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# POLYMER FLOODING

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GEOPHYSICS

**MASTER's THESIS**

**POLYMER FLOODING**

By

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*---- I am dedicating this thesis to my intelligent bright father Dr. Hildebrand John Norbert  
Kasimbazi and family ----*

## Abstract

Polymers are mixed with soluble water and form polymer solution. The purpose of adding polymers in water is to increase the apparent viscosity of water (displacing fluid) which helps to lower the mobility ratio. This condition maximizes oil-recovery sweep efficiency, creating a smooth flood front with less viscous fingering. Many studies and implementations of polymer flooding in fields have been done with most promising diverse achievements.

In spite of having promising results, polymers are expensive and the flooding process is limited by reservoir temperature, make-up brine salinity and hardness due to chemical degradation of the polymer. Also, as polymer forced through formation there is a significant reduction in polymer concentration due to adsorption and plugging which can change reservoir permeability and affect recovery either positively or negatively. Therefore the focus of this study will base on investigating the extent of the effects of polymer properties in terms of oil recovery in different reservoir permeabilities through reservoir simulation.

The main objective is to establish the quantity and quality of polymer to be injected so as the quality of the reservoir properties in terms of permeability. It is done as the determination of the screening criteria suitable for polymer flooding aiming to give best yield of oil recovery.

Reservoir simulation will be done by using Petrel software (running ECLIPSE in Petrel software) on the three layered reservoir with 300 cells. The data file SPE1A from ([www.ipt.ntnu.no/~kleppe/pub/SPE-COMPARATIVE](http://www.ipt.ntnu.no/~kleppe/pub/SPE-COMPARATIVE)) is modified and used for simulation. Four cases with different permeability are created. Two cases will have homogenous permeability one with low and the other with high permeability. Another two cases will have heterogeneous permeability with low and high permeability as well. Polymer slugs with different concentration through different injection time are injected for each case and the results are compared.

The oil viscosity ranges from 0.6 to 1.04 cP while permeability ranges from 500mD to 2250mD. The oil recovered after water flooding for Homo\_low, Homo\_high, Hetero\_low and Hetero\_high are 35.03%, 42.16%, 43.51% and 43.87% respectively. Polymer have been injected after 1, 2, 3 and 4 years for 15 years of production and the polymer concentration have been tested in the range of 0.1, 0.2, ... , 1.7 lb/lb. Hetero\_high permeability case is obtained to be suitable for polymer flooding. It provided the oil recovery of 47.53% after flooding 0.8 lb/STB polymer concentration for 1 year which is 4.02% increment recovery from water flooding. The overall oil recovered in all cases showed that high permeability is the major factor compared to heterogeneity/homogeneity distribution.

While for the distribution, heterogeneous is the suitable candidate for polymer flooding than homogeneous case. Different adsorption values have been tested with reference to different values of residual resistance factor while polymer concentration was set as 0.8lb/STB for all cases. The residual resistance factor values tested are 1, 1.1, 1.2 and 1.5 where for each value adsorption range of 0.0000017, 0.000017, 0.00017, 0.0017 to 0.17 lb/lb were tested. The maximum adsorption of 0.0000017 lb/lb gave more variation in oil recovery compared to other values.

Grid blocks are refined for better approximation in simulation. Three grids orientations used were normal grids (from origin), local grid refinement (LGR) around the wells and full grid refinement. The oil recovery after water flooding in these three different grids are 43.87%, 46.48% and 45% while after polymer flooding are 47.53%, 45.43% and 47.03% respectively. Large polymer molecules can be trapped in low permeability zones causing pore blockage which affects the recovery. For that reason, polymer cell concentration and water saturation are viewed to detect the movement. Also average maps of water saturation for all layers in all grids after water and polymer flooding are shown to see the coverage area of the injected fluid.

The rough estimation of profit or loss in oil recovered in relation to polymer injected shows that this polymer flooding project is profitable.

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## 1. Introduction

Since 1940's further means of recovery have been taken under consideration like EOR methods. This was after realizing more than two-thirds of the original oil in place is left unrecovered after primary or secondary recovery.

### 1.1 Current status for EOR

With the current growing demand for oil, oil price and the concerns about future oil supplies increases the pressure in securing oil resources. Additional of reserves is very expensive option that is why EOR techniques is driving the attention knowing that even small increment in oil add significant reserves.

Currently around 32 billion barrels of oil is produced per year in the world. For North Sea is roughly around 87 million barrels per day while fossil fuels supply >85% of energy in the world. This means in order for industry in North Sea to meet the target of replacing depleted reserves, it has to find at least twice the remaining volume of oil. In this 32 billion barrels produced per year, 22 billion is from sandstone reservoirs. The forecast of production time for sandstone is around 20 years and for carbonate reservoirs the proven and probable reserves is around 80 years [1].

The Energy Information Agency (EIA) forecasts that the world demand will grow to 119 barrels/day by 2025 as shown in fig. 1 below. Association for Study of Peak Oil studies shows that the peak production of conventional oil is behind us and future holds on unconventional resources (heavy oil, bitumen etc.).

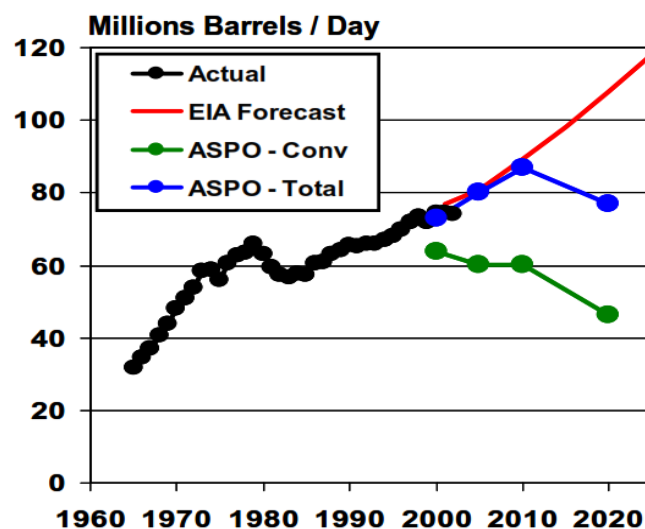


Figure 1: Showing convectional oil production forecasts [2].

EOR processes can generally be classified as thermal, miscible or chemical processes. Thermal methods mainly used in heavy oil reservoirs, miscible processes are suitable for lower viscosity oils and chemical EOR processes are used to reduce reservoir forces responsible for oil entrapment. These chemical processes depend on the types of fluid used for example **polymer**, alkaline and surfactant. Where by this thesis work focus will be on polymers.

For more than 20 years polymer flooding has been implemented in conventional (light to medium oil) reservoirs. The ultimate recovery expectation of 50% and 10-15% incremental oil recovery over water flood have been achieved [3]. Chapter 4 (4.1) of this report includes the review of polymer flooding in light oil reservoirs (Dalia field in Angola and Daqing field in China).

For the case of heavy oil (unconventional) resources are estimated to be 3396 billion barrels worldwide while the recovery is often less than 20% or below 10% [4]. Different fields from China, Canada and Oman are discussed in chapter 4 (4.2).

### **Study Scope and Limitations for this thesis**

- To document suitable and readily available polymer type used for EOR.
- To document the principle of flooding and the major challenging effects of polymer properties in the flooding process.
- To discuss ideas reviewed in different studies done in both laboratory and field scale cases.

### **1.2.2 Hypothesis**

Flooding polymer in zone/layer/reservoir with homogenous permeability will allow better sweeping efficiency and give high recovery.

## 2. Polymer Flooding for EOR

### 2.1 Types of Polymer for EOR

Polymers are long chain organic molecules made from joining together small molecules called monomers. They are flexible with high molecular weight ranging from  $2 \times 10^6$  to  $21 \times 10^6$  g/mole. Two types of polymers mostly used for Enhancing Oil Recovery (EOR) are Polyacrylamide (PAM), in its partially hydrolysed form (HPAM) and Xanthan. In fig. 2 below, there are the polymer types and structures for Xanthan, PAM & HPAM commonly used.

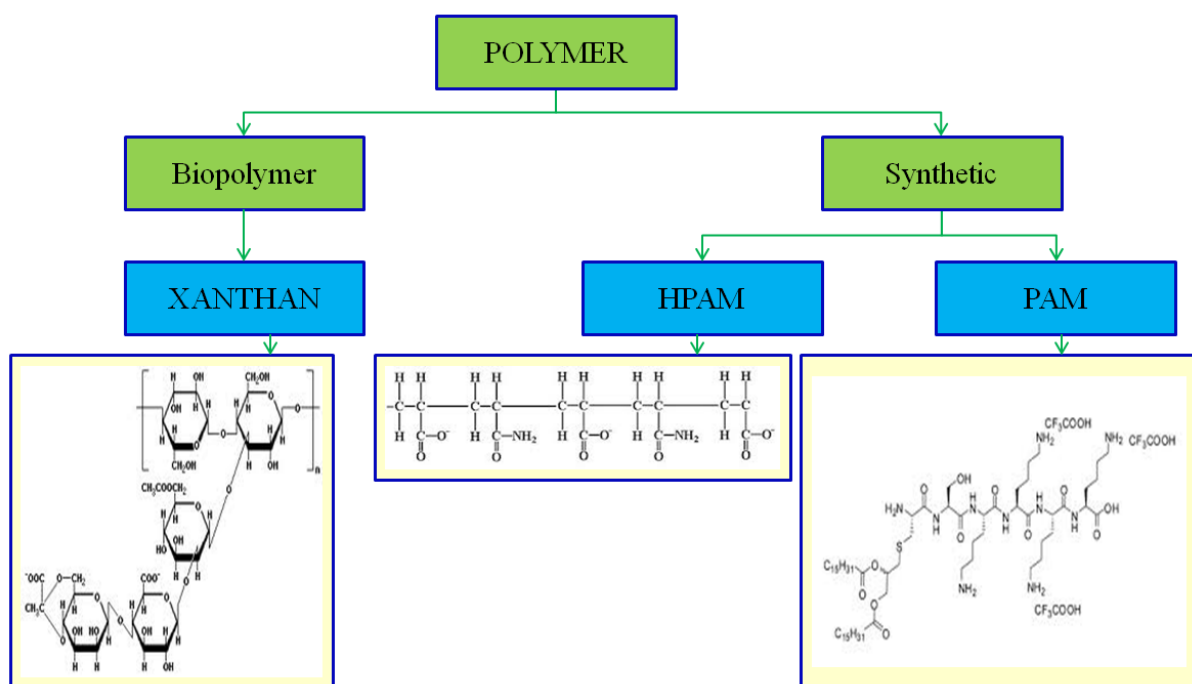


Figure 2: Showing polymers for Enhanced Oil Recovery (EOR)

#### 2.1.1 Biopolymer/ polysaccharide

There are polymers from fermentation process, produced by living organisms in other words they are polymeric biomolecules. The major defining difference between biopolymers and other polymers can be found in their structures. Because all polymers are made of repetitive units called monomers but often biopolymers have well-defined structure [5]. They have small molecular weight compared to synthetic/polyacrylamide. But their structures give the molecule great stiffness and this property gives it excellent viscofying power in salt water.

### *Xanthan Gum (corn sugar gum)*

This is another widely used EOR polymer with average reported molecular weight of  $1 \times 10^6$  to  $15 \times 10^6$  g/mole used in EOR process. It is the biopolymer produced during fermentation of glucose, whereby in order to protect bacteria from dehydration, Xanthan polymer is produced. The result of this process is the fact that this polymer becomes very sensitive to bacterial attack on surface, even after it has been injected into the reservoir. On the other hand Xanthan polymer act like a semi rigid rod and is quite resistant to mechanical degradation. Also Xanthan have the disadvantage of having low thermal stability because of the presence of  $-O-$  in the backbone of its structure. Once it is subjected on high temperature more than  $80^\circ\text{C}$ , the chemical bonds in the chain are weakened and multiple free radicals are formed. This causes the functional groups in the polymer chain to change location as the results new compound is formed and polymer structure is destroyed.

The main advantage of Xanthan polymer in EOR is that it is less sensitive to brine salinity and hardness in comparison to HPAM [6]. Also it have greater effect to reduce the heterogeneity of reservoir due to the adsorption of the molecules on the surface, Xanthan does not have tendency to retain as PAM's.

### **Synthetic/ Polyacrylamide**

#### *Hydrolysed polyacrylamide (HPAM) or ionic*

This is the polyacrylamides type of polymers that have undergone partial hydrolysis. The molecular weight of HPAM used for EOR processes reported to be higher than 20 million Daltons. But Daqing laboratory in China have reported the polymer they used with molecular weight higher than 35 million Daltons [5]. Well PAM's are partially hydrolysed to reduce adsorption, whereby they undergo reaction with a base, such as sodium- or potassium hydroxide or sodium carbonate. The hydrolysis reaction converts amide groups present ( $\text{CONH}_2$ ) to carboxyl groups ( $\text{COO}^-$ ).

Figure 2 above shows the structures for PAM and HPAM (PAM with amides groups while HPAM with carboxyl groups). The formation of carboxyl group introduces the negative charge on the backbones of polymer chains that repel each other. In fresh water, because of the charge repulsion, the HPAM flexible chain structure stretches and viscosity increases. But then in saline water, the charges are neutralized or shielded hence HPAM flexible chains are compressed, resulting in low viscosity. All in all, hydrolysis reaction creates carboxyl groups ( $\text{COO}^-$ ) which helps to decrease adsorption and increase viscosity.



The degree of hydrolysis mostly reported in mole fraction ranges are from 15% to 35% in commercial products. When it is higher than 40%, the flexible chain are seriously compressed, distorted and the viscosity reduces. In other words, when the degree of hydrolysis is higher means more carboxyl groups (COO-) are created and the chemical stability decreases owing to less CONH<sub>2</sub>.

When hydrolysis is higher than 40% in hard water (water with more Ca<sup>2+</sup> and Mg<sup>2+</sup> ions), flocculation occurs. Since EOR is the long process and stability of polymer is indispensable, then hydrolysis is required to be less than 40% at least after 3 months of flooding. Hydrolysis is very faster under acidic and basic conditions as well as at high temperature. This concludes that HPAM is not tolerant to high temperature or high salinity [7].

#### HPAM vs. Xanthan

HPAM is cheap, more bacterial resistant, have high thermal stability, have high ability to reduce permeability to water more than the relative permeability to oil in porous media compared to Xanthan [8]. But Xanthan have excellent viscofying power in saline water compared to HPAM.

Table 1 below gives the summary of some elements present in polymers, their characteristics and what effect(s) they bring when it comes to polymer flooding written by Zhao. F in 1991. The polymers of our concern are Xanthan and HPAM which have an outlining red box.

Table 1: Elements present in polymer structures and their characteristics [9]

Structure	Characteristics	Sample Polymers
-O- in the backbone	Low thermal stability, thermal degradation at high T, only suitable at <80°C	Polyoxyethylene, sodium alginate, sodium carboxymethyl cellulose, HEC, xanthan gum
Carbon chain in the backbone	Good thermal stability, degradation not severe at <110°C	Polyvinyl, sodium polyacrylate, polyacrylamide, HPAM
-COO <sup>-</sup> in hydrophilic group	Good viscosifier, less adsorption on sandstones due to the repulsion between chain links, but precipitation with Ca <sup>2+</sup> and Mg <sup>2+</sup> , less chemical stability	Sodium alginate, sodium carboxymethyl cellulose, HPAM, xanthan gum
-OH or -CONH <sub>2</sub> in hydrophilic group	No precipitation with Ca <sup>2+</sup> and Mg <sup>2+</sup> , good chemical stability, but no repulsion between chain links, thus less viscosifying powder, high adsorption due to hydrogen bond formed on sandstone rocks	Polyvinyl, HEC, polyacrylamide, HPAM

Based on the summary shown in table 1 above, hydrolysed polyacrylamide (HPAM) is a good polymer.

## 2.2 Flooding Mechanism

Polymer is added in water to lower the water-oil mobility ratio by increasing water viscosity. The lowering of water-oil mobility ratio results into improvement of oil recovery by increasing **areal**, **vertical** and **displacement** (or microscopic) sweep efficiencies.

### *Areal sweeping efficiency*

This is the areal fraction which has been contacted at time of breakthrough as referred in eqn (i) and fig. 3 below. It is a function of reservoir characteristics and well locations. Therefore, the geometric pattern for injection and producing wells affects it. For this reason, improper placement of wells will definitely lower areal sweeping efficiency even in the absence of detrimental reservoir heterogeneities [10].

$$\begin{aligned} \text{Areal sweeping efficiency, } E_{AS} \\ = \frac{\text{Area contacted by injected fluid at breakthrough}}{\text{Total area}} \dots \dots \dots (i) \end{aligned}$$

### *Vertical sweep efficiency or invasion efficiency*

It is the measure of the variation in horizontal and vertical permeability as referred to eqn (ii) and fig. 3 below. It is the function of reservoir characteristics alone. Therefore the variations in vertical direction that causes the injected fluid to advance from the injection point as an irregular front is the only factor that can alter this efficiency.

$$\begin{aligned} \text{Vertical sweeping efficiency, } E_{VS} \\ = \frac{\text{Cross – section contacted by injected fluid}}{\text{Cross – section of the all layers behind front}} \dots \dots \dots (ii) \end{aligned}$$

Polymer flooding reduces the detrimental effect of permeability variations and fractures and thereby improves both vertical and areal sweep efficiency [10].

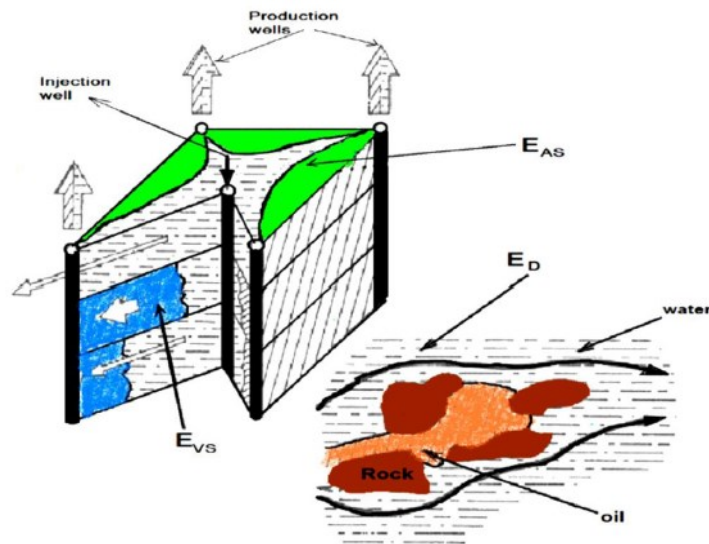


Figure 3: Showing Vertical ( $E_{VS}$ ), Areal ( $E_{AS}$ ) and Displacement ( $E_D$ ) sweeping efficiency [10]

### Mobility control

Polymer is added so as to increase the viscosity of water. Viscosity increased until mobility of water is less than that of the oil phase in place, so the mobility ratio is less than unity.

The ranges of mobility ratio,  $M$  are considered to be;

- Favourable when ( $M \leq 1$ ),
- Unfavourable when ( $M > 1$ ) and
- Piston displacement when ( $M = 1$ )

Mobility ratio is the ratio of mobility of displacing fluid to displaced fluid.

$$M = \frac{\text{Mobility of displacing fluid}}{\text{Mobility of displaced fluid}} = \frac{\text{Mobility of Water}}{\text{Mobility of Oil}} = \frac{k_{rw}\mu_o}{\mu_w k_{ro}} \dots \dots \dots (ii)$$

Where:  $k_{rw}$ : Relative permeability of water

$k_{ro}$ : Relative permeability of oil

$\mu_w$ : Viscosity of water

$\mu_o$ : Viscosity of oil

### Fractional flow of water, $f_w$

This is the ratio of the water flow rate to the total rate (oil and water) as shown in eqn (iii) these flow rate are derived from Darcy's law. The overall fractional flow of water for water-oil system is then obtained by Buckley-Leverett analysis/method shown in eqn (iv) or (v). The method works under assumptions that; the fluid has to be incompressible, no capillary dispersion at the front and the flow has to be under diffuse flow conditions.

$$f_w = \frac{q_w}{q_w + q_o} \dots \dots \dots (iv)$$

Also it can be expressed as:

$$f_w = \frac{1 + \frac{kk_{ro}A}{q\mu_o} \left( \frac{\partial P_{cow} - \Delta\rho g \sin\alpha}{\partial x} \right)}{1 + \frac{k_{ro}\mu_w}{\mu_o k_{rw}}} \dots \dots \dots (v)$$

For horizontal flow and negligible capillary pressure,  $f_w$  become:

$$f_w = \frac{1}{1 + \frac{k_{ro}\mu_w}{\mu_o k_{rw}}} = \frac{1}{1 + 1/M} \dots \dots \dots (vi)$$

The fractional flow of water is altered by changing the mobility ratio. The  $f_w$ -curve shifts more to the right as mobility ratio decreases (becomes more favourable) as shown in fig. 4 below.

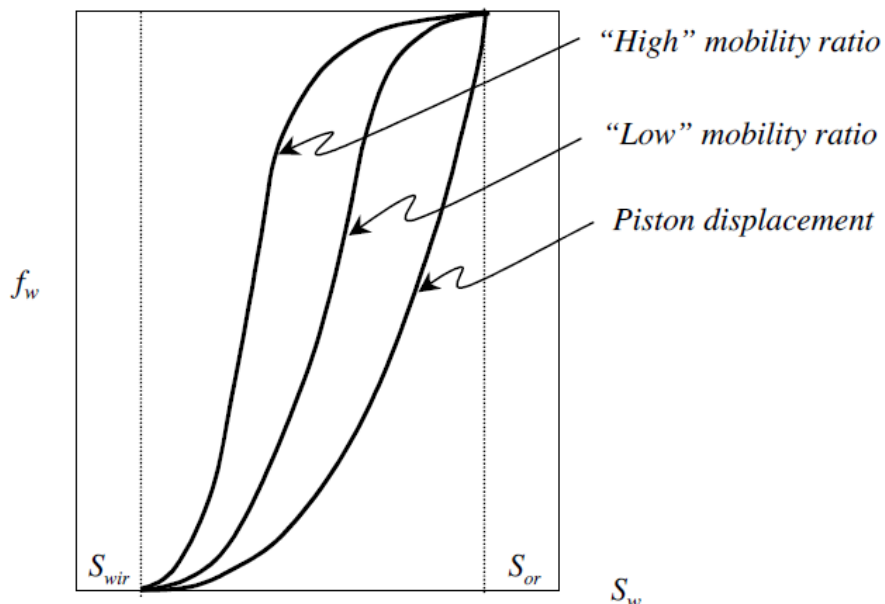


Figure 4: Showing the effects of mobility ratio in fractional flow of water

### Fingering effect

Unfavourable mobility ratio allows injected fluid to significantly bypass the residual oil. The bypass causes the injected fluids to flow in finger like structure and this flow is known as fingering effect [11]. When the mobility ratio is lowered there is low chance for bypassing to occur which decreases the water saturation behind the front. Figure 5 below shows the difference in fingering flow after water and polymer flooding.

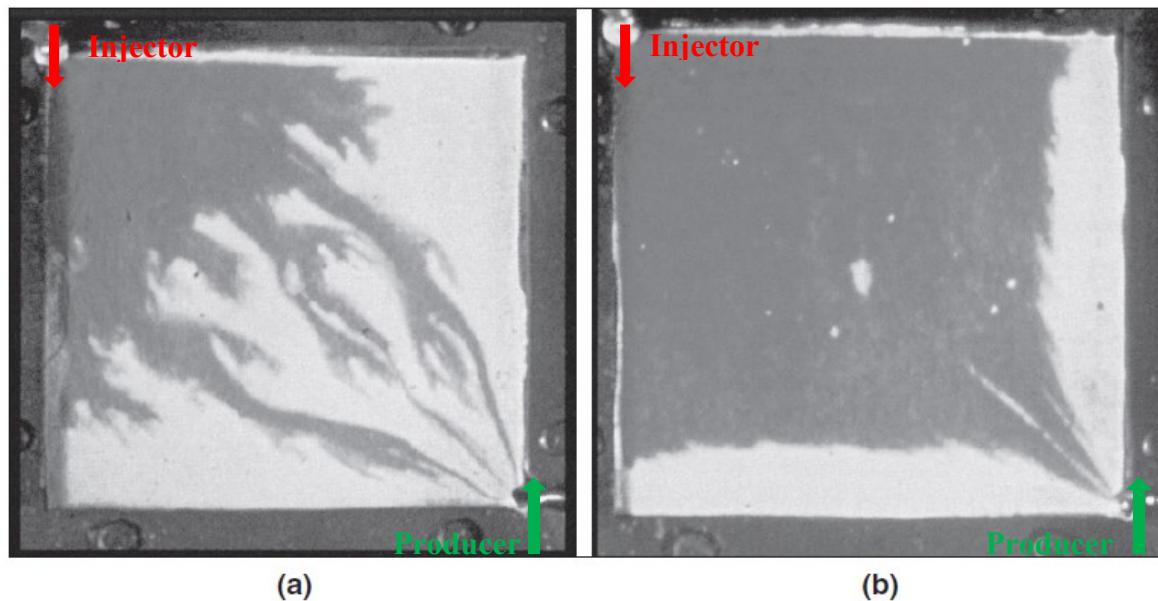


Figure 5: Showing the difference in fingering effect after water (a) and polymer (b) flooding [12]

### *Fingering effect in homogenous and heterogeneous layers*

Permeability difference in layers has effects in sweeping efficiency. If the permeability in the layer is high, low oil will be recovered after water flooding. This is because water will have high mobility leads to high fingering effect hence more oil will be left behind. As the results when polymer is injected oil from these zones will be produced late and partially at high water-cut [12]. Apart from reservoir properties, polymers properties alteration also affects the sweeping efficiency. Polymer performance depends on the type of polymer used as explained above in chapter 2 (2.1) and conditions subjected to. When polymers are subjected in unfavourable conditions such as; high salinity, high temperature, high flow rate (shear rate) etc. the viscosity of the polymer solution change (decreases/increases). The following chapter is concerned about different possible conditions that polymer can possibly be subjected to in the reservoir. Also what polymer properties are affected and what parameters should be adjusted as mitigation.

### 3. Polymer Flow Behaviours in Porous Media

#### 3.1 Polymer Adsorption

Adsorption is referred as interaction between polymer molecules and the rock surface, which causes polymer molecules to bind to the surface. This causes the reduction of concentration because of some portions of injected polymers are left behind. Polymer adsorption is considered to be irreversible process; i.e., it does not decrease as concentration decreases [13, 14]. This is not exactly true because continued exposure to water or brine injection can sort of remove some of the polymer adsorbed from porous rock. However in general, adsorption adds resistance to flow, causes loss of polymeric additive also creates the stripped water bank at the leading edge of the slug. The extent to adsorption on the rock surface depends on; the polymer type, mineralogy of the rock, the accessibility to the active surface, relative permeability to water, wettability of the rock, temperature and solvent (salinity).

##### *Mineralogy and type of polymer effect*

Adsorption is higher in calcium carbonate (limestone or dolomite) than silicate surface (sandstone or clay) owing to the presence of calcium carbonate ( $\text{CaCO}_3$ ) minerals. For example HPAM type of polymer have the carboxylate group ( $\text{COO}^-$  negatively charged), therefore the higher adsorption occurs due to the strong interactions between the surface  $\text{Ca}^{2+}$  and the carboxylate groups [15]. While silicate surfaces contain negative charge which cause electrostatic repulsion with carboxyl group ( $\text{COO}^-$ ) hence adsorption decrease.

For silicate surface in Angola, Dalia Field [16] some experiments were done for HPAM polymer on clay and 3 samples of sandstone with different permeability. The maximum adsorption was observed on clays, slightly higher for lower permeability rock and lower for high permeability sands [16]. Therefore regardless of mineralogy, lower permeability reservoirs restricts polymer to flow causing polymer to retain hence more adsorption occurs.

### *Polymer concentration effect*

Polymer adsorption is a strong function of polymer concentration. Additional of polymer concentration increases the viscosity of the polymer solution and the thick solution creates high chances for polymer to adsorb [17].

### *Wettability effect*

Less adsorption occurs in oil wet since the irregularities in the grain surface are smoothed out by the oil film. This reduces the oil/water interfacial area which decreases adsorption [15].

### *Relative permeability to water effect*

Polymer adsorption reduces the relative permeability to water because polymer is soluble in water phase and not in oil phase. So when polymers flow through pore throats, some large molecules are retained, at that point polymer blocks water flowing through and reduce relative permeability to water. Another point is; polymers tend to form hydrogen bond with water molecules which enhances the affinity between the adsorption layer and water molecules. This causes the rock surface to become more water-wet thus relative permeability to water reduced [17]. For this reasons relative permeability curve for polymer solution is expected to be lower than the corresponding relative permeability curve for water before polymer flooding.

For example in SPE36632 experiments the core samples were tested and for both water-wet and mildly oil-wet cores, the irreducible water saturation increases with increasing polymer concentration while residual oil saturation remained almost the same. They concluded that the relative permeability to water is more significant in the presence of oil than the permeability reduction at 100% water saturation [18].

### *Temperature effect*

The combination of electrostatic forces and molecular forces (like hydrogen bond, van der waals, hydrophobicity etc.) causes both anionic and non-ionic polymers adsorption to decrease with temperature. For ionic polymers (HPAM), adsorption is related to electrostatic repulsion and it decreases as temperature increase. This is because high temperature increase negative charge on the rock surface hence high repulsion occurs which lowers adsorption. But for non-ionic polymers (PAM) adsorption is related to hydrogen bond therefore increase in temperature can easily break the bond causing adsorption to decrease [5].



### *Salinity effect*

Increasing salinity (NaCl) concentration increases the level of polymer adsorption. Because Na<sup>+</sup> ion is will this plays the same role in chemical interaction with carboxyl group (COO<sup>-</sup>) in HPAM as explained above.

In ECLISPSE the keyword used to encounter polymer adsorption is **PLYADS** in **PROPS** section, describes the adsorption of the polymer by the rock formation see appendix A.

### **3.2 Polymer retention**

The retention of polymer includes adsorption, mechanical trapping and hydrodynamic retention. When large polymer molecules lodged in narrow flow channels retention by mechanical entrapment occurs. This may lead to a build-up of material close to the injection well that can cause well plugging and pore blockage. This is one of the reasons why low permeability is not suitable for polymer flooding [18]. Hydrodynamic retention is not a large contributor to total retention and can be neglected in field applications. But in comparison to alkaline and surfactant; polymer hydrodynamic retention and mechanical trapping are more significant because of large molecules in polymer. Polymer retention includes adsorption; therefore increase in adsorption increases retention and vice versa. Nevertheless it has been observed that, low polymer retention is essential for success in polymer EOR because it leads to polymer breakthrough delay

### **3.3 Inaccessible Pore Volume (IPV)**

Large polymer molecules cannot/have less access to small pore (inaccessible pore volume (IPV) in a porous medium [12]. In the presence of aqueous polymer solution and tracer, polymer molecules will run faster than the tracer because molecules flow only through the larger pores. But in the presence of polymer retention, polymer will lag behind resulting to late polymer breakthrough. For the case of adsorption; polymer adsorption can be decreased due to presence of IPV since less polymer solution will be in contact with the rock surface than total pore volume [11]. The minimum value of IPV is usually assumed to be equal to irreducible volume of the fluid in the pores. In extreme cases, IPV can be 30% of the total pore volume.

In ECLISPSE the keyword used is **PYLROCK** in **PROPS** section, it specifies the polymer rock properties mainly dead pore volume and permeability. Inaccessible pore volume is specified in the first column of this keyword refer to appendix A.

### 3.4 Permeability reduction

Polymer adsorption causes the pore blockage or permeability reduction. The permeability reduction factor is defined as the ratio of rock permeability when water flows to rock permeability when aqueous polymer solution flows. Be noted polymer adsorption assumed to be irreversible process, means even when some of polymer solution is displaced by water or polymer concentration is decreasing the adsorption will still exist. This means the permeability reduction will keep on increasing and the factor would be increasing.

Another factor that is taken under consideration when it comes to permeability reduction is *residual permeability reduction factor*. This is the ratio of the rock permeability to water before polymer flow to rock permeability to water after polymer flow [19]. Many literatures use *residual resistance factor* (RRF) as the term to present residual permeability reduction factor. Where the relationship is presented as; water mobility before polymer flow to water mobility after polymer flow. The resistance includes the effect of both permeability reduction and viscosity increase because it relates to mobility. But then again water viscosity is used before and after polymer flow, so obviously the viscosity effect is not included. For that reason [18], suggests two terms to be used, either “*permeability reduction factor*” or “*residual permeability reduction factor*”. But in order to include both permeability and viscosity increase, *resistance factor* (RF) is defined. This is the ratio of polymer mobility during polymer flow to water mobility during polymer flow.

From SPE 120807 they concluded after simulation that; RRF increases with decreasing brine concentration and injection rate (shear rate) of polymer solution. Also RRF increases with additional of polymer concentration at constant permeability [6].

In ECLIPSE it is the value specified on the second column of **PLYROCK** keyword.

### 3.5 Polymer viscosity

Viscosity of water is the major parameter to control for polymer solution. Some of the factors that affect polymer viscosity are salinity, concentration, PH, shear rate, temperature etc.

#### *Salinity and concentration effects*

For PAM polymers with amide group (-CONH<sub>2</sub>), additional of salt whether monovalent (NaCl) or divalent (CaCl<sub>2</sub>) will cause an increase in viscosity. However, for HPAM with carboxyl group (-COO<sup>-</sup>) additional of monovalent will cause decrease in viscosity. This is because the added salt will neutralize the charge in HPAM side chains. But when divalent salt is added like CaCl<sub>2</sub>, MgCl<sub>2</sub> and/or BaCl<sub>2</sub>, the effect depends on the degree of hydrolysis.

At high hydrolysis solution viscosity decreases sharply while at low hydrolysis it increases after it reaches the minimum.

### Shear rate effect

Polymers are non-Newtonian fluids therefore they have different behaviour when subjected to different shear rate (flow rate). At high shear rate they are considered to be *pseudo plastic* which implies increasing shear rate will decrease apparent viscosity. But at higher shear rate they are considered to become *dilatant* therefore increasing shear rates will increase its apparent viscosity [20]. When the shear rate approaches zero, shear stress does not approach zero some yield stress exists and at that point polymer behaves as *Bingham*, mostly HPAM [21]. Figure 6 below shows the effects of viscosity subjected in different shear rate for both Newtonian and non-Newtonian.

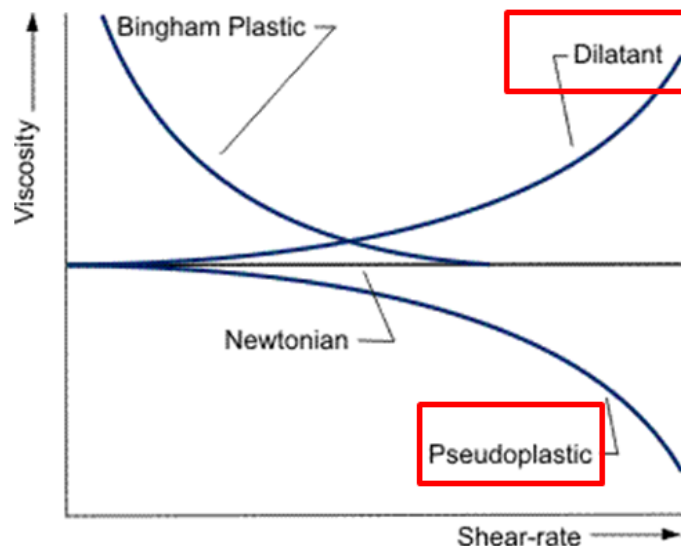


Figure 6: Showing the rheology of polymer under shear stress [20].

In ECLISPSE the keyword used to encounter polymer viscosity is **PLYVISC** in **PROPS** section as shown in appendix A.

### 3.6 Thermal stability

Polymer molecules undergo both physical and chemical changes when subjected under high temperature or heat. Heat lowers the strength of bonds in the polymer chain which causes loss of attached elements and leaves other bonds unpaired. Unpaired bonds are known as free radicals; they are unstable and very reactive. They tend to pull elements including others in

the polymer chain and the polymer is left less stable with low molecular weight and low viscosity.

More formation of free radicals are enhanced at higher temperature and in the presence of oxygen [22]. Commonly hydrogen is the atom lost in the chain and leaves the free radical. The free radical reacts with oxygen molecules to form peroxy radical which are even more reactive [12]. Peroxy radical removes another hydrogen atom on the chain to form hydro peroxide and the reaction continues. All of this reduces the polymer molecular weight, viscosity, ductility and embrittlement [23]. These reactions undergone by polymers under high temperatures are not done in ECLIPSE. Instead by using the keyword **PLYDHFLF** in **PROPS** section ECLIPSE allows to provide the temperature and the corresponding half-life of the polymer as can be seen in appendix B.

Dalia field in Angola have applied polymer flooding and from experiments they obtained results seen in table 2 SPE 116672. The experiments were done for hydrolysed polyacrylamides (HPAM) polymer in anaerobic conditions under reservoir temperature around 50 to 90°C.

Table 2: Thermal degradation of hydrolysed polyacrylamides under anaerobic condition [16]

<b>Temperature [°C]</b>	<b>Duration</b>	<b>Stability</b>
50	>1 year	stable
70	1 year	50% degraded
90	35 days	50% degraded

Therefore favourable temperature is required according to the type of the polymer used. But since reservoir temperature cannot be controlled other alternatives can be mopping up free radical to create inert products by injecting polymer chemical stabilizers [16]. Otherwise for high temperature reservoirs, more polymer concentration should be injected for replacement.

### 3.7 Polymer slug

Polymers are expensive which makes polymer flooding more expensive compared to water flooding. As expenses being one of the reason polymers are sometimes not continuously injected throughout the production period [24]. When polymer injection stops while water injection continues two different layers are created on the front because of viscosity difference. This viscous fluid; the mixture of polymer and water at the front is so called polymer slug as can be seen on fig. 7 below.

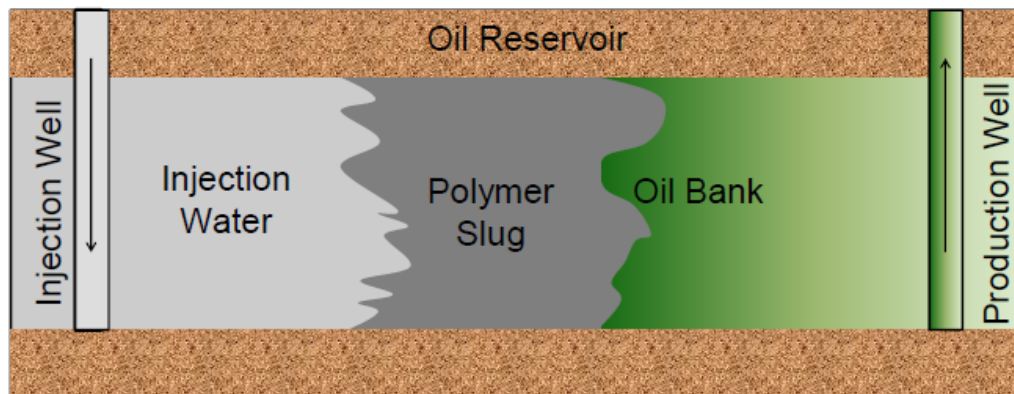


Figure 7: Showing the flow mechanism of polymer flooding and how the slug of polymer injected sweeps the oil out [24]

## **4. Field and Core Scale Cases of Polymer Flood**

### **4.1 Light Oil**

#### **4.1.1 Field Scale Cases**

##### **Dalia Field**

This is the oil field in Luanda-Angola in a camellia reservoir. It is a typical deep-offshore with 1300m water depth and 700 to 900m below sea level, 230km<sup>2</sup> with high permeability (>1D as an average) sandstone reservoir . The reservoir temperature is 50°C, 21-23 API oil is slightly under saturated with medium viscosity ranging from 3 to 7cP and water viscosity is in range of 0.5cP under reservoir temperature and pressure. Discovery was in 1997 and production started December 2006 and in 2008 the oil production plateau was equal to 240,000bbl/d.

Desulfated water was injected at the start and produced water was re-injected after water-breakthrough. The re-injected water estimated to have a maximum salinity of 53g/l corresponding to a mixture of 30% of formation water with desulfated sea water.

They used high molecular weight hydrolysed polyacrylamides under a wide range of salinities covering sea water and a mixture of sea water and produced water. According to the large well-spacing development of medium viscosity field the expectation was increment recovery on a range of 3 to 7% simulation results [16].

##### **Daqing oil field**

Daqing oil field in northern China is one of the biggest oil fields in the world and produces more than 900,000 bbl/day of oil from multiple reservoirs. Commercial production from the field started in 1959 and from 1976 to 1996, the field maintained a relatively stable oil production of 1 million bbl/day. The steady decline in production forced the field to adopt EOR that includes polymer flooding [25].

It is a sandstone reservoir with average depth of 3934 feet, pay zone thickness 328 to 393 feet, permeability value varying from 50 to 5000mD, porosity value varying from 20 to 30% and reservoir temperature is 113°F, oil viscosity is about 9-10cP, water reservoir salinity is from 5000 to 7000 ppm which considered no high salinity, injection polymer solution with concentration from 500 to 2500 ppm, finally the average incremental oil recovery is about 15% [25].

#### 4.1.2 Core Scale Cases

##### Daqing oil field

The core flood experiments used artificial cores with a 0.72 Dykstra-Parson coefficient and core permeability of about 1 Darcy. Polymer used for investigation was hydrolysed polyacrylamides (HPAM) with the molecular weights of  $17 \times 10^6$ ,  $13 \times 10^6$  and  $21 \times 10^6$  g/mole. The polymer concentration range from 1000ppm to 2500ppm and after several sensitivities, the best polymer concentrations they reported ranged from 1500 to 2500ppm. The following are the results when polymer concentration was kept constant (2500ppm) with 0.808-PV slug size for different polymer concentration.

Table 3: Flooding Efficiency for different molecular weights of polymers

Molecular weight ( $\times 10^4$ )	Water flooding recovery factor (%)	Polymer flooding recovery factor (%)	Incremental factor (%)	Molecular weight ( $\times 10^4$ )
1,300	40.20	65.87	25.67	1,300
1,700	43.92	70.91	26.99	1,700
2,100	38.70	66.13	27.43	2,100

The results above explained by the fact that higher molecular weight polymers have a higher viscoelasticity which improves sweeping efficiency and microscopic-oil displacement efficiency, and thus increases oil recovery

Another conclusion they insisted was injection time. The experimental results illustrated that the early injection of high-concentration polymer solution gives better oil recovery. Also the higher solution concentrations require less pore volume injected to reach the same recovery reduces the water cut and leads to the less production of fluids that need treatment.

## **4.2 Heavy Oil**

### **4.2.1 Field Scale Cases**

In spite all the limitations in polymer flooding it can also be applied in heavy oil reservoir. This is because heavy oil resources worldwide are estimated at 3396 billion barrels and the recovery is often less than 20% or even below 10%. Therefore polymer being one of the recovery methods with promising results has been used. Based on laboratory results, polymer can achieve tertiary recovery of more than 20% for heavy oil. Fields from China, Canada and Oman are reviewed and analysed as follows [6].

#### **Bohai Bay, Offshore China**

It is the poorly consolidated sandstone reservoir with estimation of more than 70% of the reserve to be heavy oil [21]. The reservoir have depth of around 1300 to 1600m, average thickness of pay zone 61.5m, average permeability of 2.6 Darcy, porosity of 28 to 35% and reservoir temperature of 65<sup>o</sup>C. The oil recovery was around 13.5 % after 10 years of water flooding [3].

In 2002 polymer flooding was tested in a single well for 500days. The water cut dropped from 95% to 54% with the incremental oil of 25000m<sup>3</sup> successfully [6].

In 2005 polymer was injected in 4 injection wells with 6 corresponding producers with an average spacing of 370m. The water cut reduced by 10% and 17700m<sup>3</sup> of increment oil per well was produced.

Until 2010, the total of 53 operations have been conducting polymer flooding with incremental oil of about 636000m<sup>3</sup> [6].

#### **Oman case study**

The Katala formation in Marmul field is located at 610 m deep, reservoir temperature of 46<sup>o</sup>C and medium oil viscosity of 80 to 110 cP.

In 1986 and 1988 small scale polymer flood pilot took place with one injector and four producing wells. The OOIP of the block was estimated to be 19000 m<sup>3</sup> and polymer used was PAM. The polymer solution of 1000 ppm was injected at a flow rate of 500m<sup>3</sup>/day which gave the viscosity of 15 cP at the surface under 46<sup>o</sup>C.

The polymer injection was injected in the slug form of which water was pre-flushed followed by polymer slug and finished with water post-flush. The results are summarized in the following table.



Table 4: The summary of polymer slug flooding heavy oil recovery in Oman Marmul field

Fluid	Pore volume	Time	Recovery factor
Water pre-flush	0.23	May 1986 to September 1986	12%
Polymer slug	0.63	September 1986 to August 1987	46%
Water post-flush	0.34	August 1987 to January 1988	59%

### **East Bodo Reservoir, Alberta Canada**

The reservoir has the permeability of 1 Darcy and the viscosity of 600 to 200 cP. Polymer injection in horizontal wells was initiated in May 2006 and the major challenge was the quality of injection water. In this low quality water maximum viscosity of polymer solution achieved was 10 cP at polymer concentration of 1500 ppm with no pressure resistance observed. After refreshing water the polymer solution viscosity improved to 60 cP and the wellhead pressure increase to 6 Pa at injection rate of 200 m<sup>3</sup>/day. There was no reported production data.

## 5. Description of simulation model

### 5.1 Source of the data file:

The data file used is SPE1A from ([www.ipt.ntnu.no/~kleppe/pub/SPE-COMPARATIVE](http://www.ipt.ntnu.no/~kleppe/pub/SPE-COMPARATIVE)) meant for SPE's comparative study case [26].

#### 5.1.1 Reservoir description

This is the layered (synthetic) reservoir with three layers based on 10x10x3 grid which makes the total of 300 cells. The dimensions of the grid blocks are 1000ft in X & Y-directions, and for three layers in Z-direction i.e the top, medium and lower layers are 20ft, 30ft and 50ft respectively.

#### *Original*

The reservoir contained four fluids meaning oil, gas, dissolved gas and water, with an initial reservoir pressure of 4800 psia at datum of 8400 ft. The depth for water-oil contact (WOC) located at 8500 ft and gas-oil contact (GOC) at 8200ft as shown in fig. 8 below.

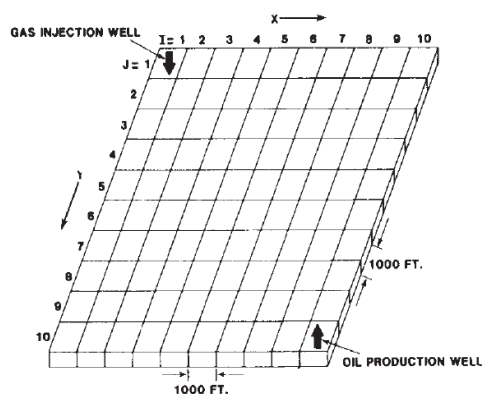


Fig. 1 – Reservoir and grid system.

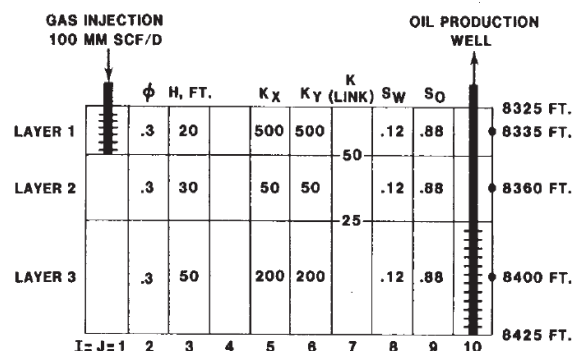


Fig. 2 – Diagonal cross section.

Figure 8: Showing grid system and diagonal cross section of the reservoir [29]

Reservoir lithology is mainly sandstone with compressibility of  $3 \times 10^{-6}$  1/psi, porosity of 30% measured @14.7 psi, average permeability of 250 mD and temperature of 200<sup>o</sup>F. Operations were done with two wells; 1 injector of gas at grid location (1 1 1) and 1 producer at (10 10 1). Gas with the specific gravity of 0.792 was injected at the rate of 100 MMScf/D. While oil was produced at maximum rate of 20,000 STB/D and the rate was limited at minimum rate of 1000 STB/D.

The producer was operating with minimum flowing BHP of 1000psi. For all wells the wellbore radius was 0.25ft with zero skin.

*Conditions set to terminate simulation run were;*

When GOR reach 20,000 Scf/STB or when oil production rate was 5100 STB/D or at the end of simulation period which was 10 years, for whichever occurs first will terminate.

### **Modifications**

The changes for reservoir fluids were made from four fluids to dead oil (oil and water only). Initial reservoir pressure remained the same so as the lithology, porosity and WOC with no GOC and temperature is changed from 200<sup>o</sup>F (93<sup>o</sup>C) to 158<sup>o</sup>F (70<sup>o</sup>C). This is because polymer properties used are obtained at 70<sup>o</sup>C and Xanthan is the type of polymer used which cannot sustain more than 80<sup>o</sup>C as explained in chapter 2 (2.1.1) above. The average permeability will depend on the cases created which is explained in chapter 5 (5.3.2). Furthermore, two more wells are added making total number of wells to be 4 (1 injector and 3 producers). The injector is in same location at (1 1 3) and producers are at (10 10 2), (1 10 2) and (10 1 2) named PROD1, PROD2 and PROD3 respectively as shown in fig. 9 below.

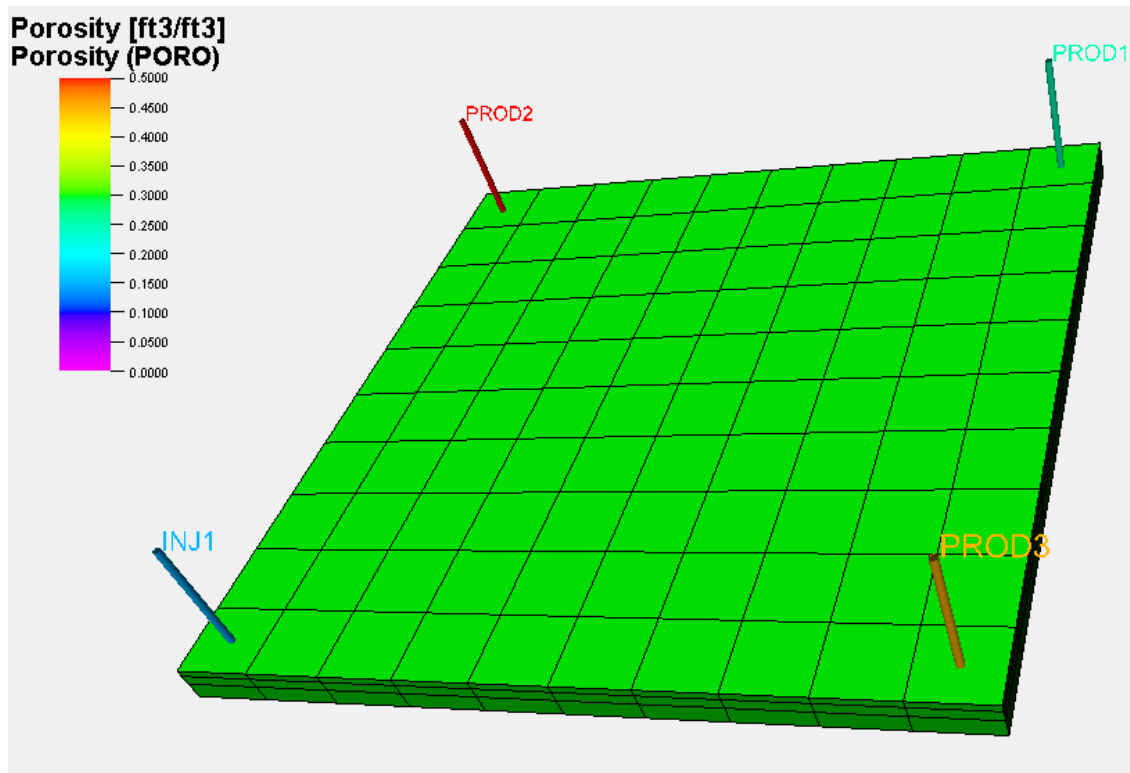


Figure 9: Showing the 3D model with porosity (30%) viewed

Since the aim is to inject polymers which are injected with water, therefore the injector is changed from gas to water with the completion from 8335ft to water @8600ft. Water will be injected at maximum rate of 30,000 STB/D and the BHP is limited at 6000 psi. While for producers; PROD1 will be producing at the maximum rate of 15,000STB/D while PROD2 and PROD3 will produce at 12,000STB/D but with same limiting BHP of 2500 psi for all. The production rate for PROD1 is high because it is located far from injector, so it has greater potential to produce and less chances for early water breakthrough considering the permeability is the same.

I decided to limit the pressure and control the flow rate for both injector and producers because additional of polymers changes the pressure of the reservoir sharply. The extent for pressure changes depends on the amount of polymer injected but mostly on reservoir permeability. With the consideration of one of the main objectives that is to compare the response of polymer flooding in different permeabilities, controlling the BHP's will be the better assistance in analysing and maintaining the reservoir pressure.

*Conditions to terminate the simulation run are;*

At the end of simulation period which is 15 years. The decision was made for the reason of minimizing simulation time because many simulations are supposed to be done.

Considering the rock and fluid properties mentioned above, Original Oil in Place is obtained as follows;

$$OOIP = (1-S_w) * \phi * A * h * (N/G)$$

$$\text{Assuming } N/G = 1$$

$$= (1-0.2) * 0.3 * (10000 \times 10000) \text{ ft}^2 * 100\text{ft} * 1$$

$$= 2400000,000 \text{ ft}^3: 1 \text{ ft}^3 = 0.17811 \text{ US bbl Oil}$$

$$= 427464000 \text{ STB}$$

$$\mathbf{OOIP \approx 4.3 \times 10^8 \text{ STB}}$$

## 5.2 Source of Polymer Properties

The polymer properties were taken from Eldar Sadikhzadeh thesis titled “*Evaluation of polymer flooding for improved recovery at the Norne Satellites*”. This thesis was submitted in 2007 at NTNU under supervision of Prof. Jon Kleppe and Adjunct Professor Jan Åge Stensen from SINTEF. The variation of other properties such as RRF and adsorption are done with reference to different SPE papers values and range from ECLIPSE manual.

### 5.3.1 Reservoir fluids and rock properties

In the data file in PROPS section (appendix A) the relative permeabilities and capillary pressure are defined along with other PVT properties of the reservoir fluids. Figure 10 below shows the relative permeability of water and oil as the function of water saturation during imbibition. The end point relative permeability of water  $krw'$  is 0.96 while for oil  $kro'$  is 0.04. The residual oil saturation is 0.2 and the irreducible water saturation is 0.2.

Other PVT properties like  $kro$ ,  $krw$  and  $P_{cow}$  are presented as follows.

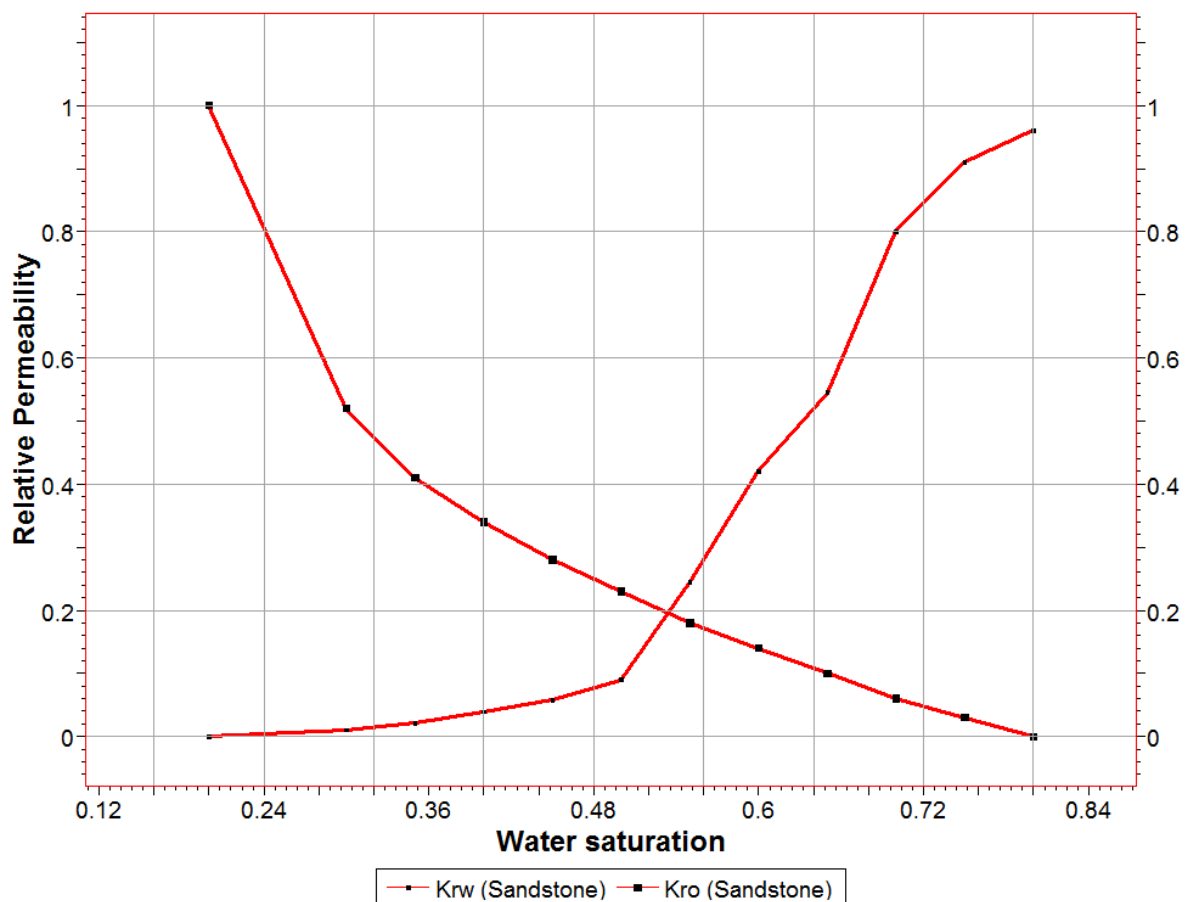


Figure 10: Showing variation of oil and water relative permeabilities,  $kro$  and  $krw$  with water saturation

The relationship characteristic of the displacement of oil from the irreducible saturation to the reducible saturation is shown in fig. 11 below. It can be seen that the irreducible water saturation,  $S_{wir}$  which is 0.2 is obtained at the highest capillary pressure which is 1 psi and is independent of increase in externally measure capillary pressure. While residual oil saturation,  $S_{or}$  is 0.2 presented as  $S_w=0.8$  is when externally  $P_c$  is decreased from high value to negative value (Forced imbibition).

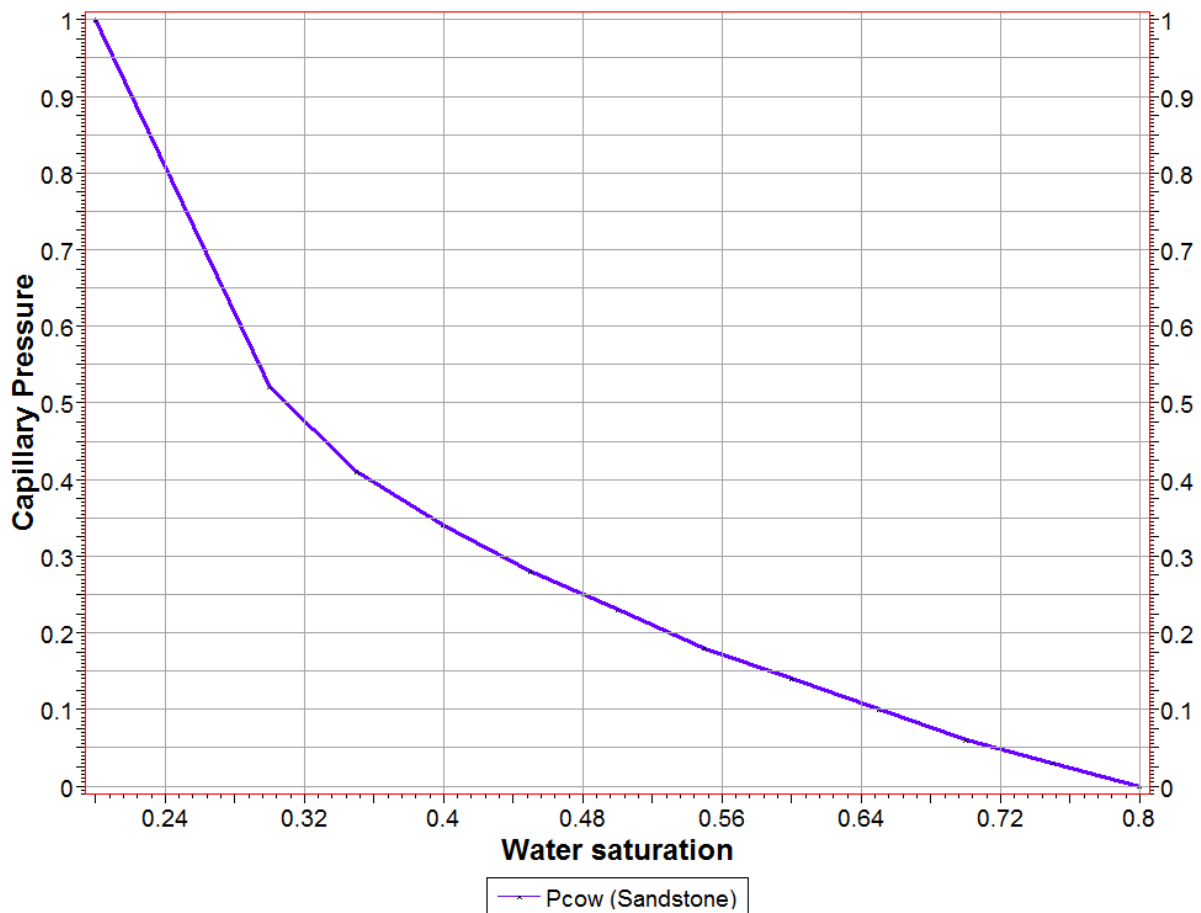


Figure 11: Showing imbibition water-oil capillary pressure curve,  $P_{cow}$

### 5.3.2 Permeability cases

Low and high permeability for homogeneous and heterogeneous distribution cases are created which make four base cases as shown in table 5 and viewed in 3D model in fig. 12 below. These values are changed in data file on keyword EQUALS as shown in appendix A. The investigation base is on determination of the quality and quantity of polymers injected that will be suitable among these cases. So the study will consider these cases as screening criteria of the reservoir performance during polymer flooding project.

Table 5: Showing the homogeneous and heterogeneous cases with different layered permeability

HOMOGENOUS DISTRIBUTION				HETEROGENEOUS DISTRIBUTION			
		Absolute permeability, k (mD)		Absolute permeability, k (mD)			
Layers	DZ (ft)	HIGH	LOW	Increase by %	HIGH	Decrease by %	LOW
Top	20	1500	500	20%	1800	20%	1200
Medium	30	1500	500	30%	1950	30%	1050
Lower	50	1500	500	50%	2250	50%	750

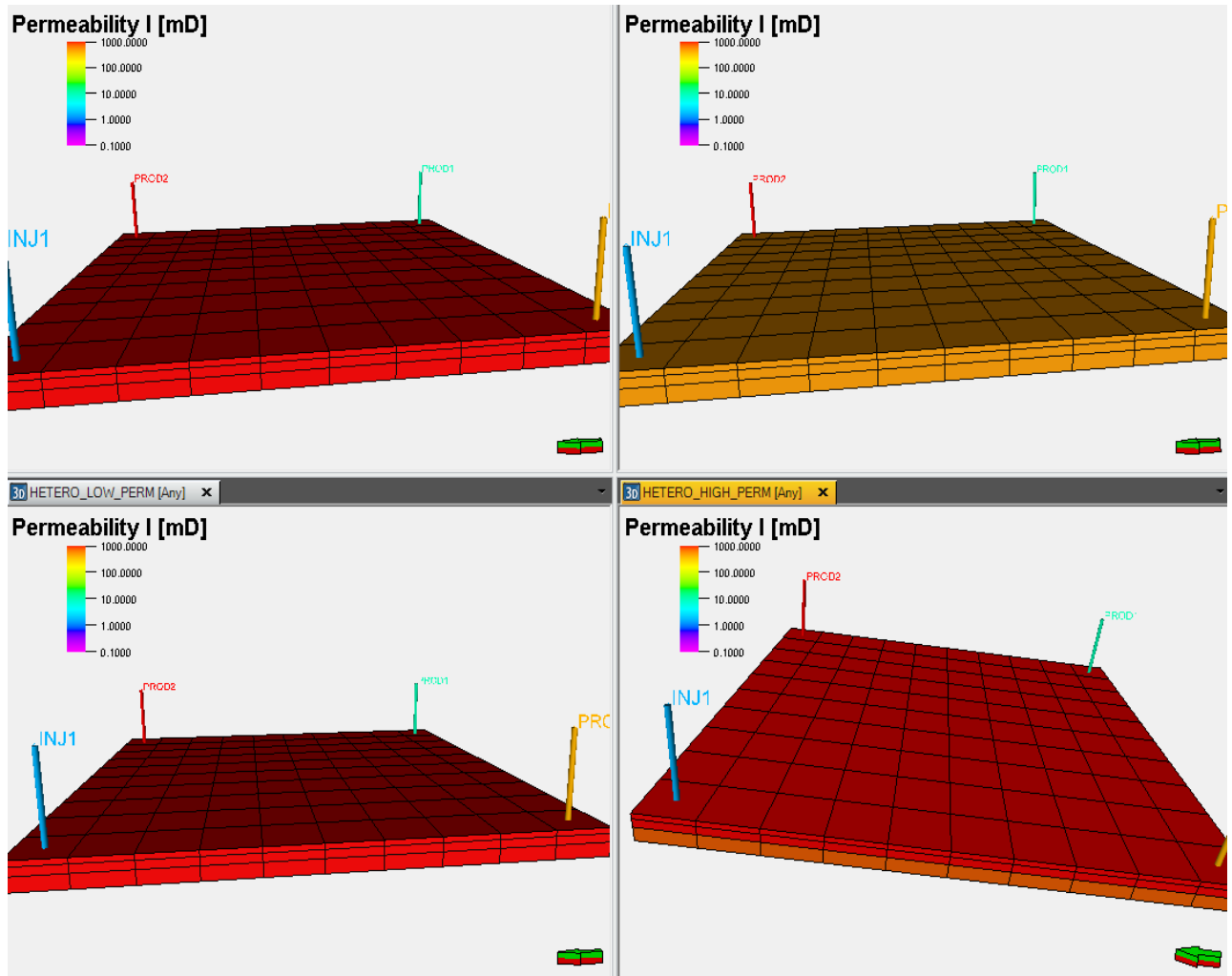


Figure 12: Showing different permeability distribution in 3D model of four base cases created

### ***Assumptions for polymer flooding simulation***

Base on the four cases created above, different polymer properties sensitivities will be done along with several assumptions included.

- Water flooding will be considered as base case for each case. Meaning, four cases will have water flooded as base case and polymer flooding will be compared to it.
- Different polymer concentration will be tested.
  - This will not be encountered for polymer concentration only, but as the assumption it will also be encountered for salinity effect sensitivity and oil viscosity sensitivity.

Salinity effect sensitivity: Xanthan polymer is less sensitive to salinity but the presence of high salinity will decrease solution viscosity. This can be encountered as low concentration of polymer injected. The reason for making this assumption is because i could not get real data for salinity.

Oil viscosity sensitivity: For the case of changing oil viscosity; it will have more or like same effect as changing polymer concentration but with different amount of polymer requirement.
- Different range for polymer adsorption in the rock surface will be tested
  - Adsorption cannot be changed in the reservoir but different possible adsorption values will be tested assuming the possibility of it to occur and the results will be discussed accordingly.
- Different RRF will be tested.
  - Adsorption of polymer causes permeability reduction and RRF represents that reduction. Therefore this value will be tested along with polymer adsorption to examine the possible effects.
  - RRF will also be considered for sensitivity in relative permeability of water, because reduction of permeability caused by large polymer molecules retention blocks water flow which lowers relative permeability of water. For this reason relative permeability curve of water with polymer is expected to be lower. But since in ECLIPSE software we cannot export the corresponding relative permeability values, RRF value will be counted as the representative in one way or another.
- Grids are going to be refined (Full grid refinement and LGR) for better approximation of simulation results. Assuming the results are going to be closer to the reality.



## TO BE NOTED

The permeability cases will be referred as *four major cases* meaning

- Homogeneous distribution with
  - LOW\_PERM and
  - HIGH\_PERM
- Heterogeneous distribution with
  - LOW\_PERM and
  - HIGH\_PERM

For the case of simulation period which is *15 years* which is the same as:

- Oil production period &
- Water injection period

Polymer slugs will be injected from the beginning of simulation period in different injection time order (1, 2, 3 & 4 years). In this report the injection cases will be referred as: *4 orders of injection*.

The legend will be presented as:

Water/Polymer Flooding \_ (Homo/Heterogeneous) \_ Injection years\_ Production period \_ Permeability case (LOW/HIGH)

Example: **Water Flooding \_ Homogeneous \_ 1\_ 15 \_ HIGH**

**Polymer Flooding \_ Heterogeneous \_ 3\_ 15 \_ LOW**

## 6. Results and Discussion

### 6.1 Water Flooding or Base case

Oil recovered after flooding water in all four major cases is as follows.

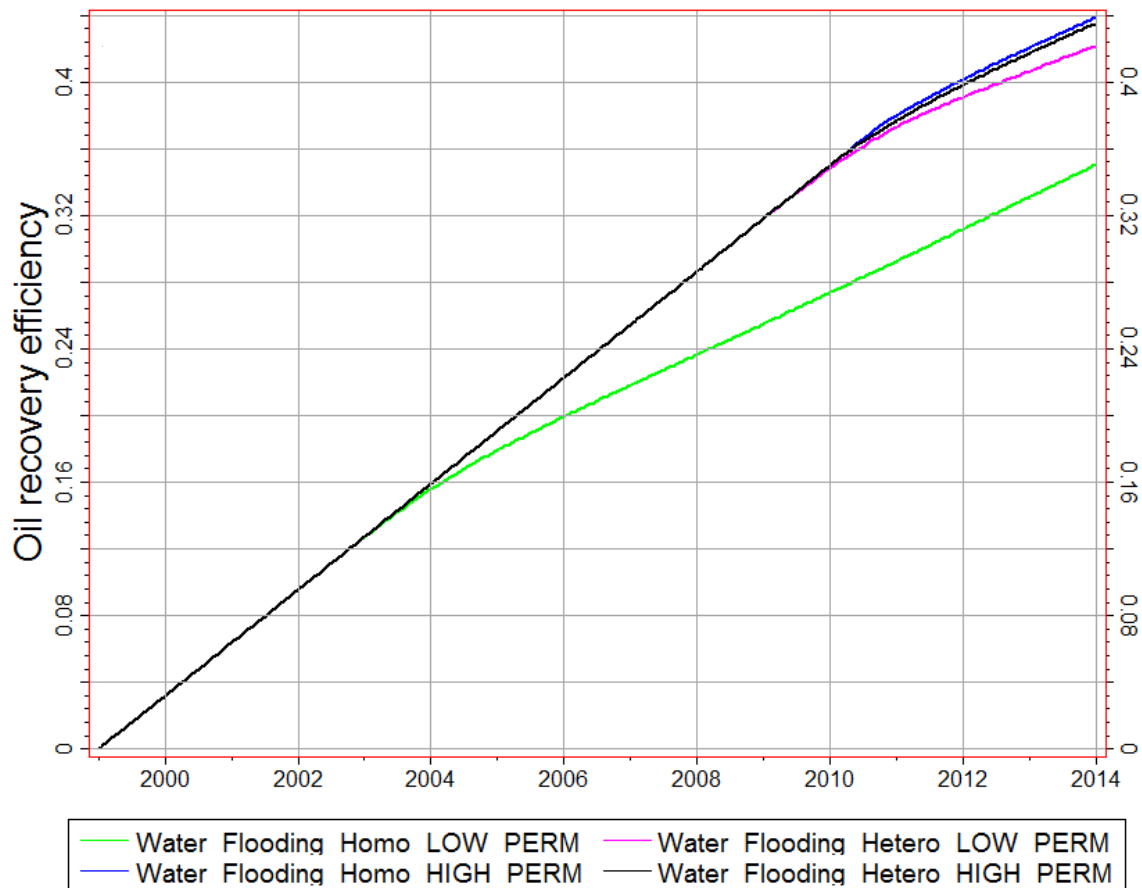


Figure 13: Showing field oil efficiency (FOE) after water flooding in four major cases

From fig.13 above, the highest oil recovery obtained is 43.87 % followed by 43.51 %, 42.16% to 35.03%. According to the trend it shows that high permeability is the major factor compared to heterogeneity distribution. While for the case of heterogeneity, heterogeneous gives better recovery than homogeneous. In homogenous case there is less resistance to flow and since the permeability is low water moves faster causing large fingering effect and early water breakthrough (green line). While in heterogeneous case, variation of permeability lowers the mobility of water which causes better sweeping efficiency (fig. 13) and later water breakthrough with high water production rate also shown in fig. 14 below.

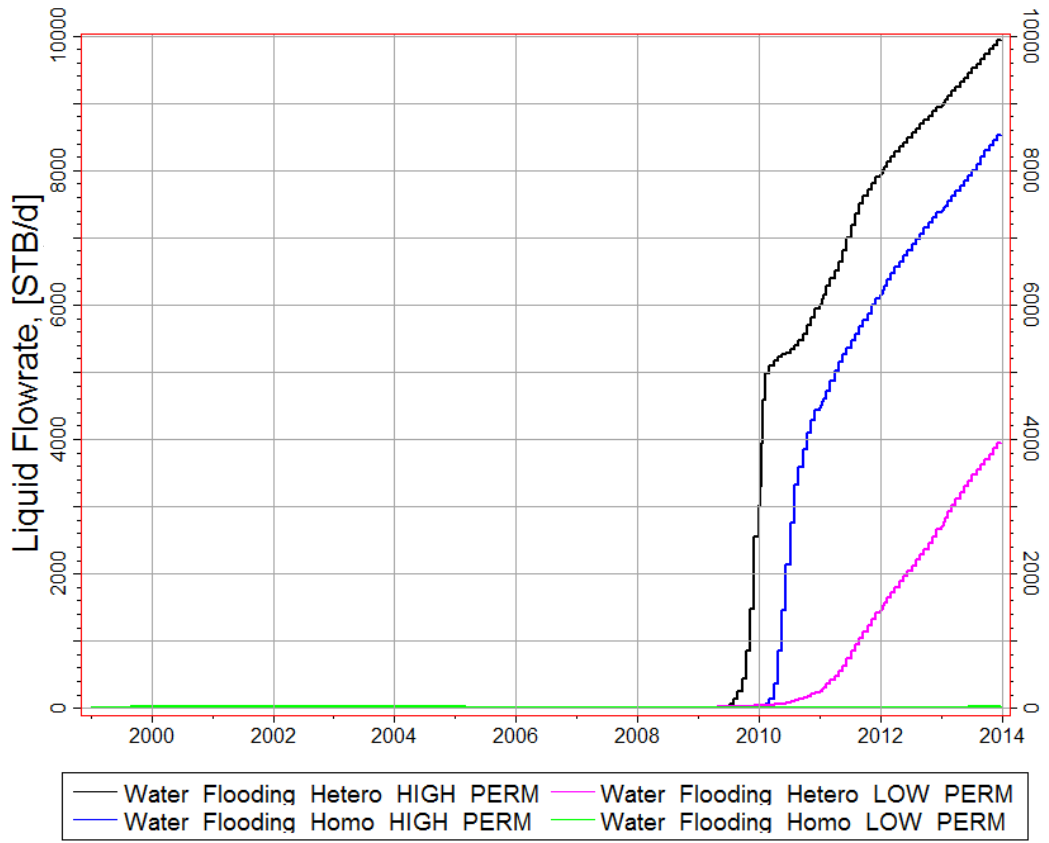


Figure 14: Showing field water flow rate after water flooding in four major cases

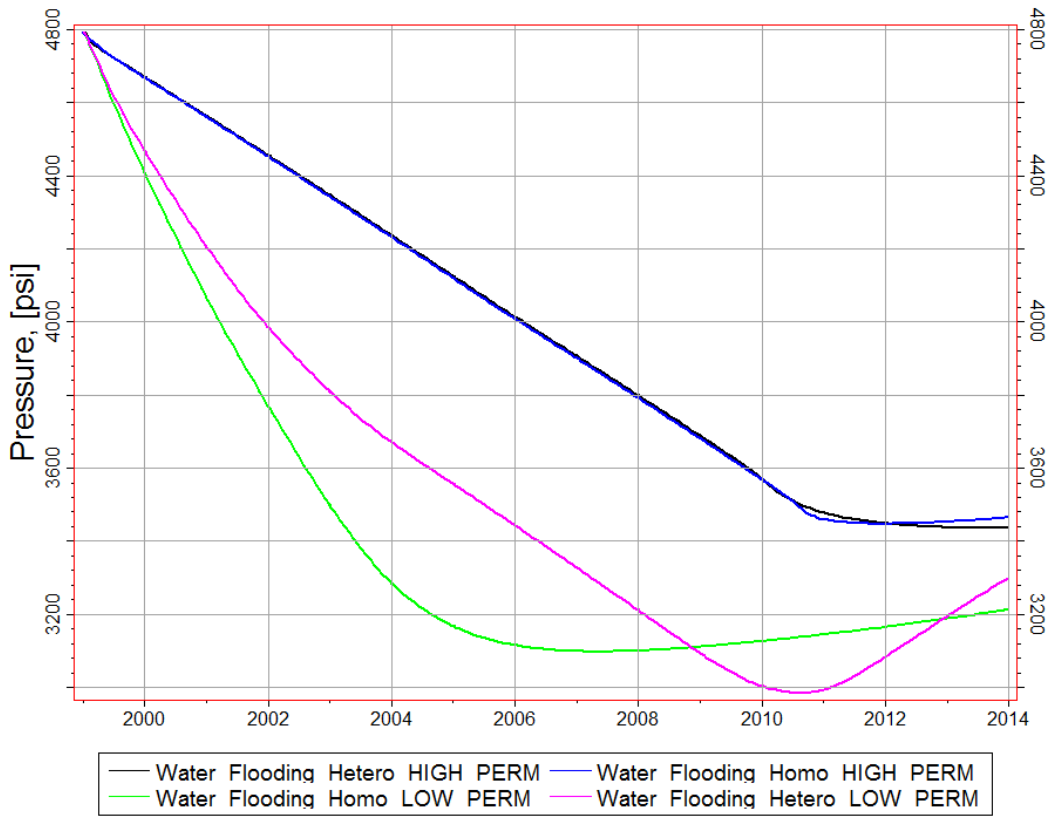


Figure 15: Showing reservoir pressure after water flooding in four major cases

Production causes the release of pressure in the reservoir, injecting water is +/- that helps to maintain it. From fig. 15 above, the results shows that drop in pressure have less proportional effects with oil recovered. High pressure drop occurs in low permeability compared to high permeability cases. This can be explained through Darcy's law presented in eqn (vii) below; pressure drop increases when permeability is low considering area and flow rate are constant with a little change in viscosity.

$$Q = \frac{kA}{\mu} \left( \frac{\Delta P}{l} \right) \dots \dots \dots (vii)$$

## 6.2 Polymer flooding

Polymer slugs were flooded from the beginning of simulation in *4 different orders*. For each case polymer concentration in a range of 0.1, 0.2, ... , to 1.7 lb/STB is tested.

Appendix B fig. 48 to 52 shows the highest oil recovered and the corresponding concentration of polymer injected for all *4 different orders* and *four major cases* each. For each figure the highest recovery among *four major cases* is given the different colour. On the whole, for all orders, the highest recovery obtained when permeability is high with heterogeneous distribution followed by homogeneous with high permeability. This concludes that sweeping efficiency based more on reservoir permeability compared to heterogeneity even after polymer flooding. This is because in high permeability cases there is fewer polymers retention or adsorption causing less reduction of slug viscosity hence better sweep. But polymer retention can be of advantage as it causes late polymer breakthrough as explained in chapter 3 (3.2). This is also shown in fig. 53 in appendix C, that high permeability cases give high polymer production. For the case of heterogeneity, heterogeneous case gives better results because polymer solution flows along high permeable layers, decreases the flow rates and enhances sweep efficiency on low permeable layers. This means oil in high and low permeable layers will be swept out eventually and high recovery will be obtained.

On the other hand, the overall highest recovery among four major cases obtained was in high permeability case with heterogeneous distribution.

### High permeability heterogeneous case

Figure 16 below shows the cumulative polymer injected in mass [lbm] with different line colours where by each line hits the corner; this corner is the presentation of the year when polymer stopped to be injected.

Also with the same line colour, there are boxes with two values displayed accordingly, the oil recovery factor in % and the corresponding polymer concentration injected in lb/STB.

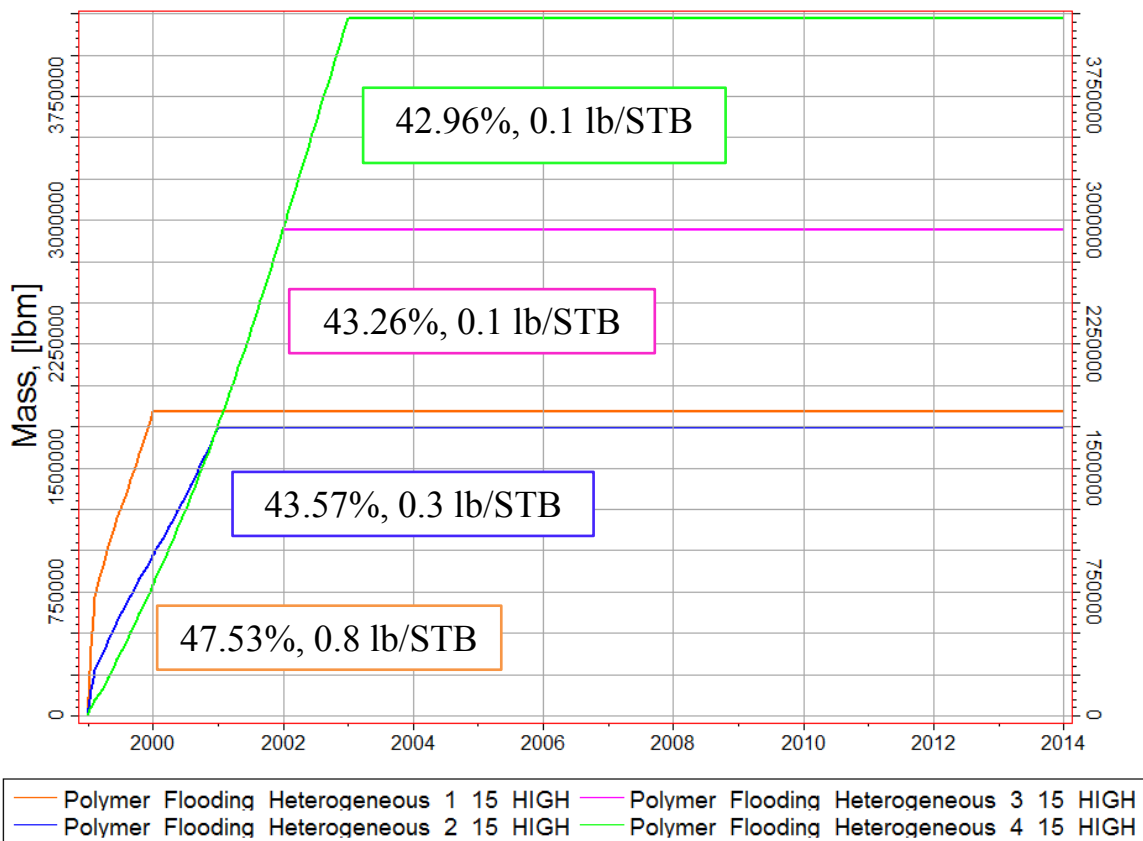


Figure 16: Showing the highest recovery, concentration of polymer injected, injection time and amount of polymer injected in mass

The highest oil recovery obtained is 47.53% after flooding 0.8 lb/STB polymer concentration for 1 year in heterogeneous high permeability case shown in fig. 16 above. Also it shows that, as injection time increases less polymer concentration is required but less recovery is obtained. This is because injecting large amount of polymer for a short time creates the more viscous slug that can be slightly altered with retention or adsorption effects of polymer. So maintained viscous slug will create sharp front meaning better sweeping efficiency will be attained.

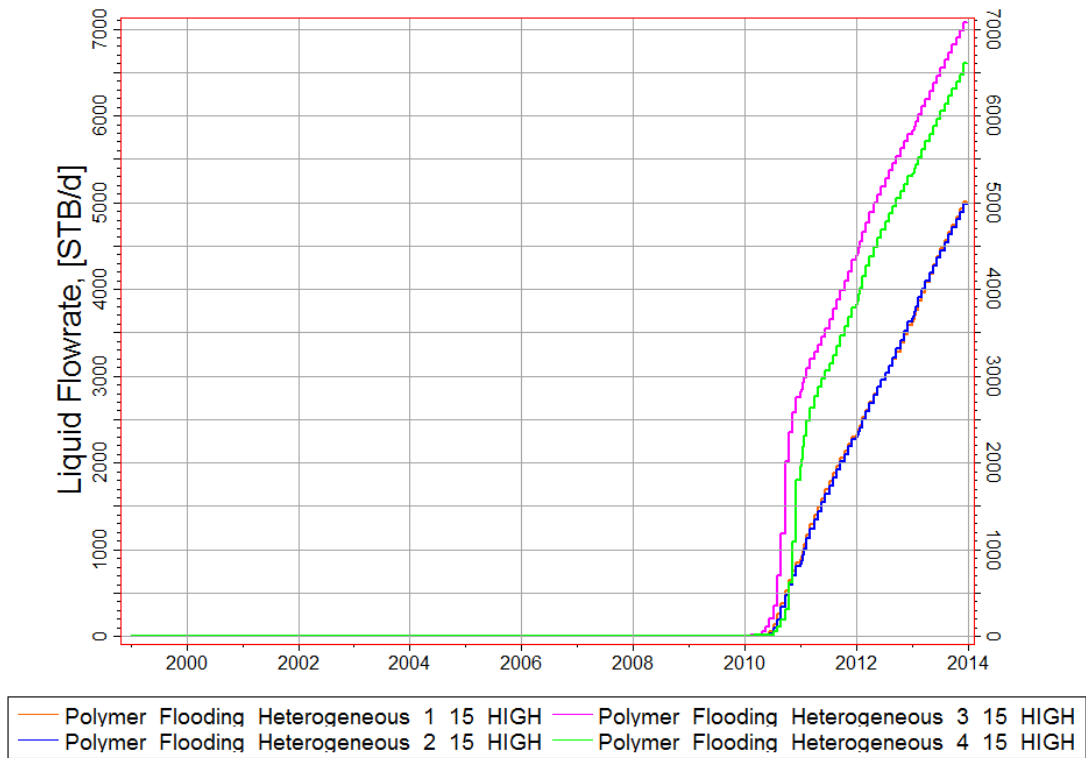


Figure 17: Showing the water production rate after polymer flooding in overall highest recovery

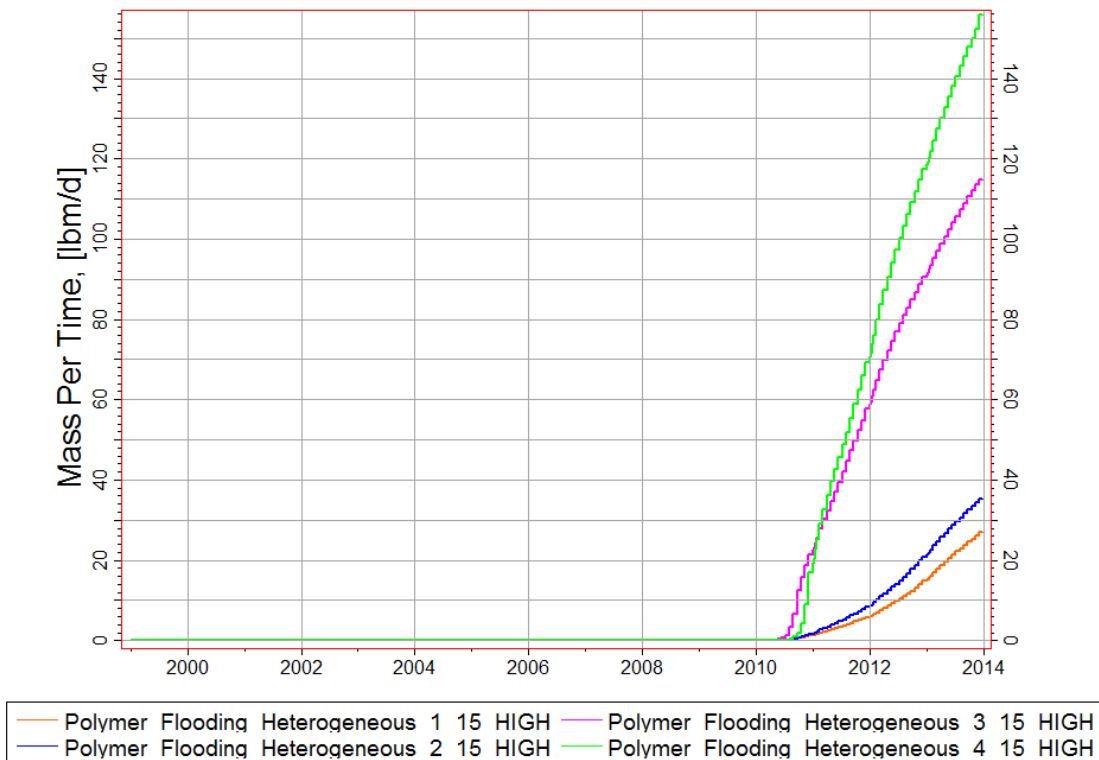


Figure 18: Showing polymer production rate after polymer flooding in overall highest recovery

Figure 17 & 18 shows the water production rate and polymer production rate for heterogeneous case with high permeability after flooding polymer in 4 orders of injection. Oil recovery decreases as injection time increases while water cut and polymer production increases. This is explained through fig. 16, as injection time increases large amount of polymer is injected with less concentration. This causes polymer solution to be less viscous with high mobility ratio and large fingering effect hence less sweeping efficiency occurs. This high fingering effect causes high water and polymer production.

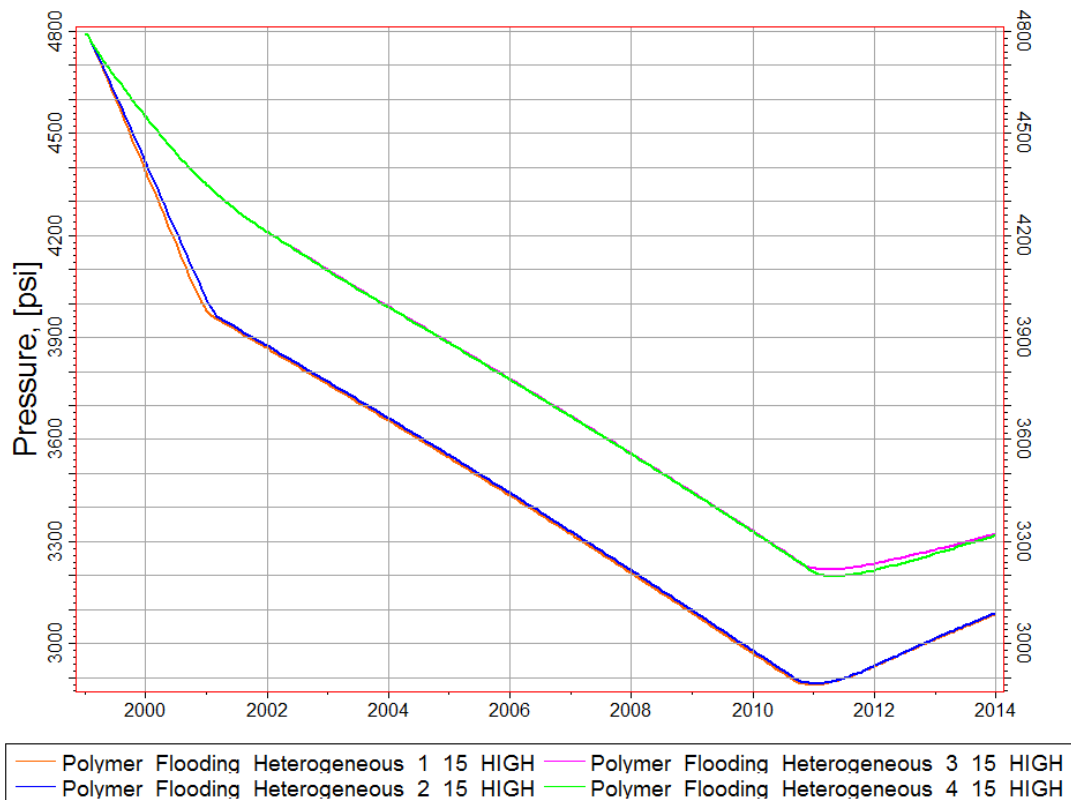


Figure 19: Showing reservoir pressure after polymer flooding in overall highest recovery

The pressure in fig. 19 above shows that the pressure is decreasing more after injecting polymers for 1 and 2 years. This is because, more oil, water and polymers are produced compared to water injected. But as the injection time increases, more polymers with less concentration are injected but the less oil is recovered therefore less pressure is drop. This proved that polymer flooding requires special attention in pressure control.

Which shows the difference is not to be big enough to show the difference in pressure drop.

In Aug. 2010 to Jun. 2011 the pressure drops constantly around 2650 psi and starts to pick up again. The reason for this is the control mode as explained in chapter 5 (5.1.1); therefore when pressure reaches the limit it starts to build up again because the injection continues.

The same effect can be seen in oil production rate in fig. 20 below. Oil rate decreases and stayed constant as the response of the pressure drop then continue to decrease because the reservoir is emptied. But water production rate is not affected by the pressure response. Figure 20 below shows that when oil production rate increases polymer production increases concurrently. All in all the overall highest recovery among 4 orders of injection is high permeability case with heterogeneous distribution after flooding polymer of 0.8lb/STB for 1 year.

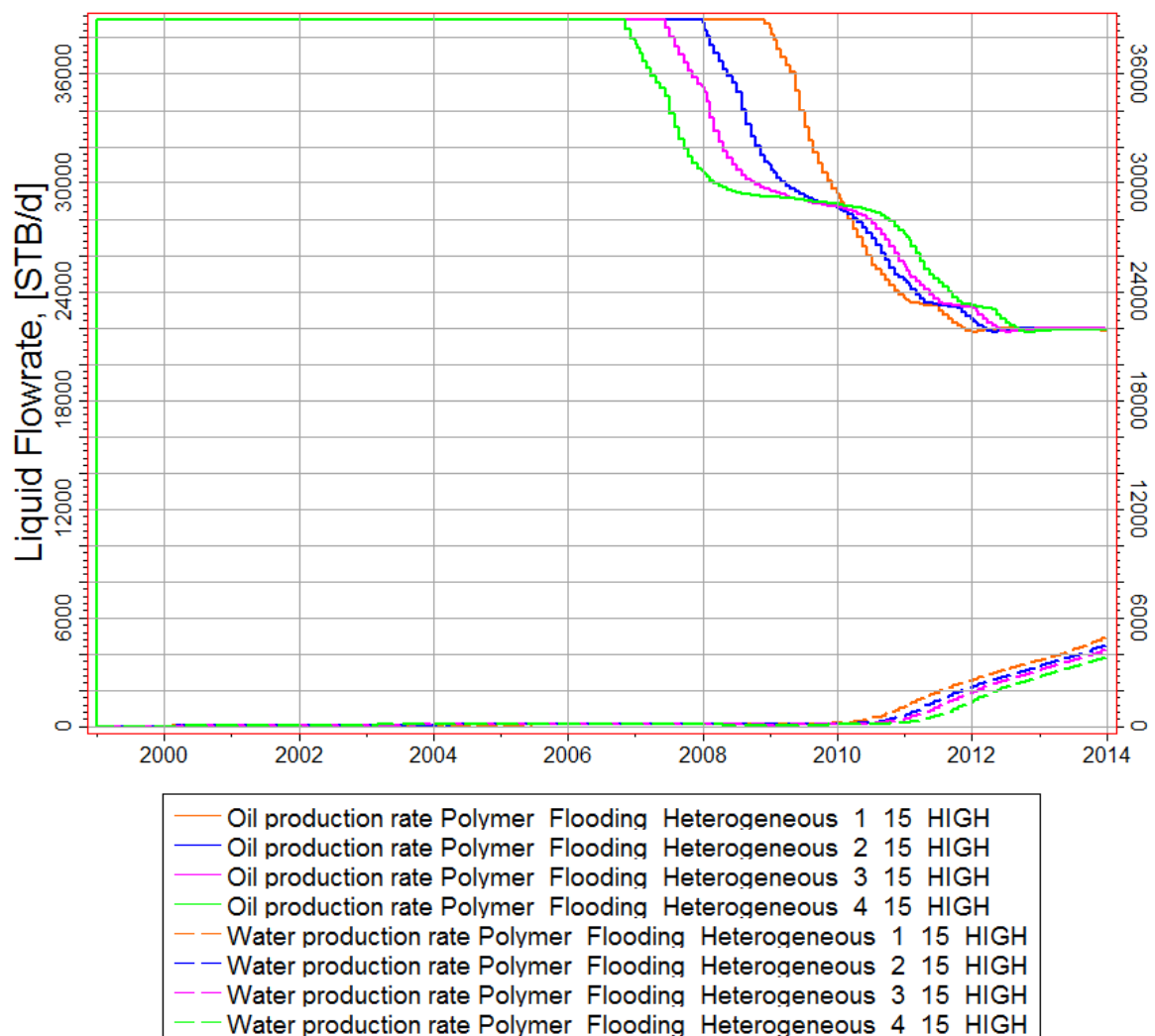


Figure 20: Showing the oil production rate and water production rate after polymer flooding in overall highest recovery



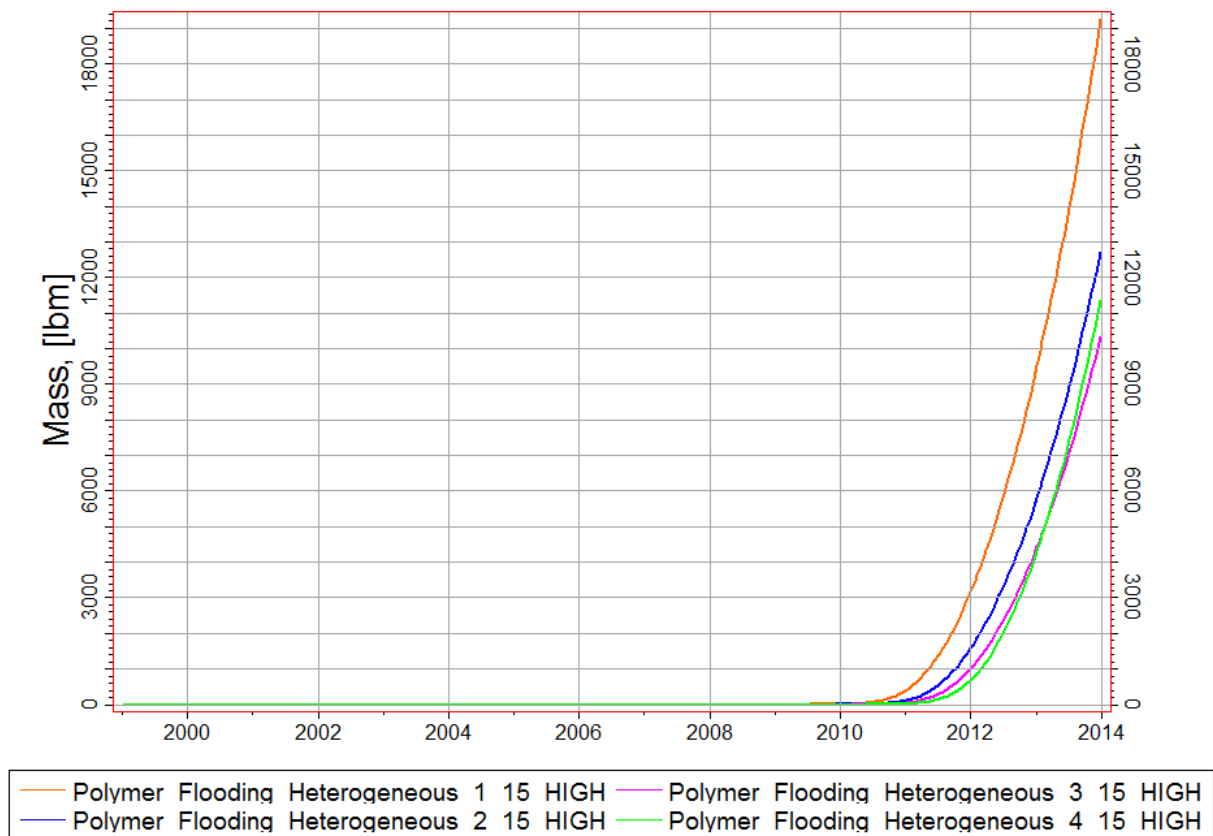


Figure 21: Showing field cumulative polymer production after polymer flooding in overall highest recovery

The following is the examination of reservoir fluid flow. Since the reservoir is symmetrical, different grid blocks in similar vector but different location are selected as shown in 3D fig. 21. The purpose is to see if reservoir fluids (for this case water saturation in fig. 21) moves symmetrically as well.

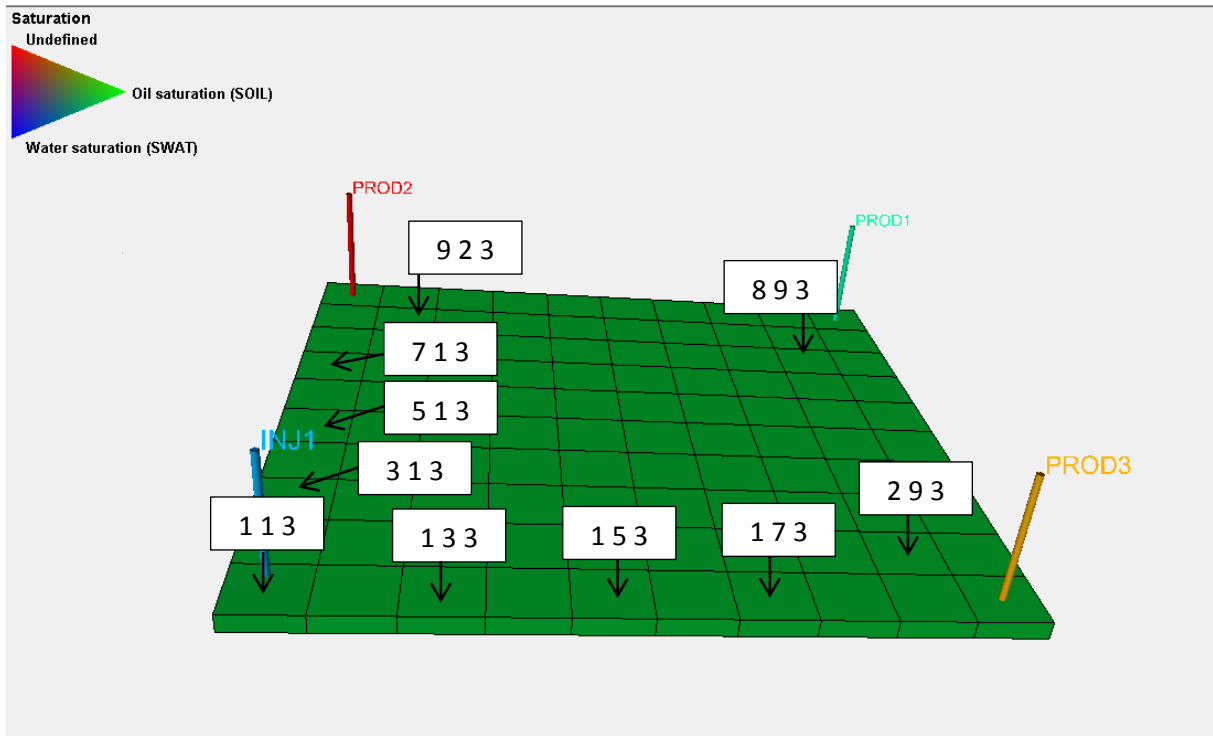


Figure 22: Showing different grid blocks for lower layer in 3D model

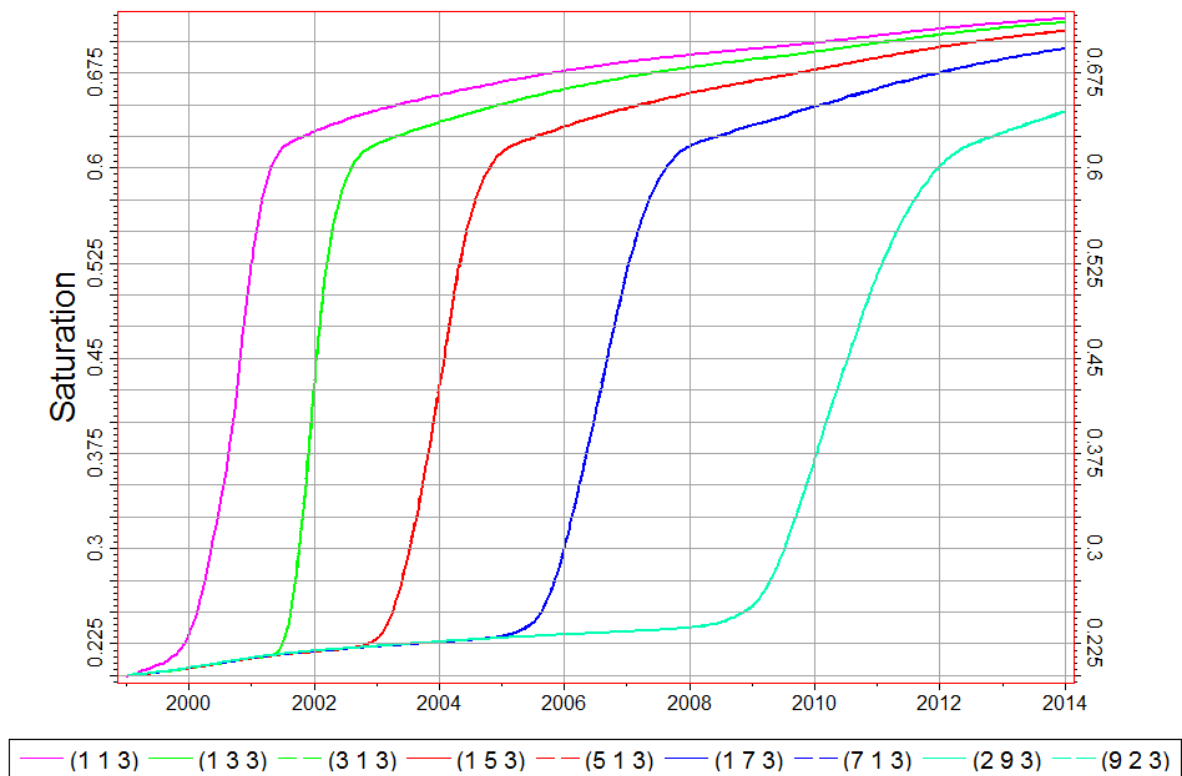


Figure 23: Showing water saturation for different grid blocks in lower layer

Water saturation along PROD3 (1 7 3) is similar to block (7 1 3) along PROD2 this proves that even reservoir fluids move symmetrically. Grid block (1 1 3) holds the injector and shows high water saturation compared to the rest but on the other hand polymers tend to plug and block the injection well. For that reason the distribution of polymer cell concentration is checked around the injector as presented in fig. 23 & 24 below.

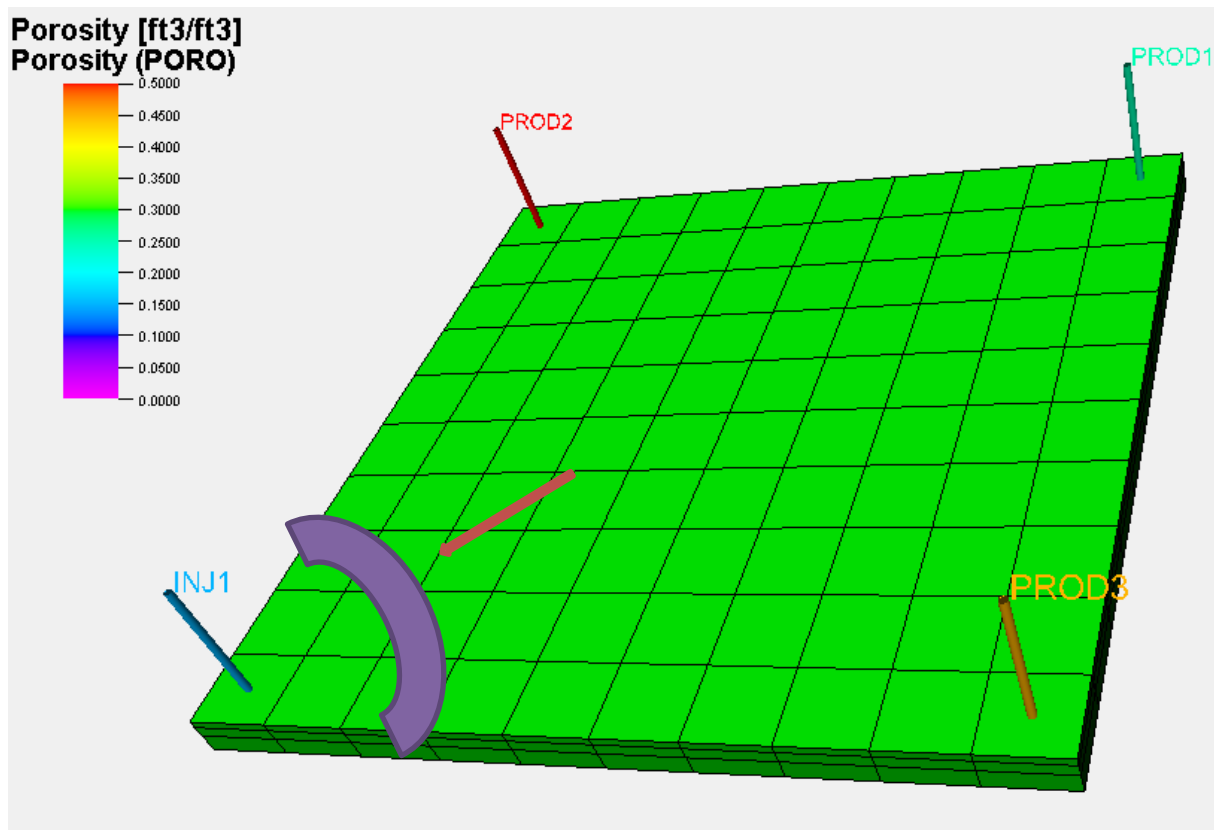


Figure 24: Showing 3D model pointing to the grid blocks around the injector

The grid blocks to be examined for polymer cell concentration are, (1 1 1), (1 1 2), (1 1 3), (1 2 1), (1 2 2), (1 2 3), (2 2 1), (2 2 2) and (2 2 3). These are grid blocks around the injector from the top to lower layer.

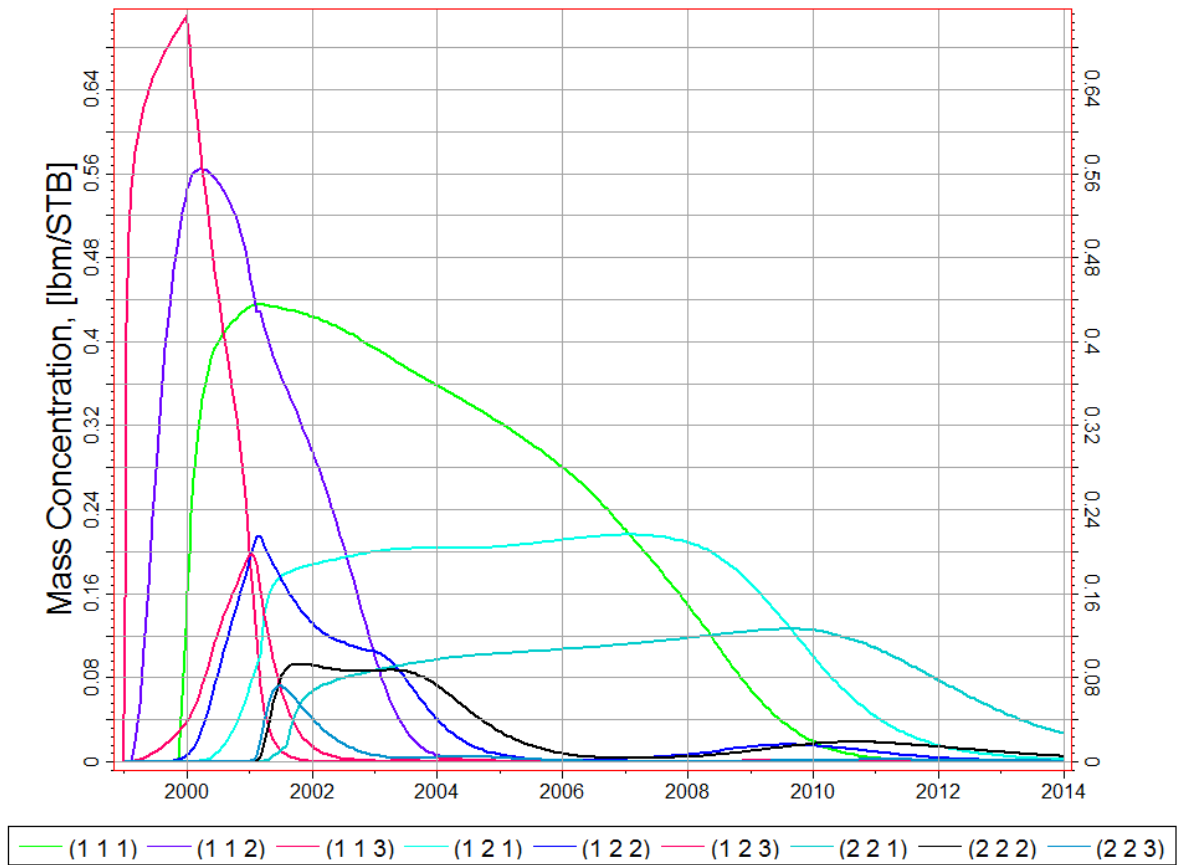


Figure 25: Showing polymer cell concentration on several grid blocks around the injector after flooding 0.8 lb/STB of polymer for 1 year

Figure 25 above shows that polymer is moving slower in the top layer (1 1 1), (1 2 1) and (2 2 1) than all other layers. This is because water is injected continuously at the lower and half of the middle layer. So for the polymer that goes on the top layer moves slower with low concentration. The polymer cell concentration around the injector decreases from 2010 after water break though. As discussed above in chapter 3 (3.1) polymers tend to adsorb on the rock source even clog the injector/producer wells if the concentration is high. Adsorption decreases the permeability of the rock which can be of advantage or disadvantage in oil recovery. Therefore the following is the adsorption and RRF sensitivity in terms of oil recovery.

### 6.2.1 Adsorption and RRF sensitivity

Figure 16 above shows that, less polymer concentration is required to give better recovery as injection time increases. So large amount of polymer is injected with less polymer viscosity and this creates high chances for polymer to adsorb on the rock surface. Figure 26 below shows that the highest field adsorptions total is in high permeability case with heterogeneous distribution among the overall highest oil recovery.

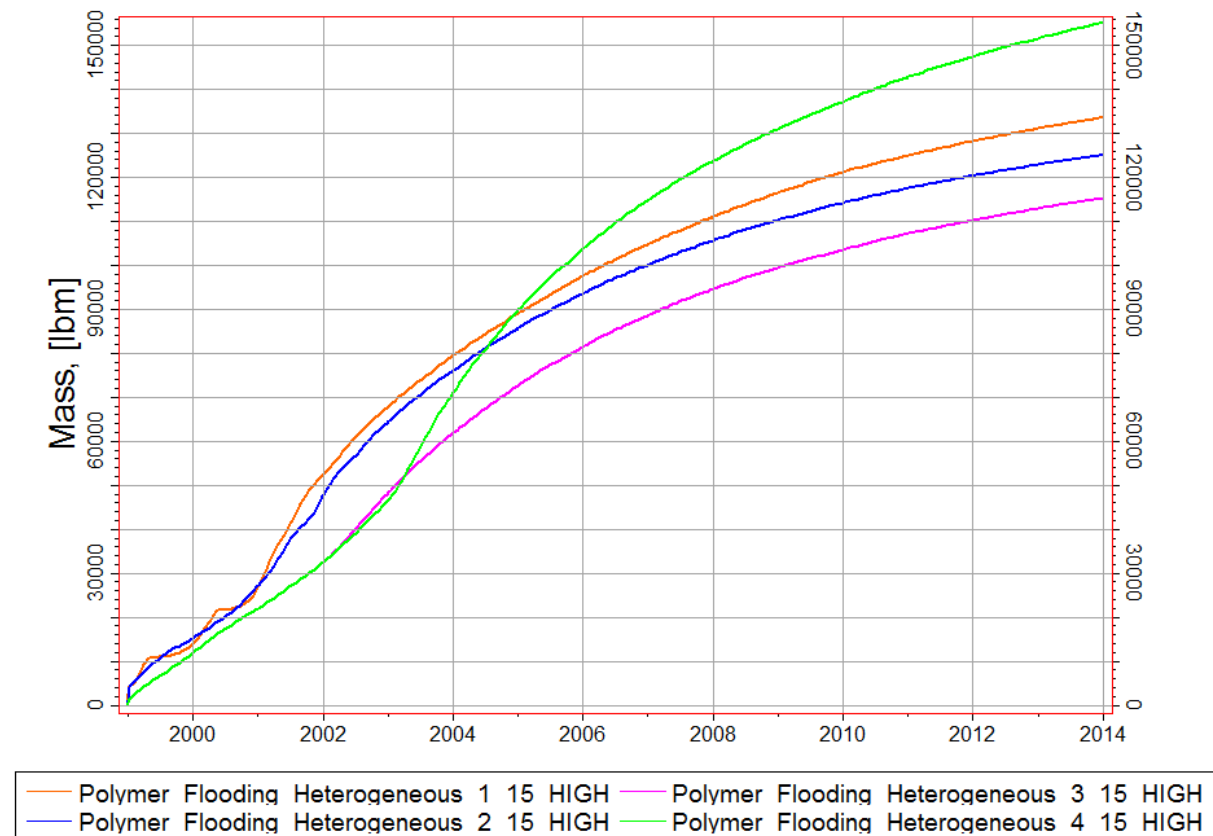


Figure 26: Showing polymer adsorption total for overall highest oil recovery

The adsorption sensitivity was done by changing the 5<sup>th</sup> value in **PLYROCK** keyword. This value represents maximum polymer adsorption used to calculate resistance factor for aqueous phase. The original value was 0.00017 lb/lb and the sensitivity was done in the following values, 0.0000017, 0.000017, 0.0017, 0.017 and 0.17lb/lb. The oil recovery remained the same for all four major cases with four orders of injecting. This happened because the 2<sup>nd</sup> value on the same keyword representing RRF was set 1.

RRF represents the decrease in rock permeability to the aqueous phase when maximum polymer has been adsorbed. Therefore if we consider the formula in equation viii below, this is used to calculate the actual resistance factor;

$$R_k = 1.0 + (RRF - 1.0) \frac{C_p^a}{C_p^{a\max}} \dots \dots \dots (viii)$$

Where: RRF is residual resistance factor and  $C_p^{a\max}$  is the value of the maximum adsorbed concentration (as 2<sup>nd</sup> & 5<sup>th</sup> values in [PLYROCK](#)).

It shows that if the value of RRF is set to 1 the actual resistance factor will be equal to 1 regardless of the value of maximum adsorption set (5<sup>th</sup> value or  $C_p^{a\max}$ ). So this is why the value of oil recovery remained the same for all case. So, when RRF increases resistance factor will increase hence the recovery is expected to be lower. But then again RRF value was set from 1.1, 1.2 and 1.5 and the oil recovery remained the same too.

Therefore all these factors and reasons be the case, sensitivity of adsorption will be done with reference to different values of the RRF. For each value of RRF listed above, range of adsorption values listed on top will be tested for all four major cases. The aim is to investigate adsorption effects when it comes to high and low permeability in homogeneous and heterogeneous cases. So, same polymer concentration of 0.8 lb/STB will be flooded for 1 year for all four major cases for comparison.

Figure 27 to 30 below shows the oil recovered as the results of polymer adsorption differences in reference to different values of RRF.

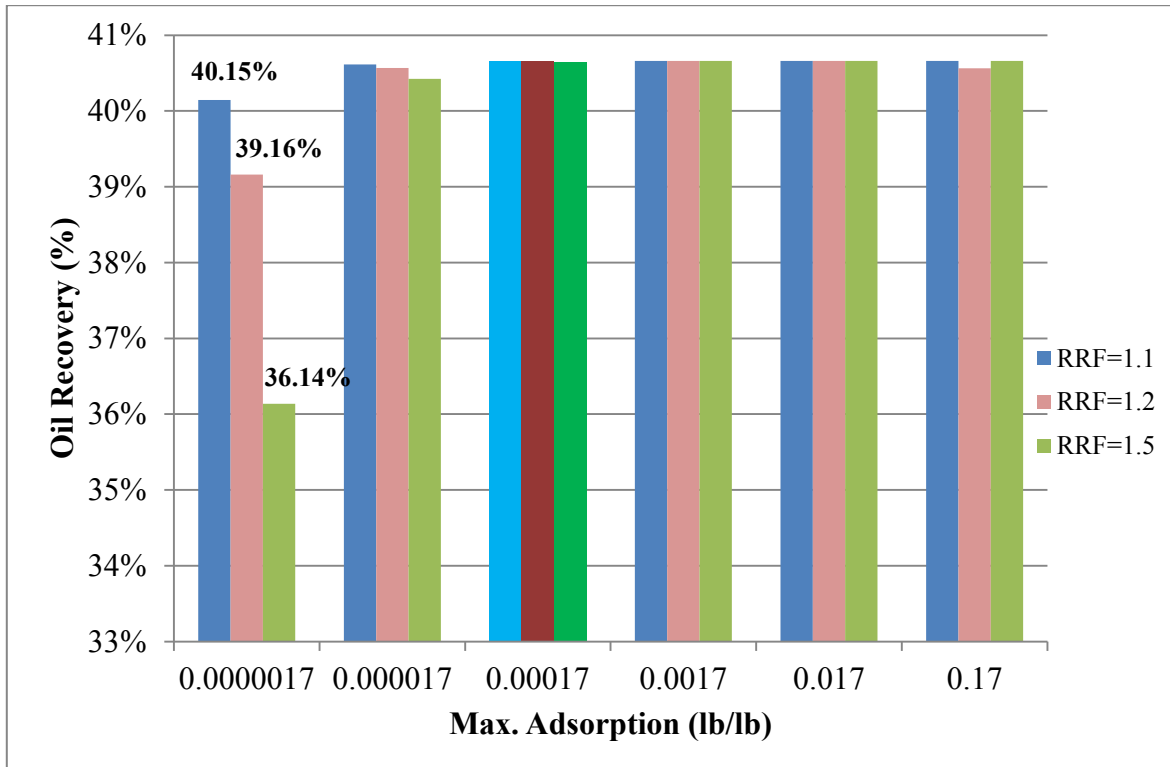


Figure 27: Showing the adsorption effect on recovery for different RRF after 1 year of 0.8lb/STB injection in HOMO\_HIGH\_PERM

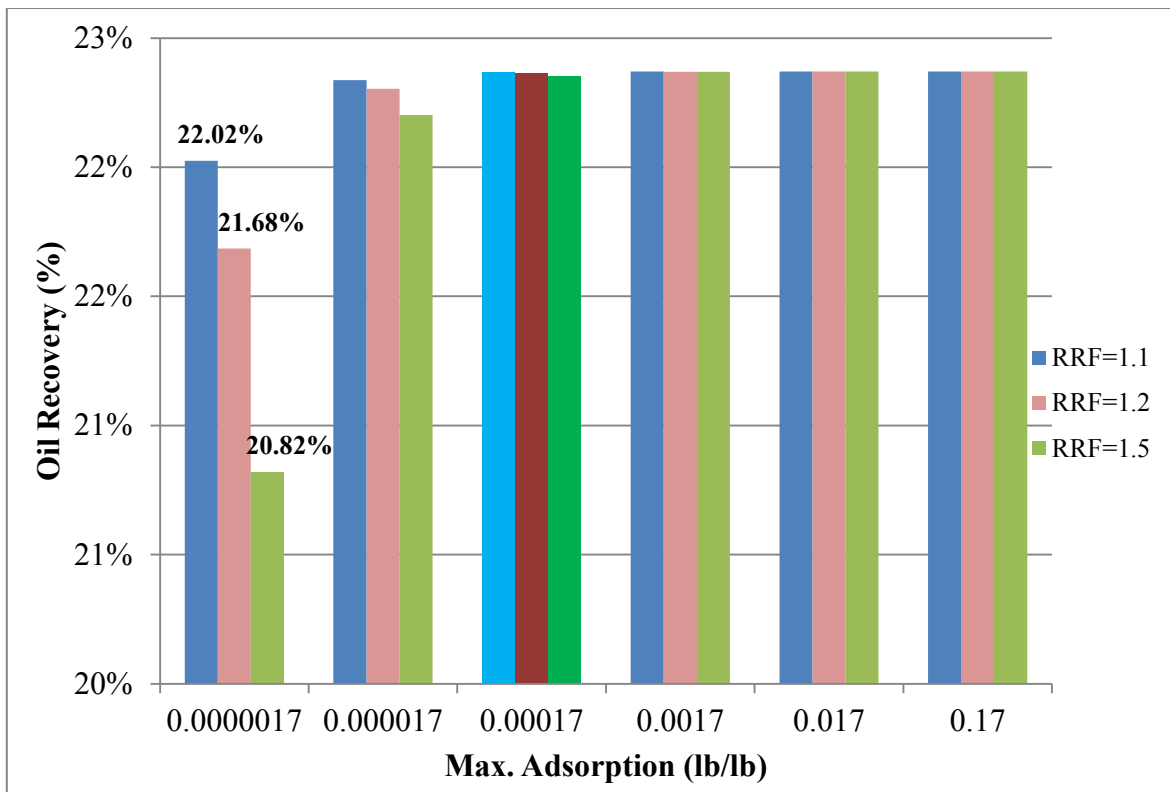


Figure 28: Showing the adsorption effect on recovery for different RRF after 1 year of 0.8lb/STB injection in HOMO\_LOW\_PERM

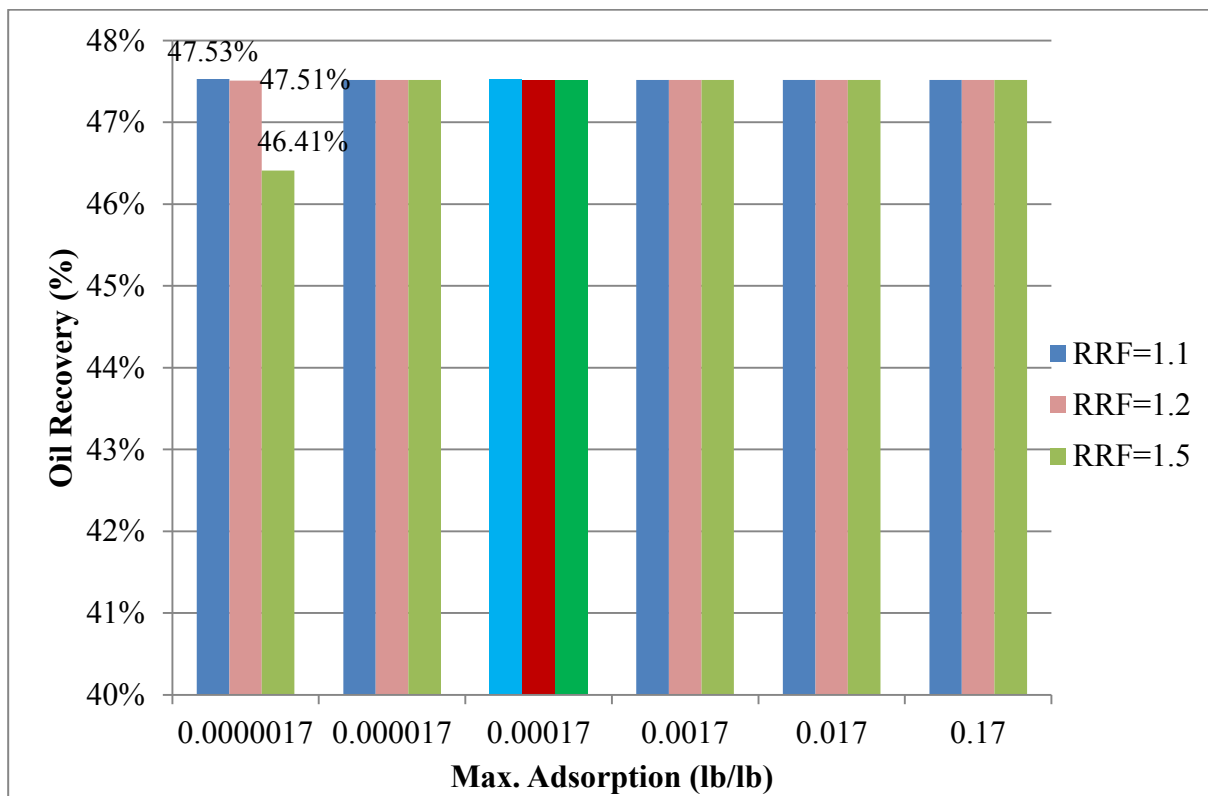


Figure 29: Showing the adsorption effect on recovery for different RRF after 1 year of 0.8lb/STB injection in HETERO\_HIGH\_PERM

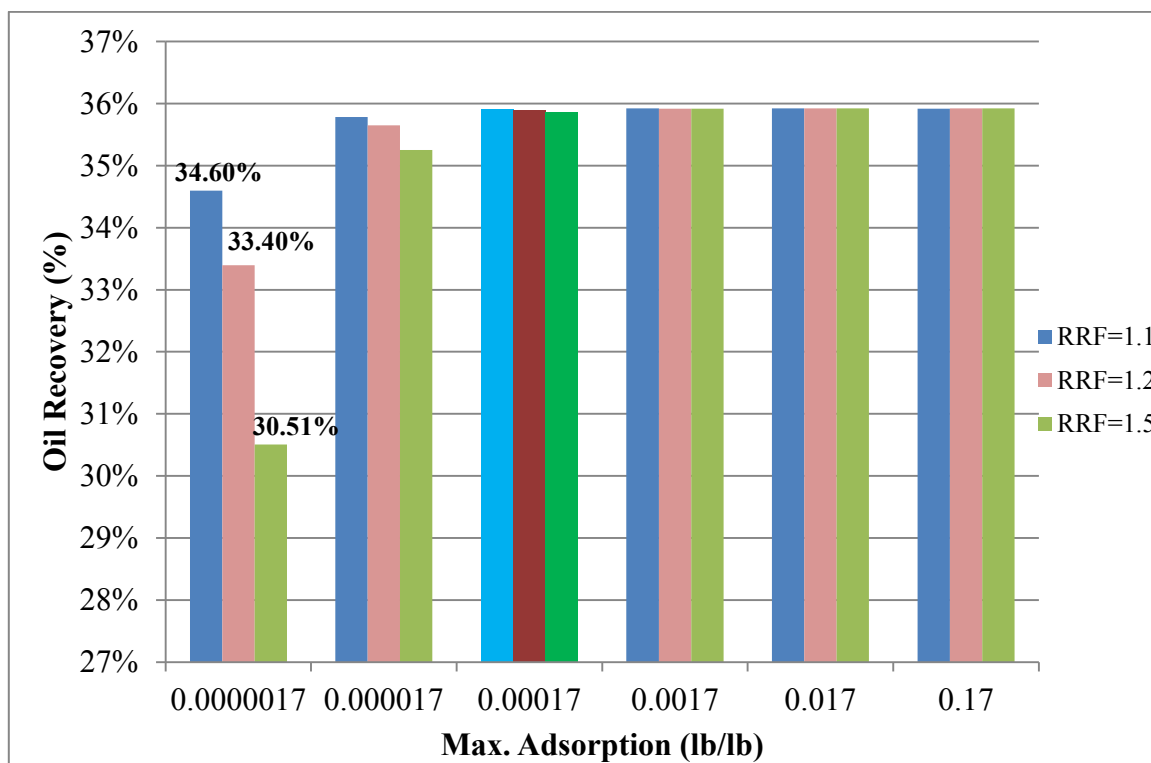


Figure 30: Showing the adsorption effect on recovery for different RRF after 1 year of 0.8lb/STB injection in HETERO\_LOW\_PERM



For all cases in fig. 27 to 30, oil recovery decreases as RRF increases when  $C_p^{a\max}$  is set as 0.0000017, 0.000017 and slight decreases when it is 0.00017 lb/lb. But remained unchanged when  $C_p^{a\max}$  is getting higher to 0.0017, 0.017 and 0.17 lb/lb. The variation in oil recovery is high at 0.0000017 lb/lb maximum adsorption. This is the same value on keyword PLYADS below.

### PROPS section

```
PLYADS
  0.0   0.0
  0.175 0.0000017
  0.351 0.0000017
```

The 1<sup>st</sup> column is the local polymer concentration in the solution and the 2<sup>nd</sup> column is the corresponding saturated concentration of polymer adsorbed by rock formation. It means this is the maximum adsorption that can saturate to the rock surface. So, increasing this value should not show any effects, but it does because of the permeability reduction effect from RRF. All in all the variation in oil recovery is high in low permeability than in high permeability. Which have been discussed in chapter 3 (3.1 and 3.2) polymer retention/adsorption decreases with increase in permeability. Heterogeneous case shows more effects in adsorption because the presences of low and high permeable zones cause the variation in water and polymer flow. So when polymer/water flows through the small zones the flow decreases which increases the opportunity for the large polymer molecules to be trapped on other words to be adsorbed.

### 6.2.2 Fractional flow of water, $f_w$

From chapter 2 above, equation (iv)-(vi) is used for calculation of fractional flow of water for water-oil system which was done by Buckley-Leverett method.  $S_w$ ,  $k_{ro}$  and  $k_{rw}$  are taken from PROPS section under keyword SWFN and SOF2 in data file shown in appendix A. Moreover, i assumed polymer is partially mixed with water and equation ix below is used to calculate the partially mixed water viscosity. Retrieved form ECLIPSE technical description manual (page 794).

$$\mu_{w,e} = \mu_m(C_p)^\omega \mu_w^{1-\omega} \dots \dots \dots (ix)$$

$\mu_m(C_p)$ ; is the viscosity of a fully mixed polymer solution as an increasing function of the polymer concentration in solution.

$\mu_w$ ; is the pure water viscosity.

$\omega$  ; is the Todd-Longstaff mixing parameter used to model the degree of segregation between the water and the injected polymer solution.

When;  $\omega = 1$ , means completely mixed and  $\omega = 0$ , means completely segregated. But since i assumed it to be the partial mixture, therefore i will set the Todd-Longstaff equation as  $\omega = 0.4$  to be used for the rest of the calculations.

For highest recovery of oil that is from high permeability with heterogeneous distribution, partially mixed water viscosity is calculated after flooding polymer of 0.8 lb/STB. The results for the fractional flow of water after water and polymer flooding are determined from different water saturations shown in table 10 in appendix D where fig. 31 below shows  $f_w$ -curves.

The purpose of showing both water and polymer flooding  $f_w$ -curves is to demonstrate the effects of mobility ratio. Polymer injection reduces the mobility ratio causing the  $f_w$ -curves to shift to the right.

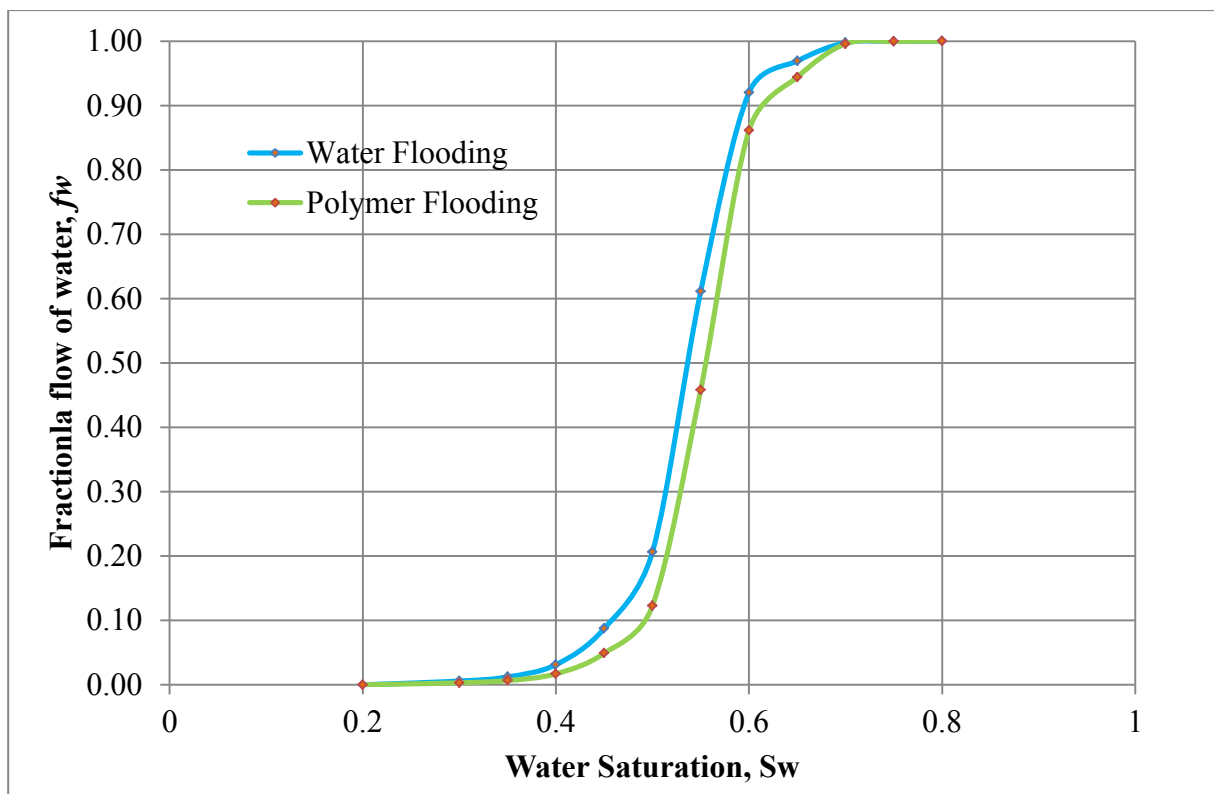


Figure 31: Showing fractional flow of water in oil-water system after water and polymer flooding

Furthermore, from  $f_w$ -curves above water saturation at the front and average water saturation can be determined as shown in fig. 32 below. The obtained average water saturation and water saturation at the front are used to determine the recovery factor and water-cut at water break through by using the following equations (x) and (xi).

$$RF = \frac{\bar{S}_w - S_{wir}}{1 - S_{wir}} \dots \dots \dots (x)$$

$$WC_R = f_{wf} \dots \dots \dots (xi) \text{ (In reservoir units)}$$

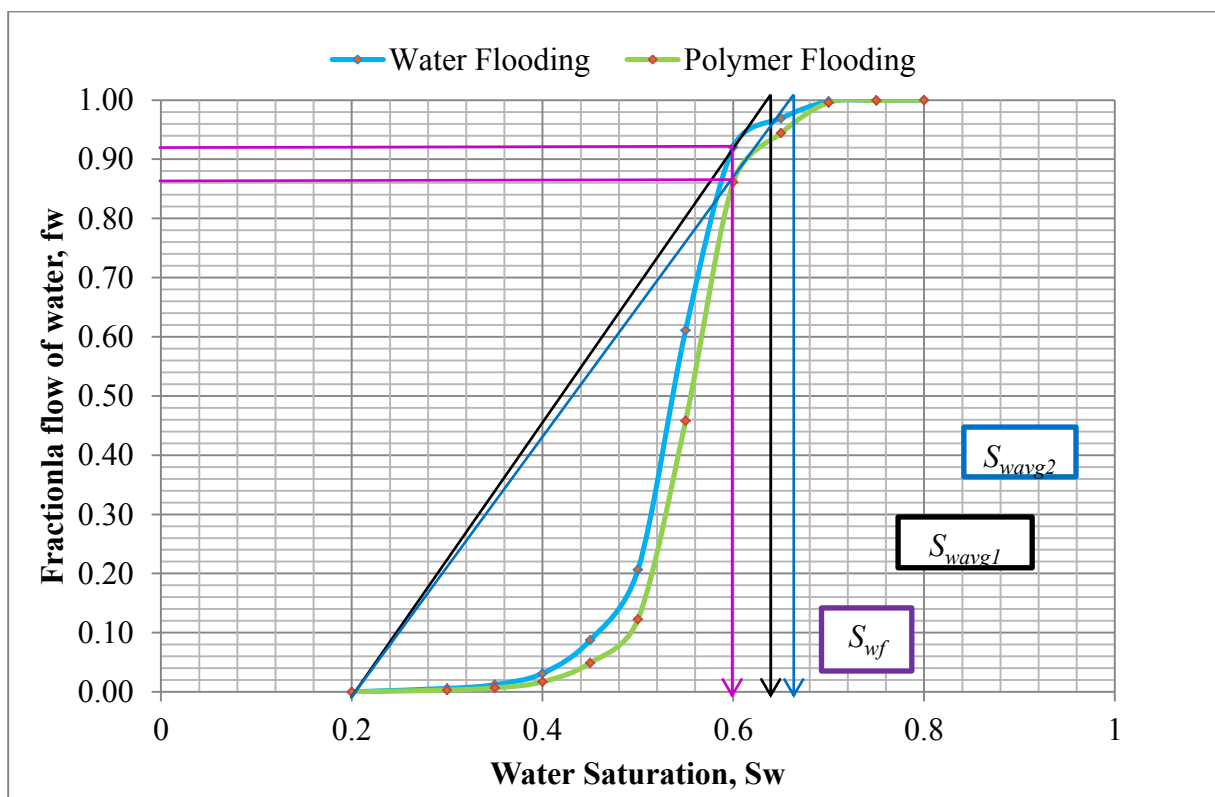


Figure 32: Showing the determination of water saturation at the front and average water saturation in  $f_w$ -curves at the water break through

From fig. 32 above average water saturation after water and polymer flooding are 0.636 & 0.66 respectively.

Water Flooding:

$$S_{wavg1} = \overline{S_{w1}} = 0.636 \text{ \& } S_{wir} = 0.2$$

$$RF = \frac{0.636 - 0.2}{1 - 0.2} = 0.545$$

Therefore, RF is 54.5% and WC = 92%

Polymer Flooding:

$$S_{wavg1} = \overline{S_{w2}} = 0.66 \text{ \& } S_{wir} = 0.2$$

$$RF = \frac{0.66 - 0.2}{1 - 0.2} = 0.575$$

Therefore, RF is 57.5% and WC = 92%

Where by, water saturation at the front for both after water and polymer flooding is 60% and its corresponding fractional flow of water is 0.92.

### **6.2.3 Local Grid Refinement (LGR) and Full Grid Refinement**

The purpose of refining is to achieve better approximation of the simulation results. The grids are refined around the wells (3 3 3) as local grid refinement using petrel software. While the full grid refine was done by using keyword AUTOREF (3 3 1) as shown in fig. 33 below. For each refinement, simulation is done with water and polymer flooded. Figure 34 & 35 shows the field oil recovery and reservoir pressure for normal, LGR and full grid refinement after water and polymer flooding.

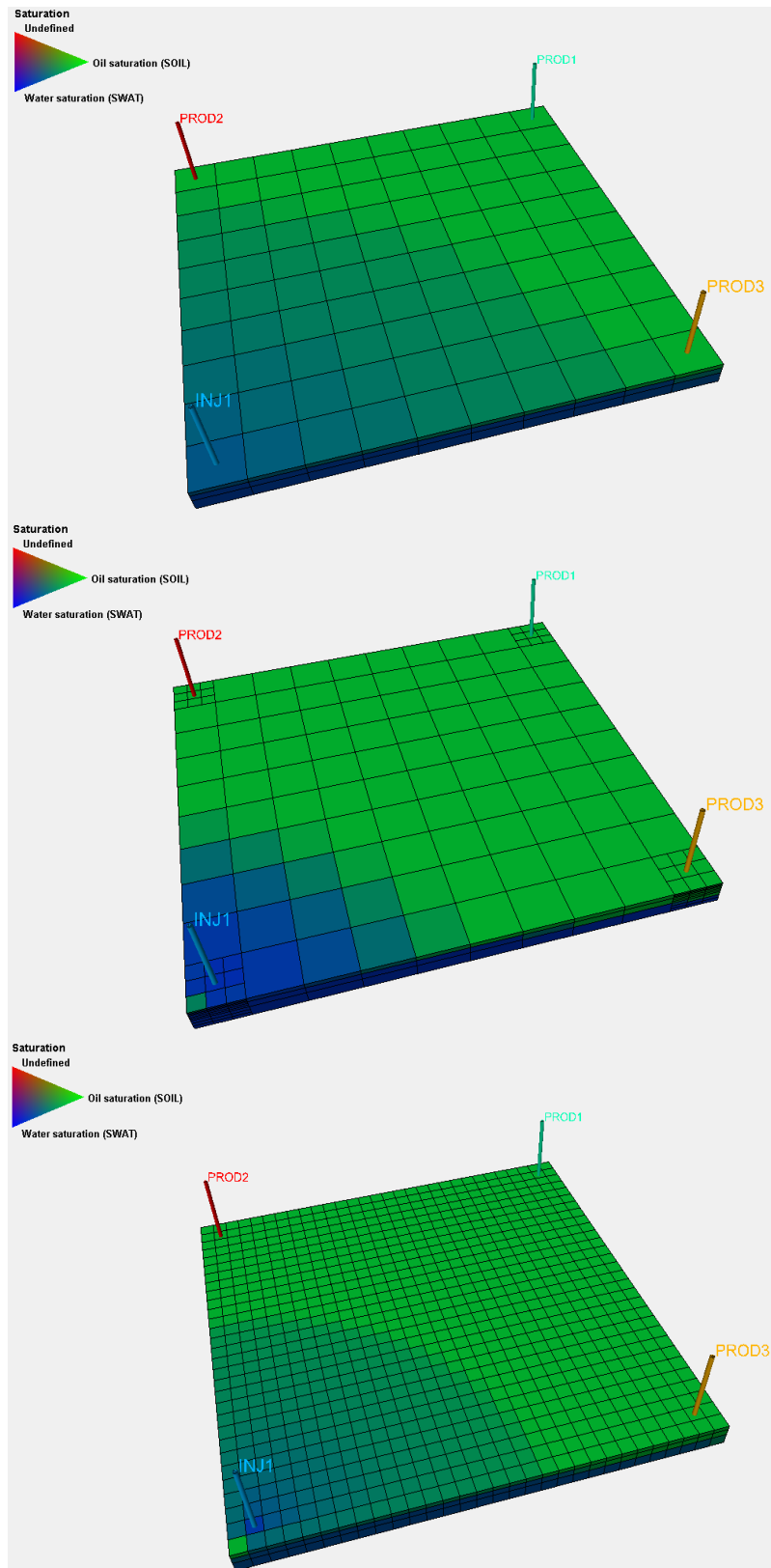


Figure 33: Showing 3D model for normal grid, LGR and full grid refinement

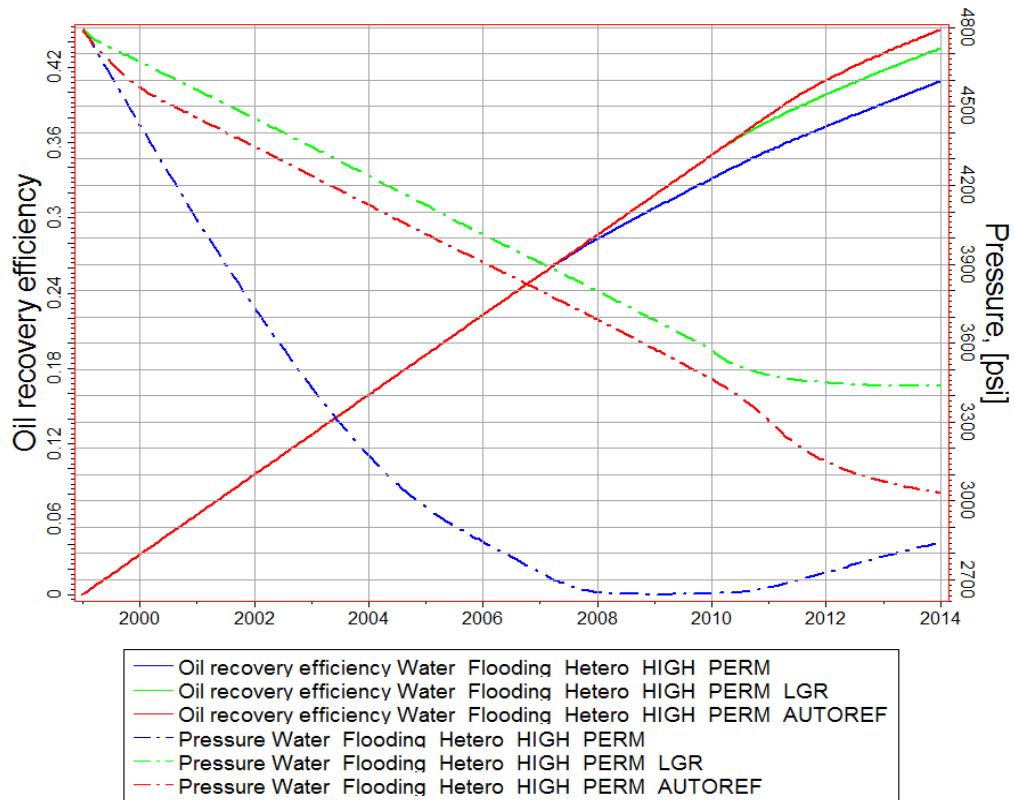


Figure 34: Showing oil recovery and reservoir pressure after water flooding for normal grid, LGR and full grid refinement (AUTOREF)

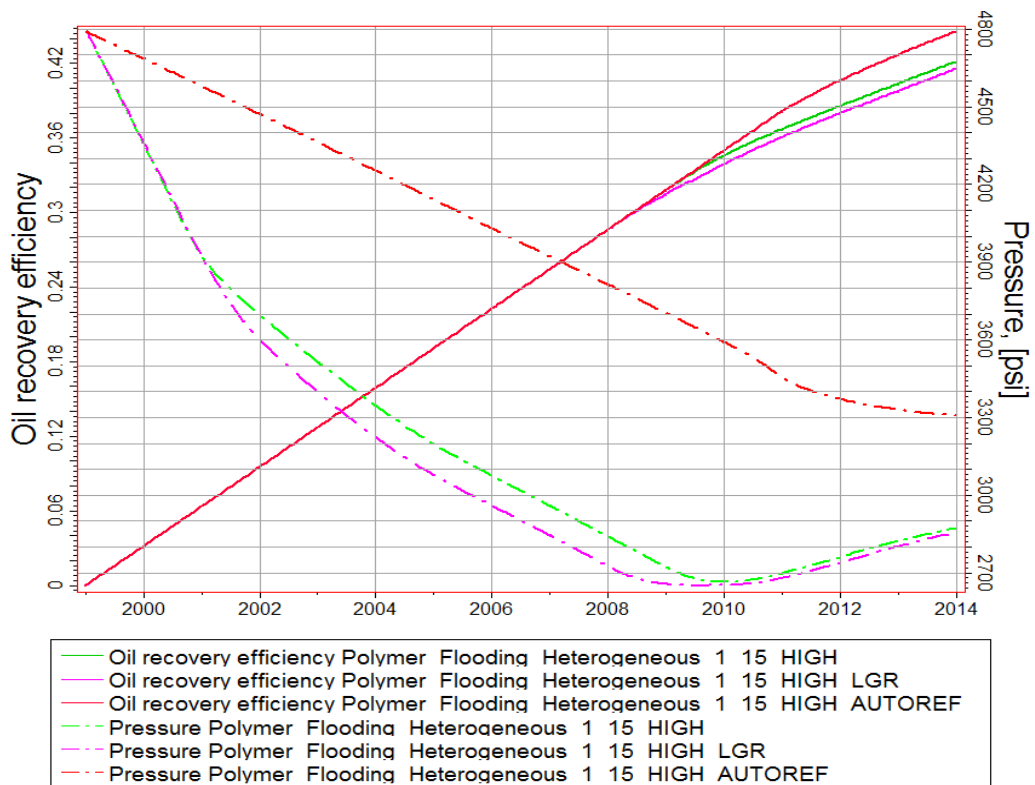


Figure 35: Showing oil recovery and reservoir pressure after polymer flooding for normal grid, LGR and full grid refinement (AUTOREF)

Figure 34 & 35 presents the oil recovery and reservoir pressure. The pressure values increases which means drop in pressure decreases as grids become more refined (normal and full refined grid). This is because water moves slow which creates the sharp front as shown in 3D fig. 33 above, and water production will be low causing the pressure drop to be low as well. For the case of LGR there is high pressure drop because water is gaining momentum around the injection well caused by refinement and starts to move much faster as it reaches to normal grids. Water flooding in normal grids seems to show high water production which causes high pressure drop as shown in both fig. 34 and 35.

But for oil recovery, it increases as grid becoming more refined because of the sharp sweeping efficiency created. Additional of polymer cause the oil recovery to decrease as grids are refined because polymer molecules retain causing less polymer to be at the front. Also polymer have less mobility compared to water therefore with the same injection and production time it will result to low oil recovery even if it will have sharp front. For this case an increase in production time will probably show an increase in oil recovery.

Average maps for water saturation after water and polymer flooding are viewed below from fig. 36 to 44 to show the coverage area of injected water. The refined grids show sharper front as explained in theory.

## 6.2.4 Map for heterogeneous HIGH permeability

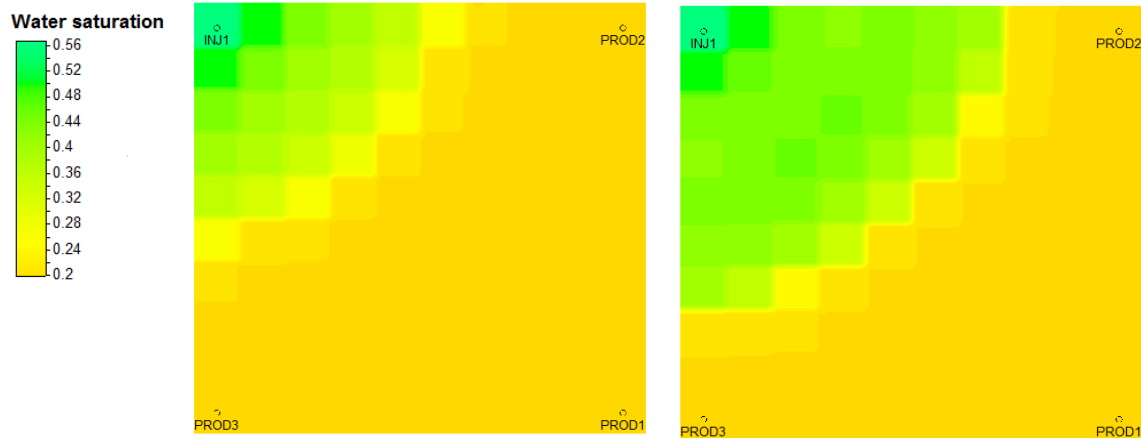


Figure 36: Showing the top layer average map of water saturation after water and polymer flooding in normal grid

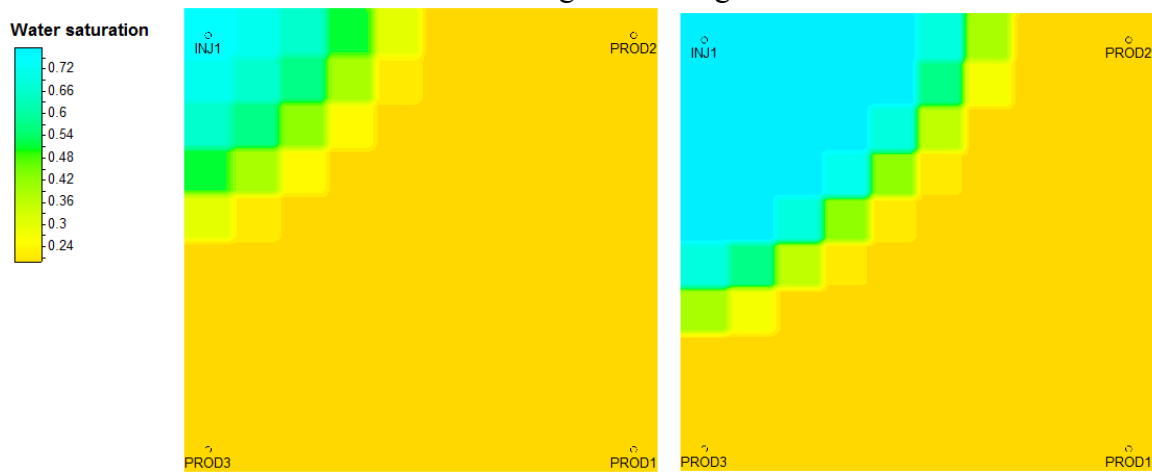


Figure 37: Showing the top layer average map of water saturation after water and polymer flooding in local grid refined (LGR)

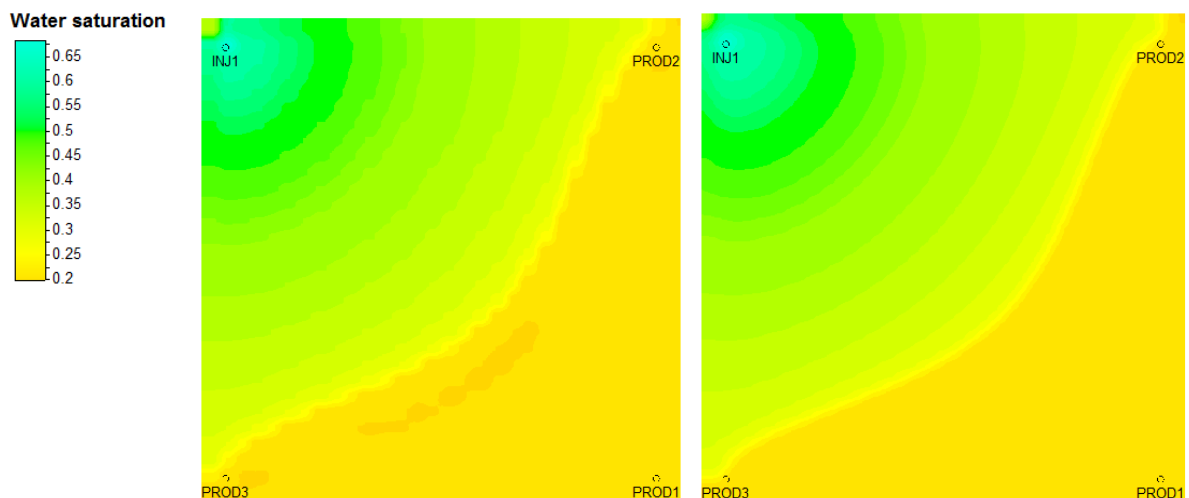


Figure 38: Showing the top layer average map of water saturation after water and polymer flooding in full grid refined



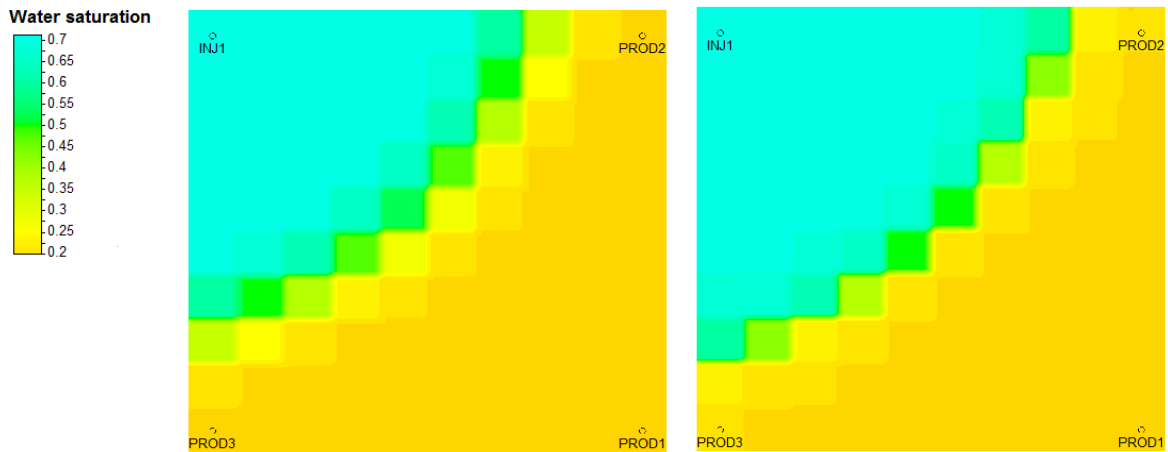


Figure 39: Showing the medium layer average map of water saturation after water and polymer flooding in normal grid

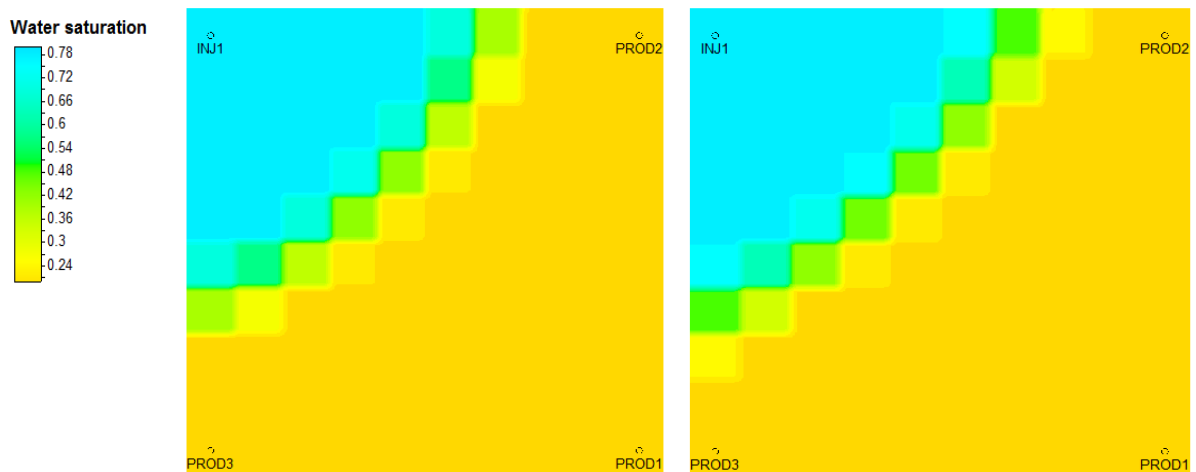


Figure 40: Showing the medium layer average map of water saturation after water and polymer flooding in local grid refined (LGR)

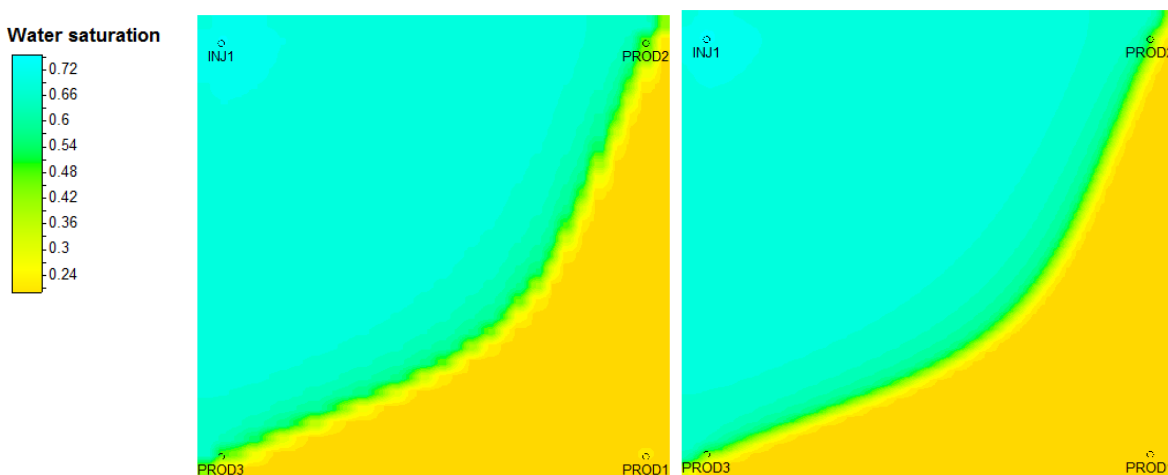


Figure 41: Showing the medium layer average map of water saturation after water and polymer flooding in full grid refined

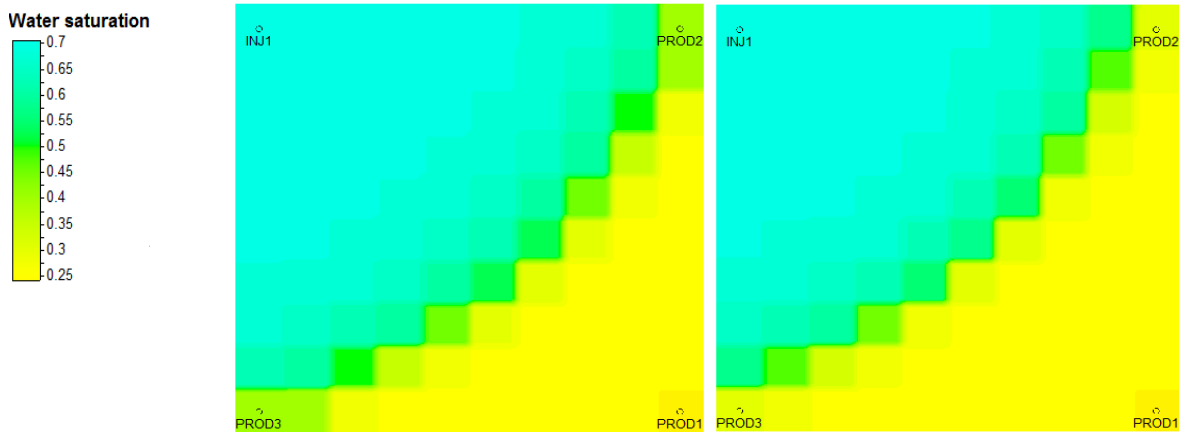


Figure 42: Showing the lower layer average map of water saturation after water and polymer flooding in normal grid

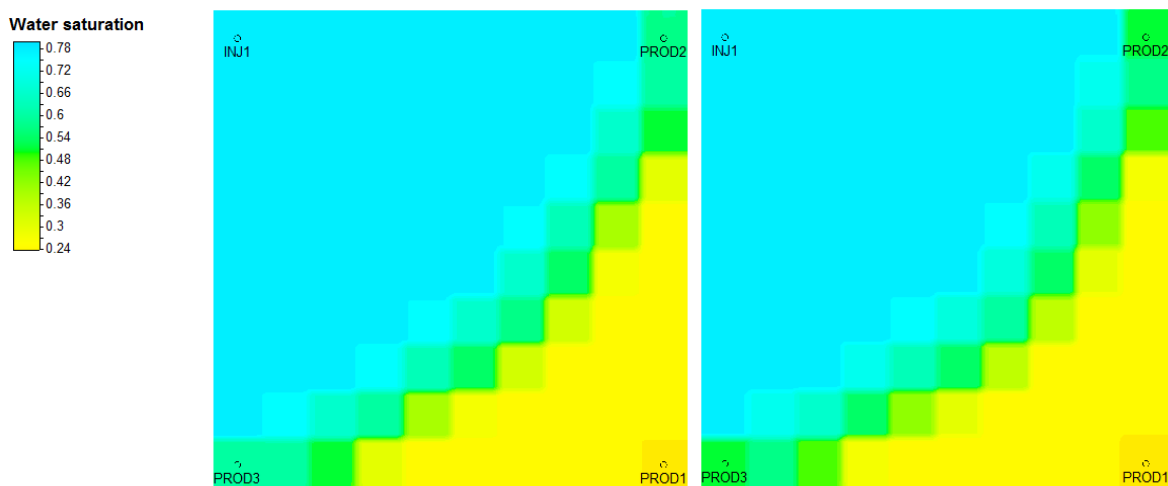


Figure 43: Showing the lower layer average map of water saturation after water and polymer flooding in local grid refined (LGR)

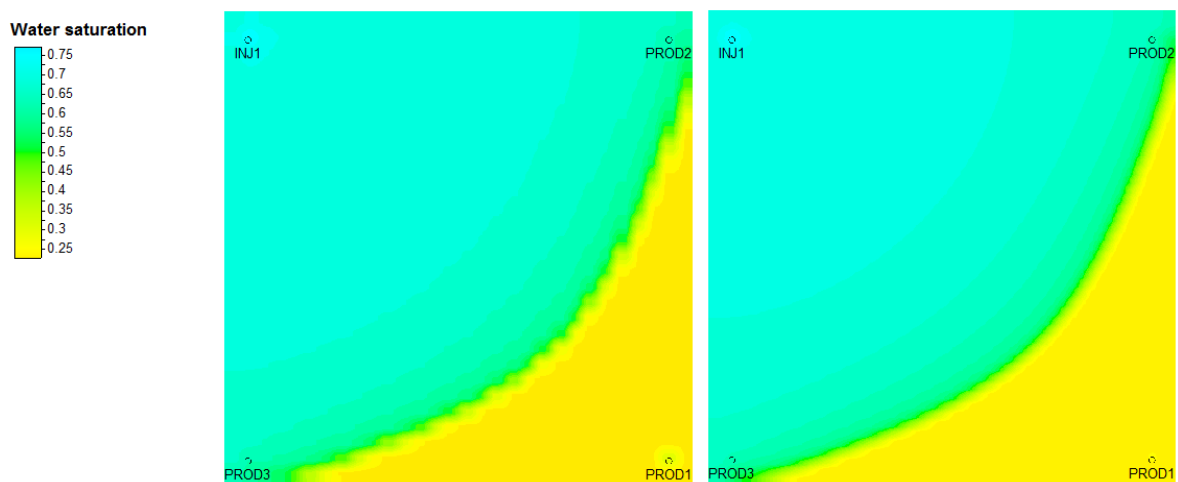


Figure 44: Showing the lower layer average map of water saturation after water and polymer flooding in full grid refined

According to the examination of the cases created above, the literature/theory has been proven that high permeability is better for polymer flooding. Heterogeneous case showed to be the good candidate for polymer flooding because of less fingering effect due to more resistance to flow of water injected. But all in all permeability is the major factor because for both high permeability cases with homogeneous and heterogeneous distribution the lower layers had the high permeability. Therefore, the distribution is not the big factor compared to permeability. Well among four major cases created heterogeneous distribution with high permeability seem to be suitable for polymer flooding. It gave the recovery of 47.53% which is 4.02% increment from water flooding after adding 0.8 lb/STB concentration of polymer for 1 year. It is the only case that required large concentration of polymer but with less amount of polymer used in mass (lbm). It shows that creating a thick slug by injecting large concentration of polymer at the beginning is better than creating less concentrated slug for a long time. This have been shown in above results discussed and figures in appendix D; that as injection time increases less polymer concentration is required and less oil was recovered whereby polymer adsorption is considered to be one of the cause. This is also the case that showed the much effect on adsorption, but in general adsorption did not have much effect in permeability reduction. So RRF values were changed for adsorption to show effects and the maximum adsorption was obtained was 0.0000017 lb/lb. The grids where refined for better approximation and the results have been discussed in chapter 6 (6.3.7). The average maps for water saturation after water and polymer flooding are viewed for all three types of grids used to show the coverage area of injected water in the reservoir.

All in all I proved my hypothesis wrong, homogeneous case gives less recovery because of less resistance to flow causes mobility of water to be high even in high permeability.

## 6.2.5 Extension of simulation time

Since at the end of simulation period we still have more oil and 15 years production period was meant for investigation of polymer and to save simulation time. The following are few simulation results after adding simulation time.

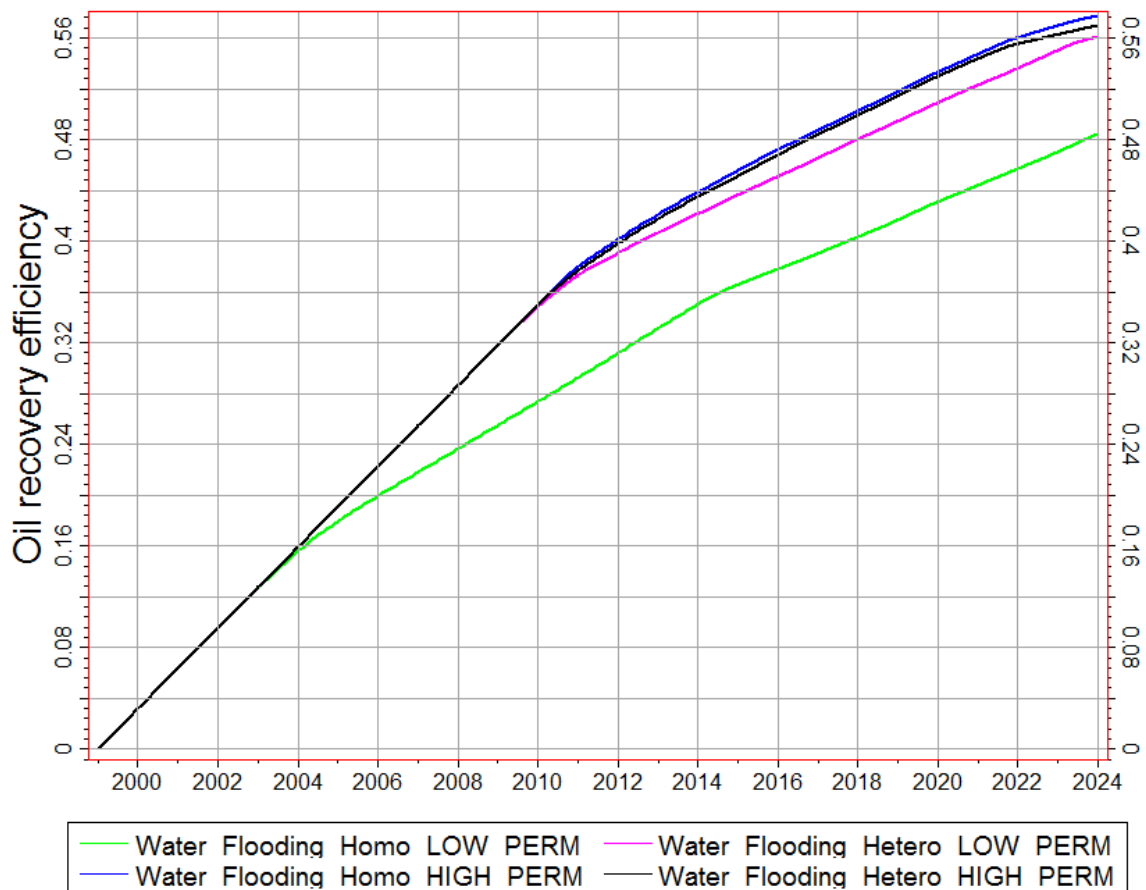


Figure 45: Showing field oil recovery after water flooding in 25 years of simulation

The oil recovery increases from 43.87 %, 43.51 %, 42.16%, 35.03% to 47.53%, 43.57%, 43.26% & 42.96% respectively as shown in fig. 45. Also fig. 46 below shows the reservoir pressure continues to build up after reaching its limit. Where the lowest oil production rate attained as shown in fig. 47 below is around 8000 STB/D for high permeability cases with homogeneous and heterogeneous distribution. While in 15 years of simulation, the lowest oil rate attained was 20,000STB/D.

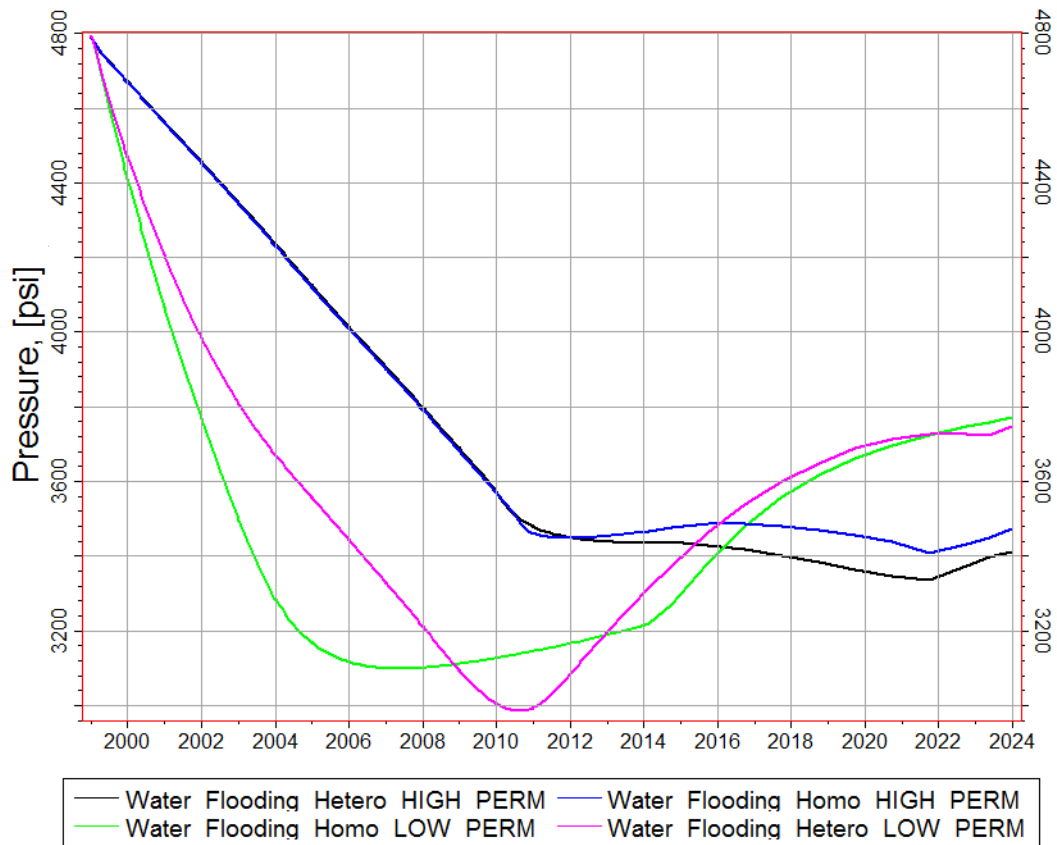


Figure 46: Showing reservoir pressure after water flooding in 25 years of simulation

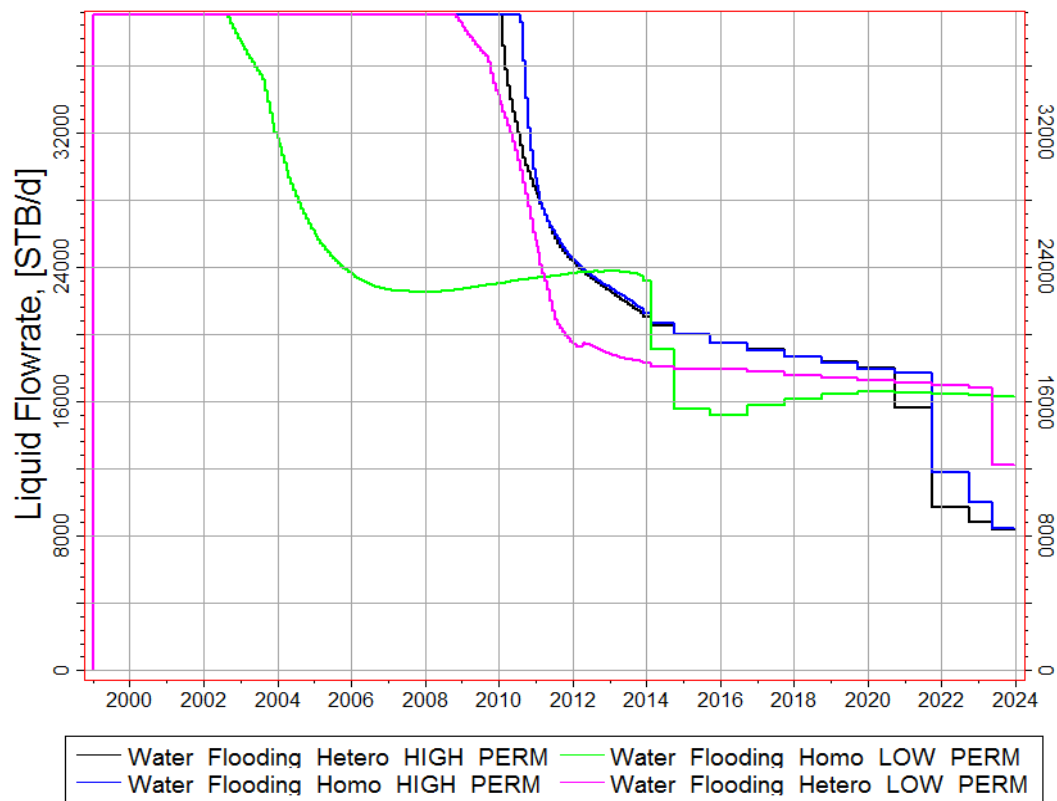


Figure 47: Showing field oil rate after water flooding in 25 years of simulation

## 7. Economical Evaluation

Polymer flooding gives promising results but they are expensive. As explained and shown above polymers adsorb, retain and others are produced which all represents loss of polymers injected. Heterogeneous case requires large amount of polymer compared to homogeneous case regardless of giving high recovery. Therefore the following is the simple economic evaluation done to evaluate rough approximation of the cost of polymer in relation to the oil produced. The case that is used is the heterogeneous case with high permeability after injecting polymer for 1, 2, 3 and 4 years.

Assumptions made

- No thermal degradation of polymer because reservoir temperature is  $<80^{\circ}\text{C}$
- No tax included
- No well costs are included
- Water is free of charge

Oil price = 110 USD/bbl = 657.8 NOK/bbl

1 USD = 5.98 NOK (2<sup>nd</sup> June, 2014)

Polymer price = 3.2 Euro/kg = 4.3667 USD/kg = 657.8 NOK/kg

1 Euro = 1.3646 USD (23<sup>rd</sup> May, 2014)

1 USD = 5.98 NOK (2<sup>nd</sup> June, 2014)

Table 6: Showing the of pore volume injected. polymer injected and oil produced

	CASES	PV of water injected	Polymer injected (kg)	Oil produced (STB)	Oil Recovery (%)
1	Hetero HIGH 1 0.8	0.319	836186.65	193639152	47.53
2	Hetero HIGH 2 0.3	0.319	836186.65	193801216	43.57
3	Hetero HIGH 3 0.1	0.342	836186.65	195378416	43.26
4	Hetero HIGH 4 0.1	0.342	836186.65	196096288	42.96

Table 7: Showing costs of oil produced, polymer injected and profit/loss obtained

	CASES	COSTS (NOK)		
		Oil produced	Polymer injected	Pofit/Loss
1	Hetero HIGH 1 0.8	127375834186	22001743	127353832443
2	Hetero HIGH 2 0.3	127482439885	22001743	127460438142
3	Hetero HIGH 3 0.1	128519922045	22001743	128497920302
4	Hetero HIGH 4 0.1	128992138246	22001743	128970136503

The above simple evaluation of oil produced in relation to polymer injected shows that the polymer flooding is profitable. But since polymer injected adsorb and others are produced the following is the evaluation of the effective polymer used to recovery oil.

Table 8: Showing cumulative polymer injected, polymer adsorbed, polymer produced, effective polymer used to recover oil and the oil produced

	Cases	Polymer injected (kg)	Polymer adsorb (kg)	Polymer produced (kg)	Effective Polymer used (kg)	Oil produced (STB)
1.	Hetero_HIGH_1_0.8	836187	198360	12806.70	625020	193639152
2.	Hetero_HIGH_2_0.3	836187	228366	17703.67	590117	193801216
3.	Hetero_HIGH_3_0.1	836187	310912	82592.45	442682	195378416
4.	Hetero_HIGH_4_0.1	836187	392341	103402.88	340443	196096288

Table 9: Showing costs of effective polymer used to recover oil, oil produced and profit or loss

		COSTS (NOK)		
		Oil produced	Effective polymer used	Profit/Loss
1.	Hetero_HIGH_1_0,8	127375834186	16445526	127359388660
2.	Hetero_HIGH_2_0,3	127482439885	15527156	127466912729
3.	Hetero_HIGH_3_0,1	128519922045	11647843	128508274202
4.	Hetero_HIGH_4_0,1	128992138246	8957728	128983180519

With the simple evaluation it seems like the adsorption and production of polymer does not cause big losses in polymer flooding project.

## 8. Conclusion and Recommendation

Formation permeability is a very critical criterion in polymer flooding. High permeability reservoirs are suitable for polymer flooding due to fewer effects on adsorption. Heterogeneous distribution gives better recovery as injected fluid (water/polymer) forced to sweep oil in both low and high permeable zones. Adsorption is high in heterogeneous case caused by the presence of flow restriction due to presence of low and high permeable zones. The original oil in place was  $4.3 \times 10^8$  STB, where the highest oil recovered after polymer flooding is 47.53% leaving the reservoir with around  $2.37 \times 10^6$  STB. The oil production rate at the end of 15 years of simulation time was 20,000 STB/D while after 25 years it was 8000STB/D which still shows there is large potential for oil to be produced.

The heterogeneous case created is the layered heterogeneous case and it gave better results. Therefore, I recommend further studies to be done in complete heterogeneous case (i.e. heterogeneous all over the reservoir). Other parameter that should be considered closely is polymer adsorption since it gave uncertainty in simulation with reference to RRF. The rough economical evaluation shows that the polymer flooding is profitable even if there was some adsorption. All in all the main objectives of this thesis was fulfilled and the problem statement was answered.



## Nomenclature

Symbol	Abbreviation	Unit [Field]
EOR	Enhance Oil Recovery	-
$E_{AS}$	Area sweeping efficiency	ft <sup>2</sup> /ft <sup>2</sup>
$E_{VS}$	Verticals sweeping efficiency	ft/ft
$E_D$	Displacement sweeping efficiency	ft/ft
M	Mobility ratio	-
$f_w$	Fractional flow of water	-
qw	Water flow rate	STB
qo	Oil flow rate	STB
GOC	Gas-Oil Contact	ft
WOC/OWC	Water-Oil Contact	ft
GOR	Gas-Oil Ratio	Scf/STB
BHP	Bottom Hole Pressure	psi
OOIP	Original Oil in Place	STB
$S_w$	Water saturation	%
$S_o$	Oil saturation	%
$\phi$	Porosity	%
A	Area	ft <sup>2</sup>
h	Depth	ft
N/G	Net to Gross	ft/ft
$\mu_o$	Oil viscosity	cP
$\mu_w$	Water viscosity	cP
krw	Water relative permeability, fraction	-
kro	Oil relative permeability, fraction	-
k	Absolute permeability	mD
keff	Effective permeability	mD
PV	Pore Volume	ft <sup>3</sup>
$\Delta P/L$	Pressure gradient (P1 –P2)	
IPV	Inaccessible Pore Volume	ft <sup>3</sup>
$R_k$	Actual resistance factor	-
RRF	Residual Resistance Factor	-
PROD1	Production well no. 1	-
PROD2	Production well no. 2	-
PROD3	Production well no. 3	-
INJ1	Injector no. 1	-
NPV	Net Present Value	NOK
LGR	Local Grid Refinement	-

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# Appendices

## APPENDIX A: Modified SPE1A data file

```
=====
-- THIS IS THE DATA FILE USED AS SYTHETIC MODEL FOR THESIS STUDY ON POLYMER FLOODING.

-- IT IS ORIGINARY FROM SPE COMPARISON PROBLEM," SPE1: COMPARISON OF SOLUTIONS TO A THREE-DIMENSIONAL BLACK
-- OIL RESERVOIR SIMULATION PROBLEM", REPORTED BY AZIS AND ODEH AT THE SPE SYMPOSIUM ON RESERVOIR
-- SIMULATION, JANUARY 1981.

-- A REGULAR GRID WITH DIFFERENT ORIENTATIONS AND ADDITIONAL OF WELLS (INJECTORS AND PRODUCERS) ARE
-- EXAMINED.IMPES SOLUTION METHOD IS USED FOR THIS SIMULATION AND THE PRODUCTION IS CONTROLLEDBY FLOW RATE
-- AND MIN. BHP.

-- STUDENT NAME: GLORIA KASIMBAZI
-- SUPERVISOR: PROF. JON KLEPPE
-- CO-SUPERVISOR: Adjunct Prof. JAN ÅGE STENSEN
=====
```

### **RUNSPEC**

TITLE

POLYMER FLOODING

DIMENS

10 10 3/

AUTOREF

3 3 1/ **For full grid refinement**

NONNC

OIL

WATER

POLYMER

FIELD

EQLDIMS

1 100 10 1 1/

TABDIMS

1 1 16 12 1 12/

WELLDIMS

10 1 1 6/

NUPCOL

4 /

START

1 'JAN' 1999/

NSTACK

24 /

UNIFOUT

UNIFIN

**GRID**

-----  
-- THE GEOMETRY OF THE SIMULATION GRID, ROCK PERMEABILITIES AND POROSITIES ARE DEFINED IN THIS  
-- SECTION  
-----

-- THE X AND Y DIRECTION CELL SIZES (DX, DY) AND THE POROSITIES ARE CONSTANT THROUGHOUT THE  
-- GRID.THESE ARE SET IN THE FIRST 3 LINES AFTER THE EQUALS KEYWORD.THE CELL THICKNESSES  
-- (DZ)AND PERMEABILITES ARE THEN SET FOR EACH LAYER.

-- THE CELL TOP DEPTHS (TOPS) ARE NEEDED ONLY IN THE TOP LAYER (THOUGH THEY COULD BE SET  
-- THROUGHOUT THE GRID)

-- THE SPECIFIED MULTZ VALUES ACT AS MULTIPLIERS ON THE TRANSMISSIBILITIES BETWEEN THE CURRENT  
-- LAYER AND THE LAYER BELOW  
-----

INIT

-- ARRAY VALUE ----- BOX -----

EQUALS

'DX' 1000 /  
'DY' 1000 /  
'PORO' 0.3 /  
  
'DZ' 20 1 10 1 10 1 1 /  
'PERMX' 1000 /  
'MULTZ' 0.64 /  
'TOPS' 8325 /  
  
'DZ' 30 1 10 1 10 2 2 /  
'PERMX' 500 /  
'MULTZ' 0.265625 /  
  
'DZ' 50 1 10 1 10 3 3 /  
'PERMX' 2000 /

Permeability cases: 'PERMX' in three different layers in Z-direction. Heterogeneous HIGH and LOW perm. values are 20, 30, 50% increase & decrease values of 1500mD which is homogenous value with HIGH perm.

HOMOGENEOUS (mD)		HETEROGENEOUS (mD)	
LOW	HIGH	LOW	HIGH
500	1500	1200	1800
500	1500	1050	1950
500	1500	750	2250

/ EQUALS IS TERMINATED BY A NULL RECORD

-- THE Y AND Z DIRECTION PERMEABILITIES ARE COPIED FROM PERMX SOURCE

-- DESTINATION

----- BOX -----

COPY

'PERMX' 'PERMY' 1 10 1 10 1 3 /

'PERMX' 'PERMZ' /

/

-- OUTPUT OF DX, DY, DZ, PERMX, PERMY, PERMZ, MULTZ, PORO AND TOPS

-- DATA IS REQUESTED, AND OF THE CALCULATED PORE VOLUMES AND X, Y

-- AND Z TRANSMISSIBILITIES

RPTGRID

1 1 1 1 1 1 0 0 1 1 0 1 1 0 1 1 1 /

**EDIT**

**PROPS**

=====

-- THE PROPS SECTION DEFINES THE REL. PERMEABILITIES, CAPILLARY PRESSURES, AND THE PVT

-- PROPERTIES OF THE RESERVOIR FLUIDS

-----

-- WATER RELATIVE PERMEABILITY AND CAPILLARY PRESSURE ARE TABULATED AS A FUNCTION OF WATER

-- SATURATION.

-----

ADD

/

SWFN

--Sw Krw Pcwo

0.2 0 1

0.3 0.01 0.52

0.35 0.021 0.41

0.4 0.039 0.34

0.45 0.058 0.28

0.5 0.09 0.23

0.55 0.245 0.18

0.6 0.42 0.14

0.65 0.545 0.1

0.7 0.8 0.06

0.75 0.91 0.03

0.8 0.96 0

/

-- OIL RELATIVE PERMEABILITY IS TABULATED AGAINST OIL SATURATION

-- FOR OIL-WATER SYSTEM

-- So Kro

SOF2

0 0

0.18 0

0.28	0.0001
0.38	0.001
0.43	0.01
0.48	0.021
0.58	0.09
0.63	0.2
0.68	0.35
0.76	0.7
0.83	0.98
0.86	0.997
0.879	1
0.88	1 /

-- PVT PROPERTIES OF WATER

REF. PRES.	REF. FVF	COMPRESSIBILITY	REF VISCOSITY	VISCOSIBILITY
4014.7	1.029	1E-6	0.95	0 /

-- PVDO USED TO SPECIFY THE PROPERTIES OF DEAD OIL FOR EACH VALUE OF RS THE  
 -- SATURATION PRESSURE, FVF AND VISCOSITY ARE SPECIFIED.  
 -- FOR RS=1.27 AND 1.618, THE FVF AND VISCOSITY OF UNDERSATURATED OIL  
 -- ARE DEFINED AS A FUNCTION OF PRESSURE. DATA FOR UNDERSATURATED  
 -- OIL MAY BE SUPPLIED FOR ANY RS, BUT MUST BE SUPPLIED FOR THE  
 -- HIGHEST RS (1.618).

POIL	FVFO	VISO
14.7	1.62	1.04
264.7	1.5	0.975
514.7	1.407	0.91
1014.7	1.395	0.83
2014.7	1.265	0.695
2514.7	1.235	0.641
3014.7	1.22	0.594
4014.7	1.195	0.51
5014.7	1.179	0.549
6014.7	1.071	0.74
7014.7	1.027	0.449
9014.7	1.026	0.605

/

-- ROCK COMPRESSIBILITY

-- REF. PRES COMPRESSIBILITY

ROCK

14.7 45.0E-6 /

-- SURFACE DENSITIES OF RESERVOIR FLUIDS

-- OIL WATER GAS

DENSITY

49.1 64.79 0.06054 /

-- OUTPUT CONTROLS FOR PROPS DATA

-- ACTIVATED FOR SOF3, SWFN, SGFN, PVTW, PVDG, DENSITY AND ROCK KEYWORDS

**PLYVISC**

--1. Polymer concentration in solution [lb/STB]

--2. Corresponding factor by which water viscosity from PVTW is

---multiplied

plyro

**PLYROCK**

--1. Dead pore space

--2. Residual Resistance Factor (RRF)

--3. Mass density of this rock type at reservoir conditions [lb/rb]

--4. The adsorption index to be used for this rock type

--5. Max. Polymer adsorption used in calculation of resistance

--- factor [lb/lb]

0.16 1.0 1000 2 0.00017 /  
          ↳ (1.1, 1.2 & 1.5)                   ↳ (0.000017, 0.0000017, ., 0)

**PLYADS**

--1. Local polymer concentration in solution surrounding the rock

---[lb/STB]

--2. Saturated concentration of polymer adsorbed by rock formation

---[lb/lb]

0.0 0.0

0.175 0.0000017

0.351 0.0000017/

**PLMIXPAR**

--Todd-Longstaff mixing for the viscosity calculation

1.0 /

**PLYMAX**

-- 1. Polymer concentration in solution used in calculation of

---maximum polymer fluid component viscosity [lb/STB]



--2. Salt concentration in solution used in calculation of maximum

---polymer fluid component viscosity [lb/STB]

0.351 0.0 /

**RPTPROPS**

-- PROPS Reporting Options

-- 1 1 1 0 1 1 1 1/

'PLYVISC'

/

**REGIONS**

**SOLUTION**

=====  
-- THE SOLUTION SECTION DEFINES THE INITIAL STATE OF THE SOLUTION VARIABLES (PHASE PRESSURES,  
-- SATURATIONS AND GAS-OIL RATIOS)  
-----

-- DATA FOR INITIALISING FLUIDS TO POTENTIAL EQUILIBRIUM

-- DATUM DATUM OWC GOC RSVD RVVD

-- DEPTH PRESS DEPTH PCOW DEPTH PCOG

EQUIL

8400 4800 8500 0 8200 0 1 0 0/

-- OUTPUT CONTROLS (SWITCH ON OUTPUT OF INITIAL GRID BLOCK PRESSURES)

RPTSOL

1 11\*0/

**SUMMARY**

=====  
-- THIS SECTION SPECIFIES DATA TO BE WRITTEN TO THE SUMMARY FILES AND WHICH MAY LATER BE USED  
-- WITH THE ECLIPSE GRAPHICS PACKAGE  
-----

-- Neat tabulated output of the summary file data

EXCEL -- RUNSUM output to be Microsoft Excel format

SEPARATE -- RUNSUM output to go to a separate RSM file

ELAPSED -- Total simulation time

TCPU -- Current CPU usage time

RUNSUM

/

--  
-- =====  
-- WELLS  
-- =====

WGOR -- Well Gas-Oil ratio for producer

'PROD1'  
'PROD2'  
'PROD3'  
'INJ1'/'

WBHP -- Well Bottom-Hole Pressure

'PROD1'  
'PROD2'  
'PROD3'  
'INJ1'/'

WWCT -- Well Water Cut

'PROD1'  
'PROD2'  
'PROD3'/'

WOPT -- Well Oil Production Total

'PROD1'  
'PROD2'  
'PROD3'/'

WOPRT -- Well Oil Production Rate Total

'PROD1'  
'PROD2'  
'PROD3'/'

WOPRH -- Well Oil Production Rate History

'PROD1'  
'PROD2'  
'PROD3'/'

WOPR -- Well Oil Production Rate

'PROD1'  
'PROD2'  
'PROD3'/'

WWIT --Well Water Injection Total

'INJ1'/'

WWIR -- Well Water Injection Rate

'INJ1' /

WCPR -- Well Polymer Production Rate

'PROD1'

'PROD2'

'PROD3' /

WCPT -- Well Polymer Production Total

'PROD1'

'PROD2'

'PROD3' /

WCIR -- Well Polymer Injection Rate

'INJ1' /

WCIT -- Well Polymer Injection Total

'INJ1'

/

-- =====

-- FIELD

-- =====

FOE -- Field Oil Efficiency

FOPR -- Field Oil Production Rate

FOPT -- Field Oil Production Total

FWPR -- Field Water Production Rate

FWPT -- Field Water Production Total

FWIR -- Field Water Injection Rate

FWIT -- Field Water Injection Total

FWCT -- Field Water Cut

FCIR -- Field Polymer Injection Rate

FCIT -- Field Polymer Injection Total

FCIP -- Field Polymer in Solution

FCPR -- Field Polymer Production Rate

FCPT -- Field Polymer Production Total

FCAD -- Field Polymer Adsorption total

-- =====

-- BLOCKS

-- =====

BGSAT -- Block gas saturation for injector and producer's blocks

10 10 1  
1 10 1  
10 1 1/

BOSAT -- Block oil saturation

10 10 1  
1 10 1  
10 1 1  
1 1 1  
1 1 2  
1 1 3  
1 2 1  
1 2 2  
1 2 3  
2 2 1  
2 2 2  
2 2 3 /  
/

BWSAT -- Block water saturation

1 1 3  
3 1 3  
5 1 3  
7 1 3  
9 2 3  
1 3 3  
1 5 3  
1 7 3  
2 9 3  
9 2 3  
8 9 3/  
/

BPR -- Block pressure for injector and producer's blocks

10 10 1  
1 10 1  
10 1 1  
1 1 1/  
/

BCCN -- Block Polymer Cell concentration

1 1 1  
1 1 2

```
1 1 3
1 2 1
1 2 2
1 2 3
2 2 1
2 2 2
2 2 3 /
/
```

BCIP -- Block Polymer in Solution

```
1 1 1
1 1 2
1 1 3
1 2 1
1 2 2
1 2 3
2 2 1
2 2 2
2 2 3 /
/
```

BCAD -- Block Polymer Adsorption Total

```
1 1 1
1 1 2
1 1 3
1 2 1
1 2 2
1 2 3
2 2 1
2 2 2
2 2 3 /
/
```

**SCHEDULE**

=====

-- THE SCHEDULE SECTION DEFINES THE OPERATIONS TO BE SIMULATED

-----

-- CONTROLS ON OUTPUT AT EACH REPORT TIME

-----

RPTSCHED

FIP/

0 0 0 0 0 0 0 0 0 0 0

```

2 0 0 2/
MESSAGE
1*1000000/

RPTRST
  BASIC=1 /
/
-- SET INITIAL TIME STEP TO 1 DAY AND MAXIMUM TO 6 MONTHS
TUNING
1   365.0   0.5/
1.0 0.5     1.0E-7/
/

-- WELL SPECIFICATION DATA
--      WELL      GROUP LOCATION  BHP          PI
--      NAME      NAME        I  J    DEPTH  DEFN
WELSPECS
      'PROD1' 'G'    10  10    8400    'OIL' /
      'PROD2' 'G'    10   1    8400    'OIL' /
      'PROD3' 'G'     1  10    8400    'OIL' /
      'INJ1'  'G'     1   1    8600    'WATER' /
/

-- COMPLETION SPECIFICATION DATA
--      WELL      LOCATION          OPEN/  SAT  CONN  WELL
--      NAME      I  J  K1 K2  SHUT   TAB  FACT  DIAM
COMPDAT
      'PROD1'  10  10  2  2 'OPEN' 0  -1  0.5 /
      'PROD2'  10   1  2  2 'OPEN' 0  -1  0.5 /
      'PROD3'   1  10  2  2 'OPEN' 0  -1  0.5 /
      'INJ1'   1   1  3  3 'OPEN' 1  -1  0.5 /
/

-- PRODUCTION WELL CONTROLS
--      WELL      OPEN/  CNTL OIL   WATER  GAS   LIQUID RES   BHP
--      NAME      SHUT   MODE RATE RATE  RATE  RATE  RATE
WCONPROD
      'PROD1' 'OPEN' 'ORAT' 15000 4*           2500 /
      'PROD2' 'OPEN' 'ORAT' 12000 4*           2500 /
      'PROD3' 'OPEN' 'ORAT' 12000 4*           2500 /
/

```

```
-- INJECTION WELL CONTROLS
-- WELL INJ OPEN/ CNTL FLOW RES BHP
-- NAME TYPE SHUT MODE RATE RATE
WCONINJE
```

```
'INJ1' 'WATER' 'OPEN' 'RATE' 35000 1* 6000/
/
```

```
-- YEAR 1
```

```
WPOLYMER
```

```
'INJ1' 0.8 0.0 /
/
```

0.1, 0.2, 0.3, 0.4... 1.7(lb/lb)

```
TSTEP
```

```
1.0 14.0 13*25.0
```

```
/
```

```
RPTSCHED
```

```
1 1 1 1 1 0 2 1 2 0
```

```
2 2 0 0 2 /
```

```
TSTEP
```

```
25.0
```

```
/
```

```
-- YEAR 2
```

```
WPOLYMER
```

```
'INJ1' 0.0 0.0 /
/
```

HOW THE POLYMER INJECTION IS TEEMINATED

```
TSTEP
```

```
1.0 14.0 13*25.0
```

```
/
```

```
RPTSCHED
```

```
1 1 1 1 1 0 2 1 2 0
```

```
2 2 0 0 2 /
```

```
TSTEP
```

```
25.0
```

```
/
```

```
-- YEAR 3
```

```
TSTEP
```

```
1.0 14.0 13*25.0
```

```
/
```

RPTSCHED  
1 1 1 1 1 0 2 1 2 0  
2 2 0 0 2 /

TSTEP  
25.0

/

-- YEAR 4

TSTEP  
1.0 14.0 13\*25.0  
/

RPTSCHED  
1 1 1 1 1 0 2 1 2 0  
2 2 0 0 2 /

TSTEP  
25.0

/

-- YEAR 5

TSTEP  
1.0 14.0 13\*25.0  
/

RPTSCHED  
1 1 1 1 1 0 2 1 2 0  
2 2 0 0 2 /

TSTEP  
25.0

/

-- YEAR 6

TSTEP  
1.0 14.0 13\*25.0  
/

RPTSCHED  
1 1 1 1 1 0 2 1 2 0  
2 2 0 0 2 /

TSTEP  
25.0

/

-- YEAR 3

TSTEP  
1.0 14.0 13\*25.0  
/



RPTSCHED  
1 1 1 1 1 0 2 1 2 0  
2 2 0 0 2 /

TSTEP  
25.0

/  
-- YEAR 7

TSTEP  
1.0 14.0 13\*25.0

/  
RPTSCHED  
1 1 1 1 1 0 2 1 2 0  
2 2 0 0 2 /

TSTEP  
25.0

/  
-- YEAR 8

TSTEP  
1.0 14.0 13\*25.0

/  
RPTSCHED  
1 1 1 1 1 0 2 1 2 0  
2 2 0 0 2 /

TSTEP  
25.0

/  
-- YEAR 9

TSTEP  
1.0 14.0 13\*25.0

/  
RPTSCHED  
1 1 1 1 1 0 2 1 2 0  
2 2 0 0 2 /

TSTEP  
25.0

/  
-- YEAR 10

TSTEP  
1.0 14.0 13\*25.0

/  
RPTSCHED

```
1 1 1 1 1 0 2 1 2 0
2 2 0 0 2 /
TSTEP
  25.0
/
-- YEAR 11
TSTEP
  1.0 14.0 13*25.0
/
RPTSCHED
  1 1 1 1 1 0 2 1 2 0
  2 2 0 0 2 /
TSTEP
  25.0
/
-- YEAR 12
TSTEP
  1.0 14.0 13*25.0
/
RPTSCHED
  1 1 1 1 1 0 2 1 2 0
  2 2 0 0 2 /
TSTEP
  25.0
/
-- YEAR 13
TSTEP
  1.0 14.0 13*25.0
/
RPTSCHED
  1 1 1 1 1 0 2 1 2 0
  2 2 0 0 2 /
TSTEP
  25.0
/
-- YEAR 14
TSTEP
  1.0 14.0 13*25.0
/
RPTSCHED
  1 1 1 1 1 0 2 1 2 0
```

```
2 2 0 0 2 /
TSTEP
  25.0
/
-- YEAR 15
TSTEP
  1.0 14.0 13*25.0
/
RPTSCHED
  1 1 1 1 1 0 2 1 2 0
  2 2 0 0 2 /
TSTEP
  25.0
/
END
```

## APPENDIX B: Water Flooding (Base case) Results

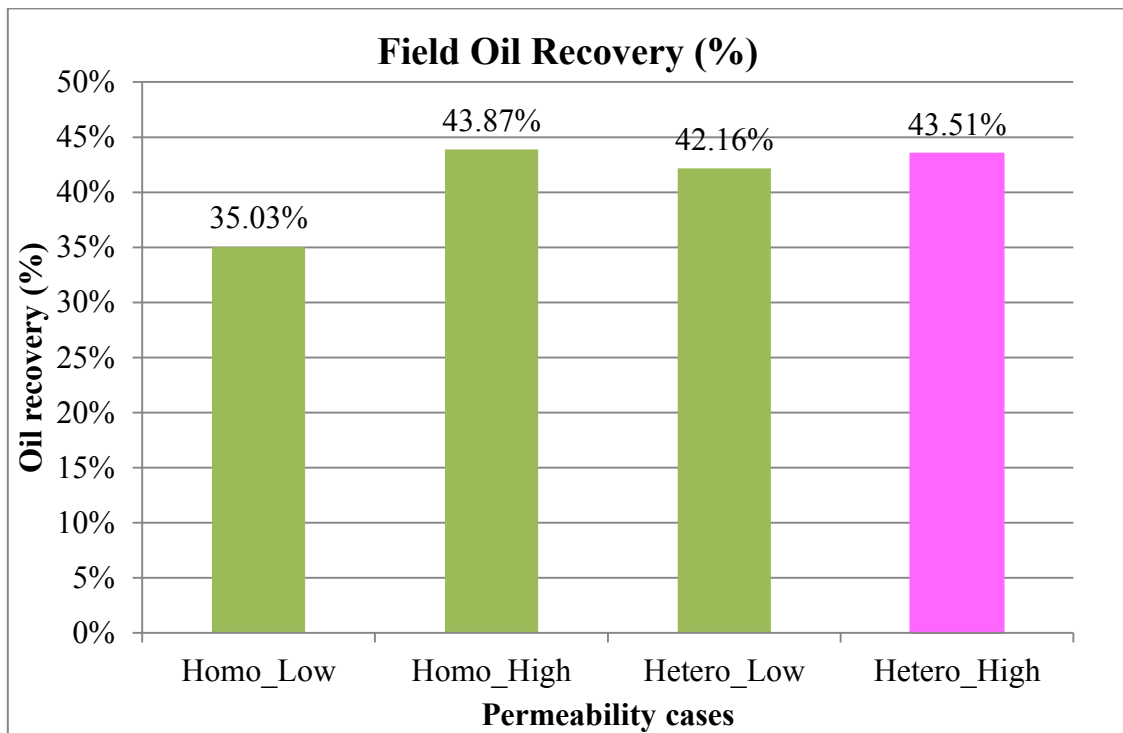


Figure 48: Showing the highest recovery in basecases for four major cases

## APPENDIX C: Polymer Flooding Results

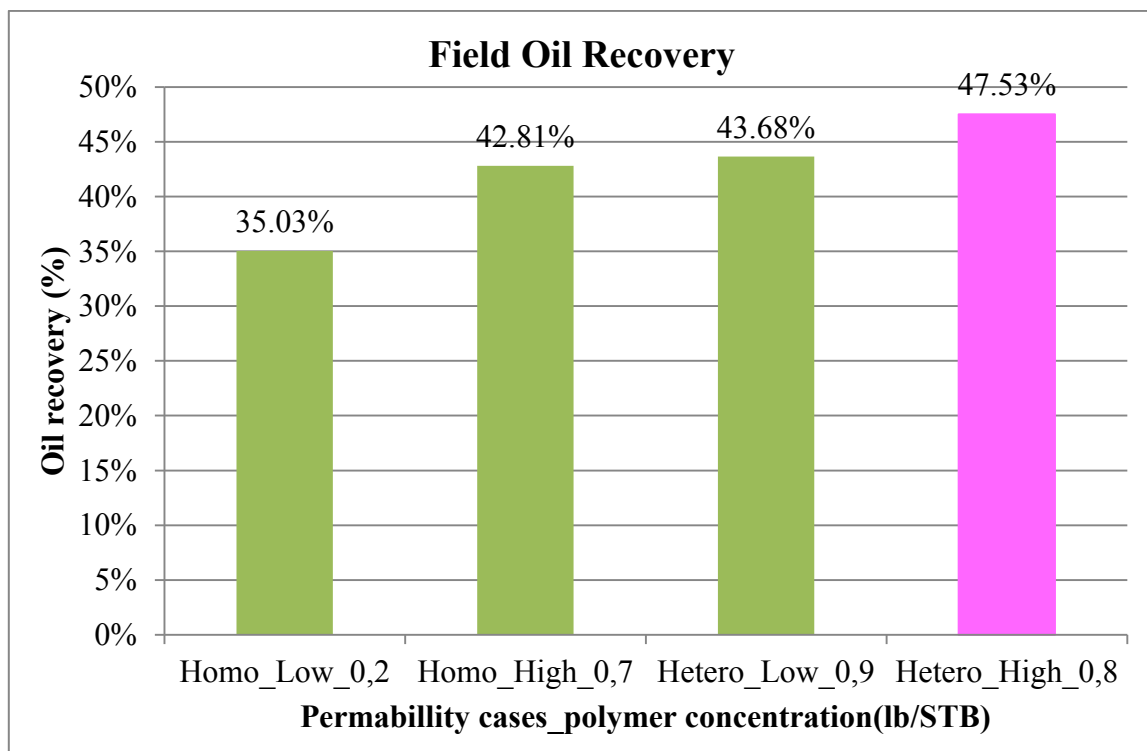


Figure 49: Showing the highest oil recovery and corresponding polymer concentration injected for 1 year in four major cases

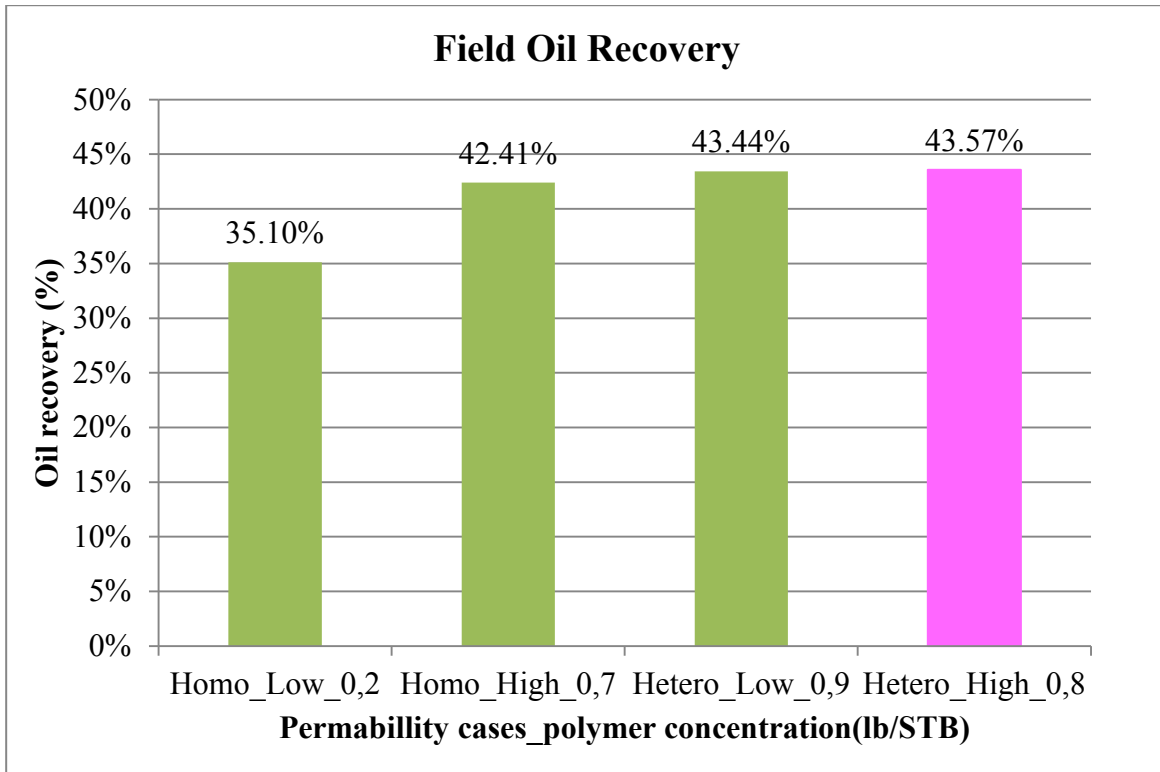


Figure 50: Showing the highest oil recovery and corresponding polymer concentration injected for 2 years in four major cases

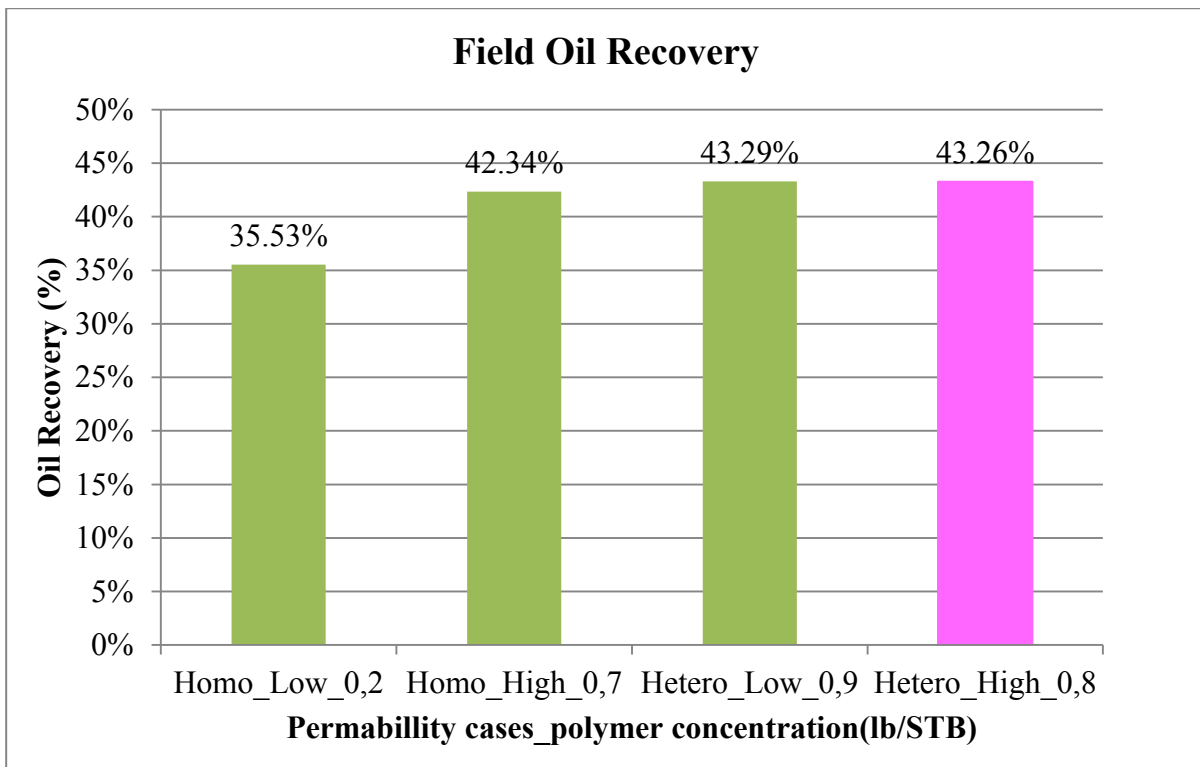


Figure 51: Showing the highest oil recovery and corresponding polymer concentration injected for 3 years in four major cases

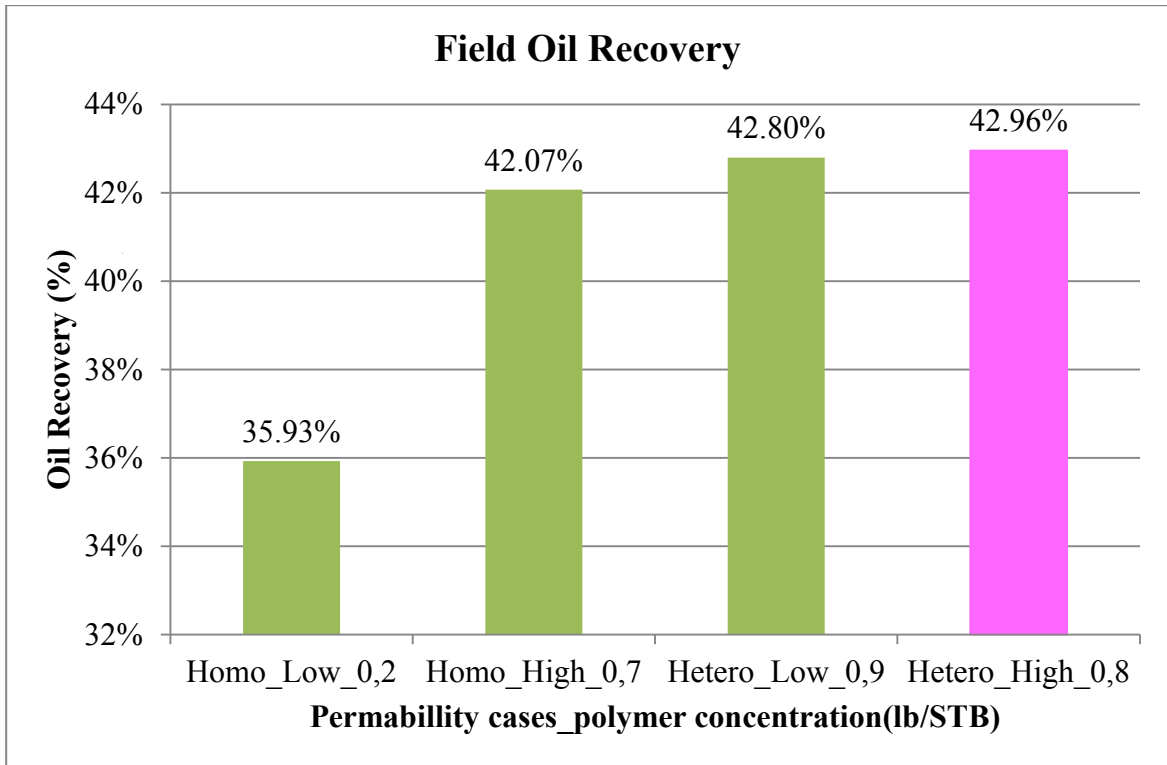


Figure 52: Showing the highest oil recovery and corresponding polymer concentration injected for 4 years in four major cases

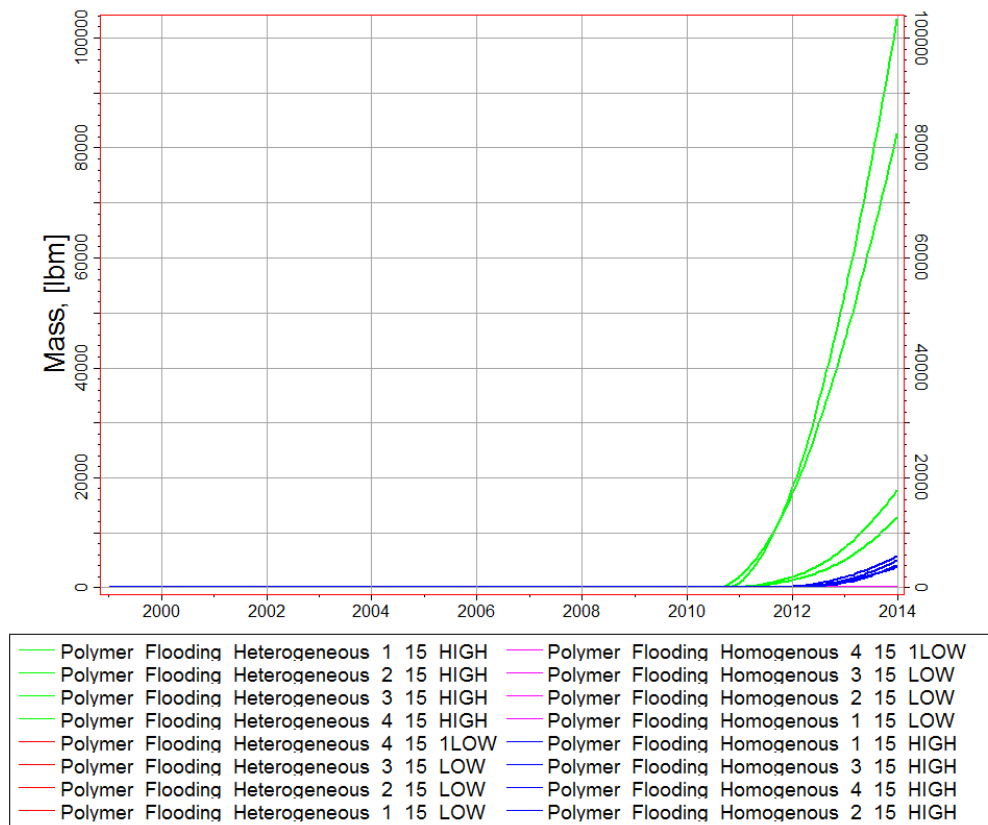


Figure 53: Showing polymer production cumulative for all four major cases

**APPENDIX D:** Determination of fractional flow of water,  $f_w$

$krw' = 0.96$  &  $kro' = 0.04$

$S_{wir} = 0.2$  &  $S_{or} = 0.2$

$P_{cow} = 0$  &  $S_{in\alpha} = 0$  (Horizontal flow)

Water viscosity,  $\mu_w = 0.95$  cP (from PVTW) & Oil viscosity,  $\mu_o = 0.55$  cP

Fully mixed polymer solution viscosity,  $\mu_m C_p = (21.2 \times \mu_w) = 21.2 \times 0.95 = 20.14$  cP

PROPS section

```

PLYVISC
0.0 1.0
0.035 1.55
0.105 2.55
0.175 5.125
0.245 8.125
0.351 21.2
    
```

Pure water viscosity @ 200°F or 70°C,  $\mu_w' = 0.4061$ cP (Perry, 1950)

Effective water viscosity,  $\mu_{w,e}$  represents the viscosity of water after polymer flooding, which calculated from equation (ix) in chapter 6: (6.2.2). The values of  $kro$ ,  $krw$  are taken from data file as explained in chapter 5 (5.1.1). Table 10 below shows the  $f_w$  calculated where the plots are discussed in chapter 6: (6.2.2). From Todd-Longstaff mixing parameter I assumed,  $\omega = 0.4$  (Assumed)

Table 10: Showing the fractional flow of water determined before and after polymer flooding

						WPOLYMER	0.80
						Water effective viscosity 1.77	
$S_w$	$S_o$	$Kro$	$Krw$	Water Flooding		Polymer Flooding	
(%)	(%)	mD	mD	1/M	$f_w$	1/M	$f_w$
0.2	0.8	1	0	0.00	0.00	0.00	0.00
0.3	0.7	0.997	0.01	172.52	0.01	320.88	0.00
0.35	0.65	0.98	0.021	80.75	0.01	150.19	0.01
0.4	0.6	0.7	0.039	31.06	0.03	57.77	0.02
0.45	0.55	0.35	0.058	10.44	0.09	19.42	0.05
0.5	0.5	0.2	0.09	3.85	0.21	7.15	0.12
0.55	0.45	0.09	0.245	0.64	0.61	1.18	0.46
0.6	0.4	0.021	0.42	0.09	0.92	0.16	0.86
0.65	0.35	0.01	0.545	0.03	0.97	0.06	0.94
0.7	0.3	0.001	0.8	0.00	1.00	0.00	1.00
0.75	0.25	0.0001	0.91	0.00	1.00	0.00	1.00

## **APPENDIX E: Keywords used for polymer in data file**

Properties of polymer in ECLIPSE data file

Summary of the key words

### **RUNSPEC section**

POLYMER

BRINE

### **PROPS section**

PLYADS: Accounts for polymer adsorption function

PLYVISC: Polymer solution viscosity function

PLYROCK: Specifies the polymer-rock properties

PLMIXPAR: Polymer Todd-Longstaff mixing parameter

PLYMAX: Accounts for polymer concentration for mixing calculation

### **SCHEDULE section**

WPOLYMER: Sets polymer concentrations for injection wells



**A: PROPS section**

*1.1 Viscosity:*

**PLYVISC:** When salt sensitivity option has not been activated

Column I	Column II
The polymer concentration in the solution. UNITS: kg/sm <sup>3</sup> (METRIC). <b>[The value: (increase monotonically down the column)].</b>	The corresponding factor by which the water viscosity (entered using the PVTW keyword) has to be multiplied to give the viscosity of the solution. <b>[Column II value = multiplication factor: (water viscosity x value = solution (polymer-water) viscosity)].</b>
<p><b>PLYVISC</b></p> <p>0.0 1.0</p> <p>0.035 1.55</p> <p>0.105 2.55</p> <p>0.175 5.125</p> <p>0.245 8.125</p> <p>0.351 21.1/</p>	

*1.2 Adsorption:*

**PLYADS**

Column I	Column II
The local polymer concentration in the solution surrounding the rock. UNITS: kg/sm <sup>3</sup> (METRIC). <b>[The value: (increase monotonically down the column)].</b>	The corresponding saturated concentration of polymer adsorbed by the rock formation. UNITS: kg/kg (METRIC). <b>[The value: (increase monotonically down the column)].</b>
<p><b>PLYADS</b></p> <p>0.0 0.0</p> <p>0.175 0.0000017</p> <p>0.351 0.0000017/</p>	

### 1.3 Polymer rock properties:

#### PLYROCK

Column I	Column II
The dead pore space or inaccessible pore volume (IPV) for the rock type. It represents the amount of the total pore volume in each grid cell that is inaccessible to polymer solution. The effect of the dead pore volume within each cell is to cause the polymer solution to travel at a great velocity than inactive tracers embedded in the water. <b>[The value: (value &gt;= 0) and (value &lt; Swmax)].</b>	The residual resistance factor ( <b>RRF</b> ) for this rock type at reservoir conditions. Represents the decrease in the rock permeability to the aqueous phase when the maximum amount of polymer has been adsorbed. <b>[The value: (value&gt;1)].</b>
Column III	Column IV
The mass density of this rock type at reservoir conditions. The quantity is used in calculation of the polymer loss due to adsorption. UNITS: kg/rm3 (METRIC)	The adsorption index to be used for this rock type. The values are either 1 or 2. 1 if the polymer adsorption isotherm is retraced whenever the local polymer concentration in the solution decreases. And 2 when no polymer desorption may occur. <b>[DEFAULT: 1].</b>
Column V	
The maximum polymer adsorption value that is to be used in the calculation of the resistance factor for the aqueous phase. UNITS: kg/kg (METRIC) <b>[The value: (value ≠0)].</b>	
<b>PLYROCK</b> 0.16 1.5 1000 2 0.000017 /	

### 1.4 Polymer thermal degradation

#### PLYDHFLF

Column I	Column II
The local temperature in the solution UNITS: OC (METRIC). <b>[The value: (increase monotonically down the column)].</b>	The corresponding half-life of the polymer UNITS: days (METRIC).
<b>PLYDHFLF</b> 0.0 365.0 50.0 240.0 100.0 180.0/	

**B: SCHEDULE section**

*1.1 Polymer concentration*

**WPOLYMER:** Sets polymer/salt concentration for injection wells.

Column I	Column II
Well name, well name template, well list or well list template	The concentration of polymer in the injection stream for the well. UNITS: kg/sm3 (METRIC)
Column III	Column IV
The concentration of salt in the injection stream for the well. If the salt-sensitivity option is not activated (using keyword <b>BRINE</b> in the <b>RUNSPEC</b> section), then the salt concentration entry is ignored. UNITS: kg/sm3 (METRIC)	The group whose produced polymer concentration should be used for the polymer concentration of the injection stream for the well
Column V	
The group whose produced salt concentration should be used for the salt concentration of the injection stream for the well	
<b>WPOLYMER</b> <b>INJ1 0.3 1.0 /</b> <b>/</b>	