Simulation of Chemical Flooding for Enhanced Oil Recovery based on Experimental Data

by

Nur Faiqa binti Mohd Fuad

Dissertation submitted in partial fulfilment of

the requirements for the

Bachelor of Engineering (Hons)

(Chemical Engineering)

JANUARY 2013

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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the

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(CHEMICAL ENGINEERING)

Approved by,

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January 2013

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.

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NUR FAIQA BINTI MOHD FUAD

ABSTRACT

The study of chemical flooding for enhanced oil recovery (EOR) in experiments can help in understanding the reservoir behavior. The reservoir behavior and the results from experiments can be scaled up for demonstrating the real oil field using simulation. However, before being scaled up, the experiment is first simulated or history matched; until the simulation results match the experimental results. This is performed to adjust the simulation model to match with experimental reservoir model. The objective of this project is to gather the knowledge on history matching for simulating the experimental results of chemical flooding for enhanced oil recovery (EOR) and to apply the knowledge on experimental results that is yet to be simulated. Two case studies on experimental results that have been successfully history matched will be used as references for this project. The simulation, or the technique for history matching, performed in these studies is to be investigated. Then, the history matching technique is to be applied on experimental results of chemical flooding that are yet to be proven. However, in this project, the complete history matching technique is not obtained. Nevertheless, through the project work, the basics required for history matching of experimental results of chemical flooding has been obtained. This knowledge can be utilized for continuation of the research.

ACKNOWLEDGMENTS

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ABBREVIATIONS AND NOMENCLATURES

AS : Alkali - surfactant

ASP : Alkali - surfactant - polymer

EOR : Enhanced oil recovery

IFT : Interfacial tension, mN / m

K : Permeability

K_r : Relative permeability, fraction

K_{ro} : Oil relative permeability, fraction

K_{rocw} : Oil relative permeability at connate water, fraction

K_{rw} : Water relative permeability, fraction

K_{rwiro} : Water relative permeability at irreducible oil, fraction

m/d : meter per day

N_{ow} : Exponent for calculating K_{row} from K_{rocw}

N_w : Exponent for calculating K_{rw} from K_{rwiro}

NaOH : Sodium hydroxide

Na_2CO_3 : Sodium carbonate

OOIP : Original oil in place, %

PHPAM: Partially hydrolyzed polyacrylamide

ppm : parts per million

PV : Pore volume, fraction

RC : Recovery, %

SDS : Sodium dodecyl sulfate, $C_{12}H_{24}SO_4Na$

So : Saturation of oil

So_{irw} : Endpoint saturation - irreducible oil for water-oil table

So_{rw} : Endpoint saturation - residual oil for water-oil table

Sw : Saturation of water

Sw_{con} : Endpoint saturation - connate water

Sw_{crit} : Endpoint saturation - critical water

CHAPTER 1: INTRODUCTION

1.   Introduction

This chapter provides the background, problem statement, objective and scope of work of this project. In background study, the overview of the field in which this project is involved in is described generally before focusing on the specific topic of the research. Previous research on similar topic as of this project is then discussed. In problem statement, problem that has been found from analyzing the previous research and the solution for the said problem is proposed. Following that, the objective of this research is set out and scope of work on this research is defined with respect to the objective.

1.1   Background Study

1.1.1   General Overview

Petroleum or also known as crude oil and natural gases have been contributing largely as a source of energy and in economic growth (Marques, Avansi, Trevisan, & Schiozer, 2012). However, in order to use them as a source of energy, they need to be extracted or recovered from the earth first. There are three phases in recovering oil and gas reserves, namely primary recovery, secondary recovery and tertiary recovery.

Primary recovery is the recovery through natural production (Stosur, Hite, Carnahan, & Miller, 2003). It is the first stage or initial hydrocarbons (crude oil and natural gases) production in which natural reservoir energy, such as expansion of gas or water displaces hydrocarbons from the reservoir. The hydrocarbons then move into the wellbore and being lifted up to the surface (Lyons & Plisga, 2005). After a certain time, a reservoir reaches its economic production limit by primary recovery (Wingen & Johnston, 1946). Therefore, secondary recovery, a method of injecting water and/or gas is performed to supplement the natural reservoir energy that has been used up after a certain period of time in primary recovery (Sajjadian, Ataabadi, & Dalaei, 2012). However, the primary and secondary recovery usually recovers on the average only one third of the original oil in place (OOIP) in the reservoir (Henry, 1978). Thus, a method to recover the remaining trapped oil is introduced; which is

tertiary recovery or also known as enhanced oil recovery (EOR). Tertiary recovery or enhanced oil recovery (EOR) occurs when fluid mobility within the reservoir is increased through certain methods and means such as the injection of water, steam, gases or chemicals into underground oil reservoirs to cause the trapped oil to flow toward producing wells (Cleveland & Morris, 2009).

Enhanced oil recovery (EOR) methods have focused on recovering the remaining oil from a reservoir that has been depleted of energy during the application of primary and secondary recovery methods (Speight, 2009). With the increasing demand and depletion of source, EOR is important in contributing to additional oil supply to be recovered (Huang, Zhang, & Dong, 2005). Three common techniques for EOR are thermal flooding, gas injection and chemical flooding (Lakatos, 2005). EOR are performed based on three basic mechanisms. The mechanisms are; reduction of the interfacial tension (IFT) between oil and the displacing fluid, reduction of oil viscosity and improvement of sweep efficiency (Alkafeef & Zaid, 2007).

1.1.2 Research Topic

This project revolves mainly on enhanced oil recovery (EOR) through chemical flooding. Chemical flooding for EOR is done by injecting alkali, surfactant (surface active agent), polymer or any combination of them. The key mechanism of the process is to reduce the interfacial tension (IFT) between oil and the displacing fluid through surfactant flooding and achieve additional recovery (Sheng, 2011). If chemical flooding is done through alkali injection, the alkali reacts with acid in the oil and form in-situ soaps which acts as surface active agent or surfactant (Pei, et al., 2012). Surfactant reduces the interfacial tension between oil and water and help to mobilize the oil (Sandersen, Stenby, & Solms, 2011). Polymer flooding helps increase the water's viscosity and thus creates a better mobility ratio and enhanced the oil recovery (Adegbesan, Liu, & Bai, 2012).

In order to obtain optimum recovery, the relationship between the cost for chemical flooding and the additional recovery achieved is important. Detailed researches are required before this technology can be implemented in real oil field, as they are relatively new and there are many aspects of chemical flooding that are yet being fully understood (Sulaiman & Lee, 2012). Thus, researchers conduct laboratory

experiments to study the chemical flooding phenomenon. However, it is completely different in scale, to compare the real oil field works and laboratory experiments. Therefore, through simulation, the experimental model is history matched. History matching is, according to Varhaug (2012),

> The act of adjusting a model of a reservoir until it closely reproduces the past behavior of a reservoir. The historical production and pressures are matched as closely as possible. The accuracy of the history matching depends on the quality of the reservoir model and the quality and quantity of pressure and production data. Once a model has been history matched, it can be used to simulate future reservoir behavior with a higher degree of confidence, particularly if the adjustments are constrained by known geological properties in the reservoir. (Varhaug, 2012)

Using the experimental study, the model of the reservoir that needs to be adjusted in the simulation is the experimental model and its results. Once the experimental model has been history matched, it can be scaled up and used to simulate field scale reservoir at increased accuracy (Maneeintr, Sasaki, & Sugai, 2010). These numerical simulation studies for field scale reservoir are often used as part of evaluation of an oil recovery project as it is more economical in determining whether good potential of oil recovery exist (Manrique, Kamouei, Kitchen, & Alvarado, 2008).

1.1.3   Previous Related Research

Many journals have been published discussing on experimental works in understanding the mechanism or situation behind chemical flooding for enhanced oil recovery (EOR). Alkaline flooding for improving oil recovery has been studied experimentally using sandpack and simulated using CMG STARS, an advanced process simulator (Wang, Dong, & Arhuoma, 2010). Alkaline-surfactant flooding has also been studied experimentally using sandpack and history-matched using CMG STARS (Dong & Wang, 2010). The alkaline-surfactant (AS) flooding has resulted with better percentage of oil recovery than alkaline flooding. Alkaline-surfactant-polymer (ASP) flooding, has been experimentally tested, also using sandpack, and results with higher additional oil recovery compared to alkaline flooding and alkaline-surfactant flooding (Bera, Samanta, Ojha, & Mandal, 2012). However, this experimental result for ASP flooding is yet to be history matched.

1.2 Problem Statement

Alkaline-surfactant-polymer (ASP) flooding has been proved experimentally to achieve the highest additional oil recovery compared to alkaline flooding and alkaline-surfactant flooding (Bera, et al., 2012). However, the experimental results for this ASP flooding is yet to be history matched. Without this history matching, the behavior of a field scale reservoir during ASP flooding cannot be simulated. This project proposes to history match the experimental results of the chemical flooding using simulator software.

1.3 Objective

- To gather the knowledge on history matching for simulating the experimental results of chemical flooding for enhanced oil recovery (EOR) and to apply the knowledge on experimental results that is yet to be simulated.

1.4 Scope of Work

The alkaline flooding (Wang, et al., 2010) and alkaline-surfactant flooding (Dong & Wang, 2010) has been successfully simulated. These two case studies will be used as references for this project. The simulation, or the technique for history matching, performed in these studies is to be learned. History matching will require a lot of trial and error effort. The knowledge gained is to be applied in simulating other experimental work on chemical flooding that is yet to be simulated. The scope of work for this project is as listed as follows.

- Investigate the theory of chemical flooding.
- Investigate the history matching technique from simulated chemical flooding experimental results.
- Applying the knowledge gained from the simulation work on experimental results of chemical flooding that are yet to be proven.

1.5 Relevancy and Feasibility of Project

This project is relevant with the current industry needs. There are still a lot of areas in enhanced oil recovery that is unknown. History matching of experimental results of chemical flooding may help the industry to understand the phenomenon in

chemical flooding to achieve more economic values in oil recovery. Through this project, knowledge on history matching the experimental results is gained. With this knowledge, simulation of field scale reservoir can be performed.

This project is a simulation-based project. With the raw data availability, this project can focus mainly on the simulation itself and should be feasible to be performed within the allocated time. However, as work for the project is progressing, there are limited resources that can help on the scope of work to be performed. As the author is not familiar with the field background of the research project given, that is enhanced oil recovery (EOR) and reservoir modeling software; a lot of time is spent on studying these subjects, before project work can be started.

CHAPTER 2: LITERATURE REVIEW AND THEORY

2. Literature Review and Theory

This chapter is divided into two main part; literature review and theory. In literature review, three journals will be mainly discussed. Two of them, one on alkaline flooding (Wang, et al., 2010) and another on alkaline-surfactant flooding (Dong & Wang, 2010), as has been mentioned in Chapter 1, will be used to aid this research to gain the knowledge on simulating the experimental results. The third journal is on experimental results of alkaline-surfactant-polymer (ASP) flooding (Bera, et al., 2012). In the next section after literature review, the theory used for this research project is discussed.

2.1 Literature Review

2.1.1 Simulation of Alkaline Flooding

Wang, et al., 2010, has performed experimental and numerical study of improving heavy oil recovery by alkaline flooding in channeled sandpack. This journal, from this onward referred as Case I, is one of the main journals that is used as a reference to aid in achieving the objectives of this project. In the journal, four experiments have been conducted. However, for this project purpose, only one experiment is simulated. The details of the experiment used for is summarized in Table 2.

The alkaline flooding in channeled sandpack is done based on actual reservoir properties, which is heterogeneous. Injecting chemical solutions into the reservoir might result with the injected chemicals to flow through more permeable areas and bypass areas with residual oil (Ma, Dong, Li, & Shirif, 2007). In demonstrating this phenomenon, channeled sandpack, as shown in Figure 1, is used to show different level of permeability in a reservoir through the usage of different size of sands.

The channeled sandpack is designed to be in cylinder form with fine sand that represents high permeability zone in the annulus; and coarse sand poured inside the cylinder around the annulus, represents low permeability zone. Both of these zones are separated by 120-mesh screen holder, which is formed into the annulus of the cylinder. Usage of 120-mesh screen holder allows the communication of the fluid

through the screen. The channeled sandpack is injected with water to demonstrate waterflooding followed by injection of alkali to demonstrate alkaline flooding to recover the trapped oil.
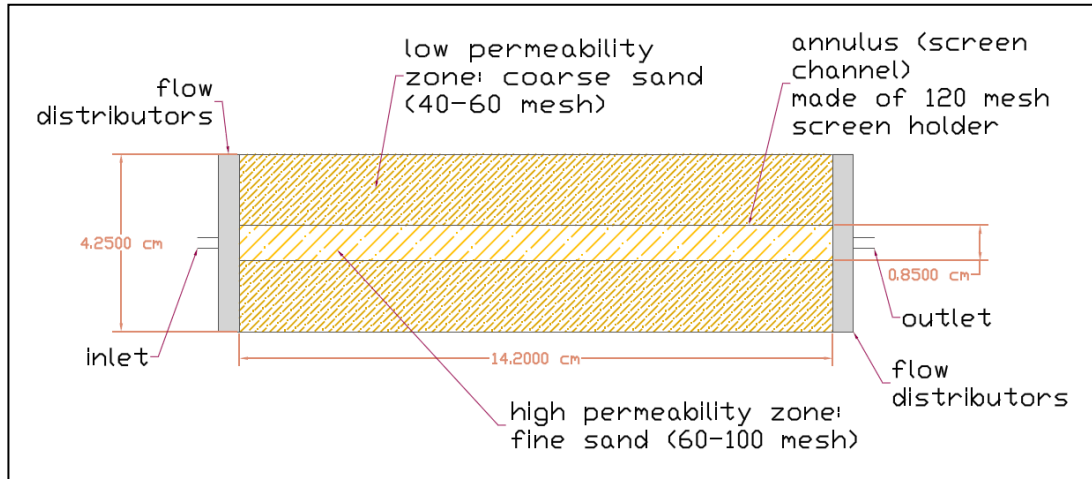
Figure 1: Schematic diagram of channeled sandpack for Case I.
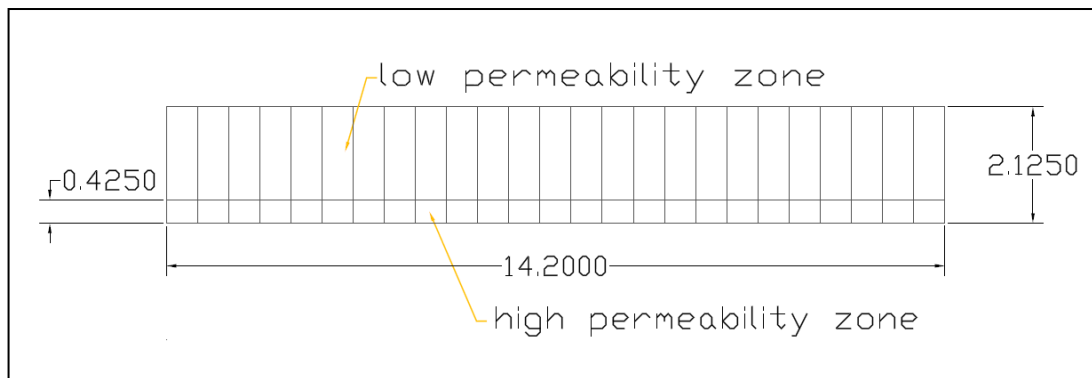
Figure 2: Schematic diagram for simulation grid system.

For simulation of this alkaline flooding, Figure 1 is transformed into grid as shown in Figure 2. There are two zones; low permeability zone and high permeability zone. These two zones are created to simulate the channeled sandpacks, which have different type of sands in the annulus and the area of cylinder around the annulus. In the simulation, the channeled sandpacks of 14.2 cm length is divided into 25 grids. There are two layers created, the bottom layer represent the condition inside the annulus (high permeability zone) and the upper layer represent the condition around the annulus of the channeled sandpacks (low permeability zone).

Table 1 summarized the components for the reservoir modeling and the alkali injected that is to be used for the simulation. The alkaline flooding is simulated using

the data as in Table 2. The relative permeability data used are attached in Appendix 1. The simulation results should match Figure 3.

Table 1: Reservoir components for Case I

Components	Molecular Weight	Details
Crude oil	380	Viscosity: 1360 mPa s Density: 966.5 kg/m^3
Water	18	Viscosity: 1002 mPa s Density: 1000 kg/m^3
Alkali (NaOH + Na$_2$CO$_3$)	73	N/A
Emulsion	350	Viscosity: 6000 mPa s

Table 2: Simulation data for Case 1

Case	1
Sandpack length, cm	14.20
Porosity, %	37.40
Permeability, μm^2 (High permeability region)	16.50
Permeability, μm^2 (Low permeability region)	4.00
Initial oil saturation, %	86.40
Waterflooding recovery, % OOIP	11.10
Chemical formula	3000 ppm Na$_2$CO$_3$ + 3000 ppm NaOH
Chemical slug size, PV	0.90
Tertiary recovery, % OOIP	14.90
Final oil recovery, % OOIP	26.00
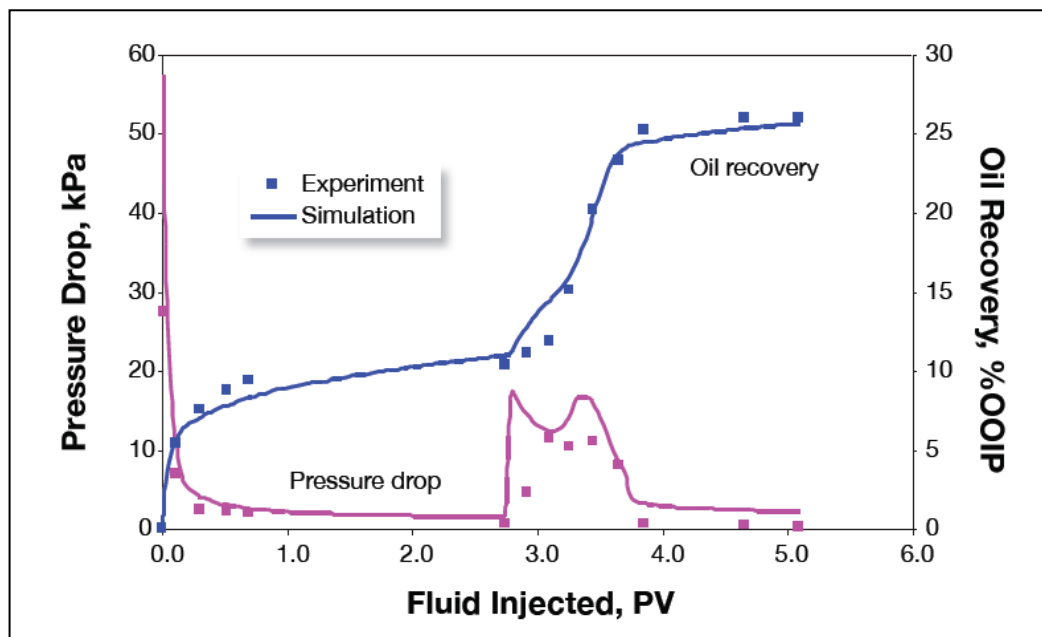
Figure 3: Experimental and simulated pressure drop and oil recovery as functions of fluid injected for Case I (Wang, et al., 2010)

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2.1.2 Simulation of Alkaline-Surfactant Flooding

Dong & Wang, 2010, has performed a study that experimentally demonstrates heavy oil recovery, which is improved by alkaline-surfactant flooding. History match is conducted for the experimental results in a numerical simulation study. This journal, from this onward referred as Case II, is also one of the main journals, besides Case I, that is used as a reference to aid in achieving the objectives of this project. In the journal, three experiments have been conducted. However, for this project purpose, only one experiment is simulated.

In Case II, the experimental data is obtained through experiment of alkaline-surfactant flooding performed using sandpack. The sandpack used is 14.2 cm in length and 4.25 cm in diameter. The sandpack is prepared to have the properties of reservoir and water flooding is conducted at velocity of 0.4 m/d. Following that, alkaline-surfactant flooding is conducted by injection of chemical slug consisting alkali and surfactant.

For simulation, a grid system of $25 \times 25 \times 1$ with grid block size 0.568 cm $\times$ 0.567 cm $\times$ 1 cm is used to represent the 14.2 cm length sandpack. Table 3 summarized the components for the reservoir modeling and the chemical injected that is to be used for the simulation. The alkaline-surfactant flooding is simulated using the data as in Table 3. The relative permeability data used is attached in Appendix 2. The same as Case I, there are two relative permeability sets; each for before and after chemical flooding is performed. The simulation results should match Figure 4.

Table 3: Reservoir components for Case II

Components	Molecular Weight	Details
Crude oil	N/A	Viscosity: 1370 mPa s Density: 961.8 kg/m^3
Water	18	Viscosity: 1002 mPa s Density: 1000 kg/m^3
Alkali (NaOH + Na$_2$CO$_3$)	73	N/A
Surfactant (Alkyl ether sulphate)	N/A	N/A
Emulsion	350	Viscosity: 6000 mPa s

Table 4: Simulation data for Case II

Case	2
Sandpack length, cm	14.200
Porosity, %	36.800
Permeability, μm^2	6.500
Initial oil saturation, %	69.300
Waterflooding recovery, %OOIP	34.100
Chemical formula	3000 ppm Na_2CO_3 + 3000 ppm NaOH + 300 ppm Surfactant
Chemical slug size, PV	1.200
Tertiary recovery, % OOIP	24.400
Final oil recovery, % OOIP	58.500
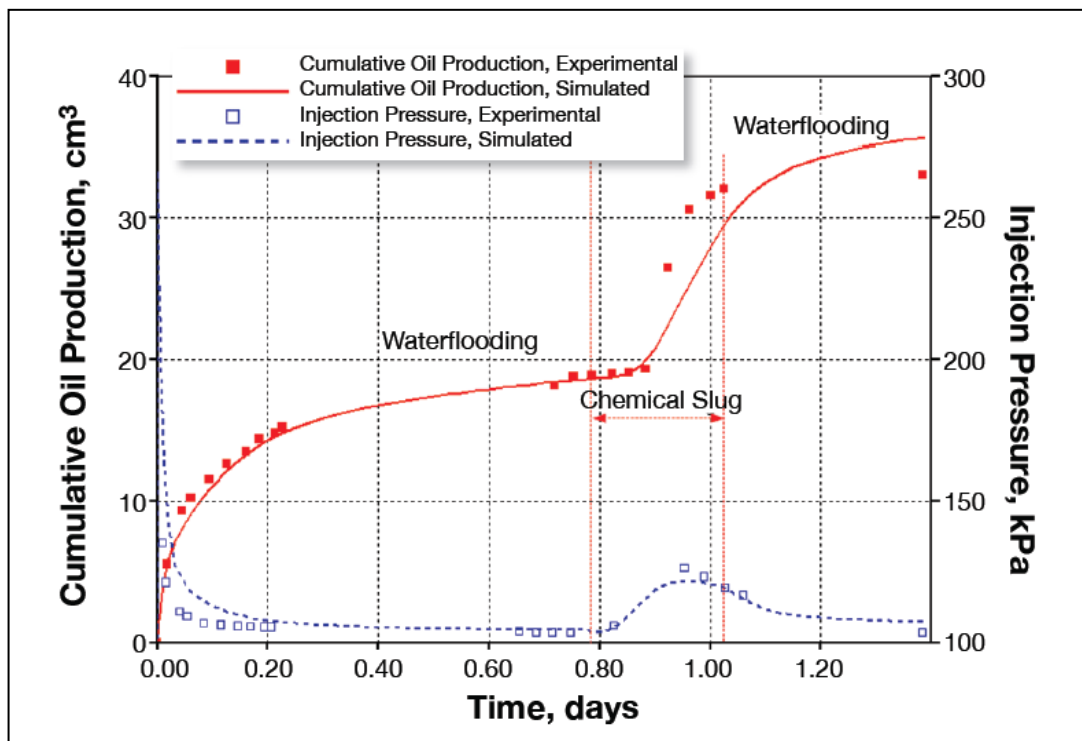
Figure 4: Experimental and simulated pressure drop and oil recovery as functions of time for Case II

2.1.3 Experimental Study on Alkali-Surfactant-Polymer (ASP) Flooding

Bera, et al., 2012, has done comparative studies between alkaline flooding, alkaline-surfactant flooding and alkaline-surfactant-polymer flooding. This case, from onward referred as Case III, is an analysis made to determine the optimum composition of the alkali-surfactant-polymer (ASP) system to be used for tertiary recovery of oil. It consists of several experiments with different combinations of

alkali, surfactant and polymer concentration. The percentage of tertiary recovery, %OOIP, is recorded and the optimum composition is then determined from the highest percentage of tertiary recovery, %OOIP, obtained. According to the journal, 14 experiments have been performed. However, for this project purpose, only one experiment is to be simulated.

Physical model used in experiment is homogenous sand-packing model vertically positive rhythm. Positive rhythm is composed of several sand layers with the sand diameter declining from bottom to top, i.e. the permeability declines in the vertical profile from bottom to top (Liu, Wang, & Wang, 2012).
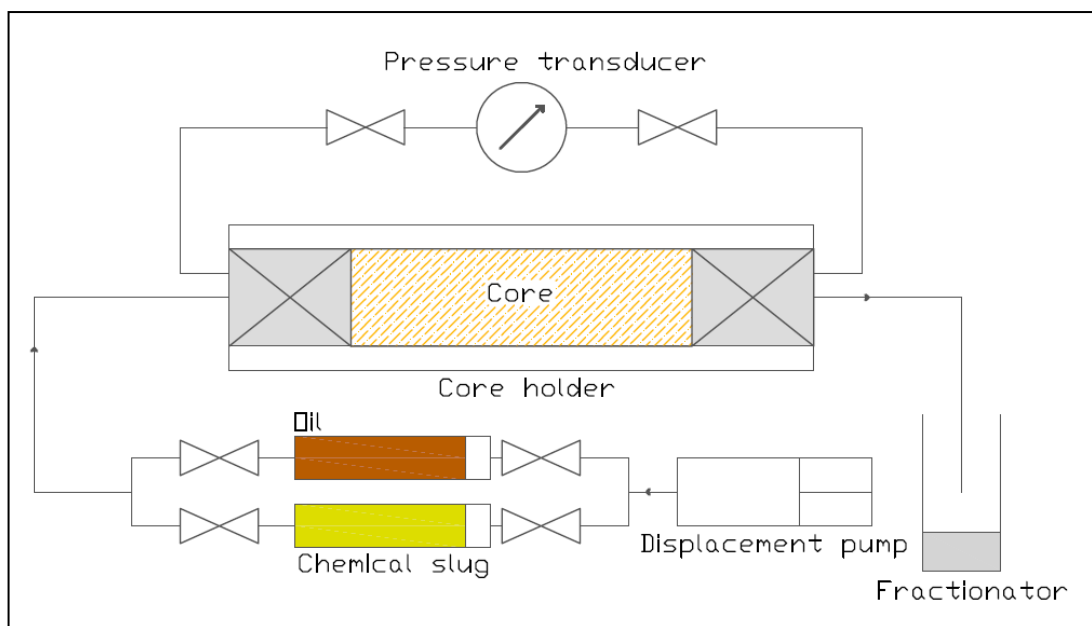
Figure 5: Schematic of experimental set -up for polymer flooding in sandpack for Case III
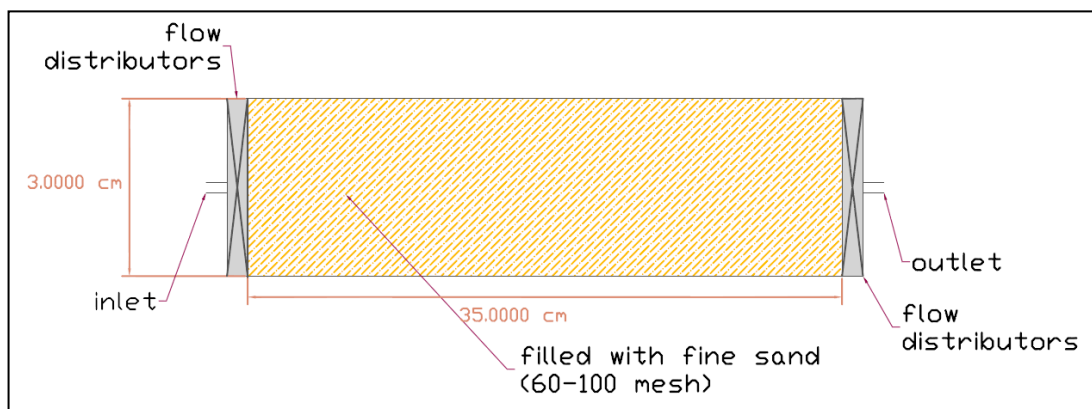
Figure 6: Geometry size of sand -packing model (core in Figure 5).

In the experiment, the sandpack is fully filled with brine to get wet-packed sandpack. Then, crude oil is injected until water production is negligible. The initial water

saturation is determined. After that, water flooding is conducted followed by 0.5 PV chemical flooding injection and 2.0 PV water injection (as chase water) is used. The details of the reservoir (experiment) components and the fluid injected into the sandpack are as listed in Table 5. The simulation should be history matched with the experiment to get results as in Figure 7.

Table 5: Reservoir components for Case III

Components	Molecular Weight	Details
Crude oil	N/A	Viscosity: 50.12 mPa s
Water	18	Viscosity: 1002 mPa s Density: 1000 kg/m^3
Alkali (NaOH)	40	N/A
Surfactant (Sodium dodecyl sulfate, $C_{12}H_{24}SO_4Na$)	287.42	N/A
Polymer (Partially hydrolyzed polyacrylamide)	N/A	N/A

Table 6: Simulation data for Case III

Case	3
Sandpack length, cm	35.000
Porosity, %	37.265
Permeability, µm^2	5.267
Initial oil saturation, %	82.716
Waterflooding recovery, %OOIP	52.900
Chemical formula	5000 ppm NaOH + 1000 ppm Surfactant + 2500 ppm Polymer + 2500 ppm Buffer
Chemical slug size, PV	0.500
Tertiary recovery, %OOIP	24.200
Final oil recovery, %OOIP	77.100
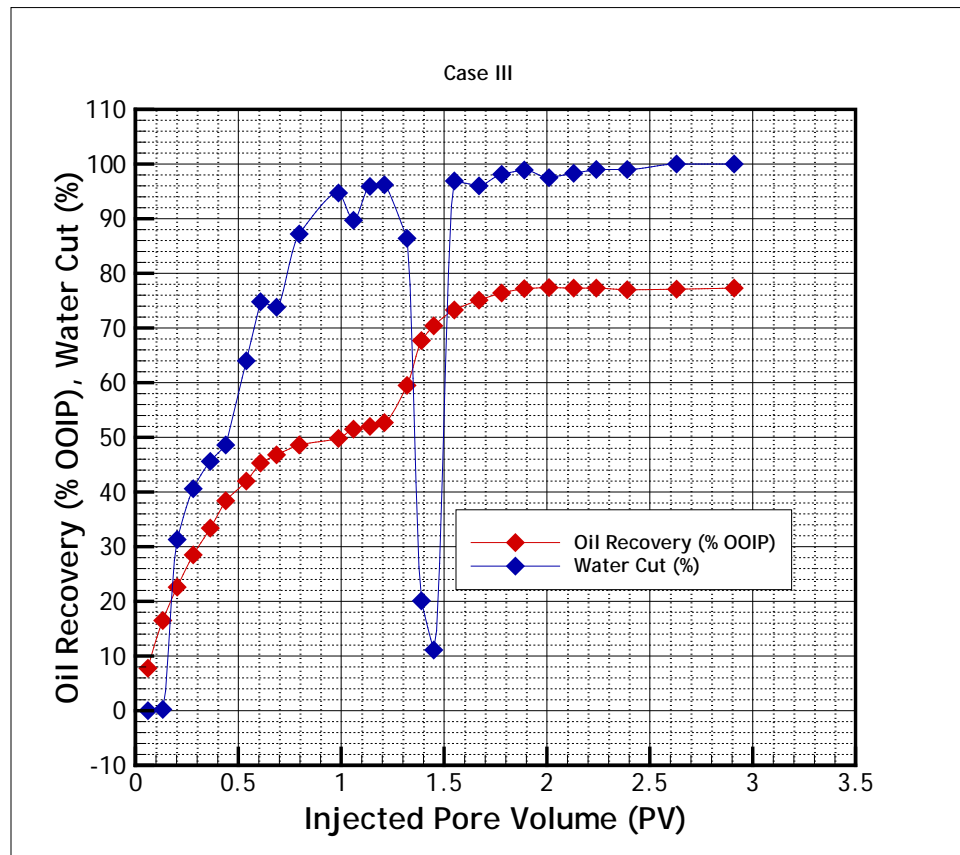
Figure 7: Cumulative oil recovery using alkali, surfactant, polymer, surfactant-polymer and alkali-surfactant-polymer flooding for Case 3

2.2 Theory

2.2.1 Chemical Flooding Experiment using Sandpack

Experimental investigation and history match of the laboratory tests were aimed at providing proper flow mechanisms and simulation parameters for designing and predicting the field performance (Wang, et al., 2010). The tertiary oil recovery is unaffected by the sandpack length thus this shows that experimental results using sandpack is applicable for field-scale numerical simulation (Tu, Liu, Dong, & Ma, 2007) (Wang, et al., 2010).

2.2.2 History Match of Sandpack Flood Tests

In simulating the experimental data, history matching is required as part of the process. History matching is the act of adjusting the parameters in a model of a reservoir in order to make the model fit the production data observed in the field previously (Silva, et al., 2005). The historical production and pressures are matched

as closely as possible (Varhaug, 2012). For this project, history matching will be based on production data in the experiment using sandpack.

There is very limited information available publicly on history matching. This is because; the simulation techniques consist of many small items that are considered unworthy to be published. Besides, the practitioners of the history matching would be too occupied with the research studies to spend time in explaining procedures of history matching (Galas, 2003). History matching requires trial and error (Carlson, 2006). There are no specific guidelines in history matching due to the different properties and complexity of each case. Therefore, in order to gain knowledge on history matching, experimental data with successful history matching simulation results are used as part of the learning process, by reproducing the same simulation results using the data available.

2.2.3   Alkaline-Surfactant-Polymer (ASP) Flooding

Alkaline-surfactant-polymer (ASP) flooding resulted due to effort in finding a method to reduce the amount of injected chemicals and to fully explore the synergy of different processes (Sheng, 2011). The outcome of ASP flooding is better than chemical flooding of single component - alkali, polymer or surfactant (Xia & Ma, 2010). Figure 8 illustrates the typical stages in an ASP flooding process. The chemicals are injected as slugs instead of continuous injection due to the cost of the chemicals (Vicente, Priimenko, & Pires, 2012). A preflush of brine is performed to lower the salinity of the reservoir. ASP solution is used to reduce the interfacial tension between the aqueous and oleic phases. A polymer solution is injected to perform a uniform sweep of the oil and the previous slugs. Finally, chase water is injected to finally drive the oil and the chemicals to the producer well (Zerpa, Queipo, Pintos, & Salager, 2005).
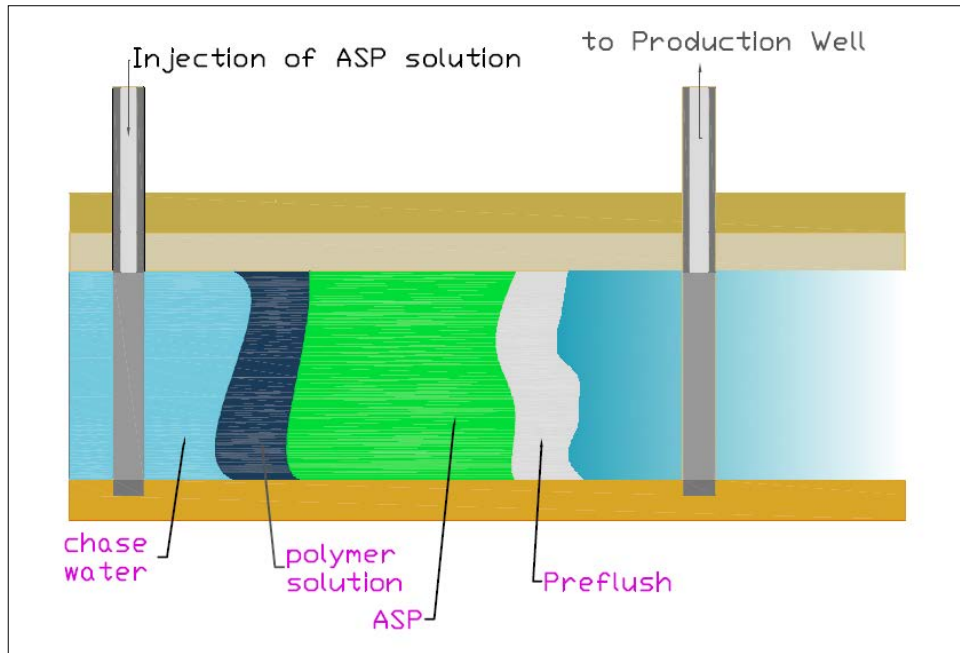
Figure 8: Alkaline-surfactant-polymer (ASP) flooding process.

In ASP flooding, the surfactant is responsible for reducing the interfacial tension between oil and water phases to a level that promotes the mobilization of trapped oil drops (Zerpa, et al., 2005). The alkaline agent is intended to react with the acids to generate in situ formation of surfactants, which in turn decreases the interfacial tension between oil and water for better oil recovery (Samanta, Ojha, & Mandal, 2011). By the addition of surfactant in the chemical formula, the interfacial tension (IFT) of oil and water is significantly reduced and the oil is more easily dispersed in formation brine and thus oil recovery made more efficient (Tu, et al., 2007). Adding the polymer increases the viscosity, which restricts the diffusion of the alkaline, surfactant, and in situ-formed surface-active species, reducing the mobility ratio and hence allowing a greater volumetric swept efficiency (Zhang, Dong, & Zhao, 2012).

2.3   Summary

This project will be based on the literature review and theory discussed. The framework of the project and the general procedure for simulating the chemical flooding experimental model is further discussed in the next chapter.

CHAPTER 3: METHODOLOGY

3.   Methodology

In Methodology, research process is explained in form of flow chart. There are two flow charts. One is the overview of the overall project research process and the other one is the framework for simulation.

3.1   Research Methodology

3.1.1   Project Flow Chart
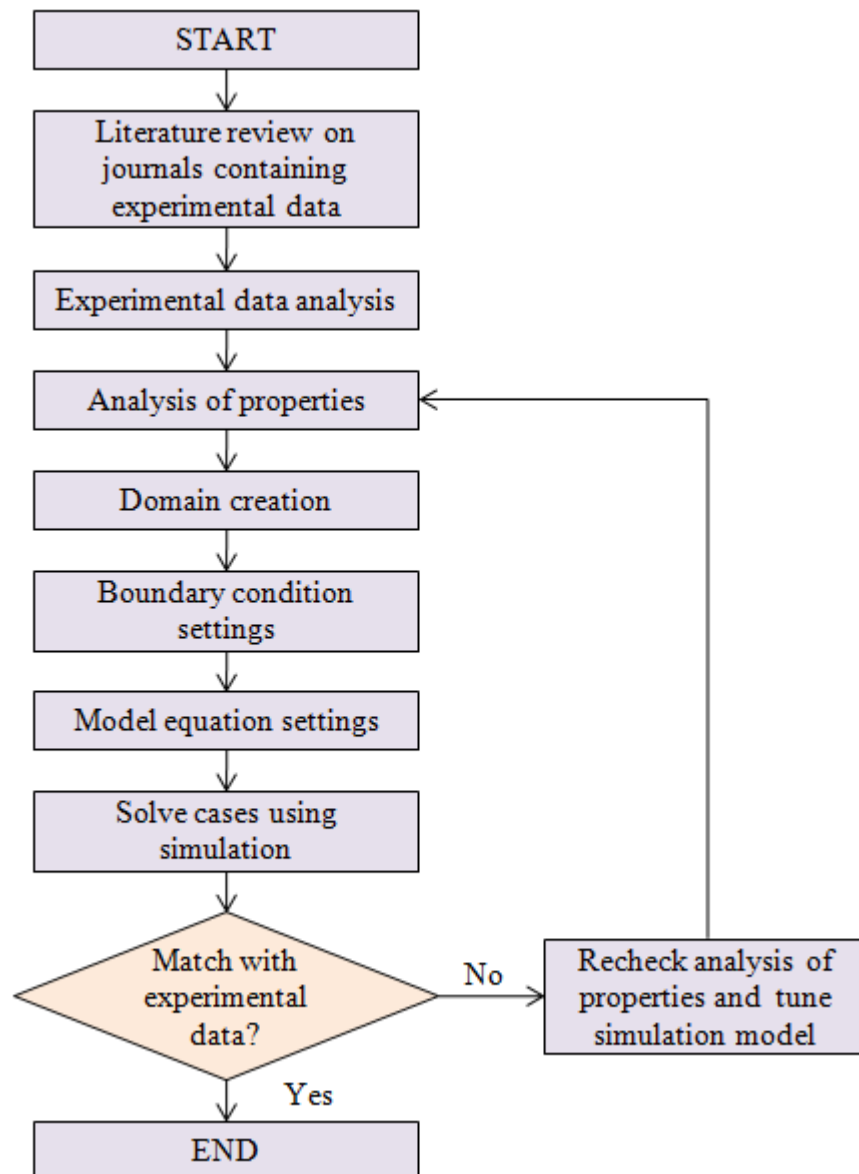
Figure 9: Flow chart for the project

3.2   Project Activities

3.2.1   Research Analysis

The objective of this project is to gather the knowledge on history matching for simulating the experimental results of chemical flooding and to apply the knowledge on experimental results that is yet to be simulated. In achieving this objective, two main journals specified in *Literature Review*, Case I and Case II, that have perform both experiment and simulation are made as reference. This is to ensure that the simulation to be carried out on the experimental data in the third journal or Case III is performed correctly. The simulations in Case I and Case II are to be reproduced, with the purpose to understand the right simulation procedures. For this purpose, experimental data and its properties are analyzed.

3.2.2   Understanding Software Requirements and Capabilities

In achieving the desired outcome, this project requires knowledge of doing simulation using a reservoir modeling software. Since the author has never been exposed to any reservoir modeling software, several practices are performed using simple tutorial provided in the simulator package. This enables the author to familiarize with the software and study the software requirements and capabilities.

3.3   Research/Analysis Software

The simulation software used for this project is reservoir simulator package by Computer Modelling Group Ltd (CMG), which contain STARS (Advanced Process and Thermal Reservoir Simulator). CMG STARS is capable to model reservoir process involving chemical flooding (Gaytan, 2009). The reservoir model is first to be build in CMG Builder with STARS (Advanced Process and Thermal Reservoir Simulator) platform. The completed model is then run in CMG STARS for results. Graphical results can be obtained from CMG ResultsGraph. In assisting the simulation data preparation and analysis, DigitizeIt, Microsoft Excel, AutoCAD and Tecplot are also used.

3.3.1 Simulation Framework

In CMG STARS, to run the simulation and obtain the graph of results, several stages have to be completed. The framework for the general procedures of the simulation is shown in Figure 10.
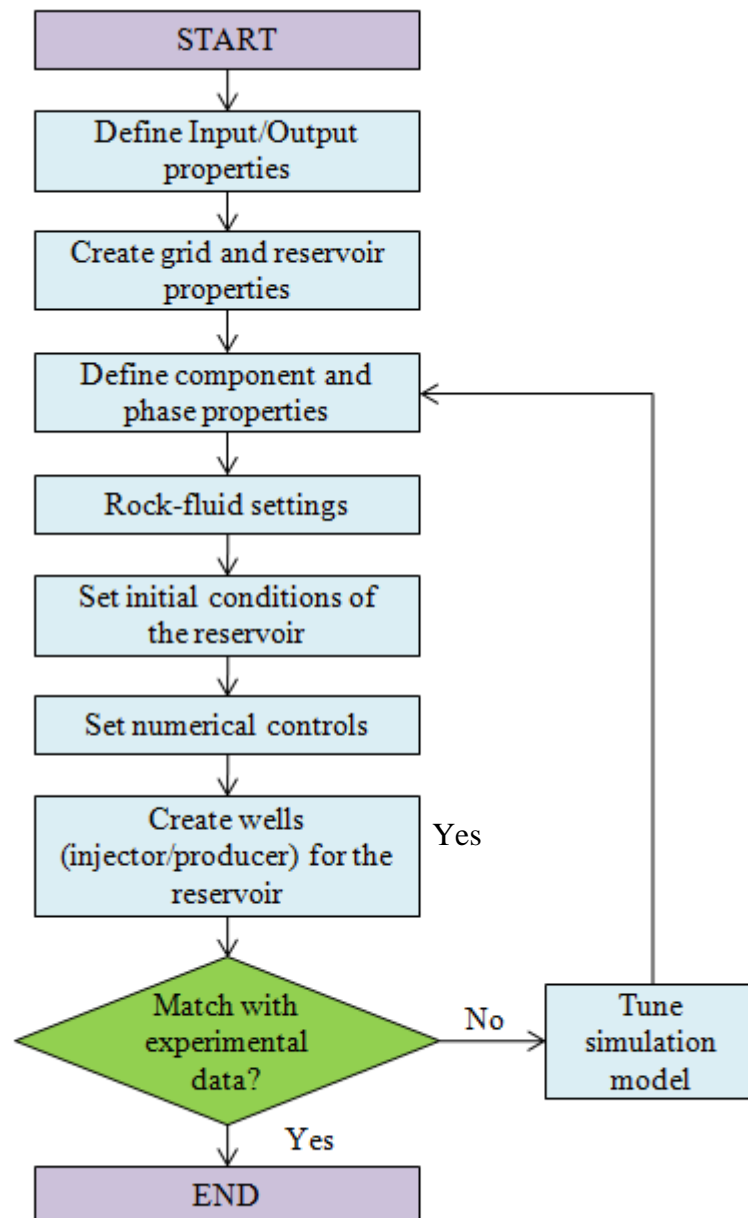
Figure 10: Simulation framework

3.4 Gantt Chart

Gantt Chart for Final Year Project (FYP) I

Project Activities for FYP I	Month/Week No													
	May		June				July				August			
	1	2	3	4	5	6	7	8	9	10	11	12	13	14
First meeting with coordinator and supervisors	▓	▓												
Literature review on journals containing experiment data			▓	▓	▓	▓								
Experimental data analysis					▓	▓	▓	▓	▓	▓	▓			
Domain creation							▓							
Boundary condition settings								▓	▓	▓	▓	▓	▓	▓
Model equation settings									▓	▓	▓	▓	▓	▓
Solve cases using simulation										▓	▓	▓	▓	▓
Comparison with experimental data													▓	▓
Submission of Interim Draft Report													▓	
Submission of Interim Report														▓

Figure 11: Gantt Chart for FYP I

Gantt Chart for Final Year Project (FYP) II

Project Activities for FYP II	Week No													
	Sept		October				November				December			
	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Experimental data analysis														
Domain creation	█					█								
Boundary condition settings	█	█	█	█	█	█	█	█	█	█	█			
Model equation settings	█	█	█	█	█	█	█	█	█	█	█			
Solve cases using simulation	█	█	█	█	█	█	█	█	█	█				
Comparison with experimental data			█	█	█			█	█	█				
Submission of Progress Report								█						
PRE-SEDEX											█			
Submission of Draft Report												█		
Submission of Dissertation (soft bound)													█	
Submission of Technical Paper													█	
Oral Presentation														█
Submission of Dissertation														█

Figure 12: Gantt Chart for FYP II

CHAPTER 4: RESULT AND DISCUSSION

4.   Result and Discussion

This chapter discusses on the results obtained from the project work. As explained in previous chapters, three cases of simulation need to be completed. Simulation of Case I and Case II can be done in parallel however; these cases have to be completed first to investigate the history matching technique before Case III can be simulated using the technique developed.

4.1   History Matching the Experimental Results of Case I

The simulation of Case I have been able to be run using CMG STARS, means the input data required is sufficient. However, the simulation results, shown in Figure 13, are far from the experiment results. This means that the history matching is yet to be fully completed due to missing steps or inaccurate input values. The history matching steps or technique the author used is as follows. The data file of the simulation is attached in the appendices.

1. Reservoir Simulator Settings

The reservoir model is developed in CMG Builder. In reservoir simulator settings, the simulator chosen is STARS (Advanced Process and Thermal Reservoir Simulator). The porosity of the reservoir is single porosity and the simulation start on 1st January, 2000.

2. Reservoir Settings

The grid system of the reservoir (the sandpack model) is created using orthogonal corner point grid. The number of grid blocks in I-J-K direction is specified as 25 × 25 × 2 with grid block size 0.568 m × 0.567 m for I and J direction. This represents the 14.2 cm sandpack length scaled up in meter, as values in centimeter are too small for simulation. In K direction there is two layers, Layer 1 for low permeability region and Layer 2 for high permeability region. The properties of the reservoir are set as in Table 7.

Table 7: Simulation reservoir properties for Case I

	Grid Thickness	Porosity	Permeability
Layer 1	3	0.374	4000
Layer 2	1	0.374	16000

3. Components/Phase Properties

There are four components used in this equation. The properties of the components are as in Table 8. The values with asterisk are assumed values. These values listed in the tables are the final values used for the simulation after many trials to get the best result.

Table 8: Component properties for Case I

Components	Phase	Molecular Weight (kg/gmole)	Density (kg/m^3)	Liquid phase viscosities (cp)
Water	Aqueous	18	100.0	1002
Alkali	Aqueous	73	900.0*	800*
Oil	Oil	380	966.5	1360
Emulsion	Oil	350	200.0*	6000

*Assumed/ Trial values

The formation of emulsion is represented by Equation 1. This equation is added into the simulation and the mass balance of the reaction must have no error.

Equation 1

$$8.0515 \; Water + 0.001 \; Alkali + 1.0 \; Oil \rightarrow 1.5 \; Emulsion$$

4. Rock/Fluid Settings

Relative permeability for Case I is shown in Appendix 1. There are two sets of rock types; before and after chemical flooding. Using Appendix 1, the relative permeability of each rock types is developed using correlations as in Appendix 4. For both rocktype, well-sorted consolidated sandstone is chosen, with exponent values equals 3.0.

For this simulation, alkali is defined as adsorption component. The adsorption is set to be independent of temperature.

Table 9: Description for relative permeability correlations for Case I

Description	Values
SWCON - Endpoint Saturation: Connate Water	0.1
SWCRIT - Endpoint Saturation: Critical Water	0.1
SOIRW - Endpoint Saturation: Irreducible Oil for Water-Oil Table	0.3
SORW - Endpoint Saturation: Residual Oil for Water-Oil Table	0.3
SOIRG - Endpoint Saturation: Irreducible Oil for Gas-Liquid Table	0.1*
SORG - Endpoint Saturation: Residual Oil for Gas-Liquid Table	0.2*
SGCON - Endpoint Saturation: Connate Gas	0.1*
SGCRIT - Endpoint Saturation: Critical Gas	0.2*
KROCW - Kro at Connate Water	1
KRWIRO - Krw at Irreducible Oil	0.35
KRGCL - Krg at Connate Liquid	1*
Exponent for calculating Krw from KRWIRO	3
Exponent for calculating Krow from KROCW	3
Exponent for calculating Krog from KROGCG	3
Exponent for calculating Krg from KRGCL	3

*Assumed/ Trial values

5. Chemical Flooding Process Wizard

Process wizard in Builder with STARS platform, use the existing fluid model and add required data to simulate the process desired. For this case, "alkali, surfactant and/or polymer model" is chosen as the process desired. Surfactant flood is chosen as the model as only one chemical component is used in the chemical flooding (alkali, which later reacts to form surfactant). The options for the model are two relative permeability sets is selected and rock type chosen is sandstone with density of 2.65 g/cm^3. A rock fluid region is set for capillary number relative permeability interpolation. Interfacial values are set based on the figure shown in Appendix 1.

6. Initial Conditions

The initial conditions of the reservoir are set. The reference pressure is 500 kPa and the reference depth is 4 m. The values of the reference pressure are trial values. It is believed that this part is critical, however, from this project work; the suitable reference pressure to be used is not obtained.

7 .Numerical Controls

In numerical controls, the step size for calculation is defined as 1 day.

8. Wells & Recurrent

Demonstrating the experiment model, the well perforations for injector is performed at the most left of the reservoir model and for producer at the most right grid of the model. For injector, three periods are defined. The first period is for injection of water for water flooding. The second period is for chemical injection. The third period is again for water injection to drive the oil out of the reservoir. The chemical injected is defined in each period. Each period is defined in parallel with the pore volume used in the experiment.

Results

The result of the simulation is shown in Figure 13. The history matching technique is far from satisfactory, as the simulated results do not even match the curves shape of the experimental results as shown in Figure 3. For oil recovery, the curve does not signify increased production after chemical injection. For pressure drop curve, it supposed to signify change in pressure, however, the pressure increase from zero before it remains as constant in short time after simulation is started.
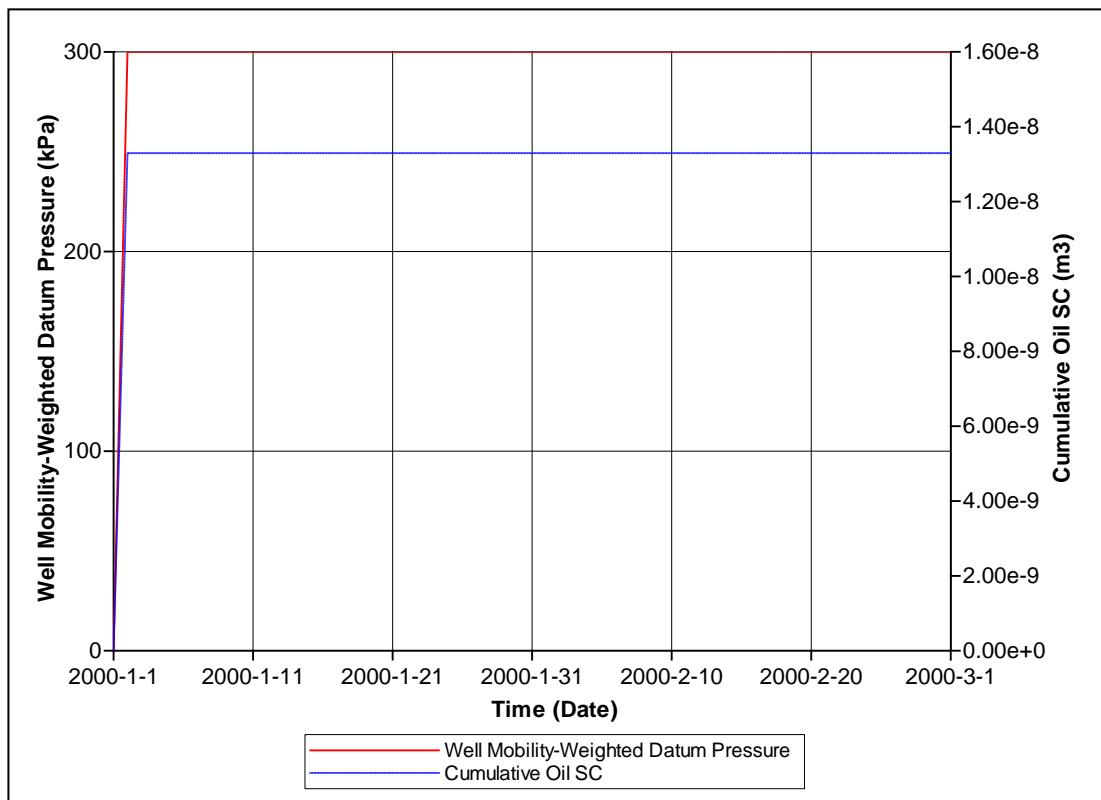
Figure 13: Simulation results for Case II

4.2   History Matching the Experimental Results of Case II

The steps as has been discussed in Case I is also applied in Case II using the data as provided in the journal and choosing alkali-surfactant flood as the model for the simulation. However, no results can be displayed as the software will not run with the reaction has mass balance error. The material balance for the reaction, as shown in Equation 2, requires a lot of trial and error to get a reaction with balanced mass. Without the correct material balance, the simulation works cannot proceed to completion.

Equation 2

$$Water + Chemical + Dead\ Oil \rightarrow O/W\ Emulsion\ \ldots\ldots \text{ Reaction 1}$$
$$O/W\ Emulsion \rightarrow Trapped\ Oil\ \ldots\ldots \text{ Reaction 2}$$
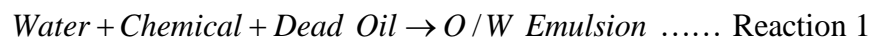
At first, it has been attempted to remove the error by changing the coefficients or reactants. However, through a series of trial and error, 0% percentage of error still cannot be obtained. Unless there is no percentage of error in the material balance, the simulation could not be run. Attempt on using Excel Solver to get the optimum value for the material balance also does not succeed, and the best percentage of error obtained using the value from Excel Solver is 6×10^{-5} %. This is however still unacceptable, as the simulator only run if the material balance is proportioned in mass.

4.3   History Matching the Experimental Results of Case III

The history matching of experimental results of Case III is not performed, as the history matching technique developed is still unsatisfactory. Upon further analysis, as the journal mainly discussed on the comparison of oil recovery between several combinations of chemicals' concentrations, the data of the experiment properties provided are not in details. Thus, if history-matching technique is obtained, still, a lot of time will need to be spent on trial and error.

CHAPTER 5: CONCLUSION AND RECOMMENDATION

5.   Conclusion and Recommendation

5.1   Conclusion

This project is relevant to the current needs with its objective to gather the knowledge on history matching for simulating the experimental results of chemical flooding for enhanced oil recovery (EOR) and to apply the knowledge on experimental results that is yet to be simulated. A simulated experimental result on chemical flooding can provide a good platform for designing a field-scale simulation.

However, upon project progress, several challenges rise and thus the objectives are not fully completed. Through project work, the history matching on experimental results of Case I and Case II is not satisfactory enough. In the journals of Case I and Case II, the simulation results have shown a close match with the experimental results. However, this project's works, that is to investigate the history matching technique and produce close match of simulation result and experimental results, as has been achieved in the journals of Case I and Case II; is not fully successful in exploring the technique of the history matching. The simulation results obtained is far from the experimental results. The history matching technique developed throughout this project work is not convincing enough as the desired output is not achieved. Thus, simulation on experimental results of alkali-surfactant-polymer that are yet to be history matched could not be performed. Nevertheless, within the limited time left, the author will continue on the project to achieve the desired objective.

5.2   Recommendation

Throughout the project work, it has been found out that history matching require a lot of trial and error. This means a lot of time has to be spent. Lack of essential raw data can also largely contribute to inaccuracy of history matching. In fact, even if the history matching technique can be fully developed as per objective of this project, there is a possibility that Case III cannot be properly history matched, unless through a long series of trial and error. This is because, after progressing with the project's

work, it is found out that the data from the journal chosen is not sufficient for history matching. Therefore, it is recommended that history matching be performed using detailed experimental data and results. Data and results from journal are very limited. It might be better if both experiment and simulation is performed in one research project, so that for history matching purpose, all the data required is within the researcher's knowledge. This could also saves the time on history matching as trial and error of data input could be reduced.

It has been a challenge to understand in depth the concept of the chemical flooding for enhanced oil recovery; and to do simulation on reservoir modeling, in which both the author has never been exposed to before. There are also very limited resources that could help giving information on simulating chemical flooding using CMG STARS. Thus, it is recommended that this project work be continued by student who has at least a basic petroleum engineering background for a more thorough understanding of the project.

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APPENDICES

APPENDIX 1: Relative Permeability Data and Interfacial Values for Case I

The relative permeability curves, which show the relative permeability before chemical injection (waterflooding) and after alkaline-surfactant flooding (Capillary number = 3.2E-3), that should be obtained from the simulation is as shown in, Figure 18. The curves show that after the alkaline-surfactant flooding, the relative permeability increases compared to before chemical injection takes place. The relative permeability curves are calculated based on the equations as shown in Appendix 4.
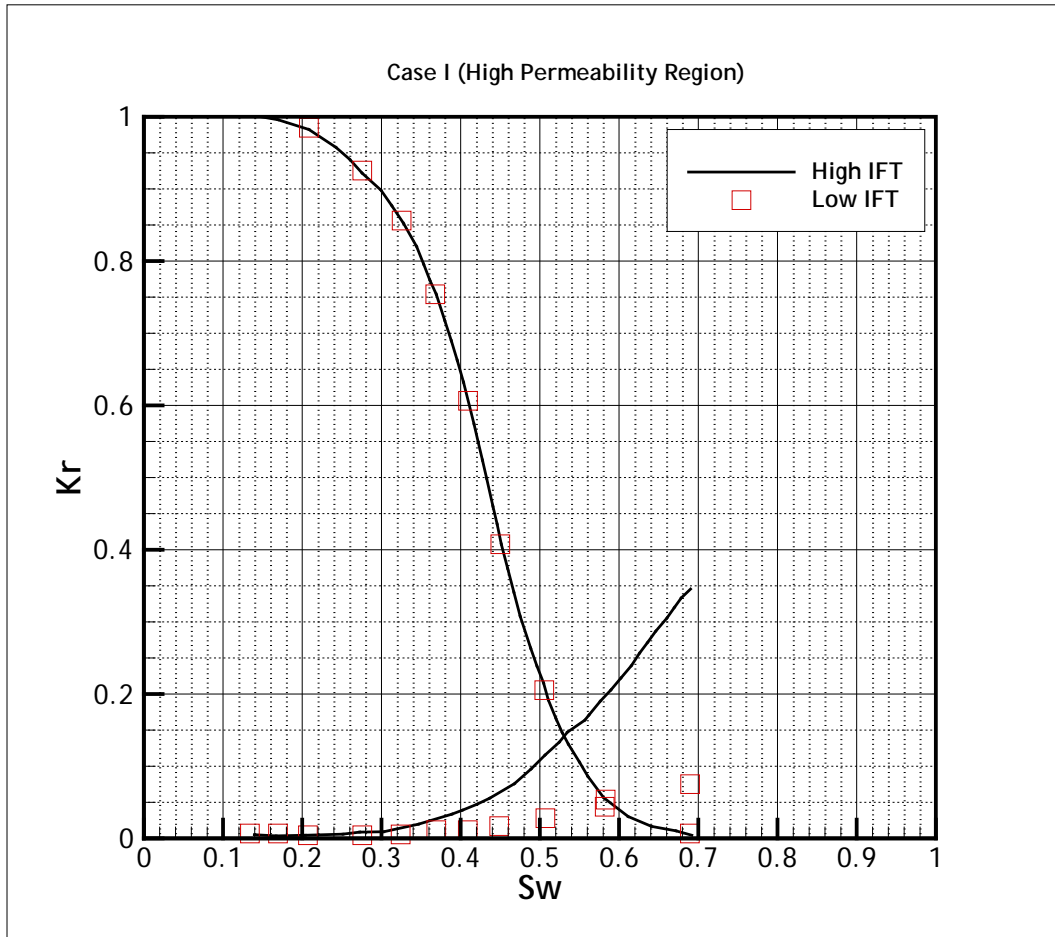
Figure 14: Relative permeability curves for simulation of Case 1 (for high permeability zone)
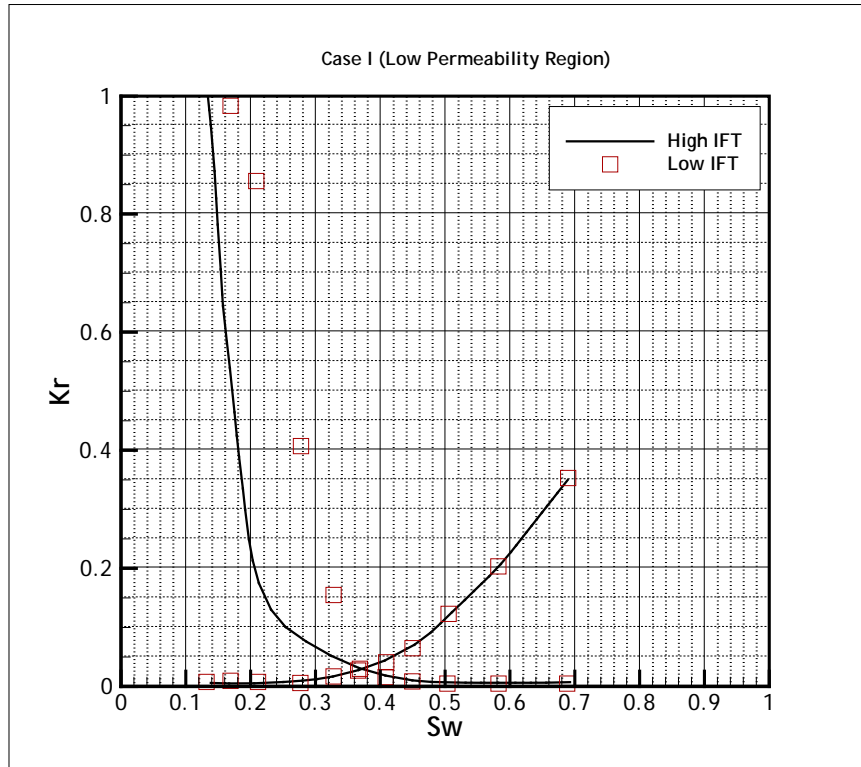
Figure 15: Relative permeability curves for simulation of Case 1 (for low permeability zone)
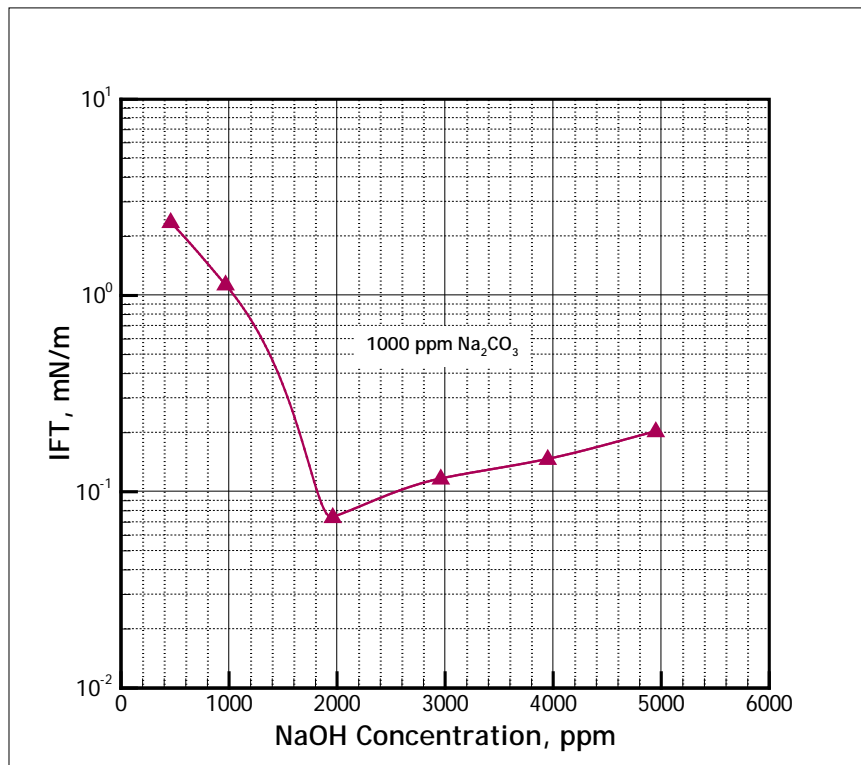
Figure 16: Interfacial tension values for Case I
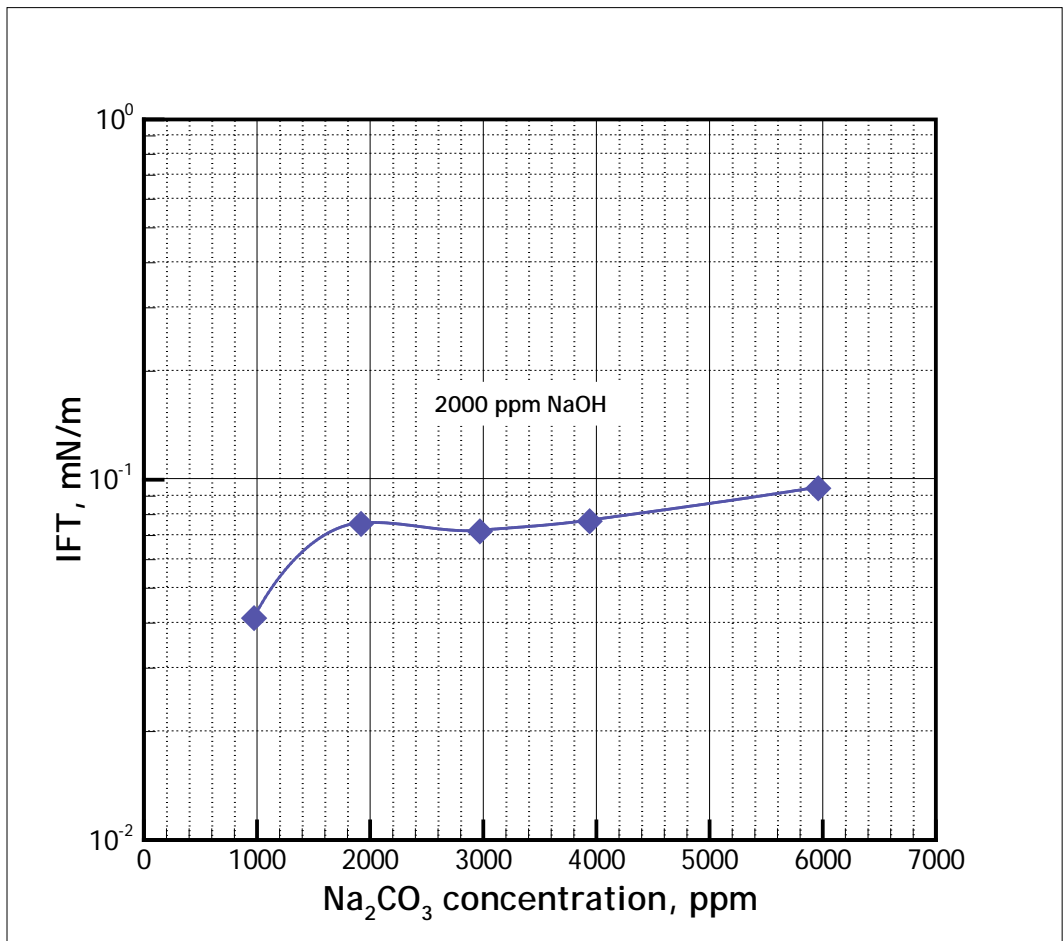
Figure 17: Interfacial tension values for Case I

APPENDIX 2: Relative Permeability Data and Interfacial Values for Case II

The relative permeability curves, which show the relative permeability before chemical injection (waterflooding) and after alkaline-surfactant flooding (Capillary number = 3.2E-3), that should be obtained from the simulation is as shown in, Figure 18. The curves show that after the alkaline-surfactant flooding, the relative permeability increases compared to before chemical injection takes place. The relative permeability curves are calculated based on the equations as shown in Appendix 4.
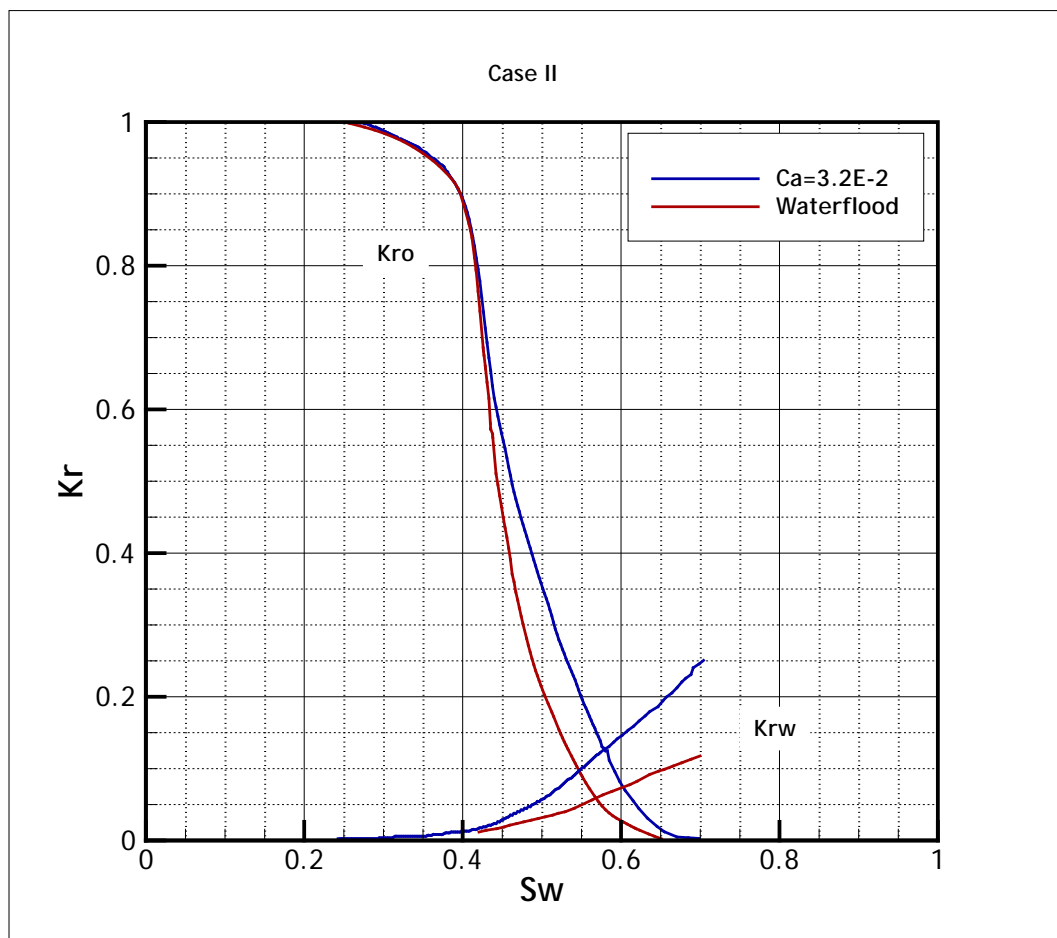
Figure 18: Relative permeability curves for simulation of Case II
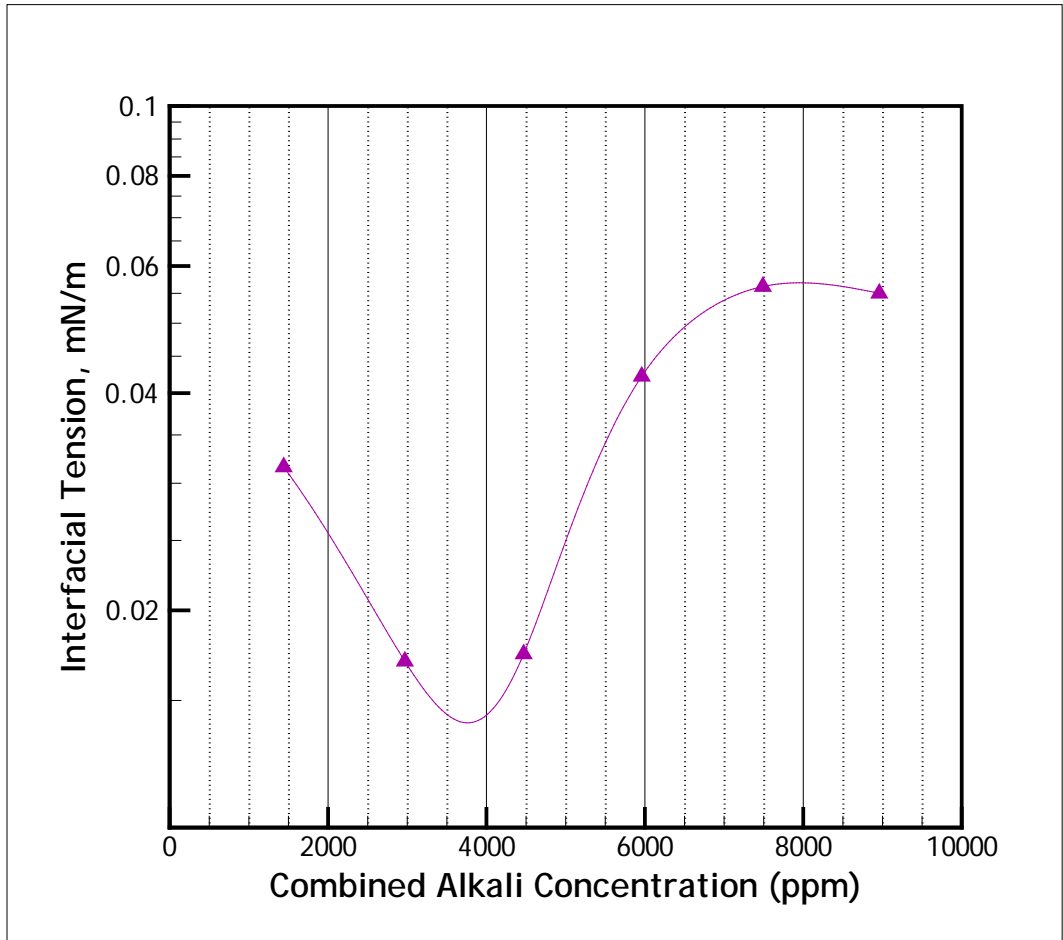
Figure 19: Interfacial tension values for Case II

APPENDIX 3: Interfacial Tension Data for Case III

Interfacial tension values against concentration of surfactant (SDS) are available from Figure 20 to be used in the simulation as input data.
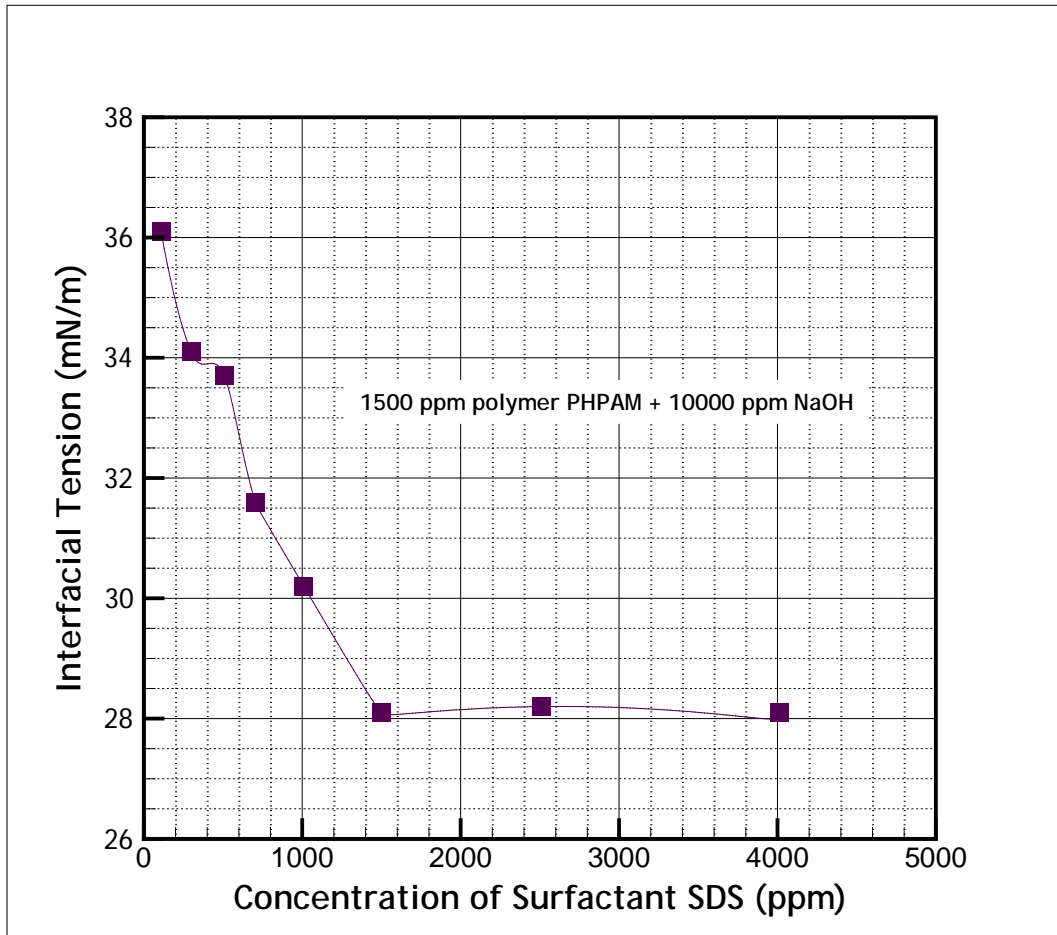
Figure 20: Interfacial tension with the presence of surfactant (SDS), polymer (PHPAM) and alkali (NaOH).

APPENDIX 4: Equation for Relative Permeability

For relative permeability, K_r, versus saturation of water, Sw plot:

$$So = 1 - Sw$$

$$K_{rw} = K_{rwiro} \left[\frac{(Sw - Sw_{crit})}{(1.0 - Sw_{crit} - So_{irw})} \right]^{N_w}$$

$$K_{row} = K_{rocw} \left[\frac{(So - So_{rw})}{(1.0 - Sw_{con} - So_{rw})} \right]^{N_{ow}}$$

$$K_{rog} = K_{rogcg} \left[\frac{(SI - So_{rg} - Sw_{con})}{(1.0 - Sg_{con} - So_{rg} - Sw_{con})} \right]^{N_{og}}$$

$$K_{rg} = K_{rgcl} \left[\frac{(Sg - Sg_{crit})}{(1.0 - Sg_{crit} - So_{irg} - Sw_{con})} \right]^{N_g}$$

APPENDIX 5: Equation for Percentage of Recovery

Percentage recovery

$$\% RC = \frac{\text{(cumulative production - cumulative injection)}}{\text{initial material in place (OOIP)}}$$

APPENDIX 6: Data File for Case I Simulation

RESULTS SIMULATOR STARS 200900

INUNIT SI
WSRF WELL 1
WSRF GRID TIME
WSRF SECTOR TIME
OUTSRF GRID PRES SG SO SW TEMP
OUTSRF WELL LAYER NONE
WPRN GRID 0
OUTPRN GRID NONE
OUTPRN RES NONE
**$ Distance units: m
RESULTS XOFFSET   0.0000
RESULTS YOFFSET   0.0000
RESULTS ROTATION   0.0000 **$ (DEGREES)
RESULTS AXES-DIRECTIONS 1.0 -1.0 1.0
**$ **
**$ Definition of fundamental corner point grid
**$ **
GRID CORNER 25 25 2
DI IVAR   0.568   0.568   0.568   0.568
        0.568   0.568   0.568   0.568   0.568
        0.568   0.568   0.568   0.568   0.568
        0.568   0.568   0.568   0.568   0.568
        0.568   0.568   0.568   0.568   0.568
        0.568
DJ JVAR   0.567   0.567   0.567   0.567
        0.567   0.567   0.567   0.567   0.567
        0.567   0.567   0.567   0.567   0.567
        0.567   0.567   0.567   0.567   0.567
        0.567   0.567   0.567   0.567   0.567
        0.567
ZCORN
 2500*0.0000 5000*3.0000 2500*4.0000
**$ Property: NULL Blocks Max: 1 Min: 1
**$ 0 = null block, 1 = active block
NULL CON   1
**$ Property: Porosity Max: 0.374 Min: 0.374
POR CON   0.374
**$ Property: Permeability I (md)   Max: 16500 Min: 4000
PERMI KVAR
 4000 16500
PERMJ EQUALSI
PERMK EQUALSI
**$ Property: Pinchout Array Max: 1 Min: 1
**$ 0 = pinched block, 1 = active block
PINCHOUTARRAY CON   1
END-GRID
**$ Model and number of components
**$ Model and number of components
**$ Model and number of components
**$ Model and number of components
**$ Model and number of components
MODEL 4 4 4 2
COMPNAME 'Alkali' 'Water' 'Oil' 'Emulsion'
CMM
73 18 380 350
PCRIT
0 22106 0 0
TCRIT
0 374.111 0 0
MASSDEN
900 1000 966.5 200
VISCTABLE
**$ temp
        35   800   1002   1360   6000
**$ Reaction specification
**$ Reaction specification
**$ Reaction specification
STOREAC
0.001 8.0515 1 0
STOPROD

38

```
0 0 0 1.5
FREQFAC 5
ROCKFLUID
RPT 1 WATWET
INTCOMP 'Alkali' *WATER
IFTTABLE
**$  Composition of component/phase  Interfacial tension
                      0            10
                    0.0004          2.5
                    0.001           1
                    0.002          0.8
                    0.003          0.1
                    0.004          0.15
                    0.005          0.2
INTLOG
KRINTRP 1
DTRAPW -5
DTRAPN -5
**$      Sw       krw      krow
SWT
      0.1        0        1
     0.1375  8.54492e-005   0.823975
     0.175   0.000683594   0.669922
     0.2125   0.00230713    0.536377
      0.25    0.00546875    0.421875
     0.2875   0.0106812    0.324951
     0.325    0.018457     0.244141
     0.3625   0.0293091    0.177979
      0.4      0.04375       0.125
     0.4375   0.0622925    0.0837402
     0.475    0.0854492    0.0527344
     0.5125   0.113733     0.0305176
     0.55     0.147656     0.015625
     0.5875   0.187732     0.0065918
     0.625    0.234473     0.00195312
     0.6625   0.288391    0.000244141
      0.7       0.35          0
**$      Sl       krg      krog
SLT
      0.2        1           0
     0.25     0.770255        0
      0.3     0.578704        0
     0.33125  0.476837   0.000141285
     0.3625   0.387686    0.00113028
     0.39375  0.310403    0.0038147
     0.425    0.244141    0.00904225
     0.45625  0.18805     0.0176606
     0.4875   0.141285    0.0305176
     0.51875  0.102997    0.0484608
     0.55     0.072338    0.072338
     0.58125  0.0484608   0.102997
     0.6125   0.0305176   0.141285
     0.64375  0.0176606    0.18805
     0.675    0.00904225   0.244141
     0.70625  0.0038147    0.310403
     0.7375   0.00113028   0.387686
     0.76875  0.000141285  0.476837
      0.8        0        0.578704
     0.85        0        0.770255
      0.9        0           1
KRINTRP 2
DTRAPW -2
DTRAPN -2
**$      Sw       krw      krow
**$      Sw       krw      krow
SWT
      0.1        0        1
     0.999       1        0
       1         1        0
**$      Sl       krg      krog
**$      Sl       krg      krog
SLT
     0.101       1        0
       1         0        1
RPT 2 WATWET
```

INTCOMP 'Alkali' *WATER
IFTTABLE
**$ Composition of component/phase Interfacial tension
0	18.2
0.0005	0.5
0.001	0.028
0.002	0.028
0.004	0.0057
0.006	0.00121
0.008	0.00037
0.01	0.5

INTLOG
FMGCP 0.0032
KRINTRP 1
DTRAPW -5
DTRAPN -5
**$ Sw   krw   krow
SWT

Sw	krw	krow
0.1	0	1
0.1375	8.54492e-005	0.823975
0.175	0.000683594	0.669922
0.2125	0.00230713	0.536377
0.25	0.00546875	0.421875
0.2875	0.0106812	0.324951
0.325	0.018457	0.244141
0.3625	0.0293091	0.177979
0.4	0.04375	0.125
0.4375	0.0622925	0.0837402
0.475	0.0854492	0.0527344
0.5125	0.113733	0.0305176
0.55	0.147656	0.015625
0.5875	0.187732	0.0065918
0.625	0.234473	0.00195312
0.6625	0.288391	0.000244141
0.7	0.35	0

**$ Sl   krg   krog
SLT

Sl	krg	krog
0.15	0.35	0
0.175	0.311149	0
0.2	0.275284	0
0.2375	0.226827	0.000244141
0.275	0.184419	0.00195312
0.3125	0.147656	0.0065918
0.35	0.116136	0.015625
0.3875	0.089454	0.0305176
0.425	0.0672081	0.0527344
0.4625	0.0489947	0.0837402
0.5	0.0344106	0.125
0.5375	0.0230524	0.177979
0.575	0.014517	0.244141
0.6125	0.00840102	0.324951
0.65	0.00430132	0.421875
0.6875	0.00181462	0.536377
0.725	0.000537665	0.669922
0.7625	6.72081e-005	0.823975
0.8	0	1

KRINTRP 2
DTRAPW -2
DTRAPN -2
**$ Sw   krw   krow
SWT

Sw	krw	krow
0.1	0	1
0.1375	8.54492e-005	0.823975
0.175	0.000683594	0.669922
0.2125	0.00230713	0.536377
0.25	0.00546875	0.421875
0.2875	0.0106812	0.324951
0.325	0.018457	0.244141
0.3625	0.0293091	0.177979
0.4	0.04375	0.125
0.4375	0.0622925	0.0837402
0.475	0.0854492	0.0527344
0.5125	0.113733	0.0305176
0.55	0.147656	0.015625
0.5875	0.187732	0.0065918

```
      0.625     0.234473  0.00195312
      0.6625    0.288391  0.000244141
       0.7      0.35         0
**$      Sl       krg        krog
SLT
       0.15      0.35         0
      0.175    0.311149       0
       0.2     0.275284       0
      0.2375   0.226827  0.000244141
      0.275    0.184419  0.00195312
      0.3125   0.147656  0.0065918
      0.35     0.116136  0.015625
      0.3875   0.089454  0.0305176
      0.425    0.0672081 0.0527344
      0.4625   0.0489947 0.0837402
       0.5     0.0344106  0.125
      0.5375   0.0230524  0.177979
      0.575    0.014517   0.244141
      0.6125   0.00840102 0.324951
      0.65     0.00430132 0.421875
      0.6875   0.00181462 0.536377
      0.725    0.000537665 0.669922
      0.7625  6.72081e-005 0.823975
       0.8       0          1
ADSCOMP 'Alkali' WATER
ADSTABLE
**$ Mole Fraction  Adsorbed moles per unit pore volume
**$ Mole Fraction  Adsorbed moles per unit pore volume
**$ Mole Fraction  Adsorbed moles per unit pore volume
          0                  0
        0.001              0.03004469631
ADMAXT 0.0300447
**$ Property: Rel Perm Set Number  Max: 2  Min: 1
KRTYPE KVAR
 2 1
INITIAL
VERTICAL DEPTH_AVE

INITREGION 1
REFPRES 500
REFDEPTH 4
NUMERICAL
DTMAX 1
DTMIN 0.05
RUN
DATE 2000 1 1
DTWELL 1
**$
**$
WELL 'Injector' FRAC 0.8
INJECTOR MOBWEIGHT EXPLICIT 'Injector'
INCOMP  WATER  0.  1.  0.  0.
TINJW  35.
PINJW  250.
OPERATE MAX  BHP  300.  CONT REPEAT
OPERATE MAX  BHW  0.00025  CONT REPEAT
**$       rad  geofac  wfrac  skin
GEOMETRY K  0.086  0.249  1.  0.
PERF GEOA 'Injector'
**$ UBA     ff  Status  Connection
  2 14 1  1.  OPEN   FLOW-FROM 'SURFACE'
**$
WELL 'Producer'
PRODUCER 'Producer'
OPERATE MIN  BHP  300.  CONT REPEAT
OPERATE MAX  STL  0.00025  CONT REPEAT
**$       rad  geofac  wfrac  skin
GEOMETRY K  0.086  0.249  1.  0.
PERF GEOA 'Producer'
**$ UBA     ff  Status  Connection
  25 14 1  1.  OPEN   FLOW-TO 'SURFACE'
DATE 2000 1  3.79999
DATE 2000 1  6.00000
DATE 2000 1 29.00000
**$
```

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WELL 'Injector' FRAC 0.8
INJECTOR MOBWEIGHT EXPLICIT 'Injector'
INCOMP WATER 1. 0. 0. 0.
TINJW 35.
PINJW 190.
OPERATE MAX BHP 300. CONT REPEAT
OPERATE MAX BHW 0.00025 CONT REPEAT
DATE 2000 2 7.00000
**$
WELL 'Injector' FRAC 0.8
INJECTOR MOBWEIGHT EXPLICIT 'Injector'
INCOMP WATER 0. 1. 0. 0.
TINJW 35.
PINJW 200.
OPERATE MAX BHP 300. CONT REPEAT
OPERATE MAX BHW 0.00025 CONT REPEAT
DATE 2000 3 1.00000
STOP
DATE 2000 4 1.00000
DATE 2001 1 1.00000
RESULTS RELPERMCORR NUMROCKTYPE 2
RESULTS RELPERMCORR CORRVALS 0.1 0.1 0.3 0.3 0.05 0.1 0.2 0.2
RESULTS RELPERMCORR CORRVALS 1 0.35 0.35 -99999 3 3 3 3
RESULTS RELPERMCORR CORRVALS_HONARPOUR -99999 -99999 -99999 -99999 -99999 -99999 -99999 -99999
RESULTS RELPERMCORR NOSWC false
RESULTS RELPERMCORR CALINDEX 3
RESULTS RELPERMCORR STOP
RESULTS RELPERMCORR NUMROCKTYPE 2
RESULTS RELPERMCORR NUMISET 2
RESULTS RELPERMCORR CORRVALS 0.1 0.1 0.3 0.3 0.05 0.1 0.2 0.2
RESULTS RELPERMCORR CORRVALS 1 0.35 0.35 -99999 3 3 3 3
RESULTS RELPERMCORR CORRVALS_HONARPOUR -99999 -99999 -99999 -99999 -99999 -99999 -99999 -99999
RESULTS RELPERMCORR NOSWC false
RESULTS RELPERMCORR CALINDEX 0
RESULTS RELPERMCORR STOP
RESULTS RELPERMCORR NUMROCKTYPE 1
RESULTS RELPERMCORR CORRVALS 0.1 0.1 0.3 0.3 0.1 0.2 0.1 0.2
RESULTS RELPERMCORR CORRVALS 1 0.35 1 -99999 3 3 3 3
RESULTS RELPERMCORR CORRVALS_HONARPOUR -99999 -99999 -99999 -99999 -99999 -99999 -99999 -99999
RESULTS RELPERMCORR NOSWC false
RESULTS RELPERMCORR CALINDEX 3
RESULTS RELPERMCORR STOP
RESULTS RELPERMCORR NUMROCKTYPE 1
RESULTS RELPERMCORR NUMISET 2
RESULTS RELPERMCORR CORRVALS 0.1 0.1 0.3 0.3 0.1 0.2 0.1 0.2
RESULTS RELPERMCORR CORRVALS 1 0.35 1 -99999 3 3 3 3
RESULTS RELPERMCORR CORRVALS_HONARPOUR -99999 -99999 -99999 -99999 -99999 -99999 -99999 -99999
RESULTS RELPERMCORR NOSWC false
RESULTS RELPERMCORR CALINDEX 0
RESULTS RELPERMCORR STOP

RESULTS SPEC 'Rel Perm Set Number'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'Layer 2 - Whole layer'
RESULTS SPEC REGIONTYPE 'REGION_LAYER'
RESULTS SPEC LAYERNUMB 2
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 1
RESULTS SPEC REGION 'Layer 1 - Whole layer'
RESULTS SPEC REGIONTYPE 'REGION_LAYER'
RESULTS SPEC LAYERNUMB 1
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 2
RESULTS SPEC STOP

RESULTS SPEC 'Permeability I'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'Layer 1 - Whole layer'
RESULTS SPEC REGIONTYPE 'REGION_LAYER'
RESULTS SPEC LAYERNUMB 1
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 4000
RESULTS SPEC REGION 'Layer 2 - Whole layer'
RESULTS SPEC REGIONTYPE 'REGION_LAYER'

RESULTS SPEC LAYERNUMB 2
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 16500
RESULTS SPEC STOP

RESULTS SPEC 'Permeability J'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC EQUALSI 0 1
RESULTS SPEC STOP

RESULTS SPEC 'Permeability K'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC EQUALSI 0 1
RESULTS SPEC STOP

RESULTS SPEC 'Porosity'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'Layer 1 - Whole layer'
RESULTS SPEC REGIONTYPE 'REGION_LAYER'
RESULTS SPEC LAYERNUMB 1
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 0.374
RESULTS SPEC REGION 'Layer 2 - Whole layer'
RESULTS SPEC REGIONTYPE 'REGION_LAYER'
RESULTS SPEC LAYERNUMB 2
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 0.374
RESULTS SPEC STOP

RESULTS SPEC 'Grid Thickness'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'Layer 1 - Whole layer'
RESULTS SPEC REGIONTYPE 'REGION_LAYER'
RESULTS SPEC LAYERNUMB 1
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 3
RESULTS SPEC REGION 'Layer 2 - Whole layer'
RESULTS SPEC REGIONTYPE 'REGION_LAYER'
RESULTS SPEC LAYERNUMB 2
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 1
RESULTS SPEC STOP