CHAPTER 1:
PROJECT BACKGROUND

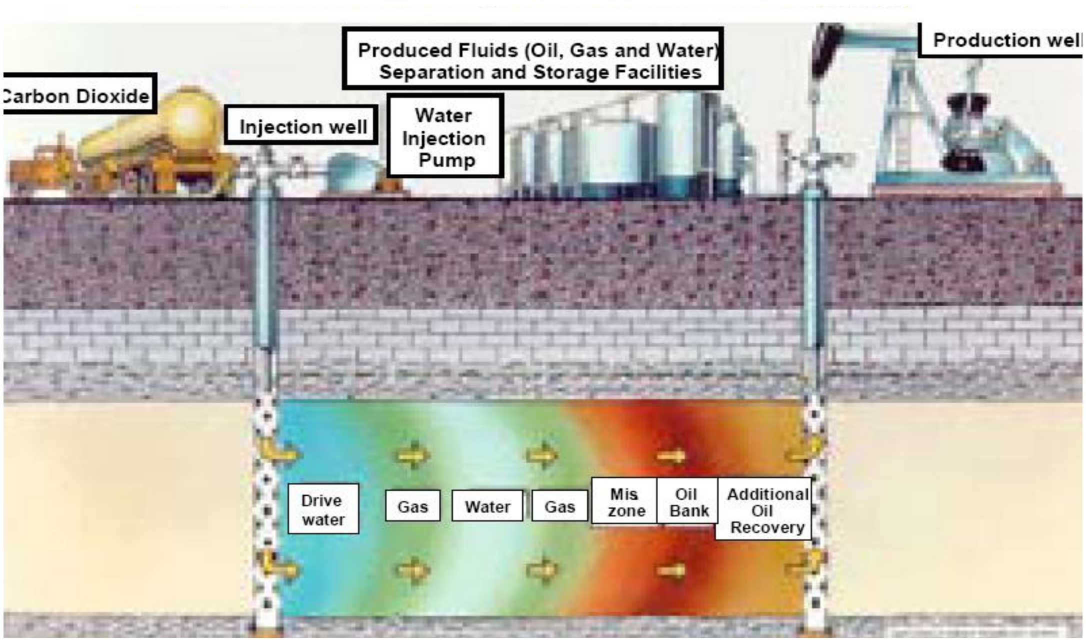
1.1 BACKGROUND OF STUDY

More than half the original oil typically remains in oil reservoirs after primary and secondary recovery operations. Primary recovery refers to production of oil because of its natural energy; fluids expand as pressure falls to push out some oil and gas. Expansion of associated aquifers and gas caps also help in pushing out oil. Primary recovery efficiency varies greatly from reservoir to reservoir and is typically in the range of 5-20% [1]. Secondary recovery refers to injection of immiscible fluids, such as water and gas, to recover oil. These fluids displace oil from the pore space immiscibly. Secondary recovery efficiency is typically another 10-20% [1]. Oil is left behind in bypassed regions as well as in swept zones. Oil is bypassed in certain zones of the reservoir because of permeability heterogeneity, lack of conformance at the wells, pattern orientation, and sometimes-viscous fingering. Oil is also left behind in the swept zones because of capillary forces in immiscible displacements during secondary recovery. Tertiary recovery techniques (also called enhanced oil recovery (EOR) techniques) are needed to recover additional oil from existing fields.

Miscible flooding is one of the commercially successful EOR methods. It constitutes the injection of CO_2, hydrocarbon gases, and even nitrogen or flue gas [2]. Typically 10-50% PV of the injectant is injected in the case of CO_2 or hydrocarbon gases. A much larger amount of nitrogen or flue gas can be injected because they are cheaper. These gases can be injected in different modes: miscible gas injection followed by dry gas injection, miscible gas injection followed by water injection or water-alternating-gas (WAG) injection.

It is believed that in recent years there has been an increasing interest in water-alternating-gas (WAG) processes, both miscible and immiscible. WAG injection is an oil recovery method which initially aimed to improve sweep efficiency during gas injection.

In some recent applications produced hydrocarbon gas has been reinjected in water-injection wells with the aim of improving oil recovery and pressure maintenance. Oil recovery by WAG injection is believed has been attributed to contact of unswept zones, especially recovery of attic or cellar oil by exploiting the segregation of gas to the top or the accumulating of water toward the bottom. Because the residual oil after gasflooding is normally lower than the residual oil after waterflooding, and three-phase zones may obtain lower remaining oil saturation, WAG injection which is the combination of both methods has the potential for increased microscopic displacement efficiency. Thus, WAG injection can lead to improved oil recovery by combining better mobility control and contacting unswept zones, and by leading to improved microscopic displacement [3]. A typical WAG process can be described as follows.



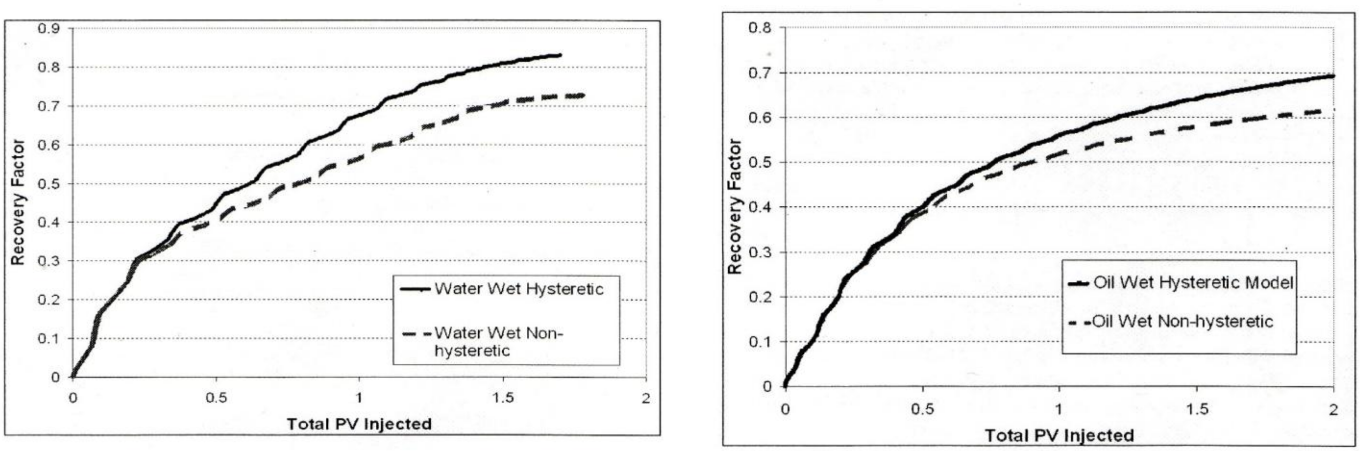
Source: http://www.spe.org/jpt/2006/12/gagd-process-works-with-nature-to-improve-light-oil-recovery/

Figure 1: Conceptual diagram of an idealized CO_2-WAG process

The CO_2 is typically injected in an alternating water and gas (WAG) process. It is injected at a pressure greater than its MMP (Minimum Miscibility Pressure) where the CO_2 acts to increase the volume of the oil miscible phase and lower its viscosity, freeing it from trapped pore spaces. As illustrated above, the water is being injected behind a "slug" of CO_2 that creates a zone which helps release the oil that had previously been trapped when using only water. This process leads to improved oil recovery by combining better mobility control and contacting unswept zones, and by leading to improved microscopic displacement.

In WAG process, during each injection period, there are cyclic changes in fluid saturation due to the different type of fluid injected (i.e. water and CO_2 gas). These changes reflect the fluid displacement mechanisms in the reservoir, specifically drainage (non-wetting phase displaces wetting phase) and imbibition (wetting phase displaces non-wetting phase) processes which will generate hysteresis on relative permeabilities.

Based on the conceptual study done by Faiza M Nasir and M Sanif Maulut (2009), it is found that by considering the hysteresis effect in WAG simulation, the oil recovery prediction is higher than the non-hysteretic model by as much as 10% [4]. This is due to the fact that the hysteretic model accounts for the gas trapping effect during cyclic changes in saturation. It is because the gas trapping effect will reduce the gas permeability, hence reduction in gas mobility. Thus, this will give better oil recovery. Please refer Figure 2 below to see the difference in oil recovery for water-wet and oil-wet systems based on the conceptual study [4].



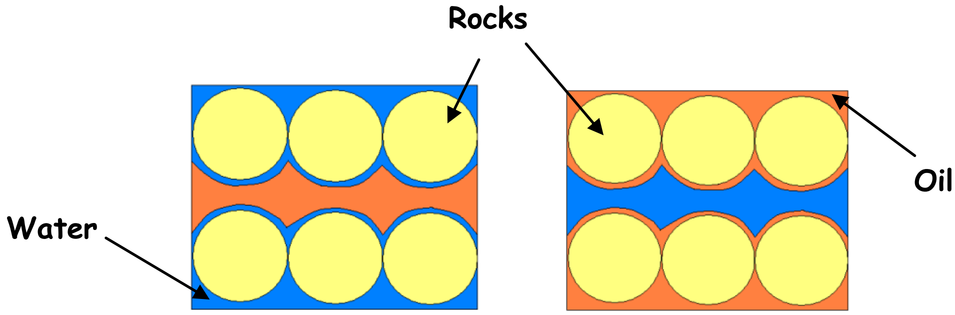
a) Oil recovery for hysteretic and non-hysteretic water-wet models

b) Oil recovery for hysteretic and non-hysteretic oil-wet models

Source: Faiza M. Nasir, M Sanif Maulut, "Wettability Influence on Hysteresis for Immiscible Water-Alternating-Gas (WAG) Injection" (2009)

Figure 2: Oil recovery for hysteretic and non-hysteretic models for water-wet and oil-wet systems

A reservoir is characterized as a water-wet system if water tends to adhere to its rock surface, hence allowing better flowing condition for oil through its pores. In this situation, the wetting fluid is water meanwhile the non-wetting fluid is oil. On the other hand, for an oil-wet reservoir, the oil tends to spread over the rock surface. Here, the wetting fluid is oil and the non-wetting fluid is water. For better understanding about these two types of reservoir, please refer Figure 3 below.



(a) Water Wet (most fields)   (b) Oil Wet (clay and carbonates)

Figure 3: Wettability characteristics of a reservoir

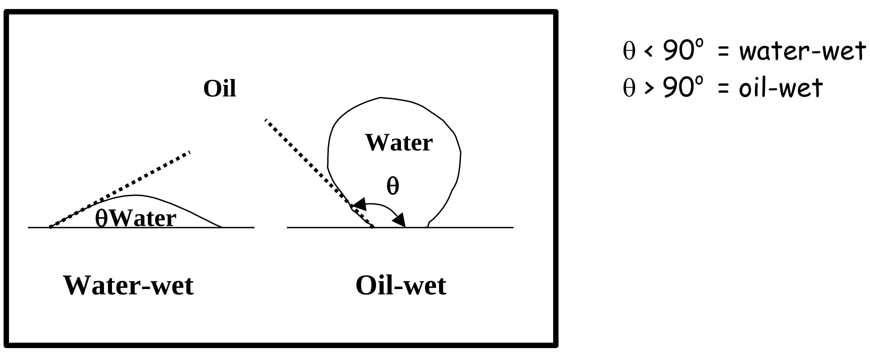


Figure 4: Contact angle for the water-wet and oil-wet systems

1.2 PROBLEM STATEMENT

As has been mentioned earlier, during the WAG injection, saturation changes are cycling due to the different type of fluid injected into the reservoir. These changes reflect the imbibition and drainage processes which will generate hysteresis on relative permeabilities.

Based on Figure 2, it is proved that the hysteretic model gives higher prediction of oil recovery compared to non-hysteretic model as the hysteretic model accounts for the gas trapping effect. This effect is actually a beneficial process that helps to reduce the gas permeability which then leads to the reduction in gas mobility. When gas mobility is reduced, it is more difficult for the gas to displace the water from high permeability zone, thus it is more preferentially redirected into zones of lower permeability. As a result, this will improve the overall conformance and sweep efficiency, hence give better oil recovery [4].

Many researches have been carried out to study the factors affecting the hysteresis in the reservoir. Majority of these studies only consider the capillary pressure and relative permeability effects on hysteresis. However, recent research shows that the wettability characteristic of a reservoir also plays an important role on hysteresis. In general, there are two types of wettability which are water-wet and oil-wet.

From Figure 2, a slightly difference in the recovery factor can be observed between water-wet and oil-wet models. The hysteretic model for water-wet system is found to have greater recovery factor compared to the hysteretic model of oil-wet system because in water-wet system, it allows the oil to smoothly flow through its pores since oil does not adhere to the rock surface. In contrast, for oil-wet system, the oil tends to adhere to its rock surface, thus more oil is left behind during the production process.

It should be reminded that this observation is only based on the conceptual model which represents a quarter of a five-spot pattern in a homogeneous three-dimensional reservoir with a dimension of 2500 x 2500 x 150 ft (to reduce the complexity of the reservoir in order to quickly observe the effects of the hysteresis, the model is discrete into 15x15x9 grid blocks). However, the effect on the real model (real reservoir) is unknown yet. Therefore, a study which focuses on the data from real reservoir need to be conducted so that this theory can be proved either it is valid for the real reservoir or not. Before further study is done, the type of wettability characteristic of the reservoir should be determined first since different type gives different result.

1.3 OBJECTIVE AND SCOPE OF STUDY

The objective of this project is to study the influence of the hysteresis phenomena of the WAG process with the oil recovery by using the ECLIPSE Black Oil Reservoir Simulator based on the previous conceptual study. For that purpose, data from the real reservoir (i.e. Angsi) will be used as the input of the simulation. Throughout the simulation, the two-phase hysteresis model (Killough's) with Stone1's interpolation method is used. This model is used because it is able to predict the trapping of the non-wetting phase and reduction of permeability during the imbibition process.

Normally, hysteresis effect is ignored during the simulation because its impact is not known. Therefore, this study is done to evaluate the importance of considering hysteresis effect for WAG process which is believed to have some influences on the outcome of oil prediction based on the previous conceptual study. Since this project emphasizes on the use of data from the real reservoir, therefore the result obtained can be compared with the conceptual study to see either the hysteresis' consideration in WAG process also helps to increase the oil prediction in the real reservoir or not.

The scope of work in this project is to understand the importance of properly established the wettability characteristics of a reservoir before further study on the WAG process is done. This is because different characteristic gives different result since they have different properties. Besides that, the effect on considering hysteresis phenomena after applying WAG injection to the reservoir will be analyzed too. This process is important in order to see whether this consideration helps in increasing the prediction of oil recovery or not. If the result obtained shows the significant of considering hysteresis, therefore it is no doubt to include/ consider the hysteresis effect in WAG simulation so that the oil in the reservoir is not being underestimated. If the reservoir is underestimated, it may cause difficulties during the production process since the design of the facilities involved in the oil production have been underdesigned. All in all, the most important thing that needs to be understood clearly is the use of simulation software which is ECLIPSE Black Oil Reservoir Simulator as it is used throughout the project.

Since this project focuses on the real reservoir, therefore the real characteristic of the reservoir should be known first. As has been stated earlier, there are two types of reservoir which are water-wet and oil-wet. Both characteristics can be distinguished conveniently using the Relative Permeability Curve as illustrated in Figure 5. The criteria used to evaluate the curve are explained in Table 1.

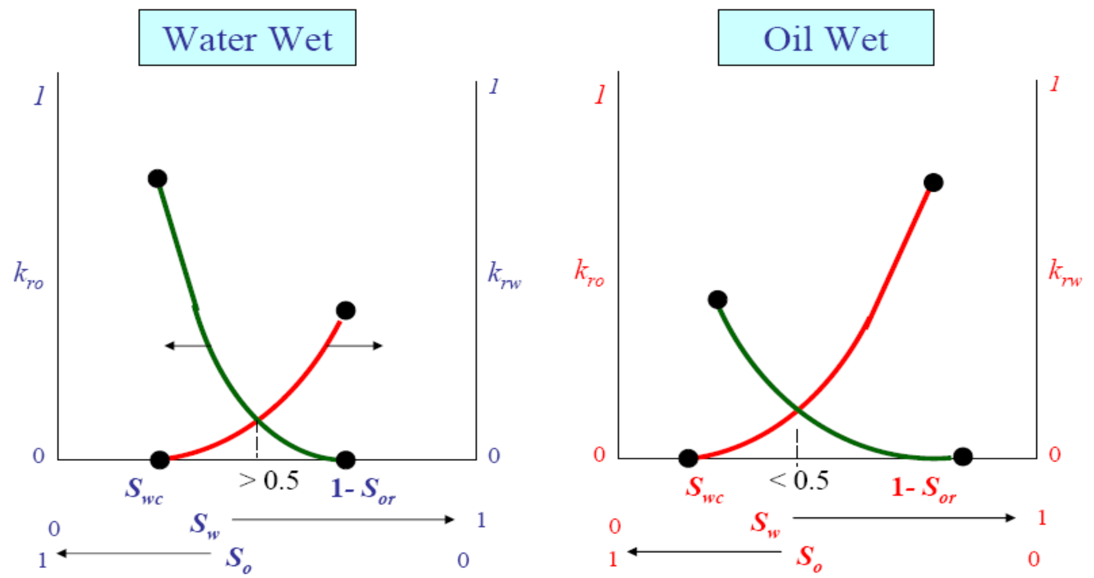


Figure 5: Typical Relative Permeability Curve for water-wet and oil-wet systems

Table 1: Criteria for relative permeability curve for water-wet and oil-wet systems [4]

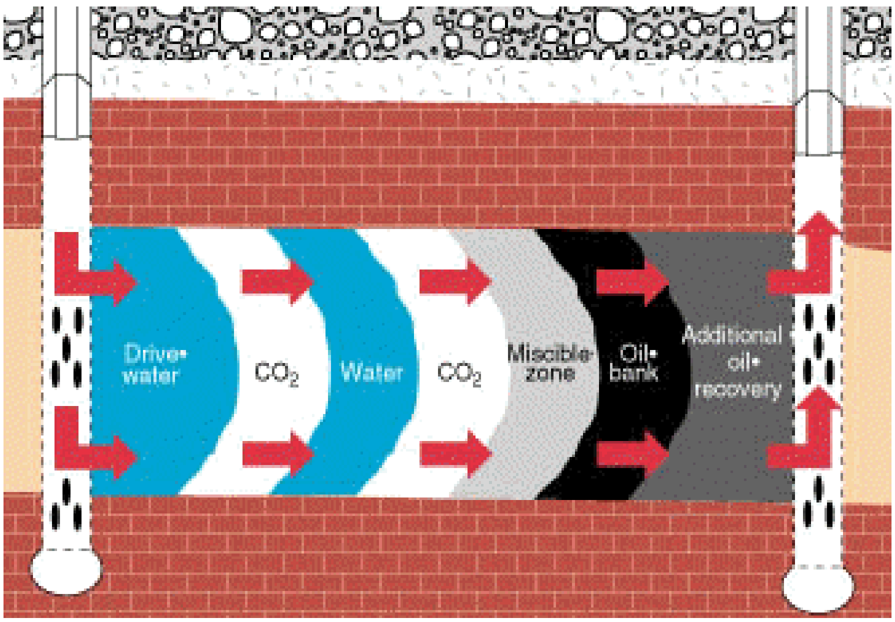
	Water wet	**Oil wet**
S_{wc} (connate water saturation)	> 20 – 25 %	< 15 % (usually 10%)
S_w @ k_{rw} = k_{ro} (water saturation when water relative permeability equals the oil relative permeability)	> 50 %	< 50 %
k_{rw} @ S_{orw} (endpoint water relative permeability)	< 0.3	> 0.5 to 1.0

For Angsi Field reservoir, it can be categorized as a water-wet reservoir as it satisfies most of the criteria for water-wet system shown in the table above. Please refer Figure 29 to see the Relative Permeability Curve of the Angsi Field reservoir.

CHAPTER 2:
LITERATURE REVIEW

2.1 WAG PROCESS

Water alternate gas (WAG) injection technology is a method which may improve oil recovery efficiency by combining effects from two traditional technologies – water and gas flooding. Both microscopic oil displacement and sweep efficiency can be improved by WAG implementation. Figure 6 below demonstrates the WAG process in a reservoir.



Source: http://www.daycreative.com/KM%20CO2%20web%20pages/co2flood_main.htm

Figure 6: WAG process in a reservoir

When CO_2 is injected into a reservoir above its minimum miscibility pressure (a miscible flood), the gas acts as a solvent. The CO_2 picks up lighter hydrocarbon components, swelling the total volume of oil and reducing the oil's viscosity so that it flows more easily.

Because gas can move through a reservoir more easily than oil, there is always a danger that the CO_2 will find a "quick-exit" and break through, leaving oil behind. To prevent this, waterflooding is often alternated with CO_2 flooding in a WAG (water alternating gas) scheme. Water moves through the reservoir more slowly than either oil or CO_2, so it creates a cheap and effective barrier to gas breakthrough and helps maintain a stable front for the CO_2 flood.

As has been mentioned earlier, the WAG process essentially relies on the ability of the injected gas to reduce the viscosity and density of the oil in place by swelling the oil despite the relative immiscibility of the gas in the oil. The injected water subsequently sweeps more oil to the production well because the oil is less viscous and less dense.

Another possible mechanism for the WAG process is gas trapping. After the injected gas displaces water in the pore spaces of the formation, the gas subsequently occupies the space. When the formation is then flooded with water, the gas in place diverts the water to oil-bearing portions of the formation which have not been previously flooded. Thus, the gas flood effectively reduces the volume of the formation which the water flood must sweep to recover a given quantity of oil and promotes sweeping of pore spaces which would not otherwise be contacted by the water [5].

A third possible mechanism for oil mobilization during the WAG process is gravity segregation. The gas is significantly less dense than oil and water. As the gas moves upward through the formation rock, it displaces oil downward [5].

Among gases that can be used in WAG process are carbon dioxide, natural gas, nitrogen, air, or a mixture thereof. The preferred injection gas is a produced gas, such as natural gas, which has been produced from the same formation or a different formation from that which is being flooded. The bulk of the gas comprises methane. If the gas injection pressure is below the minimum miscibility pressure of the gas in the oil, the process can be operated at lower cost because less gas is required than in a miscible process to displace an equivalent amount of oil. However, if it is injected at a pressure greater than its MMP (Minimum Miscibility Pressure), the gas acts to increase the volume of the oil miscible phase and lower its viscosity, freeing it from trapped pore spaces. As illustrated in Figure 6 above, the water is being injected behind a “slug” of CO_2 that creates a zone which helps release the oil that had previously been trapped when using only water. This process leads to improved oil recovery by combining better mobility control and contacting unswept zones, and by leading to improved microscopic displacement.

Injection of gas into the oil-bearing layer proceeds until oil production at the production well declines to a predetermined level. Gas injection is then terminated and water injection is initiated from an injection well while maintaining the production well in operation.

An additional quantity of water is then injected into the formation to displace the oil from the higher permeability layers to a production well. Produced brine or sea water are preferred injection waters because they are available at low cost and present a low risk of clay damage [5]. It is also possible, although maybe it is not necessary, to include additives in the injection water, such as surfactants or polymers, to further enhance the ability of the water to displace oil to the production well. The minimum quantity of water injected to sweep oil from the higher permeability layers should be about one effective pore volume of the higher permeability layers. The quantity of water injected to sweep oil from the higher permeability layers should be enough to produce all mobilized oil and water injection should continue until oil production declines to a predetermined level.

The level of oil recovery is the primary variable which determines the duration and volume of each fluid injection stage. In general, oil recovery increases when each fluid injection stage begins. As the injection stage continues, the level of oil recovery peaks and then declines. At some predetermined point on the decline curve, the injection stage for the next fluid begins. The termination point of the stage is often a function of the particular formation characteristics and the type of injection and production fluids. In most cases, it can be predetermined by experimental or theoretical modeling [5].

The frequency of alternating the working fluid in the WAG process can vary considerably from a few days to several months: it very much depends on the oil reservoir, injection and production volumes, well location and residual oil. A useful rule-of-thumb is based upon when the volume of breakthrough gas or water-cut suddenly increases compared with the volume oil that is produced.

WAG processes can be grouped in many ways. The most common is to distinguish between miscible and immiscible displacements as a first classification [3].

a) Miscible WAG Injection.

- It is difficult to distinguish between miscible and immiscible WAG injections. In many cases a multicontact gas/oil miscibility may have been obtained, but much uncertainty remains about the actual displacement process.
- Miscible projects are mostly found onshore, and the early cases used expensive solvents like propane, which seem to be a less economically favorable process at present. Most of the miscible projects reviewed are repressurized in order to bring the reservoir pressure above the minimum miscibility pressure of the fluids.
- Because of failure to maintain sufficient pressure, meaning loss of miscibility, real field cases may oscillate between miscible and immiscible gas during the life of the oil production. Most miscible WAG injections have been performed on a close well spacing, but recently miscible processes have also been attempted even at offshore-type well spacing.

b) Immiscible WAG Injection.

- This type of WAG process has been applied with the aim of improving frontal stability or contacting unswept zones. Applications have been in reservoirs where gravity-stable gas injection cannot be applied because of limited gas resources or reservoir properties like low dip or strong heterogeneity.
- In addition to sweep, the microscopic displacement efficiency may be improved. Residual oil saturations are generally lower for WAG injection than for a

waterflood and sometimes even lower than a gasflood, owing to the effect of three-phase and cycle-dependent relative permeability.

Sometimes the first gas slug dissolves to some degree into the oil. This can cause mass exchange (swelling and stripping) and a favorable change in the fluid viscosity/density relations at the displacement front. The displacement can then become near-miscible.

c) Hybrid WAG Injection.

- When a large slug of gas is injected, followed by a number of small slugs of water and gas, the process is referred to as hybrid WAG injection.

d) Simultaneous WAG Injection.

- A process where water and gas are injected simultaneously.

Since water and gas are alternately injected into the reservoir during WAG process, thus this will result in a complex saturation pattern as two saturations (gas and water) will increase and decrease alternately. Because of this, a hysteresis loop will be generated which consists of drainage and imbibition processes.

Generally, hysteresis refers to irreversibility or path dependence. In multiphase flow such as in WAG process, hysteresis can appear in both capillary pressure and relative permeability where there is a reversal in saturation changes – represented by drainage and imbibition process. Drainage process mainly describes about the increase in non-wetting phase saturation while imbibition process describes about the increase in wetting phase. Figure 7 below illustrates the drainage and imbibition process in hysteresis phenomena.

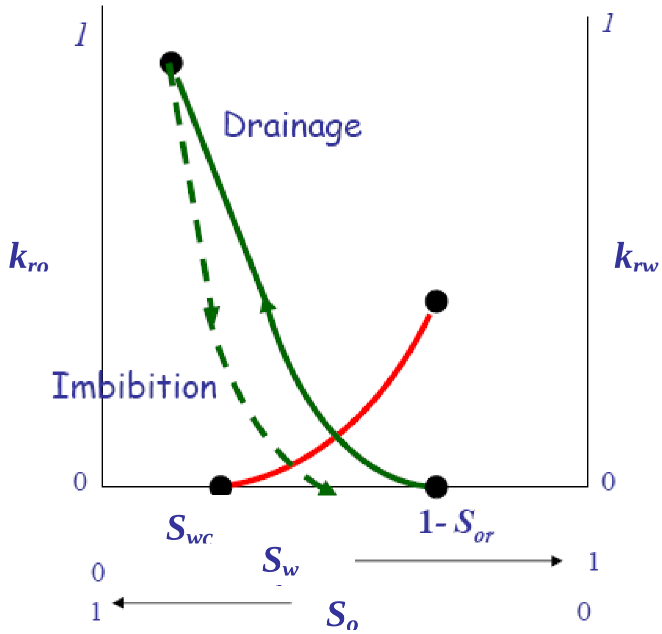


Figure 7: Drainage and imbibition processes in hysteresis effect

2.2 RELATIVE PERMEABILITY

Relative permeabilities are generally functional dependent of saturation and saturation history. The second dependency is in literature described as *relative permeability hysteresis*. The hysteresis behaviour in non-wetting phase (gas) relative permeability differs significant depending on wetting preferences of the system being investigated. Strongly water-wet systems are said can show drainage-imbibition hysteresis clearly [6] [7]. In addition, intermediate-wetting systems show complicated hysteresis behaviour depending on saturation cycle history [8]. Many reservoirs have intermediate-wetting properties, and a detailed study of the relative permeability hysteresis is important in processes involving saturation oscillation during three-phase flow.

The concept of relative permeability was introduced to modify Darcies Law, describing single phase flow in a porous media, for the extremely complex multiphase flow effects occurring when more than a single immiscible phase is present. Relative permeability values strongly control the flow mechanics, pressure and production response of virtually every producing oil or gas property and. therefore, a proper understanding of how they are influenced is important in the process of reservoir optimization. Relative permeabilities are expressed as functions of water (for water-oil systems) or total liquid saturation (for gas-liquid systems), and have strong functions of such parameters as pore system geometry and tortousity [9], wettability [10] [11] [12], initial phase saturations [13], temperature [14], viscosity of fluids [15], interfacial tension [16] and hysteresis effects [17] [18] [19].

2.3 HYSTERESIS EFFECT

Hysteretic effects refer to the difference between relative permeability and residual saturation values as a given fluid phase saturation is increased or decreased. Generally hysteresis is more pronounced in the non-wetting phase than in the wetting phase, but may occur in both phases with up to two orders of magnitude difference in relative permeability at equivalent saturations being observed. In most cases, the relative permeability for a given phase is greater when its saturation is increased rather than decreased. This phenomenon can be used to advantage in situations such as a cyclic steam injection process, since it will enhance oil mobility and retard high water production rates on a return flow cycle [20].

Two dominant mechanisms cause the saturation hysteresis. In the primary and secondary drainage case, a portion of the hysteresis is due to the disparity between the initial condition of 100% water saturation and the trapped irreducible oil saturation. This is commonly referred to as trap hysteresis. The difference in relative permeability curves caused by the motion between the same endpoint saturation states is due to microscale hysteretic effects, or sometimes called drag hysteresis. It is believed to be primarily due to a phenomenon known as contact angle hysteresis. Basically, contact angle hysteresis refers to the fact that, as immiscible interfaces advance in a porous media, the effective angle of the advancing interface, which is related by wettability and capillary dynamics to the relative ease of the fluid displacement in the porous media, is different between advancing and receding phase conditions. This difference, which appears to be a Strong factor of the degree of surface roughness and tortuosity which exists in the system, is believed to be the root cause of hysteretic microscale relative permeability effects.

Hysteretic relative permeability effects have often been used as a mobility control agent to preferentially reduces the mobility of one phase over another to achieve superior conformance control and ultimate sweep efficiency, particularly in the presence of adverse viscosity ratios. A prime example of this technology is the water alternating gas treatment or WAG process used to reduce the mobility of injected gas in a horizontal gas injection project. The interfering effects between the gas and liquid phases are used to selectively retard the speed of gas migration. Since the water, due to its higher viscosity, tends to preferentially channel into the higher permeability channels of the reservoir, it tends to screen off these better quality zones and selectively reduces the permeability to gas. Due to hysteresis and mobility effects, it is more difficult for the gas to displace the water from this zone than to be preferentially redirected into zones of lower permeability, which tends to improve the overall conformance and sweep efficiency of a horizontal gas injection project, particularly in thick pay zones or zones containing highly variable permeability or high permeability streaks [20].

The use of a simulation model with hysteretic relative permeability capability is sometimes the only method of accurately predicting the performance of some cyclic projects, particularly cyclic steamfloods in heavy oil applications. This is illustrated in relative permeability curves as pictured in Figure 6. It can be seen that the higher water phase relative permeability on the water injection cycle aids in increasing the ease of injectivity of the hot water and steam condensate into the formation. The lower oil phase permeability, as its saturation is being reduced, allows the hot water/steam to bypass some oil and penetrate deeper into the formation which improves the contact and size of the heated zone. On the other hand, on the production cycle, oil production rate is enhanced as the water mobility is reduced, since its saturation is being reduced, and the oil phase relatively permeability may be significantly increased. This results in enhanced production of oil rather than rapid production of the less viscous water phase [20].

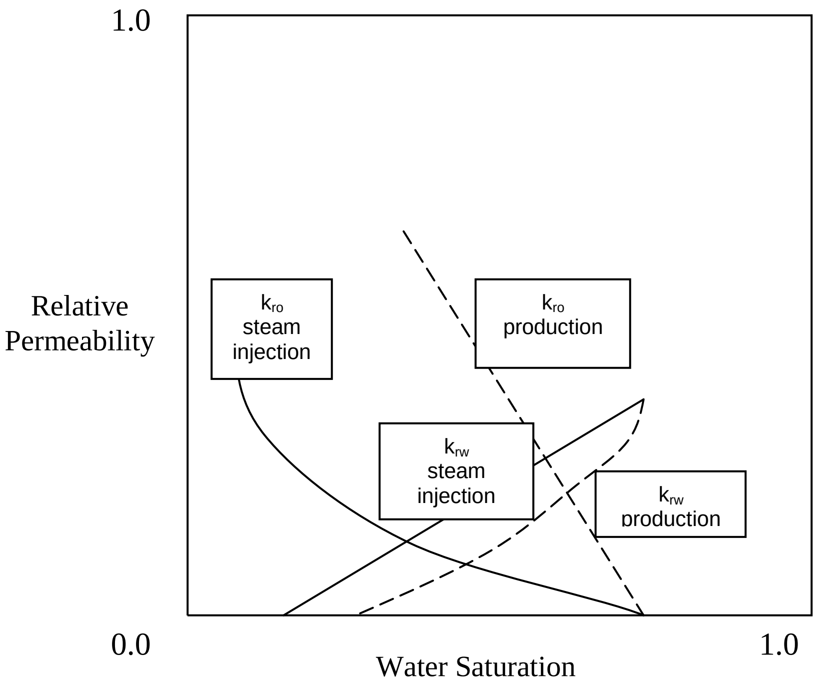


Figure 8: Illustration of cyclic hysteresis effects on enhanced production rates

2.4 WAG PARAMETERS

Oil displacement by alternating water/gas slugs is a combination of imbibition and drainage processes occurring in a three phase flow regime. One of the key mechanisms in the improvement of sweep efficiency or in the flooding profile control is the gas trapping process. Oil recovery can be enhanced if a gas slug appropriate for the particular reservoir is injected in a proper alternation with water.

a) WAG injection rate

- The dependence of oil recovery on viscous to gravity ratio is not uniform throughout stratified reservoirs. The increase of injection rate does not always lead to the total recovery improvement from the whole reservoir. Different flow regimes can occur in different layers at the same time. In the section with restricted vertical permeability an increase of injection rate may even decrease the relative volume of gas entering the top low permeability zone [21].

b) WAG ratio

- Laboratory and simulation's results have shown that in the case of segregated flow, the sweep efficiency of a reservoir can be improved by WAG injection. To achieve this, gas should be supplied to the gas/water front at a rate corresponding to the volume of gas trapped by the advancing water. A bank of gas kept ahead of the front, enables one to reduce residual oil saturation to waterflooding in the larger section of the reservoir. The choice of optimum WAG ratio can improve the sweep efficiency of the process.
- Normally, this could be achieved if gas and water travel in the reservoir at equal speed. However this effect may occur for a short time in the water-gas mixture zone, since it has a limited extend in the reservoir because of difference in viscous and gravity forces. Therefore portioning of water/gas banks and cycling are required to tune the injection scheme for particular reservoir conditions [22].

c) WAG cycle

- The decrease of gas bank volumes injected in alternated cycles with water into high permeability layer, increases the trapped volume of gas in this layer. This limits the amount of segregated gas that can penetrate to the upper layer. So, the increase of WAG cycles gives improved oil recovery from the high permeability layer at the expense of recovery from the low permeability top layer.
- Because of gas segregation in the high permeability layer, it performs in the flooded area as an additional source of gas for the upper layer. The volumes of gas and water banks to be injected and the number of WAG cycles should be primarily determined for this bottom layer. In the case of segregated flow, gas injection at high rates and large banks in cycles leads to the fast override and early breakthrough. On the other hand, water underriding gas may trap all gas ahead of the front as well as oil unswept by gas [22].

2.5 HYSTERESIS MODEL

Immiscible WAG has been simulated by use of different relative permeability hysteresis models. The oil relative permeability was generated by a modified Stone I model. The necessity of using a hysteresis model for gas relative permeability in numerical simulation of WAG is because in standard simulation study (without hysteresis) which uses only a primary drainage gas curve with no possibility of estimating trapped gas, the oil recovery is totally under predicted compared to the experimental data. [23]

A relative permeability hysteresis model should be evaluated whenever a simulation study involves saturation oscillations. In the literature, models for hysteresis in non-wetting phase permeability have mostly been restricted to extreme-wetting two-phase systems. Standard two-phase hysteresis models are founded on Land's empirical relation [24].

$$\frac{1}{S_{gt}} - \frac{1}{S_{gi}} = C \quad (1)$$

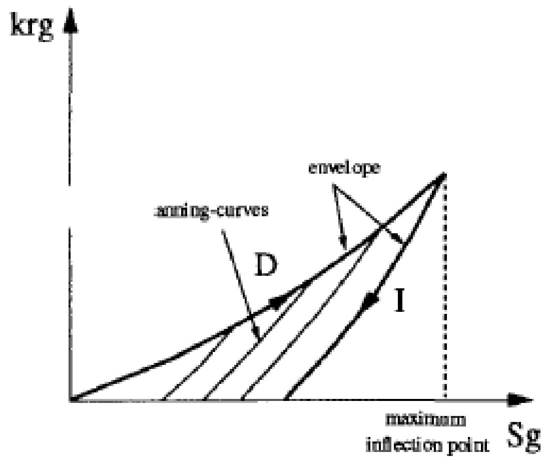
where S_{gt} = Trapped gas saturation

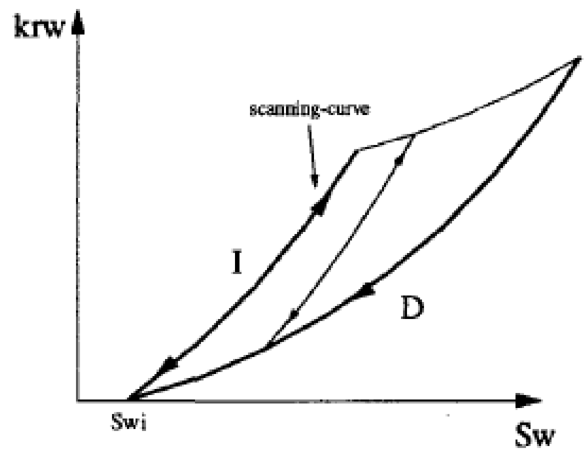
S_{gi} = Historical maximum of gas saturation

In this project, the hysteresis models used in ECLIPSE simulation are based on Carlson and Killough [22]. These models are applied for three-phase flow conditions by utilizing an interpolation model (Stone’s method).

Carlson hysteresis model [25] consists of a drainage-curve and the value of the constant C in equation (1). The imbibition curve can then be estimated from a maximum gas saturation to a trapped gas saturation using the drainage curve, Land's relation and the hypothesis that gas saturation can be separated in two parts; free saturation exhibiting flow and trapped saturation. A consequence is that all imbibition curves become parallel in spite of different origin on the primary drainage curve as showed in figure la. The coarse lines in Figure 9(a), that is the primary drainage curve connected with an imbibition curve originating from the largest possible non-wetting saturation, are a relative permeability envelope in which scanning-curves are generated. Whenever the drainage process is stopped, a subsequent imbibition process will follow a scanning-curve. The point where the displacement process shifts from drainage to imbibition is called the *inflection point.* After initiating an imbibition process all further processes are assumed reversible, i.e. the scanning-curve is followed back to the inflection point and then the primary drainage curve is followed to a new historical maximum of gas saturation. If the drainage process stops on the scanning-curve, relative permeability during saturation oscillation is computed from the same curve.

The Killough hysteresis model [26] for non-wetting phase is similar to Carlson's model founded on Land's empirical relation to estimate trapped gas as a function of the inflection point. This model also needs the drainage curve and the Land constant as input, and estimates the imbibition curves from the drainage curve using a parametric interpolation method or a normalised experimental data method. The interpolation method involves a free parameter that must be known. A water hysteresis scheme is also available, and separates the water relative permeabilities in a drainage curve and an imbibition curve. The scanning-curves are interpolated from these two curves. The imbibition curve is assumed reversible [26], thus hysteresis may occur after primary drainage process, but not after a primary imbibition. The water hysteresis scheme is shown in Figure 9(b).





(a) Carlson hysteresis model non- wetting phase

(b) Killough hysteresis model wetting phase

Figure 9: Hysteresis models used in ECLIPSE simulation to model the WAG process

2.6 TWO-PHASE RELATIVE PERMEABILITY CORRELATIONS

In many cases, relative permeability data on actual samples from the reservoir under study may not be available, in which case it is necessary to obtain the desired relative permeability data in some other approaches. The field data are unavailable for future production; therefore some substitute must be devised. Several methods have been developed for calculating relative permeability relationships. Various parameters have been used to calculate the relative permeability relationships, including:

- Residual and initial saturations
- Capillary pressure data

In addition, most of the proposed correlations use the effective phase saturation as a correlating parameter. The effective phase saturation is defined by the following set of relationships [27]:

$$S_o^* = \frac{S_o}{1 - S_{wc}} \qquad S_g^* = \frac{S_g}{1 - S_{wc}}$$

$$S_w^* = \frac{S_w - S_{wc}}{1 - S_{wc}}$$

where S_o^*, S_w^*, S_g^* = effective oil, water, and gas saturation, respectively
S_o, S_w, S_g = oil, water and gas saturation, respectively
S_{wc} = connate (irreducible) water saturation

1. Wyllie and Gardner Correlation
   - Wyllie and Gardner (1958) observed that, in some rocks, the relationship between the reciprocal capillary pressure squared ($1/Pc^2$) and the effective water saturation S^*_w is linear over a wide range of saturation. Honapour et al. (1988) conveniently tabulated Wyllie and Gardner correlations as shown below:

Table 2: Wyllie and Gardner correlations [27]

Drainage Oil-Water Relative Permeabilities		
Type of formation	**k_{ro}**	**k_{rw}**
Unconsolidated sand, well sorted	$(1 - S_w^*)$	$(S_w^*)^3$
Unconsolidated sand, poorly sorted	$(1 - S_w^*)^2 (1 - S_w^{*1.5})$	$(S_o^*)^{3.5}$
Cemented sandstone, oolitic limestone	$(1 - S_o^*)^2 (1 - S_w^{*2})$	$(S_o^*)^4$

Drainage Gas-Oil Relative Permeabilities		
Type of formation	**k_{ro}**	**k_{rg}**
Unconsolidated sand, well sorted	$(S_o^*)^3$	$(1 - S_o^*)^3$
Unconsolidated sand, poorly sorted	$(S_o^*)^{3.5}$	$(1 - S_o^*)^2 (1 - S_o^{*1.5})$
Cemented sandstone, oolitic limestone, rocks with vugular porosity	$(S_o^*)^4$	$(1 - S_o^*)^2 (1 - S_o^{*2})$

- Wyllie and Gardner have also suggested the following two expressions that can be used when one relative permeability is available:

  a) Oil-water system

$$k_{rw} = (S_w^*)^2 - k_{ro}\left[\frac{S_w^*}{1-S_w^*}\right]$$

  b) Gas-oil system

$$k_{ro} = (S_o^*) - k_{rg}\left[\frac{S_o^*}{1-S_o^*}\right]$$

2. <u>Torcaso and Wyllie Correlation</u>

- To calculate relative permeability of oil in a gas-oil system
- Useful since k_{rg} measurements are easily made compared to k_{ro}

$$k_{ro} = k_{rg}\left[\frac{(S_o^*)^4}{(1-S_o^*)^2\,(1-(S_o^*)^2)}\right]$$

3. <u>Pirson's Correlation</u>

- For wetting phase:

$$k_{rw} = \sqrt{S_w^*}\;S_w^3$$

This equation is valid for both the imbibition and drainage processes

- For non-wetting phase:

  a) Imbibition

$$(k_r)_{nonwetting} = \left[1-\left(\frac{S_w - S_{wc}}{1-S_{wc}-S_{nw}}\right)\right]^2$$

b) Drainage

$$(k_r)_{nonwetting} = (1 - S_w^*)\left[1 - (S_w^*)^{0.25}\sqrt{S_w}\right]^{0.5}$$

where S_{nw} = saturation of the nonwetting phase
S_w = water saturation
S_w^* = effective water saturation

4. <u>Corey's Method</u>

- For wetting phase:

a) Drainage

$$k_{rw} = (S_w^*)^4$$

b) Imbibition

$$k_{rw} = (S_w^*)^4_{imb}$$

- For non-wetting phase:

a) Drainage

$$\mathbf{k_{rnw} = (1\text{-}S^*_w)^3\,[1+2(S^*_w)]}$$

b) Imbibition

$$\mathbf{k_{rnw} = 1 - \frac{S_w - S_{wc}}{1 - S_{wc} - S_{nw}}}$$

where $\mathbf{(S^*_w)_{imb} = (S^*_w)_{drain} - 0.5(S^*_w)^2_{drain}}$

- For gas-oil system under drainage process:

$$\mathbf{k_{ro} = (1\text{-}S^*_g)^4}$$

$$\mathbf{k_{rg} = (S^*_g)(2 - S^*_g)}$$

2.7 ANGSI I-35 RESERVOIR

In this project, data from Angsi reservoir is used as input for the ECLIPSE simulation. Before detailed study is conducted, it is very important to know the location of the reservoir as well as the aerial distribution of the hydrocarbon-bearing.

Generally, this reservoir is part of the Angsi sub-block, which is located 170 km north northeast of the Onshore Slug Catcher (OSC). This is off the East Coast of Peninsula Malaysia in the South China Sea where the water depth is about of 69m mean sea level. Geologically, the field is located in the southern region of the Malay basin. The Angsi Field has five areas, Main, West, North, South and Southwest, as shown in Figure 10 below. The aerial distribution of the hydrocarbon-bearing reservoirs is the basis for these areas.

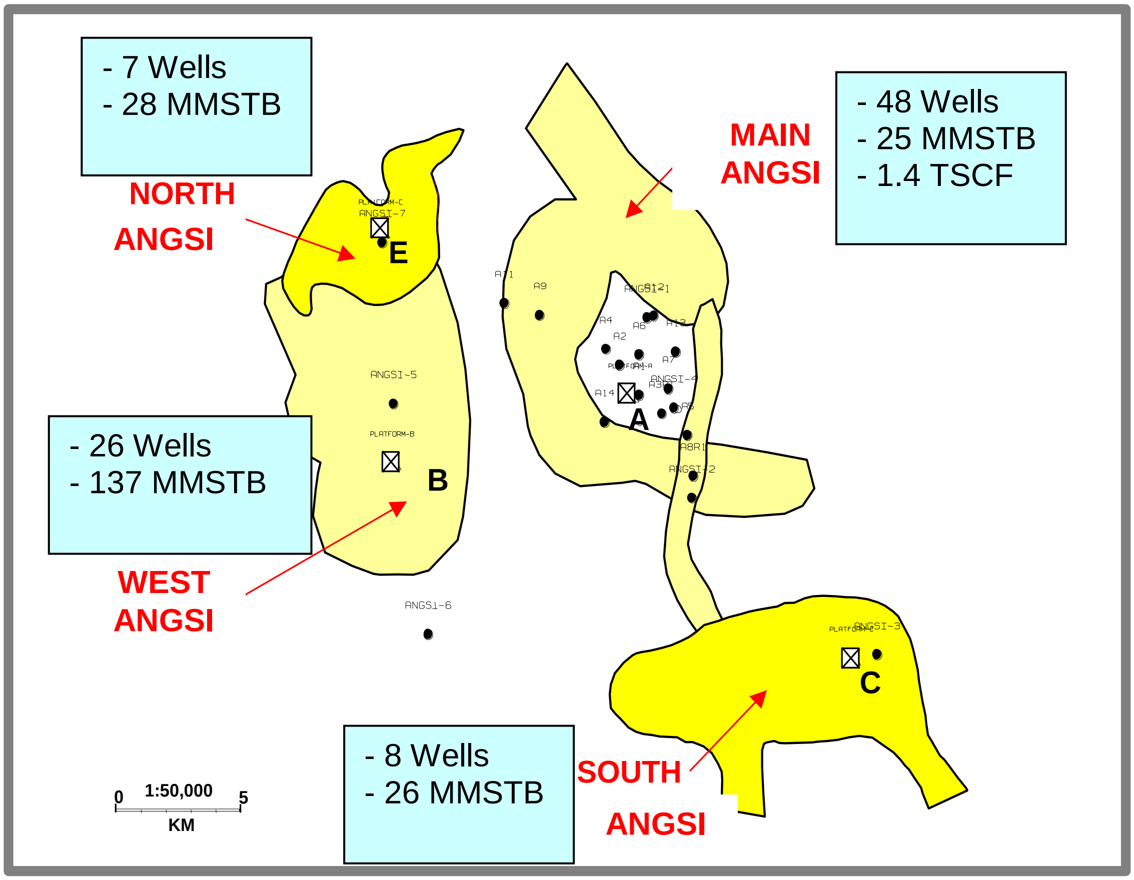


Figure 10: Angsi field area subdivision

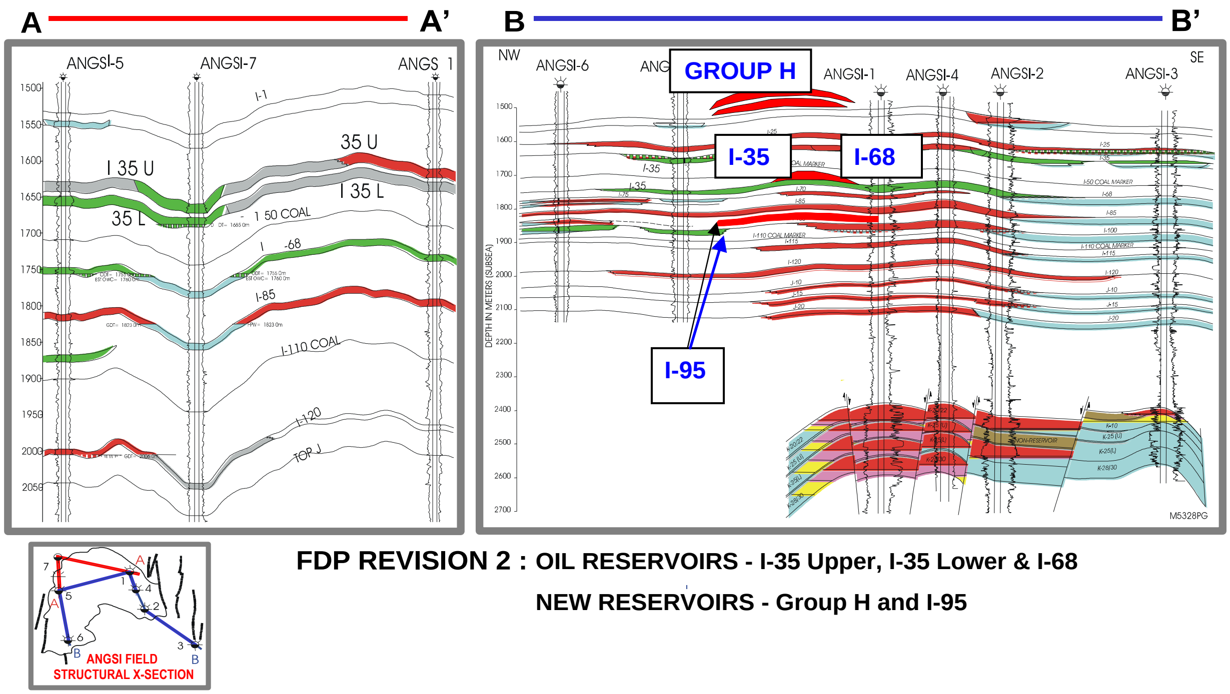


Figure 11: Field stratigraphy

Commercially viable hydrocarbon accumulations occur within Groups K, J, I and H of the field. Volumetrically, the major gas-bearing reservoirs are the K-sands (K-20/22, K-25 U/L, K-28/30/35), I-100, I-85 and I-1, sandstones while the major oil-bearing reservoirs are I-35 and I-68 sandstones. The Group H and I-95 sandstones are significant gas-bearing reservoirs.

2.7.1 I-95 Sandstone

It has an average net-sand thickness of 6.0m and porosity range from 14 to 20 percent. Analysis on the log motif indicated that the reservoir deposition could be near coastal plain possibly in a tidal environment. The net sand trend of the reservoir indicates that the sand thickens toward the western area of the field.

2.7.2 I-68 Sandstone

I-68 reservoir shows net-sand thickness varying from 4 to 6m. Overall, the I-68 reservoir has an average net-sand thickness of 5m and average porosity of 20 percent.

2.7.3 I-35 Sandstone

I-35 sandstone consists of meandering channels and point bars. These restricted deposits form a combination of structural and stratigraphic traps. Reservoir thickness and porosity ranges from 12 to 15m and from 18 to 28 percent respectively within the point bars.

2.7.4 Group H Reservoirs

The Group H reservoir is Middle Miocene in age and it is the shallowest hydrocarbon-bearing reservoir discovered in the Angsi Field to-date. The reservoir development is poor to fair and ranges from 1.0 to 10.0 m in thickness. The Group H reservoirs are gas bearing in the Main Angsi area.

a) H-20: The H-20 reservoir development occurs within the structural crest in the Main area. The reservoir net-sand thickness ranges from 5.0 to 9.0m with average porosity ranges from 18 to 26 percent.

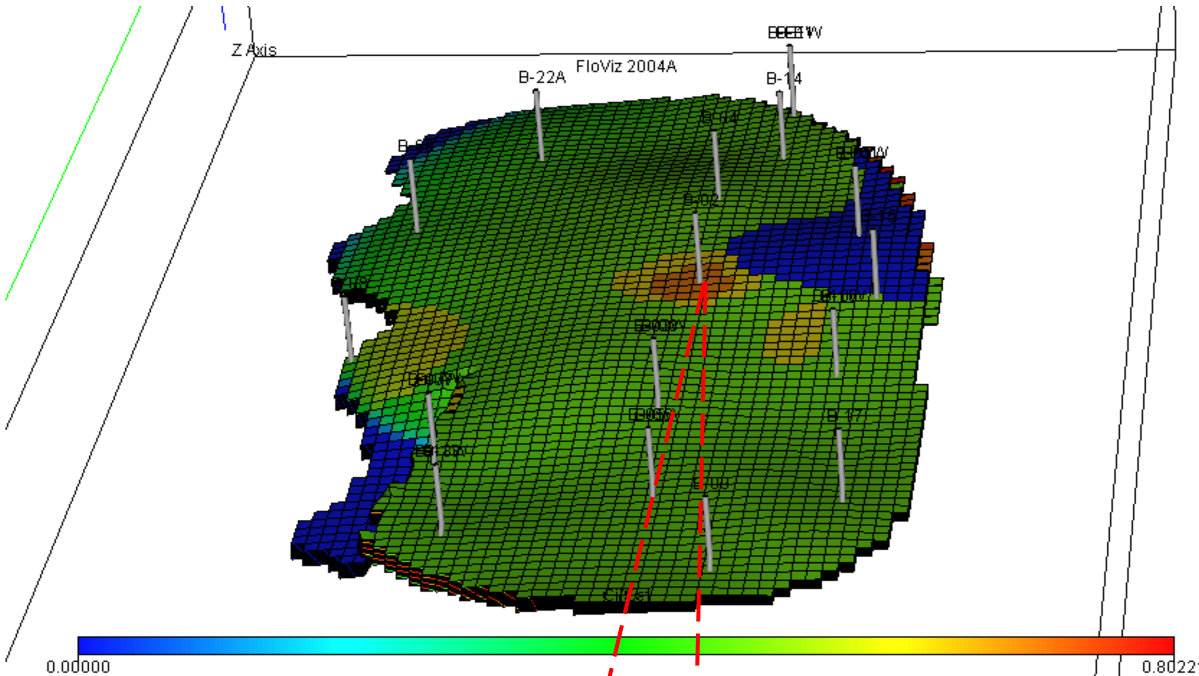
b) H-50: The H-50 reservoir is developed well only at the A-02 and A-09 well locations. Logs from A-09 well show the thickest part of its net sand to be 9.0m. Based on the restricted nature of the reservoir distribution; the interpretation is that the reservoir could possibly be a channel deposit.

c) H-60: The H-60 reservoir development occurs within the structural crest of the Main area. The reservoir net-sand thickness ranges from 3.0 to 6.0m with average porosity ranges from 20 to 24 percent.

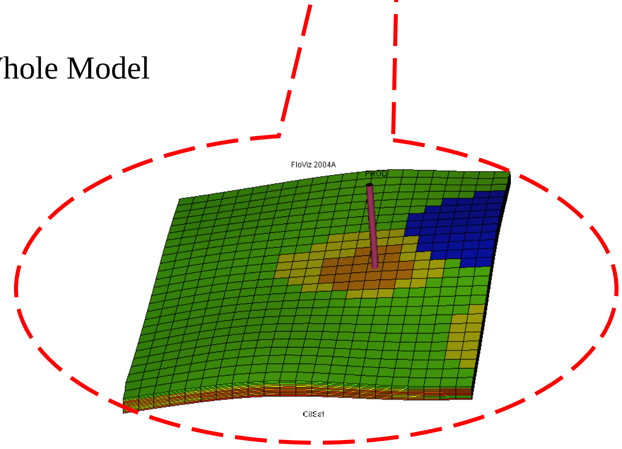
d) H-80: The H-80 reservoir development is within the crest part of Main Angsi structure. The reservoir net-sand thickness ranges form 2.0 to 8.0m with average porosity ranges from 20 to 28 percent.

e) H-90: The H-90 reservoir development is poor consisting of inter-bedded sand within thin coal streaks. The H-90 reservoir average porosity and net-sand thickness ranges from 16 to 22 percent and from 1.0 to 4.0m respectively.

From the explanation above, it can be deduced that the main oil-bearing is accumulated at I-35 and I-68 reservoirs. Among these reservoirs, only I-35 reservoir which has a dimension of 24903ft x 41293ft x 66ft is considered in this study. For simplification of the simulation process, the model is discrete into 7209ft x 8521ft x 66ft (22 x 26 x 11 grid blocks) so that the effect of hysteresis can be easily observed. This is also to avoid errors that can affect the results obtained.



(a) Angsi I-35 Reservoir Whole Model



(b) Angsi I-35 Reservoir Chopped Model

Figure 12: Angsi I-35 Reservoir Models

CHAPTER 3:
METHODOLOGY

3.1 TUTORIALS

Since this project is related to the simulation-based approach, therefore some tutorials need to be conducted in order to familiarize with the software. These tutorials mainly focused on adjusting the values that associated with the reservoir properties such as permeability, water injection rate and time steps to see which adjustments have greater impact in the oil production. After that, the results will be analyzed and compared with the base case. For these tutorials, the models used principally have the dimension of 5 x 5 x 5 grid blocks. Figure 12 below shows the example of the conceptual model used for the tutorial purposes.

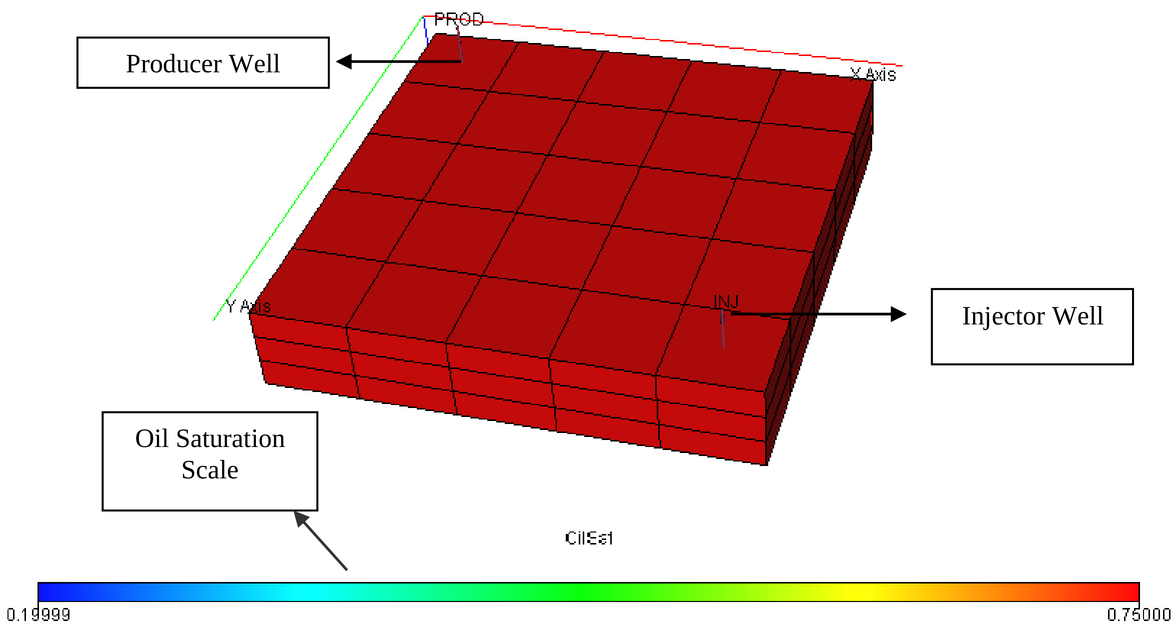


Figure 13: Conceptual model for tutorials

3.1.1 Base case

At first, the simulation is done based on the values given in the task. This is actually to give a basic idea on ECLIPSE simulation. The examples of input data of the simulation are summarized below (Refer Appendix C for the full input data):

Table 3: Input data for ECLIPSE simulation

Data	**Values**
1. Reservoir dimension	2500’ x 2500’ x 150’
2. Number of layers	3 (equal thickness for each layer)
3. Number of cells in x and y directions	5 cells for each direction
4. Number of producer and injector	1 well for each type
5. Permeability • x-direction • y-direction • z-direction	 • 200mD for 1st and 3rd layers and 1000mD for 2nd layer • 150mD for 1st and 3rd layers and 800mD for 2nd layer • 20mD for 1st and 3rd layers and 100mD for 2nd layer
6. Production gross rate	10 000 stb liquid/day
7. Water injection rate	11 000 stb water/day
8. Time steps	10 time steps of 200 days each

The required output from the simulation is Total Field Oil Production (FOPT) which is discussed in the Result and Discussion part.

After the base case is completely done, the task is then focused on manipulating the values of some input data such as permeability in x-direction, time steps and water injection rate.

3.1.2 Permeability in x-direction

Previously in the first tutorial, the permeability in x-direction is 200mD for 1^{st} and 3^{rd} layers and 1000mD for 2^{nd} layer. Then, for the second tutorial, the permeability in x-direction is changed to:

(i) 200mD for 1^{st} and 2^{nd} layers and 1000mD for 3^{rd} layer

(ii) 1000mD for 1^{st} layer and 200mD for 2^{nd} and 3^{rd} layers

3.1.3 Water injection rate

In the first tutorial, the water injection rate used is 11 000 stb water/day. Then in the second tutorial, the water injection rate is reduced to 8000 stb water/day.

3.1.4 Time steps

In the first tutorial (base case), the time steps used in the simulation is 10 time steps of 200 days each (total of 2000 days). Then, the time steps are adjusted to two different values in the second tutorial which are:

(i) 15 time steps of 200 days each (total of 3000 days)

(ii) 20 time steps of 200 days each (total of 4000 days)

3.2 OPTIMIZATION ON THE WAG PARAMETERS

After being familiarize with the simulation, the project then focuses on the use of real data which is from Angsi reservoir. At this stage, all WAG parameters i.e. WAG injection rate, WAG cycle and WAG ratio will be optimized in order to get the maximum oil production. This stage is very important in order to find the optimum value for each parameter before proceeding with the next stage which is to analyze the hysteresis effect in the WAG process. For that purpose, some sensitivity studies are carried out using some reasonable values to be put for each parameter tested. It should be reminded that the WAG injection rate need to be determined first followed by WAG cycle and then WAG ratio. As has been mentioned earlier for simplification purposes, the Angsi reservoir model is discrete into 22 x 26 x 11 grid blocks.

3.2.1 WAG injection rate

The focus of this study is to evaluate the effect of WAG injection rate on the recovery factor and the pore volume (PV) injected. Generally, the PV injected should be equal or more than 1.0 so that the residual oil which remains trapped in a porous rock after the rock has been swept with water or gas can be reduced. When PV injected is higher, that means the sweep efficiency is also higher and this will lead to increase in oil recovery. PV injected is determined based on the following equation.

$$\text{PV injected} = \frac{\text{Field Reservoir Volume Injection Total (FVIT)}}{\text{Total Pore Volume (PORV)}} \qquad (2)$$

**Pore volume (PORV) in Angsi field reservoir is 131,118,041 res bbl*

The water and CO_2 gas injected into the Angsi model have surface density of 63.6727 lb/ft^3 and 0.0573 lb/ft^3, respectively. For this study, both water and gas are injected with the same rate for each case. Four cases with different injection rates – 12000 stb/day and 12000 Mscf/day, 13000 stb/day and 13000 Mscf/day, 14000 stb/day and 14000 Mscf/day and 15000 stb/day and 15000 Mscf/day are simulated. The optimum WAG injection rate from this study will be used for the subsequent simulations.

3.2.2 WAG cycle period

WAG cycle is actually the duration where the fluids (water and gas) injected into the reservoir are being changed alternately. The relations between varying this cycle period with the recovery factor are observed and the optimum period is determined. For this purpose, four different values of WAG cycle are used, which are 6 months, 1 year, 2 years and 3 years.

3.2.3 WAG ratio

WAG ratio is the volume ratio between water and gas that are injected into the reservoir. In this study, the effects of varying the WAG ratio on the recovery factor are evaluated and the optimum value of the WAG ratio is recognized. Here, both water and gas injection rates are varied according to their ratio. Water injection rates are varied when the ratios are 1.7:1 and 2.3:1 meanwhile the gas injection rates are varied for 1:1.3 and 1:1.7 ratios. Basically, the WAG ratio is determined by using the following equation:

$$WAG\_ratio = \frac{Q_w \times B_w}{Q_{CO_2} \times B_{CO_2}} \qquad (3)$$

where
Q_W = water injection rate
Q_{CO2} = CO_2 injection rate
B_w = water formation volume factor (1.0447 res bbl/stb)
B_{CO2} = CO_2 formation volume factor (0.9 res bbl/Mscf)

The WAG cycle period for all cases used in this study is taken from the previous study.

3.3 CONSIDERATION OF HYSTERESIS

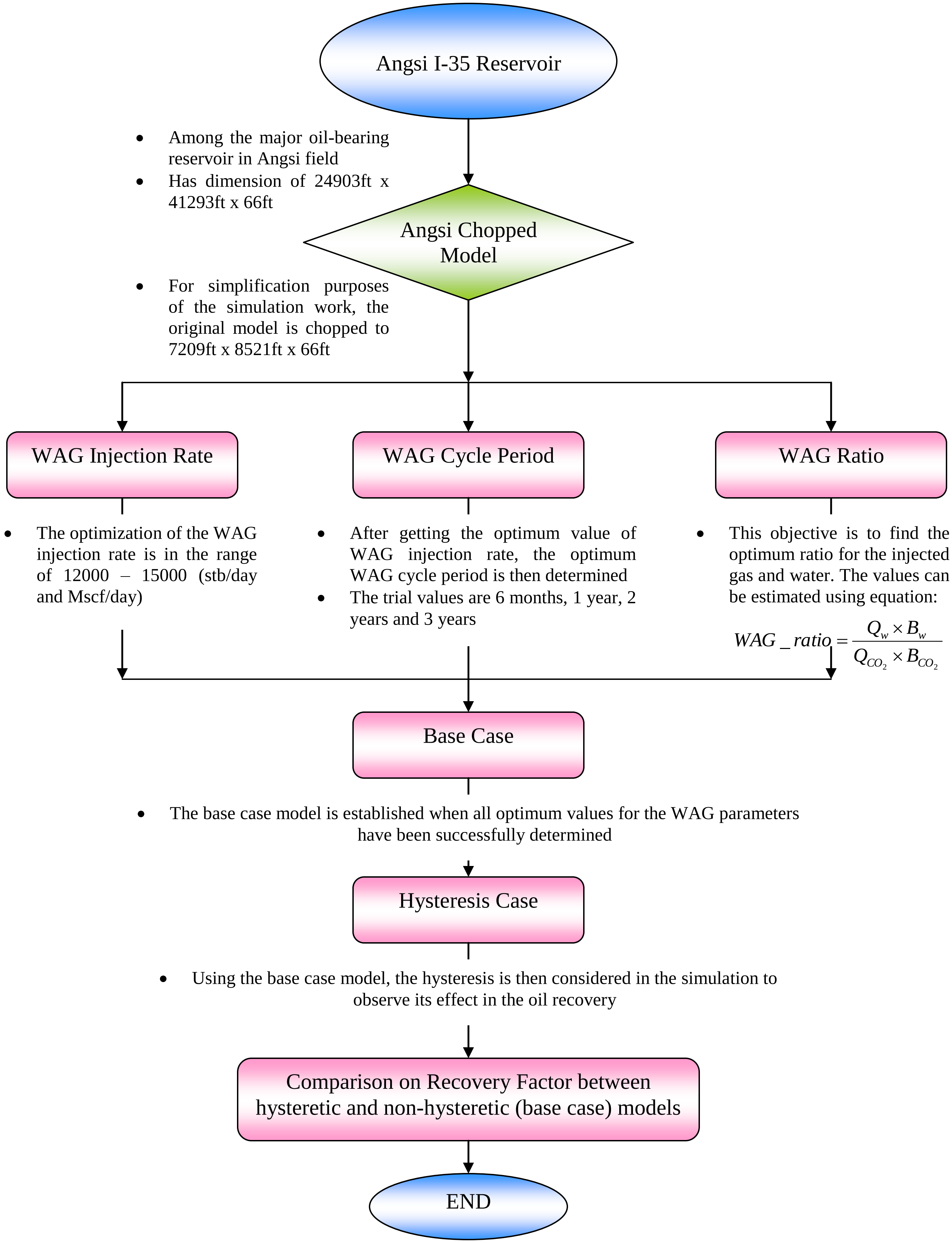
The project actually has come to the final stage when the hysteresis is considered in the simulation to see the final result either this consideration helps to increase the oil prediction or not. This stage is accomplished by simply put the keyword “HYSTER” in the datafile and change the “SWOF” (Water/oil saturation functions versus water saturation) and “SGOF” (Gas/oil saturation functions versus gas saturation) tables to

“SWFN” (Water saturation functions), “SGFN” (Gas saturation functions) and “SOF3” (Oil saturation functions for three-phase) tables by using Pirson’s and Corey’s correlations (please refer Literature Review part to see these correlations). These tables need to be developed as it is a requirement for the hysteresis keyword to be run in the ECLIPSE simulation (please refer Appendix B to see SWFN, SGFN and SOF3 tables).

After running the simulation, the result obtained is analyzed. The Recovery Factor (FOE) vs. Pore Volume (PV) injected graph for hysteretic and non-hysteretic models is drawn to compare both models. Also, for better understanding on hysteresis phenomenon as well as to see how Angsi Field reservoir is characterized as a water-wet system , the Relative Permeability Curve is drawn which basically uses the values from SWFN and SOF3 tables. These graphs can be seen in Result and Discussion part.

3.4 TOOLS/EQUIPMENT REQUIRED

In this project, the main tool used is ECLIPSE Black Oil Reservoir Simulator since most of the project tasks are based on the simulation work. However, Microsoft Excel will be used as well to plot the graph to compare the results obtained.


Angsi I-35 Reservoir
Among the major oil-bearing reservoir in Angsi field
Has dimension of 24903ft x 41293ft x 66ft
Angsi Chopped Model
For simplification purposes of the simulation work, the original model is chopped to 7209ft x 8521ft x 66ft
WAG Injection Rate
WAG Cycle Period
WAG Ratio
The optimization of the WAG injection rate is in the range of 12000 – 15000 (stb/day and Mscf/day)
After getting the optimum value of WAG injection rate, the optimum WAG cycle period is then determined
The trial values are 6 months, 1 year, 2 years and 3 years
This objective is to find the optimum ratio for the injected gas and water. The values can be estimated using equation:
$WAG\_ratio = \frac{Q_w \times B_w}{Q_{CO_2} \times B_{CO_2}}$
Base Case
The base case model is established when all optimum values for the WAG parameters have been successfully determined
Hysteresis Case
Using the base case model, the hysteresis is then considered in the simulation to observe its effect in the oil recovery
Comparison on Recovery Factor between hysteretic and non-hysteretic (base case) models
END

CHAPTER 4:
RESULT AND DISCUSSION

4.1 TUTORIALS

4.1.1 Base case

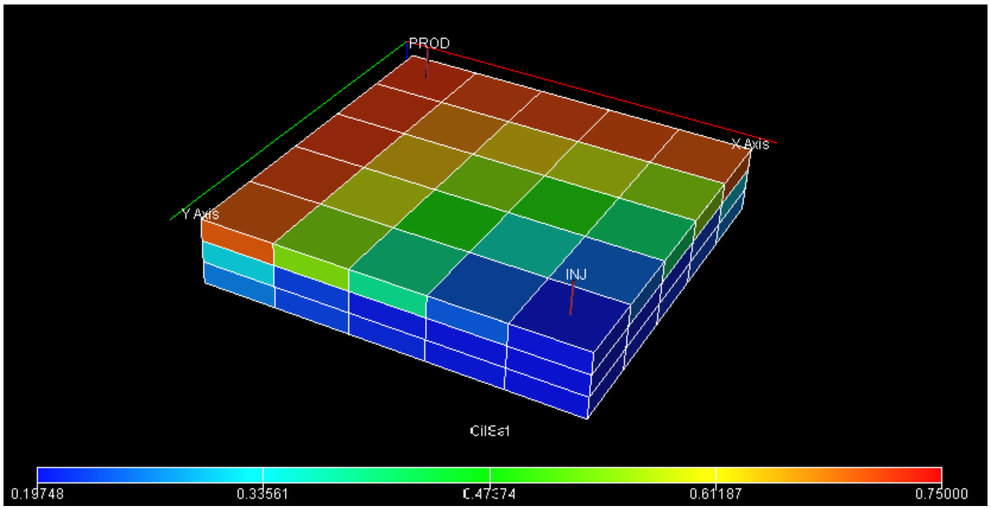


Figure 14: ECLIPSE Model after water injection (Base Case)

4.1.2 Permeability in x-direction

(i) 200mD for 1st and 2nd layers and 1000mD for 3rd layer

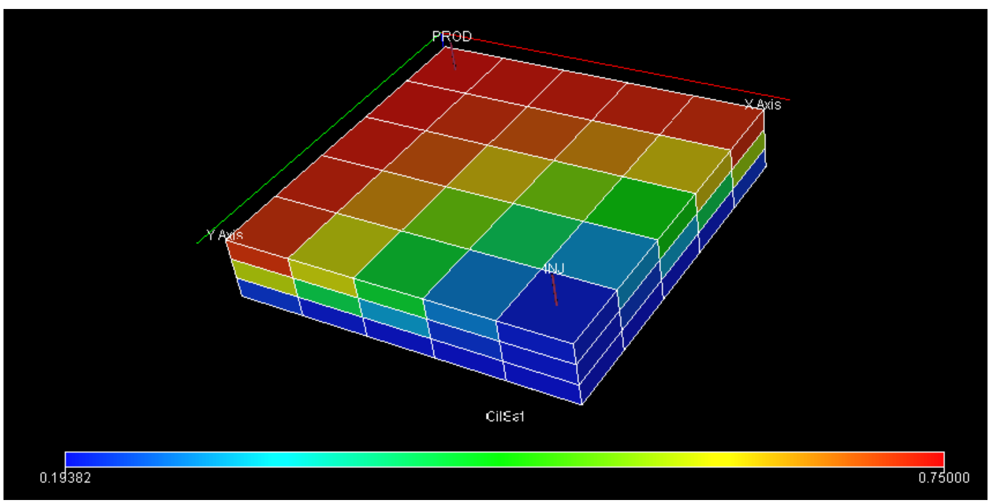


Figure 15: ECLIPSE Model after water injection (Perm-x: 200_200_1000)

(ii) 1000mD for 1st layer and 200mD for 2nd and 3rd layers

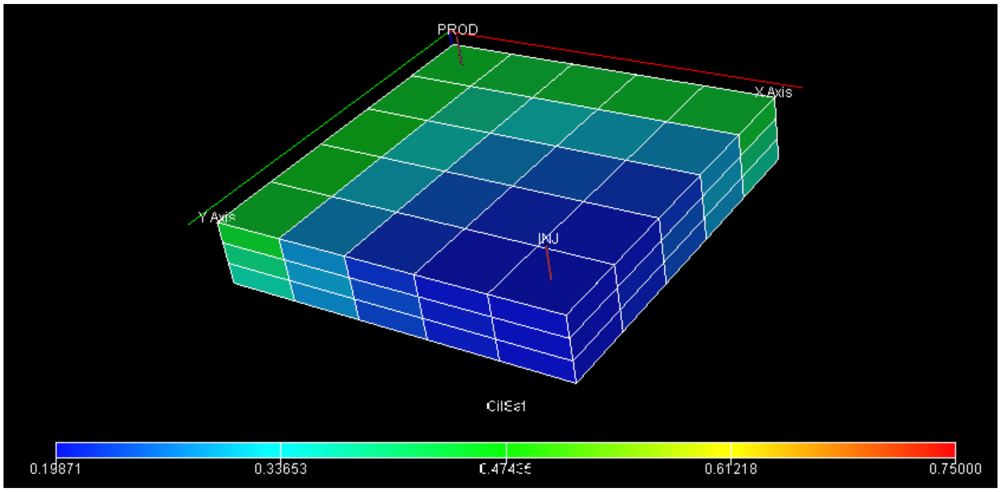


Figure 16: ECLIPSE Model after water injection (Perm-x: 1000_200_200)

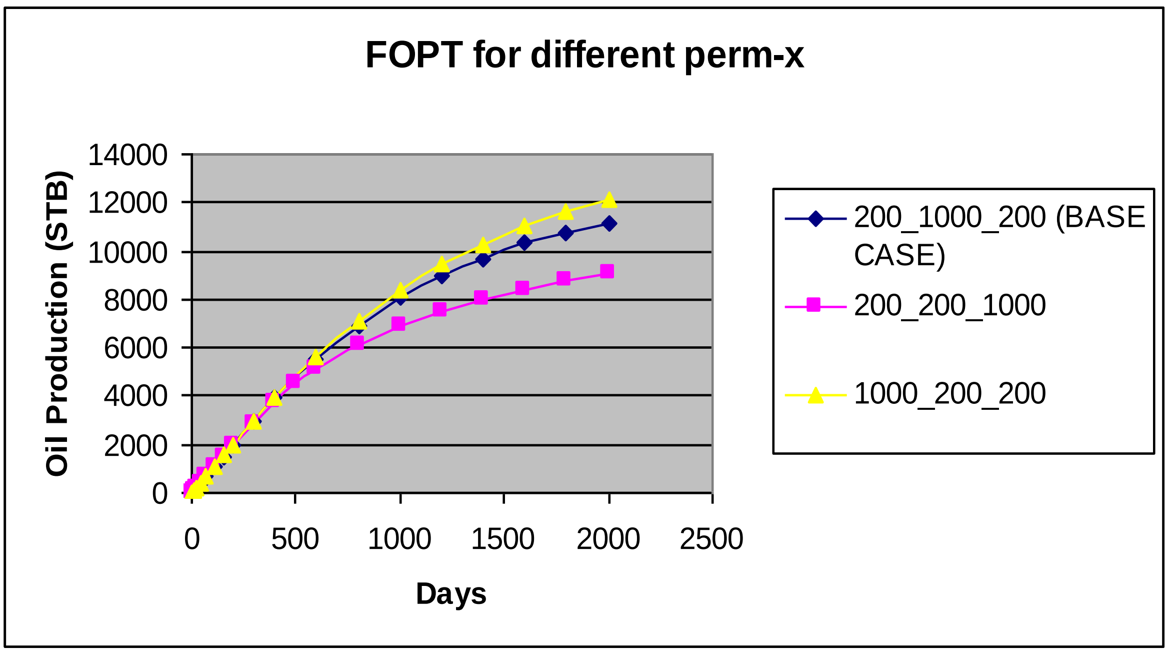


Figure 17: Total Field Oil Production (FOPT) for different permeability in x-direction

Based on the ECLIPSE Models after water injection (i.e. Figure 14, 15 and 16), it is clearly shown that most oil in Figure 16 (i.e. perm-x is the highest at the top layer) has been swept out to the Producer Well compared to Figures 14 and 15 (Refer the scale below each model to analyze the oil saturation in the reservoir – red colour has the highest oil saturation meanwhile blue colour has the lowest oil saturation). This is because, since the permeability is the highest at the top layer, therefore, the oil will be swept faster compared to the other layer. However, because of the gravity effect, the water will go down to the other layers and sweep the oil at those regions too. Therefore, the oil in the second and third layers will be recovered as well as the first layer. This will give better recovery.

In Figure 15, the oil recovery is not as efficient as in Figure 16 because the highest permeability is at the bottom. Although the bottom layer permits better sweep efficiency, but since the gravity is already acting at this region, therefore the oil in the other layers will not be swept. Thus, more oil has been ignored and not been recovered.

Among all layers, the one that gives maximum oil production is when the highest permeability is located at the top layer. This difference can be observed in Figure 17.

4.1.3 Water injection rate

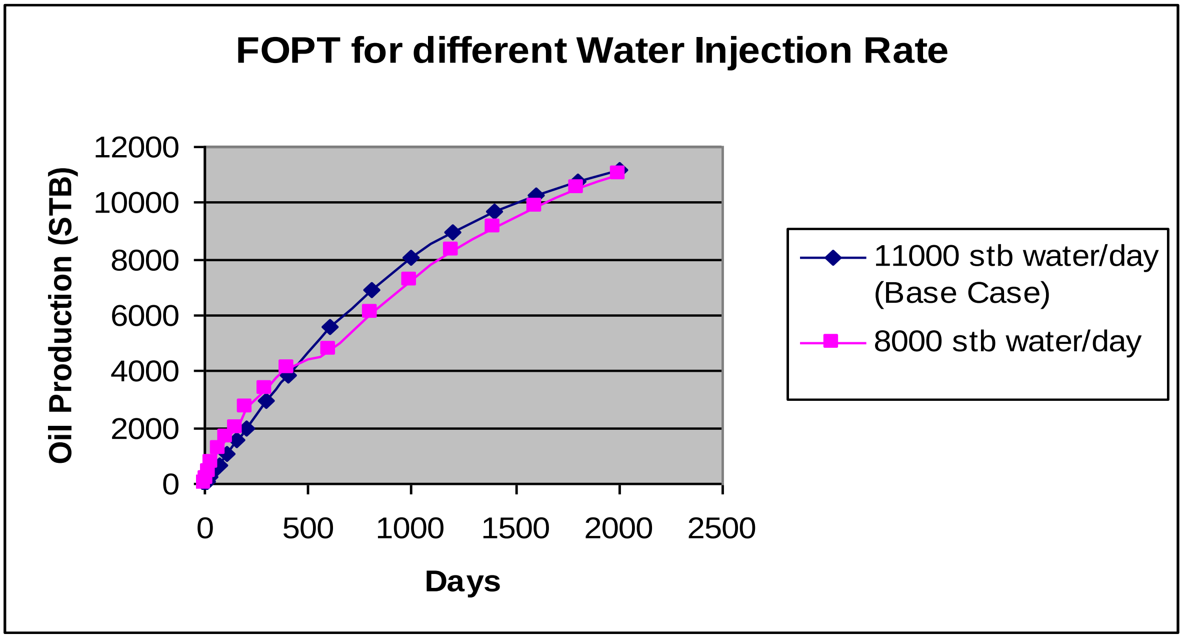


Figure 18: FOPT for different water injection rate

Figure 18 demonstrates that different water injection rate will give different oil production. Injecting 11000 stb water/day will give higher oil recovery rather than 8000 stb water/day. This is because higher injection rate means the oil is swept faster than if using lower injection rate.

However, it should be reminded that this is valid for short interval time only. For longer interval time, the lower injection rate will give better oil recovery since the lower injection rate will slowly going to all regions in the reservoir and sweep the oil to the Producer Well. If higher injection rate is used, the water will not cover the other regions in the reservoir since it goes directly to the Producer. Because of this, the water breakthrough will be experienced faster in the Producer. In other words, there is an optimum value for the water injection. Please refer Figures 19 and 20 below to see the difference in Well Oil Production Rate (WOPR) as well as Well Water Cut for Producer (WWCT) using 11 000 stb water/day and 8000 stb water/day for 5000 days.

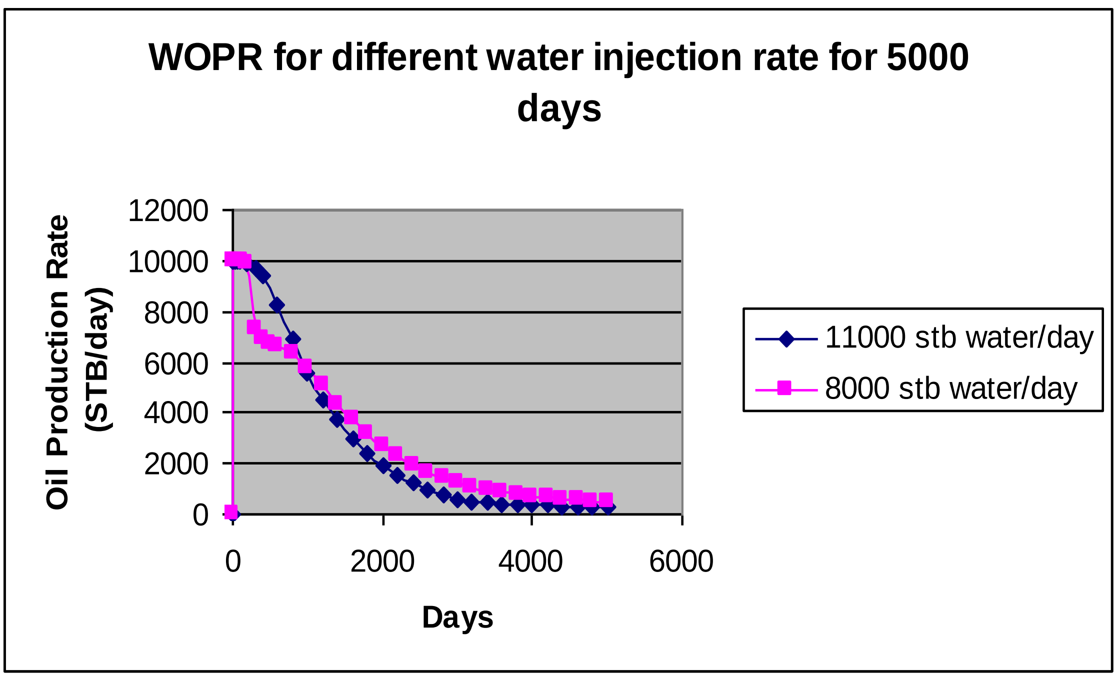


Figure 19: WOPR for different water injection rate for 5000 days

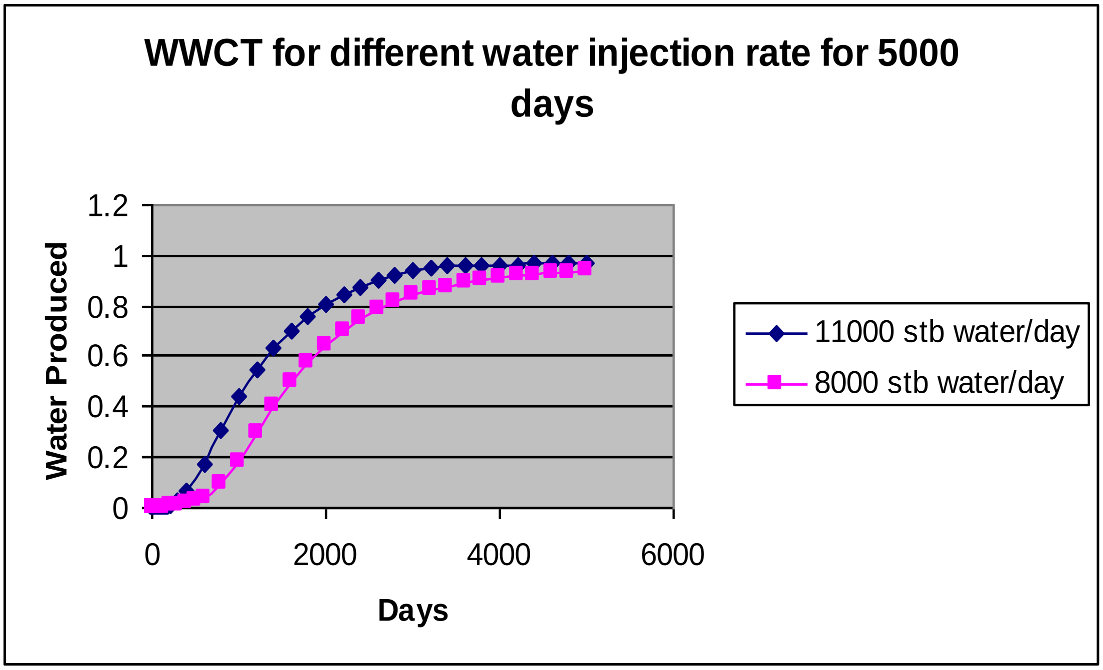


Figure 20: WWCT for different water injection rate for 5000 days

In Figure 19, at the end of 5000 days, lower injection rate gives greater oil recovery compared to higher injection rate. Meanwhile in Figure 20, the Producer Well will experience higher amount of water cut when 11 000 stb water/day is used compared to if 8000 stb water/day is used.

4.1.4 Time steps

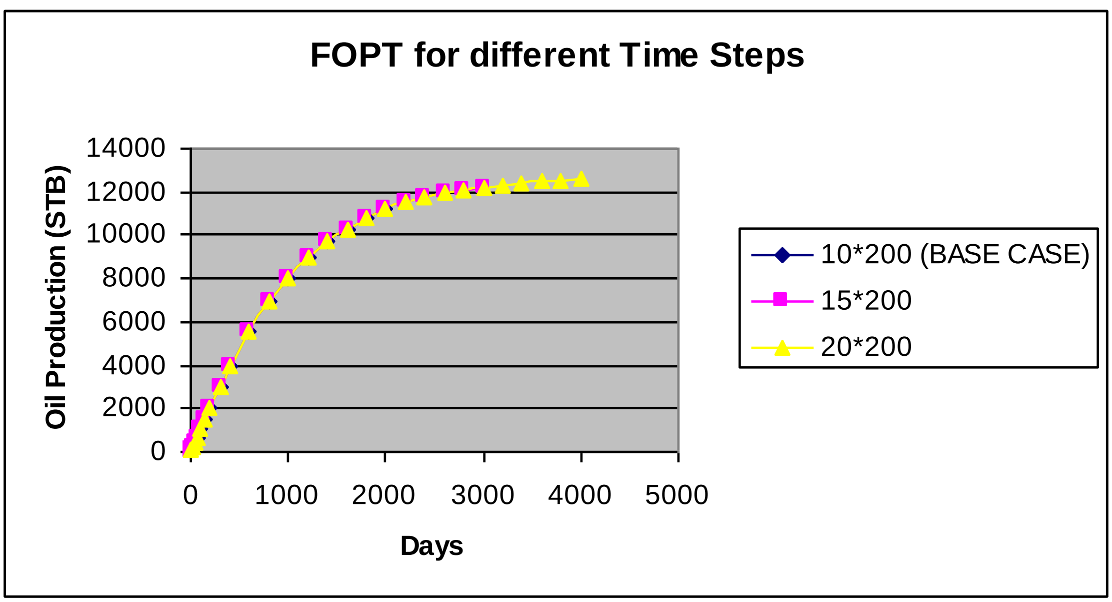


Figure 21: FOPT for different time steps

Time step is actually an interval time used to observe the oil production in certain reservoir. Basically, it has no effect in improving the oil recovery as it only shows the production profile. The longer the time step means the longer the oil production profile.

Based on Figure 21, it shows that there is no difference in oil recovery since all plots are overlapped on each other. The only difference is just the 20*200 time steps (4000 days) has longer production profile compared to 15*200 (3000 days) and 10*200 (2000 days). Hence, it can be concluded that the oil recovery is insensitive with the time steps.

4.2 OPTIMIZATION ON WAG PARAMETERS

4.2.1 WAG injection rate

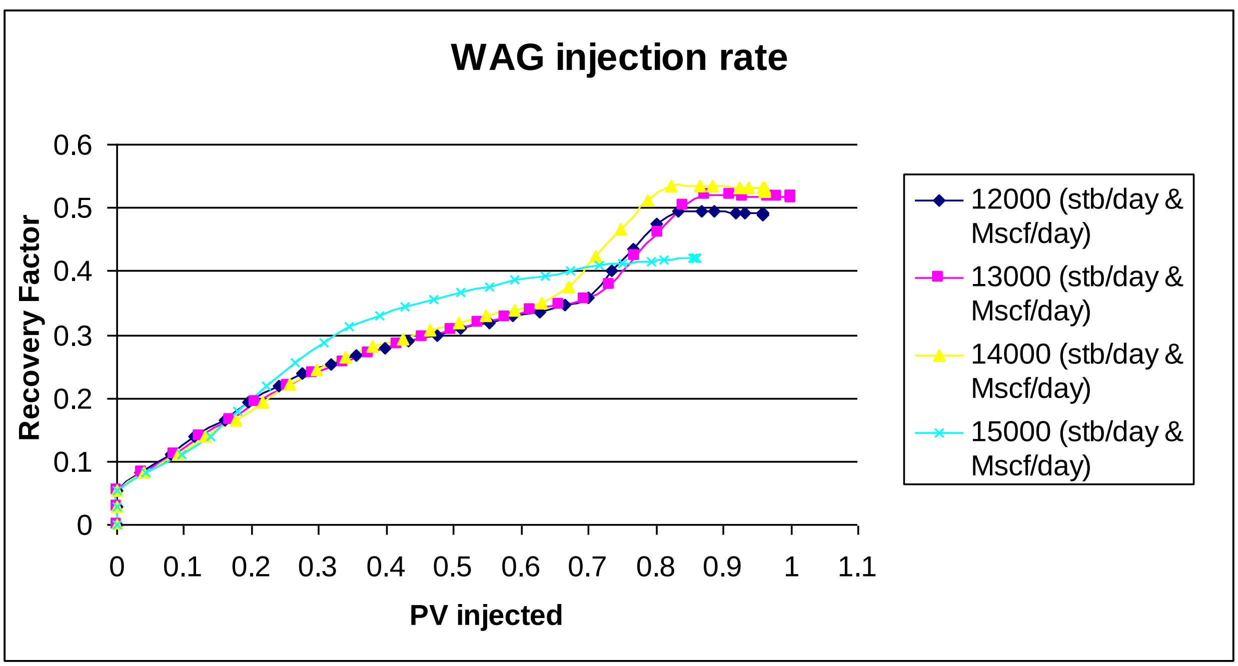
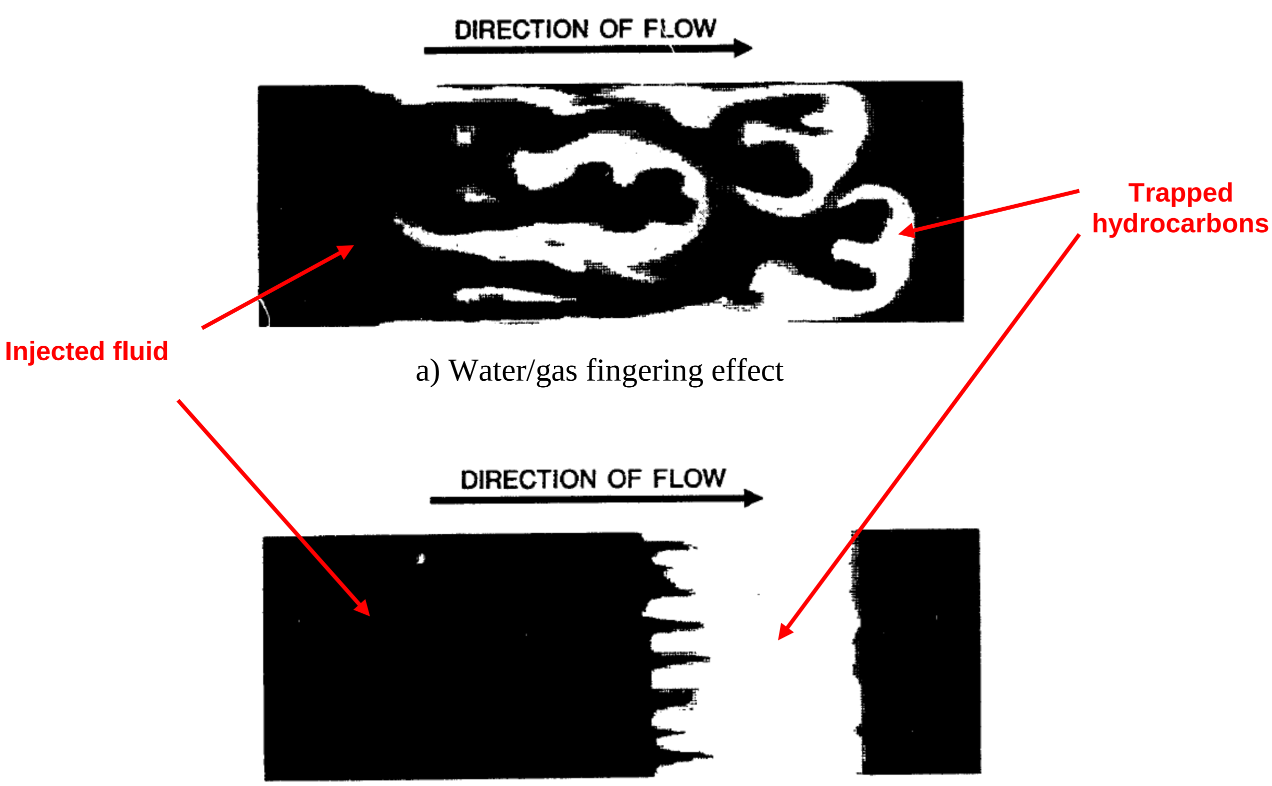


Figure 22: Recovery factor at various water/gas injection rate

According to Figure 22, it shows that the recovery factor is increasing with increasing water/gas injection rate which is from 12000 (stb/day and Mscf/day) until 14000 (stb/day and Mscf/day). However, when the injection rate used is 15000 (stb/day and Mscf/day), the recovery factor start to decrease. This result proves that "the increase of injection rate does not always lead to the total recovery improvement from the whole reservoir." This is because higher injection rate may ignore some residual oil in the rock and thus causes the oil not being recovered

When discussing about WAG injection rate, there are two possibilities that can occur. Firstly, when higher injection rate is used, the water/gas fingering effect can be observed to happen.



a) Water/gas fingering effect

b) Piston-like oil displacement

Figure 23: Type of oil displacements in reservoir

When higher injection rate is used, the water/gas molecules tend to choose the easiest path to flow. Therefore, they will probably go to the higher permeability zone in the reservoir, leaving the low permeability zone unswept. By referring to Figure 23 (a), there are some hydrocarbons (oils) trapped because of this fingering effect which leaves these oils being unswept/ not recovered. This phenomenon is highly undesirable because it leaves a large amount of trapped oil. The most desirable/ ideal oil displacement is shown in Figure 23 (b) whereby the oil is displaced like a piston which covers all regions that helps to reduce the unswept zone.

In contrast, when low injection rate is used, the gravity segregation of water will be experienced.

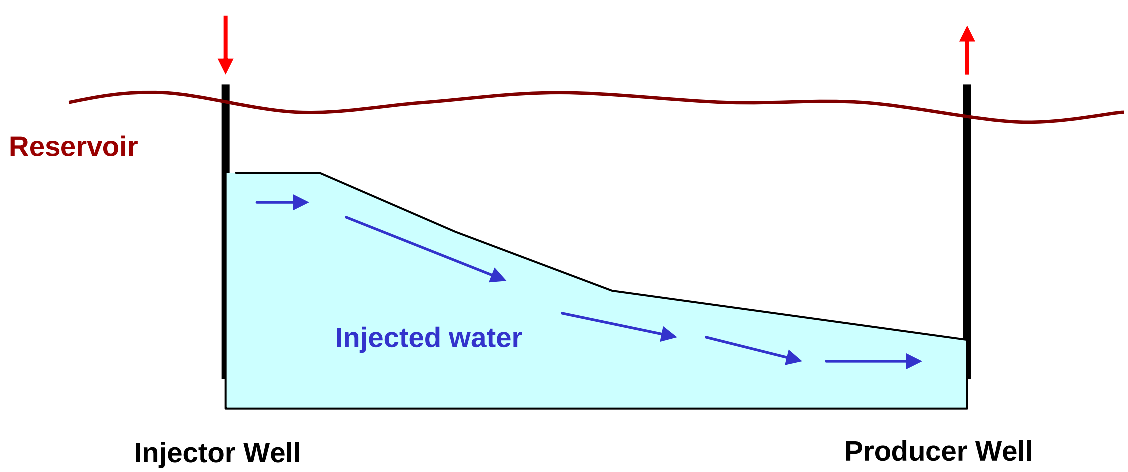


Figure 24: Gravity effect on injected water in the reservoir

Based on figure above, when low injection rate is used, the injected water tends to move downward of the reservoir because of the gravity effect as it has higher density compared to oil. This will lead to water breakthrough at the bottom of the Producer Well in a short term. This phenomenon is also highly undesirable because it may increase the cost of the oil production since water is produced together with the oil. Therefore, the optimum value of WAG injection rate needs to be carefully determined.

Among all values except for 15000 (stb/day and Mscf/day), the injection rate of 14000 (stb/day and Mscf/day) gives the highest recovery factor. However, the PV injected for this injection rate is less than 1.0. Thus, to find the optimum value of WAG injection rate, the PV injected should be equals or more than 1.0 and the recovery factor should be as high as possible. Because of that, the injection rate of 13000 (stb/day and Mscf/day) is chosen as the optimum value for WAG process in Angsi field reservoir. This value will be used for the next simulations which are to find the optimum value of WAG cycle and WAG ratio.

4.2.2 WAG cycle period

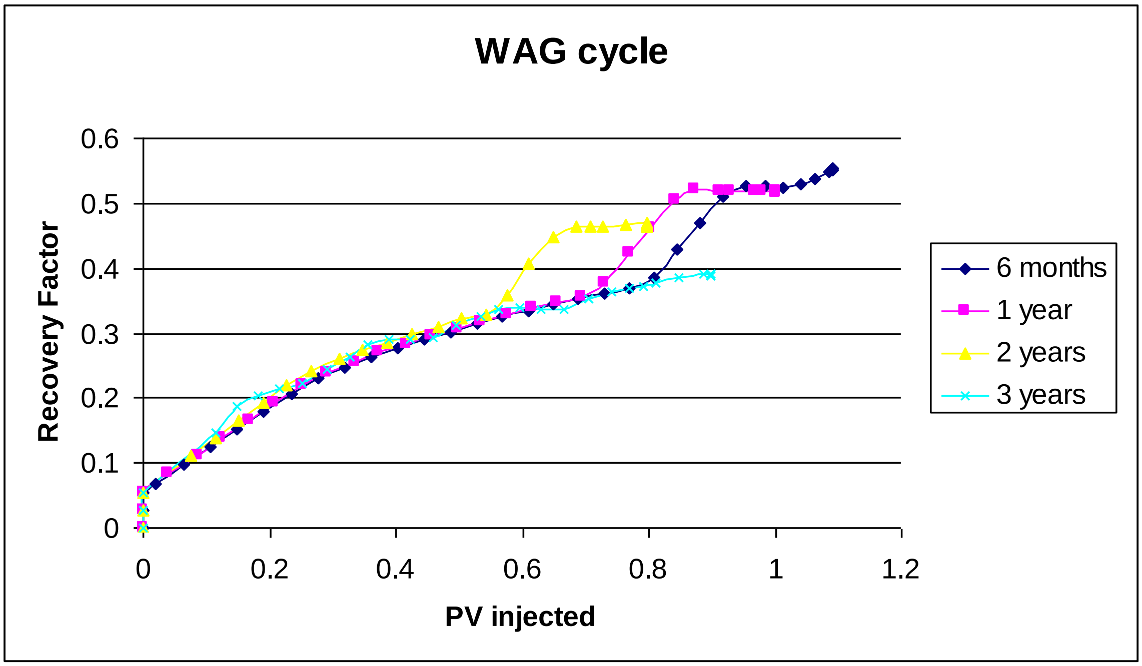


Figure 25: Recovery factor for different WAG cycle

As seen in Figure 25 above, the oil recovery seems to have large effect with the WAG cycle. Although the same amount of water and gas is injected into the reservoir for each cycle (WAG ratio = 1:1), but a shorter cycling period is more favorable compared to the longer one as it helps to reduce the gas production by controlling gas fingering and allowing better contact [4]. On the other hand, longer cycle period is said can enhance the occurrence and severity of gravity segregation of water. Hence, for this study, a WAG cycle period of 6 months is chosen as the optimum value and will be used in the subsequent simulations.

4.2.3 WAG ratio

By using equation (3), the ratio of the injected gas and water is determined. These values are shown in Table 4 below.

$$WAG\_ratio = \frac{Q_w \times B_w}{Q_{CO_2} \times B_{CO_2}} \qquad (3)$$

where Q_W = water injection rate

Q_{CO2} = CO_2 injection rate

B_w = water formation volume factor (1.0447 res bbl/stb)

B_{CO2} = CO_2 formation volume factor (0.9 res bbl/Mscf)

Table 4: WAG ratio based on water/gas injection rate

WAG ratio	Water injection rate (stb/day)	Gas injection rate (Mscf/day)
1:1	13000	13000
1.7:1	19500	13000
2.3:1	26000	13000
1:1.3	13000	19500
1:1.7	13000	26000

For 1.7:1 and 2.3:1 ratio, the water injection rate is varied meanwhile for 1:1.3 and 1:1.7 ratio, the gas injection rate is varied. The WAG cycle period used in this study is 6 months which is taken from the previous study.

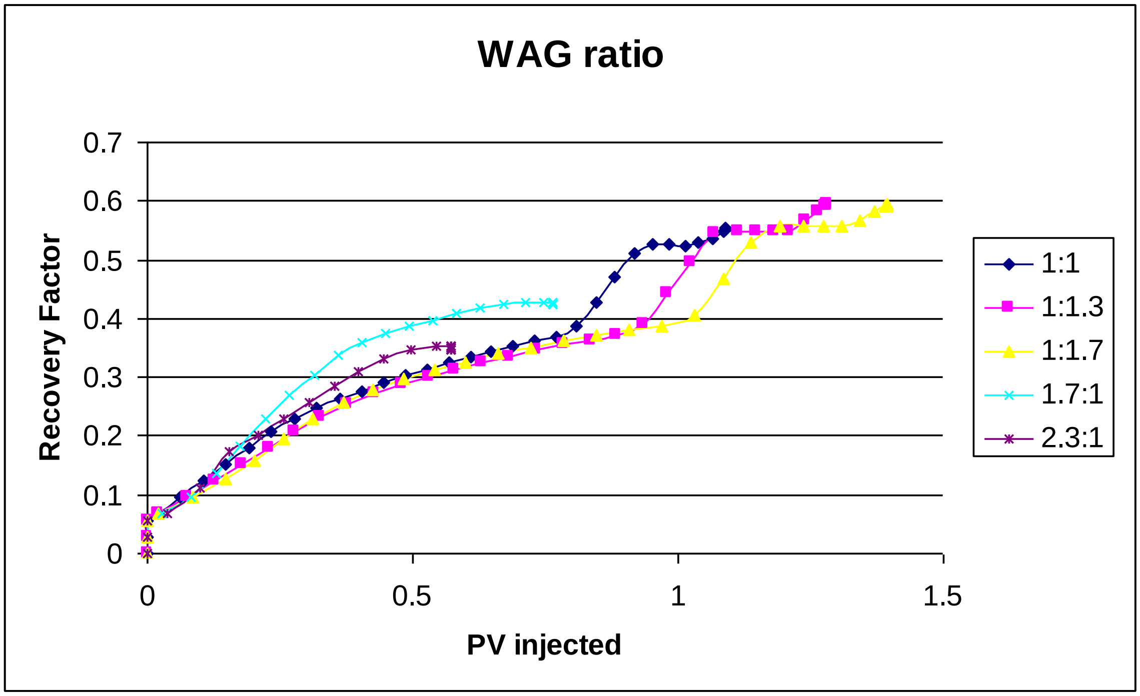


Figure 26: Recovery factor for various WAG ratios

From Figure 26, it clearly shows that when gas is varied during the WAG process, the recovery factor will increase. However, when water is varied, the recovery factor decreases rapidly.

Fundamentally, the higher the gas saturation prior waterflooding is preferable since it helps to trap large amount of gas. This gas trapping effect is a beneficial process because it reduces the gas permeability, hence helps in the reduction in gas mobility [22].

Based on Figure 26, although the ratio of 1:1.3 and 1:1.7 give the highest oil recovery, but since the ratio of 1:1 gives the highest recovery when PV injected = 1.0, therefore it is chosen to be the optimum WAG ratio for Angsi field reservoir. Even though the recovery factor of the WAG ratio of 1:1.3 does not differ much with the WAG ratio of 1:1 when PV injected = 1.0, it should be reminded that low injection rate of the gas is more desirable as it requires less facilities for the WAG process. This is because, if higher injection rate is used, some considerations need to be made such as the sufficient amount of CO_2 gas supply as well as the compressor duty to inject the gas into the reservoir. Therefore, the best ratio to be used is 1:1.

4.3 CONSIDERATION OF HYSTERESIS

4.3.1 Oil Recovery Factor for Hysteretic and Non-Hysteretic Models

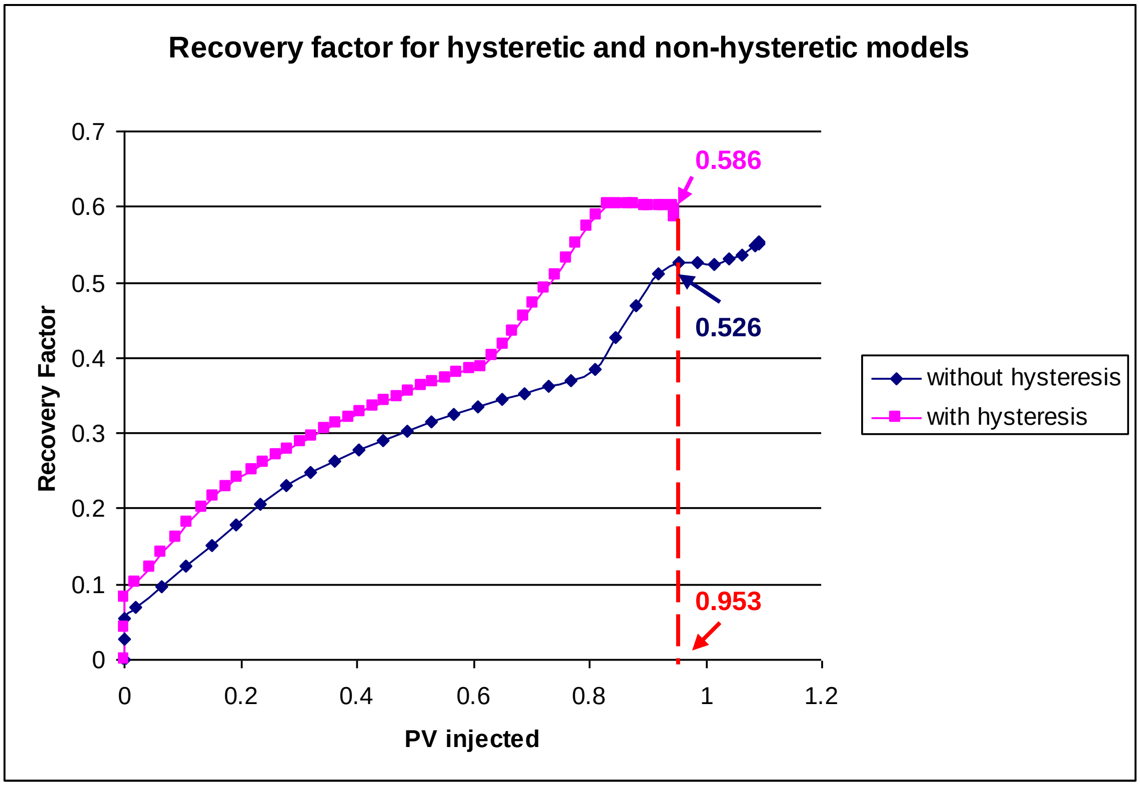


Figure 27: Recovery factor for hysteretic and non-hysteretic models

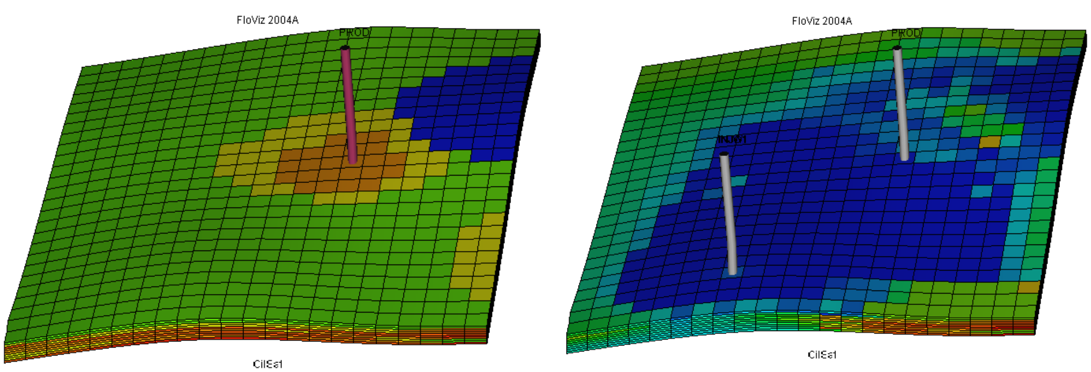
Based on Figure 27, it shows that the recovery factor is higher for hysteretic model compared to non-hysteretic model. For PV injected = 0.953, the recovery factor observed for hysteretic model is found to be 0.586 whereas for non-hysteretic model is about 0.526. The difference between these two values of recovery factor is about:

$$\text{Percentage increment} = \frac{\left[\begin{array}{c}\text{Recovery Factor for} \\ \text{hysteretic model}\end{array} - \begin{array}{c}\text{Recovery Factor for} \\ \text{non-hysteretic model}\end{array}\right]}{\begin{array}{c}\text{Recovery Factor for} \\ \text{non-hysteretic model}\end{array}} \times 100\%$$

$$= \frac{0.586 - 0.526}{0.526} \times 100\%$$

$$= 11.4\%$$

Even though the increment value for recovery factor is just 11.4%, it should be reminded that the simulation only focuses on a small portion from the whole Angsi reservoir. This chopped model is basically done to ease the simulation purposes. If the whole reservoir is considered in the simulation, definitely this value is high enough



(a) Before applying WAG injection (b) After applying WAG injection

Figure 28: Angsi Chopped Model

This increment is principally because of the WAG process itself whereby the water, due to its higher viscosity, tends to preferentially channel into the higher permeability channels of the reservoir, leading to screen off these better quality zones and selectively reduces the permeability to gas. Therefore, it is more difficult for the gas to displace the water from this zone and thus make the gas to be preferentially redirected into zones of lower permeability, which helps to improve the overall conformance and sweep efficiency. This phenomenon is basically happens because of hysteresis and mobility effects.

Basically, the reason why hysteresis should be or should not be considered in WAG simulation is because with ‘hysteresis’ keyword included in the simulation, it takes longer time for the simulation to work. Because of that, if the recovery factor is observed to increase significantly when hysteresis is considered, therefore it is worth for the operating company to do that as it helps to increase the oil prediction. If it is not really significant, therefore the hysteresis consideration can be ignored because more time can be saved.

It is very important for the operating company to carefully estimate the reserves in the reservoir because it may affect the design of the facilities involved during the oil production. Some of the design of the facilities that need to be considered are the diameter of the production tubing, the separator capacity, etc. If these facilities are underdesigned, it may cause some difficulties during the production process.

4.3.2 Relative Permeability Curve

As has been stated earlier, in WAG process, the drainage and imbibition processes happen when there is a reversal change in saturation. Drainage process is said to happen when the gas is displacing the water meanwhile the imbibition process happens when the water displacing the gas. When the water is displaced by the gas, its saturation is decreasing and vice versa. This closed loop mainly explained the hysteresis which can be illustrated by Figure 29.

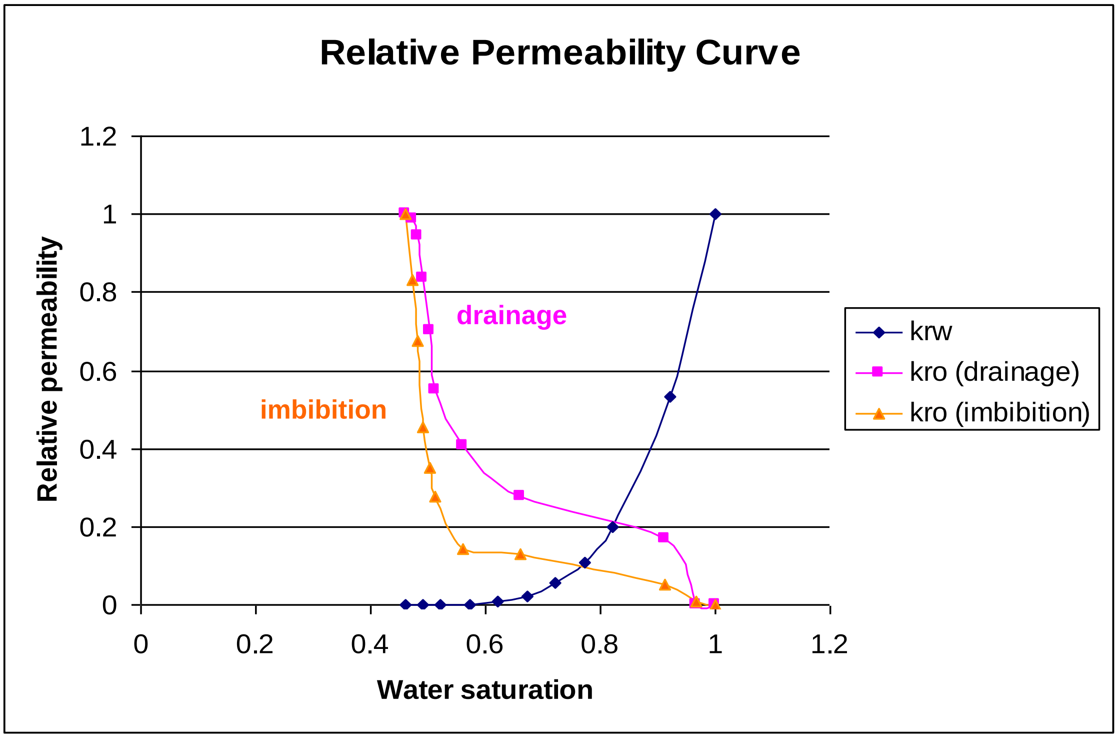


Figure 29: Relative Permeability Curve

Basically, there are some deviation patterns in figure above compared to the theoretical one (Figure 7) since the values used in this curve is generated from correlations explained in Literature Review part, thus it might have some inaccurate values. However, since these values are not the main focus in this study, therefore these values can be accepted. Based on the criteria explained in Table 1, it can be concluded that Angsi I-35 Reservoir is a water-wet type.

CONCLUSION

As a conclusion, it is clearly proved the conceptual study (Figure 2) that by considering hysteresis in WAG simulation, it helps to increase the oil recovery prediction as much as 11.4%. This is because hysteretic model accounts for the gas trapping effect during cyclic changes in saturation. The gas trapping effect is actually a beneficial process as it reduces the gas permeability, hence reduction in gas mobility. As a result, this will lead to better oil recovery.

Oil recovery by WAG injection is found to contact of unswept zones, especially recovery of attic or cellar oil by exploiting the segregation of gas to the top or the accumulating of water toward the bottom. Since the residual oil after gas flooding is normally lower than the residual oil after water flooding, and three-phase zones may obtain lower remaining oil saturation, WAG injection which is the combination of both methods has the potential for increased microscopic displacement efficiency. Hence, WAG injection can lead to improved oil recovery by combining better mobility control and contacting unswept zones, and by leading to improved microscopic displacement.

In order to recover more oil, all parameters involved in the WAG process need to be optimized. These parameters include WAG injection rate, WAG ratio and WAG cycle. For WAG injection rate, it does not necessarily to have greater value as higher injection rate may ignore some residual oil in the rock and thus causes the oil not being recovered. For WAG cycle period, it is believed that a shorter cycling period is more favorable compared to the longer one as it helps to reduce the gas production by controlling gas fingering and allowing better contact. On the other hand, longer cycle period is said can enhance the occurrence and severity of gravity segregation of water. From ECLIPSE simulation, it is found that the optimum value for WAG injection rate is 13000 (stb/day and Mscf/day) meanwhile the optimum WAG cycle is 6 months. Although high gas injection rate is preferable prior to water flooding, however low injection rate of the gas is more desirable as it requires less facilities for the WAG purpose. Because of that, it is more convenient to use 1:1 WAG ratio compared to 1:1.3.

RECOMMENDATIONS

In order to get better results in the future, here are some recommendations that can be suggested.

1. The study on full scale of Angsi I-35 reservoir should be conducted so that the overall increment in Recovery Factor can be obtained.
2. Besides focusing on the WAG parameters, the Injector Well location/ distance from the Producer Well should be analyzed too. This is because if the Injector Well is located near to the Producer Well, the water breakthrough will be experienced faster. In contrast, if it is located far from the Producer Well, the WAG process' effect does not really experienced by the Producer since the water/gas have been diverted to other places. Hence, the oil recovery still not has any improvement. Therefore, the optimum location should be determined. In addition, the number of Injector used can be optimized too if it is recognized to have some influences with the oil recovery.
3. A horizontal/ deviated well can be considered also because different well orientation may have different effect. This is because in some special cases, horizontal Injector is preferable as it gives better pressure force to the reservoir compared to the vertical Injector.
4. Comparison on different types of Hysteresis model can also be carried out because different models use different approaches in predicting the trapping gas and reduction of permeability during the WAG process. After doing this, the results obtained can be compared and the best model can be evaluated then.
5. This study can be extended to other fields in Malaysia in order to compare with the result obtained from Angsi I-35 reservoir. Or, if the data is available, the study can also focus on the other oil wet reservoirs to observe and compare with the conceptual study.

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APPENDIX A

GANTT CHART

FYP I						FYP II					
Jan	**Feb**	**Mac**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Project Development						*Project Implementation*					
Continuous Gather Information											
Project Identification											
	Feasibility Studies										
		Software familiarization									
			Perform Conceptual Study								
				Data Analysis on Conceptual Study							
					Data gathering & Model Preparation						
						Conduct Simulation & Sensitivity Studies					
								Data Analysis & Evaluate Results			

APPENDIX B

```
-- -------------------------------------------------------------------------------
-- Office Simulation File (DATA) Data Section Version 2001A_2 Dec 18
2001
-- -----------------------------------------------------------------------
---------
--
-- File: NEW03_E100.DATA
-- Created on: 10-Mar-2003 at: 16:38:55
--
--
***********************************************************************
******
-- *                                  WARNING
*
-- *                THIS FILE HAS BEEN AUTOMATICALLY GENERATED.
*
-- *          ANY ATTEMPT TO EDIT MANUALLY MAY RESULT IN INVALID DATA.
*
--
***********************************************************************
******
--

RUNSPEC

TITLE
title

START
 30 'SEP' 2001 /

FIELD

UNIFIN

UNIFOUT

GAS

OIL

WATER

DISGAS

MONITOR

RSSPEC

NOINSPEC

SATOPTS
'HYSTER' /

NSTACK
30 /

GRID

GRIDFILE
 2 /

INIT
```

```
INCLUDE
'new03_gopp.inc'  /

INCLUDE
'new03_ggo.inc'  /

INCLUDE
'new03_gpro.inc'  /

INCLUDE
'new03_goth.inc'  /


EDIT

INCLUDE
'new03_edit.inc'  /


PROPS

EHYSTR
0.1  0  1.0  /

STONE


SWFN
--
-- Water Saturation Functions
--
         0.462           0          500
         0.492   9.67e-006        38.03
         0.522    0.000155        14.29
         0.572     0.00175         5.85
         0.622     0.00782         3.25
         0.672      0.0232         2.06
         0.722      0.0545         1.39
         0.772        0.11         0.98
         0.822         0.2         0.69
         0.922       0.534         0.33
             1           1            0
/

         0.462           0         500
         0.492   9.67e-006       15.44
         0.522    0.000138       9.63
         0.572     0.00147       2.01
         0.622     0.00574       1.06
         0.672     0.01539        0.9
         0.722     0.03259       0.43
         0.772     0.05917       0.15
         0.822    0.096397       0.09
         0.922     0.20423          0
             1      0.3164          0
/
--
```

```
SGFN
--
-- Gas Saturation Functions

           0            0            0
        0.01            0            0
        0.02            0            0
        0.03            0            0
        0.04            0            0
        0.05            0            0
        0.1        0.0328            0
         0.2         0.17            0
        0.45        0.742            0
         0.5        0.885            0
       0.538            1            0
/
          0             0            0
        0.01      0.03682            0
        0.02       0.0729            0
        0.03       0.10841           0
        0.04      0.14317            0
        0.05       0.17723           0
        0.1         0.3372           0
         0.2        0.6053           0
        0.45        0.9732           0
         0.5        0.9950           0
       0.538            1            0
 /
--

SOF3

--Oil saturation Function
          0            0            0
          0.0338       0            0
          0.088        0.171        0
          0.338        0.278        0.047
          0.438        0.407        0.275
          0.488        0.551        0.549
          0.498        0.7          0.623
          0.508        0.838        0.705
          0.518        0.946        0.794
          0.528        0.986        0.893
          0.538        1            1
/

          0            0.000        0.000
          0.0338       0.007        0.0344
          0.088        0.053        0.0404
          0.338        0.13         0.1088
          0.438        0.143        0.1495
          0.488        0.277        0.2105
          0.498        0.35         0.3453
          0.508        0.455        0.513
          0.518        0.676        0.7146
          0.528        0.83         0.853
          0.538        1            1
/


INCLUDE
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REGIONS
```

```
INCLUDE
'new03_reg3.inc'  /


SOLUTION

INCLUDE
'run5ex9_init.inc'  /


SUMMARY

INCLUDE
'run1_sum.inc'  /


SCHEDULE

INCLUDE
'new03_sch2.inc'  /


END
```

APPENDIX C