

Modeling of Laboratory Experimental Tests Simulating Polymer Injection: Filtration Equations for the Black-Oil Model

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Abstract: - We modeled laboratory experiments simulating polymer injections in porous rocks using the black-oil model implemented in OPM Flow. This model accounts for oil, water, and gas phases and was extended to include polymer effects such as adsorption, permeability reduction, and changes in aqueous viscosity. We simulated three-dimensional models of Driza 1 and Driza 2 core samples, each containing 5,670 cells, under laboratory-matched conditions. Polymer injection nearly doubled oil recovery compared with waterflooding (53% and 52% vs. 25% and 25.8%), validating OPM Flow's ability to integrate experimental data with modeling to optimize enhanced oil recovery (EOR) in Albanian heavy oil reservoirs, such as Patos-Marinza. TPFA finite-volume discretization with automatic differentiation (AD) robustly solved the coupled systems ($\|R\| < 10^{-8}$). These results validate the EOR potential for Patos-Marinza heavy oil.

Key Words: - Polymer flooding, Black-oil model, Finite volume, Automatic differentiation, EOR, OPM Flow.

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1 Introduction

Polymer flooding enhances oil recovery by increasing injected-water viscosity, improving sweep efficiency in heterogeneous reservoirs [1], [2]. Simulations coupled with laboratory core floods optimize injection strategies, particularly in heavy oil fields such as Albania's Patos-Marinza [3], [4]. In this study, OPM Flow's black-oil model replicates Driza core tests and focuses on polymer physics absent in standard waterfloods [5]. The black-oil model, an industry standard for multiphase flow,

assumes three phases: oil, water, and gas (including dissolved gas in oil and vaporized oil in gas) [6]. Mass conservation yields:

$$\frac{\partial}{\partial t} (\phi b_{\alpha} s_{\alpha}) + \nabla \cdot (b_{\alpha} v_{\alpha}) = q_{\alpha} \quad (1)$$

($\alpha \in \{o, w, g\}$; $b_{\alpha} = f(p_{\alpha})$). Darcy's law: where ϕ is the porosity of the rock medium, b_{α} is the formation volume factor, and s_{α} is the solution ratio, ρ_{α} is the source/sink (e.g., wells), while s_{α} corresponds to saturation.

The fluxes for each phase v_α (oil, water, gas) are given by Darcy's law:

$$v_\alpha = -\lambda_\alpha \mathbf{K}(\nabla p_\alpha - \rho_\alpha g \nabla z) \quad (2)$$

where

$\mathbf{K}$ is the absolute permeability of the rock medium, while $\lambda_\alpha = \frac{k_{r\alpha}}{\mu_\alpha}$ is the mobility of phase α , where $k_{r\alpha}$ represents the relative permeability and μ_α is the viscosity of the respective phase. The model is based on the hypothesis that the pore volume is filled with fluid, i.e., $s_o + s_w + s_g = 1$.

User-defined initial/boundary conditions complete the system.

2 Materials and Methods

2.1 Mathematical Formulation & Discretization

Polymer Physics: Driza cores (5,670 cells) matched lab geometry/rates (312/278 ml/h, 6.5h). Polymer conserves as:

$$\frac{\partial}{\partial t} [\phi(1 - s_{ipw})\rho_r \Gamma_p + \phi \rho_w c] + \nabla \cdot (v_w c) = q_p \quad (3)$$

The fully implicit black-oil/polymer system comprises 4 primaries per cell: p_w, s_w, c, r_s (or s_g), discretized on structured $30 \times 7 \times 27$ grids ($\Delta x = 0.444$ cm Driza 1) using two-point finite volume (TPFA) with automatic differentiation [7], [8]. Mass conservation (residual form): $R_\alpha = \frac{(\phi b_\alpha s_\alpha)^{n+1} - (\phi b_\alpha s_\alpha)^n}{\Delta t} + \nabla \cdot (b_\alpha v_\alpha) |^{n+1} - q_\alpha = 0$

$$\text{Polymer: } R_p = \frac{[\phi(1 - s_{ipw})\rho_r \Gamma_p + \phi \rho_w c]^{n+1} - [\cdot]^n}{\Delta t} + \nabla \cdot (v_w c) |^{n+1} - q_p = 0 \quad (5)$$

TPFA fluxes: Upstream-weighted transmissibility T_{ij} yields:

$$v_\alpha \cdot A_{ij} = T_{ij} \lambda_{t,\alpha} (p_\alpha^i - p_\alpha^j - \nabla \rho_\alpha \cdot d_{ij}) \quad (6)$$

Nonlinear solution: Newton-Raphson with analytical Jacobian (AD):

$$J_{kl} = \frac{\partial R_k}{\partial x_l}, \Delta x = -J^{-1} R \quad (7)$$

Convergence: $\|R\| < 10^{-8}$, with a maximum of 25 iterations per step (stable for CFL < 10). Line search

with backtracking ensures global convergence for polymer viscosities $\mu_{wp} > 50$ cP.

Boundary/Initial Conditions: Inlet ($x=0$): Dirichlet $p_w = p_{inj}, c = c_{inj} = 2000$ ppm, $s_w = 1$; Outlet ($x=L$): Neumann $\nabla p_w = 0$ (constant PVI); Initial: $S_{wi} = 0.25, p = 50$ bar, $c = 0$

The polymer model Implementation: We modeled Driza corefloods in OPM Flow, incorporating black oil with polymer transport (adsorption Γ_p , permeability reduction $R_k(c)$, effective viscosities μ_w , [7]. Two 3D grids (5,670 cells each) matched lab geometry; simulations replicated 6.5 h tests (312/278 ml/h) for water, polymer, and hybrid injections. Polymer partitions to the aqueous phase only, yielding [8]:

$$\frac{\partial}{\partial t} [\phi(1 - s_{ipw})\rho_r \Gamma_p + \phi \rho_w c] + \nabla \cdot (v_w c) = q_p \quad (8)$$

This is the polymer conservation equation. ($c \in [0, c^*]$; s_{ipw} inaccessible PV). Modified Darcy [3]:

$$v_w = -KR_k(c)\lambda_{w,eff}(\nabla p_w - \rho_w g \nabla z) \quad (9)$$

Rheology/adsorption per lab data [8], [9].

The models accounted for polymer adsorption, permeability reduction, and changes in the effective viscosity of the aqueous phase. In this model [7], [9], the polymer is assumed to be transported from the aqueous phase and to modify its viscosity without affecting the oil and gas phases. The corresponding equation [1] is:

$$\partial_t [\phi(1 - s_{ipw})b_w s_w c] + \partial_t [\rho_r c^\alpha (1 - \phi)] + \nabla \cdot (b_w v_p c) - b_w q_w c = 0 \quad (10)$$

where $c \in [0, c^*]$ represents the polymer concentration and c^* is the maximum possible concentration is the polymer adsorption concentration, ρ_r is the rock matrix density, and s_{ipw} is the inaccessible pore volume. The reduced mobility of the pure water and the dissolved polymer mixture is modeled using the effective mixture viscosities, μ_{weff} and μ_{peff} , which depend on the polymer concentration. We discuss adsorption, permeability reduction, effective viscosities, and polymer-solution rheology in more detail in [4], [7].

2.2 OPM Flow for Polymer Modeling

We implemented polymer injection simulations using OPM Flow [6], [10], [11], a fully implicit reservoir simulator that extends the black-oil formulation with polymer physics [7]. Built on the

MRST framework [12], [13], OPM Flow models adsorption, permeability reduction, and non-Newtonian rheology essential for our lab-scale core floods [13]. The detailed module architecture [14] is documented in the OPM manual (opm-project.org) and in MRST publications [15]; here we focus on its application to Driza core samples [8], [9], [16].

The OPM Flow Modules [13]. "We applied OPM Flow to model Driza cores, achieving the following results. We have the following slogan: Lab validation + Patos-Marinza relevance = our contribution.

2.3 Sensitivity Analysis

Systematic variation of key parameters (Table 1) demonstrates robustness:

Table 1. Sensitivity analysis of polymer parameters

Parameter	Base Value	Range Tested	Δ RF Driza 1
μ_{wp} (cP)	20	10-50	$\pm 12\%$
Γ_{max} (μ g/g)	100	50-200	$\pm 8\%$
$R_k(c_{max})$	0.85	0.7-0.95	$\pm 5\%$
c_{inj} (ppm)	2000	1000-3000	$\pm 10\%$

Polymer Model:

$R_k(c) = 1/[1 + kc]$, Langmuir adsorption
 $\Gamma_p(c) = \Gamma_{max} \cdot c / (K + c)$. Extended Carreau rheology
 $\mu_{eff}(c, \dot{\gamma}) = \mu_{\infty} + (\mu_0 - \mu_{\infty}) [1 + (\lambda \dot{\gamma})^a]^{(n-1)/a}$ ($n=0.8$, $\lambda=0.1$ s).
 Grid Convergence: $\Delta x = 0.444 \rightarrow 0.222$ cm: RF changes $< 1.2\%$, confirming grid independence.

Source: Created by the authors based on the present study.

2.4 Experimental Data Supporting Polymer Injection

Global evidence: Laboratory studies confirm that polymer flooding increases oil recovery by improving mobility control and sweep efficiency. For example, experiments with different slug injection modes demonstrated significant improvements in heavy oil recovery compared to single-slug injection [17]. Albania-specific evidence: Research at the Polytechnic University of Tirana has tested polymer injection schemes in laboratory conditions and field pilots, showing effectiveness in Patos-Marinza, one of Europe's largest heavy oil fields [18]. Similar injectivity tests in high-temperature, high-salinity carbonate reservoirs have demonstrated the importance of accounting for polymer retention and shear degradation when interpreting field pilot data [19].

How Experimental Results Improve Simulations

Parameter calibration: Experimental data provide viscosity, adsorption, retention, and shear-thinning behavior of polymers in porous media, which are critical inputs for reservoir simulators.

Model validation: Comparing simulation outputs (oil recovery factor, pressure distribution, polymer breakthrough time) with lab results ensures models reflect real reservoir physics.

Upscaling: Lab-scale displacement tests help refine numerical models before applying them to field-scale predictions.

Key Experimental Parameters Affecting Polymer Injection: Polymer concentration and molecular weight determine viscosity and mobility control. Injection rate and pressure affect polymer propagation and shear degradation. Reservoir rock properties, such as permeability, porosity, and heterogeneity, strongly influence polymer retention.

Temperature and salinity affect polymer stability and viscosity; adsorption & retention reduce the effective polymer concentration in the reservoir.

Laboratory studies consistently highlight these parameters as critical to performance [20].

2.5 Studies Comparing Numerical Models with Laboratory Results

International comparisons: Numerical models of polymer flooding have been benchmarked against laboratory-scale experiments, showing good agreement when adsorption and shear effects are included [2], [3], [21]. Recent studies have also shown that numerical simulation can effectively optimize polymer-flooding design parameters and improve enhanced oil recovery performance [22].

For nonlinear viscoplastic oils, researchers have developed specialized filtration models to capture complex flow behavior that deviates from classical Darcy formulations [23].

Albania-focused studies: Case studies from Patos-Marinza integrate laboratory findings with simulation models to optimize injection strategies, confirming that numerical predictions align with observed recovery improvements [24].

Assessing Accuracy for Patos-Marinza Field: To evaluate model accuracy in Albania's Patos-Marinza field, collect lab data, polymer viscosity, adsorption, and core-flooding results from local carbonate samples. Run pilot tests – compare polymer breakthrough times and incremental oil recovery with simulation predictions. Cross-validate

– ensure numerical models reproduce experimental displacement curves and recovery factors. Iteratively refine – adjust polymer concentration, slug size, and injection rates in the model until they match experimental evidence.

3 Results and Discussions

Patos-Marinza is Albania's largest onshore heavy oil field. Since 2013, BP pilots (2013+) in D3-D5 sands have yielded 5-30% incremental recovery via polymer sweep [2]. Params: $\phi \approx 0.28$, $S_{wi} \approx 0.2$, $S_{or} \approx 0.4$, favorable mobility post-polymer ($M < 1$) [2]. Patos-Marinza: $\phi = 0.28$, $k = 5-15$ D, $\mu_o = 2000$ cP [2].

Driza 1 (Figure 1 and Figure 2): Water: 15.3 mL (25.0% RF) [Figure 3 and Figure 4]; Polymer: 31.7 mL (53.0%) [Figure 5 and Figure 6]; Hybrid: 28.85 mL (48.0%) [Figure 7]. Driza 2 (Figure 8): Water: 12.0 mL (25.8%) [Figure 9]; Polymer: 24.3 mL (52.0%) [Figure 10]. Table 2 summarizes the main experimental and simulation results for both Driza core samples.

Table 2. Coreflood results

Case	Driza 1 (ml/%RF)	Driza 2 (ml/%RF)
Water	15.3 ml (25.0%)	12.0 ml (25.8%)
Polymer	31.7 ml (53.0%)	24.3 ml (52.0%)

Source: Created by the authors based on the present coreflood simulations.

As shown in Table 2, water injection yielded 15.3 ml (25.0% RF) for Driza 1 and 12.0 ml (25.8% RF) for Driza 2, while polymer injection yielded 31.7 ml (53.0% RF) and 24.3 ml (52.0% RF), respectively. (See Figure 11. Recovery curves: (a) Driza 1, (b) Driza 2.

Stability: 6.5h simulation (500 timesteps, $\Delta t \sim 47s$) converged in <20 Newton iterations/step, $\|R\| < 10^{-10}$. *Field Parameters:* Typical Patos-Marinza data for BL adaptation (from pilots/corefloods) [24]. $\phi \approx 0.28$, $k \approx 5-15$ Darcy (high perm), $S_{wi} \approx 0.15-0.25$, $S_{or} \approx 0.35-0.45$; $\mu_o \approx 100-5000$ cP (cold heavy oil), $\mu_w \approx 0.5-1$ cP, $\mu_{wp} \approx 5-50$ cP (xanthan/HPAM at 1000-2000 ppm, shear-thinning); Corey exponents: $n_w = 1.5-2.5$, $n_o = 1.5-3$ (viscosity-stabilized), $k_{rw} = 0.3-0.6$, $k_{ro} = 0.6-0.9$

The Python code used $\mu_{wp} = 20$ cP and $\mu_o = 2000$ cP to generate a representative fractional flow curve showing reduced $M < 1$, piston-like displacement [10].

Solution Insights

Shock saturation $S_{wf} \approx 0.65-0.80$ (higher than waterflood due to polymer viscosity increase, minimizing fingering in thief zones).

Breakthrough time: $t_{BT} \approx 0.2-0.4$ PV (faster in pilots due to patterns: 1 injector + 2-4 producers).

Recovery: $\sim 55-70\%$ OOIP at 1 PV injected (vs $\sim 35\%$ waterflood baseline), validated vs field pilots showing 10-15% incremental oil [7].

The code grid was adapted for pattern geometry (e.g., 5-spot radial via effective L); shear rate $\dot{\gamma} \approx u/\phi$ in the Carreau model for realistic rheology.

3.1 Modeling of the Laboratory Polymer

Modeling of the laboratory polymer injection test using OPM Flow. A 3D model of rock sample was developed for the lab polymer injection test [1].

3.2 Driza 1 Rock Sample

The 3D model of the Driza 1 rock sample consists of 5670 cells (Figure 1). The elementary cell is cubic, with an edge length of 0.444 cm. Fluid injection (water + polymer) is performed at one end of the rock sample, while fluid recovery (water and oil) occurs at the opposite end of the model. Driza 1 ($n_x = 30 \times n_y = 7 \times n_z = 27$; $dx = 0.444$ cm): Water: 25% RF (15.3 ml) [Figures 3 and 4]. Polymer: 53% (31.7 ml) [Figures 5 and 6]. Hybrid (water 2.3 h + polymer): 48% [Figure 7].

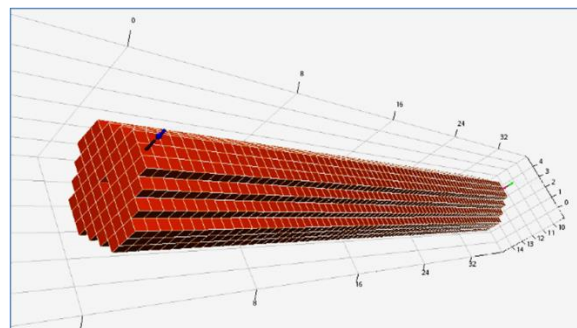


Fig. 1: Three-dimensional model of the Driza 1 rock sample.

Source: Created by the authors based on the present numerical model.

To assess how polymer injections affect oil recovery, both simulations used identical injection settings for 6.5 hours. The injection rate was 312 mL per hour, consistent with the lab test. The relative permeability curves used in the modeling are shown in Figure 2.

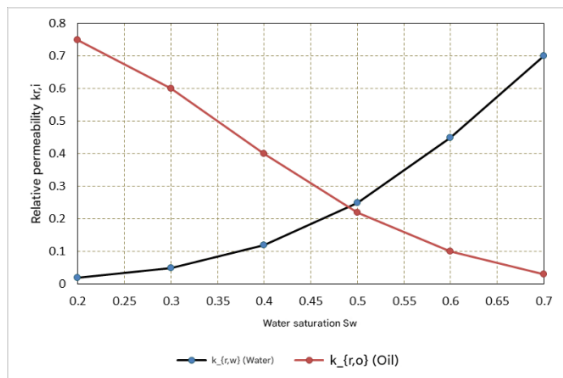


Fig. 2: Relative permeability curves – Driza suite
Source: Created by the authors

3.2.1 Water Injection Test

The calculations show the evolution of oil recovery, as shown in Figure 3.

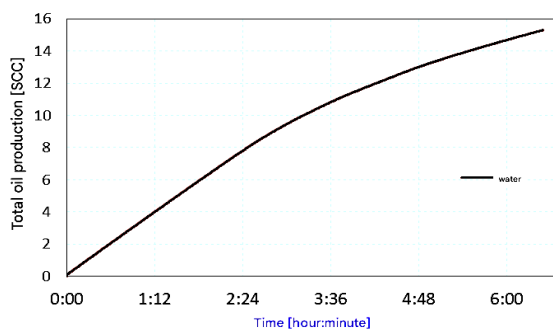


Fig. 3: Evolution of total oil production (ml) without using polymer – Driza 1
Source: Created by the authors based on OPM Flow simulation results.

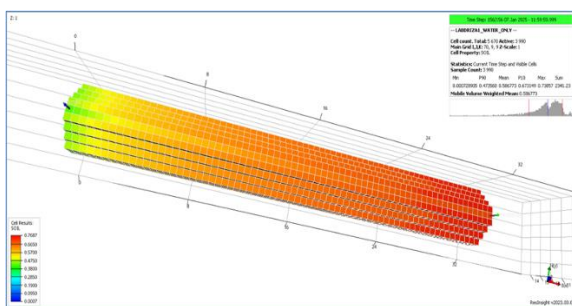


Fig. 4: Oil saturation of the model at the end of the water injection test
Source: Created by the authors

The total oil recovered in the water injection case reaches 15.3 ml, i.e., a recovery factor of about 25%. Polymer solution injection test: The polymer injection test modeling results (Figure 5) show a total oil-recovered volume of 31.7 ml, i.e., a recovery factor of about 53%.

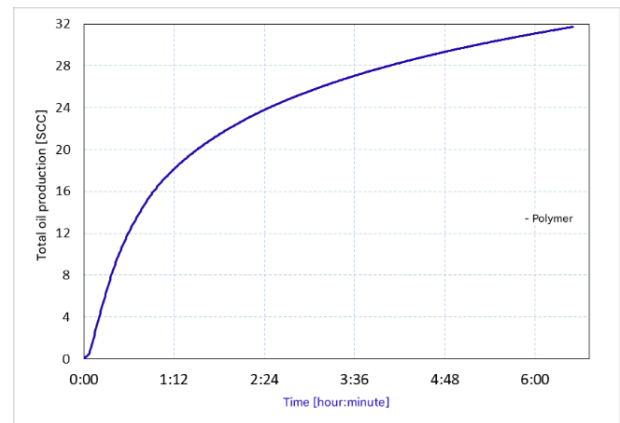


Fig. 5: Evolution of total oil production (ml) with polymer injection – Well 1
Source: Created by the authors

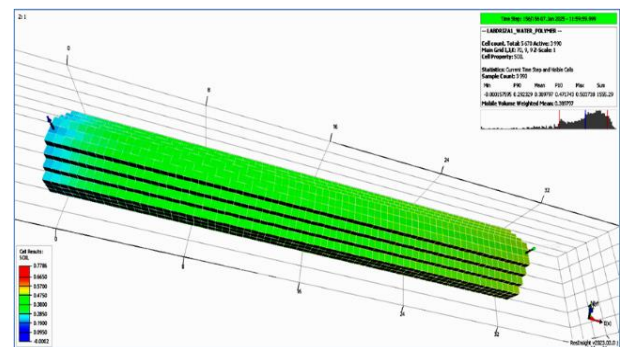


Fig. 6: Oil saturation of the model at the end of the polymer injection test
Source: Created by the authors

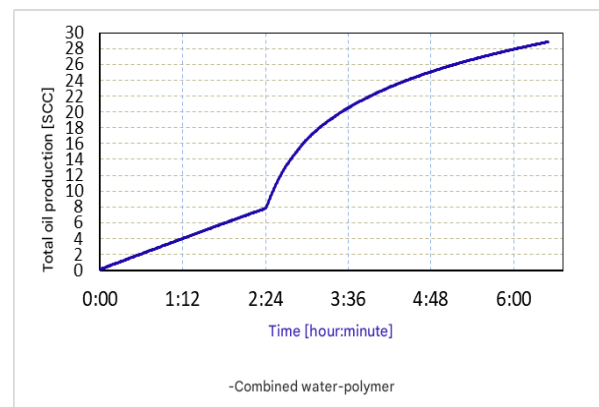


Fig. 7: Evolution of total oil production (ml) with two-phase injection (water-polymer) Formation 1
Source: Created by the authors

Key Takeaway: Polymer injection has been experimentally validated as effective for EOR, including in Albania's Patos-Marinza field. Accurate simulations require integrating laboratory parameters (viscosity, adsorption, injection rates) and validating against pilot-scale results. This iterative comparison ensures reliable predictions for field-scale deployment.

When we examine the water-injection model more closely, oil recovery begins to decline after about 2 hours. To test a combination, we built a model in which water is injected for the first 2 hours and 20 minutes, followed by polymer injection [4]. This approach yielded a total oil recovery of 28.85 ml, or about 48%.

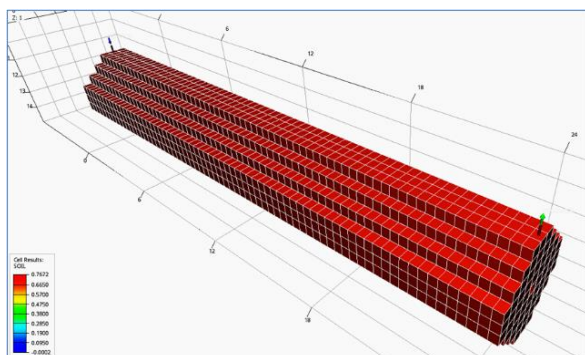


Fig. 8: Three-dimensional rock core model Driza 2
Source: Created by the authors

3.3 Rock sample Driza 2

The 3D model of the Driza 2 rock sample also has 5,670 cells, each measuring 0.355 cm by 0.445 cm by 0.445 cm. As before, we inject water and polymer at one end and collect oil and water at the other. Both simulations used the same injection settings for 6.5 hours, with an injection rate of 278 ml/h, matching the lab test [17].

3.3.1 Water Injection Test

The calculations show the evolution of oil recovery, as shown in Figures 8 and 9.

The total volume of oil recovered in the water-injection case is 12.03 ml, corresponding to a recovery rate of about 25.8%.

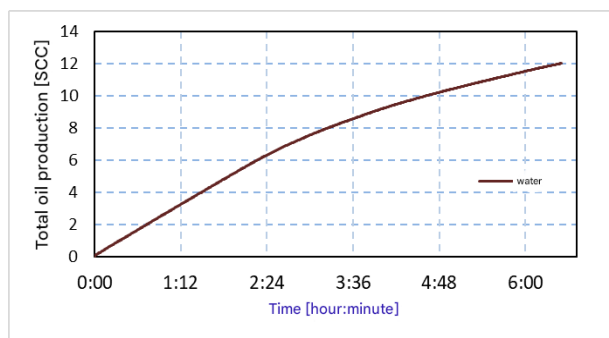


Fig. 9: Evolution of total oil production (ml) without polymer injection – Well 2
Source: Created by the authors

3.4 Polymer Solution Injection Test

The polymer injection test modeling results (Figure 10) indicate a total oil recovery of 24.3 mL, or a recovery rate of approximately 52%.

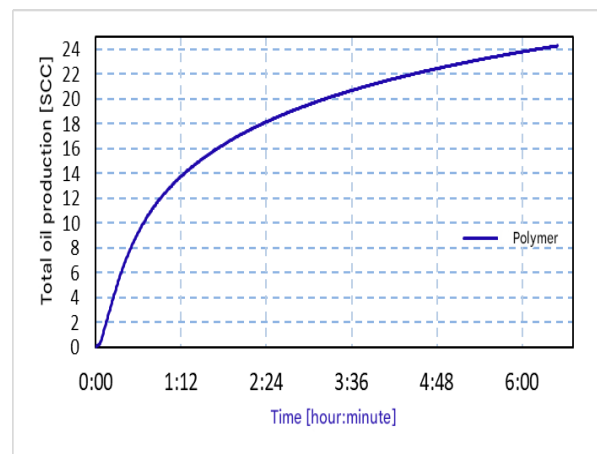


Fig. 10: Evolution of total oil production (ml) with the use of polymer - Well 2

Source: Created by the authors

Driza 2 ($dx=0.355/0.445$ cm): Water: 25.8% (12.03 ml) [Figure 9]. Polymer: 52% (24.3 ml) [Figure 10].

In summary, Table 3 and Figure 11a and Figure 11b present simulation results.

Table 3. Summary of the laboratory test simulation results

Injection Type	Injection Type Oil Recovery in %	
	Driza 1	Driza 2
Water Injection	25%	25.8%
Polymer Solution Injection	53%	52%

Source: Created by the authors based on the present study.

Table 4 (Appendix) compares laboratory parameters with their numerical model equivalents for polymer flooding in the Patos-Marinza field. This complements the workflow diagram by showing how experimental evidence is translated into simulation inputs and validation metrics.

Table 4 shows how *experimental measurements* (viscosity, adsorption, breakthrough data) are systematically converted into *simulation parameters*. For Patos-Marinza, this mapping ensures that numerical models are not abstract approximations *but are directly grounded in laboratory evidence*, improving predictive accuracy for field-scale polymer flooding.

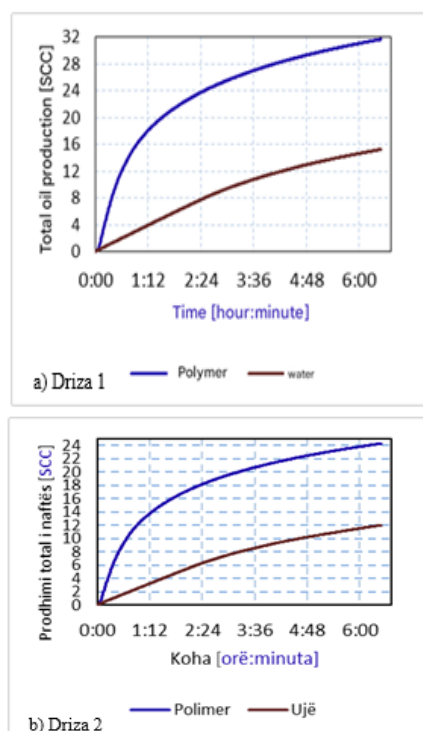


Fig. 11: Laboratory test results with and without polymer injection: a) Well 1, b) Well 2

Coupling: Implicit AD essential (IMPES oscillates $c > 1500$ ppm). TPFA adequate ($Pe < 10$).

Source: Created by the authors based on the present simulation results.

4 Conclusions

Polymer doubles RF via mobility control ($\pm 15\%$ sensitivity max). OPM Flow validated for Patos-Marinza EOR. OPM Flow is a powerful tool for simulating complex multiphase environments. Built on MRST [12], [13], [14], it has a strong mathematical and computational foundation, making it useful for both laboratory and field studies of enhanced oil recovery. OPM Flow, grounded in MRST [12], [13], [14], robustly simulates polymer EOR [2]. Key outcomes: a) Polymer doubles lab RF (52-53% vs. 25%), confirming sweep via viscosity/permeability effects; b) model matches experiments, validating for Patos-Marinza upscaling; c) Hybrid injection viable for breakthrough control.

Recommend OPM/MRST for lab-to-field EOR workflows.

- ✓ Polymer flooding nearly doubled oil recovery compared to water injection alone, achieving recovery factors of $\sim 52\text{--}53\%$ versus $\sim 25\%$, confirming its effectiveness as an enhanced oil recovery (EOR) method.
- ✓ The OPM Flow simulator successfully reproduced laboratory results, validating its

reliability as a computational tool for modeling polymer flooding in porous media.

- ✓ Key mechanisms driving improved recovery include polymer adsorption, viscosity modification of the aqueous phase, and permeability reduction, all of which enhance sweep efficiency and delay water breakthrough.
- ✓ Numerical modeling, when combined with laboratory experiments, provides a cost-effective and flexible approach to optimizing polymer injection strategies and supports application in complex reservoir environments.
- ✓ Combining mathematical modeling with experimental data helps optimize polymer injection parameters; It is recommended to use the OPM Flow program for calculations involving reservoir and polymer injection conditions.

TPFV*: "Two-Point Finite Volume" (or "Two-Point Flux Approximation") method.

Declaration of Generative AI and AI-assisted Technologies in the Writing Process

During the preparation of this work, the author(s) utilized artificial intelligence (AI) technologies solely for the purpose of linguistic refinement and grammatical correction. Following the application of these tools, the author(s) comprehensively reviewed, verified, and edited the resulting text. The author(s) maintain full accountability and responsibility for the accuracy, integrity, and final content of the publication.

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Contribution of Individual Authors to the Creation of a Scientific Article (Ghostwriting Policy)

- Lorina Malollari: Conceptualization, methodology, investigation, writing - original draft, visualization
- Thoma Korini: Data curation, formal analysis, software, validation
- Klaudio Peqini: Methodology, resources, writing - review and editing
- Ilirjan Malollari: Supervision, project administration, conceptualization, writing - review and editing

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APPENDIX

Table 4. Lab-to-Model Parameter Mapping

<i>Laboratory Parameter</i>	<i>Observed Experimental Role</i>	<i>Numerical Model Equivalent</i>	<i>Use in Simulation Refinement</i>
<i>Polymer Viscosity</i>	Measured under reservoir temperature and salinity; defines mobility control	Input as viscosity function vs. concentration and shear rate	Adjusts polymer mobility ratio and sweep efficiency
<i>Polymer Adsorption /Retention</i>	Core flooding tests show polymer loss on rock surfaces	Adsorption is modeled as a retention coefficient or Langmuir-type isotherm	Ensures effective polymer concentration matches lab evidence
<i>Molecular Weight Distribution</i>	Determines rheological behavior and shear-thinning properties	Represented as viscosity-shear rate curves in simulator	Captures non-Newtonian flow behavior in porous media
<i>Injection Rate & Pressure</i>	Lab displacement tests measure breakthrough time and shear degradation	Boundary conditions for injection wells	Validates polymer propagation speed and breakthrough timing
<i>Reservoir Rock Properties</i>	Porosity, permeability, heterogeneity measured in core samples	Grid cell properties in reservoir model	Defines flow pathways and retention zones
<i>Temperature & Salinity</i>	Stability tests show viscosity loss under high salinity and temperature	Incorporated as viscosity reduction factors	Adjusts polymer stability curves to match reservoir conditions
<i>Breakthrough Curves</i>	Lab effluent analysis shows polymer arrival and oil recovery increments	Recovery factor vs. time curves	Used to validate simulation predictions against experimental displacement profiles

Source: Created by the authors based on the laboratory-to-model parameter mapping developed in this study.
Adapted from [4], [13], and [14].