Simulation Study of the Effect of Water Alternating Gas (WAG) and Foam-Assisted Water Alternating Gas (FAWAG) With Co^2 Injection In The Presence Of Asphaltene In Light Oil Reservoir

by

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CERTIFICATION OF APPROVAL

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Approved by,

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Project Supervisor

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

MAY 2014

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that this My own original work is my own unless it is specified and mentioned in the referencs, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

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ABSTRACT

Petroleum exploration has become one of the huge contributors of world economic growth and with the advanced technology of Enhanced Oil Recovery (EOR), the maximum amount of recovery oil is planned to be extracted. CO_2 injection is one of the most commonly used EOR methods. The injection of CO_2 onto light oil reservoir can cause the formation of asphaltene precipitation which may lead to major reservoir problems. FAWAG injection or Foam Assisted Water Alternating Gas injection is the improvement of WAG injection which can improve sweeping efficiency and control gas mobility and viscous stability.

In this project, the main problems that need to be controlled is the formation of asphaltene precipitation during miscible gas injection is unnoticed because of the little amount of it and this precipitation can give huge effect to the reservoir such as oil recovery reduction. The objectives of this project is to investigate the impact of WAG and FAWAG with CO_2 injection on asphaltene precipitation in light oil reservoir and to determine the optimum parameter of FAWAG with CO_2 injection ; the injection duration cycle, the injection pressure and the concentration of surfactant for FAWAG with CO_2 injection. The optimum parameters is decided to control the asphaltene precipitation.

After all the preliminary research is done, a simulation study will be conducted by using compositional reservoir simulator known as Computer Modeling Group Ltd (CMG). As the result of the study, it is shown that FAWAG-CO_2 injection is better than WAG injection in term of oil recovery and reduction of asphaltene precipitation. The optimum parameters of FAWAG and WAG injection were successfully obtained.

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CHAPTER 1

PROJECT BACKGROUND

1.1 Background Study

In this current advanced technology era, petroleum exploration has become one of the huge contributors of world economic growth. Every industrialized country is keeping up their efforts to develop new technology or technique to ensure that there is no single drop of oil is left behind during the production. Enhanced Oil Recovery (EOR) is widely studied and practised to ensure maximum amount of recovery oil is extracted.

The most common and successful gas injection EOR method so far is gas injection or in this study is Carbon Dioxide (CO^2) injection which its applicability is expanding. However, the injection of CO^2 in light oil which have API degree greater than 30 degree, will give a result in the formation of asphaltene precipitation. (Alta'ee, Saaid, & Masoudi, 2010). The instability of asphaltene precipitation can give huge problems to the reservoir production and oil recovery.

In EOR, there are several Water Alternating Gas (WAG) methods that demonstrate the improvement in oil recovery. Recent technology shows with the addition of foam to WAG technique, it can give massive improvement in boosting oil recovery to the maximum level by improving the sweeping mechanism during gas injection, give reduction to the Gas Oil Ratio (GOR) and increase the oil production rate. (Tunio & Chandio, 2012). This advanced technology in EOR is called Foam Assisted Water-Alternating Gas (FAWAG).

There are several important elements in this study that need to be focused to compare the application of FAWAG and WAG injection method in term of oil recovery. The presence of asphaltene in light oil reservoir is also introduced to see the impact of WAG and FAWAG-CO_2 injection towards asphaltene precipitation. The parameters that will be investigated are different WAG and FAWAG cycle ratio in terms of the duration of the injection, the injection pressure for both WAG and FAWAG, and the concentration of surfactant that is optimum for reducing the gas oil ratio (GOR) and increase the oil recovery with the presence of asphaltene in the light oil reservoir.

1.2 Problem Statement

During the miscible CO_2 gas injection process in light oil reservoir, the likely of asphaltene precipitation formation is usually failed to notice or unpredicted. This is because of the very little content of asphaltene in light oil reservoir and during the first production phase of reservoir, there is no existence of asphaltene precipitation. (Sarma, 2003). The asphaltene precipitation in light oil reservoir can cause many problems that will affect reservoir performance such as reduce in permeability and porosity, change in wettability, capillary pressure alteration and wellbore plugging. (Khanifar & Demiral, 2011). The operation to remove asphaltene precipitation is very expensive and troublesome which involves chemical treatments and workover operations. Thus, the stability of asphaltene need to be controlled so that can reduce the effect of asphaltene precipitation. Important parameters such as different WAG and FAWAG cycle ratio in terms of the duration of the injection, the injection pressure for both WAG and FAWAG, and the concentration of surfactant for FAWAG injection are needed to take into account for controlling the stability of asphaltene by doing simulation study of WAG and FAWAG injection with CO^2 in light oil reservoir.

1.3 Objectives

The objectives of this simulation study are :

- To investigate and compare the effect of WAG and FAWAG with CO_2 injection on asphaltene precipitation in light oil reservoir.
- To determine the optimum injection parameters of WAG and FAWAG together with the concentration of surfactant to control the stability of asphaltene formation.

1.4 Scope of Study

The scope of study is to do a simulation study by using compositional reservoir simulator known as Computer Modeling Group Ltd (CMG). The reservoir involved is the sandstone reservoir which contain light oil. All the data inputs for reservoir and fluids model are obtained from the literature study. Three different parameters is investigated to get the optimum parameter which can control the stability of asphaltene precipitation and recover more oil. The parameters are WAG and FAWAG with CO_2 injection duration cycle, the injection pressure and the concentration of surfactant. Lab experiment is not included in this study.

1.5 The Relevancy of the Project

The investigation simulation study of WAG and FAWAG with CO_2 injection into reservoir is very relevant towards nowadays scenario. The oil recovery is very essential nowadays because of the slow development of new field. Besides that, the majority of the reservoir in Malaysia are producing light oil which can cause the formation of asphaltene precipitation which can lead to many reservoir problems. With the optimum parameters of EOR application, the impact of it is relevant to the oil production whether it can control the asphaltene precipitation formation or not and at the same time increase the oil recovery.

1.6 Feasibility of the project within the scope and time frame

Based on the time frame and submission deadline given by course coordinator, with full commitment, hard work and proper planning, the research study can be completed in time. The assistance from project supervisor is also plays a major role in order to complete the task.

CHAPTER 2

LITERATURE REVIEW

2.1 Enhanced Oil Recovery

Enhanced oil recovery is defined as the incremental ultimate oil that can be produced economically from a reservoir higher than what conventional primary and secondary methods can recover. (Bailey & Curtis, 1984). Primary recovery depends on the natural energy of reservoir to push the oil to the production wells but over the time, this natural energy will depleted and this is when secondary recovery method is introduced to provide supplementary energy to the reservoir through the injection of gas or water into the reservoir. (Bailey & Curtis, 1984). Enhanced oil recovery (EOR) or can be considered as tertiary oil recovery is classified into three different methods which are miscible flooding, chemical flooding and thermal recovery. (Bailey & Curtis, 1984).There are other methods that have been studied and tested in EOR to recover the balance of oil left behind after the application of primary and secondary methods.

2.2 Water Injection

Secondary recovery is applied when primary or natural drive mechanisms are no longer be able to recover more oil economically. Water injection or waterflooding is the most common secondary recovery method. Oil is displaced microscopically when reservoir pressure is maintained via water injection that provide drive mechanism. There are several factors that affects the water injection efficiency :

1. Lithology and rock properties : clay swelling and deflocculating might occur during water injection and cause pore clogging and formation permeability damages. Monitoring the water injection rate is essential to ensure it is not exceeding the formation fracture pressure. More oil can be recovered when

applying waterflooding in water-wet system due to the capillary pressure which can enter smaller pores.

2. Trapped gas saturation, (Sgt) : the optimum Sgt can be reached if the reservoir pressure is maintained. The residual oil saturation can be reduced at higher Sgt. This is because of the gas is more non-wetting to reservoir rock compare to oil. The pore space will be occupied with gas and reduce the amount of residual oil left when water displaced the oil.
3. Mobility ratio : when the viscosity of water increase, the mobility ratio will reduced thus increase the displacement efficiency. Early water breakthrough and water fingering will occur at high mobility ratio.

2.3 CO_2 injection.

One of the main methods of Enhanced Oil Recovery (EOR) that used to improve oil recovery is gas injection and nowadays, its application is broadly increasing. CO_2 flooding is the most regularly used gas injection in EOR method because of the bounty amount of it, the ease tendency to achieve miscible condition and greenhouse effect. (Ghasemzadeh, Momeni & Vatani, 2011). According to Yongmao et. al. (2004), the production lives of oil fields approaching depletion with waterflood mechanism can be extended until 15 to 20 years using the carbon dioxide injection. Other than that, the original oil in place might be recovered from 15% to 25%.

CO_2 injection process involves very complex phase behaviour, and it is depend on the fluid properties, temperature and pressure of a particular reservoir. CO_2 injection can contributes to oil recovery with different mechanisms involved such as reduction in viscosity, oil swelling, improvement in formation permeability, low interface tensions, gas flooding solution, and change in oil and water density. (Yongmao et. al, 2004)

The injection process of CO_2 is branched into two which are immiscible and miscible, even though during the first contact in the reservoir, the crude oils are not miscible at the first place. (Martin & Taber, 1992) In immiscible processes, the appliance of CO_2 injection comprises reduction in oil viscosity, oil swelling and dissolved-gas drive. Anyhow in miscible processes, CO_2 is more effective in recovering oil because of the solubility of CO_2 in crude oils at reservoir pressure which able to swell the net oil volume and cut down oil viscosity long before miscibility is obtained by a vaporizing-gas mechanism. (Martin & Taber, 1992).

The property that can lead to the precipitation of asphaltene inside the reservoir matrix and deposition on the reservoir rock is the miscibility of the CO_2 with the reservoir oil. (Alta'ee et al., 2010). It will lead to porosity and permeability reduction and might cause formation damage once asphaltene precipitation occurs. Based on the study of Alian et al., (2011), they agreed that injection of CO_2 will cause instability to asphaltene but with the increment of injection pressure, the deposition of asphaltene would be reduced.

2.4 Asphaltene Precipitation

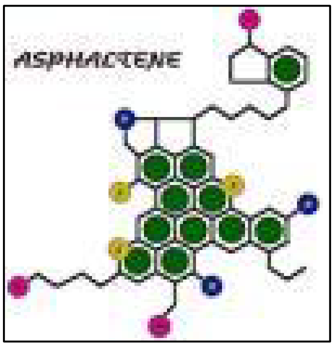


Figure 1 : Asphaltene structure

Asphaltene characterized as the n-pentane insoluble fractions of crude oil that stays in solution under reservoir pressure and temperature conditions. The stability of asphaltene will be disturbed and start to form precipitate during gas injection and primary production while composition, temperature and pressure changes occur at the same time. (Khanifar & Demiral, 2011).

One of the reasons why the potential formation of asphaltene precipitation is frequently overlooked is a very litte content of asphaltene in many light oil reservoir during gas injection implementation. Other than that, during the primary production, there is no indication of asphaltene precipitation is experienced. (Sarma, 2003).

The cause of precipitation is not come from the asphaltene content in the light oil but the stability of asphaltene play a major role in precipitation formation. The solubility of asphaltene in light oil reservoir is normally very low and this makes asphaltene become unstable and the possibility of precipitation increase. (Alian et al.,2011).

According to Akbarzadeh et al.(2007), asphaltene might be formed at various places throughout the production system starting from inside formation to pumps, tubing, wellheads, flowlines, safety valves and surface facilities. This will resulting in well clogging and reduces the oil recovery and production.


Figure 2 : Asphaltene precipitation deposited inside pipe

2.5 Water Alternating Gas (WAG) injection

Water alternating gas injection or known as WAG injection is the EOR application which combines two recovery techniques which are gas flooding and water injection. This method involves the injection of gas (commonly Carbon Dioxide) alternated with water into the reservoir according the specified ratio. By definition, WAG process is the recovery process which involves the injection of one gas slug followed by injection of water slug in general. (Christensen et al., 2001).

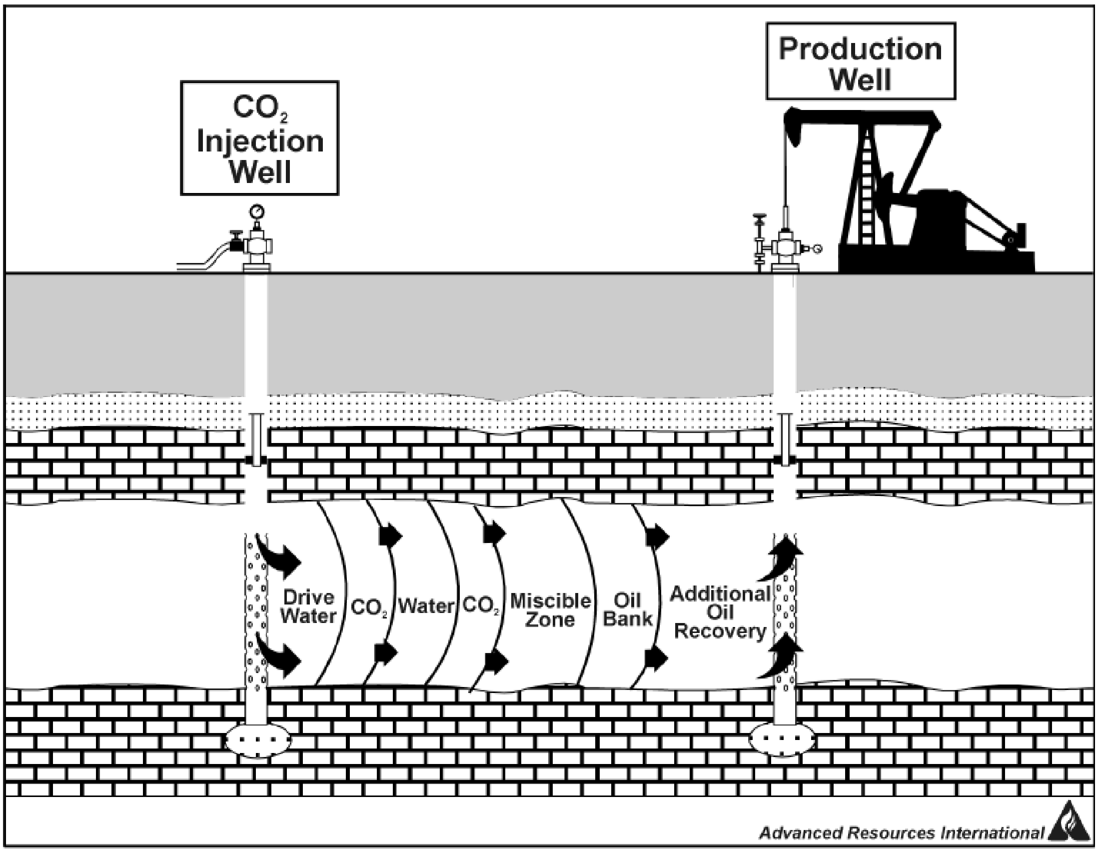


Figure 3 : Schematic of WAG injection

According to Christensen et. al. (2001), the first application of WAG was implemented in the North Pembina field in Alberta, Canada operated by Mobil in 1957. It was documented but until the publication of Caudle and Dyes research paper in 1958, there was no completed and proper research work.

WAG process can be considered as one of the matured technology because of its successful application in the Canada, US and North Sea oil fields and it is commonly used as tertiary miscible injection projects. According to the report by Ramachandran et al., (2010), the application of WAG can give an increment to the recovery in the range of 5% to 10% of oil initially in place (OIIP). WAG is one of the well-known method in EOR that can improve oil recovery in term of sweep efficiency, good gas mobility control in miscible process. (David H., 2009).

The initial goal of WAG injection oil recovery method during gas injection is to improve sweep efficiency. The attribution of WAG method in oil recovery is also to contact unsweep zones especially for the type of cellar or attic oil recovery by accumulating the water towards the bottom or exploiting the segregation of gas to the top and better overall sweep efficiency is because of the gas displacement at low permeability layer. (Sanchez, 1990). WAG also has potential for increasing the microscopic displacement efficiency since the residual oil after water flooding is higher than after gas flooding. The flood front has to be stabilize to displace oil effectively which is influenced by injection strategy (gas and water injector position), well spacing and miscible/immiscible gas. (Lake, 2008). According to the laboratory experiment conducted by Mangalsingh & Jagai, (1996), WAG ratio also plays an important role and the optimum WAG ratio obtained from their experiment is 1 to 4.

The mobility of gas also reduced by alternating the injection of gas with water by reducing the viscous fingering and breakthrough time of gas. This will increase the CO_2 oil contact time during WAG and resulting in low production of GOR. From the case study conducted by Mangalsingh & Jagai, (1996), continuos gas flooding give results of GOR as high as 2000cc while during WAG injection is below 500 cc. Other advantage of WAG application is it only requires lower pore volume. (Mangalsingh & Jagai, 1996).

In general, gas flooding has higher microscopic displacement efficiency while water displacement is better in term of macroscopic displacement. WAG injections get the benefits from both application when combined those two injection methods together thus will definitely increases the ultimate recovery of the petroleum. (Caudle & Dyes, 1958).

According to Sharma & Clements (1996), there will be a possible adverse effects towards microscopic sweep efficiency with the presence of water in WAG due to the oil trapping phenomena which occur when the remaining oil is shielded by water and prevent it from contacting the subsequent injected gas. However, the displacement efficiency of gas is not completely eliminated by water shielding because certain type of gas such as carbon dioxide can diffuse through and dissolve into water, then contact, swell and displace the oil. This means that the displacement of gas is slowed down by the adverse effect of oil trapping. (Sharma & Clements, 1996).

2.5.1 WAG injection parameters

Based on the experimental study conducted by Srivastava & Mahli (2012), there were three important parameters that affect the performance of WAG injection which are WAG cycle, WAG ratio and type of gas used in WAG injection. The tertiary recovery method is carried out by using different WAG methods which are single cycle WAG and five cycle WAG (with HC gas and CO_2 separately) and WAG tapering with different WAG ratio. The result obtained from the experiment showed the effect of different cycles in WAG injection process in term of oil recovery. With the same volume of injecting fluid, five cycles process give recovery better than single cycle. Maximum recovery is obtained from decreasing trend of tapered WAG in three cycles which improved oil recovery by decreasing the residual oil saturation and increasing trapped gas saturation. CO_2 as the gas of WAG injection gives better displacement efficiency. It can be concluded that the WAG injection process give better mobility control of gas and water phase, sweep control and improves the displacement efficiency. (Srivastava & Mahli, 2012).

2.6 FAWAG injection

The reservoir sweep efficiency is low mostly due to reservoir heterogeneity, viscous instability and gravity segregation during the CO_2 injection results in gas overriding. It can control the mobility by reducing viscous instability and improve gas sweeping efficiency incremental oil recovery or production acceleration by adding foaming agents or surfactants. (Talebian et al.,2013)

This method is termed as FAWAG injection or foam assisted water alternating gas injection which is the modification of WAG injection or water alternating gas injection. FAWAG is commonly brought in reservoirs with WAG already in use. A foam barrier is generated by FAWAG to block the movement of gas to the upper side of reservoir and forcing the gas to spread laterally. This is improving WAG technique which commonly injected gas tends to rise to the top of reservoir. The barrier is obtained by injecting water and surfactant simultaneously for a few days and continues with gas injection. (Tunio, Chandio & Memon, 2011)

The advantageous of using foam to assist gas injection are it can control the mobility of gas in porous medium and very cost effective method as it only needs a very little concentration. Reservoir effects such as gravity segregation, fingering, and channelling can be reduced as foam lessens the displacing fluid mobility. Foam has a particular characteristic of which can block high permeable layer in the reservoir, and guide other fluid to flow to un-swept areas or layers. (Langlo,2013). The interfacial tension between the fluids also can be reduced. Figure 3 below shows the beneficial effect of gas injection with foam and free gas injection.

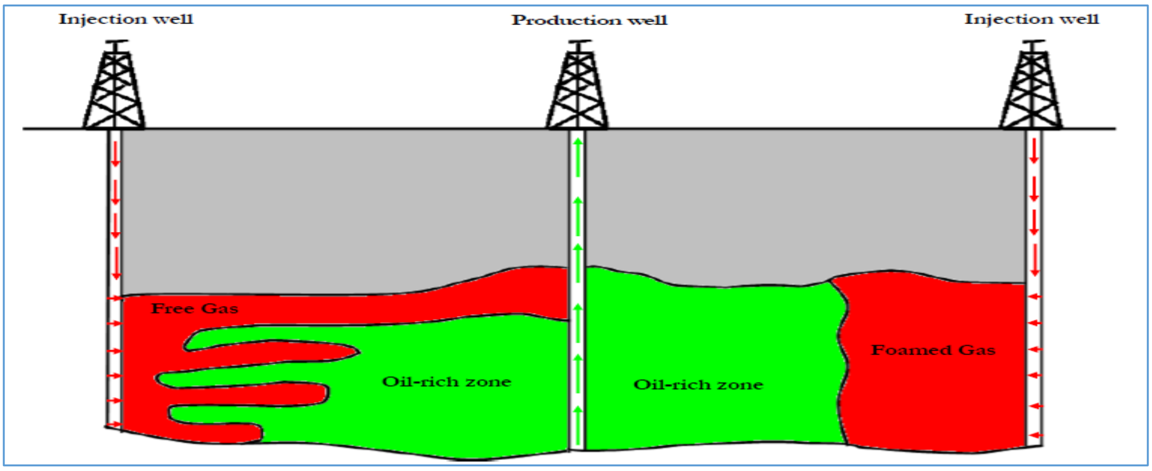


Figure 4 : Schematic illustration on the comparison of foamed gas injection (right side) and free gas injection (left side). (Langlo, 2013)

The other advantageous of FAWAG is less injection pressure is required compared to WAG which need a higher injection pressure to sustain the gravity action. The contact between water and gas is also minimized by applying FAWAG. (Kloet, Renkema & Rossen, 2009). According to Xu & Rosen (2004), the injectivity also can be improved by FAWAG. This is because of the increment of gas mobility at the wellbore area while foams move away far from the well to sustain the mobility during gas displacing water near the well area.

2.6.1 FAWAG injection in Carbonate and Sandstone formation

FAWAG injection is one of the advanced technologies in EOR. Specific EOR method is required to be applied in different reservoir lithology. This is because of different type of formation has different reservoir properties and requires different parameters of

EOR. (Alvarado & Manrique, 1996). Figure below shows the application of EOR method in different lithology.

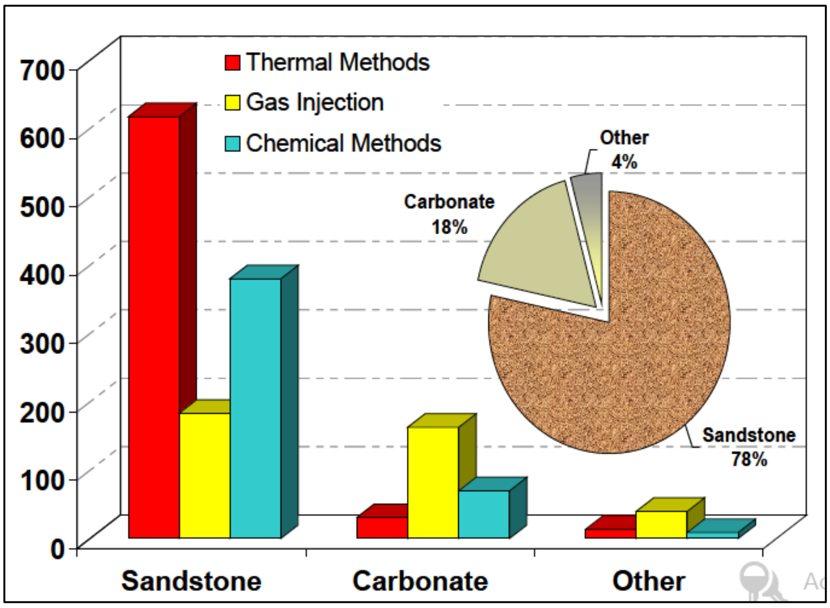


Figure 5 : Application of EOR method in different formation. (Alvarado & Manrique, 1996)

From figure above, obviously shown that thermal method and chemical method in sandstone formation are the most frequently used EOR technique compared to carbonate and other formation. FAWAG injection can be classified as the combination of gas injection and chemical methods in EOR technique and it is widely applied in sandstone formation.

According to Langlo (2013), oil recovery in fractured carbonate formation are low because approximately 80% of the reservoir are mixed-wet or oil-wet, which can lead to unsuccessful water injection. By injecting FAWAG, it can increase the efficiency of displacement in contrast to gas injection in fractured and heterogeneous reservoir. (Rossen, 1996).

2.6.2 The application of FAWAG in Snorre Field

The biggest application of FAWAG in the world took place in The Snorre field in Norway which is one of the important oil fields on the Norwegian Continental Shelf in the North Sea. The project was started in 1997 on the Central Fault Block (CFB) of the Snorre Field. (Blaker, *et al.*, 2002). Initially in 1992, the main drive mechanism developed in The Snorre Field is water injection. The downdip WAG pilot in CFB was implemented to increase the production as the first technique then the FAWAG project took place as a full-scale field application with the use foam which can improve gas sweep efficiency during WAG injection. (Skauge et. al., 2002)

According to Skauge et. al., (2002), the foam treatment from FAWAG injection is applied on production well P18 of CFB of the Snorre Field which had suffered an inflated amount of gas oil ratio (GOR) due to early gas breakthrough. The formation that undergo this treatment has 8 Darcy in permeability and 7.2 metre thick sand layer of the Stajford formation. Surfactant alternating gas injection with 2 cycles and CO_2 injection is applied on this formation. There were 32 tons of surfactant used in this treatment with the concentration of 1 or 2 wt%. This surfactant is divided into 8 tons on each cycle and 16 tons used for co-injection.

Based on all the result data collected by Skauge et. al.,(2002), it can be concluded that there were limited amount of foam generation during SAG injection but with the co injection, the strong foam was generated and removed the plug isolating in the high permeable streak. After two months of foam treatment, the Gas Oil Ratio in P18 was reduced up to 50%.

From this study, it has proven that the gas breakthroughs which can limit the oil production was delayed and low Gas-Oil-Ratio was regulated. The instant depletion in injectivity was observed which show that foam was generated. The effect of foam was remained for a long period of time. (Skauge et. al., 2002).

2.6.3 Surfactant as foaming agent

Surfactant is an organic compound that have amphipatic nature which is a chemical compound that possessing both hydrophobic (tail) and hydrophilic (head) groups. (Schramm et al., 2000) The term surfactant is originated from the term “surface active agent” which displaying its definition of material that can reduce liquid surface tension significantly especially water when low concentrations is applied. The critical micelle concentration (CMC) is the concentration of surfactant where micelles or foam are formed. (Green & Willhite, 1998). If the surfactant’s concentration is lower than CMC, the interfacial tension will decrease and the concentration will continue increasing. However, there will be only small changes in interfacial tension value when the surfactants concentration is higher than CMC. More micelles will be formed at higher concentration of surfactant. (Green & Willhite, 1998).

The foam formed from the reaction between injected gas and surfactant can reduce the carbon dioxide mobility. Khalil & Asghari (2006) has found out that the mobility of carbon dioxide can be reduced up to 85% with the application of foam. In another field test studied by Holm & Garrison (1998) in Wilmington field, the FAWAG injection is implemented at the operating pressure less than minimum miscibility pressure of carbon dioxide to improve the recovery.

2.5.4 Type and concentration of surfactant

The dissimilarity in reservoir rock mineralogy can cause the foaming agent been absorbed onto reservoir rocks during FAWAG application because of the charged solid surface. (Blaker, Celius & Lie, 1999). According to Morahdi & Johnstone (1997), there are two feasible solutions to reduce foam loss through absorption. The first one is injecting adequate amount of surfactant into reservoir and second one is by using sacrificial agent like Calcium Lignosulfate (CLS) which has stronger tendency to bind with rock surface and restrict the absorption of surfactant as the rock surface area is reduced. (Morahdi & Johnstone, 1997)**.** Some of the basic criteria for the selection of surfactant are it must have a low loss factor, can sufficiently reduce the gas mobility and the most important is must be commercially available and inexpensive. (Blaker et.al., 2002). The suitable foaming agent or surfactant must be properly selected for a different reservoir condition. In this study, two types of core samples which indicates the real reservoir condition are used which are Sandstone and Carbonate formation. The examples of surfactant that could be used in this project are Sodium Dodecyl Sulphate and Alpha Olefin Sulfonate (AOS).

There are few reasons of surfactant is not widely applied in the past because of the chemical limitation, the requirement of salinity optimization, the potential emulsion block and oil price sensitivity. (Khaled, 2011). However, the high demand of energy worldwide nowadays cause the continuous increase in the oil price which made FAWAG application is feasible.

2.4 Summary of Literature Review

After going through the literature review, the important details had been summarized. Enhanced oil recovery is defined as the incremental ultimate oil that can be produced economically from a reservoir higher than what conventional primary and secondary methods can recover. Waterflooding is the most commonsecondary method and there are several factors that affect the efficiency of water injection which are lithology and rock properties, trapped gas saturation and mobility ratio. CO_2 injection can contributes to oil recovery with different mechanisms involved such as reduction in viscosity, oil swelling, improvement in formation permeability, low interface tensions, gas flooding solution, and change in oil and water density. However, CO_2 injection into light oil reservoir may cause the formation of asphaltene precipitation which can lead to reservoir problems and affect oil recovery. WAG process is the recovery process which involves the injection of one gas slug followed by injection of water slug in general. WAG can increase the microscopic displacement efficiency and provide mobility control. The important parameter in WAG is the WAG cycle, WAG ratio and type of WAG gas injected. FAWAG injection or foam assisted water alternating gas injection which is the modification of WAG injection or water alternating gas injection.

CHAPTER 3

METHODOLOGY

3.1 RESEARCH METHODOLOGY

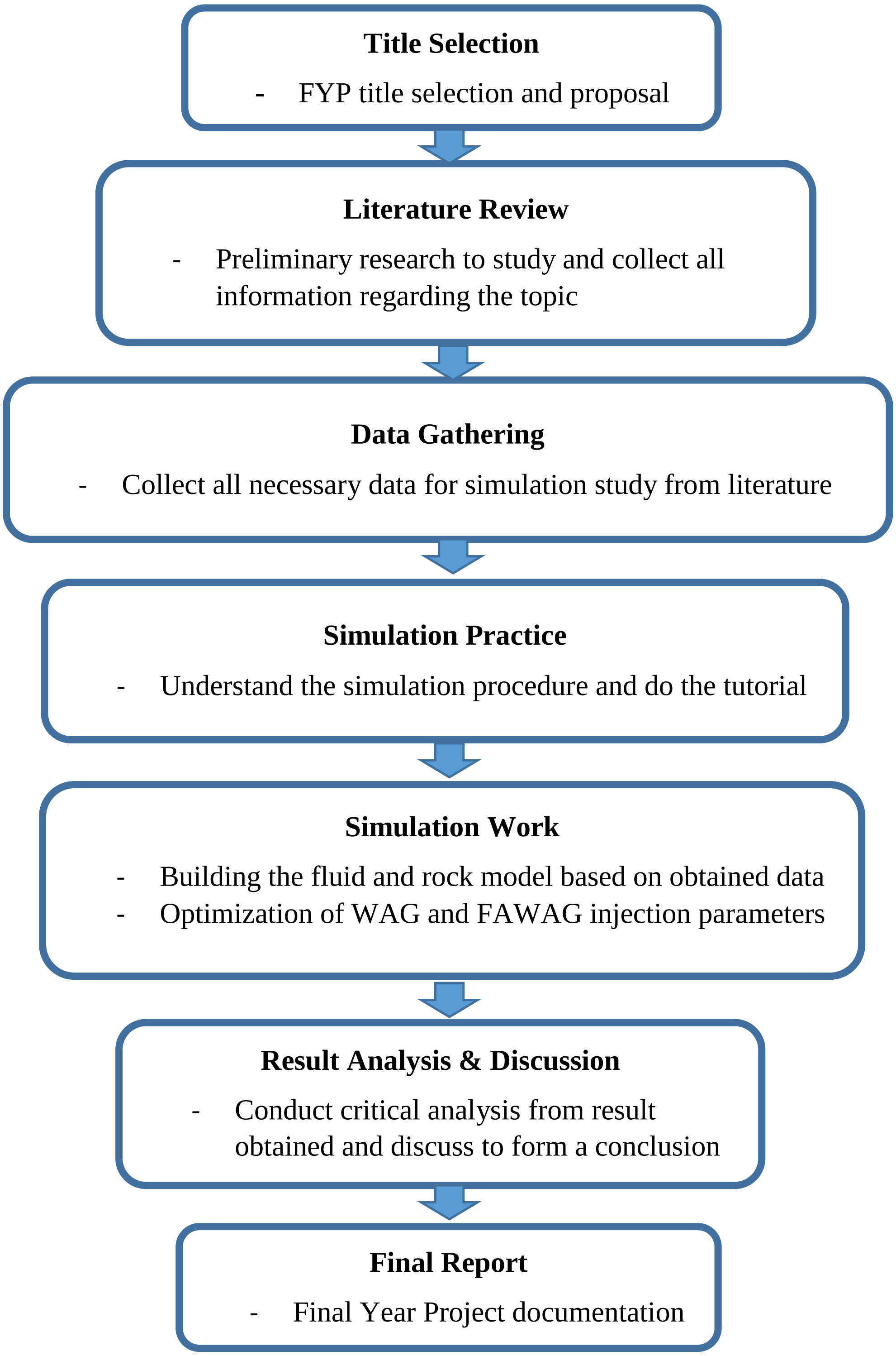


Figure 6 : Schematic diagram of project methodology

3.1.1 Data Gathering

All the information regarding WAG and FAWAG injection parameters, reservoir and fluid data are collected from literature review and gathered for the simulation purpose. The asphaltene precipitation and the factors that contribute in the deposition of asphaltene and how it precipitate are obtained from the study of literature review

3.1.2 Simulator

In this simulation study, Computer Modelling Group (CMG) software simulator is used to do the simulation which consists of various tools and applications for different type of simulation work for any purposes. The tools that been used in this project were :

1) WinProp : To model the reservoir fluids and asphaltene
2) Builder : Tools for inputting reservoir data
3) STARS. : To optimize the parameters of WAG and FAWAG and to see the impact of it towards oil recovery.

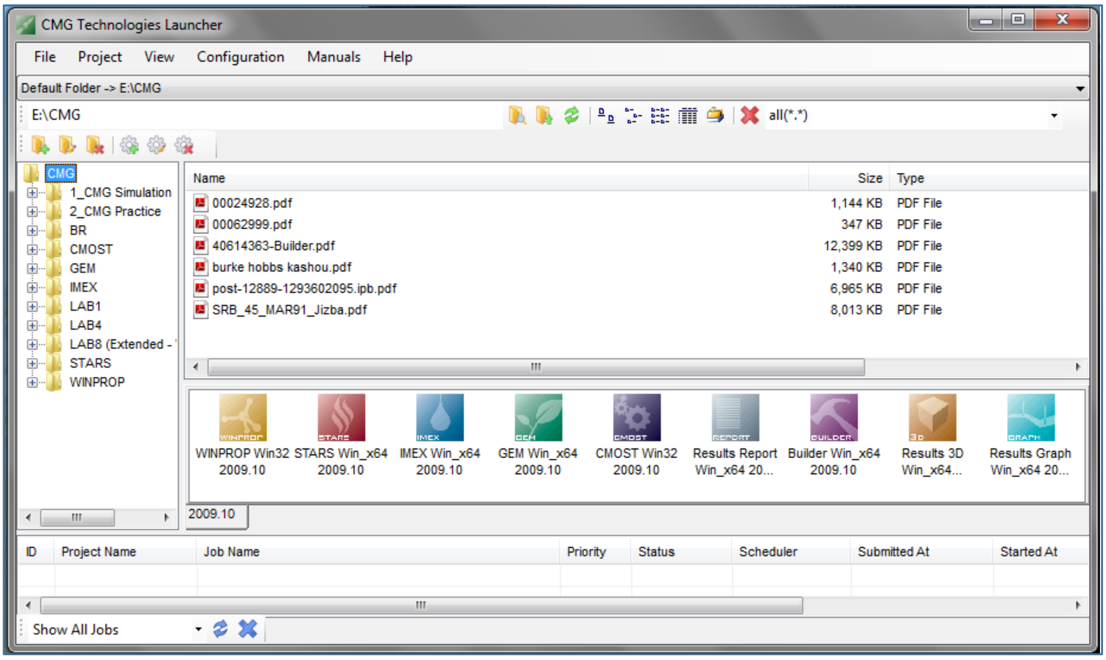


Figure 7 : Computer Modelling Group (CMG) Ltd Software interface

3.1.3 Fluid and asphaltene modelling

The data for constructing the fluid models are collected from literature review. Good description of hydrocarbon fluids sample data such as component compositions, molecular weight and characterization of heavy plus-fraction are very important to ensure the exact behaviour of the fluid model. The reference for oil samples is from the report by Burke et al. (1990) entitled *Measurement and Modelling of Asphaltene Precipitation* which provided a sufficient description of 6 difference oil samples, as shown in figure 6 below.

To build light oil model, Burke oil sample number 4 is used as the basic fluid model's component because of high reading of API gravity and asphaltene content.

	Oil					
Component	1	2	3	4	5	6
Nitrogen	0.57	0.51	0.05	0.25	0.23	0.20
CO_2	2.46	1.42	6.47	2.03	8.53	5.45
Methane	36.37	6.04	9.58	32.44	21.72	30.90
Ethane	3.47	7.00	12.00	15.50	20.80	18.04
Propane	4.05	6.86	6.83	6.54	4.82	5.45
i-Butane	0.59	0.83	0.87	0.81	1.35	1.11
n-Butane	1.34	3.35	3.78	3.20	3.47	2.56
i-Pentane	0.74	0.70	1.42	1.15	1.68	0.38
n-Pentane	0.83	3.46	2.62	2.13	2.11	2.18
Hexanes	1.62	3.16	4.95	2.46	2.53	1.93
Heptanes plus	47.96	66.68	51.43	33.49	32.76	31.80
Total	100.00	100.00	100.00	100.00	100.00	100.00
C_{7+} molecular weight	329	281	271	223	219	197
C_{7+} specific gravity	0.9594	0.9020	0.9151	0.8423	0.8533	0.8230
Live-oil molecular weight	171.4	202.4	151.6	95.2	95.1	83.6
API gravity, stock-tank oil	19.0	24.0	30.0	38.8	37.0	40.8
Asphaltene content in stock-tank oil, wt%	16.8	9.0	2.8	1.7	0.4	0.9
Reservoir temperature, °F	212	218	225	234	225	230
Saturation pressure, psia	2,950	600	1,120	2,492	2,100	2,915

Figure 8 : Properties and composition (mole %) of Burke oil samples

Table 1 : Properties of Burke Oil Sample No.4

Burke Oil		
	Value	Unit
Saturation pressure	2492	psia
Critical pressure @ 762 F	2320	psia
API gravity	38.8	-
Max asph preci. @ sat. pres	0.714	%
Low onset pressure	815	psia
High onset pressure	3610	psia
MMP (Pure CO_2)	5000	psia
MW	95.2	-
Asphaltene content	1.7	%

Table 1 shows the properties of Burke Oil sample No.4 which is a light oil with high API gravity and high content of asphaltene. In order to model this light oil reservoir with asphaltene content in CMG simulator, WinProp tool is used.

Figure 8 below shows the interface to key in the properties required for building light oil including its component with asphaltene model using Winprop.

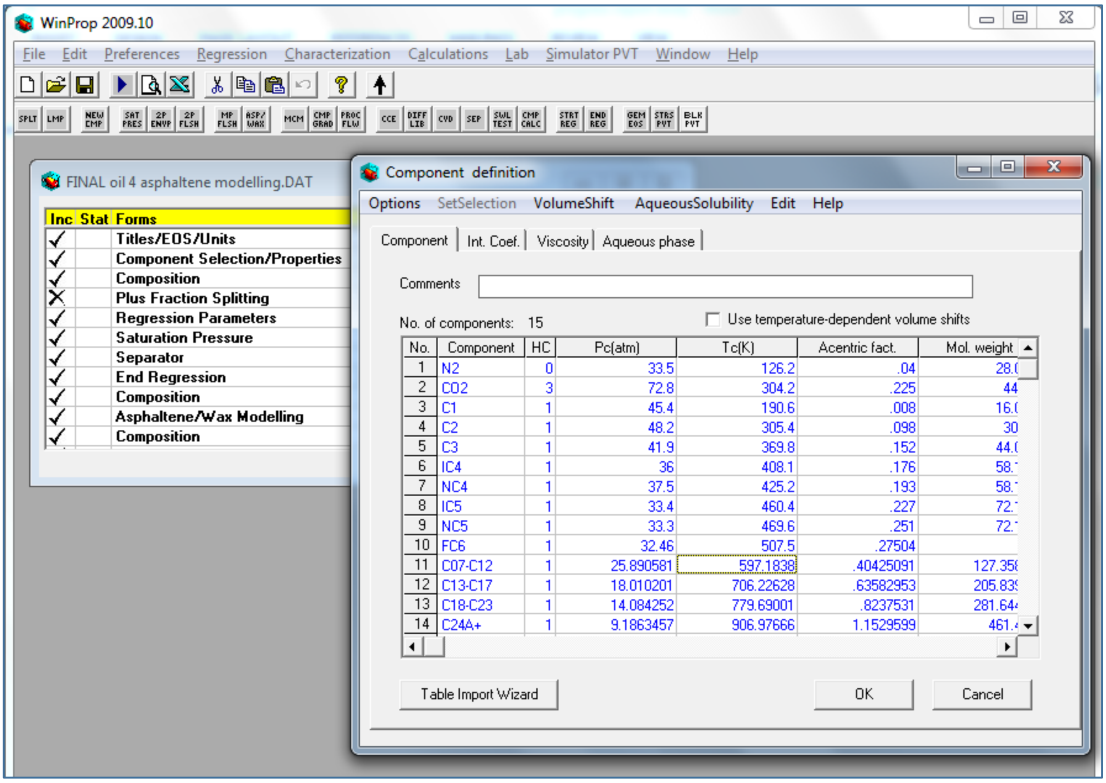


Figure 9 : Interface of Winprop tool (Component definition for light oil)

All the hydrocarbon components, its properties and compositions are inserted into the Winprop to be regressed. The saturation pressure is set at 2492 psia. To model the asphaltene, multiphase flash is needed to calculate at what pressure the asphaltene will formed. The asphaltene precipitation content in term of weight percent is plotted with pressure (psia) to determine the pressure where asphaltene precipitation is maximum.

3.1.4 Reservoir modelling

In order to model the reservoir, Builder tool in CMG simulator is used. As shown in figure-9 below, the reservoir simulator is set and in figure-10 is the properties of reservoir and well is that need to be inserted in Builder. The rock fluid interactions is also calculated in the Builder. The fluid model from Winprop is imported into Builder to simulate with WAG and FAWAG- CO_2 injection by using STARS simulator.

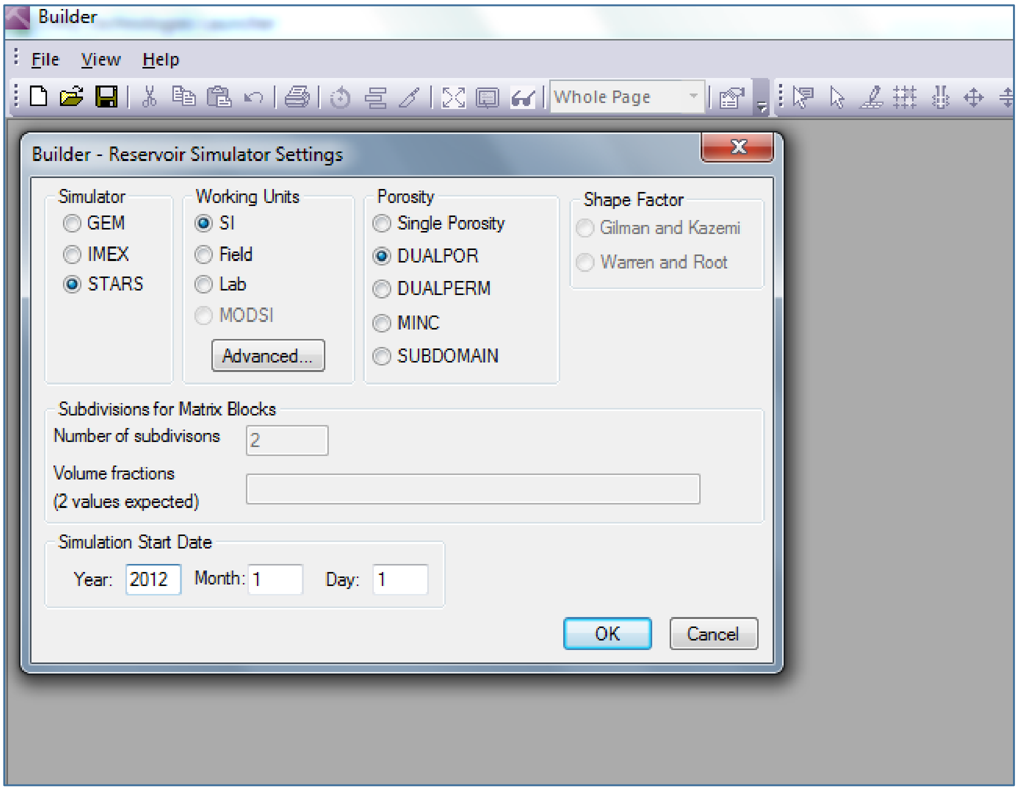


Figure 10 : Reservoir simulator settings (Builder) interface

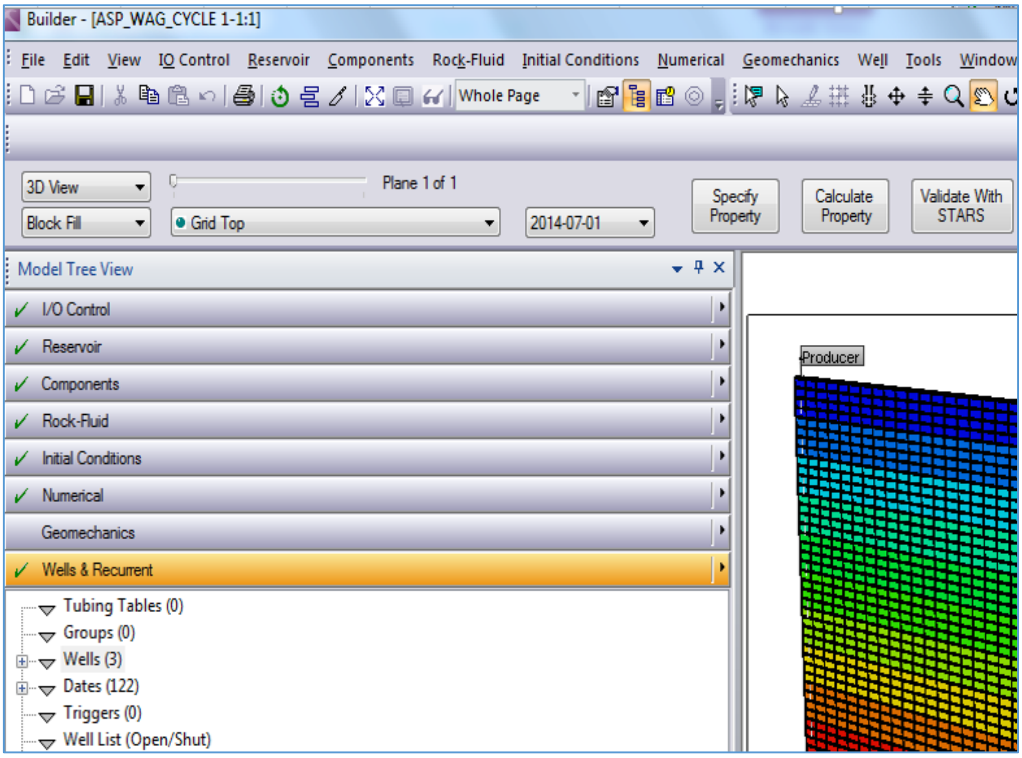


Figure 11 : Interface of Builder tool

In this simulation study, the injection of WAG and FAWAG is applied into sandstone reservoir with grid block size of 44 x 1 x 40. The properties of sandstone reservoir is shown in table-2 below.

Table 2 : Sandstone reservoir properties

Reservoir - sorted consolidated sandstone		
	Value	**Unit**
Temperature	234	F
Reservoir pressure	3500	psia
Porosity	20	%
Oil saturation	78	%
Connate water saturation	22	%
Grid block	44x1x40	-
X	4400	ft
Y	10	ft
Z	40	ft

Table 3 below shows the values of porosity and permeability for different layers in the reservoir. This reservoir have heterogeneous properties as the porosity and permeability is different for every layer.

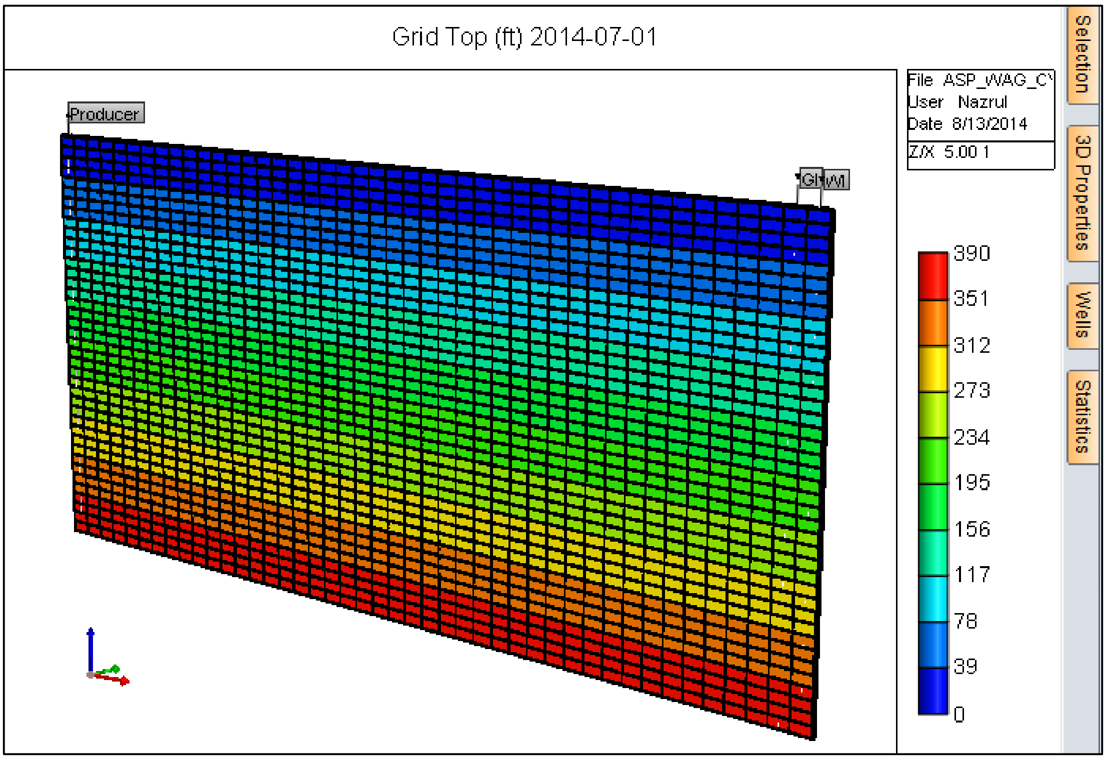
Table 3 : Permeability and porosity in different layers

Layer	Porosity	Permeability I	Permeability J	Permeability K
Layer 1	0.101	98.434	101.477	116.476
Layer 2	0.231	116.975	86.342	95.034
Layer 3	0.214	86.342	73.987	123.567
Layer 4	0.316	73.987	79.456	87.199
Layer 5	0.344	79.416	98.234	104.777
Layer 6	0.234	103.466	125.675	101.562
Layer 7	0.121	89.459	110.197	84.342
Layer 8	0.023	94.342	104.345	73.987
Layer 9	0.123	95.034	96.756	79.456
Layer 10	0.202	124.367	111.197	96.756
Layer 11	0.234	87.899	102.345	113.197
Layer 12	0.345	112.797	96.736	104.345
Layer 13	0.123	104.345	95.834	103.466
Layer 14	0.112	96.156	124.567	88.459
Layer 15	0.214	113.136	86.899	94.342
Layer 16	0.176	104.815	116.476	113.197
Layer 17	0.256	96.956	103.466	100.345
Layer 18	0.267	103.562	89.459	99.756
Layer 19	0.123	114.476	93.342	98.234
Layer 20	0.234	104.477	103.562	122.675
Mean	0.200	100.022	100.0176	100.0586
Deviation	6.125E-08	0.000243101	0.00015488	0.00171698

Table 4 below shows the location of injector well and producer well in the simulation. Figure 11 below shows the image of the location of the injector and producer well with 44x1x40 grid blocks.

Table 4 : Location of injector and producer well

Well		
	Value	**Unit**
Gas Injector location	43 1 (1-40)	-
Water Injector location	44 1 (1-40)	-
Producer location	1 1 (1-40)	-
Perforation	40	ft
EOR process		



. Figure 12 : The location of injector and producer well

3.1.5 Simulation of WAG and FAWAG with and without asphaltene precipitation.

The next stage is to do the simulation of WAG and FAWAG- CO_2 injection by using STARS simulator in Builder. In STARS, the surfactant component is introduce to create foam for FAWAG- CO_2 injection with molecular weight of 400 lb/lbmole. There are three parameters investigated in this study which are the duration cycle of injection, the injection pressure for both water and gas and the surfactant concentration for FAWAG- CO_2 injection. All the parameters are shown in table-5 until table-7 below. The oil recovery factor for all these parameters will be compared for both with and without asphaltene.

Table 5 : Duration of injection cycle

Ratio	Injection cycle (months)	Oil Recovery Factor (%)	
		WAG	FAWAG- CO_2
1 : 1	3 water , 3 gas		
1: 2	3 water, 6 gas		
2 : 1	6 water, 3 gas		

Table 6 : Gas and water injection pressure

No.	Injection pressure (psia)	Oil Recovery Factor (%)	
		WAG	FAWAG- CO_2
1	2800		
2	3300		
3	3800		

Table 7 : Surfactant concentration

No.	Surfactant concentration (mole fraction)
1	0.00005
2	0.00001
3	0.0001
4	0.0003
5	0.0005
6	0.005

The parameter for base case of WAG and FAWAG- CO_2 is stated below :

Gas Well Injection Pressure	Bottomhole pressure (psi)	3000
	Surface gas rate (ft^3/day)	1684.38
Water Injection Pressure	Bottomhole pressure (psi)	3000
	Surface water rate (bbl/day)	550
Production Well Pressure	Bottomhole pressure (psi)	2500
Injection cycles	Ratio (Months)	1 to 1 (3W, 3G)
Surfactant concentration	Mole fraction (%)	0.5

3.2 KEY MILESTONE AND GANTT CHART

No.	Item/Week	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	The project progress continue															
2	Submission of progress report															
3	The project progress continue															
4	Pre-SEDEX															
5	Submission of final draft															
6	Submission of dissertation (soft-bound)															
7	Submission of technical paper															
8	VIVA															
9	Submission of dissertation (hard-bound)															

Figure 13 : Tables for Key Milestone and Gantt Chart

CHAPTER 4
RESULT AND DISCUSSION

4.1 Asphaltene precipitation model

The precipitation of asphaltene is modelled by using a multiphase flash calculation in which fluid phases are described with an equation of state and the fugacities of components in the solid phase are predicted using the solid model described below. The precipitated phase is represented as an ideal mixture of solid components. The fugacity of a precipitating component in the solid phase is :

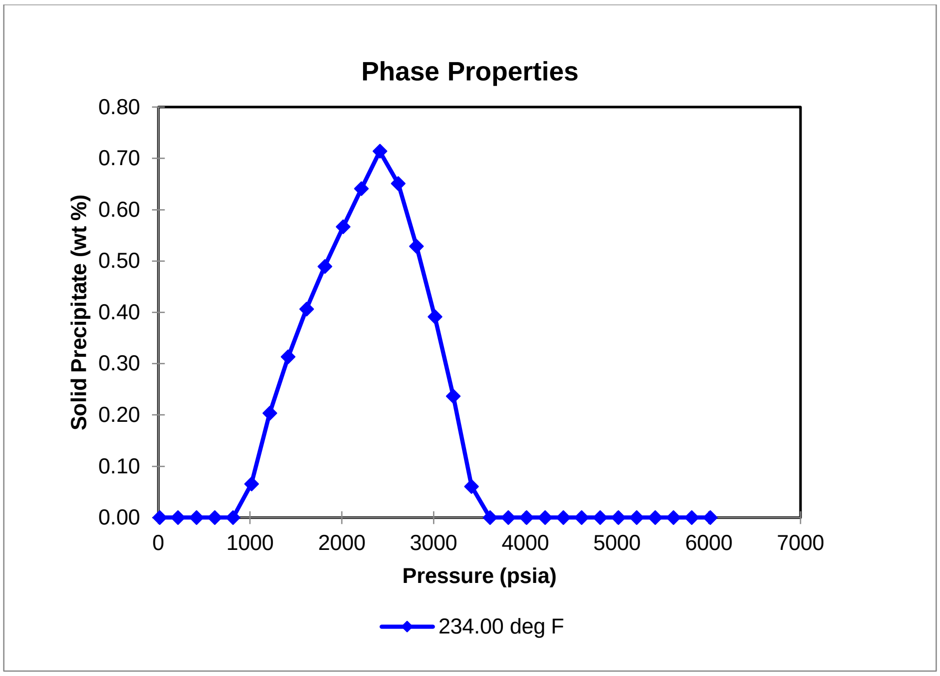


Figure 14 : Asphaltene precipitation content vs fluid pressure

From the asphaltene modelled in light oil reservoir mentioned in methodology part, the asphaltene start to precipitate when reaching 1000 psia of fluid pressure and continue increasing in weight percent until it reach its maximum value at around 0.7 wt%. The asphaltene reach its maximum value of precipitation at near the saturation pressure which is 2492 psi. This is quite successful model of asphaltene because of the high value of solid precipitation at near the saturation pressure.

4.2 WAG and FAWAG injection without asphaltene

4.2.1 Base case scenario

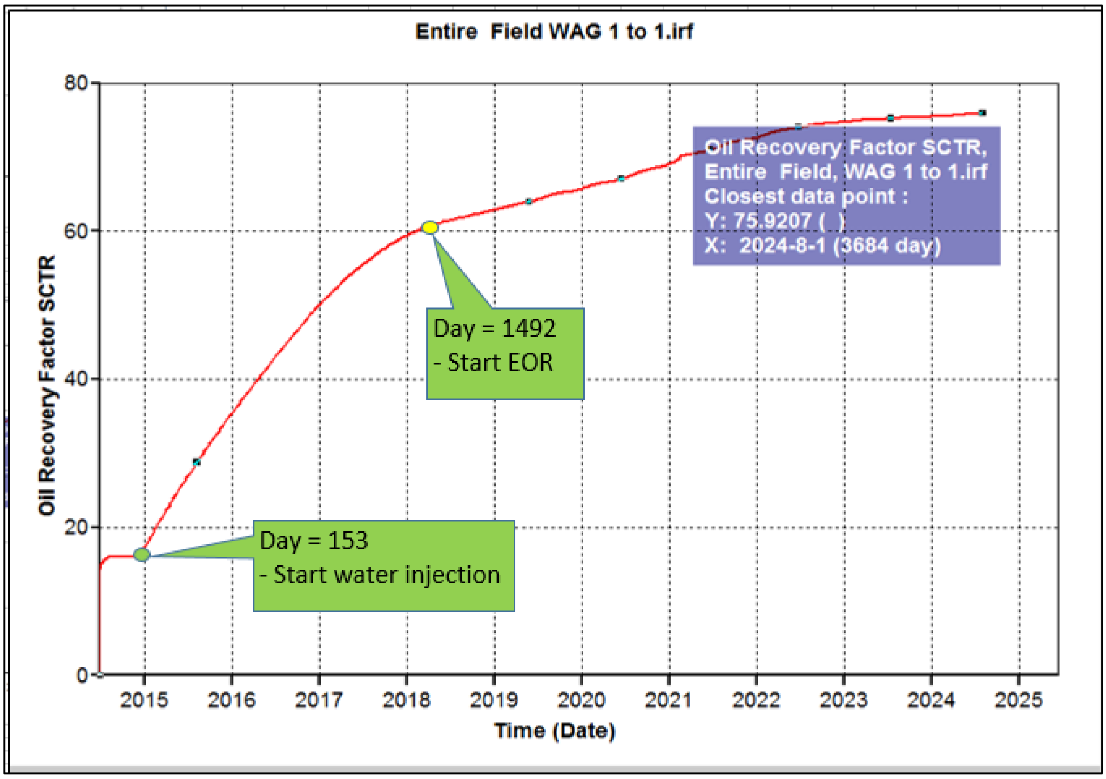


Figure 15 : WAG 1 to 1 injection cycle (Oil recovery factor vs time)

Figure 15 is the base case for WAG injection where the primary production starts in July 2014 which give results of constant recovery and the secondary recovery which is water injection took place after 5 months of primary recovery. After 1492 days which is after water breakthrough reach 80%, the EOR start with water and gas injection alternately. The simulation stop after 10 years. This time step is applied for all simulation cases in this project. For this 1 to 1 injection cycle, water is injected for about 3 months and followed with gas injection for 3 months. This cycle continue until the end of simulation which is 10 years. The oil recovery factor obtained from 1 to 1 WAG injection cycle is 75.92 %.

In Figure 16, this is the base case for FAWAG- CO_2 injection with 0.0005 mole fraction of surfactant. Both gas injection pressure water injection pressure is set at BHP of 3000 psi. The gas for FAWAG injection is Carbon Dioxide. For this 1 to 1 injection cycle, the water with 0.9995 mole fraction is injected together with surfactant (0.0005 mole fraction and alternated with gas injection for every 3 months until the end of simulation. The oil recovery factor obtained after 10 years is 78.26 %.

4.2.2 Comparison of WAG and FAWAG injection cycle (without asphaltene)

For 1 to 2 injection cycles, the water is injected (with surfactant for FAWAG) for 3 months followed by 6 months injection of gas while for 2 to 1 injection cycles, the water is injected (with surfactant for FAWAG) for 6 months followed by 3 months injection of gas and this cycle is repeated until the end of the simulation.

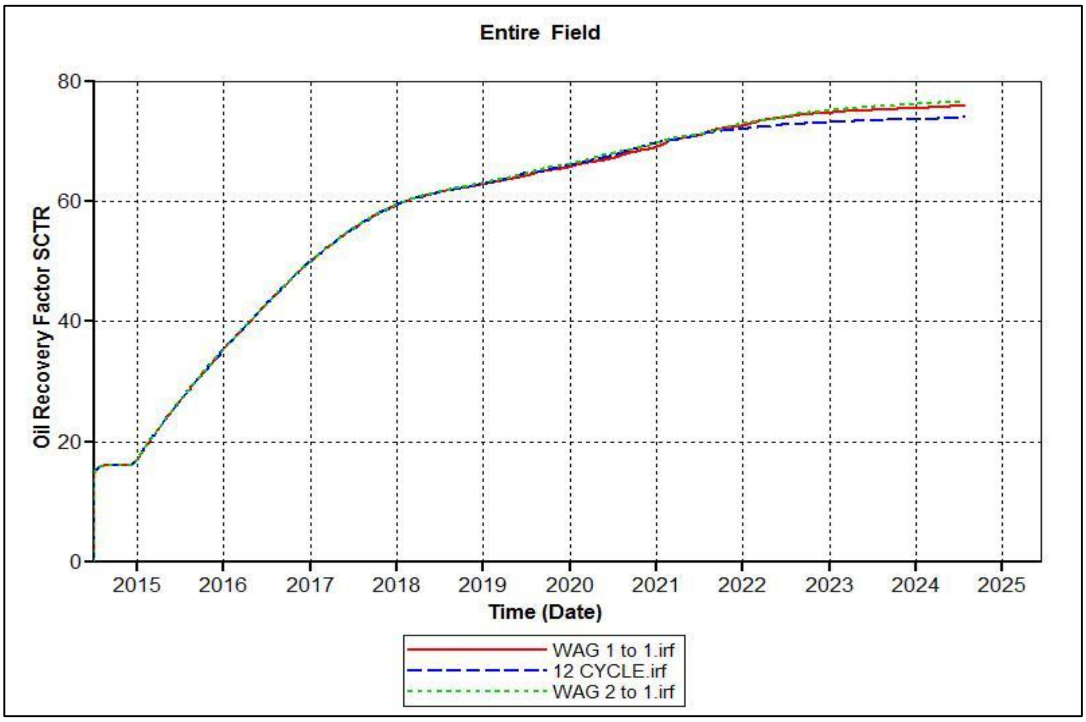


Figure 16 : Result of WAG injection cycle (without asphaltene)

Figure 16 showing that the highest recovery for parameters of cycle for injection period is 2 to 1, 6 months of injecting water and 3 months of injecting gas for both WAG injection with CO_2. This is because of better mobility control by water when increase in saturation. This indicated that WAG injection is more preferable with more water injection. The water will improve mobility control over the injected gas by increasing relative permeability of water. Ratio of 1:2 shown lowest in recovery factor due to high amount of CO_2 will cause early breakthrough thus decreasing the recovery factor. In the synthetic reservoir model, variation of high and low permeability by layers are introduced. The tendency of gas to bypass through high permeability layers are highly to occur. Once gas breakthrough is occurred, the remaining injected gas become less efficient in pushing the oil due to it flows through less resistance path that created by breakthrough. The gas will bypass the low permeability layers, hence low displacement in low permeability layers. Apart from high permeability layers, gravity segregation due to different density will affect the breakthrough. The gas tends to flow upwards rather than displace oil through lateral. Higher amount of injected water will control the gas mobility and avoid early breakthrough, hence improving the recovery factor.

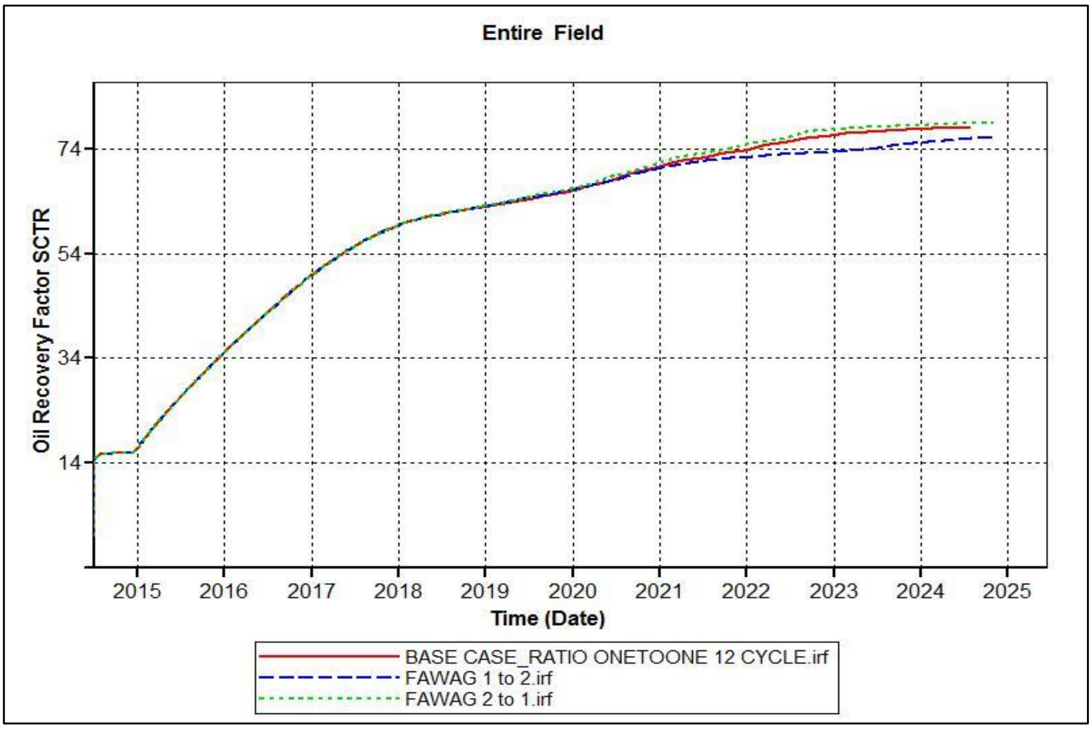


Figure 17 : Result of FAWAG injection cycle (without asphaltene)

Figure 17 showing the results of oil recovery for FAWAG with CO_2 injection without asphaltene respectively. From the result, the optimum injection cycle for FAWAG is 2:1 followed by 1:2 and 1:1. Highest recovery by ratio 2:1 is due to FAWAG requires more water to generate foam. Higher water-surfactant injection into the reservoir will optimize the amount of gas injected and envelope the gas into bubble. The foam then will block additional gas from entering high permeability zone or upper layer (due to gravity segregation) and the gas will push oil along the low permeability zone. High water saturation in the reservoir is required to maintain the foam from collapsing. Compared to ratio 1:2 which utilized more gas injection, the injected surfactant cannot cover additional gas intake to form bubble. However, the gas nevertheless will push the oil along other high permeability zone and cause gas breakthrough which makes the total recovery factor less than ratio 2:1. Ratio 1:1 shown the lowest recovery factor than other due to the ratio is underutilized, the amount of injected surfactant and CO_2 is not proportional to each other. With ratio 1:1, the surfactant only create foam and no additional gas is pushing oil toward production well.

The oil recovery for every cycle of WAG and FAWAG with CO_2 is summarized below:

Table 8 : Oil recovery factor WAG and FAWAG injection cycle

Ratio	**Injection cycle (months)**	**Oil Recovery Factor (%)**	
		WAG	FAWAG-CO_2
1 : 1	3 water , 3 gas	75.96	78.26
1: 2	3 water, 6 gas	73.98	76.41
2 : 1	6 water, 3 gas	76.55	79.17

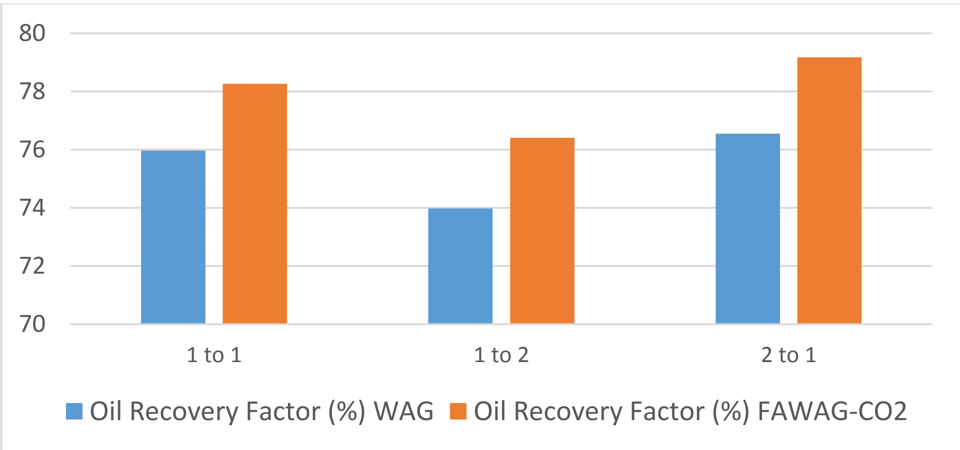


Figure 18 : Oil recovery factor for different cycles of WAG and FAWAG injection

For every cycles, FAWAG-CO_2 injection showing higher recovery factor compared to WAG injection. The comparison between WAG and FAWAG will be discussed later in the report.

4.2.3 Comparison of WAG and FAWAG with CO_2 injection pressure (without asphaltene)

Three different injection pressure is simulated to see the effect of injection pressure for both gas and water at below and above reservoir pressure. The reservoir model pressure is 3500 psia. 2800 and 3300 psia injection pressure are below reservoir pressure while 3800 psia is above reservoir pressure. The injection rate is kept constant for both gas and water injection at 1684.38 ft^3/day and 550 bbl/day respectively. The injection cycles for this simulation is set at the best injection cycle obtained from previous simulation which is 2 to 1. The surfactant concentration for FAWAG injection is kept constant at 0.00001 mole percent.

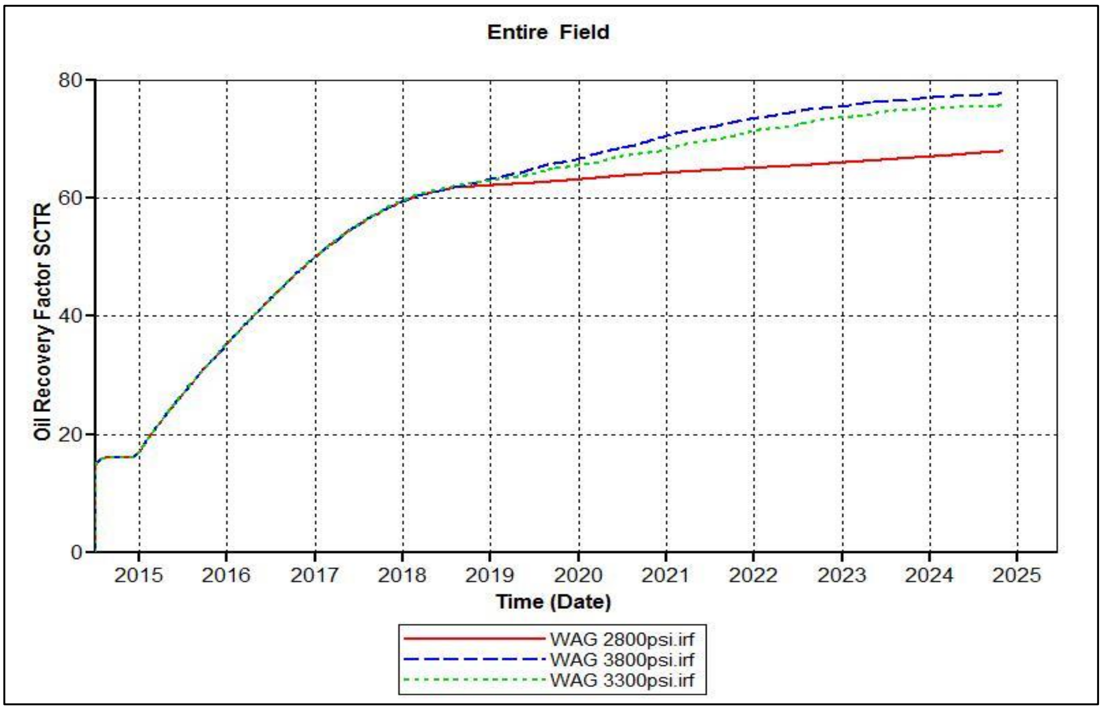


Figure 19 : Result of WAG injection cycle (without asphaltene)

From figure 19, injection pressure of 3800 psia yield the highest recovery for WAG injection followed by 3300 and 2800 psia.

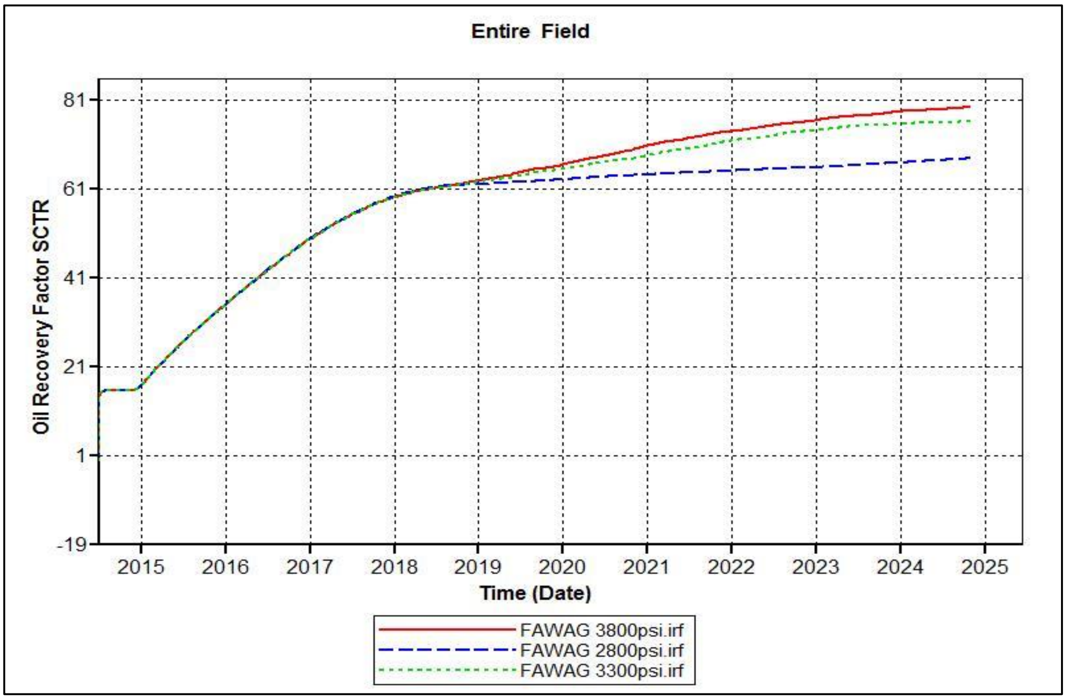


Figure 20 : Result of FAWAG injection cycle (without asphaltene)

Figure 20 showing the results of oil recovery for FAWAG with CO_2 injection with different injection pressure. The base case injection pressure is set at BHP of 3000 psi for both gas and water injector. All injection pressure must be above the saturation pressure and not exceeding reservoir pressure. The summary of the result is shown below :

Table 9 : Oil recovery factor WAG and FAWAG injection pressure

No.	Injection pressure (psia)	Oil Recovery Factor (%)	
		WAG	FAWAG-CO_2
1	2800	67.76	68.15
2	3300	75.58	76.11
3	3800	77.67	79.87

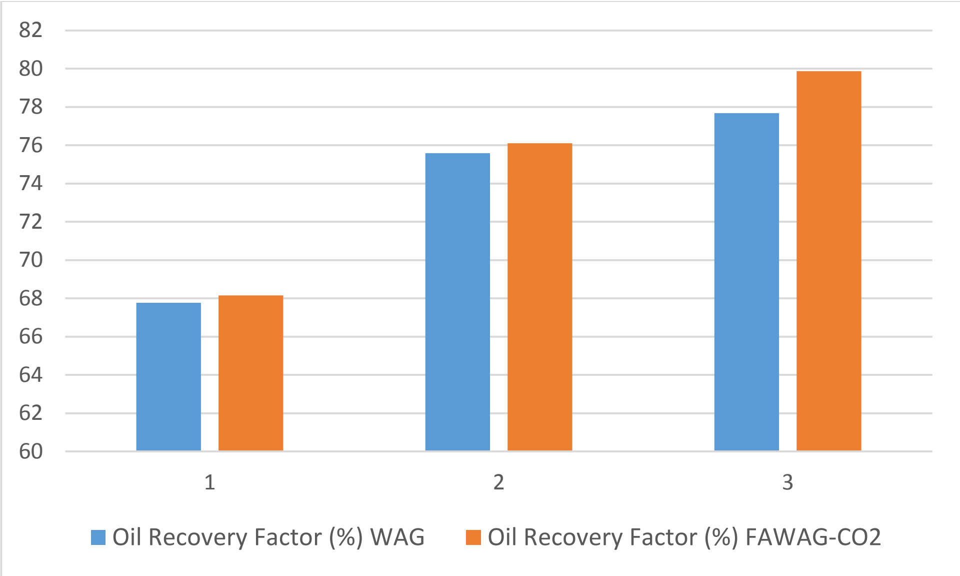


Figure 21 : Oil recovery factor for different BHP injection pressure for WAG and FAWAG.

Figure 21 showing the results of oil recovery factor for both WAG and FAWAG with CO_2 injection in terms of injection pressure. The highest recovery is by using 3800 psi BHP. As the injection pressure increase, the recovery for WAG and FAWAG injection increase. Higher injection pressure for both gas and water can yield higher oil recovery because more oil is pushed upwards. However, this 3800 psi is already exceeding the reservoir pressure which is at 3500 psi. This might cause uncontrolled fracture in reservoir which later will cause formation damage and reduce the recovery. The optimum injection pressure is at 3300 psi for both WAG and FAWAG injection. Although FAWAG recover more than WAG, but the difference is very little for every injection pressure.

4.3 WAG and FAWAG-CO_2 injection with asphaltene precipitation.

4.3.1 Injection cycle for WAG and FAWAG-CO_2 (with asphaltene)

From the previous result of WAG and FAWAG-CO_2 injection without asphaltene, the best two injection cycle is simulate with the presence of asphaltene in WAG and FAWAG-CO_2. The best two cycles are 1 to 1 and 2 to 1.

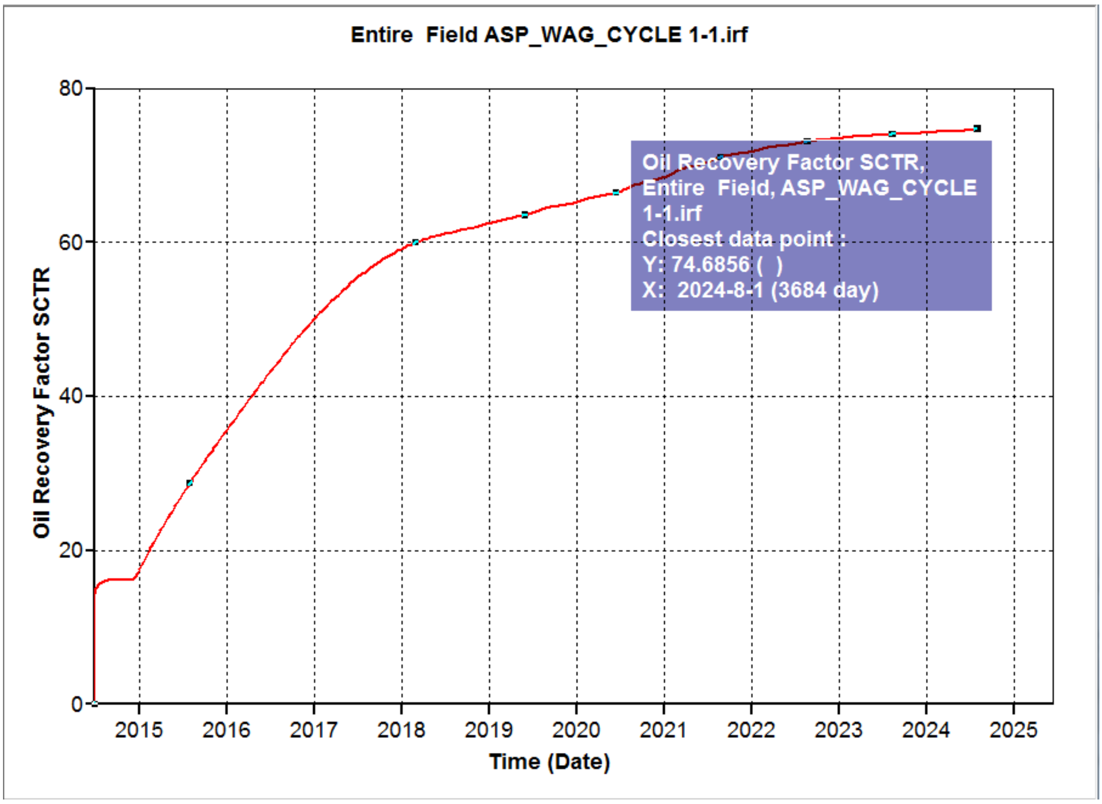


Figure 22 : Oil recovery for WAG (with asphaltene) cycle 1 to 1

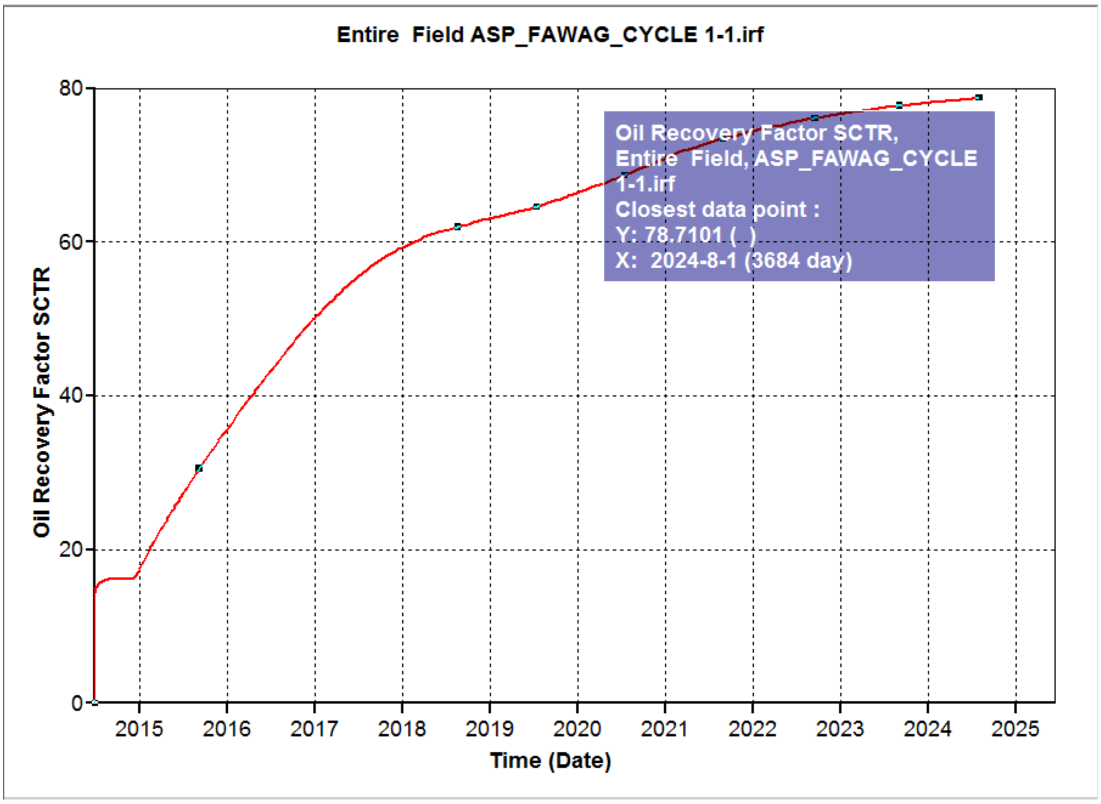


Figure 23 : Oil recovery for FAWAG (with asphaltene) cycle 1 to 1

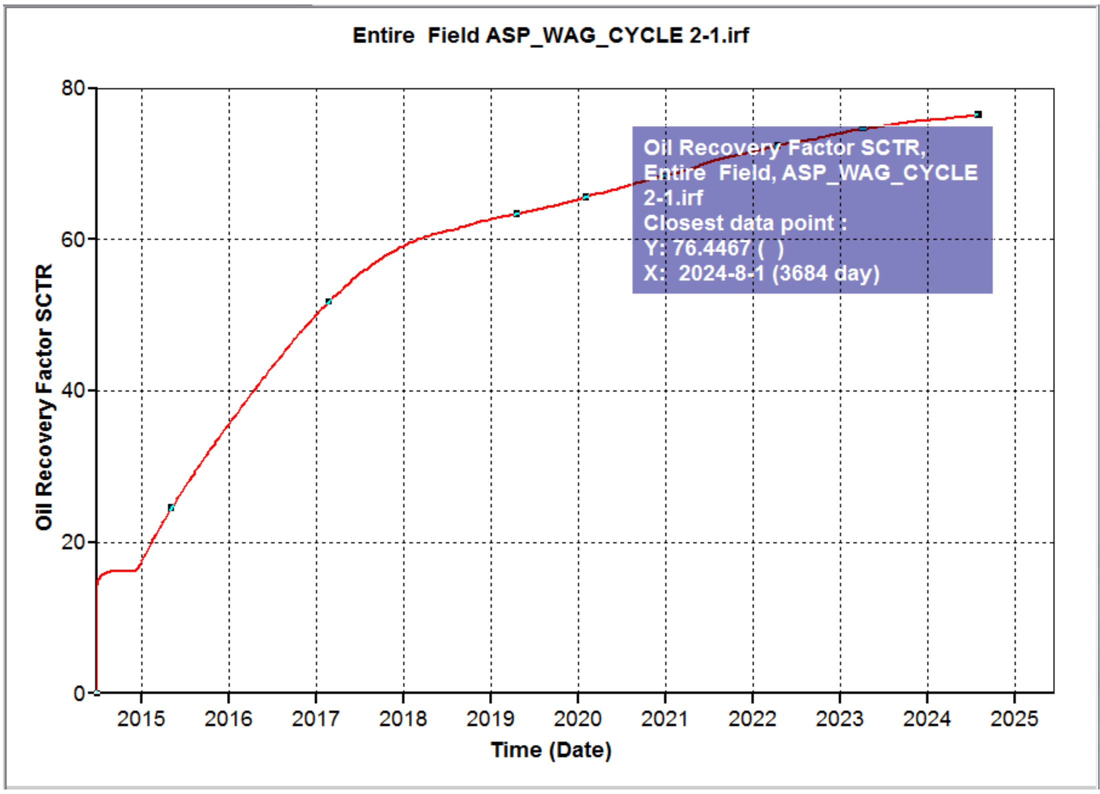


Figure 24 : Oil recovery for WAG (with asphaltene) cycle 2 to 1

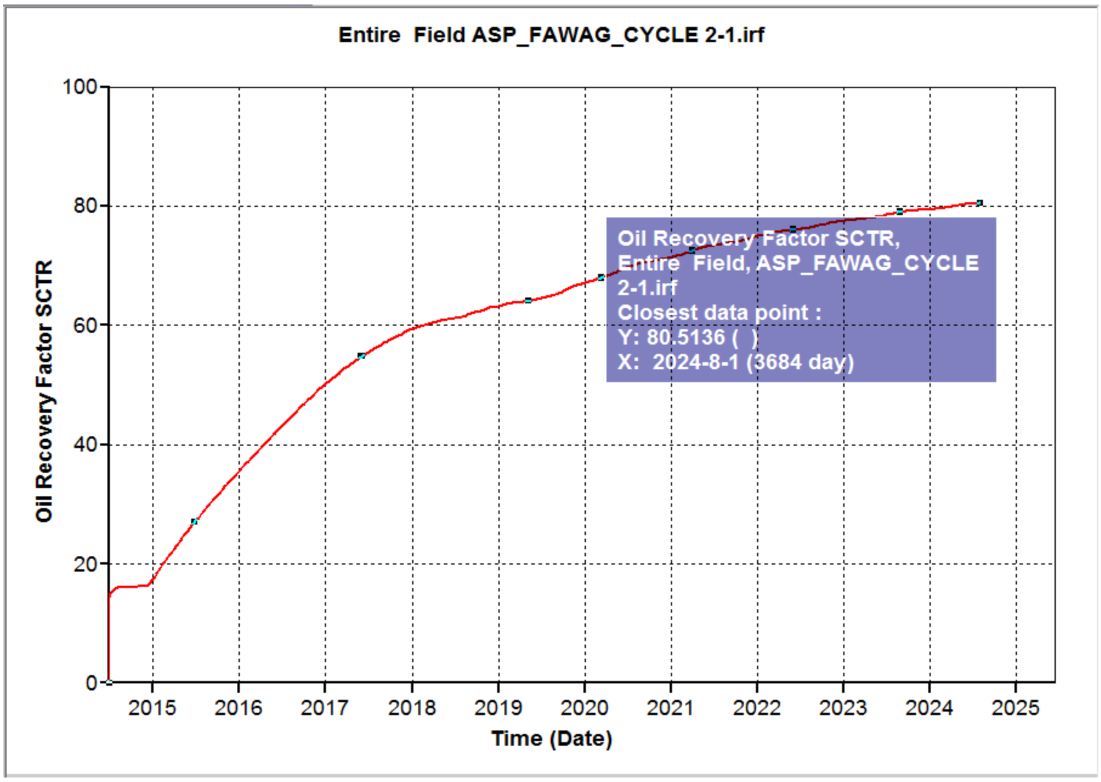


Figure 25 : Oil recovery for FAWAG (with asphaltene) cycle 2 to 1

Figure 22 until Figure 25 showing the results of oil recovery for different injection cycles for WAG and FAWAG-CO_2 injection with the presence of asphaltene. The summary of the result is discussed below :

Table 10 : Oil recovery factor for injection cycle for WAG and FAWAG-CO_2 (with asphaltene)

Ratio	Oil Recovery Factor (%)	
	WAG	FAWAG-CO_2
1 to 1	74.69	78.71
2 to 1	76.45	80.51

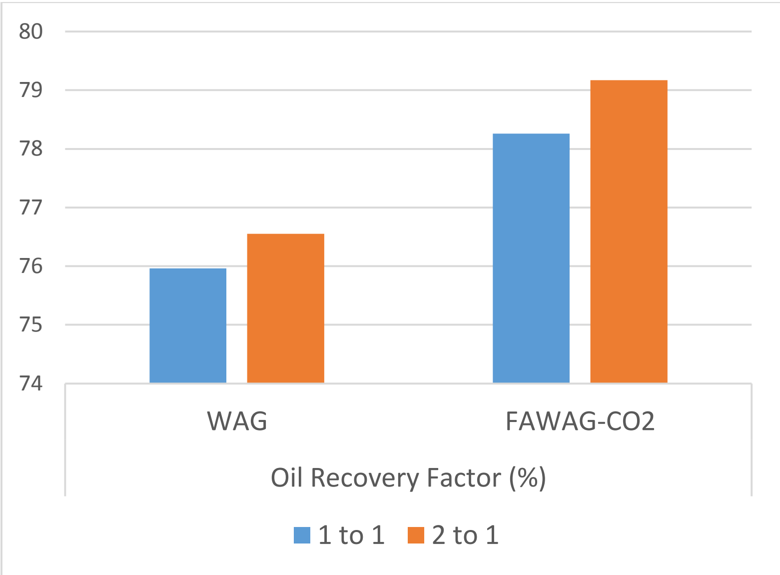


Figure 26 : Oil recovery factor for injection cycle for WAG and FAWAG-CO2 (with asphaltene)

From Figure 26, the higher oil recovery is shown by injection cycle of 2 to 1 same as the result of injection cycle without the presence of asphaltene. Cycle ratio of 2:1 yielded highest recovery than other two, followed by ratio 1:1 for both WAG and FAWAG injection with CO_2. During FAWAG-CO_2 injection, surfactant is introduced to improve the mobility control of gas by means of forming foams that blocking gas from passing through high permeability layers or upper layers by means of gravity segregation. In the reservoir, the injected CO_2 may react with reservoir fluid, causing the oil to swell which will lead towards asphaltene precipitation and deposition. Ratio

1:2 showed lowest recovery is due to injected gas may induce the asphaltene precipitation and cause reduction in permeability, hence results in lower recovery. There several reasons why ratio 2:1 has better recovery factor. First, high permeability layers is blocked by foam and injected gas channelled to unsweep layers which lead to better cumulative of produced oil. Second, pressure variation along high permeability layers caused asphaltene deposition. The deposition of asphaltene plugged pore throat and reduce the displacement efficiency at high permeability layers which will force injected fluid to travel along low permeability layers. Third, amount of injected is sufficient have good displacement efficiency. The ratio 2:1 displacement efficiency can be compared with ratio 1:1 where low amount of water is injected.

4.3.2 Injection pressure of WAG and FAWAG-CO_2 (with asphaltene)

From the previous result of WAG and FAWAG-CO_2 injection without asphaltene, the best two injection pressure is simulate with the presence of asphaltene in WAG and FAWAG-CO_2. The best two injection pressure are 2800 and 3300 psia.

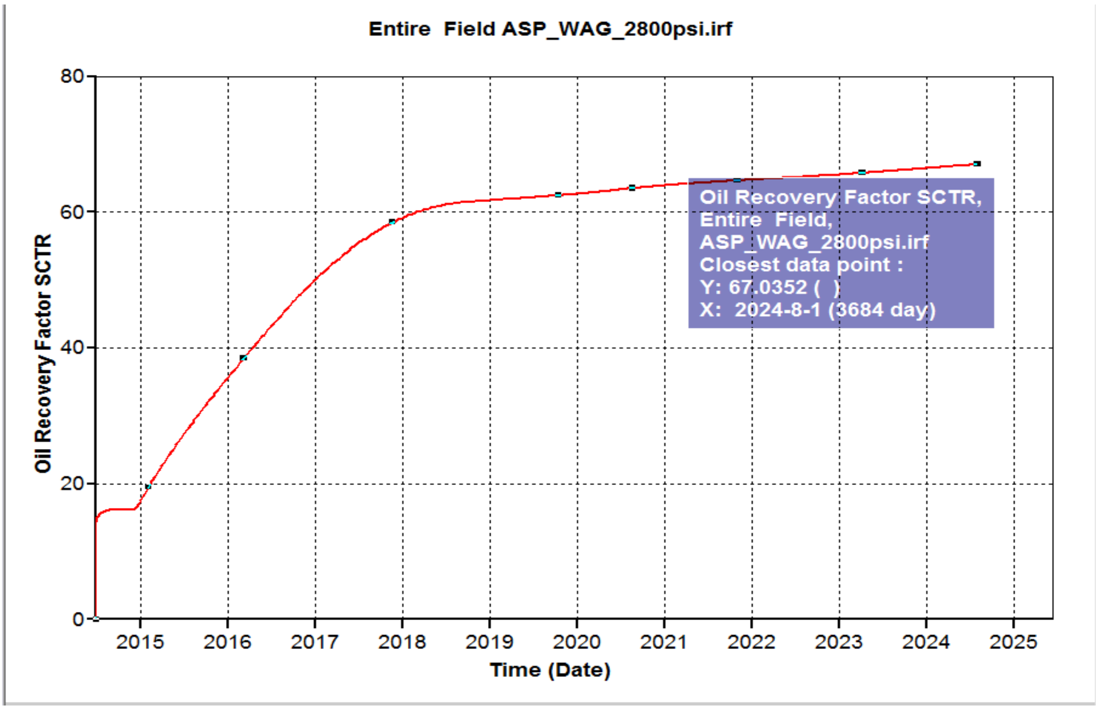


Figure 27 : Oil recovery for WAG (with asphaltene) at 2800psi injection pressure

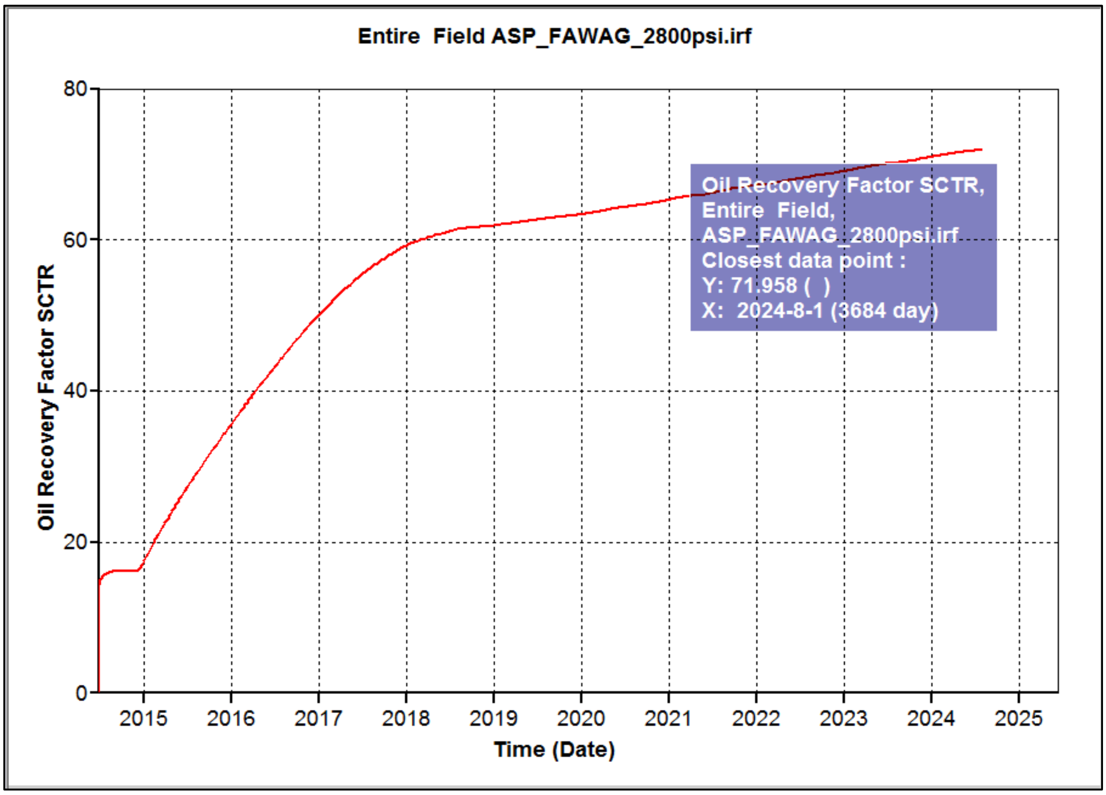


Figure 28 : Oil recovery for FAWAG (with asphaltene) at 2800psi injection pressure

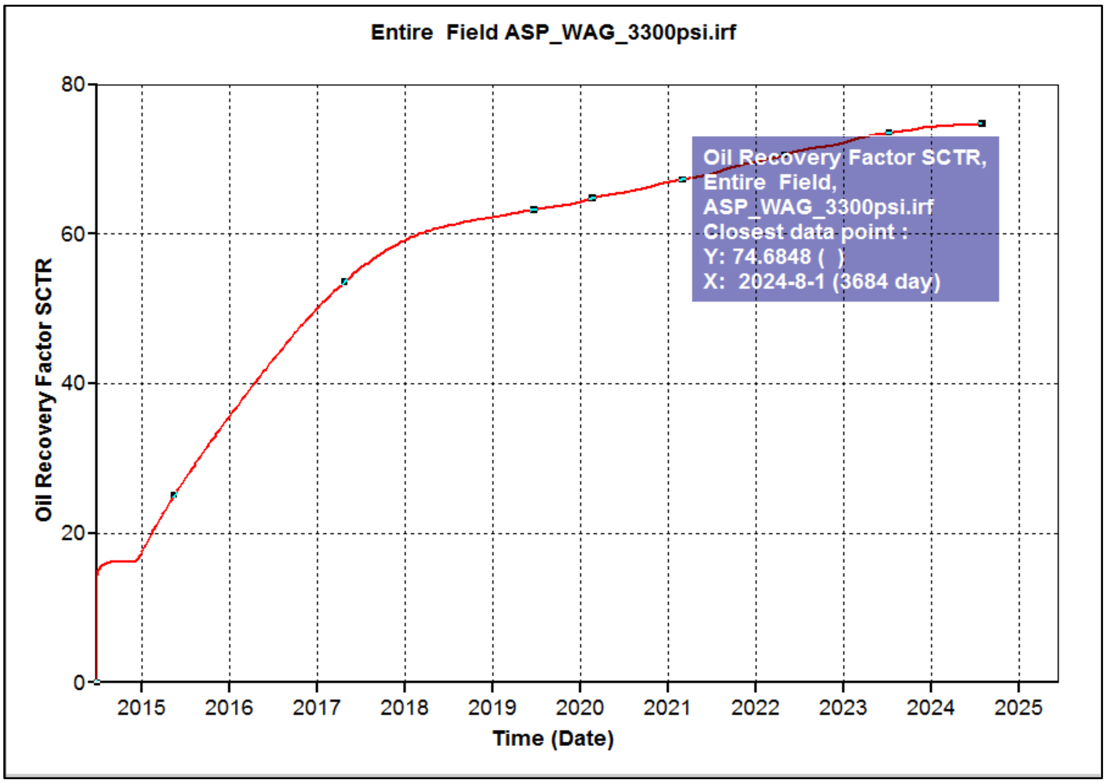


Figure 29 : Oil recovery for WAG (with asphaltene) at 3300psi injection pressure

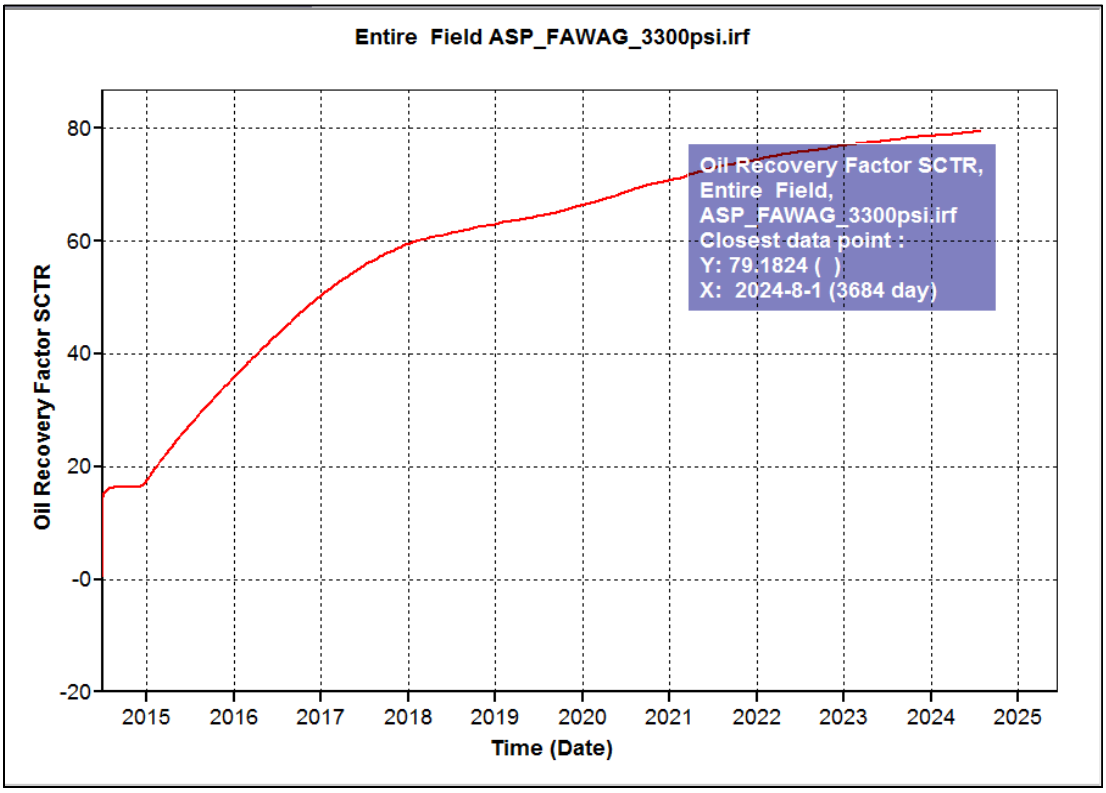


Figure 30 : Oil recovery for FAWAG (with asphaltene) at 3300psi injection pressure

Figure 27 until Figure 30 showing the result of oil recovery for different injection pressure for both WAG and FAWAG with CO_2 with the presence of asphaltene. The summary of the result is shown below.

Table 11 : Oil recovery factor for different injection pressure for WAG and FAWAG-CO_2 with asphaltene

	Injection pressure (psi)	Oil Recovery Factor (%)	
		WAG	FAWAG
1	2800	67.04	71.96
2	3300	74.68	79.18

From table 11, the oil recovery factor for FAWAG-CO_2 injection is the highest when with 3300 psi. According the study by Alian et. al, (2011), when the injection pressure of the gas increased, it will reduce the deposition of asphaltene thus less porosity and permeability reduction is observed, this will increase the oil recovery.

4.3 Comparison of WAG and FAWAG injection (with and without asphaltene)

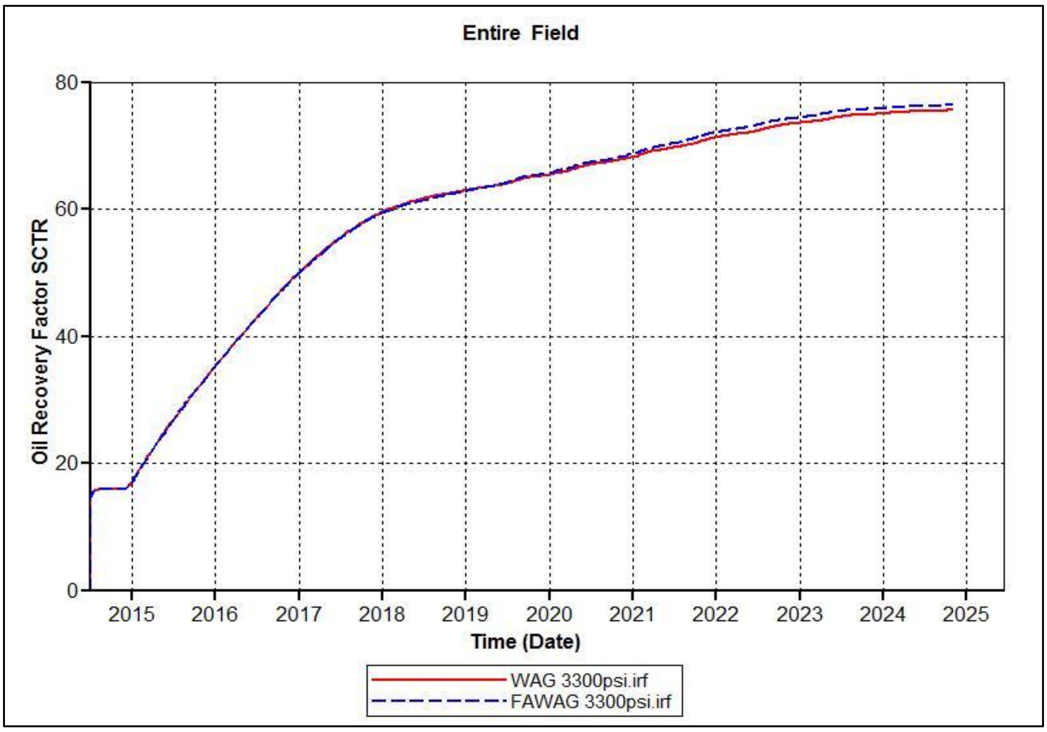


Figure 31 : Recovery factor for WAG and FAWAG (without asphaltene)

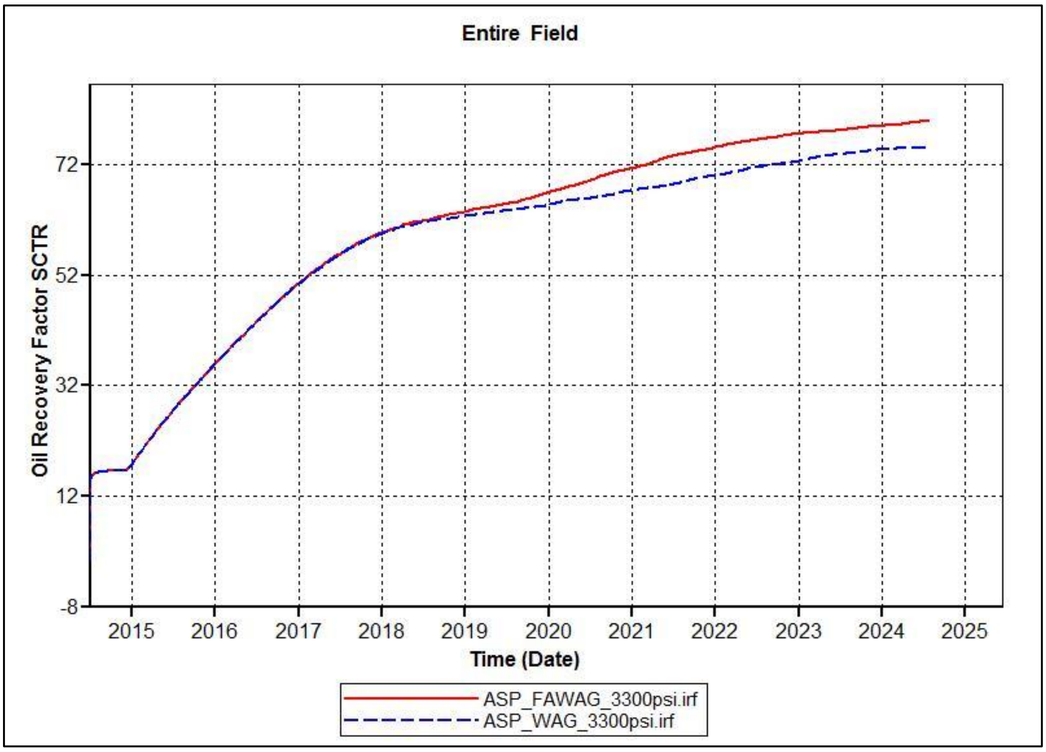


Figure 32 : Recovery factor for WAG and FAWAG (with asphaltene)

Figure 31 and 32 showing the comparison between WAG and FAWAG injection with CO_2 with and without asphaltene. The result shows that FAWAG can yield better recovery compared to WAG in both situation of with and without asphaltene presence in the reservoir. This comparison is simulated at 3300 psia injection pressure for water and gas, 2 to 1 injection cycle and with 0.00001 mole fraction of surfactant for FAWAG injection.

The WAG process only use water to control mobility of gas which eventually will caused early gas breakthrough. The gas will bypass low permeability layers and go through less resistance passage. While in FAWAG, foam is formed and block the gas from entering high permeability layers while pushing the oil through the foam by mechanism of gas and the additional gas will push the low permeability which at the end results in higher recovery compared to WAG injection.

Higher recovery by FAWAG is due to better gas mobility control by formation of foam at high permeability layers. As the foam is forming barrier that blocking the gas from entering high permeability zone which the gas has to travel along low permeability layers, ultimately increased the recovery. This theory supported by Saleem (2011) which found that FAWAG has better mobility control over gas. Another explanation of the result was the introduction of surfactant improved the interfacial tension of water and oil. Precipitation of asphaltene can alter the wettability of rock surface. Hence, the reduction of interfacial tension need to be further reduced in order to obtained higher recovery.

4.4 Comparison of WAG with asphaltene and WAG without asphaltene.

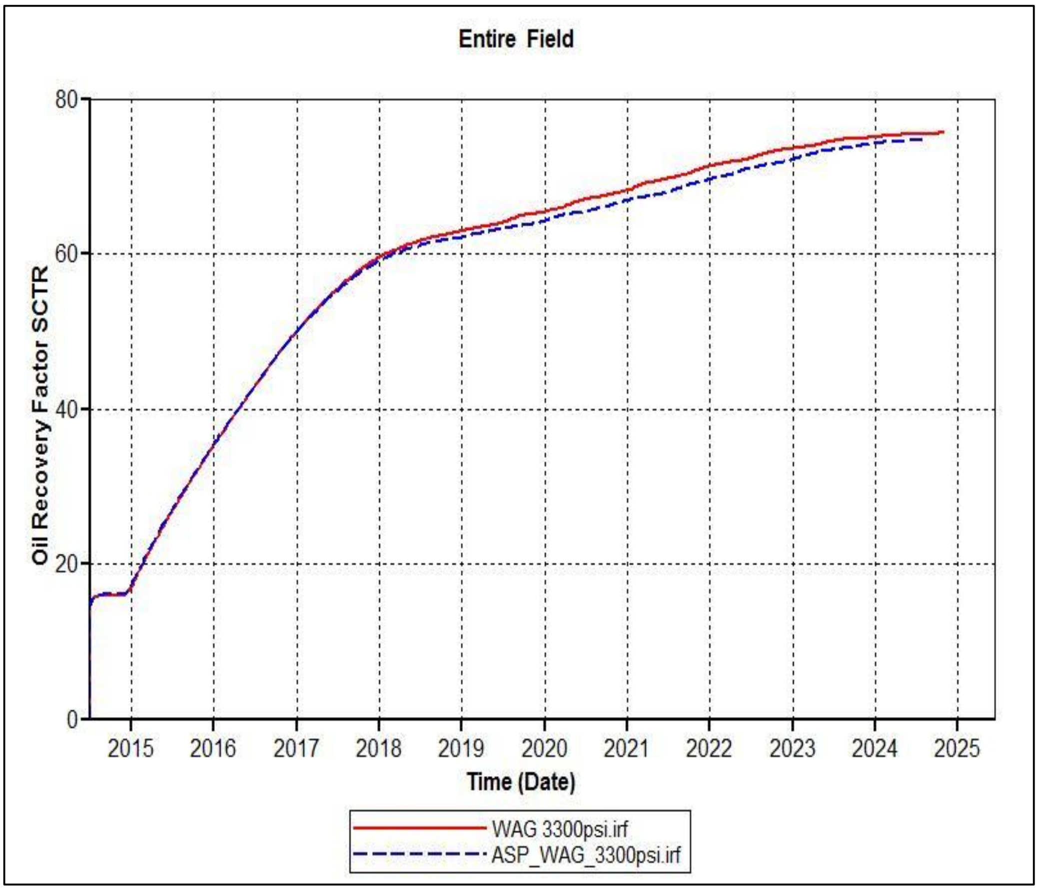


Figure 33 : The recovery factor of WAG with asphaltene and without asphaltene.

WAG injection	Recovery Factor (%)
With asphaltene	74.68
Without asphaltene	75.58

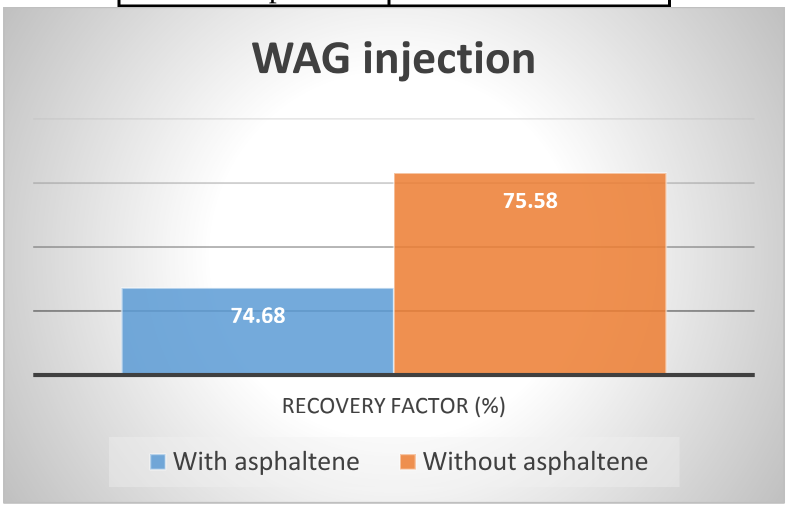


Figure 34: The comparison between WAG with asphaltene and without asphaltene.

Based on Figure 33 and 34, WAG model without asphaltene has better recovery than WAG with asphaltene. This phenomena is due to deposition of asphaltene reduced the permeability of reservoir which results in reduction in overall recovery. According to Ghedan (2009), deposition of asphaltene can induce declination of both permeability and porosity in the reservoir. The deposition of asphaltene cannot be seen from the starting of simulation. However, it can be clearly seen after water breakthrough during waterflooding process. During this process, the reservoir pressure rapidly declined and the fraction of C1-C5 which solute the asphaltene starts to produce as gas. After WAG is applied, reduction in average recovery in asphaltene model which concurrent with application of CO_2. The injected gas will depreciate the solubility of asphaltene, induced the asphaltene deposition. Although the difference in recovery is less significant, however WAG without asphaltene is having higher production rate compared to WAG with asphaltene model. Hence, it is proven that asphaltene deposition can caused clogged pore throat which directly contributes to reduction of reservoir permeability.

4.5 Comparison of FAWAG with asphaltene and FAWAG without asphaltene.

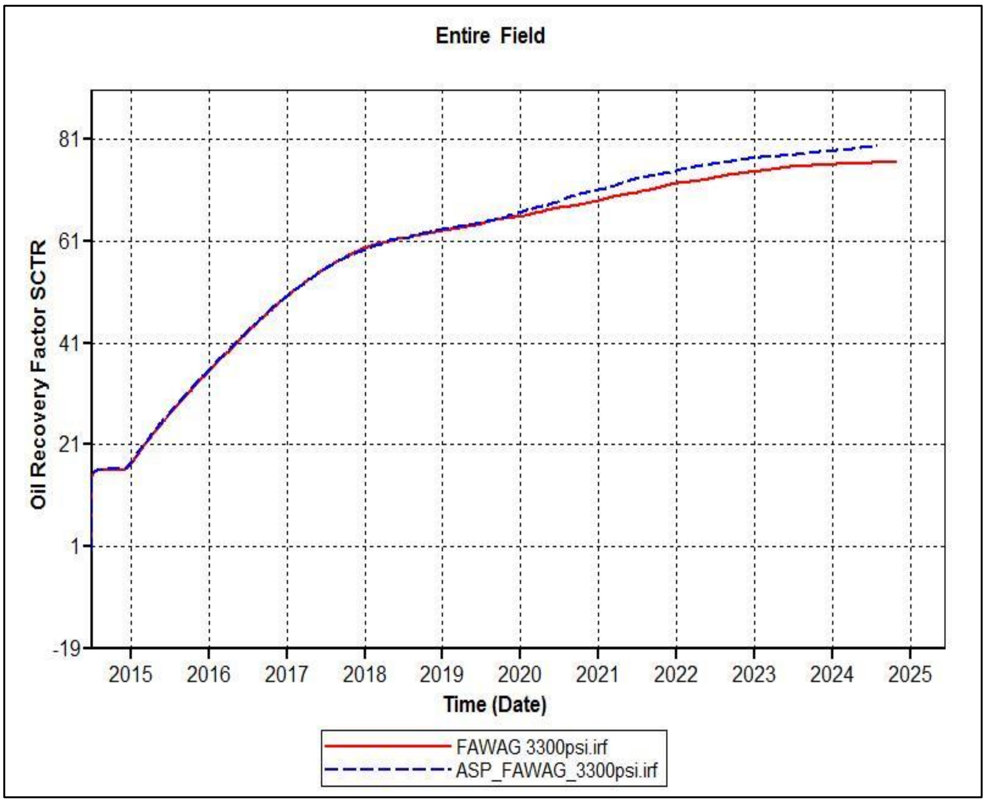


Figure 35 : The recovery factor of FAWAG with asphaltene and without asphaltene.

FAWAG injection	Recovery Factor (%)
With asphaltene	79.46
Without asphaltene	76.42

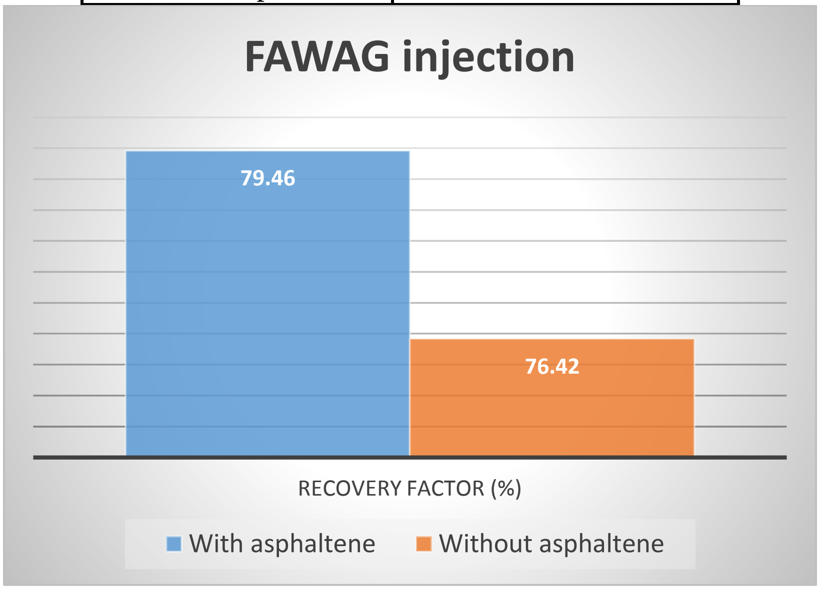


Figure 36: The comparison between FAWAG with asphaltene and without asphaltene.

The results from Figure 35 and 36 showed that FAWAG with asphaltene content recovery more oil than FAWAG without asphaltene content. In the FAWAG with asphaltene model, as gas is injected into the reservoir, it tends to travel upward rather than lateral due to permeability variation and gravity segregation. As the gas flows toward oil, asphaltene precipitation is induced. According to Ali (2009), mixing of gas with asphaltene presence-oil will enhance the deposition of asphaltene. The precipitation of asphaltene is significantly induced when gas injection is started since it will swell the oil and decrease the solubility of asphaltene. Hence, as the gas moving upward asphaltene is induced, more asphaltene is deposited at the upper most layer and the high permeability layers, which resulted in gas pushing to the lower permeability layers which contained more oil than high permeability layers. Another explanation of the result was the introduction of surfactant improved the interfacial tension of water and oil. Precipitation of asphaltene can alter the wettability of rock surface. Hence, the reduction of interfacial tension need to be further reduced in order to obtained higher recovery. Thus, implementation of FAWAG in asphaltene-presence reservoir will have a great significant increase in oil recovery.

4.6 Surfactant concentration for FAWAG injection (with asphaltene)

To get an optimum result for the best surfactant concentration for FAWAG with CO_2 injection, same 2 to 1 cycle ratio and 3300 psia injection pressure is used for all simulation. Concentration of surfactant is ranged from 0.00005 to 0.005. FAWAG injection with the presence of asphaltene is used as it yielded better recovery compared to without asphaltene as discussed earlier. The result for different concentration used is discussed as below.

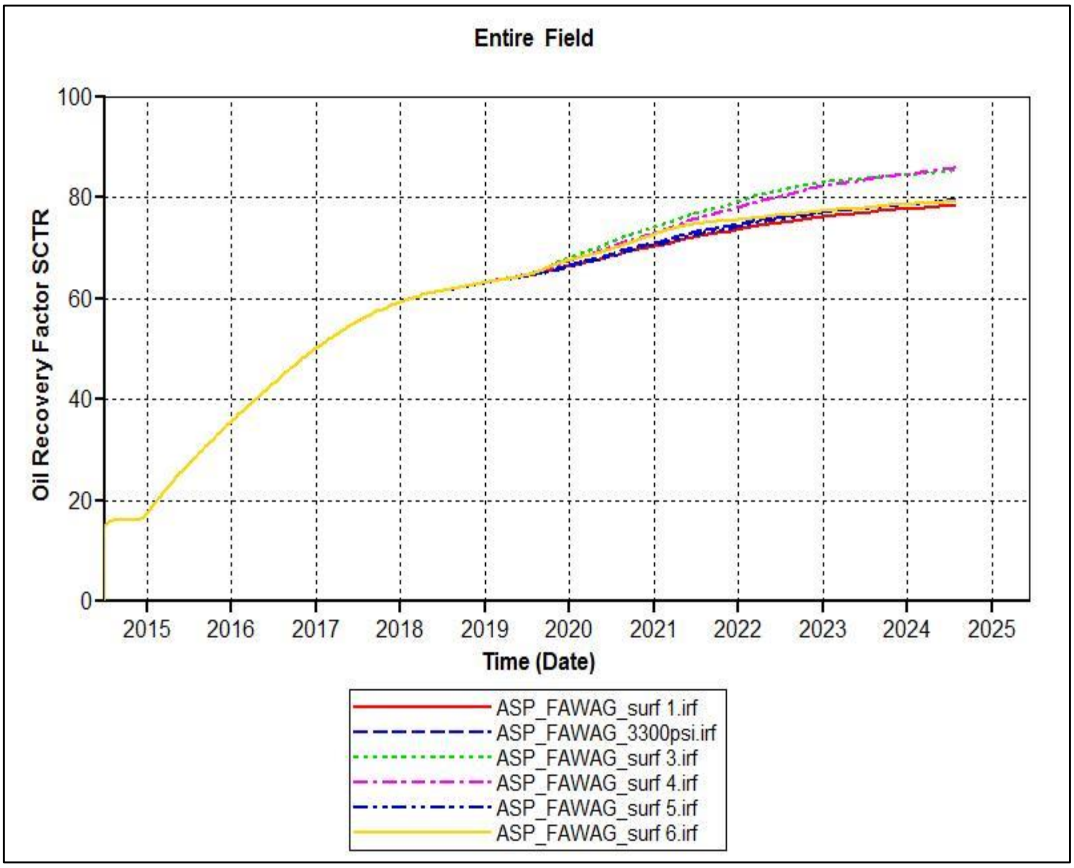


Figure 37 : The recovery factor of FAWAG with different concentration of surfactant

Table 12 : Recovery factor for different surfactant concentration

No.	Surfactant concentration (mole fraction)	RF (%)
1	0.00005	78.42
2	0.00001	79.46
3	0.0001	79.55
4	0.0003	85.77
5	0.0005	85.19
6	0.005	79.16

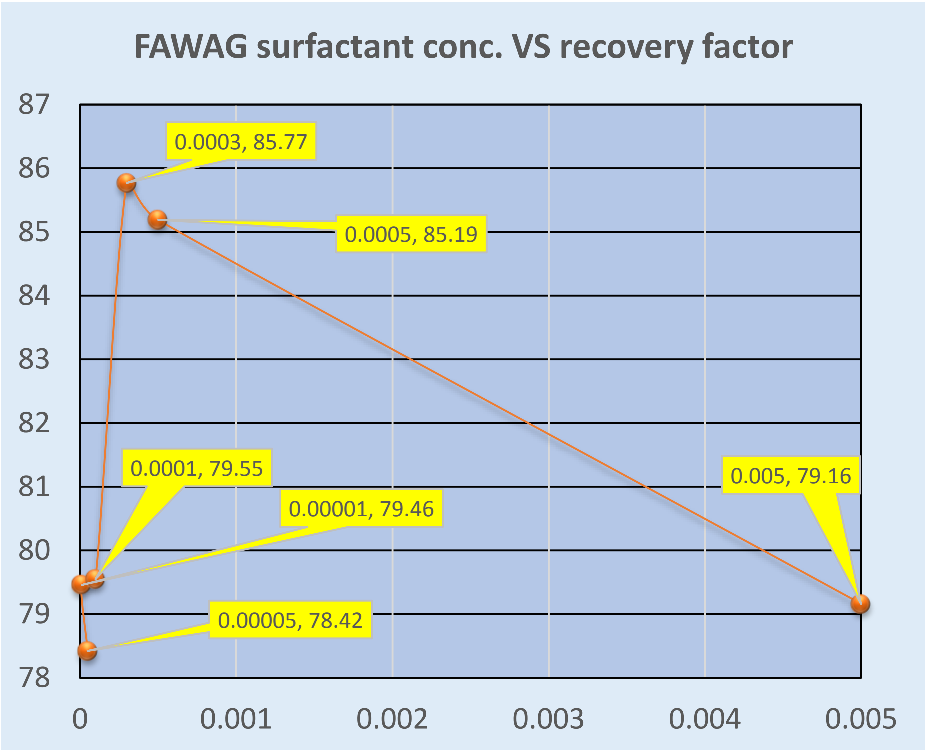


Figure 38 : FAWAG surfactant concentration VS recovery factor

As shown in Figure 37 and 38, the recovery factor is increasing from concentration of 0.00005% until 0.0003%. The recovery factor is then decreasing from concentration of 0.0003% until 0.005%. Highest recovery factor is at 0.0003% where the amount of surfactant is fully optimized with injection of CO_2. Low recovery below 0.0003% is due to insufficient surfactant for foam generation which lead to early gas breakthrough along several high permeability. While higher amount of surfactant than 0.0003% is over utilized where most all of gas is formed into foam and no additional gas to push the foam and oil along the reservoir to production well. A significant decreasing recovery after optimum point for with asphaltene presence is shown is due to adsorption effect of surfactant to reservoir rock where the adsorbed surfactant will cause pore throat and permeability reduction. The higher surfactant concentration, the higher the amount of surfactant adsorbed into reservoir, hence the lower the recovery. Thus, it is important to determine the optimum surfactant concentration before any FAWAG injection can be implemented.

4.7 Cost Estimation of Optimum Surfactant Concentration

Cost of surfactant = Number of cycles * Days in a cycle * Injection rate
*Surfactant concentration * Surfactant Price per Pound
= 12 * 90 day * 696 barrel/day * 0.2784 lb/barrel * $0.9/lb
= $ 188,341 54

Revenue using surfactant = Cumulative Volume of Oil * Average Oil Price
= 501513 stb * $100/stb
= $ 50,151,380

From the calculation, implementation of FAWAG is a revenue generating project. Nevertheless the calculation need to take account the facilities, preliminary research before implementation and any short-sighted problem which will arise. The calculation is more toward highlighting the advantage of implementing FAWAG injection.

CHAPTER 5

CONCLUSION AND RECOMMENDATION

1. The best duration of injection cycle and the optimum injection pressure for WAG and FAWAG with CO_2 injection with and without the presence of asphaltene is 2 to 1 and 3300psi respectively.

2. Both FAWAG with and without asphaltene presence shown higher recovery than WAG. The better recovery was because better gas mobility control and effect of changes in oil-water IFT.

3. WAG injection shown a better recovery in reservoir without asphaltene presence reservoir. Lower recovery of WAG in asphaltene presence reservoir is due to clogged pore throat which reduces in WAG efficiency.

4. FAWAG in asphaltene presence reservoir yielded higher recovery compared to FAWAG injection in without asphaltene presence reservoir. The higher recovery by FAWAG with asphaltene is due to improved mobility control.

5. As concentration of surfactant increasing, the recovery factor increasing until optimum surfactant concentration is reached where highest recovery factor is found. The effect of surfactant concentration is similar toward both with and without asphaltene-presence reservoir. Additional surfactant concentration above optimum point will affect recovery due to adsorption of surfactant into reservoir which will cause reduction of permeability and clogged pore throat.

It is recommended to do further studies by focusing on other WAG and FAWAG injection parameters such as different ranges of brine salinity, types of surfactant and type of gas injection. WAG and FAWAG injection should be tested in carbonate reservoir with the presence of asphaltene. Besides that, it is essential to do laboratory experiment of dynamic core flooding for FAWAG and WAG injection in core sample taken from real reservoir rock with real light oil and asphaltene content.

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