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Recommended polymer workflow
Lab (cm and m scale)

University
of Stavanger

The **National
IOR Centre**
of Norway

Reports from UiS

Recommended polymer workflow - Lab (cm and m scale)

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Objective and target audience

This document is meant for anyone that want to address and quantify the technical potential for polymer flooding. Environmental and risk assessment of polymer flooding is addressed in a separate document [DF report]. A detailed evaluation of the technical potential for polymer flooding involves several laboratory and simulation steps, described in detail in the next chapters of this report. However, there are investigations that can be done in a screening phase to ballpark the technical potential

1. Fractional flow analysis using oil water relative permeabilities. By simply increasing the water viscosity by e.g., a factor of 10 will demonstrate the potential for additional oil that can be recovered compared with a pure water flood (see more discussions on this point in the introduction section of this report)
2. Run a field scale simulation where the injected water viscosity is increased by a factor of e.g., 10. In the screening phase there is no need to use any polymer models in the field scale simulator.

If the result of 1 and 2 above indicates a significant technical potential, one should proceed with the recommendations presented in the next chapters to identify a proper polymer system given the constraints set by practical operations and reservoir conditions.

Summary

Polymer flooding is one of the most promising EOR methods (Smalley et al. 2018). It is well known and has been used successfully (Pye 1964; Standnes & Skjevrak 2014; Sheng et al. 2015). From a technical perspective we recommend that polymer flooding should be considered as a viable EOR method on the Norwegian Continental Shelf for the following reasons:

1. More oil can be produced with less water injected; this is particularly important for the NCS which are currently producing more water than oil
2. Polymers will increase the aerial sweep and improve the ultimate recovery, provided a proper injection strategy
3. Many polymer systems are available, and it should be possible to tailor their chemical composition to a wide range of reservoir conditions (temperature and salinity)
4. Polymer systems can be used to block water from short circuiting injection production wells
5. Polymer combined with low salinity injection water has many benefits: a lower polymer concentration can be used to reach target viscosity, less mechanical degradation, less adsorption, and a potential reduction in Sor due to a low salinity wettability effect

There are some hurdles when considering polymer flooding that needs to be considered

1. Many polymer systems are not at the present considered as green chemicals; thus, reinjection of produced water is needed. However, results from polymer degradation studies in the IORCentre indicates that
   a. High molecular weight polymers are quickly degraded to low molecular weight. In case of accidental release to the ocean low molecular weight polymers are diluted and the lifetime of the spill might be quite short. According to Caulfield et al. (2002) HPAM is not toxic, and will not degrade to the more environmentally problematic acrylamide.
   b. In the DF report for environmental impact there are case studies using the DREAM model to predict the transport of chemical spills. This model is coupled with polymer (sun exposure) degradation data from the IORCentre to quantify the lifetime of polymer spills. This approach should be used for specific field cases to quantify the environmental risk factor.

2. Care must be taken to prepare the polymer solution offshore. Chokes and vales might be a challenge but can be mitigating according to the results from the large-scale testing done in the IORCentre (Stavland et al. 2021).

None of the above-mentioned challenges are server enough to not consider polymer flooding. HPAM is neither toxic, nor bio-accumulable, or bio-persistent and the CO_2 footprint from a polymer flood may be significantly less than a water flood (Dupuis et al. 2021). There are at least two contributing factors to this statement, which we will return in detail to in the next section i) during linear displacement polymer injection will produce more oil *for the same amount of water injected,* hence the lifetime of the field can be shortened ii) polymers increase the arial sweep reducing the need for wells.

Introduction

Mobility ratio and displacement in simplified cases

In a homogeneous reservoir it is well known that if the viscosity of the displacing phase (e.g., water) is smaller than the displaced phase (e.g., oil) any small instability at the interface between the displacing and displaced phase will grow exponentially and lead to viscous fingering. No reservoir is homogeneous, and the criterion for instability is determined by the mobility ratio defined as, $M = {\lambda_D}/{\lambda_d} = {k_w \mu_o}/{k_o \mu_w}$, here λ_D is the displacing mobility and λ_d is the displaced mobility (Sorbie 1991). For polymer flooding it is common to use the term mobility ratio, RF, defined as the ratio between water and polymer mobility. Before we consider the more complicated case of arial sweep, let us investigate polymer flooding in a pure linear case. The following experiment on a (composite) core will clearly demonstrate the effect of polymer injection:

- Perform a steady state oil-water flood experiment, starting at low water fractional flow and after some f_w-steps, shift to steady state polymer water. The water fractional flow curve will shift to a new curve, matched with the new and lower mobility-ratio f_w curve.

The effect is easily understood by deriving the fractional flow of water curve vs. saturation, as shown in Fig. 1.
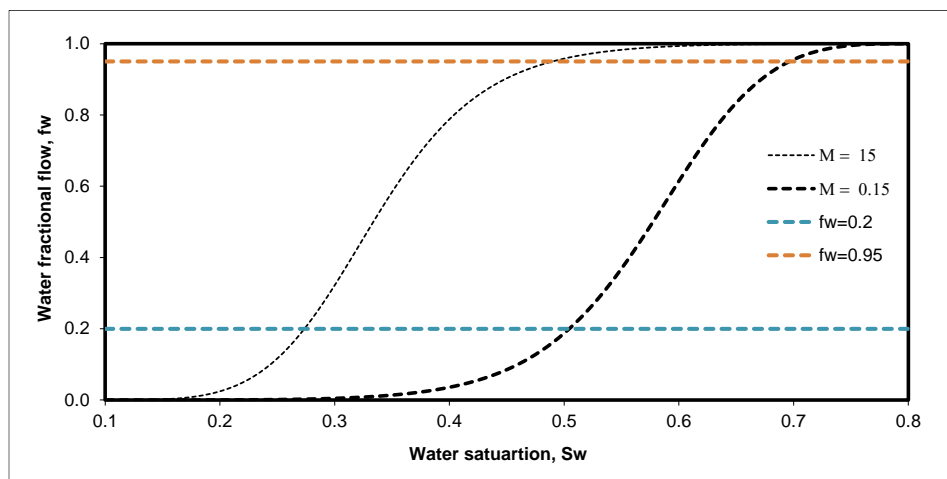

Fig. 1 Water fractional flow curves at M = 15 and M = 0.15.

The blue line in Fig. 1 shows that if one switches from water to polymer flood at f_w=0.2 (20% water cut) the oil production will increase with over 100% compared to a pure water flooding. To produce the same amount of oil using water one must allow for a prolonged water flooding at 95% water cut.

Viscous flooding will also improve the sweep efficiency in heterogenous reservoirs. If we ignore the linear displacement efficiency, which is a direct consequence of Darcy's law, and consider pure piston displacement, we can use the Dykstra-Parson's method (Dykstra & Parsons 1950). For simplicity, assume a layered reservoir containing two equal layers with different permeability. In a linear geometry, the relative invasion into the low permeability layer at breakthrough in the high permeability layer is dictated by the permeability contrast. Fig. 2 show examples for permeability contrast of 100. The sweep efficiency, E_i for unit mobility ratio: $E_i = \frac{1}{2}\left(1 + \frac{k_L}{k_H}\right) = 0.505$. If the injected viscosity is increased to infinity, $E_i = \frac{1}{2}\left(1 + \sqrt{\frac{k_L}{k_H}}\right) = 0.55$, green curve in Fig. 2. This implies that in extremely heterogeneous reservoirs the sweep efficiency is not significantly improved. On the other hand, E_i can be significantly improved by allowing some selectivity in the polymer viscosity. As an example, the orange curve in Fig. 2 shows the case were the specific viscosity of the polymer injected into the low permeability layer is a factor 10 lower than for the high permeability case and $E_i = 0.66$. The dotted yellow line denotes the case of injecting polymer only into the high permeability layer and unit mobility ratio (i.e., brine) into the low permeability layer. In theory, if the viscosity increase in the high permeability layer is $RF = \frac{2k_H}{k_L} - 1$, it will be possible to achieve stable displacement of $E_i = 1.0$.
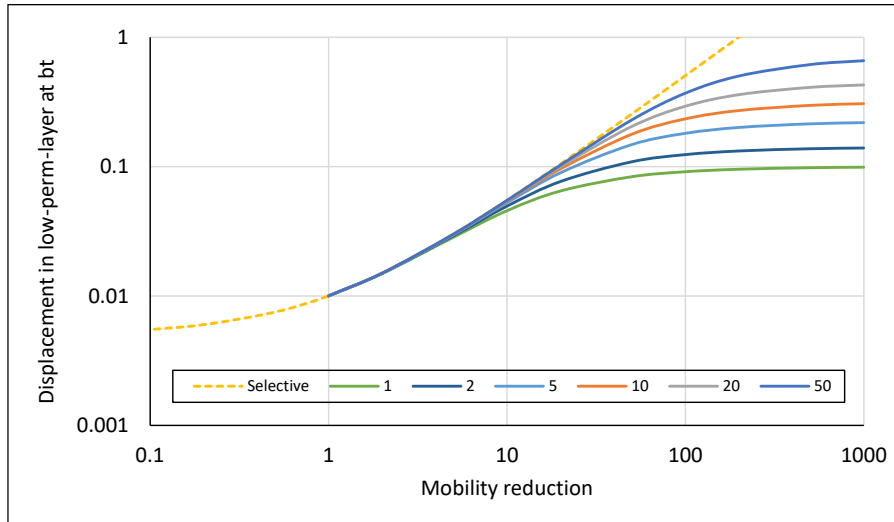

Fig. 2 Displacement efficiency derived by Dykstra-parson theory.

To summarize, polymer injection can be utilized in several scenarios. The obvious targets for polymer flooding are reservoirs with high mobility ratio and poor areal sweep efficiency. However, the sweep efficiency is also improved in situation where the oil-water-mobility ratio is less than unity. For tail-end producers the water-cut and water production are lowered, less water can be injected and will positively impact carbon-footprint. Understanding how to make the mobility reduction permeability dependent, may further improve the outcome of a polymer injection.

Mobility ratio and displacement for realistic conditions

In practical applications the polymer viscosity is not a constant, and controlled by several parameters, the solvent viscosity, η_{solv}, the intrinsic viscosity, $[\eta]$ and the Huggins constant, k', as used in the Martins equation, $\eta_{sp} = [\eta]cexp(k'[\eta]c)$. Here, $\eta_{sp} = \eta_r - 1$, is the specific viscosity and $\eta_r = \eta/\eta_{solv}$ is the relative viscosity and c is the polymer concentration. Taylor expansion gives the following equation for the viscosity:

$$\eta = \eta_{solv}\{1 + [\eta]c + k'([\eta]c)^2 + \mathcal{O}(c^3)\}$$

and the parameters $[\eta]$ and k' can be derived from viscosity data at the different concentrations. The $[\eta]$ increases as the Mw increases. A typical EOR polymer may have $[\eta] > 3000$ ml/g, thus the relative viscosity increases one order of magnitude at a concentration as low as 1000 ppm.

For synthetic polymers, the $[\eta]$ depends strongly on the solvent salinity and the viscosity decreases as the brine salinity increases (Nouri & Root 1971). It has been shown that an effective salinity can be derived from a modified ionic concentration, $c_{eff} = \frac{1}{2}\sum_i m_i z_i^{2+k_i}$, where m is the molar concentration, z is the valence number and k is a tuning parameter (Stavland et al. 2013). Interpretation of experimental viscosity data at different concentration resulted in k -values of 3.7 for HPAM polymers and somewhat lower if the ATBS content increased.

As such, master-type viscosity curves can be derived which makes it possible to define polymer concentrations to match a given viscosity target. Therefore, the smart water in regular synthetic polymer flooding is a low salinity brine where the divalent ion concentration is a low as possible. By using a softer brine composition, desired viscosity can be achieved at a significantly reduced polymer concentration. The polymers are non-Newtonian fluids, and the viscosity is normally matched with a Carreau-type curve, thus the viscosity depends strongly on the shear rate.

$$\eta = \eta_{solv} + (\eta_0 - \eta_{solv})[1 + (\lambda\dot{\gamma})^2]^{\frac{n-1}{2}}$$

Here, η_0 is the zero-shear rate viscosity, λ is the time constant, $\dot{\gamma}$ is the shear rate and n is the shear thinning index.
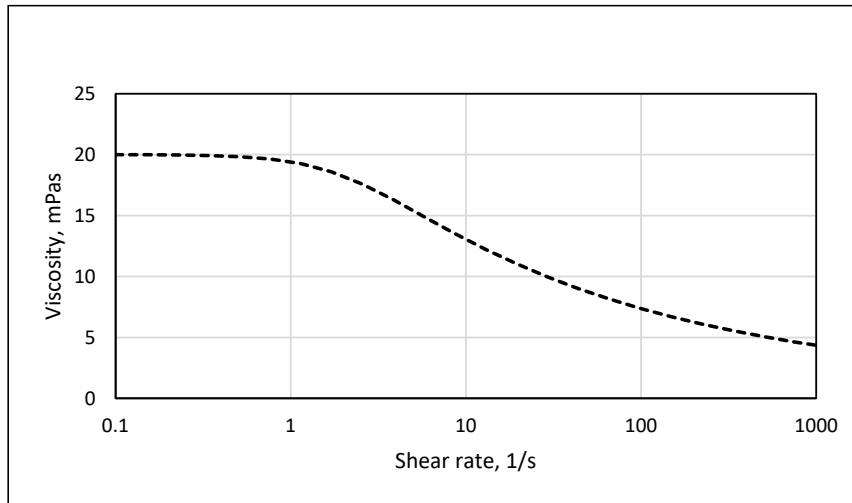

Fig. 3 Shear-dependent Carreau-type viscosity, where η_0 = 20 mPas, η_{solv}.= 1.0 mPas, λ = 0.5 s and n = 0.72.

One of the critical parameters to derive is therefore the shear rate in porous media. The simple version, adopted in most of the models, is to simplify the porous medium to a bundle of capillary tubes. For laminar flow, the analytical solution for a Newtonian fluid through a capillary tube gives, $\dot{\gamma} = 4v/r$, for the no-slip case. Here v is the velocity and r is the tube radius. From Darcy law, the pore radius, $r = \sqrt{8k/\varphi}$, where k is the permeability and φ is the porosity. A factor, α, is introduced to accommodate for the facts that the polymer is a non-Newtonian fluid, that the porous medium is not a bundle of capillary tubes and that polymers may exhibit slip. Then, α effectively corrects the effective shear rate that links to an apparent polymer bulk viscosity which we can apply in a Newtonian model. We assume that with the expression used, it should not vary much for different formations.

The shear rate is inverse proportional to the square root of the permeability and proportional to the flow velocity, therefore the shear rate in a reservoir varies. In the polymer literature, the in-depth shear rate is often assumed to be 7-10 s^{-1} (which is based on a flow velocity of 1 ft/day through a 1 Darcy reservoir). A much better assumption is to assume a fixed in-depth pressure gradient rather than a fixed flow rate.

The ideal EOR polymer should have excellent flow properties through the porous medium and have low viscosity during the injection phase, i.e., the apparent viscosity derived from core flood experiments should match a bulk viscosity curve as the one shown in Fig. 3. This is normally true for the biopolymers, such as Xanthan, Scleroglucan and Schizophyllan. The synthetic polymers such as HPAM and ATBS yields less shear tinning at low to moderate shear rates than the biopolymers and in fact exhibit shear thickening at higher shear rates. In addition, the synthetic polymers are much more easily degraded at high flow rates. Even though these non-optimum flow properties, nearly all EOR field treatments are performed with the synthetic polymers. It has therefore been an important task to better understand the effects of elongation and mechanical degradation.

Arguments have been made on the possibility for polymer to lower the residual oil saturation and that this is caused by the normal forces induced by elongated flow, see e.g., Clarke et al. (2016). Firstly, elongated flow is located to the reservoir regions where the flow velocity is highest, i.e., close to the wells and not in-depth. Secondly, it is easier (and probably more correct since most of the reported experiments have been performed with rather viscous oil) to explain incremental oil production by shift in f_w curve due to altered mobility ratio and that more oil would have been produced if water had been injected for longer period.

Mechanical degradation takes place when the polymer flows through flow restrictions at high shear rates. This can be through choke devices and through the continuum of large pore bodies and narrow pore throats in the rock formation. In the work by Stavland et al. (2021) the polymer degradation through choke devices, at different scale was investigated. It was concluded that the degradation could be understood by the applied shear rate. The simple method to interpret the data was the following:

- Introduce the shear stress, $\tau_w = \eta\dot{\gamma} = \frac{f}{8}\rho < v >^2$, where f is the friction factor, ρ is the density and $< v >$ is the flow velocity.
- For laminar flow, i.e., $Re = \frac{2 < v > r\rho}{\eta} < 2300$, use $f = 64/Re$ and for turbulent flow, i.e., $Re > 2300$, use the Newtonian friction factor derived from Blasius $f_N = 0.3164/Re^{1/4}$. The fact that polymers cause drag reduction, the polymeric friction factor was matched with $f_P < f_N$ (Stavland et al. (2020) used $f_P = 0.155/Re^{1/4}$). At turbulent flow, Re depends on the viscosity. Since the degradation takes place at high shear rates, and the viscosity is shear thinning and we successfully matched the experiments by using a constant viscosity of 2.5 mPas.

With this relatively simple approach we were able to match mechanical degradation of polymers both though narrow capillary tubes with r = 125 μm (and flow rates of ml/min) and up to tube radius of r = 50 mm (and flow rate of m³/min).

The main lessons learned was that mechanical degradation can be eliminated or strongly reduced by (i) lowering the pressure gradient across the choke device – increasing the length of the choke device, (ii) increasing the polymer concentration – perform the polymer dilution after the choke device or (iii) using multiple choke devices in series. All these methods have later been adopted by the industry (Al Baqlani et al. 2018).

It was further confirmed that mechanical degradation is more susceptible for high Mw polymers and that HPAM polymers are more easily degraded than co-polymers containing ATBS groups.

It is well known that synthetic polymers will be degraded when flooding at high velocity through a porous medium. The common understanding has been that the degradation is located to a few mm close to the core inlet and this was questioned by the paper by Åsen et al. (2019). By linear core flood experiments we reported mechanical degradation that increased by increasing flow velocity (i.e., shear rate) as well as a length effect – the degradation increased by the applied core length. However, for the tested polymers, the degradation was associated with high pressure gradient (on the order of 100 bar/m, which at field scale will be unrealistic high). And, when performing radial flood experiments – flow velocity decreases by increasing the invasion depth, there was no length effect, and the mechanical degradation will be located to the injector inlet. For high Mw HPAM polymer, degradation is anticipated if the shear rate exceeds 10^3 s^{-1}, which for a reservoir with permeability of 1 Darcy and porosity of 0.3 is equal to matrix flow velocity of 50 m/d. If the near wellbore velocity is likely to be in this range, one may consider increasing the perforation length, e.g., fracking by a few meters to lower the risk of mechanical degradation. Alternatively, one may apply a less-sensitive products, e.g., lowering the Mw or copolymers, such as ATBS.

The polymer- and water- flow through a porous medium deviate. Some of the polymer may be adsorbed on the rock surface or retained in narrow pore channels, thus the effective polymer flow velocity is slower than the water velocity. On the contrary, the polymer will not enter the entire pore volume, causing an up-concentration of polymer in the middle of the pores and the flow velocity becomes higher than the water case. The net effect, controlled by the IPV, Inaccessible Pore Volume, and the polymer retention determines the effective polymer velocity. In general, IPV is controlled by the ratio between the pore size and the polymer size and will increase by increasing the Mw and decreasing the permeability. Typical values for IPV is 10 to 20%. For polymer retention, the single most important parameter is the rock wetting condition. If the reservoir tends to be oil wet, the oil will shield the rock surface for adsorption, causing very low retention values, in the range of 5 μg/g rock. In water-wet rock, the presence of oil has almost no effect on the polymer retention and retention levels in water wet cores are 30 to 50 μg/g. Lowering the brine salinity is reported to lower the adsorption. What is the impact on the effective flow velocity? As an example, the effective breakthrough time of a polymer through a core with IPV = 10% and IPV = 20%, are shown in Fig. 4 and as seen will be significantly delayed, only for the cases of ultra-low polymer concentration and at water-wet conditions. However, the use of low polymer concentration is assumed to be in the combination with low salinity brine and at such conditions the polymer adsorption becomes low.
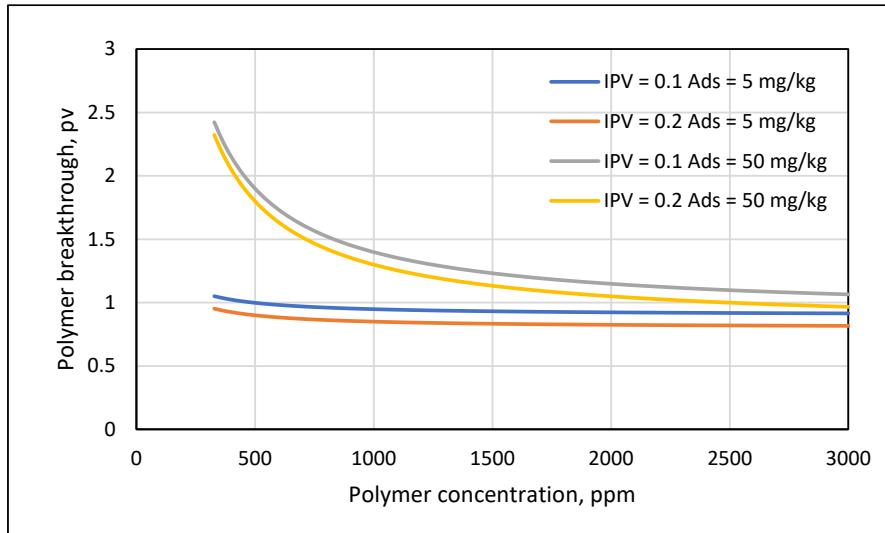
Fig. 4 Predicted polymer breakthrough time as a function of IPV and polymer retention.

Polymers, as other chemical products, may thermo-chemically degrade or precipitate during the relatively long reservoir residence time. Common for all the polymers is that presence of oxygen will speed up the degradation rate (Seright & Skjevrak 2015). Reservoir conditions are assumed to be anaerobic, however care should be taken to minimize the introduction of oxygen during mixing and injection (Gathier et al. 2020). The common understanding is that polymers will hydrolyze and at salinities above some critical values, the polymer will precipitate. The practical impact of this is that HPAM polymers can be applied at relatively low reservoir temperatures or soft brine. At harsher reservoir conditions, more temperature stable synthetic polymers should be chosen.

The polymers can be delivered as powder (90% active), as an emulsion (~30% active) or as a concentrated liquid (~ a few percent). The active polymer concentration affects the transport costs, and to some extend the higher transport costs of polymer can at offshore installations be counter balanced by space saving, more effective and less time-consuming dilution. However, quality checks to verify that inversion of the emulsion-based polymer yield the same polymer viscosity as the reference powder-based polymer and that the flow properties of the two versions are the same.

Methodological Approach

In the following we assume that a positive effect on the fractional flow curve has been observed in the lab or estimated from simulations. To achieve a positive or optimal field response the focus of a lab program should be to determine polymer transport properties. There are five important parameters that needs to be measured in the lab to determine the fate and effect of polymers on a larger scale

1. Bulk viscosity of the polymer solution at different temperatures and salinities - viscosity gain vs. polymer concentration. (Note that much data on many polymers already exists, and existing data might be used.)
2. Screening of injectivity properties in a porous medium of suitable polymer candidates – investigate polymer molecular weight vs. permeability. (Note that much data on many polymers already exists, and existing data might be used.)
3. Viscosity in the porous media at a broad range of shear rates from typical (high) injection shear rates too deep in the reservoir (lower) shear rates.
4. Retention of polymers, including retention at different wettability and salinity
5. Long-term thermal stability tests of the polymers at reservoir-like conditions – viscosity decay vs. temperature

6. Confirm in reservoir cores with oil and relevant wettability

Bulk viscosity of the polymer solution
Measure the viscosity and match the viscosity to a Carreau-type viscosity curve.

Often a polymer screening involves filterability tests through filter disks performed at constant pressure. The filter ratio derived from declined filtration rates has been used for QC of different polymer samples. Care should be taken when interpreting the filter ratio data; the flow velocity through the filter is normally significantly higher than at field scale and numerous experiments have demonstrated that product passing the filter ratio tests fails in core flood experiments. Therefore, we rather recommend core flood experiments, and ideally through serially mounted cores.

Screening and viscosity in the porous media
In core flood experiments the main parameters are the flow rate, differential pressure and analyzes of effluent samples. For polymers, where the viscosity depends strongly on shear rate it is critical to perform experiments at different velocities. The mobility reduction, Resistance Factor, RF is defined as the ratio between brine and polymer mobility. Darcy law gives, $\nabla P = \frac{1}{\lambda}q$, where ∇P is the pressure gradient, λ is the mobility and q is the flow rate. Then, $RF = \nabla P_p / \nabla P_w = \lambda_w / \lambda_p$. At constant velocity along the core length, as in a linear core this gives, $RF = \Delta P_p / \Delta P_w$. Therefore, by performing multi-rate-step polymer injection through a linear core, RF is easily derived as the ratio between the measured differential polymer pressure and the calculated brine differential pressure, at the same injection rate. Using pumps delivering accurate flow rate in the range from 10 μl/min to 100 ml/min, it is possible to derive RF by varying the velocity or shear rate 3 orders of magnitude. We recommend the use of in-line capillary tube viscometers at inlet and outlet of the core plug, as this will give additional information about in-situ rheology. The alternative to linear core plugs is to perform single rate flood experiments in a multi-pressure-port radial core. However, to achieve the same velocities in the radial geometry, the external-to-well radius need to be 1000, (i.e., if r_e = 20 cm, r_w = 0.2 mm) with severe risk of degradation of polymer in the injector. Additionally, RF must be derived from the pressure gradients and at best give RF(v) results like the linear case. However, the linear and radial differential pressure curves will deviate.

The multi-rate flood experiments will give valuable information about $RF(q)$, which can be translated to $RF(\dot{\gamma})$, and reveal the onset of shear thickening and onset of shear degradation. Further, with the use of accurate pressure readings RF at very low shear rates can be derived.

This type of experiments should be performed at different permeabilities, including both the upper and lower permeability. In all the experiments brine should be injected until stable differential pressure to determine the permeability reduction, RRF (Residual Resistance Factor). By experience, large volumes (> 100 pv) are needed to establish stable conditions. It is recommended to use serial mounted cores, where the front core act as filter.

Retention of polymers
Polymer retention and quantification of IPV should be performed by flood experiments. The basic method is to derive the mass balance between injected and produced polymer. A recommended method is to start with brine until stable conditions, followed by a slug of polymer and displaced by a large volume of brine. Then inject a new slug of polymer followed by brine. The polymer concentration can be determined by viscosity in effluent samples or by in-line capillary viscometer. The retention can be derived from the difference in polymer break through time between first and second polymer slug. The IPV is derived as the difference

between breakthrough time of brine (the addition of a water tracer can be applied, alternatively brine breakthrough is at pv = 1.0) and second polymer slug.

Retention experiments should be performed by reservoir cores at realistic wetting. The cores should be flooded to residual oil saturation since additional oil production during the polymer injection will complicate the interpretation. Further, the accuracy increases by increasing the pore volume and by lowering the polymer concentration. Care should also be taken when making the calibration curve for the concertation determination (e.g., polymer concentration is not a linear function of differential pressure across the capillary tube viscometer). In general, polymer retention depends on wettability, while IPV does not.

Often, the injectivity and retention experiments are performed separately. However, they can easily be combined (if the oil saturation is constant), e.g., single polymer slug, followed by polymer rate-step experiments, post brine injection and finally a second polymer slug.

Long-term thermal stability tests

Most EOR polymers are not thermally stable, thus the polymer properties can be altered, from the injector towards the producer. It is common practice to predict the viscosity decline by an exponential decay and the decay curves are obtained by (i) preparing and storing test samples, at anaerobic conditions and fixed temperature (mimicking the reservoir conditions), (ii) on regular basis measure the viscosity and (iii) match the measured viscosity with an exponential decay constant, λ. This type of experiments may have a duration of several years and a practical approach to lower the test period is to predict $\lambda(T)$ by performing the experiments at higher test temperatures than the actual reservoir temperature. The decay constant depends on salinity, thus the combination of regular HPAM polymer in high salinity brine and at high reservoir temperature is not recommended and addresses the search for more temperature stable polymers.

Validation

In this report validation means that experimental results are consistent with known physical, and chemical principles. This means that the experimental results should give same results if repeated in the same or any other lab. To validate lab results we believe it is crucial to be able to reproduce experimental results using physical models, or the other way around, to predict experimental results using models and then test in the lab. The simulation (or analytical) models should be capable of predicting existing experimental results and new results without changing the model, only the relevant physical or chemical parameters should be changed. As an example, most core flood measurements are done on outcrop cores without the presence of oil, because we believe that it is the permeability and porosity of the porous medium that is important and not where it came from. With a physically based simulation model we can determine parameters in the model based on outcrop core data and predict behavior on reservoir cores, which then can be tested.

Much work in the IORCentre has therefore been done to develop such a simulation model, IORCoreSim. We suggest to:

1. Perform the experimental program in the Methodology section with outcrop cores, in particularly if the polymer system has not already been included in IORCoreSim
2. Use IORCoreSim to predict the behavior of the polymer system for a reservoir core with oil present (relative permeability and retention is needed as input)
3. Test predictions from 2. in reservoir core with oil present

Conclusions and recommendations

Polymer flooding will improve the sweep efficiency. Therefore, a first step screening should be to evaluate whether increasing the viscosity of the injected water will, in the actual reservoir, contribute to sufficient improved oil production and CO_2 footprint. The two main options are the use of biopolymers or synthetic polymers. The biopolymers are insensitive to salt, and mechanical degradation is not likely. However, biological degradation has been reported to be a risk if not combined with effective biocides. The synthetic polymers can be produced in several combinations, all are salt sensitive in terms of viscosity gain. Therefore, the amount of polymer needed depends on the effective salinity of the make-up water. The chemical stability of the synthetic polymers depends strongly salinity. At harsh reservoir conditions more stable polymer types than the base-case HPAM should be chosen. The same argument is valid at conditions where mechanical degradation is critical.

If severe mobility alteration is an option, this is possible by increasing the polymer concentration and/or the Mw. However, the alternative is the use of thermo-activated polymers. These polymers contain the same polymer backbone as regular polymers with groups that become hydrophobic at elevated temperature attached to the backbone. These polymers will at elevated temperature demonstrate increased viscosity. More important is that in porous media at low shear rates, the mobility reduction may be substantially improved. Experiments have shown that the mobility reduction can be increased by several orders of magnitude, even at very low bulk viscosity.

Knowledge gaps

One of the strengths in the NIORC has been the close link between the modeling and experimental activities. So far much of the modeling development has been driven by experimental observations. Now, the models should be used to predict experimental behavior that can be tested in the lab. The models should also be used to suggests new experimental protocols that could potentially give more insight than the present protocols. There has been some experimental work on thermo-thickening associative polymers (TAPs), but more data are needed to gain insight into the associative behavior inside a porous medium. It is important to understand what triggers the resistance to flow, its time scale, and its dependency on the properties of the porous medium.

The points listed above can all be achieved with current laboratory set up and models developed in the NIORC, however one should always keep in mind that these systems are developed to produce more oil (and/or less water) on the field scale. Thus, the most important data needed to develop these systems further are data from pilots and field implementations.

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