MINISTRY OF EDUCATION OF REPUBLIC OF AZERBAIJAN

KHAZAR UNIVERSITY

FACULTY OF SCIENCE AND ENGINEERING

The code of major **60606 Oil and Gas Engineering**

The name of specialty **Petroleum Engineering**

MASTER THESIS

Title: A Comparative Study of Enhanced Oil Recovery for the Depleted Oil field in Iraq: A Simulation Modes Using Eclipse software

Master Student: **Aws Mohammed Ali Alkhateeb**

Supervisor: **Associate Prof. Dr. Gasham Zeynalov**

BAKU 2019

Abstract

Reservoir simulation is the combination of physics, mathematics, reservoir engineering and computer programming that can predict hydrocarbon reservoir performances under various operating conditions. History matching is one of the most important activities during the development and management of petroleum reservoirs. Matched models are fundamental to ensure reliable future forecasts, and give an idea of the level of understanding of the geological and reservoir model. This research is a simulation study to improve total oil production using water and polymer flooding method based on simulation model of the Thi-Qar field. A simulation study was performed on a recently discovered the Thi-Qar field oil field. Thi-Qar Field/ Uruk-1 reservoir was chosen as a model for the Iraqi oil fields to experience experiment with enhanced oil recovery methods and choosing the best possible way to produce crude from these reservoir. The best Enhanced oil recovery methods available in Uruk-1 reservoir were chosen. Five different cases of production were created using a (Eclipse simulator program) and then compared against each other. These cases included the change in permeability, Increased cross-sectional area away from wells, kv/kh , Barriers preventing vertical flow and the injection Polymer.

The objectives of this study are choosing the best enhanced oil recovery methods are applied in the Iraqi oil fields By using a small reservoir of the field model, three layers with a different permeability layer with 15 layers of grid cells, distributed over 3 geological layers were studied with one injector and one producer. The first four case

studies based to research optimal distance within them in hydrocarbon production, water breakthrough and possible sweep area. The location of the area was varied relatively. The results showed that in regions where in optimal distance i reservoirs are chacterized with relatively equal permeability, but this distance is some times affected by barriers like shale and faults. But, permeability variations resulted less effect than expected. The fifth case study is polymer flooding has shown a better outcome in comparison with water flooding project. The light crude oil has a slight effect on the increase in production energy because the viscosity of oil is neutral so the polymer is not impact on the total of oil field production. The viscosity of oil five times to whiten the effect of the polymer as they are in different properties and through this that the polymer has a high impact in the case of a reservoir containing high viscosity oil.

Xülasə

Layların modelləşdirilməsi fizika, riyaziyya, layların işlənməsi və kompüter proqramlaşdırılmasının birgə inteqeasiyası ilə müxtəlif istismar şəraitində kabohidrogen laylarının məhsuldarlığının proqnozlıaşdırmaq üçün istifadə edilir.

Neft yaraqlarının içlənməsi və idarə edilməsində tarixi yanaşma daha vacib əməliyyatlardan biridir.

Uyğun modellər gələcəkdə əsaslı proqnozların təmin edilməsi üçün böyük əhəmiyyətə malikdir və geoloji model və rezervuar model haqqında təsəvvür yaratmağa imkan verir. Bu tədqiqat İrakın Ti-Qar yatağının simulyasiya modeli əsasında su ilə sulaşdırma və polimer metodlarının istifadəsi ilə ümumi neft hasilatını yaxşılaşdırmaq üçün sumulyasiya tədqiqatının aparılmasını xarakterizə edir.

Simulyasiya tədqiqatı bu yaxınlarda yeni kəşf edilmiş Ti-Qar neft yatağında yerinə yetirilmişdir. Ti-Qar yatağının Uruk-1 rezervuar layı İrak neft yatağlarının timsalında nümunə kimi götürülmüş və neftvermənin artırılması üsulları ilə laydan xam neftin çıxarılmasının ən yaxşı mümkün yollarının seçilməsi üçün eksperimentlərin aparılması üçün tədqiq edilmişdir.

Uruk -1 layının neftverimliliyini artırlması üçün ən yaxşı yanaşmalar seçilmişdir. Eclipse simulyator proqram təminatının istifadəsi il hasilatın beş müxtəlif metodu seçilmiş və sonra onlar bir-biri ilə müqayisə edilmişdir. Bu hallarda keçiriciliyin dəyişməsi quyulardan

kənarda artırılmış eninə kəsim sahəsi, kv/kh, şaquli axının qarışısını alan baryerlər və polimerlərin laya vurulması kimi məsələlər nəzərdən keçirilmişdir.

Bu tədqiqatın əsas məqsədi İrak neft yataqlarında neftvermənin artırılmasının ən mükəmməl üsulunun seçilməsidir. Yatağ modelinin kiçik laylarını istifadə etməklə bir injektor və bir hasilat sistemi olan 3 geoloji lay üzrə paylanmış 15 kiçik laylı qrid paylanması ilə müxtəlif keçiriciliyə malik 3 lay öyrənilmişdir.

Birinci 4 hal neft hasilatı, sulaşma və işlənmə sahəsi nöqteyi nəzərdən onlar arasında optimal məsafənin müəyyənləşdirmək məqsədilə öyrənilmişdir. Sahənin vəziyyəti nisbətən fərqli olmuşdur. Aparılan tədqiqatın nəticələri nisbətən eyni məsaməliyə malik sahələrdə oprtimal məsafənin olduğunu göstərir, lakin bu məsafə gil və qırılma kimi axın baryerinə güclü təsir edir. Lakin məsaməliyin dəyişməsi gözlənildiyindən as təsirə malik olmuşdur. Polimerlə inyeksiyanin beş halı süvurma layihəsi ilə müqayisədə yaxşı nəticə göstərmişdir. Yüngül xam neft hasilatın artmasına az təsir edir, hansı ki, neftin özülülüyü neytral rola malikdir. Ona görə də polimer yataqlarda neftin ümumi hasilatına təsir etmir.

Neftin özülülüyü polimerin təsirini o halda azaldır ki, o müxtəlif xassələrə malik olsun. Ona görə polimer yüksək özülülüyə malik neftdən təşkil olunmuş kollektorlara güclü təsir edir.

Table of Contents

List of Figures

List of Tables

Nomenclature

Symbol	Description
E	total displacement efficiency
ED	Microscopic displacement efficiencies
EV	volumetric (macroscopic)displacement efficiencies
M	mobility ratio
λ_w	mobility of water
λ_o	mobility of oil
Krw	relative permeability's to water
Kro	relative permeability's to oil
μ_w	water viscosity
μ_{ow}	oil viscosity
K	Permeability
S_w	Saturation of water
S_o	Saturation of oil
PC	Capillary pressure
Po	pressures in the oil phase
Pw	pressures in the water phase
$\sigma_{\sigma w}$	interfacial tension between oil and water
R1 and R2	the principal radii of curvature at any point on the interface
ΔP	pressure drop across the porous medium
$\overline{V}$	average velocity of fluid in the pores of the porous medium
μ	fluid viscosity
L	length of the porous medium
ϕ	porosity of the porous medium
NC	capillary number
V	velocity
μ	viscosity
σ	interfacial tension

List of abbreviations

Abbreviation	Meaning
OPEC	Organization of the Petroleum Exporting Countries
IMF	International Monetary Fund
EOR	Enhanced oil recovery
IOR	Improved oil recovery
Pnw	non-wetting phase
Pw	wetting phase
CSS	Cyclic steam stimulation
SAGD	Steam assisted gravity drainage
ASP	alkali-surfactant-polymer
HPAM	hydrolyzed poly acryl amides
GOM	Gulf of Mexico
OOIP	Original oil in place
XG	Xanthan gum
SmW	Smart water
WCUT	Total water cut
SSW	Synthetic sea water
DIW	Deionized water
NSCO	North Sea crude oil
HH	hexane-hexadecane
FPR	Field average pressure
WBHP	Bottom hole pressure of all wells
FOPR	Field Oil Production Rate
FWPR	Field Water Production Rate
FOPT	Field Oil Production Total
FWPT	Field Water Production Total
FVPR	Field Volume Production Rate
FWIT	Field Water Injection Total
FOE	Field Oil Recovery Efficiency
FWCT	field Water cut in PROD

Introduction

Iraq is one of the largest oil producers of the world. Most of Iraq's major fields are producing or in development and their production potential have not been fully exhausted. Some of them located in southern coastal parts and are characterized relatively with complicated geology. Therefore, optimal analysis and estimation is needed to increase oil recovery of these fields.

Problem Statement of Research

Iraq economy is mainly depended from the petroleum (oil) with around 93% of revenues since 1990-2015 (as shown in Figure 1) and unilaterally on oil revenues has led to imbalance in the structure of the Iraqi economy and as a result was linked to the budget of the balance of these revenues heavily in the funding, on the other hand due to lack of the using for the modern methods of the enhancement oil production within some oil fields are depleted. Iraqi and international companies that have still working in the Iraqi oil fields did not use the modern methods to increasing the production oil because of easy extraction of oil and its availability. These companies have not care importance to the depleted oil fields because of there are many existence of options available. Iraqi and international Oil Companies have not taken into account the presence of large quantities of oil is stilling untapped and remaining in the reservoirs that can be produced by the modern ways thus to significant increase production oil.

Therefore, during this study will be selected one of the oil fields called (the depleted field oil) in the southern Iraq as a case study. Main approach of this work will be determine one of the modern methods of enhanced oil recovery to increasing production oil using the simulations data with the eclipse 100-2009 software.

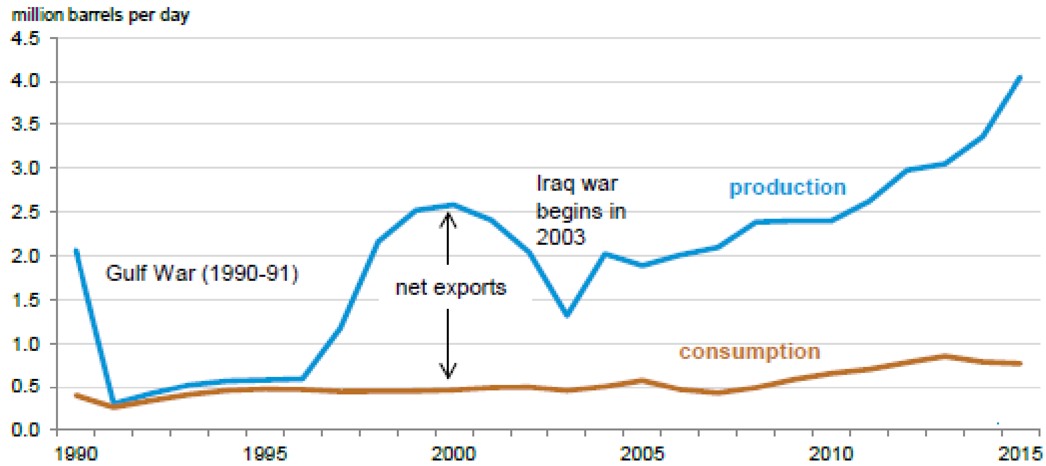

Figure 1: Iraq total petroleum production and consumption [1].

Scope

During this study, the simulations of reality of an oil reservoir using the eclipse 100-2009 software were used. The simulation was carried out for several the designed models that depended on changing properties of oil reservoir. The models were designed as follows:

- First model, the simulation of changing porosity of rocks was studied by placing different porous layers in different layers for the purpose of increasing production.
- The second model has been studied to change the dimensions of the layers to make the water injection to be different.
- The third model is the study of the effect of layering layer between layers.
- The fourth model was taken into account in the absence of capillary the expansion of the permeability of the vertical layers (of the oil reservoir) was also studied on horizontal layers for the purpose of increasing production
- The fifth model was studied and simulated if the pressure was abnormal with polymer injection and was compared with other models.

Objectives

- A comprehensive objective study using the simulation method used for the oil fields.
- Developing and improving the oil production of oil reservoirs using the simulation method of virtual reality.
- Optimal use of the methods used to improve the production and extraction of oil in the oil fields.

Chapter 1. Literature Review

1.1 Oil Recovery Mechanisms

Oil Recovery is a process of extracting crude oil from an oil field. There are three different phases of Oil Recovery, i.e., primary, secondary and tertiary (Figure 1.1, show processes of Oil recovery). Many oil wells reach their maximum production range and after several decades it becomes difficult to extract the remaining natural resources from the oil fields. Therefore, different injection methods are implemented to increase recovery factor of oil fields. Oil recovery is sometimes referred to as tertiary recovery or improved oil recovery.

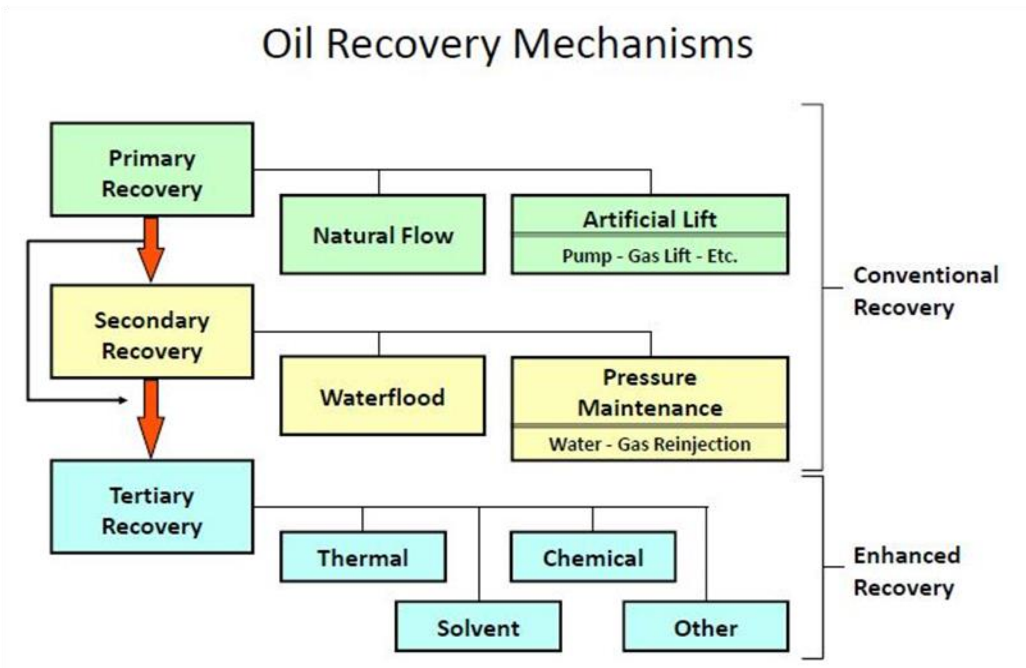

Figure1.1:Oil Recovery Mechanism [2].

1.2 Conventional Oil Reserves

Conventional oil reserves refer to the portion of oil resources that can be extracted, just after drilling, by the natural pressure of the oil in the reservoir or by pumping operations. Conventional oil reserves are those that can be extracted via primary or secondary recovery methods which both target the mobile oil of the reservoir:

- **Primary Recovery** where the natural energy of the reservoir, in the form of a displacement mechanism such as **gas drive** (gas cap or/and dissolved gas), **water drive** (active aquifer) or **gravity drainage** (high slope angle), displaces the hydrocarbons towards the well and up to surface. In primary recovery, extraction can be reinforced via **pump jacks** and other artificial lift devices. At this stage, typically a Recovery Factor between 5 to 15% is achieved [2].
- **Secondary Recovery** in which energy is added to the reservoir through water flooding or gas injection. The objective of the secondary recovery is to sustain reservoir pressure (if it is possible above bubble point) and to displace oil and gas toward the well. The subsequent use of primary and secondary recovery can result to a total Recovery Factor of 40 or 50%.

In Figure 1.2 the global quantities of conventional oil that is discovered (red curve) and produced (blue curve) with the relative predictions are illustrated [3].

1.3 Unconventional Oil Reserves

Unconventional oil reserves refer to the portion of inaccessible oil resources and to those with such a composition that cannot be recovered from an ordinary production well without being heated or diluted. For production, transportation or refinery they require specific techniques that are more complicated, more energy intensive and with higher environmental impacts when compared with the techniques used for the conventional oils. Unconventional oils or new oils include the following oil reserves [4]:

- Shale oil
- Tight oil
- Oil from Tar sands
- Deep water oil.

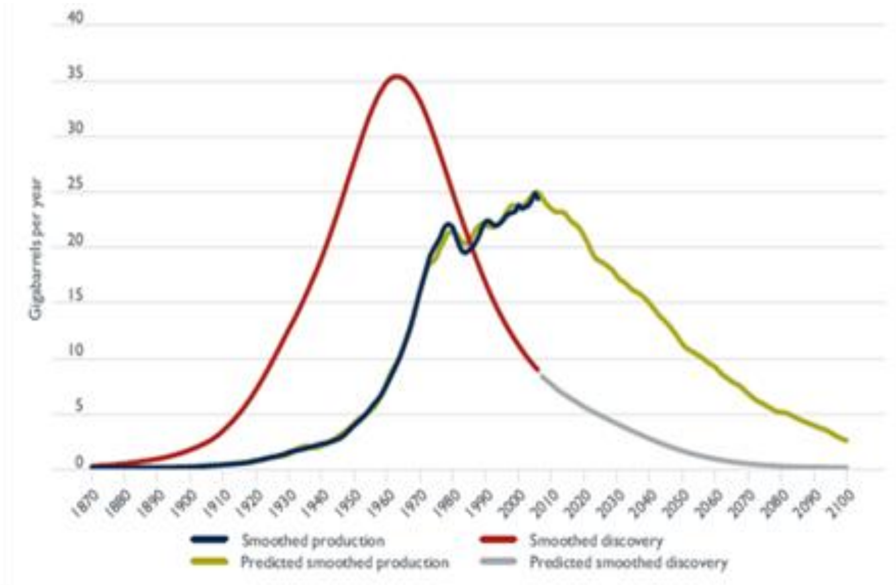

Figure 1.2: Annual world discovery and production of conventional oil [4].

1.4 Enhanced Oil Recovery Methods

The techniques are used for the extraction of the unconventional oil reserves constitute which is used to recover oil beyond secondary methods targeting the immobile oil (that oil which cannot flow towards the well due to capillary or viscous forces). The successive use of primary, secondary and tertiary recovery (Figure 1.3) can result to a total Recovery Factor of 80%. Enhanced Oil Recovery methods are classified according to the oil displacement mechanism into the following categories [10, 23-24]:

- **Thermal methods** (using heat for reduction of oil viscosity)
- **Miscible gas injection methods** (that use a solvent for miscible oil displacement)
- **Chemical methods** (that use chemicals for alteration of capillary and viscous forces).

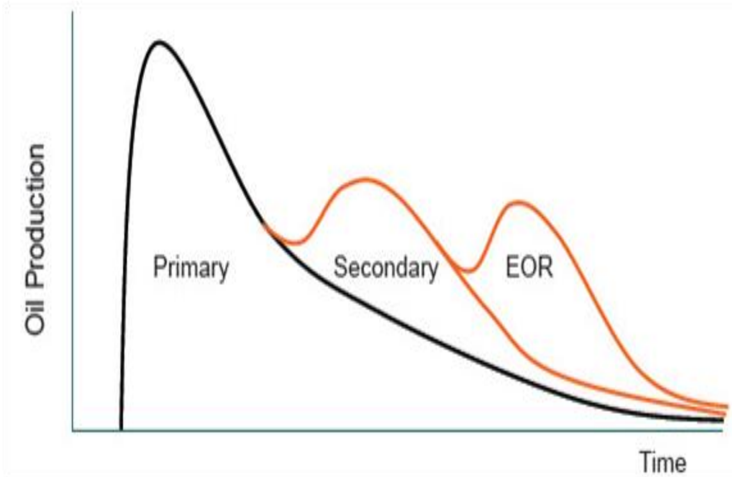

Figure 1.3: Illustration of Oil Recovery Mechanisms [36].

1.8.1 Thermal enhanced oil recovery methods

Thermal enhanced oil recovery methods are based supplying heat to the reservoir, which contain heavy oil with high viscosity and low mobility. The major mechanisms of this method are vaporize some of the oil and make a large reduction in viscosity, mobility ratio and provide a displacement mechanism other mechanisms, such as rock and fluid expansion, compaction, steam distillation and visbreaking may be present. There are three different methods, which can be identified as thermal recovery method [10, 25]:

- Cyclic steam stimulation (CSS)
- Steam flooding
- Steam assisted gravity drainage (SAGD)
- Conduction heating in situ combustion

1.8.1.1 Cyclic Steam Stimulation

Cyclic Steam Stimulation is related with one well, which a well is injected with steam and then subsequently put back on production. It consists of three stages (figure 1.4). At initial stage a slug of steam is introduced into the reservoir and it is termed for around one month, which is called steam injection. Then, at the second stage, the well is closed for a few days for heat distribution, supplied by soak. Finally, during the last stage, the thinned oil is produced through the same well and the oil recovery rate will be increased immediately to a high rate, and will stay at same level for short time, and then will decline within several months. The cycle is repeated as long as oil production is profitable [25].

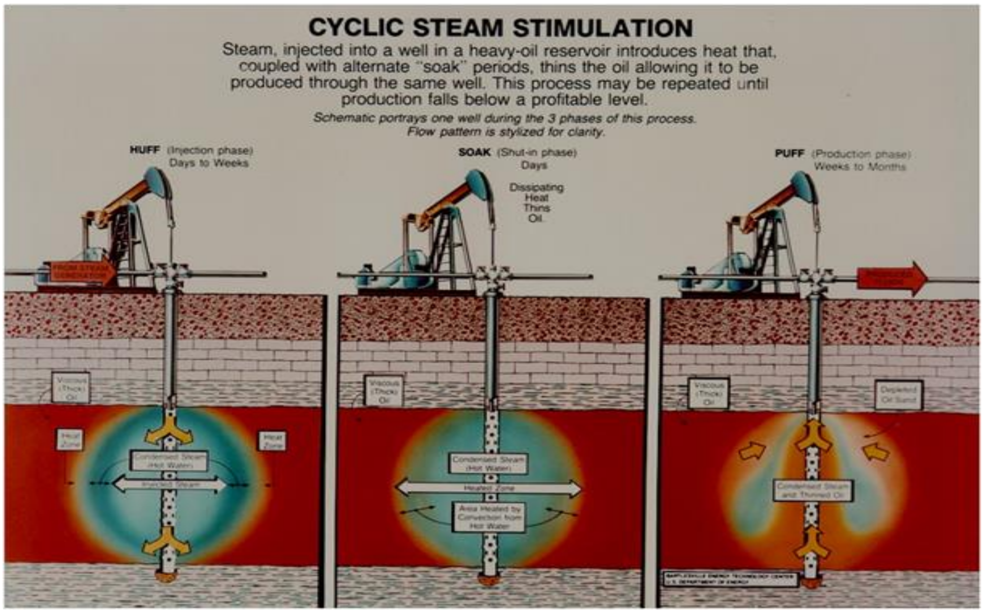

Figure 1.4 Cyclic Steam Stimulation Methods [25].

1.8.1.2 Steam flooding

Steam flooding is sometimes known as a steam drive which is similar to water flooding. In this method, steam is injected persistently, and it is resulted formation of steam zone, which is performed slowly (Figure 1.5). In this case oil will be mobilized due to decreasing of viscosity, which will be resulted a high rate of oil production [10, 26].

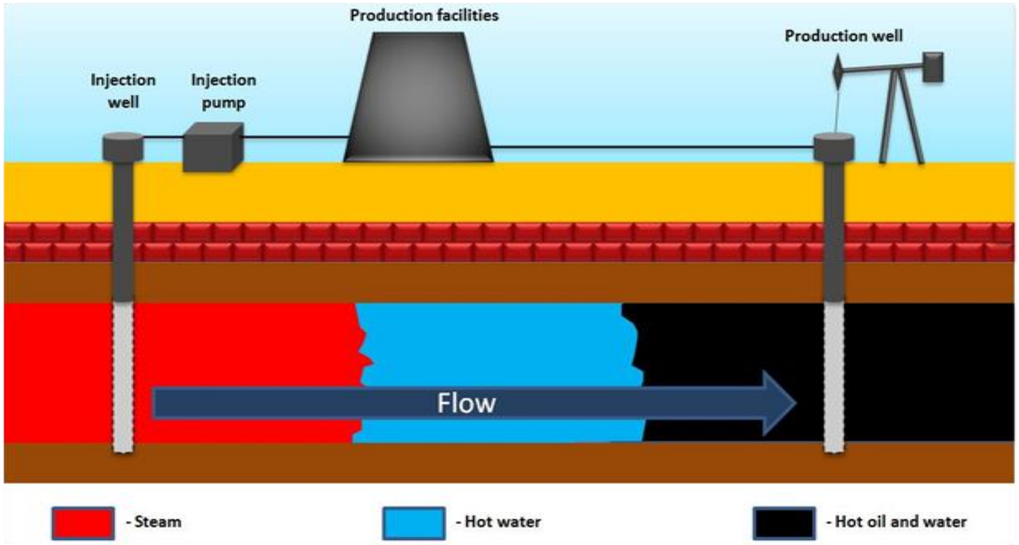

Figure1.5: Illustration of Steam Flooding[26].

1.8.1.3 Steam Assisted Gravity Drainage

This method is based on steam simulation with drilled of pair of parallel horizontal well. One of these well is drilled to the reservoir and the other one is a few meters above the reservoir . The upper wellbore is used to inject the low pressure steam and to heat the oil (Fig. 1.6). This process is continued until the high reduction of viscosity mobilization in bitumen, which drains down by gravity which is captured by the producer located near the bottom of the reservoir. [25].

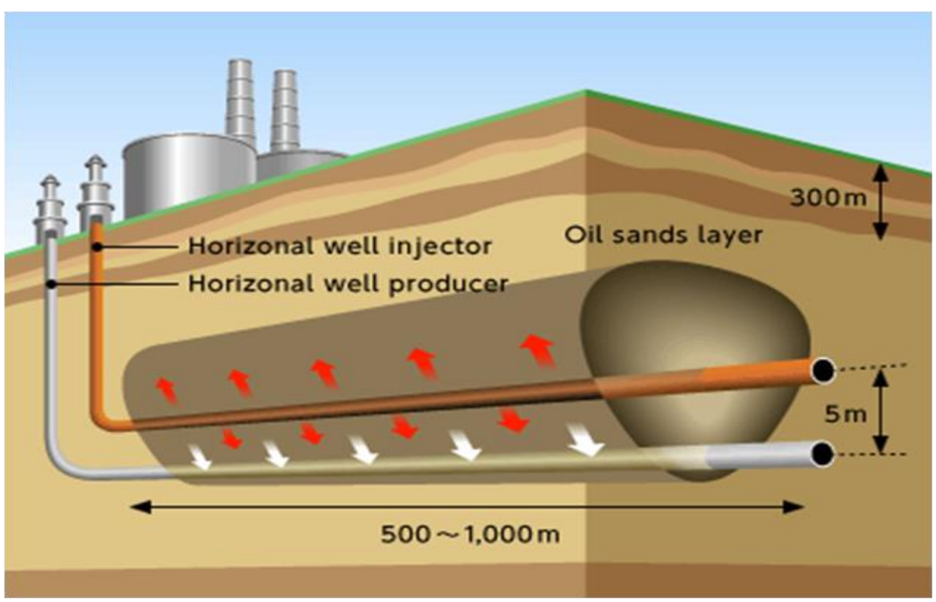

Figure 1.6: Steam Assisted Gravity Drainage [25].

1.8.1.4 Conduction heating in situ combustion

On this method, thermal energy is released in the reservoir by oxygen combination with the fuel (crude oil fractions). Oil in reservoir is ignited and fire sustained by air injection and decreasing oil viscosity occurs near the combustion zone, as illustrated in figure 1.7. This method was tested in different oil fields, but with some differences. The main variations of in situ combustion are regarded with forward and reverse combustion and high pressured air injection. This method was also applied in many oil fields, however, but some of them have been evaluated with economical significance. [25, 27].

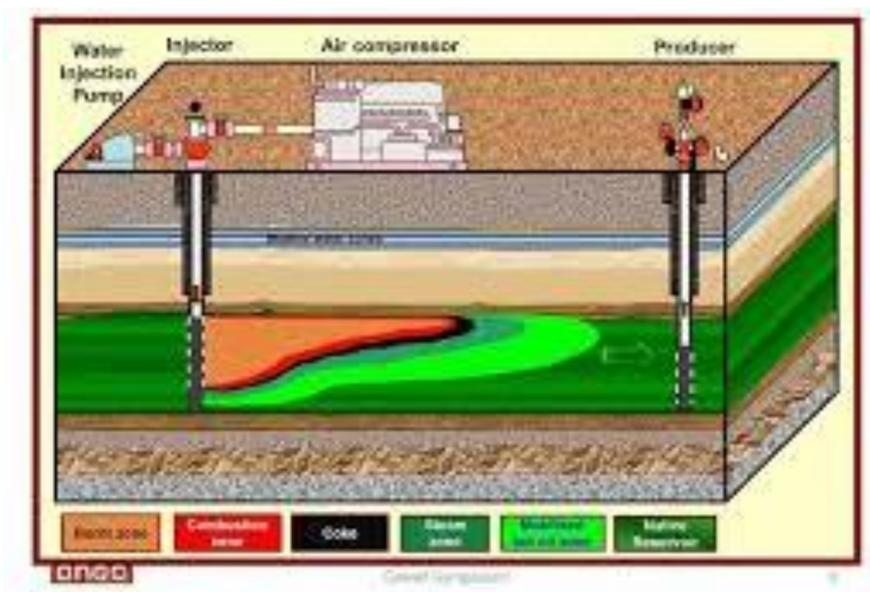

Figure 1.7: Schematic Conduction heating in situ combustion [27].

1.8.2 Miscible flooding

Miscible displacement processes are defined as processes where the effectiveness of the displacement results primarily from miscibility between the oil in place and the injected fluid [28]. Fig. 1.8 shows a schematic of miscible flooding. Displacement fluids, such as hydrocarbon solvents, CO2, flue gas and nitrogen are considered. Miscibility plays a role in surfactant flooding processes, but is not the primary recovery mechanism for these processes and also in other processes that are immiscible, such as polymer-augmented water flooding.

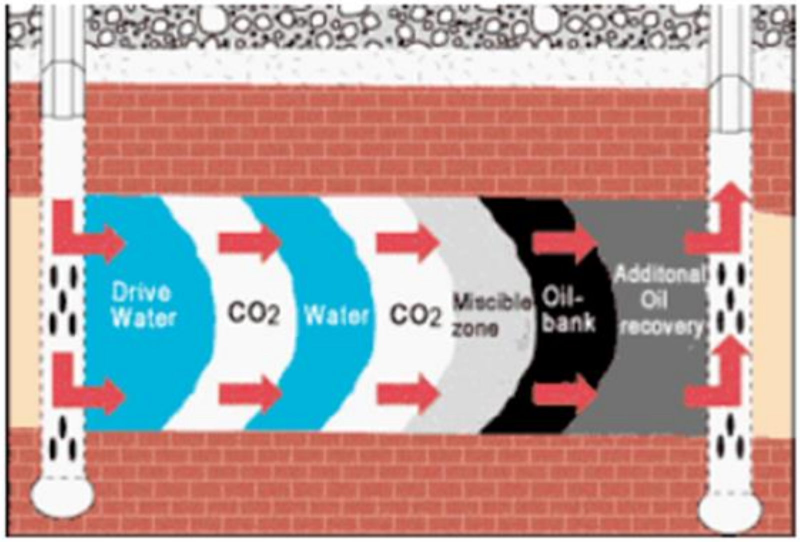

Figure 1.8: Schematic illustration of miscible flooding [28].

1.8.3 Chemical flooding

Chemical flooding is an important process for EOR, where various chemicals, such as alkaline solutions into reservoirs have been injected to the reservoir. The major chemical flooding processes are followed [30-31]:

- Polymer flooding
- Surfactant flooding
- Alkaline flooding
- Micellar flooding
- ASP (alkali-surfactant-polymer)

1.8.3.1. Polymer Flooding

Polymer flooding constitutes the most applied technique among all the other chemical EOR methods. Polymer flooding is reliable technique that has the possibility to be implemented in a wide range of oil reservoirs. Polymer flooding aims to control the mobility ratio (M) and to increase by this way the sweep efficiency of the displacement process [14, 22]. This is performed t by injection a mobility control agent – a solution of polymers to increase the viscosity of the displacing fluid. The subsequent decrease in the mobility ratio between the displacing and the displaced fluid has as a result the formation of a more uniform displacement front as it is illustrated in (Figure 1.9) which finally results in an increase in the ultimate recovery factor. The process involves the injection of a slug – solution of polymers that normally account for 30 - 50% of the target reservoir's pore volume which is then followed by water / brine injection to drive the oil bank to the surface. Field implementations have shown that polymer flooding has the potential of an incremental recovery factor that could range between 5 – 30% of the oil originally in place [33]. Another, secondary mechanism through which polymer solution displaces oil is attributed to polymers viscoelasticity properties. Generally, the shear stresses that are developed in the interfaces between oil and polymer solutions are higher when compared with the shear stresses in the case of water displacement. As a result a higher pull force can be applied when polymer solution is used as a displacing fluid and subsequently more quantities of oil can be displaced. In polymer flooding projects, water soluble polymers are used which can be classified in the two categories presented below.

The selection of the appropriate type of polymer is based on each reservoir's characteristics. The reservoir permeability and the oil viscosity define the molecular weight of the polymer whereas the absorption level defines the required degree of hydrolysis [10, 34].

1. Synthetic polymers: are those which are mostly used in polymer flooding projects as they demonstrate greater viscoelasticity and they are generally available at lower prices when compared with the biopolymers. In most cases partially hydrolyzed polyacrylamides (HPAM) are used. The performance that synthetic polymers exhibit is strongly hindered by the presence of brine water and it depends strongly on their molecular weight and their degree of hydrolysis.

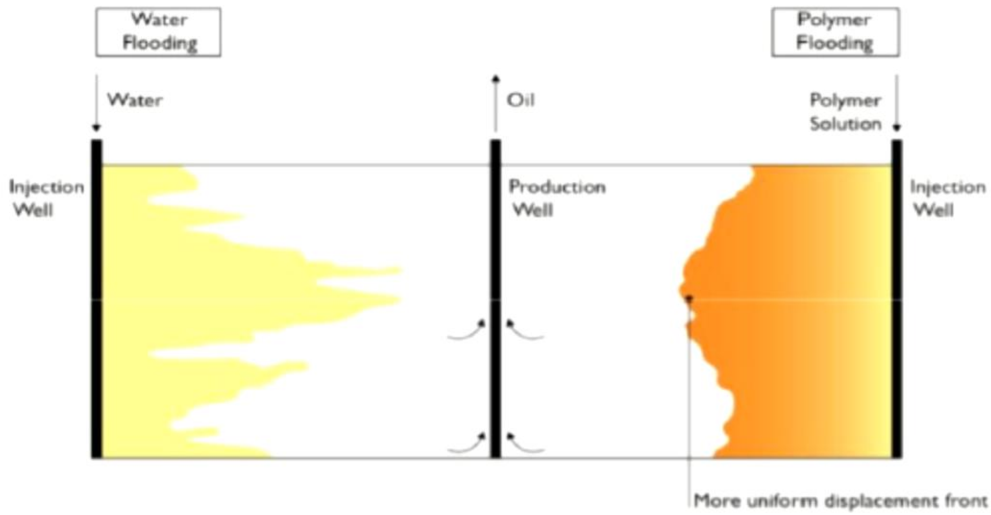

Figure 1.9: Schematic Illustration of Polymer flooding [34].

2. Biopolymers: This group of polymers (is also called polysaccharides) is synthesized by microbial activity and the most used representative is the xanthenes gum. Their performance in not influenced by the presence of brine water and are quite resistant to mechanical degradation but they are more sensitive in thermal and microbial degradation when compared with the synthetic polymers [24, 33].

Most of the times biocides are injected simultaneously to prevent microbial degradation whereas as a temperature limit for most of the biopolymers can be considered the value of 70 °C. Technically, the admixture of polymers in the injected water will definitely increase the sweep efficiency and subsequently the ultimate recovery factor at any possible reservoir [10]. The economic viability of a polymer flooding project relies on the induced benefits meaning the reduction in the mobility ratio and subsequently the increase in the ultimate recovery factor when compared with the cost for the corresponding polymer concentration [34].

Generally, polymer flooding becomes profitable in two types of oil reservoirs:

- Reservoirs with high degree of heterogeneity where conventional water flooding bypasses significant oil quantities. Polymer flooding decreases the fluids mobility in the high permeability layers resulting in a more uniform displacement front.

- Reservoirs that contain medium oils, which result in unfavorably high mobility ratios. Polymer flooding decreases the mobility ratio between displacing and displaced fluid and improves the sweep efficiency.

In both the cases mentioned, means reservoirs with heterogeneities or reservoirs where high mobility ratios occur the result is early breakthrough of the water which is followed by a production with increasing water cuts. Polymer flooding seems to be a possible solution to reverse the situation and to accelerate oil production.

1.8.3.1.1 Alkaline flooding

Alkaline flooding (Figure 1.10), also known as caustic flooding, demonstrates the lowest cost of implementation of all the other chemical EOR methods nevertheless, as a technique has never been applied successfully independently but always in combination with polymer or surfactant flooding [24, 34].The technique manages to increase the ultimate recovery factor by injection of an alkali slug at a pH value that ranges between 10 and 12. Generally, alkalis are water soluble substances and when they are dissolved in water they release hydroxide ions (OH^-). For the preparation of the alkali slug, three types of alkalies are used mostly **$NaOH$** (Sodium hydroxide), **Na_4O_4Si** (Sodium orthosilicate) and **Na_2CO_3** (Sodium carbonate). Sodium hydroxide is the most used whereas sodium carbonate the least used. Sodium orthosilicate is mostly recommended when waters with high hardness are encountered.

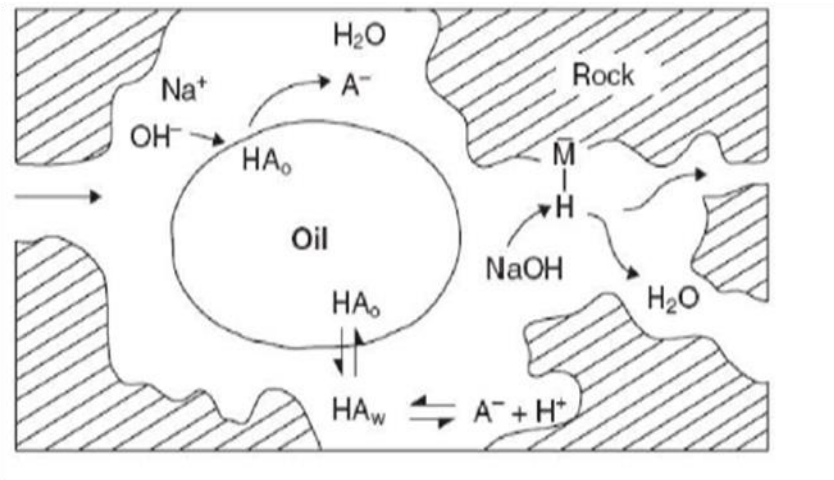

Figure 1.10: Schematic show alkaline recovery process [34].

The technique involves four displacement mechanisms that most of the times act simultaneously and are described below. Depending on the displacement mechanism that is reinforced the recovery process could emphasize more to the residual oil of the already swept zones of the reservoir or to the relatively lower permeability, un swept zones. In the first case alkaline water flooding aims to reduce the residual oil saturation from the swept zones that have been already swept by the preceding conventional water flooding (secondary production). In this case the alkali solution reacts with the organic acids of the reservoir's crude oil (naphthenic acids) to form surfactants which in turn, have the ability to improve significantly the displacement efficiency of the residual oil. In the case of oil accumulations with low concentration in organic acids, a bank of oil rich in organic acids could be injected before the alkaline flooding [10]. The mechanisms that target the already swept zones are emulsification and entrainment and wettability reversal.

1.8.3.2. Surfactant flooding

The technique targets the residual oil quantities that remain capillary – trapped after water flooding and manages to mobilize them by injecting surfactants capable to change the interfacial (water/oil) behavior properties. The possible incremental recovery factor of the technique ranges between 10% - 20% of the original oil in place. Generally, surfactant flooding is related with unfavorable mobility ratios which result in very low volumetric sweep efficiencies [22, 33]. In order to improve the rheological behavior of surfactant flooding and make the technique commercially viable, it is compulsory to use polymers both in the surfactant slug and in the drive slug. The word surfactant is derived from the words surface and act and refers to a blend of surface active organic compounds. In Figure 1.11 the discrete phases in a typical surfactant flooding are illustrated.

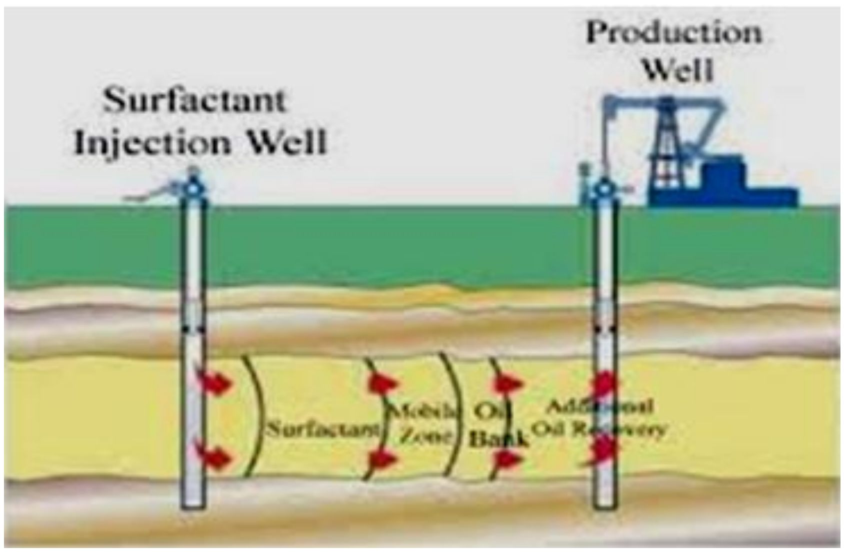

Figure 1.11: Schematic Illustration of Surfactant flooding [33].

1.9 Previous Studies on Smart Water Flooding

By Royce et al. [36] has been done water requirements for enhanced oil recovery (EOR) are thoroughly evaluated using publicly available information, data from actual field applications, and information provided by knowledgeable EOR technologists. Water quantity and quality requirements are estimated for individual EOR processes. The estimated quantity requirements represent the total water needed from all sources. A reduction in these quantities can be achieved by re-injecting all of the produced water potentially available for recycle in the oil recovery method. For injection water quality requirements, it is noted that not all of the water used for EOR needs to be fresh.

By Martin et al. [39] two modified acrylamide polymers were synthesized that show improved performance when compared to partially hydrolyzed polyacrylamide HPAM. The main improvement with these modified materials is the higher viscosities generated in salty waters.

Billal [40] customized HPLC methodology is developed to allow characterizing and screening the recovery change due to ionic variation of injected water. Extended contact time is needed to see the impact of electrolytes on oil recovery. However, a significant recovery difference between water and 0.1M $MgCl_2$ solution is detected where Mg^{2+} solution is able to recover more oil than water. The advantages of this technique compared to the currently available methodologies are due to the small sample sizes and ease of use. Many columns can be analyzed; the packing material can be changed to calcite, chalk, or silica. In addition, different types of hydrophobic layer / particles can be used to coat the packing material.

Comparing different electrolytes to one another and determining the effect of electrolyte concentration on oil recovery requires many experiments. Therefore, this technique could be useful to make studies faster and easier to validate the recovery theories.

Chapter 2: Theoretical Background

2.1 Reservoir Simulation

Reservoir simulation is a numerical modeling which can be used to quantify and interpret physical phenomena with the ability to extend these to project future performance. A typical reservoir simulation study is comprised of following steps:

· Geological Review

· Reservoir performance Review

· Data Gathering

· Approach

· Initialization

· History matching

· Predictions

· Report and presentation

Fig 2.1 depicts the major steps involved in the development of a reservoir Simulator.

Reservoir Simulation, like material balance calculation, is a form of numerical modeling which is used to quantify and interpret physical phenomena with the ability to extend these to project future performance. Material balance has the limiting characteristics of:

- No account of spatial variation (so-called “zero-dimensional”)
- Reservoir and fluid properties as well as fluid flows are averaged over the entire reservoir
- To examine the system at a number of discrete points in time requires a material balance calculation over each time interval.

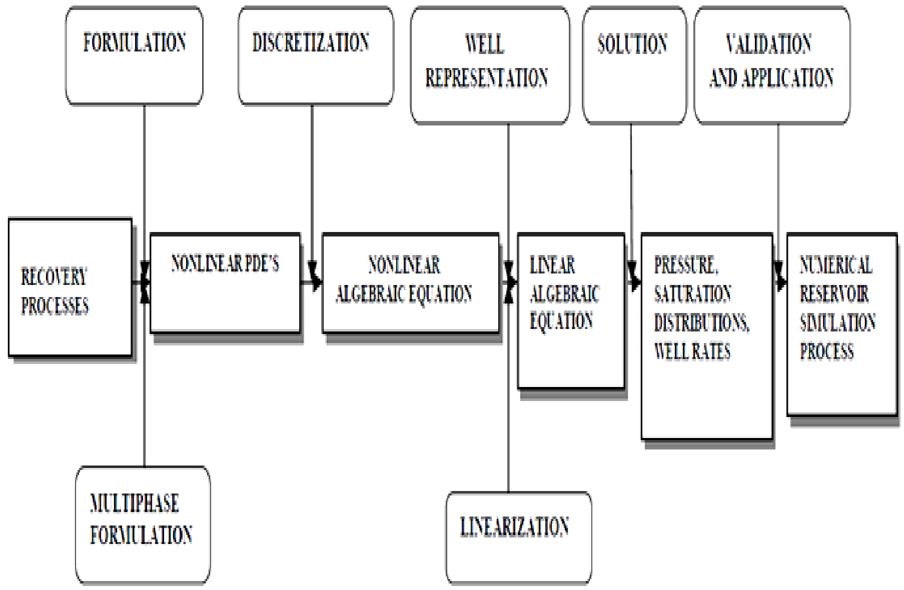

Figure 2.1: Major steps used to develop reservoir simulator

2.2 Simulation Basic Concept

Simulating two phase fluid flow in porous media involves solving a system of coupled non-linear partial differential equations. Developing a computer model for these types of systems requires the use of finite-difference approximation to discrete these equations. The various solution techniques differ with respect to how we manipulate the governing partial differential equations.

The simulator used in this thesis is Schlumberger Eclipse E100. It is a fully implicit, integrated finite difference, three phase general purpose oil simulator.

ECLIPSE 100 is a compositional simulator with cubic equation of state, pressure dependent K-value and oil fluid treatments. ECLIPSE 100 can be run in fully implicit, IMPES and adaptive implicit (AIM) modes. ECLIPSE 100 is used to build a model for the reservoir characteristics and performance predictions for (The depleted Oil field-One of fields in Southern Iraq) reservoir of Nasiriyah-Iraq field.

2.2.1 Input File for Running ECLIPSE (Data Classification)

The data files for Running ECLIPSE software are divided into sections and each input file is introduced by a keyword. Each section must contain a minimum data required. Moreover, these sections must be generated following the below order:

2.2.1.1 Run Specification Section (RUNSPEC)

This section is the first section in the input data file for ECLIPSE software. It contains the start date, run title, units, components present and various problem dimensions (number of blocks, wells, etc…), and this section must always be present.

2.2.1.2Grid Section (GRID)

- **Grid Properties:**

This section contains rock properties like permeability in (X, Y, Z) direction, porosity and net thickness ….etc, which are exported from petrel program.

- **Grid Geometry:**

Grid geometry concerns the depth of grids and the geometry of the block .In our study there is one model, In the first model, the number of model grid cells are (50* 15* 15) and the total number of grid blocks is 3500, while the active grid cells are 2450. The in active cells are the barrier between the units. In terms of simulation layering (from top to bottom),it is as follows:

Layers 1to 5;

Layers 6 to 10;

Layers 11 to 15;

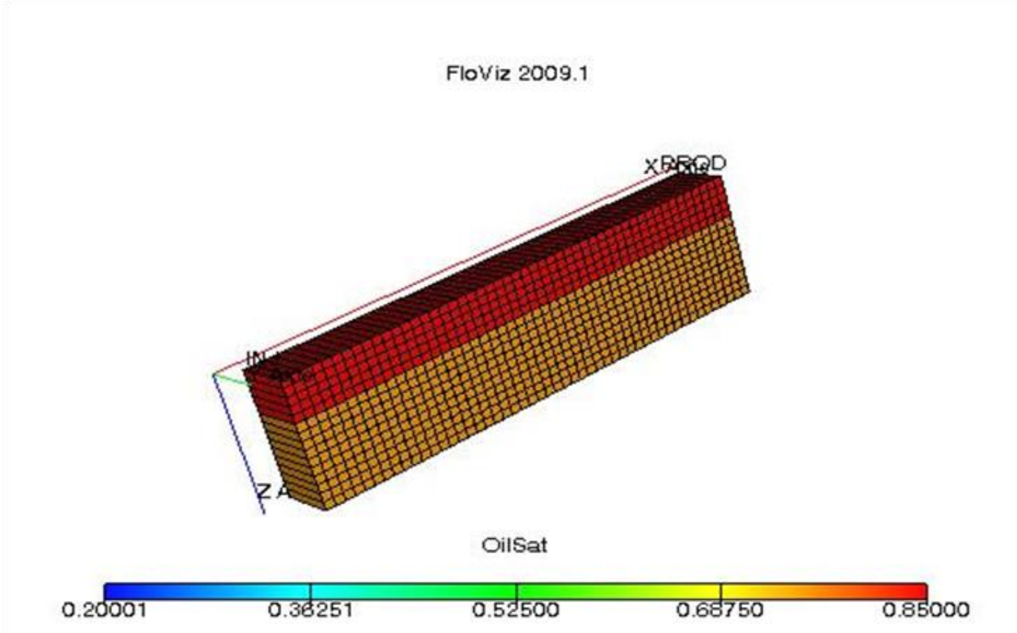

Figure 2.2 Synthetic model with high perm for 3D dimensions.

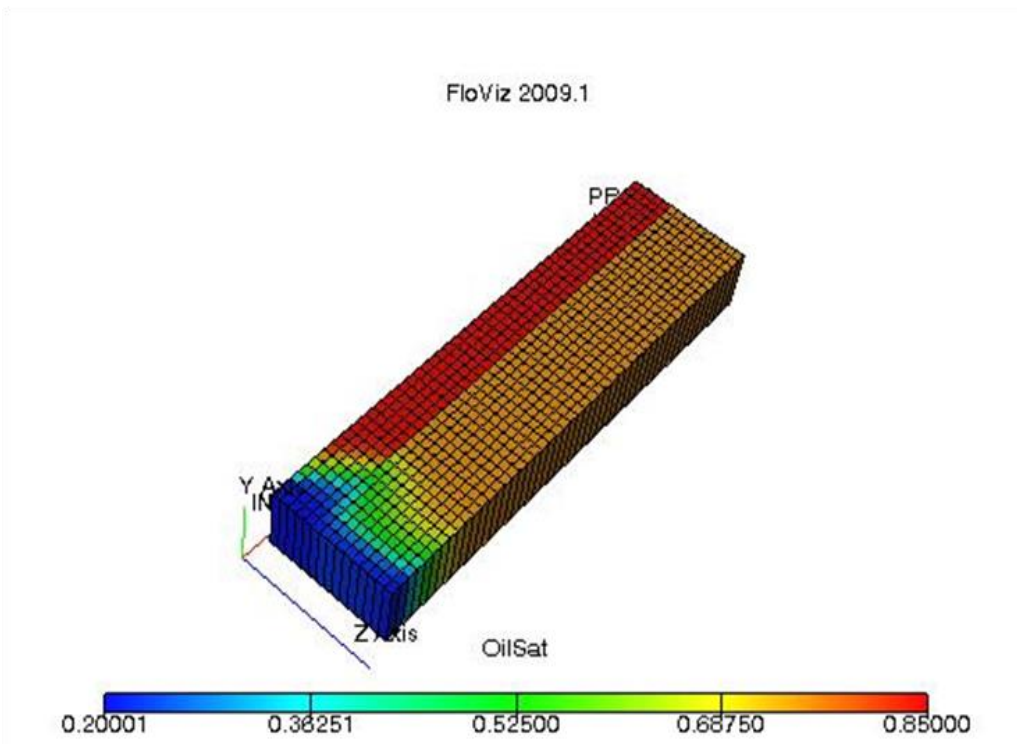

Figure2.3: Synthetic model, with injected water for one year.

2.2.1. 3 The properties section (PROPS)

The PROPS section contains both PVT data and SCAL data**.** In compositional run, the PVT data contains the equation of state description and its parameters and coefficients.

2.2.1.3.1 PVT Section

Oil and gas phases in the compositional model are represented by a mixture of multi components. What components are present is all we know, so ECLIPSE software first compute how many phases are present at a given temperature and pressure. If there are two phases, ECLIPSE calculates the composition of each phase.

2.2.1.3.2 SCAL Section

2.2.1.3.2.1Capillary Pressure

The capillary pressure data for (the depleted Oil field-Iraq) reservoir in Nasiriyah-Iraq field, the capillary pressure is estimated from log analysis as a function of height above FWL as shown in equation (2.1).

$$P_C = 0.433H[\rho_w - \rho_o] \quad (2.1)$$

Where:

Pc: Capillary pressure psi

H: Height above free water level ft.

ρ_w: Water density equal to 63lb/ft^3

ρ_o: Oil density equal to43 lb/ft^3.

2.2.1.3.2.2.Relative permeability

The relative permeability data for (the depleted Oil Field–Southern Iraq) reservoir in Nasiriyah field, the relative permeability is inferred by using mathematical models which calculate relative permeability from capillary pressure data.

2.2.1.3.2.3. REGIONS

Eclipse permits for dividing the reservoir into regions. (The depleted Oil Field–Southern Iraq) reservoir was divided into three regions with different equilibration parameters.

- ***First model***
  - region 1

    I from 1 to 50

    J from 1 to 1

    K from 1 to 15

2.2.1.4 SOLUTION

The SOLUTION section is used to define the initial conditions of the simulation. In oil reservoir the gas-oil contact should be at the same depth as the water-oil contact .Water-oil contact for (the depleted Oil Field–Sou. Iraq) reservoir is 8000 ft for model. The reference depth 3500 ft at which the initial reservoir pressure is 10000 psi.

2.2.1.5. SCHEDULE

The only way to remove or add fluids from / to the reservoir is by wells, so any simulation model will include at least one well.

2.3 History Matching

Generally, history matching is an inverse problem that involves adjusting model parameters (eq. permeability and other flow properties) until the simulation results from the reservoir model “fit” the observed (or dynamic) data, such as pressure, seismic and production data. Choosing the appropriate parameterization is helpful to obtain reliable production forecasting for reservoir development planning and optimization.

Unfortunately, historical production is not available for (the depleted Oil Field–South-Iraq) reservoir, which in turn shrinks the action of matching process. So history matching was built depending on well tests.

The history matching of the wells performance for the reservoir under study was obtained by running the numerical model after changing the permeability distribution at every run (multiply permeability by certain factor for the entire reservoir under study) until a good matching between measured and calculated data was reached.

2.4 Development of the reservoir simulation methodology

The reservoir simulation models describe the following system:

• 2 wells (1 Injection and 1 Producer)

• The simulation model (Figure 2.1) with dimensions of X= 3500 ft, Y= 1800ft and Z= 150 ft is divided into three layers with a permeabilities of 100 mD, 1000 mD, and 100 mD respectively, with Kv/Kh = 0.1, and with porosities of 0.2, 0.22, and 0.2. The initial reservoir pressure was 10000 psi and the production bottom hole pressure (BHP) was 2000 psi.

• The oil density is 49 lb/ft^{3}and the water density is 63 lb/ft^3. It is assumed that the injected water and the formation water are similar in composition.

In this simulation content from15 layers of grid cells, distributed over 3 geological layers:

- geological layer 1 corresponds to grid layers 1 - 5
- geological layer 2 corresponds to grid layers 6 - 10
- geological layer 3 corresponds to grid layers 11 – 15, as shown in figures below with different permeability in layers

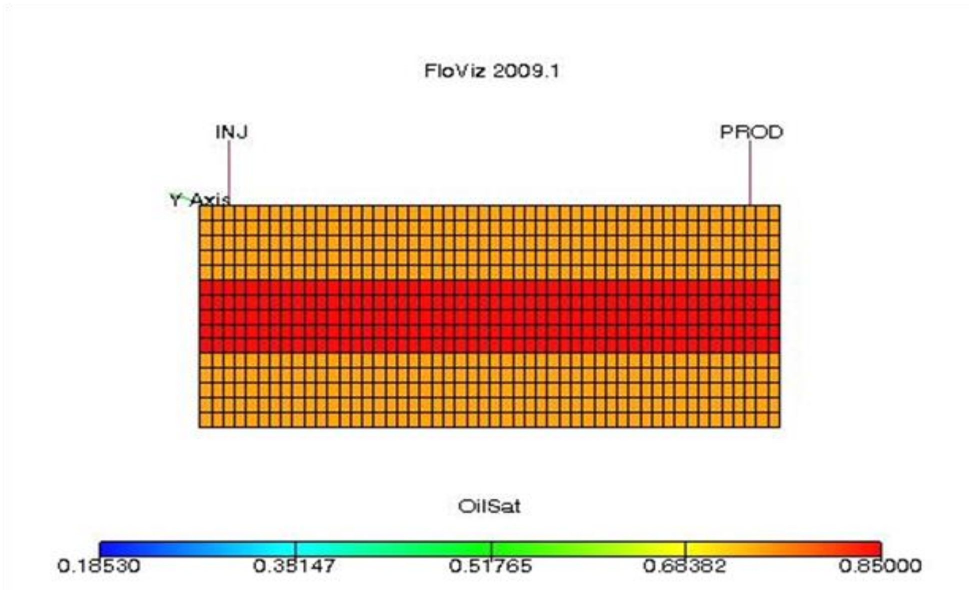

Figure 2.4: Synthetic model, with high perm in middle layer.

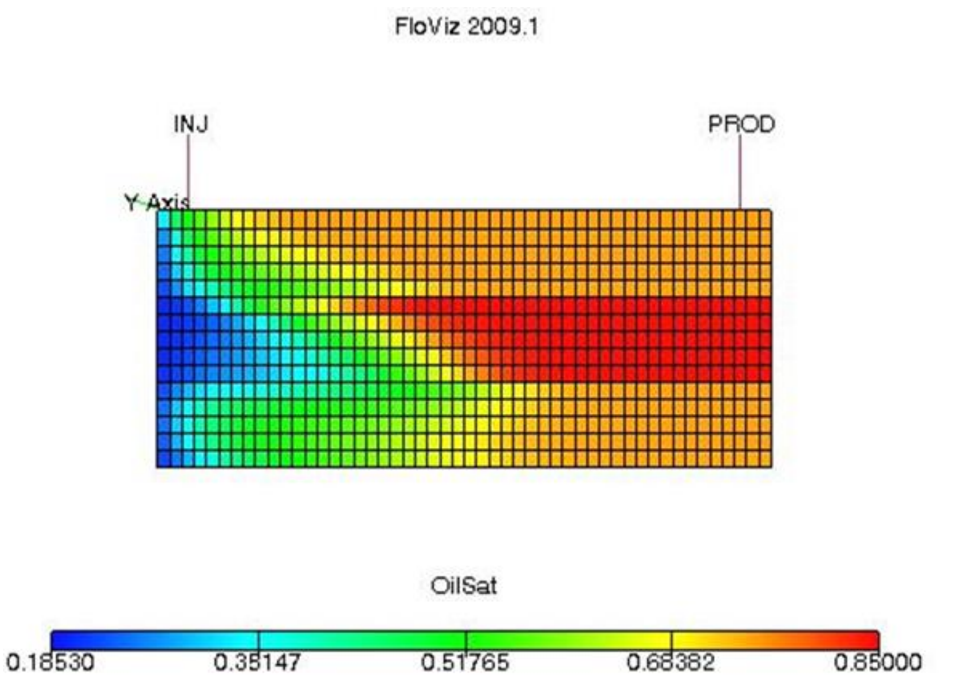

Figure 2.5: Synthetic model, with injected water in middle layer.

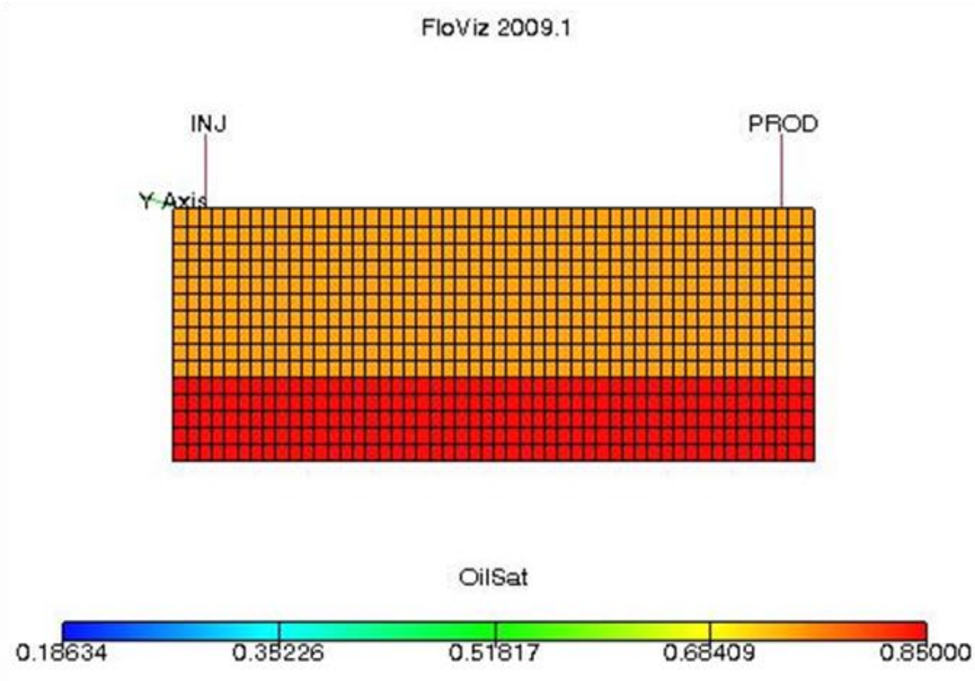

Figure 2.6: Synthetic model, with high perm in bottom layer.

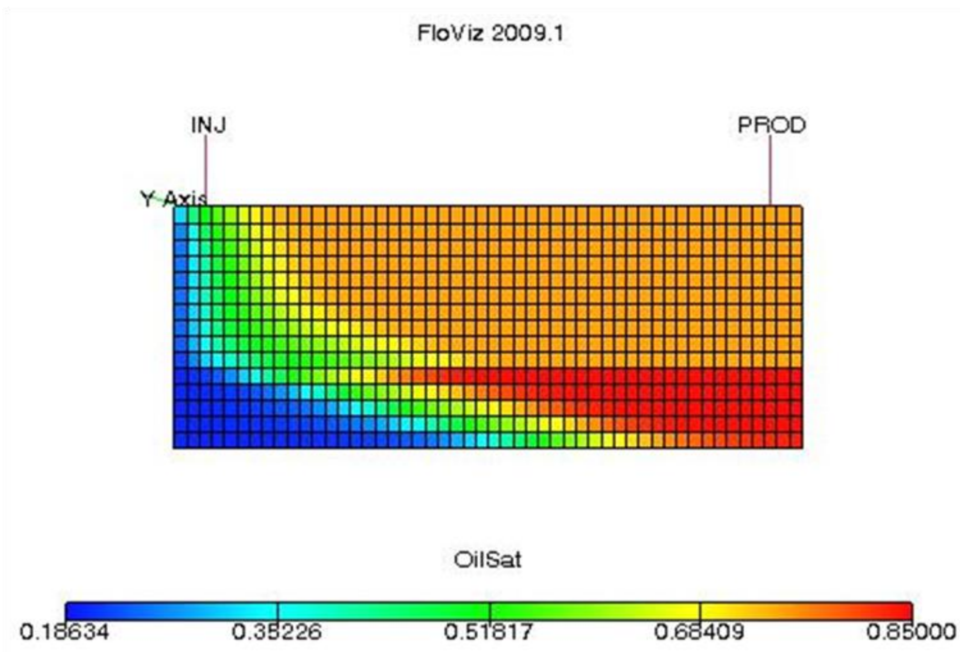

Figure 2.7: Synthetic model, with injected water in bottom layer.

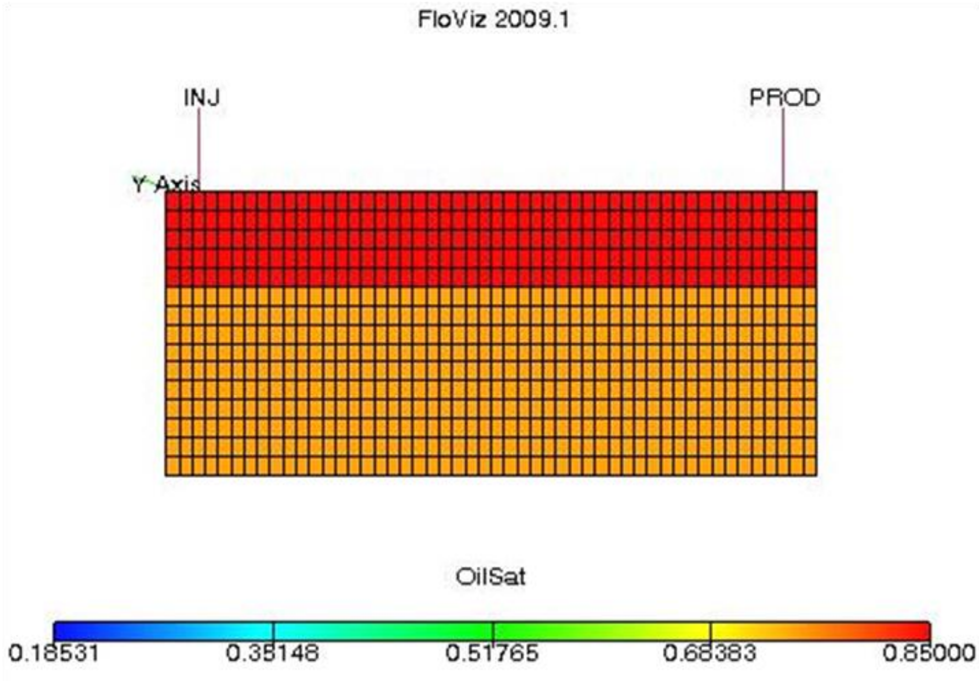

Figure 2.8: Synthetic model, with high perm in toplayer.

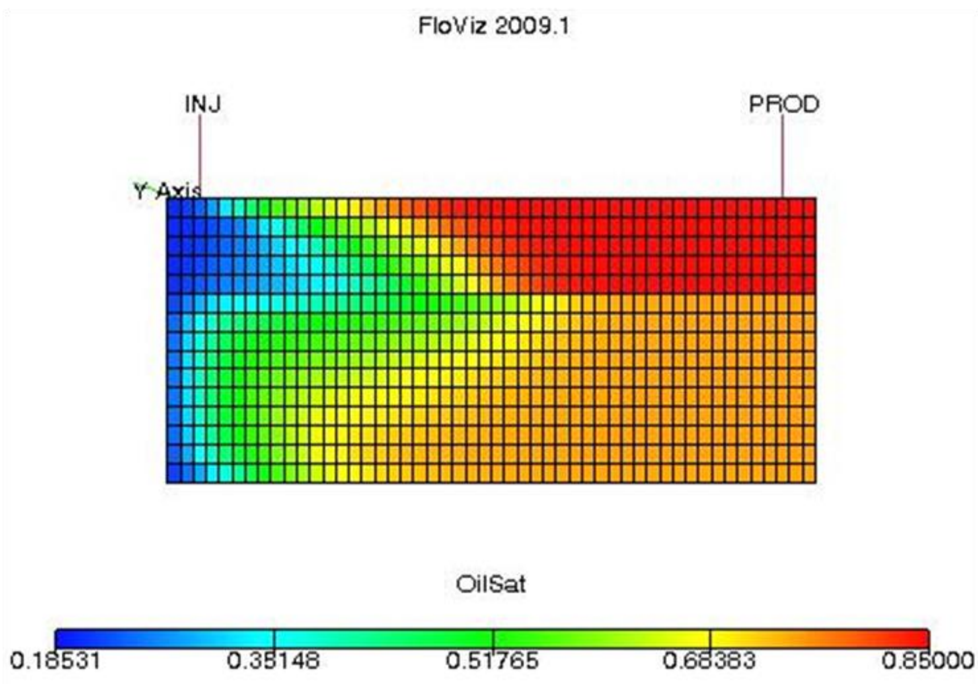

Figure 2.9: Synthetic model, with water injected in top layer.

Chapter 3. Results and Discussions

The ultimate goal of reservoir studies is to choose the optimum scheme of development and production for oil reservoir. Based on the best estimated reservoir characterization considered at the last stage, prediction studies are conducted to forecast the reservoir production performances under various production strategies that may include the number and locations of grid wells, operating conditions, application of EOR methods, and so forth. Keeping in mind that reservoir characterization must be improved by repeating the history matching (for reservoirs having some production history), and predictions need to be conducted again. In this chapter, the results of the current study will be presented and discussed. The results which concerning Uruk-1reservoir/ Thi-Qar field are obtained by using Schlumberger Eclipse Simulation 2009. Comparison has been made between these results and the available measured field data; well pressure and water cut to get a history match .Basically, the original Thi-Qar simulation model is generated from a stochastic integrated 3D Geological model built in Eclipse 100 . For this project thesis, we used simulation grid from Base Case Oil Model. The key numbers for the simulation grid are given in Table 3.1 below.

Table 3.1: Key number for simulation Grids for oil model

N_Y	N_X	N_Z
1	50	15

3.1. Prediction Results

The three-dimensional three-phase Schlumberger Eclipse Simulation 2009 has been adopted to predict the initial performance of Uruk-1 reservoirs, in respect of production, pressure and below-mentioned well constraints.

3.1.1. Prediction with simulation

Five cases have been proposed in predictions. Those cases approved under boundary conditions. Production performance was simulated among long period that extends to from 2019 to 2028 years. Depending on the permeability, porosity, Polymer Flooding and the rates have been suggested for production per well.

The predictions assume that the reservoir will put on production at the beginning of 2019. Constraints that used in this prediction are; Bubble point pressure is 10,000 psia, and the producer to a liquid production rate of 10,000 STB/D, with a minimum bottom hole pressure limit (BHP) of 2,000 psia. These five cases for prediction are summarized as follows: Reservoir simulation calculations are performed using Eclipse 100 to compare the EOR process performance to a base-case performance of conventional water flooding, and to determine the sensitivity of the EOR process to design changes and reservoir uncertainties.

The initial activity is to develop a method by using a synthetic reservoir simulation model to study the impact water flooding for comparison of the technical feasibility of EOR. For illustration, a synthetic reservoir simulation model is developed to study the impact of change permeability in layerflooding for the oil recovery.

A Cartesian model Appendix (A1) has been used in this study and run to water flooding. The reservoir rock consists of three layers with a different permeability layer with 15 layers of grid cells, distributed over 3 geological layers

geological layer 1 corresponds to grid layers 1 - 5

geological layer 2 corresponds to grid layers 6 - 10

geological layer 3 corresponds to grid layers 11 - 15

The reservoir simulation models describe the following system:

• 2 wells (1 Injection and 1 Producer)

• The simulation model with dimensions of X= 3500 ft, Y= 1800 ft and Z= 150 ft is divided into three layers with a permeability's of 100 mD, 1000 mD, and 100 mD respectively, with Kv/Kh = 0.1, and with porosities of 0.2, 0.22, and 0.2.Table (3.2) and Table (3.3), Figs.(3.1) and (3.2) show the result of this model.

Table :3.2 Relative permeability model, oil water phase (1100mD).

SW	PC	krw	krow
0.15	4.0	0.0	0.9
0.45	0.8	0.2	0.3
0.68	0.2	0.4	0.1
0.8	0.1	0.55	0.0
1	0.0	1.0	0.0

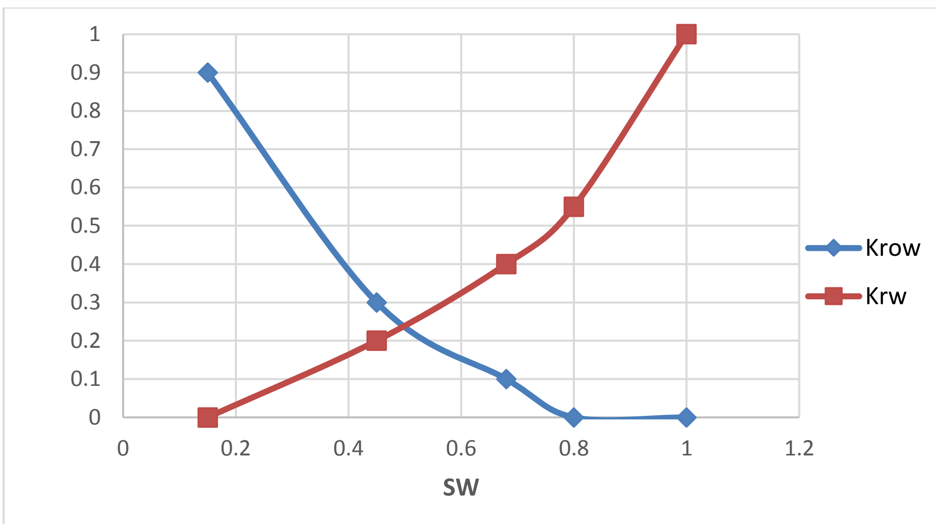

Figure 3.1 Oil and water relative permeability vs. water saturation from (1100 mD) relative permeability model.

Table: 3.3 Relative permeability model, oil water phase (250mD).

SW	PC	krw	krow
0.25	9.0	0.0	0.9
0.50	1.8	0.2	0.3
0.70	0.45	0.4	0.1
0.8	0.22	0.55	0.0
1	0.0	1.0	0.0

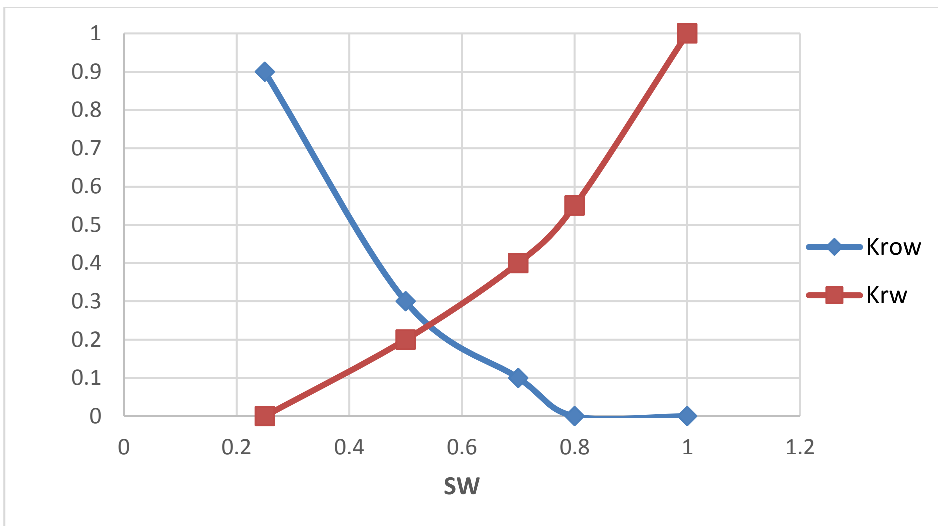

Figure 3.2 Oil and water relative permeability vs. water saturation from (250 mD) relative permeability model.

It is assumed that the injected water and the formation water are similar in composition. It is useful to perform fractional flow analysis of any reservoir system to identify whether it is suitable for any particular recovery process, before a decision is made to undertake detailed reservoir simulation studies.

3.1.1.1 Case-1 Change in the Permeability

The simulation was to take three cells out of the high permeability zone in model (**TUT2A**) and split it into 50 x 1 x 15 in I, J and K direction representing vertical heterogeneity containing three layers with different permeability and porosity was used to capture Uruk-1 reservoir simulation conditions. This represents a vertical cross section of a reservoir and effect of permeability on reduced total oil production was simulated. The original rock relative permeability data was used in these fine scale cells, and once the Eclipse simulation of a water flood in this fine scale model has been completed, the Eclipse program was used to generate relative permeability curves assuming high & low permeability values. The resulted relative permeability curves replaced the original rock curves in the middle model .By comparing the three simulations by change the relative permeability for three layers to increase the oil recovery, it was obvious that the high relative permeability curves produced a better reservoir description for High perm in top (**TUT2C**) layer than High middle and bottom (**TUT2B**) perm in layers. The simulation model showed a better recovery & sweep efficiency, hence a higher value of total field oil and field oil production compared with the rock model in the Figs. 3.3 and 3.4. From this figure observed that the relative permeability effect on the total oil field production especially in the top and middle layers compare with the bottom layer. As expected, the high permeability layer watered out quickly causing injected water to preferentially flow through it and leading to high water production, from Figures below use oil saturation in the reservoir at breakthrough to illustrate this. In both cases, the high permeability layer has very little oil left while the lower permeability layer still contains a considerable amount yet to be recovered [44].

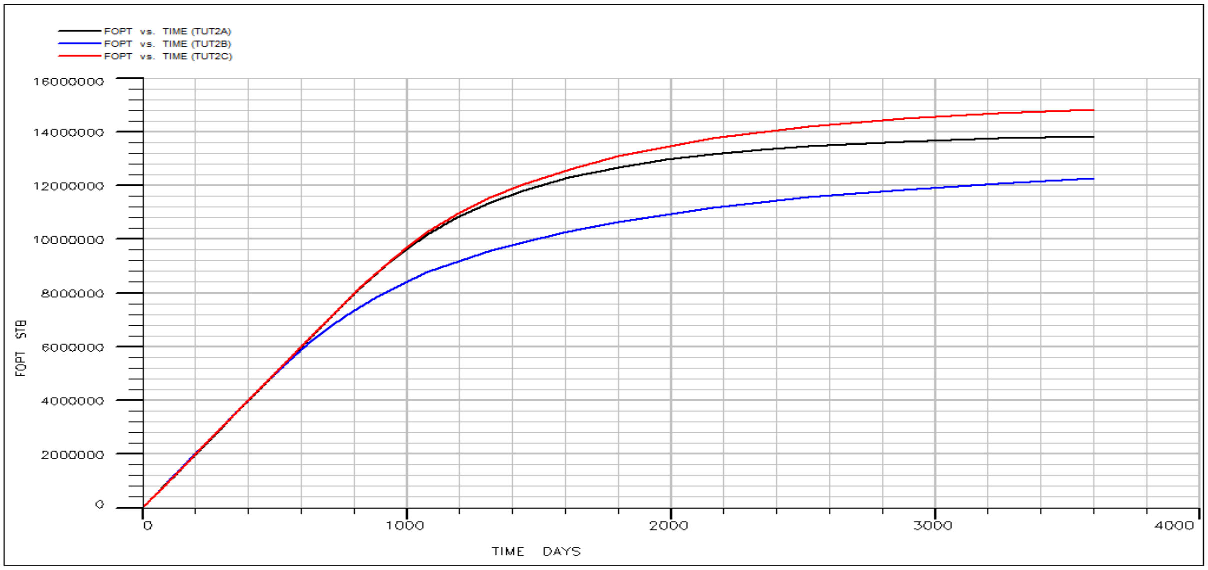

Figure3.3 FOPT for ROCK models.

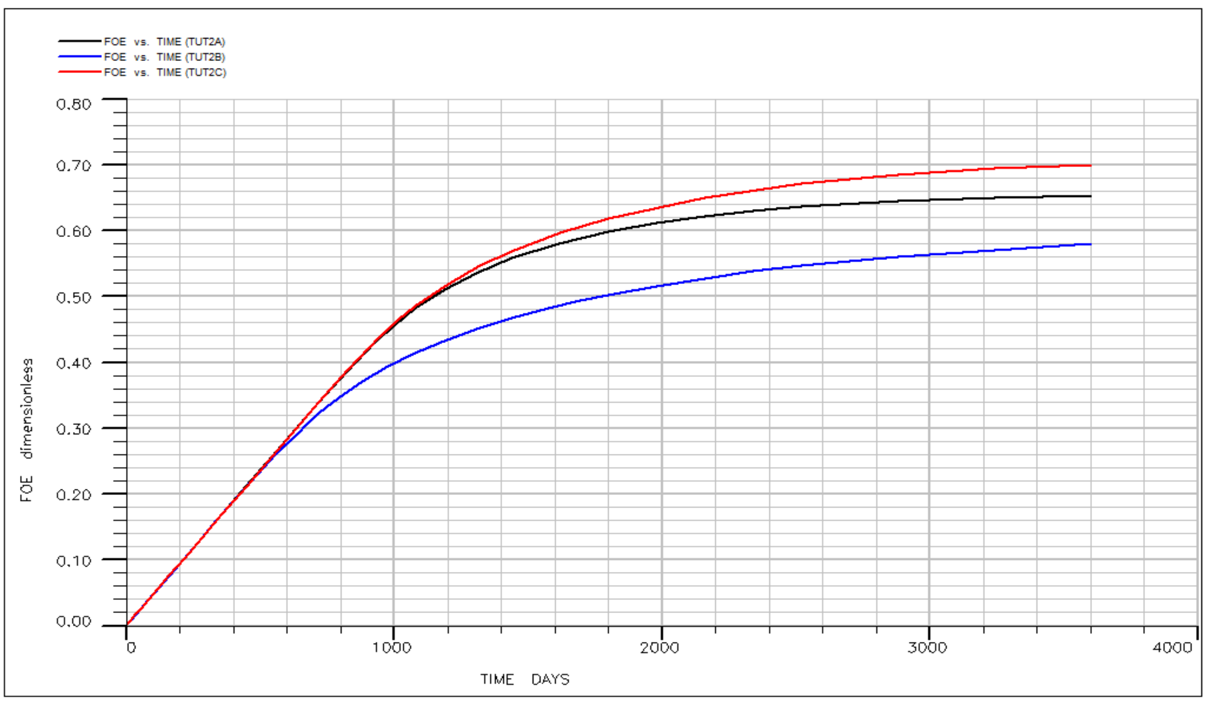

Figure 3.4. FOE for ROCK models**.**

Figure 3.5 shown that the total field Water cut in production for top permeability layer (**TUT2C**) was low with compare the middle and bottom layer , this lead the change in the permeability decrease the total field water cut in production.

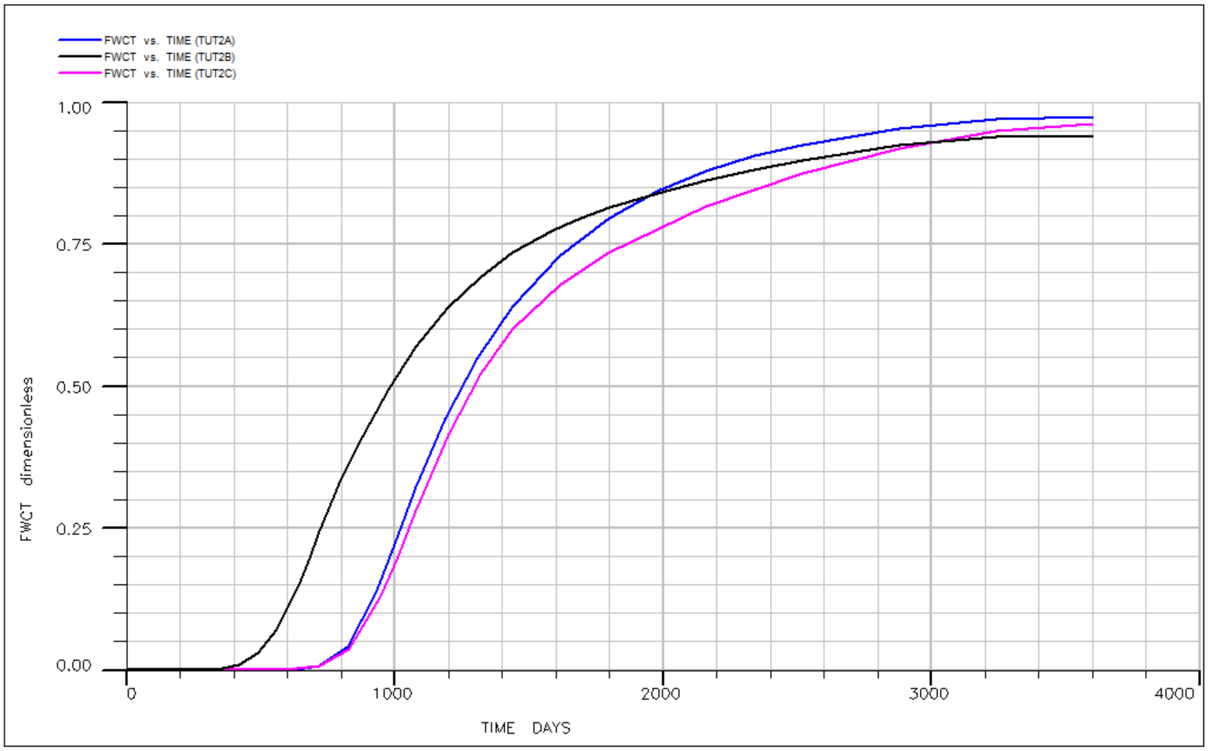

Figure 3.5. FWCT for ROCK models**.**

The model is now changed so that it represents two large blocks with low & high permeabilitie. When the oil recovery efficiency was plotted for the three layers top, middle & bottom perm, there were differences between them. The best ROE was obtained by the top & the middle layer of the model. Layers leaving the capillary trapped oil in the high permeability layers. At the model the varying permeability layers are perpendicular to the flow direction, in the perm bottom layer lead to makes it difficult to the water to sweep most of the oil because of the discontinuity of permeability across the flow. Whereas in the high perm in the top model the layers are positioned along with the flow direction which makes it easier to sweep the high perm. Layers first and by continuing the injection eventually most of the capillary trapped oil will be recovered too.

3.1.1.2 Case-2 Increased Cross-Sectional Area Away From Wells

In this model, using model (**TUT2C**) with high permeability in the top layer with the same injected 11,000 STB water/day and produced 10,000 STB/day are produced, and the time steps are increased from 360 to 3600 days each. The Change the thickness of the cells so that close to the wells they are narrow, but in between the wells they are broad. To do this, replace the old definition by a new definition of y direction. Figs3.6 and 3.7 display the field oil recovery and total oil recovery for this (**TUT2E)** model and compare with the (**TUT2C)** model. These changes will maintain the overall volume of the system, but ensure that flow speeds in mid-field will be only 4% of the flow speeds in the near wellbore region. From figures shown the field oil recovery decrease in this model because interfacial tension between oil and water was high resulting to lower oil production, from this the model with increase cross-sectional area is undesirable .

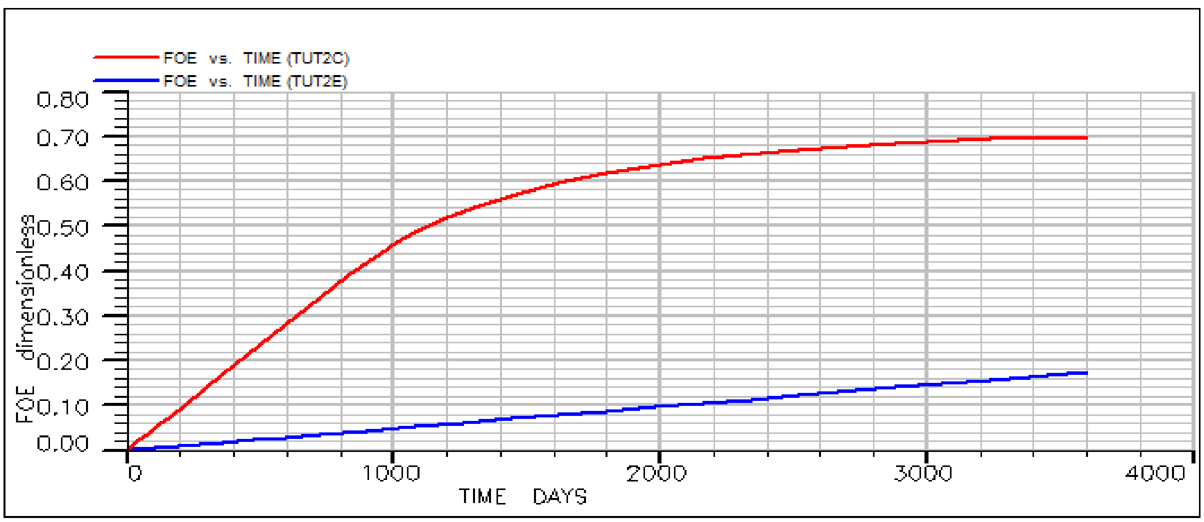

Figure 3.6 FOE for Increased Cross-Sectional Area Models.

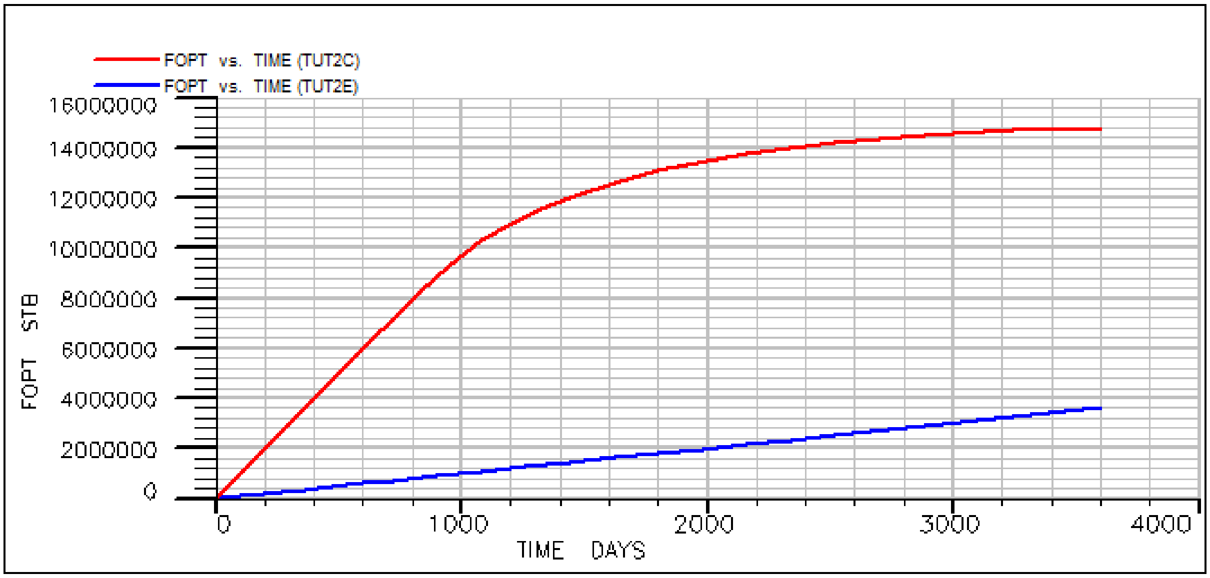

Figure 3.7 FOPT for Increased cross-sectional area models.

In this simulation was changed after one dimension to the additions of layers in order to be a three-dimensional model and compared with the original model accompanied by high permeability in the upper layer to increase the productivity of oil and compared with the layers, which is built from the forms that the previous oil production better than this model in terms of the comparison so we keep on the same model.

3.1.1.3 Case-3 Increased kv/kh

Permeability rhythmicity plays important influence in oil recovery. Different correlations can be made under different and same Kv/Kh. In most reservoirs we can have either positive rhythm, negative rhythm or combinative rhythm. When Kv/Kh=0, the results of positive, negative and combinative rhythm are very similar [57]. In this case, the same input of (**TUT2C**) is set, except, raising a kv/kh ratio of 1 instead of 0.1 (i.e. make PERMZ 1000, 200 and 200 mD in the three layers) for a period of (10) years commence at the beginning of 2019 and extend to the end of 2028. This case achieved by setting a production rate of 11000 STB/D as shown in figure 3.8 and 3.9 .from this figure observed that the FOE and FOET is increased compare with the other model due to allows the entry of water and the exit of large quantities of oil in the reservoir, which leads to increased production in addition to the Kv/Kh between the layers become ten times the previous model so the proportion of production is high as in the forms.

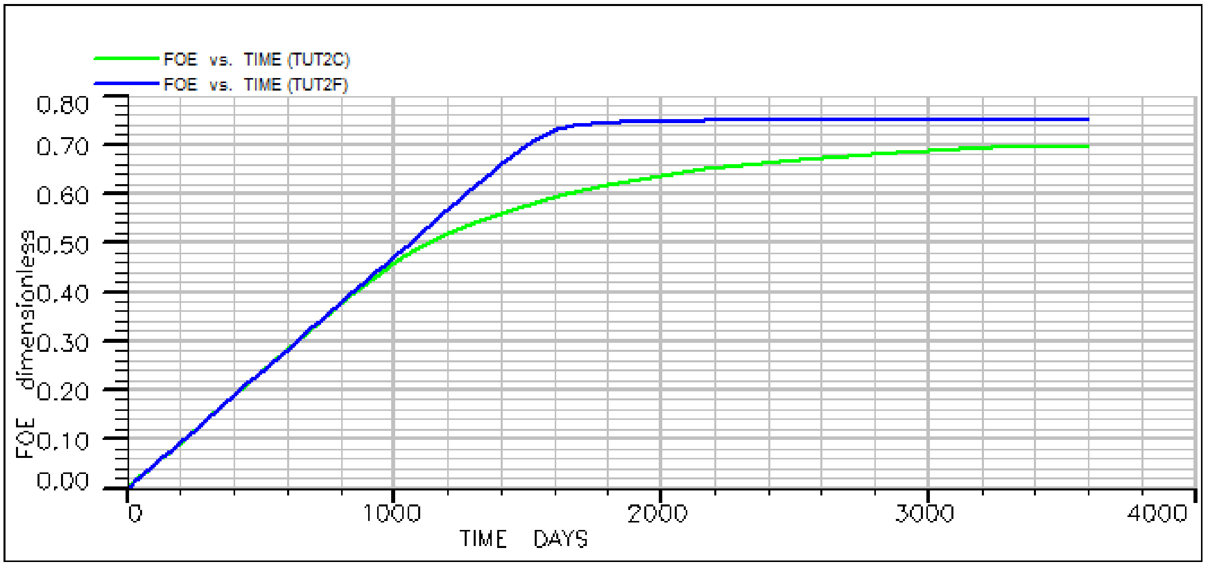

Figure 3.8 FOE with Increased kv/kh

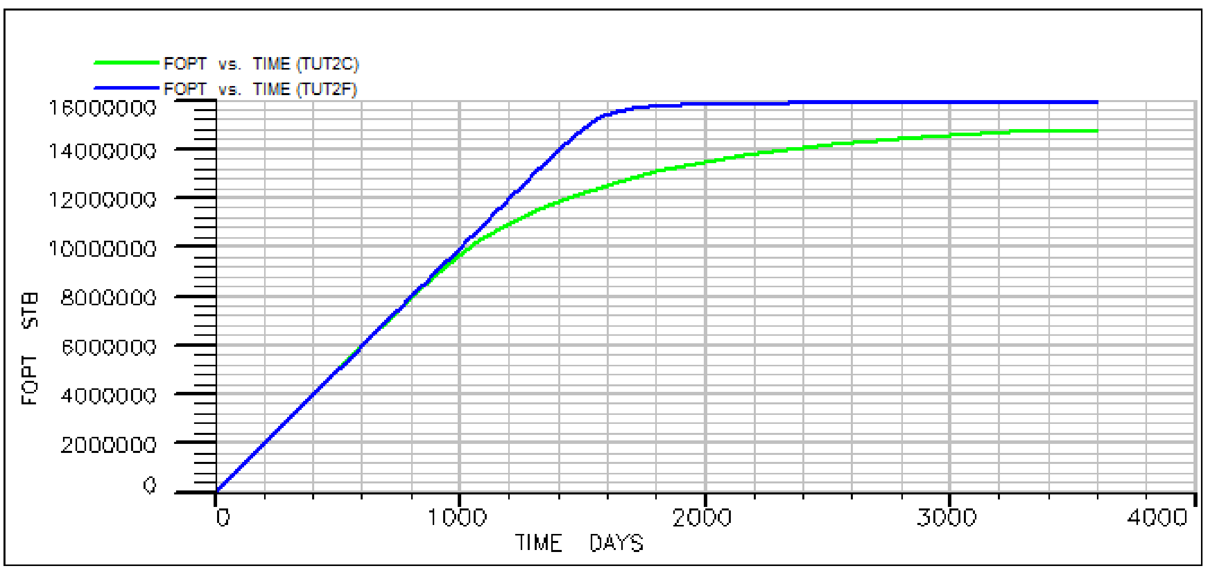

Figure 3.9 FOET with Increased kv/kh

Figure 3.10 shows the total water cut (solid) and comparisonn with the other model with low Kv/Kh for the same runs. Increasing permeability in formation gave earlier water breakthrough. Through the drawing we note that increased Kv/Kh leads to the passage of large quantities of water, which leads to increase oil production by allowing the exit of large quantities of water.

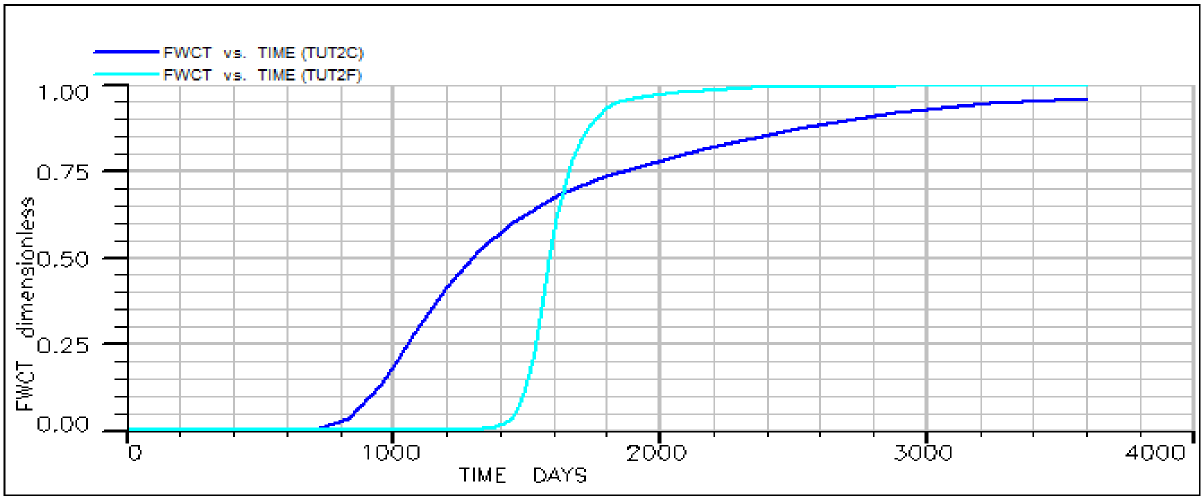

Figure 3.10. FWCT with Increased kv/kh

3.1.1.4 Case-4 Barriers preventing vertical flow.

The main pay comprises three dominated sandstone units, separated by two shale units. The shale units act as good barriers impeding vertical migration of the reservoir fluids except in certain areas where they disappear. The main pay is an important producing horizon; even though, it is considered being in a mature stage of depletion due to highly water advancement over some parts of it. In spite of that a large cumulative production from the main pay reservoir still continue, and the oil recovery during the primary production stage affected by the un balance water drive from the both sides of the field[46].The results indicated that there exist an optimal distance in the reservoir in regions of relatively equal permeability, but this distance is severely affected by flow barriers as shale and faults. The permeability variations, however, had effect than expected[47]**.**The Thi-Qar field reservoir contains both faults and stratigraphic barriers/layers which act as restriction to vertical and lateral flow stratigraphic barriers have been identified and their lateral extent and thickness variation assessed using cores and logs. The intervals which are believed to be continuous within the Thi-Qar Field, as shown in Figs 3.11,3.12 and 3.13 [48]. In this model changing all the grid cell vertical permeabilities, the transmissibilities between the three layers are to be set to zero. This will prevent any flow between grid layers 5 and 6, and between grid layers 10 and 11.

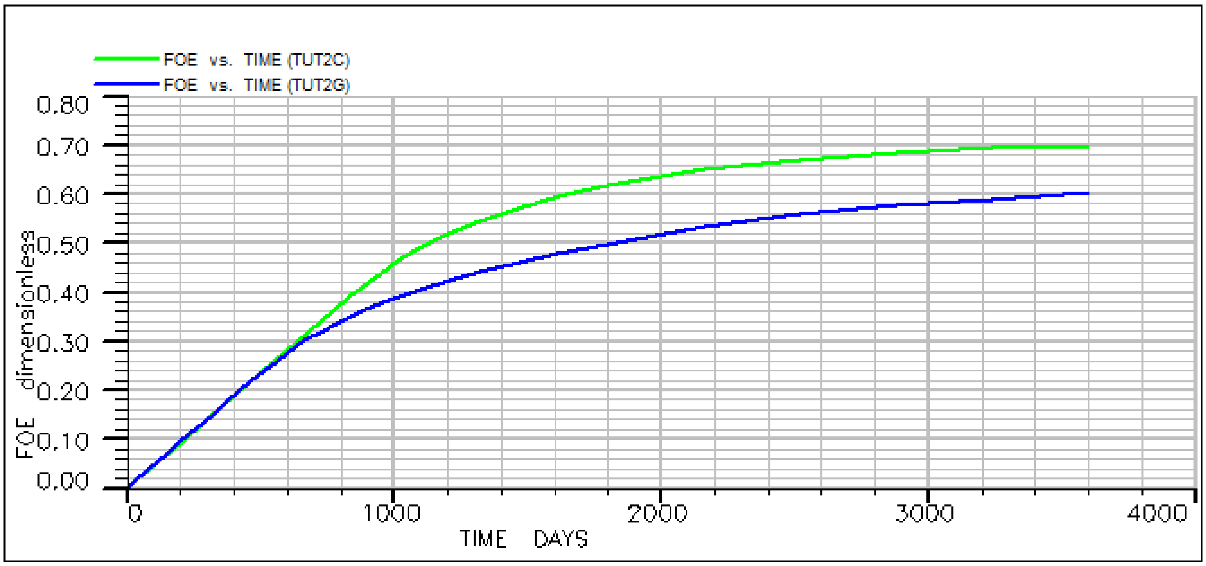

Figure 3.11 FOE with Barriers preventing vertical flow

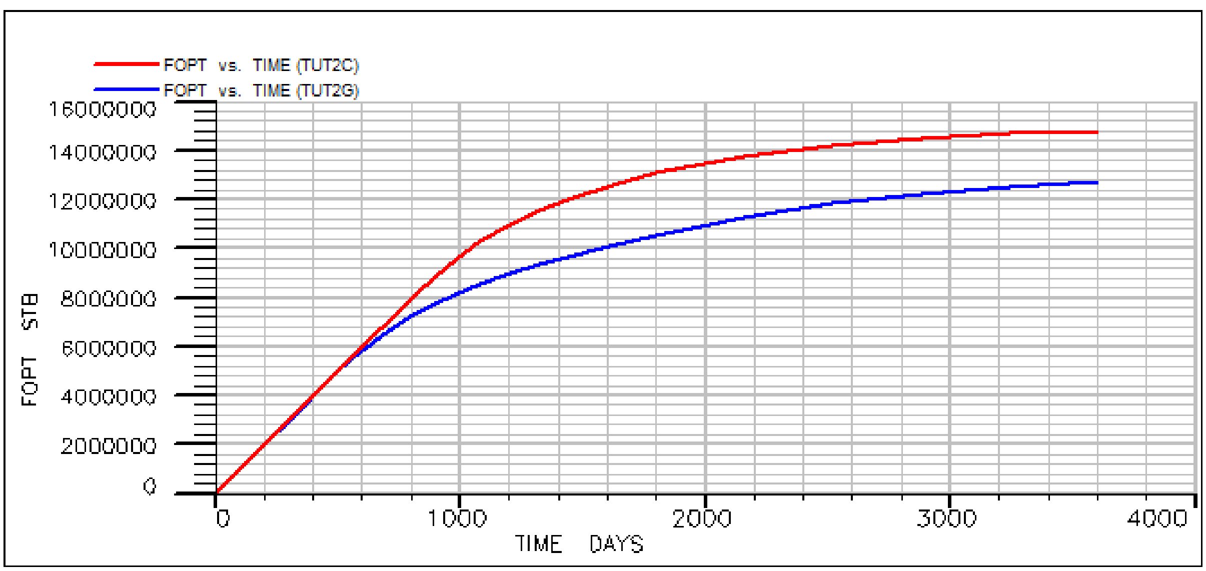

Figure 3.12 FOET with Barriers Preventing Vertical flow

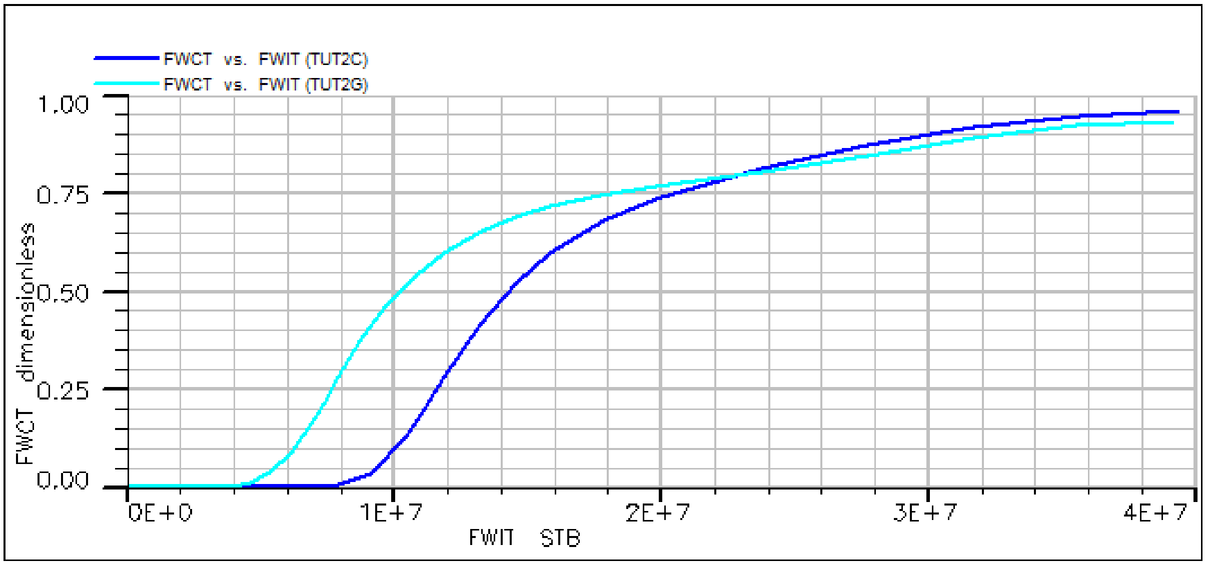

Figure 3.13 FWCT with Barriers preventing vertical flow

The results indicate that there exists a regional maximum distance beyond which the efficiency, in terms of early oil production, is reduced. This means that the water sweep significantly reduces outside the Barriers area between the grids, since the water moves from the injecting to the producing reservoir.

3.1.1.5 Case-5 Polymer Flooding

Tracers can be used as a valuable tool to investigate the efficiency of an EOR method during the pilot phase. Tracer injected prior and after polymer flooding for instance can reflect the level of improvement in the sweep efficiency in terms of increased calculated swept pore volume, as well as the reduction of the heterogeneity index. A successful polymer flood should reflect a broader tracer production curve as the flow is more uniform. As the heterogeneity index form tracer data reflects the dynamics of the flow, less heterogeneous tracer flow in the presence of polymer is an indication of a more stable and uniform displacement front. In this model, the addition of polymer is studied and the effect of increasing the oil production by adding polymer to the model of high permeability as in Figs 3.14, 3.15 and 3.16. Through these forms addition of the biomaterial has a slight effect on the increase in oil production because the viscosity of oil is neutral so the polymer does’nt influence on total oil production in the field..

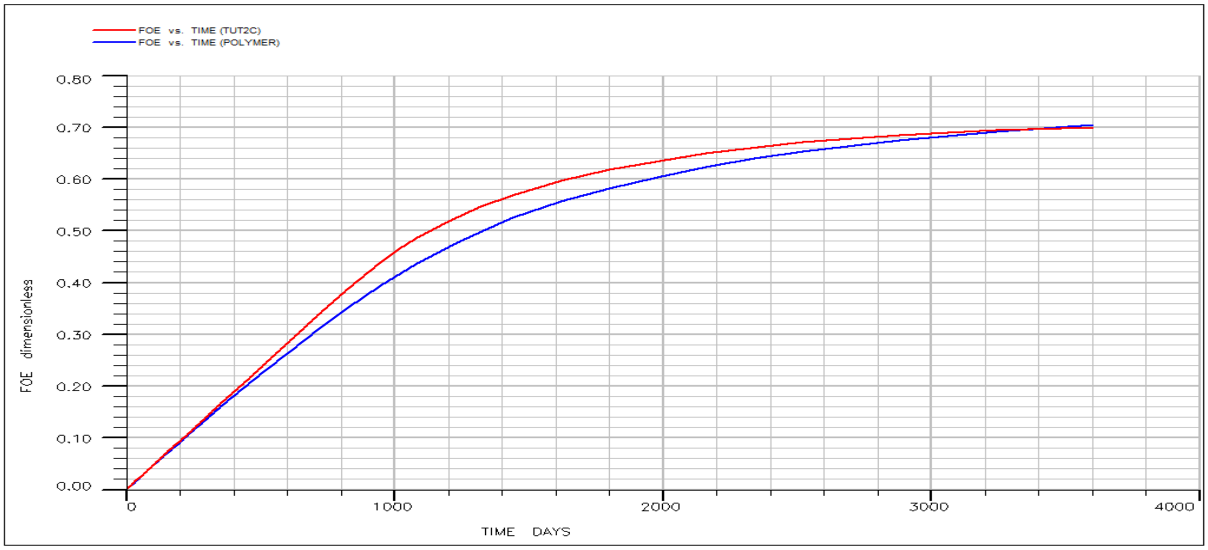

Figure 3.14 FOE with Polymer Flooding

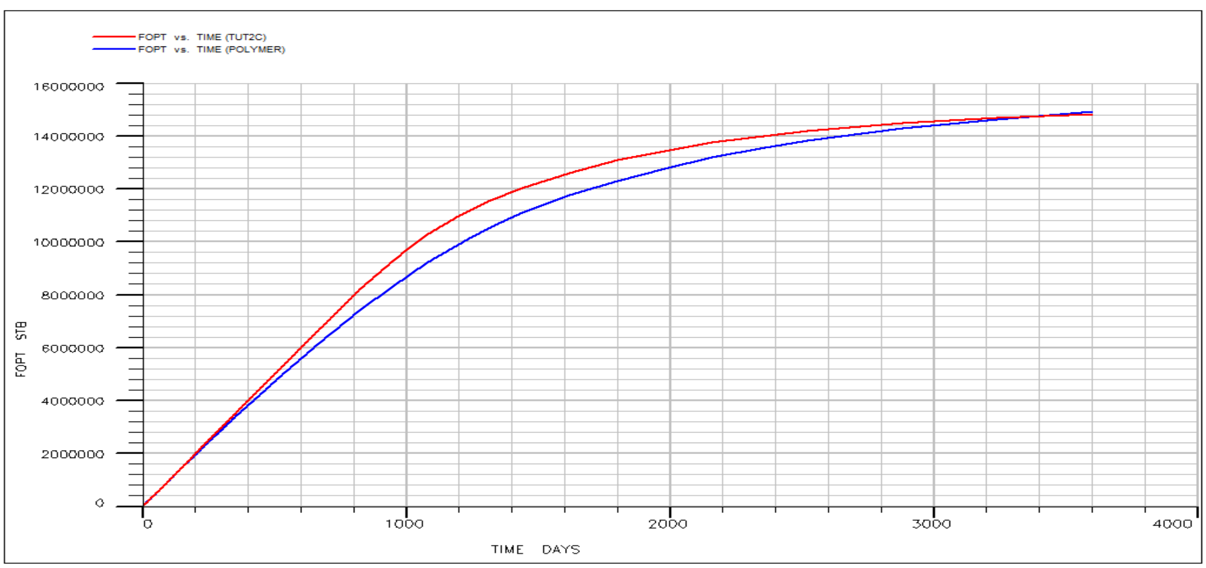

Figure 3.15 FOET with Polymer Flooding

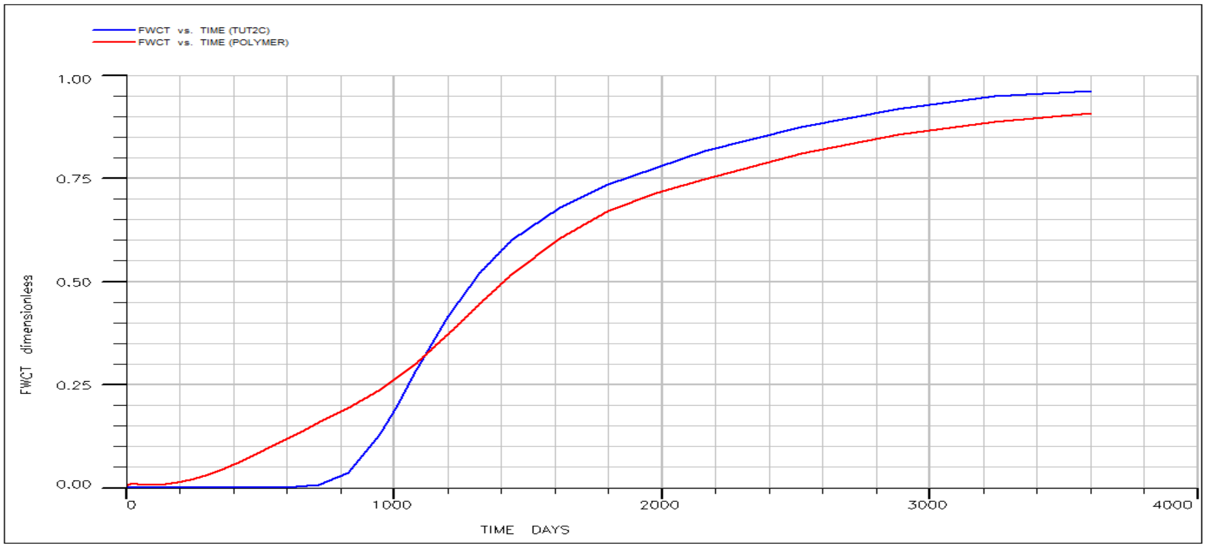

Figure 3.16 FWCT with Polymer Flooding

The viscosity of oil five times to whiten the effect of the polymer as it is in the forms and through this son that the polymer has a high impact in the case of a reservoir containing high viscosity oil as shown in figs 3.17, 3.18 and 3.19.

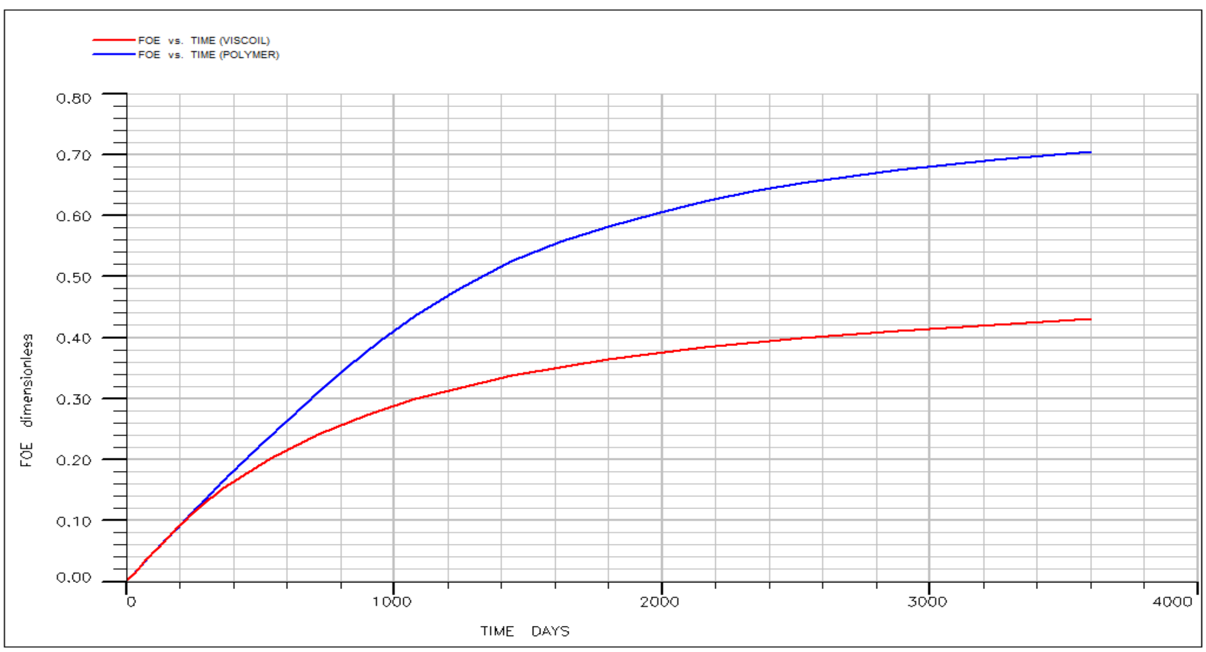

Figure 3.17 FOE with Polymer Flooding for heavy oil

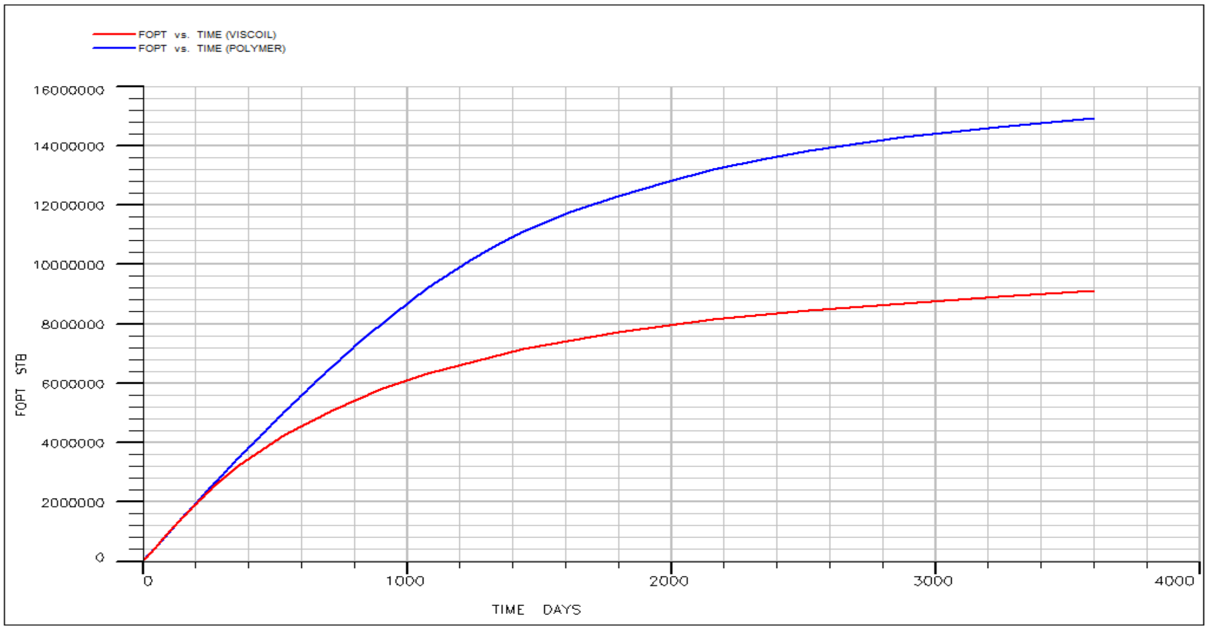

Figure 3.18 FOET with Polymer Flooding for heavy oil.

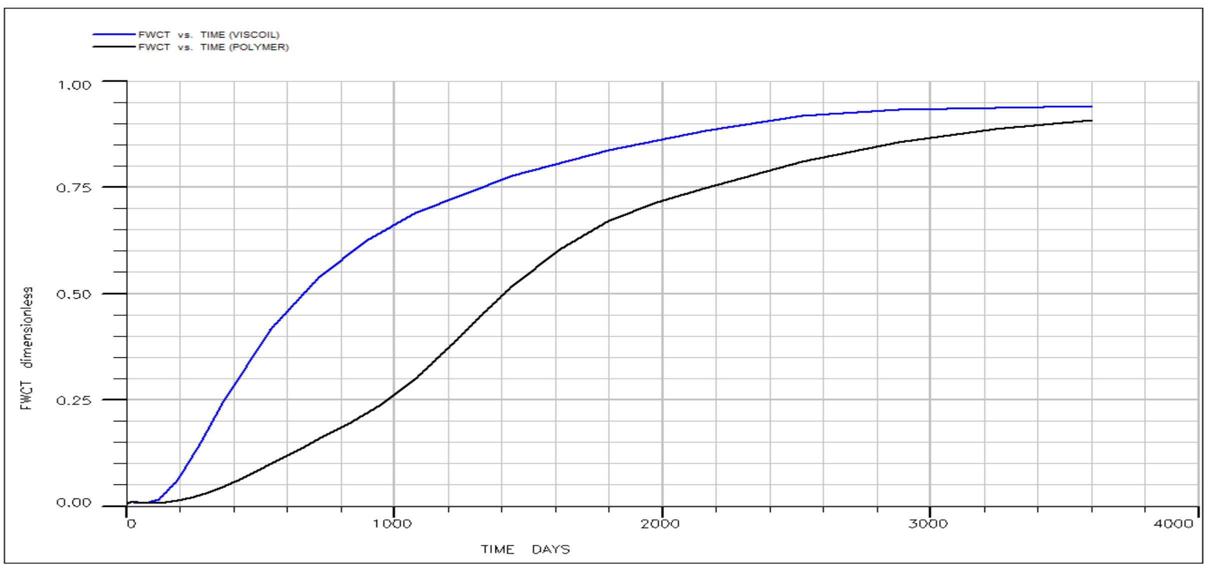

Figure 3.19 FWCT with Polymer Flooding for heavy oil.

A successful polymer flood should be improve the sweep efficiency by reducing the mobility ratio, this should result is a more stable displacement front and therefore lower flow in the highly permeable streamlines. This will result in a later tracer breakthrough from those streamlines compared with the case of no polymer injection.

Therefore the tracer curve will be shifted to the left and the broadening of the distribution. Figure 3.18 shows that total oil production for 10 years case is higher than the total oil production for 3 years case, but it should be economically viable. The anticipated incremental oil recovery for 10 years injection compared to 3 years injection is not encouraging and it is rather wasteful to inject surfactant for 10 years. Thus, polymer injection for 3 years seems better than 10 years injection. However, 3 years continuous injection still requires considerable volume of polymer that is relatively expensive. Therefore, the next step involves the polymer slug injection, and after comparing with continuous polymer injection, the better one in terms of economics will be selected [49].

Conclusions

1- This approach will be very useful to the industry in helping to make the appropriate choice of EOR vs. polymer flooding, taking full account of reservoir engineering.

2-The technique proposed, developed and applied in this thesis involves running a wide range of reservoir simulation scenarios based on the given reservoir description (in this case using the Eclipse 100 software) to test possible recovery outcomes; all these outcomes then provide input data that is used in a probabilistic economic evaluation tool. The technique shows strong positive correlations between the outcomes of the reservoir simulation calculations such as recovery factors and water cuts.

3-Fluctuation of flow rates, at the production or injection wells had a minor effect on the tracer curve and its interpretation. However major events at those could cause significant in the pressure distribution and therefore in the tracer flow direction. Therefore it is important to report the flow rates along with the tracer data.

4-High interfacial tension between oil and water leads to low recovery of residual oil. Reducing interfacial is very important as a higher recovery would be achieved.

5- High capillary pressure leads to unfavorable recovery factor. Low capillary pressure is desired to recover most of the residual oil trapped after water flooding.

Recommendations

1-Simulation with simplified fracture growth behavior in eclipse to reproduce Reveal.

2- This method has been developed to analyses polymer flooding specifically.

However, as noted in chapter 2, various other non-thermal EOR techniques will have similar inputs, and as this method will be suitable for analysis there also will be some minor modifications. Therefore, when an asset team is reviewing future recovery methods, they should first consider various technical issues which may affected the choice (e.g. does reservoir temperature make polymer flooding impossible), and perform fractional flow analysis, as a part of pre-screening process. Once this has been done, data should be gathered to use as input for this methodology – such as reservoir simulation models, laboratory data.

3-Future work should consider in more detail optimization of reservoir where polymer injection is carried out. Polymer injection necessarily involves a decrease in injectivity, and it must be remembered that as well as sweep efficiency gains from polymer flooding, reservoir pressure must also be maintained.

References

[1] U.S. Energy Information Administration based on Lloyd's List Intelligence (APEX tanker data)].

[2] Department of Infrastructure, Transport, Regional Development and Local Government –Australian Government, Report 117 - Transport Energy Futures: long-term oil supply trends and projection.
https://www.manicore.com/fichiers/Australian_Govt_Oil_supply_trends.pdf

[3]Oil Voice – January 2016 (p.33)
http://www.oilvoice.com/magazine/editions/oilvoice_46_January2016.pdf

[4] Hongjun, W. A. N. G., M. A. Feng, T. O. N. G. Xiaoguang, Liu Zuodong, Xinshun Zhang, W. U. Zhenzhen, L. I. Denghua, W. A. N. G. Bo, X. I. E. Yinfu, and Y. A. N. G. Liuyan. "Assessment of global unconventional oil and gas resources." Petroleum Exploration and Development 43, no. 6 (2016): 925-940.

[5] Oskui G. P., S.M.J., Al Matrouk, M., , Juma M. A., Al-Mahaimed, I. A., Improved oil recovery (IOR) techniques and their role in boosting the recovery factor. 2007.

[6] Lake, Larry W., Russell Johns, William R. Rossen, and Gary A. Pope. "Fundamentals of enhanced oil recovery." 2014.

[7] Olajire, Abass A. "Review of ASP EOR (alkaline surfactant polymer enhanced oil recovery) technology in the petroleum industry: Prospects and challenges." Energy 77 (2014): 963-982.

[8] Alvarado, Vladimir, and Eduardo Manrique. "Enhanced oil recovery: an update review." Energies 3, no. 9 (2010): 1529-1575.

[9] Green, D.W. and Willhite, G.P., 1998. Enhanced Oil Recovery. SPE textbook series, 6. SPE, Richardson, Texax, 545 pp.

[10] Donalson, E., G. V. Chilingarian, and T. F. Ten. "Enhanced oil recovery I, fundamental and analyses." Decimo septima edicion. Editorial Elsevier, Amsterdam, paises bajos (1985).

[11] Teletzke, Gary F., Robert C. Wattenbarger, and John R. Wilkinson. "Enhanced oil recovery pilot testing best practices." SPE Reservoir Evaluation & Engineering 13, no. 01 (2010): 143-154.

[12] Nazar, M. F., S. S. Shah, and M. A. Khosa. "Microemulsions in enhanced oil recovery: a review." Petroleum science and technology 29, no. 13 (2011): 1353-1365.

[13] Cheraghian, Goshtasp, and Luky Hendraningrat. "A review on applications of nanotechnology in the enhanced oil recovery part B: effects of nanoparticles on flooding." International Nano Letters 6, no. 1 (2016): 1-10.

[14] Ahmed, T., 2001. Reservoir engineering handbook. Gulf Professional Publishing, Houston, Texas.

[15] Anderson, G.A., 2006. Simulation of chemical flood enhanced oil recovery processes including the effects of reservoir wettability. Monograph Thesis, University of Texas at Austin.

[16] Mandal, Ajay. "Chemical flood enhanced oil recovery: a review." International Journal of Oil, Gas and Coal Technology9, no. 3 (2015): 241-264.

[17] Ahmed, Tarek. Reservoir engineering handbook. Gulf Professional Publishing, 2018.

[18] Conrad, Stephen H., John L. Wilson, William R. Mason, and William J. Peplinski. "Visualization of residual organic liquid trapped in aquifers." Water Resources Research 28, no. 2 (1992): 467-478.

[19] Chatzis, Ioannis, Norman R. Morrow, and Hau T. Lim. "Magnitude and detailed structure of residual oil saturation." Society of Petroleum Engineers Journal 23, no. 02 (1983): 311-326.

[20] Mohanty, K.K., Davis, H.T. and Scriven, L.E., 1987. Physics of oil entrapment in water-wet rock. SPE Reservoir Engineering: 113-128.

[21] Berg, Steffen, Holger Ott, Stephan A. Klapp, Alex Schwing, Rob Neiteler, Niels Brussee, Axel Makurat et al. "Real-time 3D imaging of Haines jumps in porous media flow." Proceedings of the National Academy of Sciences 110, no. 10 (2013): 3755-3759.

[22]Donaldson, Erle C., George V. Chilingarian, and Teh Fu Yen, eds. Enhanced oil recovery, II: Processes and operations. Elsevier, 1989.
[23] Department of Infrastructure, Transport, Regional Development and Local Government –Australian Government, Report 117 - Transport Energy Futures: long-term oil supply trends and projection.
https://www.manicore.com/fichiers/Australian_Govt_Oil_supply_trends.pdf
[24] Owen, Nick A., Oliver R. Inderwildi, and David A. King. "The status of conventional world oil reserves—Hype or cause for concern?." Energy policy 38, no. 8 (2010): 4743-4749.
[25] Thomas, S., Enhanced oil recovery. 200717Glossary, O.; Available from: http://www.glossary.oilfield.slb.com/Display.cfm?Term=cyclic%20steam%20injection.
[26] Peimao Zhang and T. Austad, Wettability and oil recovery from carbonates: Effects of temperature and potential determining ions. 2006.
[27] Journal of Oil, Gas and Petrochemical Sciences Application of In-situ combustion for heavy oil production in China: A Review Jia Yao1, Guihe Li2, Jinjin Wu1.
[28] Ghaffari, H., Enhanced oil recovery in limestone by seawater injection at elevated temperature, 2008, university of stavanger.
[29] How does a CO2 flood work? ; Available from:http://www.kindermorgan.com/business/co2/flood.cfm .
[30] Shah, Dinesh Ochhavlal, ed. Improved oil recovery by surfactant and polymer flooding. Elsevier, 2012.
[31] Austad, Tor, Alireza RezaeiDoust, and Tina Puntervold. "Chemical mechanism of low salinity water flooding in sandstone reservoirs." In SPE improved oil recovery symposium. Society of Petroleum Engineers, 2010.
[32] A.Z. Abidina, W.A. Nugrohoa, Polymers for enhanced oil recovery technology, Procedia Chemistry 4 (2012) 11 – 16 .
[33] Shehata, Ahmed Mahmoud, Ahmed El-Ghattas, Mahmoud Kamel, Ahmed M. Aly, and Ahmed Hassan. "Overview of Polymer Flooding (EOR) in North Africa Fields-

Elements of Designing a New Polymer/Surfactant Flood Offshore (Case Study)." In North Africa Technical Conference and Exhibition. Society of Petroleum Engineers, 2012.

[34] Ma, Baodong, Baoyu Gao, and Qinyan Yue. "Study on emulsification stability of wastewater produced by polymer flooding." Journal of Petroleum Science and Engineering 110 (2013): 27-31.

[35] Fathi, Seyed Jafar, Tor Austad, and Skule Strand. "Water-Based Enhanced Oil recovery (EOR) by" Smart Water" in Carbonate Reservoirs." SPE EOR Conference at Oil and Gas West Asia. Society of Petroleum Engineers, 2012.

[36] Royce, B., Kaplan, E., Garrell, M., & Geffen, T. M. Enhanced oil recovery water requirements. Minerals and the Environment, 6(2), 44-53. (1984).

[37] Gachuz-Muro, Heron, and Mehran Sohrabi. "Smart water injection for heavy oil recovery from naturally fractured reservoirs." SPE Heavy and Extra Heavy Oil Conference: Latin America. Society of Petroleum Engineers, 2014.

[38] Reksidler, R., et al. "Offshore Chemical Enhanced Oil Recovery." OTC Brasil. Offshore Technology Conference, 2015.

[39] Martin, F. D., et al. "Improved water-soluble polymers for enhanced recovery of oil." SPE oilfield and geothermal chemistry symposium. Society of Petroleum Engineers, 1983.

[40] Sultani, Billal, et al. "Novelty in Smart Water Screening and Designing." SPE EOR Conference at Oil and Gas West Asia. Society of Petroleum Engineers, 2012.

[41] Chakravarty, Krishna Hara, Philip Loldrup Fosbøl, and Kaj Thomsen. "Importance of fines in smart water enhanced oil recovery (SmW-EOR) for chalk outcrops." EUROPEC 2015. Society of Petroleum Engineers, 2015.

[42] Kadeethum, T., H. K. Sarma, and B. B. Maini. "Overcome Viscous Fingering Effect in Heavy Oil Reservoirs by an Optimized Smart Water Injection Scheme." SPE Canada Heavy Oil Technical Conference. Society of Petroleum Engineers, 2017.

[43] Arshad, Muhammad Waseem, et al. "Water-Oil Emulsions with Fines in Smart Water Enhanced Oil Recovery." SPE Kuwait Oil & Gas Show and Conference. Society of Petroleum Engineers, 2017.

[44] Tobenna Danial Okeke, “Simulation and Economic of improved oil recovery methods with emphasis on injection profiles control including waterflloding, Polymer flooding and A Thermally activated deep diverting gel ,” A Thesis, 2012.

[45] Tan Chunho, “Determination of OF Pb(II), Cu(II) AND Ni(II) IN Water by direct measurment using UV/VIS Spectrophotometer ,”2015.

[46] Ghazwan.N.Jreou, “Increasing of Oil Field Productivity by Implementation of Re-entry Horizontal Injection Well, Case study,” 13, 2012.

[47] Jan Morten Ferkingstad, “Numerical Simulation of Productivity Effects by Hydraulic Fracturing in a Low Permeability Fluvial Reservoir in the North Sea,” MASTER’S THESIS, 2011.

[48] Chinenye Clara, “Enhanced oil recovery: Surfacant flooding as possibility for the norne e-segment ,” 2009.

[49] Yugal Kishore Maheshwari, “A Comparative Simulation Study of Chemical EOR Methodologies (Alkaline, Surfactant and/or Polymer) Applied to Norne Field E-Segment,” 2011.

APPENDIX A

```
Synthetic model (oil/water)  --Modal A
--
Aws .MSC-
18 --th Feb. 2019
-MSc Petroleum Engineering Course
 --
--
--
==========================================================================
=
RUNSPEC
TITLE
D 2-PHASE
Number of cells-
NX      NY      NZ-
--      --      --       --
DIMENS
         50 /    1         15       Phases-
Oil
Water
Units-
Field
-Maximum well/connection/group values
#    wells  #cons/w  #grps  #wells/grp-
----------  -----  -------  ------     --
WELLDIMS
         2/       15       2         1
 --Maximum number of saturation (relative permeability) tables
TABDIMS
         2   /
 --Unified output files
-To put all output data files in one file
UNIFOUT
-Simulation start date
START
          1 /JAN 2019
--
==========================================================================
=
GRID
```

```
EQUALS
 --     Keyword          Value        X1  X2            Y1  Y2              Z1  Z2
        DX          70          50   1        1   1         15   1 /
        DY          1800                                         /
        DZ          10                                           /

        TOPS        8000        50   1        1   1         1   1   /       Geological Layer
1 corrosponds to grid layers 1 - 5
        PERMX            200         50   1        1   1         5   1   /         5grid
blocks per layer

        PERMZ            20                                              /
        PORO             0.19                                            /
        NTG         0.95                                         /

        PERMX            1100        50   1        1   1         10   6 /        Geological
Layer 2 corrosponds to grid layers 6 - 10

        PERMZ            100                                             /
        PORO             0.2                                             /
        NTG         0.99                                         /

        PERMX            200         50   1        1   1         15   11        /
        Geological Layer 3 corrosponds to grid layers 11 - 15

        PERMZ            20                                              /
        PORO             0.19                                            /
        NTG         0.95                                         /

/

 --Output file with geometry and rock properties (.INIT(
INIT
--
============================================================
=
PROPS
-Densities in lb/ft3
          --Oil     Wat     Gas
---     ---     ---         --
DENSITY
```

```
        49      63      0.01   /
 --PVT data for dead oil
       --P        Bo       Vis
-----     ----      ----      --
PVDO

        300    1.0      1.25
        800    1.1      1.20
        6000  2.0      1.15           /
 --PVT data for water
       --P        Bw       Cw         Vis     Viscosibility
-------------    -----      -----      ----       ----       --
PVTW
        4500  3      1.02    E-06    0.8                0.0    /
 --Rock compressibility
       --P          Cr
-----       ----       --
ROCK
        4500  4     E-06     /
-Water and oil rel perms & capillary pressures
--      Sw              Krw             Kro             Pc
--      -----           -----           ---             ----
SWOF
 --table 1 for 1100mD
        0.15            0.0             0.9             4.0
        0.45            0.2             0.3             0.8
        0.68            0.4             0.1             0.2
        0.8             0.55            0.0             0.1
        1.0             1.0             0.0             0.0     /

 --table 2 for 250mD
        0.25            0.0             0.9             9.0
        0.50            0.2             0.3             1.8
        0.70            0.4             0.1             0.45
        0.8             0.55            0.0             0.22
        1.0             1.0             0.0             0.0     /

--
=================================================================
=
REGIONS
```

```
SATNUM
--To specify the relative permeability table to use for each layer

        2*250        1*250        2*250/

--
==========================================================================
=
SOLUTION
 --Initial equilibration conditions
       --Datum   Pi@datum    WOC    Pc@WOC
------   -----   --------   -----       --
EQUIL
        8075  4500  8500            0       /
Output to Restart file for t=0 (.UNRST(
    --Restart file
    --for init cond
-------------    --
RPTRST
BASIC=2           /
--
==========================================================================
=
SUMMARY
-Field average pressure
FPR

-Bottomhole pressure of all wells
WBHP
        prod
        inj      /
-Field Oil Production Rate
FOPR
-Field Water Production Rate
FWPR
-Field Oil Production Total
FOPT
-Field Water Production Total
FWPT
-Field Volume Production Rate
FVPR
```

```
-Field Water Injection Total
FWIT
-Field Oil Recovery Efficiency
FOE
-field Water cut in PROD
FWCT
-CPU usage
TCPU
 --Create Excel readable Run Summary file (.RSM(
EXCEL



--
======================================================================
=
SCHEDULE
 --Output to Restart file for t>0 (.UNRST(
    --Restart file
     --every step
------------    --
RPTRST
BASIC=2    /
-Location of wellhead and pressure gauge
     --Well  Well   Location   BHP    Pref.
     --name  group   I    J   datum   phase
-----   -----   -    -    ----  -----     --
WELSPECS
        prod   G1    50   1   8075  oil      /
        inj     G2    1    1    8075  water /
/
 --Completion interval
     --Well   Location  Interval   Status                              Well
     --name    I    J    K1  K2    O or S                              ID
     ------    --  --    -    -    ----     --                  -----
COMPDAT
        prod      15    1    1   50open     1*      1*               0.67   /
        inj        15    1    1    1open    2*                       0.67   /

/
```

```
 --Production control
  --Well  Status  Control   Oil   Wat   Gas    Liq  Resv   BHP
  --name          mode    rate  rate  rate   rate  rate  limit
-----  ----  ----   ----  ----  ----    ------  ------  ----  --
WCONPROD

prod   open    lrat     3*              *1  10000     2000            /
         /
-Injection control
  --Well  Fluid  Status  Control   Surf   Resv    Voidage   BHP
  --NAME  TYPE           mode     rate   rate  frac flag  limit
-----  ---- ----  ----   ----   -------  ------  -----  ----  --
WCONINJ
inj      water  open    rate     11000    3*          10000/
         /
 --Number and size (days) of timesteps
TSTEP
         / 360*10
END
Synthetic model (oil/water/polymer) -- Polymer.DATA
  --Aws MSC
18 --th Feb. 2019
  --MSc Petroleum Engineering
 --
============================================================
=
RUNSPEC
TITLE
D 2-PHASE


       --Number of cells
      --NX      NY      NZ
--      --      --       --
DIMENS
         50      1        15      /



 --Phases
Oil
```

```
Water
 --Switches on polymer option (no associated data(
POLYMER
 --Units
Field
 --Maximum well/connection/group values
#     --wells  #cons/w  #grps  #wells/grp
----------  -----  -------  ------     --
WELLDIMS
         2        15       2        1        /

 --Maximum number of saturation (relative permeability) tables
TABDIMS
         2        /

 --Unified output files
 --To put all output data files in one file
UNIFOUT

 --Simulation start date
START
          1JAN 2019 /
--
=====================================================================
=
GRID
EQUALS
 --      Keyword              Value          X1  X2               Y1  Y2                 Z1  Z2
         DX            70              50   1          1   1           15   1 /
         DY            1800                                              /
         DZ            10                                                /

         TOPS          8000            50   1          1   1           1   1    /       Geological Layer
1 corrosponds to grid layers 1 - 5

         PERMX                1000           50   1          1   1            5   1  /

         PERMZ                100                                                  /
         PORO                 0.2                                                  /
         NTG           0.99                                              /
```

```
        PERMX           200         50  1       1  1        10  6 /       Geological
Layer 2 corrosponds to grid layers 6 - 10

        PERMZ           20                                          /
        PORO            0.19                                        /
        NTG         0.95                                        /

        PERMX           200         50  1       1  1        15  11      /
        Geological Layer 3 corrosponds to grid layers 11 - 15

        PERMZ           20                                          /
        PORO            0.19                                        /
        NTG         0.95                                        /


/


 --Output file with geometry and rock properties (.INIT(
INIT--
=================================================================
=
PROPS
 --Densities in lb/ft3
          --Oil     Wat     Gas
---     ---     ---         --
DENSITY
        49      63      0.01   /
 --viscosity multiplier vs polymer concentration
PLYVISC
        concentration       multiplier-
        0.00000             1.0
        1.00000             12.5   /

 0.8 =0.8*1.0 --cP (water viscosity(
10=0.8*12.5 --cP (polymer viscosity(

 3 --keywords switch off polymer adsorption
PLYADS
        0.0     0.0
        1.0     0.0     /
```

```
        0.0     0.0
        1.0     0.0     /
PLYROCK
        0.0     1.0     1.0     1       1.0     /
        0.0     1.0     1.0     1       1.0     /
PLYMAX
        1.0     0.0     /
 --degree of mixing between injected polymer solution and formation water
TLMIXPAR
                1.0     /
 --PVT data for dead oil
       --P        Bo       Vis
-----     ----      ----      --
PVDO
        300    5.0      1.25
        800    5.5      1.20
        6000  10.0      1.15          /
 --PVT data for water
       --P        Bw       Cw         Vis     Viscosibility
-------------    -----      -----     ----      ----      --
PVTW

        4500  3     1.02    E-06    0.8              0.0    /
-Rock compressibility
       --P          Cr
-----       ----      --
ROCK

        4500  4     E-06      /
 --Water and oil rel perms & capillary pressures
--       Sw               Krw              Kro              Pc
--       -----            -----            ---              ----
SWOF
 --table 1 for 1000mD
        0.15             0.0              0.9              4.0
        0.45             0.2              0.3              0.8
        0.68             0.4              0.1              0.2
        0.8              0.55             0.0              0.1
        1.0              1.0              0.0              0.0     /
 --table 2 for 200mD
        0.25             0.0              0.9              9.0
```

```
        0.50        0.2        0.3        1.8
        0.70        0.4        0.1        0.45
        0.8         0.55       0.0        0.22
        1.0         1.0        0.0        0.0    /
--
=======================================================================
=
REGIONS
SATNUM
--To specify the relative permeability table to use for each layer

        1*250       2*250       2*250/
--
=======================================================================
=
SOLUTION
-Initial equilibration conditions
Datum   Pi@datum    WOC    Pc@WOC-
------  -----  --------  -----     --
EQUIL
        8075  4500  8500        0     /
 --Output to Restart file for t=0 (.UNRST(
Restart file-
for init cond -
-------------    --
RPTRST
BASIC=2           /
--
=======================================================================
=
SUMMARY
-Field average pressure
FPR
Bottomhole pressure of all wells-
WBHP
        prod
        inj     /
-Field Oil Production Rate
FOPR
-Field Water Production Rate
FWPR
```

```
-Field Oil Production Total
FOPT
-Field Water Production Total
FWPT
-Field Volume Production Rate
FVPR
-Field Water Injection Total
FWIT
-Field Oil Recovery Efficiency
FOE
-field Water cut in PROD
FWCT
-CPU usage
TCPU
 --Create Excel readable Run Summary file (.RSM(
EXCEL=====================================================================--
SCHEDULE
 --Output to Restart file for t>0 (.UNRST(
    --Restart file
     --every step
------------    --
RPTRST
BASIC=2       /
 --Location of wellhead and pressure gauge
     --Well  Well   Location   BHP    Pref.
     --name  group   I    J   datum   phase
-----   -----   -    -    ----  -----     --
WELSPECS
         prod    G1    50   1      8075    oil       /
         inj      G2    1    1      8075    water   /
/
 --Completion interval
     --Well   Location  Interval   Status                              Well
     --name    I    J    K1  K2    O or S                              ID
     ------    --  --    -    -    ----     --                       -----
COMPDAT
         prod        15    1    1   50open     1*      1*              0.67    /
         inj          15    1    1    1open     2*                     0.67    /
/
-Production control
  --Well  Status  Control    Oil   Wat   Gas    Liq  Resv   BHP
  --name          mode     rate  rate  rate   rate  rate  limit
-----  ----  ----   ----  ----  ----    ------  ------  ----  --
WCONPROD
 /   prod   open    lrat     3*                *1  10000       2000    /
         -Injection control
```

```
  --Well  Fluid  Status  Control   Surf   Resv    Voidage   BHP
  --NAME  TYPE           mode     rate   rate  frac flag  limit
-----  ---- ----  ----   ----   -------  ------  -----  ----  --
WCONINJ
 /  inj  water  open    rate     11000    3*        10000  /
WPOLYMER
 --        well name       concentration
           /INJ                1.0       /
-Number and size (days) of timesteps
TSTEP
           / 360*10
END
```

APPENDIX B

Case-1 Change in the permeability

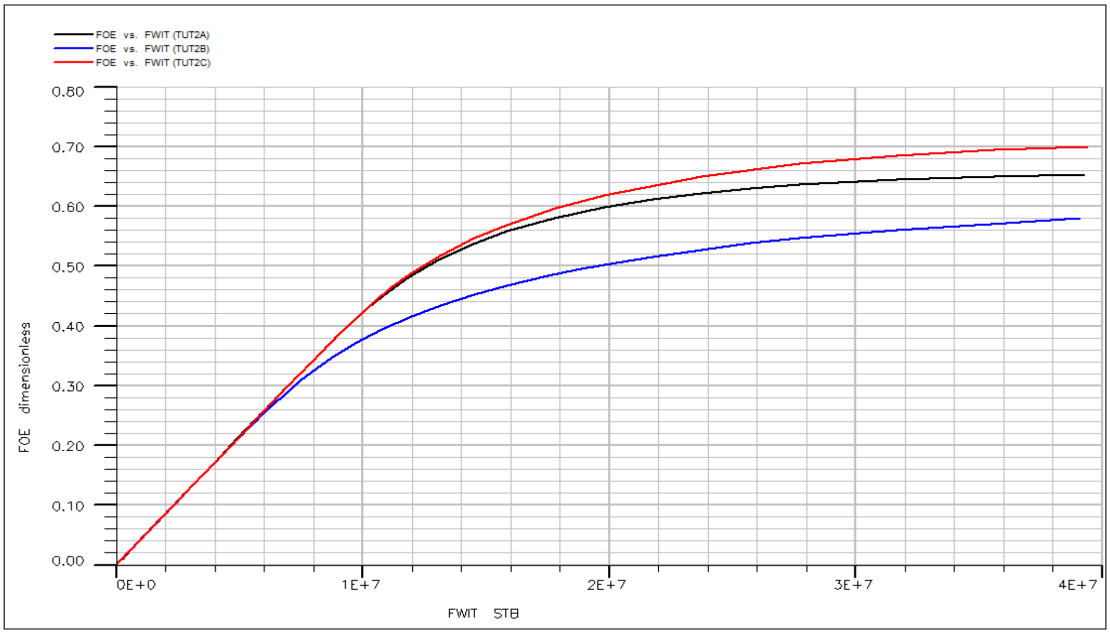

Fig.1.0. FOE vs. FWIT for ROCK models

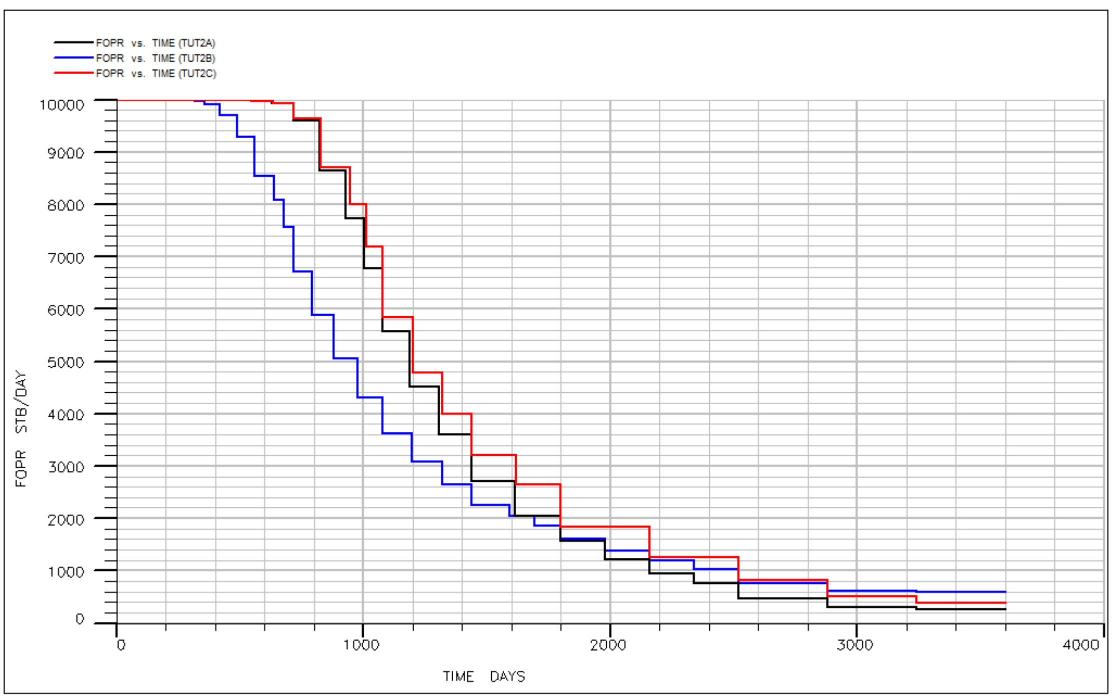

Fig.2 FOPR vs. TIME for ROCK models

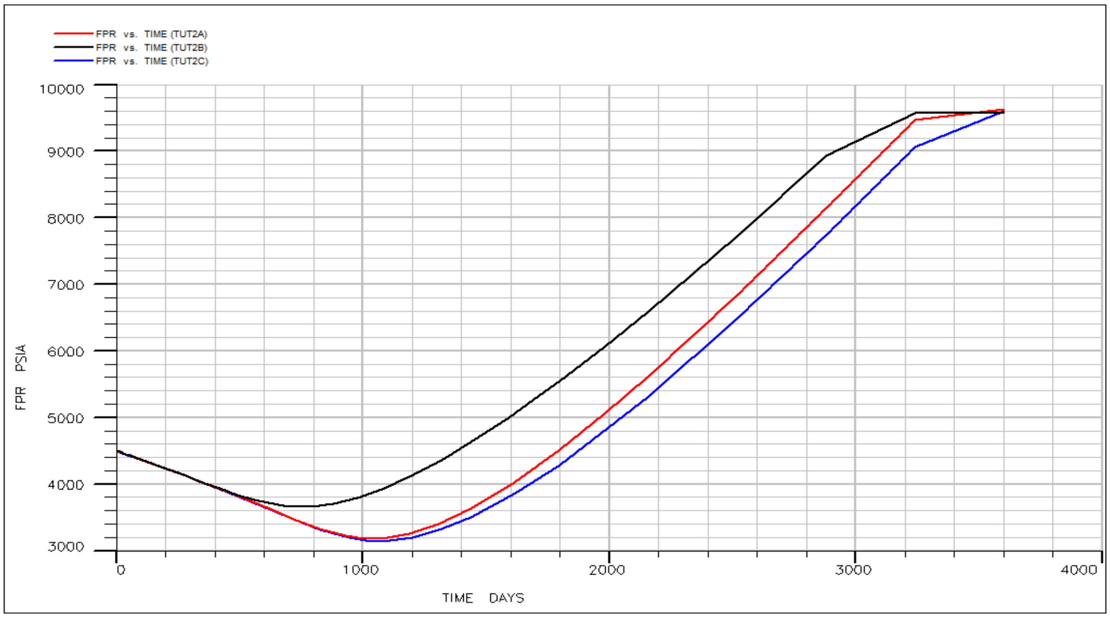

Fig.3 FPR vs. TIME for ROCK models

Case-2 Increased cross-sectional area away from wells

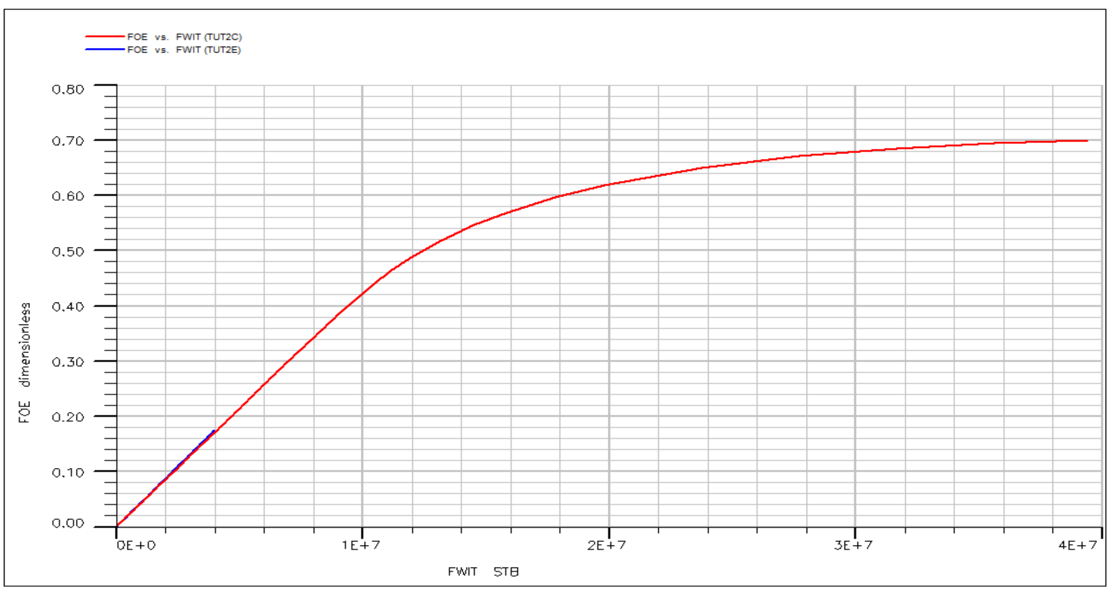

Fig.4 FOE vs. FWIT for Increased cross-sectional area

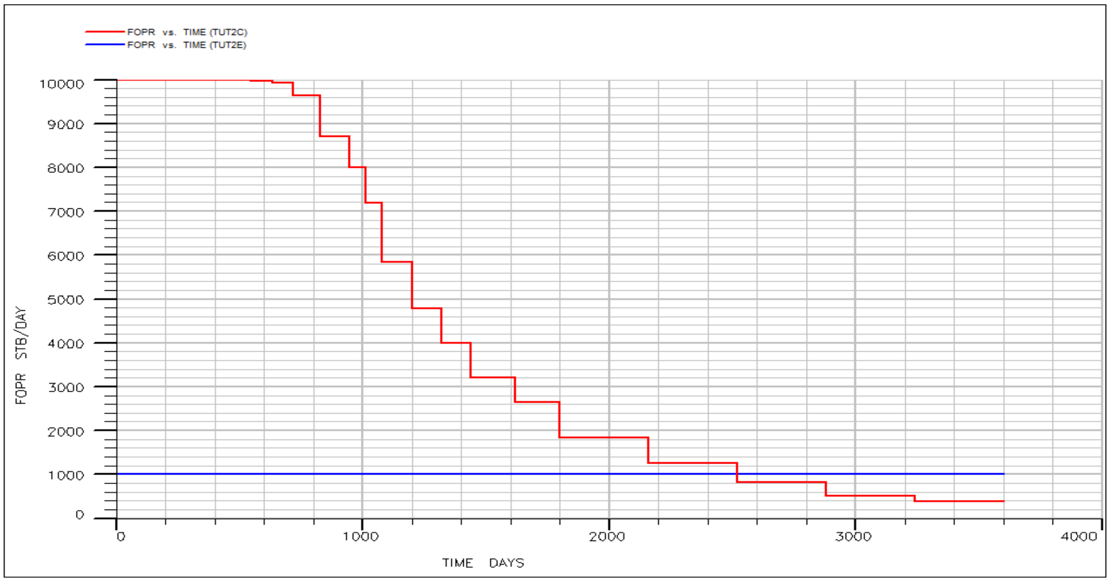

Fig.5 FOPR vs. TIME for Increased cross-sectional area

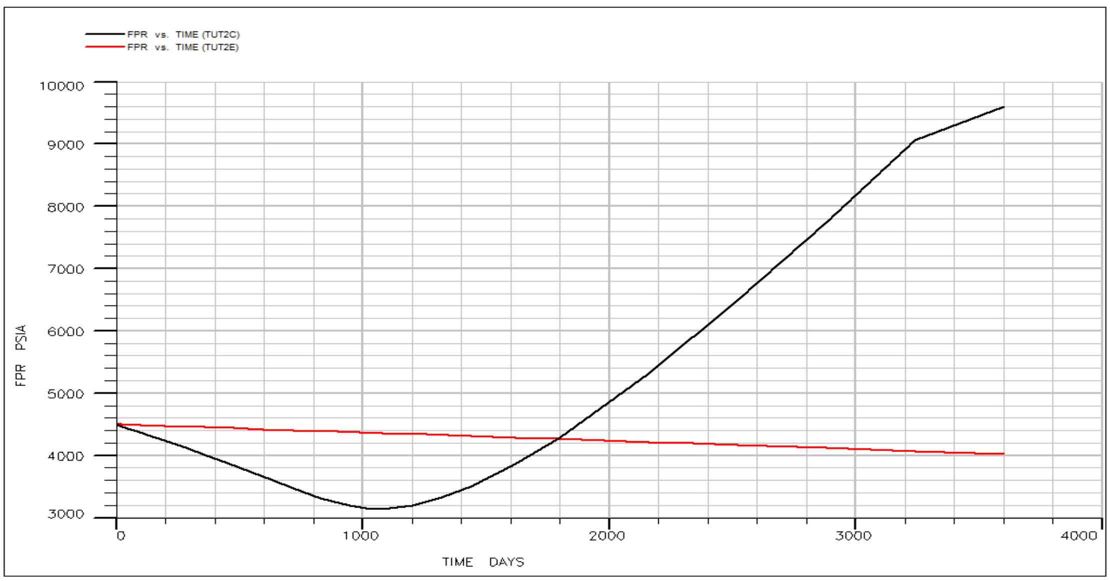

Fig.6 FPR vs. TIME for Increased cross-sectional area

Case-3 Increased kv/kh

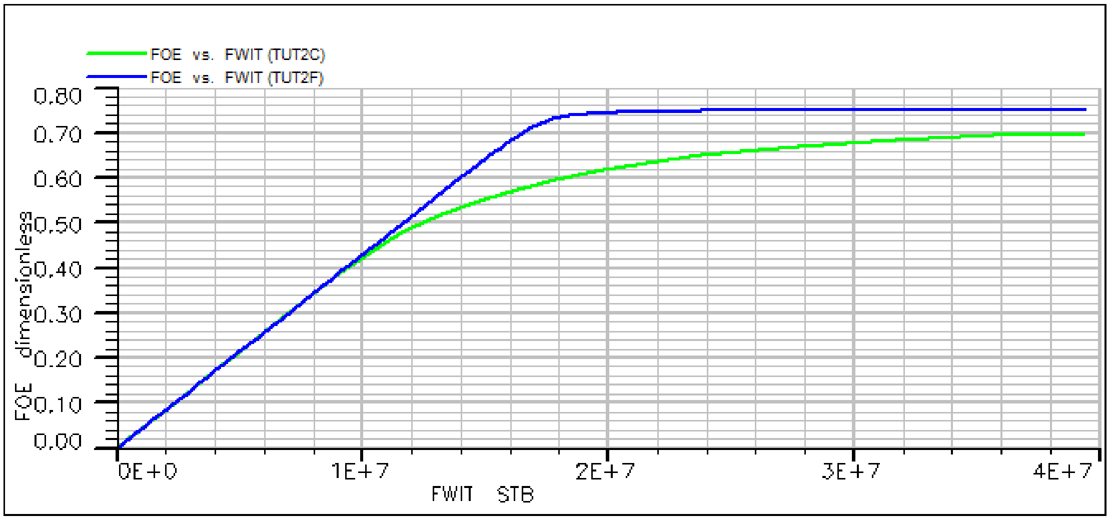

Fig.7 FOE vs. FWIT for Increased kv/kh

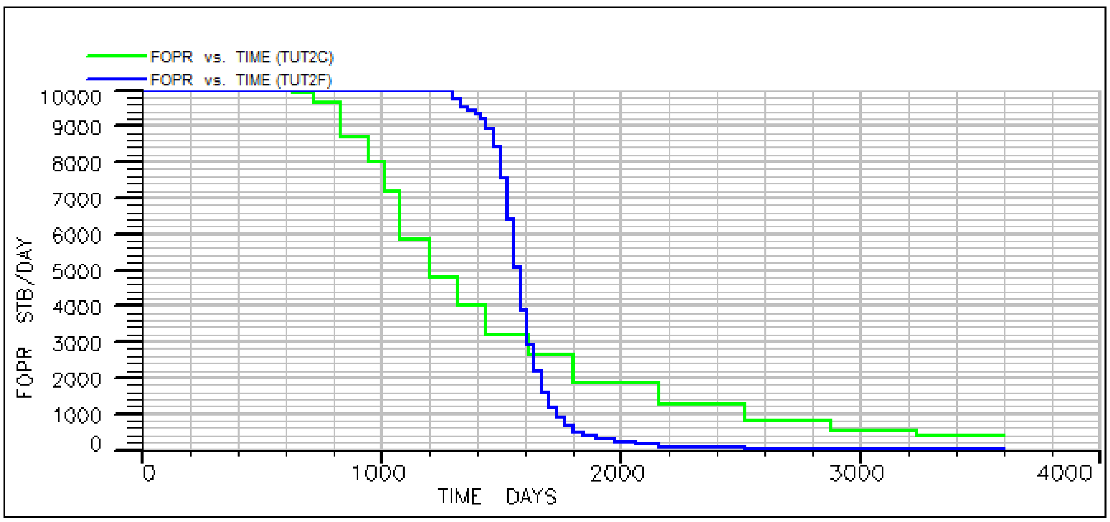

Fig.8 FOPR vs. TIME for Increased kv/kh

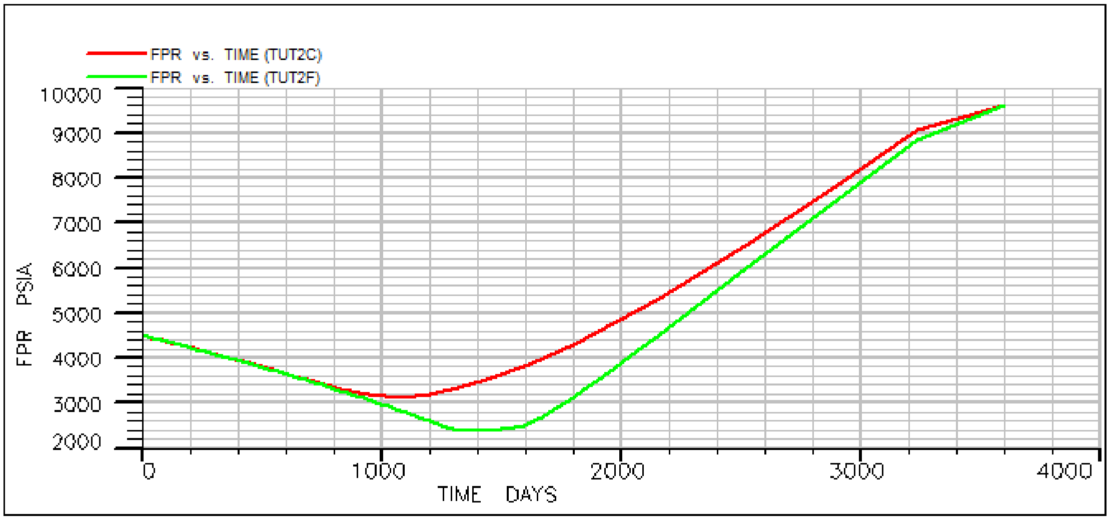

Fig.9 FPR vs. TIME for Increased kv/kh

Case-4 Barriers preventing vertical flow

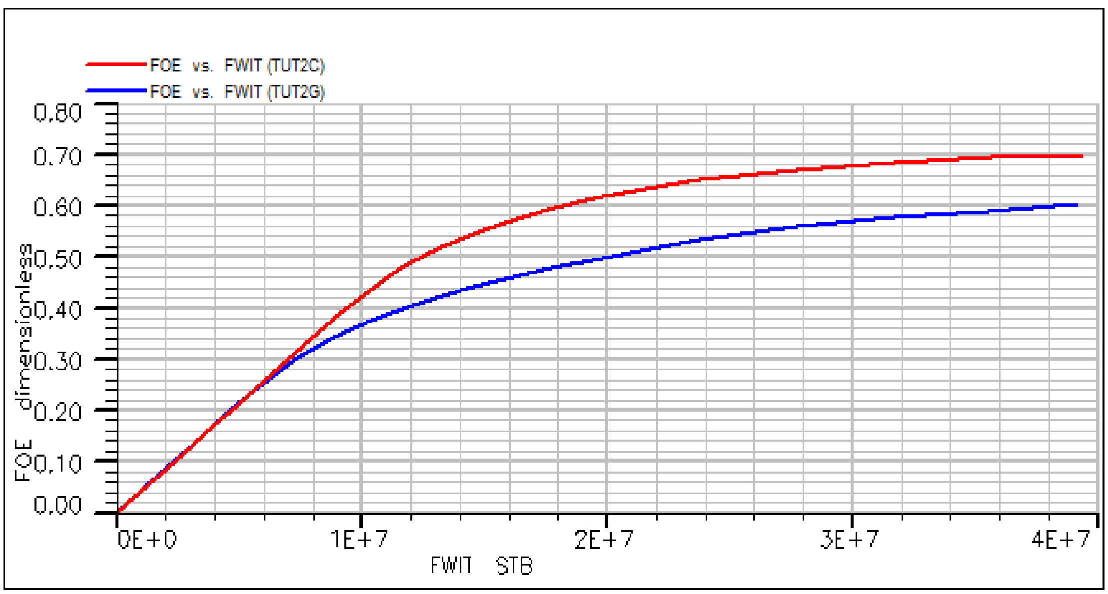

Fig.10 FOE vs. FWIT for Barriers preventing vertical flow

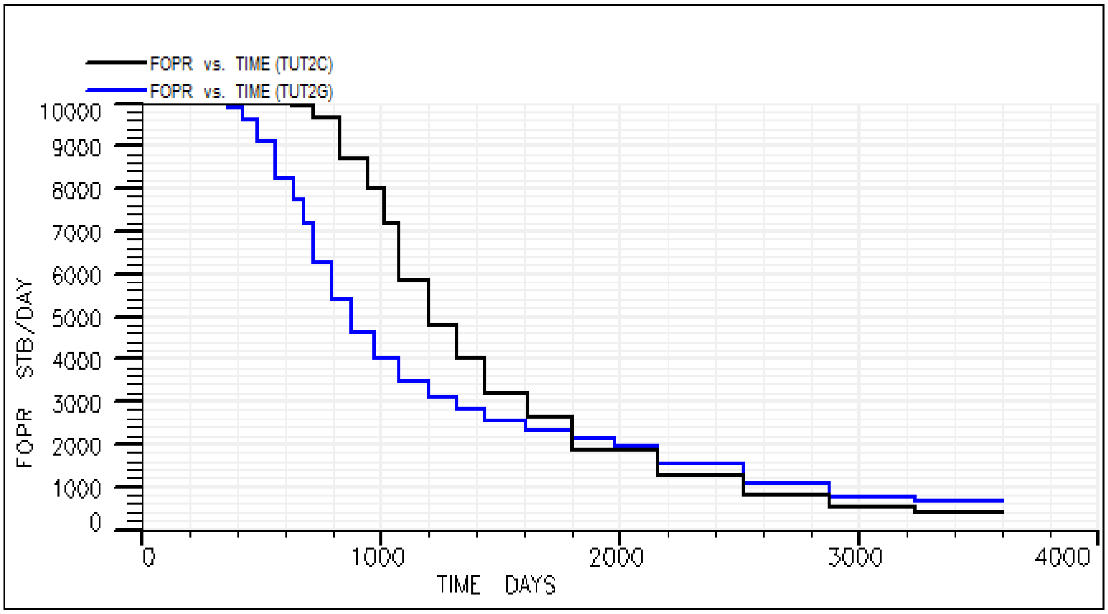

Fig.11 FOPR vs. TIME for Barriers preventing vertical flow

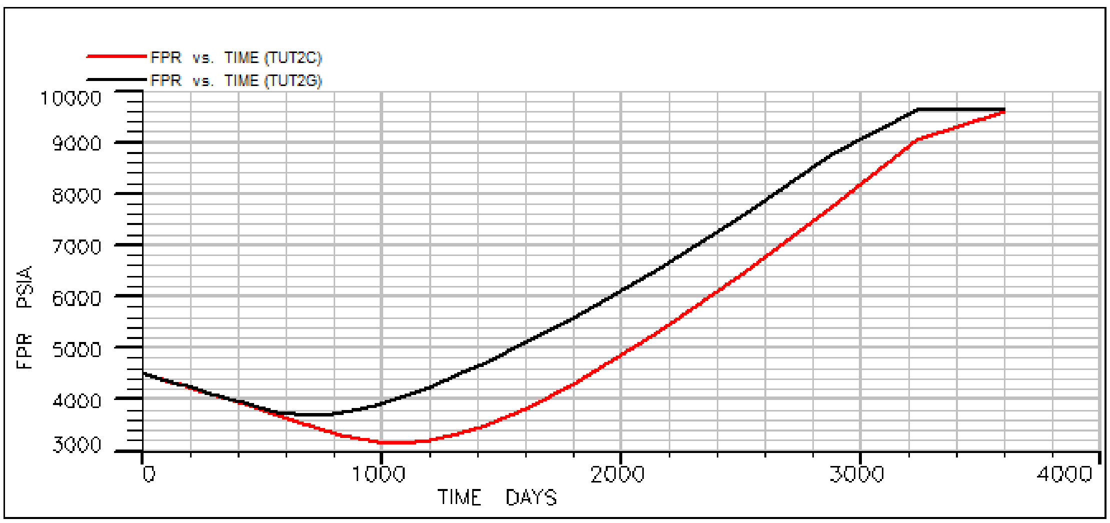

Fig.12 FPR vs. TIME for Barriers preventing vertical flow

Case-5 Polymer Flooding

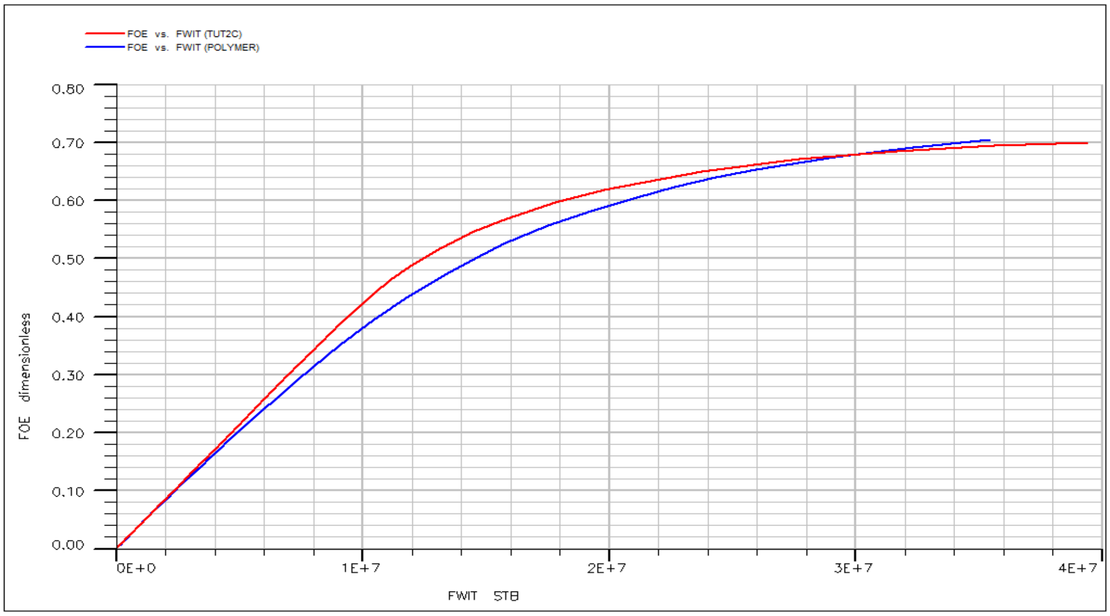

Fig.13 FOE vs. FWIT for Polymer Flooding

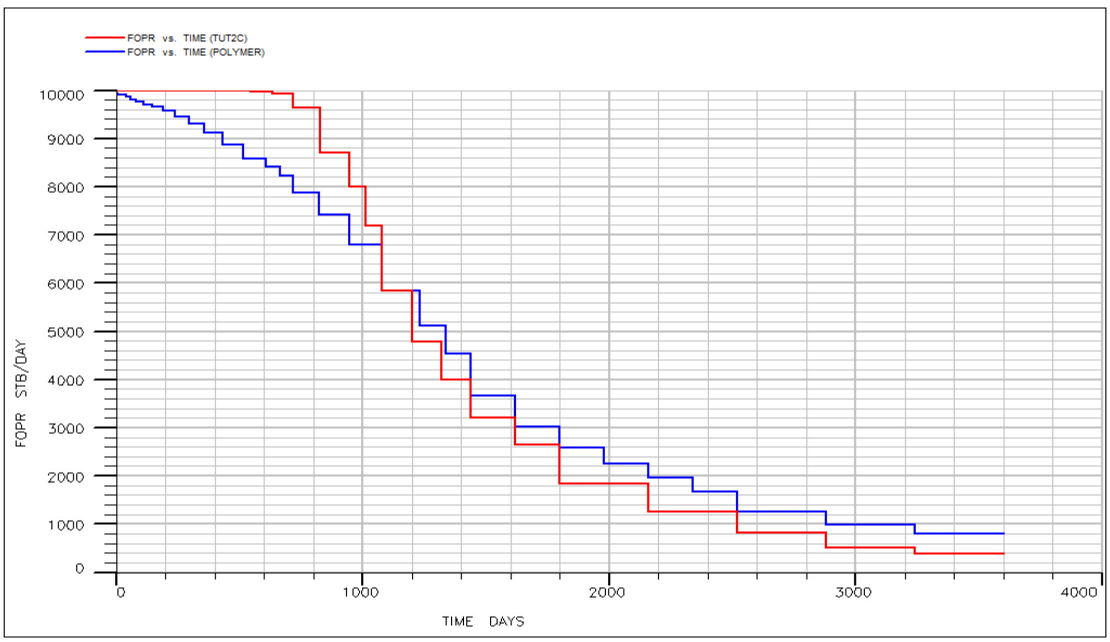

Fig.14 FOPR vs. TIME for Polymer Flooding

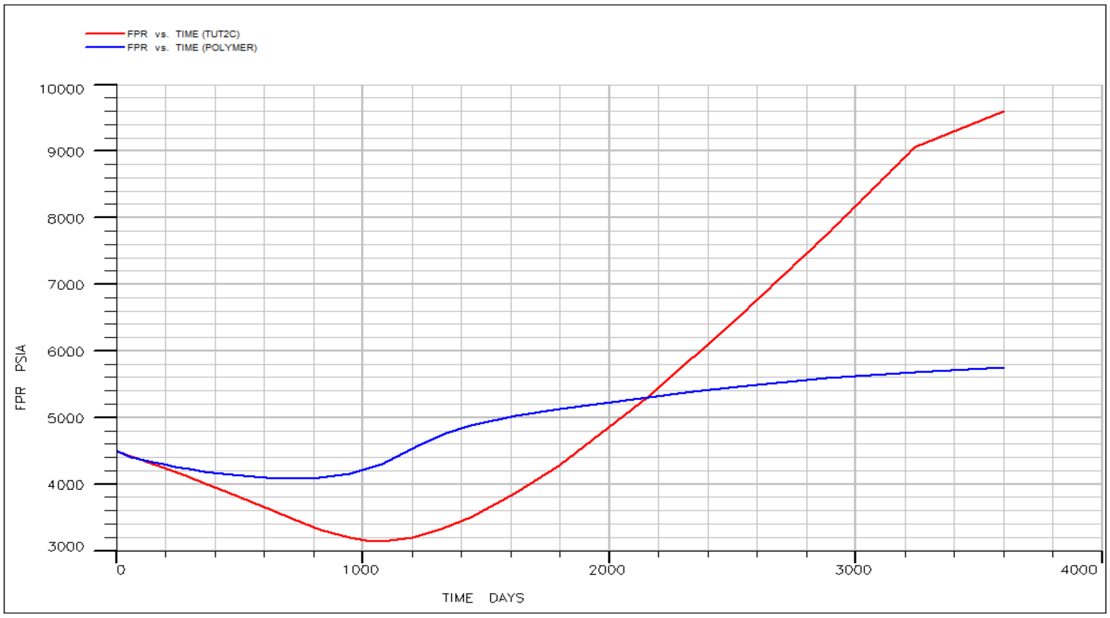

Fig.15 FPR vs. TIME for Polymer Flooding

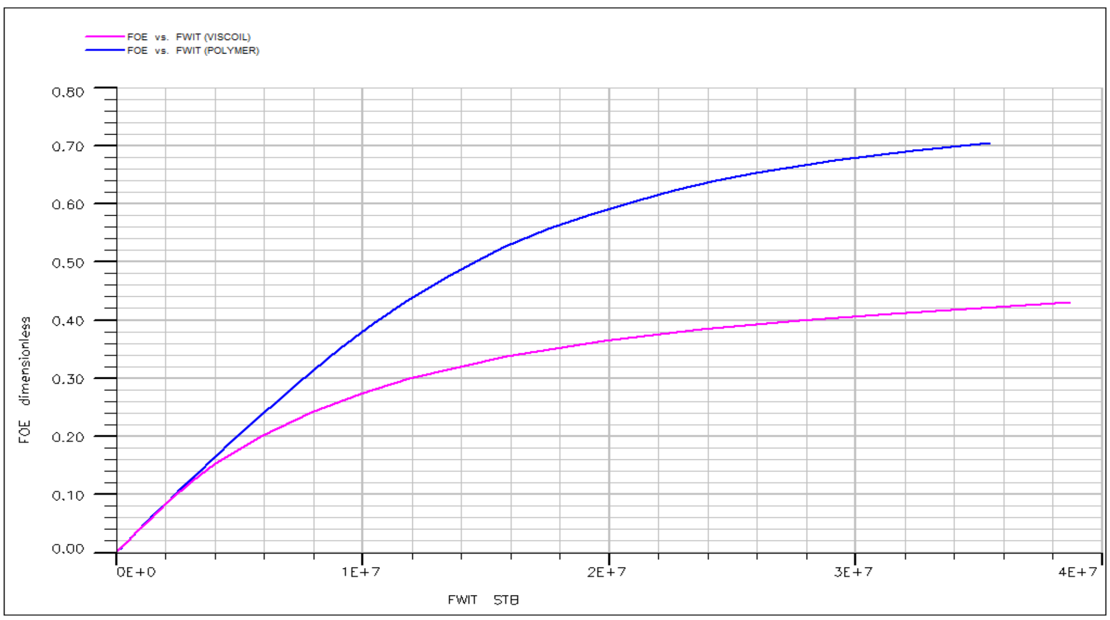

Fig.16 FOE vs. FWIT for Polymer Flooding

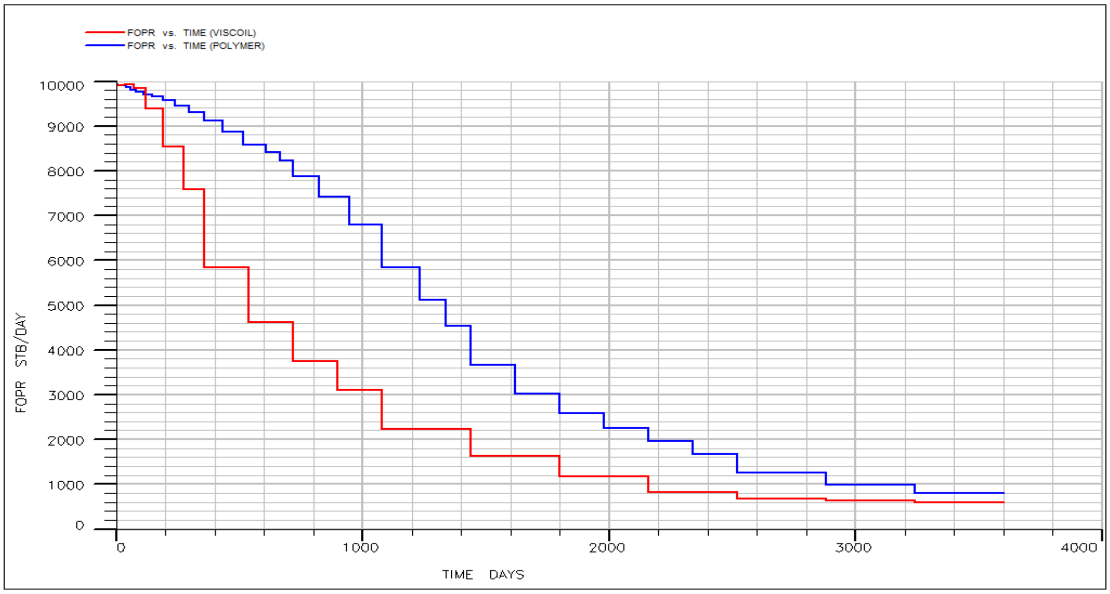

Fig.17 FOPR vs. TIME for Polymer Flooding

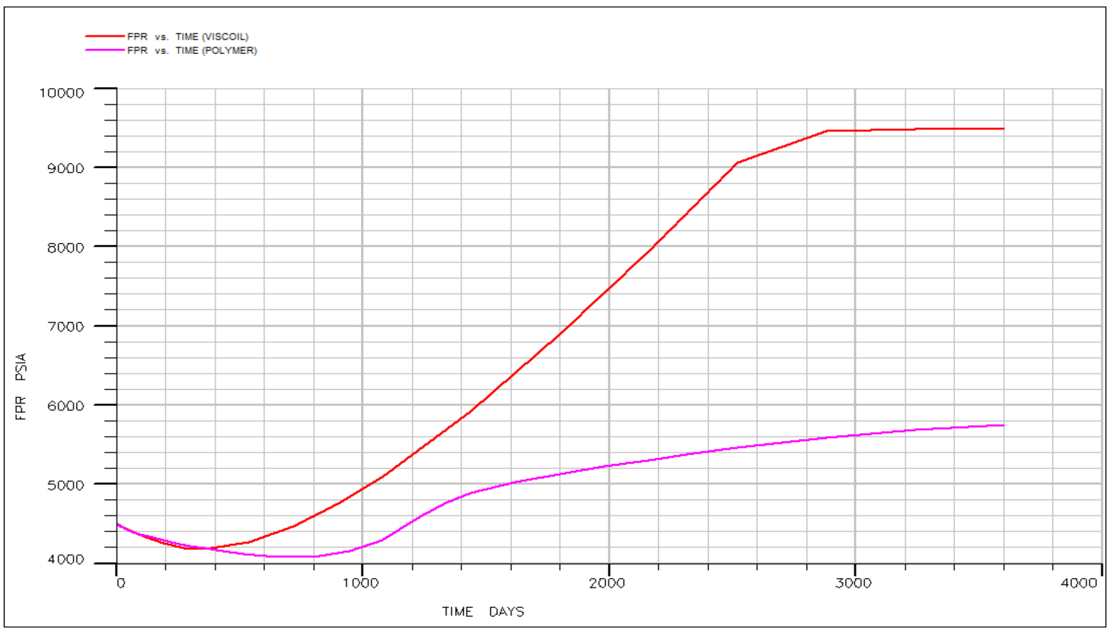

Fig.18 FPR vs. TIME for Polymer Flooding with heavy oil