Chair of Reservoir Engineering

Master's Thesis

Effect of Rock Types on Polymer Properties and Incremental Oil Recovery from Polymer Flooding

Heba Eshawesh

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I dedicate this work to the memory of my father

My mother whom I owe everything I have accomplished to,

and my best friend, Aljali Albaden, who has supported me in making my dream a reality.

AFFIDAVIT

I declare on oath that I wrote this thesis independently, did not use other than the specified sources and aids, and did not otherwise use any unauthorized aids.

I declare that I have read, understood, and complied with the guidelines of the senate of the Montanuniversität Leoben for "Good Scientific Practice".

Furthermore, I declare that the electronic and printed version of the submitted thesis are identical, both, formally and with regard to content.

Date 23.07.2020

Signature Author

Heba, Eshawesh

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Abstract

The petroleum industry has shown an increasing interest over the last decade in chemically enhancing the oil recovery in mature fields, especially polymer and alkali-surfactant-polymer injection projects. In Austria, OMV Upstream is injecting polymers into the 8 Torton Horizon and 9 Torton Horizon. Furthermore, an alkali-polymer injection project is planned for the 16 Torton Horizon (TH). These reservoirs consist of heterogeneous sandstones with different rock types, having a different impact on the polymer project intended.

Polymer injection has been one of the most used Enhanced Oil Recovery (EOR) methods implemented worldwide, due to its simplicity and efficiency. Several studies regarding the physical properties of the polymer, such as polymer adsorption, Residual Resistance Factor (RRF), and Inaccessible Pore Volume (IPV) and their impact on oil recovery, were conducted and reported.

Nevertheless, the effect of rock types on polymer behavior and incremental oil recovery was not covered; therefore, a simulation model was set to investigate the impact of having different polymer properties per rock types.

A 2D reservoir model of the 16 TH was used to examine the impact of rock types on polymer behavior and incremental oil production under uncertainty conditions. The variables used in the investigation are RRF, IPV, and polymer adsorption, where the Latin hypercube sampling model generated different variable points within a fixed variance.

Having different polymer physical properties depending on the rock type is shown to impact the polymer performance, and therefore incremental oil production. The recovery factor increased from 42.5% to almost 50% of IOIP in the numerical model based on 16 TH properties by merely understanding the influence of each rock type on the polymer properties.

Hence, understanding the impact of having different rock types on polymer behavior would correctly estimate the amount of oil that will be recovered by injecting polymer. This can be achieved by either increasing the previous laboratory work to reduce the uncertainty or by incorporating the full range of uncertainty, as shown in this work in reservoir simulation of all-polymer pilot evaluations.

Zusammenfassung

Die Erdölindustrie hat in den letzten zehn Jahren ein zunehmendes Interesse an einer chemischen Verbesserung der Ölproduktion in alten Lagerstätten gezeigt, besonderes Interesse gilt Projekten zur Injektion von Polymeren und Alkali-Surfactant-Polymeren. In Österreich injiziert OMV Upstream Polymere in den 8. Torton Horizont und 9. Torton Horizont. Darüber hinaus ist für den 16. Torton Horizont (TH) ein Alkali-Polymer-Injektionsprojekt geplant. Diese Lagerstätten bestehen aus heterogenen Sandsteinen unterschiedlicher Gesteinsarten, die sich unterschiedlich auf das beabsichtigte Polymerprojekt auswirken.

Die Polymerinjektion ist aufgrund ihrer Einfachheit und Effizienz eines der weltweit am häufigsten verwendeten EOR-Verfahren (Enhanced Oil Recovery). Es wurden mehrere Studien zu den physikalischen Eigenschaften der Polymere durchgeführt, wie z. B. Polymeradsorption, Residual Resistance Factor (RRF) und unzugängliches Porenvolumen (IPV) und deren Auswirkungen auf die Entölung. Der Einfluss von unterschiedlichen Gesteinsarten auf das Polymerverhalten und die inkrementelle Ölproduktion wurde jedoch nicht abgedeckt. Daher wurde ein Simulationsmodell erstellt, um die Auswirkungen unterschiedlicher Gesteinsarten zu untersuchen.

Ein 2D-Reservoirmodell des 16. TH wurde verwendet, um den Einfluss von Gesteinsarten auf Polymer und inkrementelles Öl unter unklaren Bedingungen zu untersuchen. Die in der Untersuchung verwendeten Variablen sind RRF, IPV und Polymeradsorption, wo das Latin-Hypercube-Stichprobeverfahren verschiedene variable Punkte innerhalb einer festen Varianz erzeugt. Es kann gezeigt werden, dass unterschiedliche physikalische Eigenschaften des Polymers in Abhängigkeit vom Gesteinstyp die Polymerleistung und damit die inkrementelle Ölproduktion beeinflussen.

Die Entölung stieg im numerischen Modell basierend auf den Eigenschaften des16. TH von 42,5% auf fast 50% des IOIP, indem lediglich der Einfluss jedes Gesteinstyps auf die Polymereigenschaften verstanden wurde. Ein Verständnis der Auswirkung unterschiedlicher Gesteinsarten auf das Polymerverhalten würde daher verhindern, dass die Menge an Öl, die durch Polymerinjektion zurückgewonnen wird, überschätzt oder unterschätzt wird. Dies kann erreicht werden, indem entweder die vorherigen Laborarbeiten vermehrt werden, um die Unsicherheit zu verringern, oder indem der gesamte Unsicherheitsbereich einbezogen wird, wie es in dieser Abhandlung durch eine Lagerstättensimulation von Polymer- Pilotevaluierungen gezeigt wird

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Nomenclature

R_f	Recovery Factor	[%]
N_c	Capillary Number	[-]
v	Fluid velocity	[m/s]
μ	Fluid viscosity	[cP]
σ	Interfacial tension	[N/m]
E_D	Microscopic (Displacement) sweep efficiency	[fraction]
E_S	Macroscopic (Volumetric) sweep efficiency	[fraction]
E_A	Areal sweep efficiency	[fraction]
E_V	Vertical sweep efficiency	[fraction]
M	Mobility ratio	[-]
λ	Fluid mobility	[mD/cP]
k	Absolute permeability	mD
k_r	Relative permeability	mD
k_{ref}	Reference permeability	mD
$\emptyset_z$	Normalized porosity	[-]
$\emptyset_{IPV}$	Inaccessible pore space	[-]
C_p	Polymer Adsorption concentration	[-]
a,b	Adsorption coefficient	
f_w	Water fractional flow	[-]

Abbreviations

EOR	Enhanced Oil Recovery
EMV	Expected Monetary Value
FZI	Flow Zone Indicator
IOR	Improved Oil Recovery
IPV	Inaccessible Pore Volume
IOIP	Initial Oil In Place
RF	Recovery Factor
RRF	Residual Resistance Factor
ROS	Residual Oil Saturation
RQI	Reservoir Quality Index
TH	Torton Horizon

Chapter 1

Introduction

Different Enhanced Oil Recovery (EOR) techniques has been implemented in the last few decades, with the target of increasing the amount of oil recovered from the fields. Applying the precise EOR technique for the reservoir could lead to an increase in total recovery factor up to 30% to 60% of the IOIP (Energy, 2020). The exploitation of new oil fields is becoming more challenging nowadays with the current economy; therefore, the focus is on further developing the existent mature fields that are not yet fully depleted.

Applying polymer flooding as a tertiary recovery mechanism post waterflooding will substantially boost the oil recovery. The main reason for associating polymer with water flooding projects is to increase the injected fluid viscosity and improving the macroscopic sweep efficiency, decrease the water cut, and increase the oil cut. The mechanisms responsible for the additional recovery are explained in 1.1.

1.1 Background Theory

1.1.1 The Principle of Polymer Flooding

Enhanced Oil Recovery processes are responsible for more than 3% of world oil production (J.J Taber, 1997), it is known to be the most implemented chemical EOR process.

Polymer injection can be used as an advanced secondary or tertiary recovery technique to prolong the life of a depleted field (J.J Taber, 1997), with an average polymer flood incremental oil recovery of 8% and 1.8% of the IOIP, respectively (Riley B. Needham, 1987). As can be seen in Figure 1, implementing EOR can increase the amount of oil recovered significantly.

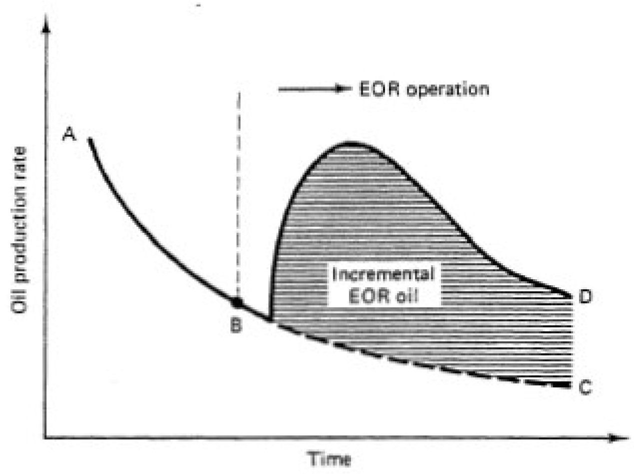


Figure 1-Effect of EOR Operation on Oil Recovery (Sorbie, 1991)

The time-scale of polymer implementation is highly dependent on reservoir conditions and characteristics (J.J Taber, 1997). And when the water flooding is no longer efficient due to high-water production and low oil recovery (Sorbie, 1991).

The success of polymer flooding or any other EOR process can be determined by the amount of additional oil that has been recovered post the initiation of EOR operations (Lake, 1989).

Oil recovered post-EOR is the oil that has been bypassed during the water flooding or trapped by capillary trapping. Trapped oil is immobilized oil due to the capillary forces and is referred to as the residual oil (Lake, 1989).

In order to remobilize the residual oil in the reservoir, the viscous forces must overcome the capillary forces. The relationship between the two forces are linked together using the Capillary Number, N_C:

$$N_C = \frac{v\mu}{\sigma}$$

The viscous/capillary forces relationship can be graphically described using the Desaturation Curve, see Figure 2. The figure shows the magnitude of the critical capillary number that needs to be decreased to remobilize the residual oil.

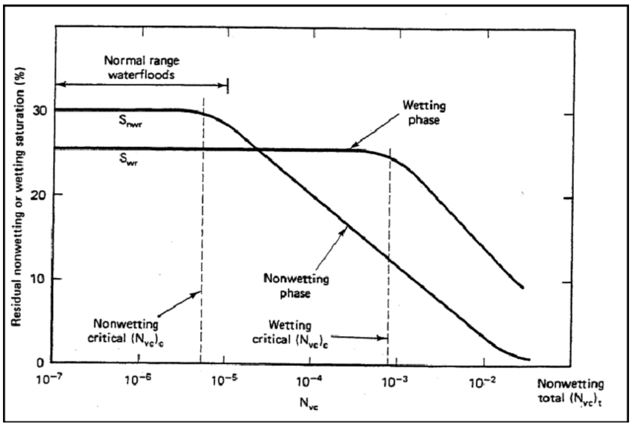


Figure 2 – Desaturation Curve (Mohd Shahid M. Shaharudin, 2013)

The capillary number of waterflooding process is around 10^{-6}; additives are needed to reduce the values and increase the recovery (Lake, 1989). The most used chemicals in the industry to lower the capillary number are polymers and surfactants. The surfactant has much more influence on reducing the capillary number by decreasing the interfacial tension, than polymer by simply increasing the viscosity.

Hence, the polymer is only used to recover the oil that has been bypassed by the flooded water (Lake, 1989) (Riley B. Needham, 1987) (Littmann, 1988). By recovering the bypassed oil, the macroscopic (volumetric) sweep efficiency E_s increases, and consequently, the recovery factor R_f.

The recovery factor is defined as the ratio of the cumulative oil produced to the initial oil in place, and in this context is the product of the microscopic (Displacement) sweep efficiency E_D and the macroscopic (Volumetric) sweep efficiency E_s (Ahmed, 2019)

$$R_f = E_D * E_s$$

The microscopic (Displacement) sweep efficiency is defined as the portion of oil recovered to the volume of oil that has been contacted by the displacing fluid (Ahmed, 2019) (Lake, 1989), and it is expressed as follows:

$$E_D = \frac{Oil\ displaced}{volume\ of\ oil\ contacted\ by\ displacing\ fluid}$$

The macroscopic (Volumetric) sweep efficiency is defined as the volume of the oil that has been contacted by the displacing fluid to the OIIP, and in this context can also be defined as the product of the areal sweep efficiency E_A and the vertical sweep efficiency E_v (Ahmed, 2019) (Lake, 1989)

$$E_s = \frac{Volume\ of\ oil\ contatced\ by\ displacing\ fluid}{IOIP}$$

$$E_S = E_A * E_V$$

The areal sweep efficiency is defined as the ratio between the area contacted by the displacing fluid to the total area. Figure 3 shows the improvement in the areal sweep from a to b, this achievement has been by the polymer flooding (Sorbie, 1991).

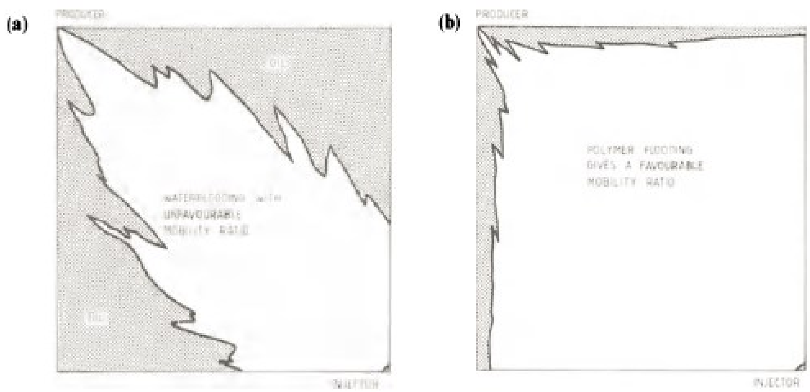


Figure 3-Improvement of Areal Sweep Efficiency caused by polymer flooding (Sorbie, 1991)

The vertical sweep efficiency is defined as the vertical cross-sectional area that has been contacted by the displacing fluid to the total cross-sectional area (Ahmed, 2019) (Lake, 1989). The improve in sweep efficiency is illustrated in Figure 4.

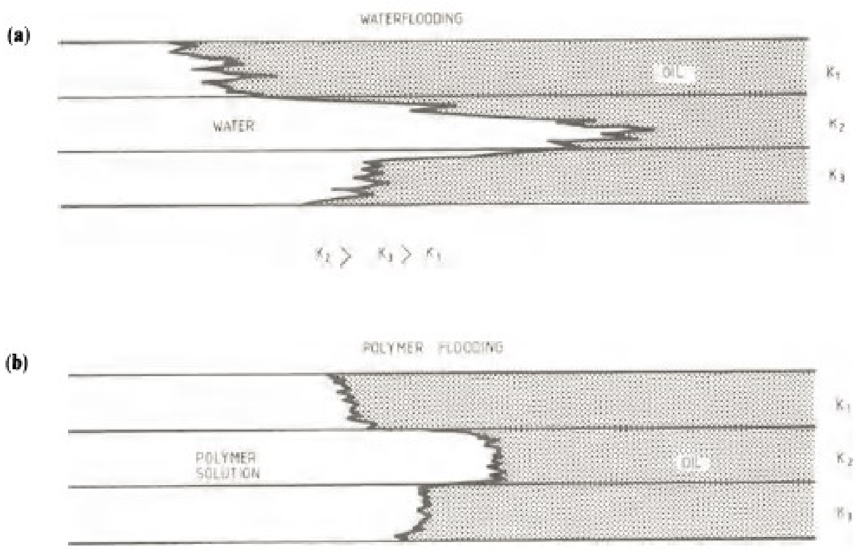


Figure 4 – Improvement of Vertical Sweep Efficiency Caused by Polymer Flooding (Sorbie, 1991)

The macroscopic displacement is improved into more piston-like displacement by controlling the injected fluid mobility, and the polymer is considered to be the perfect candidate for such an application.

Ultimately polymer flooding is used for mobility control, which can be simply described as controlling the rates at which the displacing and displaced fluids move in the reservoir (Don W. Green, 1998) by increasing the viscosity of displacing fluid by adding water-soluble polymer.

The mobility ratio is defined as:

$$M = \frac{\lambda_{Displacing\ Fluid}}{\lambda_{Displaced\ Fluid}}$$

Where

$$\lambda = \frac{Kr}{\mu}$$

The improvement in oil recovery using polymer can be mathematically described and quantified using fractional flow theory, as described in 1.1.3.

1.1.2 Physics of Polymer Flooding

1. Inaccessible Pore Volume (IPV)

Not all pore space is accessible to the polymer solution, due their relatively large molecules. The pore space that is not contacted by polymer is called inaccessible pore volume as shown in Figure 5. (Lake, 1989) (Sheng, 2013)

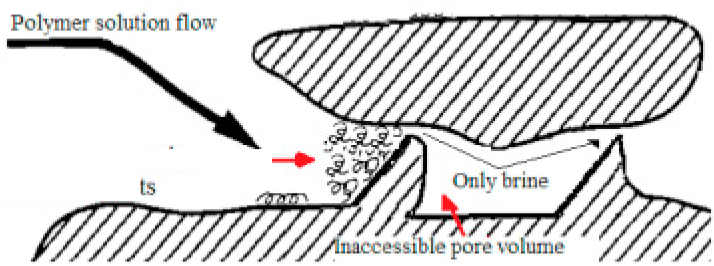


Figure 5 – Schematic Diagram Representing the Presence of IPV (Saeed Akbari, 2019)

Therefore, a portion of the oil in the reservoir is not going to be contacted by the polymer therefore it will not be recovered. As the IPV increases the polymer solution velocity increases, leading to an earlier arrival of the polymer, and consequently the oil.

On the other hand, the polymer might be delayed as a result of polymer adsorption. Therefore, the two phenomena are counterattacking each other with IPV having the most effect (Littmann, 1988) (Lake, 1989) (Sheng, 2013).

The amount of pore space invaded is dependent on polymer molecules, porosity, permeability, pore size distribution, and rock type, where IPV ranges from 1% to 30% (Littmann, 1988). IPV is typically assumed to be constant in the entire reservoir.

$$\Phi_{IPV} = (1 - IPV)\Phi$$

2. Polymer Retention

Polymer retention can be simply described as the process of removing the polymer from the flooded aqueous phase (Sorbie, 1991) (Lake, 1989).

Polymer retention mechanisms are (Figure 6):

1. Hydrodynamic retention
2. Mechanical entrapment
3. Adsorption

Hydrodynamic retention is rate-dependent phenomena; nonetheless, it is neither well defined nor understood, and its contribution to the overall polymer retention is considered to be neglected in field-scale implementation (Don W. Green, 1998) (Sorbie, 1991).

Mechanical entrapment is a more probable accruing mechanism, especially in relatively low permeable formation. Mechanical entrapment occurs when the large polymer molecules get blocked in narrow pore throats. Nevertheless, optimizing the size of the molecules or changing the type of polymer will reduce the retention caused by the mechanical entrapment with maintaining the targeted properties (Don W. Green, 1998) (Sorbie, 1991).

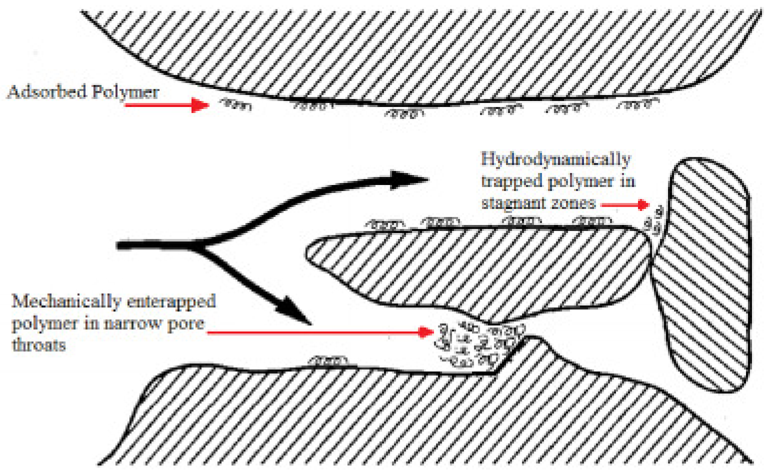


Figure 6 – Schematic Diagram Illustrate Polymer Retention Mechanisms (Saeed Akbari, 2019)

Adsorption is the most crucial mechanism when it comes to polymer retention, and it cannot be avoided even by choosing a different kind of polymer. Adsorption illustrates the interaction between the polymer molecules and the rock surface; the interaction causes the polymer molecules to attach to the solid surface (Don W. Green, 1998) (Lake, 1989) (Sorbie, 1991).

Polymer adsorption can be described using Langmuir-type isothermal:

$$C_p = \frac{aC}{1 + bC}$$

Where C_p is the amount of polymer adsorbed, a and b are empirical adsorption coefficients, and C is the polymer concentration in the aqueous phase. a is calculated as a function of water salinity, average permeability, and the reference permeability.

$$a = (a_1 + a_2 C_{SE})(\frac{k_{ref}}{k})^{0.5}$$

Where a_1 and a_2 are input parameters, C_{SE} is the effective aqueous salinity, k is the permeability, and k_{ref} is the reference rock permeability.

3. Permeability Reduction

The adsorbed polymer will cause permeability to reduce (Lake, 1989). Permeability reduction is defined using the Permeability Reduction Factor or also known as Resistance Factor (Lake, 1989) (Sheng, 2013):

$$RF = \frac{Permeability\ of\ rock\ when\ water\ flows, Kw}{Permeability\ of\ rock\ when\ polymer\ solution\ flows, Kp}$$

Blocking the pores and reducing the permeability is a relatively irreversible process, even with post water flooding. The permeability reduction then will be defined using the Residual Permeability Reduction Factor, also referred to as Residual Resistance Factor:

$$RRF = \frac{Permeability\ of\ rock\ to\ water\ prior\ polymer\ flood}{Permeability\ of\ rock\ to\ water\ post\ polymer\ flood}$$

1.1.3 Fractional Flow Theory

Buckley and Leverett were the first to develop a model for a one-dimensional displacement of oil by water under the assumptions of no mass transfer and incompressible flow.

However, a more complex representation of the fractional flow curve is used in polymer flooding to account for IPV and polymer retention (Pope, 1980); since they are considered to affect the polymer transport in porous media the most (Lake, 1989).

To obtain a simple mathematical and graphical solution for the continuity equation in the presence of polymer, several assumptions were made (Pope, 1980):

1. 1D flow in a homogenous, isotropic and isothermal reservoir
2. Three components and 2 phases are flowing
3. Incompressible fluids
4. Gravity, capillarity, and dispersion are negligible
5. Darcy's law is applicable
6. Continuous injection of constant composition

The fractional flow curve can be constructed using the following equation:

$$f_w = \frac{1}{1 + \frac{1}{M}}$$

Polymer flooding is usually associated with waterflooding projects; therefore, two fractional flow curves are typically constructed to determine the overall recovery. One curve would account for the water-oil flow and the other for polymer-oil flow, as seen in Figure 7.

Increasing the injected fluid viscosity will shift the fractional flow to the left, permitting additional oil to be recovered; however, the velocity at which the polymer solution will flow in porous media is dependent on IPV and polymer retention.

The presence of IPV will lead to faster polymer propagation in the reservoir since the water velocity is the same as the polymer. IPV will account for positive retention governing a faster movement to the polymer and shifting its velocity to the right with a higher slope.

As the effect of polymer retention is much stronger than the IPV effect, the polymer front would have a lower slope than the injected water, and a delay in the front is indicated, as seen in Figure 7.

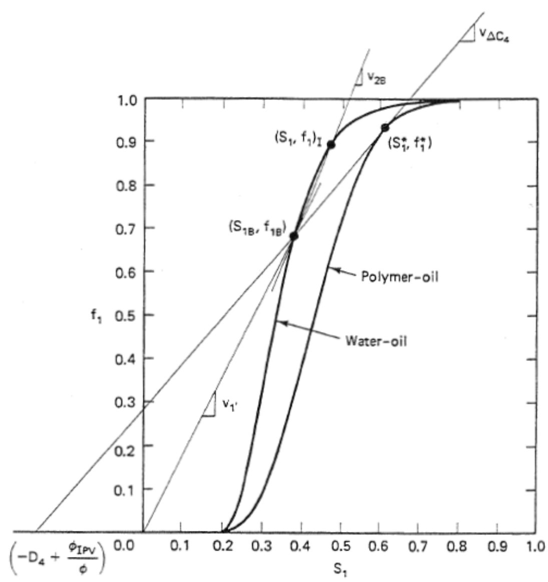


Figure 7- Fractional Flow Curve (Lake, 1989)

The saturation profile is constructed for the recovery, as seen in Figure 8. The saturation profile is illustrating the amount of oil bank formed and displaced by the polymer. A shock front along the polymer-oil fractional flow curve forms the oil bank where its amount will depend on the polymer velocity (IPV and polymer retention). The second front formed would be an indifferent front where the polymer is displacing the oil (Lake, 1989).

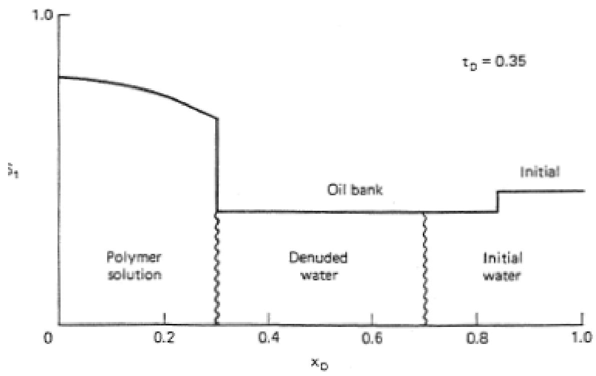


Figure 8- Saturation Profile (Lake, 1989)

1.2 Scope and Objectives

Maximizing the recovery factor of oil fields has been the aim of the industry since almost all large fields worldwide are mature. Due to the simplicity of polymer implementation in the reservoir, it became one of the most used chemical enhanced recovery methods.

OMV, in the last decade, has focused on how to improve polymer flooding to achieve higher oil recovery from its mature assets. Several studies have been conducted by OMV to understand the polymer behavior in core scale and field scale.

Starting with the effect of heterogeneity and polymer rheology on sweep efficiency (Ajana Laoroongroj, 2014). Forecasting the behavior of oil recovery under geological uncertainties (Maria-Magdalena Chiotoroiu, 2016) and establishing guidelines to assess the feasibility of polymer flooding projects (Martin Sieberer, 2016) all studies were conducted on the 8 TH reservoir of the Matzen field in Austria. Improving the understanding of the polymer physical processes would help in making better decisions on reservoir re-development and increase the EMV of these developments accordingly.

One of the aspects of polymer flooding that is yet to be understood is the impact of rock types on polymer and relative permeability parameters on incremental oil production, which is the scope of this work.

1.3 Findings

Polymer properties are sensitive to reservoir heterogeneity, thus the oil recovery. Before, the heterogeneity effect on polymer flooding had been explored by better describing the reservoir geology but with common polymer parameters. This study has shown that there is a high sensitivity to different rock types descriptions and their impact on oil recovery. When rock types exhibit different RRF, IPV, and polymer adsorption values, different oil recovery is reached. In other words, keeping these values constant for all rock types will lead in some cases to overestimating or underestimating the amount of oil recovered. However, no general trend for the effect of RRF, IPV, or polymer adsorption on oil recovery could be found, mainly because understanding the effect of each parameter is a very complex process since the parameters are dependent on the other as explained in section 1.1.2.

1.4 Overview of Thesis

The impact of the polymer physical behavior on rock quality variation has been poorly investigated over the years. The focus in previous studies was put on the understanding of each phenomena's impact on oil recovery. Chapter 2 summarizes the studies conducted to evaluate the effect of polymer physical properties on oil recovery.

Chapter 3 is discussing the approach used to investigate the effect of different polymer properties per rock types and the model used for the investigation.

Chapter 4 is discussing the results obtained on individual parameter alteration and also on the studied dependencies. All results are compared with a base case that is representative of the simulation approach used until now. The base case, therefore, uses common values for the investigated parameters for all rock types on a heterogeneous model.

Chapter 2

Literature Review

The use of polymer-augmented waterflood has proven to be an effective approach to improve the oil recovery and reduce the amount of injection water needed. Evaluating the applicability of polymer flood projects is dependent on several factors, such as displaced fluid viscosity, reservoir heterogeneity, flow rates, polymer-rock-reservoir fluid compatibility, etc.

Understanding the parameters mentioned above requires a comprehensive reservoir characterization and simulation, laboratory experiments, and field testing in order to be able to proceed to the polymer design stage. (R.D.Kaminsky, 2007).

Polymer injection has been successfully applied in many projects since the 1980s, with an estimated recovery of ~ 5% of IOIP. Further understanding of the polymer behavior due to the extensive implementation of polymer projects increased the recovery to range from 11% to 30% of IOIP (J.J.Taber, 1997).

China has reported many successful polymer projects over the years, with average oil recovery being 8.9% of IOIP. One of the projects was Xiaerman Field, a very heterogeneous reservoir with a complex structure. The incremental oil recovery with polymer injection increased to 10% of the original oil in place (Sheng, 2013).

Daqing Field is another successful polymer experience. High molecular weight polymers were injected with a high concentration in January 2009 to increase the incremental oil recovery to more than 10% of IOIP (Sheng, 2013).

To ensure successful polymer flooding projects; certain technical screening criteria have to be met. One of the essential design factors is the oil viscosity, where polymer projects are preferable to be used in reservoirs with oil viscosity ranging between 10 to 100 cP (J.J Taber, 1997). The oil viscosity in fields with ongoing polymer flood projects did not exceed 80 cP (J.J.Taber, 1997). Therefore, the ability of polymer implementation in highly viscous reservoirs is considered to be questionable.

However, a successful polymer flood implementation in Pelican lake Field in Alberta, Canada, changed the previous concept of the viscosity limitation in polymer projects. The reservoir was first discovered in 1978 with an IOIP ~ 6 billion barrels and a primary recovery of less than 7% of IOIP (Wilson, 2015).

Due to the low reservoir energy and high oil viscosity (ranges between 1000 to 2500 cP), an additional recovery technique was needed to increase the oil recovery. Polymer injection was first used as an EOR technique, but due to the thin reservoir section and the high viscous oil, the project was a failure. A solution to further increasing the injected polymer viscosity was implemented, but it failed as a lot of injectivity problems were recognized (Wilson, 2015). Horizontal wells were used to inject the polymer solving the issues that occurred at first and boosted the recovery to more than 25% (Wilson, 2015).

Polymer flooding-horizontal wells combination were again seen successful in two other viscous fields like East Bodo Reservoir in Canada and Tambaredjo Field in Suriname, where both experienced an improvement in the injectivity and additional oil recovery.

The successful implementation of polymer in the previous fields is based on understanding the mechanisms of mobility reduction, where comprehensive laboratory studies, simulation studies, and field pilots were required to characterize the physical behavior of polymer accurately.

The amount of polymer retained in the reservoir determines the rate of polymer propagation; thus, the success of the project (R.N Manichand, 2014).

Adsorbed polymer accounts for about 35% of the total polymer retention (Yoram Cohen, 1986); however, the percentage varies depending on several factors such as the rock type, the type of polymer used, and the injection flow rate (Maerker, 1973).

Permeability is another factor influencing the polymer adsorption. Generally, the permeability of more than 500 mD will not lead to polymer adsorption, since the adsorbed polymer is inversely proportional to permeability (R.N Manichand, 2014).

The influence of residual oil saturation (ROS) on polymer adsorption is still debatable; where some might argue the presence of ROS decreases the adsorption to half (D.S. Hughes, 1990)

(C. Huh, 1990), others contradict the relation. Fully characterizing the polymer behavior in the reservoir is still a working process, since, with each new project, further understanding is obtained.

Besides understanding the dependent factors, accurately quantifying, and indicating the presence or the lack of adsorption is needed. Numerous approaches have been used to quantify the amount of polymer adsorbed, either by mass balancing the injected polymer or by simply exposing the polymer solution to the reservoir rock and measuring the amount adsorbed. Each of the approaches has its limitation and advantages.

As a result of polymer being adsorbed to the rock surface, a delay of polymer propagation in the reservoir will be seen and compensated by IPV.

It has been noted that polymer molecules propagate faster than salt in the solution (Lantz, 1972). The large polymer molecules govern the rapid propagation compared to the small molecules of salt or even polymer (Qingong He, 1990).

IPV is still a not well-understood phenomenon; some might argue that the pores are not wide enough to allow the entry of polymer molecules (Lantz, 1972). But that would not be the case for moderate to high permeable formations, where the pores and the pore throats are considered to be large enough to permit the polymer flow unless clay is present.

But it is still not a well-supported hypothesis; hydrodynamic exclusion is another theory used in the industry to explain IPV (Sorbie, 1991). Hydrodynamic exclusion or depletion layer is described, such as if the polymer does not adsorb on the rock surface, then the large polymer molecules cannot get close either to the pores or the rock surface. Keeping the flow of polymer molecules concentrated on the center, then no polymer will be able to get close to hydrocarbon filled pores. However, IPV resulted from hydrodynamic exclusion cannot exceed 9% (W.C. Liauh, 1979).

But still, all previously mentioned theories are theories, and there is no substantial evidence that proves one over the other. Based on the arguments, the IPV should be proportional to permeability. However, the values that are reported in the literature contradict that assumption. A ~ 500 mD sandstone and ~ 2 Darcy found to experience the same IPV, and this can be explained by different rock types (Lantz, 1972).

Although the justifications behind IPV are yet not well understood, its effect is. Polymer molecules will propagate faster in porous media as IPV increases and counteract the impact of the polymer retained. Hence to recover the inaccessible hydrocarbon, other chemical EOR processes are used, such as Surfactant-Polymer injection or Alkali-Surfactant-Polymer injection.

Another polymer adsorption related to physical phenomena is permeability reduction. Where it is expressed in terms of RF and RRF, RRF is considered another mobility control criteria in polymer projects.

Polymer velocity and concentration are main driven parameters to a favorable RRF, where it has been found that optimizing the polymer concentration would lead to a substantial increase in RRF (Shi Leiting, 2010).

An increase in RRF would lead to an increase in the incremental oil recovery as a result of permeability reduction and improving the mobility control; doubling the RRF from 3 to 6 increased the incremental oil recovery by 4.5 times according to (Shi Leiting, 2010) in a relatively heavy oil reservoir.

Heterogeneity in permeability is another huge contributor to adsorption. As the permeability decreases the possibility of polymer adsorbing on the rock surface increases, resulting in blocking the pore throat, reducing the flow channels and increasing the RRF values (Byungin Choi, 2015).

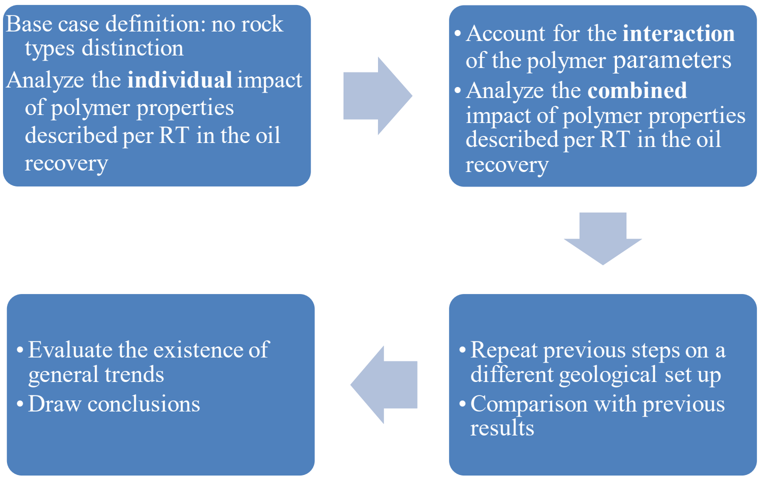
Low permeable formation results in high RRF and crossflow of polymer into the more permeable formation, the opposite would happen in high permeable formations.

Chapter 3

Methodology

The successful implementation of a polymer injection project requires an extensive understanding of its physics. As mentioned above, the effect of different rock types (RT) that are usually present in an oil reservoir on polymer properties is yet to be investigated.

In order to accomplish a reliable oil recovery forecast during a polymer project, a comprehensive workflow that accounts for the effect of different rock types was followed as shown:



The analysis started with a cross-section model of the representative reservoir; the model was provided by OMV. A detailed description of the reservoir, its rock properties, and fluid are shown in the next section.

The rock type-dependent parameters that were investigated are listed as follows:

1. Permeability Reduction in terms of RRF
2. Inaccessible Pore Volume
3. Polymer Adsorption

The effect of each variable was analyzed independently and combined using the tNavigator uncertainty analysis tool.

For further elaboration of the workflow, see the next sections.

3.1 Model Description

To investigate the effect of rock dependent polymer properties on incremental oil recovery, a 2D reservoir model is provided by OMV, as seen in Figure 9. The model properties are based on Matzen field, 16 Tortonian Horizon reservoir.

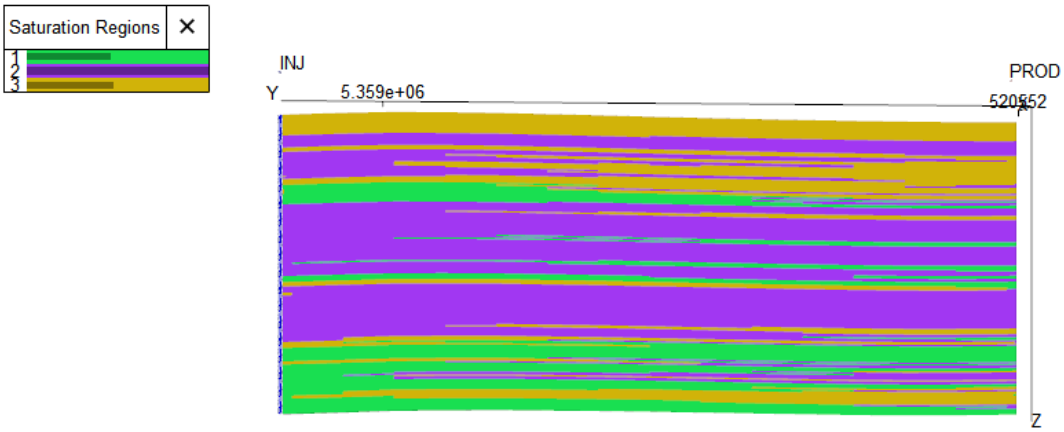


Figure 9 – 2D Reservoir Model

The reservoir model consists of three different rock types extended over a distance of 146 m between an injector (BO119) and a producer (BO98) and a thickness of almost 55m; it is discretized into 5200 active cells (26*1*200).

The general reservoir and fluid properties are summarized in Table 1.

Table 1 – Rock and Fluid Properties

Reservoir Pressure, bar	144
Bubble Point Pressure, bar	10
Dissolved Gas, sm^3/sm^3	3.58
Oil Gravity, API	30.3

Rock Compressibility, bar^{-1}	1.60428E-05
Water Compressibility, bar^{-1}	4,2912E-05
Water Formation Volume Factor, rm^3/sm^3	1.0064
Water Viscosity, cP	0.42135

Oil properties such as compressibility, viscosity, and formation volume factor were included in tNavigator as a function of pressure, as seen in Figure 10.

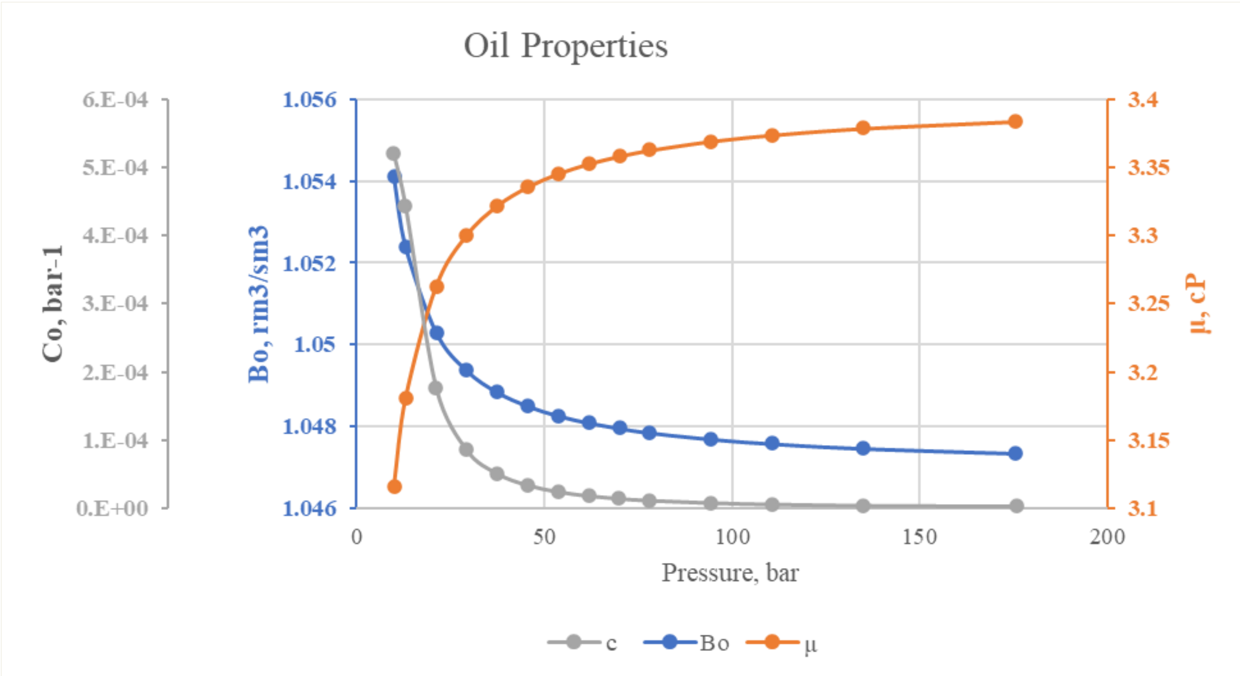


Figure 10 – Oil Properties as Function of Pressure

As mentioned above, the reservoir is composed of three different rock types that were identified using the Flow Zone Indicator (FZI) (Jude O. Amaefule, 1993). The theory behind FZI is that the hydraulic quality of the reservoir rock is controlled by the pore throat, thus mineralogy where various geological attributes in the reservoir are found to have the same pore throat, consequently the same hydraulic quality (Jude O. Amaefule, 1993):

$$FZI = \frac{RQI}{\emptyset_z}$$

$$RQI = 0.314\sqrt{\frac{k}{\emptyset}} \qquad \emptyset_z = \frac{\emptyset}{1-\emptyset}$$

Each rock type was assigned a distinct permeability function as seen in Figure 11, which helps introduce heterogeneity into the reservoir model. Figure 12 shows the grain size distribution of each rock type that has been considered here.

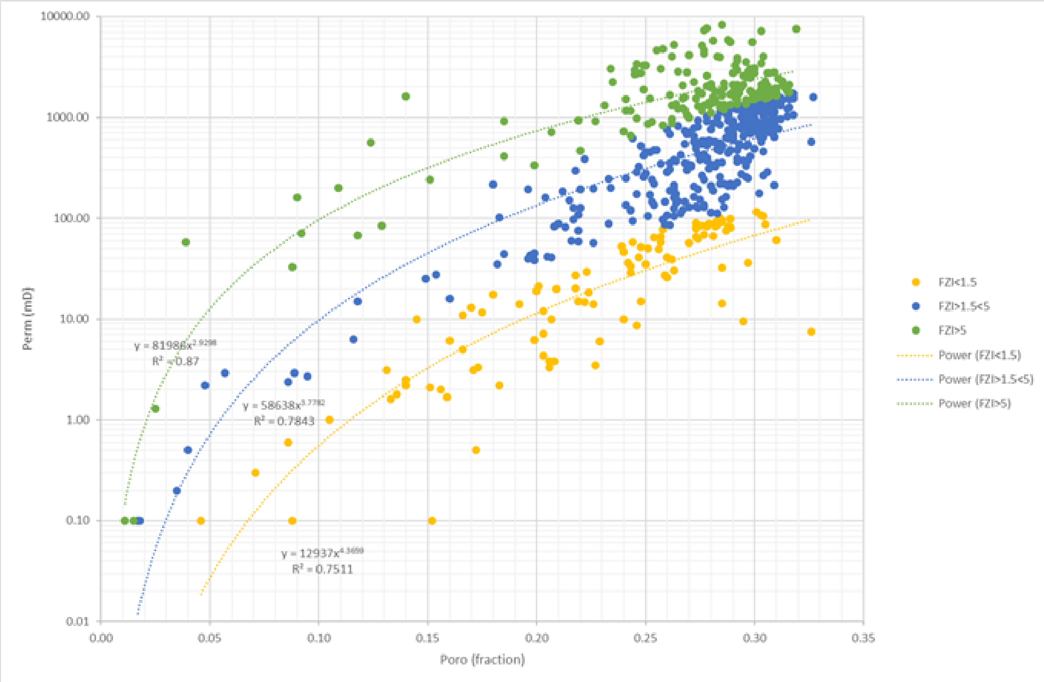


Figure 11-Permeability-Porosity Relationship (Cabas, 2018)

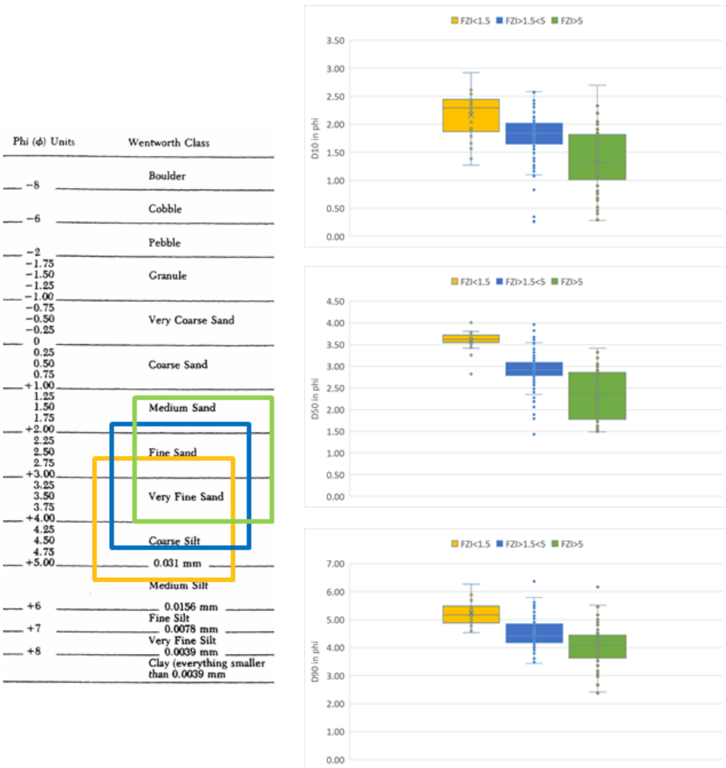


Figure 12- Rock types grain size distribution (Cabas, 2018)

The variation of permeability and porosity between the rocks has fulfilled the scope of the project, see Figure 13. Following a description of each rock type is given in Table 2:

Table 2 – Rock Type Description

	Clean Sandstone	Fine Sandstone	Silty Shale
Rock Type	1	2	3
Region	1	2	3
Average Porosity, %	31	26	12
Average permeability, mD	2650	360	1.2
Thickness, m	~ 15	~ 30	~ 7
Oil In Place IOIP, sm^3	421.92	704.73	217.1
Oil Recovered during Waterflooding, sm^3	310.87	186.62	1.33
Dissolved Gas In Place, sm^3	1497.2	2517.2	776.55

The simulation timeframe is set to start production using waterflooding for five years. Two tracers during that duration are injected, first at the beginning of the simulation for a month and the second 2 years later for a month duration.

The polymer injection starts five years later, for one whole year, followed by five years of water injection. The injection rate is assigned to replace the gross amount produced, which is 1.44 sm^3/day.

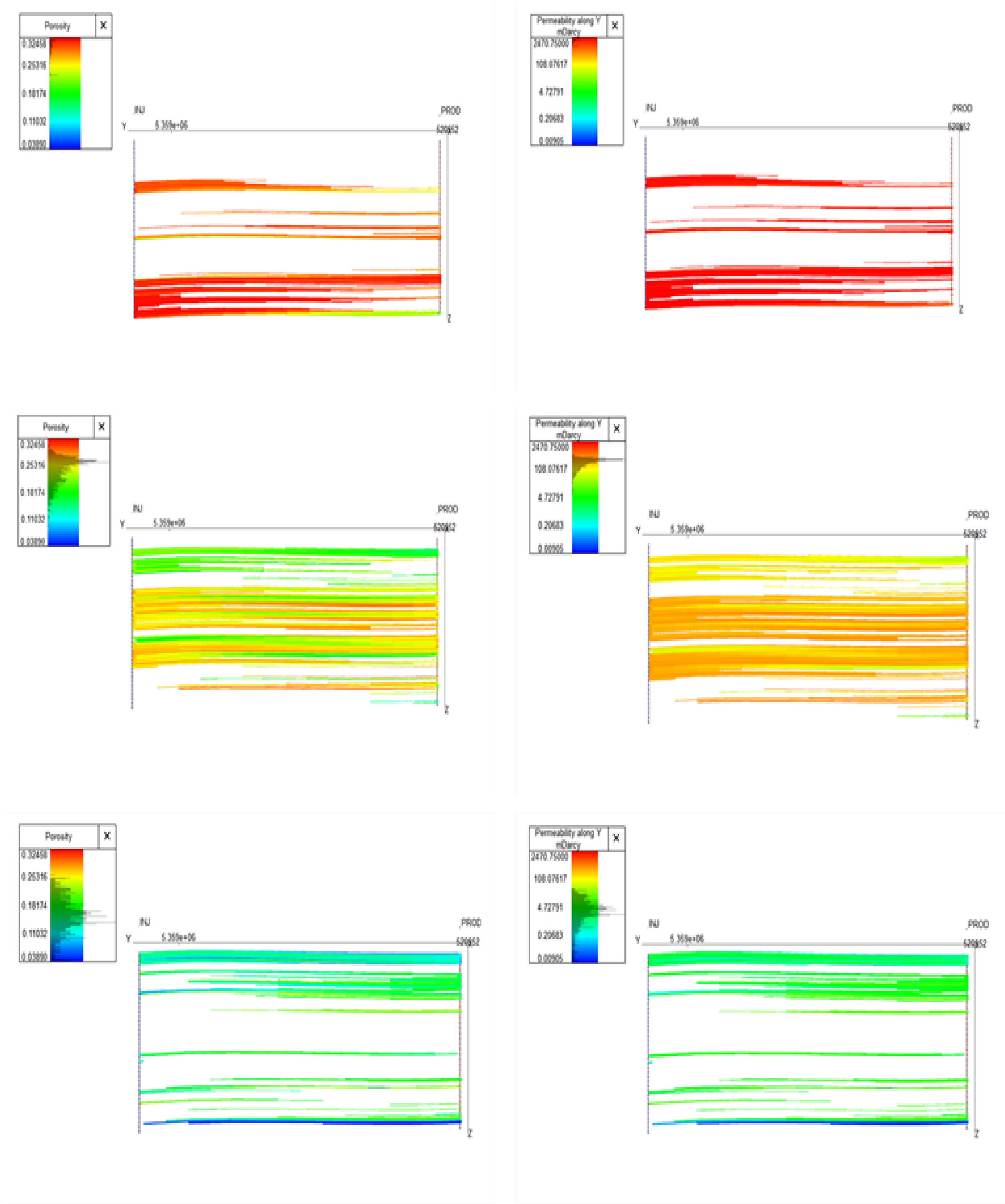


Figure 13 – Porosity and Permeability Distribution in the Model for each Rock Type, Clean Sandstone on top, Fine Sandstone in the middle and Silty Shale in Bottom

3.2 Uncertainty Analysis

The scope of the project is to investigate the effect of describing IPV, RRF, and adsorption per each rock and analyze their impact on oil recovery. To do so, tNavigator Assisted History Matching AHM and Uncertainty tool was used.

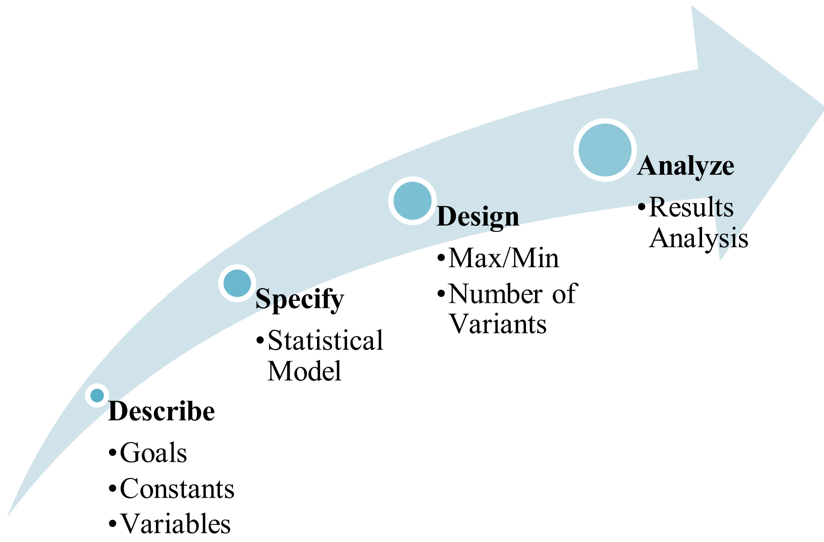
To start with the sensitivity analysis, an understanding of Design Of Experiments DOE is required. DOE is aimed at describing and explaining the diversity of information under conditions that are assumed to reflect variance.

The objective here is to determine the relationship between the investigated factors (polymer properties per rock type) affecting the process and the output of the process (incremental oil recovery).

The analysis is done based on the hypothesis test theory to determine the most influenced factors using statistical methods (Latin Hypercube sampling is chosen as seen below).

Two possibilities for the hypothesis theory are presented, the null hypothesis which is what has been done for the last decade by describing the polymer properties for all rock types as one and its impact on the incremental oil recovery. The second hypothesis is the alternative hypothesis, which is investigated in this study: the objective here is to investigate the impact of having different rock types uniquely described by polymer properties, on the incremental oil recovery.

The DOE workflow is shown next, followed by a detailed description of the work done.



Using the workflow as a guideline, the following steps were followed:

- Describing the goal needed to be achieved by the project, which is fully understanding polymer behavior under the mentioned conditions. The studied parameters were chosen to be IPV, RRF, and adsorption tables.
- Latin Hypercube was the statistical model used here. Latin Hypercube Sampling (LHS) is a method of generating random samples of the chosen parameters. LHS is based on the Latin square design, where the algorithm creates for N variants and M variables a search space. The search space is divided into N hyperplanes which then N points are generated to fill the hyperplanes, limiting the points to one per hyperplane as seen in Figure 14

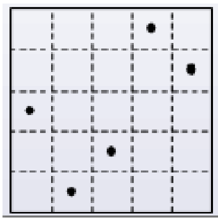


Figure 14-Latin Hypercube Theory

- The ranges for every examined parameter were chosen based on the type of rock and values mentioned in the literature.
  Table 3 summarizes the ranges assigned for each rock type

Table 3 – Investigated Parameters and their Ranges

Parameters \ Rock Type		Clean Sandstones		Fine Sandstones		Silty Shale	
		Min	Max	Min	Max	Min	Max
RRF		1	10	1	15	1	20
IPV		0	0.33	0	0.40	0.25	0.45
Polymer Adsorption	a_1	0	1	0	1	0	1
	b	1	10	1	10	1	10
Polymer Concentration, kg/sm^3		2					
Viscosity Multiplier		43.3					

The equation used in the model assumes that the flow of polymer solution in the reservoir will not influence the flow of hydrocarbon; therefore, the standard black oil equation is used to describe the hydrocarbon movements.

However, the water phase equation needed to have some modification and some addition. The first equation describes the effect of the polymer on the flow of the aqueous phase:

$$\frac{d}{dt}\left(\frac{VS_w}{B_rB_w}\right) = \sum\left(\frac{Tk_{rw}}{B_w\mu_{w.eff}R_k}(\delta P_w - g\rho_w D_z)\right) + Q_w$$

$$\frac{d}{dt}\left(\frac{V^*S_wC_p}{B_rB_w}\right) + \frac{d}{dt}\left(V\rho_r C_p^a \frac{1-\varphi}{\varphi}\right) = \sum\left(\frac{Tk_{rw}}{B_w\mu_{w.eff}R_k}(\delta P_w - g\rho_w D_z)\right)C_p + C_pQ_w$$

The left-hand side of the previous equation represents the polymer adsorption, with the need for specifying C_p, which is using Langmuir-type isothermal:

$$C_p = \frac{aC}{1+bC}$$

$$a = (a_1 + a_2C_{SE})(\frac{k_{ref}}{k})^{0.5}$$

In the model, the salt concentration was set to zero. K is the average block permeability, which is set to be 509.03 mD, and the reference permeability is the permeability for each rock type, which was previously mentioned in Table 2.

V^* accounts for the IPV with:

$$V^* = V(1 - S_{IPV})$$

Where V is the block pore volume, and S_{IPV} donates the inaccessible pore volume on each grid block.

The polymer adsorption will cause the permeability to be reduced, to quantify the amount of reduction of RRF value needs to be assigned to the next equation:

$$R_k = 1 + (RRF - 1)\frac{C_p^a}{C_p^{amax}}$$

C_p^{amax} needs to be specified for each rock type.

- The main discussion and results obtained from the simulation model are analyzed in the next chapter

3.3 Base Case Description

To establish a baseline, the first simulation models were created without addressing the impact of rock types. Rock types present in the model were only used for the description of saturation functions (i.e. relative permeabilities and capillary pressure). The polymer parameters were varied one at the time within the ranges presented before for the entire reservoir. The results of this experiment provided an insight into how the models were used before this investigation would perform. The comparison between this baseline and the investigated properties described by rock types are presented in the next chapter.

Chapter 4

Results and Discussion

In this chapter, simulation results and sensitivity analysis of the effect of different rock types on polymer behavior and incremental oil recovery are presented. The results would help to appropriately characterize the polymer behavior in the presence of different rock types by addressing the most influencing physical properties mentioned in 1.1.2.

For simplicity, the concentration-viscosity relation is assumed to be linear, simulating a Newtonian flow behavior of a target viscosity of 21.6 cP (43.3 times the water viscosity) of the polymer solution. It has been assumed that the rock type has no effect on the polymer viscosity, and no shear thinning or thickening since the model used is a simple 2D model (having a linear velocity with no significant variation).

The cross-section model is set to replace the voidage in the reservoir, where the injection volume is equal to the produced liquid, the production rate is set at 1.44 sm^3/day to achieve the conventional displacement at reservoir conditions of 1 ft/day, this value is considered to be small therefore the effect of hydrodynamic entrapment is neglected. The polymer is injected for one year at a concentration of 2 kg/sm^3, the total volume injected is 0.3 pore volume. The amount of oil recovered by the waterflood is 37.3% of IOIP.

The sensitivity analysis conducted to characterize the behavior of polymer and incremental oil recovery in the presence of different rock types are summarized next.

The investigation started by ideally generating a base case, which is used to compare the approach suggested in this thesis (characterizing the polymer properties per rock type) to the literature used approach.

Cases	Case Description	Parametric study	Results Summary
Effect of RRF	Investigating the effect of describing RRF per rock type while constant ADS and IPV is assumed for all RTs.	Individually varying RRF for RT1 (Figure 18)	An increasing trend in incremental recovery as RRF in RT1 increases. RT1 is the greatest positive contribution (Figure 19)
		Individually varying RRF for RT2 (Figure 18)	A slight decrease in the recovery as RRF in RT2 increases
		Individually varying RRF for RT1 (Figure 18)	Almost a plateau recovery is obtained as RRF in RT3 increases
Effect of IPV	Investigating the effect of describing IPV per rock type while constant ADS and RRF is assumed for all RTs.	Individually varying IPV for RT1 (Figure 20)	A decreasing trend in the recovery (~0.04% point $\downarrow$) as IPV in RT1 increases
		Individually varying IPV for RT2 (Figure 20)	An increasing trend in the recovery (~0.04% point $\uparrow$) as IPV in RT2 increases
		Individually varying IPV for RT3 (Figure 20)	Almost a plateau recovery is obtained as IPV in RT3 increases
Effect of ADS	Investigating the effect of describing ADS per rock type while constant IPV and RRF is assumed for all RTs.	Individually varying ADS for RT1 (Figure 22)	A decreasing trend in recovery as ADS in RT1 increases
		Individually varying ADS for RT2 (Figure 22)	

		Individually varying ADS for RT3 (Figure 22)	No dependency is found between varying ADS for RT1 and RT2 and incremental oil recovery
Effect of RRF and ADS	Investigating the dependency of RRF and ADS on incremental oil recovery per rock type, at constant IPV. RT3 is excluded from the analysis as its impact is negligible, due to its low permeability.	Simultaneously varying the ADS for RT1and RT2 at constant RRF RT2 and varied RRF in RT1 (Figure 23)	No general trend is observed between recovery and RRF. In comparison with the base case, 2.87% increase in the recovery is seen (Figure 25)
		Simultaneously varying the ADS for RT1and RT2 at constant RRF RT1 and varied RRF in RT2 (Figure 24)	No general trend is observed between recovery and RRF. In comparison with the base case, 1.71% decrease in the recovery is seen (Figure 25)
Effect of RRF, ADS, and IPV	Simultaneously varying IPV, RRF, and ADS. RT3 is excluded from the analysis as its impact is negligible, due to its low permeability.	Simultaneously varying the ADS and RRF for RT1and RT2 at constant IPV RT2 and varied IPV in RT1 (Figure 26)	No significant impact of IPV is observed
		Simultaneously varying the ADS and RRF for RT1and RT2 at constant IPV RT2 and varied IPV in RT1 (Figure 26)	
Geological impact	Investigate the impact of geological configuration on polymer behavior and oil recovery.	Implement the same workflow applied above (Figure 30 and Figure 31)	Trend obtained is similar to previous results

4.1 Basecase Results

As mentioned in 3.3, the investigated parameters are described for all RTs as one. The results obtained are then used in comparison with describing polymer properties per rock type.

Figure 15 shows that as the RRF increases an increase in the incremental oil recovery is observed, this behavior is indicated from the previously conducted studies (see Chapter 2). However, a decreasing trend is observed in the incremental recovery as IPV increased and less pore volume is contacted by the polymer which is illustrated in Figure 17.

Decreasing the polymer concentration as more polymer is adsorbed into the rock will lead to a decrease in the amount of oil recovered, see Figure 17.

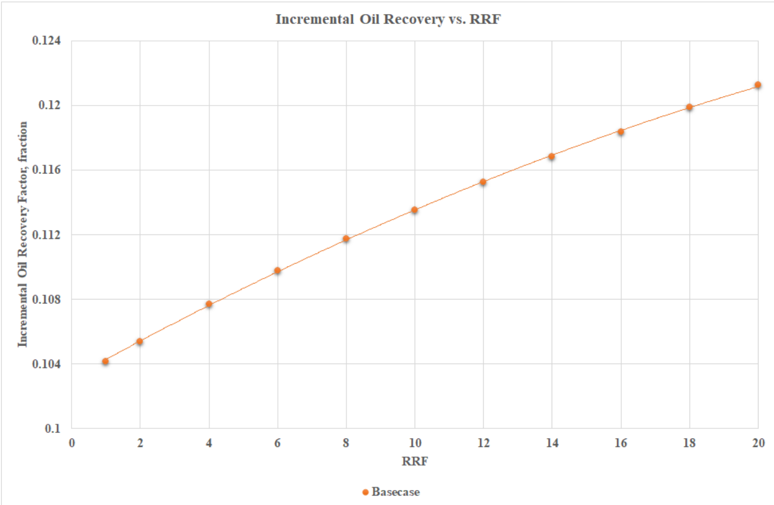


Figure 15- Effect of Describing the RRF for all RTs as one

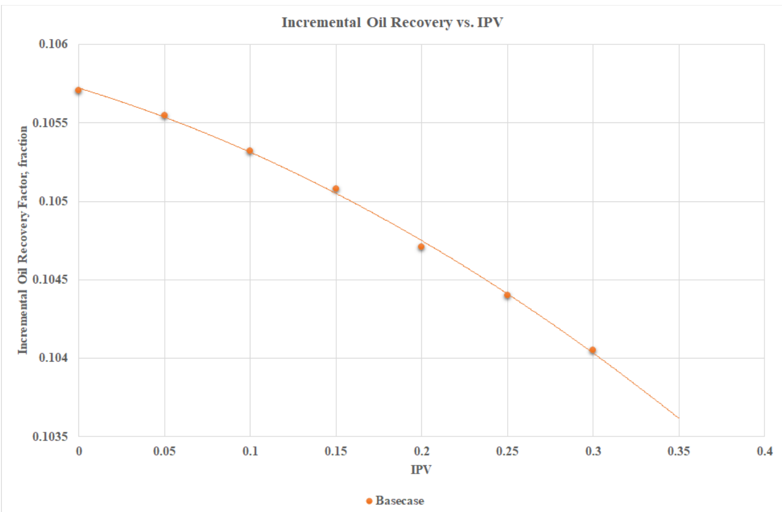


Figure 16- Effect of Describing the IPV for all RTs as one

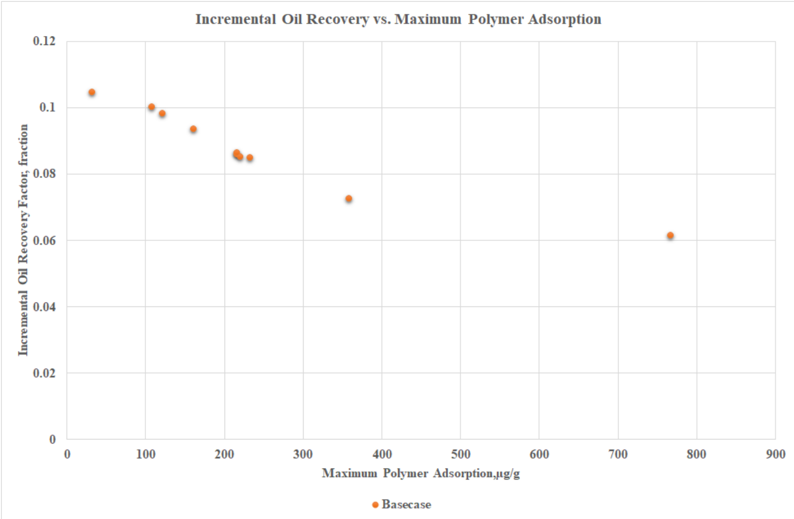


Figure 17- Effect of Describing the Polymer Adsorption Coefficient for all RTs as one

4.2 Parametric Studies

4.2.1 Effect of Varying Residual Resistance Factor (RRF)

The effect of varying the RRF in the presence of different rock types on incremental oil recovery is evaluated at constant IPV of 20% for the RT1 and RT2, and 25% for RT3. Due to its significantly lower permeability, RT3 is expected to have a higher IPV. The maximum adsorption values for RT1, RT2, and RT3 are kept constant at 31.8 µg/g, 11.7 µg/g, and 0.68 µg/g, respectively.

Figure 18 shows the effect of assigning different RRF for each rock type on the incremental oil recovery in comparison with constantly varying the RRF for all RTs (Basecase) all at constant adsorption and IPV values.

RRF was varied between 1-20, exceeding the value of 1.456 that has been used previously by OMV.

In the Basecase, the incremental oil increases as the RRF increases for all observed values. Constantly increasing the RRF values would lead to a reduction in the permeability of rock to water, accordingly a decrease in the system mobility ratio is observed and a delay in polymer propagation. As the polymer is coating the rock surface with a hydrophilic film that will swell as water passes, leading to a reduction in effective permeability of water. Such swelling does not accrue when oil is passing improving the oil recovery.

According to the Buckley-Leverett solution in Chapter 1, a further decrease in the mobility ratio that is caused by the reduction of the water permeability will tend to shift the S-shape curve to the right, permitting additional oil recovery, consequently improving the volumetric sweep efficiency across all RTs.

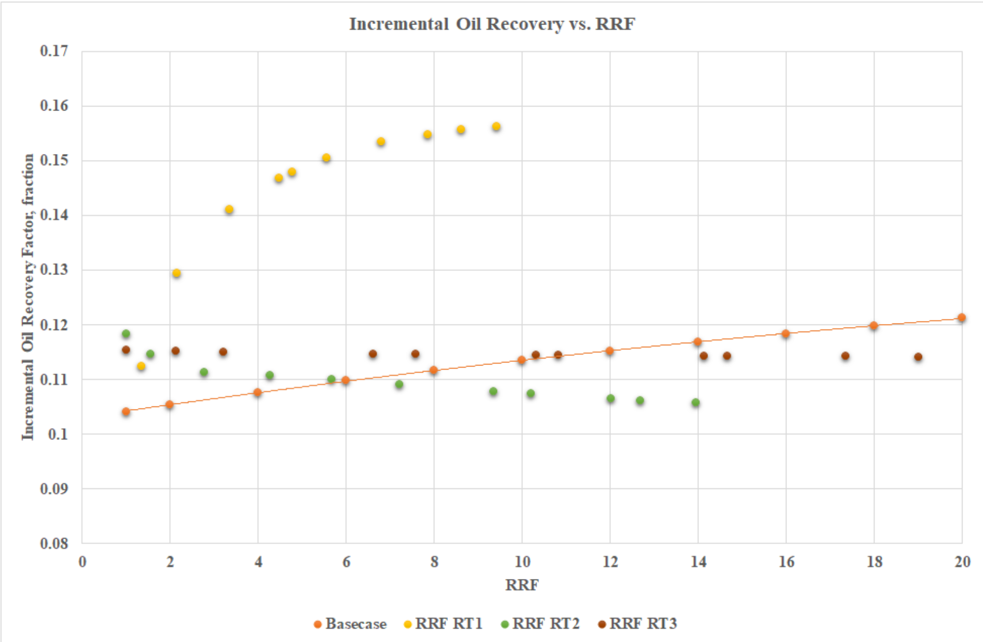


Figure 18– Effect of varying RRF in different RTs on Incremental Oil Recovery. For the sensitivity analysis, the non-varying RRF is fixed as 1.456 for all RTs

- **Varying RRF for RT1, whereas RT2 and RT3 are kept constant at 1.456**

Varying RRF RT1 significantly impacts the incremental oil recovery compared with the Basecase. As the RRF RT1 increases, the permeability to water within RT1 will decrease causing a volumetric sweep efficiency improvement. promoting the path for the polymer to flow through the less resistant path along RT2 and recovering the majority of the bypassed oil. Improving the vertical sweep efficiency will lead to a better polymer propagation across RT2, where improving the areal sweep efficiency will lead to better sweep of oil within RT1 and RT2.

Improving the vertical sweep efficiency will lead to a corresponding increase in the oil recovery associated with RT2 since most of the remaining oil post waterflood is located in RT2 (~ 38% of IOIP), the RT3 contribution to oil recovery is negligible since there it is not accessible to polymer due to its low permeability. The oil distribution in RT2 is originally higher than it is in RT1 and RT2 with 52.4% of IOIP, and during water flooding, only 13.89% of IOIP was produced from RT2.

Varying the RRF RT1 increases the incremental oil recovery from 10% of IOIP to ~15.6% of IOIP compared with an increase of ~ 2% points governed by the Basecase. Describing the polymer behavior per rock type will yield substantially different recovery values, especially with the better rock type RT1.

- **Varying RRF for RT2, whereas RT1 and RT3 are kept constant at 1.456**

Varying RRF RT2 has a negative impact on the incremental oil recovery. Further decrease in permeability within RT2 will lower the ability for the polymer to propagate causing a reduction in overall volumetric sweep efficiency since the remaining oil within RT2 will not be efficiently swept. As the rock permeability to water in RT2 decreases preventing the polymer propagation, the vertical sweep efficiency decreases, permitting a faster polymer propagation within RT1, bypassing ~ 38% of IOIP within RT2. Again, the recovery from RT3 is minor and can be neglected.

- **Varying RRF for RT3, whereas RT1 and RT2 are kept constant at 1.456**

Varying RRF for RT3 does not have an impact on incremental recovery since a further reduction of ~ 1.2 mD permeability will not aid the recovery nor the sweep efficiency. Therefore, the polymer front will propagate through RT1 at a rate higher than RT 2 as a result of rock permeability contrast.

Analysis

Additional oil obtained by polymer flood is associated with RT2, the medium quality rock class with intermediate permeability; therefore, the amount of oil recovered from RT2 will determine the improvement of the volumetric sweep efficiency.

As shown in Figure 18, varying RRF RT3 is independent of incremental oil recovery; however, varying RRF RT1 will positively impact the recovery since the vertical sweep efficiency will be improved to recover more oil from RT2 (permeability to water is reduced within RT1 promoting a less resistance path along RT2). But the permeability reduction associated with varying RRF RT2 will negatively impact the recovery as a result of poor improvement of volumetric sweep efficiency.

The effect of different RTs and RRF on the incremental oil recovery is seen in Figure 19, where RT1's effect on the incremental oil recovery is clear, reduced permeability in RT1 which is the best rock class with Darcy level permeability will lead to a better mobility control with the possibility of ~39% increase in the recovery compared to the Basecase.

The effect of varying RRF for RT2 and RT3 on the incremental oil recovery is not as significant as RT1. Still, the combination of all RTs will lead to a significant increase in the recovery. Results obtained in the sensitivity analysis presented in Figure 19, suggests that describing the permeability reduction per rock types will lead to an increase in the incremental oil recovery. However, the permeability reduction is highly affected by the polymer adsorption, and to conclude, a dependency investigation of RRF on the adsorption is done.

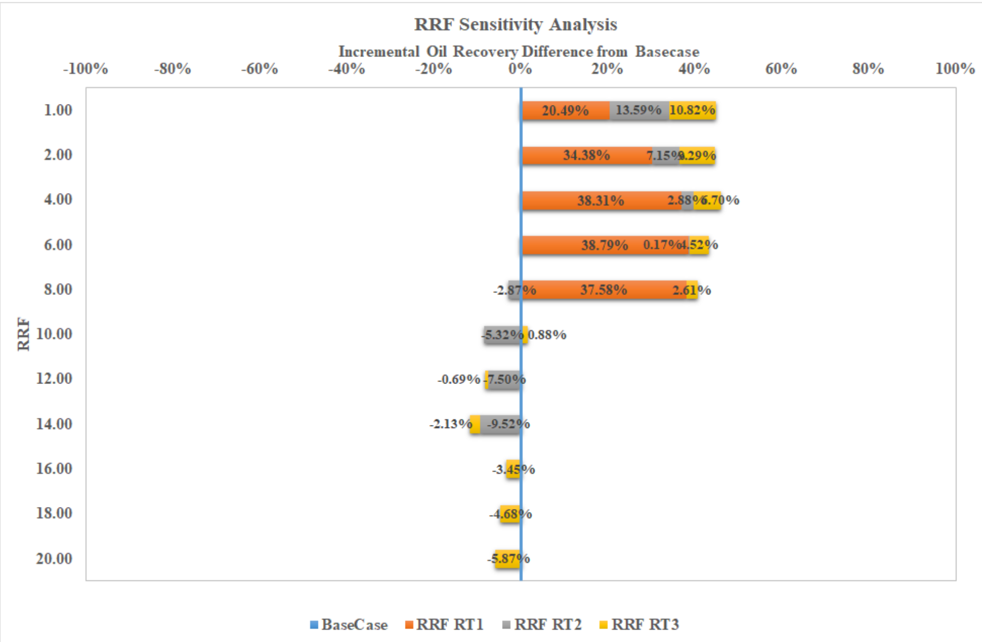


Figure 19- Sensitivity Analysis for RTS on RRF and Incremental Oil Recovery Difference from Basecase

4.2.2 Effect of varying the Inaccessible Pore Volume (IPV)

In order to investigate the effect of having different IPV in each RT on incremental oil recovery, several simulation runs were done at constant RRF values of 1.456, and the maximum adsorption values of 31.8 μg/g, 11.7 μg/g, and 0.68 μg/g, for RT1, RT2, and RT3, respectively.

Figure 20 indicates the Basecase of constantly varying the IPV for all RTs at constant RRF of 1.456 and maximum adsorption values of 31.8 μg/g, 11.7 μg/g, and 0.68 μg/g, for RT1, RT2, and RT3 has a negative impact on the recovery. Constantly increasing the IPV for all RTs will reduce the recovery by 0.2% points, since with the basecase all RTs will be treated as one the preference is still the path along RT1. In theory, increasing, IPV will increase the polymer propagation in the reservoir and will promote a faster arrival of the oil but at the same time, a large portion of the reservoir will not be contacted by the polymer.

Higher IPV means a lower slope of polymer velocity in the Buckley-Leverette solution; lower slope implies higher polymer velocity, which will lead to a decrease in the height of the oil bank formed as mentioned in 1.1.3, thus a decrease in the recovery.

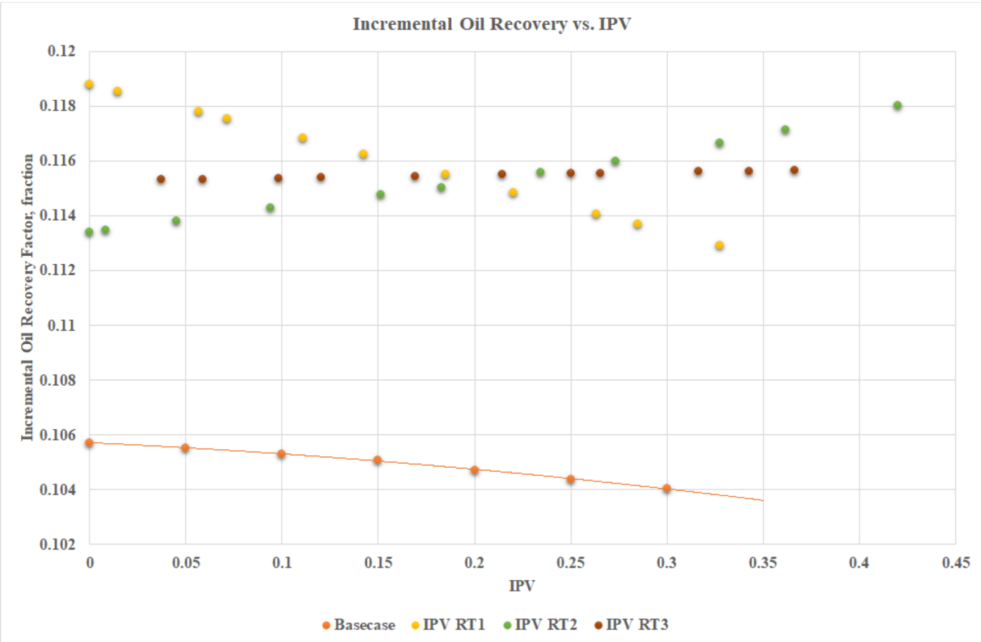


Figure 20 – Effect of Varying IPV for Different RTs on Incremental Oil Recovery. For the sensitivity analysis, the non-varying IPV for RT1 and RT2 is fixed as 0.2, for RT 3 is fixed as 0.25

- **Varying IPV for RT1, whereas RT2 is constant at 0.2 and RT3 at 0.25**

A reduction of ~ 0.6% point of IOIP is associated with increased IPV RT1, increasing the velocity of polymer in the Darcy level sand RT1 will lead to a faster production of the injected polymer. Thus, reducing its capability to propagate through RT2 and produce the remaining oil.

- **Varying IPV for RT2, whereas RT1 is constant at 0.2 and RT3 at 0.25**

Faster polymer propagation in RT2 will increase the incremental oil recovery by 0.5% points. As IPV in RT2 increases, the polymer will tend to flow through RT2 as it is less resistant than the other RTs. The slight increase in oil recovery is governed by the fast arrival of the oil to the production well only.

- **Varying IPV for RT3, whereas IPV RT1 and RT2 are constant at 0.2**

No significant impact is seen in the recovery by varying the IPV of RT3. At permeability of ~1.2 mD increasing velocity of the polymer will not aid the recovery.

Analysis

Figure 21 shows the sensitivity analysis, it confirms that individually describing the effect of RTs on polymer behavior will always impact the recovery. IPV RT1 has an inverse relation with the incremental oil recovery, since increasing IPV will increase the polymer propagation along RT1 but not RT2 (where the majority of the bypassed oil is). And it is vice versa for RT2, as IPV increases the polymer propagation within increases promoting a faster oil production boost the polymer velocity in RT1 The pore throat difference between RT1 and RT2 would be the leading influence on polymer behavior and oil recovery compared with the Basecasle.

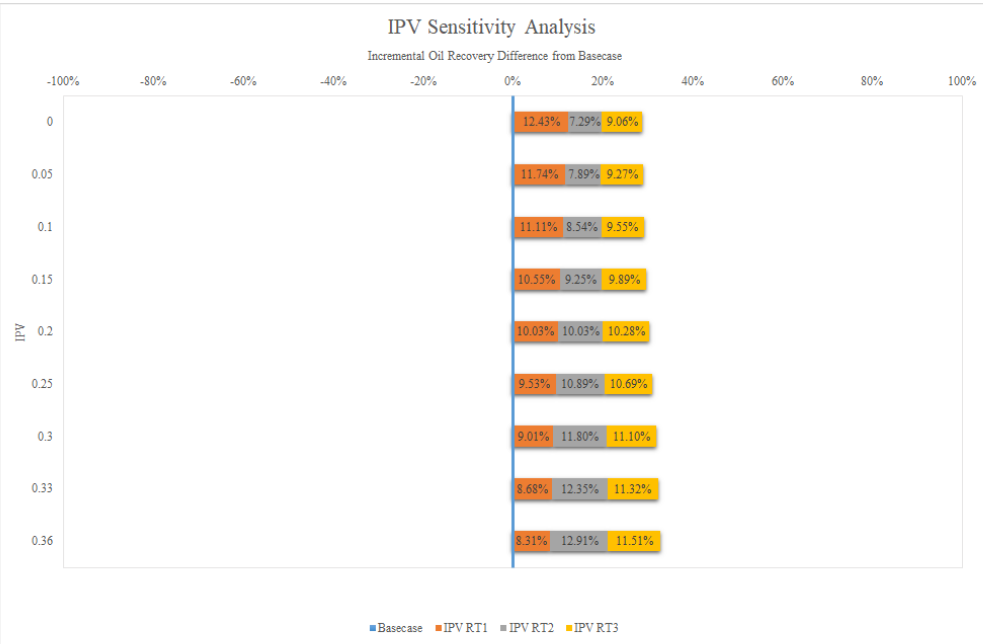


Figure 21- Sensitivity Analysis for RTs on IPV, and Incremental Oil Recovery Difference from Basecase

4.2.3 Effect of Polymer Adsorption Sensitivity

Simulation runs were done to define the effect of varying the adsorption isotherms in different RTs on incremental oil recovery. The adsorption coefficients a_1 and b in the Langmuir

Isothermal equation as seen in 1.1.2, are varied from 0 to1 and 1 to 10, respectively, for all RTs achieving different maximum adsorption levels.

The adsorption coefficients for the Basecase were constantly varied for all RTs. The variation is done at a constant RRF of 1.456 and IPV for RT1=RT2= 20% and RT3 = 25%.

- **Varying Adsorption coefficient for RT1, Maximum adsorption for RT2 is 11.7 µg/g, and RT 3 is 0.68 µg/g**

As can be seen in Figure 22, an initial conclusion is drawn where varying the maximum adsorption in RT3 does not affect the incremental oil recovery in comparison with varying the maximum adsorption in RT1 since the Langmuir Isothermal equation takes into consideration the rock permeability.

The amount of polymer adsorbed in RT1 is ranging between 31.8 µg/g to 767 µg/g, which is considerably high, and it would cause a significant delay in polymer propagation.

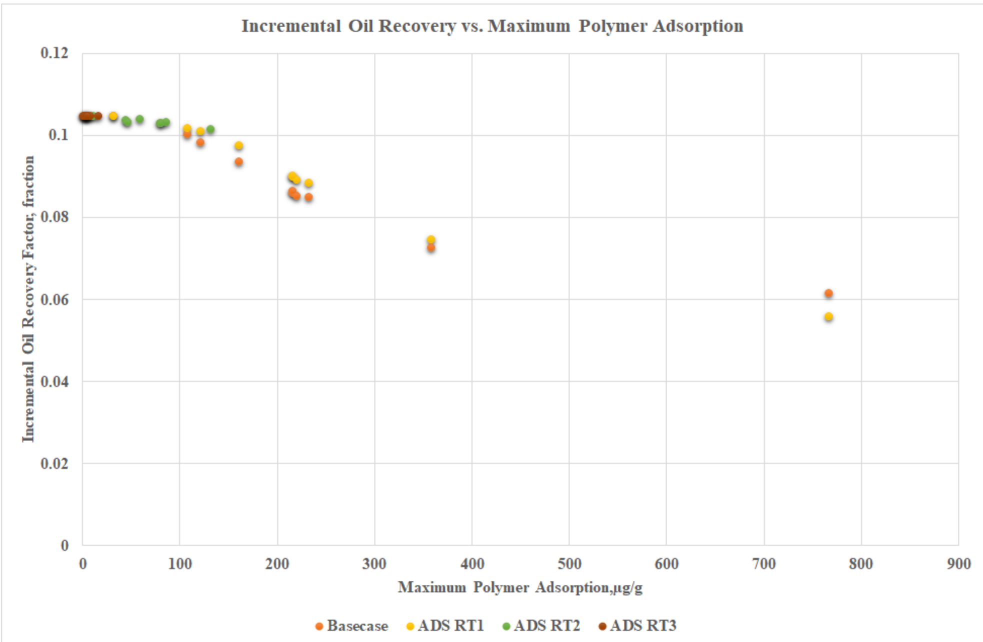


Figure 22 - Effect of Maximum Polymer Adsorption on Incremental Oil Recovery

The results obtained here contradict the results found in literature where adsorption is inversely proportioned to the permeability (R.N Manichand, 2014). As the polymer adsorption in RT1 increases, the amount of polymer in solution is reduced, and its propagation is delayed causing a decrease in the incremental oil recovery obtained from RT2.

- **Varying Adsorption coefficient for RT2, Maximum adsorption for RT1 is 31.8 µg/g, and RT 3 is 0.68 µg/g**

Higher adsorption in RT2 will lead to a slight decrease in oil recovery, as seen in Figure 22. Polymer lost to adsorption will reduce the polymer concentration, and it would delay its propagation through RT2, causing a decrease in the amount of oil contacted by the polymer. Approximately 1% of IOIP will not be recovered if the maximum polymer adsorption reaches ~ 300 µg/g.

- **Varying Adsorption coefficient for RT3, Maximum adsorption for RT1 is 31.8 µg/g, and RT 2 is 11.7 µg/g**

The amount of polymer adsorbed in RT3 is ranging between 0.68 µg/g and 16.3 µg/g, which is insignificant. Hence no substantial amount of polymer will be lost as a result of the rock's low permeability, keeping the recovery at ~ 10.5%.

The Basecase follows the same trend as RT1, concluding that varying the adsorption coefficients uniquely to each RT will not have an impact on the recovery, except at very high RT1 adsorption value where ~ 1% of IOIP difference is seen in Figure 22.

Based on the information obtained from above, describing the polymer behavior per rock type will aid the incremental oil recovery, whereas RT1 is the primary design criterion in this case.

4.2.4 Combined Effect of RRF and Polymer Adsorption

The effect of RRF is usually associated with the amount of polymer adsorbed. To determine the impact of varying the RRF; and the adsorption simultaneously per rock type on incremental oil recovery, simulation runs were performed.

A fixed IPV of 20% was used for RT1 and RT2, and 25% for RT3. The RRF varied from 1 to 20, and the adsorption coefficients a and b from Langmuir-Isothermal varied from 0-1 and 1-10, respectively.

An investigation was done by simultaneously varying polymer adsorption and RRF, as shown in Figure 23 and Figure 24. The effect of adsorption was illustrated by dividing the polymer adsorption effect into four different groups to correctly range the RRF value for each rock.

The polymer adsorption groups will be as follows:

1. Group 1: low polymer adsorption in RT1 and RT2.
2. Group 2: low polymer adsorption in RT1 and high polymer adsorption in RT2.

3. Group 3: high polymer adsorption for RT1 and RT2.
4. Group 4: high polymer adsorption for RT1 and low for RT2.

In the Basecase the maximum adsorption values and RRF increase constantly, the amount recovered starts to decrease. This can be explained by the reduction in the polymer concentration because of adsorption, leading to a sharper slope for the polymer velocity.

The sensitivity for varying RRF RT1 and adsorption values for each rock type is illustrated as a function of the four different adsorption groups described before. As shown previously in section 4.2.3, polymer adsorption in RT3 has almost no influence on incremental oil recovery as a result of its low permeability that prevents polymer propagation; therefore the groups were assigned based solely on the adsorption of RT1 and RT2.

A general increasing trend in oil recovery is observed in RRF values below four, this has resulted from mobility enhancement through RT2 as the permeability to water is decreased in RT; however, the amount of adsorption is what is defining the magnitude in the increase.

Having low adsorption for both rocks leads to an increase in the oil recovery with an increase in the RRF, a consistent behavior with the finding in4.2.1. Combining the effect of permeability reduction in terms of mobility control improvement (permeability reduction in the better class rock RT1) and minimum loss in the polymer will increase the amount of oil contacted by the polymer in RT2.

An increasing trend in the recovery is associated with an increase in polymer adsorption in RT2 but in a lower incremental oil interval (highlighted in the light green points in Figure 23). The behavior can be simply described as more polymer is adsorbed in RT2, causing a reduction in polymer concentration in the solution (this explains the reduction in the recovered oil ~ 8% to 12% compared with beige points that have a range of 12% to 14%). However, since only the impact of RRF RT1 is seen here (permeability is decreased only within RT1), where RRF RT2 is held constant; an increasing trend in the oil recovery is seen, as RT2 being the preferred path for the remaining polymer in solution.

As for increasing polymer adsorption and RRF for RT1, that will lead to a decrease in recovery, as seen in 4.2.1, limiting the possibility for polymer flow in RT2.

The same analysis was carried out with varying RRF RT2, as shown in Figure 24. The effect of varying RRF for RT2 follows the trend seen in section 4.2.1. As the polymer adsorption increases, more polymer is lost, leading to further permeability reduction in RT2 since RT1 is kept constant in this run.

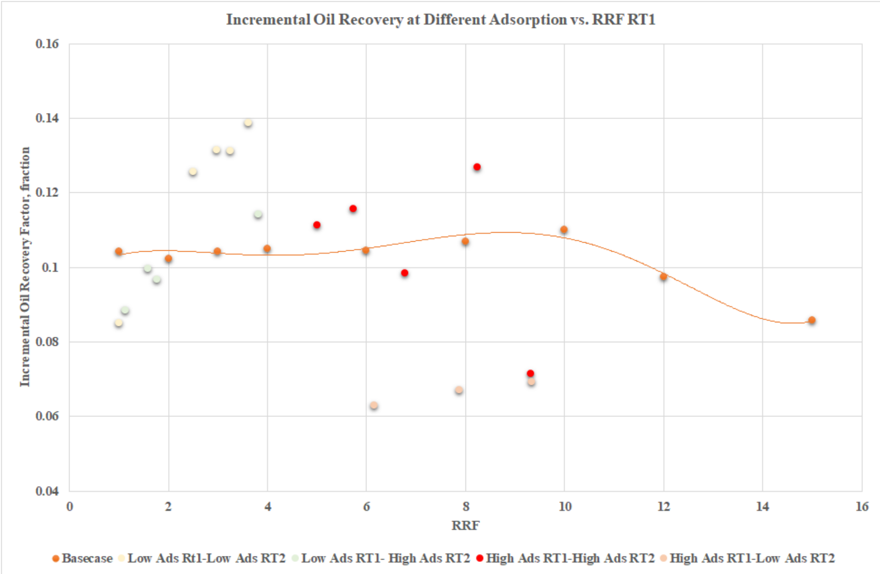


Figure 23- Effect of Varying Maximum Adsorption and RRF RT1 on Incremental Oil Recovery

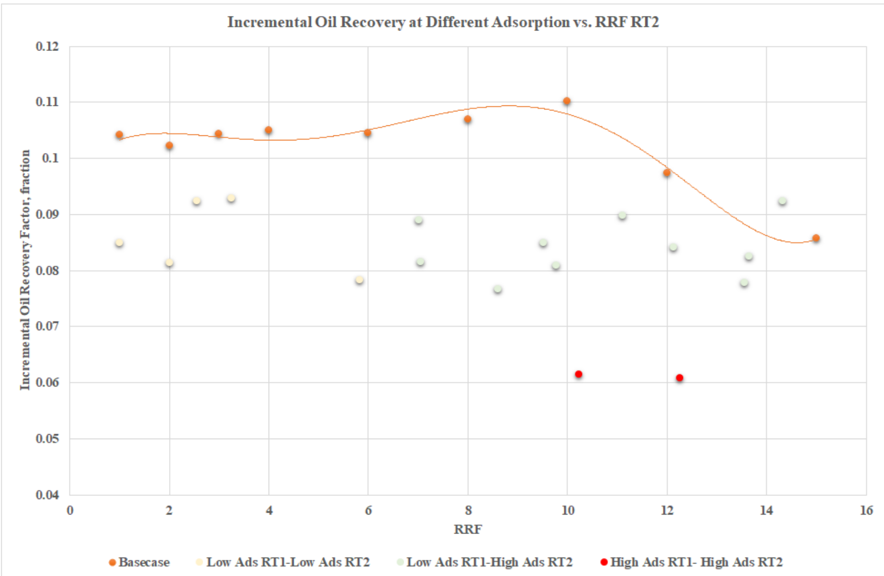


Figure 24- Effect of Varying Maximum Adsorption and RRF RT2 on Incremental Oil Recovery

The ability of the polymer to flow through RT2 is reduced as a function of RRF and adsorption; high permeability reduction in RT2 will negatively impact the vertical sweep efficiency leading to more polymer propagation in RT1 and bypassing the remaining oil in RT2. Whereas more adsorption in RT1 will lead to a delay in the polymer front propagation in the entire system.

Analysis

Figure 25 shows the maximum (Blue bars) and minimum (Orange bars) incremental oil recovery factor obtained by varying the maximum adsorption and RRF constantly, individually, and simultaneously. Describing the polymer behavior regardless of the RTs present in the reservoir might yield lower oil recovery of 11%of IOIP compared to describing the polymer behavior per rock type where the recovery would be ~12% of IOIP. The increase in the recovery based on Figure 25 is governed by mobility enhancement as a result of reducing the relative permeability of the aqueous phase in RT1.

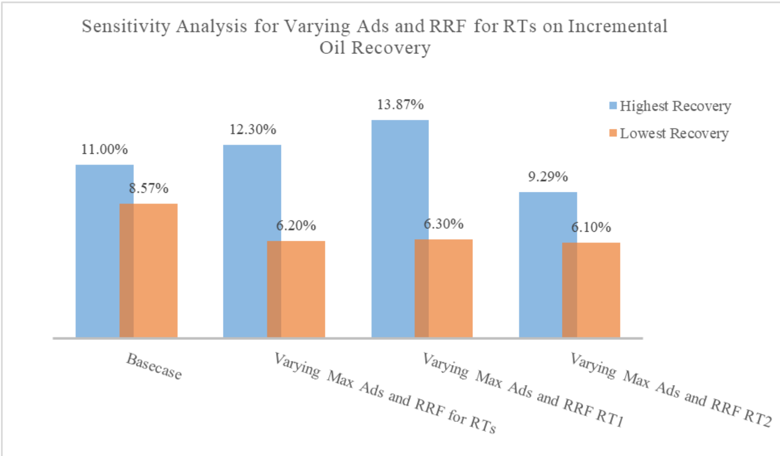


Figure 25- Sensitivity Analysis for varying Maximum adsorption and RRF for RTs on Incremental Oil Recovery

4.2.5 Combined Effect of RRF, IPV and Polymer Adsorption

The combined effect of different RTs on the physical polymer behavior and the incremental oil recovery is done by varying RRF, Adsorption, IPV RT1, and IPV RT2. Figure 26 illustrates the effect of constantly varying adsorption, RRF, and IPV (Basecase). The incremental oil recovery in Basecase does not change by varying IPV RT1 compared with the results seen in 4.2.4.

A slight decrease in the incremental oil recovery is observed as IPV RT1 increases, and the permeability reduces because of high adsorption in RT2. As seen in section 4.2.4, higher polymer losses have resulted in high permeability reduction in RT2 and consequently reducing the amount of polymer propagated through RT2 to recover the remaining oil. Adding the effect of IPV in RT1 will cause a reduction in the recovery as less polymer will propagate through RT2 as a result of faster polymer propagation in RT1.

Increased the polymer adsorption for RT1 to 767 µg/ g results in an increase in RRF RT1 and significant loss in the polymer, leading to a delay of polymer propagation through the reservoir. The lowest oil recovery of 6% of IOIP is obtained by increasing adsorption in RT1 to a degree neither the RRF nor IPV will compensate for.

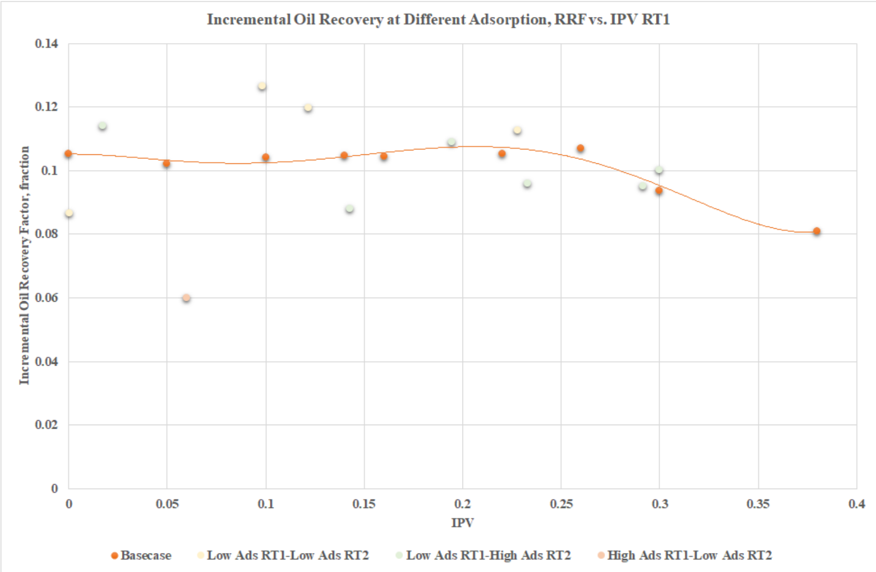


Figure 26- Effect of Varying Maximum Adsorption, RRF and IPV RT1 on Incremental Oil Recovery

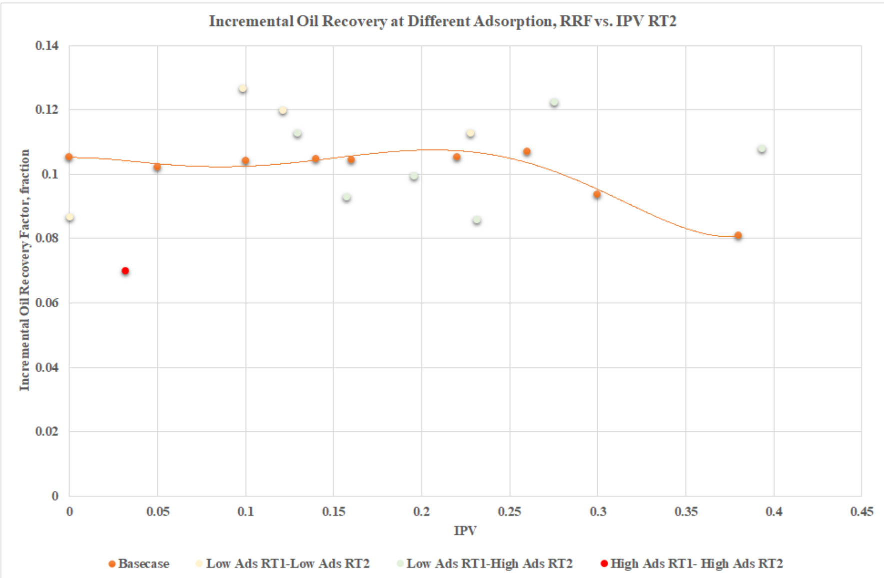


Figure 27- Effect of Varying Maximum Adsorption, RRF and IPV RT2 on Incremental Oil Recovery

Figure 27 shows no trend relating adsorption, RRF, and IPV RT2o incremental oil recovery, where the oil recovery is ranging from 9% to ~ 13% of IOIP, at low and high IPV values.

Having the right combination of the varied values can give almost the same recovery factor with two different values. When adsorption increases in RT2 the RRF will follow, causing the polymer behavior to alter and reduce the amount recovered. This alteration is compensated by the increase of polymer propagation into RT2, allowing more oil to be contacted with polymer (12.2% of IOIP is produced) even without the amount of polymer lost.

Almost the same amount of oil could be recovered (~ 12.7% of IOIP) at low RRF, adsorption, and IPV RT2, concluding that varying IPV RT2 in the presence of more pronounced behavior of RRF and adsorption will not have a major impact on the oil recovery.

Having high adsorption values in RT1 and RT2 will also reduce the polymer velocity, and increase the amount of permeability reduced, causing a lower oil recovery to ~ 7% of IOIP.

Analysis

Describing the polymer behavior per rock type will yield more recovery factor than assuming that having different rock types will not affect the polymer behavior nor the incremental oil recovery, as seen in Figure 28. However, we see that including the effect of IPV yields a 0.03% point reduction in the incremental oil recovery compared with Figure 25, a value which is considered to be neglected.

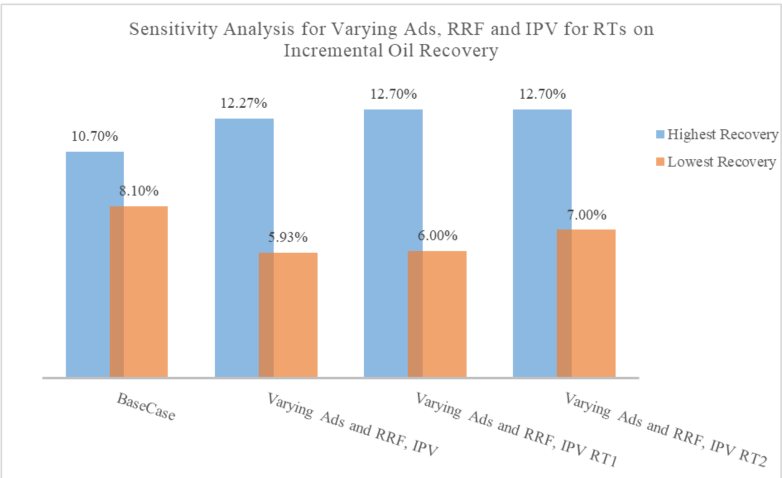


Figure 28- Sensitivity Analysis for varying Maximum adsorption, RRF, and IPV for RTs on Incremental Oil Recovery

4.3 Geological Configuration Investigation

In order to investigate the impact of the geological description of the reservoir on the obtained results, the location of the injection well and producer are swapped reversing the flow (Figure 29). Therefore, the proportion of contacted rock types by the injector is different from the previous case, allowing us to study the effect of different rock types on polymer physical behavior and incremental oil recovery under a different geological configuration (Case 2). The results are all compared with the results obtained by simulating the configuration used in 4.2.

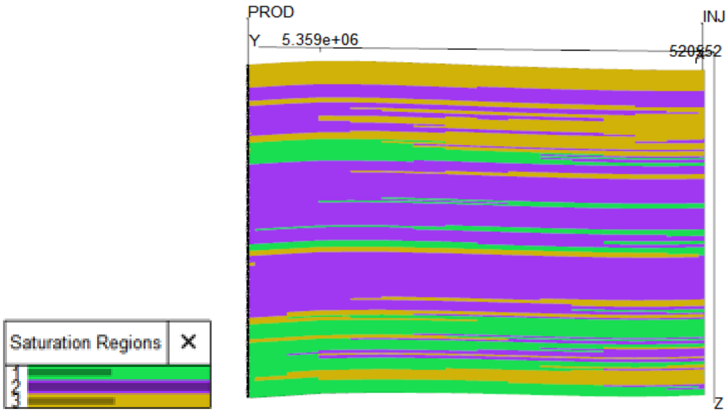


Figure 29- Case 2 Geological Configuration

The amount of oil recovered before polymer injection is 36.8% of IOIP, before 37.3% for Case 1; the remaining oil is distributed along RT1 and RT2. Injected water during the waterflooding process should have a more stable front due to the geological discontinuity in RT1 at the new injection point, limiting the fingering caused by contacting more of the highly permeable RT1 at the injection site. To investigate the effect of rock types on the polymer behavior and incremental oil recovery under a different geological configuration, the same workflow as before was implemented.

Ranges of incremental oil recovery for both configurations are similar, as seen in Figure 30 and Figure 31. The biggest difference between both cases is that the main oil contributor is no longer RT2 during polymer flood as a result of the previously mentioned RT1 geological discontinuities. In this case, experimental studies are needed to study the effect of both rock types on polymer behavior and incremental oil recovery rather than on the good quality sand as in case 1. No common trends are observed by reversing the flow indicating that the geological description has a big impact on the results. Therefore, it is important to merge stochastic modeling with polymer description per rock types to better assess incremental oil from polymer flooding.

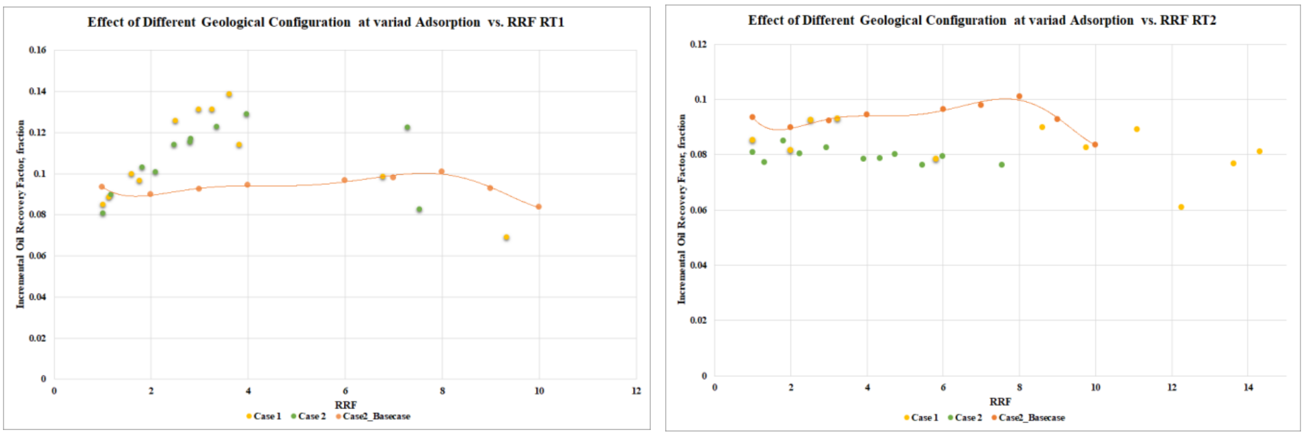


Figure 30- Effect of RTs for Different Geological Configuration at Varied Adsorption vs. RRF

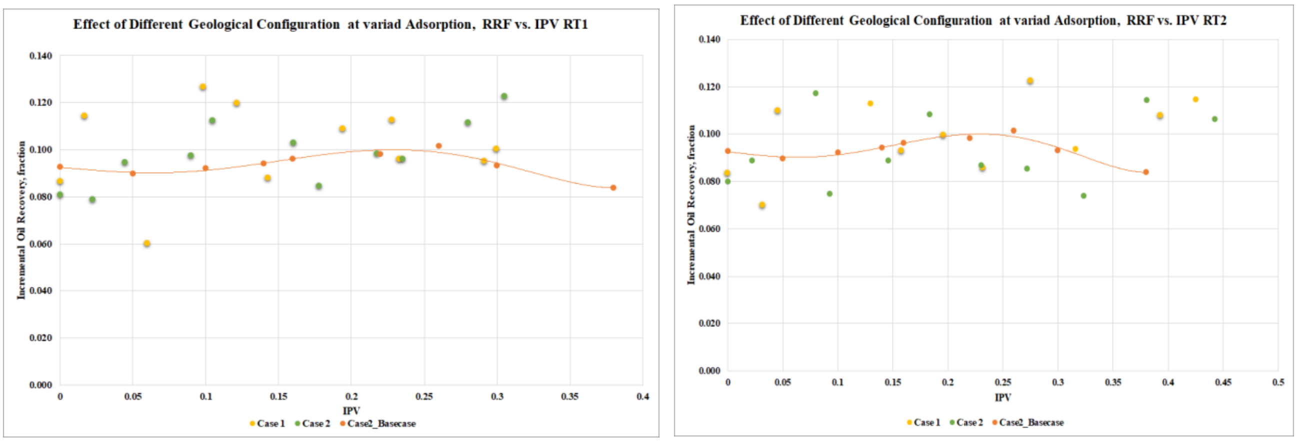


Figure 31 - Effect of RTs for Different Geological Configuration at Varied Adsorption, RRF vs. IPV

Chapter 5

Conclusion

5.1 Summary

This study is focused on using numerical simulation to determine the effect of different rock types on physical polymer properties and incremental oil recovery by varying the parameters under uncertainty analysis.

Neglecting the effect of different rock types will lead to an over or an underestimating of incremental oil recovery most of the time, so does focusing on one parameter rather than all.

Polymer adsorption and residual resistance factor have the most impact on the oil recovery; optimizing the polymer solution to complement the effect of each rock type would increase the expected recovery up to 15% of IOIP.

The inaccessible pore volume of different rock types will not have a big impact on the recovery, but it will aid the recovery in high polymer adsorption cases.

Incremental oil recovery depends on the geological configuration and the oil saturation distribution before polymer project implementation. The effect of RT is unique in each case; therefore, no general trend could be concluded.

5.2 Future Work

Based on the observation obtained regarding the effect of different rock types on polymer physical behavior and incremental oil recovery in 2D model, it is recommended for future work to include the impact of in-situ viscosity alteration as the physical properties changes.

Another aspect is to determine the effect of varying physical property based on different rock types on oil recovery and pressure response.

The effect of different geological configurations and realizations would help further understanding the impact of having different rock types on polymer behavior, also, including the effect of dispersion in the simulation and also the effect of other polymer retention phenomena.

It would also help to limit the uncertainty ranges of the varied parameters by further understanding the rock impact by additional laboratory studies.

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