Effects of Polymer Adsorption and Desorption on Polymer Flooding in Waterflooded Reservoir

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ผลกระทบของการดูดซับและการคายการดูดซับของพอลิเมอร์ที่มีต่อกระบวนการฉีดอัดด้วยพอลิเมอร์ในแหล่งกักเก็บที่ผ่านการฉีดอัดน้ำ

นางสาวสุขฤทัย ทรัพย์นิวัตต์

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วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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สุขฤทัย ทรัพย์นิวัตต์ : ผลกระทบของการดูดซับและการคายการดูดซับของพอลิเมอร์ที่มีต่อกระบวนการฉีดอัดด้วยพอลิเมอร์ในแหล่งกักเก็บที่ผ่านการฉีดอัดน้ำ (Effects of Polymer Adsorption and Desorption on Polymer Flooding in Waterflooded Reservoir) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: ฟ้าลั่น ศรีสุริยชัย, 106 หน้า.

การฉีดอัดสารพอลิเมอร์เป็นหนึ่งในเทคโนโลยีการเพิ่มผลผลิตน้ำมันที่เป็นที่รู้จักอย่างดี ซึ่งสามารถนำมาใช้ภายหลังการผลิตน้ำแบบปฐมภูมิหรือทุติยภูมิก็ได้ สารพอลิเมอร์สามารถลดอัตราส่วนการเคลื่อนที่ของกระบวนการแทนที่น้ำมันด้วยของเหลว โดยการเพิ่มความหนืดในแก่น้ำที่ถูกฉีดอัด ดังนั้นการฉีดอัดสารพอลิเมอร์จึงสามารถช่วยเพิ่มประสิทธิภาพการกวาดน้ำมันในเชิงปริมาตร นอกจากนี่การดูดซับของสารพอลิเมอร์บนพื้นผิวของหินยังช่วยลดความแตกต่างของความสามารถในการซึมผ่านในกรณีที่แหล่งกักเก็บน้ำมันมีสภาพความเป็นวิวิธพันธ์สูง เนื่องจากการลดลงของความสามารถในการซึมผ่านสัมบูรณ์ ความสามารถในการซึมผ่านประสิทธิผลของน้ำจึงมีค่าลดลงด้วย เมื่อสารพอลิเมอร์ถูกดูดซับบนพื้นผิวหิน สารพอลิเมอร์ยังสามารถคายการดูดซับเมื่อสารละลายชนิดอื่นถูกฉีดอัดเข้ามาแทนที่

การศึกษานี้มุ่งเน้นไปที่พฤติกรรมของการดูดซับและการคายการดูดซับของสารพอลิเมอร์ในแหล่งกักเก็บรวมไปถึงผลกระทบที่มีต่อตัวแปรเชิงปฏิบัติการและเงื่อนไขของแหล่งกักเก็บที่น่าสนใจ โปรแกรมสร้างแบบจำลองแหล่งกักเก็บ STARS® ผลิตโดย Computer Modeling Group ถูกใช้ประเมินผลกระทบที่สนใจ ผลการทดลองแสดงให้เห็นว่า การฉีดอัดสารพอลิเมอร์ตามหลังการฉีดอัดน้ำในเวลาเนิ่น ๆ สามารถช่วยเพิ่มประสิทธิภาพการผลิตน้ำมันในเวลาอันสั้นและผลการศึกษาที่คล้ายคลึงกันยังได้มาจากการใช้อัตราการฉีดอัดที่สูง ความแตกต่างของมวลสารพอลิเมอร์ที่ถูกฉีดอัดลงในแหล่งกักเก็บ ซึ่งแทนได้ด้วยความเข้มข้นของสารพอลิเมอร์มีผลต่อก้อนมวลสารพอลิเมอร์ที่เหมาะสม ความเข้มข้นของสารพอลิเมอร์ที่สูงต้องการก้อนมวลที่มีขนาดเล็กและให้ผลเช่นเดียวกันในทางตรงกันข้าม การคายการดูดซับสารพอลิเมอร์ทำให้เกิดการนำพอลิเมอร์ที่ถูกดูดซับไปก่อนหน้าบนพื้นผิวหินมาใช้ประโยชน์ใหม่ ซึ่งทำให้เกิดการปรับปรุงประสิทธิภาพการน้ำมันในระยะหลังของกระบวนการฉีดอัด อย่างไรก็ดี ปริมาณการคายการดูดซับที่เหมาะสมจะแตกต่างกันออกไปตามความเข้มข้นของสารพอลิเมอร์ ในกรณีที่ใช้สารพอลิเมอร์ความเข้มข้นสูง การคายการดูดซับทั้งหมดจะทำให้น้ำที่ใช้ฉีดไล่ไม่สามารถดันสารพอลิเมอร์โดยตรง จึงทำให้เกิดการแซงก้อนมวลสารพอลิเมอร์และทำให้เกิดผลด้านลบต่อประสิทธิภาพการกวาดน้ำมัน

ในแหล่งกักเก็บที่ความแปรผันของค่าความสามารถในการซึมผ่าน สารพอลิเมอร์สามารถช่วยทำให้ปัญหาการมาถึงไวของน้ำช้าลง อย่างไรก็ดีระดับการคายการดูดซับของสารพอลิเมอร์ควรจะเป็นศูนย์เพื่อทำให้เกิดการดูดซับอย่างถาวร โดยจะทำให้เกิดการลดลงของค่าความสามารถการซึมผ่านสัมพัทธ์ของน้ำ เพื่อให้มั่นใจว่าของเหลวที่ใช้ในการฉีดอัดจะเคลื่อนที่อย่างช้า ๆ ขนาดของค่าการดูดซับพอลิเมอร์ไม่มีผลกระทบต่อประสิทธิภาพการน้ำมันเท่าใดนักเมื่อระดับการคายการดูดซับสารพอลิเมอร์เปลี่ยนแปลงไป ในกรณีขนาดของค่าการดูดซับพอลิเมอร์ที่สูงและการคายการดูดซับถาวร สารพอลิเมอร์ในของเหลวจะลดลงซึ่งส่งผลในไม่สามารถรักษาความหนืดไว้ ในขณะที่ผลกระทบจากการลดลงของค่าความสามารถในการซึมผ่านสัมพันธ์ของน้ำครอบงำผลจากการรักษาความหนืดในกรณีของระดับการคายการดูดซับที่ 50 เปอร์เซ็นต์ การรวมกันของการคายการดูดซับทั้งหมดและค่าความต้านทานหลงเหลือที่สูงแสดงให้เห็นถึงผลที่น่าพึงพอใจ ความสามารถในการกวาดน้ำมันถูกปรับปรุงให้ดีขึ้นในบริเวณขอบของรูปแบบการฉีดอัด นอกจากนี้การเปลี่ยนทิศทางของน้ำที่ใช้ฉีดไล่ไปยังขอบของรูปแบบการฉีดอัดยังส่งผลให้เกิดการกวาดน้ำมันที่ดีด้วย

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ภาควิชา วิศวกรรมเหมืองแร่และปิโตรเลียม ลายมือชื่อนิสิต ....
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SUKRUTHAI SAPNIWAT: Effects of Polymer Adsorption and Desorption on Polymer Flooding in Waterflooded Reservoir. ADVISOR: FALAN SRISURIYACHAI, Ph.D., 106 pp.

Polymer Flooding is one of the most well-known methods in Enhanced Oil Recovery (EOR) technology which can be implemented after either primary or secondary recovery. Polymer can lower the mobility ratio of the displacement mechanism by means of increasing viscosity of injected water. Therefore, polymer flooding can increase volumetric sweep efficiency. Moreover, polymer adsorption onto rock surface can decrease permeability contrast in reservoir with high heterogeneity. Due to reduction of the absolute permeability, effective permeability to water is also reduced. Once polymer is adsorbed onto rock surface, polymer can also be desorbed when different fluids are injected.

This study focuses on polymer adsorption/desorption behavior in the reservoir as well as effects on operating parameters and interest reservoir conditions. Reservoir simulator called STARS® commercialized by Computer Modeling Group is utilized to assess interest effects. The results show that performing polymer flooding after water pre-injection sooner can increase oil recovery factor in the shortest period and similar results are also obtained from higher injection rate. The difference of polymer mass injected into the reservoir, represented by polymer concentration affects the optimum polymer slug size. Higher polymer concentration requires smaller slug size of polymer to attain constant oil recovery factor, vice versa. Polymer desorption causes polymer re-employment from the previously adsorbed onto rock surface, resulting in improving of sweep efficiency in the further period of polymer flooding process. However, the optimum value of polymer desorption degree in difference polymer concentration exists. When using high polymer concentration, total polymer desorption allows chasing water to bypass polymer slug, causing adverse effect on sweep efficiency.

In reservoir with variation in permeability, polymer can be injected to retard early water breakthrough. However, degree of polymer desorption should be zero to allow permanent adsorption as reduction of relative permeability to water can be maintained to ensure slow movement of inject fluid. Magnitude of polymer adsorption does not affect much on oil recovery factor when degree of polymer desorption is varied. In high magnitude of polymer adsorption, zero polymer desorption causes less effective polymer to maintain viscosity whereas effects of reduction of relative permeability dominates effects of maintaining viscosity in case of 50 percent polymer desorption. Combination of total desorption with high residual resistant factor shows favorable results. Sweep efficiency is improved also at boarder of flood pattern and moreover, diverting of chasing water to border zones results in very favorable sweep efficiency.

Department:	Mining and Petroleum Engineering	Student's Signature	....
Field of Study:	Petroleum Engineering	Advisor's Signature	....
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LIST OF ABBREVIATIONS

bbl	Barrel
bbl/day	Barrel Per Day
BHP	Bottomhole Pressure
cm^3	Cubic centimeter
CMG	Computer Modeling Group
Cont.	Continue
cP	CentiPoise
DTWELL	First time step size after well change
DWOC	Water-oil contact depth
dyne/cm	Dyne per centimeter
EOR	Enhanced Oil Recovery
ft	Foot/Feet
g	Gram
g/ml	Gram per milliliter
GOR	Gas Oil Ratio
HPAM	Hydrolyzed polyacrylamide
ISOTHERM	Isothermal option
ITERMAX	Linear solver iteration
km	Kilometer
KRGCL	Relative permeability to gas at connate liquid saturation
KROCW	Relative permeability to oil at connate water saturation
KROGCG	Relative permeability to oil at connate gas saturation

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KRWIRO	Relative permeability to water at irreducible oil saturation
lb/lbmole	Pound per mole
mD	Millidarcy
mg/100g	Milligram per hundred grams
mg/g	Milligram per gram
ml	Milliliter
ml/min	Milliliter/Minutes
MMbbl	Million barrel
MW	Molecular Weight
^{o}API	American Petroleum Institute Gravity
^{o}C	Degree Celsius
^{o}F	Degree Fahrenheit
OOIP	Original Oil In Place
PAM	Polyacrylamide
pH	Potential of Hydrogen
ppm	Part per million
psia	Pound per square inch absolute
PV	Pore Volume
PVT	Pressure-Volume-Temperature
REFDEPTH	Reference depth
REFPW	Reference pressure
RF	Recovery Factor
SCF/STB	Standard cubic feet per stock tank barrel
SGCON	Connate gas saturation

SGCRIT	Critical gas saturation
SOIRG	Irreducible oil saturation for gas-liquid table
SOIRW	Irreducible oil saturation for water-oil table
SORG	Residual oil saturation for gas-liquid table
SORW	Residual oil saturation for water-oil table
STL	Surface liquid rate
STO	Surface oil rate
STW	Surface water rate
SWCON	Connate water saturation
SWCRIT	Critical water saturation
TRES	Reservoir temperature
WCUT	Watercut
WOC	Water-Oil Contact
wt.	By Weight

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NOMENCLATURES

φ	Porosity
φ_{eff}	Effective porosity
μ_g	Gas viscosity
μ_w	Water viscosity
μ_o	Oil viscosity
μ	Viscosity of displacing fluid
v	Effective flow rate of displacing fluid
Ad	Adsorption concentration
B_g	Gas formation volume factor
B_o	Oil formation volume factor
k_h	Horizontal permeability
k_v	Vertical permeability
k_{rg}	Relative permeability to gas
k_{rog}	Relative permeability to oil for gas-liquid system
k_{row}	Relative permeability to oil for water-oil system
k_{rw}	Relative permeability to water for water-oil system
M	Molecular weight of the polymer
p_b	Bubble point pressure
q	Flow rate per unit cross-sectional area
R_s	Solution gas-oil ratio
S_l	Liquid saturation
S_{or}	Residual oil saturation

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S_w	Water saturation
S_{wc}	Connate water saturation
S_{wi}	Initial water saturation
V	Surfactant solution volume

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CHAPTER 1

INTRODUCTION

1.1 Background

In oil production, oil recovery efficiency from natural drive mechanism is estimated to be only 10-20% based on Original Oil In Place (OOIP). As a result, various technologies that are classified as Improved Oil Recovery (IOR) have been developed worldwide to obtain better efficiency. Waterflooding which is sub-classified from IOR as secondary recovery can further recover oil of about 10-40% OOIP. However, this technique is sometimes insufficient to lower residue oil in the reservoir due to several unfavorable conditions. Tertiary recovery or so-called Enhance Oil Recovery should be therefore implemented.

Polymer Flooding is one of the most well-known methods in enhanced oil recovery technology. Polymer can decrease mobility ratio by increasing viscosity of injected water. Therefore, polymer flooding can increase volumetric sweep efficiency. Moreover, polymer adsorption onto rock surface can reduce permeability contrast of reservoir with high heterogeneity and due to reduction of absolute permeability, effective permeability to water which represents flow ability of injected fluid is also reduced, resulting in more favorable conditions for displacement mechanism. Polymer adsorption is defined as physical or chemical interactions between polymer molecules and pore surface of rock. Physical adsorption is caused due to tortuous paths with rugose surface of pores together with complex structure of polymer molecule. Some polymers contain charge property and this attracts chemical adsorption onto rock surface containing the opposite charge. Once polymer is adsorbed onto rock surface, polymer molecule can be desorbed when different fluid is injected. For example, if water is utilized as chasing phase after a designed slug is pre-injected, previously adsorbed polymer may desorbed due to diluting of polymer concentration at the rock surface compared to bulk solution. From many previous studies, it has been reviewed that polymer adsorption should be minimized.

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Nevertheless, this unavoidably mechanism together with its reversible process may result in benefit for oil recovery mechanism.

This study is performed to evaluate effects of adsorption/desorption process of polymer solution on polymer flooding. To study polymer adsorption/desorption behavior in the reservoir, reservoir model is constructed using reservoir simulation called STAR® commercialized by Computer Modeling Group (CMG). The study is performed first to select appropriate operating conditions of polymer flooding including amount of pre-flushed water, polymer slug size together with polymer concentration and polymer injection rate, for selected values of polymer adsorption/desorption. Effects of reservoir heterogeneity, magnitude of polymer adsorption and resistance factor are involved after selection of operational parameters is performed. Oil recovery factor is a major consideration for effectiveness of the process. Nevertheless other parameters may be used to assist such as total production period and water production. The obtained results will help to understand effects of polymer adsorption/desorption which in turns, would provide new points of view for economics of polymer flooding project.

1.2 Objective

1. To study effects of adsorption/desorption process of polymer solutions on operating parameters in polymer flooding including starting time of polymer flooding, polymer slug size together with concentration, and injection rate.
2. To evaluate the effects of related properties on the effectiveness of polymer flooding including heterogeneity, value of magnitude of polymer adsorption and resistance factor.

1.3 Outline of Methodology

The study is firstly focused on obtaining optimum operating parameters in different degrees of polymer desorption values. After that, effects of variation of heterogeneity index, magnitude of polymer adsorption and resistance factor are performed and analyzed. The steps of procedure are shown as follow:

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1. Initialize reservoir simulation for waterflooding case to obtain reference data of oil recovery factor and water production.
2. Obtain suitable values of operating parameters including total polymer mass to be injected together with concentration, starting time of polymer flooding and injection rate for various degrees of desorption which are 0, 50, and 100 percent.
3. Analyze effects of related parameters including interest parameters as below at selected operating parameter:
    - Heterogeneity index which is quantified by Lorenz coefficient: (adding values)
    - Magnitude of polymer adsorption: (adding values)
    - Polymer resistance factor: (adding values)
4. Gather simulation outcomes to determine, and conclude findings from the study.

The workflow of this study is summarized in a flow chart in the Figure 1.1.

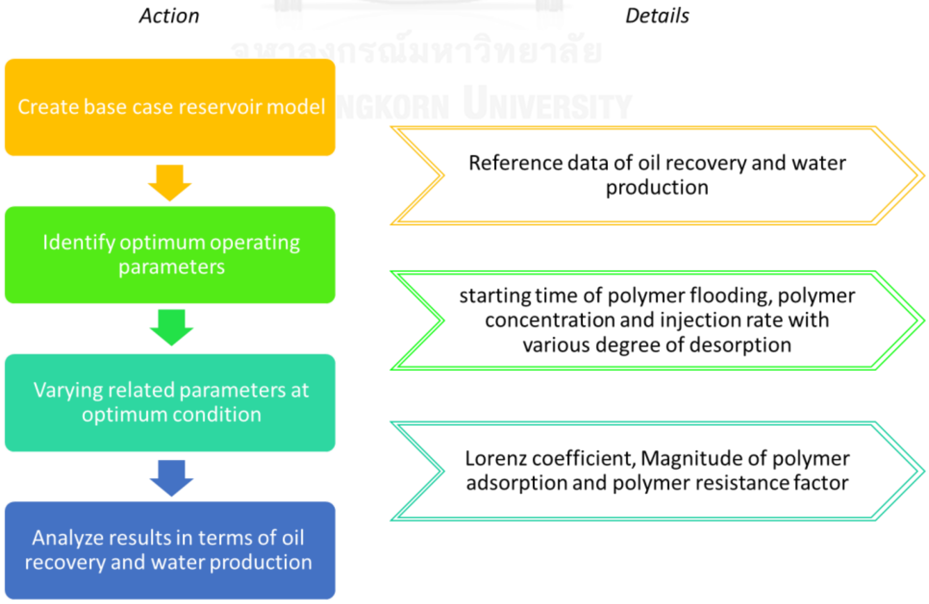

Figure 1.1 Flow chart summarizing steps of work in this study

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1.4 Outline of Thesis

The thesis is composed of six chapters as follow:

Chapter I provides motivation of the study, basic understanding of polymer flooding, proposes to study effects of polymer adsorption and desorption on polymer flooding in waterflooded reservoir as well as stating the objectives and methodology outline of this study.

Chapter II summarizes various literatures related to the study.

Chapter III present theories related to oil recovery mechanism by means of polymer flooding process and other important properties related to the process.

Chapter IV describes details of reservoir model including rock and fluid properties. In addition, details of research methodology are described at the end of this chapter.

Chapter V presents results and discussion of reservoir simulation. The key results are obtained from polymer flooding with various degree of polymer desorption.

Chapter VI concludes findings obtained from this study. Moreover, recommendations for further study are summarized at the end.

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CHAPTER 2

LITERATURE REVIEW

A study of polymer flooding has been performed around the globe. However, only a few studies have emphasized on the effects of polymer adsorption.

Ogunberu and Asghari [1] investigated reduction of permeability to water by means of polymer injection. Their experiments varied polymer shear rate and concentration of brine which was injected through the sand packs. The results showed that there was improvement in the adsorbed polymer layer at increasing shear rates by polymer injection. Therefore, it resulted in higher degree of reduction in permeability to water. This phenomenon is so-called flow-induced adsorption. Flow-induced polymer adsorption exists above a critical shear rate while desorption could occur due to mechanical degradation of polymer at high shear rates.

Omar [2] studied polymer adsorption onto the rock surfaces of porous sandstones and its effect on permeability to water. Dynamic adsorption was studied by using coreflooding of polyacrylamide solution with guar gum followed by enzyme breaker solution to study polymer desorption. Permeability and loss of polymer were investigated under controlled temperature. They mentioned that polymer solutions effectively plugged in porous media, resulting in increasing of viscosity and decreasing of permeability to water. Enzyme breaker solution effectively recovered permeability, meaning that polymer desorption can be occurred. However, this enzyme breaker reduced the loss of permeability to only 1-2% of the original value. The results indicated that polymer loss occurred and the loss caused water bank in front of the polymer solution and thus, greatly reduced benefit of polymer in waterflooding.

Goshtasp et al. [3] summarized that adsorption and rheological property changes were mainly determined by chemical structure of injected polymers, surface properties of the rock, composition of oil and reservoir fluids, nature of the polymers added and solution conditions such as salinity, pH and temperature. Moreover, Morris [4] made the experiment to study mechanical degradation of polyacrylamide solution by injecting the solution into sandstone rock. The polymer was retained onto the pores of reservoir rock. Results occurred by physical entrapment and chemical adsorption on the mineral surfaces. From the study, it was found that polymer degradation inversely depended on injected polymer concentration.

A study by Vossoughi et al. [5] used a bio-polymer produced by the Cellulomonas Flavigena strain KU to achieve reduction in permeability of the sand pack by means of a novel in-situ gelation technique. Due to the inherent physical properties of the polymer, its physical state of solution changed to the state of gel by reducing the pH of its alkaline solution. A high degree of permeability reduction could be achieved along the entire length of the sand pack and this reduction was relatively uniform throughout the core. More importantly, the initial permeability of the sand pack could be restored by injecting a sodium hydroxide solution. Therefore, transition from the gel state to the solution state and vice versa could be repeated by increasing or decreasing pH value of the solution. Creation of a layer of gel at the interface which is re-dissolved, re-gelled and possibly moves in the direction of the flow path would according to the authors provide superior selectivity compared to the currently available systems.

Major objective of the study of Sanjay et al. [6] was to experimentally investigate polymer injectivity model in porous media using unfiltered partially hydrolyzed polyacrylamide (HPAM) solutions in high permeability sandstone by coreflooding and to study effects of polymer concentrations and salinities (5-20 g/L). The results showed that the polymer adsorption was dominant mechanism for polymer retention. In high permeability porous media, irrespective of polymer concentration and salinity, the viscous nature of polymer solutions and their retentions in porous media were the main mechanisms for injectivity. It was found that for a given shear rate and salinity, viscosity increases with increase of polymer concentration. Furthermore, a decrease in viscosity of polymer solution was observed for the whole range of polymer concentrations with an increase in salinity. A numerical model for predicting the injectivity during single phase flow of polymer solutions in porous media and prediction of the injectivity losses during polymer injection was generated by using Langmuir adsorption isotherm, filtration theory, permeability reduction model, Non-Newtonian viscosity and Darcy’s laws numerical modelling. By the way, two main limitations of the model were noticed including performance of the numerical algorithm and identification of polymer behavior.

In view of its importance to the mobility control in field-scale processes, the study by Huh et al. [7] was set up both theoretically and experimentally to examine the retention of polymer in reservoir rock that leads to poor polymer propagation.

In the theoretical part, a pore-level description of mechanical entrapment of the polymer in a porous medium model was proposed. This model indicated that the rate of mechanical entrapment was proportional to the flux of polymer and decreased almost linearly with the amount of trapped polymer until maximum retention was attained. This maximum retention was dependent on polymer concentration and flow velocity (increased with raising both values). Furthermore, a polymer with good solvency property in water according to this model had fewer tendencies to be trapped, while a polymer with high permeability to water had a high tendency for trapping. An analytical solution for flow of a single-phase polymer solution in a core was obtained to interpret retention data from coreflooding experiment. The proposed retention model was shown to adequately represent two characteristic features of typical polymer effluent profiles from coreflooding which were the frontal delay and the gradual approach to feed concentration. Treating retention with adsorption alone generally failed to describe these features. The effects of dispersion and the commonly-encountered, high accumulation of polymer near the core face were also examined by analysis of coreflooding effluent data with a finite-difference numerical solution for above mentioned linear flow problem.

In the experimental part, the retention of Xanthan biopolymers solution flowing through a sandstone core was measured as a function of polymer concentration, flow velocity, polymer concentration, and permeability of rock. Experimental observations of Xanthan gum flowing in sandstone supported the proposed model as a reasonable representation of the retention phenomena. In most cases, the core effluent data could be described by the model using values of the four parameters that each spanned a narrow range for two Xanthans. The observed effects of flow rate and polymer concentration on retention were in qualitative agreement with the pore-level description. From analysis of experimental data with the proposed model, roughly 50% of the total retention could be attributed to slow process for low brine permeability conditions.

From these literature reviews, it can be seen that polymer adsorption is a dominant mechanism for polymer retention and is explained by effect of chemical structure of injected polymers, surface properties of the rock, composition of oil and reservoir fluids, the nature of the polymers added and solution conditions such as salinity, pH and temperature. Nevertheless, the study of desorption has been performed lesser compared to the study of adsorption. Hence, this study will emphasize on effectiveness of polymer flooding process when degree of desorption is taken into account together with the study of other co-parameters.

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CHAPTER 3

RELEVANT THEORY

3.1 Polymer Flooding

When an oil field is first discovered, primary oil recovery is responsible for the production, occurring through the natural pressure stored in the reservoir. Secondary oil recovery on the other hand, relies on the injection of pressurized gas or water to drive the remaining producible crude oil to production well. With reservoir maturation, the increased water production is a tradeoff in oil recovery. Hydrocarbon production decreases, affecting project economics and disposal of the excessive high amount of produced water can cause complex environmental problems. Oil and gas reservoirs are often heterogeneous, having various permeability values according to multi-layer of reservoir. This can cause channeling of injected water, causing excessive water production through high permeability layers. Large amount of producible oil remains trapped in low permeability zones which results in poor oil recovery in primary and secondary stages of production [8].

Tertiary oil recovery is performed by injecting different materials from reservoir fluids to improve oil recovery mechanisms. Polymer flooding is one of the most successful methods to enhance oil recovery due to the fact that it can drastically increase sweep efficiency by increasing the viscosity of the injected water or brine, especially the high molecular weight polymers, resulting in reduction of mobility ratio of the process. In addition, polymer adsorption onto rock surface can reduce relative permeability to water, favoring the displacement mechanism.

In oil field, commonly used polymers are Polyacrylamide (PAM), Xantan Gum (XG), Polyanionioc Cellulose (PAC) and Hydroxyethylcellulose (HEC). They can be categorized in two major groups, synthetic polymers and biopolymers as shown in Table 3.1 and Table 3.2., summarizing polymer structures and their characteristics which are beneficial in enhance oil recovery [9].

Table 3.1 Commonly used polymers in enhanced oil recovery

Polymer	Type	Biological stability	Usage
Polyacrylamide (PAM)	Synthetic	High	Most widely used
Xanthan Gum (XG)	Biopolymer	Low	Most widely used
Polyanionioc Cellulose (PAC)	Biopolymer	High	Widely available
Hydroxyethylcellulose (HEC)	Biopolymer	High	Widely available

Table 3.2 Polymer structure and their characteristics

Structure	Characteristics	Sample Polymers
-O- in the backbone	Low thermal stability, thermal degradation at high T, only suitable at <80°C	Polyoxyethelene, Sodium Alginate, Sodium Carboxymethyl Cellulose, HEC, Xantan Gum
Carbon chain in the backbone	Good thermal stability, degradation not severe at <110°C	Polvinyl, Sodium Polyacrylate, Polyacrylamide, HPAM
-COO$^-$ in hydrophilic group	Good viscosifier, less adsorption on sandstones due to repulsion between chain links, but precipitation with Ca^{2+} and Mg^{2+}	Sodium Alginate, Sodium Carboxymethyl Cellulose, HPAM, Xantan Gum
-OH or –CONH$_2$ in hydrophilic group	No precipitation with Ca^{2+} and Mg$^{2+,}$ but no repulsion between chain links; thus, less viscosifying power, high adsorption due to hydrogen bond formed on sandstone rocks	Polyvinyl, HEC, Polyacrylamide, HPAM

3.2 Mobility Reduction during Polymer Flooding

Polymer can cause an increase in viscosity of the brine being flooded through porous media. This is normally a desired effect when performing injection of polymer solutions for mobility control. Mobility ratio can be represented as equation 3.1:

$$M = \frac{\lambda_w}{\lambda_o} = \frac{k_w/\mu_w}{k_o/\mu_o} \tag{3.1}$$

where:

M= mobility ratio,

λ = mobility of each phase (oil and water),

k_w, k_o= effective permeability to water and to oil, respectively, and

μ_w, μ_o= viscosity of water and oil, respectively.

A value of mobility ratio less than unity is considered as favorable condition, because it indicates that the injected fluid cannot travel faster than the displaced fluid. Therefore, oil which is displaced fluid will not be by-passed by injected water. In terms of polymer flooding, its effect shows decreasing of effective permeability to water and increasing water viscosity. Therefore, mobility reduction is the primary conformance-improvement benefit of polymer flooding.

Polymer flow through reservoir matrix rock can cause permeability reduction due to the retention of polymer molecules in the reservoir rock [10].

The permeability reduction is measured in laboratory as corefloodiing and is expressed in two permeability reduction factors:

1. Residual Resistance Factor (R_{rf}) is a measure of the tendency of the polymer to adsorb and therefore partially block the porous medium. Residual resistance factor can be expressed as:

$$R_{rf} = \frac{\lambda_w(before\ polymer\ injection)}{\lambda_w(after\ polymer\ injection)} \tag{3.2}$$

From equation 3.2, if water that is flowing before and after polymer adsorption is the same, residual resistance factor is therefore a ratio of effective permeability to water before polymer adsorption to effective permeability to water after polymer adsorption. This ratio is therefore a change in absolute permeability due to polymer adsorption.

2. Resistance Factor (R_f) is a measurement of the decrease in mobility of the polymer solution in comparison with injection water refer to equation 3.3.

$$R_f = \frac{\lambda_w}{\lambda_p} \qquad (3.3)$$

where:

λ_w = mobility of the solvent of polymer solution, and

λ_p = mobility of the polymer solution.

Resistance factor is defined as a relative pressure drop that occurs when polymer is injected into rock formation compared to conventional waterflooding in order to obtain the same flowing rate. This value is therefore a combined effect from increment in viscosity of injectant together with reduction of effective permeability to water due to polymer adsorption.

3.3 Inaccessible Pore Volume

Accelerating the rate of polymer propagation, as compared with the rate of an inert chemical tracer dissolved in the injected polymer solution, is the Inaccessible Pore Volume (IPV) phenomenon. The large size of the polymer molecules prevents entry into smaller and dead-end pores. This promotes propagation of the polymer molecules faster than an inert chemical tracer because the polymer flows only through the larger-pore flow paths. However, amount of oil that can be displaced by polymer is also reduced.

3.4 Polymer Adsorption

Polymer adsorption is defined as the interaction between the polymer molecules and the porous medium. This leads polymer to be retained or adsorbed. Polymer adsorption results primarily from physical adsorption and not chemisorption. Polymer adsorption is often the major cause of polymer retention.

Polymer adsorption/retention mechanisms in porous media are mainly physical interaction, e.g., electrostatic attraction due to the charge differences between the solid surface and polymer or Van der Waals dipole–dipole interactions. Polymer retention consists of three main mechanisms:

1. Polymer adsorption: Polymer adsorption results primarily from physical adsorption and not chemisorption which is an adhesion of ions or molecules of polymer onto the surface of the reservoir rock.
2. Mechanical entrapment: Mechanical entrapment occurs from the when polymer molecules which are large in structural mass trapped in pore throats.
3. Hydrodynamic retention: Hydrodynamic results from polymer molecules becoming temporarily trapped in stagnant flow regimes by hydrodynamic drag forces.

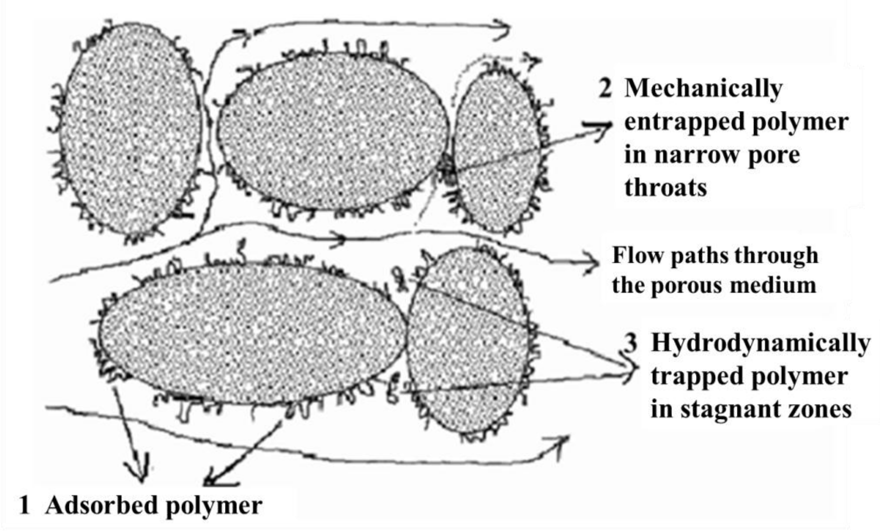

Figure 3.1 Polymer retention mechanisms in porous media [11]

Figure 3.1 illustrates three different locations where polymer adsorption and retention occurs in different patterns. Even polymer adsorption affects oil recovery in polymer flooding, loss of polymer is occurred. Therefore, polymer flooding scheme for recovering residual oil has been in general less satisfactory

There are other phenomena for example polymer precipitation. This phenomenon can occur especially in the presence of high salinity in brine and this causes a problem when certain type of polymer is used such as Hydrolyzed Polyacrylamide (HPAM) in high temperature reservoirs with formation water containing hardness divalent cations.

3.5 Parameters Affecting Polymer Flooding

1. Viscosity of Polymer Solutions

Generally, the viscosity of a fluid can be defined as the solution's resistance to being sheared as shown in an equation below where **T** is shear stress and **γ**. is shear rate:

$$\mu = \frac{\tau}{\dot{\gamma}} \tag{3.4}$$

The viscosity of a polymer solution is a measure of how thick of fluid is. Many common fluids like water exhibits Newtonian viscosity while viscosity of polymer solution causes it to be non-Newtonian fluid. For fluids with non-Newtonian viscosities, the value of viscosity at given temperature is a single value that is dependent to shear rate.

Non-Newtonian behavior of fluids can be caused by several factors. All of them are related to structural reorganization of the molecules due to flow. In polymer solutions, it is the alignment of the highly anisotropic chains that results in reduction of viscosity. The viscosity-enhancing power of a polymer is related to the size and extension of polymer molecule in a particular aqueous solution [12].

2. Molecular Weight and Size of Polymer

Size of the polymer is directly varied with molecular weight of polymer molecule. When the size of the polymer molecule increases, viscosity of polymer solution is enhanced. However, when molecular weight of polymer is increased, this causes low injectivity problem as polymer tends to retain during transportation in pore space adjacent to the injection well.

Molecular weight distribution of polymer is an important factor relating function of polymer during polymer flooding. However, it is difficult to measure, high cost and time consuming.

3. Rheology

The non-Newtonian viscosity of polymer solutions used in polymer flooding normally exhibits shear-thinning behavior when subjected to sufficiently high shear rates. It can be explained that apparent viscosity of the fluid decreases as the fluid experiences increasing shear rates. Apparent viscosity is the viscosity determined during flow of polymer solution.

The power-law model equation can be used to describe behavior of polymer solutions in terms of viscosity as a function of shear-rate behavior as shown in equation below where K and n are the power-law coefficient and exponent, respectively and $\dot{\gamma}$ is shear rate.

$$\eta = K(\dot{\gamma})^{n-1} \qquad (3.5)$$

The viscosity behavior of a polymer solution becomes more shear-thinning as the value of the power-law exponent, n, decreases. The polymer shear-thinning makes the viscosity reduction improves injectivity of the polymer solution. **ผิดพลาด! ไม่ใช่การอ้างอิงถึงตัวที่คั่นหน้าเองที่ถูกต้อง** depicts types of fluid considering shear stress as a function of shear rate and emphasizes this relationship into three fluid types comprising shear thinning, Newtonian and shear thickening fluids.

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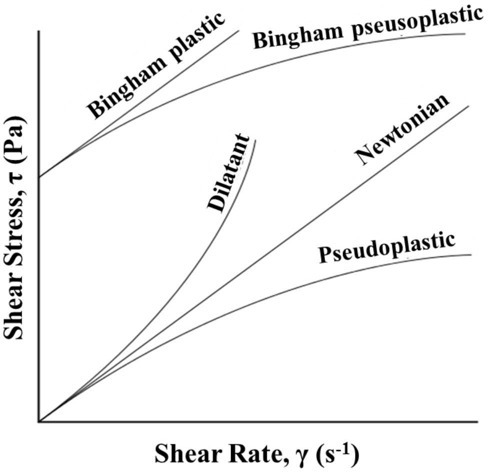

Figure 3.2 Classification of fluids with shear stress as a function of shear rate

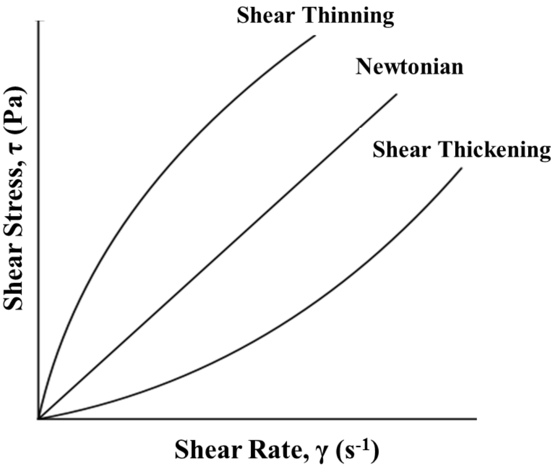

Figure 3.3 Viscosity of Newtonian, shear-thinning and shear thickening fluids as a function of shear rate

4. Effects of Salt, Hardness, and pH on Polymer Flooding

The effect of salt and hardness on viscosity and mobility-control function of polymer-flood is important. In case of HPAM polymers, cations of dissolved salts reduce electrostatic repulsion of the negatively charged hydrolyzed carboxylate pendant groups on the polymer backbone of HPAM by screening and collapsing the local negatively charged double layer formed around the carboxylate species. The degree of collapse increases when salt concentrations increases. The carboxylate groups collapse affects the viscosity of the polymer solution. It can be explained by electrostatic repulsive forces that promote polymer backbone-chain distension to decrease.

The effect of pH on viscosity of ionic HPAM can be significant. Decreasing the solution pH tends to convert the ionic salt form of the polymer’s carboxylate groups to relatively nonionic carboxylic acid form of carboxylate groups. This diminishes the electrostatic repulsion of the ionic carboxylate groups along the polymer’s backbone and leads to less distention of the polymer molecule and to less viscosity-enhancing power for the polymer in a low pH solution [13].

5. Polymer Injectivity

Injectvity is defined as an ease to inject certain fluid into formation. Injectivity is usually dependent on several parameters including rock permeability, pressure difference at injection well, relative permeability of displaced fluid and also viscosity of injected fluid. As polymer is a viscous fluid, injectivity of polymer is much lower compared to water. This results in difficulty to attain the desire injection rate. Nevertheless, injectivity of polymer solution is improved when the polymer solution exhibits shear-thinning viscosity behavior.

The injectivity index, a measure of the ability of a well to accept fluids, is defined as the injection rate divided by the injection pressure drop [14]:

$$I = \frac{Q}{\Delta P} \tag{3.6}$$

where:

Q = summation of flow rate of all the reservoir layers,

ΔP = injection pressure drop [P_{iwf} - P_e],

P_{iwf} = flowing bottomhole pressure in psi, and

P_e = external pressure in psi.

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A common technique to increase injectivity of polymer solution is performed by pre-injection of water or so-called pre-flush. After certain pore volume of pre-flushed water is injected, polymer solution is followed and in order to prevent a high cost of operation, polymer slug is followed by chasing water that is already proved to do not create fluid incompatibility.

3.6 Reservoir Heterogeneity and Lorenz Coefficient

Most of the reservoirs are heterogeneous. Understanding type of heterogeneity as well as quantifying degree of heterogeneity of the reservoir could help to forecast production performance. There are several techniques to quantify heterogeneity including static and dynamic methods. Lorenz coefficient is one of the static techniques. The reservoir is characterized as multi-layers (N layers). Lorenz coefficient defines two terms as cumulative flow capacity and cumulative storage capacity, consisting of three parameters which are permeability, porosity and thickness. The definitions of the capacities are shown as follow:

$$F_n = \frac{\sum_{i=1}^{n} k_i h_i}{\sum_{i=1}^{N} k_i h_i} \tag{3.7}$$

$$C_n = \frac{\sum_{i=1}^{n} \emptyset_i h_i}{\sum_{i=1}^{N} \emptyset_i h_i} \tag{3.8}$$

According to **Figure 3.4**, the plot between flow capacity and storage capacity is used to calculate the Lorenz coefficient. The coefficient demonstrates the value comparing between homogenous and heterogeneous one [15]. Therefore, Lorenz coefficient (*L_k*) can be calculated as the areas in the plot refer to below equation:

$$L_k = \frac{Area\ ABC}{Area\ ADC} \qquad (3.8).$$

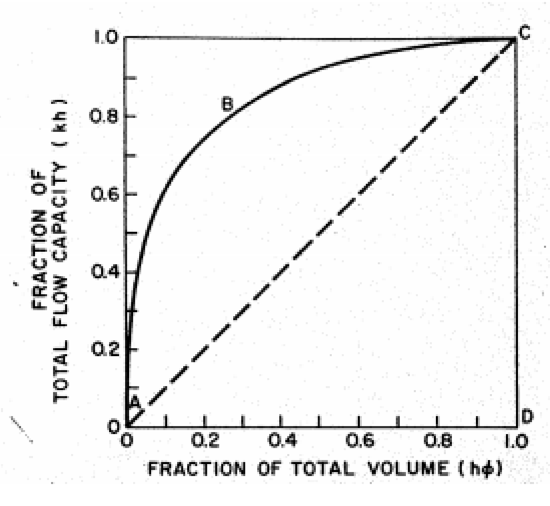

Figure 3.4 Relationship between total flow capacity and total storage capacity of Lorenz plot [16]

CHAPTER 4

RESERVOIR SIMULATION MODEL AND RESEARCH METHODOLOGY

This chapter provides specifications of reservoir simulation model used in this study. Reservoir model is generated by using reservoir simulator called STARS® commercialized by Computer Modeling Group Ltd. (CMG) in order to develop simulation study of polymer flooding process. Reservoir simulation model consists of 5 main sections including reservoir structure, components section, rock and fluid properties, well and recurrent model and injected fluid properties. Finally, thesis methodology is summarized in the last section.

4.1 Reservoir Structural Section

The model is constructed in Cartesian coordinates to represent a quarter 5-spot flood pattern. Table 4.1 summarizes expected properties to represent reservoir model in this study.

Table 4.1 Reservoir preference in the simulation

Parameters	Values	Unit
Grid dimension	33×33×9	Block
Grid size	20×20×12	ft
Top of reservoir	3,280	ft
Porosity	0.20	
Horizontal permeability	500	mD
Vertical permeability	0.1 k_H	mD

4.2 Components Section

Refer to EOR Screening Criteria of Taber [17], crude oil gravity of 25 $^{\circ}$API is chosen for this study. The most important technical screening criteria for polymer flooding is reservoir temperature due to risk of polymer decomposition. That is the temperature should be less than 200 $^{\circ}$F. The top of simulated reservoir model is fixed at depth of 3,280 ft. Typical gradient of water which is 0.433 psi/ft is used for determination of reference pressure refer to calculation in equation 4.1 while reference temperature at datum depth is determined from temperature gradients as shown in Figure 4.1. Therefore, the reference pressure and temperature are determined to be at 1,435 psia and 150 °F, respectively.

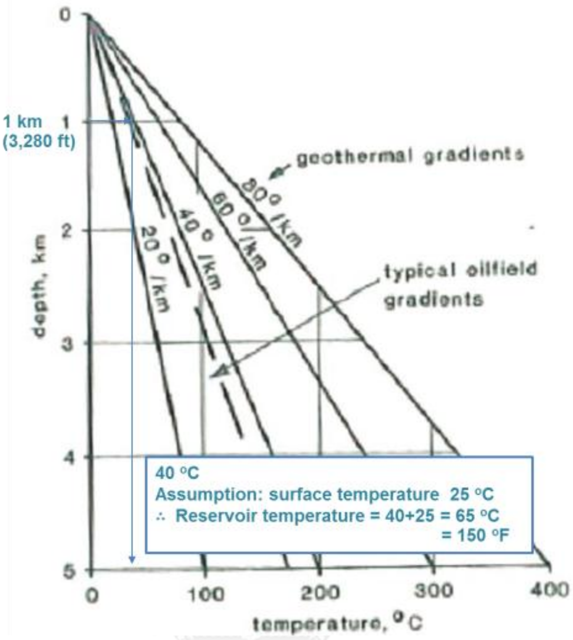

Figure 4.1 Typical geothermal gradient [18]

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Calculation of Pressure at Datum Depth

Assumption of typical pressure gradient of water = 0.433 psi/ft

$$\therefore \text{Reference Pressure} = 0.433\ \text{psi/ft} \times 3{,}280\ \text{ft} \approx 1420.2\ \text{psi} \quad (4.1)$$

$$= 1{,}435\ \text{psia}$$

Correlations in STARS® using to generate Pressure-Volume-Temperature (PVT) data of all the fluids are summarized in Table 4.2. Values of input parameters necessary for PVT data generation by correlations in STARS® are shown in **Table 4.3**.

There are two important PVT data which are solution gas-oil ratio (R_s) and bubble point pressure (P_b). Vasquez and begs correlation is used to determine solution gas-oil ratio from specified gas specific gravity, oil gravity, reference pressure and temperature. The solution gas-oil ratio of 206.3 SCF/STB can be determined. The bubble point pressure can be generated from STARS®. Figure 4.2 shows PVT data is used in the simulation.

Table 4.2 Correlation types for generating each PVT data

Parameters	Correlation Types
Oil properties (P_b, R_s, B_o) correlations	Standing
Oil compressibility correlation	Glaso
Dead oil viscosity correlation	Ng and Egbogah
Live oil viscosity correlation	Beggs and Robinson
Gas critical properties correlation	Standing

Table 4.3 PVT data using in the simulation

Parameters	Values	Unit
Reservoir temperature	150	$^{\circ}$F
Initial gas oil ratio (R_s)	206.3	SCF/STB
Oil gravity	25	$^{\circ}$API
Gas specific gravity	0.7	
Initial water saturation	20	%
Reference pressure at datum depth	1,435	psia
Water salinity	1,000	ppm
Bubble point pressure	1,350	psia

The function of PVT data versus pressure generated by STARS® is shown in Figure 4.2 to Figure 4.8. The PVT data includes oil formation volume factor (B_o), gas formation volume factor (B_g), water formation volume factor (B_w), oil viscosity (μ_o), gas viscosity (μ_g), and water viscosity (μ_w).

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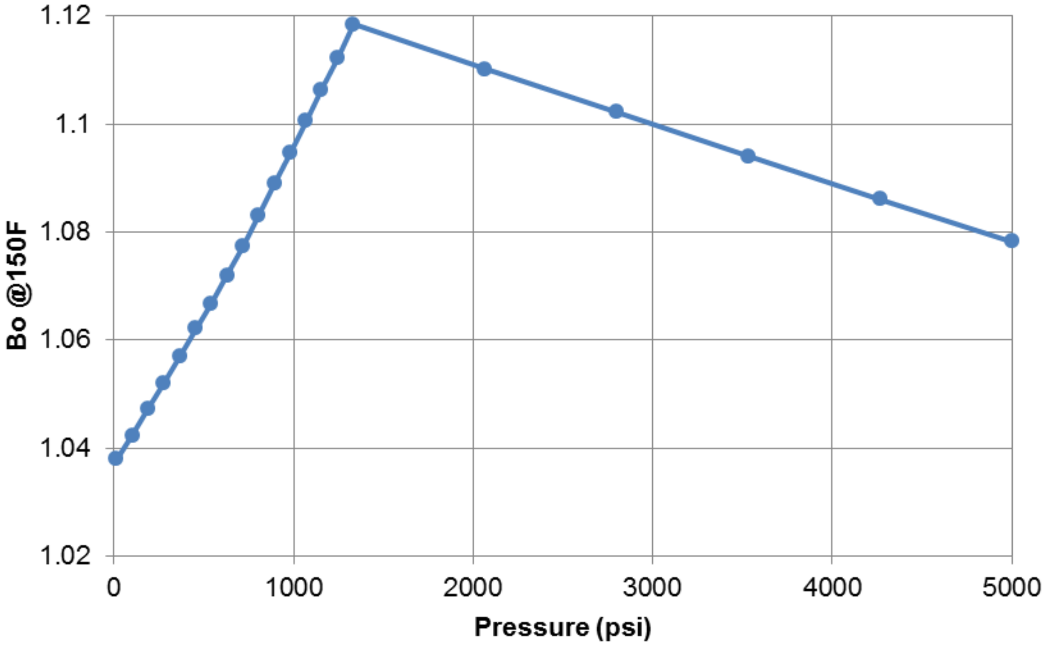

Figure 4.2 Relationship between oil formation volume factor (B_o) and pressure

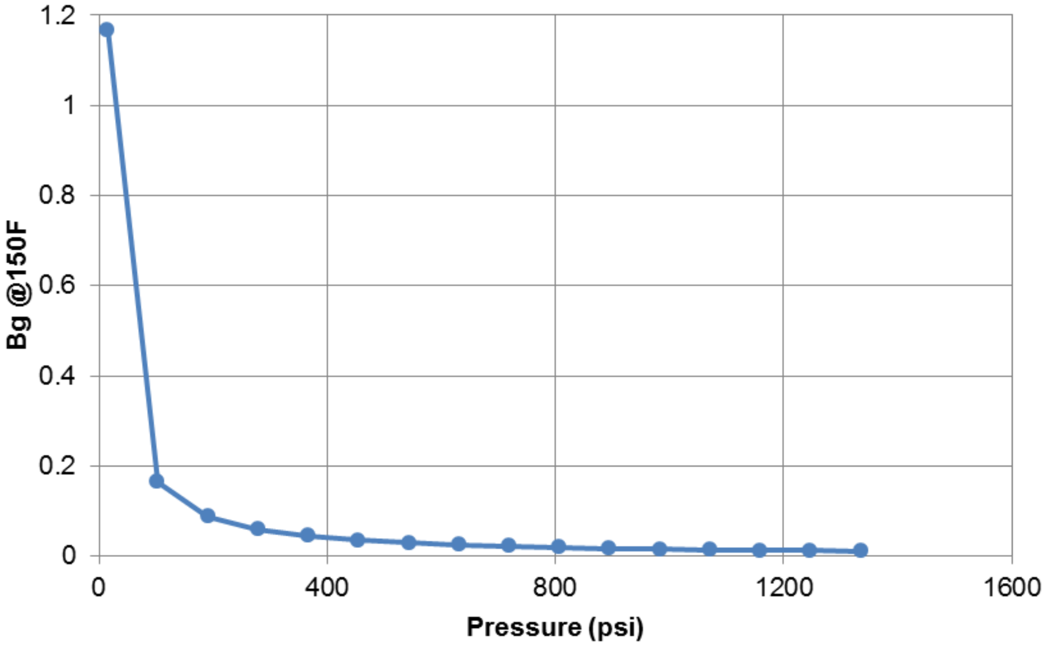

Figure 4.3 Relationship between gas formation volume factor (B_g) and pressure

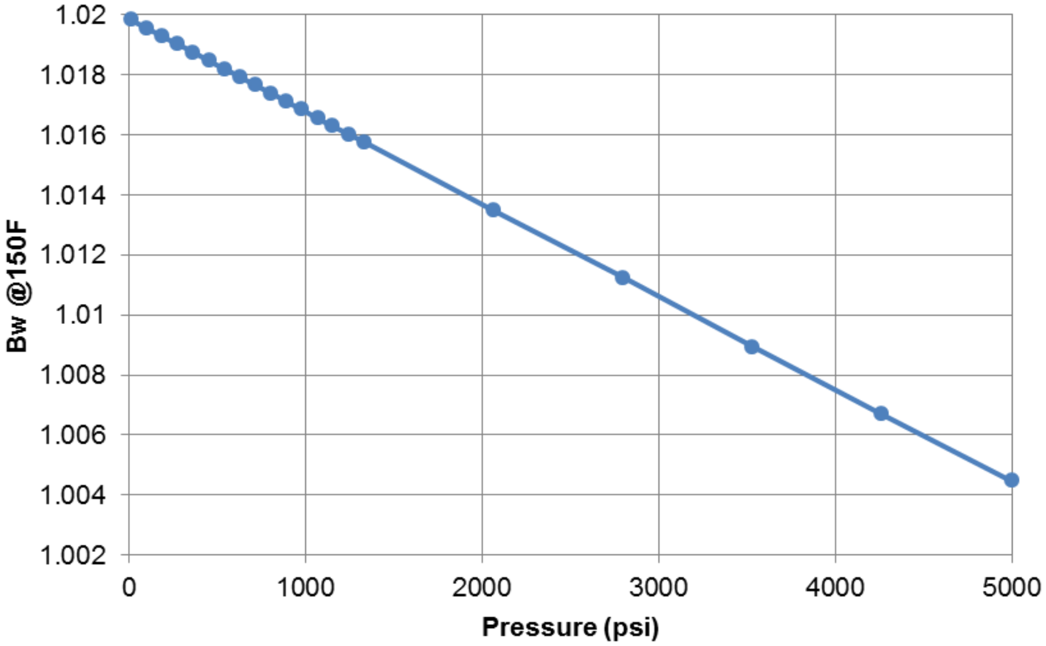

Figure 4.4 Relationship between water formation volume factor (B_w) and pressure

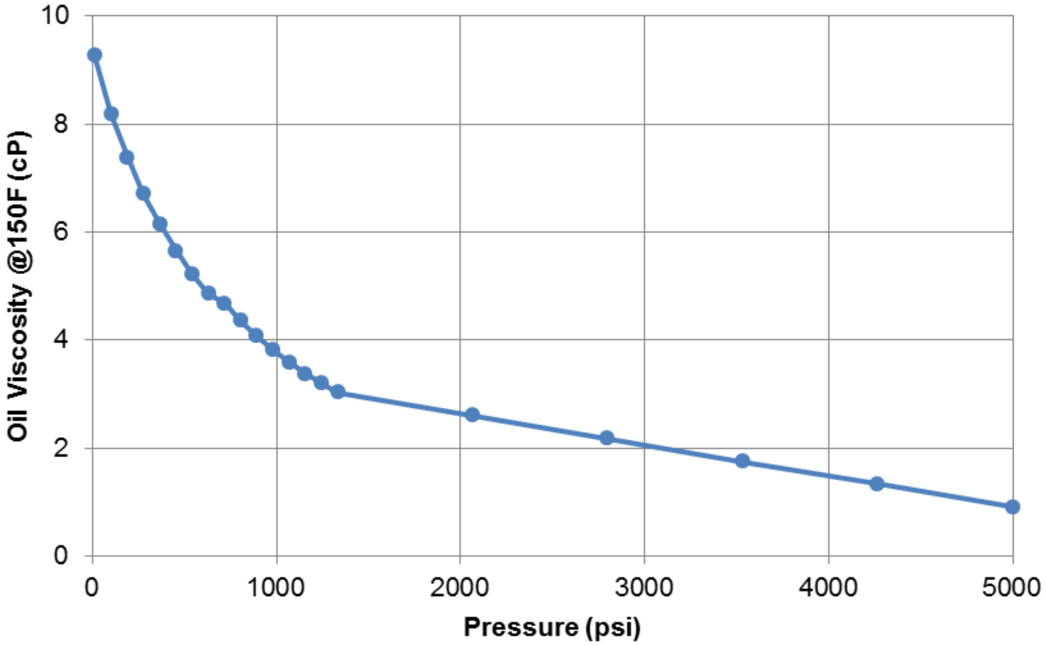

Figure 4.5 Relationship between oil viscosity (μ_o) and pressure

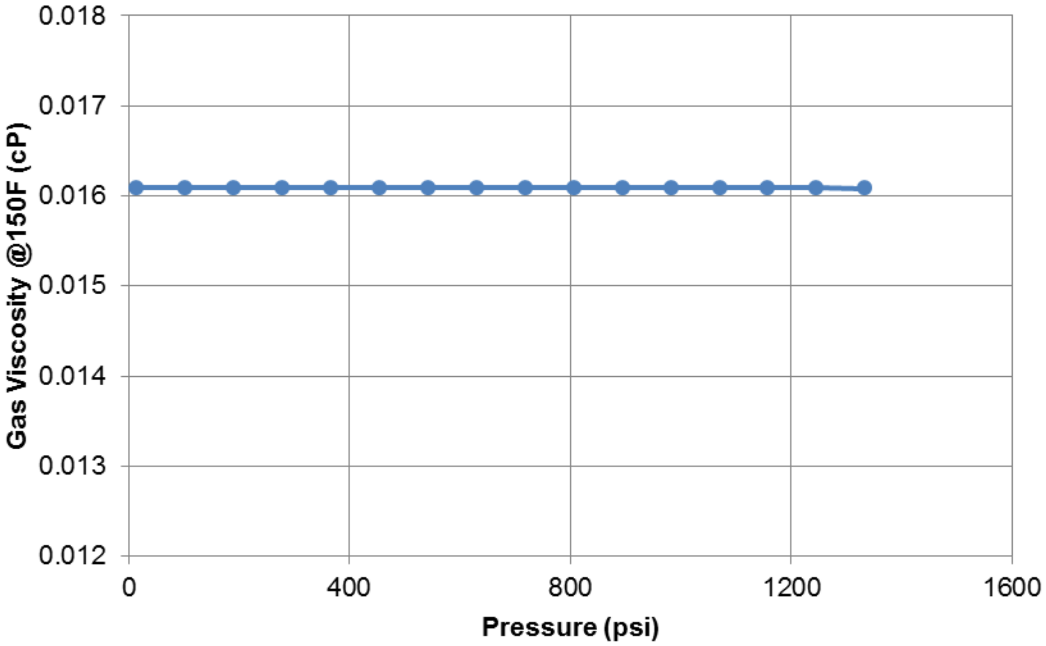

Figure 4.6 Relationship between gas viscosity (μ_g) and pressure

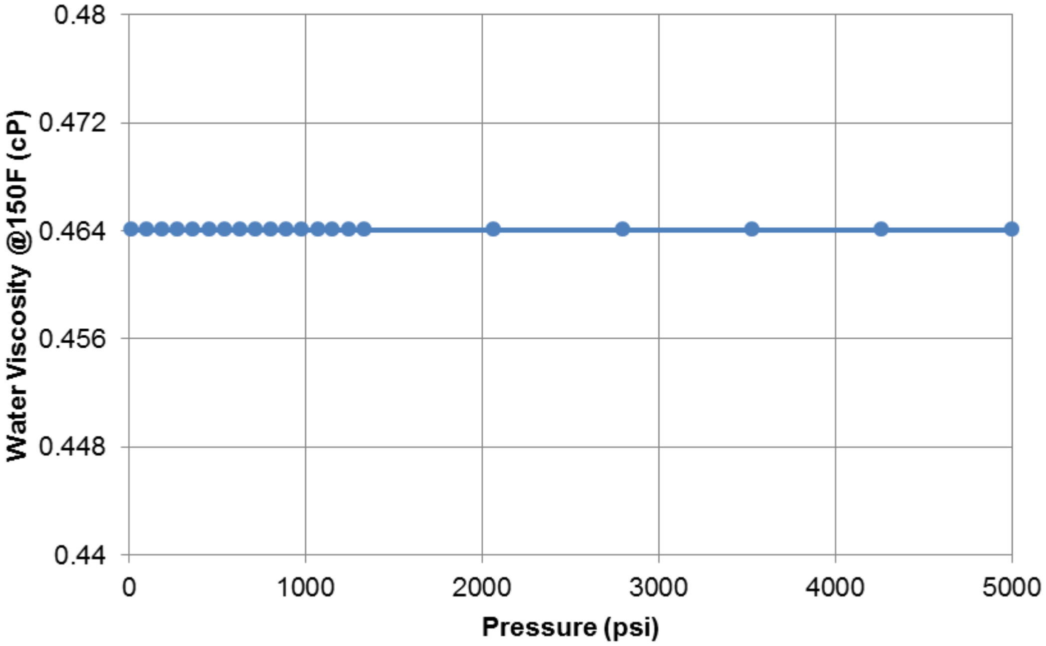

Figure 4.7 Relationship between water viscosity (μ_w) and pressure

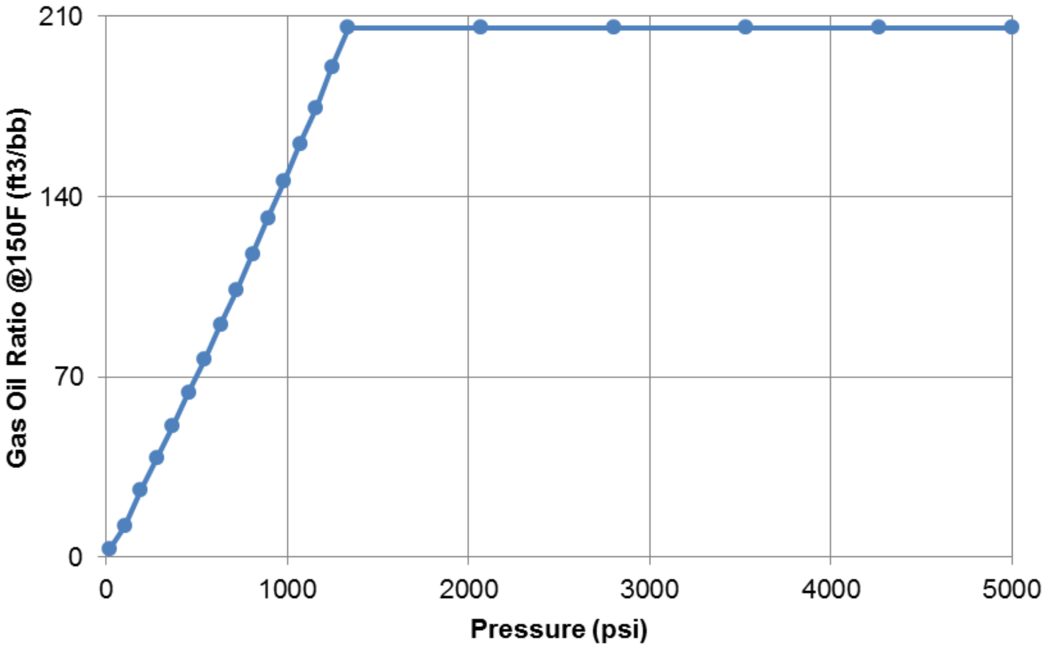

Figure 4.8 Relationship between gas-oil ratio (R_s) and pressure

4.3 Rock and Fluid Properties

This section describes construction of relative permeability curves used in this study. Sandstone formation is chosen for this thesis as it is more compatible for chemical flooding. According reservoir consists of oil, gas and water, Stone II model is used to create three-phase permeability to oil. Initial relative permeability curve between rock and fluid is generated based on water-wet condition, using Corey's exponent value of 3 for two-phase relative permeability which are oil-water and gas-liquid system. Table 4.4 demonstrates parameters required for constructing relative permeability of oil-water system in Figure 4.9.

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Table 4.4 Relative permeability correlations for initial relative permeability curves

Relative Permeability Correlations Data Setting	Value
SWCON - Endpoint Saturation: Connate Water	0.2
SWCRIT - Endpoint Saturation: Critical Water	0.2
SOIRW - Endpoint Saturation: Irreducible Oil for Water-Oil Table	0.25
SORW - Endpoint Saturation: Residual Oil for Water-Oil Table	0.25
SOIRG - Endpoint Saturation: Irreducible Oil for Gas-Liquid Table	0
SORG - Endpoint Saturation: Residual Oil for Gas-Liquid Table	0.2
SGCON - Endpoint Saturation: Connate Gas	0
SGCRIT - Endpoint Saturation: Critical Gas	0.05
KROCW - Kro at Connate Water	0.7
KRWIRO - Krw at Irreducible Oil	0.3
KRGCL - Krg at Connate Liquid	0.7
KROGCG - Krog at Connate Gas	-
Exponent for calculating Krw from KRWIRO	2
Exponent for calculating Krow from KROCW	2
Exponent for calculating Krog from KROGCG	3
Exponent for calculating Krg from KRGCL	3

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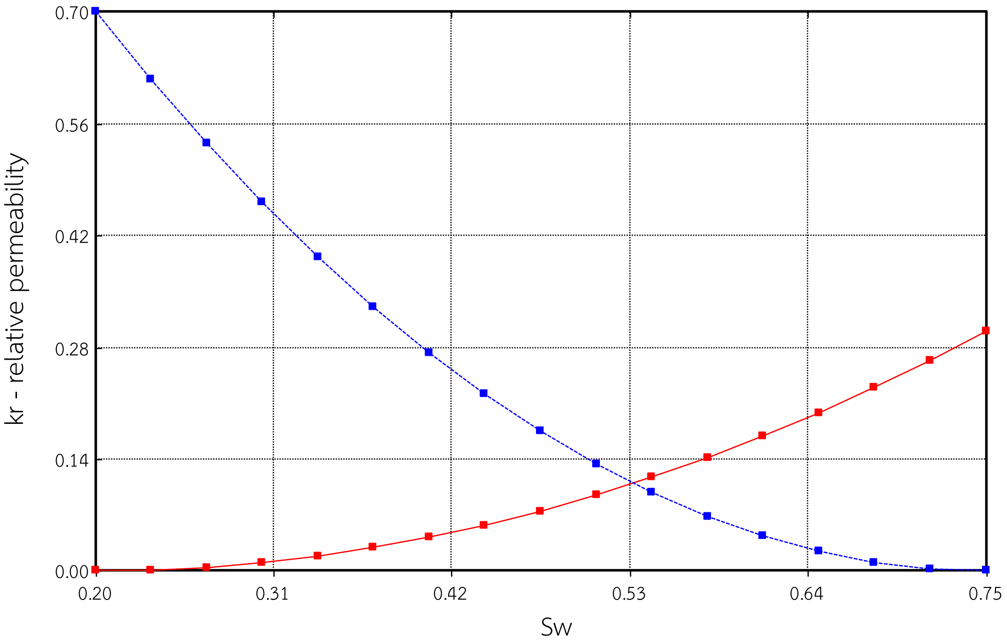

Figure 4.9 Relative permeability curves of oil-water system as a function of water saturation

4.4 Well and Recurrent Model

Producer and injector are located at the opposite corners of reservoir to represent a quarter 5-spot flood pattern as mentioned earlier. Wellbore radius is set to be at 0.25 ft. corresponding to 6 inches bit diameter. Skin around the wellbore is assumed to be zero. Full-to-base perforation throughout reservoir thickness is assumed in this study.

Waterflooding process is performed at the beginning of the reservoir simulation. Total production period of 30 years is used to represent normal concession period for this study. In the simulation, certain operations and monitoring are set as well safety and economic constraints to control the termination of simulation as well as concession period.

For injection well, there are two well constraints including bottomhole pressure and surface injection rate. Injection well bottomhole pressure is set to a maximum amount of 2,000 psi. This value is below estimated formation fracture pressure in order to prevent formation fracture. Maximum surface water injection rate is varied in order to study its effect on the process. The maximum corresponding surface liquid rate of production well is set following the surface water injection rate.

For production well, there are two operating parameters and two monitoring parameters which are bottomhole pressure and surface liquid rate, water cut and surface oil rate, respectively. Economic constrains are considered in the simulation. Simulation will be terminated whether water cut or surface oil rate attain the limitation. Table 4.5 and Table 4.6 summarize well constraints of injection well and production well, respectively.

Table 4.5 Well constraints of injection well

Constraint	Parameters	Limit/Mode	Value	Unit	Action
Operate	Bottomhole Pressure, BHP	Max	2,000	psi	Cont.
Operate	Surface Water Rate, STW	Max	Vary	bbl/day	Cont.

Table 4.6 Well constraints of production well

Constraint	Parameters	Limit/Mode	Value	Unit	Action
Operate	Bottomhole Pressure, BHP	Min	200	psi	Cont.
Operate	Surface Liquid Rate, STL	Max	Vary	bbl/day	Cont.
Monitor	Water Cut, WCUT		0.95	fraction	Stop
Monitor	Surface Oil Rate, STO	Min	25	bbl/day	Stop

4.5 Injected Fluid Properties

Hydrolyzed polyacrylamide polymer (HPAM) represents polymer in this study. Flopaam 3330S is a commercial polymer that its properties are widely studied. Choi et. al. [19] had experimented to study on adsorption of Flopaam 3330S. Table 4.7 shows polymer adsorption data which is a function of polymer concentration. Polymer viscosity can be calculated from viscosity multiplier [18] with a function of polymer concentration as shown in Table 4.8.

Table 4.7 Values of polymer adsorption as a function of polymer concentration

Polymer Concentration (%wt)	Polymer Adsorption (mg/100gm rock)
0	0
0.1	1.32
0.25	3.29
0.5	6.58

Table 4.8 Function of polymer concentration and viscosity with viscosity multiplier

Polymer Concentration (%wt)	Viscosity Multiplier	Viscosity (cp)
0	0	0.46
0.05	4.4	2.04
0.1	12	5.57
0.2	44	20.42
0.3	130	60.33

4.6 Thesis Methodology

1. Performed initialized simulation on waterflooding case to obtain reference data in order to compare with results from polymer flooding.
2. Run reservoir simulation with polymer flooding process to select optimum polymer slug size as a function of polymer concentration. The following shows ranges of operating parameters:
    a. Polymer concentration [ppm]: 500, 750 and 1,000,
    b. Polymer slug size ranging from 0.05 to 0.50 of pore volume (PV).
3. Study time to implement polymer flooding and polymer injection rate with 3 different degrees of desorption which are 0, 50 and 100 percent. The following summarizes ranges of operating parameters:
    a. Time of polymer flooding process: 0.05PV of water injection, 0.10PV of water injection, at breakthrough, 25% water cut and 50% water cut,

   b. Polymer injection rate: 300, 500 and 700 barrel per day.

4. Analyze effects of studied parameters on polymer flooding process and identify optimum operating parameters.
5. Construct polymer flooding with variation of heterogeneity, magnitudes of polymer adsorption and resistance factor with optimum operating parameter in order to investigate effects of related parameters. The following shows ranges of interest parameters:
   a. Heterogeneity (Lorenz coefficient): 0.1 and 0.2,
   b. Magnitude of polymer adsorption 9.27, 13.905 x 10^{-7} lbmole/ft^3,
   c. Polymer resistance factor: 2, 5, 10.
6. Analyze and summarize the simulation outcomes.

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CHAPTER 5

RESULTS AND DISCUSSION

After reservoir simulation models are constructed, results of polymer flooding including effects of polymer desorption process are investigated. Waterflooding process is performed as a base line for this study. Results from waterflooding are used as reference to compare with results from polymer flooding in terms of oil recovery factor as well as water production. The polymer consumption is evaluated from polymer slug size together with polymer concentrations. After that, effects of polymer desorption which is major interest of this study, are evaluated. The study is narrow down to identify the appropriate operational parameters in terms of starting time of polymer flooding and injection rate in each degree of polymer desorption. Finally, other related parameters at the selected conditions are investigated including reservoir heterogeneity, magnitude of polymer adsorption and polymer resistance factor. This chapter consists of following sub-sections:

5.1. Comparison between Waterflooding and Polymer Flooding Results

5.2. Identification of Polymer Mass for the Entire Process

5.3. Effects of Degree of Polymer Desorption

5.4. Effects of Operational Parameters

5.5. Effects of Reservoir Heterogeneity

5.6. Effects of Magnitude of Polymer Adsorption

5.7. Effects of Polymer Resistance Factor

5.1 Comparison between Waterflooding Base Case and Polymer Flooding Results

5.1.1. Waterflooding Results

Waterflooding is performed as base case starting at day one in the simulation. The results of waterflooding are used as reference for polymer flooding cases in this thesis. Oil recovery factor, production period, water injection rate, oil and water production, bottomhole pressure of producer are described in Figure 5.1 to Figure 5.4 with various injection rates. After comparisons, the results can be used to describe mechanism of polymer flooding process in 5.1.2.

Injection rate is one of studied operating parameters in this thesis. Therefore, Injection rate of waterflooding process is varied to 300, 500 and 700 bbl/day. Figure 5.1 illustrates oil recovery factors obtained from three different injection rates.

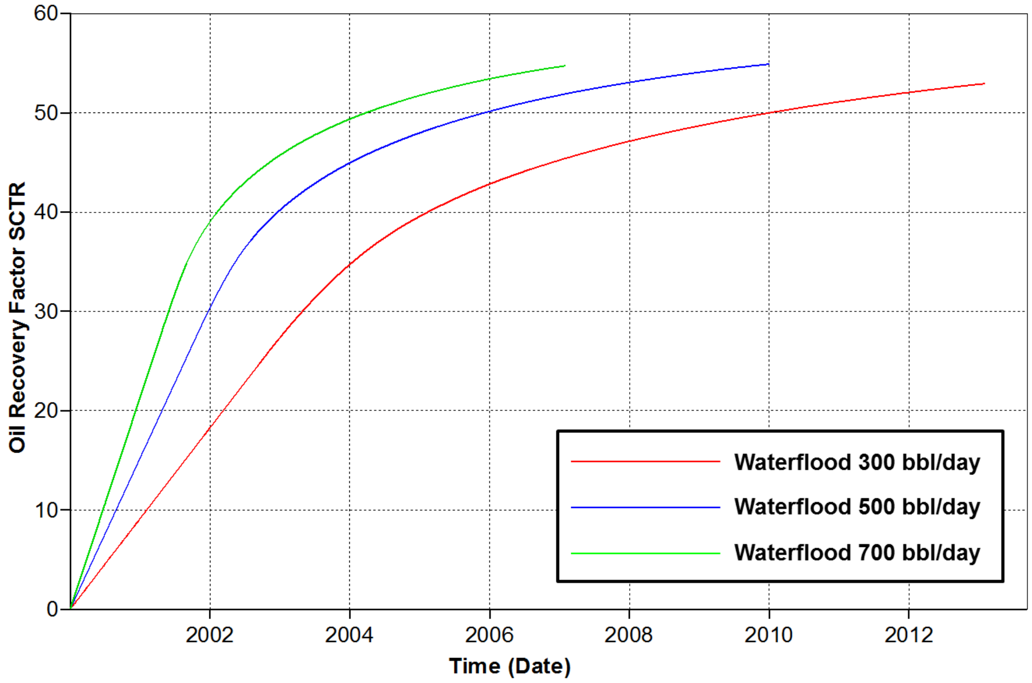

Figure 5.1 Oil recovery factor of waterflooding with various water injection rates as a function of time

From the figure, it can be observed that injection rates of 700 and 500 bbl/day yield almost the same oil recovery factor of about 55 percent. The only different is time for the highest oil recovery factor to attain due to different amount of water injected. Water injection rate is important for controlling stability of flood front. As water is heavier than oil, force provided from injection must overcome the gravity force. The effect of gravity force can be observed in the lowest water injection rate of 300 bbl/day. At this injection rate, oil recovery factor is less than other two higher injection rates due to underrunning of water as well as domination of gravity. Inappropriate water breakthrough results in part of oil remain un-swept. The water underrunning is explained in section 5.5: Effects of Reservoir Heterogeneity.

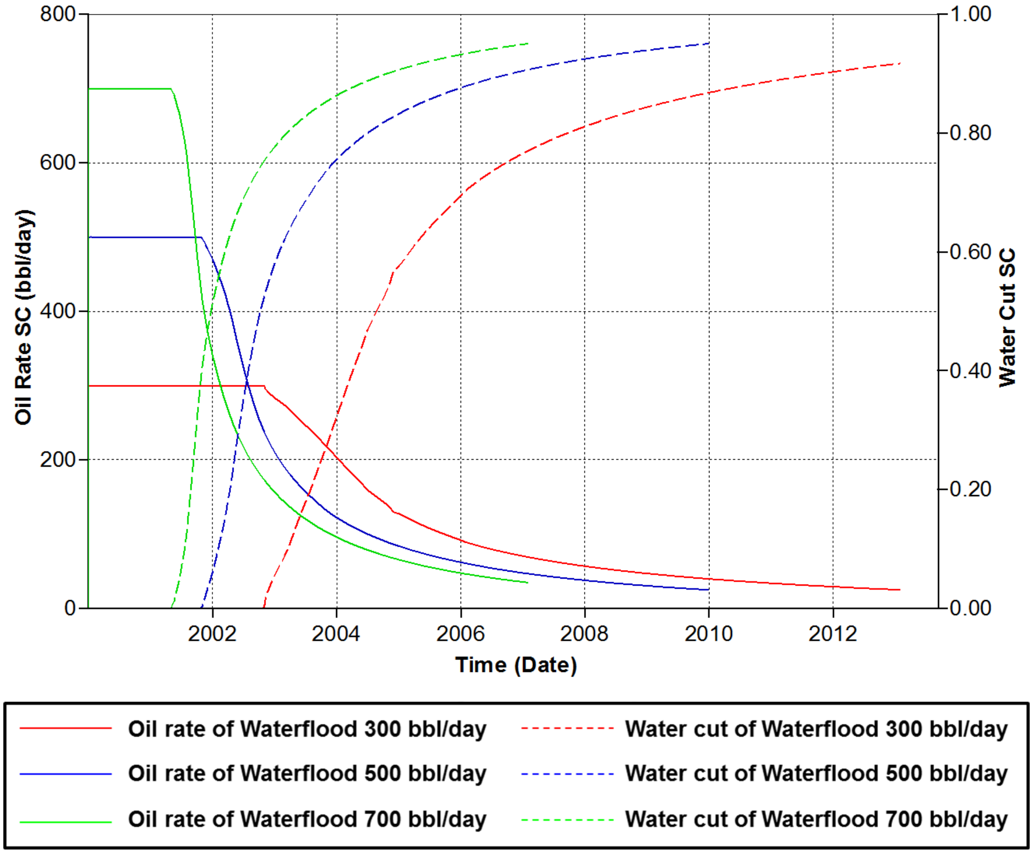

Figure 5.2 Oil production rate and water cut of waterflooding with various water injection rates as a function of time

Figure 5.2 shows oil and water production rates obtained from waterflooding at different water injection rates. Once water is injected, oil production rate can be maintained as desired rates until water breakthrough. It can be observed that the area under plateau rate is smallest in case of water injection rate 300 bbl/day which is due to early water breakthrough. After water breakthrough, oil production starts decline in all cases whereas water cut sharply increases. At late time, the production constraints are considered in term of the termination of the production, which are maximum water cut of 95% and minimum oil production of 25 bbl/day. From these three cases, only the case with water injection rate of 300 barrel per day is terminated due to minimum oil production rate, whereas cases with water injection rate of 500 and 700 bbl/day are terminated by water cut. It can be explained directly that, higher injection rate accelerates the incremental water volume into the system, resulting in termination controlled by water cut.

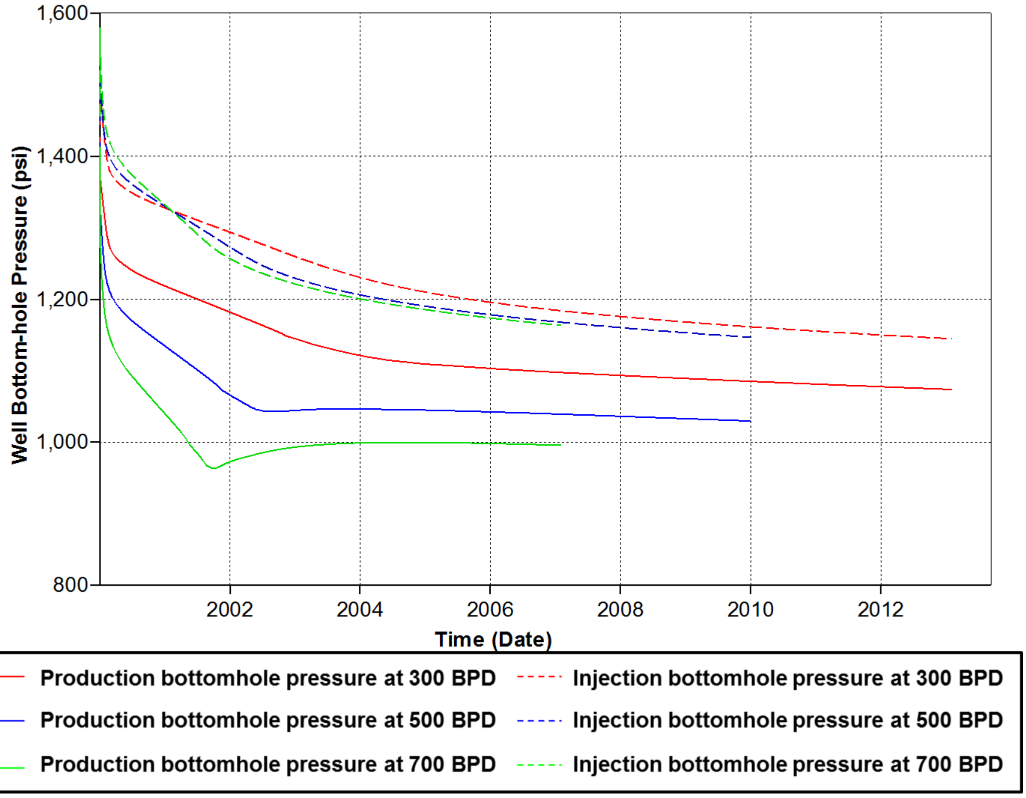

Figure 5.3 Production well bottomhole pressure and Injection well bottomhole pressure of waterflooding with various water injection rates as a function of time

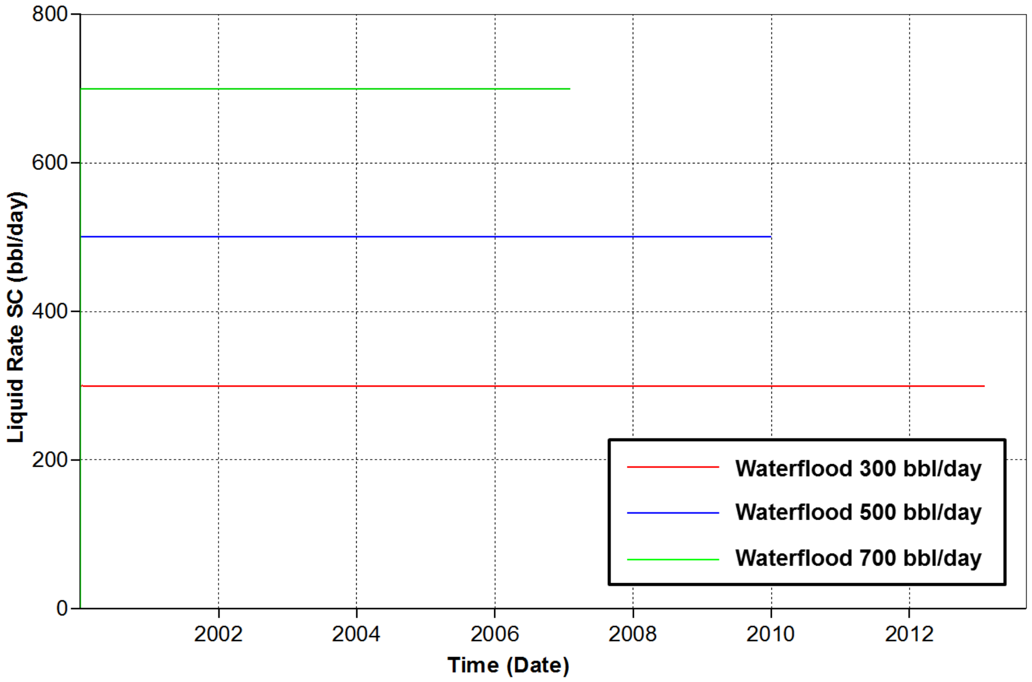

Figure 5.4 Water injection rate of waterflooding with various water injection rates as a function of time

Figure 5.3 and **Figure 5.4** illustrate bottomhole pressure of production well and actual water injection rate as a function of time, respectively. As water injection rate can be attained at the desire value, pressures at both injection well and production well must be adjusted. From **Figure 5.3** bottomhole pressure is reduced in first period for all three cases. As water is difficulty injected at first period from injection well, pressure supported from injection is not enough and bottomhole pressure must reduce its pressure to maintain pressure difference. However, with higher injection rates of 500 and 700 bbl/day, bottomhole pressure of production well starts to increase again which is due to injectivity of water that is quickly increased from water saturation around the wellbore. Pressure at injection well is slightly decreased at hence, pressure at production well slight increases. For the water injection rate shown in **Figure 5.4**, the desired injection rate can be reached in all studied rate cases by waterflooding process.

From this section, waterflooding yields oil recovery factor up to 55%. The smallest rate of 300 bbl/day yields slightly lower oil recovery factor compared to other two higher rates. Nevertheless, different injection rates results in different total production period which ranges from 7 to 13 years.

5.1.2. Polymer Flooding Results

Mechanism of polymer flooding process is described in this section. However, effect from polymer desorption process is excluded first or degree of polymer desorption is 0%. Polymer flooding cases with various injection rates are used to compare with the waterflooding cases.

Polymer flooding is not performed from the first day because polymer is viscous fluid and this might cause low injectivity problem. Therefore, waterflooding is performed first until water breakthrough and displacement mechanism is switched to polymer flooding. To demonstrate the mechanism of polymer flooding process, the concentration of polymer is set at 750 ppm with polymer slug size 30% Pore Volume (PV) and after this total amount of polymer is injected into the reservoir, the process is switched back to waterflooding to perform chasing period. **Figure 5.5** illustrates comparisons between polymer flooding and waterflooding at different injection rates.

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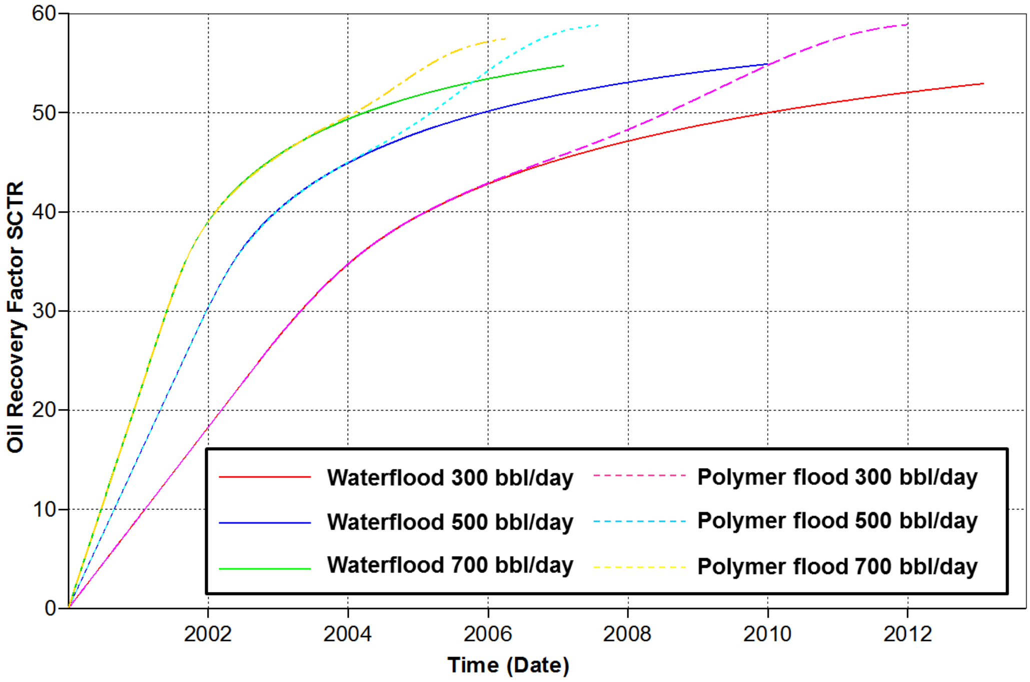

Figure 5.5 Oil recovery factors of polymer flooding with various water injection rates as a function of time in comparison with waterflooding cases

In case of polymer flooding, it shows that oil recovery factor can be improved after polymer flooding is involved into the process as well as production acceleration comparing with waterflooding cases. The oil recovery factor increases obviously in the earlier phase of polymer flooding. Figure 5.5 shows that oil recovery factors of all polymer flooding cases are higher than the recovery factors of water flooding cases. Nevertheless, the improvement is quite obvious in case of injection rate of 500 bbl/day which can be explained that at the time of water breakthrough amount of remaining oil is not too high and not too low for polymer to sweep this portion of oil. From the figure, polymer flooding can increase oil recovery factor up to 59%, approximately during 6-12 years of production period which are shorten compared to waterflooding. The example of mobility calculation is shown in this section.

Benefit of polymer flooding is reduction of effective permeability to water. Refer to simulation preferences; residual resistant factor is set at 5. This means the relative permeability to polymer solution can be decreased by 5 times compared to relative permeability to water. **Figure 5.6** shows relative permeability curve of the process.

In case of polymer concentration 750 ppm, the viscosities of oil, water and polymer solution are 9.27, 0.46 and 2.67 cP, respectively. It is assumed that (1) the viscosity of fluid in the system and the reduction of relative permeability to water are constant. (2) The relative permeability to oil before water breakthrough is fixed at 0.7 as oil only travels beyond flooded area. The fractional flow curve of waterflooding and polymer flooding cases are demonstrated by equation 5.1 and **Figure 5.7**.

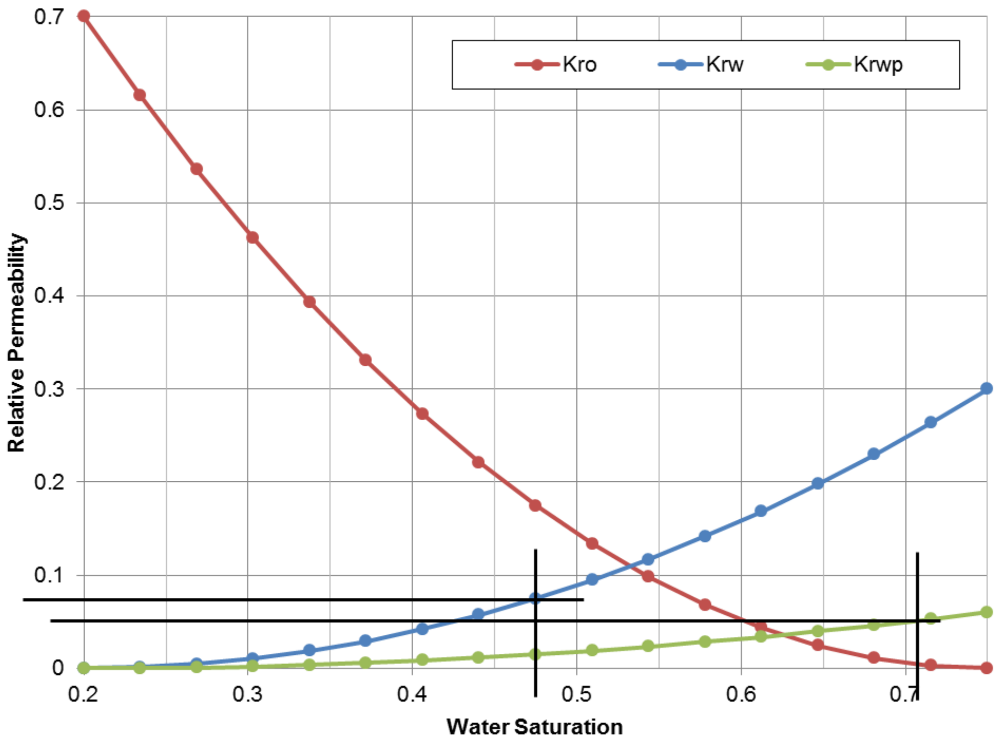

Figure 5.6 Relative permeability curves of oil-water system and oil-polymer system

Fractional Flow (f_w):

$$f_w = \frac{1}{1+\frac{\mu_w}{k_{rw}}\times\frac{k_{ro}}{\mu_o}} \tag{5.1}$$

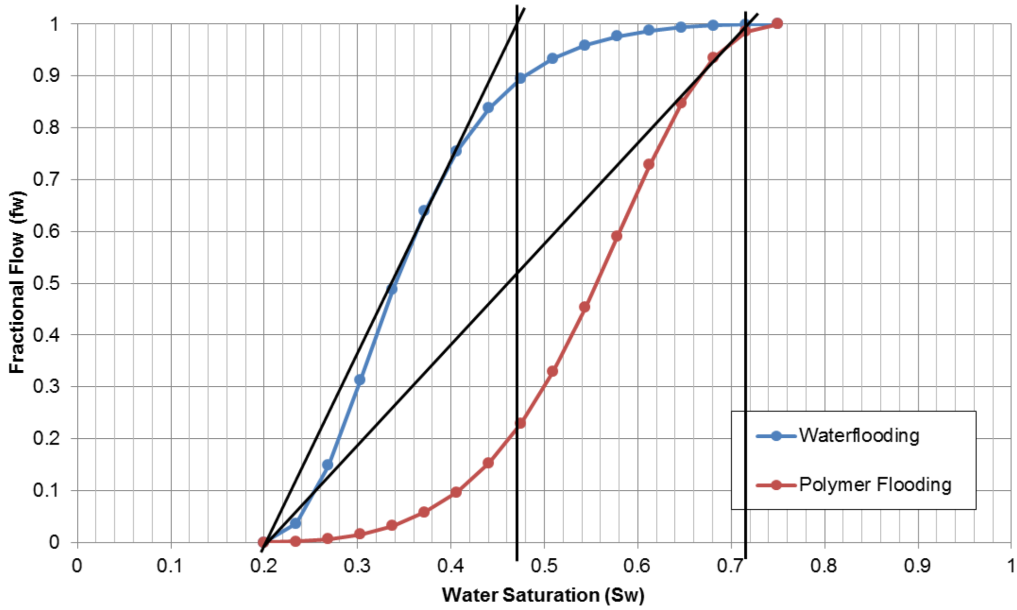

Figure 5.7 Fractional flow curve of waterflooding compared to polymer flooding

From **Figure 5.7**, average water saturation at breakthrough time ($\overline{\overline{S_w}}$) can be estimated from the tangent of the fractional flow curve. The average water saturation before water breakthrough of polymer flooding case is more than that of waterflooding case, meaning that the displacement mechanism is improved by polymer solution. This obviously shows the benefit of polymer flooding. Mobility ratio is calculated following equation 5.2 by using the average water saturation at before water breakthrough time, identifying relative permeability to water from **Figure 5.6**. The mobility ratio can be summarized in **Table 5.1**.

Mobility Ratio (M):

$$M = \frac{\lambda_w}{\lambda_o} = \frac{k_{rw}}{\mu_w} \times \frac{\mu_o}{k_{ro}} \tag{5.2}$$

Table 5.1 Summary of mobility ratios from waterflooding and polymer flooding

Case	WaterFlooding	Polymer Flooding
Average S_w	0.47	0.72
k_{rw}	0.075	0.05
M	2.14	0.25

Table 5.1 shows that mobility ratio is substantially reduced and is less than 1 in case that polymer is injected into the reservoir. The mobility ratio is decreased by polymer flooding around 8.6 times compared to waterflooding case. This results in favorable condition for displacement mechanism. More details of comparisons between polymer flooding and waterflooding are shown in **Figure 5.8** to **Figure 5.10**.

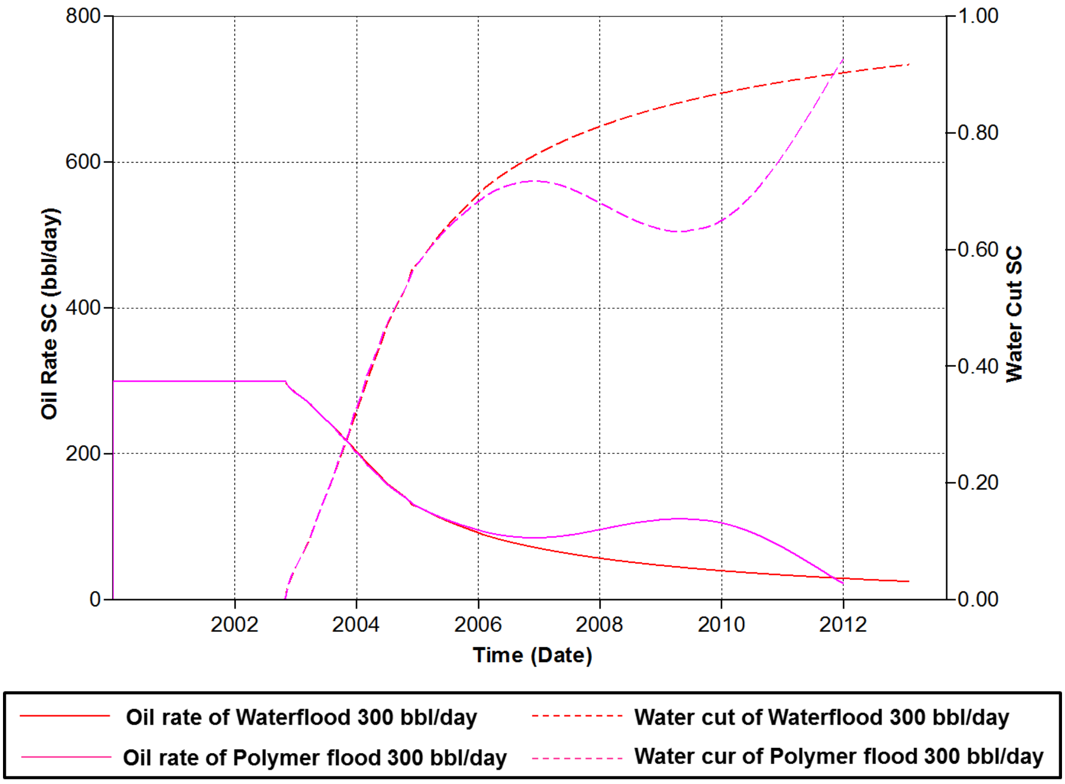

Figure 5.8 Oil production rate and water cut of polymer flooding at injection rate 300 bbl/day as a function of time compared to waterflooding case

In case of very small injection rate, water breakthrough occurs at quite early age of the production life. This could be a benefit of polymer flooding, however, polymer injection rate is also slow which causes the effect to arrive at very late time. The reduction of total production period is only one year as can be seen in **Figure 5.8**. At higher injection rate, water breakthrough occurs at a bit later compared to total production period as higher water injection rate helps prevent underrunning of water from gravity effect. The amount of oil remained in reservoir may not favor the effect of polymer flooding as in case of lower injection rate but the rate of 500 bbl/day is appropriate to be injected into the reservoir and hence, this helps to speed up the effect of polymer flooding process. By means of using polymer substance, a total production period of about 2.3 years is reduced from waterflooding as can be observed in **Figure 5.9**.

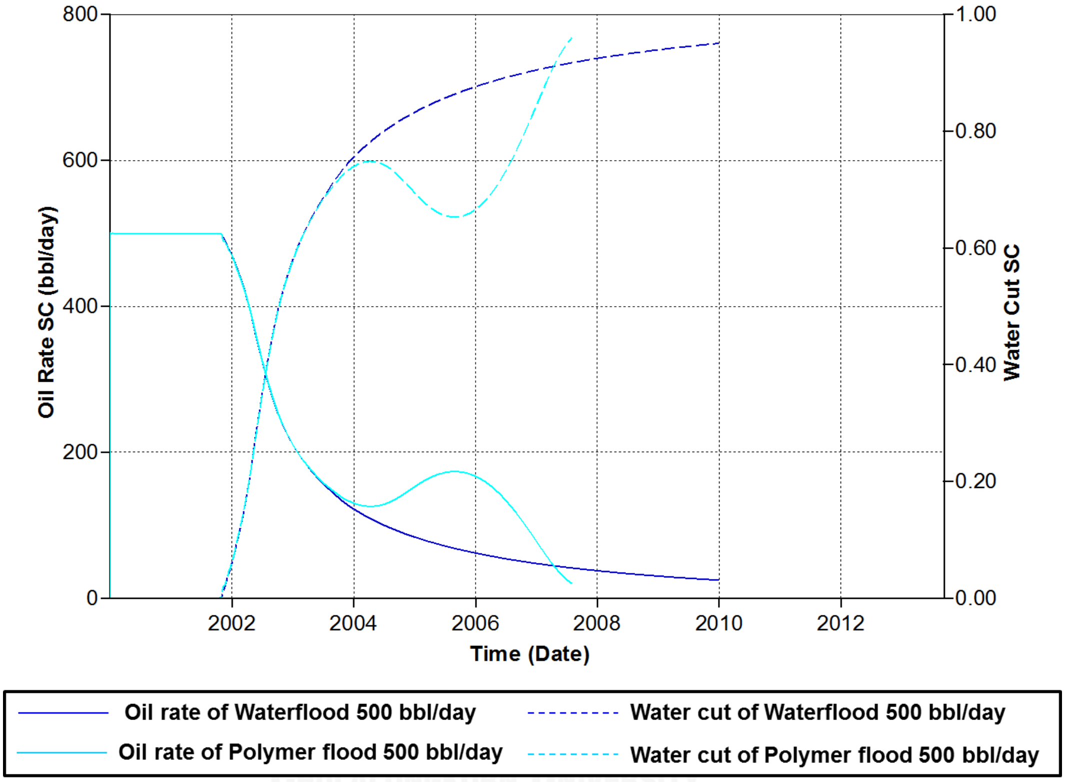

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Figure 5.9 Oil production rate and water cut of polymer flooding at injection rate 500 bbl/day as a function of time compared to waterflooding case

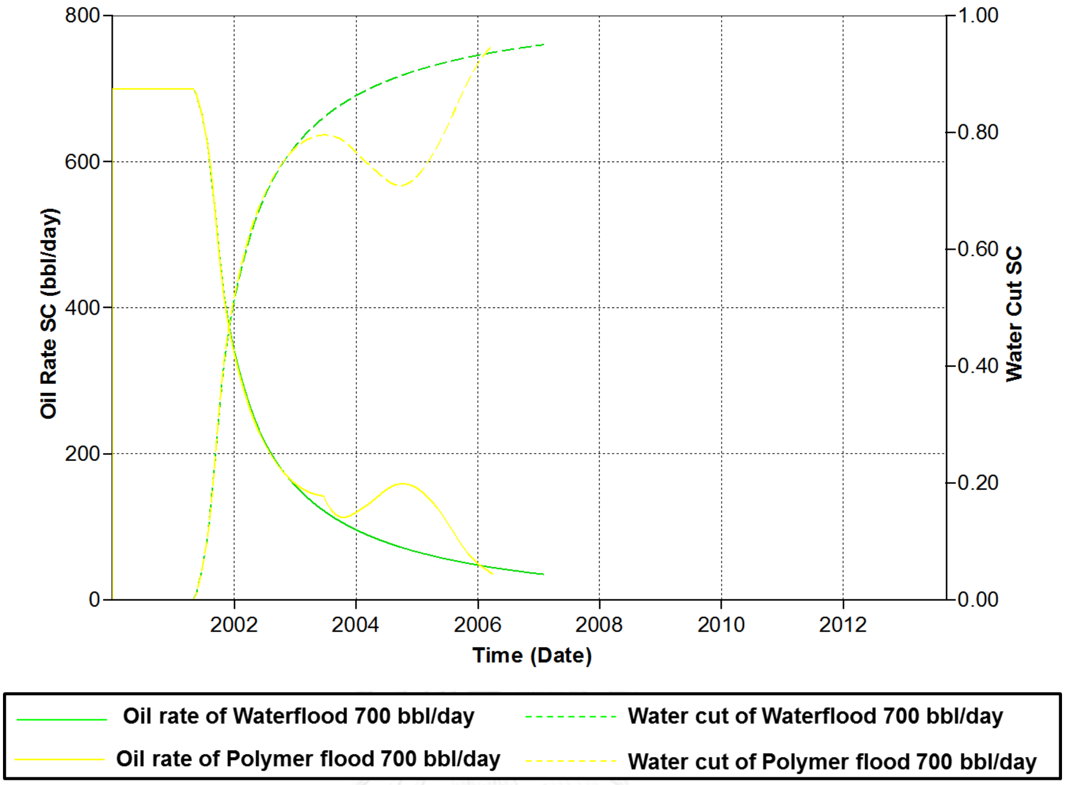

Figure 5.10 Oil production rate and water cut of polymer flooding at injection rate 700 bbl/day as a function of time compared to waterflooding case

From **Figure 5.10** it can be seen that polymer flooding can only reduce total production period as almost the same of the rate of 300 bbl/day. As water breakthrough occurs quite late compared to other cases, the benefit of polymer is lessened. Moreover, injecting polymer solution at higher injection rate may cause difficulty as the rate cannot be easily attained. This results in total reduction of production period that is not quite favorable compared to waterfooding case.

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Nevertheless, effect of polymer flooding goes in the same direction in all three cases. Polymer sweep the movable oil that is remained after waterflooding. This creates an oil bank and the arrival of bank is obvious which comes together with reduction of water cut. Similar to waterflooding, simulations are terminated at with the same constraints: the case of polymer injection rate of 300 bbl/day is terminated by the minimum oil production rate whereas cases with polymer injection rates of 500 and 700 bbl/day cases are controlled by water cut.

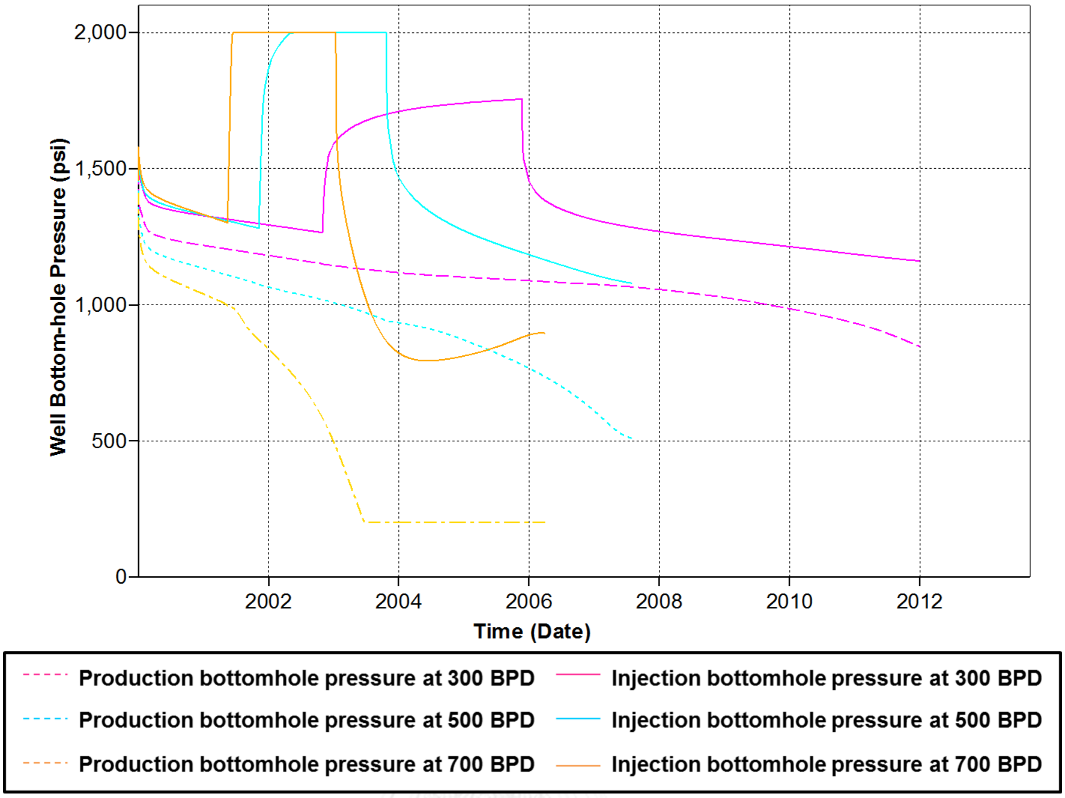

Figure 5.11 Production well bottomhole pressure and injection well bottom of polymer flooding with various water injection rates as a function of time compared to waterflooding cases

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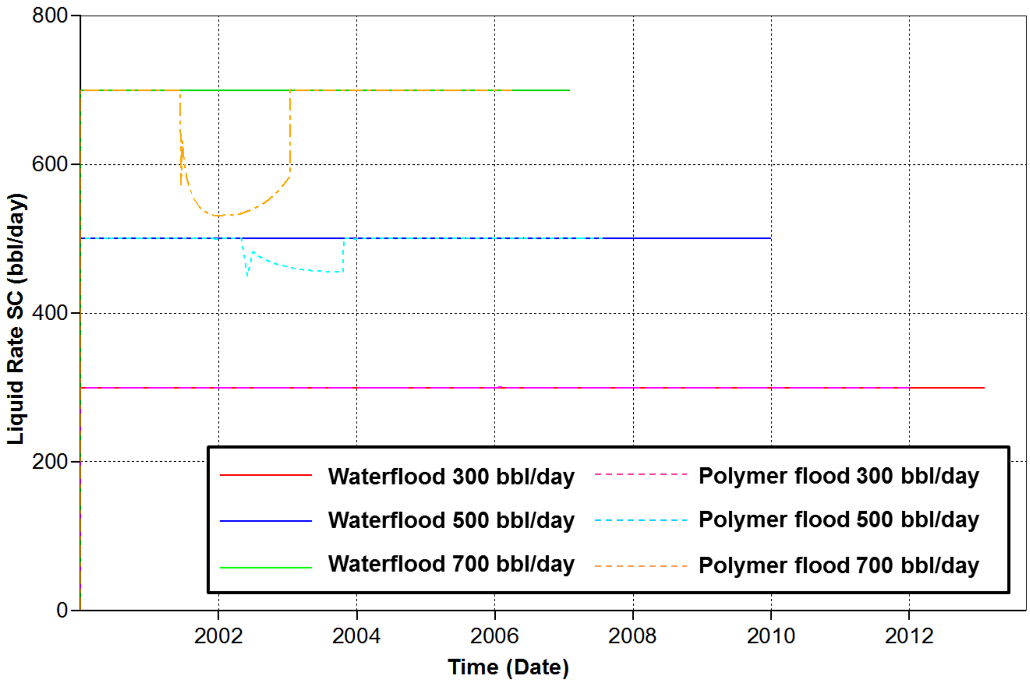

Figure 5.12 Water injection rate of polymer flooding with various injection rates as a function of time compared to waterflooding cases

From **Figure 5.11**, bottomhole pressure of production well is strikingly decreased to maintain oil production rate from insufficiency of reservoir pressure during polymer injection period. It can be explained by polymer injectivity. Polymer viscosity is much higher than water and this cause polymer to be difficultly injected. Therefore, input pressure through injected fluid is not enough and consecutively, bottomhole pressure at production well is lessened to maintain the production rate. Considering polymer injection rate of 500 and 700 bbl/day, the bottomhole pressure is reduced dramatically. This is also reason why liquid production rate is less than expected during the polymer injection period. Especially in case of the rate 700 bbl/day, the bottomhole pressure reaches 200 psi as the well constraint and hence liquid production cannot be maintained at desired value as can be seen in **Figure 5.12**. Water chasing is performed resulting in total liquid rate is increased again due to higher injectivity. However, the bottomhole pressure is further reduced to retrieve back the pressure difference.

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The enhanced oil recovery in polymer flooding gains from two effects which can be explained in **Figure 5.13** to **Figure 5.15**. **Figure 5.13** illustrates oil saturation profile from top view of layer (the first X-Y plain) of reservoir at the end of production period. It can be obviously seen that oil is thoroughly swept by the used of polymer solution at every injection rate. Polymer flooding generates higher viscosity fluid and this results in increasing of sweep efficiency.

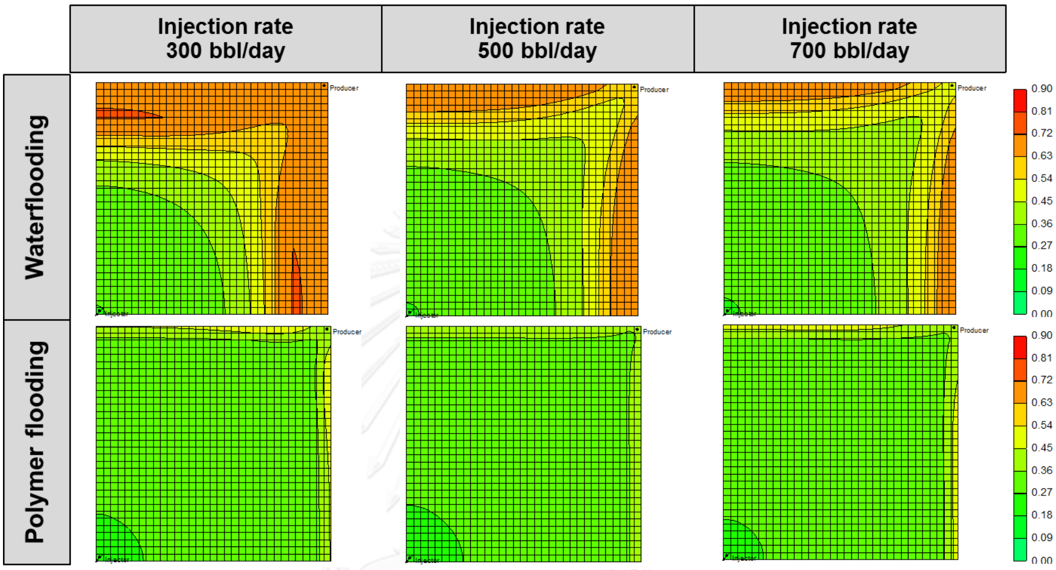

Figure 5.13 Top view of oil saturation profiles at the end of production time with different injection rate of waterflooding and polymer flooding

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It can be confirmed by **Figure 5.14** that the better sweep efficiency compared to waterflooding is obtained from viscosity increase as can be observed from viscosity profile at the end of production. From the figure, it can also be observed that at the end of production there is still high viscosity region observed in case of small injection rate. This could be explained by dilution effect of polymer which is caused from chasing water at higher injection rate.

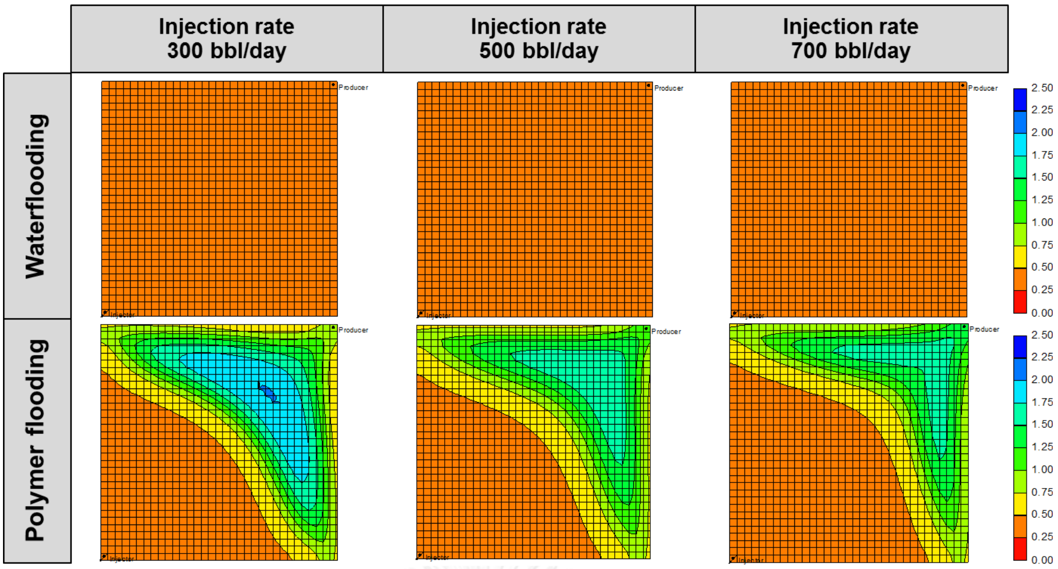

Figure 5.14 Top view of viscosity profiles of injected fluid at the end of production time with different injection rates of waterflooding and polymer flooding

Not only viscosity enhancement that can enhance oil recovery, polymer adsorption is another effect that can be obtained from polymer solution especially PAM. Figure 5.15 illustrates polymer adsorption profile occurring at different injection rates. From the figure, it could be observed that adsorption profile is almost the same. This is because the fact that desorption is set to be zero and so adsorption will occur until it reaches the highest adsorption value which is 7×10^{-7} lbmole/ft^3. However, a small difference can be observed that the highest adsorption region is larger in case of small injection rate. This is related to previous explanation of viscosity profile. According polymer is mixed with chasing water, concentration of polymer decreases causing adsorption to be lessened. Hence, the slow injection rate which maintains high polymer concentration from mixing with chasing water results in larger area of the highest adsorption value.

As polymer adsorption occurs on rock surface, residual resistance factor causes reduction of effective permeability as well as relative permeability. In polymer flooding cases, relative permeability to water is decreased in the swept area comparing with waterflooding cases. In flooded region, majority of fluid is only water and hence reduction of flowability of water causing less mobility of injectant and as a consequent, improves sweep efficiency.

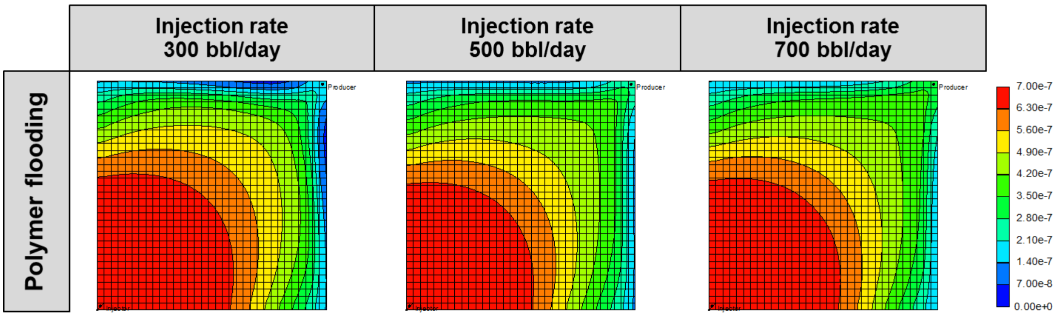

Figure 5.15 Top view of polymer adsorption profiles at the end of production time with different injection rate of polymer flooding

From this section, it can be observed that applying polymer can increase oil recovery factor and at the same time it can reduce total production period. As polymer viscosity is higher than water and more over polymer can adsorb onto rock surface, this causes favorability of injectant to displace oil. Arrival of polymer back is more uniformed compared to water and this causes a sudden increment of water production after oil bank is being produced. However, in order to obtain the benefit of polymer flooding, operational parameters should be optimized and this is being explained in the following sections.

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5.2 Identification of Polymer Mass for the Entire Process

This section describes the effect of polymer slug size on oil recovery factor in polymer flooding process. Polymer slug size represents polymer mass which is injected for the entire process. The results yield the optimum polymer slug size of various polymer concentrations.

Similar to previous section, waterflooding is performed at day one until water breakthrough occurs at the smallest injection rate of 300 BPD and then polymer is followed. The smallest injection rate is chosen in order to avoid problem of low injectivity during injection of polymer slug. The degree of polymer desorption is set at 0% (total adsorbed). Polymer concentration is varied as 500, 750 and 1,000 ppm with 10 different values of polymer slug size from 0.05 PV to 0.5 PV in order to investigate the optimum polymer slug size in each polymer concentration. After the desired amount of polymer is injected into the reservoir, waterflooding is performed as chasing fluid.

5.2.1. Identification of optimum polymer slug size and the calculation of the polymer mass

In order to identify optimum polymer slug size of various polymer concentrations, the relationship of polymer slug size and oil recovery factor is plotted. The example is shown in the **Figure 5.16**.

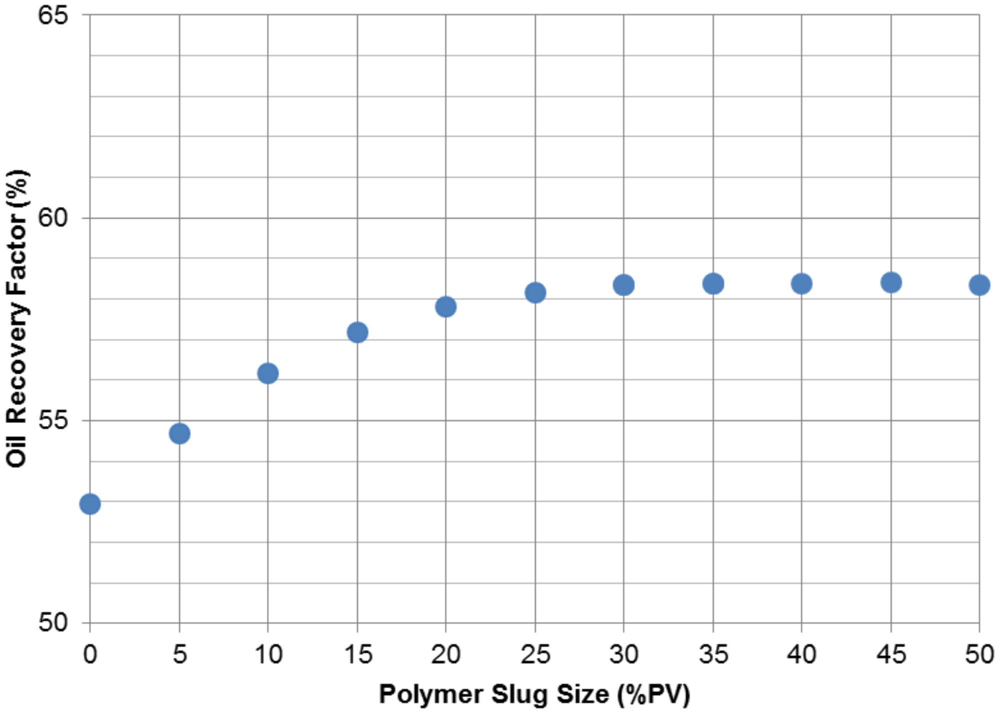

Figure 5.16 Oil recovery factors as a function of polymer slug size with polymer concentration 500 ppm at injection rate 300 bbl/day

Figure 5.16 shows that at with small slug size, oil recovery factor strikingly increases. However, beyond certain concentration, benefit of polymer is no more observed. From the figure, the first polymer slug size where oil recovery factor starts to be constant is at around 30%PV. At the concentration of 500 ppm, the mass of injected polymer can be calculated as follow:

Volume of injected polymer solution

$$= 30\%\ PV\ \times 1{,}675{,}683 \frac{ft^3}{PV} = 502{,}705\ ft^3$$

From the simulation, polymer solution density is 61.2406 lb/ft3

Mass of injected polymer solution

$$= 502{,}705\ ft^3\ \times 61.2406 \frac{lb}{ft^3} = 30{,}785{,}950\ lb$$

At polymer concentration 500 ppm, mass of polymer in injected polymer solution:

$$= 30{,}785{,}950\ lb\ x\ \frac{500}{1{,}000{,}000} \frac{lb\ polymer}{lb}$$

$$= 15{,}393\ lb\ polymer$$

The next sub-section shows the optimum polymer mass represents as polymer slug size.

5.2.2. The Effect of Polymer Concentration on the Optimum Polymer Slug Size

With different polymer concentrations, relationship between oil recovery factors and polymer slug size changes as shown in **Figure 5.17** and from the figure, it can be observed that polymer concentration has an impact on the optimum polymer slug size. Higher polymer concentration results in the smaller slug size of polymer to attain constant oil recovery factor. This can be summarized that the optimum slug size is changed due to difference of polymer mass injected into the system.

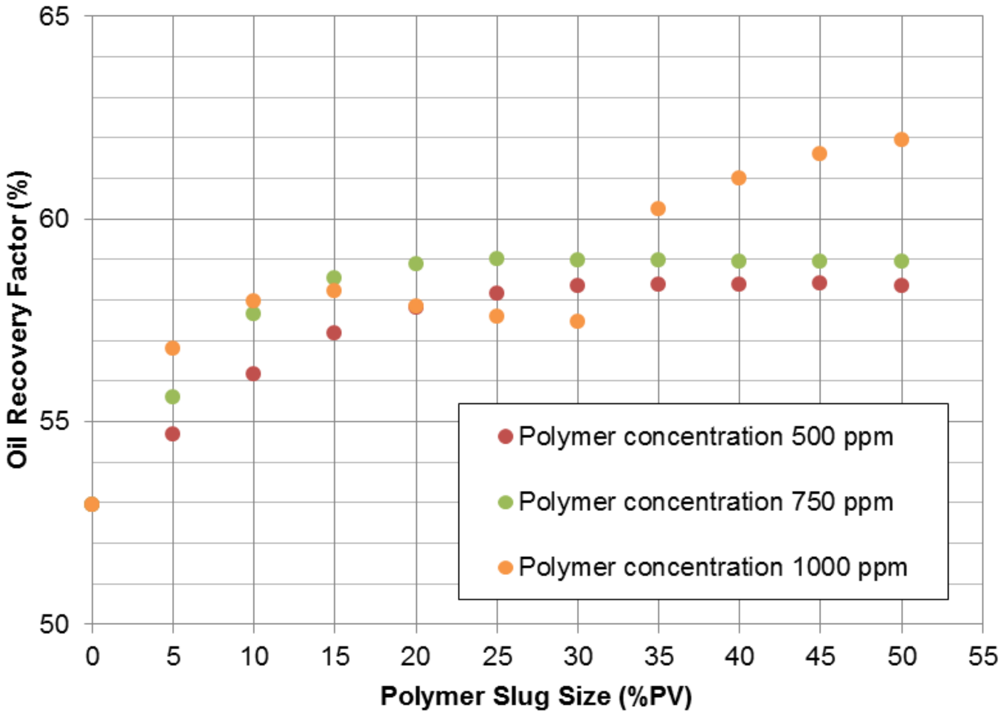

Figure 5.17 Oil recovery factors as a function of polymer slug size with various polymer concentrations at injection rate 300 bbl/day

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Nevertheless, the only exception is observed for the case of polymer concentration of 1,000 ppm. As the highest oil recovery factor is attained at 0.15 PV, oil recovery factor starts decline when slug size is increased. As polymer concentration is high and slug size is too large, the total time to complete desire slug can be long. Effects of polymer slug are obscured by early attainment of production termination. Nevertheless, it is shown that oil recovery factor increases obviously again when polymer slug size increases from 0.35 to 0.50 PV. These results can be described by **Figure 5.18** and **Figure 5.19** illustrating oil production rate as a function of time and polymer tracking profile at different periods, respectively. Moreover, average reservoir pressure, injection bottomhole pressure and production bottomhole pressure as a function of time are also plotted together with oil production rate in **Figure 5.20**.

In case of polymer concentration 1,000 ppm with total polymer slug size of 0.50 PV, there are three inclinations corresponding to oil production responses. As illustrated in **Figure 5.18**, the first hump represents an increment of oil production rate due to oil that is thoroughly swept by polymer solution. Oil production increased during 2007 to 2009 and then dramatically dropped due to lowering of injectivity as polymer mass is too large. Production bottomhole pressure is reduced until it reaches the minimum value which is 200 psi as shown in **Figure 5.20**. The second hump appears around the year 2011 is due to chasing water which is injected in January 2011. Chasing water which is less viscous than polymer solution helps improve injectivity of fluid, resulting in slightly building up of average pore pressure and as a consequence, oil production rate is increased. At this step, part of diluted polymer may already reaches the production well. As bottomhole pressure of production is always constant at 200 psi, it shows that average pore pressure due to polymer flooding was extremely low. Pressure build up in the second step is party dedicated to pushing solution gas back into liquid phase. Finally, the third hump occurs due to adequate reservoir pressure to create liquid displacement mechanism. Chasing water does starts to move polymer slug again after compressing solution gas and this results in oil production from the polymer breakthrough. By the way, fluctuation of oil rate when using polymer slug size 0.5 PV between the first hump and the second hump occurs due to change of time step preference in the simulation set up.

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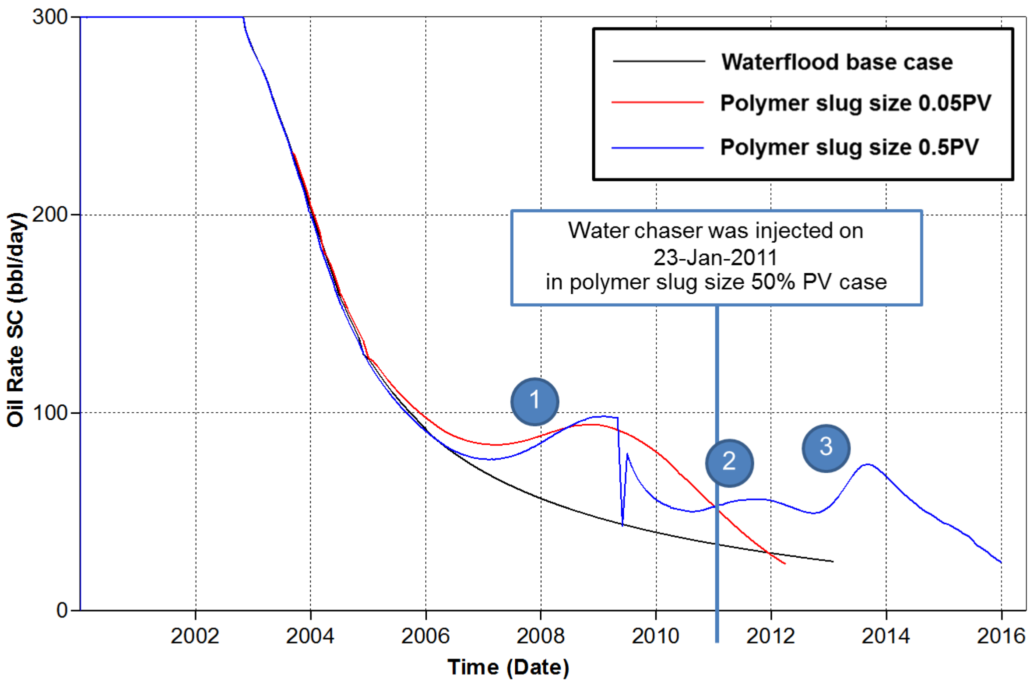

Figure 5.18 Oil production rates as a function of time using polymer concentration of 1,000 ppm with various polymer slug sizes compared to waterflooding case

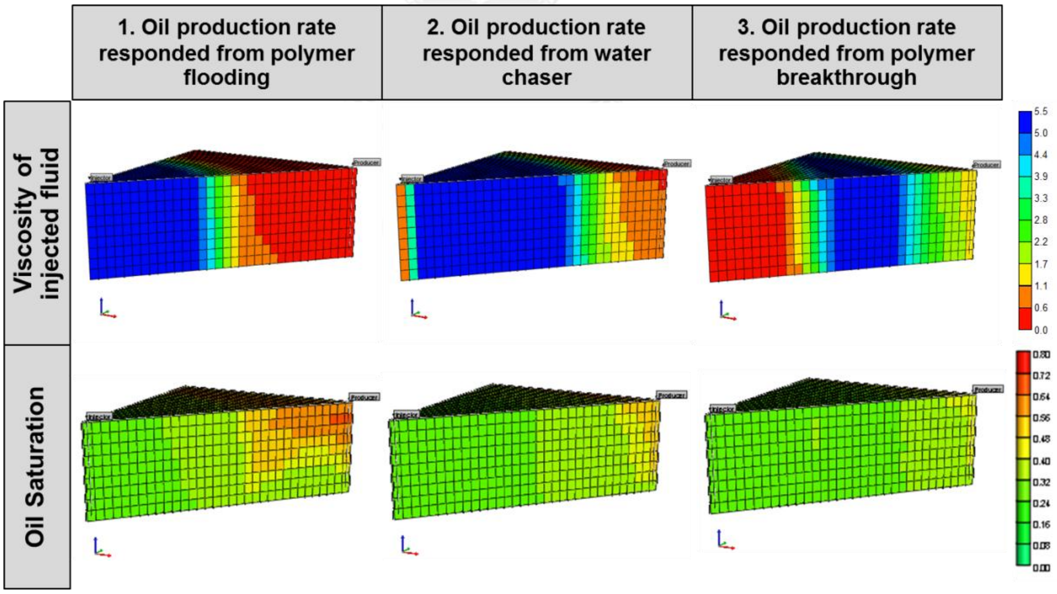

Figure 5.19 Viscosity profile of injected fluid and oil saturation profile during polymer flooding using polymer concentration of 1,000 ppm and polymer slug size of 0.5 PV at different interest periods

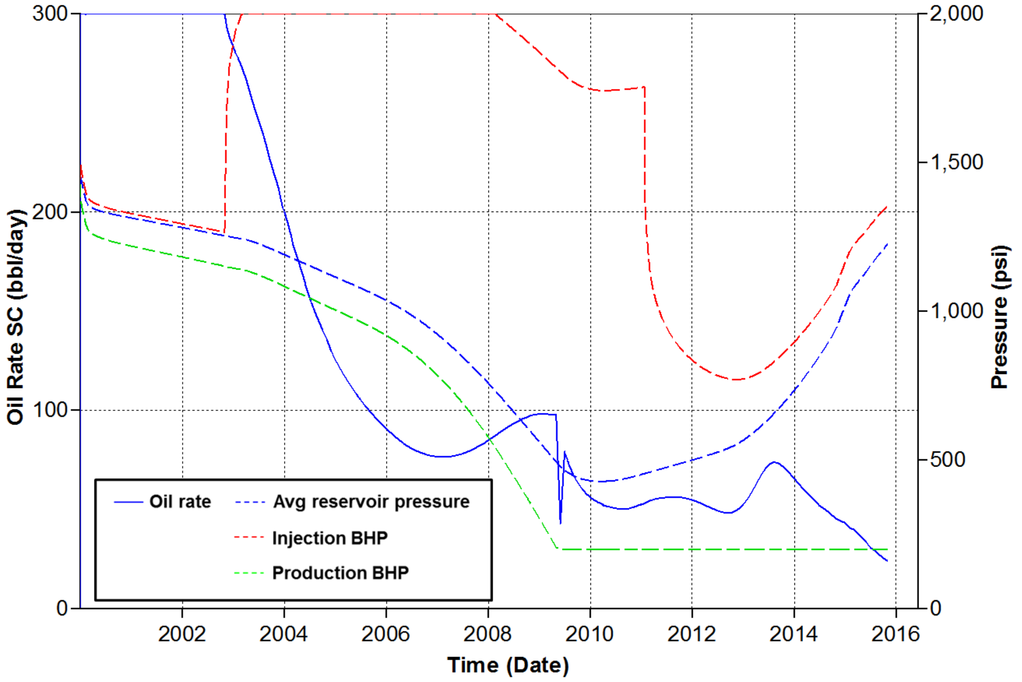

Figure 5.20 Oil production rate, average pore pressure and bottomhole pressures of injection and production wells as a function of time obtained from polymer concentration 1,000 ppm and polymer slug size 0.5 PV

Even polymer slug size of 0.5 PV yields the highest oil recovery factor which is 62% in case of polymer concentration 1,000 ppm, the optimum polymer slug size is placed in this study at 0.15 PV which represents the first attainment for the highest oil recovery factor. The reason is in case of polymer slug size 0.5PV comparing with 0.15PV, it is required more than 3 times of polymer mass to obtain 4% incremental oil recovery factor.

Figure 5.21 and **Figure 5.22** illustrate the optimum polymer slug size by plotting of oil recovery factor versus polymer slug size for polymer concentration 750 and 1,000 ppm, respectively. The optimum polymer slug size can be defined referring to section 5.2.1. The estimated optimum polymer slug size with the oil recovery factor in each polymer concentration is summarized in **Table 5.2**.

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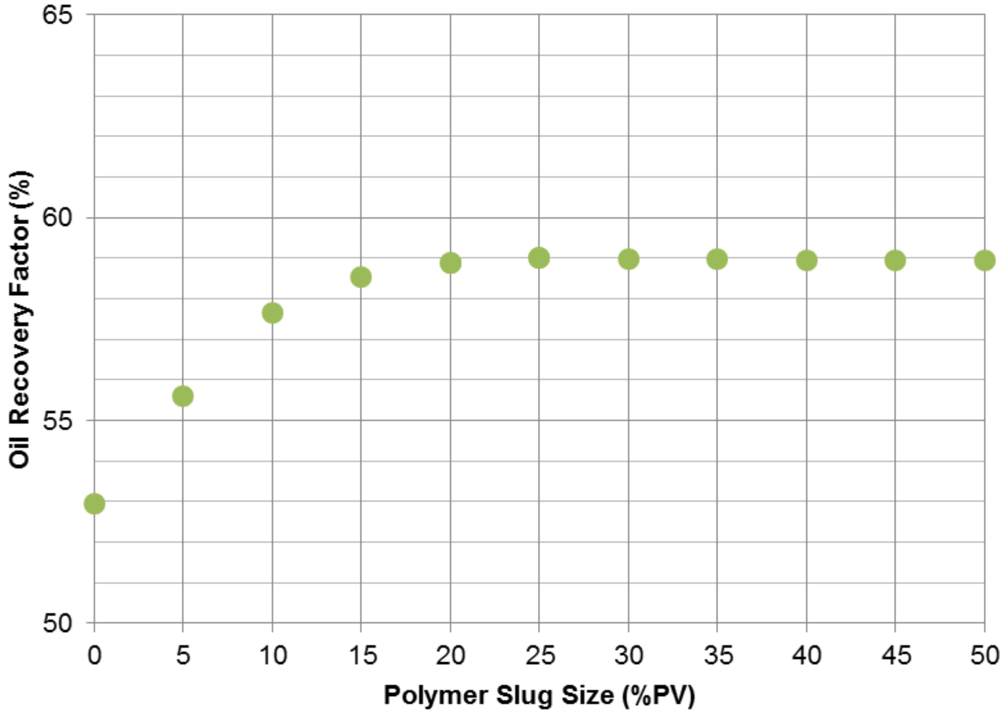

Figure 5.21 Oil recovery factors as a function of polymer slug size with polymer concentration 750 ppm at injection rate 300 bbl/day

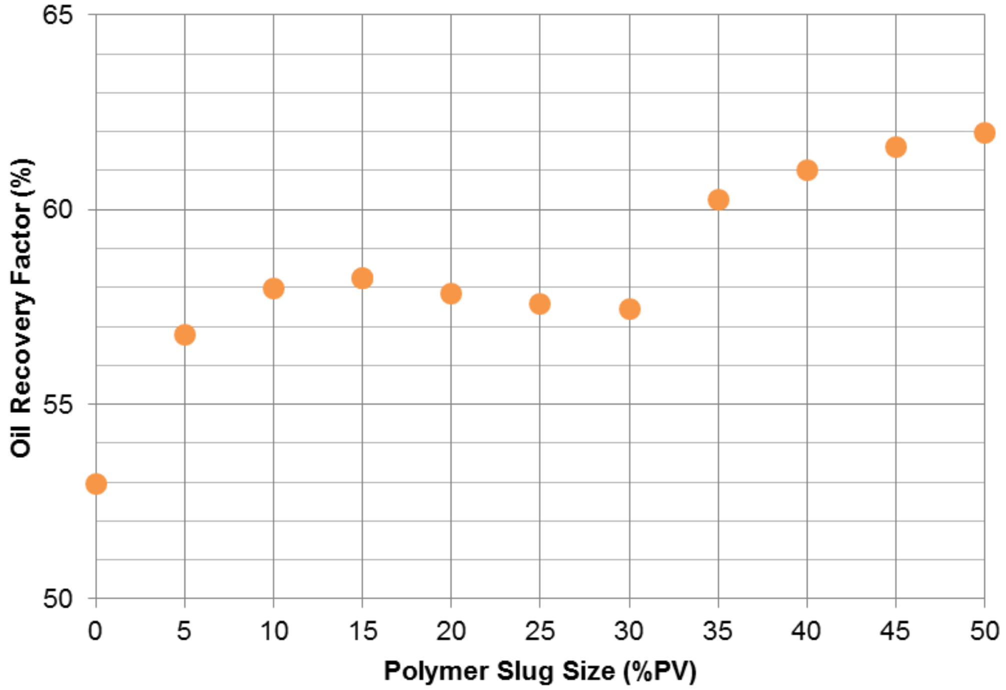

Figure 5.22 Oil recovery factors as a function of polymer slug size with polymer concentration 1,000 ppm at injection rate 300 bbl/day

Table 5.2 Summary of optimum polymer slug size and corresponding oil recovery factor for different polymer concentrations with polymer desorption of zero percent

Polymer concentration (ppm)	500	750	1,000
Optimum Polymer Slug Size (%PV)	30	20	15
Oil Recovery Factor at the Optimum point (%)	58.4	59.0	58.3

According to Table 5.2, the change of polymer solution density is assumed to be neglected due to very low polymer concentration as in ppm and as a result, mass of polymer required to achieve the highest oil recovery is equal in every polymer concentration.

5.2.3. Effect of operating parameters on polymer adsorption

The chosen operating parameters which are starting time of polymer injection and injection rate are co-investigated in this subsection with total polymer adsorbed (0% degree of polymer adsorption) at different polymer concentration of 500, 750 and 1,000 ppm. The case with injection rate 500 BPD and polymer flooding starts at water breakthrough after waterflooding is chosen as a reference case. **Figure 5.23** and **Figure 5.24** illustrate polymer adsorption profile at the end of production in the first X-Y plane from the studies of different injection rates and different time to implement polymer flooding, respectively.

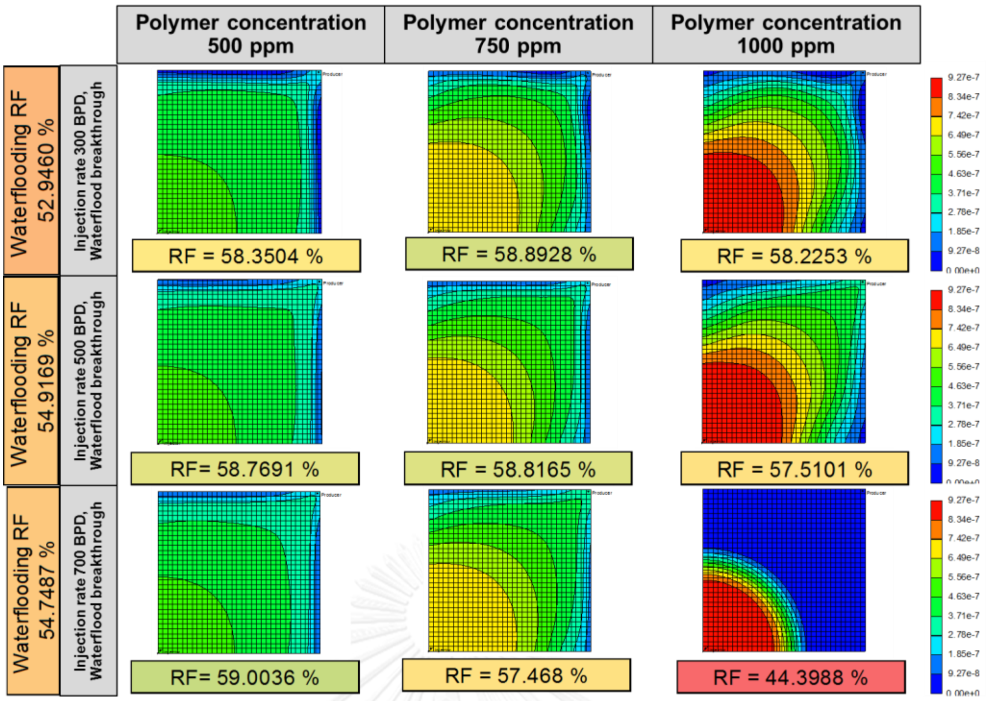

Figure 5.23 Top view of polymer adsorption profile at the end of production obtained from cases with different injection rates and various polymer concentrations at polymer starting time at water breakthrough

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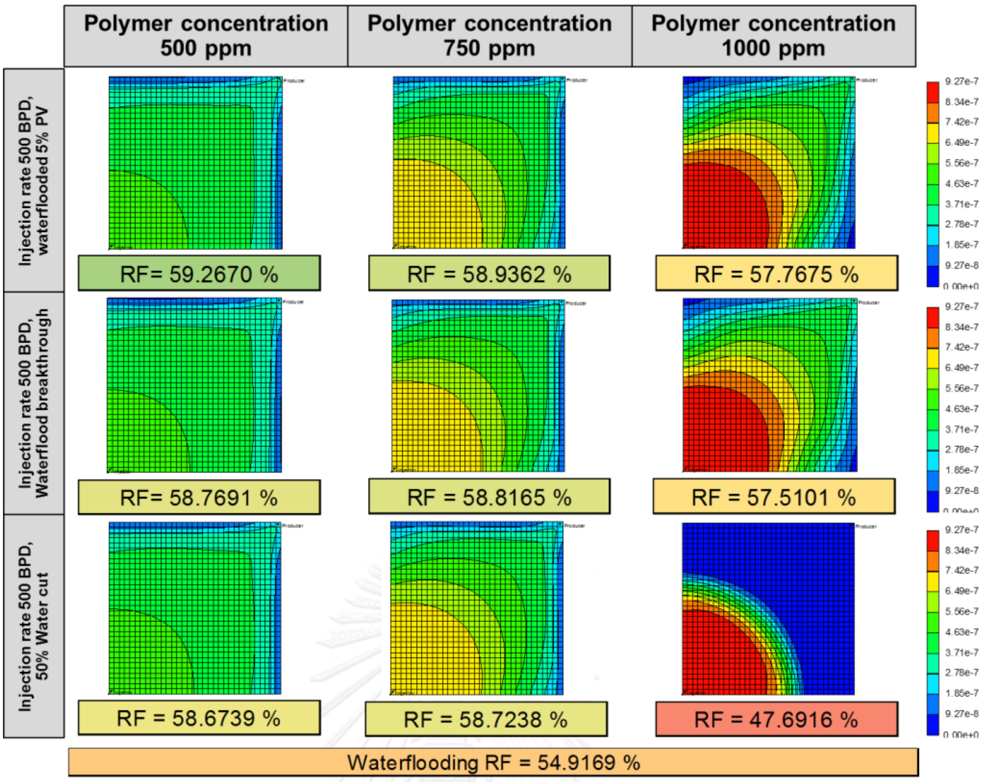

Figure 5.24 Top view of polymer adsorption profile at the end of production obtained from cases with different starting times of polymer flooding and various polymer concentrations at injection rate 300 bbl/day

From **Figure 5.23** and **Figure 5.24**, it shows that degree of polymer adsorption is changed with distance where polymer travels in the reservoir. The nearer to the injection well, the higher degree of polymer adsorption. Polymer adsorption occurs during the replacement of polymer instead of oil. Contact of polymer substance and rock surface results in polymer retention and eventually polymer adsorption. Changing to wettability to a more favorable condition is obtained from polymer adsorption and this benefit of polymer flooding can increase oil recovery factor as well as controlling viscosity of injected fluid.

However, both figures show that polymer adsorption is affected only from the polymer concentration. According to simulation preferences, polymer adsorption is a function of polymer mole fraction, proportionally. The maximum polymer adsorbed per unit pore volume with different polymer concentrations are summarixed in **Table 5.3**.

Table 5.3 The summary of maximum adsorbed polymer with different polymer concentrations

Polymer concentration (ppm)	Maximum adsorbed polymer (x 10^{-7} lbmole/ft^3)
500	4.635
750	6.9525
1,000	9.27

Refer to **Figure 5.23** and **Figure 5.24**, at the lower polymer concentration; injection rate and starting time of polymer flooding have a slight impact on polymer adsorption value. At the end of the production, the adsorption profiles as well as oil recovery factor are not different. However, at polymer concentration of 1,000 ppm, the polymer concentration obviously affects the adsorption value at the extreme cases of injection rate and starting time of polymer flooding.

For the cases of polymer concentration 1,000 ppm, it can be explained by the effect of injectivity. **Figure 5.25** and **Figure 5.26** illustrate oil production rate and water cut as a function of time with various injection rates and starting times of polymer flooding, respectively for the case of polymer concentration of 1,000 ppm. The termination of injection rate 700 BPD and polymer flooding starting at 50% water-cut are controlled by oil production rate. The oil production rate obviously decreases due to reduction of the injectivity once polymer slug is injected. This means the polymer adsorption is also stopped. The effect of operating parameters will be explained again in details in terms of impacts on polymer flooding process in section 5.4.

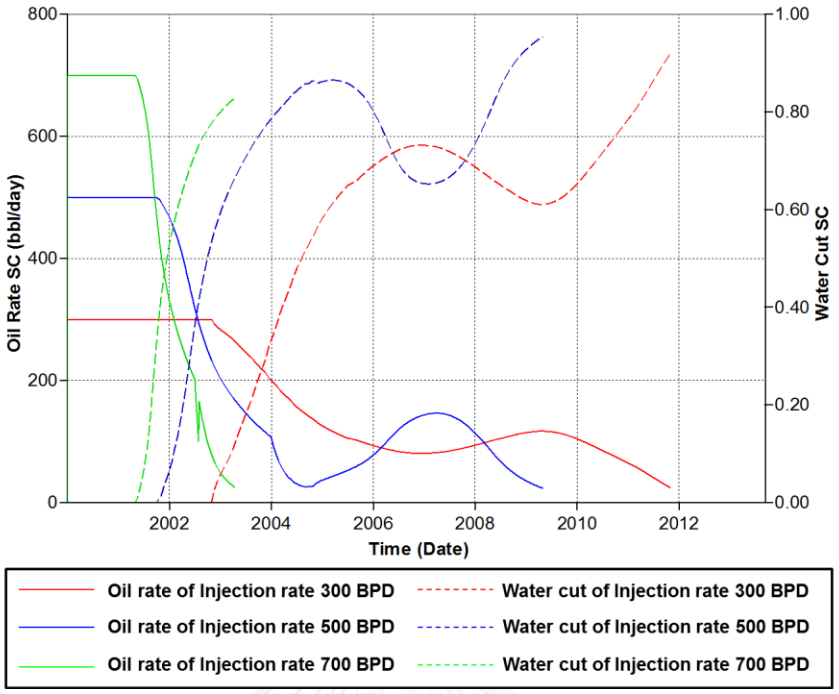

Figure 5.25 Oil production rates and water-cut as a function of time obtained from cases with different of injection rates at polymer concentration of 1,000 ppm

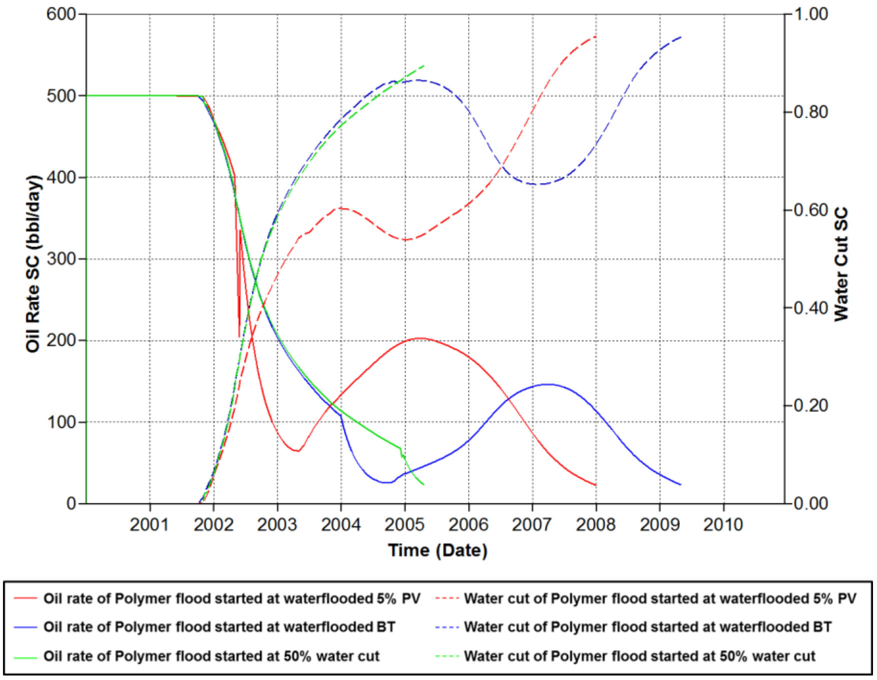

Figure 5.26 Oil production rates and water-cut as a function of time obtained from cases with different times to start polymer flooding at polymer concentration of 1,000 ppm

5.3 Effects of Degree of Polymer Desorption

The most concern parameter in this study is explained in this section which is related to mechanism of polymer adsorption and desorption. Profiles of polymer adsorption and oil saturation are mainly used for discussion. There are two major parts described in this section. The first part demonstrates the effects of operating conditions on polymer adsorption which are starting time of polymer injection, injection rate and polymer concentration. This following section focuses on polymer adsorption only. The effects of operating conditions on polymer flooding process will be explained in section 5.4.

5.3.1. Effect of degree of polymer desorption

As polymer concentration strongly impacts the maximum of polymer adsorption as described in section 5.3.1, different degrees of polymer desorption are multiplied to maximum polymer adsorption and residual polymer concentration is obtained. Refer to polymer adsorption components setting in the simulation, residue adsorption level represents degrees of polymer desorption.

Table 5.4 Summary of values related to degrees of polymer desorption with different polymer concentrations

Polymer concentration (ppm)	Maximum polymer adsorbed per unit pore volume (x 10^{-7} lbmole/ft^3)	Residue adsorbed level (x 10^{-7} lbmole/ft^3)		
		0% desorption	50% desorption	100% desorption
500	4.64	4.64	2.32	0
750	6.95	6.95	3.48	0
1000	9.27	9.27	4.64	0

To investigate the effect of degree of polymer desorption, polymer flooding cases starting at water breakthrough with injection rate 500 BPD in with difference values of polymer desorption (degree of polymer desorption of 0%, 50% and 100%) are investigated.

Figure 5.27 depicts profile of polymer adsorption in different polymer desorption degrees. From the figure, it can be observed that there is an impact of polymer desorption on the oil production. At lower polymer concentration of 500 and 750 ppm, the effect of polymer desorption is less than the case of high concentration 1,000 ppm. For the lower concentration of 500 and 750 ppm, polymer is desorbed following the preferences. Even polymer desorption profiles look different, the oil saturation profiles as shown in **Figure 5.28** look mostly the same. Oil recovery factors of these cases are in a range of 58-60%. For the polymer concentration 1,000 ppm cases, the oil saturation profiles look interestingly different. At the 100% degree of polymer desorption, the polymer is less retained at the border of the farther away from of the wells. This results in lowering of the volumetric sweep efficiency. The change of the sweep efficiency affects the oil recovery factor. As polymer adsorption is very high especially at the directly line from injection to production well, highly desorption results in chasing fluid to flow to less adsorbed area but with high desorption which is the border of the reservoir. This causes water to by-pass polymer slug. The oil recovery factors of polymer concentration 1,000 ppm cases are in a range of 55-58%.

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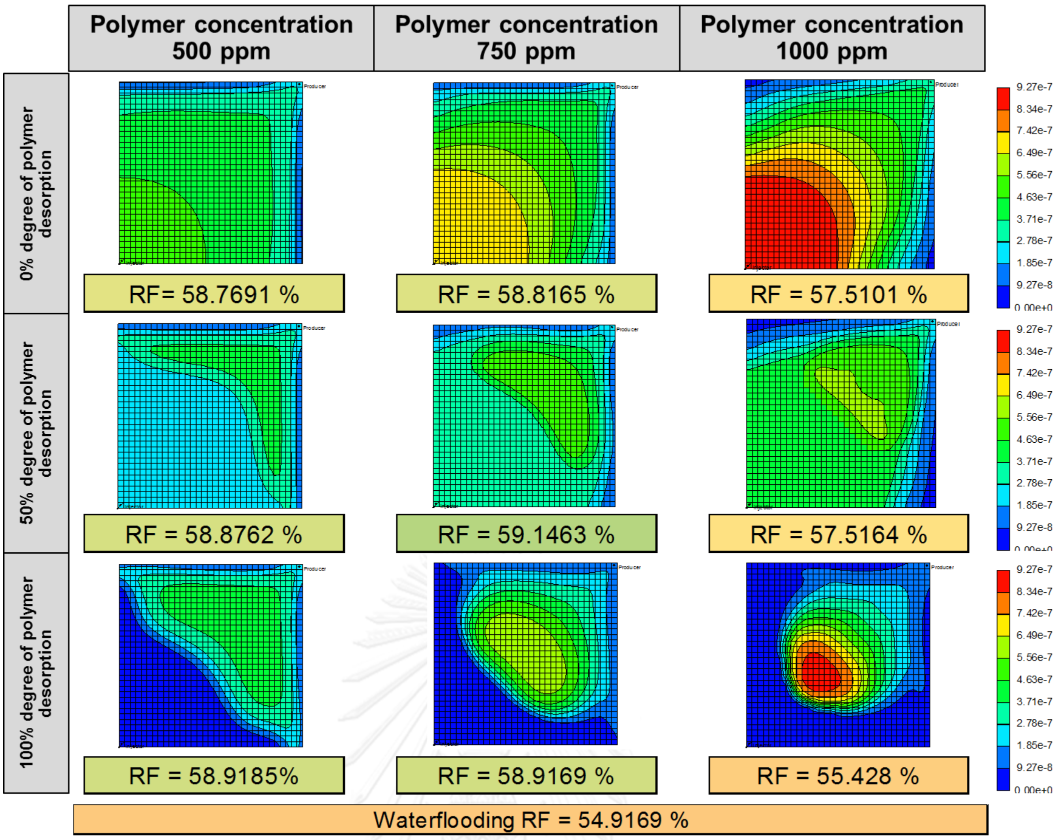

Figure 5.27 Top view of polymer adsorption profile at the end of production obtained from cases with different degrees of polymer desorption and various polymer concentrations

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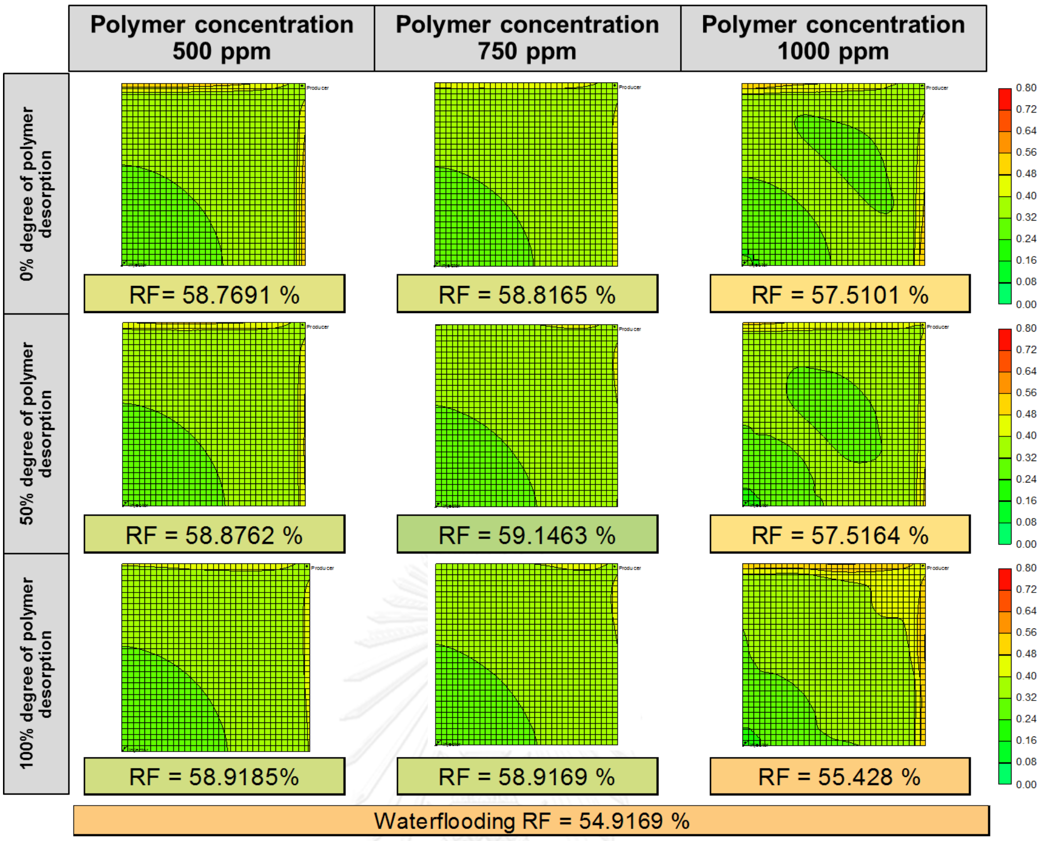

Figure 5.28 Top view of oil saturation profile at the end of production obtained from cases with different degrees of polymer desorption and various polymer concentrations

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According to the oil recovery factor, the optimum degree of polymer desorption for polymer concentration 500, 750 and 1,000 ppm are 100%, 50% and 50%, respectively. It can be explained that polymer desorption causes polymer re-employment that is previously adsorbed onto rock surface, resulting in an increase of sweep efficiency in the further period of polymer flooding process. However, beyond the optimum degree of adsorption, several drawbacks appear. In this study, it shows that total desorption in high polymer concentration causes chasing water to bypass polymer slug, resulting in breaking of mobility control slug and as a consequent, oil recovery factor is lower than other cases. Therefore, degree of polymer desorption should be investigated depending on the operating parameters to obtain its benefit.

5.3.2. The Effect of Polymer Desorption on the Optimum Polymer Slug Size

The polymer desorption is investigated in term of effect on the optimum polymer slug size. Polymer desorption is varied as 0, 25, 50, 75 and 100% in all various cases of concentrations and polymer slug sizes. **Figure 5.29** to **Figure 5.31** illustrate the effect of polymer desorption on optimum polymer slug size.

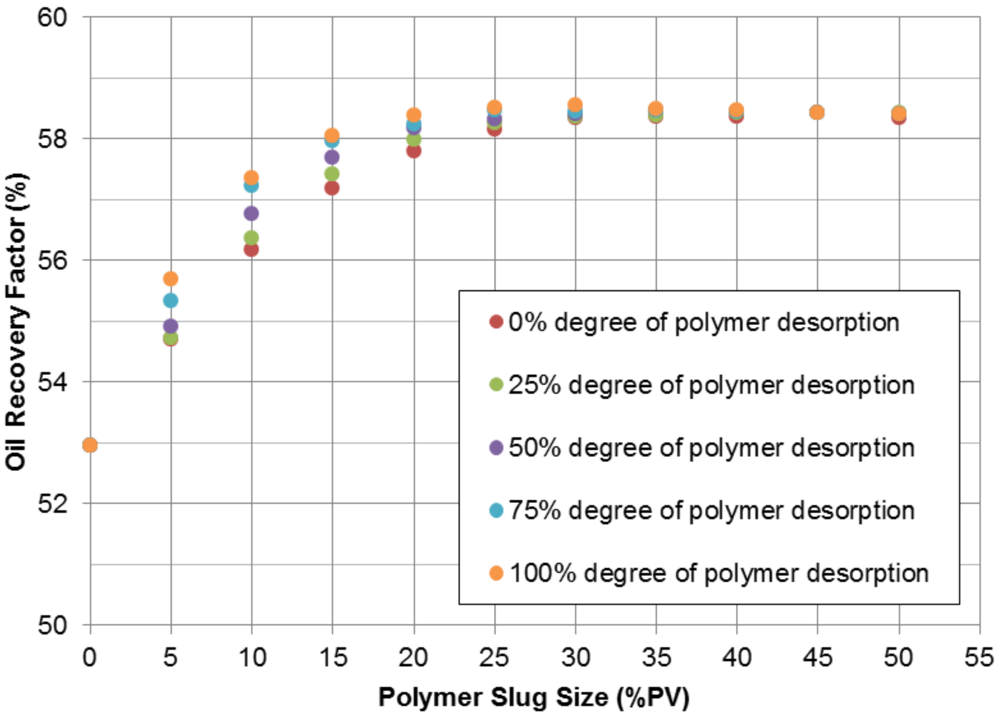

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Figure 5.29 Oil recovery factors as a function of polymer slug size with polymer concentration 500 ppm and various degrees of polymer desorption at injection rate 300 bbl/day

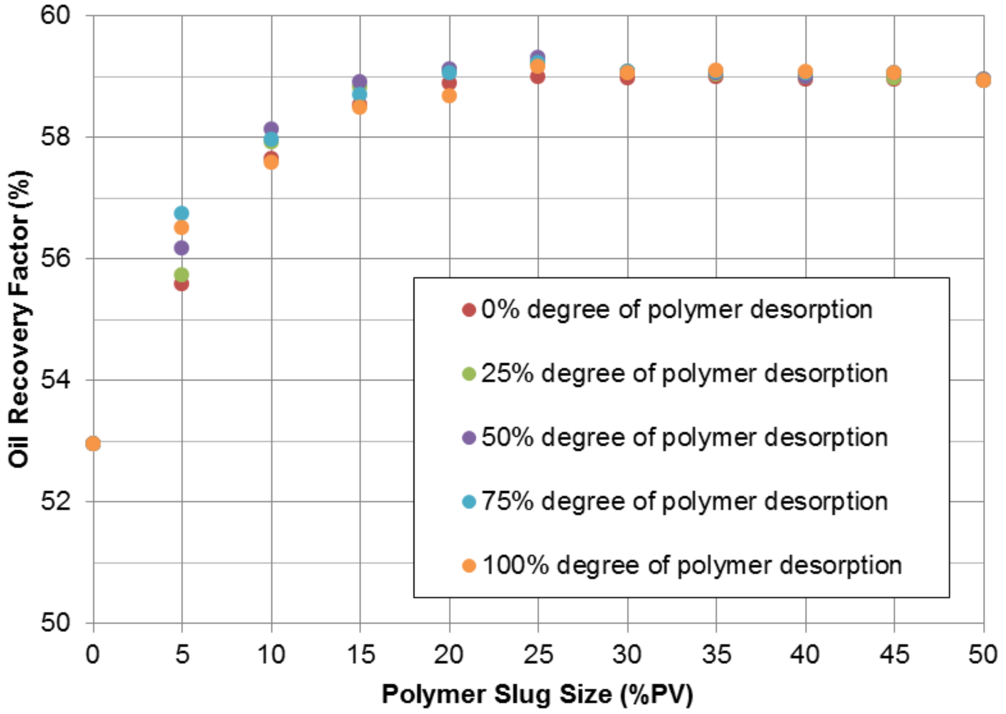

Figure 5.30 Oil recovery factors as a function of polymer slug size with polymer concentration 750 ppm and various degrees of polymer desorption at injection rate 300 bbl/day

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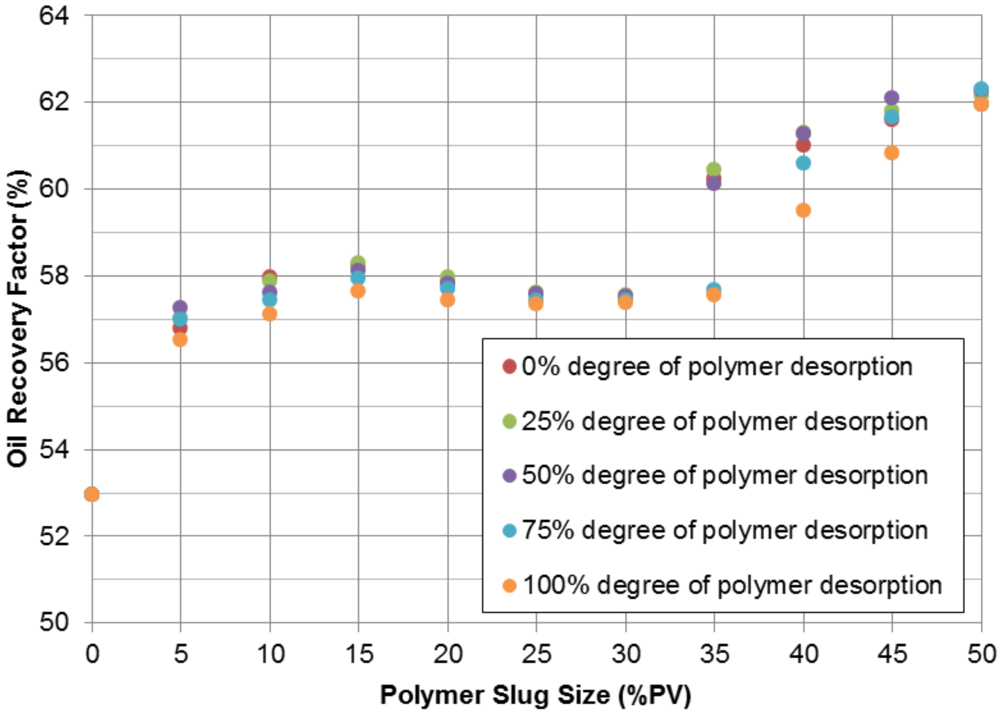

Figure 5.31 Oil recovery factors as a function of polymer slug size with polymer concentration 1,000 ppm and various degrees of polymer desorption at injection rate 300 bbl/day

From these three figures, the polymer slug size that results in maximum oil recovery factor is detected for various degrees of polymer desorption with various polymer concentrations and degrees of polymer desorption and results are summarized in **Table 5.5**.

Table 5.5 Summary of optimum polymer slug size for polymer flooding with various degrees of polymer desorption

Polymer concentration (ppm)	500	750	1,000
Degree of polymer desorption (%)	Optimum polymer slug size (%PV)		
0	30	20	10
25	30	20	15
50	30	20	15
75	25	20	15
100	20	25	15

According to **Figure 5.29** to **Figure 5.31** and summary in **Table 5.5**, degree of polymer desorption affects the optimum point of polymer slug size. Especially in case of polymer concentration 500 ppm, it can be observed that increasing of polymer desorption can decreases the optimum polymer slug size. Polymer desorption causes polymer re-employment that is previously adsorbed onto rock surface, resulting in an improvement of the polymer flooding benefits in the further period of polymer flooding process. However, at the higher polymer concentration, increasing of polymer desorption slightly shift the optimum polymer slug size to a larger slug size.

5.4 Effects of Operational Parameters

The effects of operational parameters are described in this section. The interesting parameters in this study include injection rates, starting times of polymer flooding, varying of polymer concentrations. Degree of polymer adsorption is not an operational parameter but 3 values of this parameter are added to understand effects of operational parameters when main study parameter is also changed. Nevertheless, effects of degree of polymer desorption is already explained in section 5.3 and hence, it is not repeated in this section. The results are shown in terms of the effects on oil recovery factor, and production period. At the end of this section, the optimum operating conditions of each polymer concentration are concluded. **Figure 5.32** summarizes the value of operational parameters studied in this section.

Refer to results obtained in section 5.3, degree of polymer desorption affects the optimum polymer slug size. In order to make the results to be described consistently for the further studies, the optimum polymer slug sizes for polymer concentrations 500, 750 and 1,000 ppm with polymer slug size values is set at 0.3, 0.2 and 0.15PV, respectively. The optimum slug size is referred to section 5.2.

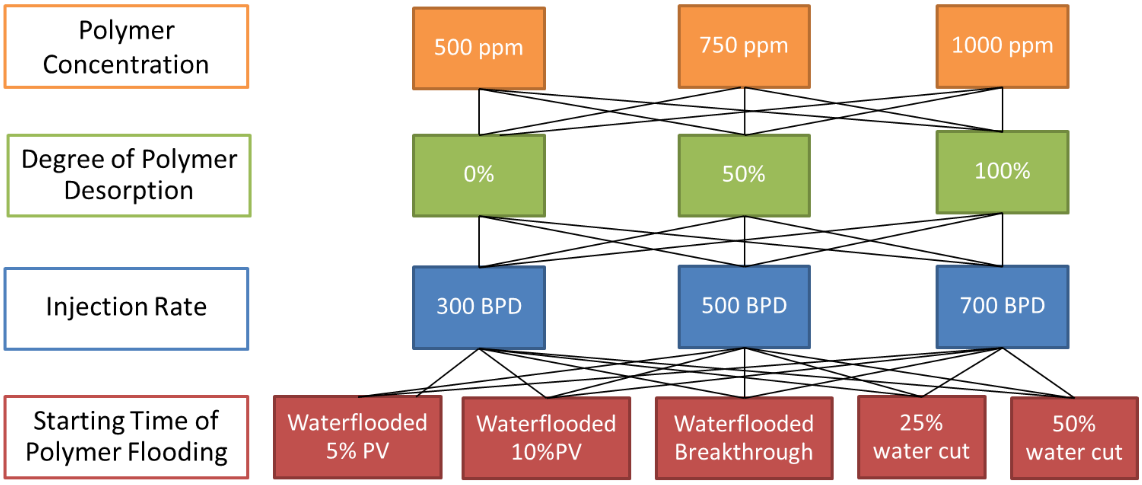

Figure 5.32 The summary of varied operational parameters

In this study, water breakthrough occurs when cumulative injected water is approximately 20% PV. Therefore, additional cases of time to implement polymer flooding are chosen at cumulative injected water after pre-water injection of 0.05 PV and 0.1 PV.

To simplify the description of the results, it can be summarized the cases of results obtained from reservoir simulation as shown in the ผิดพลาด! ไม่พบแหล่งการอ้างอิง, ผิดพลาด! ไม่พบแหล่งการอ้างอิง and ผิดพลาด! ไม่พบแหล่งการอ้างอิง which are for cases with different polymer concentrations of 500, 750 and 1,000 ppm respectively.

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Table 5.6 Oil recovery factors and total production period of polymer flooding using polymer concentration of 500 ppm

Injection Rate		300 BPD		500 BPD		700 BPD	
Degree of Polymer Desorption	Starting Time of Polymer Flooding	Oil Recover Factor (%)	Production Time (Years)	Oil Recover Factor (%)	Production Time (Years)	Oil Recover Factor (%)	Production Time (Years)
Waterflooding case		52.9460	13.08	54.9169	10.00	54.7487	7.08
0%	Waterflooded 5% PV	58.7399	10.50	59.2670	6.58	59.4100	4.75
	Waterflooded 10% PV	58.5791	11.25	59.0242	7.00	59.3018	5.08
	Waterflooded Breakthrough	58.3504	12.50	58.7691	7.92	59.0036	5.75
	25% water cut	58.3107	13.33	58.6535	8.42	58.9188	6.08
	50% water cut	58.3501	14.25	58.6739	8.83	58.8902	6.33
50%	Waterflooded 5% PV	58.8036	10.50	59.4404	6.67	59.5576	4.75
	Waterflooded 10% PV	58.6065	11.25	59.1563	7.08	59.3900	5.08
	Waterflooded Breakthrough	58.4174	12.50	58.8762	8.00	59.0788	5.75
	25% water cut	58.3682	13.42	58.8503	8.50	58.9622	6.08
	50% water cut	58.3322	14.25	58.7944	8.83	58.9604	6.33
100%	Waterflooded 5% PV	58.9625	10.58	59.3665	6.58	59.5801	4.75
	Waterflooded 10% PV	58.8230	11.33	59.1408	7.08	59.4793	5.08
	Waterflooded Breakthrough	58.5556	12.58	58.9185	8.00	59.1418	5.75
	25% water cut	58.5055	13.42	58.8721	8.50	58.9901	6.08
	50% water cut	58.5373	14.33	58.8203	8.83	59.0232	6.33

Table 5.7 Oil recovery factors and total production period of polymer flooding using polymer concentration of 750 ppm

Injection Rate		300 BPD		500 BPD		700 BPD	
Degree of Polymer Desorption	Starting Time of Polymer Flooding	Oil Recover Factor (%)	Production Time (Years)	Oil Recover Factor (%)	Production Time (Years)	Oil Recover Factor (%)	Production Time (Years)
Waterflooding case		52.9460	13.08	54.9169	10.00	54.7487	7.08
0%	Waterflooded 5% PV	59.2346	9.92	58.9362	6.17	57.6826	5.25
	Waterflooded 10% PV	59.1121	10.67	58.8101	6.67	57.6206	5.58
	Waterflooded Breakthrough	58.8928	12.00	58.8165	7.58	57.4680	6.25
	25% water cut	58.8772	12.92	58.7252	8.00	57.5348	6.67
	50% water cut	58.8592	13.75	58.7238	8.42	57.5504	6.92
50%	Waterflooded 5% PV	59.3399	9.92	58.9976	6.17	58.4550	5.58
	Waterflooded 10% PV	59.1517	10.67	59.0186	6.67	58.3226	5.92
	Waterflooded Breakthrough	59.1234	12.08	59.1463	7.58	58.3017	6.67
	25% water cut	59.0132	13.00	59.0498	8.08	58.2796	7.00
	50% water cut	58.8474	13.83	59.0509	8.50	57.3744	6.58
100%	Waterflooded 5% PV	59.1011	9.92	59.0378	6.17	57.2073	5.00
	Waterflooded 10% PV	58.9591	10.75	58.8046	6.58	57.1705	5.33
	Waterflooded Breakthrough	58.9185	12.08	58.9169	7.58	56.8700	6.00
	25% water cut	58.9173	13.00	58.7614	8.08	56.8529	6.33
	50% water cut	58.6665	13.83	58.7102	8.50	56.9014	6.58

Table 5.8 Oil recovery factors and total production period of polymer flooding using polymer concentration of 1,000 ppm

Injection Rate (BPD)		300		500		700	
Degree of Polymer Desorption	Starting Time of Polymer Flooding	Oil Recover Factor (%)	Production Time (Years)	Oil Recover Factor (%)	Production Time (Years)	Oil Recover Factor (%)	Production Time (Years)
Waterflooding case		52.9460	13.08	54.9169	10.00	54.7487	7.08
0%	Waterflooded 5% PV	58.3022	9.75	57.7675	8.00	59.0911	6.17
	Waterflooded 10% PV	58.1019	10.50	57.6144	8.50	59.6095	6.50
	Waterflooded Breakthrough	58.2253	11.83	57.5101	9.33	44.3988	3.29
	25% water cut	58.0018	12.67	46.6067	4.92	Not applicable	
	50% water cut	58.1437	13.58	47.6916	5.30	Not applicable	
50%	Waterflooded 5% PV	58.0509	9.83	57.3692	8.50	59.8560	6.83
	Waterflooded 10% PV	57.9546	10.58	57.4574	9.17	59.3676	7.25
	Waterflooded Breakthrough	58.1054	11.92	57.5164	10.17	44.5312	3.30
	25% water cut	57.7536	12.75	46.7457	5.00	Not applicable	
	50% water cut	57.8470	13.75	47.7464	5.33	Not applicable	
100%	Waterflooded 5% PV	57.7463	9.83	55.6943	7.75	56.4303	6.75
	Waterflooded 10% PV	57.4659	10.67	55.1347	8.33	56.7201	7.00
	Waterflooded Breakthrough	57.6382	12.08	55.4280	9.25	44.3988	3.29
	25% water cut	57.4736	13.00	46.8068	5.08	Not applicable	
	50% water cut	57.5043	13.83	47.8347	5.38	Not applicable	

5.4.1. The effect of starting time of polymer flooding

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For polymer concentration of 500 and 750 ppm cases, polymer flooding after 0.05 and 0.1 PV of injected water can obviously improve oil recovery for all cases as well as accelerating production time. Implementing polymer flooding after waterflood breakthrough also increases oil recovery factor but the production time is extended. The polymer flooding starting time of these cases results in longer oil production period with only a slight effect on oil recover factor.

Some cases of polymer flooding with polymer concentration of 1,000 ppm results in less oil recovery factor compared to waterflooding. Especially in cases of polymer flooding with starting time after water-cut of 25% and 50% combining with high injection rate 700 BPD. In these cases, chasing water is not started yet meaning that polymer flooding is not completely performed. The explanation of the termination of simulation is from production constraint control. When polymer is injected after water breakthrough higher rate, the oil production rate dramatically decreases due to reduction of the injectivity. The oil rate therefore reaches the termination condition before the oil production response from polymer flooding arrives. **Figure 5.33** shows the termination conditions (oil production rate and water-cut) of polymer flooding at polymer concentration 1,000 ppm and polymer flooding at injection rate 700 BPD compared to waterflooding at the same injection rate.

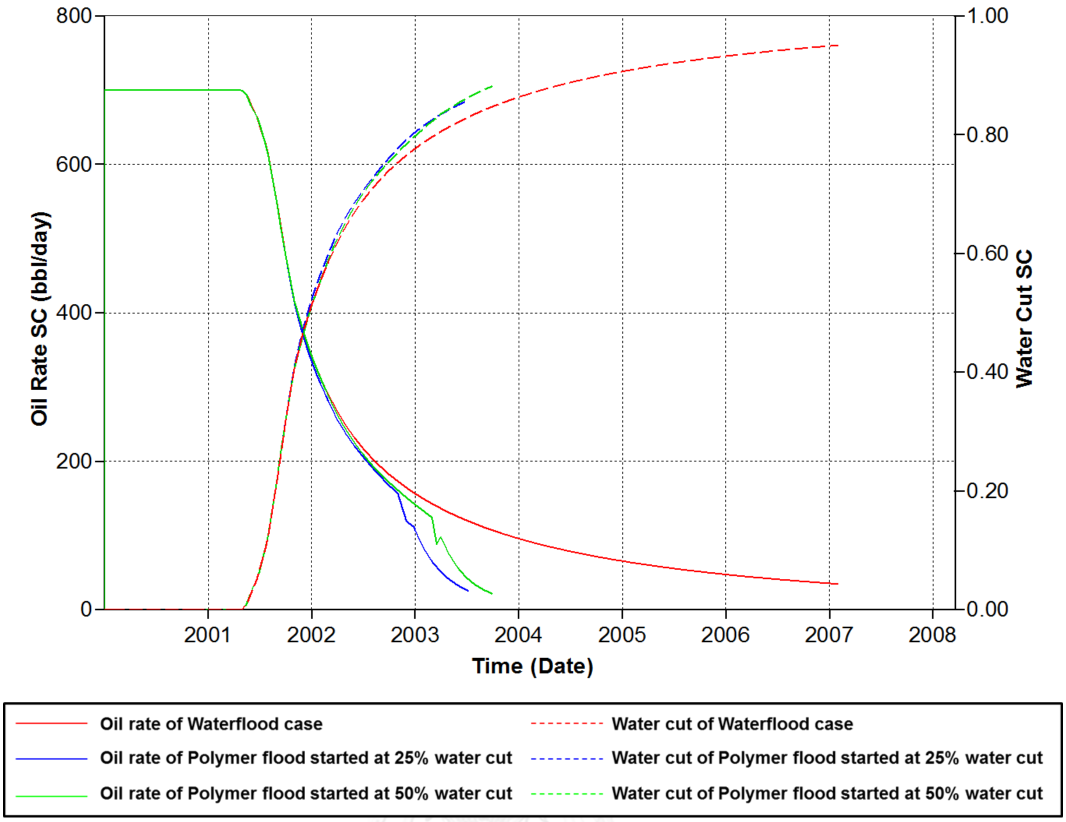

Figure 5.33 The oil production rate and water-cut as a function of time from the case of polymer concentration 1,000 ppm compared to waterflooding at injection rate 700 BPD

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In summary, starting time of polymer flooding after pre-water injection of 0.05 PV is the most suitable and is selected as optimum operational condition in this thesis.

5.4.2. The effect of injection rate

Injection rate affects the oil recover factor in straight forward way that the higher rate can accelerate the oil recovery in shorter production period as shown in **Figure 5.34** to **Figure 5.36.** However, the breakdown occurs at certain polymer concentration. Increasing of injection rate increases oil recovery factor for polymer concentration of 500 ppm, whereas increasing of injection rate in case of polymer concentration 750 ppm the results are reversed. For polymer concentration of 1,000 ppm, the earliest polymer starting time with the highest rates results in the highest oil recovery.

The effects of injection rate can be explained by polymer injectivity. **Figure 5.34**, **Figure 5.35** and **Figure 5.36** show as the examples for explanation: injection rate and production bottomhole pressure are plotted as a function of production time with starting time of polymer flooding after 0.05 PV water pre-injection and 0% degree of polymer desorption for cases with polymer concentrations of 500, 700 and 1,000 ppm, respectively.

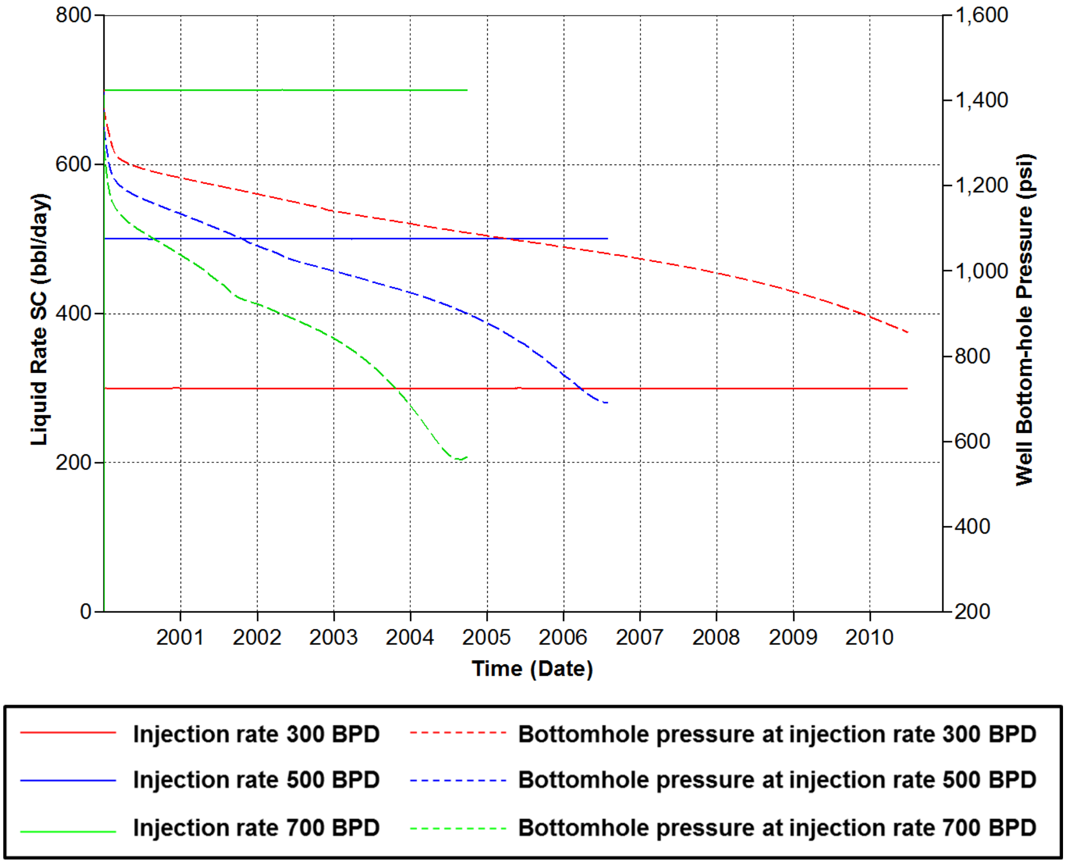

Figure 5.34 Injection rates and production bottomhole pressures as a function of time for cases with polymer concentration of 500 ppm

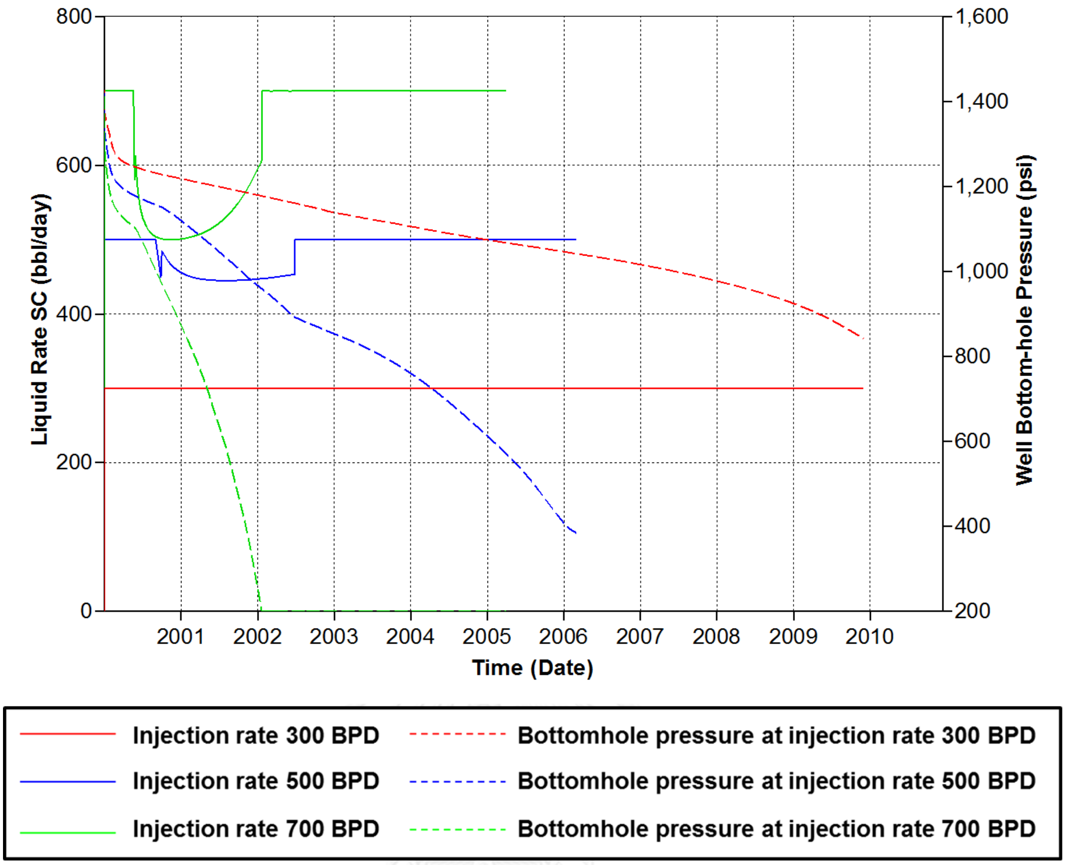

Figure 5.35 Injection rate and production bottomhole pressure as a function of time for cases with polymer concentration of 750 ppm

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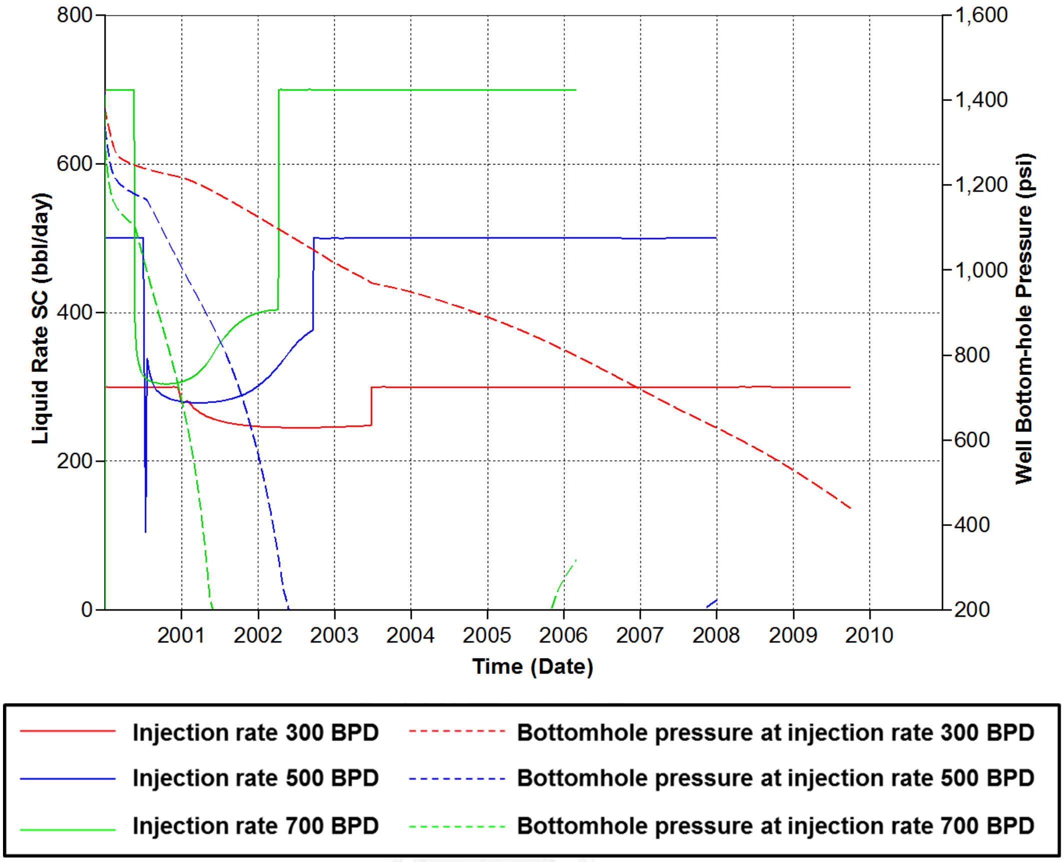

Figure 5.36 Injection rate and production bottomhole pressure as a function of time for cases with polymer concentration of 1,000 ppm

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Figure 5.34 shows that polymer solution can be injected with sustainable rate at from the first day of all injection rates with polymer concentration of 500 ppm. This means it is recommended to inject polymer at higher injection rate when low polymer concentration is applied. For polymer concentration of 750 ppm, polymer can be injected constantly from the first day only in case of low injection rate of 300 BPD, while the higher injection rate; injection rate is reduced during polymer injection period.

When polymer concentration of 1,000 ppm is applied, the injection rate cannot reach the desired rate at the beginning of polymer flooding for all the injection rates. Similar explanation, polymer is a viscous fluid and hence, desired injection rate is not balanced with injectivity of the wellbore. Interestingly, polymer flooding at this polymer concentration with injection rate of 700 BPD and starting time after 0.05 PV of injected waterflood results in the highest oil recovery. **Figure 5.37** shows liquid injection rate, liquid production rate and bottomhole pressures of production well and injection well at injection rate 700 bbl/day of polymer flooding with polymer concentration 1,000 ppm. According to **Figure 5.38** and **Figure 5.39**, even the desired rate of 700 BPD cannot be obtained, low oil production rate during polymer injection period results in high amount of oil. Once water is injected to chase polymer slug, oil bank is travelling and being produced again. Due to very high amount of oil accumulated, the oil production rate can be maintained for last long period prior to the termination and this results in exceptionally high oil recovery factor.

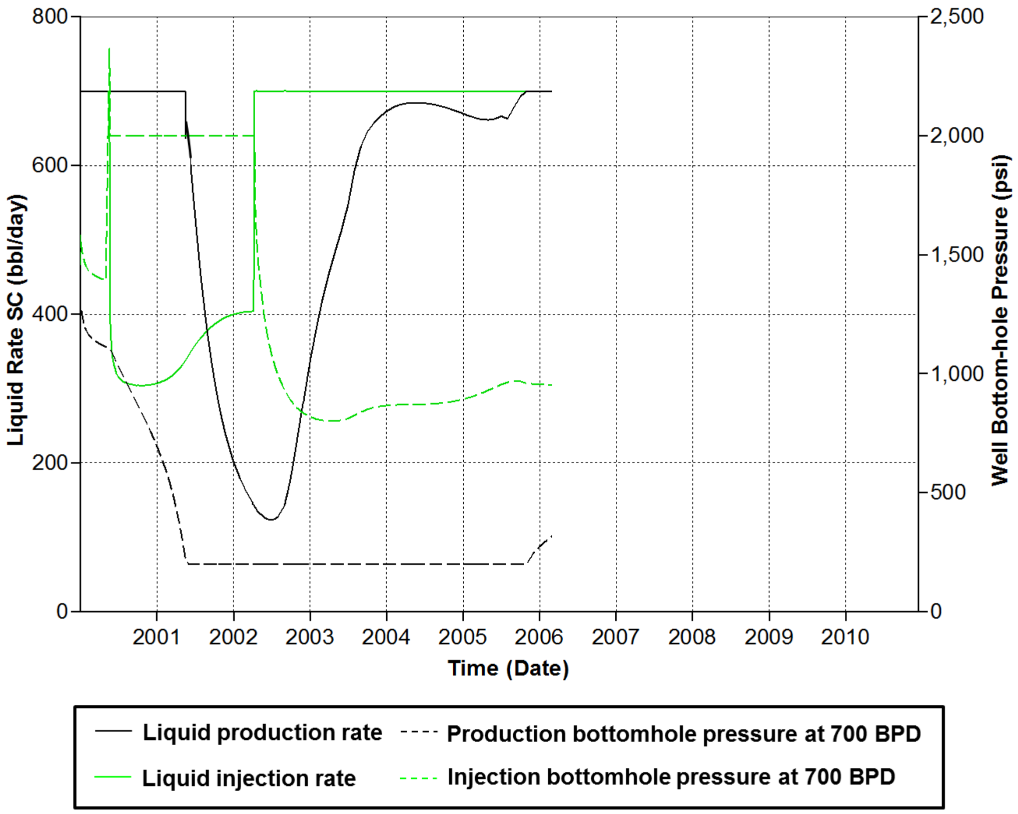

Figure 5.37 Liquid injection and production rates and bottomhole pressures of production and injection wells as a function of time for polymer concentration of 1,000 ppm at injection rate 700 bbl/day

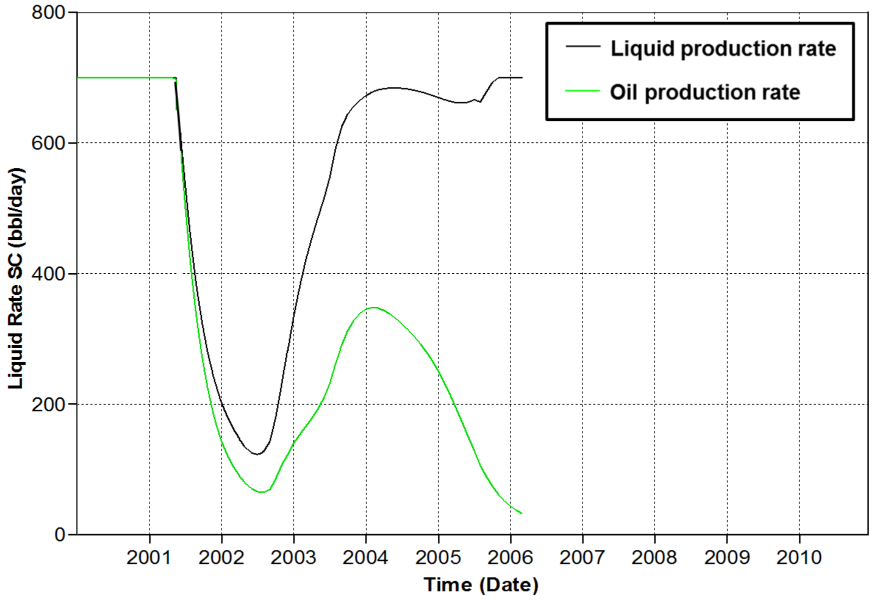

Figure 5.38 Liquid production rate compared to oil production rate and bottomhole pressures of injection and production wells as a function of time for polymer concentration of 1,000 ppm at injection rate 700 bbl/day

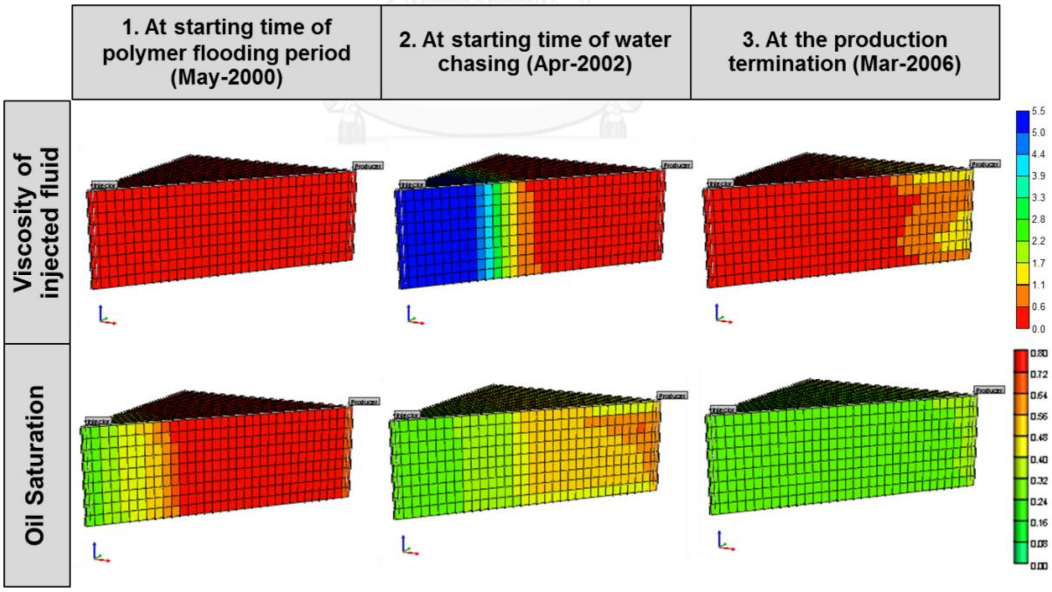

Figure 5.39 Viscosity profile of injected fluid and oil saturation profile during polymer flooding using polymer concentration of 1,000 ppm and polymer slug size of 0.5 PV with injection rate 700 bbl/day at different interest periods

In order to investigate effects of interesting parameters including reservoir heterogeneity, magnitude of polymer adsorption and polymer resistance factor in the following sections, the optimum operating conditions together with degree polymer desorption are summarize as **Table 5.6**.

Table 5.6 Summary of the optimum operating conditions of polymer flooding cases

Polymer concentration (ppm)	500	750	1,000
Polymer slug size (% PV)	30	20	15
Starting time (PV of pre-water injection)	0.05 PV	0.05 PV	0.05 PV
Polymer Injection Rate (BPD)	700 BPD	300 BPD	700 BPD
Degree of Polymer Desorption (%)	100	50	50
Oil Recovery Factor (%)	59.58	59.34	59.86

From **Table 5.6**, the case with polymer concentration of 500 ppm is chosen. Refer to ผิดพลาด! ไม่พบแหล่งการอ้างอิง, the overall recovery factors obtained from polymer concentration of 500 ppm cases are more consistent due to better injectivity compared to other cases with higher concentration. Nevertheless, polymer desorption is the most important parameter in this study, and therefore, three values of degree of desorption are applied to the chosen case while other parameters are investigated.

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5.5 Effects of Reservoir Heterogeneity

Most of the time reservoir cannot be represented as a homogeneous formation. Variation of permeability can usually occur and this causes a major difference in terms of reservoir responds. Therefore, when reservoir heterogeneity is studied, change in permeability is concerned. In this study, heterogeneity is constructed as multi-layered reservoir and therefore, Lorenz coefficient is chosen for the study to quantify degree of heterogeneity. Additional two models with values of Lorenz coefficient (L_k) of 0.1 and 0.2 are constructed to compare with the case of homogenous reservoir where L_k is zero. The reservoir is assumed to be coarsening upward as this type of reservoir can compensate the gravity effect of heavier injectant. Porosity is kept constant at 0.2. In order to compare all cases, average permeability is fixed at 500 mD for heterogeneous cases. Moreover, the maximum, median and minimum permeability values in additional two cases are fixed constant to do not bias any case. **Table 5.7** summarizes horizontal absolute permeability values and **Figure 5.40** shows flow capacity distributions with various Lorenz coefficients.

Table 5.7 The horizontal permeability in different layer and Lorenz coefficient

Layer	Horizontal Permeability (mD)		
	$L_k = 0$	L_k=0.1	L_k=0.2
1	500	800	800
2	500	503	680
3	500	502	660
4	500	501	640
5	500	500	500
6	500	499	360
7	500	498	340
8	500	497	320
9	500	200	200

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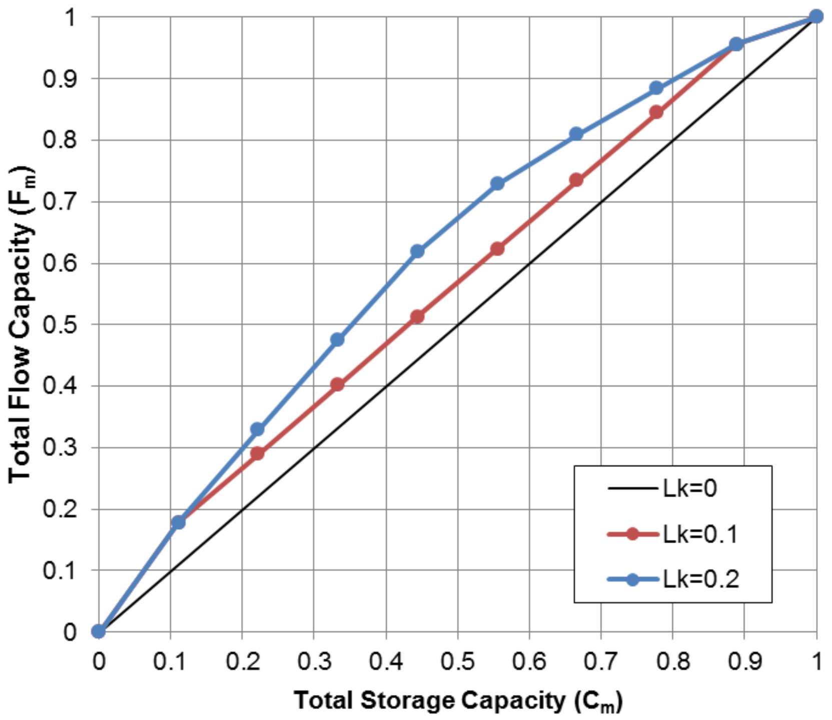

Figure 5.40 The flow capacity and storage capacity distribution with different Lorenz coefficient

Due to changes of heterogeneity, waterflooding base cases have to be investigated. **Figure 5.41**, it shows the vertical sweep pattern in reservoir with different Lorenz coefficients. In homogeneous reservoir, it can be observed that underruning of water is occurred. This is the reason why coarsening upward sequence is usually chosen for waterflooding as high permeability in the upper zone will favor the flow that compensate with gravity force. The sweep pattern is mostly vertical in the case with Lorenz coefficient of 0.1. However, with greater value up to 0.2, flow of water is more favorable in upper zone where permeability values are quite high. This results in early water breakthrough and as a consequence, the lowest oil recovery among these three cases.

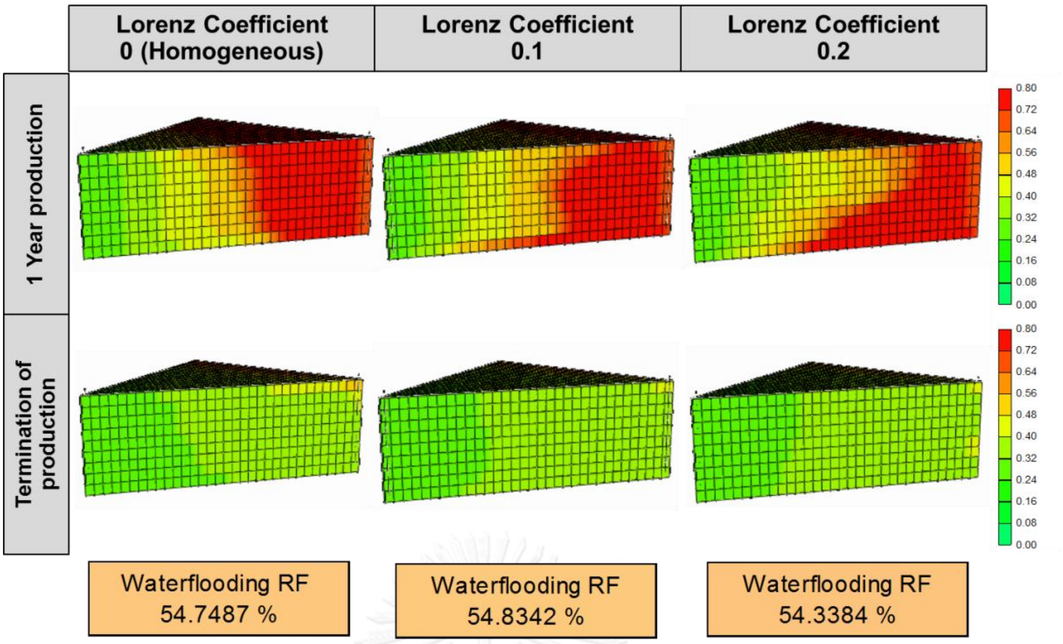

Figure 5.41 Cross sectional view of oil saturation profiles obtained from waterflooding in cases with different values of heterogeneity

Figure 5.42 and **Figure 5.43** show polymer adsorption profile and oil saturation profile of polymer flooding cases with different Lorenz coefficients and different desorption values, respectively. From **Figure 5.42**, profile of polymer adsorption is nearly the same in case that polymer desorption is zero. This also results in very small different of oil recovery factor from cases with Lorenz coefficient of zero to 2.0. This can be explained that, when there is variation of permeability, injectant which is aqueous phase will tend to flow to the highest permeability channels. Therefore permanent adsorption will slow down the travelling speed of injectant in high permeability channels by permanent reduction of relative permeability to water.

The difference in terms of adsorption profile and oil recovery factor is obvious in 100 percent polymer desorption. Chasing water will flow quickly in high permeability channels and at the same time it causes polymer desorption quickly in the same location. Therefore, adsorption profiles look very different in different cases with various heterogeneities. And this results in big difference from case without heterogeneity to case with Lorenz coefficient of 0.2 (oil recovery factor ranges from 59.58 to 57.97).

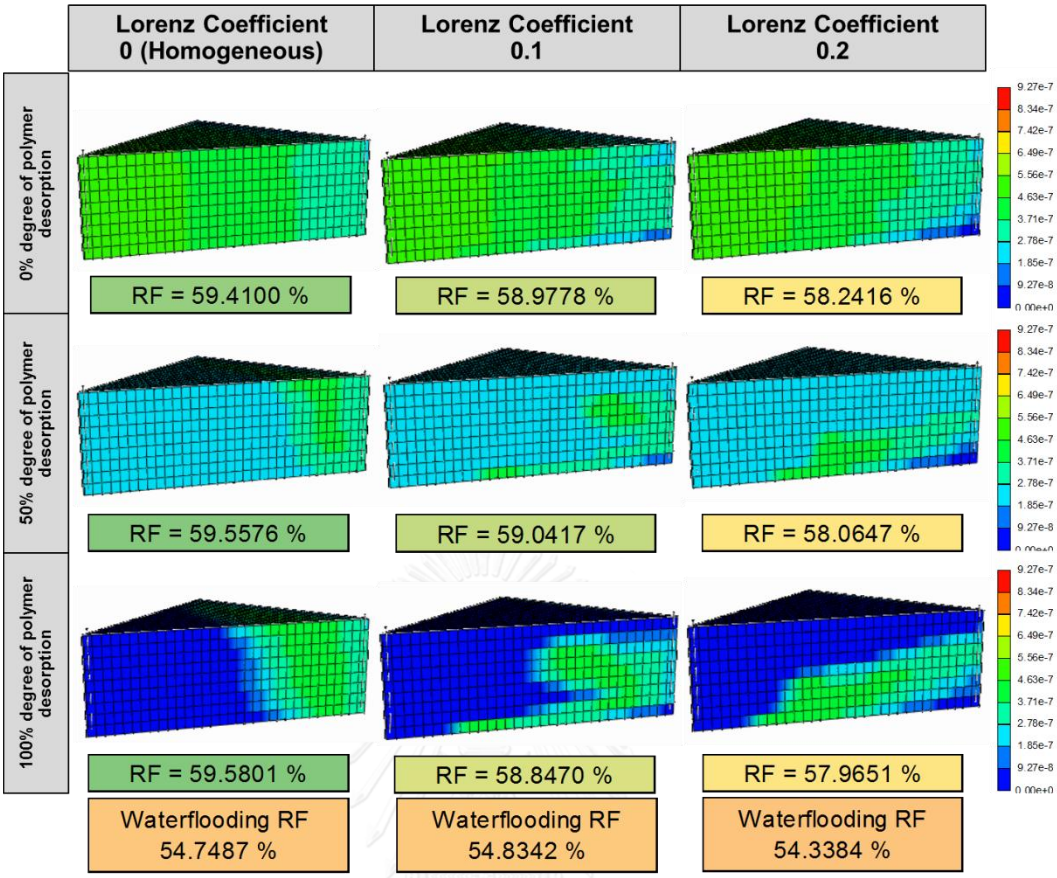

Figure 5.42 Cross sectional view of polymer adsorption profiles obtained from polymer flooding in cases with different values of heterogeneity and different desorption values

Figure 5.43 shows that the case with Lorenz coefficient of 0.2, oil saturation profiles look mostly similar when desorption value is varied. However, the different in oil recovery factor is caused by higher oil saturation remain at the bottom of the reservoir located around the production well. As permeability of lower zone is quite low, displacing fluid tends to upper location. Together with higher polymer desorption, the high oil saturation is more pronounced as displacement mechanism is only occurred in the top layers of reservoir.

In can be concluded that, reservoir with heterogeneity usually yield lower oil recovery by means of waterflooding due to early water breakthrough from high permeability channels. An attempt to reduce permeability contrast can be made by polymer flooding. However, polymer should be permanently adsorbed onto rock surface to maintain the least permeability contrast as much as possible. High polymer desorption is not recommended since it will lead to bypassing of chasing water through high permeability zone that could cause ineffectiveness of polymer slug.

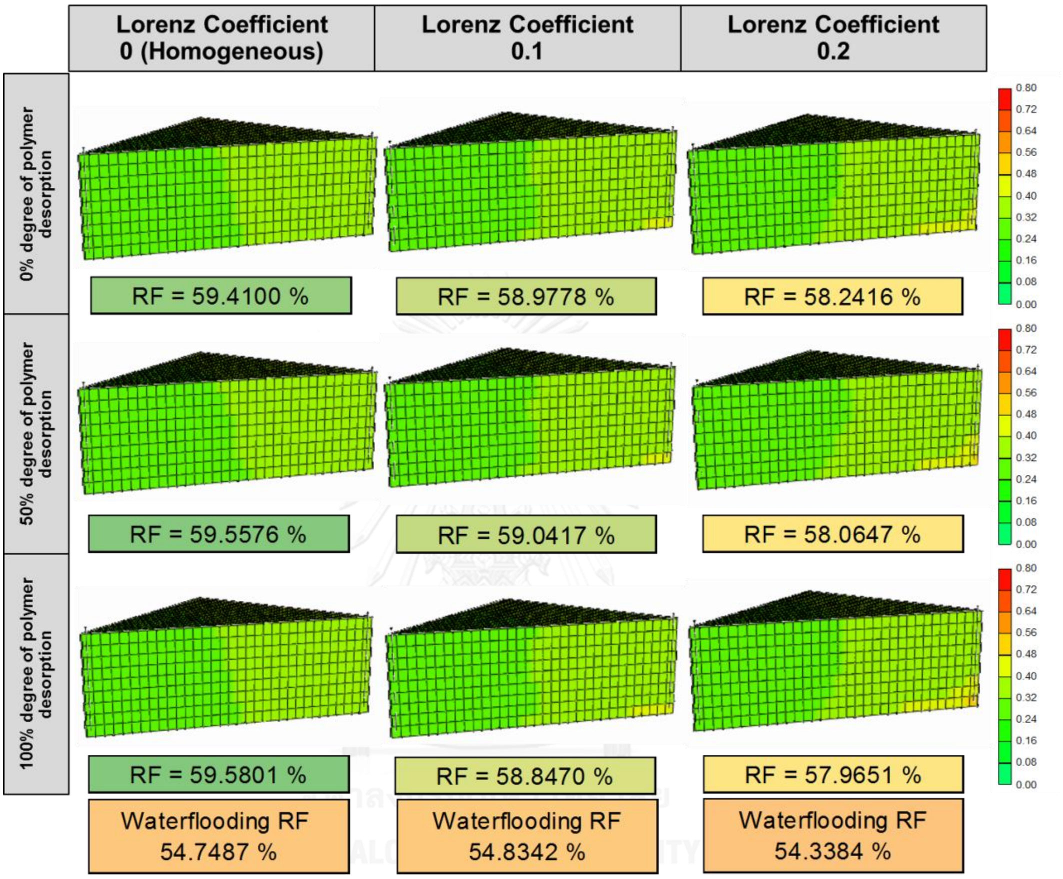

Figure 5.43 Cross sectional view of oil saturation profiles obtained from polymer flooding in cases with different values of heterogeneity and different desorption values

5.6 Effects of Magnitude of Polymer Adsorption

Another related parameter studied in this thesis is the magnitude of polymer adsorption. The magnitude depends on type of polymer and its interaction with minerals of rock surface which is recommended to be investigated in the laboratory. According to the scope of this thesis, the magnitude of polymer adsorption is studied as maximum polymer adsorption in the simulation. Additional value of maximum polymer adsorption is chosen to be 13.91×10^{-7} lbmole/f^{t3} which is 1.5 times of the maximum polymer adsorption of the original case which is 9.27×10^{-7} lbmole/ft^{3}. **Figure 5.44** illustrates polymer adsorption profiles obtained from original maximum polymer adsorption and 1.5 times of original case at different degrees of polymer desorption. To accompany the figure, oil recovery factor at the end of production is provided for each case.

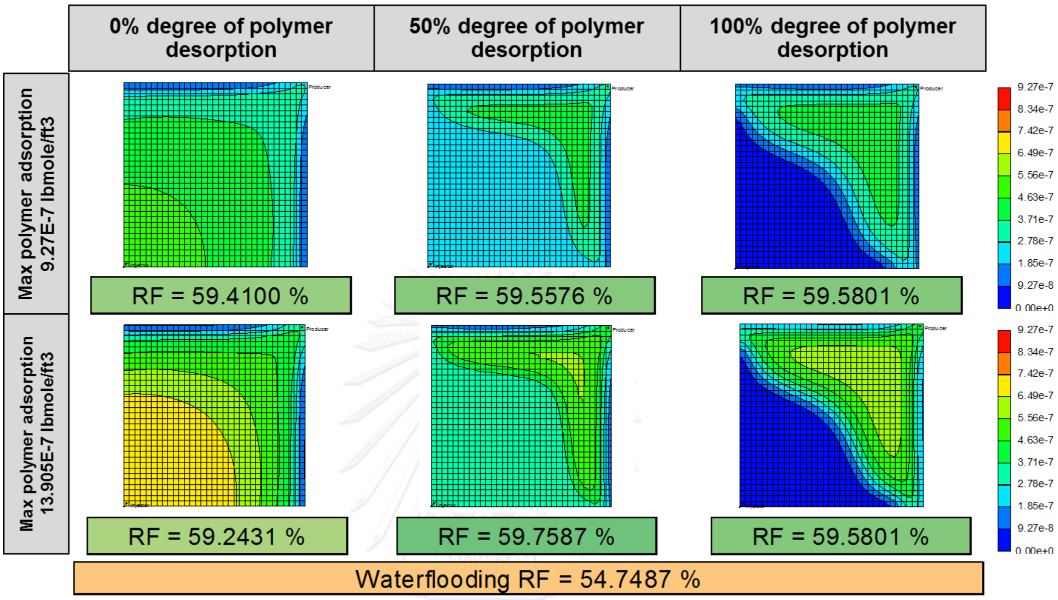

Figure 5.44 Top view of polymer adsorption profiles at the end of production obtained from cases with different magnitudes of polymer adsorption and degrees of polymer desorption

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From the above figure, maximum adsorption from the reservoir simulation at the maximum polymer adsorption of 13.91×10^{-7} lbmole/f^{t3} cannot be reached. According to section 5.4, polymer adsorption directly depends on polymer concentration. At polymer concentration of 500 ppm, maximum polymer adsorption is only half of 13.91×10^{-7} lbmole/f^{t3}. With zero degree of desorption, surfactant adsorption profile looks a bit different. Nevertheless, when desorption is included, adsorption profile starts to be different and this results in changing direction of oil recovery factor. Oil saturation profiles of different cases with different maximum polymer adsorption and various polymer desorption values are shown in **Figure 5.45**.

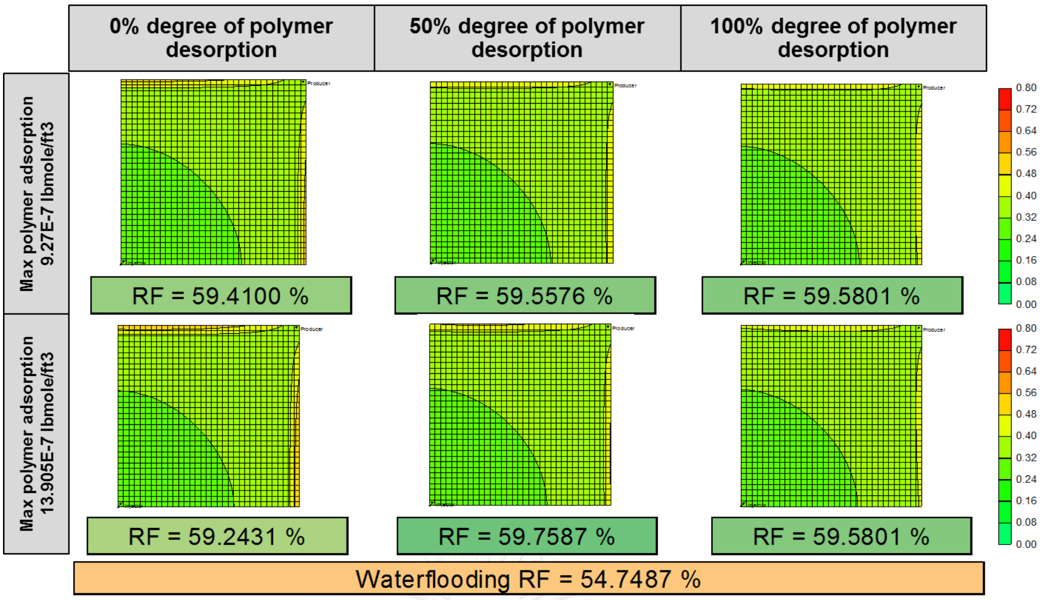

Figure 5.45 Top view of polymer adsorption profiles at the end of production obtained from cases with different magnitudes of polymer adsorption and degrees of polymer desorption

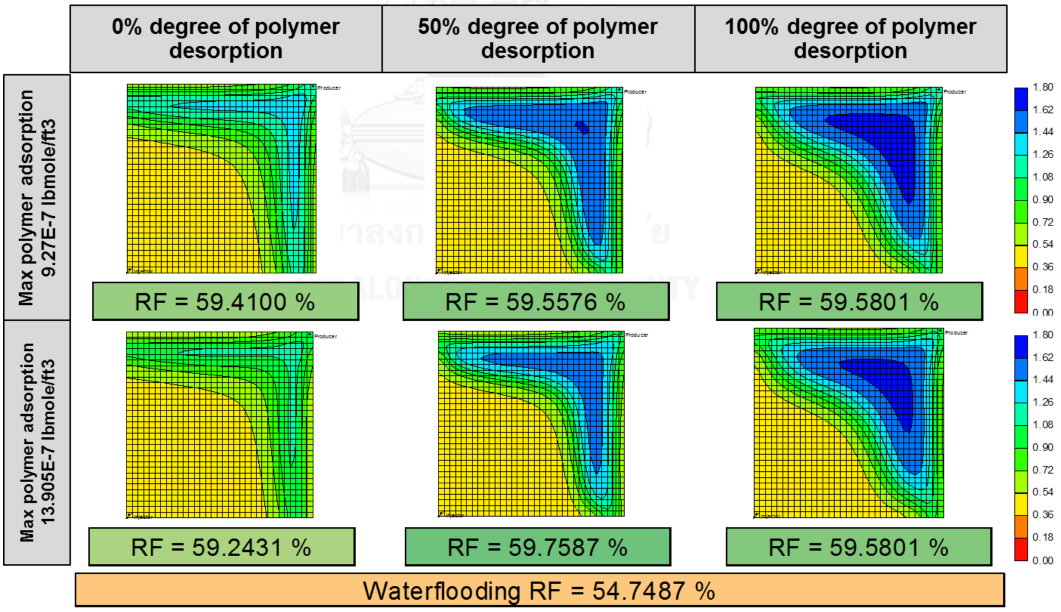

Figure 5.46 Top view of viscosity profiles of injected fluid at the end of production obtained from cases with different magnitudes of polymer adsorption and degrees of polymer desorption

From **Figure 5.45**, oil saturation does not show much different while oil recovery oil recovery factors vary different. When magnitude of polymer adsorption is higher and no polymer desorption, it is logical that higher degree of adsorption will result in less amount of active polymer and as a consequence, oil recovery factor is less in the case of high magnitude of adsorption. For the case of hundred percent polymer desorption, all desorbed polymer return to be active again. And so, when polymer concentration is not too high, the adsorbed and desorbed polymer does not cause bypassing effect that occurs only when polymer concentration is very high. Nevertheless, the interesting result is obtained when polymer desorption is at 50 percent. As explained previously, both adsorption and desorption yield benefits in their own ways. Adsorption causes displacement to be more uniform, whereas desorption results in maintaining of polymer viscosity as well as increasing abruptly the injectivity of chasing phase. From the result, it could be explained that when the magnitude of adsorption is increased, adsorbed amount as well as retaining polymer is higher than the case of less magnitude of adsorption. However, the benefit from higher polymer adsorption results in more reduction of relative permeability to water and hence, this effect may overcome effect from increasing viscosity and as a result, oil recovery factor is slightly higher. The viscosity profile of injected fluid at the end of production in different of degree of polymer desorption cases are shown in **Figure 5.46**.

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It can be summarized that for polymer concentration of 500 ppm, magnitude of polymer adsorption directly affect oil recovery in the case of no desorption. This can also be implied that, function obtained from better sweep efficiency is overruled by losing control of viscosity of injected fluid. When desorption value is higher, the equilibrium shifts and effect from sweep efficiency starts to dominate losing of viscosity of injected fluid. Therefore, higher magnitude of polymer adsorption results in better result. Eventually when there is no retaining polymer onto rock surface. Both effects are obtained but advantage and disadvantage of each effect may cancel each other appropriately and this results in no difference in oil recovery factor.

5.7 Effects of Residual Resistance Factor

Polymer resistance factor is one of the parameters that show performance of polymer. A specific term called residual resistance factor which excludes effects of polymer viscosity is investigated in this section. Additional two values of residual resistance factors are generated which are 2 and 10 (residual resistance factor from the base case is 5). **Figure 5.47** and **Figure 5.48** illustrate polymer adsorption profile and oil saturation profile respectively obtained from different residual resistance factors and different desorption values.

From **Figure 5.47**, it can be obviously seen that sweep efficiency is improved by increasing of residual resistance factor. Residual resistance factor indicates how much permeability is reduced after polymer adsorption. Fortunately, polymer concentration is quite low in this case and injectivity problem is mitigated in the case of high resistance factor.

From **Figure 5.48**, when polymer desorption is zero, the worse sweep efficiency is obtained from residual resistance of 2. Improvement in sweep efficiency can be also seen in cases of residual resistance factor of 5 and 10 but the best is found at the value of 5. As explained before, high residual resistance factor may result in lowering injectivity.

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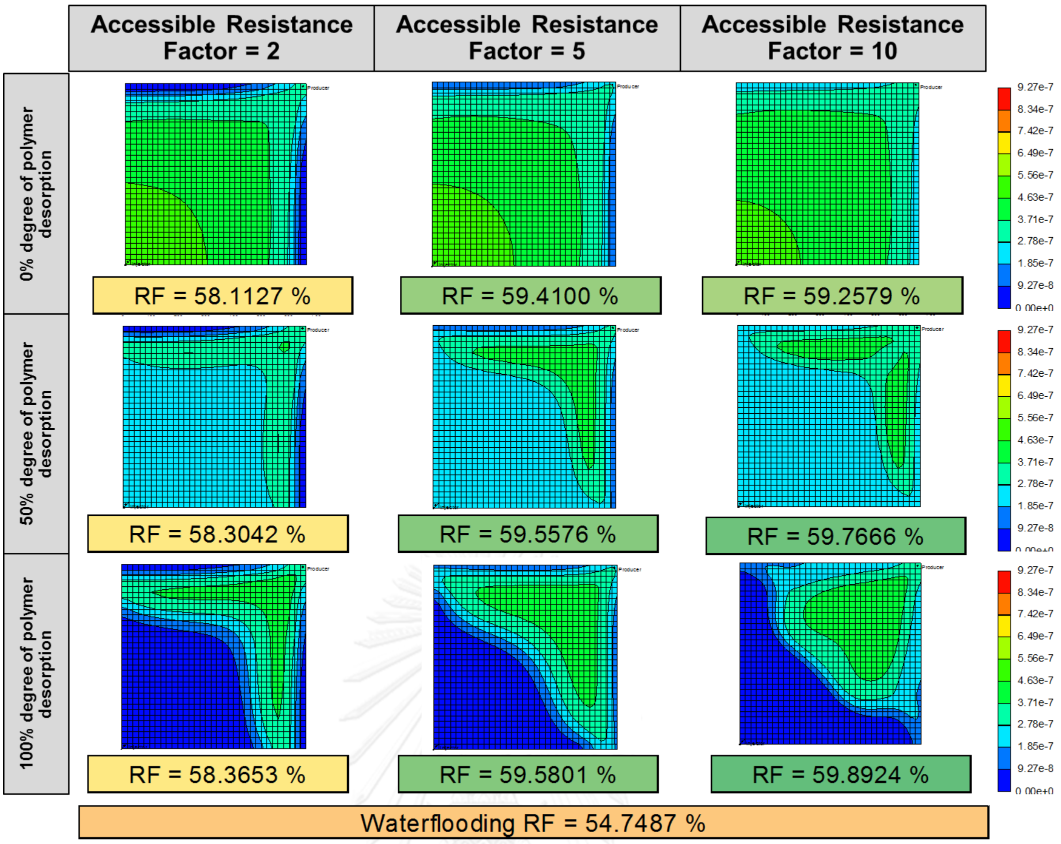

Figure 5.47 Top view of polymer adsorption profiles at the end of production obtained from cases with different residual resistance factors and different degrees of polymer desorption

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As can be expected, when desorption is included in oil recovery is improved. Oil recovery factor is higher in all residual resistance factors as polymer can be reemployed and especially for the case of residual resistance factor of 10, injectivity is improved again. Changing of sweep area can be illustrated in case of 100 percent desorption. Combination of high residual resistance factor and high desorption value results in excellent sweep efficiency. Deviation of fluid to border occurs to the highest flow resistance at the diagonal.

From **Figure 5.48**, it can be seen that in case of high residual resistance factor, flow is induced from borders of the pattern. As reduction of permeability results in reduction in relative permeability to water, sweep efficiency is improved not only in the diagonal line between injector and producer but through borders of the pattern.

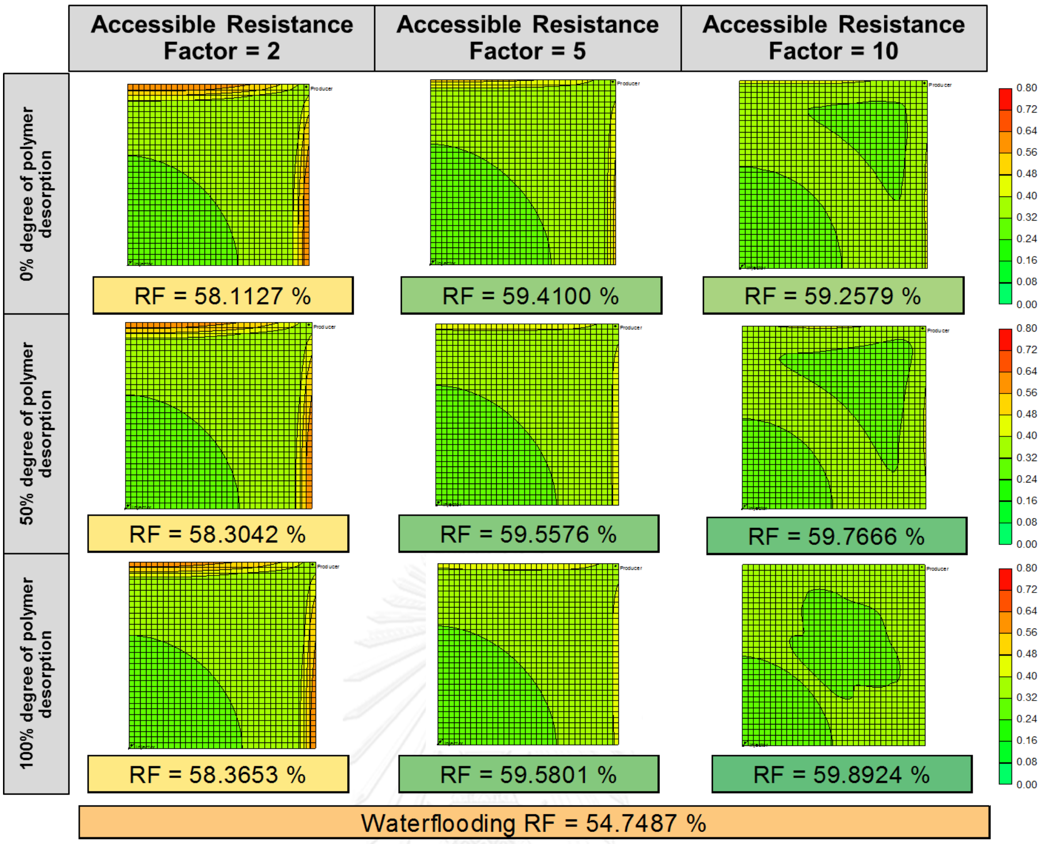

Figure 5.48 Top view of oil saturation profiles at the end of production obtained from cases with different residual resistance factors and different degrees of polymer desorption

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In this section, it can be interestingly concluded that combination of high residual resistance factor and high degree of polymer desorption exhibits the best sweep efficiency as well as obtaining viscosity control at the same time. High residual resistance factor results in reduction of relative permeability to water and it greatly improves sweep efficiency in all direction. The disadvantage of polymer adsorption is later mitigated by polymer desorption which increases injectivity again after chasing water is injected. Moreover, diverting of flow to border side due to high flow resistance at the diagonal line between injector and producer results in very favorable sweep area.

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

This chapter concluded the explanation of results from the previous chapter. The results include benefit from polymer flooding process, identification of polymer slug size of different polymer concentrations, effect of polymer adsorption and desorption, and effects of operating conditions and the interesting parameters at the optimum operating conditions on polymer flooding process. Recommendations are made in order to guide the further studies.

6.1. Conclusions

1. The difference of polymer mass injected into the process, representing as polymer concentration, affects the optimum polymer slug size. The higher polymer concentration requires smaller slug size of polymer to attain constant oil recovery factor and vice versa.
2. Polymer desorption causes polymer re-employment of adsorbed polymer onto rock surface. This results in maintaining viscosity of polymer slug and hence increases sweep efficiency. However, certain optimum degree of polymer desorption exists in difference polymer concentration and it should be thoroughly investigated.
3. When high polymer concentration is used, total desorption would cause flow resistance in diagonal line between injector and producer. This causes chasing water to bypass the polymer slug and results in low sweep efficiency.
4. The earliest time to perform polymer flooding after waterflooding shows the great benefit on both oil recovery factor as well as total production period. Performing polymer flooding at late time after waterflooding together with high polymer concentration would cause problem related to injectivity. Lack of supporting pressure would terminate the production once minimum oil rate constraint is attained.

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5. Even, higher injection rate can accelerate the production; it should be optimized based on polymer concentration.
6. Variation of permeability in layers can cause early water breakthrough by waterflooding and this results in lower oil recovery factor. Polymer flooding can be used to reduce negative effects of reservoir heterogeneity. Nevertheless, polymer should be permanently adsorbed onto rock surface to reduce relative permeability to water as much as possible. Polymer with high desorption may gain benefits from maintaining polymer viscosity but once chasing water is injected, water can bypass in high permeability channels again that could reduce effectiveness of polymer slug.
7. In this study, magnitude of polymer adsorption slightly affects oil recovery factor. Especially in cases of total desorption, the oil recovery factor does not change due to cancelation between effects from reduction of relative permeability to water and maintaining fluid viscosity. Increasing magnitude of polymer adsorption shows an effect in case of 50 percent degree of adsorption where the cancelation of reduction of relative permeability to water and maintaining fluid viscosity are not appropriate and this results in reduction in different oil recovery factor.
8. Combination between high residual resistance factor and total desorption causes great improvement in sweep efficiency. Great reduction in permeability from adsorption results in oil sweeping in all directions including borders of the pattern and 100 percent desorption after chasing water is injected causes the retard of water bypass slowing down water breakthrough. Meanwhile, diverting of chasing water to the borders helps the increases sweep efficiency.

6.2. Recommendations

1. This thesis focuses on effects of degree of polymer desorption. However, finding polymer type with controllable for polymer desorption value should be investigated in the future.

2. The parameters setting in this thesis are obtained from certain literatures. It is recommended to investigate especially values of polymer adsorption and desorption in laboratory for better simulation results.
3. Coreflooding should be performed in order to obtain relative permeability curve and actual range of residual resistance factor for chosen rock and polymer solution.

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APPENDIX

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APPENDIX A

RESERVOIR SIMULATION MODEL

Computer Modeling Group (CMG) is used to construct reservoir simulation and is employed in the thesis to investigate the results. In order to create a base case reservoir model which is water flooding process, it is required to set input data as follow.

1. Simulator Setting

Input Parameter	Value
Simulator	STARS
Working Units	Field
Porosity	Single porosity
Simulation start date	2000/01/01

2. Reservoir

2.1. Create Cartesian Grid

Input Parameter	Value
Grid Type	Cartesian
K Direction	Down
Number of Grid Blocks	33 x 33 x 9
Block widths, I direction	33×20 ft
Block widths, J direction	33×20 ft

2.2. Array Properties

Input Parameter	Value
Grid Top at Layer 1	3,280 ft
Grid Thickness (whole grid)	12 ft
Porosity	0.2
Permeability I	500 mD
Permeability J	Equals I (equal)
Permeability k	Equal I*0.1
Water Mole Fraction	1

3. Components

3.1. PVT Using Correlation

Input Parameter	Option	Value
Reservoir temperature		150 °F
Generate data up to max. pressure of		5,000 psi
Bubble point pressure calculation	Generate from GOR value	206.3 SCF/STB
Oil density at STC (14.7 psia, 60oF)	Stock tank oil gravity (API)	25 °API
Gas density at STC (14.7 psia, 60oF)	Gas gravity (Air = 1)	0.7
Oil properties (Bubble point, Rs, Bo) correlation	Standing	
Oil compressibility correlation	Glaso	
Dead oil viscosity correlation	Ng and Egbogah	
Live oil viscosity correlation	Beggs and Robinson	
Gas critical properties correlation	Standing	
Set/Update Value of Reservoir Temperature, Fluid Densities in Dataset	✓	

3.2. Water properties using correlation

Input Parameter	Value
Reservoir temperature (TRES)	150 $^{\circ}$F
Reference pressure (REFPW)	1,435 psi
Water bubble point pressure	-
Water salinity	1,000 ppm
Undersaturated Co	1E-05 psi^{-1}
Set/Update Value of Reservoir Temperature, Fluid Densities in Dataset	✓

Remark: Leaving blank for water bubble point pressure is set as default value.

4. Rock-Fluid

4.1. Rock Type Properties

Input Parameter	Value
Use Interpolation Sets	No
Rock wettability	Water wet
Method for evaluating 3-phase KRO	Stone’s second model

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4.2. Relative Permeability

4.2.1.Relative Permeability Endpoint Input

Input Parameter	Value
SWCON - Endpoint Saturation: Connate Water	0.2
SWCRIT - Endpoint Saturation: Critical Water	0.2
SOIRW - Endpoint Saturation: Irreducible Oil for Water-Oil Table	0.25
SORW - Endpoint Saturation: Residual Oil for Water-Oil Table	0.25
SOIRG - Endpoint Saturation: Irreducible Oil for Gas-Liquid Table	0
SORG - Endpoint Saturation: Residual Oil for Gas-Liquid Table	0.2
SGCON - Endpoint Saturation: Connate Gas	0
SGCRIT - Endpoint Saturation: Critical Gas	0.05
KROCW - Kro at Connate Water	0.7
KRWIRO - Krw at Irreducible Oil	0.25
KRGCL - Krg at Connate Liquid	0.7
KROGCG - Krog at Connate Gas	-
Exponent for calculating Krw from KRWIRO	3
Exponent for calculating Krow from KROCW	3
Exponent for calculating Krog from KROGCG	3
Exponent for calculating Krg from KRGCL	3

5. Initial Condition

Input Parameter	Value
Vertical Equilibrium Calculation Methods	Depth-Average Capillary-Gravity Method
Reference pressure (REFPW)	1,435 psi
Reference Depth (REFDEPTH)	3,280 ft
Water-Oil Contact Depth (DWOC)	3,388 ft

6. Numerical

Input Parameter	Value
First Time Step Size after Well Change (DTWELL)	0.001
Isothermal Option (ISOTHERM)	ON
Linear Solver Iteration (ITERMAX)	300

7. Wells and Recurrent

7.1. Date

Input Parameter	Value	Unit
Range of Date	361	months

7.2. Injection Well

7.2.1.Perforations

Input Parameter	Value	Unit
Radius	0.25	ft
Perforation start	1, 33, 1	
Perforation end	1, 33,9	

7.2.2.Well Events

ID & Type	Value
Name:	Injector
Type:	Injector Mobweight implicit

Constraint	Parameter	Limit/Mode	Value	Action
OPERATE	BHP bottom hole pressure	MAX	2,000 psi	CONT
OPERATE	STW surface water rate	MAX	Vary	CONT

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7.3. Production Well

7.3.1.Perforations

Input Parameter	Value	Unit
Radius	0.25	ft
Perforation start	33, 1, 1	
Perforation end	33, 1, 9	

7.3.2.Well Events

ID & Type	Value
Name:	Producer
Type:	Producer

Constraint	Parameter	Limit/Mode	Value	Action
OPERATE	STL surface liquid rate	MAX	Vary	CONT
OPERATE	BHP bottomhole pressure	MIN	200 psi	CONT
MONITOR	WCUT water-cut		0.95	STOP
MONITOR	STO surface oil rate	MIN	25 bbl/day	STOP

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APPENDIX B

POLYMER FLOODING MODEL IN RESERVOIR SIMULATION

Polymer model is constructed by Process Wizard in STARS simulation program. All the numerical values used in this work are shown below.

1. Process Wizard

1.1. Choose Process

Input Parameter	Value
Process	Alkaline, surfactant, foam, and/or polymer model
Model	Polymer flood (add 1 components)

1.2. Input Specific Data

Input Parameter	Value
Polymer is adsorbed onto the reservoir rock	Valid
Polymer resistance factor (1.0=no permeability blockage)	Varied
Accesible pore volume for polymer adsorption	0.85
Polymer quantity decrease with time	Invalid
Rock type for conversion of adsorption values (gm rock to PV)	Sandstone
Rock Density (gm/cm3)	2.65

1.3. Component Selection and set Adsorption Value

Input Parameter	Value
Add new component for Polymer	✓

Enter porosity of laboratory polymer adsorption sample: 0.2

Weight % Polymer	Polymer Adsorption, mg/(100gm rock)
0	0
0.1	1.3164
0.25	3.2909
0.5	6.5818

1.4. Set Polymer Value

Weight % Polymer in Water	Water + Polymer Viscosity, cp
0	0.464083
0.05	2.0419652
0.1	5.568996
0.2	20.419652
0.3	60.33079

Remark: The viscosity is obtained from viscosity multiplier as a function of polymer concentration refer to Chapter 4

2. Components

2.1. Components molecular weight

Component	MW (lb/lbmole)
Water	0
Polymer	9.27E-07
Dead_Oil	315.9
Soln_Gas	20.279

3. Rock-Fluid

3.1. Isothermal adsorption table

Mole Fraction	Adsorbed moles per unit pore volume, lbmole/ft3
0	0
2.25E-06	9.27E-07

3.2. Rock Dependent Parameters

Input Parameter	Value
Maximum adsorption capacity (ADMAXT)	9.27E-07 lbmole/ft3
Residual adsorption level (ADRT)	Varied

4. Wells & Recurrent

4.1. Injected fluid in injection wells

The mole fraction of components is varied to study effects of polymer concentration as proposed in this thesis. Table below shows mole fraction setting for varied polymer concentration.

Component	**500 ppm**	**750 ppm**	**1000 ppm**
	MW (lb/lbmole)		
Water	0.999998874	0.999998311	0.999997748
Polymer	0.000001126	0.000001689	0.000002252
Dead_Oil	0	0	0
Soln_Gas	0	0	0

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VITA

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