OPTIMIZATION STUDY OF FOAM ASSISTED WATER ALTERNATING GAS (FAWAG) IN PRESENCE OF ASPHALTENE IN LIGHT OIL

By

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Dissertation submitted in partial fulfillment of the requirement for the Bachelor of Engineering (Hons) (Petroleum Engineering)

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CERTIFICATION OF APPROVAL

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Approved by,

____
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UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

MAY 2013

CERTIFICATION OF ORIGINALITY

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

JUHAIRI ARIS BIN MUHAMAD SHUHILI

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ABSTRACT

This dissertation summarizes the overall tasks undertaken by the authors in completing the Final Year Project which entitles Optimization Study of Foam Assisted Water Alternating Gas (FAWAG) in presence of Asphaltene in Light oil. The deposition of asphaltene in light oil had been a serious predicament during the production phase. The damage caused by asphaltene deposition was extensive starting from the vicinity of wellbore up to the surface facilities. In order to mitigate the deposition, a novel approach by using FAWAG method was to be determined. The main objective of the project was the determination of the effect of FAWAG towards the asphaltene deposition and optimization of FAWAG parameters; water injection rate and surfactant concentration which result in minimum asphaltene deposition. The project also included the addition of comparison between WAG and FAWAG in mitigating asphaltene deposition. The method employed upon the completion of the project was basically performing simulation run on determining the effect of both FAWAG and WAG towards the asphaltene deposition. The result of the simulation shows that FAWAG method was more contributive compared to WAG in asphaltene deposition reduction. The asphaltene deposition is done by analyzing the Field Oil Production Total (FOPT). FAWAG model with asphaltene had more recovery than without asphaltene. An optimum surfactant concentration and water injection rate were successfully obtained.

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NOMENCLATURE & ABBREVIATION

1. API: American Petroleum Institute

2, CLS: Calcium Lignosulfonate

3. CMC: Critical Micelle Concentration

4. CO2: Carbon Dioxide

5. EOR: Enhanced Oil Recovery

6. FAWAG: Foam Assisted Water Alternating Gas

7. FOPT: Field Oil Production Total

8. FPR: Field Average Pressure

9. GOR: Gas-Oil Ratio

10. IFT: Interfacial Tension

11. STB: Stock-tank per Barrel

12. WAG: Water Alternating Gas

CHAPTER 1
INTRODUCTION

1. 1 Background Study

Petroleum is one of the most essential resources used in today's world. Apart from being the most valuable energy resources, many products are made from petroleum distillate. The main issue of petroleum industry is the depletion of the natural resources. Consequently, most oil companies resorted to tertiary method to retrieve the remaining oil which initially deemed to be unrecoverable. Basically, there are 3 ways of producing hydrocarbon. Those are primary, secondary and tertiary recovery. The latter is also known as Enhanced Oil Recovery (EOR). In the primary recovery, the production of hydrocarbon from a reservoir is solely depends on the energy of the reservoir itself. The reservoir does not acquire any additional process or being aided by any form of injection. There are several primary recovery drive mechanisms such as water drive, gas cap drive, solution gas drive, gravity drive and compaction drive. Each of the drive mechanism has their own significance in the amount of hydrocarbon recovered.

The secondary method is designated for the purpose of pressure maintenance. Prior to production of hydrocarbon, the reservoir pressure remains constant with time. The decline in pressure is observed soon after the production is initiated. The longer the production, the pressure declines more. Hence, to compensate for the loss in reservoir pressure, a pressure maintenance system is introduced. Apart from pressure maintenance, water flooding is another form of secondary recovery. In water flooding, injection wells are drilled in a pattern which usually surrounds production wells as water is injected to the reservoir to displace the remaining oil in the form of piston like displacement.

The third method is Enhanced Oil Recovery (EOR). In EOR, the main goal is to alter the properties of hydrocarbon such as viscosity and surface tension. Some EOR techniques are to control mobility of the injected fluids. The examples of EOR techniques are water alternating gas (WAG), surfactant injection, thermal flooding and in situ combustion.

In this project, Foam Assisted Water Alternating Gas (FAWAG) method will be discussed in detail. FAWAG is introduced to have a better mobility control over the injected fluid. Originally, in immiscible injection of CO2, the viscous fingering is a common sight. Viscous fingering occurs due to the significant difference in the magnitude of the displacing fluid viscosity in comparison to displaced fluid viscosity. In order to prevent the occurrence of viscous fingering, Water-Alternating Gas (WAG) technique is introduced (Green & Willhite, 1998). However, the presence of water in WAG has reduced the oil-gas contact which contributes to the overall reduction of the WAG process itself. This is because the miscibility between gas and oil is harder to achieve. Gravity segregation and presence of thief zone tend to further impair the WAG process (Safarzadeh et al., 2011).

The FAWAG technique provides solution for both the gravity segregation and thief zone cases. As the gas rises up to the upper layer of reservoir due to density difference, foam forms as gas comes in contact with the surfactant. As more gas travels to the upper part, more foam will be generated. This foam acts as a blocking or trapping agent for the gas. As time goes on, the foam layer formed will serve as a barrier for the gas to travel upward and ensures the better displacement process. The presence of thief zone will further enhance the bypassing phenomenon. The gas opts to follow the most permeable path and oil remains not displaced in low permeable zone. In this scenario, the foam forms in the thief zone will prevent more gas entering the thief zone and thus channeling the gas to the less permeable layers.

Other than FAWAG, another important element of the project is asphaltene deposition in light oil. Deposition of asphaltene in light oil can be described as a peculiar phenomenon since light oil comprises less amount of asphaltene compared to heavy oil. However, the asphaltene deposition does not occur in heavy oil. The explanation behind this strange occurrence is due to the asphaltene solubility preference. Asphaltene readily dissolves in heavy oil but does not dissolve in light oil. This is because of the difference in the properties of heavy oil and light oil. In light oil, the major components are saturates and small fraction of aromatics, resin and asphaltene. In heavy oil, the major components are resin, aromatics, and asphaltene. Heavy oil comprises of less saturates. The tendency of asphaltene to precipitate in light oil is higher due to lack of saturates. Despite of having high concentration of asphaltene, heavy oil does not show any asphaltene deposition because the content of aromatics component is substantial to prevent the precipitation of asphaltene.

Asphaltene deposition has been a serious issue in CO2 injection. This happens as the CO2 interacts with the oil and causes the oil to swell, the lighter components increase. The lighter components are reactive with resin which holds the asphaltene from precipitating. When the resin begins to react with the lighter components, the asphaltene starts to deposit (Ali, 2009).

1.2 Problem Statement

The main problem to solve by conducting this project was asphaltene deposition in light oil. Deposition of asphaltene causes serious problem such as blockage in wellbore, pipeline and also at surface facilities. Asphaltene deposition disrupts both tubing and inflow performance. The cost of cleaning the asphaltene is very expensive and might be economically unfeasible to stop the production for the sole purpose of cleaning the asphaltene deposition. The asphaltene deposition also occurs when CO2 injection is being applied. By having the asphaltene deposition during CO2 injection, the original aim of CO2 to assist in oil recovery efficiency has been defeated. Hence, a novel approach by using FAWAG instead of CO2 injection to reduce the asphaltene deposition in the light oil has been proposed. Hence, the effect of FAWAG on asphaltene deposition and the optimization of the technique was studied.

1.2.1 Problem Identification

1. The effect of FAWAG on asphaltene deposition in light oil is not being studied.

2. Optimized water injection rates and surfactant concentration resulting in minimum asphaltene deposition are unknown.

1.3 Objectives of Study

The project was conducted to determine the effect of FAWAG technique towards asphaltene deposition in light oil and optimization of the FAWAG parameters; water injection rate and surfactant concentration.

1.4 Scope of Study

The scope of the study for the project was simulation runs on a synthetic reservoir built by using Eclipse. The reservoir model and fluid model were obtained from the provided Eclipse dataset. The same grid properties, asphaltene properties and rock properties were incorporated in both WAG and FAWAG model. The properties were consistently used throughout the simulation runs. The project covered four main simulations before proceeding to the optimization stage. Those stages were WAG model, WAG with asphaltene model, FAWAG model and FAWAG with asphaltene model. Time frame to conduct this project was approximately less than 4 months, thus sufficient amount of time was available to perform different combination of injection rate and surfactant concentration. The research done was only limited to simulation work by using the software Eclipse. There was no lab experimentation involved. The project was completed within the four months period allocated.

CHAPTER 2
LITERATURE REVIEW

2.1 Asphaltene Definition & Properties

Asphaltene was defined by Nellensteyn (1924) as the fraction soluble in carbon tetrachloride and benzene but insoluble in low boiling point paraffin hydrocarbons. Boussingault (1937) defined asphaltene as the distillation residue of bitumen: insoluble in alcohol and soluble in turpentine. Asphaltene does not melt when it is heated above 300-400 °C, but decomposes and forms carbon and volatile products. In oil, asphaltene is believed to exist in dual form, partly colloidal and partly dissolved. Asphaltene has the molecular weight of 800g/mol (Boduszynski, 1981; Groenzin & Mullins, 1999). Asphaltene has a density between 1.1 to 1.20 g/mL (Speight, 2007), an atomic H/C ratio of 1.0-1.2 (Spiecker et al., 2003), and a solubility parameter between 19 and 24 MPa at ambient conditions (Hirschberg et al., 1984; Wiehe, 1996). The main constituents of oil at ambient temperature are oils (saturated or aromatic), resin, and asphaltene. Asphaltene and resins differ in color and texture. Asphaltene is black, shiny, and friable solids; while resins are dark brown, shiny, and gummy. Two concentrations regimes have been identified in crude oils: a diluted regime where viscosity increases linearly with asphaltene content and a concentrated regime where viscosity depends more than exponentially on asphaltene content (Gaoul, 2004).

2.2 Factors Affecting Asphaltene Deposition

There are a few factors that govern the asphaltene deposition. Those are variation of temperature, pressure, flow regime, composition and electro kinetic effects. The effect of composition change can be seen throughout reservoir life. Initially, in an undersaturated condition, the reservoir has high GOR in which the lighter components dominate. During this period, the asphaltene deposition increases as the pressure of the reservoir drops to the bubble point pressure. As the pressure drops, the oil in the reservoir becomes less dense and less asphaltene-soluble. The concentration of saturate in oil dominates. As the pressure drops below bubble point, the lighter components will be produced. The remaining oil in the reservoir will consist of only heavy oil which is a better solvent for asphaltene. As it can be seen, the asphaltene deposition will decrease at the later production time. The electric kinetic effect occurs mostly at the wellbore where the velocity is highest. This fluid carries along electrical potential which reacts with the asphaltene micelle and cause asphaltene to deposit. Hence, a larger drawdown should be avoided to ensure minimum asphaltene deposition (Ali, 2009).

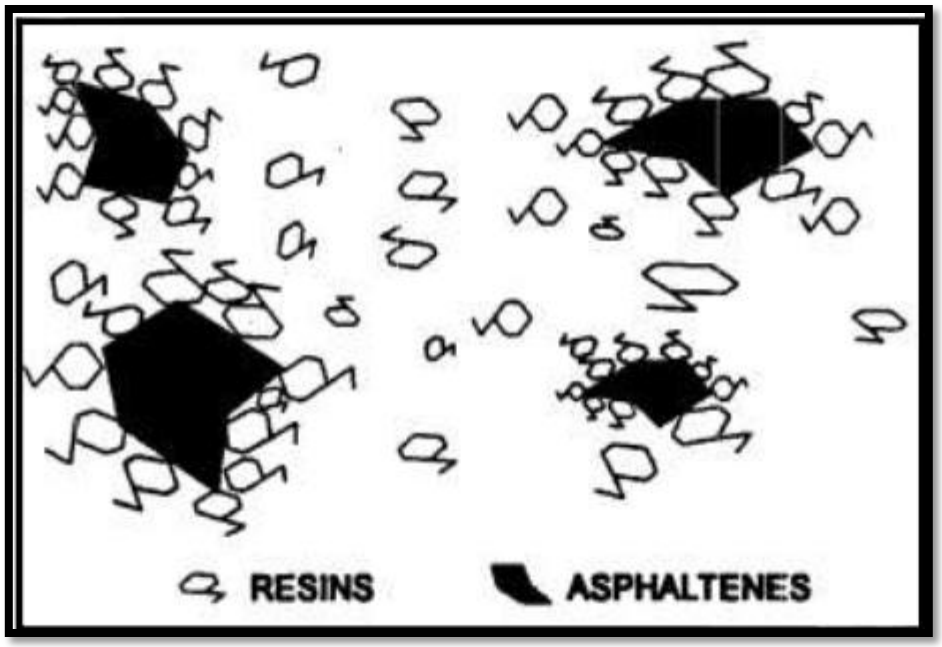

Figure 1: Asphaltene & Resin Colloidal Model

Reference : Kokal & Sayegh

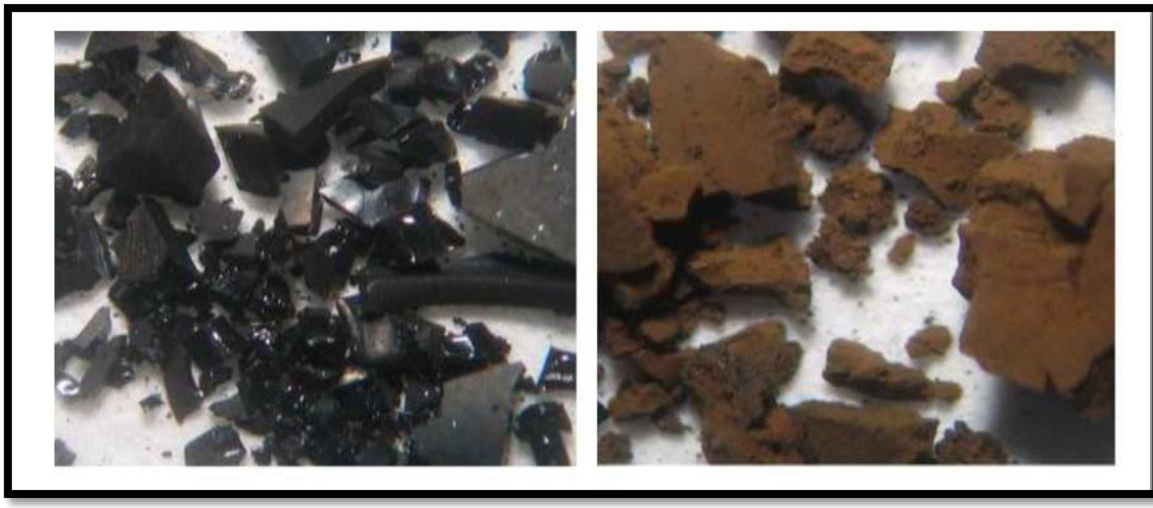

Figure 2: Asphaltene Deposition

Reference: NMT Reference FAQ

The asphaltene stability takes precedence in determining the tendency of the asphaltene to deposit compared to the amount of asphaltene. There are a few factors influencing the asphaltene deposition, including the composition of the surrounding fluid – where how good a solvent the rest of the oil is for its asphaltene, pressure and temperature (Eduardo *etc al*, 2004).

There are a few operations that affect the stability of asphaltene such as gas injection, phase separation, incompatible chemicals and changing of composition due to mixing of crude streams. In light oil reservoir, the asphaltene solubility is low which ease the asphaltene to become unstable and precipitate (Sima *et al*, 2011).

The asphaltene will precipitate under a critical resin concentration and never precipitates above the critical value at any pressure, temperature or even composition change (Lichaa, 1977 & Swanson, 1942). The concentration below the critical micelle concentration (CMC), the asphaltene in solution will remain in a molecular state, whereas, above the CMC, asphaltene micelle formation occurs as in surfactant systems. Heavy oils contain more asphaltene than light oil. However, the deposition of asphaltene is higher in light oil. The reason behind this unusual occurrence is due to the low solubility of asphaltene in light alkane (Sheu, 1996). Heavy oil is a good solvent of asphaltene. The disturbance in the thermodynamic equilibrium of the asphaltene-resins micelles due to change in the pressure, temperature and oil composition is another main reason of asphaltene precipitation (Leontaritis, and Mansoori, 1987; Saram, 2003; Buenrostro-Gonzalez et al., 2004).

Pressure has more significant effect on asphaltene stability in crude oil compared to temperature. According to an experiment carried out by Sima *et al* in year 2011, less asphaltene deposition has been reported by increasing the injection pressure of gas. The less deposition of asphaltene has been inferred by less reduction in permeability and porosity value. This result is further proven by the experiment carried out by Eduardo et al in year 2004.

The destabilization of asphaltene is mainly render by decline in pressure which eventually induces asphaltene precipitation. The pressure decline phenomenon is not only observed in the reservoir environment but at the surface facilities as well. The pressure declines as the transportation of liquid takes place in the pipeline. The drop in pipeline is mainly due to the friction with the inner wall or constraints from the equipment or geometry. Thus, asphaltene deposition can be found in the pipeline. Due to pressure drop, crude oil density decreases which prompt the interactions between asphaltene to become stronger and result in precipitation (Eduardo et al, 2004).

Hammami et al. (2000) conducted an experiment to measure the API for various Gulf of Mexico live oils through a series of isothermal pressure depletion experiments. The result obtained was the favorability of asphaltene deposition with respect to saturation pressure. The asphaltene precipitation above the saturation pressure is higher than below saturation pressure. The solubility below the saturation pressure is low.

2.3 Damage due to Asphaltene Deposition

The various arterial blockages in petroleum industry are due to the deposition of asphaltene. This phenomenon results in costly process since it hampers the overall production. The asphaltene deposition distorts flow at wellbore, pipelines and surface facilities (Mansoori, 1995).

The adverse effect in a large magnitude can be observed due to asphaltene deposition. The adverse effects emerge from permeability and porosity reduction, alteration of formation wettability, plugging of reservoir and fouling of surface facilities (Ghedan, 2009; Srivastava *et al.*, 1997).

As stated by de Boer et al. (1995), minimal amount of asphaltene contained in the light oil has more tendencies to precipitate than the high amount of asphaltene fraction in the heavy oil during the production phases. Plugging of reservoir can occur as the destabilization of asphaltene happens which triggers the precipitation of asphaltene. This clearly indicates the stability of the asphaltene plays a main role in ensuring optimum performance of crude oil production. There are a few stages in asphaltene deposition. The first stage is when the asphaltene makes itself distinct by separation from the crude oil. . The first stage is known as precipitation stage. In the next stage, the separated asphaltene particle will stick to each other and clump into lump particles. This stage is called flocculation stage. As the lumping process continues with time, the size of the asphaltene grows and becomes heavier to be carried along with the crude oil. Finally, all the clumped together particles will settle out on solid surface and deposited. This last stage is known as deposition of asphaltene.

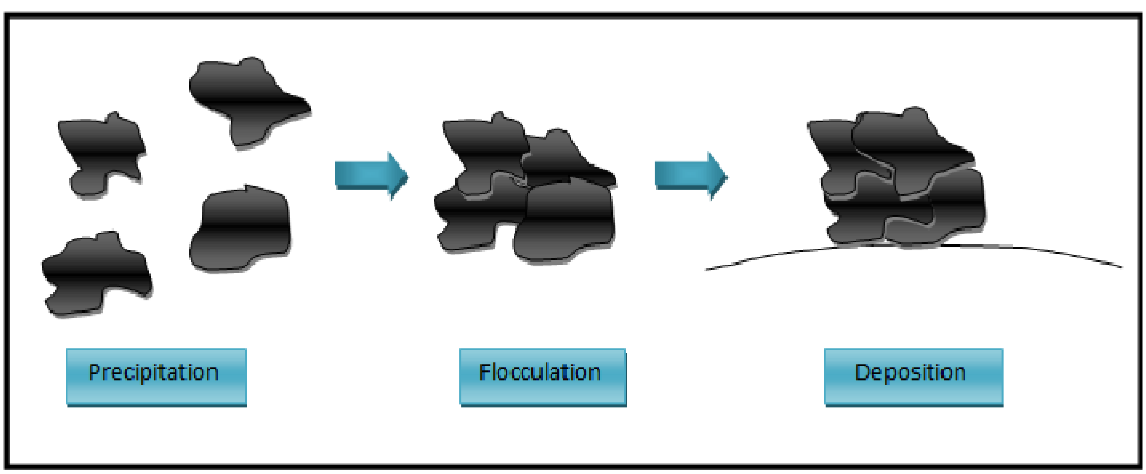

Figure 3: Asphaltene Precipitation Stages

Figure 4: Asphaltene Precipitation in Pipe

Reference : http://www.bakerhughes.com

2.4 Foam Assisted Water Alternating Gas (FAWAG)

Oil recoveries have 3 consecutive stages which are the primary, secondary and tertiary oil recovery which is also known as the EOR. Primary recovery according to the Schlumberger Oilfield Glossary is defined as the first stage of hydrocarbon recovery which uses the natural reservoir energy, such as gravity drainage, water drive and gas drive. Among the three stages of recovery, primary recovery has the lowest recovery and incurs least cost. As for the secondary recovery is defined as the second stage of hydrocarbon recovery which uses external fluid such as water or gas injected into the reservoir to maintain the pressure of the reservoir so that the reservoir pressure is strong enough to drive the oil to the wellbore. (Larry *et al*., 1992). The first 2 stages of recovery could only recover one third of the oil initially in place and the work will be abandoned once the production cost has offset the revenue obtained from the oil recovered. (Larry *et al*., 1992). As more mature fields have been abandoned due to the aforementioned reason, the tertiary recovery comes in handy. The first two stages can recover up to 10-20% of the original oil in the reservoir and the oil companies will resort to EOR which is a more enhanced technique.

FAWAG is defined as addition of foam in WAG to improve the sweep efficiency and reduce gas production or Gas Oil Ratio (GOR). Foam is usually used as an agent to block the upward movement of gas and promote the lateral movement. FAWAG is introduced in the reservoir only after WAG has taken place (Saleem & Tariq, 2011). In most cases, after FAWAG was introduced, the amount of oil recovery increased in the range of 1.5-5 folds and the reduction of water cut was up to 20% (Alex & Ashok, 1998).

The range of surfactant concentration is 500-2000mg/L. Apart from mobility control, the surfactant in FAWAG also serves to reduce the interfacial tension between oil and water. However, the impact of foam used in FAWAG towards interfacial reduction is insignificant. The presence of anhydrate, gypsum and clay will inhibit the performance of FAWAG since these minerals are reactive with surfactant. The chemical used in surfactant flooding can degrade at a very high reservoir temperature. (Tabir & Martin, 1983)

The formation of the foam as a result of injected gas reaction with the surfactant has shown significant reduction in carbon dioxide mobility. Foam managed to reduce the mobility of carbon dioxide by 40% to 85% (F. Khalil & K. Asghari, 2006). In another field test, recovery is improved by implementing FAWAG method when the operating pressure is less than the minimum miscibility pressure of carbon dioxide in the Wilmington field (Holm, L.W. & Garrison, W.H, 1998).

FAWAG is the superior method than gas injection and water alternating gas as it solves some of the problems encountered while performing these two methods. In term of ultimate recovery, FAWAG shows 10% higher than the water alternating gas (WAG) (Safarzadeh et al., 2011). The surfactant works by increasing the viscosity of the gas phase which results in decrease of gas mobility and this helps in increase of oil mobility.

The major problem faced by the gas injection is poor sweep efficiency and inefficient in low pressure reservoir (Grigg, Bai & Lu, 2004). The drawbacks of water alternating gas (WAG) method (Le & Nguyen, 2008). WAG is tempered by the reduction of oil-gas contact in the presence of water. WAG method is backfired by the gravity segregation and this flaw is magnified by the difference in permeability. Injectivity of WAG in carbonate reservoir is reduced as well. The main concern about FAWAG is not the technical issue but the economical aspect since addition of surfactant will incur additional costs (Gogoi, 2009).

The first advantage of FAWAG is minimizing the contact between gas and water which reduces corrosion. The second advantage is it requires less injection pressure (Kloet, Renkema & Rossen, 2009). In WAG, higher injection pressure is needed to overcome gravity override. This high pressure may fracture the formation and unlike the other injection method, FAWAG has the zero possibility of blocking the porous medium (Turta & Singhal, 1998).

FAWAG improves the injectivity significantly. This is because as the water is being displaced by gas from the near well region, the gas mobility increases at the wellbore vicinity while stronger and wetter foam travels away from the well to maintain mobility (Xu & Rosen, 2004).

The main concern about FAWAG is the loss of foaming agent by the adsorption onto reservoir rocks (Blaker, Celius & Lie, 1999). The difference in mineralogy of reservoir rock causes the solid surface to be charged. The mineral is usually positively charged at lower pH and negatively charged at higher pH. These charged surfaces react with the surfactant ions and cause the adsorption of the surfactant and result in major loss of foam (Liu et al, 2005).

There are 2 possible solutions to the loss of foam through adsorption. The first solution is injecting sufficient amount of surfactant into the reservoir to satisfy the surfactant adsorption prior to injection of gas or to use sacrificial agent like Calcium Lignosulfonate (CLS). CLS has stronger affinity to the rock surface. CLS will be adsorbed to the rock surface which greatly reduces the surface area exposed to surfactant for adsorption (Morahdi &Johnston, 1997).

The understanding of adsorption process is paramount in studying the chemical transportation and in assessing the volume of chemicals required for a successful FAWAG operation (Song & Islam, 1994).

There are several factors of surfactant being unfavorable in the past. Those factors are sensitivity to oil price, limitation of the chemical, high surfactant concentration, salinity optimization required and the potential of emulsion block to occur (Khaled, 2011). The oil price was not stable in the past and depends largely on the world economy and also rendered unstable due to infamous events such as war. However, the price of oil has become stable in this globalization era. In the past, due to lack of research conducted on the surfactant, the limitation on the knowledge regarding the surfactant and supplies dampened the surfactant usage in EOR. Due to less research on the surfactant, larger amount of concentration might be used since the optimization study has not been done. Lastly, the emulsion of surfactant and oil might cause blockage which will further decrease the permeability of the system.

However, the continuous increase in the oil price due to high demand from worldwide made FAWAG method feasible. The increment in the cost of FAWAG in the past years is considered insignificant compared to sharp increment in oil price. Chemical flooding is used in several countries and widely employed in China. The surfactant acts as a scrubbing agent who reduces the interfacial tension and produces the residual oil by forming emulsion of hydrocarbon in aqueous phase. The surfactant will reduce the irreducible oil saturation and increase the saturation of moveable oil. Generally, there are 3 types of surfactants. Those are anionic, nonionic and cationic surfactant. Anionic is the most widely used in EOR because of the stability at high temperature and low adsorption to the rock surface. The head group is negative charge. Nonionic is used as co-surfactant in EOR application. Even though, nonionic is not good in IFT reduction but the brine tolerance is high. The last surfactant is cationic surfactant which is not used in EOR application since it has high adsorption to the rock surface for having positive head group (Khaled, 2011).

2.5 Literature Review Summary

In a summary, by going through the literature review many important details had been recorded. The asphaltene deposition has been a serious predicament faced during the production of the light oil and made the production cost more costly. Several factors which control the asphaltene deposition had been found out. Asphaltene deposition is higher in the later life of reservoir. The asphaltene definitions according to several authors, the properties and the mechanism of asphaltene deposition in light oil preferentially had been thoroughly studied. The mechanism of FAWAG in increasing oil recovery had been studied. The factors of surfactant selection and the reason for surfactant not being used in the past had been found. The main advantages and disadvantages of FAWAG and also the method to overcome the drawback of FAWAG had also been discovered. By collecting all these details, a proper research was embarked by the author.

CHAPTER 3
METHODOLOGY

There were a few procedures involves upon the completion of the final year project. The first procedure was to gain information on asphaltene deposition and FAWAG method through literature review. The next step was building a synthetic reservoir model by and defining fluid properties. The data used were synchronized for all the simulations performed. This synthetic 3-D model and fluid data were used in all simulations run. Most of the reservoir and asphaltene properties were obtained from dataset in Eclipse. There are altogether 4 simulations done. The first simulation was WAG model without asphaltene. The second simulation was WAG model with asphaltene. The first and second simulations were repeated for FAWAG too. The FOPT of each simulation was compared and studied. The next stage was to optimize the surfactant concentration and water injection rate. There were 4 concentration of surfactant chosen and run. The resulting FOPT for each concentration is compared. The same procedure was applied to optimization of water injection but only 3 rates are taken. The end result was tabulated and studied.

Run	Surfactant Concentration (lb/stb)	Field Oil Production Total (FOPT) (stb/day)
1		
2		
3		
4		
5		
6		
7		

Table 1 : The Optimization of Surfactant Concentration

Run	Water Injection Rate (stb/day)	Field Oil Production Total (FOPT) (stb/day)
1		
2		
3		
4		
5		
6		
7		

Table 2: Optimization of Water Injection

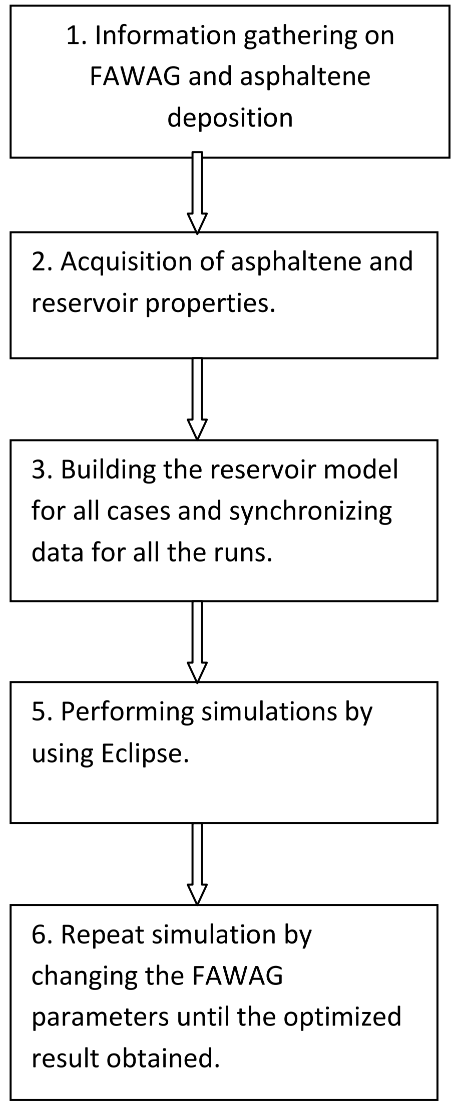

Figure 5: Methodology Flowchart

3.1 Reservoir & Fluid Properties

Properties	Value
Reservoir Dimension	10*10*3
Number of Components	7
Thickness in x-direction	100 ft
Thickness in y-direction	100 ft
Thickness in z-direction (first layer)	20 ft
Thickness in z-direction (second layer)	30 ft
Thickness in z-direction (second layer)	50 ft
Permeability in first layer	500 mD
Permeability in second layer	50 mD
Permeability in third layer	200 mD
Density of Oil	49.1 lb/scf
Density of Water	62.4 lb/scf
Density of Gas	0.06054 lb/scf
Porosity	0.3
Depth of Oil-Water Contact	8500 ft
Depth of Gas-Oil Contact	8200 ft
Bottom Hole Pressure	1000 psia
Reservoir Pressure	4800 psia
Well Diameter	0.5 ft
Producer Well Location	(10,10,3)
Injector Well Location	(1,1,1)

Table 3: Reservoir & Fluid Properties

3.2 Initial Reservoir Oil Components

Components	Percentage %
C1	0.500
C3	0.060
C6	0.000
C10	0.200
C15	0.150
C20	0.090
Asphaltene	0.000

Table 4: Initial Reservoir Oil Components

3.3 Injection Solvent Components

Components	Percentage %
C1	0.770
C2	0.200
C3	0.030

Table 5: Injection Solvent Components

3.4 Injection Mechanisms

Cycle	Injection Period (Days)	Injected Fluid	Injection Rate, Mscf/day=Gas, STB/day=Oil
1	730	Gas	100000
2	30	Gas	100000
	70	Foam	65000
3	30	Gas	100000
	70	Foam	65000
4	30	Gas	100000
	70	Foam	65000
5	30	Gas	100000
	70	Foam	65000
6	30	Gas	100000
	70	Foam	65000
7	30	Gas	100000
	70	Foam	65000
8	30	Gas	100000
	70	Foam	65000
9	30	Gas	100000
	70	Foam	65000
10	30	Gas	100000
	70	Foam	65000
11	30	Gas	100000
	70	Foam	65000
12	30	Gas	100000
	70	Foam	65000
13	30	Gas	100000
	70	Foam	65000
14	30	Gas	100000
	70	Foam	65000

15	30	Gas	100000
	70	Foam	65000
16	30	Gas	100000
	70	Foam	65000
17	30	Gas	100000
	70	Foam	65000
18	30	Gas	100000
	70	Foam	65000
19	30	Gas	100000
	70	Foam	65000
20	30	Gas	100000
	70	Foam	65000
21	30	Gas	100000
	70	Foam	65000
22	5000	Gas	100000

Table 6: Injection Mechanism

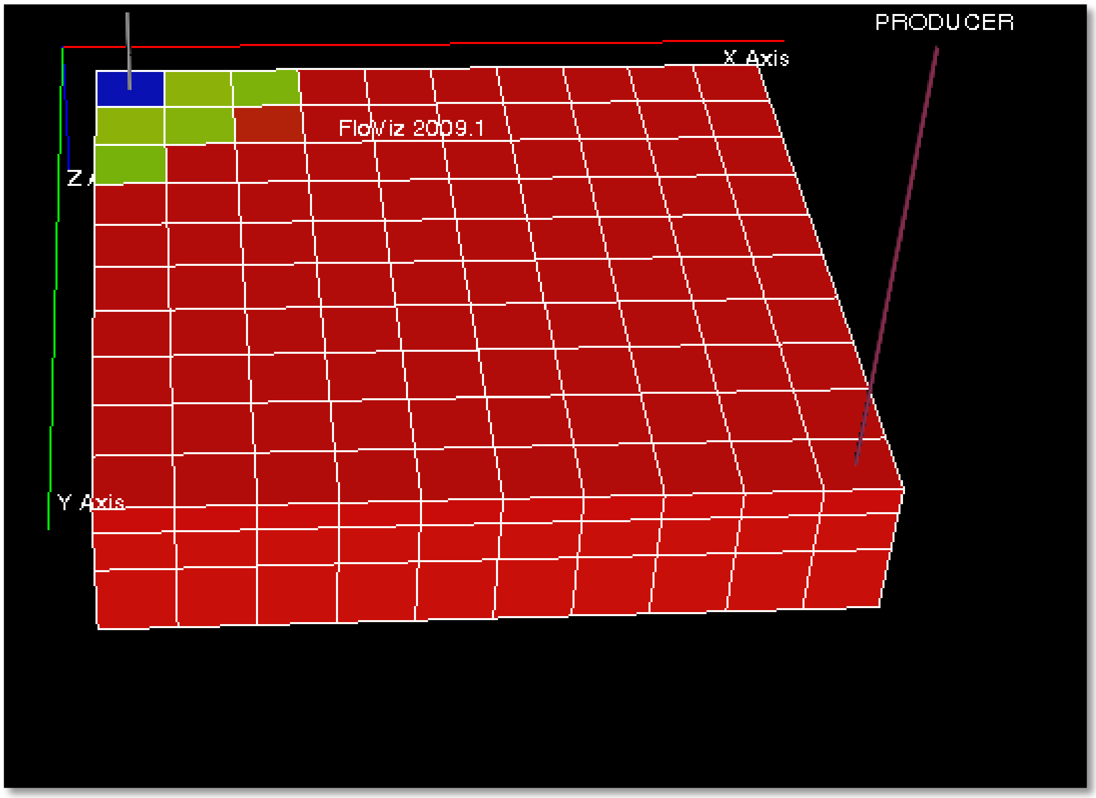

Figure 6: Synthetic Static Model

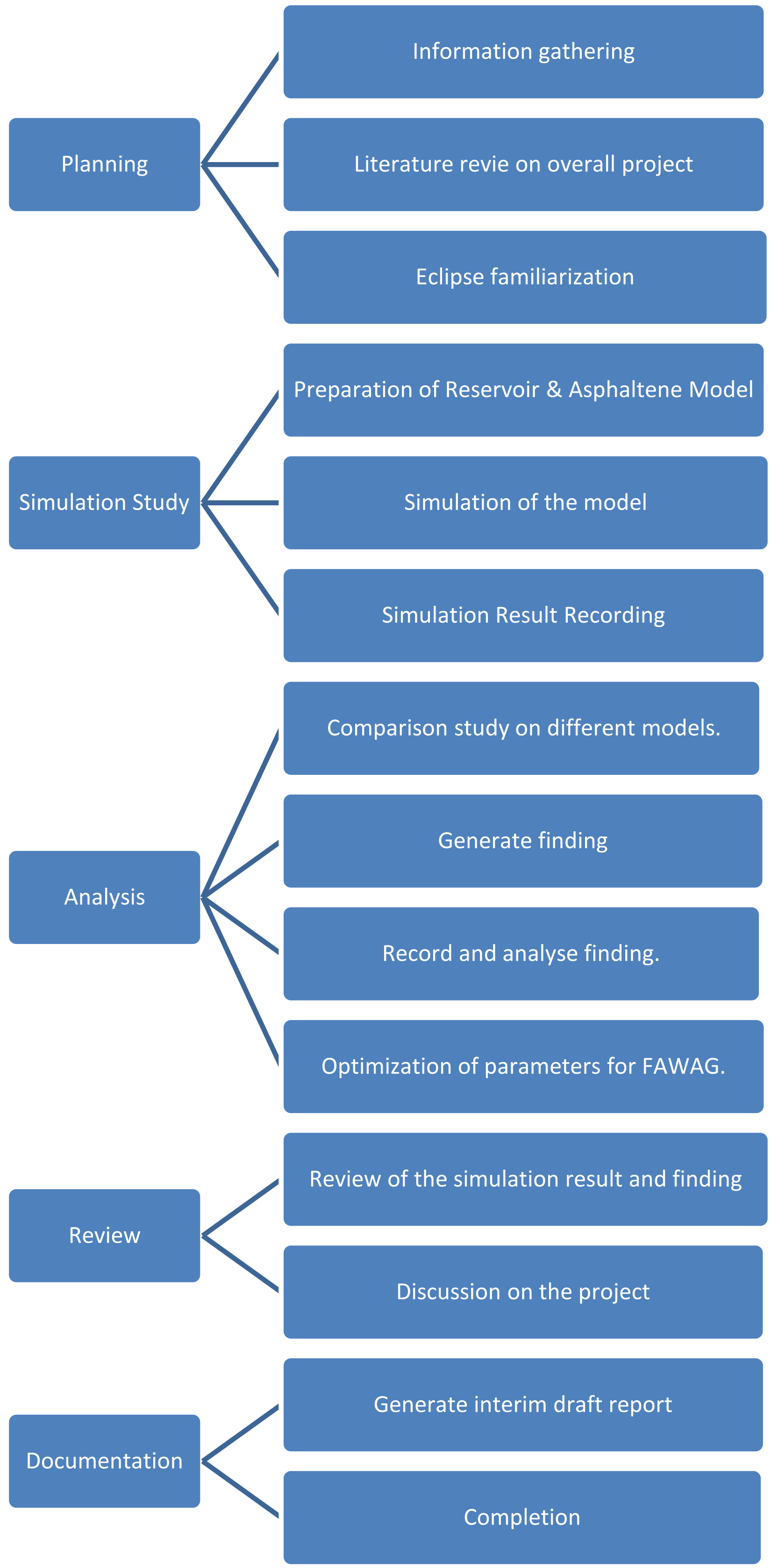

Figure 7: Project Activities

Project Activities	2013			
	June	July	August	September
Building Reservoir & Fluid Model	1 month			
Simulation of WAG and FAWAG models without Asphaltene		1 month		
Submission of Progress Report		9 July		
Simulation of WAG and FAWAG models with Asphaltene		1 month		
Optimization studies on FAWAG parameters			1 month	
Compilation of Result and Report Writing				1 month
Pre-Sedex				Week 10
Submission of Draft Report				Week 11
Submission of Dissertation (soft bound)				Week 12
Submission of Technical Paper				Week 12
Oral Presentation				Week 13
Submission of Project Dissertation (Hard Bound)				Week 14

Table 7: Key Milestone

3.5 Gantt chart

No	Project Activities	Week	1	2	3	4	5	6	7	8	9	10	11	12	13	14
		Date	14-18 Jan	21-25 Jan	28-1 Feb	4-8 Feb	11-15 Feb	18-22 Feb	25-1 March	4-8 March	11-15 March	18-22 March	25-29 March	1-5 April	8-12 April	15-19 April
1	Planning		6 weeks													
	a. Information gathering															
	- Project familiarization															
	- Literature review on Asphaltene Deposition															
	- Literature review on FAWAG															
	- Literature review on overall project															
	b.Engagement with Supervisor on The Project															
	- Review on the extended proposal															
	c.Data Acquisition															
	- Obtain data															
	d. Software practise and learning															
2	Simulation Study								4 weeks							
	a. Preparation of model															
	b. Simulation of the model															
	c. Simulation result recording															
	d. Repetition of simulation for diferent data															
	e. Recording of all the simulation result															
3	Analysis											3 weeks				
	a. Analyse the result															
	b. Comparison study on different models.															
	c. Sensitivity studies on the parameters.															
	d. Optimization of parameters for FAWAG.															
4	Review													2 weeks		
	a. Review on the simulation result and finding															
	b. Discussion on the project															
5	Documentation															1 week
	a. Generate interim draft report															
	b. Completion															

Table 8: Gantt chart

3.6 Simulation Data File

```
GRID    =================================================================

EQUALS
--      ARRAY  VALUE      ------- BOX ------
       'DX'    1000       /
       'DY'    1000       /
       'PORO'  0.3        /

       'DZ'    20         1  10  1  10  1  1  /
       'PERMX' 500        /
       'MULTZ' 0.64       /
       'TOPS'  8325       /

       'DZ'    30         1  10  1  10  2  2  /
       'PERMX' 50         /
       'MULTZ' 0.265625   /

       'DZ'    50         1  10  1  10  3  3  /
       'PERMX' 200        /

/

-- THE Y AND Z DIRECTION PERMEABILITIES ARE COPIED FROM PERMX
COPY
--      SOURCE  DESTINATION  ------- BOX ------
       'PERMX'    'PERMY'    1  10  1  10  1  3  /
       'PERMX'    'PERMZ'    /
/

RPTGRID
 'DX'   'DY'   'DZ'   'PERMX'  'PERMY'  'PERMZ'  'MULTZ'
 'PORO'  'TOPS'  'PORV'  'TRANX'  'TRANY'  'TRANZ' /
```

Figure 8: Grids of the Simulation

```
-- Asphaltene parameters

-- ... asphaltene floc components

ASPFLOC
-- first  last  floc
     6      6     7  /

-- ... define asphaltene concentration limits
-- (set here to avoid asphaltene precipitation)

ASPREWG
--   pres    %_wt
  1000.0     0.0
  2000.0     5.0
  3900.0    15.0
 10000.0   100.0   /

-- ... ashphaltene floc rates
-- (set here to cause faster floc degradation than formation)

ASPFLRT
-- CMP6
    0.0100
    0.001   /

-- ... asphaltene deposition

ASPDEPO
-- adsorp   plug   entrain   Vcr
   5.0E-4  1.0E-6  1.0E-4   2500   /

-- ... asphaltene damage ratio

ASPKDAM
-- deposit  mult
     0.0      1.0
     1.0E-5   0.99
     1.0E-4   0.90
     1.0E-3   0.80
     1.0E-2   0.50   /

-- ... asphaltene viscosity change

ASPVISO
-- vfrac    mult
    0.0     1.0
    0.01    1.2
    0.1     1.5
    1.0    10.0   /
```

Figure 9: Asphaltene Parameters

```
SCHEDULE =============================================================
-------- THE SCHEDULE SECTION DEFINES THE OPERATIONS TO BE SIMULATED
----------------------------------------------------------------------
-- CONTROLS ON OUTPUT AT EACH REPORT TIME

RPTSCHED
 'PRESSURE' 'SWAT' 'SGAS' 'SOIL' 'FOAM' 'FOAMMOB' /

RPTRST
 'PRESSURE' 'SWAT' 'SGAS' 'SOIL' 'FOAM' 'FOAMMOB' 'REAC'/

WELSPECS
--       WELL     GROUP  LOCATION   BHP    PI
--       NAME     NAME     I   J   DEPTH DEFN
    'PRODUCER'  'G'     10  10     8400 'OIL'   /
    'GINJ'      'G'      1   1     8335 'GAS'   /
    'WINJ'      'G'      1   1     8335 'WAT'   /
/

COMPDAT
--       WELL      -LOCATION- OPEN/ SAT CONN   WELL
--       NAME      I   J K1 K2 SHUT  TAB FACT   DIAM
    'PRODUCER'  10 10 3   3 'OPEN' 0    -1    0.5   /
    'GINJ'       1  1 1   1 'OPEN' 1    -1    0.5   /
    'WINJ'       1  1 1   1 'OPEN' 1    -1    0.5   /
  /



-- SPECIFY THE SURFACTANT INJECTOR

WELLSTRW
  WATER 1.0 0.0 /
  FOAM  0.9 0.1 /
/

WINJW
   WINJ STREAM FOAM /
/

GINJGAS
  G  GV  FIELD/
/
```

Figure 10: Schedule Section

```
-- FOAM MODEL-----------------------------------------------------------

FOAMFRM
1.1 /

FOAMFSC
0.001 0.1 1.0e-6 /

FOAMFST
   0     10
   0.01  5
   0.05  0.1 /

FOAMFCN
  1E-7 0.1 /

--FOAM DECAY, ADSORPTION AND DESORPTION

STOREAC
--OIL GAS SOL WAT SURF
  0.0 0.0 0.0 0.0 1.0 / Decay       SURF  -> WATER
  0.0 0.0 0.0 0.0 1.0 / Adsorption  SURF  -> SOLID
  0.0 0.0 1.0 0.0 0.0 / Desorption  SOLID -> SURF

STOPROD
--OIL GAS SOL WAT SURF
  0.0 0.0 0.0 1.0 0.0 / Decay       SURF  -> WATER
  0.0 0.0 1.0 0.0 0.0 / Adsorption  SURF  -> SOLID
  0.0 0.0 0.0 0.0 1.0 / Desorption  SOLID -> SURF

REACRATE
--DECAY    ADSORP DESORP
  0.000231 0.1    1.0 / Foam decay half life = 3000 days

REACCORD
--OIL GAS SOL WAT SURF
  0.0 0.0 0.0 0.0 1.0 / Decay      proportional to SURF  concentration
  0.0 0.0 0.0 0.0 1.0 / Adsorption proportional to SURF  concentration
  0.0 0.0 1.0 0.0 0.0 / Desorption proportional to SOLID concentration
```

Figure 11: Foam Model

CHAPTER 4
RESULTS

Keywords

FOPT: Field Oil Production Rate

FPR: Field Average Pressure

Legends

WAG without Asphaltene

WAG with Asphaltene

FAWAG without Asphaltene

FAWAG with Asphaltene

4.1 WAG with & without asphaltene

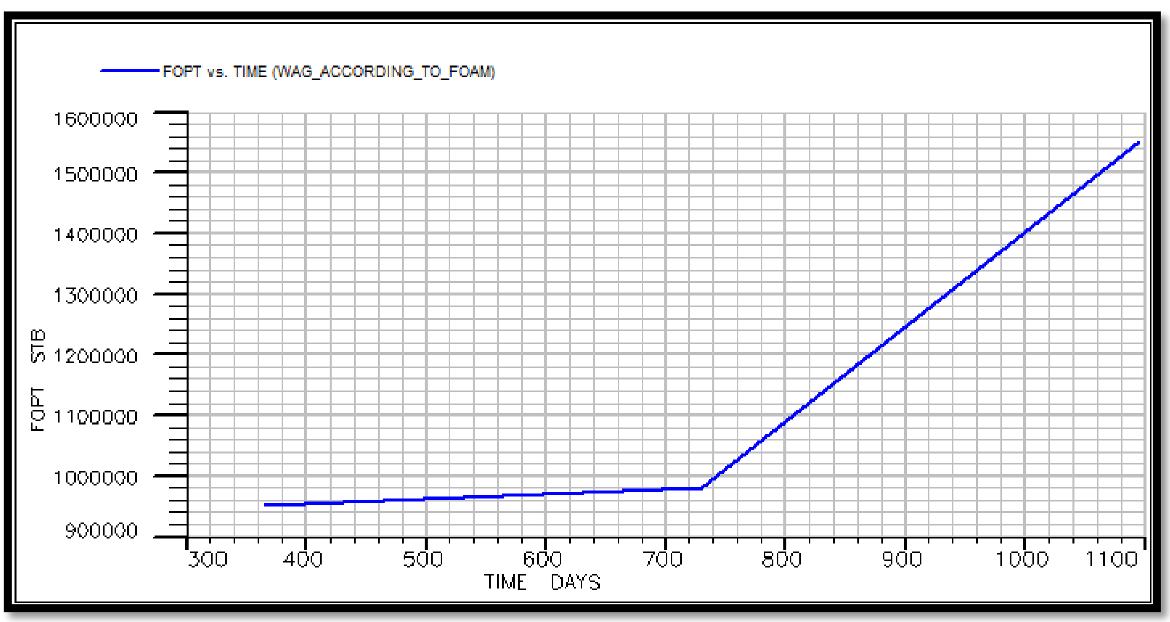

Figure 12: WAG Model (FOPT vs. time)

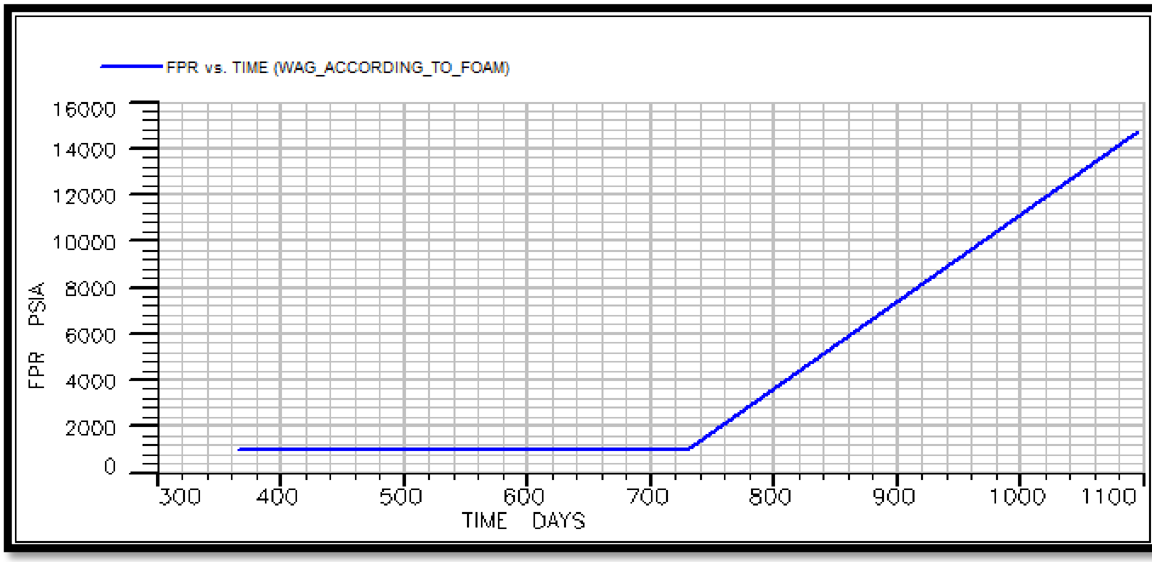

Figure 13: WAG Model (FPR vs. time)

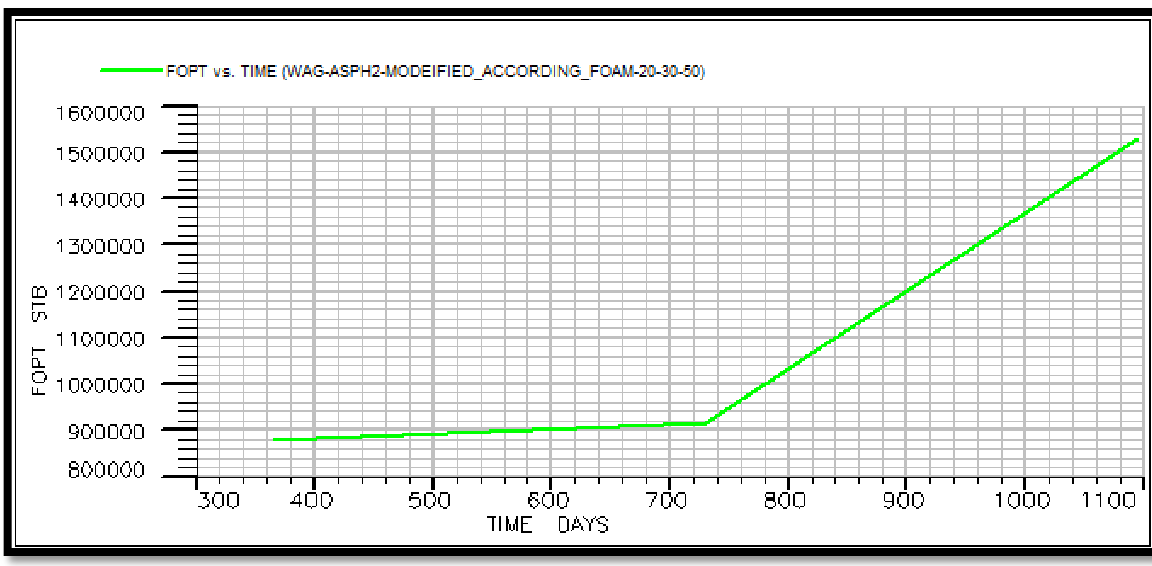

Figure 14: WAG-Asphaltene Model (FOPT vs. time)

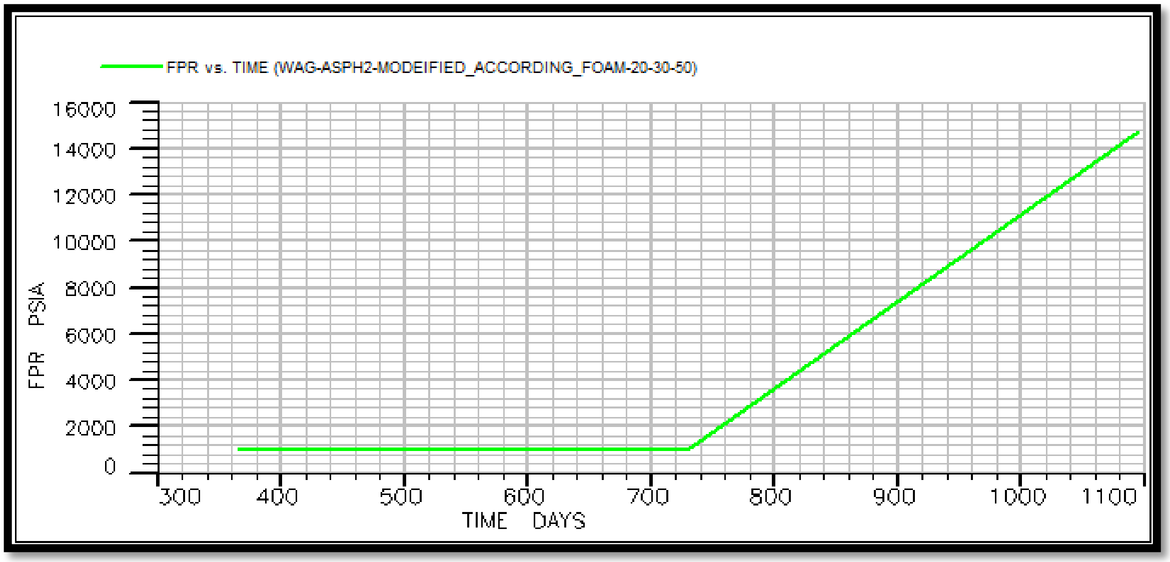

Figure 15: WAG-Asphaltene Model (FPR vs. time)

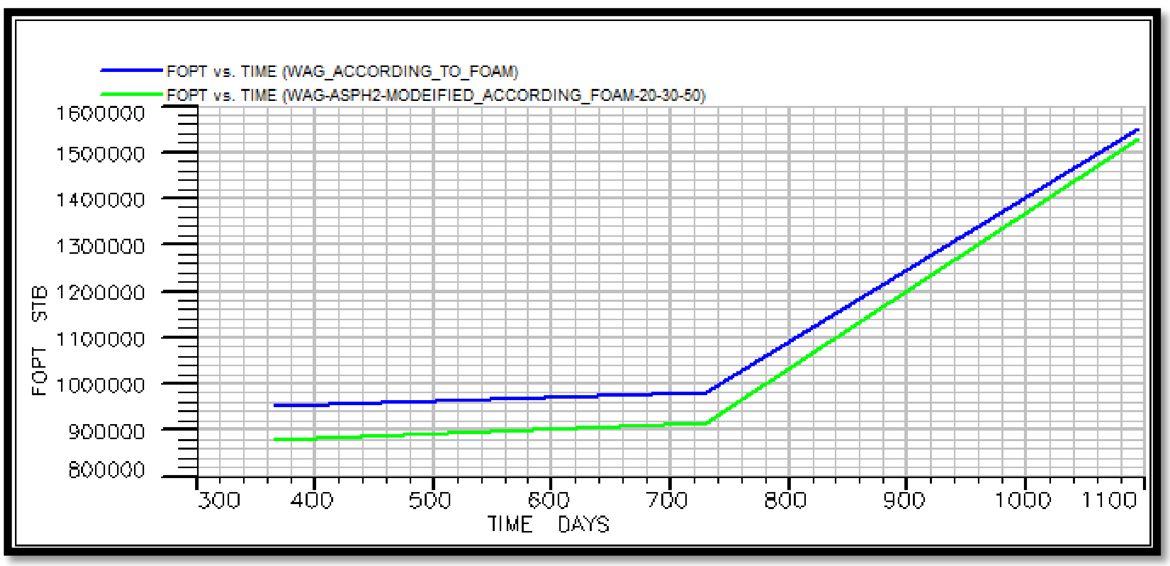

Figure 16: WAG vs. WAG-Asphaltene (FOPT vs. time)

The first comparison was made between the WAG model without asphaltene and WAG model with asphaltene as shown in the Figure 17. The analysis of the result was focused from day 360 to the 900 hundredth days. The analysis only took place until the 960th days due to the FPR limitation. Based on the Figure 18, the value of FPR is 8600 psia which was the threshold for fracture gradient. The reason for the difference was due to precipitation, flocculation and deposition of asphaltene. As the deposition of asphaltene occurs, the permeability of the reservoir is reduced significantly which reduces the overall production rate as in Darcy's Law . Ghedan (2009) also found that asphaltene deposition has caused decline in both permeability and porosity value.

$$q = -\frac{kA}{\mu}\frac{dp}{dL}$$

The reduction in production rate results in less FOPT value. The deposited asphaltene clogged the pore throats of the reservoir and further restricted the displacement of oil by water in the WAG process. Another pertinent observation made was the slight difference in the both WAG model as the pressure of reservoir increases. The pressure of the reservoir started to increase after 730^{th} days to 900^{th} days in which the FOPT between the two models became equal. This shows that during the time period asphaltene deposition was reducing as the pressure of the reservoir increases.

The WAG model implemented did not cause significant increase in the overall Field Oil Production Total. The maximum difference in the production total was 170,000 barrels. The explanation of the setback was because of permeability variation introduced earlier in the synthetic model. The permeability of the layers differs. The first strata in the synthetic model was having a vertical permeability of 500 mD, the second layer had the permeability of 50 MD while the last layer had the permeability of 200 mD. The permeability variation introduced prompted the bypassing of gas to occur. The first and the last layer played their role as the thief zones to the middle layer. On top of that, gravity segregation worsened the bypassing.

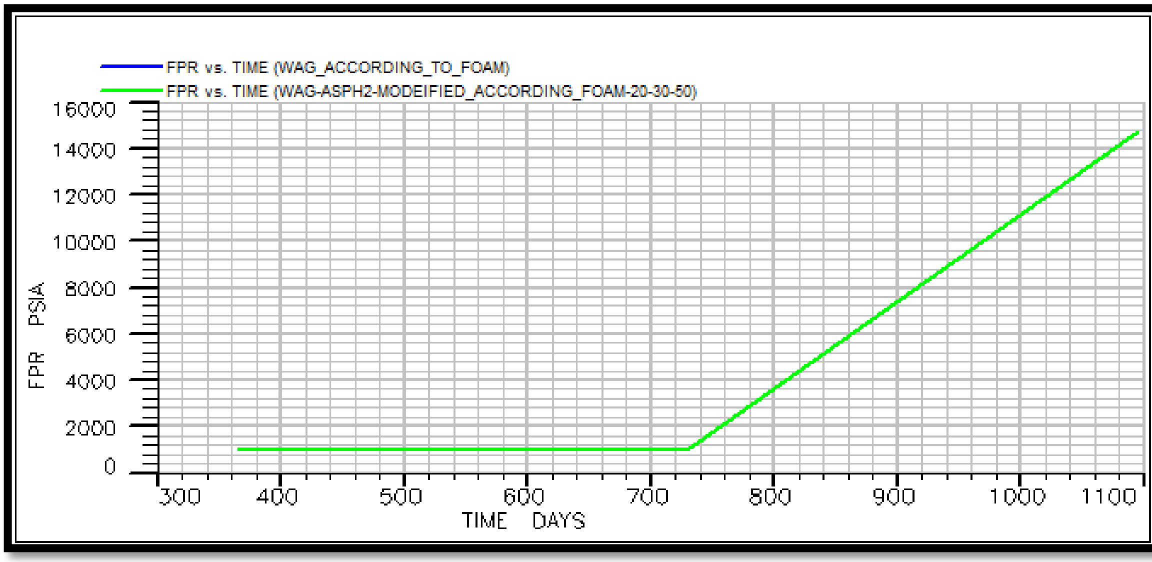

Figure 17: WAG vs. WAG-Asphaltene (FPR vs. time)

The value of FPR recorded for both of the models the same value throughout the injection period even though the value of FOPT varied between the two models. These results supported the theory that less pressure drawdown was required to produce from a reservoir without asphaltene deposition compared to the reservoir facing the problem. Despite of having the same FPR, WAG model without asphaltene registered higher value of FOPT because the permeability in the WAG model was not reduced. The permeability in the WAG model with asphaltene had been impaired with the asphaltene deposition. Thus, it was proven through the simulation cases that the asphaltene deposition caused pore throat plugging which directly detriment the permeability of the reservoir.

4.2 FAWAG with & without Asphaltene

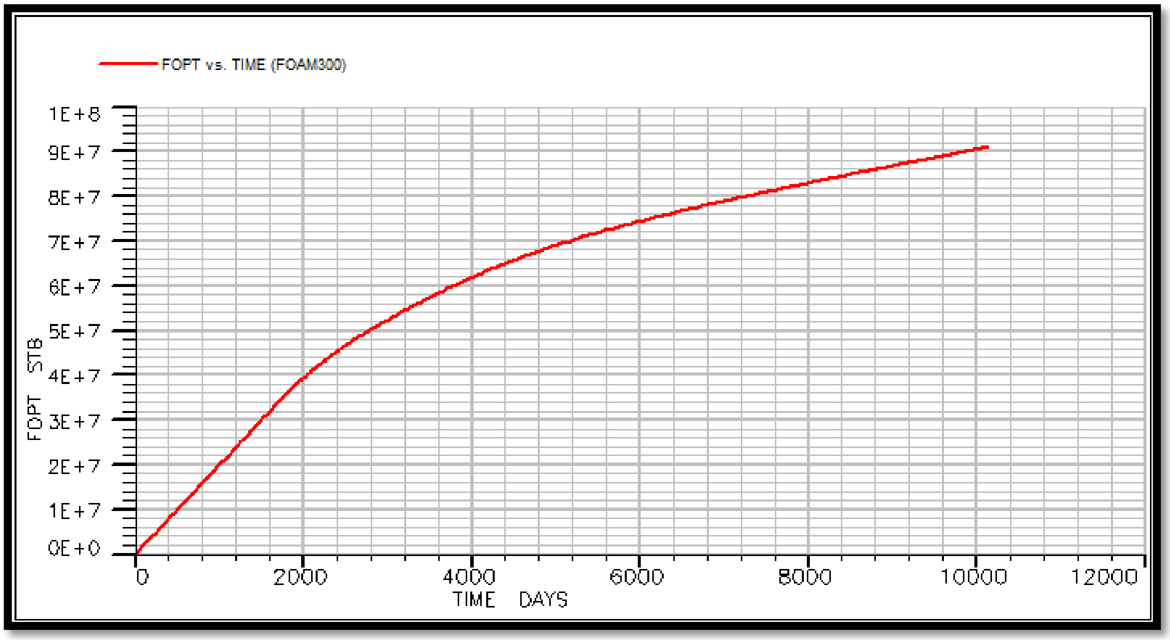

Figure 18: FAWAG Model without Asphaltene (FOPT vs. time)

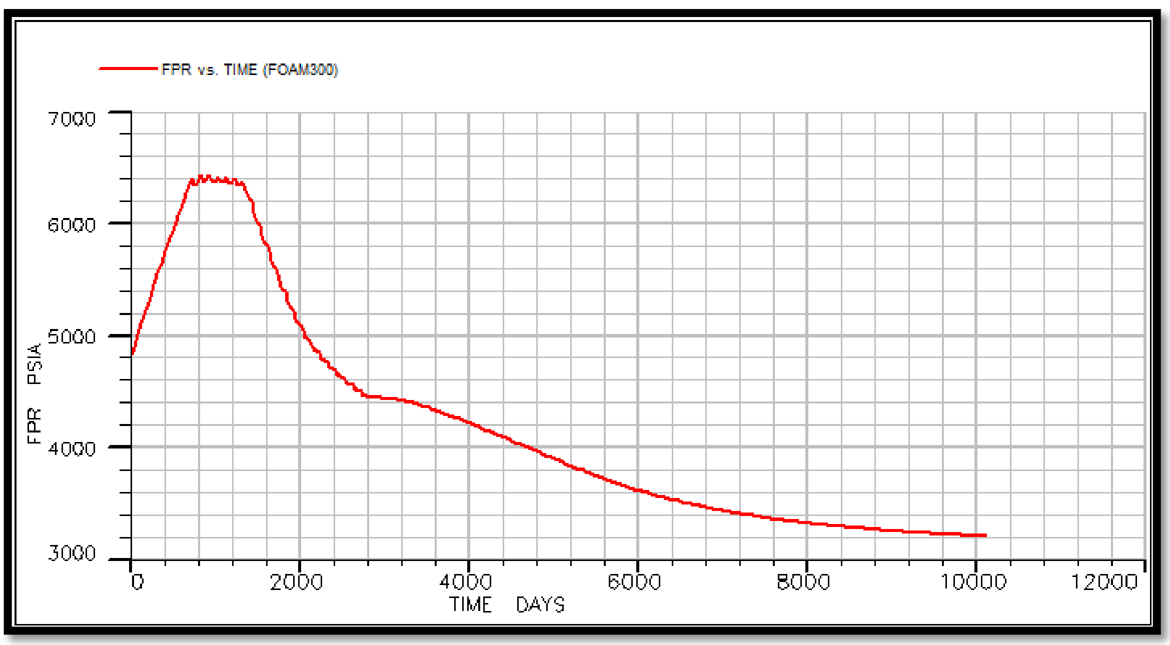

Figure 19: FAWAG Model without Asphaltene (FPR vs. time)

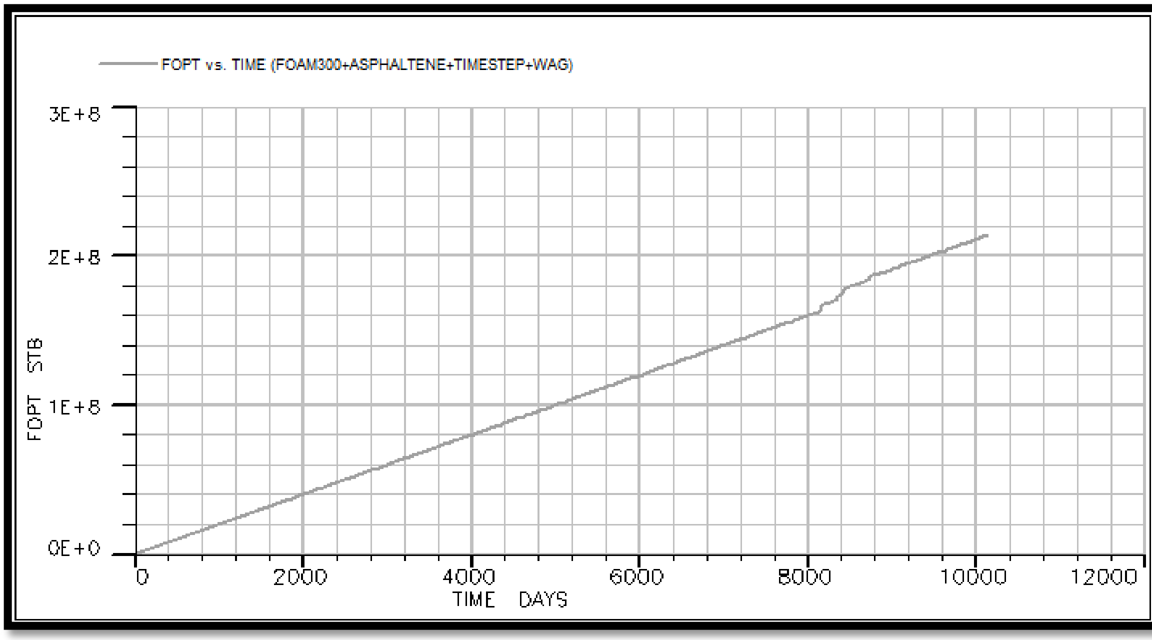

Figure 20: FAWAG Model with Asphaltene (FOPT vs. time)

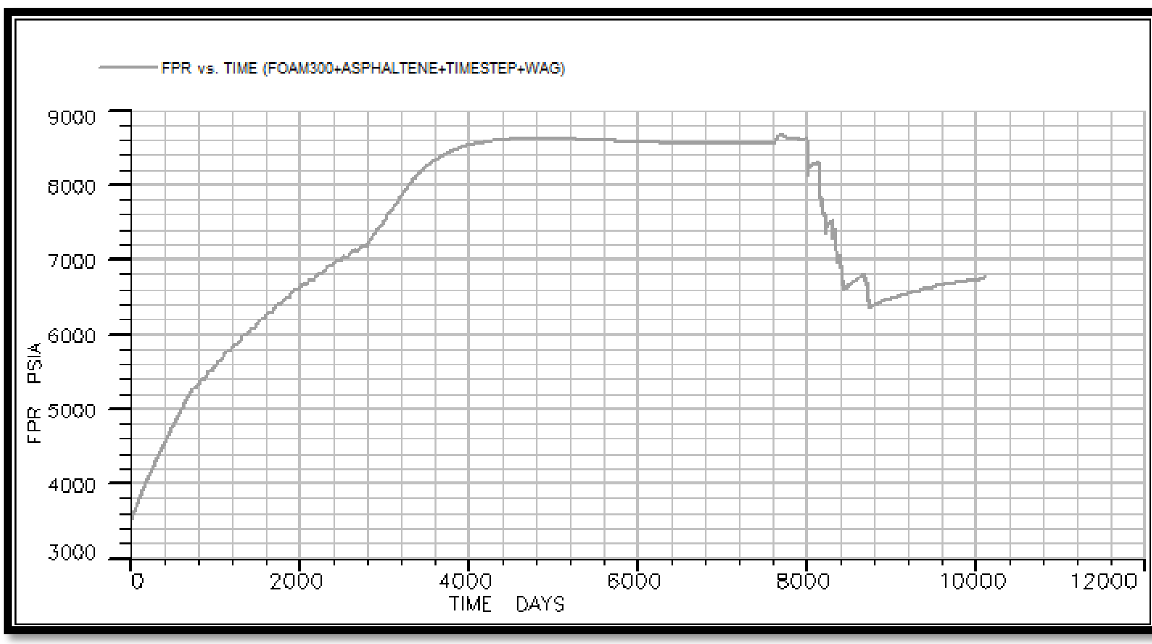

Figure 21: FAWAG Model with Asphaltene (FPR vs. time)

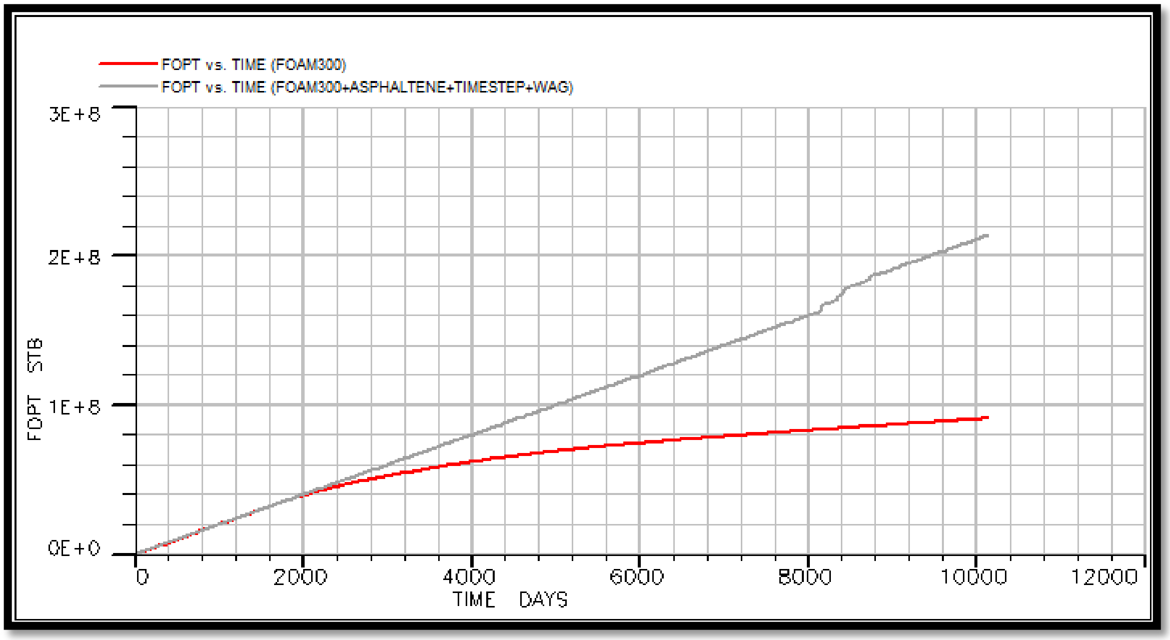

Figure 22: FAWAG Model (with vs. without Asphaltene) (FOPT vs. time)

The result obtained from Figure 23 showed that the FAWAG model with asphaltene recorded more FOPT compared to FAWAG model without asphaltene. The result obtained was unexpected since asphaltene would render the FAWAG model inefficient. The explanation behind this result was done chronologically. As the gas traveled to the upper layer due to permeability variation and gravity segregation, asphaltene precipitation was induced. Ali (2009) found that the mixing of gas with oil which resulting in lighter dominance will enhance the deposition of asphaltene. The injected gas had tendency to go to the most bottom layer since it had higher permeability than the middle layer. However, this was not necessarily true since the segregation due to components gravity will prefer the middle layer compared to the most bottom layer. From the Figure 23, the FAWAG model with asphaltene indicates higher FOPT after the 2000th days which shows that there were some period of time required before the FOPT between the two model to show distinct differences. The difference became more prominent at the later time because asphaltene had to go through several phases before being deposited. Those phases are precipitation and flocculation in which the asphaltene particles detached themselves from the oil and started to flock and eventually form a big lump.   Precipitation of asphaltene was induced more when gas injection was implemented since it swelled the oil and lighter components dominated which depreciated the solubility of asphaltene. As the gas traveled upward, the asphaltene deposition began to form at the upper layer before the layer below. This asphaltene deposition formation was a barrier to upward movement of gas in addition to the foam barrier formed concurrently. Hence, more gas was channeled to the middle and bottom layer which was left unswept previously in the WAG stage. Thus, FAWAG with asphaltene proves to have significant increase in oil recovery.

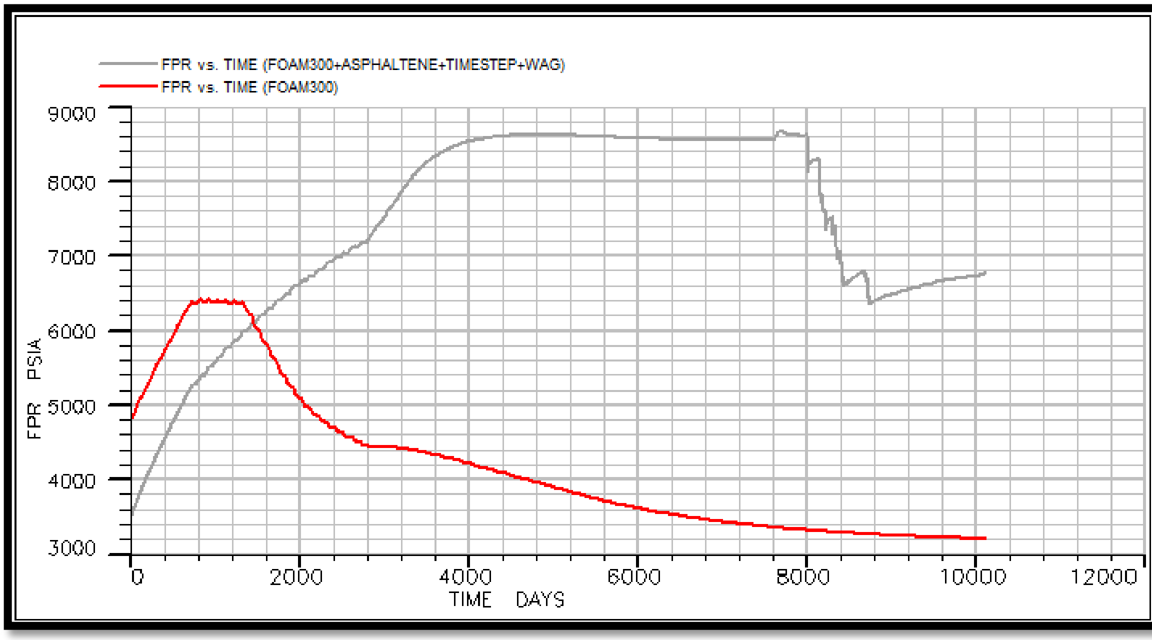

Figure 23: FAWAG Model (with vs. without Asphaltene) (FPR vs. time)

Based on the Figure 24, there were 2 distinct time period to discuss. The first one was from 0 day to 1750 days in which the pressure in the FAWAG model without asphaltene was higher than the FAWAG model with asphaltene. In this period of time, the foam started to form as the gas traveled to the most upper layer which had the highest permeability and also due to the segregation effect. As the gas cumulated at the top layer and foam was generated continuously, this increased the reservoir pressure as the gas was being compressed at the top layer. In the second period of time, the foam was already generated in the first layer for both of the model. However, in the FAWAG model with asphaltene both asphaltene and foam will be the barrier to stop the gas from entering the first layer. More foam also will be generated at the bottom layer compared to the middle layer since the permeability variation effect seems to be more prominent than the gravity segregation effect. The permeability of the bottom most layer is 200 mD while the middle layer is only 50 mD. The difference in the magnitude was four times higher. Even though the possibility of the gas to travel in the middle layer was high due to gravity effect, the thickness of the middle layer is minimal compared to the bottom layer. Since the top layer has been blocked first, the gas preferentially followed the most bottom layer which eventually formed asphaltene and foam barrier in the most bottom layer. Eventually, the gas had only the middle layer to flow through. All the injected gas will pass through the middle layer which causes gas compression since the middle layer is the thinnest among the 3 layers. Thus, the pressure increase in FAWAG model with asphaltene will be higher than FAWAG model without asphaltene.

4.3 FAWAG vs. WAG (without asphaltene)

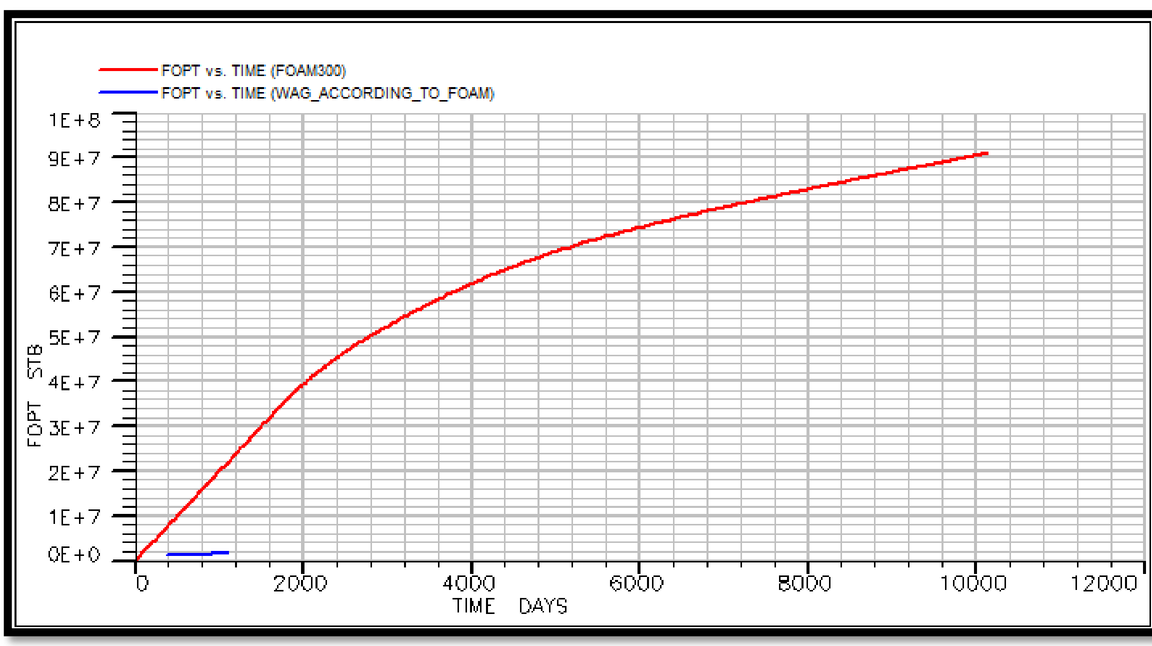

Figure 24: FAWAG vs. WAG (without Asphaltene) (FOPT vs. time)

The next comparison done was in Figure 25. The comparison was made with FAWAG model and WAG model without asphaltene content. The FAWAG model showed a better recovery than WAG. FAWAG was an advanced technique in WAG which solved the problem of permeability variation and gravity segregation which had the tendency to happen in WAG model. Safarzadeh (2011) also claimed that FAWAG is the superior method than gas injection and water alternating gas as it solves some of the problems encountered while performing these two methods. In term of ultimate recovery, FAWAG shows 10% higher than the water alternating gas (WAG).The upward movement of gas was effectively controlled by the foam formation at the high permeability layer. The foam will form a barrier for the gas to travel to the high permeability zone. Hence, more gas was channeled to the previously unswept region which ultimately increases the recovery.

In this synthetic model, permeability variation by layers was introduced. Hence, the tendency for bypassing to occur was high. The gas tended to select the least obstructed path to flow which and bypassed layers with low permeability. Apart from that, due to difference in densities of the flowing phases, gravity segregation was possible. Gas flowed upward than lateral which causes some oil not being swept out. The foam barrier formed at the upper layer as more gas reacts with the surfactant to generate foam will limit the upward movement of gas.

Another explanation for the result obtained was the surfactant in the method improves the IFT of water and oil. The IFT reduction eased the displacement of oil from pore spaces by the injection of water. Thus, the IFT reduction must be further reduced in order to retrieve more oil.

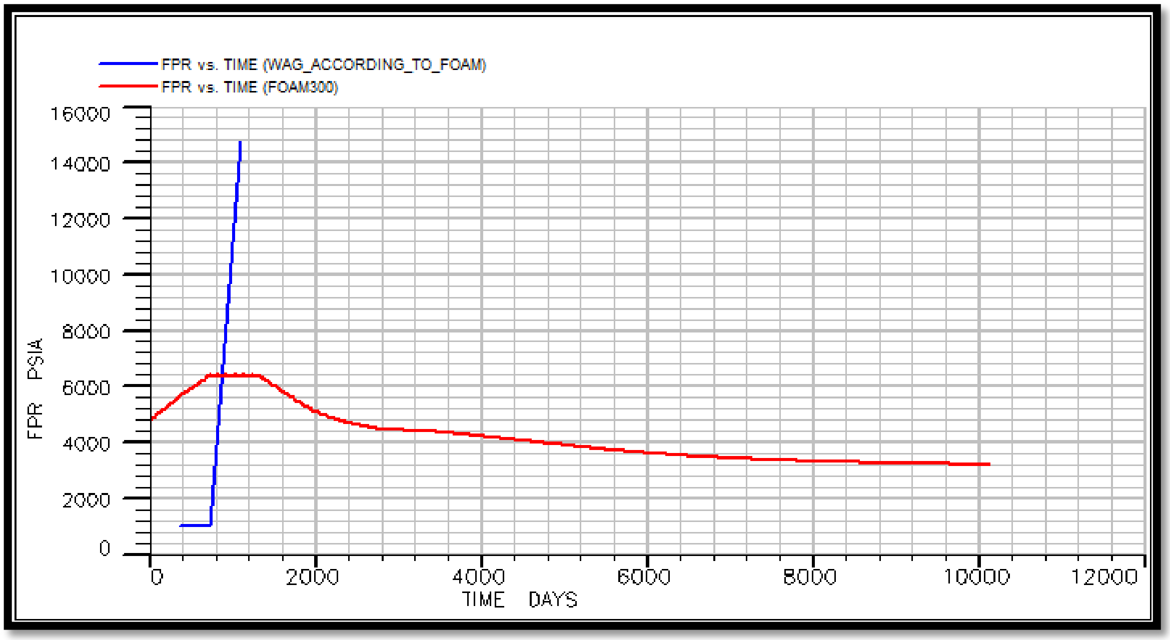

Figure 25: FAWAG vs. WAG (without Asphaltene) (FPR vs. time)

Based on Figure 26, the FAWAG model FPR was higher than the WAG model. As afore mentioned, the FPR of WAG model was only taken into account up to 900th day. The difference is caused mainly by the movement of gas. In WAG gas was free to follow less disrupted path as gas always does. The gas moved upward and flowed through the higher permeable layer. However, in FAWAG, the upper layer was off-entry to gas as the foam layer will prevent the movement of gas to the layer. This caused less flow path for gas and gas had to pass through the low permeable layer. More gas had to flow through a small layer with more disruption. Hence, the gas became more compressed in the reservoir which exerted pressure to the wall of the pore and eventually increases the overall FPR.

4.4 FAWAG vs. WAG (with asphaltene)

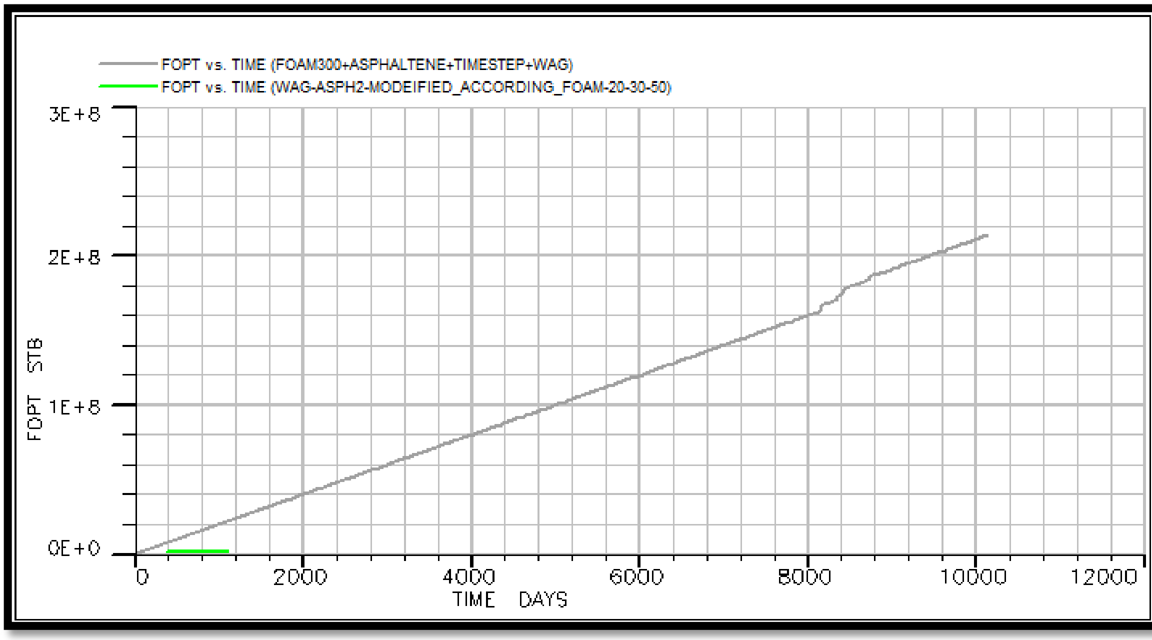

Figure 26: FAWAG vs. WAG (with Asphaltene) (FOPT vs. time)

In the Figure 27, FAWAG technique showed significant higher recovery than WAG. This indicated that the FAWAG technique was way more favorable than WAG in the presence of asphaltene. There were a few reasons for the result. The first reason was in FAWAG, the movement of gas was effectively controlled by the foam formation at the high permeability layer. Saleem (2011) also found that FAWAG shows better mobility control of the gas. The foam formed a barrier for the gas to travel to the high permeability zone. Hence, more gas was channeled to the previously unswept region which ultimately increased the recovery.

In this synthetic model, permeability variation by layers was introduced. Hence, the tendency for bypassing to occur was high. The gas tended to select the least obstructed path to flow which and bypassed layers with low permeability. Apart from that, due to difference in densities of the flowing phases, gravity segregation was possible. Gas flowed upward than lateral which caused some oil not being swept out. The foam barrier formed at the upper layer as more gas reacted with the surfactant to generate foam will limit the upward movement of gas.

Another explanation for the result obtained was the surfactant in the method improved the IFT of water and oil. The IFT reduction eased the displacement of oil from pore spaces by the injection of water. The precipitation of asphaltene on the rock surface altered the wettability of the rock. The asphaltene precipitation changed the wettability of the rock from water-wet characteristics to oil-wet. Thus, the IFT reduction must be further reduced in order to retrieve more oil.

The formation of asphaltene in the upper layer did help the movement of gas. The asphaltene formed at the upper layer further blocked the migration of gas to the layer. The movement of gas was properly channeled to the unswept area.

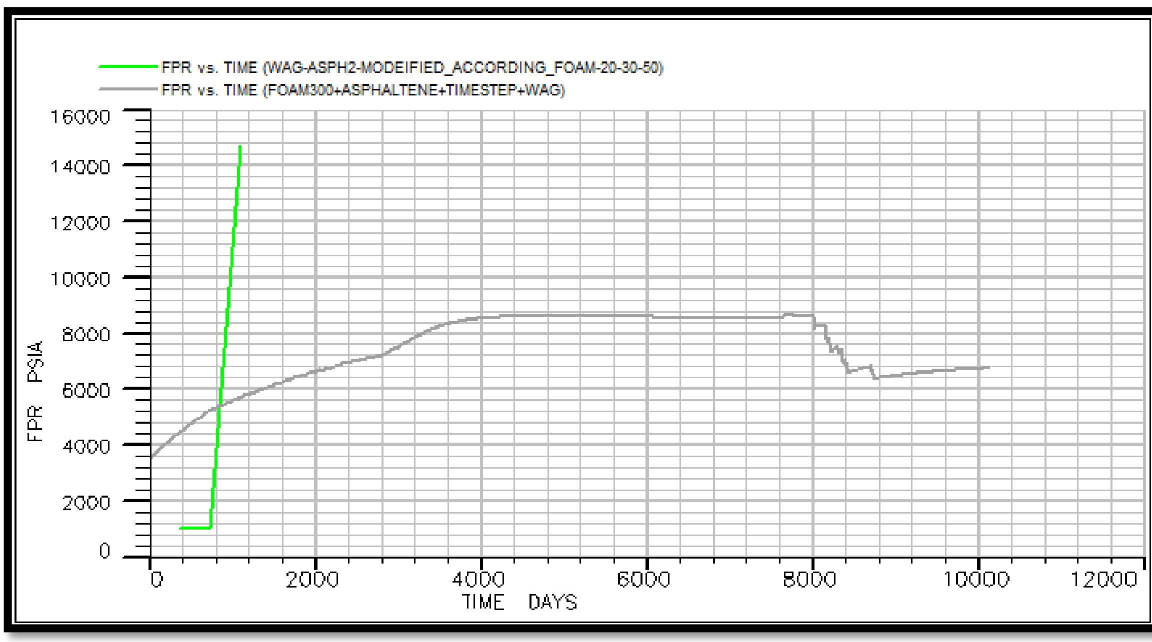

Figure 27: FAWAG vs. WAG (with Asphaltene) (FPR vs. time)

Based on Figure 28, the FAWAG model FPR was higher than the WAG model. As afore mentioned, the FPR of WAG model was only taken into account up to 900th day. The difference was caused mainly by the movement of gas. In WAG gas was free to follow less disrupted path as gas always does. The gas moved upward and flowed through the higher permeable layer. However, in FAWAG, the upper layer was off-entry to gas as the foam layer prevented the movement of gas to the layer. This caused less flow path for gas and gas had to pass through the low permeable layer. More gas had to flow through a small layer with more disruption. Hence, the gas became more compressed in the reservoir which exerted pressure to the wall of the pore and eventually increased the overall FPR.

4.5 Optimization Stages (FOPT)

4.5.1 Injection Rate

50000 STB/day

65000 STB/day

100000 STB/day

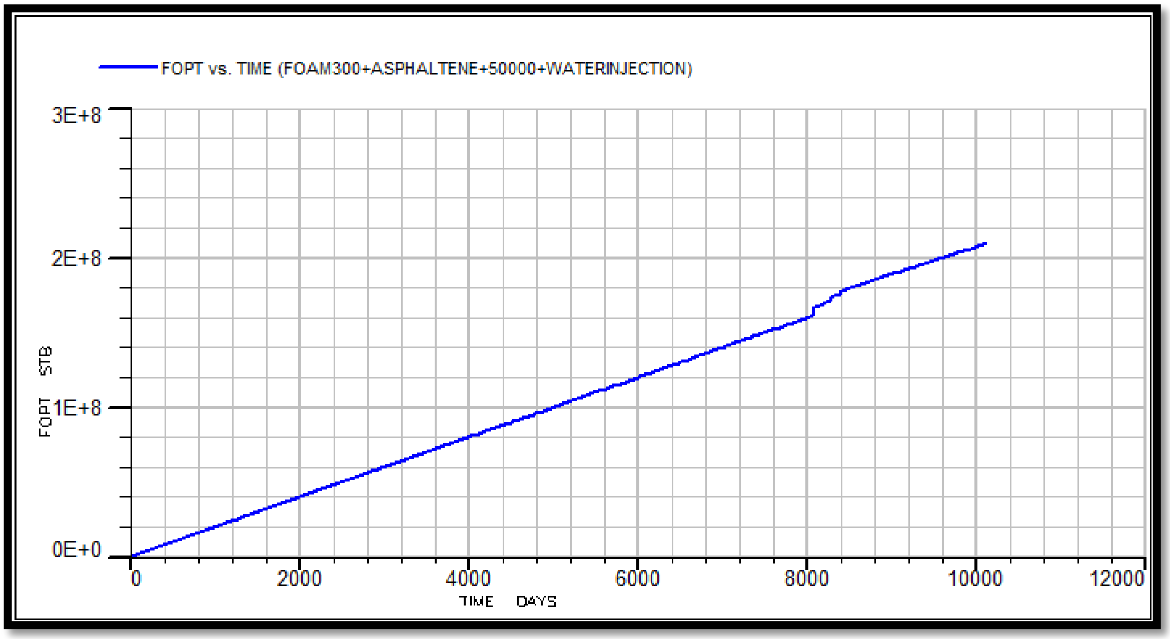

Figure 28: FOPT vs. time (50000STB/day)

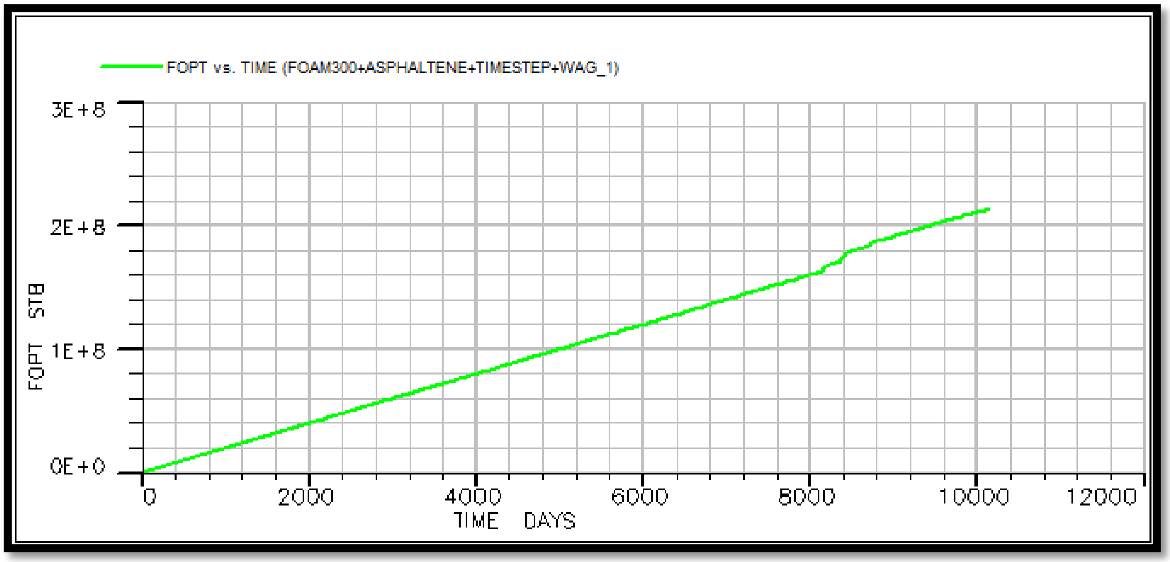

Figure 29: FOPT vs. time (65000STB/D)

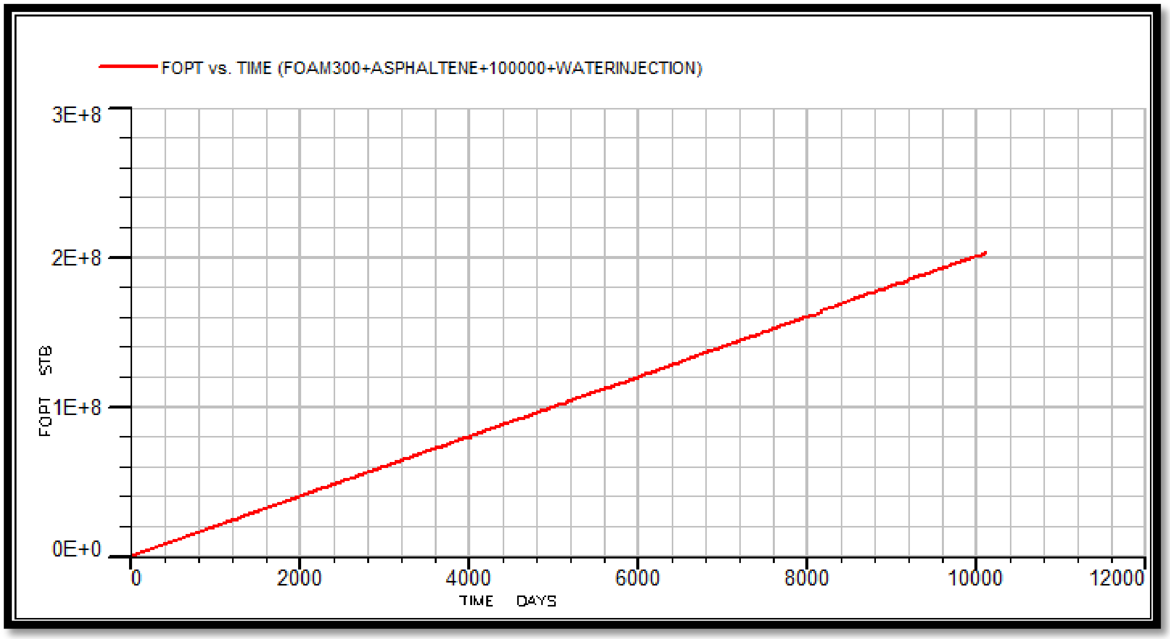

Figure 30: FOPT vs. time (100000 STB/D)

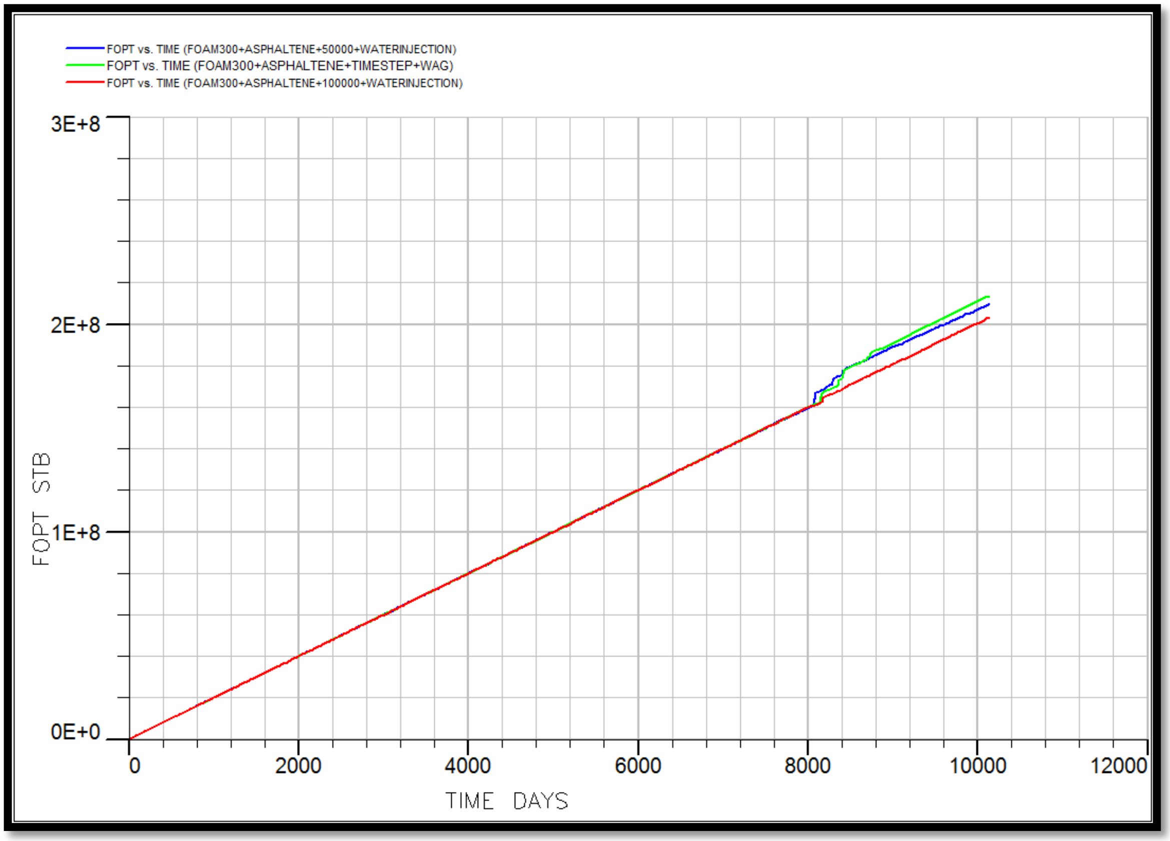

Figure 31: Different Injection Rate vs. FOPT

Based on the Figure 32, variation of water injection rate affected the value of FOPT. The highest FOPT value obtained was by injecting with an injection rate of 65000 stb/day, followed by 50000 stb/day and the injection rate with least FOPT was 100000 stb/day. From the result, there was no a direct trend between injection rate and asphaltene deposition. Based on the simulation done, 65000 stb/day was an optimum value. The injection rate of 50000 stb/day was not strong enough to displace the oil from reservoir. The injected volume was not sufficient to fill all the pores containing the remaining oil. The injection rate of 100,000 stb/day was too high which causes the displacement front to travel with a very high velocity. The electric kinetic effect took place as it was described before. Ali (2009) mentioned that the electric kinetic effect occurred mostly at the wellbore where the velocity was highest. This fluid carries along electrical potential which reacted with the asphaltene micelle and cause asphaltene to deposit. Hence, more micelle was destabilized when the water injection rate exceeded certain value and triggered the asphaltene deposition.

4.5.2 Injection Rate vs. FOPT

Injection Rate (stb/day)	FOPT (*10^8 STB)
50000	2.080
65000	2.120
100000	2.000

Table 9: Injection Rate vs. FOPT

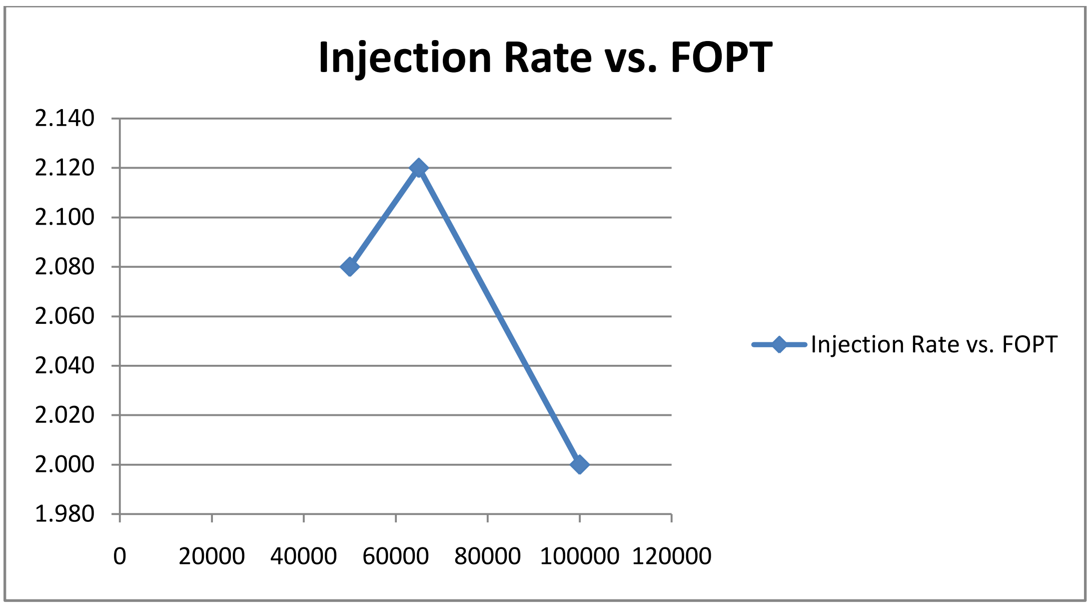

Figure 32: Injection Rate vs. FOPT

4.5.3 Surfactant Concentration

Legends	Surfactant Concentration
	0.005 lb/stb
	0.01 lb/stb
	0.10 lb/stb
	0.20 lb/stb

0.005 lb/stb

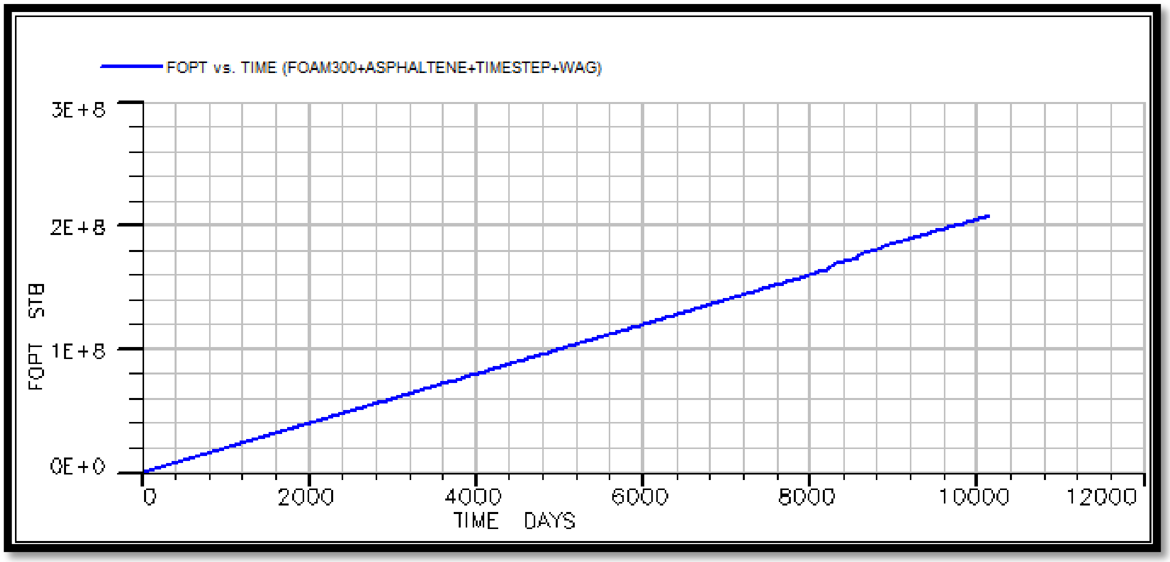

Figure 33: FOPT vs. time (0.005 lb/stb)

0.01 lb/stb

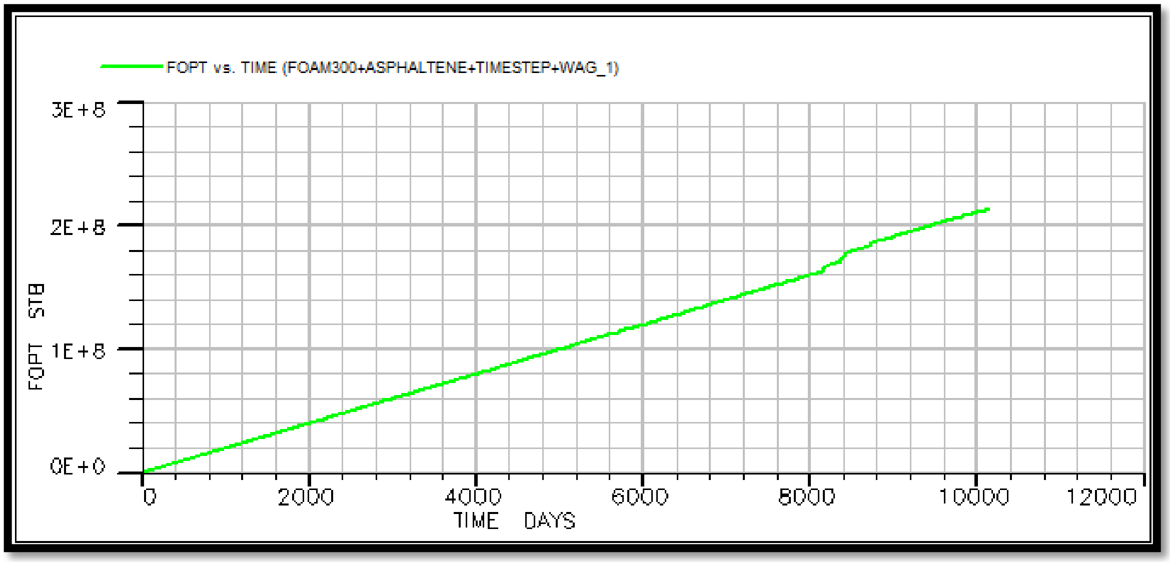

Figure 34: FOPT vs. time (0.01 lb/stb)

0.1 lb/stb

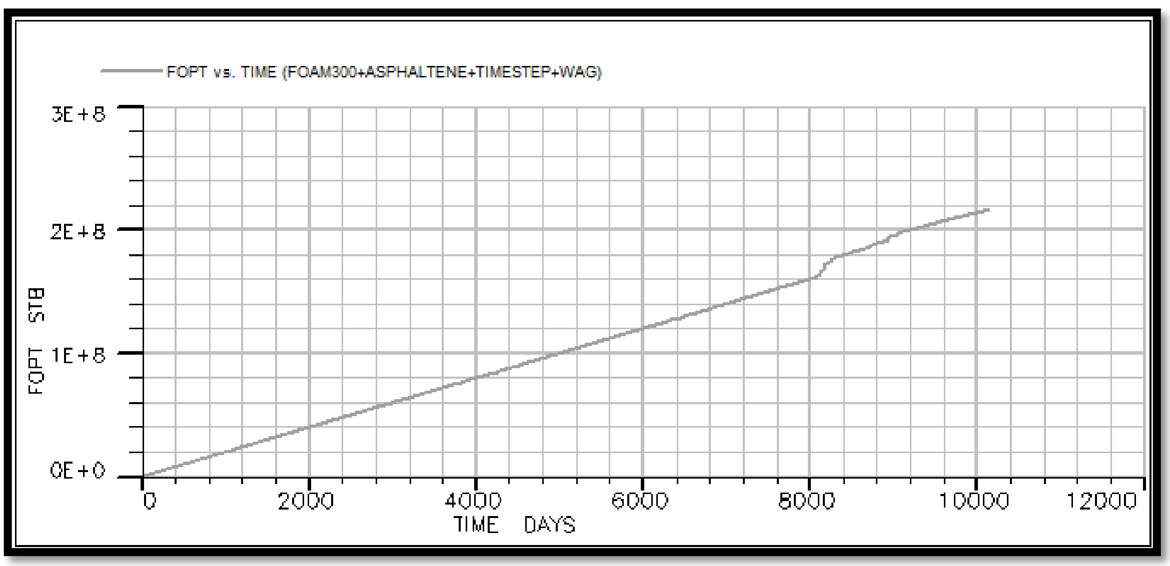

Figure 35: FOPT vs. time (0.1 lb/stb)

0.2 lb/stb

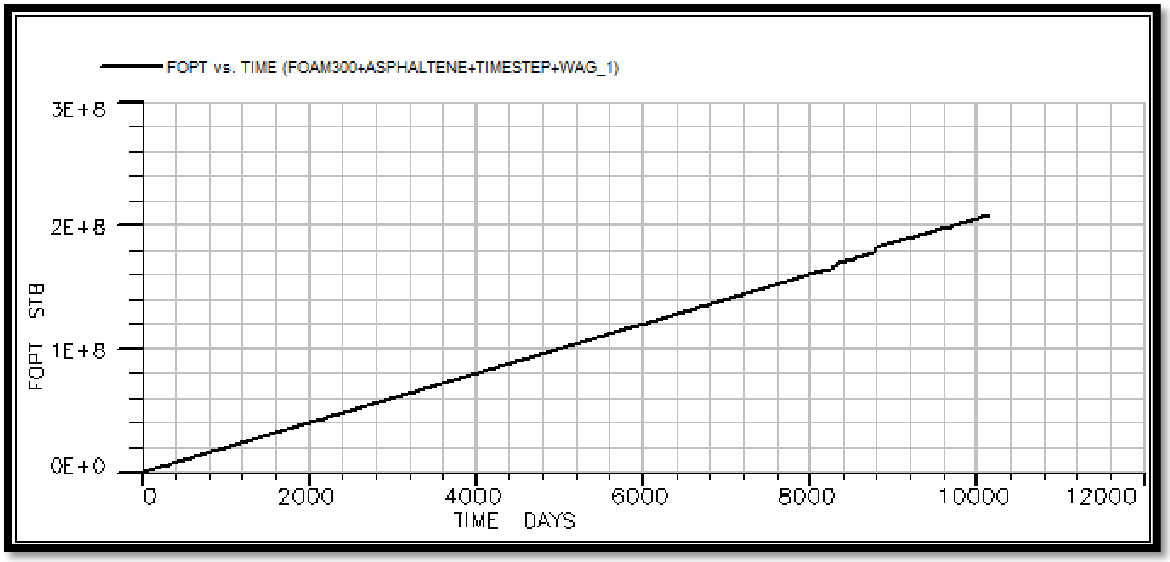

Figure 36: FOPT vs. time (0.2 lb/stb)

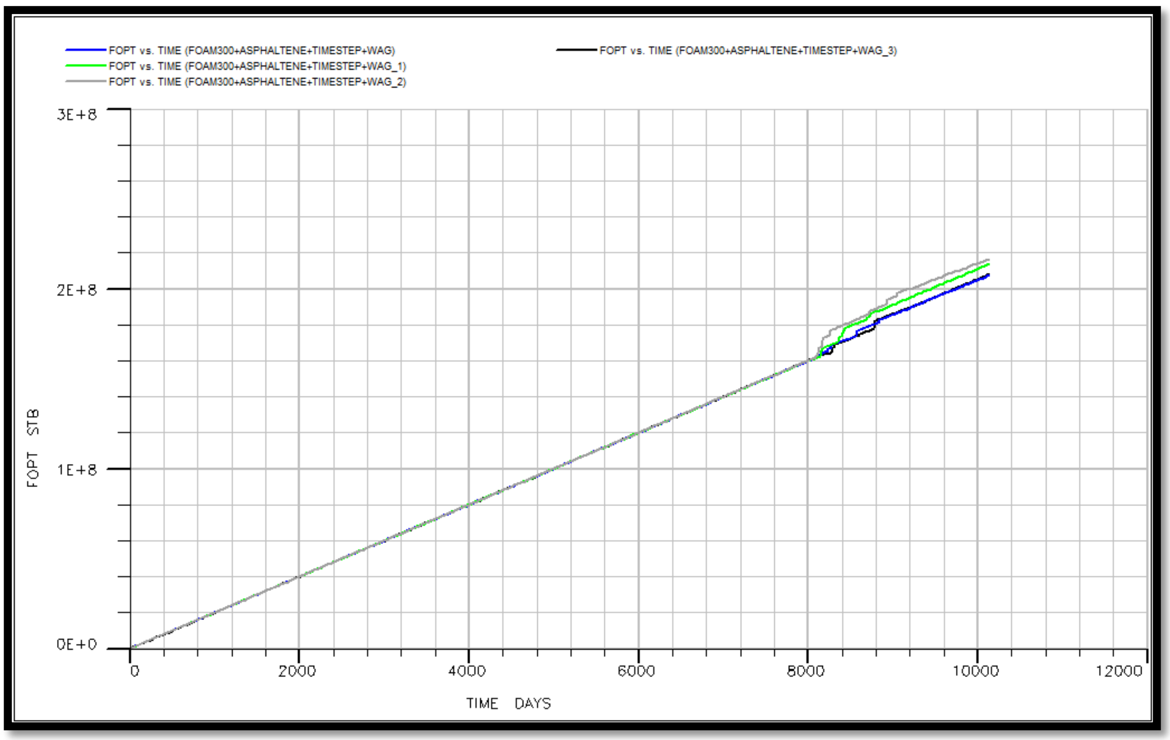

Figure 37: FOPT vs. time (Different Surfactant Concentration)

Four different concentration of surfactant were tested to observe the relationship between surfactant concentration and the FOPT. Based on the Figure 42, the concentration of surfactant was proven to have effect on the FOPT. Basically, the concentration of surfactant that yielded the highest FOPT is 0.1 lb/stb, followed by the base case, 0.01 lb/stb. The third most recovery was obtained by using the surfactant concentration of 0.2 lb/stb. The least recovery was obtained for the surfactant concentration of 0.005 lb/stb which was the lowest concentration used.

The result was plotted as below:

Concentration of Surfactant (lb/stb)	Field Oil Production Total (x10^8 stb)
0.005	2.048
0.010	2.100
0.100	2.140
0.200	2.050

Table 10: Surfactant Concentration vs. FOPT

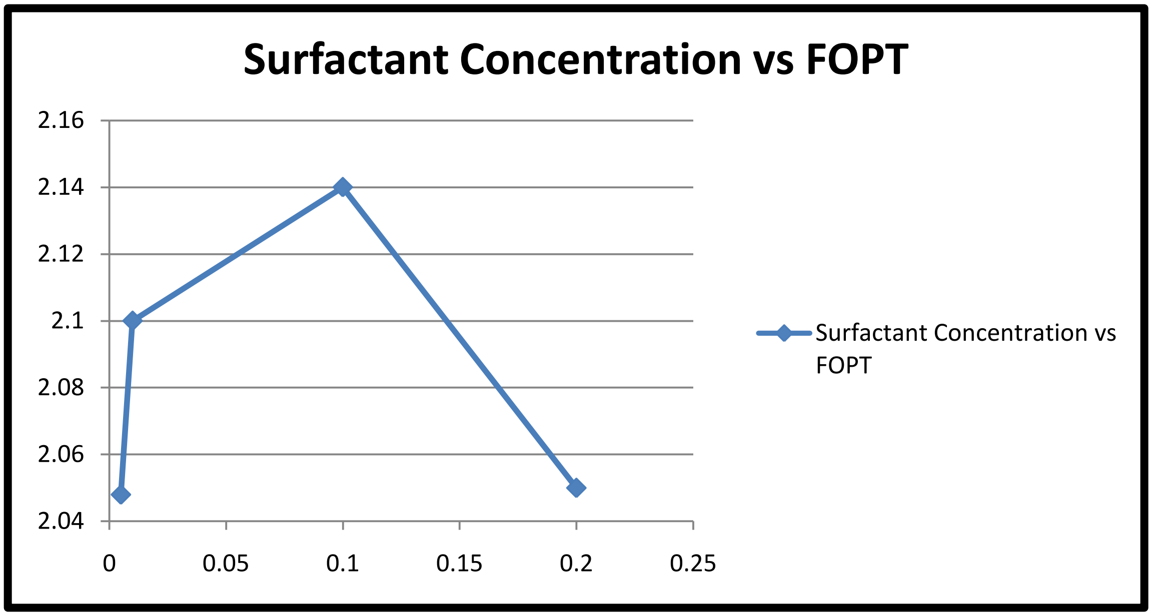

Figure 38: Plot of Surfactant Concentration vs. FOPT

Based on the Figure 42, the optimum surfactant concentration to minimize the asphaltene deposition was found to be 0.1 lb/stb. The minimum asphaltene deposition occurs at the maximum FOPT. Prior to 0.1 lb/stb, a direct relationship could be seen between the surfactant concentration and the FOPT. However, a sharp decline was observed as the surfactant concentration was increased from 0.1 lb/stb to 0.2 lb/stb. The explanation of the curve could be divided into 2 parts. The first one was on the trend before the optimum point and the next one was after. For the first part, as more surfactant concentration was used, more foam was generated at the high permeable zone which had been assisting in the gas movement continuously up to the surfactant concentration of 0.1 lb/stb. The maximum gas entrapment and foam generation occurred at the surfactant concentration of 0.1 lb/stb and maximum amount of gas was channeled to the low permeable layers.

However, beyond this concentration point, the sharp decline in FOPT can be explained by 4 theories. The first theory was the foam generation was extended to the middle layer where remaining oil mostly located and gas movement was inhibited in the low permeable layer. The chance for the miscibility to occur between gas and oil was also greatly reduced. This caused an inefficient displacement of the remaining oil. The second theory was most gas injected reacted with the surfactant and minimal amount of gas left to displace the remaining oil. The third theory was as the surfactant was found to be excess in amount, some surfactant reacted with the mineral of rock and eventually formed scum (hard deposit material) which blocked the pore throat and backfired the whole foam injection process. The last theory was the extension of the third theory in which the scum formed was being deposited and adsorbed to the surface of the rock which altered the wettability of the rock and caused detrimental change in the relative permeability of the oil.

4.6 Feasibility Studies (Optimum Surfactant Concentration)

Cost of Surfactant = Number of Cycles * Days in a cycle * Injection Rate * Surfactant Concentration * Average Surfactant Price per pound

Cost of Surfactant = 21 cycles * 30 days/cycle * 65000 stb/day * 0.1 lb/stb * $ 0.9/lb

= $ 3.69 millions

Extra Revenue by using Surfactant = Increase in Recovery * FOPT*Average Oil Price

= 20% * 2.14*10^8 stb * $ 100/stb

= $ 4.28 billions

Based on the calculation performed, the FAWAG project implemented sound profitable. However, a more thorough consideration of the cost such as facilities, expertise and preliminary research on the surfactant must be taken into account. The number obtained was simply a rough figure. A more detail and meticulous cost analysis must be performed to compute the overall profitability of the FAWAG implemented.

4.7 Comparison Studies of CO_2 and Solvent in WAG

The comparison study has been conducted for WAG cases in which the gas component has been changed from initially solvent to CO_2 injection. The original solvent composition is C1 77%, C3 20% and C6 3%. The combination of methane, propane and hexane is known as Natural Gas Liquid. Thus, the composition of well stream for gas has been changed to 100% CO_2.

Legends	Wellstream Components
(blue line)	CO2
(yellow line)	Solvent

4.7.1 CO_2 vs. Solvent (without asphaltene)

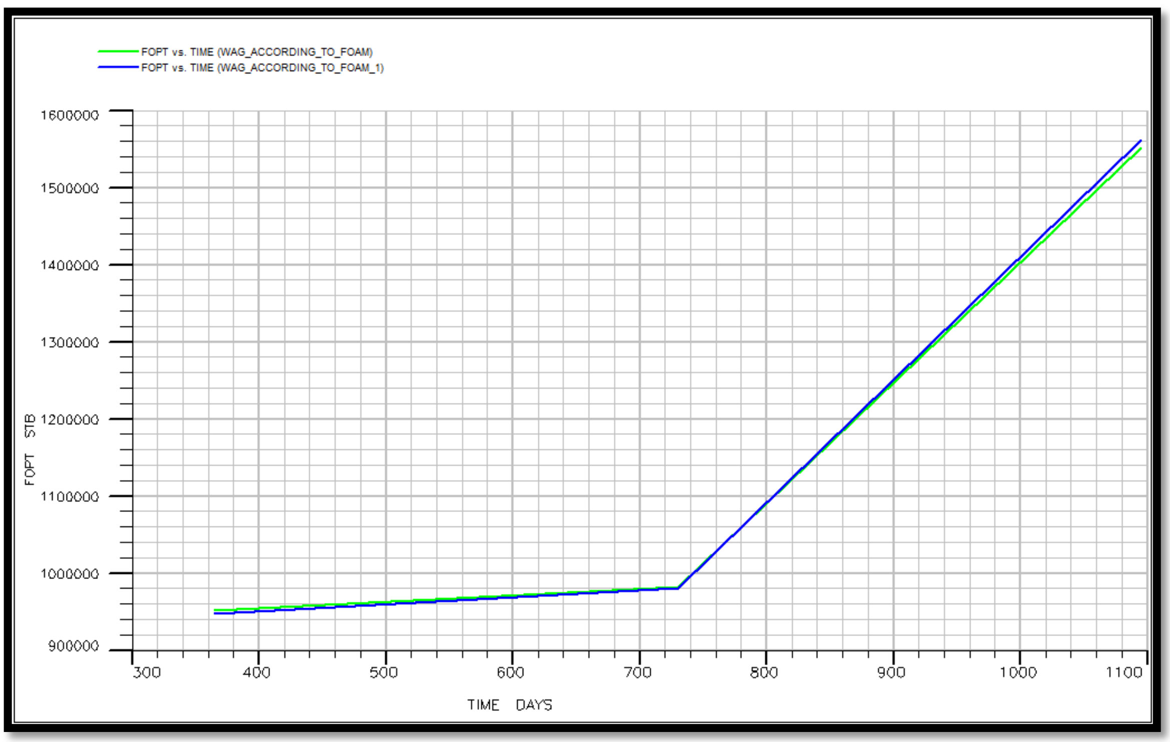

Figure 39: CO2 vs. Solvent (without asphaltene)

4.7.2 CO_2 vs. Solvent (with asphaltene)

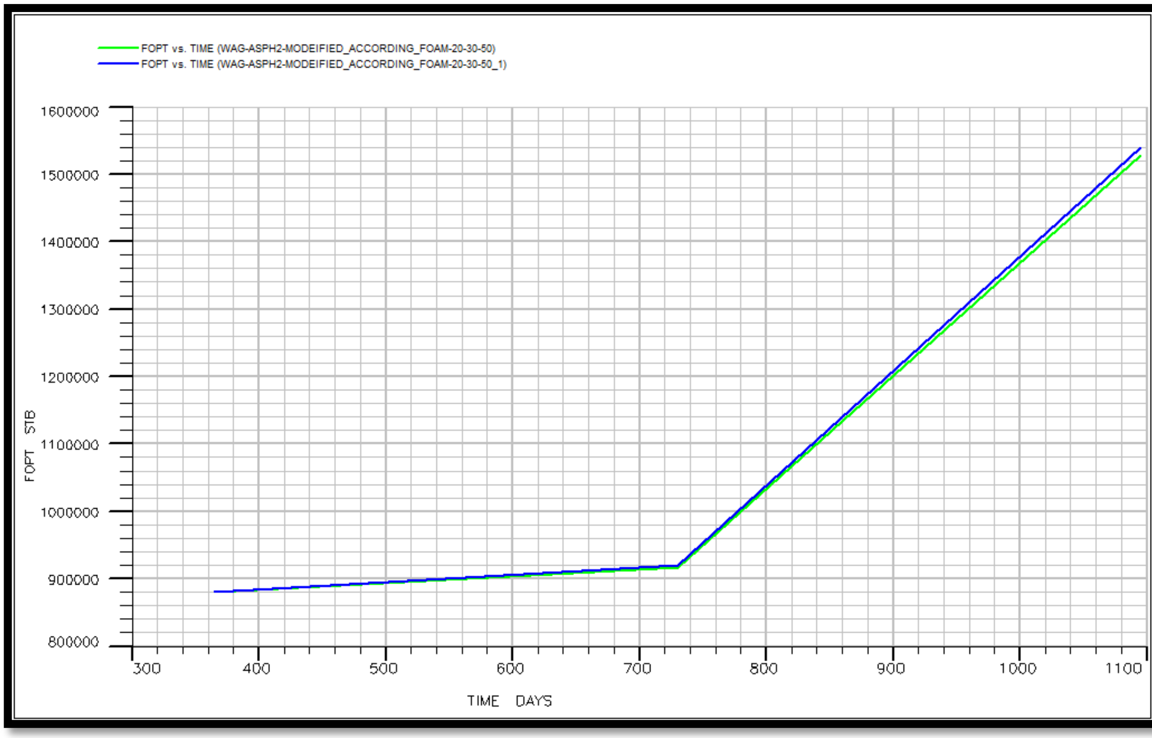

Figure 40: CO_2 vs. Solvent (with asphaltene)

Based on the Figure 39 & 40, the recorded value of FOPT was higher for CO_2 injection compared to solvent in both with and without asphaltene model. The most plausible explanation was CO_2 achieved better miscibility with the oil compared to solvent and made the oil swelled better. Although, the swelling of oil induces asphaltene deposition more, in this case the increase in the efficiency in oil displacement due to swelling had offset the induced asphaltene.

CHAPTER 5
CONCLUSION

1. WAG technique had shown better FOPT without the presence of asphaltene compared to with asphaltene. This was because the clogged pore throat due to asphaltene deposition has reduced WAG efficiency.

2. Nonetheless, FAWAG technique showed even a better recovery than the WAG. The recovery by using FAWAG was higher than WAG due to the better mobility control of gas and slight effect on the oil-water IFT.

3. FAWAG with asphaltene had yielded a better recovery than FAWAG model without asphaltene due to better mobility control of gas.

4. Optimization of FAWAG had shown injection rate does affect asphaltene deposition. The injection rate should be in the range of optimum value. The injection rate should not be too low which caused poor displacement efficiency and also not too high which may induce the electric kinetic effect which destabilized the micelle of resin and asphaltene.

5. Nevertheless, surfactant concentration had shown effect on asphaltene deposition. The asphaltene deposition was reduced as the surfactant concentration used increases until reaching an optimum point where the addition of surfactant effect caused adverse effect on the Field Oil Production Total due to the scum formation and deposition.

6. CO2 shows better recovery in both with and without asphaltene due to better miscibility.

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