Chair of Reservoir Engineering

Master Thesis

Polymer Flooding Optimization in a Romanian Field

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Danksagung / Acknowledgement

I am grateful to Prof. Holger Ott and Kata Kurgyis from Montanuniversität Leoben for their academic guidance.

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Kurzfassung

Da Wasserinjektion im rumänischen Erdölfeld Vata keine zufriedenstellendes Resultat lieferte, wurden alternative Methoden zur Steigerung der Produktion in Betracht gezogen. Es wird vermutet, dass ein unzureichendes Mobilitätsverhältnis der Grund dafür ist, dass die durchgeführte Wasserinjektion unter den Erwartungen blieb. Aus diesem Grund entschied sich die OMV Petrom eine Studie in Auftrag zu geben, welche die Effektivität verschiedener EOR Produktionsszenarien untersucht. Als Resultat wurde festgestellt, dass in diesem Falle Polymerinjektion ein großes Potential für eine Produktionssteigerung bietet. Basierend auf dieser Erkenntnis, soll anhand der hier vorliegenden Arbeit ebendieses Potential evaluiert werden.

Ein 3D Modell der Lagerstätte war bereits verfügbar, dass mittels der zur Verfügung stehenden Produktionsdaten und der Simulation des Wasserinjektionsversuches verifiziert wurde. Darauf basierend konnten Szenarien zur Polymerinjektion simuliert werden. Da nicht alle Eingabeparameter experimentell festgelegt werden konnten, entschied man sich, Daten einer analogen Lagerstätte zu verwenden. Dies bezieht sich etwa auf die Interaktion der verwendeten Polymere mit der Gesteinsmatrix. Betriebsparameter wie etwa Injektionsrate, Polymerkonzentration oder Injektionsvolumen wurden zunächst festgelegt, wobei auch ökonomische Betrachtungen stets eine Rolle spielten.

Erste Untersuchungen befassen sich mit dem Einfluss verschiedener Faktoren, wie etwa Polymeradsorptionsrate, Permeabilitätsreduktion und der unzugängliche Teil des Porenraums auf die Ausbeute – den sogenannten „Recovery Factor“, um den Grad der Unsicherheit der Simulationen zu bestimmen. Dabei konnte gezeigt werden, dass der Recovery Factor – nahezu unabhängig vom unzugänglichen Porenraum ist, wohingegen eine Permeabilitätsreduktion eine Abweichung von bis zu 20% nach sich ziehen kann.

Ein weiterer Schwerpunkt der Studie liegt auf einer Machbarkeitsanalyse einer Polymerinjektion simultan in mehrere Schichten des Feldes. Die Analyse basierte auf Regionalen Feldeigenschaften und berücksichtigt auch nicht-newtonsches Verhalten der Polymerlösung. Aus den Simulationsergebnissen lässt sich ableiten, dass tiefere Regionen aufgrund ihrer Gesteinseigenschaften nicht ausreichend geflutet werden können. Aus diesem Grund sollte von einer simultane Polymerinjektion abgesehen werden oder benötigt weitere Untersuchungen.

Bei weiterer Betrachtung des Polymerverhaltens konnte festgestellt werden, dass die Ausbeute für eine Polymerkonzentration von 1500ppm unter Berücksichtigung nicht-newtonscher Rheologie und für 1000ppm unter der Annahme newtonischer Rheologie zum gleichen Resultat führt.

Ein weiterer Faktor der in der Studie berücksichtigt wurde, ist die Sensitivität von Polymeren auf ihre Umgebung. Da bei einer Analyse des Lagerstättenwassers Salinitäten von bis zu 90.000ppm gemessen wurden, kann die Lagerstätte als hoch salinisch kategorisiert werden.

Aus diesem Grund wurden während einer Sensitivitätsanalyse, Simulationen mit Salinitäten zwischen 50.000ppm und 90.000ppm durchgeführt und dessen Auswirkung auf die Produktion analysiert. Die dabei verwendeten Intervalle wurden mithilfe verschiedener Viskositätsdiagramme bestimmt. Schlussendlich kann gesagt werden, dass mit steigender Salinität eine höhere Konzentration von Polymeren oder ein weniger sensitives Polymer eingesetzt werden muss.

Zusammengefasst kann gesagt werden, dass eine Polymerinjektion die Produktion im Vata Feld steigern kann. Um die Genauigkeit zukünftiger Studien zu erhöhen, sollten zusätzlich zu der Betrachtung der Heterogenität experimentelle Daten wie auch weitere in-situ Messdaten erhoben werden.

Suchbegriffe: Polymerinjektion ; Sensitivitätsanalyse ; newtonsch und nicht- newtonsch ; Salinität ;

Abstract

As previous attempts of water injection in the Romanian field, showed poor results mainly due to an unfavourable mobility ratio, the attention was shifted on finding different alternatives to increase incremental oil production. An EOR screening process, using both conventional and advanced methods, was performed and polymer flooding resulted to be one of the proposed options. On these grounds, an estimation of polymer flood efficiency for this field represents the scope of this study.

The availability of an already existing reservoir model for the region investigated, including the history match of observed data and prediction cases for water injection, made possible the polymer flooding evaluation on a simulation basis. This paper presents the first simulation results of polymer flood in this reservoir; therefore the polymer-rock interaction parameters used as input were taken from an analogous field, where polymer core flood experiments were available. The operating parameters used for the simulated cases, namely injection flow rate, polymer concentration and slug size, were chosen mainly based on technical reasons. Still, in the decision making process, the economic viability of the polymer project was taken into account by dint of utility factor.

A sensitivity analysis on polymer adsorption, permeability reduction and inaccessible pore volume influence on recovery factor was first performed, in order to assess simulation results' degree of uncertainty and the interval limits of production characteristics. Recovery factor showed to be almost insensitive to inaccessible pore volume; on the other hand permeability reduction was found to have the highest influence inducing up to 20% variation in RF.

One focus of the study was represented by comingle polymer injection viability evaluation as the field consists of 5 different layers. The analysis was performed on a layer region basis, including also the Non-Newtonian behaviour of polymers for increased accuracy. The observation that the deepest region, A Sand 2, and a big part of region A Sand 1, were almost untouched by polymer solution as result of poor rock quality, suggests that comingle injection should not be considered without further investigation.

A closer look to polymer behaviour showed that considering Non-Newtonian rheology, the field recovery factor for the 1500ppm polymer concentration case was equal to 1000ppm concentration and Newtonian behaviour scenario. This remark involves a downturn of expected flood effectiveness.

Polymers are known to be sensitive to harsh environments and the investigated field falls into the category of high saline reservoirs. Total dissolved solids of up to 90 000ppm had been reported throughout the years and due to lack of accurate measurements a specific narrower salinity range cannot be defined. On this basis, salinity effects, from 50000 ppm up to 90000ppm, on recovery factor were investigated and meaningful variation was determined by using different viscosity yield curves. Taking into account the impact on economics, a higher concentration of conventional or TDS tolerant polymers should be considered.

The results concluded that polymer flooding could indeed represent a viable option to increase production of the field. For future evaluations it is recommended that in addition to heterogeneity capturing via multiple realisation modelling, also SCAL and polymer core flood experiments as well as water salinity measurements should be conducted.

Keywords: polymer flooding ; sensitivity analysis ; Newtonian and non-Newtonian ; commingle injection ; water salinity ;

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Abbreviations

bbl	Barrel
cP	Centi Poise
EOR	Enhanced Oil Recovery
HPAM	Hydrolysed polyacrylamide
IPV	Inaccessible Pore Volume
M	Mobility Ratio
mD	MiliDarcy
P_b	Bubble Point Pressure
Pa	Pascal
PAM	Polyacrylamide
PV	Pore volume
PVI	Pore Volume Injected
RF	Recovery Factor
RRF	Residual Resistance Factor
UF	Utility Factor

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1 Introduction

Oil and gas reservoir lifetime goes through three different production stages, characterized mainly by the energy used for hydrocarbons production. Numerous attempts to explain the recovery methods can be found in literature, including the first stage: primary recovery as being the stage where fluid flow through porous media towards and out of production wells is driven by the natural energy of the reservoir. As primary production can be maintained only a certain period, the goal is represented by driving mechanism determination to adopt the best strategy for managing and reserves recovery in middle and later life. The most important and well known drive mechanism are: (i) Solution gas drive; (ii) Gas cap drive; (iii)Water drive; (iv)Gravity drainage; (v) Mixed drive. [1]

The second stage of hydrocarbon production is characterized by external fluid injection mainly for pressure maintenance purposes. The injected fluids, that are normally fluids present in the reservoir, including water or gas, are expected to perform the sweeping of the reservoir in a more efficient displacement process. Waterflooding has become the most widely used method as extensive research and field applications have been done since late 50s due to its availability and low costs.. The biggest drawback of this method is considered to be the insufficient stemming caused by undesired mobility ratio from water and oil viscosity discrepancy. [2]

Tertiary recovery refers to injection of fluids that are not normally present in the reservoir for two main purposes: boosting the natural energy of the reservoir and creating favourable conditions for residual oil recovery such as: reduction of interfacial tension between displacing and displaced fluid, increasing capillary number, increase water viscosity, reduce oil viscosity, provide mobility control and so on. [1]

Enhanced oil recovery methods, can be divided into three main categories: Thermal, Gas Injection and Chemical Injection, along with some other methods such as Microbial EOR and nano-particles as illustrated in Figure 1.

Figure 1: Enhanced Oil Recovery Families [3]

They are mainly applied to extend the production life of an otherwise depleted or uneconomic reservoir by modifying fluid-fluid and fluid-rock properties consequently [3]:

- Thermal EOR: it is the most widely used method and mainly applied for heavy and extra heavy oil as it affects oil viscosity by heating it up.

- Gas Injection: subdivided into miscible and immiscible flooding implies the injection of gases (hydrocarbons, carbon dioxide, nitrogen etc) to reduce oil viscosity, interfacial tension and increase oil swelling.
- Chemical EOR includes the techniques that require injection in the reservoir of a mixture composed of chemical additives and water in order to improve sweep and microscopic efficiency.

EOR methods have presented interest since early 90s while many research and field application have been done in that times with concern to this. In latest times, until the volatility of oil prices hit the industry in 2014, a renew focus and increase of EOR deployment has been observed in many regions of the work, especially in the US and Canada. A forecast of IEA from 2012 depicts that by 2035, EOR production will represent approximately 25% of total world oil production.

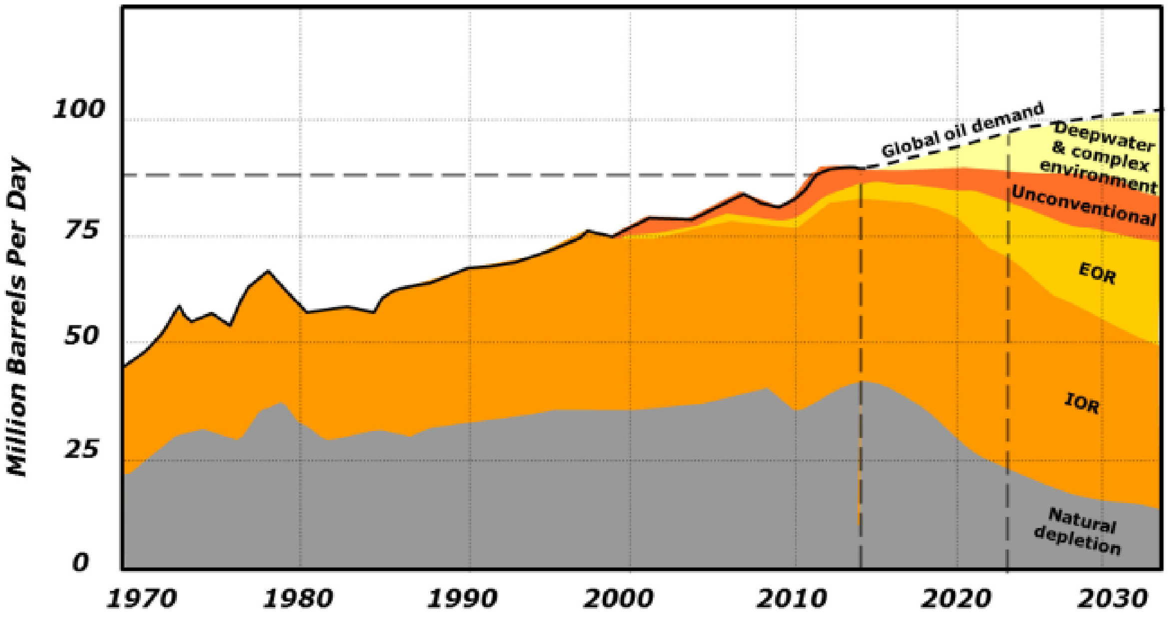


Figure 2: Worldwide Future Oil Production and Demand [4]

The success of an EOR process can be assessed from both technical and economical point of view. Focusing on the technical part, the success is given by the incremental of oil recovered compared to primary or to secondary recovery as the oil production should deviate from the declined rate forecasted before. If on a simulation basis, to assess the gain in oil production is considered to be relatively easy as it can be resumed to the comparison of two cases, on a field application basis thing become more complex.

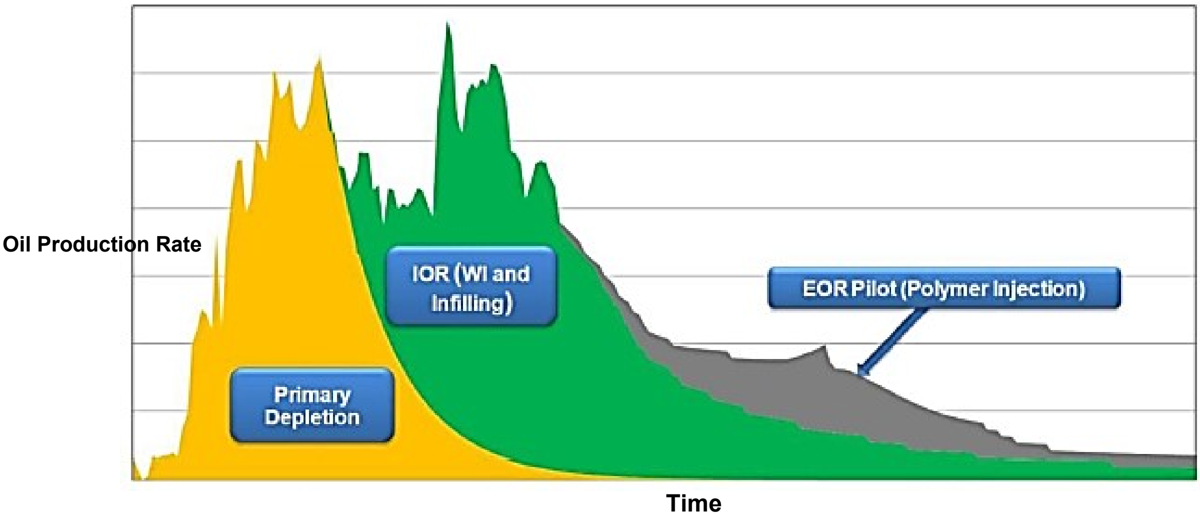


Figure 3: Incremental oil for EOR. Adapted from [3]

The majority of Romanian fields are mature brown fields that are in an advanced stage of depletion. The investigated field is one of the biggest fields in Romania, therefore many ongoing preoccupations to extend its production life and obtain incremental volumes exist. Several attempts to increase production and implement secondary recovery methods were performed and concluded by poor results. The field showed unfavorable response to waterflooding pilot due to high contrast in fluid’s viscosity, hence attention was shifted to tertiary recovery methods.

The study focuses on finding new methods to increase field production life and assessing the performance of the suitable method found.

2 Polymer Fundamentals

2.1 Polymers

Already mentioned above, polymer flooding falls under the chemical EOR methods implying a mixture of chemicals and water injected into reservoir in order to decrease the amount of oil trapped inside the porous media. As it is already known, the force balance between viscous and capillary forces is governing the quantity of oil trapped and the capillary number is used as measure to quantify it.

Larson et al. [5] defined the ratio between viscous and capillary forces as capillary number, N_c:

$$N_c = \frac{\upsilon\mu}{\sigma} \tag{1}$$

where σ is the interfacial tension, υ and μ refer to the fluid velocity and viscosity, respectively.

Polymer flooding mechanism targets to decrease the amount of oil trapped by increasing the viscosity, leading to capillarity suppression by viscous force and mobilization of a higher amount of hydrocarbons. As the increase in capillary number is just one order of magnitude, the effect of polymers in microscopic displacement is rather limited.

However, the feature that stands behind polymer action is macroscopic displacement which primarily target the oil bypassed by water flooding and which can be obtained through a key element: mobility ratio.

Mobility ratio, M, was defined by Ahmed [6] as the ratio of displacing and displaced fluid mobilities, as suggested by eq.2. In a polymer flooding case, water (polymer solution) is considered to be the displacing fluid, while oil is the displaced phased.

$$M = \frac{\lambda_W}{\lambda_O} = \frac{\frac{k_W}{\mu_W}}{\frac{k_O}{\mu_O}} = \frac{k_W}{\mu_W}\frac{\mu_O}{k_O} \tag{2}$$

where λ refers to mobility and is defined as permeability k divided by the viscosity μ and the subscript indicating the fluid, where o refers to oil and w refers to water.

From literature, for a displacement to be considered favorable, a mobility ratio value less than 1 is expected.

Mobility ratio effects are derived from Buckley Leveret theory of immiscible displacement: low mobility ratios lead to a piston like displacement, a feature extremely wanted in water and polymer flooding applications. In the plot below the water saturation profile from a water flood after 0.2 PV injected displays the differences induced by mobility ratios. Low values exhibit high shock front which leads to favorable displacements while high mobility ratios lead to a long tailing tendency of two-phase region. Moreover, unfavorable displacement implies an inefficient areal sweep as result of viscous fingering. [7]

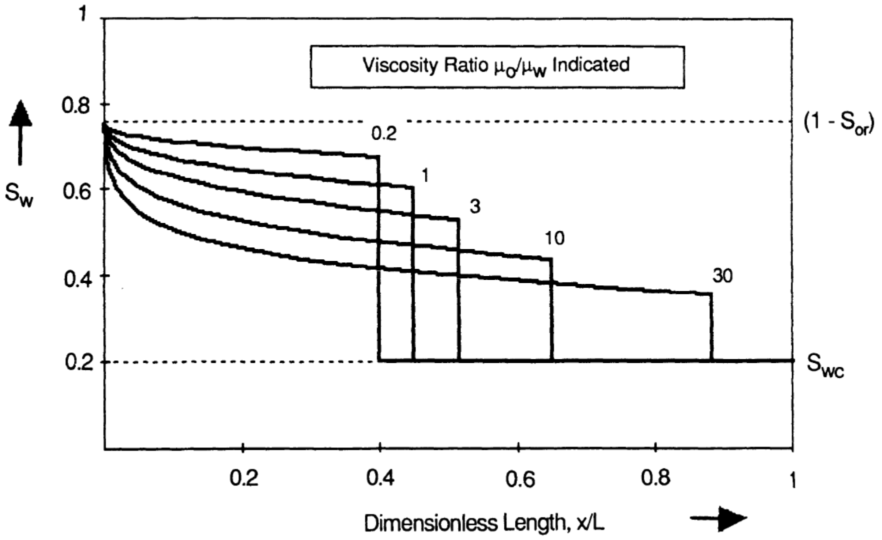


Figure 4: Mobility ratio effect on in-situ saturation profile [7]

Figure 5 depicts the difference between water injection and polymer flooding results in terms of areal sweep. The low-viscosity injection fluid is characterized by viscous fingering and an early breakthrough, whereas the higher-viscosity injection fluid causes a favorable injection front shape due to a lower mobility ratio. This allows for the flood to affect a larger reservoir area, mitigating viscous fingering and increasing areal sweep efficiency and therefore cumulative oil production.

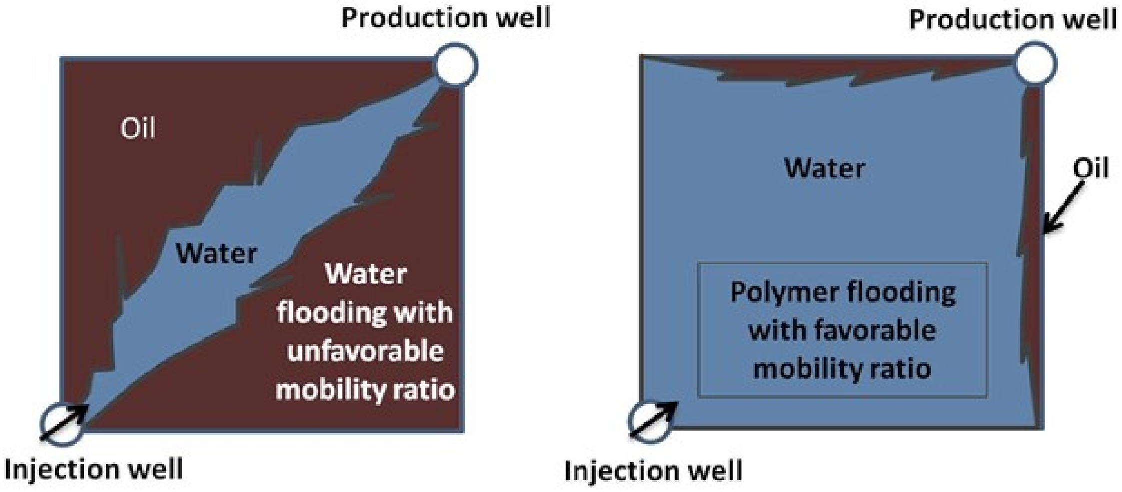


Figure 5: Water and polymer flooding areal sweep [8]

2.1.1 Polymer Type

Even though on the market there are a lot of potential chemicals suitable for water viscosifying purposes, this paper will focus only on the main once used in the field for polymer flooding: polyacrylamides (HPAM) and polysaccharides (Xanthan gum).

- **Polyacrylamides**

The polymers that fall into this category are called synthetic polymers or partially hydrolysis polymers due to their 30-35% degree of hydrolysis. The percentage has been carefully selected in order to optimize certain properties like viscosity, water solubility and retention as well as generating the negatively charged character of the molecules.

The power of HPAM to increase water viscosity is owed to its large molecular weight. The anionic repulsion between polymer molecules and segments causing the elongation of the molecules in solution is an effect that accentuates the mechanism, mainly at higher concentrations.

There are many advantages concerning HPAM usage in polymer flooding, from which permanent permeability reduction, resistance to bacterial attack and lower price are worth to be mentioned. What is more, HPAM is stable under anaerobic conditions but unstable in the presence of iron or under elevated reservoir temperatures. On the other hand, its high sensitivity to water salinity and hardness is hindering it from many field application considerations. [9]

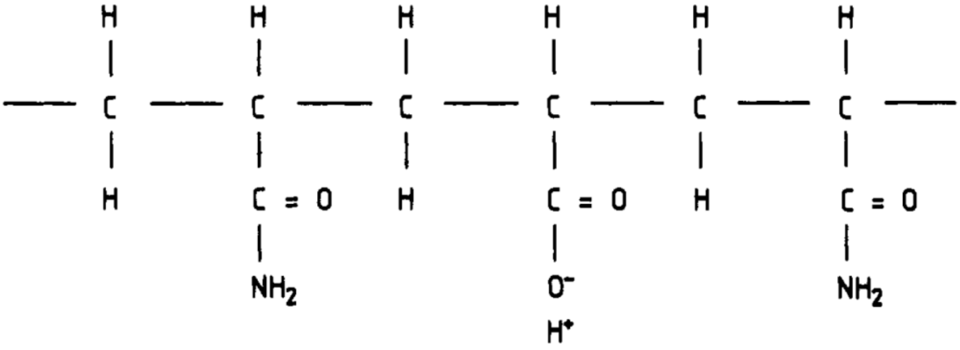


Figure 6: Molecular structure of HPAM [10]

- **Polysaccharides**

These polymers are considered biopolymers as they are produced from polymerization of saccharide molecules through bacterial fermentation process. Polysaccharides mechanism of increasing water viscosity is by snagging and adding a more rigid structure to the solution.

Without any doubt, the biggest advantage of this category of polymers is represented by the insensitivity to salinity and hardness, over countered partly by two side effects: the susceptibility to bacterial attack and no permeability reduction. [9]

All in all, as Manning et al. reported, until 1983, HPAM was used in more than 95% of field floods, statement reinforced by later studies from 2011. Even though its price per unit amount is less compared to biopolymers, total costs get closely when considering mobility reduction, in particularly for high salinity reservoirs. [2]

2.1.2 Polymer Stability

Polymer stability can be a crucial element when considering optimum injection rate and polymer type for a polymer flooding process. Three degradation mechanisms that result in an unwanted decrease of polymer's molecular weight were distinguished until now:

Chemical degradation is the general term that incorporates different process happening in the reservoir during polymer flooding such as: thermal exudation, free radical chemical reactions, hydrolysis etc. Oxidation is considered to be the most serious source of degradation so additional oxygen scavengers and antioxidants are added to mitigate or retard the chemical reactions. [9]

Biological degradation has been observed for both HPAM and Xanthan, but with drastic effects on polysaccharides, due to their biogenic origins. In order to prevent this, biocides are recommended to be used from the beginning of the flooding. [7]

Mechanical degradation is the process of breaking down the molecular structure of polymers by two reasons: high mechanical stress applied on molecules or high flow rate in near-wellbore region. Taking HPAM polymer as example, the mechanical degradation of this high molecular weight polymer into smaller weight molecules not only influences solution's viscosity but also all the intrinsic properties of the polymer and cancels the advantages that an high molecular weight polymer can lead to the flooding process. On contrary, Xanthan gum is less sensitive to this type of degradation by virtue of its rigid chain molecular structure.

There had been identified the main locations where polymer mechanical degradation could occur:

- In the surface facilities due to mixing and pumping processes.
- In the pipes and chokes encountered on the way from polymer unit to wellhead by means of excessive shear rates.
- In the reservoir owing to visco-elastic effects
- In production pumps and surface sampling as they exert high shear rate

Scientists put an emphasis on chemical degradation as all polymers undergo this mechanism and suggest that the other two degradation types could be “screened out” by either optimum injection rate or proper polymer type selection. On the other hand, when polymer flooding is considered an option, mechanical degradation is the topic that brings concern among companies' research teams as chemical and biological degradation impact has been detected from laboratory experiments and field particularities. [11]

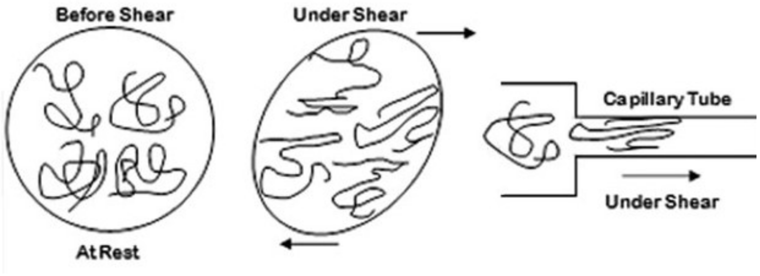


Figure 7: Stretching of coiled polymer chains under shear [12]

2.2 Polymer Rheology in Porous Media

Polymer concentration is the essential factor that determines polymer solution viscosity. It is also well known that polymer solution's viscosity is strictly dependent on the size and extension of polymer molecules, that larger molecules are generally associated with higher solution viscosities.

Typically, this relationship is modeled by a purely empirical polynomial expression, Flory-Huggins equation:

$$\mu_p^0 = \mu_w \left(1 + A_{p1} C_p + A_{p2} {C_p}^2 + A_{p3} {C_p}^3 + \cdots\right) \tag{3}$$

where μ_p^0 is the viscosity of zero shear rate, μ_w pure water viscosity, A_{p1} ... constants and C_p polymer concentration.

Figure 8 depicts the relation between the viscosity of the solution and polymer concentration for different types of polymers, at low shear rates (7.6 s^{-1}). It can be observed that the there is a proportional dependency between the two but the magnitude strongly depends on the type of polymer used, with biopolymer Xanthan showing steeper increase and reaching higher viscosity values compared to HPAM. Moreover, even at low polymer concentrations (few hundred ppm) they can reach up to 50 fold viscosities to water (around 1 cP).

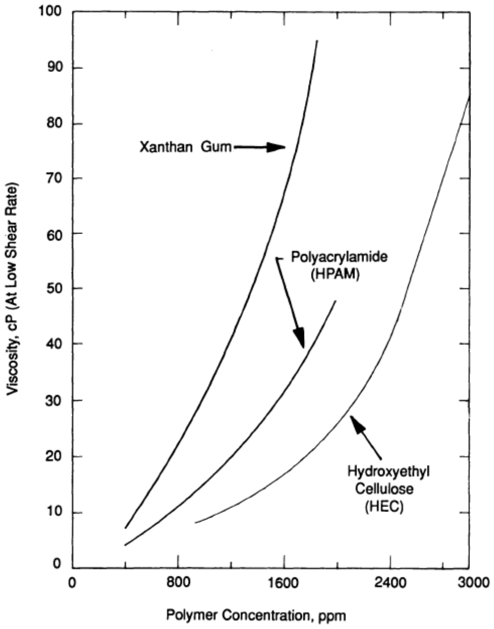


Figure 8: Polymer solution viscosity versus polymer concentration [7]

Polymer solutions are known to be generally non-Newtonian, therefore the study of viscometric flow of fluids and their sensitivity of parameters is called rheology. [2] The behavior of a fluid to exhibit decrease in viscosity with increasing shear-rate is called shear-thinning and it is owed to uncoiling and unsnagging of the chains when they are elongated in shear flow. It is also believed to be reversible only under certain conditions, when shear-rate values are below critical shear. [9]

Shear effect can be expressed by a power law, known as the Carreau model:

$$\mu_p - \mu_\infty = \left(\mu_p^0 - \mu_\infty \right)[1 + \lambda\, \dot{\gamma}^{\,\alpha}]^{\frac{n-1}{\alpha}} \tag{4}$$

where $\mu_\infty = \mu_w$ (the shear limit is equal to water viscosity), α ~2 and λ and n being polymer's specific empirical parameter.

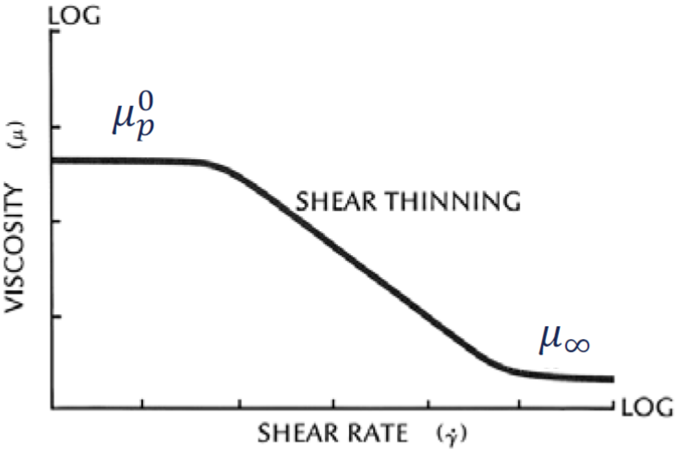


Figure 9: Shear-Thinning behavior of polymers

And if applying typical polymer values, the law becomes:

$$\mu_p = \mu_p^0(\lambda\,\dot{\gamma})^{n-1} \tag{5}$$

Typical values for exponent n, are between 0 and 1 for shear thinning behavior and 1 to indicate Newtonian fluid.

Figure 10 illustrates viscosity versus polymer concentration dependency for Xanflood at 1% NaCl brine and 24 °C, at two different shear rates: 5 s^{-1} and 100 s^{-1}. The offset of the two lines is expressing the shear thinning behavior of the polymer, with only a small influence at low polymer concentration as 200ppm and a significant drop of more than half in solution viscosity, for shear rates of 100 s^{-1}, at 1000ppm.

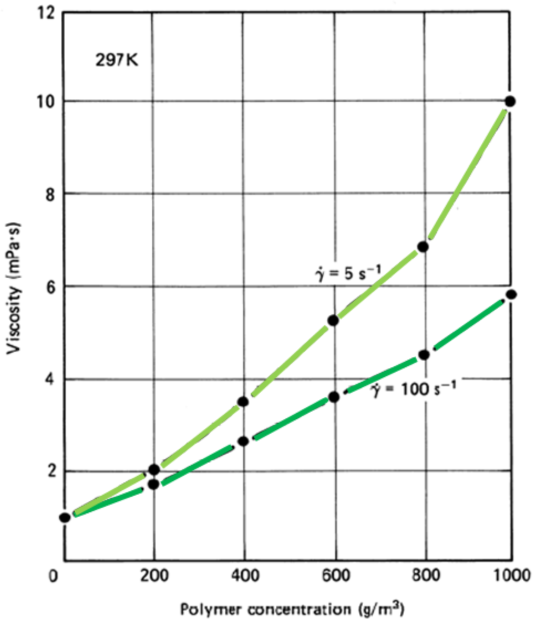


Figure 10: Xanflood viscosity versus concentration at 1% NaCl brine [9]

The shear rate behavior is favorable for polymer flooding, as during the process we can distinguish between two regions:

- Near wellbore region characterized by high shear rates and low viscosity, leading to high polymer infectivity.
- Bulk reservoir region characterized by low shear rates and high viscosity, creating favorable conditions for fluid displacement.

Figure 11 shows Newtonian to Non-Newtonian transition of polymer solution in accordance to shear-rate, at different polymer concentrations at constant temperature and salt concentration. It has been observed that at low concentrations, the fluid behaves rather Newtonian, while with increasing concentration, the shear-rate interval on which polymers tend to behave Newtonian is diminished. The tendency is to approach a second plateau just above water viscosity, so polymers behavior can be divided into three regions: low shear-rate plateau, the shear-thinning region and high shear rate plateau. [7]

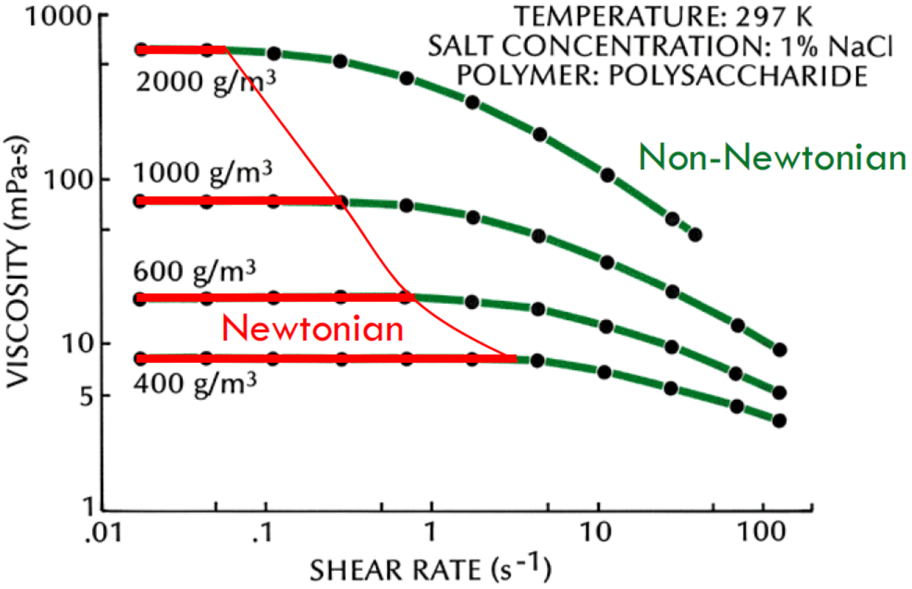


Figure 11: Viscosity variation with shear rate at different concentrations [13]

In his book, Sorbie [7] explains the similar flow characteristics (shear-thinning) for both polyacrylamide and xanthan despite their internal structure differences. The reasoning behind xanthan’s performance is simple and based on the assumption that molecule are treated as rigid. He states that in simple shear flow, the molecules have the tendency to line up in the flow and therefore they dissipate less energy during the flow. For polyacrylamide the explanations are more complex but they are still addressed in terms of polymer’s molecule structure, random coiled in this case. All in all, it has been observed that in most of the influencing conditions, xanthan is much more shear-thinning than polyacrylamide.

Even if the relationship between rheological properties of solutions and polymer structure is complex, it is the key element in understanding and quantifying their flow behavior. A general conclusion can be drawn out of “Polymer- Improved Oil Recovery” book in regards to this topic: even if other polymers than the studied ones (HPAM and Xanthan) will be used, the behavior will be similar to the ones they resemble more with. For instance, more flexible polymers will show analogous flow performance with polyacrylamide while more rigid ones will behave more like Xanthan. [7]

2.3 Transport Properties / Interactions

Since 1990s, researchers concluded from back then already existing field applications that the success of polymer flooding is in close relationship with the ability to maintain mobility control, as in the near wellbore region the process worked good but the displacement efficiency decreased throughout the flooding volume. They attributed the poor performance to failure of polymer propagation over long distances, so polymer transportation problems and subsequent causes became the focus of many studies.

2.3.1 Polymer Retention

Polymer molecules have an affinity to adsorb to the rock surfaces found in petroleum reservoirs. Polymer adsorption is not the only mechanism that causes polymer loss in porous media; in addition two types of retention have been distinguished: mechanical, where polymers accumulate in small pores and hydrodynamic, at unexpected increased flow rate.

The unit used to express retention is the retention level, Γ, also defined as the mass ratio of retained polymer and total polymer injected, in *g/g* or *µg/g*. Another term used is surface excess, Γ_S, expressing the adsorption per unit surface area of solid. [7]

The phenomena lead to additional resistance to flow and loss of polymer concentration, impacting the overall EOR process results. These consequences have contrary results: the decrease in polymer concentration reduces polymer flood efficiency while, on the other hand, permeability reduction increases it. Overall, in literature it can be found that the decrease in viscosity has the greatest impact, deteriorating therefore the total flood efficiency. [14]

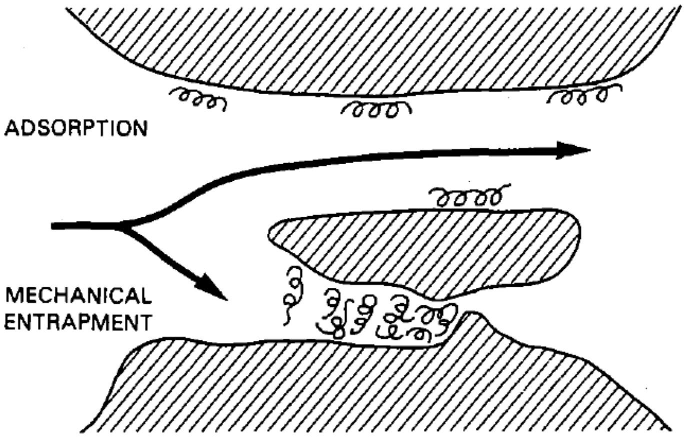


Figure 12: Dominant Mechanisms of Retention

2.3.1.1 Polymer Adsorption

Polymer adsorption is a physical interaction of polymer molecules being bond to the surface of porous media by Van de Waal's forces and hydrogen bonding. Therefore, surface area and the charge of the solid play a significant role. The polymer type, whether it is HPAM or Xanthan, and their specific characteristics: molecular weight, size distribution and the degree of hydrolysis of HPAM can neither be neglected.

Considering polyacrylamide category, there had been observed differences in HPAM and PAM level of adsorption with PAM bias to adsorb more strongly than HPAM. This was interpreted as hydrolysis is reducing polymer tendency to adhere to mineral surfaces. [13]

Polymer adsorption is mainly considered to be an irreversible process for practical purposes and can be quantified by a Langmuir type isotherm. Sorbie [7] in his book discuss both irreversible and reversible hypothesis of the phenomena, concluding that adsorption of polymers will always have same impact on the position of effluent when compared to tracers: effluent will be retarded relative to the tracer (considering also the dependency with IPV).

As adsorption is seen for simplicity as irreversible, the isotherm representing it is non-linear in concentration:

$$C_S = \frac{aC}{1+bC} \tag{6}$$

where $C_S \ and \ C$ are the species concentrations in aqueous respectively on the rock phases.

B factor controls isotherm's curvature with increasing B producing increased curvature, while the ratio between factor A and B determines the plateau value for adsorption.

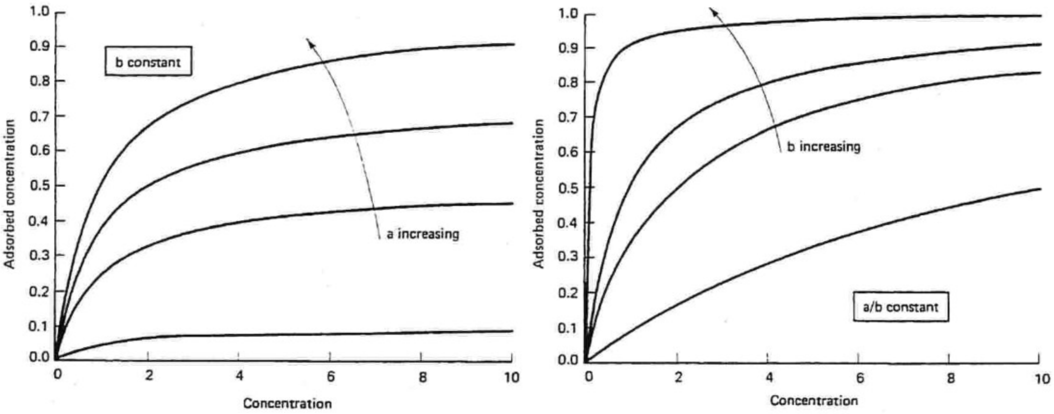


Figure 13: Typical Langmuir isotherm shapes [9]

Polymer adsorption can be measured in laboratory in two ways: static and dynamic measurements. The static method is easy and inexpensive and consists of soaking the crushed rock sample into a polymer solution and calculating the adsorbed mass by the difference in polymer concentration of the solution before and after soaking process. The second method involves core flooding considering polymer and tracer simultaneous injection. One method to calculate the adsorption is by the difference in areas between polymer and trace curves. However, experiments have always errors and the amount reported is usually smaller than the real one. [15]

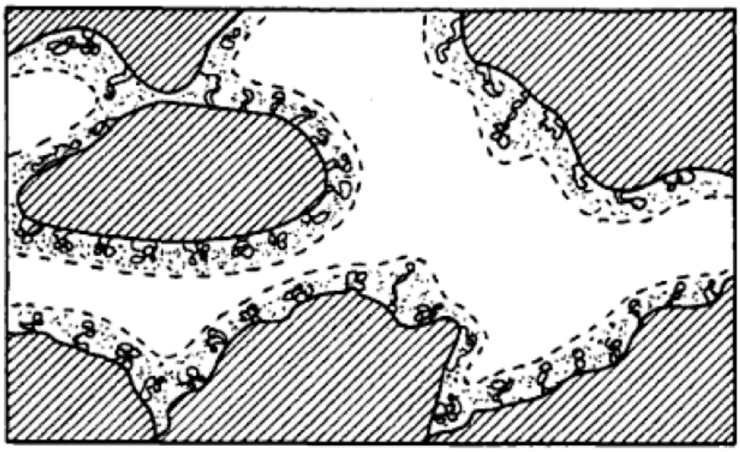


Figure 14: Polymer Adsorption in Porous Media [15]

2.3.1.2 Polymer Entrapment

The first mechanism, also called “straining” mechanism describes polymer entrapment in relation to communicating pores. As the polymer molecule average radius is closely comparable to pore cannel, by the flow through, it can get trapped due to chain absorption on opposite wall. The particularity of this mechanism is that the fluids can still flow through polymer chain and as they carry a certain concentration of polymers, they can easily form bridges and block the flow.

The second mechanism, hydrodynamic retention, is comprehensively described by the first one, except the fact that no chain adsorption happen, therefore polymer molecules got trapped due to size and when flow ceases, they can be released. This mechanism is considered to be reversible, on contrary to the “straining” one.

Huh et al., in one of his papers “Polymer Retention in Porous Media” states that these two mechanisms can be considered together and that they are not solely trapping the polymer mechanically, but that adsorption also plays a certain role. He describes the chemical potential gradient as the force that drives polymers to move out of the pores. With high adsorption energy, this gradient will be diminished so the tendency for outward release, on contrary, with low adsorption energy, the gradient will not suffer changes and when the trapping force will be stopped, the polymers could be released.

Last but not least, the third mechanism accounts for polymer entrapment in dead-end pores or crevices, but it is considered that its contribution to total retention is limited and dependent exclusively on porous media geometry. [16]

Junjian et al. realized measurements to determine and differentiate between adsorption and retention. Using material balance method, the total polymer retention mass could be calculated. By changing the wettability of the rock, from water to oil wet with silicone oil, the HPAM adsorption had been eliminate and the calculated value was exclusively owed to polymer entrapment. [17]

2.3.1.3 Influencing Factors

The following section targets factors that are considered to be influencing for polymer retention, such as permeability, polymer molecular weight, rock mineralogy, flow rate and so on.

A very important factor is considered to be rock mineralogy, especially clay and iron content. A variation from 90% retention of injected polymer in a sodium kaolinite in comparison to only 18% retention in Baker dolomite, for PAM has been reported by J. Meister [18] .Further studies linked the effect to the surface charge of the rock, as sandstones are known to be negatively charged while dolomites positively charged.

Residual oil saturation influence is a debated topic into literature as opposite results had been observed during laboratory experiments when using different polymers. Huh [16] described a tendency to increase adsorption with residual oil phase being present when Xanthan experiments had been performed. On the other hand, Huges et al. [19] considered that residual oil saturation is reducing the process.

Permeability plays a major role on this process with evidence showing that increased permeability increases retention substantially; also implying higher RF and RFF values. [20] Moreover, a correlation between high/low permeability and retention type has been found, according to Huh et al. [16], in high permeability porous media, retention is mainly attributed to adsorption while in low permeability media, to entrapment mechanism.

Another factor which shows influence on polymer retention is the flow rate. Scientist observed that high flow rates forces polymers into small pores throats causing deformations and as soon as the flow rate along with pressure gradient decreases, the molecules relax and can be transported by the flow, for both Xanthan and HPAM. The authors associate this effect with the hydrodynamic retention on the reversibility effect basis. [21]

Polymer molecular weight and the influence on adsorption were intensively studied, and contrary results had been reported. Dang et al. [15] showed that low molecular weight resulted in high adsorption levels and the mitigation action proposed was the usage of high molecular weight polymers, for the clean sand with small clay content analyzed. Consequently, high molecular weight not only reduces polymer adsorption levels, but also increases mobility and volumetric sweep efficiency. At the same time, the high molecular weight polymer molecules that are adsorbed on rock’s surface determine high adsorption energy on the molecules and leads to a steeply isotherm function at low concentrations. [7]

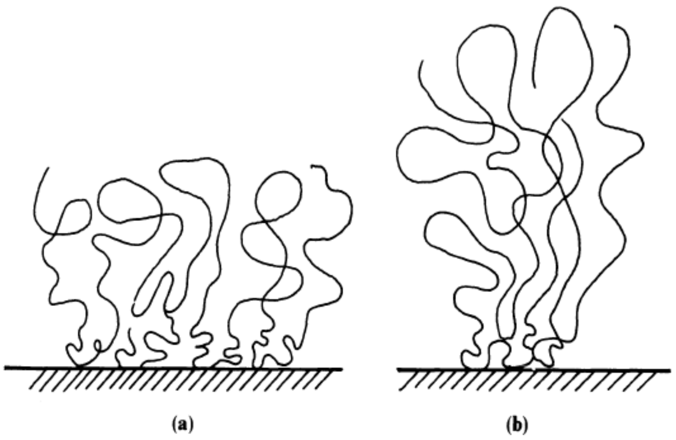


Figure 15: Adsorbed layer of HPAM molecule for (a) intermediate and (b) high

molecular weight species [7]

Furthermore, early studies noted that high molecular weight polymers are able to reduce the mobility of the aqueous solution greater than only the values obtained only by viscosity increase, This addition mobility reduction is owed to permeability reduction due to retention of large polymer molecules. [22]

2.3.2 Inaccessible Pore Volume

Dawson and Lantz [23] were the first reporting the term “inaccessible in the literature” after many studies reported that polymer molecules travel faster through porous media than tracer, when no retention is considered or maximum polymer adsorption level had been reached. They explained the effects observed, in correlation with porous media. They stated that porous media consists of a wide variety of pores throats sizes from which a part of them have dimensions smaller than polymer molecules. Therefore, they named the portion of pores that could not be reached by macromolecules, inaccessible pore volume.

Contrastively to adsorption, due to IPV, the molecules will move only through a subset of the porous media, leading to faster movement compared to tracer molecules and offsetting the delay caused by retention. [7] A second explanation by Duda et al. concerns fluid apparent slip caused by the difference in viscosity between fluid layer the pore wall and center, due to wall exclusion effect and wherefore polymers aggregate in the center of the pore. [9]

The factor influencing IPV are porous media properties: medium permeability, porosity, pore size distribution and polymer properties: molecular weight. [9]

The high molecular of the polymers even though increase significantly the viscosity, creates high inaccessible pore volume values for porous media that have the pore distribution shifted towards small pore region. This can also affect the penetration depth of polymer slug into the reservoir, hence the advantages of larger polymers are in conflict with the areal displacement disadvantages due to pore plugging. The paper “Experiences Learned after Production of more than 300 million Barrels of Oil by Polymer Flooding in Daquing Oil Field” suggests that the size polymer should have in order to mitigate excessive pore plugging has to be smaller than 0.2 of the root mean square pore radius. [24]

2.3.3 Resistance Factor

Field tests and laboratory experiments have proven that some polymers have a selective action to significantly reduce the relative permeability of water with respect to relative permeability of oil. Scientists consider that permeability reduction is a phenomena associated with polymer adsorption and a detailed understanding of polymer adsorption is need to explain this modifications as the degree of modification is governed by the degree of adsorption.

This secondary effect has not been reported for all polymer types, and a clear differentiation between synthetic polymers (HPAM) and biopolymers (Xanthan) exists. Only HPAM is supposed to exhibit this particularity and to reduce the mobility by both water viscosity increase and significant reduction of rock permeability just in respect to aqueous phase.

Related to this topic, a clear differentiation between Residual Resistance Factor and Resistance Factor has to be done before immerging into influencing factors:

- Resistance Factor (RF) represents the ratio between rock permeability to water and to polymer solution:

  $$RF = \frac{K_w}{K_p} \tag{7}$$

  where K_w is rock permeability to water and K_p is rock permeability to polymer solution.

- Residual Resistance Factor (RRF) represents the measure of permanent permeability reduction induced by polymer adsorption, as the process is considered to be irreversible:

  $$RRF = \frac{K_b}{K_f} \tag{8}$$

  where K_b is the initial permeability to brine and the K_f permeability to brine flush after polymer injection.

Early studies from 1970 by W.Smith [25] showed evidence that permeability reduction values are also dependent on polymer molecular weight and flow rate as follows: RF is larger for higher molecular weight polymers and increased flow rate. Initial permeability is another influencing factor studied by Smith in his paper, suggesting that permeability reduction is larger for lower permeability cores. As we already known, low permeability rocks are prone to entrapment mechanism; therefore it is also considered that it is partly responsible for the increase in RF.

Later, in 1981, Baijal observed a dependency between permeability reduction and the hydrolysis od the HPAM and attribute it to the idea that to achieve a satisfactory permeability reduction a optimum degree of chain flexibility is required. Another increase in RRF is seen when polymer concentration or clay content is heightened. [7]

2.4 Salinity Effects on Polymers

Until now, HPAM is the most used polymer for chemical EOR techniques due to its properties and better suitability to reservoir conditions compared to biopolymers, however its behavior in severe reservoir conditions had been intensively studied and its limitations, both technical and economical, for field applications in harsh conditions like high temperature and high salinity and hardness environments, are well documented.

An explanation was provided by Zaitoun and Potie already in 1983 and was later confirmed by a recent study from Abbas et al. in 2013. They articulate that elevated temperature and high salinity significantly accelerates HPAM's rate of hydrolysis, leading to an increased amount of polyacrylic acid in the backbones. This transformation generates HPAM's intolerance to temperature and salinity and therefore makes this polymer unsuitable for implementation in harsh reservoir conditions. [26] [27]

As both Xanthan and HPAM are polyelectrolytes (polymers with multiple charges distributed along the chain) it has been proven by different studies that salinity and pH play a significant role on solution's viscosity achieved by these types of polymers. For understanding this interdependency, a closer look has to be taken up to the interaction level between the fixed charges along the chain and the mobile ions from solution.

Recalling the repulsion forces in HPAM's structure discussed in section 2.3, it is thought that they represent the main cause of HPAM large sensitivity to salinity and hardness. An explanation provided by Lake is that the decrease in repulsion forces due to ionic shielding induces molecule coiling up and decreases snagging effects, resulting in a meaningful polymer effectiveness reduction. [9]

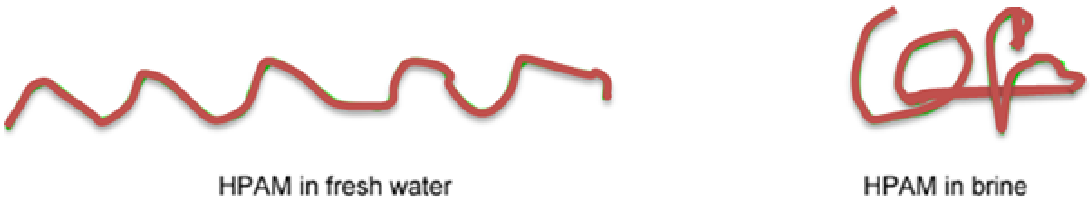


Figure 16: Sketch of HPAM structure in fresh brine and brine [28]

On contrast to HPAM, the molecular structure of Xanthan is the key property regarding salinity and harness influence, and as the molecules are relative nonionic, no ionic shielding effect is happening. From a comparative perspective, if the effect on both type of polymers are quantified, then it is legitimate to state that Xanthan behaves rather “insensitive” to brine salinity and hardness variation.

The theory that salt has an effect only on charged molecules is based on an old study from 1975, when Martin and Sherwood studied the changes in viscosity with salt concentration on two different polymers: hydrolysed HPAM which is a electrolyte and unhydrolysed PAM with neutral molecule. Figure 17 illustrates the results, where it can be clearly seen that PAM viscosity can be considered unchanged over the all interval of concentration investigated, while HPAM behavior is drastically changed even at small salt concentration values. The degrees of hydrolysis analyzed, 15%, 25% and respectively 35%, show same trend in viscosity decrease, a steep slope at the beginning and a plateau reached for concentrations higher than 40 000 mg/l. The plateau region is an indicator that water viscosity can be increased even in harsh salinity conditions meaning that polymer flooding represents a viable EOR method even in high saline environments. [7]

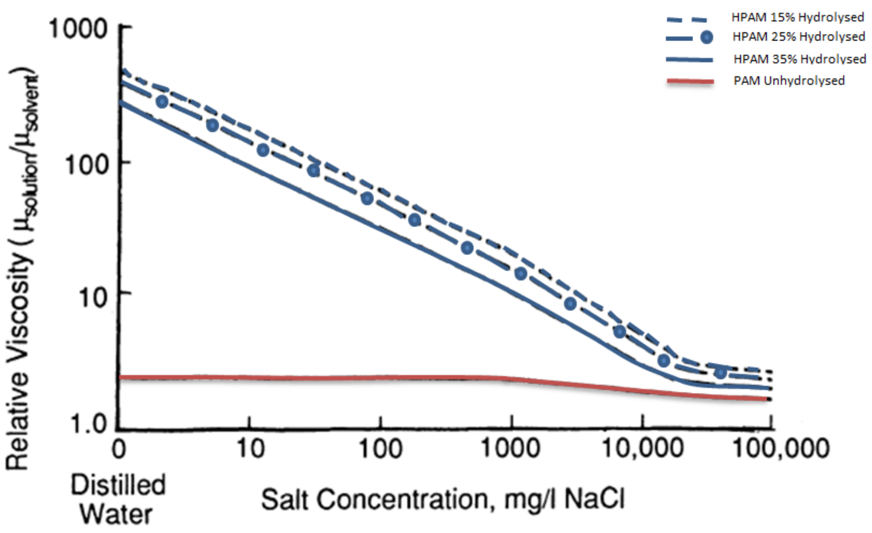


Figure 17: HPAM and PAM viscosity variation with brine salinity [7]

The explanation offered by the authors targets the local double layer that is formed by electrolyte species, which screens out the repulsion forces between backbone charges; the magnitude of screening is direct proportional to salt concentration.

Another observation points out the type of ions that cause viscosity shrinkage, as the effect of divalent species, such as Ca^{2+} and Mg^{2+} , is much more significant compared to the one of monovalent ions(Na^{+} and K^{+}). This is overdue to divalent ions higher charge and polarizability. [7]

Figure 18 reproduces viscosity – shear rate relationship for different NaCl concentration values, for AMPS polymer at fixed temperature and a concentration of 750 ppm. Furthermore, the sensitivity to salinity of HPAM is even more profound that the one exemplified in this plot. As a role of thumb it can be considered that an increase of brine salinity by a factor of 10 leads to a 10 times lower viscosity of the polymer solution. [9]

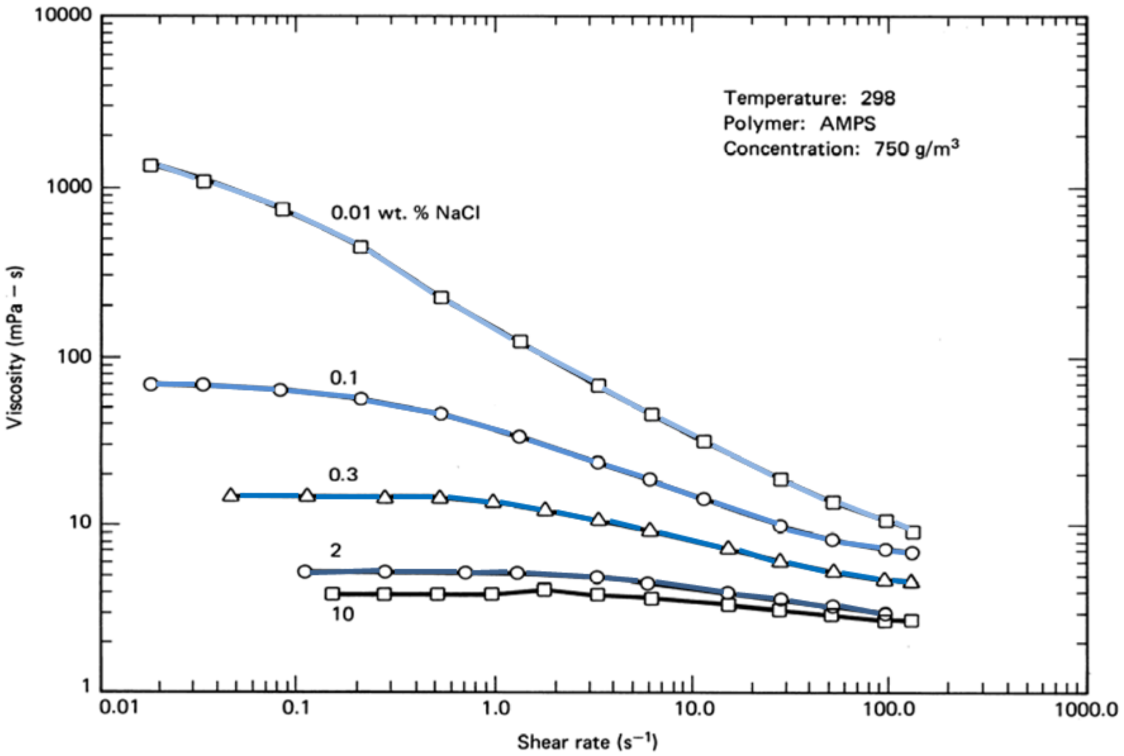


Figure 18: Viscosity variation with shear rate for different NaCl concentrations [9]

A modified version of Flory-Huggins [29], which incorporates a term to express the salinity effects, is used to calculate polymer solution viscosity variation with brine.

$$\mu_p^0 = \mu_w\left(1 + \left(A_{p1}C_p + A_{p2}{C_p}^2 + A_{p3}{C_p}^3\right)C_{sep}^{S_p}\right) \qquad (9)$$

where μ_p^0 is the viscosity of zero shear rate, Pa·s, μ_w pure water viscosity, Pa·s, A_{p1} ... constants , C_p polymer concentration, kg/m^3 and $C_{sep}^{S_p}$ the dependence with salinity and hardness, Eq/m^3.

As the dependence to salinity is the main focus of this section, the term $C_{sep}^{S_p}$ and the equations used for its calculation will be detailed as follows:

S_p can be graphically determined by the slope of the log-log plot of $\frac{\mu_p^0-\mu_w}{\mu_w}$versus C_{sep}

C_{sep} represents the effective salinity for polymer in Eq/m^3 , calculated by eq.10

$$C_{sep} = \frac{C_a+(\beta_p-1)C_d}{C_w} \qquad (10)$$

C_a - anion concentration in the aqueous phase, Eq/m^3

C_d – divalent ions concentration in the aqueous phase, Eq/m^3

C_w - water concentration in the aqueous phase, fraction

β_p is used to adjust the correlation

Even though the major impact that scientist are studying is the salinity effect on viscosity, as it represents the key element for a successful field implementation of this EOR method, brine's composition can impact polymer flooding also in other ways. Another effect of salinity, namely the polymer stability under high salinity and elevated temperature conditions, was studied in details since 1983, by Zaitoun and Poitie, and one year later by Moradi-Araghi and Doe, on polyacrylamide.

It has been shown that the cloud point, especially cloudy polymer solutions, which are the result of polyacrylamide "precipitation", can cause extreme reservoir plugging. Therefore, the influence of salinity and temperature on cloud point behavior was drawn into researchers' attention. Davison and Mentzer were the first ones that reported to see HPAM precipitation when seawater was used, and after further investigation, they concluded that divalent ions were the ones causing this behavior of polyacrylamide. [7]

The results of Moradi-Araghi and Doe will be further presented as they have studies these influence under conditions that are more appropriate to the ones that polymer solution are exposed to into the reservoir. They investigated hardness impact over a wide range, between 1 and 10 000 ppm. In literature, it is considered that a brine is "hard" if it experiences Ca^{2+} and Mg^{2+} concentrations above 100ppm.

Figure 19 illustrates one of their observation regarding not only hardness but also the degree of hydrolysis effects on the cloud point on a 1 000ppm HPAM polymer solution. Up to 90% degree of hydrolysis polymers were used as probes to withstand hardness levels of even 10 000ppm. The first remark insensitivity of soft brines up to 204°C while hard brines' cloud point experience a dramatic decrease with increasing hardness levels, no matter what rate of hydrolysis HPAM has. Regarding different hydrolysis rates, it can be stated that for a certain divalent ion concentration, the higher the hydrolysis degree of polymer, the lower is the temperature at which they precipitate in the solution. Therefore, as cloud point temperature drops extremely fast at even low harness, it can be concluded that cloud point behavior is extremely sharp for divalent ion concentration of more than 40 ppm. [30]

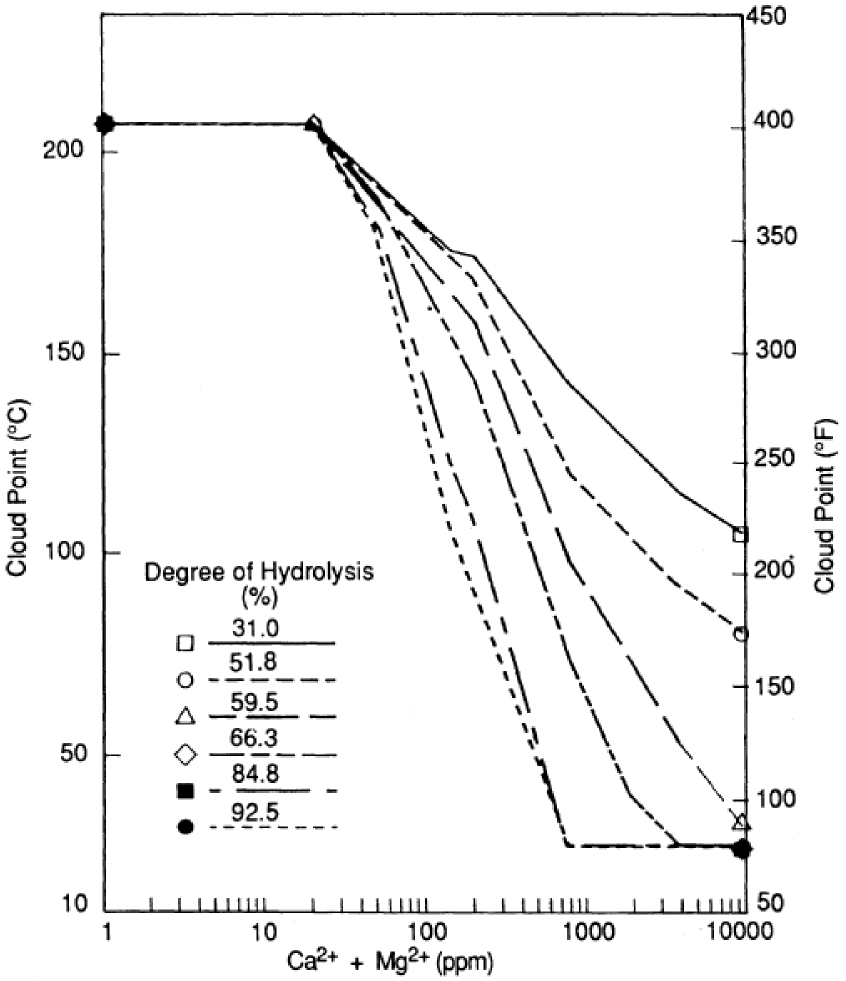


Figure 19: Hardness and degree of hydrolysis on HPAM’s cloud point [7]

Further preoccupation on polymer stability with brines, drove the authors to continue the research and to determine the time when polymers will precipitated in different brines, for the 1 000 ppm solution of unhydrolyzed PAM . For all the measurement times, the cloud point shows similar behavior, with steep decline until approximately 1 000ppm hardness and steadily plateauing afterwards. The main feature expressed by the plot is that temperature play the major role on precipitation time and for reservoirs with less than 100°C the precipitation will happen after more than 20 days for all brine ranges analyzed. [30]

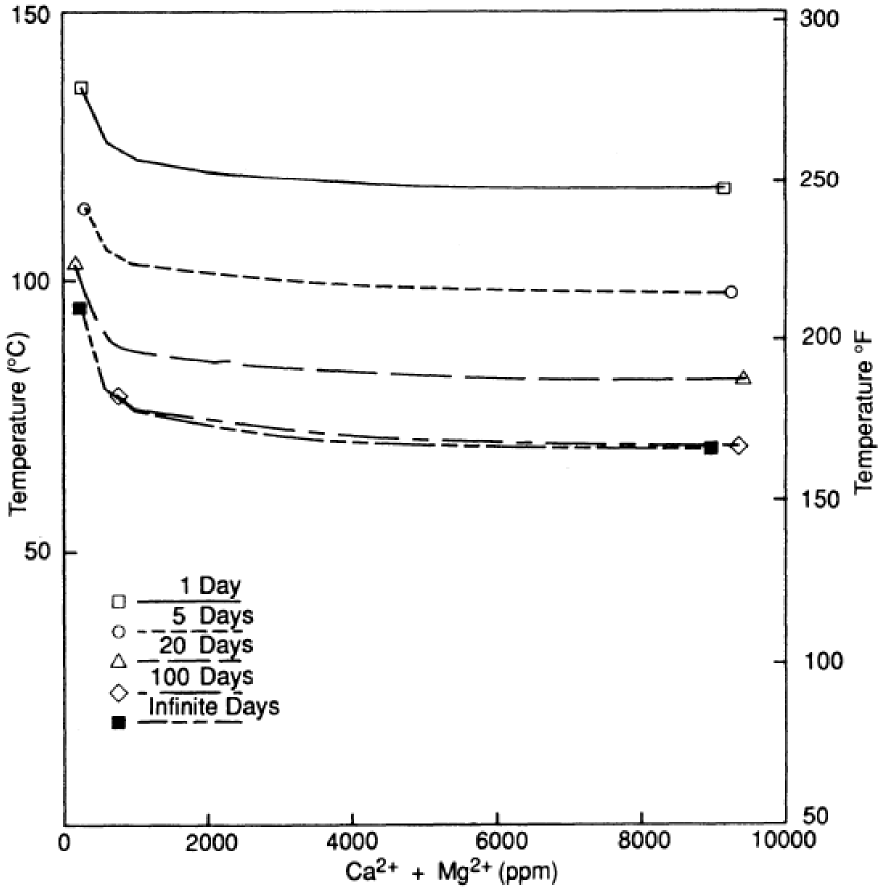


Figure 20: Precipitation time for PAM aged in brines of varying hardness [7]

Another compelling effect of salinity that was studied and reported by Smith dated back to 1970 and refers to HPAM polymer adsorption in high saline brines. He used silica powder and crushed Berea sandstone for its experiments and observed that the salinity has a significant influence on adsorption, namely increased NaCl concentration causes an increase on polymer adsorption on rock's surface

In additions, the type of ions promoting this behavior was investigated and the results were as expected. The divalent ions influence is more pregnant than the one of monovalent ions, basically at low concentrations of Ca^{2+} the adsorption level was significantly higher than at same concentration of Na^{+}. The alternative proposed to diminish this unwanted effect is to adjust Na^{+} concentration at higher levels so it screens the Ca^{2+} effects.

As expected, not only the divalent ions from brine will lead to increased adsorption values, but also the ions from rock's mineral composition. Therefore polymer adsorption on silica has been demonstrated to be even half of the value it can reach for calcium carbonates.

This observation is in concordance to all the others above-mentioned effects of salinity, which are particularly owed to divalent ions concentration. [7]

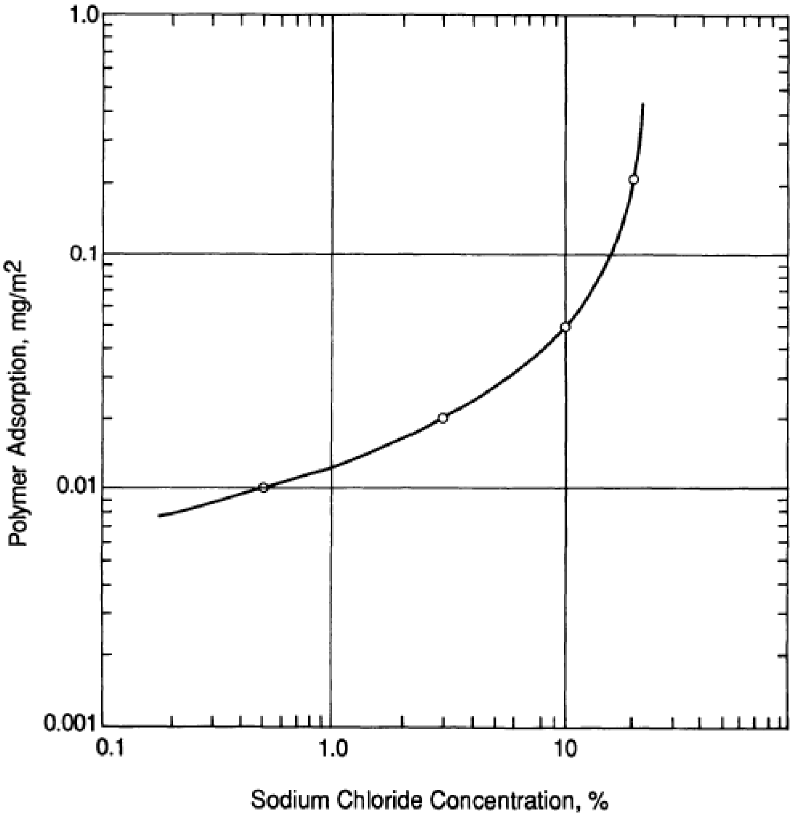


Figure 21: Salinity effect on HPAM adsorption onto silica powder [7]

3 EOR Screening

The decision-making of considering the implementation of an EOR method to a reservoir starts by assessing the EOR potential of the target reservoir, accomplished in the EOR screening phase. During this phase, the aim is to perform an accurate assessment which provides the answer for the question: “ Which is the most suitable EOR technique for the interest reservoir? “

All the existing screening methods require deep knowledge regarding field characteristics and behaviour, previous EOR experience and the most important, full understanding of the recovery mechanism of each potential EOR technique. As oil and reservoir properties are key elements in the effectiveness of the method, related literature considers that a package of six parameters are most relevant for screening process : porosity, permeability, depth, temperature, oil density and viscosity. [31]

EOR screening methods can be divided into two categories, according to their approach: conventional and advanced screenings.

- Conventional methods are based on the existence of certain ranges for reservoir and oil properties, estimated by experts or previous projects to predict the most favourable EOR techniques. Alvarado and Manrique [32] suggested that it should be used only to provide a “ go/no go” criteria because of their significant limitations.
- Advanced methods are based on identifying analogue fields (in terms of oil and reservoir properties) and the idea that similar fields should show appropriate behaviour if the same EOR techniques is applied. This approach predicts the most suitable EOR for the target reservoir conditioned by the successful implementation of this in analogues fields.

The screening method chosen to analyse the Romanian field is a combination of both above-mentioned approaches as it comprises of high (conventional) and second level(advanced) screening.

High Level Screening

The first step was an oversimplified screening, considering only 2 parameters: depth and viscosity. For a field relatively shallow (depth up to 1000m) with moderately viscous oil (approximately 100 cP) , efficient mobility control (especially polymer) could be considered as candidate EOR technique. Taking into account the well-known limitations and estimation done due to the proximity to the border between polymer flood (Figure 22 – light green box) and thermal (Figure 22 – purple and red box) the latter represents an option too. [33]

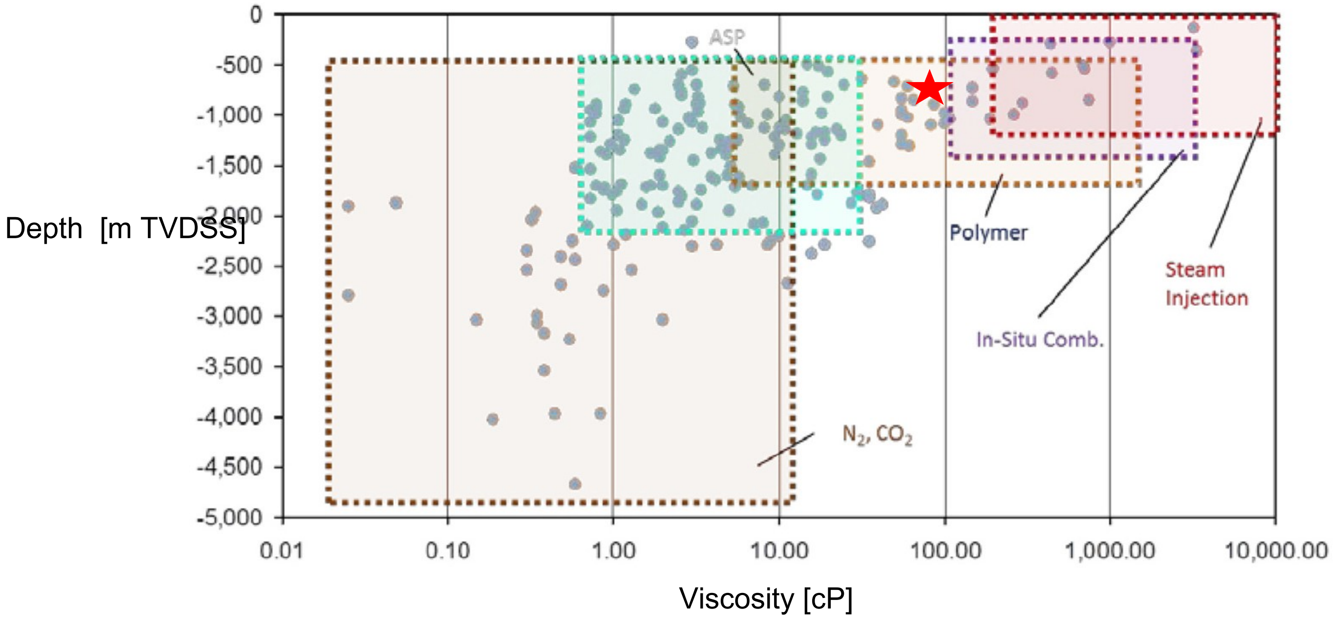


Figure 22: Reservoir screening for EOR methods [33]

Carrying on with the traditional category of screening methods, a more detailed analysis has been done utilizing the summarized screening criteria for EOR method presented in Table 1. The list focuses on the eight most important or promising methods and describes ranges for wide series of parameters characterizing oil and reservoir properties.

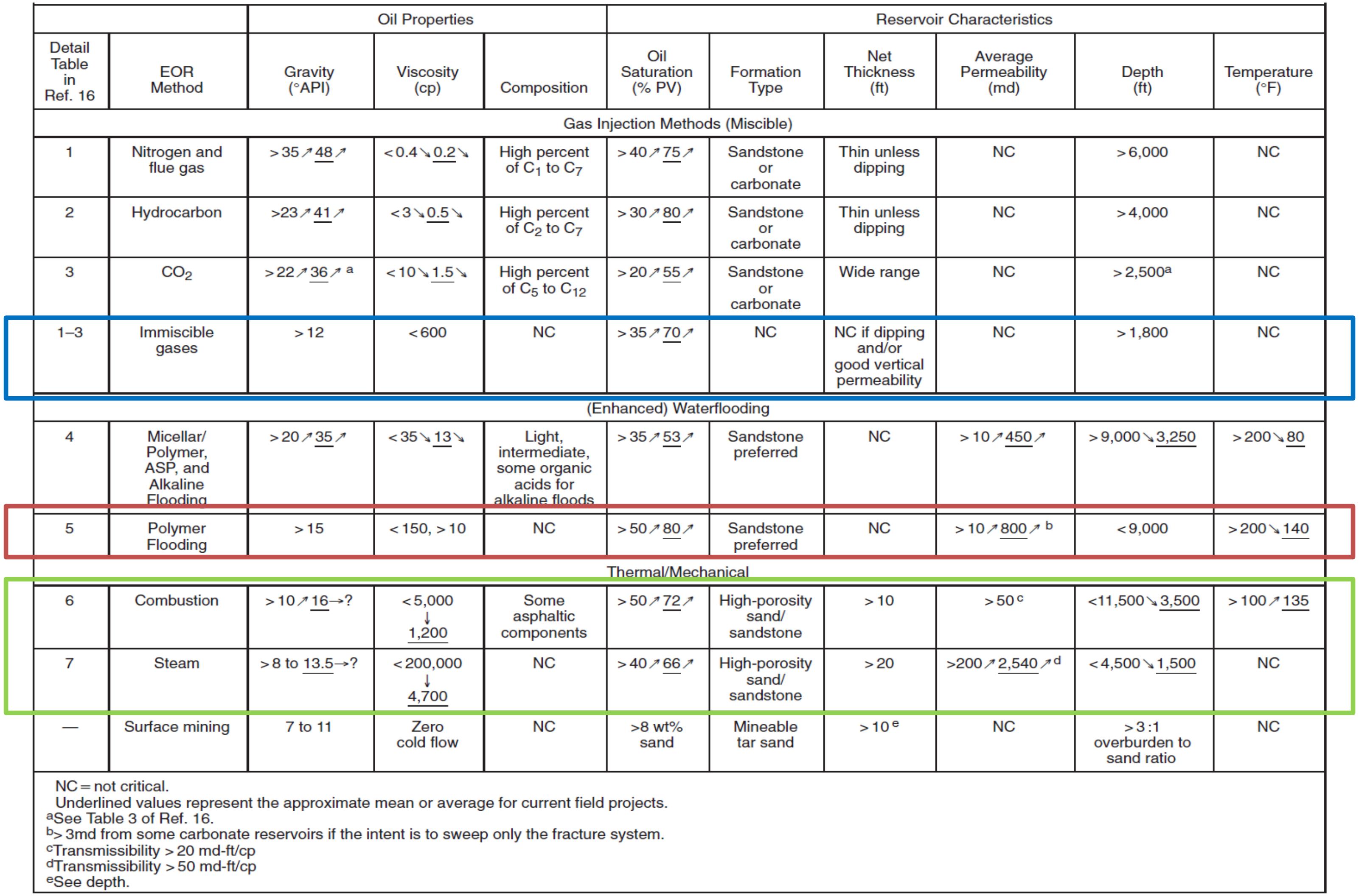
In addition, the author emphasized the interest on oil displacement mechanism to this tertiary recovery processes and identified that all the EOR methods can be divided into three main groups by the main mechanism for displacing additional oil with the injected fluid:

- Solvent extraction approach or achievement of miscibility
- Interfacial-tension reduction
- Viscosity change of displacing or displaced fluid.

Accounting for the specific characteristics of the area investigated in this paper: oil gravity around 17 °API, viscosity variation up to 100 cP, oil saturation higher than 50% in most of the regions, average permeability of 1000mD and less than 1000m depth, three EOR opportunities were found compatible according to the criteria presented inTable 1: immiscible gas injection, polymer flooding and steam injection.

Coupling the methods with their active mechanism, it can be observed that for this specific reservoir, all three of them can work as displacing mechanism for incremental oil recovery. At this early screening stage, there is no evidence of efficiency ranking for these methods.

Table 1: Summary of screening criteria for EOR methods [34]



		Oil Properties			Reservoir Characteristics					
Detail Table in Ref. 16	EOR Method	Gravity (°API)	Viscosity (cp)	Composition	Oil Saturation (% PV)	Formation Type	Net Thickness (ft)	Average Permeability (md)	Depth (ft)	Temperature (°F)
Gas Injection Methods (Miscible)										
1	Nitrogen and flue gas	$>35\nearrow\underline{48}\nearrow$	$<0.4\searrow\underline{0.2}\searrow$	High percent of C_1 to C_7	$>40\nearrow\underline{75}\nearrow$	Sandstone or carbonate	Thin unless dipping	NC	>6,000	NC
2	Hydrocarbon	$>23\nearrow\underline{41}\nearrow$	$<3\searrow\underline{0.5}\searrow$	High percent of C_2 to C_7	$>30\nearrow\underline{80}\nearrow$	Sandstone or carbonate	Thin unless dipping	NC	>4,000	NC
3	CO_2	$>22\nearrow\underline{36}\nearrow$ [a]	$<10\searrow\underline{1.5}\searrow$	High percent of C_5 to C_{12}	$>20\nearrow\underline{55}\nearrow$	Sandstone or carbonate	Wide range	NC	>2,500[a]	NC
1–3	Immiscible gases	>12	<600	NC	$>35\nearrow\underline{70}\nearrow$	NC	NC if dipping and/or good vertical permeability	NC	>1,800	NC
(Enhanced) Waterflooding										
4	Micellar/ Polymer, ASP, and Alkaline Flooding	$>20\nearrow\underline{35}\nearrow$	$<35\searrow\underline{13}\searrow$	Light, intermediate, some organic acids for alkaline floods	$>35\nearrow\underline{53}\nearrow$	Sandstone preferred	NC	$>10\nearrow\underline{450}\nearrow$	$>9{,}000\searrow\underline{3{,}250}$	$>200\searrow\underline{80}$
5	Polymer Flooding	>15	<150, >10	NC	$>50\nearrow\underline{80}\nearrow$	Sandstone preferred	NC	$>10\nearrow\underline{800}\nearrow$ [b]	<9,000	$>200\searrow\underline{140}$
Thermal/Mechanical										
6	Combustion	$>10\nearrow\underline{16}\rightarrow ?$	$<5{,}000 \downarrow \underline{1{,}200}$	Some asphaltic components	$>50\nearrow\underline{72}\nearrow$	High-porosity sand/ sandstone	>10	>50 [c]	$<11{,}500\searrow\underline{3{,}500}$	$>100\nearrow\underline{135}$
7	Steam	$>8\text{ to }\underline{13.5}\rightarrow ?$	$<200{,}000 \downarrow \underline{4{,}700}$	NC	$>40\nearrow\underline{66}\nearrow$	High-porosity sand/ sandstone	>20	$>200\nearrow\underline{2{,}540}\nearrow$ [d]	$<4{,}500\searrow\underline{1{,}500}$	NC
—	Surface mining	7 to 11	Zero cold flow	NC	>8 wt% sand	Mineable tar sand	>10 [e]	NC	>3:1 overburden to sand ratio	NC

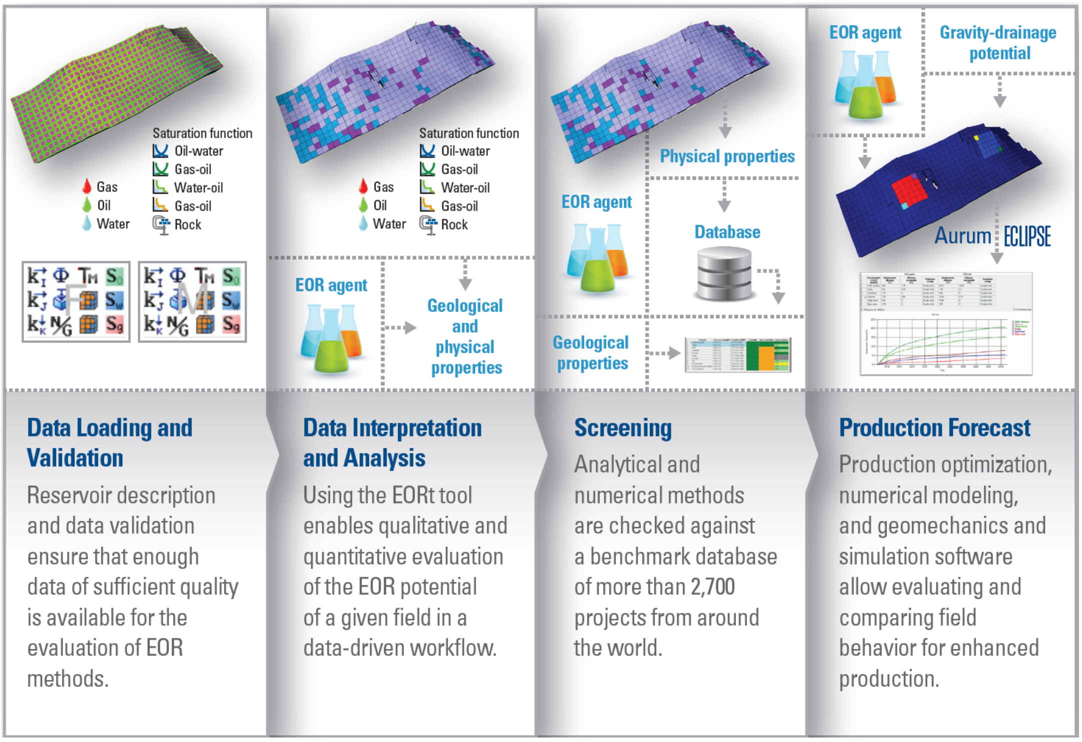
NC = not critical.
Underlined values represent the approximate mean or average for current field projects.
[a] See Table 3 of Ref. 16.
[b] > 3md from some carbonate reservoirs if the intent is to sweep only the fracture system.
[c] Transmissibility > 20 md-ft/cp
[d] Transmissibility > 50 md-ft/cp
[e] See depth.

Second Level Screening

A detailed analysis on the target reservoir has been done using the new reservoir screening module from Petrel software, EORt. It performs a quantitative and qualitative ranking of the most suitable EOR alternatives for the field by using analytical and numerical methods that compares field properties (such as current saturation distribution and rock-type distribution) with past projects from a data base composed of 2700 EOR project.

Besides the rapid assessment enhanced potential recovery and increasing conformance by matching EOR with reservoir properties another benefit brought by the tool is the quantification of the validity of rock and fluid data.

Figure 23 describes both the workflow and each of the four modules main functions.



Data Loading and Validation
Reservoir description and data validation ensure that enough data of sufficient quality is available for the evaluation of EOR methods.

Data Interpretation and Analysis
Using the EORt tool enables qualitative and quantitative evaluation of the EOR potential of a given field in a data-driven workflow.

Screening
Analytical and numerical methods are checked against a benchmark database of more than 2,700 projects from around the world.

Production Forecast
Production optimization, numerical modeling, and geomechanics and simulation software allow evaluating and comparing field behavior for enhanced production.

Figure 23: EORt workflow

The process starts by importing the reservoir model already history matched, along with fluid and SCAL data and by running an automatic consistency check and of all relevant data for the screening, as the displacement mechanisms are subject to interactions of the injected agent with both rock and reservoir fluids. The only parameters manually set at this stage were the reservoir temperature of 45°C and the water salinity. As water salinity is a parameter that includes a high uncertainty due to lack of actual measurements and high variation of available data (between 50 000 and 90 000 ppm), a salinity of 55 000ppm has been used. Moreover, operational parameters from artificial lift methods and completion data to surface facilities details were accounted for to check the compatibility with the EOR methods.

After all the input has been introduced, in the next module, the tool executes the following steps:

- Determination of the average values of formation properties and well spacing factor
- Identification of reservoir communication and fluid movement direction
- Classification of the formation based on rock quality classes
- Volume calculation

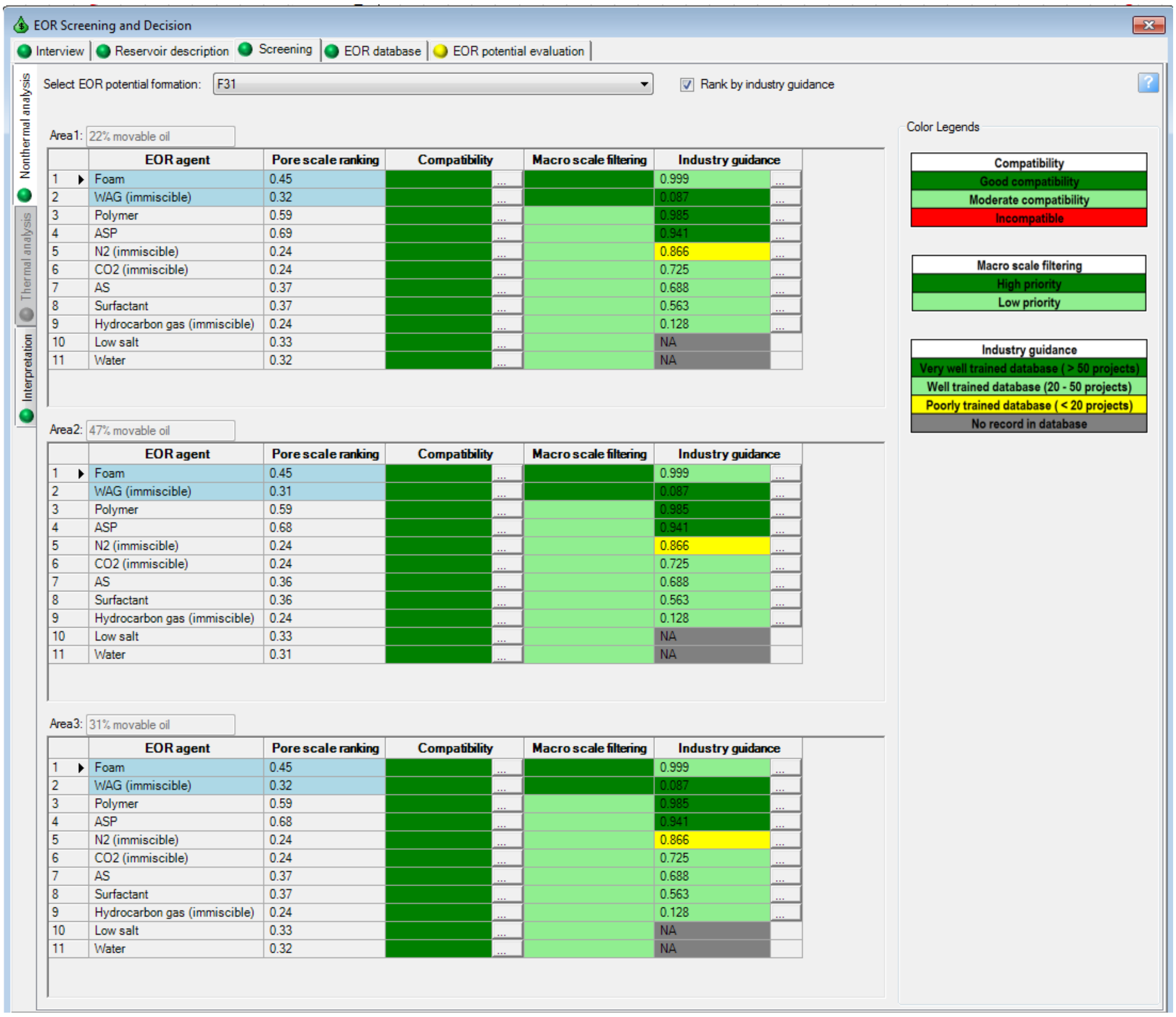
At this stage of screening workflow, based on the calculated data enlisted above, the EOR S&D identifies high potential formation for EOR and determines the amount of movable oil in place in this specific reservoir formation. It has been shown that region B Upper Sand 2 and B Lower have the highest potential in terms of available movable oil.

In the third module, the reservoir is compared with existing industrial EOR projects. Statistical average reservoir properties are taken as screening parameters (such as temperature, oil viscosity, oil API gravity, permeability, depth and formation type), then by the application of Bayesian Network, a database containing existing industrial EOR projects is searched for analogous reservoirs with similar screening parameters. As a result, a list of industry application reference is given, starting with the project with highest degree of similarity and least amount of application constraints on the selected EOR method.

The tool provides EOR possible methods on both region and field level, which represents a great advantage of the module as it can give valuable information specifically for each region and not only overall. The methods proposed are ranked by three different criteria, resulting in a pore scale, macro scale and industry guidance suggested EOR methods.(Figure 24)

The analyzes of the investigated field with the EORt tool from Petrel 2017 concluded that, for field level screening, on pore scale the best EOR agents are polymer and ASP while on both macro scale and industry guidance, foam and WAG followed by polymer and ASP. This is due to wider field implementation projects of foam and immiscible gas injection that exist all over the globe. On region level, all the 5 regions showed similar results except region A Sand 1 where only immiscible gas injection was considered as compatible method.

The findings are in line with the results obtained by using the traditional EOR screening methods.



Select EOR potential formation: F31

☑ Rank by industry guidance

Area1: 22% movable oil

	EOR agent	Pore scale ranking	Compatibility	Macro scale filtering	Industry guidance
1	Foam	0.45	🟩	🟩	0.999
2	WAG (immiscible)	0.32	🟩	🟩	0.087
3	Polymer	0.59	🟩	▨	0.985
4	ASP	0.69	🟩	▨	0.941
5	N2 (immiscible)	0.24	🟩	▨	0.866
6	CO2 (immiscible)	0.24	🟩	▨	0.725
7	AS	0.37	🟩	▨	0.688
8	Surfactant	0.37	🟩	▨	0.563
9	Hydrocarbon gas (immiscible)	0.24	🟩	▨	0.128
10	Low salt	0.33	🟩	▨	NA
11	Water	0.32	🟩	▨	NA

Area2: 47% movable oil

	EOR agent	Pore scale ranking	Compatibility	Macro scale filtering	Industry guidance
1	Foam	0.45	🟩	🟩	0.999
2	WAG (immiscible)	0.31	🟩	🟩	0.087
3	Polymer	0.59	🟩	▨	0.985
4	ASP	0.68	🟩	▨	0.941
5	N2 (immiscible)	0.24	🟩	▨	0.866
6	CO2 (immiscible)	0.24	🟩	▨	0.725
7	AS	0.36	🟩	▨	0.688
8	Surfactant	0.36	🟩	▨	0.563
9	Hydrocarbon gas (immiscible)	0.24	🟩	▨	0.128
10	Low salt	0.33	🟩	▨	NA
11	Water	0.31	🟩	▨	NA

Area3: 31% movable oil

	EOR agent	Pore scale ranking	Compatibility	Macro scale filtering	Industry guidance
1	Foam	0.45	🟩	🟩	0.999
2	WAG (immiscible)	0.32	🟩	🟩	0.087
3	Polymer	0.59	🟩	▨	0.985
4	ASP	0.68	🟩	▨	0.941
5	N2 (immiscible)	0.24	🟩	▨	0.866
6	CO2 (immiscible)	0.24	🟩	▨	0.725
7	AS	0.37	🟩	▨	0.688
8	Surfactant	0.37	🟩	▨	0.563
9	Hydrocarbon gas (immiscible)	0.24	🟩	▨	0.128
10	Low salt	0.33	🟩	▨	NA
11	Water	0.32	🟩	▨	NA

Color Legends

Compatibility
🟩 Good compatibility
▨ Moderate compatibility
🟥 Incompatible

Macro scale filtering
🟩 High priority
▨ Low priority

Industry guidance
🟩 Very well trained database (> 50 projects)
▨ Well trained database (20 - 50 projects)
🟨 Poorly trained database (< 20 projects)
⬛ No record in database

Figure 24:EOR Screening results on layer basis using EORt tool

Taking into account all the possible suitable tertiary recovery methods, polymer flooding viability was chosen to be investigated for different reasons: the field shows production characteristics that are consistent with polymer flood applications criteria found in literature: high initial water cut and poor results of waterflooding but also the internal knowledge of the company due to the already existing field pilot in Austrian field Matzen was considered.

The following chapters will focus on investigating polymer flooding viability as EOR method for the field, by using the data available at the moment.

4 Reservoir Model of the Romanian Field

The studied Romanian field is a slightly tilted primarily unconsolidated sandstone reservoir with a stratigraphic trap. The reservoir block of interest is composed of generally 2 big sections, Sector A and Sector B, with 5 distinct reservoir layers. In these sectors, a total number of 7 rock types were identified based on rock quality index.

The first production from the field started in 1957. At these times, slightly viscous oil with a viscosity degree of 20 cP was recognized. Due to unpredicted low productivity from the field, a field redevelopment phase was initiated in 2013. The simulation study performed in this work is based on data collected as part of this redevelopment phase.

The provided geological model was infeasible for flow simulation purposes due to high degree of grid resolution; hence, the transition from the static model to the dynamic one required the usage of upscaling technique.

Upscaling represents the substitution of a fine grid cells with heterogeneous property region with a homogeneous region of a single course grid cell characterized by an effective property value. In other words, the process represents the approximation of the fine scale model with a course scale model by means of averaging techniques. Global upscaling reduced the size of the model to 1 080 660 grid cells (83 x 84 x 155) with 50mx50mx1m dimensions.

The upscaling process targeted 3 parameters: clay volume, porosity and permeability. To compute the effective values Sequential Gaussian Simulation and Gaussian Random Function Simulation were applied.

To initialize the dynamic model, initial pressure distribution and saturations, of all fluids present were defined. For the pressure field, a hydrostatic pressure distribution was estimated assuming 84 bar reservoir pressure at a reference depth of 755 m. The fluid saturation distribution was determined in an iterative manner involving regression on Leveret J function, determination of maximum transition height and defining the minimum water saturation followed by capillary pressure curve conversion, for each rock group. For each of the iterations, the results of the initial model run were compared to log derived water saturation values, on a well basis, until a convenient match has been reached.

4.1 Reservoir Fluid Modelling

The first PVT reports dated from the beginning of field production, in 1957, stated oil viscosity ranges between 10 and 20 cP. However, during a redevelopment phase of the field in 2013, new PVT analysis has been performed on recombined samples taken from 4 wells at the surface including the standard PVT experiments: Constant Composition Expansion, Differential Liberation Experiment and oil viscosity measurements.

Based on the new results, 3 different PVT regions were identified (displayed in Figure 25):

- Region 1: B Upper (Sand 1 and Sand 2)

- Region 2: B Lower
- Region 3: A (Sand 1 and Sand 2)

In addition, the analysis also reported new interesting features: oil viscosities in all three regions were unexpectedly high compared to the old PVT.

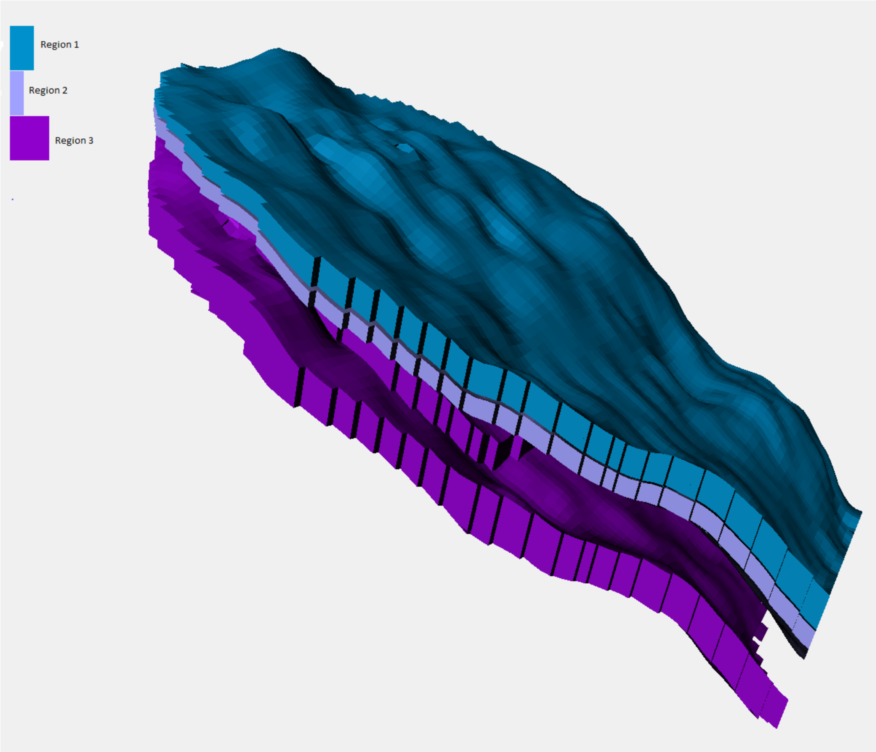


Figure 25: PVT Regions

The Differential Liberation Experiment was used to establish viscosity variation below the bubble point pressure at 45°C, reservoir temperature:

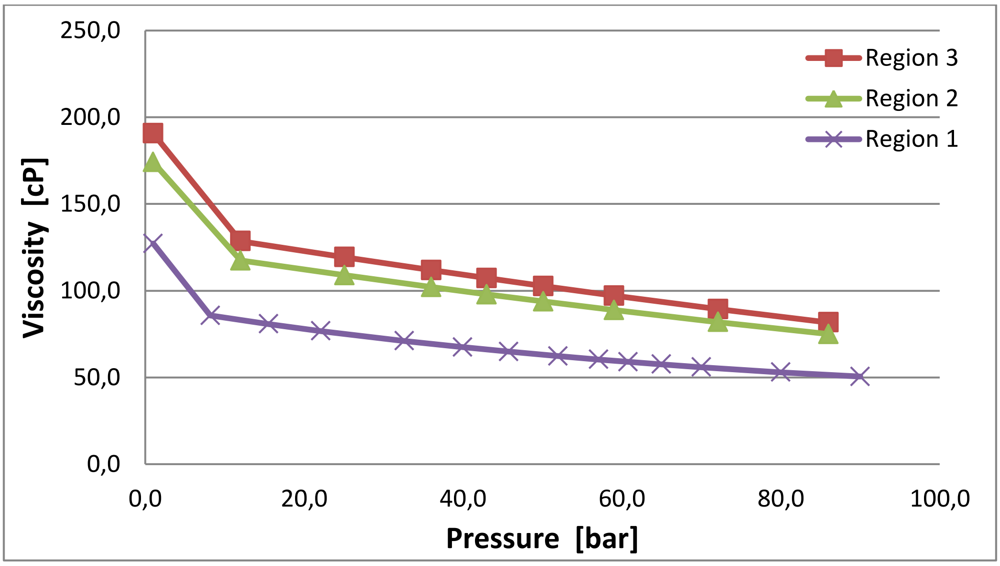


Figure 26: Oil viscosity variation below saturation pressure

Addressing the possibility of applying polymer flooding as enhanced oil recovery method, where the mobility contrast is governing the incremental oil obtained, the difference in viscosities of the three regions depicted in Figure 26 should be drawn into attention as it may impact the results of the process. Therefore this discrepancy and the consequences implied will represent one of the focuses developed in the following chapters.

Well data indicators such as Oil Down To and Water Up To found in several wells revealed the presence of aquifers in all five layers (Figure 27). Considering that aquifers could serve as support for the reservoir and understanding the crucial importance to capture and quantify the driving mechanism, further investigation has been done.

Analytical depletion analysis in MBAL proved that aquifer plays a major role in this petroleum system, demonstrating that the dominant driving mechanism is water drive. The history matching process of existing field pressure data showed good quality when considering aquifer influx for all layers. Due to lack of aquifer's characterization parameters, 4 analytical aquifers, similar from properties point of view, were attached to the existing model.

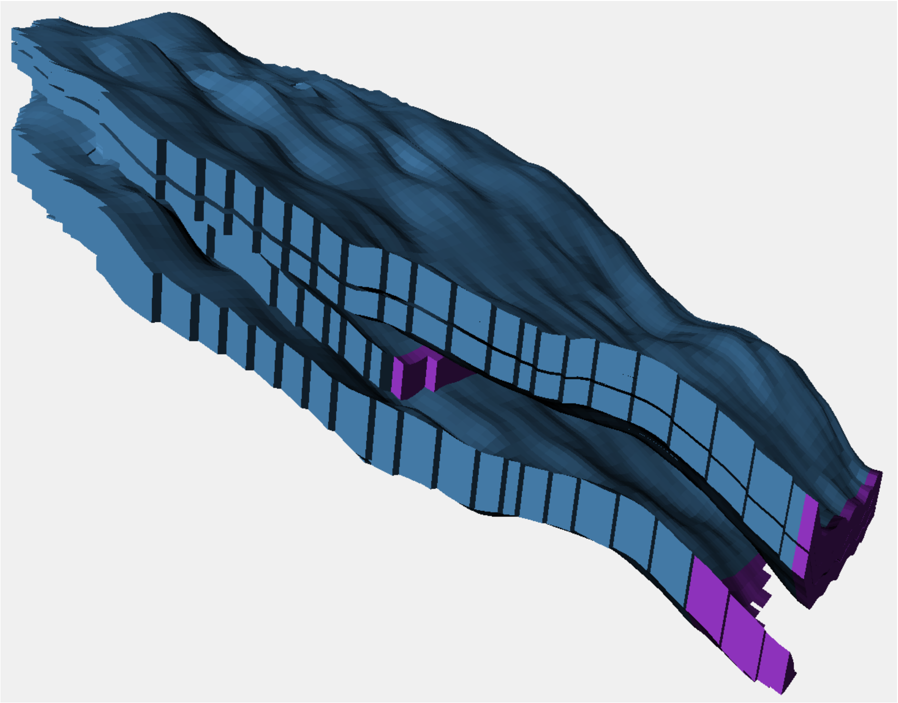


Figure 27: Reservoir Model with Aquifers Attached

4.2 History Match

The model has been history matched using the Assisted History Matching module available in Petrel software. While defining the Petrel Workflow, the parameters committed to changes were the relative permeability curves as they represent one of the highest uncertainties due to lack of data, as well as aquifer parameters (size, strength) and global permeability multipliers.

The steps taken in order to accomplish the match from field level up to well level are illustrated in Figure 28:

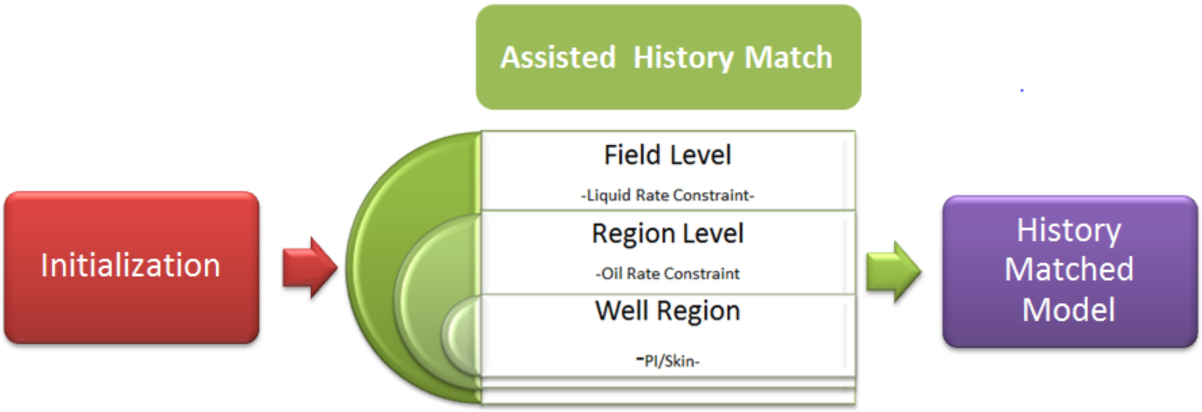


Figure 28: History Match Process

No SCAL measurements were available at the time of model building, therefore for initial assumption was mix-wet relative permeability curves for all rock types using standard Corey correlation. During the history match process, the best match of the observed data suggested a set of curves that have same Corey exponents but different initial water saturation for each of the 7 rock types. History match predicted relative permeability curves with the Corey exponents displayed in Table 2:

Table 2: Corey exponents

Parameter	***Value***
Oil Corey Exponent for Region A	2,35
Oil Corey Exponent for Region B	3,64
Water Corey Exponent for Region A	0,96
Water Corey Exponent for Region B	0,67

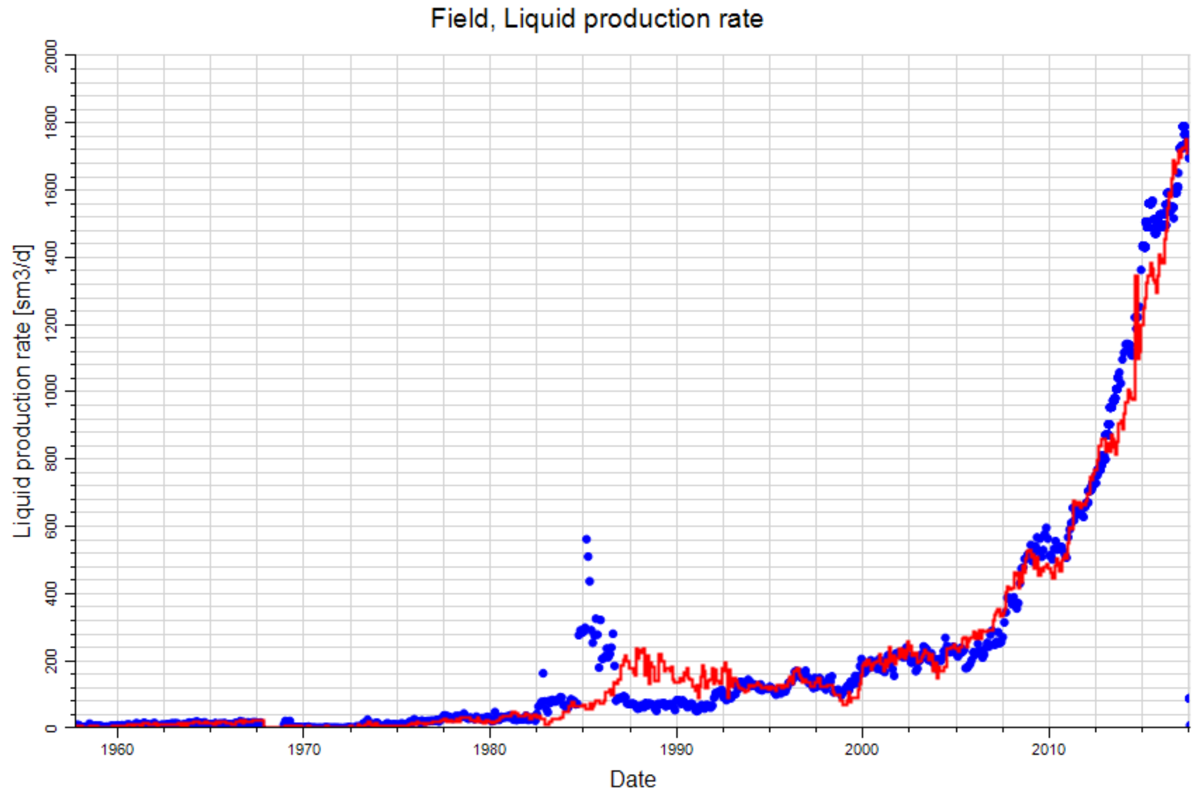
Concerning the aquifers, different permeability and external radius have been generated for each of them:

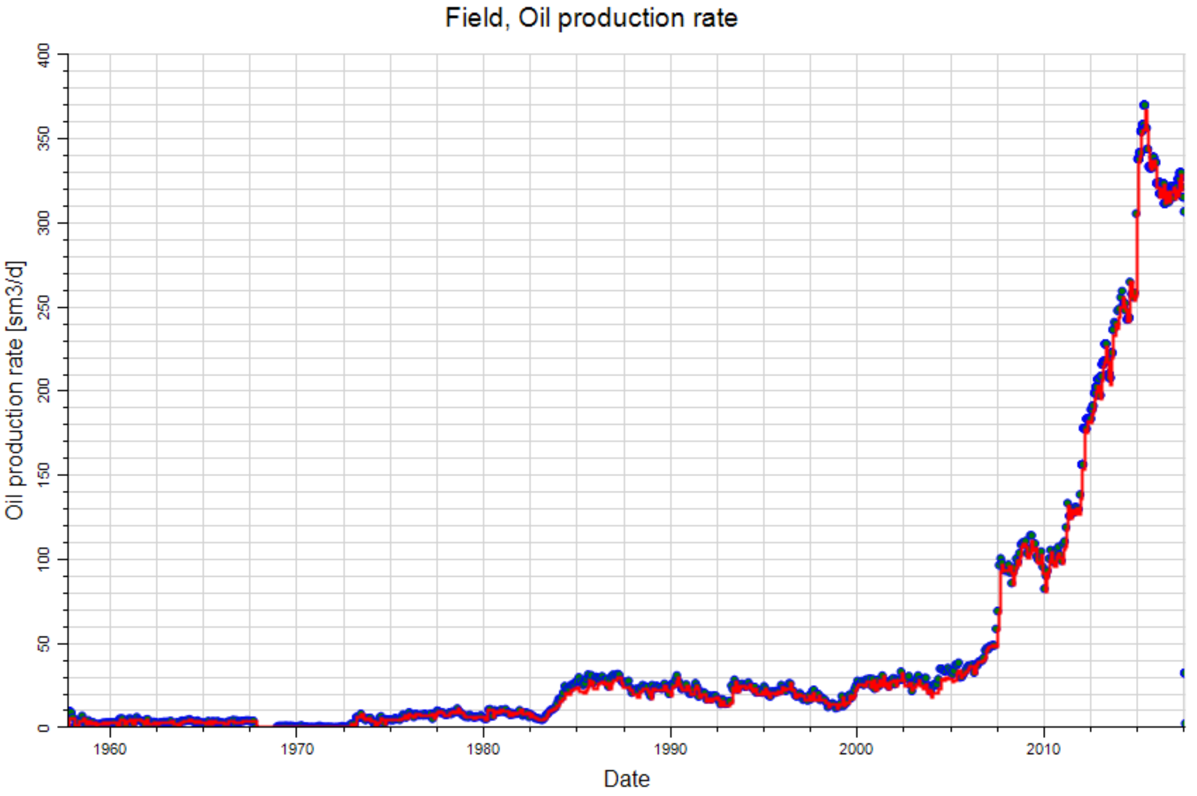
Table 3: Aquifer Properties

Aquifer	***Aquifer Model***	***PVT Region***	***Permeability [mD]***	***Porosity [%]***	***External Radius [m]***	***Contact [m]***
1	Carter-Tracy	1	357	0.25	344	-755
2	Carter-Tracy	2	153	0.25	228	-727
3	Carter-Tracy	3	372	0.25	193	-741
4	Carter-Tracy	3	50	0.25	50	-750

With respect to the permeability, global multipliers with values between 1.16 and 1.57 were used. Maps with average net values per region(permeability, porosity, water saturation and pressure distributions) are shown in Appendix A: Porosity map on regions to give a better understanding of the input data used for simulation.

Figure 29 depicts the matching at field level of observed data, since the beginning of the exploitation in 1957 until 2017, when the case has been constructed for three parameters: liquid rate, oil rate and water cut. This case was assumed to be the starting point of all the predictions presented in this paper.





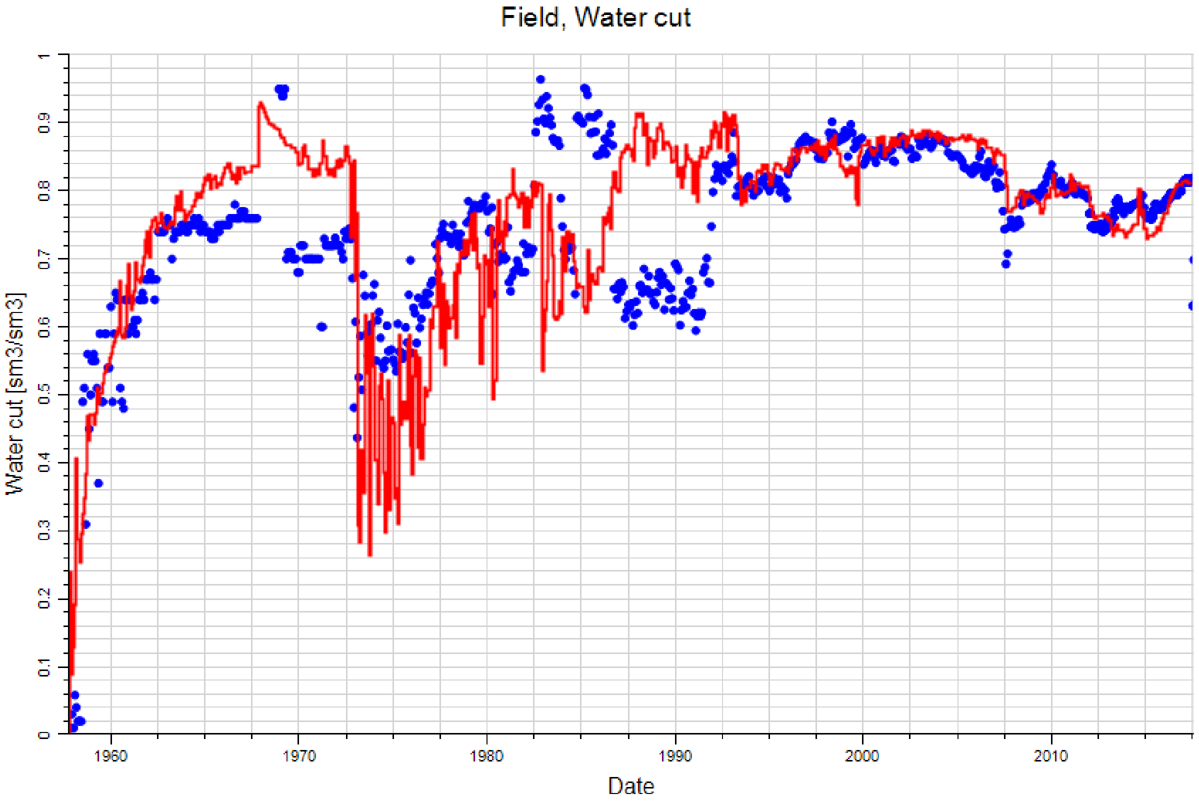


Figure 29: History match results of liquid production rate, oil production rate and water cut

4.3 Injection Pattern

The existing appraisal wells (white dots), producers (green dots) and injectors (blue dots) as well as planned wells (red dots) are displayed in Figure 30:

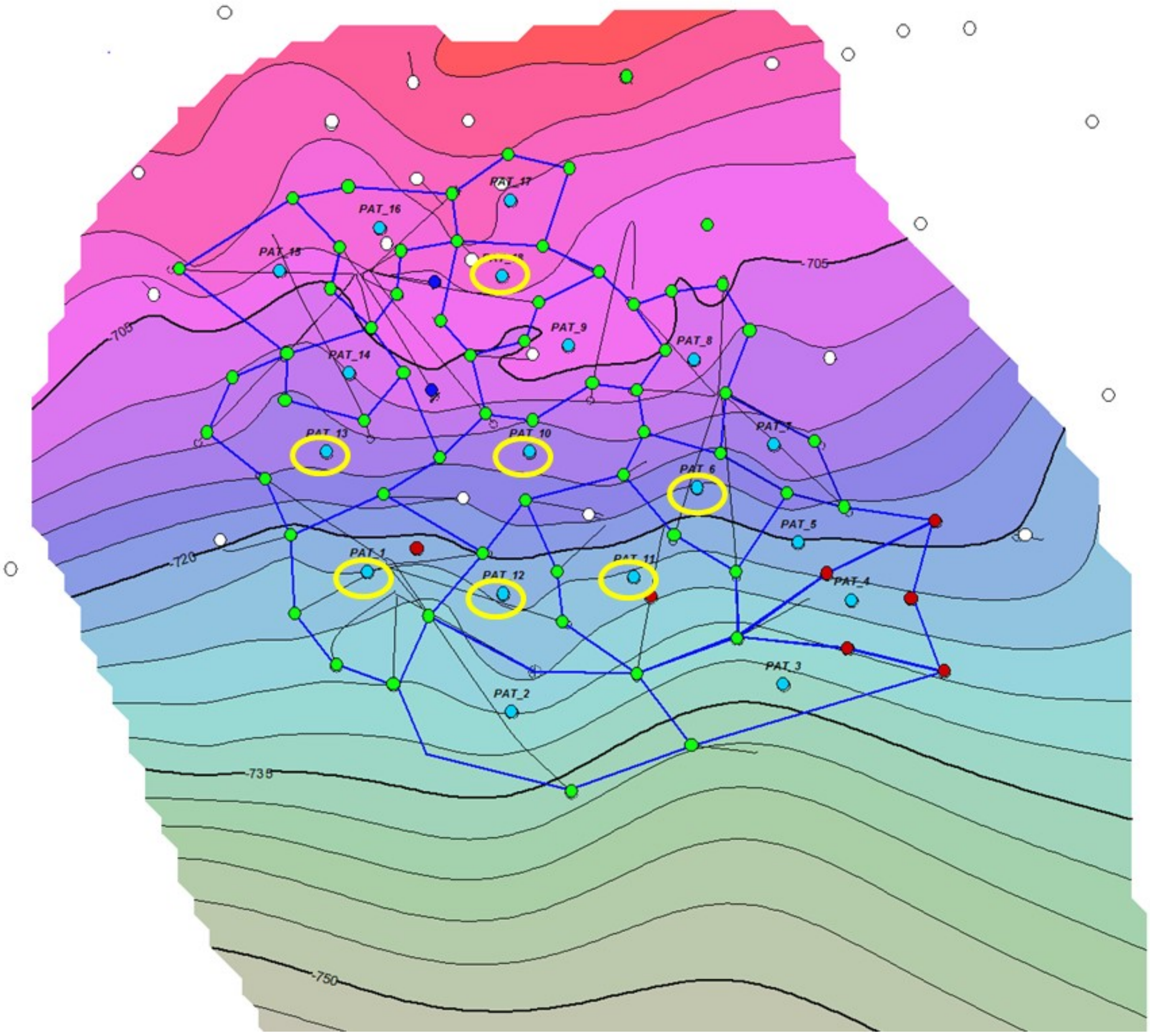


Figure 30: Polymer injection pattern

The selected injection pattern consists of 7 injectors, marked with yellow circles. As the field was developed since 1957, no regular injection pattern was possible. However, the field was divided into irregular patterns and the injection wells were positioned in the centre. As injection strategy, commingled injection in all five layers was chosen.

In all simulation introduced in the next chapter, the injection wells are set on flow rate constrain, while the producers operate on constant bottomhole pressure, fixed at 10bar as it is operated in the field.

For modelling simplicity, polymer injection starts at the same date for all the injectors with the same operating parameters such as: polymer slug concentration, flow rate and injection period in all injecting wells.

5 Polymer flood in Romanian field

Judging the production characteristics of the reservoir in term of high water cut production, polymer flooding represents a viable alternative for the field analysed, also endorsed by other studies “The Polymer Flooding Technique Applied at High Water Cut Stages in Daqing Oilfield” [35]. The application of this process points out two different situations:

- Polymer flooding is started after water flooding
- Polymer flooding is considered from the beginning since water flooding does not shown economical attractiveness.

For the first type of projects, the economics are driven by incremental oil recovery and costs, in addition to waterflooding, while for the second type, the total incremental in recovery is considered along with the expected improvements and benefits compared to waterflooding.

As waterflooding simulation did not show the expected results mainly due to an unfavourable mobility ratio by virtue of strong contrast in viscosities between the displaced and displacing fluid, this paper considers the polymer flooding process in this field as a type two project. The focus is on incremental oil recovery over the current situation, hence no further activities scenario is assumed as base case.

The injection strategy starts with polymer injection in 2020, in all 7 wells (Figure 30) followed by chase water straight afterwards, in the same injectors at 100 m^3/day flow rate until 2043. 2043 was chosen as simulation end time as it corresponds to the end of exploitation concession.

The polymer used for the study is Flopaam 3630S from SNF Floerger, characterized by a 20 Megadalton molecular weight and an anionicity of 35 %.

5.1 Polymer flood design

As the possibility of implementing such a process is still in an early phase, no simulation of polymer flooding has been done until the moment. Therefore, before weighting the influence of rock-polymer interaction characteristics, injectivity parameters have to be set.

The selection of injection flow rate and polymer concentration are two meaningful aspects as their contribution to the process efficiency is significant. The fracturing pressure represents the key element that has to be taken into account in this situation as exceeding this limiting value would induce tremendous consequences.

Fracture pressure is the pressure above which the injected fluids will induce hydraulically fracturing in the formation. For this block, there are no evidence of well tests performed or any other precise determination of its value, therefore high degree of uncertainty is attached to this parameter. The chosen 120bar fracture pressure, the value considered in this study extracted from the mud weight window of a drilling report for a well from the block, represents the pressure that the formation could withstand during the drilling process.

The base case for the sensitivity study is defined by the following input parameters: polymer concentration of 1500ppm with a corresponding adsorption level of 25 µg/g, permeability reduction of 3.5 and 0.45 for IPV. The numbers were taken from the laboratory report analysis done in the analogous field. As the simulation was meant to give a rough idea of the value and to optimize it in further runs, the polymer injection time was not a parameter considered so they were injected until the end of the simulation year.

In considerations for the flow rate, two values were chosen. Firstly, 150 m^3/day injection rate was chosen as this is the injection flow rate used for the existing water injection scenario in this field. Since it was observed that the field pressure reached almost 160 bars, which is way above the assumed fracture pressure, the second run used a reduced value of 100 m^3/day. In this case, satisfactory results were determined in terms of field pressure. Other than field level observing of the reservoir pressure, well level monitoring is also important as the pressure at the injectors represents the critical region. In Figure 31 the pressure behaviour for the injector which has the lowest injectivity and consequently the highest pressure, can be observed to ensure that the limit is not exceeded.

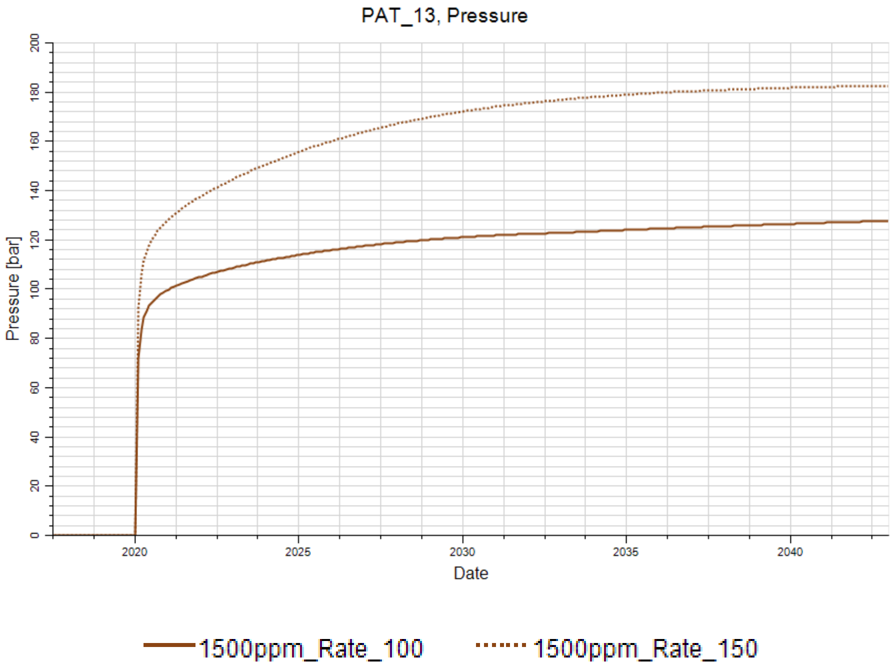


Figure 31: Pressure variation with the flow rate for one injector

5.1.1 Injection Time

Injecting polymers for 23 years is an unrealistic scenario, and even though determining the slug size is not the scope of this study, multiple cases were run in order to come up with a rational time frame for polymer injection process. For the sensitivity parameters (polymer concentration, adsorption rate, permeability reduction, inaccessible pore volume) the base case values were used as well as an injection flow rate of 100 m^3/day.

A total of 8 simulation cases were performed with an injection time window through which the polymer treated water is injected followed by untreated chase water in a range of 2 to 23 years with the specific values enlisted in Table 4. Although here injection years are mentioned, as this is the required input for the simulator, literature frequently uses the term polymer slug size measured in pore volumes injected (the ratio of the injected volume of polymer solution to reservoir pore volume). The corresponding injected polymer pore volumes in each case are summarized in Table 4.

Table 4: Simulation case definition for polymer slug size sensitivity

Simulation case	***Injection time window [years]***	***Polymer slug size [IPV]***	***Utility factor [kg/bbl]***
1	2	0,020	0,324
2	4	0,491	0,547
3	6	0,737	0,739
4	8	0,983	0,918
5	10	1,228	1,084
6	15	1,843	1,452
7	20	2,457	1,833
8	23	2,826	2,096

The injection volume is a parameter that has influence only in the economics of the project, as injecting a higher quantity of polymer would only increase the oil production, but at what costs?

According to Clemens et al. [36]capital expenditure for such a project is not the driving cost, but rather the amount of polymers. In consequence, the utility factor, which represents the amount of polymer required per incremental oil produced, is used. It is the most straightforward performance indicator for incremental operating expenditures in a polymer-injection project. Considering the high costs of polymers, the UF is a key metric in assessing the economic viability of the project as higher UF values implies higher operating costs for the polymer flood.

$$\mathrm{UF} = \frac{cumulative\ mass\ polymer\ injected}{cumulative\ incremental\ oil\ produced} \quad [\mathrm{kg/bbl}] \qquad [11]$$

The utility factor determined for each simulation case can be found inTable 4. The results are in line with other authors [37] findings for layers that show crossflow.

Another key feature used to determine the polymer injection volume is the amount of oil recovered as a response to the injected polymer, namely the incremental oil produced. The reservoir is believed to show good response to the polymer injection if a linear dependency exists between the incremental oil produced and the polymer slug size. The best response is allocated to the point where the linear dependency seizes to exist and the curve reaches a plateau. Such a plateau describes a behaviour where the incremental oil recovery is no longer responding to an increase in the polymer slug size.

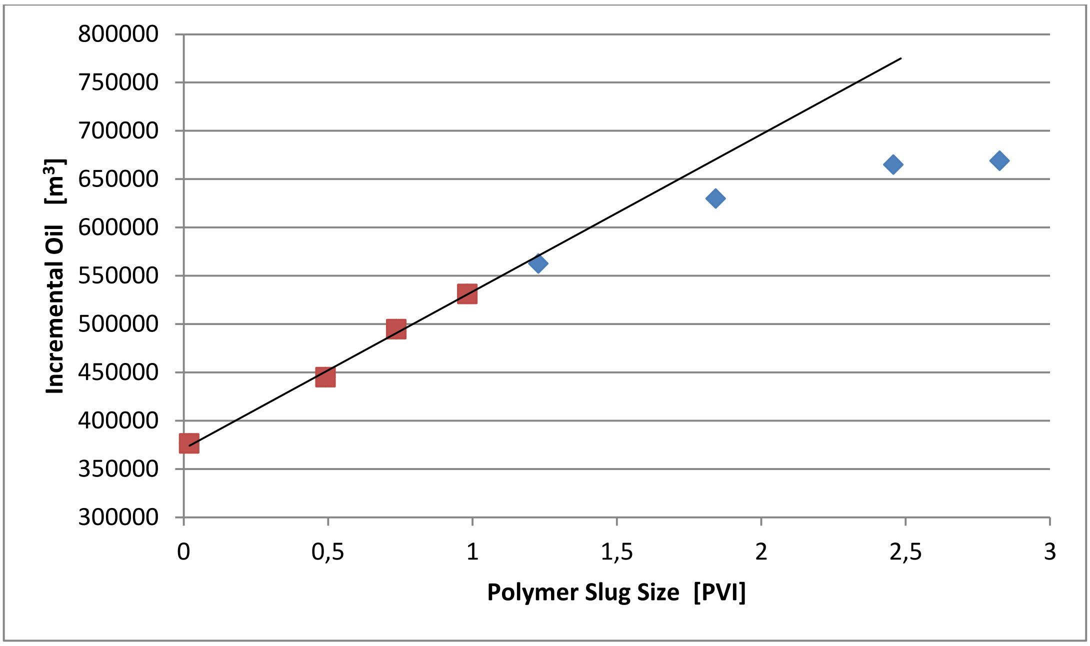


Figure 32: Field incremental oil as function of polymer slug size

The simulations show linear variation of the parameters up to 8 and10 years of injection, corresponding to 1 and 1.22 PVI respectively, followed by a plateauing tendency (Figure 32). For choosing the polymer slug size, both values (1 and 1.22 PVI) represent feasible alternatives, as they were used in many other studies on this topic.

Undoubtedly, by performing an economic calculation the trends might change and therefore the critical values could be shifted to the right or to the left (smaller respectively higher slug size) and no optimum injection time can be chosen without this. As optimum slug size determination does not represent the scope of this study, 8 years of injection (1 PVI polymer slug size) corresponding to a UF of approximately 1, was selected in a pragmatic way.

The red series from Figure 32 symbolizes the incremental oil obtained for 4 cases (with 2,4,6 and 8 years of injection corresponding to 0.02 , 0.5, 0.73 and respectively 0.98) that have same incremental in injection time , i.e. 2 years, so that they can be compared in terms of slug size and effectiveness. The increase in additional amount of oil produced with slug size is higher for small slug sizes than for larger ones. One explanation could target polymer breakthrough and that the efficiency of the flood is considerable decreasing after the breakthrough in production wells.

5.1.2 Polymer slug concentration

As already mentioned, polymer concentration in the solution has a significant impact from both technical and economical point of view, as the concentration of polymer is granting the viscosity of the solution and therefore the technical efficiency of the process, whereas higher concentrations imply higher amounts of polymers, leading to increased OPEX.

The viscosity of the polymer treated water solution as function of polymer concentration, for a shear rate of 7 s^{-1}, was taken from the laboratory report and is depicted in Appendix B.

To select a proper polymer concentration, multiple simulation scenarios had been analysed, from 500ppm up to 2 000ppm, and incremental recovery factor per field was used as evaluating parameter. The incremental recovery factor is showing increasing behaviour with increasing concentration, while the amount with which it is increasing is significantly decreasing with increased concentration. Values of potential efficiency plateauing are observed for 1500ppm and 200ppm, and will be further investigated.

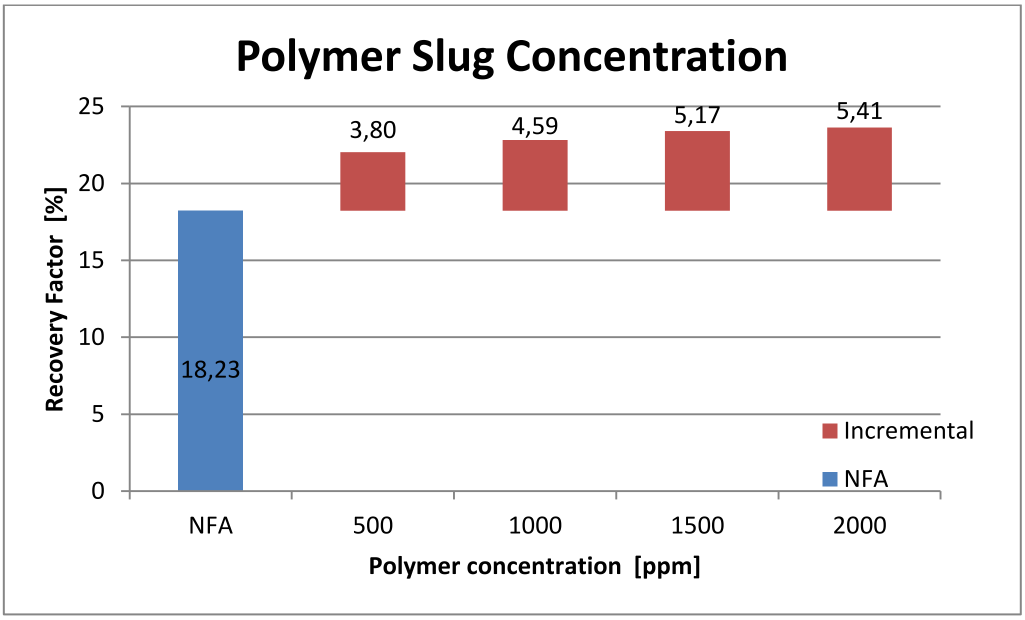


Figure 33: Recovery factor variation with polymer concentration

When referring to operating conditions, polymer slug concentration and injection flow rate should be evaluated as coupled parameters because both are interdependent factors in terms of additional pressure exerted in the reservoir(Figure 34). Comparing a case of 1500ppm polymer concentration injected with a flow rate of 100 m3/d with a scenario with higher polymer concentration (2000ppm) and 70 m^3/d injection flow rate (corresponding to the maximum flow rate inducing reservoir pressure at the vicinity of the injector close to fracturing pressure), one could observe that the results in terms of recovery factor are: 23,40 % for 1500ppm and 100 m^3/day flow rate and 23,06% for 2000ppm and 70 m^3/day injection rate, more favourable in the 1500ppm case. Now looking at the utility factor, which incorporates also economical aspects, the values are similar: 0.918 for the first case and 0.917 for the second one. Taking into consideration that the economics are very much alike but the recovery factor is higher for the first case, it is considered that the best option from the ones evaluated is to injected a 1500ppm concentration set at 100 m^3/day flow rate.

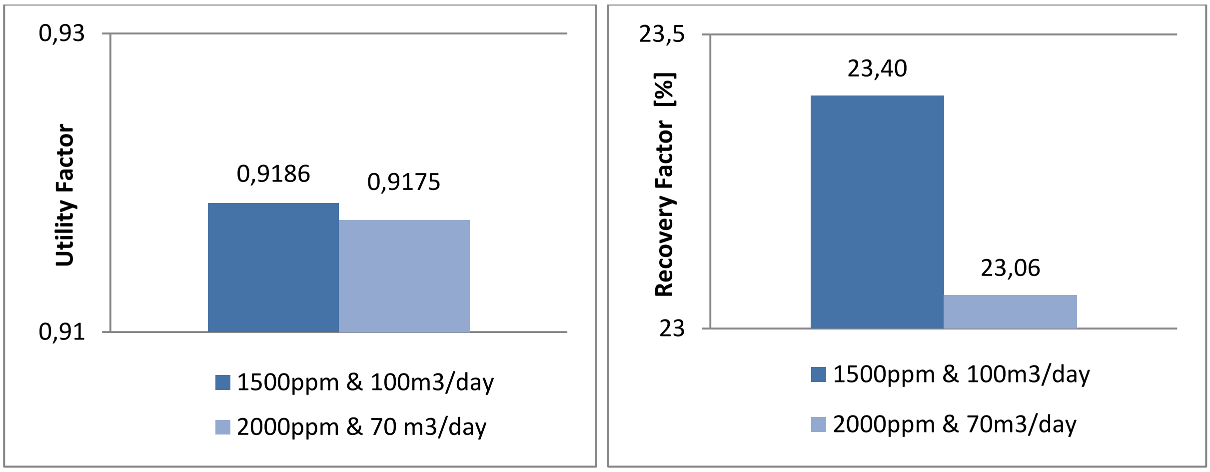


Figure 34: Utility factor and recovery factor for 2 scenarios

To summarize all the choices made, the sensitivity analysis on rock-fluid parameters will be performed under the following conditions: 1500 ppm polymer concentration, 100 m^3/day injection flow rate and 1 PVI polymer slug size (8 years of injection time).

It has to be mentioned that the chosen values for these parameters do not specifically represent the optimum neither the recommended quantities, but the base case that was used in performing the sensitivity analysis. They serve as common ground to be able to compare the results and estimate the impact of each factor.

5.2 Sensitivity Analysis

In order to be able to assess the accuracy of the simulation results in terms of oil production characteristics, a sensitivity analysis on the parameters which are considered to be the result of rock-fluid interactions in a polymer flooding process has been done as polymer flood primarily affect the fluid-matrix interaction in terms of mobility of the displaced and displacing fluid. The necessary input data to define the dynamic model for the polymer flood was taken from results of polymer flood laboratory experiments performed for another field with similar rock composition as the reservoir investigated in this study.

For the sensitivity analysis part, the crude assumption that polymer solution viscosity is constant with shear rate was made. The reason was the computation time needed to account for the non-Newtonian behaviour exhibited by the polymer chosen: one simulation running time is in order of days. Since more than 50 simulation cases were defined as port of the sensitivity study, the computational time required for simulations considering the non-Newtonian behaviour was not possible in the frame of an academic internship program.

The polymer flood sensitivity study targeted the influence of polymer adsorption, permeability reduction and inaccessible pore volume on a field scale. The focus lies mainly in estimating the degree of uncertainty that was brought in, by using data from an analogous field until the experiments on cores that belong to the studied field will reveal more precise values. In spite of this, the results are considered to be still in line with reality as the fields show high similarity in terms of geological and mineralogical grounds and same type of polymer, Flopaam 3630S was proposed as an option by the laboratory that is performing the current experiments.

5.2.1 Polymer Adsorption Rate

Numerous studies concerning polymer concentration influence on retention has been reported by researchers, from which most of them were based on static measurement methods. As expected, contradictory opinions exist on the variation mathematical model but all of them agreed on the fact that there is a dependency between these two parameters and that increased polymer concentration increases polymer retention. Szabo and Corp [38] reported a linear dependency of retention with slug concentration, while an opposed observation by Deng et al. sustains that the experimental results could be fitted with Langmuir equation and used adsorption isotherms to express it. [39]

Polymer retention reversibility is another controversial subject and the discussions play around partial reversibility of adsorbed polymers or total reversibility of mechanical entrapment. [40] In this study, for simplicity, the input for the simulation model considered that no polymer desorption may occur.

For this study, the simulation of polymer flooding used adsorption isotherms to express adsorption levels with slug concentration. Different isotherms were used to analyse the influence of adsorption on recovery factory, by using the values reported from laboratory experiments as maximum adsorption level and synthetically generating the adsorption curves based on a standard isotherm for good quality sandstones.

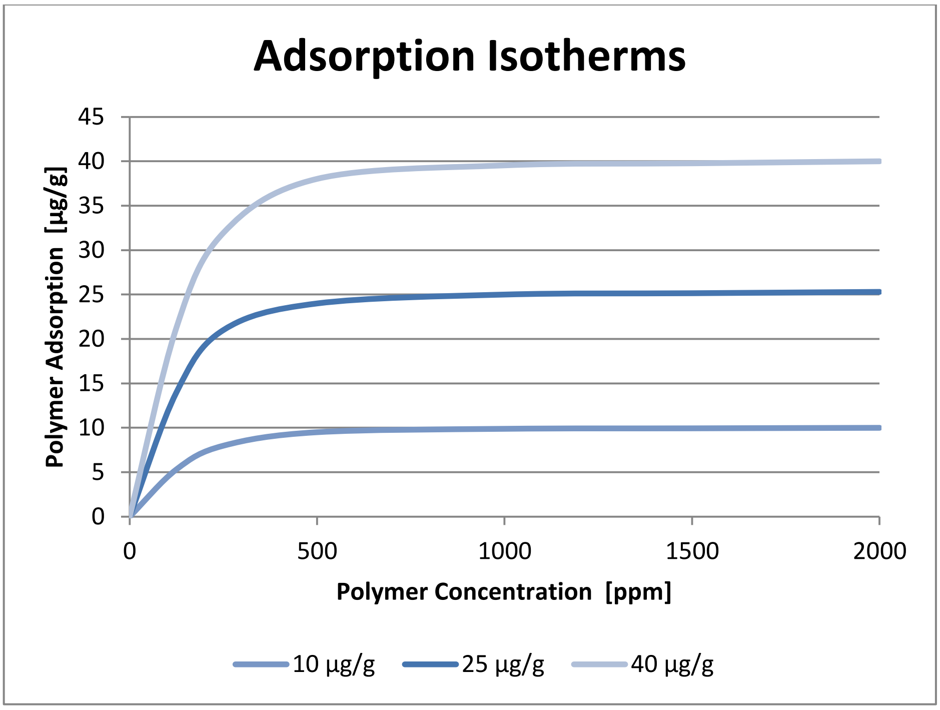


Figure 35: Adsorption Isotherms

Internal OMV studies estimated that the adsorption levels of Flopaam 3630S for a good quality sandstone are around 25 µg/g. The simulations were performed for low adsorption values, 10 µg/g, as well as for values as high as 40 µg/g, contouring the impact of low and high polymer adsorption values on recovery factor. It has to be mentioned that all the runs used a permeability reduction of 3.5 and IPV of 045, as reported from the laboratory results.

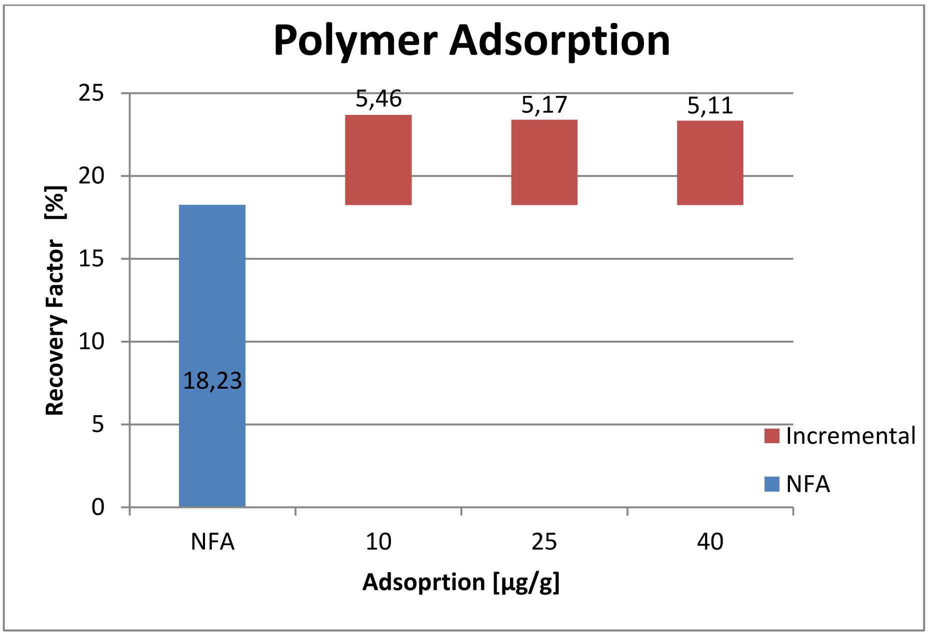


Figure 36: Polymer adsorption influence on field recovery factor

Figure 36 illustrates that field recovery factor decreases with increased polymer adsorption ratio. The results can be explained by basic adsorption influence: polymer adsorption decrease polymer slug concentration thus solution viscosity. A decrease in viscosity directly implies changes in mobility ratio that negatively affects displacement efficiency.

The results emphasis that low adsorption ratios impact on recovery factor is higher than for high adsorption levels. A decrease of adsorption from 25 µg/g to 10 µg/g, produces a variation of 0.29% in recovery factor while an increase of 15 µg/g in adsorption level induces only a 0.06% discrepancy. A possible explanation could represent the adsorption-permeability dependency and according to different authors there is a direct proportionality between these two factors: the higher the permeability the higher the adsorption levels are. Accepting this observation as valid, different studies targeted adsorption levels in high permeability layers. Dang et al. [15] reported that highly permeable rocks show nearly constant adsorbed layer thickness at low shear rates. This could give a reason for the trend showed. 25 and 40 µg/g adsorption ratios are both values that can be considered to correspond to high permeable layers and due to the existence of an almost constant adsorbed layer thickness, the impact on polymer flood efficiency is similar for both cases.

5.2.2 Permeability Reduction

A secondary effect of polymer adsorption is considered to be permeability reduction. When polymer molecules adsorb on the pore surface they form a thin adsorption layer that reduces the effective pore size, resulting in a decrease of rock relative permeability, but only towards the aqueous phase, and consequently in an increase of residual resistance factor. Permeability reduction is seen as the positive effect of polymer retention as oil permeability is hardly affected but water movement into porous media can be significantly slowed down.

The effect of variation in residual resistance factor on recovery factor is evaluated at a constant maximum polymer adsorption rate of 25 µg/g and its corresponding Langmuir isotherm. The RRF is varied within a range from 1,4 and 4,7; using values that were reported from laboratory experiments on different cores and at different oil saturations.

Figure 37 depicts the relationship between field recovery factor and RFF. Incremental oil recovery increase with increasing RRF for all observed values, however a tendency for the slope of resulting function to flatten can be speculated. To confirm this speculation a wider range of RRF values should be investigated.

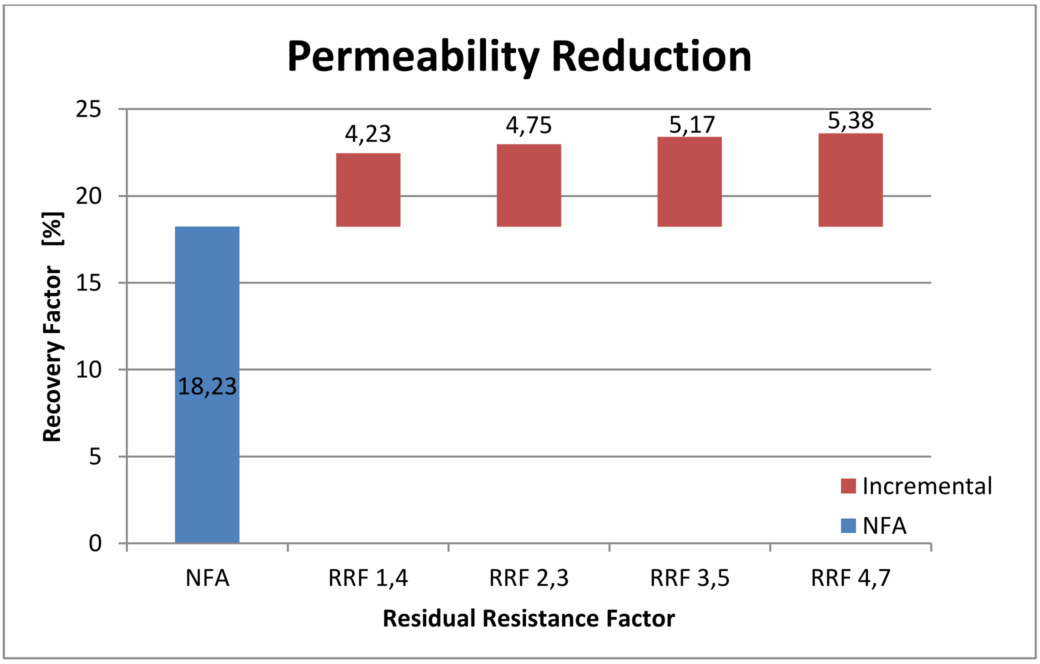


Figure 37: Residual Resistance Factor influence on field recovery factor

5.2.3 Inaccessible Pore Volume

The inaccessible pore volume plays a significant role in polymer front propagation in porous media, as it accelerates polymer slug transport into the reservoir, compensating in a certain measure or even outbalance polymer retention, which is known to retard polymer slug movement.

For inaccessible pore volume influence determination, all the simulations used a constant maximum polymer adsorption rate of 25 µg/g and its corresponding Langmuir isotherm as well as a RFF of 3,5 as input. As shown in Figure 38 , IPV variation does not induce misleading recovery factor estimation even though a broader range was analysed, from 0.2 up to values as high as 0.45.

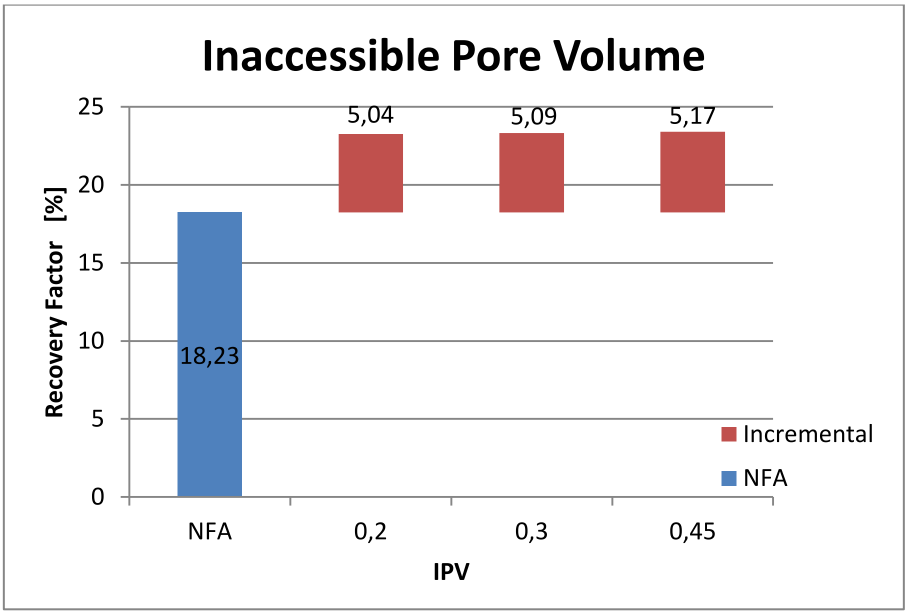


Figure 38: Inaccessible pore volume influence on field recovery factor

The recovery factor dependency with IPV for these cases, exhibits a behaviour that is in agreement with theoretical knowledge. Inaccessible pore volume is perceived to positively impact the process by increasing polymer velocity; hence, the higher the IPV value is, the higher the recovery factor should be, trend also depicted in Figure 38.

5.2.4 Summary of sensitivity analysis

Due to lack of available data on polymer-rock interaction in the investigated Romanian reservoir, a sensitivity study was perform with the scope to assess the impact on field recovery factor of parameters describing the polymer – rock interaction, namely:

- Polymer adsorption rate
- Residual resistance factor
- Inaccessible pore volume.

Base case values were taken from laboratory experimental results of an analogous field: constant maximum polymer adsorption rate of 25 µg/g and its corresponding Langmuir isotherm, RFF of 3.5 and IPV of 0.45.

In Table 5 a summary of the input data is provided for the most important simulation cases among all the sensitivity scenarios run. Values in brackets represent the variation of the value compared to the base case. Positive values indicate an increase compared to the base case, whereas negative ones a decrease.

Table 5: Main input for sensitivity analysis

Scenarios	***Adsorption Rate [µg/g]***	***Permeability Reduction [-]***	***IPV [-]***
Base Case	**25**	**3,5**	**0,45**
Case 1	10(-60%)	3,5(0%)	0,45(0%)
Case 2	40(+60%)	3,5(0%)	0,45(0%)
Case 3	25(0%)	1,4(-60%)	0,45(0%)
Case 4	25(0%)	2,3(-34%)	0,45(0%)
Case 5	25(0%)	4,7(+34%)	0,45(0%)
Case 6	25(0%)	3,5(0%)	0,2(-55%)
Case 7	25(0%)	3,5(0%)	0,3(-33%)

The spider plot displayed in Figure 39 illustrates the relative sensitivity of each of these parameters on the reservoir response to the polymer flood. A parameter exhibits strong influence on the incremental recovery factor if the linear trend line fitted to the dataset has steep slope. In the case of the reservoir at one hand, permeability reduction yields the highest impact on the polymer flood efficiency. On the other hand, inaccessible pore volume yields the least effect on the recovery factor, therefore it has the lowest degree of uncertainty in this study.

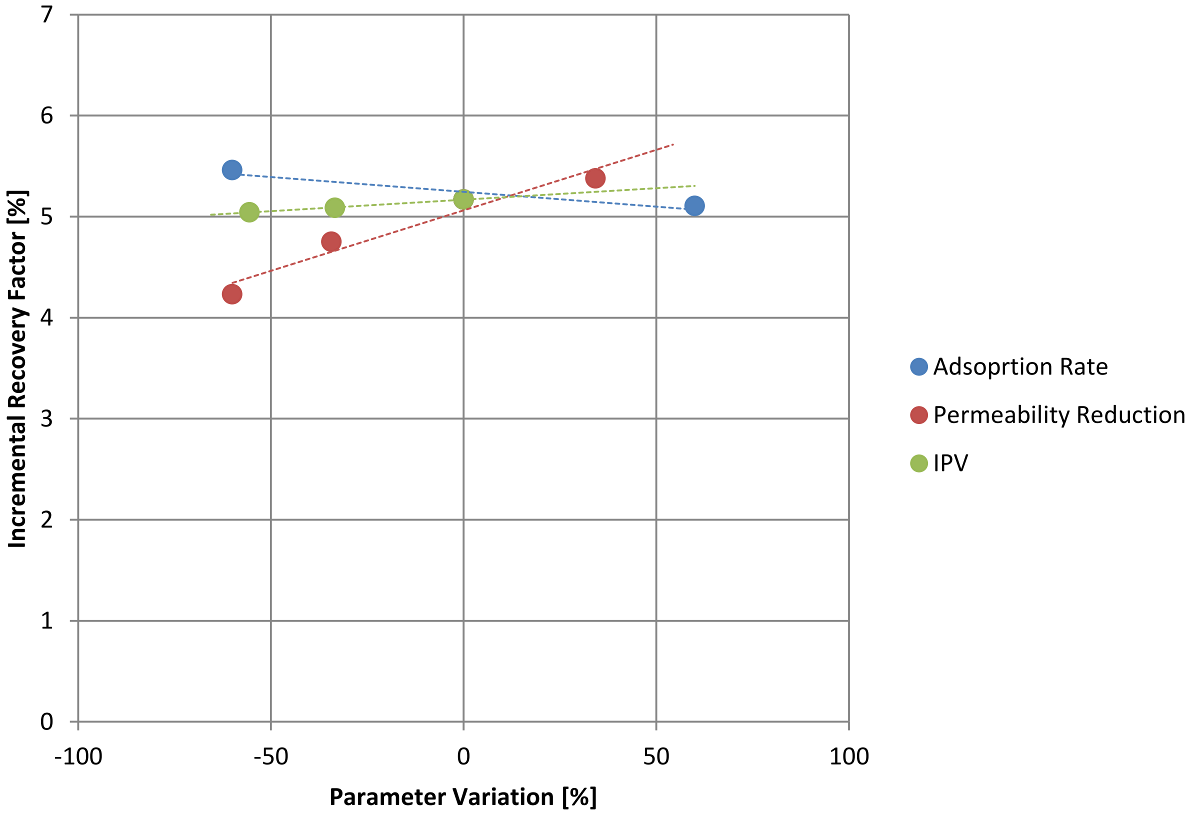


Figure 39: Sensitivity analysis results in terms of incremental recovery factor

5.3 Commingle Polymer Injection

Whether to choose commingle or separated layer for an injection process in a layered reservoir is a topic that raises questions among operating companies as it has a significant impact both on process effectiveness and economics. The field investigated in this study is a layered reservoir, consisting of 5 different layers. Therefore, our attempt is to investigate if commingle injection represents a viable development strategy.

Studies on the application of separated layer water injection and the benefits compared to commingled water injection had been reported in literature, articulating that separated layer waterflooding could represent the technology that assures oilfield long-term high and stable yield. The results present solutions to interlayer problems and high water injection efficiency. As the number of polymer flooding projects is considerable smaller than of water floods no reported analysis on this topic has been found. Still, it has to be of concern for engineers when the design a polymer flood project is carried out. [41]

All the simulation at this stage of the feasibility study considered non-Newtonian behaviour exhibited by Flopaam 3630S polymer as it highly impacts the polymer flood process effectiveness. The polymer exhibits the shear thinning behavior depicted in Figure 40:

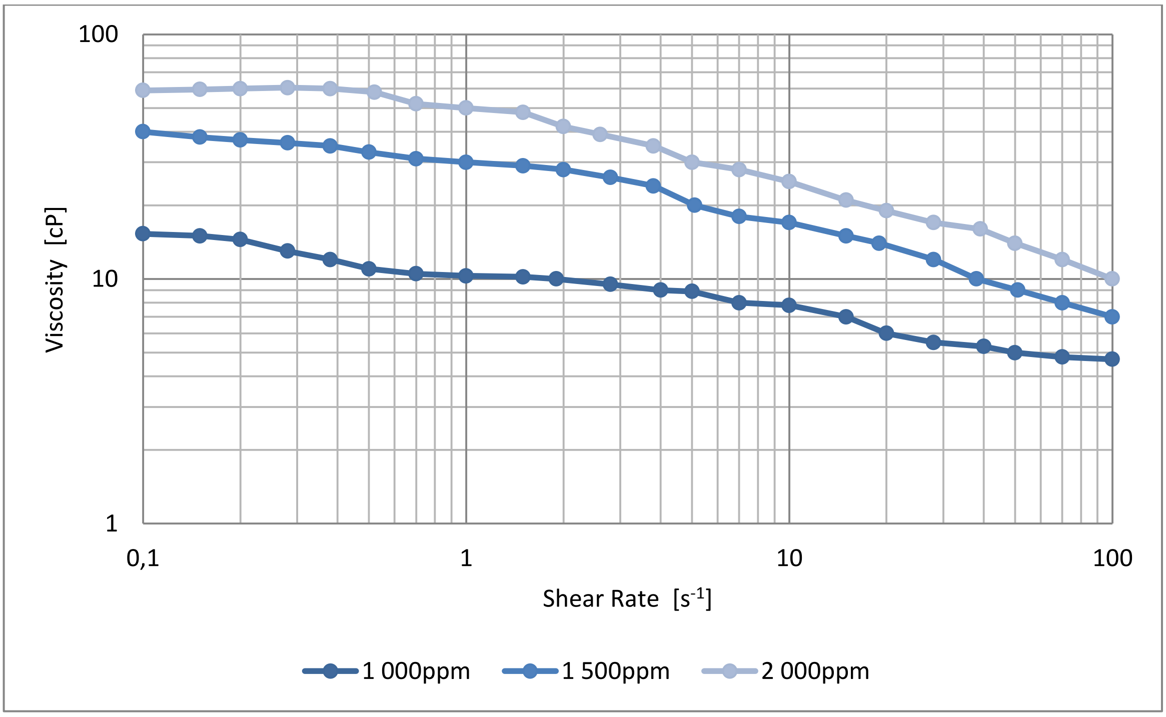


Figure 40: Viscosity variation with shear rate

As the viscosity is dependent on fluid flow velocity in the porous media, the computational time increased extraordinarily. Assuming Newtonian behaviour, one prediction simulation took approximately 2 hours and 4 hours if the history period, from 1957, was also included. While including the shear thinning behaviour simulation time was even two orders of magnitude higher, reaching up to 10 days for 2 000ppm polymer slug concentration. The heavy computational efforts required established limitations on the executed sensitivity study presented in the previous sub chapter.

All the cases used same polymer-rock parameters: 25 µg/g polymer absorption rate and the corresponding Langmuir adsorption isotherm, a permeability reduction factor of 3,5 and 0,45 IPV. A flow rate of 100 m^3/day and an injection time of 8 years were set as operating parameters with continuous water injection afterwards. Three different polymer concentrations were investigated: 1 000ppm, 1 500ppm and 2 000ppm, each associated with the corresponding polymer solution viscosity variation with shear rate, measured in the core flood experiments.

Data analysis was conducted on region level and for simplicity in explanation the layer's name was substituted with region 1, region 2 etc. The numbering of layers has been done in correlation with depth: region 1 is the shallowest while region 5 the deepest.

5.3.1 Polymer Front Propagation on layer level

Figure 41 illustrates the proportion of polymer in solution for each region at the end of injection, in 2028, which also represent peak values. Throughout the simulation years the amount of polymers in solution increases firmly until 2028 when polymer injection is stopped and then decreases steeply until 2043 as chase water injection strategy was used for the simulations. The parameter does not reach 0 values even by 2043 and its time variation shows the same tendency as polymer production concentration over time.

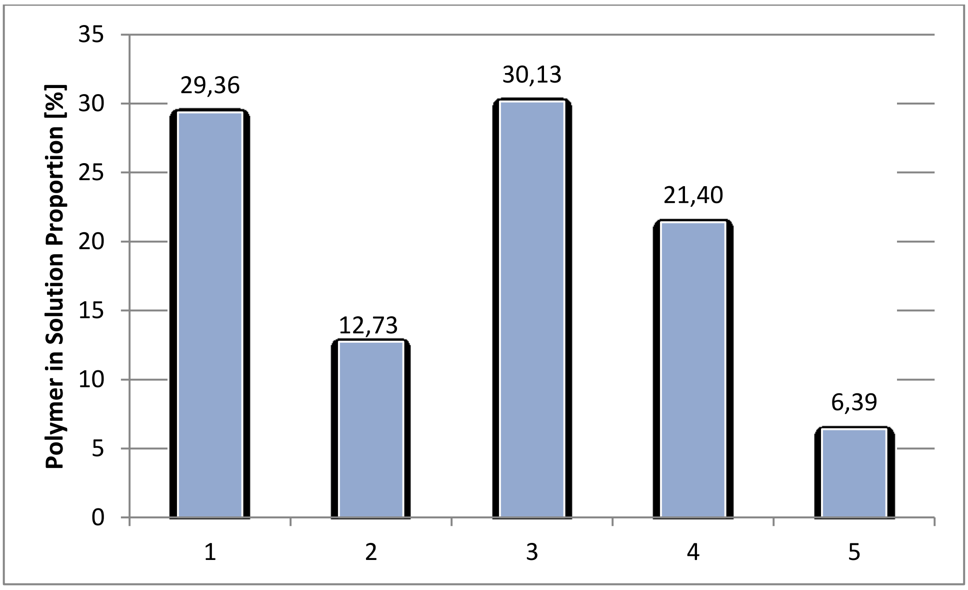
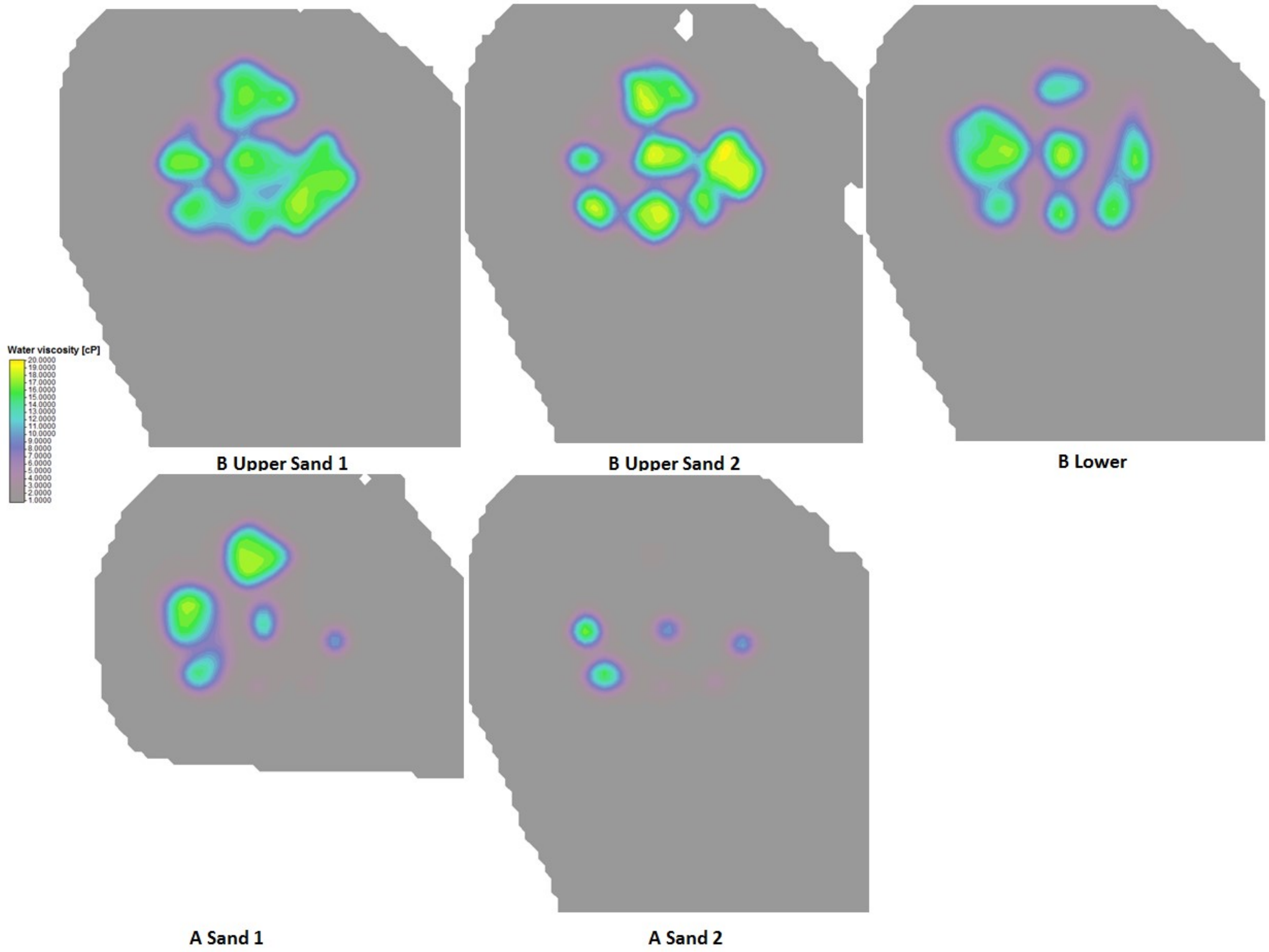


Figure 41: Proportion of polymer in each layer for 1500ppm polymer concentration case

Analyzing the amount of polymer that is injected in each region, the following observations can be drawn: the highest amount of polymers accumulates in region 3 conditioned by excellent rock properties and the least polymer quantity is linked to layer 5 as it does not present good rock properties. Also by comparing the amount in region 1 and region 3, it can be assumed that the amount injected is the same as the layers show on a high degree of similarity with regards to the associated permeability values.

As the polymer concentration in solution is the driving factor for the mixture viscosity, it is of interest to compare the amount of polymer that is injected into each layer and the increased water viscosity. Figure 42 depicts displacing fluid viscosity at the end on the injection process, in 2028, for all the regions, considering the case of 1500ppm polymer concentration and accounting for shear-thinning behavior of polymers. The viscosity ranges between, 0.7592 (untreated brine viscosity) and 20 cP for the polymer solution.



B Upper Sand 1

B Upper Sand 2

B Lower

A Sand 1

A Sand 2

Figure 42: Polymer Solution Viscosity per layer in 2028

The further a high the amount of polymer propagates in a region, the more the polymer viscosity can be increased. Analyzing the amount of polymer that is injected in each region in relation to both polymer solution viscosity and rock properties (see Appendix A), few important remarks can be phrased:

- Layer 1 and layer 3 shows high level of similarity in terms of improved water viscosity mainly attributed to the almost same amount of polymer injected into these layers as both layers fall under high-permeable layer group with insignificant contrast in the permeability values. Contrarily, the marginal difference in the shape of polymer spreading in these two layers is a consequence of the higher degree of heterogeneity of layer 3. These observations are in good agreement with remarks stated in relevant literature: better polymer transportation property and higher flood front velocity is associated with a more homogenous permeability distribution. [2]

- Water viscosity in layer 2 features an interesting behavior: it exhibits the highest solution viscosity although the amount of polymer injected in it is less than half compared to layer 1 and layer 3 quantities. Moreover, comparing the layers on permeability grounds, region 2 shows values considerable lower than both of the other two layers. A detailed analysis on fluid flow in the regions shifted the attention to the existence of crossflow between layer 1 and layer 2. Due to gravitational forces, certain amount of polymer solution injected in to layer 1 is flowing layer 2 and therefore significantly increases solution viscosity.

- The results highlighted in layer 4 and layer 5 are the key points of this analysis in regard to commingle polymer injection viability. In layer 4, 21% of the total amount of polymer is injected, fact reflected in the high water viscosity around the 3 injectors situated in the western and central area. The figure also reflects that in the southern part, no polymer solution is injected due to very low porosity characteristics of the area, and in 2 injectors only the near wellbore region is touched by polymers. This observation should raise questions weather that it is of worth to spend that high amount of polymers in this layer when only such a small area is affected. In layer 5 the remarks are straightforward: low water viscosities are attributed to small quantities of polymers injected and poor solution propagation in the layer due to bad permeability values.

The bad injectivity and flow characteristics exhibited by both layer 4 and layer 5, especially of the latter one, in the detriment of high amounts of polymer injected in these regions, strongly impacts polymer flood overall effectiveness.

5.3.2 Vertical sweep efficiency

A section view of polymer solution propagation through porous media is essential in understanding polymer slug transportation and gives valuable information on polymer flood vertical sweep efficiency on region level and overall field.

Figure 43 illustrates polymer movement in porous media throughout the injection period for a solution concentration of 1 500ppm when non-Newtonian polymer behaviour is considered. The features displayed are in accordance with polymer amount distribution per region (Figure 41) and the corresponding explanations.

It can be noticed that throughout the whole thickness of layer 4 and layer 5 the polymer solution penetration depth is restricted to near wellbore area. This is attributed to poor reservoir quality rock existent in these regions, mainly to the low values of the flow parameter. Polymer presence in these two layers is observed only in the neighbouring block of the injector, which corresponds to less than 100m penetration depth. On contrary, in the upper part of the reservoir, polymer solution is reaching a penetration depth up to 1km at the end of the injection time. The striking difference in polymer solution’s areal distribution is strictly owed to the discrepancy in permeability values between regions A and regions B. These observations harder enforce the statement that polymer flood efficiency in layers 4 and 5 is very low.

Reservoir’s layering is another feature that can be distinguished in Figure 43. All three layers that pertain to region B: layer 1, layer 2 and layer 3 respectively are visible separated by region A. While the interface between layer 3and layer 2 can be intuited between layer 2 and layer 1 no differentiation can be done as both regions exhibit crossflow.

The interface between layer 1 and layer 2 can be detected from the solution’s behaviour: the interlayer heterogeneity acts like a channel and biases polymer flow. This preferential flow can have a negative impact on overall polymer flood efficiency as the interlayer interference is increasing polymer solution adsorption capacity of the higher permeable layer and decreasing it for lower permeable layer. [42]

The crossflow between the two layers can also be recognized from the increase in both amount and viscosity of polymer solution layer 2 compared to layer 1, even though from the polymer proportion injected in these two layers, layer 2 receives less than half of layer 1. (Figure 41)

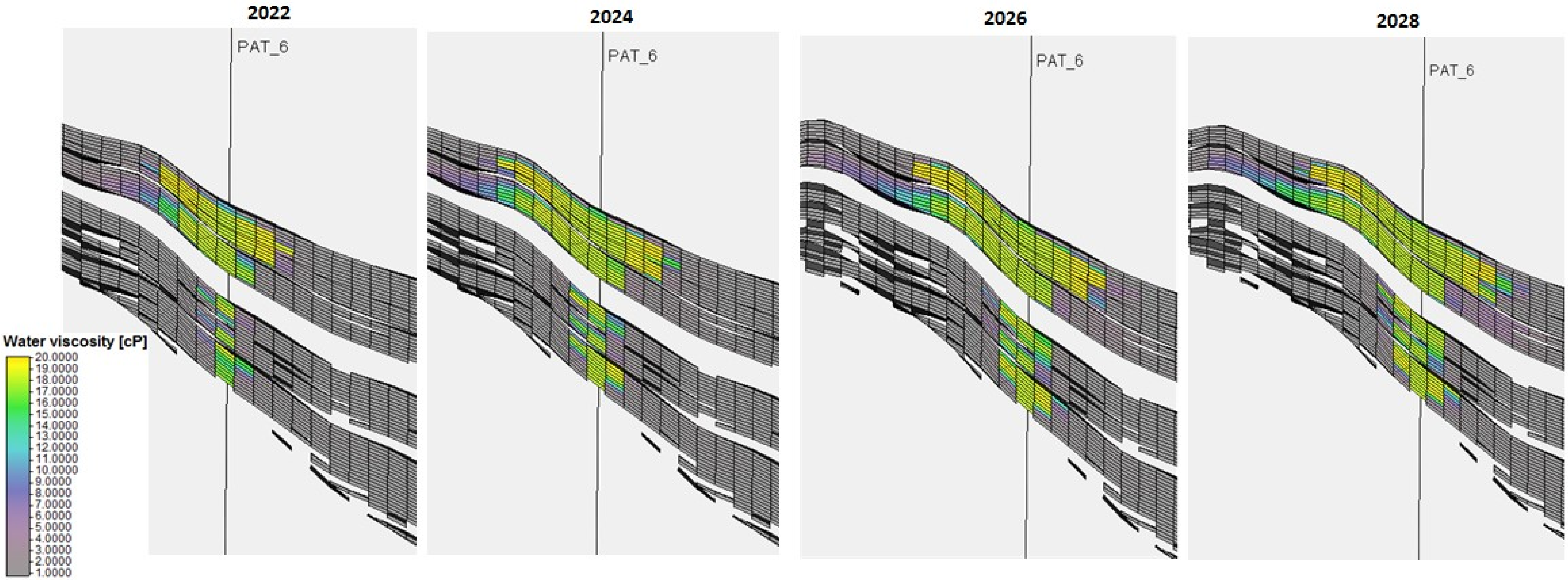


Figure 43: Section view of polymer solution propagation through porous media

5.3.3 Mobility control on layer level

PVT analysis showed proof that oil properties are not uniform for all the layers and the division based on bearing hydrocarbons split the reservoir into 3 PVT regions as presented in Table 6.

Table 6: PVT Regions

PVT Region	***Layer Region***	***Viscosity at saturation pressure [cP]***
1	B Upper Sand 1 B Upper Sand 2	50
2	B Lower	75
3	A Sand 1 A Sand 2	82

For polymer flooding the most important oil characteristic is the viscosity, as the displacement efficiency is driven by displacing and displaced fluid viscosities discrepancy, reflected by the mobility ratio. Just by taking oil viscosity into consideration a crude statement can be formulated: PVT 1 exhibits a more favourable mobility ratio than PVT 2 and PVT 3, with PVT 3 showing the most unfavourable M ratios from all the regions.

As PVT3 is the phase behaviour data associated with layer 4 and layer 5, it is forthright to say that the displacement efficiency in these two regions will be lower compared to the other regions.

This affirmation enforces that these layers will not show satisfactory results and the choice to include them in the process should be questioned. These results of polymer efficiency on region basis highly recommends further investigations concerning polymer injection in region 4 and region 5 and whether commingle injection should target also these two layers.

In Figure 44 are depicted the recovery factors for the base case, no further activities, as well as the incremental oil volume obtained by polymer flooding, on layer and overall field level for the case analysed above, namely for 1500ppm polymer concentration slug and non-Newtonian behaviour.

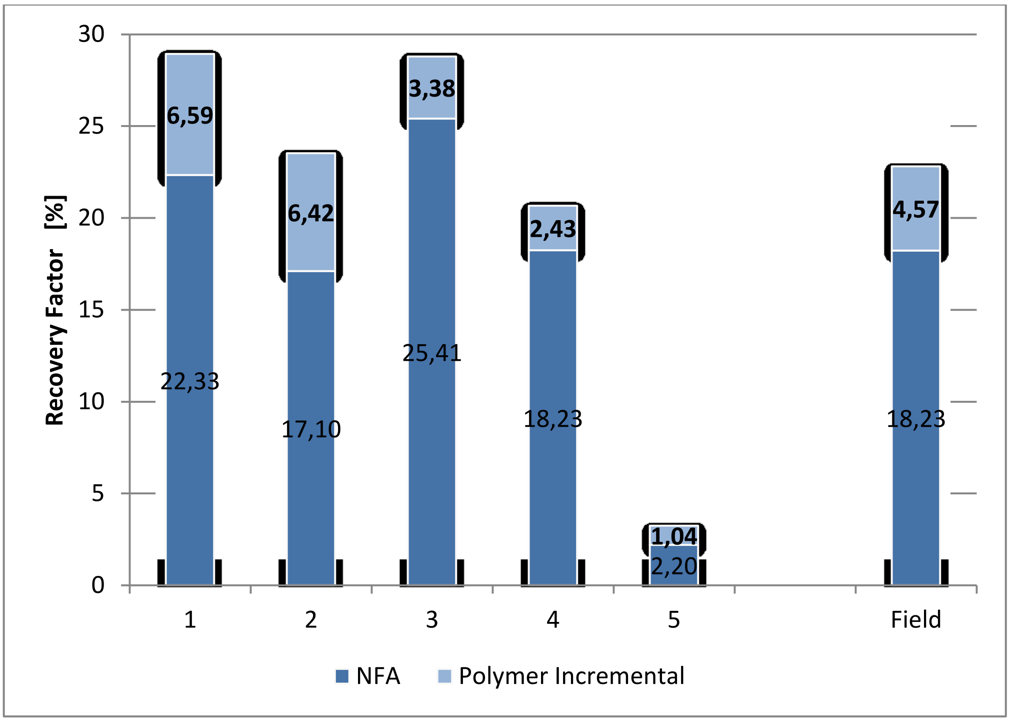


Figure 44: Recovery factor per region for 1500ppm polymer concentration case

The incremental in recovery factor can not be analyzed in interdependency with polymer solution viscosity or distribution in layers, because in the current operating conditions not all the wells produce from all layers. Some wells exploit only one layer while the majority has commingled production from multiple or even all layers.

Figure 44 reflects the potential recovery factor that could be obtained from polymer flooding with the actual exploitation state. Region 1 and region 2 show incremental in RF of more than 6%, denoting that both regions are good candidates for polymer injection and the incremental in produced volumes could significantly impact the economic viability of the project.

5.3.4 Newtonian and Non-Newtonian behavior comparison

As considering shear-thinning behaviour generates results that are closer to the reality, by accounting for the actual way polymers behave in the porous media, the next pages elaborate the comparison between Newtonian and non-Newtonian simulation results in terms of recovery factor and polymer slug propagation.

Polymer rheology impacts two key elements of polymer flood project: the injectivity of the solution and the displacement efficiency. In the next part, both effects will be discussed with main focus on displacement efficiency results compared against the ones obtained from the simulation where Newtonian behavior was assumed.

Shear-thinning is known to be a favorable polymer behavior due to the fact that for bulk reservoir volume which is characterized by low shear rates (about 1-5 s^{-1}) desirable mobility ratios can be achieved by lower polymer amounts. In addition, the high shear rates in the near-wellbore area decrease solution's viscosity inducing a greater injectivity and thus enforcing lower pressure depression in the vicinity of the injectors. [43]

Injection rate represents an important element of polymer flood design especially for the cases where large injection rates are needed to make the project economic attractive. However, the injected fluids produce extra pressure in the porous media, therefore the injected amounts are limited by the reservoir fracturing pressure. If the injector shows higher injectivity by accounting the shear thinning behavior, injection pressure at near well bore may be smaller than in the case when Newtonian behavior is considered. Thus, critical injection rate linked with the fracture pressure is higher and therefore, more favorable. As analyzed in the sensitivity chapter, by considering the Newtonian behavior (constant viscosity), a 1 500ppm concentration at a flow rate of 100 m^3/day induces a pressure below 120 bars, the fracturing limit, at the injector monitored. For the 2000ppm slug concentration case, the critical flow rate is 70 m^3/day.

The non-Newtonian cases were run with the same parameters but accounting for the shear-thinning behavior of polymers depicted in Figure 40. The injection rate was set to 100 m^3/day also in the 2 000ppm to allow comparison between cases. Simulation showed that the pressure values significantly decrease: for 1 500ppm case from 118 bars to less than 80 bars and for the 2 000ppm case down to 95 bars. These results illustrate the meaningful impact of realistic polymer behavior in porous media on injection flow rate selection. In this situation, an improved injection rate can be considered for the flood; nevertheless the economic aspects associated to a higher injection rate should not be omitted.

After the polymer non-Newtonian behavior impact on injectivity has been highlighted, the focus for the next section is shifted to the effects on displacement efficiency. As mentioned previously, shear thinning behavior has a positive impact on near wellbore region. On a bulk reservoir lever as flow velocity decreases with increasing distance from the injector, displacing fluid viscosity is higher, hence more stable displacement can be achieved yielding better sweep efficiency and essentially higher ultimate recovery. On the other hand, faster front propagation results in faster polymer breakthrough implying disadvantageous recovery factor in economic sense.

For displaying simplicity and a more straightforward explanation, when the situation allows it and the behaviour observed is similar, the results will be discussed only for one of the three concentrations analysed. All the variations and influences on field and region basis for different polymer concentrations as well as Newtonian and non-Newtonian scenarios can be found in the Appendix.

By comparing the results in terms of recovery factor per field and per region for different concentrations (1 000ppm, 1 500ppm and 2 000ppm) when considering non-Newtonian behaviour of polymers, the trend shows same characteristics as depicted in Figure 33 where Newtonian behaviour was assumed: the incremental recovery factor is increasing with increased slug concentration and the additional RF obtained by using a 1500ppm concentration instead of 1000ppm is higher than the incremental between 1500ppm and

2000ppm. Also in these cases the incremental recovery factor and slug concentration variation slope has a tendency to flatten to a certain plateau.

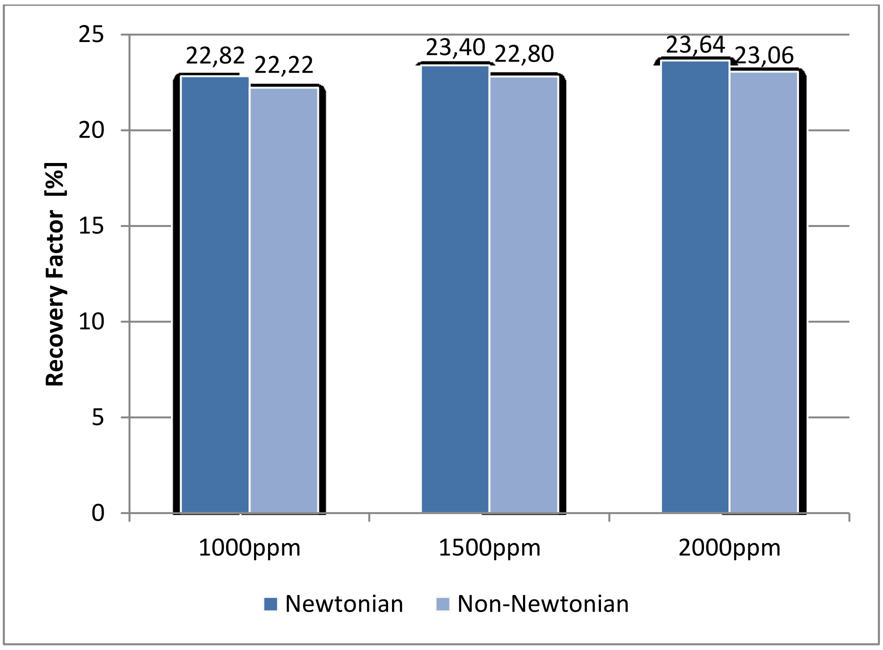


Figure 45: Newtonian and non-Newtonian field recovery factor for different polymer concentration

The discrepancy in recovery factor values shown in Figure 45 emphasis that non-Newtonian polymer behavior is decreasing polymer flood field efficiency; trend that was also observed on region level. All concentrations analyzed show differences in terms of RF and follow same tendency in both cases: increasing polymer slug concentration is increasing the recovery factor but at the same time the incremental increase is decreasing with increased polymer amounts. Therefore is can be stated that the impact of shear-thinning polymer behavior on decreasing polymer flood efficiency is higher for low viscosity solution as it is for highly viscosified solutions. Even though at the first look the differences in values can be considered small (less than 0,6 %) taking into account that they are on field level, 0,6% in recovery factor corresponds to big amounts of recoverable volume.

The juxtaposition of recovery factor values resulted from both Newtonian and non-Newtonian consideration simulations reveals a striking feature: the recovery factor for 1500ppm polymer concentration case when shear-thinning behavior is accounted shows same value as 1000ppm polymer slug concentration scenarios with Newtonian behavior assumed. The observation has effect both on technical and economic aspects: not only that the process efficiency is highly overestimated but also the economics are underrated. The costs of a polymer flood project are mainly driven by the price of polymers and a difference of 500ppm at the enormous volumes injected for field implementation has a serious impact. The influence could even downturn the project from economical viable to uneconomical.

Figure 46 illustrates recovery factor values for both Newtonian and non-Newtonian behaviour on region level, for 1500ppm polymer concentration slug scenario. The results are in line with literature reported theory: the incremental in recovery factor is smaller when non-constant viscosity with shear rate is assumed.

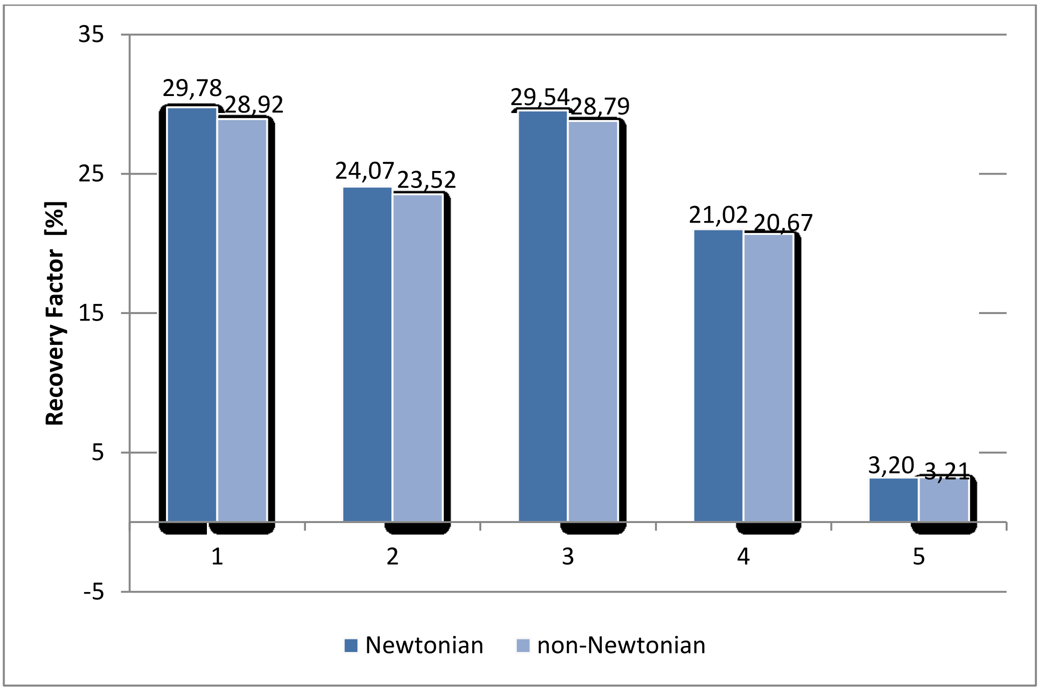


Figure 46: Newtonian and non-Newtonian results in terms of RF per region

It can be observed that even if the variations are small, a closer look or a simple calculation proves that the differences in recovery factor are not equal for all the layers. This can be attributed to the fact that the flood front travels through the layers at distinct velocities generating different viscosities for the polymer solution. Hence, higher velocities decrease solution viscosity determining less favorable mobility ratio and higher displacement efficiency reduction.

The velocity at which water flows is influenced by the injection rates in the near wellbore region and by porous media characteristics (permeability). The results are in line with observation drawn in the Newtonian cases, layer level analysis: the biggest differences are noted for layer 1 and layer 3. Both regions show better properties in terms of permeability as well as the high amount of polymer injected in these layers creates additional pressures compared to other layers.

Layer 5 presents insignificant difference in RF for the two behaviors. This is attributed to the observations stressed above in relation to the amount of polymer propagated in this region. The fact that the polymers hardly contact the rock, the impact of polymer flooding is so small that the influence of Newtonian and non-Newtonian behavior is negligible.

Figure 47 illustrates the proportion of polymer that is adsorbed onto rock surface as well as the quantity produced until the end of the simulation, in 2043, from the entire amount injected. Results are in comparison for Newtonian and non-Newtonian polymer behavior, for

1500ppm polymer slug concentration scenario. For the other concentrations, please refer to Appendix D.

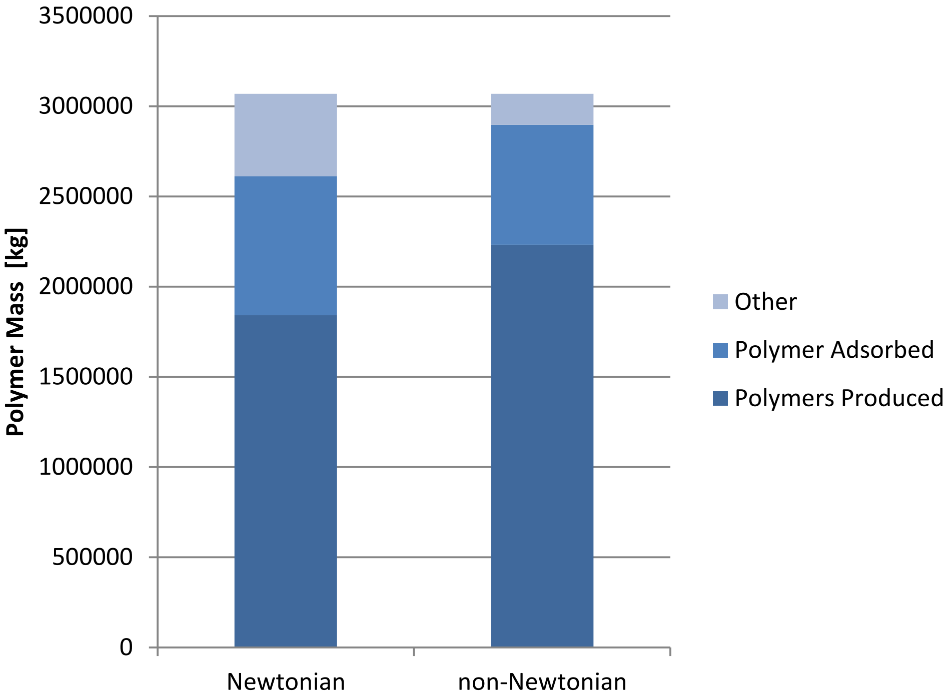


Figure 47: Polymer proportions from total polymer injected

The amount of polymer produced accounting for the real polymer behavior is considerably higher than for the Newtonian assumption. This trend is owed to the reduction in viscosity of the polymer solution in non-Newtonian case: low viscosity solution exhibits higher flow velocities through porous media. In consequence, an earlier breakthrough of polymer solution occurs and bigger amounts of polymer are produced in the wells.

For field application, this aspect of polymer flood process has to be taken into consideration and polymer treatment plants and other surface facilities have to be designed in conformity to these amounts.

In regards to polymer mass adsorbed, the case where shear-thinning behavior is considered shows smaller quantities of adsorbed polymers. This can be explained by the fact that according to the interdependency used in input, polymer adsorption rates decrease with decreased viscosity, effect induced by non-Newtonian behavior on polymer solution.

The difference are not as significant as for the amount of polymers produced as polymer adsorption rate dependency with solution viscosity follows the Langmuir adsorption isotherm depicted in Figure 35 for 25 µg/g maximum adsorption value. If the isotherm is analyzed it can be observed that for values above 500ppm polymer concentration it almost flattens to maximum adsorption limit. Therefore, the viscosity reduction promoted by polymer shear-thinning behavior does not cause severe variation on adsorption rates.

The amount of polymer mass obtained by subtracting the two above-discussed amounts from the total polymer injected quantity was categorized as other. In this portion, polymers remained in solution or trapped in pore spaces due to different entrapment mechanisms are included. No distinction in this sense can be made as by the end of the simulation time, polymer production was still ongoing.

The findings highlight the huge importance of accounting for the actual polymer behavior in porous media, especially when simulation results are used as basis for efficiency estimation and subsequent economic assessments.

5.4 Water Salinity Impact

As polymer flooding is being deployed in mild temperature and low to moderate salinity fields, reservoirs characterized by harsh temperature and salinity conditions remained inaccessible until now due to limiting performance of polymer in these circumstances. Worldwide, only few full field polymer flood projects are in commercial stages (Daqing, Marmul, Pelican Lake, Mangala and Patos Marinza) and the majority is under moderate conditions: less than 70°C and salinity below 50 000ppm. [44]

The reservoir of interest here has been reported to fall under high saline field category as produced water was identified with a salinity range between 50 000ppm and 90 000ppm. These values are approaching the limits imposed for a field to be considered attractive for polymer flood noted by Al-Bahar et al. based on EOR screening of 810 projects. [45] This evidence brought to light the interest to assess influence of salinity on this specific Romanian field, especially if reservoir brine without additional desalination would be chosen for polymer solution generation.

Figure 48 illustrates laboratory results from polymer solution viscosity variation with polymer concentration for three different brine salinities: 55 000ppm, 75 000ppm and 90 000ppm. It has to be mentioned that the brines used for the experiments were not water samples from the field analyzed but the yield curves do describe Floppam 3630S polymer behavior, the polymer used for all the simulations. The polymer sensitivity to salinity was investigated on three different polymer concentration: 1 000ppm, 1 500ppm and 2 000ppm and Newtonian behaviour was assumed to avoid misinterpretation as both parameters (water salinity and shear-thinning behaviour) impact viscosity in the same manner.

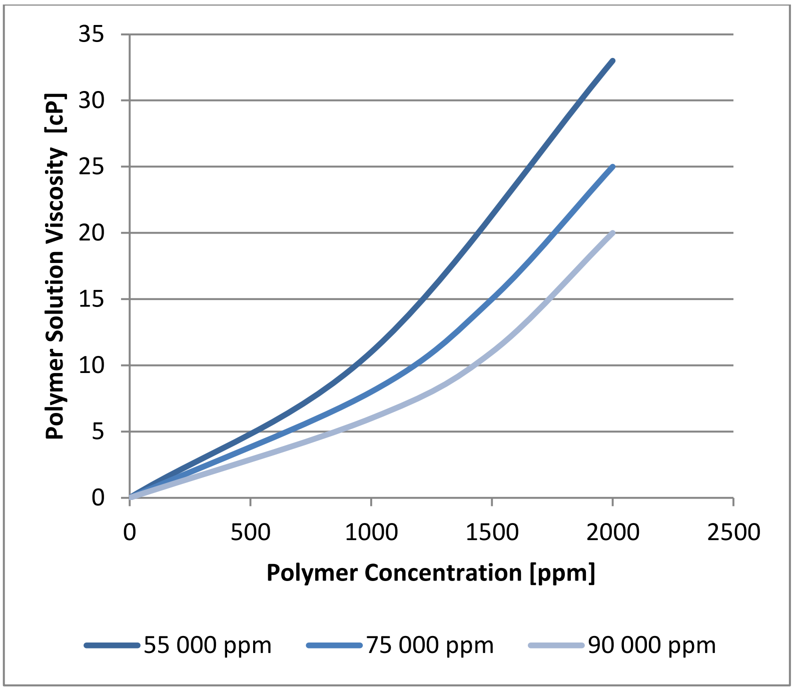


Figure 48: Polymer solution viscosity variation with water salinity

It is observed that the salinity impact on polymer solution viscosity is significant but in the same time the yield curves are close to rule of thumb described by Larry Lake in his book: a 10fold increase in brine's salinity induces a decrease in solution's viscosity with 10. [9]

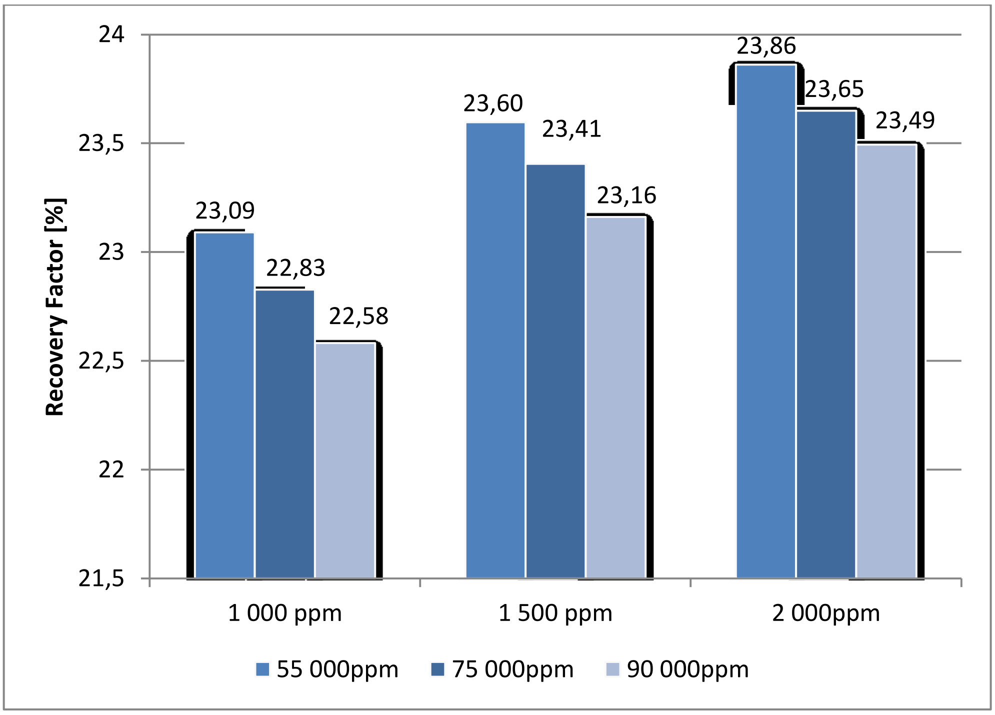


Figure 49: Recovery factor variation with salinity for different polymer concentration

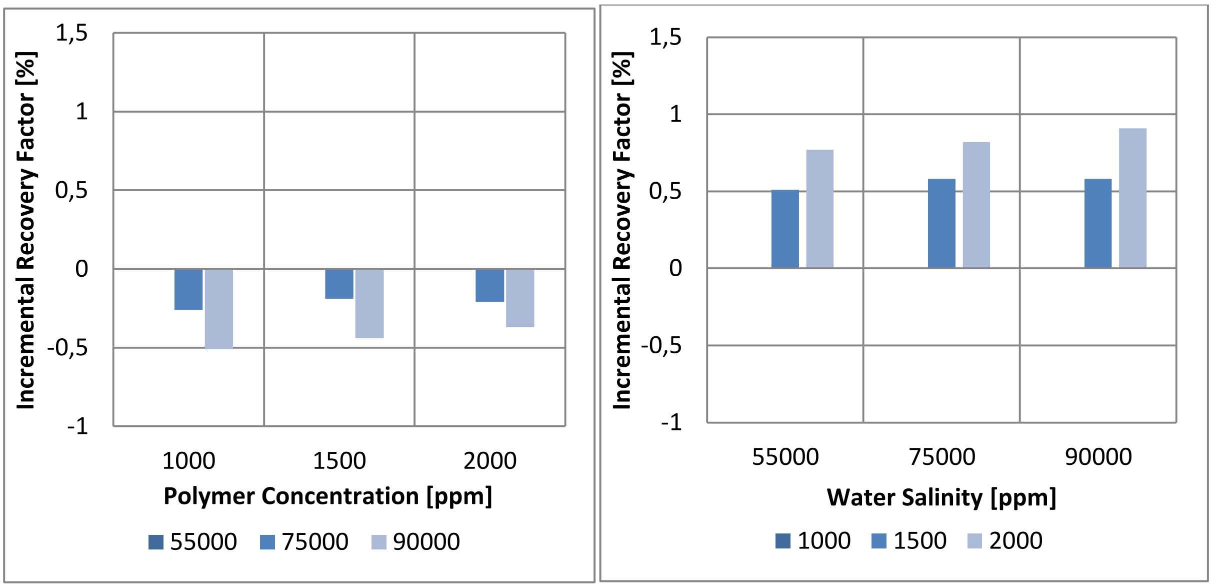


Figure 50: Recovery factor differential plots with 55000ppm salinity base case on the left and 1000 ppm polymer concentration base case on the right.

Based on simulation results illustrated in Figure 49 and in the computed differential plots considering the lowest salinity environment as base case in Figure 50 on the left side and considering the lowest amount of polymer concentration as base case on the right side, the following statements can be noted:

- The two main influences are meaningful illustrated on the recovery factor variation: the positive effects of increased polymer concentration – the higher the amount of polymer is, the higher the recovery factor is in response; and the negative impact of high salinity resulting in a decrease of field scale recovery factor.

- An important feature can be noted regarding the impact of polymer concentration on the degree of polymer sensitivity to solvent salinity: the difference in RF between 1000ppm and 2000ppm polymer slug concentration scenario is higher for 90 000ppm than for 50 000ppm salinity values. Based on this observation it can be stated that polymer sensitivity to salinity is increasing with increased water salinities.

- The computed differential plot depicts the fact that the decrease in the recovery factor caused by higher water salinity is lower at higher polymer concentration. This suggested that the negative impact of water salinity can be weakened by higher polymer amount. A possible explanation could target the mobility ratio factor: as the low viscosity polymer solution floods that are characterized by unstable displacement fronts due to unfavourable mobility ratio, are more susceptible to variation. On the other hand, high viscosity polymer solutions generate a more favourable mobility ratio and therefore a more stable displacement front that is less sensitive to fluctuation.

By analysing recovery factor in relation with water salinity, only information about technical impact can be speculated. In this respect, utility factor variation with recovery factor displayed in Figure 51 was used to incorporate a basic economical evaluation. The plot illustrates salinity influence on utility factor - recovery factor dependency for the three polymer slug concentrations mentioned and interpreted above (Figure 49).

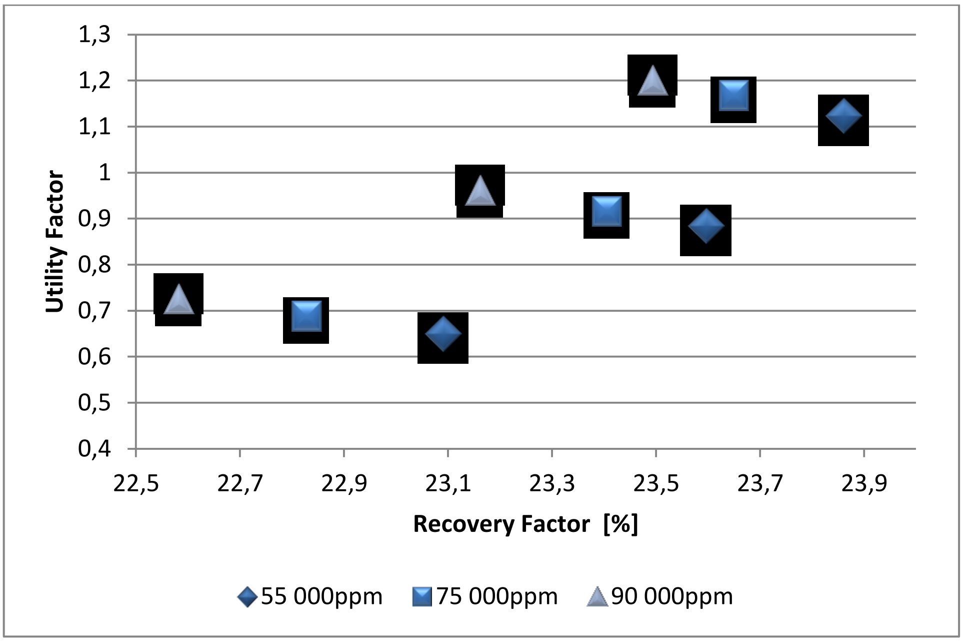


Figure 51: Utility factor variation with recovery factor for different water salinities

Using UF as key economic metric gives a wider picture of polymer flood efficiency. If a cut-off in UF is set, it can be used as guidance to find the scenarios that show the highest attractiveness and therefore to simply and narrow down the investigation area to less cases.

Few basic remarks can be pointed out from Figure 51: the higher the salinity, the higher is the utility factor for same polymer concentration and the lower is the correspondingly recovery factor.

It can be observed that three different combinations of polymer concentration and water salinity give similar results in terms of recovery factor but higher salinities always generate increased UF. The most striking discrepancy is observed for the cases that show around 23,6% RF values; as an increase of only 15 000ppm(from 75 000ppm to 90 000ppm) in water salinity induces the need of additional 500ppm in polymer concentration to generate same incremental in volumes produced. For the cases that exhibit recovery factor values around 23,1%, the salinity limits of the interval analysed produce huge variation in utility factor: the lower limit (55 000ppm salinity) is characterized by 0.6 UF while the upper limit (90 000ppm) holds an almost double value.

The observations highlight the high sensitivity of the analysed polymer to water salinity and the vitality of accurate water salinity measurements acquisition as both technical and economical polymer flood viability assessment can be significantly impacted.

6 Conclusion

The investigated field is one of the biggest Romanian fields; therefore its advanced phase of depletion represents the ground of many ongoing studies to extent field's production life. The poor results shown to waterflooding shifted the attention to tertiary recovery methods. The paper focused on finding new methods to increase field production life and assessing the performance of the suitable method found.

The EOR screening phase represents the basis for any further considerations. The screening methods chosen comprises of both conventional methods, based on parameter ranges existent in the literature, and advanced ones by using EORt tool from Petrel software, and identifying EOR methods applied in analogous fields. Immiscible gas injection and polymer flooding were found as possible compatible methods. Considering also the already existent internal knowledge of the company, this study focuses on estimating the polymer flood effectiveness as a viable EOR method.

Polymer flooding consideration as tertiary recovery method for this field is in an early stage, hence no reservoir simulation neither polymer core flood experiments have been conducted until the moment. To have the capability to assess polymer flood effectiveness on the investigated field by means of simulation methods, polymer-rock interaction parameters from an analogous field were used as input. Therefore, before any assessment, a sensitivity analysis on the parameters that are considered to be the result of rock-fluid interaction in a polymer flood process was performed.

Polymer adsorption, permeability reduction and inaccessible pore volume influence on field scale was investigated with the scope of estimating the degree of uncertainty that was brought in by using the above-mentioned input. For all the sensitivity simulations, the crude assumption of Newtonian polymer behaviour was made to decrease the computation time needed at a magnitude of several hours per run. The operational parameters for the simulations were chosen mainly from technical point of view (under fracturing conditions) but basic economics were accounted under the utility factor: 1 500ppm polymer slug concentration, 100 m^3/day injection flow rate and 1 PVI.

The sensitivity analysis on all three parameters concluded that IPV variation does not induce misleading recovery factor estimation and on contrary, permeability reduction value is the most influencing factor. The wide interval investigated for RRF, between 1,4 and 4,7, induced a variation up to 1% in field recovery factor.

Polymer flood effectiveness evaluation was done both on field and level region as one of the topics covered in the study was to investigate weather commingle polymer injection represents a viable development strategy. Moreover, non-Newtonian polymer behaviour has been accounted to increase the results' accuracy and capture a more realistic picture of polymer solution movement trough porous media.

The region analysis illustrated the high potential of layer 1, layer 2 and layer 3 for polymer flood. For two of the regions, namely layer 1 and layer 3, it is owed to the good quality of the rock and to the amount of polymer solution that is injected into these layers, approximately 30% from the total injected quantity in each one. The high amount and increased viscosity of solution from layer 2 are owed to the crossflow exhibited with layer 1 as in this it is injected only a half of the amount received by the other two layers earlier mentioned. On contrary, the results highlighted in layer 4 and layer 5 are key elements in the analysis of commingle injection viability as due to poorer rock quality the polymer solution propagation distance is modest, especially in layer 5 where it is limited to near wellbore area. In addition, these two regions fall under the PVT region with the most viscous oil, around 80 cP, generating the most unfavourable mobility ratios and decreasing even more polymer displacement efficiency.

All these cumulated with the bad injectivity and flow characteristics exhibited by both layer 4 and layer 5, especially of the latest one, in the detriment of high amounts of polymer injected in these regions (almost 30% of the entire quantity) strongly impacts polymer flood overall effectiveness.

The comparison in terms of recoverable volumes between the scenarios that used same input and operating parameters but different polymer behaviour, Newtonian and non-Newtonian, revealed a striking feature: the recovery factor for 1500ppm polymer slug concentration case when shear-thinning behavior is accounted shows same value as 1000ppm concentration scenarios with Newtonian behavior assumed.

The findings highlight the huge importance of accounting for the actual polymer behavior in porous media, especially when simulation results are used as basis for efficiency estimation and subsequent economic assessments, as the expenses of a polymer flood project is mainly driven by the costs of polymers.

The last part of the paper focuses on water salinity impact on polymer flood effectiveness as the field investigated falls under high saline reservoir category and due the lack of accurate measurements salinities between 50 000 and 90 000ppm were reported. The analysis suggested that polymer sensitivity to salinity is increasing with increased water salinity and the impact of salinity variation is higher for low viscosity polymer solutions than is for high viscosity ones. Salinity impact on the flood was evaluated using the UF-RF dependency and it has been observed that three different combinations of water salinity and polymer slug concentration showed similar results in terms of recovery factor but a drastic increase in utility factor with the increase of salinity; even up to almost double values.

The observations highlight the high sensitivity of the analysed polymer to water salinity and the vitality of accurate water salinity measurements acquisition as both technical and economical polymer flood viability assessment can be significantly impacted.

The analysis concluded that polymer flooding could indeed represent a viable option to increase field production and further investigations are recommended in this direction.

6.1 Recommendation

Due to the fact that polymer flooding considerations as method to improve recoverable volumes and extend field's life is still in an early phase, the findings highlighted in this study serve as grounds to formulate few recommendations for future work in the following directions:

- Measurement of field's fracturing pressure as it represents the limiting criteria for polymer flooding operating parameters (injection flow rate and polymer slug concentration) determination.
- SCAL and polymer core flood experiments are essential as the results of the sensitivity analysis on polymer-rock interaction parameters showed variation in field recovery factor up to 1%.
- Concerning the reservoir simulation model, assessing field's heterogeneity through multiple modelling realisations and grid refinement for capturing polymer front propagation and stability, are suggested.
- Polymer efficiency on layer level analysis results highly recommends to include real polymer rheology as well as to further investigate polymer response of region 4 and region 5 if commingle injection is considered.
- Accurate water salinity measurements need to be acquired as the investigation revealed its high impact both on technical and economical aspects. The possibility of making a low salinity preflush or the usage of high TDS tolerant polymers should also be taken into considerations.

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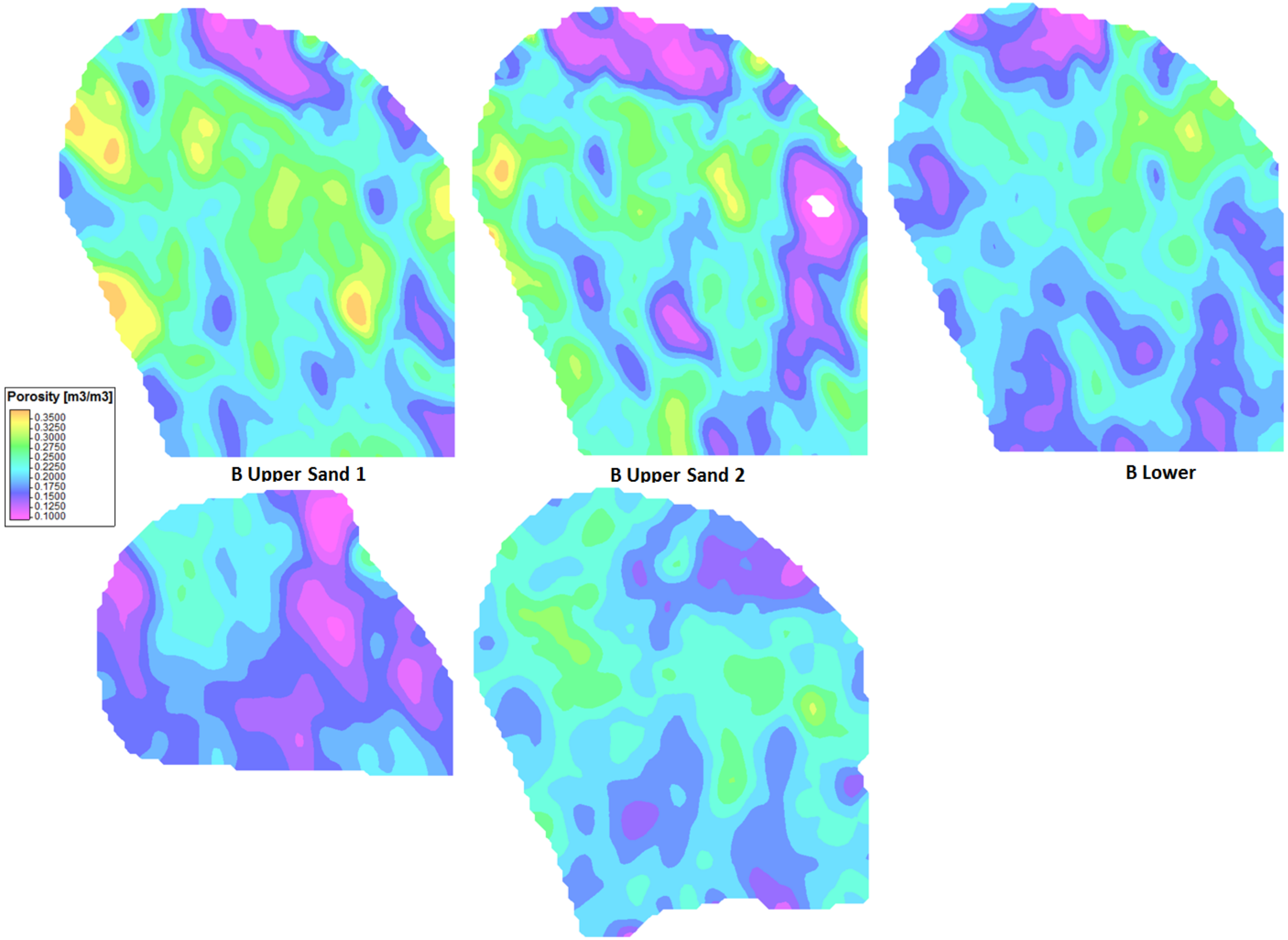
Appendices

Appendix A: Porosity map on regions



B Upper Sand 1

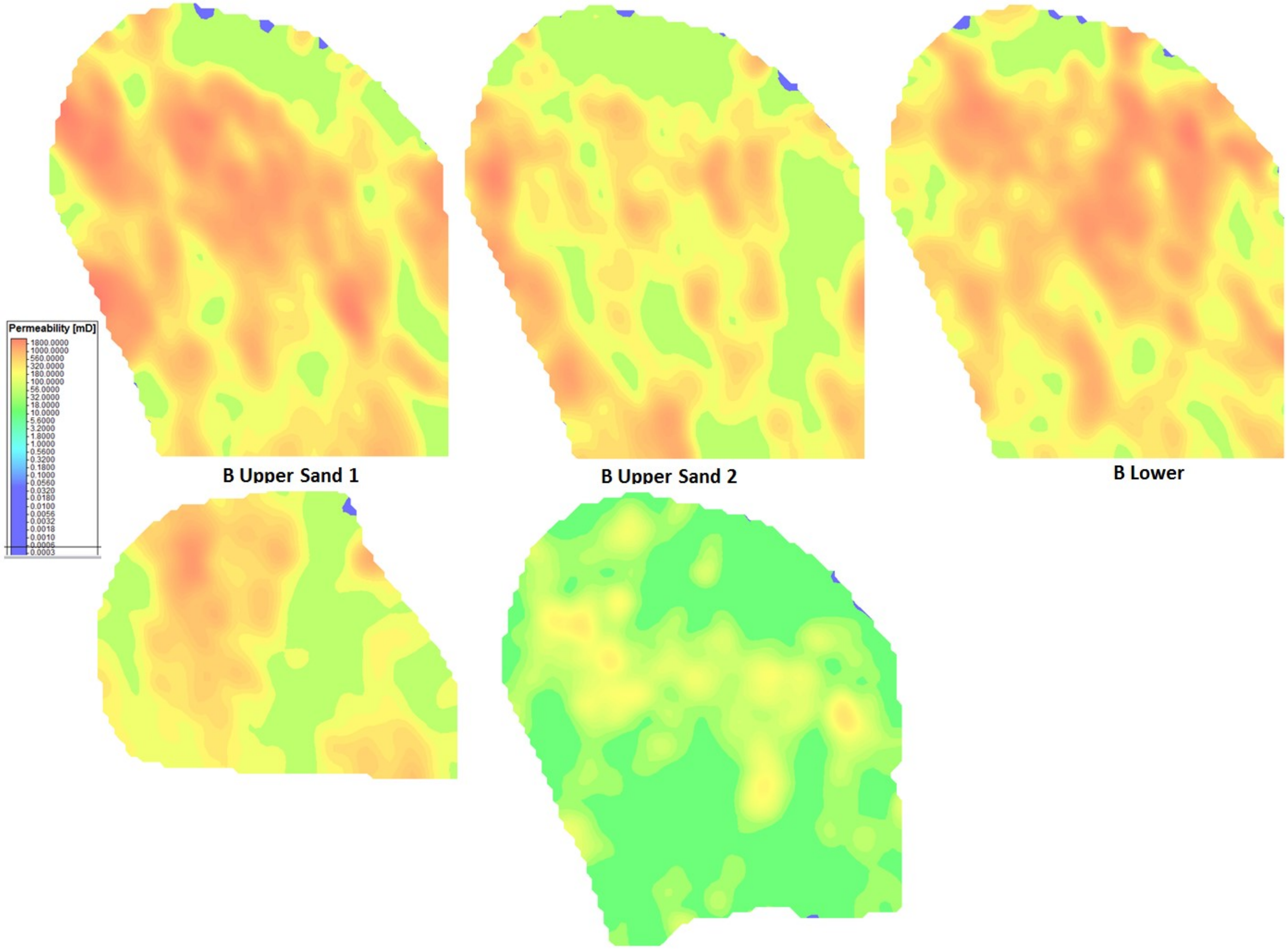
B Upper Sand 2

B Lower

A Sand 1

A Sand 2

Permeability map on regions



B Upper Sand 1

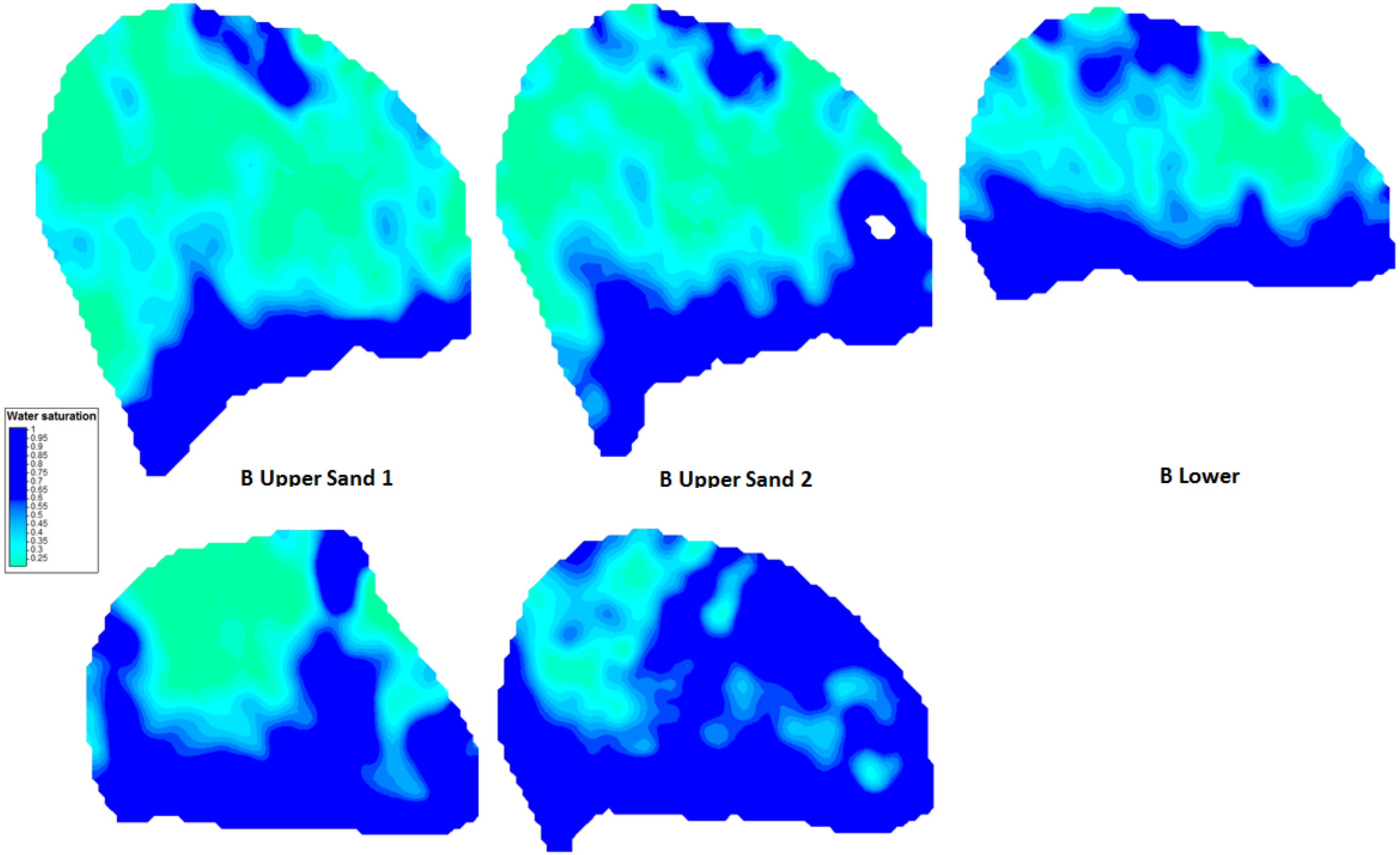
B Upper Sand 2

B Lower

A Sand 1

A Sand 2

Water Saturation map on regions



B Upper Sand 1

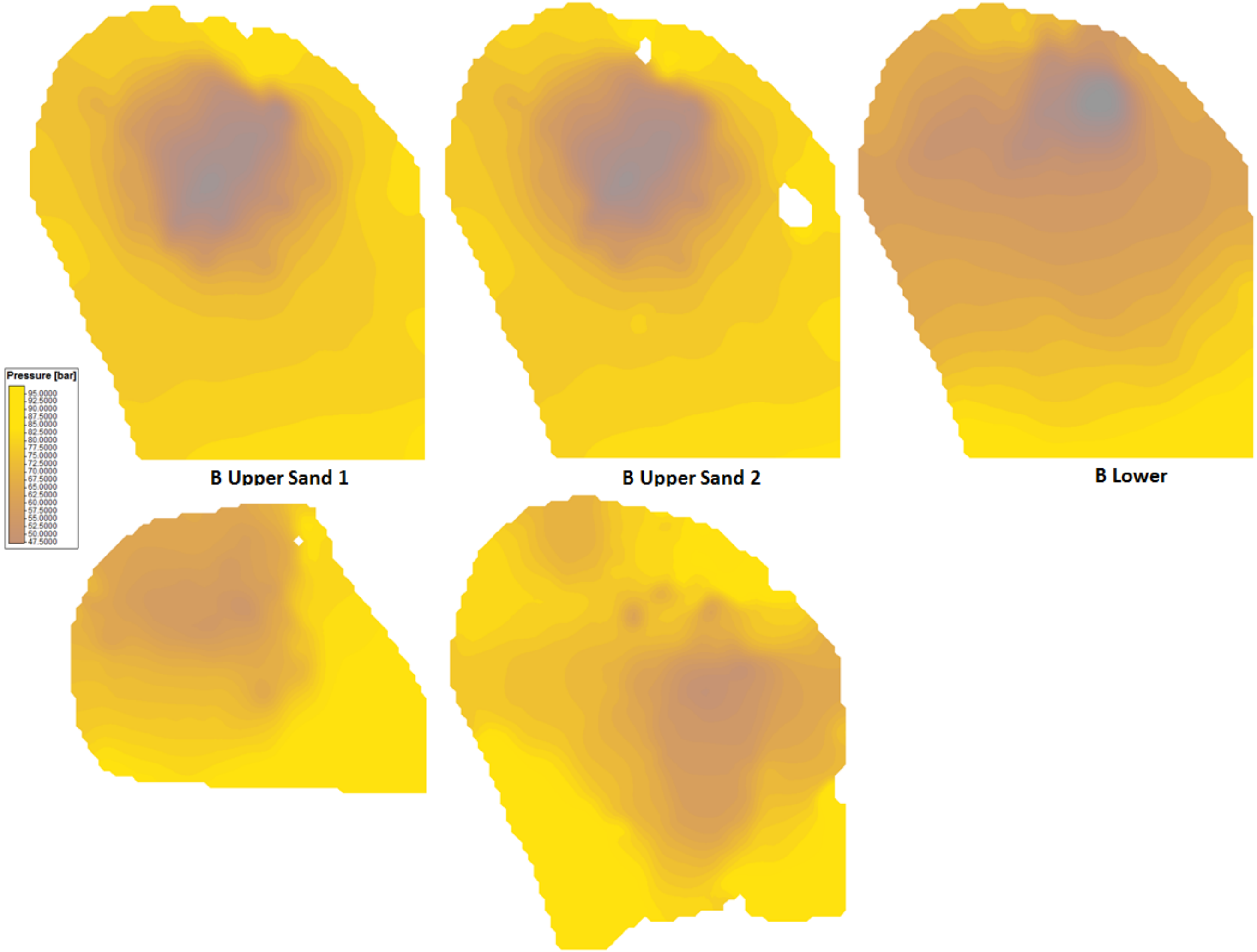
B Upper Sand 2

B Lower

A Sand 1

A Sand 2

Pressure



B Upper Sand 1

B Upper Sand 2

B Lower

A Sand 1

A Sand 2

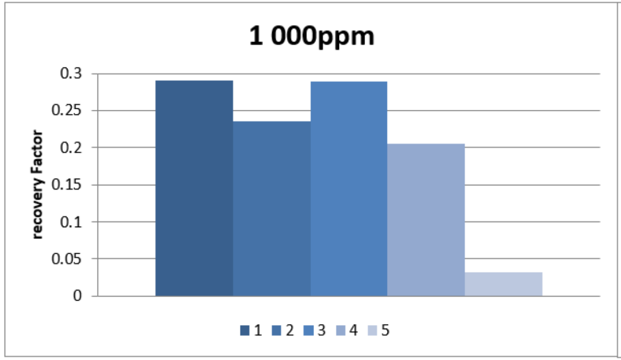
Appendix B: Water viscosity as function of polymer concentration

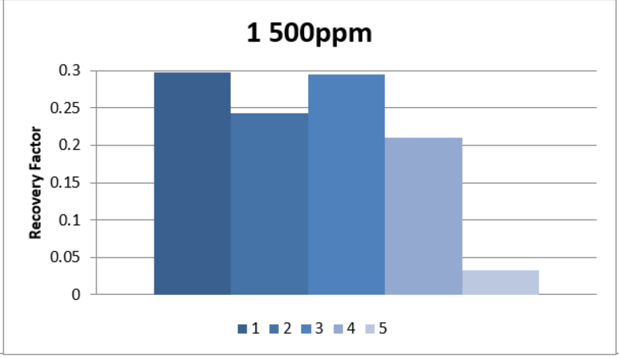
Table 7: Water viscosity as a function of polymer concentration

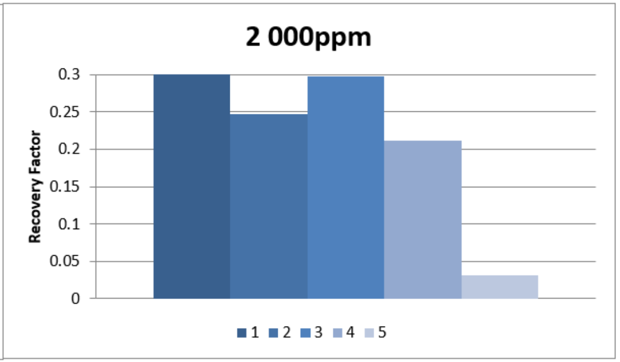
Polymer concentration *[ppm]*	*Water Viscosity* *[cP]*
1000	8
1500	17
2000	25
3500	50

Appendix C: Recovery Factor per region for Newtonian and non-Newtonian scenarious

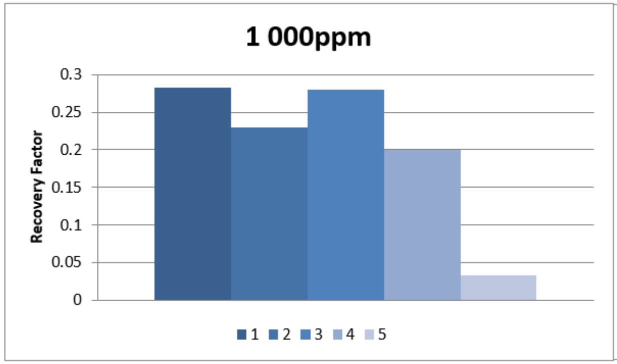
Newtonian

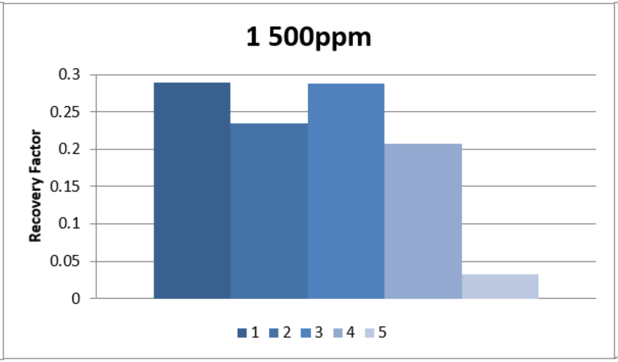


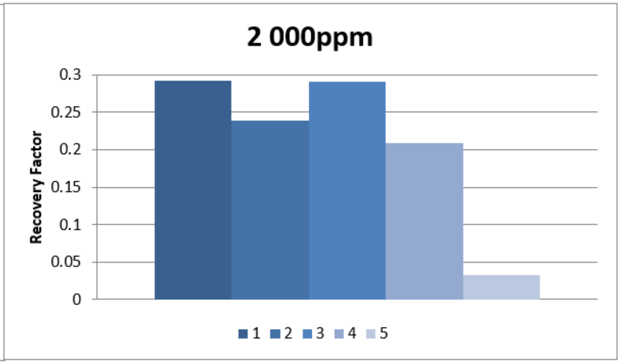




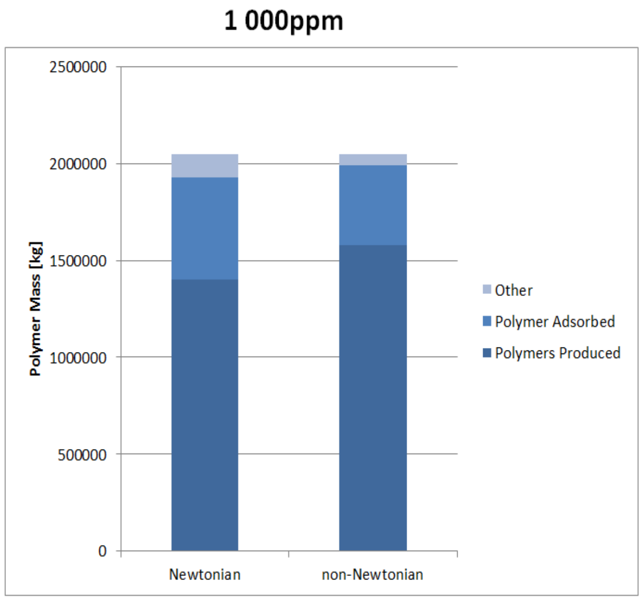
non - Newtonian

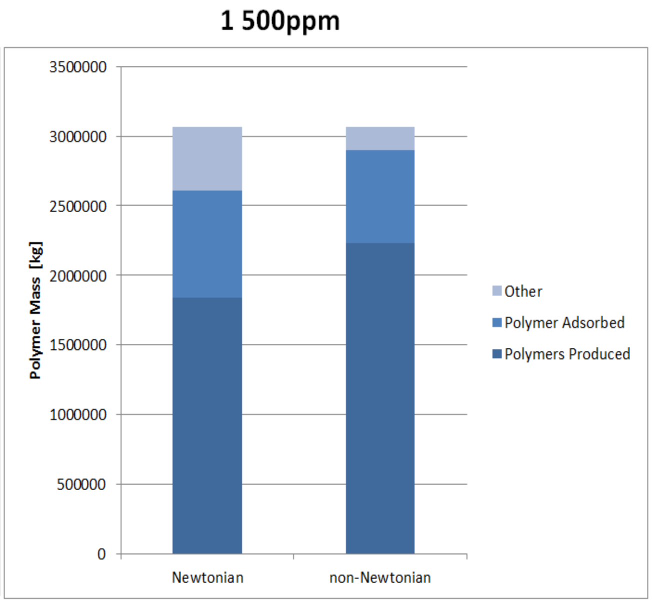


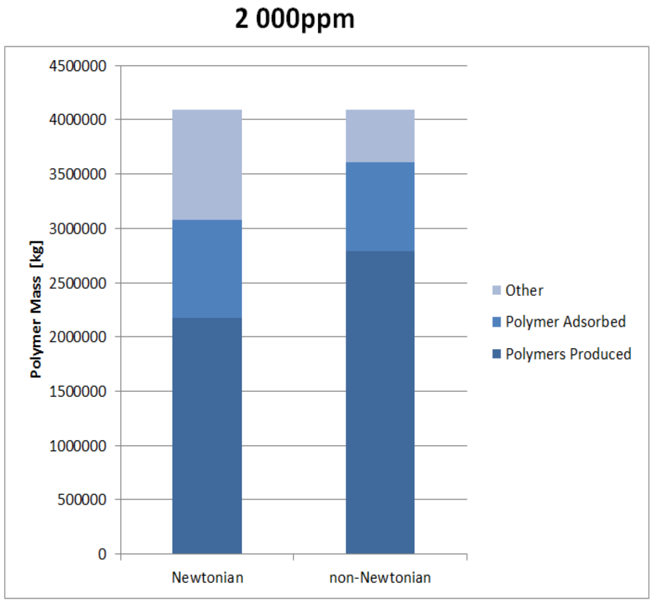




Appendix D: Proportion of polymer for Newtonian and non-Newtonian scenarious







Appendix E: Polymer Movement in Region B Upper Sand 2 for 1500ppm Polymer Concentration Case and Non-Newtonian Behaviour