Revisiting Water Injection Post-Polymer Flooding: A Global Perspective on Project Performance

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Introduction

Polymer flooding is a widely adopted Enhanced Oil Recovery (EOR) technique that enhances oil displacement by addressing sweep efficiency issues and unfavorable mobility ratios between water and oil. Unlike conventional waterflooding, where high-permeability zones dominate fluid movement, polymer flooding improves sweep efficiency by increasing the viscosity of the injected fluid. This reduces the tendency of water to channel through high-permeability zones, leading to more uniform displacement of oil across heterogeneous reservoirs, independently of in-situ oil viscosity. The effectiveness of polymer flooding is conditioned by two critical design elements: in-situ viscosity and slug size. The viscosity of the polymer solution must be sufficient to achieve a favorable mobility ratio and better sweep, ensuring that the polymer flows effectively through low permeability zones and recovers bypassed oil while delaying breakthrough in already watered-out fingers. Similarly, the size of the polymer slug dictates the extent of oil recovery before the injected polymer front is displaced by water.

These parameters are normally guided by theoretical principles such as Darcy's law, with and without crossflow, and reservoir heterogeneity contrasts, which influence fluid dynamics during polymer flooding operations. This paper will not focus precisely on these items, but on an aspect indirectly related to it: What happens when polymer injection is stopped, and water injection is resumed?

The assumptions or rationale behind expectations at this stage significantly influence decisions regarding the two previously mentioned items. Some of the critical questions are:

- Can the integrity of the polymer slug be preserved?
- What are the current beliefs and strategies and the rationale behind it?
- How do these beliefs impact the design?
- Are there strategies to mitigate the adverse effects of water injection post-polymer flood?

Addressing these issues is essential to optimizing the transition phase and extending the economic and technical lifespan of polymer flooding projects.

This paper addresses these challenges by combining theoretical insights with field data from various projects around the world, providing a framework to optimize injection parameters.

Polymer displacement by water: a brief review

It is well-established in the industry that differences in fluid viscosities, coupled with reservoir heterogeneities, inevitably give rise to viscous fingering, occurring in both miscible and immiscible fluid displacement scenarios (Koval, 1963; Chen *et al.*, 1987; Homsy, 1987; Blunt *et al.*, 1994; Kargozarfard *et al.*, 2019; An *et al.*, 2022). This is one of the main reasons behind augmenting the viscosity of the injected water with polymer and the very existence of the polymer flooding technique.

Building on the literature, while most research has historically focused on water fingering in oil reservoirs, a growing number of authors have been trying to address the challenges posed by water injection following polymer flooding.

Claridge (1978) introduced the concept of designing graded viscosity banks to delay viscous instabilities. Using Koval's equations, the approach designs graded viscosity banks with stepwise viscosity changes to control fingering within acceptable limits. The method is applied to miscible flooding with LPG and polymer flooding in linear systems, showing improved oil recovery and reduced costs compared to conventional methods. The study highlights the technical and economic feasibility of graded banks but acknowledges some very important limitations, including simplified linear displacement models and the neglect of reservoir heterogeneities.

The idea was further analyzed in studies like Ligthelm (1989), who started the paper with the challenge to address: "*In principle, viscosity grading induces instable displacement by viscous fingering*" The study introduces a heuristic model based on transverse dispersion to determine the effective viscosity ratio between slugs, which controls viscous fingering. Experimental validation shows that the mixing behavior of polymer solutions differs significantly from hydrocarbons, making Koval's mixing rule overly optimistic for polymer flooding. But, like Claridge's work, the study simplifies reservoir conditions by focusing on homogeneous porous media and linear flow. For a comprehensive review of the work until 1987, the reader can refer to Homsy (1987).

In 1988, Cyr *et al.* addressed the challenges of understanding the dynamics of polymer displacement processes, emphasizing the limitations of existing theoretical frameworks for multiphase flow in porous media. They highlighted significant advancements in recent years that improved the understanding of these processes, citing works by Chang and Slattery (1986), Hatton and Lightfoot (1981), and others. Despite these advances, they noted that a number of researchers, including Peaceman and Rachford (1962), Claridge (1972), and Giordano and Salter (1984), had incorrectly concluded that viscous fingers would not develop during miscible displacement in homogeneous porous media. Cyr *et al.* demonstrated that numerical dispersion often caused a false indication of stability in these studies, leading to the misconception that displacements were stable to infinitesimal perturbations when, in fact, they were unstable to macroscopic perturbations. The authors also address the limitations of laboratory experiments in scaling observations to field conditions. Stabilizing effects such as diffusion and dispersion observed in lab settings are negligible at field scales, where larger wavelength instabilities dominate. The authors' work questioned the stability of the water-polymer boundary and the overall viability of polymer displacement processes. They showed that under any reasonable conditions, the trailing boundary of a polymer slug of uniform concentration was too unstable to ensure viability as the process is currently envisaged. Moreover, they demonstrated that even for a graded polymer slug, one must question the usefulness of the process.

In 1992, Takaki *et al.* shared their conclusions for a simulation study for Chateaurenard polymer pilot. The study highlighted that the simulation results closely matched the field performance of the Courtenay polymer pilot in the Chateaurenard field when using a statistically generated permeability field. This stochastic approach provided better insight into reservoir heterogeneity compared to models with uniform layers, despite the lack of detailed conditioning data such as logs and tracers. The study demonstrated that oil recovery was minimally affected by changes in gridblock size and permeability distribution, as heterogeneity (measured by the Dykstra-Parsons coefficient) had limited influence on the results. As per the authors, key factors influencing the pilot's success were polymer adsorption and fractional flow effects, rather than viscous fingering, due to the favorable combination of reservoir conditions, a high length-to-thickness ratio, and effective polymer design. Graded polymer injection schemes and single large slugs performed similarly in simulations, indicating that polymer grading had minimal impact under these conditions. The excellent oil recovery (1.5 barrels of incremental oil per pound of polymer) was attributed to the appropriate polymer use, favorable reservoir properties, and careful implementation of the technology. It is unclear though if the authors were able to properly model viscous fingering effects.

Abdul Hamid and Muggeridge (2018) presented an analytical solution to determine the minimum polymer slug size needed to prevent viscous fingering of chase water into the polymer slug, emphasizing its implications on the integrity of polymer flooding in enhanced oil recovery (EOR). Using the Todd and Longstaff model (Todd & Longstaff, 1972), the study identifies a critical slug size (~0.52 PV for viscosity ratios of 10 to 50) to maintain slug integrity and optimize oil recovery. Smaller slug sizes (e.g., 0.3 PV) result in premature slug breakdown and reduced oil recovery, while larger slug sizes (e.g., 0.65

PV) offer no significant improvement beyond the critical size. The study assumes idealized 1D homogeneous systems, neglects reservoir heterogeneities and adsorption effects.

More recently, Bakharev *et al.* (2021) explored the application of advanced models such as the Koval and Todd-Longstaff approaches to optimize polymer injection profiles, highlighting the potential of graded profiles to significantly reduce polymer consumption while maintaining sweep efficiency

Anand and Ryiami (2022) investigated methods to enhance the efficiency of a mature polymer flood project in a medium-to-heavy oil field in Oman, using only simulation. The study focused on optimizing polymer slug size, assessing Water-Alternating-Polymer (WAP) injection, and modeling viscous fingering effects. Using a combination of high-resolution 2D and 3D simulations, the research evaluated the impact of reservoir heterogeneity, frontal velocity, and slug size on recovery performance. The authors concluded that polymer grading (tapering viscosity over time) could significantly improve oil recovery while reducing polymer costs, but only after sufficient polymer injection occurred. We will see later in the paper that actual data from a field in this area showed almost instantaneous oil production decline when water injection was resumed.

Bakharev *et al.* (2021) and Tikhomirov *et al.* (2020) presented a mathematical framework for optimizing graded viscosity banks (GVB) in surfactant-polymer flooding. The study aimed to minimize polymer usage while maintaining displacement efficiency by tapering the viscosity of injected slugs. Using models such as Koval, Todd-Longstaff, and Transverse Flow Equilibrium (TFE), the authors estimated mixing zone propagation velocities and determined optimal slug sizes and concentrations to prevent viscous fingering and early breakthrough. Numerical simulations showed that 2–5 slugs achieved near-optimal savings, reducing polymer volumes by 20% to 45% depending on the viscosity model. The inclusion of polymer adsorption highlights efficiency losses under irreversible adsorption conditions. Some simplifications overlook capillary effects, reservoir heterogeneity, and multi-phase flow and the economic analysis, though briefly mentioned, lacks depth, making it challenging to assess the practicality of implementing multi-slug injection schemes.

In 2024, Qi *et al.* explored the impact of immiscible viscous fingering on polymer flooding efficiency. Using core-scale simulations, the study evaluated various injection schemes, including graded viscosity polymer flooding, to improve Enhanced Oil Recovery (EOR). Results showed that graded viscosity polymer flooding delays water breakthrough, reduces polymer usage, and enhances oil recovery. The first 0.5 pore volume of polymer injection significantly influences fingering behavior and recovery efficiency. Once again, the study relied entirely on simulation, ignoring reservoir heterogeneities (among other things).

The evolution of graded viscosity bank at the end of polymer injection has been continuously discussed over the last decades, starting with Claridge's work in 1978, which introduced stepwise viscosity changes to mitigate viscous instabilities during polymer and miscible flooding. Despite its promise, past and current research, including Ligthelm (1989), Takaki *et al.* (1992), Bakharev (2020), Qi et al (2024) often relied solely on simulation using simplified models, neglecting benchmarking with actual field data, key reservoir complexities such as heterogeneities and multi-phase dynamics. While these studies provide valuable insights, including the identification of optimal viscosity ratios and the role of fractional flow effects, their applicability to real-world reservoir conditions remained constrained by their focus on homogeneous, linear systems and the lack of benchmarking with field data.

Key factors influencing the design, limitations and impact on grading design

The design of a polymer injection project usually encompasses laboratory and simulation work to assess the feasibility and economics of the project. Rare have been the publications where commercial simulators have properly predicted the actual injectivity of the polymer or the final recovery factor. This challenge is particularly significant given the critical reliance engineers place on simulator outputs for tasks such as forecasting injectivity and approving pilot projects. This is an important lead-in to the next paragraph, as most studies on graded banks rely only on simulations, which are only as reliable as the inputs and models they use.

To run a 3D simulation, we need an accurate reservoir model and correct inputs. We will set the model aside for this discussion, despite its significant impact on unsuccessful simulations. Designing a polymer injection project usually starts with calculating the mobility ratio, which is a key measure for assessing displacement stability and sweep efficiency. The mobility ratio is the ratio of the displacing fluid's mobility to the displaced fluid's mobility. A stable displacement happens when the mobility ratio is less than or equal to 1, reducing the risk of viscous fingering and improving sweep efficiency. If the mobility ratio is greater than 1, the process becomes less stable, leading to channeling and uneven displacement (Seright, 2017). While aiming for a mobility ratio of 1 is a good starting point, it may not fully account for the natural differences in permeability across reservoir layers, which can cause the polymer front to move unevenly. Additionally, there is still debate about the ideal viscosity for the injected polymer, as it depends on the quality of the data at hand, such as relative permeabilities and heterogeneity.

Once a mobility ratio has been determined, the next step consists in screening polymers and plot viscosity curves in the injection brine to determine the required concentration to achieve the desired viscosity. After the necessary rheological characterization, corefloods are generally performed to assess propagation, retention and oil recovery. Although simulators require specific parameters, it is important to note that there is no standard protocol among researchers for determining these values (Thomas, 2023).

What are the main parameters required in most commercial simulators?

Viscosity. Rheological data from rheometers often serve as the primary input for simulators to model polymer behavior, despite the well-documented differences between polymer behavior in rheometers and in porous media (Seright *et al.* 2011). For instance, it should be confirmed that the viscosity at low shear is the same in a high permeability and low permeability core, not using the same value whatever the rock type. The most critical value to determine accurately is the resistance factor at the shear rate representative of conditions deep within the reservoir, often corresponding to the Newtonian plateau. It is therefore compulsory to estimate the shear gradient from the surface down to the deepest parts of the reservoir to design the experiments and the project accurately.

Adsorption/Retention. Retention is a term englobing adsorption, hydrodynamic and mechanical entrapment. It is generally determined during coreflooding tests using either the integration method or the 2-fronts method where polymer retention is inferred from the difference between injected and effluent polymer concentrations. This approach accounts for adsorption, mechanical entrapment, and other retention mechanisms that can affect polymer propagation.

The integration method consists in injecting a front of polymer and displace this polymer front injecting water. The polymer concentration in the effluents is determined and integrated to determine the amount of polymer being recovered at the outlet of the core. The difference with the amount of polymer being injected is calculated and used to determine polymer adsorption.

The 2-fronts method consists in injecting 2 fronts of polymer with a slug of brine in between. This method can be combined with tracer injection. The polymer concentration in the effluents is determined to establish the polymer breakthrough curves. During the injection of the first front polymer breakthrough is delayed in comparison to the tracer because polymer adsorbs on the rock. The brine is used to eliminate from the core sample all the polymers not being adsorbed on the rock surface. During the injection of the second front of polymer, adsorption is already satisfied, and the polymer breakthrough occurred earlier. This difference of polymer breakthrough between the two fronts of polymer is used to determine polymer adsorption. If all the porous space is not available for the polymer (usually when permeability is below 200 millidarcies), the breakthrough of the second front of polymer arrives earlier than the tracer. The difference of breakthrough between the second front of polymer and the tracer is used to determine the inaccessible pore volume (IPV or IAPV depending on the convention).

Both methods assume that the injection of water is efficient enough to displace the non-adsorbed polymer out of the core despite their unfavorable mobility ratio. A study from Seright & Wang (2022) highlights the overestimation of inaccessible pore volume (IAPV) in earlier works, often due to inadequate brine flushing during laboratory experiments. This leads to inflated retention predictions, particularly in high-permeability reservoirs where IAPV should theoretically be negligible. Additionally, the paper emphasizes discrepancies between field and laboratory retention values, noting that many simulation models are not calibrated to account for observed variations in factors like salinity, mineralogy, and polymer structure.

In simulation, retention is typically modeled using mathematical relationships like Langmuir isotherms, which assume that retention increases with polymer concentration until a maximum value is reached. These models are often validated or calibrated using laboratory coreflood experiments. In addition, some simulations incorporate kinetic parameters, to capture tailing effects observed during some experiments, which delay effluent polymer concentration build-up. Not considering kinetic parameters can lead to an erroneous determination of the adsorption value (Silva *et al*., 2024).

Residual Resistance Factor. Residual resistance factor (RRF) is defined as the ratio of water mobility before polymer injection to water mobility after polymer injection, quantifying the permeability reduction caused by the polymer. In theory, a high RRF reduces the mobility contrast between water and oil when switching back to water after polymer injection, improving sweep efficiency and delaying viscous fingering. However, if the RRF is unity, no permeability reduction occurs, resulting in a high mobility ratio and inefficient displacement during water injection. The literature shows a wide variation in reported RRF values, often due to insufficient brine injection to stabilize the measurement (Seright, 2017). Studies reveal that achieving a stabilized RRF requires extensive flushing, with some experiments indicating continued reductions even after 100 pore volumes (PV) of brine (*Figure 1*). Variability in RRF values is also influenced by core mineralogy, polymer adsorption, and the presence of high-molecular-weight polymer species that may not propagate far into the formation.

For effective design, a conservative assumption of RRF values close to unity is recommended, particularly in reservoirs with high permeability (>200 millidarcies), to avoid overestimating the efficiency of polymer floods (). This ensures adequate polymer bank size and concentration, minimizing the risks of early breakthrough and insufficient mobility reduction. In highly heterogeneous reservoirs, damage in high-permeability zones will be less significant than in low-permeability zones, causing water to preferentially flow through the more conductive zones once again.

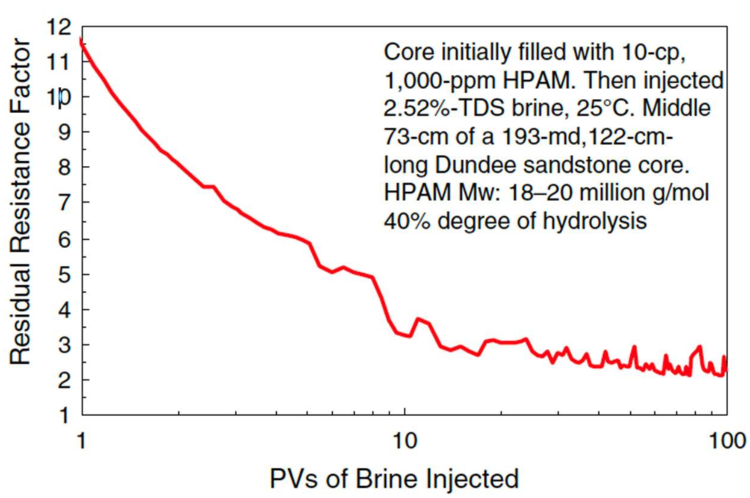


Figure 1: *Residual resistance factor vs. water pore volume injected showing a continuous decrease until 100 pore volumes injected. (Seright, 2017)*

Resistance Factor and In-situ rheology. The resistance factor (RF) is defined as the ratio of water mobility before polymer injection to polymer mobility during polymer injection. For cores with relatively high permeability, RF usually correlates well with the relative viscosity measured in solution using viscometers or rheometers. However, when permeability decreases (below approximately 500 millidarcies), RF values tend to be significantly higher than the relative viscosity measured in solution.

In simulators, RF is typically calculated by multiplying the relative viscosity by the residual resistance factor (RRF). This assumes a proper determination of RRF, as discussed in the previous section, and the correct input of the relative viscosity, specifically the apparent relative viscosity in porous media given by RF over RRF. However, this is often not the case. Generally, the viscosity measured in solution using a viscometer or rheometer is used as an input parameter and then multiplied by RRF, which is usually overestimated, leading to an overestimation of RF in the simulation.

Another often overlooked parameter is the conversion of flow rates into shear rates. RF is determined by injecting polymer solution at different rates through the core while measuring viscosity as a function of shear rate. Ultimately, velocity needs to be converted into shear rates or vice versa. Several equations are available, all with a similar structure: a constant or conversion factor, which may or may not depend on the polymer, multiplied by interstitial velocity. Calibrating this parameter is crucial for accurately describing the shear dependency of the polymer in porous media. Ideally, what matters most is the viscosity deep in the reservoir, where the velocity is low enough to be considered at the Newtonian plateau, but this significantly affects injectivity.

Resistance factor at lower velocities, representative of polymer propagation deep in the reservoir, are usually higher than the relative viscosity measured in solution using a rheometer or a viscometer by 30% in relatively high permeability cores and by much more when permeability decreases as described by Dupuis and Ould Metidji, 2023. Unexpectedly high resistance factors in low-permeability rock indicate an inability of the polymer to propagate through that rock (Seright et al. 2011). Accordingly, the authors strongly recommend considering resistance over any viscosity measurement for a proper design of the polymer slug. Since many reservoir simulators requires entering the viscosity of the polymer and the residual resistance factor, the authors recommend replacing the viscosity measured (η_{bulk}) using a rheometer or a viscometer by the apparent viscosity in porous media (η_{app}), defined by resistance factor times brine viscosity. Again, we emphasize that resistance factor measurements must be made in a realistic way (Seright et al. 2011). If resistance factor times brine viscosity is greater than twice the low-shear rate viscosity, the resistance factor should be questioned.

Coreflood experiments typically aim to measure resistance factors at different flow velocities, retention and oil recovery. However, during polymer flooding in core samples at a constant rate, the pressure gradient within the core often exceeds that between injection and production wells in the actual reservoir. This represents a key difference between laboratory core experiments and field conditions. Additionally, when using linear core samples, the challenge lies in accounting for higher flow rates and the potential onset of shear-thickening behavior. This behavior is likely to occur only if the polymer solution enters the matrix at rapid rates, a scenario in which injectivity would sharply decline or the polymer would degrade instantly—issues that do not align with field observations (Thomas *et al.*, 2019, Sagyndikov *et al.*, 2022a, Seright & Wang, 2023). Linear cores are more suitable for studying low shear resistance factors typical of the deeper sections of the reservoir.
Extracting information from coreflood experiments for simulation purposes requires careful consideration. For example, including data on shear-thickening behavior in the simulator without accounting for the differences between polymer solutions prepared in the laboratory and in the field (especially after entering the reservoir), or the presence of fractures near the wellbore can result in overly pessimistic injectivity predictions and jeopardize the viability of the project.

Sagyndikov *et al.* (2022b) demonstrated that for the high-permeability conditions of the Kalamkas field (>500 millidarcies), the residual resistance factor (RRF) is approximately equal to unity. This finding supports our conservative approach to polymer-flood design, which assumes that the resistance factor is accurately estimated using low-shear-rate viscosity measurements without accounting for permeability reduction. Consequently, we recommend setting the RRF to 1 in the simulator. However, even with the assumption of no permeability reduction, the model fails to replicate the performance during post-polymer water injection. This discrepancy arises due to viscous fingering of the chase water through the polymer bank in highly permeable pathways. This effect has been experimentally validated by Seright (2017), as shown in *Figure 2*, numerically confirmed by Sagyndikov (2022b), as illustrated in *Figure 3*, and will be demonstrated in the next section by analyzing actual Field cases.

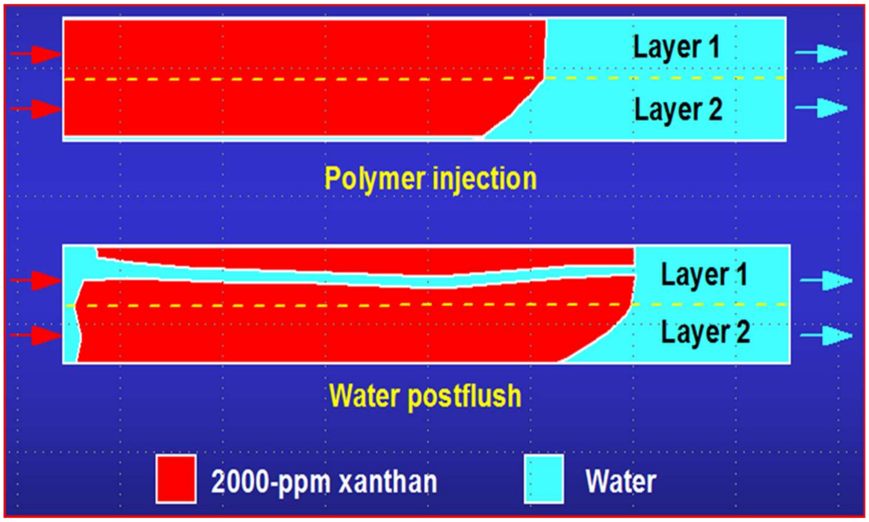


Figure 2: *Viscous fingering during water injection after polymer flood (Seright 2017).*

In *Figure 3*, the red curve shows polymer flood responded oil production and the black dashed curve is the waterflood baseline derived from the decline curve analysis (DCA). The blue curve shows projections from the model during post-polymer chase water injection, while the green curve shows the projection for continued polymer injection. In this model, the switch from polymer to water injection began at the starting point for modelling different scenarios. These projections suggest that a post-polymer waterflood will maintain oil rates that are significantly more desirable than associated with waterflooding alone (e.g., the black dashed curve). Additionally, the difference in oil production between continuing polymer flood (green curve) and returning to water injection (blue curve) is only 9.2%. Clearly, an economically rational scenario is a chase waterflood. However, as the Kalamkas field cases showed, oil rates are actually expected to return to the water flood base case after returning to water injection (grey curve). Thus, considering the model's ability and real polymer flood physics, we suggest an accurate forecast for water chase flood rapidly returns to the waterflood base case line (grey curve – our view).

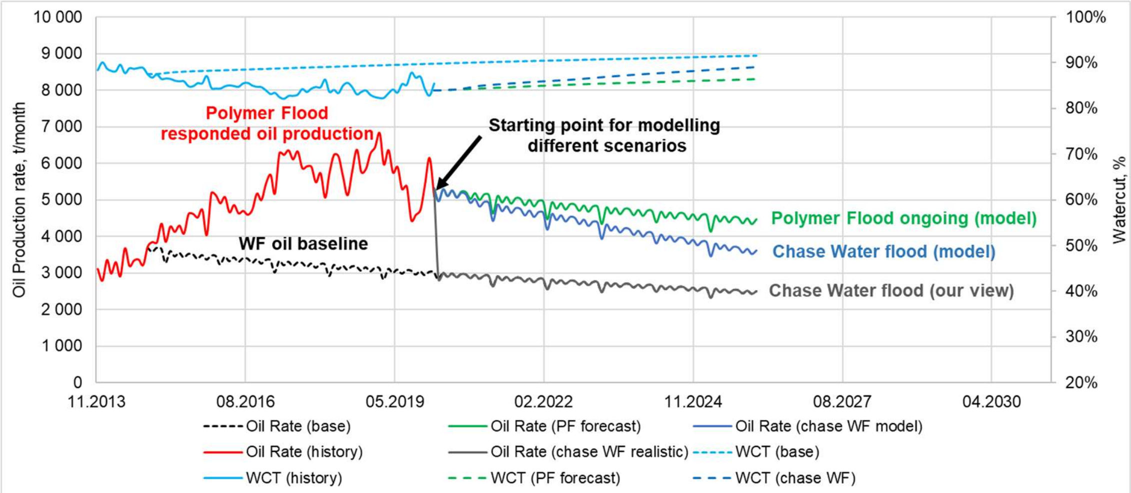


Figure 3: *Post polymer waterflood oil production response in the model.*

Field cases

Several field cases will provide additional insights on what is happening when water injection is resumed.

Oman – Marmul *(Al Sawafi & Aljabri, 2024).* The Marmul project targets unconsolidated sandstone reservoirs at depths ranging from 0.9 to 1.5 km, characterized by high heterogeneity and moderate permeability (50–500 millidarcies). These reservoirs contain medium to heavy oil with viscosities of 100–1000 cP at reservoir conditions. The injection patterns include both vertical and horizontal wells, with an injector-producer spacing of approximately 300 meters. The Marmul Polymer Plant (MPP) supports operations with a polymer preparation capacity of 4,000 cubic meters per day, designed to handle high-molecular-weight HPAM polymers used for improving sweep efficiency and mobility control.

When water injection resumed after polymer flooding, the field experienced a rapid and significant increase in water cut, with some wells showing increases of up to 40% within weeks. Oil production also saw a steep decline, with rates quickly returning to pre-polymer flooding levels, effectively negating much of the incremental oil gains achieved during the polymer phase. Intermittent water injection during polymer pump downtime, known as the Water-Alternating-Polymer (WAP) effect, exacerbated these challenges. Cumulative oil production deviated negatively by approximately 15–20% during these interruptions. These disruptions highlighted the critical need for continuous polymer injection to sustain performance and avoid re-establishing high-permeability preferential flow paths that dominate during water flooding (*Figure 4*).

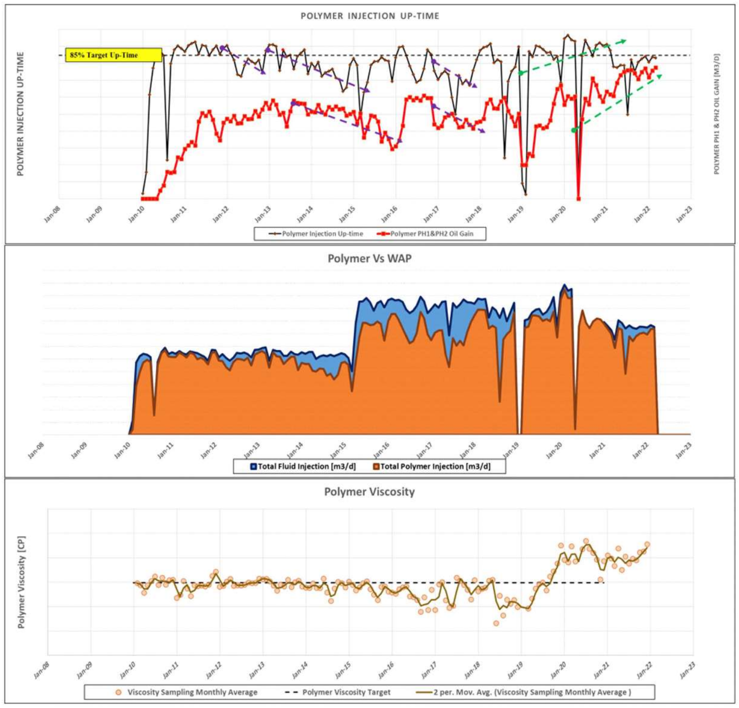


Figure 4: *Performance of oil production during polymer injection and Water-Alternating-Polymer injection in PDO's Marmul oilfield in Oman. Top graph: polymer injection up-time in purple; Oil gain in red. Middle graph: water injection volumes in blue, polymer in orange. Bottom: injected viscosity.*

Oman – South Oman *(Al-Sulaimani et al., 2022).* The polymer flood pilot was conducted in an unconsolidated sandstone reservoir in the south of Oman, characterized by low permeability (average 100 millidarcies) and high heterogeneity. The field features an inverted five-spot pattern with an injector-producer spacing of 75 meters. The reservoir's challenging conditions, including its lower permeability compared to typical polymer flooding projects, required the use of a specially designed, relatively low molecular weight polymer to sustain injectivity and improve recovery. Fiber optics were used for real-time monitoring of injection conformance during the transition from water to polymer injection. The Distributed Temperature Sensing (DTS) and Distributed Acoustic Sensing (DAS) tools installed in the injectors provided valuable insights into fluid flow behavior. During water injection, the fiber-optic data revealed that most of the fluid was entering the lower perforations, while the upper perforations were not utilized. Upon switching to polymer injection, a more uniform injection profile across all perforations was observed, indicating improved conformance. Additionally, fiber-optic monitoring identified anomalies such as temporary loss of acoustic signals, which correlated with a drop in injection pressure and suggested variations in polymer viscosity which appear to have a direct impact on sweep and conformance efficiency. This clearly shows that, between the two layers, the one that received the majority of fluid during water injection continued to remain active when viscosity decreased, indicating that the preferential flow path persisted (*Figure 5*).

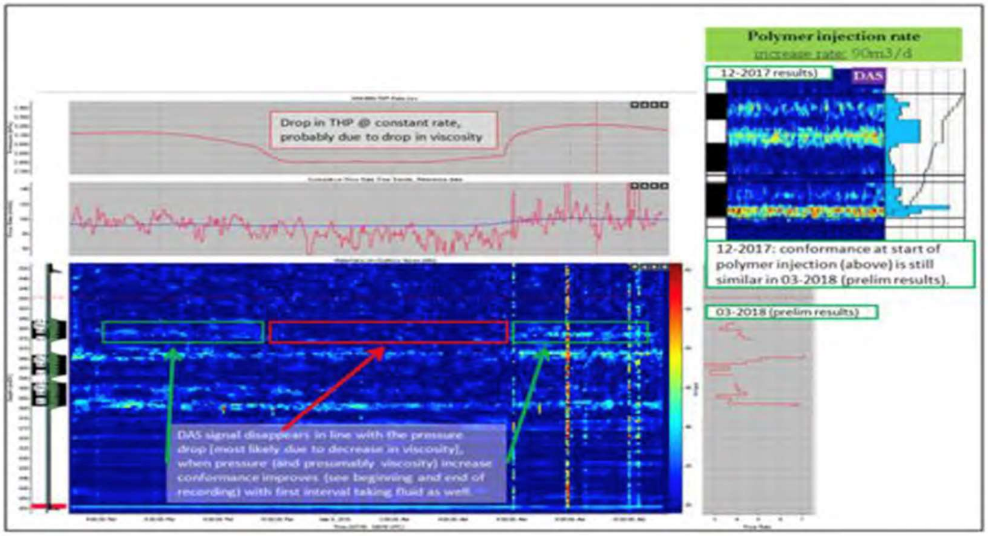


Figure 5: *DAS monitoring of conformance profile during polymer and water injection. "Noise" appears in green to red colors, blue being no "noise". The X-axis represents time with polymer injection corresponding to the green rectangles, and water injection to the red rectangle. We see that noise disappears in the upper layer in the red rectangle, meaning water only goes into the bottom high permeability layer. Caption reads: DAS signal disappears in line with the pressure drop (most likely due to decrease in viscosity), when pressure (and presumably viscosity) increase conformance improves (see beginning and end of recording with first interval taking fluid as well) (Al-Sulaimani et al., 2022).*

China - Daqing. The La-Sa-Xing field in the Daqing complex is the one of the largest oilfields in China and the largest polymer flood project in the world. The fieldwide commercial polymer flood application started in 1996. By 2021, the cumulative additional oil production by polymer flood accounted at 1,782 million barrels. In 2019 this project covered 9,983 injectors and 11,200 producers. The Daqing project targets multilayered, heterogeneous sandstone reservoirs deposited in a lacustrine river delta, consisting of >100 flow units with an air permeability of 50–4,000 millidarcies (610 millidarcies on average) at average depth of 750 m, characterized by high heterogeneity (interlayer permeability contrast of >10) and individual flow unit thickness of 2-20 ft. The crude oil has an API gravity of 33° and in-situ viscosity of 8.5-10.3 cP. Based on the permeability, three types of reservoir sands are identified. Currently, Type I and Type II sands are the main targets, and Type III is the potential (Lu *et al.*, 2023). At Daqing, after injecting ~1 PV of 40-cP polymer solution (well spacing: 250 m), water cuts typically stabilized at about 90% (Seright, 2017). When injection was switched from polymer to water at Daqing, water breakthrough was first noted after ~0.02 PV (by the first increase in water cut). During continued water injection, the water cut rose and stabilized at 96%-98% after 0.23 PV of water (Han 2015).

Mangala- India. The Mangala is the largest oil field in the Barmer basin of Rajasthan, India. It is the largest polymer flood in India, and second largest in the world (after Daqing). The Mangala field put on commercial production with waterflood in 2009 and full field polymer flood started in 2015. Polymer flood enhanced oil recovery above the anticipated waterflood recovery nearly 93 million barrels in 6 years. The major producing intervals are shallow Paleocene Fatehgarh sandstones. The paraffinic oil is moderately viscous (8 to 16 cP) with wax appearance temperature only 2–3°C lower than the average reservoir temperature of 67°C (Shankar *et al.*, 2022).
At the Mangala polymer flood pilot, the main polymer-bank concentration was 2000-2500-ppm HPAM. After the polymer concentration was reduced to 1700-1800-ppm HPAM, injection profiles gradually deteriorated (Prasad *et al.* 2014).
At Daqing and Mangala, evidence (described above) reveals that the post water injection led to severe viscous fingering/channeling (water breaking through the polymer bank) and/or re-establishing high-permeability preferential flow paths that dominate during water flooding.

Kazakhstan - Kalamkas. Sagyndikov *et al.* (2018, 2022a, 2022b) reported on the performance of one of the first polymer flooding pilots at the Kalamkas field, highlighting its initial success and challenges following the resumption of water injection. The project began with laboratory studies in 2014 to select a suitable polymer solution, targeting a viscosity of 22–25 cP using 2600 ppm of HPAM GL-50. Pilot injection started on the West side in 2014 and expanded to the East side in 2015. In the "East-1" pilot area, involving a 5-spot pattern with 4 injectors and 9 offset producers, polymer flooding showed promising results: oil rates increased by 60%, and water cut decreased from 91% to 86% at 30% of injected pore volume (PV). However, in 2017, when 50% PV was reached, the injectors were switched back to waterflooding. This transition led to a rapid rise in water cut during the first month, and oil production rates returned to their pre-polymer levels, effectively negating the incremental gains achieved through polymer flooding (*Figure 7*).

A subsequent extension of polymer flooding to the "East-2" area began in 2018, using 2700 ppm of Flopaam 1630s to maintain the target viscosity. This phase yielded over 180,000 tons of incremental oil by June 2022. Despite the continued potential for increased oil recovery, the project was again transitioned to water injection due to lower economic returns compared to the West pilot. As observed previously, this change caused an immediate increase in water cut and a return of production rates to baseline levels, underscoring the challenges of sustaining the benefits of polymer flooding after water injection resumes (*Figure 7*).

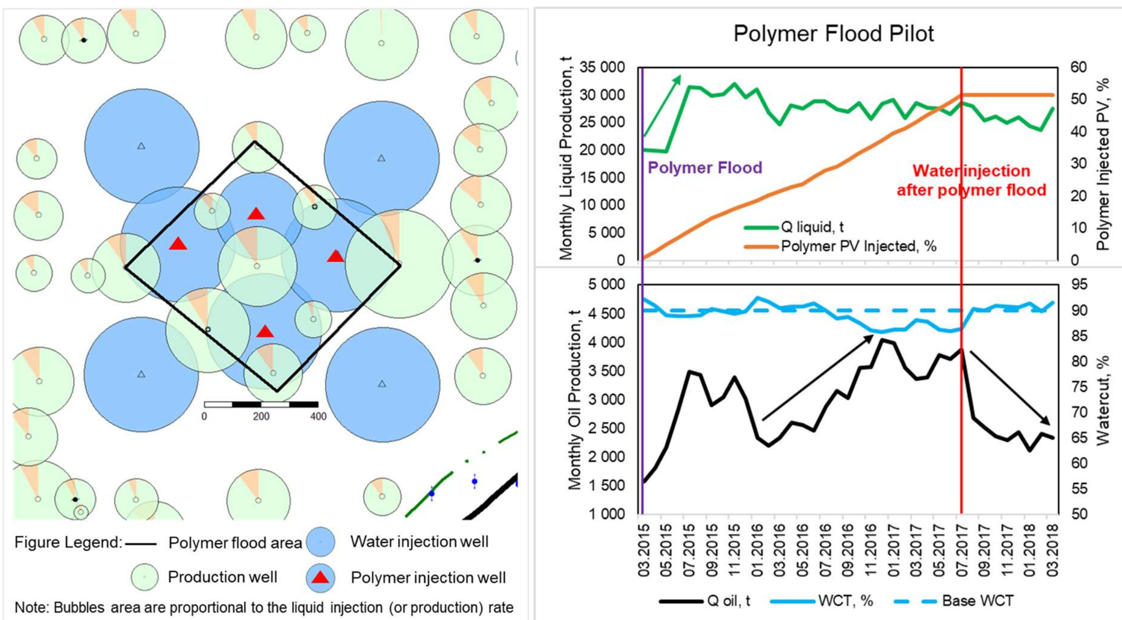


Figure 6: *Reservoir response in Kalamkas oilfield during and after polymer injection "East-1" (Sagyndikov et al. 2022b)*

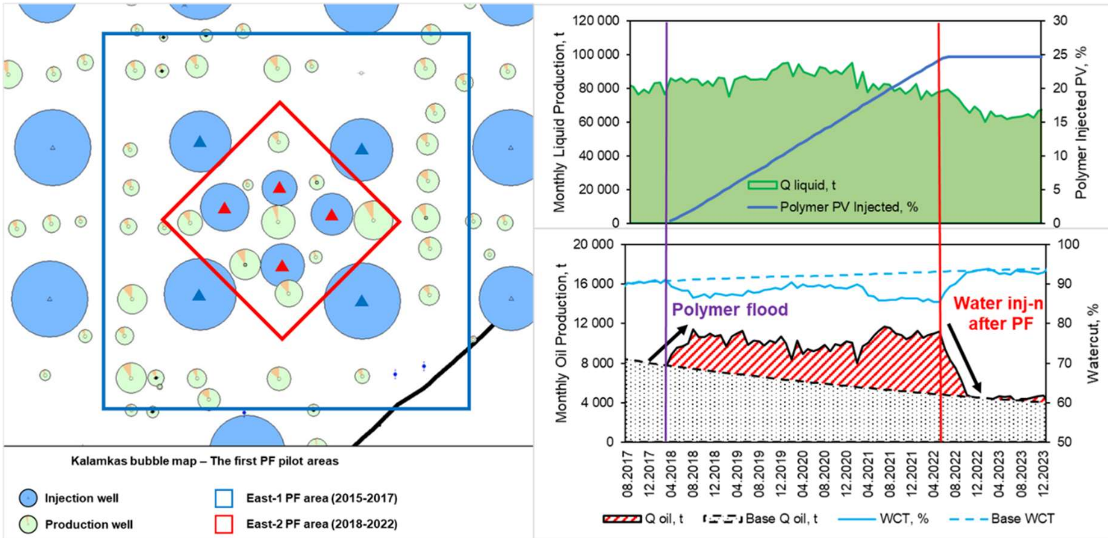


Figure 7: *Reservoir response in Kalamkas oilfield during and after polymer injection "East-2"*

Despite the negative experience with post-polymer waterflooding, the polymer response demonstrated the effectiveness of polymer flooding, revealing the potential to extend polymer flooding to neighboring well patterns. Additionally, it was concluded that polymer flooding should be conducted for as long as possible until the economic limit is reached, without reverting to waterflooding. This important finding has been recommended for the full-field implementation at the Kalamkas field (Kushekov *et al.* 2024) and the pilot test at the Uzen field (Imanbayev *et al.* 2022).

Carmopolis – Brazil. Carmopolis was among the first Brazilian oilfield in implementing polymer flooding, first at the end of the 60's from 1969 until 1972 and then at the end of the 90's from 1997 to 2003. This second pilot will be the focus of the discussion below. The Carmopolis oilfield, located in Northeastern Brazil's Sergipe/Alagoas basin is the country's largest onshore oil accumulation, with an OOIP of 253 x 10^6 m^3 (Mezzomo *et al.*, 2001). The field was discovered in 1963 and produces from a complex multilayered reservoir system composed primarily of sandstones and conglomerates in the Carmopolis/Muribeca formation, with additional production from the Barra de Itiuba formation and the fractured basement. Main reservoir characteristics can be summarized as follows:

- Lithology: Predominantly sandstone and conglomerate
- Thickness: 50 meters in the main producing zones
- Porosity: Varies significantly across different facies
    - Conglomerates: ~9%
    - Coarse-grained sandstones: ~14%
    - Fine-grained sandstones: ~20%
- Permeability: Ranges from 36 millidarcies in conglomerates to 128 millidarcies in sandstones
- Water/Oil contact: Shows a slight inclination, with the depth ranging from –760 m in the Northeast to –800 m in the south. This variation is attributed to differential cementation, lithology variations, and biodegradation effect.
- API gravity: Varies significantly due to different formations
- Oil viscosity:
    - 90 to 100 cP for the Carmopolis/Muribeca formation
    - Higher viscosity for the Barra de Itiuba formation
- Gas-Oil-Ratio: Low to moderate
- Capillary pressure & wettability: Mixed wettability, with a tendency toward water-wet behavior.

The main reservoir challenges are the high heterogeneity because of the intercalation of shale lenses and conglomerate facies leading to complex flow dynamics, the adverse mobility ratio reducing waterflood efficiency, early water breakthrough caused by high-permeability streaks and poor sweep efficiency, lack of vertical conformance due to reservoir layering and permeability contrasts.

The implementation of polymer flooding technology appeared as the best solution to overcome these issues and improve field performance. The polymer pilot consisted of four inverted nine-spot patterns, each covering approximately 4 hectares and referred to as patterns A, B, C and D as shown in *Figure 8*. Polymer injection targeted five multilayered reservoirs.

- In patterns B, C and D, injection wells were completed across all target zones to maximize polymer distribution
- In pattern A, the injector was completed only in the bottom of zone CPS-2, targeting a single porous rock body

The pattern highlighted in green, consisting of the four injectors and 5 producers (wells 1, 2, 3 and 4 and the central producer) was designed as the central pattern while the combination of the four A, B, C, D patterns was referred as the Pilot total pattern. The Pilot total pattern, highlighted in red includes 4 injectors and 21 producers.

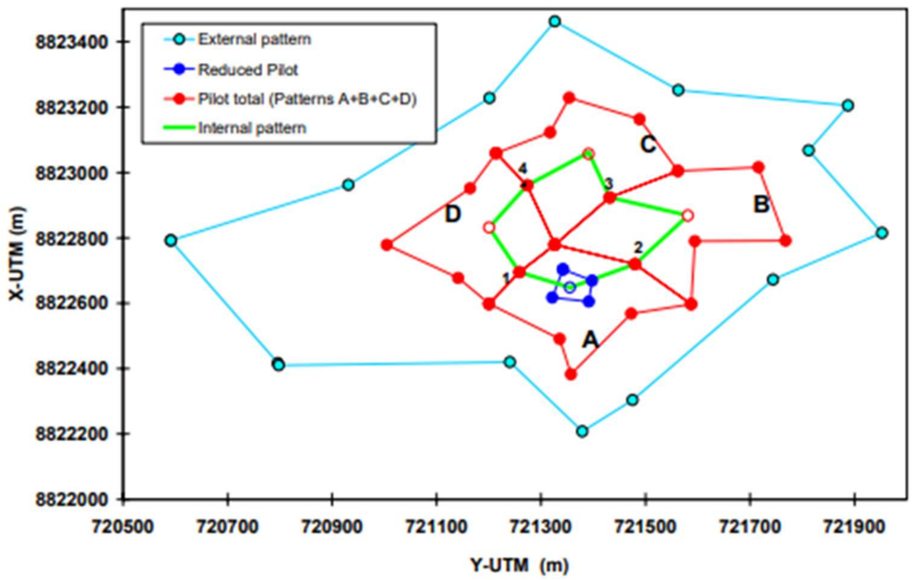


Figure 8: *Polymer flooding pilot area in Carmopolis oilfield (taken from Melo et al. 2010).*

To monitor the flood's performance, four observation wells were drilled in pattern A, each located around 60 meters from the central injector and completed in the same interval. This specific pattern, referred to as the reduced pilot and highlighted in dark blue served two purposes:

1. Enhancing monitoring capabilities by providing detailed insights into polymer propagation
2. Accelerating production response, as the additional wells were expected to detect early changes in oil production

In the literature there is not much interpretation of the pilot afterwards. Mezzomo *et al.* (2001) reported an early breakthrough (2-3 months) of the polymer in reduce pattern because of the severe heterogeneity of the reservoir and of the low spacing between the central producers and the observation wells (60 m only). More interesting are the data shared by Melo *et al.* (2017) and reported in *Figure 9* for both the internal pattern (left) and the pilot total pattern (right). These graphs represent the evolution of the Oil production rate and of the Water/Oil ratio (WOR) as a function of the cumulative oil production for both patterns:

- Prior to the start of the polymer injection (vertical purple line) oil production was strongly declining and WOR was following an increasing trend.

- During polymer injection, a sharp decline in WOR was observed and oil production stabilized, indicating improved mobility control and sweep efficiency
- After the stop of the polymer (green vertical line), oil production started declining sharply as the polymer effect diminished and WOR resumed its upward trajectory, finally surpassing pre-polymer levels, which indicates a return to poor sweep efficiency and increasing water cut.

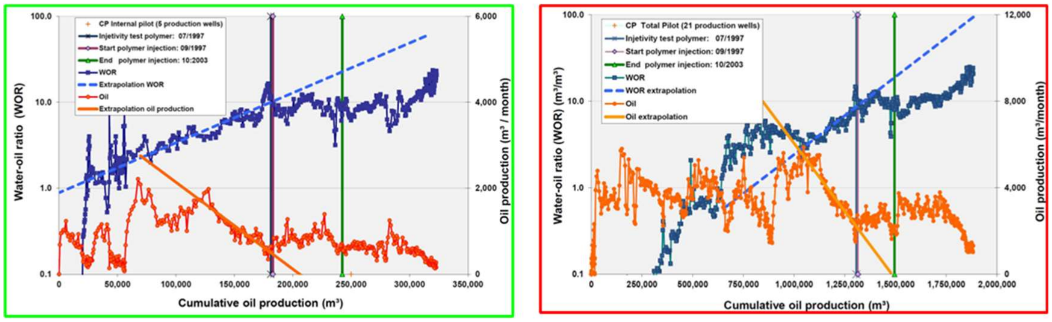


Figure 9: *Production profile of the internal pilot (5 production wells – green line – left) and of the pilot total pattern (21 production wells – red line – right) of the Carmopolis polymer flooding pilot (adapted from Melo et al. 2017).*

The main conclusions from the Carmopolis polymer flooding pilot are that polymer flooding significantly reduced WOR and increased oil production, confirming its efficiency in improving mobility control and correcting vertical conformance issues. Stopping polymer injection reversed these benefits, leading to increasing WOR and declining oil output. These data support the continued use of polymer flooding in such reservoirs to sustain production and delay excessive water production.

Canada - Heavy Oil Polymer Floods

Many heavy oil reservoirs in western Canada were original drilled with vertical wells, marginally produced, or possibly with some success through Cold Heavy Oil Production with Sand (CHOPS); however, much of the production and subsequent development came from horizontal drilling and polymer flooding. Depending on the reservoir permeability, oil viscosity, well completion (sand control) to mitigate the formation of void spaces) and flood strategy, recovery responses could be variable.

The following example is of a horizontal development in the General Petroleum sand having an average reservoir permeability of 2,000 millidarcies and heavy oil viscosity ranging from 2,000-5,000 cP, depending on how degassed the oil is at the time of production. As shown in *Figure 10*, after a 1-year long primary production phase, waterflood was implemented at fairly high rates (100+ m^3/d/well) and within 2 months, peak oil of 56 m^3/d (for 4 producers) was momentarily achieved, before water breakthrough increased watercut to 95% and WOR increased to 20 m^3/m^3 before a tertiary polymer flood was initiated in 2017.

Due to the prior water breakthrough and non-conformance in the waterflood, the polymer flood response required a conformance treatment (vertical green arrow) to fix the problematic breakthrough before oil response was observed approximately 6 months after polymer injection start with rapid reduction in water cut down to 82% and increase in oil rate from 8 m^3/d to 32 m^3/d for the pattern. The decision to return to water injection was made (instead of staying on polymer) for the approximate time period of 1 year while the entire field was readied for commercial polymer flood. This is indicated by the second blue vertical arrow and the watercut immediately spiked back to 95% and rapid rise of the WOR back up to ~30 m^3/m^3. The polymer flood was resumed in 2019, however, watercut never decreased below 85% and a broad peak oil response was obtained requiring 2.5 years to reach a new peak oil of ~22 m^3/d and currently exhibits a similar decline profile to the waterflood of 30%. Current Recovery Factor is approximately 19 %OOIP after 1.5 years of primary production, 3-4 years of waterflood and 7 years of polymer flood.

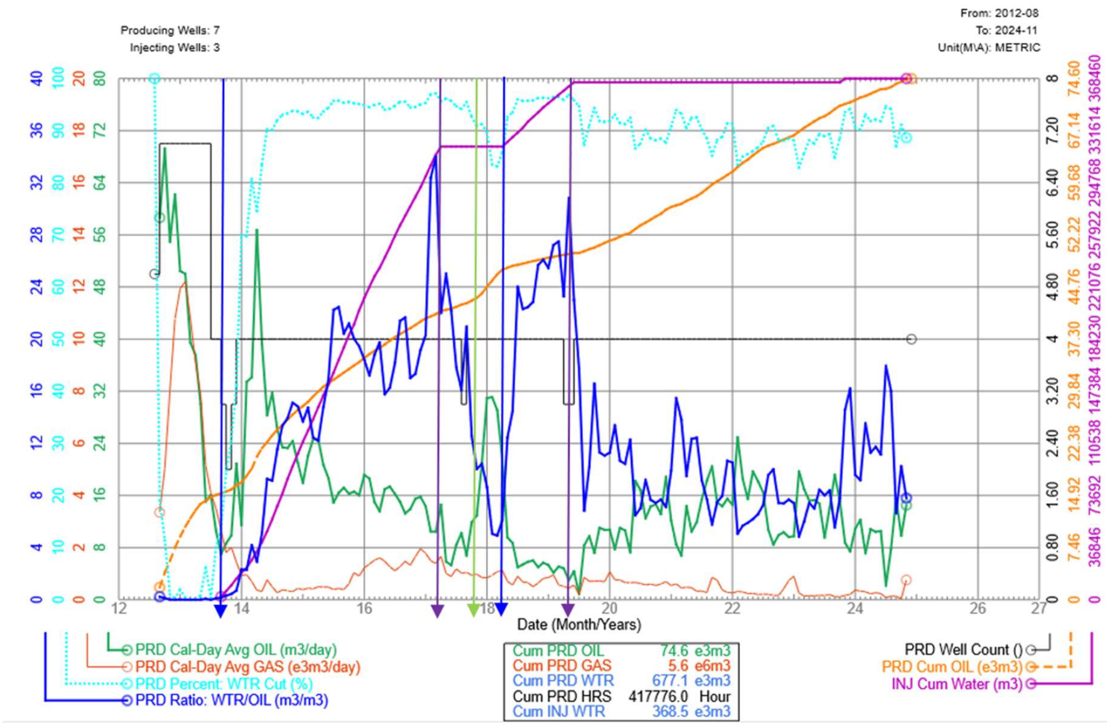


Figure 10: *Tertiary, horizontal heavy oil, polymer flood: 1-year Primary, 3.5-yr Waterflood and 7-yr Polymer Flood showing strong breakthrough after return to waterflood.*

The next example is of a horizontal development in the Lloydminster sand having an average reservoir permeability of 800-1,100 millidarcies and heavy oil viscosity of 2,300 cP. As shown in *Figure 11*, after a 3-year long primary production phase, waterflood was implemented at fairly high rates (100+ m^3/d/well) in 2014 and within 2 months, peak oil of 60 m^3/d (for 8 producers) was achieved for nearly 1 year before declining at ~35% to a base oil rate of 25 m^3/d, 95% watercut and WOR of 20. After nearly 3.5 years of waterflood a tertiary polymer flood was initiated in 2018. The tertiary polymer flood was performed in a high-to-low viscosity gradient, consisting of a 50-cP slug for ~1 year, followed by a larger pore volume of 30-cP for 3 years and then down to a 20-cP slug in 2022 as discussed in greater detail by Raffa and Abedini (2023). Although no micromodel tests were performed at the different viscosities, a separate work by Qi et al. (2022) evaluated the influence of injected polymer viscosity nominally of 20 cP and 40 cP, as well as oil recovery performance comparison when chip wettability was more oil- or water-wet, as shown in *Figure 12* where polymer displaces brine, followed by brine fingering through the polymer bank at 1/3 the pressure; 3b) where 40-cP polymer recovered ~55 %OOIP in ~1/3 of the time and c) where oil wettability is observed to delays and reduces ultimate recovery efficiency and is in line with field performance trends with polymer viscosity graduation.

Due to the prior water breakthrough and non-conformance in the waterflood, the polymer flood response required a conformance treatment in late 2018 (vertical green arrow) to fix the problematic breakthrough from two injection wells to one common producer, before a dramatic increase in oil response was observed approximately 6 months after polymer injection start. A gradual reduction in water cut down to 85%, WOR down to 7 and increase in oil rate from 22 m^3/d to 78 m^3/d for the pattern. Oil production was maintained above 70 m^3/d for 2 years, with a shallow 11% decline, before more severe breakthrough began to occur with reductions in polymer viscosity. With the WOR back over 12, the pattern is at a decision point to continue polymer, transition back to water, or explore conformance intervention to improve the back-end polymer efficiency. As of 2023, a shallower decline profile to the waterflood is observed of ~25%, with the current Recovery Factor at approximately 13.9 % OOIP after 3 years of primary production, 3.5 years of waterflood, and 7 years of polymer flood.

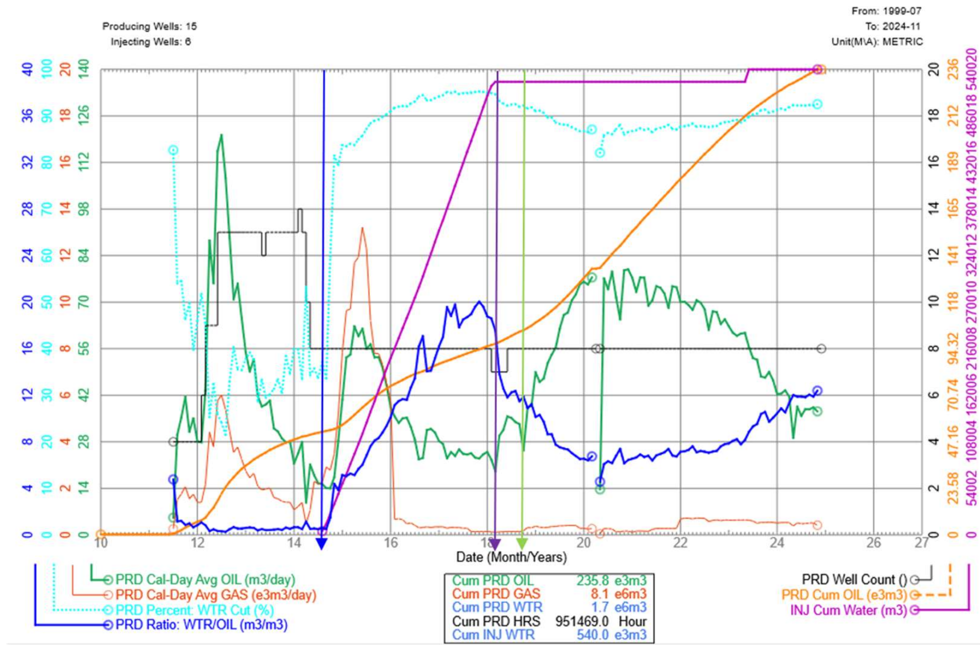
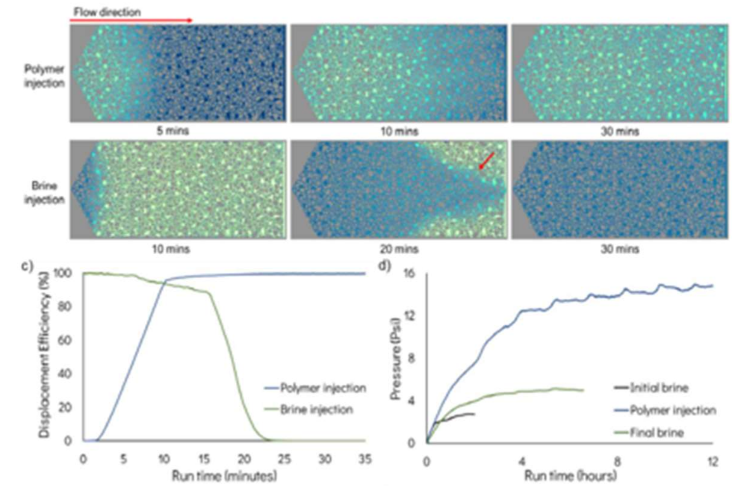
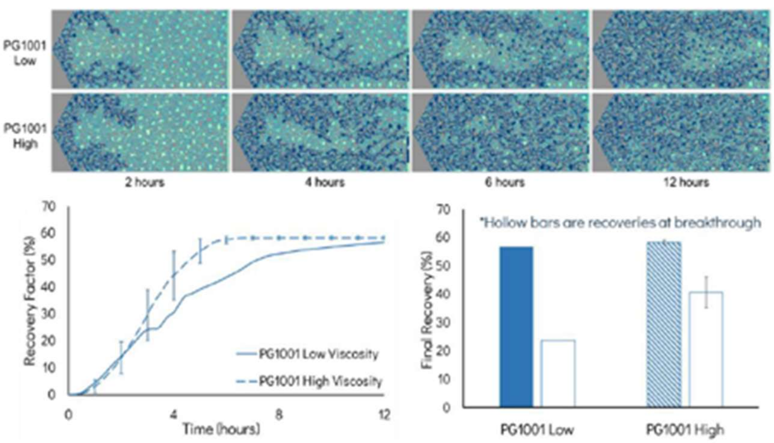


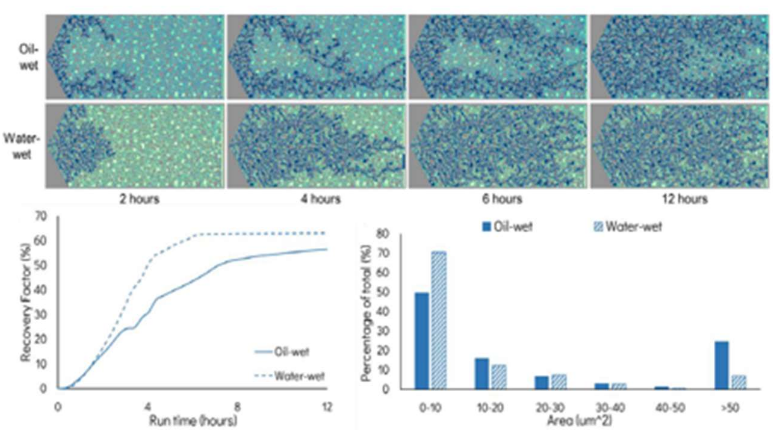
Figure 11: *Tertiary, horizontal heavy oil, polymer flood: 3-year Primary, 3.5-yr Waterflood and 7-yr Polymer Flood showing strong breakthrough delayed.*



a)



b)



c)

Figure 12: *a) Polymer displacing brine, followed by brine fingering/displacing polymer; b) 20-cP vs. 40-cP polymer flood; c) 20-cP polymer flood for oil-wet vs. Water-wet conditions, Lloydminster Case.*

A similar reservoir in the Big Gully area of the western Canadian heavy oil region of Lloydminster also developed with horizontal wells; however, this pattern recovery strategy forewent waterflood and proceeded directly to primary polymer flood from day 1. The average reservoir permeability of 750 millidarcies and average heavy oil viscosity ranging from 2,700 cP, gives a comparison to the previous case. The successful demonstration is further outlined in Ulovich et al. (2023)

As shown in *Figure 13*, the polymer flood response was nearly immediate, achieving a peak oil rate of 42 m^3/d (for four producers) for the pattern after four months; however, a fairly flat oil production rate ranging between 35 to 40 m^3/d was maintained for 7 years, with WOR remaining below 3 m^3/m^3. Approximately 4 years after starting the polymer flood, a peak oil of 45 m^3/d was achieved with a WOR low of 1.8. There appears to be a period between 2023-2024 where approximately 4,000 m^3 of water was injected. This change caused a much larger increase in WOR up to 5, watercut to increase past 80% for the first time in the flood and oil rate decreased down to 25 m^3/d. It is difficult to discern what the decline of this pattern may be with continued water injection; however, the pattern Recovery Factor for this flood is on the order of 11 %OOIP after 7 years of polymer flood only and still shows signs of resilient production and low WOR. An additional Recovery Factor is expected with continued polymer flood and selective gel conformance intervention to redistribute the polymer flood.

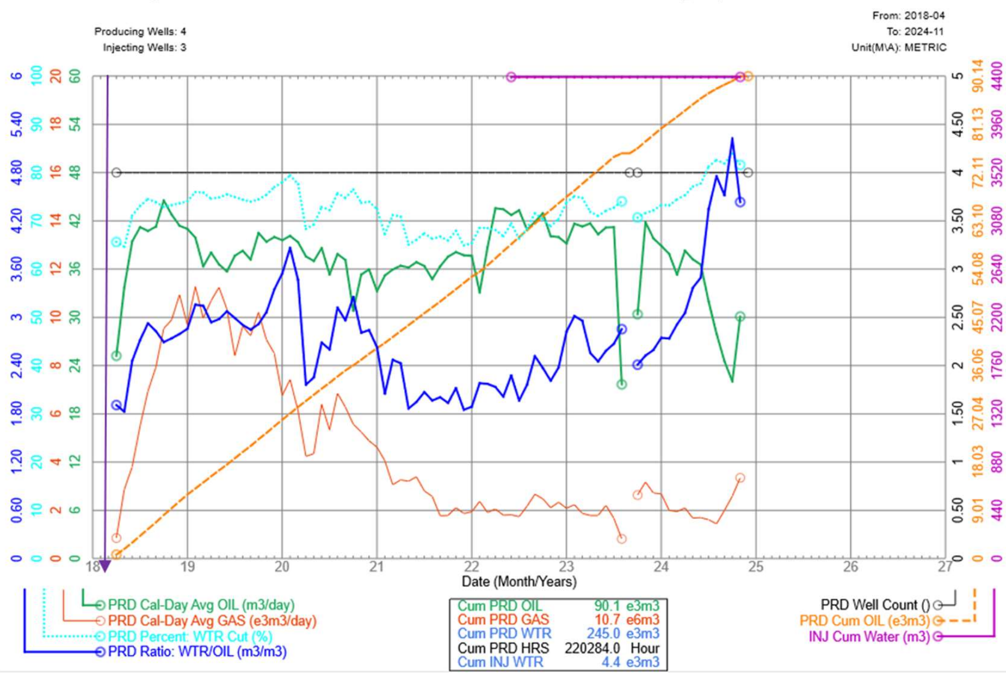


Figure 13: *Tertiary, horizontal heavy oil, polymer flood: No Primary, No Waterflood and 7-yr Primary Polymer Flood showing strong breakthrough greatly delayed.*

This was also observed in the Brintnell Wabiskaw field where the majority of new polymer flood development over the past decade has utilized the primary/secondary polymer flood strategy and foregoing prior waterflood recovery. With *Figure 14* adapted from Delamaide (2016), the graph shows a clear contrast between tertiary and primary/secondary polymer flood patterns in Brintnell. It was observed that tertiary polymer floods produced most of the oil at WOR of 5-10, while polymer floods without prior water injection produced most of the oil at WOR of 0.1-1. Further evaluation revealed that the early polymer floods exhibited 10 %OOIP incremental recovery before the WOR reaches 1 vs. the tertiary floods. This is largely due to the fact that the tertiary polymer flood can channel through existing water channels, reducing the efficiency of the flood from the beginning, while the primary polymer flood does not exhibit water channels or enhanced permeability features through scouring and reduced chance of dilation.

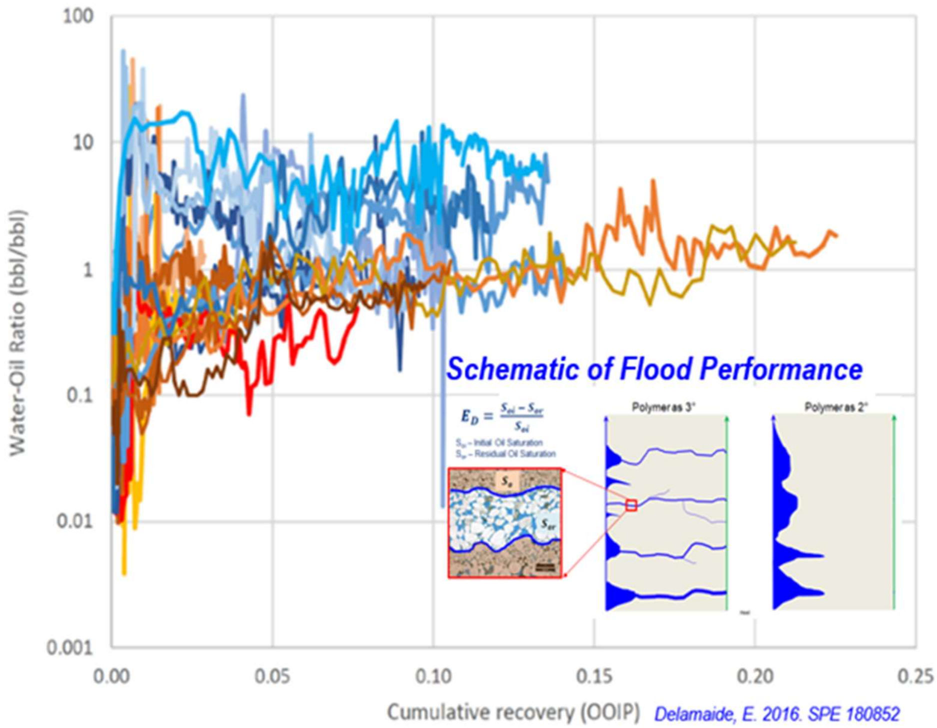


Figure 14: *Comparison of Tertiary and Secondary polymer floods in Brintnell Wabiskaw (adapted from Delamaide, 2016).*

Lastly, in order to better understand the heavy oil displacement mechanism of waterflood and polymer flood, Wilton (2015) constructed a large 3D physical sandpack model to evaluate and compare to a heavy oil field case of a Lloydminster sandstone with an average permeability of 2,500 millidarcies, with some layers approaching 9,000 millidarcies and heavy oil viscosity was on the order of 1,500-2,000 cP (*Figure 15*). The oil field had been primary developed with vertical wells and line-drive flooded by water flood for approximately 2.2 PVs. The recovery factor from the field at this time was ~16 %OOIP, and the average watercut was 95%. The model was wet-packed with a representative sand particle-size distribution and permeability confirmed in 1D corefloods to be ~5,000 millidarcies. After 2.2 PVs of waterflood, the 3D physical model recovered approximately 18.5 %OOIP at an oil cut of 3%. Upon switching to a 25 cP viscosity polymer flood, response was timely (after 0.1 PV, ~1-2 months in field) and the producing oil cut averaged 30-40% through the next 0.7 PV of polymer flood injection. Despite the fact the model was still producing at good oil cut, the decision to move to waterflood was made since the field design called for return to waterflood after 0.7 PVs of polymer injected. Within 0.01 PVs, (~days in field), severe water breakthrough was observed and oil rate across the model plummeted to 2.5 %, with an extended waterflood sequence recovering oil~4 %OOIP under very high water cut conditions. At the end of the test, the model was excavated and imaged, the cleaned sections are polymer flood recovery, while the dyed sections are where post-polymer flood waterflood went and show strong channeling through both oil and polymer banks. The inset shows the water drainage channel (yellow) into a corner well vs. swept polymer drainage channel (purple).

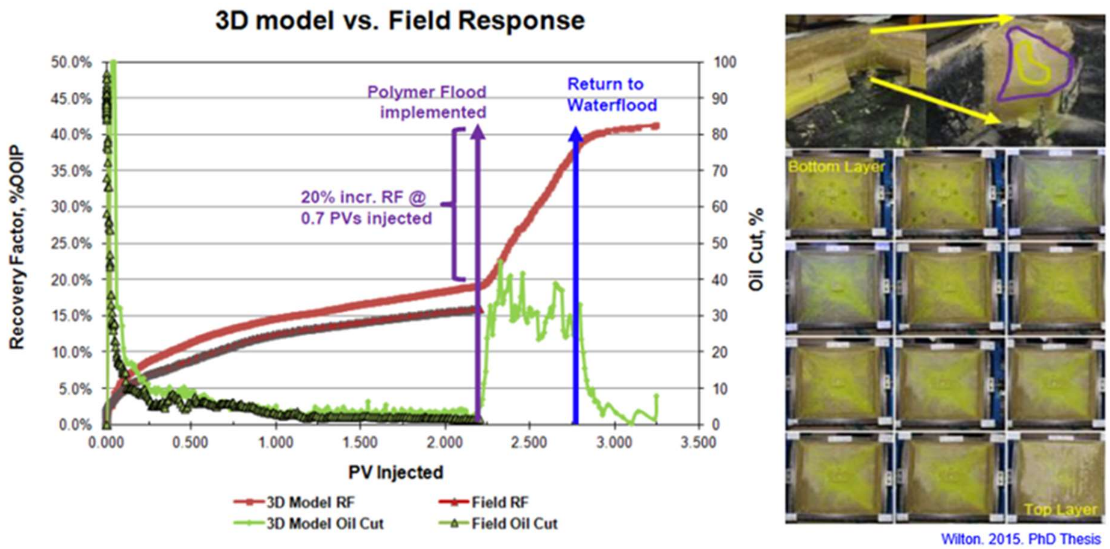


Figure 15: *3D Physical model of heavy oil waterflood and polymer flood process, illustrating the early return to waterflood and impact on production performance (Adapted from Wilton, 2015).*

Conclusions & Implications on the design

The transition from polymer flooding to water injection remains a critical phase in enhanced oil recovery (EOR) operations, with significant implications for reservoir performance and long-term recovery efficiency. This paper has demonstrated that while theoretical models and simulation frameworks provide valuable insights, their predictive capability remains constrained by underlying assumptions and simplifications. Many simulation-based approaches fail to account for the complexities of real reservoir conditions, including heterogeneity, multi-phase flow dynamics, and the persistence of preferential flow paths established during earlier production stages.

A key takeaway from the global case studies analyzed is that laboratory tests must be designed to closely replicate field conditions. Polymer flooding performance depends on a precise understanding of mobility control, polymer retention, and in-situ rheological behavior under varying shear conditions. Laboratory workflows should incorporate representative shear rates, permeability contrasts, and reservoir characteristics to avoid erroneous estimations of injectivity, retention, and oil recovery factors.

Furthermore, while numerical simulations offer a structured methodology for assessing polymer injection strategies, they must be calibrated against field data and physical evidence. This includes ensuring that the input parameters, such as polymer adsorption, residual resistance factor, and polymer propagation behavior, are derived from reliable laboratory experiments and validated with field-scale performance data. The frequent overestimation of polymer effectiveness after water injection is resumed and the underestimation of viscous fingering effects in simulation studies highlight the necessity of benchmarking simulation outputs against observed post-polymer waterflooding responses.

Field evidence strongly suggests that transitioning back to water injection after polymer flooding often leads to rapid increases in watercut and substantial reductions in oil production, effectively negating prior gains. This trend, observed in multiple fields, underscores the need for an informed, data-driven approach when designing polymer floods, particularly in defining the appropriate slug size and injection tapering strategies. Instead of relying solely on theoretical constructs, operators should integrate insights from historical field cases, recognizing the limitations of graded viscosity bank models and optimizing injection protocols to sustain recovery gains for as long as economically viable.

Future research should prioritize improving the representativity of laboratory tests, refining simulation models with enhanced physics, and continuously validating theoretical predictions with real-world reservoir behavior. By doing so, the industry can move toward more robust, adaptable polymer flooding strategies that maximize oil recovery while mitigating the adverse effects of post-polymer water injection.

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