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Polymer Flooding

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Abstract

The focus of this chapter is on polymers and their use to enhance oil recovery through the process known as polymer flooding. Emphasis is given to practical information relevant to field application(s) of polymer flooding. Therefore, the purpose of this chapter is to provide a brief but thorough overview of key concepts necessary to understand this technology for its successful implementation in the field.

Keywords: polymer flooding, polymers, polyacrylamide, chemical enhanced oil recovery, viscosity, sweep efficiency, pilot

1. Introduction

Among all the chemical-enhanced oil recovery methods (cEOR), polymer flooding is a straightforward technique with a lengthy commercial history and proven results. This technology by far outnumbers other chemical technologies because the risk of polymer flooding application is indeed very low and the envelope of application has greatly widened over the past years, with field cases in high temperature and high salinity reservoirs. Polymer flooding consists of injecting polymer-augmented water into a subterranean oil formation in order to improve the sweep efficiency in the reservoir. The increased viscosity of the water causes a better mobility control between the injected water and the hydrocarbons within the reservoir.

The early pioneering work on polymers was carried out by Pye [1], Sandiford [2], Mungan [3], and Gogarty [4] with later studies performed by Mungan et al. [5], Smith [6], Szabo [7], and others. The first “large” commercial uses of polymers to increase oil recovery date back to the 1960s and 1970s in the United States during a crude oil price control period. Economic incentive programs have played an important role in the development of chemical EOR processes in the

United States. ERDA (Energy Research and Development Association), DOE (Department of Energy), and the Cost-sharing Program provided direct financial support to oil companies for the implementation of EOR processes from 1974 through 1980. The DOE-EOR Incentive Program launched from 1979 to 1981 allowed frontend recoupment of expenses by allowing companies to sell oil at higher prices. The Crude Oil Windfall Profit Tax Act of 1980 reduced tax rates for EOR projects. The Economic Recovery Tax Act of 1981 provided research and experimentation tax credits. However, that program had a loophole which allowed EOR project incentives to be ring-fenced with full field production, which was exploited by oil companies. The result was higher “Tier 3” oil prices for projects that barely used EOR techniques, bringing economic successes but technical failures. For polymer flooding, few studies were carried out at the time and a number of projects used minute amounts of polymer, being totally inefficient at improving the sweep efficiency in reservoirs. In the end, the misconception that the technology did not work remained in the minds of petroleum engineers.

The number of projects abruptly decreased in the 1980s for several reasons including oil prices and poor global understanding of the technology. However, research has continued over the years and polymer flooding regained interest in China in the mid-1990s.

The largest polymer injection aimed at improving the mobility ratio was implemented in 1996 in the Daqing oilfield. As of 2004, more than 31 commercial projects were implemented, involving approximately 2427 injection wells and 2916 production wells. Polymer injection in the Shengli and Daqing oilfields yielded incremental oil recoveries ranging from 6 to 12%, contributing to 250,000 barrels per day in 2004. At the end of 2006, water consumption had decreased by 21.8 m³ per cubic meter of oil produced, with a water-cut reduction of one-fourth resulting in important savings in regards to produced water treatment and disposal.

Another example of successful polymer injection in the 1990s was in Courtenay, France, where extra oil recoveries from 5 to 30% have been reported after the technology was conducted in a secondary recovery mode as augmented waterflooding. Other examples will be discussed later in this chapter.

The objective of the following work is to give a summarized overview of the key concepts necessary to understand this technology, which would allow its successful implementation in the field. Other chemical-enhanced oil recovery techniques that involve the use of polymers such as surfactant-polymer flooding and alkali-surfactant-polymer flooding are not discussed in detail here. There has been a wealth of papers and books published in recent years that the reader can refer to for further clarifications or details on polymer flooding and other cEOR techniques, part of which are cited in the following sections of this chapter.

2. Introduction to polymer flooding

2.1. History and concepts

Muskat [8] first recognized in 1949 that fluids mobility would affect waterflood performance. In 1950, Stiles [9] used permeability and capacity distribution in waterflood calculations; while

Dykstra and Parsons showed the effect of mobility ratio and permeability variations on oil recovery. The mobility ratio concept was then discussed by Aronofsky and Ramey as well as its influence on flood patterns, injection, and production histories in a five-spot waterflood in 1956. Dyes et al. [10] presented studies of the influence of mobility ratio on oil production after breakthrough. Following these studies, it was suggested to increase water viscosity to improve reservoir sweep efficiency. It was established a couple of years later by Pye and Sandiford [1, 2] that the mobility of the injected brine could be effectively reduced by the addition of small quantities of water-soluble polymers. More recently, studies have focused in essence on polymers and their behavior in reservoirs. This will be discussed in more detail shortly.

If waterflooding of an oil reservoir proves to be inefficient, due to premature water production and low oil recovery factor at water breakthrough, polymer flooding may be considered as a possible option. The value of adding polymer to a conventional waterflood can be explained by the mobility ratio which is defined by the following relationship:

$$M = \frac{\lambda_o}{\lambda_w} = \frac{\mu_o / k_o}{\mu_w / k_w}$$

where λ , μ , and k are the mobility, viscosity, and effective endpoint permeabilities, respectively, and where the subscripts w and o refer to water and oil. Effective permeabilities are considered since it allows considering the selective reduction of (usually) water permeability by polymer retention and pore-blocking mechanisms.

Oil is left behind in a waterflood either because it is trapped by the capillary forces (residual oil) or because it is bypassed [11]. The mobility ratio improvement associated with the use of polymers minimizes the bypassing effect.

Polymer flooding is often implemented in two cases [12]:

- When the mobility ratio during a waterflood is not favorable, continuous polymer injection can improve the sweep efficiency in the reservoir.
- Even with a favorable mobility ratio, if the reservoir has some degree of heterogeneity, polymer injection can help to reduce the water mobility in the high-permeability layers supporting the displacement of oil from the low-permeability layers [13].



Figure 1. Water breakthrough can be delayed and sweep efficiency improved by increasing the viscosity of the injected fluid with polyacrylamide polymers (PAM) (modified with permission from Sorbie [11]).

In the first case, there is an inefficient macroscopic displacement that promotes early water breakthrough followed by a long period of two-phase production with increasing water-cuts. This situation can simply be illustrated by the viscous fingering concept which occurs especially in heavy oil reservoirs or when the mobility ratio M is larger than 1 ($M > 1$) (**Figure 1**). Fractional flow calculations extensively described in the literature can be useful to visualize the benefits of polymer injection and compare simple cases.

The second case is often overlooked. It appears that, even if the mobility ratio is equal or below 1, the presence of high-permeability channels or large-scale reservoir layering and heterogeneities can greatly impair the areal and vertical sweep efficiencies during water injection. The presence of high-permeability layers will also lead to early water breakthrough, in these cases significant improvement can be gained using polymers to increase the viscosity of the injected water. This aspect should be remembered when screening the candidates for polymer injection to not overlook reservoirs that contain very light oils. The mechanisms of oil recovery using polymers in heterogeneous systems are quite complex and a detailed explanation of those mechanisms is beyond the scope of this chapter. A proper overview is given in Sorbie's *Polymer Improved Oil Recovery* [11].

An important parameter in polymer flooding is how the improvement in oil recovery can be assessed compared to waterflooding. For this, two approaches can be used. The first one considers that polymer flooding produces only the moveable oil and does not change the residual oil saturation. In this case, the final amount of oil recovered should be the same between a waterflood and a polymer flood: the only difference would be the timescale to produce the same amount of oil for each case with polymer essentially accelerating oil production (**Figure 2**). However, this approach is highly dependent on reservoir characteristics since the presence of important heterogeneities would greatly hinder water from sweeping the entire reservoir, leaving some mobile oil behind.

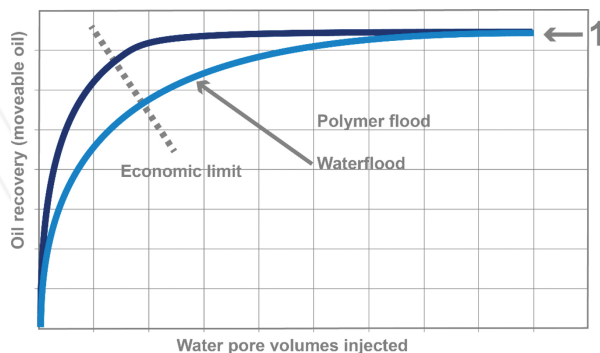


Figure 2. Production profiles for waterflood and polymer flood showing the economic limit [11].

Some recent studies [14, 15] have discussed the possible impact of polymers on residual oil saturation bringing forward the notion of viscoelasticity. In this case, in addition to pushing

mobile oil, polymers would be able to decrease the residual oil saturation therefore recovering more oil than a simple waterflood, whatever the timescale considered.

The definition of incremental oil is therefore linked to the mechanisms behind polymer injection and the timescale considered for the project. For the latter, it would be necessary to compare water injection and polymer injection scenarios over the practical reservoir development period and the corresponding economic limits. This can be done with simulation studies which are not discussed in detail here.

2.2. Polymer flooding plan

There is no general rule defining the quantity of polymer that should be injected into a reservoir. The number generally given, based on experience, is a minimum of 30% of the reservoir pore volume, with the following sequence:

- Viscosity ramp-up at the beginning of the project to observe the reservoir response and possible pressure increases.
- Viscosity plateau with a minimum of 30% reservoir pore volume (the worldwide average is approximately 50% of pore volume injected). The larger the slug, the better the efficiency during polymer injection and after. The maximum efficiency will be reached after 1 PV injected.
- Viscosity ramp-down over the last 5% of pore volume injected, which serves to decrease the viscosity contrast between the polymer slug and the water chase.

As previously indicated, the larger the volume of polymer injected expressed as reservoir pore volume, the higher the efficiency of the process. This is explained by looking at what is happening when the injection of polymer is switched back to water injection at the end of the process: if the polymer slug volume is too small, there is a high probability that the chase water will again finger through the polymer slug, thereby decreasing the efficiency of the whole process.

Another technique described in the literature in regards to the application of polymer flooding in the Daqing oilfield is the sequential injection of high-viscosity polymer slugs to improve reservoir conformance and redistribute the flow inside the reservoir by decreasing the flow in the high-permeability zones [16].

The vast majority of polymer floods inject concentrations of active polymer between 1000 and 2000 parts per million (ppm), whatever the reservoir characteristics and oil viscosity. These “magic” numbers do not always have a scientific basis: normally, if the oil viscosity is very high or the reservoir heterogeneities are important, a higher viscosity should be considered at least for the pilot stage to check the acceptable reservoir pressure limits; while the final viscosity of the polymer solution to be injected is often dictated by the economics and the oil price at the time of the project approval.

Finally, the incremental oil recovery from polymer injections averages an extra 10% of oil originally in place (OOIP). The Courtenay oil field in France yielded from 5 up to 30%, the

Daqing oil field showed approximately 12%, and the Marmul field roughly 10% of incremental oil recovery.

2.3. Timing

The paradox with enhanced oil recovery methods is that they are often classified as tertiary recovery methods, even if it is well-known that primary recovery followed by water injection is, for a significant number of reservoirs, not able to produce more than 35% OOIP on average. The question that pops up is therefore: why do we wait to change the field development approach and implement the so-called enhanced oil recovery techniques from the very beginning? There are probably multiple answers to this question:

- Lack of knowledge on the green field: geometry, fluid distributions, pressure responses to a viscous fluid injection, optimal well placement, and connectivity between zones, etc.
- How to quantify the efficiency of an EOR method and incremental oil without baseline data for comparison?

The appropriate timing for a polymer injection can be summarized in a simple statement: the earlier the better! The economics of secondary EOR application will always be better than the economics of tertiary (and late) EOR, knowing that polymer flooding brings forward the oil production profile, delays water breakthrough and the overall handled water volumes and associated costs of water treatment and disposal. Nevertheless, there is still a significant benefit of implementing the technology even in watered-out reservoirs and especially for heavy oil pools [17].

2.4. Screening criteria for polymer application

Historically, it appears that sandstones were preferred over carbonates when considering polymer injection. For instance, when looking at the projects in the USA between 1971 and 1990, 320 pilot projects or field wide chemical floods have been identified in the literature among which 57 were conducted in carbonate reservoirs. This preference can probably be explained by the fact that anionic polymers present several advantages: they have a high viscosifying power, very high molecular weights, and are cheap to produce by opposition to synthetic cationic polymers which are expensive to produce, highly shear sensitive, and display lower molecular weights on average. For sandstone and clayey reservoirs, which are negatively charged, the injection of anionic macromolecules is obviously preferred to limit ionic interactions.

Papers published in the 1960s, 1970s, or even 1980s indicate that polymers for EOR were limited to a narrow range of oil field conditions (**Tables 1 and 2**). A literature review on polymer field applications shows that the maximum reservoir temperature was 200°F (90°C), crude oil viscosity had to be below 200 cP, and injection water must not exceed a certain amount of divalent ions (300–500 ppm).

Reservoir temperature (°F)	<200
Polyacrylamide	<160
Xanthan gums	<200
Crude oil viscosity (cP)	<200
Water-oil mobility ratio	>1
Mobile oil saturation (%PV)	>10
Water-to-oil ratio (WOR)	<15 preferred
Average reservoir permeability (mD)	>20
Lithology	Sandstone preferred
Reservoirs with strong natural water drive, large gas caps, gross channeling, or major natural fractures should be avoided	

Table 1. Screening criteria for polymer flooding according to Chang [18].

In 1991, Sorbie described some limits which were within the same range, i.e., $T_{\max} = 95^{\circ}\text{C}$, oil viscosity < 70 cP, and reservoir permeability above 20 mD (**Table 2**).

Seright [17] proposed several explanations for these screening criteria considering the state of the technology and oil prices at that time:

- Considering an oil price of \$20, 150 cP was viewed as the most viscous oil that could be recovered economically using polymers.
- For oil viscosities above 150 cP, the viscosity requirements to achieve a favorable mobility ratio were expected to decrease injectivity.

Many improvements have widened the range of polymer applicability for polymers in cEOR. In addition to a better understanding of polymer flow behavior through the rock formation and a better knowledge of the geology and dynamics of the reservoirs, many developments in chemistry have allowed manufacturing polymers that are more stable to high temperatures, tolerant to high salinity and hardness concentration, and shear resistant polymers. The addition of protective additives to prolong the chemical stability of the polymers has been also performed. Furthermore, new equipment has been designed to maximize the injection efficiency of polymer solutions while decreasing the overall risk of degradation before entering the reservoir. For instance, Vermolen et al. [19] described the stability of *N*-vinyl pyrrolidone (NVP)-based ter-polymers for 1 year at 120°C in 180 g/L TDS brine. Gaillard et al. [20] tested the efficiency of protective additives on temperature and salinity resistant polymers. Seright et al. described the implementation of polymers in a field with 500 cP oil. Kulawardana et al. [21] demonstrated the efficient propagation of NVP ter-polymers in 50 mD cores at 100°C. This is just a very small view into the work that has been conducted in the past years to validate the polymer technology for EOR applications. Many references are given for further reading at the end of the chapter.

Some unchanging parameters that must be considered before the implementation of polymer flooding are:

- Water injectivity: obviously, good water injectivity will ensure appropriate polymer injectivity. Several guidelines will be provided later on.
- Clays: a high percentage of clays can be detrimental to polymer propagation (adsorption and retention).
- Presence of aquifers: to avoid dilution and chemical losses, injection should occur outside of the aquifer zone.

Screening criterion	Viscosity control polymer flood	Heterogeneity control polymer flood	Comment
Oil viscosity	Usually $5 \text{ cP} < \mu_o < 30 \text{ cP}$ Max 70 cP	Usually $0.4 \text{ cP} < \mu_o < 10 \text{ cP}$ Max 20 cP	The indicator in both cases is early water breakthrough and low sweep efficiency
Level of large-scale heterogeneity	Low formation should be as homogeneous as possible	Some heterogeneity by definition $4 < \text{horizontal perm.} / \text{average permeability} / k_{av} < 30$	For heterogeneity control less severe contrast does not require polymer and more severe is too high for normal polymer
Absolute permeability	>20 mD		To avoid excessive polymer retention
Temperature	Lower temperature Best <80°C Max <95°C	best	Polymers degrade at higher temperatures
Water injectivity	Should be good preferably with some spare injection capacity—fracturing may help		If there are some problems with water, they will be worse with polymer
Aquifer/oil/water contact	Injection not deep in aquifer or far below oil/water contact		Additional retention losses in transport to oil leg
Clays	Should be generally low		Tend to give high polymer retention
Injection brine salinity/hardness	Not critical but determine which polymer can be used		High salinity/hardness biopolymer Low salinity/hardness = PAM

Table 2. Screening criteria for polymer flooding according to Sorbie [11].

Table 3 presents updated screening criteria for polymer flooding, in which only the upper values of the respective ranges are provided for the most important criteria.

Parameter	Year 1970s and 1980s	After 2000
Oil viscosity	<200 cP	<10,000 cP
Temperature	<95°C	<140°C
Permeability	>20 mD	>10 mD
Salinity	Low (<30 g/L TDS)	<200 g/L TDS

Table 3. Current screening criteria for polymer flooding application (updated after [11] and [18]).

2.5. Other technologies

- Surfactant-polymer (SP) and alkali-surfactant-polymer (ASP)

Capillary forces cause large quantities of oil to be bypassed in well-swept zones of water-flooded oil reservoirs [13, 22]. Surfactant injection (surface active agents) can reduce the interfacial tension between the oil and water and release trapped oil; while the injection of a large polymer slug provides mobility control. However, it is often necessary to inject significantly higher dosages of costly surfactants to balance their adsorption onto the rock surface. This effect can be offset by addition of alkali to the solution. The latter will adsorb onto rocks (decreasing surfactant adsorption), increase the pH, and generate *in situ* soaps. This process often requires expensive water treatment facilities, and combined with the surfactant, can generate difficulties to break the produced emulsion. Surfactant-polymer and alkali-surfactant-polymer require a careful design and should be monitored cautiously [13].

- Gels and derivatives

As discussed by Seright et al. [23], the preliminary discussion is to point out the main differences between a gel used for reservoir conformance control and a polymer flood. Conventional gels used in “conformance control” are intended to block or reduce the flow capacity of high-permeability channels without damaging the less-permeable hydrocarbon-productive zones. It is therefore compulsory to minimize penetration of gelants into the less-permeable zones. Any gel or blocking agent that enters the less-permeable zones can hinder or even shut off any subsequent injected fluids from entering and displacing oil from those

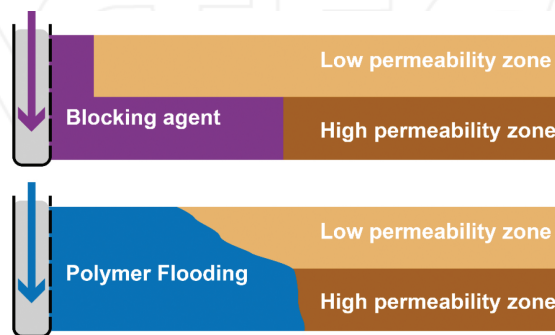


Figure 3. Comparison between polymer flood and gel systems (modified with permission from Seright [23]).

zones. In contrast, polymer floods are designed to directly displace oil from lower permeability zones. As a matter of fact, a viscous polymer solution should enter as much as possible into these lower permeability zones to displace oil from these poorly swept areas (**Figure 3**, [23]).

Particularly, colloidal dispersion gels—low polymer concentration with a metallic cationic cross-linker—are often claimed to be more efficient and cost-effective than conventional polymer floods. Several questions arise in regards to this claim and are as follows:

- Does the cross-linker propagate inside the reservoir without any retention on the negatively charged clays and sandstone? Obviously, the answer would be probably no in this case.
- Are these gels plugging mainly the high-permeability layers allowing the chase fluid to go into the low-permeability zones? This statement defies basic reservoir engineering laws including Darcy's law.

Some positive results have been reported from field applications of this technology. However, the extra-oil recovery observed might be caused by:

- A decreased mobility ratio obtained by the added polymer within the colloidal dispersion gel formulation, even at low polymer concentrations. It should be noticed that increasing the water viscosity from 1 to 2 cP divides the mobility ratio expression by 2.
- A decreased relative permeability to water that could be induced by both: overall polymer retention (mechanical retention and adsorption) and the formation of gel in all zones of the reservoir, with a temporary effect on the oil recovery.

In any case, laboratory studies involving coreflooding using long reservoir core plugs should be performed to ensure that the entire system propagates through the core plug prior to implementation in the field.

3. Polymer characteristics

Polymers are chemical compounds composed of repeating units called monomers. Biopolymers and synthetic polymers are the two families of polymers usually considered by the oil industry when attempting to increase water viscosity and to improve the sweep efficiency of the reservoir. These types of polymers will be briefly described in the following paragraphs. However, a particular focus will be directed to synthetic polymers, which are the most commonly used polymers by the oil industry, primarily due to their availability and favorable costs.

3.1. Biopolymers

Xanthan gum and more recently schizophyllan are the main biopolymers considered for applications in the oil industry.

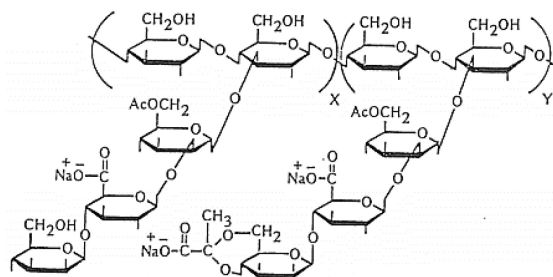


Figure 4. Molecular structure of Xanthan gum [24].

Xanthan gum is a fermentation product produced by a mutant of *Xanthomonas campestris*. Xanthan gum is a polysaccharide made from saccharide monomer units which are D-glucose, D-mannose, and D-glucuronic acid. This biopolymer has a cellulose-like backbone composed of repeating β -D-(1-4) glucose units with mannose and glucuronic acid side chains, and the mannose partially modified with acetyl and pyruvate ketal groups (**Figure 4**). The rigid structure of xanthan gum provides good shear and brine tolerance when compared to polyacrylamides. However, some drawbacks still remain such as cost and availability and the fact that the biopolymer should be protected from any biological attack with biocides.

Xanthan gum is available in different forms:

- Broth: from 5 to 13% active content in an aqueous medium that contains a biocide.
- Powder: dry form with an active content >90%.

Schizophyllan is a homo-glucan with an average molecular weight of 2–3 million Dalton produced by a fungus in a fermentation process from a carbon source (**Figure 5**) [13]. The polymer has a linear structure without charged functional groups which yields high viscosity as well as salt tolerance. The rigidity of the structure is also responsible for the mechanical and temperature stabilities.

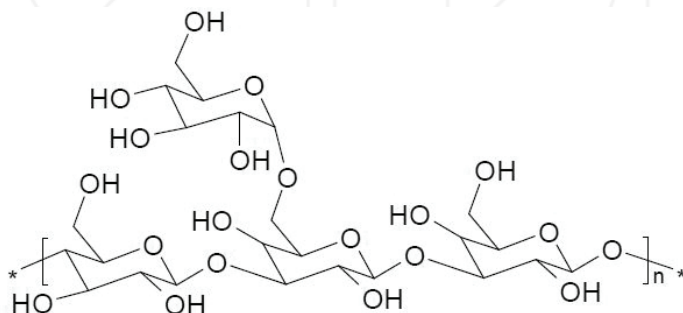


Figure 5. Chemical structure of β -1, 3: β -1,6 glucan [13].

A critical step for the development of this biopolymer was the biotechnological process required to separate the fungus from the biopolymer and make it viable at large scales.

3.2. Partially hydrolyzed polyacrylamide

The most common synthetic polymers used in polymer flooding are partially hydrolyzed polyacrylamides (HPAMs) and synthetic flexible straight chains of acrylamide monomers.

HPAMs are prepared with a typical degree of hydrolysis of 30%, but it can be adjusted to be higher or lower. These polymers are usually delivered in two forms:

- Powder: >90% active content.
- Emulsion: as a water-in-oil emulsion with 30% active content, which must be properly inverted to release the polymer (**Figure 6**).

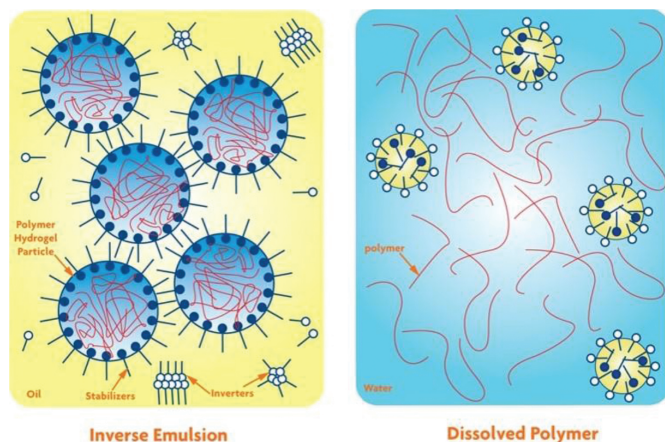


Figure 6. Inverse emulsion system [25].

3.2.1. Polymerization processes

These polymers can be manufactured using different chemical paths as follows:

- Copolymerization of acrylamide and sodium acrylate (or/and sodium acrylamido-tertiary-butyl sulfonate (ATBS)) (**Figure 7**).
- Cohydrolysis or posthydrolysis of a polyacrylamide (**Figure 8**).
- Copolymerization or terpolymerization of acrylamide with other ionic or nonionic functional monomers. Functional monomers can enhance the resistance to temperature and salinity (example of *N*-vinylpyrrolidone for improved thermal and salinity resistance) [26].

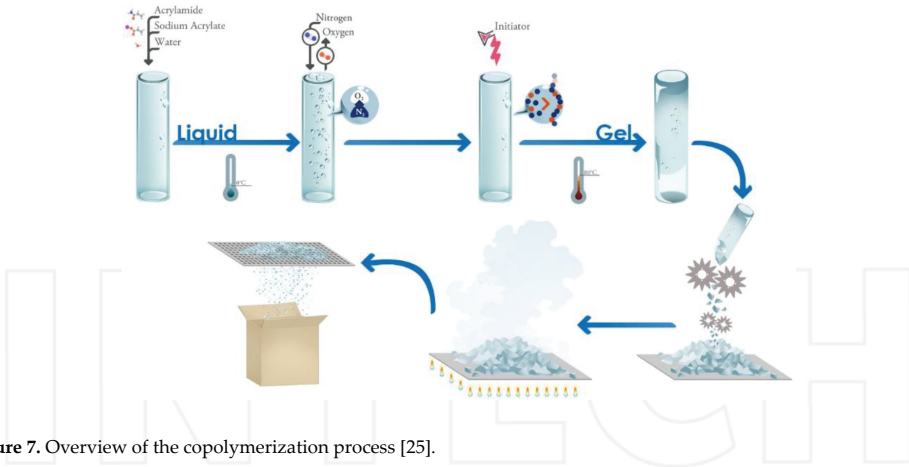


Figure 7. Overview of the copolymerization process [25].

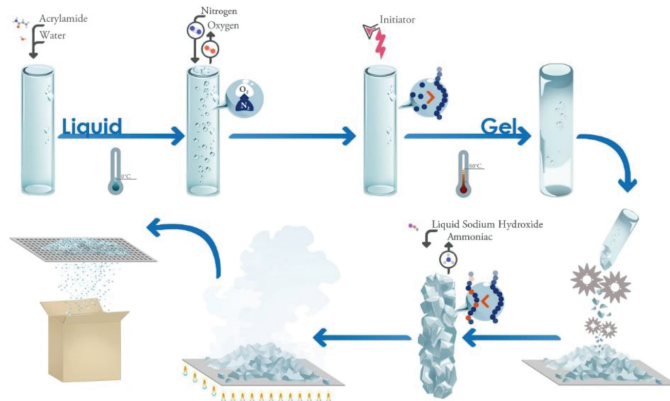


Figure 8. Overview of the posthydrolysis process [25].

Depending upon the manufacturing process, the distribution of the anionic charges along the polymer chain differs, which induces different physical properties during and after hydration. Posthydrolyzed polyacrylamides are composed of a wide range of anionic chains, some being highly charged and others less charged. The copolymerization of acrylamide and sodium acrylate produces a polymer with a more even charge distribution along the backbone. These properties are paramount for the behavior of the polymers in an aqueous solution, especially in the presence of divalent cations such as calcium and magnesium [13].

There are several ways to characterize anionic polyacrylamides including their molecular weight (M_w) and molecular weight distribution or polydispersity index (PDI). The range of M_w typically lies between 4 and 30 million g/mol and it is often determined using intrinsic viscosity measurement. As of today, PDI cannot be determined since neither standards with low PDIs

nor GPC (gel permeation chromatography) techniques exist today for such high M_w . However, as with the anionicity, a relatively wide range of molecular weights is present in one given product. Moreover, the structure of copolymers is more easily controlled than the post-hydrolyzed molecules. **Figures 9** and **10** show some common polymer structures [26].

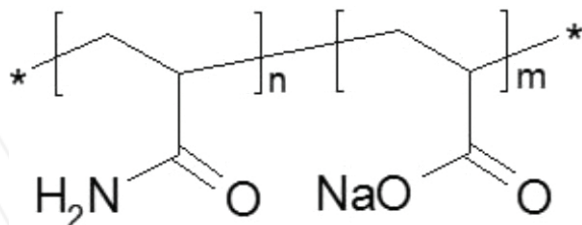


Figure 9. Example of acrylamide and sodium acrylate copolymer [26].

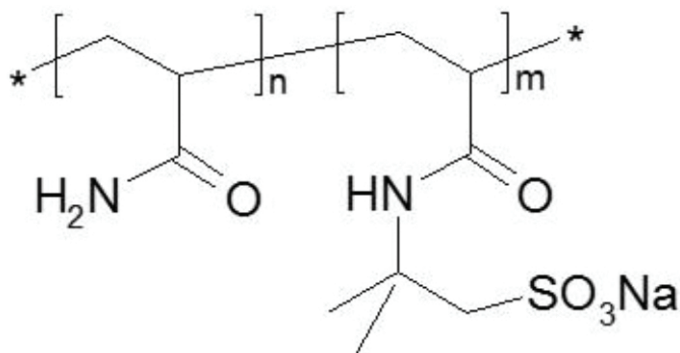


Figure 10. Example of acrylamide-ATBS copolymer [26].

3.2.2. Viscosity

The thickening or viscosifying capability of anionic polyacrylamides is linked to the level of entanglement of the high molecular weight macromolecules and also to the intra- and intermolecular electrostatic repulsions between polymer coils. When polyelectrolytes are dissolved in water containing electrolytes (salts), a reduction in viscosity is observed [27]. This is attributed to the shielding effect of the charges leading to a decreased electrostatic repulsion and therefore to a minimum expansion of the polymer coils in the aqueous solution. The result is a lower hydrodynamic volume and consequently a lower viscosity [28]. In addition to the salt dependency, other factors influencing the viscosity of partially hydrolyzed polyacrylamide solutions are the degree of hydrolysis, solution temperature, molecular weight (**Figure 11**), tridimensional structure, and solvent quality [29].

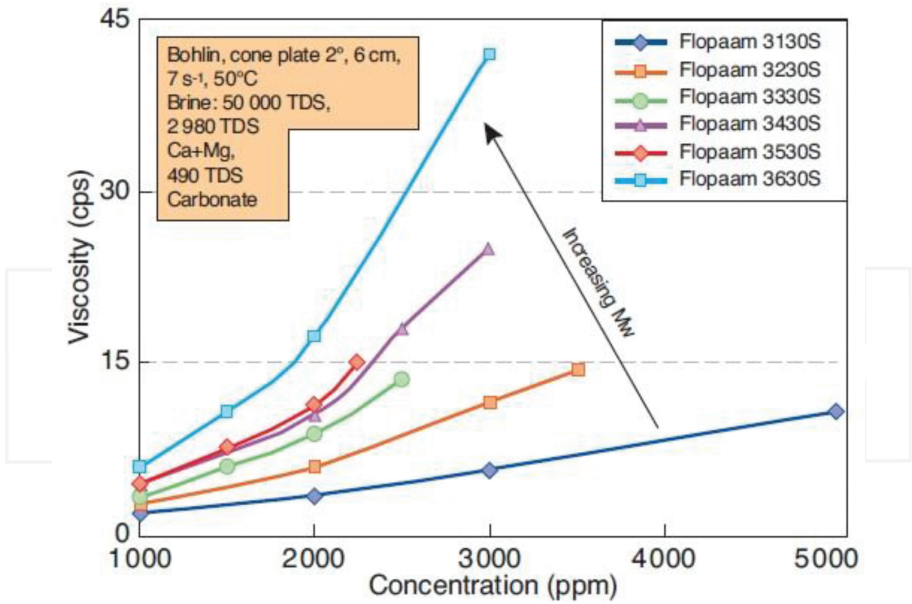


Figure 11. Viscosity of several polymers as a function of concentration. The average molecular weight increases from Flopaam 3130S to 3630S [25].

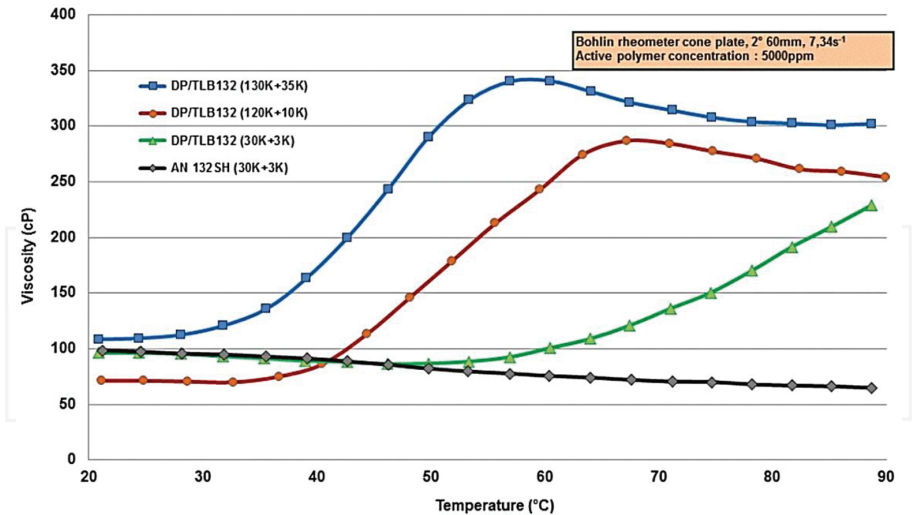


Figure 12. Viscosity versus temperature for several polymers including thermoresponsive (DP/TLB) and conventional polymers (AN132SH). Brines are displayed as 130K + 35K meaning 130 g/L NaCl + 35 g/L CaCl₂ (from Leblanc et al. [31]).

At isomolecular weight and at isoconcentration conditions, polyelectrolytes are likely to behave differently depending on their chemistry and on the composition of the aqueous media. For instance, if the polymer is compatible with the injection and/or formation brine, the polymer molecule will uncoil allowing interchain interactions. In the other case, if the polymer is not compatible with the injection and/or formation brine, the polymer molecule will coil up resulting in intramolecular associations.

Other strategies exist to enable intermolecular associations independently of the molecular weight of the polymer. One approach is the incorporation of hydrophobic moieties within a hydrophilic molecule in the polymer backbone—leading to segments that associate. A concise overview of this technology including the chemistry of these so-called associative polymers is given by Wever et al. [30]. More recently [31], thermosensitive polymers have been developed (**Figure 12**). The thermosensitive concept involves water-soluble main chains with blocks or side groups which possess lower critical solution temperature or LCST moieties [32]. These thermosensitive polymers display viscosity increase as a function of salinity and temperature. Other advantages of these thermosensitive polymers would include the highly improved injectivity of the viscous polymer solutions inside oil-bearing formations since the viscosity would build progressively with temperature and/or salinity.

3.2.3. Rheology

Polyacrylamide fluids behave as non-Newtonian fluids meaning that the viscosity is dependent on the applied shear (**Figure 13**). They show a pseudo-plastic (or shear thinning) behavior: viscosity decreases as shear stress increases following a power-law model (**Figure 14**). The viscosity is dependent upon the concentration and the molecular weight of the polymer in the aqueous solution. Moreover, the rheological behavior of synthetic polymers in porous media is quite different from their rheological behavior in bulk (in a viscometer measuring device). This topic is beyond the scope of this chapter and it will not be discussed here.

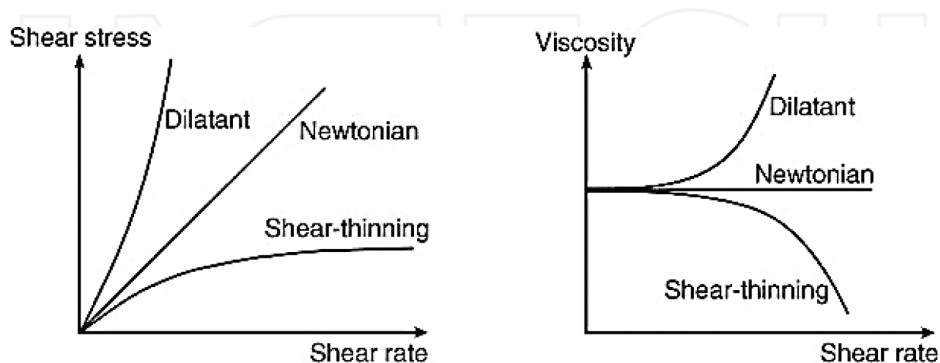


Figure 13. Types of fluids and their characteristics [25].

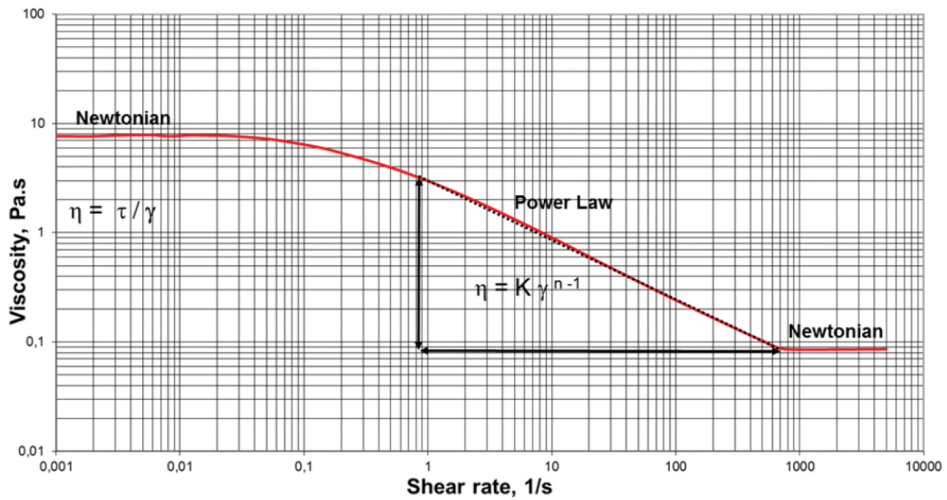


Figure 14. Viscosity profile for a typical non-Newtonian polyacrylamide fluid as a function of shear rate fitted using a power law equation [33].

3.2.4. Solubility

In the field, polyacrylamides are solubilized in injection brine which contains dissolved salts. Total dissolution of the polyacrylamide in the brine is achieved when no insoluble or swollen particles remain in the solution, as determined by the filtration test. If high molecular weight polymers with $M_w > 1$ million g/mol or even higher molecular weight ($M_w \approx 18$ million g/mol) polymers are used in the field, injectivity issues can be observed if total dissolution of the polymer in the brine is not achieved. Furthermore, polymers may contain low concentration of partially soluble species (i.e., branched or cross-linked chains) due to the manufacturing process. Therefore, it is necessary to ensure that minute undissolved polymer clusters known as fish-eyes are not formed during the polymer dissolution process, in order to limit potential damages to the formation during polymer injection.

3.2.5. Stability tests

Long-term stability tests are useful to ensure that polymer degradation will not occur within the reservoir during the transit time between the injection and production wells. Polymer solutions are prepared under anaerobic conditions inside a glove (**Figure 15**) and stored in specially designed stainless steel ampoules which are stored in oven at the specific reservoir temperature. Viscosity is checked on a regular basis inside the glove box using concentric cylinder Brookfield rheometers. Some stability studies can last several years for offshore projects where the spacing between the injector and producer is large and transit times are significant.

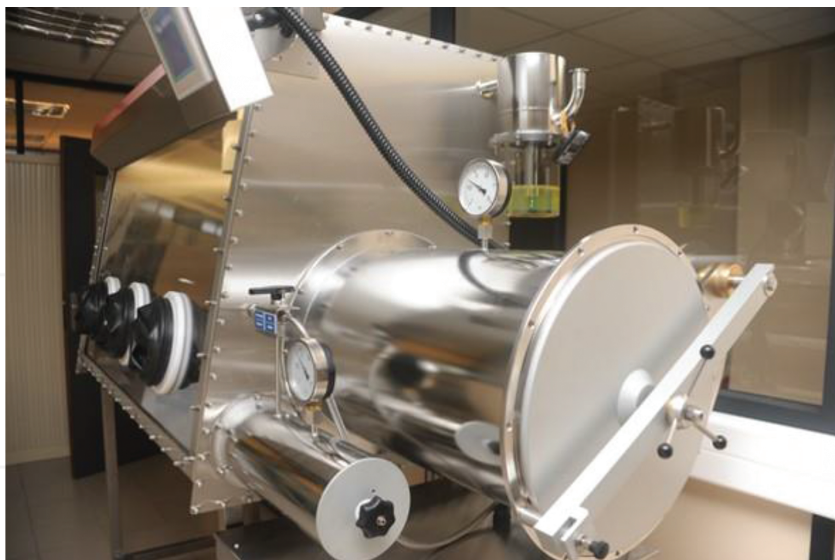


Figure 15. Typical glove box set-up to perform tests in anaerobic conditions [25].

3.2.6. Coreflooding

Polymer injection into porous medium (i.e., coreflooding tests) is a useful testing procedure to check the propagation of the macromolecules through core plugs from the reservoir to ensure that irreversible damage to the formation will not occur. However, it is necessary to be mindful that a core plug will never be representative of what will happen in a field application, in particular at the harsh conditions near the injection wellbore. Therefore, it is important to define the goal of coreflooding testing, such as the establishment of face plugging and the verification of proper polymer propagation along the core plug. Likewise, it is important to understand that coreflooding testing will not provide information on the following aspects:

- Polymer coreflooding testing does not provide information of the actual injectivity of the polymer in the field. Wellbore effects (even if radial corefloods are performed) on polymer flooding, such as completion, flow rates, the presence of microfractures, and damage formation, among others, cannot be evaluated during coreflooding testing. An example is the polymer shear-thickening behavior observed in the laboratory that will probably never occur in the field when considering the presence of microfractures created after completing the well (i.e., perforations, stress changes) or during the waterflooding stage.
- Polymer coreflooding testing does not provide information on true polymer overall retention values. Even if it seems obvious, it is important to remember that every reservoir has some degree of heterogeneity, therefore, polymer retention in the field will be likely greater than polymer retention observed in the laboratory [34].

More realistic objectives for polymer coreflooding testing are:

- To compare several polymers in terms of propagation and pressure drop stabilization.
- To compare the relative retentions of several polymers as well as residual resistance factors (permeability reduction).
- To establish the efficiency of oil recovery as a function of polymer type and viscosity injected.
- To gather data to use (wisely) in simulation models for upscaling (resistance factors and retention, among others).

Preliminary screening can be performed using analog core plugs before using the actual reservoir core plugs to obtain more realistic retention and mobility reduction values.

Two important parameters are usually evaluated, the mobility reduction (or resistance factor) and the permeability reduction (or residual resistance factor). The mobility reduction (*FR*) is the apparent relative viscosity of polymer solution during its flow through the porous medium, defined by:

$$FR = \frac{\Delta P_{\text{polymer solution}}}{\Delta P_{\text{brine}}} \propto \frac{\mu_{\text{polymer solution}}}{\mu_{\text{brine}}}$$

where $\Delta P_{\text{polymer solution/brine}}$ is the pressure drop during polymer injection and brine, respectively, and μ is the viscosity of the fluid considered.

The permeability reduction or residual resistance factor, *FRR*, is the reduction of permeability due to several mechanisms such as polymer adsorption onto the rock surface, mechanical retention of polymers in pore constrictions that are of smaller size than the polymer macromolecules, and any other condition that retains polymer in the porous media (i.e., polymer precipitation due to interactions with divalent cations present in the reservoir brines). The residual resistance factor (*FRR*) is defined as:

$$FRR = \frac{\Delta P_{\text{post polymer}}}{\Delta P_{\text{brine}}} \propto \frac{k_{\text{brine}}}{k_{\text{post polymer}}}$$

Polymer retention would be a more appropriate wording since it includes adsorption, mechanical, and hydrodynamic entrapment as explained for instance in Sorbie [11] (**Figure 16**). Retention can be determined using several methods, either in static or dynamic conditions, the latter being the most relevant. Common acceptable values for polymer retention by sandstones range from 10 to 50 μg of lost polymer per gram of rock. Polymer retention depends on the lithology of the rock (i.e., the presence of clay, clay content, and types of clays) and on the polymer characteristics (i.e., molecular weight, chemistry, degree of hydrolysis, etc.).

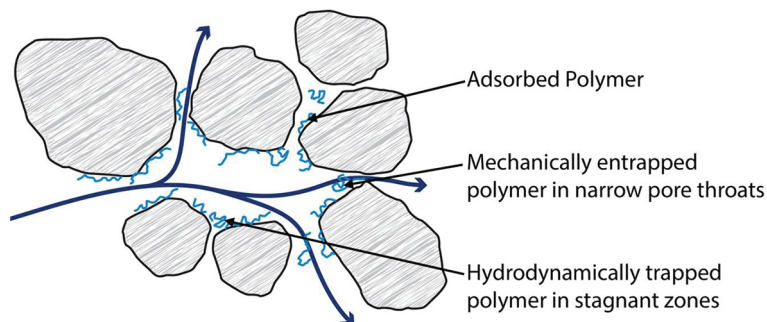


Figure 16. Mechanisms of polymer retention (modified with permission from Sorbie [11]).

Polymer retention in the porous media can be controlled by manipulating the polymer chemistry (i.e., the addition of ATBS is known to favor polymer propagation), the molecular weight (lower molecular weight means less hydrodynamic retention), and by adding sacrificial agents upfront to condition the reservoir before polymer injection, such as low molecular weight polyacrylates [35]. Determining a “true” residual resistance factor often requires the injection of many pore volumes of water. Injecting water behind a polymer slug creates an unstable displacement front and cleaning the core from any residual polymer in this case could take a long time. It is therefore recommended to take a value of FRR equal to 1 for simulation purposes to be conservative.

3.2.7. Polymer degradation

The stability and chemical reliability of polymers used for cEOR are significant factors for oil field applications. Polymers can undergo chemical, mechanical, and thermal degradation during EOR flooding operations.

Currently, there are limited data available from actual polymer oil field applications in regards to the degree of degradation endured by the polymer injected during the flooding operation. Internal reports and papers published on polymer floodings carried out at the Daqing and Shengli oil fields (China), indicate that the viscosity of the produced polymer solution was low [36, 37]. Additionally, polymer concentration in the produced solution was 50% lower than the concentration of the injected polymer, the anionicity of the polymer was increased, and the produced polymer average molecular weight was much lower compared to the molecular weight of the injected polymer. For field applications, it is also important to determine where polymer degradation occurs—at the surface facilities, down hole of the injection well, or inside the reservoir. In any case, it is paramount to minimize any potential degradation to maintain a reasonable viscosity of the polymer solution injected during the duration of the cEOR flooding to maximize the extra oil recovery.

A brief review on the chemical, mechanical, and thermal degradation of polymers within the context of cEOR is presented in the following paragraphs.

- Chemical degradation

Chemical degradation is related to the formation of free radicals that can react with the polymer backbone resulting in a drop of molecular weight [38, 39] and viscosity loss. Redox reactions are often involved in the formation of free radicals [40]. The presence of chemicals or contaminants such as oxygen contributes to the formation of such radicals. For example, iron II and/or H₂S in contact with oxygen cause polymer degradation. Stabilizer compounds are added to some commercial grade polymers to delay the unavoidable occurrence of chemical degradation. **Figure 17** shows the percentage of viscosity loss of the polymer solution as a function of iron and oxygen concentration. The viscosity loss can reach 50% with the addition of only 1 ppm of iron and 300 ppb of oxygen.

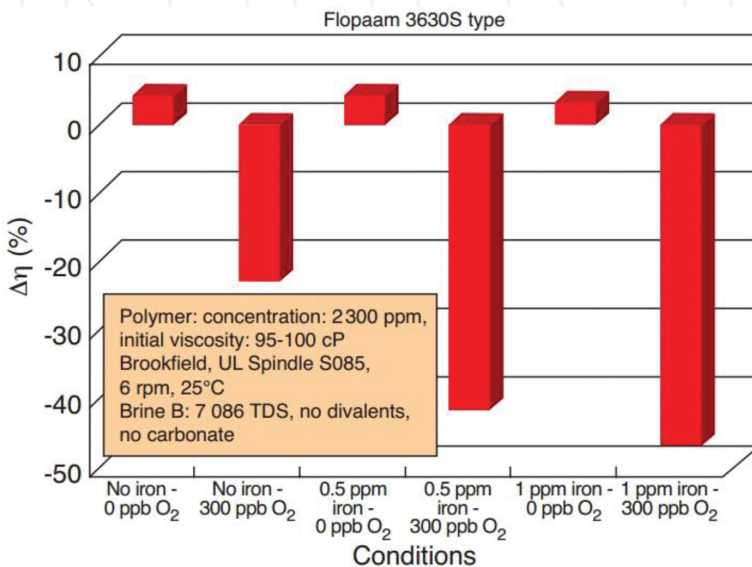


Figure 17. Polymer degradation in presence of oxygen and iron 2 in 7.086 g/L TDS brine [26].

Oxygen. A concentration of oxygen below 5 ppb allows for good stability of a polyacrylamide solution up to 120°C for more than 200 days [41, 42]. The addition of oxygen scavengers such as dithionite and sodium sulfite [41, 43] to the brine is beneficial to maintain the concentration of free oxygen at a low level in the brine. However, any reexposure to any trace of oxygen in the presence of residual oxygen scavenger will act to break the polymer chains. It is therefore compulsory to keep the oxygen content as well as the presence of oxygen scavenger in the brine under control.

Iron. To limit the effect of polymer degradation due to the presence of iron in the injection brine, several complexing agents can be added to the solution such as EDTA (ethylene diamine tetra-acetic acid). However, using a chelating agent to complex iron can lead to an increase of

the degradation of the polymer [44]. Another approach is to partially precipitate the iron contained in the injection brine by increasing the pH of the solution with sodium carbonate [42].

- Mechanical degradation

Mechanical degradation occurs when the polymer backbone is subjected to a large shear rate, high velocity (i.e., flow rate), and singular pressure drop. The critical points which must be assessed along the injection facilities are chokes, valves, and certain types of pumps, as well as the well completion [26, 45].

In every case, choosing the right polymer is paramount: the higher the average molecular weight, the higher the sensitivity to shear. Breaking a high molecular weight polymer can possibly improve the injectivity with a minor viscosity loss. A drawback to this method can be the loss of the viscoelastic effect which is mainly given by the highest molecular weight fraction of the polymer [46]. **Figure 18** shows the impact of shear degradation on polymers with different molecular weights. This experiment was carried out using a pipe of 0.875 mm internal diameter and a pipe length of 200 mm. As mentioned previously, the higher the molecular weight, the higher the irreversible viscosity loss. Large-scale studies and field cases (especially dealing with the effect of well completion on the mechanical degradation of polymer) can be found in the following references [47–49].

- Thermal degradation

Thermal degradation varies with the type of polymer and reservoir conditions. For typical HPAM polymers, a temperature increase will lead to an increase in the hydrolysis of acryla-

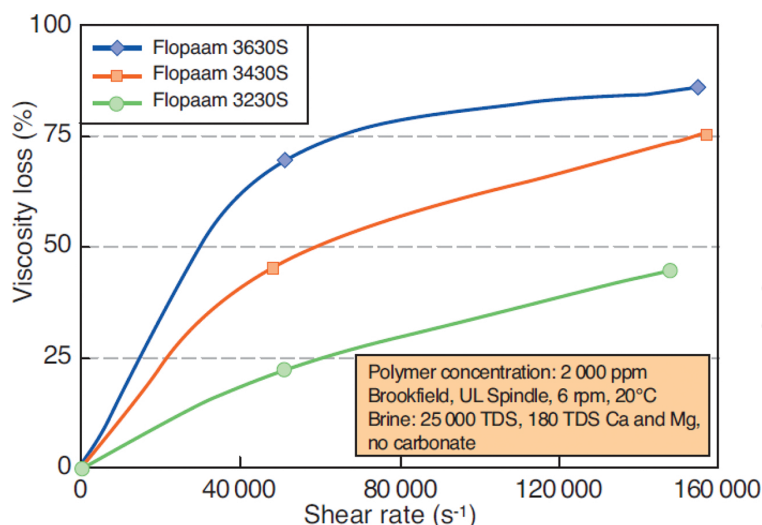


Figure 18. Shear degradation and percentage of viscosity loss for polymers having the same chemistry but different molecular weights (from high molecular weight polymer, Flopaam 3630S, to lower molecular weight polymer, Flopaam 3230S) [26].

amide moieties generating a higher charge density of anionic functionalities along the polymer backbone (**Figure 19**).

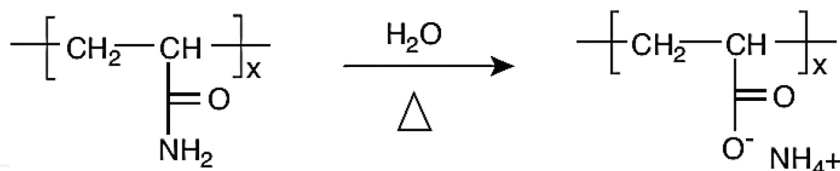


Figure 19. Hydrolysis of acrylamide moieties along the polymer backbone [25].

If the brine contains significant amounts of divalent cations such as calcium and magnesium, a viscosity drop is observed due to ionic bridges that can ultimately result in precipitation of the polymer [50]. The incorporation of sulfonate monomer (ATBS) to the polymer backbone improves its tolerance to calcium (AN125SH) at high temperature but in general with an increased polymer cost (**Figure 20**). An optimal polymer composition (i.e., addition of ATBS monomers) can be customized in the laboratory for a particular reservoir and its unique conditions.

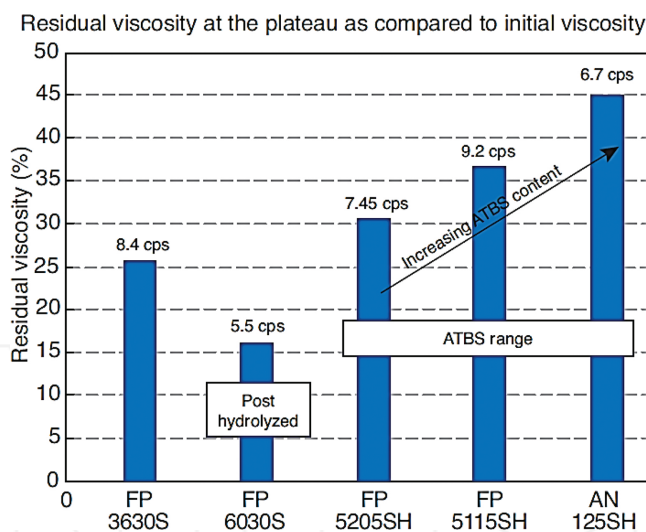


Figure 20. Salt tolerance of different polymer chemistries. The three polymers on the right side of the graph have increasing ATBS content [25].

It is clear that fine-tuning the polymer chemical structure (i.e., composition and molecular weight) is crucial to optimize the polymer stability for application at specific reservoir conditions. The selection of the best reservoir for polymer flooding application must take into consideration the analysis of the following three reservoir parameters: reservoir temperature,

brine composition (salinity, divalent cations, dissolved oxygen, iron, and hydrogen sulfide), and permeability. Polymer stability tests can be carried out over several months or years to ensure that viscosity loss is not observed during ageing in the presence of contaminants [26]. It is mandatory to perform these experiments under controlled anaerobic conditions (in glove box for instance) to quantify the level of degradation.

4. Polymer flooding: design and implementation

4.1. Reservoir screening

The objective of any reservoir screening process is to identify the best technology to improve oil recovery at a reasonable cost. Several criteria can be used during the screening process. General guidelines are provided in the following paragraphs. However, very often, a variety of parameters are assessed and obtaining a clear depiction of what would be the best technology-reservoir duo could be difficult.

Two general screening rules for polymer flooding are:

- The selection of reservoirs which have poor waterflooding sweep efficiency due to high oil viscosity and/or large-scale heterogeneity.
- The review of the overall conditions of the selected reservoir to determine if polymer flooding implementation will fix the poor sweep efficiency problem.

Specific parameters that need to be checked to determine if polymer flooding would be a viable option for the selected reservoir(s) are as follows:

- Lithology: sandstone
- Temperature: below 140°C (preferred below 100°C)
- Permeability: above 10 mD
- Oil viscosity: below 10,000 cP
- Current oil saturation: above residual oil saturation or presence of mobile oil
- Salinity of injection water: <200 g/L total dissolved salts. For salinity, another parameter called R^+ is usually considered. It is defined as the weight ratio of cationic divalent ions divided by the total of cationic ions as in following equation:

$$R^+ = \frac{\sum(\text{Divalent cations})}{\sum(\text{Cations})}$$

The above list can appear to be quite short and simple, when indeed there are many other factors related to the oil field that should be considered. However, if these criteria are met, there is already a good chance that injecting polymer would, technically speaking, increase the recovery factor. The next question would be: is it economically viable?

Obviously, among the mentioned parameters, the most important is probably the oil saturation and the corresponding remaining oil in place. If it is considered (and generally accepted) that polymer flooding does not displace residual oil saturation, then the presence of moveable oil is compulsory to make the injection viable. The *in situ* oil viscosity is a secondary criterion: even in those cases where oil viscosity is low and the mobility ratio of the displacement process (i.e., waterflooding) appears to be favorable, oil formations are generally heterogeneous by nature. Therefore, there is a good chance that even in those cases of favorable mobility ratio, sweep efficiency can be improved by the implementation of a polymer flooding.

Other parameters for consideration are linked to the choice of the most suitable polymer chemistry and the polymer concentration needed to reach a reasonable target viscosity. The higher the temperature and salinity, the higher the polymer concentration needed to obtain a sufficient viscosity to improve the recovery factor and, therefore, the higher the cost of the polymer flooding.

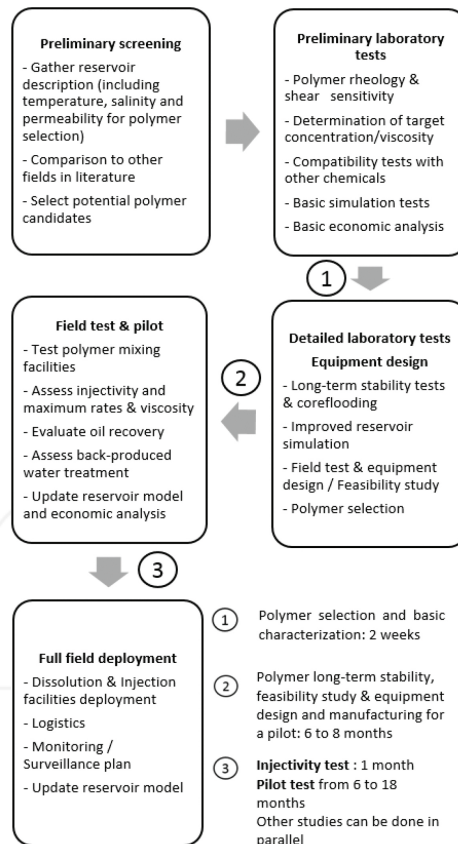


Figure 21. Example of workflow for polymer flooding implementation [25].

After the first selection has been made, more conventional reservoir studies can be performed before the implementation of a pilot test (**Figure 21**). The engineers should look at the reservoir geology (large-scale sand body connectivity and heterogeneity), distribution of target oil, presence and location of faults, shales, aquifers, and distribution of clays. The simultaneous analysis of the reservoir production history helps to understand and refine the current knowledge of the reservoir and the behavior of the injected and produced fluids to avoid chemical dispersion and polymer losses during polymer flooding.

Tracer test. Tracer flooding testing aids in improving the reservoir description using a range of techniques. This test provides information on well-to-well communication and transit time, data on large-scale layering, and an approximate estimate of areal sweep, and in-layer dispersion. Frequently, it is not necessary to perform an explicit tracer flood since there is virtually always a difference in the composition of each ion in the injection and formation brines (Na^+ , Ca^{2+} , Cl^- , SO_4^{2-} , etc.). Therefore, a careful analysis of the breakthrough composition of the produced brine would provide very useful information. However, it can be complicated by ion exchanges within the reservoir, especially for Ca^{2+} . It should be pointed out that the polymer is in itself a good tracer, with its detection in producing wells during the pilot using the kaolinite flocculation method. This will provide additional input regarding the flow streams.

In some cases, profile modification before polymer injection has been reported [51]. Another approach would be to start polymer injection with high-viscosity slugs in an attempt to seal the high-permeability zones without plugging them irreversibly. This approach has been demonstrated successfully in both the Daqing and Kazakhstan oil fields.

4.2. Importance of water quality

Field observations showed that a well-performing waterflood with “clean water” and good injectivity will translate into a well-performing polymer flood. The composition of a “clean water” provided here is a common guideline found in the oil industry when considering injecting water in order to maintain a decent injectivity during the life of a project [52, 53]. The recommended composition of “clean water” is:

- Oil content <100 ppm (to minimize reservoir plugging)
- Solids content <20 ppm
- Solid particle size <5 μm (to minimize reservoir plugging)
- Consistent salinity over the life of a project to minimize viscosity variations
- Oxygen content <20 ppb (to avoid polymer degradation if iron II or H_2S are present)

The composition of a “clean water,” except for oxygen content, do not have a major impact on the polymer behavior or stability, but it could affect the overall performance of surface facilities and injection wells.

The viscosity of the polymer solution is designed to reduce the overall mobility ratio of the fluids in the reservoir. Other than minimizing polymer degradation, it is important to inject

the polymer consistently at the target viscosity. This can be achieved with periodic polymer sampling or by inline viscosity monitoring of the polymer injected. Since water quality can change, a target concentration of polymer shall not be considered. Inversely, polymer concentration must be adapted to obtain the target viscosity, depending on water quality changes.

4.3. Pilot injection and monitoring

The objectives of a pilot polymer injection are to:

- Check the efficiency of the entire polymer injection process;
- Gather information on the reservoir response during polymer injection (pressure, flow rate, viscosity, injectivity, etc.). This information is useful to upgrade the reservoir model, if one exists; and
- Quantify the incremental oil recovery necessary to calculate the economics of polymer flooding in a view of a full-field extension.

The most important goal of a pilot polymer injection test is to determine the maximum flow rates and viscosities that can be accepted by the reservoir. Some guidelines for consideration during the implementation and monitoring of a pilot polymer flooding test are given below:

- Polymer injection should be ramped up over a period of days in order to initiate the flow of polymer into the reservoir.
- Injection rate, wellhead pressure, bottom-hole pressure, and cumulative injection should be recorded throughout the pilot.
- Polymer viscosity must be monitored by proper sampling or use of inline viscometers.
- Proper control of the formation parting pressure can be helpful to improve injectivity and minimize overall polymer mechanical degradation. The Hall Plot is a useful tool to follow the reservoir response during polymer flooding [54] (**Figure 22**). For instance, if the formation parting pressure is reached, it is recommended to slightly decrease the polymer injection rate to avoid changing the viscosity of the polymer due to mechanical degradation.
- The more viscous the polymer solution injected, the better the polymer flooding sweep efficiency (a mobility ratio <1 takes into account reservoir heterogeneity).
- Step-rate tests should be conducted to gather information on the maximum allowed injection rates, pressure, and polymer viscosity.
- Maintaining good water quality is paramount to ensure success.
- No real consensus exist on how should polymer injection be stopped: with or without tapering. Most probably, in any case, water will finger again through the slug in the high-permeability zones.

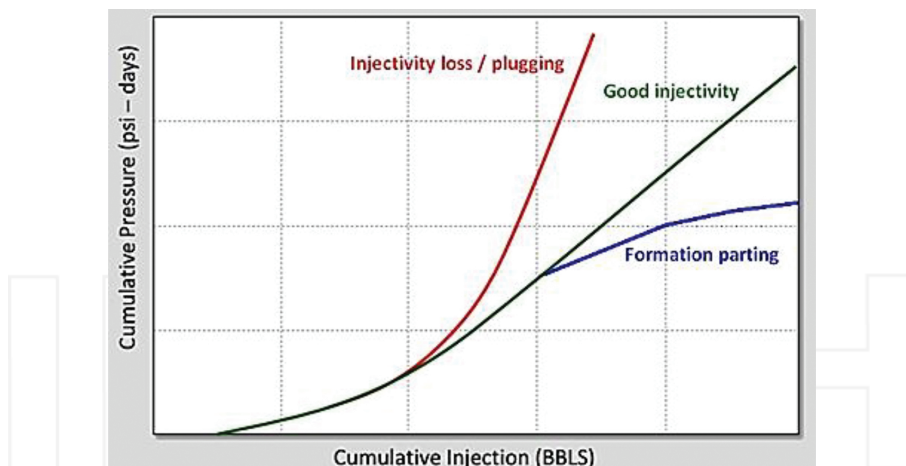


Figure 22. Hall Plot indicating different injection profiles and their interpretation (modified after [55]).

Continuous viscosity monitoring can be achieved by the use of an inline viscometer and periodic sampling at the wellhead to make sure the viscosity of the injected solution is the targeted one. This fluid sampling process must be carried out carefully to ensure the measured viscosity corresponds to the produced solution and not to a degraded polymer sample. An inaccurate sampling method can induce shearing or oxygen entry into the polymer sample, which will trigger chemical reactions between oxygen and potential reducers such as iron II and H_2S . This will lead to the formation of free radicals that act to chemically degrade the polymers, with an immediate polymer viscosity drop. This issue is also valid in the laboratory, where viscosity measurements in the presence of contaminants must be performed under an inert atmosphere, such as a nitrogen-blanketed glove box.

Injectivity. Injectivity is a hot topic among reservoir engineers and projects managers. Large polymer injection projects that have been successful in injecting high polymer viscosities are the polymer flooding implemented in the Daqing, Suriname, and Kazakhstan oil fields.

Interestingly, there are very few cases of bad injectivity reported in the literature during polymer flooding. Injectivity failures during polymer injection are usually linked to a flaw flooding design including improper polymer dissolution systems or polymer protection against degradation (chemical, mechanical, and thermal degradation), issues with water quality, well completion, injection of polymer solutions having very low viscosities, and/or polymer injection out of the target zone. Another possible reason is near-wellbore effects. If the near wellbore area is not modeled properly, or not understood at all, it is easy to overlook this area and to misinterpret what really happens in this zone.

Engineers from Oman Petroleum Development [56] have brought forward ideas to explain why the observed injectivity was better than the injectivity expected and predicted by models:

- Polymer degradation during injection. This hypothesis is very often discarded when polymer viscosity and concentrations are measured in the production fluids. Also, a significant viscosity loss would translate into a bad sweep efficiency and low extra oil recovery which is not the case.
- Polymer rheology: shear thinning and drag reduction effects are often not considered in the injection well before entering the reservoir. These effects will impact positively polymer injectivity. Shear thickening is possible but highly improbable considering the existence of microfractures.
- Uncharacterized reservoir heterogeneities.
- Dilution mechanisms in surrounding aquifers.
- Radial versus linear flow. A better understanding of the flow regimes is important, especially when considering the different well completion types (cased and perforated, gravel packs, vertical vs. horizontal wells, microfractures, and the skin factor, etc.).
- In addition, injecting a higher viscosity polymer induces a more stable displacement front that would translate into enlarged swept surface and therefore less pressure drop per linear meter. In other words, if the swept area is enlarged for the same amount of fluid, the pressure drop over a certain distance decreases.
- Most of the wells are injecting under fracturing conditions.

The last hypothesis is probably the most plausible explanation of the observed remarkable polymer injectivity that has been confirmed by other authors [37]. If this is the case, then it is important to understand the type of “fractures” that has been induced in terms of fracture geometry and extension. In this regards, some thoughts are given as follow:

- Well drilling and completion will change the stress repartition around the wellbore and create instabilities which, in addition to natural reservoir heterogeneities, will set favorable conditions for microfracture creation and extension.
- There is a great deal to learn from the nonconventional segment of oil and gas production and especially from the use of hydraulic fracturing to produce hydrocarbons from low-permeability reservoirs. In particular, regarding fracture creation, extension, and orientation. Geomechanics can be a useful tool to understand formation of fracture in the context of conventional oil reservoirs. It is well known that it is quite difficult to propagate long fractures even at high pumping rates. Additionally, the newly created or reactivated fractures can easily be contained in the formation which presents the most favorable stress orientation (this is important when discussing over cap rock integrity) [57, 58].
- Prolonged reservoir waterflooding will aggravate the near-wellbore formation damage. Especially, if the injected water is not at reservoir temperature.

All in all, it is important to characterize the near-wellbore area as best as possible and to work with the local heterogeneities to improve the overall chemical injection. Higher area for flow means less pressure drop and therefore less mechanical degradation. Using common reservoir

monitoring methods (step-rate tests, interference tests, and Hall plots, etc.), controlling injection rates and pressure to open up or close microfractures can bring significant improvement to the polymer flooding field operation. Another simple tool consists in analyzing the value of $q/\Delta P$:

If $q/\Delta P \leq (\Sigma k h)/[141.2 \mu \ln(r_e/r_w)]$, radial flow is probable (matrix injection)

If $q/\Delta P \geq (\Sigma k h)/[141.2 \mu \ln(r_e/r_w)]$, linear flow is probable (fracture-dominated regime)

where q is the injection or production rate (BPD), P pressure drawdown (psi), k permeability (md), h formation height (ft), μ fluid viscosity (cP), r_e external drainage radius (ft), and r_w wellbore radius (ft).

Last but not the least, it is paramount to translate these findings into the reservoir simulation models, which often give pessimistic results when injecting a viscous solution into the ground, especially when pressure constraints are set without a clear picture of polymer injectivity as obtained after a pilot test.

Numerical modeling and simulation. 3D modeling is a useful tool to predict the efficiency of a polymer flooding, assuming that the user has the proper understanding of the polymer characteristics and polymer flow properties. The most critical issue is modeling the near-wellbore area to duplicate the results observed during the field pilot injection. Polymer rheology regimes such as shear-thinning or shear-thickening properties should be used carefully, together with a suitable understanding of the well completion, formation damages, and reservoir fractures.

The most important parameters that can be obtained from the laboratory experiments that are useful during numerical simulation of polymer flooding are resistance factors, such as retention and residual resistance factors. If coreflooding experiments were not performed, it is possible to use the low shear viscosity information obtained from conventional rheometers for simulation purposes. Polymer degradation inside the reservoir is usually limited since the chemistry of the polymer is always selected to ensure the stability of the polymer during polymer injection and propagation throughout the reservoir. However, useful information can be gathered from long-term polymer stability tests.

4.4. Quality control

Routine quality control procedures are available to check the quality of the polymer to be injected. The main parameters for polymer quality controls are:

- Active content of the polymer: active material of the solid powder.
- Yield viscosity: definition of the polymer concentration needed in the injection brine to reach the target viscosity.
- UL viscosity: viscosity of polymer solution at 0.1% active in 1 mole NaCl.
- Filterability of the polymer solution: it is important to determine polymer dissolution issues, such as the formation of undissolved polymer clusters and/or fish-eyes (**Figure 23**).



Figure 23. Typical set-up used to perform filter ratio tests with vessels (top) and graduated cylinders connected to a stopwatch (bottom) [25].

Some of the laboratory procedures commonly used for polymer quality control are described in the API procedure RP63. Discussions with suppliers can also bring important inputs on the proper handling of the products and control of the overall quality.

As previously indicated, during reservoir polymer flooding, the main parameter to be monitored is polymer solution viscosity, which can be performed via an inline viscometer or by manual and careful polymer solution sampling for bench-scale viscosity analysis.

5. Back-produced polymer

A pilot injection can bring important information on the quality and quantity of back-produced polymer, as well as its impact on the existing water treatment facilities if the effluents can be isolated and polymer dilution limited.

For an extended field project, the crude and produced water separation stage and the produced water treatment stage must be considered as an important part of the polymer flooding implementation design. The treated water can be either reused or disposed of. The main aspects of the treatment of back-produced polymer are the following:

- Anionic polymer can interact with the oil emulsions breaker system, possibly resulting in an inefficient oil-water separation. Service companies generally select the most appropriate

and compatible oil-water breaker through several tests including bottle testing. Since polyacrylamide polymers are water soluble, they are considered absent from the oil phase [26].

- Anionic polyacrylamides are used widely in water treatment processes as flocculating agents. If the TSS (total suspended solids) is relatively high in the produced fluid, some agglomerates can appear and precipitates can deposit on the surface of process equipment (i.e., heating units). These deposits have to be periodically removed.

Equipment for back-produced water treatment is usually sized to operate with water viscosities below 4 cP. An increase in water viscosity after polymer breakthrough will reduce the efficiency of the treating devices in separating hydrocarbons and wetted suspended materials. For example, if the viscosity of the water produced reaches 10 cP, the residence time required for treatment is five times longer and the size of the devices are five times larger [26].

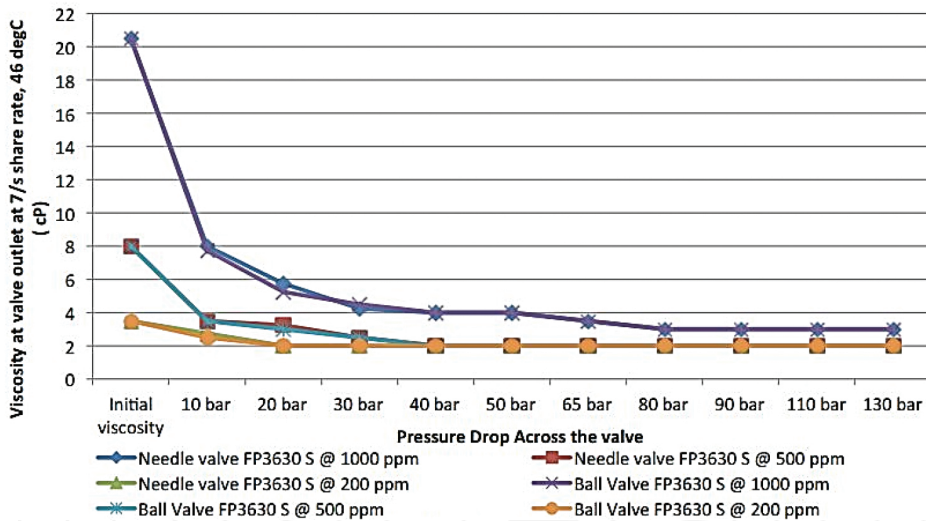


Figure 24. Mechanical degradation of polymer solutions at different concentrations (Flopaam 3630S) [25].

Several methods (mechanical, chemical, and filtration, etc.) can be used to decrease the viscosity of the produced effluent in order to maintain the efficiency of the water treatment process [59] as follows:

- Mechanical degradation is often a viable and efficient method to decrease the molecular weight of the polymer and thereby to decrease the viscosity of the solution (Figure 24). A shearing pump or a choke valve can be used to achieve the required degradation to decrease the viscosity of the polymer solution produced. However, too much shear can stabilize oil in water (O/W) emulsions.

- Polyacrylamides experience chemical degradation in the presence of oxidizers that generate free radicals that react with the polymer backbone chain, resulting in a decrease of the molecular weight and viscosity of the polymer solution. A preferred oxidizer is sodium hypochlorite (NaClO). However, if the treated water needs to be reused to hydrate polymer for a further injection, any remaining excess of oxidizer must be neutralized with a reducing agent to prevent any excess of oxidizer from degrading the new batch of dissolved polymer.
- Polymer precipitation: can be performed by using trivalent metal salts (i.e., aluminum sulfate, polyaluminum chloride, ferric chloride, etc.). However, this method entails several disadvantages: the reagents acidify the water, which must be corrected to prevent equipment corrosion. In addition, the formed colloidal precipitate would require a large settler-flocculator and a centrifugation/filtration sludge system. This sludge would then require disposal in a landfill, when permitted by local regulation or incinerated. Additionally, the recovery of any adsorbed oil on the precipitate would be very difficult.

The back-produced polymer can also have several benefits:

- It can be reused to possibly decrease the amount of fresh polymer added, reducing the operational expenditures. This does not impact standard dissolution facilities.
- Polymer remaining in the water will act as a drag reducing agent when pumping the water for reinjection or disposal, thereby reducing the pumping energy and increasing injection rates for the same pressure drop.
- If water is injected into a virgin part of the reservoir, the polymer present in the water phase will act as a sacrificial agent by adsorption onto the rock surface. Therefore, if chemical injection is envisaged, less chemicals will be lost to retention.
- Anionic polymers have other benefits such as clay stabilizers, sand control, and even anticorrosion (passivation).

6. Equipment and surface facilities

6.1. Process examples

Depending on the polymer form (emulsion or powder), two different approaches can be considered. When the polymer is supplied in powder form, it should be dissolved into the injection water prior to being pumped for dilution and injected into the reservoir at the target viscosity. A typical set-up for powder dissolution is presented in **Figure 25**. The polymer in powder form is stored in a hopper and distributed with a dosing screw into a nitrogen-blanketed polymer slicing unit (PSU) where it is hydrated. The solution will then pass into a maturation tank where it will achieve full hydration/dissolution. Finally, the mother solution is pumped and diluted to the target concentration (**Figure 25**).

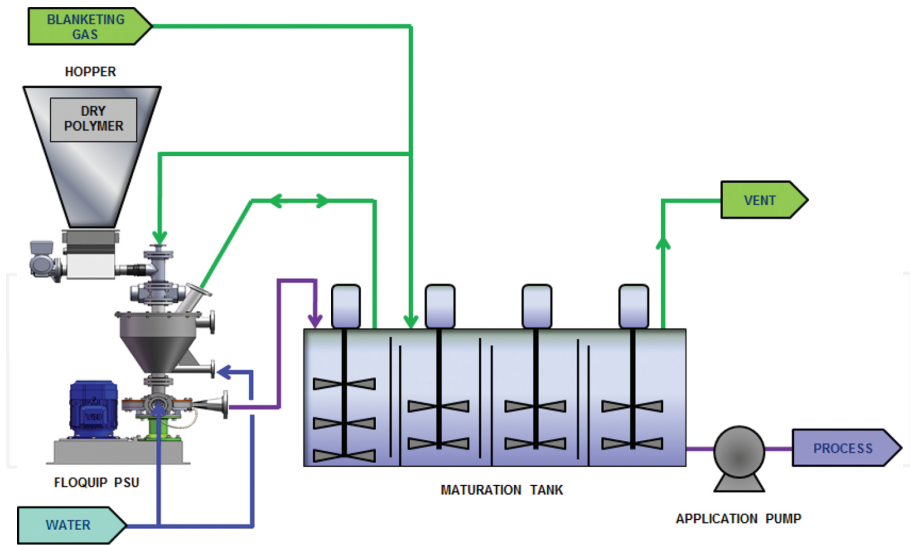


Figure 25. Typical dissolution process for polymers in powder form [25].

Skid-mounted systems are widely used onshore: the polymer dissolution and hydration systems as well as the pumps are placed inside 20 or 40 feet containers that are adapted to the local field conditions (weather, accessibility). As discussed previously, it is recommended to blanket the main equipment with nitrogen to avoid any oxygen ingress and further degradation of the polymer solution viscosity. This type of system with a slicing unit allows for quick and proper hydration of the polymer, avoiding fish-eyes and gels formation, which would require filtration of the polymer solution.

Two configurations can be considered based on the water supply:

- If high pressure water is available, then the configuration shown in **Figure 26** is recommended.
- If low pressure water is available, the configuration displayed in **Figure 27** should be used to ensure the proper hydration of the polymer.

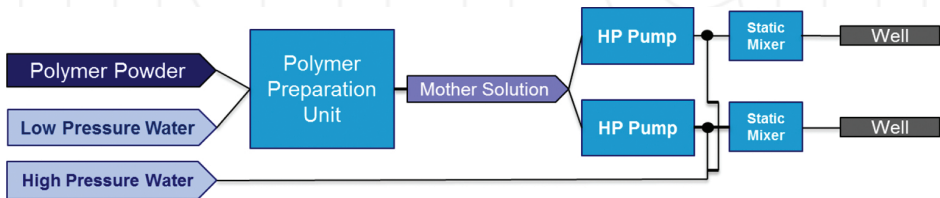


Figure 26. Configuration for polymer preparation when high pressure water is available [25].

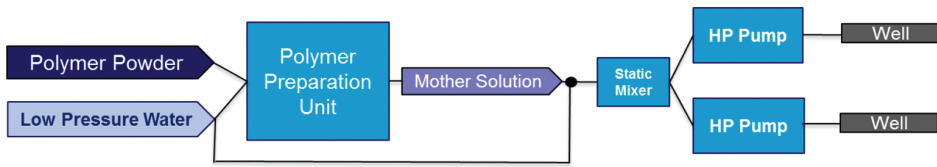


Figure 27. Configuration for polymer preparation when low pressure water is available [25].

When using polymer in emulsion form, inline static mixers (with a sufficient pressure drop) are required to invert the water-in-oil emulsion (W/O) into an oil-in-water emulsion (O/W) which is then injected in the reservoir. The footprint for the process is much less extensive than in the case of polymer in powder form. Nevertheless, due to the active content and the density of the emulsion, the volume of the tank necessary to store the emulsion is often twice the volume of the tank used to prepare polymer in powder form. **Figure 28** presents a simplified flow diagram for the dilution process of polymer in inverse emulsion form.

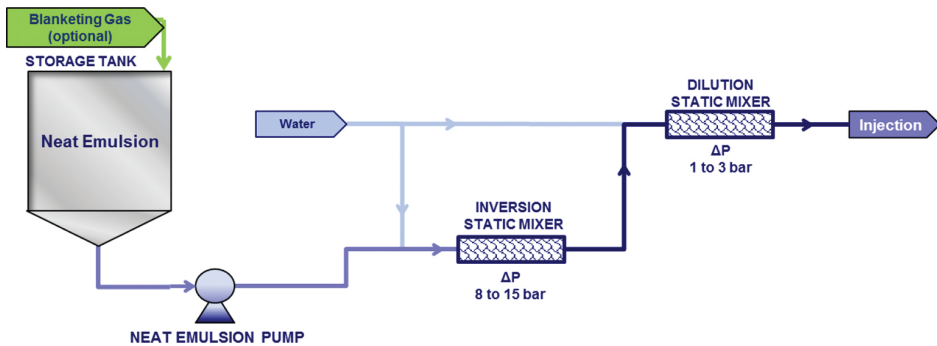


Figure 28. Typical inversion and dilution process for the preparation of polymer in inverse emulsion form [25].

Among the three main types of degradation, chemical and mechanical polymer degradations are susceptible to occur at surface facilities.

Chemical degradation can be minimized by blanketing the equipment with nitrogen or by adding specific scavengers in the flow stream. It is also possible to remove as many contaminants as possible or to add protective additives to the polymer.

Specific guidelines should also be applied to minimize mechanical degradation in dissolution and surface equipment or in the injection lines if restrictions or chokes are present. Progressive cavity or rotary lobes pumps are recommended for low pressure processes. For high pressure, plunger or diaphragm pumps (Triplex or Quintuplex) are preferred. The maximum velocity of the fluid must remain below a critical value, wherever the fluid is moved such as in the agitation process with impellers or in pipes (short distance). For example, in a 2-inch pipe, it must be kept below 7 m/s.

Chokes must be removed, bypassed, fully opened, or replaced by nonshearing systems to avoid any uncontrolled shearing that would be detrimental to the final viscosity of the polymer solution. Well completion influences the amount of degradation; for example, the density and number of perforations must be taken into account and correlated to the flow rate of the fluid to assess the potential shearing occurring at this step (a value of 12 shots per foot is usually recommended) [26].

6.2. Key points for offshore polymer flooding implementations

The constraints are very different when designing an offshore or an onshore polymer flooding project. Equipment footprint is the key in offshore operations, therefore it is necessary to know the space and load limits of the Floating Production Storage Offloading (FPSO) or the offshore platform. Logistics and local weather conditions can also dictate the form of the product to be used. Polymer in inverse emulsion form is easier to handle offshore, especially when the weather conditions are particularly unfavorable. It does not require specific systems, the inversion is performed on the fly with sufficient energy and the solution can then be diluted and injected into the reservoir. However, polymer in powder form, with a higher active content (up to 90% compared to the 30 or 50% for an emulsion), is cheaper to implement and requires less logistics.

The main points to consider during the design of polymer flooding for offshore applications are the following:

- Specific design considering footprint limitations and loads constraints.
- Modular solution to limit the installation activities on the FPSO, platform, or any offshore vessel. Those modules should also comply with lifting/handling constraints such as crane limitation and specific offshore procedures, among others.
- Sensitivity to vibrations during operations (pumps running, conveying, etc.). Specific attention shall be paid on loads interaction and structural issues.
- Hazardous classified area: specific design is to be provided to adapt equipment and modules to the hazardous classification constraints, especially for the control room, motor control center, and utilities shelters.
- Environmental conditions: consideration of the vessel motions (rolling, sagging, pitching, heaving), wind loads, and blast loads on structural and equipment design.
- Corrosion: protection against the corrosive atmosphere (stainless steel equipment, specific painting procedures, nitrogen blanketing, greasing).
- Waste management and back produced water: use of chemicals offshore and possible waste to be handled. Specific cleaning procedures have to be foreseen as well.
- Subsea: polymer is a shear sensitive chemical. For offshore projects, nonshearing injection pumps should be used to transfer the injected solution through the main risers up to the several subsea Christmas trees dedicated to each well. Choke valves will then be used to

control the flow and the pressure at each wellhead. Specific solutions shall be selected to minimize viscosity degradation.

- Logistics: for chemical EOR, a large quantity of chemicals has to be handled either in liquid or powder form. Therefore, the supply chain has to be secured accordingly.

7. Field cases and economics

7.1. Economics

Three areas of expenses can be defined when considering polymer injection:

- Laboratory studies and simulation.
- Equipment design, fabrication, installation, and other costs associated with the start-up of the flooding process.
- Chemical costs.

Out of the three aforementioned sections, the first one represents approximately 1% of the overall costs while the following two represent 25% and 70–75%, respectively. It is obvious that the bulk of the cost is linked to the injection of the chemicals. An important aspect is the field development plan and the deployment of the injection facilities. Two approaches are often encountered:

- Centralized polymer dissolution and injection plants.
- Modular skid-based polymer dissolution and injection systems.

The latter helps to optimize the deployment of the facilities in the field by adding modules for polymer dissolution or polymer injection modules, minimizing the capital expenditures upfront. It also allows moving the systems to other parts of the field for short-term tests.

The average cost of polymer per incremental barrel ranges from \$1 to \$4. The cost of polymer per incremental barrel of oil produced at the Daqing oil field polymer flooding has been estimated at approximately \$2.7/barrel. In this case, it was shown that polymer injection was less expensive than water injection considering the average capital costs per well and the volumes of fluids injected and produced which are significantly less for polymer injection than for water injection.

Another example is the Brintnell polymer flood project (CNRL, Canada) where the average incremental cost for polymer flooding was \$13, but including incremental wells, mixing facilities, water-treating facilities, additional production facilities, maintenance capital, and the polymer itself, whereas the cost of the polymer alone was \$4 per incremental barrel of oil produced.

7.2. Field cases of polymer flooding

In 2015, there were more than 50 polymer injections running worldwide, excluding the projects still in the design phase or about ready to start in the field.

It would be hard to summarize the entirety of field cases here, so only few examples will be addressed, highlighting some important design aspects and some key learnings. Also, only publicly available information will be discussed in the upcoming paragraphs.

7.2.1. Canada

Canadian operators have gained significant experience in the last years on polymer injection for heavy oils. Interestingly, the vast majority of the cases are publicly released in corporate presentations, providing a wealth of information on the efficiency of the process. The constant here is the benefit of injecting viscous solutions to improve recovery from heavy-oil pools. The list of fields is extensive: Pelican Lake, Brintnell, Mooney, Horsefly, Countess, Bodo, Suffield Caen, Wainwright, Giltedge, Seal, Taber, Wildmere, Wrentham, Provost, Edgerton, etc. [60–62]. These wells are mainly horizontal, with a short-spacing often between 50 and 100 m and oil viscosities up to 10,000 cP. **Table 4** presents a summary of reservoir properties of three typical Canadian oil fields in which polymer flooding has been implemented. The incremental oil recovery obtained from each polymer flooding project is also indicated in **Table 4**.

Project	Pelican Lake	Mooney	Seal
Company	CNRL & Cenovus	Black Pearl	Murphy
Average depth	300–450	900–950	610
Average net pay	1–9	2.5	8.5
Permeability	300–5000	100–10,000+	300–5800
Reservoir temperature	12–17	29	20
API gravity	12–14	12–19	10–12
Dead oil viscosity	800–80,000	300	5000–12,000
Live oil viscosity	800–80,000	1000–3000	3000–7000
Incremental oil recovery	10–25%	~10%	9%

Table 4. Summary of reservoir properties of three typical Canadian oil fields in which polymer flooding has been implemented (modified after [60]).

7.2.2. China

The Daqing polymer flooding case has been extensively discussed previously in this chapter. Incremental oil recovery as a result of polymer injection is approximately 12% OOIP. Other successful polymer flooding projects in Chinese oil fields such as the Shengli and Bohai Bay have been described in the literature [65]. Additionally, some papers report the use of high-viscosity polymer slug to further improve oil recovery: the objective is to inject very high

viscosity slugs followed by a regular polymer flooding with possible repetition in order to account for reservoir heterogeneities [62–64].

7.2.3. Europe and Middle East

The number of polymer flooding pilot tests and projects has greatly increased in the past years in Europe, some examples are as follows:

- Bockstedt oil field in Germany where Wintershall has injected the schizophyllan biopolymer.
- Matzen oil field in Austria operated by the OMV Group.
- Patos-Marinza oil field (heavy oil reservoir) operated by Bankers Petroleum in Albania.
- Other polymer flooding pilots in the North Sea, Eastern Europe, Russia, and Kazakhstan whose oil field names are often protected by nondisclosure agreements.
- Polymer flooding pilots in Egypt and the Marmul field polymer flooding project in Oman.

In the Marmul oil field, Petroleum Development Oman (PDO) implemented a pilot polymer injection in 2010. A polyacrylamide polymer and a protective additive were injected in 27 wells. The high-permeability (multi-Darcy) reservoir contains a 22° API crude oil with a viscosity of around 90 cP; injection patterns are inverted 9- and five-spot patterns. The polymer solution (15 cP) was injected at an average flow rate of 13,000 m³/day. Preliminary results as of 2012 are presented in **Figure 29** [56].

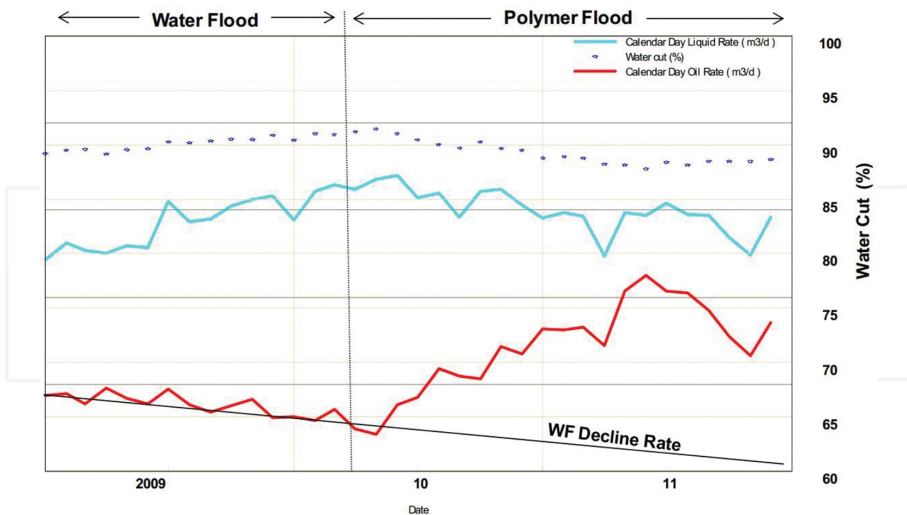


Figure 29. Water-cut and oil production rate from the Marmul oil field before and after the start-up of polymer injection [56].

7.2.4. South America

Polymer flooding pilot injections are on-going in Argentina, Suriname, and Colombia with polymer flood projects in Brazil and Venezuela. An interesting case is the Sarah Maria field operated by Staatsolie [37] in Suriname. This reservoir is a heterogeneous sandstone, with permeabilities of several Darcie's and a live oil viscosity around 500 cP. Moe Soe Let et al. (2012) have reported the first observations of this polymer flooding. In this project, reservoir fractures have been used to improve the injectivity of the highly viscous polymer solutions (up to 160 cP). The creation and extension of fractures have been monitored through pressure profiles, interwell tracer tests, water-cut variations, salinity, and polymer breakthrough: the aim was to increase water injection and oil production rates without risking irreversible reservoir damages.

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