with no stability issues observed across 6 months at 37, 85, and 95 °C. It also showed excellent resistance to hydrogen sulfide (H_2S) and ferrous ions (Fe^{2+}) under aerobic conditions [52,107]. A study be T. Jensen and his coworkers evaluates the performance of the biopolymer scleroglucan for enhanced oil recovery (EOR) in carbonate reservoirs under harsh conditions of high temperature (90 °C) and high salinity (up to 167,000 ppm TDS). Rheological tests revealed that scleroglucan exhibits a high viscosifying power and strong shear-thinning behavior, which becomes more pronounced at higher polymer concentrations. It maintained better filterability at high temperatures compared to room temperature (25 °C), and its injectivity was confirmed to be effective in carbonate outcrop cores even at elevated salinity levels, such as seawater (43,000 ppm TDS) and formation water (167,000 ppm TDS). The injectivity tests showed that the resistance factor (RF) decreased with increasing flow rate, indicating favorable shear-thinning characteristics within porous media. Notably, the polymer demonstrated no severe plugging or injectivity issues, making it suitable for application in challenging carbonate environments. Unlike earlier studies that focused on sandstone reservoirs under milder conditions [52]. Table 4 show the main differences between biopolymers and synthetic polymers in EOR application. The use of biopolymer-based EOR methods not only enhances oil recovery but also offers a more sustainable and environmentally friendly option compared to synthetic polymers. This is particularly important as the oil and gas industry increasingly looks for solutions that reduce its environmental footprint. Additionally, because biopolymers are biodegradable, they do not persist in the environment for long periods, which minimizes the potential for long-term contamination or harm to surrounding ecosystems[103,108-110].

Table 4: The Main Differences Between Biopolymers and Synthetic polymers in EOR Application

Origin	Natural, derived from microbial fermentation	Man-made, synthesized chemically
Environmental Impact	Biodegradable and environmentally friendly	Less biodegradable, may require environmental management
Thermal Stability	High – maintains viscosity at elevated temperatures	Moderate – degrades more easily at high temperatures
Salinity Tolerance	Excellent – tolerant to high salinity and divalent ions	Poor to moderate – viscosity drops in high salinity
Shear Resistance	High – retains viscosity under high shear rates	Lower – significant viscosity loss under shear
Filterability at High Temperature	Good – better performance at elevated temperatures	Moderate – filterability can decline
Viscosifying Power	High – especially at low concentrations	Moderate – may require higher concentrations
Injectivity	Good in both sandstone and carbonate cores	Generally good in sandstone, limited in carbonates
Cost	Typically more expensive due to fermentation and purification processes	Generally cheaper and more scalable
Adsorption on Rock Surface	Lower – better mobility and recovery efficiency	Higher – more prone to retention on rock surfaces
Field Application Maturity	Emerging – limited field trials (e.g., scleroglucan)	Widely used and field-proven for over 40 years
Performance in Harsh Conditions	Superior – withstands high temp/salinity without severe degradation	Limited – requires additives or special formulations

Challenges in Polymer Flooding

Despite the many advantages of polymer flooding in enhancing oil recovery, several challenges must be addressed to optimize its effectiveness. One of the primary challenges is degradation due to high temperature and high salinity. Under these harsh conditions, polymers, particularly synthetic ones like HPAM, can break down, losing their viscosity and mobility control capabilities. This degradation limits the effectiveness of the polymer in improving oil displacement and may require the use of more resistant materials like crosslinked polymers or biopolymers. Another significant challenge is shear degradation during the injection process. As the polymer is injected through the reservoir, the high shear forces can break down the polymer chains, reducing their ability to maintain high viscosity. This issue is particularly prevalent in reservoirs with high flow rates or turbulent conditions, where the polymer molecules can be stretched and damaged. To mitigate this problem, optimized injection rates and polymer formulations with better shear resistance are essential [111-113].

Adsorption and retention on rock surfaces is another challenge in polymer flooding. Polymers can adsorb onto the surface of the reservoir rock, leading to a loss of the polymer in the reservoir, which reduces the effectiveness of the flooding process. This adsorption not only diminishes the overall recovery factor but can also increase operational costs. Solutions include enhanced polymer formulations with reduced adsorption tendencies or the use of nanocomposite polymers, which have improved retention properties. Finally, there are economic and environmental concerns associated with polymer flooding. The cost of polymer injection, especially in large-scale operations, can be substantial, and in some cases, the financial viability of the method may be questioned. Additionally, environmental concerns arise from the use of synthetic polymers, as some materials may persist in the environment if not adequately handled. This has led to increased interest in biopolymer-based solutions, which are biodegradable and offer a more environmentally friendly alternative. However, the high cost of biopolymers and their availability can still present challenges [106, 114-118]. Table 5 recapitulates the main challenges in polymer flooding and the suggested solution for each one.

Table 5: The Main Challenges in Polymer Flooding and the Suggested Solution for Each One

Polymer Degradation (High Temperature & Salinity)	Polymers, especially synthetic ones like HPAM, degrade under high temperature and high salinity, losing viscosity and mobility control.	Use of more resistant materials like crosslinked polymers or biopolymers which are more stable under harsh conditions.

Shear Degradation	High shear forces during polymer injection can break down polymer chains, reducing viscosity.	Use shear-resistant polymer formulations and optimized injection rates to reduce shear degradation.
Adsorption and Retention on Rock Surfaces	Polymers can adsorb onto reservoir rock surfaces, leading to loss of polymer in the reservoir, which reduces effectiveness and increases costs.	Use of nanocomposite polymers, enhanced polymer formulations with reduced adsorption tendencies, and optimized formulations.
Polymer Filterability	Polymers can experience poor filterability, causing issues during injection, especially in high salinity environments.	Optimizing polymer concentration, using biopolymers with better filterability, or adding nanoparticles for better retention and flow.
Polymer Viscosity Loss Due to High Salinity	High salinity conditions can reduce polymer viscosity, leading to less effective displacement.	Polymer modification (e.g., increasing salt tolerance) and using biopolymers like xanthan gum which exhibit less viscosity loss under high salinity.
Polymer Injection Efficiency	Difficulty in ensuring uniform distribution of polymer throughout the reservoir, leading to uneven displacement.	Optimized injection rates, use of foams or gel systems to enhance polymer distribution, or advanced formulations to improve injectivity.
Cost of Polymers	Synthetic polymers and biopolymers can be expensive, impacting the economics of large-scale EOR projects.	Use of biopolymers, which are often more cost-effective and environmentally friendly, or optimizing polymer concentrations to minimize usage.

Recent Advancements and Future Perspectives

Recent innovations in polymer flooding have led to the development of more robust polymer systems that address the challenges of high temperature, high salinity, and adsorption. Researchers are focusing on enhancing the thermal stability, salt resistance, and adsorption reduction of polymers to ensure their effectiveness in challenging reservoir conditions. One of the most promising advancements is the development of smart polymers, which have stimuli-responsive properties. These polymers can adjust their behavior based on environmental changes such as temperature, pH, or salinity, allowing for controlled activation and improved oil displacement. Another emerging trend is the use of nanocomposite-enhanced polymers, which incorporate nanoparticles like silica or clay to improve the thermal stability, shear resistance, and polymer retention in reservoirs. These advancements show promising results both in laboratory testing and field applications, offering more efficient and adaptable solutions for enhanced oil recovery (EOR) [20, 76, 100, 101, 119-121]. Looking toward the future, research will likely continue to focus on making polymer flooding methods more cost-effective. This includes finding cheaper materials, more efficient polymer synthesis processes, and developing scalable solutions that can be applied to large-scale field operations. Additionally, environmental sustainability will be a key concern, with increasing efforts to develop biodegradable biopolymers or reduce the environmental impact of synthetic polymers. Ensuring that polymer flooding methods are not only effective but also environmentally friendly will be crucial as the industry moves toward more sustainable oil recovery practices.

Conclusion

Polymer flooding has long stood as a cornerstone in the realm of enhanced oil recovery (EOR), demonstrating its ability to significantly improve sweep efficiency and boost oil displacement. Over the years, this method has matured from basic applications to more tailored, condition-specific deployments. However, like any evolving technology, polymer flooding faces its share of challenges particularly in reservoirs marked by high temperatures, elevated salinity, and complex geological formations. Issues such as thermal and salinity-induced degradation, shear breakdown during injection, and polymer loss due to adsorption have historically limited its effectiveness in harsher environments. Recent advancements in polymer science are transforming how we approach these hurdles. Smart polymers, with their stimuli-responsive behavior, offer a new level of control, activating precisely when and where they are needed, improving efficiency while minimizing waste. Nanocomposite-enhanced polymers bring added resilience, showing remarkable improvements in thermal stability, shear resistance, and reduced adsorption rates. Meanwhile, the resurgence of interest in biopolymer-based solutions like xanthan gum and scleroglucan reflects a broader shift toward more environmentally conscious and sustainable EOR practices, especially given their biodegradability and superior performance under extreme conditions. As the oil and gas industry pivots towards more sustainable and cost-effective recovery methods, polymer flooding continues to evolve, not just as a technique, but as a flexible, intelligent system that adapts to the complexities of modern reservoirs. With ongoing research pushing the boundaries of polymer design and application, the future of EOR is poised to be smarter, greener, and more efficient.

Data availability statements

No primary research results, software or code have been included and no new data were generated or analysed as part of this review.

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