NEAR EAST UNIVERSITY

INSTITUTE OF GRADUATE STUDIES

DEPARTMENT OF PETROLEUM AND NATURAL GAS ENGINEERING

COMPARISON OF FOAM FLOODING AND WATER ALTERNATING GAS IN THE ASMARI RESERVOIR, IRAN

M.Sc. THESIS

Ikechukwu James NWANJA

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Approval

We certify that we have read the thesis submitted by Ikechukwu James NWANJA, titled "**Comparison of Foam Flooding and Water Alternating Gas in the Asmari Reservoir, Iran**" and that in combined opinion it is fully adequate, in scope and in quality, as a thesis for the degree of Master of Educational Sciences.

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Declaration

I hereby declare that all information, documents, analysis and results in this thesis have been collected and presented according to the academic rules and ethical guidelines of the Institute of Graduate Studies, Near East University. I also declare that as required by these rules and conduct, I have fully cited and referenced information and data that are not original to this study.

Ikechukwu James NWANJA

21/06/2022

Acknowledgments

Firstly, my profound respect and gratitude go to my thesis supervisor, Prof. Dr. Cavit Atalar for his continuous support, advice, and encouragement, during my research period, up until the ending period of my thesis. Also, I'm grateful for all his guidance and follow-up as my course advisor during my master's degree program. For the same cause, I would also like to appreciate Prof. Dr. Salih Saner, Assoc. Prof. Dr. Serhat Canbolat, Assit. Prof. Dr. Ali DENKER and Dr. Yashar Osgouei for their support and tutor both in class and online during my master's degree programme period, I really do appreciate you all for the knowledge imparted, only God in heaven can repay you for all your efforts.

Secondly, I would like to express my honest appreciation to MSc. Palang Moronke Guful, for her assistance and guidance during my thesis simulation, I really do appreciate the time, effort, and hard work put together to help me get my required results to be able to complete my thesis.

I want to also say a big thank you to my friends and classmates for their help and advice during my study period both in class and at home.

Finally, I would like to offer my deepest appreciation to my family, late father, mother, brothers, and sisters for their continued support and for their motivation, prayers, advice, and the fact that without their efforts, I wouldn't have accomplished this study.

Ikechukwu James NWANJA

Abstract

Comparison of Foam Flooding and Water Alternating Gas in the Asmari Reservoir, Iran

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Msc, Department of Petroleum and Natural Gas Engineering

June, 2022, 91 pages

On average, primary oil production can only produce between 25% - 30% of the initial oil in place, the other 65% - 70% which is essential should be a focus for EOR processes. The use of gas flooding as an EOR technique normally results in low sweep efficiency. The mobile instability of the gas, requires the use of foam for mobility control and to enhance the sweep efficiency.

The purpose of this project is to model foam flooding as an EOR method in the reservoir. The idea is to target mainly: the average pressure pore volume per sector, the oil recovery factor, the cumulative oil production, and the oil production rate. All the results were compared against gas flooding and natural depletion.

A commercial simulator, CMG STAR 2015.10 simulation model was used to create a model for this research. The model was created using the properties of the Asmari reservoirs, after which the simulator was then used to validate the simulation of foam injections and other simulation scenarios used for the project. Six different foam flooding scenarios were applied, and the concentration fraction of the surfactant used against water fraction for the different scenarios are 0.015, 0.1, 0.2, 0.3, 0.4, and 0.5.

Finally, simulated results such as oil recovery factor, cumulative oil production, oil production rate and so on, of the primary production scenario, the WAG scenario and the foam scenarios were all compared. Foam flooding had the highest oil recovery of 40.1% compared to WAG flooding of 25.4% and the no injection scenario with least oil recovery of 20.2%. Also, foam flooding gave an increased cumulative oil and oil production rate. An economic analysis process (Net Present Value) was also employed to check the economic effectiveness of the project which happened to be profitable.

***Keywords**:* Modelling, porous media, flow physics, EOR, foam flooding.

Özet

İran, Asmari Rezervuarında Köpük Taşması ve Su Alternatif Gazın Karşılaştırılması

NWANJA, Ikechukwu James

Yüksek Lisans, Petrol ve Doğal Gaz Mühendisliği Bölümü

Haziran, 2022, 91 sayfa

Ortalama olarak, birincil yağ üretimi, başlangıçtaki yağın yalnızca %25 - %30'unu yerinde üretebilir, diğer %65 - %70'i EOR süreçleri için bir odak noktası olmalıdır. Bir EOR tekniği olarak gaz taşması kullanımı normalde düşük tarama verimliliği ile sonuçlanır. Gazın mobil kararsızlığı, hareketlilik kontrolü ve petrol üretiminin süpürme verimliliğini.

Bu projenin amacı, rezervuarda bir EOR yöntemi olarak köpük taşmasını modellemektir. Buradaki fikir temel olarak şunları hedeflemektir: sektör başına ortalama basınçlı gözenek hacmi, petrol geri kazanım faktörü, kümülatif petrol üretimi ve petrol üretim oranı. Tüm sonuçlar gaz taşması ve doğal tükenme ile karşılaştırıldı.

Bu araştırma için bir model oluşturmak için ticari bir simülatör, CMG STAR 2015.10 simülasyon modeli kullanılmıştır. Model, Asmari rezervuarlarının özellikleri kullanılarak oluşturuldu, ardından simülatör, köpük enjeksiyonlarının simülasyonunu ve proje için kullanılan diğer simülasyon senaryolarını doğrulamak için kullanıldı. Altı farklı köpük taşması senaryosu uygulanmış ve farklı senaryolar için su fraksiyonuna karşı kullanılan yüzey aktif maddenin konsantrasyon fraksiyonu 0.015, 0.1, 0.2, 0.3, 0.4 ve 0.5'tir.

Son olarak, birincil üretim senaryosu, WAG senaryosu ve köpük senaryolarının petrol geri kazanım faktörü, kümülatif petrol üretimi, petrol üretim hızı vb. gibi simüle edilmiş sonuçları karşılaştırılmıştır. Köpük taşması, %25,4'lük WAG taşması ve %20,2'lik en az petrol geri kazanımı ile enjeksiyonsuz senaryo ile karşılaştırıldığında %40,1 ile en yüksek petrol geri kazanımına sahipti. Ayrıca, köpük taşması, artan bir kümülatif petrol ve petrol üretim oranı verdi. Karlı olan projenin ekonomik etkinliğini kontrol etmek için bir ekonomik analiz süreci (Net Bugünkü Değer) de kullanıldı.

Anahtar Kelimeler: Modelleme, gözenekli ortam, akış fiziği, EOR, köpük taşması.

Table of Contents

CHAPTER III

CHAPTER IV

CHAPTER V

CHAPTER VI

List of Tables

List of Figures

List of Abbreviations

ASF:	Alkaline-Surfactant-Foam
ASP:	Alkaline-Surfactant-Polymer
Bg:	Gas formation Volume Factor
Bo:	Oil Formation Volume Factor
CMC:	Critical Micelle Concentration
CMG:	Computer Modelling Group
CO_2:	Carbon dioxide Gas
DGOC:	Gas-Oil Contact Depth
Ea:	Area Sweep Efficiency
Ed:	Microscopic Displacement Efficiency
EOR:	Enhanced Oil Recovery
FAWAG:	Foam Assisted Water Alternating Gas
GOC:	Water Oil Contact
GOR:	Gas Oil Ratio
GUI:	Graphical User Interface
IFT:	Interfacial Tension
MMP:	Minimum Miscible Pressure
MRF:	Mobility Reduction Factor
N_2:	Nitrogen Gas
OOIP:	Original Oil in Place
P_c:	Capillary Pressure
POVO:	Pore Volume
PVT:	Pressure-Volume Temperature
RF:	Recovery Factor

SAG: Surfactant Alternating Gas

SCTR: Sector

Sl: Liquid Saturation

S_{oi}: Initial Oil Saturation

S_o: Oil Saturation

S_{or}: Residual Oil Saturation

STW: Surface Water Rate

S_{wr}: Residual Water Saturation

WAG: Water Alternating Gas

WOC: Water Oil Contact

CHAPTER I
Introduction

Gases like carbon dioxide (CO_2), nitrogen gas (N_2), and hydrocarbon gases, are utilized for gas-flooding and typically have less viscosity and less density when compared to both water and unrefined petroleum, which permits gas to start diverting through the high permeable or void zones and gravity overriding. Due to its nature, gas flooding typically has very low volumetric sweep efficiency, mostly conversant with an immiscible displacement phase. The primary benefit of gas is its efficient microscopic sweep prompting reduced saturation of oil in the voids occupied with water-flood. However, the main challenges with gas flooding are its poor sweep efficiency, because of that gas doesn't contact a huge part of oil. Consequently, the general oil recovery stays low. (Farajzadeh et al., 2012).

Due to the vast movement of gas, a control means is required which has prompted the utilization of foam for the improvement of oil recovery and enhanced production. Foam is utilized to work effectively by using a displacing fluid like surfactant, to sweep the reservoir efficiently and contact more oil to enable effective recovery.

Problem of Study

The various gases used for the gaseous flooding which is one of the Enhanced Oil Recovery (EOR) methods are: CO_2, N_2, and some hydrocarbon gases such as methane. Illustration of gas flooding against foam flooding is shown in Figure 1. This happens in light of the channelling (mainly heterogeneous reservoirs with increased permeability streaks during gas flow), viscous fingering that occurs when there is viscosity difference between the oil and gas, and gravity override because of the high-density log between oil and gas.

Due to the continuous process of gas infusion to help in further increasing of oil recovery and its extensive use all through the world, it is important to further develop clear efficiency of injected gas. There is extensive involvement in the use of foam in improved oil recovery method including immiscible or miscible gas displacement. Foaming of the gas that have been injected is an expected solution for the previously mentioned difficulties in the gas EOR technique, see Figure 1.

Foam can likewise be utilized to support thermal (for example steam) or chemical (for example alkaline-surfactant-polymer) EOR (Li et al., 2010).

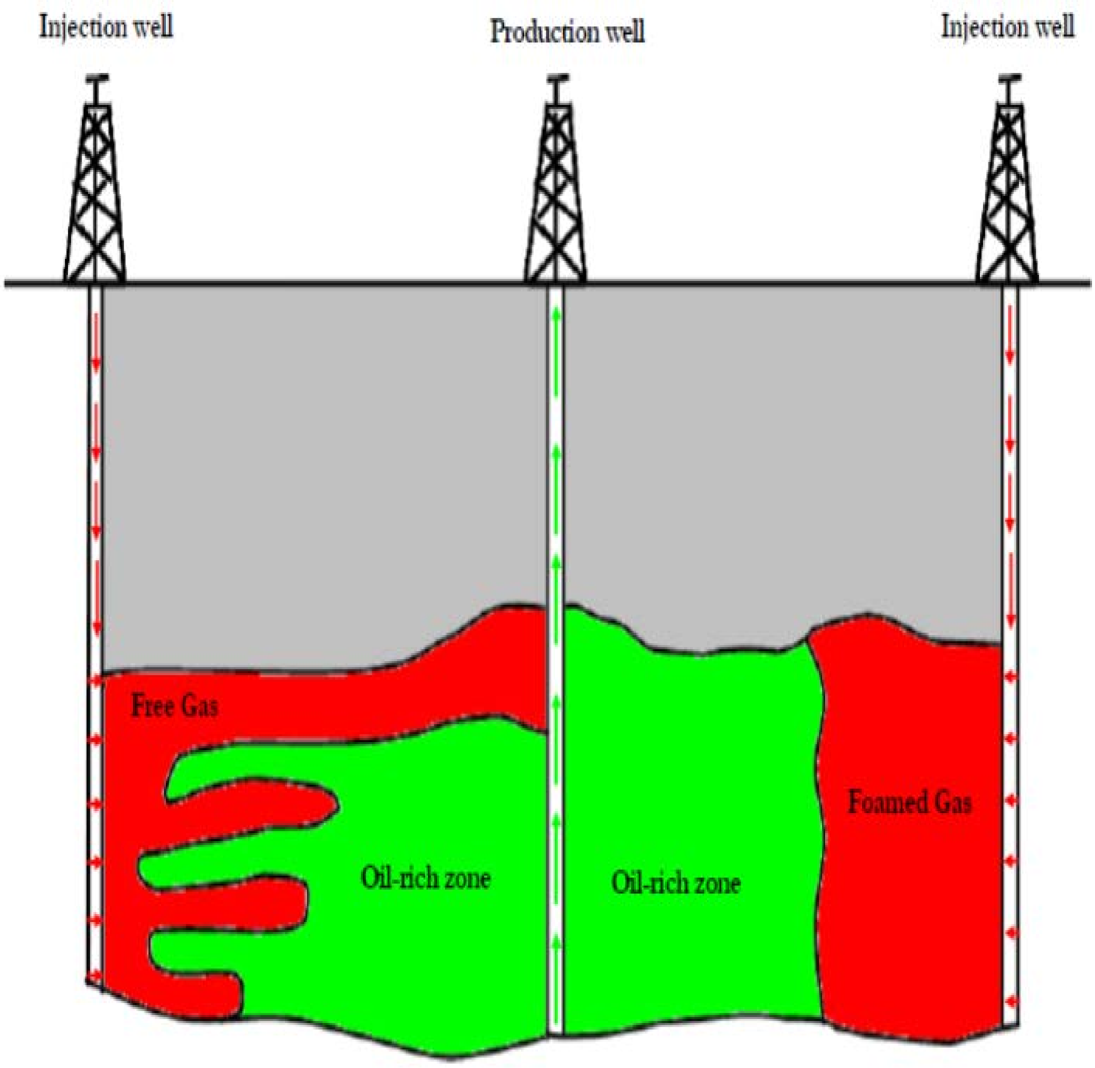

Figure 1.1. *Comparison of Gas Flooding versus Foam Flooding (Farajzadeh et al., 2012)*

Aim and Importance of the Study

The reason for this study is to:

- Investigate the foam injection application in oil reservoirs as an enhanced oil recovery method, and compare with gas injection and primary production.

- To examine the possible improvement of oil production rate and cumulative oil production through the use of foam as gas mobility reduction agent in the porous media, thereby improving oil recovery.

Limitation of the Study

The study is only limited to extensive literature research. The reservoir data used for the methodology were all gotten from literature, no laboratory experiment was conducted for this project. It implies therefore, that any variable or data used which have not been published publicly will only have to be estimated realistically to obtain the desired results.

Overview of Study

The following guidelines have been stated below to briefly discuss how this project was carried out:

Chapter 1 is the introduction which is an overview of the topic and the main problem of producing and recovering oil from reservoirs. The objectives of this study and its importance is also discussed in this chapter.

Chapter 2 includes literature review. A detailed literature study has been discussed in this chapter. Subjects related to this topic including EOR methods of foam flooding are discussed.

Chapter 3 describes the methodology applied. In this chapter, all the procedures involved to complete this project are discussed and mentioned in detail, and all the reservoir rock and fluid data are listed in addition to injection scenarios.

Chapter 4 shows all the results and discussion obtained in this study. The simulation results are all shown and analysed in this chapter.

Chapter 5 shows the economic analysis to check for the economic gas or loss of this study.

Chapter 6 illustrated the conclusions and recommendations. In this chapter, the conclusive remarks are listed in addition to some recommendations for further study.

CHAPTER II

Literature Review

This chapter of the project helps to illustrate the background and application of foam flooding in enhanced oil recovery and thus, was backed up by various articles and references to support the project and simulation involved in the process of foam injection. The description of the literature review is shown in the following sub-chapters.

Background of Foam for EOR Processes

Foam stability and mobility decrease attributes rely upon the type of rock and liquids and parameters used for the design process, for example, horizontal or vertical permeability, injection of foam type, and the mole ratio or size of the chemical used. The effects of these boundaries which enable the existence of the foam flooding method should be learned to decide its ideal potential for EOR. Most foam owes its presence to the presence of surfactants, that is to say, materials that are surface dynamic. They are aggregated at the connection point of a liquid and act to reduce the surface tension between interfaces. More importantly for preventing foam termination, they stabilize the thin fluid film against rupture. In aqueous foams, surfactant molecules are amphiphilic; their two sections are hydrophobic and hydrophilic so they can remain on the water surface. In void areas, foam bubbles whose shapes adjust to the solid matrix. Hirasaki (1989) expatiates that in a porous media, foam is "a means of displacement on gas with liquid to the level in which the liquid will be continuous phase while the gas phase is in discontinuous phase that is actualized by some tinny liquid films called lamellae."

Foam is characterized by higher viscosity when compared to gas with lesser viscosity and water (Zitha et al. 2006; Nguyen et al. 2007). This prompted the recommendation that in a chemical EOR process, foam can provide good sweep efficiency (Yan et al. 2006). Due to the increased volume gas in foam, it’s likewise viewed as a method for restricting the level of compounds employed for chemical enhanced oil recovery and in this way reducing the related costs. A few research facilities studies Liu et al. (2002), Kovscek and Bertin(2003), Li et al. (2008) and field trials Wang et al. (2011) proved also that foam could be a drive for a normal alkaline surfactant polymer (ASP) process.

Introducing Foam Flooding in Porous Media

The possibility of additional improvement in sweep efficiency can be guaranteed by foam, particularly in heterogeneous reservoirs, on the grounds that foam movement is lower (apparent viscosity is higher) in layers with increased permeability than in those of decreased permeability. The utilization of foam to further improve the sweep efficiency relies upon two foam attributes: First, is the increased resistance to flow that is related to foam and second is the high gas-liquid surface region. Generally, small quantities of an aqueous or water solution of a foaming agent need be used with somewhat a lot of gas or dense liquid. The gas that's dispersed in the fluid, produces a huge interfacial region and a huge volume of foam, subsequently extending the refusal to flow. If this resistance to flow is in the zones of the reservoir where the resistance is least, then the displacing fluid is compelled to flow through the regions of increased resistance, sweeping enormous parts of the reservoir and recovering bigger amounts of oil. Consequently, the utilization of foam further increases efficiency in terms of contacting and holding fluids. Special gases, like steam, carbon dioxide, and hydrocarbon gases are infused into oil reservoirs to basically improve the recovery of oil.

These gases are substantially with less density and less viscosity when compared to oil, they will generally escape through or migrate drastically to the highest part of the reservoir, while leaving a voluminous amount of the oil behind. Foam is capable of assisting these gases to massive sweep of the oil in the reservoirs more effectively (Ashoori et al., 2010).

Foams can be utilized in the following ways:

- Gas shut off utilizing foam
- To reduce gas mobility
- To reduce water cut

The moment the foam films are introduced in porous media, the flow of gas is stabilized. Therefore, the infused gas can as well reach the porous region that would have not been reached by gas in any case. Regardless of whether the oil recovery isn't increased, the cost of treatment of the gas will obviously be reduced, this effect occurs directly because the gas production/recycling volumes will reduce as well (Farajzadeh et al., 2012). The process of oil dispersal by foam (co-injection of surfactant and water) differs from that of only surfactant flooding due to the level of the gas phase present.

The effect of foam in oil recovery can be illustrated in three different ways compared to gas or water alternating gas flooding (Shrivastava et al., 1999):

- To stabilized the process of the displacement phase caused by gas, which will alter effectiveness if the viscosity of the displacing fluid is increased
- By obstructing the high-permeable swept zones and redirecting the fluid contacted into the zones that have not been swept; and
- The capillary force is also decreased which is possible by first decreasing the interfacial tension involved, and this is so because of the presence of the surfactant.

Notwithstanding these three significant mechanisms, in light of the fact that the gas has more contact with oil, the interfacial exchange of mass between gas and oil will likewise play a big part in shifting the oil in-place to a form of dissolution, viscosity decrease and swelling of oil (Zhu et al., 1998). Another potential advantage of involving foam is its effect in modifying profile properties, especially in heterogeneous systems. Foam has lower-level mobilizing displacing fluids in higher permeable layers and, therefore, will obstruct the flow in these layers for the sake of lower permeable layers (Farajzadeh et al., 2012).

An investigation of foam in media with pores should represent three stream systems experienced in field applications. Surface equipment and the main well, where flow of inertial flow may create bulk foam. Also, in the wellbore region where the flow rate and pressure gradient are high. Thirdly, information away from the injection well where flow rate and pressure gradient are very low (Rossen, 1995). Each flow mechanism brings about totally separate flow behaviours, thus the foam production mechanisms. It is usually acknowledged that lamella is made by using the three mechanisms inside porous media:

1. The mechanism that deals on production of stabilized liquid films or lenses in pore throats as gas push adjacent pore bodies through different throats. Although sometimes referred to as an ineffective foam, the abandoned process can make an enormous level of lamellae. Nevertheless, assuming that it is just a creation mechanism with lamellae, the gas will surely have a persistent medium for flow (Chen et al., 2004).

2. Lamella division is process whereby one lamella can make a two lamellae pattern. Each time an assembled lamella elapse through a void body, with more than

one pore throat abandoned with fluid or another lamella, the lamella should maybe break or extend a few open throats.

3. Snap-off is another mechanism for lamella occurrence: lamellas are with pore throat, if the capillary pressure made locally drops to maybe 50% of the capillary pressure of the throat. While it relies on the calculation of the throat and wettability of void medium, the capability of one-half is a standard value for three-dimensional pore geometries (Chen et al., 2004).

As an agent for movement control, the foam has the strength for processes in modern cycles which liquid injection into formation that are porous, EOR (Farajzadeh and Andrianov, 2012), matrix acidization treatments (Frenier, et al., 2007), gas spillage avoidance (Jikich and Smith, 1993), and debased spring remediation (Mulligan, 2009; Hirasaki et al., 1997).

Past examinations uncover that foam in place doesn't straightforwardly change relative permeability of water (Krw) or the viscosity of water (μw) (Jacobs and Bernard, 1965). Foam can incredibly stabilize the movement of gas in a porous phenomenon in two ways: decrease relative permeability in gas (Krg) and viscosity of gas (μg) (Falls et al., 1990). The reduction effect gas relative permeability is because of a huge compelling caught gas immersion made by foam. The stretching of lamellae with flowing phase along pore dividers drives extra protection from the stream of frothing air pockets contrasted with free gas that contains foam. The protection from foam moving along smooth surface as well as tightening influences adds to the expansion in obvious gas thickness in permeable media (Lawson, 1985).

The morphology of foam, particularly gas division and air pocket size, significantly affects foam versatility. Gas fragmentary stream in the foam move through permeable media is depicted as foam quality. It is observed that foam occurs in form of a coarse-foam which can also be termed fragile-foam, or a mid-strength state also known as powerful-foam state which rests on acquired pressure gradient for dependence (Kam and Rossen, 2003; Gauglitz and Kam, 2008, Friedmann, et al., 2002). Two stream exits in the systems in the solid foam state itself overwhelmed by various components. In the purported high-quality regime with the relatively increased gas fractional flow and decreased water saturation, the strength of foam lamellae is overwhelmed by the slender attraction's combination while in the weak quality regime with the relatively decreased gas fractional flow and increased-water saturation, foam movement is constrained by bubble catching and preparation (Wang and Rossen, 1999).

Foam mobility additionally relies upon the injection of gas and fluid velocities and/or pressure gradient. Trial results show that foam displays shear-thinning behaviours in void media, showing that an extension in gas velocity causes a lessening in foam's apparent viscosity. Genuinely, this process is because of both the yield stress and a shear-thinning drag on the moving bubbles (Nguyen et al., 2007). However, the rheology of foam obvious thickness at generally decreased gas stream rate was likewise announced at times in writing (Vassenden and Holt 2000). Additionally, it is observed where sudden foam revolution happens after expanding rate of injections to a velocity that is critical, or proportionally, surpassing the pressure gradient at minimum. The sudden decrease in gas movement additionally alludes to a foam change in weak state to the strong state (Nguyen et al., 2007).

Different elements, for example, surfactant type with concentration, brackish water saltiness, temperature, permeability at formation and variations of permeability, likewise assume a part in influencing foam movement in media of void state.

Effects of Process Variables on Foam Mobility Control

1. Permeability: Trial proof shows that foam decreases more gas movement in high permeability region than in low permeability region. Inspection was done in CO_2 relocation productivity with foaming concentrations in equal one-layered void medium with various permeabilities. It was observed that foam stretched the resistance to flow in upper permeability layers and shelved the injected CO_2 to downside permeable regions. Bertin et al. (1998) developed a heterogeneous penetrable region with penetrable sand encompassing a sandstone centre with a porousness differentiation of around 70:1. Without even a trace of foam, very minimal gas streamed into the decreased permeability sandstone core. Within sight of foam notwithstanding, a critical piece of infused gas was redirected. Nguyen et al. (2004) applied inspection on foam flow in heterogeneous cores using high-resolution computed tomography (CT) to check for pore-scale occurrence.

2. Injection Rate: To a degree, the gas and fluid injection rates decide the in-situ nature of foam during the interaction. Various examinations of foam quality have shown that foam displays versatility and decreased properties where the foam quality

is evaluated somewhere in the range of 45 and 95% (Chang, 1998). Over a froth nature of 95%, foam turns out to be too dry to be in any way steady; underneath 45% the foam loses its consistency and mirrors the conduct of flow of the comprising fluid stage. Studies have likewise proved that inside a specific scope of foam characteristics, the level of gas displacement into a water phase increase with the increase in the quality of foam.

3. Pressure: By and large, higher pressure favours foam dependability. Gases like CO_2 become denser at higher pressure, which improves the intermolecular relationship between the gas and the hydrophobic tails of the surfactant atoms. In a micromodel study, it was observed that clear efficiencies related to CO_2 foam flowing at a pressure just underneath the MMP were similarly all around as high as the efficiencies estimated at pressures well over the minimum miscibility pressure (MMP). In this way, it was presumed that the high scope efficiencies can be achieved utilizing a minimal measure of CO_2 assuming the foaming flood is led at the strain around MMP as opposed to a lot higher tension (Chang et al., 1994).

4. Temperature: An advantage of high-temperature arrangements is that the adsorption of surfactant in the development will be lower. The primary obstacles to the use of foams in deep, hot formations include the decrease of surfactant solvency for saltwater that regularly happens with expanding temperature, the thermal degradation of the surfactant that is upgraded with expanding temperature, the slight expansion in the interfacial pressure between the CO_2 and the saline solution, and decreased foam soundness, particularly at temperatures above 60°C that should be made up for by higher centralizations of surfactant (Liu et al., 2005).

5. Brine Salinity: In general, for a given surfactant, expanded salinity might quite often undermine foam or contingent upon the surfactant, make little difference. The impact of salinity on surfactants might be more articulated when the surfactant is broken down in the CO_2 instead of the brackish water. Such frameworks depend on low convergences of non-ionic surfactants, and the presence of disintegrated solids in the saline solution can decrease the dissolvability of the surfactant in the brine and drive it toward the CO_2 (Torino et al., 2010). The lower solvency of non-ionic surfactants in CO_2 is likewise proven by the lessening in cloud point temperature (the temperature at which a 1 wt. % arrangement of surfactant in a fluid stage displays a two-stage fluid way of behaving) when brine solutions are in compared to water solutions.

6. Oil: Different examiners propose that oil turns to barrier with foam at oil immersions above 6% to 19% by different centre flooding tests (Schramm, 1994). Among various systems of foam/oil communication proposed in the writing, (three primary reservoir model have arisen to endeavours participation of foam in stable form to oil: lying and penetrating coefficients, lamella number, and pseudo-emulsion film models Schramm, 1994; Manlowe and Radke, 1990). Estimations of the lying and penetrating coefficients of mass fluid have been utilized with some achievement (Kristiansen and Holt, 1992). However, these estimations do not show the direct pattern and relationship with foam strength in presence of oil (Schramm and Novosad, 1990; Manlowe and Radke, 1990). The lamella number is utilized to evaluate the perception of destabilization of foam by soaking up the emulsified oil into the foam lamellae (Schramm and Novosad, 1990). Pseudoemulsion film models express foam must steady within the sight of oil assuming the oil is wetted by the fluid stage, assuming oil and gas stages stay isolated by a film of the watery stage, the pseudo emulsion film (Manlowe and Radke, 1990). Albeit various models have been effectively applied to various circumstances, deciphering the central components of foam/oil association into by and large pertinent standards for field application stays troublesome.

7. Synthetic substances (Foam Agent)- Surfactant: Chou (1991) showed that the foam is promptly shaped during an uprooting of the fluid stage by the gas stage at whatever point the permeable layers is being soaked earlier with a solution filled with surfactant. The decrease of surfactant focuses beneath the critical micelle concentration (CMC) caused a shift of the change zone of the stream systems to bring down the upsides of the gas partial stream and slender tension (Alvarez et al., 1999). As it is referenced in the foam termination mechanisms, foam blend powers are conversely relative to surfactant fixation, accordingly the foam drops strength and the dispersing efficiency reduces as the surfactant concentration reduces.

8. Other Foam Agent: Guo et al. (2011) detailed the consequences of a research facility investigation of an alkaline surfactant foam (ASF) process. They planned the soluble surfactant framework to give great foam strength and bring down the capacity of the interfacial tension (IFT) as well as to characterized ideal salinity. They revealed the oil recuperation of ASF framework to the water overflowed centre was two times AS flood oil recuperation to water overwhelmed centre. The

components capable of higher oil recuperation were an arrangement of emulsified oil and versatile control of produced froth individually.

The adsorption is a function of the surfactant formulation, crude oil and brine compositions, rock mineralogy, and conditions of pressure and temperature of reservoir showed that the surfactant adsorption decreases with increasing the temperature, and increases with the presence of clays in the unconsolidated sandstone core between 50°C to 150°C. Grigg et al. (2007) proved that during the adsorption an element of the condition of the smooth motion get close by the other referenced boundaries, and the adsorption thickness on the stone is best portrayed as a component of the accessible surfactant volume in the framework instead of by the surfactant fixation.

He et al. (2010) momentarily presented profile adjustment of nitrogen foam flood to control the fingering and further developed oil recovery in a heterogeneous multi-facet sandstone reservoir pilot. A static foam test was utilized to gauge the effect of temperature, salinity, and oil saturation on nitrogen foam. The combination of an unknown surfactant and foam stabilizer was utilized to make nitrogen foam reasonable for the temperature of 50° C and salinity of under 10000 ppm. Additionally, a pilot test showed the rising of the reservoir pressures answers rapidly.

The Approach of Foam Flow and Its Concept in Porous Media

The foam process is a possible answer for tackling a normal decrease of gas movement; the segregation process of the gas and the unstable displacement of viscous fluids reoccurrence in normal gas flooding as well as water alternating gas. (Wang and Li, 2016). Foam can handle the gas mobility appropriately, by stopping a lot of gaseous phases that occurs in the void media and the viscous phase of the gas (Hirasaki and Lawson, 1985). Wang and Li additionally showed the process of mobility reduction using SAG (surfactant alternating gas), which was a lot improved than using WAG process, while fluid movement surfactant arrangement and another hydrocarbon gas like propane on the other hand by glass bead pack. This study likewise saw that higher SAG proportion brought about more prominent versatility decrease. (Wang and Li, 2016). Froth additionally decreases the general penetrability of gas definitely. Foam process for gas portability decrease at first time of introduction. This reduction is shown by mobility reduction factor (MRF) which is the ratio of movement of foam separated by gas mobility. The MRF can be stated mathematically by dividing the drop of pressure of foam flooding by the pressure drop of gas flooding (Nguyen et al., 2000).

Another concept is the foam displacement model with Radke (1993) who integrated population balance into regular summed up Darcy's regulation models utilizing exploratory relationships with depict bubbles age and blend. Utilizing a traditional test system Islam and Farouq-Ali et al (1990) created models in light of the idea of restricting slim strain, implying that foam can be steady provided that fine tension doesn't surpass a basic worth permitting the presence of a steady slight film. In this methodology, restricting slim strain gives the comparing immersion, and afterward an arrangement of conditions can be addressed utilizing the fragmentary stream hypothesis. An elective method for reenacting foam stream in penetrable media is to consider relative permeability of gas decrease because of froth lamellae stoppage. In this methodology, relative permeability of gas can be assessed utilizing the permeability hypothesis (Chou, 1990).

Techniques for Modelling Foam Flow

ECLIPSE, and CMG are basically the two major reservoir simulators to utilize the compositional dealings with the code-material equilibrium satisfied, using the known equation for mass-conservation and the Darcy’s law equation (momentum balance). Foam methods are categorized into local- equilibrium models, population-balance models, and other approaches displayed in Figure 2.1.

In 1990, Chang and others developed a model to lay out a connection around the mobility of gas and fractional flow of gas, interstitial gas velocity, surfactant fixation, and stage immersions.

In 1997, Robert and Mack utilized a model to depict foam conduct which supports matrix acidizing phase. In this model, the gradient of the pressure is supported by the foam infusion constraints conditions, which rely upon surfactant focus, velocity and quality of foam, temperature, and permeability of rock. Notwithstanding, the numerical subtleties of these connections are not tended to. All things considered, various upsides of the strain angle estimated tentatively for various foam injection reservoir conditions were utilized in their recreation (Robert and Mack, 1997).

Mohammadi et al. (1995) illustrate the impact of surfactant and tension slope on foam conduct in void media. This model is strictly to modify the relative permeability of gas with a portability decrease factor. The surfactant fixation is standardized with a most extreme surfactant focus, and the tension slope is standardized on that without a trace of foam.

The foam model utilized in the STARS test system was created by Computer Modelling Group (Computer Modelling Group, 2011). The focus on this model is to proposes a means of portability decrease factor. The versatility decrease factor is made out of seven capacities, from F1 through F7, to address various elements that control foam security in porous media.

Zanganeh et al. (2011, 2012, 2013) have proposed some modifications to the STARS froth model. They called attention about the foam injection that was not totally obliterated at remaining saturation of water (S_{wr}) with the first F7 work in STARS Model which was a relic since foam ought to implode as the saturation of water approaches S_{wr} and the capillary pressure (P_c) approaches infinity (Zanganeh et al., 2011). Hence, another F7 work indicated as F_w in STARS Model is defined to guarantee that F7 equals zero when S_w is equivalent to S_{wr}. They likewise concentrated on a case in which foam is declined at reduced water saturation (Swr is not as much as/equivalents to S_w not as much as/equivalents to fmdry).

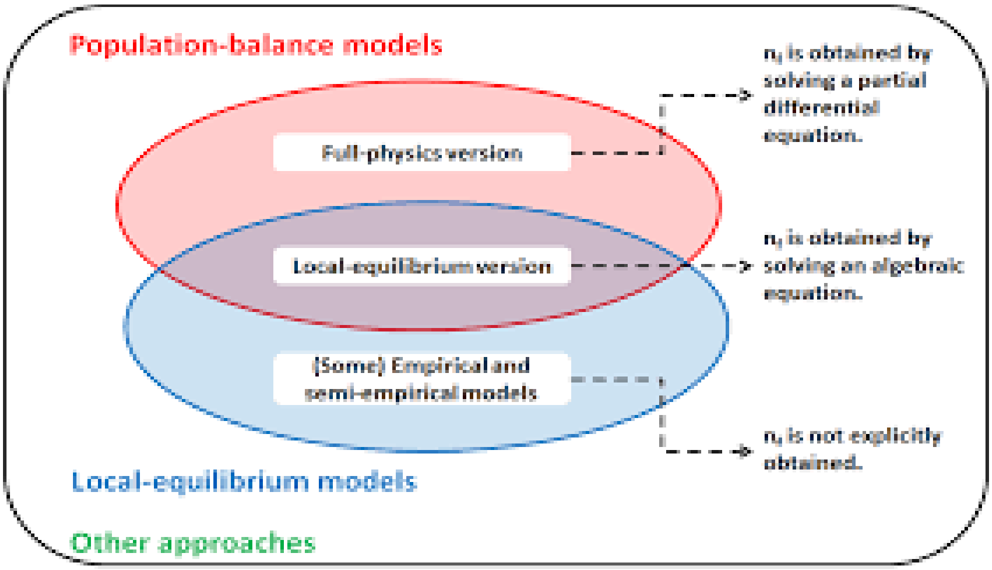

Figure 2.1. *Different Techniques for Modeling Foam Flow in Porous Media. (Chen et al., 2010)*

Reservoir Simulators Comparison in Mechanistic and Empirical Foam Modeling

Ma et al. (2015) formulated different strategies to the process of foam within void media. Foam was classified as displaying processes into mechanistic models and empirical models. The population balance models which is also known as mechanistic models were categorized into two types; (1) full physics version and local equilibrium version. The primary contrast between these two models is the style that they get foam surface. The foam flow displaying in three repository test systems (ECLIPSE, UTCHEM and CMG-STARS) was portrayed and analysed. UTCHEM and CMG-STARS utilize both unthinking and exact models. Obscure, nonetheless, is just furnished with an exact model that apparently looks almost like the CMG-STARS model, while the UTCHEM uses the Chen et al. (2010) model for mechanistic reproduction and the Rossen et al. (1999) model as the empirical methodology. In CMG-STARS, the model depends on the response energy of stages and the experimental model is depicted in the "Empirical Modeling" segment. Hematpur et al. (2018) looked at three experimental and robotic models in light of their fitting capacity with trial information. UTCHEM, CMG-STARS and Vassenden and Holt (2000) models were looked at for the certain surface methodology. In view of their recreations, both UTCHEM and CMG-STARS could anticipate trial information extraordinarily. Nonetheless, the Vassenden model couldn't match the bad quality district until the speed term of the model was modified. For mechanistic displaying, Chen et al. (2010) and Kam (2008), UTCHEM models were used. Each of the three models showed legitimate coordinates with the exploratory information.

Modeling of Foam Flow using Mechanistic Approach for Porous Media in the Presence of Oil

The population balance models (mechanistic models) approach requires numerous calculations to determine the foam origin and mixture rate and also the foam surface. Then again, the observational models work out the versatility decrease factor without computing the froth surface and froth blend and age on the grounds that the nearby balance idea (equivalent qualities for froth age and mixture) is looked into in the robotic methodology. The idea was proven otherwise that Implicit-Texture (IT) characteristics will not be sufficient in reaching out the fundamental material science of foam in porous media. Their consistent state trial information showed that both IT displays and PB (population balance) models at nearby harmony similarly honour the physical science of foam conduct in permeable media. In any case, the evolution of mechanistic model is better in addressing sudden heterogeneities that contort the neighbourhood harmony, shock foams, and the entry locale (Lotfollahi et al., 2016). As it can be seen in Figure 2.2, all mechanistic models tackle two issues: acquiring the foam surface and then to substitute the foam movement.

Obtaining models parameters for simulator models, most authors have not mentioned specific method to obtain model's parameters for mechanistic models because there are several parameters which cannot be derived directly from experimental data. They accepted a few qualities as fitting boundaries or played out the set of experiences matching through mathematical test system to acquire models' area boundaries (Afsharpoor et al., 2010). In any case, different dealings been directed to introduce a strategy to acquire boundaries for exact models which are used in supply test systems (Boeije, 2015). The majority of these techniques just focus on boundaries of dry-out (water saturation) work in mobility reduction factor and ignoring oil, surfactant, and salinity functions.

Foam surface (or air pocket thickness), characterized or known to be the quantity of lamellae per unit volume of the gas stage, is contrarily relative to the air pocket size. Bubble populace balance froth models recreate froth stream from the primary rule of physical science by following the progressions in bubble thickness in situ in the repository through expressly characterized froth age and blend capacities (Lotfollahi et al., 2016; Farajzadeh et al. 2016). In the midst of wide range of numerical plans proposed in the past by different examination bunches as per their own self-reliable translation of material science, Zitha and Du, (2010), very limited attempts have been made to tackle the problem in the presence of oil (Myers and Radke, 2000).

Complex foam oil connections were accounted for in the writing. Existing theories include surfactant depletion and local fluctuation for the film thickness entering/spreading/connecting coefficients in light of interfacial pressures between oil, gas and fluid stages oil emulsification and lamella digit for mass foam (Schramm and Novosad, 1992), and pseudo-emulsion film hairlike tension (Myers and Radke, 2000). Itemized surveys on the material science and theory behind these instruments are accessible somewhere else (Farajzade and Andrianov, 2012).

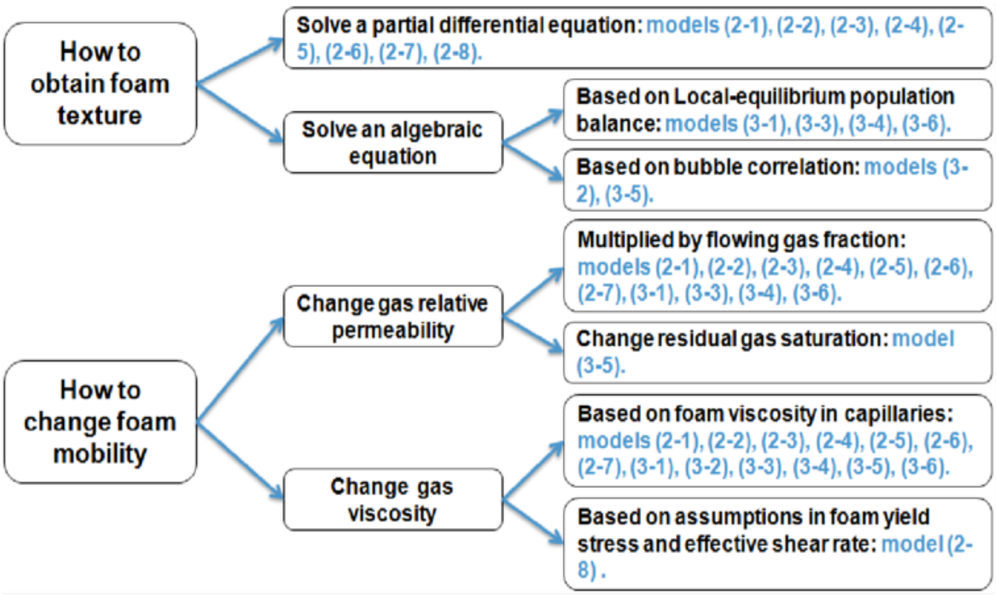

Figure 2.2. *A Modeling Approaches in Mechanistic Models. (Ma et al, 2015)*

Population Model for Foam Flow in Porous Media using Random Bubble

The population balance approach also called the mechanistic model process, was first presented by Patzek (1988) and further by Kovscek et al. (1994) depends on the reason that foam portability relies upon the level of foaming of the gas-fluid blend, as estimated by the air pocket thickness n (number of air pockets per unit gas volume). As for the pre-investigations of Bernard et al. (1980); his own model divides gas injection into flowing and caught parts.

A progression of foam concentrates on utilizing X-beam processed tomography acted in our gathering showed no noticeable gas catching during transitioning foam movement (Nguyen, 2004). Foam movement appropriation planned to utilize a unique X-ray tracker procedure during consistent state foam flows Nguyen et al. (2007) showed an expansive variety, in order for the foam to seem caught in pieces of the flow area where the portability of foam is tiny. Nonetheless, such caught froth could as a matter of fact be gradually moving; plus, the division among versatile and fixed froth isn't well defined, and shifts in that frame of mind of time.

The Modelling of Foam in Porous Media in Presence and Absence of Oil

Simjoo and Zitha (2013), concentrated on the transient foam stream in a porous media without oil by utilizing the stochastic air pocket populace model. The reason for this model is that foam stream in void media is a perplexing liquid and air pocket age is a stochastic cycle. They got a decent match between the mathematically determined liquid immersion and strain information from the ones gotten from the examinations at which foam was gotten by co-injecting nitrogen and alpha-olefin sulfonate surfactant in Bentheimer sandstone. Boeije et al. (2015), introduced a process to work out the boundaries of the saturation of water dependent work and furthermore shear-diminishing capacity beginning from foam pressure slope information at reduced and improved-quality systems at fixed complete speed. This strategy can give the underlying evaluations to the froth model actual boundaries to be utilized in the repository test system for froth reproduction at a huge scope. Mama et al. (2013), assessed the boundaries of the water-immersion subordinate capacity to portray the dry-out impact without a trace of the oil stage. In their methodology, shear-slim conduct with a faded quality system of foam flooding was disregarded.

The impact of the penetrability variety of void media on the way of behaving of foam stream without a trace of oil was concentrated tentatively and hypothetically by (Kepetas et al., 2015). They showed penetrability can altogether affect the basic froth immersion with the end goal that the higher porousness layer displays lower basic water saturation (S_w). Nonetheless, they didn't think of a powerful connection between the porousness and progress unexpectedness normal for the model associated with the LE-IT foam model for the foam quality-filter tests at various foam stream system. Jones et al. (2016), joined the center flood after effects of foam flooding that has no oil, for various surfactant fixation by the LE-IT foam model. To have the option to anticipate the impact of the focus on the froth obvious consistency, they expand the model to such an extent that five froth boundaries change with surfactant fixation.

Lotfollahi et al. (2015) introduced a mathematical model to recreate foam flooding within the sight of the microemulsion stage. Notwithstanding, in this work no approval was given regarding the trial information. Likewise, an application of the dark oil model framework combined with the miniature emulsion stage conduct for recreation of low-pressure gas flooding. They utilized the interfacial strain (IFT) decrease as the fundamental component to control the steady oil recuperation despite the fact that this system in foam flooding doesn't necessarily in all cases work. Along these lines, the vast majority of intended works in place have displayed froth stream in penetrable void either in the nonappearance or the presence of oleic stage. Then again, numerous trial information of foam flooding processes for EOR application have been accounted for as displayed in Table 2.1.

Table 2.1.

The Experimental Procedures Generally used for the Foam Flooding Experiments with and without Oil (Simjoo and Zitha, 2013).

Injection step sequence	Flowrate (cm^3/min)	Back pressure (bar)	Injection direction
Foam flooding without oil			
CO_2 flushing to remove air	>20	5	Downward
Core saturation with brine	1.0-6.0	25	Upward
Surfactant pre-flush	1	20	Upward
Foam flooding (co-injection)	1.1	20	Upward
Foam flooding with residual oil			
CO_2 flushing to remove air	>20	5	Downward
Core saturation with brine	1.0-6.0	25	Upward
Oil injection (drainage)	0.5	5	Downward
Water flooding (imbition)	0.5	5	Upward
Surfactant pre-flush	1	20	Upward
Foam flooding (co-injection)	1.0	20	Downward

Critical Concentration of Foam and Enhanced Oil Recovery

Foams act principally on further developing the compass effectiveness, both viscous fingering of injection water as the actual blockage of high permeability channels accordingly, the foam force the injected fluid to contact areas not swept. Foam has been generally utilized in EOR processes in the oil industry for many years (Mayberry et al., 2008). There are two principal components by which the utilization of foam in the oil recovery process becomes significant. The first is that it permits to stabilise of the movement of the infused gas. That is, the gas infusion applications or methods of exchanging injection of water and gas in timed period (WAG) in the reservoir, the high mobility and lower density of the gas, it streams in channels through zones of higher permeability, and afterward to the highest point of the supply by gravity isolation. Hence, the froth has been utilized to control the versatility of gas further developing the breadth productivity by expanding the compelling consistency and the diminishing in relative porousness of gas. A second use of the foam is in charge of the gas coning, which happens while reaching the oil/gas arrives at the creation well, and thus the gas, which is more versatile, begins to be delivered rather than oil. Froth is infused to be stored on top of the delivering development, lessening the convergence of gas into the creative well, (Vikingstad, 2006). The foam is generated at the surface facilities, injecting gas through the mixture of aqueous phase/ surfactant. It delivers a steady scattering of gas rises in the fluid. The froth can be conveyed with a gas stream into the repository. As remarked, the foam acts decreasing the gas portability.

According to Al-Mossawy and others in 2011, the elaboration on foam injection project requires broad research center examinations and complex investigations of supplies re-enactment. The working boundaries that should be researched by lab tests are the definition and the surfactant fixation, the tension inclination expected to settle the progression of froth, and the infusion technique might be a co-infusion of a surfactant arrangement and gas, or a substituting infusion of gas with a surfactant arrangement. One more significant use of the foam is presently natural recovery, as in defiled springs in which the froth dislodges contaminating substances. The froth can likewise be utilized for firefighting through its capacity to go about as a boundary between the air and fuel (Vikingstad, 2006). It can likewise be utilized in penetrating liquids to grease up the bore and convey cuttings to the surface. The penetrating activities with foam-based liquids permit the use of low tensions in the arrangement, which is significant in low strain supplies (Han, 2004).

Enhancing Foam Stability

In EOR applications, persistent recovery of foam lamellae in porous media is a fundamental instrument for foam transport (Singh and Mohanty, 2016). Besides, the created lamellae ought to be dependable and ought to have the option to make an interpretation of from one pore to another without break (Zhu et al., 2004; Andrianov et al., 2012). In any case, balancing out species have a high inclination to corrupt in the repository within the recovery of oil and at increased saltiness and temperatures causing surfactant, polymer, and protein upgraded froths to become unsound and may bring about harming the arrangement. The possibility of particles balancing out foam and emulsions was first portrayed by Ramsden (1903) and Pickering (1907). As of late, nanotechnology has acquired a ton of consideration for giving expected arrangements or enhancements to challenges in different oilfield regions including detecting or imaging, gas portability control, penetrating and finishing, delivered liquid treatment, among different regions (Lau et al., 2017). Additionally, the utilization of strong nanoparticles as settling species has been proposed for EOR applications (Yousif et al., 2018). Attributable to their minuscule size, nanoparticles have high adsorption partiality that permits them to decrease fluid seepage, gas dispersion, and the pace of film burst and air pockets coarsening, eventually improving foam steadiness at unforgiving supply conditions (Yu et al., 2012). Yekeen et al. (2018), reports that the most by and large utilized nanoparticles with the end goal of foam adjustment are silica nanoparticles. Nanoparticles can be utilized as an option for a surfactant or blended in with surfactants to balance out froths (Yousef et al., 2018). As indicated by Almahfood and Bai (2018), the communications among surfactants and nanoparticles can prompt a significant change in the surface action of surfactants.

Surfactants as a Foam Component for Enhanced Oil Recovery in an Oil-Wet Reservoir

Different surfactant-screening techniques can be found in the literature, going from mass froth soundness tests (Vikingstad et al., 2005) to estimating a surfactant's capacity to change boundaries like interfacial pressure and rock wettability to estimating foaming execution in model permeable media that can be flushed and reused rapidly (Chen and Mohanty, 2014).

A foam segment device can be utilized to subjectively survey other frothing execution boundaries, like foam stability, by deciding the half-existence of a created foam section, or foam strength (or surface) through visual air pocket size investigation (Singh and Mohanty, 2014). Nonetheless, a surfactant's foaming performance in bulk is not illustrative of its exhibition inside permeable media.

Conflicting results can be found in the writing: Tsau and Grigg (1997), found a fair connection between frothing in mass and permeable media, while Kam and Rossen (2003), did not find great arrangement between the two kinds of tests. One of the first studies that comprises both the bulk and porous media of foam-screening experiments was that by Duerksen (1986), who directed tests on different surfactants and zeroed in on their warm dependability. Chabert et al. (2012) contrived a strategy for quick estimation of interfacial pressure and froth soundness in mass for an enormous number of surfactant combinations.

Field Application of Foam Flooding for EOR

There are different examples of foam's field application for EOR, for example, Kern River and Midway-Sunset fields in the US Hirasaki (1989); Friedmann et al. (1994), Snorre field in Norway, Tore et al. (2002); Aarra et al. (2002), Oseburg field in Norway, Aarra and Skauge (1994). These implementations result in a significant increment of recovery factor, for example in San Andres utilizing foam helped process further develop an oil production by 10%-30%. The method of foam application would rely upon the nature and source of the problem. In the field application, foam is injected in different ways which are more diverse compared to that in the laboratory (Turta and Singhal, 2002).

Skauge et al. (2002), and Blaker et al. (2002) introduced insights concerning the world's biggest use of foam in the oil industry: Foam assisted WAG (FAWAG) project in Snorre Field. The in-depth mobility control foams were utilized effectively and productively to recover significant measures of oil at Snorre Field in the North Sea. Two foam pilot projects have been directed in this field. One venture was to lessen the GOR at a creation well and the subsequent undertaking was to control the gas mobility in the depth of the reservoir by FAWAG. Both of the tasks were effective in further improvement of the oil recovery. For the FAWAG project, the field application began following two years of arranging and numerous many years of active research (Blaker et al., 1999).

CHAPTER III
Methodology

This project was done using the numerical simulation modelling method and the particular type used was CMG-STARS software, which is a thermal compositional reservoir simulator, also used for simulating other methods of EOR, like foam flooding which is a case study for this work. This chapter talks about firstly, the simulation process of the reservoir. These are the reservoir description process, the definition of reservoir components, the rock fluid analysis, the fluid contact and initialization, numerical placement, and the creation and completion of the production and injection well. Secondly, the different scenarios processes for foam flooding, gas flooding and primary production were analysed to get the best result for oil recovery and production.

Reservoir Simulation Model

The model was created and run with CMG-STARS 2015.10, for 12 years from the 1st of January, 2010 to the 10th of February, 2022. The reservoir fluid is a light oil with API gravity of 29°, a viscosity of 1.19 cp, and a GOR of 546 Scf/Stb. The reservoir has a bubble point pressure of 2,155 psi with an initial pressure of 3840 psi. Four injectors and two producers were used in the model. The producer has a producing BHP of 1000psia while the injectors have a maximum BHP of 11,000psia. For the producer constraints, a maximum surface oil production rate of 10,000 STB/day was imputed, while for the injectors, maximum surface gas injection rate of 1000 MScf/day was used. The other reservoir properties used for the simulation model are shown in Table 3.1

Reservoir Description

The reservoir was created with a 24×12× 9 cartesian grid making a total of 2,592 grid cells. The hydrocarbon-bearing reservoir covers an area of 968,800,000 sq. ft, the reservoir width was calculated to be 31,125.5ft. I-block width of 1296.9ft and J-block width of 2,593ft was used for both I and J directions.

By populating the model with average petrophysical properties, the reservoir array properties were defined, which included the depth to the top of the reservoir of 7100ft, a reservoir thickness of 200ft, which was divided between the 9 layers of the reservoir, the whole grid array properties that include porosity of 20%, horizontal permeabilities of 150md, and vertical permeability of 133.5md (0.89 of horizontal permeabilities).

Table 3.1.

Reservoir *Data Used in the Model (Alizadeh, 2007)*

Properties (Units)	Values
Reservoir Area (Sq.ft)	9.688e+8
Reservoir Thickness (ft)	200
Vertical Permeability (md)	133.5
Horizontal Permeability (md)	200
Porosity (%)	20
Reservoir Temperature (F)	140
Initial Pressure (Psi)	3490
Reference Depth (ft)	7100
API Gravity (API)	29
Water Density (Ib/ft3)	69.23
Gas Density (Ib/ft3)	0.068
Oil Saturation (%)	70
Oil Production Rate (STB/day)	1e+4
Irreducible Oil Saturation (%)	40
Gas Injection (ft^3/Day)	1e+6

A 3D model of the reservoir simulation showing all cells both horizontal and vertical layers were created as shown in Figure 1. Each colour represents a different layer and depth. Within the reservoir, the four injection wells are positioned in the far corners of the reservoir while two producer wells are centred within the injection wells. All the wells were perforated within a range of grid blocks between layers one to nine as shown in Figure 3.1.

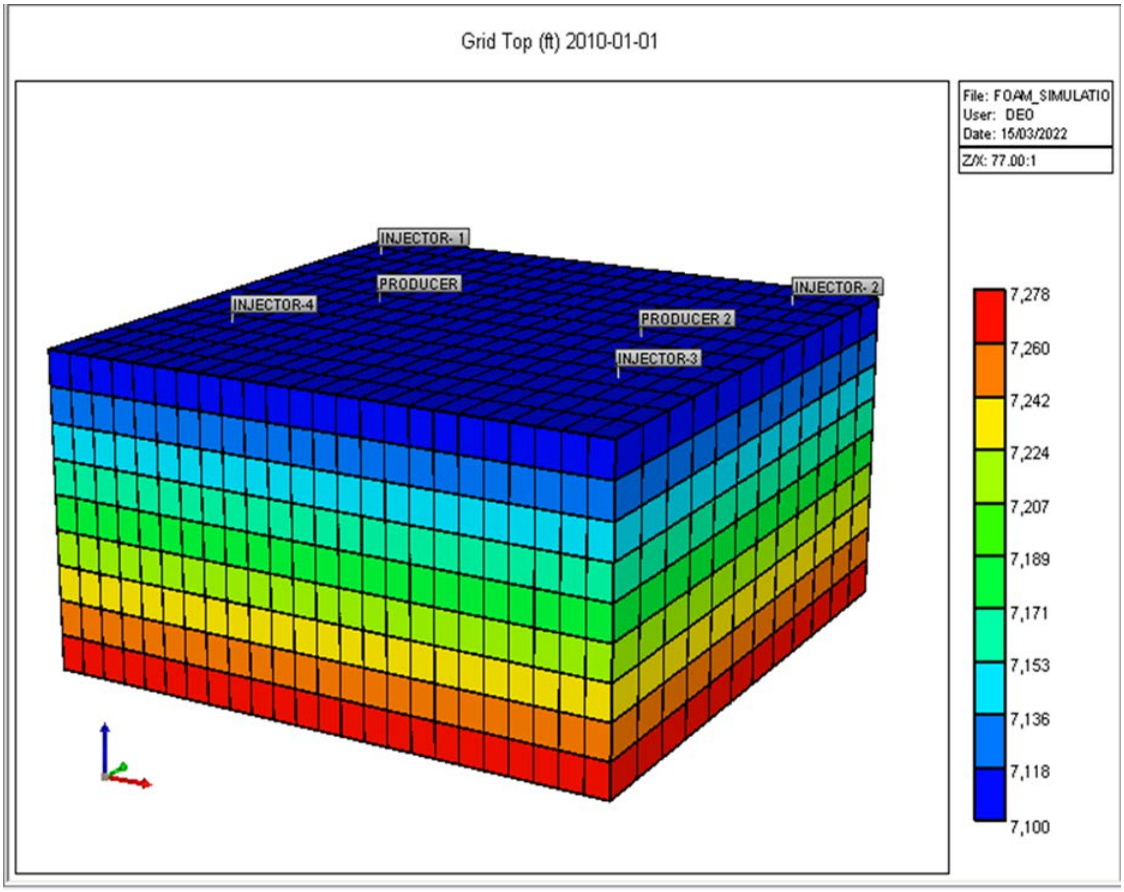

Figure 3.1. *3D Reservoir Model (generated by CMG Builder, 2015)*

Components of the Reservoir

This section of the model involves using the relevant correlations to determine pressure, volume, and temperature properties. The PVT tables were gotten from the PVT graphical user interface (GUI) in the model. The tools used for generating the PVT tables are reservoir temperature of 140 F, maximum pressure of 3840 psi, stock tank oil gravity (API) of 29°, gas gravity (Air=1) of 0.068 1b/ft^3, water salinity of 10,000, and water density of 69.23 Ib/ft^3. To get a matched column, a bubble point pressure of 2,155 psi and an increased viscosity of 120 cp were used. Finally, the correlation was used to generate plots for the water to oil to gas system, which enabled the refined PVT properties of the reservoir such as formation volume factor as a function of pressure, solution gas-oil ratio as a function of pressure, and viscosity of the water as shown in the following figures below.

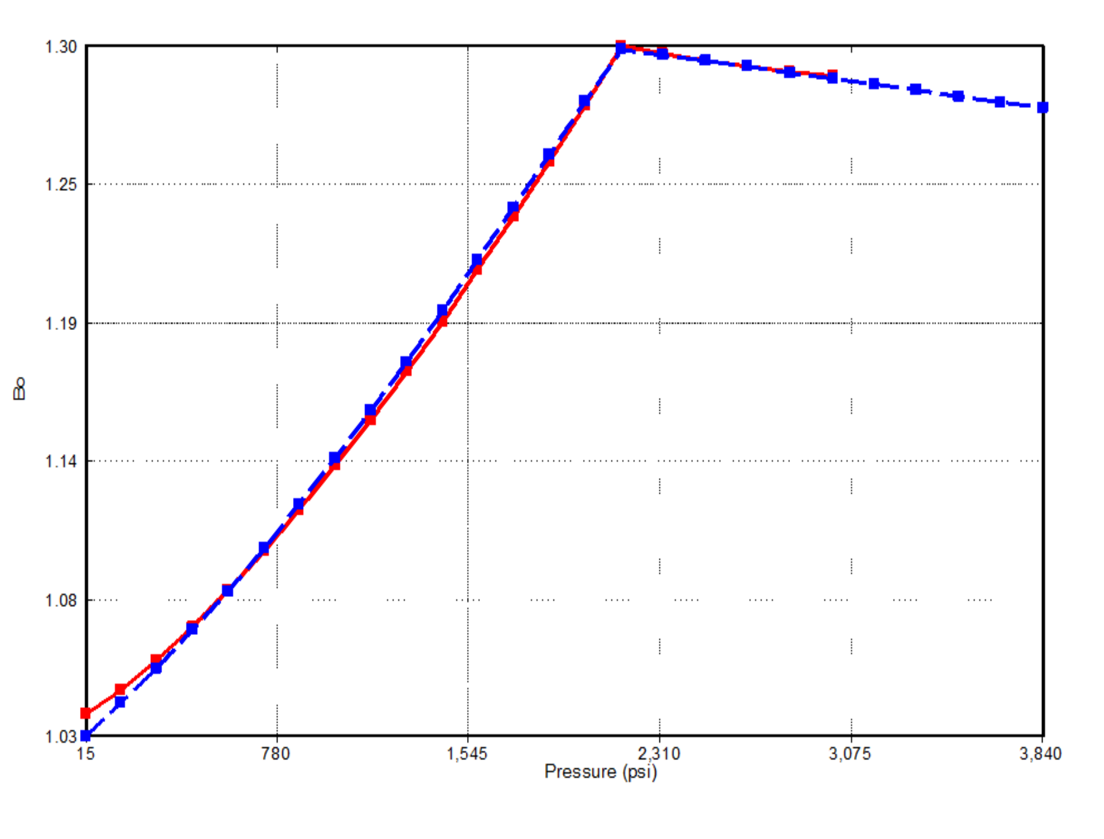

Figure 3.2. *Oil Formation Volume Factor (Bo) versus Pressure (generated by CMG Builder, 2015)*

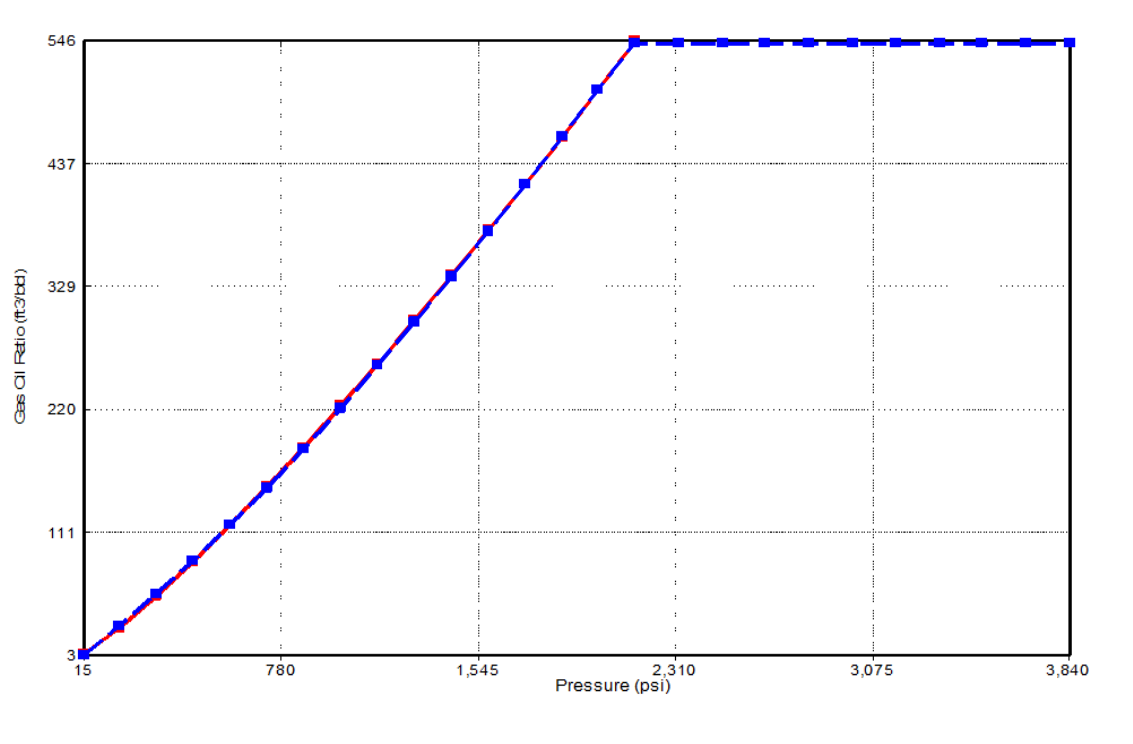

Figure 3.3. *Gas Oil Ratio versus Pressure (generated by CMG Builder, 2015)*

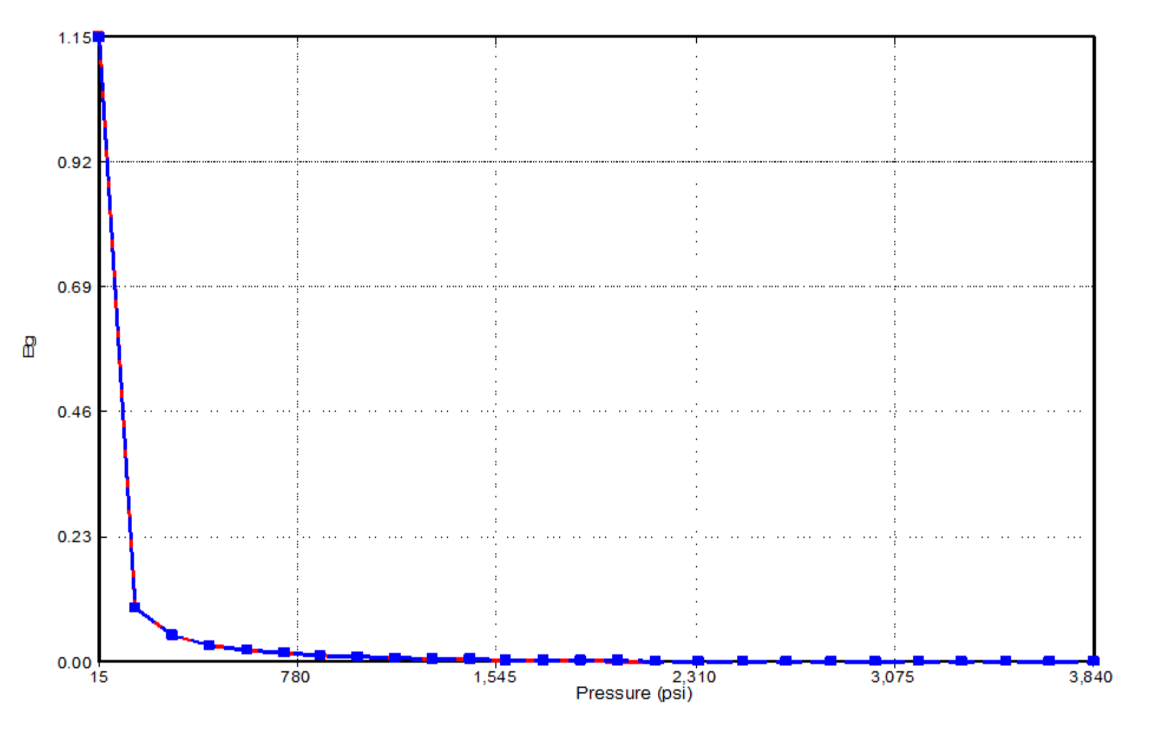

Figure 3.4. *Gas Formation Volume Factor (Bg) versus Pressure (generated by CMG Builder, 2015)*

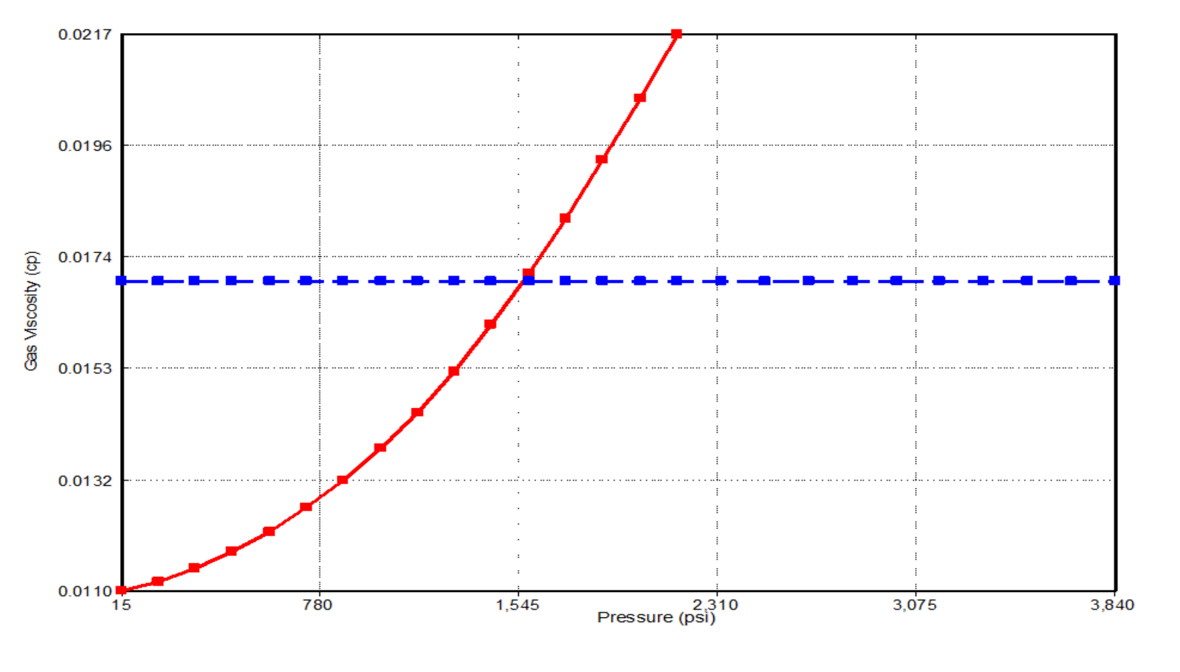

Figure 3.5. *Gas Viscosity as a Function of Pressure (generated by CMG Builder, 2015)*

Rock Fluid Interaction Data

Mohammadi (1978), illustrated the Asmari reservoir and splitted it into 8 different zones. Zones 1, 6, and 8 carry carbonated rocks whereas Zones 2, 3, 4, and 5 carry sandstone, and Zone 7 was plainly sandy. Alizadeh (2005) in his research, listed the thickness of all the zones as follows:

Zone 1: 59 ft

Zone 2: 98 ft

Zone 3: 230 ft

Zone 4: 311 ft

Zone 5: 157 ft

Zone 6: 360 ft

Zone 7: 190 ft

Zone 8: 200 ft

This project simulation is based on the 8^{th} zone which contains a carbonated rock. In the rock fluid simulation process, a new rock type (carbonate rock) was created and a correlation was used to generate the relative permeability table for both the gas-oil system and the water-oil system. Therefore, the table data gotten from the correlations will be used to plot the relative permeability curves against gas-oil saturation or water-oil saturation.

Relative permeability which is known to be the ratio of the effective permeability of a fluid at a known saturation to the absolute permeability of that fluid at total saturation. For oil-water phase, Figure 3.6 shows that the relative permeability of gas starts to increase at 0.35 water saturation as denoted by the red colour and the water relative permeability reduces over time (decline to zero at 0.58 Sw) with increasing water saturation as represented in blue colour. However, for the gas-liquid phase, Figure 3.7 shows the relative permeability curve versus liquid saturation. Based on the plot, the gas's relative permeability reduces over time until it reaches zero at liquid saturation of 0.86. In contrast, the relative permeability of water declines from the initial liquid saturation until 0.77 of its saturation where it starts to increase with an increase in liquid saturation as denoted in blue colour line.

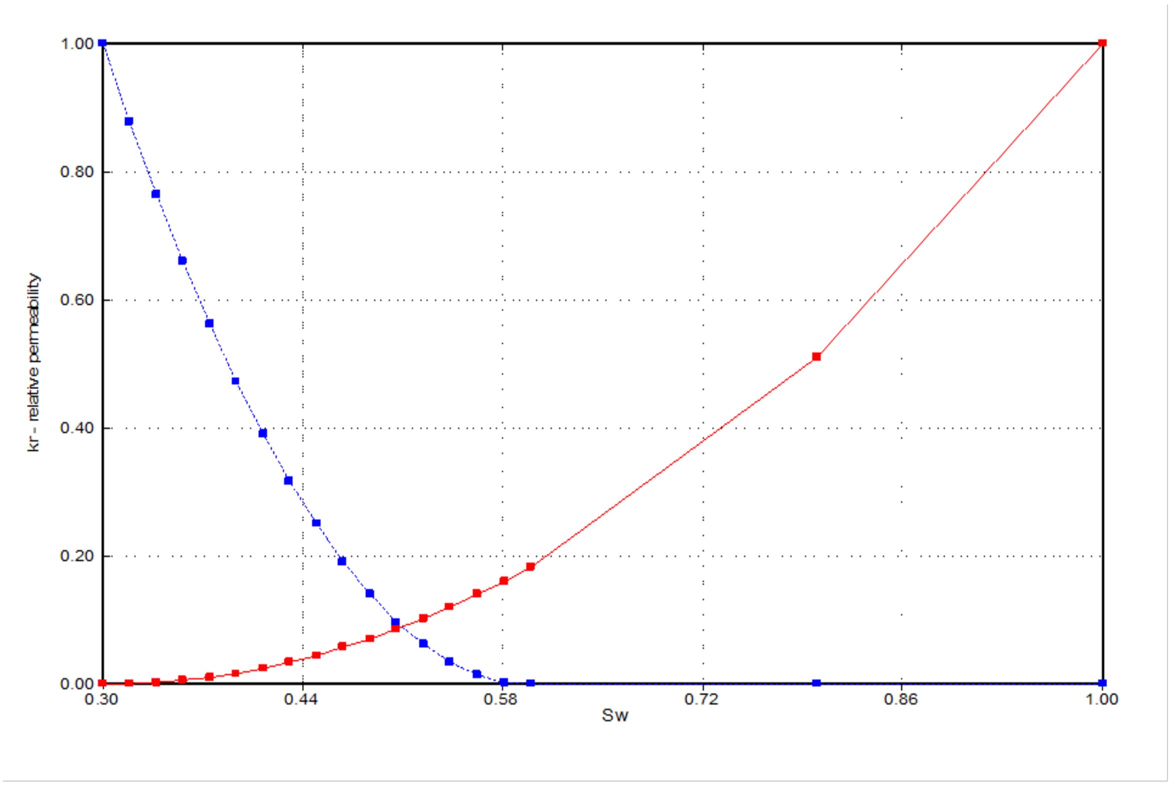

Figure 3.6. *Relative Permeability against Water Saturation (generated by CMG Builder, 2015)*

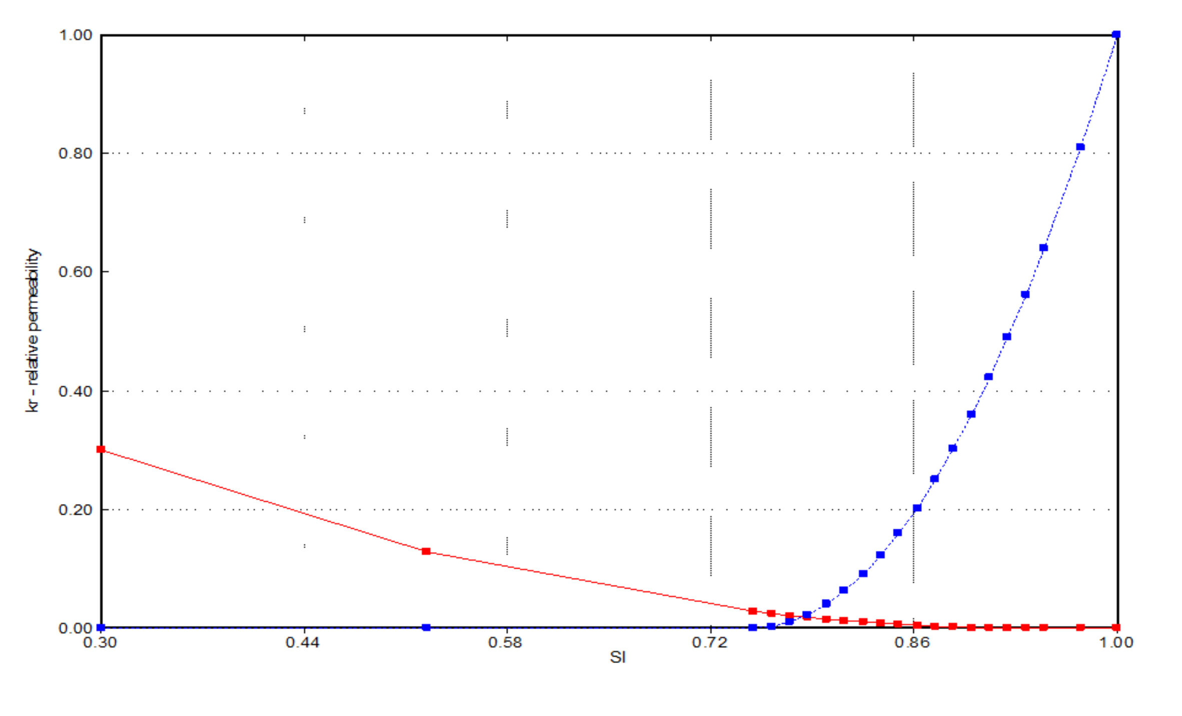

Figure 3.7. *Relative Permeability against Liquid Saturation (generated by CMG Builder, 2015)*

Fluid Contacts and Initialization

For a simulation to be validated, the pre-conditions at the start of the simulation should be known, which include; reference pressure and phase saturation for the grid cells, reference depth, and the contact depths of the fluid, that is oil water contact (OWC) depth and gas oil contact (GOC) depth. For this project, the reference depth, pressure at reference depth of the reservoir, and depth of water oil contact, and GOC were all imputed to defined the initial condition of the reservoir model. Initial pressure has 3840 psi with a reference depth of 7100 ft., initial water oil contact (WOC) depth is 7250 ft., while the depth of gas oil contact (DGOC) is at 7100 ft.

Production and Injection Well Constraints

For production constraints, a minimum BHP of 1,000 psi was used, and a maximum surface oil rate of 10,000 Stb/day was used for the producing well. For the injectors, maximum bottom-hole pressure of 11,000 psi was specified, and a maximum surface gas rate of 1,000,000 SCF/Day. The four injectors used for the model were all perforated at the flank of the model and all the layers were all perforated, same goes for the two producing well in terms of the layer perforation, the producers were located in between the four injectors to allow more oil to be efficiently pushed by the injectors to the production well.

The first simulation was validated successfully by CMG-STARS 2015.10 simulator, using a water alternating gas as injection fluid, after which foam flooding was employed which comprises of co-injection of water and surfactant. Six different foam flooding scenarios were run successfully. The concentration fraction of the surfactant used against water fraction for the different scenarios are 1.5%, 10%, 20%, 30%, 40%, and 50%.

The water alternating gas and Foam flooding scenarios were all injected with a steam temperature of 100 F.

Hence, the WAG, the natural depletion (no injection), and the foam injection simulations were all validated successfully and the foam injection results as shown in the next section indicate an improvement in oil recovery and production.

CHAPTER IV

Results and Discussion

In this chapter, all the scenario simulation results for the project will be analysed and discussed. These results include average pressure pore volume per sector, oil recovery factor, cumulative oil production, oil production rate, GOR, and water cut.

No Injection Scenario

This scenario is known as the base case scenario. It is considered as the primary production scenario because no injection well was included except for the two producing wells that were positioned at the centre of the reservoir. Both wells were perforated at the grid cell of 7,6,1 and 19,6,1 through 7,6,9 and 19,6,9 as shown in Figure 4.1.

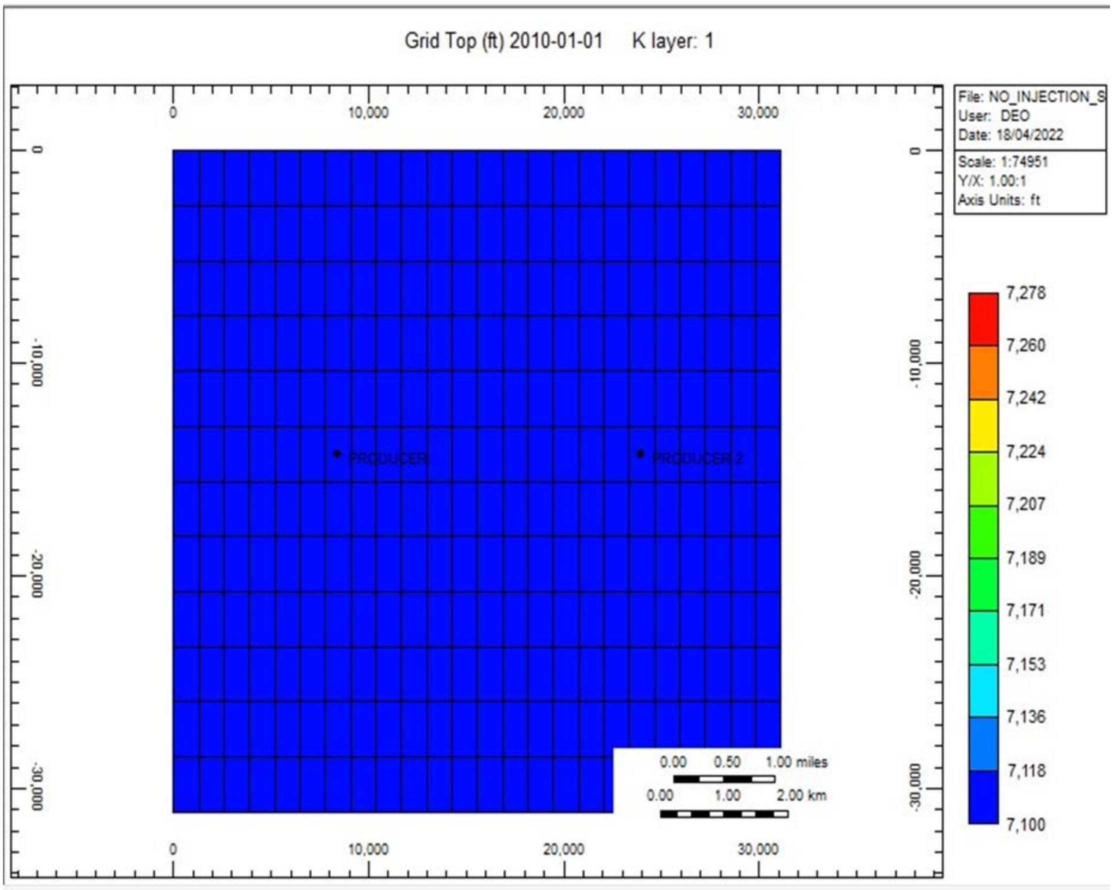

Figure 4.1. *2D Reservoir Model (generated by CMG Builder, 2015)*

The results for the natural depletion after the simulation were run from 2010 to 2022 (12 years), it showed that the oil recovery factor was 21.3% of oil recovered, the cumulative oil production was 8 million barrels after 12 years, the reservoir produced oil at the rate of 1,718.48 bbl/day, the reservoir pressure decline to 3,686.73 psi, and the water cut, which is the ratio of water produced compared to the total fluid produced is valued at a fraction of 0.00762264. The results discussed above are shown in the following plots as seen in Figures 4.2, 4.3, 4.4, and 4.5.

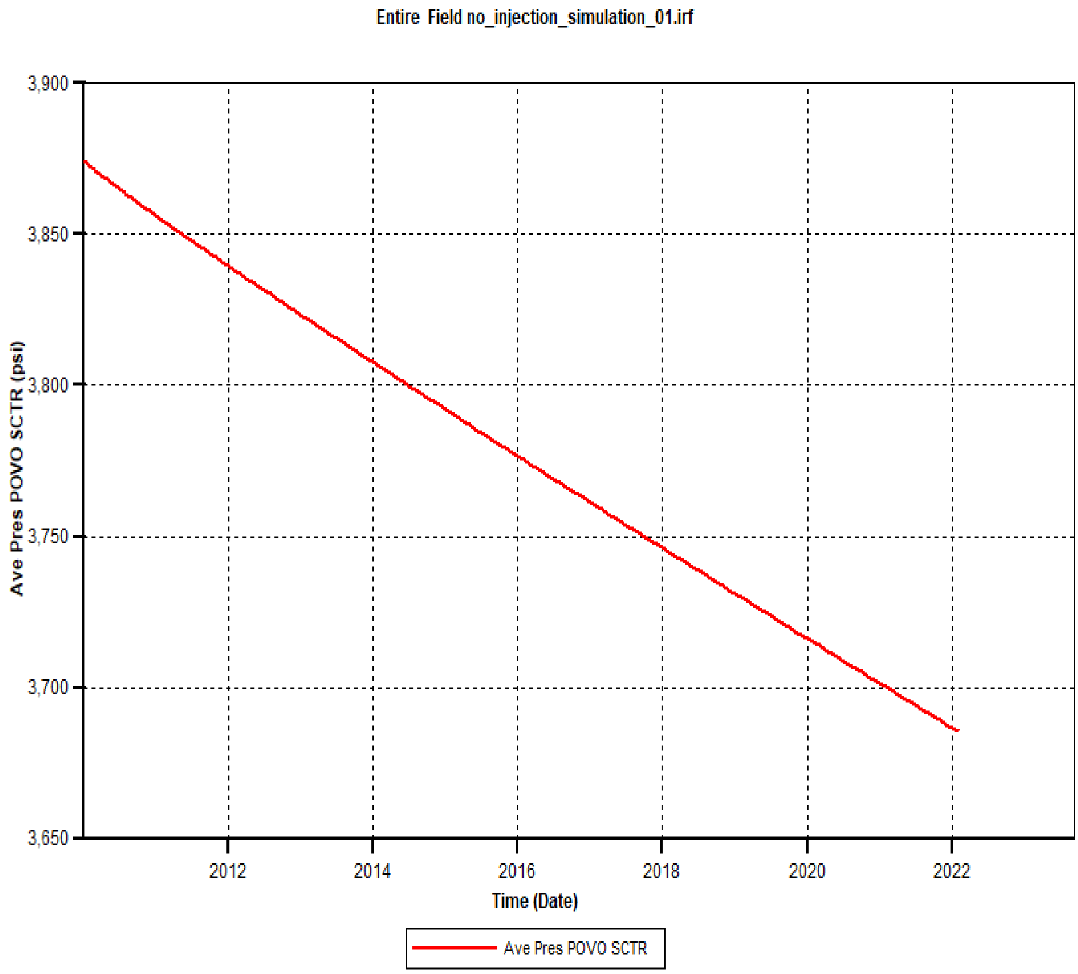

Figure 4.2. *Average Pressure Povo SCTR vs Time for No Injection (generated by CMG Results, 2015)*

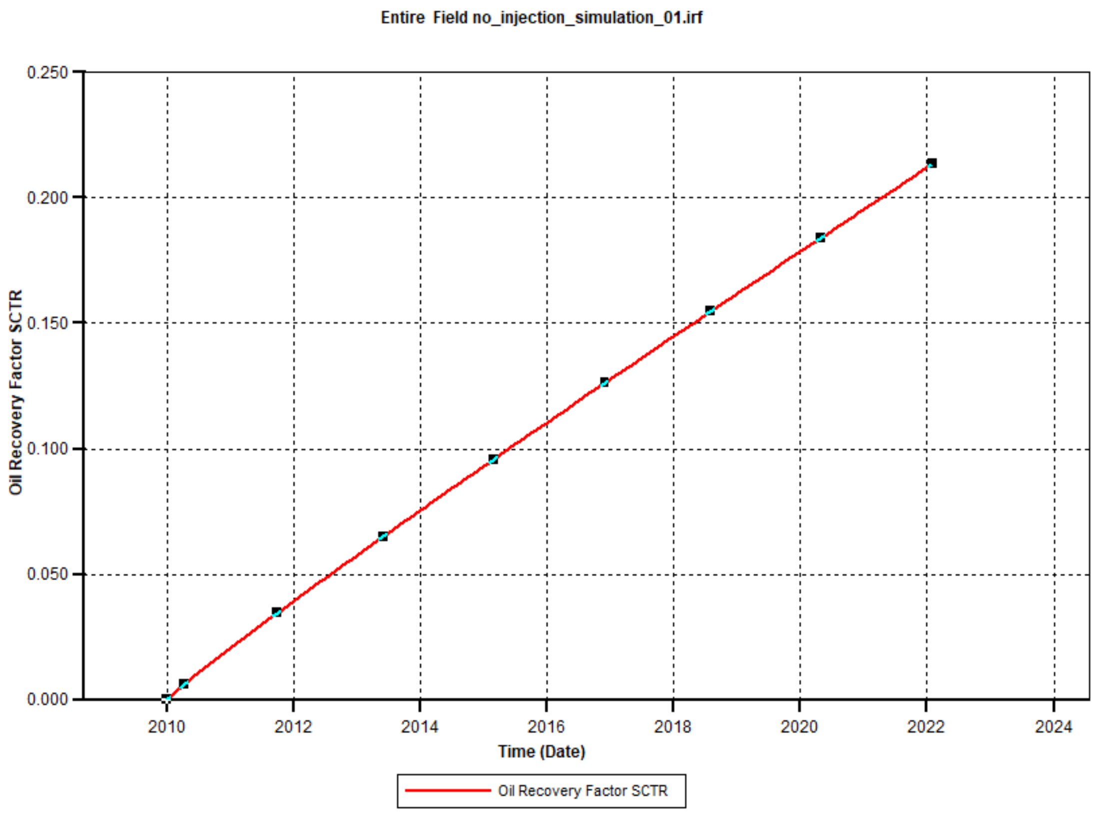

Figure 4.3. *Oil Recovery Factor vs Time for No Injection (generated by CMG Results, 2015)*

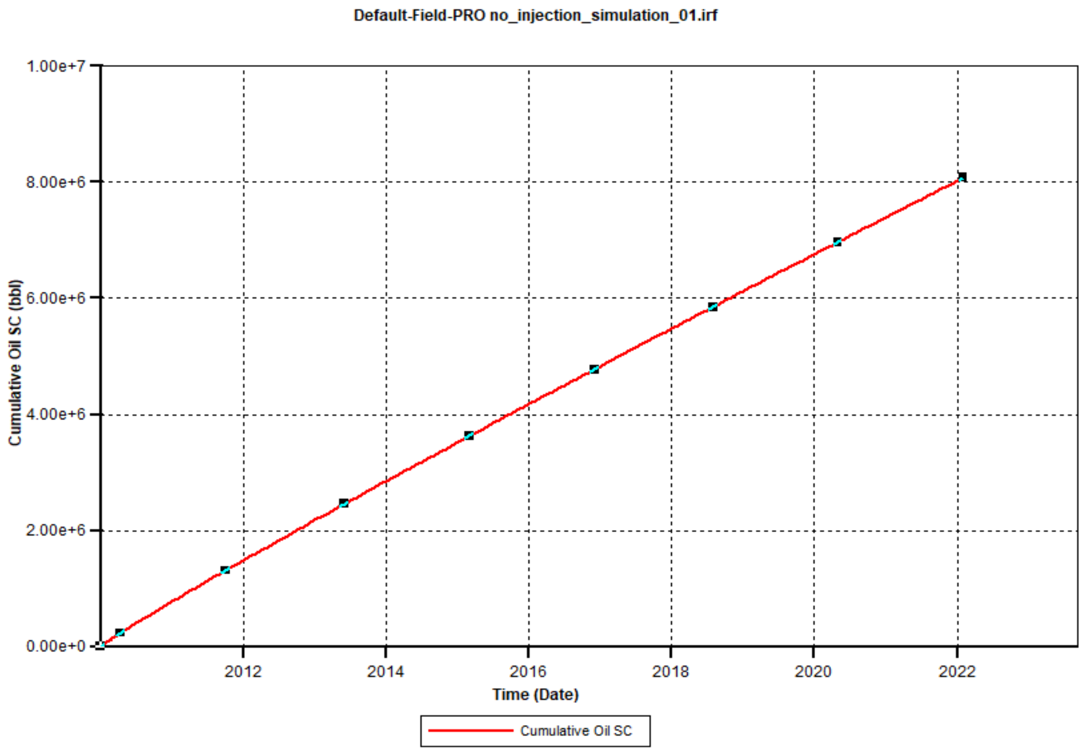

Figure 4.4. *Cumulative Oil vs Time for No Injection (generated by CMG Results, 2015)*

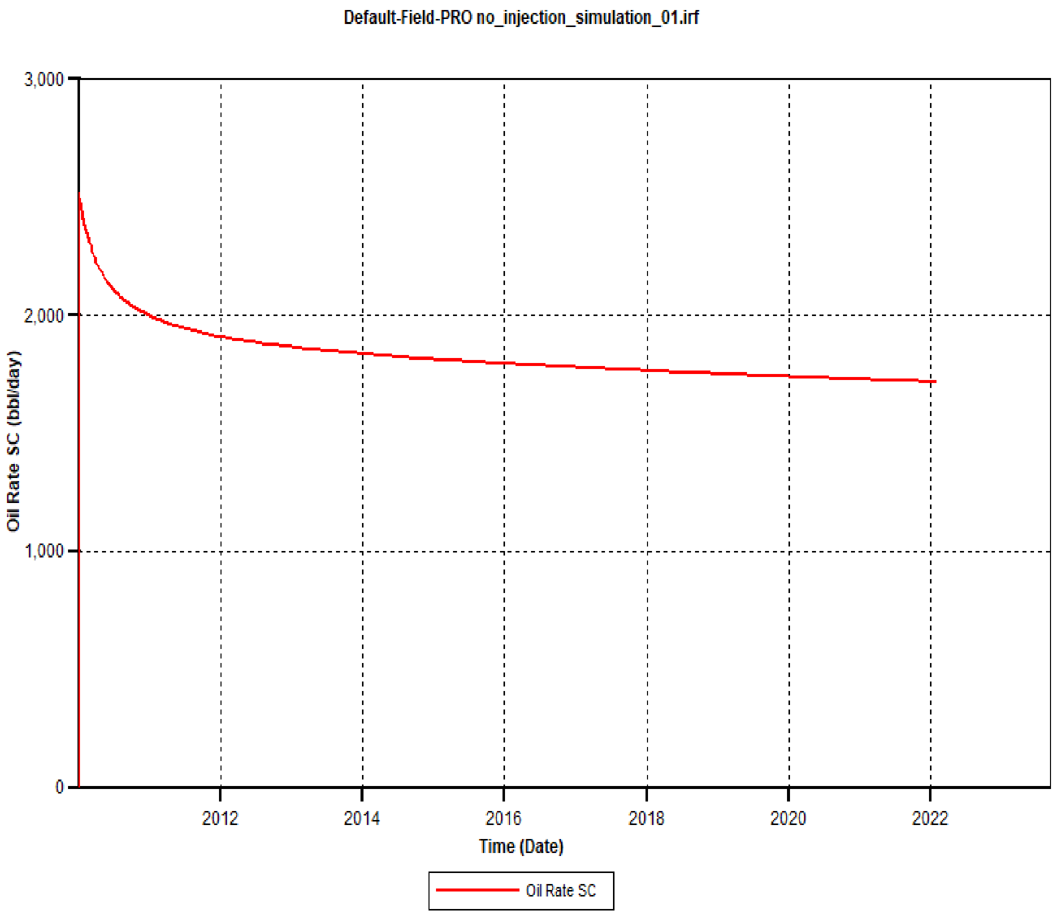

Figure 4.5. *Oil Production Rate vs Time for No Injection (generated by CMG Results, 2015)*

Water Alternating Gas Scenario

The water alternating gas scenario follows the natural depletion scenario with four injection wells added to make the reservoir have six wells in total. The injection wells are positioned at the flank of the reservoir to be able to inject more water into the production well in order to move the oil from the high permeable zone to the low permeable zone for more oil to be captured and produced. The four injectors are perforated between the grid cell of 2 2 1, 22 2 1, 4 9 1 and 22 9 1 to grid cell of 22 2 9, 22 2 9, 4 9 9 and 22 9 9 respectively.

The WAG maintains reservoir pressure more than the no-injection scenario because the average POVO pressure of WAG was calculated to be 5797.28 psi as compared to the no-injection scenario which has lower pressure. The WAG gives a recovery factor of 25.4% of the reservoir oil recovery as shown in Figure 4.6.

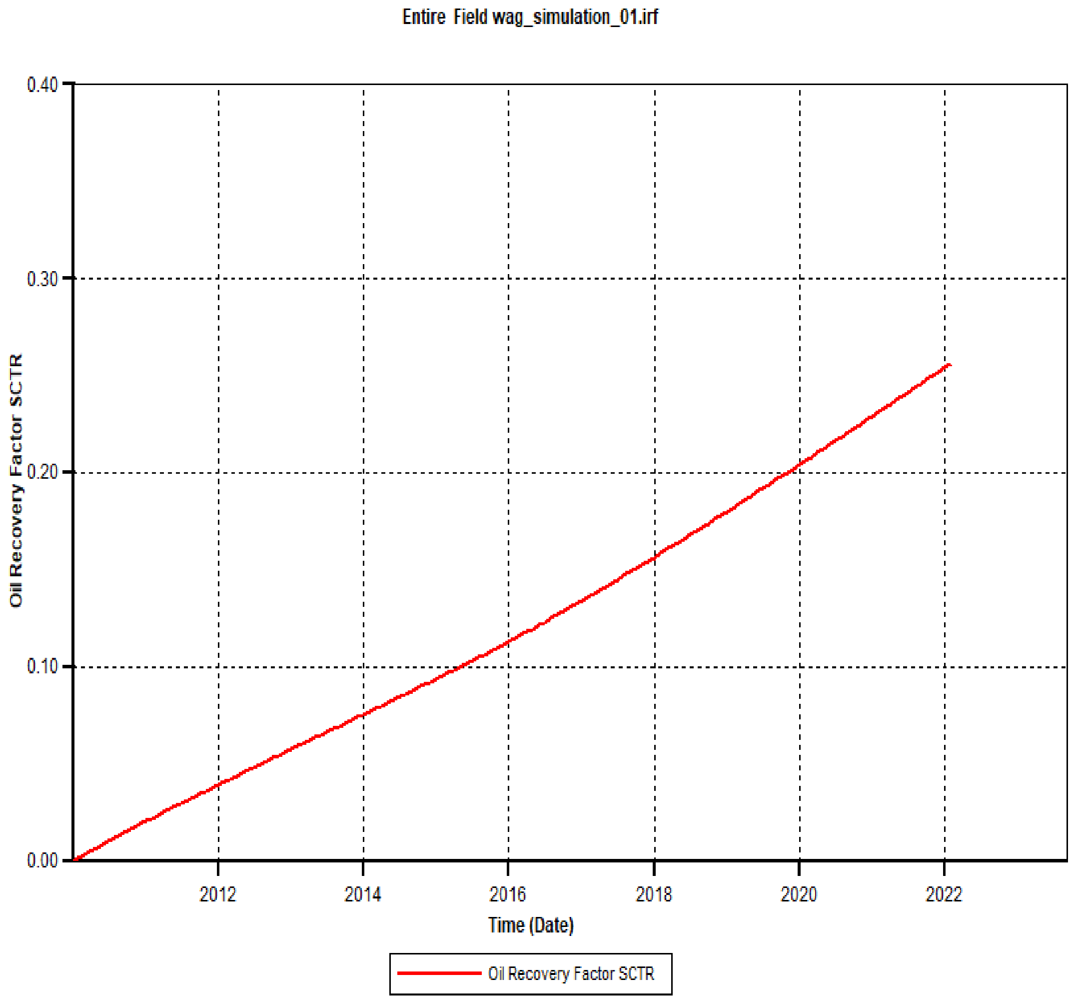

Figure 4.6. *Oil Recovery Factor vs Time for WAG (CMG-STARS Result, 2015.10)*

The WAG has gathered a cumulative oil of 9.7 million barrels which is higher as compared to the no injection scenario. Also, the total oil production rate at the end of 12 years interval was taken to be 2,634.4 bbl/day. These results were effective enough because of the four injections well added with maximum bottom hole pressure and maximum gas injection rate, i.e., the surface water rate (STW) with an injection fluid of water as the component fluid. The water cut is 0.0822813 which is higher and therefore, undesirable when compared to the no injection scenario. The cumulative oil, the oil production rate, and the average pressure pore volume of WAG are shown in Figures 4.7, 4.8, and 4.9, with a value of 9.7 MMSTB, 2634.4 STB/day and 5797.28 psi

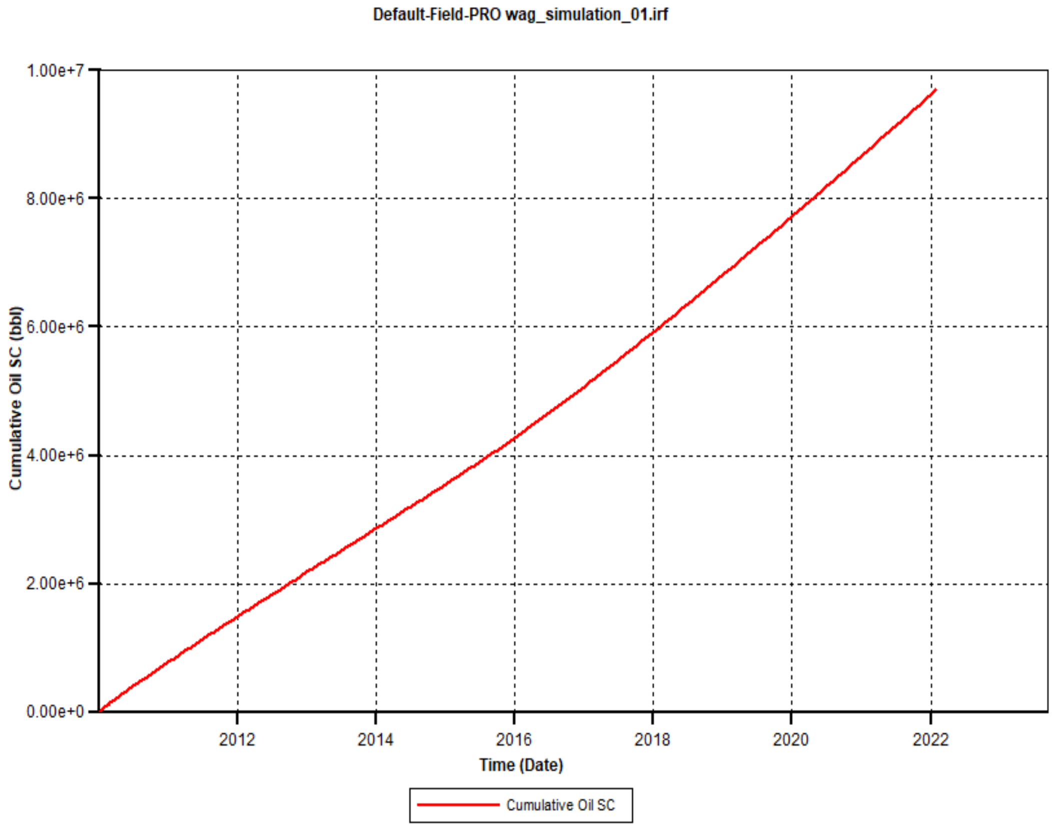

Figure 4.7. *Cumulative Oil vs Time for WAG (generated by CMG Results, 2015)*

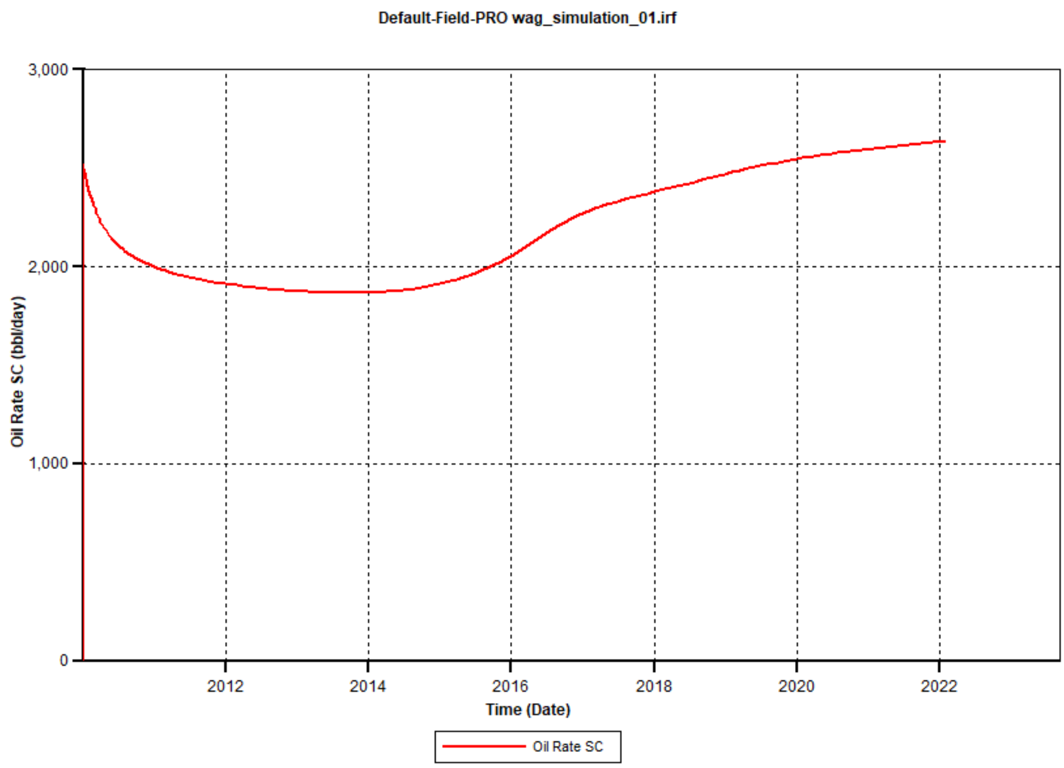

Figure 4.8. *Oil Production Rate vs Time for WAG (generated by CMG Results, 2015)*

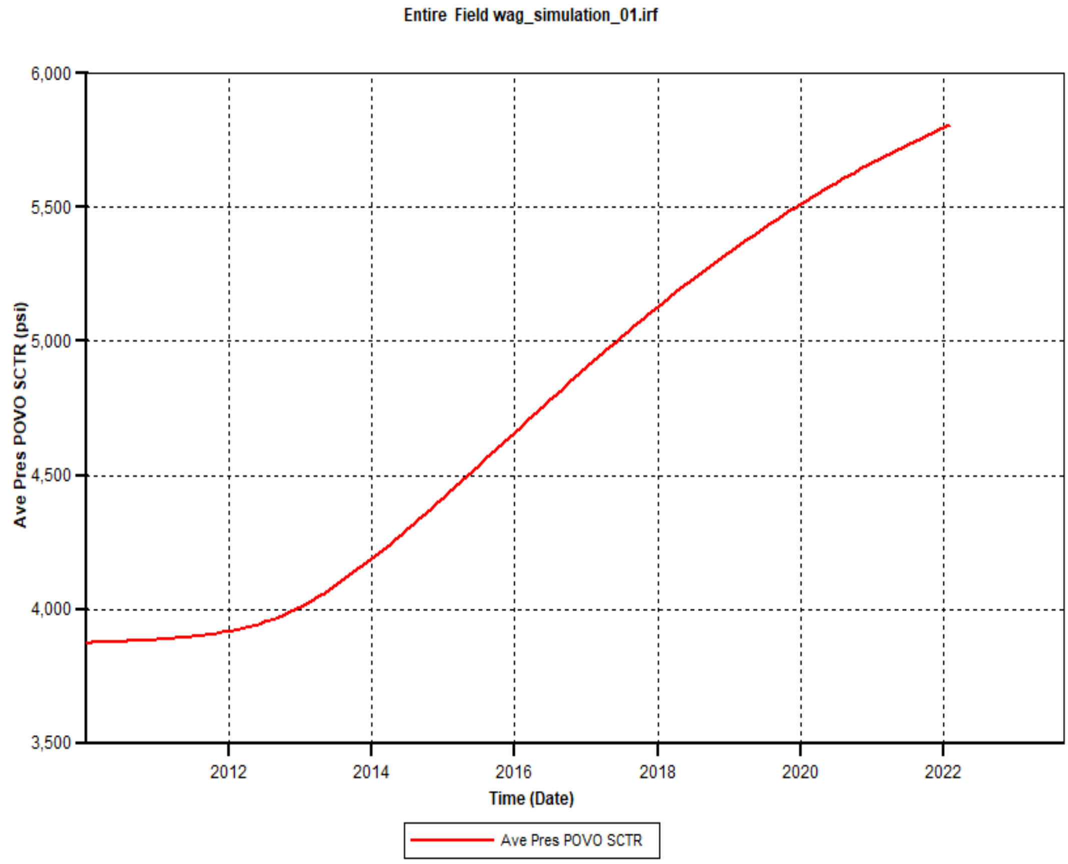

Figure 4.9. *Average Pressure Povo SCTR vs Time for No Injection (generated by CMG Results, 2015)*

Foam Injection Scenarios

Average Pressure for Pore Volume per Sector for Foam Injections

To compare the results of the foam injection simulations, each of the foam injection scenarios are plotted in the same graph to have one view of how the foam injection scenarios performed against each other. From the result of this study showed that the foam injection with a higher surfactant mole fraction against water maintains reservoir pressure compared to the lower surfactant mole fraction against water.

The average pressure for pore volume per sector for the foam injection 1 (with the co-injection fluid of surfactant of mole fraction of 0.015 and water mole fraction of 0.985), has an increased reservoir pressure of 6,244.57 psi. Foam injection 2, with surfactant mole fraction of 0.1 and water mole fraction of 0.9 resulted in an increased reservoir pressure of 6,894.88. Foam injection 3, with surfactant mole fraction of 0.2 and water mole fraction of 0.8 resulted in an increased reservoir pressure of 7,845.86. Foam injection 4, with surfactant mole fraction of 0.3 and water mole fraction of 0.7 resulted in an increased reservoir pressure of 8,750.06. Foam injection 5, with surfactant mole fraction of 0.4 and water mole fraction of 0.6 resulted in an increased reservoir pressure of 10,092.4 psi. Finally, foam injection 6, with surfactant mole fraction of 0.5 and water mole fraction of 0.5 resulted in an increased reservoir pressure of 10,123.5 psi, which is close to foam injection 5 results. The simulation scenarios were actually stopped at the foam injection of 40% surfactant concentration scenario due to the same results gotten after an increased surfactant mole fraction of 0.5. The graph to back up the results is shown in figure 4.10.

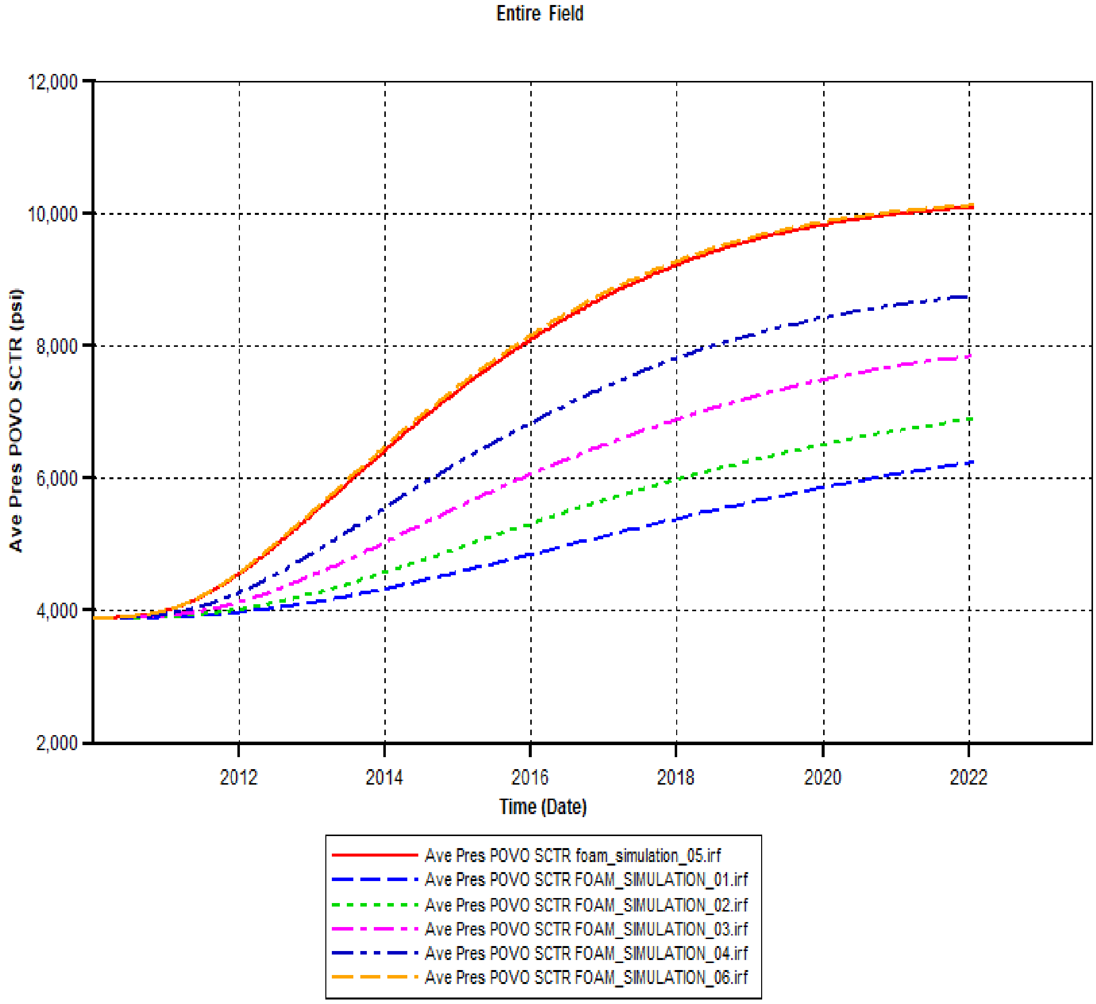

Figure 4.10. *Average Pressure Povo SCTR vs Time for Foam Injections (generated by CMG Results, 2015)*

Oil Recovery Factor per Sector for Foam Injections

The oil recovery factor represents the percentage of oil in place that has been recovered, also the key factor to assess the feasibility of an EOR process is the recovery factor achieved by it. As seen in Figure 4.11, it is observed that the best scenario is the foam simulation 6, which has a surfactant mole fraction of 0.5 and a water mole fraction of 0.5. From the results graph, foam simulation of 1.5% surfactant concentration gave an oil recovery factor of 26.2%, foam simulation of 10% surfactant concentration gave an oil recovery of 28.2%, foam simulation of 20% surfactant concentration gave an oil recovery factor of 31.4%, foam simulation of 30% surfactant concentration gave an oil recovery factor of 34.6%, foam simulation of 40% surfactant concentration resulted in an incremental oil recovery factor of 39.9%, and finally foam simulation of 50% surfactant concentration, which was used to check if there's any further increment in excess of oil recovery gave an oil recovery factor of 40.1% which is almost the same result as foam injection of 40% surfactant concentration. Therefore, the results gotten with the foam simulation scenario showed that foam flooding should be a recommended case study for future development in EOR.

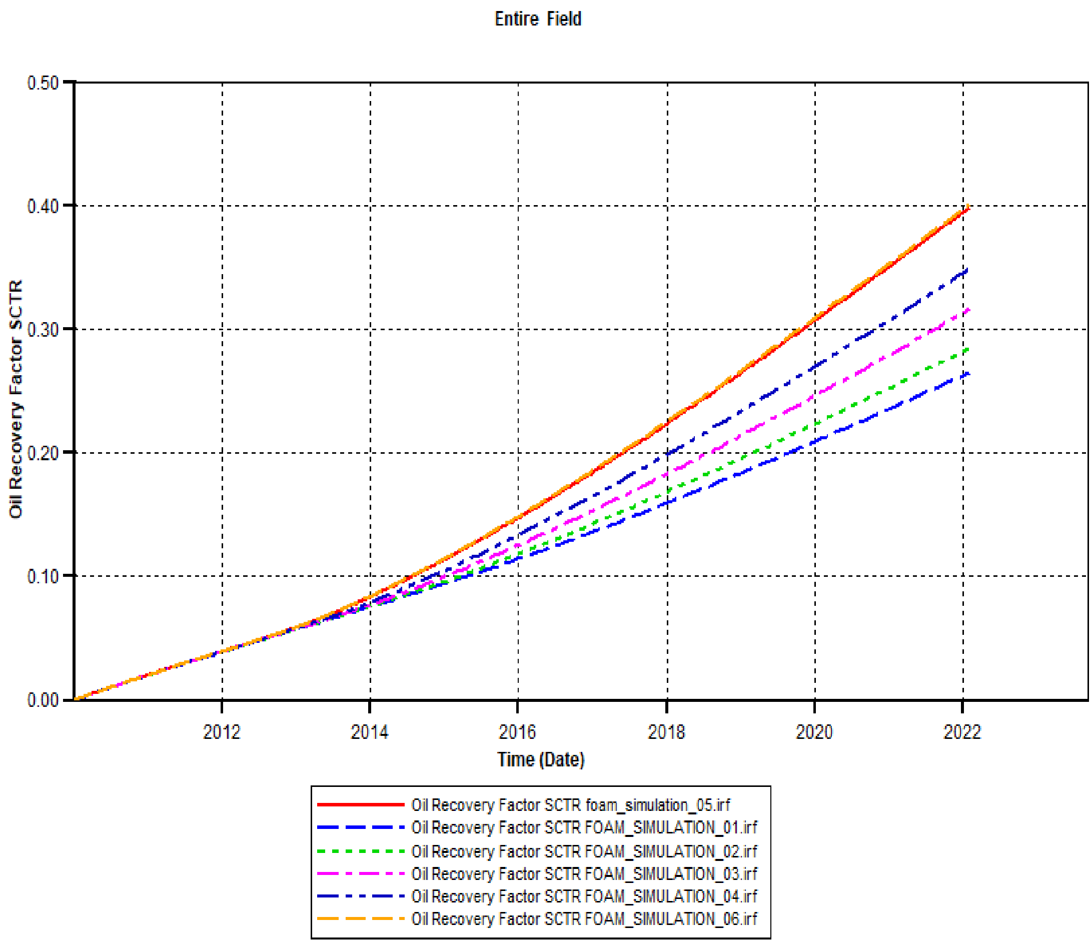

Figure 4.11. *Oil Recovery Factor vs Time for Foam Injections (generated by CMG Results, 2015)*

Cumulative Oil production for Foam Injections

This cumulative oil production is the amount of oil produced at the end of 12 years of the simulation period. Compared to the other scenario, foam injection scenarios gave an increased cumulative oil, with the result of each scenario being improved as the surfactant mole fraction increases against the water mole fraction. From Figure 4.12, it's shown that the cumulative oil production of foam simulation of 1.5% surfactant concentration amounted to 9.94 Mbbl after 12 years, foam simulation of 10% surfactant concentration gathered a cumulative oil production of 10.69 Mbbl, foam simulation of 20% surfactant concentration cumulated 11.87 Mbbl, foam simulation of 30% surfactant concentration cumulated 13.09 Mbbl, foam simulation of 40% surfactant concentration cumulated 15.09 Mbbl, and finally, foam simulation of 50% surfactant concentration has cumulative oil production of 15.19 Mbbl, which is a close result to foam simulation of 40% surfactant concentration.

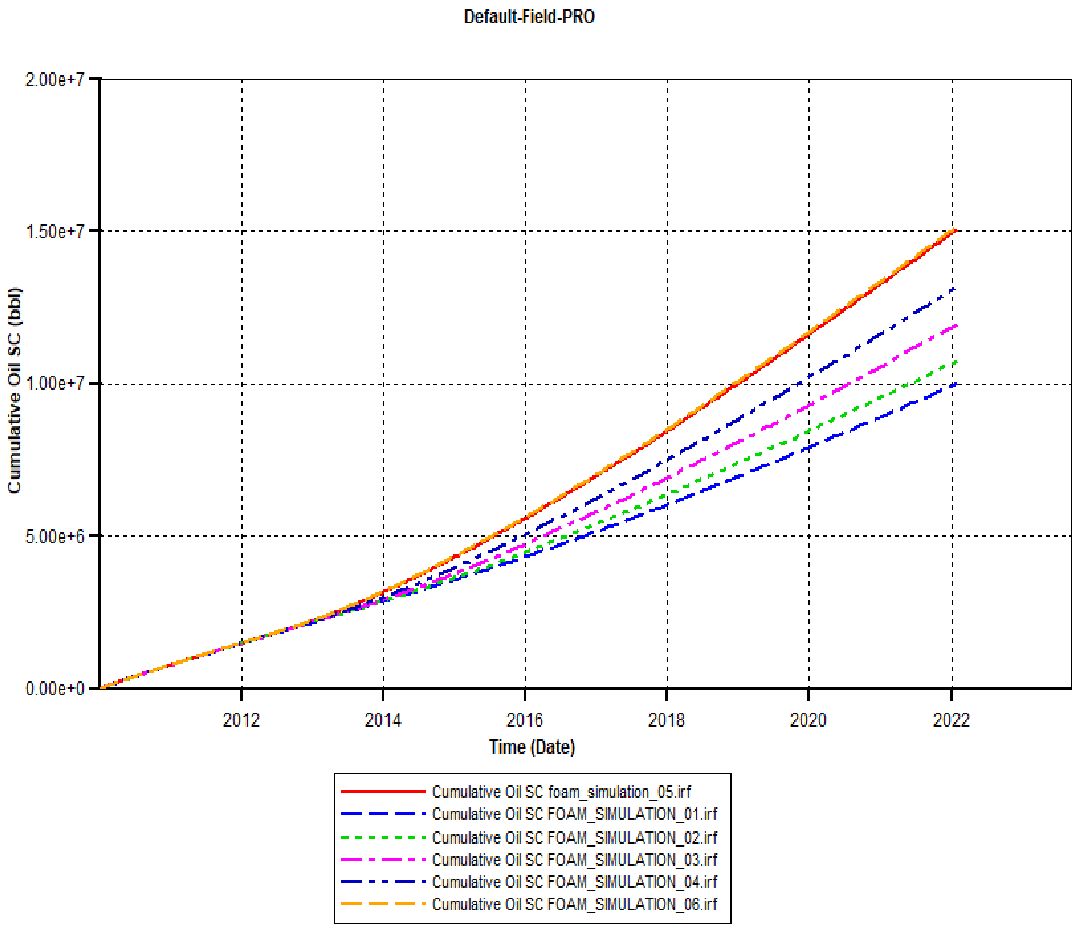

Figure 4.12**.** *Cumulative Oil vs Time for Foam Injections (generated by CMG Results, 2015)*

Oil production Rate for Foam Injections

The oil production rate is the amount of oil produced per day. From the simulation results, it was noticed that the daily oil rate was increased for the foam scenarios compared to other scenarios. Within the foam simulations, it appears that the oil production rate increased more for the large mole fraction of surfactant used against water. Foam simulation of 1.5% surfactant concentration has an oil production rate of 2,817.91 bbl/day, foam simulation of 10% surfactant concentration produces oil at a rate of 3110.86 bbl/day, foam simulation of 20% surfactant concentration produces oil at a rate of 3,559.64 bbl/day, foam simulation of 30% surfactant concentration produces oil at a rate of 3991.32 bbl/day, foam simulation of 40% surfactant concentration produces oil at a rate of 4,582.11 bbl/day. And finally, a last foam simulation of 50% surfactant concentration which produces an oil rate of 4,597.99 bbl/day was checked for further incremental oil production rate which indicates to be almost the same as the foam simulation of 40% surfactant concentration. Therefore, it was concluded with the aid of plots (Figure 4.13) showing foam scenarios have better production rate results than other scenarios.

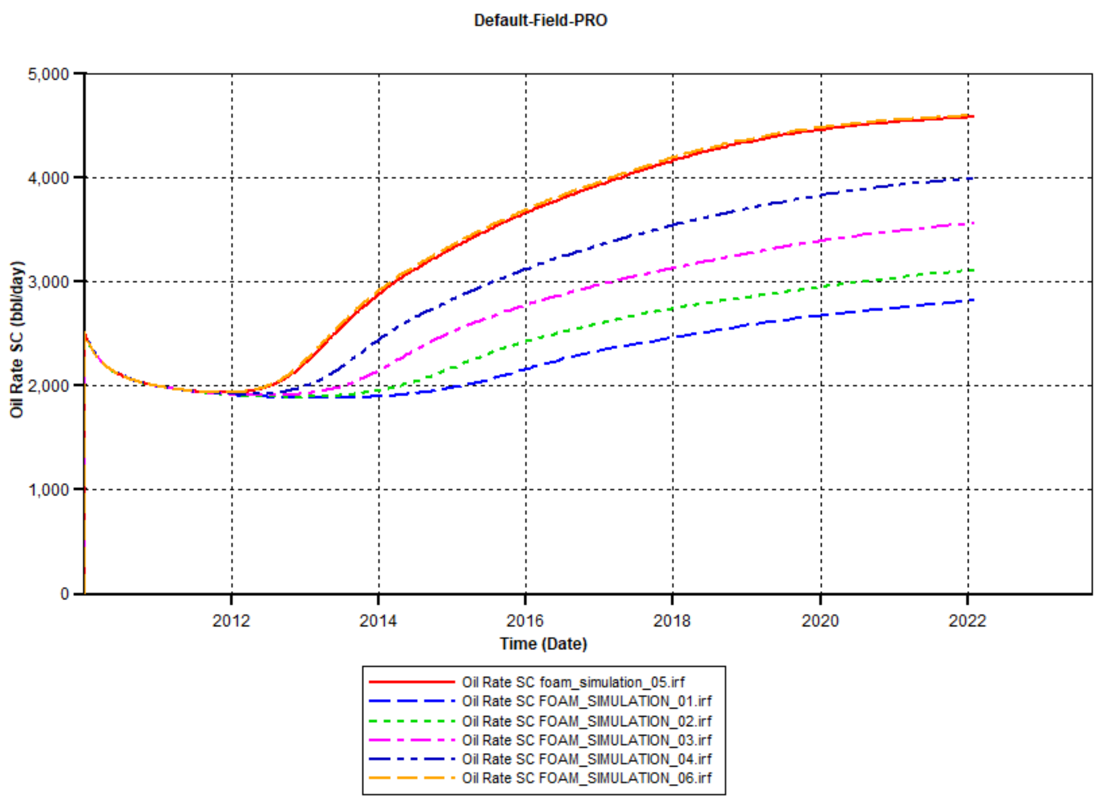

Figure 4.13**.** *Oil Production Rate vs Time for Foam Injections (generated by CMG Results, 2015)*

Water Cut for Foam Injections

Water cut simply means the ratio of water produced compared to the volume of total liquids produced. From the simulation results, it appears that foam simulation scenarios maintain a higher rate of water cut compared to other scenarios, and obviously, results also showed that amongst the foam simulation flooding, foam injection with increased surfactant mole fraction maintained a higher rate of water cut compared to lower surfactant mole fraction. Foam simulation 1 has a water cut of 83.7%, foam simulation 2 has a water cut of 88.7%, foam simulation 3 has a water cut of 92.1%, foam simulation 4 has a water cut of 93.5%, foam simulation 5 has a water cut of 94.8%, and lastly foam simulation was tried to see if it has better water cut, but rather gave the same result as foam simulation 5. Results are shown in Figure 4.15 below.

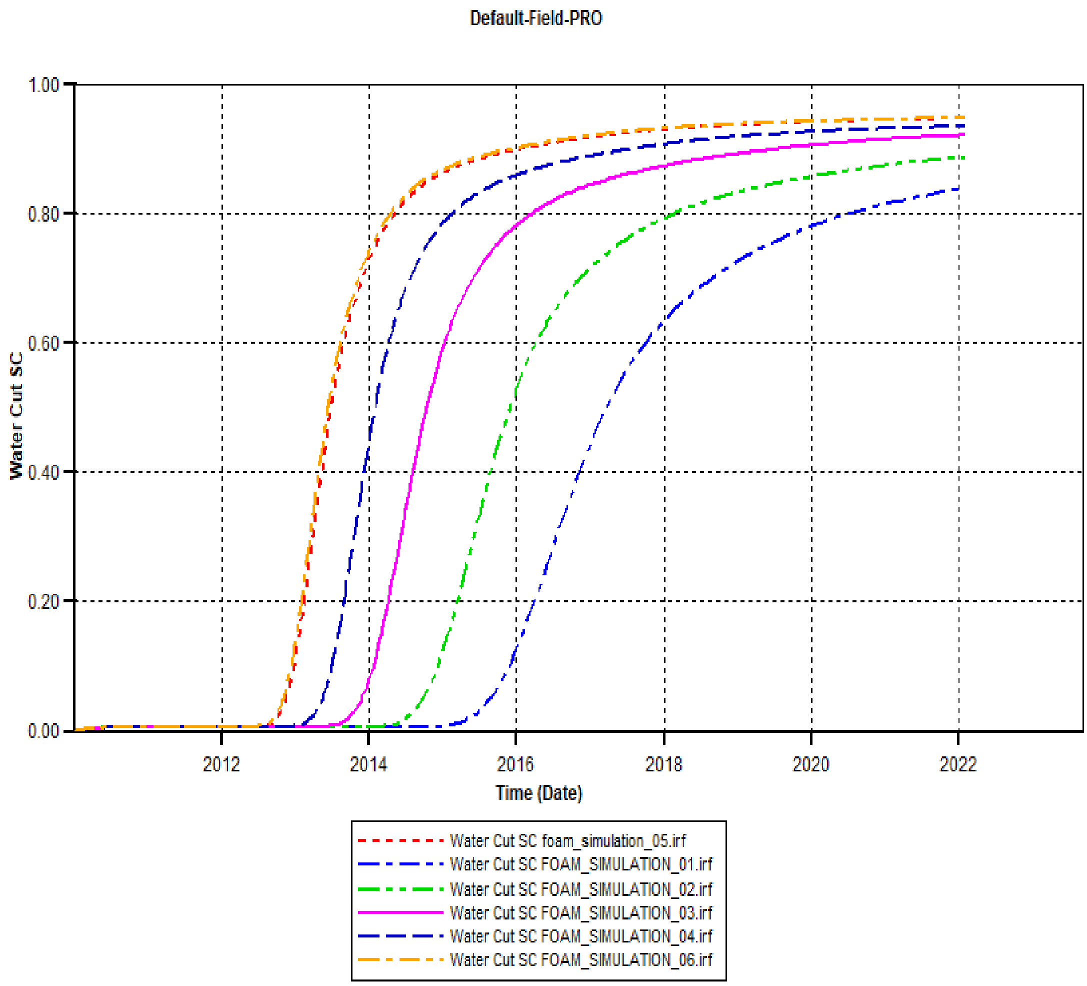

Figure 4.15. *Water Cut Sc vs Time for Foam Injections (generated by CMG Results, 2015)*

Summary of the Results Showing the Different Scenarios

Results from the different scenarios are tabulated in Table 4.1. Results such as field oil recovery factor, field cumulative oil production, oil production rate, and average pressure for pore volume per sector, etc were plotted and analysed to give an idea of how the reservoir performed. With the foam injections, a significant increase in field oil recovery was observed compared to gas injection and no injection case. Foam injection 5 with surfactant concentration of 40% has the optimal result compared to other scenarios, while the Foam injection 6 with surfactant concentration of 50% was simulated to check for further oil recovery, which gave a slight increased oil recovery of about 40.1% as the best result (see Figure 4.16). The same goes for the production rate and cumulative production (Figures 4.17 & 4.18).

In a nutshell, it’s clear to say that foam is a better method for EOR with its improved sweep efficiency and oil recovery.

Table 4.1.

Short Description of the Simulated Case Result (generated by CMG Builder, 2015)

Case No.	Oil Recovery Factor %	Cumulative Oil Production (MMSTB)	Oil Production Rate (STB/day)	Pressure at the End of Simulation (Psi)
Base Case	20.2	8.0	1718.48	3686.73
WAG Injection	25.4	9.7	2634.40	5797.28
Foam Injection 1 (1.5%)	26.5	10.0	2823.65	6244.57
Foam Injection 2 (10%)	28.3	10.8	3110.86	6894.88
Foam Injection 3 (20%)	31.6	11.9	3559.64	7845.86
Foam Injection 4 (30%)	34.6	13.1	3991.32	8750.96

Foam Injection 5 (40%)	39.9	15.1	4579.42	10,092.4
Foam Injection 6 (50%)	40.1	15.2	4595.48	10,123.5

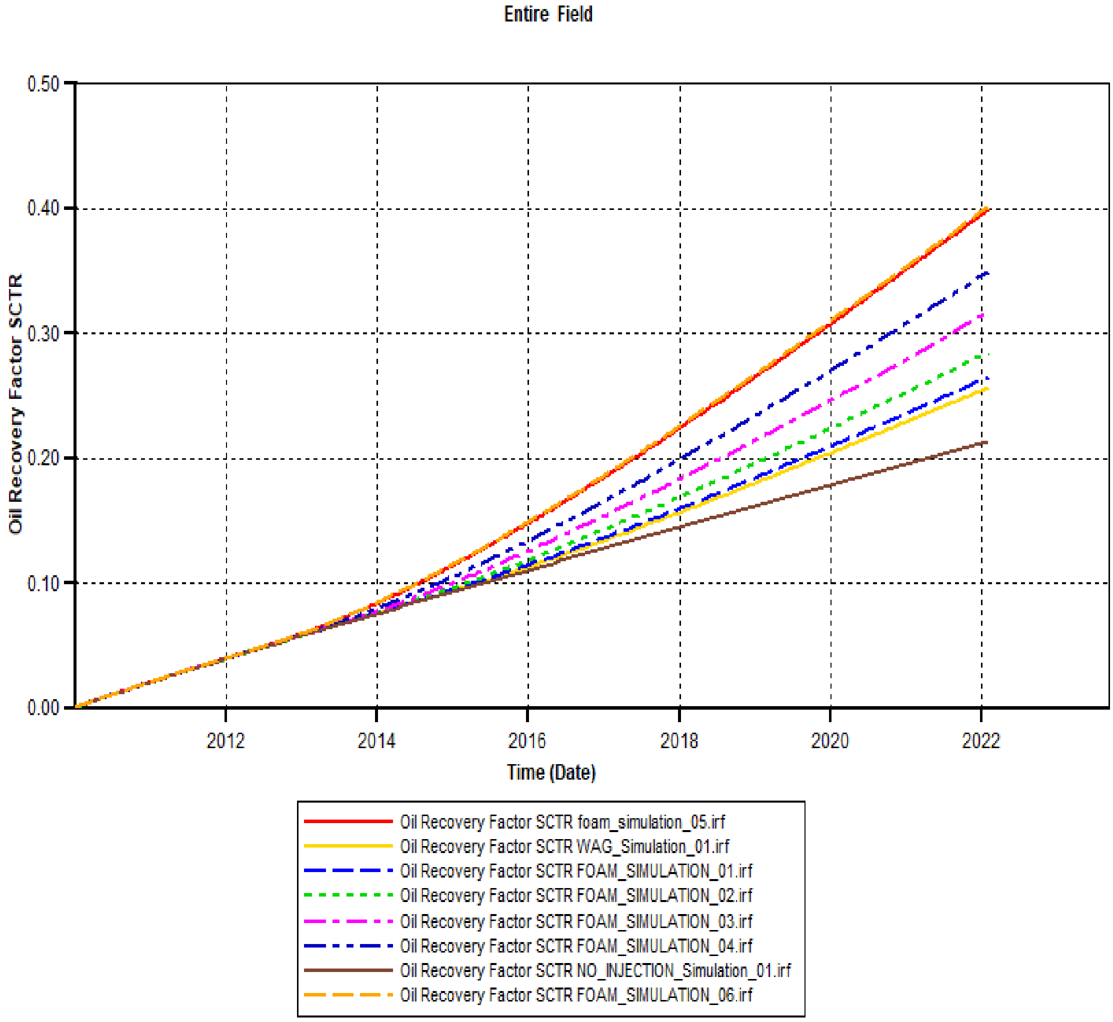

Figure 4.16. *Oil Recovery Factor SCTR vs Time for All Scenarios (generated by CMG Results, 2015)*

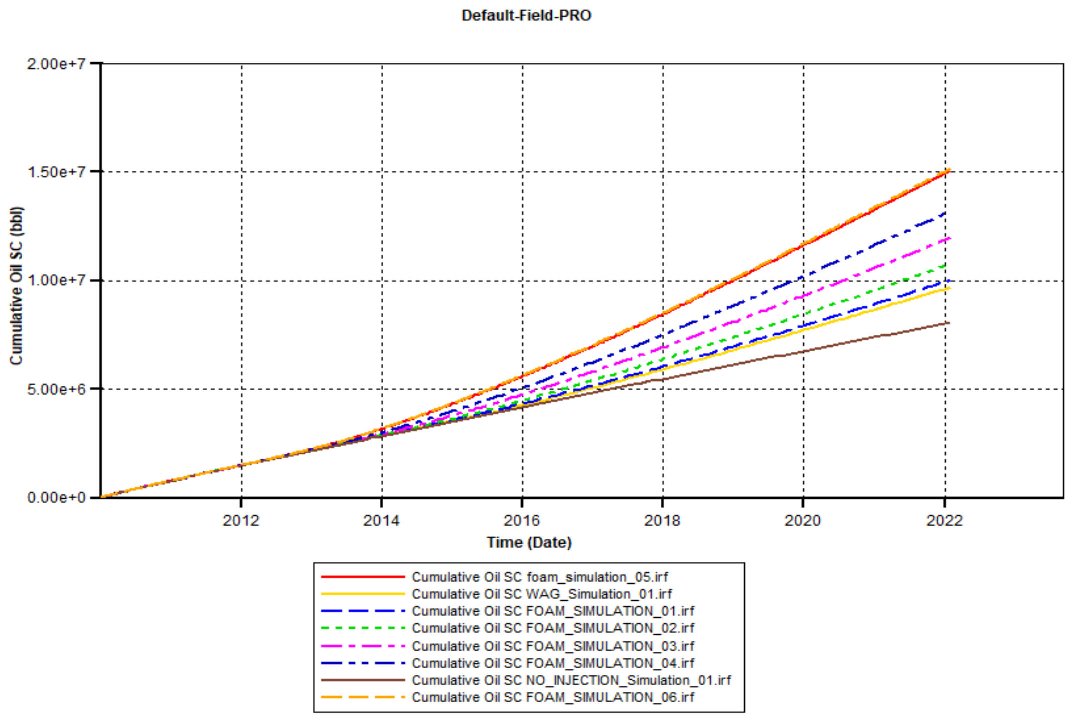

Figure 4.17. *Cumulative Oil Production vs Time for All Scenarios (generated by CMG Results, 2015)*

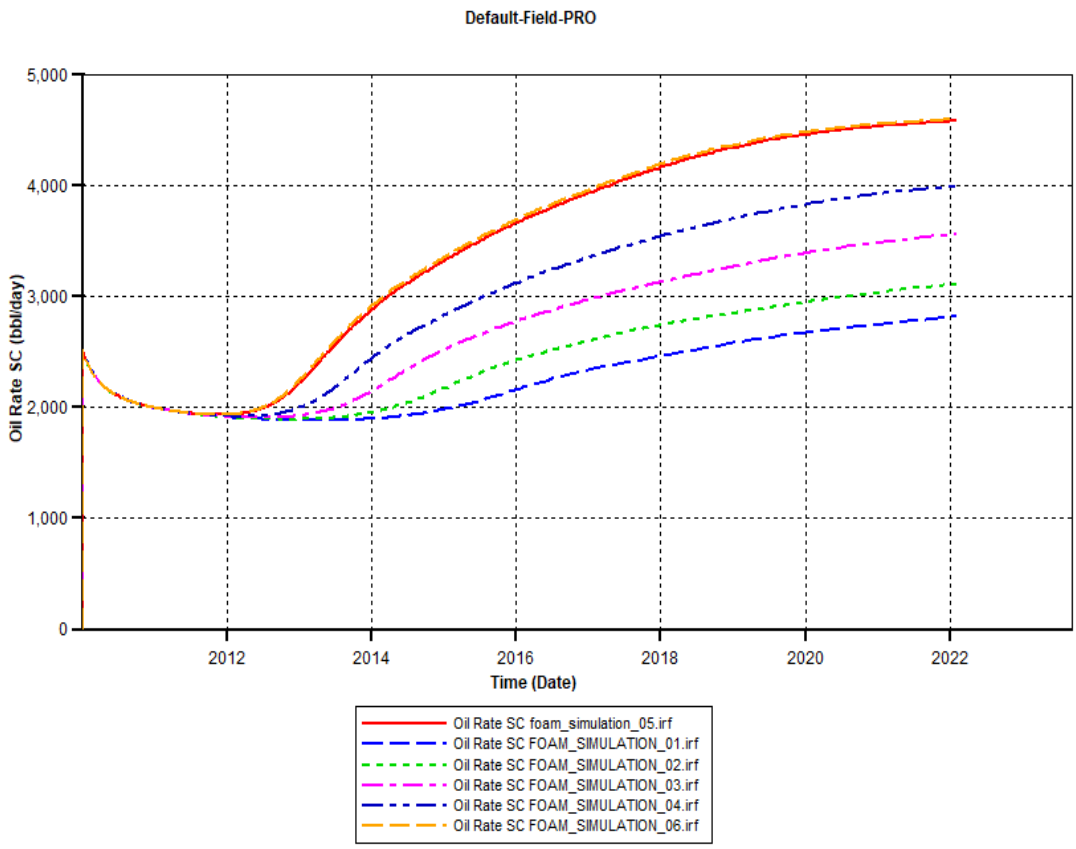

Figure 4.18. *Oil Production Rate vs Time for All Scenarios (generated by CMG Results, 2015)*

CHAPTER V

Economical Analysis

An economic analysis tool called Net Present Value (NPV) was used for this project to illustrate further the economic gain or loss of this study. The NPV analysis gives a measure of the present value of the investment, and the economic viability of how the project was determined. The following economic assumptions as shown in Table 5.1 were made in carrying out the analysis and the results are summarized in Table 5.2. From the foregoing analysis, foam injection gave a higher NPV value compared to normal gas flooding. Not only was the oil recovery increased significantly but the project proved to be economical as well.

Table 5.1

Economic Assumptions (Summonu, et al., 2013)

	Vertical Well
Well Drilling Cost	\$12 Million
Injection Cost	\$8/SCF (Surfactant), \$2/SCF (M
OPEX	\$30MM/year
CAPEX	\$235 MM

Based on the fact that capital is a significant factor for EOR projects, it is very necessary to analyse projects in terms of the Net Present Value (NPV) (Jang, 2011).

The NPV of the water alternating gas application and foam flooding application is calculated using the revenue owing to the oil recovery based on all the cost items outlined above in the table.

The NPV, which is defined as a discounted flow method that consider time value of money in evaluating capital investment is computed as:

$$NPV = \frac{C_t}{(1+i)^t} \tag{5.1}$$

where t = time of the cash flow

Ct = net cash flow at time t, $

i = discount rate, %

The total cash inflow for the entire production period is given by:

$$C = \left(FOPT\ X\frac{\$}{bbl}\right) - \left(FISIT\ X\frac{\$}{Ton}\right) - \left(FIWIT\ X\frac{\$}{wat}\right) - \left(FWPT\ X\frac{\$}{dwat}\right) + \left(FSTR\ X\frac{\$TAX}{TON}\right) \quad (5.2)$$

where, C = net cash flow, $

$/bbl = Oil price per bbl, $

$/Ton= Cost of surfactant injection per ton, $

$wat = Cost of water injection per bbl, $

$dwat = Cost of water disposal per bbl, $

$ TAX /Ton = Tax credit of gas stored per ton, $

FOPT = Cumulative oil production, stb

FWPT = Cumulative water production, stb

FISIT = Cumulative surfactant injection, stb

FWIT = Cumulative water injection, stb

An annual discount rate of 20% was used to estimate the present value of money. The net cash flow was calculated from the oil, surfactant and water productions of the reservoir. The price of oil was considered from the then oil price which was estimated to be $99 per barrel, and was used for the entire 12-year production period while the water disposal cost was valued at $1.5 per barrel of produced water. The injection cost of gas (methane) and foam are shown above in Table 5.1.

The production wells were operated at a constant bottom-hole pressure, while for the injection wells, the injectors have constant rates of gas and surfactant injection. The summary of the economics analysis is shown in Table 5.2 where the foam flooding 6 scenario with the best result is compared against the WAG scenario. The oil recovery factor and cumulative oil production was gotten from the simulated results.

Table 5.2

Summary of Economical Analysis

Case Scenario	Oil Recovery Factor %	Cumulative Oil Production MMSTB	Total Cash Flow (Ct) MM$	Cost ($/bbl)	Profit ($/bbl)	NPV (MM$) i = 20%
WAG Injection	25.4	9.7	3,421.44	4.4	63.5	384
Foam Injection	40.1	15.2	4,152.06	3.2	65	466

Equation 5.2 was used to calculate the total cash flow of the total production period over time, while the value of Ct gotten from both WAG injection scenario and foam injection scenario was used in equation 5.1 to calculate the net profit value.

In summary, it can be observed from the results in Table 5.2, that the NPV is higher in the 6th foam injection scenario compared to water alternating gas scenario which proved this project to be economical.

CHAPTER VI

Conclusion and Recommendations

Conclusions

To draw a conclusion after successful simulations, based on the different scenarios used for this project, starting from the no injection scenario, WAG scenario, up until the foam flooding scenarios, it was observed from the results attained that foam injections have increased pressure used in the reservoir. Therefore, this helps the reservoir to greater strength and prevent from early depletion.

The introduction of foam after the gas flooding gave an increased oil recovery factor and production of the reservoir, and this was done with the co-injection of surfactant and water for foam flooding that helps to recovers more oil from reservoir zone that have not been swept. Based on the results comparison of all the simulation scenarios, it was observed that foam injection scenarios 6 with surfactant concentration of 50% gave better results in terms of oil recovery factor compared to other foam scenarios, water alternating gas scenario and the primary production scenario. The foam flooding 6 also has the best results for cumulative oil production and oil production rate when compared with other foam flooding scenarios, water alternating gas scenario and the no injection scenario.

Recommendations

With an expansion in world interest for petroleum, administrator reductions in exploration ventures, and the normal downfalls of existing fields, it becomes incumbent on reservoir engineers to upgrade reserves in existing fields by carrying out the suitable enhanced oil recovery plans focused on boosting production. Foam flooding ends up being one of the ways by which this can be accomplished. Foam flooding decreases gas mobility in this manner decreasing the development of undesirable gas in this manner preventing its erupting. Be that as it may, laboratory practical test should be done earlier on foam flooding. Additionally, further works ought to be completed utilizing miscible foam assisted water alternating Gas injection (FAWAG) as it can give greater recovery compared to immiscible foam injection alone.

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Appendices

Appendix A

Foam Flooding CMG-STARS Data with 0.5 Surfactant Concentration

```
INUNIT FIELD
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: ft
RESULTS XOFFSET          0.0000
RESULTS YOFFSET          0.0000

** (DEGREES)
** (DEGREES)
** (DEGREES)
** (DEGREES)
** (DEGREES)
RESULTS ROTATION          0.0000 ** (DEGREES)
RESULTS AXES-DIRECTIONS 1.0 -1.0 1.0

**
***********************************************************************
*****
** Definition of fundamental cartesian grid
**
***********************************************************************
*****
GRID VARI 24 12 9
KDIR DOWN
DI IVAR
 24*1296.9
DJ JVAR
 12*2593.8
DK ALL
 2016*22.2002 576*22.2998
DTOP
 288*7100
** 0 = null block, 1 = active block
NULL CON           1
PERMI CON          150
POR CON         0.2
PERMK CON        133.5
** 0 = pinched block, 1 = active block
PINCHOUTARRAY CON            1
```

```
PERMJ CON        150
END-GRID
** Model and number of components
** Model and number of components
** Model and number of components
MODEL 4 4 4 2
COMPNAME 'Water' 'Surfact' 'Dead_Oil' 'Soln_Gas'
CMM
0 299.41 213.547 25.8188
PCRIT
0 0 0 653.339
TCRIT
0 0 0 -29.6738
KV1
0.0 0.0 0.0 45900.8
KV2
0.0 0.0 0.0 0.00186747
KV3
0.0 0.0 0.0 4.59498
KV4
0.0 0.0 0.0 -1583.98
KV5
0.0 0.0 0.0 -446.782
PRSR 14.6488
TEMR 140
PSURF 14.6488
TSURF 62.33
MASSDEN
68.4931 236.694 53.5476 21.7427
CP
2.82708e-006 2.82708e-006 1.06333e-005 1.06333e-005
CT1
0.000206059 0.000206059 0.000352778 0.000352778
AVG
0 0 0 2.83096e-005
BVG
0 0 0 1
VISCTABLE
**      temp
         37    1.80551    1.80551   1081.24   6.76293 ** Live oil visc (P=2155) = 86.806
         50    1.43604    1.43604   869.715    7.0522 ** Live oil visc (P=2155) = 79.4399
         70    1.07359    1.07359   635.133   7.43441 ** Live oil visc (P=2155) = 69.626
        140   0.516363   0.516363   635.133   7.43441 ** Live oil visc (P=2155) =
69.626
        212   0.309803   0.309803   90.3334   2.85621  ** Live oil visc (P=2155) =
16.2277
        284    0.21457    0.21457     21.68   1.41749  ** Live oil visc (P=2155) = 5.58848
        356   0.169027   0.169027   7.47066  0.839805  ** Live oil visc (P=2155) =
2.52103
        428   0.138837   0.138837   3.32496  0.564033  ** Live oil visc (P=2155) =
1.37666
```

```
        500   0.117754   0.117754    1.7801  0.414747  ** Live oil visc (P=2155) =
0.862951
        572  0.0999595  0.0999595   1.09166  0.325996  ** Live oil visc (P=2155) =
0.59869
        644  0.0875591  0.0875591  0.740959  0.269332  ** Live oil visc (P=2155) =
0.448065
        716  0.0776075  0.0776075  0.543138  0.231091  ** Live oil visc (P=2155) =
0.355177
        788  0.0695055  0.0695055  0.422366  0.204126  ** Live oil visc (P=2155) =
0.294258
        860  0.0627602  0.0627602  0.343889   0.18443  ** Live oil visc (P=2155) =
0.252305
        932   0.057057   0.057057  0.290286  0.169623  ** Live oil visc (P=2155) =
0.222252
       1004  0.0521719  0.0521719  0.252163  0.158223  ** Live oil visc (P=2155) =
0.20002
       1076  0.0479405  0.0479405  0.224135  0.149269  ** Live oil visc (P=2155) =
0.183131
       1148  0.0442399  0.0442399  0.202954  0.142116  ** Live oil visc (P=2155) =
0.170011
       1220   0.040976   0.040976  0.186572  0.136319  ** Live oil visc (P=2155) =
0.159626
       1292   0.038076   0.038076  0.173653   0.13156  ** Live oil visc (P=2155) =
0.151273
       1364  0.0354821  0.0354821  0.163292  0.127612  ** Live oil visc (P=2155) =
0.144459
       1436  0.0331483  0.0331483  0.154862  0.124304  ** Live oil visc (P=2155) =
0.138835
       1508  0.0310374  0.0310374  0.147917  0.121508  ** Live oil visc (P=2155) =
0.134142
VSMIXCOMP 'Soln_Gas'
VSMIXENDP 0.00797116 0.51
VSMIXFUNC 0.00797116 0.0761352 0.136785 0.191817 0.242731 0.290437
0.335853 0.379797 0.422786 0.465378 0.508075
ROCKFLUID
RPT 1 WATWET
INTCOMP 'Surfact' WATER
IFTTABLE
**  Composition of component/phase  Interfacial tension
                         0                30
                     0.001                 1
INTLIN
FMMOB 0.1
KRINTRP 1
DTRAPW 1
DTRAPN 1
**        Sw         krw        krow
SWT
        0.3            0               1
    0.31875   0.000717474    0.878906
     0.3375   0.0028699       0.765625
```

```
    0.35625   0.00645727     0.660156
      0.375   0.0114796      0.5625
    0.39375   0.0179369      0.472656
     0.4125   0.0258291      0.390625
    0.43125   0.0351563      0.316406
       0.45   0.0459184      0.25
    0.46875   0.0581154      0.191406
     0.4875   0.0717474      0.140625
    0.50625   0.0868144      0.0976563
      0.525   0.103316       0.0625
    0.54375   0.121253       0.0351563
     0.5625   0.140625       0.015625
    0.58125   0.161432       0.00390625
        0.6   0.183673       0
        0.8   0.510204       0
          1      1           0


**       Sl          krg            krog
SLT
        0.3        0.3                0
      0.525        0.128254           0
       0.75        0.0284024          0
     0.7625        0.024963           0.0025
      0.775        0.0217456          0.01
     0.7875        0.01875            0.0225
        0.8        0.0159763          0.04
     0.8125        0.0134246          0.0625
      0.825        0.0110947          0.09
     0.8375        0.00898669         0.1225
       0.85        0.00710059         0.16
     0.8625        0.00543639         0.2025
      0.875        0.00399408         0.25
     0.8875        0.00277367         0.3025
        0.9        0.00177515         0.36
     0.9125        0.000998521        0.4225
      0.925        0.000443787        0.49
     0.9375        0.000110947        0.5625
       0.95        0                  0.64
      0.975        0                  0.81
          1        0                  1

KRINTRP 2
DTRAPW 0.909091
DTRAPN 0.909091
**       Sw         krw       krow
SWT
        0.3           0          1
    0.31875  0.000717474    0.878906
     0.3375   0.0028699    0.765625
    0.35625   0.00645727    0.660156
```

```
      0.375    0.0114796      0.5625
    0.39375    0.0179369    0.472656
     0.4125    0.0258291    0.390625
    0.43125    0.0351563    0.316406
       0.45    0.0459184        0.25
    0.46875    0.0581154    0.191406
     0.4875    0.0717474    0.140625
    0.50625    0.0868144   0.0976563
      0.525     0.103316      0.0625
    0.54375     0.121253   0.0351563
     0.5625     0.140625    0.015625
    0.58125    `0.161432 0.00390625
        0.6     0.183673           0
        0.8     0.510204           0
          1            1           0



**       Sl          krg      krog

SLT
        0.3          0.3         0
      0.525     0.128254         0
       0.75    0.0284024         0
     0.7625     0.024963    0.0025
      0.775    0.0217456      0.01
     0.7875      0.01875    0.0225
        0.8    0.0159763      0.04
     0.8125    0.0134246    0.0625
      0.825    0.0110947      0.09
     0.8375   0.00898669    0.1225
       0.85   0.00710059      0.16
     0.8625   0.00543639    0.2025
      0.875   0.00399408      0.25
     0.8875   0.00277367    0.3025
        0.9   0.00177515      0.36
     0.9125  0.000998521    0.4225
      0.925  0.000443787      0.49
     0.9375  0.000110947    0.5625
       0.95            0      0.64
      0.975            0      0.81
          1            0         1
KRWIRO 0.909091
KRGCW 0.909091
ADSCOMP 'Surfact' WATER
ADSTABLE
**     Mole Fraction Adsorbed moles per unit pore volume
**     Mole Fraction Adsorbed moles per unit pore volume
                  0                              0
     6.024164656e-005                  0.0004573024163
ADMAXT 0.000457302
```

```
BSOIRW CON         0.4
INTERP_ENDS ON
INITIAL
VERTICAL DEPTH_AVE

INITREGION 1
REFDEPTH 7100
DWOC 7250
DGOC 7100
REFPRES 3840
SO CON         0.7
MFRAC_WAT 'Water' CON           1
MFRAC_OIL 'Soln_Gas' CON     0.497041
MFRAC_OIL 'Dead_Oil' CON     0.502959
NUMERICAL
RUN
DATE 2010 1 1
DTWELL 0.01
**
WELL  'PRODUCER'
PRODUCER 'PRODUCER'
OPERATE  MIN  BHP  32.0  CONT
OPERATE  MAX  STO  10000.0  CONT
**          rad  geofac  wfrac  skin
GEOMETRY  K  0.28  0.249  1.0  0.0
     PERF     GEOA  'PRODUCER'
** UBA            ff         Status Connection
   7 6 1        1.0  OPEN    FLOW-TO  'SURFACE'  REFLAYER
   7 6 2        1.0 OPEN     FLOW-TO  1
   7 6 3        1.0  OPEN    FLOW-TO  2
   7 6 4        1.0  OPEN    FLOW-TO  3
   7 6 5        1.0  OPEN    FLOW-TO  4
   7 6 6        1.0  OPEN    FLOW-TO  5
   7 6 7        1.0  OPEN    FLOW-TO  6
   7 6 8        1.0  OPEN    FLOW-TO  7
   7 6 9        1.0  OPEN    FLOW-TO  8
**
WELL  'INJECTOR- 1'
INJECTOR MOBWEIGHT EXPLICIT 'INJECTOR- 1'
INCOMP  WATER  0.5  0.5  0.0  0.0
TINJW  100.0
OPERATE  MAX  BHP  12000.0  CONT
OPERATE  MAX  STG  1000000.0  CONT
**          rad  geofac  wfrac  skin
GEOMETRY  K  0.28  0.249  1.0  0.0
     PERF     GEOA  'INJECTOR- 1'
** UBA            ff         Status  Connection
   2 2 1        1.0  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
   2 2 2        1.0  OPEN    FLOW-FROM  1
   2 2 3        1.0  OPEN    FLOW-FROM  2
   2 2 4        1.0  OPEN    FLOW-FROM  3
```

```
   2 2 5       1.0  OPEN    FLOW-FROM  4
   2 2 6       1.0  OPEN    FLOW-FROM  5
   2 2 7       1.0  OPEN    FLOW-FROM  6
   2 2 8       1.0  OPEN    FLOW-FROM  7
   2 2 9       1.0  OPEN    FLOW-FROM  8
**
WELL  'INJECTOR- 2'
INJECTOR MOBWEIGHT EXPLICIT 'INJECTOR- 2'
INCOMP  WATER  0.5  0.5  0.0  0.0
TINJW  100.0
OPERATE  MAX  BHP  12000.0  CONT
OPERATE  MAX  STG  1000000.0  CONT
**        rad  geofac  wfrac  skin
GEOMETRY  K  0.28  0.249  1.0  0.0
    PERF     GEOA  'INJECTOR- 2'
** UBA            ff        Status  Connection
   22 2 1       1.0  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
   22 2 2       1.0  OPEN    FLOW-FROM  1
   22 2 3       1.0  OPEN    FLOW-FROM  2
   22 2 4       1.0  OPEN    FLOW-FROM  3
   22 2 5       1.0  OPEN    FLOW-FROM  4
   22 2 6       1.0  OPEN    FLOW-FROM  5
   22 2 7       1.0  OPEN    FLOW-FROM  6
   22 2 8       1.0  OPEN    FLOW-FROM  7
   22 2 9       1.0  OPEN    FLOW-FROM  8
**
**
WELL  'INJECTOR-3'
INJECTOR MOBWEIGHT EXPLICIT 'INJECTOR-3'
INCOMP  WATER  0.5  0.5  0.0  0.0
TINJW  100.0
OPERATE  MAX  BHP  12000.0  CONT
OPERATE  MAX  STG  1000000.0  CONT
**        rad  geofac  wfrac  skin
GEOMETRY  K  0.28  0.249  1.0  0.0
    PERF     GEOA  'INJECTOR-3'
** UBA            ff        Status  Connection
   21 9 1       1.0  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
   21 9 2       1.0  OPEN    FLOW-FROM  1
   21 9 3       1.0  OPEN    FLOW-FROM  2
   21 9 4       1.0  OPEN    FLOW-FROM  3
   21 9 5       1.0  OPEN    FLOW-FROM  4
   21 9 6       1.0  OPEN    FLOW-FROM  5
   21 9 7       1.0  OPEN    FLOW-FROM  6
   21 9 8       1.0  OPEN    FLOW-FROM  7
   21 9 9       1.0  OPEN    FLOW-FROM  8
**
**
WELL  'INJECTOR-4'
INJECTOR MOBWEIGHT EXPLICIT 'INJECTOR-4'
INCOMP  WATER  0.5  0.5  0.0  0.0
```

```
TINJW  100.0
OPERATE  MAX  BHP  12000.0  CONT
OPERATE  MAX  STG  1000000.0  CONT
**        rad  geofac  wfrac  skin
GEOMETRY  K  0.28  0.249  1.0  0.0
    PERF     GEOA  'INJECTOR-4'
** UBA          ff        Status  Connection
   4 9 1       1.0  OPEN   FLOW-FROM  'SURFACE'  REFLAYER
   4 9 2       1.0  OPEN   FLOW-FROM  1
   4 9 3       1.0  OPEN   FLOW-FROM  2
   4 9 4       1.0  OPEN   FLOW-FROM  3
   4 9 5       1.0  OPEN   FLOW-FROM  4
   4 9 6       1.0  OPEN   FLOW-FROM  5
   4 9 7       1.0  OPEN   FLOW-FROM  6
   4 9 8       1.0  OPEN   FLOW-FROM  7
   4 9 9       1.0  OPEN   FLOW-FROM  8
**
WELL  'PRODUCER 2'
PRODUCER 'PRODUCER 2'
OPERATE  MIN  BHP  32.0  CONT
OPERATE  MAX  STO  10000.0  CONT
**        rad  geofac  wfrac  skin
GEOMETRY  K  0.28  0.249  1.0  0.0
    PERF     GEOA  'PRODUCER 2'
** UBA           ff        Status  Connection
   19 6 1       1.0  OPEN   FLOW-TO  'SURFACE'  REFLAYER
   19 6 2       1.0  OPEN   FLOW-TO  1
   19 6 3       1.0  OPEN   FLOW-TO  2
   19 6 4       1.0  OPEN   FLOW-TO  3
   19 6 5       1.0  OPEN   FLOW-TO  4
   19 6 6       1.0  OPEN   FLOW-TO  5
   19 6 7       1.0  OPEN   FLOW-TO  6
   19 6 8       1.0  OPEN   FLOW-TO  7
   19 6 9       1.0  OPEN   FLOW-TO  8
DATE 2010 2  1.00000
DATE 2010 3  1.00000
DATE 2010 4  1.00000
DATE 2010 5  1.00000
DATE 2010 6  1.00000
DATE 2010 7  1.00000
DATE 2010 8  1.00000
DATE 2010 9  1.00000
DATE 2010 10  1.00000
DATE 2010 11  1.00000
DATE 2010 12  1.00000
DATE 2011 1  1.00000
DATE 2011 2  1.00000
DATE 2011 3  1.00000
DATE 2011 4  1.00000
DATE 2011 5  1.00000
DATE 2011 6  1.00000
```

DATE 2011 7 1.00000
DATE 2011 8 1.00000
DATE 2011 9 1.00000
DATE 2011 10 1.00000
DATE 2011 11 1.00000
DATE 2011 12 1.00000
DATE 2012 1 1.00000
DATE 2012 2 1.00000
DATE 2012 3 1.00000
DATE 2012 4 1.00000
DATE 2012 5 1.00000
DATE 2012 6 1.00000
DATE 2012 7 1.00000
DATE 2012 8 1.00000
DATE 2012 9 1.00000
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RESULTS PVTIMEX TABLE 1085.12 4.90752 1.04627 0.104287 517.025 0.0112062 846.898 10.4448 4.35113e-006
RESULTS PVTIMEX TABLE 2068.91 9.83239 1.058 0.0532138 431.088 0.0114665 842.579 20.4694 4.35113e-006
RESULTS PVTIMEX TABLE 3052.7 15.2348 1.0712 0.03506 365.429 0.0117889 837.69 31.0683 4.35113e-006
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RESULTS PVTIMEX TABLE 5020.29 27.0303 1.10106 0.0201147 276.001 0.0126266 826.641 54.1523 4.35113e-006
RESULTS PVTIMEX TABLE 6004.08 33.3104 1.11748 0.0163328 244.956 0.0131533 820.616 66.6914 4.35113e-006
RESULTS PVTIMEX TABLE 6987.84 39.7996 1.13479 0.0136338 219.885 0.0137616 814.327 79.8937 4.35113e-006
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RESULTS PVTIMEX TABLEDO 21.1111 250
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RESULTS PVTIMEX BPP 15
RESULTS PVTIMEX BWI 1.00519
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RESULTS PVTIMEX WATERCVW 0
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RESULTS PVTIMEX TABLE 10923 67.4479 1.21189 0.00791978 155.313 0.0171133 787.371 137.536 3.53335e-006
RESULTS PVTIMEX TABLE 11906.8 74.7149 1.23294 0.00715365 144.647 0.0181732 780.348 152.266 3.15856e-006
RESULTS PVTIMEX TABLE 12890.6 82.1042 1.25465 0.00653501 135.361 0.0193021 773.26 166.68 2.84893e-006
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RESULTS PVTIMEX TABLE 16023.4 106.37 1.29667 0.00522097 120 0.0231739 760.898 208.631 2.14778e-006
RESULTS PVTIMEX TABLE 17188.6 115.656 1.29401 0.00489942 120 0.0246526 762.467 222.324 1.96078e-006
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RESULTS SPEC STOP


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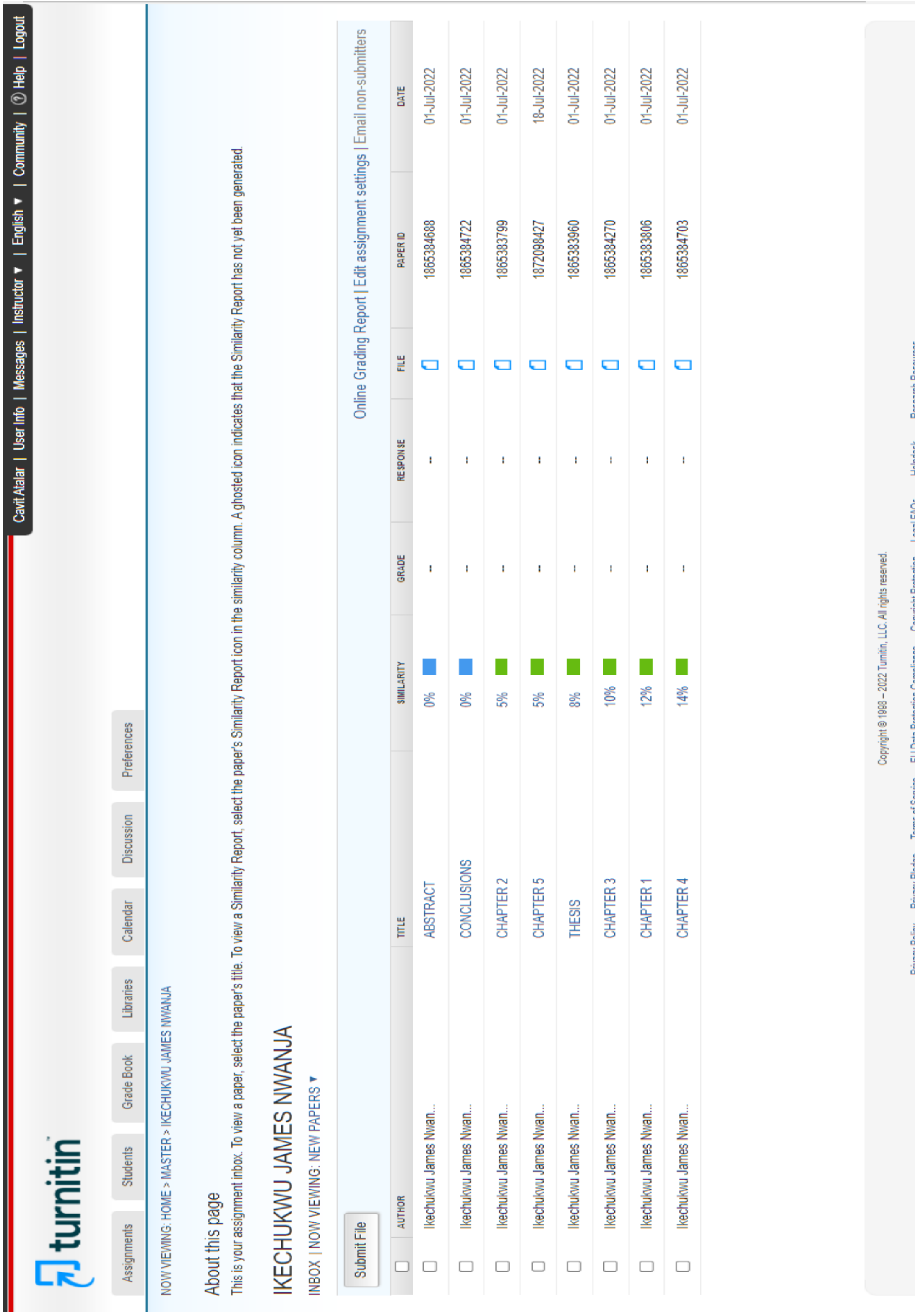
Appendix B

Turnitin Similarity Report



AUTHOR	TITLE	SIMILARITY	GRADE	RESPONSE	FILE	PAPER ID	DATE
Ikechukwu James Nwan...	ABSTRACT	0%	--	--		1865384688	01-Jul-2022
Ikechukwu James Nwan...	CONCLUSIONS	0%	--	--		1865384722	01-Jul-2022
Ikechukwu James Nwan...	CHAPTER 2	5%	--	--		1865383799	01-Jul-2022
Ikechukwu James Nwan...	CHAPTER 5	5%	--	--		1872098427	18-Jul-2022
Ikechukwu James Nwan...	THESIS	8%	--	--		1865383960	01-Jul-2022
Ikechukwu James Nwan...	CHAPTER 3	10%	--	--		1865384270	01-Jul-2022
Ikechukwu James Nwan...	CHAPTER 1	12%	--	--		1865383806	01-Jul-2022
Ikechukwu James Nwan...	CHAPTER 4	14%	--	--		1865384703	01-Jul-2022

APPENDIX C

ETHICAL APPROVAL LETTER

YAKIN DOĞU ÜNİVERSİTESİ
ETHICAL APPROVAL DOCUMENT

Date: 21/06/2022

To the **Institute of Graduate Studies**

The research project titled "**COMPARISON OF FOAM FLOODING AND WATER ALTERNATING GAS IN THE ASMARI RESERVOIR, IRAN**'' has been evaluated. Since the researcher will not collect primary data from humans, animals, plants or earth, this project does not need through the ethics committee.

Title: Prof. Dr.

Name Surname: Cavit ATALAR

Signature:

Role in the Research Project: Supervisor