SIMULATION STUDY OF IMPROVING OIL RECOVERY BY POLYMER FLOODING IN A KAZAKHSTANI FIELD

by

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Originality Statement

I, Adel Sarsenova, hereby declare that this submission is my own work and to the best of my knowledge it contains no materials previously published or written by another person, or substantial proportions of material which have been accepted for the award of any other degree or diploma at Nazarbayev University or any other educational institution, except where due acknowledgement is made in the thesis.

Any contribution made to the research by others, with whom I have worked at NU or elsewhere is explicitly acknowledged in the thesis.

I also declare that the intellectual content of this thesis is the product of my own work, except to the extent that assistance from others in the project's design and conception or in style, presentation and linguistic expression is acknowledged.

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ABSTRACT

Nowadays, different technologies, such as waterflooding, gas flooding, in-situ combustion and other technologies are implemented for improving oil recovery. Despite the fact that waterflooding is the most common method for pressure maintenance purposes and increasing oil production, utilizing this method, most of the oil remains unrecovered. This research is a simulation study aimed at improving oil recovery in a Kazakhstani field by implementing waterflooding and polymer flooding methods based on the data acquired from available literature. The field selected for this study is the mature oil field with a high of water cut and low recovery. At this stage of the production, in order to improve oil recovery, different IOR or EOR methods are needed. Since polymer flooding has the capability of increasing the water viscosity, controlling mobility of the water phase, and at the same time increasing volumetric sweep efficiency, it has been selected for the reservoir simulation.

As the main goal of this research was finding optimum flooding conditions, two aspects of the design of the polymer flooding process were studied. First, the investigation of the design of the polymer flooding project in terms of the effect of the slug size on the recovery factor and second is the initiation of the polymer injection time. The results have revealed that it is always profitable to start polymer flooding as early as possible, especially for the short-term projects. In this study, the results of comparison of the recovery efficiency between polymer flooding and waterflooding have revealed that it is possible to increase the recovery by 10 % with implementing polymer flooding technique. The costs of polymer flooding projects were also studied, and it was found that it can be more economical to conduct waterflooding for 3 years before injecting polymer into the reservoir.

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1. Introduction

1.1 Background

1.1.1 Oil Recovery Stages

The urge for seeking new efficient methods for hydrocarbon extraction is essential since a great amount of hydrocarbon volume remains unrecovered using conventional oil recovery techniques. Oil production technologies available nowadays can be divided into three classes: primary, secondary, and enhanced oil recovery (EOR) operations. Primary oil recovery operations work on the mechanism of depletion of natural energy initially present in the reservoir. These “natural” sources of energy are provided by primary drive mechanisms such as an expansion of free gas, solution gas drive, natural water drive, fluid and rock expansion and gravity drainage. Influenced by these forces, oil moves toward producing wells. Secondary recovery operations are usually applied after primary production has fallen. At this stage, elevation of natural energy is required. This is typically achieved through injection of water or gas. However, because of the capillary forces and immiscibility of the oil and water, it isn’t possible for these fluids to completely remove one another from the reservoir, that’s why most of the oil originally in place remains unrecovered (Needham, R.., et al., 1987). It was investigated that oil recovery can be substantially improved with the use of EOR and improved oil recovery (IOR) methods (Bai, B., 2008). The term EOR refers to the process of hydrocarbon extraction by injecting the fluid typically not present in reservoir. Another descriptive designation IOR, encompasses all of the recovery methods apart from natural production. EOR processes work on principle of injection of gases, chemicals and utilization of thermal energy (Green, D., 1998). The main objective of EOR is to increase hydrocarbon extraction using different methodologies, such as creating favorable mobility ratios, by adjusting reservoir heterogeneity or decreasing residual oil saturations (Green, D., 1998). A lot of studies published these days indicate that it is possible to recover around 20-30% at the primary stage of oil extraction. By utilizing secondary recovery methods, the recovery factor can reach up to 40 % (Tunio, S., 2011). However, by means of EOR techniques, recovery factor for heavy oils can reach up to 50-70% (Muggeridge, A., et al.,2014). Moreover, by using advanced EOR techniques, particularly gas flooding, water alternating gas (WAG), and polymer flooding, the recovery factor can account for 60-65% (Tunio, S., 2011).

EOR methods can be subdivided into different categories, depending on author and criteria. For example, in 1992, Lake identified three of them, including thermal, chemical, and solvent methods as shown in Fig.1.1 (Lake, L., 1992). Meanwhile, in 1998, Green and Willhite highlighted five categories, such as mobility-control, chemical method, miscible, thermal, microbial (Green, D., 1998). According to them mobility-control processes are focused on creating favorable mobility ratios. Cases include polymer injection for increasing water viscosity and foam flooding in order to lower gas mobility. Chemical processes, in turn, aim at reducing interfacial tension (IFT) by adding surfactants or alkaline agents. Miscible operations involve the injection of fluids that can be miscible with oil or can alter composition of the fluids in-situ for creating miscibility. CO_2 or hydrocarbon solvent injection can be examples of the implementation of miscible methods. Oil recovery from the thermal processes based on the mechanism of injection of the thermal energy or heat generation in-situ. Steam, hot water injection, in-situ air or oxygen combustion are the examples of thermal methods (Green, D., 1998).

Generally, EOR methods can work along two directions: improving volumetric efficiency and displacement efficiency (Tunio, S., 2011). The performance of EOR processes relies on the progress of the process on macro- and microscales. Microscopic efficiency outlines displacement of the fluid at the pore scale. At this scale, pore size parameters such as its geometry, magnitude, capillary pressure, and other parameters, including viscous forces, wettability, and rheological behavior have significant impact on the displacement efficiency of the fluid. The macroscopic efficiency is mainly affected by the rock heterogeneity, permeability, the mobility ratio, and the gravitational segregation (Druetta, P., 2018).

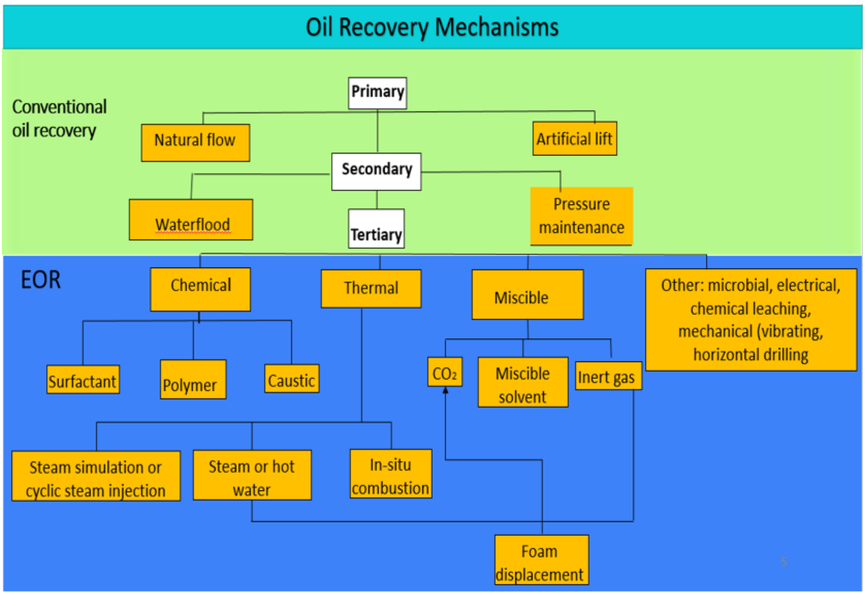


Figure 1. 1. Oil Recovery Mechanisms (Lindley, 2001)

1.1.2 Recovery efficiency

Overall productivity of any secondary or tertiary oil recovery technique depends on three main parameters as demonstrated in the eq. 1.1. (Ahmed, 2006):

$$RF = E_D \times E_A \times E_v \tag{1.1}$$

Where:

E_D – displacement efficiency, fraction or percent

E_A – areal sweep efficiency, fraction or percent

E_v - vertical sweep efficiency, fraction or percent

Displacement Efficiency

Displacement efficiency, more commonly known as microscopic sweep efficiency. Microscopic sweep efficiency depicts displacement of the fluid at a pore scale. Displacement efficiency in waterflood and polymer flood operations can be computed through saturation of the fluid behind the front at the breakthrough and initial water saturation (Cossé, R., 1993). This is given by (Green, D., 1998):

$$E_D = \frac{S_{oi} - S_{or}}{S_{oi}} \tag{1.2}$$

Where:

S_{or} – residual oil saturation

S_{oi} – initial oil saturation of reservoir

Areal Sweep Efficiency

Areal sweep efficiency is the ratio of the area that is being swept over the total area that is contacted by the displacing fluid (Cossé, R., 1993):

$$E_A = \frac{Area\ swept\ by\ the\ front}{Total\ Area} \tag{1.3}$$

Areal sweep efficiency depends on time, volume injected, well pattern, and mobility ratio. Areal sweep efficiency progressively increases with the start of waterflood till the time of breakthrough. Once it reaches breakthrough propagation of areal sweep continues to increase at a slower pace (Cossé, R., 1993). Fig.1.2 represents the propagation of areal sweep efficiency at different times of waterflood process.

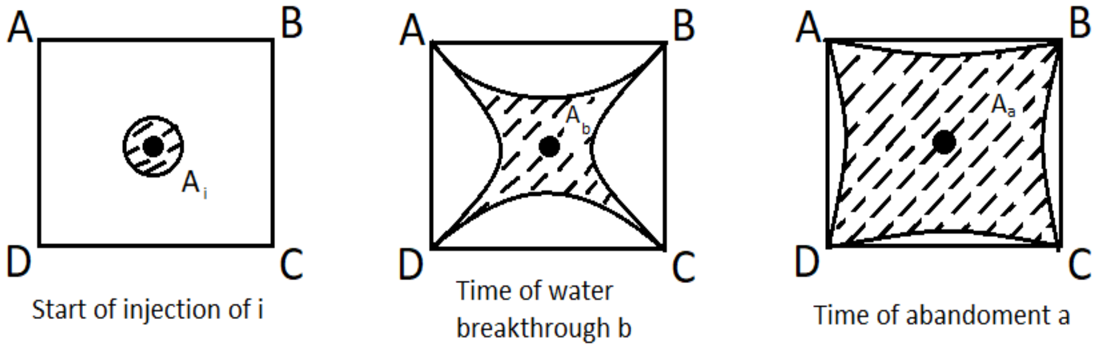


Figure 1. 2. Areal sweep efficiency for five-spot well pattern (Cosse, 1993)

Vertical Sweep Efficiency

It is the ratio of the vertical area swept to the total vertical area. Vertical sweep efficiency is highly influenced by reservoir heterogeneities, such as different permeabilities, faults, fractures. These factors significantly distort movement of the front and have a negative impact on sweep. In many cases vertical sweep efficiency plays a dominant role in waterflooding operations and given by eq. 1.5 (Cossé, R., 1993):

$$E_v = \frac{Area\ swept\ by\ the\ front}{total\ vertical\ cross - section} \qquad (1.5)$$

1.1.3 Waterflooding and mobility ratio

Waterflooding is one of the inexpensive and most commonly preferred recovery technique for improving oil recovery. This is due to economic reasons: water is comparably cheap and its availability, particularly in offshore fields; however, special treatment must be taken before injecting seawater in order to avoid unwanted reaction of water with formation (Lake, L.,1992). In oil fields where pressure significantly dropped and recovery efficiency became unprofitable, waterflooding is used as the secondary oil recovery method. For the first time, the ability of water to increase oil recovery was discovered in the Pithole city area Pennsylvania in1865 by accidental injection of water into a hydrocarbon zone (Craig, F., 1971). Large-scale implementation of waterflooding had started in the 1940s, and over a time, it has grown into a well-established secondary recovery technique (Lake, L., 1992). Water is injected into the reservoir in order to maintain pressure (Binder et. al, 1956) and displace the remaining oil, which in some cases accounts for 60 % of original oil in place. Nowadays, this method is broadly utilized at the early stages of the reservoir development (Morrow et. al, 2011). Implementation of waterflooding causes increase in water production (Bai, et al., 2013). High levels of water production during oil and gas production is a matter of concern for reservoirs all over the world (Bai, et al., 2013). Typically, oil production is accompanied with water production (Launtz, et al., 2014). It was reported that for production of 1 barrel of oil there are 3 barrels of water production (Bailey, et al., 2000). After waterflooding in mature oil fields water production increases with its age and can reach up to 98% (Yusta-Gracia, et al., 2017). Therefore, after some time of production, the level of water cut in producing fluids rises, and for some fields, it can remain economical until it reaches 99%. Although at a certain point it becomes unprofitable. Expenses for water disposal exceed the revenue from the oil production, and at that stage of production, waterflooding has to be ceased (Morrow et. al, 2011). Excessive water production drastically decreases anticipated economic life of the field and causes technical and environmental problems (Imqam, et al., 2017). Technical problems can include cost of handling, pumping, lifting, and large amounts of water disposed. Environmental problems can include damage to the formation due to re-injection. All these issues are associated with early water breakthrough. They raise the cost of production and considerably affect ultimate oil recovery (Seright, et al., 2000).

The success of the waterflooding projects depend on stability of the displacement. The main factor controlling displacement efficiency is mobility ratio (M). In the waterflooding projects M is a function of viscosity and relative permeability and can be defined as:

$$M = \frac{k_{rw} / \mu_w}{k_{ro} / \mu_o} \tag{1.6}$$

Where: k_{ro}; k_{rw} – relative permeabilities to oil and water; μ_o; μ_w – oil and water viscosities. Generally, it is considered that M equal to or less than 1 is favorable, and M greater than 1 is unfavorable (Craig, 1971). Therefore, it is expected that hydrocarbon recovery improves when the mobility ratio of displacing (water) and displaced (oil) phase is around one. Drastic difference between water and oil viscosities can lead to viscous fingering of water through more viscous oil, decreasing hydrocarbon recovery (Cenk, T. et al., 2017). From the works conducted by Kumar et al. (2008) on understanding of high-mobility ratio waterfloods, it was observed that viscous fingering prevails in high-viscosity ratio floods, and that oil recovery can be drastically decreased by mobile water. Additionally, reservoir heterogeneities, such as thief zones, promote poor hydrocarbon displacement. Their study has shown that any progression in mobility ratio can have effect on improvement of reservoir sweep efficiency (Kumar, M. et al., 2008).

Efficiency of the waterflooding performance can be improved to a greater extent, by decreasing the water/oil mobility ratio and increasing the viscosity of the displacing water. This technique is implemented in polymer flooding operations. In polymer flooding, water soluble agent is added into the brine. Compared to the conventional waterflooding with unfavorable mobility ratio, the displacement front of polymer solution is much smoother, without viscous fingering, and the reservoir is swept more completely. This process can be clearly seen in the Fig. 1.3. It was investigated that polymer flooding does not affect residual oil saturation; however, it helps to reach residual oil saturation more economically in a short amount of time (Chang, H., 1978). Pressure support is a crucial parameter in polymer flooding operations. Reservoirs with strong aquifer or gas cap require significantly lower amount of energy for pressure support due to the presence of the primary sources of energy. However, the presence of a gas cap or strong aquifer can reduce the efficiency of polymer operations, because polymer can shift into aquifer zones (Sheng, J. et al., 2015).

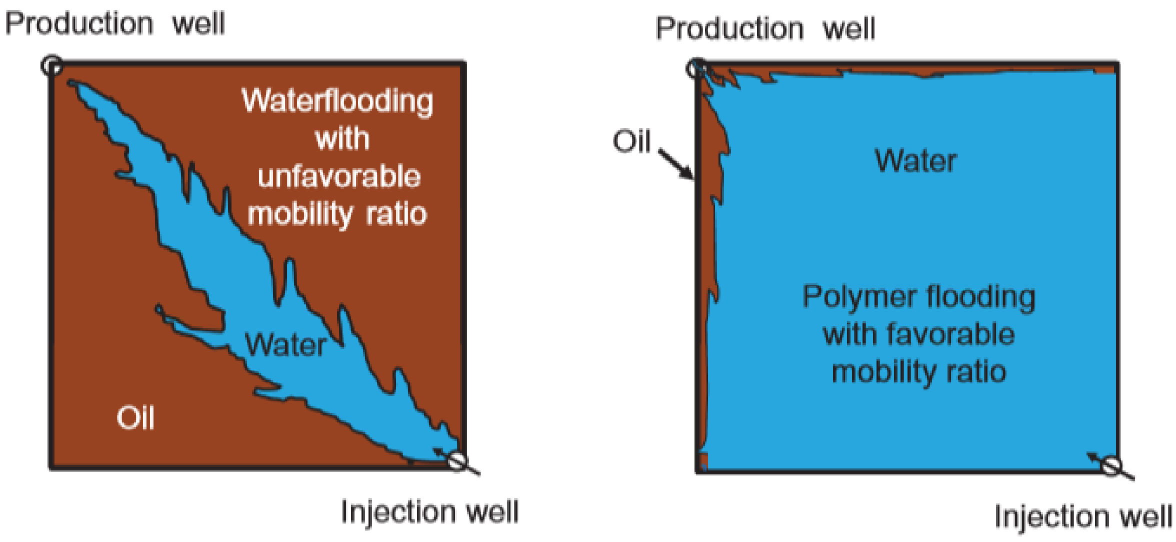


Figure 1. 3. Comparison of displacement fronts during water flooding and polymer flooding for different mobility ratios: (a) Waterflooding with unfavorable mobility ratio (M>1) which lead to fingering, (b) Polymer augmented waterflooding with favorable mobility ratio (M≤1) (Sydansk & Romeo-Zeron, 2011)

1.2 Problem definition

The field under the study is the mature oil field. It has been under waterflooding over the last few decades. There was an early water breakthrough, and currently, it is facing the problems of excessive water production and decrease in level of oil production. Because of the problems mentioned above, at this stage of production, there is a need for applying new efficient methods for improving oil recovery and at the same time reduce the levels of the water cut. It is considered that most of the unwanted water production is due to the conformance problems present in heterogeneous reservoirs (Thrasher et al., 2016). One of the methods frequently used to address this problem is polymer flooding (Alshawaf, et al., 2017). Thus, for this field we want to suggest polymer injection and study its benefits in improving oil recovery by simulation of different injection scenarios. Previously, no reports were published on conducting polymer flooding projects or polymer flooding simulation work about this field. Application of simulation results would aid in determining the relevance and suitability of the selected solutions to the industry. Simulation of the process will also aid in better evaluation and prediction of the process and moreover will help in selecting and reducing the amount of the polymer needed for operation, therefore improving cost effectiveness of the applied technology.

1.3 Objectives of the thesis

1.3.1 Main objectives

The primary objective of this research is to investigate the effect of water-soluble polymers in increasing recovery efficiency in the Kazakhstani field.

Another important objective is finding optimum flooding conditions to make production more economical.

1.3.2 Thesis structure

In the first chapter, we briefly discuss overall enhanced oil recovery techniques and classify goals of the research.

The second chapter presents a project plan, including project schedule, resource requirements, risk management, physical hazards and project hazard.

Third chapter addresses a detailed review of significant parts of the research, including the polymer flooding mechanism, its characteristics, and in-situ rheology.

The fourth chapter describes geological structure, reservoir and fluid parameters of the field.

The fifth chapter outlines reservoir simulation data, model characteristics, and description of different simulation scenarios.

The sixth chapter presents an analysis of the results of the reservoir simulation model.

The seventh chapter gives conclusions and suggestions for future work.

2. Project Plan

2.1 Project schedule

Below Gannt Chart is presented. It was developed to ensure that the project will be delivered on time.

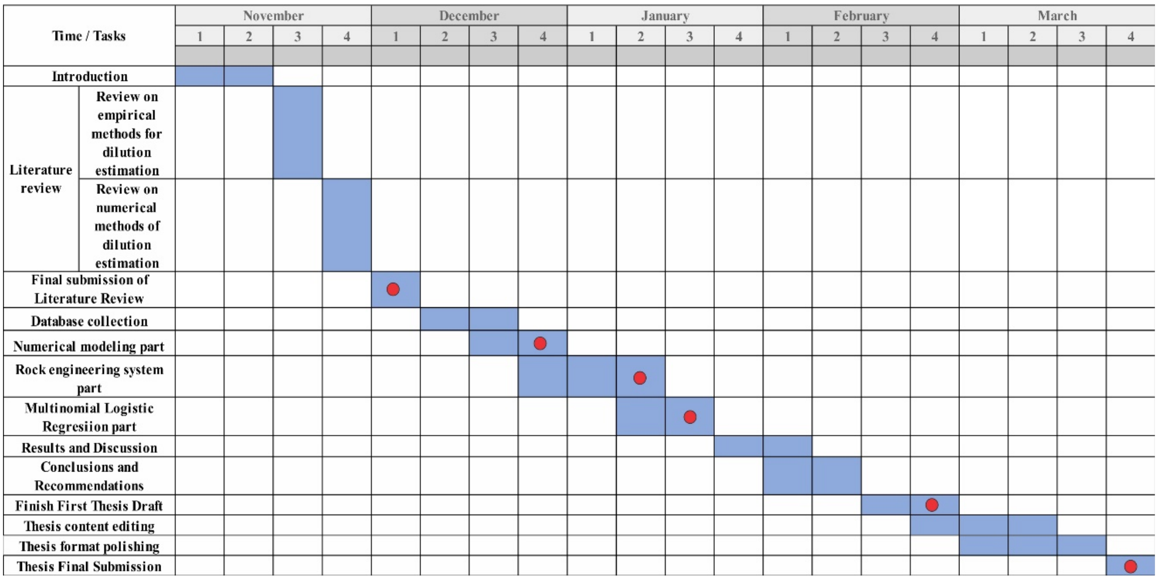


Figure 2. 1. Thesis schedule

● - milestones

2.2 Resource requirements

The necessary resources for project completion are identified and listed.

Table 2. 1. Required resources

Device/material	Function
Laptop or PC	My own laptop or PC from computer lab is used to conduct the research
Database from Internet resources	To construct a synthetic model of the reservoir as close to the real field as possible
Access to an online library of technical literature for the oil and gas industry	Research articles for conducting literature review
Printer	To print out articles or papers
Access to internet	To download essential materials related to my thesis
Access to CMG	To perform reservoir simulation

2.3 Risk management

Risk is a measure of probability of not achieving expected outcome, and it can be avoided or mitigated through well thought out planning. Risk mitigation plan was developed for this thesis to identify the possible risks and the ways of avoiding or controlling them. One of the common risk assessment tool is WRAC analysis that uses a 5x5 likelihood-consequence matrix. Table 2.2 illustrates the risk rating from low to extreme cases.

Table 2. 2. Risk ranking matrix

Risk matrix		Consequence				
		Negligible	Minor	Moderate	Major	Catastrophic
Likelihood		1	2	3	4	5
Almost certain	5	6	7	8	9	10
Likely	4	5	6	7	8	9
Possible	3	4	5	6	7	8
Unlikely	2	3	4	5	6	7
Very unlikely	1	2	3	4	5	6

Risk rating	
Extreme	≥ 8
High	7
Medium	5-6
Low	≤ 4

2.3.1 Physical hazards

Physical hazard is a factor that can harm a person’s mental or physical condition without the need for physical contact. The possible physical hazards that can occur during the thesis work and the ways to avoiding them are given in Table 3.

Table 2. 3. Physical hazards

Physical Hazard	Description	Risk rating	Risk Control
Eye-strain	Fatigue of the eyes due to prolonged presence in front of the computer screen	7 High	Regular exercise for eyes, regular breaks during using the computer
High stress	Irritation from the overwork	5 Medium	Good study/relax balance, proper time management
Illness	Disease from mild colds to flu	5 Medium	Maintain immunity of the body, dress warmly at cold conditions, stay away from sick people

2.3.2 Project hazard

Project hazards are the factors that can affect to the provision of the thesis on time due to unexpected situations.

Table 2. 4. Project hazards

Project hazard	Description	Risk level / rating	Risk control
Sudden computer crash	Accidental fall to the floor	3 Low	Obligatory carrying in a bag
Thesis related documents loss	Sudden failure of the hard drive, computer crash due to viruses, not saving the thesis files	5 Medium	Use cloud services like google drive, do not forget to save, installation of anti-virus software
Change of thesis supervisor	Supervisor may be unable to continue student supervision due to some circumstances	5 Medium	Advice with co-supervisor or another professor competent in student's thesis topic
Software inaccessibility	Access to CMG	5 Medium	Contact support center
Lack of real field data	No access to the production, SCAL and experimental data	5 Medium	Work with another reliable database

3. Literature Review

3.1 Chemical Methods

Chemical EOR methods were widely spread in the 1980s and mostly implemented in sandstone reservoirs (Manrique, E.J., 2010). Chemical EOR processes include the injection of polymer (P), surfactant-polymer (SP), and alkali-surfactant-polymer (ASP), microgels, nanogels and other methods (Thomas, A., 2019). Chemical methods refer to the processes which involve injection of chemical formulation into a displacing fluid decreasing mobility ratio or increasing capillary number. Mobility ratio can be altered by thickening the injected water through addition of water-soluble polyacrylamide, and therefore, improve sweep efficiency of the reservoir. Meanwhile, capillary number can be altered by addition of surface-active agents (surfactants), which in turn leads to decrease of interfacial tension and releases residual oil trapped in the reservoir. Another parameter that can be altered by addition of alkali is wettability. Alkali flooding also known as caustic flooding process, involves chemical reaction that would reduce interfacial tension between water and oil by generating in-situ surfactants. Surfactant flooding processes involve the injection of surfactant solutions at very low concentrations within the range of 1% or even less. This is opposed to micellar solution where surfactant solutions at the concentration of 10% or even more and co-surfactant are injected into the reservoir. Among all EOR operations, surfactant flooding is one of the riskiest. It requires tremendous financial investment and thorough consideration of reservoir parameters, because its performance largely depends on reservoir heterogeneities. Therefore, the design of a surfactant flood should be varied from case to case, adapting for salinity, temperature, clay content, crude oil composition of the reservoir (Lake, L., 1992).

Microgels and nanogels are chemical approaches used for the purpose of decreasing the permeability of thief zones by sealing off the fractures and redirecting the water into the areas which were previously unswept. One or combination of these methods can be applied depending on the reservoir type, field development and economics (Thomas, A., 2019).

3.2 Polymer Flooding

One of the most commonly implemented EOR techniques for mobility-control purposes is polymer flooding (Chang, H., 1978). During the last few years, the application of polymer flooding has improved. It is easily implemented and involves comparatively low financial spending (Lake, L., 1992). Total cost of polymer flooding projects is typically less than of waterflooding projects due to reduction in water cut levels and increased oil production. Polymer flooding is a well established EOR technology with more than 40 years of field implementation (Abidin, A. et al., 2012). For the first time, polymer flooding was introduced in the 1960s. In the years between 1980 to 1986, it gained broader implementation. In 1996, one of the largest polymer flooding project was launched in Daqing field in China. Since that time, polymer flooding encountered irreversible improvements in terms of technology development and field application (Thomas, A., 2019). Generally, it involves injection of water-soluble polymeric additives at a concentration of 250 to 1500 ppm into a brine. Typically, the molecular weight of the polymer is around 9-25 million Daltons (Muggeridge, A., 2014). By addition of high molecular weight polymer, viscosity of water increases, improving volumetric sweep efficiency of waterflood to a greater extent (Lake, L., 1992). The polymer solutions aim to generate favorable mobility ratios for developing uniform displacement of the oil/water bank (Thomas, A., 2019). By utilizing a polymer flooding method, it is possible to recover around 8% of incremental oil in place (Muggeridge, A., 2014).

Firstly, the concept of the influence of the fluid mobilities on the waterflood efficiency was introduced in 1949 by Muskat. Stiles in 1950 used permeability and capacity distribution for performing waterflood calculations, whereas the works of Dykstra and Parson demonstrated the effect of mobility ratio and vertical permeability on hydrocarbon displacement. Later on in 1956 Aronofsky and Ramey conducted several studies on the influence of mobility ratio in flood patterns. These investigations gave clear indication that sweep efficiency can be significantly improved by increasing water viscosity (Thomas, A., 2019).

Typically, polymer flooding projects are conducted for an extended period of time before 1/3-1/2 of reservoir pore volume injected. After which polymer slug is chased by water for moving polymer solution and oil bank toward producing wells (Abidin, A. et al., 2012). Schematic illustration of polymer flooding sequence are demonstrated in Fig. 3.1.

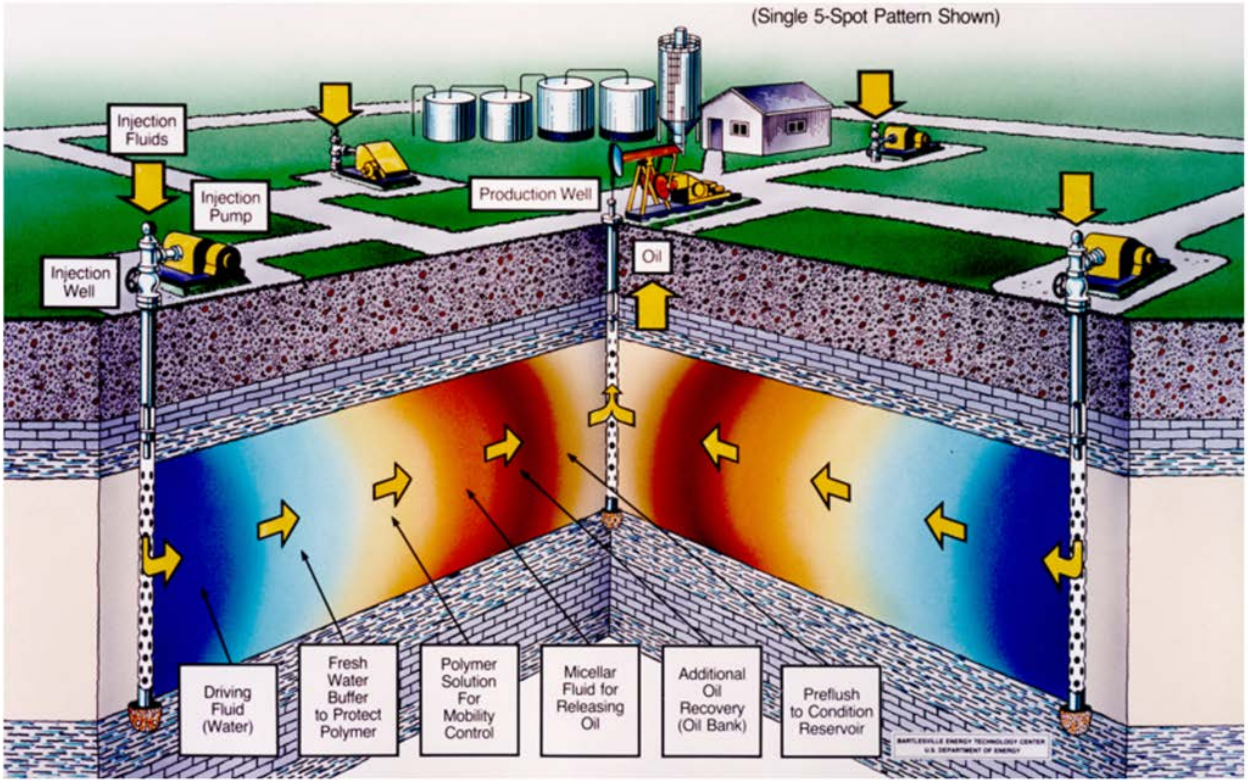


Figure 3.1. Schematic illustration of polymer flooding sequence (Donaldson, Chillingarian, & Yen, 1985)

3.3 Polymer characteristics

Polymers are materials which consist of repeating units of molecules, called monomers (Romero-Zerón L., 2016). There are two types of polymers that are used in EOR processes, synthetic polymers, known as polyacrylamides (PAM), and polysaccharides. Since 1970s these types of polymers were widely applied in the petroleum industry. It was revealed that synthetic polymers, in its hydrolyzed form (HPAM) are more frequently used due to lower cost.

3.3.1 Synthetic Polymers

Polyacrylamide polymers have been developed by manufacturers and have a variety of applications (Needham, R. B., 1987). It was the first polymer in use for water thickening purposes. Polyacrylamides are generated from the polymerization of acrylamide or other monomers. The acrylamide compound is derived from acrylonitrile. Thermal stability of PAM is up to 90℃ in normal water salinity and up to 62℃ in seawater salinity (Cenk, T. et al., 2017). The chemical structure of polyacrylamide is represented in Fig. 3.2.

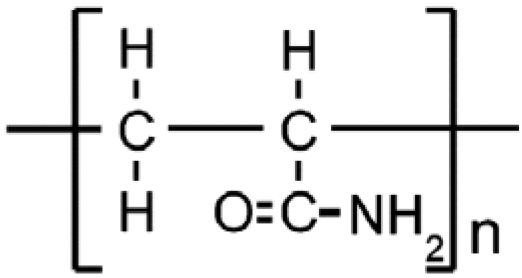


Figure 3.2. Repeating unit of PAM (Cenk, T. et al., 2017)

Generally, behavior of the polyacrylamide largely depends on its molecular weight and the degree of hydrolysis. For instance, partially hydrolyzed polyacrylamides tend to increase viscosity of the freshwater, but due to its sensitivity to salt, they tend to decrease its viscosity. The higher molecular weight, the higher viscosity and resistance factor it will generate and vice versa (Needham, R. B., 1987). Apart from increasing viscosity, polyacrylamides can change the permeability of the reservoir rock, which results in reduction of the effective mobility of the injected water. Polyacrylamides are prone to mechanical degradation when subjected to shear stress, that's why careful treatment in surface handling is needed in order to prevent shear degradation (Chang, H., 1978).

One of the increasingly used synthetic polymers is partially hydrolyzed polyacrylamide (HPAM). Studies of Standes and Skjevrak (2014) revealed that over 90% of EOR operations implemented all over the world utilized HPAM polymers. The molecular weight of HPAM used in EOR projects is usually high and more than 10 million Daltons (Al-Shakry, B. et al., 2019). However, HPAM has some restrictions in use due to its shear instability, especially in low permeable reservoirs. Another parameter that limits its utility is injectivity. Successful oil production requires good polymer injectivity. During polymer injection, many problems can be encountered, such as formation damage, fracturing of the formation, chemical/biological/mechanical degradation. That is why thorough analysis of the injection performance should be conducted (De Simoni, M. et al., 2018). Furthermore, HPAM is not resistant to high temperatures, above 60 or 70 ℃ (Al-Shakry, B. et al., 2019). High temperatures, and salinity can decrease HPAM viscosity, leading to lowering sweep efficiency, and therefore, reducing recovery factor (Cenk, T. et al., 2017). The key factors that influence polymer injectivity are shear thinning and retention (Al-Shakry, B. et al., 2019).

3.3.2 Biopolymers (Xanthan Gum)

One of the most commonly applied polysaccharide is xanthan gum, which is the product of fermentation of the bacterium xanthomas campestris. It is believed that these bacteria generate polymers in order to save them from dehydration. Xanthan gums are comparably insensitive to salinity and relatively resistant to mechanical degradation, which makes them more convenient for working with different field equipment such as injection pumps and others. Nevertheless, xanthan gums are prone to bacterial degradation and uneconomical to use. Structure of the xanthan biopolymer is demonstrated in Fig. 3.3. In EOR projects, the molecular weight of biopolymer xanthan gum varies between 1 million to 15 million. In the field operations, xanthan gum biopolymers are implemented in two forms in two physical forms as a dry powder or concentrated broth (Green, D., 1998).

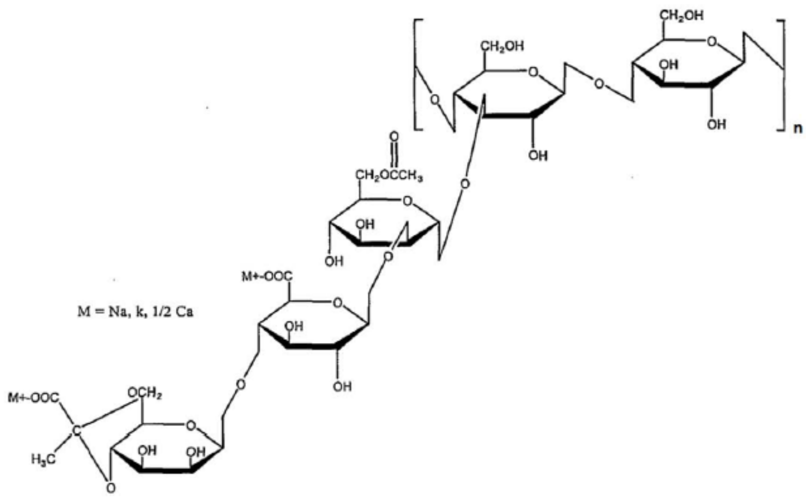


Figure 3.3. Structure of xanthan biopolymer (Cenk, T. et al., 2017)

Biopolymers have found their application offshore and in severe reservoir conditions, such as high salinity, high temperature (Kulawardana, E., 2012).

3.4 Polymer behavior in porous media

3.4.1 Viscosity of Polymer Solution

Viscosity of the fluid is its resistance towards deformation (Sorbie, K., 1991). Viscosity of the polymer solution is a key parameter in polymer flooding operations. It is controlled by many factors, including polymer concentration, polymer degradation, temperature, and the salinity of water used (Xin, X., 2018). Discoveries from the lab experiments depict a direct relationship between viscosity and concentration of polymer solution (Sheng, J., 2010). Therefore, higher concentration of polymer solution will result in higher viscosity of polymer solution. This in turn will lead to more effective injectivity and reduction in water cut (Wang, D., et al., 2008).

3.4.2 Rheology. Effect of Shear Rate.

For more precise prediction of polymer performance in-situ, it is crucial to model properly polymer rheological behavior. It is known that solutions of polyacrylamides and xanthan gums demonstrate non-Newtonian fluid behavior. In Newtonian fluids, there is a linear dependency between shear stress and shear rate. Consequently, in Newtonian fluids, the value of the viscosity is constant with regard to shear rate and shear history (Chhabra, R., et al., 1999). This relationship is represented in eq.3.2:

$$\tau = \mu \times \gamma \tag{3.2}$$

Where: τ – shear stress (Pa), μ – viscosity of the solution (cP), γ – shear rate (s^{-1})

However, the fluids can be characterized as Newtonian not only by exhibiting constant viscosity value, but also by completely satisfying Navier-Stokes equations (Chabra, R., et al., 1999). Non-Newtonian fluids refer to those that have a non-linear relationship between shear rate and shear stress. Moreover, non-Newtonian fluids can be grouped into three classes:

- *Time independent*: this class encompasses fluids in which viscosity is only dependent on shear rate and also known by various names, such as “purely viscous”, “inelastic”, or “generalised Newtonian fluids (GNF)”;
- *Time dependent*: this class represents more complex fluids in which viscosity is also a function of shear history;
- *Viscoelastic*: where fluid represents partial elastic recovery after deformation.

However, as a practical matter, real materials oftentimes demonstrate a combination of two or even all of the three types of non-Newtonian fluids traits. Nevertheless, it is possible to determine the most influential non-Newtonian fluid characteristic. Generally, non-Newtonian fluids exhibit time-independent fluid behavior. These types of fluids can be further classified into:

- *Shear-thinning (pseudoplastic)*: the behavior of this group fluids shows the reduction of apparent viscosity with increasing shear rate. At both very low and at very high shear rates shear thinning polymer solutions for the most part represent constant Newtonian viscosities (Chhabra, R., et al., 1999). The term “pseudoplastic” was coined in order to differentiate the behavior of such fluids from viscoplastic fluids (Brodkey, R., 2003).

- *Viscoplastic (Bingham)*: distinctive feature of this type of fluids is that they demonstrate yield stress that has to be exceeded before fluid will deform.
- *Shear-thickening (Dilatant)*: the behavior of these types of fluids characterized by the increase of the viscosity with increasing shear rate.

Generally, viscosity of the polymer solutions exhibit pseudo-plastic (or shear thinning) behavior: increase in shear stress results in viscosity decrease. This shear-thinning fluid behavior described by the power law model. Generalized form of the power law model for non-Newtonian fluids is given in equation 3.3:

$$\mu = K\gamma^{(n-1)} \tag{3.3}$$

Where: μ – apparent viscosity (cP), K – power law constant, n – power law exponent, γ – shear rate (s^{-1}).

Fig. 3.4 represents a typical rheology of shear-thinning fluid. With low shear rates, fluid exhibits Newtonian fluid behavior. In contrast, with increasing shear rate, there is a shift to shear-thinning fluid behavior, followed by transition to Newtonian fluid behavior at high shear rates (Green, D., 1998).

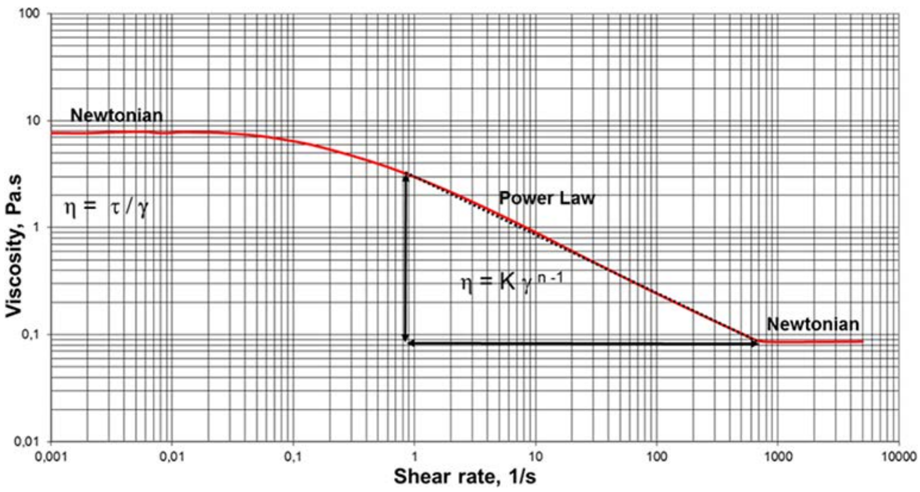


Figure 3. 4. Rheology of a shear-thinning fluid (Romero-Zerón L., 2016)

3.4.3 Polymer Stability

Stability of the polymer is one of the major issues during polymer injection. From the field experience, it was investigated that during injection and production operations, polymers can be subjected to chemical, mechanical, thermal, microbial degradations. All these factors have destructive effects on polymer viscosity (Eiroboyi, I., 2018). Chemical or oxidative degradation make up the majority of the cases. (Chang, H., 1978). Chemical degradation can be characterized as the polymer molecules breakdown (Lu, X. A., 2015). Chemical degradation can occur through oxidation reaction-reduction or due to the presence of divalent cations, in particular Ca^{2+}, Mg^{2+} and Fe^{2+} (Eiroboyi, I., 2018). Among all the factors that can provoke chemical degradation, oxidation and effect of ferric ions are of great importance. Oxygen contamination can create serious stability problems. The amount of oxygen in the solution can be reduced by oxygen scavengers (Yang et al., 1985). In 1991, Sorbie demonstrated the impacts of certain additives on the stability of hydrolyzed polyacrylamide (HPAM). In order to prevent polymer degradation from oxygen, polymer make-up equipment should be preserved under a nitrogen blanket (Yang et al., 2001). It was investigated that an oxygen concentration lower than 5 ppb can provide good stability of acrylamide and acrylic acid up to 120℃ for 200 days. If the oxygen concentration is lower than 200 ppb and temperatures are below 50℃, there is expected insignificant degradation of polymer (Thomas, A., 2019).

Mechanical degradation is usually caused by the influence of high shear conditions, high velocity, and pressure drop (Romero-Zerón Laura., 2016). Mechanical degradation of polymer can be characterized as molecule breakdown due to shear stresses. It can occur near well regions where high-flow-rates are expected. This effect can happen around the perforation, near the wellbore region, in chokes, and others (Sheng, J. et al., 2015). Oftentimes high molecular weight polymers are more sensitive to mechanical degradation (Thomas, A., 2019). Eventually, this degradation will result in reduction of polymer solution viscosity. In order to lower mechanical shearing effects, screw pumps are used for transporting polymer solution, moreover polymer-injection wells are completed with perforations (Sheng, J. et al., 2015). Viscosity loss of the polymer due to shear degradation can be seen in the Fig. 3.5. Despite the fact that biopolymers are more likely to be degraded biologically, it may also be the case for synthetic polymers. In order to prevent polymers from biological degradation it is necessary to use biocides (e.g., formaldehyde) (Sheng, J. et al., 2015).

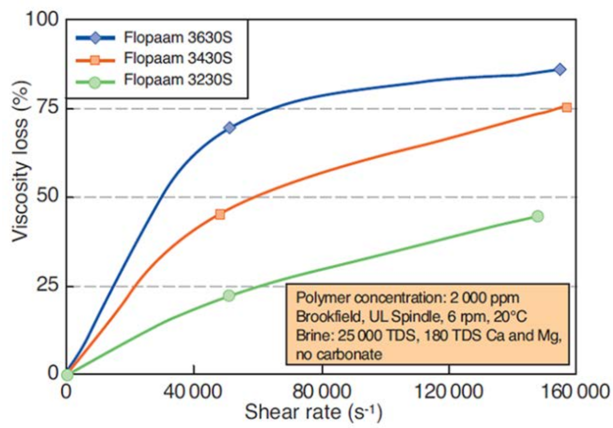


Figure 3. 5. Viscosity loss of the polymer due to shear degradation. In the graph there are polymers with same chemistry, but different molecular weight (Romero-Zerón Laura., 2016)

Thermal degradation of polymers depends on the type of polymer used and reservoir conditions (Romero-Zerón Laura., 2016). Synthetic polymers, especially HPAM, are not stable at temperatures above 60 or 70℃ (Masalmeh, S., 2019). Thermal degradation of the polymer causes degradation of macromolecules of the polymer into smaller molecules, thereby decreasing molecular weight and lowering viscosity (Lu, X. A., 2015).

It was investigated that for alkali/surfactant/polymer operations, reservoir temperature should be less than 93.3℃ (Teber et al. 1997). Regarding the Delamaide's paper published in 2018, the high temperature polymer floods were performed in several fields, including Northeast Hallsville Crane (USA, 109℃), Hitts Lake Unit (USA, 99℃), Sanand (India, 85℃), Mangala (India, 85℃), Caracara Sur ASP (Colombia, 86℃), West Salym ASP (Russia, 83℃).

3.4.4 Adsorption

The process in which a polymer solution flows through porous medium and adsorbs onto the rock surface called adsorption (Pancharoen, M., et al., 2010). Adsorption of the polymer solution depends on the rock mineralogy and permeability (Hidayat, W., et al., 2019). The adsorption causes reduction in permeability of porous media, narrowing the flow path, and in some cases, can even lead to full plugging (Pancharoen, M., et al., 2010).

3.4.5 Residual Resistance Factor

The permeability reduction or residual resistance factor (R_k) is a parameter that estimates the decrease of permeability after injecting polymer solution (Hidayat, W., et al., 2019). It is the ratio of initial water permeability (k_w) to water permeability after polymer flooding (k_p) (Pancharoen, M., et al., 2010). Residual resistance factor is controlled by many factors, such as type of the polymer, the molecular weight, shear rate, the degree of hydrolysis etc. Residual resistance factor is given by:

$$R_k = \frac{(k_w)_{before}}{(k_w)_{after}} \tag{3.1}$$

It was observed that concentration of polymer solution has considerable effect on permeability reduction (higher than 1500 ppm) (Pancharoen, M., et al., 2010).

3.4.6 Inaccessible Pore Volume

The physical phenomena of “Inaccessible pore volume” (IPV) was investigated for the first time by Dawson and Lantz (Dawson, R., et al.,1972). IPV depicts the process during which polymer solutions are unable to contact all pores because polymer molecules have much greater size than pore throats (Pancharoen, M., 2010). The part of the pore volume which is not accessed by polymer solution can be defined as inaccessible PV (Green, D., 1998).

3.5 Polymer implementation

Polymer flooding is a mature EOR technology. Up until now, more than 865 polymer flooding projects have been conducted all over the world. The cost of polymer flooding projects is much lower compared to SP and ASP flooding (Guo, H., 2017). Historically polymers were implemented for three main reasons (Bradley, D., 1987):

- They were utilized as a treatment in near-well regions for improving productivity of water injection or production wells with high level of water cut, by sealing off high-conductivity zones;
- Other than that, they were implemented as agents for crosslinking in-situ to block high conductive zones at a depth.
- Another reason of implementation is mobility control

First commercial use of polymer flooding on a large scale was in the Daqing field of China. The incremental oil recovery in the Daqing field increased up to 12 % OOIP. By injecting a viscous polymer solution at Daqing it was possible to reduce the endpoint mobility ratio from unfavorable (9.4) to favorable one (0.3). Several projects in China used high viscosity slugs previous to regular polymer flooding with the aim of correcting reservoir heterogeneities (Romero-Zerón L., 2016. There are various large-scale ongoing projects of polymer flooding in the Pelican Lake and Cactus Lake in Canada, Patos Marinza in Albania, Diadema in

Argentina, Marmul in Oman and Mangala in India (Delamaide, E., 2018). During recent years of polymer injection in heavy oil reservoirs Canadian operators have learned a lot of lessons. Canadian oilfields where polymer injection was implemented are numerous, including Pelican Lake, Mooney, Seal, etc. Incremental oil recovery for these fields accounted for 10-25%, 10%, 9% change, respectively. The main purpose of these projects was to improve recovery in heavy oils by injecting polymer solution. The first successful implementation of polymer flooding in heavy oils was in Pelican Lake field. Originally polymer flooding was not considered as a viable technology in highly viscous oil reservoirs. This was true until it was utilized in combination with horizontal wells. Before that time, and even these days, standard screening criteria for polymer injection limit its application to light and medium oils with viscosities up to 150 cp. In Pelican Lake, field viscosity of oil is 1000-2500 cp. Nevertheless, polymer flooding in the Pelican Lake proved to be successful with an additional 25% of incremental oil and low water cut (Delamaide, et al., 2014). Recently, the number of polymer flooding projects has increased in Europe and the Middle East. For instance, in the Bocksted oil field in Germany, schizophyllan biopolymers were injected for recovery improvement. Several polymer flooding projects were conducted in the North Sea, Eastern Europe, Russia and Kazakhstan (Romero-Zerón L., 2016).

Furthermore, there are many polymer injection projects in South America, including polymer flooding in Argentina, Suriname, Brazil and Venezuela. Interestingly, the Sarah Maria field in Suriname contains a heterogeneous sandstone formation with the permeabilities of several Darcys. In this field, reservoir fractures were utilized in order to increase the injectivity of polymer solution (Romero-Zerón L., 2016). Polymer flooding in this field began in 2008. The results of this project have proven that the process can recover incremental oil of 5.9-20.5% STOOIP (Delamaide, 2016). In Brazil, application of polymer started in the 1970s after primary production in the field Carmopolis. Outcomes of the project have revealed that there was an increase by 5 % in OOIP. A couple decades later, the research was reinitiated in three more onshore fields in the northeast of Brazil. Contrary to the previous project, outcomes of this one were demonstrating splendid results with higher oil recovery, water reduction, and lower incremental oil cost. More importantly, the best result was achieved with the lowest pore volume injected (0.1 PV) and the lowest mass (1000 ppm Vp) (da Silva, et al., 2017). Another case of implementing polymer flooding in mature oil fields with high levels of water cuts (up to 90 %) is Palogrande Cebu in Columbia. Pilot testing started in 2015 and resulted in an increase of incremental oil recovery and reduction of water cuts of up to 10 %. The results of this test have proven that polymer flooding can be efficient in a field that was waterflooded for more than 30 years (Pérez, et al., 2017).

Pilot testing in the mature oilfield Diadema in Argentina has shown appealing results with an increase in oil production by 100% and decrease in water production by 50 % in central wells. The reservoir is characterized by high permeability (an average of 500 md), high heterogeneity (10 – 5000 md), high porosity (30%), and oil viscosities of 100 cp. Prior to polymer injection, the reservoir was under waterflooding. During waterflooding, mobility ratio was very unfavorable leading to viscous fingering and severe channeling. Also, early water breakthrough increased water cut up to 97.5%. By injecting a polymer solution, it was possible to decrease mobility ratio to 5, which resulted in improvement of areal and volumetric sweep efficiency, and after 5 years of polymer injection, water cut decreased to 83 %. Results of this test showed that polymer flooding projects can be very efficient in previously waterflooded mature reservoirs (Wilson, 2014).

So, it can be seen that polymer flooding projects have been successfully implemented all over the world and have widened application to low permeability and highly viscous oil reservoirs. Nevertheless, application of polymer flooding is still restrained in high temperature, offshore and carbonate fields. The majority of polymer flooding projects were applied in onshore sandstone formation.

3.6 Modeling and Simulation of Polymer Flooding

In 1968, Zeito introduced a 3D numerical simulator for modeling polymer injection in homogeneous and heterogeneous formations. In this model, miscibility of the polymer with water was designed. The results of this study have illustrated that vertical sweep efficiency was greater for polymer flooding compared to waterflooding scenarios, even for cases with high permeability difference in the reservoir at the excessive water production stage. In 1969, comprehensive review of 61 polymer flooding projects was conducted by Jewett and Shurz. On the basis of their studies, they proposed two-dimensional (2D), two phase simulators that can mimic linear and five-spot patterns. In their model, the fluid displacement process was governed by the Buckley-Leverett equation. Later, the concept of polymer influence on the water mobility reduction was considered in the simulator developed in 1970 by Slater and Faroq-Ali. They proved that by using both numerical and experimental approaches, polymers can increase areal sweep efficiency, particularly in cases with highly unfavorable mobility ratios.

In 1972, a group of researchers including Bondor and Hirasaki, and thereafter in 1974 Hirasaki and Pope, proposed mathematical models where polymer was designed as a completely miscible component of the aqueous phase. The effects of polymer onto rock surface, such as adsorption, and permeability reduction, were included in the developed model. Additionally, rheological behavior of the polymer solution was modified by using Blake-Kozeny model for non-Newtonian fluids (Pope, 1980). Vela et al. (1976) described a simulator that accounted for the effects of polymer retention, inaccessible pore volume, polymer shear degradation and salinity on oil recovery. In 1987, Scott et al., introduced a new chemical flood simulator for modeling surfactant and polymer flooding processes where they included the effects of adsorption, injectivity, and temperature. During 1970s to 1980s, Exxon evaluated surfactant/polymer project by utilizing reservoir simulators in several fields such as Louden (Pursley, S. A.et al.,1973) and West Yellow Creek field (Holstein, E.,1981) in the United States, and Pembina field (Groeneveld, H., 1977) in Canada. In 1992, Masuda et al. accounted for the viscoelasticity effect for polymer flooding in their 1D simulator. The results of this study highlighted that viscoelastic effects of polymer solution contribute to the oil recovery.

In 2013, Gourdazi et al. assessed the use of different simulators including UTCHEM, CMG-STARS (Computer Modeling Group Ltd, 2013), ECLIPSE (Schulmberger, 2010) for modeling chemical enhanced oil recovery operations. Polymer modules of these simulators account for basic functions: polymer viscosity as a function of concentration and shear rate, adsorption, inaccessible pore volume, salinity effects and etc. Nowadays with these sophisticated reservoir simulators, it is possible to model complex chemical flood processes such as surfactant-polymer, alkaline-polymer, and alkaline-surfactant-polymer.

In 2018 Fernandes et al. conducted a large-scale reservoir simulation of polymer and surfactant flooding for 4 oil reservoirs using commercial reservoir simulator UTHCHEM. More than 3 million grid blocks were used for model development. The polymer module considered adsorption, shear thinning, salinity effects and others effects. The results for polymer simulation demonstrated that the polymer flood had good sweep efficiency, and there was a 10 % increase in cumulative oil recovery compared to waterflooding scenario. Additionally, optimization of polymer flooding by reservoir simulation was conducted by a group of researchers in the same year. A synthetic but realistic model was generated using real data that reflected geological heterogeneities and uncertainties. Results of this study demonstrated that it is better to inject polymer solution as early as possible. It is noteworthy that optimized polymer flooding can gain an additional NPV of $300 million compared to optimized waterflood (Ibiam, 2018).

4. Description of the field

4.1 Field A (Case Study)

The field of interest is a well-known giant oil field situated in Western Kazakhstan, having 6 oil bearing formations with 1 billion barrels of recoverable oil. The field A was discovered in 1970s with productive zones distributed between 360 and 2200 m (Sparke et al, 2005). The field has anticlinal structure with extension around 40 km by 10 km and covers the area of 250 km^2 (61776 ac.). Structure of the field can be seen in the Fig. 4.2.

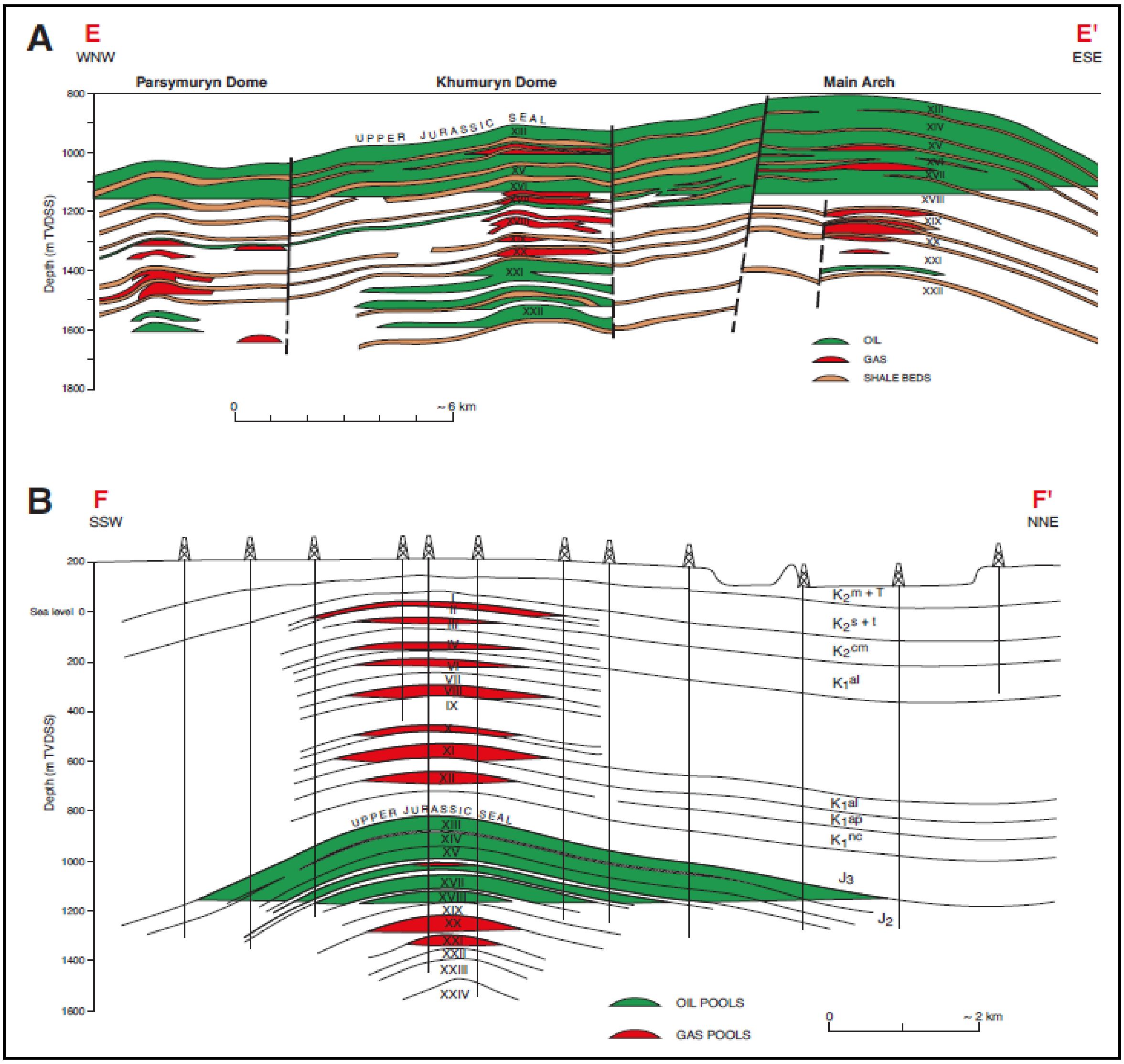


Figure 4. 1. Structural section over the Field A anticline showing the distribution of oil and gas (Field Evaluation Report, 2011)

Initially, estimated original oil in place is around 8000 million barrels (Sparke et al, 2005). Original reservoir pressure is around 155 – 185 bars and reservoir temperature 55-70℃, with production distributed between 25 layers. Permeability of the field varies from 0.2-1 D, porosity varies from 21-25 %. Reservoir rock is mainly sandstones and siltstone with high clay content (Ulmishek, 1981). Reservoir units consist from separate layers with very poor vertical conductivity. Layers 1- 13 are located at depths of 180-900 m. They mainly contain sandstone and siltstone with porosities 26-34 %, and permeabilities of 200-600 md. The thickness of these horizons varies 10-50 m. However, the main accumulation of the hydrocarbon reserves is at the layers below. Underlying strata thickness varies from 30 – 60 m. Pools of these layers have a common oil water contact at the depths of 1124 - 1150 m. Among all of the horizons the 14th horizon has the greatest thickness with average thickness of 60 m. The average thickness of the other underlying three layers varies from 30-50 m. All of the horizons together make up a 310 m pool (Ulmishek, 1981). The reservoir is under a weak edge water drive and had an early water breakthrough. The field has more than 7600 wells drilled and long-term production history (Fig. 4.1). Different technologies were implemented during production life of the field, including cool water injection in the 1970s which hindered production by plugging low permeable layers, due to paraffin precipitation. Other methods include hot water injection and surfactant flooding. From the late 1990s and subsequent years, modified water injection techniques, injection of the hot water for eliminating wax content from wellbore, sucker rod pumps and drilling of new wells were utilized for production optimization (Field evaluation report, 2010). Field characteristics can be seen in the Table 4.1.

Table 4. 1. Field Characteristics

Reservoir temperature	122 °F at 1055 m TVD
Original reservoir pressure	1624 psi at 1055 m TVD
Aquifer pressure gradient	0.39 psi/ft
Water salinity	120000-165000 ppm
Natural drive mechanism	Weak edge-aquifer, solution-gas, and minor gas-cap expansion drives
Secondary recovery method	Water injection (hot water from 1973)
Tertiary recovery method	Surfactant and electric discharge treatment
Improved recovery method	Revised water injection schemes; optimization of pump units
Recovery factor	33% (estimated by C&C)
Production well spacing	10-20 ac (660-993 ft)
Injection rate	252000 BWPD (1996)
Gross reservoir thickness	All 1-6 layers: 310 m, individual layers: 35 - 60 m

4.2 Production history of the Field A

Cool water injection for pressure maintenance started in 1970th. However, due to problems with water supply, hot water injection was applied only in 1975 (Bedrikovetsky, 1997). Production of the field peaked in 1975 reaching 320000 bopd, followed by sharp reduction in oil production. During 1980-1990 there was a slow increase in water cut, and production level was kept the same for a few more years. In 1990s 2.8 million tons was produced; water cut was 0.654 with recovery factor 0.446. In 1996 it decreased to 50000 bopd. In 2000s production decreased to 2.6 million tons, water cut was 0.7 with recovery factor 0.48. (Sparke, 2005). Because of the inefficiency of waterflooding, a rehabilitation programme was established after 2000, and thereafter, there has been an improvement in oil production (Sparke, 2005). Production of the field was facing considerable difficulties because of the oil properties, reservoir characteristics and employed waterflooding regime. After implementing modified water injection techniques, it was possible to increase production up to 132000 bopd. However, it is significant to note that levels of the water cut remained high and some wells produced water cuts up to 90 % (Field Evaluation Report, 2010).

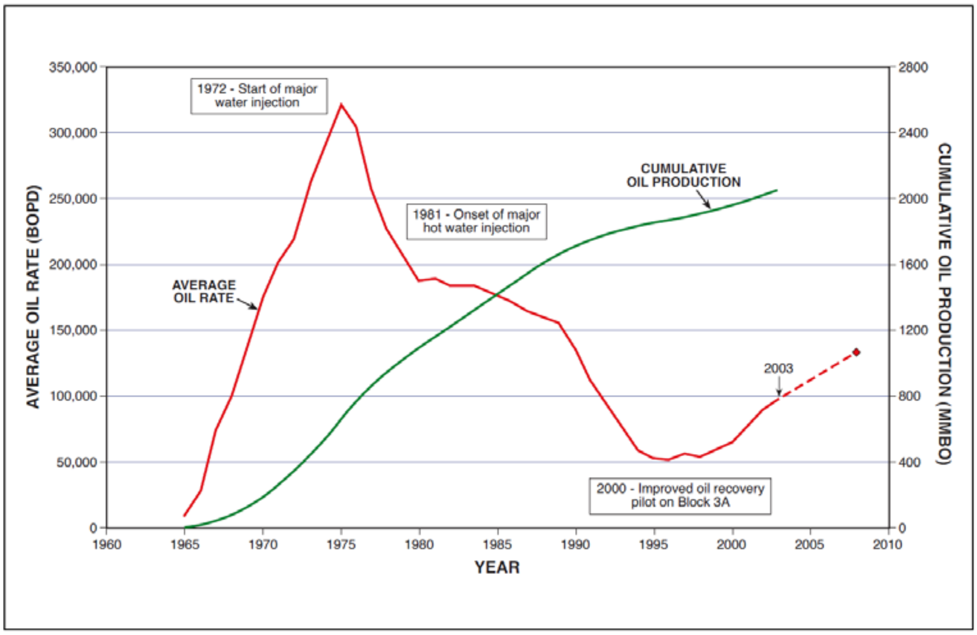


Figure 4. 2. Production history of Field A 1965 – 2008 (modified from Sparke et al., 2005, EIA, 2009)

4.3 Fluid properties

Density of the crude oil varies from 0,763-0,777 g/cm^3, and the density of the dead oil is around 0,85 g/cm^3. Oil of the field is characterized by methane-series hydrocarbons, by huge tar (10 – 21 %) and paraffin (around 28%) and low concentration of sulfur (0,1-0,24%). Oil viscosity in-situ is around 3,2 - 4,2 cp. Hydrocarbon composition, and fluid properties by hyrozon can be seen in the tables 4.2 and 4.3.

Table 4. 2. Hydrocarbon composition

API gravity	33-36.5°
Viscosity	3.2-4.2 cp at reservoir conditions
Sulphur content	0.1 - 0.24 wt%
Wax content	7 - 20 wt%
Gas gravity	0.59 - 0.96
Gas content	80 - 92% C_1; 1.8 – 7.6% N_2; 0.12 – 2.0% CO_2; no H_2S
Initial GOR	405-478 SCF/STB
FVF	1.2 RB/STB
Saturation pressure	Bubble point: 1067-1579 psi

Table 4. 3. Reservoir pressure and fluid properties by the year of 2005

Horizon	Date	Reservoir Pressure, (MPa)	Bubble point pressure weighted average, (MPa)	Reservoir Temperature	Oil formation volume factor	Density g/sm3	Viscosity (cp)
XIII	Initial	10.44	7.65	57.4	1.1950	0.7730	4.24
	1987		7.20		-	0.7960	4.70
	01.01.05		5.90		1.1680	0.7810	4.51
XIV	Initial	10.89	9.17	60.4	1.1900	0.7710	3.20
	1987		7.80		-	0.7870	3.20
	01.01.05		6.80		1.1449	0.7869	3.58
XV	Initial	11.26	10.05	63.1	1.2100	0.7627	3.17
	1987		8.00		-	0.7800	3.70
	01.01.05		7.50		1.1830	0.7746	3.85
XVI	Initial	11.72	10.12	65.2	1.2000	0.7658	3.49
	1987		8.20			0.7850	3.80
	01.01.05		7.60		1.1700	0.7946	3.96
XVII	Initial	12.08	10.36	67	1.1900	0.7696	3.89
	1987		8.30		-	0.7900	4.00
	01.01.05		7.59		1.1589	0.7959	4.28
XVIII	Initial	12.46	11.29	-	1.200	0.7700	3.60
	1987		9.20		-	0.7870	3.90
	01.01.05		8.20		1.153	0.7796	4.21

(Mullayev, 2016)

5. Methodology

5.1 Methodology phases

In order to investigate the effect of water-soluble polymers on the efficiency of the oil recovery and find optimum flooding conditions, it was necessary to carry out three phases of the research:

Phase 1: Develop the sector of the reservoir as close to the real field as possible using CMG STARS (Computer Modeling Group Ltd, 2018), by inputting the data available in the literature

Phase 2: Study and test the efficiency of water flood and polymer flood scenarios on the developed model

Phase 3: Investigate the oil and water cut levels and the recovery factors

5.2 Model Development

5.2.1 General Description of the Simulator

Successful simulation of any model requires profound understanding of the simulator and ways it functions. CMG STARS simulator operates using keywords, and for the purpose of conducting this research it was important to understand which keywords are utilized for modeling polymer and its rheological behavior. CMG STARS is a three phase multi-component thermal and steam additive simulator. The version used for this study is 2018. It allows us to model two-dimensional, and three-dimensional configurations. It supports Cartesian, cylindrical, and variable depth/variable thickness coordinate systems (STARS User's Guide). In the polymer module of stars, it is possible to model Viscosity vs Polymer Concentration, Viscosity vs Shear Rate, Adsorption, Permeability Reduction, Inaccessible Pore Volume and Effect of Salinity on Viscosity.

5.2.2 Synthetic Field Model

Since the field under the study is a giant oil field, for the purpose of conducting this research, a small section of the reservoir from 13-18 was selected and modeled (Fig. 5.1). Simulations were run in this heterogeneous reservoir by using a Cartesian coordinate system with 30 × 30× 7 grid blocks. The total number of grid blocks is 6300. The area of the reservoir is 900 m^2. The reservoir was modeled to have porosity distribution between 18-26%, as shown in Fig. 7.1, Table 7.1, and heterogeneous permeability distribution from 88-250 mD presented in Fig. 7.2, 7.3. The reservoir pore volume is $3.94 \times 10^6 m^3$ and original oil in place $2.11 \times 10^6 m^3$.

Relative permeabilities are different for each layer and represented in Fig. 5.2. The fluid represents light-oil reservoir properties. For modeling fluid composition a black oil model has been used. Oil and water viscosities are 4.2 and 0.6 cP, respectively. Oil and water densities are equal to 773 and 1100 kg/m^3, respectively. Capillary pressure is neglected, and relative permeability curves are generated using the data available in the literature. Relative permeability data is represented in Table 5.1. Simulations were run for a period of 70 years with a 1 - month timestep. Input data for simulation study such as reservoir temperature, pressures were acquired from the data available in the literature and presented in the Table 4.3.

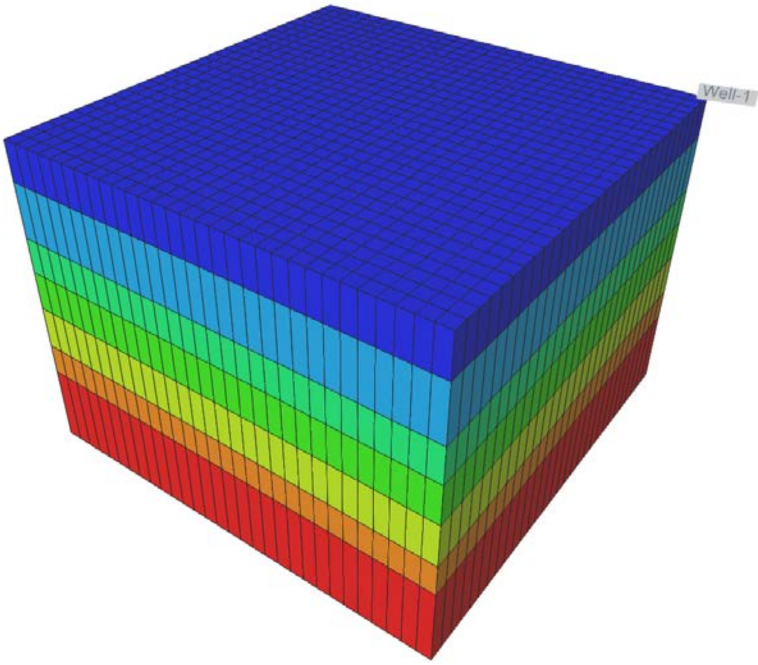


Figure 5. 1. Synthetic model

5.2.3 Modeling Aquifer

Initial Pressure of the aquifer is 13.5 MPa. Aquifer thickness = 100 m. Aquifer was set at the depth of 1150 m to match real field geological structure. As can be seen in the depth - structure map of the field given in the Appendix (Fig. 7.5) OWC level occurs at the depth of 1130 m. Aquifer location is shown in Table 7.5.

5.2.4 Well Model

In the CMG launcher, different operating options for modeling injection and production wells are available, i.e. constant production rate, constant bottomhole pressure. The producers are pressure constrained and operate with bottomhole pressure of 8000 kPa. Injectors are rate constrained and operate with the rate of 100 m^3/day. Well properties and operating constraints are demonstrated in Table 7.4.

5.2.5 Degradation

CMG stars require at least 2 parameters to model polymer degradation including reaction activation energy and the frequency factor. Frequency factor and activation energy were assumed to be 360000, 75000 J/gmole. Polymer half-life time were also considered in the model and assumed to be 1040 days.

5.2.6 Relative Permeability Model

Relative permeability curves and related parameters are by far the most important petrophysical characteristics for conducting EOR operations. Relative permeability data used for the model development was constructed via generalized correlations, given by eq. 5.1, 5.2, 5.3 in the simulator and entered using tables. For each layer different relative permeability curves were modeled. Parameters for generating different rock types are shown in the table below.

Table 5. 1. Table of parameters of oil/water relative permeability parameter

Parameters of oil/water relative permeability parameter	Layer 1	Layer 2	Layer 3	Layer 4	Layer 5	Layer 6
Endpoint relative permeability to water	0.29	0.28	0.31	0.32	0.26	0.25
Endpoint relative permeability to oil	0.34	0.33	0.36	0.4	0.32	0.35
Residual oil saturation, S_{or}	0.34	0.33	0.36	0.4	0.32	0.35
Kro at connate water	1	1	1	1	1	1
Krw at irreducible oil	0.12	0.9	0.64	0.82	0.28	0.27

Generalized equations for predicting relative permeability in sandstone and conglomerate set in stars are equations developed by Honarpour for water displacement of for water oil sytems (Honarpour et al., 1986):

$$k_{rw} = \frac{(S_w - S_{wi})}{(1 - Sw_i - So_{rw})} - 0.010874 \times \left[\frac{(S_w - S_{orw})}{(1 - S_{wi} - S_{orw})}\right]^{2.9} + 0.56556(S_w)^{3.6}(S_w - S_{wi}) \ (water\ wet) \tag{5.1}$$

$$k_{rw} = 1.5814\left[\frac{S_w - S_{wi}}{1 - S_{wi}}\right]^{1.91} - 0.58617\frac{(S_w - S_{orw})}{(1 - S_{wi} - S_{orw})} \times (S_w - S_{wi}) - 1.2484\varphi(1 - S_{wi})(S_w - S_{wi}) \text{ (Intermediately wet)} \tag{5.2}$$

$$k_{row} = 0.76067\left[\frac{\left(\frac{S_o}{1 - S_{wi}}\right) - S_{or}}{(1 - S_{orw})}\right]^{1.8} \times \left[\frac{S_o - S_{orw}}{1 - S_{wi} - S_{orw}}\right]^2 + 2.6318\varphi(1 - S_{orw})(S_o - S_{orw}) \text{ (any wettability)} \tag{5.3}$$

Relative permeability curves generated for each layer are shown in the Fig. 5.2.

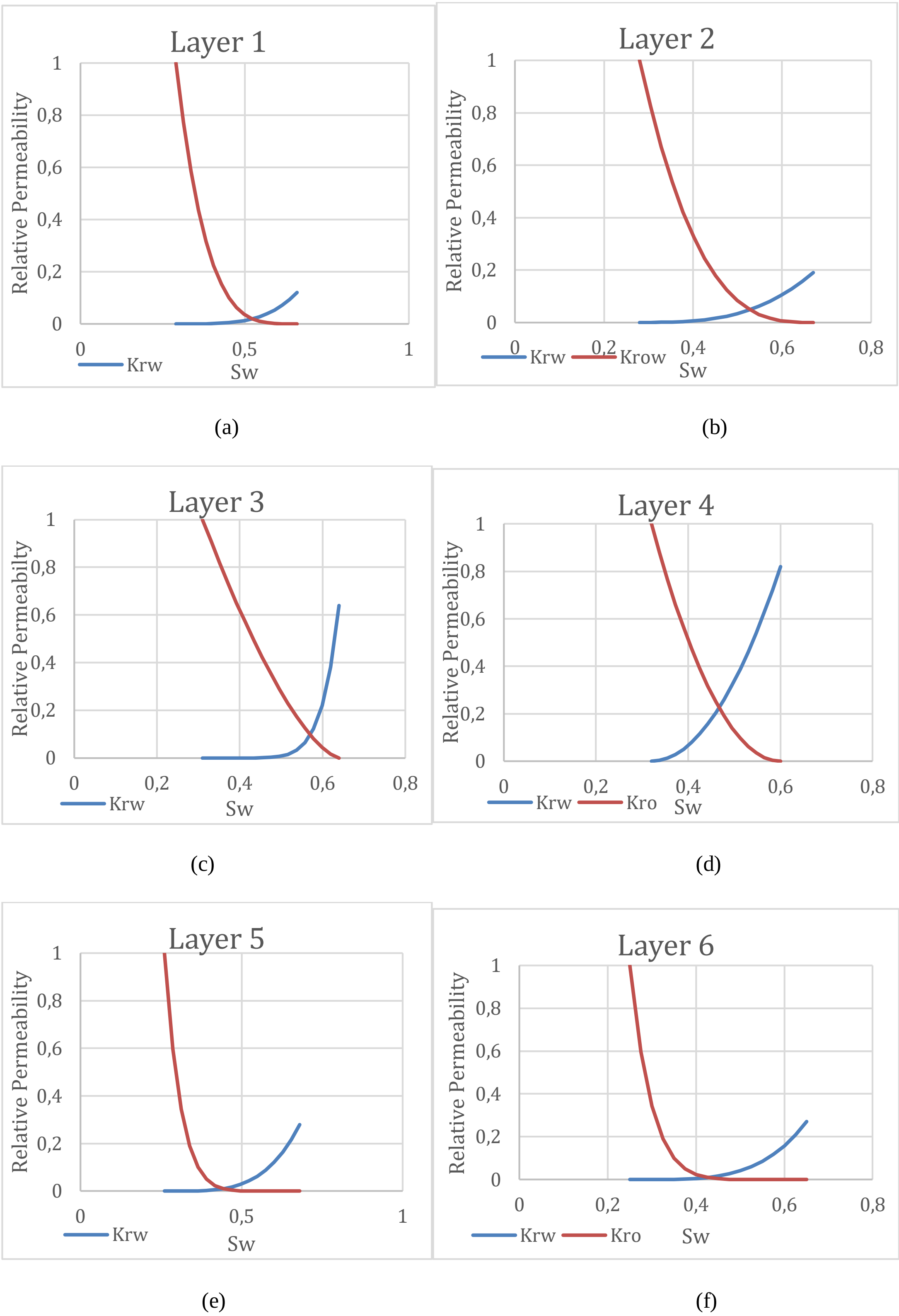


Figure 5. 2. Relative Permeability Curves: (a) – relative permeability for layer 1, (b) – relative permeability for layer 2, (c) – relative permeability for layer 3, (d) – relative permeability for layer 4, (e) – relative permeability for layer 5, (f) – relative permeability for layer 6

5.2.7 Polymer Module

Polymer flood simulation was accomplished by the process wizard section in CMG simulator. When polymer flows through porous media, it adsorbs onto the rock surface and reduces the effectiveness of chemical flooding (Sorbie, 1991). The module includes adsorption on rock surface, inaccessible pore volume. For modeling polymer flooding, the following assumptions were made:

- Isothermal condition
- The adsorption of polymer on rock surface is 0.5 gmole/m^3
- Polymer resistance factor 5

Shear thinning behavior was modeled by power law model $\mu = K\gamma^{n-1}$ using fitting parameters and represented in Table 5.2.

Table 5. 2. Viscosity as a function of Shear Rate

Shear Rate 1/S	Slug viscoisity (cp)		
	3000 ppm Polymer	2000 ppm Polymer	1000 ppm Polymer
1	32.4	14.2	3.4
5	22.73	9.66	3.27
10	25.6	11.2	3.4
15	17.46	8.01	3.13
50	13.08	6.53	2.98
70	12.06	6.17	2.94
100	10.5	6.6	2.8

5.3 Simulation of natural reservoir depletion

In this study, the section of 7 horizons of the field were modeled in three dimensions using 7 overlaying layers. A Cartesian grid system was used to demonstrate reservoir formations. In the first case, oil is produced by naturally occurring pressure in the reservoir with aquifer support. (Primary Production). Grid blocks were set as follows:

Table 5. 3. Input parameters

Grid Type	Cartesian
I direction	30
J direction	30
K direction	7

From the Fig. 5.3 it can be seen that water cut starts rise almost from the beginning of the production, which matches actual field history data.

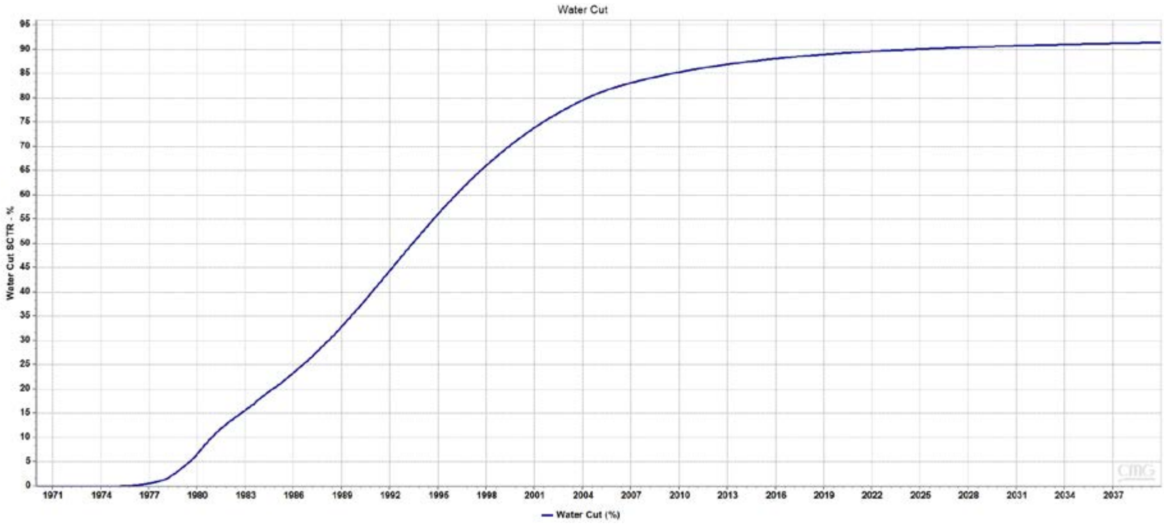


Figure 5. 3. Water Cut vs Time of the Model

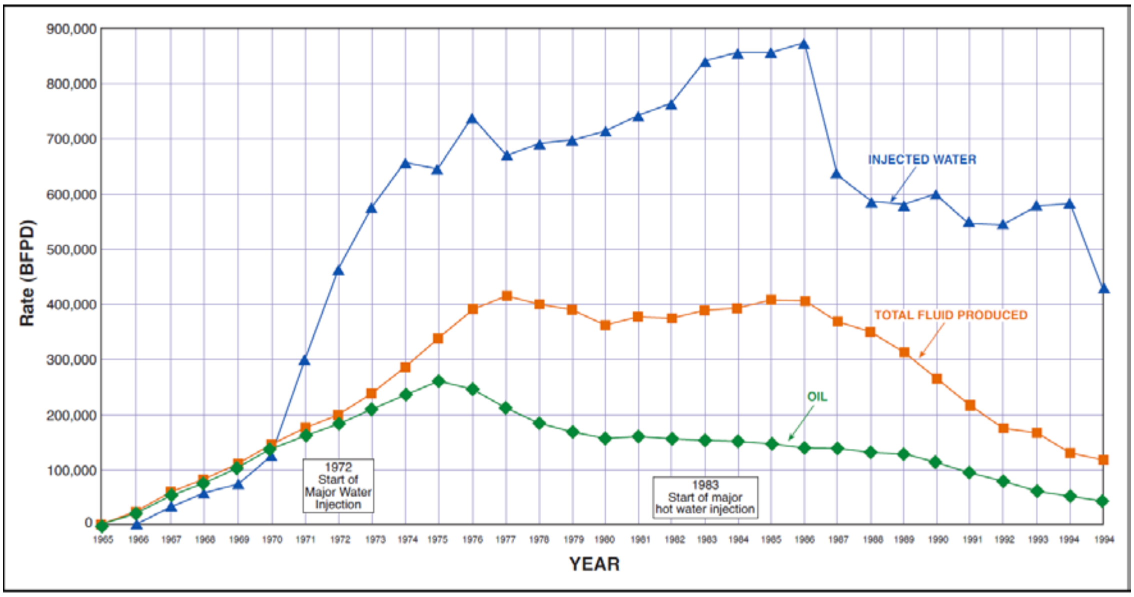


Figure 5. 4. Production history of the field (Field Evaluation Report, 2011)

In this study, by the means of primary production, it is possible to recover around 15,3 % of original oil in place. The data for primary production simulation was used for history matching.

5.4 Simulation of waterflooding

Waterflooding was simulated before attempting polymer flooding simulation to better understand the simulator. The waterflooding case scenario was performed in a quarter 5-spot pattern with the model of 1 injector and 1 producer. This method resulted in recovery of 32 % of the original oil in place, which is in the range of the normal waterflooding response as seen in Fig. 5.5. At the end of the waterflood it can be seen from the Fig. 5.6., that oil saturation is still high and in the range of 0.5 – 0.7, there is still a possibility to recover more oil. Possibility of application of polymer flooding for increasing oil recovery is discussed in the next chapter.

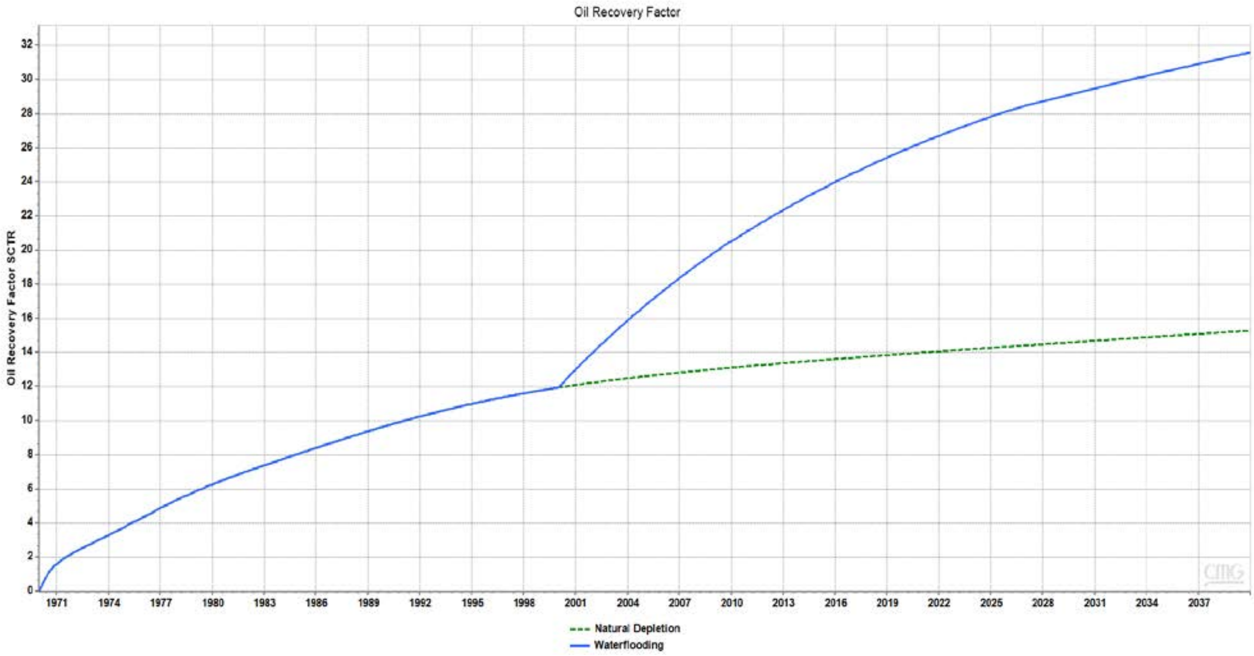


Figure 5. 5. Oil Recovery for Natural Depletion and Waterflooding

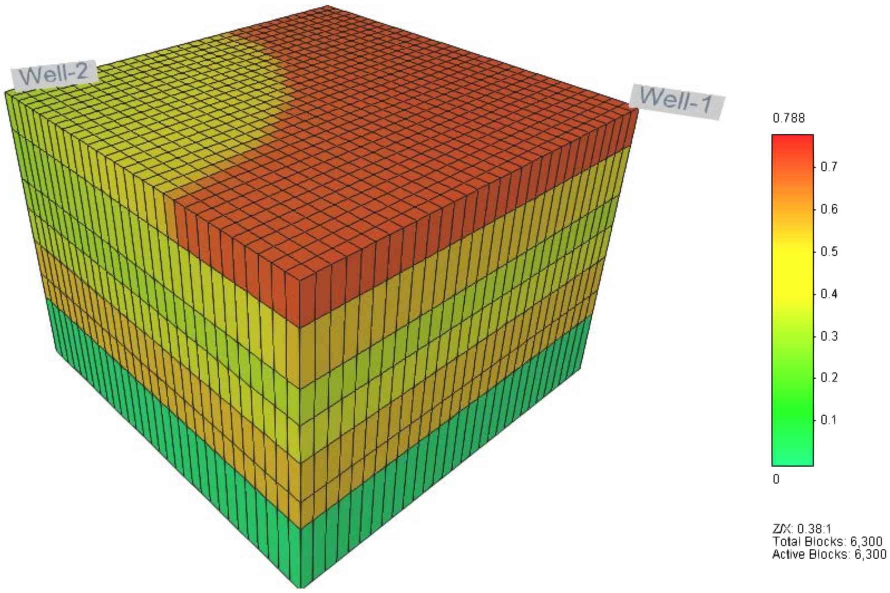


Figure 5. 6. End of waterflooding oil saturation

6. Simulation and Optimization of the Polymer Flooding

For the purpose of finding optimal reservoir development strategy three models with different polymer injection scenarios were tested. In the first test only polymer injection is simulated for multiple injection time durations. In the second test, polymer injection followed by water injection was simulated. The third test simulates the injection of water followed by polymer and later switching back to waterflooding again. The sequence of the different injection scenarios is presented in Table 6.2. All reservoir properties including but not limiting to porosity, permeability distribution, pressures, saturations and etc. were identical to the base case described in the model development part of the thesis. The simulation model has 1 production and 1 injection well. The injection rate of polymer and water was set 100 m^3/day. For finding the best-case scenario different factors were considered such as oil price, polymer cost, water cost and etc.

Table 6. 1. Sequence of injection scenarios

Test №	Sequence		
	Water	Polymer	Water
Test 1	-	+	-
Test 2	-	+	+
Test 3	+	+	+

6.1 Reservoir Simulation Results for Test 1

For the first test, where only polymer flooding is simulated, 7 different times of polymer injection initiation were selected and run in the reservoir simulator. Polymer flood injection rate was set up to 100 m^3/day. As can be seen from Fig. 6.1 it is possible to reach 42% of hydrocarbon recovery, if we initiate polymer injection in the years of 2005, 2010, 2015. As for the other four cases, it should be noted that the recovery factor is much lower and does not reach a plateau of production. The effect of polymer initiation time on recovery factor is presented in Table 6.2.

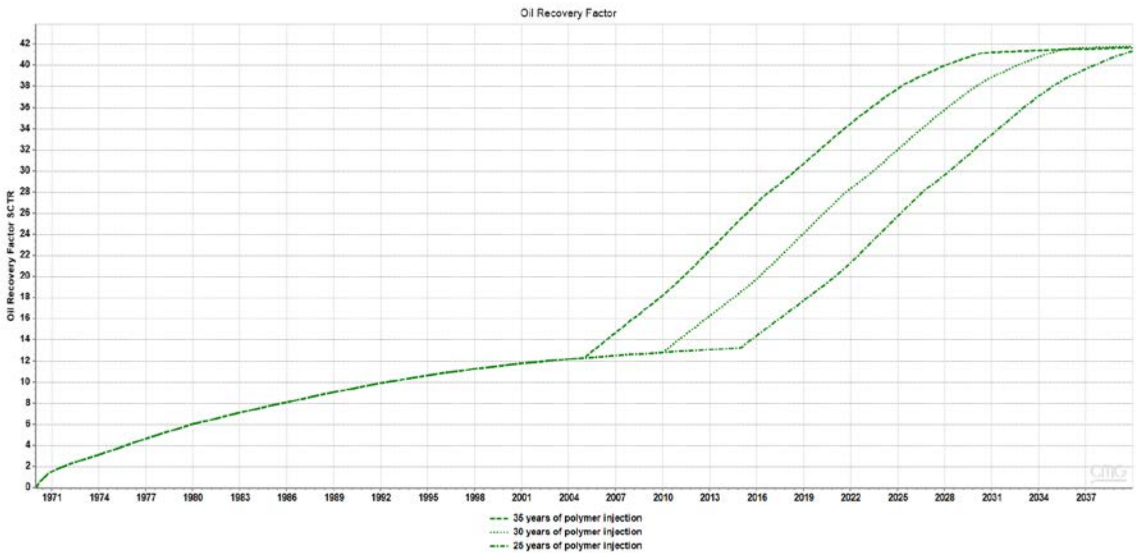


Figure 6. 1. Field oil recovery for the years of injection 2005, 2010, 2015

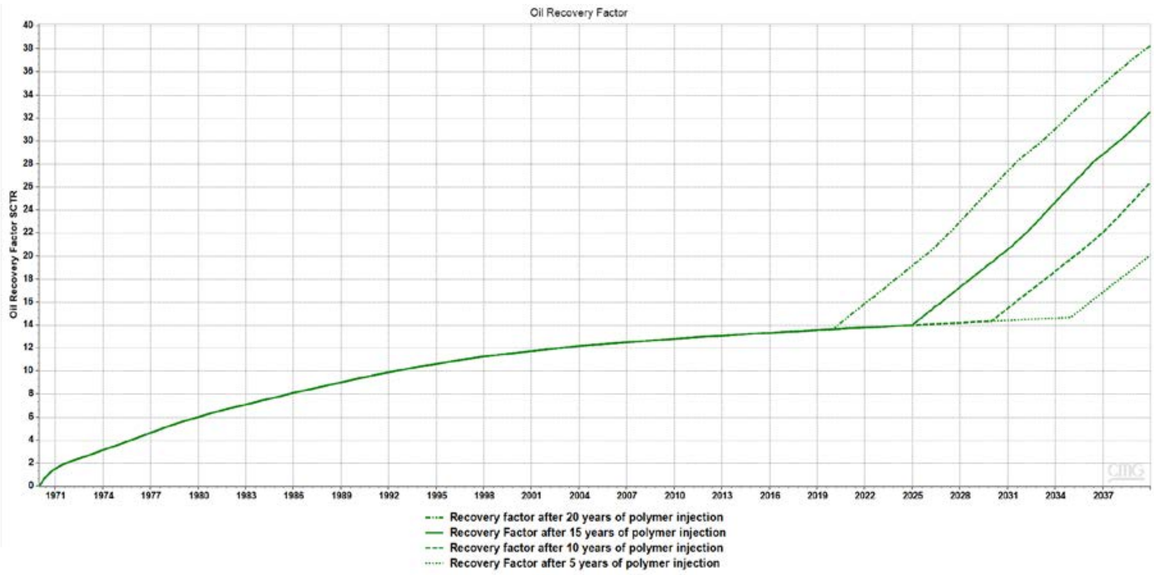


Figure 6. 2. Field oil recovery for the years of injection 2020, 2025, 2030, 2035

Table 6. 2. The effect of polymer on recovery factor

Polymer injection initiation year	Years of injection	Pore Volume of polymer injected	Ultimate Recovery Factor
2005	35 years of polymer injection	0.32	41.93 %
2010	30 years of polymer injection	0.27	41.80 %
2015	25 years of polymer injection	0.23	41.36 %
2020	20 years of polymer injection	0.19	38.29 %
2025	15 years of polymer injection	0.14	32.54 %
2030	10 years of polymer injection	0.09	26.34 %
2035	5 years of polymer injection	0.05	20.1 %

Oil saturation at the different times of polymer injection can be seen in the oil saturation map Fig. 6.3. Different colors in the oil saturation profile represent different oil saturations. In the Fig. 6.3 a, b, c all of the reservoir area contacted by the polymer is colored yellow and represents residual oil saturation. Residual oil saturation in the Fig. 6.3 a, b, c accounted for 0.36, 0.37, 0.38 respectively. In the Fig. 6.3 d, e, f, g it can be seen that not all of the area was swept by the polymer and it should be noted that the later the injection of the displacing fluid the lesser area is swept by the fluid.

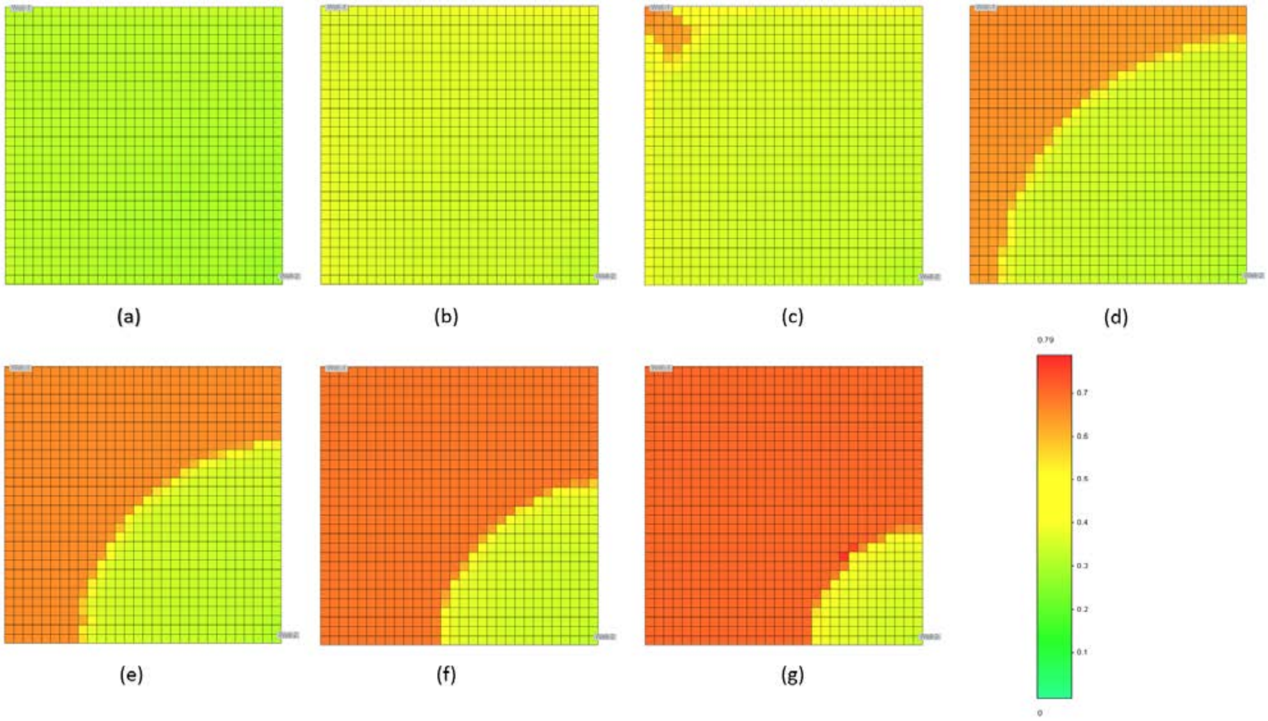


Figure 6. 3. Oil saturation at different Polymer Flood timing for layer 1: (a) – oil saturation after 35 years of polymer injection, (b) – oil saturation after 30 years of polymer injection, (c) – oil saturation after 25 years of polymer injection, (d) –oil saturation after 20 years of polymer injection, (e) – oil saturation after 15 years of polymer injection, (f) – oil saturation after 10 years of polymer injection, (g) – oil saturation after 5 years of polymer injection

As can be seen from the graphs Fig. 6.4 and Fig. 6.5 polymer injection timing and pore volumes injected play an important roles in the efficiency of the recovery factor. The three different starting times corresponding to 2005, 2010, 2015 have best recovery efficiency and accounted for 41.93 %, 41.80 %, 41.36 % respectively. The results of the simulation for other times suggested that injection of the polymer at the later stage of the production isn't a feasible strategy for improving oil recovery, since there is still a possibility of further increase of oil production which can't be achieved due to the time target of the project. From the results, it can be concluded that it is better to inject polymer for at least 25 years. Early injection of a polymer slug can have a significant effect on recovery factor, due to the propagation of the polymer solution. Compared with the process of polymer injection at the later stage of production, it has higher oil production and lower water cut, which determines the effectiveness of the polymer in decreasing mobility ratio and increasing ultimate oil recovery.

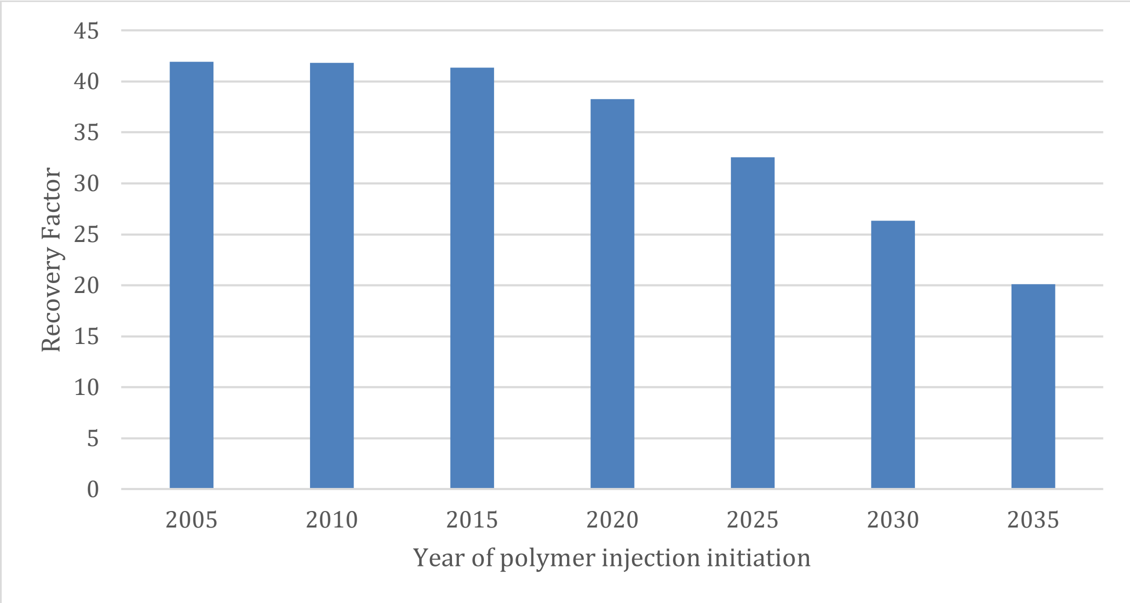


Figure 6. 4. Recovery Factor at different times of polymer injection

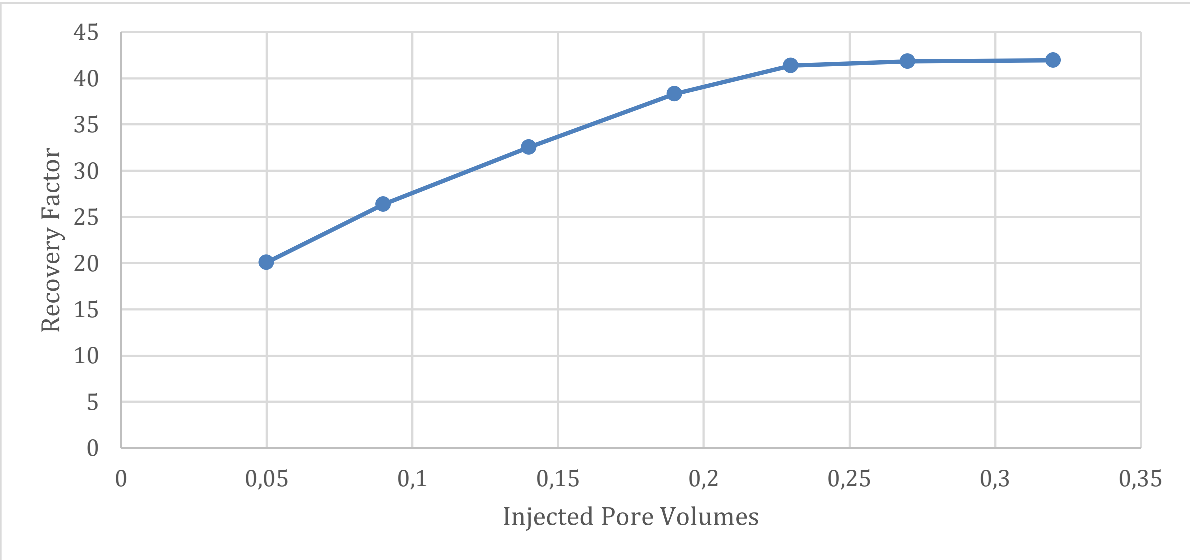


Figure 6. 5. Recovery Factor vs Pore Volume of Polymer Injected

6.2 Reservoir Simulation Results for Test 2

The main goal of this test was finding the best time for injection of polymer solution. For that purpose, 3 different starting times of polymer injection with various slug sizes were simulated. Each polymer slug was chased by water. The data obtained from the results was analyzed for two periods: one for the short-term, which is from 2000 to 2016, and one for a long-term from 2000 till 2040. This was done in order to investigate the effectiveness of polymer flood in a short and a long run. More detailed description of the simulation scenarios is presented in Table

6.4. Polymer initiation time, pore volumes of polymer and water injected, and the duration of polymer injection for the short period are presented in the Tables 6.5, 6.6, 6.7.

Table 6. 3. Model scenarios description

Case	Water/Polymer Solution injection scenarios	Project Lifetime
1	First case simulates 9 injection scenarios corresponding to 9 different time durations such as injection of polymer for 1 month, 3 months, 6 months, 1 year, 2 years, 3 years, 5 years, 10 years, 15 years. Each of these polymer slugs is injected at the year of 2000. After which the polymer was chased by water.	40 years
2	Second case simulates injection of polymer at the year of 2005. 9 injection scenarios corresponding to 9 different time durations including injection of polymer for 1 month, 3 months, 6 months, 1 year, 2 years, 3 years, 5 years, 10 years, 15 years. After which polymer is chased by water.	40 year
3	Third case simulates injection of different slugs of polymer at the year of 2010. Polymer was injected for 9 different time durations corresponding to 1 month, 3 months, 6 months, 1 year, 2 years, 3 years, 5 years, 10 years, 15 years. After which polymer is chased by water.	40 years

6.2.1 *Results of the short-term projects*

Table 6. 4. The effect of polymer on recovery factor for Case 1

Polymer injection initiation year	Duration of polymer injection	Pore Volume of polymer injected	Pore Volume of water injected	Recovery Factor (%)
2000	1 month	7.86×10^{-4}	0.147	41.76
	3 months	2.33×10^{-3}	0.146	41.76
	6 months	4.56×10^{-3}	0.144	41.76
	1 year	9.25×10^{-3}	0.139	41.76
	2 years	0.0185	0.129	41.76
	3 years	0.0278	0.12	41.76
	5 years	0.0463	0.102	41.76
	10 years	0.093	0.056	38.92
	15 years	0.139	9.25×10^{-3}	34.4

Table 6. 5. The effect of polymer on recovery factor for Case 2

Polymer injection initiation year	Duration of polymer injection	Pore Volume of polymer injected	Pore Volume of water injected	Recovery Factor (%)
2005	1 month	7.86×10^{-4}	0.099	38.06
	3 months	2.33×10^{-3}	0.098	38.06
	6 months	4.56×10^{-3}	0.096	38.06
	1 year	9.25×10^{-3}	0.091	36.68
	2 years	0.0185	0.082	36.21
	3 years	0.0278	0.073	35.73
	5 years	0.0463	0.054	33.5
	10 years	0.093	7.73×10^{-3}	28.05
	11 years	0.101	0	26.71

Table 6. 6. The effect of polymer on recovery factor for Case 3

Polymer injection initiation year	Duration of polymer injection	Pore Volume of polymer injected	Pore Volume of water injected	Recovery Factor (%)
2010	1 month	7.86×10^{-4}	0.053	27.24
	3 months	2.33×10^{-3}	0.051	27.24
	6 months	4.56×10^{-3}	0.049	26.55
	1 year	9.25×10^{-3}	0.044	25.58
	2 years	0.0185	0.035	24.47
	3 years	0.0278	0.026	21.19
	5 years	0.0463	0.00727	20.94
	6 years	0.056	0	20.05

From Fig.6.6 a, b, and c it can be seen that higher recovery factor can be acquired with injection of polymer at a shorter period. So that with the injection of polymer solution for 1, 2, 3 months with 7.86×10^{-4}, 2.33×10^{-3}, 4.56×10^{-3} PV, respectively, it is possible to achieve the RF of more than 40%. It is interesting to note that overall, there is a decreasing trend of the recovery with the increasing volume of polymer injection. Moreover, the year of polymer injection plays a major role in improvement of the recovery factor. The injection of the polymer at the earlier stages, such as 2000, can give higher recovery and reach almost 42 %, compared to the injection at the 2005 and 2010, which accounted for 38%, 27%, which is illustrated in Fig. 6.7 (a). Furthermore, the injection of the polymer for 3, 5 years slightly decreases recovery factor as indicated in Fig. 6.7 b, c.

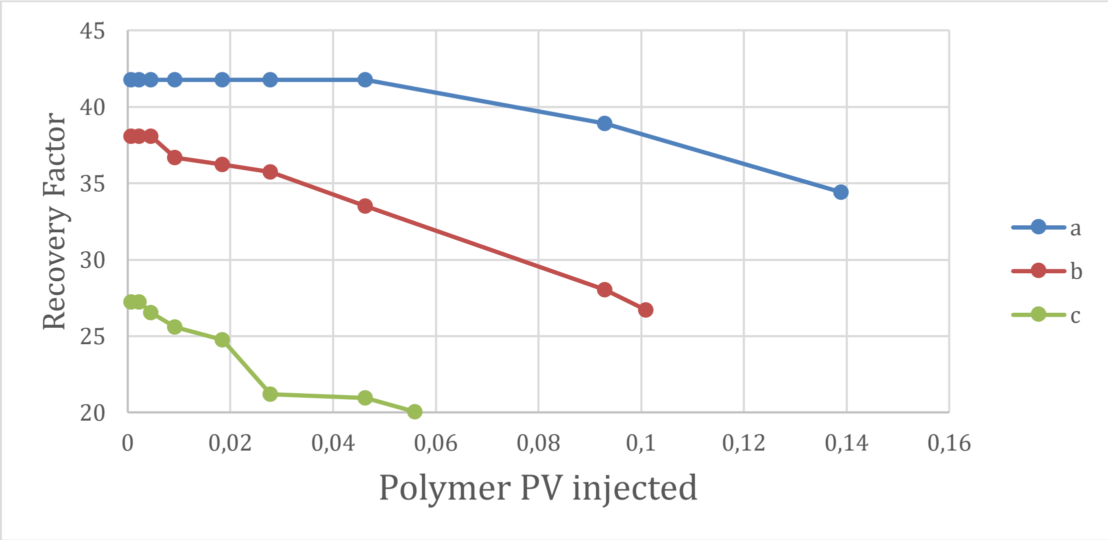
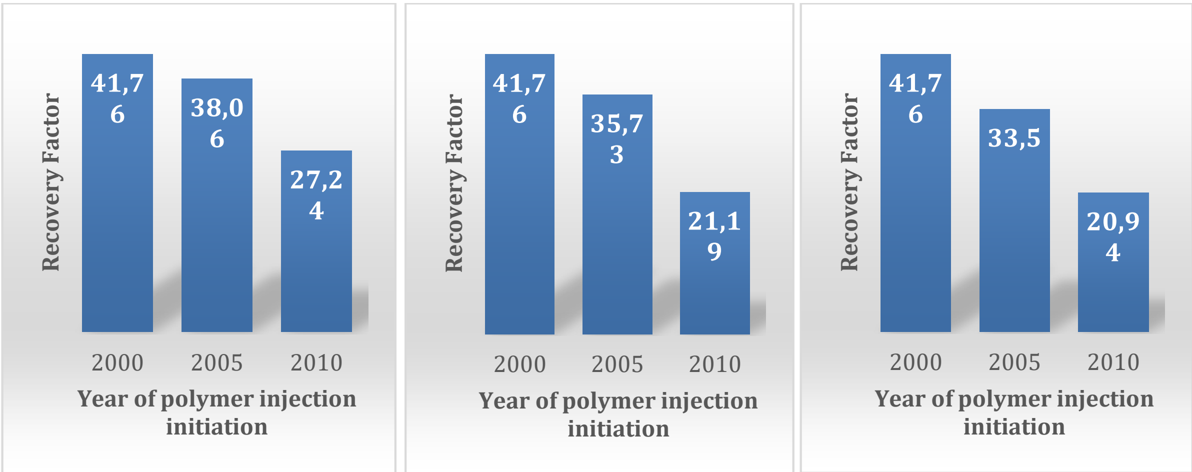


Figure 6. 6. Production performance as a function of pore volume injected: (a) - initiation of polymer injection at the year of 2000, (b) - initiation of polymer injection at the year of 2005, (c) - initiation of polymer injection at the year of 2010



(a) (b) (c)

Figure 6. 7. RF vs Polymer injection timing: (a) – polymer injection for one month at different starting times; (b) – polymer injection for 3 years at different starting times; (c) – polymer injection for 5 years at different starting times

As it was mentioned in the previous case, different colors in the oil saturation map (Fig.6.8) represent different oil saturation. Yellow and green colors indicate the values of oil saturation of 0.36 - 0.38. Orange and red colors represent oil saturation of 0.7 - 0.79. These results suggested that area contacted by the polymer solution gradually decreases with the injection of the more polymer pore volume. One of the reasons behind of this is polymer adsorption, resulting in permeability reduction. Another reason is that polymer solution becomes more viscous and propagates at a much slower pace. One more parameter, which is valid for polymer propagation is the year of polymer injection. As can be observed from the figures the later polymer is injected the less area can be contacted by the solution.

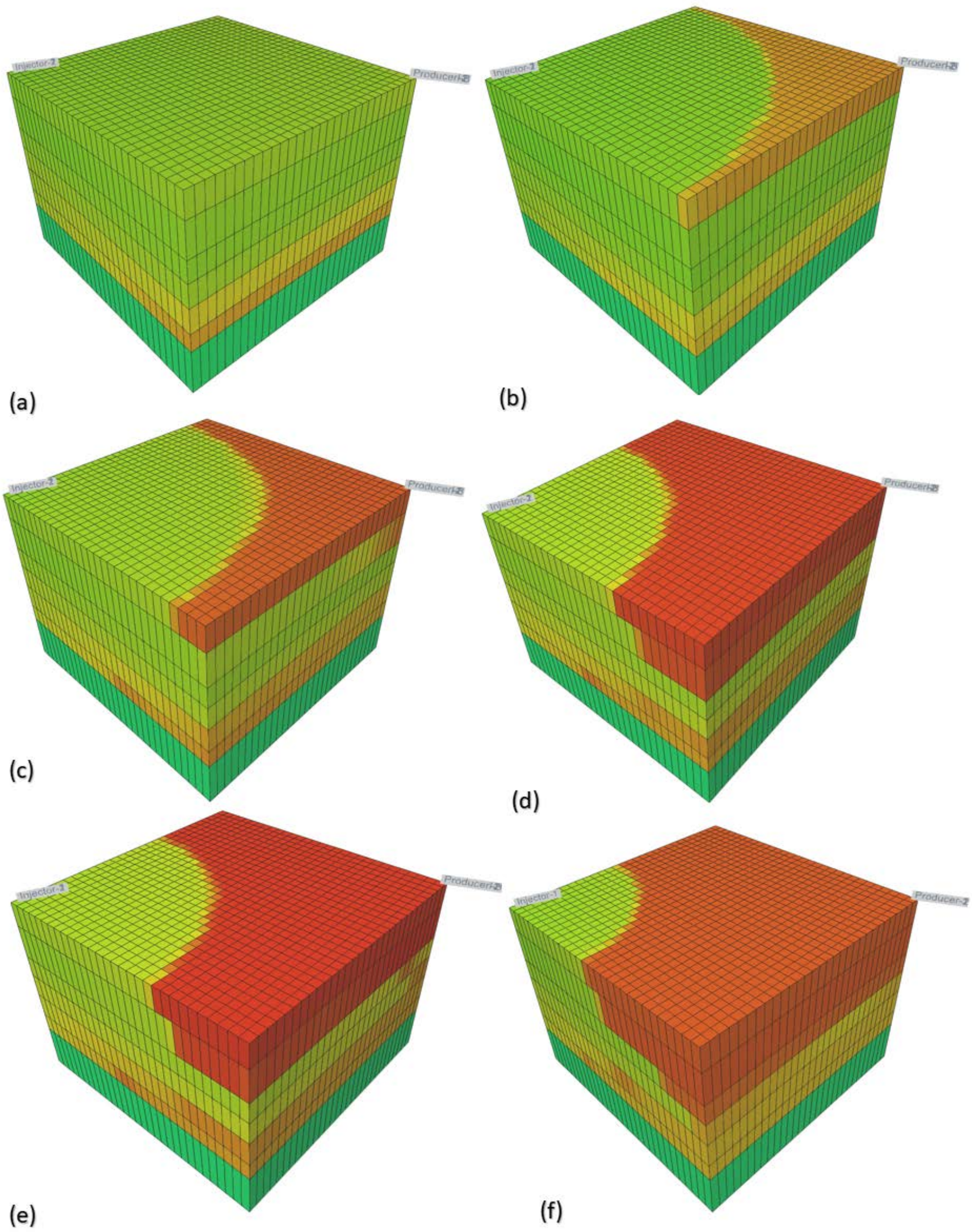


Figure 6. 8. Oil Saturation map by the year of 2016. (a) – injection of the polymer for 1 month at the year of 2000; (b) – injection of the polymer for 10 years at the year of 2000; (c) – injection of the polymer for 1 month at the year of 2005; (d) – injection of the polymer for 10 years at the year of 2005; (e) – injection of the polymer for 1 month at the year of 2010; (f) – injection of the polymer for 10 years at the year of 2010

The Fig.6.9 represents the level of the water cut by the year of 2016. The results have shown that water cut level can be decreased to a great extent with more polymer injection, so that time of the water breakthrough can be delayed. However, with the injection of less polymer PVs, water cut level reaches its maximum value which is almost 95%. So that, at this stage of production, another method has to be applied. Therefore, when polymer is injected for a shorter period, it is possible to reach a recovery factor much faster, however, water breakthrough occurs earlier, and there is increased water production. If the target of the project is to produce oil as soon as possible with less water production, it is better to inject polymer for 5 years and follow it with water injection.

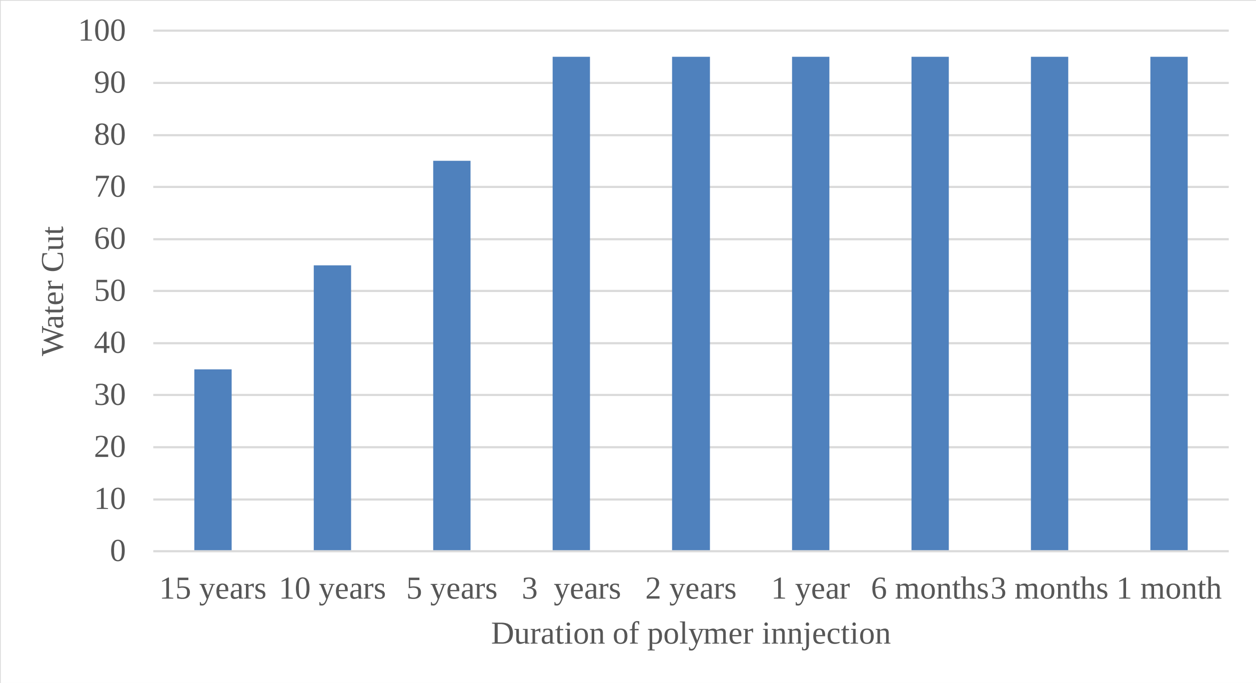
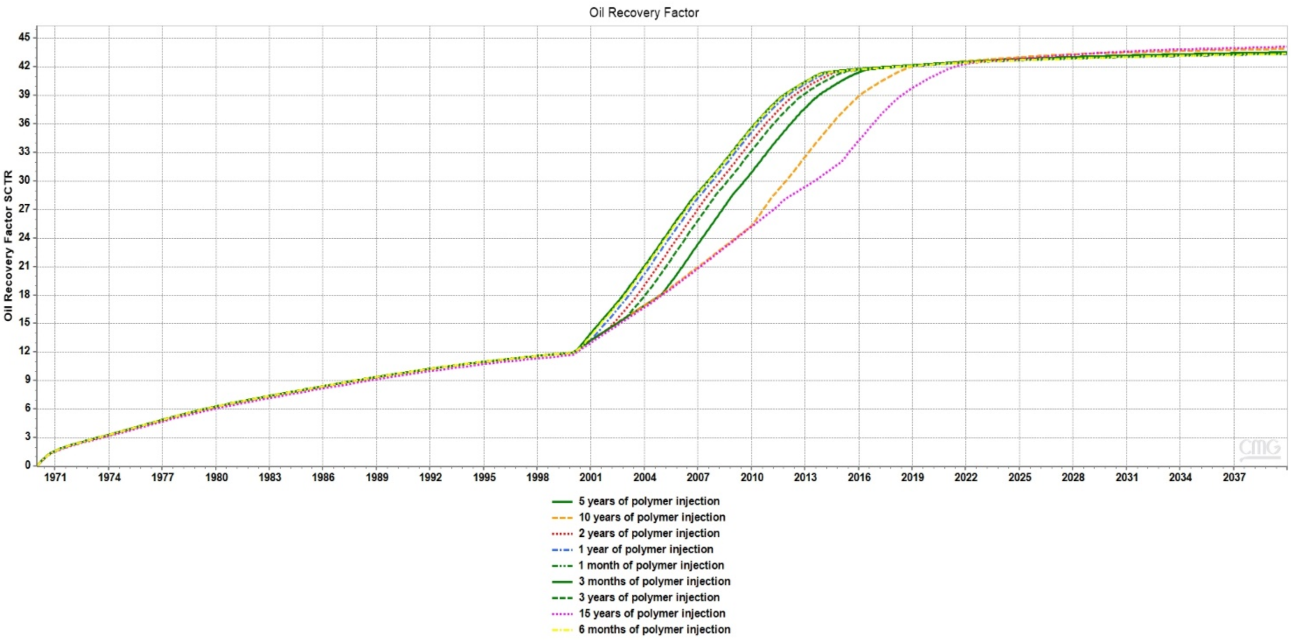


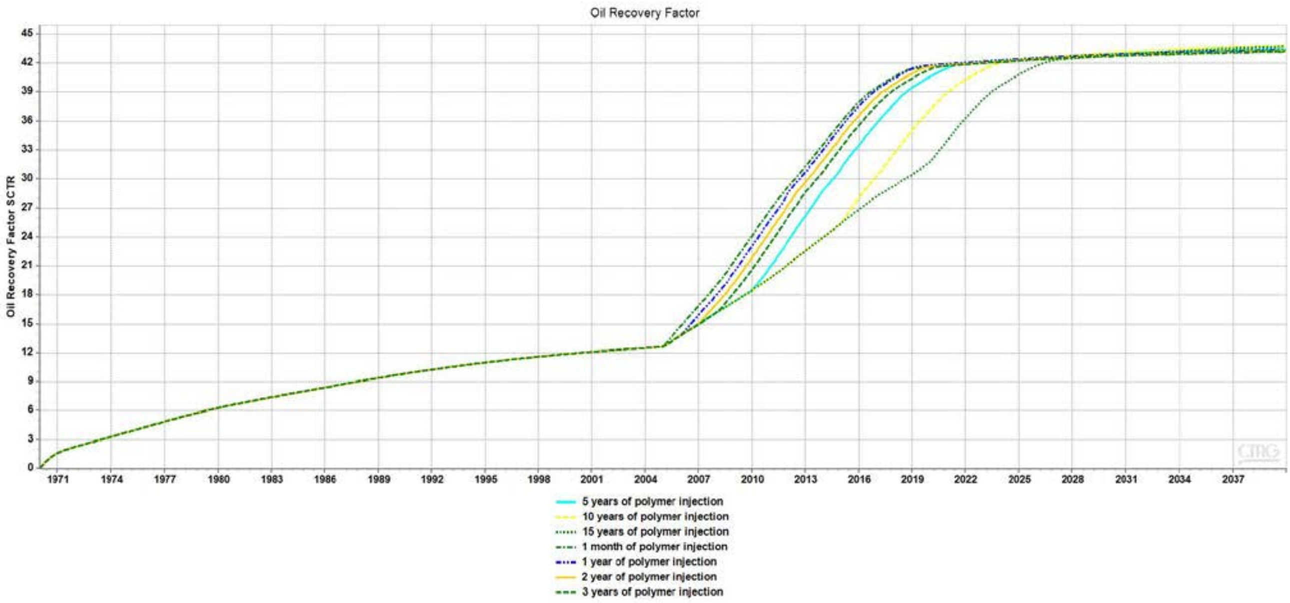
Figure 6. 9. Water Cut level by the year of 2016 after polymer injection initiation at the year of 2000.

6.2.2 Results for the long-term projects

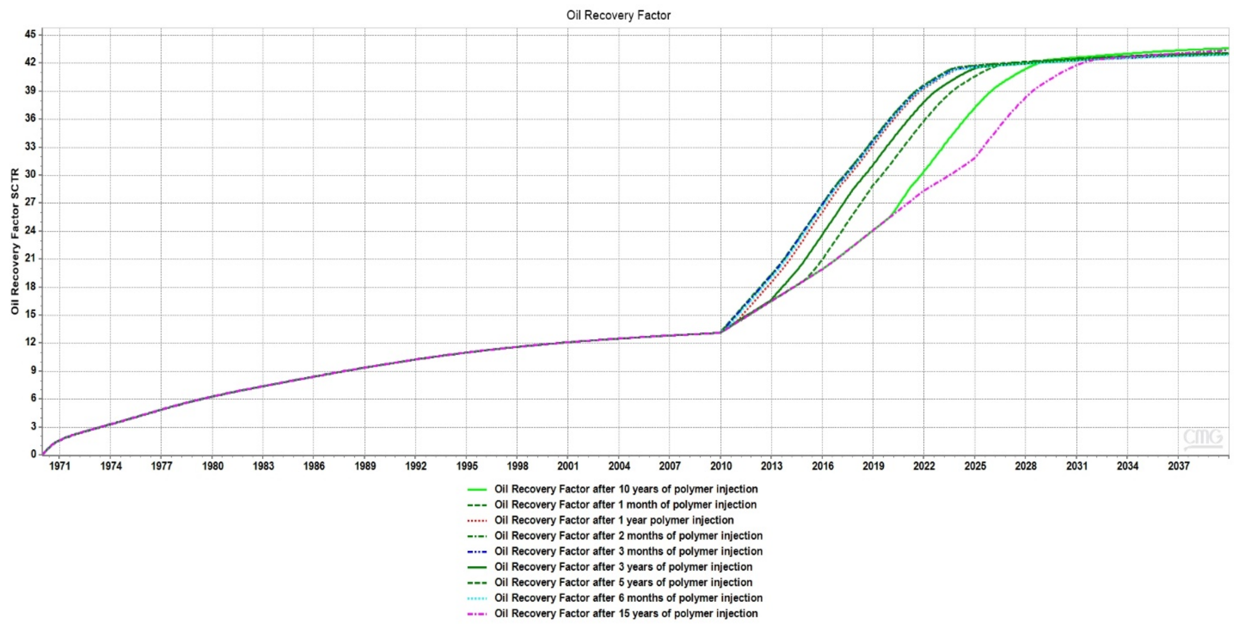
The results from the long-term project suggested that injection of the polymer at different times does not affect ultimate oil recovery, but delays it (Fig. 6.10 a, b, c).


Oil Recovery Factor
Oil Recovery Factor SCTR
5 years of polymer injection
10 years of polymer injection
2 years of polymer injection
1 year of polymer injection
1 month of polymer injection
3 months of polymer injection
3 years of polymer injection
15 years of polymer injection
6 months of polymer injection

(a)


Oil Recovery Factor
Oil Recovery Factor SCTR
5 years of polymer injection
10 years of polymer injection
15 years of polymer injection
1 month of polymer injection
1 year of polymer injection
2 year of polymer injection
3 years of polymer injection

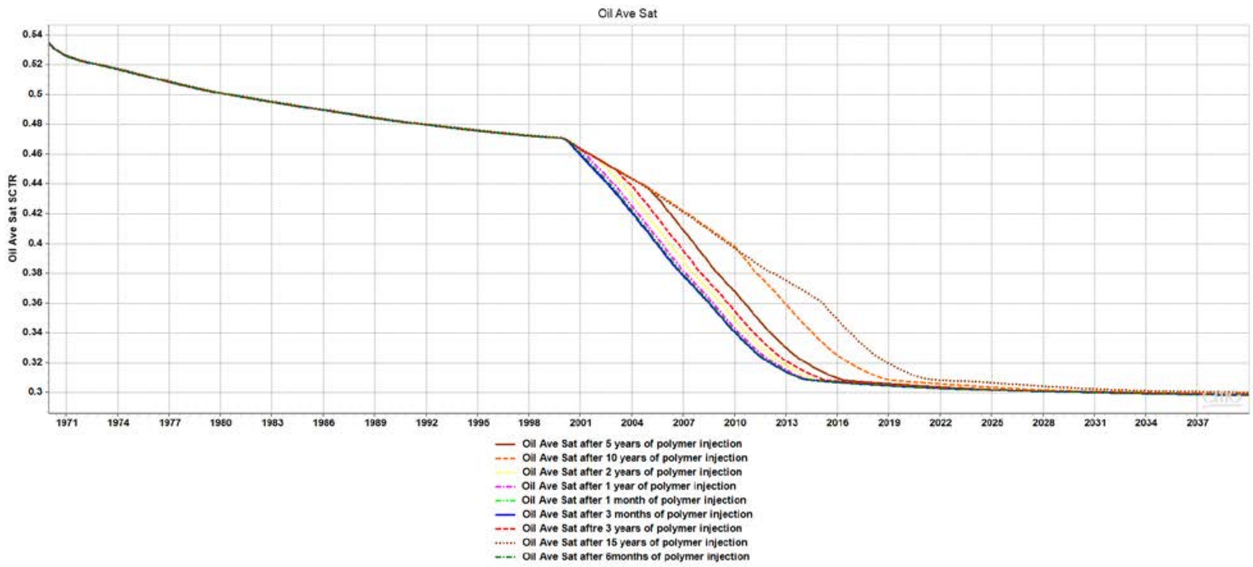
(b)



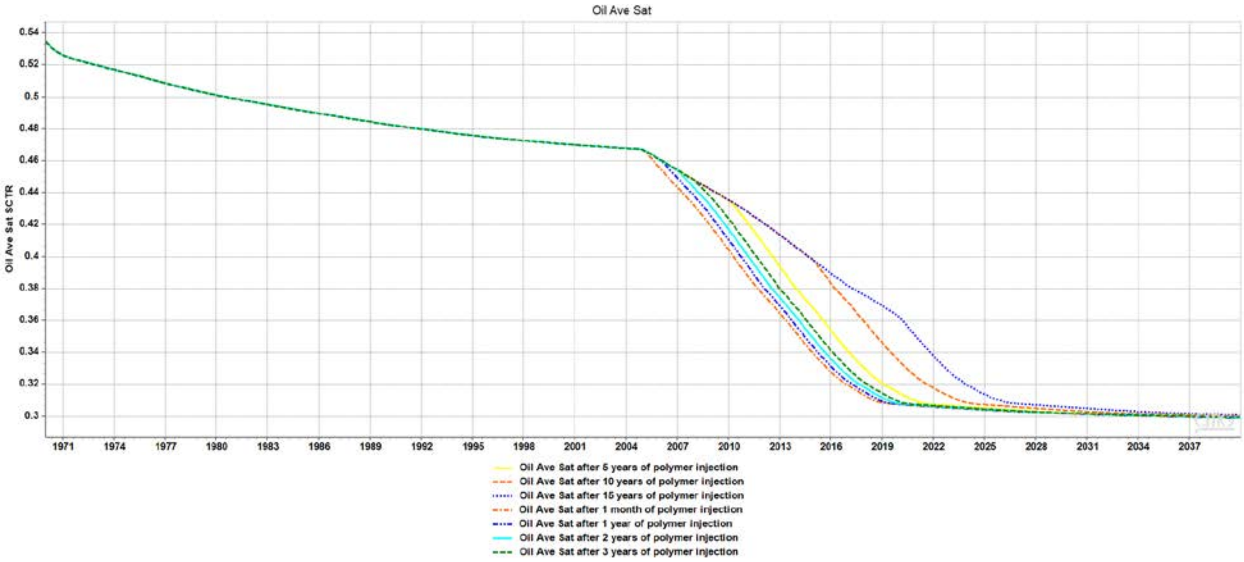
(c)

Figure 6. 10. Oil recovery factor vs. Time of model: (a) – initiation of polymer injection at the year 2000, (b) – initiation of polymer injection at the year 2005, (c) – initiation of polymer injection at the year 2010

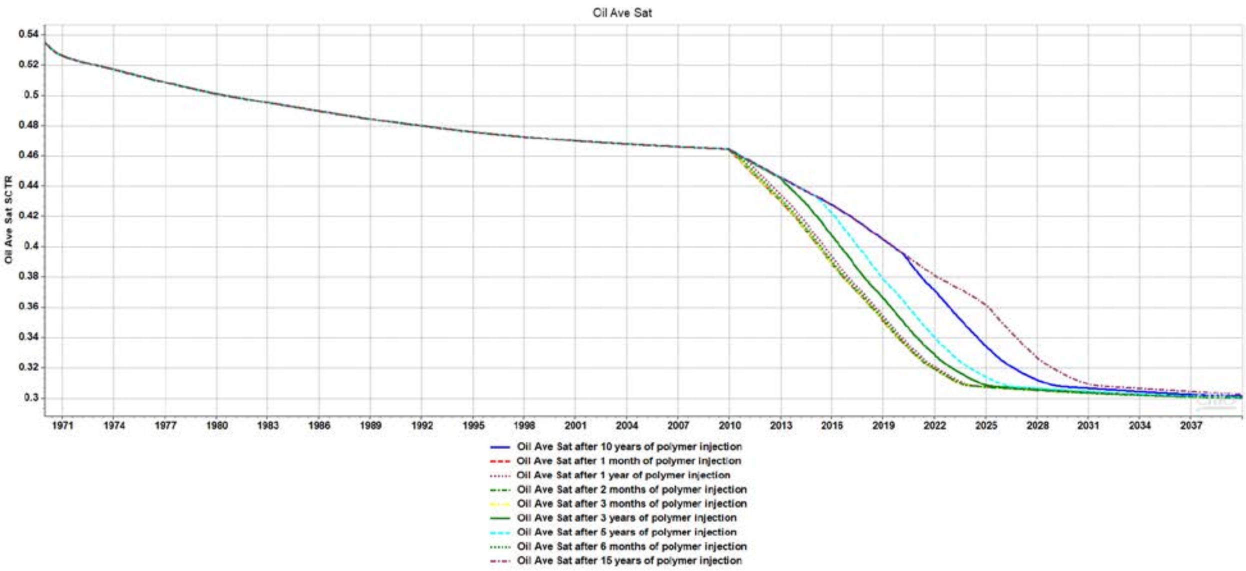
From the oil saturation curves it can be seen that ultimate value of residual oil saturation isn't affected by the polymer injection timing and PVs of polymer injected as can be seen in the Figure 6.11.



(a)



(b)



(c)

Figure 6. 11. Average oil saturation: (a) – scenario 1a, (b) – scenario 2b, (c) – scenario 3b

By the injection of the polymer it is possible to reduce water cut level by 20%. One such example is illustrated in the Fig. 6.12.

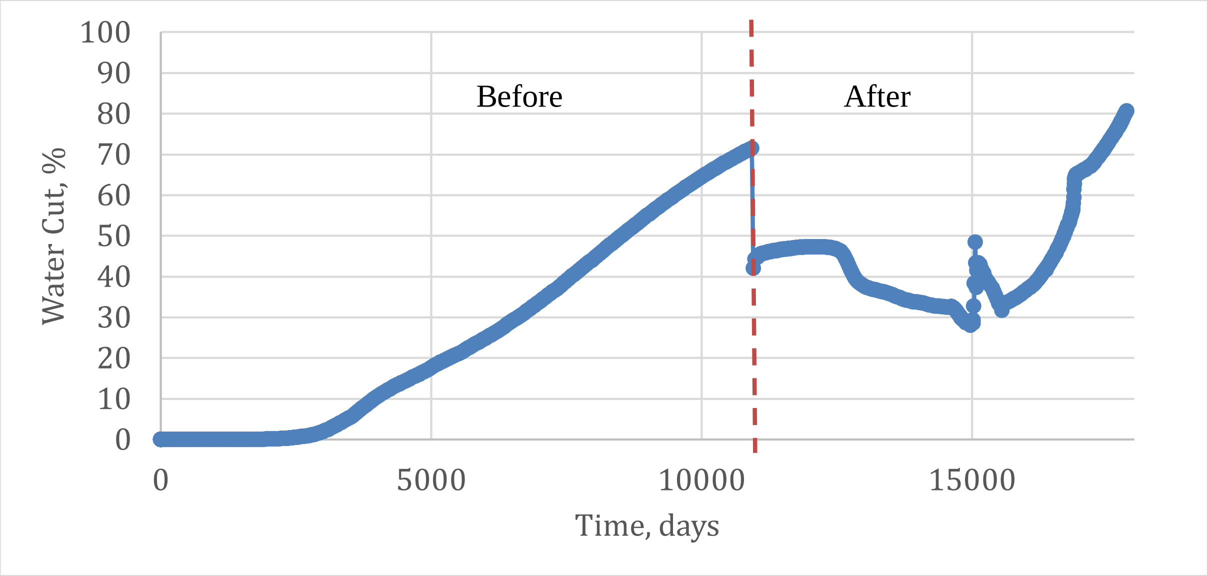


Figure 6. 12. An example of the change in Water Cut level before and after Polymer treatment

For the long-term projects, as shown in the tables 6.8, 6.9, 6.10, injection of more polymer pore volumes doesn't affect the ultimate recovery factor. However, it is important to mention that with injection of more polymer pore volumes comes higher operation costs, higher processing costs, and less profit. Due to the reasons highlighted above, it can be concluded that it is better to start polymer injection at early stages with the least amount of pore volumes injected.

Table 6. 7. The effect of Polymer and Water Injection on Recovery Factor for Case 1

Polymer injection initiation year	Duration of polymer injection	Pore Volume of polymer injected	Pore Volume of water injected	Recovery Factor (%)
2000	1 month	7.86×10^{-4}	0.37	43
	3 months	2.33×10^{-3}	0.367	43
	6 months	4.56×10^{-3}	0.365	43
	1 year	9.25×10^{-3}	0.36	43
	2 years	0.0185	0.35	43
	3 years	0.0278	0,34	43
	5 years	0.0463	0.32	43.5
	10 years	0.093	0.27	43.5
	15 years	0.139	0.23	43.5

Table 6. 8. The effect of Polymer and Water Injection on Recovery Factor for Case 2

Polymer injection initiation year	Duration of polymer injection	Pore Volume of polymer injected	Pore Volume of water injected	Recovery Factor (%)
2005	1 month	7.86×10^{-4}	0.32	43
	3 months	2.33×10^{-3}	0.32	43
	6 months	4.56×10^{-3}	0.319	43
	1 year	9.25×10^{-3}	0.314	43
	2 years	0.0185	0.305	43
	3 years	0.0278	0.296	43
	5 years	0.0463	0.278	43.5
	10 years	0.093	0.231	43.5
	15 years	0.139	0.185	43.5

Table 6. 9. The effect of Polymer and Water Injection on Recovery Factor for Case 3

Polymer injection initiation year	Duration of polymer injection	Pore Volume of polymer injected	Pore Volume of water injected	Recovery Factor (%)
2010	1 month	7.86×10^{-4}	0.277	43
	3 months	2.33×10^{-3}	0.275	43
	6 months	4.56×10^{-3}	0.273	43
	1 year	9.25×10^{-3}	0.268	43
	2 years	0.0185	0.259	43
	3 years	0.0278	0.249	43
	5 years	0.0463	0.231	43.5
	10 years	0.093	0.185	43.5
	15 years	0.139	0.139	43.5

6.3 Reservoir Simulation Results for Test 3

In this test, polymer flooding was simulated as a tertiary method after waterflooding. Waterflooding was conducted for three different time periods, more specifically for 3, 5, and 10 years, after which polymer injection was conducted. The polymer slug is then chased by water. More detailed description of the scenarios can be seen in the table 6.11. The analysis of the data is also performed for two different time periods: for a short term from 2000 till the year of 2016 and for a long term from 2000 till the year of 2040. Duration of polymer injection, pore volume of polymer injected, recovery factors for a short-term period are represented in the tables 6.12, 6.13, 6.14.

Table 6. 10. Model scenarios description

Case	Water/Polymer Solution injection scenarios	Project Lifetime
1	In the first case water injection starts at the year of 2000 and is conducted for 3 more years after which different PVs of polymer solution are injected into the reservoir and followed by the chased water. As in the previous model polymer was injected for 9 different time durations corresponding to 9 injection scenarios, including injection of polymer for 1 month, 3 months, 6 months, 1 year, 2 years, 3 years, 6 years, 10 years, 15 years.	40 years
2	In the second case water injection starts at the year of 2000 and is conducted for 5 years after which different PVs of polymer solution are injected into the reservoir and followed by the chased water. Polymer slugs were injected for 9 different time durations corresponding to 9 injection scenarios, including injection of polymer for 1 month, 3 months, 6 months, 1 year, 2 years, 3 years, 6 years, 10 years, 15 years.	40 year
3	In the third case water injection starts at the year of 2000 and is conducted for 10 years after which different PVs of polymer solution are injected into the reservoir and followed by the chased water. Polymer slugs were injected for 9 different time durations corresponding to 9 injection scenarios, including injection of polymer for 1 month, 3 months, 6 months, 1 year, 2 years, 3 years, 6 years, 10 years, 15 years.	40 years

6.3.1 Results for the short-term projects

Based on the results from the simulation PVs of polymer and water for the short-term projects are calculated and demonstrated in Tables 5.11, 5.12, 5.13. As indicated in the tables, initiation time of polymer injection highly affects oil recovery. The later polymer is injected, the lesser amount of oil can be recovered. The effect of injection of polymer PVs are shown in Fig. 5.13.

Table 6. 11. The effect of polymer injection on recovery factor

Polymer injection initiation year	Duration of polymer injection	Pore Volume of polymer injected	Pore Volume of water injected	Recovery Factor (%)
2003	1 month	7.86×10^{-4}	0.147	42.7
	3 months	2.33×10^{-3}	0.146	42.7
	6 months	4.56×10^{-3}	0.144	42.58
	1 year	9.25×10^{-3}	0.139	42.58
	2 years	0.0185	0.129	42.58
	3 years	0.0278	0.12	41.76
	6 years	0.0463	0.102	41.73
	10 years	0.093	0.056	41.28
	13 years	0.12	0.028	41.22

Table 6. 12. The effect of polymer injection on recovery factor

Polymer injection initiation year	Duration of polymer injection	Pore Volume of polymer injected	Pore Volume of water injected	Recovery Factor (%)
2005	1 month	7.86×10^{-4}	0.147	42.7
	3 months	2.33×10^{-3}	0.146	42.7
	6 months	4.56×10^{-3}	0.144	42.7
	1 year	9.25×10^{-3}	0.139	41.94
	2 years	0.0185	0.129	41.94
	3 years	0.0278	0.12	41.94
	6 years	0.0463	0.102	39.15
	10 years	0.093	0.056	39.15
	11 years	0.101	0.046	39.15

Table 6. 13. The effect of polymer injection on recovery factor

Polymer injection initiation year	Duration of polymer injection	Pore Volume of polymer injected	Pore Volume of water injected	Recovery Factor (%)
2010	1 month	7.86×10^{-4}	0.147	35.21
	3 months	2.33×10^{-3}	0.146	35.21
	6 months	4.56×10^{-3}	0.144	35.21
	1 year	9.25×10^{-3}	0.139	35.21
	2 years	0.0185	0.129	33.07
	3 years	0.0278	0.12	32.49
	5 years	0.0463	0.102	30.52
	6 years	0.056	0.093	30.52

As can be seen from Fig. 6.13, in the short-term projects, recovery factor is highly affected by the amount of polymer injection. With more PVs of polymer injected, there is a decrease in recovery factor. The reason behind this is that the polymer solution becomes more viscous and propagates at a slower pace. However, the impact of the injection of large polymer slug sizes can be seen in long-term projects as shown in Fig. 6.15. Injection of greater polymer PVs is effective in the long-run, but isn't suitable for the short-term projects.

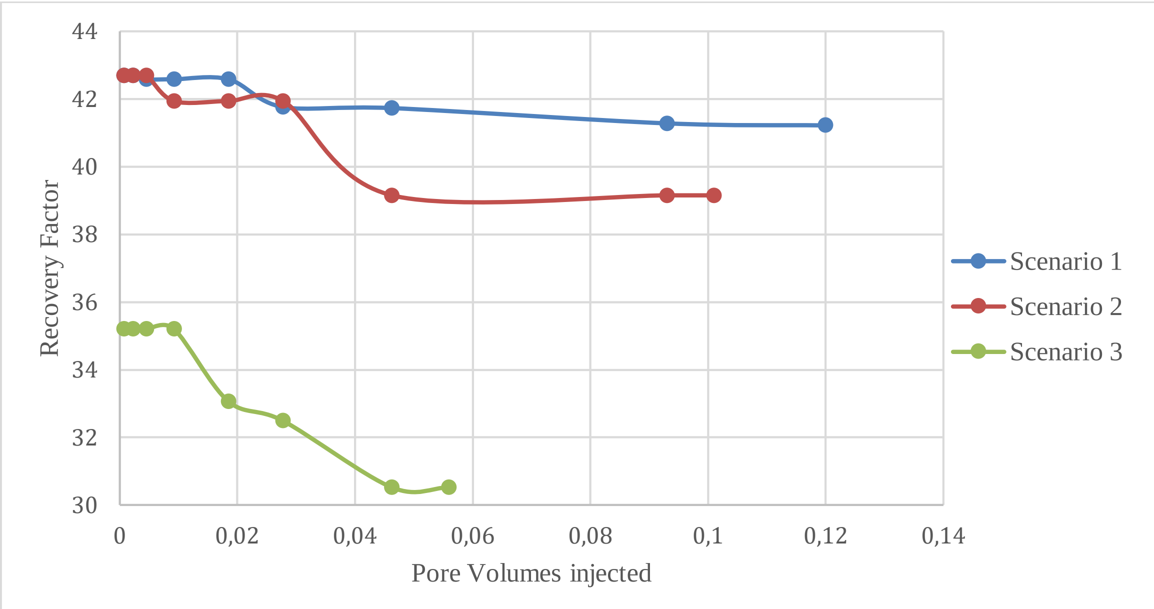


Figure 6. 13. Recovery Factor vs Pore Volumes injected

The movement of the polymer and water solution by the year 2016 can be seen in the oil saturation profile. The oil saturation map in Fig. 6.14 shows that injection of the polymer for a short period, more specifically for one month, chased by water can propagate much faster, compared to the scenarios of continuous polymer injection. Additionally, prolonged waterflooding, particularly for 10 years, can also reduce the efficiency of the oil recovery, because more area remains unswept. Polymer solution doesn't have enough time to spread and contact the displaced fluid due to the time limit of the project. If the target of the project is to recover oil sooner, it is better to conduct waterflooding for a short period and start polymer injection as tertiary method and conduct it for 3 or 5 years, depending on the budget of the project.

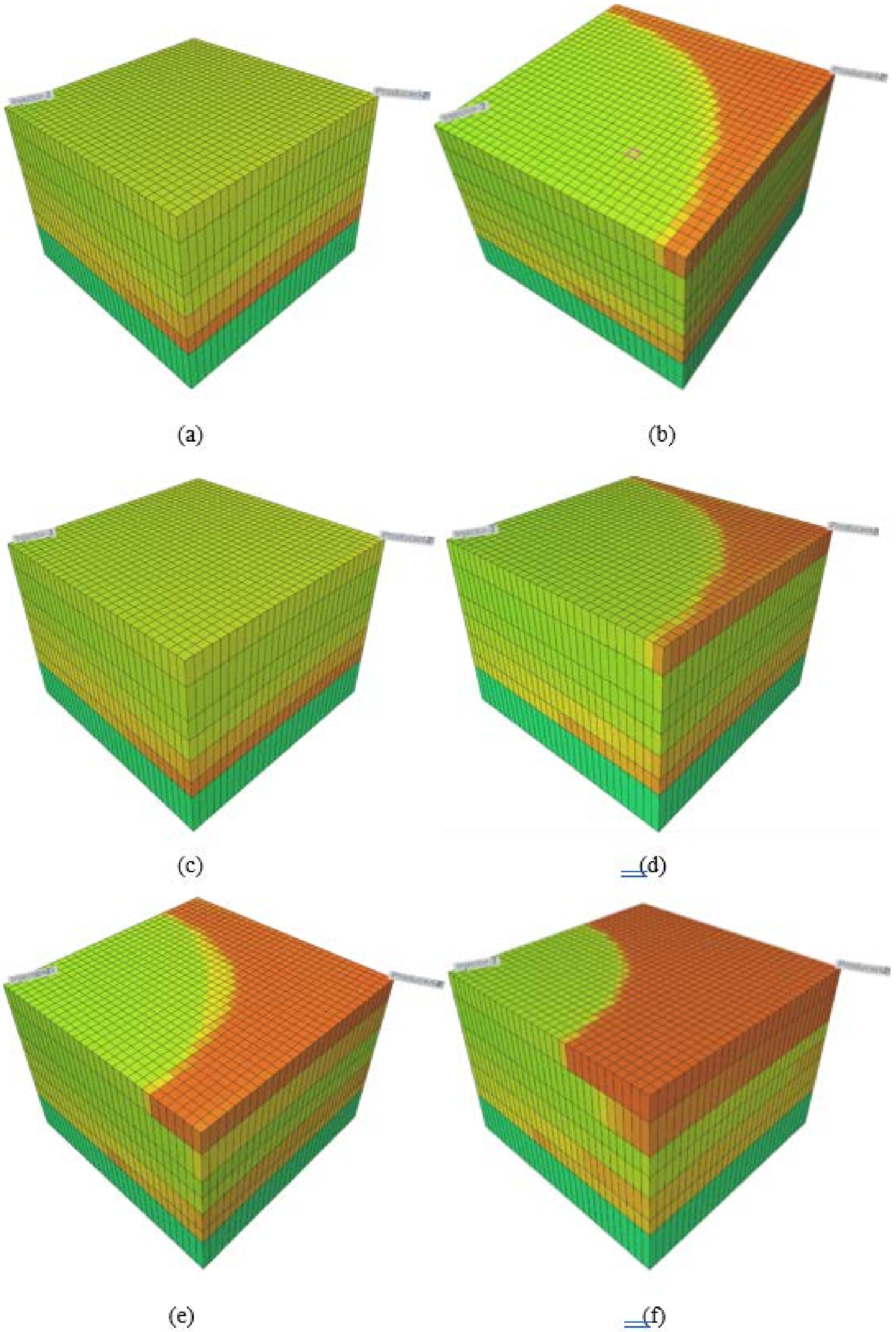
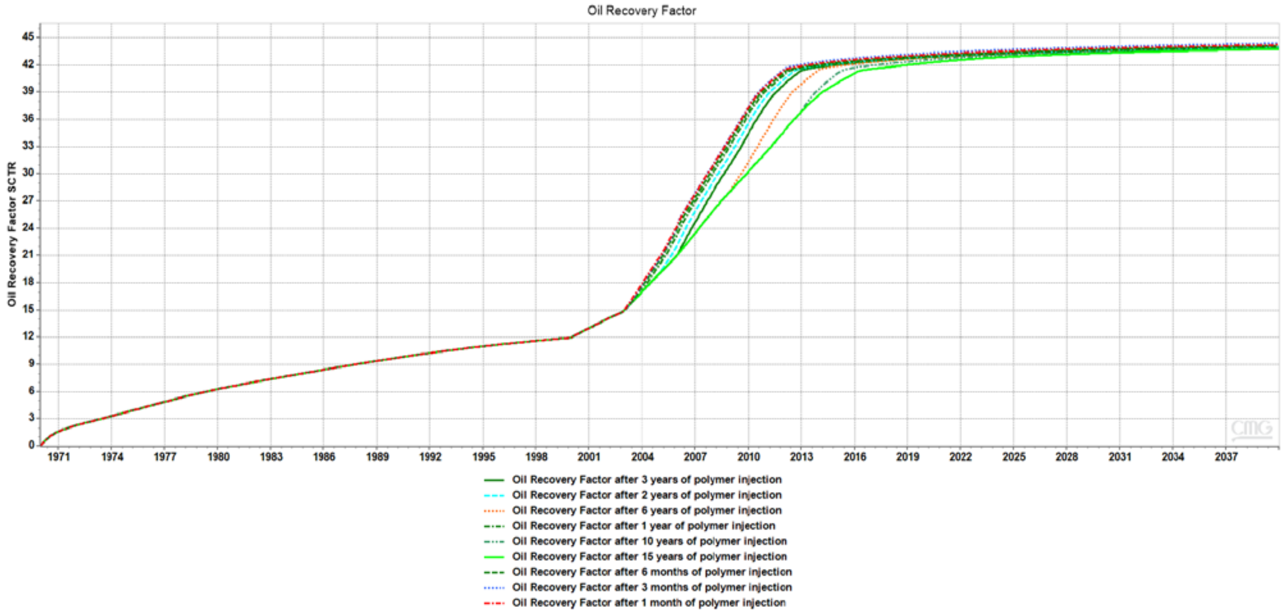


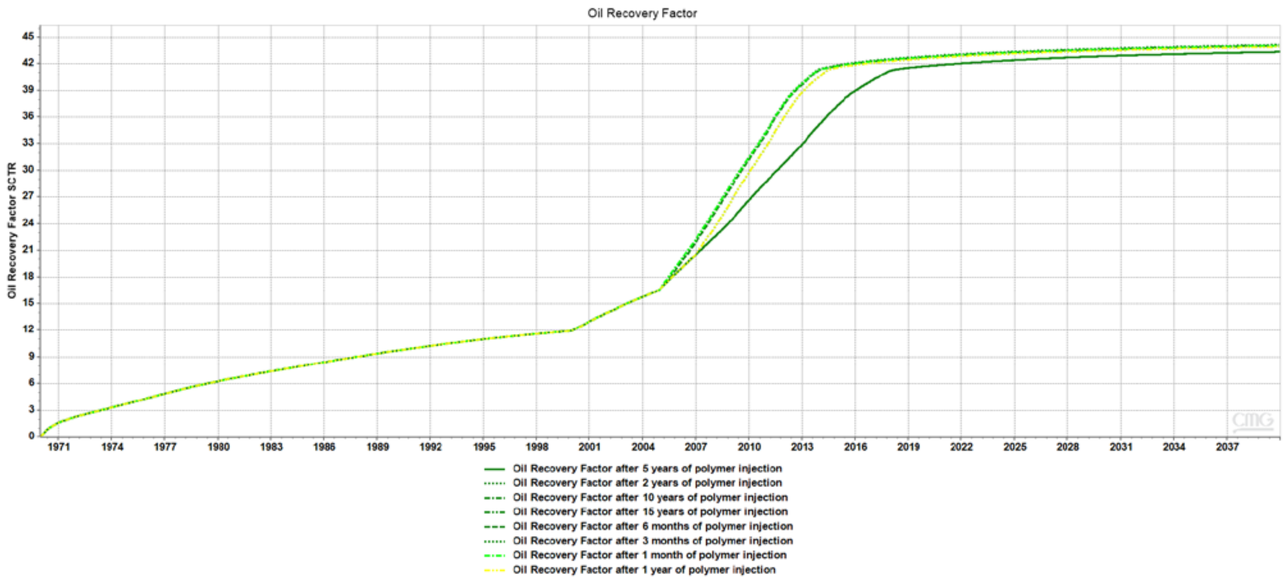
Figure 6. 14. Oil Saturation map by the year 2016: (a) – 10polymer injection for 1 month after waterflooding for 3 years; (b) – polymer injection for 10 years after 3 years of waterflooding; (c) – polymer injection for 1 month after 5 years of waterflooding; (e) – polymer injection for 1 month after 10 years of waterflooding; (f) – polymer injection for 6 years after 10 years of waterflooding

6.3.2 *Results for long-term projects*

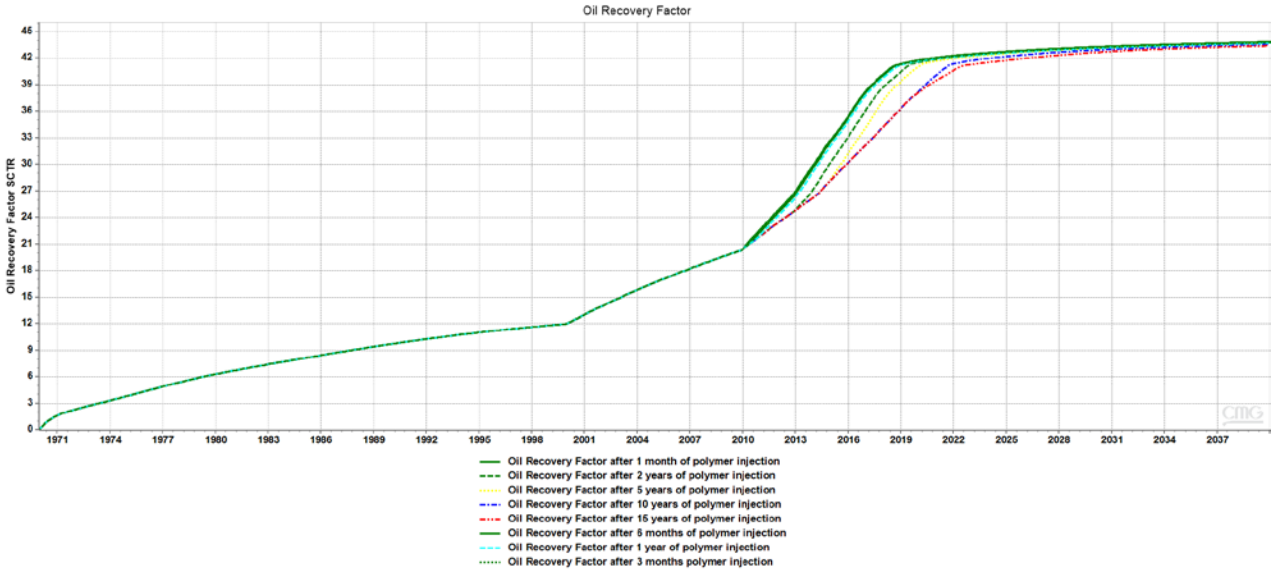
From Fig. 6.15 it can be seen that sequence and duration of the polymer and waterflooding does not significantly affect ultimate oil recovery. However, there are significant variations in the time of water breakthrough. Water breakthrough occurs earlier for the first case at the year 2012 after which no more oil can be recovered, and the recovery factor reaches a plateau. For the other two cases water breakthrough are delayed and occur 2014 and 2018. Fig. 6.16 demonstrates the level of the water cut for different cases.



(a)



(b)



(c)

Figure 6. 15. Oil Recovery vs. Time of the model: (a) – polymer injection after 3 years of waterflooding, (b) – polymer injection after 5 years of waterflooding, (c) – polymer injection after 10 years of waterflooding

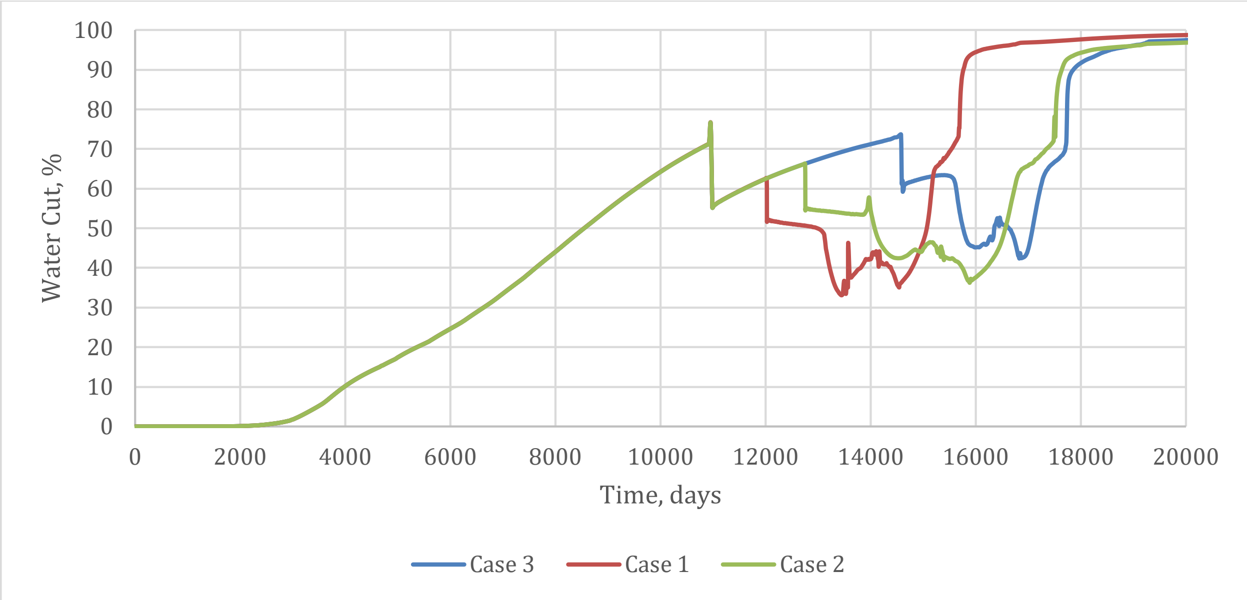
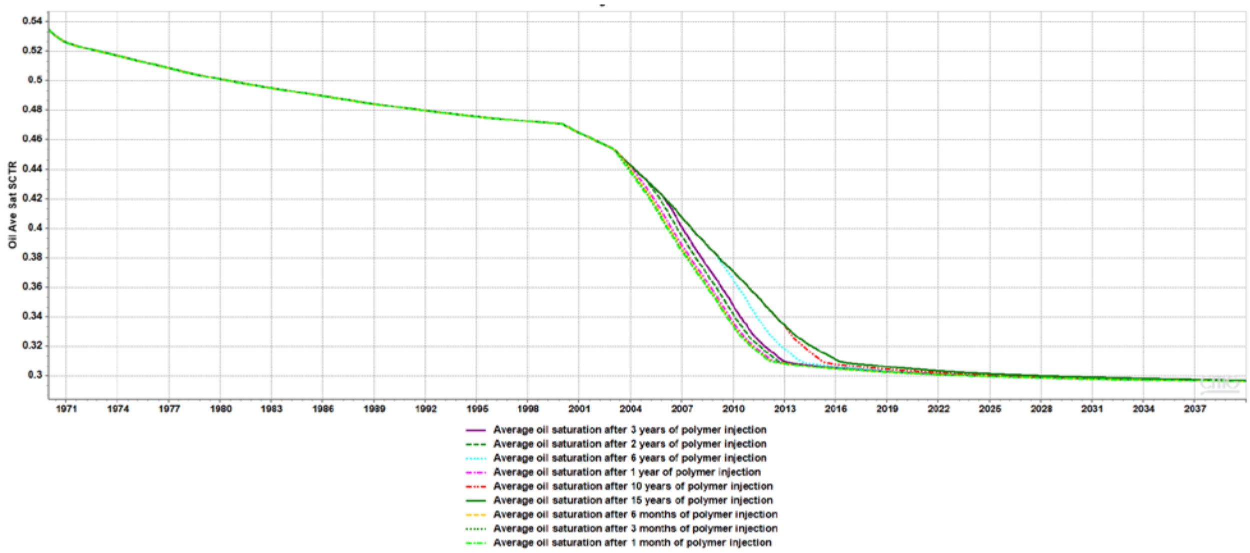
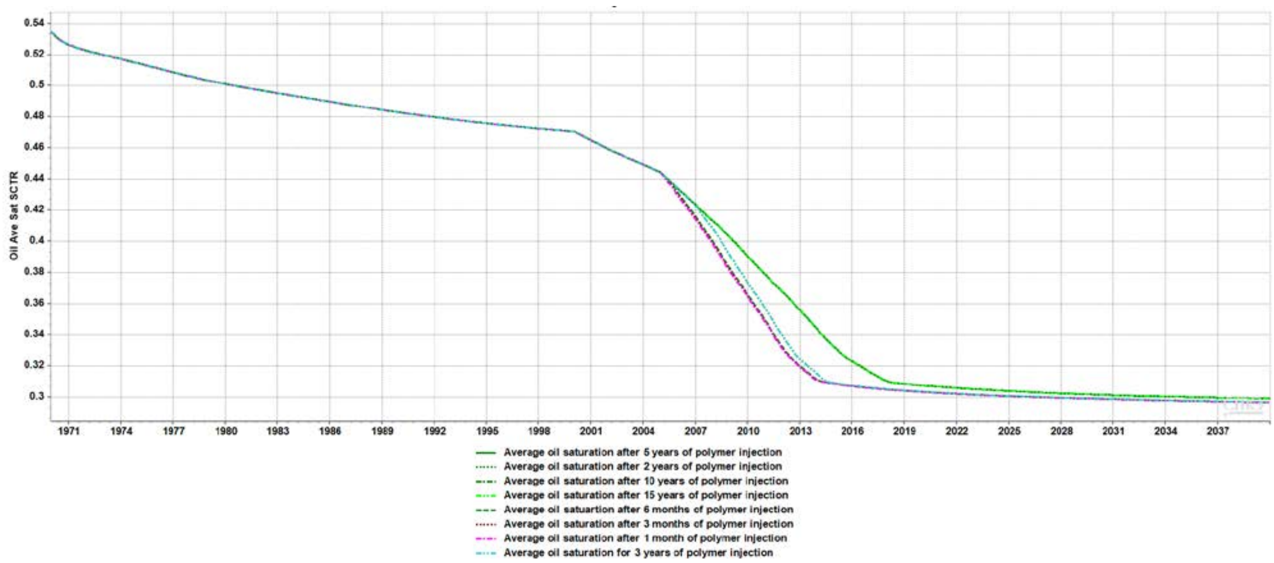


Figure 6. 16. Level of the Water Cut for different cases

From the saturation profile Fig.6.17 it can be seen that residual oil saturation is equal for all of the cases. These results suggested that residual oil saturation is not affected by the amount of pore volume injected into the reservoir.


Oil Ave Sat SCTR
0.54
0.52
0.5
0.48
0.46
0.44
0.42
0.4
0.38
0.36
0.34
0.32
0.3
1971 1974 1977 1980 1983 1986 1989 1992 1995 1998 2001 2004 2007 2010 2013 2016 2019 2022 2025 2028 2031 2034 2037
Average oil saturation after 3 years of polymer injection
Average oil saturation after 2 years of polymer injection
Average oil saturation after 6 years of polymer injection
Average oil saturation after 1 year of polymer injection
Average oil saturation after 10 years of polymer injection
Average oil saturation after 15 years of polymer injection
Average oil saturation after 6 months of polymer injection
Average oil saturation after 3 months of polymer injection
Average oil saturation after 1 month of polymer injection

(a)


Oil Ave Sat SCTR
0.54
0.52
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0.48
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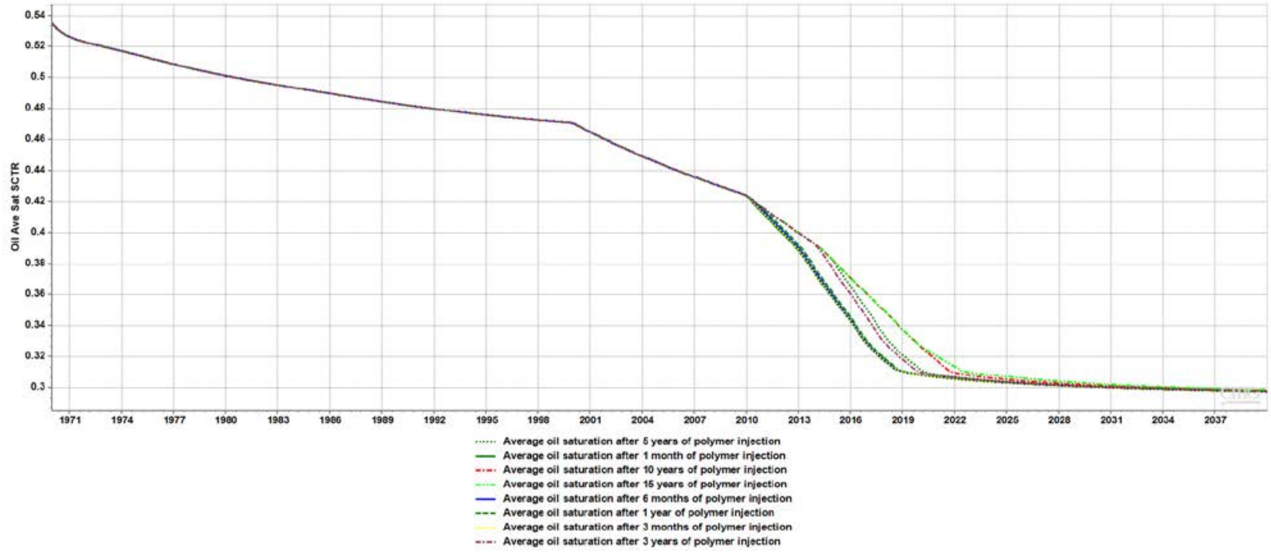
1971 1974 1977 1980 1983 1986 1989 1992 1995 1998 2001 2004 2007 2010 2013 2016 2019 2022 2025 2028 2031 2034 2037
Average oil saturation after 5 years of polymer injection
Average oil saturation after 2 years of polymer injection
Average oil saturation after 10 years of polymer injection
Average oil saturation after 15 years of polymer injection
Average oil satuartion after 6 months of polymer injection
Average oil saturation after 3 months of polymer injection
Average oil saturation after 1 month of polymer injection
Average oil saturation for 3 years of polymer injection

(b)



(c)

Figure 6. 17. Average oil saturation profile: (a) – for the first case, (b) – for the second case, (c) – for the third case

Economic analysis

From the results section highlighted above, it should be noted that long-term economics will benefit from the early implementation of the polymer injection, maximizing oil production early in the life of the field and delaying water breakthrough. In order to find cost-effective scenario polymer cost, water cost and time to reach ultimate recovery factor were considered. For that purpose simple economic analysis was conducted and analyzed on Microsoft Excels spreadsheets. The economic summary results are presented in the Table 6.14. The operating cost for water and polymer injection was assumed to be 0.5 and 1 US$/bbl respectively (Jutikarn, K., 2011), which is if converted to SI metrics 3 and 6 US$ per m^3. The amount of water and polymer needed for achieving ultimate oil recovery were calculated based on the results of the simulation for the long-term projects.

Table 6. 14. Estimation of operating costs of simulated scenarios

Model	Case	Scenario	Amount of Water injected (m^3)	Amount of Polymer injected (m^3)	Cost of Water injection	Cost of polymer injection	Total injection cost
Model 1	Case 1	1	0	949000	0	5694000	5694000
	Case 2	2	0	912500	0	5475000	5475000
	Case 3	3	0	912500	0	5475000	5475000
Model 2	Case 1	1	579886	3101	1739657	18604	1758260
		2	575941	9191	1727822	55148	1782971
		3	568051	17988	1704154	107930	1812083
		4	548327	36489	1644982	218936	1863918
		5	508879	72979	1526638	437873	1964510
		6	473376	109665	1420128	657993	2078121
		7	402370	182644	1207109	1095865	2302974
		8	327418	364894	982255	2189364	3171619
	Case 2	1	544500	3000	1633500	18000	1651500
		2	511000	36500	1533000	219000	1752000
		3	474500	73000	1423500	438000	1861500
		4	438000	109500	1314000	657000	1971000
		5	511000	182500	1533000	1095000	2628000
		6	328500	365000	985500	2190000	3175500
		7	255500	547500	766500	3285000	4051500
	Case 3	1	544500	3000	1633500	18000	1651500
		2	541400	6100	1624200	36600	1660800
		3	538300	9200	1614900	55200	1670100
		4	529200	18300	1587600	109800	1697400
		5	511000	36500	1533000	219000	1752000
		6	438000	109500	1314000	657000	1971000
		7	438000	182500	1314000	1095000	2409000
		8	328500	365000	985500	2190000	3175500
		9	255500	547500	766500	3285000	4051500

Table 6. 15. Estimation of operating costs of simulated scenarios continued

Model	Case	Scenario	Amount of Water injected (m^3)	Amount of Polymer injected (m^3)	Cost of Water injection	Cost of polymer injection	Total injection cost
Model 3	Case 1	1	471500	3000	1414500	18000	1432500
		2	468400	6100	1405200	36600	1441800
		3	465300	9200	1395900	55200	1451100
		4	456200	18300	1368600	109800	1478400
		5	438000	36500	1314000	219000	1533000
		6	401500	73000	1204500	438000	1642500
		7	365000	109500	1095000	657000	1752000
		8	255500	219000	766500	1314000	2080500
		9	219000	365000	657000	2190000	2847000
		10	73000	547500	219000	3285000	3504000
	Case 2	1	581000	3000	1743000	18000	1761000
		2	574800	9200	1724400	55200	1779600
		3	565700	18300	1697100	109800	1806900
		4	547500	36500	1642500	219000	1861500
		5	511000	73000	1533000	438000	1971000
		6	547500	182500	1642500	1095000	2737500
		7	365000	365000	1095000	2190000	3285000
		8	182500	547500	547500	3285000	3832500
	Case 3	1	727000	3000	2181000	18000	2199000
		2	720800	9200	2162400	55200	2217600
		3	711700	18300	2135100	109800	2244900
		4	693500	36500	2080500	219000	2299500
		5	657000	73000	1971000	438000	2409000
		6	584000	182500	1752000	1095000	2847000
		7	474500	365000	1423500	2190000	3613500
		8	365000	547500	1095000	3285000	4380000

In order to find optimum reservoir development strategy, several production and injection scenarios were investigated:

- Production scenarios:
    - ✓ Primary oil production;
    - ✓ Water injection;
    - ✓ Polymer injection;
- Injection scenarios:
    - ✓ Simulate polymer injection with different slug sizes;
    - ✓ Simulate polymer injection at different times;

The major physical effect of polymer flooding technique is improvement in volumetric sweep efficiency and reservoir pressure maintenance. According to sensitivity analysis, it was determined that the polymer flooding technique is a more efficient method compared to conventional waterflooding, due to higher recovery factor, low water cut and better sweep efficiency. The following is the comparison of the distribution of the oil saturation after injection of the cheapest polymer flooding scenario and waterflooding as shown in Fig.6.18. It can be seen that oil saturation has been drastically decreased, particularly in the upper four layers. Notably, the polymer solution has made apparent improvement in volumetric sweep efficiency. These results suggested that compared to waterflooding, by implementing polymer injection techniques, it is possible to recover additional 8-10% of incremental oil in place.

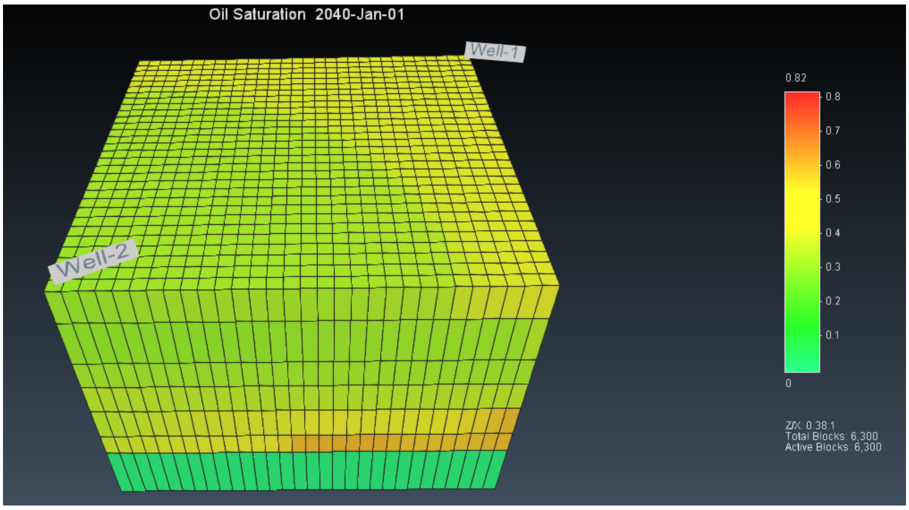


Figure 6. 18. Oil saturation after polymer flooding

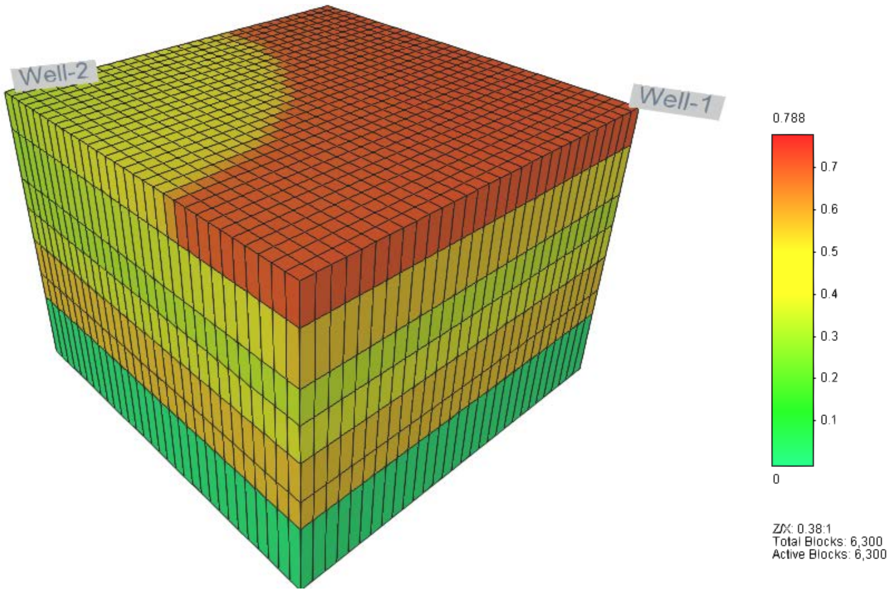


Figure 6. 19. End of waterflooding oil saturation

Based on the results of simulation study and according to the economic analysis, it can be concluded that one of the best scenarios, that could give high recovery performance efficiency in a cost-effective manner is Test 3, case 1 with 1 month of polymer injection. Furthermore, it was found that all scenarios have greater incremental oil recovery from polymer injection than that obtained from only waterflooding.

7. Conclusion and Recommendations

- In this study, primary recovery was able to recover around 15 % of oil, whereas by conducting secondary recovery (waterflooding), it was possible to increase recovery to approximately 33 %. Meanwhile, tertiary operations (polymer flooding) are able to recover 43 % of oil. Thus, it was determined that simulation of polymer injection demonstrated good performance, recovering an additional 10 % of oil original in place for all of the scenarios compared to the simulation of waterflooding alone.
- The modeled reservoir has strong aquifer support which leads to early water breakthrough. That is why it is very important to inject the polymer as early as possible, therefore decreasing the water cut and recovering the oil before water cut reaches extreme values. Furthermore, it was investigated that water cut levels can be decreased with injection of more polymer PVs.
- The time and duration of the polymer injection were found to be very important parameters for successful performance of the polymer flooding projects.
- By conducting simple economic analysis, it was found that the most cost-effective scenario is injection of the polymer for 1 month after three years of waterflooding.

Various types of polymers should be studied and analyzed in order to find the most suitable one for the field application. The appropriate polymer type with desirable parameters can be generated in the laboratory. As soon as the polymer will be generated it needs to be tested in the model in order to see if there is any change in its performance.

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Appendix

1. Graphs of the geometry and array data

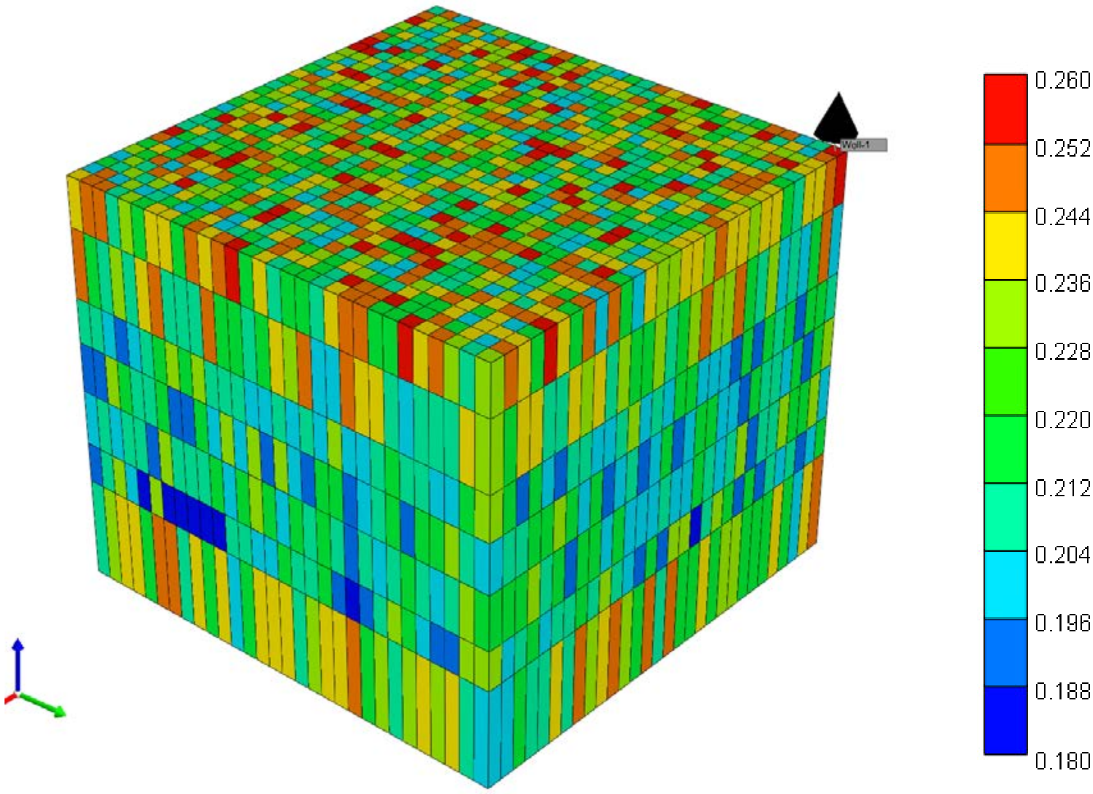

Figure 7. 1. 3D view of the porosity distribution. Porosity values were distributed randomly within a different range of values for each layer.

Table 7. 2. Porosity values

Layer	Porosity range (%)
1	20-26
2	20-25
3	19-23
4	19-23
5	19-23
6	18-23
7	20-25

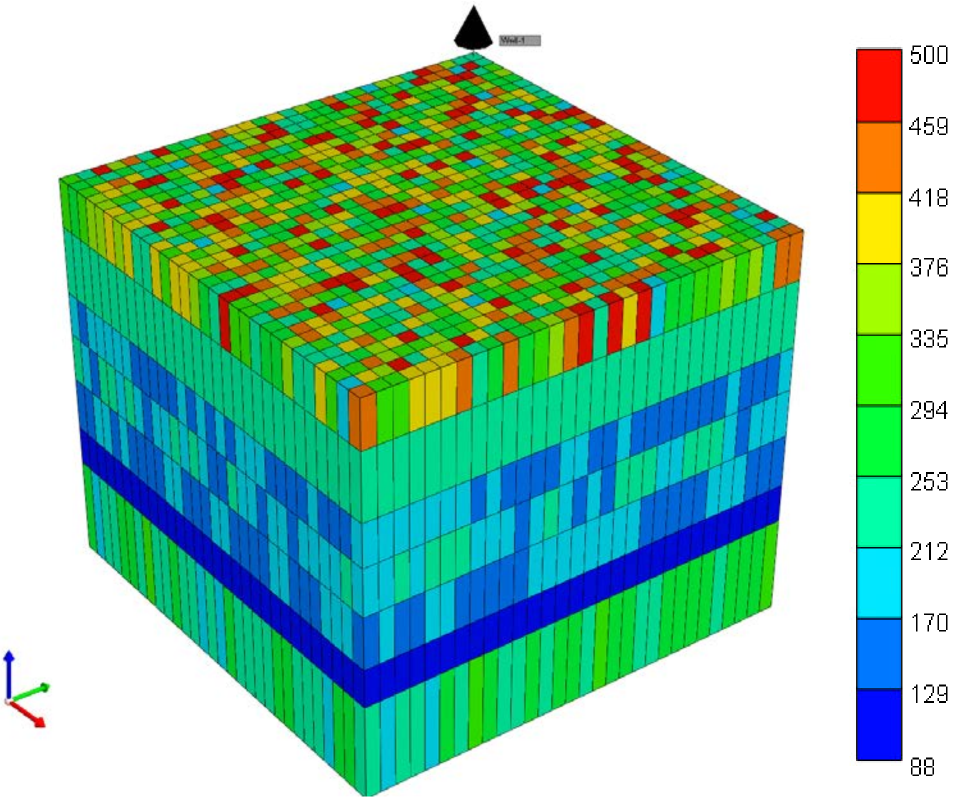

Figure 7. 2. 3D view of reservoir permeability (in I direction =J direction)

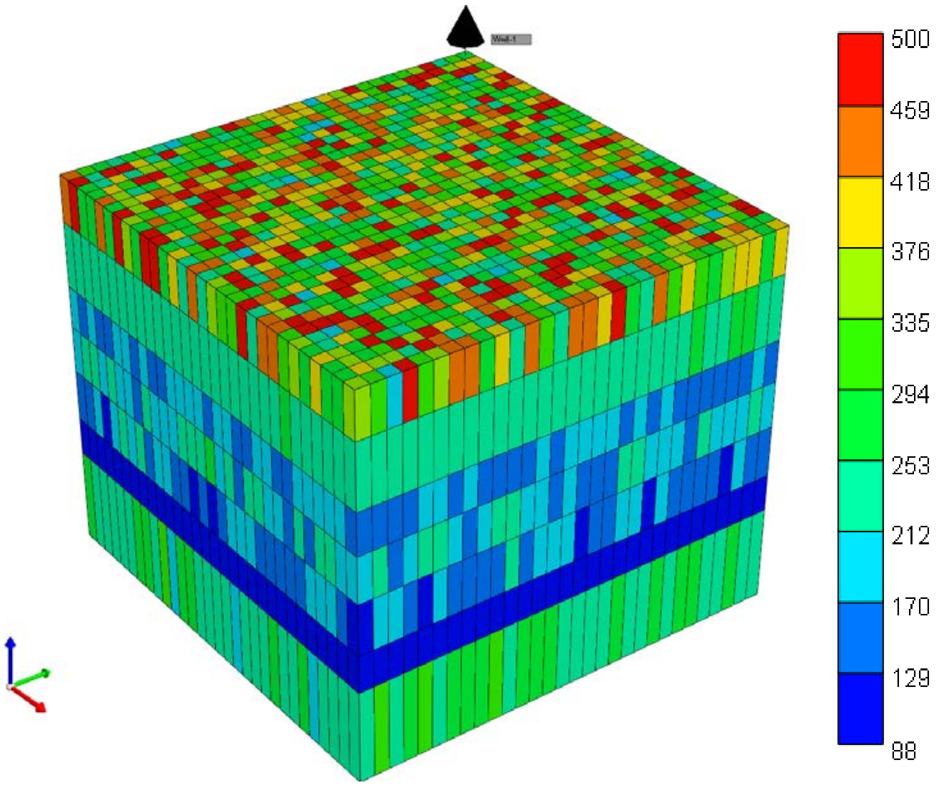

Figure 7. 3. 3D view of reservoir permeability (k direction)

Table 7. 2. Reservoir and fluid properties for the model

Reservoir dimensions	30 by 30 by 7 gridblocks
Number of grid blocks	6300
Reservoir top, m	840
Permeability in i, j, directions mD	Variable (115-250)
Permeability in k direction mD	Variable (11-25)
Porosity (fraction)	Variable (18-26)
Oil column, m	300
Water column, m	100
OWC, m	1150
Aquifer permeability, mD	Variable (218-234)
Water compressibility, 1/kPa	4.35×10^{-7}
Water density, kg/m^3	1100
Oil density, kg/m^3	773
Oil viscosity, cp	4.2
Water viscosity, cp	0.6

Table 7. 3. Reservoir model properties

	Layer 1	Layer 2	Layer 3	Layer 4	Layer 5	Layer 6	Layer 7
Grid Thickness (m)	50	70	45	50	55	40	100
Pressure (kPa)	10440	10890	11260	11720	12080	12460	13100
Water mole fraction	1	1	1	1	1	1	1
Temperature C	57.4	60.4	63.1	65.2	67	67	67

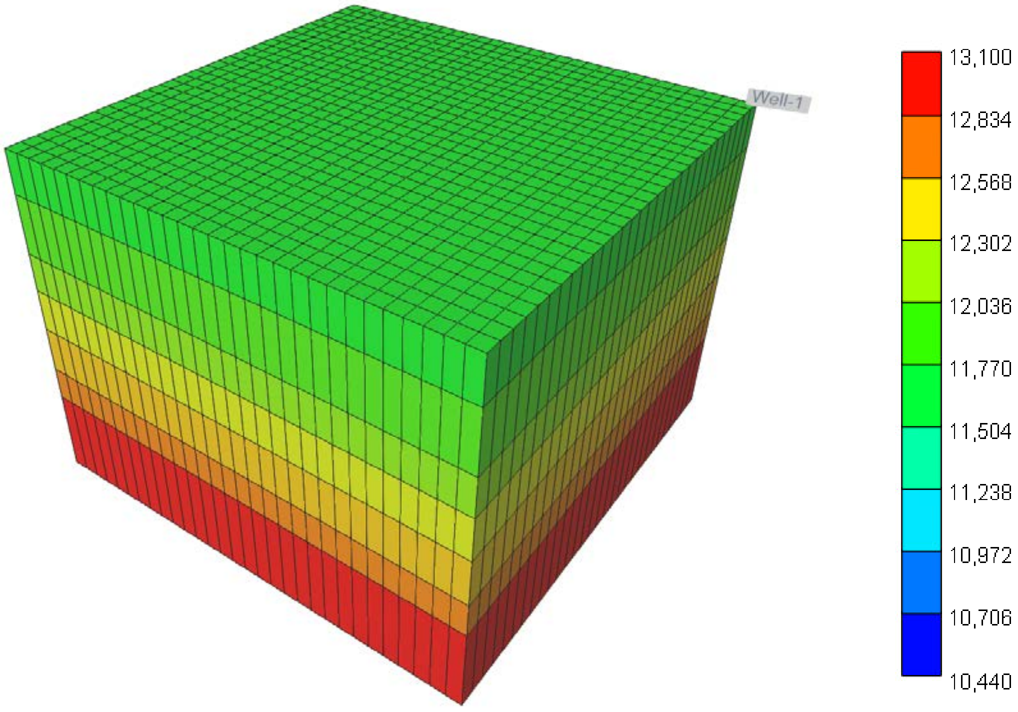

Figure 7. 4. Pressure distribution profile

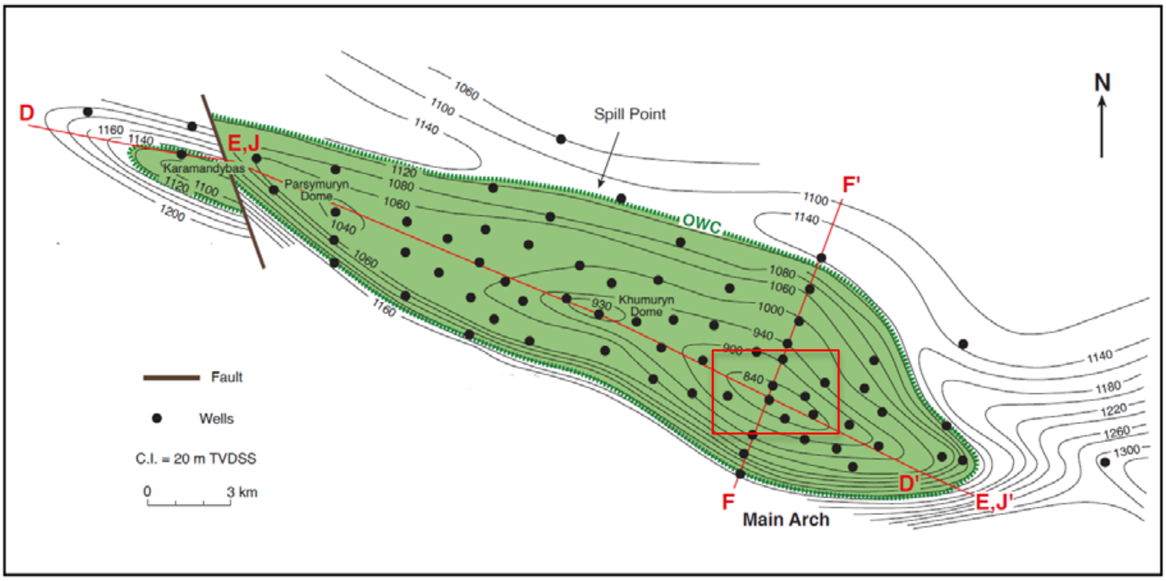

Figure 7. 5. Depth - structure map of the field at the top of unit XIII. The OWC is shown at 1130 m. (Field Evaluation Report, 2010). Red rectangle depicted in the figure shows a quarter 5-spot used for the model development.

Table 7. 4. Basic Well Inputs

Maximum injection rate (m^3/day)	100
Producers bottom hole pressure (kPa)	8000
Well radius (m)	0.0762

Table 7. 5. Aquifer location

Grid Type	From	To
I	1	7
J	1	7
K	30	7