A STUDY OF BRIGHTWATER INJECTION EFFICIENCY ON SECTOR MODEL USING STARS SOFTWARE

A THESIS SUBMITTED TO
THE GRADUATE SCHOOL OF NATURAL AND APPLIED SCIENCES
OF
MIDDLE EAST TECHNICAL UNIVERSITY

BY

NARIMAN PASHAYEV

IN PARTIAL FULFILLMENT OF THE REQUIREMENTS
FOR
THE DEGREE OF MASTER OF SCIENCE
IN
PETROLEUM AND NATURAL GAS ENGINEERING

SEPTEMBER 2011

Approval of thesis:

A STUDY OF BRIGHTWATER INJECTION EFFICIENCY ON SECTOR MODEL USING STARS SOFTWARE

Submitted by **NARIMAN PASHAYEV** in partial fulfillment of the requirements for the degree of **Master of Science in Petroleum and Natural Gas Engineering Department, Middle East Technical University** by,

Prof. Dr. Canan Özgen ____________________
Dean, Graduate School of **Natural and Applied Sciences**

Prof. Dr. Mahmut Parlaktuna ____________________
Head of Department, **Petroleum and Natural Gas Engineering**

Prof. Dr. Serhat Akın ____________________
Supervisor, **Petroleum and Natural Gas Engineering Dept., METU**

Examining Committee Members:

Prof. Dr. Mahmut Parlaktuna ____________________
Petroleum and Natural Gas Engineering Dept., METU

Prof. Dr. Serhat Akın ____________________
Petroleum and Natural Gas Engineering Dept., METU

Prof. Dr. Mustafa Kök ____________________
Petroleum and Natural Gas Engineering Dept., METU

M.Sc. Murat Demir ____________________
Production Dept., Turkish Petroleum Corporation

M.Sc. Serhan Tanrısınıbilir ____________________
Research Center, Turkish Petroleum Corporation

Date: __14/09/2011 ___

I hereby declare that all information in this document has been obtained and presented in accordance with academic rules and ethical conduct. I also declare that, as required by these rules and conduct, I have fully cited and referenced all material and results that are not original to this work.

Name, Last name: Nariman Pashayev

Signature:

ABSTRACT

A STUDY OF BRIGHTWATER INJECTION EFFICIENCY ON SECTOR MODEL USING STARS SOFTWARE

Nariman Pashayev

M.Sc., Department of Petroleum and Natural Gas Engineering
Supervisor: Prof. Dr. Serhat Akin

September 2011, 141 pages

Maintaining proper waterflood conformance is a critical component of waterflood management. Most methods used to control waterflood conformance have proven to be only marginally effective. A unique technique has been developed for creating a durable reservoir flow restriction that diverts injected water into unswept reservoir sections. Placement of the restriction is based in the location of the thermal front between the injector and producers. A thermally activated nano-sized particle system-BRIGHTWATER - was developed that gives us this restriction.

A sector model of ACG field has been developed to study applicability of BRIGHTWATER injection in ACG field. A decrease in oil production and increase in water production were seen in wells after production started. The water cuts were high for South flank wells. From the simulation it was seen that there were unswept zones. So this new technology was decided to apply in this thesis work.

Several runs were conducted to study effect of BRIGHTWATER concentration, crosslinker concentration, injection rate and pressure, injection temperature, injection times and injection well locations. Results are given in tables and figures and briefly discussed. Also the best and the worst cases are chosen from the results, and analyzed in detail. Finally, economical analysis is given.

It has been observed that injecting the polymer in slug form is better than continuous injection. Injecting polymer in early times may give better results. Injection of polymer with 3 slug sizes between 6 month injection periods seems more beneficial. According to the simulation results optimum polymer injection temperature was 78^0 F. Good results were obtained when polymer was injected at 65000, 75000 and 85000 bbl/day injection rates. Oil recoveries obtained during simulation were in the range of 1.4% to 3.8 % which gives additional recovery of 11 to 31 MMSTB of oil. BRIGHTWATER injection has been found to be applicable to ACG field.

ÖZ

"STARS" BİLGİSAYAR PROGRAMI KULLANILARAK SEKTOR MODELİ ÜZERİNDE "BRIGHTWATER" ENJEKSİYON VERİMİ ÇALIŞMASI

Nariman Pashayev

Yüksek Lisans, Petrol ve Doğal Gaz Mühendisliği Bölümü
Tez Yöneticisi: Prof. Dr. Serhat Akin

Eylül 2011, 141 sayfa

Rezervuarda etkin bir su enjeksiyonu sağlayabilmek/devam ettirebilmek su enjeksiyonunun en kritik aşamasıdır. Etkin su enjeksiyon için kullanılan yöntemler çoğu zaman yetersiz kalmaktadır. Basılan suyu rezervuarın süpürülmemiş bölgelerine yönlendirmek ve daha kararlı/etkin akış sağlayabilmek için özgün bir yöntem geliştirilmiştir. Bu yöntemde rezervuardaki sınırlama enjeksiyon ve üretim kuyuları arasında termal bölgede olacaktır. Bu sınırlamayı sağlayabilmek için ısı yolu ile aktif hale gelen nano parçacıklı sistem olan "Brightwater" geliştirildi.
ACG sahasında BRİGHTWATER enjeksiyonunun uygulanabilirliğini araştırmak için ACG sahasının sektör modeli geliştirildi. Üretime başladıktan sonra bazı kuyularda petrol üretiminde azalma ve su üretiminde artma görüldü. Güney kanadı kuyuları çok fazla su üretiyordu. Simulasyon sonuçlarına göre süpürülmemiş alanların varlığı görüldü. Bu sebeplerden dolayı bu tez çalışmasında yeni teknolojinin denenmesine karar verildi.
BRİGHTWATER yoğunluğunun, çapraz bağlayıcı yoğunluğunun, enjeksiyon hızının ve basıncının, enjeksiyon sıcaklığının , enjeksiyon zamanının ve enjeksiyon kuyusu yerlerinin etkisini öğrenmek için çeşitli simülasyon çalışmaları yapıldı. Sonuçlar tablolar ve çizimler halinde verildi ve kısaca tartışıldı. Aynı zamanda en iyi ve en kötü senaryolar belirlendi ve detaylı şekilde analiz edildi. Son olarak ekonomik değerlendirme yapıldı.

Polimerin slag halinde enjeksiyonun devamlı enjeksiyondan daha faydalı olacağı görüldü. Polimeri enjeksiyon projesinin daha erken zamanlarında basmanın daha iyi sonuçlar verebileceği sonucuna varıldı. Polimer enjeksiyonunun 3 slug boyutunda 6 ay aralıklarla yapılmasının daha faydalı olacağı görüldü. Simülasyon sonuçlarına göre en uygun polimer yoğunluğunun 0.0005 % ve polimer enjeksiyon sıcaklığının 78 °F olduğu anlaşıldı. En iyi sonuçlar 65000, 75000 ve 85000 varil/gün enjeksiyon debisinde alındı. Simülasyonlar sonucunda 1.4% ile 3.8 % oranında petrol artışına karşılık gelen 11 ile 31 MMSTB arasında ekstra petrol üretimi görüldü. Simülasyon sonuçlarına göre BRİGHTWATER enjeksiyonunun uygulanabilir olduğu sonucuna varıldı.

ACKNOWLEDGEMENTS

I would like to express my grateful appreciation to my advisor Prof. Dr. Serhat Akin according to his great help and guidance in my thesis work.

I would like to thank to Dr. Turan Ibrahimov for his valuable support and advisory throughout the study.

I would like to express my gratitude to BP because of scholarship and financial support for my study at METU.

I would like to thank to my family for their encouragements throughout my study.

TABLE OF CONTENTS

LIST OF TABLES

TABLES

LIST OF FIGURES

FIGURES

CHAPTER 1

1. INTRODUCTION

Excess water production is a big problem during production of the reservoir which causes the reduction in oil recovery. This excess water production also creates many problems from corrosion and fluid –handling facility to waste water handling and can lead to well shut-in. Many producing zones are often abandoned because of the high water-cut. Controlling water production has become more and more important to both oil industry and environmental protection. Gel and polymer treatments are widely used to reduce excess water production and to improve oil reservoir conformance during oil and gas production. Traditionally in-situ formed gels are widely used for these purposes. Polymer and crosslinker is injected into formation and there, they react to form gel which seals the water-thief zones in the formation. Thus, gelation occurs in reservoir conditions. Published documents indicate that several particle gels have been economically applied to reduce water production and increase oil production in mature fields. One of these gel treatments is BrightWater **[9].** Brightwater is a sub-micron particulate chemistry that is injected downhole with the injection water as a one-time batch. It can be deployed with conventional chemical injection equipment and requires no modification to the existing water injection system. The particle sizes are sufficiently small (0.5 micron) to propagate through the rock pores with the injected water. As the polymer passes through the reservoir it gradually warms towards the reservoir temperature. As it heats up, the polymer expands to many times their original volume (a factor of four to ten depending on salinity), blocking pore throats and diverting any water following behind it. Managing BrightWater injection projects requires making decisions with the treatment design and optimum polymer treatment size, optimum water-polymer injection rate. The impact of these decisions affects the capital cost of polymer purchase, handling of fluid, operation costs and ultimate incremental oil recovery. Simulation model is a tool for examining different strategies for these decisions.

Simulation model for evaluation BrightWater injection efficiency on sector model is developed by using STARS software. In this thesis 44 cases with different polymer injection parameters (polymer concentration, injection temperature and rate, injection locations and times, slug sizes) were carried out to evaluate the effect BrightWater polymer project on sector model. Results are given in tables and figures and briefly discussed. The best and the worst cases are chosen from the results, and analyzed in detail. Finally, economical analysis is provided.

CHAPTER 2

LITERATURE REVIEW

2.1 Polymer injection:

2.1.1 Introduction

Oil reserves can be recovered in three stages depending on the producing life of a reservoir; primary, secondary, and tertiary. As we already know, primary recovery is recovery by natural drive energy initially available in the reservoir. During secondary recovery, reservoir is recovered by injection of external fluids such as water and/or gas, for the pressure maintenance and volumetric sweep efficiency. Tertiary recovery is characterized by injection of special fluids such as chemicals, miscible gases, and injection of thermal energy. Enhanced Oil Recovery (EOR) is the injection of gases, chemicals, and thermal energy into the reservoir **[10].**

One of the most important methods of EOR is polymer injection. Polymer injection consists of adding polymer to the water during waterflooding to decrease mobility of the water. Decreased mobility ratio is the result of increase in viscosity, as well as decrease in water phase permeability. Lowering the mobility ratio increases the efficiency of the waterflood through greater volumetric sweep efficiency and lowers the swept zone oil saturation. By polymer injection, remaining oil saturation decreases, but irreducible oil saturation does not decrease. Generally a polymer flood is economic only when the waterflood mobility ratio is high, the reservoir heterogeneity is high, or a combination of these two occurs **[10]**.

Polymers have been used in oil production in 3 ways **[10]**.

1. As near-well treatments to improve the performance of water injectors or watered-out producers by blocking off high-conductivity zones.

2. As agents that may be cross-linked in situ to plug high-permeability zones at depth in the reservoir.
3. As agents to lower water mobility or water-oil mobility ratio.

2.1.1a PERFORMANCE EVALUATION of EOR PROCESSES

To be able to define the success of an EOR process, incremental oil recovery factor must be known. Figure 2.1 shows how to find incremental oil recovery from an EOR process.

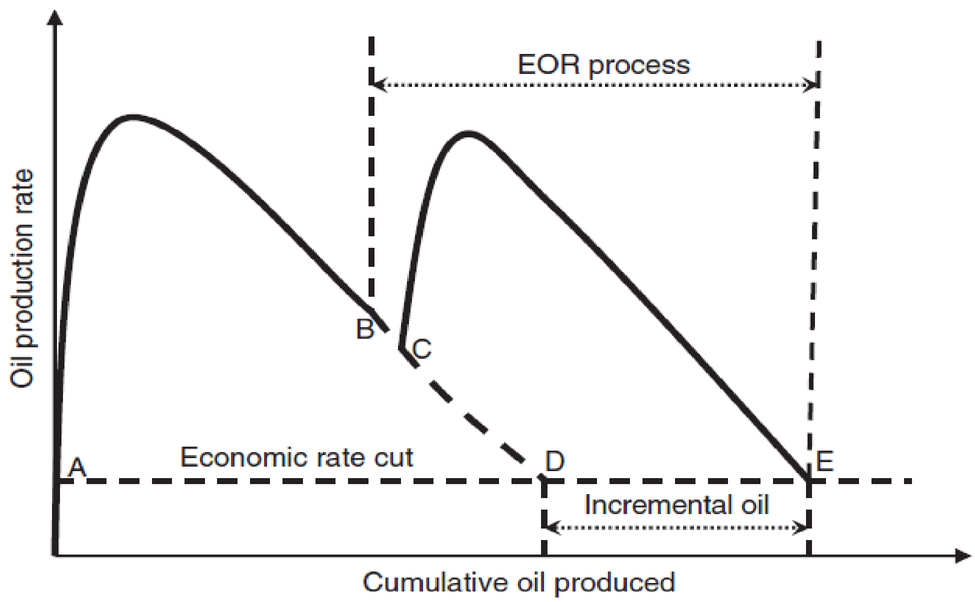

Figure 2.1 Incremental oil recovery from an EOR process [20].

Oil production rates from B to C are extrapolated and cumulative oil at D is the predicted ultimate oil recovery without application of EOR process. EOR process is applied at point B and a respond to EOR process is required, which is from B to C. At the end of EOR process, the ultimate oil recovery is the cumulative oil at point E. The difference of cumulative oil between E and D is the incremental (EOR) oil recovery. Incremental EOR recovery is represented by the incremental oil recovery factor, which is the incremental oil recovered divided by the original oil in place (OOIP).

To measure the success of chemical EOR process, there is another measure which is the amount of chemical injected in pounds per barrel of incremental oil produced (lb/bbl).

2.1.1b MOBILITY CONTROL

The main purpose of EOR methods is to:

- improve sweep efficiency by reducing the mobility ratio between injected and insitu fluids
- eliminate or reduce the capillary and interfacial forces and improve displacement efficiency.

One of the most important concepts in any EOR process is mobility control. It can be achieved by the changes in mobility ratios through injection of chemicals. This changes displacing fluid viscosity or reduces specific fluid relative permeability.

The mobility is the ratio of the effective permeability (k) to the viscosity (µ) of the phase.

$$\lambda = \frac{k}{\mu} \qquad (1)$$

If permeability (k) is replaced by relative permeability, k_r, we have relative mobility λ_r;

$$\lambda_{rj} = \frac{k_{rj}}{\mu_{rj}} \qquad (2)$$

Here, subscript j represents the phase’s j: j=w, o, t for water phase, oil phase and total relative permeability, respectively. The unit of relative mobility is $(mPa.s)^{-1}$ or $(cp)^{-1}$. An example of water and oil relative permeability curves and the corresponding water, oil, and total relative motilities are shown in Figures 2.2 and 2.3.

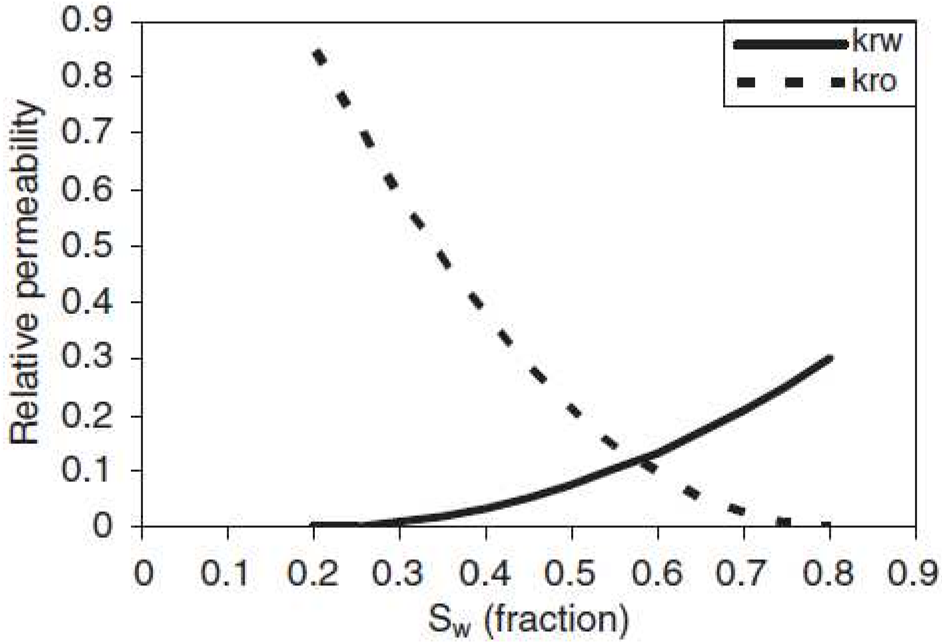

Figure 2.2 Water and oil relative permeabilities [20].

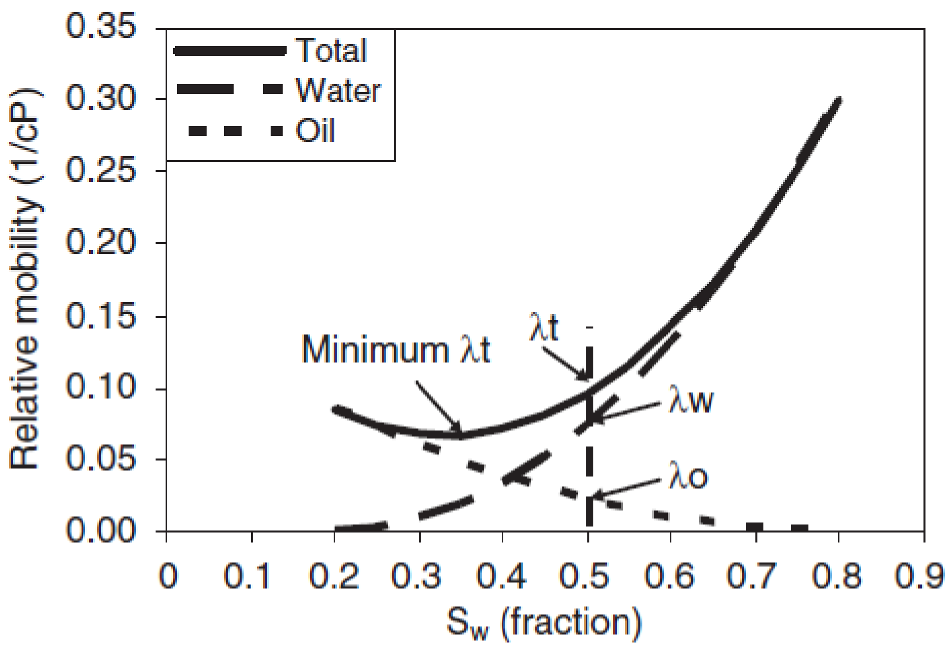

Figure 2.3 Water, oil, and total relative mobilities [20].

The total mobility is the sum of water and oil mobilities. There is another important concept which is viscous fingering that occurs during displacing of one fluid by another one. Displacing fluid mobility in the upstream (λ_u) should equal to or less than the displaced fluid mobility in the downstream (λ_d) for not occurring the viscous fingering.

$$\lambda_u \leq \lambda_d \qquad (3)$$

The mobility ratio (M_r) is the ratio of the displacing phase mobility to the displaced phase mobility:

$$M_r = \frac{\lambda_u}{\lambda_d} = \frac{\lambda_{displacing}}{\lambda_{displaced}} \qquad (4)$$

A mobility ratio equal to or less than one ($M_r \leq 1$) is favorable and $M_r>1$ is unfavorable. When $M_r>1$, water flows at a higher velocity through the least resistance path, because λ_w is greater that λ_o, and reaches producing wells earlier than oil. This process is called fingering. The frontal region is unstable and mobility ratio in that case is unfavorable.

2.1.2 General description of Polymer injection process

Conventional waterflooding operations to increase the oil recovery resulted in poor and incomplete sweeps of the reservoir volume. First attempts to improve sweep efficiency in water flooding were done by Detling (1944). He used a number of additives, including water-soluble polymers, to increase the viscosity of injected water and the volume of the reservoir affected. In the following decades, several patents were issued for polymers to be used under different reservoir conditions. Because of lower cost, the water-soluble polymers prevailed over other additives (molasses, glycerin, glycols, etc.) tested in the field. After 1964, field test results and other significant laboratory studies made possible the development of polymer flooding as a method to enhance oil recovery **[11].**

The role of water –soluble polymers is to increase the water viscosity and also to reduce the permeability of the rock to water that result in reducing the water-oil mobility ratio close to unity or less than unity. This gives the improved volumetric sweep efficiency (areal*vertical) and a higher oil recovery with polymer flooding than with waterflooding.

Permeability reduction and a higher water viscosity will increase the resistance to flow of the polymer solution diverting it toward areas unswept by water.

The fractional flow equation of the two phases (water and oil) in the swept area of the reservoir after water breakthrough into the producers is given by Buckley-Leverett (1942),

$$f_w = \frac{1}{1 + (k_o / \mu_o)(\mu_w / k_w)} \qquad (5)$$

f_w = fractional flow of water in the flowing stream

k_o, k_w = Effective rock permeabilities to oil and water at one given water saturation at one point in the reservoir

μ_o, μ_w = Oil and water viscosities

This equation is simplified by ignoring the capillary pressure and gravitational effects. Fractional flow of oil is;

$$f_o = 1 - f_w = 1 - \frac{1}{1 + (k_{ro} / \mu_o)(\mu_w / k_{rw})} \qquad (6)$$

As seen from the equation, when water viscosity μ_w increases and the permeability of the rock to water decreases, fractional flow of oil, f_o will increase, improving the rate of oil recovery.

2.1.2a Resistance Factor

Measure of the mobility reduction is known as the resistance factor, R.

$$R = \frac{\lambda_w}{\lambda_p} = \frac{k_{rw} / \mu_w}{k_{rp} / \mu_p} = \frac{M_{w-o}}{M_{p-o}} \qquad (7)$$

λ_p = water-soluble polymer mobility

μ_p =viscosity of polymer solution (apparent)

k_{rw}, k_{rp} = relative permeabilities to water and to polymer solution, respectively

M_{w-o}, M_{p-o} = water-oil and polymer solution-oil mobility ratios, respectively.

High resistance factor polymers used to plug the more permeable strips to reduce the variations in permeability.

2.1.2b Residual Resistance Factor

The reduction of rock's permeability to water after polymer flow is measured by Residual Resistance Factor, R_R.

$$R_R = \frac{(k_{rw} / \mu_w)\,\text{before polymer flow}}{(k_{rw} / \mu_w)\,\text{after polymer flow}} \qquad (8)$$

Reduction in rock's permeability to water is the result of adsorption of polymer on the rock surface and the mechanical entrapment of polymer molecules.

2.1.2c Polymer Adsorption

When polymer solutions such as polyacrylamides polymer, propagates through reservoir they are adsorbed by the surface of the most reservoirs rocks. The adsorbed polymer layers show both an additional resistance to flow and a loss of polymer. Polymer solutions after leaving the porous medium have a lower concentration than before, if adsorption takes place. Adsorption increases with the increasing amount of polymer concentration. Adsorption of polymers to the rock surface decreases the concentration of polymer solution. Adsorption occurs at the front edge of the polymer bank. The amount of polymer lost from a bank depends on the nature of the polymer and rock surface.

2.1.2d Polymer Entrapment

There is a variety of opening sizes in the porous space in a reservoir rock. Polymer molecules trap when the molecules flow into a large pore opening but can not leave it because of the smaller opening of the other end. Entrapment can also take place when the flow is restricted or stopped. In the case of entrapment of polymer molecules, only the passage of brine is permitted.

2.1.2e Inaccessible Pore Volume in Polymer Flooding

According to Dawson and Lantz (1972) [5] some waterflooding polymers do not enter all of the connected pore volume in porous media. This is because some high molecular weight polymer molecules can not access all of the connected pore volume where pore throats are small. Polymer molecules are relatively large compared with solvent molecules and pores in a reservoir rock. These pore volume is inaccessible to polymer. Inaccessible pore volume is occupied by water that contains no polymer.

Polymer adsorption and inaccessible pore volume affects the polymer propagation through porous media. Plugging of pores due to adsorption and/or mechanical entrapment would also contribute to Inaccessible Pore Volume (IPV). In the absence of adsorption large polymer molecules move through porous rocks more rapidly than small molecules such as water molecules due to inaccessible pore volume.

An explanation for the acceleration of the polymer front may be given as follows. Propagation of polymer solution fronts through the accessible pore volume is perfectly normal; these fronts seen from the end of the core after injection of one accessible pore volume. But salt fronts are delayed by transfer of salt into the water that located in the inaccessible pore volume. Inaccessible pore volume results in an earlier polymer response at production wells.

2.1.3 Method Description

In a polymer flooding, polymer solutions are injected into the reservoir either as a slug or continuous injection. The polymer solution is injected into the reservoir with a prior injection of low-salinity brine (freshwater) slug. Polymer slug is followed by another low-salinity water slug and by continuous drive water injection. The cross-section view of a polymer injection is given in Figure 2.4.

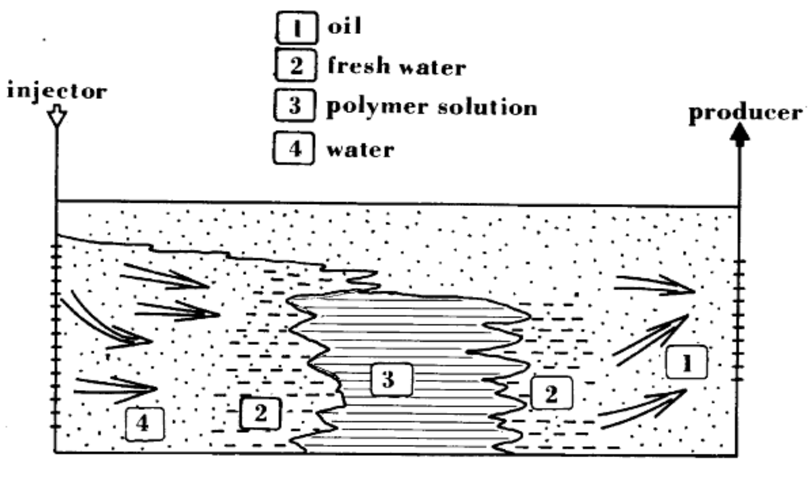

Figure 2.4 Schematic view of polymer flood [11].

The reason for the polymer solution slug which is injected between two freshwater buffers is to prevent the direct contact of polymer with the saline reservoir water since it reduces the polymer solution viscosity.

Polymer flooding does not reduce the residual oil saturation; it improves oil recovery over waterflooding by increasing the reservoir volume contacted. Also, polymer injection accelerates oil production, and a higher recovery is obtained at breakthrough **[11].**

2.1.4 Problems with Polymers

Field tests have exposed severe operational problems with polymers. Injectivity problems were encountered during polymer flooding in most field pilots. A combination of water and polymer quality caused these injectivity problems. Mechanical degradation of polymers causes major operational problems when subjected to high shear stresses. Molecules are stretched and ruptured by shear stresses and their ability to reduce mobility is permanently reduced. High shear stresses can be seen in surface pumps, valves, and meters as well as at the point where fluids heave the wellbore and enter the formation. Another problem with polymers occurs when the salinity of water is high.

The retention of polymer in the pores of the rock is a very serious problem for most polymers. Some part of injected polymer is adsorbed on the walls of main flow channels and it may plug narrow pore channels.

2.1.5 Facilities

Facilities for generating and delivering polymer solutions seldom involve simply scaling up laboratory methods. Thus the demonstration and certification of mixing equipment for field-scale generation of polymer solution is important. These activities are typically combined with field testing and piloting activities. In addition to proper equipment determination, piping and flow behavior requires study. Identification and minimization of high-shear points in facility designs is important to minimize shear degradation of the polymer solution during its generation, pumping, and the flow down to the reservoir through constrictions. [1]

2.2 BRIGHTWATER Injection

2.2.1 What is BRIGHTWATER?

BRIGHTWATER is a new Technology for Waterflood Sweep Improvement. BRIGHTWATER is a sub-micron particulate chemistry that is injected downhole with flood water during an EOR process. It is designed to activate at a pre-determined “in-depth” location within the reservoir. After activation, BRIGHTWATER particles begin to expand their original sizes to many times, blocking pore throats and directing injection water into unswept, oil-rich zones. This causes additional oil to be swept toward the producing wells.

Over time, production begins to improve. With a simple treatment, one can recover up to an additional 10 percent of the original oil in place. Several grades of BRIGHTWATER chemistry have been designed [12, 13].

2.2.2 Properties of BRIGHTWATER

BRIGHTWATER is not a classic viscous polymer. Sub-micron particles are inert and give virtually no viscosity and adsorption, so during injection its viscosity is very close to water. It can not be damaged by shear during injection and it is not active initially. It is also different from conventional gels. The size of particles is about 0.3-0.5 microns. Typical pore throat size is much bigger than this for permeability of 500 mD or higher. Density and viscosity of the BRIGHTWATER technology as supplied is close to that of seawater.

With the increase in temperature, the reversible crosslink breakdown and allow the particle to quickly expand, agglomerate and adhere to the rock formation, thereby increasing viscosity and creating a viscous slug/block. After activation, expanded particles are sticky and have increased solution viscosity. Activation time and the strength of the block can be selected

BRIGHTWATER particles supplied as dispersion in hydrocarbon solvent and the active content in the dispersion is about 30%. [12, 13, 14].

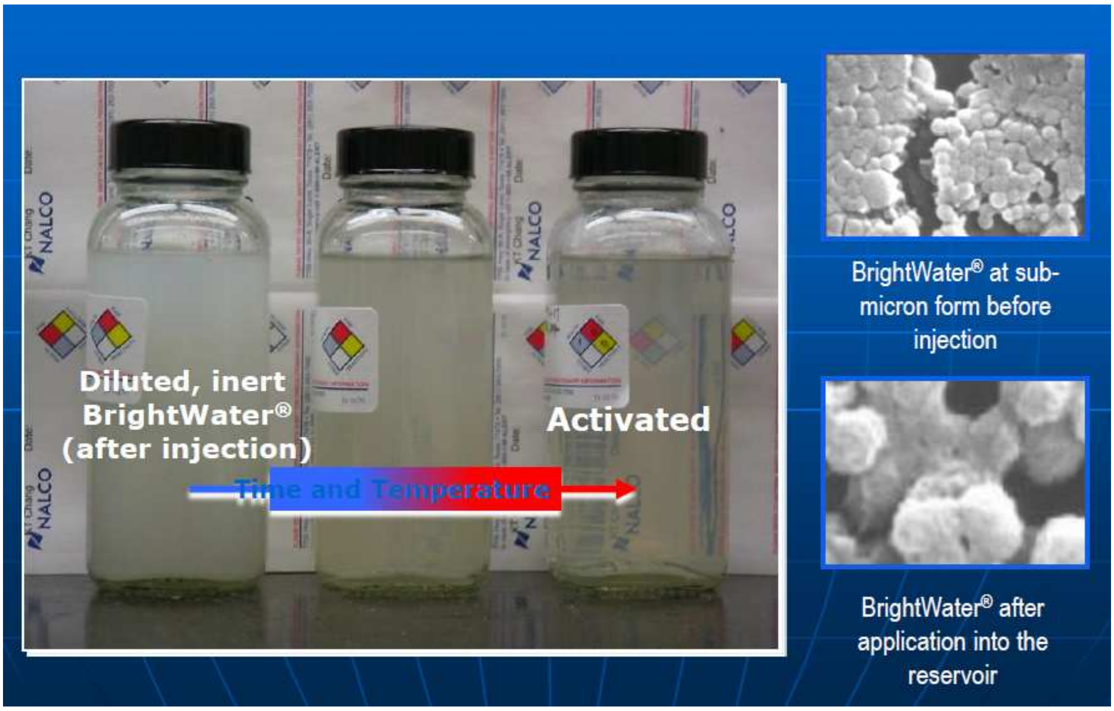

Figure 2.5 BRIGHTWATER **–** Reaction in the reservoir [14].

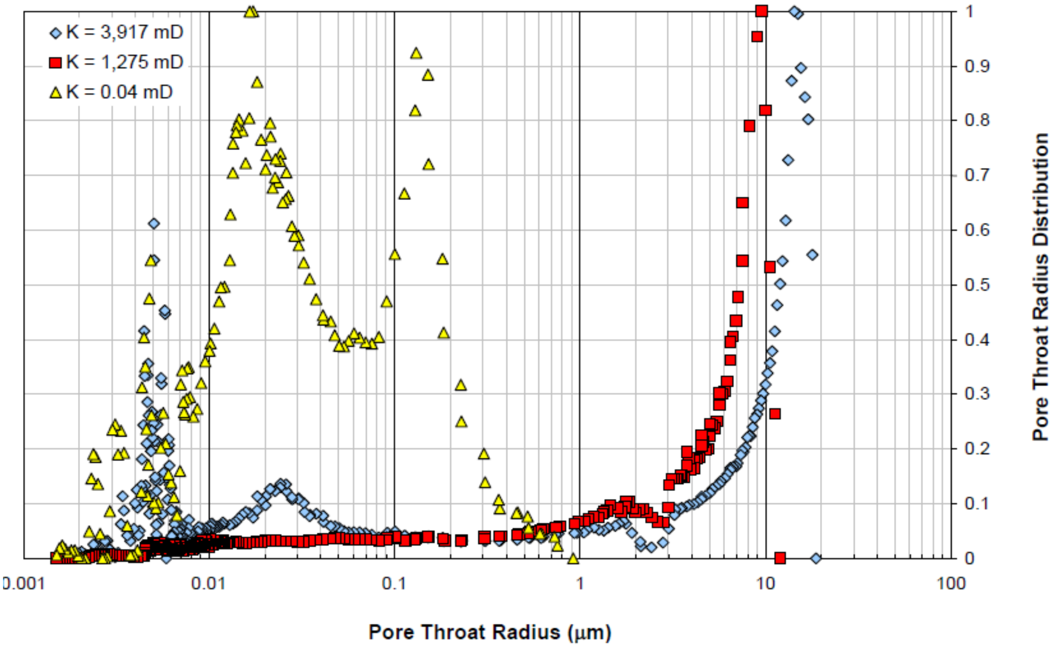

Figure 2.6 Pore throat radius and distribution from capillary pressure [14].

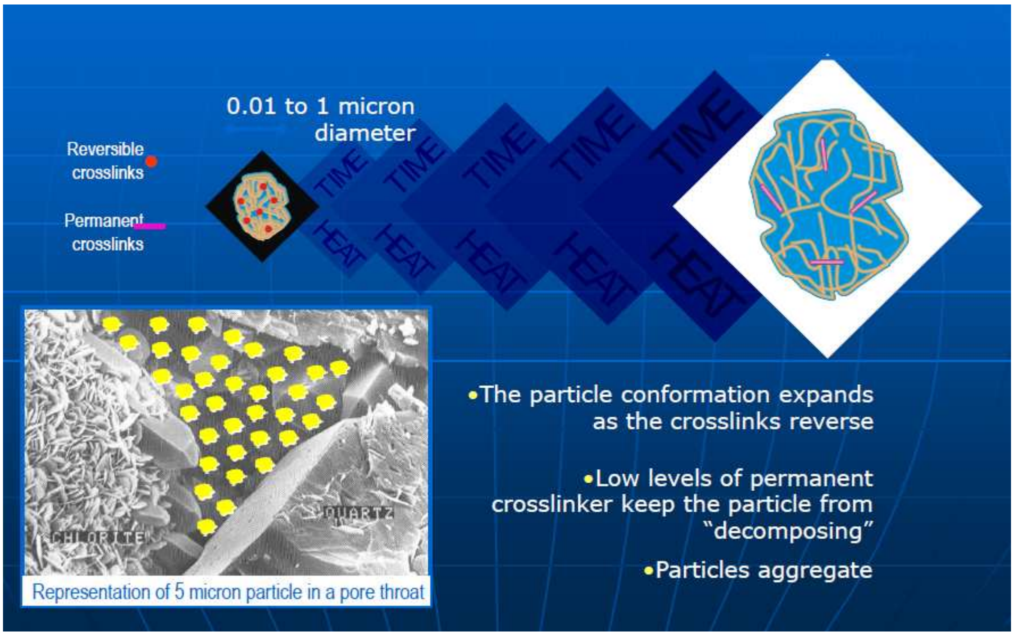

Figure 2.7 BRIGHTWATER Mechanism-Pore scale [14].

Table 2.1 Comparison of BrightWater with classic polymers

	BW	CLASSIC POLYMER FLOOD	CLASSIC WSO POLYMER GEL
Function	Flow diverting agent	A pusher, mobility control	
Treatment fluid	Water like	Viscous fluid	
Shear degrading	NO	Yes	Yes
Injectivity	Like water	Low	Low
Mechanism of EOR	Expand WF reachable zones	Mobility control	
Treatment volume	Small	Large	Small
Set up zones	Far away from injector		Near
Implementation	Bullhead		Isolation
Matrix rock	Yes		Yes
Fractures	No		Yes

2.2.3 Benefits of BRIGHTWATER

- Restricts flow of water into high permeability thief zones
- Reduces unwanted costly water production
- Improves sweep efficiency
- Improves reservoir oil recovery by up to 10 percent
- Can be deployed with conventional chemical injection equipment and existing water injection systems
- Water miscible solution
- Has no risk to the reservoir or the environment

- No shutdowns required
- Designed to overcome injectivity and cost limitations of classical polymer treatments [12].

If barriers to vertical flow are absent, water channels through the thief zone and will bypass the patch plug or gel block.

Figure 2.8 Before BrightWater injection [13].

BrightWater is injected into, and expands in the vertically isolated thief zone. If barriers to vertical flow are absent and deep reservoir profile modification is in place, water is diverted to the unswept formation

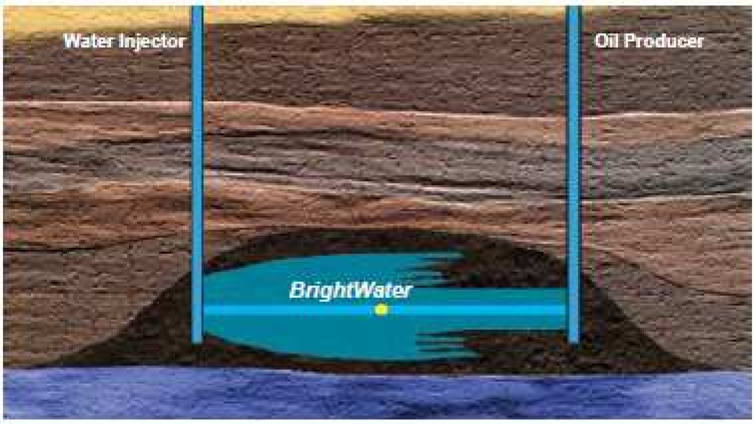

Figure 2.9 After BrightWater injection [13].

Table 2.2 Candidate Selection Criteria [14]

Available movable oil at least 10% OOIP
Early water breakthrough to high water-cut
Sandstone reservoirs
Injection water salinity under 150,000 ppm
Expected tracer transit time >30 days
A high permeability contrast is desirable
Injection water pH > 6
Minimal natural fracture
Reservoir temperature between 15°and 120^{0}C

Table 2.3 Candidate Rejection Criteria [14**]**

Injector is completed in an aquifer
Uniform formation or remaining mobile oil is <10%
Fractured reservoirs, not carbonates (yet)
Very low permeability thief
Very slow water transit time (years)
Highly acidic systems (pH < 6)
Very viscous oil

CHAPTER 3

FIELD STUDIES

North Sea

One of the operators in the North Sea field experienced declining production due to poor sweep efficiency of the existing waterflooding operation. Water cuts were high and oil cut were declining. BrightWater product was selected to challenge this problem. After the injection of Brightwater an incremental oil of 100,000 barrels were experienced by the operator in less than 12 months. The predicted incremental oil gain is expected to be over 300,000 barrels. 100 tons of BRIGHTWATER EC9398A and 50 tons of dispersant EC9360A were injected. The treatment was injected together with the existing seawater over a period of 8 days. Based on the results, operator decided to evaluate other wells for this new treatment and again to develop a second treatment on the previous well [12].

North America

In one of the North American fields, production wells were showing high water cuts of above 70 %. It produced over 13 billion barrels of oil since 1970's. Operator of the field decided to implement Brightwater technology on this field. Brightwater was injected in late 2004 and by mid 2005 producers gave incremental oil of 500,000 barrels. That means $20 million increase of revenue [12]. Oil cut increases of 10-50 % and corresponding water cut decreases was seen at individual production wells. For next 15 years, operator expects to see an additional 2 million barrels of incremental oil [12].

Recently SITEP and Eni [15] have started to evaluate some EOR methods for El Borma field. A commercial chemical product called BRIGTHWATER was chosen to evaluate the applicability and efficiency. They provided information about the work performed in El-Borma field, which used Brightwater technology to design a field test. The main purpose was to achieve the highest probability of success and to gather as much information as possible to use in future applications.

TARGETS of the Project were listed as:

- To verify the applicability and efficiency of the process “Brightwater”, EOR technology
- To evaluate the technical feasibility to extend the Brightwater application to other candidates parallel with the evaluation of additional oil volumes produced.
- To test some conventional and not conventional well and reservoir monitoring technologies to understand potentialities, optimal conditions and problems in use and possibilities of application in other reservoirs.

Pilot wells pairs identified; one for injection and one for production. Poor open-hole log data set has been integrated with the core data available for the reservoir “A” in EB-15(injector). Monitoring operations including the pre-treatment monitoring program was done. The main purposes were:

-To access flow profile while water injection in EB-15(injector).
-To verify the connectivity between the wells EB-15 and EB-24(producer).
-To chart reservoir response before Brightwater Treatment
-The polymer treatment

The efficiency of polymer treatment was approved by the monitoring operations done in El-Borma pilot area. The presence of thief zones and the injector-producer connectivity was confirmed by the pre-treatment monitoring program (production logging, pulse pressure test, injection and Falloff tests). The injected tracer (March 2009) is not present yet in the producer water at EB-24. A continuous data collection and well parameters monitoring are ongoing to confirm the efficiency of the new treatment [15].

Roussenac et al [16] studied The Salema field (Campos Basin, Brazil) that has been suffering from early water breakthrough. Sweep efficiency was very poor on the south part of the field. To increase the sweep efficiency a new technology called BRIGHTWATER has been selected. The purpose of this paper was, to describe the feasibility, maturation, execution, monitoring and results of the Brightwater Trial in Brazil.

BRIGHTWATER:

Brightwater® is a polymer particle. The sizes of particles are in range 0.1-0.5 microns with internal crosslink. It is injected downhole with the water, reaches reservoir, passes through the reservoir and gradually warms because of reservoir temperature. As it warms up, the polymer expands to many times their original volume (4-10), blocking pore throats and diverts any water following behind it.

First, sweep efficiency and thief zones were identified between iSA-I and SA-F wells, by interference tests, Fall-off tests. A thermal reservoir model was built to predict temperature profile, model tracer, model polymer injection, model inactivated polymer transformation into gel and to predict permeability reduction associated with adsorbed gel and increase of recovery. Polymer performance tests were done such as Bottle tests, slim tube test, core test during maturation phase. Also Treatment design (optimum treatment size, optimum rate during polymer injection, optimum BW placement) and Final Trial design works were done. Execution phase includes offshore design, pumping of the products, monitoring and Results.

After these extensive evaluation works, a new in-depth waterflood conformance control technology “BRIGHTWATER” was selected to attempt.
The injection, activation of polymer and improvement in sweep were modeled with thermal Reservoir simulator. Parameters determined from laboratory tests. The results are still under investigation and so far we cannot see any incremental oil. Injector fall-off tests, pressure interference between injector and producer tell us a successful blockage of the thief zone. The reservoir has been positively impacted by the treatment. Surveillance program will continue to quantify the oil gain resulting from this treatment [16].

Danielle et al [18] gave information about a novel, heat activated polymer treatment trial in BP Alaskan field. The treatment was designed using numerical simulation and laboratory tests. *Pressure fall off analysis* and *injectivity tests* confirmed the placement of treatment deep in the reservoir between injector and producer. *Pre-treatment simulation* was done to help in planning the treatment and predicting the outcome. A basic model of the injector/producer was used. Interference test was performed and a good communication between injector and producer confirmed.
A slower activating particle grade was selected for the treatment according to the simulation results.
Slim tube sand pack tests were conducted to model the different phases of the treatment and the effect of the “popped” particles on the permeability of the medium.
The change in the reservoir and the simulation and laboratory results are in quite well agreement [18].

An Industry consortium (BP, Chevron Texaco and Nalco Company) conducted a joint research project known as Brightwater. The purpose was to develop a novel highly expandable particulate material that would improve the sweep efficiency of a waterflood. H. Frampton et al [17] gave an overview of the development of this particular system.

The polymeric “kernel” particles are capable of “popping” under the influence of temperature and time. Expanded particles block the fluid flow path and divert the fluid.

In this paper, various properties of the kernel dispersions are summarized. To illustrate the *injection*, *propagation* and *expansion* of the particles, laboratory tests are conducted and presented here.

Slim tube tests, kernel particle swelling tests, filtration tests, and bottle tests are conducted to learn the feasibility of the system.

Screening criteria for Brightwater use:

In November 2001, the first of these water flood profile modification treatments was pumped in the Minas field.

According to relatively low oil Recovery and High Water Cut in Minas field, they concluded that a sweep problem exists.
Following conclusions were made from the tests conducted for the Minas field trial of Brightwater:
- The Brightwater kernel particles could be injected into packs and cores of permeability 124-3400 mD.
- When the particles popped on heating, they give rise to a build of viscosity in bottle tests. This was noted as a Resistance Factor.
- Resistance factor was dependent on the particle concentration and the porous medium.
-To design treatment in the field, data that gathered from laboratory tests could be used [17].

CHAPTER 4

STATEMENT OF THE PROBLEM

High water cuts have always been a big problem for production wells. It causes conformance problems such as corrosion, waste water handling and etc. Many unswept oil zones can be left during waterflooding because of high permeability zones. ACG field located in Caspian Sea also suffers from these problems. In order to overcome these problems and increase the production, a sector simulation model created using CMG STARS simulation software was conducted. The feasibility of Brightwater injection in ACG field was studied using the sector model developed in this study.

Different sensitivity cases were run to evaluate and analyze the behavior BRIGHTWATER injection in this sector model. Effects of BRIGHTWATER concentration, crosslinker concentration, injection temperature and pressure, and injection rates on recovery factor, GOR, and WOR are analyzed. The best and the worst cases are discussed and analyzed and economical aspects of projects are provided. General view of BRIGHTWATER injection in terms of profitability are discussed.

CHAPTER 5

METHOD OF SOLUTION

5.1 USE OF COMMERCIAL SOFTWARE

5.1.1 INTRODUCTION

CMG STARS is an advanced processes and thermal reservoir simulator. STARS means, **S**team, **T**hermal and **A**dvanced processes **R**eservoir **S**imulator. It is a thermal, K-value compositional, chemical reaction and geomechanics reservoir simulator. STARS has the options for chemical/polymer flooding, steam injection, thermal applications, dual porosity/permeability, directional permeability, flexible grids and many more. You can model the complex oil and gas recovery processes with its huge reactions kinetics and geomechanics capabilities [19].

There is also non-oil and gas related applications in STARS:

- ground water movement
- pollutant clean-up and recovery
- hazardous waste disposal and re-injection
- geothermal reservoir production,
- solution mining operations
- Near wellbore exothermic reactions.

Table 5.1 Reservoir processes that can be modeled with STARS [19]

Thermal
- Steam flooding
- Cyclic steam
- SAGD - (Steam Assisted Gravity Drainage)
- ES-SAGD - (Expanding Solvent - Steam Assisted Gravity Drainage)
- Thermal VAPEX
- Hot water flooding
- Hot solvent injection
- Combustion (air injection)
  - *HTO & LTO (High and Low Temperature Oxidation)*
  - *THAI (Toe-to-Heel Air Injection)*
- Electrical heating
- Differential temperature water injection

Chemical
- Gellation, simple or multi-stage, multi-component
- Foams, emulsions and foamy oil
- ASP (Alkaline-Surfactant-Polymer) flooding
- Microbial EOR
- VAPEX
- Low salinity waterflooding
- Reservoir souring

Solids Transport & Deposition
- Fines transport
- CHOP (Cold Heavy Oil Production)
  - *Sand transport and production (Worm-holes)*
- Asphaltene precipitation, flocculation, deposition and plugging
- Wax precipitation

Geomechanics
- Compaction and subsidence
- Rock failure
- Dilation
- Creep

Naturally and Hydraulically Fractured Reservoir Modelling
- Dual porosity
  - *Multiple interacting continua*
  - *Vertical refinement*
- Dual permeability
- Integrated to Pinnacle Technologies, Inc.'s FracProPT fracture design software
- Integrated to Fracture Technologies Ltd.'s WellWhiz well, completion and fracture design software

The advanced futures of STARS include,

- User-Defined Reactions Kinetics
- User-Defined Components
- Dispersed Components Model
- Well Modeling-Source/Sink, Semi-Analytical and Discretized Models
- Performance Enhancing Features
- Gridding Options
- Comprehensive Rock-Fluid Interaction Definition
- Geomechanical Model

5.1.2 DATA GROUPS

STARS uses the data set that created initially by the user and then STARS itself creates three other files. These three files are text output file, an SR2 index file (IRF) and a SR2 main file (MRF).

During a restart run, several existing files are needed and another three files are created.

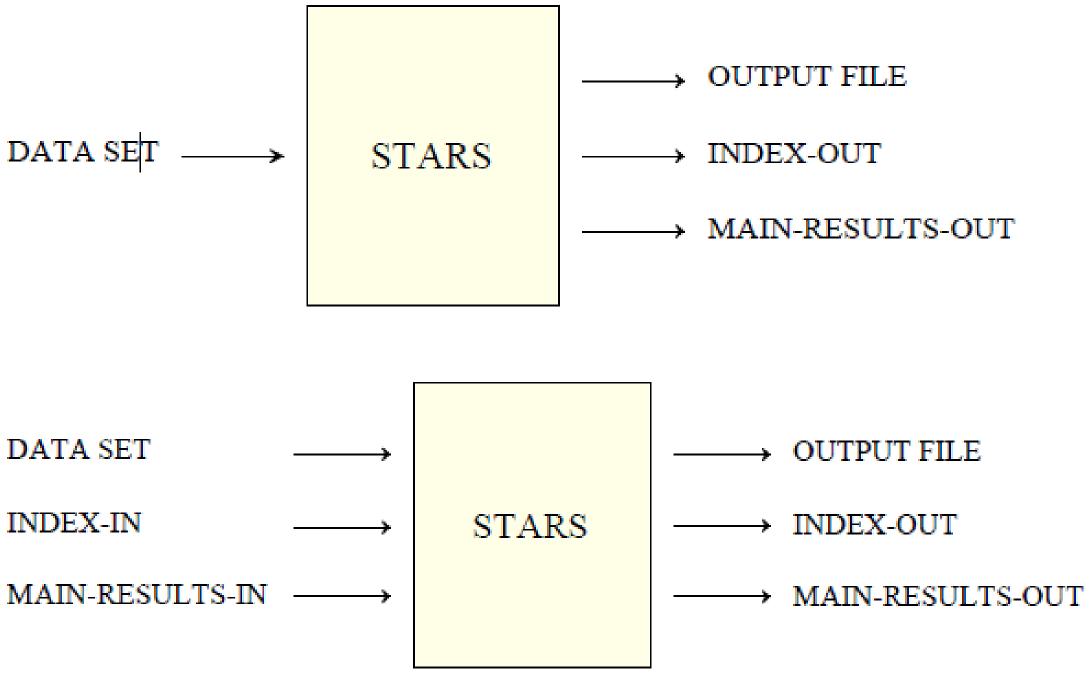

Figure 5.1 STARS files

To build a data set we use the keyword input system. Keyword input system contains nine different data groups. These data groups are given below and must appear as in the given order:

- Input/Output Control
- Reservoir Description
- Other Reservoir Properties

- Component Properties
- Rock-fluid Data
- Initial Conditions
- Numerical Methods Control
- Geomechanical Model
- Well and Recurrent Data

Keywords which are in the one group can not be used in the other group, unless it is specifically indicated. Also, attention must be paid to the order of the keywords within an each group.

5.1.2.1 INPUT/OUTPUT CONTROL

Input/Output Control, control the simulator's input and output activities including filenames, units, titles, choices and frequency of writing to both the output and SR2 file, and restart control. The keywords are optional. It does not contain any required keywords. There is a default value for each keyword.

5.1.2.2 RESERVOIR DESCRIPTION

Reservoir description section describes the basic reservoir definition and grid options. This section contains following data groups:

- Simulation Grid and Grid Refinement Options
- Choice of Natural Fracture Reservoir Options
- Well Discretization Options
- Basis Reservoir Rock Properties
- Sector Options

The grid options are Finite-Difference Grid and Corner Point Grid. Finite-Difference Grid have *Cartesian*, *Radial* and *variable depth/thickness* options.

5.1.2.3 OTHER RESERVOIR PROPERTIES

Here other reservoir properties can be described. These are:

- Rock compressibility
- Reservoir Rock Thermal Properties
- Overburden Heat Loss Options

5.1.2.4 COMPONENT PROPERTIES

We prepare the fluid data input with Component Properties section. It indicates number of each type of component. Densities, critical pressures, molecular weights, K values of components can be entered in this section.

5.1.2.5 ROCK-FLUID DATA

Relative permeabilities, capillary pressures and component adsorption, diffusion and dispersion are defined in this section. The minimum required data is one set of relative permeability curves (*SWT and *SLT).
To see how the adsorption and gelation processed is modeled in this work see Appendix B.

5.1.2.6 INITIAL CONDITIONS

*INITIAL is the first keyword of the "Initial Conditions" section and must be after the Rock-Fluid Data keyword group. Initial pressure distribution keywords are the only required data for this group.

5.1.2.7 NUMERICAL METHODS CONTROL

This section controls the simulator's numerical activities such as time stepping, iterative solution of non-linear flow equations and the solution of resulting system of linear equations. There are no required keywords in this section, all keywords are optional and each keyword has a default value.

5.1.2.8 WELL AND RECURRENT DATA

The Well and Recurrent Data section includes data and specifications that change with time. Well and related data is the largest part of this section. Also there are keywords that define other time-dependent information. The minimum required keywords are given below;

```
*RUN
*TIME or *DATE    ** Starting time
*DTWELL           ** Starting timestep size

*WELL             ** Well definition (at least one set)
*INJECTOR or *PRODUCER
*INCOMP (injector only)
*TINJW  (injector, thermal only)
*OPERATE
*PERF or *PERFV

*TIME or *DATE    ** Stopping time
```

Figure 5.2 Minimum required keywords for Well and Recurrent Data

5.2 SECTOR MODEL SIMULATION

5.2.1 Sector Model Description

The sector model used in this thesis work simulates Central Azeri part of ACG field. Pereriv B reservoir of Central Azeri field is modeled. Simulation runs were made on the model created by Farid Babayev [21]. Sector model is an anticline and has different characteristics in North and South flanks. The top of model is located at 8531 ft and continues to 9851 ft in South flank and 10830 ft in North flank. There is a 1036 ft difference in water-oil contact at flanks which is 9431 ft and 10467 ft in the South and North flanks, respectively. The reference pressure is 4370 psi at a reference depth of gas-oil contact (8650 ft). Model has 8 producers (4 in South and 4 in North flank), 4 sidetracks of South flank wells and 3 injection wells (2 water and 1 gas injection). Water is injected from South and gas from crest. The injected gas tends to flow into North flank rather than South. The location of injection and production wells is described in figure 5.3.

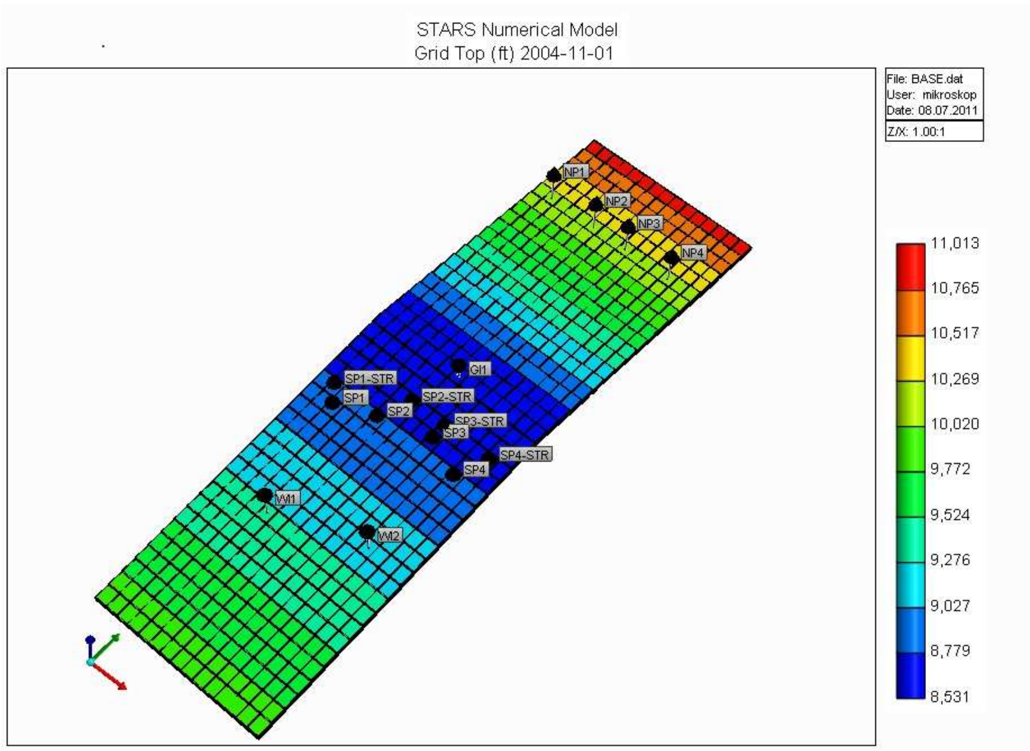

Figure 5.3 Location of production and injection wells in sector model

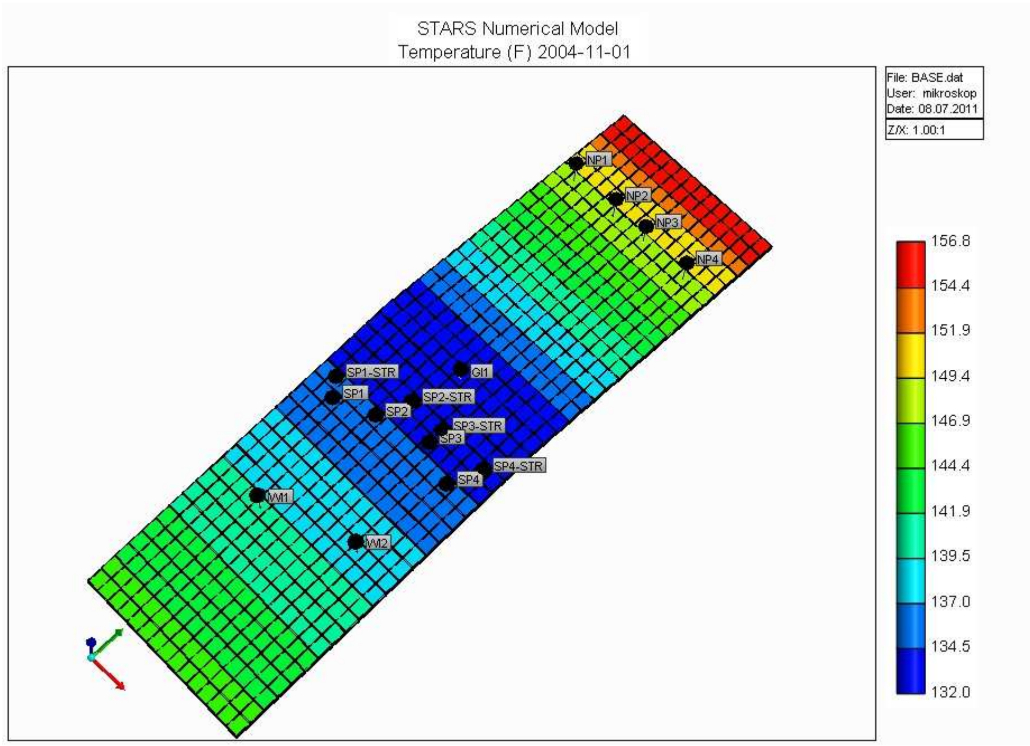

Figure 5.4 Initial temperature distribution of sector model

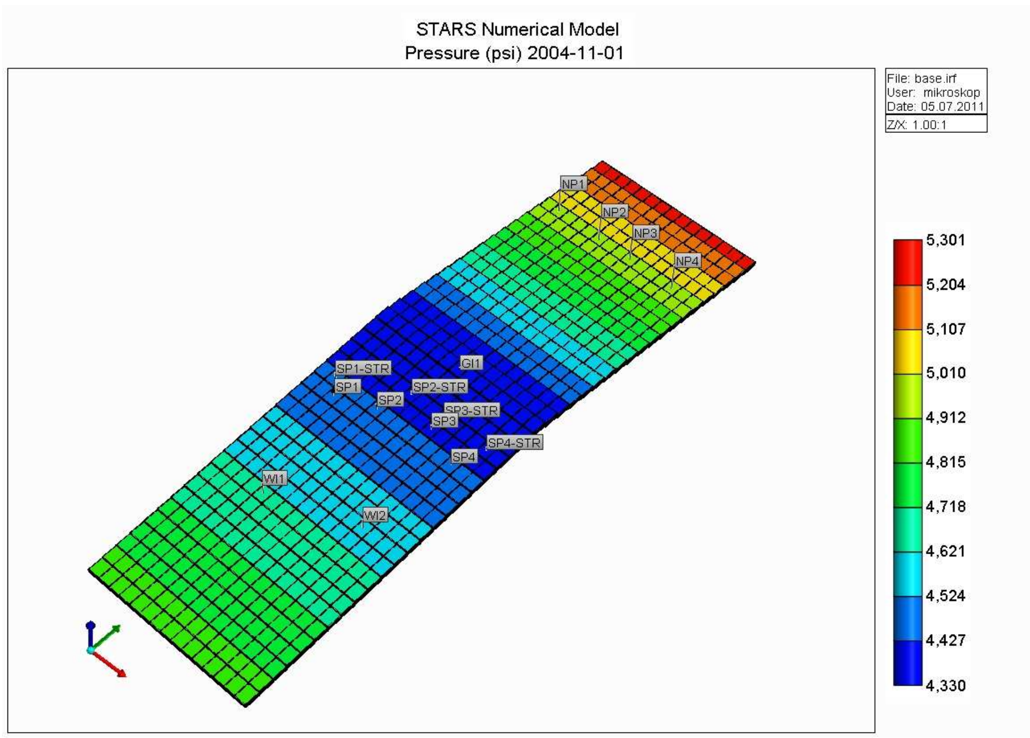

Figure 5.5 Initial pressure distributions of sector model

There are total 5030 grids in the model; 15 in direction I, 42 in direction J and 8 in direction K. Cartesian grid system was used with dimensions of 656x820x26.2 ft.

Porosity and permeability values for all grids are not constant. Figures 5.6, 5.7, 5.8, 5.9, 5.10, 5.11, 5.12, and 5.13 below show the porosity, permeability, net-to-gross ratio and initial saturation distributions throughout the model.

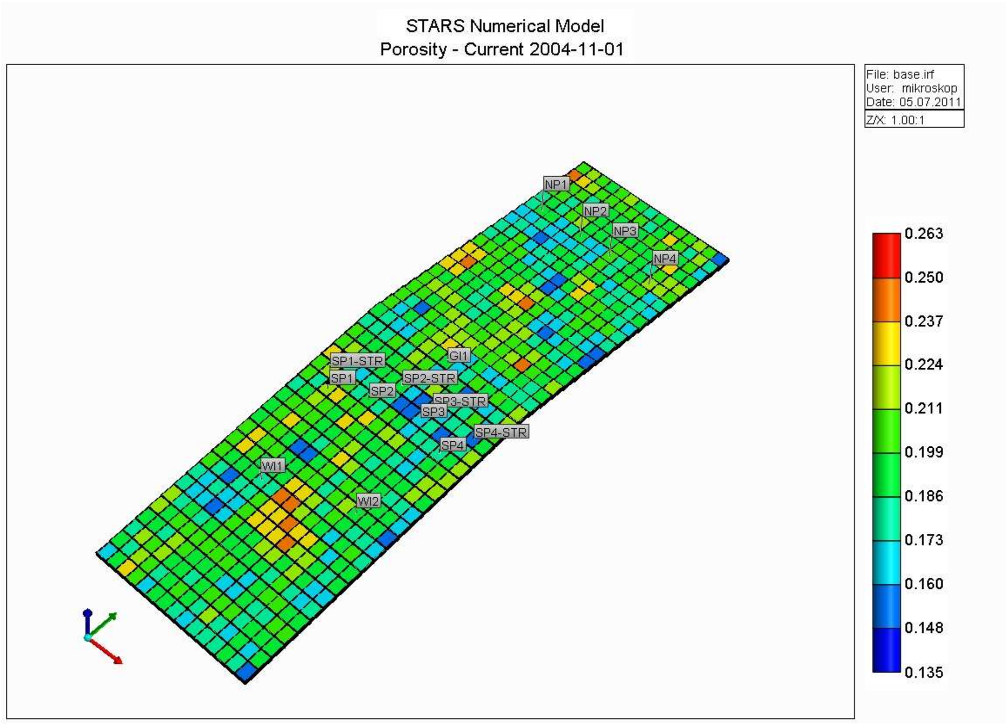

Figure 5.6 Porosity distribution

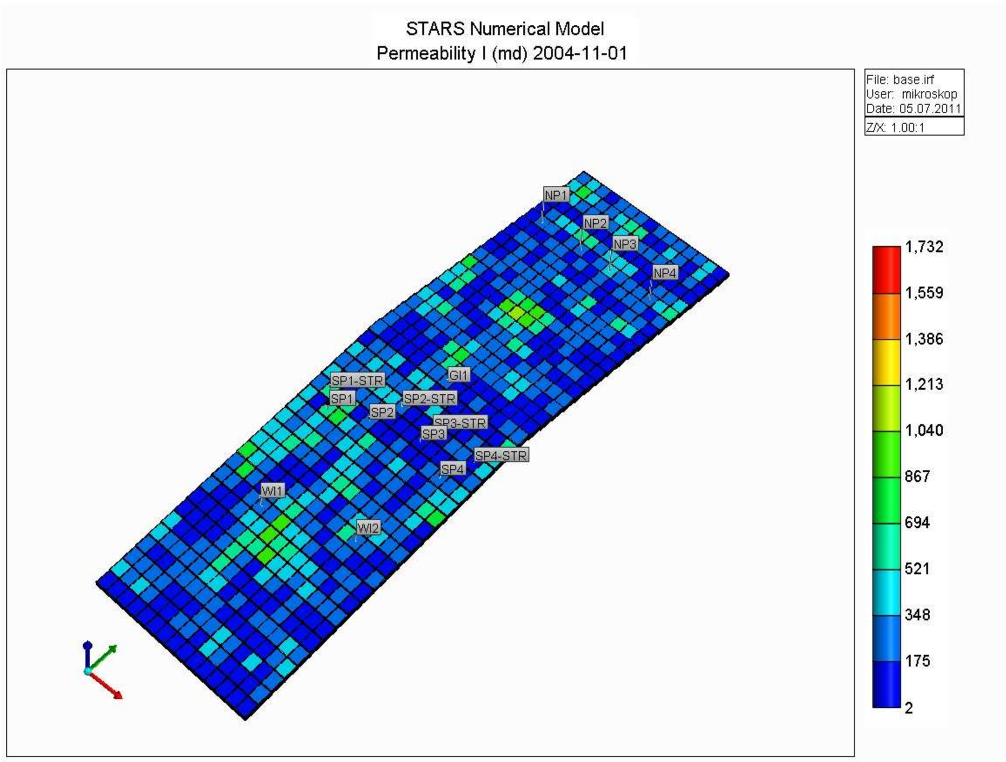

Figure 5.7 Permeability distributions in I direction

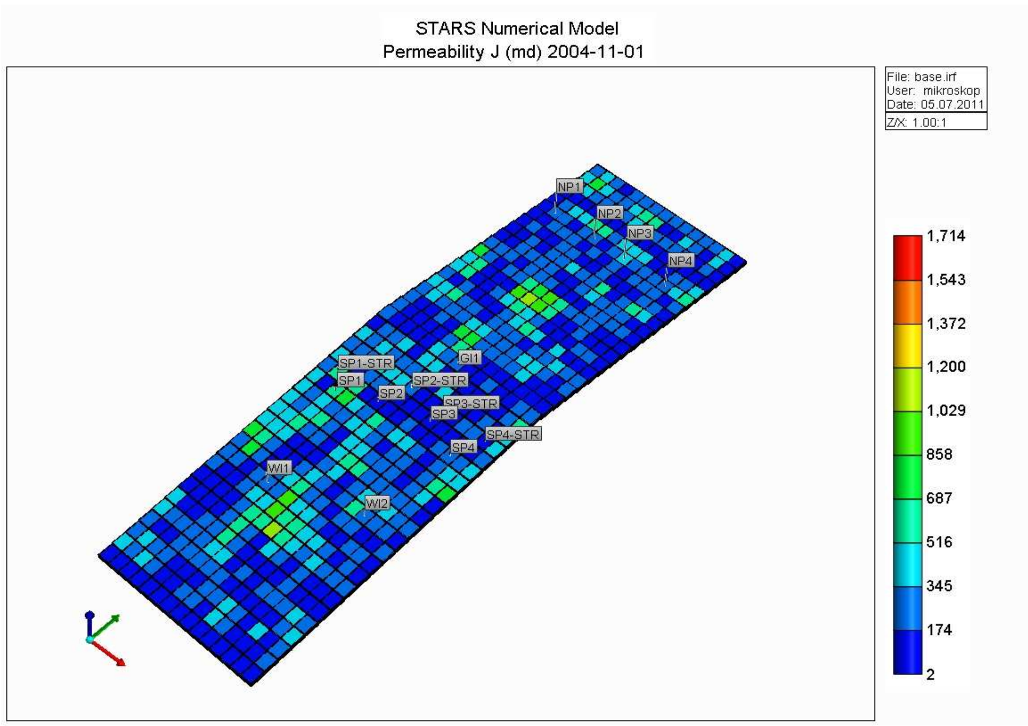

Figure 5.8 Permeability distributions in J direction

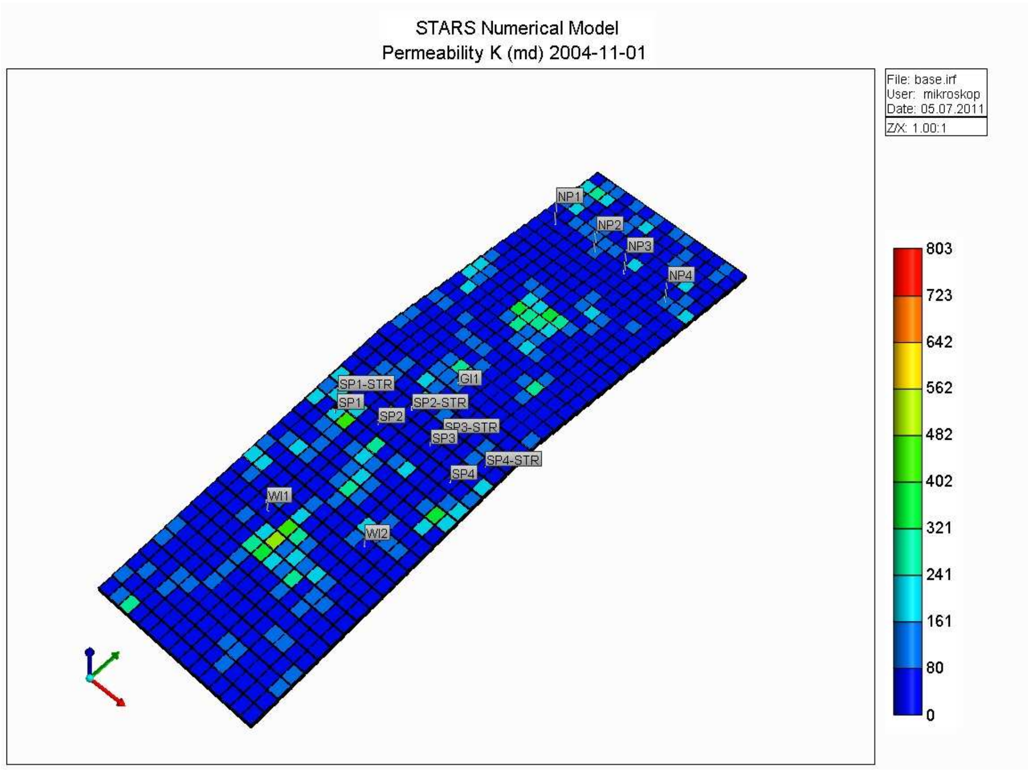

Figure 5.9 Permeability distributions in K direction

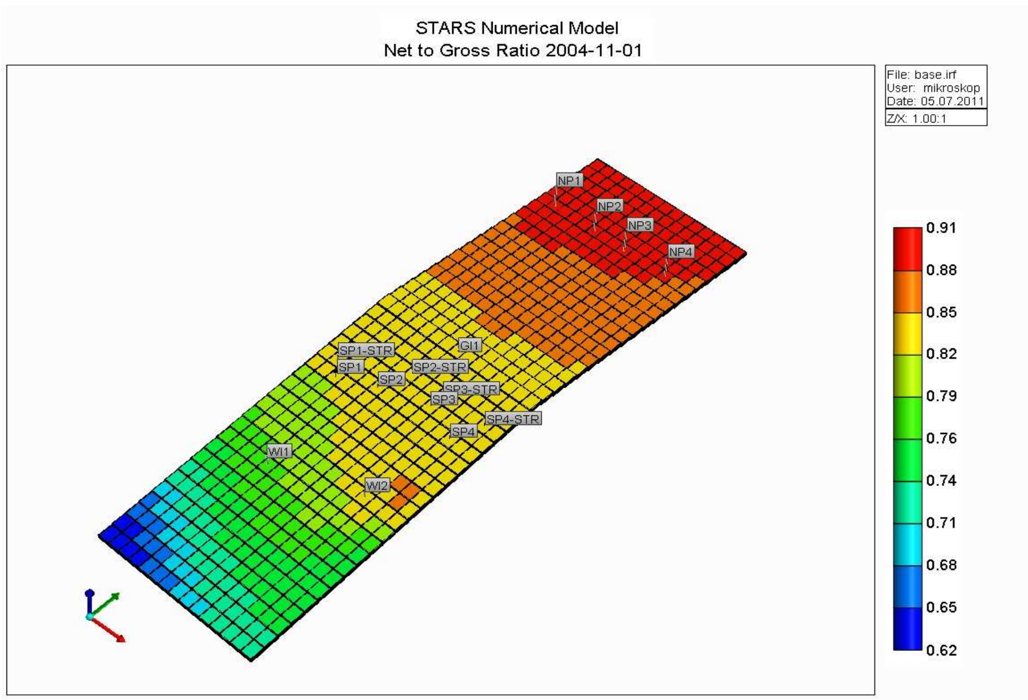

Figure 5.10 Net-to-gross distributions

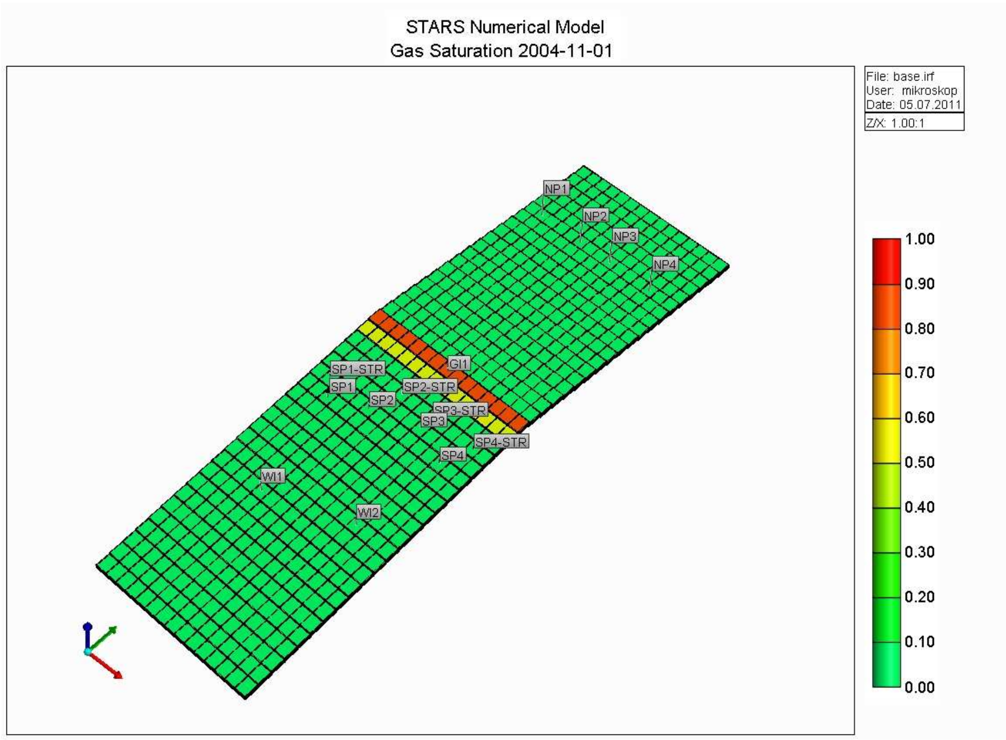

Figure 5.11 Initial saturation distributions for gas

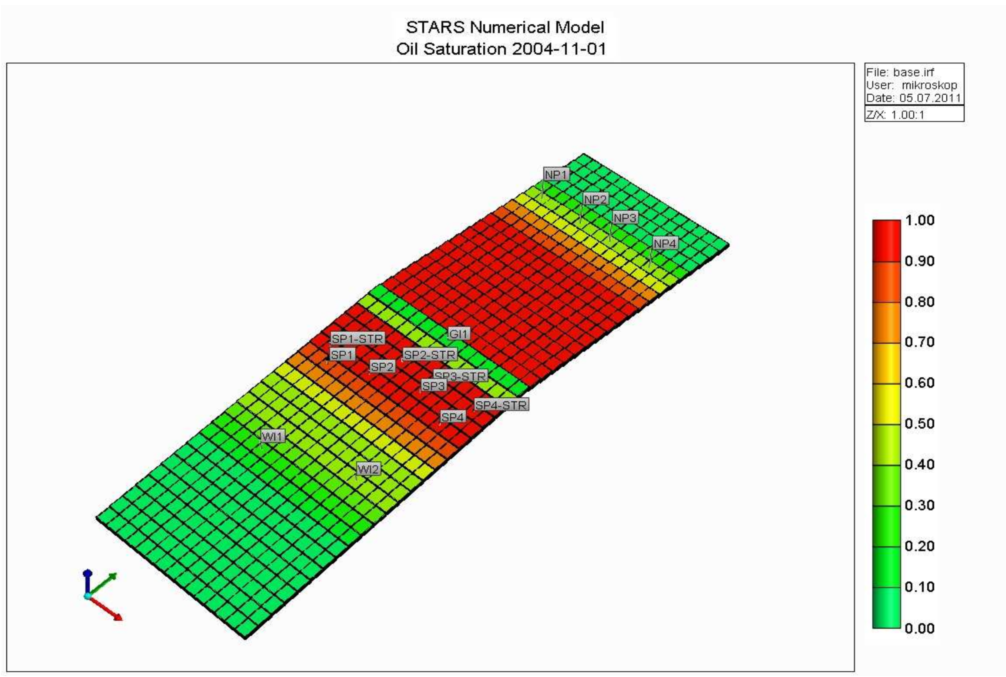

Figure 5.12 Initial saturation distributions for oil

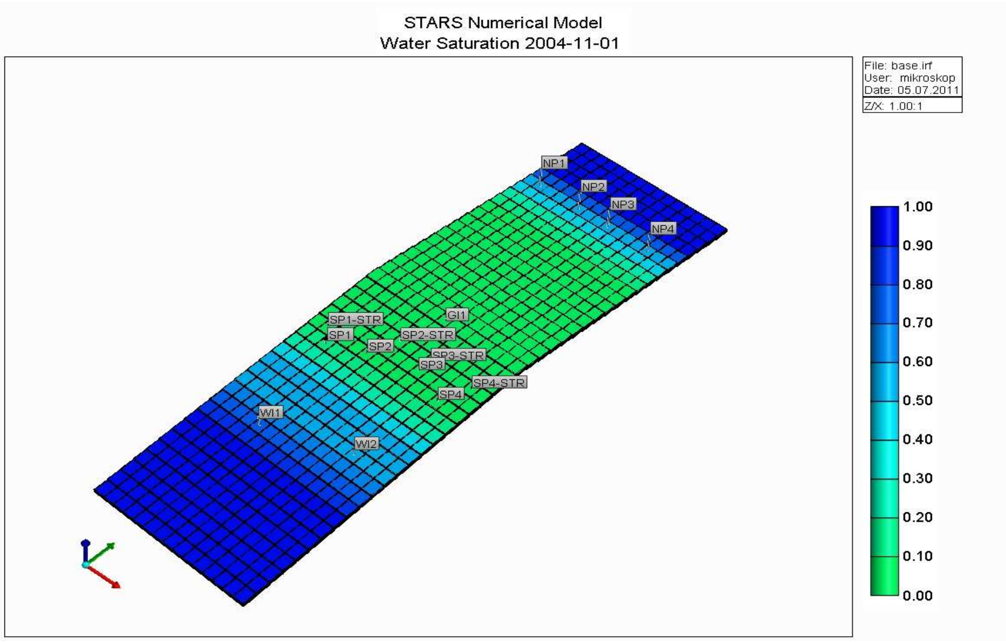

Figure 5.13 Initial saturation distributions for water

There are two sets of relative permeability data; one for North flank and one for South flank.

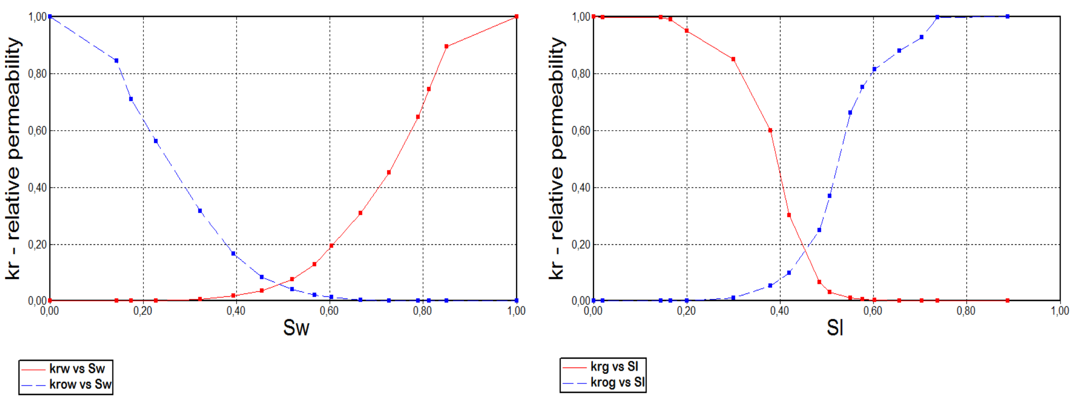

Figure 5.14 Relative permeabilities to water and oil (left) and to gas and oil (right) in the North flank

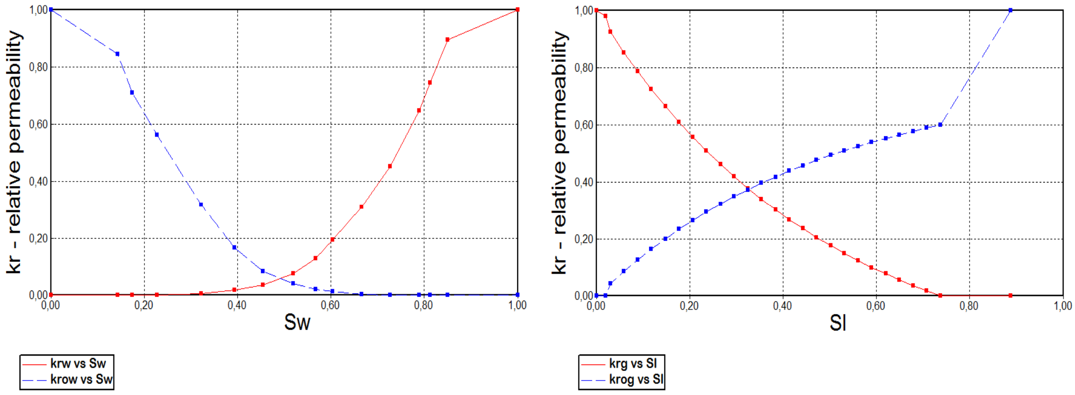

Figure 5.15 Relative permeabilities to water and oil (left) and to gas and oil (right) in the South flank

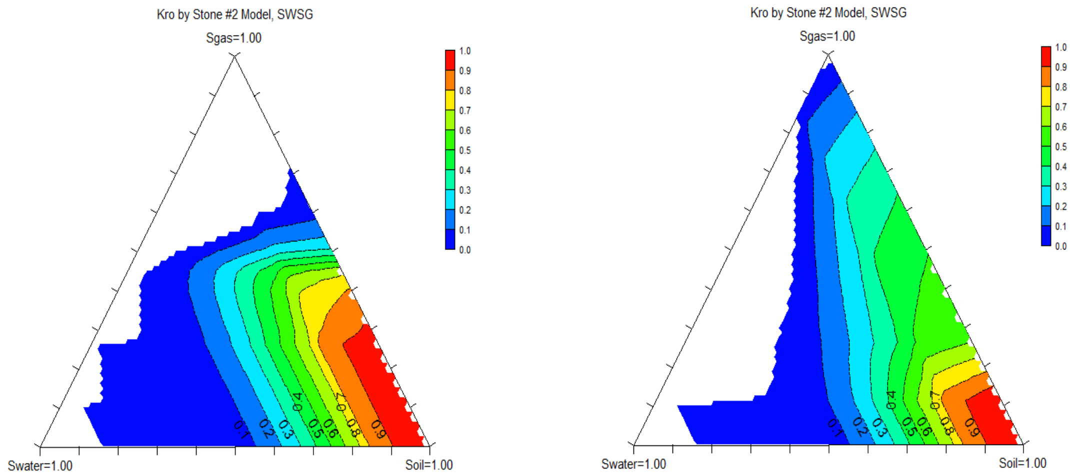

Figure 5.16 Three phase oil relative permeabilities in the North (left) and South flank (right)

5.2.2 Base Case Performance Analysis

Sector model has two flanks, South and North flanks. Totally, it consists of 15 wells. Twelve of them are production wells and there are 3 injection wells, which one of them is gas injection well and other 2 are water injection wells. These 2 water injection wells are at the South flank and gas injection well is located at the crest of the flanks.

There are 4 production wells at the North flank (NP1, NP2, NP3, and NP4). North flank production wells are located near the water-oil contact and the main drive system is gravity drainage.

South flank consist of 8 production wells which four of them are sidetracks that opened after the water injection began.

The production rate of all production wells in the base case is 23 MSTB/day. The maximum injection rate for water injection wells is 65 MSTB/day and 35 MMSTB/day for gas injection well. Production profiles for the base case and for each individual well are illustrated in figures through 17 to 34.

South flank region totally produced 129.25 MMSTB of oil in base case. Produced oil amount for each well at South flank and North flanks region is given below tables 5.2 and 5.3. Totally 401.15 MMSTB of oil produced from the sector model.

Totally 236.24911 MMSTB of water produced from all wells and $8.99*10^{11}$ ft3 of gas produced from the entire model. Water and gas productions for each well are given below tables 5.4 and 5.5.

The cumulative injected water is 174.2 MMSTB for WI1 and 166.20 MMSTB for WI2 well. Oil recovery factor for the entire model is 49.89.

Table 5.2 Cumulative oil productions for South flank wells in Base case

SP1	**SP1-STR**	**SP2**	**SP2-STR**	**SP3**	**SP3-STR**	**SP4**	**SP4-STR**
MMSTB	MMSTB	MMSTB	MMSTB	MMSTB	MMSTB	MMSTB	MMSTB
20.26244	10.68127	16.07633	20.23407	16.07611	17.62211	13.269996	15.02473

Table 5.3 Cumulative oil productions for North flank wells in Base case

NP1	NP2	NP3	NP4
MMSTB	MMSTB	MMSTB	MMSTB
70.324176	67.677624	69.96716	63.97676

Table 5.4 Cumulative water and gas productions for North flank wells

	NP1	NP2	NP3	NP4
Cumulative Water SC (MMSTB)	21.849886	18.08094	22.77193	10.407203
Cumulative Gas SC (ft3)	1.15E+11	1.37E+11	1.19E+11	1.18E+11

Table 5.5 Cumulative water and gas productions for South flank wells

	SP1	SP1-STR	SP2	SP2-STR	SP3	SP3-STR	SP4	SP4-STR
Cumulative Water SC (MMSTB)	1.0787955	73.7414	0.596393	27.067452	0.013389	33.522	0.63117	26.48855
Cumulative Gas SC (ft3)	3.31E+10	1.93E+10	3.06E+10	1.18E+11	3.33E+10	9.93E+10	2.13E+10	5.44E+10

Initial production rates for wells were 23000 STB/day, whereas abandonment rates for wells SP1-STR, SP2-STR, SP3-STR, and SP4-STR were 740.67, 507.19, 747.1, and 486.43 STB/day respectively. The beginning and shut in times for wells is given below table 5.6.

Table 5.6 The beginning and shut-in times for wells in base case

WELLS	Beginning date	Shut-in date
GI1	2006-07-02	
SP1	2005-02-01	2007-04-01
SP1-STR	2007-04-01	
SP2	2005-07-02	2007-06-01
SP2-STR	2007-06-01	
SP3	2005-11-01	2007-10-01
SP3-STR	2007-10-01	
SP4	2006-01-01	2007-08-01
SP4-STR	2007-08-01	
NP1, NP2	2005-02-01	
NP3	2005-04-01	
NP4	2006-04-01	
WI1	2006-10-01	
WI2	2007-01-01	

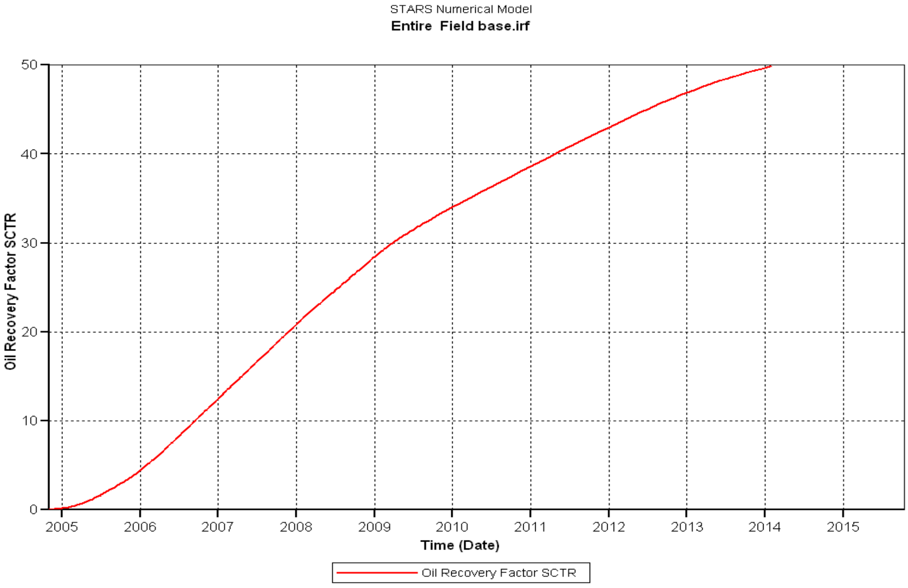

Figure 5.17 Ultimate oil recovery factors for base case

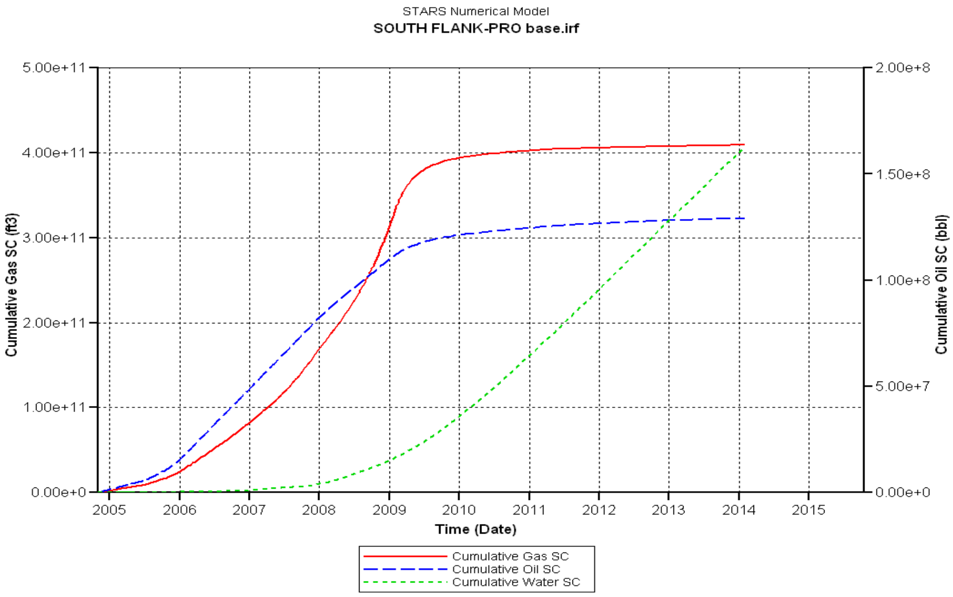

Figure 5.18 Cumulative gas, oil and water productions at South flank

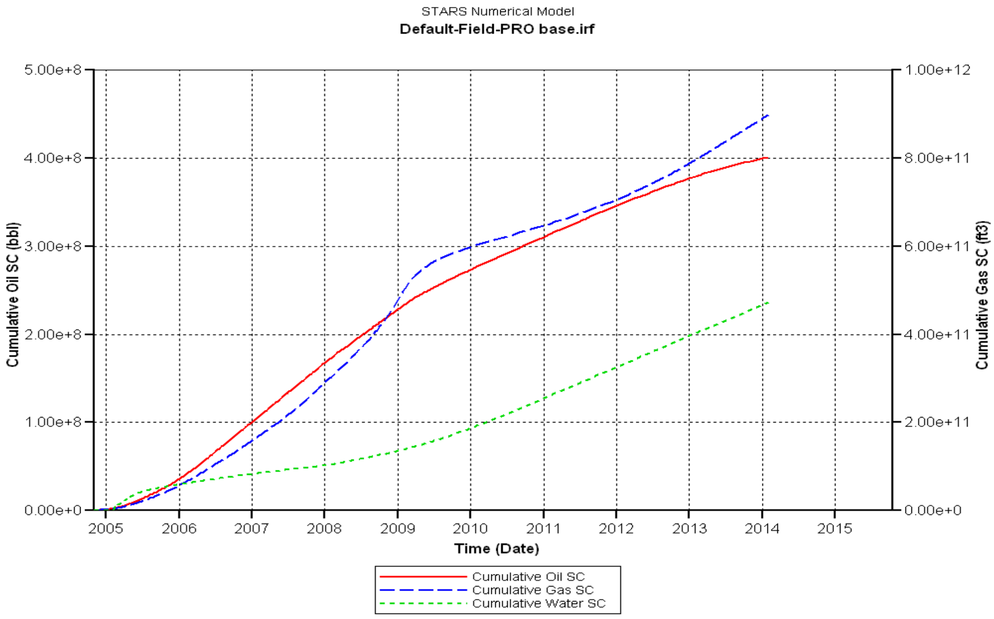

Figure 5.19 Cumulative gas, oil and water productions for entire model

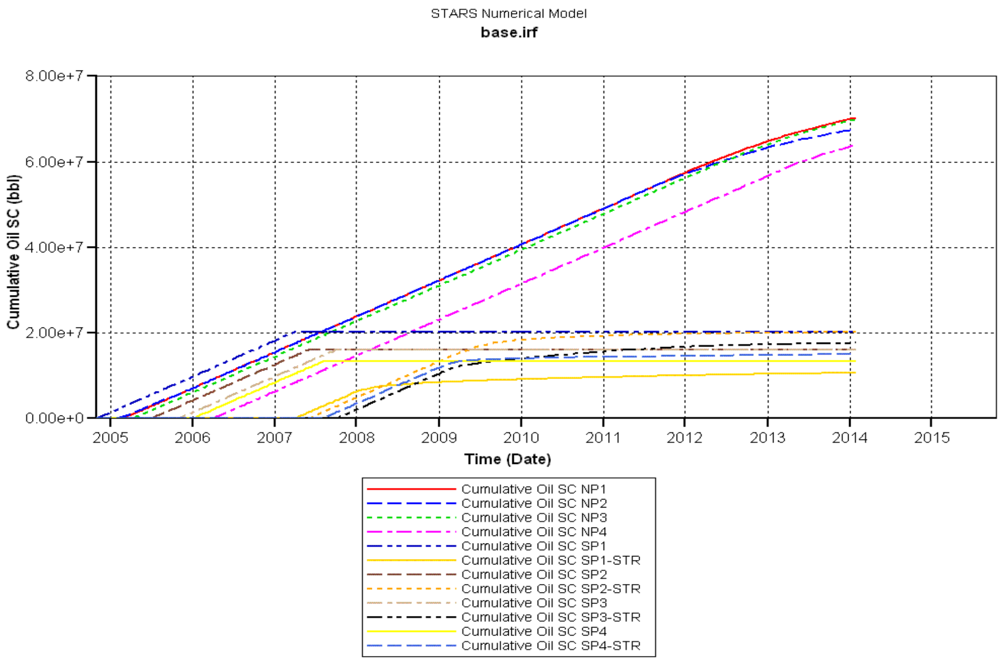

Figure 5.20 Cumulative oil productions for each well

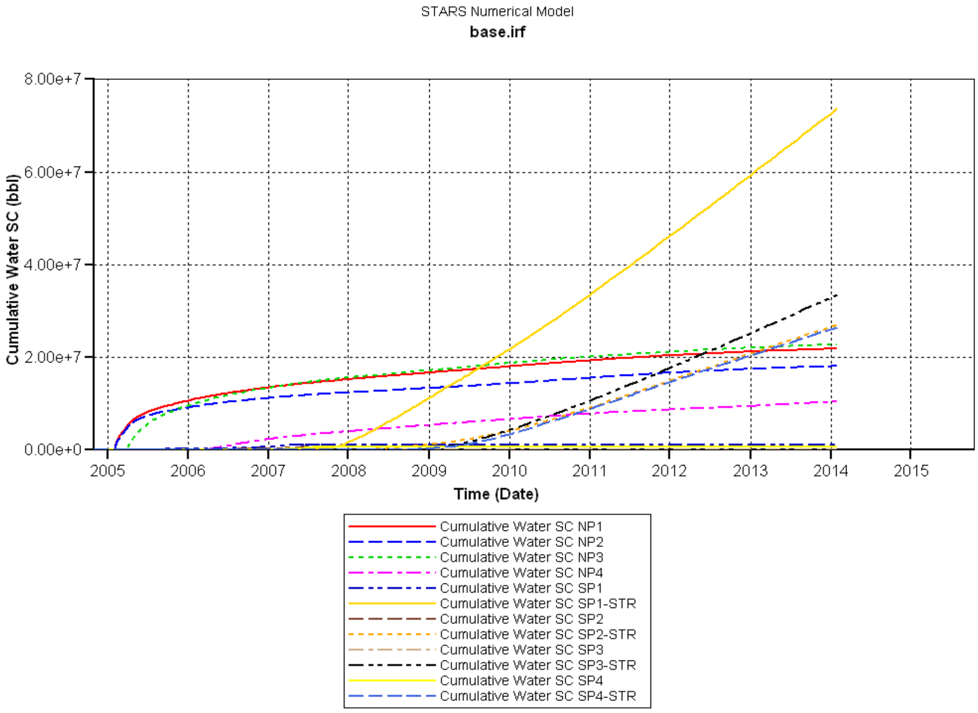

Figure 5.21 Cumulative water productions for each well

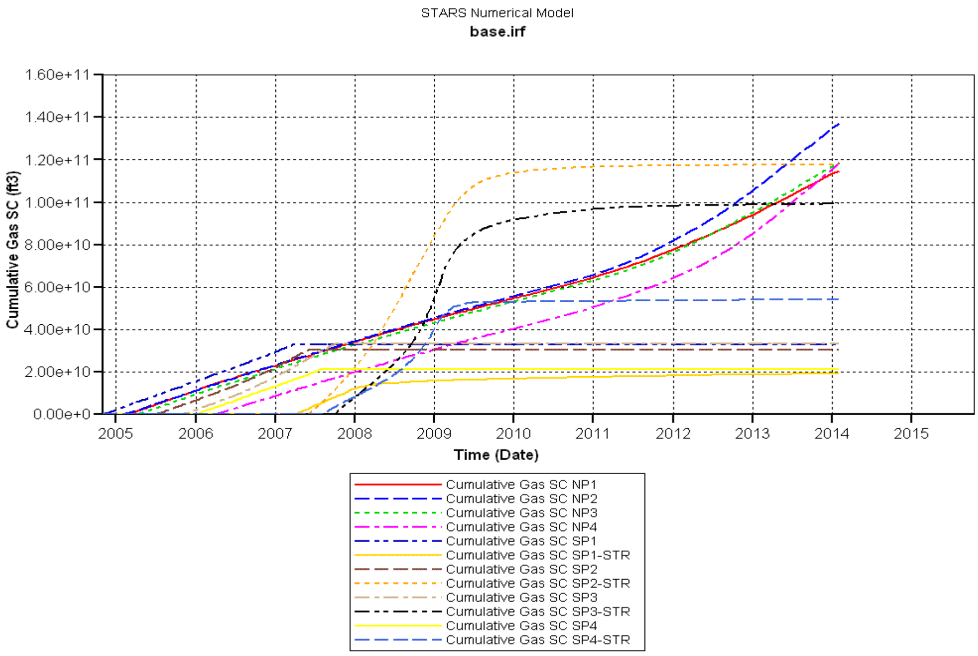

Figure 5.22 Cumulative gas productions for each well

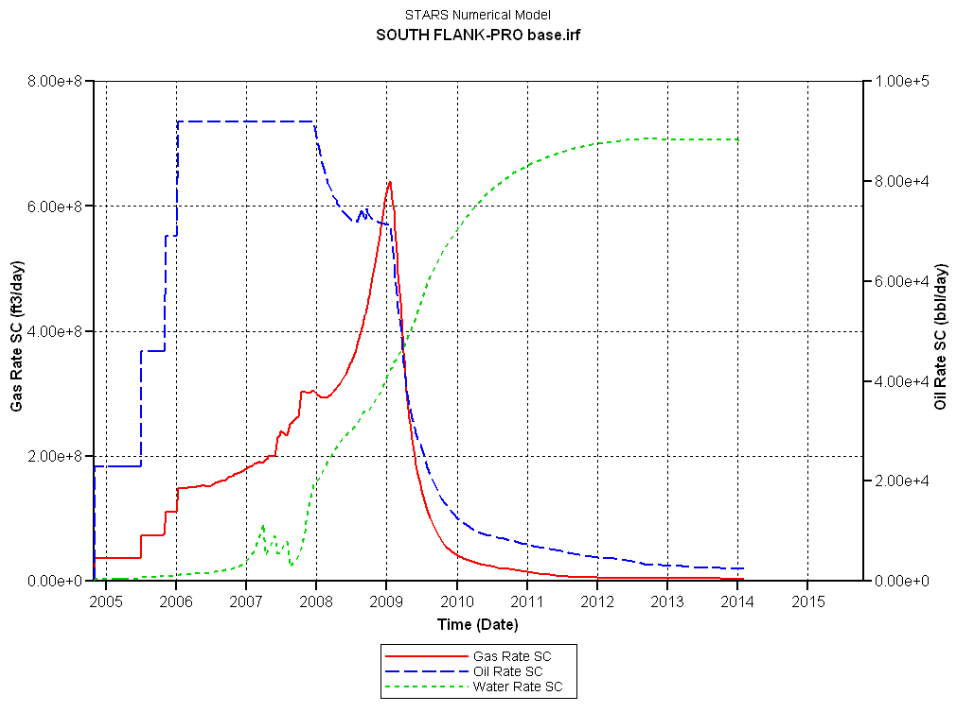

Figure 5.23 Gas, oil and water rates at South flank

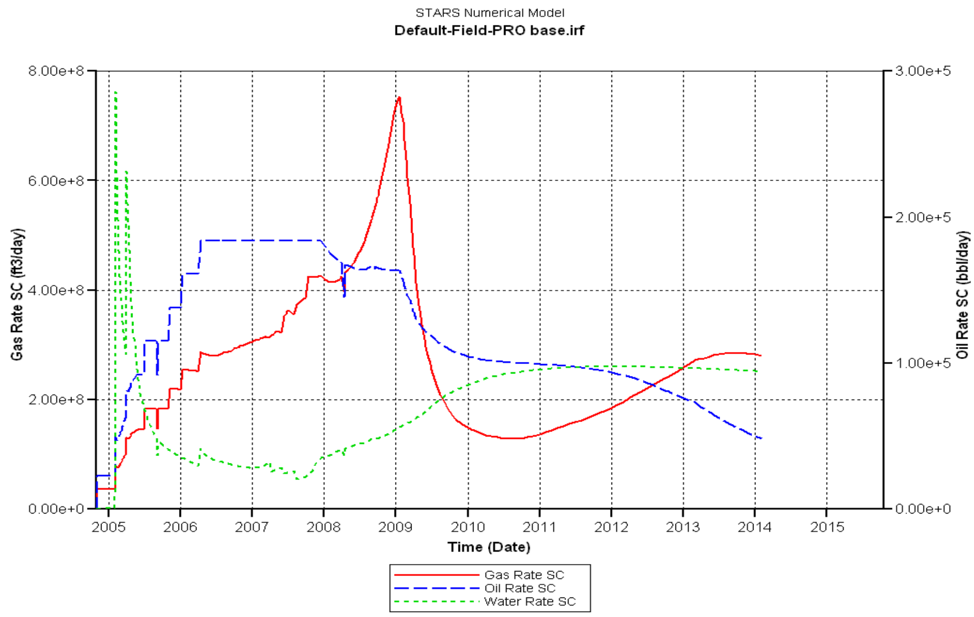

Figure 5.24 Gas, oil and water rates for entire model

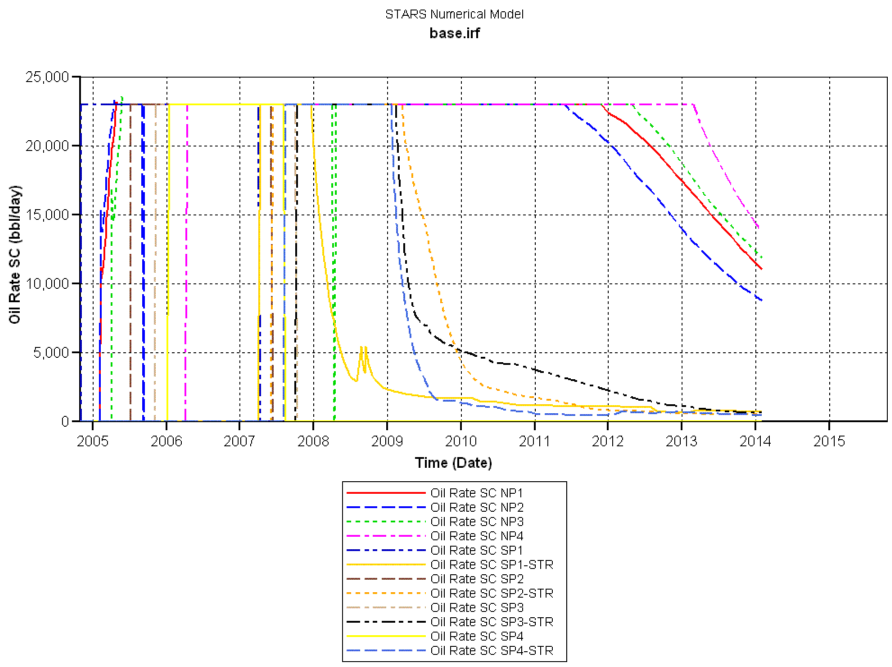

Figure 5.25 Oil rates for each well

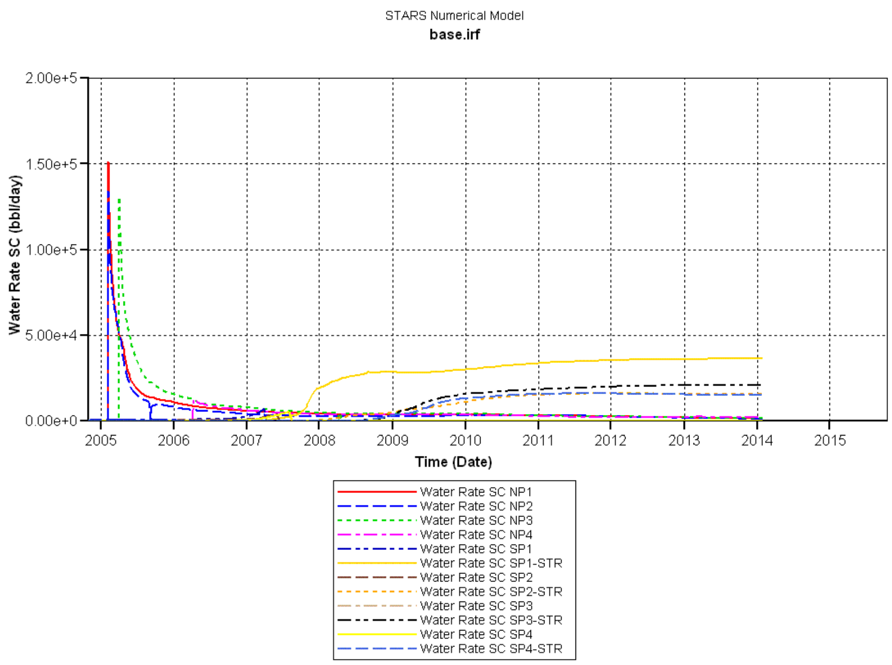

Figure 5.26 Water rates for each well

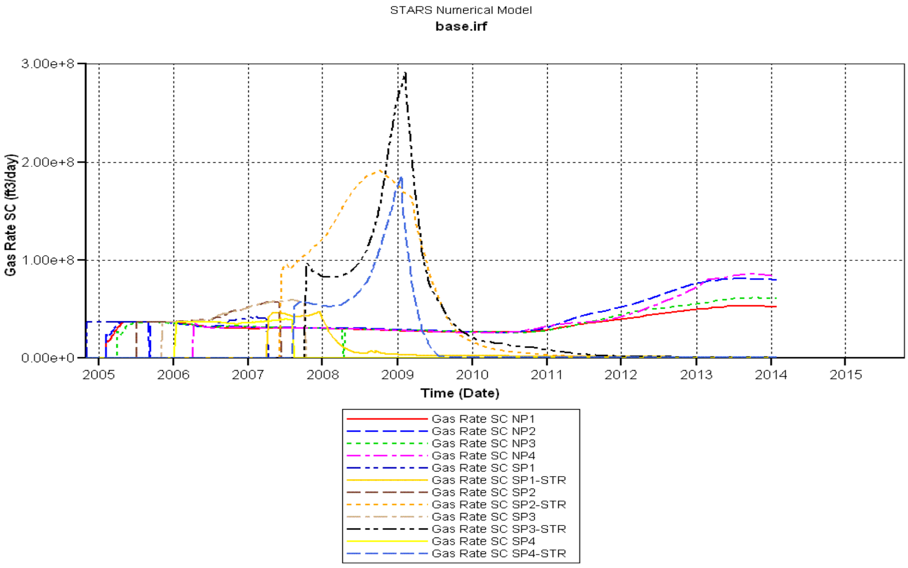

Figure 5.27 Gas rates for each well

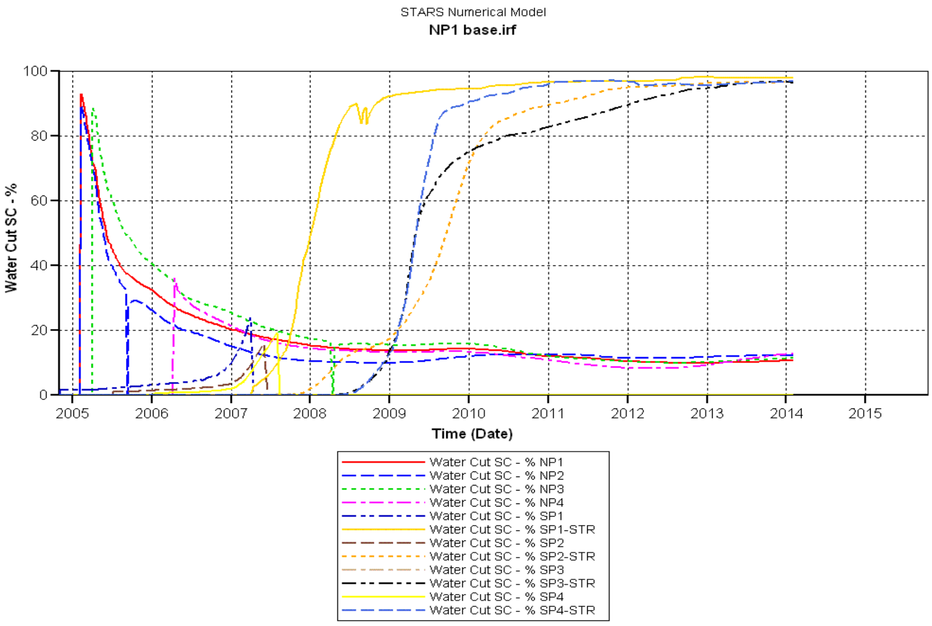

Figure 5.28 Water cuts for each well

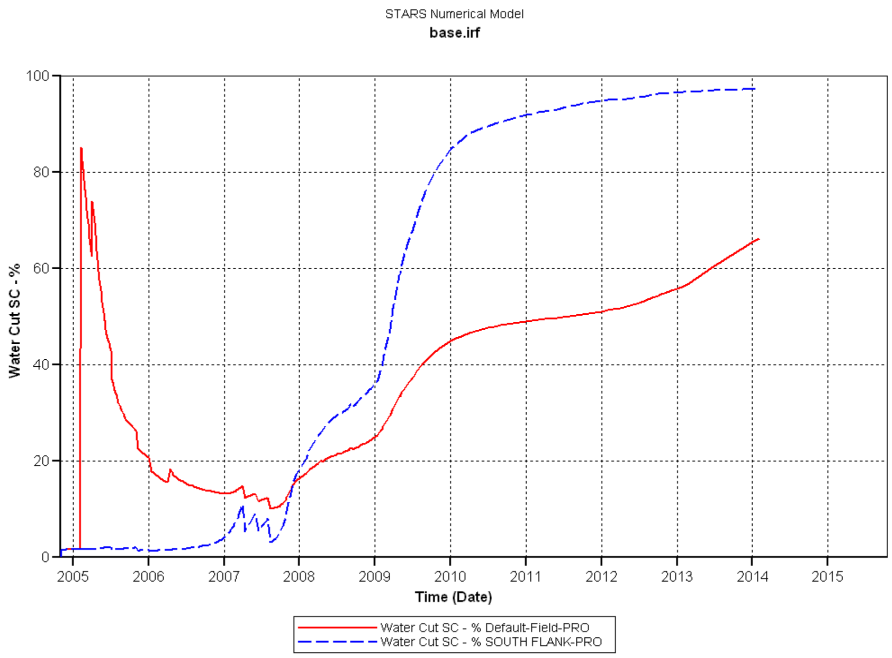

Figure 5.29 Water cuts at South flank and for entire model

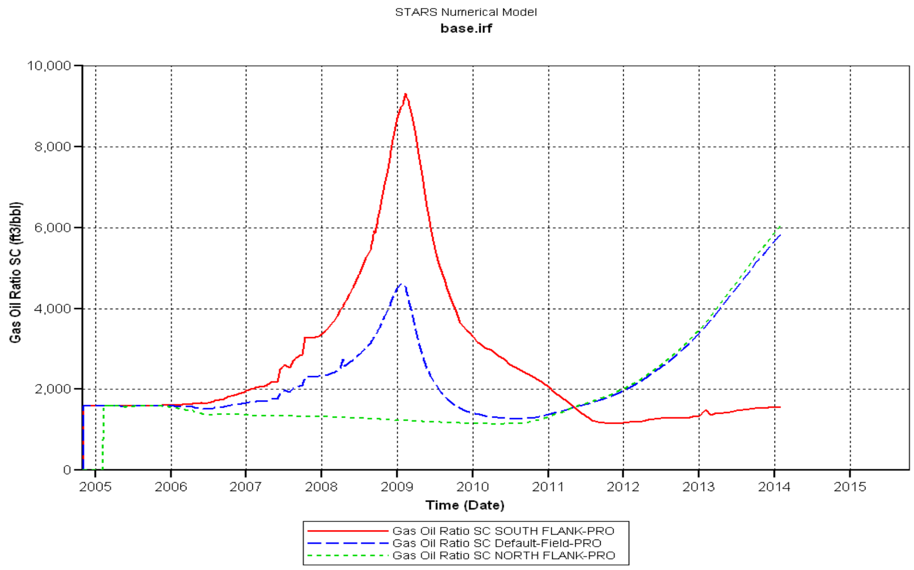

Figure 5.30 Gas-oil ratios at South and North flanks and for entire model

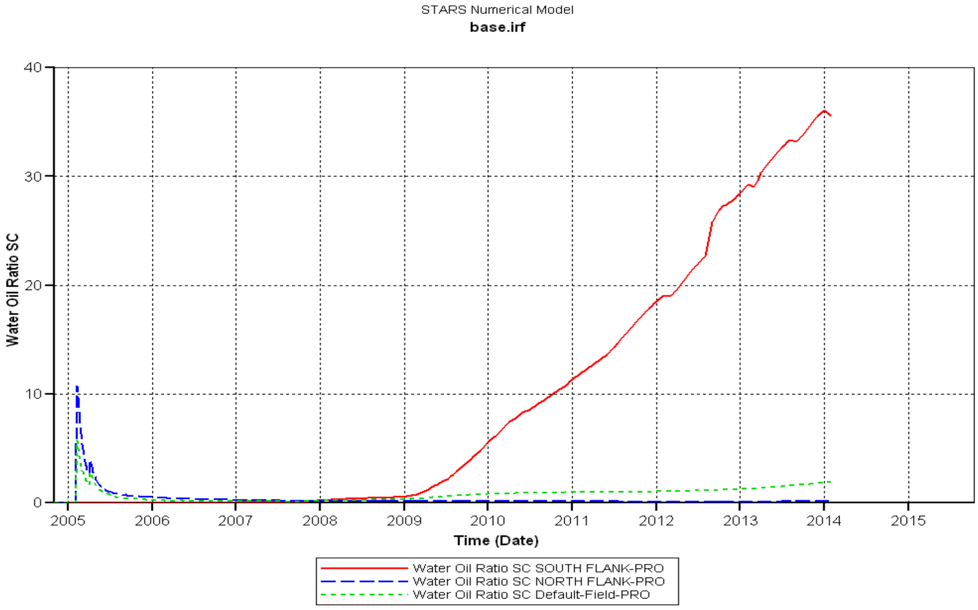

Figure 5.31 Water-oil ratios at South and North flanks and for entire model

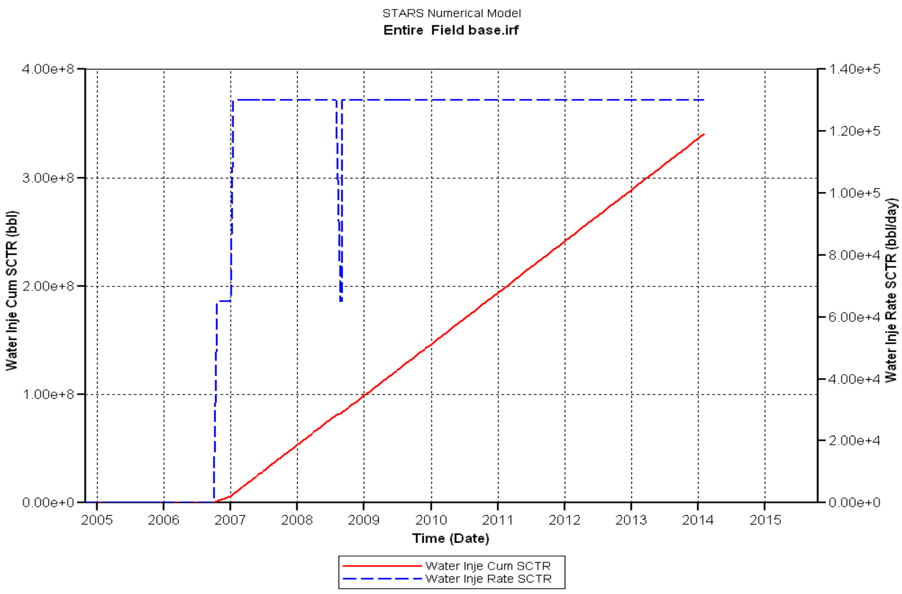

Figure 5.32 Water injection rate and cumulative injected water for entire model

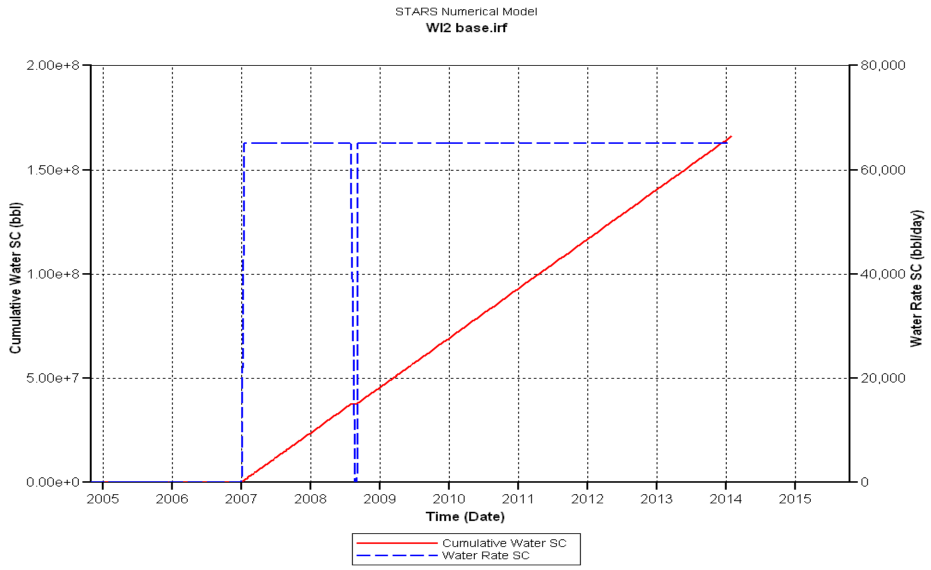

Figure 5.33 Water injection rate and cumulative injected water for WI2 well

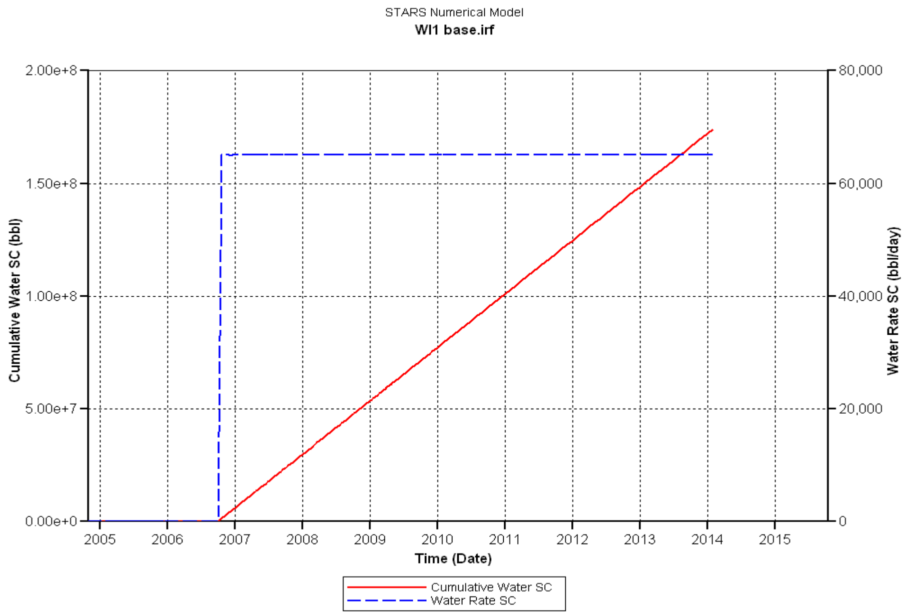

Figure 5.34 Water injection rate and cumulative injected water for WI1 well

5.2.3 Sensitivity scenarios for Polymer injection

South Flank of the entire model was chosen as the main interest zone for my research work, because injection wells are at the South Flank zone. The base case has been changed from conventional water injection to polymer injection profiles, in order to investigate the performance of polymer injection mechanisms.

Various sensitivity scenarios for polymer project have been assigned to determine the optimal polymer profile. Different polymer and xlinker fractions, different injection temperatures, well bottom hole pressures, water injection rates and different polymer injection times and wells and slug sizes are assigned for these sensitivity scenarios. The set of different cases with these parameters are given in table 5.7

Table 5.7 Sensitivity scenarios with different Polymer parameters

	WATER %	XLINKER %	POLYMER %	INJECTION TEMPE-RATURE (F°)	WELL BHP (psi)	SURFACE WATER INJECTION RATE (bbl/day)	POLYMER INJECTION WELL and TIME (P-WI1)	POLYMER INJECTION WELL and TIME (P-WI2)	POLYMER INJECTION WELL and TIME (P-SP1)	POLYMER INJECTION WELL and TIME (P-SP4)	POLYMER INJECTION WELL and TIME (P-SP2)
BASE	1	0	0			65000					
CASE 1	0.99898	2.00E-05	0.001	68		65000	1.01-1.03=2009	1.01-1.03=2009			
CASE 2	0.99898	2.00E-05	0.001	78		65000	1.01-1.03=2009	1.01-1.03=2009			
CASE 3	0.99898	2.00E-05	0.001	88		65000	1.01-1.03=2009	1.01-1.03=2009			
CASE 4	0.99898	2.00E-05	0.001	58		65000	1.01-1.03=2009	1.01-1.03=2009			
CASE 5	0.99898	2.00E-05	0.001	48		65000	1.01-1.03=2009	1.01-1.03=2009			
CASE 6	9.99E-01	2.00E-05	0.0005	68		65000	1.01-1.02=2010	1.01-1.02=2010			
CASE 7	9.99E-01	2.00E-05	0.0005	78		65000	1.01-1.02=2010	1.01-1.02=2010			
CASE 8	9.99E-01	2.00E-05	0.0005	88		65000	1.01-1.02=2010	1.01-1.02=2010			
CASE 9	9.99E-01	2.00E-05	0.0005	58		65000	1.01-1.02=2010	1.01-1.02=2010			
CASE 10	9.99E-01	2.00E-05	0.0005	48		65000	1.01-1.02=2010	1.01-1.02=2010			
CASE 11	0.99498	2.00E-05	0.001	68		65000	1.01-1.02=2010	1.01-1.02=2010			
CASE 12	0.99498	2.00E-05	0.001	78		65000	1.01-1.02=2010	1.01-1.02=2010			
CASE 13	0.99498	2.00E-05	0.001	88		65000	1.01-1.02=2010	1.01-1.02=2010			
CASE 14	0.99498	2.00E-05	0.001	58		65000	1.01-1.02=2010	1.01-1.02=2010			
CASE 15	0.99498	2.00E-05	0.001	48		65000	1.01-1.02=2010	1.01-1.02=2010			
CASE 16	0.99973	2.00E-05	0.00025	68		65000	1.01-1.02=2010	1.01-1.02=2010			

Table 5.7 (continued)

CASE 17	0.99973	2.00E-05	0.00025	78		65000	1.01-1.02=2010	1.01-1.02=2010			
CASE 18	0.99973	2.00E-05	0.00025	88		65000	1.01-1.02=2010	1.01-1.02=2010			
CASE 19	0.99973	2.00E-05	0.00025	58		65000	1.01-1.02=2010	1.01-1.02=2010			
CASE 20	0.99973	2.00E-05	0.00025	48		65000	1.01-1.02=2010	1.01-1.02=2010			
CASE 21	0.999	0.00E+00	0.001	68		65000	1.01-1.02=2010	1.01-1.02=2010			
CASE 22	0.999	0.00E+00	0.001	78		65000	1.01-1.02=2010	1.01-1.02=2010			
CASE 23	0.999	0.00E+00	0.001	88		65000	1.01-1.02=2010	1.01-1.02=2010			
CASE 24	0.999	0.00E+00	0.001	58		65000	1.01-1.02=2010	1.01-1.02=2010			
CASE 25	0.999	0.00E+00	0.001	48		65000	1.01-1.02=2010	1.01-1.02=2010			
CASE 26	0.99973	2.00E-05	0.00025	68		45000	1.01-1.02=2010	1.01-1.02=2010			
CASE 27	0.99973	2.00E-05	0.00025	68		55000	1.01-1.02=2010	1.01-1.02=2010			
CASE 28	0.99973	2.00E-05	0.00025	68		75000	1.01-1.02=2010	1.01-1.02=2010			
CASE 29	0.99973	2.00E-05	0.00025	68		85000	1.01-1.02=2010	1.01-1.02=2010			
CASE 30	0.99973	2.00E-05	0.00025	68		100000	1.01-1.02=2010	1.01-1.02=2010			
CASE 31	0.99973	2.00E-05	0.00025	68	5244		1.01-1.02=2010	1.01-1.02=2010			
CASE 32	0.99973	2.00E-05	0.00025	68	4807		1.01-1.02=2010	1.01-1.02=2010			
CASE 33	0.99973	2.00E-05	0.00025	68	4588.5		1.01-1.02=2010	1.01-1.02=2010			
CASE 34	0.99973	2.00E-05	0.00025	68	4370		1.01-1.02=2010	1.01-1.02=2010			
CASE 35	0.99973	2.00E-05	0.00025	68		65000			1.01-1.02=2008	1.01-1.02=2008	

Table 5.7 (continued)

CASE 36	0.99973	2.00E-05	0.00025	68		65000			1.01-1.02=2009	1.01-1.02=2009	
CASE 37	0.99942	8.00E-05	0.0005	78		65000	1.01-1.02=2010	1.01-1.02=2010			
CASE 38	9.99E-01	2.00E-05	0.0005	78		65000	(1.01-1.02=2009)--(1.08-1.09=2009)	(1.01-1.02=2009)--(1.08-1.09=2009)			
CASE 39	9.99E-01	2.00E-05	0.0005	78		65000	(1.01-1.02=2009)--(1.02-1.03=2010)	(1.01-1.02=2009)--(1.02-1.03=2010)			
CASE 40	9.99E-01	2.00E-05	0.0005	78		65000	(1.01-1.02=2009)--(1.08-1.09=2010)	(1.01-1.02=2009)--(1.08-1.09=2010)			
CASE 41	9.99E-01	2.00E-05	0.0005	78		65000	(1.01-1.02=2009)--(1.02-1.03=2011)	(1.01-1.02=2009)--(1.02-1.03=2011)			
CASE 42	9.99E-01	2.00E-05	0.0005	78		65000	(1.01-1.02=2009)--(1.08-1.09=2009)--(1.02-1.03=2010)	(1.01-1.02=2009)--(1.08-1.09=2009)--(1.02-1.03=2010)			
CASE 43	9.99E-01	2.00E-05	0.0005	68		65000			1.01-1.02=2009	1.01-1.02=2009	1.01-1.02=2009
CASE 44	9.99E-01	2.00E-05	0.0005	68		65000			1.01-1.02=2009	1.01-1.02=2009	1.08-1.09=2009

CHAPTER 6

RESULTS AND DISCUSSIONS

In this section the results obtained from the sector model simulations are discussed and compared with base case and with each other. Firstly general view of simulations are given and then effects of polymer concentration, injection temperature, and injection rates on Recovery factor, GOR, and WOR are analyzed. The best and the worst cases discussed and analyzed and economical aspects of projects are provided.

6.1 General view of simulation results

Recovery factors, cumulative oil for both South Flank and entire field, and incremental oil recoveries for each cases are given in Table 6.1. According to the table, all cases look beneficial when comparing the incremental oil recoveries of different cases with the base case. İt is seen that Case 42 is the most beneficial in terms of recovery factor which has 53.76 % recovery. In Case 42, total produced oil is 432.3 MMSTB and for Base case it is just 401.2 MMSTB. As wee see, Case 42 produced extra 31.11 MMSTB of oil.

From the Table 5.7 and 6.1 and Figure 6.1 general picture of injection is quite noticeable: Polymer injection with slug sizes is more beneficial in terms of recovery factors than one time injection. In cases, 38, 39, 40, 41, and 42 injection of polymer was performed in both 2 and 3 slug sizes with 6, 12,18, 24 month injection period in 2 slug size and 6 month injection period in 3 slug size strategy. In slug size injections, 0.0005 % of polymer concentration is used at 78^0 F injection temperature and 65000 bbl/day injection rates. All slug size injections began in the first month of 2009.

Cases 31, 32, 33, and 34 were run with the constant bottom-hole pressures instead of constant injection rates. The bottom-hole pressures were 5244, 4807, 4588.5 and 4370 psi respectively. When compared with constant injection rates in terms of recovery factor, it is seen that the constant bottom-hole pressure cases are generally worse than constant injection rates. Injecting the polymer at constant BHP reduces the volume of water and polymer which injected to the reservoir. Thus, less injected water gives poor sweep efficiency resulting in less incremental oil.

Polymer was injected from other well locations rather than WI1 and WI2 wells in cases 35 and 36 at different times. Injected polymer concentration was 0.00025 % at 68^0 F injection temperature. The injection rate was 65000 bbl/day. In both cases polymer was injected through wells SP1 and SP4. It is seen that changing the location did not affect the recovery in this model. For Case 35 injection started on the 1st of January and stopped on the 1st of February in 2008 in both wells. In case 36 polymer injections started on the 1st of January and stopped on the 1st of February in 2009 in both wells. In the Case 16, polymer injected with the same parameters but in 2010. When we compare these cases with the Case 16, we see that Case 35 is the best case in terms of incremental recovery. The recovery factors for cases 16, 36 and 35 are 52.95, 53, and 53.19 respectively. From these results we can say that, the earlier the polymer injection start time, the more the recovery factor.

In Case 37, this time effect of xlinker concentration was measured. 4 times higher concentration was used which is 0.00008 %. Case 7 has the xlinker concentration with 0.00002 %. When comparing these cases, it is seen that Case 7 has more incremental oil than 37. So it can be said that less xlinker concentration may give high recoveries.

From Table 6.2, it is obviously seen that water cut for Base case is 66.27, gas-oil ratio is 5836.16 ft^3/bbl and water-oil ratio is 1.96. When we compare the water cuts for cases, from Figure 6.2 we see that Case 1 has the least water cut which is 54.15. Case 1 also has the least GOR when we look at the Figure 3, which is 2933.6 ft^3/bbl. WOR comparison chart is given in Figure 6.5 and when we compare the WOR, the best case is again Case 1, which has WOR of 1.18. So, from this discussion we see that in terms of GOR, WOR, WATERCUTS, Case 1 is the best case. GOR, WOR, WATERCUT values are given in Table 6.2

Table 6.1 Recovery factor and Incremental oil recovery values for each case

CASE	RECOVERY FACTOR %	CUMULATIVE OIL at South flank (MMSTB)	CUMULATIVE OIL for entire model (MMSTB)	INCREMENTAL OIL (MMSTB)	INCREMENTAL OIL RECOVERY %
BASE	49.88925552	129.24704	401.192768		
CASE 1	53.30593109	140.35952	428.668512	27.475744	3.416675571
CASE 2	52.21456528	136.641632	419.892128	18.69936	2.325309757
CASE 3	52.52124023	136.265408	422.358272	21.165504	2.631984714
CASE 6	52.94854736	138.385296	425.79456	24.601792	3.059291843
CASE 7	53.69787598	143.434352	431.820416	30.627648	3.808620457
CASE 8	52.40136719	135.431936	421.394304	20.201536	2.512111668
CASE 9	53.01233292	138.652384	426.307456	25.114688	3.123077396
CASE 10	53.27995682	140.987664	428.459648	27.26688	3.390701298
CASE 11	52.88208389	136.572784	425.260096	24.067328	2.992828373
CASE 12	53.04744339	137.942752	426.589856	25.397088	3.15818787
CASE 13	52.5813446	136.110448	422.841632	21.648864	2.692089084
CASE 14	53.38834381	141.698224	429.331264	28.138496	3.499088291
CASE 15	52.29941177	135.544496	420.5744	19.381632	2.410156254
CASE 16	52.94985199	138.39808	425.805024	24.612256	3.06059647
CASE 17	52.45782089	136.030816	421.848288	20.65552	2.568565372
CASE 18	52.68334675	137.468184	423.6618917	22.46912367	2.794091228
CASE 19	53.01250076	138.659664	426.308832	25.116064	3.123245243
CASE 20	52.31321335	136.784176	420.685408	19.49264	2.423957828
CASE 21	53.41303635	141.771552	429.529824	28.337056	3.523780826

Table 6.1 (continued)

CASE 22	52.55002594	136.413024	422.589792	21.397024	2.66077042
CASE 23	52.614357	135.92896	423.107104	21.914336	2.725101475
CASE 24	53.33760071	141.094016	428.923168	27.7304	3.448345188
CASE 25	52.70074463	136.669184	423.801792	22.609024	2.811489109
CASE 26	52.61148453	137.40248	423.084	21.891232	2.722229008
CASE 27	53.42193604	141.853472	429.601408	28.40864	3.532680515
CASE 28	52.59259415	136.990016	422.932096	21.739328	2.703338627
CASE 29	53.43649292	141.861376	429.718464	28.525696	3.5472374
CASE 30	52.56837082	135.657584	422.737312	21.544544	2.679115299
CASE 31	52.84775925	181.112256	424.984096	23.791328	2.958503727
CASE 32	51.98513794	187.018608	418.047136	16.854368	2.095882419
CASE 33	51.66219711	190.03552	415.450176	14.257408	1.772941593
CASE 34	51.32824326	192.661376	412.764608	11.57184	1.438987736
CASE 35	53.1914978	140.449184	427.748288	26.55552	3.302242283
CASE 36	53.00209045	138.463168	426.225152	25.032384	3.112834934
CASE 37	52.76541519	137.451248	424.321856	23.129088	2.876159672
CASE 38	53.74136734	144.067232	432.170176	30.977408	3.85211182
CASE 39	53.72995377	143.9336	432.078336	30.885568	3.840698246
CASE 40	53.72855759	143.943936	432.067136	30.874368	3.839302067
CASE 41	53.73023224	143.926912	432.080608	30.88784	3.840976719
CASE 42	53.75808334	144.180288	432.304576	31.111808	3.868827824
CASE 43	53.08768463	139.447824	426.91344	25.720672	3.198429111
CASE 44	53.04098511	139.285216	426.53792	25.345152	3.151729587

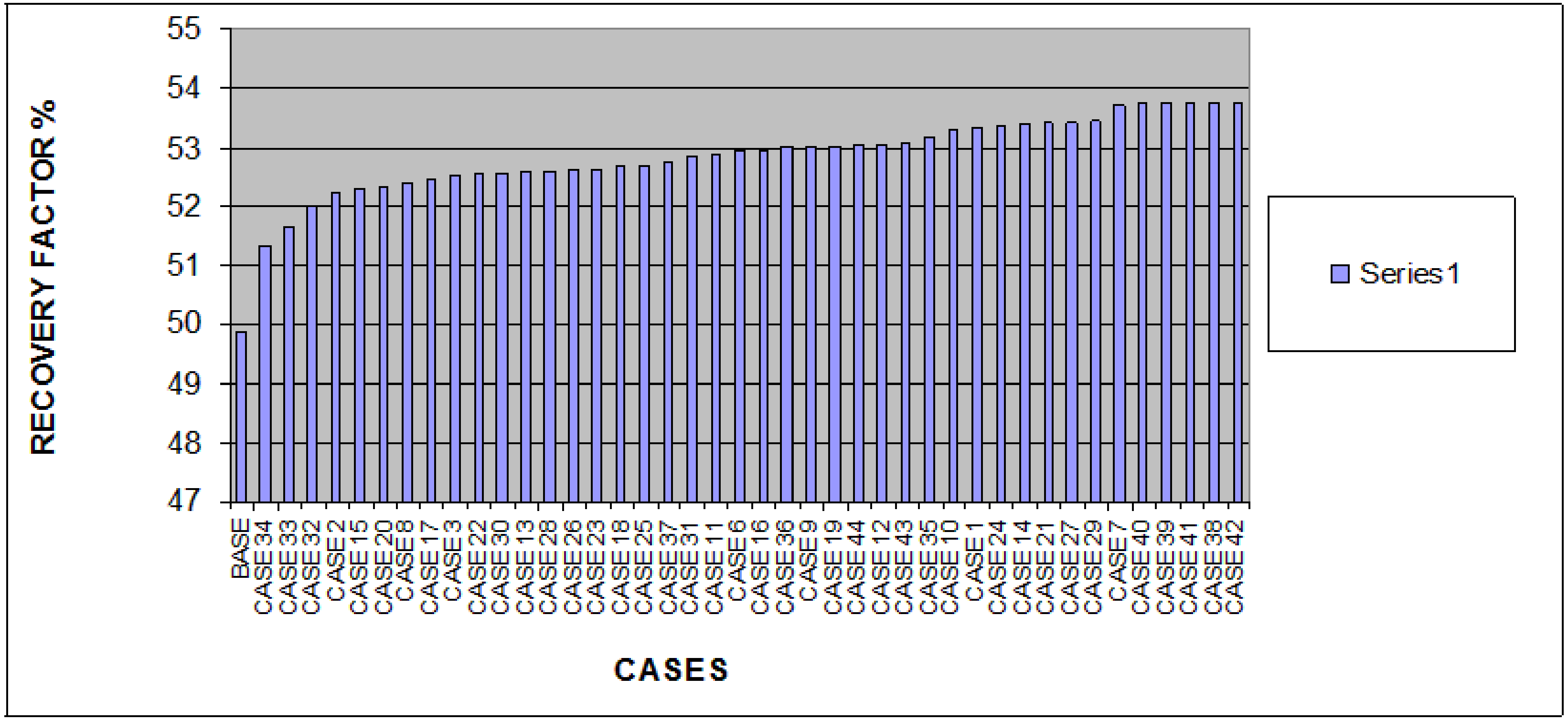

Figure 6.1 Comparison chart of recovery factors

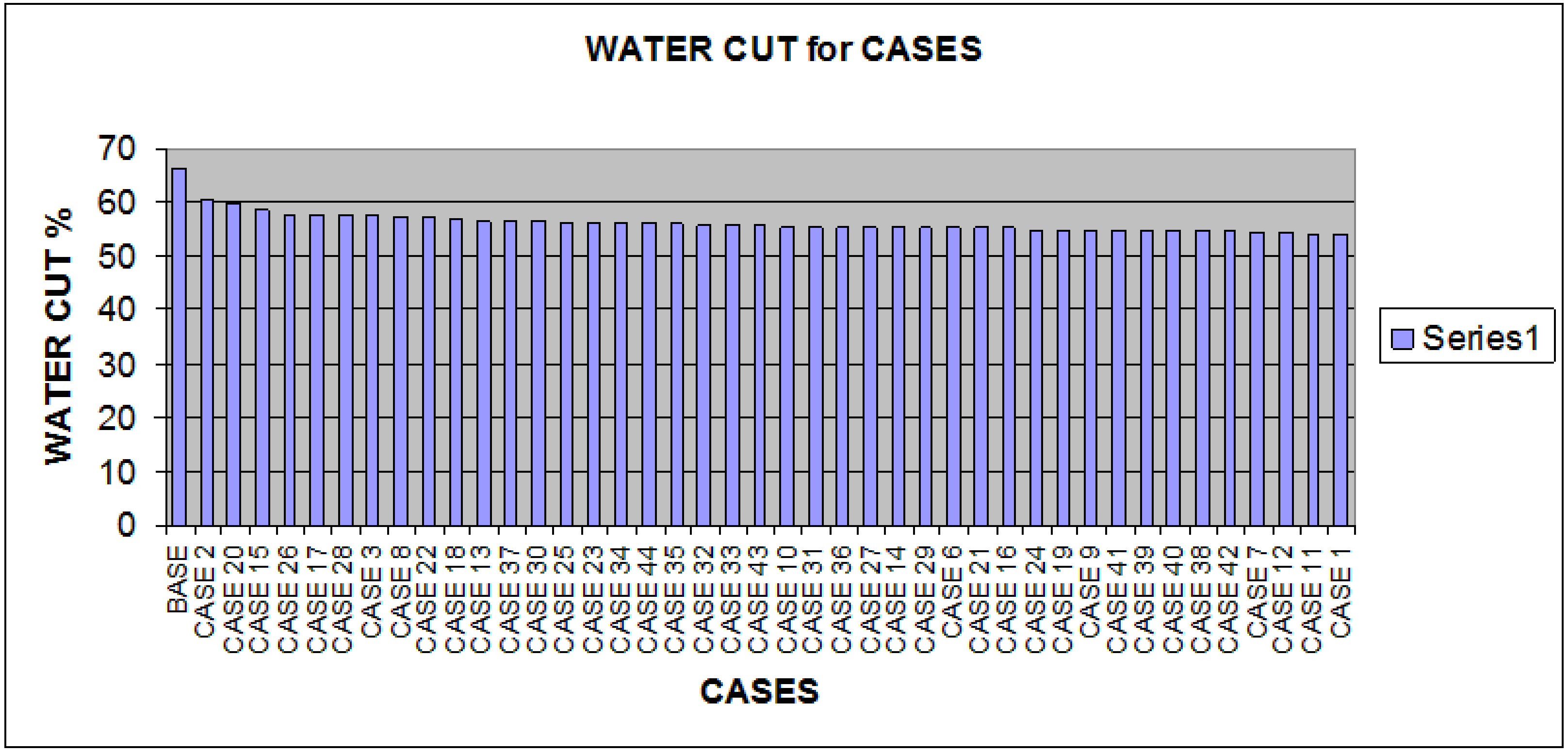

Figure 6.2 Comparison chart of WATER CUTS

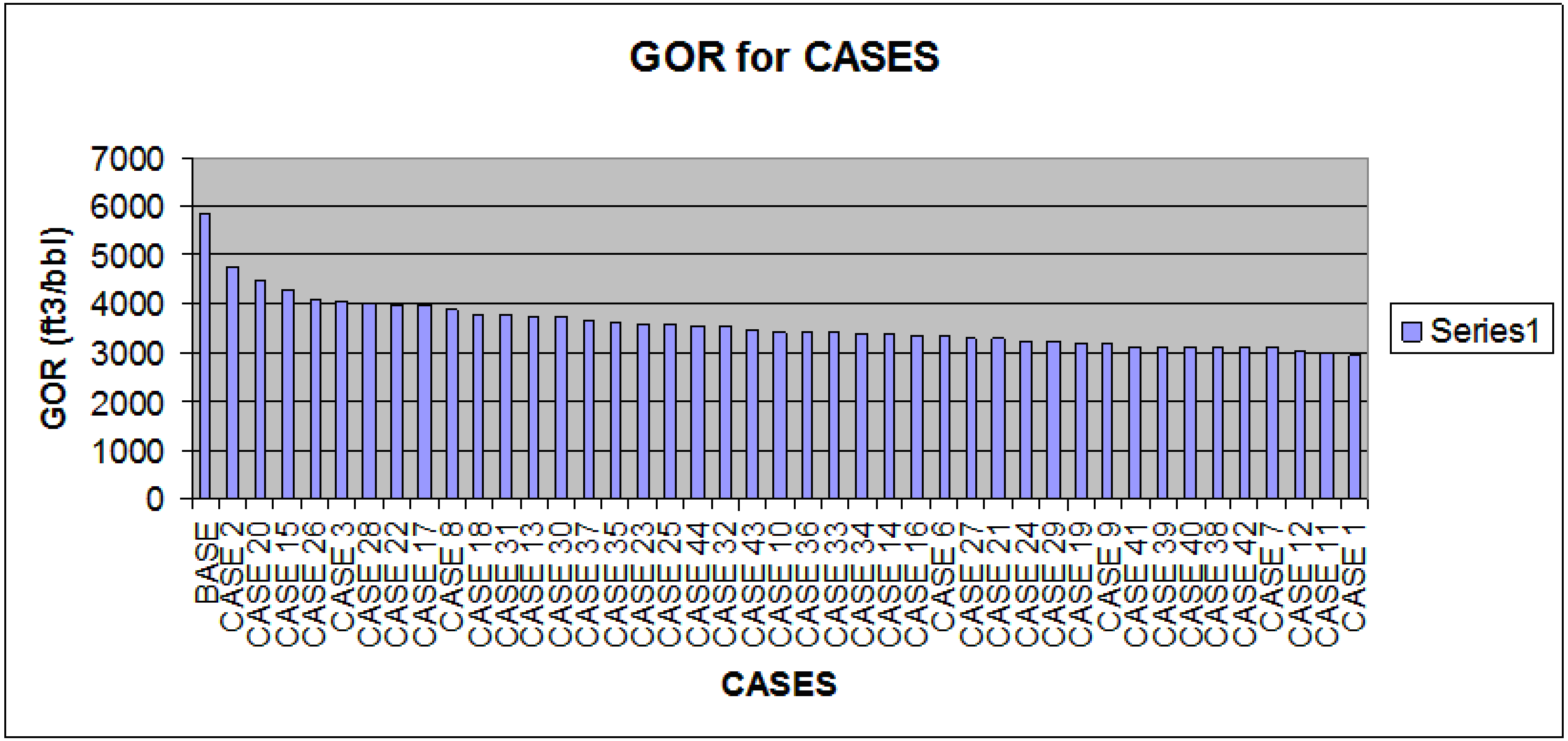

Figure 6.3 Comparison chart of gas-oil ratios

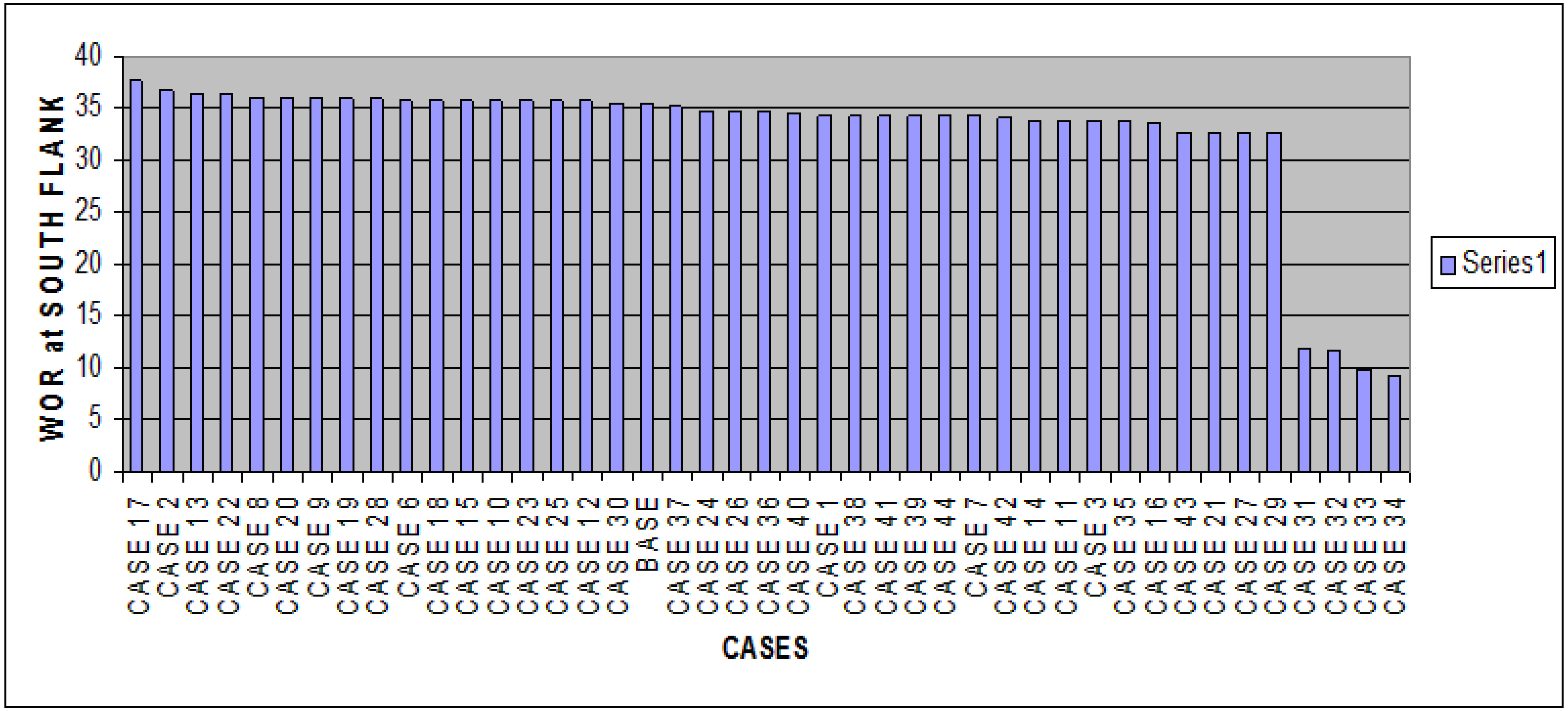

Figure 6.4 Comparison chart of water-oil ratios at South Flank

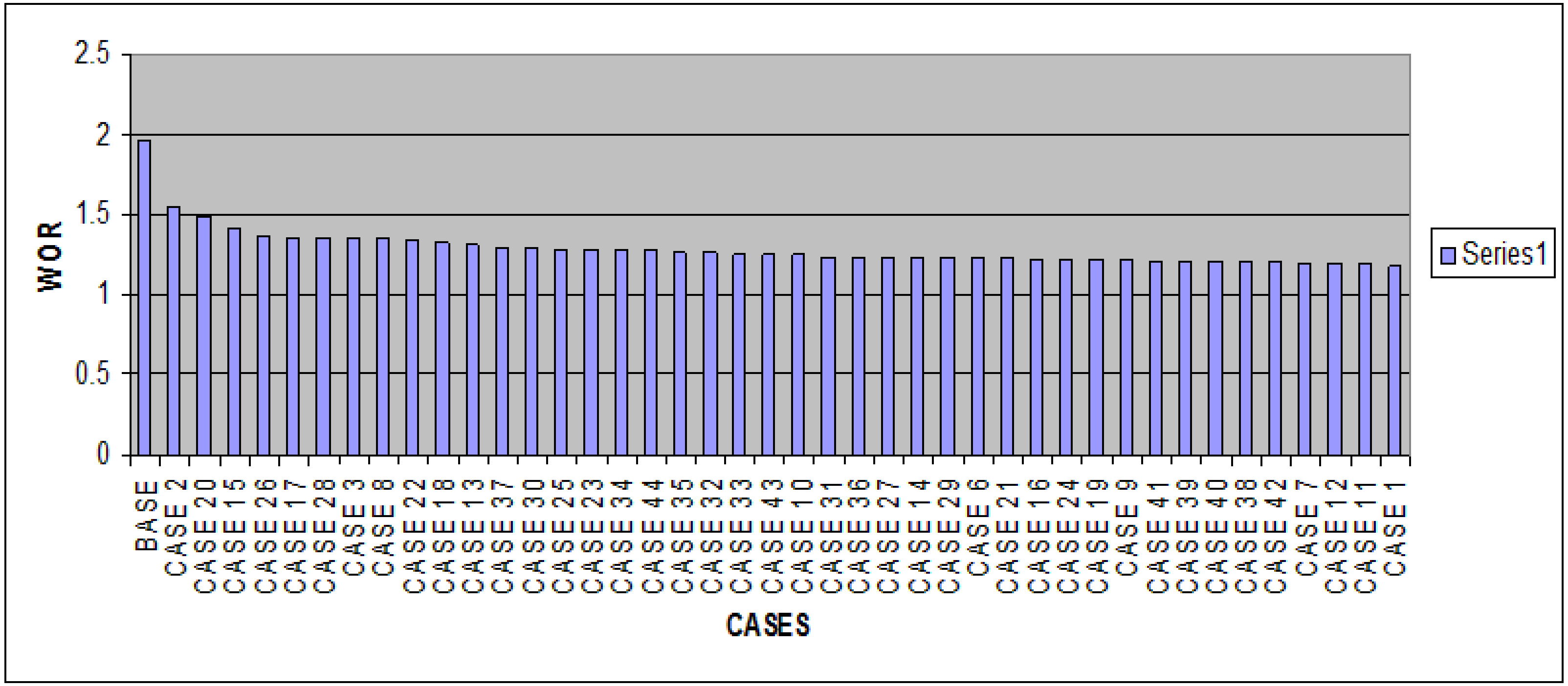

Figure 6.5 Comparison chart of water-oil ratio

Table 6.2 Water cuts, GOR and WOR values for each case

CASE	WATER CUT %	GOR (ft3/bbl)	WOR at SOUTH FLANK	WOR
BASE	66.26992035	5836.163574	35.54000473	1.964712739
CASE 1	54.15259552	2933.608154	34.37308121	1.181148529
CASE 2	60.74799347	4743.5	36.74087143	1.547640443
CASE 3	57.5610466	4046.29248	33.8302536	1.356325626
CASE 6	55.12600708	3329.692139	35.80237579	1.228462219
CASE 7	54.49110794	3094.168213	34.18089294	1.197372794
CASE 8	57.40715408	3891.914795	36.00367355	1.347811937
CASE 9	54.85917282	3184.450684	35.97420883	1.215289354
CASE 10	55.45461273	3429.196777	35.73084641	1.2449013
CASE 11	54.22373581	2966.983398	33.87553024	1.184538245
CASE 12	54.27560043	3005.392334	35.6774025	1.18701613
CASE 13	56.68803024	3723.484863	36.526371	1.3088305
CASE 14	55.16376495	3361.491211	33.87656784	1.230338931
CASE 15	58.55223465	4277.288086	35.75804901	1.412675381
CASE 16	55.06473923	3331.748047	33.56481934	1.225423694
CASE 17	57.64452362	3959.452393	37.62255096	1.360969544
CASE 18	56.83750248	3750.405518	35.77591324	1.321913987
CASE 19	54.89468384	3195.550049	35.91616821	1.217033625
CASE 20	59.74606323	4514.871582	36.00011444	1.484229088
CASE 21	55.11892319	3279.691162	32.61998749	1.228110552
CASE 22	57.32737351	3970.338135	36.43837738	1.343422413
CASE 23	56.12059403	3602.292969	35.68687058	1.278973341
CASE 24	54.99549103	3258.11084	34.85077286	1.221999407
CASE 25	56.22748184	3586.818359	35.68344498	1.284538508
CASE 26	57.83362961	4118.26709	34.81557083	1.37155807
CASE 27	55.1860466	3291.729248	32.56550598	1.231447697
CASE 28	57.6386261	4032.155762	35.84915924	1.360641003

Table 6.2 (continued)

CASE 29	55.1265831	3252.342041	32.52729034	1.22849083
CASE 30	56.42812347	3699.488281	35.57864761	1.29505837
CASE 31	55.36120987	3743.361572	11.89500713	1.240204334
CASE 32	55.70963669	3534.735352	11.64451885	1.25782752
CASE 33	55.5580864	3393.017822	9.733942032	1.25012815
CASE 34	56.09309769	3389.010986	9.310474396	1.277546167
CASE 35	55.93408203	3614.420166	33.71189499	1.269327641
CASE 36	55.28225708	3422.233887	34.75376129	1.236248851
CASE 37	56.51226807	3686.776367	35.17690659	1.299498916
CASE 38	54.65898514	3115.1521	34.36850739	1.205508471
CASE 39	54.69287491	3119.629883	34.28585053	1.207158446
CASE 40	54.68556976	3119.105713	34.45235062	1.206802487
CASE 41	54.69986725	3122.220215	34.34722519	1.207499027
CASE 42	54.65114594	3108.61084	34.14490128	1.205127358
CASE 43	55.5534668	3457.200684	32.64521408	1.249894261
CASE 44	56.03635788	3550.957031	34.24134064	1.274606824

6.2 Effects of polymer concentration, injection temperature, and injection rates on Recovery factor, GOR, and WOR

Figures through 6.6 to 6.32 show how Recovery factor, GOR, and WOR changes when we change the polymer concentration, injection temperature and injection rates. Analyzing these figures, we can find the optimum polymer concentration, optimum injection temperature and rate.

Incremental oil recovery versus polymer concentration charts were created at 48^0, 58^0, 68^0, 78^0, and 88^0 F injection temperatures. From Figure 6.6 we see that at 68^0 F injection temperature, as the polymer concentration increases the incremental oil recovery decreases. At polymer concentration of 0.00025 incremental recovery is the maximum and 3.06 %. This case is Case 16. At 78^0 F injection temperature, the best case is Case 7 with incremental recovery of 3.8 at 0.0005 % of polymer concentration. For injection temperature 88^0 F, incremental recovery first decreases then increases as the polymer concentration increases. The best case for this 88^0 F temperature is Case 18 with 2.8 % incremental recovery at 0.00025 polymer concentration. At injection temperatures 58^0 and 48^0 F, the best cases are 14 and 10 with incremental recoveries of 3.5 and 3.39 at polymer concentrations of 0.001 and0.0005, respectively.

When polymer concentration increases adsorption also increases thus permeability decreases. İncreasing the polymer concentration until some point also increases the recovery factor because of increasing permeability reduction. But after some point this does not help for recovery increase. After this critical point some pore volumes in the reservoir are inaccessible to polymers and adsorption does not occur, early breakthrough of polymers can bee sen. So, some of injected polymer does not contribute to the oil recovery. Because of that reason we see that for different injection temperatures, different polymer concentrations are needed to identify the best case in each category.

Figures 6.11, 6.12, and 6.13 shows the incremental recovery versus injection temperatures for each polymer concentration. At 0.00025 % polymer, the highest incremental recovery case is Case 19 with incremental recovery of 3.12 at 58^0 F injection temperature. At 0.0005 % polymer, the highest recovery case is Case 7 with 3.8 % of incremental recovery at 78^0 F. When we look at the 0.001 % polymer concentration, the best case is Case 14 with 3.5 % of incremental oil recovery at 58^0 F.

When temperature increases it affects the viscosity of polymer resulting in decreasing in viscosity. Lower viscosity polymer means poor sweep improvement, and so less incremental recovery of oil. This is true for low temperature ranges. High temperature ranges may effect the gelation time and gel strength.

Figure 6.14 shows the incremental recovery versus injection rate at 0.00025 % polymer concentration and 68^0 F injection temperature. Cases 26, 27, 16, 28, 29, and 30 with injection rates of 45000, 55000, 65000, 75000, 85000, and 100000 bbl/day were used. The highest incremental recovery is 3.55 % for Case 29 at 85000 bbl/day injection rate.

But at 0.00025 % polymer and 68^0 F temperature, we can say that the optimum injection rates are 55000 and 85000 bbl/day which is for Cases 27 and 29 respectively. Total produced oil for Cases 27 and 29 are 429.6 and 429.71 MMSTB, respectively.

When we look at the figure 6.14, we see that as the injection rate increases, recovery factor shows different increasing and decreasing trends. Between injection rate of 45000 and 55000 bbl/day, recovery increases. This is because, more polymer was injected and adsorption increases resulting in reduced permeability. But at injection rates of 55000-75000 bbl/day, recovery decreases. This is because, reduction in permeability decrease. Reason for decrease in permeability reduction is higher injection rates at which polymer does not adsorb easily any more. Until here adsorption behavior of polymer is assumed static. But after 75000 bbl/day of polymer injection, we again see the increase in recovery. This 75000 bbl/day rate is critical rate and adsorption behavior after this point is called flow-induced adsorption. Under flow-induced adsorption behavior, as injection rate is increased improvements in the adsorbed polymer layer can be seen. So, the recovery factor increases again. This increase continues until 85000 bbl/day rate. After that rate recovery again decreases. This phenomena may be due to the mechanical degredation of the polymer because of high shear rates.

Normally when the crosslinker concentration increases, more crosslinks form between the seperate base polymer molecules and the gel gets stronger. More crosslinks cause a denser gel network and more adsorption which yields lower microscopic permeability. But simulation results showed that increasing the crosslinker concentration gave worse results. This may be due to the finite crosslink sites of the base polymer. At 0.000008% crosslinker concentration crosslink sites of base polymer may be reached and excess concentration of crosslinker may cause this result. It will be good to rerun the other cases with different crosslinker concentrations to see how crosslinker affects the production.

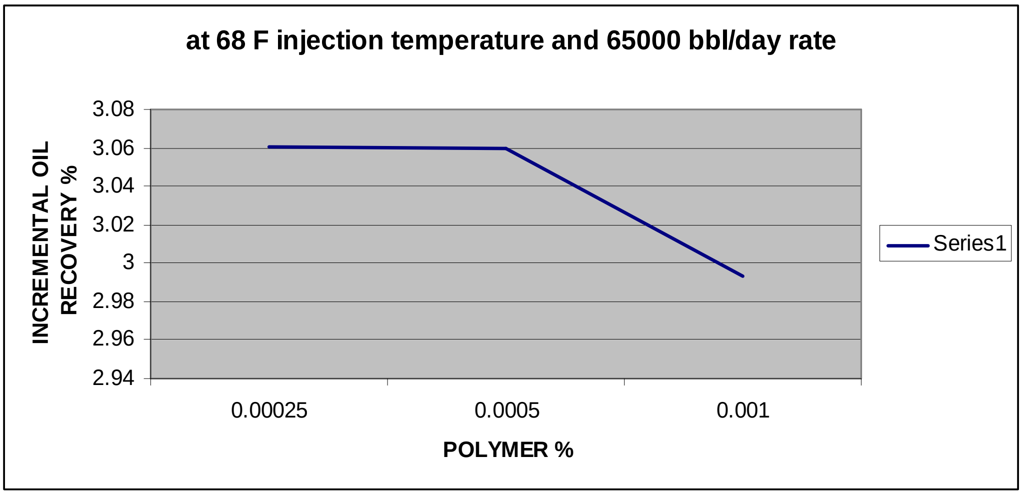

Figure 6.6 Incremental oil recovery versus polymer concentration at 68 F^o

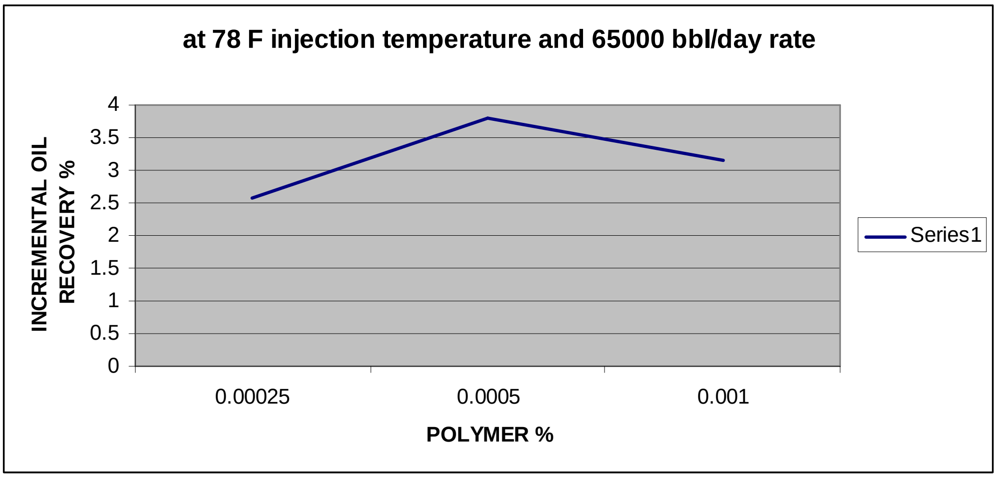

Figure 6.7 Incremental oil recovery versus polymer concentration at 78 F^o

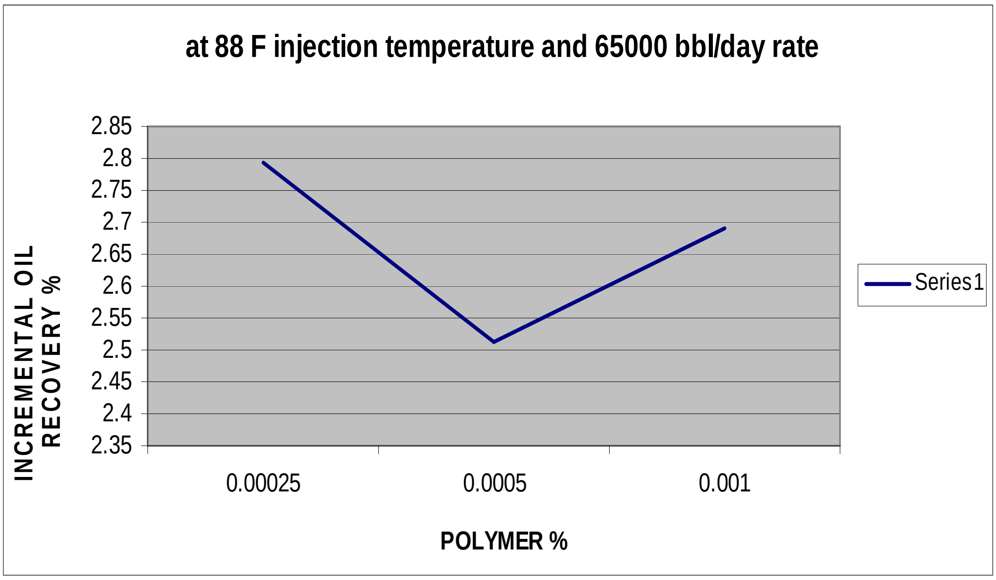

Figure 6.8 Incremental oil recovery versus polymer concentration at 88 F^o

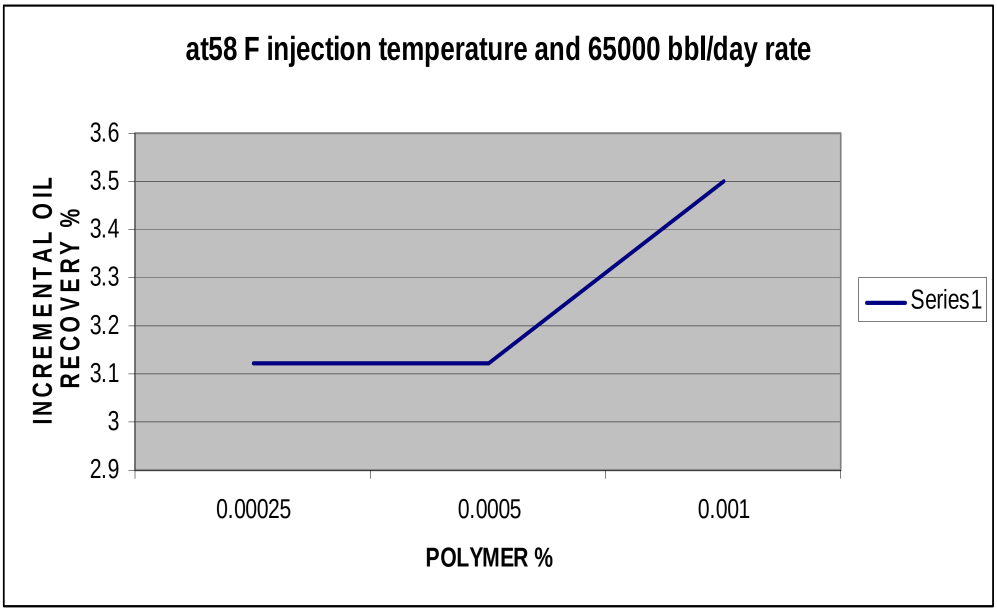

Figure 6.9 Incremental oil recovery versus polymer concentration at 58 F°

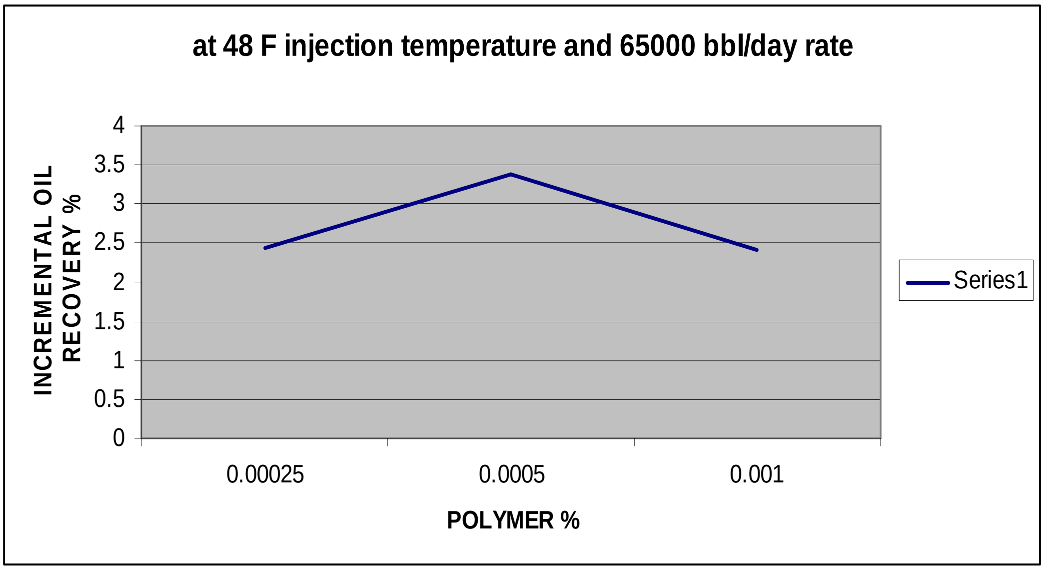

Figure 6.10 Incremental oil recovery versus polymer concentration at 48 F°

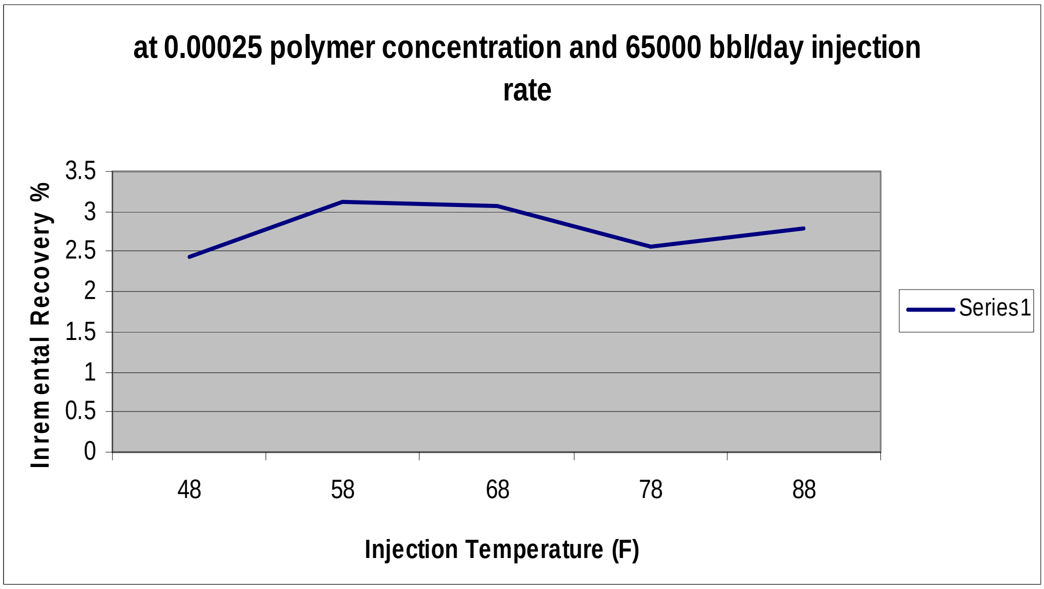

Figure 6.11 Incremental recovery versus injection temperature at 0.00025% polymer

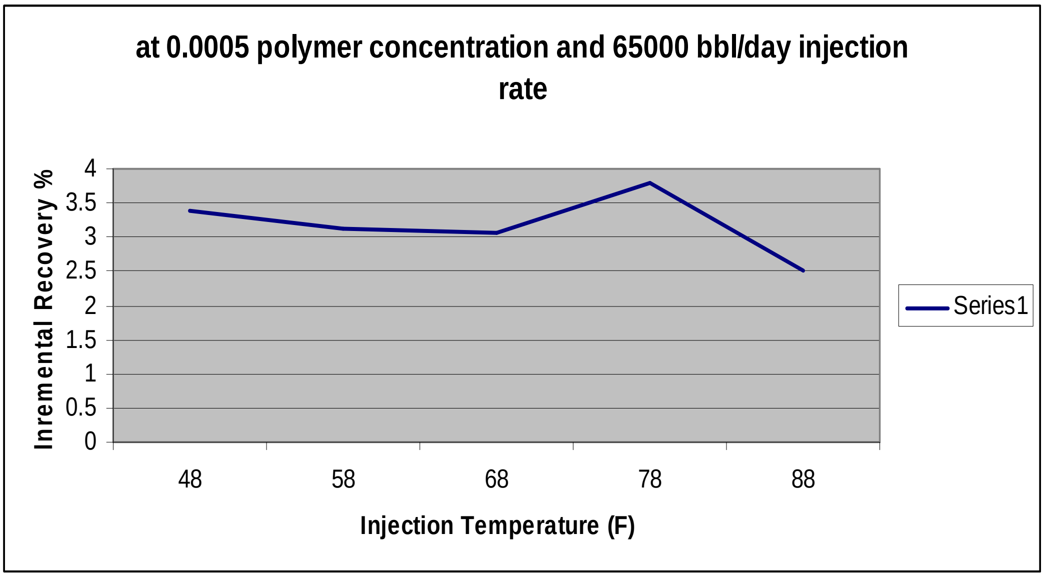

Figure 6.12 Incremental recovery versus injection temperature at 0.0005% polymer

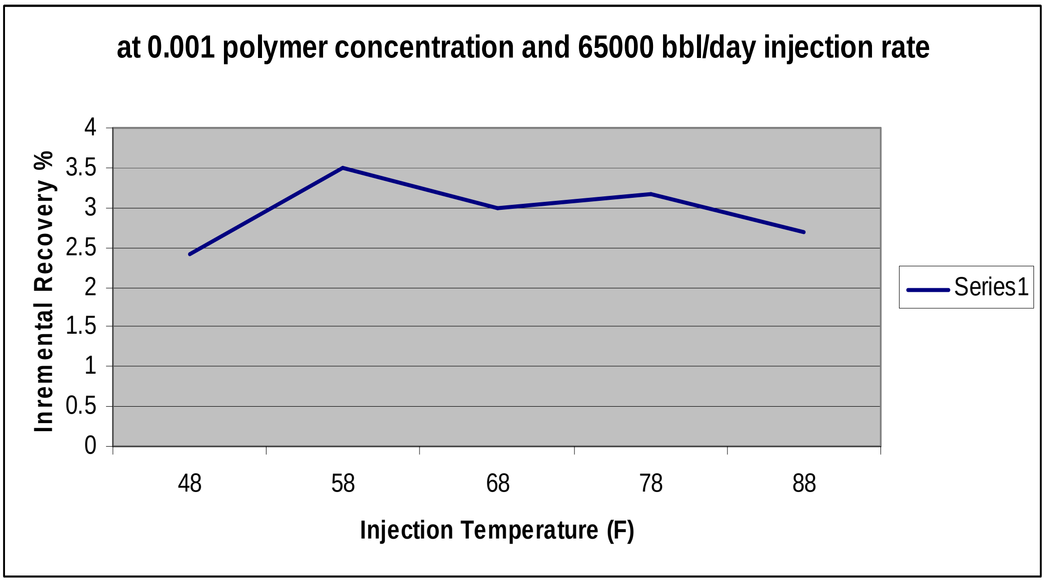

Figure 6.13 Incremental recovery versus injection temperature at 0.001% polymer

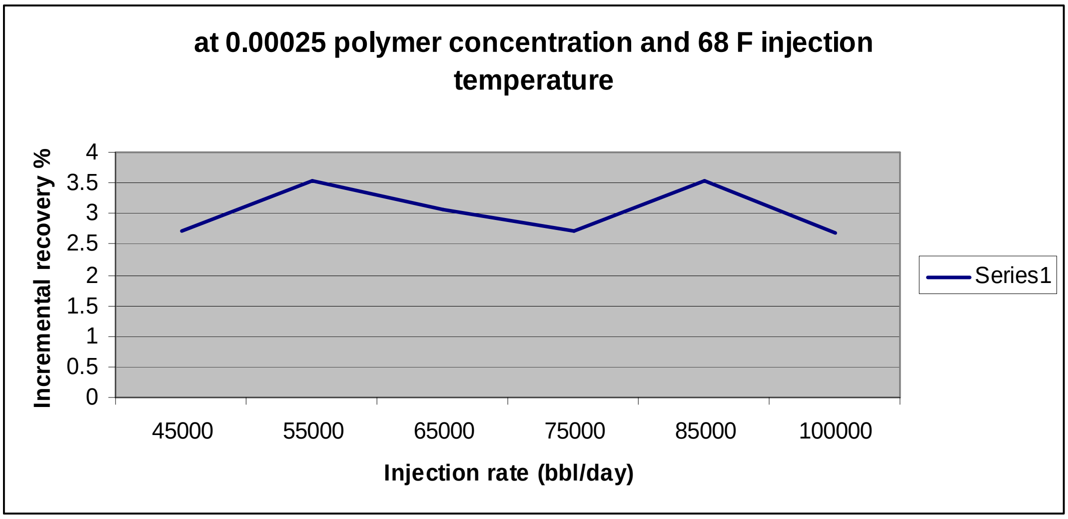

Figure 6.14 Incremental recovery versus injection rate at 0.00025% polymer

Figures through 6.15 to 6.24 give us the GOR and WOR versus polymer concentrations at injection temperatures. At injection temperature of 48^0 F, the best case is Case 10 with the lowest GOR and WOR at 0.0005 % polymer. At 58^0 F injection temperature, Case 9 is the best case with lowest GOR and WOR at 0.0005 % polymer. At injection temperatures of 68^0, 78^0, and 88^0 F, the best cases are 11, 12, and 13 respectively, at 0.001 % polymer concentration. GOR and WOR values are given in Table 6.2.

GOR and WOR versus injection temperatures at different polymer concentrations are given in Figures through 6.25 to 6.30. At polymer concentration of 0.00025 %, the lowest GOR and WOR case is 19, with 58^0 F injection temperature. At 0.0005 % polymer, Case 7 has the lowest GOR and WOR, with 78^0 F injection temperature. Case 11 is the best case at 0.001 % polymer injection with 68^0 F injection temperature, in terms of lowest GOR and WOR.

Figures 6.31 and 6.32 show the GOR and WOR versus injection rates respectively. The runs were made at 68^0 F injection temperature and 0.00025 % polymer concentration. For lowest GOR, the best case is 29 with 85000 bbl/day injection rate. And for lowest WOR , the best case is 16 with 65000 bbl/day injection rate. The optimum rates are 55000, 65000 and 85000 bbl/day for good (lower) WOR and GOR results.

As we see GOR and WOR increasing and decreasing trends are in good agreement with the recovery trends as injection rate increased. From 45000 to 55000 bbl/day rate, as recovery increases, GOR and WOR decreases. Decrease is due to the permeability reduction and so less water production. Between 55000-75000 bbl/day injection rates, WOR and GOR increases, because of decrease in permeability reduction. Polymer cannot adsorb at this high rates easily anymore, sore more water and gas produces again. But after 75000 bbl/day injection rate, as explained above, flow-induced absorption process occurs and adsorption increases again, so increase in permeability reduction occurs. At this rate polymer adsorbs more and reduce the pore sizes resulting in decreased production of WOR and GOR.

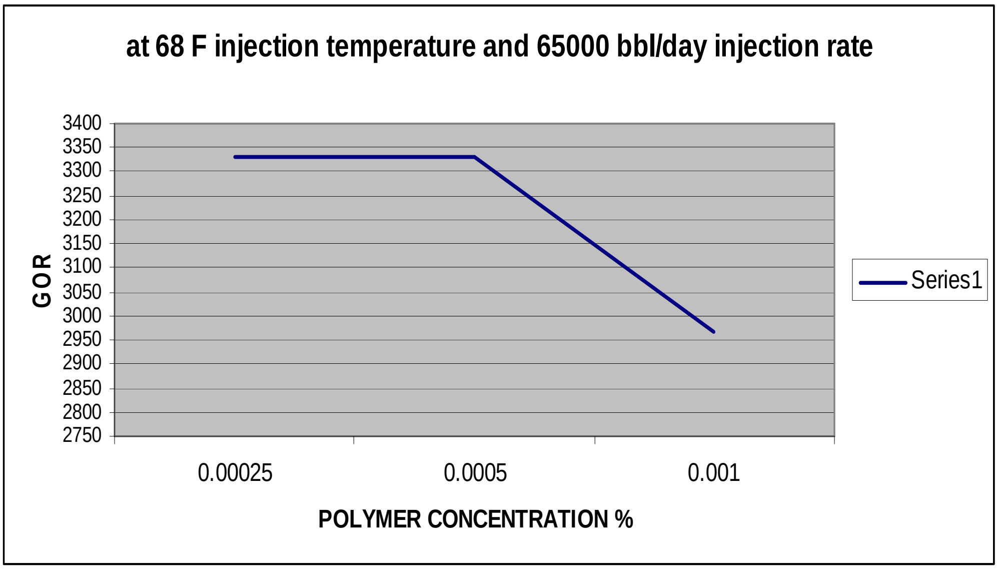

Figure 6.15 GOR versus polymer concentration at 68 F^{o}

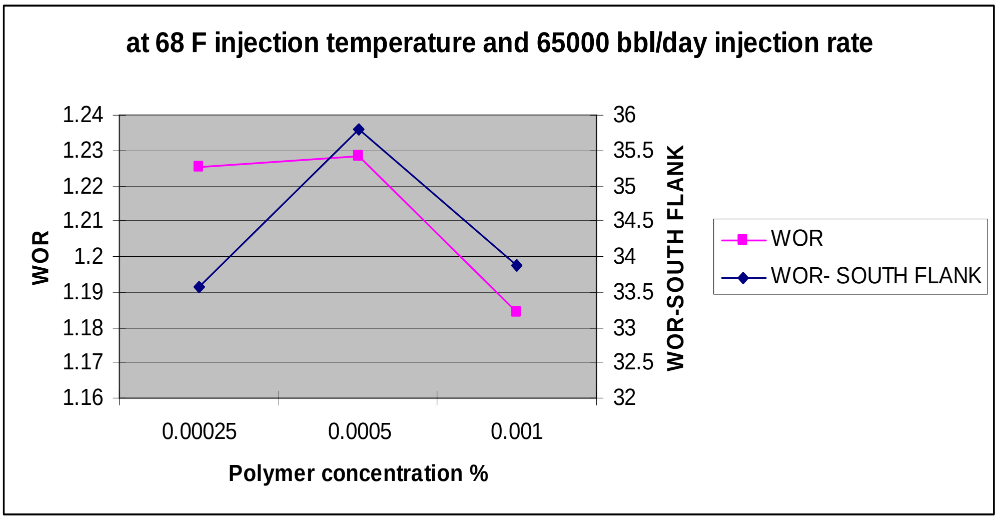

Figure 6.16 WOR versus polymer concentration at 68 F^{o}

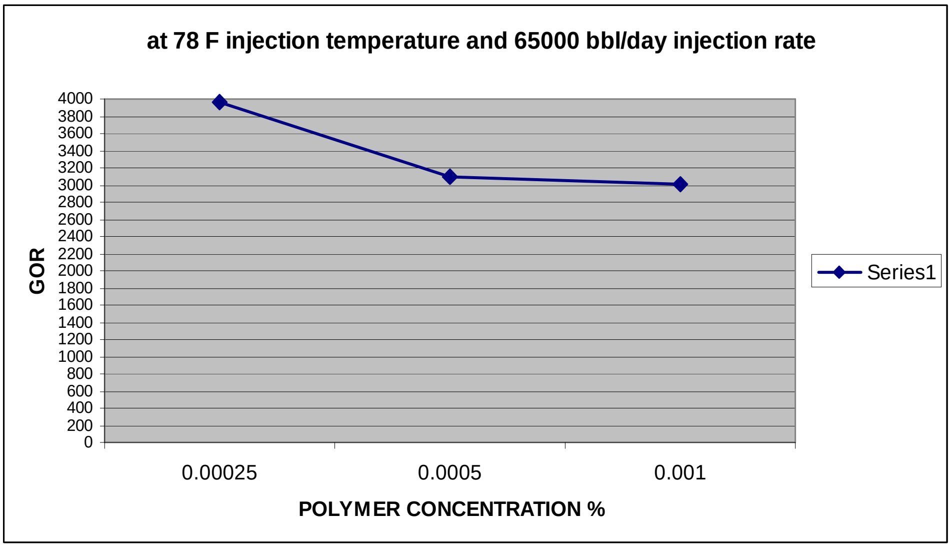

Figure 6.17 GOR versus polymer concentration at 78 F^{o}

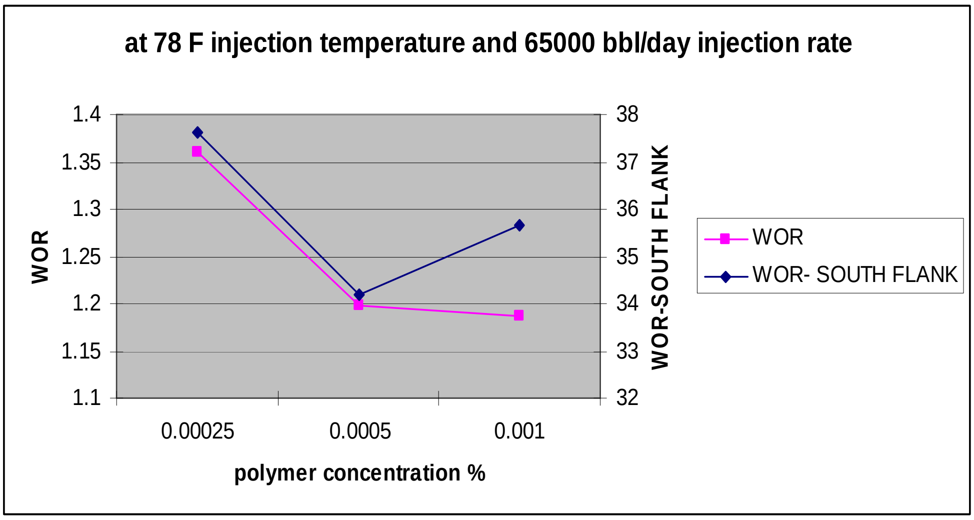

Figure 6.18 WOR versus polymer concentration at 78 F^{o}

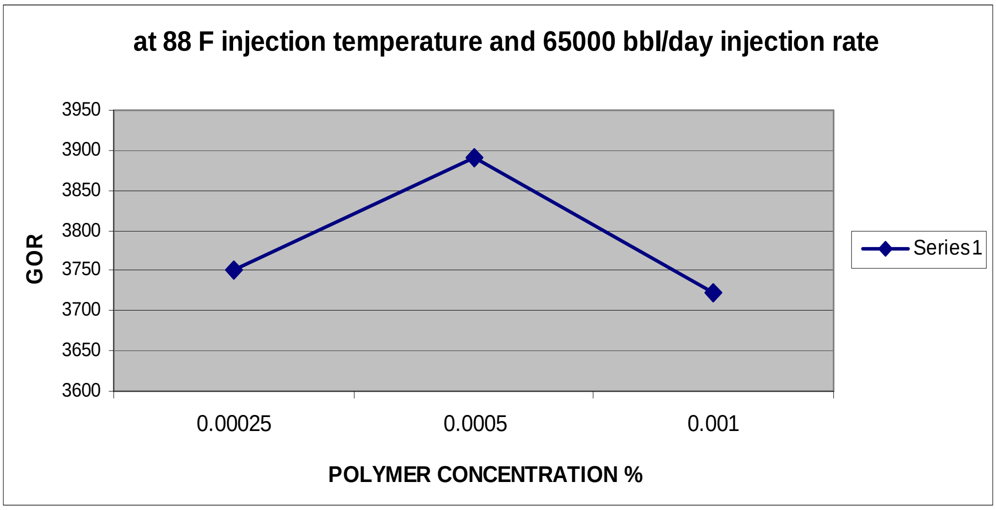

Figure 6.19 GOR versus polymer concentration at 88 F°

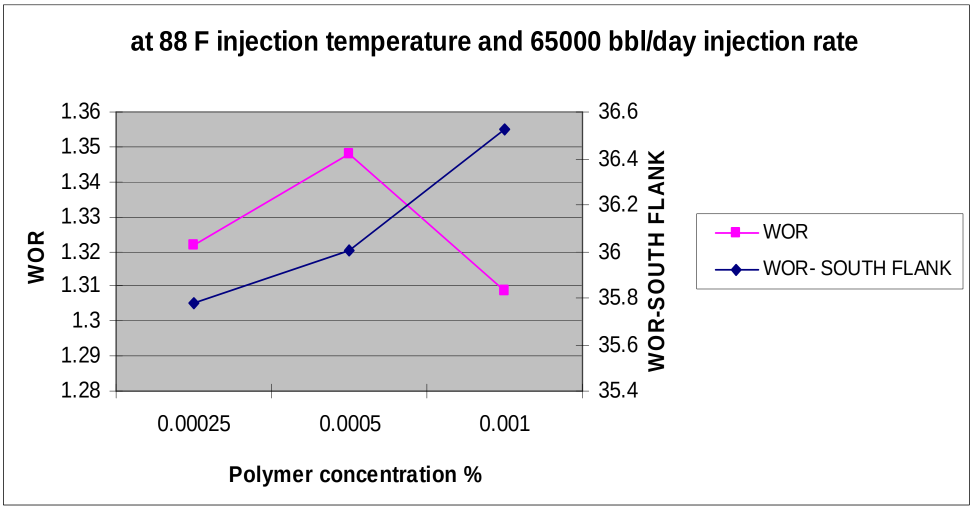

Figure 6.20 WOR versus polymer concentration at 88 F°

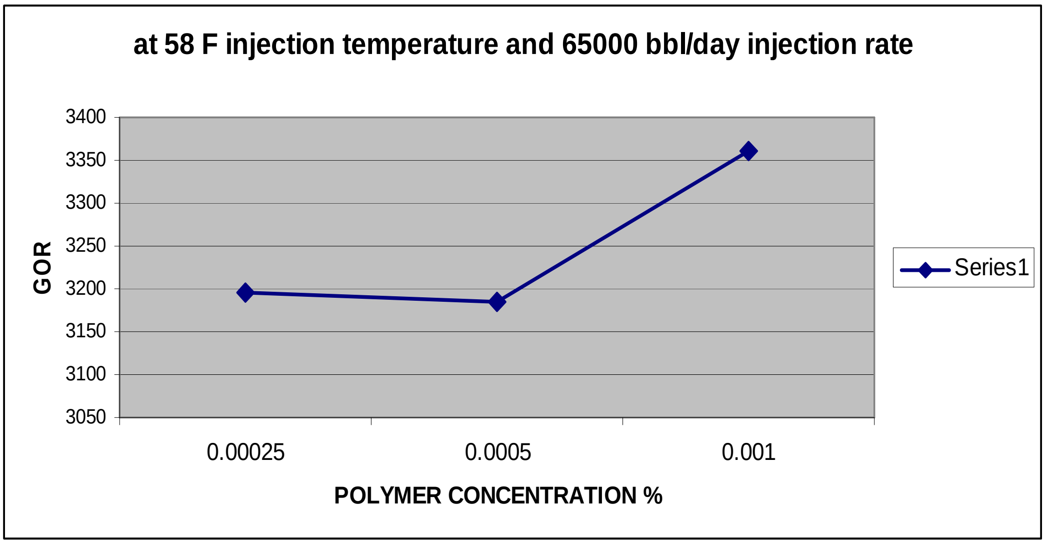

Figure 6.21 GOR versus polymer concentration at 58 F^o

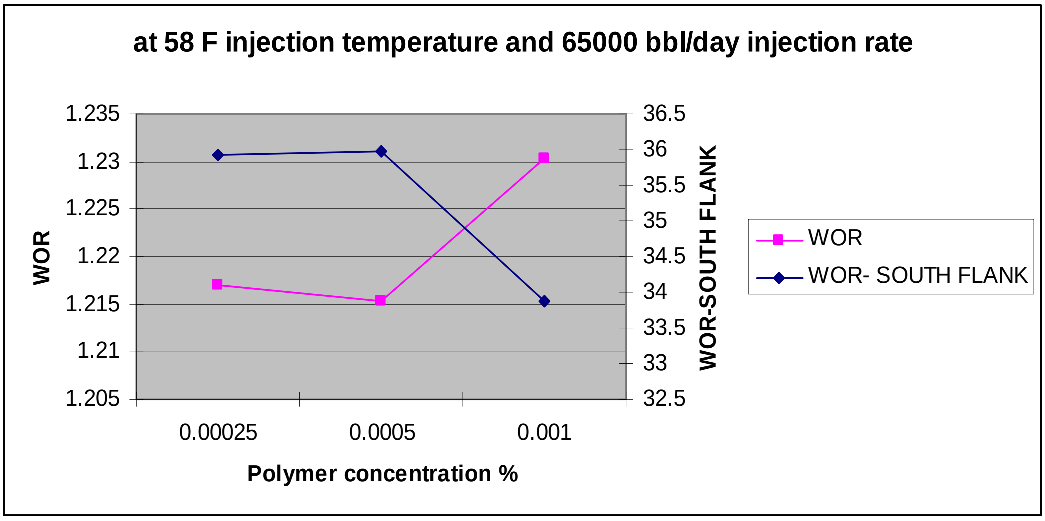

Figure 6.22 WOR versus polymer concentration at 58 F^o

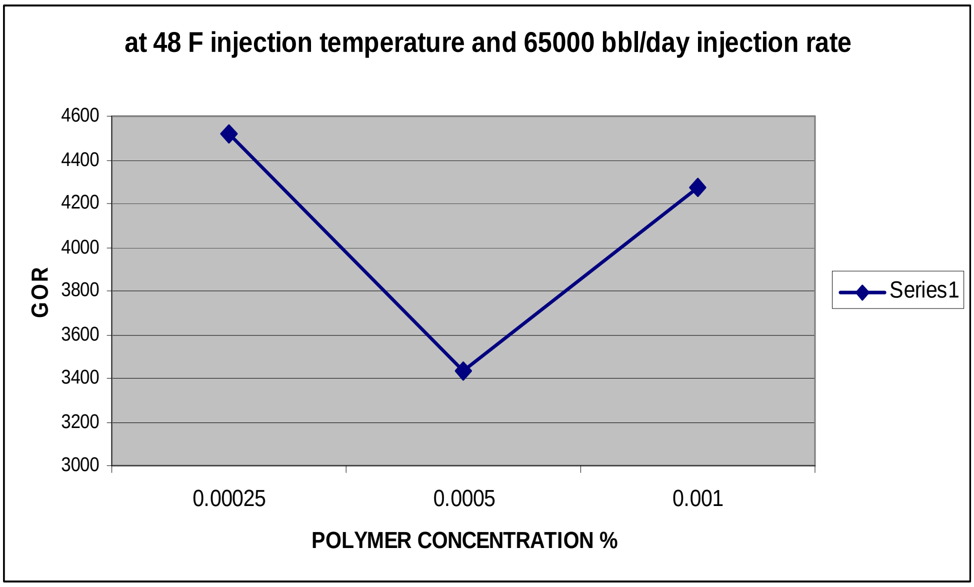

Figure 6.23 GOR versus polymer concentration at 48 F°

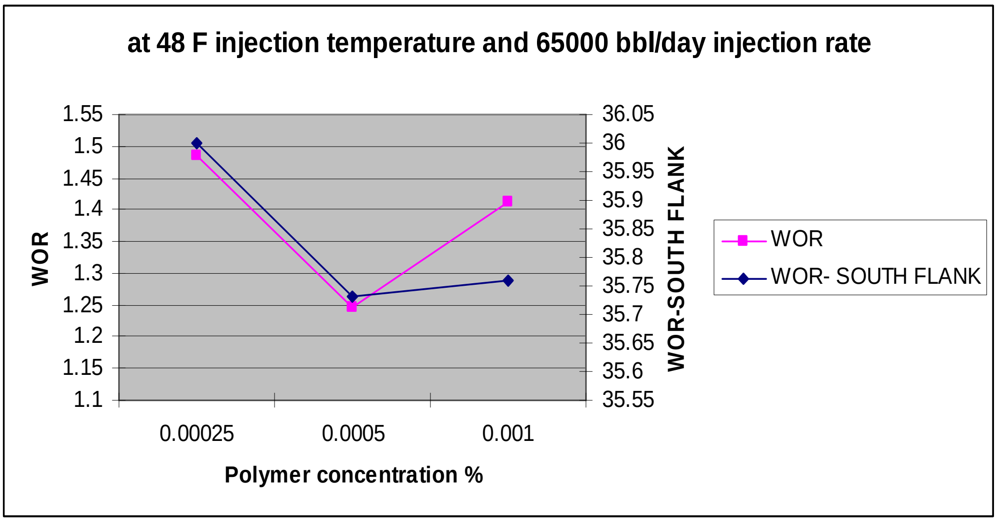

Figure 6.24 WOR versus polymer concentration at 48 F°

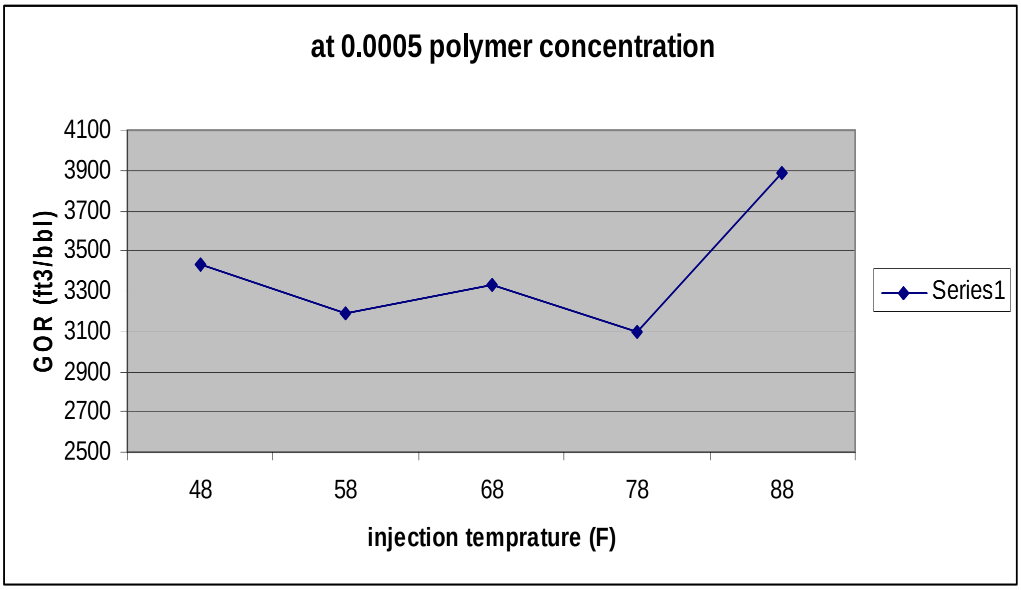

Figure 6.25 GOR versus injection temperature at 0.0005% polymer

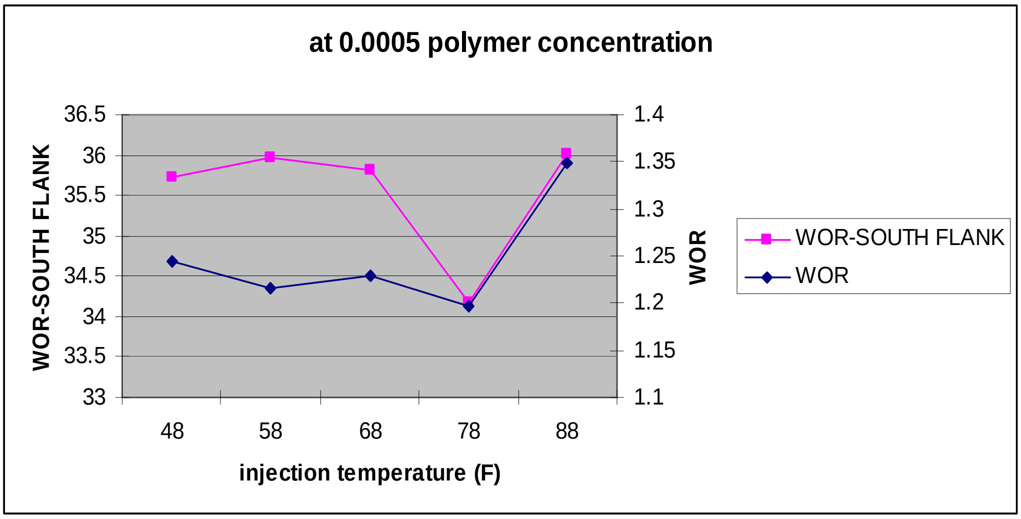

Figure 6.26 WOR versus injection temperature at 0.0005% polymer

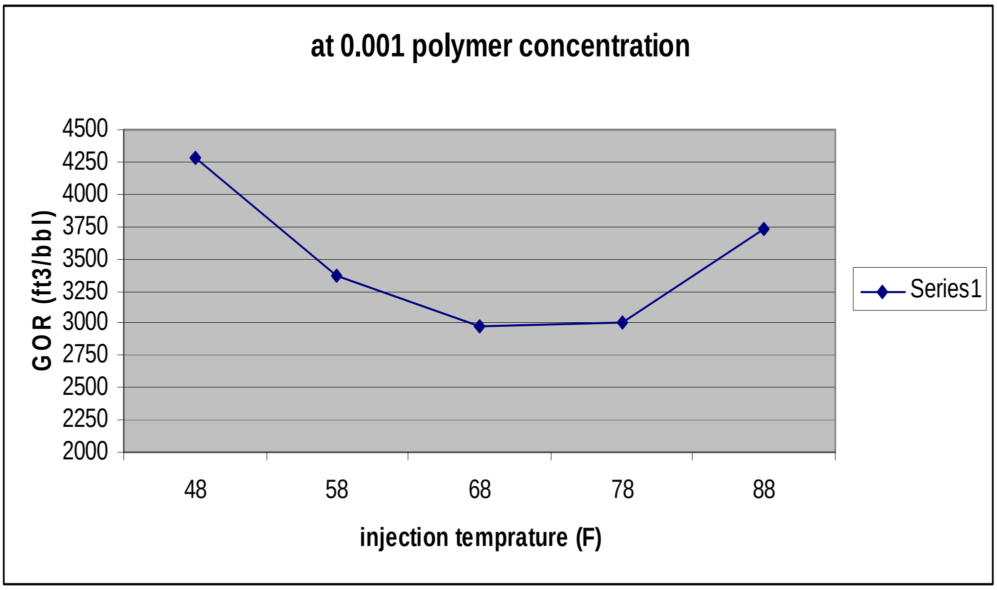

Figure 6.27 GOR versus injection temperature at 0.001% polymer

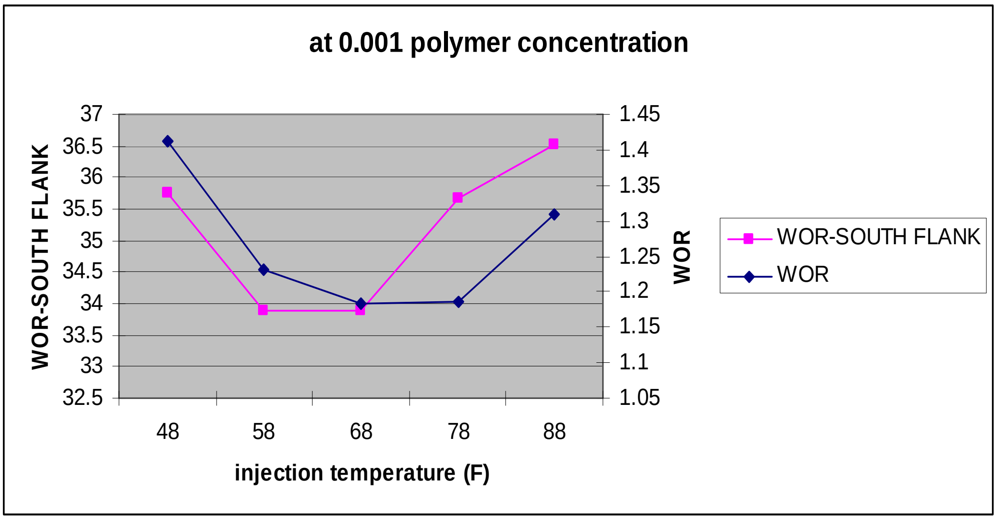

Figure 6.28 WOR versus injection temperature at 0.001% polymer

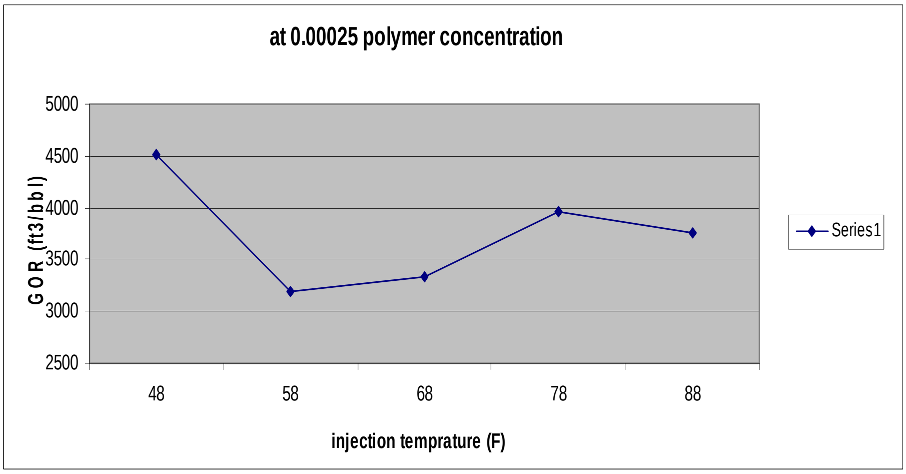

Figure 6.29 GOR versus injection temperature at 0.00025% polymer

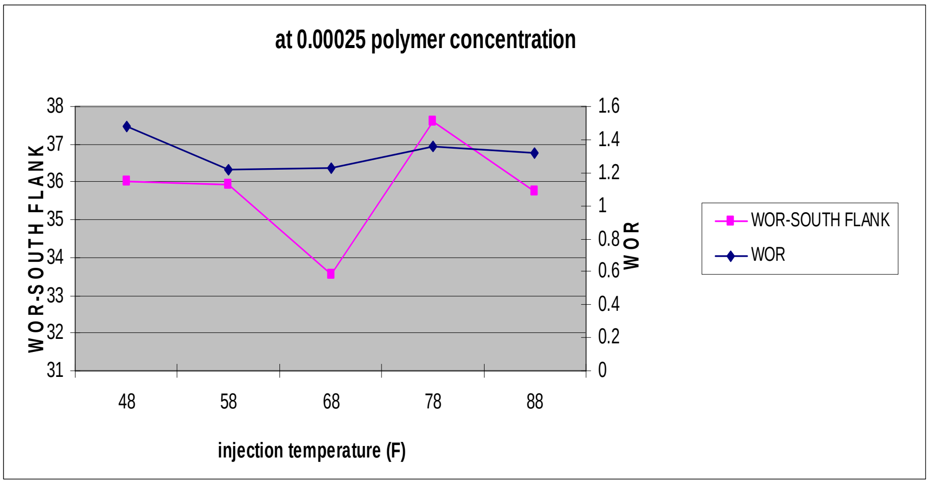

Figure 6.30 WOR versus injection temperature at 0.00025% polymer

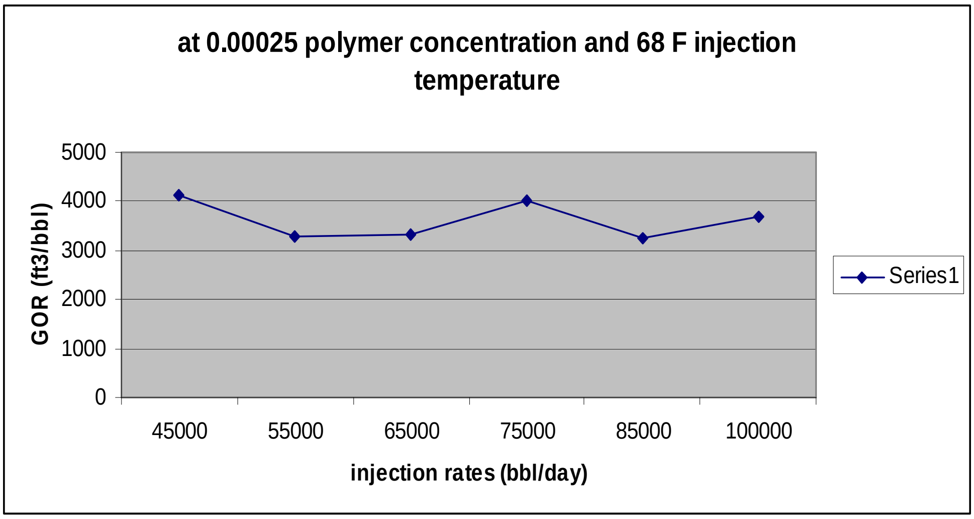

Figure 6.31 GOR versus injection rate at 0.00025% polymer

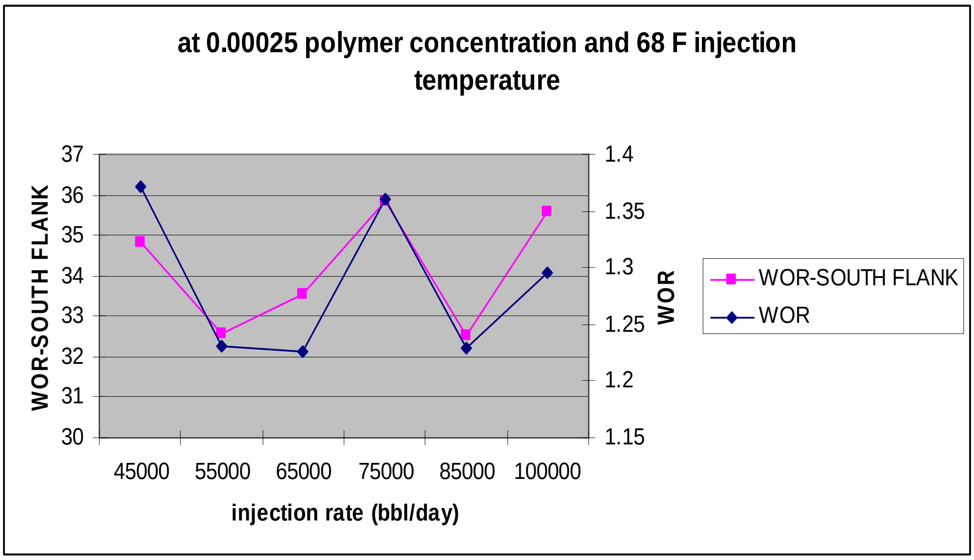

Figure 6.32 WOR versus injection rate at 0.00025% polymer

6.3 The Best and the Worst Case Scenarios

The case with the best result in terms of recovery factor is Case 42. Its recovery factor is 53.76 %. In this case polymer is injected at concentration of 0.0005 % and at 78^0 F injection temperature with 65000 bbl/day injection rates. Totally 432.3 MMSTB of oil produced which is 31.11 MMSTB is more than the Base case. Polymer was injected through the water injection wells WI1 and WI2 at the same time with 3 slug sizes, each slug with one month injection. The slug intervals were 6 months. The first slug was injected on the 1^{st} of January until the 1^{st} of the February in 2009. The second slug injected on the 1^{st} of august until the 1^{st} of September in 2009. And the third slug was begun on the 1^{st} of February until the 1^{st} of March in 2010.

The worst case in terms of oil recovery obtained from the runs performed, is the Case 34 which has recovery factor of 51.33 %. Total produced oil for this case is 412.76 MMSTB and this is 11.6 MMSTB more than Base case. But still this case is also beneficial when compared to Base case. Case 34 was performed with the 0.00025 % of polymer and at 68 F^0 injection rate. Polymer was injected with constant bottom-hole pressure of 4370 psi, instead of constant injection rate. Polymer was injected through the WI1 and WI2 injection wells at the same time, which is started on the 1^{st} of January and finished on the 1^{st} of February in 2010.

6.4 Economical Aspects

In this section economical analysis of cases is discussed. To choose the best case in terms of oil recovery is not enough, because there may be some cases, which oil recovery is high, but in terms of economical aspects may not be beneficial. For that reason, economical analyses are performed. Firstly the price of polymer injected was estimated, and then water recycling and disposal costs, gas recycling costs are estimated. The cost of injected polymer is 80$ per kilogram of polymer. Water recycling costs are taken as 0.25$ per 1 barrel of injected water and water disposal costs are 1.5$ per barrel of produced water. The gas recycling costs are estimated on the basis of 0.1$ per 1000 scf of gas. Total capital expenditures are evaluated as 1.5$ million.

Figure 6.33 show the comparison of the cases in economical aspects. So from the figure we see that the best economical case is Case 38 with the Net Inflow cash of 34081.32 MM$, which is 2436.46 MM$ more than the Base case. Case 38 is also one of the best cases in terms of recovery. The worst case has the Net Inflow cash of 33006.7 MM$. The incremental Net Inflow for this worst Case 33 is 1361.83 MM$. Cases 42, 40, 39, 41 and 7 also look beneficial in terms, recovery and economical terms. So one can get the best results from one of these cases.

Table 6.3 Economical aspects of cases

	COST of INJECTED POLYMER (MM$)	Total Capital expenditures (MM$)	Water recycling cost (MM$)	Water disposal cost (MM$)	Gas recycling costs (MM$)	Total oil cost at 80$ (MM$)	Net inflow (MM$)	Incremental net inflow (MM$)
BASE		1.5	85.101056	354.37368	9.58987223	32095.42144	31644.85683	
CASE 1	99.1617744	1.5	85.604888	352.154736	9.59013929	34293.48096	33745.46942	2100.612591
CASE 2	99.1617744	1.5	85.604608	350.380632	9.590123725	33591.37024	33045.1331	1400.27627
CASE 3	99.1617744	1.5	85.604848	352.970472	9.590042624	33788.66176	33239.83462	1594.977791
CASE 6	25.61679172	1.5	85.60508	355.456728	9.590075392	34063.5648	33585.79612	1940.939293
CASE 7	25.61679172	1.5	85.604912	344.639976	9.590063923	34545.63328	34078.68154	2433.824705
CASE 8	25.61679172	1.5	85.605616	355.0986	9.589967258	33711.54432	33234.13335	1589.276513
CASE 9	25.61679172	1.5	85.605032	355.726416	9.590141747	34104.59648	33626.5581	1981.701267
CASE 10	25.61679172	1.5	85.604952	346.785696	9.590094234	34276.77184	33807.67431	2162.817474
CASE 11	51.23358344	1.5	85.605936	354.641088	9.589941043	34020.80768	33518.23713	1873.3803
CASE 12	51.23358344	1.5	85.604912	352.134912	9.590274458	34127.18848	33627.1248	1982.267966
CASE 13	51.23358344	1.5	85.60472	351.72108	9.590082765	33827.33056	33327.68109	1682.824262
CASE 14	51.23358344	1.5	85.604864	347.229768	9.590117171	34346.50112	33851.34279	2206.485956
CASE 15	51.23358344	1.5	85.604896	351.183264	9.590105702	33645.952	33146.84015	1501.983319
CASE 16	12.80839586	1.5	85.604936	355.49304	9.590095872	34064.40192	33599.40545	1954.54862
CASE 17	12.80839586	1.5	85.604976	353.691912	9.590068019	33747.86304	33284.66769	1639.810856
CASE 18	12.80839586	1.5	85.605084	353.786778	9.590078464	33892.95133	33429.661	1784.804165
CASE 19	12.80839586	1.5	85.605056	355.691016	9.590147482	34104.70656	33639.51194	1994.655113
CASE 20	12.80839586	1.5	85.605368	350.271144	9.590002483	33654.83264	33195.05773	1550.200898
CASE 21	51.23358344	1.5	85.605016	347.773248	9.589989376	34362.38592	33866.68408	2221.827251
CASE 22	51.23358344	1.5	85.604888	351.484992	9.590192538	33807.18336	33307.7697	1662.912872

Table 6.3 (continued)

CASE 23	51.23358344	1.5	85.604832	352.140432	9.590108979	33848.56832	33348.49936	1703.642532
CASE 24	51.23358344	1.5	85.605048	347.11344	9.59023104	34313.85344	33818.81114	2173.954306
CASE 25	51.23358344	1.5	85.605032	351.23436	9.590249882	33904.14336	33404.98013	1760.123303
CASE 26	8.86735098	1.5	85.294904	349.480632	9.590134374	33846.72	33391.98698	1747.130147
CASE 27	10.83787342	1.5	85.450024	346.951536	9.58999511	34368.11264	33913.78321	2268.92638
CASE 28	14.7789183	1.5	85.759808	350.219304	9.590117171	33834.56768	33372.71953	1727.862701
CASE 29	16.74944074	1.5	85.915024	349.329336	9.590020506	34377.47712	33914.3933	2269.536467
CASE 30	19.7052244	1.5	86.14744	354.270744	9.590163866	33818.98496	33347.77139	1702.914556
CASE 31	6.779104524	1.5	45.625756	213.834888	9.590000026	33998.72768	33721.39793	2076.5411
CASE 32	5.768851041	1.5	38.213008	189.153996	9.590004941	33443.77088	33199.54502	1554.688188
CASE 33	5.185106811	1.5	34.189196	178.8561	9.590068019	33236.01408	33006.69361	1361.836777
CASE 34	4.613108244	1.5	30.308912	164.200248	9.590031974	33021.16864	32810.95634	1166.099508
CASE 35	12.80839586	1.5	85.605024	345.463296	9.590088499	34219.86304	33764.89624	2120.039404
CASE 36	12.80839586	1.5	85.604984	350.399736	9.590208922	34098.01216	33638.10884	1993.252003
CASE 37	25.61679172	1.5	85.605088	349.588872	9.59004672	33945.74848	33473.84768	1828.99085
CASE 38	51.23358344	1.5	85.605056	344.363856	9.59001641	34573.61408	34081.32157	2436.464736
CASE 39	51.23358344	1.5	85.605056	344.452872	9.590004941	34566.26688	34073.88536	2429.028532
CASE 40	51.23358344	1.5	85.605064	344.402976	9.590024602	34565.37088	34073.03923	2428.1824
CASE 41	51.23358344	1.5	85.605048	344.451816	9.590029517	34566.44864	34074.06816	2429.211331
CASE 42	74.3713308	1.5	85.604912	344.313576	9.590043443	34584.36608	34068.98622	2424.129386
CASE 43	37.1856654	1.5	86.108744	349.4838	9.590073754	34153.0752	33669.20692	2024.350085
CASE 44	37.1856654	1.5	86.108792	349.196832	9.590095872	34123.0336	33639.45221	1994.595383

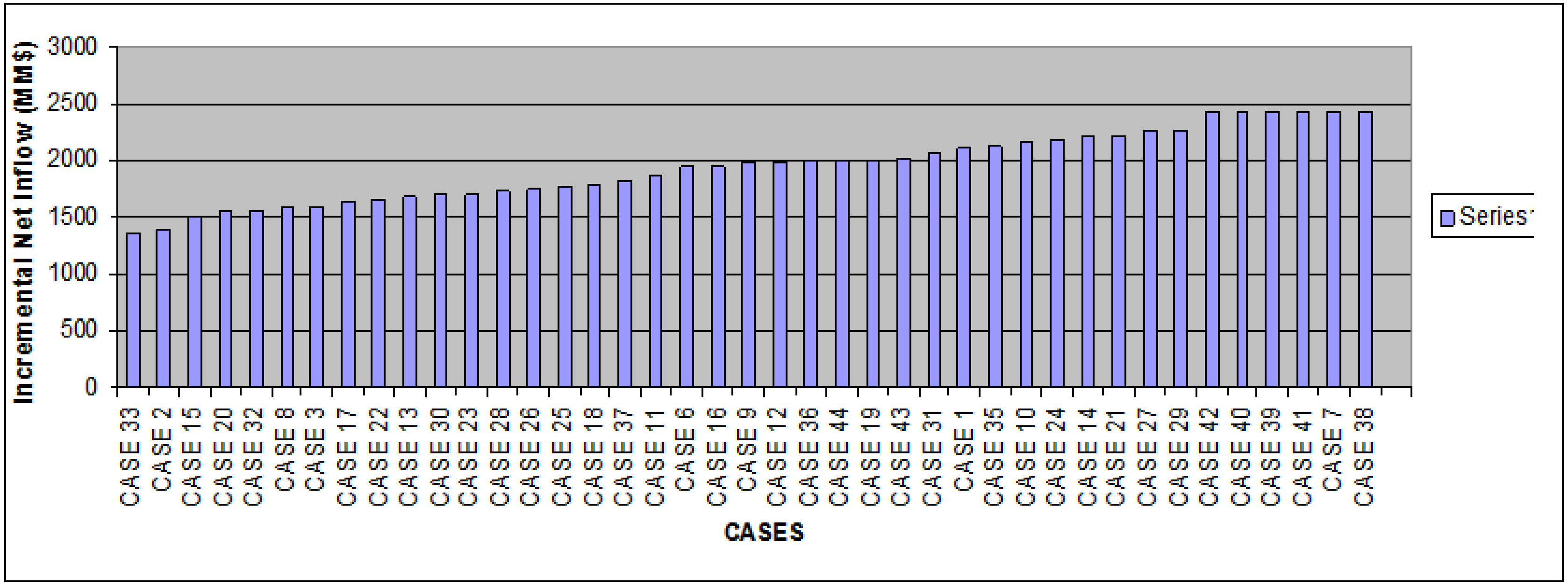

Figure 6.33 Incremental Net inflow comparisons

CHAPTER 7

CONCLUSIONS

Simulation of sector model for evaluation of BRIGHTWATER injection feasibility was carried out and 44 simulation runs were conducted. The results of these runs were evaluated and compared with a base case in which only water is injected. Based on the simulation results the following conclusions were drawn:

- Ranges of incremental recoveries changed between 1.438 % and 3.868%. These recoveries are in accord with cases provided in the literature.

- When comparing the Cases with the Base Case, an improvement in oil production was observed. WOR and GOR decreased for all cases. 31.11 MMSTB of incremental oil was produced in Case 42 (the best case) where Brightwater is injected at a concentration of 0.0005 %, at 78^0 F injection temperature with a 65000 bbl/day injection rate. The resulting recovery factor was 53.76 %. A total of 432.3 MMSTB of oil was produced in this case.

- Simulation results in terms of recovery factors and economical aspects were better with the slug rather than continuous injections.

- Injection polymer in early times may give better results.

- When compared with constant injection rates it was seen that the constant bottom-hole pressure cases are generally worse than constant injection rates.

- When crosslinker concentration was increased by a factor of 4 no improvement was observed. Other crosslinker concentrations must be tried to see how crosslinker affects the production.

- Economical analysis was carried out to compare different cases. From the simulations, cases 7, 38,39,40,41, and 42 were chosen as the best cases both economically and in terms of recovery. In Case 7 polymer injection concentration was 0.0005 %, injection temperature was 78 ^{0}F at 65000 bbl/day rates. But in cases, 38, 39, 40, 41, and 42 injection of polymer was performed in both 2 and 3 slug sizes with 6, 12, 18, and 24 month injection periods in 2 slug size and 6 month injection period in 3 slug size strategy and injected at 78^0 F injection temperature and 65000 bbl/day rates with polymer amount of 0.0005 %.

- These results show that the polymer (BRIGHTWATER) injection project is favorable and has potential to be applied in the field. Laboratory tests must be conducted before injection to study the feasibility of the application to the real reservoir.

REFERENCES:

1) R.D. Kaminsky, SPE, R.C Wattenbarger, SPE, R.C. Szafranski, SPE, and A.S. Coutee, SPE, ExxonMobil Upstream Research Company, " ***Guidelines for Polymer Flooding Evaluation and Development*** ", IPTC 11200, 2007

2) Jose Ferrer, Member AIME, Universidad del Zulia, " ***Some Mechanistic Features of Flow of Polymers Through Porous Media*** ", SPE 4029, 1972

3) J.G. Dominguez, G.P. Willhite, Members of SPE-AIME, " ***Retention and Flow Characteristics of Polymer Solutions in Porous Media*** ", SPE 5835, 1977

4) A.L Ogunberu, SPE, and K. Asghari, SPE, U. of Regina, "**Water** ***Permeability Reduction under Flow-Induced Polymer Adsorption*** ". SPE 89855, 2004

5) Rapier Dawson, Ronald B. Lantz, Members AIME, " ***Inaccessible Pore Volume in Polymer Flooding*** ", SPE 3522, 1972

6) A. Zaitoun and N. Kohler, SPE Member " ***The Role of Adsorption in Polymer Propagation Through Reservoir Rocks*** ", SPE 16274, 1967

7) A.M. Sarem, Member AIME, Union Oil Co. of California, " ***On the Theory of Polymer Solution Flooding Process*** ", SPE 3002, 1970

8) Hossein H. Nouri and Paul J. Root, Members AIME, the U. of Oklahoma, " ***A Study of Polymer Solution Rheology, Flow Behavior, and Oil Displacement Processes***", SPE 3523, 1971

9) Yu-Shu Wu, SPE, Colorado School of Mines, and Baojun Bai, SPE, Missouri University of Science and Technology, " ***Modeling Particle Gel Propagation in Porous Media***", SPE 115678, 2008

10) Larry W. Lake. 1989, " ***Enhanced Oil Recovery*** ", University of Texas at Austin, Prentice-Hall, Inc

11) AUREL Carcoana. 1992, " ***Applied Enhanced Oil Recovery*** ", Prentice-Hall

12) http://www.nalco.com/applications/brightwater-technology.htm, last visited on 19th June 2011

13) http://www.tiorco.com/pdf/cutsheet/BrightWater_cutsheet.pdf, last visited on 19th June 2011

14) http://hungary.spe.org/images/hungary/articles/30/BrightWater_Presenation.pdf, last visited on 19th June 2011

15) F. Ghaddab, K. Kaddour, and M. Tesconi, SITEP and A. Brancolini, C. Carniani, and G. Galli, Eni E&P, " ***EL BORMA-BrightWater: A Tertiary Method for EOR for a mature field*** ", SPE 136140, 2010

16) Bruno Roussenac, SPE, Shell Brasil ltda. And Celso Toschi, Shell Brasil ltda, " ***Brightwater® Trial in Salema Field (Campos Basin, Brazil)***", SPE 131299, 2010

17) H. Frampton, J.C Morgan, S. K. Cheung, L.Munson, K.T Chang, D. Williams, " ***Development of a novel waterflood conformance control system*** ", SPE 89391, 2004

18) Danielle Ohms, SPE, Jenifer Mcleod, SPE, and Craig J. Graff, SPE, BP Alaska; Harry Frampton, SPE, BP EPT; Jim C. Morgan, SPE, Jimtech; Stephen Cheung, SPE, Chevron; and Katrina Yancey, SPE, and K. T. Chang, SPE, Nalco, " ***Incremental Oil Success from Waterflood Sweep Improvement in Alaska*** ", SPE 121761, 2009

19) http://www.cmgroup.com/software/brochures/Stars_FactSheet.pdf , last visited on 22nd June, 2011

20) James J. Sheng, 2011, " ***Modern Chemical Enhanced Oil Recovery: Theory and Practice*** ", GULF PROFESSIONAL PUBLISHING

21) Farid Babayev, thesis, " **Estimation of Water Alternating Gas (WAG) Injection Performance of an Offshore Field (Azeri Field, Azerbaijan) Using a Sector Simulation Model** ", August 2008

APPENDIX A

COMPONENT ADSORPTION AND BLOCKAGE

Interaction of many additives (polymers, surfactants, and caustic) and in situ generated species (fines, emulsions, and gelants) with the rock matrix strongly affects the rate of propagation of these additives. Chemical (ion change) and mechanical (blockage, straining capture) type of interactions or some combination of mechanisms can exist. Fluid concentrations, temperature and rock type (permeability) determines the capture level.

A phenomenological description of these events is given in STARS, wherein a group of constant temperature adsorption isotherms (adsorption level as a function of fluid composition) are input. The Langmuir isotherm correlation is given below.

$$AD = \frac{Az}{1+Bz} \text{ ....1A}$$

z-fluid component composition

A and B- temperature dependent

User specifies the component and the fluid phase. The maximum adsorption level is A/B.

Up to 4 different temperature isotherms can be supplied. Generally it is seen that adsorption decreases with increasing temperature. Multiple components can adsorb, each with their individual isotherms, although it is supposed that individual species adsorb independently.

In STARS, maximum adsorption level and residual adsorption level is given by keywords **ADMAXT** and **ADRT**, consecutively. These ADMAXT and ADRT can be made region dependent. These parameters can change from grid block to grid block. The allowed range of ADRT is from 0 to ADMAXT. **ADRT 0** means that adsorption is completely reversible, while ADRT=ADMAXT means completely irreversible adsorption. Values between **0** and **ADMAXT** are partially reversible process.

STARS uses the given below Langmuir adsorption isotherm equation.

$$ad = \frac{(tad1 + tad2 * xnacl) * ca}{(1 + tad3 * ca)} \text{………………..2A}$$

tad1 = First parameter in the Langmuir adsorption isotherm (gmol/m^3 | lbmol/ft^3 | gmol/cm^3).

tad2 = Second parameter in the Langmuir adsorption isotherm. It is associated with salt effects (gmol/m^3 | lbmol/ft^3 | gmol/cm^3).

tad3 = Third parameter in the Langmuir adsorption isotherm. It must be equal or bigger than 1e-15.

xnacl = salinity of brine

ca = mole fraction of *comp_name* in *phase_des*. At high concentration (ca>>) the maximum adsorption is **(tad1+tad2*xnacl)/tad3**.

Adsorption properties (inaccessible pore volume, residual resistance factor, component retention, and desorption level) depend upon the formation permeability. These properties significantly can change within a reservoir due to reservoir heterogeneities. Therefore, equilibrium adsorption is a function of location, component temperature and concentration.

$$ad(C,T,I) = ADMAXT(I) * ad(C,T) / AD_{max,TI} \text{……….3A}$$

ADMAXT(I) = the maximum adsorption capacity at grid block I

$AD_{max,T1}$ = the maximum possible adsorption obtainable from the adsorption isotherm of the first input temperature

The reduced porosity for adsorbing component **ic**, adsorption rock type **k**, at grid block **i** is,

Redpor = porft(k,ic) * por(p(i),T(i))……..4A

Adsorption or mechanical entrapment can cause a reduction in the effective permeability. This is called the permeability reduction factors.

RKW = 1 + (RRF-1) * AD(C,T)/ADMAXT……….5A

RKO = 1 + (RRF-1) * AD(C,T)/ADMAXT……….6A

RKG = 1 + (RRF-1) * AD(C,T)/ADMAXT……….7A

RKW=water phase permeability reduction

RKO=oil phase permeability reduction

RKG=gas phase permeability reduction

This definition affects the permeabilities **AKW(I)**, **AKO(I)**, **AKG(I)**. AK(I) is standard block permeability.

AKW(I) = AK(I) * krw / RKW(I)……….8A

AKO(I) = AK(I) * kro / RKO(I)…………9A

AKG(I) = AK(I) * krg / RKG(I)………….10A

As a result, the relative mobility of a phase that contains an adsorbing component is generally affected by viscosity and blockage.

APPENDIX B

ADSORPTION DATA USED IN MODEL

```
** Adsorption Data
 *ADSCOMP 'POLYMER' *WATER      ** Data for polymer
 *ADSROCK 1  *ADMAXT 0.0136   *ADRT 0.0136  *RRFT 1.8
 *ADSROCK 2  *ADMAXT 0.0286   *ADRT 0.0286  *RRFT 2.5
 *ADSLANG 1.36E3 0 1.E5                  ** Langmuir concentration coefficients

*ADSCOMP  'PREGEL'  *WATER          ** Data for GEL adsorption
*ADSROCK 1
*ADMAXT 0.0276
*ADRT 0.0276
*RRFT 40                             ** irreversible adsorption
*ADSROCK 2
*ADMAXT 0.0575
*ADRT 0.0575
*RRFT 80
*ADSLANG 276 0 10000                 ** Langmuir concentration coefficients
*ADSTYPE *KVAR 1 1 2 2 2 2
```

APPENDIX C

PVT PROPERTIES OF SECTOR MODEL

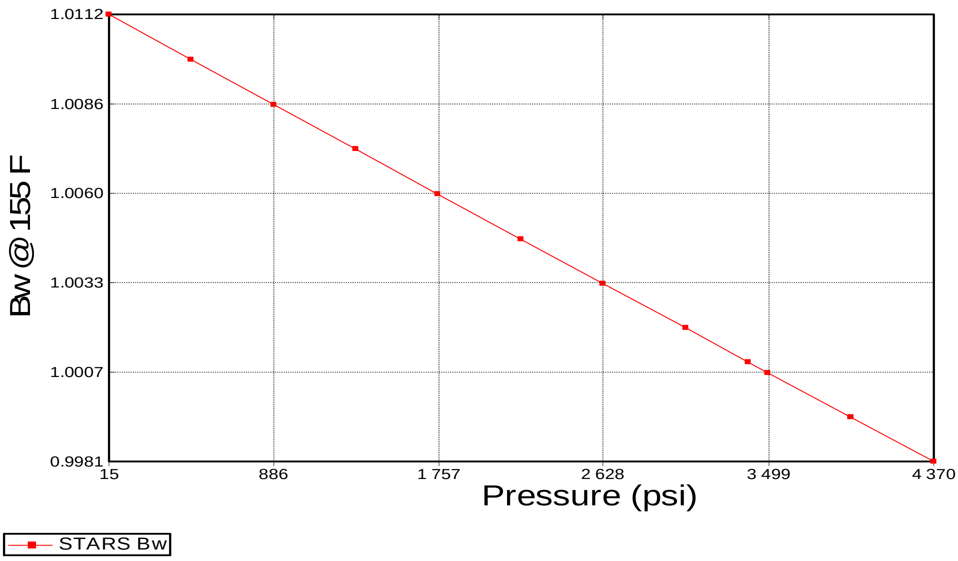

Figure C.1 Water formation volume factor at 155°F

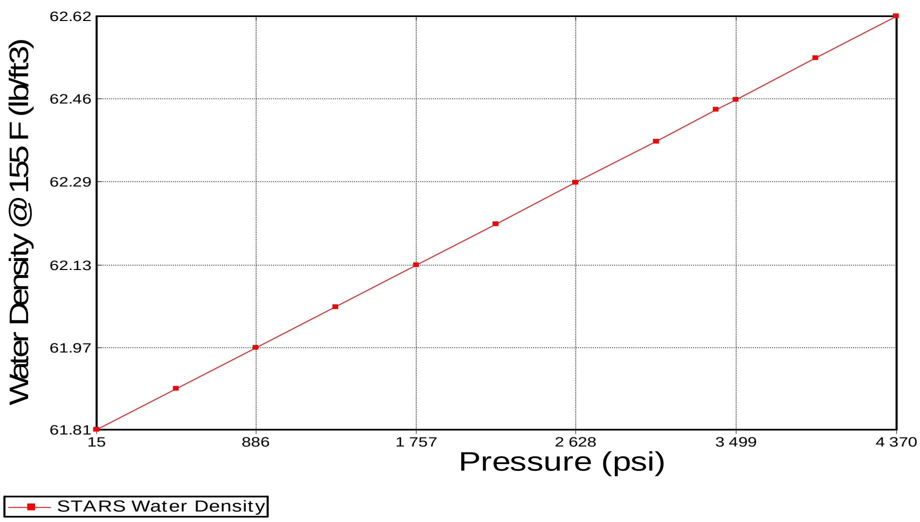

Figure C.2 Water density at 155°F

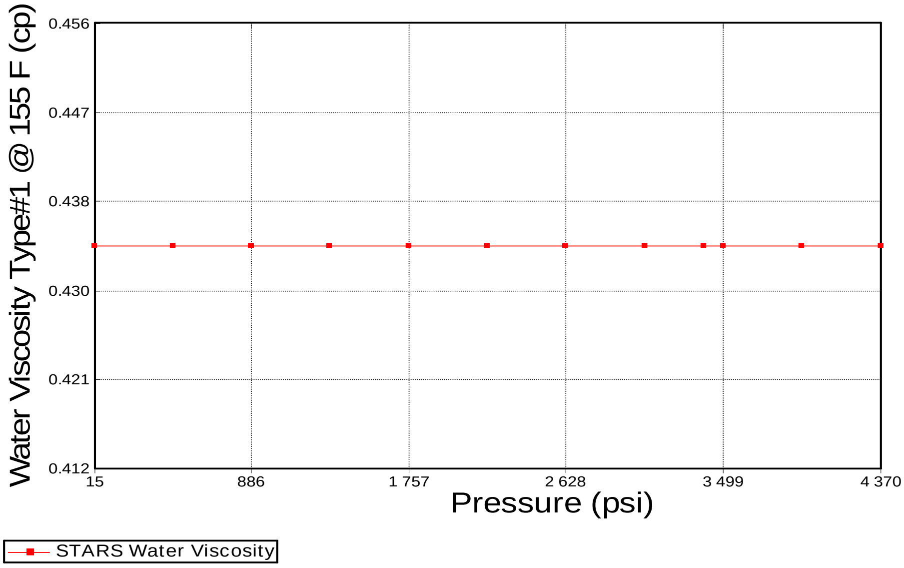

Figure C.3 Water viscosity at 155°F

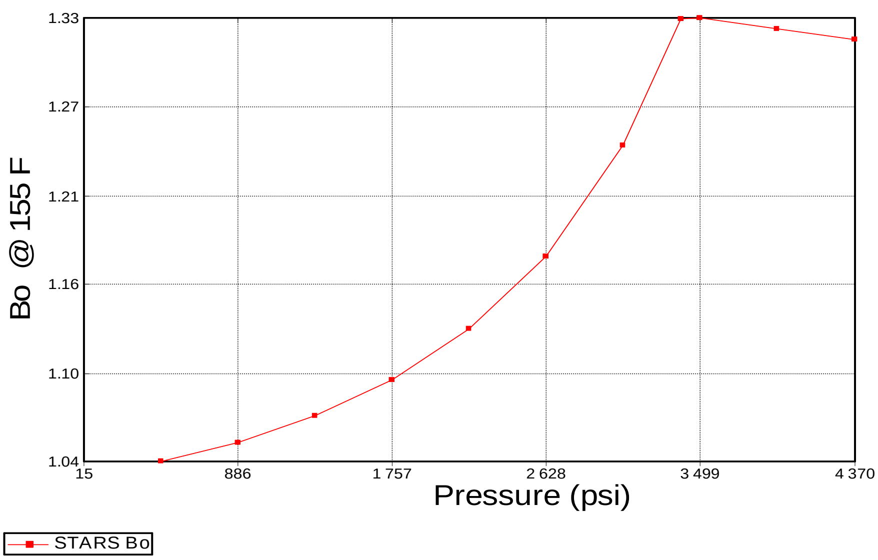

Figure C.4 Oil formation volume factor at 155°F

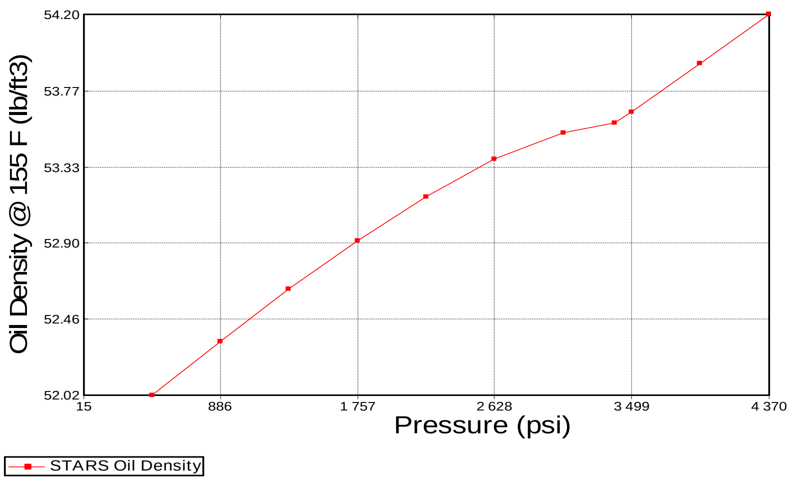

Figure C.5 Oil density at 155°F

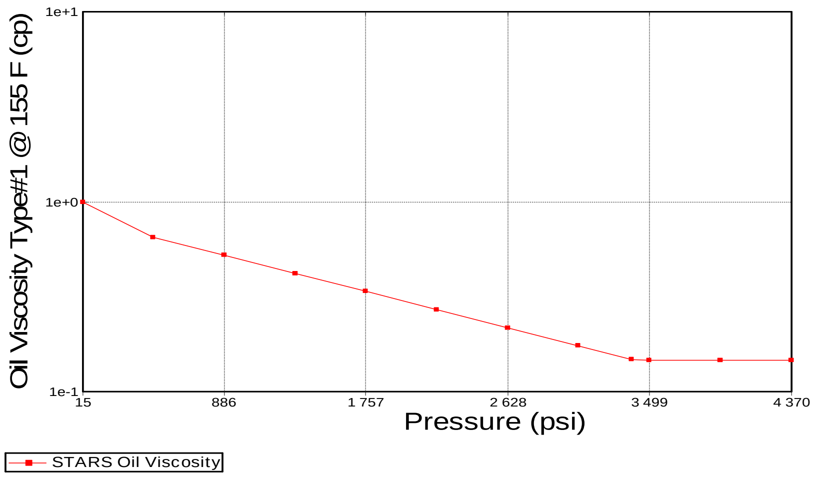

Figure C.6 Oil viscosity at 155°F

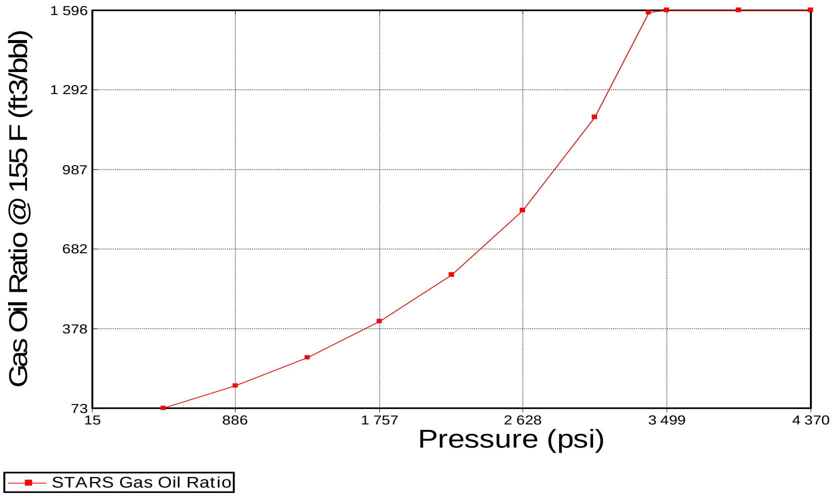

Figure C.7 Gas-oil ratio at 155°F

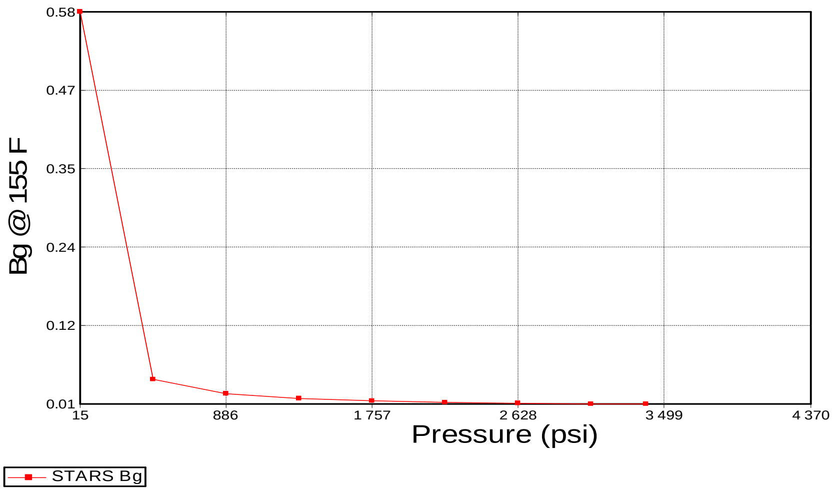

Figure C.8 Gas formation volume factor

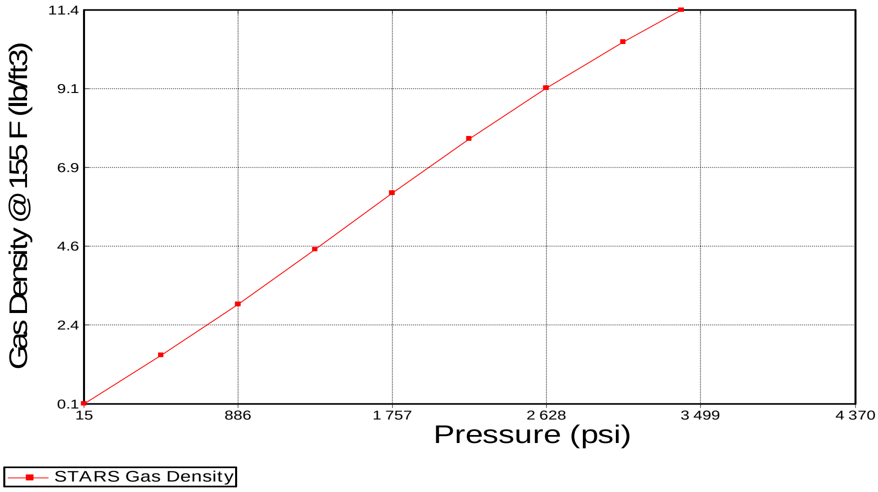

Figure C.9 Gas density at 155°F

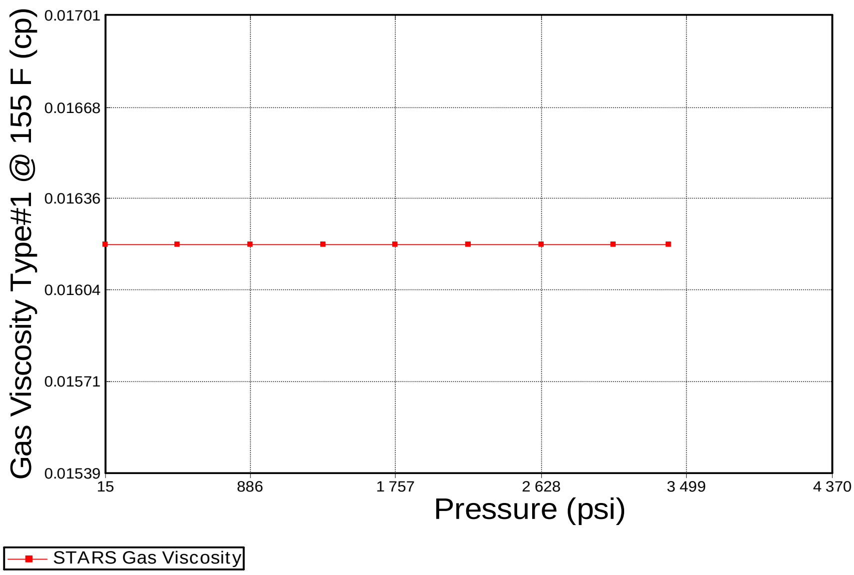

Figure C.10 Gas viscosity at 155°F

APPENDIX D

REPRESENTATIVE MODEL

RANGECHECK ON

** 2011-06-17, 16:59:45, mikroskop
** 2011-07-01, 10:54:21, mikroskop
RESULTS SIMULATOR STARS 200900

** ============ INPUT/OUTPUT CONTROL =====================
*TITLE1 'STARS Numerical Model'
*TITLE2 'Sandstone reservoir'
*TITLE3 'A STUDY OF BRIGHTWATER INJECTION EFFICIENCY ON SECTOR MODEL USING STARS SOFTWARE'
INUNIT FIELD
WSRF WELL 1
WSRF GRID TIME
WSRF SECTOR TIME
OUTSRF GRID PRES SG SO SW TEMP
OUTSRF WELL LAYER NONE
WPRN GRID TIME
OUTPRN GRID ALL
OUTPRN RES NONE
**$ Distance units: ft
RESULTS XOFFSET 0.0000
RESULTS YOFFSET 0.0000
RESULTS ROTATION 0.0000 **$ (DEGREES)
RESULTS AXES-DIRECTIONS 1.0 -1.0 1.0

```
**$*************************************************************
**$ Definition of fundamental cartesian grid
**$**************************************************************
GRID VARI 15 42 8
KDIR DOWN
DI IVAR
15*656
DJ JVAR
42*820
DK KVAR
8*26.2
*DTOP
15*10830 15*10709 15*10588 15*10467 15*10346 15*10225 15*10104 15*9983
15*9862 15*9741 15*9620 15*9499 15*9378 15*9257 15*9136 15*9015 15*8894
15*8773 15*8652 15*8531 15*8591 15*8651 15*8711 15*8771 15*8831 15*8891
15*8951 15*9011 15*9071 15*9131 15*9191 15*9251 15*9311 15*9371 15*9431
15*9491 15*9551 15*9611 15*9671 15*9731 15*9791 15*9851

**$ Property: NULL Blocks  Max: 1  Min: 1
**$  0 = null block, 1 = active block
NULL CON            1


*POR *ALL
  2.01151000E-01  2.17712000E-01  2.01981000E-01  1.92383000E-01
  2.08074000E-01  2.12419000E-01  1.85172000E-01  1.82808000E-01
  1.94389000E-01  1.90417000E-01  2.08599000E-01  2.00524000E-01
  .
  .
  .

*PERMI *ALL
```

```
  2.10543137E+02  4.29014191E+02  1.88717728E+02  1.16968796E+02
  3.00928680E+02  3.20045868E+02  3.13434540E+02  1.74916748E+02
  2.01210556E+02  1.78666382E+02  2.78713776E+02  2.60478149E+02
  .
  .
  .

*PERMJ *ALL
  2.09243317E+02  4.22843445E+02  1.89109238E+02  1.15888725E+02
  2.98404907E+02  3.21609467E+02  3.04487579E+02  1.77380707E+02
  2.04294098E+02  1.73870148E+02  2.67324249E+02  2.57744873E+02
  .
  .
  .

*PERMK *ALL
  6.43539280E+01  1.52494919E+02  8.24105380E+01  2.27947850E+01
  1.07542557E+02  7.59705280E+01  9.52150570E+01  3.58952560E+01
  8.36100850E+01  8.94609220E+01  6.05334130E+01  3.60669750E+01
  .
  .
  .


*NETGROSS *ALL
  9.34081400E-01  9.33134800E-01  9.32039600E-01  9.30802300E-01
  9.29428100E-01  9.27923900E-01  9.26293700E-01  9.24541700E-01
  9.22669700E-01  9.20679200E-01  9.18568900E-01  9.16334300E-01
  .
  .
  .
```

```
*TRANSI *CON 1
*TRANSJ *CON 1
*TRANSK *ALL
  1.00000000E+00  1.00000000E+00  1.00000000E+00  1.00000000E+00
  1.00000000E+00  1.00000000E+00  1.00000000E+00  1.00000000E+00
  1.00000000E+00  1.00000000E+00  1.00000000E+00  1.00000000E+00
  1.00000000E+00  1.00000000E+00  1.00000000E+00  0.00000000E+00


**$ Property: Pinchout Array  Max: 1  Min: 1
**$  0 = pinched block, 1 = active block
PINCHOUTARRAY CON            1



END-GRID

*ROCKTYPE 1
*THTYPE *con 1
*CPOR 8.03309E-06
*CTPOR 0.0000021
*ROCKCP 38
*THCONR 27.7392
*THCONW 8.32016616
*THCONG 1.10935548

**$ Model and number of components
MODEL 4 4 3 1
COMPNAME 'Water' 'Oil' 'Sln gas' 'Free gas'
**           --------  ----------  ----------  ----------
CMM
```

```
18 152 19.244 16.043
PCRIT
3217.1 306 668.316 667.174
TCRIT
705.47 651 -74.992 -116.59
KV1
1.7202e+6 1.5145e+5 1.0356e+5
KV4
-6869.59 -5240.38 -1813.53
KV5
-376.64 -357.95 -442.94
PSURF 14.65
TSURF 62
**$ Surface conditions

SURFLASH W O G G
MASSDEN
62.388 52.972 50.9966
CP
3e-6 1.5e-5 1e-6
CT1
1.2e-4 3.11e-4 1e-4
**Spec. Grav.        0.92    0.85    0.703
AVISC
0.00752 0.0115577 0.0229832
BVISC
2492.75 2617.9 649.05



ROCKFLUID
RPT 1 WATWET
**SW   KRW    KROW
```

```
**$	Sw	krw	krow
**$	Sw	krw	krow	Pcow
SWT
 SMOOTHEND LINEAR
	0	0.000	1	36
	0.143	1.00E-05	0.8458131	33
	0.174	9.00E-5	0.7101837	30
	0.228	0.001	0.562	27
	0.322	0.007	0.316	24
	0.394	0.018	0.166	21
	0.455	0.037	0.0837778	18
	0.519	0.077	0.0410063	15
	0.568	0.13	0.0219707	12
	0.604	0.195	0.0125945	9
	0.666	0.31043	0.0039063	8
	0.727	0.45168	0.0008352	6
	0.789	0.64789	0.0000522	4
	0.813	0.74442	0.0000063	2
	0.850	0.89667	0	1
	1.000	1.000	0	0
**$	Sl	krg	krog
**$	Sl	krg	krog	Pcog
SLT
	0.000	1	0	36
	0.020	0.9999	0	34
	0.144	0.999	0.0006	32
	0.165	0.99	0.0009	30
	0.200	0.95	0.002	28
	0.300	0.85	0.012	26
	0.379	0.6	0.054	24
	0.419	0.30079	0.1	22
	0.484	0.0675	0.25	20
```

```
      0.507    0.03207  0.368978        16
      0.550   0.011379    0.6621        14
      0.576   0.007179    0.7531        12
      0.602  0.0039585    0.8151        10
      0.655  0.0011119    0.8821         6
      0.704  0.0001644     0.929         3
      0.738          0     0.998         2
      0.888          0         1         1

*KRTYPE *IJK 1:15 1:20 1:8 1
RPT 2 WATWET
**$       Sw      krw      krow
**$       Sw      krw      krow     Pcow
SWT
          0     0.000         1        36
      0.143  1.00E-05  0.8458131        32
      0.174   9.00E-5  0.7101837        30
      0.228     0.001      0.562        28
      0.322     0.007      0.316        26
      0.394     0.018      0.166        24
      0.455     0.037  0.0837778        22
      0.519     0.077  0.0410063        20
      0.568      0.13  0.0219707        16
      0.604     0.195  0.0125945        12
      0.666   0.31043  0.0039063        10
      0.727   0.45168  0.0008352         8
      0.789   0.64789  0.0000522         5
      0.813   0.74442  0.0000063         4
      0.850   0.89667          0         1
      1.000     1.000          0         0
**SG     KRG    KROG
**$       Sl      krg      krog
```

```
**$      Sl      krg      krog      Pcog
SLT
        0.000   1.000   0.000     36
        0.020   0.980   0.000     34
        0.030   0.925   0.045     32
        0.059   0.854   0.087     31
        0.089   0.788   0.127     30
        0.118   0.725   0.165     28
        0.148   0.666   0.200     27
        0.177   0.611   0.234     26
        0.207   0.558   0.265     25
        0.236   0.509   0.295     24
        0.266   0.463   0.322     22
        0.295   0.419   0.349     21
        0.325   0.378   0.373     20
        0.354   0.339   0.397     18
        0.384   0.303   0.418     16
        0.413   0.268   0.439     13
        0.443   0.236   0.458     12
        0.472   0.205   0.477     10
        0.502   0.177   0.494      9
        0.531   0.150   0.510      8
        0.561   0.124   0.525      7
        0.590   0.100   0.540      6
        0.620   0.078   0.553      5
        0.649   0.057   0.566      4
        0.679   0.037   0.578      3
        0.708   0.018   0.589      2
        0.738   0.000   0.600      1
        0.888   0.000   1.000    0.9
KRTYPE IJK 1:15 21:42 1:8 2
```

```
INITIAL
VERTICAL DEPTH_AVE

INITREGION 1
REFPRES 4370
REFDEPTH 8650
DWOC 10467
DGOC 8650

INITREGION 2
REFPRES 4370
REFDEPTH 8650
DWOC 9431
DGOC 8650


INTYPE JVAR 20*1 22*2


*TEMP ALL
15*155     15*154.79  15*152.58  15*151.37  15*150.16  15*148.95  15*147.74
15*146.53  15*145.32  15*144.11  15*142.9  15*141.69   15*140.48  15*139.27
15*138.06  15*136.85  15*135.64  15*134.43  15*133.22  15*132.01  15*132.61
15*133.21  15*133.81  15*134.41  15*135.01  15*135.61  15*136.21  15*136.81
15*137.41  15*138.01  15*138.61  15*139.21  15*139.81  15*140.41  15*141.01
15*141.61  15*142.21  15*142.81  15*143.41  15*144.01  15*144.61  15*145.21
15*155.262 15*154.052 15*152.842 15*151.632 15*150.422 15*149.212
15*148.002 15*146.792 15*145.582 15*144.372 15*143.162 15*141.952
15*140.742 15*139.532 15*138.322 15*137.112 15*135.902 15*134.692
15*133.482 15*132.272 15*132.872 15*133.472 15*134.072 15*134.672
15*135.272 15*135.872 15*136.472 15*137.072 15*137.672 15*138.272
```

15*138.872 15*139.472 15*140.072 15*140.672 15*141.272 15*141.872
15*142.472 15*143.072 15*143.672 15*144.272 15*144.872 15*145.472
15*155.524 15*154.314 15*153.104 15*151.894 15*150.684 15*149.474
15*148.264 15*147.054 15*145.844 15*144.634 15*143.424 15*142.214
15*141.004 15*139.794 15*138.584 15*137.374 15*136.164 15*134.954
15*133.744 15*132.534 15*133.134 15*133.734 15*134.334 15*134.934
15*135.534 15*136.134 15*136.734 15*137.334 15*137.934 15*138.534
15*139.134 15*139.734 15*140.334 15*140.934 15*141.534 15*142.134
15*142.734 15*143.334 15*143.934 15*144.534 15*145.134 15*145.734
15*155.786 15*154.576 15*153.366 15*152.156 15*150.946 15*149.736
15*148.526 15*147.316 15*146.106 15*144.896 15*143.686 15*142.476
15*141.266 15*140.056 15*138.846 15*137.636 15*136.426 15*135.216
15*134.006 15*132.796 15*133.396 15*133.996 15*134.596 15*135.196
15*135.796 15*136.396 15*136.996 15*137.596 15*138.196 15*138.796
15*139.396 15*139.996 15*140.596 15*141.196 15*141.796 15*142.396
15*142.996 15*143.596 15*144.196 15*144.796 15*145.396 15*145.996
15*156.048 15*154.838 15*153.628 15*152.418 15*151.208 15*149.998
15*148.788 15*147.578 15*146.368 15*145.158 15*143.948 15*142.738
15*141.528 15*140.318 15*139.108 15*137.898 15*136.688 15*136.478
15*134.268 15*133.058 15*133.658 15*134.258 15*134.858 15*135.458
15*136.058 15*136.658 15*137.258 15*137.858 15*138.458 15*139.058
15*139.658 15*140.258 15*140.858 15*141.458 15*142.058 15*142.658
15*143.258 15*143.858 15*144.458 15*145.058 15*145.658 15*146.258
15*156.31 15*155.1 15*153.89 15*152.68 15*151.47 15*150.26 15*149.05
15*147.84 15*146.63 15*145.42 15*144.21 15*143 15*141.79 15*140.58
15*139.37 15*138.16 15*136.95 15*136.74 15*134.53 15*133.32 15*133.92
15*134.52 15*135.12 15*135.72 15*136.32 15*136.92 15*137.52 15*138.12
15*138.72 15*139.32 15*139.92 15*140.52 15*141.12 15*141.72 15*142.32
15*142.92 15*143.52 15*144.12 15*144.72 15*145.32 15*145.92 15*146.52
15*156.572 15*155.362 15*154.152 15*152.942 15*151.732 15*150.522
15*149.312 15*148.102 15*146.892 15*145.682 15*144.472 15*143.262
15*142.052 15*140.842 15*139.632 15*138.422 15*137.212 15*137.002

```
15*134.792 15*133.582 15*134.182 15*134.782 15*135.382 15*135.982
15*136.582 15*137.182 15*137.782 15*138.382 15*138.982 15*139.582
15*140.182 15*140.782 15*141.382 15*141.982 15*142.582 15*143.182
15*143.782 15*144.382 15*144.982 15*145.582 15*146.182 15*146.782
15*156.834 15*155.624 15*154.414 15*153.204 15*151.994 15*150.784
15*149.574 15*148.364 15*147.154 15*145.944 15*144.734 15*143.524
15*142.314 15*141.104 15*139.894 15*138.684 15*137.474 15*137.264
15*135.054 15*133.844 15*134.444 15*135.044 15*135.644 15*136.244
15*136.844 15*137.444 15*138.044 15*138.644 15*139.244 15*139.844
15*140.444 15*141.044 15*141.644 15*142.244 15*142.844 15*143.444
15*144.044 15*144.644 15*145.244 15*145.844 15*146.444 15*147.044
**$ Property: Oil Mole Fraction(Oil)  Max: 0.32  Min: 0.32
MFRAC_OIL 'Oil' CON         0.32
**$ Property: Oil Mole Fraction(Sln gas)  Max: 0.68  Min: 0.68
MFRAC_OIL 'Sln gas' CON         0.68


NUMERICAL
MAXSTEPS 99999999

RUN
DATE 2004 11 1
DTWELL 5

*NOLIST
** *WELL 1 'GI1'
**$
WELL  'GI1'
INJECTOR MOBWEIGHT IMPLICIT 'GI1'
INCOMP  GAS  0.  0.  0.  1.
TINJW  68.
OPERATE  MAX  STG  3.5e+007  CONT
```

```
MONITOR  MIN  BHP  0.  SHUTIN
** i j k ff status
**$          rad  geofac  wfrac  skin
GEOMETRY  K  0.354331  0.249  1.  5.
PERF  GEO  'GI1'
**$ UBA     ff  Status  Connection
   8 20 1  1.  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
   8 20 2  1.  CLOSED  FLOW-FROM  1
   8 20 3  1.  CLOSED  FLOW-FROM  2
   8 20 4  1.  CLOSED  FLOW-FROM  3
   8 20 5  1.  CLOSED  FLOW-FROM  4
   8 20 6  1.  CLOSED  FLOW-FROM  5
   8 20 7  1.  CLOSED  FLOW-FROM  6
   8 20 8  1.  CLOSED  FLOW-FROM  7
SHUTIN 'GI1'
** *WELL 2 'WI1'
**$
WELL  'WI1'
INJECTOR MOBWEIGHT IMPLICIT 'WI1'
INCOMP  WATER  1.  0.  0.
TINJW  68.
OPERATE  MAX  STW  65000.  CONT
MONITOR  MIN  STW  0.  SHUTIN
** i j k ff status
**$          rad  geofac  wfrac  skin
GEOMETRY  K  0.354331  0.249  1.  5.
PERF  GEO  'WI1'
**$ UBA     ff  Status  Connection
   5 33 1  1.  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
   5 33 2  1.  OPEN    FLOW-FROM  1
   5 33 3  1.  OPEN    FLOW-FROM  2
   5 33 4  1.  OPEN    FLOW-FROM  3
```

```
   5 33 5  1.  OPEN    FLOW-FROM  4
   5 33 6  1.  OPEN    FLOW-FROM  5
   5 33 7  1.  OPEN    FLOW-FROM  6
   5 33 8  1.  OPEN    FLOW-FROM  7
SHUTIN 'WI1'
** *WELL 3 'WI2'
**$
WELL  'WI2'
INJECTOR MOBWEIGHT IMPLICIT 'WI2'
INCOMP  WATER  1.  0.  0.
TINJW  68.
OPERATE  MAX  STW  65000.  CONT
MONITOR  MIN  STW  0.  SHUTIN
** i j k ff status
**$          rad  geofac  wfrac  skin
GEOMETRY  K  0.354331  0.249  1.  0.
PERF  GEO  'WI2'
**$ UBA      ff  Status  Connection
   12 31 1  1.  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
   12 31 2  1.  OPEN    FLOW-FROM  1
   12 31 3  1.  OPEN    FLOW-FROM  2
   12 31 4  1.  OPEN    FLOW-FROM  3
   12 31 5  1.  OPEN    FLOW-FROM  4
   12 31 6  1.  OPEN    FLOW-FROM  5
   12 31 7  1.  OPEN    FLOW-FROM  6
   12 31 8  1.  OPEN    FLOW-FROM  7
SHUTIN 'WI2'
**$
WELL  'NP1'
PRODUCER 'NP1'
OPERATE  MAX  STO  23000.  CONT
OPERATE  MIN  BHP  500.  CONT
```

```
MONITOR   GOR  20000.  SHUTIN
** i j k ff status
**$         rad  geofac  wfrac  skin
GEOMETRY  K  0.354331  0.249  1.  0.
PERF  GEO  'NP1'
**$ UBA    ff  Status  Connection
   2 6 1  1.  OPEN    FLOW-TO  'SURFACE'  REFLAYER
   2 6 2  1.  OPEN    FLOW-TO  1
   2 6 3  1.  OPEN    FLOW-TO  2
   2 6 4  1.  OPEN    FLOW-TO  3
   3 6 5  1.  OPEN    FLOW-TO  4
   3 6 6  1.  OPEN    FLOW-TO  5
   3 6 7  1.  OPEN    FLOW-TO  6
   3 6 8  1.  OPEN    FLOW-TO  7
SHUTIN 'NP1'
** *WELL 5 'NP2'
**$
WELL  'NP2'
PRODUCER 'NP2'
OPERATE  MAX  STO  23000.  CONT
OPERATE  MIN  BHP  500.  CONT
MONITOR   GOR  20000.  SHUTIN
** i j k ff status
**$         rad  geofac  wfrac  skin
GEOMETRY  K  0.354331  0.249  1.  0.
PERF  GEO  'NP2'
**$ UBA    ff  Status  Connection
   6 6 1  1.  OPEN    FLOW-TO  'SURFACE'  REFLAYER
   6 6 2  1.  OPEN    FLOW-TO  1
   6 6 3  1.  OPEN    FLOW-TO  2
   6 6 4  1.  OPEN    FLOW-TO  3
   6 6 5  1.  OPEN    FLOW-TO  4
```

```
   6 6 6  1.  OPEN    FLOW-TO  5
   6 6 7  1.  OPEN    FLOW-TO  6
   6 6 8  1.  OPEN    FLOW-TO  7
SHUTIN 'NP2'
** *WELL 6 'NP3'
**$
WELL  'NP3'
PRODUCER 'NP3'
OPERATE  MAX  STO  23000.  CONT
OPERATE  MIN  BHP  500.  CONT
MONITOR    GOR  20000.  SHUTIN
** i j k ff status
**$          rad  geofac  wfrac  skin
GEOMETRY  K  0.354331  0.249  1.  0.
PERF  GEO  'NP3'
**$ UBA    ff  Status  Connection
   9 6 1  1.  OPEN    FLOW-TO  'SURFACE'  REFLAYER
   9 6 2  1.  OPEN    FLOW-TO  1
   9 6 3  1.  OPEN    FLOW-TO  2
   9 6 4  1.  OPEN    FLOW-TO  3
   9 6 5  1.  OPEN    FLOW-TO  4
   9 6 6  1.  OPEN    FLOW-TO  5
   9 6 7  1.  OPEN    FLOW-TO  6
   9 6 8  1.  OPEN    FLOW-TO  7
SHUTIN 'NP3'
** *WELL 7 'NP4'
**$
WELL  'NP4'
PRODUCER 'NP4'
OPERATE  MAX  STO  23000.  CONT
OPERATE  MIN  BHP  500.  CONT
MONITOR    GOR  20000.  SHUTIN
```

```
** i j k ff status
**$          rad  geofac  wfrac  skin
GEOMETRY  K  0.354331  0.249  1.  0.
PERF  GEO  'NP4'
**$ UBA     ff  Status  Connection
   13 6 1  1.  OPEN   FLOW-TO  'SURFACE'  REFLAYER
   13 6 2  1.  OPEN   FLOW-TO  1
   13 6 3  1.  OPEN   FLOW-TO  2
   13 6 4  1.  OPEN   FLOW-TO  3
   14 6 5  1.  OPEN   FLOW-TO  4
   14 6 6  1.  OPEN   FLOW-TO  5
   14 6 7  1.  OPEN   FLOW-TO  6
   14 6 8  1.  OPEN   FLOW-TO  7
SHUTIN 'NP4'
** *WELL 8 'SP1'
**$
WELL  'SP1'
** *WELL 9 'SP2'
**$
WELL  'SP2'
PRODUCER 'SP2'
OPERATE  MAX  STO  23000.  CONT
OPERATE  MIN  BHP  500.  CONT
MONITOR   GOR  20000.  SHUTIN
** i j k ff status
**$          rad  geofac  wfrac  skin
GEOMETRY  K  0.354331  0.249  1.  0.
PERF  GEO  'SP2'
**$ UBA     ff  Status  Connection
   6 25 1  1.  OPEN   FLOW-TO  'SURFACE'  REFLAYER
   6 25 2  1.  OPEN   FLOW-TO  1
   6 25 3  1.  OPEN   FLOW-TO  2
```

```
   6 25 4  1.  OPEN    FLOW-TO  3
   6 25 5  1.  OPEN    FLOW-TO  4
   6 25 6  1.  OPEN    FLOW-TO  5
   6 25 7  1.  OPEN    FLOW-TO  6
   6 25 8  1.  OPEN    FLOW-TO  7
SHUTIN 'SP2'
** *WELL 10 'SP3'
**$
WELL  'SP3'
PRODUCER 'SP3'
OPERATE  MAX  STO  23000.  CONT
OPERATE  MIN  BHP  500.  CONT
MONITOR    GOR  20000.  SHUTIN
** i j k ff status
**$          rad  geofac  wfrac  skin
GEOMETRY  K  0.354331  0.249  1.  0.
PERF  GEO  'SP3'
**$ UBA      ff  Status  Connection
   10 24 1  1.  OPEN    FLOW-TO  'SURFACE'  REFLAYER
   10 24 2  1.  OPEN    FLOW-TO  1
   10 24 3  1.  OPEN    FLOW-TO  2
   10 24 4  1.  OPEN    FLOW-TO  3
   10 24 5  1.  OPEN    FLOW-TO  4
   10 24 6  1.  OPEN    FLOW-TO  5
   10 24 7  1.  OPEN    FLOW-TO  6
   10 24 8  1.  OPEN    FLOW-TO  7
SHUTIN 'SP3'
** *WELL 11 'SP4'
**$
WELL  'SP4'
PRODUCER 'SP4'
OPERATE  MAX  STO  23000.  CONT
```

```
OPERATE  MIN  BHP  500.  CONT
MONITOR   GOR  20000.  SHUTIN
** i j k ff status
**$         rad  geofac  wfrac  skin
GEOMETRY  K  0.354331  0.249  1.  0.
PERF  GEO  'SP4'
**$ UBA      ff  Status  Connection
   13 25 1  1.  OPEN    FLOW-TO  'SURFACE'  REFLAYER
   13 25 2  1.  OPEN    FLOW-TO  1
   13 25 3  1.  OPEN    FLOW-TO  2
   13 25 4  1.  OPEN    FLOW-TO  3
   13 25 5  1.  OPEN    FLOW-TO  4
   13 25 6  1.  OPEN    FLOW-TO  5
   13 25 7  1.  OPEN    FLOW-TO  6
   13 25 8  1.  OPEN    FLOW-TO  7
SHUTIN 'SP4'

** *WELL 12 'SP1-STR'
**$
WELL  'SP1-STR'
PRODUCER 'SP1-STR'
OPERATE  MAX  STO  23000.  CONT
OPERATE  MIN  BHP  500.  CONT
MONITOR   GOR  20000.  SHUTIN
** i j k ff status
**$         rad  geofac  wfrac  skin
GEOMETRY  K  0.354331  0.249  1.  0.
PERF  GEO  'SP1-STR'
**$ UBA     ff  Status  Connection
   2 25 1  1.  OPEN    FLOW-TO  'SURFACE'  REFLAYER
   2 25 2  1.  OPEN    FLOW-TO  1
   2 25 3  1.  OPEN    FLOW-TO  2
```

```
   2 25 4  1.  OPEN    FLOW-TO  3
   2 25 5  1.  OPEN    FLOW-TO  4
   2 25 6  1.  OPEN    FLOW-TO  5
   2 25 7  1.  OPEN    FLOW-TO  6
   2 25 8  1.  OPEN    FLOW-TO  7
SHUTIN 'SP1-STR'
** *WELL 13 'SP2-STR'
**$
WELL  'SP2-STR'
PRODUCER 'SP2-STR'
OPERATE  MAX  STO  23000.  CONT
OPERATE  MIN  BHP  500.  CONT
MONITOR    GOR  20000.  SHUTIN
** i j k ff status
**$          rad  geofac  wfrac  skin
GEOMETRY  K  0.354331  0.249  1.  0.
PERF  GEO  'SP2-STR'
**$ UBA     ff  Status  Connection
   7 23 1  1.  OPEN    FLOW-TO  'SURFACE'  REFLAYER
   7 23 2  1.  OPEN    FLOW-TO  1
   7 23 3  1.  OPEN    FLOW-TO  2
   7 23 4  1.  OPEN    FLOW-TO  3
   7 23 5  1.  OPEN    FLOW-TO  4
   7 23 6  1.  OPEN    FLOW-TO  5
   7 23 7  1.  OPEN    FLOW-TO  6
   7 23 8  1.  OPEN    FLOW-TO  7
SHUTIN 'SP2-STR'
** *WELL 14 'SP3-STR'
**$
WELL  'SP3-STR'
PRODUCER 'SP3-STR'
OPERATE  MAX  STO  23000.  CONT
```

```
OPERATE  MIN  BHP  500.  CONT
MONITOR   GOR  20000.  SHUTIN
** i j k ff status
**$        rad  geofac  wfrac  skin
GEOMETRY  K  0.354331  0.249  1.  0.
PERF  GEO  'SP3-STR'
**$ UBA     ff  Status  Connection
   10 23 1  1.  OPEN   FLOW-TO  'SURFACE'  REFLAYER
   10 23 2  1.  OPEN   FLOW-TO  1
   10 23 3  1.  OPEN   FLOW-TO  2
   10 23 4  1.  OPEN   FLOW-TO  3
   10 23 5  1.  OPEN   FLOW-TO  4
   10 23 6  1.  OPEN   FLOW-TO  5
   10 23 7  1.  OPEN   FLOW-TO  6
   10 23 8  1.  OPEN   FLOW-TO  7
SHUTIN 'SP3-STR'
** *WELL 15 'SP4-STR'
**$
WELL  'SP4-STR'
PRODUCER 'SP4-STR'
OPERATE  MAX  STO  23000.  CONT
OPERATE  MIN  BHP  500.  CONT
MONITOR   GOR  20000.  SHUTIN
** i j k ff status
**$        rad  geofac  wfrac  skin
GEOMETRY  K  0.354331  0.249  1.  0.
PERF  GEO  'SP4-STR'
**$ UBA     ff  Status  Connection
   14 23 1  1.  OPEN   FLOW-TO  'SURFACE'  REFLAYER
   14 23 2  1.  OPEN   FLOW-TO  1
   14 23 3  1.  OPEN   FLOW-TO  2
   14 23 4  1.  OPEN   FLOW-TO  3
```

```
   14 23 5  1.  OPEN    FLOW-TO  4
   14 23 6  1.  OPEN    FLOW-TO  5
   14 23 7  1.  OPEN    FLOW-TO  6
   14 23 8  1.  OPEN    FLOW-TO  7
SHUTIN 'SP4-STR'
PRODUCER 'SP1'
OPERATE  MAX  STO  23000.  CONT
OPERATE  MIN  BHP  500.  CONT
MONITOR    GOR  20000.  SHUTIN
** i j k ff status
**$          rad  geofac  wfrac  skin
GEOMETRY  K  0.354331  0.249  1.  0.
PERF  GEO  'SP1'
**$ UBA     ff  Status  Connection
   3 26 1  1.  OPEN    FLOW-TO  'SURFACE'  REFLAYER
   3 26 2  1.  OPEN    FLOW-TO  1
   3 26 3  1.  OPEN    FLOW-TO  2
   3 26 4  1.  OPEN    FLOW-TO  3
   3 26 5  1.  OPEN    FLOW-TO  4
   3 26 6  1.  OPEN    FLOW-TO  5
   3 26 7  1.  OPEN    FLOW-TO  6
   3 26 8  1.  OPEN    FLOW-TO  7

*LIST
TIME 30
TIME 61
TIME 92.000000
OPEN 'NP1'
OPEN 'NP2'
OPEN 'SP1'
TIME 120.00000
TIME 151.00000
```

```
OPEN 'NP3'
TIME 181.00000
TIME 212.00000
TIME 243.00000
OPEN 'SP2'
TIME 273.00000
TIME 304.00000
SHUTIN 'NP2'
TIME 314.00000
OPEN 'NP2'
TIME 334.00000
TIME 365.00000
OPEN 'SP3'
TIME 396.00000
TIME 426.00000
OPEN 'SP4'
TIME 457.00000
TIME 485.00000
TIME 516.00000
OPEN 'NP4'
TIME 546.00000
TIME 577.00000
TIME 608.00000
OPEN 'GI1'
TIME 638.00000
TIME 669.00000
TIME 699.00000
OPEN 'WI1'
TIME 730.00000
TIME 760.00000
TIME 791.00000
OPEN 'WI2'
```

Time 822.0000

TIME 850.00000

TIME 881.00000

OPEN 'SP1-STR'

SHUTIN 'SP1'

TIME 911.00000

TIME 942.00000

OPEN 'SP2-STR'

SHUTIN 'SP2'

TIME 972.00000

TIME 1003.0000

OPEN 'SP4-STR'

SHUTIN 'SP4'

TIME 1034.0000

TIME 1064.0000

OPEN 'SP3-STR'

SHUTIN 'SP3'

TIME 1095.0000

TIME 1125.0000

TIME 1156.0000

TIME 1187.0000

TIME 1216.0000

TIME 1247.0000

SHUTIN 'NP3'

TIME 1257.0000

OPEN 'NP3'

TIME 1277.0000

TIME 1308.0000

TIME 1338.0000

TIME 1369.0000

SHUTIN 'WI2'

TIME 1400.0000

OPEN 'WI2'

TIME 1430.0000

TIME 1461.0000

TIME 1491.0000

TIME 1522.0000

SHUTIN 'GI1'

TIME 1553.0000

OPEN 'GI1'

TIME 1581.0000

TIME 1612.0000

TIME 1642.0000

TIME 1673.0000

TIME 1703.0000

TIME 1734.0000

TIME 1765.0000

TIME 1826.0000

TIME 1856.0000

TIME 1887.0000

TIME 1918.0000

TIME 1946.0000

TIME 1977.0000

TIME 2007.0000

TIME 2038.0000

TIME 2068.0000

TIME 2099.0000

TIME 2130.0000

TIME 2160.0000

TIME 2191.0000

TIME 2221.0000

TIME 2252

TIME 2283

TIME 2311

TIME 2342

TIME 2372

TIME 2403

TIME 2433

TIME 2464

TIME 2495

TIME 2525

TIME 2556

TIME 2586

TIME 2617

TIME 2648

TIME 2677

TIME 2708

TIME 2738

TIME 2769

TIME 2799

TIME 2830

TIME 2861

TIME 2891

TIME 2922

TIME 2952

TIME 2983

TIME 3014

TIME 3042

TIME 3073

TIME 3103

TIME 3134

TIME 3164

TIME 3195

TIME 3226

TIME 3256

TIME 3287

TIME 3317

TIME 3348

TIME 3379

STOP