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Polymer-Oxygen Scavenger for Oil Recovery in Sandstone

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ABSTRACT - Polymer degradation is caused by dissolved oxygen remains a major challenge in Enhanced Oil Recovery (EOR) for sandstone reservoirs, especially under moderate salinity (18,000 ppm) and temperature (60°C) conditions, which accelerate viscosity loss. While HPAM polymers are highly effective, ensuring their long-term stability requires strategies that preserve molecular integrity throughout the injection process. This study employs laboratory experiments to assess two HPAM variants (FP 3630 and FP 3230), both in conventional formulations and with an oxygen scavenger ($NaHSO_3$), using Bentheimer synthetic cores. Evaluations cover fluid-to-fluid (compatibility, rheology, filtration, thermal stability) and fluid-to-rock (injectivity, core flooding) performance under reservoir conditions. Results identify FP 3630 at 1400 ppm with 0.1% $NaHSO_3$ as the optimal formulation. The oxygen scavenger significantly improves thermal stability and reduces viscosity degradation from 32.83% to 4.24%. This formulation achieves an ideal Resistance Factor (11.44) and causes minimal formation damage (RRF 1.01), while enhancing the Recovery Factor from 67.38% to 87.29%. These findings confirm that the incorporation of oxygen scavengers effectively minimizes polymer degradation and establishes them as a crucial component for the successful implementation of EOR in moderate-salinity sandstone reservoirs.

Keywords: enhanced oil recovery, oxygen scavenger, polimer HPAM, recovery factor, sodium bisulfite.

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INTRODUCTION

Conventional oil production methods comprising primary and secondary recovery typically recover only about 20–40% of the total original oil in place (OOIP), leaving more than 60% of the oil still trapped within the pores of the reservoir rock (Olajire 2014). This low efficiency is caused by an imbalance in mobility between the injected fluid and the oil, where the lower-viscosity injected fluid tends to flow faster through the dominant pathway, causing viscous fingering and low sweep efficiency (Beteta et al., 2022).

As a solution to the limitations of conventional recovery methods, enhanced oil recovery (EOR) techniques are employed to improve oil extraction by altering reservoir fluid properties and enhancing fluid–rock interactions. Through these mechanisms, EOR has the potential to increase the recovery factor to as much as 60–70% of the OOIP. (Abidin et al., 2012; Sheng, 2019). In Indonesia, the implementation of EOR is crucial given that most oil fields have entered the mature phase and are experiencing declining production (Ministry of Energy and Mineral Resources 2021). EOR techniques include steam injection, surfactant and polymer injection (chemical EOR), gas injection, and microorganism-based technology (Sun & Bai 2022).

Among the various CEOR methods, polymer flooding has proven to be the most well-established technique, especially in sandstone reservoirs containing light to medium oil. This has been demonstrated in several laboratory studies on Sumatran light oil, where reservoir heterogeneity was shown to have a significant impact on sweep efficiency (Ramadhan et al., 2023). This technology has been implemented in more than 300 projects worldwide, recognized for its effectiveness in enhancing oil recovery efficiency by increasing the viscosity of the injected fluid (Alvarado & Manrique 2010; Sorbie 1991). A study by Ambirbayov (2014) reported that this technique can increase additional recovery by 5–20% OOIP (Rellegadla G.; Agrawal, A. 2017). The fundamental principle of polymer flooding lies in controlling the mobility ratio the ratio between the mobility of the injected fluid and that of the oil. By adjusting the fluid mobility to be equal to or lower than the oil's mobility ($M \leq 1$), polymer flooding helps prevent viscous fingering and enhances the overall sweep efficiency of the displacement process (Don W. Green 1998; Cao et al., 2022).

The most commonly used polymer is Partially Hydrolyzed Polyacrylamide (HPAM) due to its viscosity stability, chemical properties tuning, and relatively low cost (Thomas N.; Favero, C., 2012; (Seright 2017). HPAM is non-Newtonian with shear-thinning behavior, making it easy to inject into rock formations (Larsen 2014). However, challenges arise, especially in reservoirs with moderate salinity (15,000–30,000 ppm), where multivalent ions such as Ca^{2+} and Mg^{2+} can reduce viscosity through ionic interactions resulting in polymer chain contraction (Hassan et al., 2022; Zaitoun et al., 2003; Shakeel M. S.; Al-Harthi, M. A. 2022). Despite this, high-molecular-weight HPAM can still maintain 60–75% of its initial viscosity at a salinity of 18,000 ppm (Wei L.; Rodrigue, D., 2014).

HPAM degradation in reservoirs is a critical issue, encompassing thermal, mechanical, chemical, and biological degradation (Slaughter 2010). Among these factors, oxidative degradation is the most detrimental, as it results from free radical reactions that attack the polymer chainsespecially under high-temperature conditions and in the presence of dissolved oxygen. (Sandengen et al., 2017; Du et al., 2024). Similar degradation issues have been observed in laboratory investigations of polymer flood performance in light oil reservoirs, where thermal stability tests showed viscosity reductions up to 30% over 90 days (Saputra et al., 2022). To overcome this challenge, oxygen scavengers such as sodium bisulfite ($NaHSO_3$) are utilized to neutralize dissolved oxygen and prevent the formation of free radicals. Their effectiveness has been well demonstrated in maintaining stable HPAM viscosity under reservoir conditions with a salinity of 18,000 ppm and a temperature of 60°C. (Wellington 1983; Jouenne 2020). Modern HPAM polymer formulations, such as FP 3230 and FP 3630, have been developed to enhance resistance to salinity and ionic degradation (Alli 2019). Polymer EOR with oxygen scavengers is particularly suitable for reservoirs containing medium to light oils (viscosity 2–10 cP, API gravity 30–40°), where the polymer increases the viscosity of the displacing fluid to match or exceed that of the oil, reducing mobility ratio and viscous fingering. The tested oil (viscosity 2.97 cP, API 32.3°) represents light-medium crude, ideal for HPAM as it allows effective sweep without excessive shear degradation. Heavy oils (>100 cP) may require higher polymer concentrations or alternative EOR methods due to injectivity issues. While polymer flooding is applicable to both sandstone and carbonate reservoirs, it is more effective in sandstones due to lower polymer adsorption (typically 0.1–0.5 mg/g rock) and more uniform pore structures, leading to better sweep efficiency. In carbonate reservoirs, higher polymer adsorption levels (0.5–2 mg/g) are commonly observed due to their positively charged surfaces and complex fracture networks, often necessitating the use of sulfonated polymers (such as ATBS-based types) to improve tolerance to high salinity. In contrast, this study focuses on sandstone formations (using Bentheimer cores), which closely resemble the geological characteristics of Indonesian reservoirs, particularly those in Java. In such formations, polymer adsorption is relatively low, allowing for Recovery Factor (RF) improvements of 15–25%, compared to only 5–15% typically achieved in unmodified carbonate systems. (Auni et al., 2023). This study conducted a comprehensive evaluation of the rheological behavior, thermal stability, and injectivity of the two polymers under simulated moderate-salinity sandstone reservoir conditions. The primary goal was to identify the most effective injection strategy to enhance CEOR performance and ensure success under the characteristic conditions of Indonesian georeservoirs. To ensure successful implementation, a multi-stage screening methodology was adopted. The initial phase involved evaluating the visual compatibility, viscosity, filterability, and thermal stability of the polymer solutions to determine their suitability for further testing and reservoir application (Veerabhadrappa & Nguyen 2011; Levitt & Pope 2008). The next stage includes a 30–90-day aging test to assess viscosity degradation at high temperatures, with a tolerance threshold of <30% viscosity reduction (Levitt & Pope 2008). Finally, a core flooding test was carried out to assess the oil recovery efficiency, focusing on key parameters such as initial oil saturation, recovery achieved through waterflooding, and the additional oil recovered through chemical (polymer) flooding (Al -Shakry et al., 2018; Green G. P., 1998).

Through a systematic evaluation approach and careful formulation selection, polymer flooding demonstrates strong potential to enhance oil production, particularly in Indonesia's mature fields positioning it as a vital component of the nation's future energy management strategy. This study also provides a comprehensive assessment of the rheological behavior, thermal stability, and injectivity of both polymers under simulated moderate-salinity sandstone reservoir conditions, with the goal of identifying the most effective injection strategy to ensure the success of CEOR operations within the unique geological characteristics of Indonesian reservoirs.

The novelty of this research lies in its integrated approach to fluid-to-fluid and fluid-to-rock characterization under controlled laboratory conditions simulating moderate-salinity and moderate-temperature sandstone reservoirs. It uniquely combines these evaluations with the use of oxygen scavenger–enhanced polymer formulations specifically designed to match the operational and geochemical characteristics of Indonesian reservoirs. This approach aligns with recent advancements in CEOR research that emphasize environmentally friendly chemical alternatives, such as vegetable-based sulfonate surfactants synthesized through Strecker modification, which could serve as complementary agents to polymer systems for improved environmental sustainability. (Putra et al., 2025). This targeted approach has not been systematically explored in previous studies for the region.

METHODOLOGY

Methods

This study is a laboratory-based experimental investigation designed to evaluate two types of Partially Hydrolyzed Polyacrylamide (HPAM) polymers SNF FP 3630 and FP 3230 both with and without the addition of the oxygen scavenger sodium bisulfite ($NaHSO_3$). The experiments were conducted under simulated conditions representative of a sandstone reservoir with moderate salinity (Larsen 2014). Tests were conducted via fluid-to-fluid and fluid-to-rock methods at 60°C and 18,000 ppm salinity to quantitatively assess the viscosity, thermal stability, and injectivity of the polymer.

The independent variables in this study were the polymer type and concentration (300–5000 ppm) as well as the $NaHSO_3$ concentration (0% and 0.1%). The control variables included the rock characteristics (Bentheimer sandstone with a permeability of 1800 mD), oil properties (viscosity of 2.97 cP and API gravity of 32.3°), temperature, salinity, and injection rate—all maintained consistently throughout the experiments to ensure reliable comparisons. The simulated reservoir characteristics include porosity of 23%, density of 1.0034 g/cc, and brine viscosity of 0.89 cP. The research process comprised several key stages: literature review, preparation of materials and equipment, experimental testing, data analysis, and conclusion drawing. The ultimate goal was to develop optimal polymer formulation recommendations capable of enhancing oil recovery efficiency during the advanced stages of production.

Data analysis in this study was divided into three main parts: fluid-to-fluid analysis, fluid-to-rock analysis, and mobility ratio (impingement stability) analysis. The fluid-to-fluid analysis involved visual evaluation, plotting viscosity versus concentration, calculating the Filtration Ratio (FR), and determining the rate of viscosity degradation. The fluid-to-rock analysis covered calculations of water permeability, Resistance Factor (RF), Residual Resistance Factor (RRF), recovery factor, and incremental oil recovery. The mobility ratio analysis was conducted using the End-Point method and the approach proposed by James Sheng (2011) to verify that the value of $M \leq 1$, indicating a stable displacement front.

Materials

The successful implementation of this research required adequate laboratory facilities and specific chemical materials to ensure a smooth process from sample preparation to data analysis. The equipment used included standard laboratory tools such as measuring cylinders of various sizes, drop and volumetric pipettes, beakers, volumetric flasks, funnels, spatulas, sample cups, high-precision digital scales, stopwatches, and Duran bottles. In addition, equipment for fluid property testing included a rheometer with a ULA spindle, magnetic and overhead stirrers, a filtration apparatus with 5 µm membrane paper, and an oven. Core flooding experiments utilized specialized tools such as a core holder, hydraulic pump, back pressure regulator, nitrogen cylinder, differential pressure gauge, Quizix pump, desiccator, vacuum pump, transfer cell, and an Ostwald viscometer (Type 200). To ensure the precision and reliability of all experimental results, the study was also supported by an integrated measurement and data acquisition system.

Table 1. Research workflow for polymer solution evaluation with oxygen scavenger in moderate salinity sandstone reservoirs.

Step	Description	Key Parameters/Tools
1. Preparation	Synthetic brine, polymer stock, oxygen scavenger addition	Salinity: 18,000 ppm; pH: 6.5-7.5; Stirring: 300-400 rpm for 2 hours + 24-hour hydration
2. Fluid-to-Fluid Tests	Compatibility, rheology, filtration, thermal stability	Rheometer (shear rate 7 s^{-1}); Filtration (5 µm, 2 bar N_2); Aging (60°C, 30 days)
3. Fluid-to-Rock Tests	Core preparation, injectivity, core flooding	Core: Bentheimer sandstone; Injection rate: 0.5-1 mL/min; PV slug: 0.5-1.5 PV
4. Analysis	Calculate RF, RRF, recovery factor, mobility ratio	Tolerance: Viscosity loss <30%; FR ≤1.2; M ≤1

The materials used in this study included HPAM FP 3630 and HPAM FP 3230 polymers both hydrophilic polyacrylamides designed for sandstone reservoirs with moderate to high salinity along with an oxygen scavenger ($NaHSO_3$) of ≥98% purity. Additional materials comprised synthetic brine formulated to match the target reservoir's formation water, distilled water (aquabidest), a Bentheimer sandstone core sample with a permeability of 1800 mD, and crude oil from the target reservoir, characterized by a viscosity of 2.97 cP and a gravity of 32.3°API.

Working procedure

The workflow of this research began with the solution preparation stage, which involved several key steps: preparing the synthetic brine, formulating the polymer stock solution, creating polymer solutions at various concentrations, and adding the oxygen scavenger to achieve the desired formulation. Synthetic brine was prepared by dissolving NaCl, $CaCl_2{\cdot}2H_2O$, $MgCl_2{\cdot}6H_2O$, $NaHCO_3$, and Na_2SO_4 in distilled water until a moderate salinity level of 18,000 ppm was achieved. The solution was stirred thoroughly to ensure homogeneity, after which the pH was measured and adjusted to remain within the range of 6.5–7.5. Polymer brine was prepared by dissolving HPAM FP 3630 or FP 3230 in synthetic brine using an overhead stirrer (300-400 rpm) for ±2 hours, followed by 24 hours of hydration at room temperature. Polymer solutions at different concentrations were prepared by diluting the polymer in brine and gently mixing it with a magnetic stirrer at low speed. The oxygen scavenger $NaHSO_3$ was then added according to the target concentrations (0% and 0.1%), following literature recommendations that identify 0.1% as the optimal dosage for maintaining polymer stability at a reservoir temperature of 60°C.

Fluid-to-fluid testing methods

The fluid-to-fluid testing stage comprised several evaluations, including compatibility, rheology, filtration, and thermal stability tests. The compatibility test was carried out by storing the polymer solutions in sealed vials under two temperature conditions (25°C and 60°C) for 30 days, during which changes in clarity, sediment formation, color, and phase separation were closely monitored. Rheological tests measured viscosity using a rheometer at a shear rate of 7 s^{-1} to determine the polymer formulation with optimal viscosity. Filtration tests were performed using 5 µm filter paper under a nitrogen pressure of 2 bar to determine the Filtration Ratio (FR), where FR values ≤ 1.2 indicate good filtration quality. The thermal stability test involved storing the polymer solution at 60°C for up to 30 days and measuring the percentage reduction in viscosity. According to API (2010) standards, a well-formulated polymer should exhibit less than a 30% decrease in viscosity over this period.

Fluid-to-rock testing methods

The experimental procedure encompassed core and fluid preparation, injectivity testing, and core flooding experiments. Core preparation involved vacuum saturation with synthetic brine, followed by measurements of dry and wet weights to calculate porosity. The oil sample was filtered and conditioned to the test temperature prior to viscosity measurement using an Ostwald viscometer.

The injectivity test was conducted by injecting synthetic brine followed by the polymer solution at a constant flow rate, allowing for the calculation of the Resistance Factor (ResF) and the Residual Resistance Factor (RRF). Core flooding experiments followed standard EOR protocols to simulate reservoir conditions. Key parameters included: core length 30 cm, diameter 3.8 cm; overburden pressure 2000 psi; temperature 60°C; injection rate 0.5-1.0 mL/min (equivalent to Darcy velocity 0.5-1 ft/day for low shear); pore volume (PV) ~20 mL; brine salinity 18,000 ppm; polymer slug size 0.5-1.5 PV, followed by 2 PV post-flush water. Monitoring involved differential pressure for Resistance Factor (RF = ΔP_polymer / ΔP_brine, target 5-15) and Residual Resistance Factor (RRF = $\Delta P_{post\text{-}flush}$ / $\Delta P_{initial}$, target <1.5 to minimize damage); oil recovery calculated from produced volumes. These parameters ensure realistic simulation of field-scale flooding, with shear rates (7-10 s^{-1}) mimicking reservoir flow (Seright, 2017). Variations in PV slug tested (1 PV vs. 1.5 PV) optimized chemical efficiency, aligning with recent studies showing 0.3-1 PV as ideal for HPAM.

RESULT AND DISCUSSION

Compatibility, rheology and thermal stability analysis of polymers

This test was designed to compare the performance of two types of HPAM polymers—FP 3630 and FP 3230—in both their conventional forms and with the addition of an oxygen scavenger ($NaHSO_3$), under sandstone reservoir conditions characterized by moderate salinity (18,000 ppm) and a temperature of 60°C.

Formulation compatibility with brine reservoir

The first stage of formulation screening focused on verifying the chemical compatibility between the polymer and the reservoir brine. Visual compatibility tests conducted over 30 days revealed that all formulations both FP 3630 and FP 3230, with and without the addition of $NaHSO_3$ remained clear and homogeneous, showing no signs of precipitation or phase separation. These results confirm that both polymers are fundamentally compatible with the tested salinity and temperature conditions, making them strong candidates for further detailed performance evaluation.

Comparison of rheology and concentration selection

Rheological performance serves as a crucial indicator of a polymer's capability to control fluid mobility. Rheological testing conducted at 60°C and a shear rate of 7 s^{-1} revealed a clear difference in efficiency between the two polymers.

Figure 1 shows the relationship between the concentration and viscosity of the two polymers. It is evident that viscosity increases proportionally with higher polymer concentrations. At a concentration of 1400 ppm, FP 3630 achieved a viscosity of 12.53 cP, accompanied by a torque value of 11.12%, demonstrating its strong rheological performance. Meanwhile, FP 3230 only achieved a similar viscosity, namely 12.79 cP, at a much higher concentration, namely 3500 ppm, with a torque value of 11.80%.

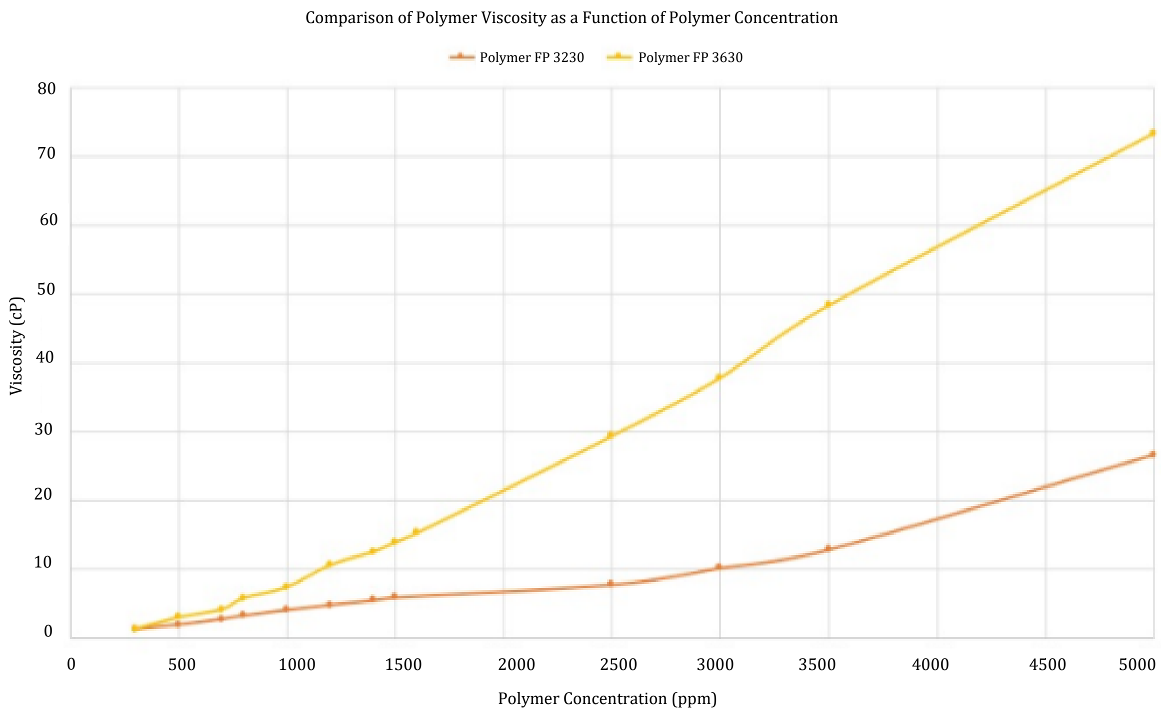

Figure 1. Comparison of the viscosity of HPAM FP 3630 and FP 3230 polymer solutions with respect to concentration variations (Processed by researchers 2025).

Table 2. Summary of comparison of rheological characteristics of FP 3630 and FP 3230 polymers at a temperature of 60°C and a shear rate of 7 s^{-1}(Processed by researchers 2025)

Types of Polymer	Selected Concen-tration (ppm)	Visco-sity (cP)	% Torque	Notes
FP 3630	1400	12,53	11,12	Meets viscosity and torque % targets
FP 3230	3500	12,79	11,80	Meets viscosity and torque % targets

Tabel 3. Summary of thermal stability of HPAM polymers FP 3630 and FP 3230 at 60°C for 30 days (Processed by researchers 2025)

Types of polumers	Polymer concentrat ion (ppm)	Addition of $NaHSO_3$	Initial viscosity (cP)	Final viscosity (cp))	%Viscosity Change	Stability Category
FP 3660 0	120	0	10,57	7,10	-32,80%	Not eligible
FP 3630 0	140	0,1	10,86	10,40	-4,24%	Qualify
FP 3230 0	300	0	10,10	8,10	-19,8%	Qualify
FP 3230 0	350	0,1	11,50	12,30	+6,96%	Qualify

Tabel 2 The viscosity of both polymers increased with higher concentrations. However, FP 3630 demonstrated far greater efficiency in reaching the desired target viscosity. At a concentration of just 1400 ppm, FP 3630 achieved a viscosity of 12.53 cP, whereas FP 3230 required a concentration 2.5 times higher—3500 ppm—to reach a comparable viscosity of 12.79 cP. This difference in efficiency is attributed to the higher molecular weight (MW) of FP 3630 (18 million Daltons) compared to FP 3230 (9 million Daltons). The higher molecular weight (MW) enables the formation of a more intricate molecular network, which leads to greater viscosity even at lower concentrations. From both a technical and efficiency standpoint, FP 3630 demonstrated a clear advantage early on.

Thermal stability analysis and the crucial role of oxygen scavenger

The thermal stability of polymer solutions is a critical factor in ensuring the long-term effectiveness of chemical injection, particularly in reservoirs with temperatures around 60°C. Elevated temperatures can significantly accelerate polymer degradation through oxidative and thermal processes, ultimately reducing viscosity and compromising the polymer's ability to maintain fluid mobility control within the formation. To mitigate this risk, this study comprehensively evaluates the role of sodium bisulfite ($NaHSO_3$) as an oxygen scavenger added to two HPAM polymer formulations, namely FP 3630 and FP 3230. The testing was conducted over a 30-day aging period at 60°C in a solution with moderate salinity (18,000 ppm). The primary goal was to evaluate the effectiveness of $NaHSO_3$ in mitigating viscosity degradation and to understand its specific role in enhancing the long-term stability of the polymer solution.

Thermal stability testing was performed by incubating the polymer solution at 60°C for 30 days, with the final viscosity measured as the key indicator of degradation. The complete results of this assessment are presented in Table 3.

As shown in Table 3, in the absence of $NaHSO_3$, FP 3630 experienced a 32.8% reduction in viscosity surpassing the acceptable degradation threshold of less than 30%. This clearly indicates that the polymer is prone to instability under prolonged thermal conditions. In contrast, FP 3230 showed a 19.8% degradation, which is still within acceptable tolerance limits. After adding 0.1% $NaHSO_3$, the viscosity degradation of FP 3630 decreased dramatically to just 4.24%,

Table 4. Comparison of polymer flow characteristics in porous media (Processed by researchers 2025)

Polymer $NaHSO_3$	Type +	Concentration (ppm)	FR	ResF	RRF
FP 3630 +	$NaHSO_3$	1400	1,06	11,44	1,01
FP 3230 +	$NaHSO_3$	3500	1,01	20,94	3,35

demonstrating the strong effectiveness of $NaHSO_3$ in preventing oxidative degradation. Interestingly, FP 3230 exhibited a 6.96% increase in viscosity after the aging process, which may suggest enhanced interchain interactions or molecular rearrangements occurring during thermal incubation.

These findings strongly highlight that protection against oxidative degradation is a critical factor in developing effective Enhanced Oil Recovery (EOR) formulations. Therefore, incorporating oxygen scavengers such as $NaHSO_3$ should be regarded as an essential strategy for polymer stabilization.

HPAM FP 3630 and FP 3230 polymer flow

The flow characteristics of polymer solutions in porous media play a vital role in determining injection feasibility and evaluating how the fluids interact with reservoir rocks. In this study, three key parameters were assessed: the Filtration Ratio (FR), which indicates solution clarity and potential clogging risk; the Resistance Factor (ResF), which measures the polymer's effect on fluid mobility; and the Residual Resistance Factor (RRF), which evaluates changes in relative permeability following injection. All tests were conducted on polymer solutions supplemented with 0.1% $NaHSO_3$ to ensure chemical stability and prevent oxidative degradation throughout the evaluation process.

The results of the polymer flow tests in porous media, summarized in Table 3, show that both formulations FP 3630 (1400 ppm) and FP 3230 (3500 ppm) with the addition of $NaHSO_3$ exhibited excellent filtration quality, as indicated by their Filtration Ratio (FR) values, all below the threshold of 1.2. The slight difference in FR values between the two formulations is not practically significant, suggesting that both can be safely injected without the risk of initial plugging or formation damage. However, a more notable difference appears in the Resistance Factor (ResF) and Residual Resistance Factor (RRF) values. While FP 3230 exhibited a higher ResF of 20.94, reflecting a stronger resistance to water flow, its RRF value of 3.35 reveals a considerable increase in residual resistance within the pores suggesting the possibility of plugging or excessive polymer retention that could hinder long-term injectivity. In contrast, the FP 3630 formulation achieved a moderate Resistance Factor (ResF) of 11.44 and an RRF value very close to 1 (1.01). These results demonstrate its strong ability to control fluid mobility while preserving formation permeability after injection. Therefore, the FP 3630 + $NaHSO_3$ formulation offers a well-balanced performance between mobility control and long-term injectivity, making it a highly promising candidate for successful chemical injection in Enhanced Oil Recovery (EOR) applications.

Interpretation of filtration test results (filtration ratio – FR)

Filtration testing provides a crucial initial indication of the quality of the polymer solution prior to injection into the core or reservoir formation. Specifically, the test results showed a Filtration Ratio (FR) of 1.06 for FP 3630 (1400 ppm) + $NaHSO_3$ and 1.01 for FP 3230 (3500 ppm) + $NaHSO_3$. Both values fall well below the generally accepted upper limit of 1.2, confirming excellent filtration quality. An FR value close to 1 strongly suggests that the solution is clean and free from large particles, micro-gels, or other impurities that could clog rock pores or impair injectivity. Although FP 3230 showed a slightly lower FR value, the difference is practically negligible. Hence, both polymer formulations can be regarded as having excellent filtration quality and are proven to be well-suited for application in porous media, particularly for Enhanced Oil Recovery (EOR) operations.

Analysis of resistance factor (ResF) and residual resistance factor (RRF)

Resistance factor (ResF) and residual resistance Factor (RRF) analyses were carried out to evaluate how the polymer formulations influence fluid flow behavior and the preservation of formation permeability. Injectivity tests using synthetic sandstone cores revealed that the FP 3630 (1400 ppm) + $NaHSO_3$ formulation achieved a ResF of 11.44 and an RRF of 1.01. The relatively high ResF value reflects the formulation's strong ability to control water mobility, while the RRF value being very close to 1 indicates that no permanent damage occurred in the rock pores, allowing fluid flow to return to normal after injection.

In contrast, the FP 3230 (3500 ppm) + $NaHSO_3$ formulation exhibited a higher Resistance Factor (ResF) of 20.94 and an RRF of 3.35. Although the elevated ResF value demonstrates the polymer's capacity to enhance the mobility ratio, the RRF value—substantially greater than 1 reveals a considerable rise in residual flow resistance, suggesting potential injectivity issues and a risk of formation plugging. This suggests a high likelihood of polymer clogging or retention within the pore network, which could permanently reduce the effective permeability of the formation and pose a serious risk to the long-term effectiveness of the EOR process.

Selection of polymer solution formulation for core flooding

Based on a comprehensive evaluation of flow characteristics in porous media, the FP 3630 + $NaHSO_3$ formulation (1400 ppm + 0.1%) was selected as the leading candidate for core flooding. The combination of a high Resistance Factor (ResF) of 11.44 and a near-ideal Residual Resistance Factor (RRF) of 1.01 demonstrates excellent mobility control while preserving formation permeability. The low RRF value confirms that the polymer solution effectively resists water flow without causing permanent blockage, allowing smooth flow continuity after injection. In contrast, the FP 3230 + $NaHSO_3$ (3500 ppm) formulation exhibited a higher ResF (20.94) but an unfavorable RRF of 3.35, indicating potential issues such as plugging or excessive polymer adsorption that could negatively impact injectivity and long-term reservoir performance.

To support these findings from a theoretical perspective, the Mobility Ratio (M) was calculated. Under the initial waterflooding condition, the system exhibited instability (Mw-o = 1.18), which explains the low sweep efficiency observed. However, after the injection of the selected polymer, the displacement front became highly stable (Mp-o = 0.10). This substantial reduction in M well below one demonstrates the strong effectiveness of the polymer's viscosity (10.86 cP) and its favorable interaction with the rock matrix (as indicated by the Residual Resistance Factor, ResF) in maintaining a stable and efficient displacement process.

Therefore, by combining excellent rheological performance, strong thermal stability enhanced by the oxygen scavenger, and safe flow behavior validated through both experimental RRF and theoretical mobility ratio (M) the FP 3630 (1400 ppm) + $NaHSO_3$ (0.1%) formulation stands out as the optimal candidate for the final validation phase.

Core flooding testing for selected polymer solutions

Core flooding represents the most reliable laboratory approach for evaluating fluid injection scenarios in reservoirs, as it closely replicates the natural conditions of porous media and captures the real flow dynamics that occur under actual reservoir temperatures and salinity levels. In this study, the HPAM FP 3630 polymer formulation combined with 0.1% $NaHSO_3$ at a concentration of 1400 ppm was specifically chosen for testing. This selection was based on the formulation's outstanding performance in rheological behavior, thermal stability, and flow characteristics within porous media, all of which demonstrated its strong potential for enhanced oil recovery applications.

Oil drainage stage analysis

Before the polymer injection stage, the initial core characteristics and secondary oil recovery results from waterflooding were determined as the baseline for performance evaluation. After the oil saturation phase, the initial oil saturation (SoI) reached 83.60%, corresponding to an original oil in place (OOIP) of 13.06 cc. This confirms that the porous medium was in an oil-rich condition, making it highly suitable for EOR research. The subsequent waterflooding test produced a Recovery Factor of 67.38% OOIP, representing the upper limit of recovery achievable through conventional methods.

However, following this secondary waterflooding stage, the residual oil saturation (Sor) was measured at 27.26%, clearly showing that more than a quarter of the pore volume was still filled with oil that could not be mobilized by water injection alone. This Sor value underscores the limitations of conventional waterflooding in addressing viscosity contrasts and uneven oil distribution within the reservoir. It also reflects significant residual oil trapping caused by the unfavorable water-to-oil mobility ratio. Consequently, there remains substantial potential for enhanced recovery through chemical enhanced oil recovery (CEOR) techniques particularly polymer flooding which are specifically designed to overcome these challenges by increasing the viscosity of the aqueous phase and improving the overall injection profile.

Analysis of incremental and total oil recovery from polymer injection

The injection of the FP 3630 polymer solution combined with 0.1% $NaHSO_3$ was performed after the conventional water flooding phase, following an injection scheme consisting of 1, 1.5, and 2 PV of polymer, each succeeded by 2 PV of flush water. The results revealed an impressive incremental oil recovery of 19.91% OOIP, clearly demonstrating the formulation's strong capability to mobilize residual oil that remained unrecovered during the water flooding stage. With this additional oil recovery, the total Recovery Factor (RF) reached 87.29% of the OOIP a remarkable outcome for a simulated sandstone reservoir under moderate salinity conditions (18,000 ppm) and a temperature of 60°C. This result highlights the strong performance and adaptability of the formulation under realistic reservoir environments. This nearly 20% increase in Original Oil in Place (OOIP) recovery not only showcases the polymer's exceptional ability to control mobility but also signifies the achievement of a near-optimal mobility ratio (M < 1)—a core principle in EOR.

Table 5. Summary of oil recovery parameters from core flooding tests with FP 3630 + NaHSO3 (Processed by researchers 2025)

Parameter	Value	Unit
Initial oil saturation (SOI)	83,60	%
Original oil in place (OOIP)	13,06	cc
RF water flood	67,38	% OOIP
Sor after water flood	27,26	%
Incremental RF polymer flood	19,91	% OOIP

Tabel 6. Summary of oil recovery parameters from core flooding tests with FP 3630 + NaHSO3 (continued)

Parameter	Value	Unit
Total RF	87,29	% OOIP
Polymer injection volume 1	1	PV
Flush water injection volume	2,0	PV
Polymer injection volume 2	1,5	PV

These findings firmly establish the FP 3630 + $NaHSO_3$ formulation as the most promising and reliable polymer system identified in this study.

The values presented in Table 5 clearly demonstrate a positive and consistent correlation between polymer injection and increased sweep efficiency. This polymer formulation not only proved efficient in increasing the Recovery Factor (RF), but also successfully maintained fluid flow without causing significant damage to the rock pore system, which is an important indicator of injection sustainability.

Factor interpretation of injection PV curve vs recovery factor

The progression of recovery factor (RF) enhancement during the injection process is depicted through a curve that relates the injected fluid volume, expressed in Pore Volume (PV), to the cumulative RF achieved over time. During the initial water flooding phase (0–4 PV), the RF increases sharply, then levels off at 67.38% of OOIP, marking the limit of secondary recovery. Following the chemical injection using the FP 3630 polymer combined with $NaHSO_3$ (from 4 to 5.5 PV), and subsequently flushed with water, the RF shows a sharp increase to 87.29%. This surge occurs primarily at the onset of polymer injection, when the remaining oil is effectively displaced. As the curve begins to level off, it signifies that most of the recoverable oil has already been mobilized. This pattern clearly underscores the vital role of the oxygen scavenger in boosting the overall effectiveness of the enhanced oil recovery (EOR) process.

In addition to ResF improvement, the obtained residual resistance Factor (RRF) of 1.06 confirms excellent compatibility between the FP 3630 + $NaHSO_3$ formulation and the reservoir rock, showing no significant pore blockage post-injection. In contrast, higher RRF values (above 2–3), as seen with FP 3230, suggest potential polymer retention and long-term injectivity issues.

Thus, the successful RF enhancement results not only from increased viscosity but from the synergistic effect of proper injection volume design, chemical stability of the FP 3630 + $NaHSO_3$ system, and its strong interaction with porous media. These combined factors make this formulation a strong candidate for field-scale application in moderate salinity reservoirs.

Relationship of findings with previous studies

The results of this study do not stand alone, but rather actively contribute to and can be directly compared with the existing body of knowledge in the scientific literature on chemical enhanced oil

Table 7. Comparison of research findings with relevant literature studies (Processed by researchers, 2025)

Discussed Aspects	**Previous Research**	**Research Findings**	**Implications**
Polymer stability with oxygen scavenger	(Qiao et al., 2023)	Viscosity degradation decreased by only 4.24%	Oxygen scavenger effectiveness proven on viscosity and injectivity
FP 3630 viscosification efficiency	(Serhan et al., 2019);	Higher viscosity at the same concentration compared to FP 3230	More economical and stable at high salinities
Polymer injectivity	(Quadri et al., 2015)	FR FP 3630 = 1.06 < industrial limit	Safe for injection into sandstone reservoirs
Stepwise PV design	(De-nt, 2009)	Incremental RF 19.91% (1.5 PV polymer)	Proven efficient staged injection design
CEOR polymer effectiveness	Gbadamosi et al. (2022)	RF increased from 67.38% to 87.29%	Includes optimal range of 8–20%, with stable design

recovery (CEOR), specifically HPAM-based polymer injection. This comparison is crucial for validating the findings, identifying aspects of novelty and originality of the study, and positioning this research contribution within the broader scientific landscape. Table 2.6 below presents a summary comparison between the main findings of this study and several relevant previous studies.

This research strongly strengthens the findings by (Qiao et al., 2023 that the addition of oxygen scavenger significantly reduces the viscosity degradation of polymers during aging at high temperatures. Beyond merely confirming the chemical aspects, this study importantly demonstrates that stabilization using oxygen scavengers also plays a vital role in improving injectivity and flow performance within porous media. The minimal viscosity degradation of FP 3630—only 4.24% after 30 days of incubation at 60°C—along with a Filtration Ratio (FR) of 1.06, provides strong evidence that $NaHSO_3$ offers highly effective protection under dynamic conditions such as injection into sandstone formations.

In addition, the viscosification efficiency of FP 3630 at 18,000 ppm salinity strengthens the report by (Serhan et al., 2019 which comprehensively emphasizes the importance of molecular structure and ionic stability on the viscosity of polymer solutions. In line with this, the study revealed that FP 3630 demonstrates stronger viscosification capabilities than FP 3230, highlighting its superior performance in enhancing fluid thickness. Because of its elastic properties, FP 3630 forms filaments that are more resistant to thinning during droplet formation, exhibiting the characteristic "beads-on-a-string" pattern commonly observed in elastic fluids. FLOPAAM 3230, due to its low elasticity, tends to exhibit Newtonian-like behavior during the droplet formation process. Consequently, FP 3630—with its higher viscosity at the same concentration—emerges as a more economical and efficient option for CEOR applications, particularly in formations with moderate salinity levels. In terms of injectability, the Filtration Ratio (FR) value of the FP 3630 solution remained consistently below the acceptable threshold ($1.06 < 1.2$), in accordance with the criteria established in the study by (Quadri et al., 2015, which recommends an FR value of <1.2 to prevent plugging. However, this study offers an important layer of practical insight: the polymer solution is not only theoretically safe but also demonstrably easy to inject into porous rock formations. This finding significantly reinforces the argument that the combination of FP 3630 and $NaHSO_3$ is not just stable under laboratory conditions but also genuinely feasible for application in real-world field simulations.

Furthermore, the core flooding test results, which showed a 19.91% increase in Recovery Factor from water flooding, are consistent with the polymer injection effectiveness range of 8–20% reported by (Gbadamosi et al., 2022 under similar reservoir conditions. However, the most significant contribution of this study lies in validating the effectiveness of the Pore Volume (PV)-based staged injection method. The findings reveal that using PV variations of 1 PV and 1.5 PV, combined with intermittent water flushing, achieves the optimal balance between sweeping efficiency and chemical utilization for this particular formulation.

From a scientific standpoint, this study makes several noteworthy contributions. First, it provides comprehensive insights into the behavior of two HPAM polymers under specific Indonesian reservoir conditions—18,000 ppm salinity and 60° C temperature—settings that have received little attention in previous research. Second, the exceptionally low Residual Resistance Factor (RRF) observed for the FP 3630 formulation suggests a minimal risk of formation damage, reinforcing its potential for long-term injection sustainability. Third, the inclusion of $NaHSO_3$ as an oxygen scavenger has proven not merely beneficial but essential, serving a critical role in preventing oxidative degradation of the polymers.

In conclusion, this study not only reinforces existing literature but also broadens its scope by demonstrating that the effectiveness of polymer-based Chemical Enhanced Oil Recovery (CEOR) can be greatly optimized through the synergistic integration of three key factors: selecting a polymer type that aligns with reservoir characteristics, stabilizing the solution using the proven oxygen scavenger $NaHSO_3$, and designing a measured, proportionate injection strategy based on Pore Volume (PV). When applied in an integrated manner, these three aspects have been shown to not only significantly enhance oil recovery but also to ensure the sustainability and safety of the injection process within porous media.

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CONCLUSION

This study concludes that both HPAM polymers, FP 3630 and FP 3230, are compatible with the brine conditions of sandstone reservoirs characterized by a salinity of 18,000 ppm and a temperature of 60°C. However, FP 3630 demonstrated markedly better performance under these conditions. FP 3630 polymer was able to achieve the target viscosity at a lower concentration (1400 ppm) compared to FP 3230 (3500 ppm), and the addition of 0.1% $NaHSO_3$ was proven to be effective in suppressing viscosity degradation significantly. In terms of injectivity, the FP 3630 + $NaHSO_3$ formulation demonstrated the most promising performance, achieving a Resistance Factor (ResF) of 11.44 and a Residual Resistance Factor (RRF) of 1.01. These values suggest that the formulation poses minimal risk of formation damage. Moreover, it enhanced oil recovery by 19.91% of the original oil in place (OOIP) after water flooding, resulting in a total recovery factor of 87.29% OOIP. The Mobility Ratio also improved significantly, decreasing from 1.18 to 0.10, which indicates a more stable and efficient injection process overall.

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GLOSSARY OF TERMS AND SYMBOLS

Terms & Symbol	Definition	Unit
cP	A unit of dynamic viscosity used to describe fluid thickness and flow behavior, commonly applied to oils and polymer solutions.	mPa·s
EOR	Advanced techniques used to increase oil recovery beyond primary and secondary production, including polymer flooding.	%OOIP
FR	A measure of polymer solution quality and injectivity. Values ≤ 1.2 indicate a stable solution with low plugging potential.	
HPAM	A widely used polymer in EOR to increase the viscosity of the injected fluid and improve sweep efficiency.	
M	The ratio of the displacing fluid's mobility to that of the displaced oil. Values ≤ 1 promote stable displacement fronts.	

mD	A standard unit of rock permeability that indicates how easily fluids can flow through porous media.	
$NaHSO_3$	An oxygen scavenger added to polymer solutions to prevent oxidative degradation.	%Concentration
OOIP	The total volume of oil contained in a reservoir or core before any production occurs.	cc
ppm	A concentration unit used for brine salinity and polymer dosage.	mg/L
PV	The total pore space within a core sample, used as a reference volume for injected fluids.	
ResF	The ratio of pressure drop during polymer injection to that during brine injection, reflecting increased flow resistance.	
RF	The percentage of OOIP recovered during production.	%OOIP

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