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Oil Recovery by Polymer Flooding; Sensitivity Analysis to Technical Parameters

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Declaration of Original Work

I, Rana Osama Fahmi Saqer, the undersigned, a graduate student at the United Arab Emirates University (UAEU), and the author of this thesis entitled "*Oil Recovery by Polymer Flooding: Sensitivity Analysis to Technical Parameters*", hereby, solemnly declare that this thesis is my own original research work that has been done and prepared by me under the supervision of Dr. Gamal Alusta, in the College of Engineering at UAEU. This work has not previously been presented or published, or formed the basis for the award of any academic degree, diploma or a similar title at this or any other university. Any materials borrowed from other sources (whether published or unpublished) and relied upon or included in my thesis have been properly cited and acknowledged in accordance with appropriate academic conventions. I further declare that there is no potential conflict of interest with respect to the research, data collection, authorship, presentation and/or publication of this thesis.

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Abstract

Numerous enhanced oil recovery techniques including miscible gas injection, chemical, thermal and other methods are applied at the third phase of production after both primary and secondary recovery have been exhausted. Polymer flooding is one of the chemical methods that recover more oil by decreasing the mobility of the system; by increasing the viscosity of the injected water that results in an improvement in the volumetric sweep efficiency.

The objective of this work is to asses and select the development options using polymer process that maximize oil recovery for a synthetic reservoir model where technical parameters are optimized thoroughly.

Reservoir simulation study using ECLIPSE 100 was used to simulate the synthetic model to investigate the different development options of polymer flooding applied and compare them to waterflooding. The development options include continuous polymer injection, water alternating polymer, and polymer slug injection. Through the study, the effect of injection rate, polymer concentration, slug size, and well completion were investigated by setting up a range of sensitivities. According to the sensitivity analysis performed on injection rate when waterflooding is applied; 1500 STB/D was considered the most suitable operating injection rate for the study.

Results of the study reveal a general trend of improved oil recovery with the implementation of polymer flooding over waterflooding in the range of 3 - 8%. In the continuous polymer injection, the highest field oil efficiency of more than 50% was obtained using polymer concentration of 200 ppm where all the layers were completed. On the other hand employing the water alternating polymer technique, a

maximum oil recovery was achieved at 200 ppm polymer concentration, three months of WAP cycle, and using the same completion as in the continuous process. Results also indicated that both continuous and polymer slug injection have the same optimum concentration of 200 ppm. Furthermore, the study recommends using well completion one, two years of polymer slug injection, and polymer concentration of 1000 ppm. The selected system yields an oil recovery of 49.26%.

The outcomes of this work should assist the oil industry in planning polymer flooding for heterogeneous reservoirs; keeping in mind that UAE hydrocarbon reservoirs are normally complex with high degree of heterogeneity.

Keywords: Enhanced oil recovery, polymer flooding, continuous polymer injection, water alternating polymer, polymer slug injection, field oil efficiency.

Title and Abstract (in Arabic)

انتاج النفط باستخدام حقن محلول كيميائي (البوليمر)؛ دراسة تحليلية للعوامل التشغيلية

الملخص

العديد من التقنيات المتقدمة لاستخراج النفط بما في ذلك حقن الغاز الخلوط، الطرق الكيميائية، و الطرق الحرارية و غيرها يتم تطبيقهم في المرحلة الثالثة من الإنتاج بعد استنفاذ الطرق الأولية و الثانوية. حقن المحلول الكيميائي (البوليمر)، هو إحدى الطرق الكيميائية المستخدمة لاستعادة المزيد من النفط. يتم ذلك عن طريق خفض التنقل في النظام؛ من خلال زيادة لزوجة الماء المحقون مما يؤدي إلى تحسين الكفاءة الحجمية للخزان.

الهدف من المشروع هو تقويم و تحديد خيارات التطوير باستخدام البوليمر لزيادة إنتاج النفط لنموذج اصطناعي للخزان حيث يتم بذلك تحسين المعايير الفنية بدقة.

لإجراء دراسة المحاكاة، تم استخدام ECLIPSE 100 لمحاكاة النموذج الاصطناعي و دراسة الخيارات التطويرية للحقن بالبوليمر. الخيارات التطويرية تشمل حقن البوليمر المستمر، الحقن المتناوب للمياه و البوليمر، و حقن البوليمر على هيئة جرعة. خلال الدراسة، تأثير كل من تركيز البوليمر، حجم جرعة البوليمر، و كمالية البئر تم تحليلهم عن طريق وضع العديد من الخيارات التحليلية. و بناءً على الدراسة التحليلية التي أجريت على معدل الحقن عند تطبيق الحقن بالماء، اعتبر معدل الحقن 1500 برميل سطحي/اليوم هو الأكثر مناسبة للدراسة.

كشفت نتائج الدراسة بشكل عام على تحسين معدلات استخراج النفط باستخدام طريقة الحقن بالبوليمر على الحقن بالمياه بنسبة تتراوح ما بين 3 - 8%. في حقن البوليمر المستمر، تم الحصول على أعلى كفاءة للنفط بنسبة تزيد عن 50% باستخدام بوليمر تركيزه 200 جزء/مليون و إكمال البئر في جميع الطبقات. من ناحية أخرى و باستخدام تقنية التناوب بين المياه و البوليمر، تم الحصول على أعلى إنتاجية من خلال حقن 200 جزء/مليون من محلول البوليمر، ضخ جرعات متعاقبة من المياه و البوليمرلثلاثة شهور و قد تم استخدام نفس التكميل للبئر كما في الحقن المستمر. كما أشارت النتائج إلى أن كلاً من الحقن المستمر للبوليمر و الحقن بالجرعة أعطيا نفس التركيز الأمثل للبوليمر و هو 200 جزء/مليون. و توصي الدراسة أيضاً بإكمال البئر من

خلال التثقيب في جميع الطبقات للضخ و الإنتاج، ضخ جرعة البوليمر لعامين، و تركيز المحلول يساوي 200 جزء/مليون. النظام المختار في هذه الحالة يعطي إنتاجية بنسبة 49.26%.

نتائج هذه الدراسة ينبغي أن تساعد القطاع الصناعي للنفط في التخطيط لعمليات الحقن باستخدام البوليمر في الخزانات الغير متجانسة؛ مع الأخذ في الاعتبار أن الخزانات الهيروكربونية في دولة الإمارات العربية المتحدة عادة معقدة مع درجة عالية من عدم التجانس.

أدلة البحث: الاستخراج المعزز للنفط، الحقن بالبوليمر، الحقن المستمر للبوليمر، الحقن المتناوب للمياه و البوليمر، حقن جرعة البوليمر، الإنتاج الكلي للنفط.

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Special thanks go to my parents, brother, sisters, and family who helped me along the way. I also would like to thank, in particular, my grandfather and my uncle Abdulla, who encouraged and advised me all throughout and gave me the benefit of their experience and knowledge.

Dedication

To my beloved parents and family

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List of Abbreviations

API	American Petroleum Institute gravity
ASP	Alkaline surfactant polymer flooding
BHP	Bottom hole pressure
COMP#	Well completion #
E	Overall displacement efficiency (fraction)
E_{areal}	Areal sweep efficiency (fraction)
E_D	Microscopic displacement efficiency (fraction)
EOR	Enhanced oil recovery
E_V	Macroscopic (volumetric) displacement efficiency (fraction)
$E_{vertical}$	Vertical sweep efficiency (fraction)
F_{kr}	Permeability reduction factor
FOE	Field oil efficiency
HPAM	Hydrolyzed polyacrylamides
IFT	Interfacial tension
IOIP	Initial oil in place
IOR	Improved oil recovery
IRR	Internal rate of return
k	Permeability (md)
k_{ro}	Relative permeability to oil (md)
k_{rw}	Relative permeability to water (md)
k_{rwp}	Relative permeability to water after polymer contact (md)
MR	Mobility ratio
N_c	Capillary number
NPV	Net present value
OOIP	Original oil in place
P/I	Production to injection rate
ppm	parts per million
PV	Pore volume
PVT	Pressure volume temperature

ROIP	Recoverable oil in place
RRF (F_{krr})	Residual permeability reduction factor
S_{or}	Residual oil saturation (fraction)
TDS	Total dissolved solids
WAP	Water alternating polymer
WC	Water cut
WOR	Water oil ratio
XA	Xanthan polymer
λ	Mobility (md/cP)
μ	viscosity (cP)

Chapter 1 : Introduction

1.1 Oil Recovery Mechanisms

The life of an oil reservoir goes through three distinct phases namely primary, secondary, and tertiary or enhanced oil recovery. The importance of EOR techniques is to improve the displacement efficiency by reducing the residual oil saturation that results in high ultimate oil recovery. Primary oil recovery is limited to hydrocarbons that rise naturally to the surface, or those that use artificial lift devices, such as pumps, but only 0 to 30% of the reservoir original oil-in-place is produced. Secondary recovery employs water and dry gas injection, displacing the oil and driving it to production wells. Due to its availability and low cost, water is usually used as a secondary recovery method or it is pumped to maintain the required pressure of the reservoir. After primary recovery, 25 to 45% oil recovery can be obtained by the implementation of water flooding (Khan, 2000).

EOR refers to the recovery of the oil by the introduction or the injection of fluids and energy not normally present in the reservoir and it comprises mainly gas injection methods, chemical methods, thermal methods and other methods. Different factors must be taken into consideration during the design stage of an EOR process including: oil type, reservoir rock, and formation type, as well as the oil distribution, saturation, and physical state resulting from past operations (Green & Willhite, 1998; Zeron, 2012).

Improved Oil Recovery (IOR) is another term that is commonly used in the oil business and it is defined as any recovery process that is implemented in the secondary or tertiary stages of the reservoir. IOR is defined by the Norwegian

Petroleum Directorate (1993) as "Actual measures resulting in an increased oil recovery factor from a reservoir as compared with the expected value at a certain reference point in time". It involves a broader range of activities beside EOR, like reservoir characterization, improved reservoir management and infill drilling (Sarker, 2012).

The three different oil recovery mechanisms are presented in Figure 1.1. Furthermore, the different methods used as EOR processes are listed each under its own category.

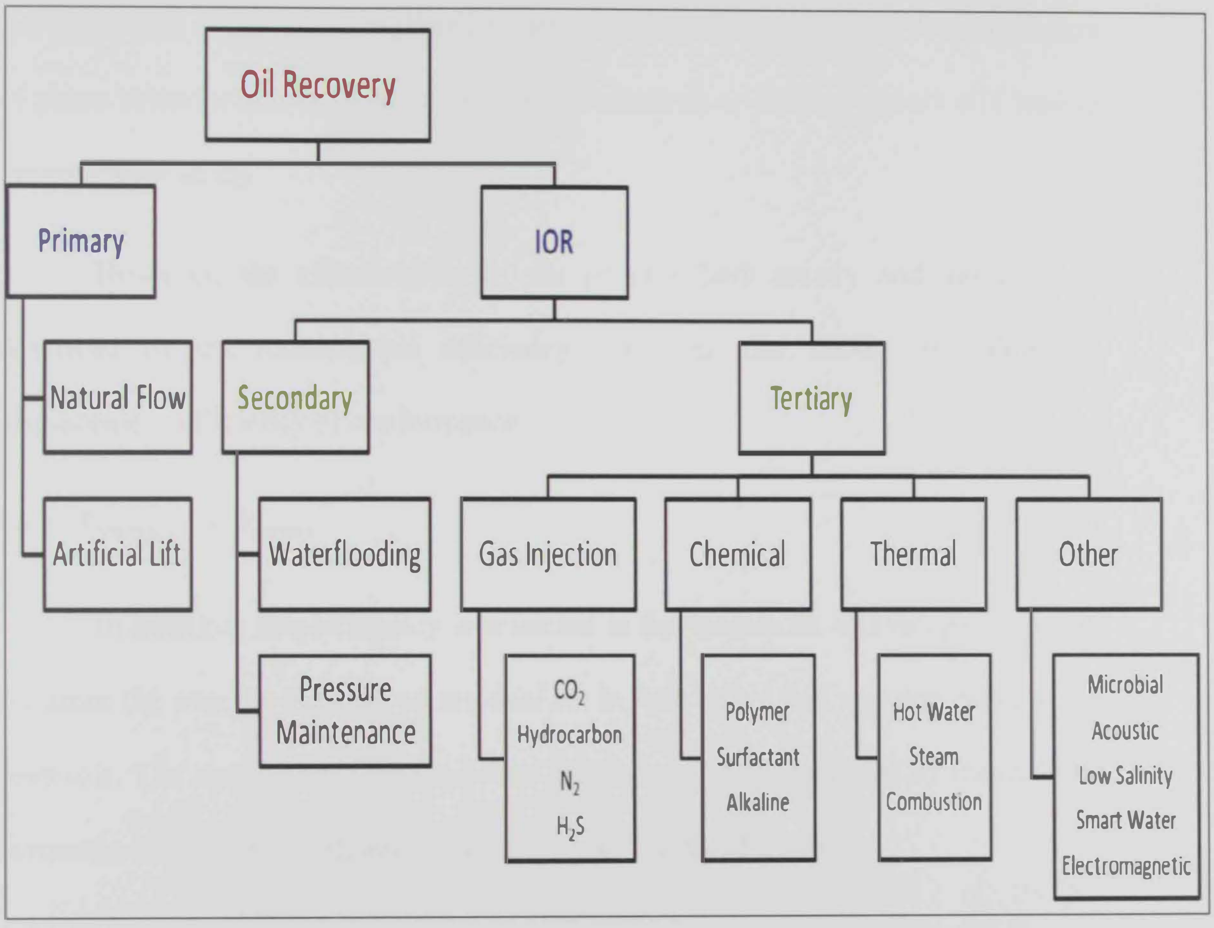

Figure 1.1: Oil recovery mechanisms

EOR processes are implemented in order to improve the overall displacement efficiency of the oil which includes the microscopic and macroscopic displacement efficiency.

$$E = E_D \times E_V \quad (1.1)$$

Where E = overall displacement efficiency (fraction), E_D = microscopic displacement efficiency (fraction), and E_V = macroscopic or volumetric displacement efficiency (fraction). The microscopic efficiency is described on pore scale and it increases by reducing capillary forces or interfacial tension, and it is also reflected in the magnitude of S_{or} in the regions contacted by the displacing fluid. A combination of phase behavior and IFT reduction using surfactants or alkaline agents will lead to improvement in E_D.

However, the effectiveness of the process both areally and vertically is described by the macroscopic efficiency which is also known as volumetric displacement efficiency or conformance.

$$E_V = E_{vertical} \times E_{areal} \quad (1.2)$$

In addition, this efficiency is reflected in the magnitude of average or overall S_{or} since the average is based on residual oil in both swept and unswept parts of the reservoir. The macroscopic displacement efficiency can be achieved by maintaining favorable mobility ratio between displacing and displaced fluids.

The efficiency of any EOR process is not measured only by its technical feasibility but also from the economics point of view, where there are some factors controlling the economic implementation of the process mainly crude oil price and the cost of injection fluid (Green & Willhite, 1998; Zeron, 2012).

1.2 Polymer Flooding

Polymer flooding is one of the mostly used chemical EOR methods. It uses polymer solutions to increase the viscosity of the displacing fluid and/or reduce the effective permeability of rock to the injected fluid and thus lower the displacing fluid (water)/oil mobility ratio leading to an increase in oil recovery. After normal waterflooding, polymers maybe injected for one to two years to effectively reach the residual oil saturation; since polymer flooding does not affect the end point S_{or}, a reduction in the effective S_{or} is achieved at the economic limit. This reduction is dependent on the nature of the fractional flow curve and the volume of injected water (Zeron, 2012; Abadli, 2012).

Exponential increase of polymer flooding projects has been due to the affordable price of polymers compared to oil; where the mostly used polymers by the industry are hydrolyzed polyacrylamides (HPAM) and biopolymer xanthan (Zeron, 2012).

The primary mechanism of a polymer flood is to increase the volumetric sweep efficiency by means of mobility control. Mobility control is always discussed in terms of mobility ratio, where it is described as the ratio between the mobility of the displacing and displaced fluids.

$$MR = \frac{\lambda_{\text{displacing (behind the flood front)}}}{\lambda_{\text{displaced (ahead of the flood front)}}} = \frac{(k/\mu)_{\text{displacing}}}{(k/\mu)_{\text{displaced}}} \qquad (1.3)$$

Where λ = mobility, k = effective permeability, and μ = viscosity.

Mobility ratio less than or equal to one (MR $\leq$ 1.0) reflects favorable displacement process (piston like displacement) and thus an improvement in volumetric sweep efficiency is attained. It is also recommended to operate at MR < 1.0, especially in reservoirs with substantial variation in areal and vertical permeability.

Furthermore, the implementation of polymer process reduces fingering effect which is a main problem in waterflooding application. By doing so, the volumetric sweep efficiency increases. Figure 1.2. is a schematic presenting the difference in fingering effect in both water and polymer flooding (Green & Willhite, 1998; Sarker, 2012; Huseynli, 2013).

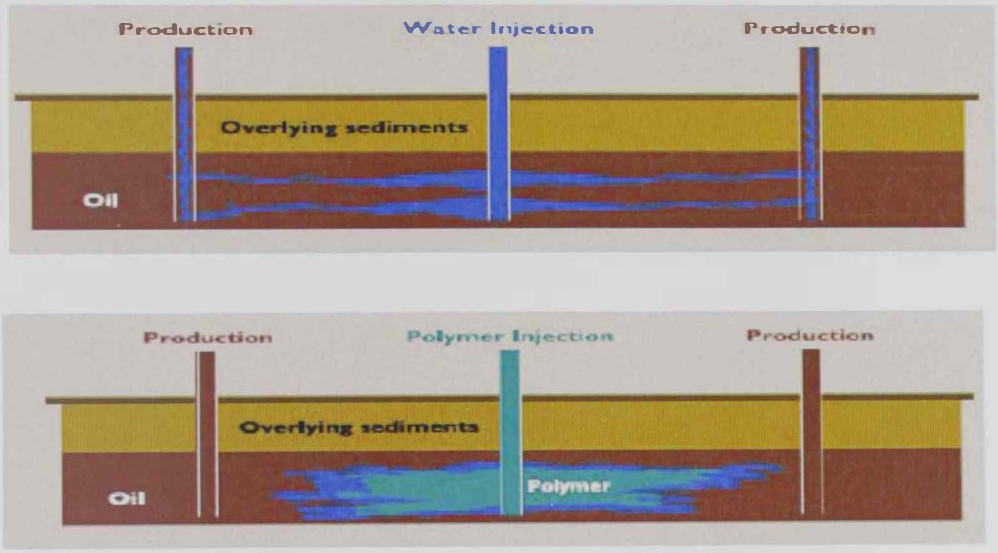

Figure 1.2: The effect of fingering in water and polymer flooding (Huseynli, 2013)

1.3 Objectives

The current work will assess and select the development options using a polymer process that maximize oil recovery for a synthetic reservoir model. Different parameters will be optimized technically including:

- Different injection rates.

- Polymer injection process (continuous injection, water alternating polymer (WAP) injection, polymer slug injection),
- Different polymer concentrations,
- Different starting times for polymer injection and,
- Different well completions.

The main objectives of this study will be as follows:

1. Apply reservoir engineering concepts to design polymer flooding for a synthetic reservoir model.
2. Identify and analyze the engineering design aspects of polymer flooding.
3. Asses full field development options for polymer injection that will achieve ultimate recovery.

Chapter 2 : Literature Review

The following is a review of representative examples of previous works done by other researchers on the same subject.

Zeron (2012) reviewed the oil recovery and EOR processes, where she highlighted more on EOR processes and their developing trends. Her review resulted in the following:

- EOR processes can be implemented any time during the life of a reservoir.
- Surfactants and alkaline flooding are good and practical EOR processes to increase the capillary number (N_c).
- Volumetric sweep efficiency can be controlled using polymers, gels, or cross-linked polymers.
- Polymer flooding is considered to be the simplest and most widely used chemical EOR process.
- Low polymer concentrations are often used, ranging from 250 to 2000 ppm.
- Polymer slug size ranges from 15 to 25% of the reservoir pore volume.
- An increment of 12 to 30% OOIP has been reported for some fields after the application of polymer flooding.
- One to two pounds of polymer are required to produce a barrel of oil.
- Lower capital costs are required by chemical EOR processes over thermal and miscible methods.

Aladasani and Bai (2010) updated the EOR screening criteria by Taber, et al. (1996). The updated screening guidelines are based on 633 projects reported in The Oil and Gas Journal from 1998 through 2008 and SPE publications. Table 2.1 shows the range oil and reservoir properties used as guidelines for polymer flooding. Note that the reported values here have extreme values that impact the respective average and range.

Table 2.1: Reservoir criteria for polymer flood project (Aladasani & Bai, 2010)

Oil Properties	Gravity (°API)	13 - 42.5 Avg. 26.5
	Viscosity (cP)	0.4 - 4000 Avg. 123.2
Reservoir Characteristics	Porosity (%)	10.4 - 33 Avg. 22.5
	Oil saturation (%)	34 - 82 Avg. 64
	Formation type	Sandstone (preferred)
	Permeability (md)	1.8 - 5500 Avg. 834.1
	Depth (ft)	700 - 9460 Avg. 4221.9
	Temperature (°F)	74 - 237.2 Avg. 167

Gao (2011) presented the scientific research and field applications of polymer flooding in heavy oil recovery worldwide. Recently, polymer flooding becomes a favorable technique to recover heavy oil due to the use of horizontal wells. Moreover, polymer floods are useful in reservoirs at great depth or having thin pay zones where thermal methods failed to recover promising quantities of heavy oil. Based on past laboratory research, polymer floods can improve heavy oil recovery by 20%. The implementation of polymer floods was successful in several reported field cases in Oman, China, and Turkey.

The major challenge of polymer flood applications is to maintain good polymer viscosity. Other challenges include low injectivity, low productivity, and plugging of formations by polymer.

Abou-Kassem (1999) presented a quantitative analysis of the performance of an oil reservoir where polymer slug injections was applied. Different reservoir parameters were considered in the study including reservoir permeability, initial water saturation, and oil viscosity along with polymer viscosity, rock adsorption characteristics, and polymer slug size to aid in evaluating the success of polymer injection process. The study was performed using highly implicit, three-phase, four components, polymer injection model simulator. Based on the results obtained, the following conclusions were drawn:

- Polymer injection delays the start of water breakthrough.
- One of the main advantages of polymer flood applications is reducing the produced WOR.
- Crossover point is noticed where 6% additional recoverable oil-in-place (ROIP) is achieved when the producing WOR was plotted versus pore volume of fluid injected, leading to the efficiency of the EOR scheme applied.
- The process is sustainable up to WOR = 15.
- Polymer flooding is not adequate for low permeability reservoirs due to high injection pressure required in low permeability formations.
- The process is more efficient at higher initial water saturation (higher incremental oil recovery) although the recoverable oil is less since less oil content of the rock is available at polymer slug initiation.

- Increasing the polymer viscosity increases the incremental oil recovery over waterflooding, however at less rate.
- High polymer adsorption yields low oil recovery due to earlier dilution and breakdown of the polymer slug.
- An increase in oil recovery is noticed with increasing polymer slug size. A slug 0.1 PV is reported as not effective and beyond it, an improvement is attained.
- Slug size optimization is achieved by minimizing viscosity contrast in the trailing edge while maximizing the viscosity contrast at the leading edge.

Gharbi, et al. (2012) developed a full field simulation model for a Middle Eastern sandstone reservoir. Surfactant/polymer flood was the selected EOR method to optimize recovery % of the remaining oil in the reservoir.

Reservoir simulation runs were performed on a sector model to achieve maximum profitability of the project in terms of net present value (NPV) and internal rate of return (IRR) by running different sensitivity analysis on surfactant and polymer concentrations and slug size. Based on their study, they concluded that the optimum design parameters for surfactant/polymer flood were: surfactant concentration of 15 vol%, polymer concentration of 2800 ppm and a chemical slug of 1.2 PV. The NPV and IRR at the optimized design parameters were 340 million dollars and 35.2%, respectively. Moreover, it is more beneficial to run the flood at high polymer concentration and low surfactant concentration for the candidate reservoir.

They assumed constant saturation functions for all the runs, although fluid flow is a strong function of relative permeability and capillary pressure curves.

Teeuw et al. (1983) designed a pilot polymer flood in the Marmul field in Oman. The candidate field is promising for EOR where the recovery factor after waterflood is determined at 20%. The study showed that both polyacrylamides and biopolymers are good candidates for Marmul field, but polyacrylamides considered to be more attractive and was used in liquid form because of the hot climate in the region.

The candidate field is characterized by locally high permeability, high oil viscosity of 80 cP, 21° API and low formation water salinity of about 7000 ppm TDS. The mobility ratio in Marmul when water drive was applied was 46, resulted in early water breakthrough and high water cut. The main objective was to reduce mobility ratio to achieve better sweep efficiency. Comparable oil recoveries were achieved with mobility ratios equal to 2, 3, 4 and 5, with the use of lower viscosities than the one used when piston like displacement is applied.

The study concluded that mobility ratio of 2.5 was the optimum; resulting in higher oil recovery and the earliest it is applied the better the oil recovery is.

The pilot test applied to the field was examined in two stages: small size pilot test (open inverted five-spot) and medium size pilot test (quadruple five-spot). Furthermore, they investigated the effect of balancing the production and injection rates per well (P/I = 1.0) using water and polymer respectively. They concluded that the oil recovery using polymer is 1.7 times the oil recovery using water.

Wang and Dong (2009) studied the effect of effective viscosity of polymer solution on the recovery of heavy oils. Five heavy oils were used in the study with a viscosity range between 430 to 5500 cP. Each sample of oil was subjected to different concentrations of polymer solution in sand pack flood tests. All polymer flood tests were exposed to waterflooding before and after. He concluded that the injected polymer solution has a minimum and maximum value of effective viscosity. An increase in oil recovery is noticed as the effective viscosity increases between the minimum and maximum values. In addition, higher oil viscosity leads to an increase in minimum and optimum effective viscosity of polymer solution.

Huseynli (2013) built a reservoir simulation model for the Norne E-segment which is part of the Norne main structure. It is a sandstone reservoir with permeability ranges between 20-2500 md. Water injection was used for pressure maintenance as well as the re-injection of the produced gas.

A fully implicit, three dimensional model, three-phase black oil model was used in ECLIPSE. In order to get better match between the base and history curves in terms of oil, water and gas production rates. Adjustments in relative permeability curves, skin factor and kh product were made.

The reservoir simulation study started in 2005 and continued until 2017, where the injection of polymer took place in January 2006 until January 2009, followed by waterflooding. Through the study, the effects of polymer concentration (0.3, 0.6, 0.9 kg/m^3) and injection rate (1000, 4000, 7000 std m^3/day) were investigated. The following conclusions were drawn:

- The oil recovery factor was increased about 0.5 - 1.0 % with the use of polymer flooding over waterflooding.
- Injector F-3H was selected for the polymer flooding study since it is located in the oil region. The other injector F-1H is located in water region.
- Polymer concentration of 0.6 kg/m^3 is considered most appropriate since it recovers the same oil as that 0.9 kg/m^3 having but with less polymer usage.

- Injection rate of 1000 std m^3/day was the favorable rate since lower pressure drop was observed along with similar behavior for both formation and injection pressure.

Fulin, et al. (2004) presented a new technique to enhance oil recovery in highly heterogeneous and high permeable reservoirs. The study was performed on artificial cores where the effects of polymer concentration, polymer injection timing and polymer molecular weight on oil recovery were investigated. During the study, all other parameters are held constant and the following conclusions were drawn:

- A high oil recovery is obtained when 2500 ppm and 4790 ppm of HPAM and XA polymers were injected respectively.
- When the apparent viscosity of HPAM polymer is 185 cP and of XA polymer is 70 cP, a higher recovery is achieved.
- Polymer elasticity should be considered in oil recovery beside its viscosity.
- The injection of high concentration polymer early in the life of the reservoir, results in higher oil recovery and lower water cut.
- Incremental recovery of 22.86~27.61% OOIP over waterflooding can be accomplished by the injection of high concentration of polymer flooding at different periods, and they are near or above the incremental recovery of alkaline/surfactant/polymer flooding (ASP).
- Improvement in microscopic and macroscopic efficiencies is attained using high molecular weight of 2100×10^4. Where all the runs were conducted using polymer slug size of 0.81PV and 2500 ppm polymer concentration of HPAM polymer.

Shedid (2006) developed an experimental approach to examine the effect of fracture orientation on oil recovery by water and polymer flooding processes on a carbonate reservoir. Five runs were carried out in the laboratory under simulated reservoir conditions of pressure and temperature. four experiments were conducted using fractured core samples with different fracture angles of 0. 30. 60 and 90 degrees. The fifth experiment was considered as the base case where the core sample has no fractures in it.

The variation of oil viscosity with temperature and the effect of temperature on polymer viscosity for different polymer concentrations were recorded. The results show that during a waterflooding process. maximum oil recovery was achieved using the unfractured core sample with 90% IOIP. For the fractured cores. as the fracture inclination angle increases. the oil recovery decreases reaching about 40% IOIP for the 90°. However. when polymer flooding is applied. different results were achieved where higher oil recovery is obtained using the fractured cores over the unfractured one. The highest recovery was attained using 30° inclination angle and the lowest was with 90°. As well. improved results can be accomplished by the implementation of combined water and polymer processes to the candidate carbonate reservoir.

Wang et al. (2007) reviewed some key aspects for a successful design of a polymer flood. It has been observed through a numerical simulation study applied in Daqing wells that profile modification before polymer injection can improve OOIP by 2-4 %. A gel treatment is one of the profile modification methods. Furthermore. the results obtained from pilot tests reveal that separate layer injection enhances flow profiles. reservoir sweep efficiency. and injection rates. and can reduce water cut in production wells.

Deng et al. (1998) addressed the combined EOR technology of 'high strength in-depth profile modification with ultra-high molecular weight polymer flooding'. The technology was applied on a commercial oilfield where sandstone is unconsolidated, porous and highly permeable with high oil viscosity. The formation is extremely heterogeneous with large channels. The results showed an improvement in mobility ratio and sweep efficiency where an increase in oil recovery by 10% OOIP is noted.

Chapter 3 : Reservoir Simulation Model Description

The performance of an element reservoir simulation two-phase (oil/water) synthetic model as presented next was investigated using ECLIPSE 100 software (black oil model).

3.1 General Description

A 3-D element of the reservoir is being modeled and it has dimensions of 2250′ × 1575′ × 150′, where each layer has 30 × 21 cells and each cell is 75′ × 75′ × 10′. There are 15 layers of grid cells, distributed over three geological layers as shown in Figure 3.1.

- Geological layer 1 corresponds to grid layers 1 - 5
- Geological layer 2 corresponds to grid layers 6 - 10
- Geological layer 3 corresponds to grid layers 11 – 15

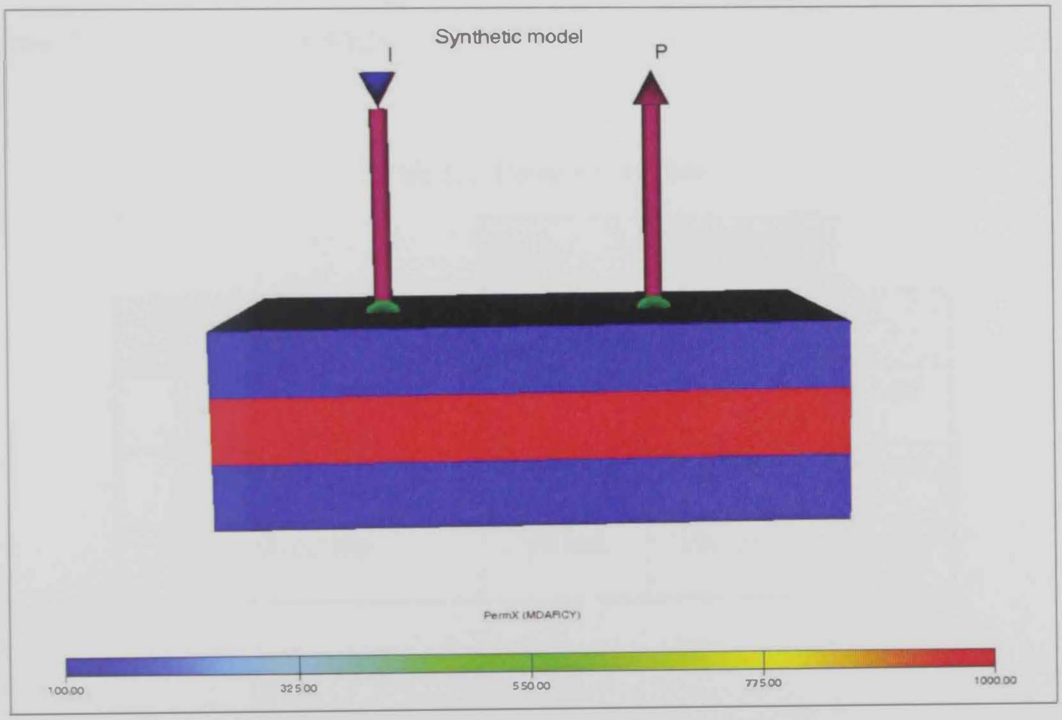

Figure 3.1: Reservoir simulation synthetic model

Figure 3.1 signifies the initial conditions of the reservoir. As shown two wells were drilled one injector in block number (8, 11) and one producer in block number (22, 11) where both have been completed in all three layers. The initial reservoir pressure was 4000 psia at datum depth of 4000 ft and the production bottom hole pressure (BHP) was 3500 psia.

The oil viscosity is 1.74 cP and the water viscosity is 0.8 cP. It is assumed that the injected water and the formation water are similar in composition.

The simulation started on 1st of January 2009, and lasted for 41 years up to 2050. The simulation run will stop once the water cut reaches 90%.

3.2 Rock Data

The synthetic reservoir model is also described in terms of rock data. The porosity of the three layers is 0.2, 0.22, and 0.2 respectively. The permeability data in the x, y, and z directions for all layers are presented in Table 3.1, with high permeability layer in the middle.

Table 3.1: Permeability data

	Layer number		
Permeability direction	**1**	**2**	**3**
x-direction	100 md	1000 md	100 md
y-direction	100 md	1000 md	100 md
z-direction	10 md	100 md	10 md

3.3 Fluid PVT and Fluid-Rock Interaction Properties

The water and oil relative permeability curves are presented in Figure 3.2.

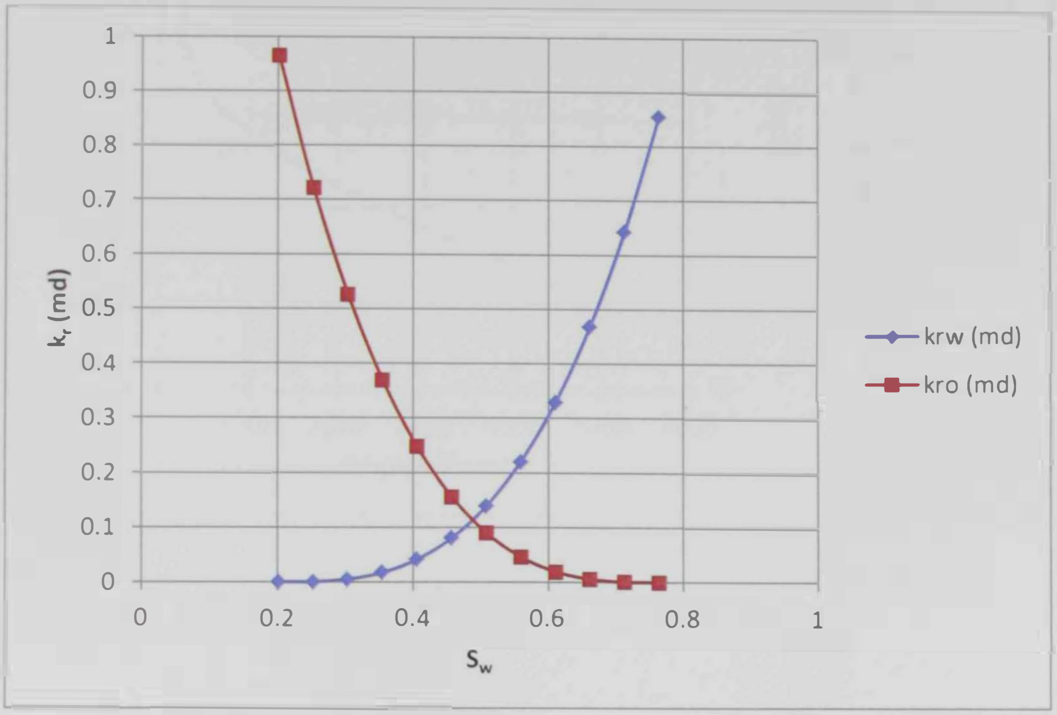

Figure 3.2: Water and oil relative permeability data

The water PVT data at reservoir pressure and temperature along with oil PVT data are shown in Table 3.2 and Figure 3.3 respectively. The bubble point pressure equals 300 psia.

Table 3.2: Water PVT Data

Pressure (psia)	**B_w (RB/STB)**	**c_w ($psia^{-1}$)**	**μ_w (cP)**
4500	1.02	3.0E-06	0.8

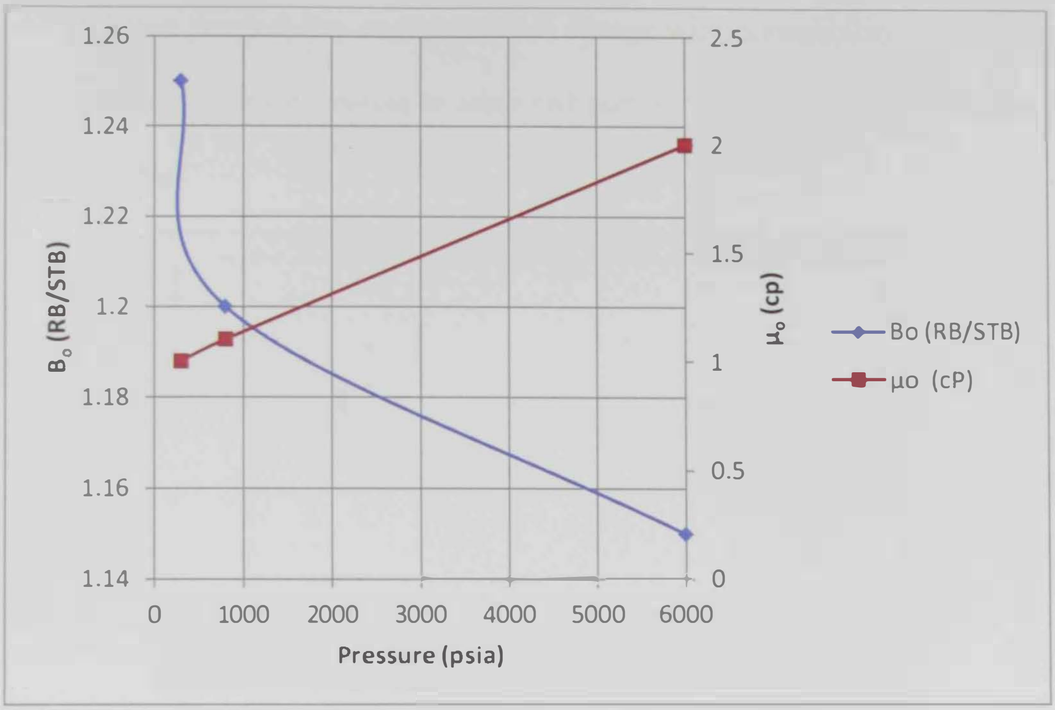

Figure 3.3: Oil PVT data

Other properties include:

- Rock compressibility at 4500 psi = 4E-06 psi^{-1}
- Oil density at surface conditions = 49 lbs/scf
- Water density at surface conditions = 63 lbs/scf

3.4 Assumptions

For the synthetic reservoir simulation model, the following assumptions were considered:

- Heterogeneous layered reservoirs.
- The injection pattern is presented in Figure 3.4.
- No flow boundary.

- Relative permeability curve does not change with permeability, porosity, and capillary pressure: leading to same end points (same residual oil saturation for all grids).

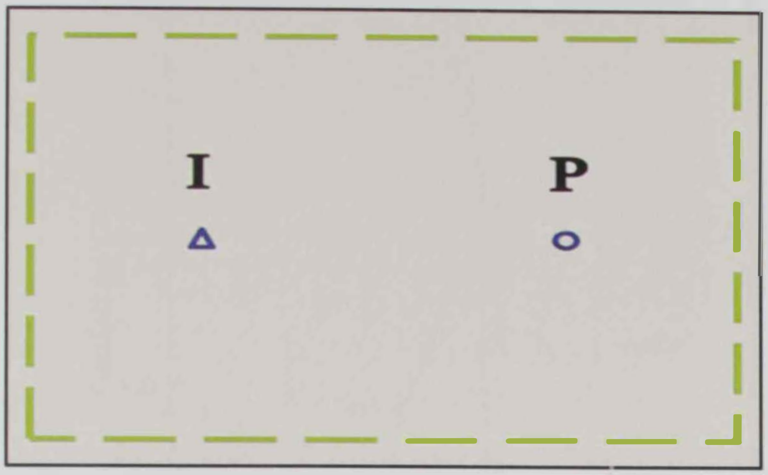

Figure 3.4: Model injection pattern

The last assumption was supported by some experiments. Schneider and Owens (1982) conducted an experiment to study the effect of polymer solution on relative permeability. They observed that the relative permeability to oil was not affected by the polymer flow. The relative permeability of polymer solution, however, was considerably lower than the corresponding relative permeability to water before polymer flow. A comparison between the relative permeability data for oil and water phases before (with subscript 1) and after (with subscript p) polymer contact is illustrated in Figure 3.5. The RRF in the figure represents F_{krr} and it is defined as residual permeability reduction factor.

$$F_{krr} = \max \{(F_{kr})^1, (F_{kr})^2, (F_{kr})^n\} \qquad (3.1)$$

Where 1, 2, …, n indicate time steps with the current time step being n and F_{kr} is the permeability reduction factor.

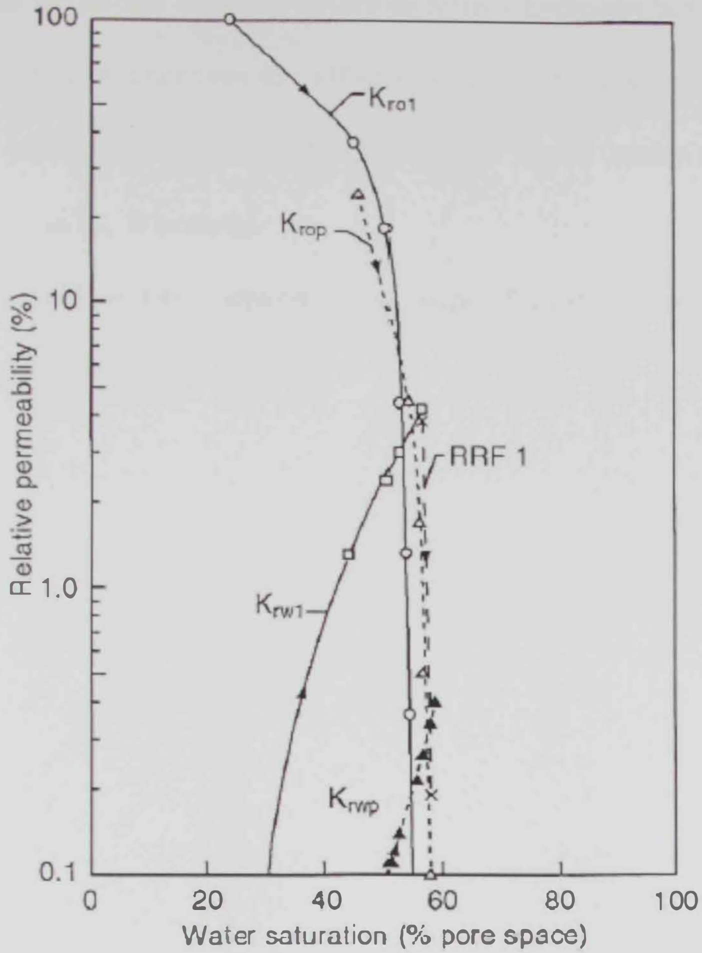

Figure 3.5: Water/oil relative permeabilities before and after polymer contact (Sheng , 2011)

The parallelism of k_{rw1} and k_{rwp} presented in Figure 3.3; however, indicates that permeability reduction by polymer adsorption is the main reason of water relative permeability after polymer contact (k_{rwp}).

According to the previous discussion, water relative permeability, k_{rw}, in polymer flooding is reduced, whereas oil relative permeability, k_{ro}, is little changed. The reasons behind that are summarized as:

- Polymer is soluble in water but not in oil. During the flowing of polymer solution through the pore throats, polymers with high molecular weight are retained at the throats, leading to a blockage of flowing water which results in reduction in k_{rw}.

- Polymer molecules have the ability to form a hydrogen bond with water molecules; this improves the affinity between the adsorption layer and water molecules. Rock surfaces become more water-wet; thus a reduction in k_{rw} is noticed.
- Polymer and oil have separate flow paths. Therefore, polymer reduces k_{rw} but not k_{ro} (Sheng , 2011).

Chapter 4 : Reservoir Development and Development Options

4.1 Reservoir Development Plan

A reservoir development plan presented in Figure 4.1 consists of two main components, pilot-field tests and development option identification. The dependent variables of the technical ultimate recovery are defined through the development option, where it mainly consists of:

- Development scheme.
- Development process.
- Reservoir management.
- Business plan.

This plan forms a basis for this thesis, where different development processes will be studied.

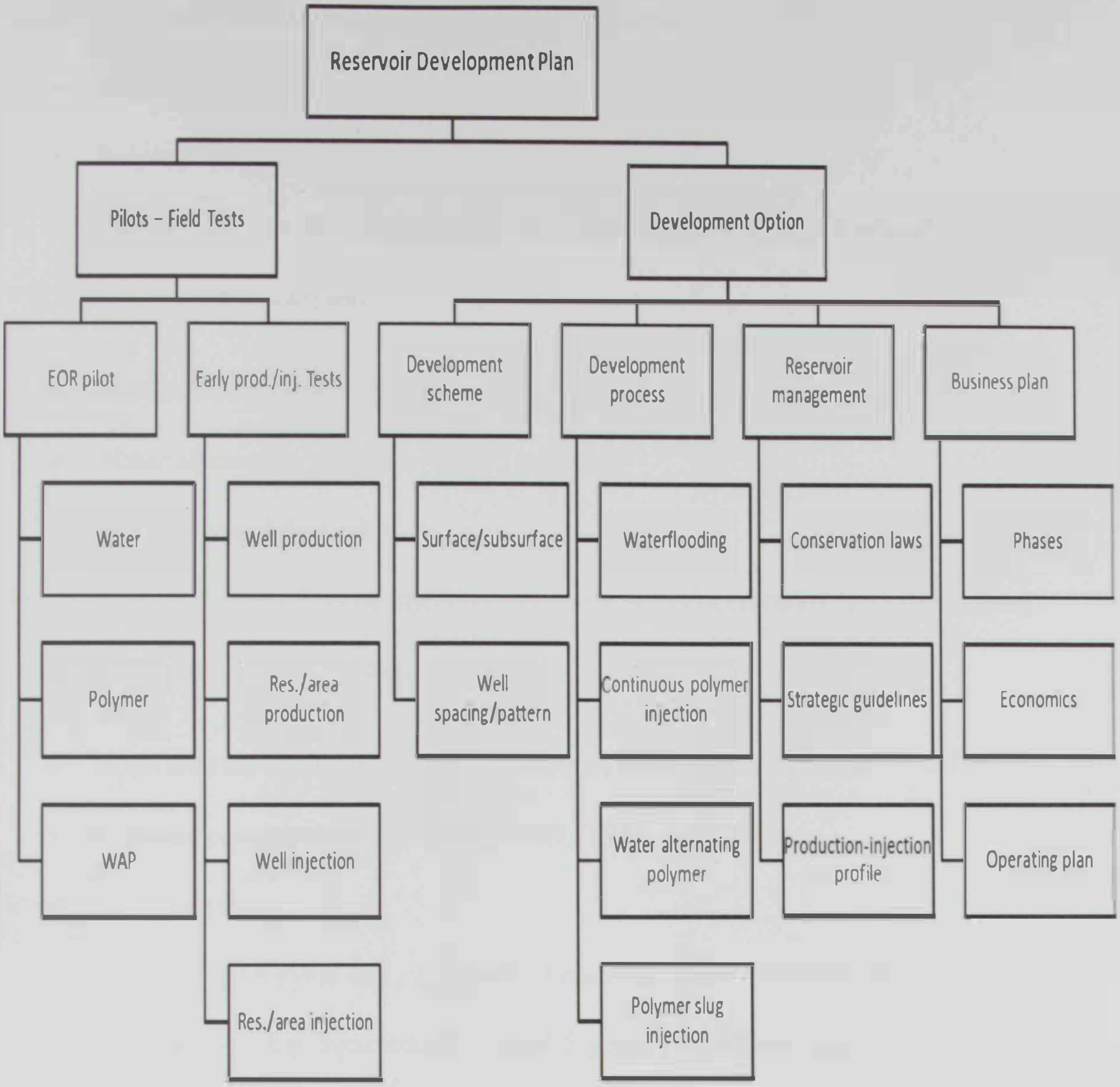

Figure 4.1: Full field development plan optimization (Abed, 2008)

4.2 Reservoir Development Option Identification

The assessment and selection of the development option that will maximize the oil recovery needs to be defined through viable development options and processes.

In defining the constraints, all dependent variables that will affect the results of the study will be considered (Abed, 2008).

In this study, two development processes were identified:

- Waterflooding
- Polymer flooding

For the polymer flooding process, the following development injection plans will be identified for analysis:

- Continuous polymer injection
- Water alternating polymer (WAP) injection
- Polymer slug injection

Through the study the effect of injection rate, polymer concentration, polymer timing and well completion were studied.

- Injection rate (200, 500, 1000, 1500, 2000, 2500, 3000, and 3500 STB/D)
- Polymer concentration (200, 500, 1000, 1500, and 2000 ppm)
- Polymer timing
    - WAP time cycle of 1, 3, 6, and 12 months, where the WAP ratio is 1:1.
    - Polymer slug injection: 2, 3, and 5 years of polymer injection after two years of waterflooding, and then the injection proceed with water.
- Well completion (COMP1, COMP2, COMP3, COMP4, and COMP5) where, each completion is defined in Table 4.1

Table 4.1: Well completion intervals

Well Completion	Injector	Producer
COMP1	All layers	All layers
COMP2	Layers 2 & 3	Layers 1 & 2
COMP3	Layers 1 & 3	Layers 1 & 3
COMP4	Layers 1 & 3	Layer 2
COMP5	Layer 2	Layer 2

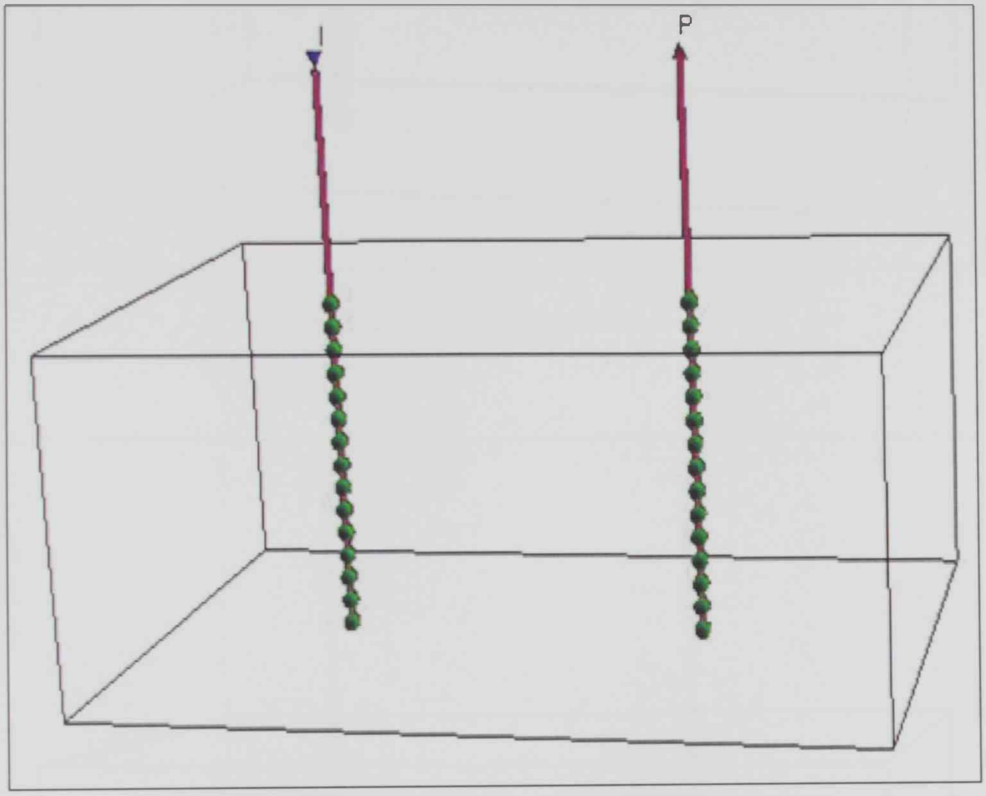

Figure 4.2: Well completion 1

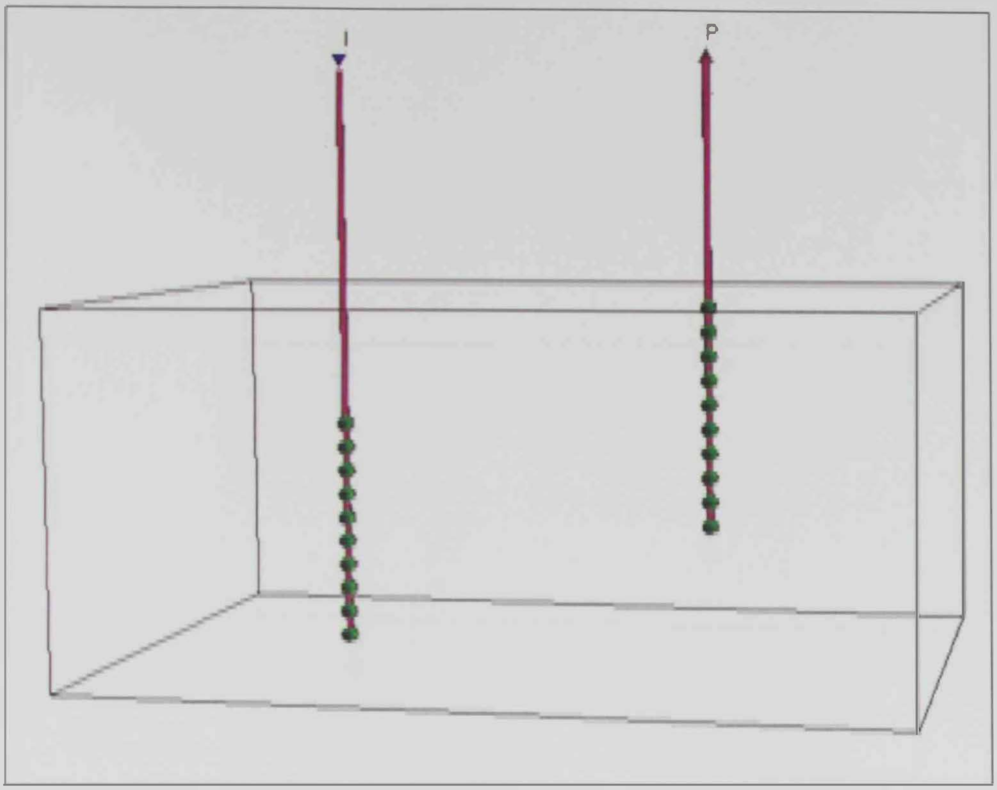

Figure 4.3: Well completion 2

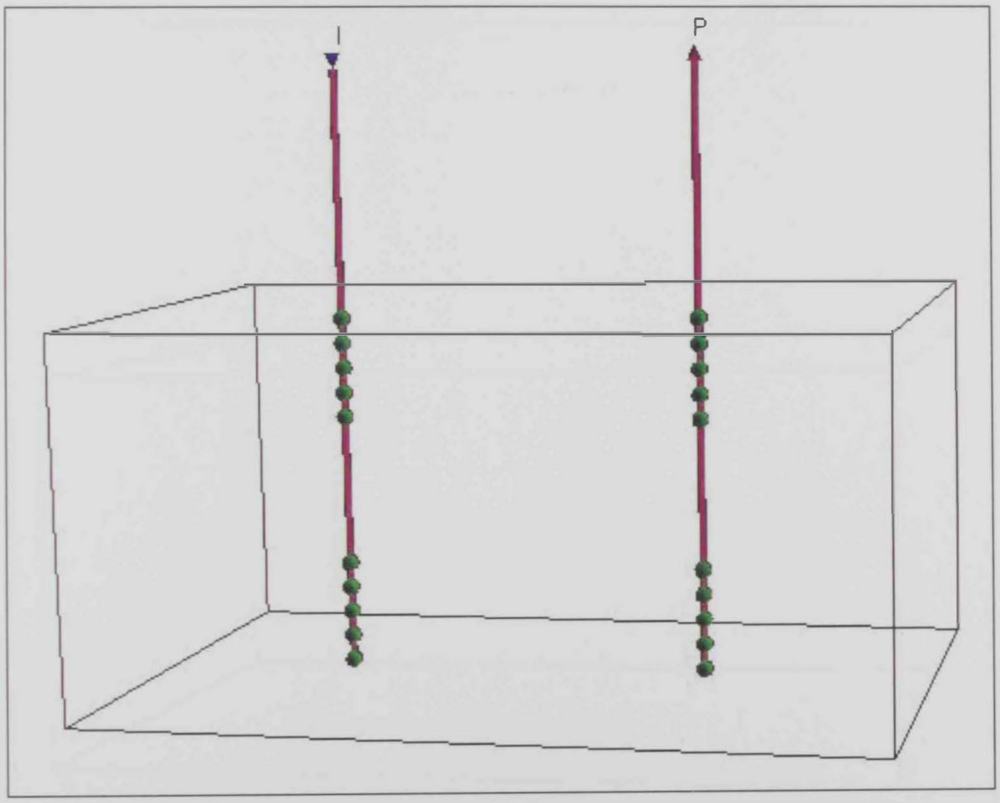

Figure 4.4: Well completion 3

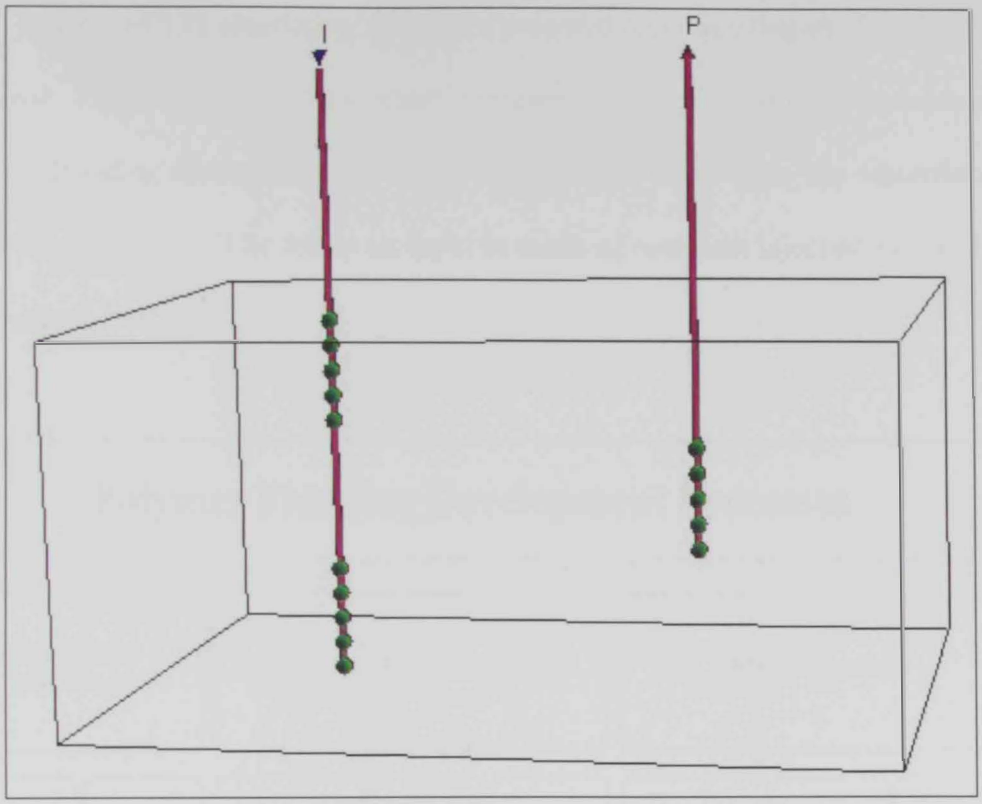

Figure 4.5: Well completion 4

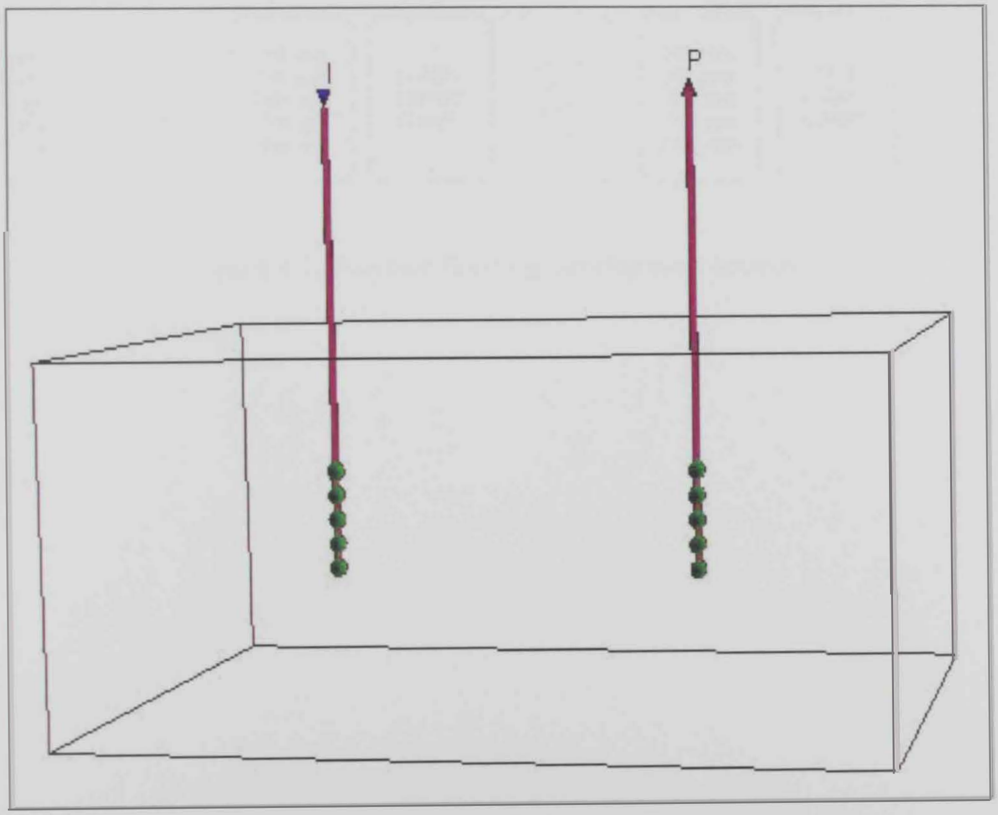

Figure 4.6: Well completion 5

A total of 133 simulation runs were prepared and run using the ECLIPSE 100 simulator. Figure 4.7 is a flow chart representing the development processes of polymer flooding throughout the study, where the output from the waterflooding sensitivity analysis will be fed as an input in terms of optimum injection rate and best completion practices.

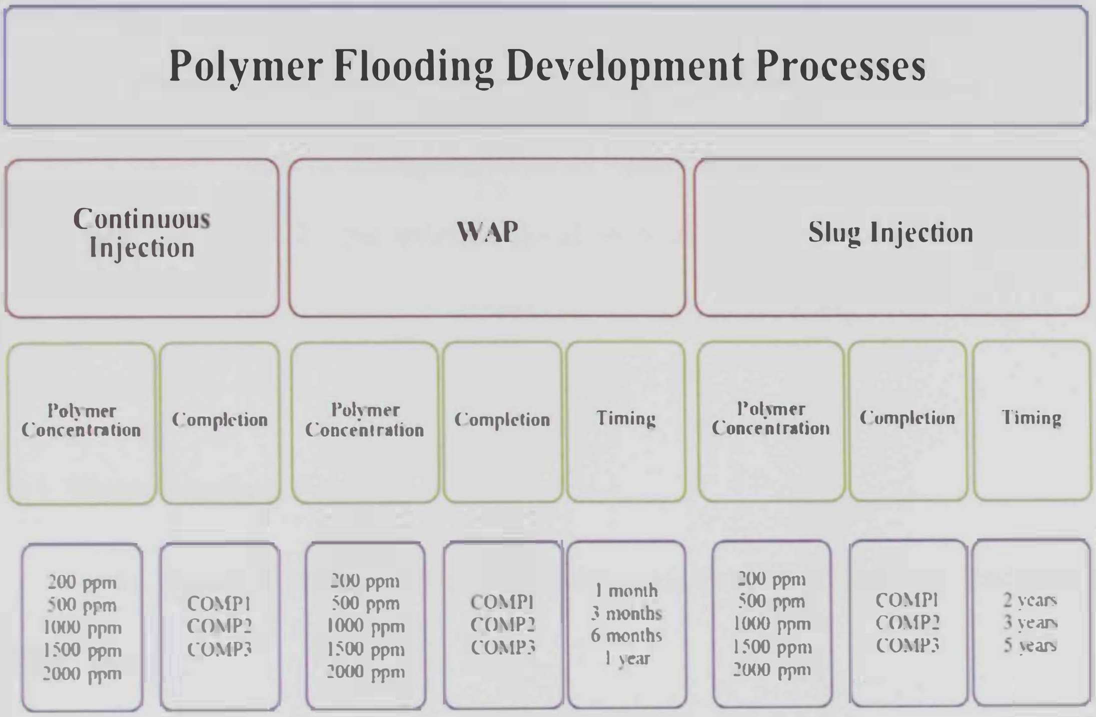

Figure 4.7: Polymer flooding development options

Chapter 5 : Development Process Assess Study

Two processes were defined in the study, waterflooding and polymer flooding. For the polymer flooding process, three development processes were investigated.

The main development processes are continuous polymer injection, WAP injection, and polymer slug injection.

Different sensitivities were handled for both processes as defined in chapter 4. In the case of waterflooding, the effect of injection rate and well completion were examined. However, for the polymer flood process, the sensitivities were carried on the effect of different polymer concentration, polymer timing, and different well completions.

5.1 Waterflooding Process

As stated previously, the prediction runs were simulated by studying the effect of:

- Injection rate (200, 500, 1000, 1500, 2000, 2500, 3000, 3500 STB/D)
- Well completion (COMP1, COMP2, COMP3, COMP4, COMP5)

5.1.1 Injection Rate Sensitivity Analysis

The base case completion (COMP1) was set for all runs to study the effect of various injection rates on the performance of the waterflood where 2000 STB/D is the base case injection rate.

The results of the five simulation runs where the variable is the injection rate are shown in Tables 5.1 to 5.8 and Figures 5.1 to 5.8.

The main results of each run throughout the study are summarized by the following terms as follows:

- FOE: Field Oil Efficiency (%)
- FOPR: Field Oil Production Rate (STB/D)
- FOPT: Field Oil Production Total (STB)
- FPR: Field Pressure (psia)
- FWCT: Field Water Cut (dimensionless)
- FWIR: Field Water Injection Rate (STB/D)
- FWPT: Field Water Production Total (STB)
- WCIR: Field Polymer Injection Rate (LB/D)
- WCPT: Field Polymer Production Total (LB)

Table 5.1: Waterflooding injection results (COMP1, 200 STB/D)

Development Process Results						
Development Process	FOPR (STB/D)	FOPT (STB)	FWPT (STB)	WCIR (LB/D)	WCPT (LB)	FOE (%)
H_2O	126.87	2.40E+6	0.34E+6	0.0	0.0	18.02

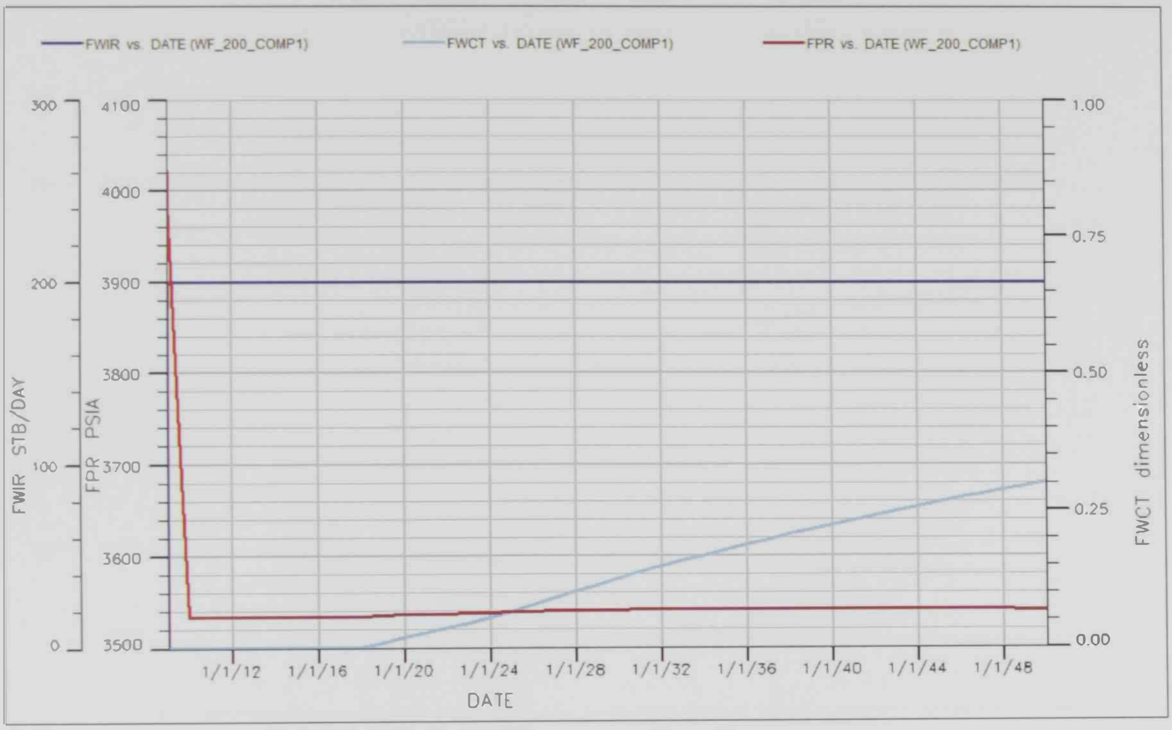

Figure 5.1: Waterflooding injection at 200 STB/D (COMP1) reservoir performance

Table 5.2: Waterflooding injection results (COMP1, 500 STB/D)

Development Process Results						
Development Process	**FOPR (STB/D)**	**FOPT (STB)**	**FWPT (STB)**	**WCIR (LB/D)**	**WCPT (LB)**	**FOE (%)**
H_2O	163.36	3.97E+6	3.03E+6	0.0	0.0	29.78

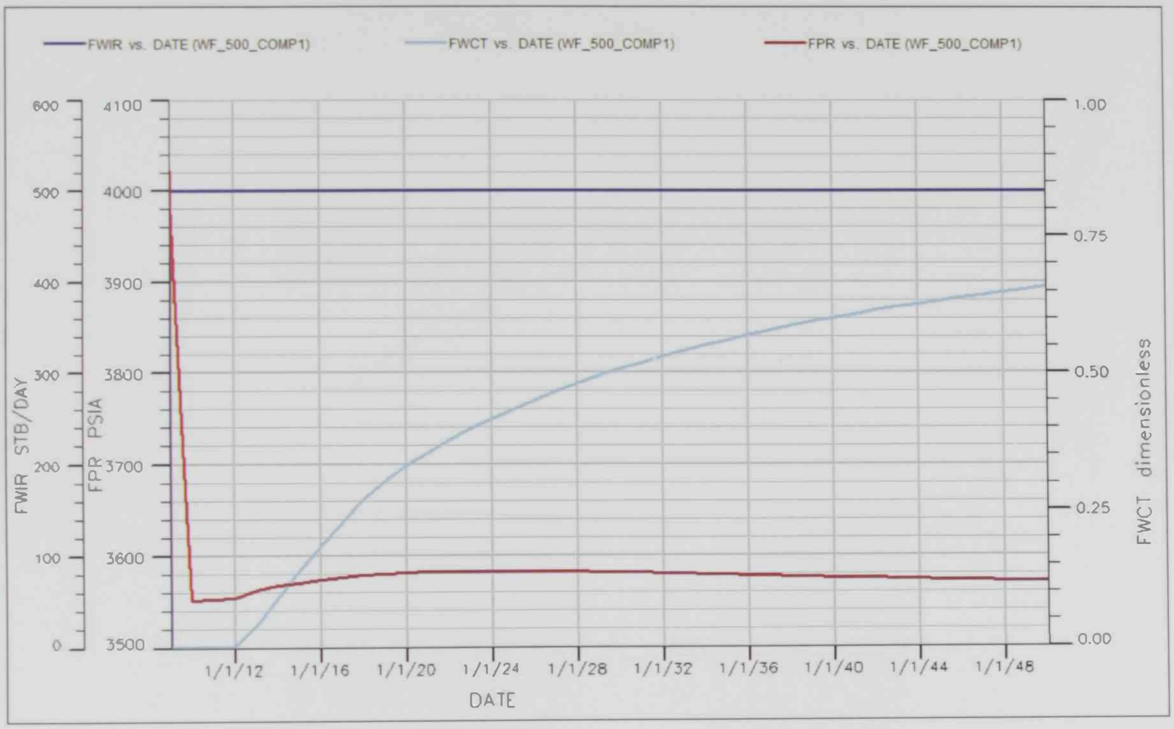

Figure 5.2: Waterflooding injection at 500 STB/D (COMP1) reservoir performance

Table 5.3: Waterflooding injection results (COMP1, 1000 STB/D)

Development Process Results						
Development Process	FOPR (STB/D)	FOPT (STB)	FWPT (STB)	WCIR (LB/D)	WCPT (LB)	FOE (%)
H_2O	173.05	5.40E+6	8.88E+6	0.0	0.0	40.43

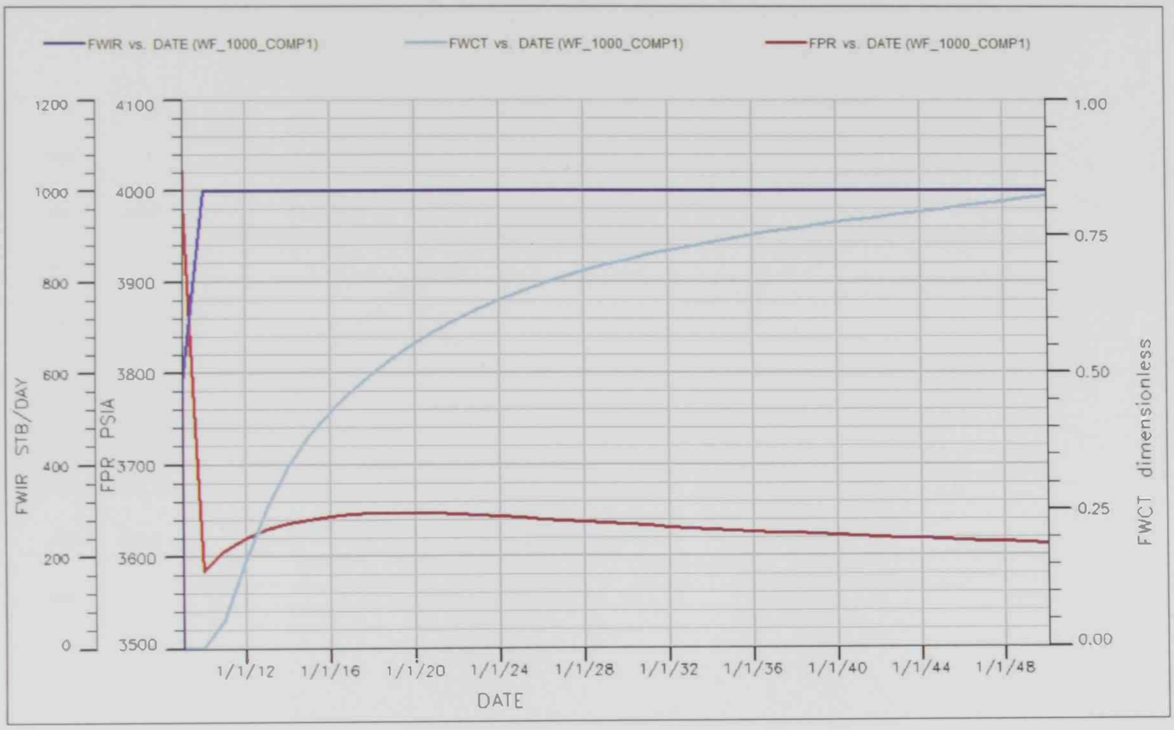

Figure 5.3: Waterflooding injection at 1000 STB/D (COMP1) reservoir performance

Table 5.4: Waterflooding injection results (COMP1, 1500 STB/D)

Development Process Results						
Development Process	**FOPR (STB/D)**	**FOPT (STB)**	**FWPT (STB)**	**WCIR (LB/D)**	**WCPT (LB)**	**FOE (%)**
H_2O	149.92	6.13E+6	15.5E+6	0.0	0.0	45.98

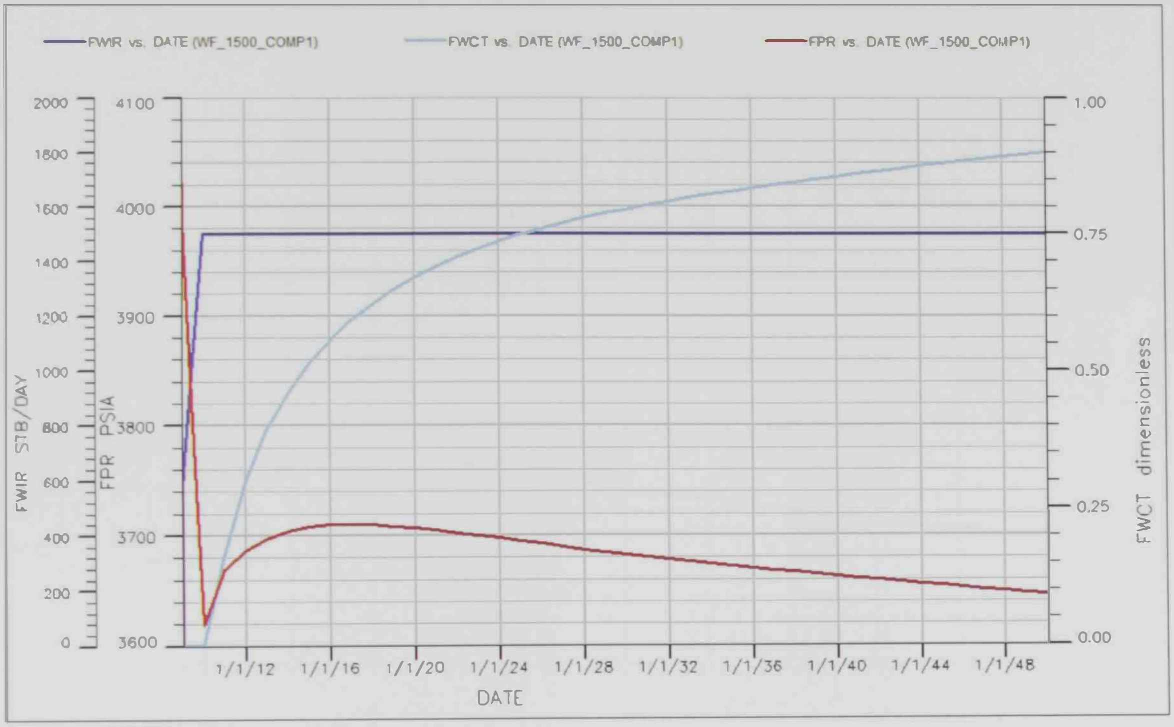

Figure 5.4: Waterflooding injection at 1500 STB/D (COMP1) reservoir performance

Table 5.5: Waterflooding injection results (COMP1, 2000 STB/D)

Development Process Results						
Development Process	**FOPR (STB/D)**	**FOPT (STB)**	**FWPT (STB)**	**WCIR (LB/D)**	**WCPT (LB)**	**FOE (%)**
H_2O	195.73	6.00E+6	15.83E+6	0.0	0.0	44.93

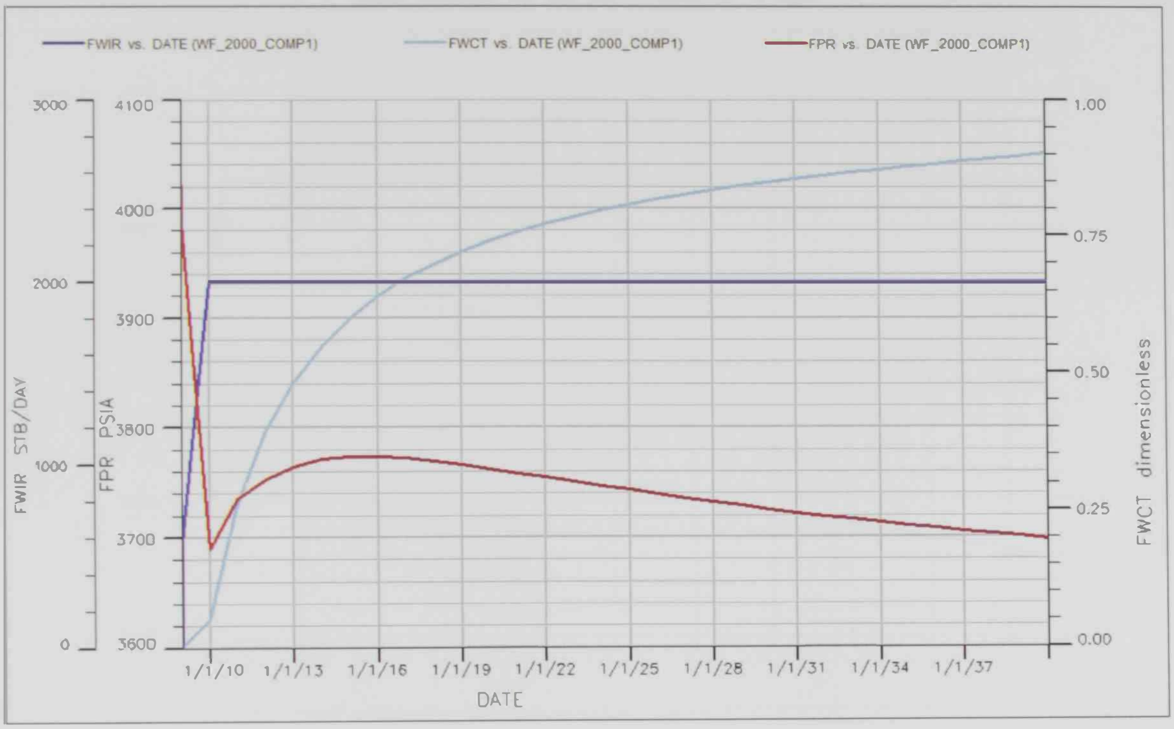

Figure 5.5: Waterflooding injection at 2000 STB/D (COMP1) reservoir performance

Table 5.6: Waterflooding injection results (COMP1, 2500 STB/D)

Development Process Results						
Development Process	**FOPR (STB/D)**	**FOPT (STB)**	**FWPT (STB)**	**WCIR (LB/D)**	**WCPT (LB)**	**FOE (%)**
H_2O	249.90	5.82E+6	15.29E+6	0.0	0.0	43.60

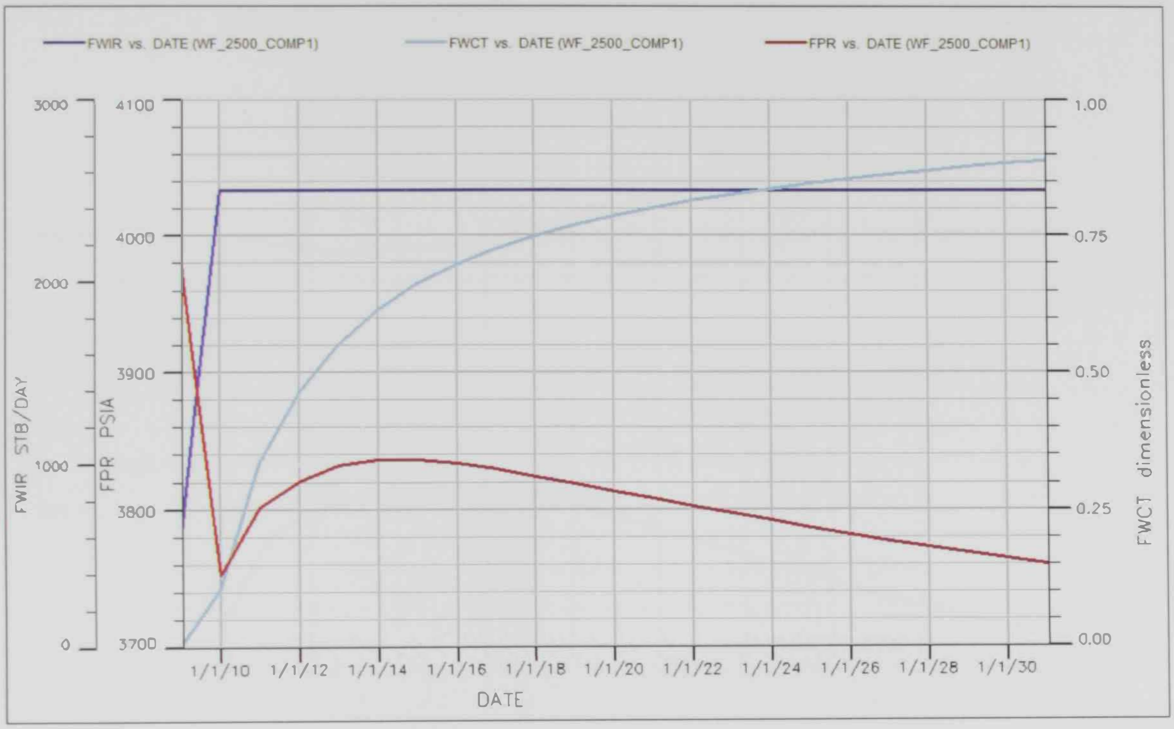

Figure 5.6: Waterflooding injection at 2500 STB/D (COMP1) reservoir performance

Table 5.7: Waterflooding injection results (COMP1, 3000 STB/D)

Development Process Results						
Development Process	FOPR (STB/D)	FOPT (STB)	FWPT (STB)	WCIR (LB/D)	WCPT (LB)	FOE (%)
H_2O	293.09	5.72E+6	15.18E+6	0.0	0.0	42.88

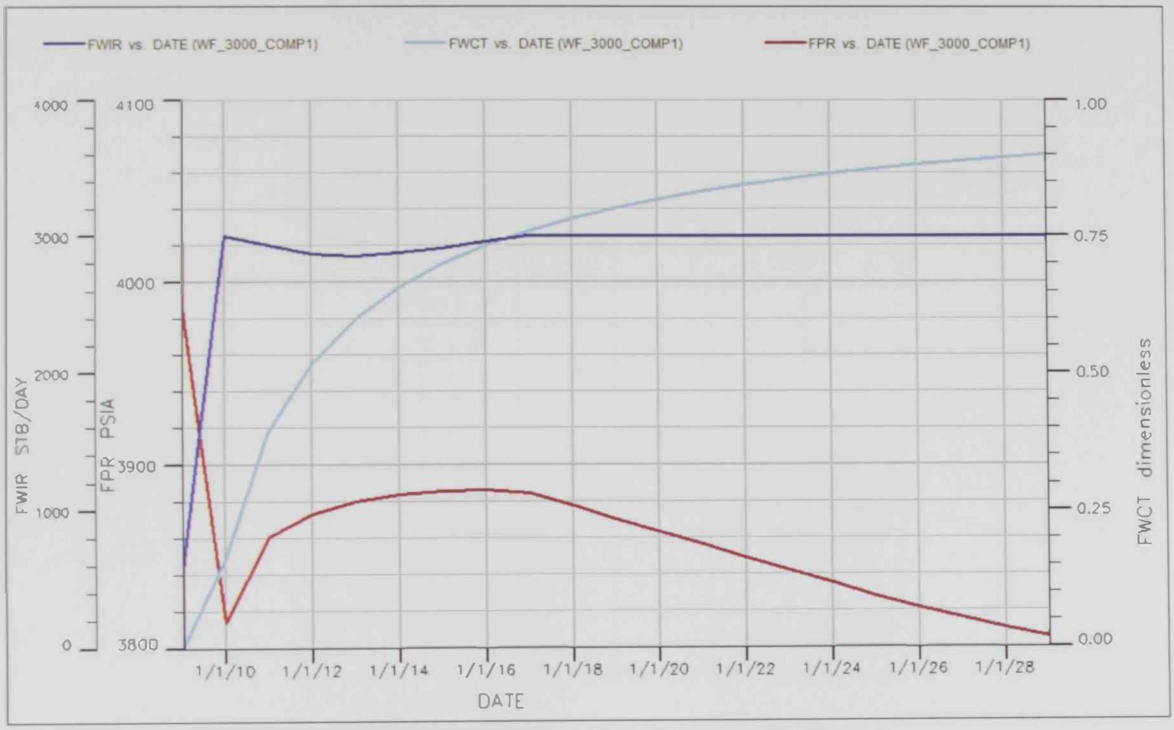

Figure 5.7: Waterflooding injection at 3000 STB/D (COMP1) reservoir performance

Table 5.8: Waterflooding injection results (COMP1, 3500 STB/D)

Development Process Results						
Development Process	**FOPR (STB/D)**	**FOPT (STB)**	**FWPT (STB)**	**WCIR (LB/D)**	**WCPT (LB)**	**FOE (%)**
H_2O	355.06	5.61E+6	14.39E+6	0.0	0.0	42.02

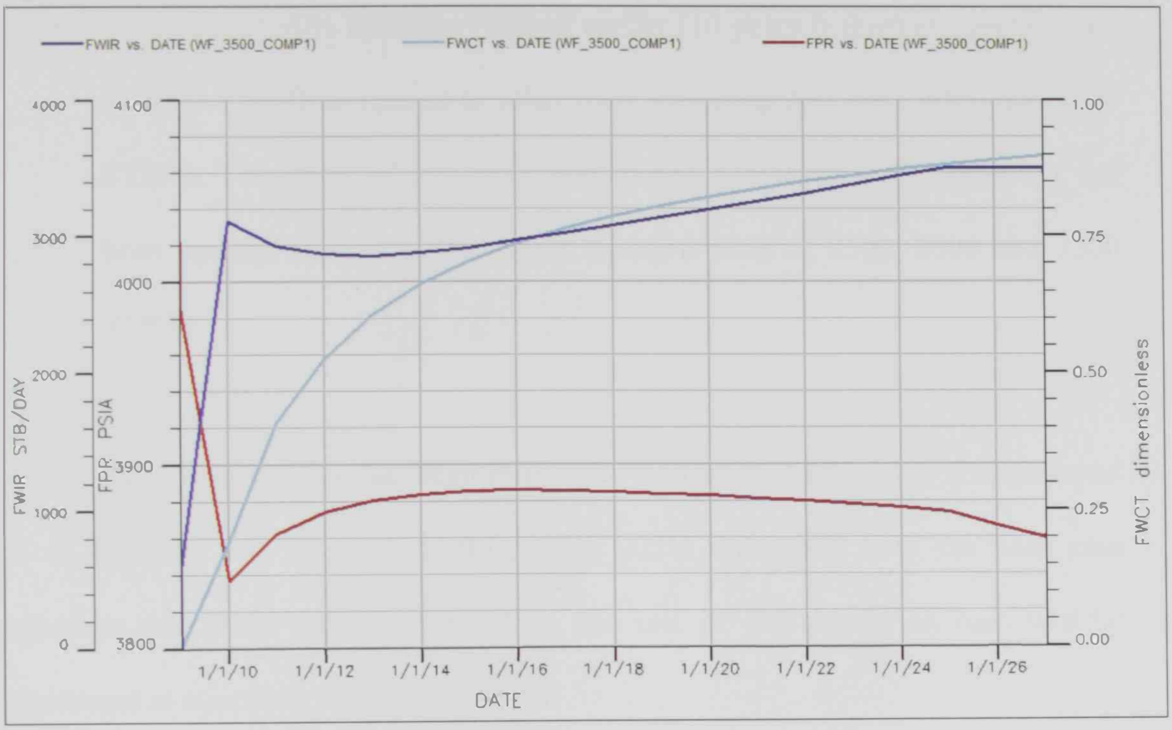

Figure 5.8: Waterflooding injection at 3500 STB/D (COMP1) reservoir performance

Based on the illustrated results, the following conclusions can be drawn:

- The attempted injection rate was kept constant through each run.
- A 30% water cut has been reached at 200 STB/D where the water started to breakthrough after 9 years of water injection.
- Water breakthrough was observed after 4 years at 500 STB/D, 2 years at 1000 and 1500 STB/D, and 1 year at 2000 STB/D and higher injection rates.
- An improvement in FOE of about 10% is noticed at 1000 STB/D compared to 200 and 500 STB/D.

- After the drawdown period which lasted for a year, the pressure started to build up since the effect of water has been felt.
- Injecting 1500 STB/D gave the highest recovery at maximum water cut of 90%.
- Water cut of 90% has been reached earlier (10 years before) at injection rate of 2000 STB/D compared to other rates including 200, 500, 1000 and 1500 STB/D. Therefore, oil producer was closed. However, 90% water cut has been reached further earlier using injection rates of 2500, 3000 and 3500 STB/D.

According to what has been found, the maximum oil recovery was achieved at an injection rate of 1500 STB/D, with 1.05% difference from the base case injection rate (2000 STB/D). Therefore, the rest of the simulation runs will be conducted at injection rate of 1500 STB/D.

Table 5.9 shows the oil recovery obtained at 90% water cut for different injection rates and the recovery profile at 90% water cut using different injection rate is illustrated in Figure 5.9. Furthermore, Figure 5.10 is a bar graph representing FOE at each injection rate attempted when COMP1 has been used.

Injection rate of 200 and 500 STB/D are considered to be too low and they delay the breakthrough with bad recovery compared to other injection rates. Fast breakthrough was observed at 2000 STB/D and at higher injection rates. Thus, 1500 STB/D was considered the most suitable operating injection rate for this study.

Table 5.9: Oil recovery at 90% water cut for different injection rates, waterflooding process

Injection rate (STB/D)	FOE (%)	Date
200	18.02	01 Jan 2050
500	29.78	01 Jan 2050
1000	40.43	01 Jan 2050
1500	45.98	01 Jan 2050
2000	44.93	01 Jan 2040
2500	43.60	01 Jan 2033
3000	42.88	01 Jan 2029
3500	42.02	01 Jan 2027

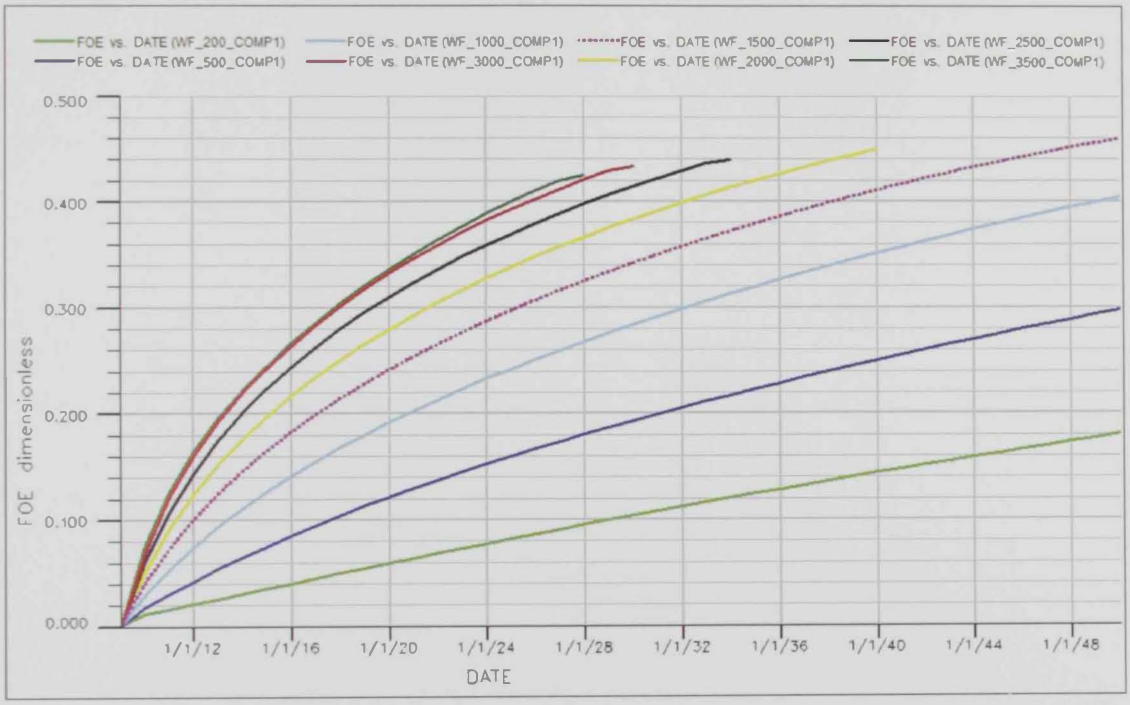

Figure 5.9: Oil recovery at 90% water cut for different injection rates, waterflooding process

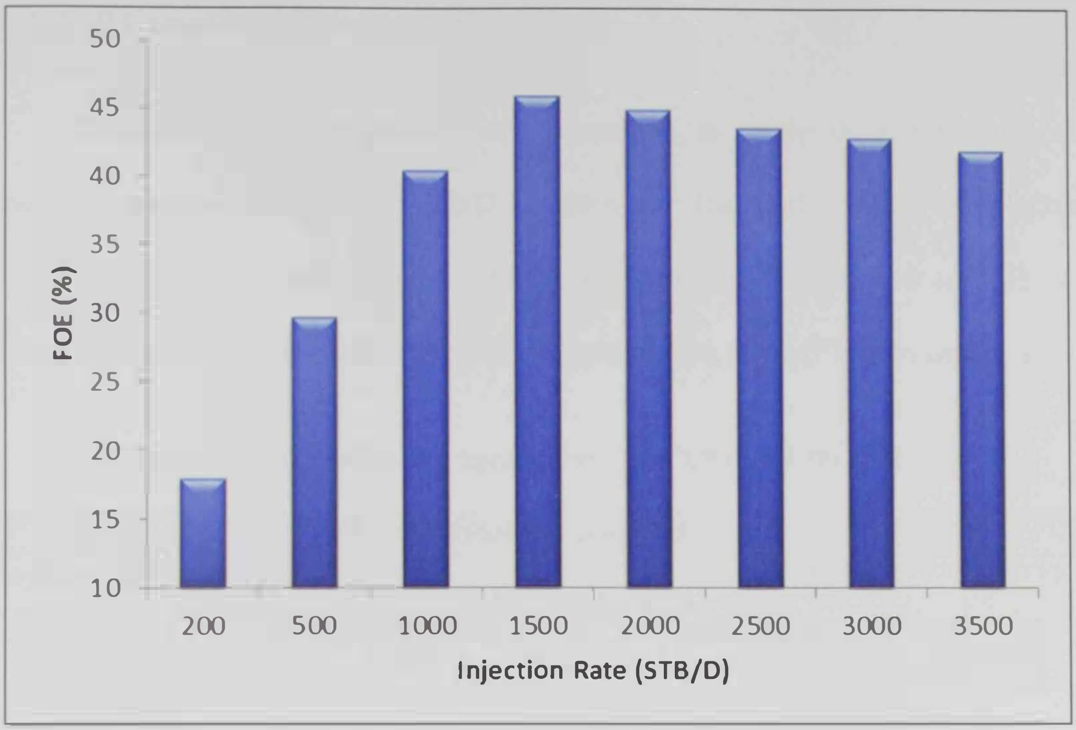

Figure 5.10: FOE vs. injection rate using COMP1, waterflooding process

5.1.2 Well Completion Sensitivity Analysis

Different well completions were attempted to study their effect on the waterflood performance at 1500 STB/D injection rate, the results of four completions (COMP2, COMP3, COMP4, and COMP5) are shown in Tables 5.10 to 5.13 and Figures 5.11 to 5.14 along with the base case completion (COMP1) for comparison.

Table 5.10: Waterflooding injection results (COMP2, 1500 STB/D)

Development Process Results						
Development Process	FOPR (STB/D)	FOPT (STB)	FWPT (STB)	WCIR (LB/D)	WCPT (LB)	FOE (%)
H_2O	150.22	6.20E+6	15.42E+6	0.0	0.0	46.47

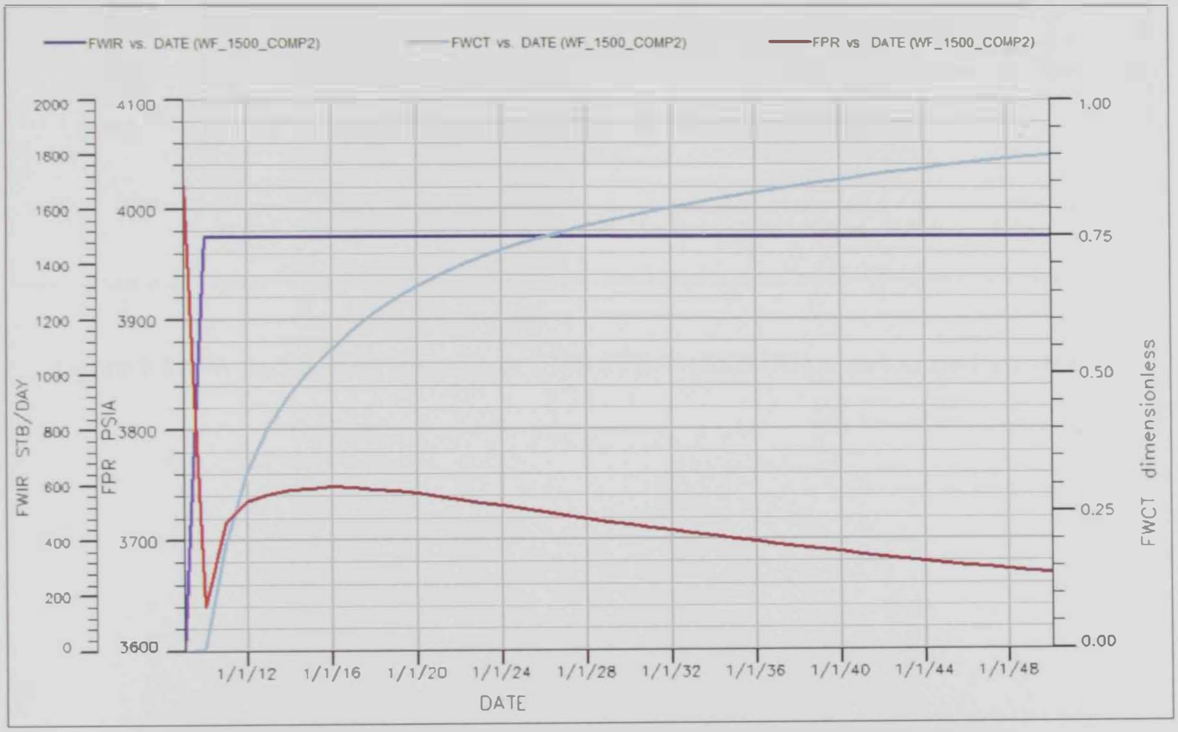

Figure 5.11: Waterflooding injection at 1500 STB/D (COMP2) reservoir performance

Table 5.11: Waterflooding injection results (COMP3, 1500 STB/D)

Development Process Results						
Development Process	**FOPR (STB/D)**	**FOPT (STB)**	**FWPT (STB)**	**WCIR (LB/D)**	**WCPT (LB)**	**FOE (%)**
H_2O	153.83	6.12E+6	14.46E+6	0.0	0.0	45.85

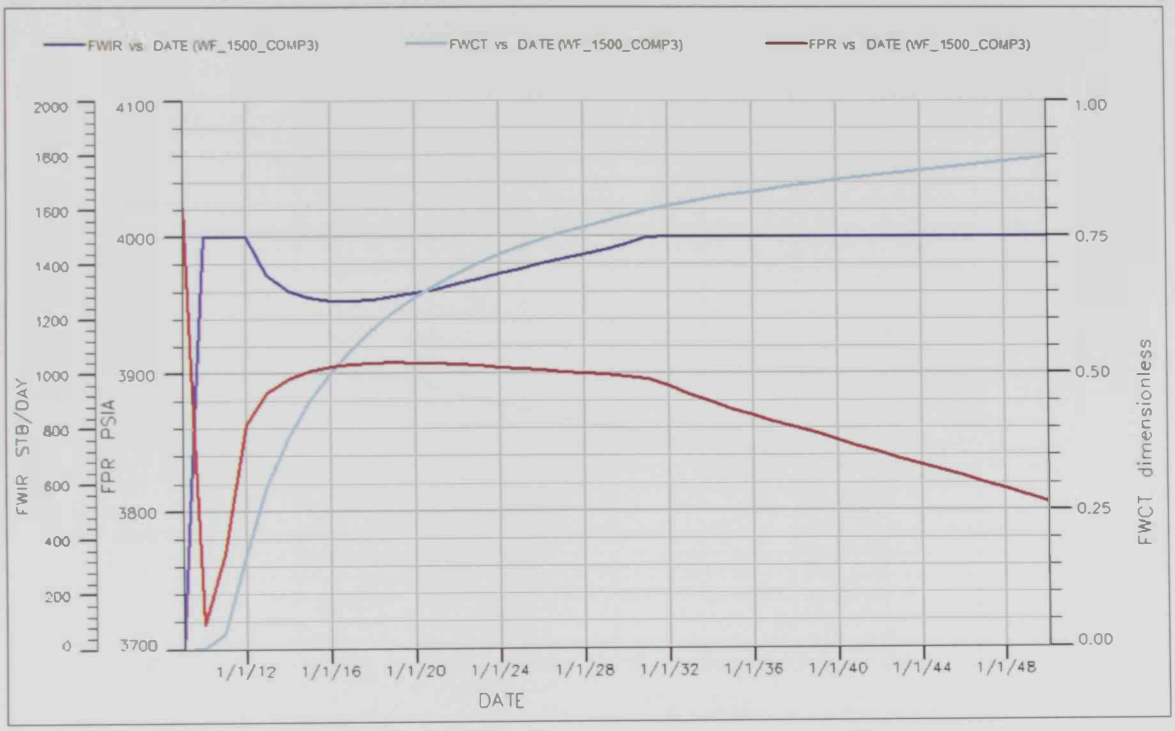

Figure 5.12: Waterflooding injection at 1500 STB/D (COMP3) reservoir performance

Table 5.12: Waterflooding injection results (COMP4, 1500 STB/D)

Development Process Results						
Development Process	FOPR (STB/D)	FOPT (STB)	FWPT (STB)	WCIR (LB/D)	WCPT (LB)	FOE (%)
H_2O	148.70	5.96E+6	14.58E+6	0.0	0.0	44.68

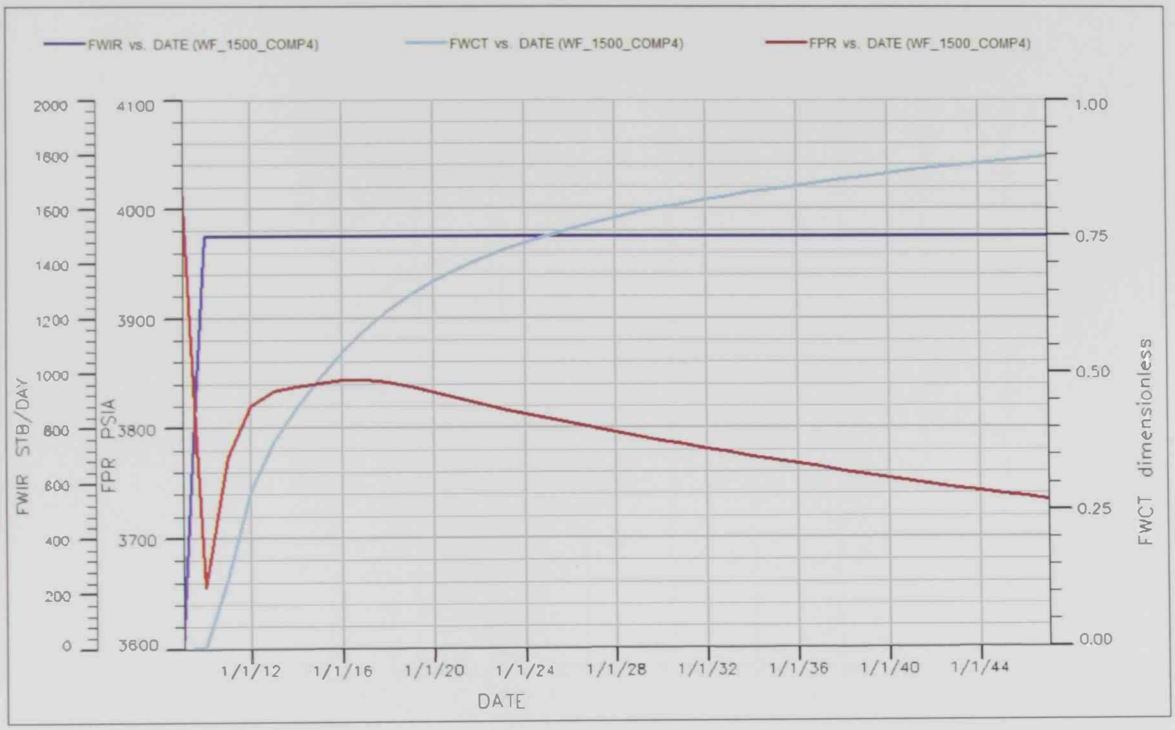

Figure 5.13: Waterflooding injection at 1500 STB/D (COMP4) reservoir performance

Table 5.13: Waterflooding injection results (COMP5. 1500 STB/D)

Development Process Results						
Development Process	FOPR (STB/D)	FOPT (STB)	FWPT (STB)	WCIR (LB/D)	WCPT (LB)	FOE (%)
H_2O	150.56	5.92E+6	15.74E+6	0.0	0.0	44.34

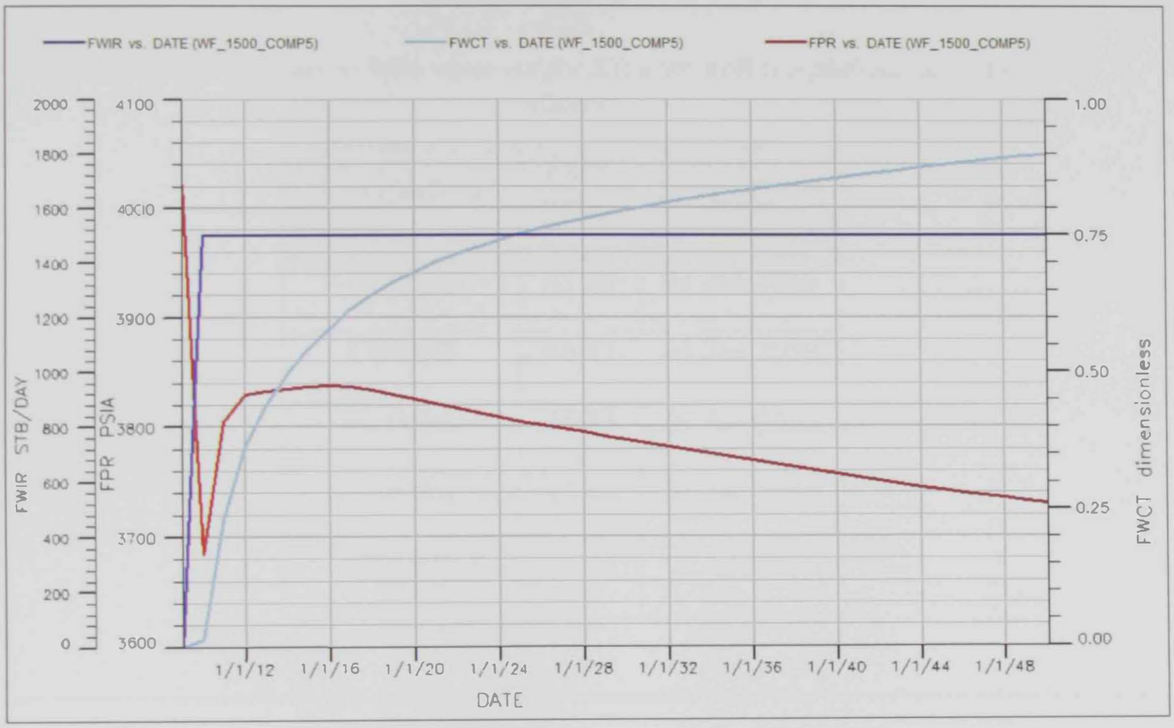

Figure 5.14: Waterflooding injection at 1500 STB/D (COMP5) reservoir performance

Table 5.14 shows the field oil efficiency obtained at 90% water cut for different well completions where the operating injection rate is 1500 STB/D. Figure 5.15 shows a comparison between the different options and Figure 5.16 presents the recovery profile.

Table 5.14: Oil recovery at 90% water cut for different well completions, waterflooding process

Completion	FOE (%)	Date
COMP1	45.98	01 Jan 2050
COMP2	46.47	01 Jan 2050
COMP3	45.85	01 Jan 2050
COMP4	44.68	01 Jan 2048
COMP5	44.34	01 Jan 2050

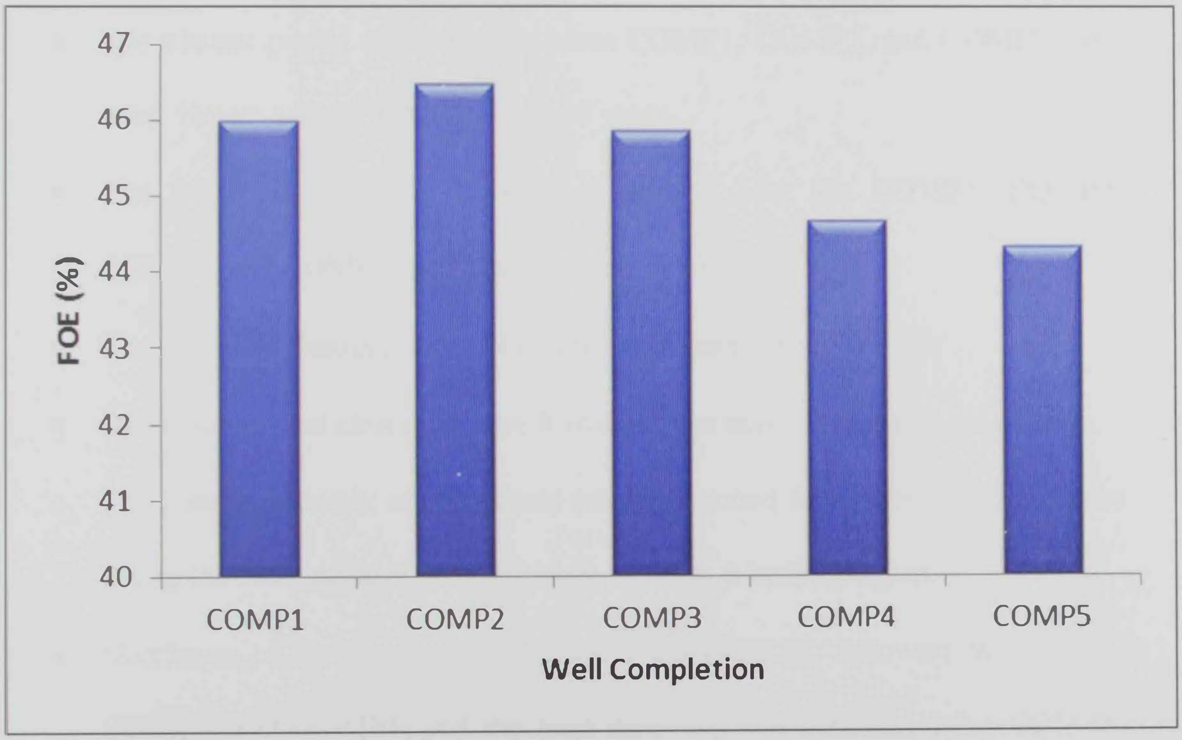

Figure 5.15: FOE vs. well completion using 1500 STB/D, waterflooding process

Figure 5.16: Oil recovery at 90% water cut for different well completions, waterflooding process

The main findings can be summarized as follows:

- The plateau period was 40 years when COMP1, COMP2, and COMP5 were used. Hence, using COMP4 it was 38 years.
- The water breakthrough took place after 1 year for COMP1, COMP2, COMP3, and COMP4; and after 2 years for COMP5.
- The reservoir pressure started to increase at water breakthrough.
- Oil producer was closed because it reached the maximum water cut of 90%.
- The plateau of water injection rate was maintained for a short period of time due to the increase in reservoir pressure. Then, it built up again.
- Maximum oil recovery was achieved using COMP2, followed by COMP1, COMP3, and COMP4, and the least recovery was obtained using COMP5. An increment of 2.13% in FOE using COMP2 is obtained over COMP5.

- It is preferable from the technical point not to perforate high permeable zone. In this case the oil in the lower permeability intervals will be bypassed.

Based on that, the first three completions will be used in the technical sensitivity analysis of different development options of polymer flooding.

5.2 Polymer Flooding Process

The prediction runs attempted at this stage were simulated by studying the effect of different parameters on the performance of the flood as follows, where three development processes were investigated:

- Continuous polymer injection
    - Polymer concentration (200, 500, 1000, 1500, and 2000 ppm)
    - Well completion (COMP1, COMP2, and COMP3)
- Water alternating polymer (WAP) injection
    - Polymer concentration (200, 500, 1000, 1500, and 2000 ppm)
    - Well completion (COMP1, COMP2, and COMP3)
    - WAP time cycle (1 month, 3 months, 6 months, and 1 year)
- Polymer slug injection
    - Polymer concentration (200, 500, 1000, 1500, and 2000 ppm)
    - Well completion (COMP1, COMP2, and COMP3)
    - Polymer timing injection (2, 3, and 5 years) after two years of water injection

Figure 5.17 is a schematic showing the different polymer flooding development options attempted throughout the study along with normal waterflooding process. In here the WAP process is drawn for five years for illustration and the pattern is repeated.

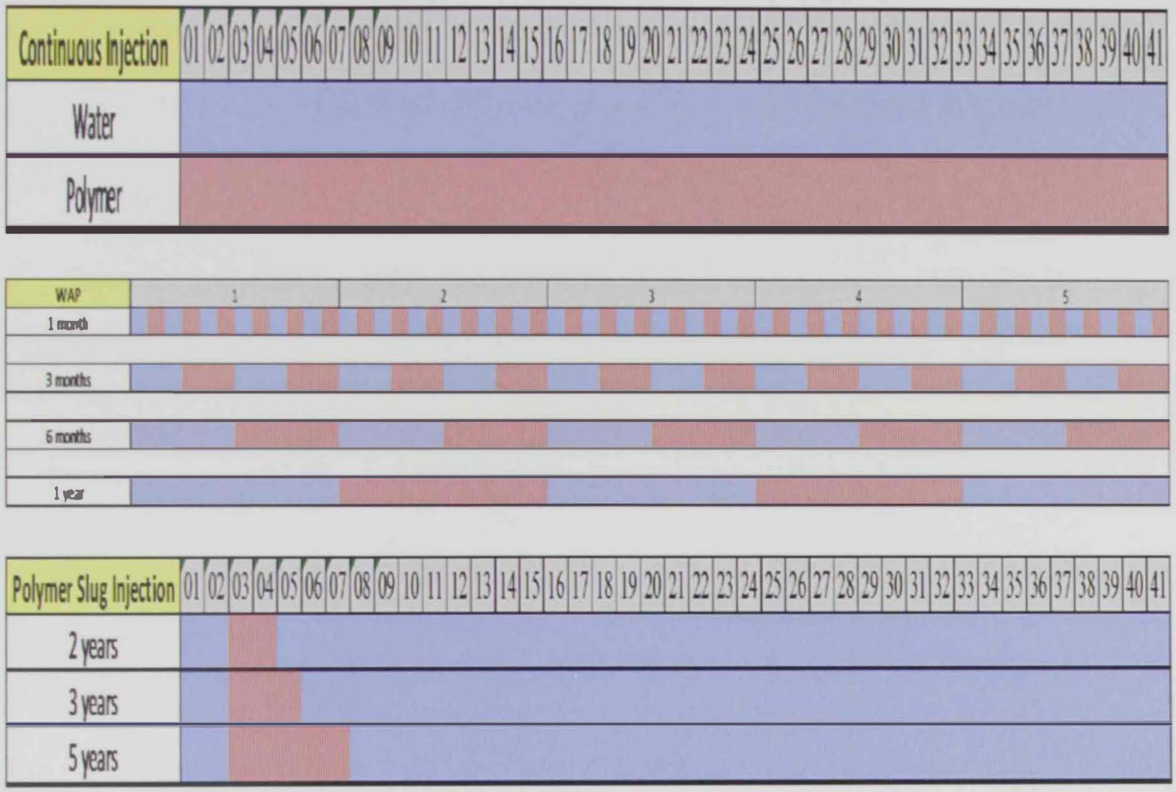

Figure 5.17: Schematics of polymer flooding development processes

5.2.1 Continuous Polymer Injection

A total of fifteen runs were simulated using ECLIPSE 100 and the effect of different polymer concentrations and completions were studied. The results of three runs all at 200 ppm polymer concentration and at different well completions are presented in Tables 5.15 to 5.17 and Figures 5.18 to 5.20. Similar results and trends were obtained for other polymer concentration including 500, 1000, 1500, and 2000 ppm. A comparison between all different scenarios will be presented in terms of oil recovery.

Table 5.15: Continuous polymer injection results (200 ppm, COMP1, 1500 STB/D)

Development Process Results						
Development Process	FOPR (STB/D)	FOPT (STB)	FWPT (STB)	WCIR (LB/D)	WCPT (LB)	FOE (%)
Polymer	187.69	6.86E+6	2.67E+6	106.67E+3	3.47E+8	51.42

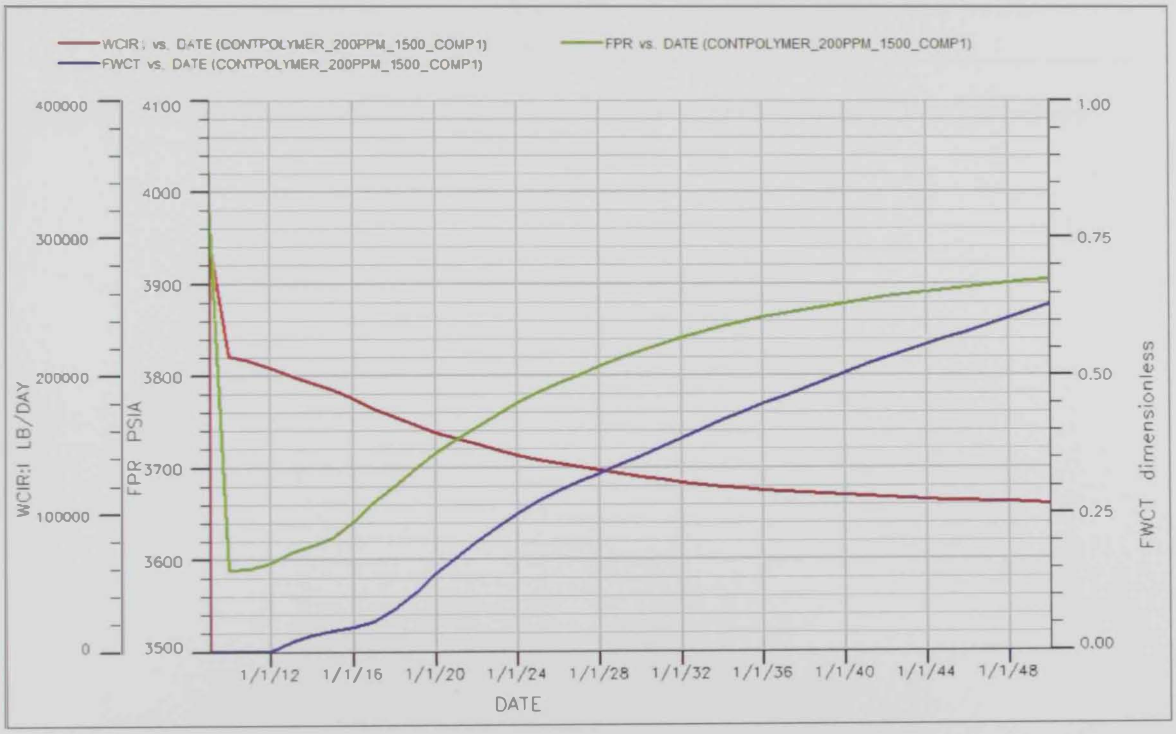

Figure 5.18: Continuous polymer injection at 1500 STB/D (200 ppm, COMP1) reservoir performance

Table 5.16: Continuous polymer injection results (200 ppm, COMP2, 1500 STB/D)

Development Option Results						
Development Option	**FOPR (STB/D)**	**FOPT (STB)**	**FWPT (STB)**	**WCIR (LB/D)**	**WCPT (LB)**	**FOE (%)**
Polymer	206.25	6.45E+6	1.79E+6	92.76E+3	2.52E+8	48.35

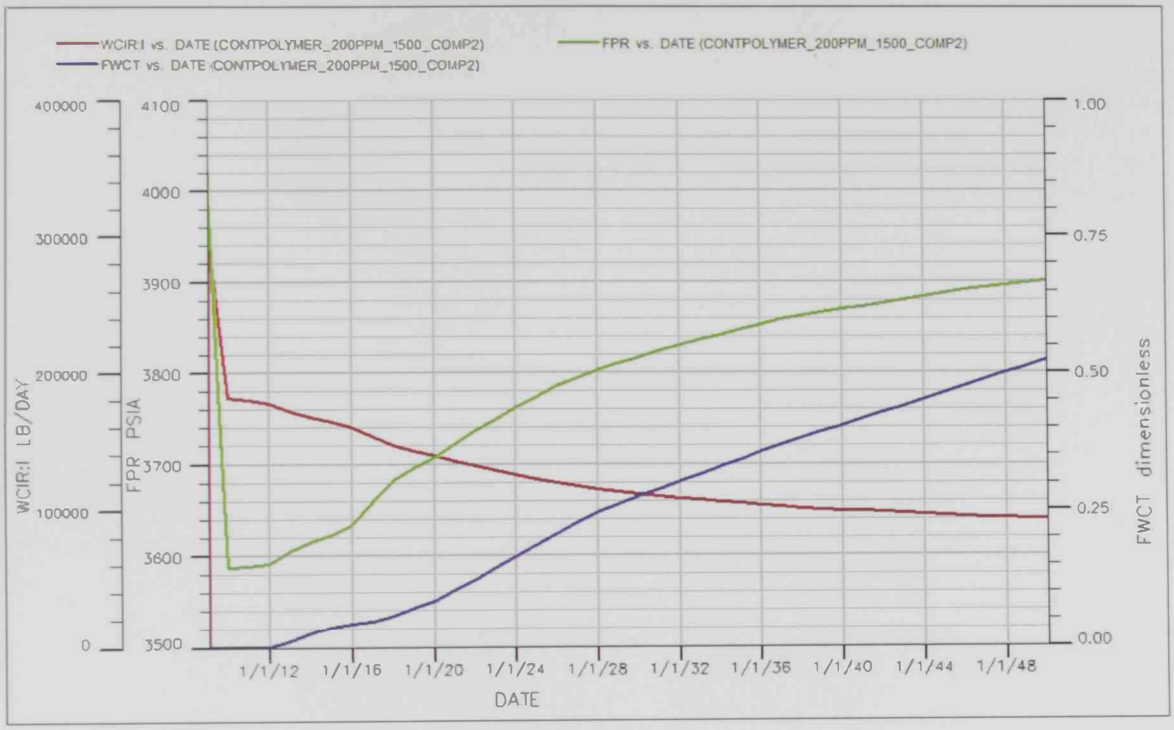

Figure 5.19: Continuous polymer injection at 1500 STB/D (200 ppm, COMP2) reservoir performance

Table 5.17: Continuous polymer injection results (200 ppm, COMP3, 1500 STB/D)

Development Process Results						
Development Process	FOPR (STB/D)	FOPT (STB)	FWPT (STB)	WCIR (LB/D)	WCPT (LB)	FOE (%)
Polymer	195.44	4.95E+6	600.62E+3	64.07E+3	2.95E+7	37.13

Figure 5.20: Continuous polymer injection at 1500 STB/D (200 ppm, COMP3) reservoir performance

From the illustrated results at 200 ppm where the three completion options were attempted, the following findings can be drawn:

- Delay in breakthrough for three years was noticed when COMP1 is used at 200 ppm, and for five years for other concentrations.
- The same delay in breakthrough is obtained at 200 ppm when COMP 2 is used, while it took six years for the rest of concentrations.
- Completing the well as defined by COMP3; delayed the breakthrough for 10 years at 200 ppm, for 14 years at 500 ppm, and for 16 years at higher concentrations.
- The highest total oil produced was accomplished using COMP1.
- The build-up of the pressure was the same using COMP1 and COMP2 for all concentrations. Thus, a slower rate of build-up was noticed using COMP3.

Table 5.18 shows the oil recovery obtained for different polymer concentrations corresponding to the three completions.

Table 5.18: Oil recovery for continuous polymer injection scenarios at 2050

Completion	Polymer Concentration (ppm)	FOE (%)
COMP1	0	45.98
	200	51.43
	500	50.76
	1000	50.48
	1500	50.43
	2000	50.42
COMP2	0	45.98
	200	48.35
	500	47.31
	1000	47.02
	1500	46.97
	2000	46.97
COMP3	0	45.98
	200	37.13
	500	37.06
	1000	37.05
	1500	37.04
	2000	37.03

A 5.45% increase in oil recovery is obtained over waterflooding once polymer injection is applied at minimum concentration of 200 ppm using COMP1. On the other hand, completing the well using COMP3 reduces the oil recovery by

8.85 % respectively over waterflooding at minimum polymer concentration used. This can be justified due to perforating both the injector and producer in the two geological layers of low permeability, where the continuous injection of polymer solution in this case leads to pores blockage even at low concentrations of polymer. As a result, COMP3 will not be utilized as an option to improve oil recovery and completing the well at all layers for injection and production gave the highest recovery for all polymer concentrations attempted.

Furthermore, reducing the polymer concentration from 2000 ppm to 200 ppm improved the recovery by 1% using COMP1 and by 1.38% using COMP2. It is necessary in this case to choose and select the appropriate polymer concentration to be injected in order to minimize extra costs, since the effect of increasing polymer concentration beyond a certain value will not be sound.

Based on theory, fingering can be avoided by continuous injection of polymer solution instead of water. This will improve the mobility of the injectant; thus, increases the oil recovery efficiency. But since the polymers are more expensive than water, this will limit the volume of injected polymer solution (Wang et al., 2007). In most cases, continuous injection of polymer is not economical.

Figures 5.21, 5.22, and 5.23 present the recovery profiles for the fifteen runs of continuous polymer injection along with the three runs of waterflooding. Polymer injection could be resumed after 2050 since water cut economic limit of 90% has not been reached while for water injection it has been. At 2050, an average water cut is reached of about 65%, 55%, and 35% using COMP1, COMP2, and COMP3 respectively.

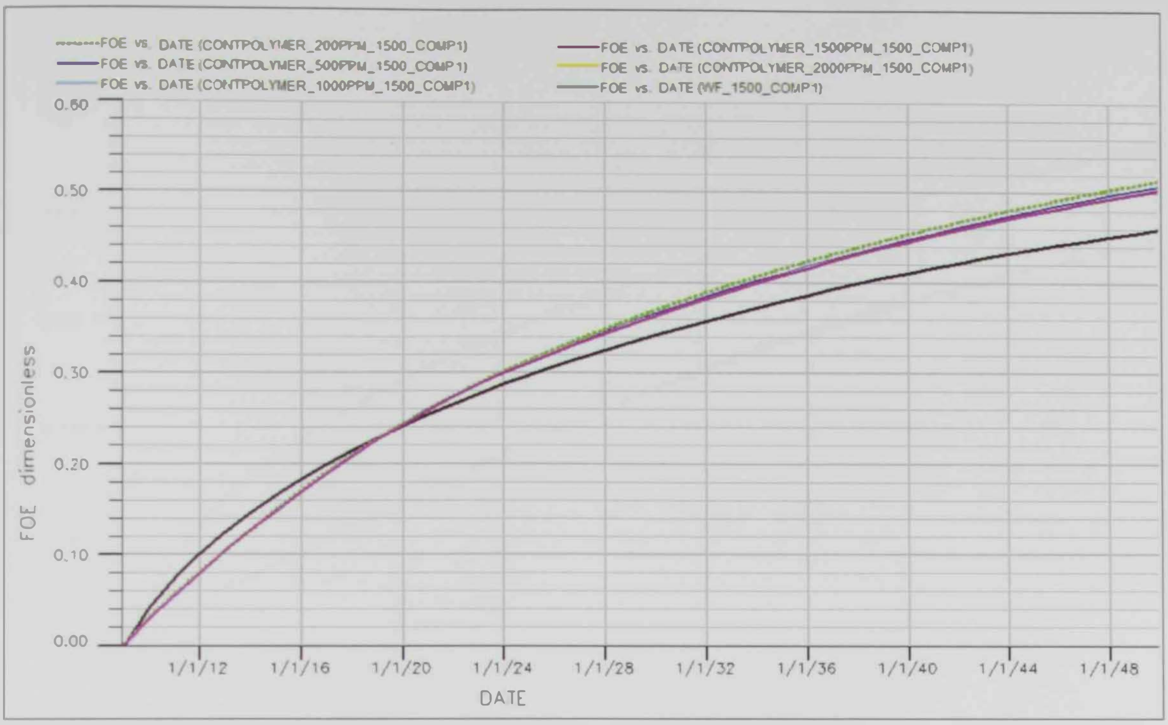

Figure 5.21: Oil recovery by continuous polymer injection using COMP1

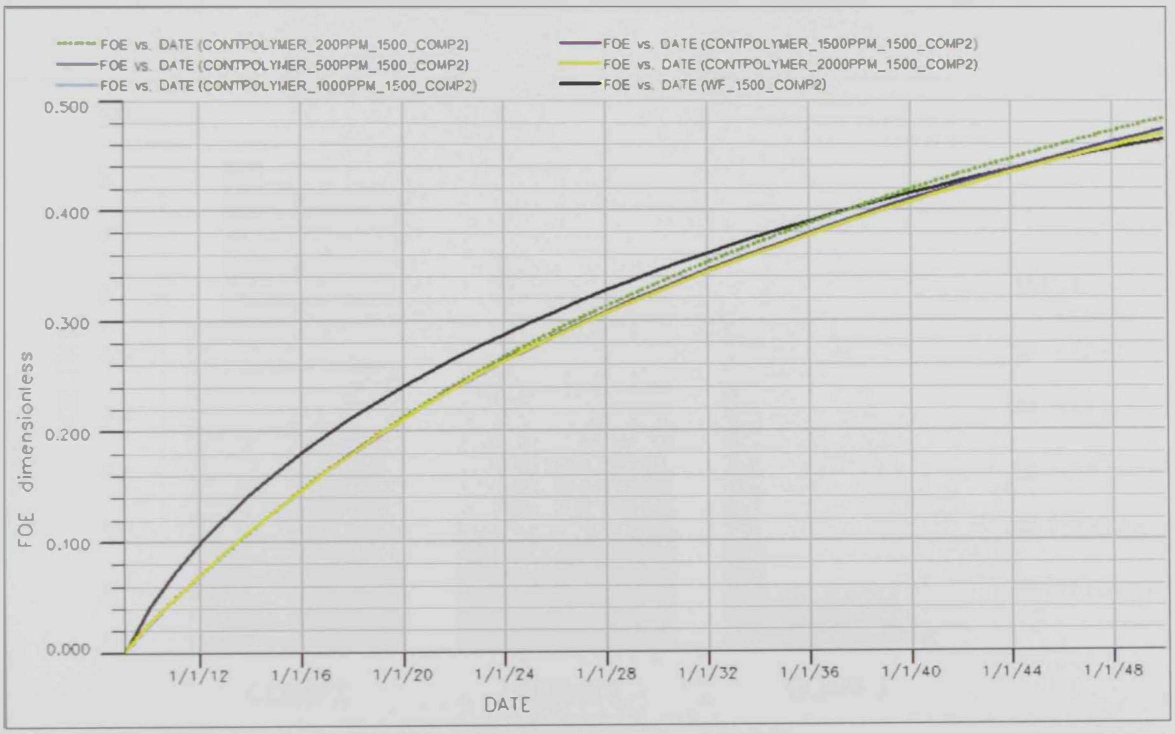

Figure 5.22: Oil recovery by continuous polymer injection using COMP2

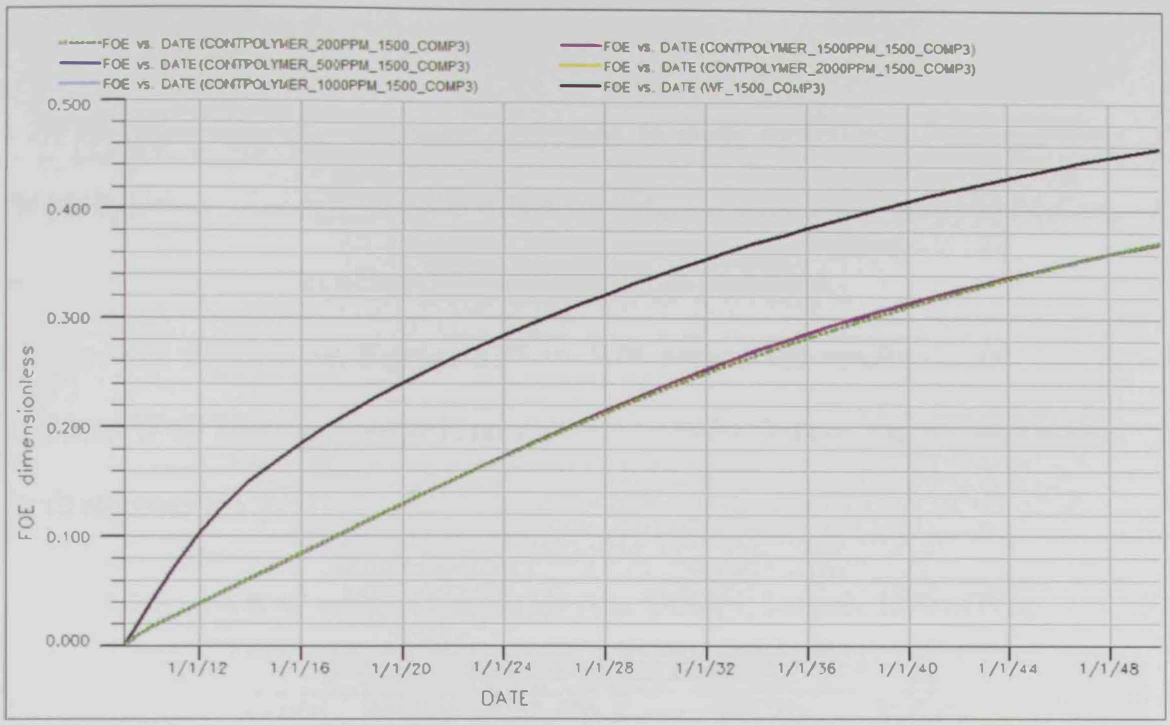

Figure 5.23: Oil recovery by continuous polymer injection using COMP3

A comparison between the different options stated earlier is shown in Figure 5.24.

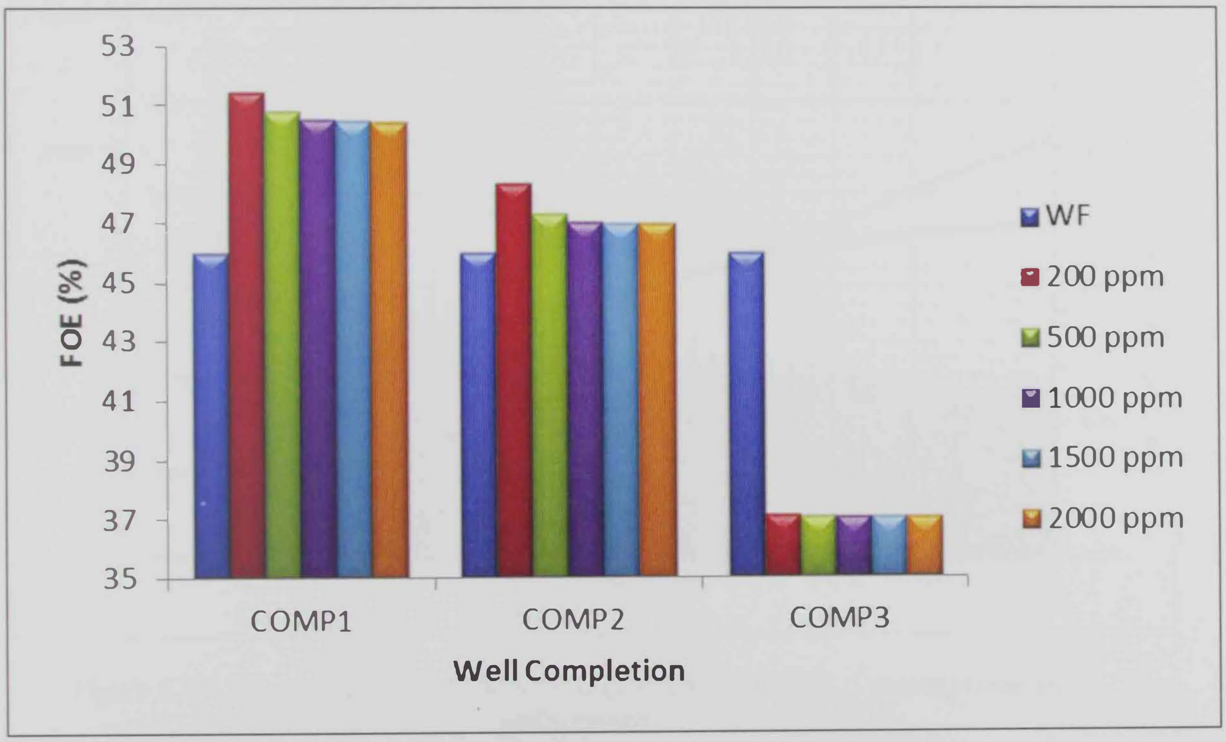

Figure 5.24: FOE vs. well completion at different polymer concentrations (continuous polymer injection)

5.2.2 Water Alternating Polymer (WAP) Injection

Sixty simulation runs were performed to study the effect of implementing WAP injection. Through this, the effect of different parameters listed before was investigated. The results of best combination will be presented.

Tables 5.19 to 5.22 and Figures 5.25 to 5.28 present the results of 200 ppm at different WAP injection pore volume applying COMP1. Where, the WAP ratio used in all attempts is 1:1.

Table 5.19: WAP injection results (200 ppm, COMP1, 1 month, 1500 STB/D)

Development Process Results						
Development Process	**FOPR (STB/D)**	**FOPT (STB)**	**FWPT (STB)**	**WCIR (LB/D)**	**WCPT (LB)**	**FOE (%)**
WAP	143.25	7.00E+6	4.48E+6	177.7E+3	1.36E+8	52.50

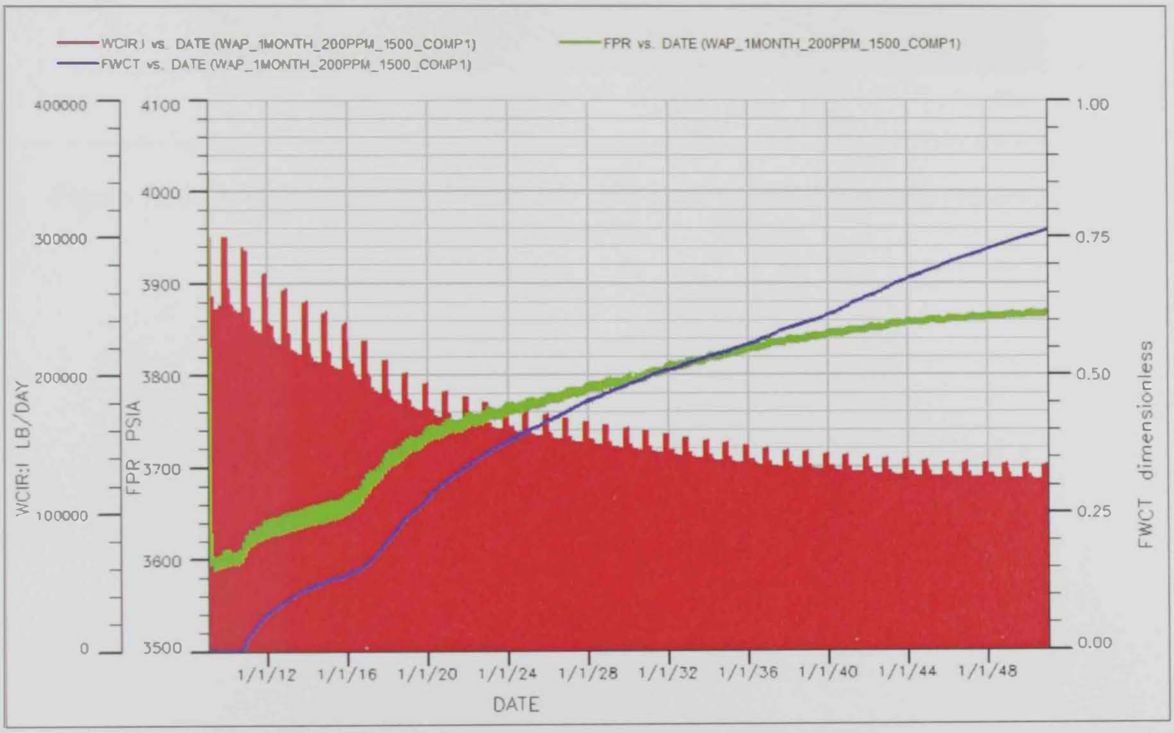

Figure 5.25: WAP injection at 1500 STB/D (200 ppm, COMP1, 1 month) reservoir performance

Table 5.20: WAP injection results (200 ppm, COMP1, 3 months, 1500 STB/D)

Development Process Results						
Development Process	**FOPR (STB/D)**	**FOPT (STB)**	**FWPT (STB)**	**WCIR (LB/D)**	**WCPT (LB)**	**FOE (%)**
WAP	120.23	7.22E+6	5.86E+6	117.45E+3	1.48E+8	54.08

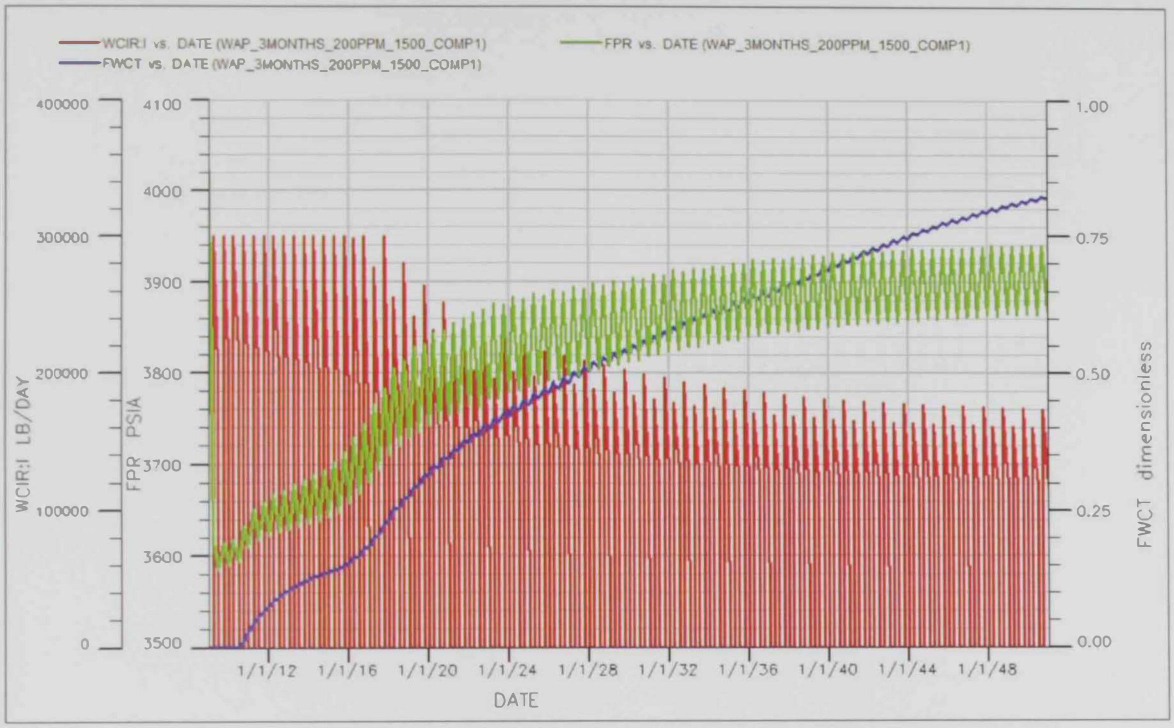

Figure 5.26: WAP injection at 1500 STB/D (200 ppm, COMP1, 3 months) reservoir performance

Table 5.21: WAP injection results (200 ppm, COMP1, 6 months, 1500 STB/D)

Development Process Results						
Development Process	FOPR (STB/D)	FOPT (STB)	FWPT (STB)	WCIR (LB/D)	WCPT (LB)	FOE (%)
WAP	126.55	6.79E+6	4.81E+6	97.79E+3	8.84E+7	50.91

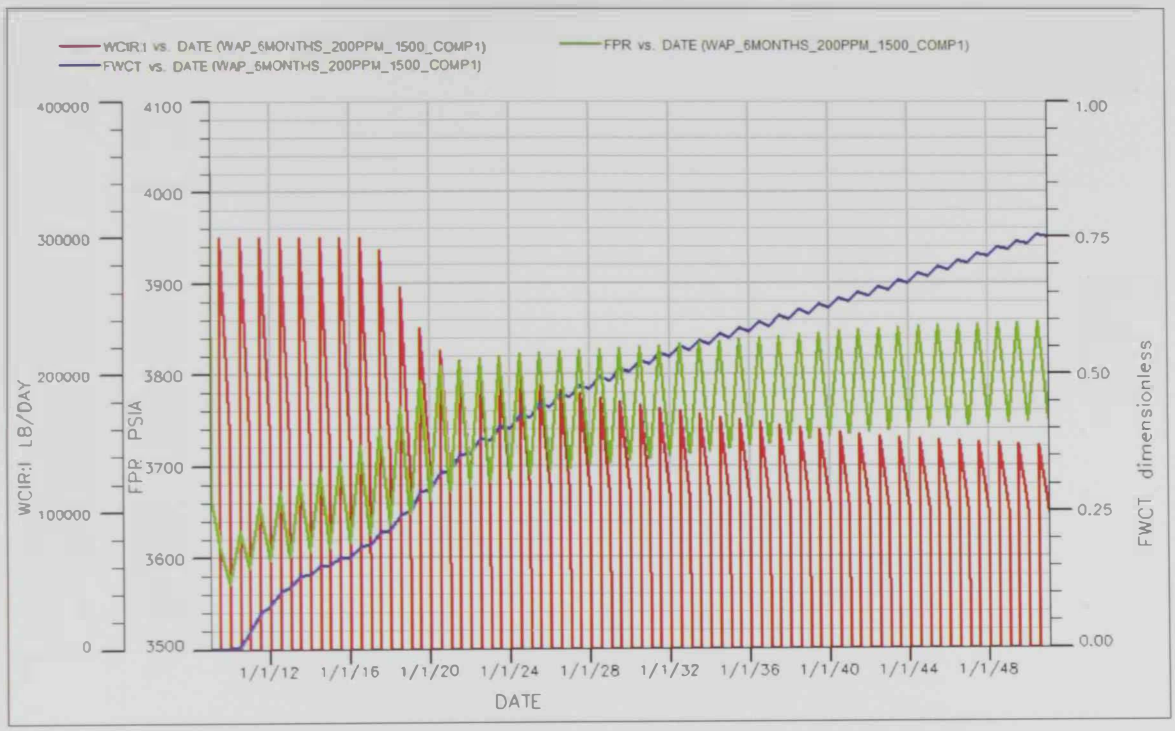

Figure 5.27: WAP injection at 1500 STB/D (200 ppm, COMP1, 6 months) reservoir performance

Table 5.22: WAP injection results (200 ppm, COMP1, 1 year, 1500 STB/D)

Development Process Results						
Development Process	FOPR (STB/D)	FOPT (STB)	FWPT (STB)	WCIR (LB/D)	WCPT (LB)	FOE (%)
WAP	124.23	6.51E+6	4.51E+6	8.73E+4	6.49E+7	48.82

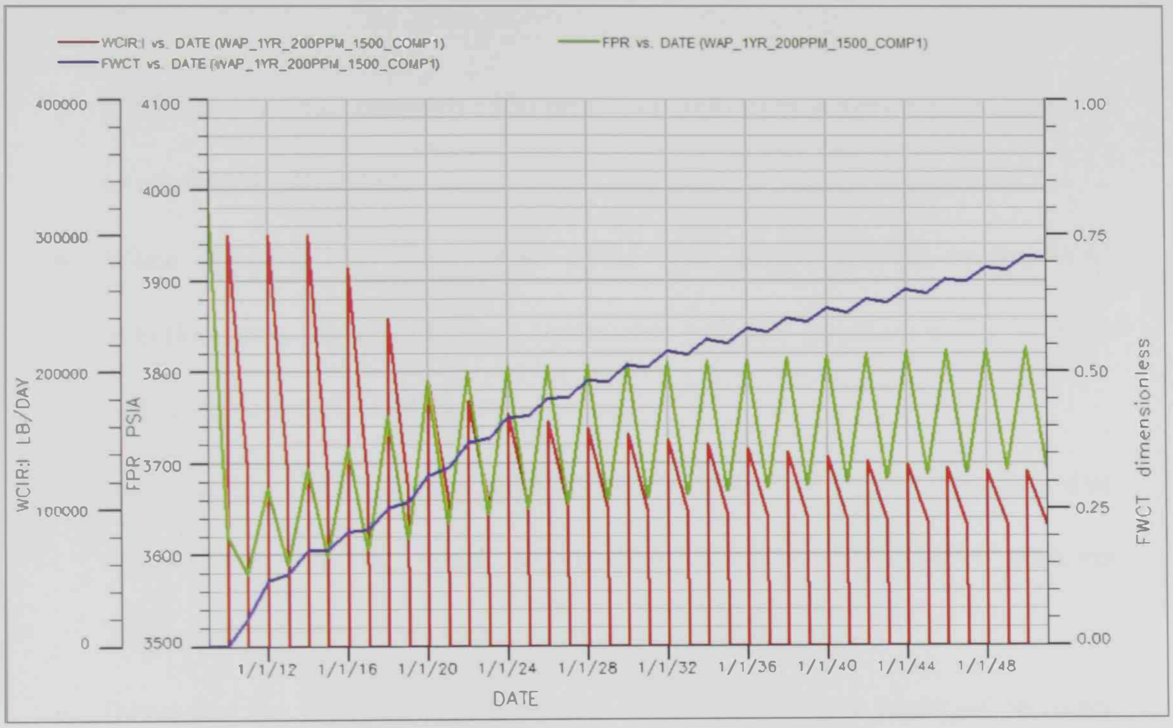

Figure 5.28: WAP injection at 1500 STB/D (200 ppm, COMP1, 1 year) reservoir performance

From the illustrated results, similar trends of FPR and FWCT were observed during the WAP process for all WAP cycle time intervals attempted. Increasing the polymer concentration from 200 to 2000 ppm has an adverse effect on the oil recovery; thus, an increment of 8.1% in oil recovery can be attained using 200 ppm when it has been injected as a slug of 0.00704 PV alternating with the same pore volume of water.

The effect of injecting different pore volumes of water followed by the same pore volume of polymer solution (WAP ratio 1:1) including 0.00235, 0.00704, 0.014, and 0.0285 where each denotes that both slugs (water and polymer solution) will last for one, three, six, and twelve months respectively, keeping both the polymer concentration and the selected completion constant is significant. A summary of the FOE results is illustrated in Table 5.23. From the results presented, the following points can be deduced:

- Difference in FOE between 1500 ppm and 2000 ppm is very minor compared to other concentrations.
- When applying the same WAP cycle time period for the study, WAP injection gave higher FOE than continuous polymer injection using the same well completion (COMP1).
- Injecting 0.00235, 0.00704, and 0.014 PV improves the oil recovery over normal waterflooding; while the injection of 0.0285 PV of 1500 ppm and 2000 ppm polymer concentrations reduces the FOE.
- Increasing the injection slug time as a WAP process gave lower oil recovery; thus applying WAP injection at relatively small slugs is preferable in this case.

Table 5.23: Oil recovery for WAP injection using COMP1 at 2050

WAP Cycle Time Interval (months)	Polymer Concentration (ppm)	FOE (%)
1 (0.00235 PV)	0	45.98
	200	52.50
	500	52.19
	1000	51.65
	1500	51.36
	2000	51.31
3 (0.00704 PV)	0	45.98
	200	54.08
	500	53.46
	1000	52.33
	1500	51.71
	2000	51.52
6 (0.014 PV)	0	45.98
	200	50.91
	500	49.52
	1000	48.17
	1500	47.30
	2000	46.79
12 (0.0285 PV)	0	45.98
	200	48.82
	500	47.47
	1000	46.25
	1500	45.40
	2000	44.79

Furthermore, the results can be presented as shown in Figures 5.29 to 5.32. Also, a comparison between the different attempts is presented in Figure 5.33. Generally, injecting a slug of water followed by polymer for three months (0.00704 PV) will be the most attractive option to minimize the cost of polymer solution used and maximize the oil recovery.

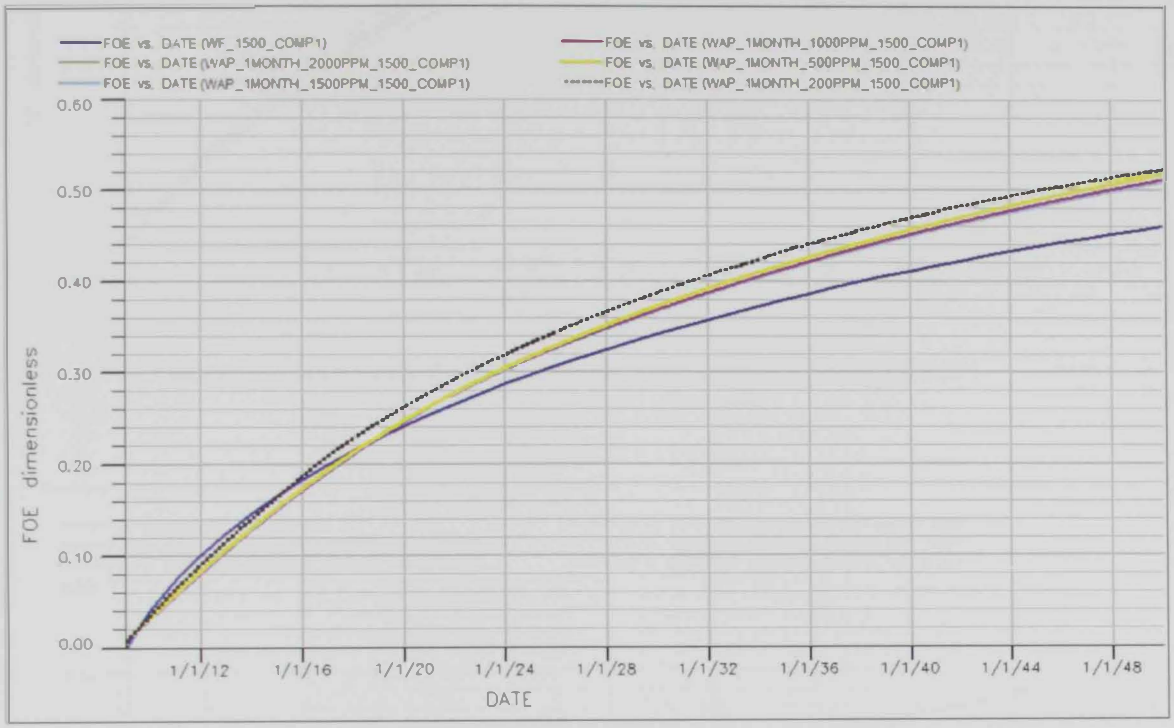

Figure 5.29: Oil recovery for 1 month WAP injection using COMP1

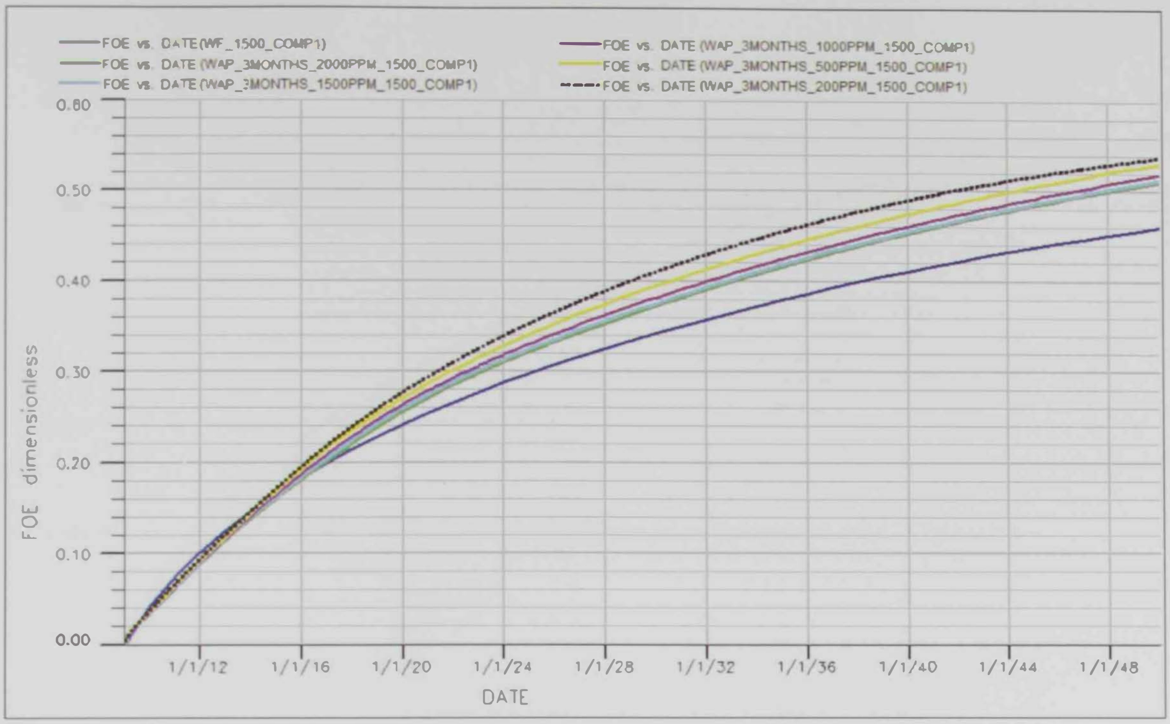

Figure 5.30: Oil recovery for 3 months WAP injection using COMP1

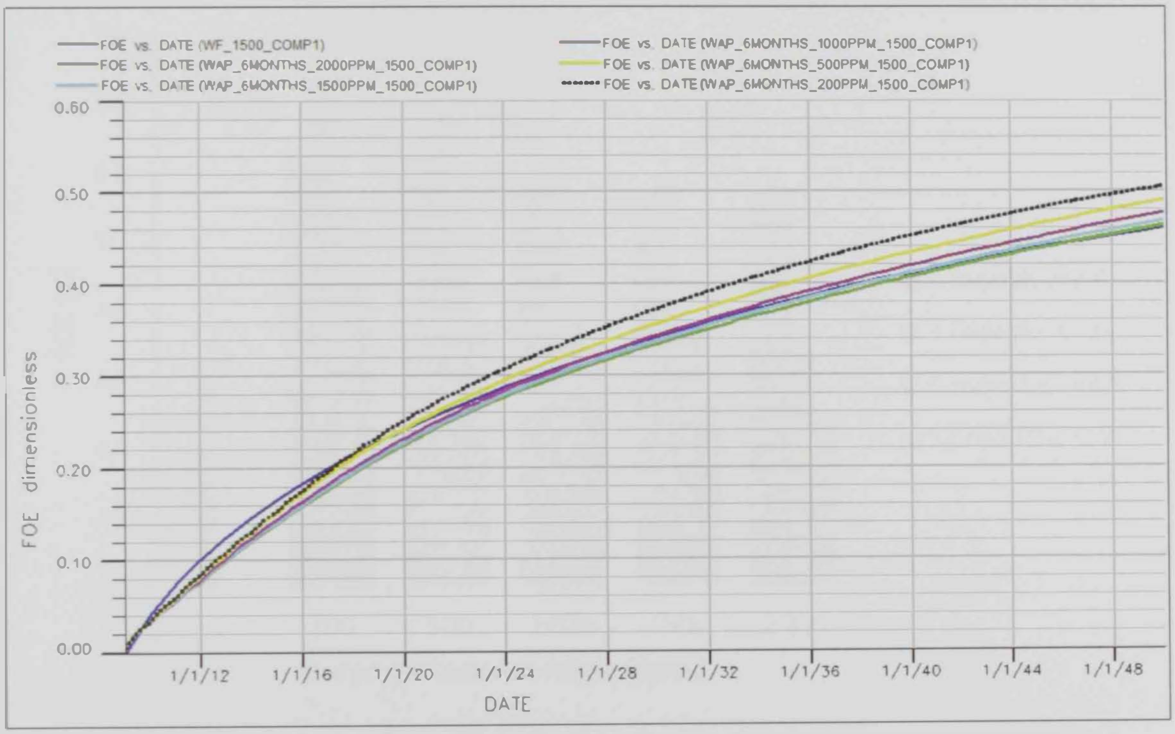

Figure 5.31: Oil recovery for 6 months WAP injection using COMP1

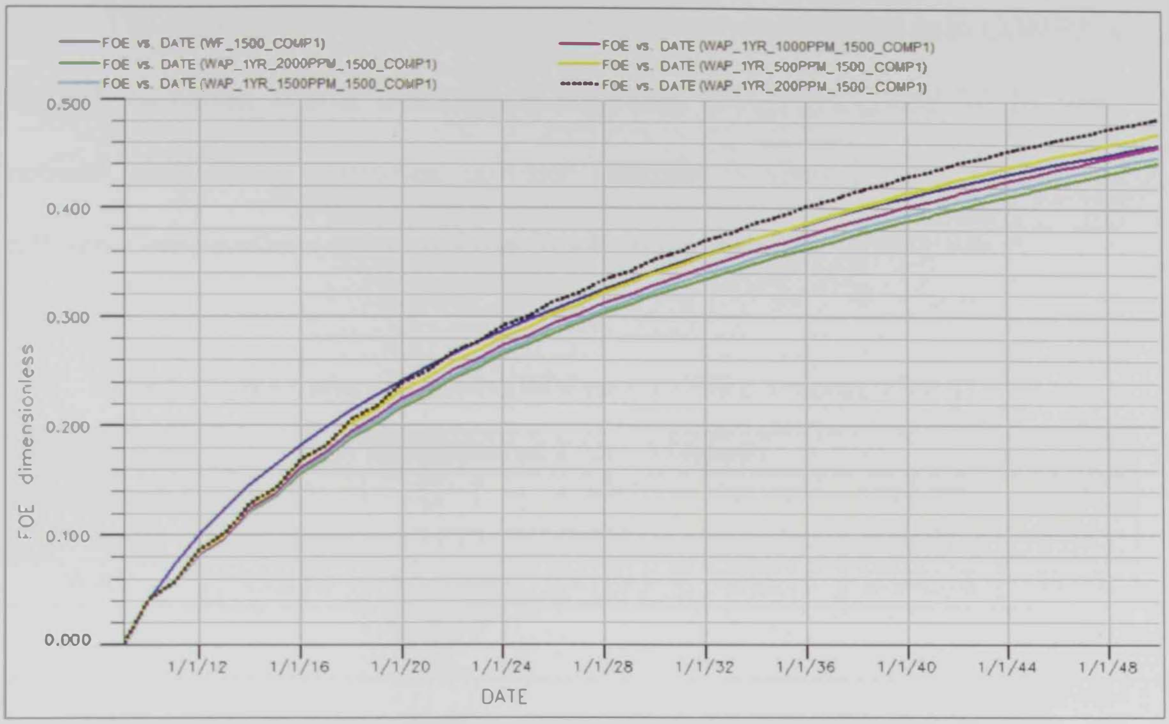

Figure 5.32: Oil recovery for 1 year WAP injection using COMP1

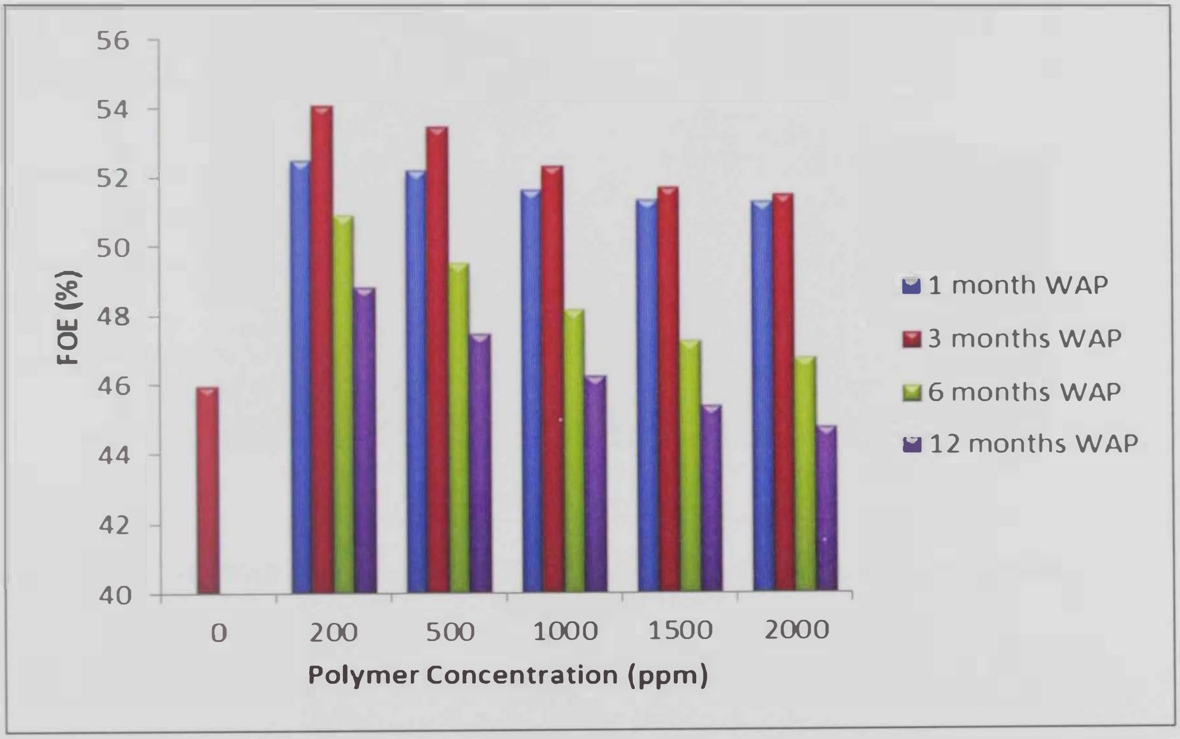

Figure 5.33: FOE vs. polymer concentration using COMP1 (WAP injection)

The same outline of results as before is shown where in this case COMP2 is applied. However, similar observations regarding FPR, FWCT, and WCIR were noticed when water alternating polymer injection is applied using COMP2 at different concentrations and at different WAP timing intervals.

Table 5.24: WAP injection results (1000 ppm, COMP2, 1 month, 1500 STB/D)

Development Process Results						
Development Process	**FOPR (STB/D)**	**FOPT (STB)**	**FWPT (STB)**	**WCIR (LB/D)**	**WCPT (LB)**	**FOE (%)**
WAP	192.50	5.13E+6	6.81E+5	3.18E+5	2.94E+8	38.50

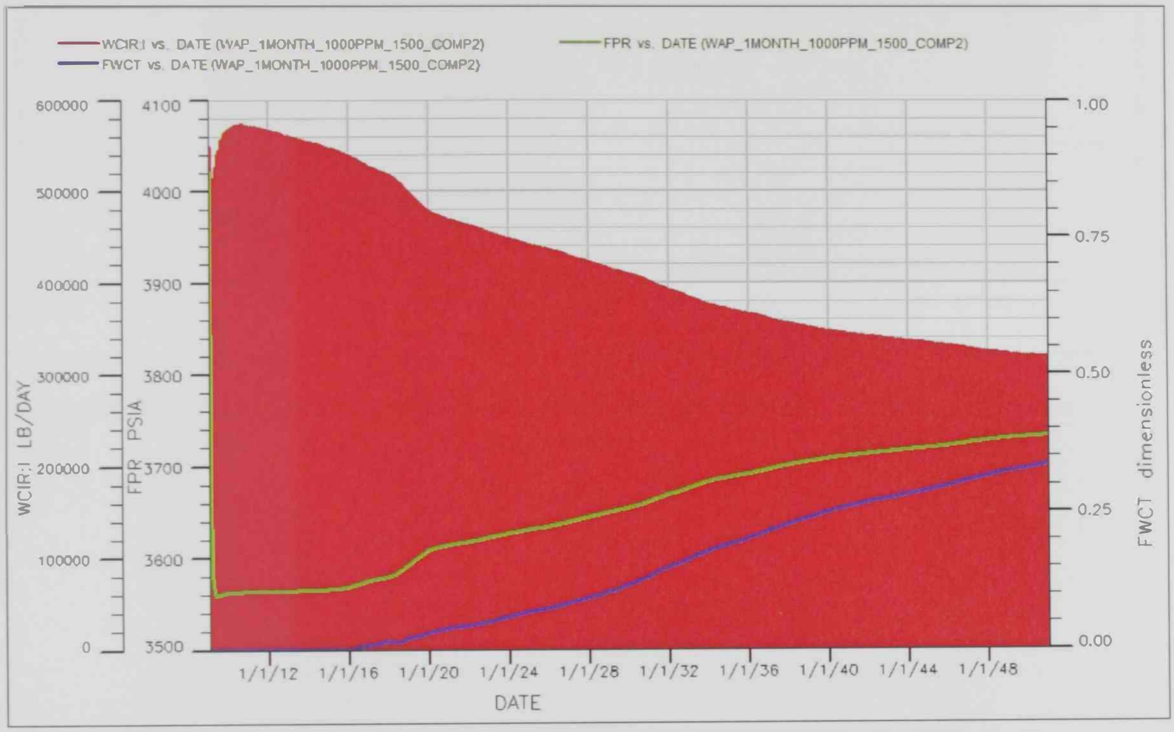

Figure 5.34: WAP injection at 1500 STB/D (1000 ppm, COMP2, 1 month) reservoir performance

Table 5.25: WAP injection results (1000 ppm, COMP2, 3 months, 1500 STB/D)

Development Process Results						
Development Process	FOPR (STB/D)	FOPT (STB)	FWPT (STB)	WCIR (LB/D)	WCPT (LB)	FOE (%)
WAP	189.97	5.23E+6	7.33E+5	3.17E+5	3.01E+8	39.22

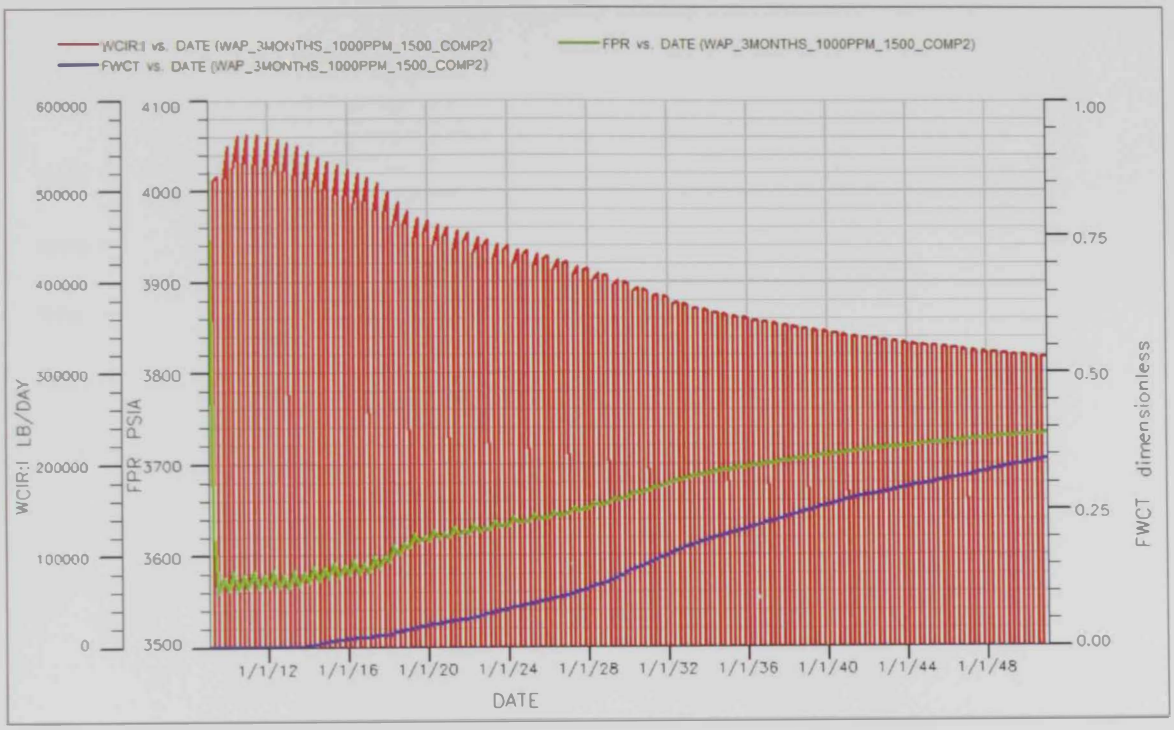

Figure 5.35: WAP injection at 1500 STB/D (1000 ppm, COMP2, 3 months) reservoir performance

Table 5.26: WAP injection results (1000 ppm, COMP2, 6 months, 1500 STB/D)

Development Process Results						
Development Process	**FOPR (STB/D)**	**FOPT (STB)**	**FWPT (STB)**	**WCIR (LB/D)**	**WCPT (LB)**	**FOE (%)**
WAP	197.53	5.59E+6	9.79E+5	3.04E+5	3.15E+8	41.92

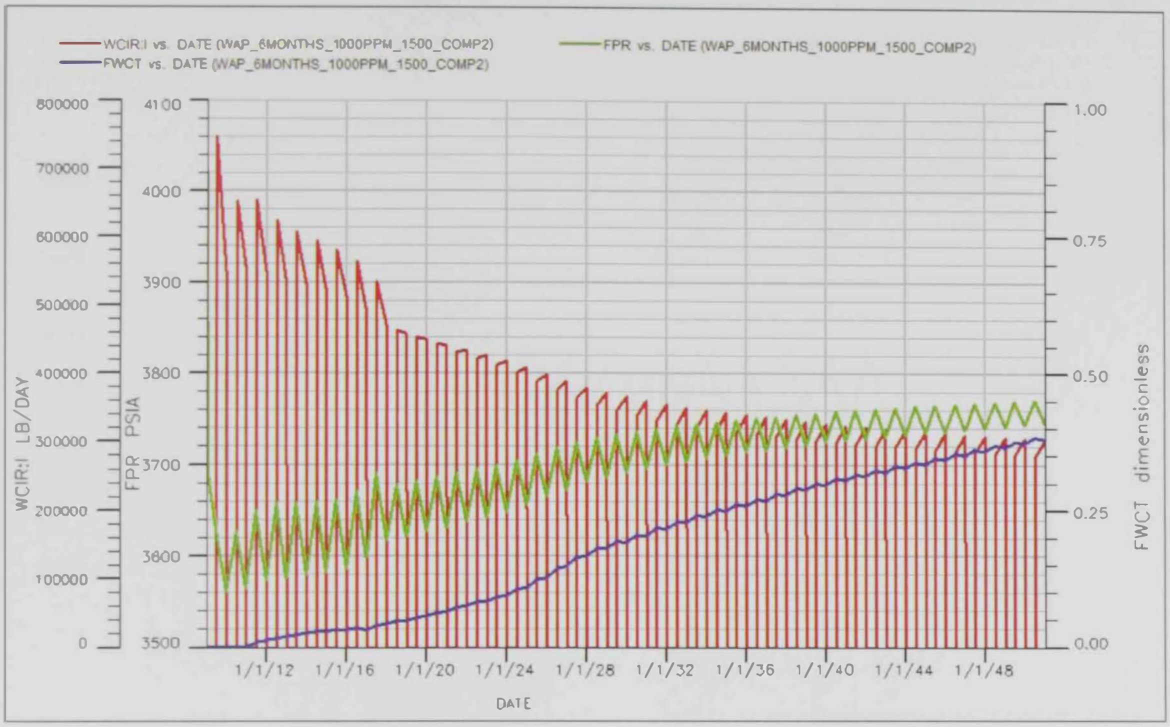

Figure 5.36: WAP injection at 1500 STB/D (1000 ppm, COMP2, 6 months) reservoir performance

Table 5.27: WAP injection results (1000 ppm, COMP2, 1 year, 1500 STB/D)

Development Process Results						
Development Process	**FOPR (STB/D)**	**FOPT (STB)**	**FWPT (STB)**	**WCIR (LB/D)**	**WCPT (LB)**	**FOE (%)**
WAP	164.83	5.91E+6	1.29E+6	3.00E+5	3.26E+8	44.27

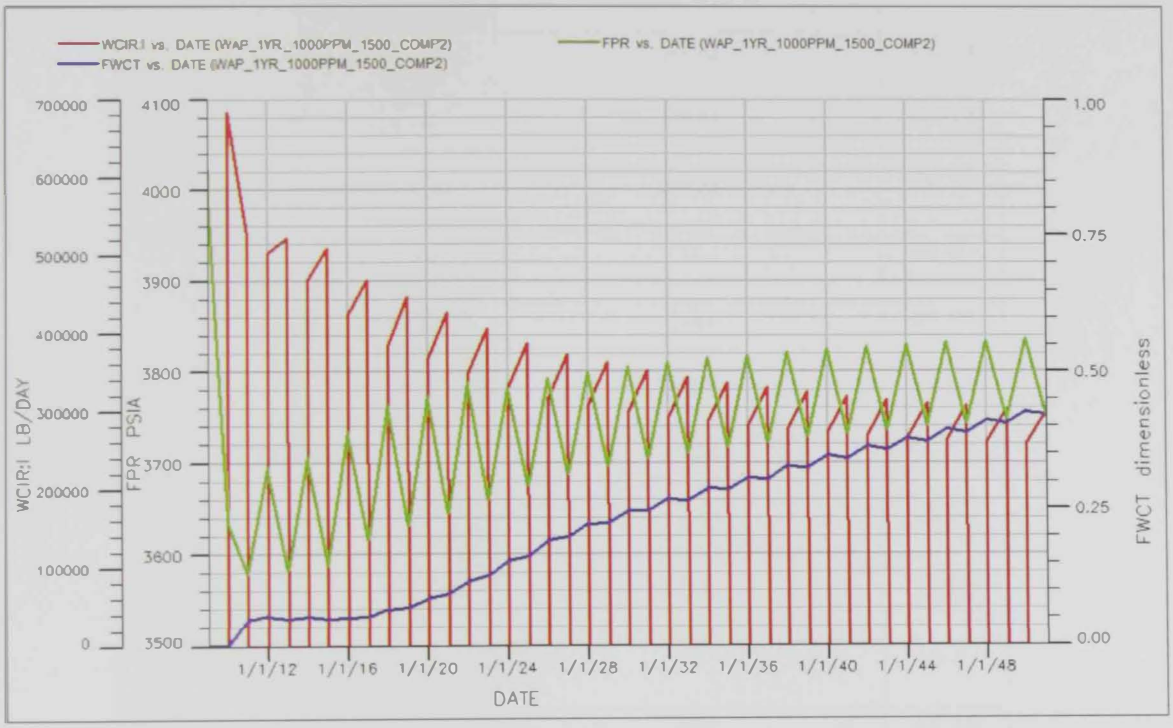

Figure 5.37: WAP injection at 1500 STB/D (1000 ppm, COMP2, 1 year) reservoir performance

The overall results of the fifteen simulation runs are presented in Table 5.28 and Figures 5.38 to 5.41.

In this case, the minimum requirements in terms of polymer should be considered to increase the recovery over normal waterflooding.

Table 5.28: Oil recovery for WAP injection using COMP2 at 2050

WAP Cycle Time Interval (months)	Polymer Concentration (ppm)	FOE (%)
1	0	46.47
(0.00235 PV)	200	41.76
	500	39.32
	1000	38.50
	1500	38.27
	2000	38.17
3	0	46.47
(0.00704 PV)	200	45.62
	500	41.67
	1000	39.22
	1500	38.50
	2000	38.27
6	0	46.47
(0.014 PV)	200	48.10
	500	44.22
	1000	41.92
	1500	40.77
	2000	40.03
12	0	46.47
(0.0285 PV)	200	47.96
	500	46.03
	1000	44.27
	1500	43.22
	2000	42.55

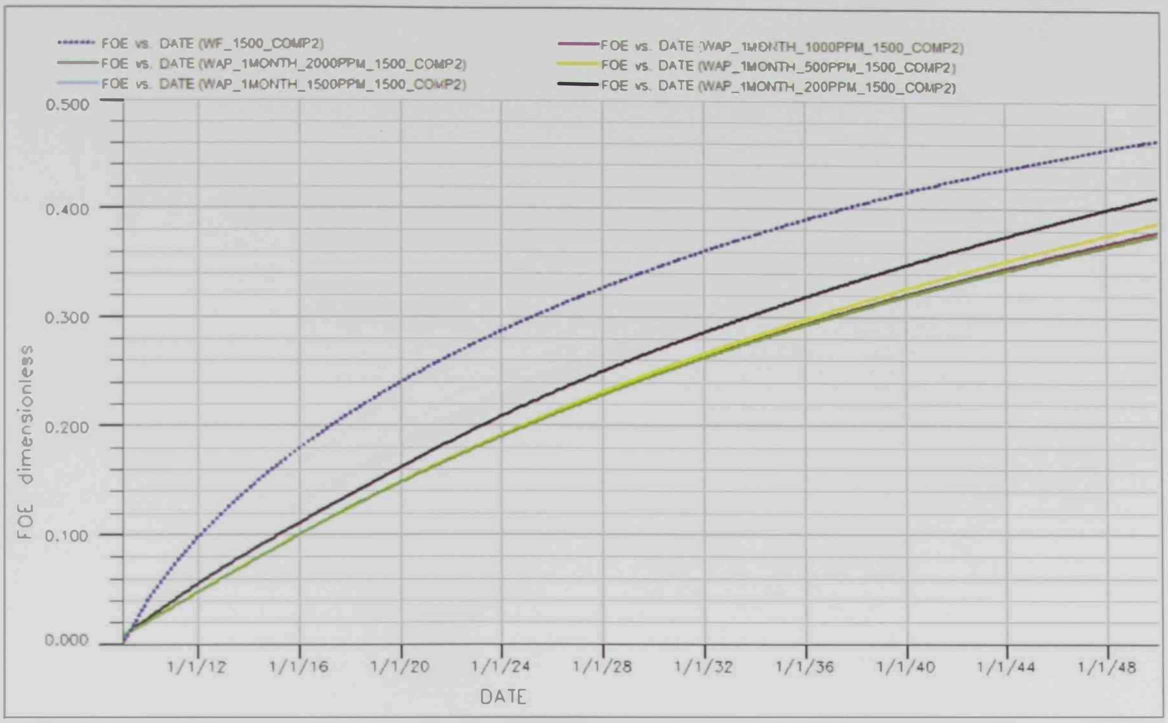

Figure 5.38: Oil recovery for 1 month WAP injection using COMP2

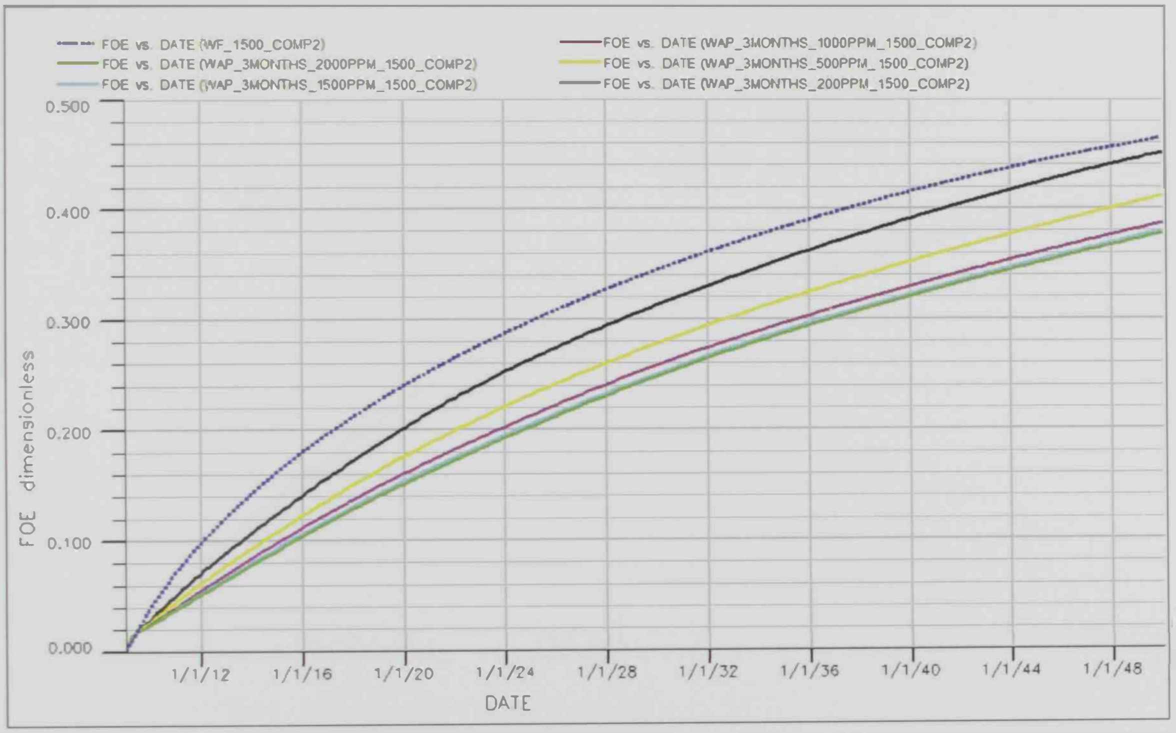

Figure 5.39: Oil recovery for 3 months WAP injection using COMP2

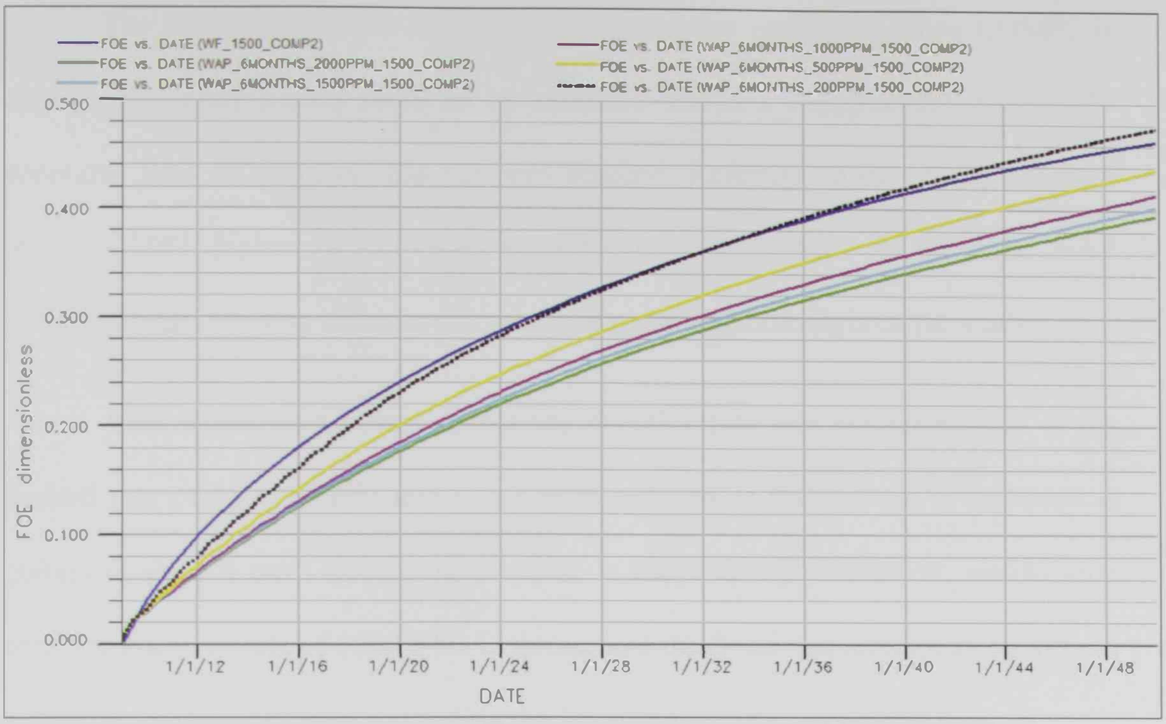

Figure 5.40: Oil recovery for 6 months WAP injection using COMP2

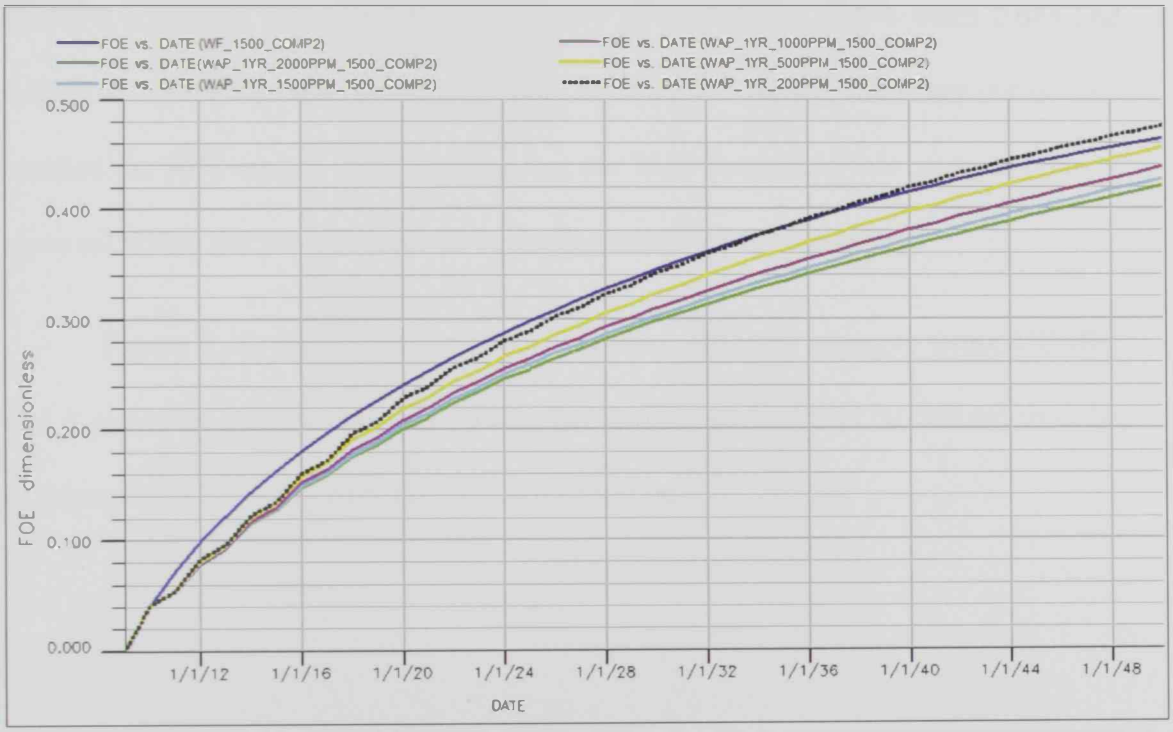

Figure 5.41: Oil recovery for 1 year WAP injection using COMP2

The results reveal that in order to obtain higher recoveries when COMP2 is applied, the study period needs to be extended and this is applicable; since 90% economic limit of water cut has not been reached. Referring to the results obtained using COMP1, higher oil recoveries are achieved over COMP2 for the same WAP cycle intervals; keeping the reservoir pressure maintained throughout the study.

Also, it has been observed that the injection rate was not maintained at the desired rate of 1500 STB/D and it has been reduced as the process of injection is going on; since it can't sustain the pressure in the reservoir. Moreover, maintaining constant injection rate of 1500 STB/D throughout the flood was attempted, leading to a sharp increase in pressure exceeding the fracture pressure of the formation.

In addition, injecting relatively larger slugs in the WAP process when COMP2 is applied increased the oil recovery by 1.63% and 1.49% when 0.014 and 0.0285 PV were injected respectively both at 200 ppm. Hence, the water cut has not reached the 90% limit at 2050; leading that the WAP process in this case can recover more oil where the project needs to be implemented for further time.

Figure 5.42 shows a comparison between different attempts using COMP2 and it presented clearly that two options (as defined earlier) can be utilized in order to improve the recovery over normal waterflooding.

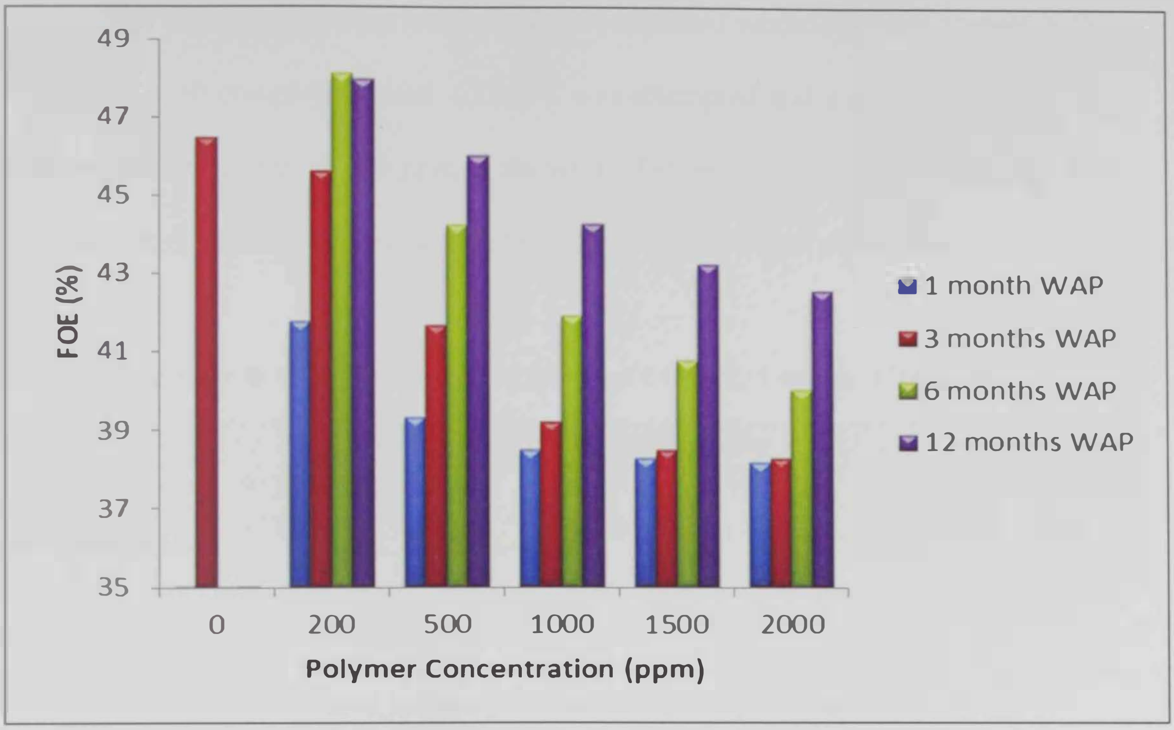

Figure 5.42: FOE vs. polymer concentration using COMP2 (WAP injection)

The same twenty simulations run were repeated where the only change in this case is the well completion used. COMP3 was attempted and a representation of the reservoir performance at 200 ppm is shown in Tables 5.29 to 5.32 and Figures 5.43 to 5.46. Similar trends were observed for other concentrations attempted.

Table 5.29: WAP injection results (200 ppm, COMP3, 1 month, 1500 STB/D)

Development Process Results						
Development Process	**FOPR (STB/D)**	**FOPT (STB)**	**FWPT (STB)**	**WCIR (LB/D)**	**WCPT (LB)**	**FOE (%)**
WAP	183.00	3.69E+6	3.75E+5	5.50E+4	2978.87	28.12

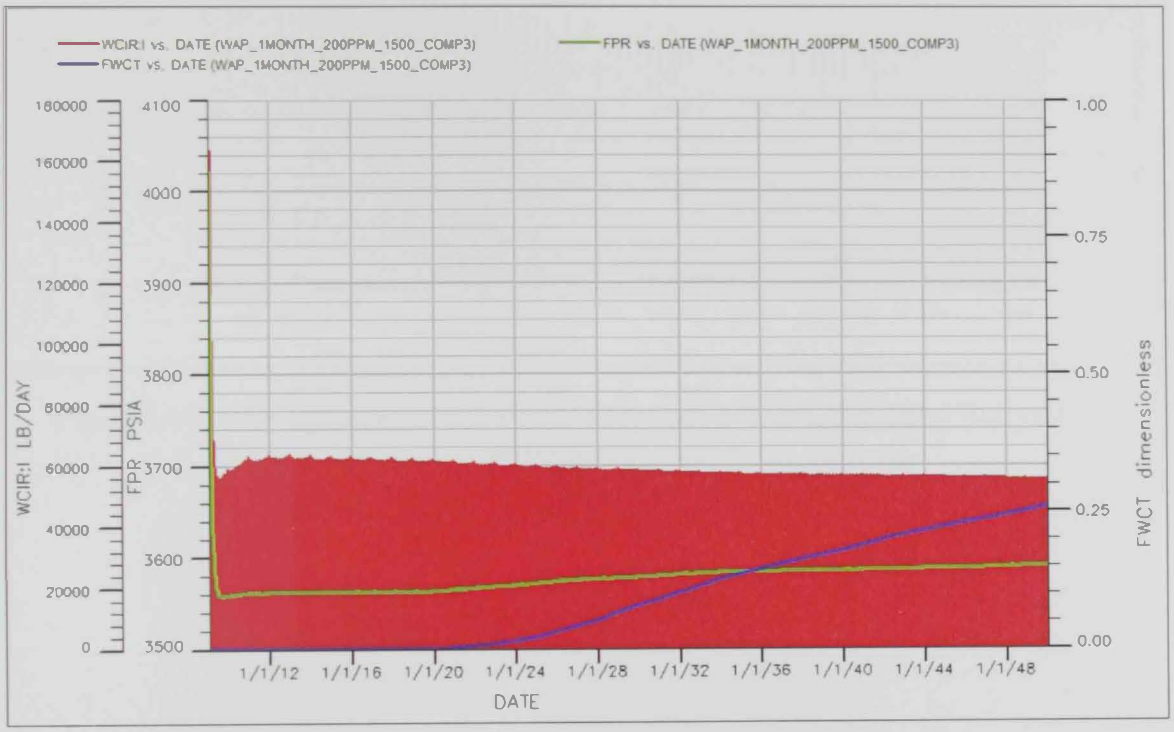

Figure 5.43: WAP injection at 1500 STB/D (200 ppm, COMP3, 1 month) reservoir performance

Table 5.30: WAP injection results (200 ppm, COMP3, 3 months, 1500 STB/D)

Development Process Results						
Development Process	**FOPR (STB/D)**	**FOPT (STB)**	**FWPT (STB)**	**WCIR (LB/D)**	**WCPT (LB)**	**FOE (%)**
WAP	171.67	4.22E+6	7.28E+5	5.25E+4	3.60E+5	31.60

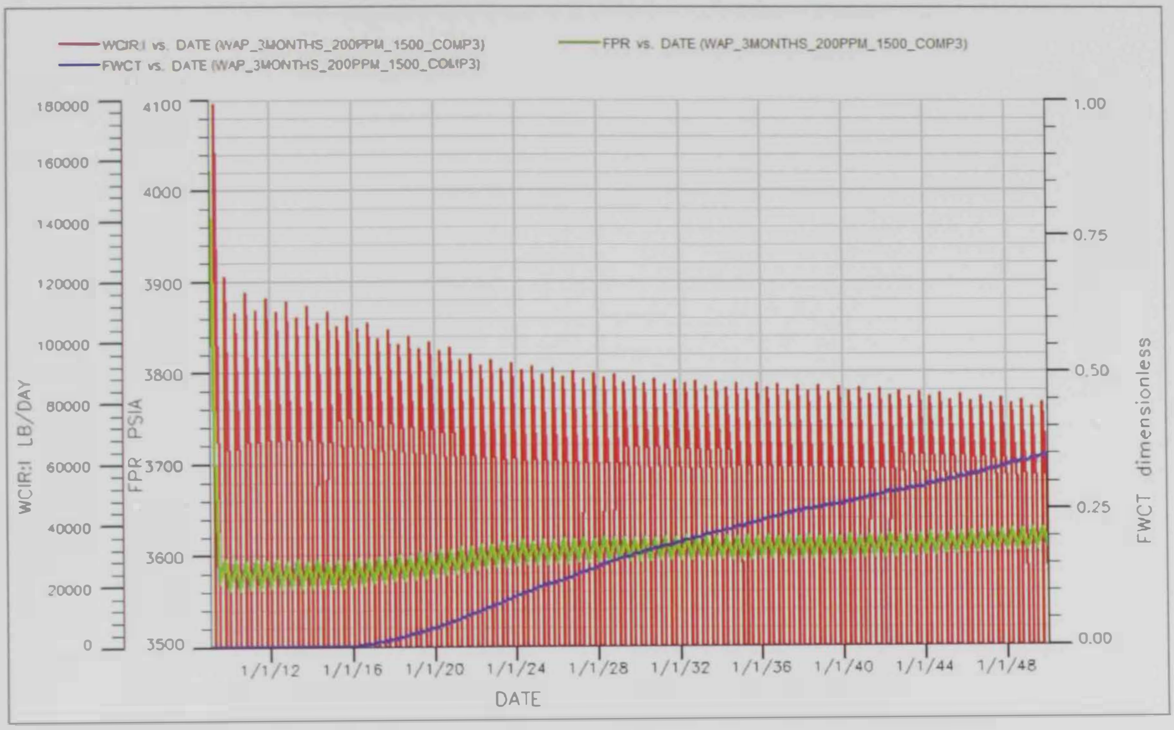

Figure 5.44: WAP injection at 1500 STB/D (200 ppm, COMP3, 3 months) reservoir performance

Table 5.31: WAP injection results (200 ppm, COMP3, 6 months, 1500 STB/D)

Development Process Results						
Development Process	**FOPR (STB/D)**	**FOPT (STB)**	**FWPT (STB)**	**WCIR (LB/D)**	**WCPT (LB)**	**FOE (%)**
WAP	141.64	4.79E+6	1.50E+6	5.07E+5	1.74E+6	35.87

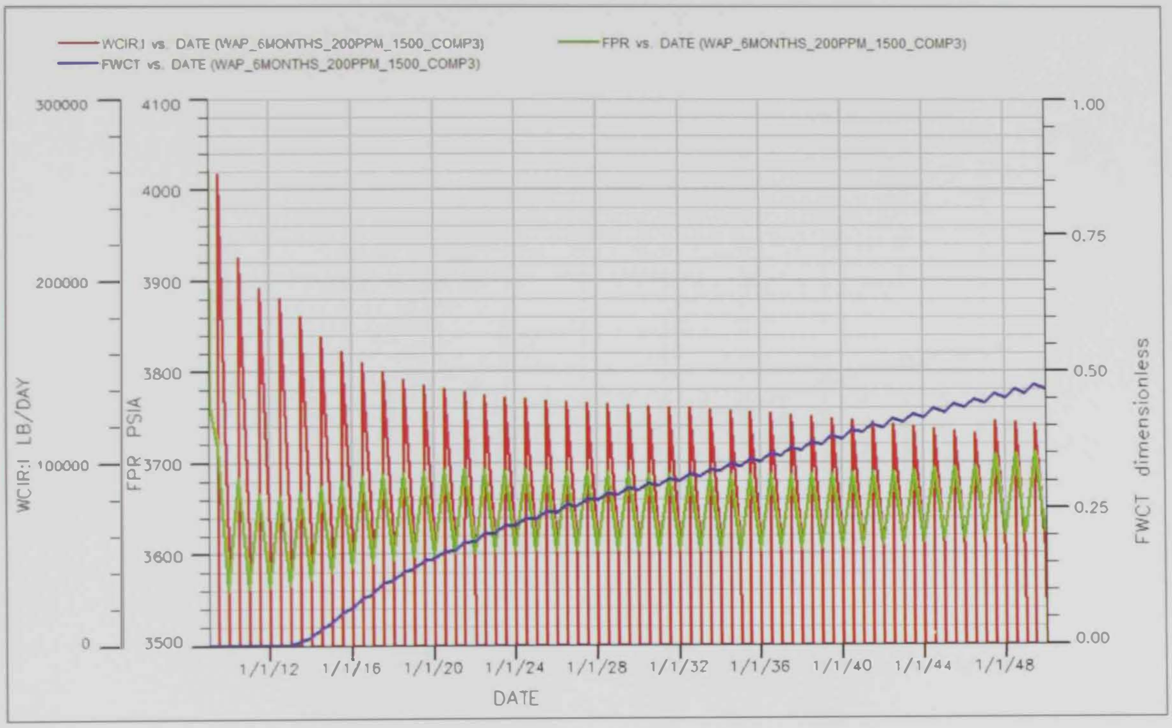

Figure 5.45: WAP injection at 1500 STB/D (200 ppm, COMP3, 6 months) reservoir performance

Table 5.32: WAP injection results (200 ppm, COMP3, 1 year, 1500 STB/D)

Development Process Results						
Development Process	FOPR (STB/D)	FOPT (STB)	FWPT (STB)	WCIR (LB/D)	WCPT (LB)	FOE (%)
WAP	114.00	5.19E+6	2.40E+6	5.09E+4	4.17E+6	38.87

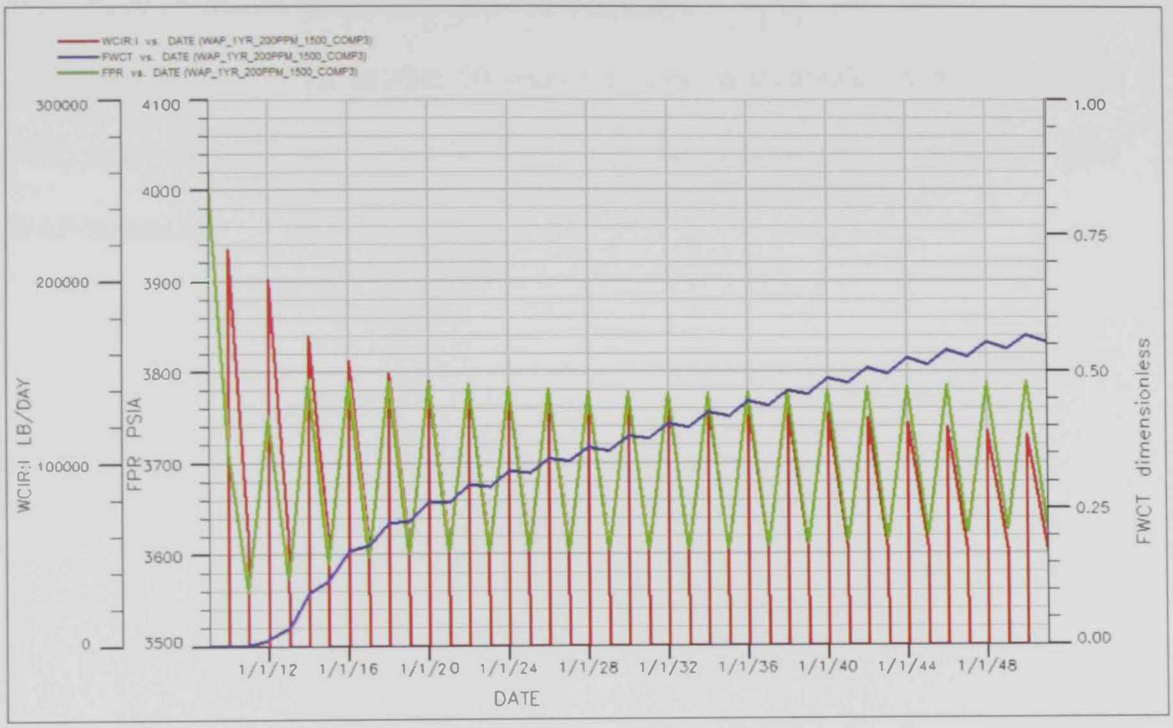

Figure 5.46: WAP injection at 1500 STB/D (200 ppm, COMP3, 1 year) reservoir performance

From the performance of the reservoir at different WAP timing and polymer concentrations, the following points were observed:

- Delay in breakthrough compared to the other well completions applied.
- A further delay in breakthrough is noticed as the concentration of polymer solution increases from 200 ppm to 2000 ppm.
- Water cut was in the range of 10 to 15% when 2000 ppm is used.
- Reservoir pressure is maintained better when the WAP cycle time increases.

A summary of FOE results at 2050 for all runs attempted using COMP3 are illustrated in Table 5.33 and through Figures 5.47 to 5.50.

Generally, the results reveal that COMP3 is not favorable to be implemented as a WAP process. Moreover, what has been recovered at 2050 by water injection is much more promising technically and economically.

Extending the project for another 50 years may lead to favorable results in terms of FOE, since the water cut is still below 60% in the extreme case (200 ppm, 1 year WAP injection).

Table 5.33: Oil recovery for WAP injection using COMP3 at 2050

WAP Cycle Time Interval (months)	Polymer Concentration (ppm)	FOE (%)
1 (0.00235 PV)	0	45.85
	200	28.12
	500	28.59
	1000	28.54
	1500	28.54
	2000	28.54
3 (0.00704 PV)	0	45.85
	200	31.60
	500	28.41
	1000	28.69
	1500	28.79
	2000	28.81
6 (0.014 PV)	0	45.85
	200	35.87
	500	32.10
	1000	29.23
	1500	29.14
	2000	29.19
12 (0.0285 PV)	0	45.85
	200	38.87
	500	36.44
	1000	33.79
	1500	32.91
	2000	32.32

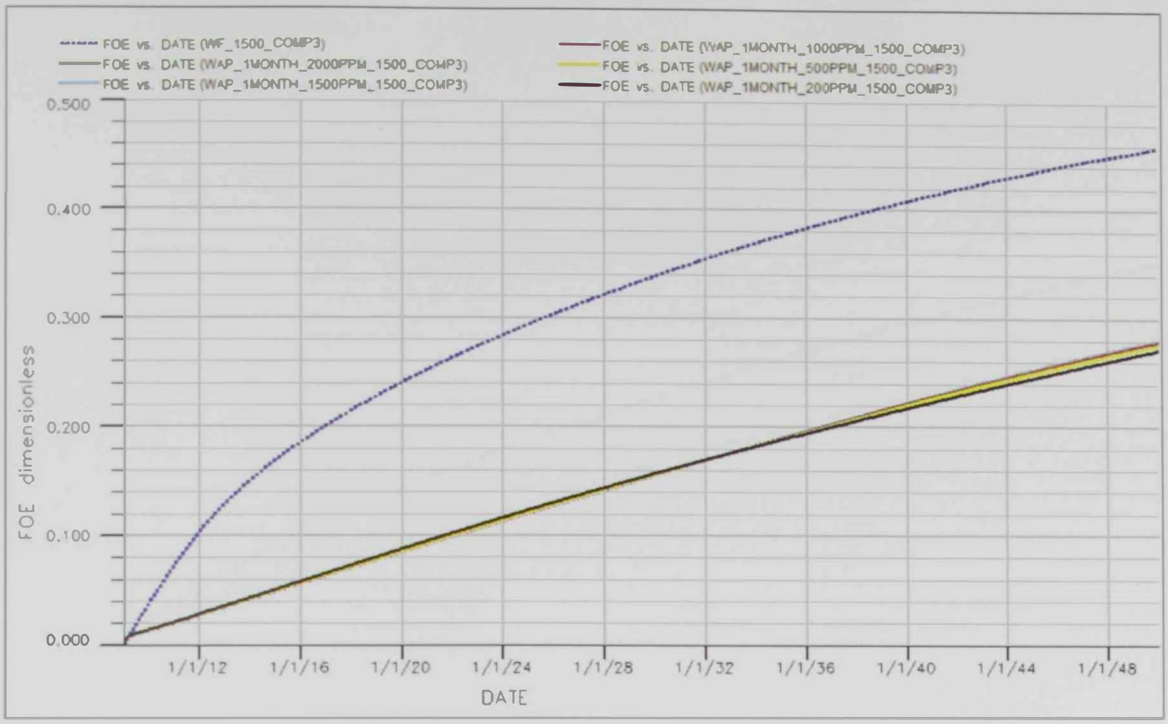

Figure 5.47: Oil recovery for 1 month WAP injection using COMP3

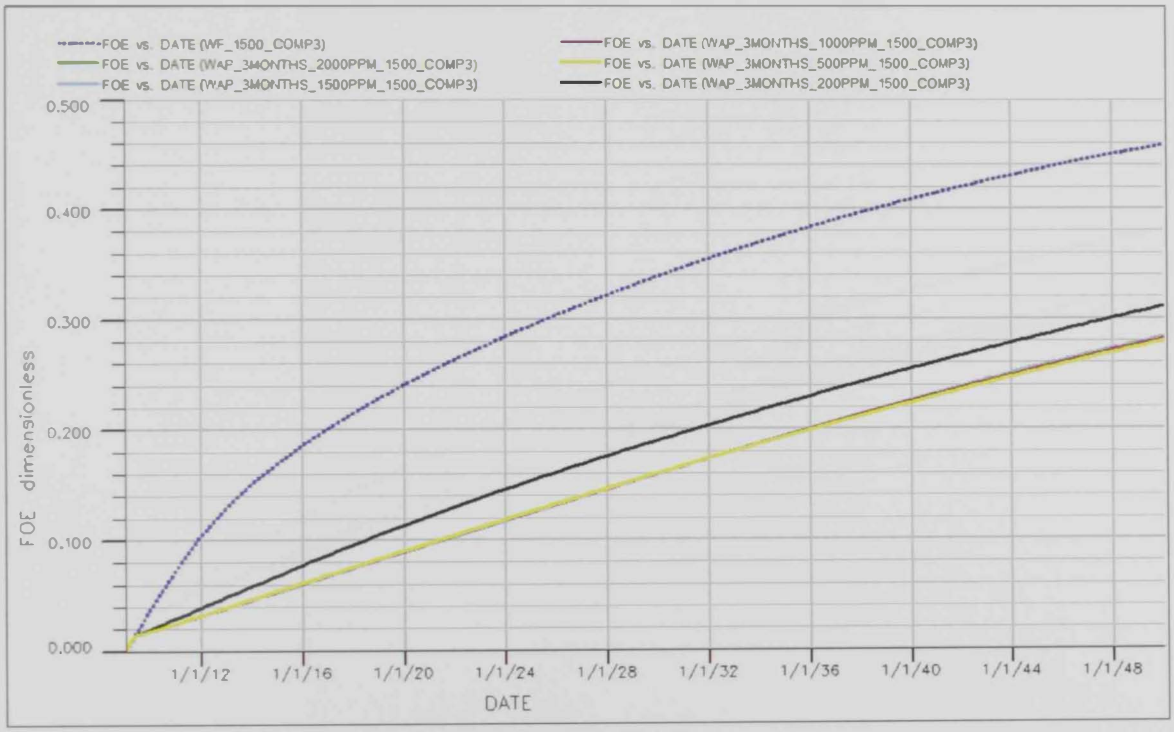

Figure 5.48: Oil recovery for 3 months WAP injection using COMP3

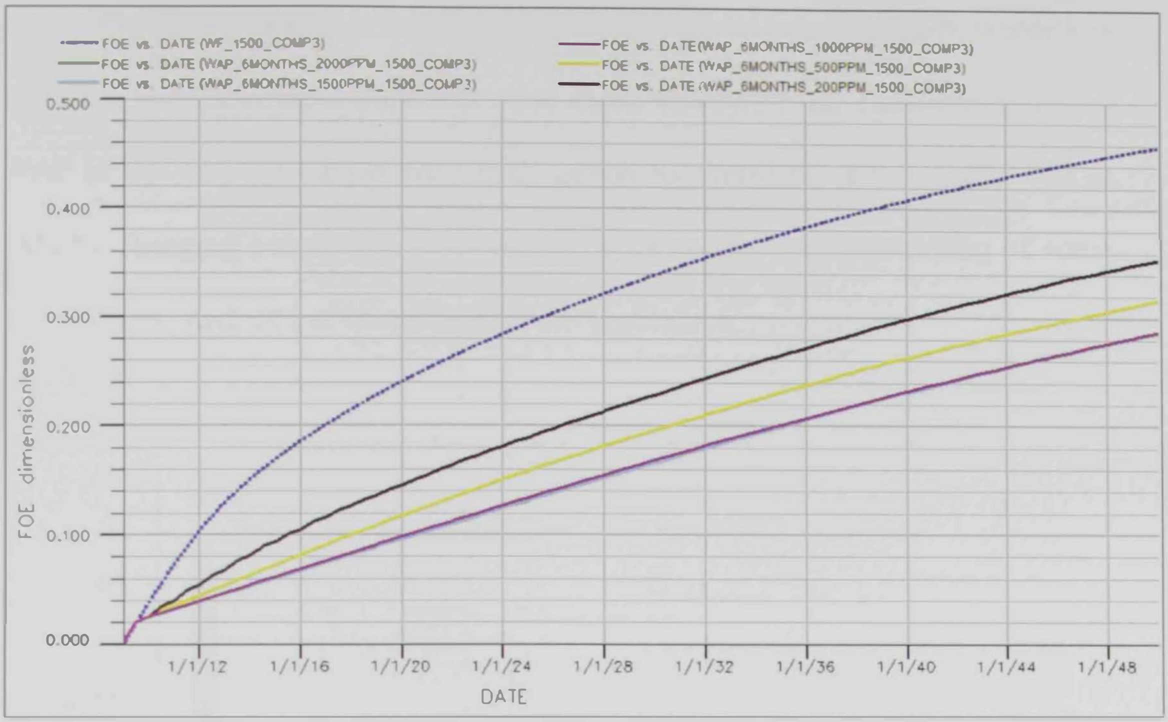

Figure 5.49: Oil recovery for 6 months WAP injection using COMP3

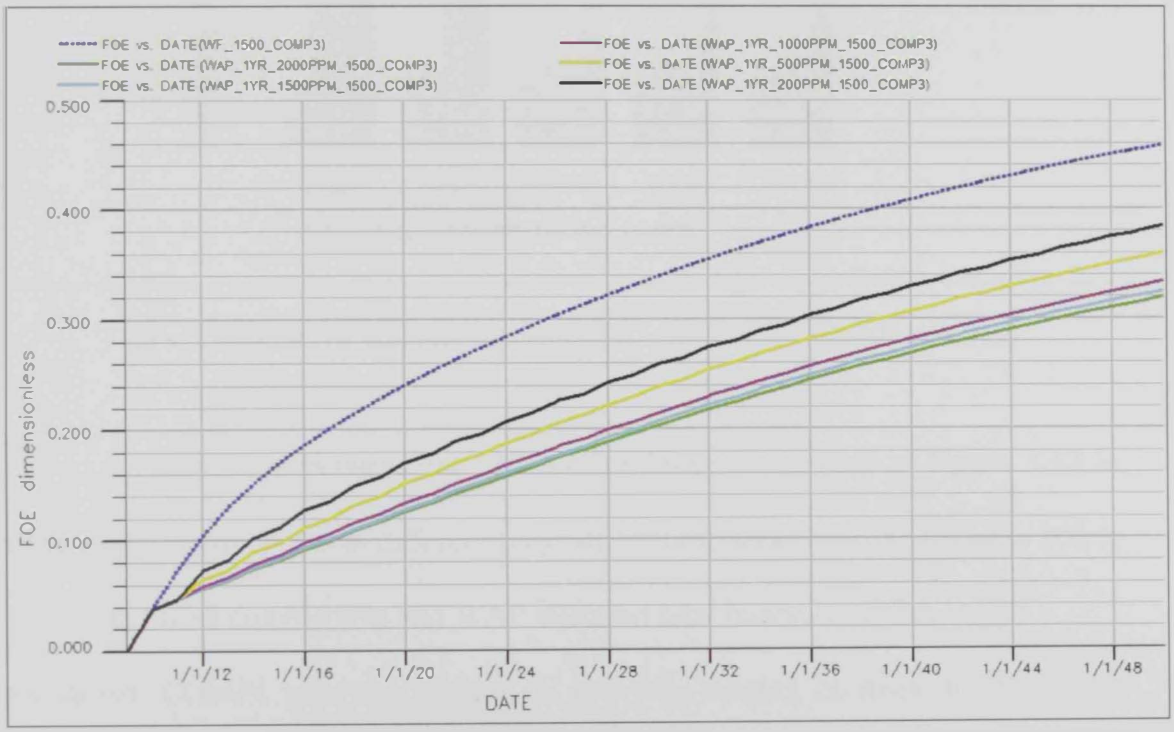

Figure 5.50: Oil recovery for 1 year WAP injection using COMP3

Figure 5.51 shows a comparison between options using COMP3, where it is clear that waterflooding at 2050 recovered about 46% of the oil. Thus, implementing WAP in this case for the assigned study period recovered oil in the range of 28 to 38% by changing polymer concentration of pore volume injected as slug of water and polymer. And still, at least 6% less FOE is obtained.

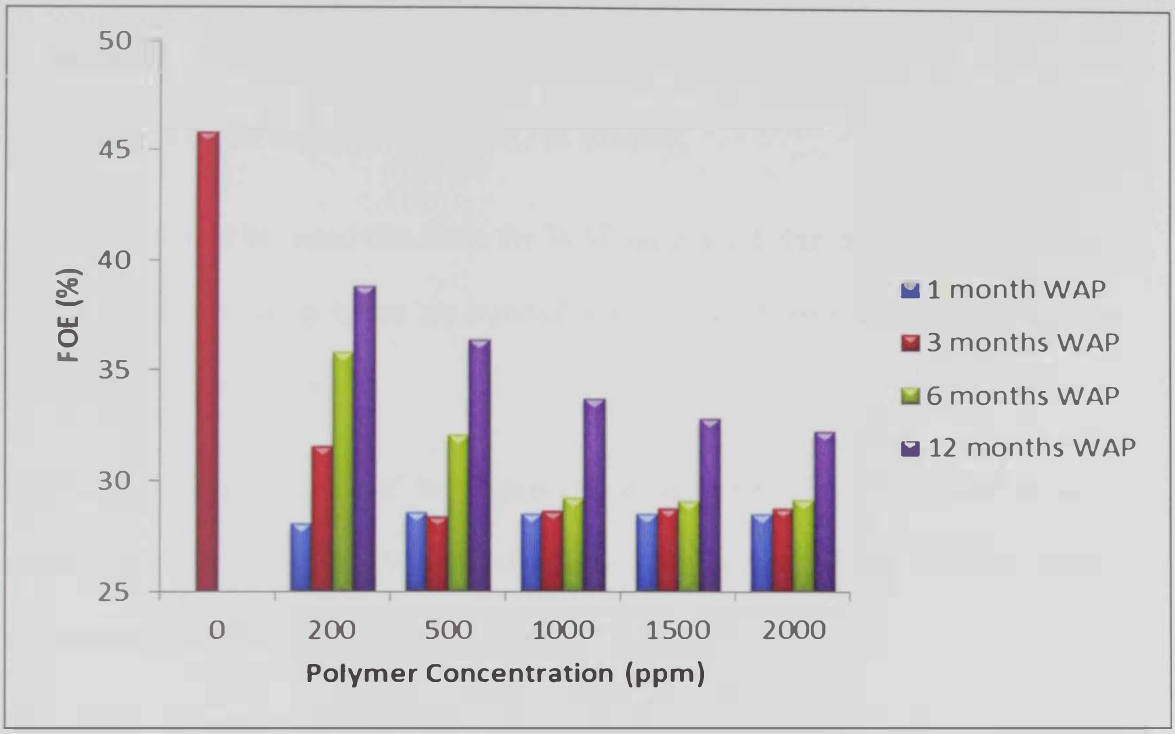

Figure 5.51: FOE vs. polymer concentration using COMP3 (WAP injection)

A comparison between the different options is presented in Figure 5.52 in terms of oil recovery versus different polymer concentrations ranging between 200 to 2000 ppm for all completions and WAP injection time intervals (different PV).

As shown, COMP1 gave the highest oil recovery ranging between 46.25% using 1000 ppm when 0.0285 PV is injected to 54.08% using 200 ppm when 0.00704 PV is injected. Moreover, the oil recovery increases with lower polymer concentration used.

Furthermore, the least recovery was obtained when each slug of water and polymer solution is injected for a year and the highest is when both slugs are injected for a period of one and three months, this is applied when COMP1 is used.

In general, as polymer concentration deceases as well as the WAP timing decreases, improvement in recovery is attained using COMP1. The opposite occurred using COMP2, where increasing the slug size is favorable in this case at low concentration of 200 ppm. Furthermore, COMP3 showed unfavorable results for all cases, and improvement in the sweep efficiency is not attained.

In here, it should be noted that since the WAP ratio is 1:1; this means that equivalent volumes of water and polymer are injected and the only difference in this case is the slug size of the injectant.

Therefore, implementation of WAP process at small time interval of one to three months (0.00235, 0.00704 PV) gave the highest oil recovery where COMP1 is used at relatively low polymer concentrations of 200 ppm.

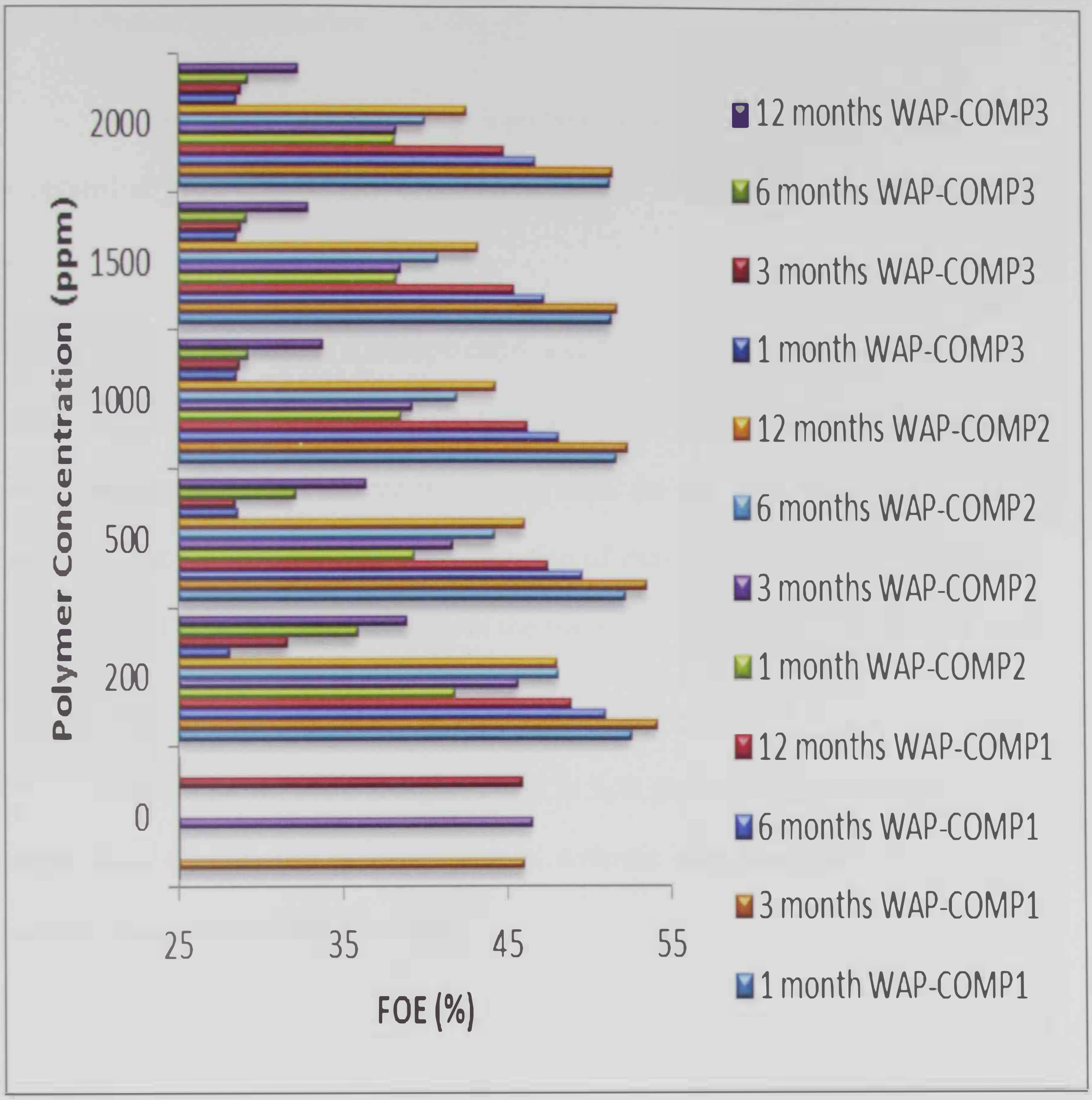

Figure 5.52: FOE of different scenarios of WAP injection

5.2.3 Polymer Slug Injection

To implement polymer slug injection, forty five simulation runs were simulated at different polymer concentrations, well completion, and polymer slug sizes.

The slug size in this case is 0.0685, 0.0856, and 0.143 PV which corresponds to two, three, and five years of polymer injection. The polymer slug injection started after implementing waterflooding for two years; then the run will proceed with water injection. Out of the forty five runs, a selection of vital nine runs will be presented in this section. The selected ones represent the maximum oil recovery obtained for each combination of parameters.

Tables 5.34 to 5.36 and Figures 5.53 to 5.55 present the results and reservoir performance of different concentrations at different slug sizes (different polymer timing) where COMP1 has been used.

Table 5.34: Polymer slug injection results (1000 ppm, COMP1, 2 years, 1500 STB/D)

Development Process Results						
Development Process	**FOPR (STB/D)**	**FOPT (STB)**	**FWPT (STB)**	**WCIR (LB/D)**	**WCPT (LB)**	**FOE (%)**
Polymer slug	156.95	6.57E+6	14.36E+6	0.0	40.74E+6	49.26

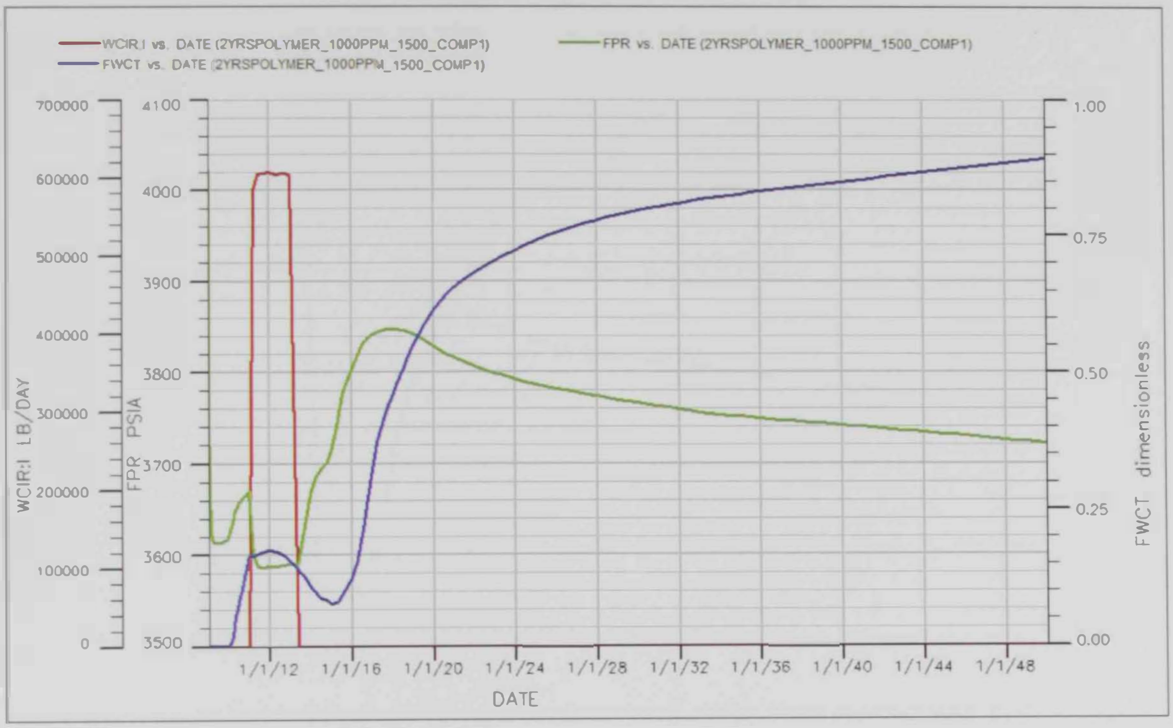

Figure 5.53: Polymer slug injection at 1500 STB/D (1000 ppm, COMP1, 2 years) reservoir performance

Table 5.35: Polymer slug injection results (1000 ppm, COMP1, 3 years, 1500 STB/D)

Development Process Results						
Development Process	**FOPR (STB/D)**	**FOPT (STB)**	**FWPT (STB)**	**WCIR (LB/D)**	**WCPT (LB)**	**FOE (%)**
Polymer slug	164.10	6.56E+6	13.83E+6	0.0	67.86E+6	49.17

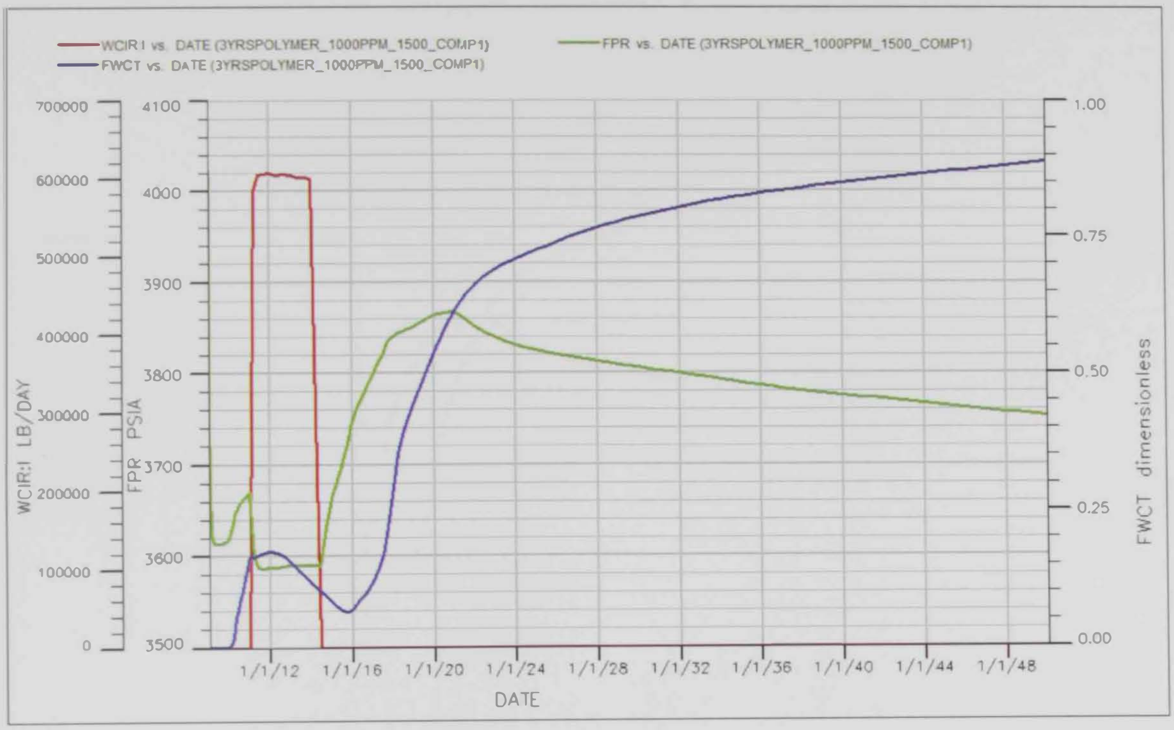

Figure 5.54: Polymer slug injection at 1500 STB/D (1000 ppm, COMP1, 3 years) reservoir performance

Table 5.36: Polymer slug injection results (500 ppm, COMP1, 5 years, 1500 STB/D)

Development Process Results						
Development Process	**FOPR (STB/D)**	**FOPT (STB)**	**FWPT (STB)**	**WCIR (LB/D)**	**WCPT (LB)**	**FOE (%)**
Polymer slug	164.54	6.55E+6	13.22E+6	0.0	56.70E+6	49.07

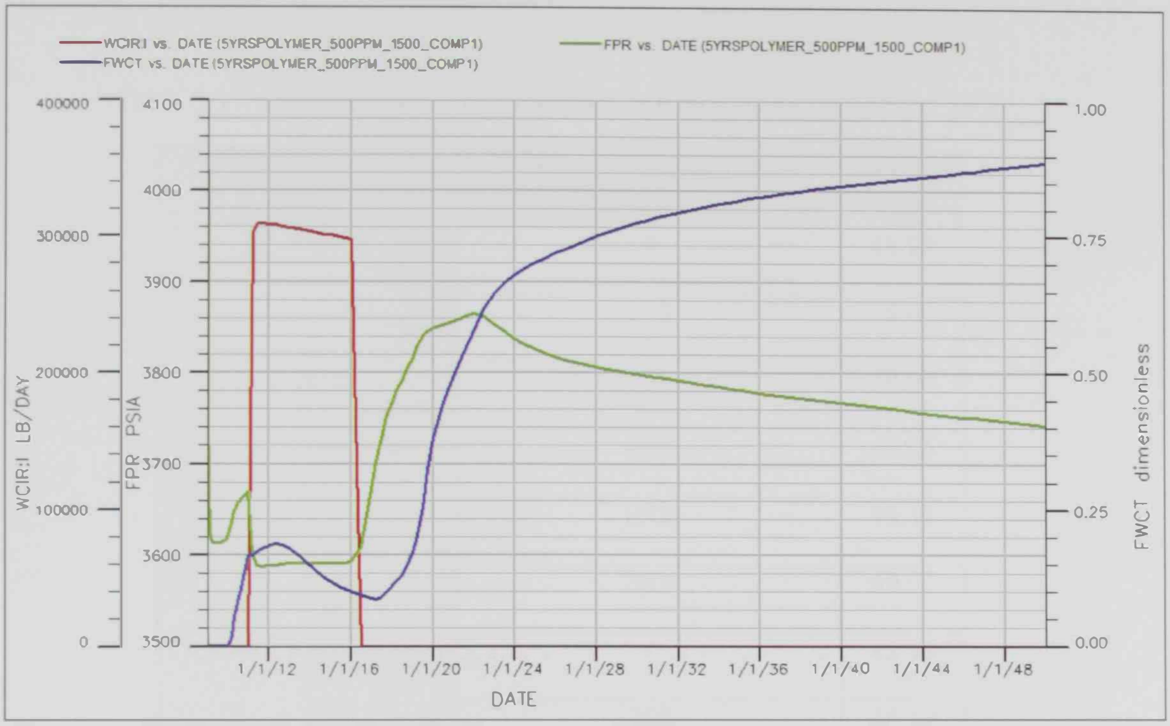

Figure 5.55: Polymer slug injection at 1500 STB/D (500 ppm, COMP1, 5 years) reservoir performance

From the illustrated results, the water cut has decreased by 6 to 9 % during the polymer injection period; after that the curve started to rise up again to 90% once the pressure started to build up.

At the start of the flood, the reservoir pressure decreases and as soon as the injected solution started to breakthrough, the pressure raised a little bit. During the polymer injection period, the pressure is decreased and maintained at about 3600 psia.

In addition, when 90% water cut has been reached; the FPR is about 3750 psia. Furthermore, as the polymer slug size increases, less polymer concentration is required to be injected to achieve high oil recoveries.

The complete set of results using COMP1 is presented in Table 5.37 and Figures 5.56 to 5.58.

Table 5.37: Oil recovery for polymer slug injection using COMP1 at 2050

Slug Size (PV)	Polymer Concentration (ppm)	FOE (%)
0.0685 (2 years polymer)	0	45.98
	200	48.00
	500	49.00
	1000	49.26
	1500	49.18
	2000	49.05
0.0856 (3 years polymer)	0	45.98
	200	48.40
	500	49.03
	1000	49.17
	1500	48.85
	2000	48.53
0.143 (5 years polymer)	0	45.98
	200	48.75
	500	49.07
	1000	48.61
	1500	47.96
	2000	47.45

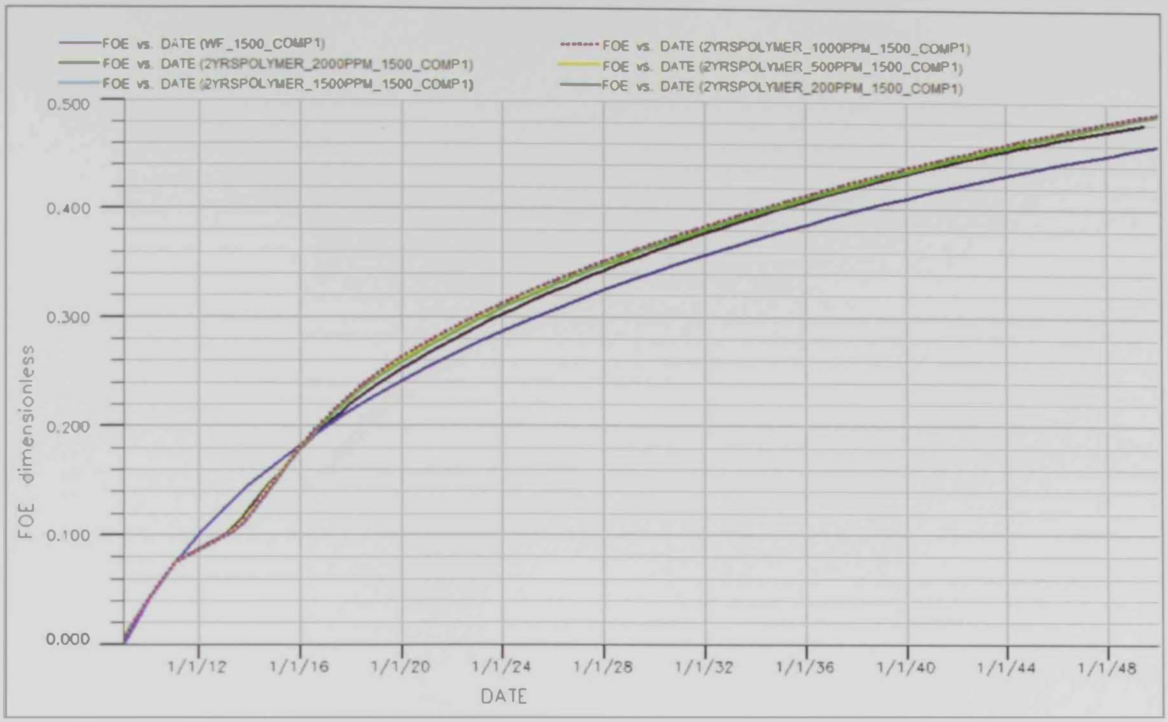

Figure 5.56: Oil recovery for 2 years polymer injection using COMP1

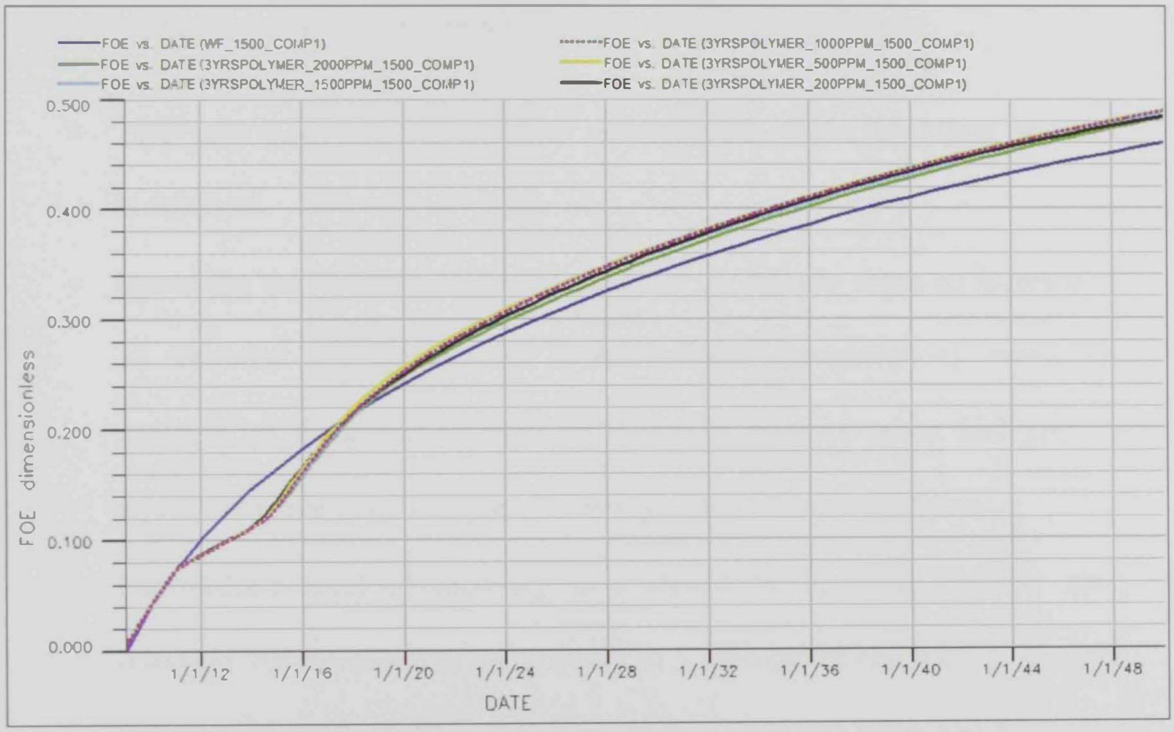

Figure 5.57: Oil recovery for 3 years polymer injection using COMP1

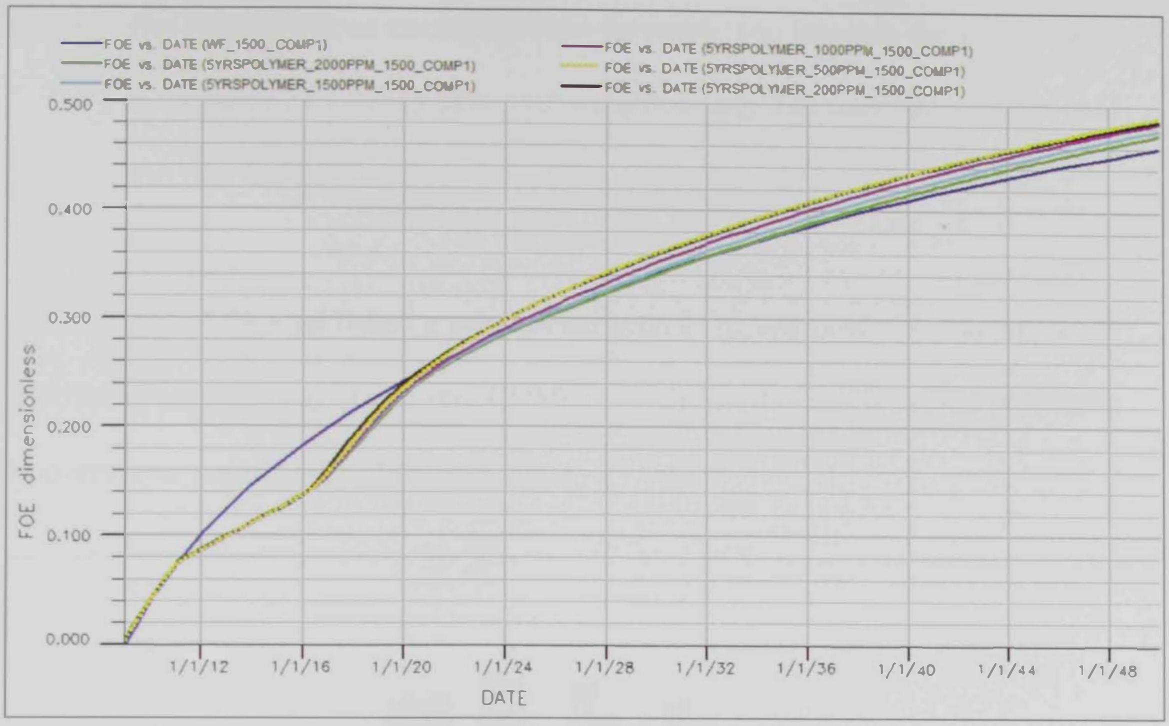

Figure 5.58: Oil recovery for 5 years polymer injection using COMP1

The following inferences can be drawn regarding the illustrated results:

- 1000 ppm is the optimum polymer concentration where maximum recovery is achieved.
- Increasing the polymer slug size; does not necessarily mean an increase in oil recovery. This might work at low polymer concentrations; where for example an increment in FOE of 0.75% is attained when 200 ppm is injected for five years compared to two years of polymer injection.
- Intermediate level of recovery is observed by applying polymer slug injection. An increment in oil recovery of 3.28% can be reached by injecting polymer solution of 1000 ppm concentration over two years and this is the maximum that can be achieved when all layers were completed for injection and production.

- The fifteen options attempted were favorable and increase the oil recovery in the range of 1.47 - 3.28% over waterflooding. The economics in this case will take the decision.

Figure 5.59 established a relation between FOE and polymer concentrations at different polymer slug sizes using COMP1. As shown the results exhibit promising recovery over normal water flooding.

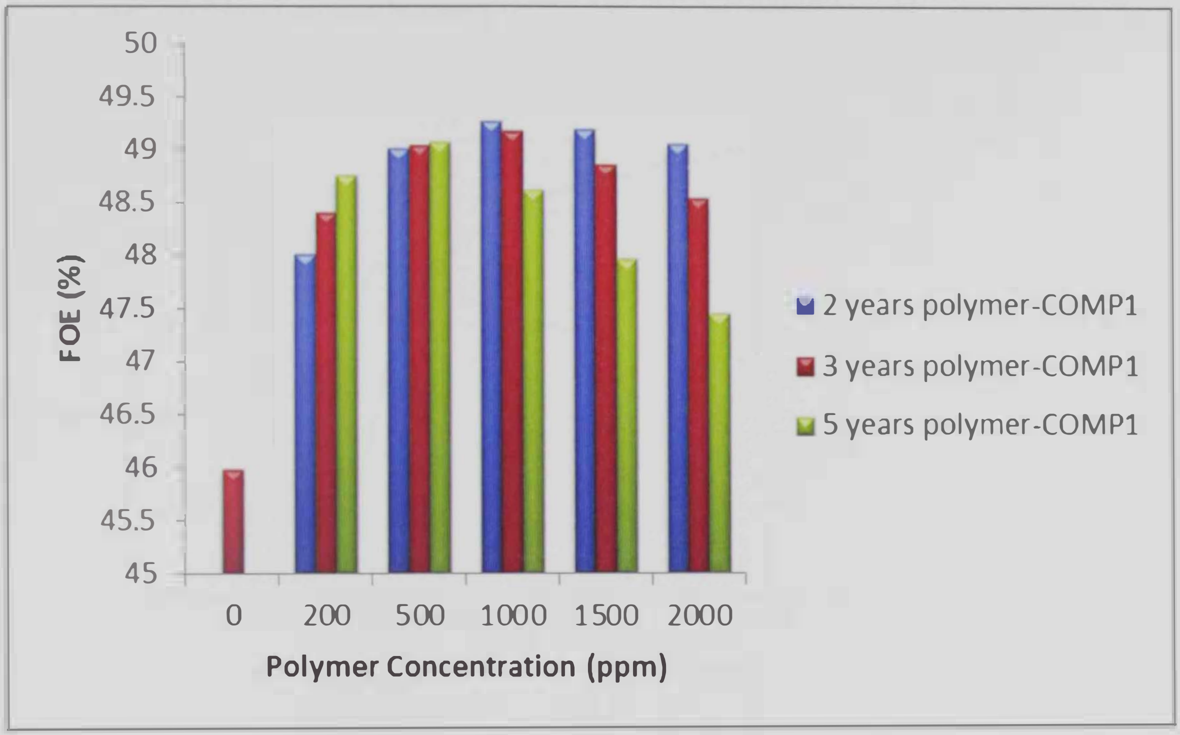

Figure 5.59: FOE vs. polymer concentration using COMP1 (polymer slug injection)

Again, three sets of results were selected for illustration using COMP2. The results are presented in Tables 5.38 to 5.40 and Figures 5.60 to 5.62.

Table 5.38: Polymer slug injection results (500 ppm, COMP2, 2 years, 1500 STB/D)

Development Process Results						
Development Process	FOPR (STB/D)	FOPT (STB)	FWPT (STB)	WCIR (LB/D)	WCPT (LB)	FOE (%)
Polymer slug	147.85	6.53E+6	14.42E+6	5.48E+8	12.31E+6	48.98

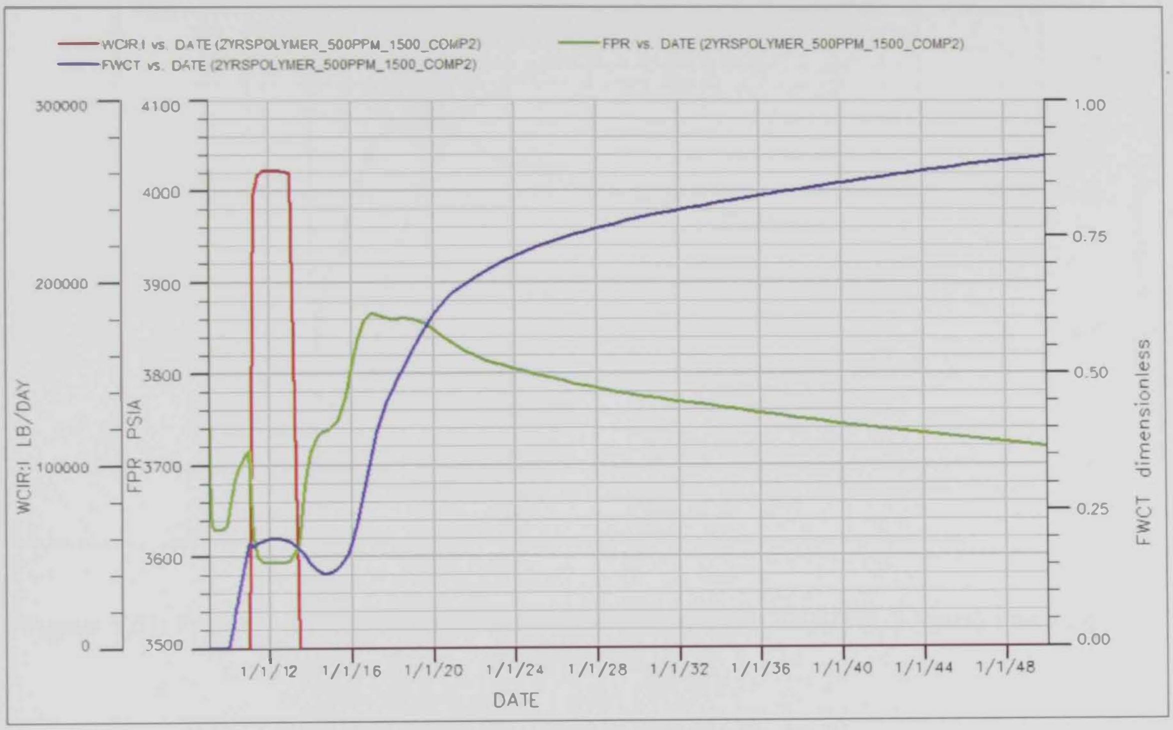

Figure 5.60: Polymer slug injection at 1500 STB/D (500 ppm, COMP2, 2 years) reservoir performance

Table 5.39: Polymer slug injection results (500 ppm, COMP2, 3 years, 1500 STB/D)

Development Process Results						
Development Process	FOPR (STB/D)	FOPT (STB)	FWPT (STB)	WCIR (LB/D)	WCPT (LB)	FOE (%)
Polymer slug	154.81	6.51E+6	13.90E+6	0.0	22.80E+6	48.76

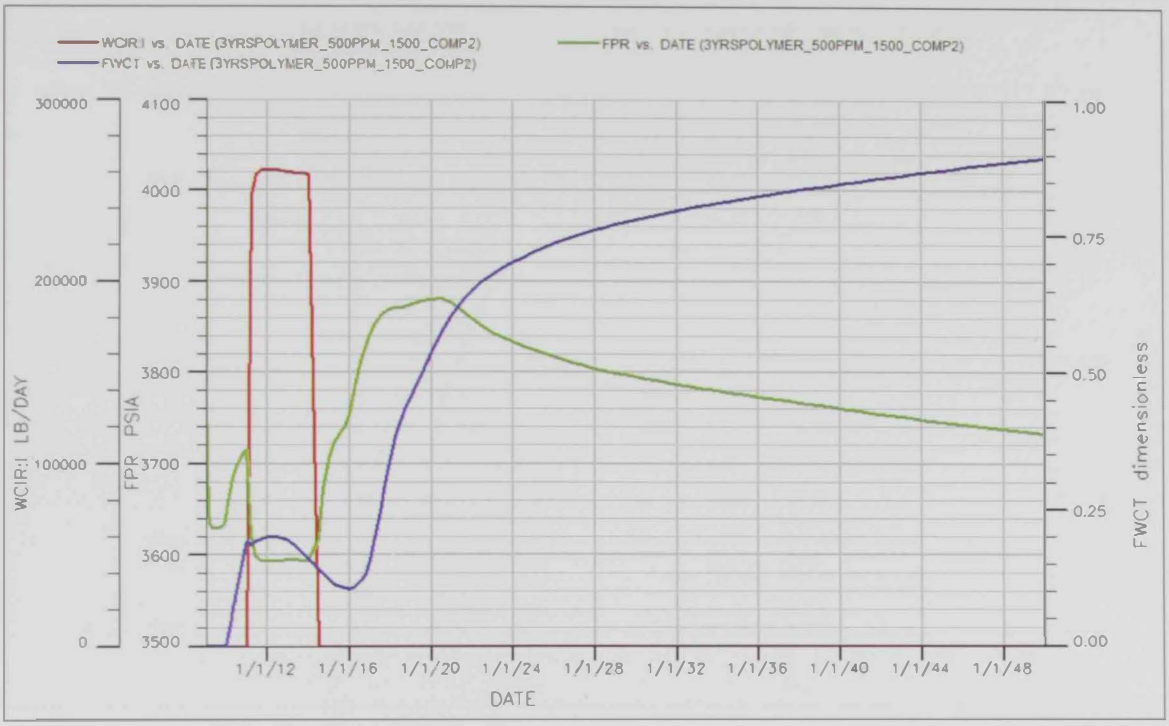

Figure 5.61: Polymer slug injection at 1500 STB/D (500 ppm, COMP2, 3 years) reservoir performance

Table 5.40: Polymer slug injection results (500 ppm, COMP2, 5 years, 1500 STB/D)

Development Process Results						
Development Process	**FOPR (STB/D)**	**FOPT (STB)**	**FWPT (STB)**	**WCIR (LB/D)**	**WCPT (LB)**	**FOE (%)**
Polymer slug	160.20	6.30E+6	13.30E+6	0.0	32.91E+6	47.25

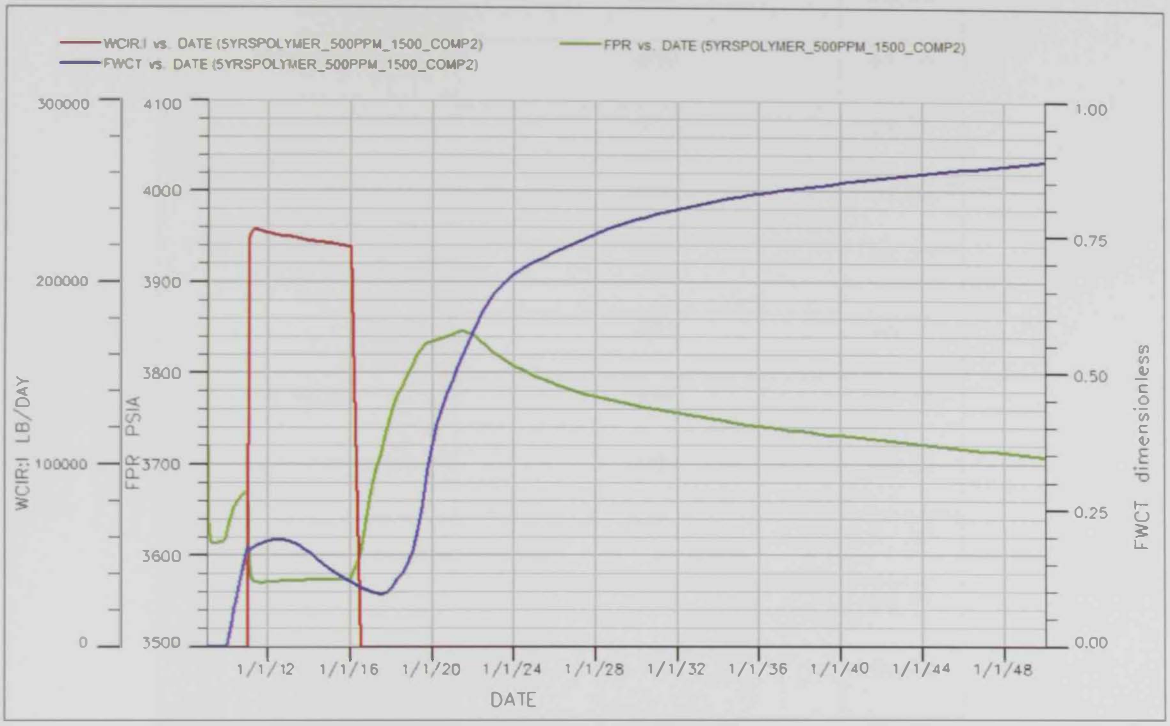

Figure 5.62: Polymer slug injection at 1500 STB/D (500 ppm, COMP2, 5 years) reservoir performance

The demonstrated results show that the reservoir performance when COMP2 is applied followed the same trends as in COMP 1

The complete set of results and comparisons using COMP2 is presented in Table 5.41 and Figures 5.63 to 5.65.

Table 5.41: Oil recovery for polymer slug injection using COMP2 at 2050

Slug Size (PV)	Polymer Concentration (ppm)	FOE (%)
0.0685 (2 years polymer)	0	46.47
	200	48.40
	500	48.98
	1000	48.66
	1500	48.26
	2000	47.94
0.0856 (3 years polymer)	0	46.47
	200	48.70
	500	48.76
	1000	48.19
	1500	47.63
	2000	46.91
0.143 (5 years polymer)	0	46.47
	200	47.17
	500	47.25
	1000	46.81
	1500	46.00
	2000	45.45

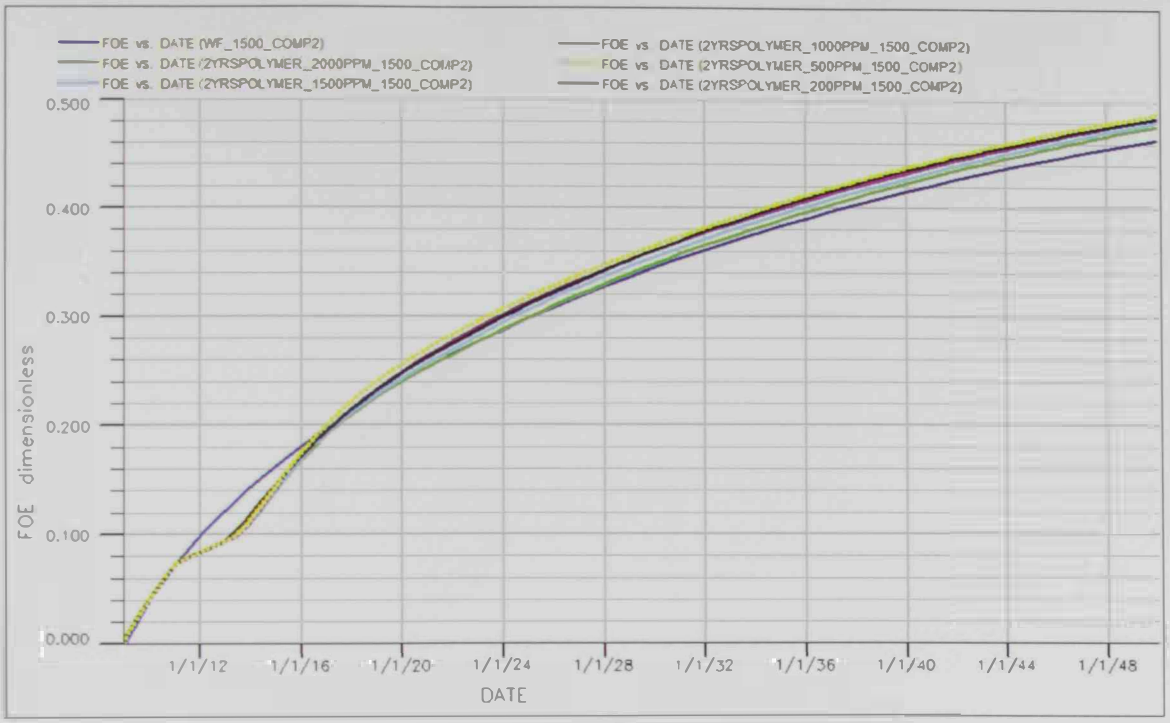

Figure 5.63: Oil recovery for 2 years polymer injection using COMP2

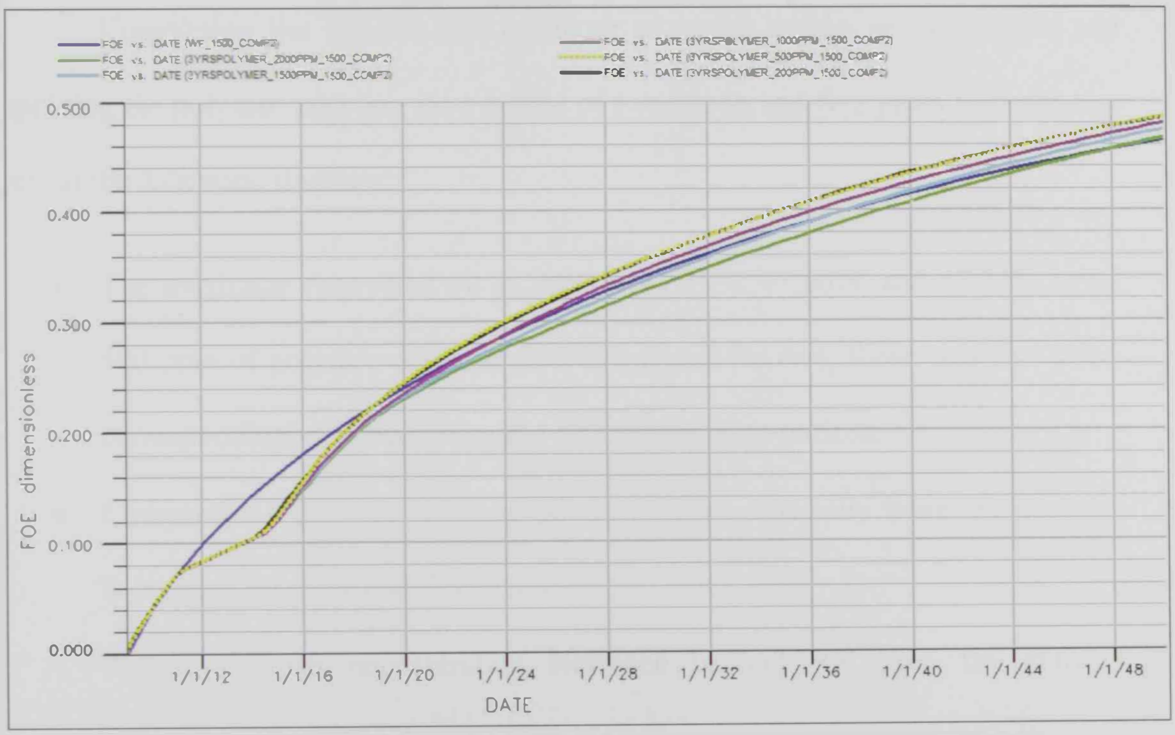

Figure 5.64: Oil recovery for 3 years polymer injection using COMP2

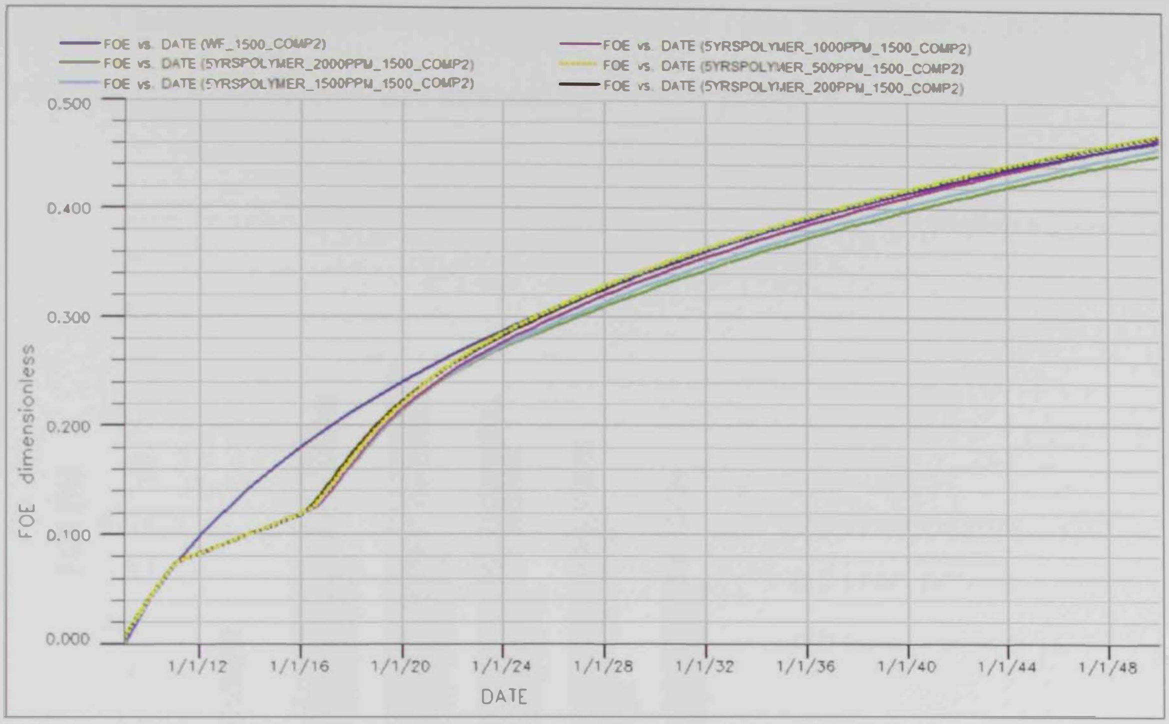

Figure 5.65: Oil recovery for 5 years polymer injection using COMP2

Completing the injector and producer as stated by the second option and applying the polymer injection for a period of two, three, and five years respectively; reveal the following findings:

- The maximum recovered oil at 2050 is 47.55%, 47.50%, and 47.34% when 500 ppm of polymer concentration is injected for two, three, and five years correspondingly. Hence, marginal differences were noticed.
- Comparable FOE was obtained using 200 ppm especially when the polymer is injected for three and five years.
- As the polymer concentration increased beyond 500 ppm, the FOE is reduced.
- Injecting polymer solution of 1500 ppm and 2000 ppm for five years showed a decrease in oil recovery by 0.47% and 1.02% respectively.

A comparison of the listed simulation runs in Table 5.41 is shown in Figure 5.66; where similar observations as stated before were proven.

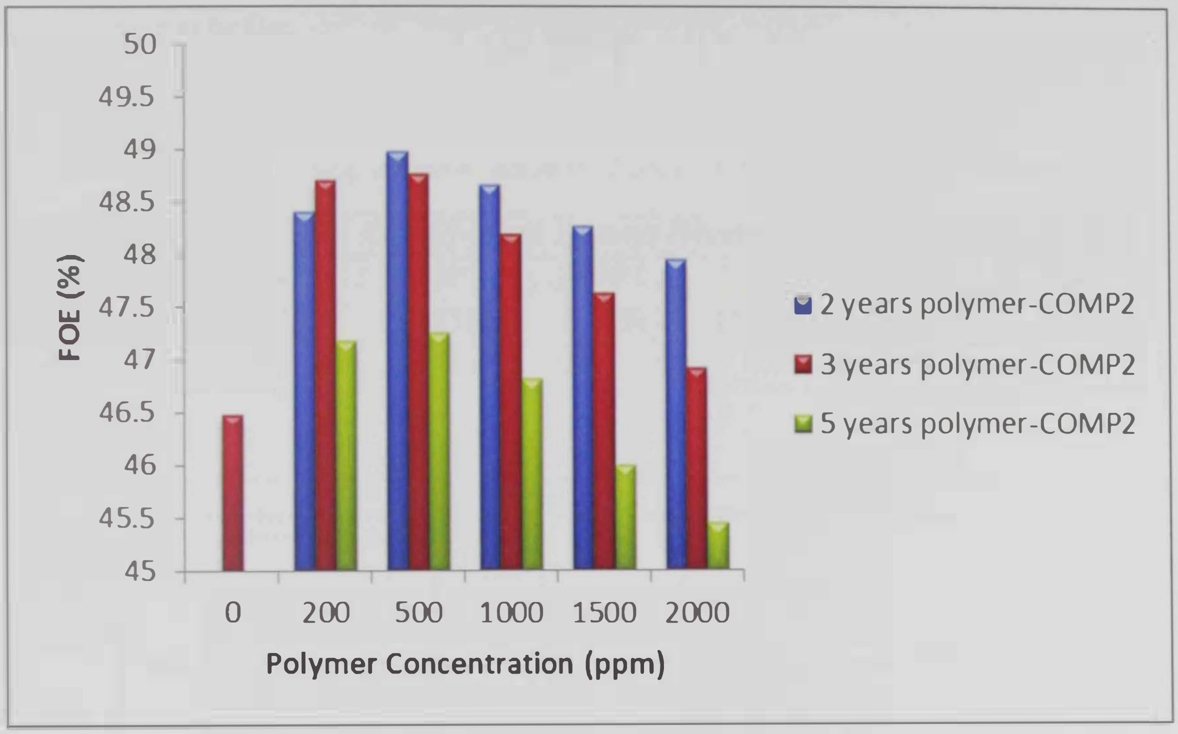

Figure 5.66: FOE vs. polymer concentration using COMP2 (polymer slug injection)

Tables 5.42 to 5.44 show the main results of the reservoir performance. Three reservoir performance profiles representing COMP3 are shown in Figures 5.67 to 5.69 represent different polymer timing attempted, where similar trends are encountered as before.

Table 5.42: Polymer slug injection results (500 ppm, COMP3, 2 years, 1500 STB/D)

Development Process Results						
Development Process	**FOPR (STB/D)**	**FOPT (STB)**	**FWPT (STB)**	**WCIR (LB/D)**	**WCPT (LB)**	**FOE (%)**
Polymer slug	176.25	6.14E+6	10.62E+6	0.0	7.15E+5	45.90

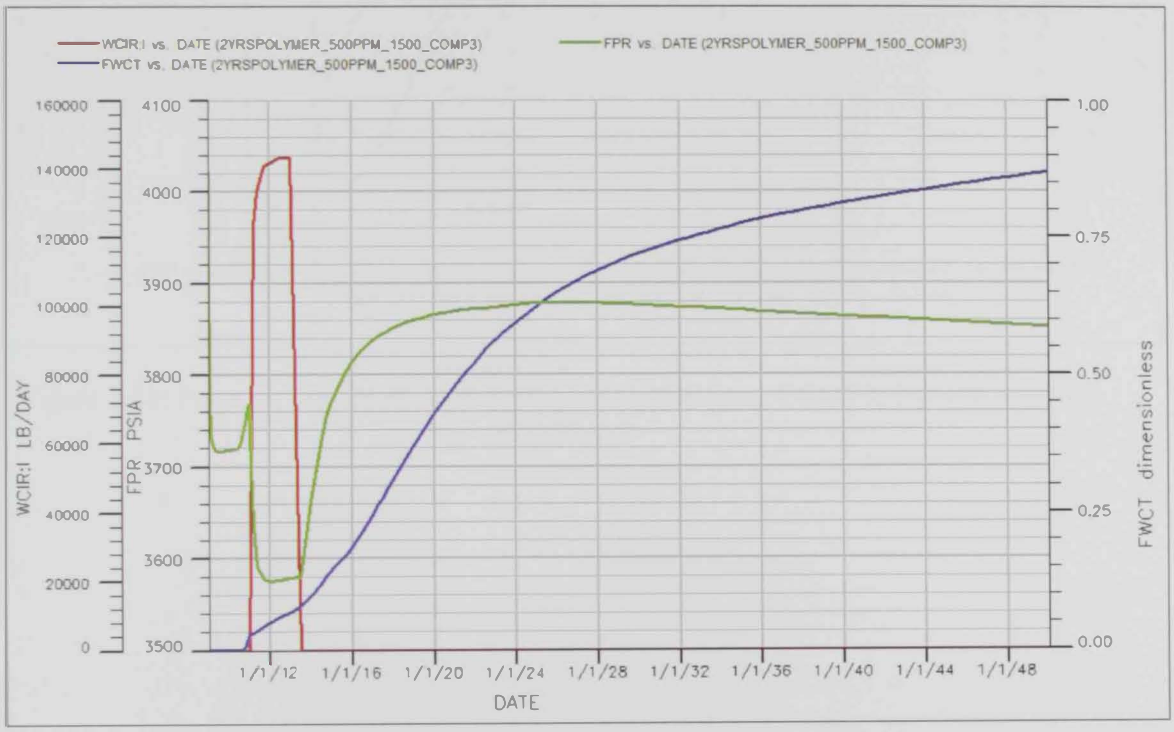

Figure 5.67: Polymer slug injection at 1500 STB/D (500 ppm, COMP3, 2 years) reservoir performance

Table 5.43: Polymer slug injection results (500 ppm, COMP3, 3 years, 1500 STB/D)

Development Process Results						
Development Process	**FOPR (STB/D)**	**FOPT (STB)**	**FWPT (STB)**	**WCIR (LB/D)**	**WCPT (LB)**	**FOE (%)**
Polymer slug	161.20	6.40E+6	12.37E+6	0.0	9.00E+6	47.87

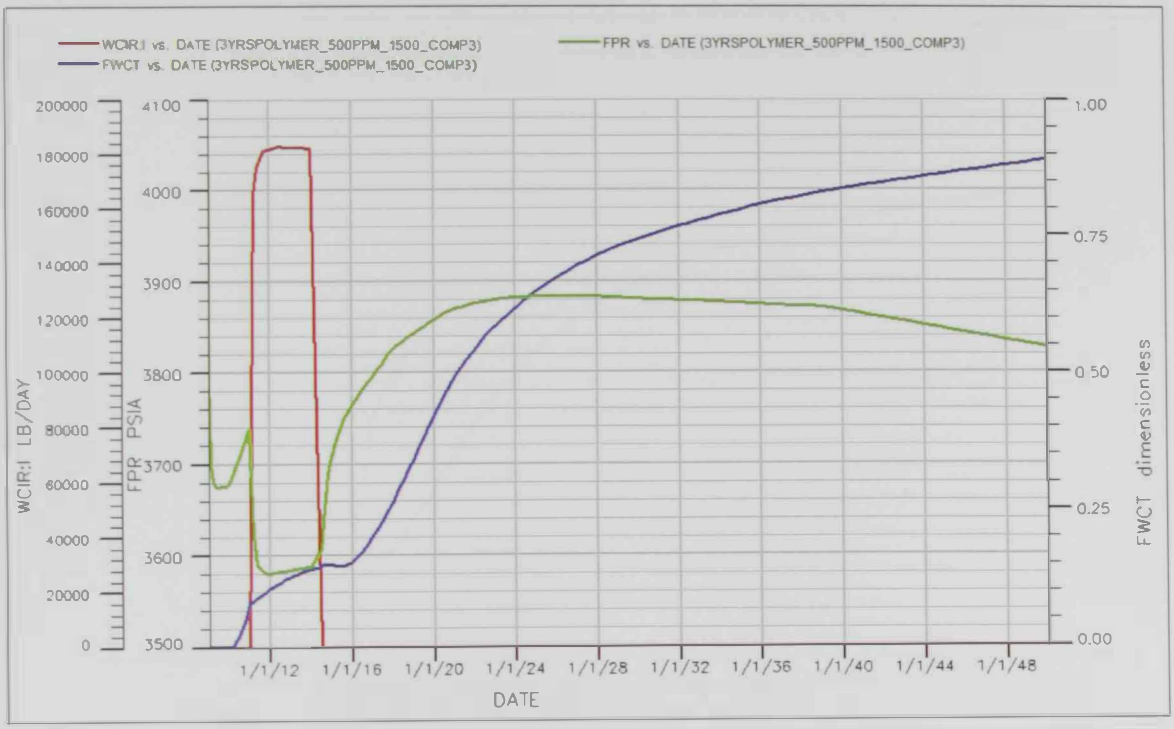

Figure 5.68: Polymer slug injection at 1500 STB/D (500 ppm, COMP3, 3 years) reservoir performance

Table 5.44: Polymer slug injection results (200 ppm, COMP3, 5 years, 1500 STB/D)

Development Process Results						
Development Process	FOPR (STB/D)	FOPT (STB)	FWPT (STB)	WCIR (LB/D)	WCPT (LB)	FOE (%)
Polymer slug	184.00	6.00E+6	9.70E+6	0.0	9.36E+5	45.30

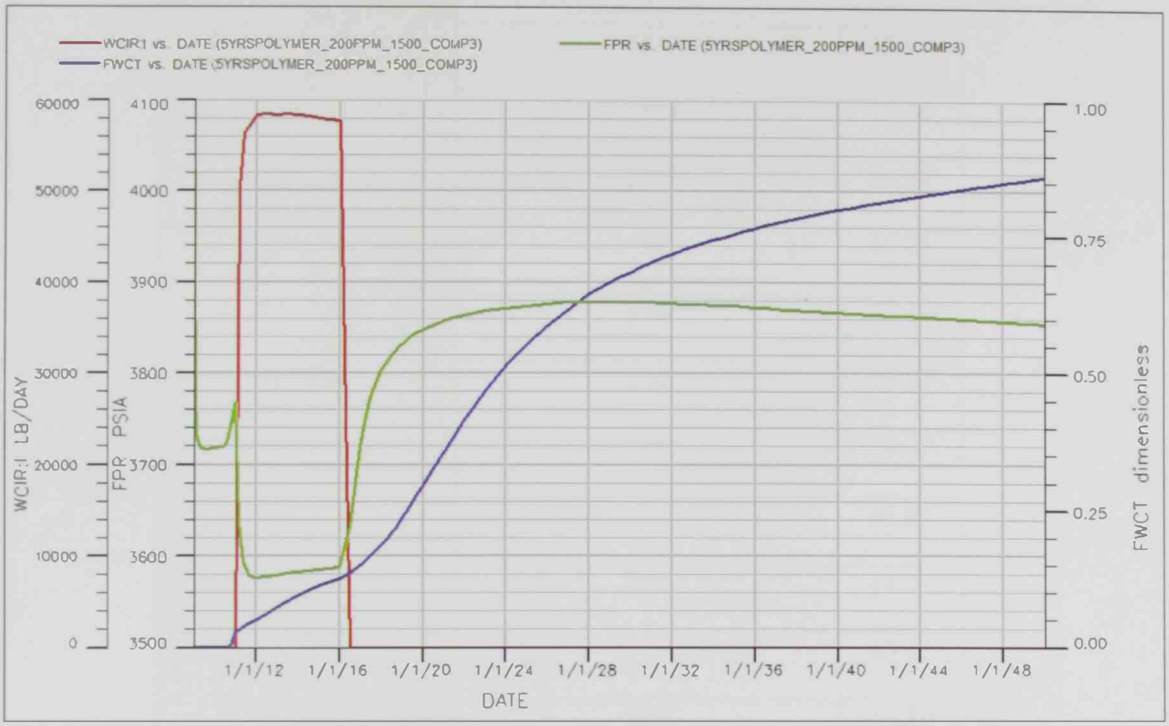

Figure 5.69: Polymer slug injection at 1500 STB/D (200 ppm, COMP3, 5 years) reservoir performance

Table 5.45 presents a summary of the studied options by implementation of polymer slug injection using COMP3 at different polymer injection periods and polymer concentrations with the normal waterflooding. The maximum oil recovery of about 48% is obtained by the use of 500 ppm when the polymer slug is injected for three years. Also, it has been observed that marginal differences encountered between 200 ppm and 500 ppm when the polymer in injected for the same period; where the selection of the best option will be based on the economic study.

Table 5.45: Oil recovery for polymer slug injection using COMP3 at 2050

Slug Size (PV)	Polymer Concentration (ppm)	FOE (%)
0.0685 (2 years polymer)	0	45.85
	200	45.79
	500	45.90
	1000	45.62
	1500	45.10
	2000	44.50
0.0856 (3 years polymer)	0	45.85
	200	47.53
	500	47.87
	1000	47.07
	1500	45.84
	2000	44.71
0.143 (5 years polymer)	0	45.85
	200	45.30
	500	44.68
	1000	43.30
	1500	42.00
	2000	41.00

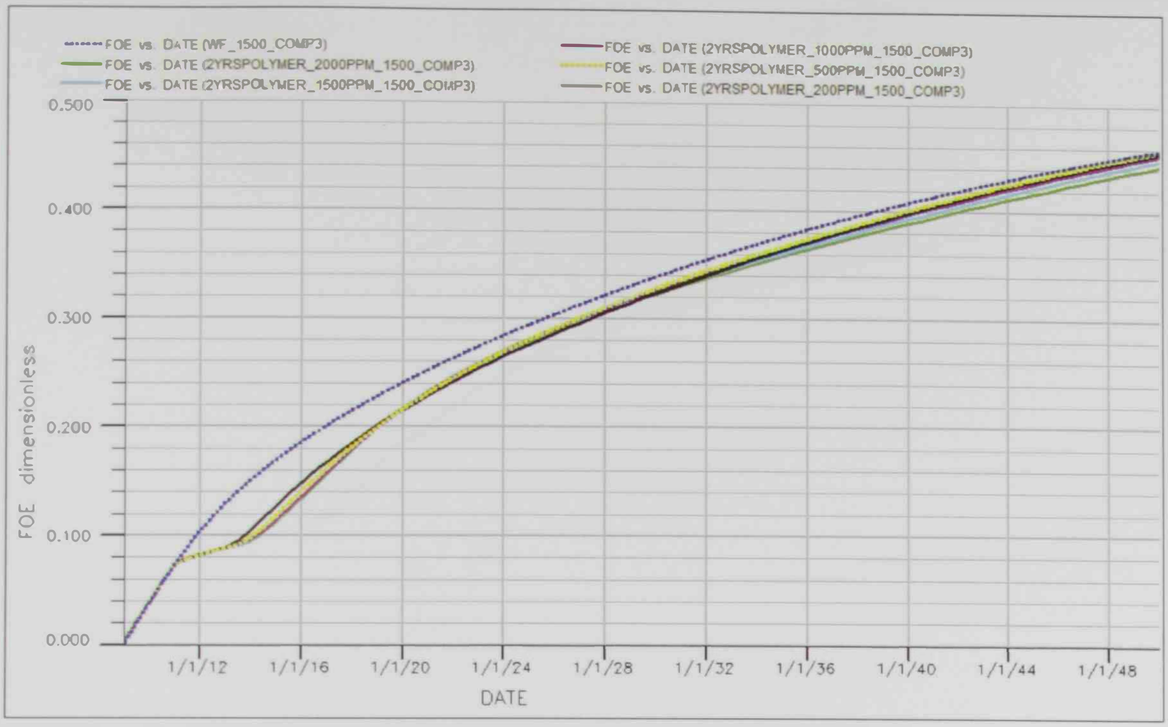

Figure 5.70: Oil recovery for 2 years polymer slug injection using COMP3

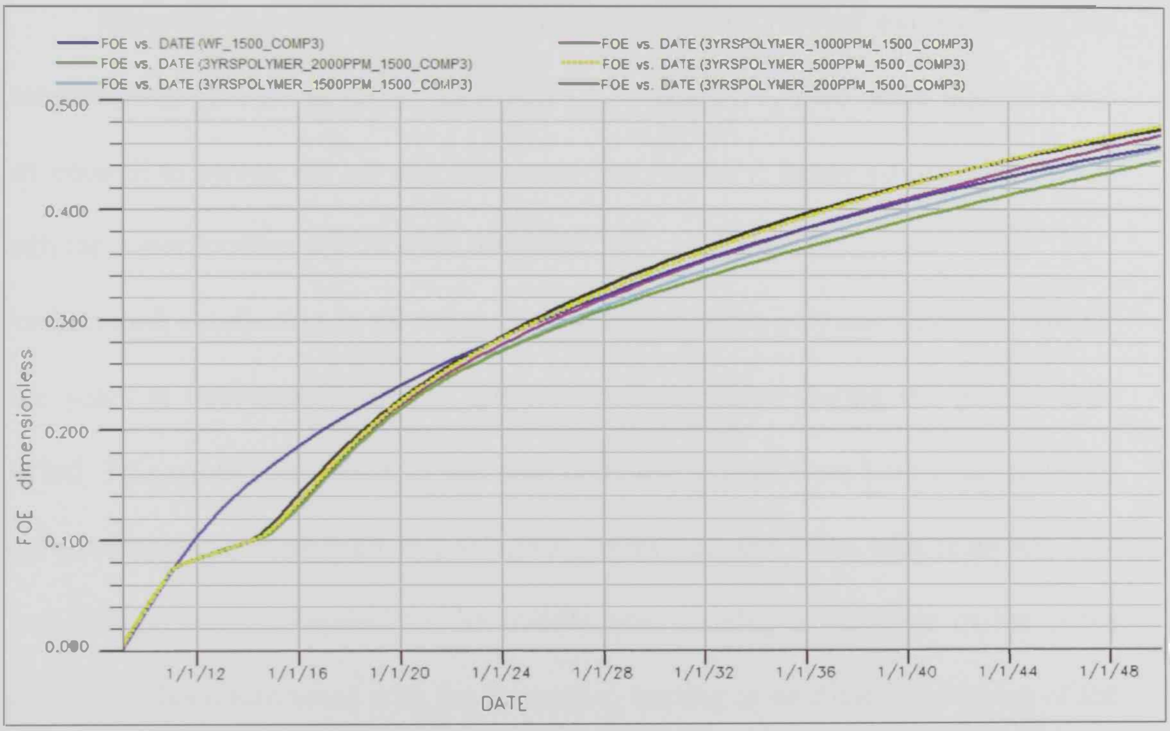

Figure 5.71: Oil recovery for 3 years polymer slug injection using COMP3

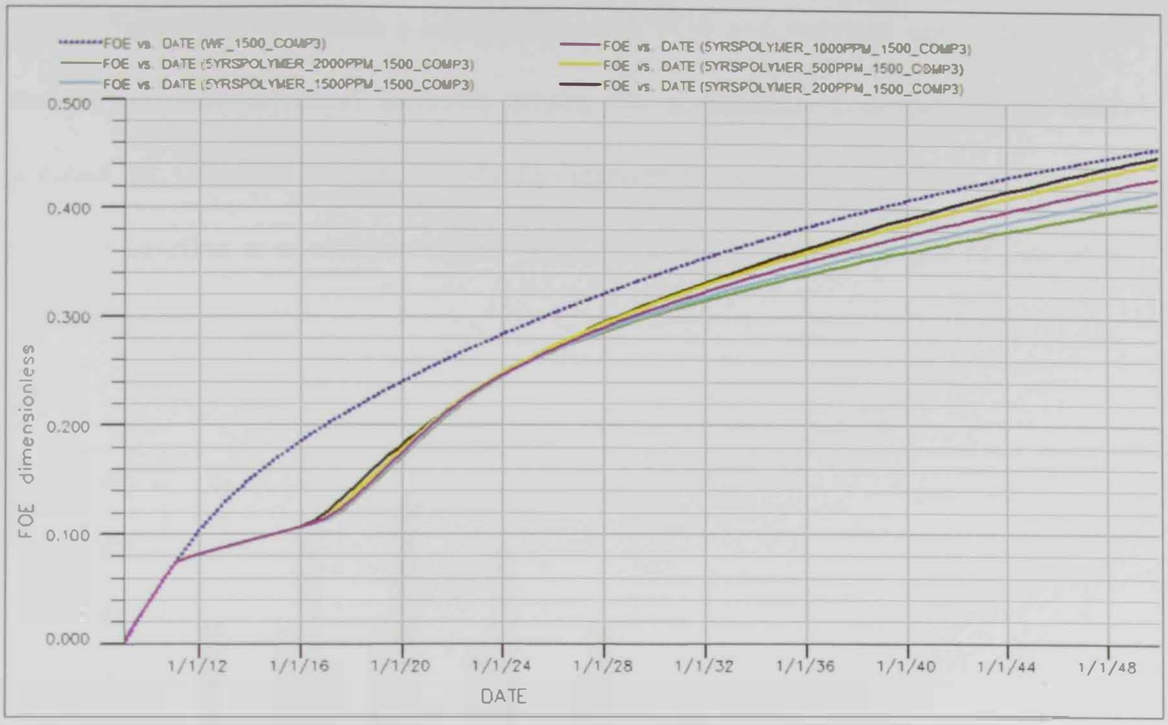

Figure 5.72: Oil recovery for 5 years polymer slug injection using COMP3

Injecting polymer for two and five years didn't recover extra oil over the waterflooding process as shown in Figures 5.70 and 5.72. Two years injection was not enough to sweep the oil and increment the recovery; hence comparable results with the waterflooding option were obtained.

Furthermore, a reduction in oil recovery is observed when polymer slug injection for five years is implemented at the different concentrations during the project time period. This could be referred to the well completion used were both wells (injector and producer) are completed in geological layers one and three with relatively low permeability when compared to the middle one; causing a blockage of the pores when it has been interacted with the formation, leading to inefficient sweeping of the oil.

Generally, COMP3 is not recommended to be used as an option to maximize the oil recovery by polymer flooding.

Figure 5.73 provides a relation between FOE and polymer concentration at various polymer injection intervals where the completion configuration is held constant at COMP3. As shown, better recoveries could be obtained when the polymer solution is injected for three years at quite low concentrations of 200 ppm and 500 ppm.

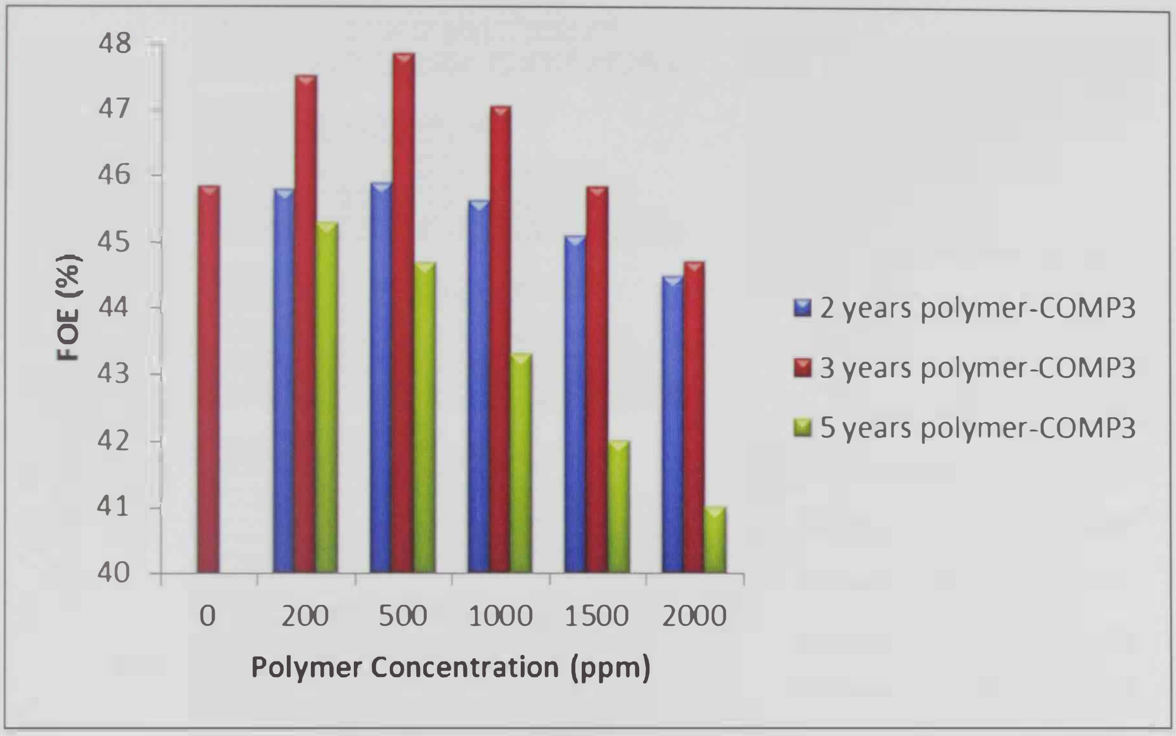

Figure 5.73: FOE vs. polymer concentration using COMP3 (polymer slug injection)

A comparison between the different options attempted as polymer slug injection is presented in Figure 5.74 in terms of FOE versus different polymer concentrations ranging between 200 and 2000 ppm, for the three well completions investigated, and polymer injection period (different PV).

The maximum oil recovery could be achieved by implementation of polymer slug injection after two years of water flooding for a period of two years using well completion 1, and by injecting 1000 ppm of the polymer solution. Furthermore, injecting the polymer solution at high concentrations of 1500 ppm and 2000 ppm is not beneficial as well as completing the well as in well completion 3, where both the injector and producer are completed in geological layers one and three.

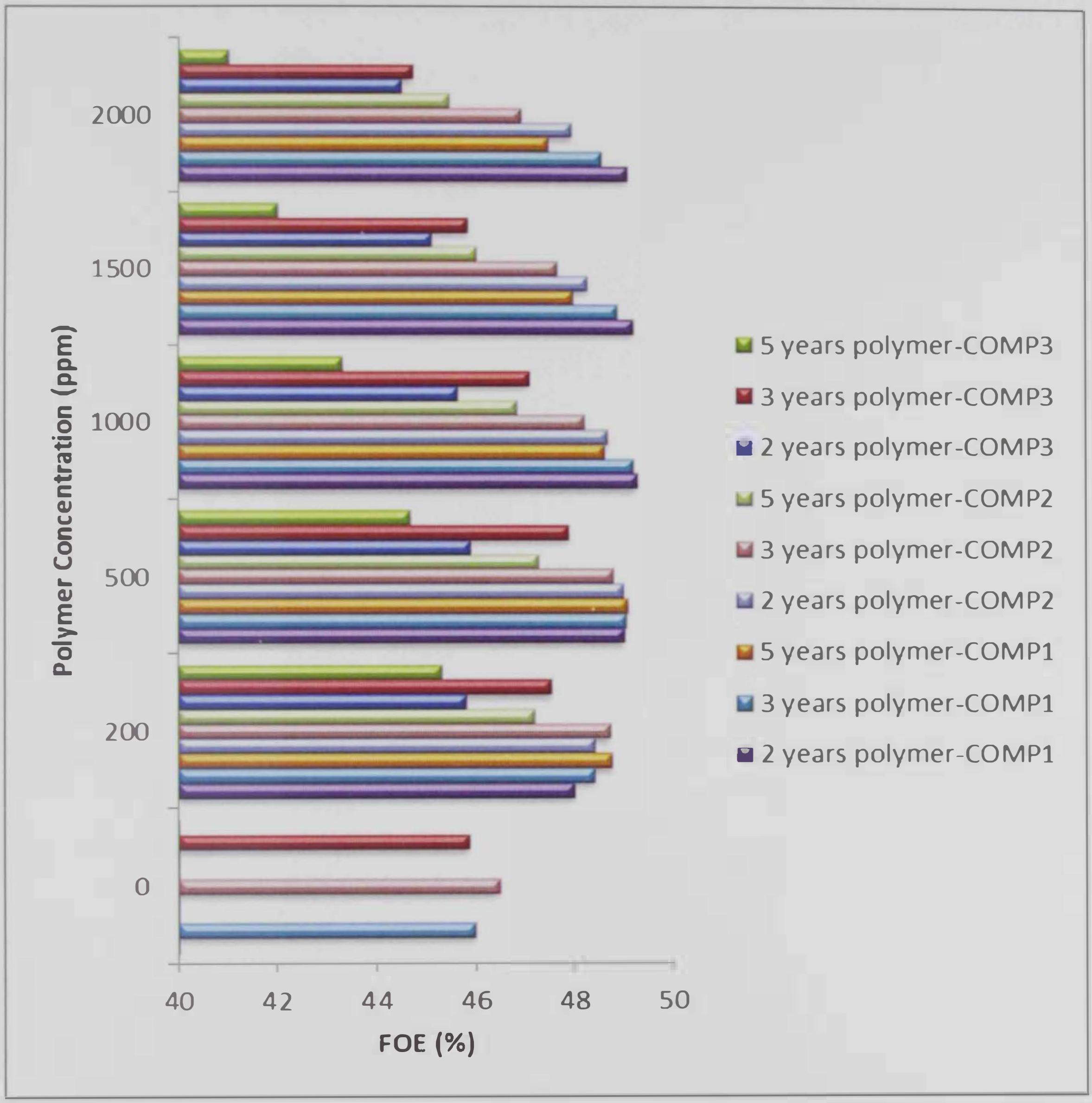

Figure 5.74: FOE at different scenarios of polymer slug injection

In general, the required volumes of polymer solution to be injected using the slug injection process is less than the other two options including continuous polymer injection and WAP injection. Also, through the polymer slug injection sensitivity analysis; the water cut approaches its economic limit of 90% in 2050. Therefore, when the polymer is injected in a continuous basis or as equally alternating slug with water; the economic limit of water cut is still not reached. This lead that extending the study period for more than 41 years could improve the oil recovery; keeping in mind that any decision is based on the management and business plan of the project.

Chapter 6 : Conclusions and Recommendations

6.1 Conclusions

The results of this study lead to the following conclusions:

- Injection rate of 1500 STB/D is the optimum operating injection rate for the synthetic reservoir model.
- Implementation of polymer flooding by different processes including continuous polymer injection, WAP injection, and polymer slug injection proves that the sweep efficiency has been improved.
- A recovery factor of more than 50% could be achieved by continuous polymer injection process, using well completion 1 where the polymer concentration ranges between 200 and 2000 ppm.
- The effect of polymer concentration on the continuous polymer injection process is not clear. Thus, it is more economical to use 200 ppm that gives the highest FOE.
- Continuous polymer flooding is not practical since it requires large volumes of polymer to be injected.
- A maximum oil recovery of 54% could be achieved by the employment of WAP injection using minimum polymer concentration of 200 ppm, WAP cycle of three months and using well completion 1.
- Well completion 2 failed to recover extra oil over waterflooding and in all cases it recovers less. The only increment of 1.5% could be achieved when 200 ppm is injected for a WAP interval time of 6 or 12 months.

- Implementation of WAP process using well completion 3 showed unfavorable results in terms of oil recovery at different polymer concentrations and WAP timing through the project life.
- A maximum oil recovery of 49.26% could be achieved by polymer slug injection for two years at 1000 ppm using well completion 1. The effect of polymer concentration is minimal in this case.
- Lower FOE has been obtained using well completion 2 over well completion 1 when polymer flooding is implemented. Furthermore, well completion 3 was not effective as an option for maximization of oil recovery.
- Polymer slug timing is an effective technical parameter to be studied and it is a function of formation properties. Three years of polymer slug injection gave the maximum oil recovery.
- Generally, the oil recovery has been affected by polymer concentration when other technical parameters are held constant. Decreasing the polymer concentration, increases the oil recovery in the synthetic model used.
- Polymer flooding promotes incremental oil production by increasing the amount of oil produced before reaching the economic water cut limit of 90%.
- The effect of polymer flooding options attempted will be more favorable when it is applied on heavy oils.

6.2 Recommendations

The recommendations for future work could include:

- Attempting multi contact well completion to study its effect on the sweep efficiency of the polymer flood.
- Study the effect of polymer adsorption on the saturation functions.
- Implementing water alternating polymer injection at different WAP ratios and examine its effect in improving the oil recovery; to come up with the optimum one.
- Implementing the polymer flooding project on any candidate reservoir by following the standard procedure reported in Figure 6.1 to optimize the development option.

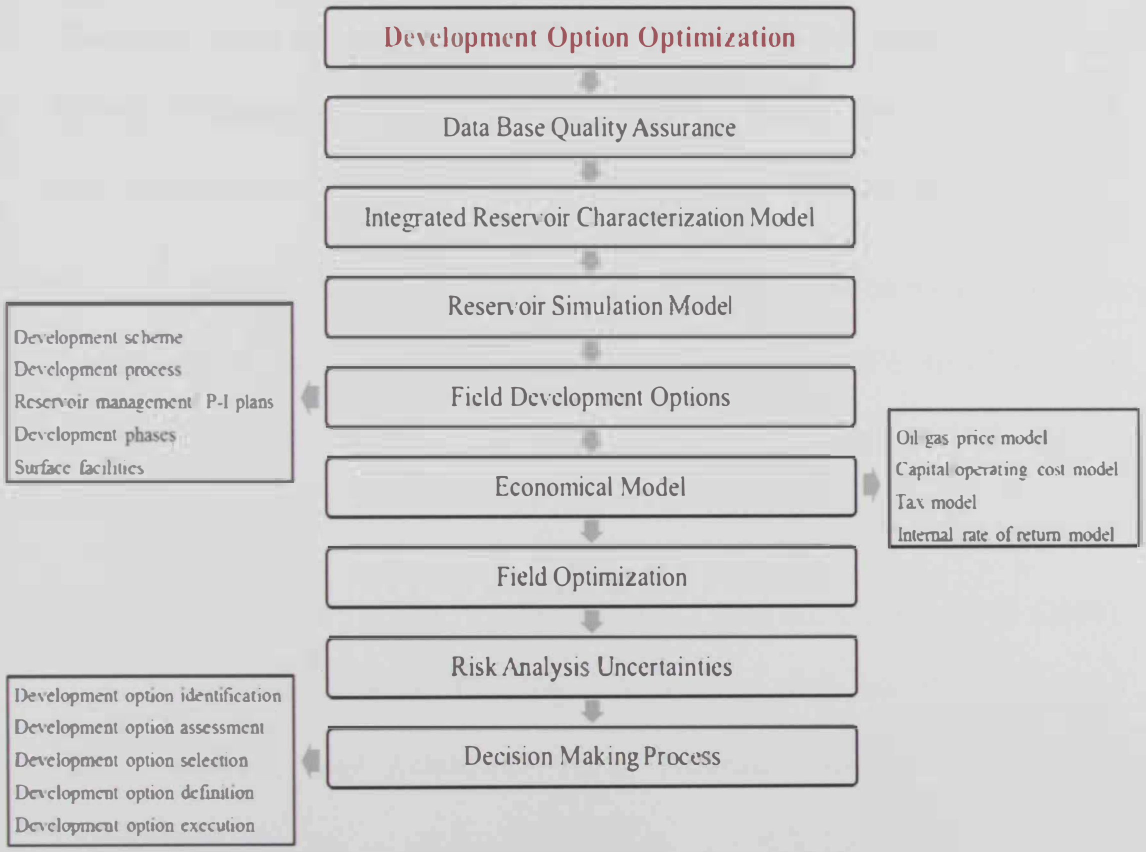

Figure 6.1: Development option optimization flow chart

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Appendix

Polymer Flooding Model Data File (2 years polymer "slug injection", 1000 ppm, 1500 STB/D, COMP1)

RUNSPEC

TITLE

Synthetic model oil/water/polymer

DIMENS

30 21 15 /

OIL

WATER

POLYMER

FIELD

WELLDIMS

2 20 1 2 /

START

1 'JAN' 2009 /

NSTACK

100 /

UNIFOUT

GRID

==

INIT

BOX

1 30 1 21 1 1/

TOPS

630*4000/

EQUALS

'DX' 75 1 30 1 21 1 15/

```
'DY'    75/
'DZ'    10/
'PERMX' 100   1 30   1  21    1  5/
'PORO'  0.2 /
'PERMX' 1000   1 30   1  21    6  10/
'PORO'  0.22 /
'PERMX' 100   1 30   1  21    11  15/
'PORO'  0.2 /
/
COPY
 PERMX PERMY  /
 PERMX PERMZ  /
 /
MULTIPLY
  PERMZ   0.1  /
/
PROPS
================================================================
SWOF
0.2016 0.0000 0.9656 0.2469
0.2527 0.0006 0.7221 0.1583
0.3038 0.0051 0.5264 0.0963
0.3550 0.0173 0.3697 0.0548
0.4061 0.0411 0.2477 0.0286
0.4573 0.0802 0.1560 0.0133
0.5084 0.1386 0.0903 0.0052
0.5595 0.2202 0.0462 0.0015
0.6107 0.3286 0.0195 0.0003
0.6618 0.4679 0.0058 0.0000
```

```
0.7129 0.6418 0.0007 0.0000
0.7641 0.8543 0.0000 0.0000
/
-- Densities in lb/ft
--          Oil     Wat     Gas
--          ---     ---     ---
DENSITY
            49      63      0.01 /
-- PVT data for dead oil
--        P       Bo       Vis
--      ----     ----     -----
PVDO
        300      1.25      1.0
        800      1.20      1.1
       6000      1.15      2.0 /
-- PVT data for water
--        P       Bw       Cw        Vis     Viscosibility
--      ----     ----     -----     -----    -------------
PVTW
       4500      1.02     3e-06      0.8         0.0 /
-- Rock compressibility
--        P        Cr
--      ----     -----
ROCK
       4500      4e-06 /
PLYVISC
 0.0   1.0
 70.0  10.0 /
PLYROCK
```

```
  0.16  1.5  1000.0  1  0.005 /
 PLYADS
  0.0  0.000
 20.0  0.010
 70.0  0.010 /
TLMIXPAR
 1.0 /
PLYMAX
 50.0  0.0 /
RPTPROPS
 -- PROPS Reporting Options
 --
 'PLYVISC'
/
--RPTREGS
-- Controls on output from regions section
--'MISCNUM'
--/
SOLUTION
=====================================================
EQUIL
4000  4000  6000  0   0   0   0   0   0 /
RPTRST
BASIC=2/
--RPTSOL
-- Initialisation Print Output
--'RESTART=2' 'FIP=2' 'PBLK' 'SALT' 'PLYADS' 'RK' 'FIPPLY=2' /
SUMMARY
=====================================================
-- Field average pressure
```

```
FPR
-- Bottomhole pressure of all wells
WBHP
/
-- Field Oil Production Rate
FOPR
-- Field Water Production Rate
FWPR
-- Field Oil Production Total
FOPT
-- Field Water Production Total
FWPT
-- Field Water cut
FWCT
-- Field Water injection total
FWIT
-- Field oil recovery efficiency
FOE
--Well Polymer production rate
WCPR
'P' /
--Well Polymer production total
WCPT
'P' /
--Well Polymer injection rate
WCIR
'I' /
--Well Polymer Injection total
WCIT
```

```
'I' /
EXCEL
SCHEDULE
===============================================================
--RPTSCHED
--'PRES' 'SWAT' 'RESTART=2' 'FIP=2' 'WELLS=2' 'SUMMARY=2' 'CPU=2'
'WELSPECS'
--'NEWTON=2' 'PBLK' 'SALT' 'PLYADS' 'RK' 'FIPSALT=2' /
WELSPECS
'I' 'G' 8 11 4000 'WAT' 0.0 'STD' 'SHUT' 'NO' /
'P' 'G' 22 11 4000 'OIL' 0.0 'STD' 'SHUT' 'NO' /
/
COMPDAT
'I' 8 11 1 15 'OPEN' 0 .0 1.0 /
'P' 22 11 1 15 'OPEN' 0 .0 1.0 /
/
WCONPROD
'P' 'OPEN' 'BHP' 5* 3500.0 /
/
WECON
'P' 1* 1* 0.9 2* WELL YES /
/
WCONINJE
'I' 'WAT' 'OPEN' 'RATE' 1500.0 /
/
WPOLYMER
'I' 0.0 0.0 /
/
TUNING
1* 185 /
```

/

2* 100 /

DATES

1 APR 2009/

1 JUL 2009/

1 OCT 2009/

1 JAN 2010/

1 APR 2010/

1 JUN 2010/

1 JUL 2010/

1 JAN 2011/

/

WPOLYMER

'I' 1000.0 0.0 /

/

DATES

1 JAN 2012/

1 JAN 2013/

/

WPOLYMER

'I' 0.0 0.0 /

/

DATES

1 JAN 2014/

1 JAN 2015/

1 JAN 2016/

1 JAN 2017/

1 JUL 2017/

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