Pressure Behaviour and Fracture Development during Polymer Injection in a Heavy Oil Saturated Unconsolidated Sand

24-01-2014 Ruben Logister
<table>
<thead>
<tr>
<th>Title</th>
<th>Pressure Behaviour and Fracture Development during Polymer Injection in a Heavy Oil Saturated Unconsolidated Sand</th>
</tr>
</thead>
<tbody>
<tr>
<td>Author(s)</td>
<td>Ruben Logister</td>
</tr>
<tr>
<td>Date</td>
<td>January 2014</td>
</tr>
<tr>
<td>Professor(s)</td>
<td>Prof. dr. P.L.J. Zitha</td>
</tr>
<tr>
<td>Supervisor(s)</td>
<td>Prof. dr. P.L.J. Zitha and Dr. A. Barnhoorn</td>
</tr>
<tr>
<td>TA Report number</td>
<td>AES/PE/14-01</td>
</tr>
<tr>
<td>Postal Address</td>
<td>Section for Petroleum Engineering Department of Geoscience &amp; Engineering Delft University of Technology P.O. Box 5028 The Netherlands</td>
</tr>
<tr>
<td>Telephone</td>
<td>(31) 15 2781328 (secretary)</td>
</tr>
<tr>
<td>Telefax</td>
<td>(31) 15 2781189</td>
</tr>
</tbody>
</table>
Abstract

Polymer flooding is an important EOR method in heavy oil reservoirs, where field studies showed a recovery up to 59%. However, accurate assessment of injectivity of viscous polymer solutions can give major challenges. Little research has been devoted to pressure build-up phenomena with polymer injection in porous media. Therefore, the objective of this study is to experimentally investigate the water and polymer injectivities in an unconsolidated sand pack saturated either with brine or with heavy oil, subject to confining axial and radial stresses in the range of those encountered in reservoirs. In particular we are interested in the typical reservoir conditions under which failure/hydraulic fracturing of the sample occurs. We also intend to investigate the effect such a hydraulic fracture will have on polymer injectivity. The injection experiments were conducted in a biaxial pressure vessel containing a porous medium, in which flow rates can be controlled and pressures can be measured.

Data from rheological measurements and a single phase water flood experiment carried out in this study were utilised for understanding and comparing the injectivity results for polymer flood experiments. The outcome of experimental analysis showed that the viscous nature of the polymer solution and the viscosity of the oil are the main causes for the loss in injectivity compared to a water flood. A change in confining pressure does not influence the injectivity. However, it does affect the occurrence of fracturing. It was found fracturing occurred at a pressure drop of 4.3 times the minimum confining pressure and caused injectivity to rise.

Pressure data obtained from the water flood experiments was fitted with prediction models that describe pressure behaviour during injection in a porous medium. Fitting resulted in a value for permeability of the porous medium and was used in prediction models that describe a polymer flood. Polymer flood data gave a best fit when polymer with a constant average viscosity was assumed to have displaced all saturation fluid. The rheology showed that the polymer solution has shear thickening behaviour, making a non-Newtonian model that only considers shear thinning invalid. A displacement model, which describes the displacement of water by a polymer solution with constant viscosity, made clear that retention effects are highest close to the wellbore and decrease when polymer is further invaded in the porous medium.

Finally, the results from this study lead to recommendations to refine future experimental polymer flood of this scale.
Acknowledgements

During each stage of this MSc thesis project of research, experiments and report writing, I received advice, guidance and support from many people around me. I would like to mention and thank several people in particular who have been valuable for my MSc thesis project.

First of all, I am grateful to my supervisors Prof. dr. P.L.J. Zitha and Dr. Auke Barnhoorn for their patience, support and guidance during the course of my thesis. In spite of their busy schedule they provided me with the necessary feedback and ideas in approaching the objective in this study. I appreciate the time they spend on reviewing my work.

I am very thankful to the technicians Jan Etienne en Marc Friebel for the time they spend on assisting me with my experiments. Their knowledge on the Borehole Simulator and other equipment was of great importance for executing my experiments in a safe and proper way. They were very organized and reliable, which made working together very pleasant.

I would like to thank my family for always believing in me. Their constant motivation and encouragement supported me during the course of this thesis.
Thanks to my friends in Delft, Horst and friends who are far away for all the support, motivation, interest and advice.
Besides that I would like to thank my fellow graduate students, for the nice time at the “afstudeer zolder”, the interesting conversations and rejuvenating coffee breaks during my thesis work.
Nomenclature

\(a_1, a_2, a_3\) fitting constants for viscosity relation [-]

\(A\) cross sectional area of core [cm\(^2\)]

\(c\) compressibility [-]

\(c_A\) shape factor, circular shape = 31.6 [-]

\(c_p^*\) critical overlap concentration [g/cm\(^3\), ppm]

\(c_p\) polymer concentration [g/cm\(^3\), ppm]

\(H\) height [m]

\(H_{pl}\) power law viscosity [Pa.s]

\(I_p\) polymer injectivity [ml/min.bar]

\(I_w\) water injectivity [ml/min.bar]

\(I_r\) indicator of injectivity decline [-]

\(k\) permeability [cm\(^2\), Darcy]

\(k_w\) permeability for water [cm\(^2\), Darcy]

\(k_p\) permeability for polymer [cm\(^2\), Darcy]

\(k_e\) equilibrium rate constant [cm\(^3\)/ g]

\(k_H\) Huggins coefficient [-]

\(K_{pl}\) power law coefficient [-]

\(M_w\) molecular weight of polymer [g/mol]

\(n\) exponent for porous medium [-]

\(n_{pl}\) power law exponent [-]

\(P_i\) initial fluid pressure in the porous medium [bar, Pa]

\(P_{wf}\) flowing well pressure [bar, Pa]

\(Q\) injection flow rate [ml/min]

\(r\) radial coordinate [m]

\(R_w\) radius of wellbore/ injection pipe [m]

\(R_e\) radius of border of the porous medium [m]

\(R_G\) radius of gyration [m]

\(R_p\) radial distance of polymer front [m]

\(r_p\) average pore throat radius [m]

\(R_m\) mobility reduction [-]

\(R_k\) permeability reduction [-]

\(F_R\) resistance factor [-]

\(R_{RF}\) residual resistance factor [-]

\(S_{aq}\) saturation of the aqueous phase [fraction]

\(S_p\) saturation of polymer [fraction]

\(S_w\) saturation of water [fraction]

\(S_{or}\) residual oil saturation [fraction]

\(t\) time [s, min]

\(u\) Darcy velocity [cm/s]
u_r  radial Darcy velocity [cm/s]
v  interstitial velocity [m/s]
x  axial coordinate [m]
α_g  shift factor, to take structure of porous medium into account [-]
β  maximum damage factor [-]
Φ  universal constant [4.2×10^{24} mol^{-1}]
φ  porosity [fraction]
φ_w  aqueous phase porosity [fraction]
γ_{eq}  equivalent shear rate [s^{-1}]
γ_c  critical shear rate [s^{-1}]
γ  shear rate [s^{-1}]
y  Euler constant 1,781 [-]
ΔP  pressure drop from experiments [bar]
ΔP_p  pressure drop during polymer injection [bar]
ΔP_{b,0}  pressure drop for brine prior to polymer injection [bar]
λ  mobility [D/Pa/s]
λ_w  mobility of water [D/Pa/s]
λ_{wa}  mobility of water after contact with polymer [D/Pa/s]
λ_p  mobility of polymer [D/Pa/s]
μ_w  viscosity of water [Pa.s]
μ_{w,eff}  effective viscosity of water [Pa.s]
μ_b  viscosity of brine [Pa.s]
μ_{app}  apparent viscosity of polymer [Pa.s]
μ_p  polymer viscosity [Pa.s]
μ_{p,eff}  effective viscosity of polymer [Pa.s]
μ_p^0  polymer viscosity at zero shear rate [Pa.s]
μ_p^{\infty}  minimum viscosity of polymer [Pa.s]
[μ]  intrinsic viscosity [cm^{3}/g]
μ_s  specific viscosity [-]
ρ  density [kg/m^{3}]
**System of Units**

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>m</td>
<td>meter</td>
</tr>
<tr>
<td>ml</td>
<td>milliliter</td>
</tr>
<tr>
<td>mD</td>
<td>milliDarcy</td>
</tr>
<tr>
<td>D</td>
<td>Darcy</td>
</tr>
<tr>
<td>L</td>
<td>liter</td>
</tr>
<tr>
<td>cm</td>
<td>centimeter</td>
</tr>
<tr>
<td>kg</td>
<td>kilogram</td>
</tr>
<tr>
<td>g</td>
<td>gram</td>
</tr>
<tr>
<td>Pa</td>
<td>Pascal</td>
</tr>
<tr>
<td>bar</td>
<td>bar</td>
</tr>
<tr>
<td>s</td>
<td>second</td>
</tr>
<tr>
<td>ppm</td>
<td>parts per million</td>
</tr>
<tr>
<td>mol</td>
<td>moles</td>
</tr>
</tbody>
</table>

**Abbreviations**

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>EOR</td>
<td>Enhanced Oil Recovery</td>
</tr>
<tr>
<td>HPAM</td>
<td>Hydrolyzed Polyacrylamide</td>
</tr>
<tr>
<td>PAM</td>
<td>Polyacrylamide</td>
</tr>
<tr>
<td>PV</td>
<td>Pore Volume</td>
</tr>
<tr>
<td>WIW</td>
<td>Water injection in a water saturated porous medium</td>
</tr>
<tr>
<td>PIW</td>
<td>Polymer injection in a water saturated porous medium</td>
</tr>
<tr>
<td>PIO</td>
<td>Polymer injection in an oil saturated porous medium</td>
</tr>
</tbody>
</table>
## Table of Contents

Abstract ...................................................................................................................................... 1  
Acknowledgements .................................................................................................................. 2  
Nomenclature ............................................................................................................................ 3  

1. Introduction .......................................................................................................................... 8  

2. Background .......................................................................................................................... 10  
   2.1 General polymer properties ............................................................................................... 10  
   2.2 Polymer concentration ...................................................................................................... 11  
   2.3 Polymer rheology .............................................................................................................. 12  
   2.4 Polymer retention ............................................................................................................. 14  
   2.4.1 Low permeability porous media ................................................................................... 15  
   2.4.2 High permeability porous media ................................................................................. 15  
   2.4.3 Intermediate permeability porous media .................................................................... 15  

3. Modelling ............................................................................................................................. 16  
   3.1 Physical model ................................................................................................................... 16  
   3.2 Governing equations ......................................................................................................... 17  
   3.3 Additional equations ......................................................................................................... 19  
   3.3.1 Permeability reduction ................................................................................................. 19  
   3.3.2 Mobilities .................................................................................................................... 19  
   3.3.3 Injectivity ..................................................................................................................... 20  
   3.4 Analytical solutions .......................................................................................................... 21  
   3.4.1 Water injection into water saturated porous medium .................................................. 22  
   3.4.2 Polymer injection into water saturated porous medium .............................................. 23  
   3.4.3 Polymer injection into oil saturated porous medium .................................................. 24  

4. Experiments .......................................................................................................................... 25  
   4.1 Experimental set-up .......................................................................................................... 25  
   4.2 Materials and Methods .................................................................................................... 26  
   4.3 Preparation of the polymer solution ............................................................................... 26  
   4.4 Porous medium sample ................................................................................................... 26  
   4.5 Experimental procedure .................................................................................................. 29  

5. Results and Discussion ........................................................................................................ 31  
   5.1 Experimental results and interpretation ........................................................................... 33  
   5.1.1 Water injection in a water saturated porous medium .................................................. 33  
   5.1.2 Polymer injection in a water saturated porous medium .............................................. 35  
   5.1.3 Polymer injection in an oil saturated sample ............................................................... 38  
   5.2 General discussion ......................................................................................................... 42
6. Conclusion and Recommendations ................................................................. 44
   6.1 Conclusion .............................................................................................. 44
   6.2 Recommendations ................................................................................. 44

Appendices ........................................................................................................ 45
   A. Shear rate versus viscosity graphs ........................................................ 45
   B. Rheology models ...................................................................................... 48
   C. Preparation before starting the experiment .......................................... 49
   D. Pressure/Flow rate relation ................................................................. 50
   E. Polymer retention interval ................................................................. 51
   F. Sand sample properties ......................................................................... 52
   G. Visual results of PIW and PIO experiment ........................................... 53
      G.1 PIW results of experiment 11 .......................................................... 53
      G.2 PIO results of experiment 12 .......................................................... 54
   H. Experimental results ............................................................................... 55
      H.1 Experiment 1 ..................................................................................... 55
      H.2 Experiment 2 ..................................................................................... 58
      H.3 Experiment 3 ..................................................................................... 61
      H.4 Experiment 1,2,3 combined .............................................................. 64
      H.5 Experiment 4 ..................................................................................... 67
      H.6 Experiment 5 ..................................................................................... 70
      H.7 Experiment 6 ..................................................................................... 73
      H.8 Experiment 7 ..................................................................................... 76
      H.9 Experiment 8 ..................................................................................... 79
      H.10 Experiment 9 ................................................................................... 82
      H.11 Experiment 10 ................................................................................. 85
      H.12 Experiment 8,9,10 combined ......................................................... 88
      H.13 Experiment 11 ................................................................................. 91
      H.14 Experiment 12 ................................................................................ 94
   I. Experimental results comparison ............................................................... 98
      I.1 Water in water 600 ml/min ................................................................. 98
      I.2 Water in water 1200 ml/min ............................................................... 98
      I.3 All WIW graphs ................................................................................. 99
      I.4 Polymer in water 600 ml/min ............................................................ 99

References .......................................................................................................... 100
1. Introduction

Based on current status of technology, hydrocarbons will remain the primary source of energy for the next three to four decades. Energy supply to sustain world economies requires developing additional crude oil reserves. For some areas, this additional development will be in the form of exploration and drilling, but for most oil-producing areas it will very likely be sustained by applying enhanced oil recovery (EOR). High energy demand and depletion of light oils, made interest in production of heavy oil grow (Gao, 2011).

Heavy oil deposits in Canada, Venezuela and the United States comprise several trillion barrels. However, the vast heavy oil formations of Western Canada and in particular of Alberta represent tremendous challenges for reservoir and production engineers. In particular, thin heavy oil formations with oil viscosity between 100 and 2000 cP present unique challenges and opportunities for additional recovery beyond the primary production. Therefore, we have to investigate technically and economically feasible EOR methods to produce these heavy oils (Wassmuth et al., 2007).

Conventional oilfields are typically developed in three main phases: primary, secondary and tertiary recovery. Primary recovery relies on natural drive mechanisms such as solution gas, water influx, gas cap drive or gravity drainage. Secondary recovery refers to techniques, such as gas or water injection, whose purpose, in part, is to maintain reservoir pressure. Tertiary recovery is any technique applied after secondary recovery (Lake, 1989). Enhanced oil recovery is oil production by injection of materials not normally present in the reservoir (Lake, 1989). The definition does not restrict EOR to a particular phase (primary, secondary or tertiary) in the producing life of a reservoir. According to a survey (Koottungal, 2010), thermal methods such as steam flood and hot water flood are successful strategies for producing heavy oil. However, these methods are not suitable for thin layers and deep reservoirs. A non-thermal recovery method gives the outcome.

In western Canadian heavy oil reservoirs, water flooding gives a recovery up to 10%. Miller (2006) reviewed the Canadian heavy oil water flooding projects and observed that there was insufficient literature on this subject. He stated that process of assessing water flooding projects is empirical, rather than understanding the fundamental processes involved. His study revealed that these water floods exhibit very poor sweep efficiency, because of the extremely adverse mobility ratio. In order to improve the mobility ratio between injected water and heavy oil, polymer flooding has been used (Asghari and Nakutnyy, 2008). Five field cases (Bohai Bay, Offshore China; East Bodo and Pelican Lake, Canada; Tambaredjo, Suriname; Bati Raman, Turkey; Marmul, Oman) where polymer flooding in heavy oil has been tested, show results of recovery up to 59% of heavy oil (Gao, 2011).

Based on past experiences, polymer flood is recommended for oil viscosity less than 100 cP under reservoir temperature, and sandstone reservoir with oil saturation higher than 30 %, reservoir permeability greater than 20 mD, net thickness more than 3 m, and reservoir temperature less than 90 °C (Lake et al., 1992; Alkaleef and Zaid, 2007; Gao and Towler, 2011).

The basic principle of polymer flooding consists in adding polymer to the water in order to increase its viscosity. The resulting decrease in water mobility and lower mobility ratio between the drive (displacing) fluid and to be displaced oil, increases the volumetric sweep efficiency of the injected fluid substantially. Irreducible oil saturation does not decrease although the remaining oil saturation does approach $S_{or}$, which is assumed to be practically
the same for both water flooding and polymer flooding. In order for polymer flooding in heavy oil to be effective, the concentration of the polymer solution must be beyond a threshold value.

Injection rate is also of influence on the oil recovery. High injection rates can cause viscous fingering, but will give a higher sweep efficiency in the end. The larger recovery efficiency is the basis for the economic success of polymer flooding. According to Lake (1989), a polymer flood is expected to be economic when the water flooding mobility ratio is between 1 and 50, the reservoir heterogeneity is high (Dykstra-Parson coefficient of 0.75), or a combination of these two occurs.

Another aspect of polymer flooding which needs to be taken into account is the increase in pore pressure. When pore pressure exceeds the confining pressure, the rock will fracture and polymers will flow through the fracture, losing sweep efficiency.

Zhou and others (2010) conducted several injectivity experiments using honey injection with different viscosities in an unconsolidated sand. The results showed failure occurs when injection pressure was 2.5 to 3 times the minimum confining pressure. Honey was used instead of polymers to preserve the Newtonian character of the injection fluid.

Meng (2010) conducted hydraulic fracturing tests, in which he used viscous Newtonian fluid and cross-linked (or X-linked) gel as injection fluid. He applied tri-axial loadings on a porous medium (Colton sandstone, Pierre Bleue limestone and Felser sandstone) that were varied to relate fracture occurrence with the in-situ stresses. The results showed a fracture pressure of 2.5 to 4 times higher than the minimum confining pressure.

Little research has been devoted to pressure build-up phenomena with polymer injection in porous media. When water-soluble, high molecular weight polymers like HPAM are used for EOR, polymer retention retards propagation into the formation. Consequently, high polymer retention can substantially delay oil displacement and recovery (Zhang and Seright, 2013).

In early experiments, high-molecular-weight hydrolysed polyacrylamide samples were injected by steps of increasing flow rates in low-permeability (small pores) granular porous media obtained by packing crushed quartz grains. At high flow rates, a slow pressure build-up was observed, followed by a levelling off to a plateau. The plateau value increased with flow rate and were always higher than the values that could be expected from viscosity measurements (Desremaux et al., 1971; Zitha et al., 2001).

The objective of this study is to investigate the water and polymer injectivities in an unconsolidated sand pack saturated either with brine or with heavy oil, subject to confining axial and radial stresses in the range of those encountered in reservoirs. In particular we are interested in the typical reservoir conditions under which failure/hydraulic fracturing of the sample occurs. We also intend to investigate the effect such a hydraulic fracture will have on polymer injection.

In chapter 2, background information concerning the polymer characteristics is given. In chapter 3, the physical model, governing equations, additional equations and the analytical solutions will be explained. In chapter 4, all materials used, procedures for preparing the polymer solution, the porous medium and executing the experiments is explained. In chapter 5, the observations of the results are discussed and compared with the Newtonian and non-Newtonian flow models. In chapter 6, the objective of this thesis will be discussed which will lead to the final conclusion. Further, recommendations will be suggested for future research.
2. Background

2.1 General polymer properties

In this study hydrolysed polyacrylamide (HPAM) was used to conduct experiments. Hydrolysed polyacrylamides is a co-polymer where some of the acrylamide is replaced by, or converted into, acrylic acid. These groups are randomly distributed along the polymer chain. Typical degree of hydrolysis is 30%-35% of acrylamide monomers; hence the HPAM molecule is negatively charged, which accounts for many of its physical properties. The degree of hydrolysis has been selected to optimize certain properties such as water solubility, viscosity and retention. If hydrolysis is small, the polymer will have a low water solubility. If it is too large, its properties will be too sensitive to salinity and hardness (Shupe, 1981). The viscosity increasing feature of HPAM lies in its large molecular weight. This feature is accentuated by the anionic repulsion between polymer molecules and between segments on the same molecule. The repulsion causes the molecule in solution to elongate and snag on others similarly elongated, an effect that accentuates the mobility reduction at higher concentrations. In high salinity brines, this repulsion is greatly decreased through ionic shielding since the freely rotating carbon-carbon bonds allow the molecule to coil up. The shielding causes a corresponding decrease in the effectiveness of the polymer since snagging is greatly reduced.

Radius of gyration ($R_g$) is a property to characterize the size of polymer in solution (Lake, 1989). It is defined as the average squared distance from the centre of mass of coil to its monomer unit.

$$R_g = \left( \frac{[\mu]M_w}{\Phi} \right)^{\frac{1}{2}}$$

(1)

where $[\mu]$ is the intrinsic viscosity, $M_w$ is the molecular weight of the polymer and $\Phi$ is a universal constant with a value of $4.2 \times 10^{24}$ mol$^{-1}$

Virtually all HPAM properties show a large sensitivity to salinity and hardness, an obstacle to using HPAM in many reservoirs. On the other hand, HPAM is inexpensive and relatively resistant to bacterial attack, and it exhibits permanent permeability reduction. (Lake, 1989)
2.2 Polymer concentration

When polymer concentration \((c_p)\) increases, the polymer conformation changes and the polymer molecules interact (Teraoka, 2002). Coiled up polymer molecules have almost no interaction with each other due to low polymer concentration. They behave independently and mainly interact with the solvent molecules. When the polymer concentration increases, the interaction between the polymer coils increases as well, because the average distance between the coils is decreased. At a certain polymer concentration \((c_p^*)\), called the critical concentration, the polymer coils start to overlap each other. This is because the solution is packed with these coils. This critical concentration marks the onset of semi-dilute regime.

Above critical concentration, the polymer molecules are overlapping and some are uncoiled. They also start to entangle each other. For this reason the mobility of each polymer molecule is reduced significantly compared to molecules in the dilute regime. Thus with increased concentration, the viscosity will be higher in this regime compared to in the dilute regime.

The relation between viscosity and the polymer concentration has been modelled by the Flory-Huggins equation (Flory, 1953; Lake, 1989).

\[
\mu_p = \mu_w \left[ 1 + a_1 c_p + a_2 c_p^2 + a_3 c_p^3 + \ldots \right]
\]  

where \(\mu_p\) is the polymer viscosity, \(\mu_w\) is the water (solvent) viscosity, \(c_p\) is the polymer concentration in the aqueous phase and \(a_1, a_2\) and so on are constants.

When the polymer concentration approaches zero, so at infinite dilution, the intrinsic viscosity is defined. It is a way of measuring the thickening power of a polymer.

\[
[\mu] = \lim_{c_p \to 0} \left[ \frac{\mu_{sp}}{c_p} \right]
\]  

with

\[
\mu_{sp} = \left[ \frac{\mu_p - \mu_w}{\mu_w} \right]
\]

\(\mu_{sp}\) is the specific viscosity. The intercept of the initial part of \(\frac{\mu_{sp}}{c_p}\) versus \(c_p\) on a Cartesian plot gives the value of \([\mu]\). The slope gives the value of the Huggins coefficient \((k_H)\). The Huggins coefficient accounts for hydrodynamic interactions between the macromolecules.
2.3 Polymer rheology

The rheology of a polymer is characterized by a viscosity increase or decrease depending on shear rate effects. The shear rate effects become clear when the polymer solution has a constant concentration and viscosity is measured at varying shear rates.

Figure 1 shows bulk measurements of polymer viscosity $\mu_p$ versus shear rate $\gamma$ obtained in a rheometer. At low shear rates, $\mu_p$ is independent of $\gamma$ ($\mu_p = \mu_p^0$), and the solution behaves like a Newtonian fluid. At higher $\gamma$, $\mu_p$ decreases, approaching a limiting ($\mu_p = \mu_p^\infty$) value not much greater than the water viscosity $\mu_w$ at some critical high shear rate. The shear thinning behaviour of the polymer solution is caused by the uncoiling and unsnagging of the polymer molecules when they are elongated in shear flow.

![Figure 1: Viscosity versus shear rate. Measurements obtained in a rheometer of a HPAM AN905 polymer solution with $c_p = 5000$ ppm, salinity of 0 g/L NaCl and shear rates ranging from 0.01 s$^{-1}$ to 1000 s$^{-1}$.](image)

Figure 2 shows the sketch of the polymer solution viscosity $\mu_p$ versus shear rate $\gamma$ obtained in porous media at sufficiently high permeabilities so that retention effects are negligible at fixed temperature and salinity.

In a conventional shear rheometer only the first two regimes, Newtonian and shear thinning, can be observed as shown in Figure 1. The thickening regime is a consequence of the extension of polymer coils to a stretched state, resulting in a large increase in polymer-solvent friction (De Gennes, 1971; Bird et al., 1987). This coil-stretch transition is induced by the elongational deformation gradients present in the complex porous medium flow geometries.
Figure 2: Viscosity versus shear rate. The onset of shear thinning and shear thickening behavior, indicating \( \mu_p^0 \) for zero shear rate and \( \mu_p^\infty \) as the minimum viscosity with the red and blue line respectively.

The viscosity for low shear rates is favourable, because for the bulk of a reservoir’s volume, \( \dot{\gamma} \) is usually low (about 1-5 s\(^{-1}\)), making it possible to attain a design mobility ratio with a minimal amount of polymer. But near injection well, \( \dot{\gamma} \) can be quite high, which causes the polymer viscosity to be greater than that expected based on \( \mu_p^0 \).

In the shear-thinning regime, the relationship between polymer solution viscosity and shear rate may be described by a power-law model

\[
\mu_p = K_{pl} (\dot{\gamma})^{npl-1}
\]

where \( K_{pl} \) and \( n_{pl} \) are the power-law coefficient and exponent, respectively. For shear thinning fluids, \( 0 < n_{pl} < 1 \); for Newtonian \( n_{pl} = 1 \) and \( K_{pl} \) becomes the viscosity. \( \dot{\gamma} \) is always positive.

A relationship for polymer viscosity that describes both the Newtonian regime at low shear rates as well as the shear-thinning regime is defined with the Meter model (Meter and Bird, 1964).

In porous media \( \mu_p \) is also called the apparent velocity \( \mu_{app} \) and the effective shear rate \( \dot{\gamma}_{eq} \) is estimated based on capillary tube concepts. The apparent viscosity of a flowing polymer is

\[
\mu_{app} = H_{pl} u_n^{n_{pl}^{-1}}
\]

where (Hirasaki and Pope, 1974)

\[
H_{pl} = K_{pl} \left( \frac{1+3n_{pl}}{n_{pl}} \right)^{n_{pl}} \left( 8k_w \phi_w \right)^{(1-n_{pl}/2)}
\]
The right-hand side of equation (7) is $K_{pl} \gamma_{eq}^{n_{pl}^{-1}}$, which yields the equivalent shear rate for flow of a power-law fluid. The shear rate is defined as

$$\gamma_p = \alpha_g \frac{4u}{\phi r_p} \tag{8}$$

with

$$\alpha_g = \frac{3n_{pl} + 1}{4n_{pl}} \tag{9}$$

and

$$r_p = \sqrt{\frac{8k_w}{\phi_w}} \tag{10}$$

where $u = Q/A$ ($u$, for radial flow) and $r_p$ is the pore throat radius. The shift factor $\alpha_g$ takes into account the porous medium structure and is a slowly varying factor of $n_{pl}$.

In both equations (7) and (8), $k_w$, the aqueous phase permeability, is the product of the phase relative permeability and the absolute permeability. The aqueous phase porosity $\phi_w$, is $\phi_S w$.

### 2.4 Polymer retention

Polymer adsorption, mechanical entrapment and a hydrodynamic retention (rate dependent retention) are the main retention effects causing permeability reduction in porous media (Szabo, 1979; Domiguez an Willhite, 1977; Huh, 1990).

Adsorption is the most important cause for permeability reduction in typical reservoir permeabilities (10 to 1000mD). A bridging effect that happens under adsorption conditions was found by Zitha (2001). Bridging adsorption takes place when velocity is high enough to induce coil stretching and the length of a stretched macromolecule is larger than the average pore throat radius.

Mechanical entrapment can take place both under adsorption and non-adsorption conditions. Retention occurs at any flow rate and will increase with increasing flow rate (Sorbie, 1991).

The flow of dilute polymer solutions in porous media can be classified in three main regimes by considering the ratio between the characteristic polymer coil radius, i.e. the radius of gyration ($R_G$), and the characteristic pore radius ($r_p$), i.e. an indication for permeability. In the following, the occurring retention mechanisms in low permeability porous media ($r_p < 3R_G$), high permeability porous media ($r_p > 50R_G$) and intermediate permeability porous media ($3R_G < r_p < 50R_G$) will be discussed respectively (Denys, 2003).

For polymer concentrations above a critical point ($c_p^*$), the polymer chains are entangled (see Section 2.2). During injection of a polymer solution in porous media, these entangled chains maybe retained in the porous medium, but close to the inlet as a result of filtration (mechanical entrapment). For higher molecular weights and lower permeability, the filtration degree can be expected to be higher. (Huh, 1990; Yerramilli et al., 2013).

2.4.1 Low permeability porous media

Polymer molecules can be filtered out when passing constrictions in a porous media. Considering a cylindrical pore, the polymer coil can just enter before adsorption has taken place. Due to adsorption the pore radius decreases with $2R_G$. So mechanical entrapment will take place when $r_p < 3R_G$. This is represented in Figure 3.

![Figure 3: A coiled up polymer chain enters a cylindrical pore which has been pre-adsorbed](image)

2.4.2 High permeability porous media

In this regime ($r_p > 50R_G$), the average pore diameter is very large compared to the polymer coil size, therefore retention by filtration (mechanical entrapment) on pore throats is negligible. Polymer retention can only occur by adsorption, if the polymer has a tendency to adsorb on the porous medium (Denys, 2003). The mobility reduction $R_m$ is a function of the (in-situ) viscosity, which depends on the flow rate and the permeability reduction $R_k$ of the porous medium due to adsorption. The mobility reduction increases with shear rate above critical value due to coil stretching (Zitha, 1995). For high permeability porous media, the permeability reduction $R_k$ is usually independent of the flow rate. $R_k$ depends on the ratio between the adsorbed layer thickness and the pore radius. The value of the permeability reduction after adsorption $R_k$ is small and does not vary with the solvent flow rate.

2.4.3 Intermediate permeability porous media

In the intermediate permeability porous media ($3R_G < r_p < 50R_G$) the retention of polymer occurs due to both mechanical entrapment and adsorption. (Zitha, 1994; Zitha, 1995) found a critical shear rate. Below this rate only a small permeability reduction resulted due to polymer adsorption. Above this rate $R_m$ increased continuously in time during injection due to coil stretching as described earlier. The stretched chains can bridge pore throats by adsorption. This bridging process, resulting in a continuous permeability reduction, can last as long as still free adsorption sites around the pore throat are available.
3. Modelling

3.1 Physical model

The purpose of this work is to investigate pressure behavior and the injectivity of polymer in the context of polymer flooding compared to water-flooding in unconsolidated heavy oil reservoirs. Let us consider a cylindrical homogeneous and isotropic porous medium with radius $R_e$ and height $H$, having porosity $\phi$ and permeability $k$, with well-rounded sand grains of diameter $d_g$. Three models will be considered to match the experiments conducted in this study. The first model is water injection in a water saturated porous medium (WIW). The second model is polymer solution of concentration $c_p$, injected into a water saturated porous medium (PIW). The final model is the same polymer solution of concentration $c_p$ injected in an oil saturated porous medium (PIO). Fluids are injected in the porous medium at constant flow rate $Q$. The analysis is restricted to incompressible, non-inertial and isothermal flows. For the remainder of the work the following assumptions will be considered.

1. Polymer degradation by chemical, mechanical, thermal and bacterial means is not considered and chromatographic separation in porous medium is neglected.
2. No chemical reactions between polymer, rock and formation brine.
3. No mass transfer between the stagnant and flowing regions of the fluid.
4. The polymer adsorption onto the rock surface is instantaneous and mixing zone between the water and polymer fronts is negligible.
5. The density ($\rho$) of aqueous phase is constant, i.e. polymer does not change the density of aqueous phase.

Another major assumption, made in this study, concerns the flow profile. As a consequence of the experimental set-up, flow in the BHS has spherical symmetry (see Appendix G). Therefore, the analysis of the flow problems outline above, should honour the spherical symmetry. However, we are not aware of any analysis of these spherical flows in the context of petroleum sciences and engineering and derivation of corresponding equation is out of the scope of this study. The studies reported in the literature concerning flow around a well assume a radial flow profile cylindrical. Numerous solutions are available in the literature for almost every conceivable cylindrical flow problem. Since in this study we are primarily concerned with qualitative differences in injectivity between the difference injection schemes, we have decided to analyse the experiments using radial cylindrical flow equations, even though the error made might be large.
3.2 Governing equations

The above flow problem can be described formulating and solving a system of equations describing polymer flow in porous media. We are interested in the pressure behaviour during the water-flood and polymer flood for different flow rates. We will describe how bottom-hole flowing well pressure varies as a function of time.

The governing partial differential equation for flow in porous media is called the diffusivity equation. The diffusivity equation for a compressible liquid is given as

\[
\frac{1}{r} \frac{\partial}{\partial r} \left( \frac{k \rho}{\mu} r \frac{\partial P}{\partial r} \right) = \phi c \rho \frac{\partial P}{\partial t}
\]

where \( r \) is the radial distance from the injection point and \( c \) is the compressibility. Depending on conditions of the reservoir model and type of injection experiments, the partial diffusivity equation is solved to describe the transient, semi-steady state and steady state regime for Newtonian fluids. The flow regimes are explained with the analytical solution for each injection model, namely the water injection in a water saturated core, polymer injection in a water saturated core and polymer injection in an oil saturated core.

For every type of experiment, the initial conditions are the same. Prior to injection, the bottom-hole flowing well pressure \( (P_{wf}) \) is equal to the initial pressure \( (P_i) \). Therefore, the initial condition is given by

\[
P_{wf}(t=0) = P_i \quad \text{for} \quad r = R_w
\]

\[
P(t=0) = P_i \quad \text{for} \quad R_w < r < R_e
\]

In the experimental results the moment when injection is started is assumed as \( t = 0 \). The initiation of injection will always be after a few seconds after the measurement was started.

Initially, the pressure response can be described using a transient solution of the diffusivity equation. It is assumed during this period that the pressure response at the wellbore is not affected by the drainage boundary of the well and vice versa. This is frequently referred to as the infinite reservoir case since, during the transient flow period, the reservoir appears to be infinite in extent. The condition for transient state is

\[
\frac{\partial P}{\partial t} = f(r,t)
\]

The bottom-hole flowing well pressure for transient state during injection with injection rate \( 'Q' \) is described with (Chaudry, 2004).

\[
P_{wf} = P_i + \frac{Q \mu}{4 \pi k H} \left[ \ln \left( \frac{4 k t}{\gamma \phi c R_w^2} \right) \right]
\]

Eventually, stabilised flow conditions will prevail, which means that the boundary affects the pressure and is considered as solid “brick wall”, which prevents the flow of fluid out of the radial cell.

This corresponds to the semi-steady state condition.
\[
\frac{\partial P}{\partial r} = 0 \quad \text{at } r = R_e
\]

if the well is injecting at a constant flow rate, then the rate of change of wellbore pressure with respect to time is constant. The cell pressure will increase in such a way that

\[
\frac{\partial P}{\partial t} = \frac{Q}{c\pi R_e H \phi}
\]

The bottom-hole flowing well pressure for semi-steady state during injection is described with (Chaudry, 2004).

\[
P_{wf} = P_i + \frac{Q \mu}{2\pi kH} \left[ \ln \left( \frac{4A}{yc_A R_w^2} \right) + 2\pi \left( \frac{kt}{\phi \mu c A} \right) \right]
\]

(13)

where \(y=1.781\) and \(c_A=31.6\)

Reservoirs with injection wells can reach true steady-state condition when total injection rate is equal to total production rate. This condition is present when the reservoir model has an open boundary and therefore,

\[
P(r,t) = \text{constant} \quad \frac{\partial P}{\partial t} = 0
\]

The bottom-hole flowing well pressure for steady state during injection is described with (Chaudry, 2004).

\[
P_{wf} = P_i + \frac{Q \mu}{2\pi kH} \ln \left( \frac{R_e}{R_w} \right)
\]

(14)

Polymers behave non-Newtonian and retention effects cause permeability reduction. Equation (15) describes the bottom-hole flowing pressure and takes the shear thinning and permeability reduction \(R_k\) into (Lake, 1989).

\[
P_{wf} = P_i + \left( \frac{Q}{2\pi H} \right)^{n_{pl}} \frac{H_{pl} R_k}{k_w (1-n_{pl})} (R_e^{1-n_{pl}} - R_w^{1-n_{pl}})
\]

(15)
3.3 Additional equations

3.3.1 Permeability reduction

During polymer injection in a porous medium, retention of the polymer molecules takes place leading to a reduction of permeability as explained in Section 2.5. Permeability reduction manifests itself through increase in pressure drop. Permeability reduction is only one of three measures in permeable media flow (Jennings et al., 1971; Lake, 1989). The resistance factor \( F_R \) is the ratio of the mobility of brine to that of a single-phase polymer solution flowing under the same conditions.

\[
F_R = \frac{\lambda_w}{\lambda_p} = \left( \frac{k_w}{\mu_w} \right) \left( \frac{\mu_p}{k_p} \right)
\]  \hspace{1cm} (16)

For constant flow rate, \( F_R \) is the inverse ratio of pressure drop; for constant pressure drop, \( F_R \) is the ratio of flow rates. \( F_R \) is an indication of the total mobility lowering contribution of a polymer. To describe the permeability reduction effect alone, a permeability reduction factor \( R_k \) is defined as

\[
R_k = \frac{k_w}{k_p} = \frac{\mu_w}{\mu_p} F_R
\]  \hspace{1cm} (17)

A final definition is the residual resistance factor \( R_{RF} \), which is the mobility of a brine/water solution before and after polymer injection.

\[
R_{RF} = \frac{\lambda_w}{\lambda_{wa}}
\]  \hspace{1cm} (18)

where \( \lambda_{wa} \) is the mobility of the brine/water after contact with polymer

3.3.2 Mobilities

The mobilities are given by

\[
\lambda_p = \frac{k_p}{\mu_{p, \text{eff}}}
\]  \hspace{1cm} (19)

\[
\lambda_w = \frac{k_w}{\mu_{w, \text{eff}}}
\]  \hspace{1cm} (20)

where \( \mu_{p, \text{eff}} \) and \( \mu_{w, \text{eff}} \) are the effective viscosities of water and the polymer solution
A way to determine the efficiency is by means of mobility ratio $M$. The mobility ratio is calculated by

$$ M = \frac{k_{\text{ing}}/\mu_{\text{ing}}}{k_{\text{ed}}/\mu_{\text{ed}}} $$

where the subscripts “ing” and “ed” stand for the displacing fluid and the displaced fluid respectively.

Mobility reduction $R_m$ is an indication of loss of injectivity during polymer injection. It takes into account the pressure drop due to viscosity and adsorption of polymer to the rock. It is defined as

$$ R_m = \frac{\Delta P_p}{\Delta P_{b0}} $$

where $\Delta P_p$ is the pressure drop during polymer injection and $\Delta P_{b0}$ pressure drop for brine prior to polymer injection.

### 3.3.3 Injectivity

The injectivity of a well is defined as (Lake, 1989)

$$ I = \frac{Q}{\Delta P} $$

where, $Q$ is the volumetric injection rate into the well, and $\Delta P$ is the pressure drop between the bottom-hole flowing pressure and some reference pressure, i.e. the initial pore pressure. Injectivity is preferred to be high, meaning high injection rates and low pressure drop. High flow rates lead to increased sweep efficiency.

Another useful measure is the relative injectivity

$$ I_r = \frac{I}{I_w} $$

where, $I_w$ the water injectivity in ml/min/bar. $I_r$ can be used to visualize more easily the injectivity decline to be anticipated when injecting polymer. Both $I$ and $I_r$ are functions of time, but the long-time limit of $I_r$ for a Newtonian polymer solution is simply the viscosity ratio if skin effects are small.
3.4 Analytical solutions

Two analytical solutions are found that consider the displacement of water or oil by a polymer solution. The first solution takes the non-Newtonian behaviour into account and the second solution assumes the polymer has a constant average viscosity. The three experimental models are explained with the analytical solution considering the assumptions.

The flow model is solved for a well, of radius $R_w$, in a horizontal, homogeneous and circular drainage area of radius $R_e$. The pressures at $R_e$ and $R_w$ are $P_i$ and $P_{wf}$, respectively. $P_i$ is constant (steady-state flow), but $P_{wf}$ can vary with time.

The fluids flowing in the reservoir are single aqueous phase, at residual oil or water saturation, which are both incompressible with pressure-independent rheological properties.

The volumetric injection rate is defined as:

$$Q = 2 \pi r H u_r$$

(25)

where $u_r$ is the Darcy velocity, which is used in shear rate calculations.

During injection there is a polymer-water or polymer-oil front depending on the experimental model. The region $R_w < r < R_p$ accounts for the polymer which has displaced the water (or oil) from the well ($R_w$) to a certain point in the reservoir ($R_p$), the polymer-water front. In the region $R_p < r < R_e$ accounts for the water or oil that is displaced by the polymer to the polymer-water front ($R_p$) and reaches to the end of the reservoir ($R_e$).

The pressure drop during polymer injection with non-Newtonian effects is defined as:

$$P_{wf} - P_i = \left( \frac{Q}{2 \pi H} \right)^{\nu} \frac{H \mu_p R_p}{(1 - \eta_p)} k_w (R_w^{1 - \eta_p} - R_p^{1 - \eta_p}) + \frac{Q \mu_f}{2 \pi k_f H} \left( \ln \left( \frac{R_e}{R_p} \right) \right)$$

(26)

The first term on the right hand side of equation (26) gives the pressure drop of the polymer region ($R_w < r < R_p$) and takes into account the non-Newtonian effect and the permeability reduction effect. The second term gives the pressure behaviour of the water region ($R_p < r < R_e$).

If the polymer viscosity $\mu_p$ is taken as a constant value, the model for pressure drop is defined as:

$$P_{wf} - P_i = \frac{Q \mu_p}{2 \pi k_p H} \left( \ln \left( \frac{R_p}{R_w} \right) \right) + \frac{Q \mu_f}{2 \pi k_f H} \left( \ln \left( \frac{R_e}{R_p} \right) \right)$$

(27)

The first term on the right side of equation (27) gives the pressure drop of the polymer region ($R_w < r < R_p$). The second term gives the pressure drop of the water or oil region ($R_p < r < R_e$).

In both equation (26) and (27), $\mu_f$ is the viscosity of the saturation fluid of the porous medium (water or oil), $k_p$ is the polymer permeability, $k_f$ is the permeability of the saturation fluid phase (water or oil) and $R_p$ is the radial distance of the injected polymer front. If $\mu_p$ is equal to $\mu_f$, it becomes a single phase steady state flow model as in equation (14).

The viscosity of the polymer, $\mu_p$, is estimated for different shear rates. The shear rates are calculated using equation (8). Once the shear rates are calculated at each radial distance of the
polymer solution, the viscosity can be determined from Figure 4. Viscosities for shear rates higher than 1000 s\(^{-1}\) are estimated using a relation between shear thinning and shear thickening slopes obtained from measured data found by Zitha (2001). The estimation procedure is explained in Appendix A. The estimated viscosities will help to justify the non-Newtonian model with shear thinning effects and the model with a constant polymer viscosity.

![Figure 4: Viscosity versus shear rate of AN905 HPAM with a concentration of 5000 ppm and salinity of 0 g/L NaCl. Newtonian plateau and shear thinning regime from rheometer measurements. Shear thickening regime estimated from slope relations (Appendix A).](image)

3.4.1 Water injection into water saturated porous medium

The WIW model assumes a single phase liquid flow. The equations for each flow regime assume single phase liquid flow as well (equations 12, 13 and 14). So the flow equations give a good prediction of what is happening during the WIW experiments. Figure 5 shows the pressure drop versus time for each flow regime in the case of the WIW model. It can clearly be seen that the transient state pressure drop increases fast for short times and will reach a constant pressure drop if time is infinite. The semi-steady state pressure drop keeps increasing with a constant rate. Due to the effect of no outflow at the boundary, injected fluid will build up pressure. If the inflow is equal to the outflow, pressure drop will not increase but will stay constant and reach steady state flow as explained before. The experimental set-up in this study has an open boundary. Therefore, the water outflow will eventually be equal to the injection rate of water and flow will reach a steady state. It takes time to reach steady state flow, so transient state flow will describe the pressure drop increase before it reaches the steady state flow. Due to the small size of the porous medium, steady state flow will be reached in less than 3 seconds.

To estimate the permeability of the porous medium, the flow models are fitted with the experimental results in Section 5.1.1. The flow model that fits best is used to determine the permeability.
Figure 5: Transient state, semi-steady state and steady state pressure drop versus time for the WIW model. Flow rate, viscosity and permeability are constant.

3.4.2 Polymer injection into water saturated porous medium

The model for PIW is a pseudo-two-phase flow (assumed single phase flow) model were the polymer solution displaces the water. Both fluids are considered incompressible, injection rate is equal to outflow rate after some time, so eventually steady state flow conditions prevail. Given the size of the porous medium, the time to reach steady state will again be less than 3 seconds. Figure 6 shows the graphs corresponding to the analytical solutions for the displacement flow and the steady state flow where the polymer has already displaced all the water (equations 26, 27 and 14).

It is assumed that polymer (viscous fluid) displaces water (less viscous fluid) in a front like manner. The viscous polymer will create a higher pressure drop compared to the WIW model. The pressure drop increases over time, because low viscosity fluid is displaced by a higher viscosity fluid.

In Section 5.1.2 the model compared with the experimental data considering the shear rate dependency.

Figure 6: Single phase steady state, displacement non-Newtonian flow and displacement flow with constant polymer viscosity pressure drop versus time for the PIW model. Flow rate and permeability are constant.
3.4.3 Polymer injection into oil saturated porous medium

Figure 7 shows the graphs corresponding to the analytical solutions for the displacement flow and the steady state flow where the polymer has already displaced all the oil (equations 26, 27 and 14). It is assumed that polymer displaces oil in a front like manner. Oil is more viscous than water resulting in more resistance to displace by the polymer solution. This leads to a higher pressure drop compared to the PIW model. The pressure drop decreases over time, because high viscosity fluid (oil) is displaced by a lower viscosity fluid (polymer solution). The experimental results are presented in Section 5.1.3 and are compared to the PIO model.

![Graph showing pressure drop versus time for different flow types](image)

**Figure 7:** Single phase steady state, displacement non-Newtonian flow and displacement flow with constant polymer viscosity pressure drop versus time for the PIO model. Flow rate and permeability are constant.
4. **Experiments**

This chapter presents the core flooding experiment using water, and hydrolysed polyacrylamide (HPAM) into porous samples saturated with either water or oil (at connate water saturation). The injection of water and polymers will give information on pressure behaviour at different injection rates. Because of the different flow characteristics between the three fluids, the pressure behaviour will also be different. During injection, fracture development is also an outcome. Results of the injection experiment will be discussed and compared with the analytical models in Chapter 5.

4.1 **Experimental set-up**

Figure 10 shows schematically the borehole simulator (BHS) set-up for performing polymer injection experiments. It consists mainly of a biaxial pressure vessel, a high pressure injection system and a data-acquisition system. (Zhou et al. 2010)

Figure 9 shows how the porous medium is placed in the biaxial pressure vessel. The biaxial pressure vessel is able to create the reservoir pressures onto a porous medium using silicon oil. The biaxial pressure vessel can supply pressures up to 300 bar with an accuracy of 0.1 bar.

The high pressure injection system consists of a high pressure pump, MTS servo controller and injection cell. With the MTS controller the injection rate is set. The high pressure pump will provide the pressure needed to obtain the correct injection rate. The maximum pressure to not overload the pump is 200 bar. The injection cell is connected to the high pressure pump and contains the injection fluid. An injection line connects the injection cell with the injection pipe. The maximum volume for one time injection is 550±10 ml. A second pump, an ISCO pump, is used to fill the injection line an injection pipe and it is used to create the same fluid pressure in the injection system as the initial pore pressure in the porous medium. The ISCO pump can inject 100±3ml and can produce a pressure up to 700 bar.

The data-acquisition system uses ‘Natural Instruments, Labview 8.6’ software to record data every 0.1 sec. The axial pressure, radial pressure and injection pressure are measured by means of pressure transducers with an accuracy of 0.001 bar. Axial displacement of the sample is measured with an accuracy of 0.001 mm. A balance measures the weight of the outflow and is also recorded by the data-acquisition system. The balance is accurate up to 0.1 gram and sends a signal to the data-acquisition system every 20±1 seconds.
4.2 Materials and Methods

The porous medium used to conduct the experiments was a pack of quartz grains having an average diameter of 113±0.1 µm. The three kinds of fluids that were selected for testing are water, polymer solution and silicon oil. Tap water was used for the saturation of the sand pack and for injection during the WIW experiment. Partially hydrolysed polyacrylamide (HPAM, 30%-35% degrees of hydrolysis) having molecular weight between 8 and 9 million Dalton was used to prepare the polymer solution. The polymer (AN905 Lot E 2686) was supplied by SNF Floerger in powder form. Silicon oil (Rhodorsil, Huile 47 V 1000) having viscosity of 1000 cP was used for the saturating the porous medium with oil (after water saturation).

4.3 Preparation of the polymer solution

A polymer solution with concentration of 5000 ppm was prepared by dissolving the required weight of AN905 polymer in demineralised water. The desired amounts of water and polymer were weighted using a precision balance. The demineralised water was placed in a Erlenmeyer. Then it was stirred, using a magnetic stirrer, at sufficiently high speed to create a vortex. The polymer powder is then added slowly, grain-by-grain, to avoid agglomeration of polymer particles. The flask containing the polymer solution is sealed with a cap. Nitrogen is flushed over the polymer solution to remove the remaining air in the flask to reduce the oxygen in contact with the polymer solution as much as possible. After one hour, the speed of the stirrer was reduced and left to stir at a slow speed for 24 hours to obtain a homogeneous solution.

4.4 Porous medium sample

The porous sample was prepared by pouring sand into the sample cell of the borehole simulator (BHS). The cell shown in Figure 8 includes a permeable metal filter at the top and bottom, a pipe at the centre of the filter for simulating a borehole, and a cylindrical rubber sleeve for holding the porous medium sample. Pore size of the filter is smaller than sand grain size. The cylinder is built up through putting a rubber sleeve around the bottom plate, fixed with a metal ring on which a double-part metal mantle is mounted. There are two holes at the bottom of the cylinder under the filter, which are used for regulating the amount of water during sample build-up and for drainage during compaction and conducting the experiment. The top plate has a similar filter as the bottom plate to ensure that pore water can drain through the top and bottom of the sample. Dimensions of the samples are 0.5±0.01 m in length and 0.4±0.001 m in diameter. While filling up the rubber sleeve with sand the metal mantle is hit with a hammer, compacting the porous medium, resulting in the lowest possible porosity.

The petrophysical properties of the samples prepared during this study are summarized in Table 2. The porosity was determined by mass balance from the total amount of water injected into the sample (Appendix F). Permeability was determined by analysing the water injection in a water saturated porous medium in Chapter 5.
Figure 8: Left, bottom filter with injection pipe. Middle, rubber sleeve with porous medium on top of filter being covered by the metal mantle. Right, top filter being placed on the porous medium.

Figure 9: Left, sample being placed in the biaxial pressure vessel of the BHS. Right, set-up of the biaxial pressure vessel.
Figure 10: Set up of a borehole simulator injection experiment

Figure 11: Close up of the porous medium with the injection pipe (borehole pipe) and its injection point
4.5 Experimental procedure

The preparations of one experiment may take up to two weeks. The time includes assembling, dissembling and cleaning the set-up.

The porous sample from Figure 8 is placed in a biaxial pressure vessel Figure 9. The vessel can put the sample under axial and radial pressure to create reservoir conditions. Pressures vary between 0 bar and 100 bar in this experiment. The axial and radial pressures were created by injecting silicon oil onto the rubber sleeve (radial) and on top of the filter (axial). Axial pressure should always be 10 bar higher than radial pressure to prevent leakage from radial pressure chamber into the axial pressure chamber on top of the sample. These oil pressures chambers are coloured purple in Figure 10.

When the porous sample is in place and the system is closed so no leakage can occur, the final procedure must be taken to prepare the injection experiment. This procedure is presented in Table 1. During each step the data acquisitions system is used to record pressure changes, axial displacement and outflow rates.
Table 1: Step by step procedure of preparing the BHS (full description of procedures in Appendix C).

<table>
<thead>
<tr>
<th>Step</th>
<th>Title</th>
<th>Description</th>
<th>Parameters varied</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Q (ml/min)</td>
<td>V_{fluid} (L)</td>
</tr>
<tr>
<td>1</td>
<td>Removal of air in porous medium</td>
<td>Evacuation and CO$_2$ flushing</td>
<td>100</td>
</tr>
<tr>
<td>2a</td>
<td>Water saturating</td>
<td>Inject water through bottom filter until it flows out from the top. Wait one hour. Water flushing 4 times</td>
<td>30</td>
</tr>
<tr>
<td>2b</td>
<td>Oil saturating</td>
<td>Inject oil though bottom filter until it flows out from the top. Wait two hours. Oil flushing 4 times</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Increase axial and radial pressures</td>
<td>Make sure axial pressure is always 10 bar higher than radial pressure. Record pressures and axial displacement -Exp. 1 to 10 -Exp. 11 and 12</td>
<td>100</td>
</tr>
<tr>
<td>4</td>
<td>Fill injection pipe</td>
<td>When saturated, open the bottom of the injection pipe. Saturation fluid flows in the pipe and displaces air out. Use ISCO pump to fill pipe with polymer for PIW and PIO experiment types. The polymer displaces saturation fluid back into sample</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Connect injection cell</td>
<td>The injection cell is connected to injection pipe via injection lines. The cell and lines must be filled with injection fluid.</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Pressurize fluids in injection lines</td>
<td>Use ISCO pump to put injection lines under the same pressure as the initial pore pressure in the sample</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Set MTS servo controller</td>
<td>Choose the right injection rates for each experiment. Start data-acquisition</td>
<td></td>
</tr>
</tbody>
</table>
5. Results and Discussion

Table 2 gives an overview of the experiments with the injection rate, the injected volume, the confining pressures and the flowing well (injection) pressures during injection. In Table 2 we can also see that 550 ml is injected in three parts for Exps. 1, 2 and 3 (WIW). Here the flow rate was changed 2 times during the injection of 550 ml. Time to switch from one flow rate to another flow rate was 10 seconds. The same procedure was used in Exps. 8, 9 and 10 (PIW).

For the WIW, PIW and PIO experiments, observations will be discussed for the case of an injection rate of 600 ml/min. The PIW experiments will be discussed for two confining pressures 100/70 bar and 50/30 bar (Exps. 10 and 11). Further, injectivity will be discussed and the WIW injectivity will be the base case for the relative injectivity.
Table 2: Summary of sample properties, experimental parameters and measured pressures. Experiment type WIW, PIW and PIO stands for water injection in a water saturated sample, polymer injection in a water saturated sample and polymer injection in an oil saturated sample, respectively.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>wiw</td>
<td>60</td>
<td>87</td>
<td>90.8</td>
<td>27.6</td>
<td>0.44</td>
<td>2.3</td>
<td>96</td>
<td>72</td>
<td>2.38</td>
<td>2.10</td>
<td>0.28</td>
</tr>
<tr>
<td>2</td>
<td>wiw</td>
<td>300</td>
<td>174</td>
<td>90.8</td>
<td>27.6</td>
<td>0.44</td>
<td>2.3</td>
<td>96</td>
<td>72</td>
<td>2.45</td>
<td>2.10</td>
<td>0.35</td>
</tr>
<tr>
<td>3</td>
<td>wiw</td>
<td>600</td>
<td>289</td>
<td>90.8</td>
<td>27.6</td>
<td>0.44</td>
<td>2.3</td>
<td>96</td>
<td>72</td>
<td>2.95</td>
<td>2.10</td>
<td>0.85</td>
</tr>
<tr>
<td>4</td>
<td>wiw</td>
<td>600</td>
<td>550</td>
<td>90.8</td>
<td>27.6</td>
<td>0.44</td>
<td>2.3</td>
<td>97</td>
<td>72</td>
<td>3.30</td>
<td>2.10</td>
<td>1.20</td>
</tr>
<tr>
<td>5</td>
<td>wiw</td>
<td>600</td>
<td>550</td>
<td>90.8</td>
<td>27.6</td>
<td>0.44</td>
<td>2.3</td>
<td>96</td>
<td>71</td>
<td>3.43</td>
<td>2.10</td>
<td>1.33</td>
</tr>
<tr>
<td>6</td>
<td>wiw</td>
<td>1200</td>
<td>550</td>
<td>90.8</td>
<td>27.6</td>
<td>0.44</td>
<td>2.3</td>
<td>100</td>
<td>74</td>
<td>4.35</td>
<td>2.10</td>
<td>2.25</td>
</tr>
<tr>
<td>7</td>
<td>wiw</td>
<td>1200</td>
<td>550</td>
<td>90.8</td>
<td>27.6</td>
<td>0.44</td>
<td>2.3</td>
<td>99</td>
<td>74</td>
<td>3.98</td>
<td>2.10</td>
<td>1.88</td>
</tr>
<tr>
<td>8</td>
<td>piw</td>
<td>10</td>
<td>50</td>
<td>90.8</td>
<td>27.6</td>
<td>0.44</td>
<td>2.3</td>
<td>99</td>
<td>71</td>
<td>2.92</td>
<td>2.10</td>
<td>0.82</td>
</tr>
<tr>
<td>9</td>
<td>piw</td>
<td>120</td>
<td>241</td>
<td>90.8</td>
<td>27.6</td>
<td>0.44</td>
<td>2.3</td>
<td>99</td>
<td>71</td>
<td>11.02</td>
<td>2.10</td>
<td>8.92</td>
</tr>
<tr>
<td>10</td>
<td>piw</td>
<td>600</td>
<td>259</td>
<td>90.8</td>
<td>27.6</td>
<td>0.44</td>
<td>2.3</td>
<td>99</td>
<td>71</td>
<td>28.40</td>
<td>2.10</td>
<td>26.30</td>
</tr>
<tr>
<td>11</td>
<td>piw</td>
<td>600</td>
<td>550</td>
<td>91.8</td>
<td>27.4</td>
<td>0.44</td>
<td>2.3</td>
<td>46</td>
<td>33</td>
<td>27.71</td>
<td>2.00</td>
<td>25.71</td>
</tr>
<tr>
<td>12</td>
<td>pio</td>
<td>600</td>
<td>550</td>
<td>91.8</td>
<td>26.5</td>
<td>0.42</td>
<td>2.3</td>
<td>51</td>
<td>30</td>
<td>57.44</td>
<td>1.90</td>
<td>55.54</td>
</tr>
</tbody>
</table>
5.1 Experimental results and interpretation

5.1.1 Water injection in a water saturated porous medium

Figure 12 shows the pressure drop versus time over the radius of the BHS measured during water injection in a water saturated sand-pack at injection rate of 600 ml/min (Exp. 4). The injection rate (600 ml/min) was set at the start of the experiment, from the first moment the pressure starts to increase and lasts for 53 seconds. From 3 to 10 seconds the pressure seems to increase linearly. The data acquisition system records measurements every 0.1 seconds, but it does not show recorded measurements on the linear slope. The time of the beginning of the linear slope matches with the time when the balance, for water outflow measurements, sends a signal to the data acquisitions system. This can be seen in the graphs in Appendix H where water outflow is presented together with the pressure drop measurements. Communication between the balance and recording device causes a break in the recording of 7 seconds, hence the linear interpolation between measurements at 3 and 10 seconds respectively. After 10 seconds the pressure fluctuates between 0.9 bar and 1.5 bar with an average of approximately 1.2 bar. At 24 seconds there is another recording break, at 45 seconds there is a peak in the pressure drop, followed by another break in recording as explained above. After 55 seconds the injection stops and the pressure drop decreases almost immediately.

![Figure 12: Exp. 4. Injection with q=600 ml/min. The pressure drop (Pwf-Pi) and flow rate in are presented versus time](image)

The experimental data from WIW Exps. 4 and 5 with an injection rate of 600 ml/min are presented against time in Figure 13. To compare the experimental data with the model predictions of Section 3.4.1., they are shown together in the graph in Figure 13. The data from the two experiments are similar which indicated reproducibility (within experimental error margins).

The main uncertainty for these water injection experiments is the permeability. Therefore the permeability was chosen as the fitting parameter for matching the model predictions of different flow regimes to the experimental data. As can be seen in Figure 13, the steady-state model gives a better fit to the measured data than the transient and semi steady state models. This supports the statement that the time to reach steady-state is short on account of the small dimensions of the samples compared to the reservoir situation. Because of this observation, the rest of the discussion will be based on a steady-state flow assumption. The corresponding
permeability was 2.3±0.1 D. This value was also used as the absolute permeability for the analysis (model predictions, curve fitting) of the polymer injection experiments into the water- and oil-saturated sand-packs (Exp. 8 to 12). In these experiments the main uncertainties are the rheology, and retention of the polymer and the geo-mechanical properties of the sand-pack.

Figure 13: Pressure drop of Exp. 4 and 5 together with the transient, semi-steady and steady-state models for \( q = 600 \text{ ml} \) and \( k = 2.3 \text{ Darcy} \) are presented versus time

Injectivity of the water flood for experiments 4 and 5 is presented in Figure 14. Injection starts at approximately 3 seconds. At this moment in time the injectivity is zero. After 10 seconds, the injectivity in Exp. 4 reached a value of 550±5 ml/min/bar. From 10 to 20 seconds injectivity declined to a value of 490±2 ml/min/bar, with fluctuations between 420 and 530 ml/min/bar. The reason for a higher injectivity around 10 seconds of injection and decline to an average value of 500 ml/min/bar is due an increasing pressure drop from zero pressure drop when injection is initiated, because when pressure drop is low, injectivity is high. The injectivity results for Exp. 5 show the same results as Exp. 4, only with a slightly lower value, starting from an injectivity of 530 ml/min/bar with a decline to a value of approximately 460 ml/min/bar with fluctuations between 420 and 570 ml/min/bar.

Figure 14: Injectivities of Exps. 4 and 5
5.1.2 Polymer injection in a water saturated porous medium

Figure 15 shows the pressure drop obtained during polymer injection in a water saturated sample versus time, again for an injection rate of 600 ml/min (Exp. 10). The axial and radial pressures on the sample were 99 and 71 bar respectively. Injection starts after 10 seconds and lasts approximately 25 seconds. The pressure drop increases up to a value of 26±2 bar. The pressure remains around this value with fairly large fluctuations between 21 and 32 bar. When injection stops, the pressure decreases steeply to the initial pore pressure $P_i$ (0 bar pressure drop) in approximately 15 seconds.

![Figure 15: Exp. 10 (PIW) with $q=600$ ml/min. The pressure drop ($P_{wf}-P_i$) and flow rate in are presented versus time. Exp. 10 has a axial and radial pressure of 99 bar and 71 bar, respectively](image)

In Figure 16 results of a similar experiment (Exp. 11) as in Figure 15 are presented. Only in this injection experiment the confining pressure has been lowered to an axial pressure and radial pressure of 46 bar and 33 bar respectively. The pressure drop increase starts around 28 seconds and rises to 25±2 bar, with fluctuations between 23 bar and 30 bar. After 80 seconds (52 seconds of injection), the injection stops and pressure drop decreases immediately and smoothen out to zero pressure drop in approximately 13 seconds.

![Figure 16: Exp. 11 (PIW) with $q=600$ ml/min. The pressure drop ($P_{wf}-P_i$), flow rate in are presented versus time. The experiment was performed with axial and radial pressure of 46 bar and 33 bar, respectively](image)
In Figure 17, pressure drop results of experiments 10 and 11 (PIW) are presented together versus time. Here it is visible, even though the confining pressure is different, the pressure drop of Exps. 10 and 11 is the same (i.e. the same within experimental error margins). Although Exps. 10 and 11 are executed in different sand packs, we assume that any differences in the properties of these porous media are negligible for the purposes of these experiments. Exp. 10 has a shorter injection time, because three injection rates were chosen during the injection of 550 ml (Exps. 8, 9 and 10) as explained earlier. The graphs with the results of Exp. 8, 9 and 10 are in Appendix H.

The experimental data and PIW model prediction from section 4.3.2. are shown together in Figure 17. Because the pressure drop takes on a stable value virtually immediately after the start of injection, the steady-state model gives the best fit. The viscosity that fits for this model is 20 cP, which is 20 times higher than the viscosity of water used in the WIW model, corresponding to a 20 times higher pressure drop. This viscosity was used as input for the displacement model with constant polymer viscosity. As explained, when the polymer has displaced all the water, the pressure drop will show the same result as the steady-state model where all the water is displaced.

In the non-Newtonian displacement model the polymer solution is assumed to be shear thinning. As we can determine from in Figures 29 and 30 (Appendix B), shear rates are higher than 1000 s⁻¹ up to 13.5 cm of injection radius. This means the polymer solution is shear thickening over the main part of the injection radius, with a viscosity of 134 cP at the wellbore and 12 cP at 13.5 cm, resulting in a higher predicted pressure drop than shown in Figure 17. Therefore, the non-Newtonian model is not valid for an injection rate of 600 ml/min or higher, causing the high shear rates. The rheology values of the PIW experiment are equal to the values of the PIO experiment, because injection rate and penetration depth are the same. Therefore the non-Newtonian model will also not be valid in the PIO model and will not be discussed.

The permeability reduction $R_k$ is assumed to be 1, because we have no data on retention. Retention does take place, therefore permeability was reduced and $R_k$ is in reality higher than 1, which results in higher pressure drop for both displacement models than Figure 17 shows.
To clarify the effects of permeability reduction on pressure drop, the displacement model with constant polymer viscosity is presented in Figure 18 versus time for $R_k$ higher than 1, meaning $k_p$ is lower than 2.3 D. When $R_k$ is higher than 1, we can see that the curve has a steeper initial pressure drop. For $Rk2.5$ ($R_k = 2.5$) the modelled pressure drop matches the slope of initial experimental pressure drop, but will reach a pressure drop that is double the experimental pressure drop as time passes. If we look at $Rk1.5$ ($R_k = 1.5$) we see that this curve does not match the initial pressure drop increase as well as $Rk2.5$, but as time passes $Rk1.5$ matches with the experimental data around 10 seconds. The $Rk1$ ($R_k = 1$) curve matches with the data when all water is displaced by the polymer solution. A good match can be found when $R_k$ is taken as a variable parameter that will decrease when time passes and the polymer has displaced more water. This means most retention effects occur at short time and close to the wellbore, causing $R_k$ to be high. When time passes and the polymer solution invades further into the porous medium, retention effects decrease, decreasing $R_k$.

Injectivity of the polymer flood is presented in Figure 19 for Exp. 10 and 11. The injectivities show peaks at the beginning and at the end of the injection. This is due to the same reason as mentioned for the injectivities from Exps. 4 and 5; a low pressure drop that quickly increases after injection is initiated. Both Exps. 10 and 11 stay around and average value of 23 ml/min/bar. Compared to the injectivities of Exps. 4 and 5, this value is approximately 20 times lower. This means pressure drop is 20 times higher. The difference in pressure drop compared to water injection experiment, is caused by the higher viscosity of the polymer solution and retention effects. According to equation (26) we can see both properties increase the pressure drop.
Figure 19: Injectivities of Exps. 10 and 11

5.1.3 Polymer injection in an oil saturated sample

In Figure 20 the result of Exp. 12, a polymer injection in an oil saturated sand (PIO) is shown. After 13 seconds the injection starts with an injection rate of 600 ml/min and continues for 52 seconds. When injection starts, the pressure increase is 130±1 bar for nearly 1.0 s. After this peak in the pressure drop, the pressure drop decreases to 51 bar and takes on an average value of 55 bar with fluctuations between 51 bar and 58 bar. At 65 seconds the injection of the polymer stops and the pressure drop decreases exponentially until 120 seconds when it is back to zero bar pressure drop.

Figure 20: Exp. 12 (PIO) with $q=600$ ml/min. Polymer injection in an oil saturated sample. The pressure drop ($P_{wf}-P_{i}$), flow rate in are shown versus time. Exp. 12 has a axial and radial pressure of 51 bar and 30 bar, respectively.
The experimental data is compared with PIO model predictions in Figure 21. Because the pressure increase takes on a stable value almost directly after the start of injection, the single phase steady state model gives the best fit, with a viscosity of 43 cP. This is 43 times higher than the water viscosity. This corresponds with the pressure drop increase, which is also 43 times higher than the pressure drop of the WIW experiment. For the displacement model with a constant polymer solution viscosity, we take 43 cP. The curve will eventually reach stable pressure drop when all the oil has been displaced by the polymer. If displacement is has a shorter time constant, the model prediction would give a better fit as it reaches the stable pressure drop faster.

The displacement model with constant polymer viscosity has a very high initial pressure drop. The initial pressure drop for the displacement model is 1334±1 bar. The initial pressure drop represent the pressure drop, when is no polymer present in the porous medium. So the fluid that provides the pressure drop is oil. The oil has a high viscosity of 1000 cP, therefore it causes more pressure drop compared to the viscous polymer. Both curves decrease, because the high viscosity oil is displaced by a lower viscosity polymer solution.

![Figure 21: Exp. 12 (PIO) results versus time together with the single-phase steady state and the displacement with constant polymer viscosity models for q=600 ml and k=2.3 Darcy and polymer viscosity 43 cP.](image)

To find an explanation for the peak pressure, we need to understand what happens when pressure drop reaches the high values predicted by the displacement model. As seen in earlier research done by Zhou (2010) and Meng (2010), were they studied fracture development for injecting high viscosity fluids in unconsolidated sands, the porous medium will develop fractures if the pressure drop is 2.5 to 4 times higher than the minimum confining pressure. The minimum confining radial pressure in Exp. 12 is 30 bar. So we can expect a fracture development when the pressure drop reaches a value between 75 and 120 bar. The peak pressure drop is 130±1 bar, so a fracture did occur, but initiated at a higher pressure drop than was claimed by Zhou and Meng. In the fracture, permeability will be higher creating a smaller pressure drop. Figure 34 in Appendix G.2 shows the distribution of the polymer solution caused by increased fracture permeability, corresponding to the fracture. The viscosity that fits with the peak in the steady state model is 100 cP (Figure 22). Fracture occurrence makes use of displacement model predictions invalid.
The injectivity of Exp. 12 is presented in Figure 23. The first peak the graph shows is again due to the low pressure drop that increases very quickly right after injection starts. Right after the first high peak, we see a low peak. The low injectivity peak is the same as the peak from the pressure increase where the fracture developed. The peak injectivity has a value of around 5 ml/min/bar. Compared to the water flood case, this is 100 times smaller, meaning pressure drop was 100 times higher during injection of the polymer in an oil saturated sand pack. Compared to the polymer injection in a water saturated sand pack, the injectivity is 5 times smaller. This means due to oil saturation, the pressure increase is 5 times higher.

After the low peak, the injectivity stays around 10 ml/min/bar. This is 50 times smaller than the water flood case and 2.5 times smaller than the polymer flood in water saturated sand pack case.
An overview of the relation between water flood injectivities and the polymer flood injectivities is shown in Figure 24. The relation is the relative injectivity with respect to water injectivity and indicates the decline to be anticipated when injecting polymer. So the injectivity of Exps. 10 and 11 is 0.05 times water injectivity and for Exp. 12 the injectivity is 0.02 times water injectivity.

![Figure 24: Relative injectivities of Exps. 10, 11 and 12 in relation to water injectivity](image-url)
5.2 General discussion

From the WIW experiments it was found that, flow can be adequately described by a steady-state model. Using the steady-state model, we found that a permeability of $2.3 \pm 0.1$ D gave the best fit. Assuming the preparation procedure is done the same way for each sand pack, the permeability for all the other experiments can be expected to be $2.3 \pm 0.1$ D. Pressure drop is very low for WIW experiments and thus gives a high injectivity of 500 ml/min/bar. The PIW experiments with the injection rate of 600 ml/min were reproducible for different confining pressures. Therefore we can conclude that confining pressure has negligible influence on the pressure drop during a polymer flood. The pressure drop in PIW experiments was 20 times higher than the pressure drop in WIW experiments. This is related to the higher viscosity of the polymer solution compared to water. The expectation when injecting polymer is that pressure drop will increase over time as it displaces the water which has a lower viscosity. The two analytical solution models for displacement both show this expectation. The non-Newtonian displacement model was expected to give the best fit as it considers the rheology and retention of the polymer solution. The results, however, showed a stable pressure drop over time. The non-Newtonian model was found to not be valid for higher shear rates than 1000 s$^{-1}$. The shear thickening and retention effects have to be considered to give a good fit, although it will not fit as well as the steady state model that assumes all water has been displaced by the polymer solution. The displacement model with constant polymer viscosity will eventually give the same fit as the single phase steady state model, but does not reach the stable pressure drop quickly enough to fit the experimental results. When the retention effect is analysed, causing permeability reduction, it became clear that the displacement model fits when $R_k$ is high close to the wellbore and decreases when the polymer solution further invades the porous medium. The stable pressure drop fits best with the single phase steady state model when a viscosity of 20 cP is assumed, which is 20 times higher as the water viscosity. Therefore, in PIW experiment, the polymer flood can best be considered as a single phase steady state flow where the polymer solution with average viscosity of 20 cP has displaced all the water.

According to the injectivity comparison of WIW with PIW the pressure drop, when the polymer HPAM AN905 with a concentration of 5000 ppm is used for the polymer flood, will be 20 times higher than the pressure drop in a water flood, corresponding with increased viscosity.

The PIO model predicted a decrease in pressure drop when a displacement flow is considered, because a high viscosity oil is displaced by a lower viscosity polymer solution. The results of the PIO experiment, however, showed a peak pressure which was 4.3 times higher than the confining radial pressure. According to the work of Zhou and Meng this means a fracture has occurred, but at a higher pressure drop as was claimed. The peak pressure lasted only for 1.0 sec. After the 1.0 sec the pressure declined to a stable average value. As observed with PIO experiments, the steady state model showed the best fit to the measurements, and the best fit was found using a viscosity value of 43 cP. This is 43 times higher than viscosity of water and corresponds to the pressure drop, which is also approximately 43 times higher than the pressure drop of the WIW experiment.

When the peak pressure was used to fit model predictions to observed data, a viscosity of 100 cP is required. The analytical solution model that considers displacement with constant polymer solution viscosity, gives a pressure drop that is significantly higher than the experimental data shows, due to the high oil viscosity. The predictions of high pressure drop explains why pressure has been able to reach the fracture pressure.
When the injectivities of the PIO experiment is compared with the WIW experiment, we see that the stable average pressure drop has an injectivity 50 times smaller than the water injectivity and the peak pressure drop has an injectivity 100 times smaller (Figure 24).

A way to see the relation between the water flood injectivity and polymer flood injectivity is by means of the relative injectivity. This work has showed that injectivity decline for PIW is 0.05, for PIO this decline is 0.02 and for the peak in PIO experiment this is 0.01. Injectivity is preferred to be high to give the best recovery results. The experiments clearly showed when injection fluid or displaced fluid have a higher viscosity than water, injectivity decreased. The occurrence of the fracture in the PIO experiment, however, increased injectivity during the experiment. If the fracture had not occurred the injectivity would reach even lower values than the peak injectivity showed.

We need not forget that assumptions are made to cover limitations of the experiment. With the BHS set-up it is not possible to measure polymer retention effects such as mechanical entrapment or adsorption, which are known characteristics of HPAM. The outflow of the flooding experiment is measured with a mass balance. The mass balance measurements are recorded by the data acquisition system. The limitation is that measurements are recorded every 20 seconds and not every 0.1 seconds. Outflow results cannot be used for comparison with the injection flow rate, especially for the short time interval of the experiment.

The pressure measured inside the sample is the pressure at the bottom of the of the injection pipe. Pressures inside the sample at different radii cannot be measured. For the steady state model, radial cylindrical flow is assumed. Analysing the porous medium after the flooding experiment, showed that the fluid spreads in a spherical way. Not enough literature is present to model steady state spherical flow. Modelling cylindrical or spherical flow makes a difference for the flow rates inside the sample at different radii, this determines shear rates and thus viscosity for the polymer solution.

The injection cell can only inject 550 ml during one injection. 550 ml is not enough for the injection fluid to reach the borders of the set-up.

The permeability is determined by fitting the steady state model with the experimental results of the WIW experiments. Exps. 11 and 12 are both performed in new prepared porous medium. For these two porous media, the same permeability is assumed, which is potentially a false assumption.
6. **Conclusion and Recommendations**

6.1 **Conclusion**

Results of the experiments showed flooding experiments are reproducible, proving the reliability of the BHS set-up.

The injectivity of a water flood decreased when the polymer HPAM AN905 is added to create a solution of 5000 ppm. Displacing water, the injectivity decreases with a factor 20. When displacing oil of 1000 cP, the injectivity decreases with a factor 50. During displacement of oil, the resultant pressure drop over the sample was more than 2.5 to 4 times (4.3 times) higher than the confining radial pressure which initiated fracturing. This leaded to an increase in permeability and thus a lower pressure drop over the sample. Due to the fracture the injectivity doubled. So polymer flood decreases injectivity, but when a fracture develops it will increase to a stable value.

Predicting pressure behaviour for a polymer flood experiment is best approached using a single phase steady-state flow model that assumes all saturation fluid has been displaced. Although it remains unclear what viscosity should be considered for the injection fluid as it is a result of fitting the experiments and not an input value beforehand. The non-Newtonian model needs to consider permeability reduction, shear thickening effects and the actual spherical flow to give a good fit. Not enough data was collected for these parameters, therefore the model did not give a good fit. The displacement model with constant polymer viscosity made clear that retention is highest close to the wellbore and decreases when polymer is further invaded in the porous medium.

6.2 **Recommendations**

To improve experiments and models for a similar experiment, some recommendations are made for future work.

A relation between true viscosity of the polymer solution and the estimated viscosity which gave the best fit for a single phase steady-state flow model must be found. This gives good results and can save time creating a model that considers all parameters.

We assumed radial flow behaviour, but in reality we observed spherical flow. More research is needed on spherical flow to take this into account in theoretical predictions.

The outflow of the displaced fluid was in axial direction through the top and bottom filter. This setup inhibits spherical flow. If we want flow to be strictly radial, we require outflow in radial direction. In the present setup this is not possible due to the rubber sleeve. Adjustment of the set-up to allow for radial outflow is highly recommended.

The outflow was measured by a mass balance which did not communicate very well with the data-acquisition system. This resulted in outflow volumes/mass to be measured every 20 seconds and disturbing the data recordings, making these measurements incompatible with other data. In addition, the mass outflow recordings disturbed the injection pressure recording. This issue could be resolved by replacing the mass balance and updating the required software.

The injection cell can only inject a maximum volume of 550±10 ml. If we want fluids to reach the border of a porous medium we need to be able to inject a larger volume.

Finally and maybe most important is doing a core flood experiment beforehand to determine all unknown parameters of the porous medium and polymer solution.
Appendices

A. Shear rate versus viscosity graphs

For the shear rate calculations the combination of equations (8), (9) and (10) is used

\[
\gamma_{eq} = \left(\frac{1+3n_{pl}}{n_{pl}}\right) \frac{u}{\sqrt{8k_u \phi_w}}
\]

The measured shear rates from the rheometer go up to 1000 s\(^{-1}\). When shear rates exceed 1000 s\(^{-1}\), we need to estimate the shear thickening regime.

Figure 25 shows the viscosity measurement of the AN905 HPAM obtained from a rheometer up to a shear rate of 1000 s\(^{-1}\).

![Figure 25](image)

**Figure 25**: Viscosity versus shear rate results from rheometer of AN905 HPAM. Concentration \(c_p=5000\) ppm and salinity 0 g/L NaCl.

The slope was determined with a power-law trendline (Figure 26) which gave a slope \(m = -0.376\)

![Figure 26](image)

**Figure 26**: Power-law trendline gives slope of \(m = -0.376\)
To create the shear thickening regime, we use research data found by Zitha and others (2001). The data is presented in Figure 27. With this data we determine the relation between the shear thinning slope and the shear thickening slope. The shear thinning slope is called mA and the shear thickening slope is called mB. Three shear rate points are important. The first is $\gamma_0$ below which the polymer solution acts Newtonian. Belonging to this shear rate is the viscosity $\mu_0$. For higher shear rates the viscosity has a declining slope to a shear rate $\gamma_{\text{mid}}$, with viscosity $\mu_{\text{mid}}$. The shear thickening regime for higher shear rates ends at a shear rate $\gamma_{\text{end}}$, with viscosity $\mu_{\text{end}}$.

From the graph in Figure 27 we found the values

\[
\begin{align*}
\gamma_0 &= 45 \text{ s}^{-1} \quad \text{with } \mu_0 = 2.9 \text{ Pa.s} \\
\gamma_{\text{mid}} &= 110 \text{ s}^{-1} \quad \text{with } \mu_{\text{mid}} = 1.9 \text{ Pa.s} \\
\gamma_{\text{end}} &= 1500 \text{ s}^{-1} \quad \text{with } \mu_{\text{end}} = 20 \text{ Pa.s}
\end{align*}
\]

**Figure 27:** Mobility versus shear rate data from Zitha et al. (2001).

Slope mA is calculated with

\[
mA = \frac{\log(\frac{\mu_{\text{mid}}}{\mu_0})}{\log(\frac{\gamma_{\text{mid}}}{\gamma_0})}
\]

Slope mB is calculated with

\[
mB = \frac{\log(\frac{\mu_{\text{end}}}{\mu_{\text{mid}}})}{\log(\frac{\gamma_{\text{end}}}{\gamma_{\text{mid}}})}
\]
from Figure 27 mA and mB are determined which give

\[ mB = 0.900 \]
\[ mA = -0.473 \]
\[ mB/mA = -1.904 \]

Using slope mA from Figure 25 and the mB/mA relation from Figure 27 gives a slope for AN905 HPAM with

\[ mB = 0.695 \]

To calculate the end value for viscosity the following relationship is used

\[ \frac{\mu_{end} - \mu_{mid}}{\mu_0 - \mu_{end}} \]

Figure 27 gives a factor of 18.1, leading to an end viscosity \( \mu_{end} = 1.398 \) Pa.s for the AN905 HPAM. With the slope mB and \( \mu_{end} \). The shear thickening regime is created for the polymer solution shown in

![Figure 28: Viscosity versus shear rate for AN905 HPAM. Concentration \( c_p = 5000 \) ppm and salinity is \( 0 \) g/L NaCl. Viscosities of shear rates up to \( 1000 \) s\(^{-1}\) measured in rheometer. Shear thickening regime determined through slope relations, estimated from data found by Zitha (2001).](image-url)
B. Rheology models

The shear rates are highest close to the wellbore and this gives lower viscosities using a non-Newtonian model. The viscosity of the polymer solution has a minimum value of 12 cP and for low shear rates the Newtonian plateau has a viscosity of 100 cP (Figure 4). The non-Newtonian model does not take a minimum or a maximum viscosity into account for high or low shear rates.

The shear rates during injection are calculated at each radial distance from the wellbore with equation (8), presented in Figure 29. The viscosities are estimated for these shear rates with Figure 4. This gives the result in Figure 30. The highest shear rate closest to the wellbore is 26323 s$^{-1}$. This shear rate lies in the shear thickening regime of the polymer and gives a viscosity of 134 cP. The volume of fluid that is injected reaches a penetration depth of 15 cm if flow is radial cylindrical flow. At this radial distance the shear rate is 877 s$^{-1}$ which relates to a viscosity of 13 cP. The shear rates do not lie in the Newtonian plateau, so for the lowest shear rates the non-Newtonian model is valid. For shear rates higher than 1000 s$^{-1}$ the non-Newtonian model gives lower viscosity values than the minimum viscosity of 12 cP, resulting in a lower estimated pressure drop with the non-Newtonian model.

Figure 29: Shear rate versus radial distance from wellbore

Figure 30: Viscosity versus radial distance from wellbore
C. Preparation before starting the experiment

The full explanation that goes with Table 1

1. To ensure that the sample and injection tubes do not contain any air before saturation, the sample is vacuumized and flushed with CO$_2$. This step is repeated two times and finally the sample is vacuumized again before saturating with water.

2. Water is injected for saturation from the bottom through the filter at a flow rate of 100 ml/min. When water flows out from the top, the water saturation is stopped to let the water settle and distribute over the whole radius of the sample. After one hour water saturation is continued in four steps of injecting 1 liter of water to ensure best possible saturation. Depending on the experiment the sample can be saturated with oil after water saturation creating an oil saturated sample with residual water saturation. Oil is injected from the bottom filter with a rate of 30 ml/min. The rate is slower, because oil has a viscosity of 1000 cp. A slower rate ensures better radial distribution. Again after oil flows out, the sample saturation is stopped and continued in four steps to inject 4 liters of oil.

3. Now that the sample is saturated, the axial and radial pressures can be set to the right values for each experiment.

4. Depending on the experiment type and which fluid will be injected, the injection pipe needs to be filled with injection fluid.

   When the sample is only saturated with water (WIW and PIW experiments) the injection pipe is filled with water by opening the bottom of the injection pipe to let the saturation fluid flow out of the bottom. This also pushes out air that is present in the injection pipe. This is important, because in PIW experiments, the saturation fluid will be displaced back into the sample with the injection fluid.

   In WIW experiments the injection fluid will be water, so the injection pipe is filled with the correct fluid.

   In PIW experiments the injection fluid is polymer solution. To fill the injection pipe with polymer solution, the ISCO pump is used to displace the water in the injection pipe back into the sample until the injection pipe is fully filled with polymer.

   In PIO experiments, the saturation fluid is oil, so during oil saturation the bottom of the injection pipe is opened to let oil fill the injection pipe. After this step the ISCO pump is used again to displace the oil in the injection pipe back into the sample and fill the injection pipe with the polymer solution.

5. Now the injection cell can be connected to the injection line and injection pipe. Before connecting the injection cell, the injection cell must be filled with the injection fluid. The same goes for the injection line. Filling of the injection line is done with the ISCO pump.

6. When everything is filled with injection fluid, the fluid pressure needs to be the same as the pore pressure in the sample. This fluids in the injection line and pipe are put under pressure with the ISCO pump.

7. Last step is to set the right injection rate on the MTS controller and start the experiment. Make sure the data acquisition is recording.
D. Pressure/Flow rate relation

Another way to show the relation between pressure drop and injection rate is shown in Figure 31. In this figure we can see pressure drop versus injection rate for the WIW, PIW and PIO experiments. The slope of the curves is pressure drop divided by injection rate. This is the same as the inverse of injectivity.

![Figure 31: Pressure drop versus Injection rate. The pressure drop data points are averaged values of the pressure drop during injection.](image-url)
E. Polymer retention interval

The interval in which the experiment has taken place is dependent on the radius of gyration and the pore throat radius. The radius of gyration is determined with equation (1) and pore throat radius with equation (10).

In the equation for radius of gyration, the intrinsic viscosity is a varying parameter. Intrinsic viscosity was determined by Yerramilli (2010) to be 1542 ml/g for pH = 5.8±0.1 and salinity of 20±0.1 g/L NaCl.
This leads to $R_G = 1.66 \times 10^5$ cm

With decreasing salinity the intrinsic viscosity increases, which further results in an increase in size of the macromolecule and thus higher viscosity

The pore throat radius can be calculated with permeability (2.3 D) and porosity (44%).
This gives $r_p = 6.32 \times 10^8$ cm

Therefore $r_p = 38 \ R_G$

This lies in the interval $3R_G < r_p < 50R_G$ for intermediate permeibility porous medium where adsorption and mechanical entrapment are the retention mechanisms.
F. Sand sample properties

Table 3: Sand properties, determination of porosity. WIW sample for Exps. 1 to 7; PIW1 sample for Exps. 8 to 10; PIW2 sample for Exp. 11; PIO sample for Exp. 12

<table>
<thead>
<tr>
<th>Properties of sand</th>
<th>WIW</th>
<th>PIW1</th>
<th>PIW2</th>
<th>PIO</th>
</tr>
</thead>
<tbody>
<tr>
<td>grain size [μm]</td>
<td>113</td>
<td>113</td>
<td>113</td>
<td>113</td>
</tr>
<tr>
<td>matrix density [g/cm³]</td>
<td>2.65</td>
<td>2.65</td>
<td>2.65</td>
<td>2.65</td>
</tr>
<tr>
<td>bulk density [g/cm³]</td>
<td>1.5</td>
<td>1.5</td>
<td>1.5</td>
<td>1.5</td>
</tr>
<tr>
<td>air density [g/cm³]</td>
<td>0.018</td>
<td>0.018</td>
<td>0.018</td>
<td>0.018</td>
</tr>
<tr>
<td>predicted porosity</td>
<td>0.437</td>
<td>0.437</td>
<td>0.437</td>
<td>0.437</td>
</tr>
</tbody>
</table>

Steps of pouring sand in sample

<table>
<thead>
<tr>
<th>Steps of pouring sand in sample</th>
<th>1 mass [kg]</th>
<th>2 mass [kg]</th>
<th>3 mass [kg]</th>
<th>4 mass [kg]</th>
<th>total sand mass in sample [kg]</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>23</td>
<td>25</td>
<td>25</td>
<td>17.8</td>
<td>90.8</td>
</tr>
<tr>
<td></td>
<td>23</td>
<td>25</td>
<td>25</td>
<td>26</td>
<td>90.8</td>
</tr>
<tr>
<td></td>
<td>26</td>
<td>26</td>
<td>26</td>
<td>26</td>
<td>91.8</td>
</tr>
<tr>
<td></td>
<td>25</td>
<td>26</td>
<td>26</td>
<td>26</td>
<td>93.925</td>
</tr>
</tbody>
</table>

Volume of total sand sample and water saturation

<table>
<thead>
<tr>
<th>Volume of total sand sample and water saturation</th>
<th>volume [cm³, ml]</th>
<th>volume [dm³, L]</th>
<th>volume [m³]</th>
<th>pore volume (predicted porosity * sand volume)</th>
<th>volume water saturation [L]</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>60533</td>
<td>60.533</td>
<td>0.060533</td>
<td>26,449</td>
<td>27.6</td>
</tr>
<tr>
<td></td>
<td>60533</td>
<td>60.533</td>
<td>0.060533</td>
<td>26,449</td>
<td>27.6</td>
</tr>
<tr>
<td></td>
<td>61200</td>
<td>61.200</td>
<td>0.061200</td>
<td>26,740</td>
<td>27.4</td>
</tr>
<tr>
<td></td>
<td>602617</td>
<td>62,617</td>
<td>0.062617</td>
<td>27,359</td>
<td>26.54</td>
</tr>
</tbody>
</table>

Porosity

| Porosity                                      | 0.456           | 0.456           | 0.448        | 0.424                                       |
|                                              | 0.439           | 0.439           | 0.436        | 0.422                                       |
G. Visual results of PIW and PIO experiment

G.1 PIW results of experiment 11

The pictures top and side views at the centre of injection of Exp. 11 are shown in Figure 32 and 33. Methyl blue was added to indicate the polymer front. Unfortunately the colour was filtered out due to chromatographic effects. The polymer-water front is still visible, because the water was dehydrated, causing a lighter colour compared to the polymer solution. In the right image of Figure 32 the polymer-water front is indicated with a black marker. The ruler indicated the polymer front is located at a radial distance of 6 cm. This corresponds to the distance of a spherical distribution of the polymer solution. Whereas for a cylindrical distribution the polymer front would be located at 15 cm. In Figure 33 the spherical distribution can clearly be seen.

Figure 32: Left image shows the top view of the center of injection of Exp. 11, with a methyl blue circle and a polymer-water front circle. Right image indicates the polymer-water front at a radial distance of 6 cm.

Figure 33: Left image shows the side view 2 cm below center of injection of Exp. 11. Left image indicates the polymer-water front of Exp. 11.
G.2 PIO results of experiment 12

The pictures of the top and side view at the centre of injection of Exp. 12 are shown Figure 34. This time the polymer-oil front is not visible, because both have the same colour (methyl blue is filtered out) and are not dehydrated. The right image of Figure 34 clearly shows spherical flow indicated by methyl blue. Methyl blue also indicated that the polymer solution distribution to the right is larger than the distribution to the left. The larger distribution is caused by a fracture, corresponding with the pressure data analysis of Exp 12 in Chapter 5.

Figure 34: Left shows the top view at the center of injection of Exp. 12. Right image shows spherical distribution of the polymer solution, where it is visible more polymer solution has been distributed to the right, due fracturing.
H. Experimental results

H.1 Experiment 1

Table 4 Solution and petrophysical parameters of core flood experiment 1

<table>
<thead>
<tr>
<th>Solution parameters</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Polymer</td>
<td>AN905 Lot E 2686</td>
</tr>
<tr>
<td>Molecular weight (g/mol)</td>
<td>$9 \times 10^6$</td>
</tr>
<tr>
<td>Degree of Hydrolysis (%)</td>
<td>5</td>
</tr>
<tr>
<td>Concentration (ppm)</td>
<td>5000</td>
</tr>
<tr>
<td>Salinity (g/L)</td>
<td>0</td>
</tr>
<tr>
<td>Flow rate (ml/min)</td>
<td>$60 \pm 0.5$</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>44</td>
</tr>
<tr>
<td>Permeability (Darcy)</td>
<td>$2.3 \pm 0.1$</td>
</tr>
</tbody>
</table>

Figure 35: Results of Exp. 1 with pressure drop and water injection flow rate versus time
Figure 36: Results of Exp. 1 with axial pressure and water injection flow rate versus time

Figure 37: Results of Exp. 1 with radial pressure and water injection flow rate versus time
Figure 38: Results of Exp. 1 with water injection flow rate and cumulative water outflow versus time

Figure 39: Results of Exp. 1 with axial pressure and cumulative water outflow versus time
Figure 40: Results of Exp. 1 with radial pressure and cumulative water outflow versus time

H.2 Experiment 2

Table 5 Solution and petrophysical parameters of core flood experiment 2

<table>
<thead>
<tr>
<th>Solution parameters</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Polymer</td>
<td>AN905 Lot E 2686</td>
</tr>
<tr>
<td>Molecular weight (g/mol)</td>
<td>$9 \times 10^5$</td>
</tr>
<tr>
<td>Degree of Hydrolysis (%)</td>
<td>5</td>
</tr>
<tr>
<td>Concentration (ppm)</td>
<td>5000</td>
</tr>
<tr>
<td>Salinity (g/L)</td>
<td>0</td>
</tr>
<tr>
<td>Flow rate (ml/min)</td>
<td>$300 \pm 0.5$</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>44</td>
</tr>
<tr>
<td>Permeability (Darcy)</td>
<td>$2.3 \pm 0.1$</td>
</tr>
</tbody>
</table>

Figure 41: Results of Exp. 2 with pressure drop and water injection flow rate versus time
Figure 42: Results of Exp. 2 with axial pressure and water injection flow rate versus time

Figure 43: Results of Exp. 2 with radial pressure and water injection flow rate versus time
Figure 44: Results of Exp. 2 with pressure drop and cumulative water outflow versus time

Figure 45: Results of Exp. 2 with axial pressure and cumulative water outflow versus time
Figure 46: Results of Exp. 2 with radial pressure and cumulative water outflow versus time

H.3 Experiment 3

Table 6 Solution and petrophysical parameters of core flood experiment 3

<table>
<thead>
<tr>
<th>Solution parameters</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Polymer</td>
<td>AN905 Lot E 2686</td>
</tr>
<tr>
<td>Molecular weight (g/mol)</td>
<td>(9 \times 10^6)</td>
</tr>
<tr>
<td>Degree of Hydrolysis (%)</td>
<td>5</td>
</tr>
<tr>
<td>Concentration (ppm)</td>
<td>5000</td>
</tr>
<tr>
<td>Salinity (g/L)</td>
<td>0</td>
</tr>
<tr>
<td>Flow rate (ml/min)</td>
<td>(600 \pm 0.5)</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>44</td>
</tr>
<tr>
<td>Permeability (Darcy)</td>
<td>(2.3 \pm 0.1)</td>
</tr>
</tbody>
</table>

Figure 47: Results of Exp. 3 with pressure drop and water injection flow rate versus time
Figure 48: Results of Exp. 3 with axial pressure and water injection flow rate versus time

Figure 49: Results of Exp. 3 with radial pressure and water injection flow rate versus time
Figure 50: Results of Exp. 3 with pressure drop and cumulative water outflow versus time

Figure 51: Results of Exp. 3 with axial pressure and cumulative water outflow versus time
Figure 52: Results of Exp. 3 with radial pressure and cumulative water outflow versus time

H.4 Experiment 1,2,3 combined

Figure 53: Results of Exps. 1, 2 and 3 with pressure drop and water injection flow rate versus time
Figure 54: Results of Exp. 1, 2 and 3 with axial pressure and water injection flow rate versus time

Figure 55: Results of Exp. 1, 2 and 3 with radial pressure and water injection flow rate versus time
Figure 56: Results of Exps. 1, 2 and 3 with water injection flow rate and cumulative water outflow versus time.

Figure 57: Results of Exps. 1, 2 and 3 with axial pressure and cumulative water outflow versus time.
H.5 Experiment 4

Table 7 Solution and petrophysical parameters of core flood experiment 4

<table>
<thead>
<tr>
<th>Solution parameters</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Polymer</td>
<td>AN905 Lot E 2686</td>
</tr>
<tr>
<td>Molecular weight (g/mol)</td>
<td>$9 \times 10^7$</td>
</tr>
<tr>
<td>Degree of Hydrolysis (%)</td>
<td>5</td>
</tr>
<tr>
<td>Concentration (ppm)</td>
<td>5000</td>
</tr>
<tr>
<td>Salinity (g/L)</td>
<td>0</td>
</tr>
<tr>
<td>Flow rate (ml/min)</td>
<td>$600 \pm 0.5$</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>44</td>
</tr>
<tr>
<td>Permeability (Darcy)</td>
<td>$2.3 \pm 0.1$</td>
</tr>
</tbody>
</table>

Figure 58: Results of Exp. 1, 2 and 3 with radial pressure and cumulative water outflow versus time

Figure 59: Results of Exp. 4 with pressure drop and water injection flow rate versus time
Figure 60: Results of Exp. 4 with axial pressure and water injection flow rate versus time

Figure 61: Results of Exp. 4 with radial pressure and water injection flow rate versus time
Figure 62: Results of Exp. 4 with water injection flow rate and cumulative water outflow versus time

Figure 63: Results of Exp. 4 with axial pressure and cumulative water outflow versus time
Figure 64: Results of Exp. 4 with radial pressure and cumulative water outflow versus time

H.6 Experiment 5

Table 8 Solution and petrophysical parameters of core flood experiment 5

<table>
<thead>
<tr>
<th>Solution parameters</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Polymer</td>
<td>AN905 Lot E 2686</td>
</tr>
<tr>
<td>Molecular weight (g/mol)</td>
<td>$9 \times 10^3$</td>
</tr>
<tr>
<td>Degree of Hydrolysis (%)</td>
<td>5</td>
</tr>
<tr>
<td>Concentration (ppm)</td>
<td>5000</td>
</tr>
<tr>
<td>Salinity (g/L)</td>
<td>0</td>
</tr>
<tr>
<td>Flow rate (ml/min)</td>
<td>$600 \pm 0.5$</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>44</td>
</tr>
<tr>
<td>Permeability (Darcy)</td>
<td>$2.3 \pm 0.1$</td>
</tr>
</tbody>
</table>

Figure 65: Results of Exp. 5 with pressure drop and water injection flow rate versus time
Figure 66: Results of Exp. 5 with axial pressure and water injection flow rate versus time

Figure 67: Results of Exp. 5 with radial pressure and water injection flow rate versus time
Figure 68: Results of Exp. 5 with water injection flow rate and cumulative water outflow versus time

Figure 69: Results of Exp. 5 with axial pressure and cumulative water outflow versus time
Figure 70: Results of Exp. 5 with radial pressure and cumulative water outflow versus time

H.7 Experiment 6

Table 9 Solution and petrophysical parameters of core flood experiment 6

<table>
<thead>
<tr>
<th>Solution parameters</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Polymer</td>
<td>AN905 Lot E 2686</td>
</tr>
<tr>
<td>Molecular weight (g/mol)</td>
<td>$9 \times 10^6$</td>
</tr>
<tr>
<td>Degree of Hydrolysis (%)</td>
<td>5</td>
</tr>
<tr>
<td>Concentration (ppm)</td>
<td>5000</td>
</tr>
<tr>
<td>Salinity (g/L)</td>
<td>0</td>
</tr>
<tr>
<td>Flow rate (ml/min)</td>
<td>$1200 \pm 0.5$</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>44</td>
</tr>
<tr>
<td>Permeability (Darcy)</td>
<td>$2.3 \pm 0.1$</td>
</tr>
</tbody>
</table>

Figure 71: Results of Exp. 6 with pressure drop and water injection flow rate versus time
Figure 72: Results of Exp. 6 with axial pressure and water injection flow rate versus time

Figure 73: Results of Exp. 6 with radial pressure and water injection flow rate versus time
Figure 74: Results of Exp. 6 with water injection flow rate and cumulative water outflow versus time

Figure 75: Results of Exp. 6 with axial pressure and cumulative water outflow versus time
Figure 76: Results of Exp. 6 with radial pressure and cumulative water outflow versus time

H.8 Experiment 7

Table 10 Solution and petrophysical parameters of core flood experiment 7

<table>
<thead>
<tr>
<th>Solution parameters</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Polymer</td>
<td>AN905 Lot E 2686</td>
</tr>
<tr>
<td>Molecular weight (g/mol)</td>
<td>$9 \times 10^6$</td>
</tr>
<tr>
<td>Degree of Hydrolysis (%)</td>
<td>5</td>
</tr>
<tr>
<td>Concentration (ppm)</td>
<td>5000</td>
</tr>
<tr>
<td>Salinity (g/L)</td>
<td>0</td>
</tr>
<tr>
<td>Flow rate (ml/min)</td>
<td>$1200 \pm 0.5$</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>44</td>
</tr>
<tr>
<td>Permeability (Darcy)</td>
<td>$2.3 \pm 0.1$</td>
</tr>
</tbody>
</table>

Figure 77: Results of Exp. 7 with pressure drop and water injection flow rate versus time
Figure 78: Results of Exp. 7 with axial pressure and water injection flow rate versus time

Figure 79: Results of Exp. 7 with radial pressure and water injection flow rate versus time
Figure 80: Results of Exp. 7 with water injection flow rate and cumulative water outflow versus time

Figure 81: Results of Exp. 7 with axial pressure and cumulative water outflow versus time
Figure 82: Results of Exp. 7 with radial pressure and cumulative water outflow versus time

H.9  Experiment 8

Table 11 Solution and petrophysical parameters of core flood experiment 8

<table>
<thead>
<tr>
<th>Solution parameters</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Polymer</td>
<td>AN905 Lot E 2686</td>
</tr>
<tr>
<td>Molecular weight</td>
<td>$9 \times 10^5$</td>
</tr>
<tr>
<td>Degree of Hydrolysis</td>
<td>5</td>
</tr>
<tr>
<td>Concentration</td>
<td>5000</td>
</tr>
<tr>
<td>Salinity (g/L)</td>
<td>0</td>
</tr>
<tr>
<td>Flow rate (ml/min)</td>
<td>$10 \pm 0.5$</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>44</td>
</tr>
<tr>
<td>Permeability (Darcy)</td>
<td>$2.3 \pm 0.1$</td>
</tr>
</tbody>
</table>

Figure 83: Results of Exp. 8 with pressure drop and polymer injection flow rate versus time
Figure 84: Results of Exp. 8 with axial pressure and polymer injection flow rate versus time

Figure 85: Results of Exp. 8 with radial pressure and polymer injection flow rate versus time
Figure 86: Results of Exp. 8 with polymer injection flow rate and cumulative water outflow versus time

Figure 87: Results of Exp. 8 with axial pressure and cumulative water outflow versus time
Figure 88: Results of Exp. 8 with radial pressure and cumulative water outflow versus time

H.10 Experiment 9

Table 12 Solution and petrophysical parameters of core flood experiment 9

<table>
<thead>
<tr>
<th>Solution parameters</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Polymer</td>
<td>AN905 Lot E 2686</td>
</tr>
<tr>
<td>Molecular weight (g/mol)</td>
<td>$9 \times 10^6$</td>
</tr>
<tr>
<td>Degree of Hydrolysis (%)</td>
<td>5</td>
</tr>
<tr>
<td>Concentration (ppm)</td>
<td>5000</td>
</tr>
<tr>
<td>Salinity (g/L)</td>
<td>0</td>
</tr>
<tr>
<td>Flow rate (ml/min)</td>
<td>$120 \pm 0.5$</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>44</td>
</tr>
<tr>
<td>Permeability (Darcy)</td>
<td>$2.3 \pm 0.1$</td>
</tr>
</tbody>
</table>

Figure 89: Results of Exp. 9 with pressure drop and polymer injection flow rate versus time
Figure 90: Results of Exp. 9 with axial pressure and polymer injection flow rate versus time

Figure 91: Results of Exp. 9 with radial pressure and polymer injection flow rate versus time
Figure 92: Results of Exp. 9 with polymer injection flow rate and cumulative water outflow versus time

Figure 93: Results of Exp. 9 with axial pressure and cumulative water outflow versus time
Figure 94: Results of Exp. 9 with radial pressure and cumulative water outflow versus time

H.11 Experiment 10

Table 13 Solution and petrophysical parameters of core flood experiment 10

<table>
<thead>
<tr>
<th>Solution parameters</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Polymer</td>
<td>AN905 Lot E 2686</td>
</tr>
<tr>
<td>Molecular weight (g/mol)</td>
<td>$9 \times 10^3$</td>
</tr>
<tr>
<td>Degree of Hydrolysis (%)</td>
<td>5</td>
</tr>
<tr>
<td>Concentration (ppm)</td>
<td>5000</td>
</tr>
<tr>
<td>Salinity (g/L)</td>
<td>0</td>
</tr>
<tr>
<td>Flow rate (ml/min)</td>
<td>$600 \pm 0.5$</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>44</td>
</tr>
<tr>
<td>Permeability (Darcy)</td>
<td>$2.3 \pm 0.1$</td>
</tr>
</tbody>
</table>

Figure 95: Results of Exp. 10 with pressure drop and polymer injection flow rate versus time
Figure 96: Results of Exp. 10 with axial pressure and polymer injection flow rate versus time

Figure 97: Results of Exp. 10 with radial pressure and polymer injection flow rate versus time
Figure 98: Results of Exp. 10 with polymer injection flow rate and cumulative water outflow versus time

Figure 99: Results of Exp. 10 with axial pressure and cumulative water outflow versus time
Figure 100: Results of Exp. 10 with radial pressure and cumulative water outflow versus time

H.12 Experiment 8,9,10 combined

Figure 101: Results of Exps. 8, 9 and 10 with pressure drop and polymer injection flow rate versus time
Figure 102: Results of Exps. 8, 9 and 10 with axial pressure and polymer injection flow rate versus time

Figure 103: Results of Exps. 8, 9 and 10 with radial pressure and polymer injection flow rate versus time
Figure 104: Results of Exps. 8, 9 and 10 with polymer injection flow rate and cumulative water outflow versus time

Figure 105: Results of Exps. 8, 9 and 10 with axial pressure and cumulative water outflow versus time
Figure 106: Results of Exp. 8, 9 and 10 with radial pressure and cumulative water outflow versus time

H.13 Experiment 11

Table 14 Solution and petrophysical parameters of core flood experiment 11

<table>
<thead>
<tr>
<th>Solution parameters</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Polymer</td>
<td>AN905 Lot E 2686</td>
</tr>
<tr>
<td>Molecular weight (g/mol)</td>
<td>$9 \times 10^6$</td>
</tr>
<tr>
<td>Degree of Hydrolysis (%)</td>
<td>5</td>
</tr>
<tr>
<td>Concentration (ppm)</td>
<td>5000</td>
</tr>
<tr>
<td>Salinity (g/L)</td>
<td>0</td>
</tr>
<tr>
<td>Flow rate (ml/min)</td>
<td>$600 \pm 0.5$</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>44</td>
</tr>
<tr>
<td>Permeability (Darcy)</td>
<td>$2.3 \pm 0.1$</td>
</tr>
</tbody>
</table>

Figure 107: Results of Exp. 11 with pressure drop and polymer injection flow rate versus time
Figure 108: Results of Exp. 11 with axial pressure and polymer injection flow rate versus time

Figure 109: Results of Exp. 11 with radial pressure and polymer injection flow rate versus time
Figure 110: Results of Exp. 11 with pressure drop and cumulative water outflow versus time

Figure 111: Results of Exp. 11 with axial pressure and cumulative water outflow versus time
Figure 112: Results of Exp. 11 with radial pressure and cumulative water outflow versus time

H.14 Experiment 12

Table 15 Solution and petrophysical parameters of core flood experiment 12

<table>
<thead>
<tr>
<th>Solution parameters</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Polymer</td>
<td>AN905 Lot E 2686</td>
</tr>
<tr>
<td>Molecular weight (g/mol)</td>
<td>$9 \times 10^6$</td>
</tr>
<tr>
<td>Degree of Hydrolysis (%)</td>
<td>5</td>
</tr>
<tr>
<td>Concentration (ppm)</td>
<td>5000</td>
</tr>
<tr>
<td>Salinity (g/L)</td>
<td>0</td>
</tr>
<tr>
<td>Flow rate (ml/min)</td>
<td>$600 \pm 0.5$</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>44</td>
</tr>
<tr>
<td>Permeability (Darcy)</td>
<td>$2.3 \pm 0.1$</td>
</tr>
</tbody>
</table>

Figure 113: Results of Exp. 12 with pressure drop and polymer injection flow rate versus time
Figure 114: Results of Exp. 12 with axial pressure and polymer injection flow rate versus time

Figure 115: Results of Exp. 12 with radial pressure and polymer injection flow rate versus time
Figure 116: Results of Exp. 12 with polymer injection flow rate and cumulative oil outflow versus time

Figure 117: Results of Exp. 12 with axial pressure and cumulative oil outflow versus time
Figure 118: Results of Exp. 12 with radial pressure and cumulative oil outflow versus time.
I. Experimental results comparison

I.1 Water in water 600 ml/min

![Figure 119](attachment:image1.png)

Figure 119: Pressure drop results of polymer injection Exps. 10 and 11 in a water saturated sample versus time. During Exp. 3 a smaller volume is injected and thus has a shorter injection time. Injection rate is 600 ml/min.

I.2 Water in water 1200 ml/min

![Figure 120](attachment:image2.png)

Figure 120: Pressure drop results of water injection Exps. 6 and 7 in a water saturated sample versus time. Injection rate is 1200 ml/min.
I.3 All WIW graphs

Figure 121: Pressure drop versus time of all WIW experiments. Injection rates are presented in Table 2

I.4 Polymer in water 600 ml/min

Figure 122: Pressure drop results of polymer injection Exps. 10 and 11 in a water saturated sample versus time. Injection rate is 600 ml/min. Exp. 10 has axial and radial pressure of 100 bar and 70 bar respectively. Exp. 11 has axial and radial pressure of 50 bar and 30 bar respectively.
References

1. Alkaleef, A.F., Zaid, A.M., Review of and outlook for enhanced oil recovery techniques in Kuwait oil Reservoirs. IPTC11234 presented at International Petroleum Technology Conference held in Dubai A.A.E., 4-6 December 2007
12. Gao C.H., Advances of Polymer Flood in Heavy Oil Recovery, SPE Heavy Oil Conference and Exhibition, 12-14 December 2011, Kuwait City, Kuwait
33. Zhang, G., Seright, R.S., Effect of Concentration on HPAM Retention in Porous Media, SPE Annual Technical Conference and Exhibition, 30 September–2 October 2013, New Orleans, Louisiana, USA
34. Zhou, J., Dong, Y., de Pater, C.J., Zitha, P.L.J. Experimental Study of Hydraulic Fracturing Caused by Polymer Injection in Unconsolidated Heavy Oil Reservoirs, International Oil and Gas Conference and Exhibition in China, 8-10 June 2010, Beijing, China.