Simulation Study on Water-Alternating-Gas (WAG) Injection with Different Schemes and Types of Gas in a Sandstone Reservoir

by

Chiew Kwang Chian

Dissertation submitted in partial fulfilment of

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CERTIFICATION OF APPROVAL

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Approved by,

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UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

April 2012

CERTIFICATION OF ORIGINALITY

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

CHIEW KWANG CHIAN

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ABSTRACT

Water-Alternating-Gas (WAG) injection is one of the Enhanced Oil Recovery (EOR) techniques applied in oil and gas industry. In a WAG application, there are a lot of combinations of WAG schemes to be selected from. The common stated problem is to determine the optimum WAG schemes for a certain field. Different WAG schemes can be formed by adjusting the WAG parameters, i.e. WAG ratio, WAG injection rate, WAG cycle sizes and etc. Another problem is the ambiguous feasibility of other type of gas in WAG application. The objective of this Final Year Project (FYP) was to simulate and determine the impacts of WAG parameters on the recovery for a sandstone reservoir, and also to evaluate the feasibility of different types of gas in WAG injections. This project was carried out by using a compositional simulator developed by Computer Modeling Group Ltd (CMG). The inputs needed for the simulations were collected from the literatures available. This study focuses on WAG application in a sandstone reservoir. The performance of each scheme was evaluated based primarily on the ultimate recovery. From these outcomes, various WAG schemes and the impacts of each WAG parameter can be compared, and thus deciding the optimum one. It was concluded that WAG ratio, WAG injection rate and types of WAG gas have profound effects on WAG performance, while WAG cycle sizes has insignificant impact on the recovery.

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CHAPTER 1
INTRODUCTION

1.1. Background of Study

Gas injection is the second most-practiced enhanced oil recovery (EOR) technique in oil & gas industry, the first one being steam injection. Compared to water injection, gas injection possesses higher microscopic sweep efficiency due to the lower interfacial tension (IFT) values between oil and gas phases (Wafaa *et al*., 2009). The gas used in gas injection is usually carbon dioxide (CO_2), as it is proven that carbon dioxide is a very effective miscible injectant (Stalkup, 1983) which can lead to the nearly complete mobilization of residual oil (Sharma and Clements, 1996).

To further improve the sweep efficiency, Caudle and Dyes, (1958) proposed the simultaneous injection of water and gas as a form of enhancement of gas injection. The practice was then changed to the alternating injection of water and gas slugs into the reservoir to displace the hydrocarbon. This method is known as the Water Alternating Gas (WAG) injection. Since the introduction of WAG, researches had been conducted since then to determine the optimum WAG schemes for different types of formation. For instance, Surguchev *et al*., (1992) conducted simulation study to evaluate the optimum WAG for stratified reservoirs.

This paper presents the studies on WAG involving the use of the simulation software, Computer Modelling Group Ltd (CMG), to simulate WAG application on a sandstone reservoir, subsequently determining the optimum schemes of WAG for sandstone reservoir. A wide variation of WAG schemes can be formed by changing the WAG ratio, WAG cycle sizes and more. In addition, this simulation study also assessed the feasibility of different types of gas (the common gas used is carbon dioxide gas) in WAG applications.

1.2. Problem Statement

Some of the common WAG parameters which highly affect the optimization of WAG are the WAG ratio, WAG cycle sizes, WAG injection rate, and types of gas used in WAG. WAG ratio refers to the ratio of the pore volume of water injected to the pore volume of gas injected in a WAG application. On the other hand, WAG cycle size refers to the period of time for a complete loop of injecting water and gas. Larger WAG cycle sizes implies longer period of each injection of gas and water. Different combination of these parameters will result in different recovery rates.

One of the main problems during a WAG application is selecting the proper WAG schemes. The optimum WAG scheme for a certain field differs from another and there is no 'common' optimum WAG scheme. An optimum WAG displacement is one in which the gas and water are travelling at the same velocity in the reservoir. Due to the heterogeneity and variation of reservoir factors, optimum conditions may occur only to a limited extent, usually in the water/gas-mixing zone. Therefore, optimum WAG varies across different reservoirs.

Another problem regarding WAG applications is the lack of study on the feasibility of other type of gas other than carbon dioxide. Reviewing through the history of WAG application, only a few fields inject other types of gas aside from CO_2. For instance, Jay Little Escambia and Wilmington injected nitrogen in their WAG projects, and Twofreds injected exhaust gas as the displacing gas in WAG application. The feasibility of these alternative gases is still remaining ambiguous.

1.2.1. Problem Identification

The problems identified are:

1. No common rules of thumb for setting the WAG parameters for optimum schemes since the individual impacts of each WAG parameter are ambiguous
2. The feasibility and effectiveness of other types of gas other than CO_2 is not well-understood

1.2.2. Significance of the Project

This project focused on determining the impacts of different WAG parameters (i.e. WAG ratio, WAG cycle sizes etc.) on the performance of WAG.

Upon the completion of this project, this study can provide a good reference on the procedures and vital points whenever one wants to determine the optimum WAG schemes for other reservoirs. Moreover, this project can provide a clearer view of the feasibility and impacts of other gases in WAG injections.

1.3. Objectives of Project

The main objectives of this simulation study are:

a) To determine the impacts of WAG parameters, namely WAG ratio, WAG injection rate and WAG cycle sizes;
b) To investigate the impact of different types of gas

on the performance of WAG for a sandstone reservoir.

1.4. Scope of Study

The scope of study for this project was limited to purely simulation studies on the different WAG schemes by using a numerical simulator known as the Computer Modeling Group Ltd (CMG). The type of reservoir focused in this study was a sandstone reservoir. The input data of the fluid and reservoir was acquired from the literatures reviewed. Another topic to be covered in this study is the viability of different types of gas in WAG applications.

1.5. Relevancy of Study

This FYP is highly relevant to the Petroleum Engineering, as WAG had been one of the popular EOR technique applied in Oil and Gas (O&G) field. This study focuses on investigating and documenting the performance of different WAG schemes, which can be a very beneficial research to the industry. In addition, this FYP exposes the author to more simulations and modeling practices, which are one of the crucial reservoir management activities. The skills and experiences acquired throughout the FYP can be very valuable in the future.

1.6. Feasibility of the Project within the Scope and Time Frame

This project is feasible as it is a pure simulation study; therefore it is expected to have less technical problems compared to experimental studies. However, a few limiting factors or problems do exist.

The simulation study was implemented by using simulation software known as CMG. This software is available in the computer laboratory at Academic Block 15 of Universiti Teknologi PETRONAS (UTP), and the licenses required to run the simulation were provided by UTP, thus this project can be implemented at minimal cost. However, the licenses provided are academic licenses which have limited simulation capacities. Thus this project was limited to a 2-dimensional (2D) simulation study due to insufficient capacity to run massive grids simulation.

In terms of time frame, time losses were expected as the author is new to the software. In addition, no tutorial or guidance was provided. A few simulation exercises and self-learning sessions were conducted to familiarize with the software. Initially in phase 1 (FYP I), this project was planned to simulate WAG applications on a few types of reservoir, namely sandstone reservoir, carbonate reservoir, fractured reservoir and etc. However, due to the limiting time factor, the objective of the project was redefined to limit the study on sandstone reservoir only, in order to meet the time constraint requirements.

CHAPTER 2
LITERATURE REVIEW

2. 1 Gas Injection

Gas injection is one of the most commonly applied EOR methods in oil and gas industry. Its credibility lies in the better microscopic sweep efficiency and lower residual oil after displacement, thus maximizing oil recovery from reservoirs. The most commonly used gas in gas injections is carbon dioxide, CO_2, due to the fact that CO_2 can achieve miscibility more easily compared to other gas (Stalkup, 1983). Necmettin, (1979) mentioned in his review report that the presence of carbon dioxide will alter the viscosities, densities and compressibility of oil, in a direction which increase the oil recovery efficiency. The 'gas injection' in the latter part of the discussion refers to the CO_2 gas injection, unless stated otherwise.

Gas injection can be classified into 2 categories: miscible displacement and immiscible displacement (Necmettin, 1979).

Miscible gas displacement refers to the process where the injected gas mixes thoroughly with the oil in the reservoir and both move as a single phase. Miscible gas displacement occurs at the reservoir pressure above the Minimum Miscible Pressure (MMP), and it can be achieved either through first-contact miscibility or multi-contact miscibility. Stalkup, (1983) explained that first-contact miscibility is achieved if the injected gas mixes directly with the hydrocarbon in the reservoir upon their first contact, regardless of the proportions. Multi-contact miscibility, on the other hand, refers to the miscibility achieved through in-situ mass transfer (vaporizing-gas drive and condensing-gas drive) of oil and injected gas after repeated contacts between the two. The interfacial tension (IFT) between the reservoir oil and injected gas tends towards zero when miscibility is achieved (Wafaa *et al.*, 2009). Thus, less residual oil was left after gas displacement and total (or near total) oil recovery can be achieved in the swept area. Theoretically, all contacted oil can be recovered under miscible gas displacement, but in real cases, the recovery is usually 10 – 15% of the oil initially in place (OOIP) (Amarnath, 1999).

In immiscible displacement, the reservoir pressure is usually far below the MMP, thus the miscibility between the injected gas and the oil cannot be achieved. The injected gas, however, can still serve as the displacement fluid which sweeps the oil towards the production wells. The gas and oil remain physically distinct from each other. Although the miscibility is not achieved in this type of gas injection, immiscible gas injection can still benefit from the reduction of IFT through the mass transfer mechanisms, leading to higher recovery compared to other EOR methods such as water injection (Wafaa *et al*., 2009). In addition, other mechanisms such as oil swelling and viscosity reduction of oil by the injected gas also contribute to the improved recovery.

Despite the fact that miscible gas injection yields higher recovery compared to the immiscible displacement, real field cases usually are unable to achieve fully miscible gas displacement because the reservoir pressures were normally depleted below the MMP before gas injection was implemented. In addition, even if waterflooding or other pressure maintenance methods were conducted, it is very hard to restore the reservoir pressure and maintain it sufficiently high for miscible gas flooding.

2. 2 Viscous Fingering

The recovery of gas injection method can be restricted by viscous fingering problems (Jackson *et al*., 1985). Viscous fingering occurs whenever the mobility ratio of the injected (displacing) fluid to the displaced fluid is higher than unity, in other words, the displacing fluid moves faster than the displaced fluid. A brief explanation on mobility and mobility ratio, M can be helpful in understanding the concept.

Mobility of a phase is defined as the ratio of its effective permeability to its viscosity of that phase: k/μ. Mobility ratio, M, on the other hand, is the ratio of the mobility of the displacing fluid (injectant) to the mobility of the displaced fluid (Seright, 2005):

$$M = \frac{(k/\mu)_{displacing\ fluid}}{(k/\mu)_{displaced\ fluid}} \quad \ldots\ldots (1)$$

From equation (1), it is clear that when a gas or other less viscous fluid is injected as displacing fluid to displace oil (a more viscous fluid) in the reservoir, the mobility ratio is higher than 1. The gas with higher mobility will finger through (or channel through) the oil, leading to early gas breakthrough and lower recovery (Christle *et al.*, 1991). This had been reported in the many published literatures, for example in Adena, Granny's Creek, and Lick Creek (Christensen *et al.*, 2001). In the opposite scenario where fluid of less mobility is injected to displace the oil, the mobility ratio is less than unity, and the displacing fluid will act as if it is a physical piston which displaces the oil in the reservoir. **Figure 1** shows how the mobility ratio affects the stability of a displacement.

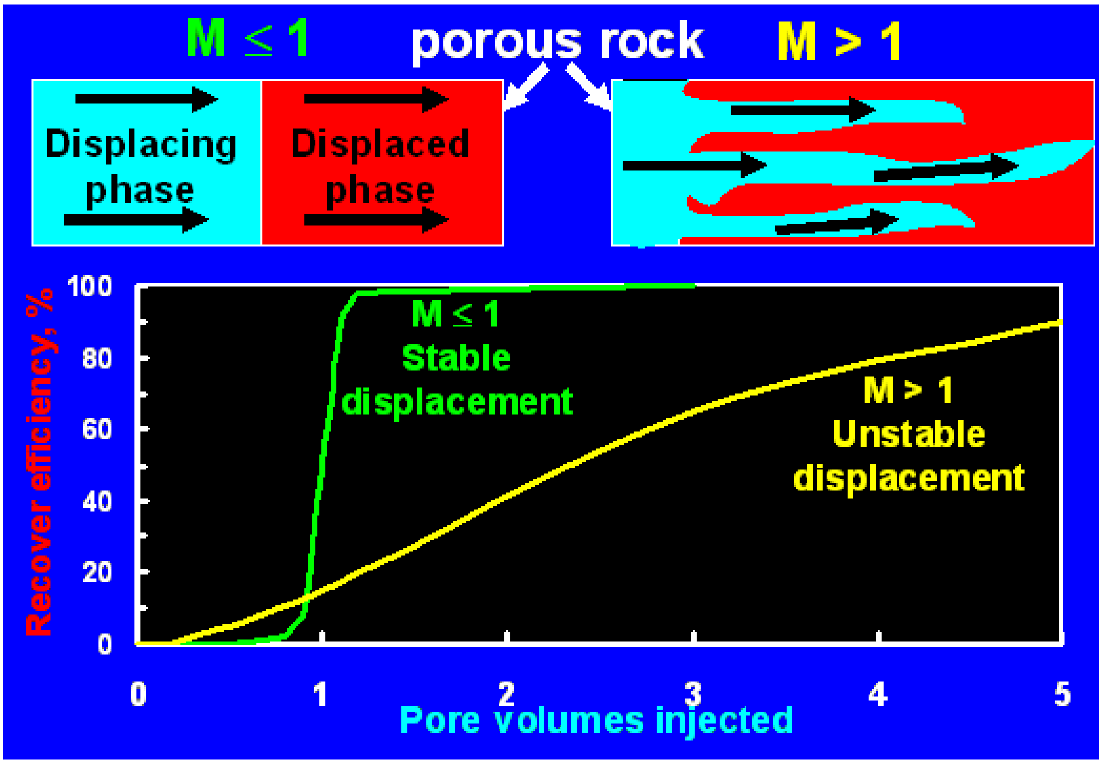

Figure 1 Mobility ratio & viscous fingering.

Gas flooding usually has a mobility ratio of higher than unity (M > 1) due to the low viscosity of the displacing gas. High mobility ratio represents unstable displacement and will lead to the problem of fingering in gas flooding **(**Seright, 2005**)**. In attempts to solve this problem, Caudle and Dyes, (1958) proposed to inject water and gas simultaneously to control the mobility ratio of gas injection.

2. 3 Water-Alternating-Gas (WAG) Injection

Water-alternating-gas (WAG) injection is a method which combines two recovery techniques, namely water injection and gas flooding. This application involves the alternating injection of gas (usually carbon dioxide) and water into the reservoir according to the pre-designed ratios, as shown in **Figure 2** below. In general, recovery process in which the injection of one gas slug is followed by injection of water slug can be considered as a WAG process by definition (Christensen *et al*., 2001).

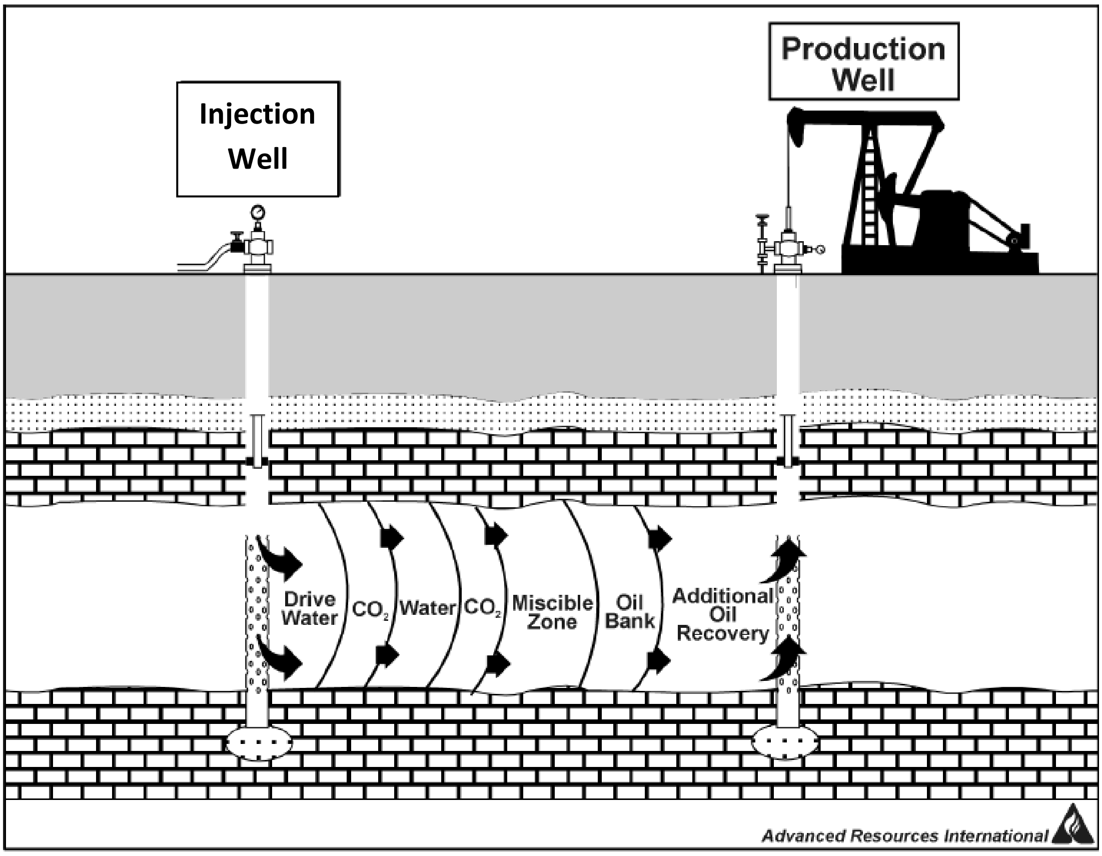

Figure 2 Schematic of Water-Alternating-Gas (WAG) Injection.

The history of application of WAG can be dated back to the 1950's. The first documented field application of WAG was implemented in 1957 in the North Pembina field in Alberta, Canada, and was operated by Mobil (Christensen *et al*., 2001). However, there was no proper research work on WAG injection until the publication of Caudle and Dyes' research paper in 1958.

2. 4 Ultimate Recovery of a Flooding EOR

Sharma & Clements, (1996) mentioned that the ultimate recovery of a flooding EOR is a function of two major factors, namely volumetric sweep efficiency (E_v) and displacement efficiency (E_D). Volumetric sweep efficiency is also known as the *macroscopic* sweep efficiency and displacement efficiency is also known as the *microscopic* sweep efficiency. (Basnieva *et al*., 1994). The former two and the latter two terms will be used interchangeably in the following discussions.

2.4.1. Macroscopic Sweep Efficiency (E_v)

Hite *et al*., (2004), in their paper, explained that macroscopic sweep efficiency is controlled by the mobility ratio and reservoir heterogeneity. As explained in previous section, mobility ratio lower than 1 results in stable piston-like displacement while mobility ratio higher than 1 will lead to unstable displacement. On the other hand, the reservoir heterogeneities which affect sweep efficiency are the reservoir dip angle and variation in permeability and porosity. In general, porosity and permeability increasing downward increases the stability of the front of WAG and hence favours WAG injection (Christensen *et al*., 2001).

Although it is impracticable to control the reservoir heterogeneities, it is possible to reduce any adverse impacts of the reservoir heterogeneity on volumetric sweep efficiency by improving the mobility ratio of an EOR flooding, thus improving the overall recovery. By "improving mobility ratio", it means that to reduce the mobility ratio to a value less than unity. To achieve this, Caudle and Dyes, (1958) proposed to inject water along with the gas which drives the miscible gas slug. The principle behind this is that the injected water will reduce the relative permeability to gas (displacing fluid) in this area and hence lower down the overall mobility ratio.

2.4.2. Microscopic Sweep Efficiency (E_D)

Microscopic sweep efficiency is affected by the interfacial interactions involving interfacial tension (IFT) and dynamic contact angles (Kulkarni, 2003). Gas displacement has a more favorable microscopic sweep efficiency compared to water because miscibility of gas reduces the IFT between the oil and the gas (Wafaa *et al*., 2009), and therefore reducing the capillary forces which hold the residual oil. Even in the immiscible gas displacement where miscibility is not achieved, the residual oil saturation after gas flooding is normally lower in amount compared to water. This is due to the combined effects of oil swelling and oil viscosity reduction by the dissolved gas, and also the IFT reduction, three-phase effect and hysteresis effect (Saleem *et al*., 2011).

2.4.3. WAG – Improving Ultimate Recovery

WAG application injects water and gas alternately to displace the oil in the reservoir. In general, water displacement has higher macroscopic displacement efficiency while gas flooding has better microscopic displacement efficiency. By combining the two injection methods together, WAG injection benefits from the advantages of both. This, undoubtedly, increases the overall recovery of WAG. Caudle and Dyes, (1958) had conducted a laboratory works on core flooding, and the results showed that a 5-spots WAG injection pattern can achieve 90% of the ultimate sweep pattern efficiency, which highly outperformed the sweep efficiency of 60% of gas injection alone.

However, Sharma & Clements, (1996) pointed that the presence of water in WAG cycles can possibly cause adverse effects to the microscopic sweep efficiency of gas due the phenomena of oil trapping, especially in water-wet reservoirs. Oil trapping happens when the water shields the remaining oil from being contacted by the subsequent-injected gas. However, this does not mean that water shielding will completely eliminate the displacement efficiency of gas. Gas such as carbon dioxide can dissolve into and diffuse through water, eventually contact, swell and displace the oil. In other words, the adverse effect of oil trapping is slowing down the displacement by gas.

2. 5 Classification of WAG

Similar to gas injection, WAG can be categorized into two major groups: miscible and immiscible displacement. In their review paper on WAG, Christensen *et al*., (2001) attempted to classify all the WAG field applications up to 1998. They suggested the classification of WAG into 4 groups, namely Miscible WAG Injection, Immiscible WAG Injection, Hybrid WAG Injection and Others.

Miscible WAG injection is one where the gas displacement is miscible. The reservoirs in most of the miscible WAG projects are re-pressurized above the MMP of the fluids in order to achieve miscibility (Christensen *et al.*, 2001). However, due to the pressure sustainability problem, the real field cases usually oscillate between miscible and immiscible WAG process. Immiscible WAG injection, on the other hand, is one in which the miscibility is not achieved during the displacement. However, the recovery of this type of WAG still benefits from mechanism such as the oil swelling, oil viscosity reduction, IFT reduction, three-phase and hysteresis effects. Hybrid WAG injection is one in which one injected large slug of gas is followed by a number of smaller-slugs of 1:1 WAG injections (Kulkarni, 2003). The rest of the WAG applications which fall under the category of 'Other' refer to the uncategorized and uncommon WAGs, such as the Foam-Assisted WAG injection (FAWAG), Water Alternating Steam Process (WASP), and Simultaneous WAG injection (SWAG).

2. 6 Past published works on WAG

As mentioned in the previous sections, the first notable research done on WAG was conducted by Caudle and Dyes, (1958). The main objective of their research was to determine the economical way to improve the sweep efficiency of a miscible gas injection. The outcome of their laboratory research was the recommendation of injection of water and gas simultaneously, in order to control the mobility ratio and stabilize the displacement front. However, in field application, water and gas are usually injected separately instead of simultaneously for better injectivity (Christensen *et al*., 2001). If both fluids were injected simultaneously, the injectivity would be decreased significantly. Reduce in injectivity implies lower volume of fluid is injected at a time, and this leads to a more rapid pressure drop in reservoir.

Surguchev *et al.,* (1992) had implemented simulation studies of optimum WAG ratios for stratified reservoirs. The study focused on the stratified Brent reservoir in the North Sea. The impacts of various WAG design parameters such as WAG ratio, number of WAG cycles, cycle size and injection rate were investigated. The result of simulation showed that the optimum WAG scheme for this stratified reservoir is WAG ratio of 1:1 with large injection cycles (around 300 days for each cycle). One of the noteworthy remarks presented in the paper is the importance of hysteresis model in WAG. Surguchev *et al.,* (1992) pointed that an optimization of WAG process and its vertical conformance requires hysteresis modeling in order to tune the WAG injection parameters with respect to the heterogeneities of different reservoirs.

Christle *et al.,* (1991) presented their research paper on a 3D simulation of viscous fingering and WAG schemes. The aims of the simulation study is to provide a high-resolution 3D simulations to evaluate the combined effects of gravity segregation in the vertical plane and areal viscous fingering for miscible displacements with substantial viscous fingering and WAG injection. From there, they precede to their research purposes, which is to quantify the effects of fingering and also the improvement in recovery from WAG. Their study revealed that 2D and 3D simulations give identical result at high injection rates, but as the density contrast increases, it is essential to simulate the recovery process in 3D.

Minssieux and Duquerroix, (1994) studied the flow mechanisms of WAG in the presence of residual oil. They implemented WAG core floods in uni-dimensional sandstone with dry gas (mostly methane and some fraction of nitrogen), and then simulate the observed mechanisms in a modified black oil model. The research shows that in case of under-saturated oil in place, the mobilization of tertiary oil can be increased through the combined effect of oil swelling by the injected methane in gas injection step and the gas trapping during water injection step. Another conclusion drawn from the experiment is that the dissolution of gas can delay the gas breakthrough. When the gas dissolution becomes negligible, the gas breakthrough happened even before tertiary oil production.

Nadeson *et al.,* (2004) presented the evaluation of EOR methods in Dulang Field of Penisular Malaysia. In their laboratory studies, immiscible WAG (IWAG) was determined as the most optimum and practical method to recover the oil, with additional recovery of 5 to 7% of the OOIP. Miscible WAG was impossible to achieve because the field had depleted far below the minimum miscible pressure. A test on IWAG was conducted in one of the sub-block (South-3 block) in Dulang Field, and it was the first EOR application in Malaysia. The IWAG strategy adopted in this field was to re-inject the produced gas and treated seawater for improved oil recovery. No official research was done to determine the recovery mechanism, but it was expected that the contributing factors are the drainage of attic oil, improved sweep efficiency, sweep of less swept tighter intervals in E12/13 and partial vaporization of the un-swept oil.

A study on WAG by using glass micromodels was conducted by Sohrabi *et al.*, (2001). The study aims to present experimental results of researches on a series of capillary-dominated WAG test. The research repeatedly uses the same glass micromodel for all experiments, but with varying wettability for different scenarios. This research work is highly noteworthy as it provides invaluable experimental observations and references for other simulation works in future. A few important conclusions were drawn from the experiments. In a strongly water-wet system, water flows in the form of filaments surrounding the oil-filled pores. The filaments will thicken progressively during waterflooding, and eventually form stable thick water layers around the oil and trap the oil by snapoff at pore throats. In a strongly oil-wet system, water displaces the oil like a piston without causing snapoff, thus complete recovery of contacted oil. In a mixed-wet system, addition oil recovery was lower initially, but increasing gradually in the following cycles afterwards, approaching the recovery of oil-wet model. In contrast, the additional recovery in both water-wet and oil-wet system diminished after the first few cycles. The comparison of recovery of WAG in different wettability systems is shown in **Figure 3** below:

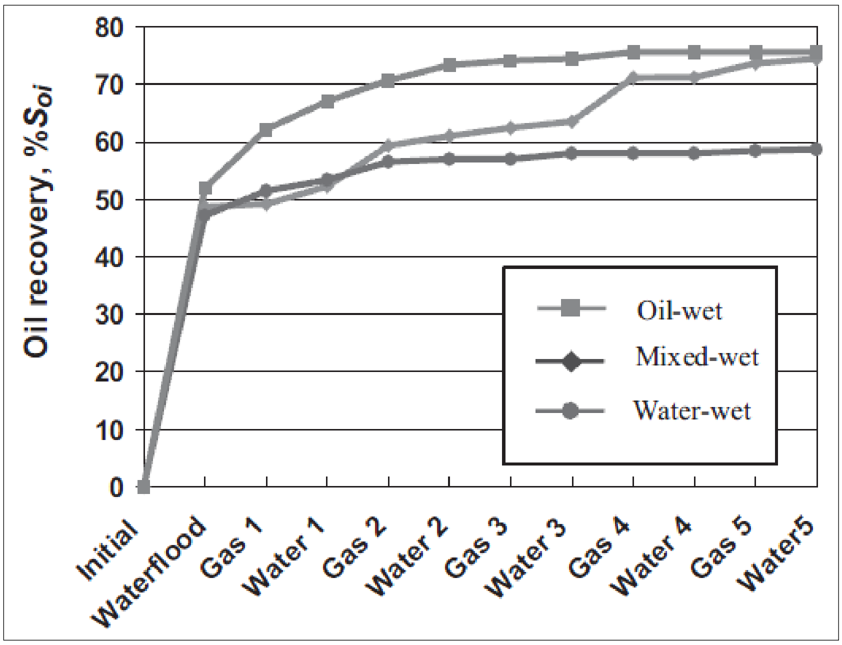

Figure 3 Oil recoveries for different wettability systems.

Wafaa *et al.*, (2009) used a 3-D black oil reservoir simulator to determine the optimum strategies for Simultaneous WAG (SWAG) schemes. SWAG, as the name implies, refers to the simultaneous injection of water and gas into the reservoir through dual strings. The purpose of this simulation study is to determine, numerically, the impacts of different SWAG design and reservoir parameters on the SWAG performances. The results showed that SWAG scheme is most sensitive to the water and gas injection rate. The optimum SWAG would be the schemes with high water and gas injection rates. The location of the injectors can impact the recovery minimally when the gas injector is placed far away from the water injector. Another finding of this research is that the use of horizontal injectors yields the best recovery compared to other well configurations.

2. 7 Summary

With the introduction of WAG techniques, the recovery of hydrocarbon can be greatly improved, due to the combination of better volumetric sweep efficiency of waterflooding and better displacement efficiency of gasflooding. The better control over the mobility ratio by WAG also minimizes the viscous fingering problems which commonly occur in gas injection.

WAG is a complex EOR method as the saturations of gas and water increase and decrease alternately throughout the application of WAG. In addition, different formation and reservoir heterogeneities result in varying optimum WAG schemes across different reservoirs. To understand and thus optimize this EOR method, researches and simulation studies had been implemented by engineers. Their works, without doubt, provide invaluable information for the future engineers and researchers in this field.

CHAPTER 3

METHODOLOGY

3. 1 Research Methodology

Figure below shows the research methodology for this FYP:

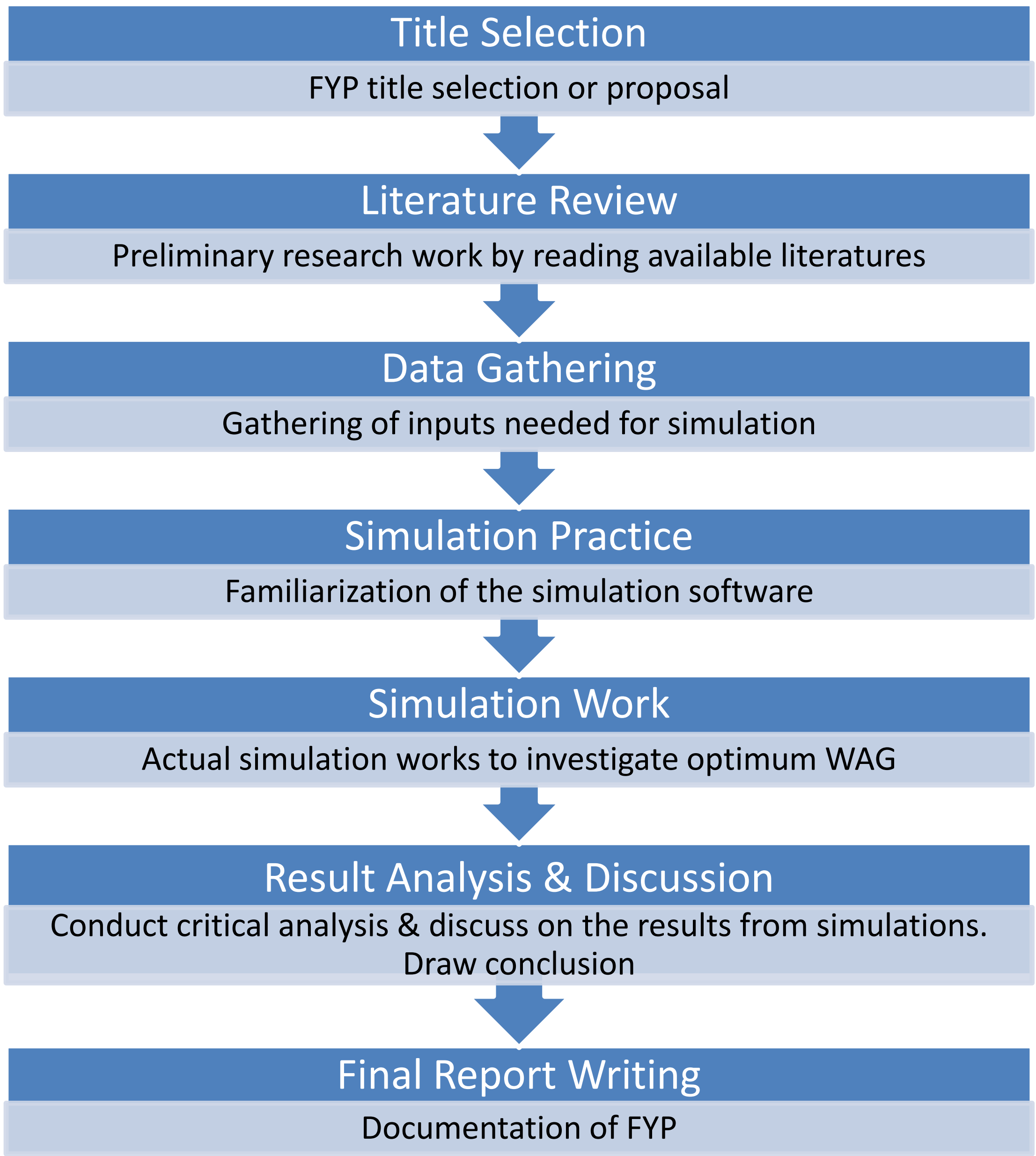

Figure 4 Schematic diagram of project flow

The subsequent paragraphs describe the methodology of this FYP in brief. Following the selection of FYP title, the project started with the literature review of the SPE papers and other online journals related to WAG simulation and optimum WAG researches done by the previous engineers and researchers. The objective of this stage is to gain thorough understanding on the concept of WAG and thus forming strong basic knowledge to assist the future study.

The next stage is to collect the parameters and data for the inputs for the studies, mostly from literature review of the published papers. The data collected are the reservoir and rock properties, as well as the description of the reservoir. From the literature review, the collected data and information will be inputted into the simulator, namely Computer Modelling Group Ltd. (CMG).

The simulations are conducted to investigate the performance of different WAG schemes and to assess the feasibility of other gas in WAG application. Subsequently, upon the acquisition of the simulation results, analysis on the trend behaviors and graphs will be conducted to discuss the impacts of different WAG parameters on the optimization of recovery.

Finally, the literature reviews, simulation works, research outcomes, findings and discussions will be documented in the Final Report.

The project activities for this FYP can be generalized into 4 groups/stages:

a) Literature Review & Data Gathering
b) Simulation/Modelling
c) Analyses
d) Documentations

The first item, literature review was conducted in FYP I and the rest of the stages were carried out in FYP II. These activities will be elaborated in details in the following sections.

3. 2 Literature Review & Data Gathering

The activities included in this group are the readings and reviews of the articles and research papers available mostly from the internet. Some of the important knowledge for this FYP was already presented in Chapter 2.

Data collection was implemented concurrently with literature review. For reservoir data, the focuses are the wettability, absolute permeability, relative permeability curves, effective porosity, initial saturation, initial reservoir pressure and etc. For example, the following example of reservoir properties was extracted from one of the literatures (not all of the information was used in the simulation):

Table 1 Reservoir rock and fluid properties.

Property	Value
System length, ft	1,200
System width, ft	600
System thickness, ft	60
Porosity, %	20
Horizontal permeability, md	200
Vertical permeability (no shales), md	200
Effective vertical permeability (for shale distribution)	30
Oil viscosity, cp	1.3
Water viscosity, cp	0.31
Gas viscosity, cp	0.045
Oil density (reservoir conditions), lbm/ft^3	42.1
Water density (reservoir conditions), lbm/ft^3	62.4
Gas density (reservoir conditions), lbm/ft^3	24.0
Oil relative permeability	$k_{ro}(S_w)=0.85\left(\frac{1-S_w-S_{or}}{1-S_{wc}-S_{or}}\right)^3$
Water relative permeability	$k_{rw}(S_w)=\left(\frac{S_w-S_{wc}}{1-S_{wc}-S_{or}}\right)^3$
Critical water saturation	0.40
Residual oil saturation	0.25

On the other hand, the data for hydrocarbon fluids such as the fluid compositions, characterization of heavy plus-fractions, molecular weight of fluid etc. were also collected through literature review. This is particularly important because good descriptions of the oil samples are very important in ensuring the modeling of accurate behaviors of the fluids. One of the good examples is the paper *Measurement and Modeling of Asphaltene Precipitation* by Burke *et al.* (1990). In their report, they provided a sufficiently decent description of 6 oil samples, as shown in the table below:

Table 2 Compositions (mole %) and properties of 6 Burke oil samples.

	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

The data gathered in this stage were used as the inputs for the subsequent activity, namely simulations

.

3. 3 Simulation/Modeling

The simulations were carried out using a simulator known as the Computer Modeling Group Ltd. (CMG). CMG software consists of 'packages' of applications and tools for different kinds of simulation purposes. However, only some of these tools were used for this FYP, namely WinProp, Builder, GEM simulator, Result Graph and Result 3D.

WinProp is the package used to model reservoir fluids; Builder is the tools for inputting reservoir data; and Result Graph & 3D are used to visualize the simulation results. To conduct the simulations, three distinctive simulators are available in CMG, namely GEM, IMEX and STARS. GEM is the compositional simulator applications while IMEX is the 3-phase black-oil simulator of CMG.

STARS is the 3-phase multicomponent thermal and steam additive simulator. Prior to any simulation, the user must choose either one of these simulators. Depending on the type of simulator chosen, the interfaces for the subsequent tools and packages will change in order to fulfill the data input requirements. This project only uses the compositional simulator (GEM) since this FYP was formulated based on the idea to use compositional simulator. **Figure 5** below shows the interface of the CMG software:

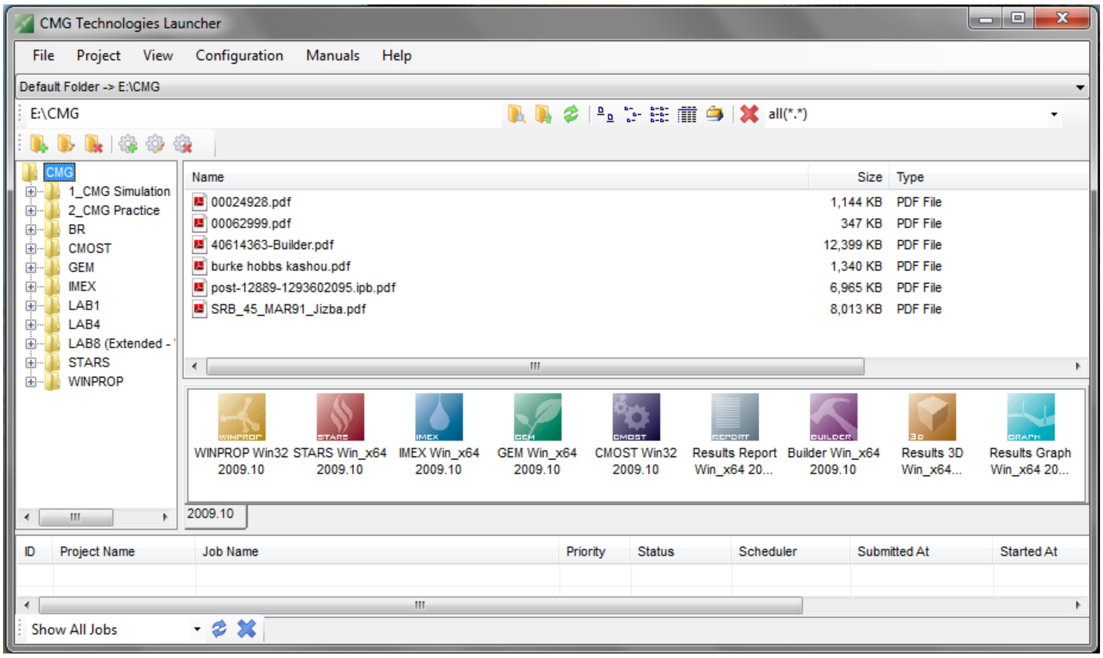

Figure 5 Interface of Computer Modelling Group (CMG) Ltd.

Further discussion on the simulations will be presented in the following sections.

3. 3. 1 Fluid Modeling

The tool used to model fluid behaviours in CMG is the WinProp package. WinProp is an equation-of-state (EOS) multiphase equilibrium and properties determination program. Aside from its main role to model fluid behaviours, WinProp can also perform fluid PVT calculations (two-phase flash calculations, multiple contact test calculations), characterize reservoir fluid (plus-fractions splitting, lumping components of fluid) and generate the plots of fluid PVT behaviours.

The interface to key in the compositions and other properties of the fluids is shown in **Figure 6** below:

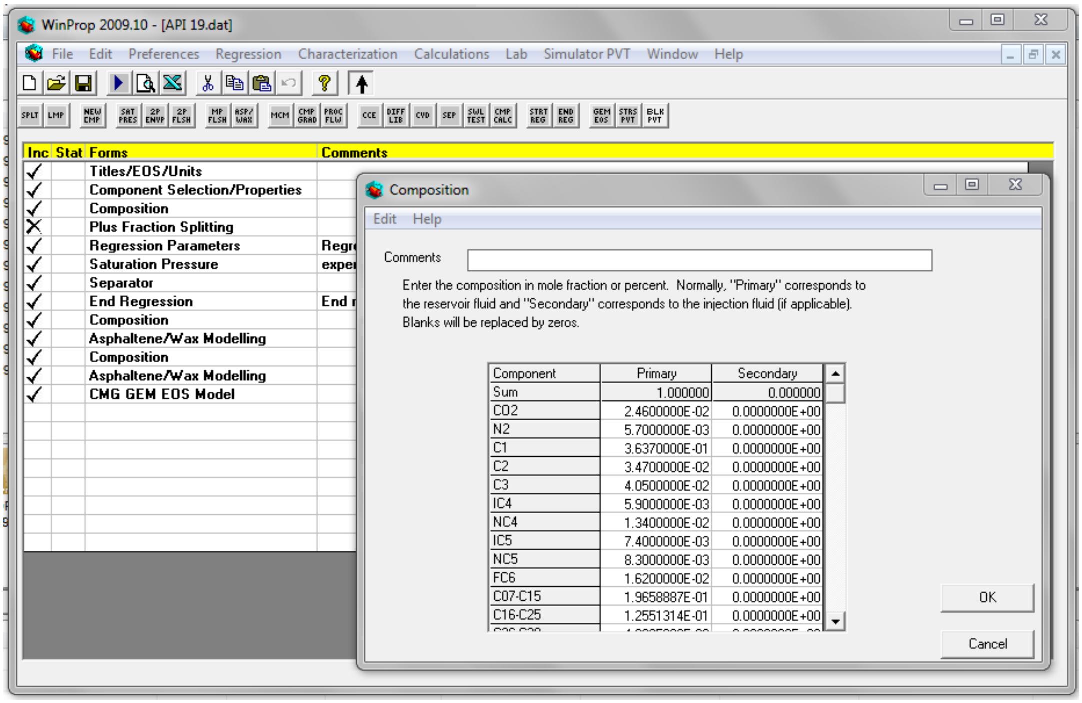

Figure 6 Interface of WinProp tool

2 different fluids samples had been modeled. The data of these fluids were obtained from the Burke *et al.*'s report (Table 2). The modeled fluids are the Oil 1 with 19 °API and the Oil 4 with 38.8 °API. The rest of the oil samples in Burke's report are not modeled due to insufficient data such as the deposition rate of asphaltene as pressure decreases. However, the two modeled fluids are sufficient to serve the simulation purpose since they represent the heavy oil (Oil 1) and light oil (Oil 2). In its successive simulations, only the light oil sample was used. The heavy oil was kept as the backup sample for future simulation, but due to the time constraint, it was never been used.

In the fluid-modeling, the asphaltene precipitation and deposition behaviors of the fluids were given special attention, as the author intended to compare the effects of formation damages due to asphaltene deposition. To achieve this, an extra component which serves as the asphaltene content has to be added in manually into the composition. Since the addition of this extra component will result in total composition of higher than 1.0, the composition of the fluid is normalized by subtracting the mole percentage of asphaltene heaviest component of the fluid.

It is then tuned as close as possible to the behaviors and properties of the asphaltene reported in the literature. Some of the crucial properties to be tuned are the weight percentage deposited at different pressures and temperatures, saturation pressure and the °API of asphaltene. One important behavior of asphaltene deposition is reversibility of precipitation, in other words, the precipitated solids will re-dissolve into the liquid phase after the pressure drops below the saturation pressure. Below this pressure, liberation of gas from the oil changes the solubility parameter of the liquid phase and allows re-dissolution of the precipitated asphaltene. At sufficiently low pressures, all of the precipitated asphaltene will completely dissolved into the hydrocarbon fluid.

WinProp does not have the function to predict this phenomenon automatically. However, this behavior can be modeled by manually adjusting the interaction coefficients between the precipitating asphaltene and the light ends of the oil, normally including C_1 to C_5. Increasing the interaction parameters with the light components will force the asphaltene to redissolve at lower pressures. **Figure 7** shows the result of deposition behavior of the modeled asphaltene as the system pressure decreases from 6,000 psia to standard pressure of 14.7 psia.

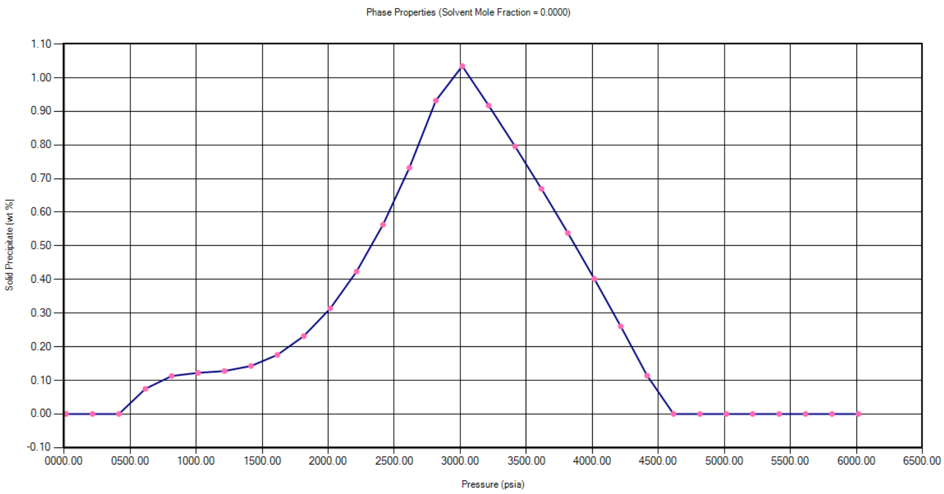

Figure 7 Behaviors of asphaltene deposition in WinProp

3. 3. 2 Static Reservoir Modeling

Builder is the graphical user-interface in CMG which is used for generating the simulation input files for CMG simulators. In other words, Builder is the software wizard which facilitates the users to key-in and modify the reservoir model parameters, such as the reservoir gridding, rock-fluid properties, well locations and trajectories, initial reservoir conditions, geomechanical regions and etc. In addition, Builder possesses the functions to visualize and validate the input data, thus the users can preview and check their reservoir model before running the actual simulation in the simulators. Builder supports three of the CMG simulators, namely GEM, IMEX and STARS. This is summarized in **Figure 8** below:

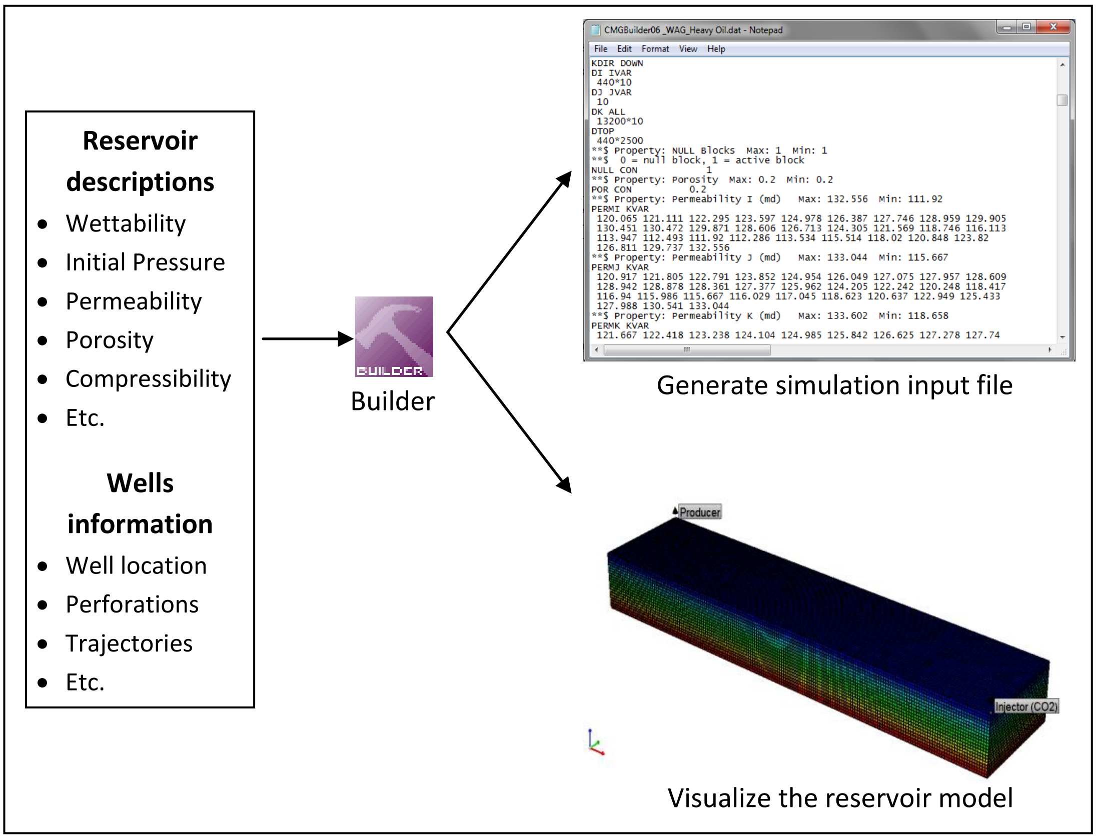

Figure 8 Builder – GUI to create input files of simulation

The dimension of the reservoir model of this project is limited to 2-dimensional, due to the insufficient capacity of the license provided by UTP. The licenses installed in UTP lab are of academic nature, which permit the modeling of reservoir up to only 20,000 grid blocks. Due to this limitation, the modeling in 3-dimensional would shorten the length of the reservoir, and consequently minimize the visualization and comparison of some of the important effects in WAG, such as the viscous fingering.

Initially, the reservoir model generated was of 17,600 grids, with the dimensions of 440 grids × 1 grid × 40 grids; each grid having the dimensions of 10 ft × 10 ft × 10 ft. However, the simulation time was too long, where one simulation usually took about 16 to more than 24 hours to complete. This might be due to the complex compositional and EOS calculations resulted from the interactions between the components, or the computational power of the lab machines. In order to meet the requirements of the time constraint, the dimensions of the reservoir model were later reduced to 330 grids × 1 grid × 20 grids (total of 6600 grids) and each grid was reduced to 10 ft × 10 ft × 1 ft, in order to reduce the enormous simulation time.

The injector and the producer are respectively placed at one of the ends of the model. Since the length of the model is 3300 ft (around 1 km), the injector and producer are placed sufficiently far apart. Both the water and gas injectors inject fluids directly into the oil zone, instead of aquifer or gas cap, because the main purpose of the injections is to displace the remaining oil, not to maintain the reservoir pressure. **Figure 9** and **Figure 10** below show the reservoir model in the preview scale (84:1) and actual scale (1:1):

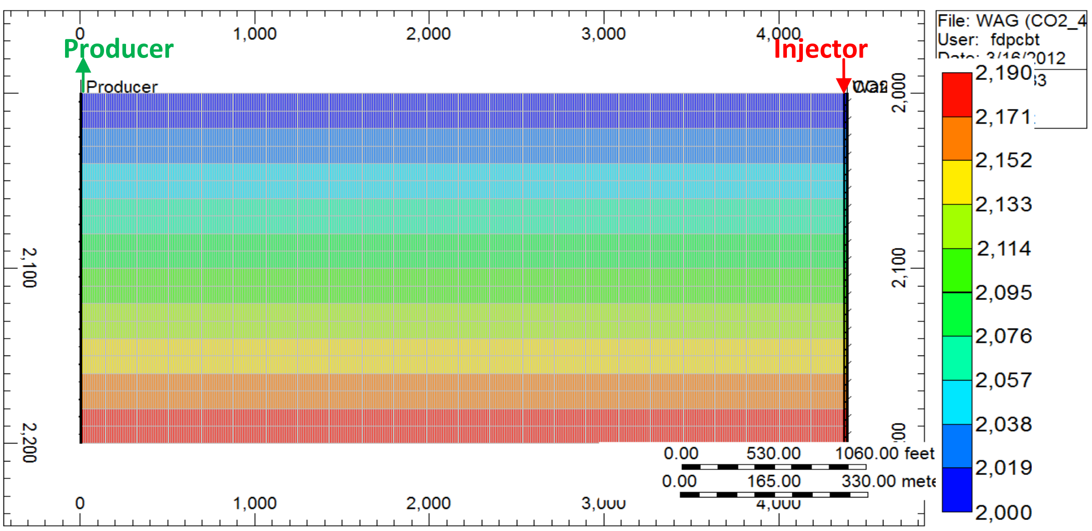

Figure 9 Static reservoir model in 84:1 scale

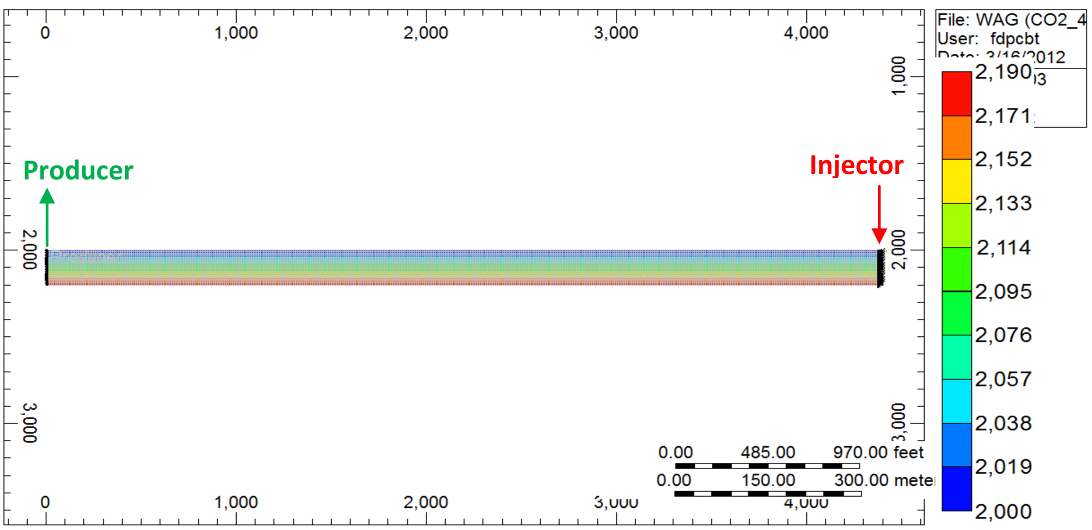

Figure 10 Static reservoir model in 1:1 scale

The reservoir model shown above represents the 20-ft pay zone of the reservoir, instead of the whole reservoir. The producer and injectors are perforated throughout the whole intervals of the model above, resulting in a total of 20 ft perforations. The reservoir is modelled as a heterogeneous reservoir, with gradual variation of permeability between the layers. Generally, the permeability is increasing downward. It is a sandstone reservoir ranging between consolidated and unconsolidated sorting. The summary of the reservoir description is shown in the table below:

Table 3 Reservoir model descriptions

Reservoir Bulk Volume, V_b	660×10^3 cu ft
Average Porosity, ⌀	20 %
Reservoir Pore Volume, PV	132×10^3 cu ft
Connact Water Saturation, S_{wc}	22 %
Initial Reservoir Pressure, P_i	3500 psi
Top of reservoir	2800 ft

3. 3. 3 Dynamic Reservoir Modeling

After the input data had been created from Builder and WinProp, it is imported into GEM simulators to run the calculations. GEM is an advance Equation of State (EOS) compositional simulator which enables the modeling of recovery processes where the fluid composition affects recovery.

The following cases of WAG had been modeled to compare and determine the performance of different WAG schemes. For all cases, only the WAG parameter of interest was manipulated, while the other parameters were kept constant:

- WAG injection with different WAG ratio. Ratios of 1:1, 2:1, 3:1 and 1:2 were modeled. Gas injection (0:1 WAG ratio) and waterflooding (1:0 WAG ratio) were also modeled to compare the effect of recoveries between these 2 cases and WAG injections.
- WAG injection of different WAG cycle sizes. The scenarios modeled in this project are WAG cycle of 2 months, 4 months and 6 months.
- WAG injection with different gases. The gases used are carbon dioxide (CO_2), nitrogen (N_2), and hydrocarbon gases (HC) with varying concentrations of lean gas and Liquefied Petroleum Gas (LPG).

- WAG injections with different injection rates. 5 different injection rates for 1:1 WAG injection were modeled.

For all cases, the reservoir was simulated to be depleted first by natural depletion. After the reservoir was unable to produce from natural energy, waterflooding was carried out to recover the oil, until the producer well was shut-in at the economic constraint, i.e. when the water cut at the surface reaches 80% of total production. The producer well was then reopened when WAG injection was implemented.

The results can be viewed in either of the tools: Result 3D or Result Graph, depending on the nature of results desired. Result 3D is used to displayed the results in illustrative form, where the fluid flow in the reservoirs can be shown as animations. Result Graph, on the other hand, shows the results in the forms of plotted curves against some varying parameters, usually time and distance.

3. 4 Analyses

This is the core of the FYP, where the simulation outcomes and results obtained from the simulations are critically analyzed in order to understand the trends behavior. Strong basic knowledge and understandings on the topic are required to implement this stage successfully. The results of analyses for this FYP will be presented in Chapter 4.

3. 5 Documentations

Documentation includes all the data compilation and report writing throughout the timeline of FYP I and II. So far one preliminary report, one interim report and one progress report had been produced and submitted. This Final Report is the last paper to be produced to document all the subjects related to this FYP.

3. 6 Project Planning

The key milestones of this FYP are shown in the following table. To date, all milestones are completed and works are delivered in time.

Table 4 Key milestone & Progress

	Milestone	Planned Timescale	Status
FYP I	Selection of FYP topic	Week 2	Completed
	Prelim research work	Week 2 - Week 5	
	Submit Proposal Defense Report	03-Nov-11	
	Project Work (Literature Review)	Week 2 - Week 14	
	Proposal Defence Oral Presentation	Week 8 - Week 9	
	Start Pre-Lab Preparation	Week 10 - Week 14	
	Submit Interim Draft Report	15-Dec-11	
	Submit Interim Final Report	22-Dec-11	
FYP II	Software learning	Week 1 – Week 3	Completed
	Simulation – Fluid Modeling	Week 3 – Week 5	Completed
	Simulation – Reservoir Modeling	Week 4 – Week 10	Completed
	Result Analysis & Discussion	Week 7 – Week 10	Completed
	Progress Report Submission	16-Mar-12	Completed
	Pre-EDX (Poster)	2-Apr-12	Completed
	Dissertation Submission (Softbound)	13-Apr-12	(Done)
	Technical Paper Submission	13-Apr-12	-
	Oral Presentation	23-Apr-12	-
	Dissertation Submission (Hardbound)	11-May-12	-

To facilitate planning and scheduling for better time management, two Gantt charts below had been produced. The first one corresponds to the planning of FYP I while the second one corresponds to the Gantt-chart of FYP II.

Table 5 Gantt-Chart of FYP I & II

Final Year Project I

Details/Week	1	2	3	4	5	6		7	8	9	10	11	12	13	14
Topic Selection & Confirmation							Mid Semester Break								
Preliminary Research Work															
Preliminary Report submission															
Proposal Defense Presentation															
Project Work Continues															
Interim Draft Report submission															
Submission of Interim Report															

Final Year Project II															
Details/Week	**1**	**2**	**3**	**4**	**5**	**6**		**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**
Software learning							Mid Semester Break								
Simulation – Fluid Modeling															
Simulation – Reservoir Modeling															
Result Analysis & Discussion															
Progress Report Submission															
Pre-EDX															
Draft Report Submission															
Dissertation Submission (Softbound)															
Technical Paper Submission															
Oral Presentation															
Dissertation Submission (Hardbound)															

Legend

Process

Key milestone

3. 7 Tools/Software Required

The main software for this study is the Computer Modeling Group (CMG). The logo of CMG is shown in **Figure 11** below. The licenses of the software were provided by the Enhance Oil Recovery (EOR) center of Universiti Teknologi PETRONAS. The licenses are shared to two of the lab machines in Academic Block 15 through network.

Figure 11 Logo of Computer Modelling Group Ltd. (CMG)

CHAPTER 4

RESULT AND DISCUSSION

The objective of this FYP is to simulate and determine the performance of different WAG schemes by assessing the recoveries of different schemes. In this simulation study, different WAG schemes were created by changing any one of the WAG parameters (i.e. WAG ratio, WAG cycle sizes) while setting the rest of the parameters constant. In this chapter, the results of the simulations will be presented and discussed.

4. 1 Effect of WAG Ratio

WAG ratio refers to the ratio of the reservoir pore volume of water injected to the pore volume of gas injected in a WAG application. WAG ratio of 1:1 means a unit volume of water injected is followed by a unit volume of gas, both equivalent in terms of reservoir volume. WAG ratio of 2:1 refers to the injection of 2 unit volumes of water and 1 unit volume of gas in a complete WAG cycle. Gas injection can be considered as WAG of ratio 0:1 while water injection can be considered as WAG of ratio 1:0. If the injection rate is constant, WAG ratio can also be defined as the ratio between the injection period of water and injection period of gas.

In this simulation study, 6 different WAG ratios with the same injection rate (26 bbl/day) were simulated for a sandstone reservoir. One unit of injection period was set as 30 days. Results of the simulations are shown in **Figure 12** below, where the recoveries of all schemes were plotted against time.

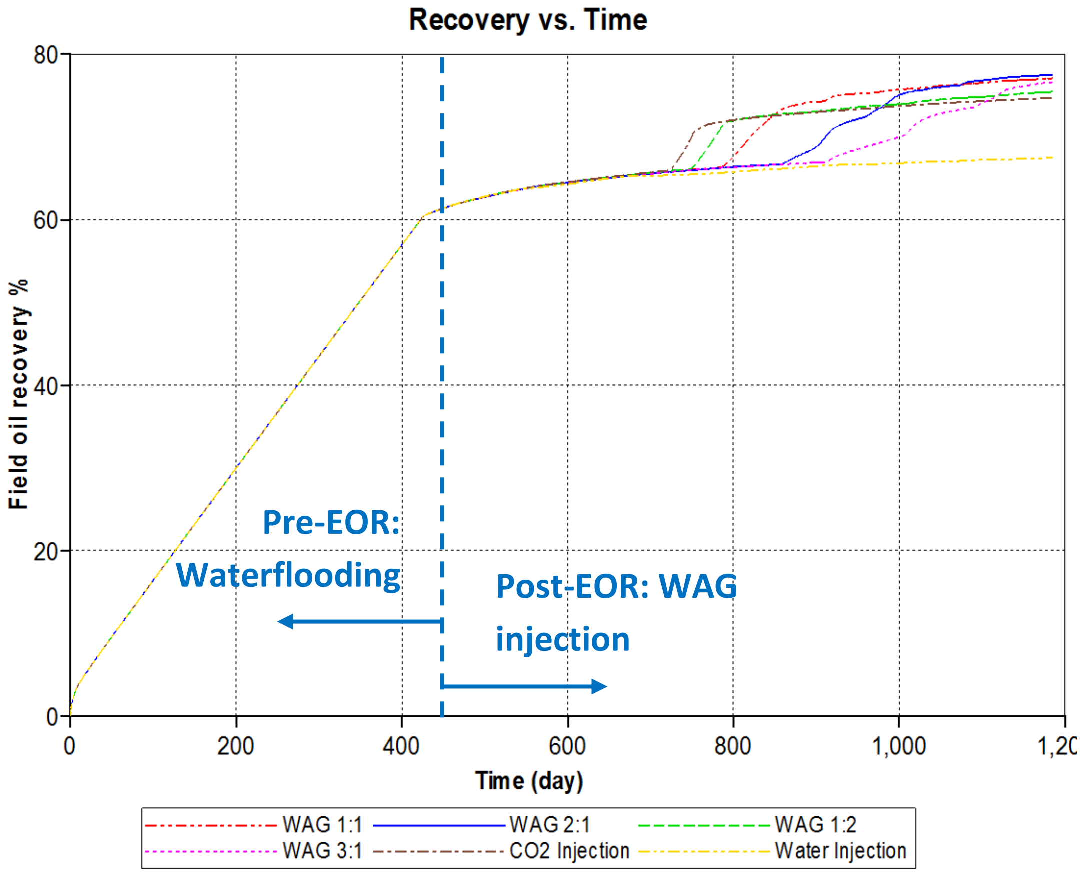

Figure 12 Field recoveries vs. production time for different WAG ratios

Previously, it was mentioned that the simulated reservoir was depleted and waterflooded before the WAG was applied on the field. Thus the timeline of the graphs can be divided into two stages, namely pre-EOR and post-EOR. In the pre-EOR stage, all of the scenarios with different WAG ratio yield the same recovery trends because only water flooding is involved. All scenarios have the same water injection rate and injection period during the waterflooding. Nonetheless, these pre-EOR trends will not be analyzed. Instead, the focus of analyses is the post-EOR stage because the main objective of this FYP was to determine the performance of different WAG schemes, which occurs in the post-EOR stage.

Figure 13 below shows the magnification of Figure 12 in the post-EOR stage. The post-EOR stage, where the WAG was initiated, started at 430th day in the simulation. This is the time when the water cut at the surface exceeded 80% of the total production (economic constraint for waterflooding). For convenience, the lower boundary of the abscissa was set to the 400th day.

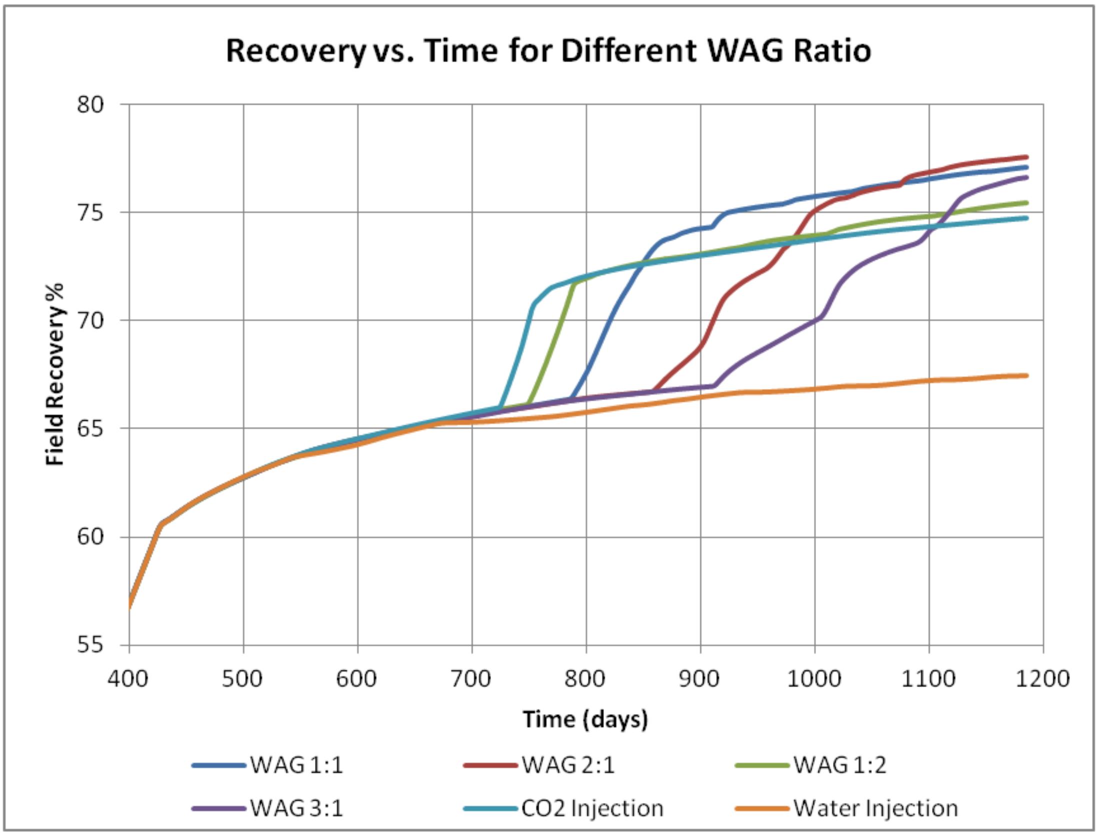

Figure 13 Post-EOR field recoveries vs. production time for different WAG ratios

One must note that the timing to initialize the WAG injections might be different for each scenario due to the difference in time to water breakthrough. The reason is that different WAG schemes will result in slightly different values of total pore volume injected after a period of time. Consequently, the time to water breakthrough varies for different scenarios. Thus, it is more reasonable to plot and interpret the field recovery for different WAG schemes against the total fluid injected in terms of pore volume injected (PVI) because water breakthrough for a same reservoir model occurs after the same value of PV of fluid has been injected (Example of calculation of PVI can be found in Appendix A). However, in this simulation case, the time to water breakthrough are almost the same for all scenarios. So, the WAG are applied at the same time, and hence the *Field recovery vs. PVI* plot gives the same trends as the *Field recovery vs. time* plot, as shown in the following **Figure 14**. From the graph, the WAG ratio which gives the highest recovery after 1.3 PV of fluid had been injected is WAG ratio of 2:1, followed by 1:1, 3:1, 1:2, carbon dioxide injection and lastly water injection.

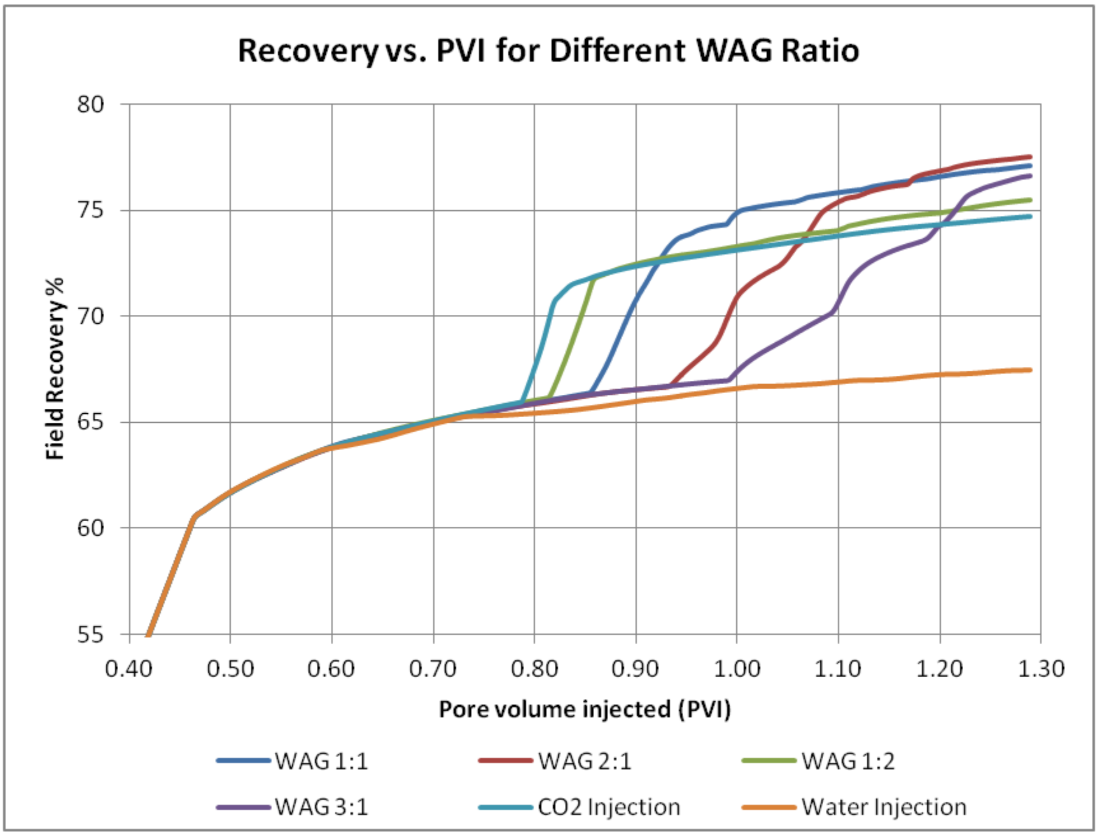

Figure 14 Post-EOR field recoveries vs. Pore Volume Injected (PVI) for different WAG ratios

The water injection curve (orange curve) represents the recovery for the continued water-flooded after the water cut has exceeded 80%. This curve serves as the comparison between the ultimate recovery of waterflooding and WAG injections. From the ultimate recovery, the optimum WAG ratio is 2:1.

However, the conclusions drawn above are based purely on the ultimate recovery of each WAG schemes after 1.3 PV of displacing fluids were injected. The operating constraints were not taken into consideration. In real life practices, the operating constraints especially the economical constraint is the prime factor which affects the determination of optimum schemes. As suggested by Green and Willhite (1998), the economic limit consideration for a WAG application is to stop the EOR WAG and abandon the well at 90% water cut after the displacing fluid reached the production well. Consequently, the ultimate recovery of the WAG schemes is taken as the field oil recovery at the economic limit of 90% water cut. **Figure 15** below shows the modified graphs of Figure 14:

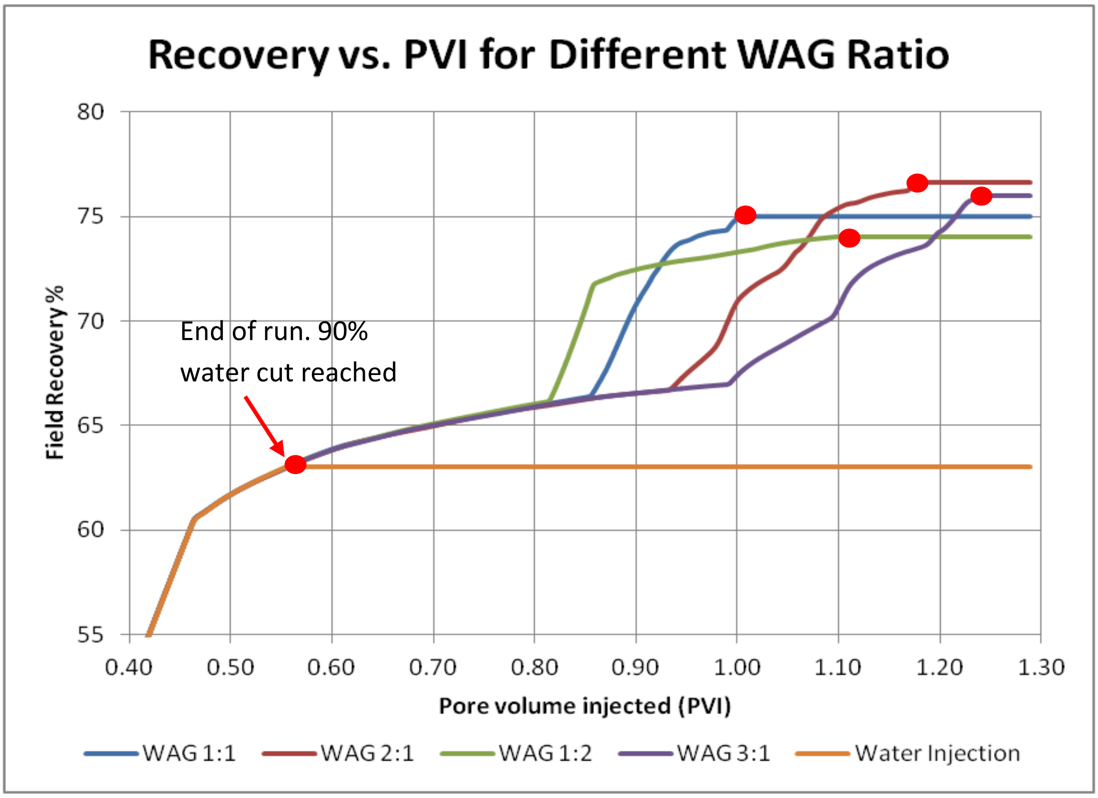

Figure 15 Post-EOR field recoveries vs. Pore Volume Injected (PVI) for different WAG ratios (with economic constraint)

The CO_2 injection curve was omitted from the graph because there will be no water breakthrough or water cut. The red dots in the graph are the points where 90% water cut was reached. The well was shut in and abandoned after that, thus the field recovery stays unchanged and the curve forms a plateau. The summary is shown in the table below. The additional recoveries from each WAG scheme is calculated as the differences between the WAG injection-curves with the water injection curve:

Table 6 Performance for different WAG ratios

WAG Ratio	Without economic constraint		With economic constraint		PVI before Incremental Production
	Ultimate Recovery (%)	Additional Recovery (%)	Ultimate Recovery (%)	Additional Recovery (%)	
1:1	77.09	9.62	74.99	11.94	0.85
2:1	77.54	10.07	76.63	13.59	0.93
1:2	75,47	8.00	74.01	10.96	0.81
3:1	76.61	9.14	75.97	12.93	0.99
1:0 (Water Injection)	67.47	N/A	63.04	N/A	N/A

If the economic constraint is to be taken into account, it is clear that the most optimized WAG ratio is 2:1 WAG, followed by 3:1, 1:1, 1:2, and water injection. WAG with ratio of 2:1 yields the highest recoveries of all WAG ratios. Generally, the recovery increases as the WAG ratio increases. Higher WAG ratio means more water and less gas were injected in a WAG cycle. However, too much water volume in 1 complete WAG cycle will result in decrease in field recovery. This is demonstrated by the lower recovery of 3:1 WAG compared to 2:1 WAG. This can be explained by the oil trapping theory proposed by Sharma & Clements, (1996). According to Sharma and Clements (1996), water presents adverse effect on the microscopic displacement efficiency of gas because too much water will form 'shields' of water which block the communication between the gas and oil, thus preventing the gas from displacing the oil at pore scale.

As shown in the graph, the oil production responses were different for different WAG ratio. The WAG ratio which gives the earliest incremental production is WAG ratio of 1:2 at 0.81 PVI, followed by WAG ratio of 1:1 at 0.85 PVI, WAG ratio of 2:1 at 0.93 PVI and WAG ratio of 3:1 at 0.99 PVI. From here, we can conclude that the higher the WAG ratio, the slower is the production response. This, again, can be related to the statement made by Sharma & Clements (1996). The water shields the gas from contacting the oil immediately. The gas has to dissolve into and diffuse through the water to contact, swell and displace the oil. As a result, the microscopic displacement by gas is delayed.

The continuity in displacing forces also contributes to earlier recovery by lower WAG ratio. The diagram following this paragraph, **Figure 16** shows the illustrative comparison between the oil displacement by 1:1 WAG and 1:2 WAG. Lower WAG ratio gives a relatively larger continuous slug of gas, which has higher microscopic displacement efficiency. This larger continuous gas slug serves as the displacing agent which continuously pushes the oil towards the producer. If water is injected, the water will not contribute to the displacing forces to the gas phase. Instead, the injected water flows to the bottom of the reservoir due to gravity segregation. This would create a discontinuity in the displacing forces, consequently slower displacement of oil towards the producer:

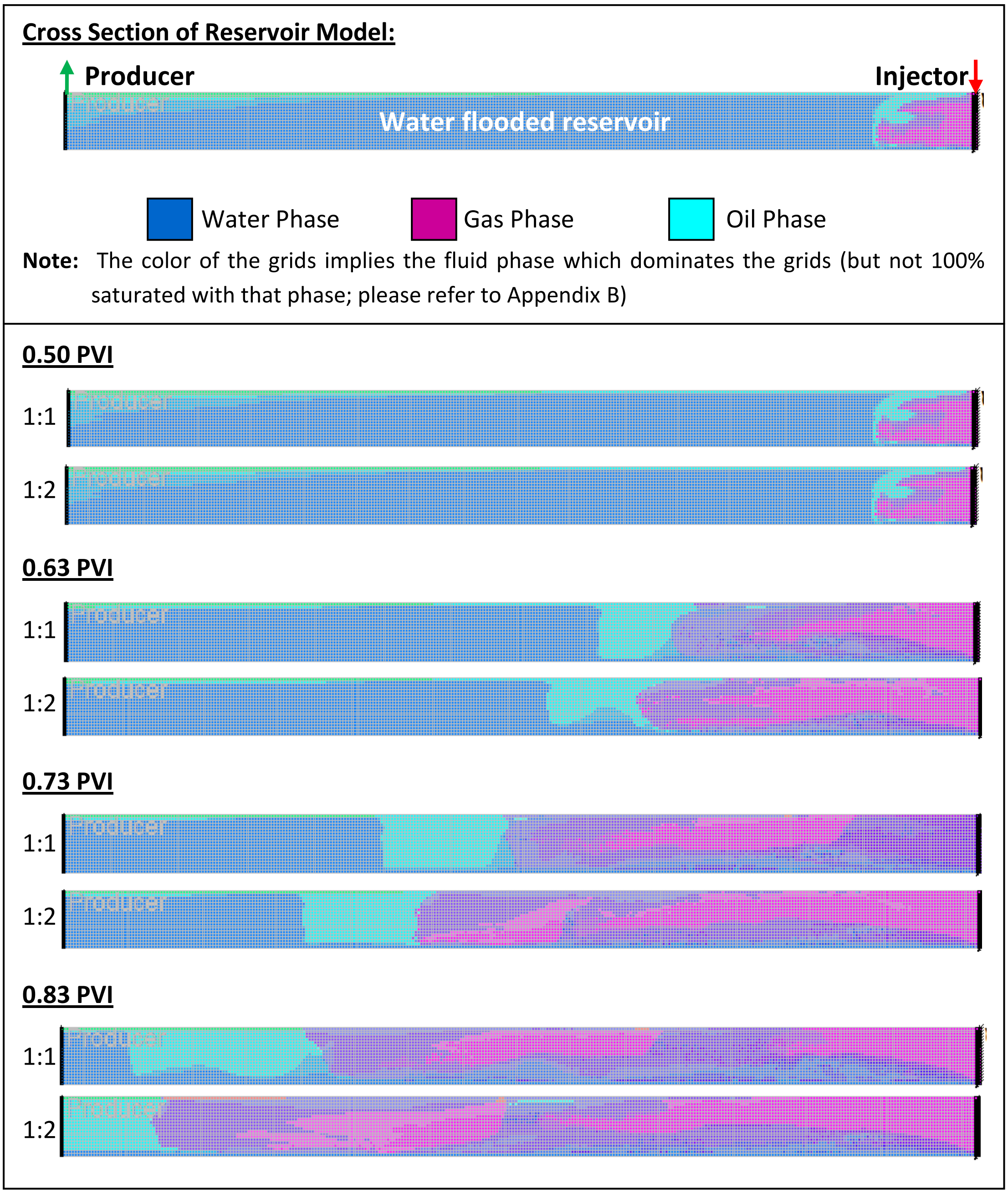

Figure 16 Illustrative Comparisons between 1:1 WAG and 1:2 WAG

In the nutshell, although giving the highest recovery, 2:1 WAG might not be the most attractive WAG schemes due to the delayed in production. The selection of optimum schemes depends on the policy of the operator, whether to produce faster but losing a slight number of recoverable OIIP, or increase the reserves but produce slower. However, from the perspective of ultimate recovery, WAG ratio of 2:1 is the optimum WAG ratio to be applied on a sandstone reservoir. In addition, 2:1 WAG is also more economic favorable because it injects less gas (more expensive) than water (cheaper), compared to WAG of 1:1 or 1:2 ratio.

4. 2 Effect of WAG Cycle Size

The WAG cycle size refers to the period of time for a complete loop of gas and water injection. The larger is the WAG cycle size, the longer is the injection period. 1:1 WAG with 100 days cycle means that the gas is injected for 50 days, followed by water injection for another 50 days.

3 simulation runs with different WAG cycle sizes were conducted. **Figure 17** shows the recoveries from the 3 scenarios, with economic consideration.

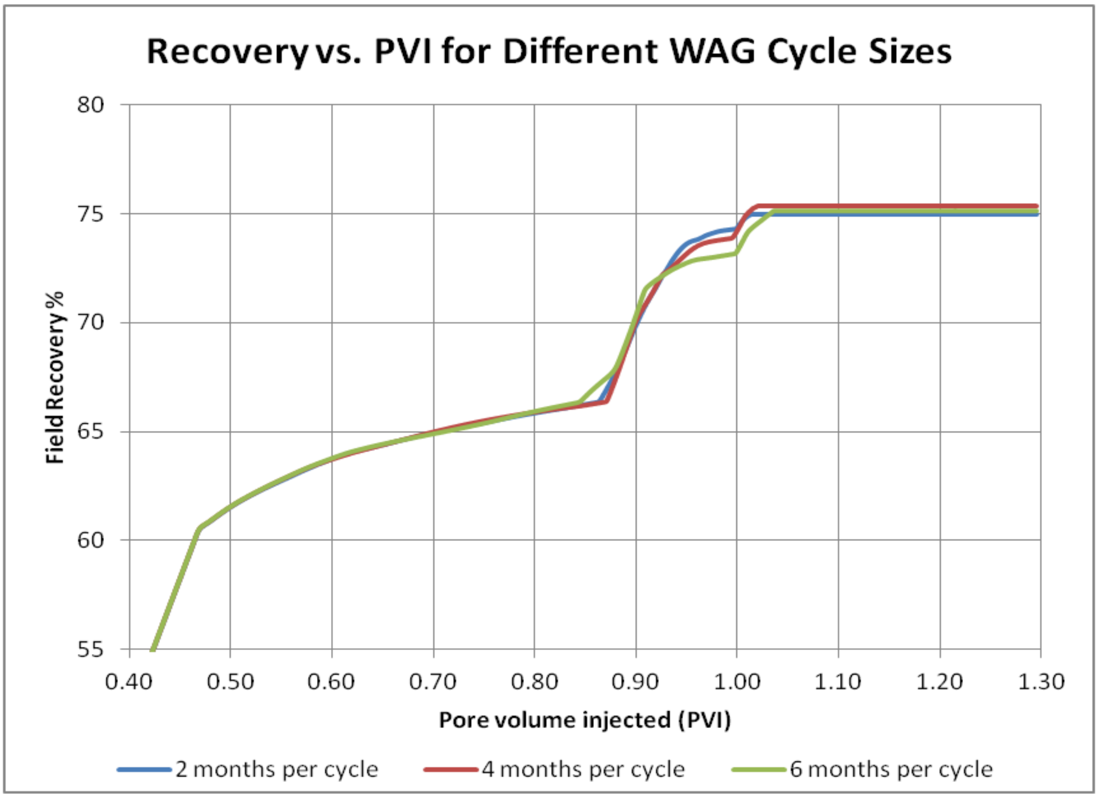

Figure 17 Post-EOR field recoveries vs. Pore Volume Injected (PVI) for different WAG cycle sizes (with economic constraint)

From the simulations results, it can be concluded that the WAG cycle sizes impact the performance of WAG in this reservoir model to a minimum extent. The main concern of WAG application is to improve the mobility ratio and reduce viscous fingering. The injected slug size must be sufficiently large enough to prevent the subsequent slugs from penetrating it. If the slug is too small and consequently deteriorated by the following slugs, the application of WAG loses it purpose because viscous fingering might occur. Hence, it is crucial to determine the minimum slug size required before applying WAG. The slug size is actually proportional to the

WAG cycle size if the injection rate is constant. The required WAG cycle size depends on the size of the reservoir. One can easily deduce that larger reservoir requires larger WAG cycle sizes in order to maintain the slugs injected.

The simulation results above showed insignificant impact of WAG cycle sizes on the performance of the WAG because the reservoir model is not large enough to exhibit the consequences of using inappropriate cycle sizes. The simulations above adopted a 2-dimensional reservoir and small reservoir size due to the constraint in license capacity. Nevertheless, one insight which can be obtained from the results above is that when the WAG cycle size is already large enough to prevent slugs deterioration, an incremental in the cycle size will not give significant increase in the ultimate recovery.

4. 3 Effect of WAG Gas

As mentioned previously, one of the objectives of this FYP is to assess the potential and feasibility of other types of gas to be applied in WAG. Normally CO_2 is used because it is economically preferable (cheaper than other types of gas such as hydrocarbon gas) and possesses relatively lower minimum miscibility pressure (MMP). However, some operators did use some other gases for WAG application but it is very rare.

5 different gases were simulated for WAG applications in this simulation study. In the first scenario, carbon dioxide (CO_2) was injected as displacing fluid and in the second scenario, nitrogen (N_2) was injected. The remaining 3 scenarios used hydrocarbon gases (HC) as displacing fluids, but with different compositions. 2 of the HC gases are enriched gases, both having liquefied petroleum gas (LPG, i.e. C_2 – C_4) concentration of 40% and 60% respectively. The compositions of the enriched gases were obtained from the literature by Shyeh-Yung and Stadler (1995). **Table 7** below shows the compositions of the two enriched gas. The last scenario uses displacing fluid composed of mainly lean gas (methane). Technically, only 3 types of gas were included in this simulation study, namely carbon dioxide, nitrogen, and hydrocarbon gas. All of the gases were used in a 1:1 WAG injection with constant injection rate of 26 bbl/day.

Table 7 Compositions of injected HC gas

Component	60% LPG	40% LPG
Methane, C_1	0.378	0.506
Ethane, C_2	0.457	0.432
Propane, C_3	0.098	0.033
Butane, C_4	0.054	0.011
Nitrogen	0.013	0.018

Figure 18 below shows the comparison of post-EOR field recoveries of WAG using different types of gas:

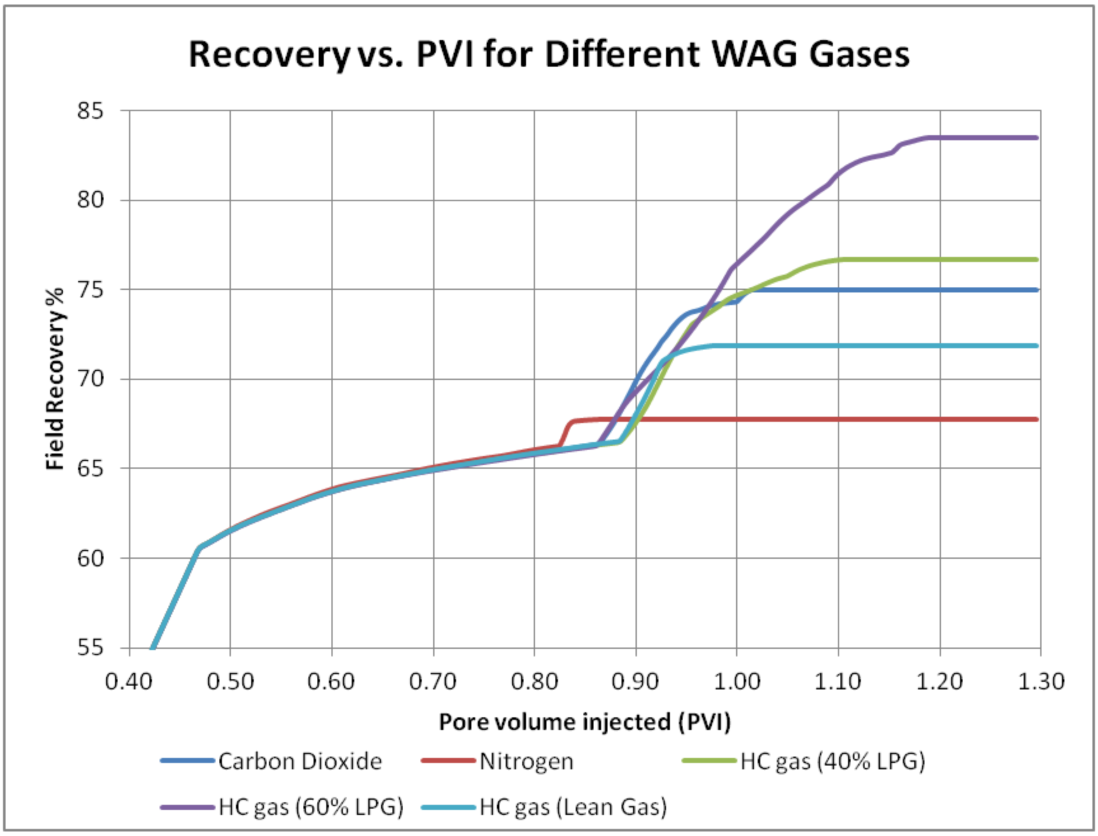

Figure 18 Post-EOR field recoveries vs. Pore Volume Injected (PVI) for different WAG gases (with economic constraint)

The result shows that with an economic constraint which sets the abandonment at 90% water cut, WAG using HC gas with 60% LPG gives the highest ultimate recovery. It is followed by WAG using HC gas with 40% LPG components, WAG using carbon dioxide, WAG using lean gas, and WAG using nitrogen gas.

The high recovery by HC gases is credited to the miscibility of HC gas with the reservoir oil. A separate simulation in WinProp shows that none of the gases above can achieve first contact miscibility (FCM) with the reservoir oil due to the depleted reservoir pressure below MMP. However, multiple contact miscibility (MCM) is still possible by condensing gas drive and vaporizing gas drive. MCM is a dynamic process where the miscibility is achieved after the mass exchanges between the injected gas and the reservoir oil. The injected gases will exchange components with the reservoir oil by either condensing the light intermediate components (C_2 – C_4) from the injected gas into the reservoir oil, or vaporizing the middle intermediate components (C_{4+}) from the reservoir oil into the gas. Through multiple repeated contacts and components exchanges between the gas front and the reservoir oil, the compositions of both fluids will eventually became similar with each other. The miscibility is then achieved and the residual oil (which was bypassed during waterflooding) is displaced as one phase with the gases. This results in lower residual oil saturation and higher oil recovery.

From **Figure 18**, it is obvious that the LPG components in HC gases play a crucial role in achieving MCM. HC gas with 60% LPG can achieve higher total oil recovery compared to HC gas with 40% LPG. On the other hand, HC gas with low LPG concentration and high methane content yields relatively lower recovery. This is simply due to the condensing role of LPG components in the condensing gas drive. Lee *et al*. (2001) also suggested that the enrichment of injected gas has profound effects on reducing the residual oil saturation, and this reduction is related to fluid thermodynamic effects.

From the WinProp EOS calculations, the minimum pressure to achieve MCM between CO_2 and reservoir oil is around 4370 psia. Thus it can be concluded that the WAG using CO_2 in this simulation study is actually immiscible displacement. Nevertheless, immiscible WAG using CO_2 can still improve the recovery through 4 mechanisms, namely viscosity reduction, oil expansion, interfacial tension reduction and blowdown recovery (Mangalsingh & Jagai, 1996). The CO_2 in contact with the oil will extract some of the heavier components of the oil, resulting in reduction of viscosity. The dissolution of CO_2 will swell the reservoir oil, increasing its volume, thus making it easier to be displaced. In addition, the introduction of acidic CO_2 will alter the system pH, eventually reducing the system interfacial tension (IFT). During an immiscible CO_2 injection, the CO_2 was ‘forced’ to solute into the oil by the high injection pressure. This dissolution of CO_2 will store some of the energy inside the

CO_2. As the production continues, the CO_2 will be liberated and the energy stored will serve as the blowdown recovery mechanism to drive the fluid to the producer.

The WAG with N_2 gas in this simulation is also an immiscible WAG. Hardly any oil bank was formed in front of the gas front. **Figure 19** shows the illustrative comparison between the WAG using HC gas (60% LPG), N_2 gas and CO_2:

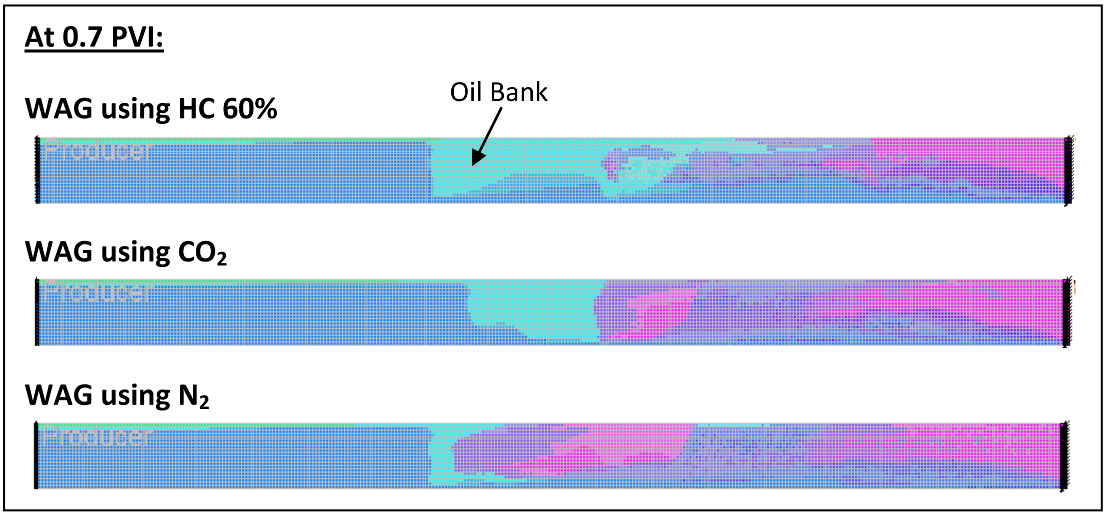

Figure 19 Illustrative Comparisons between WAGs using different gases

Shyeh-Yung and Stadler (1995) suggested that the higher nitrogen-oil IFT resulted in less dissolution of nitrogen into the reservoir oil. In addition, comparing with carbon dioxide, less oil components were extracted into the nitrogen gas. All of these contributed to the low efficiency of nitrogen gas to displace residual oil, thus lower oil recovery.

On a side note, notice from **Figure 19** that at the same reservoir PVI with same injection rate, the oil bank for WAG using 60% LPG is bigger than of CO_2 WAG; and the gas volume in the former one is less than the latter one, even though the same reservoir barrels of gas were injected. This is due to the higher miscibility of LPG WAG, as compared to CO_2 WAG. As mentioned previously, the LPG WAG can achieve MCM while the CO_2 WAG is an immiscible WAG, thus more oil is bypassed in the CO_2 WAG.

No matter how successful a gas in WAG application, the economical value of the project had to be taken into account. Hydrocarbon gases with LPG are extremely expensive compared to other types of gas. Thus, it has to be optimized by injecting the suitable size of HC gases in order to balance the cost. In most field cases, LPG-enriched gases are usually not adopted because of the high cost. In addition, the availability of the gases is also one of the main issues to be considered.

4. 4 Effect of WAG Injection Rate

All the simulations discussed above were implemented at a constant injection rate of 26 res bbl per day. To investigate the impacts of injection rates on the ultimate recovery of WAG, 5 different injection rates were simulated for a 1:1 CO_2 WAG injection. **Figure 20** shows the simulation results where the post-EOR recoveries of WAG using different injection rates are plotted against PVI. Similar to the analysis conducted above, the economic constraint is to abandon the well at 90% water cut.

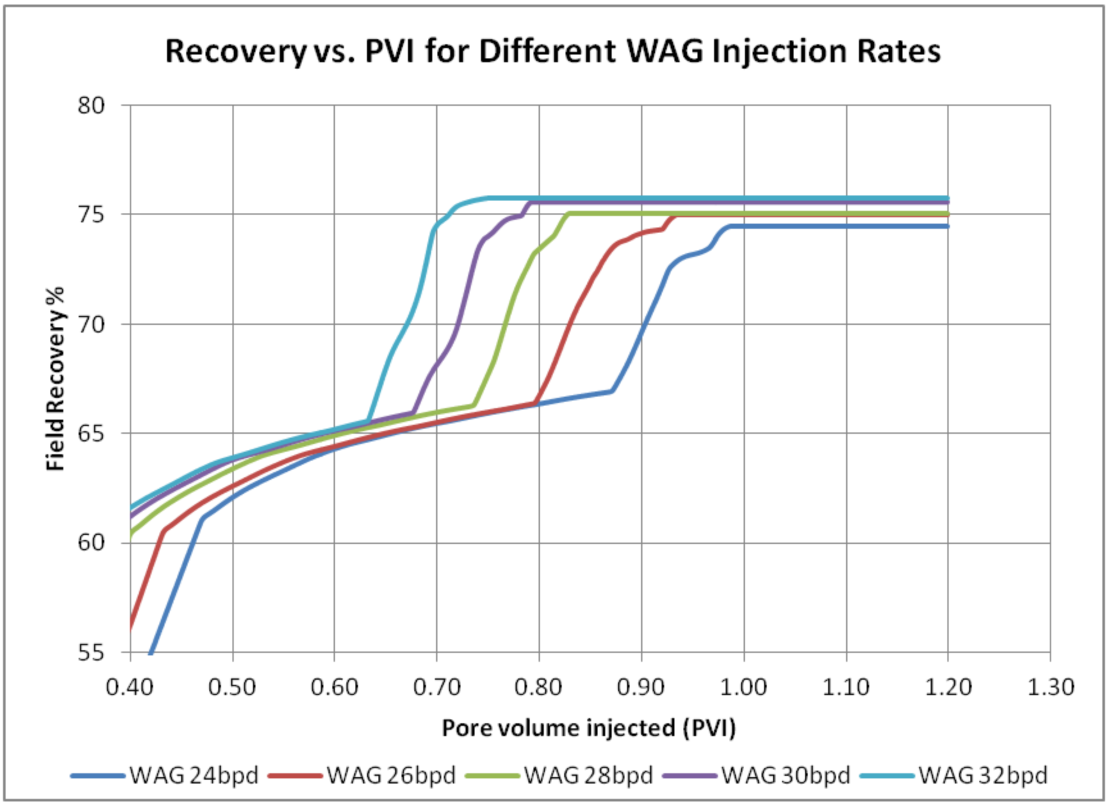

Figure 20 Post-EOR field recoveries vs. Pore Volume Injected (PVI) for different WAG injection rates (with economic constraint)

Generally, the higher the injection rates, the higher is the ultimate recovery and the faster is the production response. The mild incremental in injection rates present relatively smaller impacts on the ultimate recovery. As a contrast, the incremental in injection rates will lead to significantly earlier production response. As shown in the figure above, when the injection rate is increased from 24 bpd to 26 bpd, the production response was detected earlier by a PVI of 0.80.

The observations on the ultimate recovery and production response above can be related to the viscous force domination resulted from the incremental in both water and gas injection rate. When the water injection rate is increased, the effect of viscous force is also amplified, thus the displacing front can displace better. As a result, the production response comes earlier. On the other hand, when the gas injection rate is increased, the viscous force will dominate over the gravity effects, leading to less gas overriding the water. Consequently, as gas injection is increased, more gas will displace the residual oil at the lower part of the reservoir and microscopic sweep efficiency increased.

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

5. 1 Conclusions

From the simulation study conducted, the following conclusions can be drawn:

1. Increase in WAG ratio generally increases the ultimate recovery, but WAG ratio must not be too large to cause severe oil trapping, which will decrease the ultimate recovery. On the other hand, higher WAG ratio will lead to slower production response due to the water shielding effects.
2. Variation in WAG cycle sizes does not impact the WAG recovery significantly if the WAG slug sizes are big enough to prevent the deterioration of slugs. The main concern is to design the WAG cycle sizes so that the slugs will not be penetrated by subsequent slugs.
3. Types of gas used in WAG present a big impact on the field recovery of WAG. The types of gas used determine the miscibility of the gas injectants and the reservoir oil. HC gases with high LPG content were proven to yield higher recovery, followed by CO_2 WAG, lean gas WAG, and nitrogen WAG. However, the economic considerations have to be taken into account, i.e. cost and availability of the gases.
4. Increase in injection rate will lead to higher and earlier recovery due to the increase in viscous force to gravity ratio.

In conclusion, the objectives of this FYP were achieved. The impacts of each of the WAG parameters listed were thoroughly investigated, and the results were summarized in the conclusions above. In addition, the performances using different types of gas were also evaluated. All these findings shall provide a good insight for the WAG applications in the industry.

5. 2 Recommendations

The time is the main limiting factor of this project, as the students are only given 12 academic weeks to conduct the preliminary researches (FYP I) and another 12 weeks to complete the actual researches (FYP II). The available time is further reduced considering that the students need to attend classes and lectures.

Another progress limiting factor is the learning of the software. There was no expert or experienced CMG user in the college. Thus references and assistances in learning to use the software were not available. Self-learning and trial-and-error exercises were the only way to learn to use the software. Although the support department of CMG can be access through email, the consultants are not always available. Thus, it is recommended to provide the students with the tutorial to assist the learning of this software, in order to speed up the progress of FYP similar to this.

Besides, it is recommended to get some of the actual field data from the companies, such as PETRONAS. This would add the credibility of this research aside from helping the companies to conduct researches. In fact, the actual field data can serve as good inputs for economic analysis of WAG. One of the main reasons economical analysis was not conducted to determine the feasibility of different types of gas in WAG application is due to the lack of information regarding the actual field data, i.e. cost of solvents, injectivity of solvent etc.

Last but not least, it is recommended to expand the CMG license capacity. Due to the limitation of license capacity, the permitted number of grids in the simulations is restricted, and this FYP is unable to conduct the simulation study on a wide 3D scale. In addition, there are only 2 licenses available for CMG, and there were more than 2 students (including the post-graduate students) involving in simulation study using CMG. As a result, during the whole process of this FYP, there were interruptions in the progress due to insufficient number of licenses.

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APPENDICES

Appendix A: Pore Volume Injected Calculation

The following shows the calculation of the pore volume injected at 430^{th} day:

Injection rate, Q = 26 bbl/day

At 430^{th} day, t = 430 days

Cumulative injected volume = 430 × 26 = 11180 bbl = 63×10^3 cu ft

Reservoir pore volume, PV = 132×10^3 cu ft (Table 3)

PVI at 430^{th} day = $63 \times 10^3 / 132 \times 10^3$ = 0.48 PVI

Appendix B: Explanation of Ternary Saturation Distribution Diagram

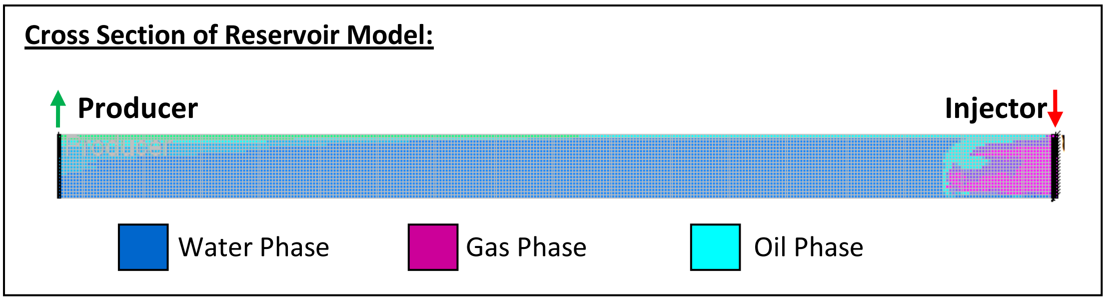

Figure 21 Ternary saturation distribution diagram

Figure 21 shows the ternary saturation distribution across the reservoir model at 0.5 PVI. The reservoir model is consisted of many grids and the colors in the diagram represent the phase which **dominates** the grids. However, the grid is not 100% saturated with the dominating phase.

One must not confuse this diagram representation with the actual fluid distribution in the reservoir model. In the diagram, almost 80% of the reservoir model is color-coded blue (water phase). This, however, does not imply that 80% of the reservoir is fully filled with water. The correct interpretation is that 80% of the reservoir model grids are dominated by water phase. Within each of these water-dominated grids, gas phase and oil phase are still exist, but their individual saturation is less than the water saturation (thus water dominates the grid). For example, the water saturation in a grid is 40% while the gas saturation and oil saturation is 30% respectively, then the ternary saturation distribution diagram will color-code the grid as blue.

On the other hand, in the case of 0.5 PV of fluid had been injected into the reservoir, one cannot expect to see a phase distribution like the following diagram:

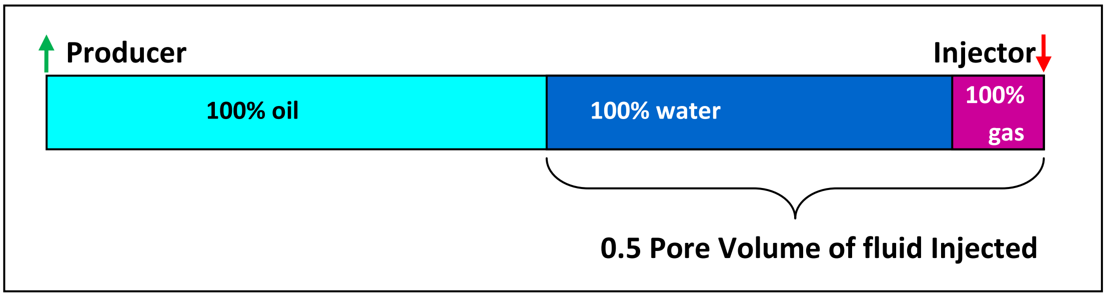

Figure 22 Piston-like displacements

The displacement profile in **Figure 22** is an extreme simplification of the water/gas displacement, i.e. a piston-like displacement. One should not expect this kind of displacement because the heterogeneities of the reservoir and the residual saturations of oil would not allow the injected displacing fluid to fill the reservoir grids completely. Instead, the injected fluid phase will move to other grids before fully filling the previously-contacted grids. Eventually, the injected fluid might already reach the production ends even though only 0.5 PV of fluid (instead of 1.0 PV) is injected into the reservoir, as shown in **Figure 21**.

Thus, by referring to **Figure 21** above, even though it seems that the whole reservoir model had been flooded by the injected fluid, the actual PVI is less than 1.0 (0.5 PVI in this case).