Study of foam flow principles across horizontal heterogeneity

by

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14184

Dissertation submitted in partial fulfilment of
the requirements for the
Bachelor of Engineering (Hons)
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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the
Petroleum Engineering Programme
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In partial fulfillment of the requirement for the
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(PETROLEUM)

Approved by,

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(Dr. Masoud Rashidi)

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

SEPTEMBER 2014

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

Olimjon Muminov

Abstract

A considerable number of technical papers have been published by many researchers on studies of foam behavior in porous medium. Also, experimental studies were conducted before this work to facilitate understanding of the behavior of foam flow and its application in gas flooding processes. The experiments which were reviewed by the author were designed to observe and quantify the behavior of foam under various conditions, such as foam quality, surfactant concentration, and temperature. Most of the papers concentrated on descriptions of foam behavior in laboratory coreflood tests, and its effectiveness as mobility control agent for different types of gases.

This report reviews the mechanisms and theories suggested in the literature to explain the impact of horizontal heterogeneity on foam flow.

As foam flow in porous media is complex study, it demands analysis of its behavior under conditions involving simpler constraints. Considering this, current research intends to meet the demand and expectations of analysing reservoir parameters affecting foam flow across horizontal heterogeneity, investigation of foam model parameters, and analysis of different strategies for foam flooding processes.

In this work, effect of several parameters were analysed and the author intended to correlate the results to each other. Effect of heterogeneity due to permeability and porosity were studied under various model conditions. In addition, the change in gas mobility reduction factor due to fluctuations in surfactant concentration and water saturation were inspected to achieve the second objective of the work.

The structure of the paper is as follows: initially, deeper insight to the problem is given. Then, knowledge and information obtained by author from the previously completed works is summarized. Results achieved up to date are presented, and their discussion is given. Finally, the paper ends with the summary of the author's own conclusions and understandings.

Acknowledgement

Completing this study has definitely been a challenge and could not have been accomplished without an assistance and support of others. I would like to thank and express my greatest appreciation to my supervisor Dr. Masoud Rashidi for his guidance, kindness, patience, and encouragement. Besides the research, I learned a lot from him, as he has served as a role model to me demonstrating that respect towards work being done and professionalism are very important in academics.

Also, I am grateful towards Mr. Hamed Hematpoor, PhD candidate Petroleum Engineering student, who advised and shared his knowledge on performing the simulation works.

Additional gratitude is also extended to all lecturers and staff in Petroleum Engineering Department. I am also very grateful to all my friends who make the supportive environment for me.

I would like to thank Universiti Teknologi Petronas which gave me an opportunity to get academic knowledge to follow my higher education.

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Nomenclatures

C_s	the surfactant concentration
C_s^r	the reference surfactant concentration
e_s	an exponent which controls the steepness of the transition about the point where
f_w	a weighting factor which controls the sharpness in the change in mobility
GOR	Gas Oil Ratio
HPOZ	High Porosity Zone
HPZ	High Permeability Zone
LPOZ	Low Porosity Zone
LPZ	Low Permeability Zone
mD	milliDarcy
SAG	Surfactant Alternating Gas
S_w	the water saturation
S_w^l	the limiting water saturation below which the foam ceases to be effective
M_r	the reference mobility reduction factor.
F_s	he mobility reduction factor component due to surfactant concentration
F_w	the mobility reduction factor component due to water saturation
F_o	the mobility reduction factor component due to oil saturation.
F_c	the mobility reduction factor component due to gas velocity (capillary number

Chapter 1

Introduction

1.1 Background

Usually almost all oil reservoirs are target of water flooding or gas flooding to displace the remaining oil, so that recovery efficiency stays high. But the gas injection may not give the desired results due to its poor sweep efficiency, inefficient gas utilization, and low incremental oil recovery due to viscous channeling or fingering and gravity segregation (Apaydin, 2000, Farajzadeh, 2012). Gases have large flow mobility in porous media relative to oil or water, this causes their displacement effectiveness to be low (Li, 2006).

These are caused by rock heterogeneity as well as the low density and viscosity of the injected gas (Kam, 2007). To mitigate these drawbacks foam can be injected into the oil reservoir by co-injection of surfactant solution and gas, or by SAG mode (Chou, 1991). Foamed gas is a promising agent for achieving mobility control in porous media (Chou, 1991). Foam can be formed deep within rock formations, but the rate of propagation will be slow (Schramm, 1994).

1.2 Problem Statement

While discussing various Enhanced Oil Recovery techniques, the word heterogeneity is often used in a negative context, the assumption being that performance (recovery rate) would necessarily suffer due to pay zone being not homogeneous. To test this hypothesis, anticipated EOR performance in different types of heterogeneities (homogeneous, numerous shale intervals, numerous vertical fractures, fining upward. and fining downward) was already analyzed before this work (Llave et al., 1990), (Mannhardt et al., 1998), (Mohamed Idrees Al-Mossawy et al., 2011). The results provided insights into screening and design of various EOR techniques in different geological settings (Llave et al., 1990). It was seen that oil recovery definitely benefits from some heterogeneities (Mannhardt et al., 1998).

Consequently, it is important to make a distinction between heterogeneities potentially improving recovery and those resulting in a poor performance. According to Li et al. (2008), It was also reinforced that the same heterogeneity could be a bad in the context of one technique, and a good for some others. Therefore, screening and design of recovery increment schemes must take into account the existing heterogeneity and stratification Fergui et al. (1995). He also tells that there is a growing realization that most reservoirs deposited under different geological environments are usually more heterogeneous and complex than commonly perceived. Because of environment of deposition and digenetic changes, different parts of a sedimentary formation may have different levels of heterogeneity Fergui et al. (1995). Likewise, due to different minerals, grain sizes, pore shapes and wettability, there can be heterogeneity in porosity and permeability, variations in saturation, oil viscosity and pressure at different horizontal or vertical locations within a reservoir (Friedmann and Jensen, 1986).

The main contribution of this paper will be on examining how these heterogeneities affect reservoir performance, and whether they can create an opportunity, or be beneficial in achieving economic production rates in specific cases.

1.3 Objectives

The objective of this work lies on investigation of reservoir parameters affecting foam flow across horizontal heterogeneity, investigation of foam model parameters,
and analysis of different strategies for foam flooding processes.

1.4 Scope of Study

If different intervals or regions within a reservoir are not completely isolated from each other, some flow between them due to differential pressure or saturation would occur (Li et al., 2006). At favorable mobility ratios between the injected phase and oil, cross-flow acts to increase oil recovery. On the other hand, at unfavorable mobility ratios, it decreases the volumetric sweep (Li et al., 2006).
Considering the above said statements, the effort will be directed to create a model which will give an insight to observe the flow behavior and reservoir performance (recovery percentage or production rate of reservoir) under different conditions of parameters which affect injected foam. Being more specific, in this research foam flow is considered to be horizontal across the porous medium.

Chapter 2

Literature Review and Theory

2.1 Foam in Porous media

Kovscek (1993) describes that, foam in porous media is defined as a dispersion of gas in a liquid such that the liquid phase is continuous, and at least some part of the gas is made discontinuous by thin liquid films called lamellae. The lamellae are stabilized by the presence of surfactant in the liquid phase (Nguyen, 2004).

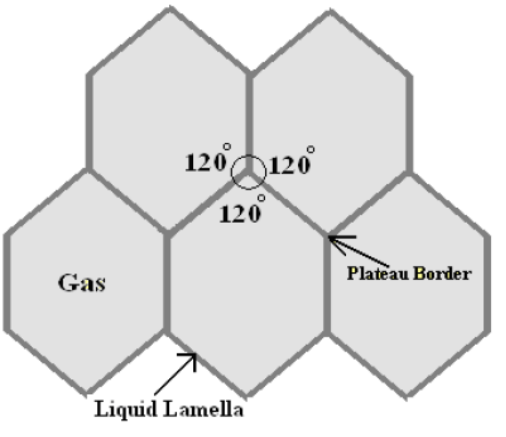


Figure 1: Schematic illustration of foam system (Mohamed Idrees Al-Mossawy et al.,2011)

The use of foam to improve the sweep efficiency of the displacing fluid involves the utilization of two foam properties (Rossen et al., 1999), (Shrivastava and Singhal, 1997). The first is the high resistance to flow that is associated with foam. The second property is the high gas-liquid surface area. Thus, only relatively small amounts of an aqueous solution of a foaming agent need be used with relatively large amounts of gas or dense fluid. Kam and Rossen, (2007) say that the gas disperses in the liquid, generating a large interfacial area and a large volume of foam, thereby increasing the resistance to flow. If this resistance to flow is in those regions of the reservoir where the resistance is least, then the displacing fluid is forced to flow through regions of higher resistance, sweeping larger portions of the reservoir and recovering larger quantities of oil Li et al. (2008). Thus, the use of foam improves sweep efficiency as it is shown in Figure 2 below (Farajzadeh et al., 2012).

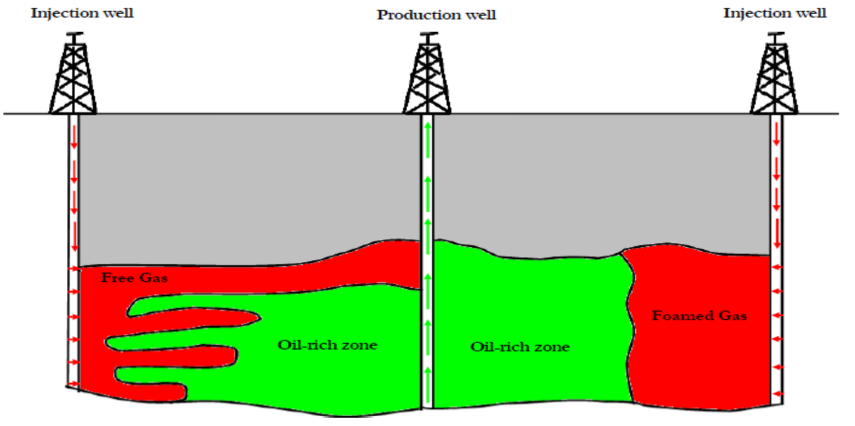


Figure 2: Schematic of normal gas flooding versus foam flooding (Farajzadeh et al., 2012)

A preferred method of generating the foam in-situ within the reservoir comprises injecting the aqueous slug together with or ahead of a slug of the displacing fluid (Djabbarah et al., 1990). The aqueous slug can also be injected between two slugs of the displacing fluid. The size or volume of the aqueous slug varies between about 1 and 90% (vol.) of the pore volume. The size of the displacing fluid slug is dictated by reservoir size, well spacing, reservoir fluids saturation, and reservoir and rock properties (Djabbarah et al., 1990). The ratio of the displacing fluid slug size to the aqueous slug size can vary between about 100:1 and 1:1. The displacing fluid can be one or a mixture of the following carbon dioxide, nitrogen, air, methane, ethane, propane, butane, hydrogen sulfide, flue or exhaust gas, or stream (Nguyen, 2004).

Foam reduces gas mobility in two manners (Mannhardt et al., 1998). First, stationary or trapped foam blocks a large number of channels that otherwise carry gas. Second, bubble trains within the flowing fraction encounter significant drag because of the presence of pore walls and constrictions, and because the gas liquid interfacial area of a flowing bubble is constantly altered by viscous and capillary forces. Hence, foam mobility depends strongly on the fraction of gas trapped and on the texture or number density of foam bubbles. Bubble trains are in a constant state of rearrangement by foam generation and destruction mechanisms (Li et al., 2006). Individual foam bubbles are molded and shaped by pore-level making and breaking processes that depend strongly on porous medium

2.2 Foam flow across heterogeneity

Nikolov et al. (1986), studied foam generation and transport in layered beadpacks that simulated reservoir strata. In these experiments he surmised that foam blocked the high permeability layer. Taber et al. (1997) and Llaye et al. (1990) observed that foam can divert gas flow from high permeability layers to low permeability layers when the layers are isolated. For the most part, the effect of flow among parallel layers in capillary communication has not been much investigated. It is denoted as cross flow (Kovscek et al., 1993).

In case of gas flooding an oil pool viscous fingering of the injected phase may dominate the production behavior. Depending upon mobility ratio, break-through could occur very early and the volumetric sweep may be very poor (Gauglitz et al., 2002). In addition, in a stratified pay zone flow distribution is also deeply influenced by permeability contrasts between different strata. In high permeability intervals, the flow velocity would be relatively high and viscous fingering is likely to be more severe (Gauglitz et al., 2002).

Foam can mitigate gravity override of oil-rich zones and selective channeling through high permeability streaks, thereby improving volumetric displacement efficiency. For example, Patzek et al. (1990) report that two different pilot studies in the Kern River Field (Kern Co., California) showed major incremental oil-recovery response after about two years of foam injection.

2.3 Foam injection parameters

Rossen et al. (1999) who investigated the diversion characteristics of foam in Berea sandstone cores of contrasting permeabilities found that the diversion performance strongly depended on permeability contrast, foam quality and total flow rate.

Taber et al. (1997) studied foam propagation in an annularly heterogeneous porous medium having a permeability ratio of approximately 70. Experiments were performed with and without crossflow between the porous zones. In situ water saturations were measured continuously using X-ray computed tomography. They observed that foam fronts moved at the same rates in the two porous media if they were in capillary contact. On the other hand, when crossflow was prohibited due to the presence of an impervious zone between the layers, gas was blocked in the high permeability zone and diverted towards the low permeability core. Mannhardt et al. (1998) also conducted experiments to study foam-induced fluid diversion in isolated and capillary-communicating double layer cores. They found that there existed a threshold injection foam quality below which foam no longer invaded the low permeability layer. This threshold depends on the permeability contrast and foam strength in the high permeability layer.

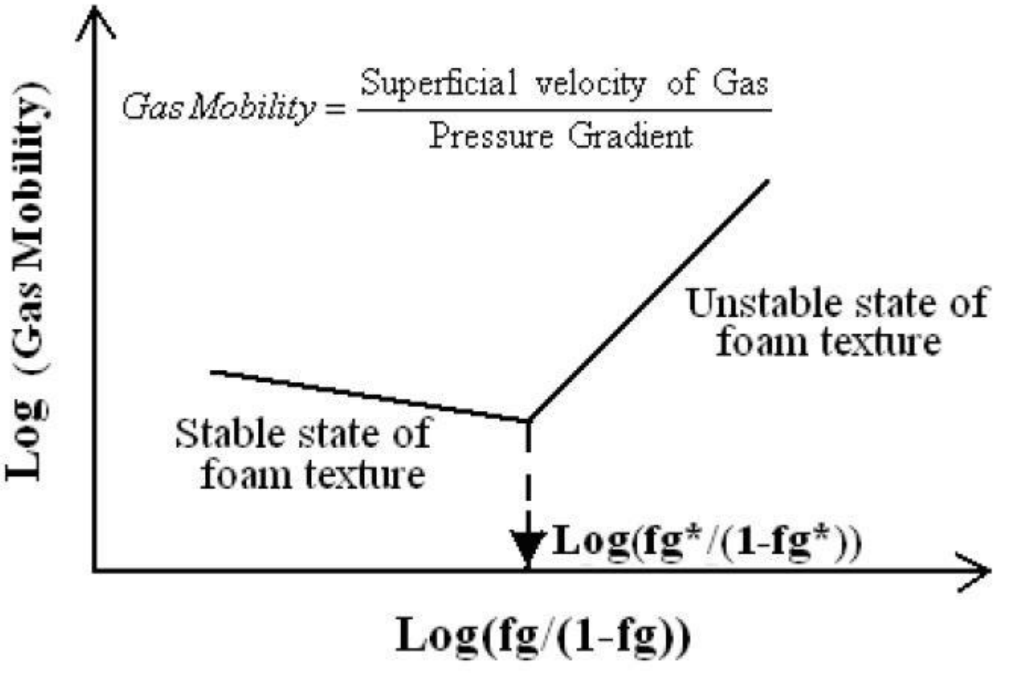


Figure 3: Schematic plot for the relationship between fg and gas mobility (Mohamed Idrees Al-Mossawy et al., 2011)

Another paper deserving a review is the experimental work conducted by Yunxiang (2000). The figure below indicates that foam resistance factor (RF) increases with the increase of core permeability, i.e., foam has stronger blocking effect in high permeability core than in low permeability core.

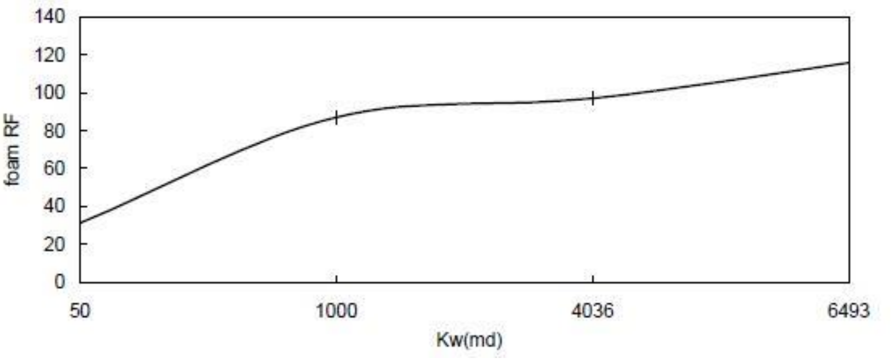


Figure 4: Foam resistance factor (RF) vs core permeability (Yunxiang, 2000)

This phenomenon is beneficial in applying foam to recover oil in heterogeneous reservoir. The main mechanism lies in foam's shear-thinning characteristic (Prieditis, 1988). Because the average pore radius of low permeable core is smaller than that of high permeable core, at a constant injection rate, the real velocity (or shear rate) in a small pore throat is greater than in a large pore throat, thus the apparent viscosity of foam in low permeable core is lower than in high permeable core, and results in a relative smaller flowing resistance. Also, work of Prieditis, (1988) which is focused on the experimental work to understand the relationship between the positions of layers having different permeability gives good fundamental understanding about foam flow. The conclusion arrived after reading this work are listed down:

- A low permeability layer of the reservoir is hardly swept
- In reservoirs, regardless of location of a high-permeability or a low-permeability layers, injecting a large first surfactant slug to correct for adsorption throughout the process results in too much surfactant in the high-permeability layers, much of which is wasted
- Within the low-permeability layer there is little surfactant much beyond the injection well. Therefore, gas rapidly segregates in that layer and arrives at the production well

2.4 Foam model parameters

The foam model in Eclipse Software contains a function M_{rf} which controls the reduction in gas mobility. The description of the foam model given below is taken from Eclipse Technical Manual (2012). For this function, the gas mobility reduction factor is modeled in terms of a set of functions which represent the individual reduction factors due to surfactant concentration, oil saturation, water saturation and capillary number. These are combined multiplicatively with a reference mobility reduction factor to determine the net mobility reduction factor.

However, this functional gas mobility reduction model is only available if water is specified as the transport phase Eclipse Technical Manual (2012). The formulation of the model is described below:

$$Mrf = \frac{1}{1 + (Mr * Fs * Fw * Fo * Fc)}$$

Equation 1: gas mobility reduction factor

(Rossen et al., 2012)

Considering the complexity of the foam model parameters, and due to the limited time allocation of the current work, analysis of only the mobility reduction factor component due to surfactant concentration and water saturation were done.

The first parameter which was studied, mobility reduction factor dependence upon surfactant concentration, is expressed in the form:

$$F_s = \frac{Cs^{e_s}}{C_{sr}^{e_s}}$$

Equation 2: mobility reduction factor dependence upon surfactant concentration

(Rossen et al., 2012)

The second parameter which was studied, the mobility reduction factor, F_w, represents the dependence upon water saturation and is expressed as:

$$F_w = 0.5 + \frac{\operatorname{atan}[f_w * (S_w - S_w^l)]}{\pi}$$

Equation 3: mobility reduction factor dependence upon water saturation

(Rossen et al., 2012)

Chapter 3

Methodology

3.1 Gantt Chart

Gantt chart shown above was created at the early stages of project initiation. It will help to the author to keep track of all activities done towards successful compilation of project. Considering the weight and importance of each activities, certain amount of time period is allocated to finish respected task.

Table 1: Gantt chart of the Project

Activity	Time allocated (in days)	Week no
Literature reading about chosen topic : • Variables determining success of any EOR project • Basic principles of foam injection • Effect of heterogeneity on recovery • Fluid flow across horizontal heterogeneity	20	6
Data Gathering: • Finding out which rock and fluid properties affect horizontal flow • Understanding previous experiments conducted which are relevant to subject matter • Read the description of several reservoir simulators which can help to plan a steps of project development	15	8
Creation of simulation model • Identifying the right chain of steps to create the model • Trying to create a model which will be used to simulate horizontal flow	25-28	12-13
Representing progress achieved • Preparing all necessary written reports and presentation materials for evaluation	10	14

3.2 Research flow chart

The chart below shows the steps of the current research work in details. It was used as a guide to achieve the desired outcomes at the end of the completion of work.

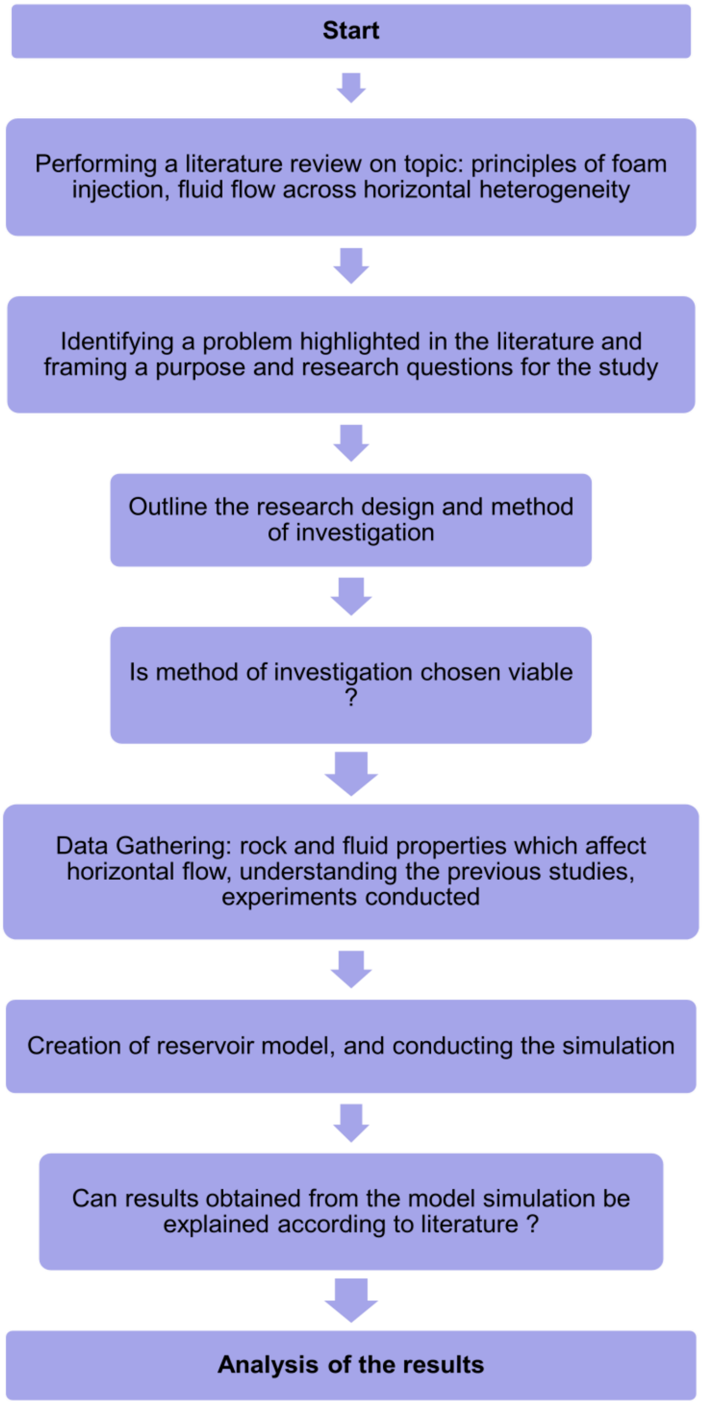


Figure 5: Research flow chart

3.3 Software Required

Considering the objectives of the current project, several simulation softwares' capabilities and functional descriptions were studied to choose the most optimal one which is going to help to analyse effects of vertical heterogeneity. Taking into account the availability of the software in Universiti Teknologi Petronas, Schlumberger Eclipse sowftware was chosen. Eclipse software simulates the majority of chemical EOR techniques, including foam.

When using Eclipse, the following points were followed:

- The model is not identical to the reservoir
- Model performance depends on data quality and quantity
- The model reflects the reservoir behavior if the reservoir is accurately represented
- Data modifications must be physically viable and justified

3.4 Estimated Cost

As the nature of the work shows, it doesn't require any lab equipments or samples to conduct an experiment. There will not be any costs involved, as the only tool required for this reserch work is a software, and it is available in University.

Chapter 4

Results and Discussion

4.1 Description of the Base Case

Before simulation work was started, Base Case model, the initial model whose parameters were changed later was created. It has the following characteristics:

- No. of grid blocks (in X, Y, Z directions): 60-60-6
- Porosity is same throughout the whole model, it has a value of 0.3
- Permeability is same in only certain regions of model, and it was changing horizontally only. Model was divided into 3 sections and permeability was varying in each 20 grid blocks across X direction. Base Case has the following set up: 300mD in 1-20, 100mD in 21-40, 50mD in 41-60 grid blocks. Initially, injection well was located in high permeable zone.
- Vertical permeability was not changed (in all cases), and it had a value of 30mD
- No. of wells: 1 injector (in 1-1-1 coordinate), 1 producer (in 60-60-1 coordinate)
- Both wells had perforations in all 6 layers
- Foam is generated by co-injection of gas and water
- Gas is injected in a rate of 4000 STB/day, while water is 400 STB/day
- The initial concentration of foam in the injection stream was 3 lb/Mscf

To clarify the layout of the model more, it can be said that model represent quarter of the five spot injection pattern. According to Schlumberger Oil Field Glossary, a five spot is an injection pattern where one injector is located at the centre of a square and four producers sit in the corners. Generated pressure drive will displace the oil towards the central producer.

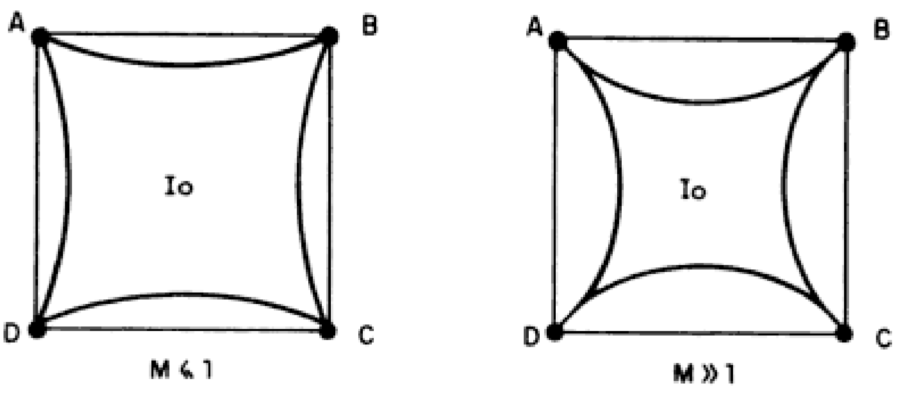


Figure 6: Five spot injection pattern

(M. Latil, 1982)

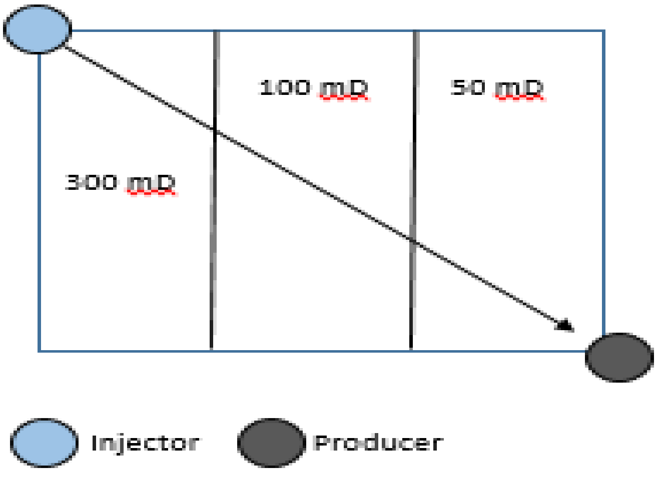


Figure 7: Schematic of flow from injector to producer

The figures below represent the reservoir model created by the author to study the foam flow behaviour across horizontal heterogeneity. Figure 8 shows the initial state of the model, a time when there is no foam injected. After, in Figure 9 oil saturation change across the model is represented. As it can be seen from the oil saturation scale displayed, Figure 10, when foam injection has stopped, the oil saturation in the top left side of the model has increased, indicating that the area around the injection well was swept.

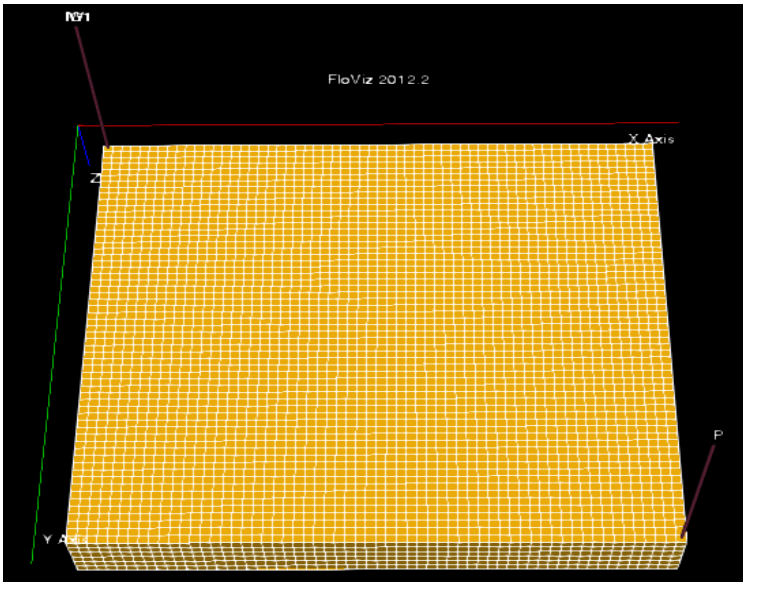


Figure 8: The initial state of the model

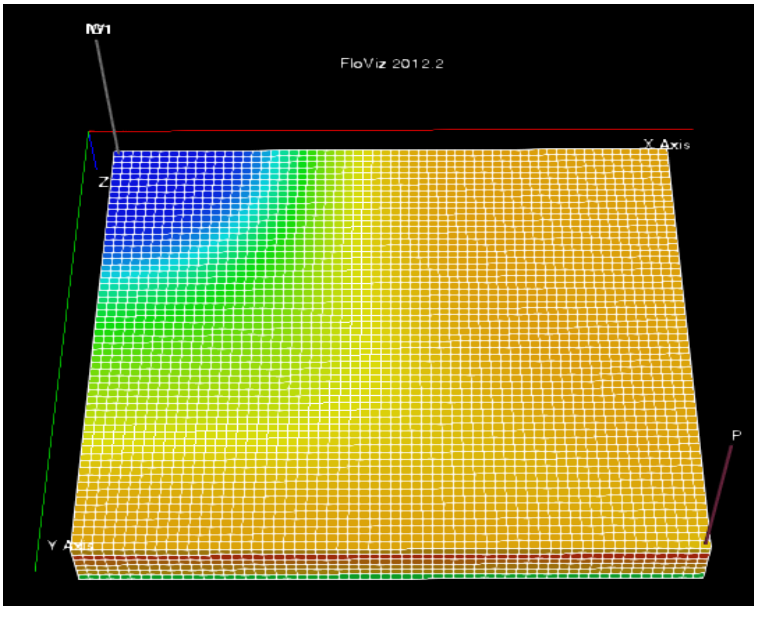


Figure 9: Oil saturation change across the model at the end of injection

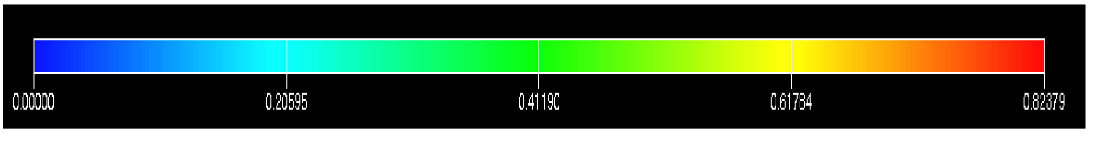


Figure 10: Oil saturation scale

Simulations conducted to analyze the reservoir parameters

4.2 Effect of horizontal change in permeability

In this analysis, permeability was changing across X-Y plane and it was kept uniform in Z direction having value of 30mD. This case was run to observe the effect of change in permeability horizontally. Porosity was 0.3. Permeability changed each 20 grid blocks, and they had the following values: Grid 1 to 20: 300 mD; Grid 21 to 40: 100 mD; Grid 41 to 60: 50 mD. Gas and water injection rate were 4000 STB/day and 400 STB/day respectively. The concentration of foam in the injection stream was 3 lb/Mscf.

This case represents the difference in the foam flow according to position of the injector. Figure 11 represents the case when injector is located in the top left corner, HPZ of the model. It was observed that injection front started propagating in 300mD zone, and once it reached 100mD zone it started flowing faster, and soon breakthrough occurred. It can be observed that, most of the area in the right side of the model was left upswept.

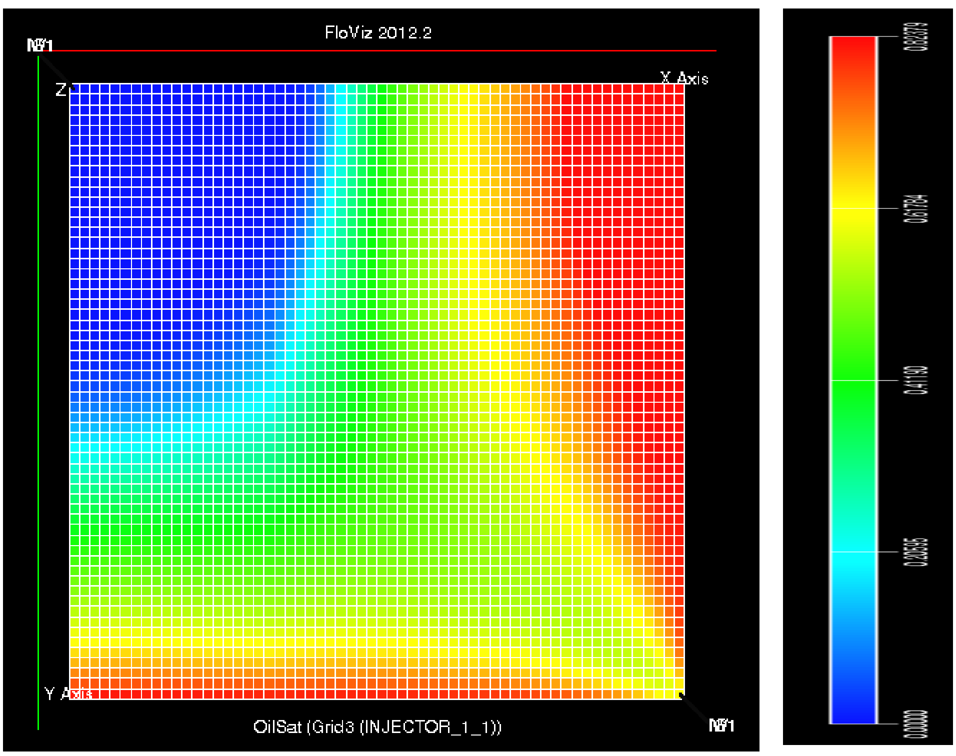


Figure 11: The injector is located in the top left corner (HPZ)

However, when the injector was positioned to the bottom right side of the reservoir, LPZ, Figure 12, different scenario was observed. Foam was uniformly flowing through the reservoir, no faster propagation or early breakthrough was observed when foam flew from 50mD zone to 100mD, and later to 300mD area. This observation verifies the principle of foam being gas mobility controller, and functioning in the case of the model simulation.

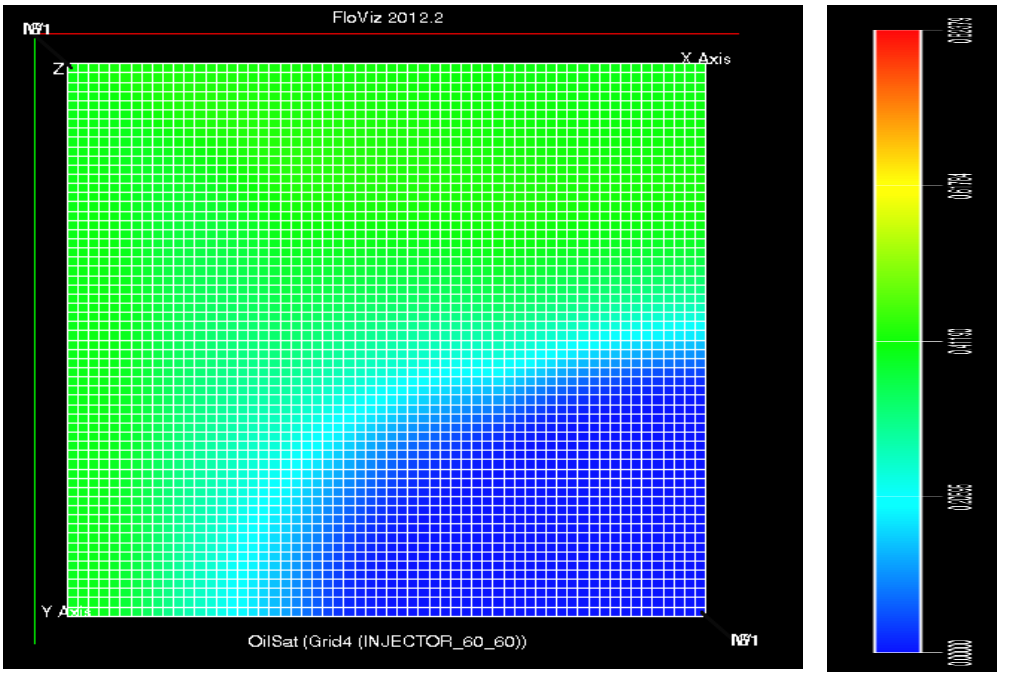


Figure 12: The injector is located in the bottom right corner (LPZ)

It can be seen that Gas Mobility Factor, Figure 13 and Gas Oil Ratio, Figure 14 are lower when flow occurs from HPZ to LPZ. Figure 13 indicates that much difference in the Gas Mobility Factor is not achieved regardless of the direction of the flow. But, still when the flow is from HPZ to LPZ, mobility factor is less, again indicating the functionality of the foam. When the flow is from HPZ to LPZ, GOR stays constant for 5.8 years (time when injection front reaches 100mD zone) and gradually increases. The reason is that, during that time oil in the HPZ is swept first, and then foamed gas moves towards LPZ. But when flow occurs from LPZ to HPZ, GOR increases smoothly from the beginning of the injection due to uniform propagation of the front.

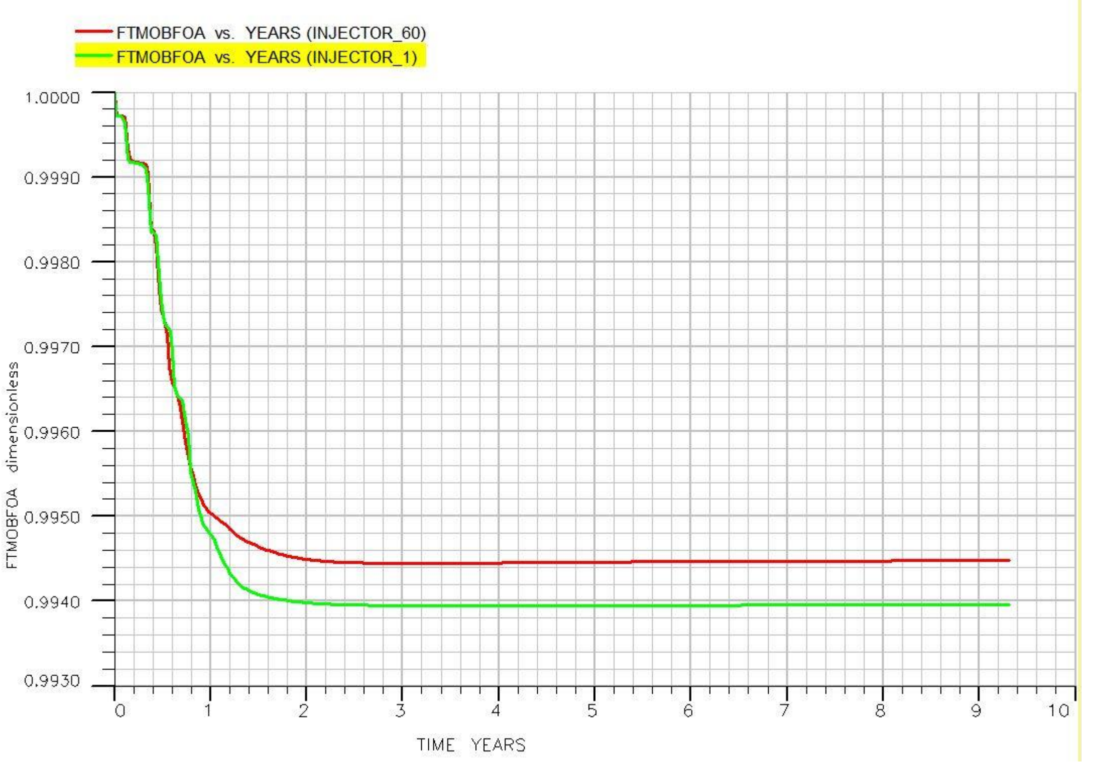


Figure 13: Difference in Gas Mobility Factor when Injector is located in HPZ (green line) and LPZ (red line)

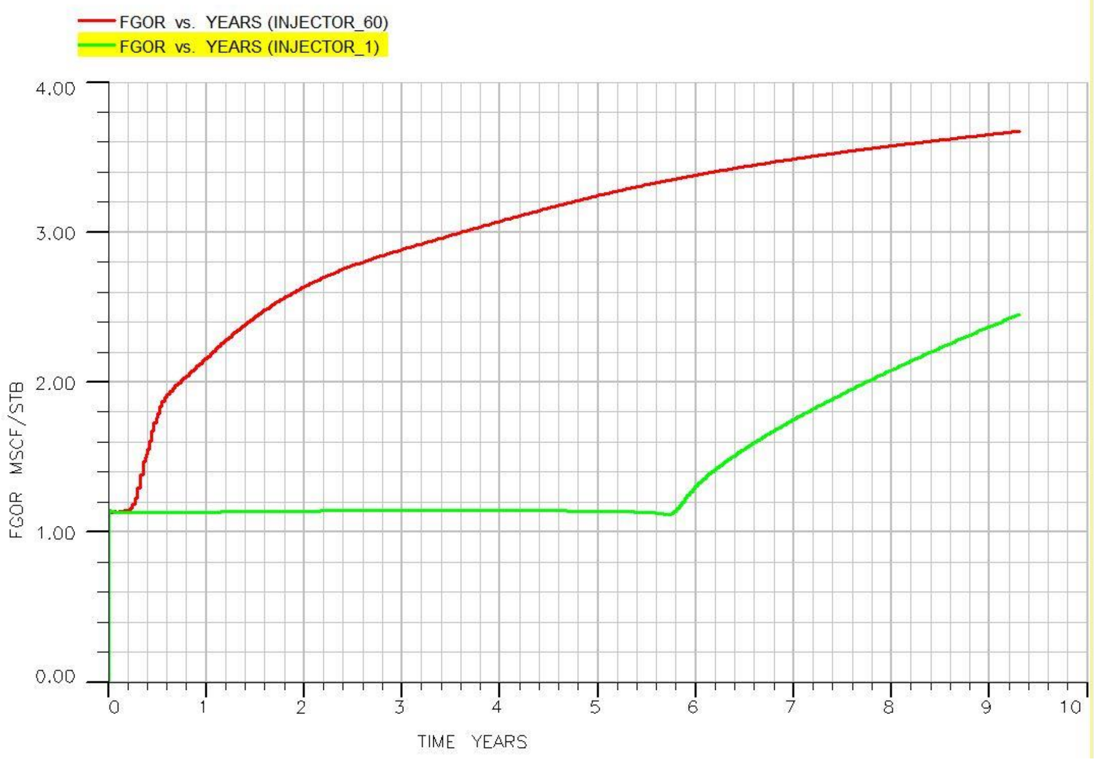


Figure 14: GOR when Injector is located in HPZ (green line) and LPZ (red line)

Obtained results on GOR and Gas Saturation in Time across the reservoir are same as the explanation given in Prieditis (1988), and conforms his conclusion. The reason for obtaining lower GOR when flow is from HPZ is that, within the HPZ due to bigger size of the pore channels surfactant concentration in there is a lot more beyond the injection well. The opposite is in LPZ. Due to ease in surfactant solution injectivity in HPZ, foam immediately starts forming and functioning. These explanations can be supported observing Figure 11. Once foam front injected in HPZ reaches LPZ, foam stops being formed and gas flows fast in that area and soon breakthroughs (gas rapidly segregates in that layer) (Year 6, Figure 14) into producer. This is the reason why top right corner of the Figure 11 was left unswept.

When the change in the Gas Saturation with Time across the reservoir was examined, Figure 15, it was noticed that high Gas Saturations exist closer to the Injector, and values get smaller away from the well region (Grid Blocks 50-60). The reason is that Gas even didn't reach away from the well region as it started flowing towards Producer when it entered LPZ (50mD zone). However, Gas Saturation values were same during LPZ to HPZ flow, Figure 16.

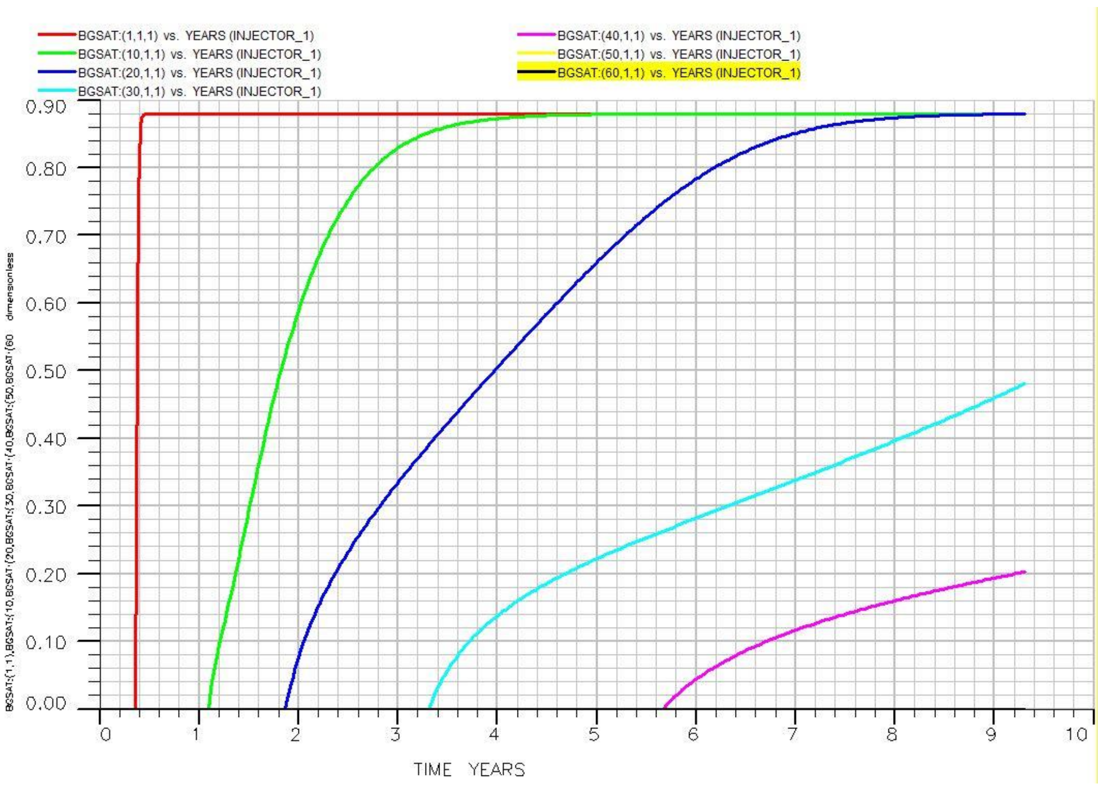


Figure 15: Gas Saturation in Time across the reservoir (flow from HPZ to LPZ)

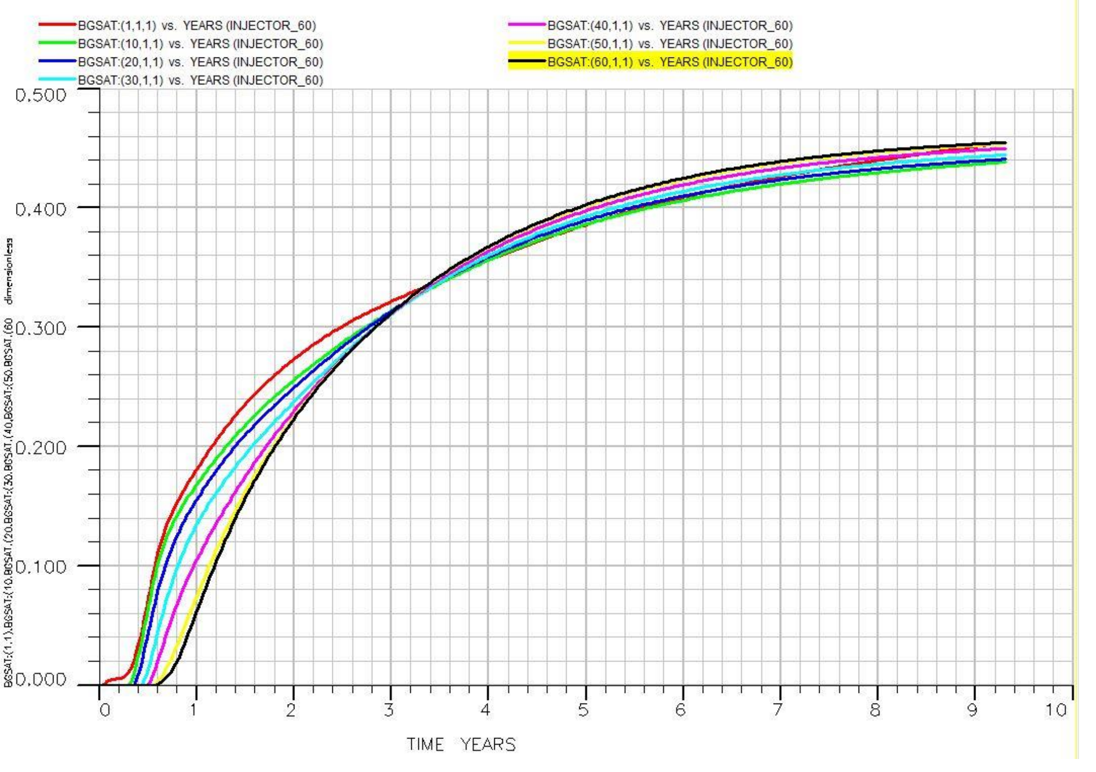


Figure 16: Gas Saturation in Time across the reservoir (flow from LPZ to HPZ)

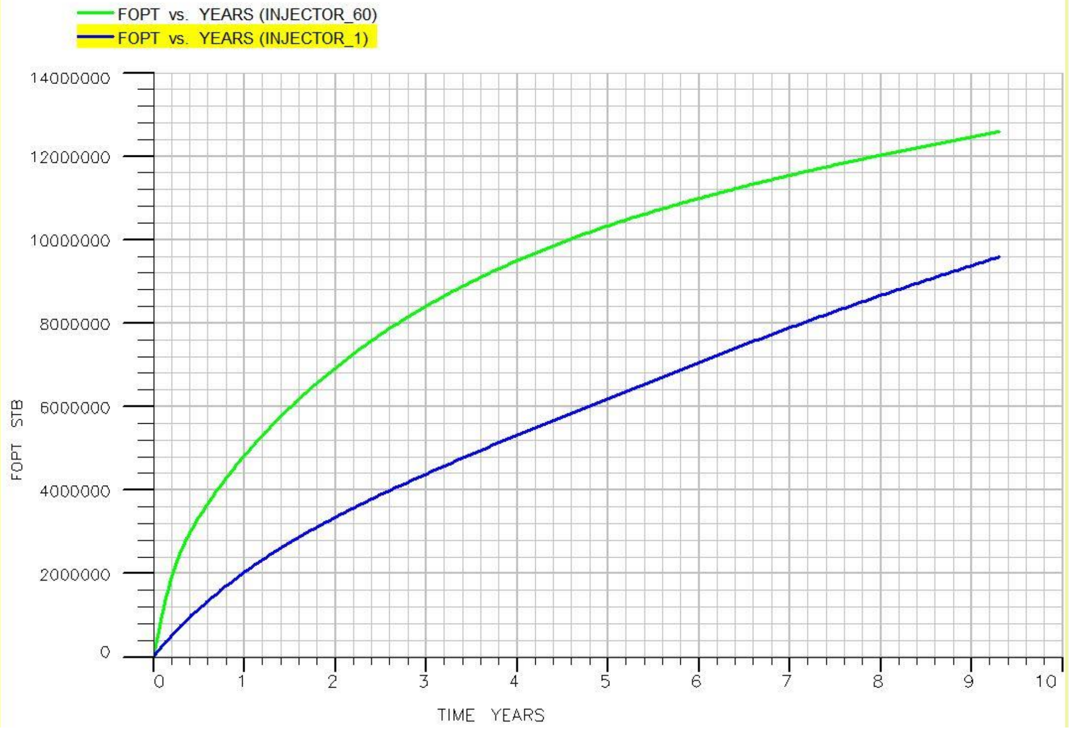


Figure 17: Field Total Oil Production when Injector is located in HPZ (blue line) and LPZ (green line)

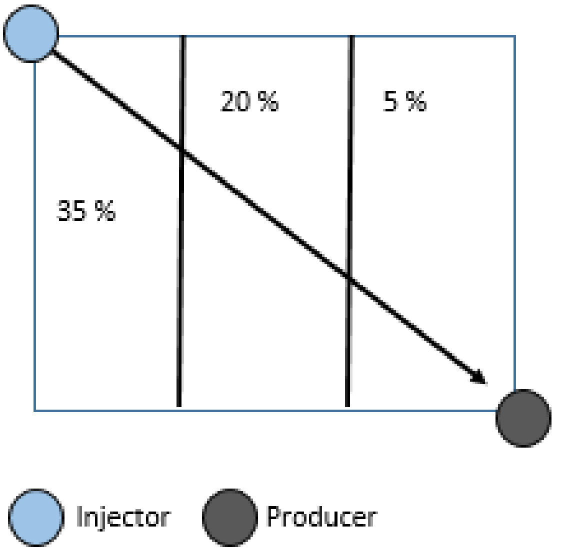
Also, it can be observed from Figure 17 that foam flow from LPZ to HPZ outperforms flow from HPZ to LPZ when it comes to oil production. It can be related to the observation that some of the area was left upswept when flow occurred from HPZ to LPZ.

4.2.1 Discussion of results obtained from horizontal change in permeability

The reason of Gas Saturation in Time across the reservoir in Figure 16 being lower than Figure 15 is that, due to the presence of the higher concentrations of foam in HPZ, gas is being arrested and stopped being mobile, while it does not happen when flow is from LPZ. When injection of surfactant solution occurs from LPZ, it cannot be expected that solution will flow deep into the reservoir. Despite the fact of better performance of foam in HPZ, Field Total Oil Production is lower than LPZ case. The reason is that big portion of the area (top right corner of the model) was left unswept. Also Prieditis (1988) suggests that if injection time is long enough, probability exists that Total Oil Production will be more in injection from HPZ than injection from LPZ.

4.3 Effect of horizontal change in porosity

In this analysis, permeability was not changing across X-Y plane and it was kept uniform having value of 90 mD. Vertical permeability was 30 mD. This case was run to observe the effect of change in porosity horizontally. Porosity was changed each 20 grid blocks, and they had the following values: Grid 1 to 20: 0.35; Grid 21 to 40: 0.2; Grid 41 to 60: 0.05. Gas and water injection rate were 4000 STB/day and 400 STB/day respectively. The concentration of foam in the injection stream was 3 lb/Mscf.



From Figure 18 it can be seen that horizontal change in porosity doesn't have noticeable effect in Total Oil Production.

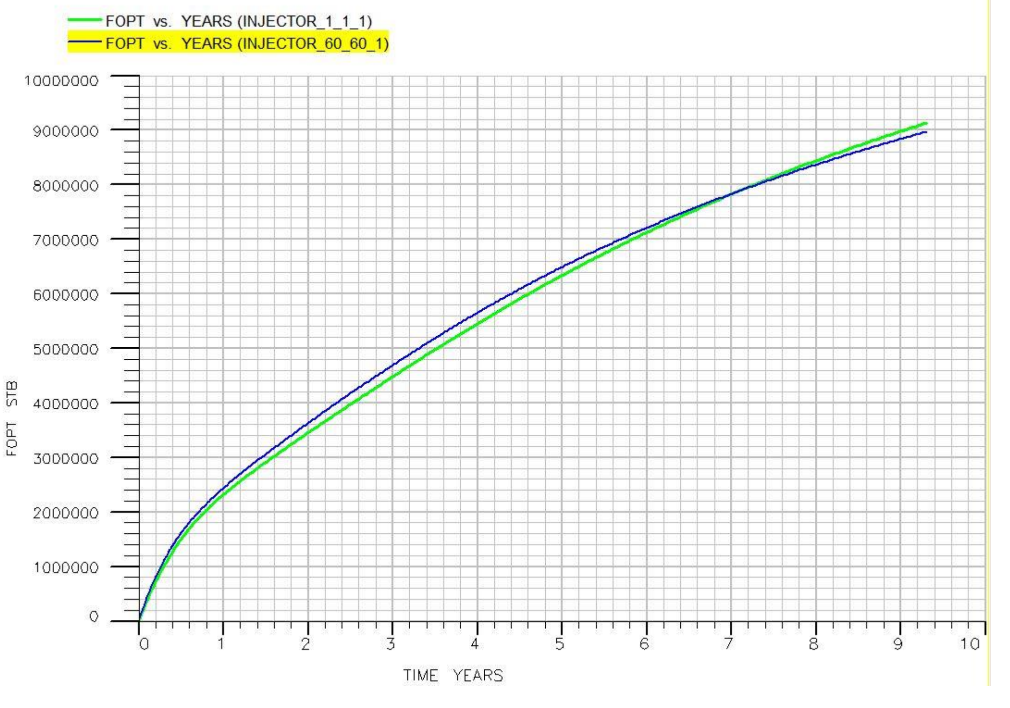


Figure 18: Field Total Oil Production when Injector is located in HPOZ (green line) and LPOZ (blue line)

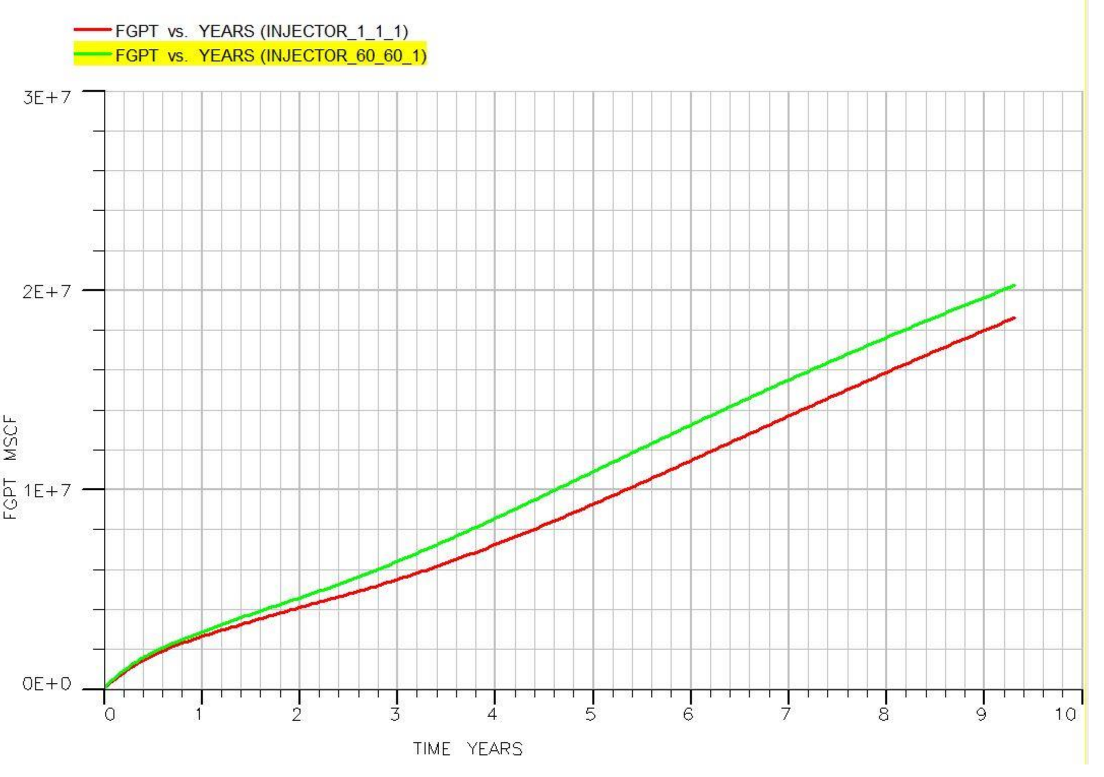


Figure 19: Field Total Gas Production when Injector is located in HPOZ (red line) and LPOZ (green line)

4.3.1 Discussion of results obtained from horizontal change in porosity

Regardless of injection direction, whether foam is injected from high porous zone (HPOZ) to low porous zone (LPOZ), or vice versa, the results are same for Total Oil Production. It gradually increases and reaches 9 MM STB at the end of injection.

Also, there was no significant change in Gas Mobility Factor for both cases. Field Oil Recovery Efficiency for both cases was same, and the value reached to 20% after 9 years of injection. Figure 19 illustrates that when flow is from high to low porous region, Total Field Gas Production is lower, compared to flow from low to high porous region.

The results obtained conform the assumption of Ettinger and Radke (1992). In the experimental work they have conducted, it was observed that, porosity may not have much effect on performance of the foam flow. It is related to the value of the effective porosity, as it gets bigger flow through porous medium may be increased. The reason why Field Total Gas Production is lower when injection is from HPOZ is similar to the case of flow from HPZ. Because as number of pores, and ultimately pore volume is higher in HPOZ, amount of surfactant concentration is also more. Since surfactant solution it is able to control the mobility of gas, and it is a little bit lower in that zone, it reduced the Gas Production.

Kam (2007) tells that effect of change in porosity of layers is not much, unless the injection is conducted for a long term, or porous medium is pre-satured with surfactant.

4.4 Effect of change in thickness of the layers having different properties

Figure 20 and 21 display the GOR when layers having equal thickness, high porous/ permeable layer being thickest layer, and high porous/permeable layer being thinnest layer. Under the same scenario, Figure 22 and 23 show Field Total Oil Production.

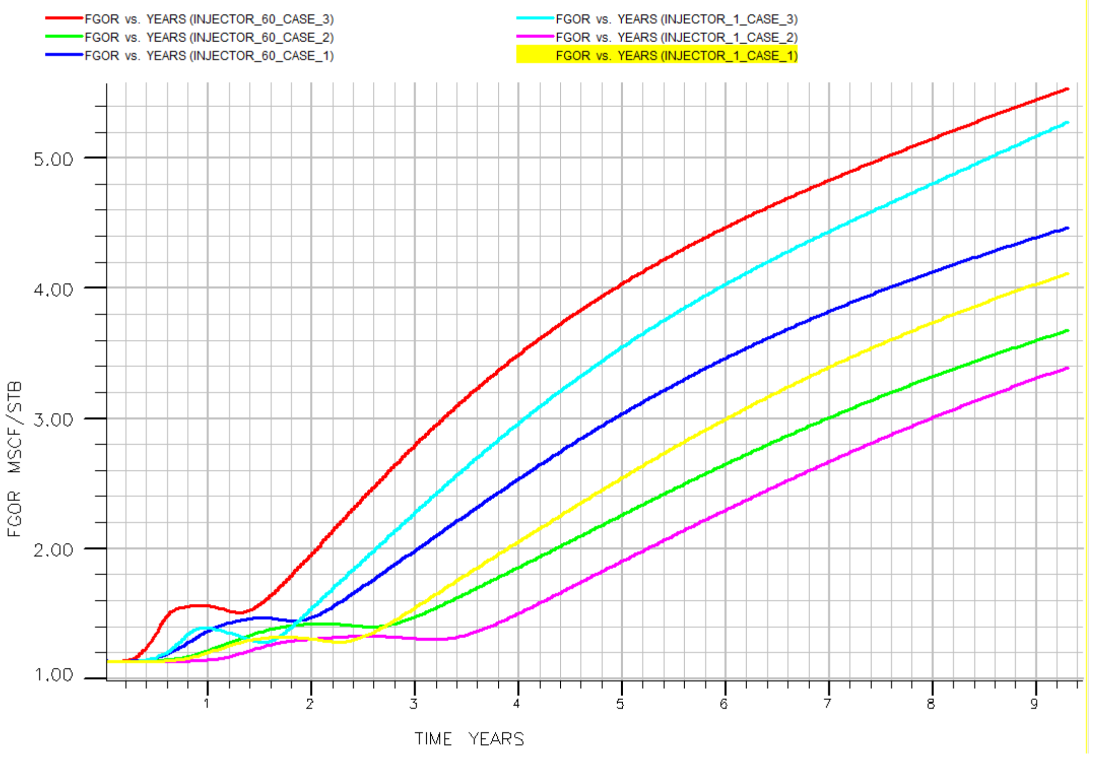


Figure 20: GOR when Injector is located in HPOZ and LPOZ

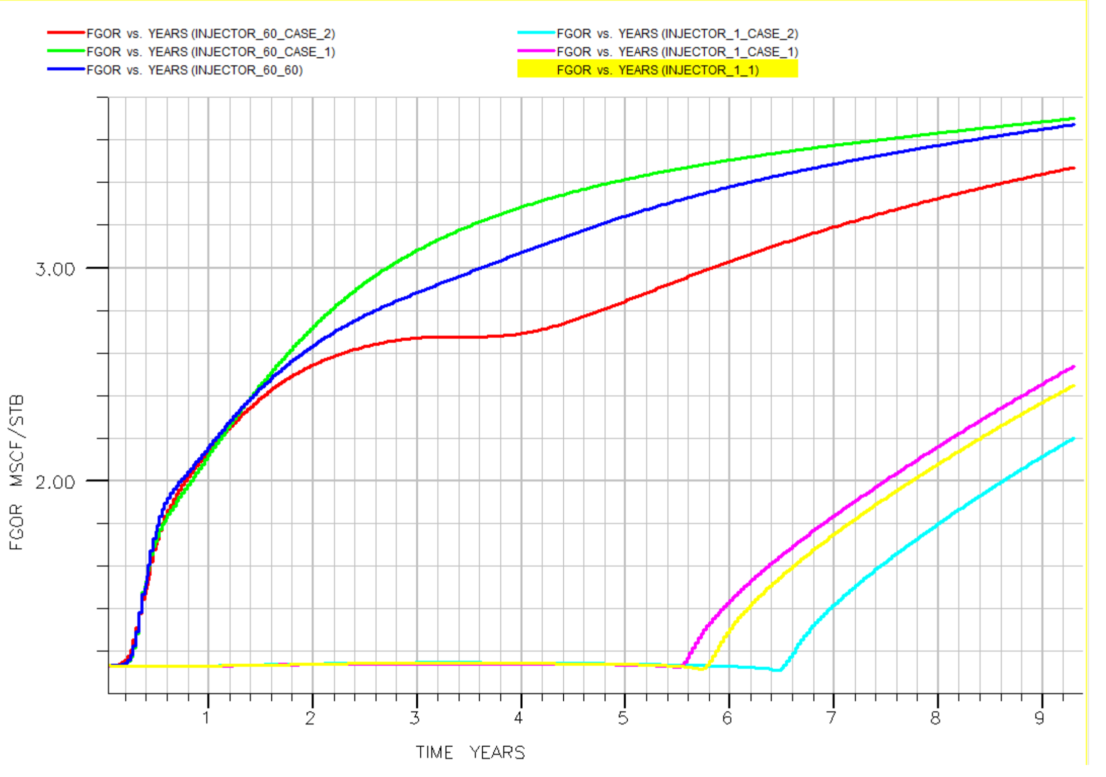


Figure 21: GOR when Injector is located in HPZ and LPZ

It can be seen from Figure 20 that regardless of the direction of the flow, values of GOR will be close to each other in cases having the similar thickness. GOR is the highest when the high porous zone is the thinnest. And it decreases when the highest porous zone is the thickest. But it is not the same way in Figure 21. Regardless of the direction of the flow, as the thickness of the HPZ is increasing, GOR is rising.

The reason for obtaining lower GOR when HPZ is the thickest is that, within the HPZ due to bigger size of the pore channels surfactant concentration in there is a lot more beyond the injection well. The opposite is in LPZ. Due to ease in surfactant solution injectivity in HPZ, foam immediately starts forming and functioning.

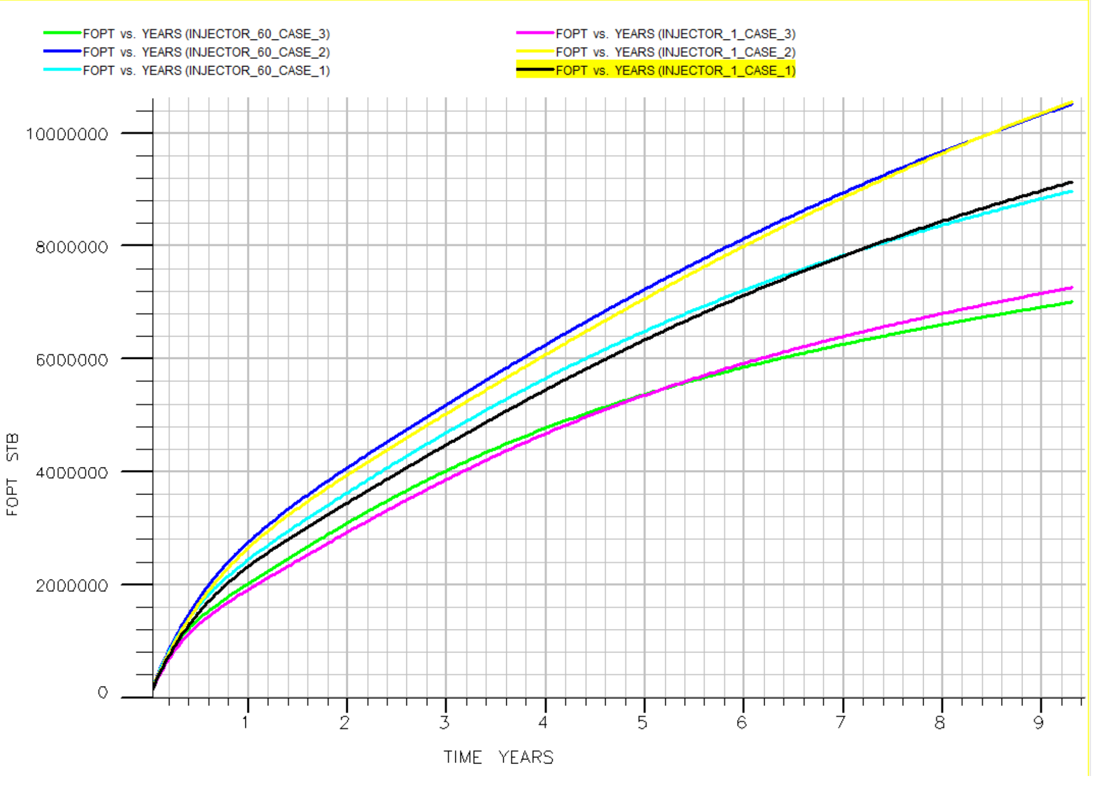


Figure 22: Field Total Oil Production when Injector is located in HPOZ and LPOZ

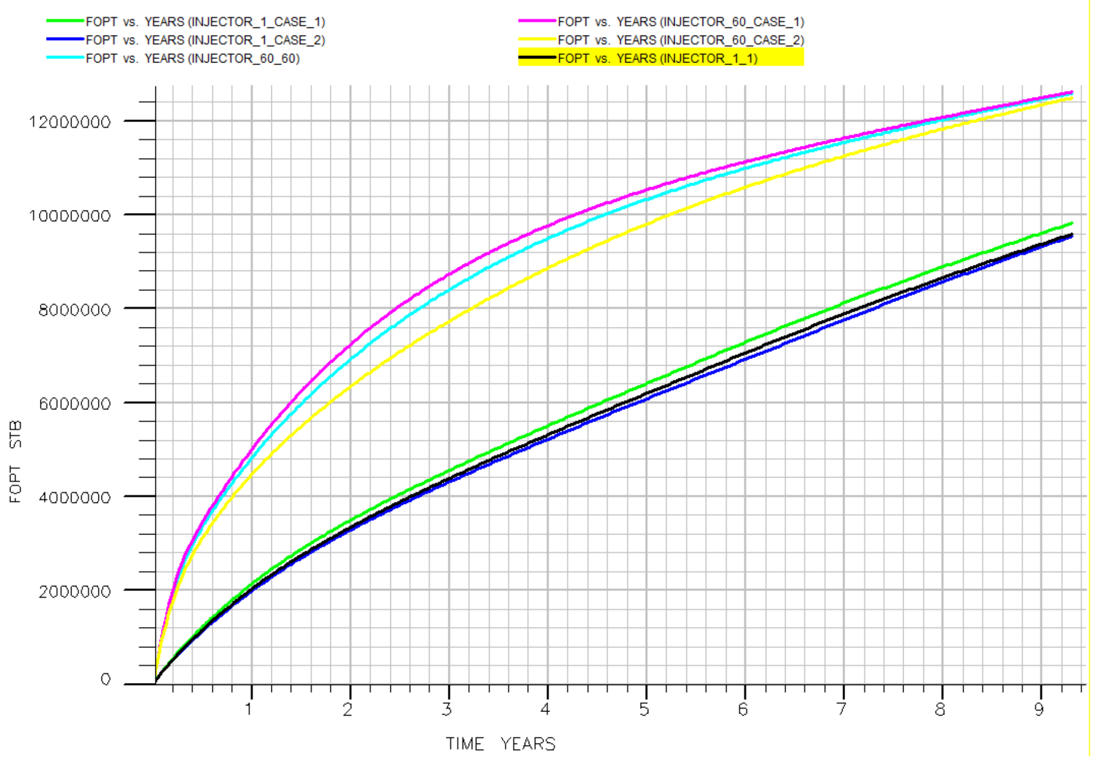


Figure 23: Field Total Oil Production when Injector is located in HPOZ and LPOZ

4.4.1 Discussion of results obtained from change in thickness of the layers having different properties

The relationship between Field Total Oil Production and layer thickness (Figure 22 and 23) is the same way. As the thickness of the HPOZ or HPZ is increasing, performance of the Field Total Oil Production. The reason being is that injection front sweeps mostly and easily high permeable zone, but struggling to do so in low permeable zone.

Also Prieditis (1988) suggests that if injection time is long enough, probability exists that Total Oil Production will be more in injection from HPZ than injection from LPZ. Because, when the thickest layer is HPZ, foam will have more time to sweep the zone.

4.5 Effect of change in injection rates

Another simulation was carried out by increasing both gas and water injection rates. Injection rates of gas and water were in the following amount:

Table 2: Injection rates of gas and water

Run	Gas injected (STB/Day)	Water injected (STB/Day)
1	4000	400
2	5500	550
3	6000	600

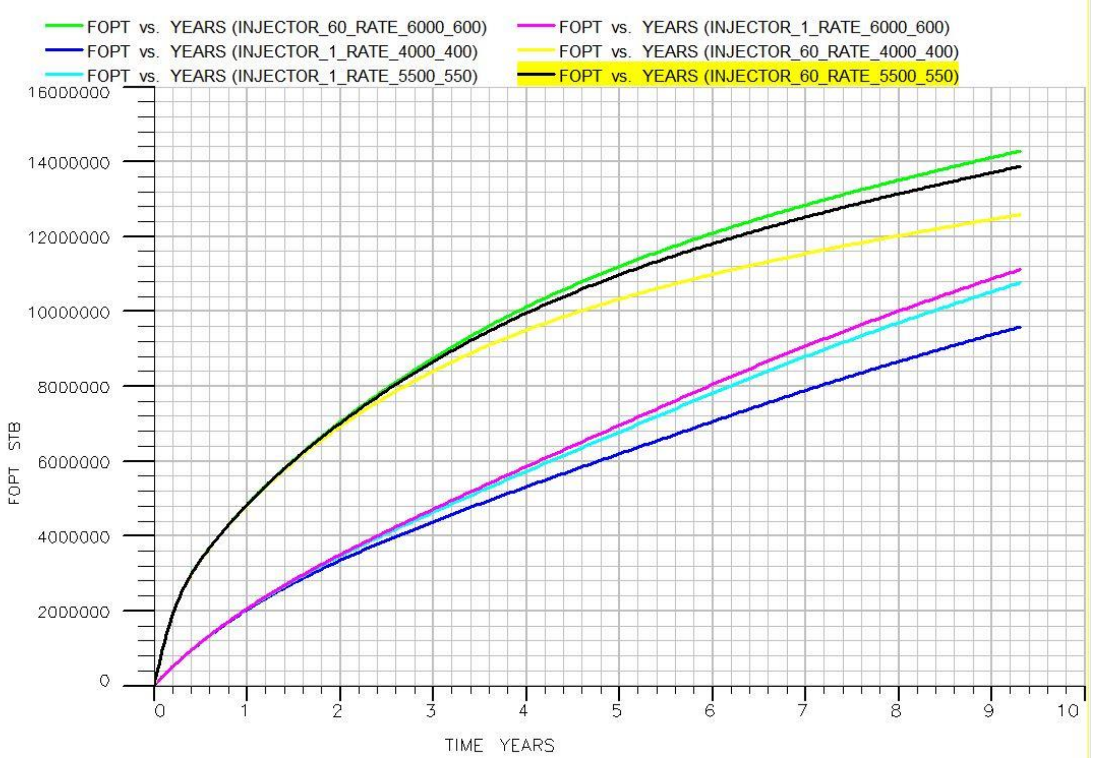


Figure 24: Field Total Oil Production (injection from high, and from low permeable region)

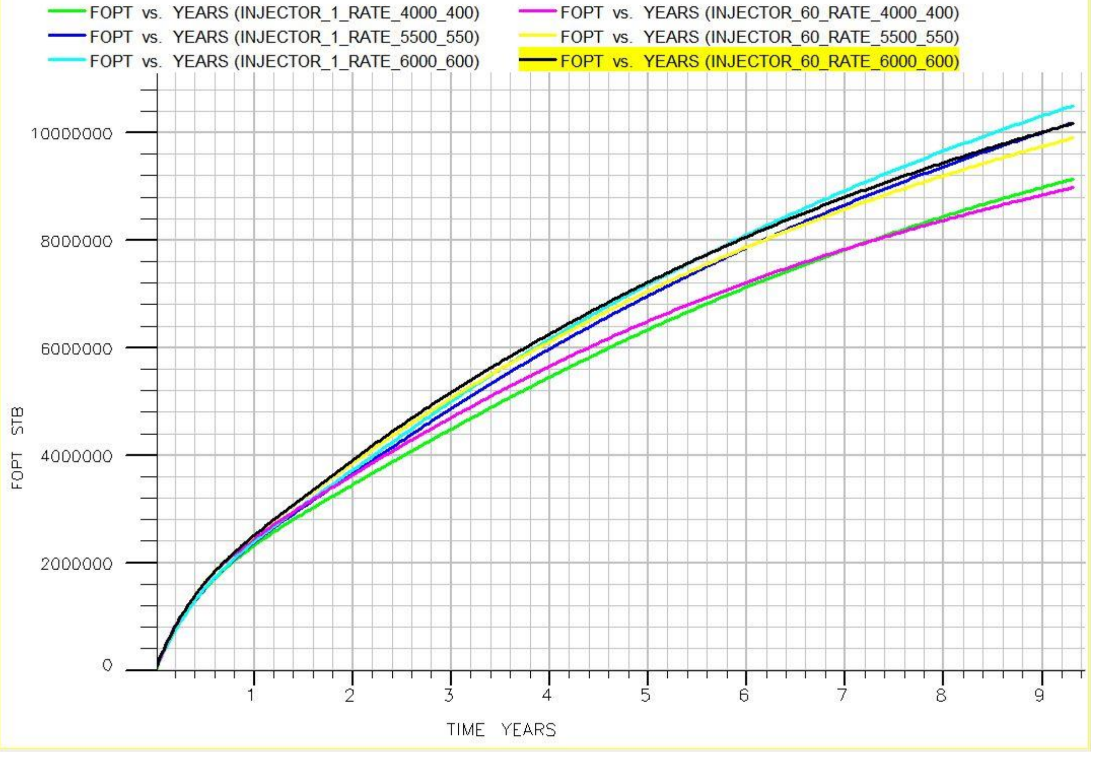


Figure 25: Field Total Oil Production (injection from high, and from low porous region)

4.5.1 Discussion of results obtained from change in injection rates

Figure 24 and Figure 25 show that, with increment in injection rate regardless of the cause of heterogeneity and direction of flow, Total Oil Production increases. I should be mentioned that in all cases, foam quality was kept at the same value 0.91, indicating high quality.

Tanzil (2002) says that as injection rate is increased, foam formation speed also increases. He also mentions that, when injection rate is raised, there is a high chance that bubbles in small size are formed. Small size bubbles lat longer and perform better in terms of sweep efficiency.

4.6 Effect of surfactant concentration

In this part of simulation process, effect of surfactant concentration on foam flooding was planned to study. Initial surfactant concentration was 3%, and runs with 6, 9 and 15% were also conducted. Gas and Water Injection Rates were 4000 STB/Day and 400 STB/Day respectively.

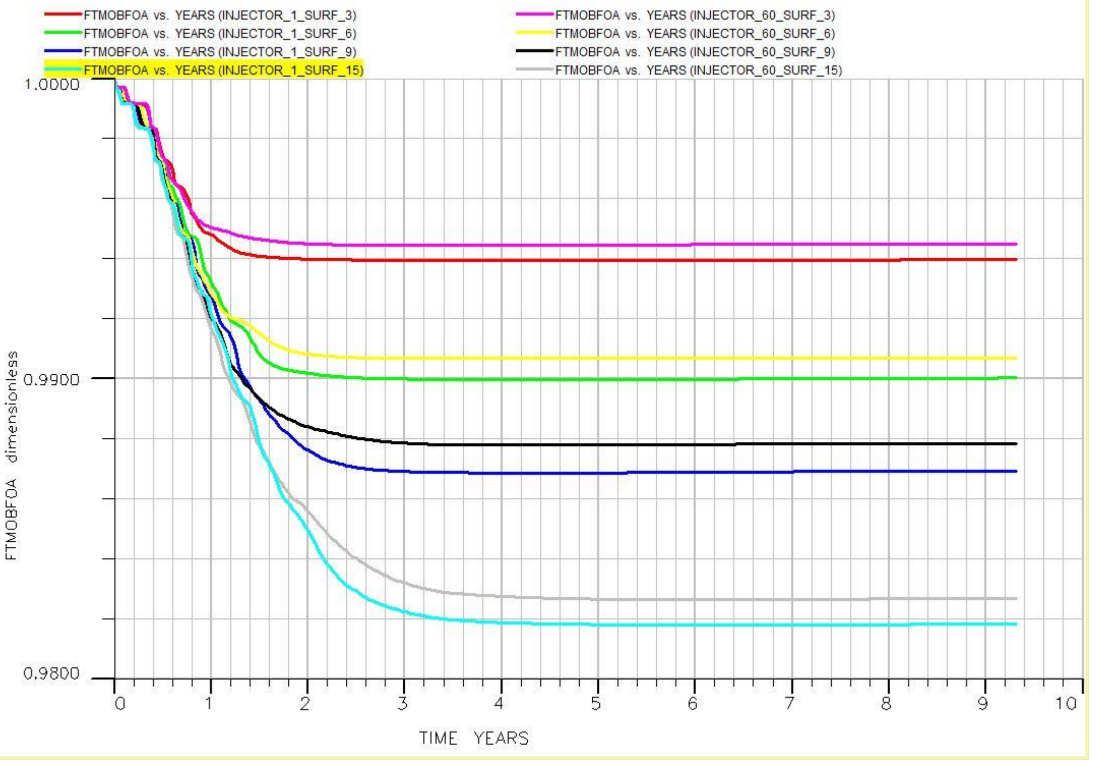


Figure 26: Gas Mobility Factor for different Surfactant Concentration values (change in permeability)

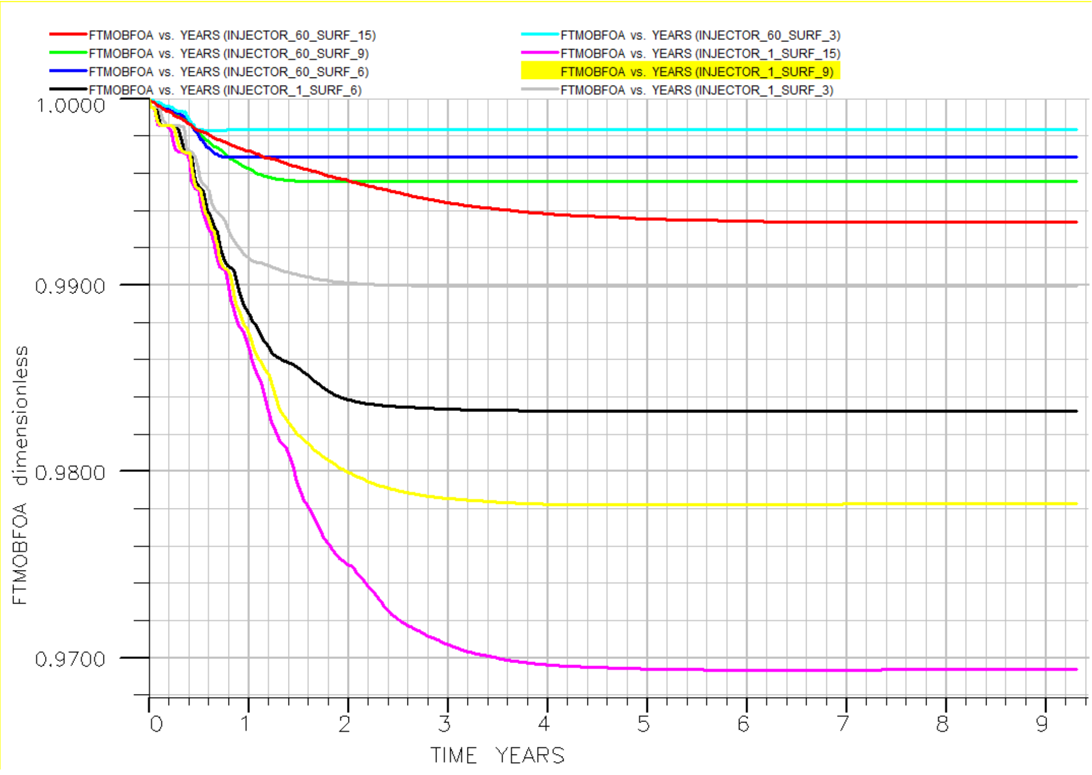


Figure 27: Gas Mobility Factor for different Surfactant Concentration values (change in porosity)

4.6.1 Discussion of results obtained from change in surfactant concentration

It is noticed from Figure 26, when surfactant concentration increased, Gas Mobility Factor decreased, but the effect of increment is more on cases when flow is from HPZ, compared to cases when flow is from LPZ. The same relationship between Surfactant concentration and direction of flow is observed in change of porosity. Yunxiang (2000) says that effect of surfactant concentration is determined by amount of surfactant solution existing in the flow stream. He says that as surfactant concentration increases, viscosity of foam increases. Viscosity in LPZ is lower compared to the one in HPZ. This results in a smaller flowing resistance. Also, Yunxiang's (2000) work which was focused on the experimental work to understand the relationship between the positions of layers having different porosity and permeability delivered a clear understanding about foam flow under various surfactant concentration. The conclusion came after reading this work is that no matter how much surfactant concentration is increased, it is difficult to achieve a good sweep in a low permeability and porosity layer.

Simulations conducted to analyze foam model parameters

4.7 Effect of mobility reduction factor component due to surfactant concentration

Figure were plotted to show the Gas Mobility Factor for different reference surfactant concentrations (0.0005, 0.005 and 0.05) when e_s is 0.05, 0.5 and 5. Each line represents the case when flow is either from HPZ or LPZ.

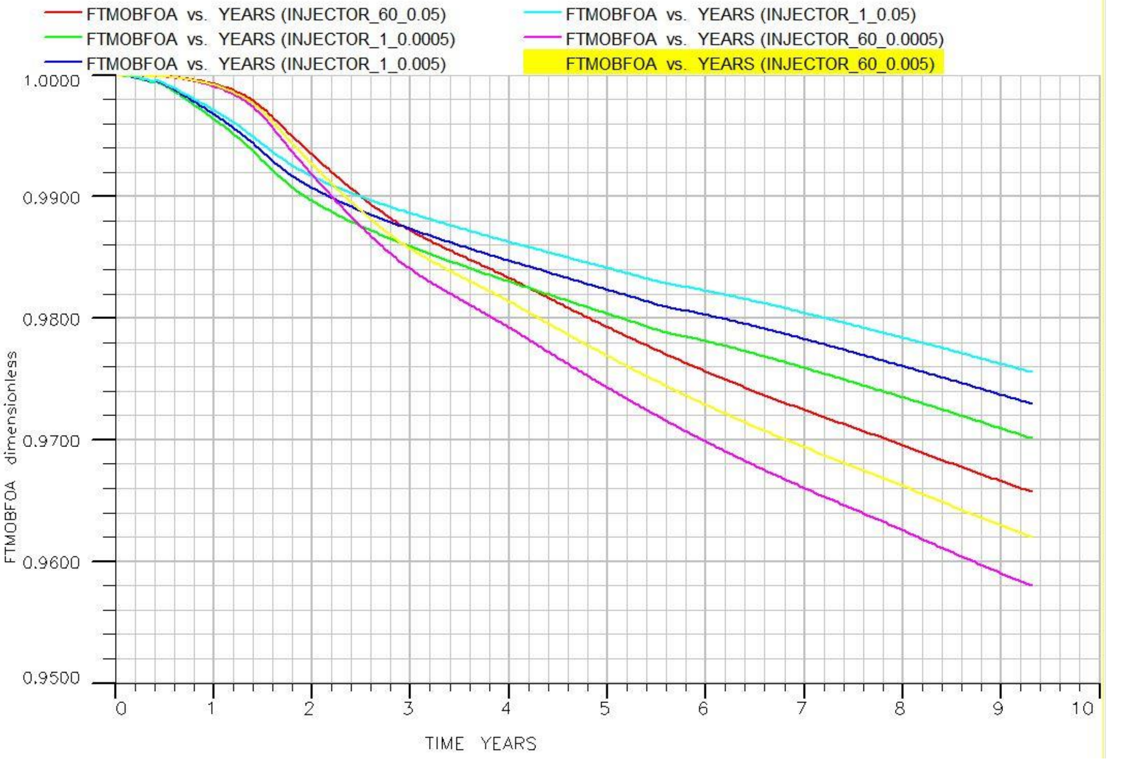


Figure 28: Gas Mobility Factor for different reference surfactant concentrations (e_s=0.05)

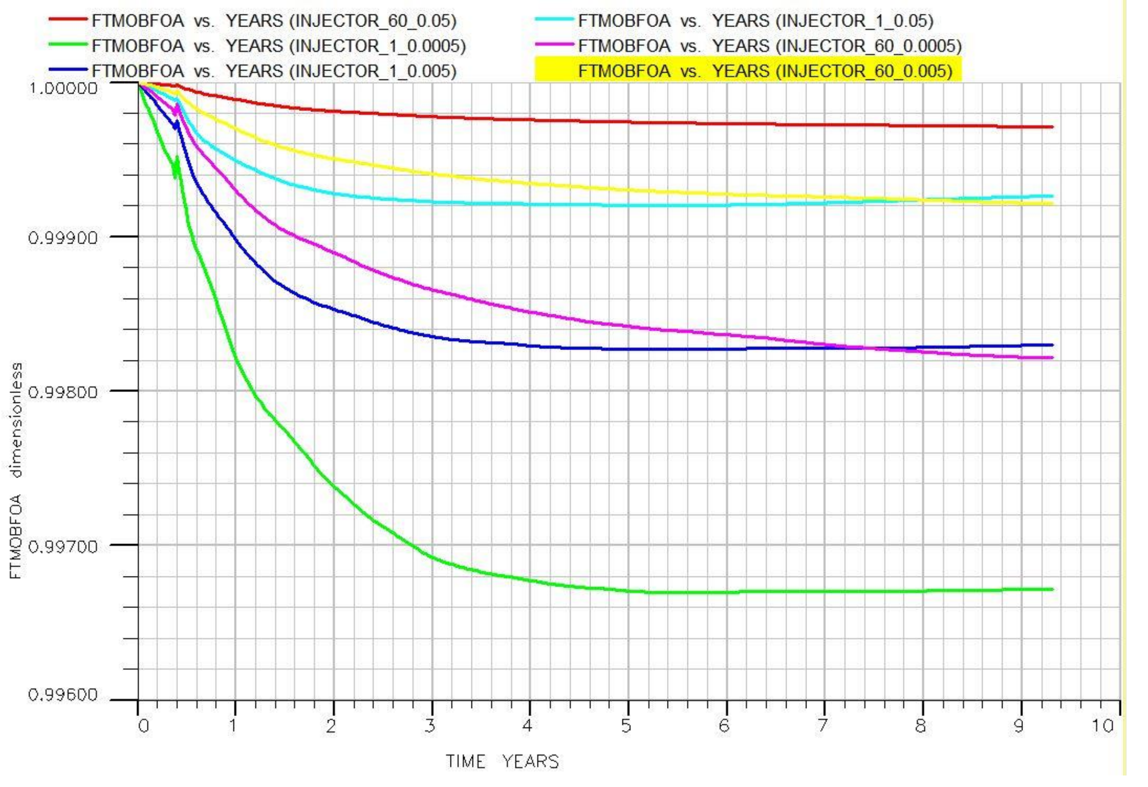


Figure 29: Gas Mobility Factor for different reference surfactant concentrations (e_s=0.5)

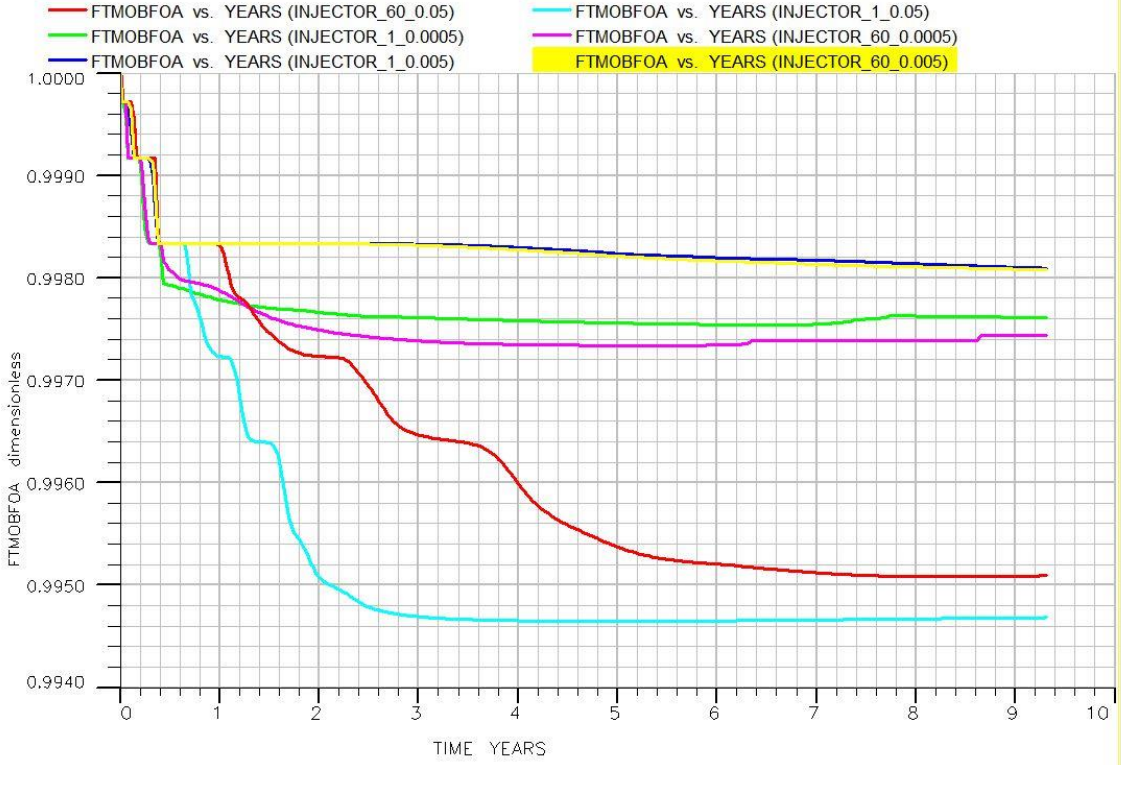


Figure 30: Gas Mobility Factor for different reference surfactant concentrations (e_s=5)

4.7.1 Discussion of results obtained from change in mobility reduction factor component due to surfactant concentration

The general observation is that Gas Mobility Factor is higher when flow is from HPZ. As reference surfactant concentration decreases, Gas Mobility Factor also decreases. Highest Gas Mobility Factor is observed when e_s=0.05. Commonly, decrement is sharp (but value is still high) and remains constant when e_s gets high. When e_s is low, continuous and gradual decrement is seen. These results can be explained with the fact that for low surfactant concentrations (weak foam), the value of F_s will be less than 1 and will tend to 0 as the surfactant concentration decreases to 0. This conforms the experimental results obtained by Rossen (1999). It can be concluded that steepness and curvature of the graph mostly depends on e_s.

Rossen (1999) also observed that the significance of F_s is determined by the reference surfactant concentration above which the presence of surfactant becomes significant in the creation of foam. According to his work, for low surfactant concentrations (weak foam), the value of will be less than 1 and will tend to 0 as the surfactant concentration decreases to 0. Conversely, for high surfactant concentrations (strong foam), the value of F_s will be greater than 1 and will increase with increasing surfactant concentration.

4.8 Effect of mobility reduction factor component due to water saturation

In this part of the study, same procedure was followed as described in previous section. Figure were plotted to show the Gas Mobility Factor for different limiting water saturation below which the foam ceases to be effective (0.3 and 0.003)
when weighting factor which controls the sharpness in the change of mobility was 0.02 and 2.

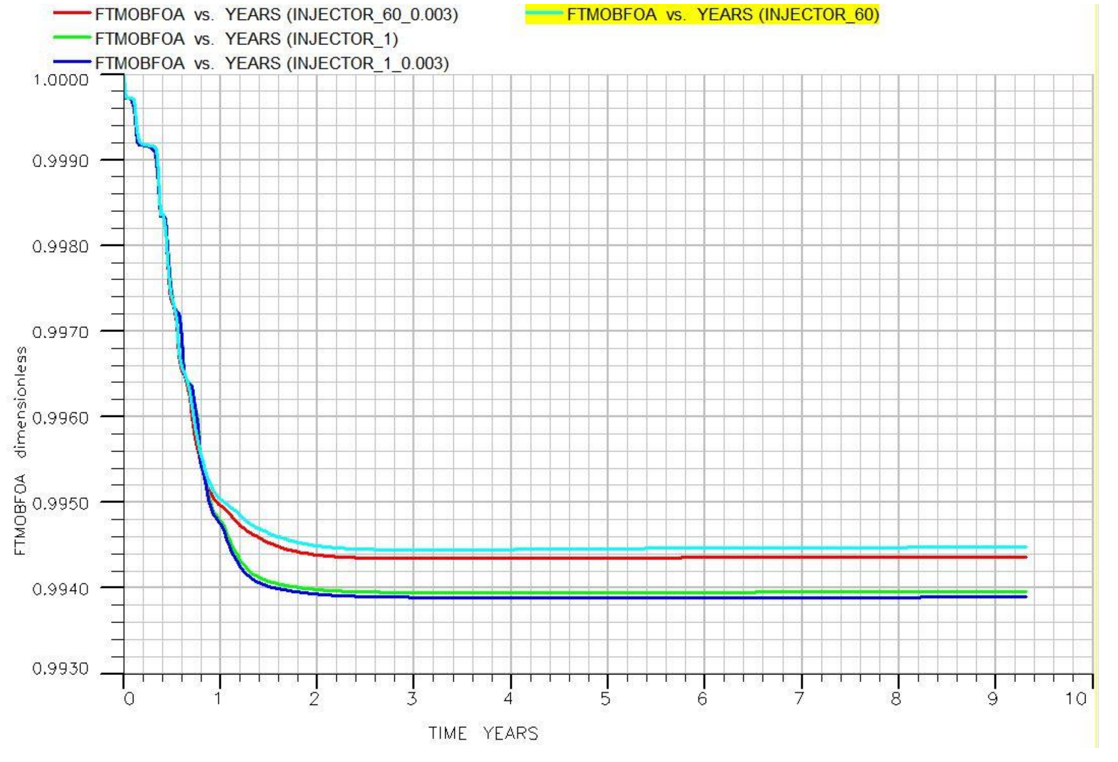


Figure 31: Gas Mobility Factor for different limiting water saturations weighting factor

4.8.1 Discussion of results obtained from change in mobility reduction factor component due to water saturation

Difference between Gas Mobility Factor when flow was from HPZ or LPZ was not much. Change in limiting water saturation below which the foam is to be effective did not have any effect. Minute decrement was observed when weighting factor increased. It can be concluded that weighting factor has greater effect on mobility reduction than limiting water saturation.

Ying (2005) informs that the gas mobility increases sharply as water saturation decreases towards this limiting value. It is suggested that deeper insight can be given to this secton in future work.

Chapter 5

Conclusion and Recommendations

5.1 Conclusion

Foam flooding proves to be one of the one of the ways to reduce and control the mobility of the gas. It was observed that, when injection is designed properly, foam flooding increases total field oil production. Foam flooding utilization can not only optimizes recovery but also accelerate oil production.

Thus, taking into account site-specific heterogeneity and stratification, individual recovery methods may require additional conditions for their economic success.

Therefore, it is important to screen and design foam injection and its horizontal flow performance schemes.

After completing the work, several conclusions regarding the project were made:

- If horizontal heterogeneity is due to only change in permeability, it is preferable to locate Injector in Low Permeable Zone, and Producer on High Permeable Zone. This will lead to achieve higher Field Recovery Efficiency and Field Total Oil Production. Also, low and uniform distribution of Gas Saturation across the reservoir will be reached.
- If horizontal heterogeneity is due to only change in porosity, it is preferable to locate Injector in High Porous Region as it will lead to achieve lower Gas Oil Ratio and Total Field Gas Production. However, locating Injector in any other region of the reservoir will not have much effect on performance of Producer.
- Change in the thickness of the heterogeneous layer does not have much effect on change of performance.
- Oil Recovery Efficiency increases with rising Injection Rate.
- It was observed that when flow occurs from high to low permeable zone, surfactant concentration did not have significant effect on Total Field Oil Production, Total Field Gas Production, Flow Rate of Oil and Flow Rate of Gas.
- Steepness and curvature of the Gas Mobility factor graph mostly depends on e_S.

- Change in limiting water saturation below which the foam ceases to be effective did not have any effect. Minute decrement was observed when weighting factor increased.

The conceptual understanding of the author about heterogeneity specifically is summarized by points below. They are assumed to be the main guidance while developing the project further in the following stages:

- Any type of the existing heterogeneity in the reservoir, could be favourable or unfavourable to oil production and recovery, depending upon the context.
- The relative importance or beneficial effects of a given heterogeneity may change. Deciding on the plan of oil recovery and production method requires a close inspection of heterogeneities and how they are likely to interact with the parameters affecting foam flow.
- Reservoir simulation is one of the most practical way of analysing the heterogeneities. Simulations can be very convenient in examining a reservoir model for a given mode production and its design. Also, conclusions about optimizing operation plans can be easily reached.

5.2 Recommendations

Regardless of how accurately the reservoir simulator solves mathematic equations of the flow among the model grid blocks, or how fast it delivers the requested result to the operator, author's opinion is that simulator cannot fully generate the genuine interaction between rock and injected/ original in place fluid. Considering the above said, authors suggestion is to verify simulator generated results in actual laboratory procedure. Since it is a big challenge to build actual heterogeneity of the reservoir (or even in a core scale) using numerical simulator, great dependence on experimental work exists.

As an extension to this work, study on foam flow behavior in the reservoir having different types of rocks distributed horizontally can be done. This will address the issue of surfactant solution absorption to the rocks as they have different mineralogy.

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