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Next-Generation Polymer Flooding for Enhanced Oil Recovery: A Critical Review of Nano-Reinforced Formulations, Hybrid Injection Strategies, and Data-Driven Performance Forecasting

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Abstract

Traditional polymer flooding for enhanced oil recovery (EOR) suffers from shear instability, poor low-permeability injectivity, and viscosity loss in high-salinity, high-temperature reservoirs. This review critically assesses emerging polymer flooding technologies—including nano-reinforced polymers, hybrid injection techniques, and machine learning-based performance predictions—from 21 publications between 2020 and 2026. Nano-reinforced polymer flooding yields recovery factors (RF) of 44–72% of original oil in place (OOIP), with silica nanoparticles reaching displacement efficiencies up to ~94% and reversing contact angles from ~72° (oil-wet) to ~115° (water-wet). Hybrid injection (polymer-enhanced foam, CO₂-aided surfactant/polymer, and CO₂-cyclic solvent injection) achieves maximum recoveries of 70–97% OOIP via combined mobility reduction and ultra-low interfacial tension (10⁻³ mN/m). Capsule polymer flooding demonstrates delayed thickening (resistance factors increasing from 2 to 25–32), making it ideal for high water cut and offshore wells. Critical performance factors include optimal nanoparticle concentration (0.25–0.5 wt%), type and shape (SiO₂ > Al₂O₃/TiO₂; fibrous > spherical), salinity/temperature tolerance, and reservoir heterogeneity. Key challenges include nanoparticle agglomeration/retention, high synthesis costs, gas channeling, and limited understanding of long-term reservoir impact and scalability. Next-generation systems will feature smart responsive polymers, sustainable nano-enhancers, real-time digital twins with adaptive control, and reservoir-specific customization protocols.

Keywords: Polymer flooding; Enhanced oil recovery (EOR); Wettability alteration; Mobility control; Hybrid injection.

1. Introduction

The world is hungry for energy and the oil and gas industry faces a huge challenge to recover as much as possible of the hydrocarbons available from conventional and nonconventional reservoirs. Conventional primary and secondary production processes recover less than half the original oil, and require enhanced oil recovery (EOR) strategies to boost sweep efficiency and prolong production lifetimes [1]. From the various EOR techniques explored for the past few decades, chemical flooding techniques, especially polymer flooding, have proven to be efficient and economical approaches to improve the macroscopic displacement efficiency across various reservoir conditions [2]. Polymer flooding works by elevating the viscosity of the water phase, thus decreasing the mobility ratio of the displacing and displaced phases. This results in enhanced vertical and horizontal sweep efficiency, especially in reservoirs with heterogeneities, where viscous fingering and channelling are the key loss mechanisms [3]. The viscoelastic behavior of some polymer systems provides other advantages, such as microscale pore-scale displacement effects to improve oil detachment [4]. These effects have been observed in both sandstone and carbonate reservoirs, but are dependent on reservoir temperature, salinity and permeability.[5]

Conventional polymer flooding is, however, severely hindered under extreme reservoir conditions. Elevated temperature and salinity (HTHS) accelerate polymer degradation and loss of viscosity, along with polymer adsorption onto reservoir rocks, which reduces performance [6]. Polyacrylamide (PAM)-containing solutions are the most commonly used type of polymer; however, their effectiveness in HTHS environments necessitates ongoing development in molecular design, including the incorporation of nanomaterials, supramolecular structures and heat-resistant functional groups [7]. Therefore, the mechanisms responsible for displacing oil during polymer flooding in complex oil reservoirs need to be understood to design efficient polymer injection and regain more oil [8]. In an effort to bypass the shortcomings of single-phase EOR methods, in recent years, mixed injection schemes have attracted presumed interest from authors and field staff. For example, low-salinity water flooding combined with polymer flooding has been shown to have a positive impact on heavy oil recovery by simultaneously changing the wettability and enhancing sweep efficiency [9]. Likewise, the improvement of the rheological properties of PAM solutions has been essential to maintain the effectiveness of polymer flooding over long injection times, especially in deep reservoirs with long flow paths between injection and production wells [10]. Such combined and engineered systems are part of a more general trend towards "customized" EOR strategies.

The integration of nanotechnology into polymer flooding solutions is a breakthrough in next-generation EOR. Polymeric nanofluids, where nanoparticles are embedded in the polymer matrix, have been shown to be more thermally stable, rheologically improved and more effective in displacing oil than traditional polymer formulations [11]. But the application of these innovative materials in reservoir conditions also presents challenges, such as nanoparticle aggregation, compatibility with reservoir fluids, and retention under extreme environmental conditions [12]. To overcome these challenges, it is essential to understand the rock-polymer-fluid interactions, and how scale formation and asphaltene deposition may impact injectivity [13, 14]. In terms of modelling and simulation, it is difficult to describe the complex rheology and transport of the polymer solution in the pore space. When simulating polymer flooding, reservoir simulation models must consider the effects of shear-thinning, viscoelasticity,

inaccessible pore volume and polymer adsorption, and these effects lead to considerable uncertainty in performance forecasts [15]. Recent work on surfactant-polymer flooding has aimed to address these issues by incorporating these effects in commercial and in-house reservoir simulators, but there still remains a need to better represent nano-reinforced polymers and hybrid injection techniques in field-scale simulations [16]. The contributions of injection fluids' elasticity to microscopic displacement efficiency have also been identified as a critical factor that needs more detailed experimental and numerical study [17].

Experience from field applications of polymer flooding has provided insight for a variety of reservoir types. Lessons from large-scale field operations have highlighted the achievements and operational challenges of polymer injection, such as the loss of injectivity, near-wellbore plugging and polymer breakthrough [18]. In carbonate reservoirs, where extreme wettability and complex pore structures pose additional hurdles, polymer-based EOR processes need to be tailored to the reservoir conditions for satisfactory performance in terms of high temperature and salinity [19]. Quantitative approaches to assess the individual roles of chemical components in surfactant-polymer flooding have also improved the practical understanding of the mechanisms of oil recovery in conglomerate reservoirs [20]. The surfactants, along with polymers, have been widely used to investigate capillary-dominated simultaneous alleviation and viscosity-dominated displacement inefficiencies. Surfactants lower the oil-water IFT, enabling trapped residual oil to mobilize that polymer flooding cannot reach [21].

The combined run of low-salinity water (LWS), nanoparticles, and surfactants flooding in integrated EOR formulations is an emerging area of chemical EOR research that is rapidly gaining traction in both research and commercial applications [22]. Simultaneously, reviews that combine laboratory research and field experience have begun to define the limits of polymer flooding performance in the face of (combined high-salinity and high-temperature) stresses, and provide key insights for field application [23]. The development of new block polymer systems and instant-soluble temperature- and salt-tolerant polyacrylamide products has overcome the challenges of using conventional polymer products in the field. These products, tested in laboratory and pilot-scale evaluations in large oilfields, exhibit faster dissolution, superior injectability, and high-temperature stability [24, 25]. And, building on these chemical innovations, hybrid polymer-alternating carbon dioxide (CO₂) gas injection has emerged as an approach that combines the benefits of miscibility enhancement and mobility control to enhance recovery efficiency, with environmental advantages from CO₂ recycling [26].

On the microscale, viscous fingering continues to plague heavy-oil polymer flooding due to high viscosity ratios between the oil and injected fluid [27]. Biosurfactants represent an environmentally benign approach to minimize interfacial tension in EOR formulations and potential for remediation and recovery applications as green alternatives to petrochemical surfactants [28, 29]. In addition, smart gel formulations for CO₂ mobility control in heterogeneous reservoirs are a new generation of stimuli-responsive materials that can improve conformance under reservoir conditions [30]. Figure 1 illustrates a co-occurrence network that provides a visual representation of the research landscape and themes in polymer flooding for enhanced oil recovery (EOR). This network likely highlights the relationship between key terms like "polymer flooding", "enhanced oil recovery", "wettability alteration", "mobility control", "nanoparticles", "surfactant-polymer flooding" and "hybrid injection", and how new terms (e.g., nano-reinforced formulations, CO₂-assisted methods, and machine learning) are on the rise while

others are more established. This approach aids in recognizing key research fronts, gaps, and the shift from traditional polymer injection to multi-agent next-generation systems.

Although progress has been made in polymer flooding for enhanced oil recovery (EOR), there is a major gap in the integration and comparative assessment of next-generation technologies - particularly nano-reinforced formulations, hybrid injection of polymers, and big data forecasting - under a holistic framework to address field-scale implementation, long-term fate, and economic efficiency. Although individual research shows enhanced recovery factors through nanomaterials (e.g., silica nanoparticles with ~94% displacement efficiency) or hybrid techniques (e.g., CO₂-assisted polymer flooding with up to 97% OOIP), there remains a need for a comprehensive view of their combined mechanisms, performance drivers, key controlling factors (e.g., nanoparticle type, concentration, morphology, salinity/temperature sensitivity), and comparative effectiveness relative to conventional polymers. Moreover, there remains a lack of understanding about nanoparticle agglomeration, retention, gas breakthrough in heterogeneous formations, and the lack of adaptive predictive models to guide real-time process optimization. This review seeks to critically integrate the insights of 21 peer-reviewed papers (2020-2026) to: (1) systematically evaluate the mechanisms and recovery factors of nano-reinforced polymers, polymers with capsules, and hybrid injection methods; (2) describe key factors (polymer concentration, nanoparticle type and size, reservoir heterogeneity, and well placement) and their influence on sweep efficiency and oil recovery; (3) assess the feasibility of machine learning models (PSO-ANN, ARIMA) for predicting performance with lower computational costs; and (4) highlight technical challenges, knowledge gaps, and strategies for optimizing performance for field-scale applications, with a resulting roadmap towards smart, responsive and cost-effective next-generation polymer flooding systems.

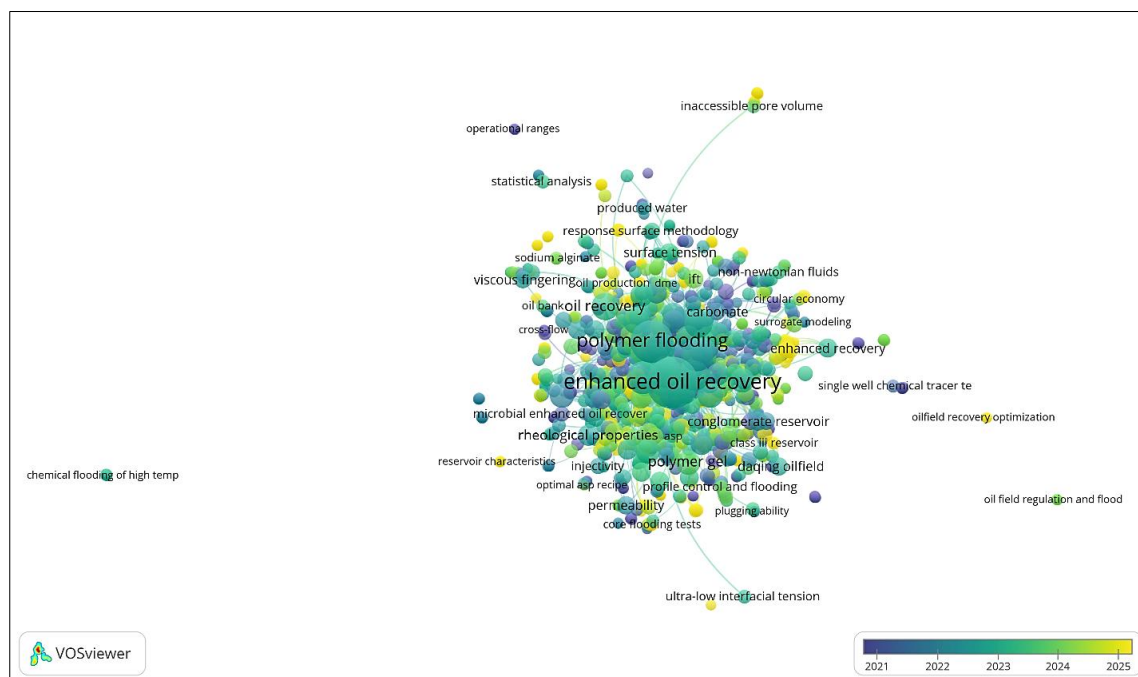


Figure 1. Visualizing Research Trends Polymer Flooding for Enhanced Oil Recovery: A Co-occurrence Network Analysis.

2. Review Method

This review's methodology was systematically devised to assess emerging technologies for polymer EOR, with a survey range of 2020-2026. The rehearsal study was conducted, reviewing 21 peer-reviewed articles obtained from online databases on nano-reinforced polymer flooding, hybrid injection processes, and data analytics-driven performance prediction. Studies considered covered experimental, computational, and field-scale procedures with quantitative recovery factors, mechanisms of wettability modification or mobility control, and advanced additives (nanoparticles, capsule polymers, CO₂-assisted polymer flooding) .

Criteria excluded those that do not present comparative performance results, or concern conventional polymer flooding without modification. The final review was organised into three sub-sections - innovative polymer formulations and additives, hybrid/assisted injection, and simulation, modelling, pore-scale mechanisms and field studies - to compare and contrast insights on performance drivers and highlight research gaps.

2.1 .Advanced Polymer Formulations & Additives

The guar gum solution (in terms of rheology in the presence of silica nanoparticles at various warming conditions) was investigated, observing that the viscosity rises when the concentration of silica nanoparticles increases [31]. Imbibition tests were performed on sandstone cores saturated with waxy crude oil to examine the wettability modification in the presence of these materials using a variety of test solutions: Case 1 was a 2000 ppm brine and 4000 ppm guar gum solution, Case 2 was 0.2 wt% silica nanoparticles in distilled water, and Case 3 was a 4000 ppm guar gum and 0.2 wt% silica nanoparticles solution. A recovery factor (RF) for case 4 (0.2 wt% silica nanoparticles concentration and 4000 ppm guar gum solution) is 44.28% of OIP, which was higher than that of other solutions. Furthermore, two cases (first was a 2000 ppm brine solution, 0.025 wt% silica nanoparticles in distilled water, and the second was a 2000 ppm guar gum and 0.025 wt% silica nanoparticles mixture) were run to recognize the wettability by estimating the contact angles between crude oil and sandstone; The second case alters the contact angle from an oil-wet ($\sim 72^\circ$) to a water-wet state ($\sim 115^\circ$). Figure 2 illustrates the recovery factor (RF) of the original oil in place for all three cases.

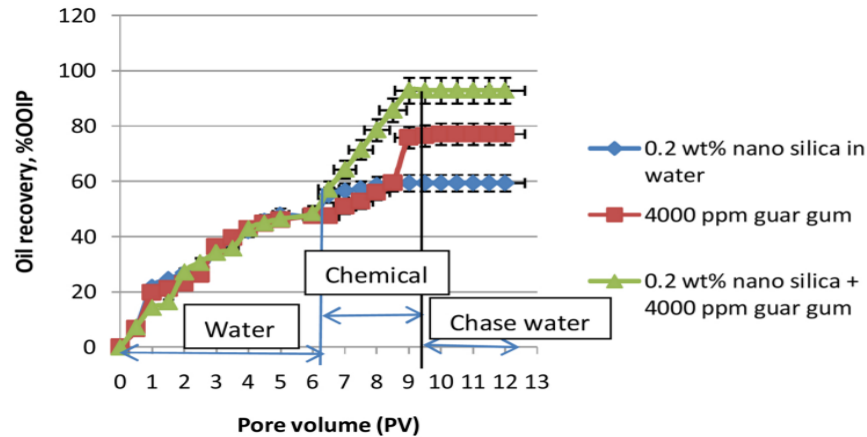


Figure 2. Comparison of oil recovery factors for the cases under study by [31].

Polymer injection, surfactant, and alkali as a microemulsion were deliberated by Dantas et al. (2021) [32]. They chose a water-rich microemulsion system (1.5% effective substance, 0.05% oil, and 98.39% aqueous phase with additives including 1.5% Na_2CO_3 and 0.06% polymer). The systems were evaluated based on the droplet size, surface tension, pH, and viscosity. The mechanism of the interaction between the microemulsion and the reservoir rock was studied by measuring the wettability of the reservoir rock (Botucatu sandstone) before and after microemulsion flooding. The micro-emulsions virtually influenced the surface tension and dramatically altered the sandstone from oil-wet to water-wet. The core flooding experiment with an oil recovery factor of 97% assures the effectiveness of micro-emulsions of alkali and polymer for enhanced oil recovery applications.

By Abchiche et al. (2022) [33], the terpolymer (PAM-ATBS-NVP) (in terms of rheological characteristics) was utilized for polymer flooding as an EOR agent under reservoir conditions, focusing on many parameters, in addition to nanoparticle (NPs) types and intensity. It was found that the polymer viscosity decreased with rising shear rate (shear thinning) and increased with rising polymer concentration. The polymer was also relatively stable at high temperatures; however, although it was designed to be stable under harsh temperature and salinity/hardness conditions, the viscosity decreased with increasing salinity/hardness. The addition of (NPs) showed that three types (alumina, titanium, and silica NPs) did not change viscosity for the first two kinds (alumina and titanium) but decreased for silica NP-polymer mixture with increasing concentration of the silica NP, due to the polymer molecules' adsorption onto the NP surface. This decrease was slight and then stopped at a shear rate of 616 s^{-1} (Figure 3), and the solutions showed a decrease in viscosity with increasing brine concentration (Figure 4).

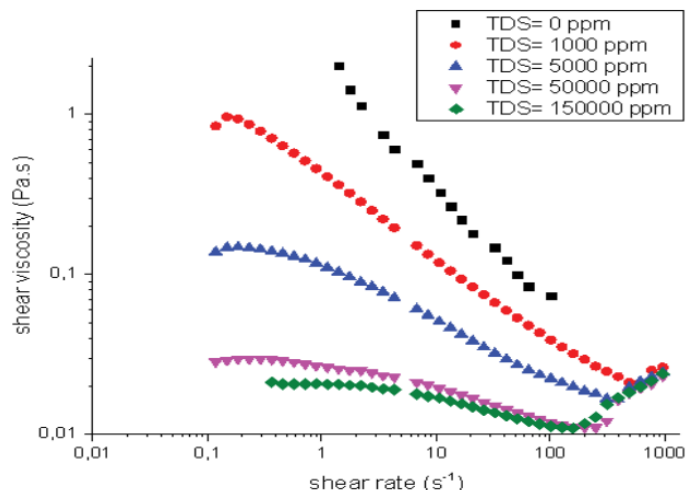


Figure 3. Effect of salinity on polymer viscosity at 2,000 ppm [33].

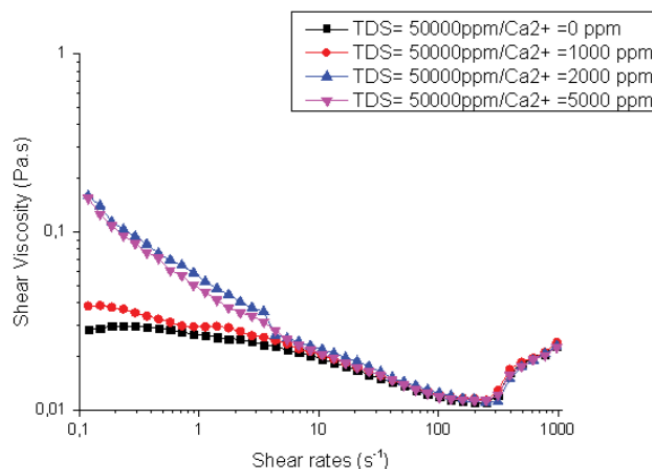


Figure 4. Effect of hardness on the viscosity of 2,000 ppm polymer in the presence of 50,000 ppm of NaCl [33].

Li et al. (2022) [34] developed a flooding system regarding graphite oxide nanoparticle-reinforced polymer (GORP). This flooding suit, containing a lower concentration of graphite oxide nanoparticles (0.15%), has better viscosity-increasing, shear, and aging resistance than the classical polymer flooding apparatus. Owing to the consolidating GON impact on the 3D polymer framework, the GORP flooding procedure exhibits better residue impedance than the Capsule Polymer (CP) in the cores (in terms of mobility control performance) with various permeabilities. The results of the nuclear magnetic resonance (NMR) displacement test indicate that the GORP procedure is a better EOR effect with a cumulative recovery factor (RF) of 72.87%, which is 5.04% higher than CP flooding. Hence, the GORP flooding system could potentially be a long-term effective method for controlling the water cut problem in oil wells.

Hou et al. (2024) [35] put forward Capsule Polymer Flooding (CPF) for EOR. The flow and oil displacement characteristics of this procedure were investigated under the attention of multi-scale flow experiments and simulation techniques. The most interesting findings of the study are that the system has several advantages, including ease of injection, anti-shear, controllable release, low retention, and strong migration capability over long distances, which enables viscosity increase in deep reservoirs. With every rise in the capsule polymer viscosity, suppression of viscous fingering will be stronger, the polymer front will be more efficient, and the swept range will be longer. The capsule polymer is characterized by good temperature sensitivity, and its viscosity increases at higher temperatures, but it is insensitive to salinity. The technique applies in reservoirs with higher water cut values where polymer flooding can fail, to offshore sites for polymer flooding, where wells are widely spaced, and to reservoirs with medium or low permeabilities, where conventional polymers can't be injected. Capsule polymer flooding (CPF) needs to be tailored to the reservoir, with capsule size and release time adjusted to reservoir conditions to obtain optimum displacement efficiency. CP is characterized by delayed thickening with a low viscosity near the wellbore but high in the target area (as shown in Figure 5). The un-thickened capsule polymer is characterized by a resistance factor of 2 at most, while it is 25 to 32 for the thickened capsule polymer solution, as shown in Figure 6.

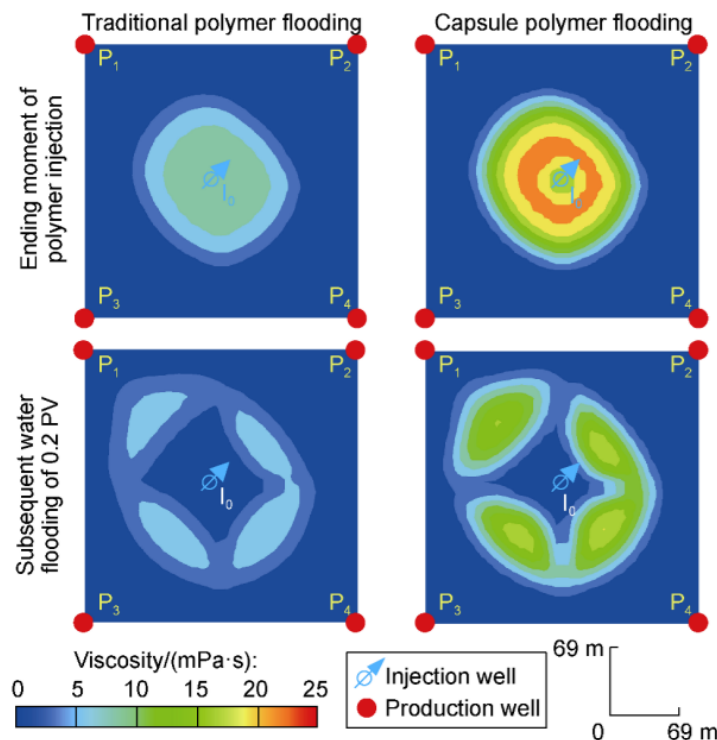


Figure 5. Comparison of the viscosity field between traditional polymer flooding and capsule polymer flooding [35].

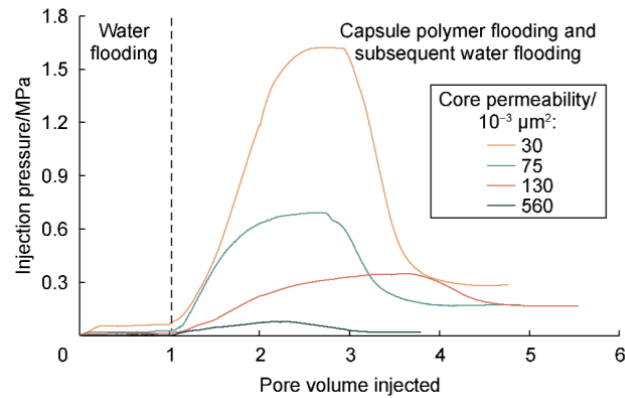


Figure 6. Change curve of injection pressure of capsule polymer after fully thickening [35].

Pandey et al. (2024) [36] investigated the prospect of carbon nanotube-based nanofluids (CNBN) to upgrade oil recovery efficiency and alter interfacial tension. High-purity multi-walled carbon nanotubes (purity exceeding 95%) from Plasma Chem GmbH, which underwent further modification and testing to evaluate their impact. Different concentrations of these modified multi-walled carbon nanotube-based fluids were prepared using a surface tensiometer. Adsorption experiments were performed to minimize surfactant loss, and contact angle measurements were carried out using a goniometer, which allowed modification of the wetting characteristics of the rock substrate. Finally, a displacement test was conducted using two pore volumes of the nanofluid to determine the optimal modified multi-Wall carbon nanotubes (mMWCNTs), SDS, and 1000 ppm of polymer for RF. The findings showed that the mMWCNTs lowered the surface and IFT by 59% and 56%, respectively, at the optimal concentration. Moreover, the nanotubes reduced the surfactant loss by 49.3%.

Microfluidic experiments on the petroleum displacement in a porous medium pattern using a xanthan gum solution, which is one of the biodegradable polymers containing different types and sizes of NPs (SiO_2 , TiO_2 , Fe_3O_4 , Al_2O_3 , and Al_2O_3 nanofibers or ANF) with up to 1 wt% concentration have been reported by Minakov et al. (2016) [37], who conducted their experiments on epoxy resin microfluidic chips. The research investigated rheological characteristics of more than two dozen NP solutions and their impact on oil displacement efficiency (DE), revealing that DE was enhanced by more than 10% compared with solutions of the same polymer, and by more than 30% with some cases, with water flooding. High efficiency was observed at 0.25-0.5 wt% NPs, coinciding with the highest effective viscosity. An increase in DE was due to larger NP sizes. NP shapes were important: ANF produced a significant increase in DE compared to spheres. The type of NP also significantly affected the DE: SiO_2

was the most effective, with DE up to ~94%, followed by Al_2O_3 and TiO_2 , while Fe_3O_4 was less effective due to the poor NPs stability and flocculation.

In their 2026 research, Chen et al. [38] used extended ethylene oxide (EO)/propylene oxide (PO) carboxylate (EPEC) as the main surfactant and alkylbenzene sulfonate (ABS) as the co-surfactant, with no adjuvants (alcohols) present in the formulation. Using phase behavior studies, the optimal EPEC structure, surfactant mixture ratio, and the salt added were selected to achieve the optimal IFMF formulation. They then used instrumental analysis and physical experiments to assess the overall performance.

They found that the optimum surfactant blend was the identified EPEC (C24 Guerbet, 10-EO/25-PO), and ABS produced an extremely low IFT of 10^{-3} mN/m and desirable phase attitude. Further petroleum sulphonate supplement decreased the optimum salinity (1.1 wt% to 0.4 wt%) and equilibrium time. At low concentrations (0.3-1.2 wt%), the optimum IFMF salinity formulation was found to be lower with higher temperatures (42-50°C) and lower surfactant concentrations. Displacement tests in the laboratory were extremely successful, with an incremental oil recovery of 45% in sandstone formation, and surfactant detention (0.09-0.14 mg/g rock) can be negligible.

Yang et al. (2026) [39] studied the potential of nanofluid (iNanoW) and polymer binary flooding to maximize oil recovery efficiency by enhancing rheological properties, injectability, interfacial ability, sweep volume, and recovery factor of the polymer solution in high and medium-permeability reservoirs, where conventional methods still require further development. Laboratory findings indicate that the injectability of the polymer solution can be highly enhanced, and the size of polymer aggregates can be minimized (shown by aggregate size and rheological performance tests).

The power-law model analysis in this study shows that polymer solution flowability in the presence of iNanoW can be enhanced, reflected in reduced shear-thinning, lower viscosity, and improved flowability. In addition, iNanoW modifies the polymer molecules, reducing surface tension and improving wettability, thus enhancing the oil-water separation efficiency. Core flooding experiments indicate that the addition of iNanoW greatly increases sweep volume, especially in the medium- and small-pore spaces, with oil recovery efficiencies of 57.97% and 61.54%, respectively. Table 1 illustrates previous studies of advanced polymer formulations & additives.

2.2. Hybrid/Assisted Injection Processes

Rezaeiakmal and Parsaei (2021) [40] studied foam flow through a heterogeneous model consisting of two layers and tested a surfactant-polymer combination as a stabilizer. The authors contrasted conventional foam (with a surfactant as a stabilizer) and polymer-enhanced foam (PEF) (a

surfactant and PVA polymer as a stabilizer) in the models with various permeability ratios (PR) (2:1, 4:1, and 8:1), in which the model is packed with glass beads of 150-600 μm diameter.

The ternary mode of the two procedures (conventional foam and PEF flooding) was used to displace residual oil. Although the injection of foam and PEF was found to be more effective than gas injection, the PEF front moved more like a piston, resulting in 15-20% higher ultimate oil recovery than conventional foam flooding in all heterogeneous packed models. In a higher-contrast heterogeneous medium, where foam's sweeping potential is reduced, PEF still outperforms conventional foam via cross-flow due to its stability.

Without cross-flow, foam mostly passes through the high-permeability zones, resulting in an earlier breakthrough of foam from the high-permeability zone, as illustrated in Figure 7. Also, as the heterogeneity of the porous medium increases, the ability of PEF (and foam) to sweep the medium for oil recovery becomes limited, as shown in Figure 8.

Table 1. A summary of studies related to advanced polymer formulations & additives.

Authors and year	Polymer/Agent Type	Additives	Main Mechanism	Key Outcome / Recovery Factor
Bera et al. (2020) [31]	Guar gum	Silica nanoparticles (0.2 wt%)	Wettability alteration (to water-wet), viscosity increase	Max RF: 44.28% OOIP (nano-silica + polymer). Contact angle changed from $\sim 72^\circ$ to $\sim 115^\circ$.
Dantas et al. (2021) [32]	Microemulsion (polymer-alkaline)	Na_2CO_3 (1.5%)	Surface tension reduction, wettability change to water-wet	RF up to 97% in coreflooding.
Abchiche et al. (2022) [33]	Terpolymer (PAM-ATBS-NVP)	Silica, alumina, TiO_2 nanoparticles	Shear thinning, thermal stability	Viscosity decreased with higher salinity/hardness. Silica NPs decreased viscosity (adsorption).
Li et al. (2022) [34]	Graphite oxide reinforced polymer (GORP)	Graphite oxide nanoparticles (0.15%)	Reinforced 3D network, mobility control	Total RF: 72.87% (5.04% higher than conventional polymer).
Hou et al. (2024) [35]	Capsule polymer	None (delayed thickening)	Easy injection, shear resistance, deep reservoir viscosity increase	Resistance factor: 2 (un-thickened) $\rightarrow$ 25–32 (fully thickened). Suitable for reservoirs with higher water cut rates.
Pandey et al. (2024) [36]	Surfactant-polymer	Modified multi-wall carbon nanotubes (mMWCNT)	Reduced IFT (56%), minimized surfactant loss (49.3%)	Significant surface tension reduction ($\sim 59\%$). Core flooding is performed at optimal concentration.

Minakov et al. (2026) [37]	Xanthan gum (biodegradable)	SiO ₂ , TiO ₂ , Fe ₃ O ₄ , Al ₂ O ₃ nanoparticles (0.25–0.5 wt%)	Increased effective viscosity, morphology effect	Max DE: ~94% (SiO ₂ NPs). Higher efficiency with larger NPs & ANF fibers.
Chen et al. (2026) [38]	Extended EO/PO carboxylate (EPEC) + ABS	Petroleum sulfonate	Ultralow IFT (10 ⁻³ mN/m), phase behavior	Incremental RF: 45% in Berea sandstone reservoir with low surfactant preservation (0.09–0.14 mg/g).
Yang et al. (2026) [39]	iNanoW–polymer binary flooding	iNanoW (nanofluid)	Improved injectability, weakened shear-thinning, wettability	RF in medium pores: 57.97%, small pores: 61.54% . Reduced polymer aggregate size.

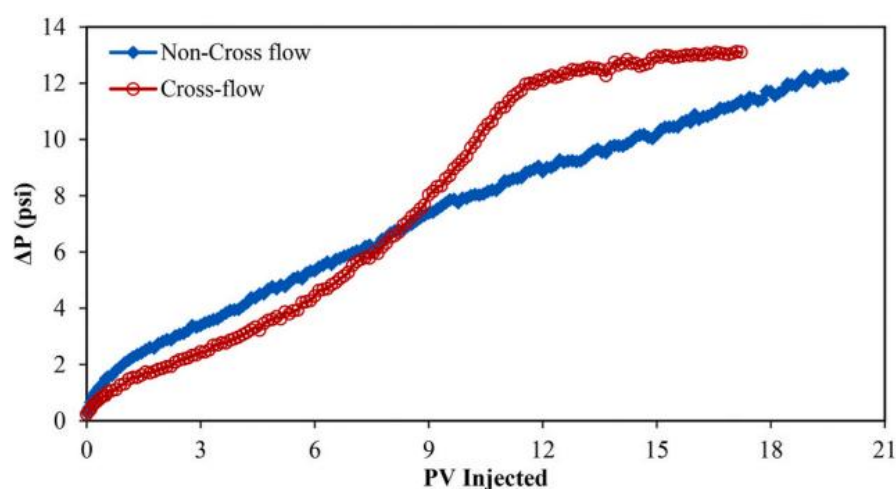


Figure 7. Effect of cress-flow on pressure profile in the porous medium with permeability ratio = 2 [40].

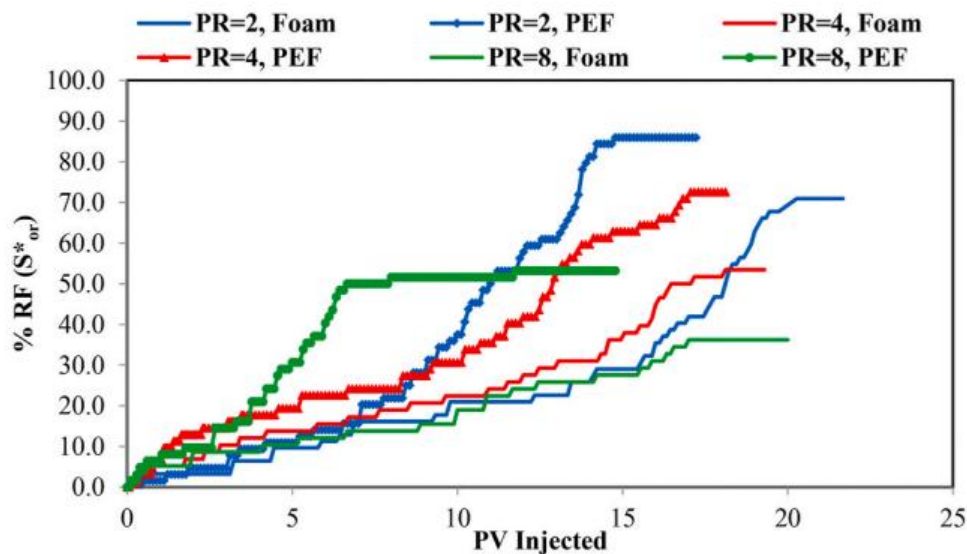


Figure 8. Effect of permeability ratio on cumulative tertiary oil production profile during PEF injection [40]

Figure 9 shows the RF for some studies in Table 1.

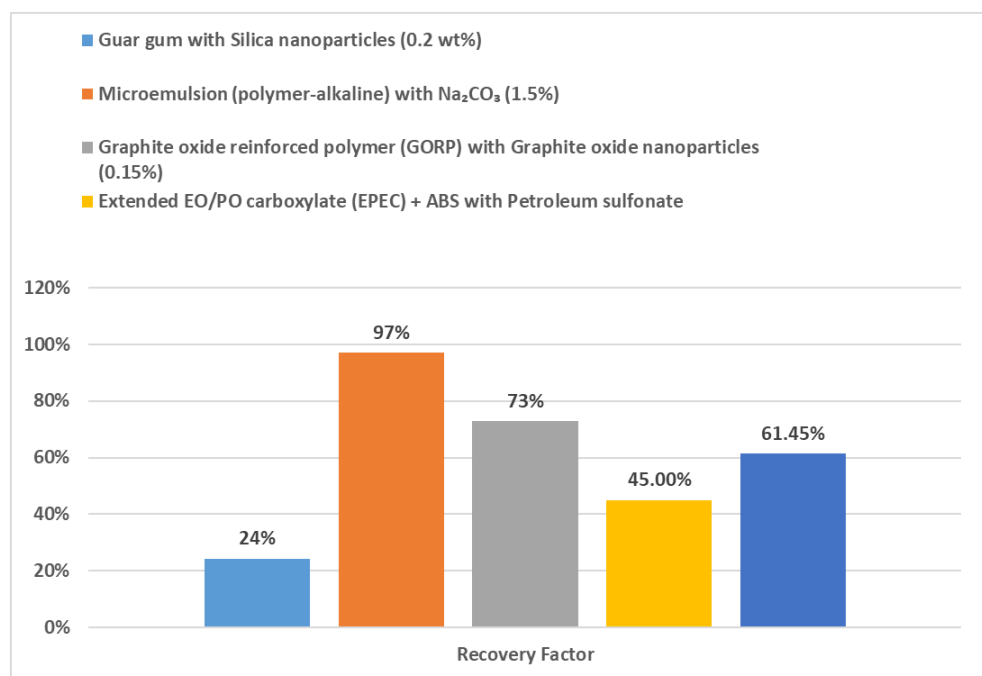


Figure 9. Comparison between RF% for some studies with multiple additives in Table 1.

Zhao et al. (2022) [41] conducted a substantial polymer-flooding followed by a fire-flooding simulation experiment under laboratory conditions to enhance residual oil extraction. They examined the stabilization of the front and the characteristics of in situ combustion (ISC), and the oil quality prior to fire flooding and after the process. The findings indicated that the trend and temperature variation range are consistent with the front of burning in the polymer and fire flooding, as well as those of the classical fire injection experiment. The burning front at any specific depth shifts gradually, ensuring that residual oil can be fired after polymer and fire flooding. The apparent H/C atomic ratio of the combustion front is calculated to be 1.33 from the tail gas composition. The combustion front provides a high-temperature oxidation reaction with 72.1% displacement efficiency for the burned oil layers. Comparing the oil state prior to and next to flooding with fire, the n-alkanes' carbon number in the produced oil increases after the injection process; thus, improving crude oil quality.

Cheng et al. (2023) [42] studied the effects of CO_2 on improving Alaska North Slope (ANS) heavy oil recovery in solvent-assisted polymer flooding. They performed seven experiments on well cores under reservoir conditions to test the production performance of ANS viscous oil using EOR methods with five various solvents: a solvent of light hydrocarbon (LHS), followed by low salinity water (LSW) flooding, then LHS with enriched CO_2 , alternating LSW, LHS-alternating low salinity polymer

(LSP) flooding, CO₂-enriched LHS-alternating-LSP flooding, and LHS with enriched CO₂-LSW-LSP flooding. They investigated the leverage of CO₂ on the effectiveness of these solvent-assisted EOR methods. The findings demonstrated that the five proposed EOR methods exhibit excellent production performance with recovery factors ranging from 79.73 to 92.23%. The primary mechanisms were in two paths: one that involved oil swelling and viscosity reduction impacts that amended microscopic displacement efficiency during the solvent injection stage, and the second improved macroscopic sweep efficiency during the LSW/LSP injection process by better mobility control. However, for the recovery factor in the first stage, solvent containing CO₂ did not show optimum performance.

Lin et al. (2025) [43] developed a new hybrid EOR system, alternating CO₂ with (Cyclic Solvent Injection) (CO₂-CSI), then with injection of polymer. Five experimental groups were carried out to investigate the EHOR efficiency and other key operational parameters using a one-dimensional model of a sand-pack. The highest extraction of 70.72% was observed when CO₂-CSI was shifted with polymer injection (with a concentration of 1000 ppm). This improvement is due to the combined effects of two processes: the CO₂-CSI stage mobilizes and recovers heavy oil, and enhances the remaining heavy oil mobility; the polymer flooding in alternating procedure promotes the creation of an oil bank for CO₂ with Cyclic Solvent Injection, and thus improves the next cycles. They also present a new mechanism, called (dual-mobility-ratio-control), as an effective way to adjust the mobility ratios in both superseding and replacing phases. The economic assessment showed that this procedure has superior economic performance, with more than a 70% reduction in material costs. The total pressure increase ratio in Group 2 is significantly lower than the increase ratio for the polymer flooding stage 1 in Group 1, as shown in Figure 10. The pressure increase ratio during the polymer flooding stage 1 is greater than the pressure increase ratios of other polymer flooding stages, as shown in Figure 11.

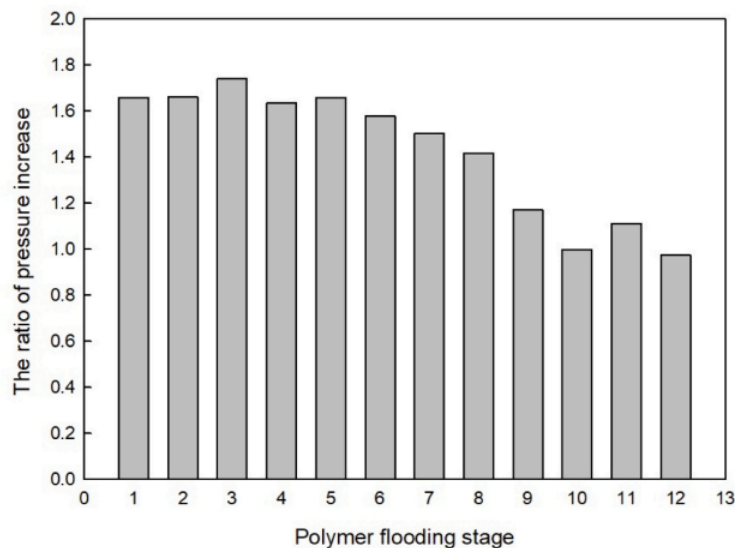


Figure 10. The pressure increase ratio during each polymer flooding stage [43].

A CO₂-assisted surfactant-polymer (ASP) flooding strategy was developed, and the ASP system was screened by estimating the oil-water IFT and viscous properties. Multiple experiments were performed on core samples to enhance RF with bottom water. On this basis, oil displacement agent screening, oil output, well placement, and injection pressure rate were optimized.

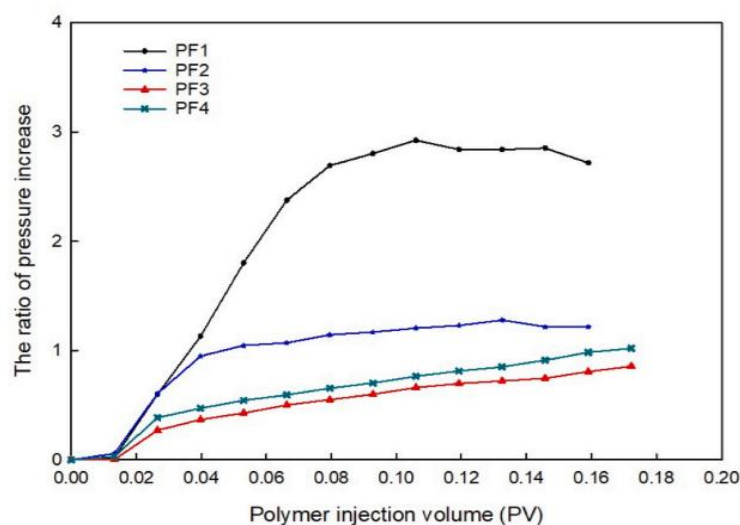


Figure 11. The pressure increase ratio between the assistance port and CSI port during the polymer flooding stage [43].

Through a detailed test of the produced liquid, the oil recovery mechanism of CO₂-ASP flooding was investigated with a low oil-water IFT of 3.79×10^{-3} mN/m for surfactant BS, and salinity minimized the viscosity of the SP solution. It was observed that performing chemical flooding before the CO₂ injection method (Huff and puff) can yield a higher RF. Chemical flooding using CO₂ with surfactant (anionic-nonionic) and a polymer system, which is called salt-resistant, was found to have the highest

extraction among the four chemical material agents. Moreover, the position of the oil production well, in terms of proximity to the bottom water layer, correlated with recovery. The maximum depth between the oil horizon and the underlying water horizon during the experiment was 2.5 cm, yielding the highest RF of 70.9% and bottom water breakthrough rate of 2.4% of [44]. Table 2 and Figure 12 present a summary of studies related to hybrid/assisted injection processes.

2.3. Simulation, Modeling, Pore-Scale Mechanisms & Field Analysis

A restricted CEOR volume simulator was developed in MATLAB to predict RF from polymer flooding with low-salinity water (LSWPF) using modelling of the suggested geostatistical approach for porous media. A novel crossbred smart proxy pattern, representing a particle swarm optimization artificial neural network (PSO-ANN) with extraction rate correlation, for LSWPF performance from the weights and biases, was sophisticated. The simulator was benchmarked against the geochemical simulator (PHREEQC) and a second LSWPF coreflood experiment, resulting in perfect history matching. The best architecture for the PSO-ANN RF model has 7 inputs, 3 hidden neurons, and 1 output. It's also important to note that storage capacity has a crucial role when creating realizations [45]. The extraction rate for all methods (LSWPF, HSWPF, LSWF, and normal waterflood) is 39%, 31%, 24%, and 11%, respectively, after production period of 50 days. (Figure 13).

Table 2. A summary of studies related to hybrid/assisted injection processes.

Authors and year	Polymer/Agent Type	Additives	Main Mechanism	Key Outcome / Recovery Factor
Rezaeiakmal & Parsaei (2021) [40]	Polymer enhanced foam (PEF) – PVA polymer	Surfactant	Cross-flow mechanism, foam stabilization	PEF oil recovery 15–20% more than conventional foam. Higher stability at high permeability contrast (8:1).
Zhao et al. (2022) [41]	Fire flooding after polymer	None (in situ combustion)	High-temperature oxidation, combustion front stability	Displacement efficiency: 72.1% . H/C atomic ratio = 1.33 (oxidation confirmed).
Cheng et al. (2023) [42]	Solvent-assisted LSP (low salinity polymer)	CO ₂ , light hydrocarbon solvent	Oil swelling, viscosity reduction, mobility control	RF range: 79.73% to 92.23%. CO ₂ enrichment did not improve 1st solvent flooding.
Lin et al. (2025) [43]	CO ₂ -CSI + polymer flooding alternation	CO ₂	Dual-mobility-ratio control, oil bank formation	Max RF: 70.72% (1000 ppm polymer). Material costs reduced by >70%.
He et al. (2025) [44]	CO ₂ -assisted surfactant/polymer	CO ₂ , BS surfactant (IFT 3.79×10 ⁻³ mN/m)	CO ₂ huff & puff after chemical flooding	Highest RF: 70.9% (2.5 cm well distance from bottom water).

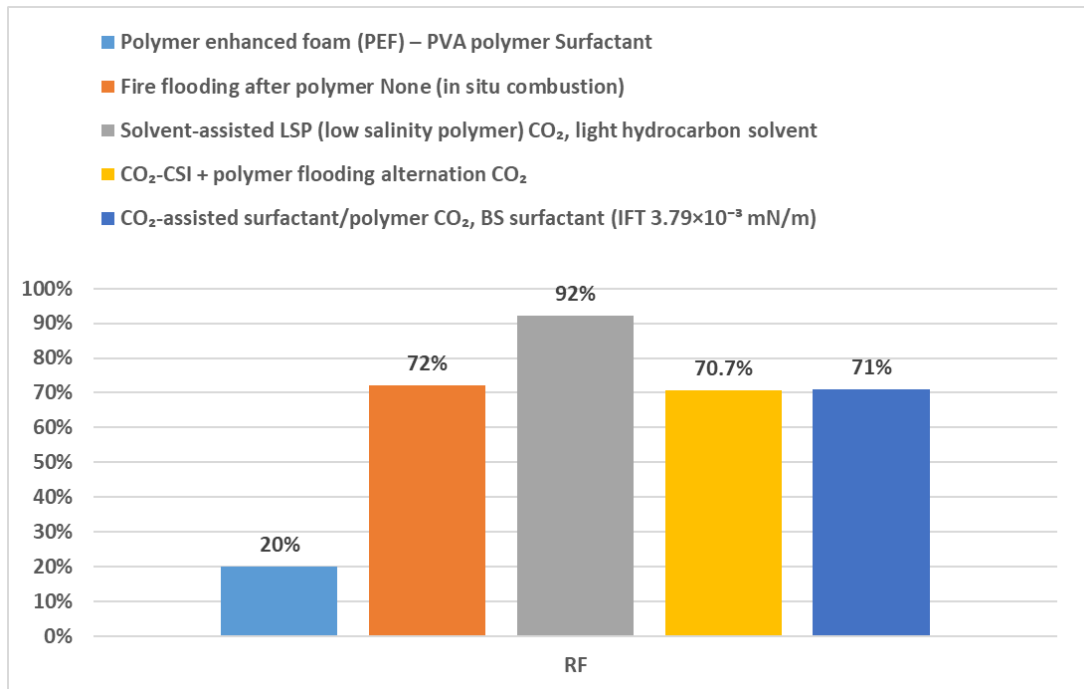


Figure 12. Maximum oil recovery with and without additives hybrid/assisted injection and different additives.

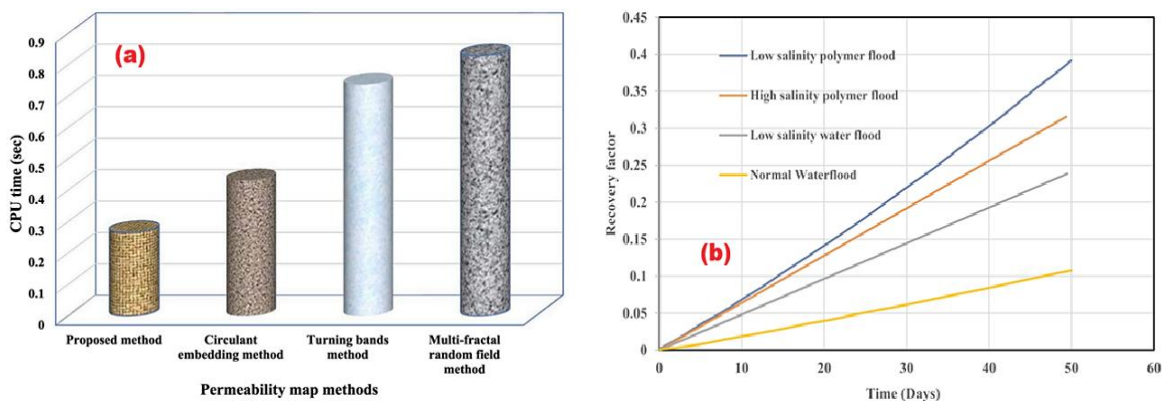


Figure 13. a- CPU run-times for permeability map methods, b- Recovery factors for LSWPF, HSWPF, LSWF and normal water flood [45].

The pore structure impact on EOR during SP injection was investigated (on pore, core, and field scales) with natural cores of three different pore structures. In-situ nuclear magnetic resonance (NMR) core flooding was conducted to expose properties of the remaining oil during the injection of both water and SP. Next, displacement performances and effects of water and SP flooding in these three core types were assessed through full-size core flooding experiments. The findings show that as the pore structure complexity increases, the performance of water flooding decreases, but the incremental RF from SP flooding increases and improves the oil production from 1-3 μm pores in unimodal and bimodal core samples, whereas in multimodal core samples, it mostly produces oil from medium and large pores of

radius larger than 3 μm . In block B, water cut and liquid output are significantly reduced, and there is no apparent breakthrough during polymer flooding in the sandstone reservoir. The channelling can occur in the multimodal conglomerate reservoir which is more susceptible to it, and small well spacing exacerbates this channelling, as shown in Figures 13 and 14.

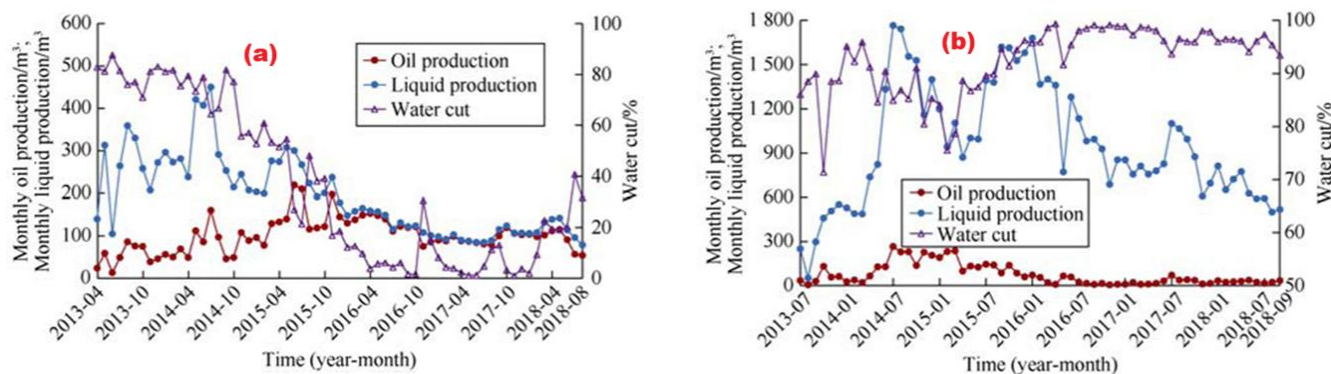


Figure 14. a- Production performance of a typical well during the SP flooding in Block B, b-Production performance of the typical well in the adjacent polymer flooding pilot [46].

Lu et al. (2021) [47] studied the EOR polymer flooding approach by contrasting the displacement performance of the conventional polymer, glycerol, "sheet-net" structured polymer, and heterogeneous weak gel (HG) with the same viscosity and intensity, which proves a correlation between displacement performance and viscous properties, providing a way to enhance the polymer flooding effect. They discovered that the polymer agent viscosity is not linearly related to the effect of polymer flooding. In contrast, the "sheet-net" structure polymer greatly increases viscosity; the pore-throat structure of reservoir rocks, low injectability, and low shear resistance indicate a poor match was identified. On the other hand, a heterogeneous weak gel system has a high capture capacity and adsorption in porous medium. It is easier to be retained in this medium, and valuably forms seepage impedance in high-permeability zones, and it has a stronger volume expansion effect compared to the same viscosity or concentration polymer solution. But continuity injection of polymer agents will result in profile reversal and deterioration of the flooding effect. To resolve this issue, high and low-injection or non-retention displacement agents can, in turn, further enhance displacement performance. In Figure 15, due to the strong retention of the heterogeneous gel in the core, the injection pressure of the heterogeneous gel was much higher.

Hazarika and his group in 2023 [48] studied the recovery efficiency of chemical EOR agents, Polyacrylamide (PAM) and xanthan gum (XG), for tertiary phase polymer flooding in the Upper Assam basin by comparing the rheological characteristics of PAM and XG, and core-flooding experiments to estimate the recovery efficiency of both polymer solutions.

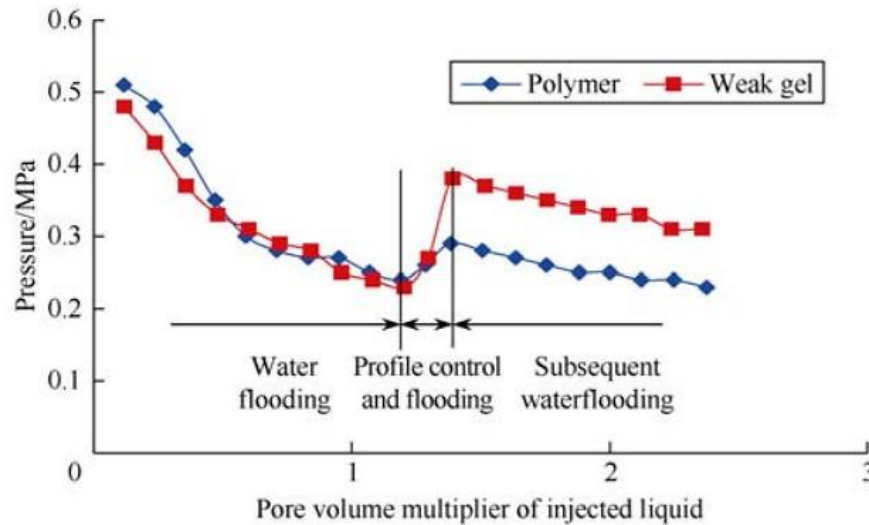


Figure 15. Injection pressures of polymer and weak gel flooding [47].

The findings suggest that the most important factor in recovery efficiency is macroscopic sweep efficiency. Injecting hydrogel polymer into the reservoir would increase fluid viscosity, leading to a significant drop in mobility, and as a result, increasing oil production. The shear-thinning phenomenon of PAM suggests dominance of front advance theory, and as PAM imitates both piston-like displacement and front advance theory, it effectively improves macroscopic sweep efficiency and microscopic displacement efficiency. The RF for the flooding process of PAM was 53% of OOIP, and XG polymer was 45% of OOIP, indicating that the latter polymer was less efficient than PAM. The cost-effectiveness of such projects also helps determine their success, and a simulation using the Computer Modelling Group (CMG) was performed to verify the experimental results. The cumulative oil production values from experiment and simulation were very close before the polymer injection, as shown in Figure 16.

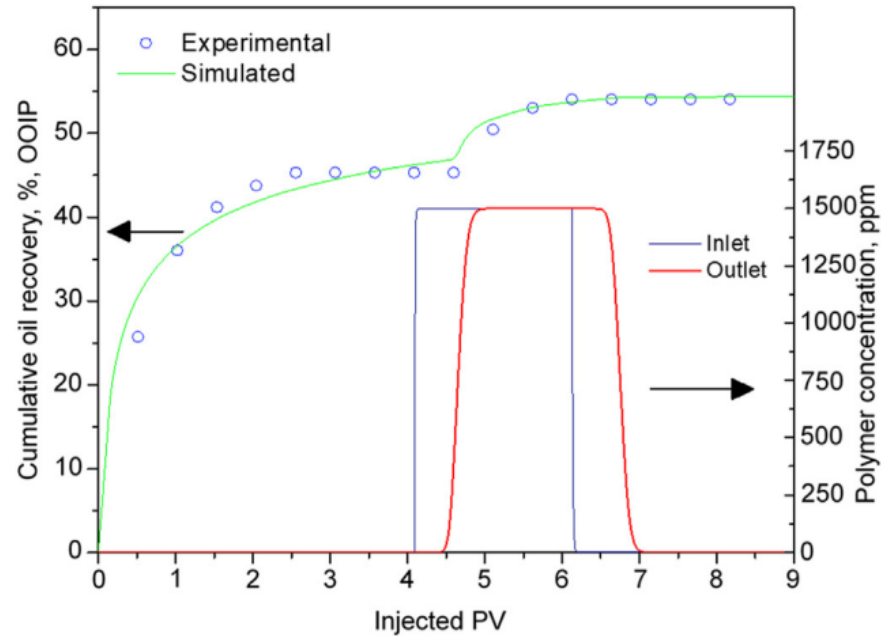


Figure 16. Production profile of the experimental and simulated core flooding [48].

Wei et al. (2023) [49] conducted microscopic oil displacement experiments to observe waterflooding and SP flooding in terms of remaining oil. They calculated the RF related to the produced liquid (NMR) technique, which gave similar results (with a 10% difference). They used NMR to compare the contributions of pore and throat diameters. They found that the pore limit and throat diameter for SP flooding are much lower than those for waterflooding, suggesting that SP flooding can effectively increase sweep efficiency and improve the recovery rate by about 30%. Finally, they used the frozen-slicing technique and ultraviolet fluorescence excitation to examine the status and distribution of residual oil, revealing that water and SP flooding can effectively extract all types of crude oil that may remain after injection. They also compared the remaining oil proportions in high- and low-permeability cores and found that high permeability is a factor in the success of both waterflooding and SP flooding.

In their research, Olabode et al. (2024) [50] investigated polymer injection and the effect of salt concentrations on heavy oil recovery. They first created six concentrations of Guar Gum (GG), which were dissolved in 300 ml of water, and the rheological properties were used in six reservoir models (oil density of 20 lb/ft³) using the Eclipse black oil model, and keywords for polymer/salt, rock, and fluid properties. The effects of two salt concentrations were studied separately for each polymer concentration, along with a natural case. The recorded oil recoveries were 5.90% for primary production, 30.78% for water injection, and under polymer flooding: 48.53%, 48.74%, 48.78%, 49.18%, 49.34%, and 55.49%. The oil recoveries at 1.0 wt% GG were 55.04% for 5 wt% salt concentration and 54.60% for 10 wt%

salt concentration. In summary, higher GG concentration leads to better oil recovery (due to increased viscosity index) while higher salt concentration leads to lower oil recovery.

Madhumaya et al. (2026) [51] pioneered a new approach of employing Time Series Machine Learning (TSML) to establish a data-driven model for predicting cumulative oil recovery of laboratory-scale EOR experiments by leveraging RF data from a single core flooding experiment using a polymer-based EOR system, where the cumulative recovery was 49.05% of the Original Oil In Place (OOIP) (25% from the initial waterflood and 24.05% during the polymer EOR phase). The Auto Regressive Integrated Moving Average (ARIMA) model was trained on the oil RF data to forecast future RF, thus bypassing the need for reservoir model building; using a 60:40 train-test data split, the optimum ARIMA (1,0,2) model predicted an end value of RF to be 23.62%, which is a slight off (0.43% RF) from the experimental value, with the accuracy of the prediction determined by RMSE and MAPE of 0.236 and 0.784%, respectively. The cumulative oil recovery for the polymer EOR process was about 24.05% of the OOIP (Figure 17). Table 3 and Figure 18 show a summary of studies related to simulation, modelling, pore-scale mechanisms & field analysis.

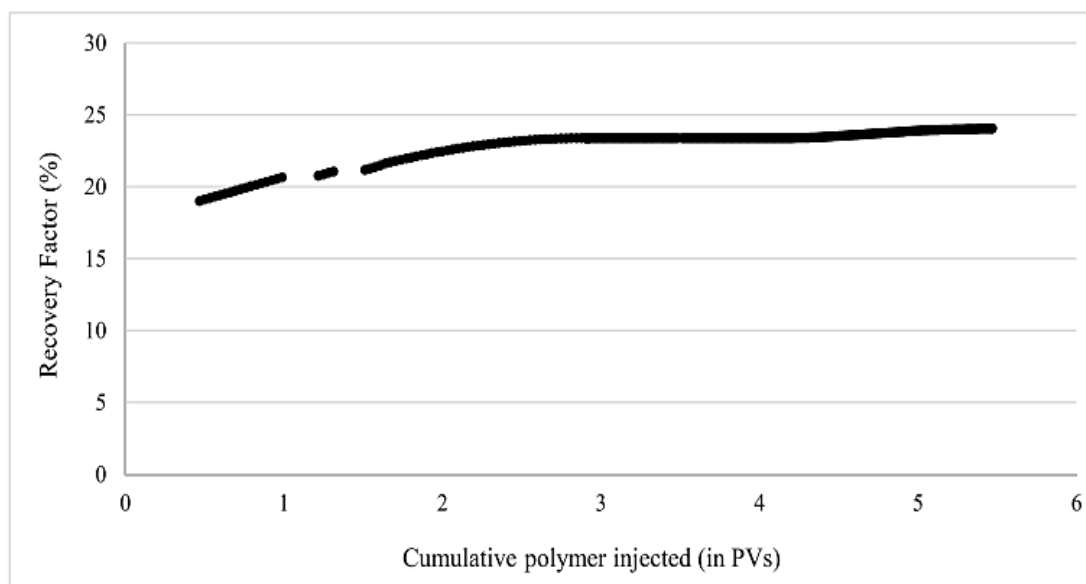


Figure 17. Oil recovery under polymer EOR stage [51].

Table 3. A summary of studies related to simulation, modeling, pore-scale mechanisms & field analysis.

Authors and year	Polymer/ Agent Type	Additives	Main Mechanism	Key Outcome / Recovery Factor
Brantson et al. (2020) [45]	Low salinity water polymer (LSWPF)	None (hybrid PSO-ANN proxy model)	Ion exchange, wettability alteration, fluid flow transport	RF: LSWPF 39%, HSWPF 31%, LSWF 24%, waterflood 11% (50 days). PSO-ANN model errors <1% AAPE.
LIU et al. (2020) [46]	Surfactant/polymer (SP)	None	Producing oil from medium-large pores (>3 μm)	Incremental RF by SP flooding higher in complex pore structures. Multimodal cores prone to channelling.
LU et al. (2021) [47]	Heterogeneous weak gel	None	Adsorption/capture in porous media, expanding swept volume	Heterogeneous gel has higher retention & injection pressure than ordinary polymer. Viscosity not positively correlated with effect.
Hazarika et al. (2023) [48]	Polyacrylamide (PAM) vs Xanthan gum (XG)	None	Macroscopic sweep efficiency, frontal advance	PAM RF: 53% OOIP , XG RF: 45% OOIP . CMG simulation validated.
Wei et al. (2023) [49]	Surfactant/polymer (SP)	None	Improving sweep efficiency in small pores	SP flooding improved EOR by ~30% (NMR & slicing techniques).
Olabode et al. (2024) [50]	Guar gum (GG)	Salt (5% & 10% wt)	Viscosity index increase	Max RF at 1% GG: 55.49% . Increasing salt reduced recovery (55.04% $\rightarrow$ 54.60%).
Madhumaya et al. (2026) [51]	Polymer (type not specified)	None (ARIMA machine learning model)	Data-driven forecasting without reservoir characterization	Polymer stage RF: 24.05% OOIP . ARIMA(1,0,2) predicted 23.62% (0.43% deviation).

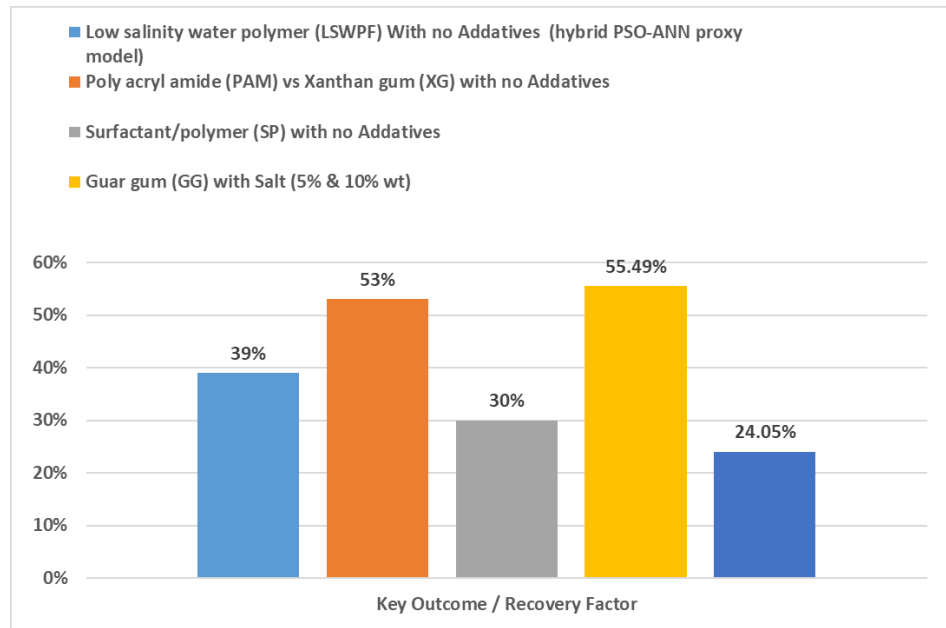


Figure 18. Oil recovery Factor under different polymer flooding modalities and additives.

3. Comparative Assessment of Polymer Flooding Modalities

A review of the literature shows a shift from traditional polymer flooding to next-generation methods that overcome specific challenges. Traditional polymer flooding with partially hydrolyzed polyacrylamide (HPAM) or xanthan gum generally produces recovery factors of 30-50% OOIP (oil originally in place) following waterflooding, but has poor injectivity in low-permeability formations, mechanical degradation at high shear rates, and low viscosity stability in high-salinity or high-temperature environments. To overcome these limitations, nano-reinforced polymer systems, such as silica nanoparticle-guar gum blends, graphite oxide-reinforced polymers (GORP), and nanofluids containing carbon nanotubes, show improved performance, with recovery factors from 44% to 72% OOIP. Such formulations increase viscosity, shift wettability towards water-wet (contact angle changes from $\sim 72^\circ$ to $\sim 115^\circ$), and impart greater shear stability. Hybrid injection methods, such as Polymer Enhanced Foam (PEF), CO₂-assisted surfactant/polymer flooding, and CO₂-cyclic solvent injection combined with polymer flooding, reach even greater recoveries (70-97% OOIP) through the combined effects of mobility control, interfacial tension, and oil swelling. But nano-reinforced polymer formulations face issues associated with nanoparticle agglomeration, retention, and cost, and hybrid injection demands intricate multi-stage injection strategies and may experience gas breakthrough in heterogeneous reservoirs. Capsule polymer flooding is an emerging technology providing delayed viscosity buildup, high penetration, and resistance factors increasing from 2 to 25-32 (at full activation),

thus suitable for high-water-cut and offshore reservoirs. Table 4 and Figure 19 compare the performance of these polymer flooding methods.

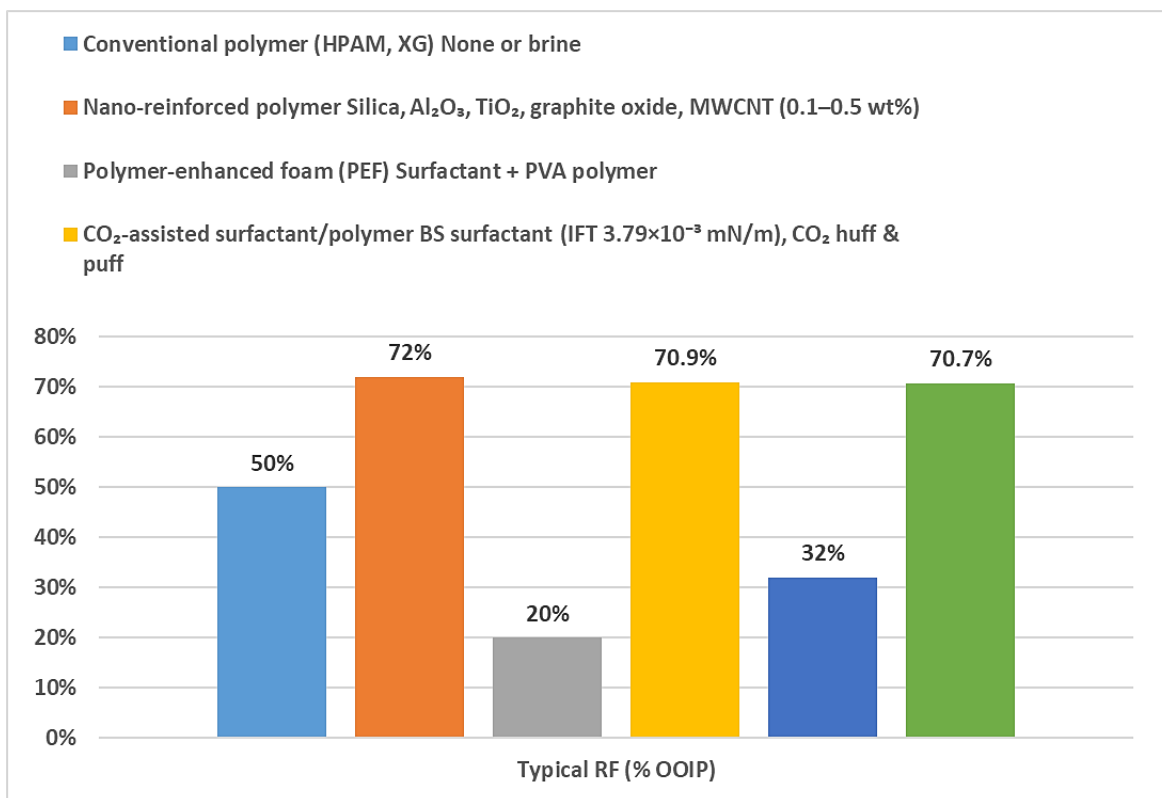


Figure 19. Maximum oil recovery factor under different polymer flooding modalities and additives.

Figure 20 illustrates the number of cores for the reviewed studies. Most of these studies failed to mention the numbers.

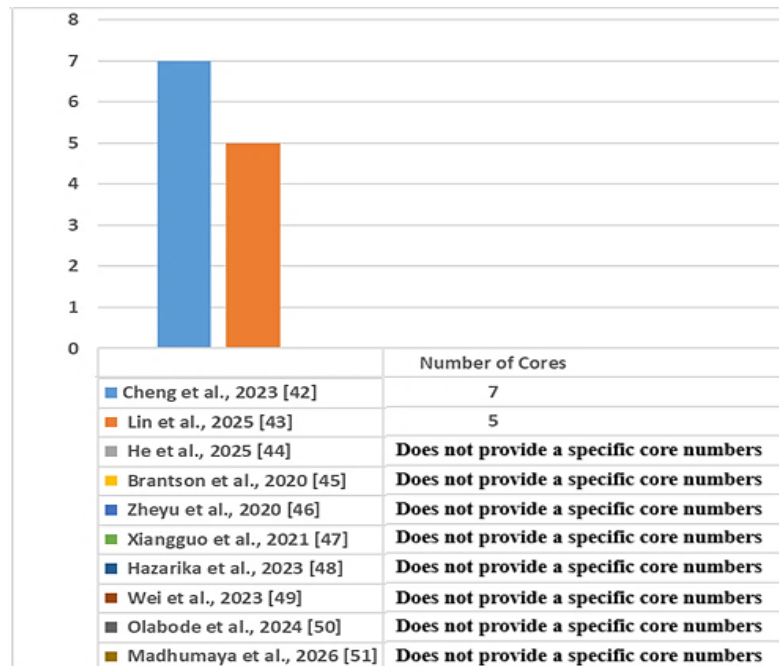


Figure 20. Number of cores for the reviewed studies.

Table 4. Comparative assessment of polymer flooding modalities.

Modality	Key Additives/ Agents	Typical RF (% OOIP)	Advantages	Limitations	Suitable Reservoir Conditions
Conventional polymer (HPAM, XG)	None or brine	30–50%	Proven technology, lower cost	Shear degradation, salinity/temperature sensitivity, poor injectivity in low-permeable zones	Moderate temperature (<80°C), low–medium salinity
Nano-reinforced polymer	Silica, Al ₂ O ₃ , TiO ₂ , graphite oxide, MWCNT (0.1–0.5 wt%)	44–72%	Enhanced viscosity, wettability alteration (to water-wet), shear resistance, thermal stability	Nanoparticle agglomeration, adsorption/retention, higher cost, colloidal stability issues	Wide range; SiO ₂ NPs most effective
Polymer-enhanced foam (PEF)	Surfactant + PVA polymer	15–20% incremental over conventional foam	Improved stability in heterogeneous media, cross-flow mechanism, piston-like advancement	Foam breakthrough in high-perm layers, gas channeling risk	Permeability contrast up to 8:1
CO ₂ -assisted surfactant/polymer	BS surfactant (IFT 3.79×10 ⁻³ mN/m), CO ₂ huff & puff	Up to 70.9%	Oil swelling, viscosity reduction, improved microscopic displacement	Well placement critical (optimum 2.5 cm from bottom water), CO ₂ supply required	Heavy oil, bottom-water reservoirs
Capsule polymer	Delayed-thickening capsules	Resistance factor: 2 → 25–32	Easy injection, shear resistance, deep reservoir viscosity	Customization required (particle size, release time),	High-water-cut, offshore,

			increase, low adsorption	temperature-sensitive release	medium-low perm reservoirs
CO ₂ -CSI + polymer alternation	CO ₂ + polymer (1000 ppm)	70.7%	Dual-mobility-ratio control, oil bank formation, 70% material cost reduction	Complex injection alternation, requires detailed cycle optimization	Heavy oil, viscous oil reservoirs

4. Key Controlling Factors and Performance Drivers in Polymer-Augmented EOR

According to the review paper, the critical factors and drivers for performance in polymer-enhanced EOR include polymer concentration, salinity/temperature, nanoparticle type, reservoir heterogeneities, and injection scheme. Polymer concentration is a key control on viscosity, which leads to improved recovery (up to an optimum concentration, where injectivity drops), but does not always correlate with performance (reservoirs with a "sheet-net" structure may have poor fit with pore throats). Salinity and temperature are important for polymer stability: increasing salinity/hardness lowers viscosity (due to chain shrinkage and adsorption), and increasing temperature increases degradation rate and capsule polymer release. Nanoparticle type (SiO₂ is more efficient than Al₂O₃ and TiO₂), size (increasing particle size enhances efficiency), morphology (nanofibers are more efficient than nanoparticles in improving efficiency), and concentration (0.25-0.5 wt% optimal) modify viscosity, alter wettability towards water-wet states (contact angles change from 72 to 115 degrees), and improve shear resistance. Reservoir pore structure affects flooding efficiency: complex pores result in worse waterflood efficiency but greater incremental gains with polymer (polymer/surfactant) flooding, with multimodal conglomerate reservoirs susceptible to channelling. Heterogeneity affects sweep efficiency, with polymer-enhanced foam continuing to drive cross flow at high permeability variation (8:1). Injection parameters, such as well location (best distance from bottom water 2.5 cm), alternate injection of high- and low-retention agents, and delayed thickening properties (resistance factor from 2 to 25-32) also affect the recovery. Table 5 illustrates critical parameters, performance-enhancing factors, and their effect on recovery in polymer-enhanced EOR.

Table 5. Key controlling factors, performance drivers, and their impact on recovery in polymer-augmented EOR.

Controlling Factor	Performance Driver	Impact on Recovery
Polymer concentration	Viscosity enhancement vs. injectivity trade-off	Higher concentration increases RF up to optimum; beyond optimum reduces injectivity
Salinity & hardness	Polymer chain conformation, adsorption, thermal stability	Increased salinity/hardness decreases viscosity; capsule polymer release less affected

Temperature	Degradation rate, capsule polymer activation	Higher temperature accelerates degradation but improves capsule thickening rate
Nanoparticle type	Colloidal stability, adsorption behavior, IFT reduction	SiO ₂ gives highest DE (~94%); Fe ₃ O ₄ poor due to flocculation
Nanoparticle size & morphology	Effective viscosity, pore-throat interaction	Larger size & fibrous morphology (ANF) enhance efficiency vs. spherical particles
Nanoparticle concentration	Viscosity peak, agglomeration risk	Optimal 0.25–0.5 wt%; higher leads to agglomeration and retention
Reservoir pore structure	Remaining oil mobilization, sweep efficiency	Complex pores yield poorer waterflood but higher incremental SP recovery
Permeability heterogeneity	Cross-flow, channeling risk	PEF effective up to 8:1 contrast; higher contrast reduces sweep
Well placement	Bottom-water breakthrough control	Optimum distance from bottom water (e.g., 2.5 cm) maximizes RF (70.9%)
Injection scheme	Mobility control, delayed thickening	Alternating high/low retention agents; capsule polymer resistance factor 2 → 25–32

5. Challenges, Knowledge Gaps, and Optimization Strategies for Field-Scale Implementation

While tremendous progress has been made in nano-reinforced polymers, hybrid injection methods, and forecasting models, critical challenges remain in successfully implementing next-generation polymer flooding at the field scale. Critical technical hurdles include agglomeration and retention of nanoparticles in porous media, which hinder injectivity and cause formation damage; high cost and laborious synthesis of functionalized nanoparticles and capsule polymers; and challenges in maintaining uniform dispersion and long-term stability of nanoparticles and capsule polymers under reservoir conditions, such as high salinity, hardness, and temperature. Further challenges include field implementation of hybrid schemes (e.g., CO₂-assisted or foam-assisted polymer flooding), which are complicated by gas channeling, foam instability with oil, and the complexity of controlling alternation cycles. There are significant uncertainties about the long-term behaviour of nanoparticles and capsule polymers in reservoirs (e.g., chemical degradation, desorption, and environmental risks), the scaling up of lab-optimized formulations, and the absence of models that couple multi-scale processes (pore to field) with real-time field data for adaptive control. Field-scale optimization strategies should include: (1) using tailored nanoparticle-polymer systems with controlled size, surface functionalization and concentration (0.25-0.5 wt%) to enhance viscosity while maintaining injectivity; (2) developing efficient, cheap, eco-friendly (biodegradable or recyclable) nano-additives; (3) adopting adaptive injection schemes such as alternating high retention-low retention agents or delayed-thickening capsule polymers for enhanced sweep efficiency in heterogeneous and high water-cut formations; (4) using data-

driven smart proxy models (e.g. PSO-ANN, ARIMA) combined with field sensors to predict performance and optimize injection strategies; and (5) long-term pilot studies to assess environmental and economic feasibility. A summary of challenges and gaps in knowledge, and optimization strategies for field-scale applications of next-generation polymer flooding is presented in Table 6.

Table 6. Summary of field-scale challenges, knowledge gaps, and optimization strategies for next-generation polymer flooding.

Category	Specific Issues	Optimization Strategies
Technical Challenges	Nanoparticle agglomeration & retention; injectivity loss; formation damage; gas channeling in hybrid methods; foam instability	Optimize NP concentration (0.25–0.5 wt%); surface functionalization; use capsule polymers with delayed thickening; adaptive injection alternation
Economic Challenges	High cost of functionalized NPs & capsule polymers; complex synthesis; expensive surfactants	Develop cost-effective biodegradable NPs; recycle injection fluids; reduce material costs via hybrid schemes (70% cost reduction reported)
Operational Challenges	Poor colloidal stability under high salinity/temperature; non-uniform dispersion; well placement sensitivity	Tailor polymer-NP pairs for specific brine compositions; optimize production well distance (from bottom water); controlled release design
Knowledge Gaps	Long-term NP fate (degradation, desorption, toxicity); scalability from lab to field; lack of multi-scale predictive models; real-time adaptive control	Conduct long-term pilot tests; integrate PSO-ANN or ARIMA models with field sensors; develop digital twins for reservoir-specific customization
Reservoir-Specific Constraints	High permeability contrast (up to 8:1) reduces sweep; complex pore structures cause channeling; high-water-cut reservoirs	Use polymer-enhanced foam for cross-flow; apply capsule polymers (resistance factor 2→25–32); alternate high/low retention agents

6. Economic Considerations

Economic impacts are an essential axis of innovation, with new technologies expected to impact the financial outlook of polymer EOR. Distributed injection systems reduce capital costs by avoiding a wide range of facilities and significantly improve Net Present Value (NPV). The amount of 0.999 MMbbl will be maximized through HPAM flooding as opposed to water flooding, which yields 0.799 MMbbl [52]. Optimizing the polymer concentration is the best way of controlling costs. Studies have established that, where mobility ratios are negative due to viscous oil, even low polymer concentrations result in a significant reduction in costs [53]. The use of modified biopolymers could reduce costs by 15% to 20% compared to synthetic alternatives [54]. It normally takes between eight and twelve years to undertake a polymer flood.

7. Environmental Impact

A reduction in CO₂ emissions was noticed in the case of polymer flooding [55]. The technique can significantly enhance energy efficiency during oil recovery operations. The main issue is that synthetic polymers are persistent in the environment [56]. Biopolymers, such as xanthan gum, provide the best framework for dealing with this problem with 90% degradation rate in just 28 days [57]. HPAM Synthetic polymers not only persist in the environment but are also associated with various toxicity issues in the aquatic environment [7]. Biopolymers and other green compounds made up of natural sources are considered environmentally friendly alternatives [58]. In the case of polymeric nanofluids and optimized polymer formulations with low concentrations, there is a reduced need for chemicals [11].

8. Conclusions and Future Outlook: Toward Next-Generation Polymer Flooding Systems

This review of emerging technologies for polymer flooding shows a clear evolution from traditional polymer injection towards multifunctional systems that overcome the inherent drawbacks of conventional enhanced oil recovery techniques. Although conventional polymer flooding is well-established and economical, it only reaches 30-50% recovery factor (RF) of original oil in place and is prone to degradation, salinity and temperature sensitivity, and low injectivity for low-permeability formations.

1. Nanoparticle-enhanced polymer systems have shown enhanced recovery factors (44-72%) of original oil in place. An optimum nanoparticle concentration range (0.25-0.5 weight percent) achieves a balance between enhanced viscosity and agglomeration, with silica nanoparticles being the most effective (with displacement efficiencies up to approximately 94%) and fibrous particle shapes being more effective than spherical ones.
2. Combined injection techniques, such as foam with polymer, carbon dioxide-aided surfactant/polymer flooding and solvent/polymer alternating injections, yield the highest reported recoveries (70-97% of OIP), combining mobility control, interfacial tension reduction (ultra-low values of 10^{-3} mN/m), oil swelling and viscosity reduction. But they add complexities in terms of gas breakthrough in heterogeneous reservoirs, foam collapse in the presence of oil, and well placement sensitivities.
3. Capsule polymer flooding is a new type of polymer flooding with delayed-thickening property. It is being suitable for reservoirs with high water cuts, offshore wells with large well spacing, and medium- to low-permeability reservoirs where conventional polymers cannot be injected.

4. The main factors controlling the performance of polymer-augmented EOR are polymer concentration, salinity and temperature, nanoparticle type, size, shape and concentration, reservoir pore structure complexity, permeability heterogeneity, well placement, and injection scheme design.

The strategic directions for the development of next-generation polymer flooding systems will probably be:

- I. Responsive polymer systems will evolve from static viscosity enhancement to dynamic systems according to reservoir conditions. They exhibit controlled changes in rheological properties, which control the release and activation in targeted reservoir regions. Capsule polymers and smart systems may feature multiple release mechanisms, sequenced activation, and even self-repair mechanisms to ensure system performance despite changing reservoir conditions.
- II. Sustainable nanoparticles (biodegradable or bio-inspired synthesis) and recyclable or recoverable nanomaterials will reduce environmental impacts and costs, enabling economic viability through formulation and injection design rather than relying solely on expensive high-performance nano-additives.
- III. The results of the machine learning models suggest that smart proxy models can replace much more costly numerical simulation models. Upcoming field trials will combine downhole sensors, real-time rheological monitoring, and edge computing with digital twin technology to optimize injection, early detection of anomalies, and autonomous injection control.
- IV. The long-term behavior of nanoparticles and capsule polymers in the reservoir is currently unknown and will be determined using long-term pilot tests and state-of-the-art characterization tools.

Declaration of generative AI and AI-assisted technologies in the writing process

-None

Disclosures

The authors have no conflicts of interest to declare in relation to this manuscript.

Abbreviations

The following abbreviations are used in this manuscript:

ANF	Al ₂ O ₃ nanofibers
AP	Aqueous phase

AAPE	Average absolute percentage error
ABS	Alkylbenzene sulfonate
ARIMA	Auto Regressive Integrated Moving Average
CP	Conventional polymer
CEOR	Chemical enhanced oil recovery
CSI	Cyclic solvent injection
DE	Displacement efficiency
EOR	Enhanced oil recovery
EPEC	Ethylene oxide (EO)/propylene oxide (PO) carboxylate
GG	Guar gum
GORP	Graphite oxide nanoparticle-reinforced polymer
H/C	Hydrogen to carbon atomic ratio
HSWPF	High salinity water polymer flooding
IFMF	In-situ formed middle-phase microemulsion flooding
IFT	Interfacial tension
ISC	In-situ combustion
LHS	Light hydrocarbon solvent
LSP	Low salinity polymer
LSW	Low salinity water
LSWF	Low salinity water flooding
LSWPF	Low salinity water polymer flooding
MAPE	Mean absolute percentage error
mMWCNT	Modified multi-wall carbon nanotubes
NaCl	Sodium chloride
NMR	Nuclear magnetic resonance
NPs	Nanoparticles
OP	Oil phase
OOIP	Original oil in-place
PAM	Poly acryl amide
PEF	Polymer enhanced foam
PSO-ANN	Particle swarm optimization artificial neural network
PVA	Polyvinyl alcohol
PR	Permeability ratio
RF	Recovery factor
RMSE	Root mean square error
SDS	Sodium dodecyl sulfate
SP	Surfactant/polymer
TSML	Time Series Machine Learning
XG	Xanthan gum

Greek Letters

M	Viscosity
Θ	Contact angle

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تقنية حقن البوليمر من الجيل التالي لتحسين استخلاص النفط: مراجعة نقدية للتركيبات المدعمة بتقنية النانو، واستراتيجيات الحقن الهجينة، والتنبؤ بالأداء القائم على البيانات

الخلاصة: تعاني تقنية حقن البوليمر التقليدية لتعزير استخلاص النفط من عدم استقرار القص، ومشاكل الحقن في المناطق ذات النفاذية المنخفضة، وفقدان اللزوجة في المكامن ذات الملوحة العالية ودرجة الحرارة المرتفعة. تستعرض هذه الدراسة بشكل نقدي تقنيات حقن البوليمر الناشئة، بما في ذلك البوليمرات المدعمة بتقنية النانو، وتقنيات الحقن الهجينة، وتوقعات الأداء القائمة على التعلم الآلي، وذلك استنادًا إلى 21 منشورًا بين عامي 2020 و2026. تُحقق تقنية حقن البوليمر المدعمة بتقنية النانو (مثل السيليكا-صمغ الغوار، والبوليمر المدعم بأكسيد الجرافيت، والسوائل النانوية القائمة على أنابيب الكربون النانوية) عوامل استخلاص تتراوح بين 44% و72% من النفط الأصلي الموجود في المكامن، حيث تصل كفاءة إزاحة جزيئات السيليكا النانوية إلى حوالي 94%، وانعكاس زاوية التلامس من حوالي 72 درجة (مبللة بالزيت) إلى حوالي 115 درجة (مبللة بالماء). يحقق الحقن الهجين (الرغوة المعززة بالبوليمر، وحقن البوليمر/المواد الخافضة للتوتر السطحي بمساعدة ثاني أكسيد الكربون، وحقن المذيبات الدورية بثاني أكسيد الكربون متبوعًا بحقن البوليمر) أعلى معدلات استخلاص (70-97% من النفط الأصلي في المكان) من خلال الجمع بين تقليل الحركة وانخفاض التوتر السطحي البيئي إلى 10^{-3} ملي نيوتن/متر. يُظهر حقن البوليمر في الكيسولات تأخرًا في زيادة اللزوجة (معاملات المقاومة من 2، قبل زيادة اللزوجة، إلى 25-32، بعدها عند زيادة اللزوجة بالكامل)، مما يجعله مثاليًا للآبار ذات نسبة الماء العالية والآبار البحرية. تشمل العوامل الحاسمة المؤثرة على الأداء التركيز الأمثل للجسيمات النانوية (0.25-0.5% وزنيًا)، ونوع وشكل الجسيمات النانوية ($\text{SiO}_2 > \text{Al}_2\text{O}_3/\text{TiO}_2$)؛ الليفية < الكروية)، وتحمل الملوحة/درجة الحرارة، وعدم تجانس المكامن. تشمل التحديات تكثف الجسيمات النانوية/احتجازها، وارتفاع تكلفة تصنيعها، وتوجيه الغاز، ومحدودية فهم تأثيرها على الخزانات على المدى الطويل وقابليتها للتوسع. تتميز أنظمة الجيل القادم ببوليمرات ذكية سريعة الاستجابة، ومعززات نانوية مستدامة، وتوائم رقمية فورية مع تحكم تكيفي وبروتوكولات تخصيص خاصة بالخزانات لتعزير الاستخلاص إلى ما هو أبعد من الحدود الحالية.

الكلمات المفتاحية: حقن البوليمر، استخلاص النفط المعزز (EOR)، تغيير قابلية التبلل، التحكم في الحركة، الحقن الهجين.