Study of Liquid Injectivity in SAG –Foam Process

by

Parisa Sarani

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Dissertation submitted in partial

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Universiti Teknologi PETRONAS

Bandar Seri Iskandar

31750 Tronoh

Perak Darul Ridzuan

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

BACHELOR OF ENGINEERING (Hons)

(PETROLEUM)

Approved by,

____

(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.

(PARISA SARANI)

ABSTRACT

Surfactant Alternating Gas (SAG) is an EOR process which involves injection of surfactant and gas alternatively into the reservoir. Different type of gas has been used in SAG injection; however the selection of gas is normally based on its availability and economic considerations. Only few studies are conducted to study the liquid injectivity in SAG-Foam process. Thus, the project is conducted to study CO2 as the gas used in SAG process to generate the foam in the reservoir. Foam injection is used as an EOR method to help the reduction of gas mobility in the reservoir. High mobility of the gas in the reservoir may cause gravity override and early breakthrough of the injected gas. This project involves simulation study using reservoir model constructed with reservoir data obtained from the literature. A preliminary study has been conducted to study the behavior of the liquid injectivity in homogeneous reservoir. More comprehensive study is required to fully understand and validate the result. Future project work includes generation of reservoir model and simulation of SAG- foam parameters to study the liquid injectivity and foam propagation behavior in the reservoir.

ACKNOWLEDGEMENT

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF EQUATIONS

LIST OF TABLES

NOMENCLATURE

μ_g	Gas viscosity
μ_o	Oil viscosity
μ_w	Water viscosity
B_w	Water formation factor
E_h	Horizontal sweep efficiency
E_m	Microscopic displacement efficiency
E_v	Vertical sweep efficiency
g	Gravitational acceleration
h_i	thickness
II	Injectivity index
k_{rg}	Gas relative permeability
k_{ro}	Oil relative permeability
k_w	water permeability
N_g	Dimensionless gravity number
P	Local pressure gradient
P_{bhi}	Initial bottom hole pressure
P_e	Reservoir pressure
Q	Injection rate
r_e	external radius
R_f	Recovery factor
r_w	well bore radius
s	skin factor
x_D	Dimensionless position
$\Delta\rho$	Difference in density between gas and aqueous phase

CHAPTER 1

INTRODUCTION

1.1 Background of Study

With the decreasing amount of oil and gas reserves and increasing demand, exploration on oil and gas has moved on to harsher environments such as deepwater reservoir and high pressure high temperature reservoir. Despite that, it is important to maximize the quantity of oil that can be produced in the remaining reserves. Using only primary and secondary methods which are natural drive mechanism and pressure maintenance, less than 40% of the oil reserves are recovered (Nangacovié, 2012). Tertiary recovery, Enhanced Oil Recovery has been applied to producing fields to optimize recovery. Enhanced Oil Recovery (EOR) refers to any type of oil recovery done by injection of materials initially not in the reservoir.

There are several EOR techniques, such as thermal recovery, gas injection, microbial process and surfactant alternating gas (SAG) process. Different techniques of EOR are selected depending on the properties of fluid and the reservoir condition. For example, thermal recovery is more commonly used in heavy oil reservoirs in order to reduce the viscosity and increase the permeability of heavy oil.

Gas injection has been used widely in the EOR process. This is because gas is able to produce higher microscopic displacement efficiency than water due to lower gas-oil interfacial tension (Al-Ghanim, Gharbi, & Algharaib, 2009). However, it is often associated with the low mobility ratio which causes low volumetric sweep. It limits the volume of oil that is in contact with injected gas (LaForce & Jessen, 2007). Thus, Surfactant Alternating Gas (SAG) is developed to overcome the limitations in gas injection. SAG involves the injecting both surfactant and gas alternatively in the reservoir. By combining the better gas microscopic displacement efficiency with the volumetric sweep efficiency of surfactant, higher oil recovery can be achieved compared to gas or water flooding alone (Tewari, et al., 2010). Due to the complexity of the process, it is important to select the suitable design of SAG in order to produce optimum recovery with considerable cost. Moreover, foam improves sweep in miscible and immiscible gas-injection EOR processes. SAG-Foam process offers many advantages over co-injection of foam for both operational and sweep efficiency reasons (Rossen, et al., 2013). There have been researches conducted in order to investigate the optimum SAG-foam process on different type of reservoirs since the introduction of SAG.

Injection of gases, such as supercritical CO2, hydrocarbon gases, N2 or steam for enhanced oil recovery (EOR) can be very effective at displacing oil, but ultimate oil recovery is reduced by poor efficiency of the gas (Lake, 1989). Sweep efficiency is poor due to reservoir heterogeneity, gas gravity segregation causing gravity override, and viscosity difference between injected gas and the residual oil. Foam can improve all of the above issues, as well as sweep efficiency of the reservoir when gas is injected as an EOR method (Schramm, 1994; Rossen, 1996).

In current practice, there are differences in SAG-foam design depending on the reservoir characteristics. However, in terms of gas composition, carbon dioxide is more commonly used in compare to hydrocarbon gas during SAG process. It is important to understand the characteristic of the gas which might affect the SAG.

1.2 Problem Statement

There are several factors which will affect the injectivity of the injected fluid in the reservoir such as surfactant and gas slug size in SAG process and the mobility near the wellbore. However, increase in the slug size of gas and surfactant which is being injected alternatively into the reservoir has a significant advantage in gravity override and injectivity in a SAG-foam process. (Shan and Rossen, 2004; Kloet et al., 2009; Leeftink et al., 2013).

The feature of high mobility of the injected gas in the formation is an issue which needs high consideration in EOR process. The injected gas due to lower density in compare to the residual oil provides the possibility of occurring gravity override. The key advantage of the foam injection along with SAG process is to control the gas mobility in wellbore area and prevent the gravity override issue in the wellbore region.

On the other hand, there are few studies to investigate the impact of liquid injectivity on foam generation in the reservoir. The gas injected is normally selected based on the availability of the gas and economic considerations. Carbon dioxide is normally selected during gas injection due to lower miscibility pressure (Jiang, Nuryaningsih, & Adidharma, 2012). In this study, the focus will be narrowed to foam generation by Carbon Dioxide injection in SAG-foam process.

Although, there are number of studies which conducted theoretical, lab experiments and simulations to examine the SAG-foam injection process, it is necessary to conduct a research to study this EOR process in detail. This study will concentrate on investigation and identification of the parameters influencing liquid injectivity, as well as suggesting the methods which will improve liquid injectivity in the reservoir as well as foam propagation.

1.3 Objectives

- Identification of parameters influencing liquid injectivity and Investigation of possibilities to improve liquid injectivity in SAG foam process
- Study the impact of identified parameters on foam propagation in reservoir

1.4 Scope of Study

Laboratory experiments which use the core samples of the reservoir for SAG-foam process are not economically reliable. This project is limited only to purely simulation work using reservoir simulation software. Only carbon dioxide gas will be used for the SAG process to generate the foam in the formation. The reservoir model will be built based on the data obtained from the literature review.

1.5 Relevancy of the project

This project is highly relevant to the oil and gas industry, as SAG-foam is one of the main EOR process used in the field. It is important to identify the impact of SAG-foam process in terms of sweep efficiency in order to select the optimum SAG-foam process which is economically viable and produce high oil recoveries. As it is mentioned earlier, selection of gas used in SAG-foam injection is based on availability and economic constraints. This project is highly relevant to the industry as it is looking on the aspect that how to optimize this EOR process to achieve to highest amount of recovery which is economically reliable.

1.6 Feasibility of the project

This project is feasible to be done as only simulation study is conducted. It is expected to be less time consuming and less technical problems compared to experimental studies. To ensure that this project can be finished on limited time frame, only one reservoir model will be created to study on CO_2 SAG-foam injection. Since the simulation study is conducted using ECLIPSE software, there is no cost required in the project as the license for this software is available in simulation lab of Universiti Teknologi PETRONAS (UTP).

CHAPTER 2

LITERATURE REVIEW

Foam improves sweep efficiency in both miscible and immiscible gas injection in EOR process. SAG-foam process which is injecting slugs of surfactant solution and gas alternatively in the reservoir. This EOR method offers significant results over co-injection of foam for both operational and sweep efficiency reasons (Rossen, Boeije, 2013). Injection of surfactant solution and gas in SAG process is done in several cycles. The number of cycles for SAG-foam injection depends on factors such as recovery efficiency, type of the reservoir and the economic consideration of both CO2 gas and surfactant solution.

2.1 Recovery Efficiency of EOR

Recovery of oil depends on two main factors, which are volumetric sweep efficiency and displacement efficiency (Hite, Avasthi, & Bondor, 2004). Volumetric sweep is normally known as macroscopic sweep while displacement efficiency refers to microscopic sweep. According to Christensen et al. (2001), the effectiveness of oil recovery, recovery factor (Rf) are determined by three main factor, which are vertical sweep efficiency (Ev), horizontal sweep efficiency (Eh) and microscopic displacement efficiency (Em) which can be related in the Equation 1 :

$$R_f = E_v \cdot E_h \cdot E_m$$

Equation 1: Relationship between Oil Recovery and Microscopic and Macroscopic Sweep Efficiency (Christensen et al., 2001).

Macroscopic sweep efficiency, which includes vertical sweep efficiency and horizontal sweep efficiency are generally influenced by reservoir heterogeneity and mobility ratio. Reservoir heterogeneity which refers to the condition when different properties of rock exist in a single reservoir is capable of changing the sweep patterns during flooding process (Kulkarni, 2003).

The other factor influencing the sweep efficiency is mobility ratio. It is the mobility of the displacing fluid to mobility of displaced fluid (Arogundade, Shahverdi, & Sohrabi, 2013; Nangacovié, 2012; Sobers, 2012).

$$M = \frac{k_{rg}/\mu_g}{k_{ro}/\mu_o}$$

Equation 2: Mobility Ratio Equation

(Arogundade, Shahverdi, & Sohrabi, 2013; Nangacovié, 2012; Sobers, 2012).

To improve sweep efficiency, it is preferable to have mobility ratio of less than 1, where the viscosity of displacing phase is higher than the displaced phase. At low mobility ratio, a piston-like displacement can be achieved where the injected fluid will be able to displace the remaining oil in the reservoir.

On the other hand, it is unfavorable to have mobility ratio higher than 1, as the flow is unstable and result in viscous fingering, a condition when bypass of fluid occur in reservoir section (Nangacovié, 2012; Sobers, 2012). This is because the displacing fluid moves faster than the displaced fluid – oil, resulting in low sweep efficiency and early breakthrough. This situation normally occurs during gas injection due to its low viscosity compared to oil in reservoir (Al-Ghanim et al., 2009; Arogundade et al., 2013).

Foam reduces gas mobility by trapping a large percentage of gas in place; up to 80-90 % of gas is trapped even if foam flows at high pressure gradient (Friedmann et al., 1991; Gillis et al., 1990). Foam also reduces gas mobility by increasing the effective viscosity of the flowing gas (Bretherton et al., 1961; Hirasaki et al., 1985; Falls et al., 1989; Xu et al., 2003). These two effects are depended on capillary forces that give foam an apparent yield stress and trap bubbles in place (Xu et al., 2003; Rossen, 1990).

On the other hand, as stated by Hite et al. (2004) and Kulkarni (2003), microscopic displacement efficiency is influenced by capillary action, which includes the interfacial tension and contact angle between fluids. Microscopic displacement efficiency can be improved by reducing the capillary pressure which holds the oil in the reservoir especially in small pores. In general, gas-oil displacement will produce better microscopic efficiency (Christensenet al., 2001; Righi et al., 2004). This is because gas is able to sweep through the small pores with its low gas-oil interfacial tension. Besides that, by having miscible gas injection, it is able to reduce the interfacial tension to zero, which enhance the oil recovery further (Al-Ghanim et al., 2009; Jiang, Nuryaningsih, & Adidharma, 2012).

While gas injection produces high microscopic displacement efficiency but low macroscopic efficiency due to high mobility ratio therefore SAG-foam process offers many advantages over co-injection of foam for both operational and sweep efficiency reasons (Rossen et al., 2013).

2.2 Classification of Foam generation in SAG-foam process

In terms of SAG-foam design, foam can be generated in the reservoir in different methods. Foam can be generated by simultaneous injection of gas and aqueous surfactant solution from a single well when two fluids will be in contact in the surface facilities like in tubing or after fluids enter the formation. Foam can also be formed when gas and surfactant are injected alternatively into the formation by separate slugs but from a single well. In this process foam is either generated from the recent injected gas with the pervious injected surfactant solution or when the surfactant solution meets the pervious injected gas in the reservoir (Rossen and Boeije, 2013).

Another method for foam generation which is introduced by Le and Ashorri is that foam is formed by dissolving some surfactants into supercritical CO2. In this case there is no need for injection of aqueous surfactant solution; injected CO2 along with dissolved surfactant will react with the water existing in the reservoir. Stone and Rossen proposed that foam can be formed when Surfactant solution and gas can be injected simultaneously, but from different sections of a vertical well (gas injected below the surfactant solution), or from parallel horizontal wells (gas injected from the lower well). There is no clear evidence to determine which method for foam generation is the optimum one since there are many factors which decide the best foam design process (e.g. type of the reservoir).

Based on experiments done to examine the foam generation with flow rate variation, this was achieved that strong foam can be generated in low flow rate in a steady state condition. On the other hand, weak foam can be created at low concentration of surfactant. In addition, experiment showed that there was no delay in generation of weak foam and there was no difference in the rate of foam generation between low and high flow rates. Increasing flow rate may or may not accelerate the foam generation (S.I Chou, 1991).

Foam generation is highly dependent on the concentration, composition and surfactant structure but it is also related to the liquid saturation, gas and liquid flow rate as well (Ransohoff et al., 1988; Jimenez et al., 1989). Due to the velocity rate and redistribution of the wetting phase (liquid) in its own flow paths, foam mobility is not generally expected to be a function of fractional flow or saturation (Friedmann et al., 1991; Friedmann et al., 1986; Ettinger, 1989; Jimenez et al., 1989).

2.3 Injectivity, mobility and Gravity Override in SAG-foam process

Injectivity is defined as process to determine the rate and pressure at which fluids can be pumped into the target without fracturing the formation (Schlumberger, 2011). Moreover, the injectivity index quantifies the pressure increase due to pumping a known rate and volume of fluids into the formation; this can be described in form of an equation which is the ratio of injection flow rate divided by the pressure increase (Craft and Hawkins, 1991).

$$II = \frac{Q}{P_{bhi} - P_e} = \frac{k_w \cdot h_i}{141.2 \cdot \mu_w \cdot B_w \cdot \left(\ln {}^{r_e}\!/_{r_w} + S \right)}$$

Equation 3: Injectivity Index Equation (Settari, 2000)

Figure below illustrates the effect of injectivity in the formation, considering SAG-foam process; firstly a slug of surfactant solution will be injected into the reservoir therefore a bank of injected fluid will be formed then a slug of CO2 gas will be injected into formation. After the two injected fluid meet in the reservoir and will be miscible then a bank of foam will be formed which reduces the mobility of injected gas and pushes the residual oil toward the producer. However, depending on the reservoir type and injection strategies some parts of the reservoir may remain unaffected and unwept. Different parameters should be considered in order to achieve high sweep efficiency and oil recovery.

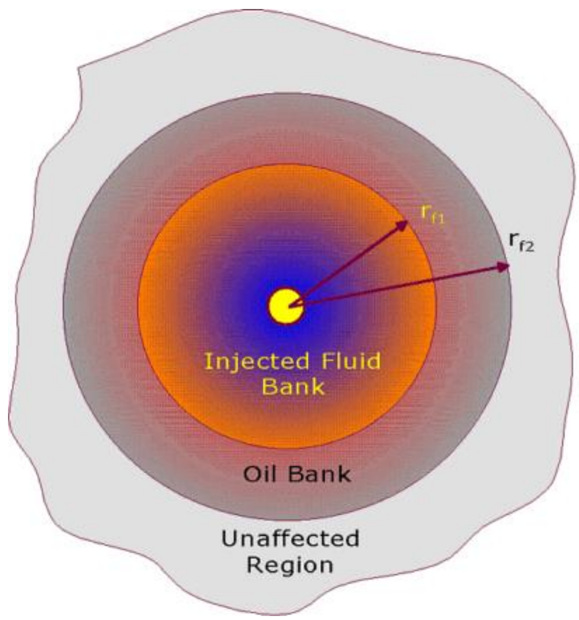


Figure 1: Liquid Injectivity Illustration (Zaki, 2002)

Gravity override is one of the issues which are raised due to difference in the density of injected gas and the residual oil. Injected gas in a SAG process because of having lower density and higher mobility in compare to oil tends to rise over the oil and cause early breakthrough instead of displacing the oil in place. Foam is used as an agent in EOR process to reduce the mobility of the gas. Previous studies showing that in a region away from the well, high gas mobility near the well will not lead to gravity override effect. This is due to increase in injectivity which allows higher injection rates which simultaneously increase the injection rate and pressure gradient away from the well (Rossen et al., 1995).

A study which examined the foam behavior and mobility of the gas in near wellbore region, showing that as water is being displaced from the near wellbore region; generation of foam weakens due to reduction in water saturation. As foam weakens and it collapses; gas mobility increases and injectivity rises (Lake, 1989). When the gas is being injected and the injectivity is low through the formation, the injection rate of gas should be decreased otherwise there is the possibility of formation fracturing (Jonas et al., 1990; Holm, 1970; Kuehne et al., 1990).

Moreover, as gas is injected in the formation, water saturation decreases due to displacement of fluid by SAG-foam process. This causes the mobility of the injected gas to rise near the wellbore area which this helps to prevent fracturing of the reservoir. Figure below shows the relation of relative permeability of injected gas with distance from the well after injection of 0.2 PV gas in a large bank of surfactant. As the saturation of water decreases foam dries out and the mobility of gas increases near wellbore region. Based on the figure 1, by employing higher injection rate in a SAG process, gravity override can be prevented without increase in injection pressure since foam has high mobility near wellbore region when gas injection is taking place (D.Shan et al.)

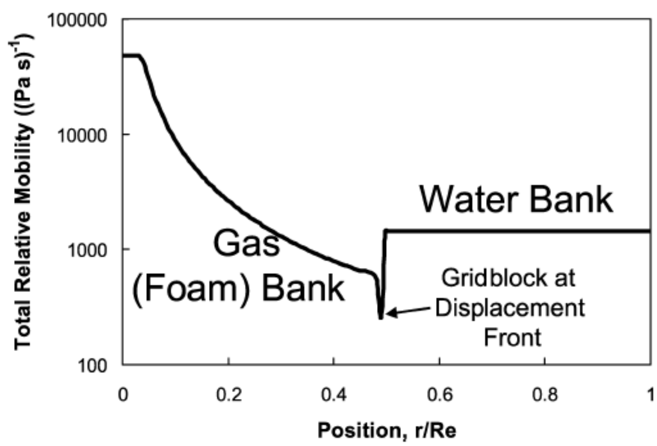


Figure 2: Total relative mobility after 0.2 PV gas injections into a Large slug of surfactant for a SAG process (D.Shan et al.)

A study shows the conditions for Foam generation near the wellbore region; in order for foam to be generated high velocity is required (Rossen et al., 1990; Friedmann et al., 1991). Another factor is minimum flow rate which is required for foam generation which is dependent to the surface tension of liquid and gas (Rossen et al., 1990). Rossen proposed in one of his studies that the minimum flow rate for CO_2 foam generation is much lower than that for N_2; therefore this factor is not significant for CO_2. On the other hand it was shown by Friedmann (1991) that for weak foam exceeding the minimum flow rate for foam generation is not necessary.

When the gas mobility rises in near wellbore region, gas fingering and gravity override occur. The injected gas with high mobility near the wellbore override the foam with lower mobility away from the well (Rossen et al., 1991). As it is mentioned earlier foam has the ability to decrease the mobility of injected gas near the wellbore which results in prevention of gravity override. Foam depends on a dimensionless gravity number Ng that depends on local pressure gradient. The following equation illustrates the relationship between Ng and local pressure gradient; which they are inversely proportional.

$$N_g \equiv \left(\frac{\Delta\rho\ g}{\nabla P}\right)$$

Equation 4: Dimensionless Gravity Number Formulae (Rossen, et al., 1994)

Where Δρ is the difference in density between gas and aqueous phase (referring to water here). Gravitational acceleration is shown as g. large values of Ng prompts gravity override. This can occur in the presence of foam, low flow rate and local pressure gradient (Rossen et al., 1994). This can be concluded that increase in injectivity during gas injection reflects decrease in pressure gradient near wellbore region which might cause occurrence of gravity override (Rossen et al., 1995).

A study proposed that injectivity can be computed as a function of time during gas injection. This can be done by plotting of the advance of displacement in time on diagram with axes of dimensionless position and dimensionless time. Injectivity can be estimated by conversion from XD to radial position r by using the equation below and then integrating the pressure outward from the well using Darcy's law and the total relative mobility at each value of r (Leeftink et al., 2013).

$$x_D \equiv \frac{r^2 - r_w^2}{r_e^2 - r_w^2}$$

Equation 5: Dimensionless Distance Formulae (Rossen, et al., 1999)

As it is shown by Rossen et al. (1995) injectivity and mobility can be interrelated and combined in the SAG-foam process in a way that as the saturation of water decrease in near wellbore region, generated foam will be weaken and injected gas mobility rises then resulting increase in injectivity. This effect may cause shear thinning that is due to change in water saturation as well as foam mobility. Moreover, In a SAG-foam process, good sweep efficiency can be achieved when the injectivity is high because sweep efficiency is dependent to low mobility away from the wellbore while high injectivity can be due to high mobility near wellbore region.

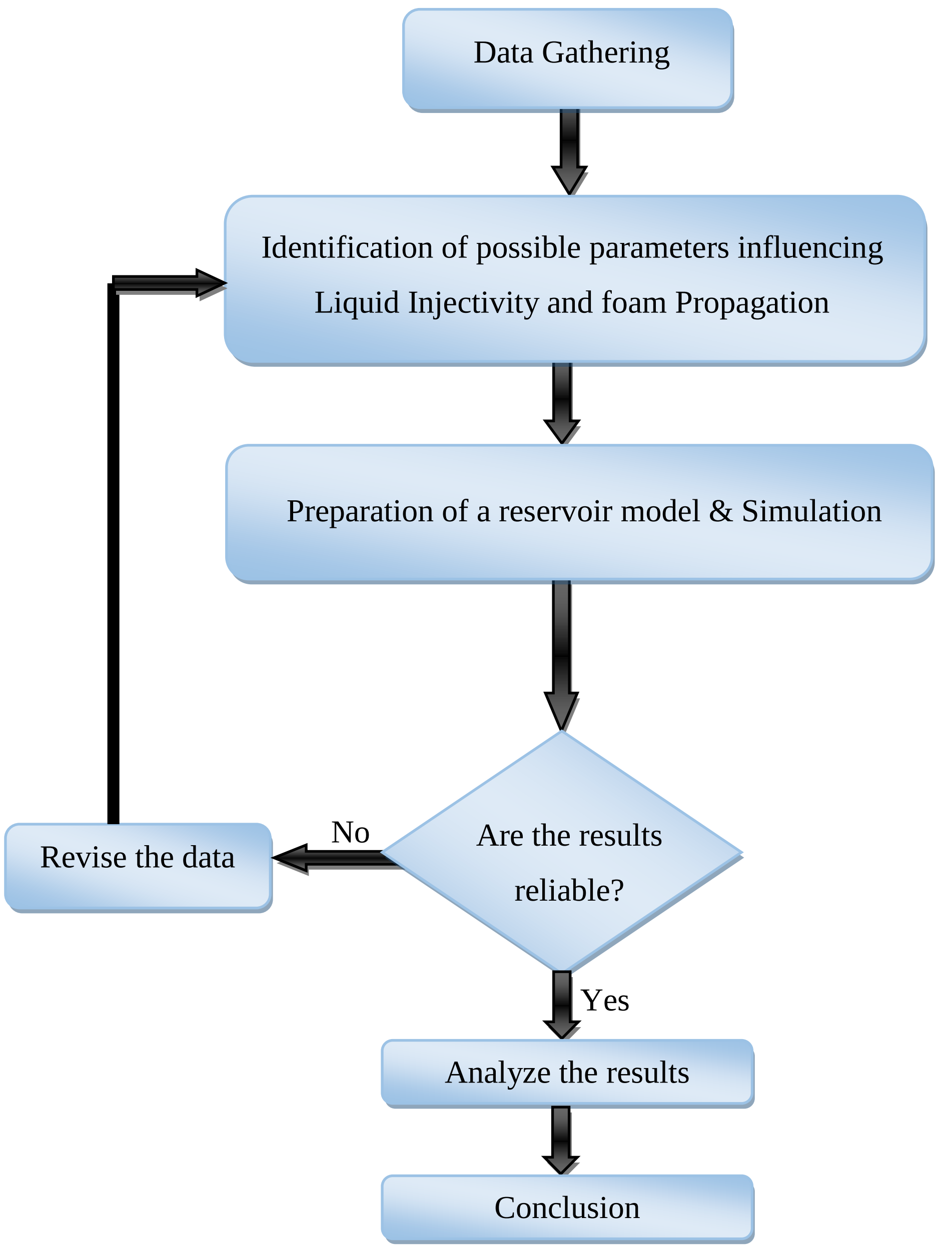
In another study which examined the foam-acid diversion in well stimulation treatment, liquid injectivity was poor due to co-injection of gas and liquid rather than injection of gas in a SAG process (Zerhboub et al., 1991; Persoff, 1990; Kibodeaux et al., 1994; Zeilinger et al., 1995; Robert and Mack, 1997; Cheng et al., 2002; Nguyen et al., 2009).

CHAPTER 3

METHODOLOGY

3.1 Research Methodology

The following flowchart shows the steps which are required to be completed for this project. A step by step procedure is illustrated for a better understanding of this study.



3.2 Project Activities

The project is started with the selection and understanding of the project topic. Preliminary research work has been conducted to study on the SAG-foam process, factors affecting the efficiency of a SAG-foam process. The purpose of doing literature review is to provide strong basic knowledge and to define the current problem and the objectives of the project.

Next, necessary data such as the reservoir parameters and its rock and fluid properties will be collected from the published research paper. Reservoir model will be generated using the data gathered through the use of reservoir simulation software. Before the start of simulation work, training will be done to familiarize the proposed simulation software, ECLIPSE. Self-training will be done.

The model will be validated and rechecked to ensure that there are no wrong input of information and all necessary desired output are stated in the simulation models. The results will then be carefully analyzed and documented in the report.

3.3 Key Milestones

	Project Milestone	Week No
FYP 1	Selection of Project Topic	2
	Submission of Extended Proposal	6
	Proposal Defense	9
	Submission of Interim Draft Report	13
	Submission of Interim Report	14
FYP 2	Preparation of Simulation Model	4
	Submission of Progress Report	7
	Result and Analysis	8
	Pre-SEDEX	9
	Submission of Draft Final Report	12
	Submission of Dissertation (Soft Bound)	12
	Submission of Technical Paper	12
	Viva	14
	Submission of Dissertation (Hard Bound)	16

3.4 Gantt Chart

Week No **FYP 1 Activities**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**
Title selection																
Literature review																
Submission of extended proposal																
Proposal Defense																
Data Gathering																
Learning Simulation software																
Submission of interim draft report																
Submission of interim report																
Week No **FYP 2 Activities**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**
Preparation of the Reservoir Model in ECLIPSE																
Validation of simulation model																
Result and analysis																
Submission of progress report																
Preparation for Pre-SEDEX																
Pre-SEDEX																
Submission of Draft Final Report																
Submission of Dissertation (soft bond)																
Submission of technical paper																

Viva																
Submission of Dissertation (hard bond)																

3.5 Data Gathering

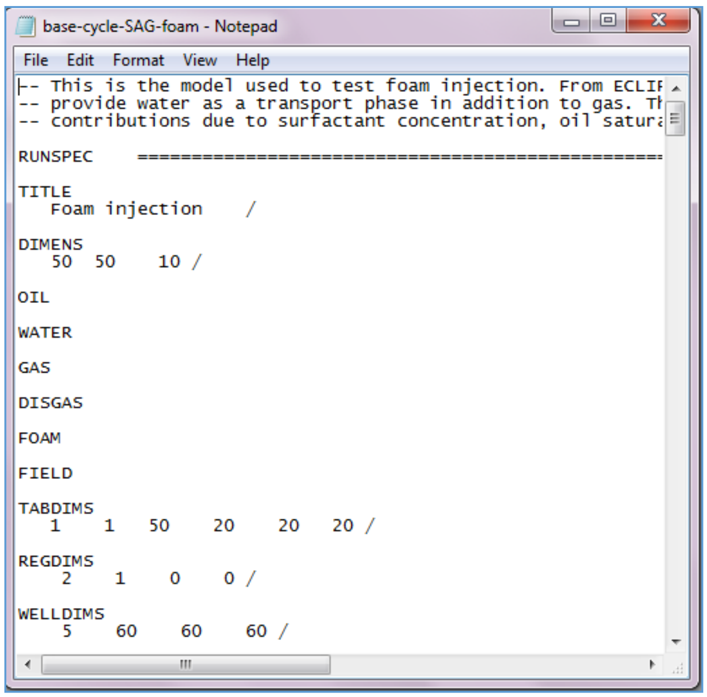
In order to achieve reliable results, a high quality simulation model should be created. Selection of required data to develop a model to simulate a real reservoir is essential. This will ensure that less assumptions and estimations are used therefore the results will be more accurate. The necessary reservoir data are obtained through the study of pervious the research papers. Several data has been tested to construct the reservoir model in order to select the more relevant data which will fulfill the scope of this study. The following table illustrates the summary of the reservoir data which are used to develop the simulation model in ECLIPSE.

Table 1: Summary of reservoir data

Reservoir Characteristic	Value
Grid Dimension	50 x 50 areal with 10 layers
Water density (Stock Tank)	62.43 lb/ft³
Oil density (stock tank)	49.94 lb/ft³
Gas density	0.061 lb/Mft³
Porosity	20 %
Permeability in X, Y and Z directions	200 mD
Reference depth	5000 ft
Reservoir Temperature	160˚F
Initial oil saturation	0.88
Initial water saturation	0.12
Initial reference pressure	5300 psia

3.6 Reservoir Static Modeling

The reservoir model is constructed by preparing and writing the required ECLIPSE codes in notepad and saving the file as .DATA to be readable by the ECLIPSE simulation software. In order to make the simulation model more accurate and reliable, the number of grid blocks should be high. For this study the simulation model is constructed of 50 x 50 x 10 which has the dimension of 50 ft x 50 ft x 10 ft. For simplicity, the reservoir is considered to be a homogeneous reservoir having the permeability of 200 mD in X, Y and Z directions. The following figure illustrates the prepared data file for this model.




```
-- This is the model used to test foam injection. From ECLIP
-- provide water as a transport phase in addition to gas. Th
-- contributions due to surfactant concentration, oil satura

RUNSPEC     ==================================================

TITLE
   Foam injection     /

DIMENS
   50  50    10 /

OIL

WATER

GAS

DISGAS

FOAM

FIELD

TABDIMS
   1    1    50     20     20     20 /

REGDIMS
    2    1     0     0 /

WELLDIMS
    5    60     60     60 /
```

Figure 3: ECLIPSE Data file

Two wells have been designed for this model which one of them is injection well and one producer. The injector is injecting surfactant solution and followed by the injection of gas from the same well. Since the process is SAG-foam process, water and gas injector that is one well located in a grid block will be alternatively shut and open and injection takes place in cycle. The figure below shows the 3D view of the grid for this model.

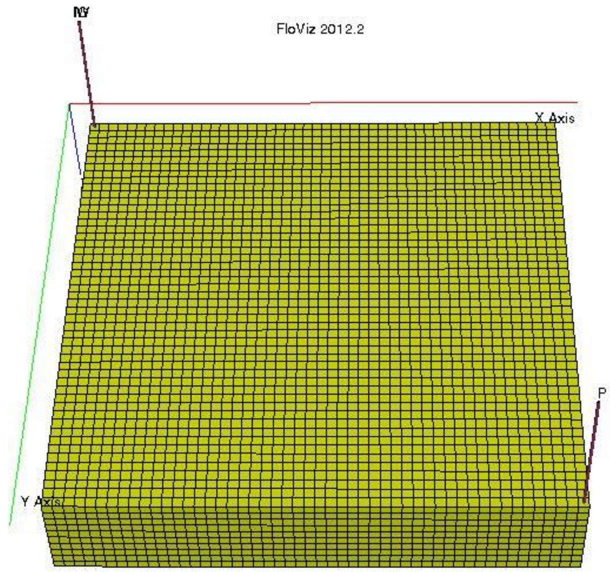


Figure 4: 3D View of Reservoir Static Model

3.7 Reservoir Dynamic Modeling

SAG- foam process as an EOR method is chosen for this reservoir model to be simulated. The simulation will use CO2 gas for injection in SAG- foam process and the surfactant solution. Surfactant solution and gas will be injected alternatively into the formation and foam will be formed into the reservoir once the injected gas passes through the injected surfactant solution which is injected initially. Several parameters will be simulated in this model to identify the properties which influence liquid injectivity as well as foam propagation in the reservoir.

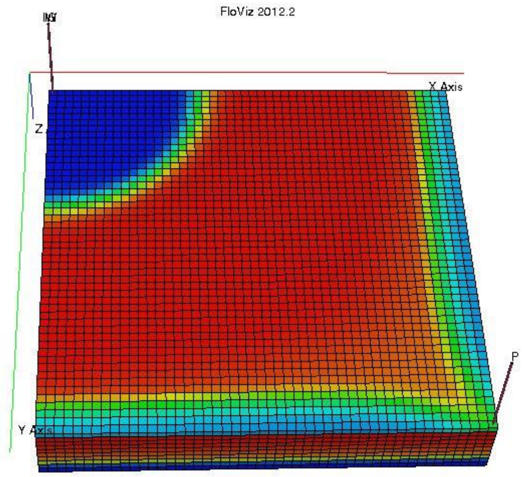


Figure 5: 3D View of Reservoir Dynamic Model

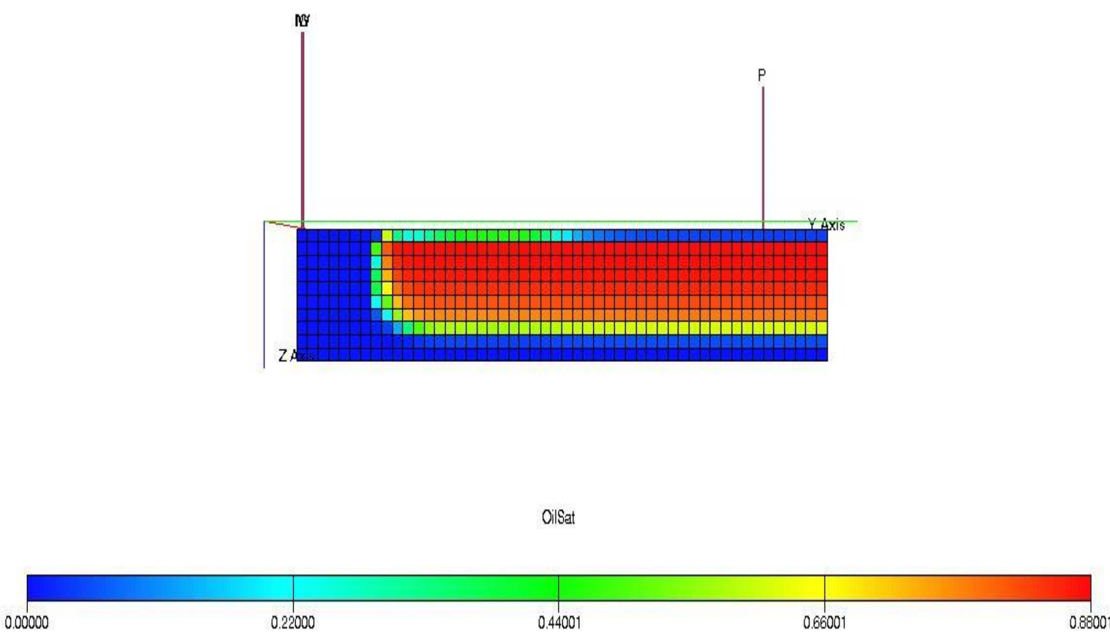


Figure 6: Side View of Reservoir Dynamic Model Represented by Oil Saturation

CHAPTER 4

RESULTS AND DISCUSSION

The constructed reservoir model is used to conduct a set of results for this study. Different simulation cases have been simulated to test several parameters; the analysis of the procedure as well as the results will be shown in the following section. The effect of different parameters has been simulated for this model to identify the parameters which are influencing liquid injectivity and further to investigate the foam propagation behavior based on the modification applied to the properties. Modified properties are:

- Surfactant solution injection rate
- Number of SAG cycles
- Formation permeability
- SAG ratio
- Timing of SAG process
- Surfactant concentration

4.1 Liquid Injectivity (Surfactant Solution Injectivity)

4.1.1 Effect of Surfactant Injection Rate

Several properties' variations have been simulated to examine the liquid injectivity behavior in this model. Selection of optimum surfactant solution injection rate is important in both optimizing the recovery as well as economic constrains. As the first parameter, surfactant solution injection rate has been varied. Based on the injectivity index formula in ECLIPSE 100 (2012), injection rate of surfactant solution as one of parameters was simulated. According to the obtained results shown in Figure 7a and 7b; surfactant solution injection rate has been varied in the range of 100-3200 STB/day. As surfactant solution injection rate is increased, liquid injectivity becomes lower. This trend continues only for the early time stages. After, sharp decline is observed in all cases, including those having low surfactant solution injection rate. This means pressure difference increases due to fluid injection into the formation and it can accept certain amount of the injected fluid (Craft and Hawkins, 1991). High injection rate may fracture the formation as well as the injection well.

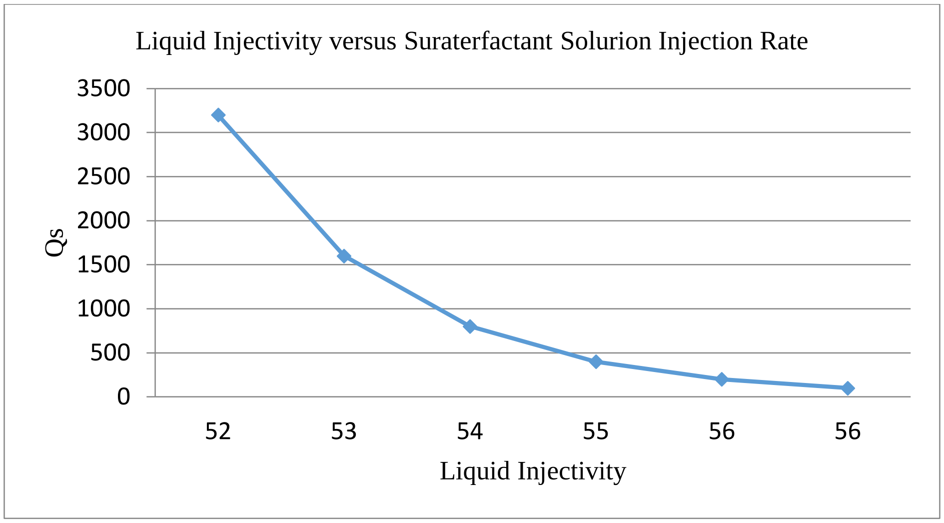


Figure 7a: The impact of different Surfactant Solution Injection rate on liquid injectivity

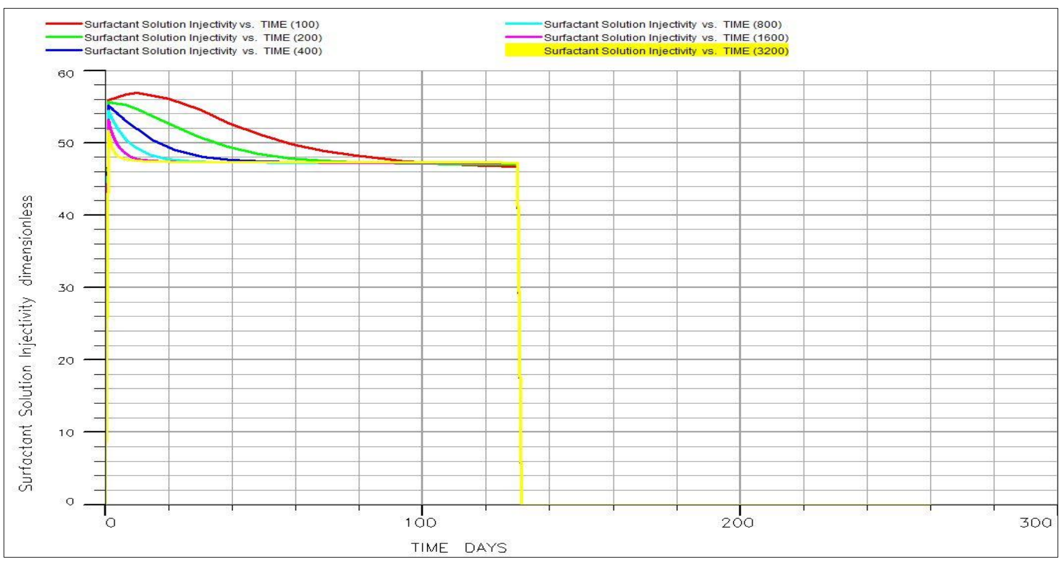


Figure 7b: The impact of different Surfactant Solution Injection rate on liquid injectivity

Field pressure as one of the parameters that influences liquid injectivity have been considered, as the injection rate of the surfactant solution increases the field pressure drop will be less in comparison to the case that has lower injection rate (Eclipse, 2012). This is due to the fact that as more fluid is injected into the reservoir it will maintain the pressure and it declines slightly less. Furthermore, this result can be proved by Darcy's law that as pressure change value increases flow rate also will rise since they are proportional (Darcy’s Law). Overall the field pressure change by time for all the cases approximately is the same. Figure 8 demonstrates this statement.

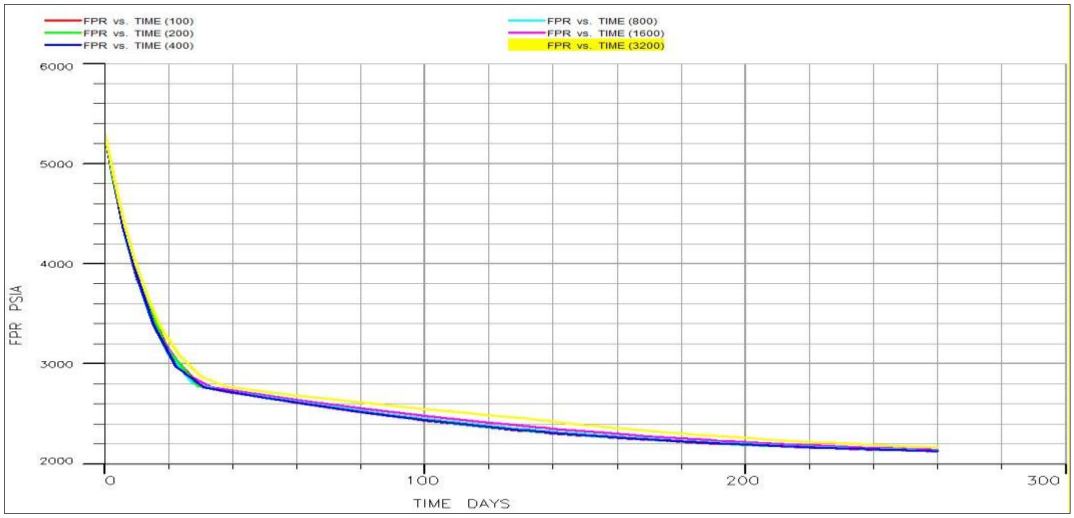


Figure 8: Field Pressure versus Time with different surfactant solution injection rate

4.1.2 Effect of Formation Permeability

Second parameter that has been modified to evaluate liquid injectivity was formation permeability. Formation permeability has been varied in range of 50 md to 300 md. As the permeability of the reservoir increases the liquid injectivity value rises as well (Settari, 2000). This relation can be clearly observed in Figure 9a and 9b which illustrates surfactant solution injectivity. This is due to the fact that as the permeability of the reservoir increases it will be easier for the injected fluid to flow through the formation and displace the residual oil. The injectivities of surfactant solution and gas in low and high permeability layers can be controlled by injection rates (Surguchev, 1992).

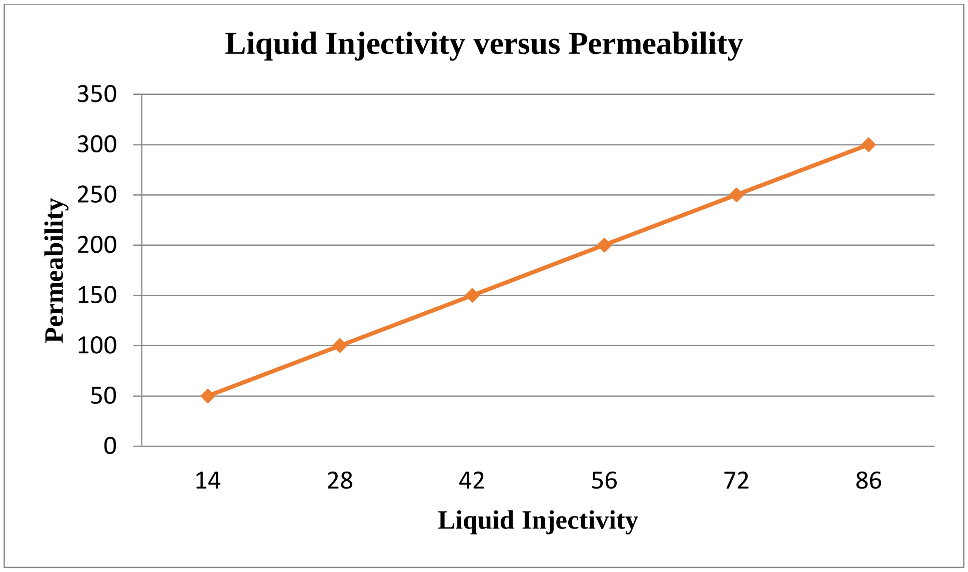


Figure 9a: The impact of different formation permeability on liquid injectivity

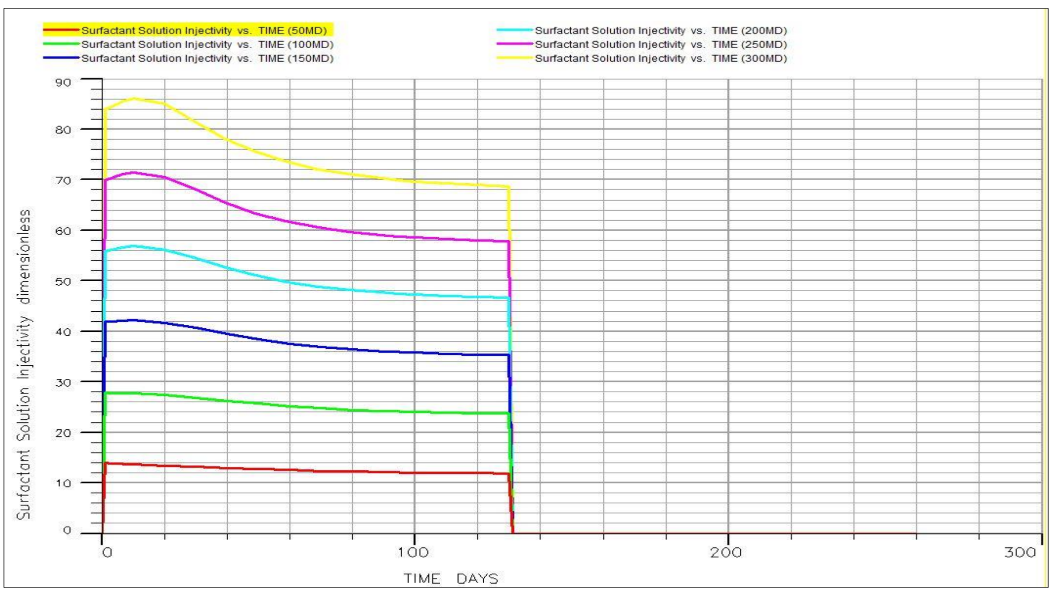


Figure 9b: The impact of different formation permeability on liquid injectivity

In the case where the formation permeability is varied; the field pressure change is more obvious in contrast to the case that the surfactant solution injection rate has been differed. Figure 10 illustrate the Field Pressure change for 260 days of the total SAG-foam process for this simulation study.

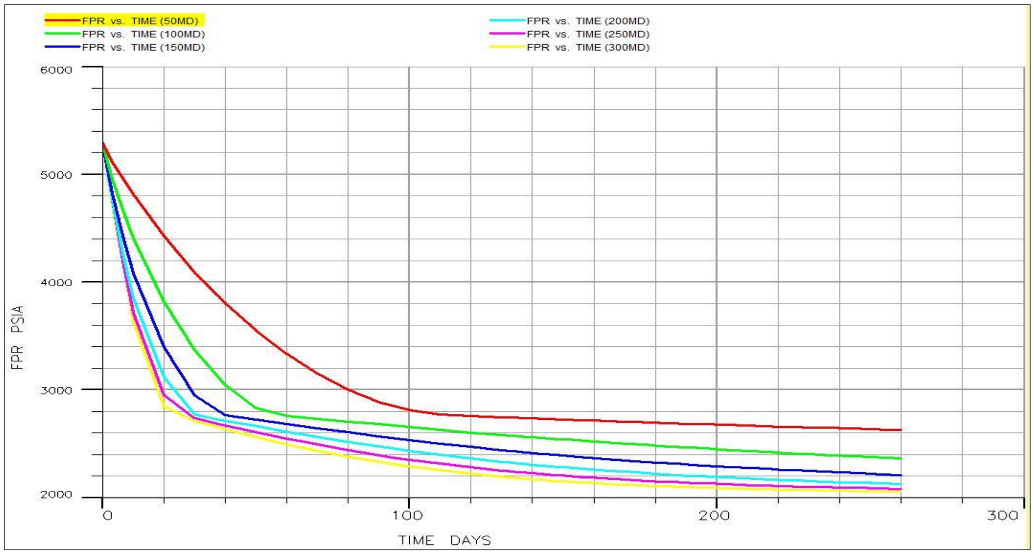


Figure 10: Field Pressure versus Time for Different Formation Permeability cases

4.1.3 Effect of SAG Ratio

Another case study was to change the SAG ratio and examine its effect on liquid injectivity. The SAG ratio change was 5 cases which are shown in the table 2.

Table 2: SAG Ratio Case Study

	SAG Ratio	**Slug Size**
Case 1	1:1	• 1000 STB/day of surfactant solution • 1000 SCF/day of CO2 gas
Case 2	2:1	• 2000 STB/day of surfactant solution • 1000 SCF/day of CO2 gas
Case 3	3:1	• 3000 STB/day of surfactant solution • 1000 SCF/day of CO2 gas
Case 4	4:1	• 4000 STB/day of surfactant solution • 1000 SCF/day of CO2 gas
Case 5	5:1	• 5000 STB/day of surfactant solution • 1000 SCF/day of CO2 gas

As table 2 illustrates, 5 cases have been simulated to study the effect of SAG ratio on liquid injectivity. The SAG ratio has been varied from 1:1 to 5:1, surfactant solution injectivity decreases this is because the formation is able to accept certain amount of surfactant aqueous in certain time causing increase in bottom hole flowing pressure therefore increase in pressure and injection rate cannot take place at the same time. In order to satisfy injectivity equation if the injection rate increases the pressure difference should decrease in an amount to achieve injectivity into the formation from borehole (Settari, 2000; Eclipse, 2012). Selection of SAG ratio requires consideration of economic constrains as well since surfactant is usually expensive to inject in high volume. Figures 11 and 12 show the surfactant solution injectivity results.

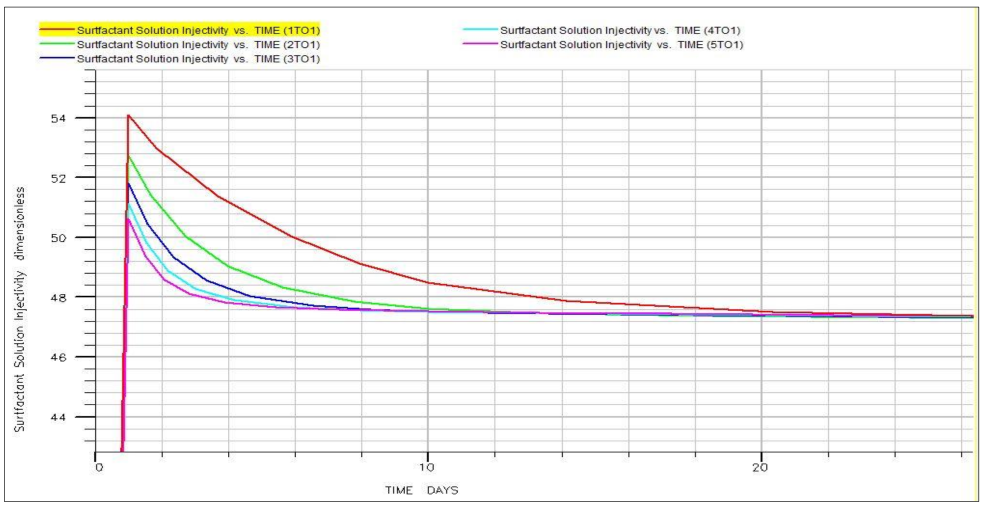


Figure 11: Surfactant Solution Injectivity versus Time for Different SAG ratio cases

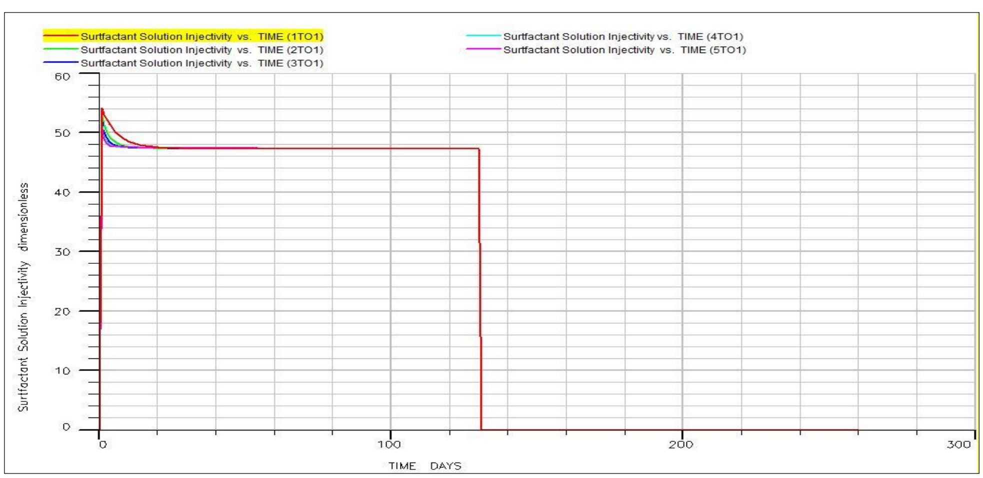


Figure 12: Surfactant Solution Injectivity versus Time for Different SAG ratio cases

4.2 Foam Generation

In this study foam is formed when gas and surfactant are injected alternatively into the formation by separate slugs but from a single well. In this process foam is either generated from the recent injected gas with the pervious injected surfactant solution or when the surfactant solution meets the pervious injected gas in the reservoir (Rossen and Boeije, 2013). In homogenous reservoirs, foam will be formed in higher permeability formations at higher liquid injection rates and higher surfactant concentration (Li and Rossen, 2005).

Surfactant solution and gas are injected separately for the period of 130 days through one cycle from a single injection well. This SAG process is done totally during 260 days to generate foam in the reservoir. The injection rate of the surfactant solution is varied in the range of 100-3200 STB/day while the injection rate of CO2 gas is in a constant rate of 1000 STB/day.

There are number of factors that are influencing foam generation in the reservoir such as concentration, composition and surfactant structure but it is also related to the liquid saturation, gas and liquid flow rate as well (Ransohoff et al., 1988; Jimenez et al., 1989).

4.2.1 Effect of Surfactant Injection Rate

Simulation of several cases with different injection rate for surfactant solution shows that increase in the surfactant solution injection rate decreases the field gas mobility factor. This shows that the generated foam is functioning well and reduces the mobility of the gas.

In all the cases of this simulation study the mobility factor of the gas is lower than 1 which is favorable because foam can be formed if the mobility ratio is lower than 1. It is unfavorable to have mobility ratio higher than 1, as the flow is unstable and result in viscous fingering, a condition when bypass of fluid occur in reservoir section (Nangacovié, 2012; Sobers, 2012). Moreover, increase in the injection rate causes decline in the gas saturation. Figures 13 and 14 illustrate the effect of surfactant solution injection rate on gas mobility factor and gas saturation.

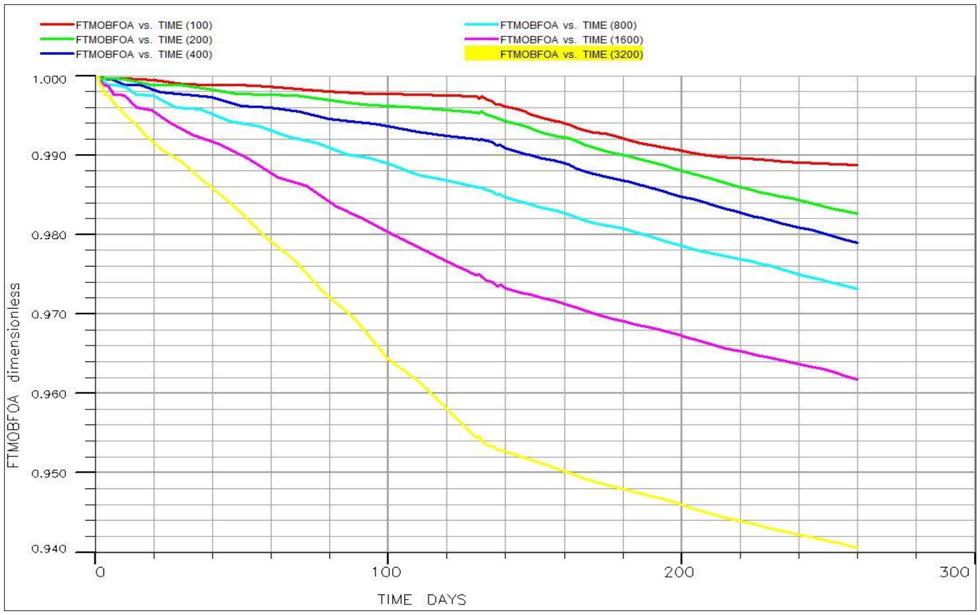


Figure 13: The effect of different surfactant solution injection rate on gas mobility factor

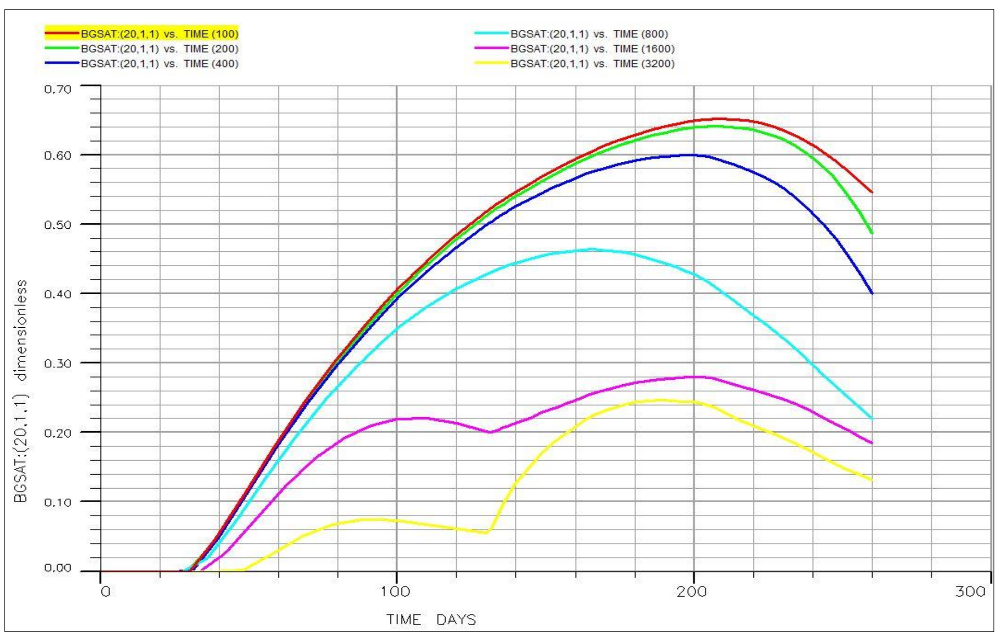


Figure 14: The effect of different surfactant solution injection rate on gas saturation

Strong foam can be generated at low surfactant solution injection rate. This effect was studied when surfactant solution was injected in various injection rates into the formation. However, the role of flow rate is not critical, because foam does not appear everywhere in the core simultaneously when the flow rate increases nor does it collapse when the flow rate is reduced to its previous value or to zero (S.I Chou, 1991).

4.2.2 Effect of Surfactant Concentration

Several cases were created to examine the effect of surfactant concentration on foam propagation. Surfactant plays a significant role on generation and stability of the foam (Al-Mossawy, Demiral & Raja, 2011). As surfactant concentration increases the foam will have higher strength (Al-Mossawy, Demiral & Raja, 2011).

The weak foam can be created at low concentration of surfactant (S.I Chou, 1991). This result can be obtained in the case where the concentration of surfactant varied in the range of 3-15 % of the aqueous solution. As the foam weakens, gas mobility rises and this result can be observed when the concentration of surfactant decreases in the aqueous solution therefore shear thinning of the foam occurs and mobility of the gas increases in compare to the case where the surfactant concentration is higher as it was discussed by Li and Rossen (2005). Figure 15 and 16 illustrate this result.

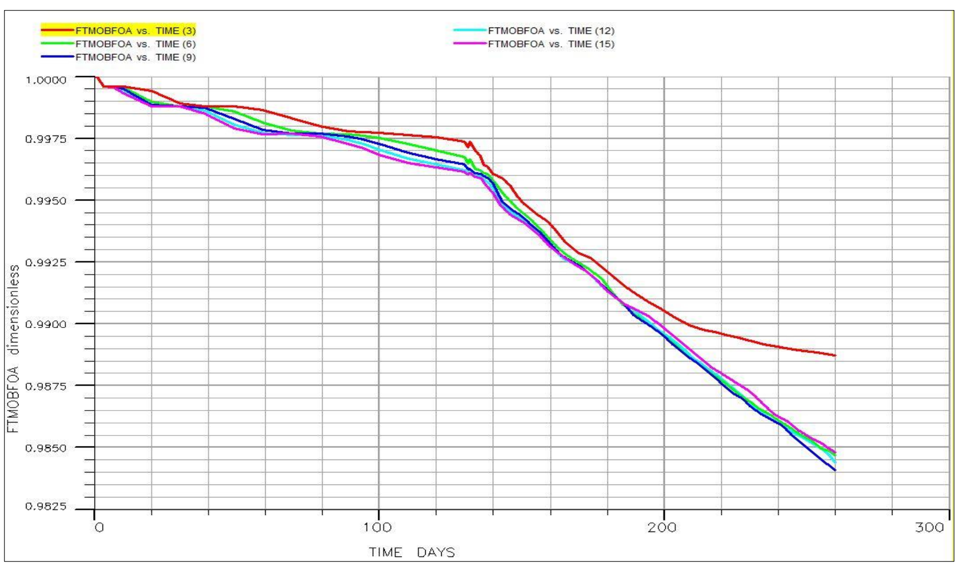


Figure 15: The effect of different surfactant concentration on field gas mobility factor

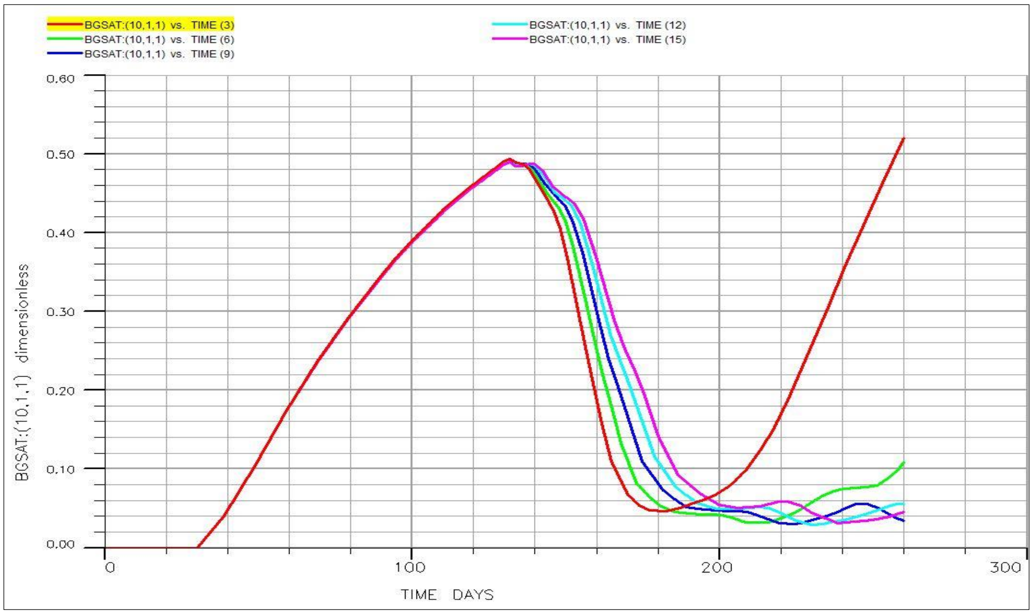


Figure 16: The effect of different surfactant concentration on gas saturation

4.2.3 Effect of Formation Permeability

In order to investigate further parameters influencing foam generation, the formation permeability of this homogeneous reservoir has been differed in the range of 50md to 300md. Based on the results, it is observed that as the formation permeability increases, foam generation will occur and the gas mobility factor declines further. Figure below illustrates this effect. In homogenous reservoirs, foam will be formed in higher permeability formations (Li and Rossen, 2005). This is shown in figure 17.

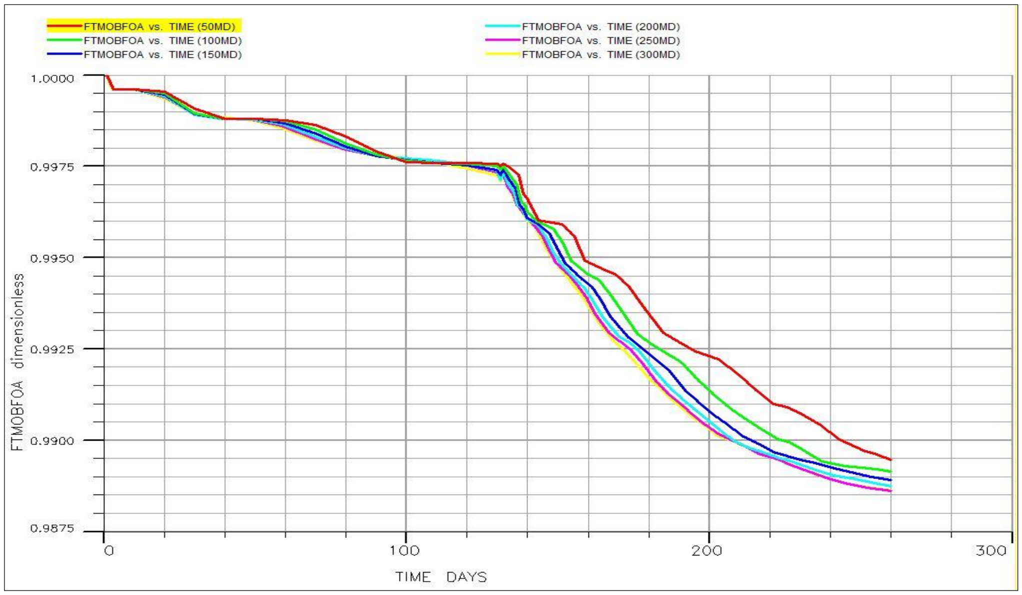


Figure 17: The effect of different Formation Permeability on field gas mobility factor

4.3 Oil Recovery Efficiency

4.3.1 Effect of Surfactant Injection Rate

The simulation results of different parameters have been examined to observe the field oil recovery. Based on the variation of the injection rate of surfactant solution; oil recovery has an increment as the injection rate increases. This is due to the fact that higher amount of foam will be generated to displace the residual oil therefore the oil efficiency will be positively affected. The field oil efficiency increases as the 12.5 % as the surfactant solution injection rate increases from 100 STB/day to 3200 STB/day. Similarly, total oil production increases with the increment in the surfactant solution injection rate (Eclipse, 2012). Figures 18 and 19 show this result.

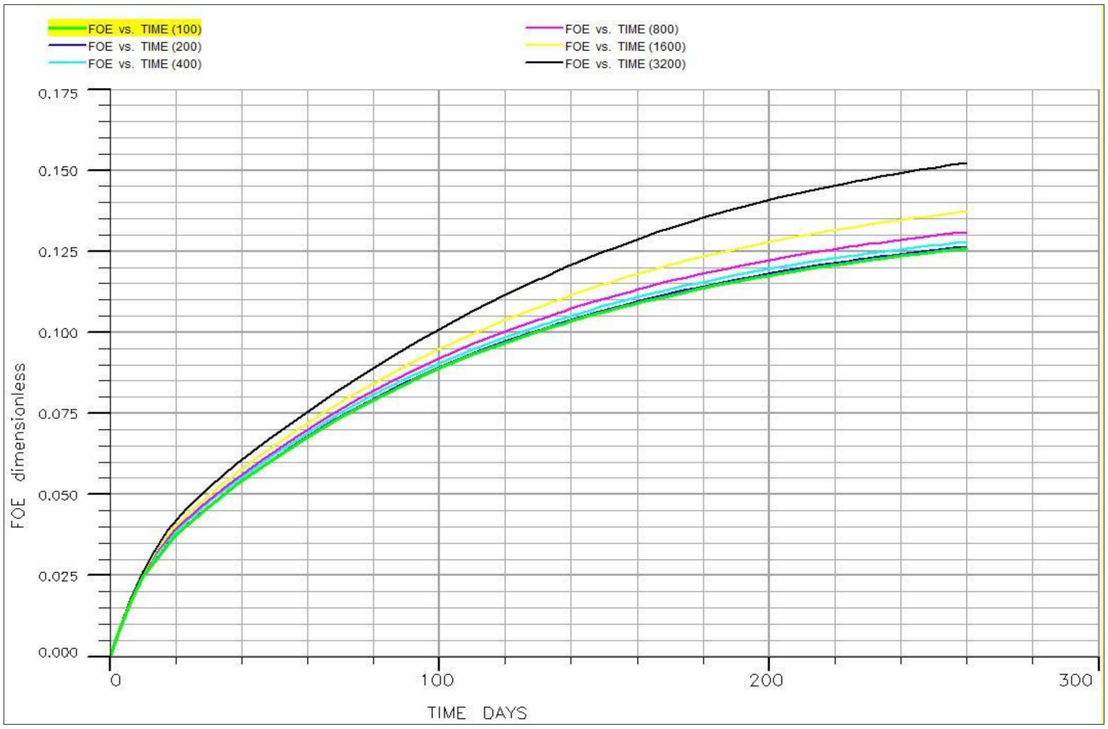


Figure 18: The effect of different surfactant solution injection rate on field oil efficiency

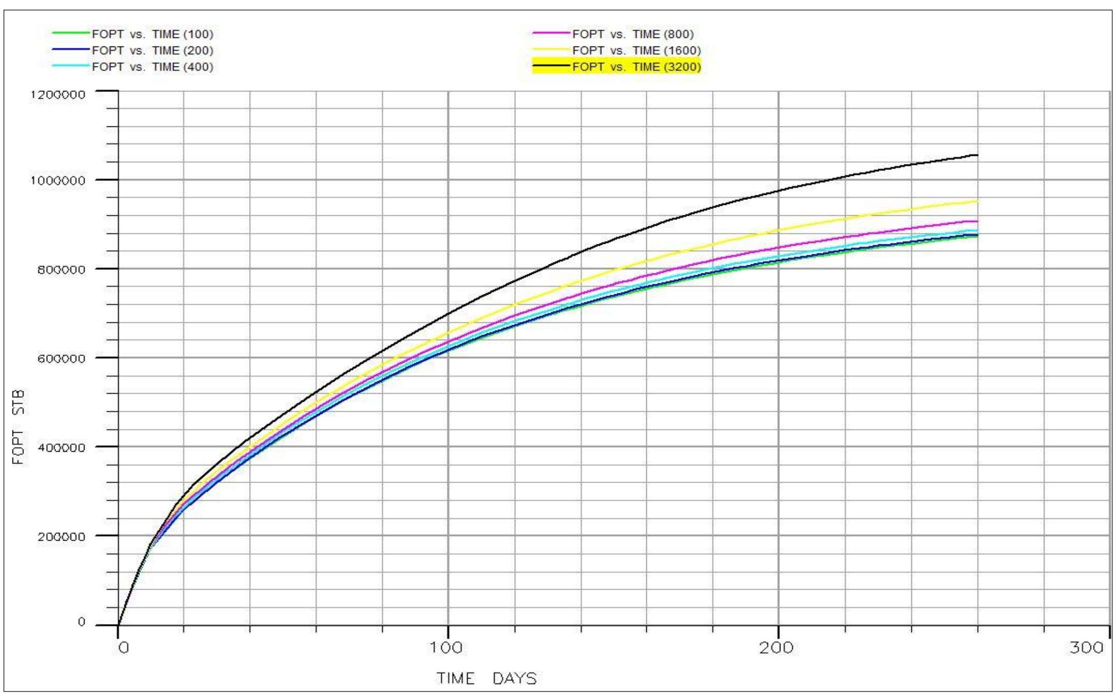


Figure 19: The effect of different surfactant solution injection rate on total field oil production

Figure 20 illustrates the oil saturation change during the SAG-foam process which is taking place for 260 days. It is shown a step by step process of sweep of residual oil. As the time passes the residual oil will be swept and move towards production well.

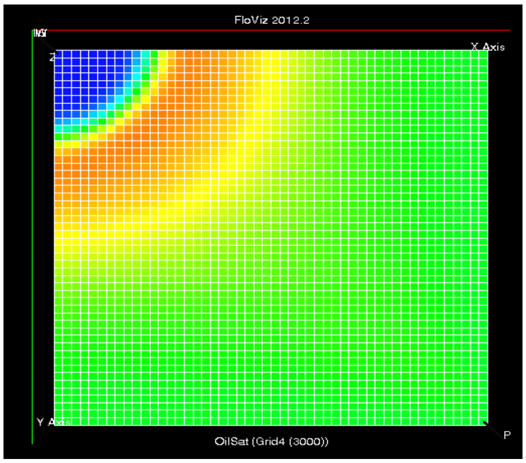


Figure a

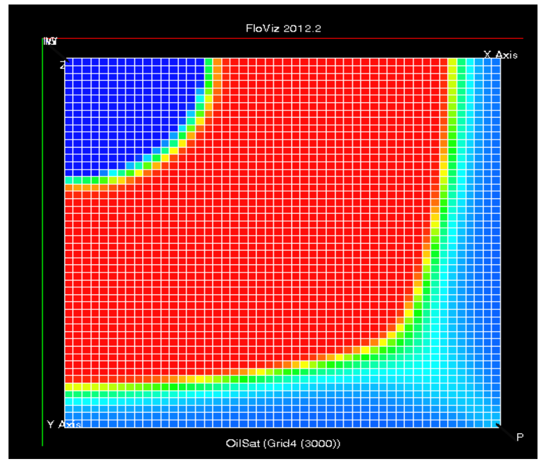


Figure b

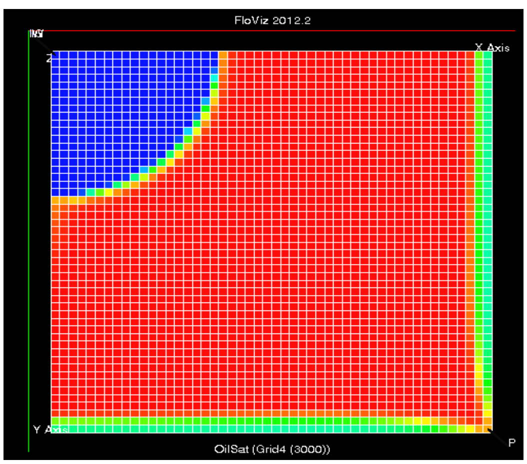


Figure c

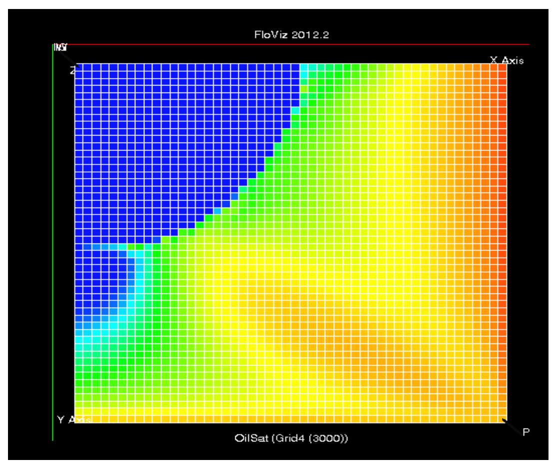


Figure d

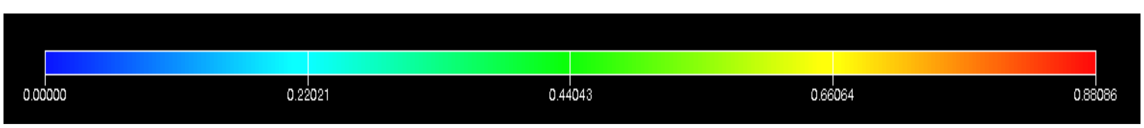


Figure 20: Figure a, b, c and d illustrates the oil saturation change during SAG-foam process

4.3.2 Effect of Formation Permeability

The other tested parameters such as variation of formation permeability and SAG ratio illustrating the same result both for field oil efficiency as well as field total oil production when the surfactant solution injection rate increases. Thus when formation permeability increases from 50md to 300md, FOE and FOPT increases significantly similarly when the SAG ratio changes from 1:1 ratio to 5:1 ratio. On the other hand increasing gas in SAG ratio decreases the recovery (Schlumberger, 2012). This is due to macroscopic efficiency of surfactant solution (Salehi et al, 2014). Results are shown in figures 21, 22, 23 and 24.

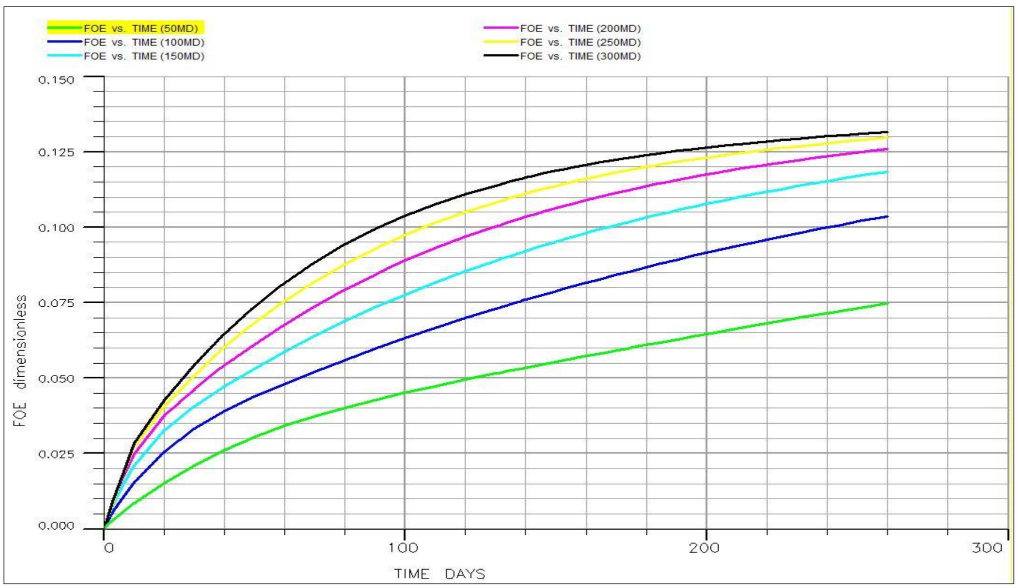


Figure 21: FOE versus Time when Formation Permeability is varied

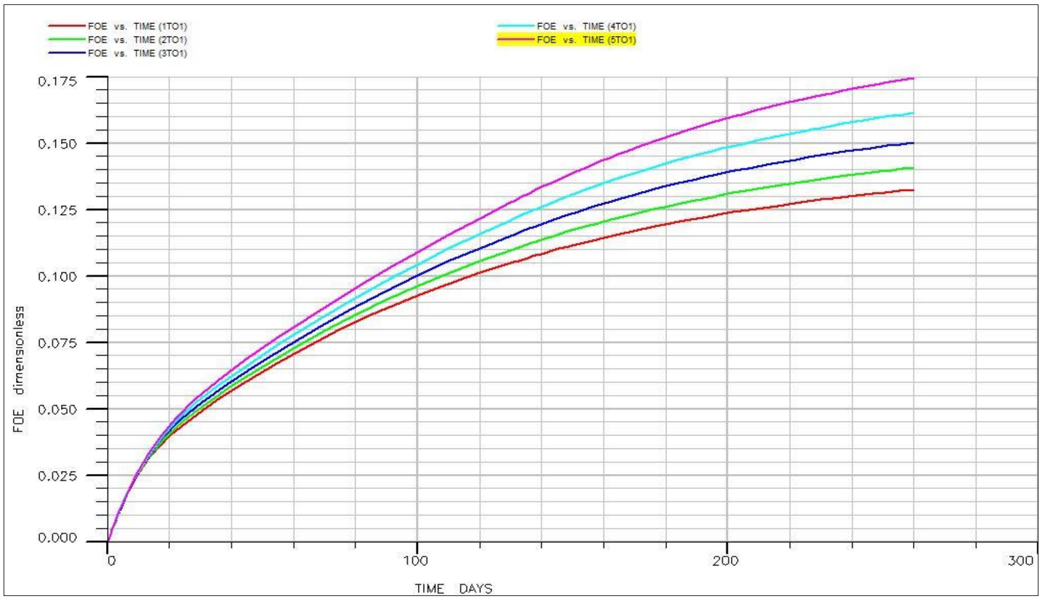


Figure 22: FOE versus Time when SAG ratio is varied

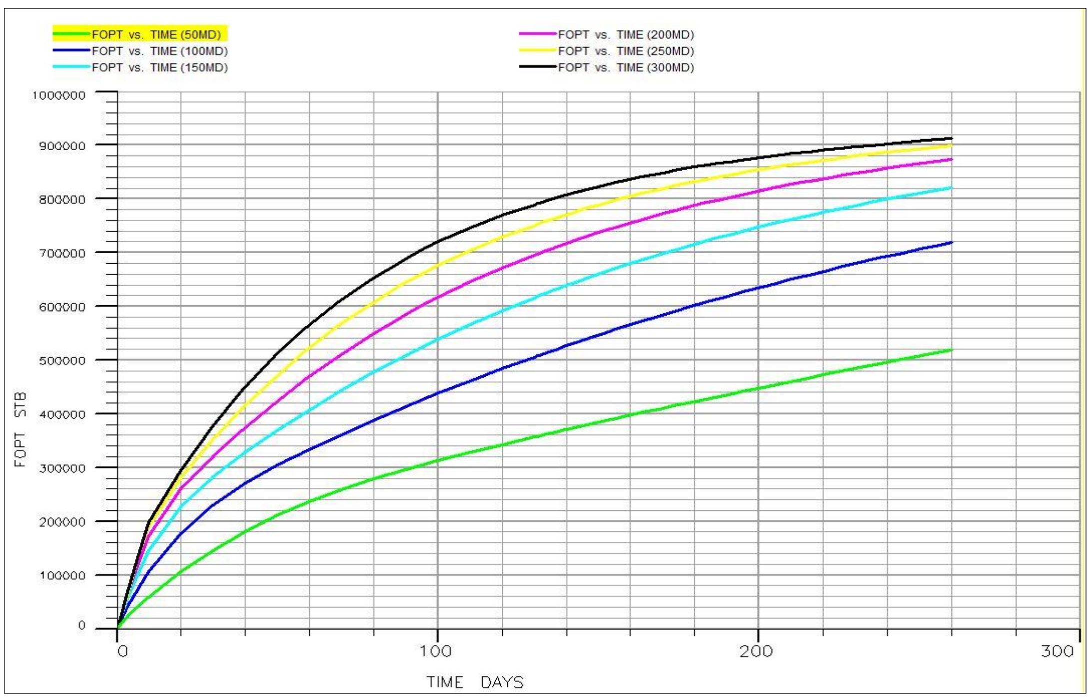


Figure 23: FOPT versus Time when formation permeability is varied

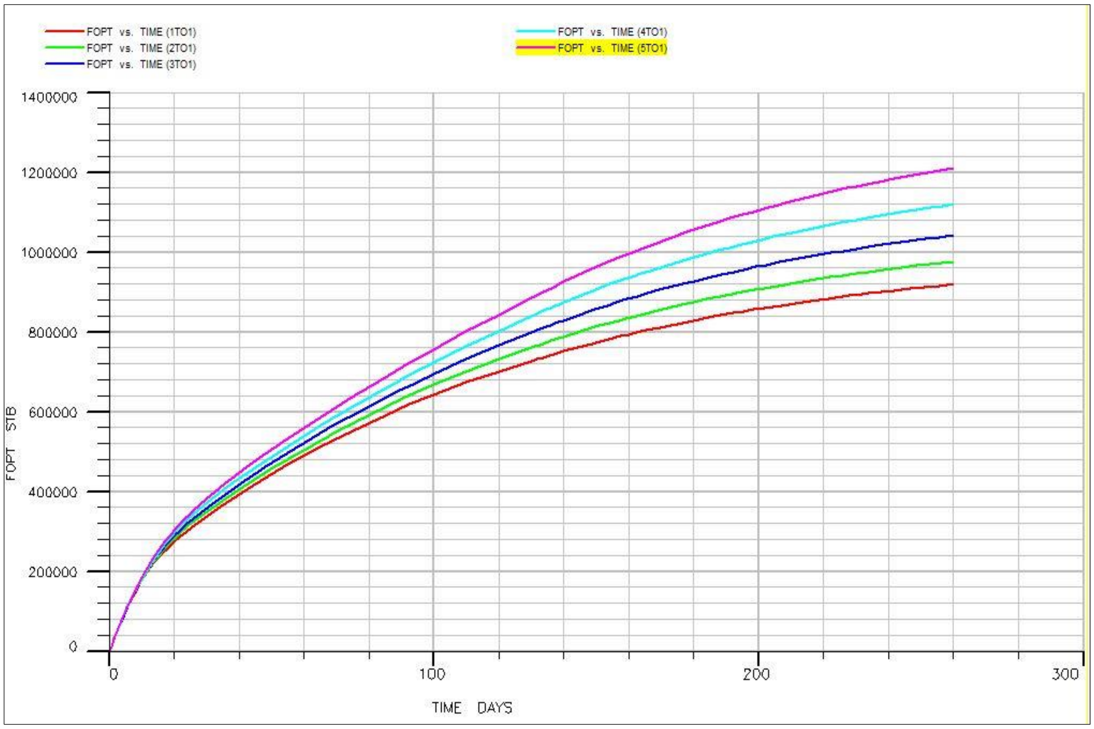


Figure 24: FOPT versus Time when SAG ratio is varied

CHAPTER 5

CONCLUSION AND RECOMMENDATION

5.1 Conclusion

Surfactant Alternating Gas (SAG) is an important EOR process which has been greatly applied in the field in oil and gas industry. A combination of SAG-foam process offers sweep efficiency and operational efficiency. The recovery for production can be increased in compare to the time where only gas or water is injected for the recovery. There have been lots of researches done to study the optimum SAG parameters to be applied in each field to produce the highest recovery and achieving high injectivity. However, only few studies are conducted to examine the parameters influencing liquid injectivity as well as foam generation.

Based on the homogeneous reservoir model simulated in Eclipse 100, parameters such as injection rate of surfactant solution, formation permeability, SAG ratio are influencing the liquid injectivity or in another word surfactant solution injectivity. Simulated results showing that as the injection rate of surfactant solution increases the liquid injectivity declines this is due to the fact that borehole can only accept certain amount of injected fluid into the formation at the certain time. The same result can be observed when the SAG ratio changes from 1:1 ratio to 5:1 ratio. Since surfactant can be absorbed by the reservoir rock economical consideration should be taken into account on the selection of SAG ratio. Formation permeability as another property influencing liquid injectivity is important in a way that increase in the formation permeability will cause an increment in the liquid injectivity.

Parameters such as formation permeability, surfactant injection rate, and SAG ratio and surfactant concentration are influencing foam propagation in the reservoir. It is observed that as the formation permeability increases, foam generation will occur and the gas mobility factor declines further. Furthermore, as the foam weakens, gas mobility rises and this result can be observed when the concentration of surfactant decreases in the aqueous solution therefore shear thinning of the foam occurs and mobility of the gas increases in compare to the case where the surfactant concentration is higher.

The field oil efficiency increases as the 12.5 % as the surfactant solution injection rate increases from 100 STB/day to 3200 STB/day. Similarly, total oil production increases with the increment in the surfactant solution injection rate. The other tested parameters such as variation of formation permeability and SAG ratio illustrating the same result both for field oil efficiency as well as field total oil production when the surfactant solution injection rate increases. Thus when formation permeability increases from 50md to 300md, FOE and FOPT increases significantly similarly when the SAG ratio changes from 1:1 ratio to 5:1 ratio.

5.2 Recommendations

To ensure the simulation results are correct, laboratory studies should be conducted to verify the results. By doing laboratory work, the effect different parameters can be observed and measured on surfactant solution injectivity (liquid injecivity). The effect of different properties both reservoir and injected fluid of foam generation can be examined in the lab on different core samples.

In addition to that, the simulation work can be extended to the case where a more complicated reservoir could be constructed such as heterogeneous and stratified reservoir to further study the liquid injectivity as well as foam generation. This is because actual reservoir field are hardly homogenous.

Tuning of the parameters is required in order to generate a reservoir model that represents the actual reservoir field. Further studies could be conducted by identifying further parameters influencing both liquid injectivity and foam propagation.

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