# SIMULATION STUDY TO INVESTIGATE THE EFFECT OF NATURAL FRACTURES ON THE PERFORMANCE OF SURFACTANT-POLYMER FLOOD IN CARBONATE RESERVOIRS

A Thesis

by

NAWAF IBRAHIM A. SAYEDAKRAM

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2010

Major Subject: Petroleum Engineering

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Approved by:

| | |
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## ABSTRACT

Simulation Study to Investigate the Effect of Natural Fractures on the Performance of Surfactant-Polymer Flood in Carbonate Reservoirs. (August 2010)

Nawaf Ibrahim A. Sayedakram, B.S., Montana Tech University

Chair of Advisory Committee: Dr. Daulat D. Mamora

This thesis presents a comprehensive simulation study on the impact of natural fractures on the performance of surfactant polymer flood in a field scale surfactant-polymer flood. The simulation model utilized for the study is a dual porosity dual permeability model representing 1/8 of a 20-acre 5-spot pattern. The model parameters studied include wettability alteration, IFT changes and mobility reduction effect. The results of this study clearly indicate the importance of reservoir description and fracture modeling for a successful surfactant-polymer flood.

Naturally fractured carbonate reservoirs are usually characterized by mixed wettablility and low matrix permeability which leads to low oil recovery and high remaining oil saturation. Enhanced oil recovery methods such as surfactant-polymer flood (SPF) enhance the recovery by increasing the spontaneous imbibitions either by lowering the interfacial tension or altering the wettability. However, one of the main reasons for failed surfactant-polymer floods is under-estimating the importance of the reservoir especially the description of natural fractures and their effect on recovery.

Sensitivity runs were made to compare oil recovery capillary force, buoyancy force and viscous force. The simulation study indicates that critical water saturation should be reached before the start of surfactant-polymer flood to maximize oil recovery and utilize the capillary force. Also, when a surfactant alters the rock wettability, an optimum IFT should be identified for faster and higher imbibitions. The study shows that a contrast in permeability between that of the fracture and that of the matrix will result in a slightly lower oil recovery. Having the fracture perpendicular to the injector producer will result in a higher areal sweep and lower residual oil.

A sensitivity study on the effect of the size of surfactant polymer slug was not conclusive. Maximum adsorption capacity was reached which was one of the causes of low imbibitions rate. Following the surfactant-polymer with water flood was able to reverse the adsorption and restore some of the movable oil. The results show that if the enhanced fluid that alter the wettability, imbibed in the matrix, injecting high IFT brine will increase the rate of imbibition. The study calls for further investigation of this phenomenon through research using a scaled laboratory model to verify the simulation results.

## DEDICATION

I dedicate this work to my wife Lamees Yousef and my daughters Deema and Rital Sayedakram.

## ACKNOWLEDGEMENTS

I would like to express heartfelt gratitude to my committee chair, Dr. Daulat D. Mamora, for his support and advice throughout my two years at Texas A&M University in the Department of Petroleum Engineering. For this support, I am most grateful. I would also like to thank my committee members, Dr. D. Schechter and Dr. L. Gresham, for their encouragement and academic support.

Special thanks to Saudi ARAMCO for the full sponsorship and support during my study. It was a great and generous opportunity.

I give my heartfelt appreciation to my parents for their support, also for their constant prayers and love throughout the last two years. I would also like to thank my wife, Lamees Yousef, for her patience, love, support and encouragement throughout my study. I am forever grateful for everything she did.

Last, but not least, I would like to acknowledge my friends and colleagues and the department's faculty and staff for making my time at Texas A&M University a great and enjoyable experience.

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# 1. INTRODUCTION

About 40-60% of the original oil-in-place (OOIP) in reservoirs is left behind after secondary recovery. Over 60% of the remaining oil in the world can be found in carbonate reservoirs, which makes it a big area of interest for Enhance Oil Recovery (EOR) methods especially with the current oil price and increasing demand. Carbonate reservoirs can be fractured or non-fractured, oil-wet or mixed-wet (Mohan, 2009). The main characteristics of fractured reservoirs are the permeability enhancement provided by the fractures. In tight matrix blocks, fractures are the only means of fluid flow into a production well. However, the heterogeneity between fractures and matrix blocks can result in by-passed oil.

In fractured reservoirs, most of the oil is located in the matrix porosity. In general, the oil is expelled into the fractures by spontaneous imbibition which is a phenomenon that enables water to imbibe into the matrix blocks from the fractures and expel oil into the fractures. However, this phenomenon is most pronounced when the matrix is more water-wet (Salehi, 2009). A survey done by Allan and Sun on hundreds of fractured reservoirs shows that the range of oil recovery factor values was very wide, from 0 to 70% OOIP, and the distribution peaks between 20 and 30% OOIP. The reservoirs studied were Type III fractured reservoirs, which are both characterized by low-permeability matrix. The study also showed that in high matrix porosity reservoir (Type

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III), oil recovery factor for all well-fractured water-wet reservoirs ranges between 25 to 45% OOIP, and between 5 to 25% OOIP for the oil-wet reservoirs (Bourbiaux, 2009).

The percentage of oil recovery in fractured reservoirs can be affected by several factors, such as matrix permeability, matrix block height, wettability, fracture density, fluid properties (Adibhatla and Mohanty, 2005), interfacial tension IFT and heterogeneity of the rock (existing of fractures, vugs, impermeable layers, etc.) (Salehi, 2009). Many studies in the petroleum industry have been conducted focusing on how to reduce the residual oil saturation to get the maximum recovery from these reservoirs. Most of the studies fall under Enhance Oil recovery (EOR) which usually follows water flooding. Thus, it can also be referred to as tertiary recovery. EOR methods can be classified under three main categories: chemical, thermal and miscible methods. All these methods are intended to either increase the displacement efficiency from areas previously swept by water flood or increase the sweep efficiency by reaching areas that was not swept by water flood.

Performance prediction of chemical EOR - such as surfactant-polymer flooding - in naturally fractured reservoirs is essential for pilot testing, field wide implementation and reservoir management. Generally, recovery prediction continues to be a challenging topic in fractured reservoirs. Not having a good simulation model that can capture all the interaction of the additives injected in the reservoir that describes the existing fractures can lead to a faulty estimation of field performance or wrong pilot design.

## 1.1 Surfactant-polymer flooding

Surfactant polymer flooding is part of chemical EOR. Chemical EOR is becoming more attractive with the current economics especially for water flooded reservoirs. Chemical EOR utilizes surfactant, polymers, alkaline agents or combination of these chemicals (Thomas, 2006). The use of the surfactant is either to:

- lower the interfacial tension between the hydrocarbon and the injected fluid,
- create macro or micro-emulsions with oil and water that leads to improved sweep efficiency,
- change wettability to water wet through adsorption in the rock formation, or
- combination of the above.

A polymer is usually added to the injected water to enhance sweep efficiency by decreasing the mobility or increasing viscosity of the displacing fluid.

IFT reduction plays a significant role in reducing the residual oil saturation ($S_{or}$). Taber (1969) found that, in order for a water flood to have effect on $S_{or}$ reduction from the reservoir, interfacial tension must be lowered by a factor of 1,000 or more. IFT is generally hard to be measured in the field due to the high sensitivity to temperature, pressure and presence of contaminants (Stegemier, 1974). The use of surfactant to reduce the IFT will diminish the capillary force which is the main driving force for spontaneous imbibitions in water wet conditions. However, spontaneous imbibitions will still occur by buoyancy force which becomes the dominant force of displacement even in oil wet conditions. **Fig.1.1** illustrates the spontaneous imbibition caused by buoyancy in a fractured system (Hirasaki and Zhang, 2004).

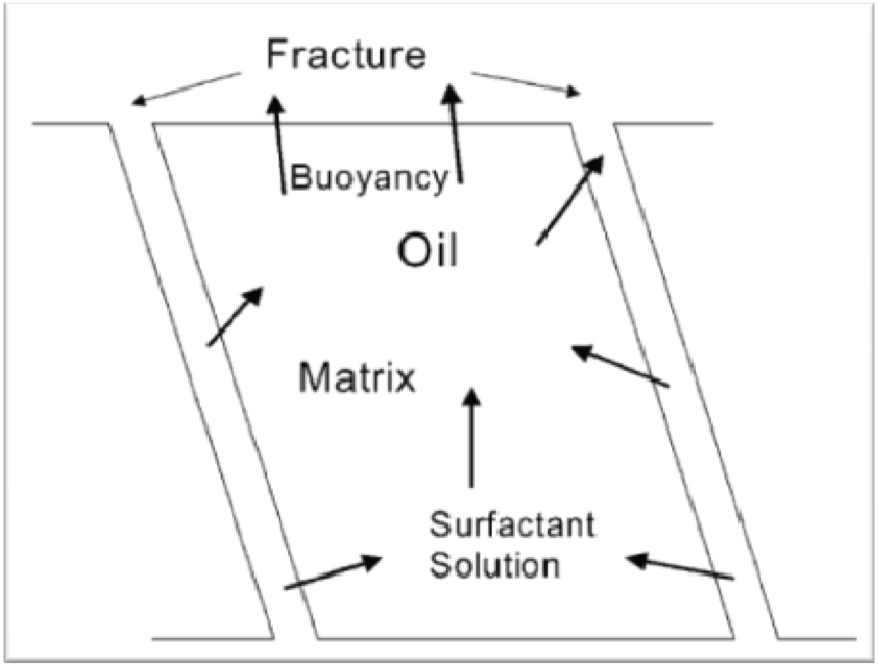


**Fig. 1.1 Spontaneous imbibition through buoyancy force (Hirasaki and Zhang, 2004).**

Wettability alteration has been a proven method to enhance spontaneous imbibitions. In a mixed wet or oil wet rock, buoyancy driven flow will be resisted. In other words, reducing IFT to even ultra low will not recover the oil adhered to the rock surface. The surfactant should be designed depending on the original wetting phase (Najafabadi et al., 2008). **Fig.1.2** shows the affect of water flood based on wettability.

Schecter et al. (1991) have studied capillary forces and gravity forces impact on imbibition. The scale of contribution of each force is given by the inverse bond number, $N_B^{-1}$ (Eq.1.1):

$$N_B^{-1} = C \frac{\sigma\sqrt{\phi/k}}{\Delta\rho g \mathrm{H}} \qquad (1.1)$$

where C is a constant for capillary tube model, σ is interfacial tension, ϕ is the porosity, k is the permeability, Δρ is the density difference (m/L$^3$), g is the gravitational acceleration, and H is the hight of the matrix block.

Schechter et al. (1994) found that the imbibition at high values of $N_B^{-1}$ (>5) is dominated by capillary forces which increase by the current and counter-current of wetting phase and non-wetting phase. While at low values $N_B^{-1}$ gravity force is the dominant one with vertical flow. At intermediate values of $N_B^{-1}$, recovery of the none wetting phase was much faster than in each dominant force alone (Aldejain, 1999).

When designing a chemical EOR flood, one should study all the interaction of the surfactant that might occur during the process which includes water-surfactant compatibility, adsorption in the formation and IFT reduction. After finding the desired surfactant concentration, the data can be used in simulation for performance prediction of the surfactant flooding before carrying out a field pilot test.

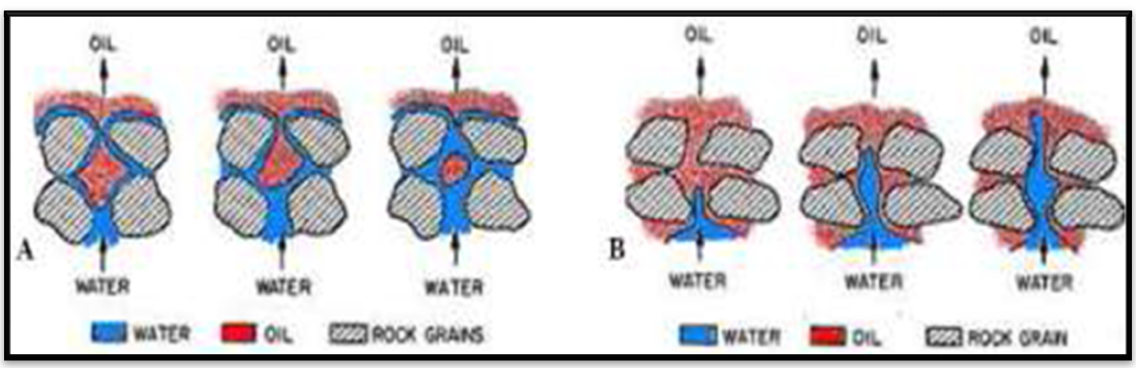


**Fig. 1.2 Wettability effect on water flooding (A) water-wet (B) oil wet (Salehi, 2009).**

## 2. RESEARCH OBJECTIVES

The main objective of this research is to study the effect of natural fractures on surfactant polymer flood (SPF) performance on a field scale using a dual-porosity dual-permeability (DPDP) simulation model. The parameters to be studied will include: fracture permeability, spacing and orientation, matrix permeability and wettability, and the use of low interfacial tension versus capillary pressure for recovery. The main performance measurements used in this study are oil recovery with respect to the original oil-in-place (OOIP) and oil production rate.

## 3. METHODOLOGY

To achieve the research objective a hypothetical naturally fractured reservoir model has been built. A commercial simulator, CMG Stars version 2009.1, has been utilized which has the capability simulate chemical EOR processes. The study involved the following steps.

- Build a 1/8 model of an inverted 5-spot pattern to simulate a surfactant-polymer flood in a carbonate light oil reservoir (black-oil model).
- Include dual-permeability dual-porosity (DPDP) model to capture the effect of fracture system in the field.
- Add rock and fluid parameters based on published data that represent a common carbonate reservoir from permeability and porosity to wettability conditions and capillary pressure.
- Assume that surfactant used has impact on both wettability alteration and IFT reduction while the polymer changes viscosity of the injected fluid.
- Run a sensitivity study on fracture spacing, permeability, flow direction, and matrix permeability.
- Run sensitivity study on surfactant polymer flooding (SPF) performance in terms of the start of the process and the length of the injection through the life of the field.

# 4. LITERATURE REVIEW

The section is divided into three main parts: fracture parameters, dual porosity modeling, and simulation studies in fractured reservoirs. The literature review has helped narrow down the parameters selected for the sensitivity study of my work and to build a simulation model that describes a fractured carbonate reservoir.

## 4.1 Basic parameter fractures

Fracture parameters are usually different from those of the main rock (matrix). Fractures are defined as a surface where loss of cohesion occurs (Van Golf-Racht, 1982). The study of a fracture system in a reservoir is divided into two categories: single-fracture parameters and multi-fracture parameters.

### 4.1.1 Single fracture parameters

Single-fracture parameter defines the fracture itself such as width, size, and orientation. Fracture width (opening) is the distance between the fracture walls which varies between 10-200 microns but statistics have shown that the range 10 – 40 micron is more typical. Fracture size is the length of the fracture with respect to layer thickness. Fracture orientation is critical when looking at the fracture with respect to a reservoir.

### 4.1.2 Multi-fracture parameters

Multi-fracture parameters define the group of fractures which results in creating matrix blocks. Such parameters are distribution, intensity, density. A continuous fracture system affects the size, and connectivity of trapped matrix blocks within the system. The matrix blocks usually have irregular shapes. However, for simplification of the volume calculations, several models of regular block shapes has been proposed to describe the matrix blocks all of which assumes an orthogonal fracture system. The shape of the matrix block depends on the ratio between linear fracture density in the vertical section and horizontal section. **Fig.4.**1 shows the different block shapes of matrix caused by different fracture systems (van Golf-Racht, 1982).

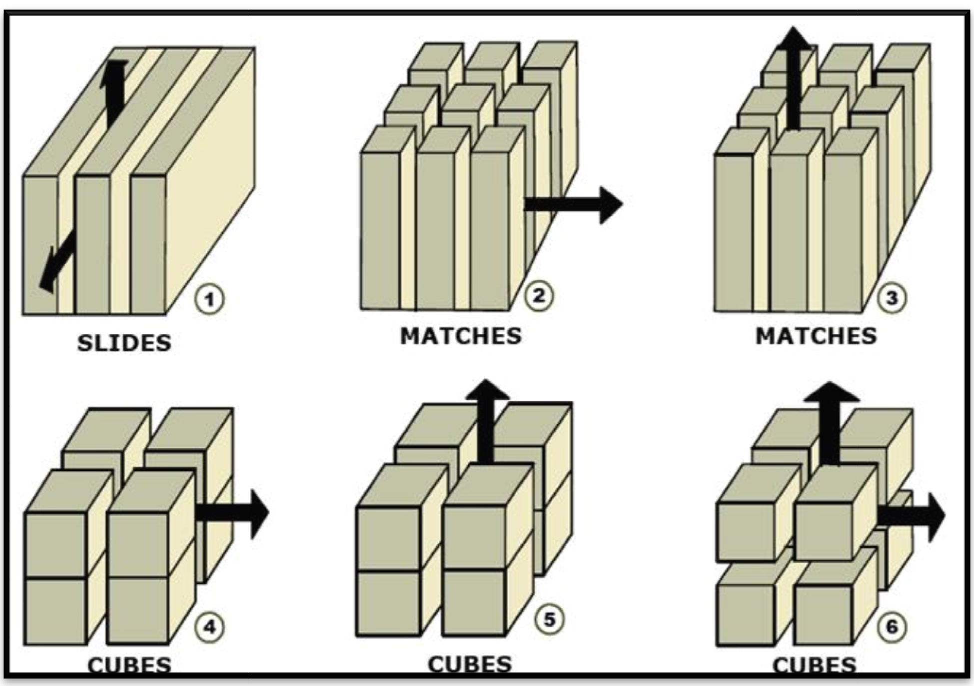


**Fig. 4.1 Simplified matrix block of different fracture system (van Golf-Racht, 1982).**

### 4.2 Petrophysical parameters

The difference between the fracture properties and matrix property creates heterogeneity in the flow system. Some fractures can block the flow (i.e., faults) while other fractures enhances the flow (i.e. joins). The two important properties in the fracture are permeability and porosity.

Fracture permeability might be referred to as single fracture permeability or network permeability. Depending on the orientation of the fracture, the permeability is calculated. However, knowing the total permeability (matrix permeability + fracture permeability) in a fractured system is very difficult due to the big difference between the matrix permeability and the fracture permeability.

The fracture porosity, also called secondary porosity, is significantly lower than matrix porosity (primary porosity). Therefore, fracture porosity is not important in terms of storage. However, it is critical in terms of transient flow (Tarahhom et al., 2008). Due to the heterogeneity in the fracture system, several models have been made to have a qualitative representation of the entire system by representing idealization of the fracture system. Depending on which model is chosen, the porosity and permeability of the fractures and matrix blocks are determined.

### 4.3 Modeling fracture reservoir

Simulation of chemical flooding in a fractured reservoir is either modeled as single porosity with discretized fractures or continuum such as multi-component dual porosity model with multiphase capability (Aldejain, 1999; Delshad et al. 2009). Both methods have their limitation. Discrete model is more detailed in representing fracture direction and flow behavior for each fracture property in a reservoir. However, in a well-fractured reservoir, discretization requires a huge computational demand which is considered one of its disadvantages. The dual porosity system has some limitation pertaining to fracture spacing, length, orientation and matrix flow contribution in extreme heterogeneous systems. However, dual porosity systems have been evolved through the years and are still considered the best way and are widely used when modeling a naturally fractured reservoir (Tarahhom et al., 2009).

## 4.4 Dual porosity properties

Dual porosity conceptual model was introduced to the petroleum industry by Warren and Root (1962) to enhance the simulation of naturally fractured reservoirs. The model was only introduced then as an analytical solution for unsteady-state flow in naturally fractured reservoirs with no simulation work done. The concept of dual porosity is based on the existence of two porosities, primary and secondary, in each block with the following assumptions:

- All of the primary porosity (matrix porosity) is homogenous, isotropic and identically shaped.
- All of the secondary porosity (fracture porosity) is surrounding the primary porosity as orthogonal system of continuous fractures.
- The fractures that are normal to each other have same fracture spacing and width.
- There is matrix-fracture flow, fracture-fracture flow.

- There is no matrix-matrix flow.

The fluid transfer between components is governed by the differential pressure, fluid viscosity, matrix permeability, and a geometric factor called the shape factor which is a function of the matrix block dimensions. **Fig. 4.2** illustrates the conceptual model of dual porosity model. The shape factor proposed by warren and Root was:

$$\sigma = \frac{4\,n(n+2)}{L^2} \quad \text{..........................................................................(4.1)}$$

where n is the number of normal fractures, L is the characteristic length that is calculated based on the dimension of the matrix block.

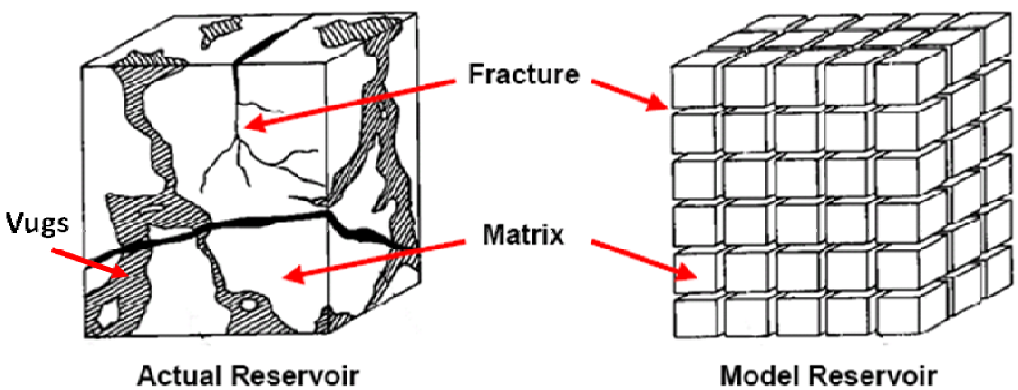


**Fig. 4.2 Idealization of dual porosity reservoir (Warren and Root, 1963).**

Kazemi et al. (1976) have extended the Warren and Root model to multi-phase reservoir simulation by applying the dual porosity concept to each grid-block. Each grid block has its own properties and values associated with both fractures and matrix. Kazemi et al.'s model differs from Warren and Root's model by including:

1. Heterogeneous reservoir with three-dimensional flow through defining local properties.
2. Two-phase or single-phase flow by defining relative mobilities as functions of saturation.
3. The effect of gravity in the fractures.
4. The effect of imbibitions through modeling capillary pressure as a function of saturation.
5. Numerically solved flow equations.
6. New shape factor.

The shape factor presented by Kazemi is as follows,

$$\sigma = 4\left[\frac{1}{l_x^2} + \frac{1}{l_y^2} + \frac{1}{l_z^2}\right] \quad \text{.....(4.2)}$$

where $l_x^2$, $l_y^2$, $l_z^2$ are the dimensions of the fracture bounded by matrix blocks. Later, Gillman and Kazemi (1983) included polymer flooding and tracer transport by modifying the flow equations of Kazemi et al. (1976). The modified flow equations include weight fractions of chemicals in the fracture network matrix blocks. The model was capable of increasing water viscosity as the polymer concentration increased (Aldejain, 1999).

Guzman and Aziz (1992) have developed a capillary number to illustrate their work on the effect of fracture relative permeability, matrix capillary pressure, and matrix/fracture capillary pressure on oil recovery. Their capillary number $N_{cap}$ is defined as follows,

$$N_{cap} = \frac{kP_c(S_{cw})X}{q\mu} \quad \text{……………………………………………………………(4.3)}$$

where $S_{cw}$ is critical water saturation and X is fracture spacing. Their study was indicates that at high to moderate $N_{cap}$ fracture relative permeability has very small effect on oil recovery. However, fracture relative permeability has a bigger impact on recovery at low $N_{cap}$. This high impact of relative permeability was noticed at $N_{cap}$ equal to 20.

Several studies have been done to improve the modeling of dual porosity system dealing with the matrix-fracture transfer flow. The transient flow has been characterized by three flow regimes. First flow regime is before breakthrough of water at the producer where few imbibitions of injected water occur. Second flow regime is the transient flow inside the matrix block where the most imbibitions occur. Third flow regime is when fracture and matrix flow approaches a pseudo-steady type behavior. Rates and water cut in matrix-fracture transient flow is characterized by two dimensionless parameters similar to the pressure transient analysis parameters which are called global time scale ratio ($N_t$) and storativity ratio ($\omega$) (Chen, 1995).

### 4.4.1 Dual-porosity dual-permeability (DPDP)

As a dual porosity model does not allow fluid to have matrix to matrix flow, dual permeability model should be used especially with relatively high matrix permeability. The dual permeability model will account for matrix-matrix flow as the pressure gradient increase in the matrix increases (Aldejain, 1999). With matrix-matrix flow included the gravity drainage is represented better than in a dual porosity model.

However, it is not fully captured. **Fig. 4.3** shows the fluid flow connectivity concept in DPDP model.

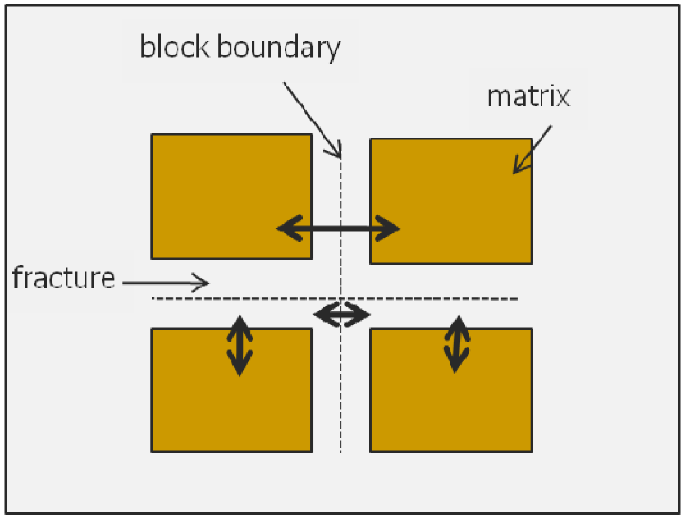


**Fig. 4.3  Dual-porosity dual-permeability fluid comunication.**

### 4.5 Chemical EOR simulation studies in fractured reservoirs

Adibhatla et al. (2005) developed a 3D flexible grid finite volume simulator that can account for wettability and IFT alteration. Surfactant is modeled under the assumption that surfactant can exist in the aqueous or the oil phase and be adsorbed onto the rock. Assuming that micro-emulsion phase is so low, the model was only considers two phases: oil phase and aqueous phase. The simulation results were first matched with imbibitions experiments performed on fractured core before any scale up.  Some of their conclusions emphasized on the importance of capillary pressure prior to lowering the interfacial tension to avoid counter-current imbibitions. An increase in matrix block height, or decrease in the degree of wettability alteration, or decrease in matrix permeability can decrease the oil production rate.

Adibhatia and Mohanty (2007) have carried out the study of Adibhatla et al. (2005) by running additional sensitivity studies on the same developed simulator. The study was focused on the effect on rate of recovery by IFT reduction, wettability alteration, and matrix permeability. A summary of their study conclusions is as follows.

- Surfactants that alter the wettability recover oil at a higher rate in higher IFT system.
- Surfactant that does not alter wettability recovers oil at a higher rate in low IFT (>0.1 mN/m).
- In low permeability reservoir, wettability alteration has a big affect in recovery rate when IFT is high. However, the affect is less significant in high permeability reservoir.

A method for up-scaling laboratory imbibitions experiment was presented by Stoll et al. (2008). The model used is a 1D model to simulate wettability modification then the time scale equation is used for upscaling in order to obtain the same recovery fraction of OOIP from the core plug. The time scale equation used is as follows,

$$t_{block} = \left( \frac{L_{block}}{L_{plug}} \right)^2 t_{plug} \qquad (4.4)$$

where L represent the matrix block length scale. They concluded that imbibitions and diffusion is much slower and limited once the wettability is altered. Also, in carbonate rock that is oil-wet and fractured, wettability alteration is not economically feasible.

However, the study of buoyancy and viscous force was not made to complete the support this conclusion.

Najafabadi et al. (2008) have made several sensitivity studies on chemical injection, including alkaline-surfactant flood (ASF), on a fractured carbonate lab experiment. The laboratory experiment that was simulated includes 9 cores arranges together and assuming the spacing between the cores are fractures. The cores had mixed wettability and were flooded with a sequence of water, alkaline, then surfactant. Even after chemical flood, the cumulative oil recovered as a percentage of OOIP was 36%. The results from the sensitivity studies are as follows.

- Grid refinement sensitivity analysis shows negligible different in oil recovery.
- Fracture permeability study showed that increase in fracture permeability with constant matrix permeability will cause the performance of injection to decrease.
- Molecular diffusion coefficient on surfactant and alkali shows very small effect on the oil recovery.
- Injection rate only affected the rate of recovery not the total recovery. The higher the injection rate the faster the oil recovery achieved.
- Injection of alkaline and surfactant showed that performing ASF from the beginning results in more recovery than the base case.

The study concluded that the main recovery mechanisms are wettability alteration, IFT reduction, emulsification, and oil mobilization. The chemical injection should be performed before critical water saturation is reached and the viscous forces are balance with negative capillary forces.

Delshad et al. (2009) has modeled wettability alteration in fractured reservoirs using the UTChem simulator. They used several relative permeability curves and capillary pressure that correspond to the wettability condition. The wettability model that was implemented in the simulator was validated with reported laboratory experiment on surfactant imbibitions. The study was done in a 3D single porosity model with discrete fractures and hypothetical reservoir data, varying the value of the parameter studied for each run. The model assumes fracture network connected to a producer and another connected to the injector dividing the matrix blocks equally into three groups of matrix blocks. The study demonstrated the importance of wettability alteration from mixed-wet to water-wet on increasing production rate. The authors have mentioned that dynamic laboratory experiments are required and the imbibition-cell experiments are not representative of field scale measurements because it does not take into account viscous and buoyancy forces.

Tarahhom et al. (2009) have developed a compositional chemical dual porosity model with full permeability tensor. The model was built to simulate large-scale chemical flooding process. It was validated against UTCHEM simulator for chemical flooding. The permeability tensor was validated with FracMan software that showed a good match for tracer flood simulation. The permeability tensor showed importance of off-diagonal permeability in unparallel fracture system.

# 5. SIMULATION MODEL SETUP

This section describes construction of the simulation, the parameters and properties used in the base case model. The simulation study was done using a commercial simulator, CMG STARS 2009. The simulator is capable of simulating the viscous, capillary, gravity and diffusive effects in a fractured reservoir. The data used are based on the information gained from the literature and previous CMG simulation work. After building the base case model, several sensitivity studies were conducted using the model. The results are discussed in the "Results and discussion" section.

## 5.1 Model construction

A 16 x 31 x 5 Cartesian grid model has been used to represent a 1/8 of a 20-acre 5-spot pattern. The distance between the injector and the producer is 633ft. The grid blocks are constructed so that the grid blocks sides are either parallel or normal to the injector-producer direction. **Fig. 5.1** is a schematic diagram showing the 1/8 of 5-spot pattern in plan view and 3D view. A 1/8 symmetry element of the pattern is used (instead of the typical 1/4) to reduce the number of grid blocks and hence cut down on the simulation run time. The production rate was set at a maximum of 1000 bbl/day (total oil and water) while the injection rate is constrained based on a maximum injector bottom hole pressure of 2500 psi which is the initial reservoir pressure.

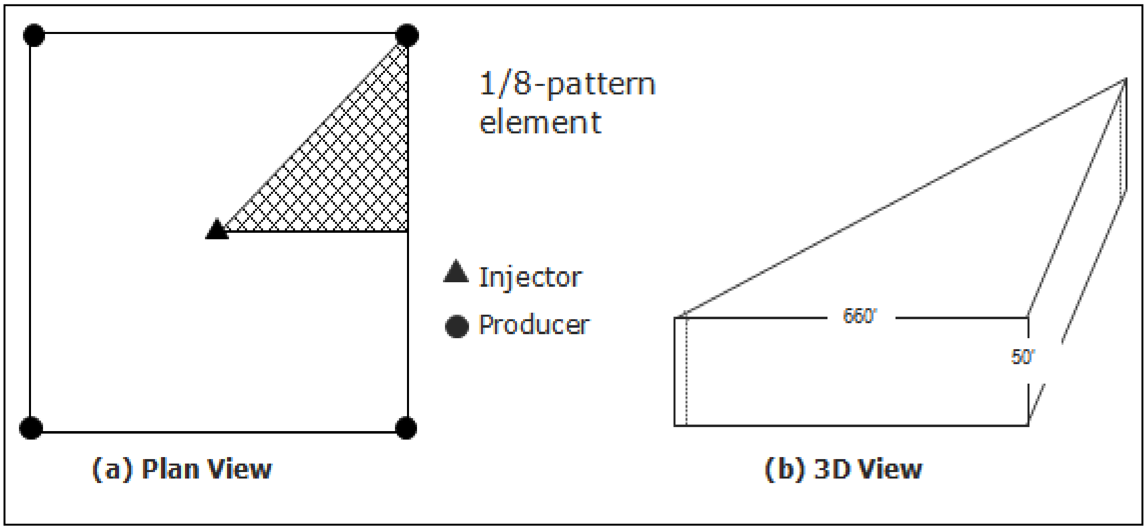


**Fig. 5.1 Plan view and 3D view of the simulation model representing 1/8 of a 20-ac 5-spot pattern.**

### 5.1.1 Dual porosity dual permeability model (DPDP)

The reservoir is assumed to be a fractured carbonate reservoir characterized by high fracture flow and low matrix flow. Because matrix to matrix flow was not neglected, Dual Porosity Dual Permeability (DPDP) model was used to capture this flow behavior. Using DPDP model will add matrix-matrix flow term to the matrix mass balance and the total energy balance equations used in the dual porosity model, where this term is considered zero in the DP model. **Appendix A** includes the governing equations used in stars simulator in the DPDP model. Gilman and Kazemi shape factor was used in the model,

$$\sigma = 4V_b \sum_i \frac{k_{mi}}{L_i^2} \quad \text{……………………..……………………..…………………………..…..(5.1)}$$

where $L_i$ is the fracture spacing in x, y and z direction, $K_{mi}$ is the effective matrix permeability in all directions and $V_b$ is a block volume. The shape factor is used in the transmissibility function in the fracture-matrix fluid flow. **Table 5.1** lists the basic parameter for fracture and matrix blocks used in building this model.

**Table 5.1 Base case basic simulation data**

| | | |
|---|---|---|
| grid block size | 30x30x10 | $ft^3$ |
| number of grid blocks | 16x31x5 | |
| injector-producer distance | 9334 | ft |
| reservoir depth | 5000 | ft |
| reservoir pressure | 2500 | psi |
| **Matrix properties:** | | |
| horizontal perm. (kh) | 50 | md |
| vertical perm. (kv) | 5 | md |
| initial oil saturation ($S_{oi}$) | 0.81 | |
| matrix porosity ($\phi$) | 0.2 | |
| connate water saturation ($S_{wc}$) | 0.19 | |
| **Fracture properties**: | | |
| permeability ($k_f$) | 1000 | md |
| porosity ($\phi_f$) | 0.01 | |
| fracture spacing | 10 | ft |
| initial oil saturation ($S_{oi}$) | 0.99 | |

## 5.2 Injection sequences

In experimental core floods it is common to continuously inject chemically enhanced brine from initial oil saturation until ultimate recovery. However, in field application, the chemical injection period is much shorter, i.e. they are injected only in slugs. One of the factors affecting the injection of chemicals is the cost compared with the oil price. Therefore, to have a sensible sensitivity study on a field scale, I will use an injection period and sequence based on the published pilot trial on Big Muddy field (Saad and Sepehrnoori, 1989). In this study the surfactant polymer flooding (SPF) will consist of:

- One year injection of surfactant-polymer
- Two years injection of polymer slug
- One year of polymer taper (lower concentration).

The base case will include one year of water flood before the chemical injection, and continuous water flood after the chemical injection period until the end of the assigned time of the simulation. **Fig.5.2** illustrates the injection profile in the base case model. The chemical process in this simulation was based on previous work done by CMG on surfactant-polymer flood pilot test on Big Muddy field. The fluid properties of the injected fluid can be found in **Table 5.2**.

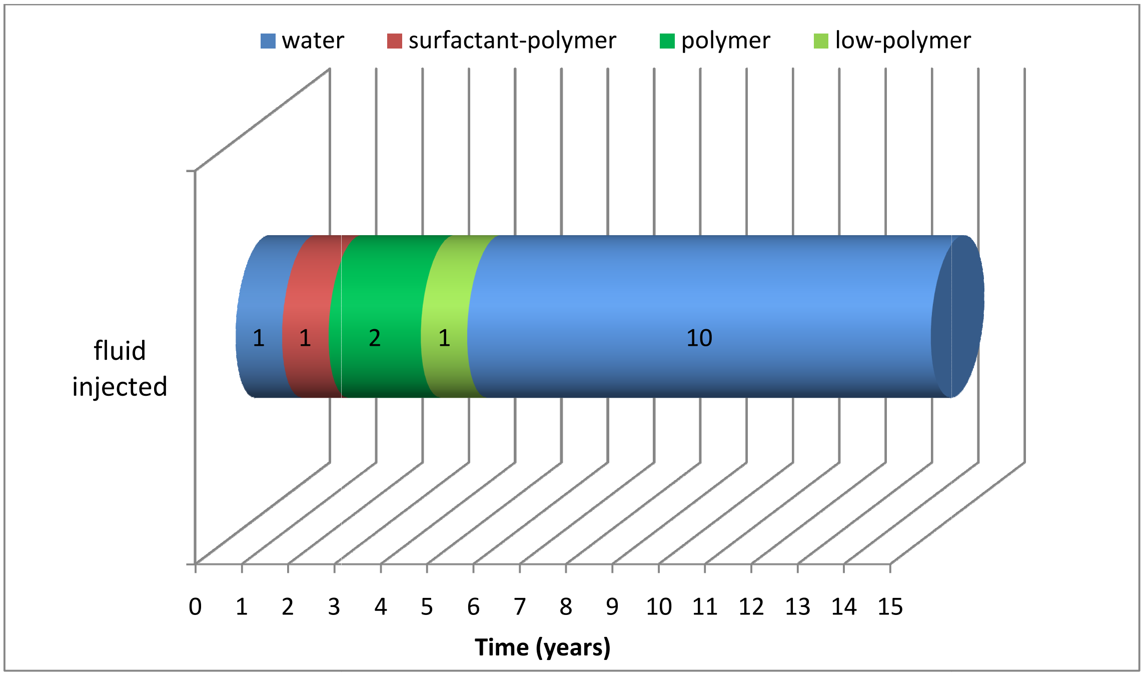


**Fig. 5.2 Injection profile of base case model showing sequesnce of liquids injection.**

**Table 5.2 Fluid properties used in simulation**

| | ***water*** | ***polymer*** | ***surfactant*** | ***oil*** |
|---|---|---|---|---|
| Phase | aqueous | aqueous | aqueous | oleic |
| Mass density, lb/ft3 | 62.97 | 62.97 | 62.97 | 58.2 |
| Mol Weight | 18 | 100000 | 548 | 100 |
| liquid compressibility, 1/psi | 3.00E-06 | 3.00E-06 | 3.00E-06 | 1.00E-05 |
| liquid expansion coefficient, 1/F | 0.00E+00 | 0.00E+00 | 0.00E+00 | -5.88E-04 |
| Viscosity, cp | 0.6 | 70 | 0.6 | 3.2 |
| Phase concentration, (wt %) | 0.91 | 0.00075 | 0.09 | 0.00 |

## 5.3 Wettability modeling

The wettability of the matrix in the base case was assumed to be mixed-wet. The alteration in wettability affects the relative permeability curves and capillary pressure. As for the fracture system, a straight-line relative permeability and zero capillary pressure were assumed. These fracture properties were validated in previous literature (Chen, 1995).

The modeling of the wettability alteration is based on an interpolation between the interfacial tension (IFT) and the capillary number which leads to calculating the relative permeability and capillary pressure at dimensionless time. There are two sets of relative permeability curves and capillary pressure that are input parameters; one set represents the rock conditions with no surfactant, and the other set represents the rock condition at maximum surfactant concentration. **Fig.5.3** and **Fig.5.4** show the relative permeability curves before and after surfactant effect. The initial relative permeability curves and capillary number behavior were selected based on the average curves of different trapping numbers presented by Delshad et al. (2009).

There are two sets of correlation that leads to interpolate between the relative permeability and capillary pressure curves before and after chemical injections. The first set of correlations is the IFT alterations based on the dissolved oil in the water caused by surfactant at each grid block. The second set of correlations is the capillary number (Nc $= \frac{v\mu}{\sigma}$ ) which requires the interpolation of IFT first, in order to calculate the capillary number. Capillary number is presented in the simulator as the $\log_{10}$(Nc) and called the trapping number (DTRAP). There are two trapping number for each interpolation set: one set for the wetting phase (DTRAPw) and the other for the non-wetting phase (DTRAPn).

The relative permeability curves for matrix blocks for each phase are then calculated from the following equations:

$k_{rl} = k_{rli} \cdot (1-\omega_l) + k_{rlf} \cdot \omega_l$ …………………………………………………………(5.2)

and,

$P_c = P_{ci} \cdot (1-\omega_{pc}) + \omega_{pc} \cdot P_{cf}$ ……………………………………………………..(5.3)

where $k_r$ is the relative permeability of phase $l$, i is the initial condition, f is for final condition or at maximum surfactant affect, $P_c$ is the capillary pressure, and $\omega$ is the interpolation factor which is calculated from the interpolation equations of DTRAP number. $\omega_{pc}$ is the interpolation factor for the capillary pressure which is the average of the interpolation factor of each phase. Both interpolation factors are calculated as follows:

$$\omega_l = \frac{\log_{10}(Nc) - DTRAP_i}{DTRAP_i - DTRAP_f} \quad \text{………………………………………………………(5.4)}$$

$\omega pc = (\omega_{oil} + \omega_{water})/2$ ……………………………………………………………...(5.5)

In base case model, the maximum amount of oil dissolved in water is set at 0.03 wt% which will result in IFT of $10^{-3}$ dyne/cm. The DTRAP numbers at initial and final condition for oil are, -4 and -3 and for water are -5 and -1.5 respectively. These values are used to represent the change from mix-wet rock to water wet rock at high surfactant concentration.

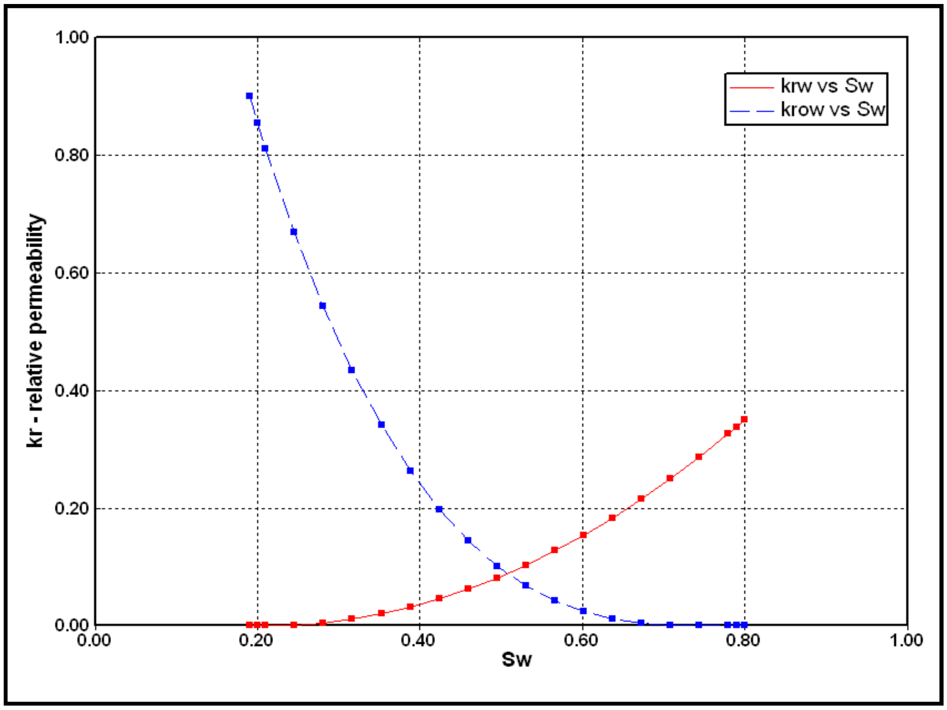


**Fig. 5.3 Oil – water relative permeability curves at initial condition.**

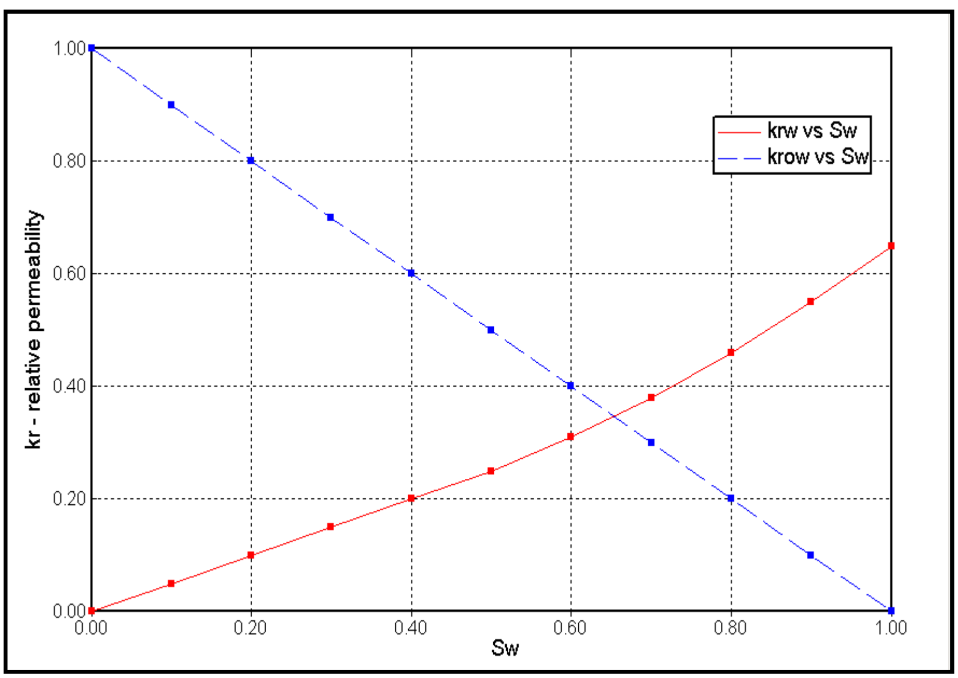


**Fig. 5.4 Oil-water relative permeability curves at maximum surfactant concentration.**

### 5.4 Adsorption

The simulator has the capability to model additive adsorptions in the rock and add the adsorption term, $\frac{\partial}{\partial t}[\phi \text{Adsop.}]$, in the flow equations (presented in Appendix A). In order to simulate this phenomenon, temperature effect, rock density, porosity, and fluid composition have to be known. Also the rate of increase of adsorption with fluid composition should be known as well as the maximum adsorption capacity. All these parameters are needed for the Langmuir isotherm correlation.

Adsorption modeling is essential when chemical precipitation is formed. It simulates the amount of blockage in the pores and changes the local permeability of the rock. The adsorptions can be expressed in mass per unit volume or mole fraction per unit volume.

A hypothetical adsorption behavior was added in the model, based on previously built-in CMG model, for the completeness of the surfactant polymer flooding process and flow equations. A maximum adsorption capacity of 0.1336 lb-mole/ft$^3$ surfactant and 0.28 lb-mole/ft$^3$ polymer was set for the matrix blocks. **Fig.5.5** and **Fig.5.6** show the adsorption of polymer and surfactant in the base case model run receptivity. **Fig. 5.7** shows the calculated IFT that correspond to the surfactant effect.

### 5.5 Validation runs

To validate the effect of the chemicals injected, the base case model (SPF) was run against water flooding, surfactant flood, and polymer flood. The properties used for the surfactant and polymer properties are taken directly from the simulator sample models.

No lab work has been accomplished during this study to evaluate the potential effect of such a process. Also, there was no fully published field case pilot on a fractured reservoir. The results of the validation runs are presented in the "Results and Discussion" section.

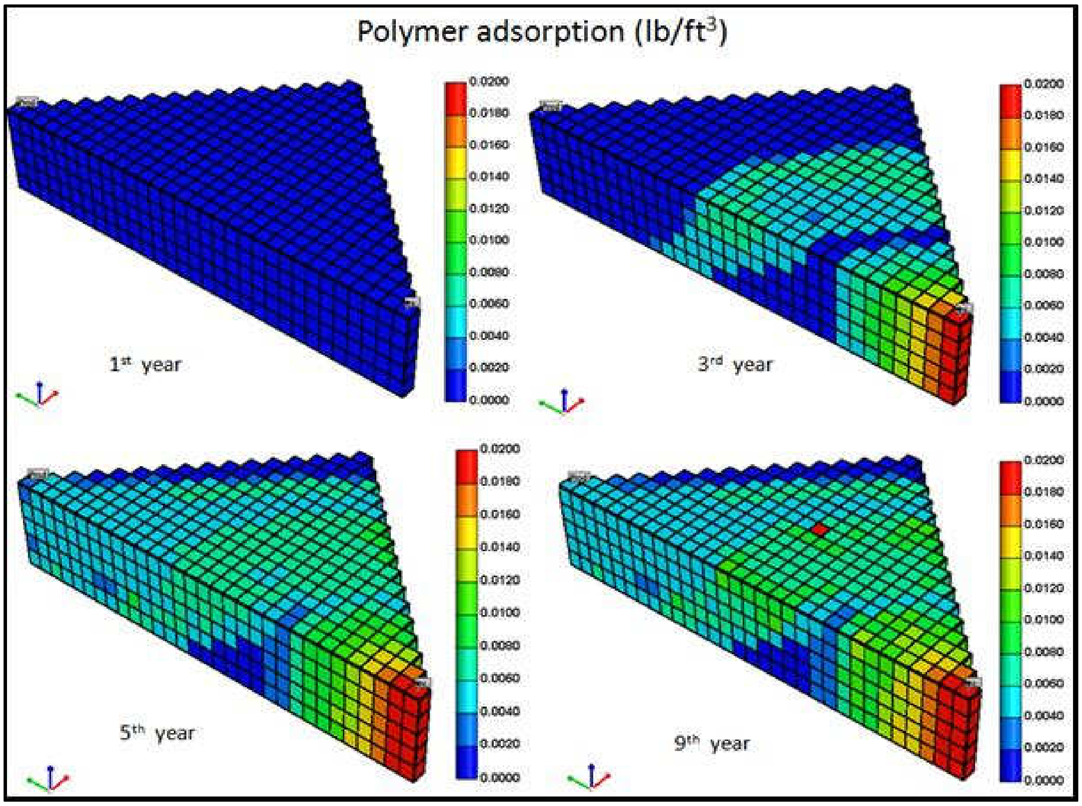


**Fig. 5.5 Adsorption of polymer in the matrix blocks at different injection times.**

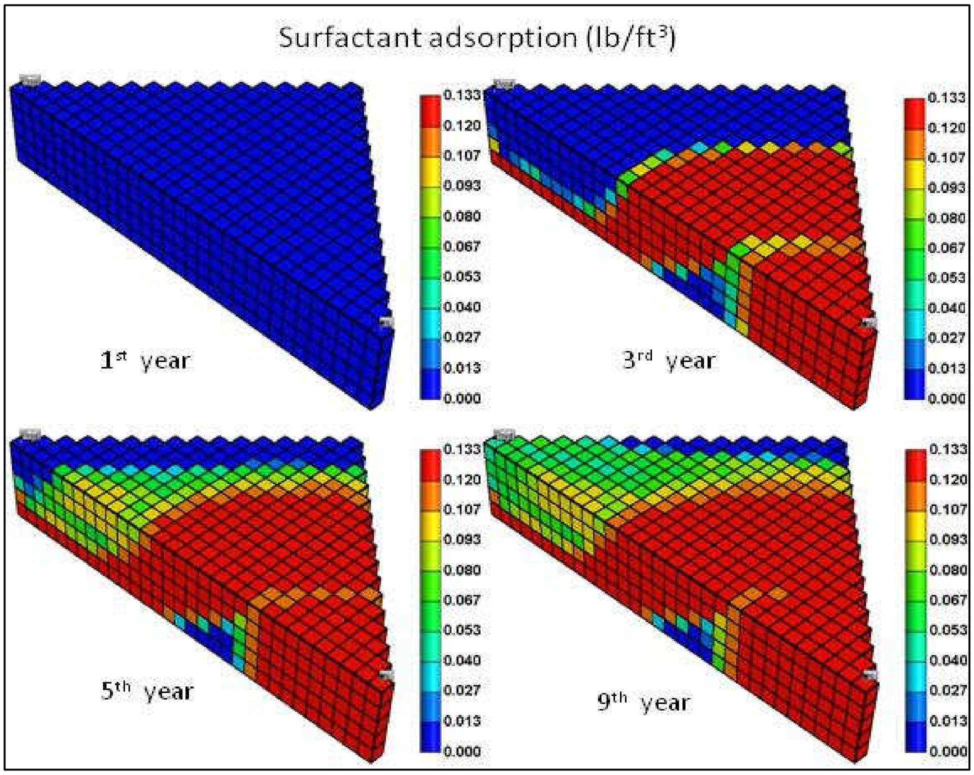


**Fig. 5.6 Surfactant adsorbed in the matrix at different injection times.**

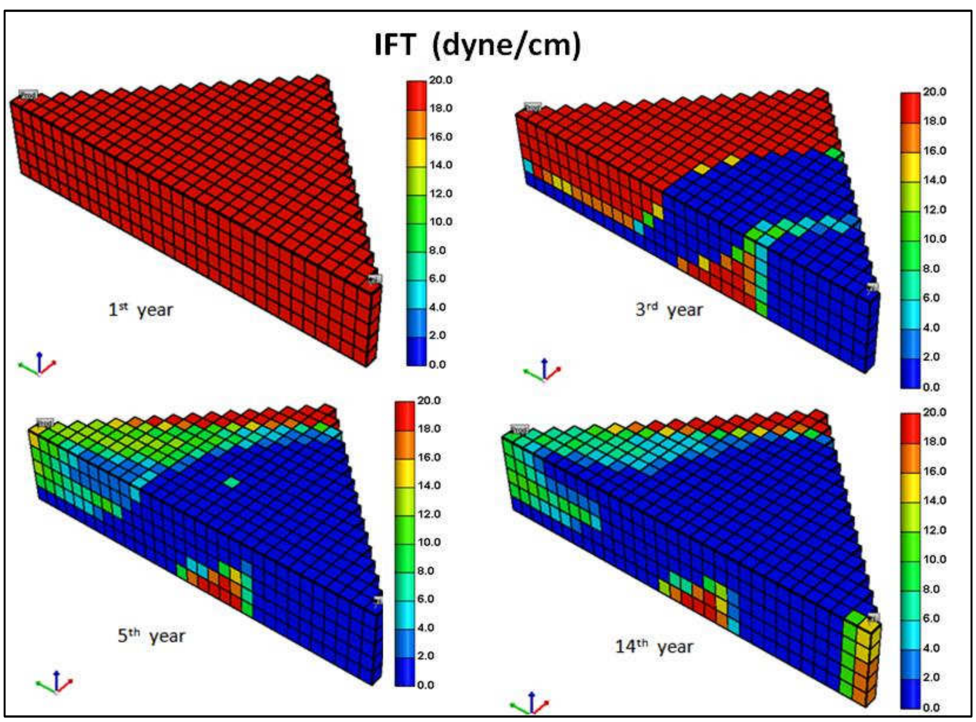


**Fig. 5.7 IFT alterations corresponding to the surfactant adsorptions.**

# 6. RESULTS AND DISCUSSION

The base case was used to run several sensitivity and case scenarios for different parameter that might affect the performance of a surfactant-polymer flood. The parameters include injection strategy, permeability of fractures and matrix, fracture spacing, and fracture orientation. This section is divided according to the parameter used in the sensitivity study.

This study was done to illustrate the surfactant-polymer performance on different fracture system. The work was not intended for a complete optimization of the surfactant polymer process. Before making any conclusion, one should make an in-depth screening of surfactant and polymer that best suit the reservoir fluid and rock properties. Then a comprehensive sensitivity study can result in an optimization of such a process. Most of the data used to calculate the effect of such process (i.e. adsorption, IFT, wettability) are extremely sensitive to reservoir conditions and differ from rock type to another.

To validate the use of surfactant polymer flooding (SPF) in fracture reservoir, the base case model was compared with water flooding (**Fig. 6.1**). Surfactant flooding (SF) and polymer flooding (PF) was also compared against the base case model to insure the effect of each chemical in the base case model (**Fig. 6.2**). The results shows high oil recovery in the base case model, around 15% incremental gain, compared to water flooding, SF, or PF. Results also show that polymer flooding (i.e. improving areal sweep), results in higher and faster recovery than surfactant flood. However, surfactant flooding shows increased slope in the oil recovery curve toward the end of the simulation time. With polymer flood, the oil recovery curve start flattening which means there is no increase after water breakthrough. The increase in the surfactant flooding shows the effect of wettability alteration which reduces the increase in water cut.

The combined surfactant-polymer process, as seen in the base case, shows high oil recovery due to the improved mobility that causes the surfactant to imbibe in more matrix blocks and change the wettability. **Fig. 6.3** shows the remaining oil saturation in the matrix blocks for all four cases: water flooding, surfactant flooding (SF), polymer flooding (PF), and surfactant-polymer flooding (SPF). The highest remaining oil saturation in each case was less than 50%, therefore the color range is set from 0 to 0.5 to increases the color contrast. The surfactant flooding case shows scattered matrix blocks with very low oil saturation surrounded by high oil saturation blocks. The polymer flood shows good sweep but high remaining oil saturation.

The base case model was converted to a single porosity model (no fractures) to compare the sweep efficiency. As expected, the single porosity model showed much higher level of areal sweep in both water flood case and surfactant polymer flood (SPF) case but with less oil recovery. **Fig. 6.4** shows the remaining oil saturation of the single porosity model with 50 md rock recovery by water flooding and SPF.

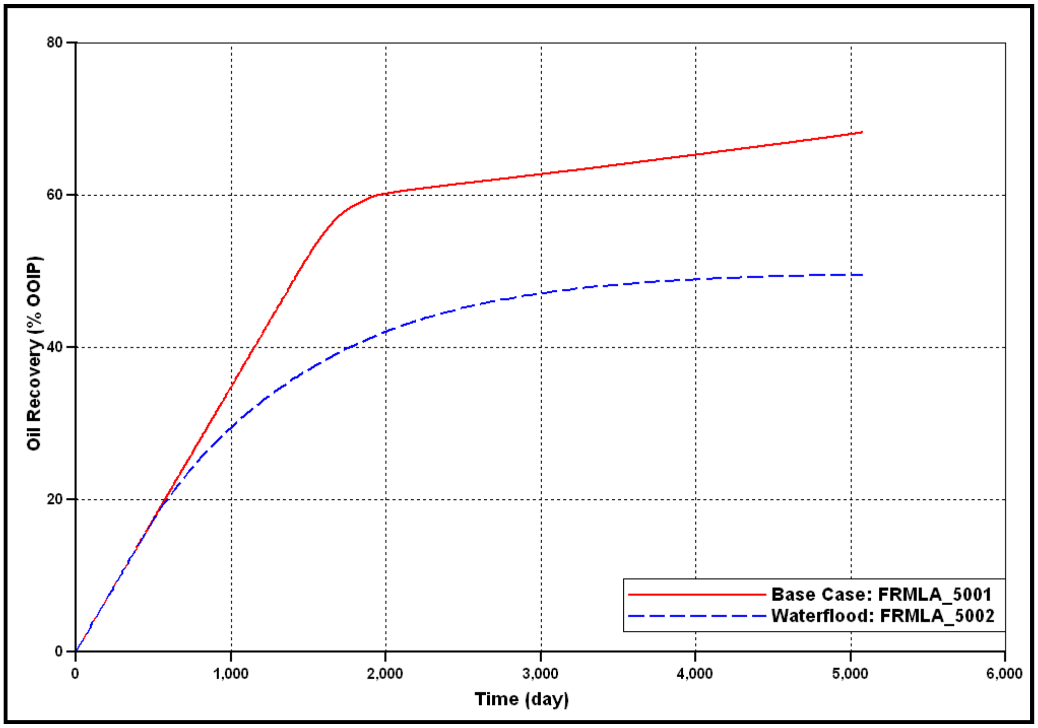


**Fig. 6.1 Oil recovery in base case model and water flood cases.**

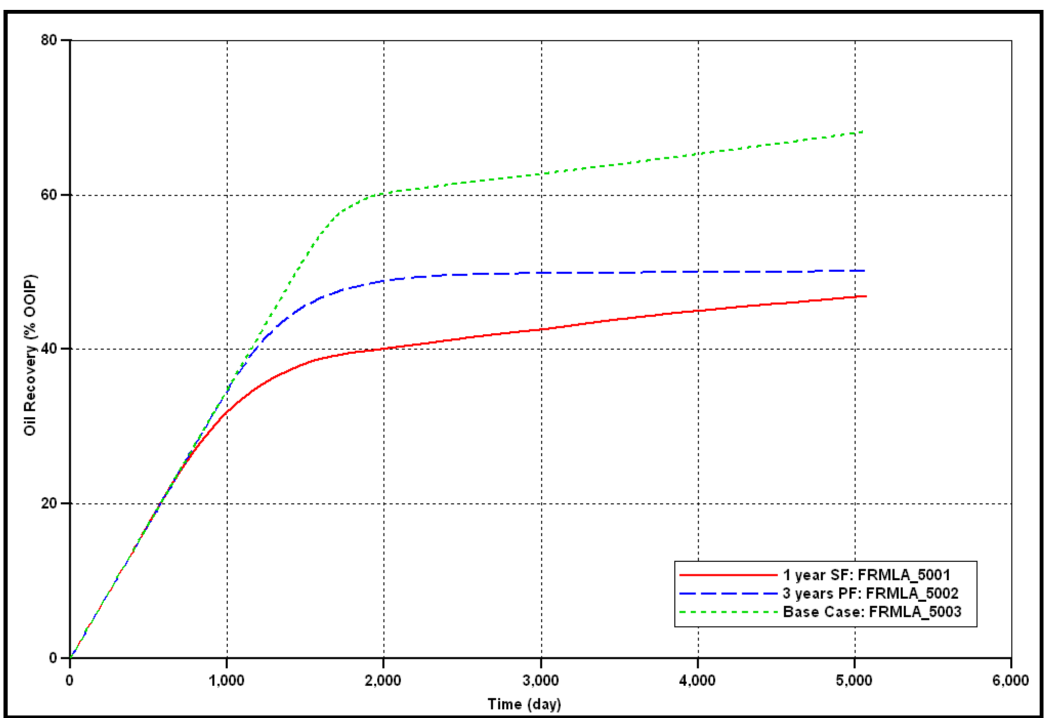


**Fig. 6.2 Oil recovery of base case (SPF) compared with each chemical injected used separately: (SF) and (PF).**

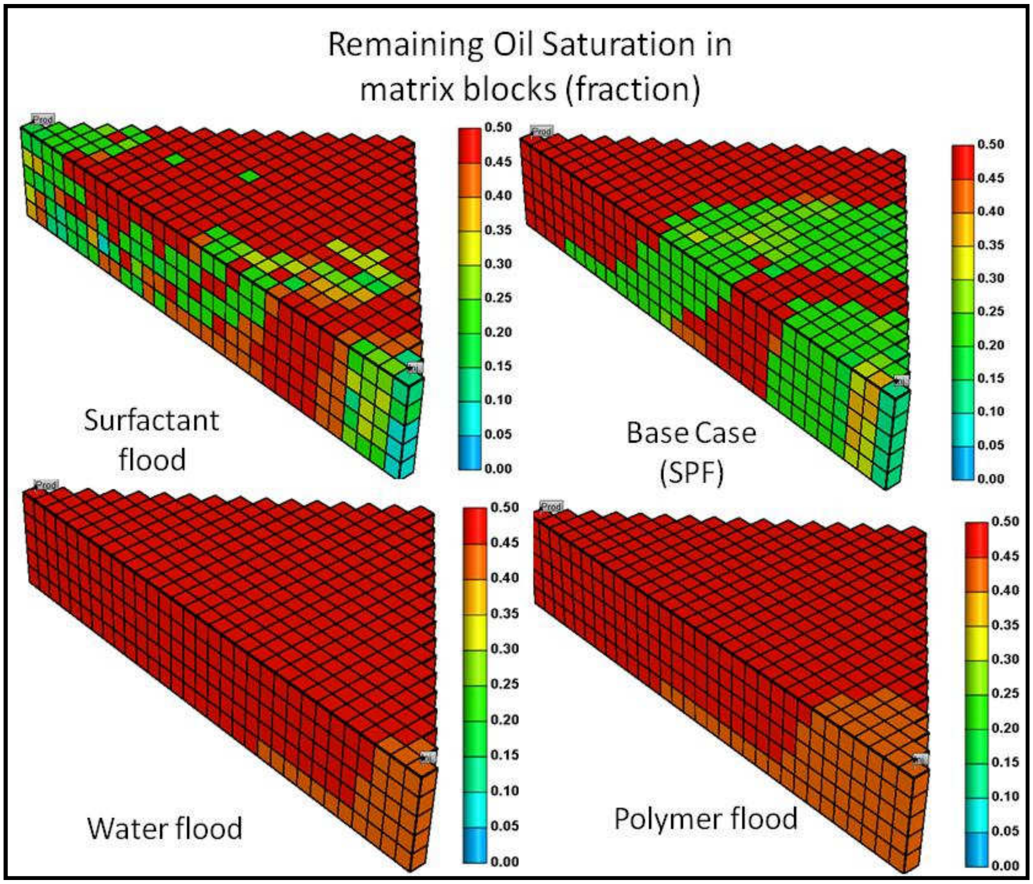


**Fig. 6.3 Remaining oil saturation at end of simulation in different flooding cases on the 1/8 DPDP model.**

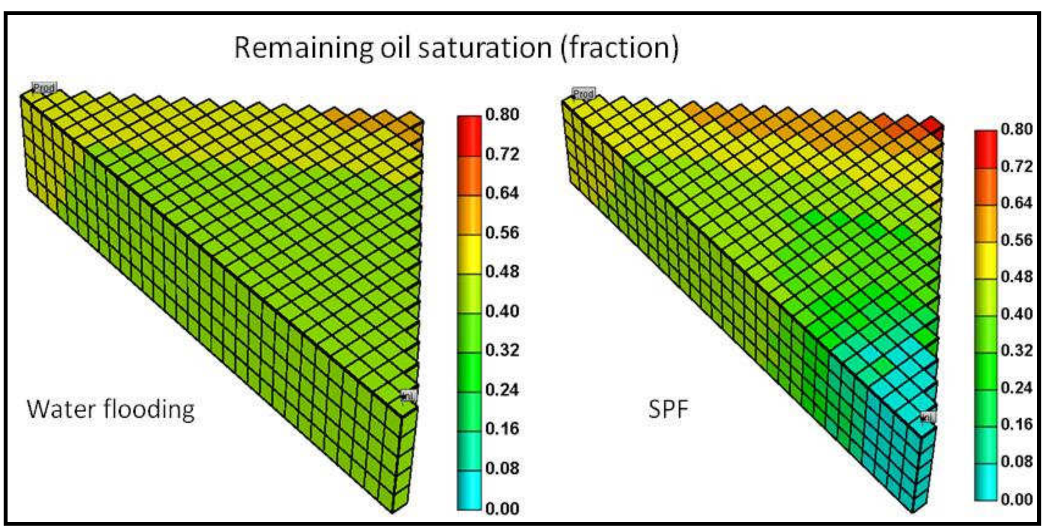


**Fig. 6.4 Remaining oil saturation at end of simulation in non fractured 1/8 model.**

## 6.1 Injection scenario

Having only one year of surfactant flood makes it critical to decide at which oil saturation should chemical injection process start. Several injection scenarios have been simulated on the base case model. **Fig. 6.5** shows the injection profile for each case. The results of varying the start of the surfactant-polymer flood (SPF) showed inconsistent relationship with total recovery **(Fig.** 6.6**)**. It seems that there is a critical water saturation that affects the recovery as seen in the decreasing recovery as the water saturation increase. On the other hand, starting the surfactant polymer process with no pre water injection resulted in less oil recovery when compared to the base case where there was a pre water flood. This could be related to the initial lowering of the capillary force by reducing the IFT before the effect of wettability alteration occurs. Nevertheless, injection of surfactant polymer as a secondary process still outperforms conventional water flood. **Fig.6.7** summarizes the total oil recovery of each run.

Additional sensitivity cases have been run to investigate the trend of surfactant polymer performance with respect to different SPF starting time and changing a second property. The properties changed are: change original wettability, fracture spacing, and no fracture base case model.

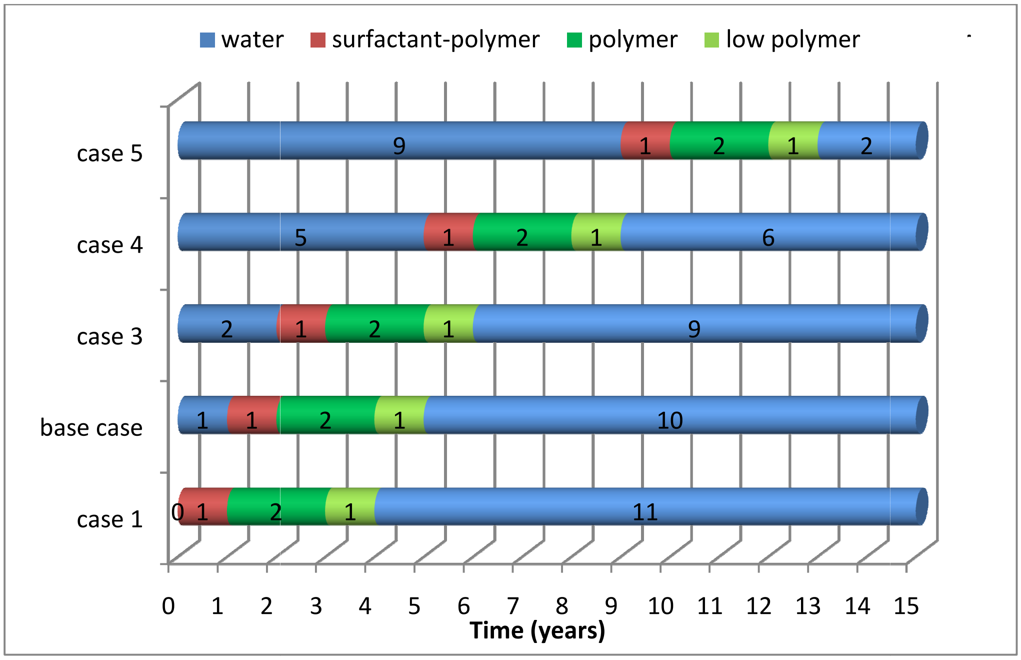


**Fig. 6.5 Injection profiles for different injection cases.**

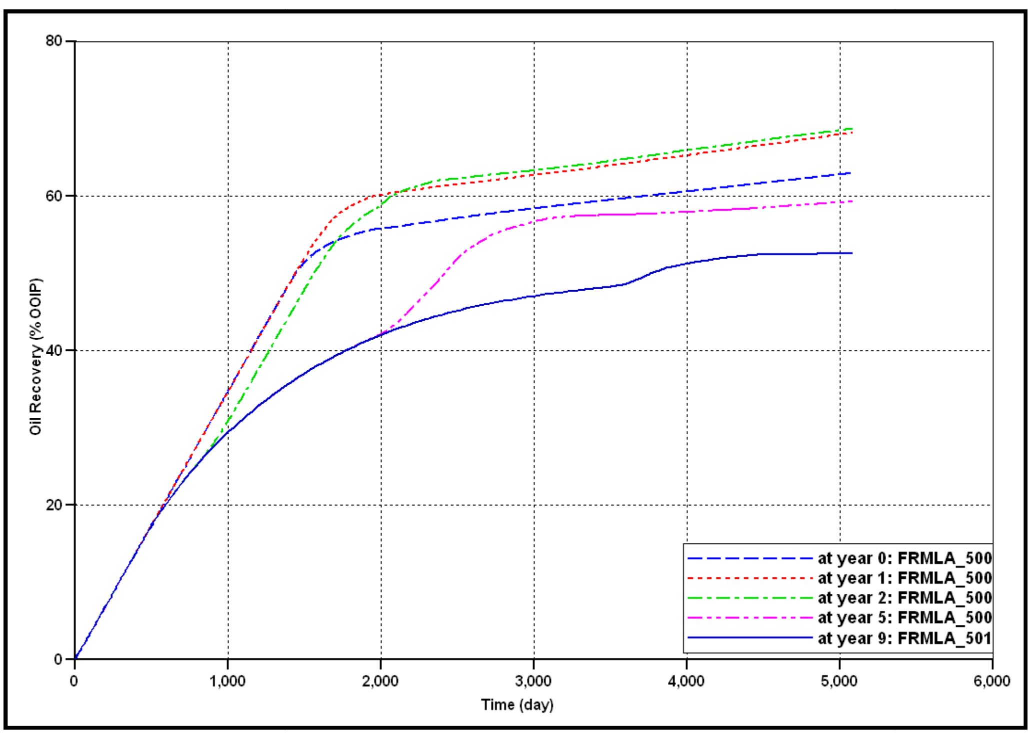


**Fig. 6.6 Recovery factor for base case at different SP injection times.**

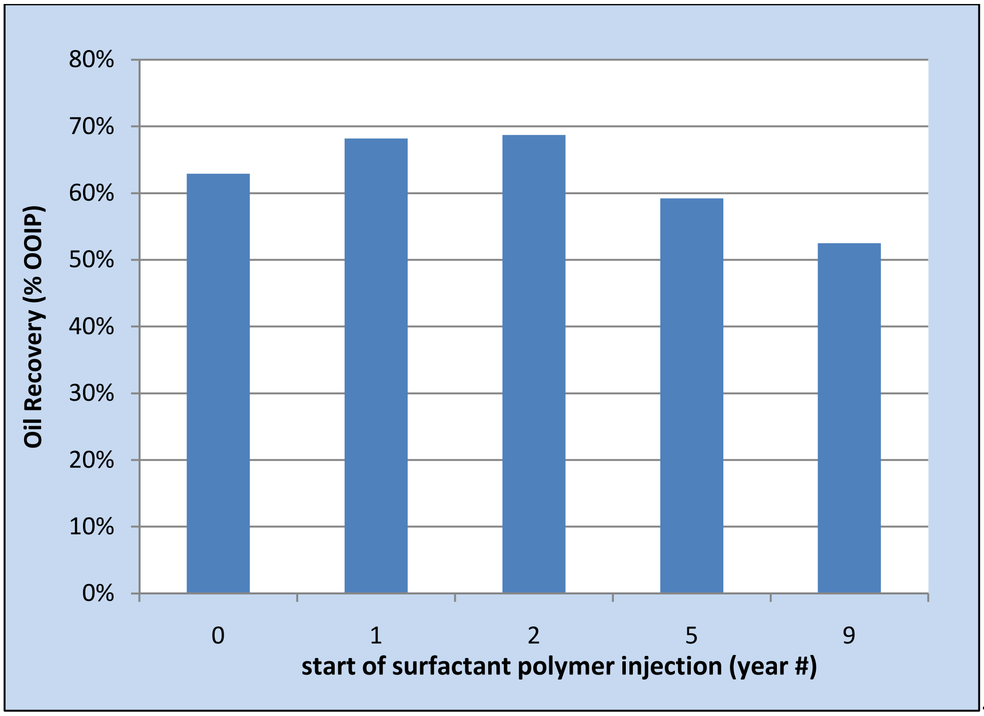


**Fig. 6.7 Total oil recovery vs. start of surfactant polymer flooding in base case.**

### 6.1.1 Water-wet case

Similar runs on injection scenarios have been made done after changing the initial wettability of the matrix to more water-wet. The change has been done in the original relative permeability curves, capillary pressure curve, and capillary number. The capillary pressure curve has increased to remove the negative capillary pressure, ranges from 10 to 0 psi. The results of this study showed similar trend as the mixed-wet case in the change in oil recovery with respect to the starting time of surfactant polymer injection. Both sensitivity cases indicate that higher oil recovery is achieved in pre water injection case. **Fig. 6.8** shows the oil recovery for each run with respect to time.

The water-wet case results in much higher oil recovery than the mix wet case.. Due to the higher rock wettability to water-wet, the imbibition by capillary force is higher which resulted in a higher recovery by water flood. The incremental recovery by SPF in the water-wet cases was slightly less than incremental gain in the mix-wet case. However, the overall oil recovery in the water wet SPF case is higher. **Fig. 6.9** shows the final oil recovery of each run in the water-wet scenario.

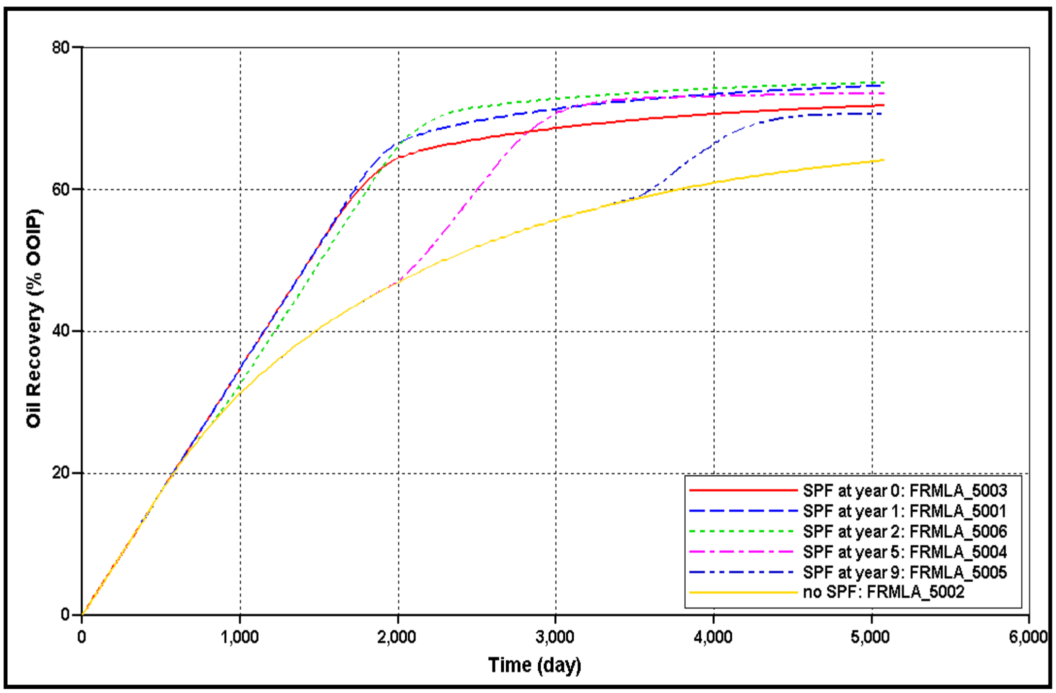


**Fig. 6.8 Effect of SPF on a water-wet reservoir at different injection times.**

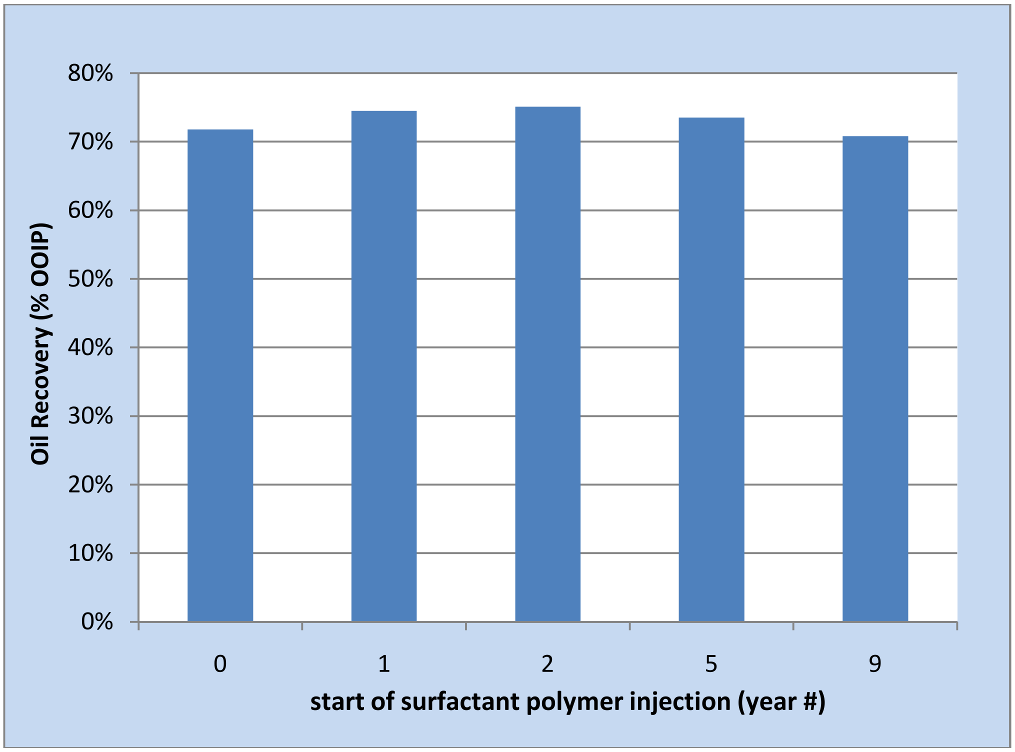


**Fig. 6.9 Total oil recovery in water-wet case at different SPF starting times.**

### 6.1.2 Oil-wet case

Oil-wet rock is characterized by with the absence of a positive capillary pressure and the relative permeability curves intersect at less than 0.5 water saturation. Water flooding in that case is not effective. The capillary pressure in this study ranges from 0 to -10 psi. The surfactant polymer flood was able to increase the oil recovery however, total recovery being less than 35% OOIP. **Fig. 6.10** shows the oil recovery for each run with respect to time. Due to the negative capillary effect, low capillary imbibition, the oil recovery increases when surfactant polymer is injected at the beginning of the flooding process. **Fig. 6.11** shows the final recovery of each run in the oil-wet scenario.

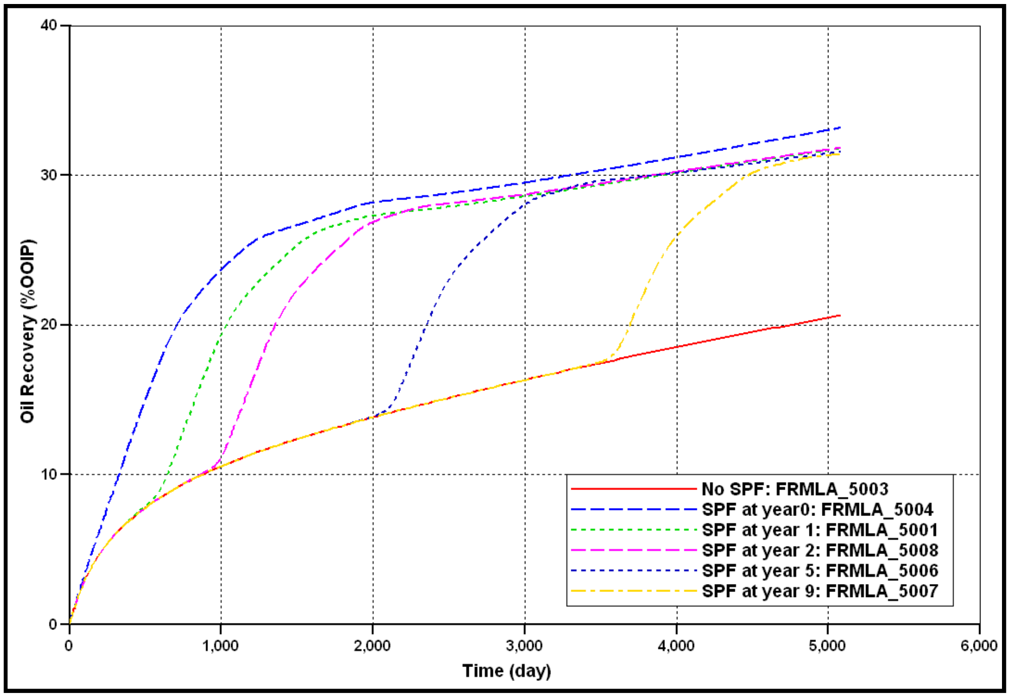


**Fig. 6.10 Effect of SPF on oil-wet reservoir case at different injection times.**

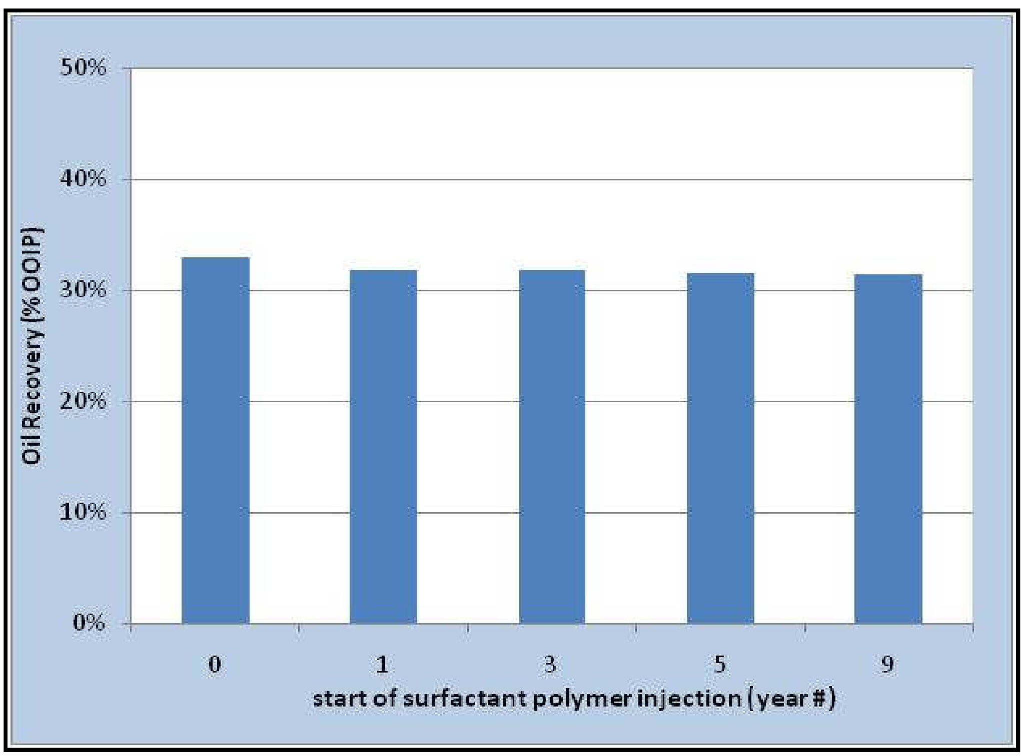


**Fig. 6.11 Total oil recovery for oil-wet case at different injection times.**

### 6.1.3 Single porosity case

To investigate whether the importance of pre-water injection is more critical to a fractured reservoir, the base case model has been converted to a single porosity model, removing all the fracture attributes. The single porosity model has homogenous matrix blocks with permeability of 50 md and $k_v/k_h$ of 0.1. Three runs have been made: (1) no SPF, (2) SPF without a pre-water injection, and (3) SPF with one year pre-water injection (**Fig.6.12)**. Unlike the fractured reservoir case, the difference in oil recovery with or without pre-water injection was negligible.

Due to the low matrix permeability, the rate of oil recovery in the two cases that include SPF was less than the case with no SPF. However, the total recovery at the end of the simulation was higher in the SPF cases. But no generalized conclusion can be drawn from this result. Different design of surfactant flood can outperform water flood in rate of recovery.

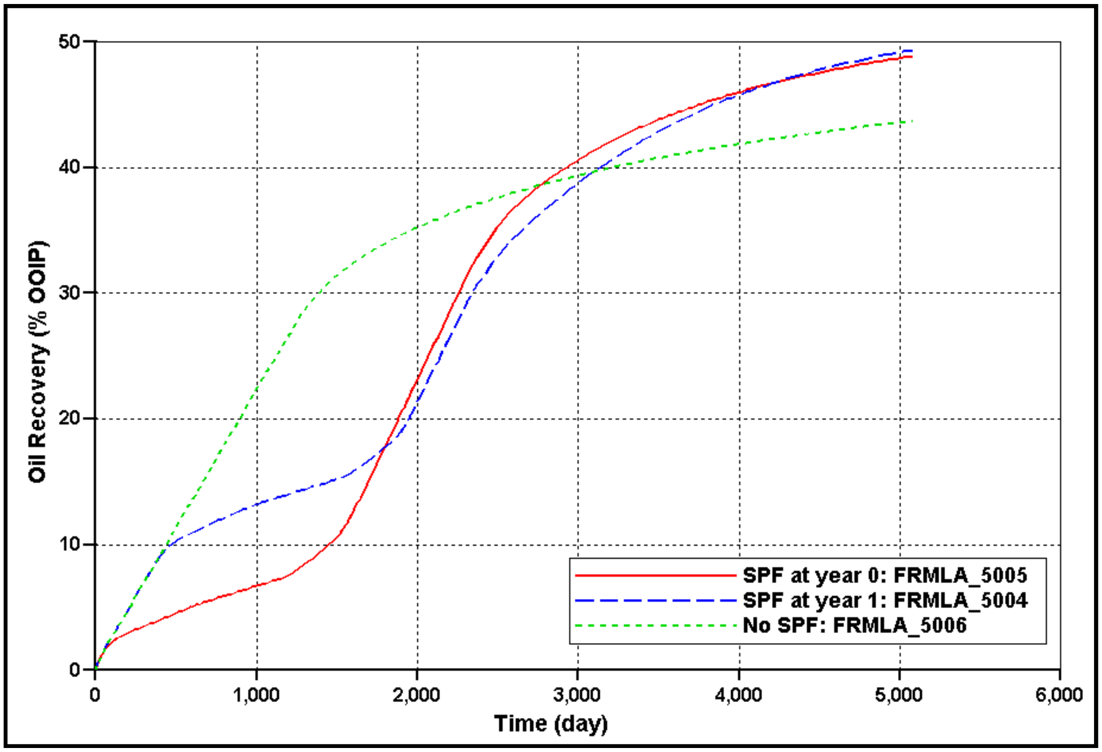


**Fig. 6.12 Oil recovery for different water flood cases for 50md single porosity model.**

The three runs of single porosity model have been repeated after increasing the matrix permeability to 500 md. **Fig. 6.13** shows the recovery performance of these cases. The cases with SPF have significantly outperformed the no SPF case. Both SPF cases have the same final recovery. The SPF with no pre water flood has faster oil recovery than the pre water flood case which contradicts the result of the fractured reservoir base case.

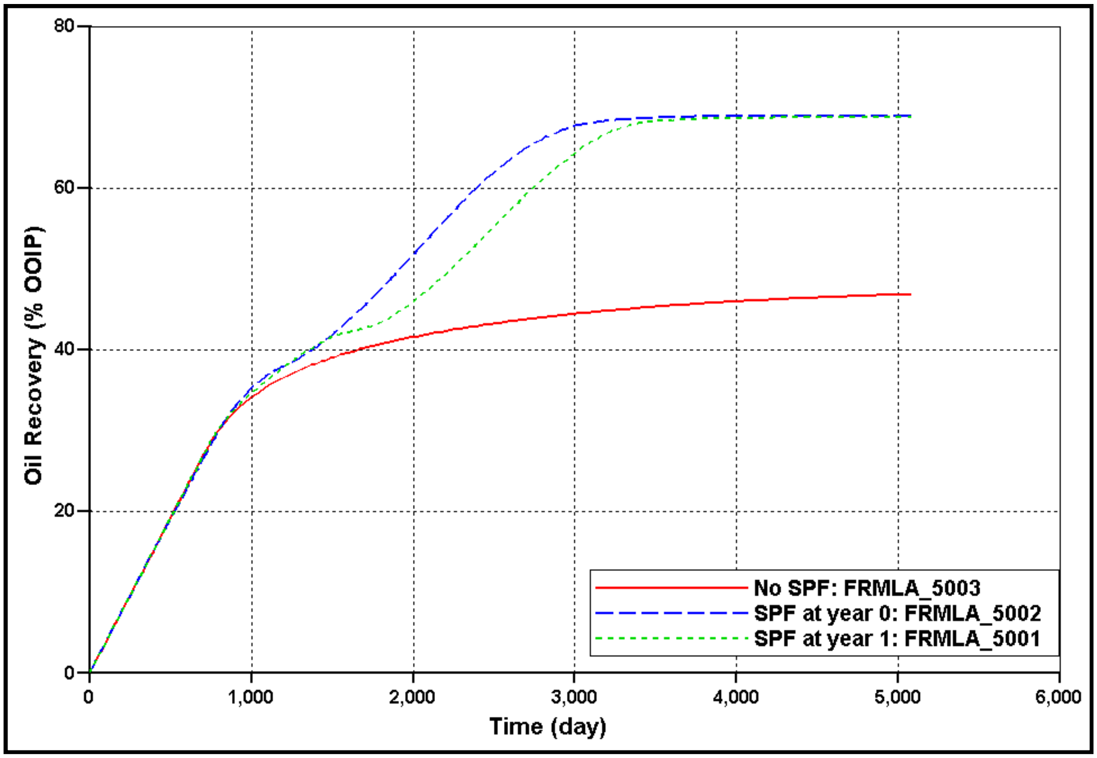


**Fig. 6.13 Oil recovery for different water flood cases for 500md single porosity model.**

### 6.1.4 Fracture spacing

The fracture spacing in DPDP base case model has been changed to: 5ft and 20ft spacing to change the fracture density. Two runs have been completed with each fracture spacing to compare the affect of pre-water injection on surfactant polymer flooding and verify the cases run in the base case. **Fig 6.14 and Fig 6.15** show the oil recovery in 20ft and 5 ft fracture spacing respectively. The results show that the pre flush out performs the no pre-water injection case. Also, as the fracture density increases, the effect of pre-water injection increases.

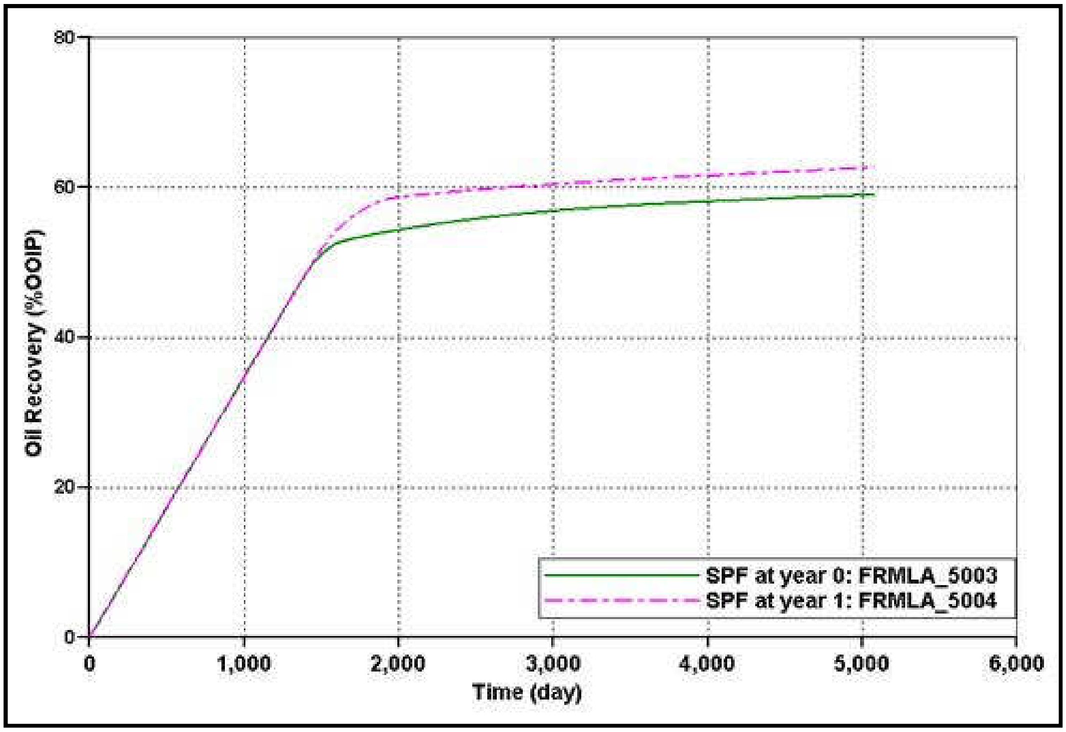


**Fig. 6.14 Effect of pre-water injection on 20 ft fracture spacing reservoir.**

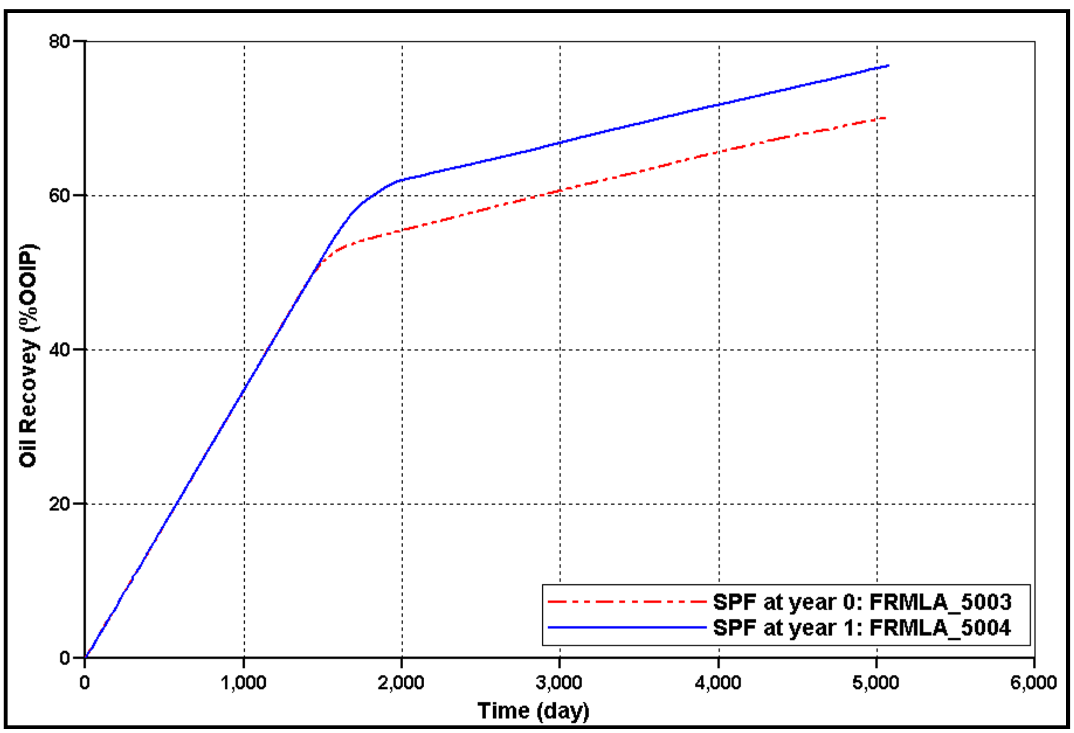


**Fig. 6.15 Effect of pre-water injection on 5 ft fracture spacing reservoir.**

## 6.2 Permeability contrast

Several simulation runs have been made with different fracture permeability and different matrix permeability. As expected, the difference between fracture and matrix permeability increases the performance of enhanced fluid injection will decrease. This is due to the increase in residence time of the injected chemicals which will increase its effect. However, the presence of polymer has reduced the impact of the permeability variation. **Fig. 6.16** and **Fig.6.17** show the recovery for different fracture permeability and matrix permeability respectively.

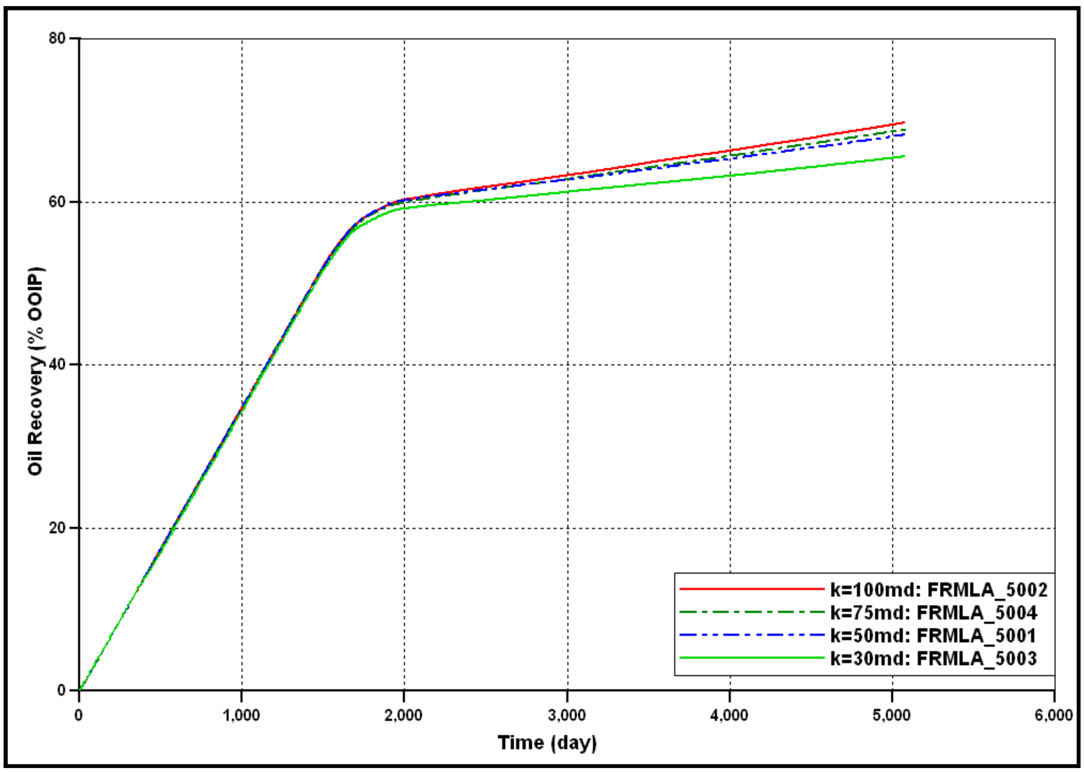


**Fig. 6.16 Sensitivity of oil production to matrix permeability in SPF.**

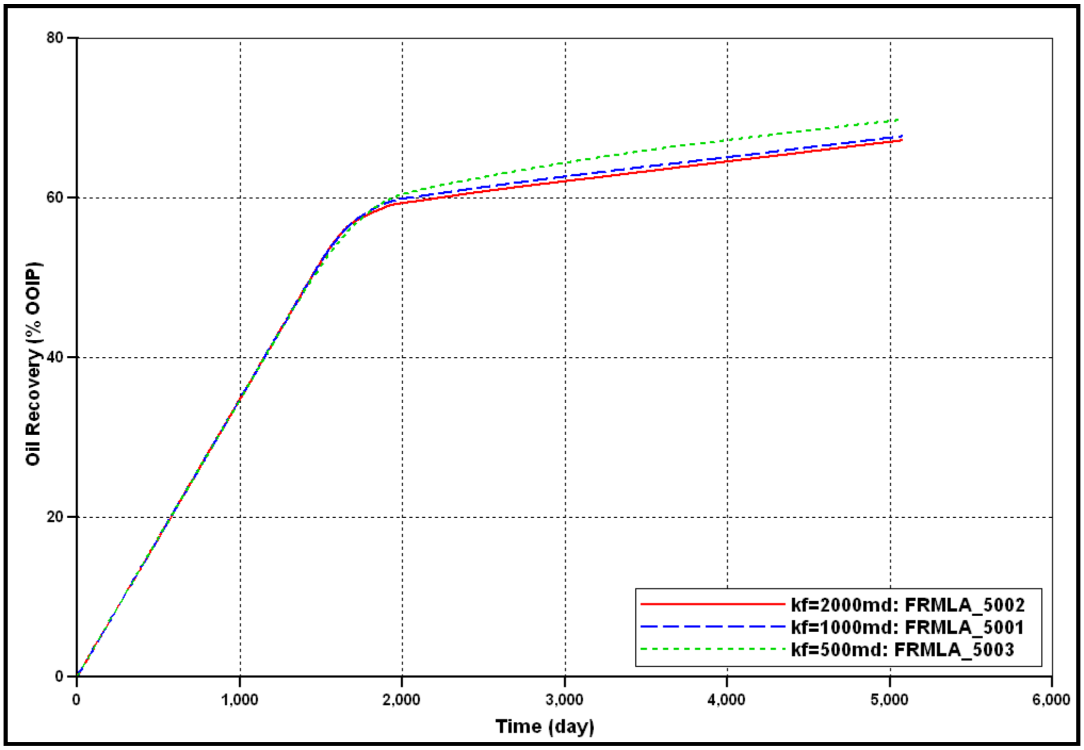


**Fig. 6.17 Sensitivity of oil production to fracture permeability in SPF.**

## 6.3 Fracture spacing

The base case run has been repeated with different fracture spacing (5ft, 10ft, and 20 ft). The spacing of the fracture in the DPDP model affect the width of the fracture as well as the matrix blocks size and thus, affects the communication between the matrix and fractures. The results show that as the fracture spacing decreases, the oil recovery increases as seen in **Fig 6.18** The results show the more fracture there is, smaller the matrix block; this results in faster imbibitions between matrix blocks and fractures.

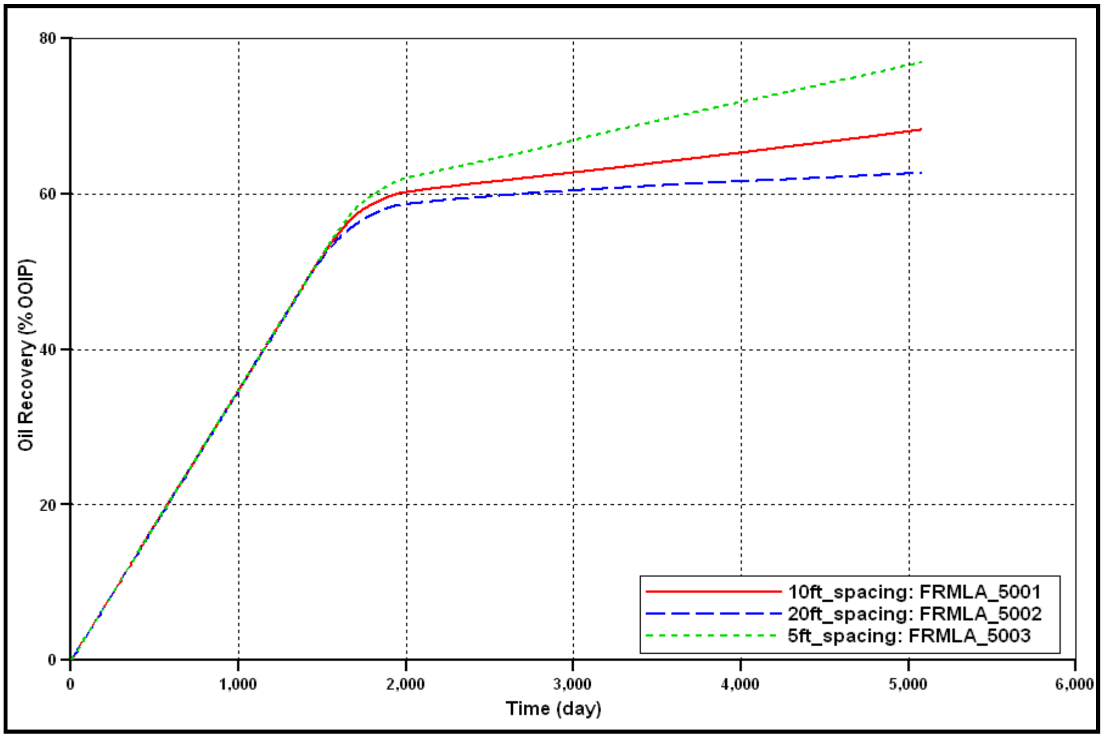


**Fig. 6.18 Sensitivity of oil recovery to fracture spacing.**

## 6.4 Fracture orientation

Another parameter that affects the recovery in naturally-fractured reservoirs is fracture orientation. Using DPDP model alone will not give enough representation of such a parameter. In the constructed grid block, there are only two cases of fracture flow direction (parallel or normal) with respect to the injector producer direction. In each case I assumed 1000 md for fracture orientation and 50md for the opposite direction which is equal to matrix permeability. SPF injection sequence was similar to the base case model. **Fig**.**6.19** shows the oil recovery comparison between SPF and water flooding in the parallel fractures orientation. **Fig.6.20** shows the oil recovery comparison between SPF and water flooding in fractures normal to the injector-producer direction.

There was a delay of the chemical response in the normal fracture case due to the higher viscosity fluid which makes the less viscous water flood case recover oil earlier. However after water has imbibed in the SPF case and water start injected back, the oil recovery was much faster and resulted in 20% OOIP incremental gain.

The water was moving faster through the matrix and fracture in the parallel case resulting in large volumes of bypassed oil and even untapped areas. The SPF has helped improved the areal sweep as well as reduce oil saturation. It is worth mentioning that fractures parallel to injector producer direction recover less than when fractures are at normal direction. The normal direction case along with the mobility control fluid has created more residence time for the surfactant slug which resulted in more imbibition and thus displacement of oil from the matrix. **Fig.6.21** shows the remaining oil saturation after SPF in both fracture cases. The remaining oil saturation shows a high areal sweep and low oil saturation in the normal fracture case compared to the parallel case.

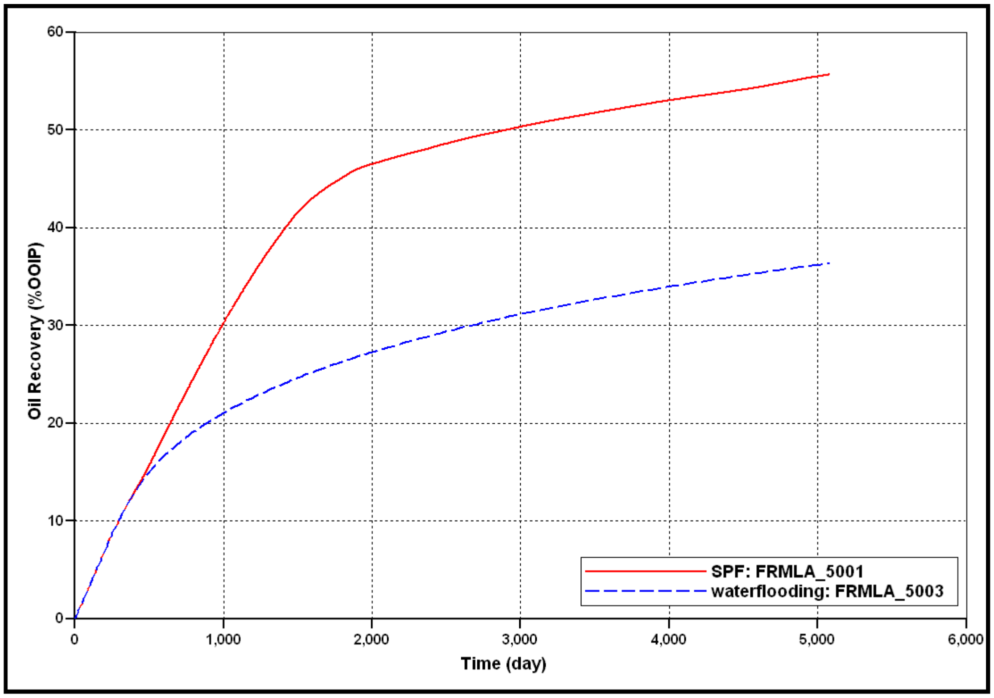


**Fig. 6.19 Oil recovery comparison in fractures parallel to injector-producer direction.**

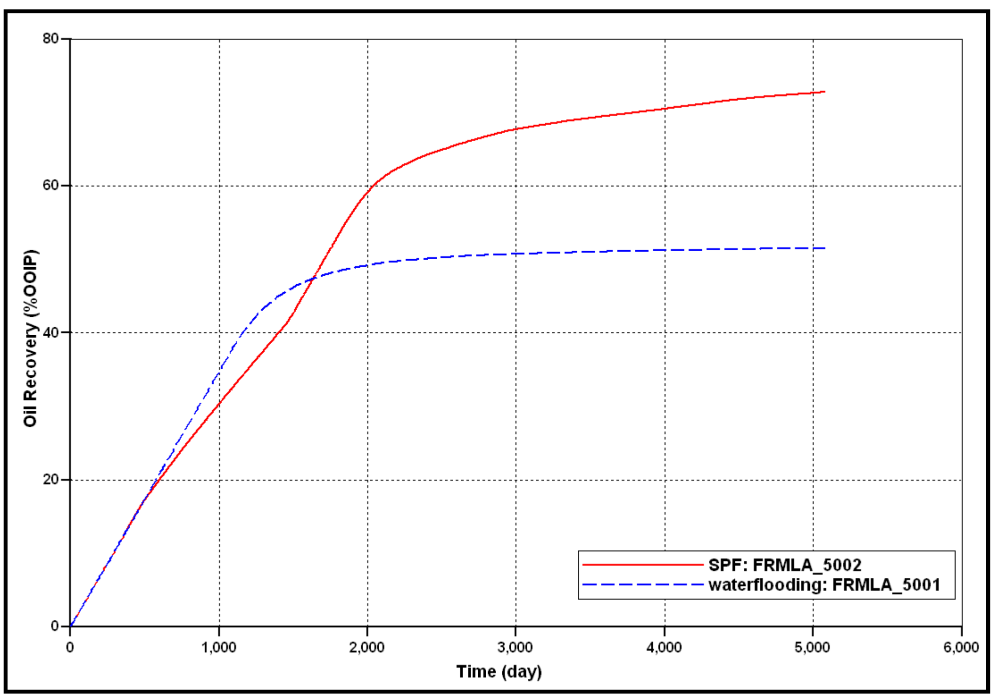


**Fig. 6.20 Oil recover comparison in fractures normal to injector producer direction.**

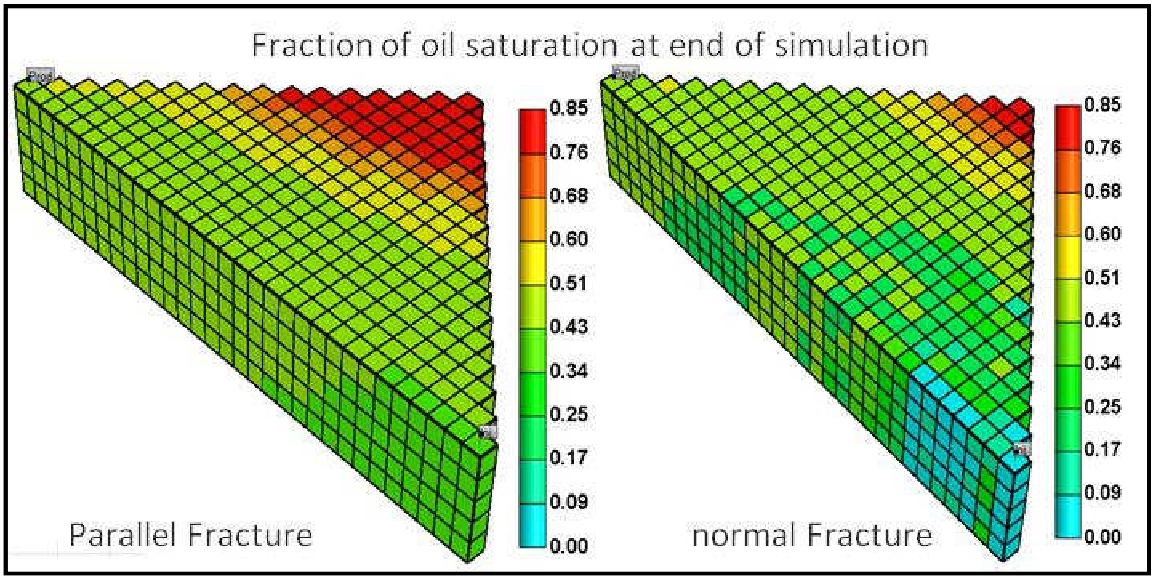


**Fig. 6.21 Remaining oil saturation distibution at the end of SPF case for different fracture orientation.**

### 6.5 Surfactant polymer slug size

The amount of surfactant-polymer used in SPF is a critical issue when it comes to cost of the chemical used per incremental oil recovered. This part of the study will focus on the effect of increasing the amount of surfactant-polymer during the life of the field and how it impacts the oil recovery. The sensitivity study has been done by comparing only surfactant polymer flood (SPF). All runs do not have polymer flood after the surfactant polymer injection. All cases include a one year pre water injection. The SPF injection period has been increased from 1 year to 2, 3, 4, 6 and 9 years. **Fig.6.22** shows the injection sequence of each case. The total PV injected was around 1.4 in all cases. **Fig.6.23** shows the oil recovery profiles for the sensitivity runs. The results indicate there is an optimum volume of of surfactant polymer injected. Before that, the more surfactant is injected, the higher the oil recovery. Beyond the optimum length, the oil production rate starts to decline as well as the total oil recovery. It was noticed that in all cases the total production rate was not changing which indicate only the water cut is changing. This behavior is not observed in a single porosity rock where any resistance or blockage in matrix will result in a drop in the total fluid produced. This is an essential knowledge in optimizing the use of surfactant polymer flooding in a fractured reservoir in order to maximize the recovery and reduce cost.

The drop in production can be related to several factors. One important factor is the fluid adsorption which reduces the relative permeability and my cause some blockage in the pores. There is a water-cut increase after reaching the maximum adsorption of surfactant. In other words, the injected fluid will continue to flow through the fractures with lower fluid imbibitions to matrix which explain the constant fluid production rate when switching back to water flood more fluid imbibed at a higher rate due to the reversibility character of the adsorption modeled in this study.

Another possible reason of the slight increase in oil rate is that the high IFT fluid injected will imbibe faster in the altered water-wet rock with higher capillary pressure which will cause faster oil recover. This phenomenon complements the study done by Gupta et al. (2009) which concluded that recovery oil increase in water-wet rock is at higher IFT. The study was done in an imbibition cell experiment. In our case the mobility is adding more force not only in delaying the recovery but rather, decrease the recovery since the oil rate was dropping as more surfactant slug is injected.

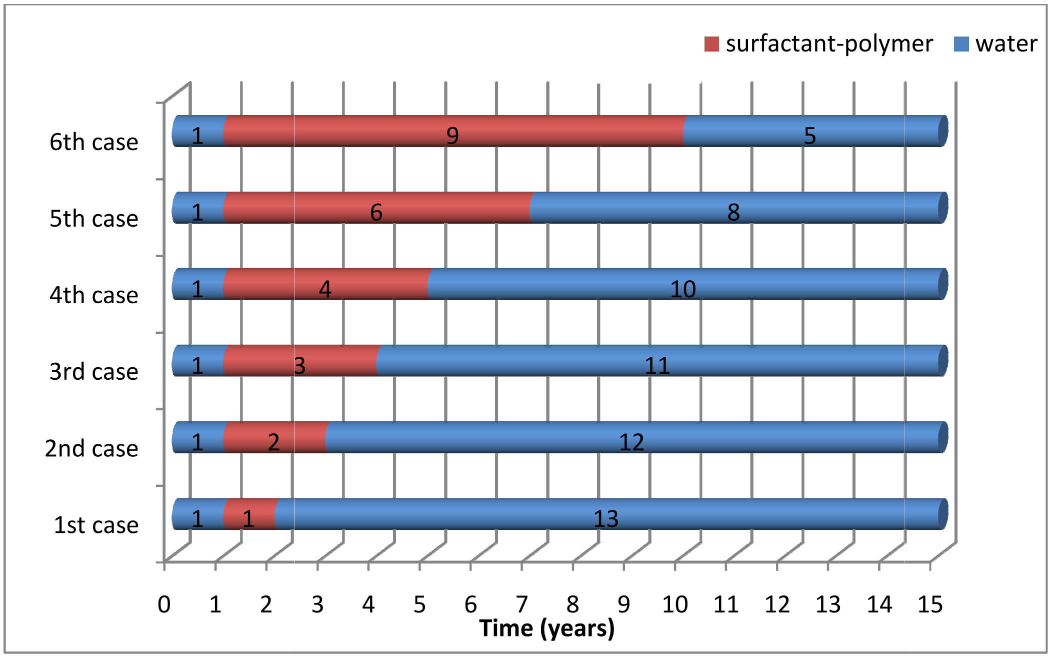


**Fig. 6.22 Injection profile for each case in surfactant-polymer injection length study.**

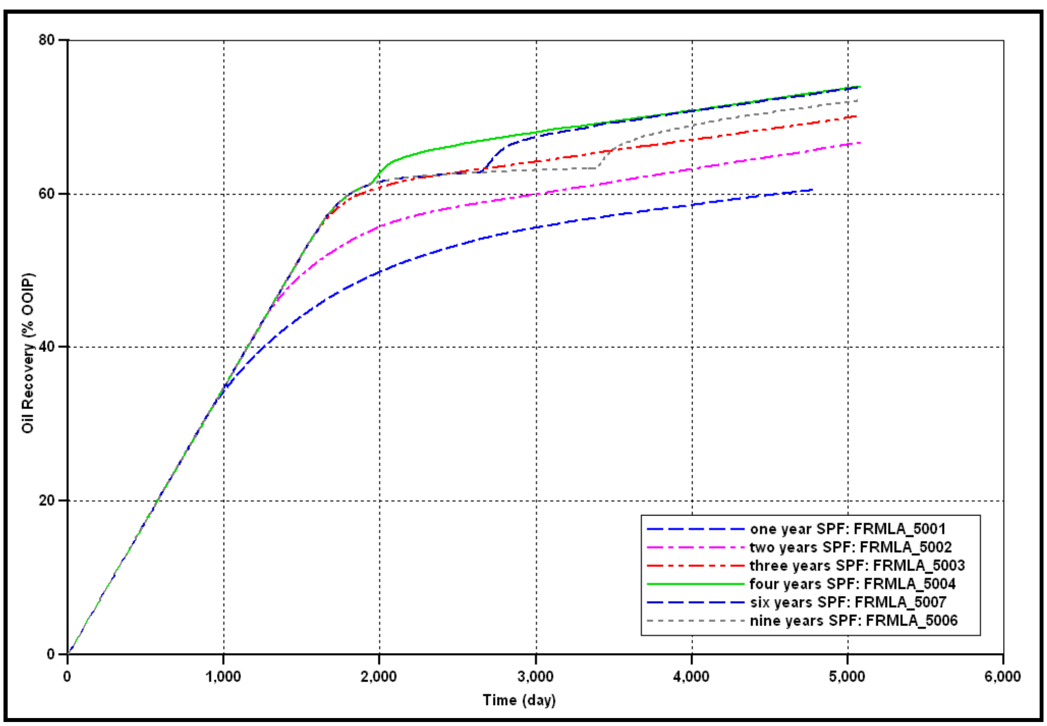


**Fig. 6.23 Sensitivity of oil recovery to surfactant polymer flooding injection length.**

Additional run has been made with no pre water injection to the 4 year surfactant polymer flood (**Fig. 6.24**). The results agree with the injections scenario sensitivity study that indicates a pre-water injection case performs better than the case with no pre-water injection.

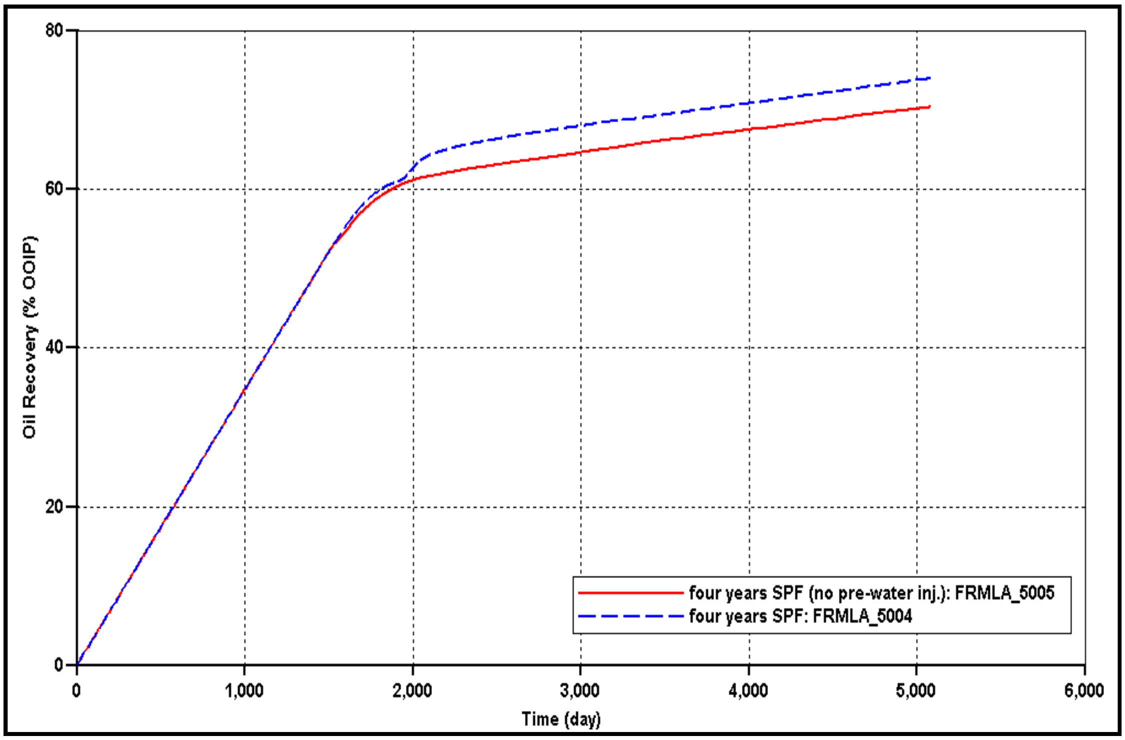


**Fig. 6.24 Oil recovery in four years of SPF with and without pre-water injection.**

## 6.6 IFT effect

A sensitivity study of oil recovery to interfacial tension, IFT, has been done on the base case model by keeping the concentration of the surfactant constant and changing the IFT value that corresponds to that concentration. Four simulation runs have been made with the final IFT value of 0.1, 0.01, 0.001 and 0.0001 dyne/cm. The wettability alteration was kept constant in all runs. The injection of surfactant polymer was continuous from day 1 until the end run. No pre-water injection or polymer drive following the SPF. **Fig. 6.25** shows the performance of continuous surfactant polymer flooding with different IFT effect. It was clear from the result that when surfactant is altering wettability in a fractured reservoir, an optimum IFT has to be achieved to maximize oil recovery. In the case with the lowest IFT, most of the injected fluid travel in a very high velocity through the fractures, until there is a barrier so more imbibitions will occur and increase the wettability alteration in the matrix.

The IFT sensitivity analysis shows that there is an optimum capillary number between fracture and matrix. This capillary number is altered by IFT reduction, wettability alteration, viscosity, or combinations of these factors. The results complement the work done by of Guzman and Aziz (1992) on injections rate in fractured reservoirs and its affect on capillary number. Also, this study shows that there is an optimum inverse bond number $(N_B)^{-1}$ that result in not only faster oil recovery but a much higher one. There is a need for further investigation and validation prior to making such assumptions, thus the need for more experimental and simulation research.

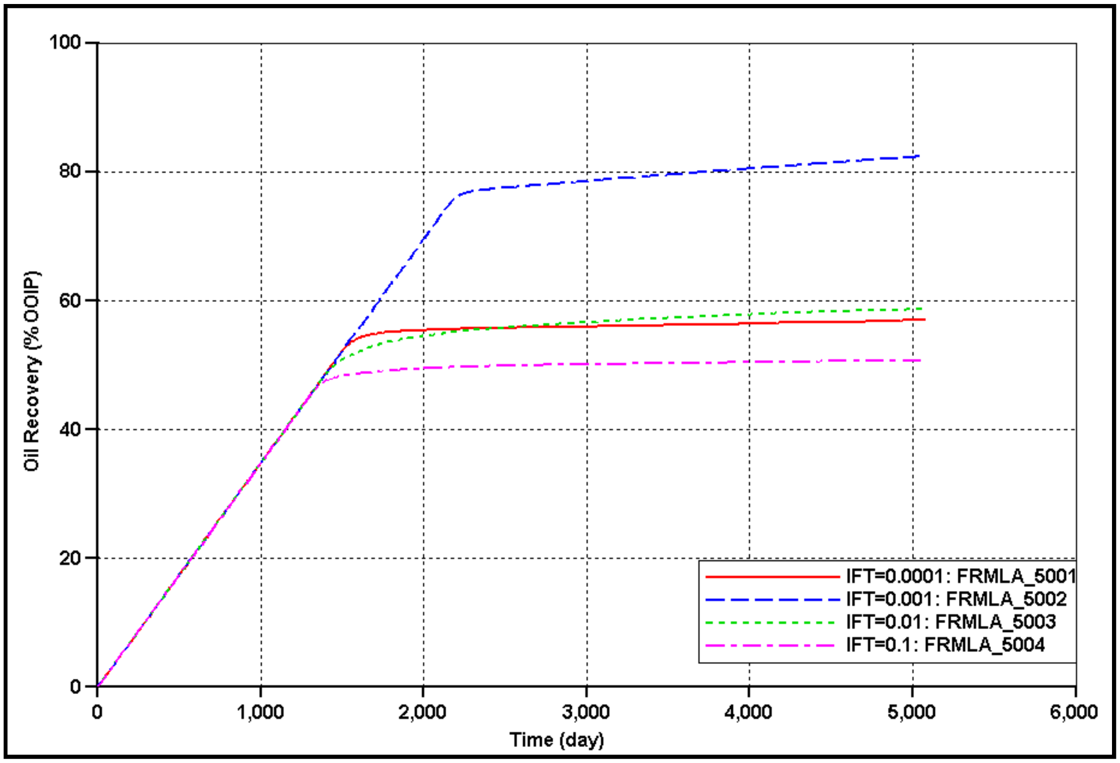


**Fig. 6.25 Sensitivity of oil recovery to IFT in a continuous surfactant polymer flooding.**

Two additional runs have been made to combine the effect of IFT with the effect of pre water injection. A one year pre-water injection has been added to the lowest IFT cases (0.001 dyne/cm and 0.0001 dyne/cm). **Fig. 6.26** shows the results of both cases along with original cases of no pre-water injection. In the lowest IFT case, the pre water injection was able to improve the oil recovery as seen in previous sensitivity analysis. However, in the optimum IFT case for this study (0.001 dyne/cm) the pre injection lowered the oil recovery comparing to the performance of the continuous SPF without a pre-water injection. These results support the previous results which indicated that the optimum inverse bond number would yield maximum oil recovery.

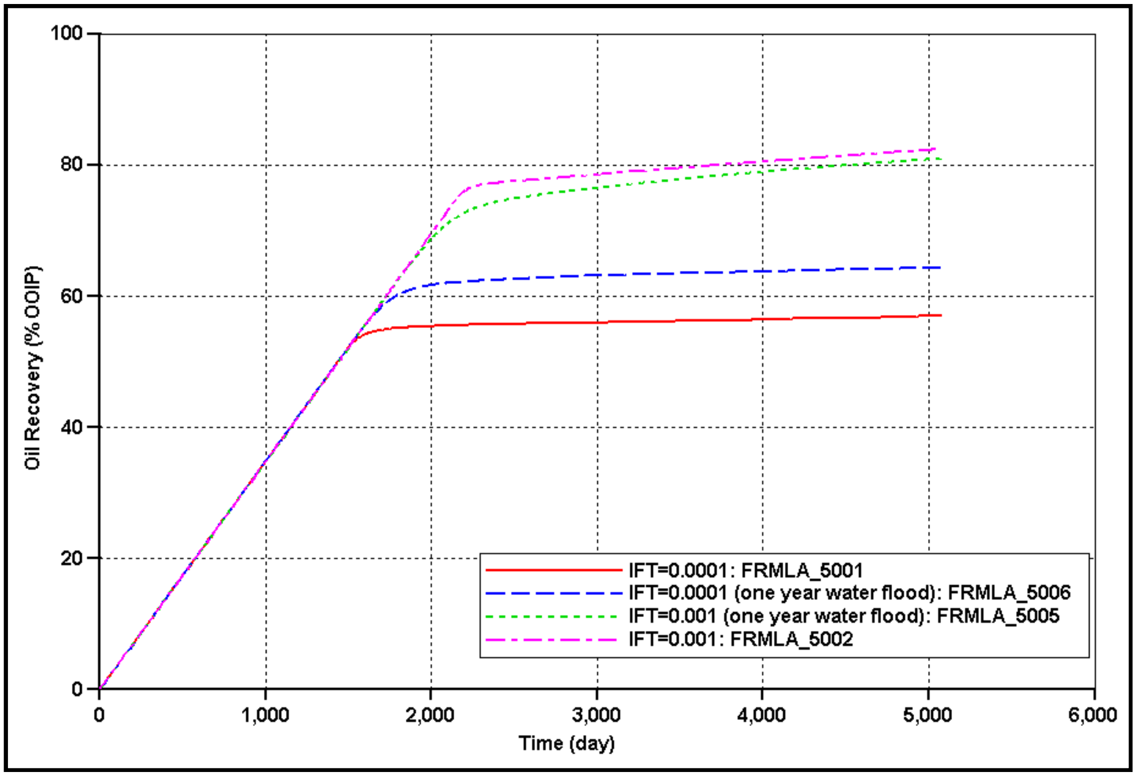


**Fig. 6.26 Effect of pre-water injection on continuous SPF with different IFT reduction.**

# 7. SUMMARY, CONCLUSIONS, AND RECOMMENDATIONS

## 7.1 Summary

A simulation study has been performed to evaluate the effect of natural fractures on the performance of surfactant-polymer floods. The study utilized a 16x31x5 Cartesian model that represents a 1/8 of a 20-ac 5-spot pattern unit. Fractures were incorporated in the CMG STARS with a dual-porosity dual-permeability model. Simulation runs were made in which the following parameters were modified: injection scenarios, matrix wettability, IFT, and fracture and matrix properties.

## 7.2 Conclusions

The following main conclusions may be drawn from results of the simulation study and results of studies by researchers as gleaned from literature.

- When spontaneous imbibition is the main drive for production from a reservoir, low IFT surfactant polymer should be injected after optimum water saturation has been reached by water flooding in order to utilize the capillary force and maximize oil recovery.
- Only in oil wet reservoir with no positive capillary pressure, injecting enhanced brine at initial water saturation will result in higher oil recovery than if injected at higher water saturation. A pre-flush injection has other benefits that such as reducing salinity or ion exchange – this should be considered as to its effect on whether a pre-water injection will yield faster oil recovery or not.

- In the study of continuous injection or surfactant-polymer flood, the result shows that in wettability altering surfactant, an optimum IFT should be combined in the surfactant effect. A change in the IFT effect from the optimum value will result in lower oil recovery.
- The smaller the permeability contrast between fractures and matrix, the higher the oil recovery. However, improved mobility will reduce this effect.
- When blockage is formed in the matrix blocks due to high chemical adsorption on the matrix, the injected fluid channels through the fractures, giving an increase in water cut without decreasing the total liquid rate.
- Injecting water after surfactant-polymer slug injection will enhance the imbibition of water from the fractures into the matrix and remove some of the precipitate because the matrix has been made more water-wet. These results need further evaluation which was outside the scope of this study.
- The higher the fracture density, the higher the imbibitions rate which leads to a higher oil recovery.
- Performance of surfactant polymer flood can be affected positively or negatively by fracture orientation with respect to the injector-producer direction. The design of such EOR process should take into consideration this fracture parameter.
- Defining contribution of spontaneous imbibitions on the total recovery is an important parameter for a successful chemical EOR pilot.

### 7.3 Recommendations

Based on results obtained in this study, the following recommendations for research are made.

1. A validation of a field scale simulation is required. Imbibition cell experiments may not adequately represent field conditions due to the lack of representation of viscous force. Research using a scaled quarter of 5-spot physical model containing a fractured porous medium is recommended.
2. Using the physical model mentioned in item 1 above, experimental research should be conducted to investigate the effect of injecting high IFT brine after wettability altering surfactant into the model.

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# APPENDIX A

The following data are based on CMG STARTS user guide. The DPDP model accounts for matrix fluid and heat transfer. matrix-matrix flow terms are added to the governing equations in the DP model presented in **Fig.A.1**. The added terms are:

matrix-matrix fluid flow = $\sum_{\mathrm{ph-1}}^{\mathrm{nph}} \Delta\left[\mathrm{T}\rho_{\mathrm{ph}}\lambda_{\mathrm{ph}}x_{\mathrm{ph}}(\Delta p + \Delta Pc_{\mathrm{ph}} - \gamma_{\mathrm{ph}}\Delta \mathrm{z})\right]$……………………(A.1)

matrix-matrix heat flow = $\sum_{\mathrm{ph-1}}^{\mathrm{nph}} \Delta\left[\mathrm{T}\rho_{\mathrm{ph}}\lambda_{\mathrm{ph}}\mathrm{H}_{\mathrm{ph}}(\Delta p + \Delta Pc_{\mathrm{ph}} - \gamma_{\mathrm{ph}}\Delta \mathrm{z})\right] + \Delta\left[\mathrm{T_c}\Delta \mathrm{T}\right]$ ……...(A.2)

Mass balance in fracture, component ic

$$\sum_{ph=1}^{nph}\underbrace{\left[\Delta\left[T\,\rho_{ph}\lambda_{ph}x_{ph,ic}\left(\Delta p+\Delta Pc_{ph}-\gamma_{ph}\Delta z\right)\right]_f\right]}_{\text{fracture-fracture flow}}+\underbrace{\sigma_p\,\rho_{ph}\lambda_{ph}x_{ph,ic}\,\Delta\Phi_{fm}}_{\text{fracture-matrix flow}}=$$

$$\left[\underbrace{\frac{V}{\Delta t}\Delta_t\sum_{ph=1}^{nph}\phi\,\rho_{ph}S_{ph}x_{ph,ic}}_{\text{accumulation}}-\underbrace{\sum_{rx=1}^{nrx}sr_{rx}}_{\text{reaction}}-\underbrace{q}_{\text{injection/ production}}\right]_f \qquad \text{(E8.1)}$$

Mass balance in matrix, component ic

$$\left[\text{matrix}-\text{matrix flow}\right]-\sum_{ph=1}^{nmp}\underbrace{\sigma_p\,\rho_{ph}\lambda_{ph}x_{ph,ic}\,\Delta\Phi_{fm}}_{\text{fracture-matrix flow}}=$$

$$\left[\underbrace{\frac{V}{\Delta t}\Delta_t\sum_{ph=1}^{nph}\phi\rho_{ph}S_{ph}x_{ph,ic}}_{\text{accumulation}}-\underbrace{\sum_{rx=1}^{nrx}sr_{rx}}_{\text{reaction}}-\underbrace{q^*}_{\text{injection/ production}}\right]_f \qquad \text{(E8.2)}$$

Total energy balance in fracture

$$\sum_{ph=1}^{nph}\underbrace{\Delta\left[T\,\rho_{ph}\lambda_{ph}H_{ph}\left(\Delta p+\Delta Pc_{ph}-\gamma_{ph}\Delta z\right)\right]_f}_{\text{fracture-fracture flow}}+\underbrace{\Delta\left[Tc\Delta T\right]_f}_{\text{fracture heat conduction}}+$$

$$\sum_{ph=1}^{nph}\underbrace{\sigma_p\,\rho_{ph}\lambda_{ph}H_{ph}\Delta\Phi_{fm}+\sigma_T\,\Delta T_{fm}}_{\text{fracture-matrix flow}}$$

$$=\left[\underbrace{\frac{V}{\Delta t}\Delta_t\sum_{ph=1}^{nph}\phi\,\rho_{ph}S_{ph}U_{ph}}_{\text{fluid accumulation}}+\underbrace{(1-\phi)\left(\rho c_p\right)_r\left(T-T_r\right)}_{\text{rock accumulation}}\right]_f$$

$$-\underbrace{\sum_{rx=1}^{nrx}sru_{rx}}_{\text{reaction}}-\underbrace{qu}_{\text{injection/ production}}-\underbrace{hloss}_{\text{heatloss O/U}}-\underbrace{hext}_{\text{external heaters}} \qquad \text{(E8.3)}$$

Total energy balance in matrix

$$\left[\text{matrix}-\text{matrix flow}\right]-\sum_{ph=1}^{nph}\underbrace{\sigma_p\,\rho_{ph}\lambda_{ph}H_{ph}\Delta\Phi_{fm}+\sigma_T\,\Delta T_{fm}}_{\text{fracture-matrix flow}}=$$

$$=\left[\underbrace{\frac{V}{\Delta t}\Delta_t\sum_{ph=1}^{nph}\phi\,\rho_{ph}S_{ph}U_{ph}}_{\text{fluid accumulation}}+\underbrace{(1-\phi)\left(\rho c_p\right)_r\left(T-T_r\right)}_{\text{rock accumulation}}\right]_m$$

$$-\sum^{nrx}sru_{rx}-qu-hloss-hext$$

**Fig. A.1 Demonstration of the governing equations in the dual-porosity model based on CMG manual.**

# APPENDIX B

Additional data used in the simulation study at different cases:

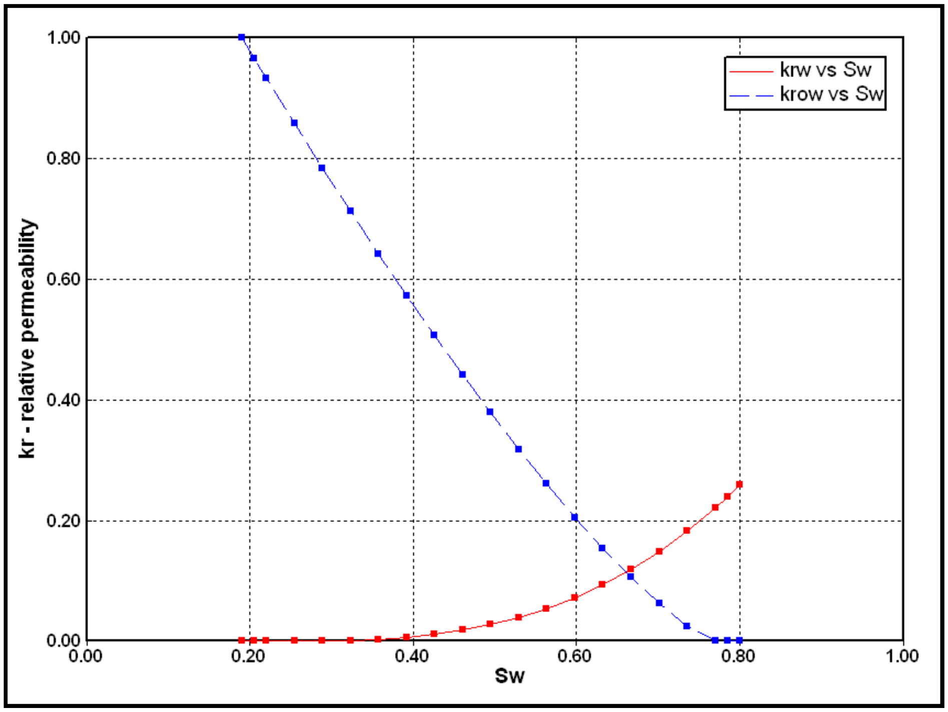


**Fig. B.2 Relative permeability curves of the water wet case.**

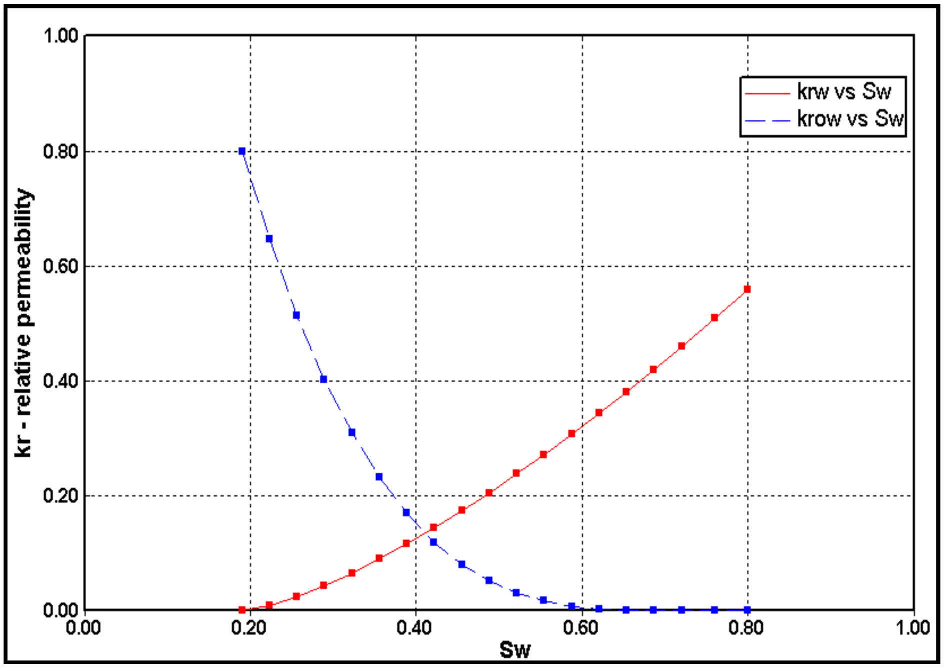


**Fig. B.3 Relative permeability curves of the oil wet case.**

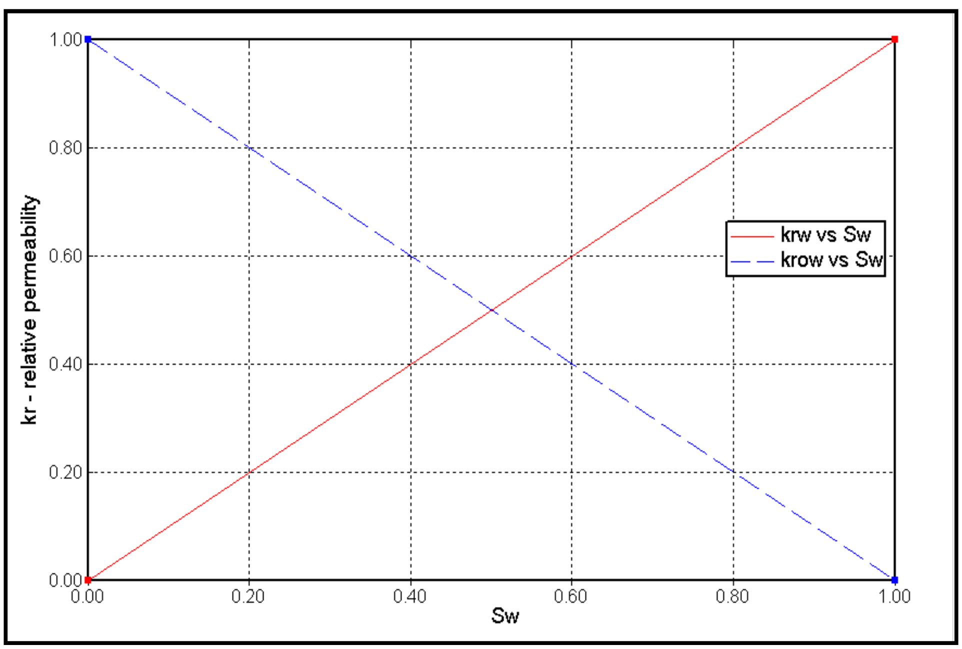


**Fig. B.4 Relative permeability curves assigned for fractures.**

# APPENDIX C

## NOMENCLATURE

| | |
|---|---|
| B | Formation volume factor (resbbl/STB) |
| *bbls* | Barrels |
| *g* | Fluid gradient, psi/ft |
| K | Permeability |
| Kr | Relative permeability |
| *q* | Flow rate, bbl/d |
| *S* | Saturation |
| *stb* | Stock tank barrel |
| *t* | Time, days |
| $\Delta t$ | Time step size, days |
| *T* | Fluid transmissibility, STB/D.psi |
| $\mu$ | Fluid viscosity, cp |
| $\rho$ | density, lbm/cu ft |
| $\sigma$ | Shape factor, $ft^{-2}$ |
| $\varphi$ | Porosity, fraction |
| $\Phi$ | Potential of phase, mL-1t-2 |

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| | |
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