IMPACT OF CAPILLARY PRESSURE ON NUMERICAL SIMULATION OF IMMISCIBLE WATER-ALTERNATING-GAS (IWAG) INJECTION

by

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Dissertation submitted in partial fulfilment of

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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the
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Approved by,

____

(Ms Azeb Demisi Habte)

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

January 2015

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.

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IZZATI BINTI ZULKIFLI

ABSTRACT

IWAG is extensively used as an enhanced oil recovery method worldwide with diverse extent of success. IWAG simulations normally do not incorporate capillary pressure effect. This parameter is always neglected due to unavailability of reliable measured data or the assumption of insignificant effect. However, former studies indicate that capillary pressure is important in porous media flow description because of the saturation distribution in the capillary-like pore spaces. The aim of this project is to investigate the impact of three-phase capillary pressure on the field oil recovery, water cut and oil relative permeability of IWAG injection process at different water-oil mobility ratio. The study involves fully penetrating wells, vertical injection and production wells in a three-dimensional oil reservoir which is homogeneous, isotropic, and with uniform thickness. To examine the effect of three-phase capillary pressure, the injection rate is varied from low to high. The finding of this study shows that three-phase capillary pressure has significant impact in IWAG simulation process. This work found that capillary pressure and its hysteresis have significant impacts on the field oil recovery, water cut and oil relative permeability under favorable water-oil mobility ratio. Field oil recovery increases up to 3% under low injection rate but decreases up to 7% under high injection rate. This indicates that high rate of injection dominates the effect of capillary forces. It is also shown that oil relative permeability is higher when capillary pressure is included. Incorporating capillary pressure also causes earlier water breakthrough with maximum 8.4% differences is recorded.

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CHAPTER 1

INTRODUCTION

1.1 Background

Substantial quantities of oil normally remain in the reservoir after conventional recovery which is around 65-70 % OIP, Terry (2000) & Thomas (2008). A significant portion of this residual oil can be economically recovered through Water-Alternating-Gas (WAG) injection. In WAG injection, water and gas injection are carried out alternately in a reservoir for a period of time to provide both microscopic and macroscopic sweep efficiencies. WAG injection improves oil recovery by taking benefit of the increased microscopic displacement of gas injection with the improved macroscopic sweep efficiency of water flooding. Both miscible and immiscible WAG (IWAG) injections have been successfully applied worldwide with typical recovery of 5-10% OIP, Christensen et al. (2001) & Skauge & Dale (2007). Despite of widely successful application of WAG injection, numerous laboratory experiments, modelling and numerical simulation on the WAG recovery method continues to be major interest in EOR. This study is focusing on IWAG numerical simulation with inclusion of three-phase capillary pressure specifically in three-phase flow porous media.

1.2 Problem Statement

Contructing numerical simulation model for any EOR process is a key to the forecasting of ultimate oil recovery. However, the influence of capillary pressure is often disregarded in numerical simulation of IWAG due to insufficient data or the assumption of insignificant capillary effect. Yet, previous studies show that capillary pressure has significant effect particularly in three-phase flow. Without capillary pressure effect, relative permeability of oil will be underestimated whilst relative permeability of injectants, gas and water will be overestimated thus providing erroneous estimation in total oil recovery.

1.3 Objective

The objective of this project is to investigate the impact of three-phase capillary pressure on the field oil recovery, water cut and oil relative permeability of IWAG injection process at different water oil mobility ratio.

1.4 Scope of Study

This study is restricted to numerical simulation of IWAG process with 1:1 WAG ratio. According to Kulkarni (2001) this ratio is the most popular in field applications. The simulation approach encompasses drainage and imbibition processes, relative permeability and capillary pressure hysteresis in three-phase flow for a water-wet system. Fully penetrating, vertical injection and production wells in a three-dimensional oil reservoir which is homogeneous, isotropic, and with uniform thickness will be considered. Gas and water are injected at constant rate from the surface. Gravity and temperature effects are negligible.

CHAPTER 2

LITERATURE REVIEW

2.1 Displacement Efficiency

Overall displacement efficiency is defined as

$$E = E_V \times E_D \quad (1)$$

where;

E = Overall hydrocarbon displacement efficiency
E_V = Macroscopic (volumetric) displacement efficiency
E_D = Microscopic (volumetric) displacement efficiency

The macroscopic displacement efficiency is made up of two terms

$$E_V = E_A \times E_L \quad (2)$$

where;

E_A = Areal sweep efficiency
E_L = Vertical sweep efficiency

Macroscopic efficiency is affected by the fluids density difference and rock heterogeneity. The microscopic displacement efficiency is influenced by the interfacial interactions involving interfacial tension and dynamic contact angles.

2.2 Mobility Ratio

Mobility is defined as the ratio of its relative permeability in a porous medium to its viscosity. Mobility controls the relative ease with which fluids can flow through a porous medium. General equation for mobility ratio is expressed as:

$$M = \frac{\lambda_{ing}}{\lambda_{ed}} = \frac{k_{rw}/\mu_w}{k_{ro}/\mu_o} \quad (3)$$

where;

M = mobility ratio

λ_{ing} = mobility of displacing fluid

λ_{ed} = mobility of displaced fluid

k_n = relative permeability for a specific phase, n

μ_n = viscosity for a specific phase, n

A value of M < 1 is considered as favourable where the displaced fluid flows easier than the displacing fluid. Otherwise, M > 1 reflected an unfavourable condition.

2.3 Capillary Pressure

Ahmad (2006) in his Reservoir Engineering Handbook explains capillary forces in a petroleum reservoir are the result of the combined effect of the surface and interfacial tensions of the rock and fluids, the pore size and geometry, and the wetting characteristics of the system. Any curved surface between two immiscible fluids has the tendency to contract into the smallest possible area per unit volume. This is true whether the fluids are oil and water, water and gas (even air), or oil and gas. When two immiscible fluids are in contact, a discontinuity in pressure exists between the two fluids, which depends upon the curvature of the interface separating the fluids. The pressure difference between the immiscible fluids is known as capillary pressure or the pressure in the non-wetting phase minus the pressure in the wetting phase.

$$P_c = P_{non-wetting} - P_{wetting} \quad \text{......} \quad (4)$$

That is, the pressure excess in the nonwetting fluid is the capillary pressure, and this quantity is a function of saturation. This is the defining equation for capillary pressure in a porous medium.

There are three types of capillary pressure which are water-oil capillary pressure (Pcwo), gas-oil capillary pressure (Pcgo) and gas-water capillary pressure (Pcgw). Applying the mathematical definition of the capillary pressure, the three types of the capillary pressure can be written as:

$$P_{cwo} = P_o - P_w \quad \text{......} \quad (5)$$

$$P_{cgo} = P_g - P_o \quad \text{......} \quad (6)$$

$$P_{cgw} = P_g - P_w \quad (7)$$

where;

Pg, Po, and Pw = Pressure of gas, oil, and water

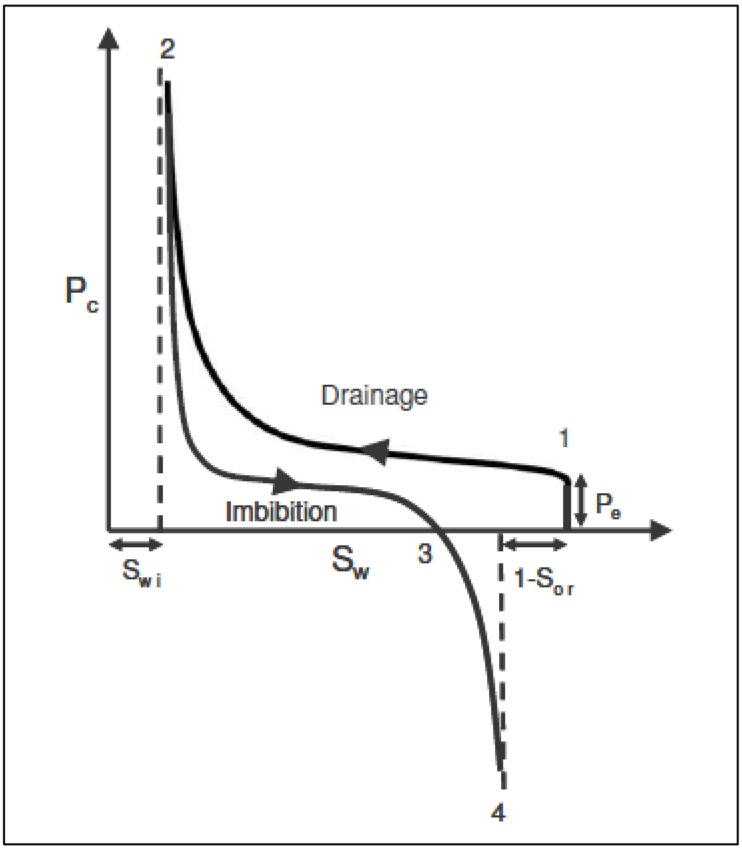

Figure 1: Capillary pressure curves, Elisabeth (2008)

In describing capillary pressure, drainage and imbibition terms are always be incorporated. Drainage is the process where the non-wetting fluid displaces the wetting fluid, and imbibition is the process where the wetting fluid displaces the non-wetting fluid.

When oil is forced into the oil-water system by increasing the oil pressure between point 1 and 2, primary drainage occurred. When decreasing the oil pressure after primary drainage the capillary pressure will decrease, and the water will spontaneously enter the rock, between point 2 and 3. This spontaneous imbibition will stop when the capillary pressure reaches zero, point 3. In order to increase the water saturation further the pressure in the water phase has to be increased. The capillary pressure will get a more and more negative value, between point 3 and 4. This is called forced imbibition. When the residual oil saturation is reached the capillary pressure goes towards minus infinity. Because of hysteresis effects, the capillary pressure is different for drainage and imbibition.

According to Tiab & Donaldson (2011), capillary number is a dimensionless group that represent the ratio of viscous forces to the iterfacial forces affecting the fluid flow in porous media. The capillary – viscous number is an indication of the importance of capillary forces in the displacement process and whether capillary equilibrium can be reached.

$$N_c = \frac{v\mu}{\sigma} \quad \text{.......} \quad (8)$$

where;

N_c = capillary number,
v = velocity (m/s),
μ = viscosity of displacing fluid,
σ = IFT between displacing and displaced fluids

Baker (1998) remarked that the capillary-viscous number is useful in that it indicates how sharp or diffuse the flood front will be and how much viscous fingering may occur. It is also critical in understanding if capillary forces are a dominant force.

2.4 Enhanced Oil Recovery (EOR)

Industry conventionally recovers an average of around 35% of oil from reservoirs worldwide while the rest remains trapped, Gurgel et al. (2008); Terry (2000); Zitha et al. (2011). The techniques applied to increase the amount of crude oil that can be extracted by conventional methods is commonly referred to as Enhanced Oil Recovery (EOR). Various EOR methods have being employed for the recovery of light and heavy oils, with varying degree of success. A typical categorization of these methods is presented in Fig. 2 below.

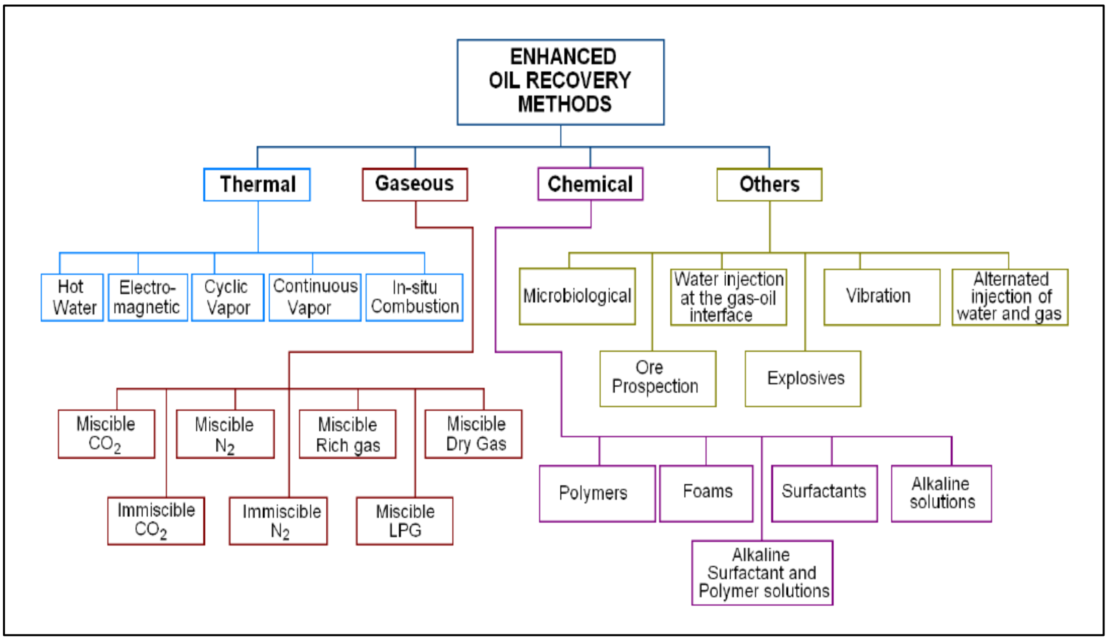

Figure 2: General classification of EOR methods, Gurgel et al. (2008)

Have being tested since 1950's, thermal flooding best suited for heavy oils (10-20 °API) and tar sand (≤ 10 °API), Thomas (2008). Heavy oil is characterized by high viscosity. Reduction in viscosity always acts as the major mechanisms in thermal method. Thermal recovery introduces heats to the reservoir to raise the temperature of oil and reduces its viscosity, hence improving mobility ratio. Steam injection, hot water and in-situ combustion are the popular thermal recovery methods. Terry (2000) cites that most of the oil produces from EOR method to date are as a result of thermal process.

Gas flooding normally can be achieved by two process, miscible or immiscible based on minimum missibility pressure (MMP). At constant temperature and composition, MMP is the least pressure at which first or multiple contact miscibility can be achieved. A miscible process is one in which the displacing fluid mix with oil to form one phase, driving interfacial tension to zero, Terry (2000). In immiscible process, displacing fluid does not mix or go into solution. Gas flooding typically includes CO2, natural gas or nitrogen as the injected gas. Miscible flooding is more efficient and common in EOR application, yet immiscible flooding may become important when the reservoir conditions are incompatible for miscible flooding.

Chemical flooding relies on the addition of chemicals into the displacing fluid. Depending on the process, these may change the IFT, viscosity, and sweep efficiency. Among notable chemical flooding processes are polymer flooding, surfactant flooding, alkaline flooding, micellar flooding and alkaline-surfactant-polymer (ASP) flooding. Polymers able to improve the viscosity of injectant while surfactants are effective in lowering interfacial tension between oil and water. The addition of alkalines produce surfactant in situ, Thomas (2008) but also used to lower the adsorption of surfactant against pore walls under ASP flooding, Muggeridge et al. (2014).

2.5 Water – Alternating – Gas (WAG)

The Water-Alternating-Gas (WAG) process has been proven to be a successful way to improve oil recovery at both miscible and immiscible. An extensive literature review by Christensen et al. (2001) where they reviewed 59 WAG field both miscible and immiscible and showed an increase of 5-10% OIP. IWAG involves cycles of gas and water injection, but the gas can not develop miscibility with the oil, Skauge & Dale (2007). The purpose of IWAG injection is to improved frontal stability and increase contact with the unswept areas of the reservoir, Christensen et al. (2001).

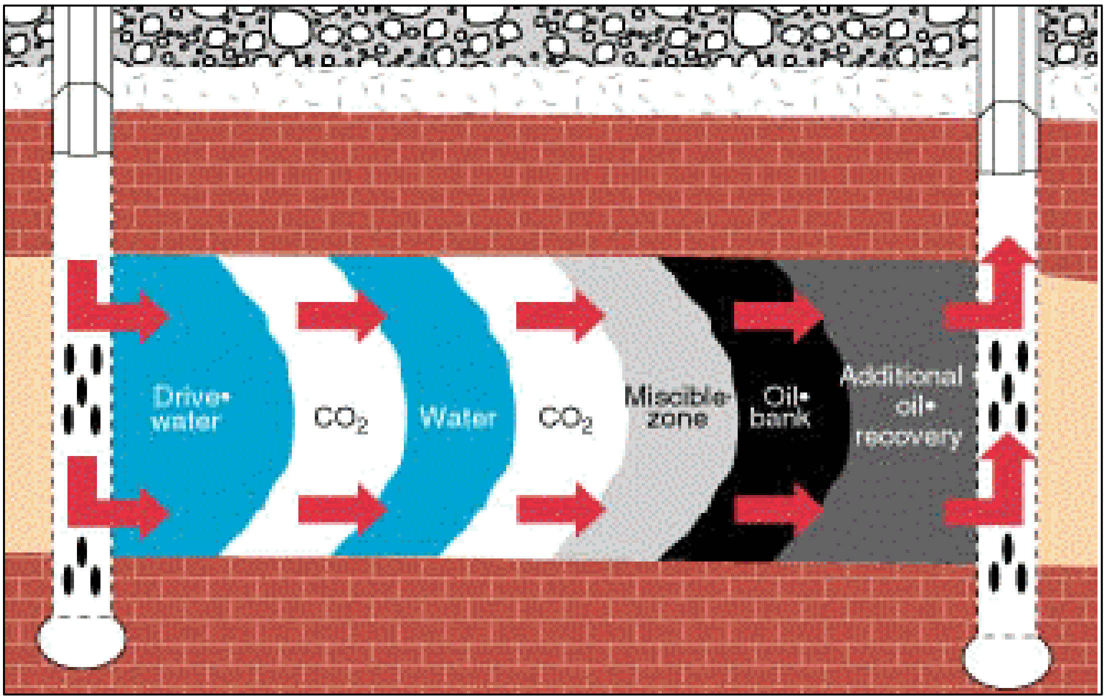

Figure 3: Schematic of WAG process (Kinder Morgan Co.)

WAG injection involves three-phase flow of water, oil and gas in the reservoir. Oil recovery efficiency of IWAG can be higher than normal water flood by a few mechanisms, Righi et al. (2004). One of the mechanisms is improved volumetric sweep by water following gas where the presence of gas in porous media causes water relative permeability in three-phase zones to be lower than in pores occupied by only water and oil, which favors water diversion to previously unswept areas. Oil viscosity reduction resulting from gas dissolution makes the mobility ratio of water-oil displacement more favorable. Besides, oil swelling by dissolved gas causes residual oil to contain less stock tank oil and thus increases recovery.

Righi et al. (2004) also touched on interfacial tension (IFT) reduction (gas-oil IFT beign lower than water-oil IFT) in principle allows gas to displace oil through small pore throats not accessible by water injection alone. In water-wet rock, trapping of gas during imbibition can cause oil mobilization at low saturations and an effective reduction in the three-phase residual oil saturation due to three-phase and hysteresis effect.

As compared to gas injection and water flooding alone, WAG combines the benefit of both recovery methods. WAG injection can improve oil recovery by better displacement efficiency at both macroscopic and microscopic levels. At macroscopic level, the water restrict the mobility of gas which influences the horizontal sweep, and the vertical sweep is improved because the gas segregates to the top whilst water slopes to the bottom. Due to lower residual oil saturation after gas injection compared to after water injection, the microscopic efficiency is improved.

Experimental studies by Oak, Baker & Thomas (1990) show that the three-phase relative permeability is highly dependent on saturation history. The models testified may be probabilistic models such as Stone I, Stone (1970) and Stone II, Stone (1973) models. A study on the impact of relative permeability hysteresis was done by Spiteri & Juanes (2006) on the field-scale predictions of WAG. Their investigation shows that three-phase hysteresis models bring higher recovery estimations than nonhysteretic models, because they account for the reduced mobility due to gas trapping during water injection. They showed that Stone I model predicts the residual oil saturation during water injection following gas injection better, making the model preferable for the cyclic IWAG injection simulation.

Frequently, the application of these models in numerical simulations of IWAG do not account for capillary pressure. Nevertheless, studies in the past show that capillary pressure has significant effect in three-phase flow, Be et al. (2011); Kleppe et al. (1997); Skauge & Dale (2007). Skauge & Dale (2007) conclude that inclusion of capillary pressure effect in simulation of IWAG injection process shows a reduction in relative permeability of the injected fluid and an increase in relative permeability of oil. In separate study by Be et al. (2011) under different wettability, three-phase capillary pressure has the most significant effect in strongly water-wet reservoir. These finding bring them to have a better history match.

Capillary pressure is one of the crucial parameter that manipulate three-phase flow. Emphasizing on capillary pressure in IWAG process, Dale (2008) studied the effect of capillary pressure on three-phase flow. This study determined that including capillary pressure leads to reduction in total oil recovery. When compared to the experimental data, history matching with capillary pressure shows closer result. Besides, the shape of total oil production and differential pressure are more identical to experimental data. The finding is very well correlates with the output from Skauge

& Dale (2007) where history matching is improved when capillary pressure is taken into consideration.

It is crucial to model the three-phase capillary pressure correctly when studying the effect of capillary pressure on three-phase flow. Killough's method is often used to model three-phase capillary pressure, Kleppe et al. (1997). To date, the only correlation available in the simulator for three-phase capillary pressure is Killough's method, Killough (1976). The three-phase capillary pressure is constructed as a weighted average between the two-phase as displayed in Fig. 4. However, as pointed by Tan (1990), Killough's method was specially formulated for the case where drainage and imbibition curves meet at residual saturation. Thus, the method is frequently inadequate.

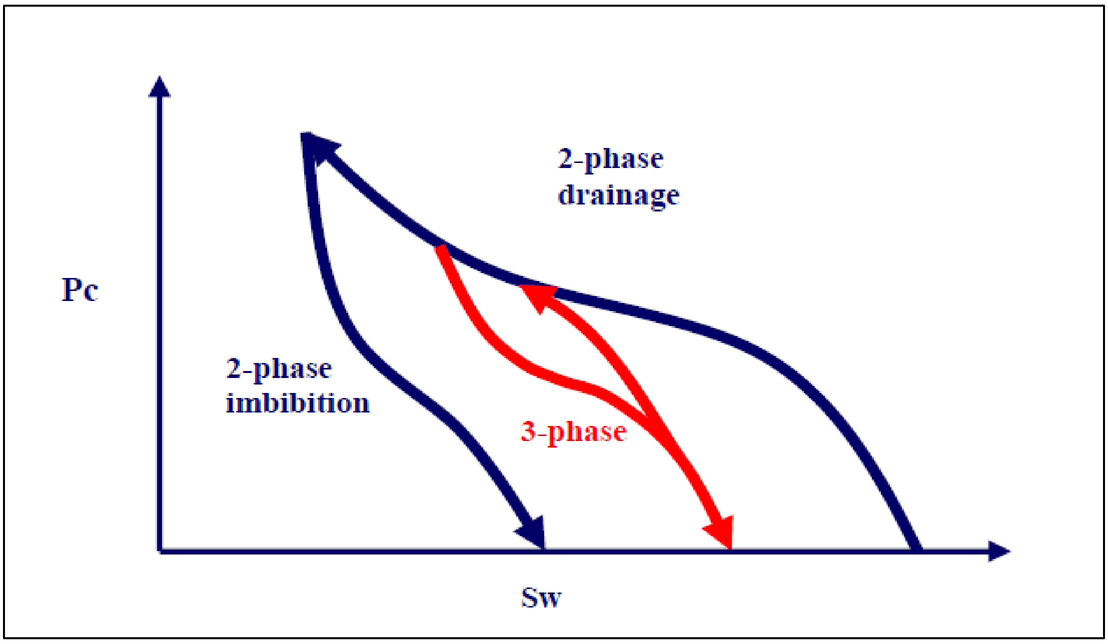

Figure 4: Illustration of standard three-phase capillary pressure estimated from interpolation of two-phase data, Kleppe et al. (1997)

Dale & Skauge (2008) used Killough's three-phase capillary pressure correlation as three-phase flow input in their study discovered that without capillary pressure effect, relative permeability of oil will be underestimate whilst relative permeability of injectants, gas and water will be overestimated. It was concluded that capillary pressure had an important effect on production behavior and subsequently on history matching of relative permeability. The result from their study strengthen the findings that capillary pressure has a significant effect on three-phase flow in porous media.

There are more simulation work rather than experimental work on three-phase capillary pressure. The reason is the fact that three-phase capillary pressure is difficult to measure experimentally, thus the data is rarely available. A famous three-phase capillary pressure experiment on an outcrop water-wet was performed by Kalaydjian (1992). He also measured three-phase capillary pressure on unconsolidated water-wet cores. Both drainage and imbibition processes are considered in his experimental study. Among the highlighted results in his study are dependent of three-phase capillary pressure on all phase saturations and spreading coefficient must be taken into consideration in the three-phase flow model.

Van Dijke et al. (2000); Mani & Mohanty (1997) mentioned that more recently there has been quite a number of attempts of using network modelling for three-phase capillary pressure estimation. Mani & Mohanty (1997) discovered that the gas/water capillary pressure curves depends greatly on the spreading coefficient than the oil/water capillary pressure curve. Other finding is the dependence of three-phase capillary pressure onto three-phase flow mechanicm is comparable as in the experimental data from Kalaydjian (1992). The network data has been generated by anchoring the network to drainage and imbibition two-phase capillary pressure. Thereafter the three-phase capillary pressure was estimated on the conditioned network representing pore size distribution and wetting properties.

Being introduced to the industry recently, Ensemble Kalman Filter (EnKF) technique becomes another promising method to produce three-phase capillary pressure. The idea of EnKF is to update the models continuosly without having to rerun it from time zero. Holm et al. (2009) in their experimental construction of capillary pressure also applied EnKF method instead of classic Killough’s method. Aanonsen et al. (2009) cited that introduction of EnKF has attracted attention as an assuring method in solving history matching problem.

CHAPTER 3

METHODOLOGY

This study is a numerical simulation using ECLIPSE 100. Modified Stone I three-phase relative permeability interpolation model is selected to simulate the three-phase flow in WAG, Spiteri & Juanes (2006), and Killough's correlation to model three-phase capillary pressure. The objective of this project needs to be achieved by following procedures:

1. Generate BASE CASE (BC) model.
2. Simulate IWAG injection without capillary pressure.
3. Simulate IWAG with capillary pressure.
4. Simulate IWAG injection with and without capillary pressure effect on favourable and unfavourable mobility ratio.
5. Observe and compare the oil recovery, water cut and oil relative permeability from each simulation.

This study is divided into favorable and unfavorable mobility of water to oil. Using Eq. 3, viscosity of oil and water is modified to make the reservoir fall under desired mobility system as presented in Table 1.

Table 1: End point mobility for mobility condition

	Favorable Mobility ratio = 0.4	Unfavorable Mobility ratio = 3.6
$K_{rw}@S_{wi}$	0.627	0.627
$K_{ro}@S_{or}$	0.88	0.88
μ_w	0.60	0.50
μ_o	0.30	2.50

Two-phase relative permeability and capillary pressure is obtained from Oak's experimental data. The three-phase relative permeability of oil is modeled by requesting the Stone I model using the STONE1-keyword. Three-phase relative permeability hysteresis is modeled using WAGHYSTR-keyword, Larsen & Skauge. (1998). For this study, a typical value of Land's constant (C = 2.0), drainage reduction factor (β = 5.0) and residual oil modification factor (R = 1.0) is employed, Be et al. (2011).

In the numerical simulator Eclipse the input data for capillary pressure is the primary drainage curve, i.e. the oil-water capillary pressure curve, and the imbibition curve, i.e. the gas-oil capillary pressure (Eclipse ref. 2012.2). Killough correlation is chosed to model the three-phase capillary pressure where it expresses three-phase capillary pressure as a weighted average of the two-phase drainage and imbibition curves. EHYSTR keyword is activated to model capillary pressure hysteresis with curvature parameter of 0.08.

In order to examine the effect of three-phase capillary pressure, the injection rate is varied from low to high injection rate. Using 1:1 WAG ratio, we set the rate of water injection while rate of gas injection is calculated using Eq. 9. The cases based on injection rate are presented in Table 2.

$$Q_g = \frac{Q_w \times B_w}{B_g} \qquad (9)$$

where;

Q_g = Gas flow rate (Mscf/day)

Q_w = Water flow rate (stb/day)

B_w = Water formation volume factor (bbl/stb)

B_g = Gas formation volume factor (bbl/Mscf)

Table 2: Rate of injection for all cases

	Low Injection Rate			High Injection Rate	
	Water (Stb/Day)	Gas (Mscf/Day)		Water (Stb/Day)	Gas (Mscf/Day)
SET 1	3500	5200	SET 3	10000	14800
SET 2	5000	7400	SET 4	15000	22200

3.1 Flow Chart

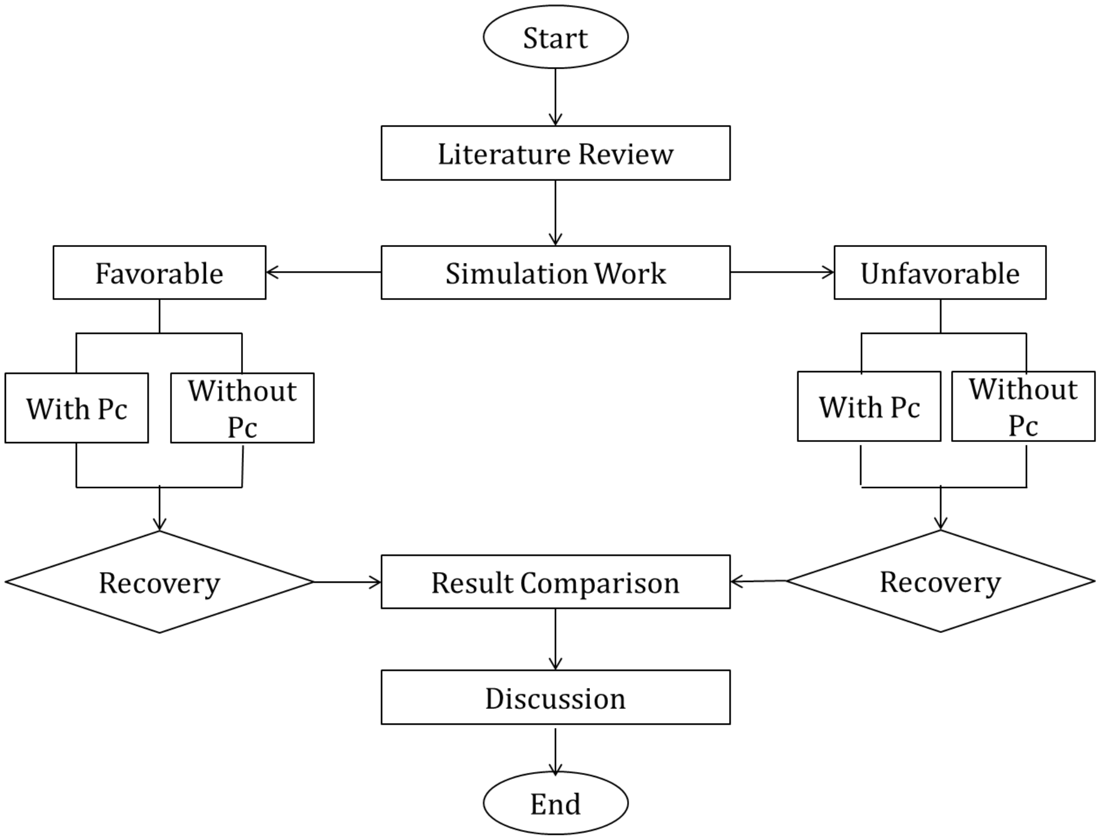

Figure 5: Flow chart

3.2 Gantt Chart

Table 3: Gantt chart

	FYP I														FYP II													
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Selection of Project Topic	■	■																										
Preliminary Research Work		■	■	■	■																							
Submission of Extended Proposal						■																						
Proposal Defence Presentation							■	■	■																			
Simulation Design & Data Collection										■	■	■																
Submission of Interim Draft Report													■															
Submission of Interim Report														■														
Project Work Continuation															■	■	■	■	■	■	■							
Submission of progerss Report																					■							
Project Work Continuation																						■	■	■	■	■		
Pre-SEDEX																								■				
Submission of Draft Final Report																									■			
Submission of Dissertation																										■		
Submission of Technical Paper																										■		
Viva																											■	
Submission of Dissertation (Hardbound)																												■

3.3 Key Milestones

Table 4: Key milestones

FYP I	
Key Milestones	**Week**
Eclipse Data Set	10
Eclipse Model Development	13
Preliminary Result	14
FYP II	
Key Milestones	**Week**
Base Case Analysis	6
Favorable Condition Analysis	7
Unfavorable Condition Analysis	8
Final Results	11

CHAPTER 4

RESULTS & DISCUSSIONS

4.1 Reservoir Description

To evaluate IWAG performance, a synthetic and homogeneous three-dimensional reservoir is generated. Homogeneous model was chosen to isolate the effect of saturation function. The model is a quarter of a five spot pattern in a horizontal reservoir. Injection well is set at one corner and production well is on the opposite corner, diagonally. Both wells are fully perforated. For simplicity, PVT data which represent immiscible fluids (dead oil and dry gas) is used. Parameters of the model are summarized in Table 5.

Table 5: Input data

Parameter	Value
Dimension	$20 \times 20 \times 3$
Block Size	$\Delta X = \Delta Y = 100\text{ft}; \Delta Z = 50\text{ft}$
Porosity, Φ	0.2
Permeability, k	200 mD
Initial Water Saturation, S_{wi}	0.31
Initial Pressure, P_i	4500 psia
Temperature, T	220°F
Reservoir Thickness, h	150ft
Compressibility of Oil, c_o	3.21×10^{-5} psi^{-1}
Compressibility of Water, c_w	3×10^{-6} psi^{-1}
Compressibility of Rock, c_f	4×10^{-6} psi^{-1}
Density of Oil, ρ_o	45.11 lbm/ft^3
Density of Water, ρ_w	70 lbm/ft^3
Density of Gas, ρ_g	0.02 lbm/ft^3

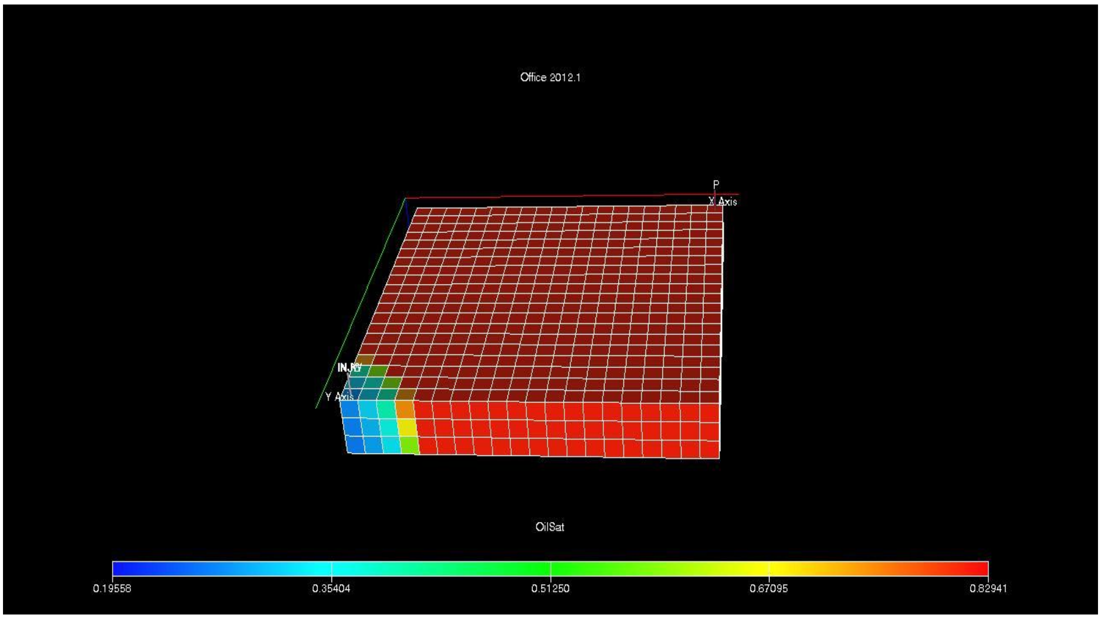

Figure 6: 3D reservoir model

4.2 Simulation Results and Discussions

The effect of three-phase capillary pressure on different water-oil mobility system is studied by comparing field oil recovery, water cut and oil relative permeability at the producing well.

4.2.1 Field Oil Recovery

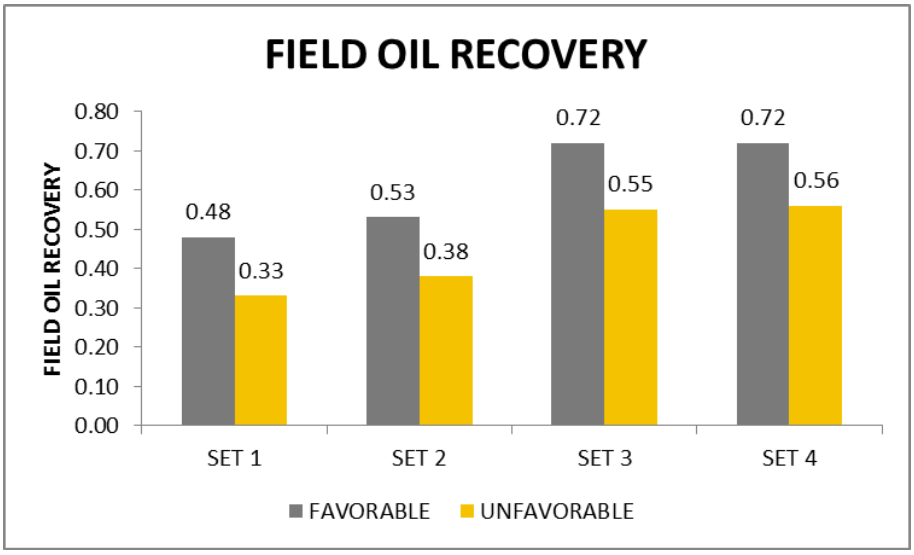

Figure 7: Field oil recovery in favorable and unfavorable water-oil mobility ratio

Simulation result in Fig. 7 shows that field oil recovery in favorable water-oil mobility ratio (M=0.4) is higher compared to field oil recovery in an unfavorable water-oil mobility ratio (M=3.6) when there is no capillary pressure. The efficiency of a water flood depends greatly on the mobility ratio of the displacing fluid to the displaced fluid, $\frac{k_{ro}}{\mu_o}\frac{\mu_w}{k_{rw}}$ as may be observed in fractional flow expression in Eqs. 10 and 11. The lower this ratio, the more efficient displacement occurs.

$$f_w = \frac{1+\frac{kk_{ro}A}{q\mu_o}\left(\frac{\partial P_{cow}}{\partial x} - \Delta\rho g sin\alpha\right)}{1+\frac{k_{ro}}{\mu_o}\frac{\mu_w}{k_{rw}}} \quad (10)$$

Assuming a horizontal flow with negligible capillary pressure, the expression reduces to Eq. 11.

$$f_w = \frac{1}{1+\frac{k_{ro}}{\mu_o}\frac{\mu_w}{k_{rw}}} \quad (11)$$

where;

f_w = Fraction of water (bbl/bbl)

kk_{ro} = Relative permeability of water (mD)

A = Cross-sectional area (ft^2)

Q = Total flow rate (bbl/day)

μ_o = Oil viscosity (cp)

P_{cow} = Oil-water capillary pressure

$\Delta\rho$ = Difference in densities between oil and water (g/cm^3)

$g sin\alpha$ = Angle of dip (°)

$\frac{k_{ro}}{\mu_o}\frac{\mu_w}{k_{rw}}$ = Water-oil mobility ratio

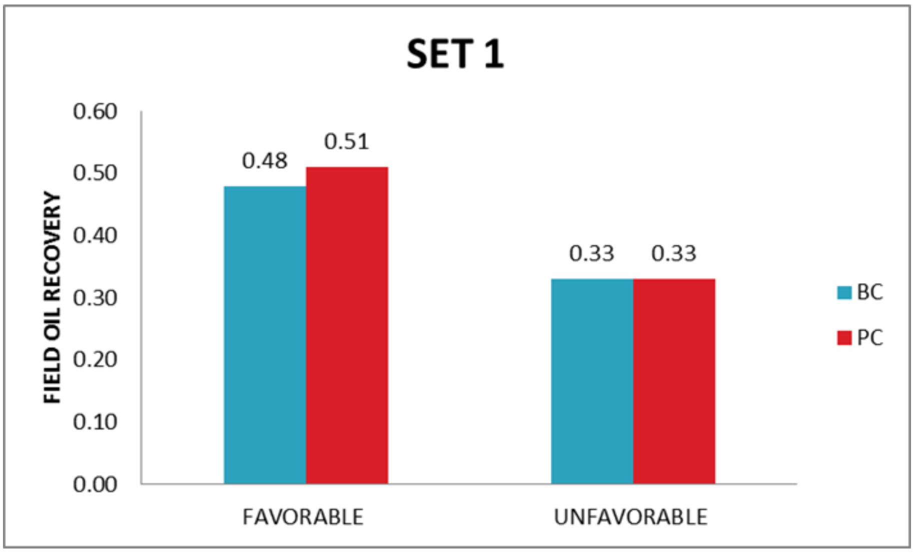

Figure 8: Field oil recovery at Qw = 3500 stb/day, Qg = 5200 Mscf/day

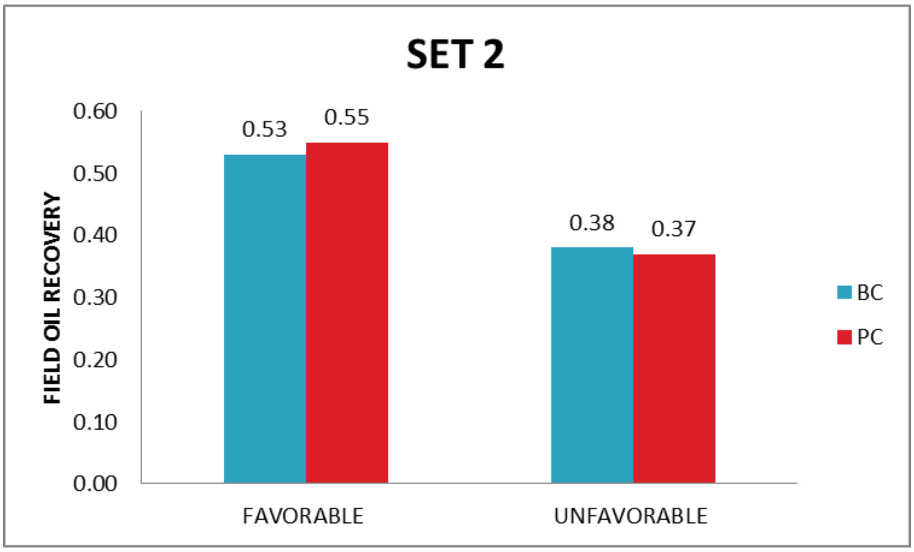

Figure 9: Field oil recovery at Qw = 5000 stb/day, Qg = 7400 Mscf/day

Under low injection rates, Figs. 8 and 9 show that for favorable water-oil mobility ratio condition, field oil recovery increases to 3% when capillary pressure is included.

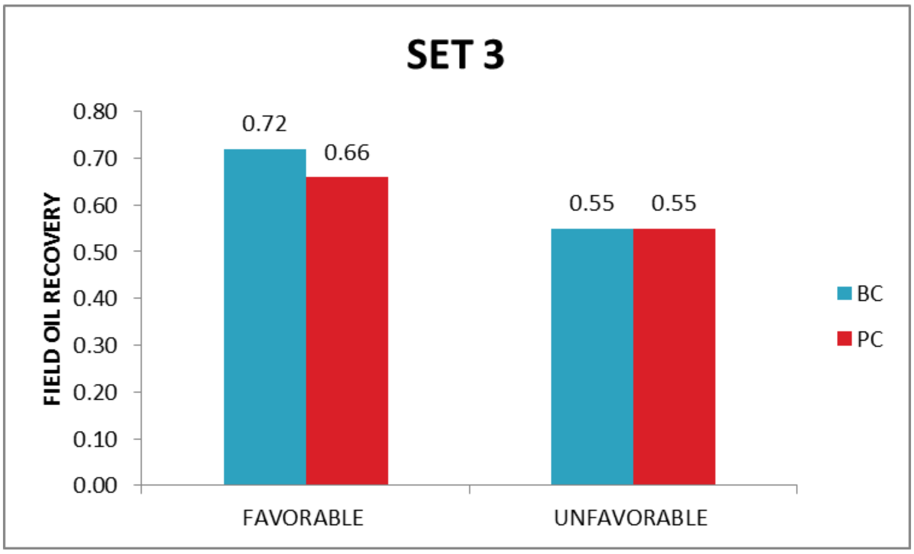

Figure 10: Field oil recovery at Qw = 10000 stb/day, Qg = 14800 Mscf/day

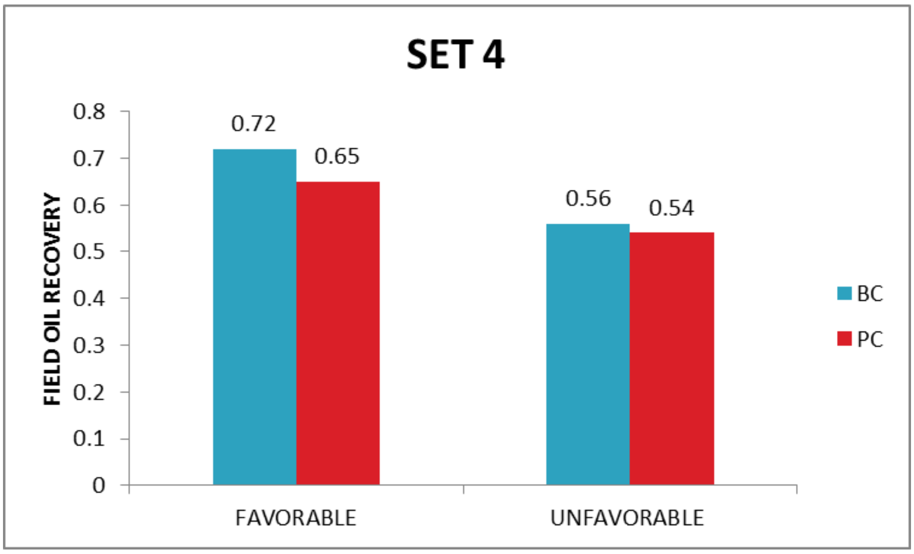

Figure 11: Field oil recovery at Qw = 15000 stb/day, Qg = 22200 Mscf/day

In previous study by Dale & Skauge (2008), they observed that total oil production is lower when capillary pressure was included. This is the same results as seen in Figs. 10 and 11 where we observed that favorable mobility ratio field oil recovery decreases up to 7% when capillary pressure is incorporated. Hence we can conclude that high rate of injection reduces the effect of capillary forces to enhance oil recovery.

Referring to Figs. 8 – 11, field oil recovery in unfavorable water-oil mobility ratio condition has not shown significant difference in all cases. This might be due to the fact that the unfavorable mobility ratio is too small (M = 3.6) thus the effect is not showing. Table 6 summarized the field oil recovery differences for all cases.

Table 6: Field oil recovery differences for all cases

Cases		Field oil recovery		Difference
		BC	PC	
SET 1	Favorable	0.48	0.51	3%
	Unfavorable	0.33	0.33	0%
SET 2	Favorable	0.53	0.55	2%
	Unfavorable	0.38	0.37	1%
SET 3	Favorable	0.72	0.66	6%
	Unfavorable	0.55	0.55	0%
SET 4	Favorable	0.72	0.65	7%
	Unfavorable	0.56	0.54	2%

4.2.2 Field Water Cut

In favorable water-oil mobility ratio cases, field oil water cut shows earlier water breakthrough with the inclusion of three-phase capillary pressure. Figs. 12 – 15 display the differences for all cases. According to fractional flow expression in Eq. 10, capillary pressure will contribute to a higher fw since $\frac{\partial P_{cow}}{\partial x} > 0$, thus contributes to a less efficient displacement. If capillary pressure is included in the analysis, such a front will not exist, since capillary dispersion (i.e., imbibition) will take place at the front. Thus, in addition to a less favorable fractional flow curve, the dispersion will also lead to an earlier water break-through at the production well.

Similar behavior of field oil water cut is seen in unfavorable water-oil mobility ratio. However, the breakthrough occurs even earlier due to the mobility effect.

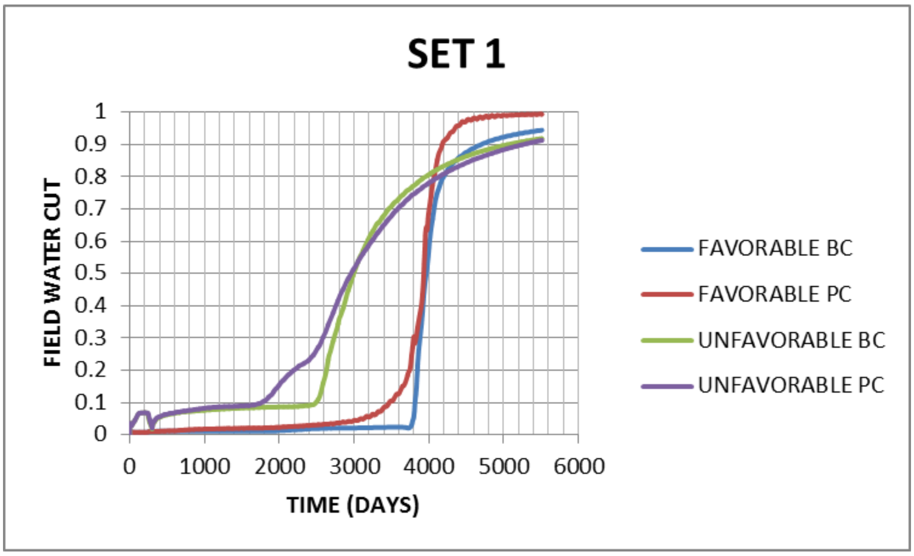

Figure 12: Field water cut at Qw = 3500 stb/day, Qg = 5200 Mscf/day

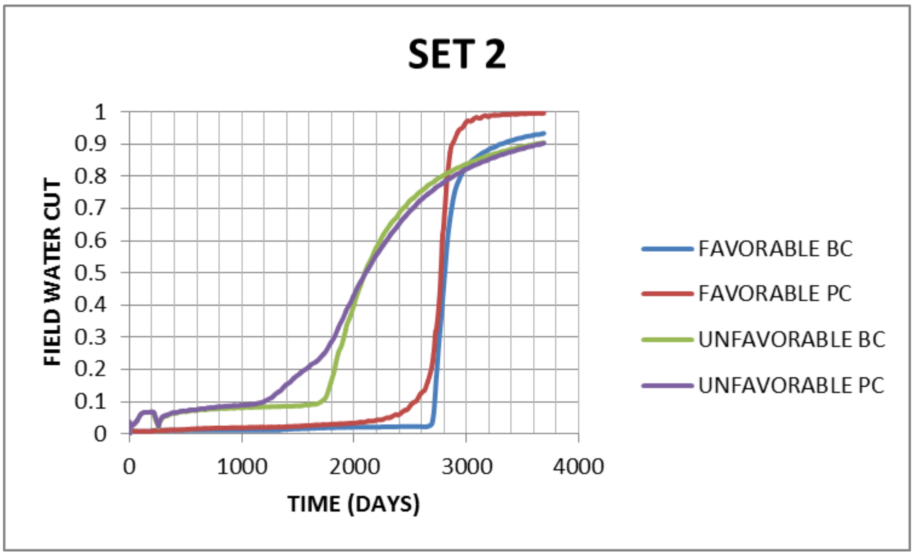

Figure 13: Field water cut at Qw = 5000 stb/day, Qg = 7400 Mscf/day

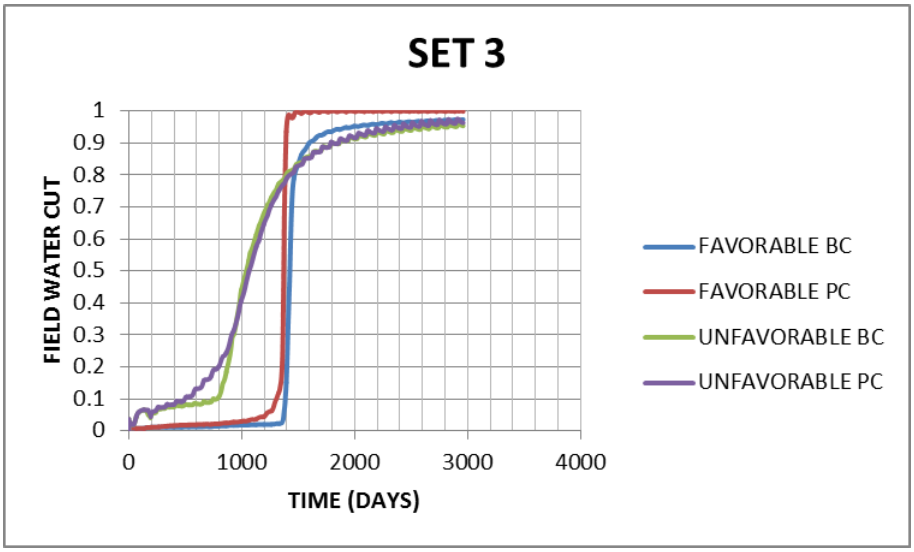

Figure 14: Field water cut at Qw = 10000 stb/day, Qg = 14800 Mscf/day

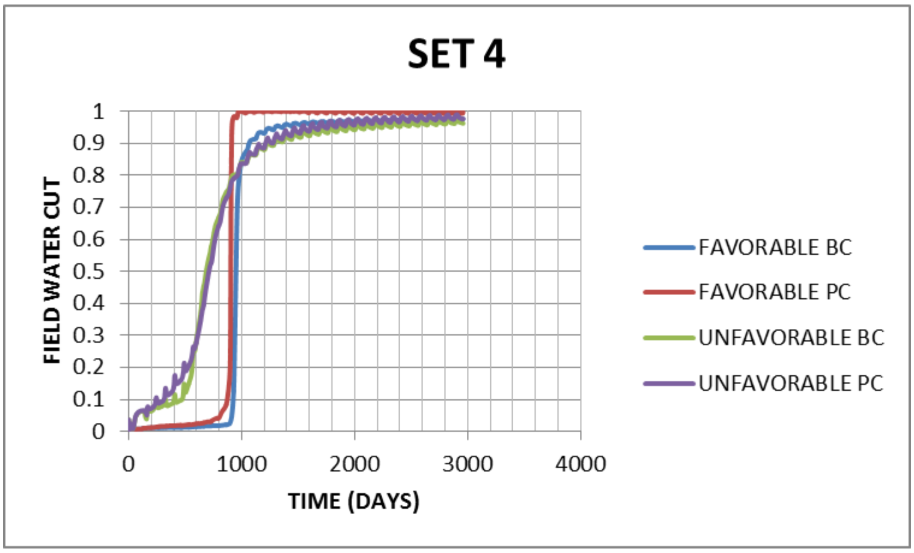

Figure 15: Field water cut at Qw = 15000 stb/day, Qg = 22200 Mscf/day

The difference between the breakthrough time of base case and with inclusion of capillary pressure recorded as high as 10%. A higher difference is seen in unfavorable condition. As we increased the rate of injection, the breakthrough time difference is reduced. A detailed difference is presented is Fig. 16.

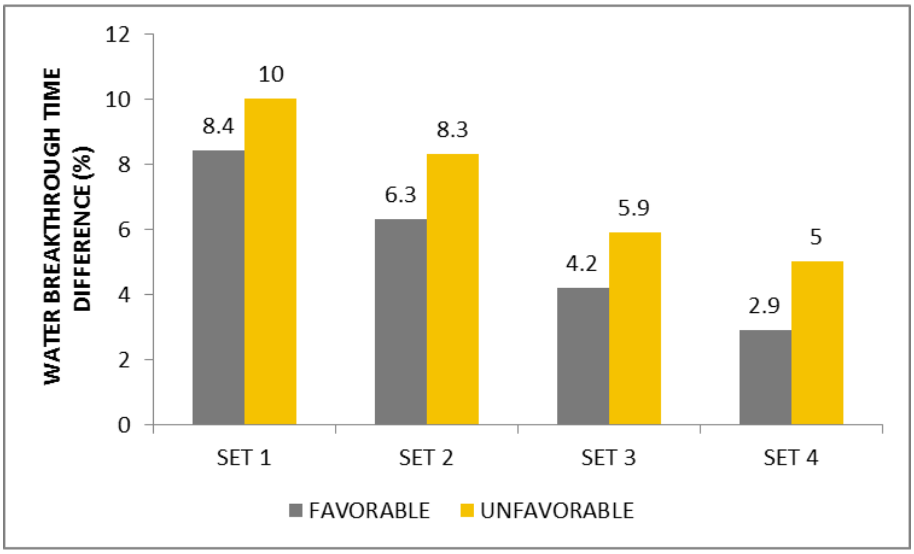

Figure 16: Difference of water breakthrough time for all cases

4.2.3 Oil Relative Permeability

It is an established fact that analytical methods for calculation of relative permeability, like JBN-method will underestimate the oil recovery. This is because these methods neglect capillary pressure. Element and Goodyear (2002) analyzed a two-phase water injection case. The simulated fractional flow curve was compared to a curve calculated by the JBN-method which neglects capillary pressure. The simulated fractional flow curve showed higher mobility for the oil when including the effect of capillary pressure. This is in agreement with our results in Figs. 17 – 20 where the oil relative permeability is higher when capillary pressure is included.

Dale & Skauge (2008) reported that relative permeability of oil must be increased and/or the relative permeability of the injected fluid must be reduced to get a match. When oil relative permeability increases, the production should be increase. However this is contradict at high injection rate where it shows less production despite of increasing oil relative permeability. This might be as a result of high injection rate had overcome the capillary forces to drive the oil towards production. Unfavorable oil relative permeability has not shown any significant changes for all cases.

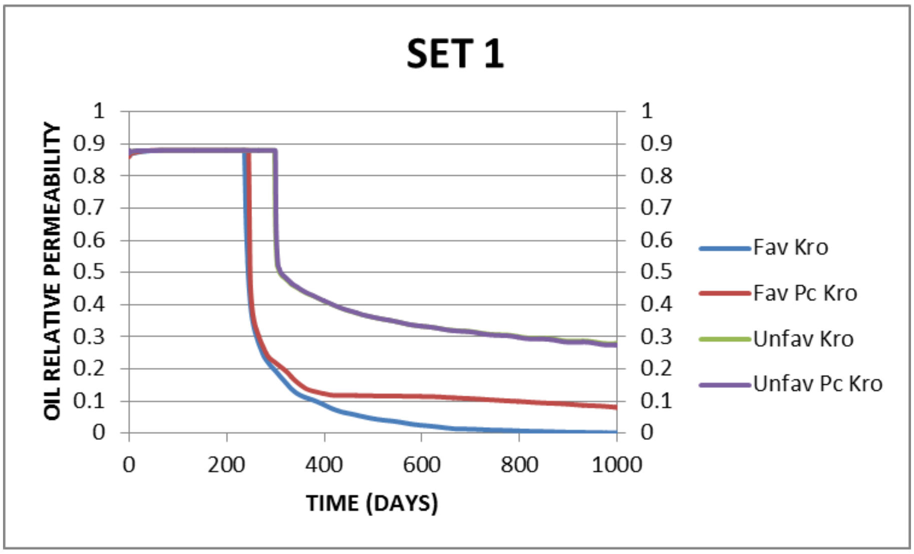

Figure 17: Oil relative permeability at Qw = 3500 stb/day, Qg = 5200 Mscf/day

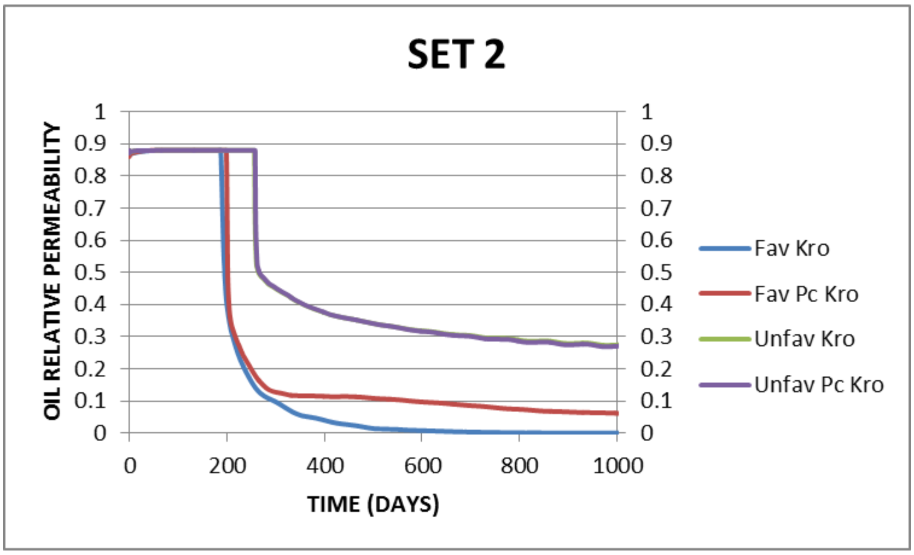

Figure 18: Oil relative permeability at Qw = 5000 stb/day, Qg = 7400 Mscf/day

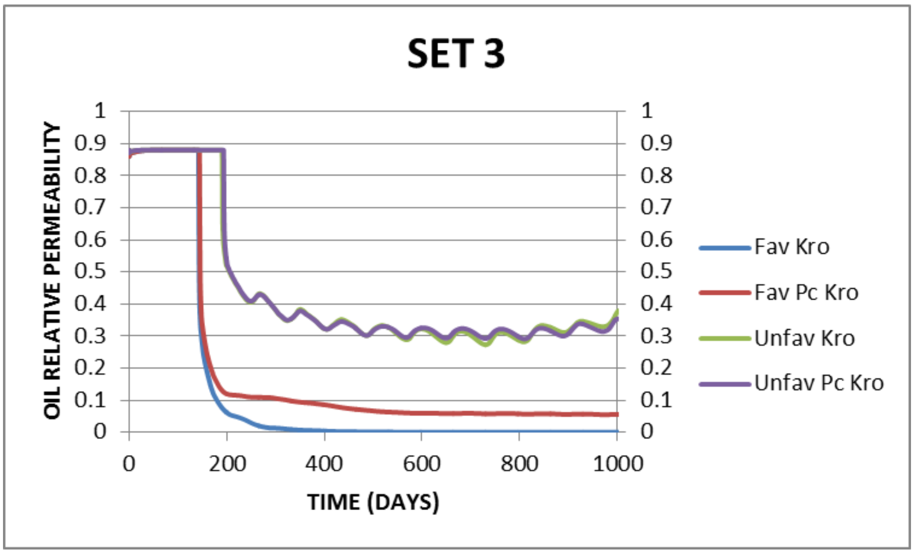

Figure 19: Oil relative permeability at Qw = 10000 stb/day, Qg = 14800 Mscf/day

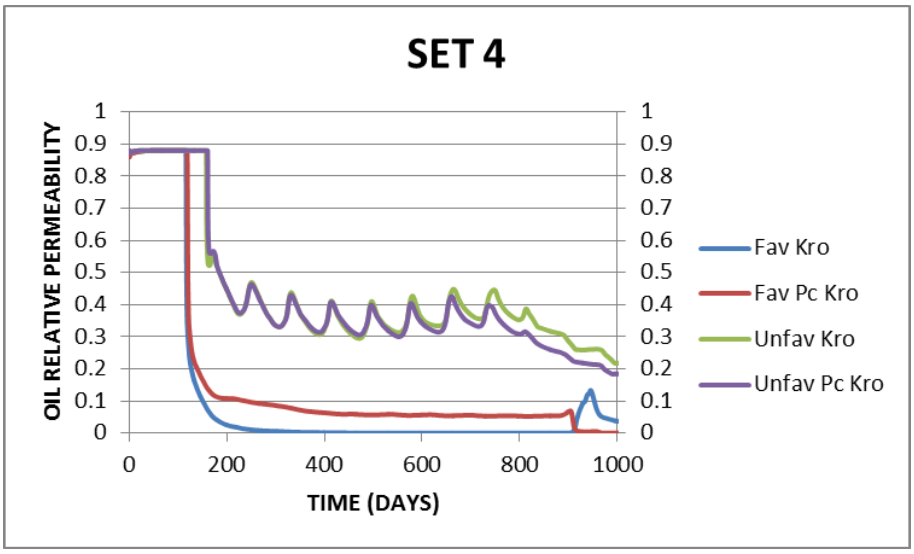

Figure 20: Oil relative permeability at Qw = 15000 stb/day, Qg = 22200 Mscf/day

CHAPTER 5

CONCLUSIONS & RECOMMENDATIONS

This simulation study has investigated the effect of capillary pressure of field scale water/gas injection at different water-oil mobility ratio. It was found that capillary pressure and its hysteresis have significant impacts on the field oil recovery, water cut and oil relative permeability under favorable water-oil mobility ratio.

For favorable water-oil mobility ratio, field oil recovery increases up to 3% under low injection rate but decreases up to 7% under high injection rate. This shows that high rate of injection dominates the effect of capillary forces. It is also shown that oil relative permeability is higher when capillary pressure is included. Incorporating capillary pressure also causes earlier water breakthrough with maximum 8.4% differences is recorded.

In this work, we discovered that capillary pressure has significant effect in favorable water-oil mobility ratio which has not been specified in the previous study. In fact, favorable mobility ratio is very difficult to be achieved in real reservoir condition. However, favorable or near favorable mobility ratio is possible to be achieved by using polymer injection. In this case, it is crucial to account for capillary pressure.

The results of this investigation support the view that IWAG injection cannot be modeled correctly without accounting for three-phase capillary pressure in favorable water-oil mobility ratio.

As for recommendation on this topic, we would like to suggest to increase the unfavorable water-oil mobility ratio to 10 or even as high as 20. The reason why we observed insignificant changes on unfavorable condition might be due to the small value of water-oil mobility ratio which is 3.6. Apart from that, comparison with real data should be done to validate the results and make overall project more meaningful.

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APPENDIX A

Table A: Oak's relative permeability experimental data

Sw	Krw	Krow	Pcow	Sg	Krg	Krog	Pcog
0.31	0	0.88	20.46166	0	0	0.88	1.158288
0.318408	0.031348	0.852459	18.355	0.01	0	0.864494	1.214587
0.378109	0.034483	0.512855	9.135751	0.06	0	0.661878	1.556894
0.457711	0.043887	0.259072	4.205992	0.13	0.008646	0.486278	2.283263
0.542289	0.056426	0.09111	2.112965	0.2	0.034585	0.337693	3.52442
0.614428	0.08464	0.008967	1.272557	0.27	0.077816	0.216123	5.817437
0.676617	0.125392	0	0.860354	0.34	0.138339	0.169547	10.52325
0.733831	0.191223	0	0.618799	0.41	0.216155	0.121569	21.73724
0.778607	0.272727	0	0.486538	0.48	0.311264	0.054031	55.38348
0.80597	0.354232	0	0.422878	0.55	0.423664	0.013508	206.944
0.825871	0.438871	0	0.383006	0.565	0.45	0	299.1305
0.853234	0.510972		0.335531				
0.865672	0.561129		0.316384				

0.912935	0.62069		0.254967				
0.947761	0.683386		0.219014				
0.955224	0.755486		0.21215				
0.972637	0.862069		0.197147				
0.977612	0.931034		0.193105				
0.99005	0.984326		0.183443				
1	1		0.176145				

APPENDIX B

BASE CASE model data file.

RUNSPEC

TITLE

FYP

START

1 JAN 2014/

FIELD

OIL

WATER

GAS

DIMENS

20 20 3/

TABDIMS

1 1 50 50 3/

WELLDIMS

3 3 3 2/

UNIFOUT

GRID

INIT

TOPS

400*8000 400*8050 400*8100/

DX

1200*100/

DY

1200*100/

DZ

```
400*50 400*50 400*50/

OLDTRAN
BOX
1 20 1 20 1 3/
ENDBOX
PORO
1200*0.2/
PERMX
400*200 400*200 400*200/
PERMY
400*200 400*200 400*200/
PERMZ
400*200 400*200 400*200/
PROPS
DENSITY
45.11 70.00 0.02/
PVTW
4500 1.02 3.0E-06 0.6 0.0 /
PVCDO
4500 1.12 3.21E-05 0.3 0.0 /
PVDG
600     5.247544     0.012391
800     3.818393     0.013300
1000    2.966723     0.014239
1200    2.405790     0.015206
1400    2.012705     0.016199
1600    1.725381     0.017215
1800    1.509135     0.018251
```

2000 1.342643 0.019304

2516 1.058303 0.022084

2800 0.958053 0.023638

3000 0.902856 0.024736

3200 0.857127 0.025833

3400 0.818993 0.026928

3600 0.786808 0.028016

3800 0.759453 0.029096

4000 0.735860 0.030164

4200 0.715411 0.031218

4400 0.697444 0.032255

4500 0.689249 0.032767

4600 0.681485 0.033274

4800 0.667213 0.034272

5000 0.654220 0.035248

5200 0.642358 0.036200

5400 0.631437 0.037126

5600 0.621359 0.038026

5800 0.611975 0.038899

6000 0.603216 0.039743/

SWFN

0.31 0 0

0.318408 0.031348 0

0.378109 0.0344828 0

0.457711 0.0438871 0

0.542289 0.0564263 0

0.614428 0.0846395 0

0.676617 0.125392 0

0.733831 0.191223 0

0.778607	0.272727	0
0.80597	0.354232	0
0.825871	0.438871	0
0.853234	0.510972	0
0.865672	0.561129	0
0.912935	0.62069	0
0.947761	0.683386	0
0.955224	0.755486	0
0.972637	0.862069	0
0.977612	0.931034	0
0.99005	0.984326	0
1	1	0/

SGFN

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0.01	0	0
0.06	0	0
0.13	0.008646211	0
0.2	0.034584845	0
0.27	0.0778159	0
0.34	0.138339378	0
0.41	0.216155279	0
0.48	0.311263602	0
0.55	0.423664347	0
0.565	0.45	0/

SOF3

0.125	0	0
0.195	0	0.013507714
0.265	0	0.054030856
0.335	0	0.121569426

0.373	0	0.169546621
0.405	0.00896735	0.216123424
0.475	0.091109674	0.33769285
0.545	0.259072336	0.486277704
0.615	0.512855337	0.661877986
0.685	0.852458677	0.864493696
0.69	0.88	0.88/

```
ROCK
4500 4E-06/
/
SOLUTION
PRESSURE
  1200*4500.0 /
SWAT
  1200*0.31/
SGAS
  1200*0.0 /
SUMMARY
FOE
/
FWCT
/
FOPT
/
WGOR
/
WBHP
/
BKRO
```

```
20 1 1/
/

BKRG
20 1 1/
/
BKRW
20 1 1/
/
RPTSMRY
1 /
EXCEL
SCHEDULE
RPTRST
BASIC=2 NORST=1/
TUNING
1e-2    1e-1   1e-2/
/
/
WELSPECS
'P' G1 20 1 8000 OIL/
'INJW' G2 1 20 8000 WATER/
'INJG' G2 1 20 8000 GAS/
/
COMPDAT
'P' 20 1 1 3 OPEN 2* 0.6667/
'INJW' 1 20 1 3 OPEN 2* 0.6667/
'INJG' 1 20 1 3 OPEN 2* 0.6667/
/
```

```
WCONPROD
'P' OPEN BHP 5* 500/
/
```

WAG CYCLE

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WCONINJE
'INJW' WATER OPEN RATE 3500/
'INJG' GAS OPEN RATE 5200/
/
WCYCLE
'INJW' 40.0 40.0 1* 10.0 YES/
'INJG' 40.0 40.0 1* 10.0 YES/
/
WELOPEN
'INJW' OPEN/
'INJG' SHUT/
/
TSTEP
40.0/
WELOPEN
'INJG' OPEN/
/
TSTEP
15*365/
/
END
```