EVALUATION OF IMPROVED OIL RECOVERY (IOR) SCHEMES FOR A VOLATILE OIL RESERVOIR

Mr. Wasin Saengnumpong

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By	Mr. Wasin Saengnumpong
Field of Study	Petroleum Engineering
Thesis Advisor	Assistant Professor Suwat Athichanagorn, Ph.D.
Thesis Co-Advisor	Falan Srisuriyachai, Ph.D.

Accepted by the Faculty of Engineering, Chulalongkorn University in Partial Fulfillment of the Requirements for the Master's Degree

....Dean of the Faculty of Engineering

(Professor Bundhit Eua-arporn, Ph.D.)

THESIS COMMITTEE

....Chairman

(Assistant Professor Sarithdej Pathanasetpong)

....Thesis Advisor

(Assistant Professor Suwat Athichanagorn, Ph.D.)

....Thesis Co-Advisor

(Falan Srisuriyachai, Ph.D.)

....Examiner

(Assistant Professor Jirawat Chewaroungroaj, Ph.D.)

....External Examiner

(Dalad Nattwongasem, Ph.D.)

วศิน แสงนุ่มพงษ์ : การประเมินวิธีการเพิ่มการผลิตน้ำมันสำหรับแหล่งกักเก็บน้ำมันที่ง่ายต่อการระเหย. (EVALUATION OF IMPROVED OIL RECOVERY (IOR) SCHEMES FOR A VOLATILE OIL RESERVOIR) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร. สุวัฒน์ อธิชนากร, อ.ที่ปรึกษาวิทยานิพนธ์ร่วม: อ. ดร. ฟ้าลั่น ศรีสุริยชัย, 163 หน้า.

การแทนที่น้ำมันด้วยแก๊สและน้ำนั้นเป็นหนึ่งในวิธีที่จะเพิ่มการผลิตน้ำมัน สำหรับน้ำมันที่ง่ายต่อการระเหย การนำวิธีการเหล่านี้มาใช้มีความสำคัญมากกับปริมาณน้ำมันที่ผลิตได้และความคุ้มค้าในการลงทุนของโครงการ อย่างไรก็ตามวิธีการเพิ่มการผลิตน้ำมันที่ต่างกันนั้นจะมีกลไกในการเพิ่มประสิทธิภาพในการผลิตและการรักษาความดันในแหล่งกักเก็บที่แตกต่างกัน ดังนั้น การเข้าใจหลักการทำงานของแต่ละวิธีการผลิตก็จะช่วยให้การเลือกใช้เป็นไปอย่างเหมาะสม

แบบจำลองที่ใช้องค์ประกอบทางเคมีถูกนำมาใช้ในการศึกษานี้เพื่อที่จะหาวิธีที่เหมาะสมที่สุดสำหรับการผลิตน้ำมันที่ง่ายต่อการระเหย การจำลองการแทนที่น้ำมันด้วยน้ำและแก๊สรวมถึงการแทนที่ด้วยน้ำสลับกับแก๊สได้ถูกนำมาศึกษาและเปรียบเทียบในแง่มุมของประสิทธิภาพในการเพิ่มการผลิตและความคุ้มค่าทางเศรฐกิจของโครงการ

จากผลการจำลอง เราพบว่าการแยกชั้นของแก๊สที่ละลายในน้ำมันจากแรงโน้มถ่วงนั้นส่งผลอย่างมากต่อการผลิตด้วยวิธีธรรมชาติดังนั้นการเพิ่มประสิทธิภาพของการแยกชั้นนี้คือประเด็นสำคัญในการควบคุม และการออกแบบหลุมผลิต สำหรับการแทนที่น้ำมันด้วยแก๊สและน้ำนั้นการเริ่มรักษาความดันในแหล่งกักเก็บให้สูงกว่าความดันไอของน้ำมันก่อนที่จะมีแก๊สผลิตออกมาจะช่วยให้เราผลิตน้ำมันได้มากทีสุด สำหรับการแทนที่ด้วนน้ำถ้ามีแก๊สอยู่จะทำให้ประสิทธิภาพของการแทนที่ต่ำลงเนื่องมาจากการขวางทางของแก๊ส สำหรับการแทนที่ด้วนแก๊สถ้ามีแก๊สอยู่ในแหล่งกักเก็บแล้ว ความสามารถในการผสมกันจะลดลงเนื่องจาก องค์ประกอบที่หนักปานกลางในน้ำมันจะเปลี่ยนเป็นสถานะแก๊สและไม่สามารถใช้สำหรับการเกิดการแทนที่แบบผสมได้ เมื่อเราเปรียบเทียบการผลิตทุกรูปแบบที่ได้ทำการศึกษามาเราพบว่า การแทนที่ด้วยน้ำจะสามารถผลิตน้ำมันได้น้อยกว่าการแทนที่ด้วยแก๊สแต่สามารถทำกำไรได้ใกล้เคียงกับการแทนที่ด้วยแก๊สเพราะใช้เงินลงทุนน้อยกว่า ขณะที่การแทนที่ด้วยน้ำสลับกับแก๊สจะผลิตน้ำมันได้มากที่สุดและจะให้ผลกำไรมากที่สุดเพราะวิธีนี้ได้รวมข้อดีของการแทนที่ด้วยน้ำและแก๊สเข้าด้วยกัน

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WASIN SAENGNUMPONG: EVALUATION OF IMPROVED OIL RECOVERY (IOR) SCHEMES FOR A VOLATILE OIL RESERVOIR. ADVISOR: ASST. PROF. SUWAT ATHICHANAGORN, Ph.D., CO-ADVISOR: FALAN SRISURIYACHAI, Ph.D., 163 pp.

Gas and water flooding are known as improved oil recovery method. Implementation of these IOR for volatile oil reservoir is essential to oil recovery and project economic. Different IOR schemes provide different mechanisms of flooding and pressure maintenance for volatile oil reservoirs. Hence, understanding of volatile oil behavior and each IOR performance will lead to a proper scheme selection.

Compositional simulation study is performed in order to find the optimum way to recover volatile oil. Simulation of natural depletion, waterflooding, gasflooding, and water alternating gas are investigated and compared in aspect of oil recovery performance and project economic.

From simulation results, we found that gravity segregation of solution gas is the most influential drive mechanism to volatile oil recovery of natural depletion. Hence, enhancement of this drive mechanism is the key to production optimization and completion design. For water and gas flooding, starting maintaining the reservoir pressure above the bubble point pressure and before free exists in the reservoir will maximize the recovery. For waterflooding, if free gas exists, displacement efficiency is reduced due to gas blockage effect. For gasflooding, existing of free gas is lower capability in miscibility condition achievement because the intermediate components in oil phase already flash to gas phase and cannot be used to develop miscible flood front. And when compared all studied production schemes, waterflooding can recover oil less than gasflooding, but can yield similar net profit due to lower investment cost required. While water alternating gas yields the highest total oil recovery and net profit because it combines the advantages of both water and gas flooding.

Department:	Mining and Petroleum Engineering	Student's Signature	....
		Advisor's Signature	....
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ABBREVIATIONS

BHFP	bottom hole flowing pressure
BHP	bottom hole pressure
CAPEX	capital expenditure
DPI	discounted profitability index
EOR	enhanced oil recovery
GOC	gas oil contact
GOR	gas oil ratio
GoT	gulf of Thailand
ID	inside diameter
IFT	interfacial tension
IOR	improved oil recovery
IRR	internal rate of return
mD	millidarcy
MMP	minimum miscibility pressure
MMscfd	million standard cubic feet per day
Mscfd	thousand standard cubic feet per day
Mstb	thousand stock tank barrels per day
NPI	net present investment
NPV	net present value
OD	outside diameter
OOIP	original oil in place
OPEX	operational expenditure
PPM	partial pressure maintenance
psi	pounds per square inch
psia	pounds per square inch absolute
PVT	pressure-volume-temperature
RF	recovery factor
SCAL	special core analysis
scf	standard cubic foot

stb	stock-tank barrel
scf/stb	standard cubic feet per stock-tank barrel
THP	tubing head pressure
TVD	true vertical depth
VFP	vertical flow performance
VRR	voidage replacement ratio
WAG	water alternating gas

NOMENCLATURES

B_g	gas formation volume factor
B_o	oil formation volume factor
B_w	water formation volume factor
e_o	exponent of relative permeability curve to oil
e_w	exponent of relative permeability curve to water
e_{og}	exponent of relative permeability curve to oil in gas phase
e_{ow}	exponent of relative permeability curve to oil in water phase
E_A	areal sweep efficiency
E_{ABT}	areal sweep efficiency at breakthrough
E_D	displacement efficiency
E_V	vertical sweep efficiency
F	miscibility interpolation factor
G	dimensionless gravity number
G_p	cumulative gas production
i_w	water injection rate
k	absolute permeability
k_{rg}	gas relative permeability
k_{ro}	oil relative permeability
k_{ro}^o	end point relative permeability to oil
k_{rog}^o	end point relative permeability to oil in gas phase
k_{row}^o	end point relative permeability to oil in water phase
k_{ro}^{immis}	relative permeability to oil at immiscible condition
k_{ro}^{mis}	relative permeability to oil at miscible condition
k_{rog}	relative permeability to oil in presence of gas phase
k_{row}	relative permeability to oil in presence of water phase
k_{rw}	relative permeability to water
k_v	vertical permeability
$M*$	end-point mobility ratio

N_g	gravity number
N_p	cumulative oil production
P_{bub}	bubble point pressure
Q_{ginj}	gas injection rate
Q_{winj}	water injection rate
Q_o	oil production rate
Q_w	water production rate
Q_g	gas production rate
r_e	drainage radius
R_{si}	initial solution gas-oil ratio
S_g	gas saturation
S_{gc}	critical gas saturation
S_{gr}	residual gas saturation
S_{gro}	residual gas saturation in presence of oil phase
S_o	oil saturation
$\bar{S}_o$	average oil saturation in the flood pattern
S_{org}	residual oil saturation in presence of gas phase
S_{orw}	residual oil saturation in presence of water phase
S_{wi}	initial water saturation
S_{wc}	connate water saturation
$\bar{S}_{wBT}$	average water saturation in the swept area when injected water has breakthrough.
W_{inj}	cumulative water injected
W_{iBT}	cumulative water injected at breakthrough
W_p	cumulative water production
x_i	liquid mole fraction of component i
y_i	vapor mole fraction of component i
σ_i	surface tension
ρ_g	gas density
ρ_o	oil density
ρ_w	water density
ρ_L^m	liquid phase molar density

ρ_V^m	vapor phase molar density
μ_o	oil viscosity
μ_w	water viscosity
γ	specific gravity

CHAPTER I

INTRODUCTION

Production performance of volatile oil usually drops dramatically after the reservoir pressure falls below the oil bubble point pressure. When light components leave the liquid phase, gas blockage and reduction of liquid mobility are encountered. Conventional production plans for volatile oil deposited in a structural dip are pressure maintenance by water and gas injection. However, selection and implementation of improved oil recovery (IOR) schemes can greatly affect the recovery performance and project economic. Therefore, the understanding of particular IOR schemes is a key success for production planning. Once we can distinguish rock and fluid characteristics that influence flooding recovery, we understand key factors and process fundamentals that affect volumetric sweep and displacement efficiency. Then we can proper select the flood design which result in efficiency and profitability of the project.

In this study, investigation of various IOR schemes and its particular operating conditions such as water injection, miscible gasflooding, and water alternating gas is performed using numerical compositional simulation. Then, the oil recovery performance (e.g. recovery factor, water and gas usage, timing and etc.) are compared under different conditions. Finally, advantages for each scheme are discussed including economic perspective.

1.1 Research Objectives

1. To evaluate and compare volatile oil recovery performance among various IOR schemes under different operating conditions.
2. To identify key factors and process fundamentals that affect volumetric sweep and displacement efficiency for each IOR schemes.

1.2 Outline of Methodology

1. Study the theory from literature review of volatile oil production improvement by water and gas flooding.
2. Create base case reservoir using corner grid in ECLIPSE300 reservoir simulator.
3. Start the reservoir simulation with natural flow cases to observe the best criteria and followed by water and gas flooding under different conditions of reservoir rock and fluid properties.
4. Conduct economic analysis for each case.
5. Analyze and conclude the results.

1.3 Thesis Outline

This thesis consists of six chapters as outlined below:

Chapter I introduces the main idea and concepts of this work.

Chapter II reviews previous studies on volatile oil recovery improvement and concepts of water and gas flooding as well as water alternating gas injection.

Chapter III describes theory and concepts related to this study.

Chapter IV explains the detail of model construction and reservoir conditions used in the simulation.

Chapter V shows the simulation results and discussion.

Chapter VI concludes the results obtained from the study.

CHAPTER II

LITERATURE REVIEW

2.1 Case Study on Volatile Oil Recovery Improvement

Flores [1] performed a compositional simulation study to select EOR scheme for a volatile oil reservoir. The author examined the feasibility of water flooding and gas injection for “Caroline Cardium E Pool, Alberta”. The results indicated that water flooding was not feasible due to low injectivity while dry-gas miscible displacement provides an ultimate oil recovery of approximately twice the primary depletion.

Schenewerk and Heath [2] reported a case study from South Back Draw (Dakota) field containing volatile oil. Since waterflooding operation was not feasible due to reservoir discontinuities and oil wet formation, feasibility of partial pressure maintenance by injection of produced gas above and below the bubble point pressure was studied. Simulation results show that the recovery increases around 30% of OOIP from partial pressure maintenance operation and found that the higher the injection pressure the greater oil recovery. However, small difference in incremental recovery between operation above and below bubble point pressure was reported (around 5% difference) because the oil production from this field did not have a drastic decline when the pressure fell the below bubble point.

Siti et al. [3] pointed out the advantage of gravity segregation for the Mbede field containing volatile oil with presence of primary gas cap. A simulation study was carried out, and the results showed that gravity segregation is an effective drainage mechanism which can recover oil up-to 50% of OOIP for this case. The favorable condition for the mechanism was indicated as good vertical and horizontal permeability, high gravity difference between phases, low oil viscosity and slow GOC advancement. The authors also inferred that secondary recovery project may not guarantee a higher recovery but mainly accelerated the production. Finally, they concluded that if displacement by gas is much more favorable than displacement by water, then gas injection project could be justified even in case of strong natural water drive.

Stright Jr. and Fallin [4] reported a successful miscible gas flood project in a small volatile oil reservoir (Dolphin field). The field project demonstrated that early characterization of the reservoir fluid can identify the need for pressure maintenance above the bubble point and showed that miscible gas injection could results in 2 MMSTB of additional oil recovery which may have been lost by normal pressure depletion.

2.2 Gas Injection Strategy and Its Associated Recovery Mechanism

Thomas et al. [5] investigated gas injection for EOR by trying to quantify the degree of immiscibility so called “near miscible” in order to optimally design gas injection system. After reviewing a case history and laboratory work, the authors made the following observations:

- From a case study, the project which was designed as miscible flood would be better described as near miscible depending on the technique used to evaluate it.
- Laboratory testing should be done to determine the interaction between viscosity, IFT and pore size distribution rather than concentrating only upon the assessment of what is miscible. That is, the quantification of IFT reduction and how that IFT reduction interacts with mobility in the pore size distribution is important to measure.
- Low IFT is a necessary condition for efficient recovery from most reservoirs, but in many cases, zero IFT is unnecessary unless the pore throat size distribution is extremely tight and the rock is oil-wet.

Mitri and Cray [6] demonstrated the benefit of down-dip gas injection for oil recovery from Middle East layered carbonate reservoir. The reservoir simulation study revealed that down-dip gas injection could benefit oil recovery at relatively higher sustainable rates as supplemental to a water injection scheme or as a standalone option. The location of down-dip gas injector was found to be critical to oil recovery performance. Furthermore, the authors suggested that impact of relative permeability should be taken into account since miscibility is not maintained throughout the reservoir. Thus, improvement of SCAL data would be required.

Vark et al. [7] reported a simulation study that was performed with the objective of identifying the impact of alternative (gas) injectants on oil recovery factor for the low permeable areas of large carbonate oil reservoirs. Four type of injectants which are lean gas (CH_4), sour gas (60% CH_4, 30% H2S, 10% CO_2), pure CO_2 and acid gas (75% H_2S, 25% CO_2) have different characteristics in miscibility development, density and viscosity ratio as shown in Table 2.1.

Table 2. 1: Injection gas properties.

Gas type	Miscibility	ρ_{oil} - ρ_{gas} (lb/cuft)	μ_{oil} / μ_{gas}
Lean gas	None	27	6.0
Sour gas	Some swelling	20	4.4
CO_2	Dynamic	Zero	2.6
Acid gas	First – contact	-5	1.4

The simulation results indicated that sweep efficiency improves with increased degree of miscibility as a longer plateau period is seen in comparison to other cases. Therefore, a miscible acid gas injection is the preferred recovery mechanism for part of the reservoir under study. This is a result of several key factors, including the favorable miscibility with the native oil, better solvent for asphaltene, a more favorable mobility ratio due to high acid gas viscosity, density, and availability.

Farzad and Amani [8] compared and evaluated various Minimum Miscibility Pressure (MMP) correlations for a miscible gas injection project. They also performed a parametric study on gas injection process using compositional simulation. They concluded that experimental MMP measurement should always be performed for gas injection projects and calibration of fluid model. For simulation study, the results showed that miscible flooding can increase oil recovery substantially but increasing the injection pressure higher than MMP does not significantly affect the amount of incremental oil. The authors also concluded that if a system is viscosity-dominated, the injection gas composition may not be important from an interfacial tension perspective. In this situation, an alternative water flooding may show more productivity improvement with less investment.

2.3 Evaluation of Water Alternating Gas (WAG)

The Water Alternating Gas (WAG) process is an enhanced oil recovery method defined as a cyclic method of injecting alternating cycles of gas followed by water and repeating this process several cycles as desired. The objective of implementing WAG is to enhance sweep efficiency of gasflooding.

Wu et al. [9] studied the effect of various well completion types, reservoir heterogeneity, injected fluid, and operating parameters to misccible gasflooding and WAG. They used stocastic model to assigned permeability distribution in reservoir simulation model. Waterflooding is also simulated as a base case for comparison with miscible gas flooding and WAG process. The simulation results show that WAG process yields the highest displacement efficiency. The oil recovery factor obtained from WAG is up to 85% when using CO2 as an injected gas while the waterflooding yields lowest oil recovery at around 20%. The authors point out that heterogeneity of reservoir or variation of permeability in this study has a high impact on oil recovery and should be taken into account for actual field development. For completion schemes evaluation, the factor that affects the well placement and optimum perforation intervals is the density difference between injection fluid and reservoir oil. For this study, the authors suggest that the injector should be completed at the bottom part of the reservoir while the producer should be completed at the upper part of the reservoir to avoid early gas breakthrough. Furthermore, the longer horizontal well provides higher oil recovery and the bottom hole pressure should be maintain near the bubble point pressure to avoid early breakthrough of gas. For WAG operating parameters, small WAG cycle length and small slug sizes yields a better oil recovery than large cycle and slug sizes.

CHAPTER III

THEORY AND CONCEPTS

This chapter describes basic of volatile oil characteristics and miscible gas flooding mechanism. The effect of injected gas composition is also discussed using ternary diagram. Next, three phase relative permeability modeling and calculations of voidage replacement ratio used in ECLIPSE are mentioned. Finally, waterflooding performance related topics like displacement, sweep efficiency and stability of waterflooding condition are mentioned for further detailed discussion in the later chapters.

3.1 Characteristics of Volatile Oil Reservoir

Definitions of volatile oil from different authors are summarized in Table 3.1. Volatile crude oils contain relatively few heavy hydrocarbon molecules and more intermediate ones compared to black oil. They are also characterized by high liquid shrinkage immediately below the bubble point. For isothermal depletion experiment, oil viscosity decreases with decreasing pressure due to volumetric expansion of oil until it reaches a minimum value at the bubble point pressure. Reducing the pressure below the bubble point leads to a net increase in oil viscosity due to liberation of the solution gas until dead oil viscosity is reached at atmospheric pressure [10].

When the bottomhole pressure (BHP) of volatile oil reservoir falls below the bubble point pressure, two phases are created in the region around the wellbore, and a single phase (oil) appears in regions away from the well. The oil relative permeability reduces towards the near-wellbore region due to increasing gas saturation. The gas saturation around the wellbore is illustrated in Figures 3.1. The reservoir region can be categorized into three parts, similar to a gas-condensate reservoir [11].

Table 3. 1: Literature definition of volatile oil.

Author	Definition	API	GOR (scf/stb)	Bo (rb/stb)
Whitson *et al*. [12]	High GOR, High shrinkage to 50%	≥ 35°	1,000 - 3,000	> 1.5
Moses [13]	High shrinkage immediately below the bubble point pressure. High shrinkage (can go as high as 45%)	≥ 40°	2,000 – 3,500	≥ 2
Ahmed [14]	Produce more gas than black oil for same pressure drop. Greenish to orange color	45° to 55°	2,000 – 3,500	≈ 2
McCain [15]	Relatively fewer heavy molecules and more intermediates. Brown, Orange or green color	≥ 40°	2,000 – 3,300	≥ 2

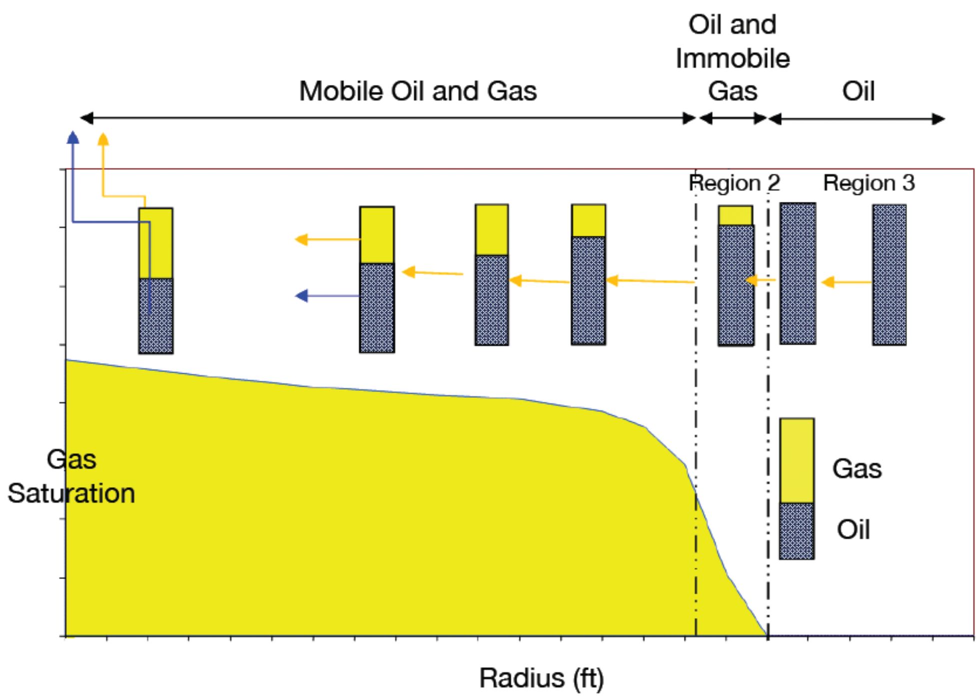


Figure 3. 1: Gas saturation in typical volatile oil reservoir (after [11]).

3.2 Gravity Segregation of Solution Gas Drive

Primary recovery of volatile oil reservoir is influenced by several drive mechanisms like rock and liquid expansion drive, solution gas drive, water drive and combination drive. However, if the reservoir is not connected with an aquifer, then the recovery performance is dominated by solution gas drive and/or gas cap drive due to a high level of vaporization of solution gas in volatile oil. Therefore, in this study, we focus on the performance of gravity segregation of solution gas that affects the total oil recovery with natural depletion.

When the reservoir pressure falls below the bubble point pressure, gas is liberated from the crude oil and subsequently expands and forces crude oil out of the pore space. The expanding gas provides the force to drive the oil; thus, it is called solution gas drive. For very volatile oil, since large amount of liberated gas occurs in the reservoir, some gas flow to the well bore due to viscous force but some moves upwards to the high structure of the reservoir due to gravity force. The vertical movement of solution gas helps maintain the pressure of the reservoir and may later accumulate as a secondary gas cap if we have appropriate reservoir geometry and well placement.

Vertical communication and gravity segregation are principally controlled by three variables: (1) vertical permeability of the reservoir, (2) production rate, and (3) well spacing. As the well spacing and vertical permeability increase and the production rate decreases, the effect of gravity segregation increases.

The gravity segregation can be measured in term of a gravity number, N_g. N_g is defined as the ratio of the time it takes the fluid to move from the drainage radius to the wellbore to the time it takes a fluid to move from the bottom of the reservoir to the top [16]. In the oil field units, the gravity number is given by:

$$N_g = \frac{2.46\times10^{-5} k_v \Delta\rho r_e^2}{\mu_o q} \quad (3.1)$$

where

k_v	=	vertical permeability, md
$\Delta\rho$	=	density difference, ρ_o - ρ_g, lbm/ft^3
r_e	=	drainage radius, ft
q	=	production rate at reservoir conditions, RB/day
μ_o	=	oil viscosity, cp

Gravity segregation is likely important if $N_g > 10$, and less likely if $N_g < 0.1$.

3.3 Ternary Diagram

Ternary diagram is a graphical plot representing liquid and vapor phase behavior as a function of fluid composition of three main components at fixed pressure and temperature. Multiple components fluid can be displayed on the ternary diagram by grouping the fluid composition to three main components which are:

- A light group, consisting of C_1 and N_2
- An intermediate group, of CO_2, H_2S and the hydrocarbons C_2,C_3,…C_6
- A heavy group, of all the heavy components, C_{7+}

Figure 3.2 is an example of ternary diagram, the phase envelop separates single phase and two-phase region. If the fluid compositions fall in the phase envelope, the fluid appear as two-phase, and we can identify composition in liquid and vapor phase by follow the tie line to the lines at the edge of phase envelop. These two lines are bubble point and dew point line and the point at which these two lines meet is defined as plait point. At this point, fluid compositions in gas and vapor phases are identical.

The tangent line from the plait point to the bottom of the diagram is an extension of critical tie line which is used as a separation region. We use this line for a further analysis of miscible condition when mixing reservoir fluid with different injected gas composition.

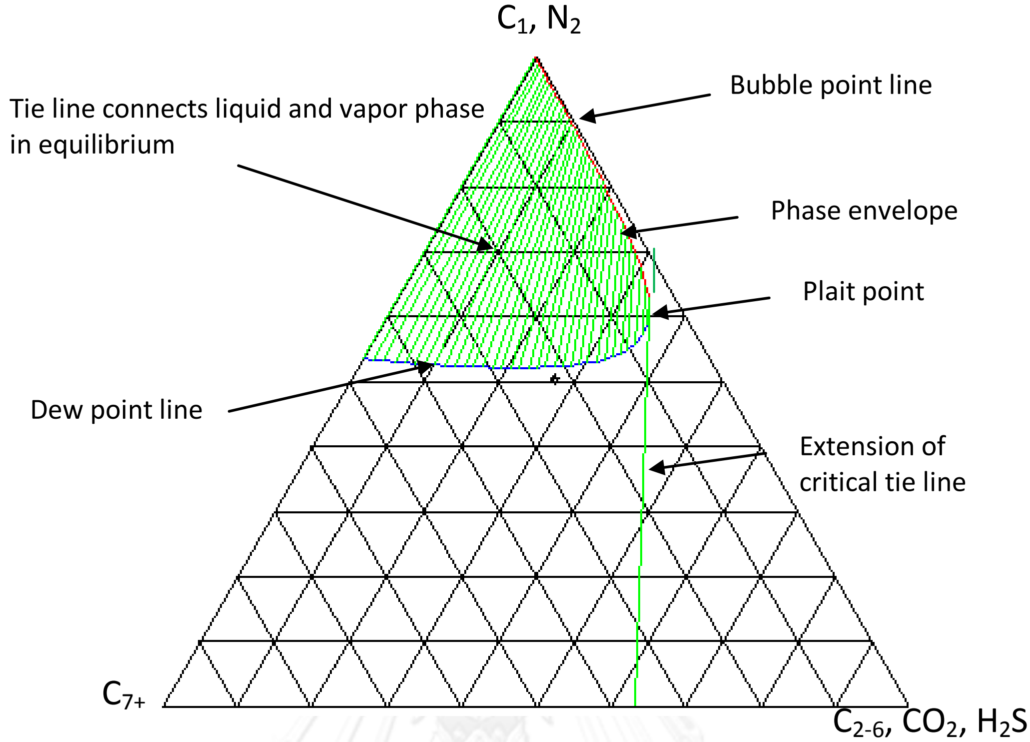


Figure 3. 2: An example of ternary diagram.

3.4 Miscibility Concept and Gas Drive Mechanism

3.4.1 Definition of Miscibility

For petroleum reservoirs, miscibility is defined as the ability of two or more fluids (liquid or gas) to form a single homogeneous phase without the existence of an interface when mixed in all proportions. If two phases form after certain proportion of one fluid is added, the fluids are considered immiscible.

When we inject gas into oil, the mixture can either form one hydrocarbon phase or two separate oil and gas phases. If the mixture is single phase, then the injection process or the displacement process is miscible but if the mixture is two-phase, then the process is immiscible.

In a reservoir with a gas-oil contact, there is an interface between gas phase and oil phase. This interface is associated with interfacial tension (IFT). As the IFT reduces to zero, the interface disappears. The condition at which the two fluids become one is called miscibility condition.

From a simulation point of view, the main advantage of miscibility is that there is no residual oil to gas displacement. Therefore, achieving miscibility means increasing recovery.

3.4.2 Classification of Miscible Displacements

For a given temperature, miscibility depends on fluid composition and pressure. There is a minimum pressure we need to achieve miscibility, and this pressure depends on the process. Miscible displacement processes in the oil reservoirs are usually divided into two classes:

1. First contact miscible processes: Displacements in which the injection fluid and the in-situ reservoir fluid form a single phase mixture for all mixing proportions.

2. Multi-contact miscible processes: Processes in which the injected fluid and the reservoir oil are not miscible in the first contact but miscibility could develop after multiple contacts (dynamic miscibility). These processes are categorized into vaporizing, condensing, and combined vaporizing-condensing drive mechanisms.

In general, to achieve first contact miscibility, we require a high cost of injected gas type like liquid petroleum gas (LPG) or a high cost of maintaining high reservoir pressure at which suitable for achieving miscibility condition. On the contrary, multiple contact miscibility can be achieved with cheaper injected gas like nitrogen, carbon dioxide and lean natural gas. In this study, we focus on this type of miscibility.

3.4.3 Multi-Contact Miscibility

Multi-contact miscibility is achieved by in-situ transfer of component between injected gas and oil in the reservoir. The miscible condition normally occurs after multiple contacts and results in a transition zone depending on the initial composition of injected and reservoir fluid. The injection gas drive process is classified into two main categories (Orr. [17]):

1. Vaporizing gas drives
2. Condensing gas drives

Other types of gas drives can be interpreted as a combination of vaporizing and condensing gas drives.

3.4.3.1 Vaporizing Gas Drive

For vaporizing gas drive, the miscibility is achieved by vaporizing of intermediate component in oil phase by injected gas. After successive contacts between injected gas and reservoir oil, the injected gas composition get richer as it move through the oil bank until this rich gas has enough in intermediate components to develop miscibility with the oil. Injection gases, which are lean in intermediate components, such as nitrogen, methane, carbon dioxide and flue gases generally, develop miscibility through vaporizing gas drive mechanism (Stalkup, [18]).

Figure 3.3 shows the ternary diagram for this drive, the initial composition of reservoir oil and injected gas is O_1 and G_1, respectively. Consider a mixture of original oil and injected gas, this mixture has a composition as M_1 and flash to be oil L_1 and gas V_1. Gas V_1 is at the leading edge of gasflood front, and then mix with the original oil to further form a mixture M_2. This enrichment process is repeated and moves the new equilibrium mixture gas composition toward the plait point until the mixture of enriched gas and original oil is out of the phase envelope or two-phase region where the miscibility occurs.

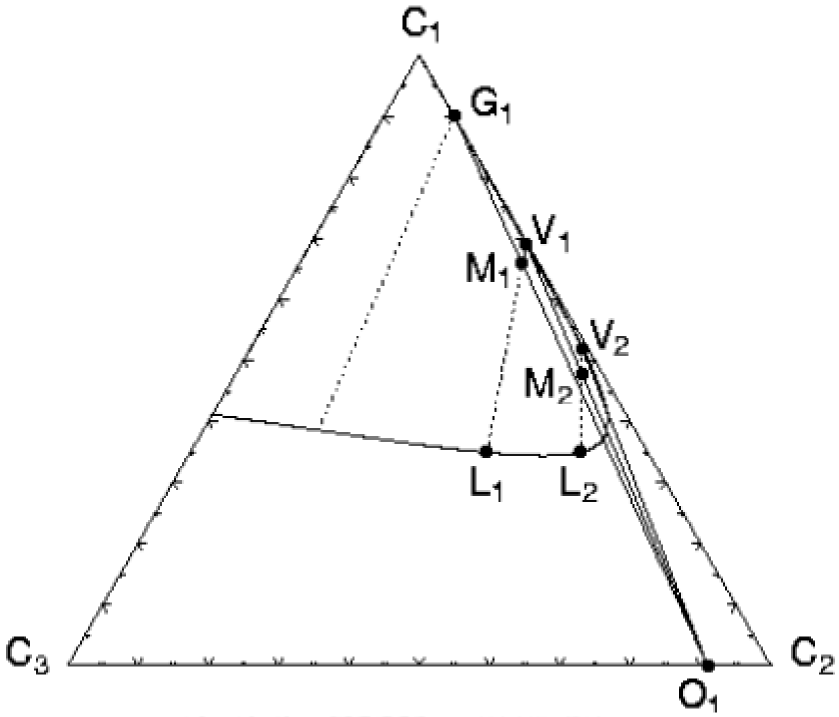


Figure 3. 3: Ternary diagram of enrichment process for vaporizing gas drives through multiple contacts (after Orr. [17])

3.4.3.2 Condensing Gas Drive

For condensing gas drive, the injection gas is already rich in intermediate components. And when the injected gas contacts the oil multiple times, the gas become lean because oil is absorb these intermediate components and getting lighter as more gas flow through it. This lighten oil is finally mixed with injected gas and subsequently develops miscibility. Figure 3.4 depicts a development of miscibility from a condensing gas drive using ternary diagram. The initial composition of reservoir oil and injected gas is O_2 and G_2, respectively. Consider a mixture of original oil and injected gas, this mixture has a composition as M_1 and flash to be oil L_1 and gas V_1. This oil L_1 is lighter than the original oil. And since gas G2 has transferred intermediate components to oil O_2, gas V_1 is more mobile than the oil L_1 and then move away. Later, next volume of injected gas G_2 mix with oil L_1 and form a mixture M_2, which consequently flash to oil L_2 and gas V_2. The gas V2 moves away, leaving oil L_2. Oil L_2 will further mix with gas G2 until mixture composition reaches the plait point at which it becomes miscible with the injected gas G_2.

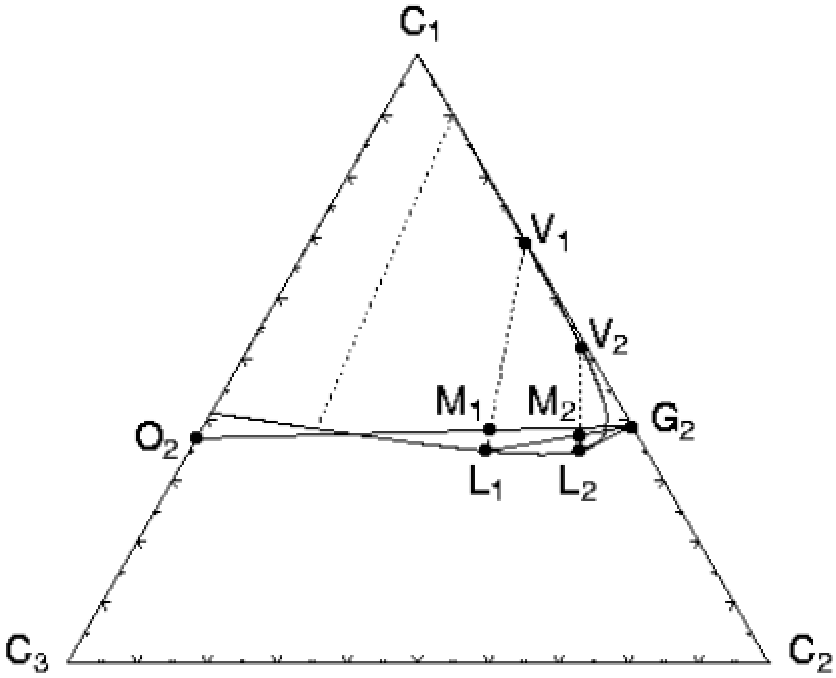


Figure 3. 4: Ternary diagram of enrichment process for condensing gas drives through multiple contacts (after Orr. [17]).

3.4.4 Combined Condensing-Vaporizing Gas Drive

In realistic gas drive process, the processes that occur in the reservoir may not be categorized as either a vaporizing drive only or a condensing drive only. Both processes probably happen at the same time. Zick [19], proposed the following theory to explain the condensing and vaporizing gas drive mechanism. When injected gas becomes richer in the intermediate components by vaporizing gas drive mechanism at leading edge of injected gas, at the same time the light intermediate condenses back into the oil at trailing edge (condensing gas drive mechanism). And the forward moving gas becomes more similar to the reservoir oil where miscibility is achieved within a transition zone as illustrated in Figure 3.5.

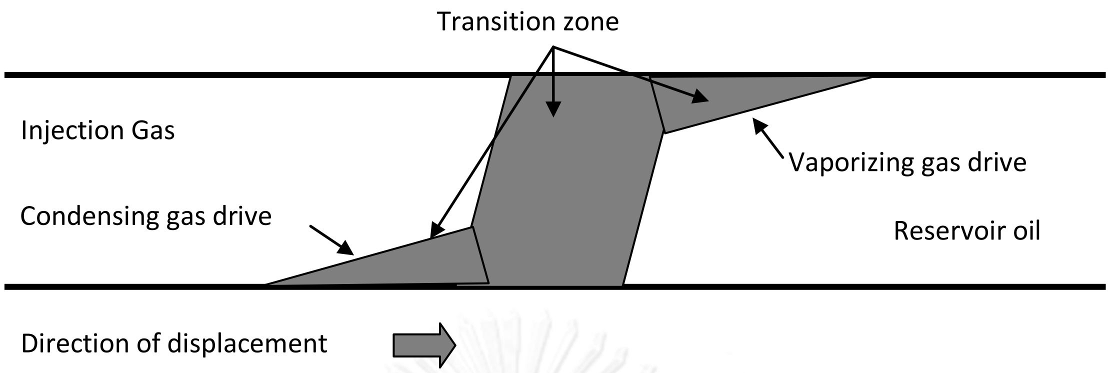


Figure 3. 5: One dimension schematic showing miscible process of combined condensing-vaporizing gas drive.

3.4.5 CO_2 Miscible Process

Carbon dioxide (CO_2) can be classified either into as vaporizing gas drive or condensing gas drive. Holm and Josendal [20], conducted various displacement experiments by injecting CO_2 into crude oil to show that the drive mechanism is vaporization due to the extraction of intermediate hydrocarbon components from the oil. While Stalk up [21] and Zick [19] performed various multiple-contact experiments to show that a combined condensing and vaporizing gas drive mechanism is responsible for several laboratory displacements of reservoir fluid by enriched gas injection.

Therefore, it can be inferred that CO_2 will vaporize the light to intermediate components of oil into the injected CO_2 phase and the rich CO_2 gas will transfer the light intermediates by condensing into the oil phase as it move through the reservoir as illustrated in Figure 3.6.

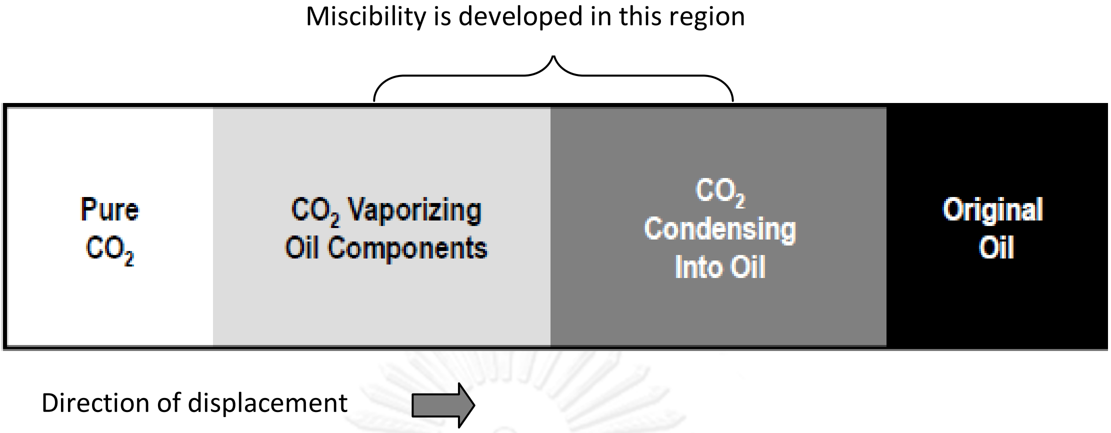


Figure 3. 6: One dimension schematic showing CO_2 miscible process.

3.5 Effect of Injected Gas Composition on Miscibility Condition

Ternary diagram is used to identify a miscibility condition between specific oil and injected gas composition. Figure 3.7 shows an example for moderately volatile oil at reservoir pressure and temperature equal to 4,200 psig and 189 F. Most of injected gas compositions like CO_2, H_2S are categorized as intermediate group (C_2-C_6). And based on the theory, it is obvious that for this volatile oil if we use CO_2, or the gas which have percent C_1 or N_2 less than 30%, miscibility condition will always achieve. Therefore, for volatile oil which is more responsive to gas injection than black oil, the difference in injected gas compositions mainly causes a difference in cost of injected gas supply and compression.

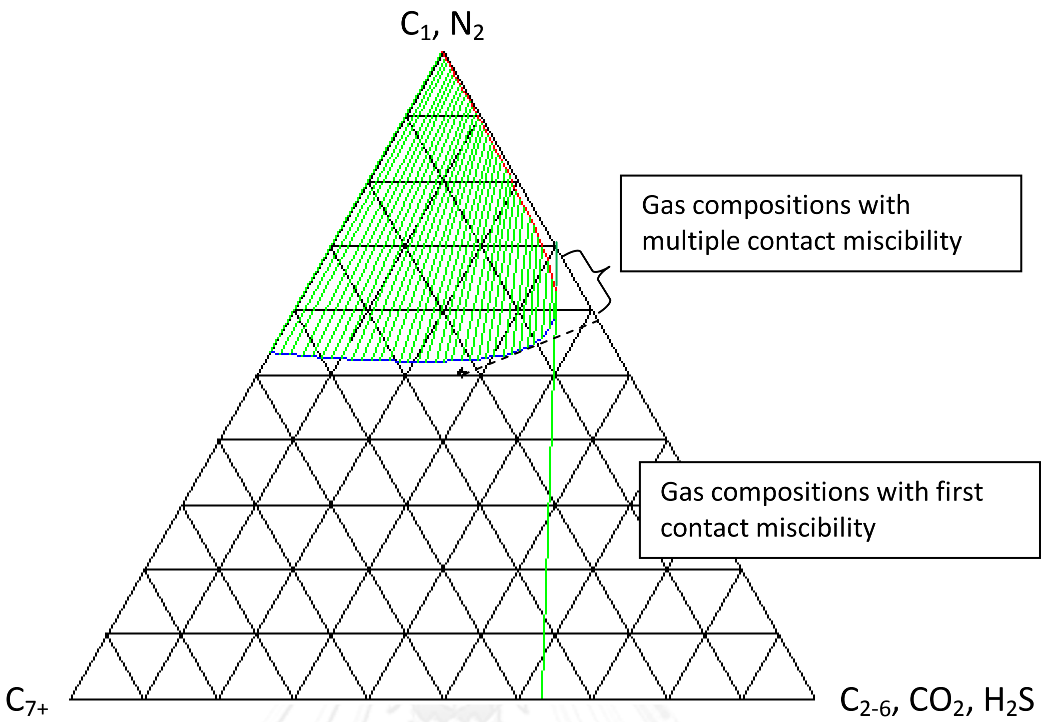


Figure 3. 7: Ternary diagram of moderately volatile oil case at 4,200 psig and 189 F.

3.6 Miscibility Modeling in Compositional Simulator (ECLISPE 300)

ECLIPSE compositional model deals with miscibility naturally since phase equilibrium is completed in every grid. An additional accounting of miscibility must be taken by modifying the relative permeability curves. Since IFT between fluids will change the residual oil saturation and consequently relative permeability curve will be modified. The scaled relative permeability curve is evaluated as a weighted average of miscible and immiscible relative permeability curves. Calculation of surface tension using Macleod-Sugden [22] correlation and weighted average of relative permeability curves is as follows:

$$\sigma = \left\{\sum_{i=1}^{N_c} \sigma_i \times \left(x_i \times \rho_l^m - y_i \times \rho_v^m\right)\right\}^4 \tag{3.2}$$

where

x_i	=	liquid mole fraction of component *i*
y_i	=	vapor mole fraction of component *i*
σ_i	=	component surface tension, dyne/cm
ρ_L^m	=	liquid phase molar density, g-mole/cc
ρ_V^m	=	vapor phase molar density with unit of g-mole/cc

Calculated surface tension by this correlation becomes zero at the critical point where the phase compositions and densities are the same, and two phases become fully miscible. An interpolation factor, *F* is defined:

$$F = \left(\frac{\sigma}{\sigma_o}\right)^N \tag{3.3}$$

where σ_o is a reference arbitrary surface tension value. Maximum value of 1 is attributed to the dominant immiscible flow whereas the zero value of *F* is indicative of a miscible displacement mechanism. This interpolation factor, *F* is used in obtaining a weighted average of immiscible (entered saturation data curves) and miscible (straight line) relative permeability curves and residual oil saturation as can be written in equations 3.4 and 3.5, respectively.

$$k_{ro} = F k_{ro}^{immis} + (1 - F) k_{ro}^{mis} \tag{3.4}$$

$$S_{or} = F S_{or}^{immis} + (1 - F) S_{or}^{mis} \tag{3.5}$$

where

k_{ro} = relative permeability to oil

k_{ro}^{immis} = relative permeability to oil at immiscible condition

k_{ro}^{mis} = relative permeability to oil at miscible condition

S_{or}^{immis} = residual oil saturation at immiscible condition

S_{or}^{mis} = residual oil saturation at miscible condition

The immiscible residual oil saturation S_{or}^{imm} is obtained from the user-defined saturation whereas the critical miscible saturation is usually zero. The scaled miscible relative permeability is a straight line when F approaches zero.

3.7 Relative Permeability Model

Three phase relative permeability depends on rock's wettability where oil, water, and gas curves are defined by end point saturations and Corey exponent. Referring to Corey's method [23- 24], the following equations are used to construct the relative permeability curves for oil-water and oil-gas systems.

$$k_{ro} = k_{ro}^{o}\left(\frac{S_o - S_{or}}{1 - S_{or} - S_{wr} - S_{gr}}\right)^{e_o} \tag{3.6}$$

where

S_{or} = residual oil saturation

k_{ro}^{o} = end point relative permeability to oil

e_o = exponent of relative permeability curve to oil

S_{wr} = residual water saturation

S_{gr} = residual gas saturation

In the absence of experimental data for three-phase oil exponent and end point relative permeability, the following can be used.

$$k_{ro}^{o} = bk_{row}^{o} + (1-b)k_{rog}^{o} \tag{3.7}$$

$$e_{o} = be_{ow} + (1-b)e_{og} \tag{3.8}$$

where

$$b = 1 - \frac{S_g}{1-S_{wr}-S_{org}} \tag{3.9}$$

k_{row}^{o} = end point relative permeability to oil in water phase

k_{rog}^{o} = end point relative permeability to oil in gas phase

S_{org} = residual oil saturation in gas phase

e_{ow} = exponent of relative permeability curve to oil in water phase

e_{og} = exponent of relative permeability curve to oil in gas phase

3.7.1 Internal Function of Three Phase Relative Permeability for ECLIPSE Model

The default model assumed by ECLIPSE is known as saturation weighted model. The oil saturation is assumed to be constant and equal to the block average value, S_o, throughout the cell. The gas and water are assumed to be completely segregated, except that the water saturation in the gas zone is equal to the connate saturation, S_{wco}. Assuming the block average saturations are S_o, S_w, and S_g which $S_o + S_w + S_g = 1$. The oil relative permeability is then given by:

$$k_{ro} = \frac{S_g k_{rog} + (S_w - S_{wco}) k_{row}}{S_g + (S_w - S_{wco})} \tag{3.10}$$

where

k_{rog} = oil relative permeability for a system with oil, gas and connate water (tabulated as a function of S_o)

k_{row} = oil relative permeability for a system with oil, and water only (also tabulated as a function of S_o)

3.8 Voidage Replacement Ratio (VRR) Calculation

Voidage replacement ratio (*VRR*) is commonly used to measure the rate of change in reservoir energy. *VRR* optimization is often an important factor in planning and managing enhanced oil recovery (EOR) projects. *VRR* is easily calculated in black oil waterflooding operations. However, in reservoirs impacted significantly by compositional effects, calculation of *VRR* is nontrivial [25].

The primary purpose of any EOR operation is to balance reservoir voidage by injecting a replacement fluid into the reservoir with the goal of maintaining or increasing oil production rate and/or ultimate recovery. Reservoir pressure effectively represents the energy within a given system. The injectant replenishes reservoir energy that has declined due to the withdrawal of hydrocarbons and water from the reservoir. This is typically achieved via waterflooding and/or gas injection. Injecting some supporting fluid at volumes that exceed the voidage from the system results in a *VRR* over 1 (increasing reservoir pressure) while injecting volumes which fall below system voidage results in a *VRR* of less than 1 (decreasing reservoir pressure).

3.8.1 *VRR* Calculation for Waterflooding

Calculating the overall material balance within a reservoir undergoing waterflooding operations provides a good method for evaluating *VRR*. The injection water, converted to reservoir barrels, balances the oil, water, and gas produced from the reservoir (measured in reservoir barrels). This is because water and hydrocarbons are essentially immiscible. A simple equation for the calculation of *VRR* is:

$$VRR = \frac{V_{inj}}{V_{prod}} \tag{3.11}$$

In a typical black oil system, V_{prod} is the volume produced, and V_{inj} is the volume injected, both converted to reservoir units. For a typical waterflooding operation producing above the saturation pressure, this equation can be rewritten as:

$$VRR = \frac{Q_{winj} \times B_w}{Q_o \times B_o + Q_w \times B_w} \tag{3.12}$$

where

Q_{winj}	=	water injection rate, STB/day
Q_o	=	oil production rate, STB/day
Q_w	=	water production rate, STB/day
B_w	=	water formation volume factor, RB/STB
B_o	=	oil formation volume factor, RB/STB

If the reservoir pressure is below the saturation pressure, a more rigorous material balance calculation is necessary as gas evolves from the liquid phase.

3.8.2 *VRR* Calculation for Immiscible Gas Injection

With first contact or multi-contact miscible gas injection, gas dissolves into the oil resulting in swelling of the oil. Alternatively, the system can be immiscible, resulting in the formation or expansion of the gas phase. For immiscible gas injection in reservoirs at or below the saturation pressure, the equation to determine *VRR* becomes:

$$VRR = \frac{Q_{ginj} \times B_g}{\left[Q_o \times B_o + Q_w \times B_w + \left(Q_g - R_s \times Q_o\right) \times B_g\right]} \tag{3.13}$$

where

Q_{ginj}	=	gas injection rate, scf/day
B_g	=	gas formation volume factor, RB/scf
R_s	=	solution gas-oil ratio scf/STB
Q_g	=	gas production rate, scf/day

Rock compressibility, overpressure complications, etc., can be incorporated into this calculation but the need for this refinement is generally of limited practical value. A detailed analytical solution can incorporate such refinements if desired.

3.9 Calculation of Displacement and Sweep Efficiency of Waterflooding

3.9.1 Overall Recovery Efficiency

For waterflooding, overall recovery efficiency is a product of displacement efficiency, areal and vertical sweep efficiencies.

$$RF = E_D \times E_A \times E_V \tag{3.14}$$

where

RF	=	overall recovery factor
E_D	=	displacement efficiency
E_A	=	areal sweep efficiency
E_V	=	vertical sweep efficiency

3.9.2 Calculation of Displacement Efficiency

Displacement efficiency can be defined as the fraction of movable oil which has been displaced in the swept zone at any given time. E_D can be expressed in as:

$$E_D = \frac{Volume\ of\ oil\ at\ start\ of\ flood - Remaining\ oil\ volume}{Volume\ of\ oil\ at\ start\ of\ flood}$$

$$E_D = \frac{(Pore\ volume)\frac{S_{oi}}{B_{oi}} - (Pore\ volume)\frac{\overline{S}_o}{B_o}}{(Pore\ volume)\frac{S_{oi}}{B_{oi}}}$$

or

$$E_D = \frac{\frac{S_{oi}}{B_{oi}} - \frac{\overline{S}_o}{B_o}}{\frac{S_{oi}}{B_{oi}}} \tag{3.15}$$

where

S_{oi} = initial oil saturation at start of flood

B_{oi} = oil FVF at start of flood, bbl/STB

$\bar{S}_o$ = average oil saturation in the flood pattern

If we maintain a constant reservoir pressure during the flooding, we may assume that oil formation volume factor is constant. Then, equation 3.16 is reduced to

$$E_D = \frac{S_{oi} - \bar{S_o}}{S_{oi}} \tag{3.16}$$

In order to express the effect of gas saturation, we may replace oil saturation with water saturation and gas saturation as follows:

$$E_D = \frac{\bar{S_w} - S_{wi} - S_{gi}}{1 - S_{wi} - S_{gi}} \tag{3.17}$$

where

$\bar{S}_w$ = average water saturation in the swept area

S_{gi} = initial gas saturation at the start of the flood

S_{wi} = initial water saturation at the start of the flood

3.9.3 Calculation of Areal Sweep Efficiency

The areal sweep efficiency E_A is defined as the fraction of the total flood pattern that is contacted by the displacing fluid. In this study, we use the following equations for areal sweep efficiency at and after breakthrough estimation.

Areal sweep efficiency at breakthrough

$$E_{ABT} = \frac{W_{inj}}{(PV)(\bar{S}_{wBT} - S_{wi})} \tag{3.18}$$

where

W_{inj} = cumulative water injected, bbl

(PV) = flood pattern pore volume, bbl

$\bar{S}_{wBT}$ = average water saturation in the swept area when injected water has breakthrough.

Areal sweep efficiency after breakthrough

$$E_A = E_{ABT} + 0.633 \log\left(\frac{W_{inj}}{W_{iBT}}\right) \tag{3.19}$$

where

E_A = areal sweep efficiency after breakthrough

W_{inj} = cumulative water injected

W_{iBT} = cumulative water injected at breakthrough

3.10 A Stability Condition of Waterflooding

For immiscible displacement like water flooding, if displacing water is more viscous than displaced fluid, water tends to advance as a tongue at the bottom of the reservoir or fingers through the oil bank known as viscous fingering.

For a dipping reservoir, there are two main forces which are gravity and viscous forces acting on a displacing fluid. Dake [26] developed a gravity segregation model that allows the calculation of flooding parameters required to create a stable displacement. The condition for stable displacement is that the angle between the fluid interface and the direction of flow should remain constant throughout the displacement as shown in Figure 3.8. Dake [26] introduced two parameters, the dimensionless gravity number "*G*" and the end-point mobility ratio M^*, that can be used to define the stability of displacement. These two parameters are defined by the following relationships:

The dimensionless gravity number G is given by:

$$G = \frac{7.853\times10^{-6} k k_{rw} A(\rho_w - \rho_o)\sin\theta}{i_w \mu_w} \tag{3.20}$$

where

k	=	absolute permeability, md
k_{rw}	=	relative permeability to water as evaluated at Sor
A	=	cross-sectional area,ft^2
ρ_w	=	water density, lb/ft^3
θ	=	dip angle
i_w	=	water injection rate, bbl/day
μ_w	=	water viscosity, cp

The end-point mobility ratio M^* is defined by:

$$M^* = \frac{k_{rw}@S_{or}}{k_{ro}@S_{wi}} \frac{\mu_o}{\mu_w} \tag{3.21}$$

Dake [26] used the above two parameters to define the following stability criteria:

• If $M^* > 1$**.** The displacement is stable if $G > (M^* - 1)$, in which case the fluid interface angle $\beta < \theta$. The displacement is unstable if $G < (M^* - 1)$.

• If $M^* = 1$. This is a very favorable condition, because there is no tendency for the water to bypass the oil. The displacement is considered unconditionally stable and is characterized by the fact that the interface rises horizontally in the reservoir, i.e., $\beta = \theta$.

• If $M^* < 1$. When the end-point mobility ratio M^* is less than unity, the displacement is characterized as unconditionally stable displacement with $\beta > \theta$ (Figure 3.8).

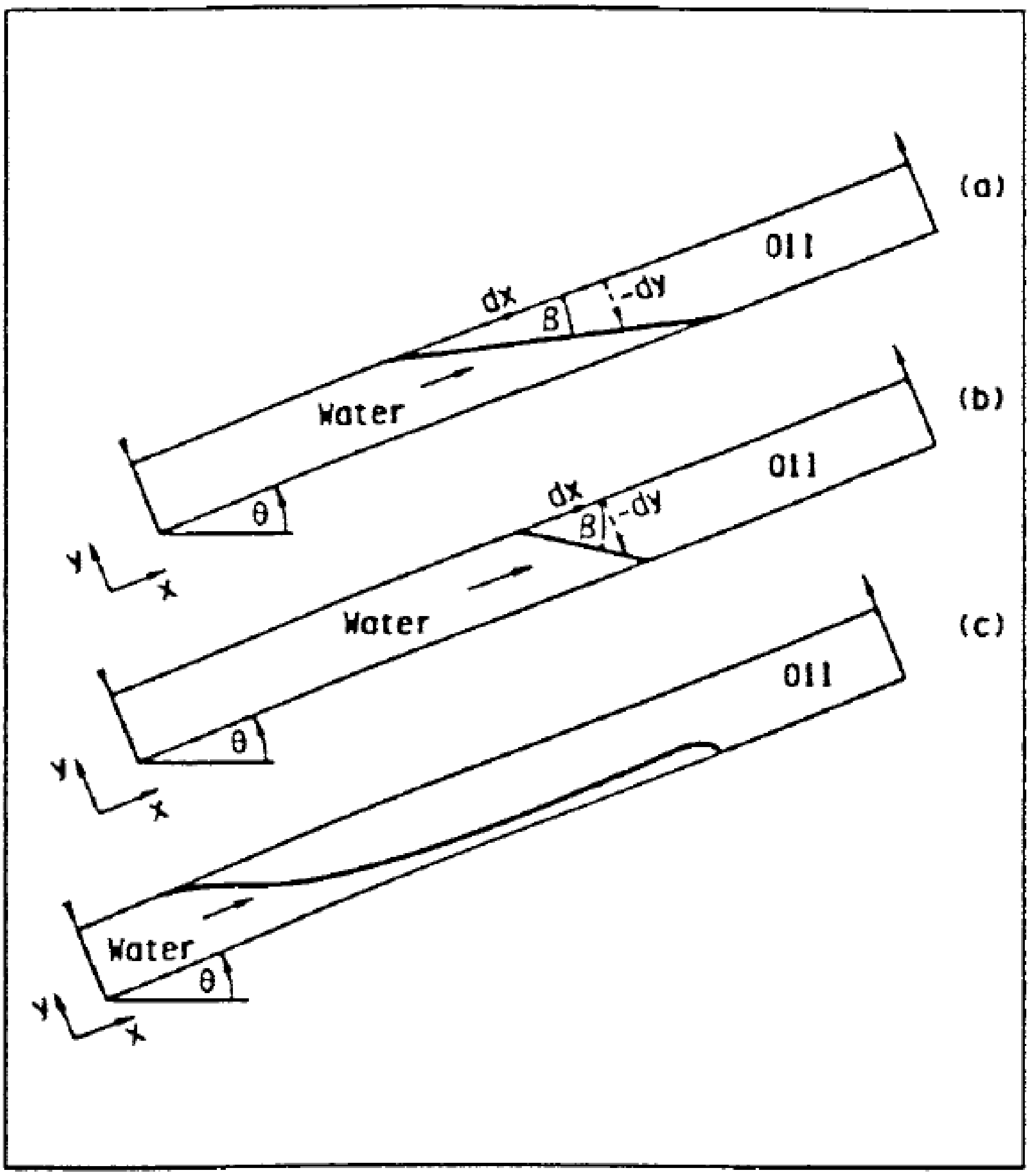


Figure 3. 8: Stable and unstable displacement in gravity segregated displacement: (a) stable: G > m – 1, M > 1, and β < θ; (b) stable: G > M– 1, M < 1, β > θ; and (c) unstable: G < M – 1. (after Dake [26])

3.11 Water Alternating Gas (WAG)

Water alternating gas technique is proved to provide better oil recovery than stand-alone water or gas injection. The WAG process provides higher microscopic gas displacement efficiency and better macroscopic water sweep efficiency, which leads to better overall oil recovery when compared to water or gas injection. A typical WAG process is shown in Figure 3.9. In general, it can be divided into miscible and immiscible displacement process.

Several parameters that affect WAG process are injection and reservoir fluid properties, WAG ratio, reservoir heterogeneity, injection pattern, and rock wettability which were studied by Christensen et al. [27] and Raj et al. [28].

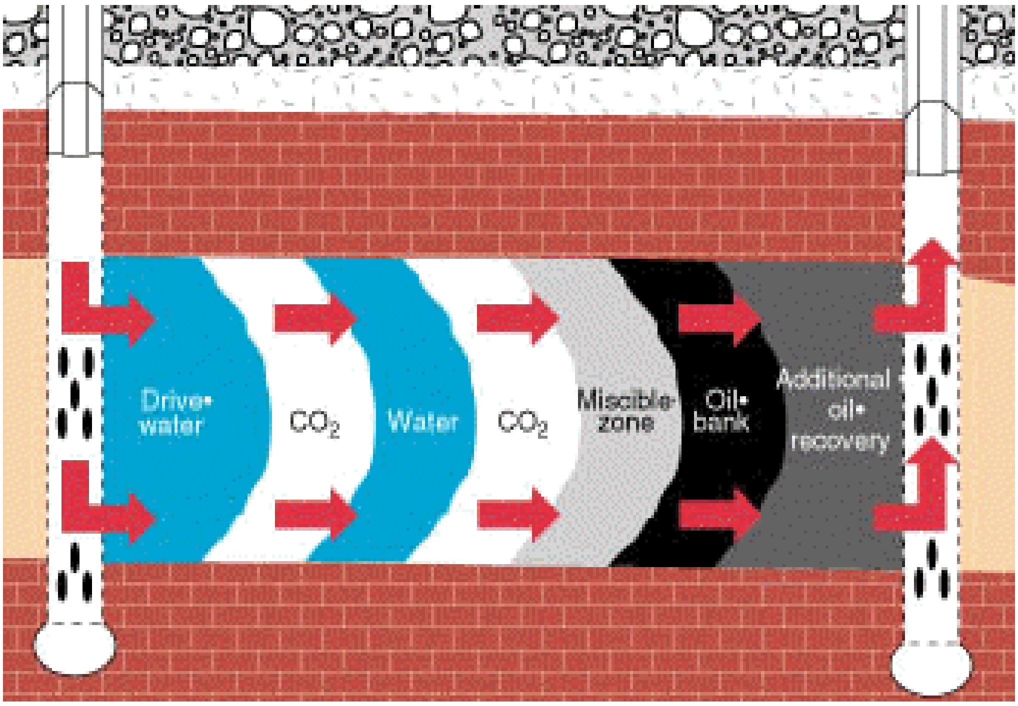


Figure 3. 9: Schematic diagram of WAG process (From Kinder Morgan Co. [29]).

3.12 Petroleum Fiscal Regime and Economic Analysis

In this study, we perform an economic analysis for different IOR schemes and compare them in order to obtain an economic perspective apart from recovery performance perspective. The fiscal regime used in this study is Thai-I which is currently implemented in several operating areas in the Gulf of Thailand. This section explains details of the fiscal regime and economic indicators used for this study.

3.12.1 Thai-I Fiscal Regime

In Gulf of Thailand, the concessionary system is used as a fiscal regime. This regime has three key items to deduct or add to the gross revenue as follows:

- Government's take:
  - Royalty flat 12.5%
  - Income tax 35%
- Expense before tax:
  - OPEX
  - Depreciation (5 year straight line for tangible assets)
- Expense after tax:
  - Royalty on exported oil (remitted tax, 23.08 %)
- Deduction after tax:
  - Domestic sales tax credit (minimum value between 6.25% of domestic sale revenue and remitted tax).

Figure 3.10 illustrates revenue flow and sharing for one barrel of oil between the contractor and government of Thai-I fiscal regime. As the contractor received oil sale revenue, $100, a royalty is 12.5% deducted from this portion as a government take. The revenue after royalty, $87.5 is further deducted by operating cost and depreciation portion of capital cost, $10. Thus, taxable income is equal to $77.5 and the income tax is 35% of this portion which is $27.125. After paid an income tax, the contractor also needs to remit oil exporting tax which is 23.08% of revenue after income tax. However, if the contractor got revenue from domestic sale, the government returns domestic sale tax credit equal to minimum figure between remitted tax and 6.25% of domestic sale revenue.

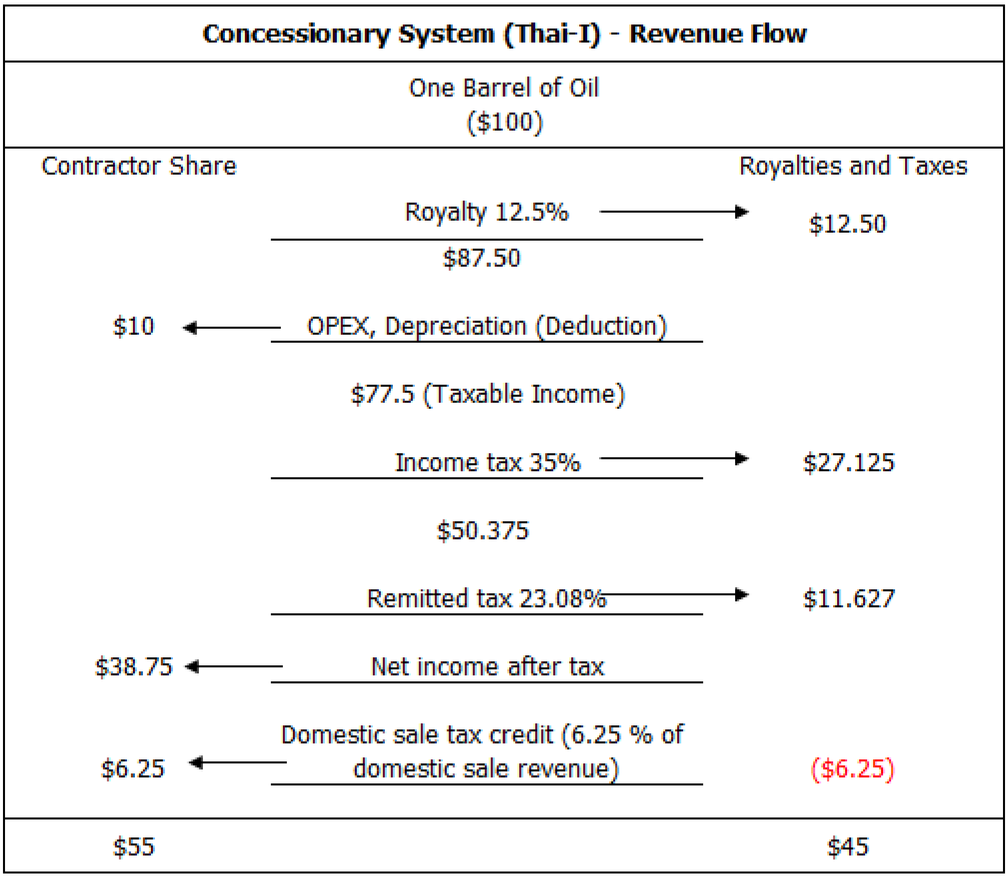


Figure 3. 10: Revenue flow diagram of Thai-I fiscal regime.

3.12.2 Economic Decision Tools

Analysis of various investment alternatives to a given objective may result in different aspects of cost, profit, and etc. The general method is to apply one or more parameters to measure economic performance. The purpose of using economic decision tools in evaluating investment alternatives is to establish consistent criteria for determining which options meet the investment objective and which ones are not. The following economic parameters are used for this study.

3.12.2.1 Internal Rate of Return (IRR)

The internal rate of return (IRR) is a measurement of the effective rate of return earned by an investment as through the money has been loaned at that rate. This parameter is intended as a measure of the profitability of a project. The IRR value of the project cash flow is the discounted rate at which the present value of the cash flow is zero. Another perspective of IRR is to assume that the net cash income from a project is used to repay the project investment plus interest on the investment. The interest rate which would allow the investment to be repaid plus interest over the life of the project is the IRR. Hence, for a general decision if IRR, as a percentage, exceeds the hurdle rate percentage, accept the project but if IRR is less than the hurdle rate, reject the project.

3.12.2.2 Net Present Value (NPV) and Net Present Investment (NPI)

Net present value (NPV) is the difference between the present value of the cash inflows and the present value of the cash outflows generated by the investment and discounted at the assumed hurdle rate (10 % for this study).

The net present investment (NPI) denotes the purchase price of the equipment to be used for the project. The cost of installation is also included as part of the purchase price.

For a general decision rule, if NPV is greater than zero, accept the project but if NPV is less than zero, reject the project.

3.12.2.3 Discounted Profitability Index (DPI)

DPI is the ratio of a project's NPV to NPI plus one as shown in Equation 3.22. DPI is a measure of investment efficiency; it is an indicator of how much value is added per dollar invested. This provides a particularly useful tool for a ranking of investment alternatives if the total capital requirement exceeds the available funds.

$$DPI = \frac{NPV\ of\ the\ project}{NPI\ of\ the\ project} + 1 \tag{3.22}$$

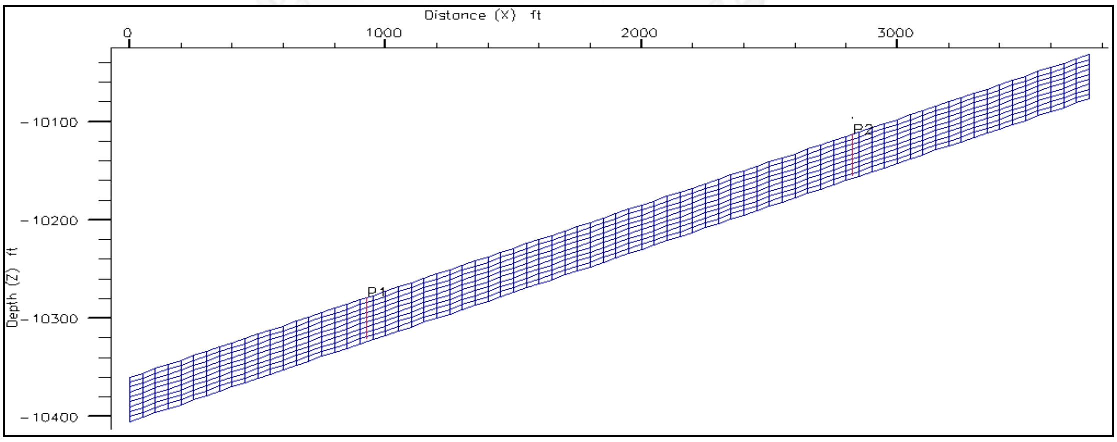
CHAPTER IV

RESERVOIR MODEL DESCRIPTION

To perform a reservoir simulation, a simple reservoir model with no-flow boundaries was set up. The reservoir structural parameters such as dip angle and net thickness are set based on average values from Gulf of Thailand (GoT). In this study, commercial numerical reservoir simulator, ECLIPSE 300 (Trademark: Schlumberger-Geoquest) is used for all simulations.

4.1 Physical Properties of Reservoir Model

The reservoir size in this study is relatively small which represents the marginal reservoir generally found in Gulf of Thailand (GoT). The schematic of reservoir is illustrated in Figure 4.1. Table 4.1 lists the key dimensions and reservoir properties for the model.



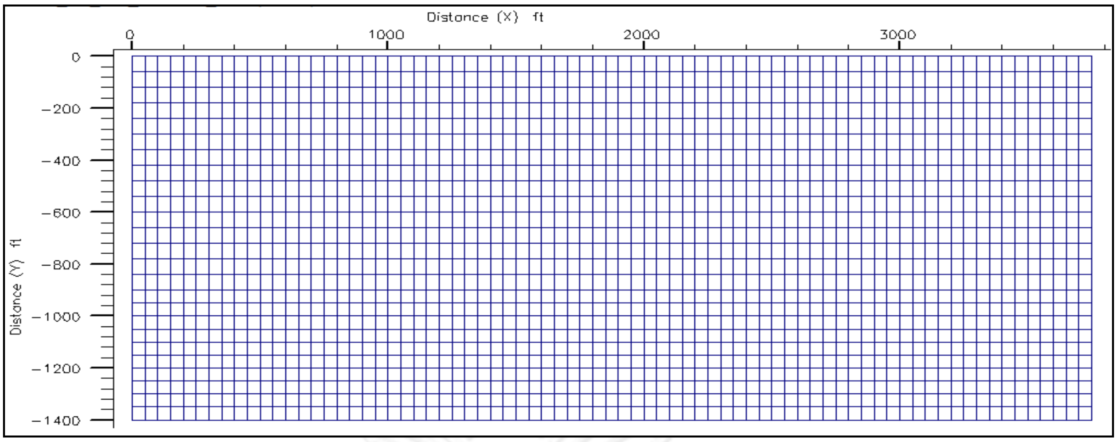


Figure 4. 1: Reservoir schematic in simulation study.

Table 4. 1 : Reservoir properties.

Variable	Value	Units
Geometry		
Length (x direction)	3750	ft
Width (y direction)	1400	ft
Height (z direction): reservoir thickness	45	ft
Number of grid blocks in x direction	75	-
Number of grid blocks in y direction	25	-
Number of grid blocks in z direction	9	-
Top depth	10,030	ft
Dip angle	5	degrees
Number of wells	2	well
Well drainage area	40	acres
Reservoir		
Average porosity*	20	%
Average absolute permeability*	70	md
Anisotropic ratio	1	
Temperature	189	^{o}F
Initial pressure @ top depth	4952	psia
Initial water saturation	0.22	fraction

*Note that the reservoir consists of 9 layers having different porosities and permeabilities.

To further represent reservoir characteristic in GoT, varying of vertical porosity and permeability was assigned to the model to represent fining upward depositional environment as shown in Figure 4.2.

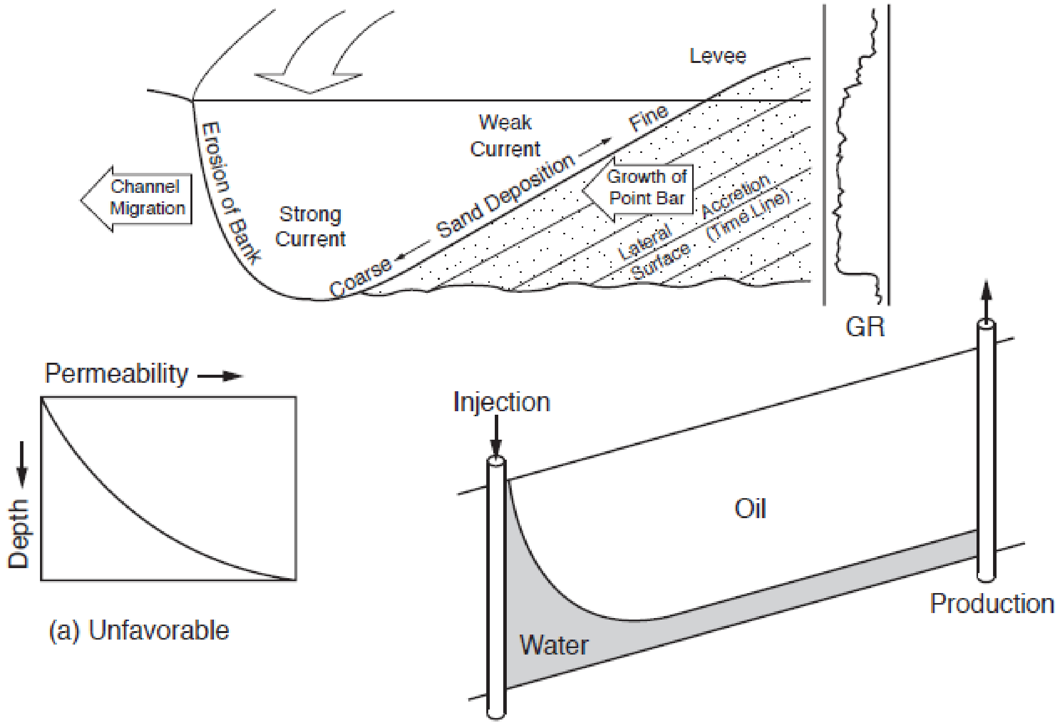


Figure 4. 2: Fining upward depositional environment (after Institute of Petroleum Engineering, Heriot-Watt University [30]).

Table 4. 2: Vertical heterogeneity data.

Layer	Absolute permeability (md)	Porosity
1	30	0.186
2	40	0.191
3	50	0.195
4	60	0.198
5	70	0.201
6	80	0.204
7	90	0.206
8	100	0.209
9	110	0.211

4.2 Fluid Properties

Volatile oil compositions are referred from Sanni and Gringarten [10] as shown in Tables 4.3, 4.4 and 4.5. The compositions are further used as an input to Peng-Robinson equation of state for PVT study at different reservoir condition. In this study, we are interested in studying the effect of volatility. Thus, moderately and very volatile oils are compared.

Table 4. 3: Summary of volatile oil properties.

Fluid type	Fluid A: Very volatile oil	Fluid B: Moderately volatile oil
P_{bub} (PSIA)	4,177 at 176 ^oF	4,060 at 189 ^oF
R_s (SCF/STB)	3,091 at 176 ^oF	1,406 at 189 ^oF
B_o (BBL/STB) at P_{bub}	2.68	1.74

Table 4. 4: Composition of volatile oil samples.

Components	Mole fraction	
	Fluid A	Fluid B
N_2	0.0030	0.0087
CO_2	0.0090	0.0016
H_2S	-	0.0000
C_1	0.5347	0.4943
C_2	0.1146	0.0728
C_3	0.0879	0.0802
IC_4	0.0456	0.0231
NC_4		0.0361
IC_5	0.0209	0.0180
NC_5		0.0179
C_6	0.0151	0.0232
C_{7+}	0.1692	0.2241

Table 4. 5: Properties of heavy components.

Properties of C_{7+}	Fluid A	Fluid B
MW of C_{7+}	173	215
γ of C_{7+}	0.83648	0.8479

Figures 4.3 and 4.4 show the phase diagram of very and moderately volatile oil, respectively. For highly volatile oil, the cricondentherm shifts to the left while the cricondenbar does not change much when compared with those for moderately volatile oil.

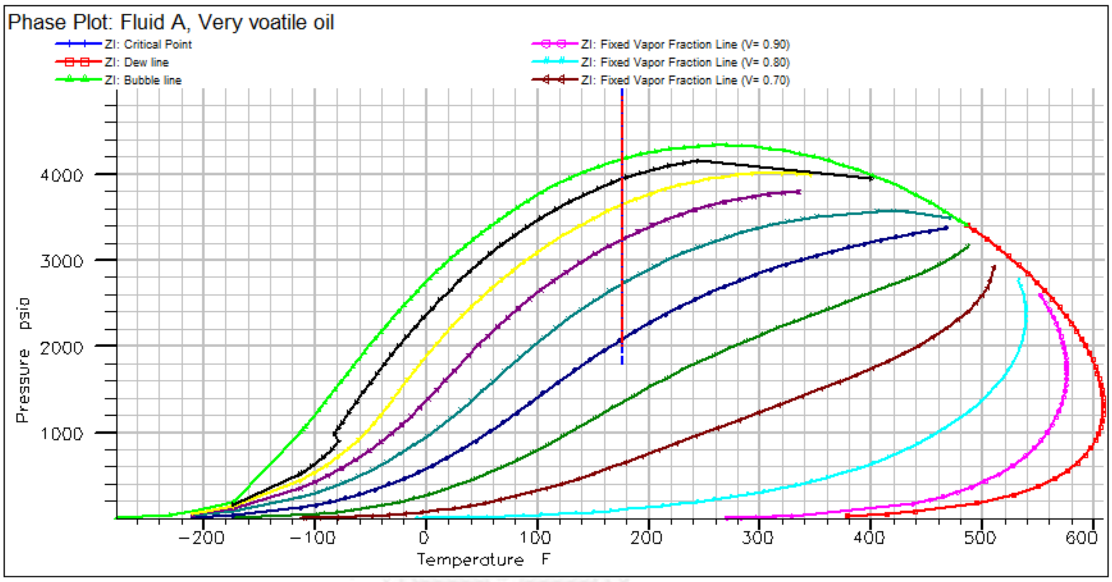


Figure 4. 3: Phase diagram of very volatile oil.

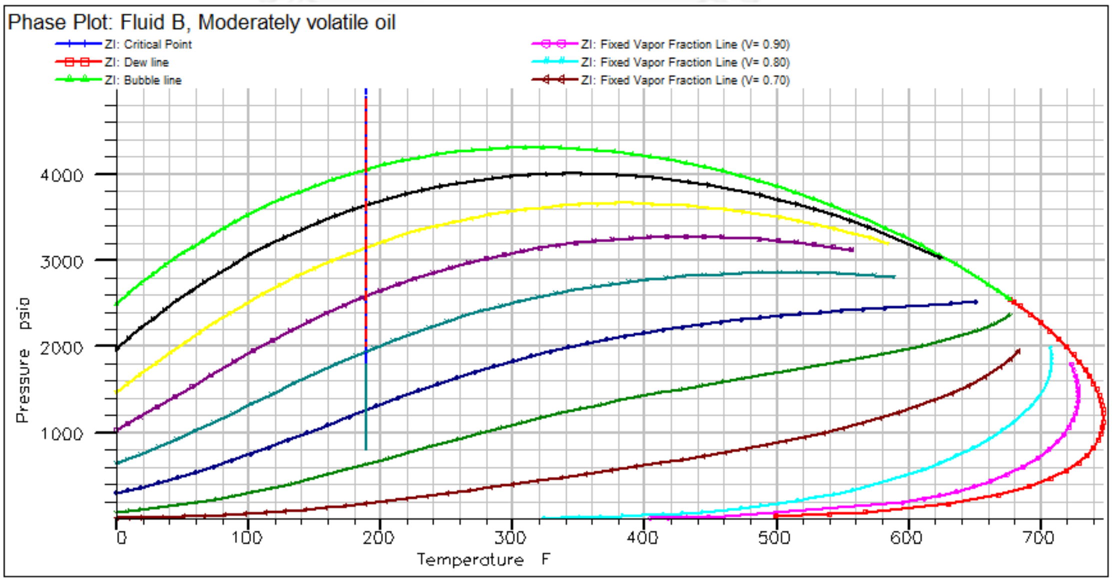


Figure 4. 4: Phase diagram of moderately volatile oil.

Figure 4.5 compares general oil properties for the two types of fluid having different volatility. For solution gas oil ratio (GOR), very volatile oil has a higher initial value of GOR, and the GOR drops faster when pressure decreases below the bubble point. On the other hand, viscosity and density of highly volatile oil increases faster when the pressure drops below the bubble point. Above the bubble point pressure, oil density and viscosity are not much different between very and moderately volatile oil. Oil properties with higher degree of volatility have higher variations after the pressure drops below the bubble point.

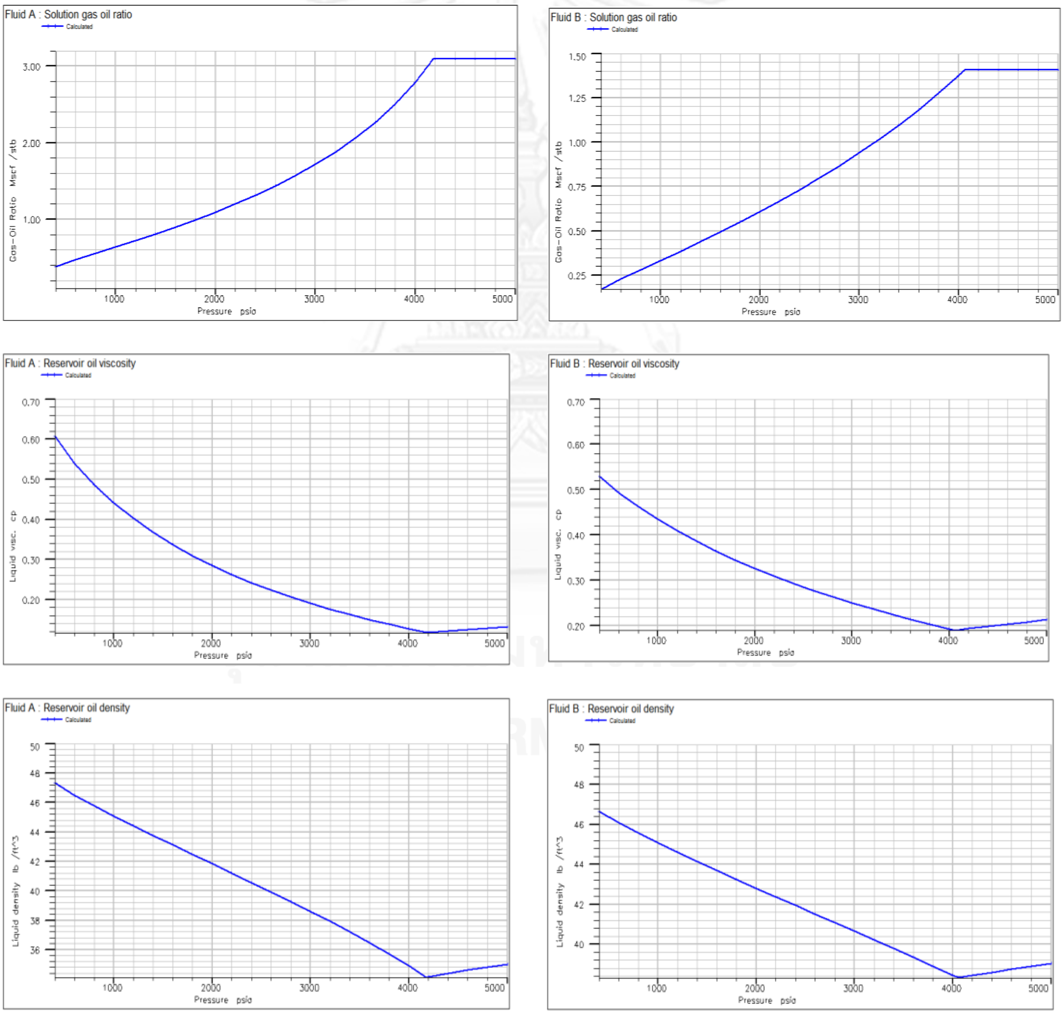


Figure 4. 5: GOR, oil viscosity, and density of very and moderately volatile oil.

4.3 Relative Permeability Data

A data set of moderately water wet rock relative permeability curves are generated using Corey correlation [24]. A typical range of exponents varying with rock wettability are shown in Table 4.6. Table 4.7 shows Corey exponents and critical saturations chosen for this study. Figures 4.6 and 4.7 show relative permeability curves of moderately water wet case which are used for the entire simulation study.

Table 4. 6: Typical range of Corey's exponents for each rock wetting type (after HELIX RDS, Module 8 relative permeability, page 26, [31]).

Wettability	Corey's exponent to oil	Corey's exponent to water
Water-wet	2 to 4	5 to 8
Intermediate wet	3 to 6	3 to 5
Oil-wet	6 to 8	2 to 3

Table 4. 7: Corey exponents and critical saturations used in this study.

Parameter	Value
Corey exponent: Oil-water	3
Corey exponent: Oil-gas	5
Corey exponent: Water	6
Corey exponent: Gas	2
S_{wi}	0.22
S_{orw}	0.2
S_{gc}	0.03
S_{org}	0.08
k_{rw}	0.3
k_{row}	0.9
k_{rg}	0.9
k_{rog}	0.9

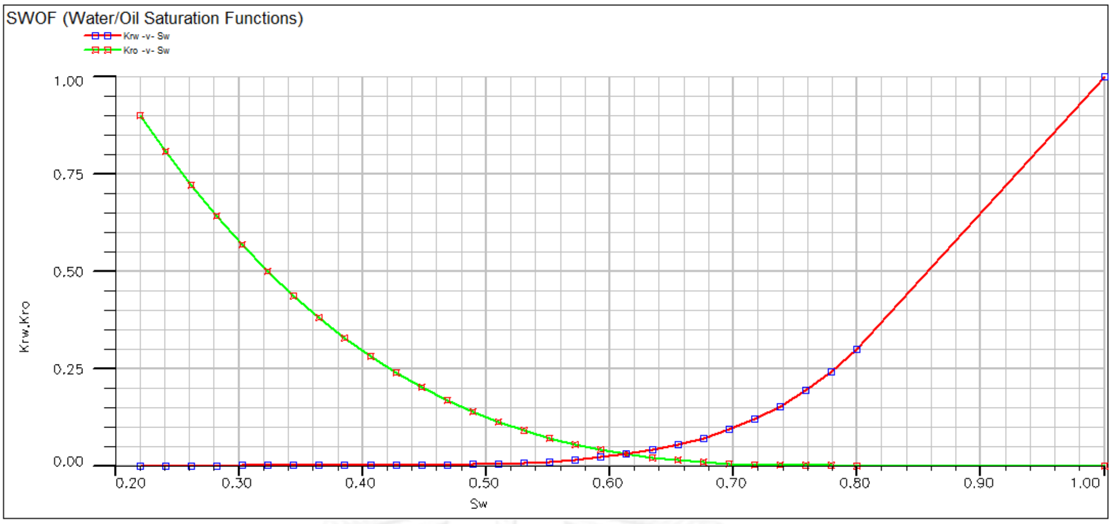


Figure 4. 6: Water and oil relative permeability curve of moderately water wet rock.

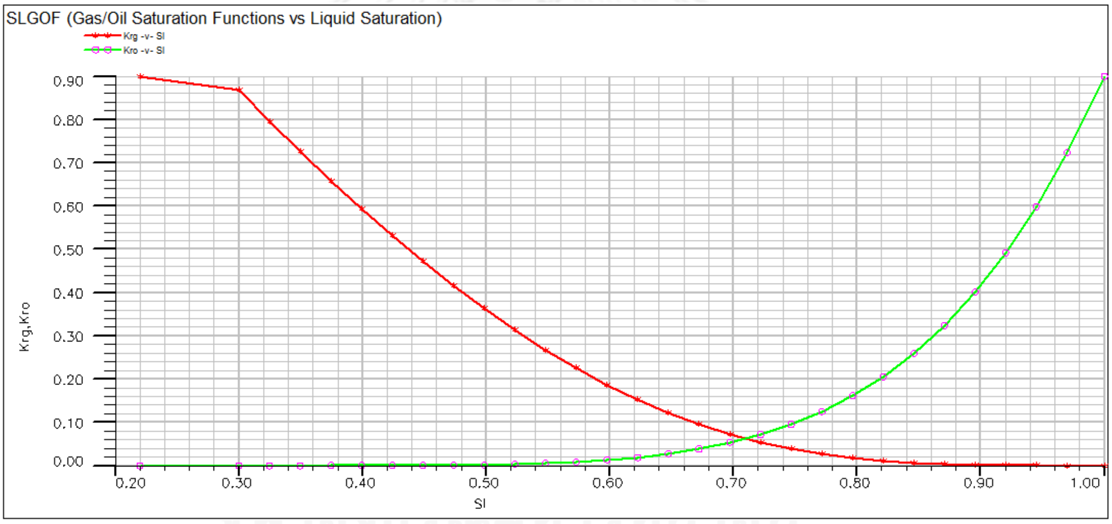


Figure 4. 7: Oil and gas relative permeability curve of moderately water wet rock.

4.4 Original Oil and Gas in Place

Table 4.8 lists values of original oil and gas in place, initial gas oil ratio and initial formation volume factor of very and moderately volatile oil base cases.

Table 4. 8: Original hydrocarbon in place.

Oil volatility	OOIP (MSTB)	OGIP (MMscf)	Initial GOR (scf/stb)	Initial Bo (rb/stb)
Moderately volatile oil	3,671	5,827	1,588	1.82
Very volatile oil	2,621	7,854	2,996	2.55

4.5 Well Model Description

Coupling of vertical flow performance (VFP) with numerical reservoir simulator helps improve prediction of petroleum production from subsurface to be more realistic than using the reservoir simulator alone. VFP acts as a constraint to the production well bottom-hole pressure which has to be sufficient to overcome the pressure loss through tubing at particular conditions (GOR, water cut and tubing head pressure).

In this study, VFP tables are generated from IPM-PROPSPER program. The input for PVT section is the same as those in the previous section. Tubing size is 3.958-inch ID and 4.5-inch OD. A 3-inch ID subsurface safety valve is set at TVD of 1000 ft. Casing size is selected to be 6.184-inch ID with 7-inch OD. A corresponding to bit size is equal to 8.75” (equal to wellbore ID).

Table 4.9 shows production constraints in term of minimum oil production rate and minimum tubing head pressure. For natural depletion, and waterflooding cases, we assume abandonment oil production rate to be 50 STB/day. For gasflooding, and water alternating gas cases, we assume abandonment oil production rate to be 200 STB/day. This is because operating cost for gasflooding is normally higher than that for waterflooding. For a constraint for minimum tubing head pressure, if we assume that operating environment is at offshore, a high minimum tubing head pressure is usually required to overcome pressure drop in subsea pipeline.

Table 4. 9: Economic limits and operational constraints for simulation study.

Parameters	Economic limit
Min. oil production rate (STB/day)	50 / 200
Min. tubing head pressure (psia)	514.7

CHAPTER V

RESULTS AND DISCUSSIONS

In this chapter, influential factors that affect volatile oil production performance are varied in simulation model in order to quantify and address key variables and its effects. The effect of oil volatility degree is investigated by simulating parallel cases of moderately and very volatile oil. First, for natural depletion investigation, the effect of pressure drawdown is investigated by varying production rates and well configurations. Second, for waterflooding, we start with the base case in which water injection is started since the first day of production and maintaining the average reservoir pressure to be above the bubble point pressure. Later, the effect of time to start waterflood and suitable reservoir pressure during the flooding are studied. For gas flooding, similar investigation patterns of waterflooding are studied. The effects of pressure and timing to gasflooding performance are discussed. Apart from full pressure maintenance production schemes, partial pressure maintenance production scheme by re-injection of produced gas is introduced and simulated. Next, we study water alternating gas scheme, which is expected to enhance and compensate the advantage and disadvantage of water and gas flooding in order to maximize oil recovery. Finally, all production schemes are compared in term of oil recovery performance and economic perspective to determine suitable type of production scheme for volatile oil reservoir.

5.1 Natural Depletion Performance of Volatile Oil Reservoir

We begin with discussion of volatile oil production characteristic from base case results described in Section 5.1.1. Next, effect of pressure drawdown is studied by comparing different well configurations and production rates in Section 5.1.2 and 5.1.3, respectively since we suspect that drawdown pressure has an effect on two-phase flow near the wellbore and gas coning from secondary gas cap. The degree of oil volatility and partial perforation effect are also taken into account. Figure 5.1 shows the top view of the reservoir model with well locations for two production wells used for the base case.

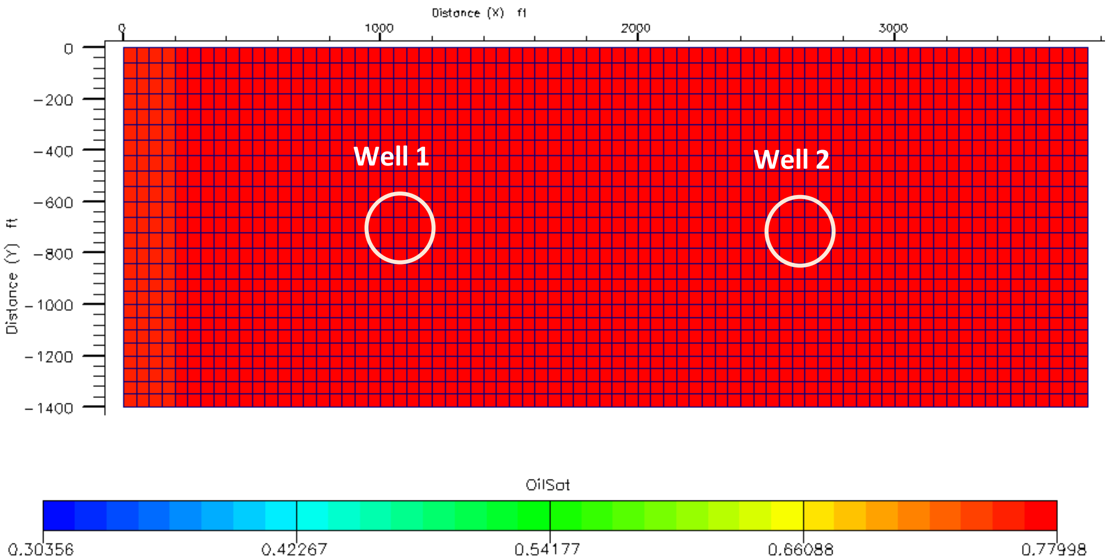


Figure 5. 1: Schematic of reservoir model with two production wells.

5.1.1 Base Case of Natural Depletion

In this section, the reservoir model with two vertical producers is used for simulation. We control oil production rate at 1,000 STB/day and stop simulation at 50 STB/day which is considered as economic limit for natural depletion case. Moderate and high degrees of oil volatility are also compared in this section. Table 5.1 presents base case results. We obtain similar value of oil recovery factors for moderately and very volatile oil. And very volatile oil case can recover more solution gas due to higher solution gas oil ratio. For this study, the field life of very volatile oil case is shorter than that for moderately volatile oil because very volatile oil has lower original oil in place (in STB) to be produced as a result of higher shrinkage factor.

Table 5. 1: Base case results of natural depletion.

Degree of oil volatility	Q_o (STB/day)	N_p (MSTB)	G_p (BCF)	W_p (MSTB)	Oil RF (%)	Field life (days)
Moderately	1,000	884	3.82	0	24.09	1,063
Very	1,000	612	5.48	0	23.34	722

First, when we consider oil production rate, gas production rate and oil productivity with time as shown in Figures 5.2 and 5.3, the production can be classified into 3 periods. The first period is when the near wellbore pressure is still above the bubble point pressure. During this period, the pressure depletion results in lower oil viscosity, making the oil productivity value to be higher. For the second period, gas starts to be liberated out from oil and accumulates near the wellbore but gas is still not able to flow since its saturation (S_g) has not reached the critical gas saturation (S_{gc}) yet. In the third period, free gas flows into the wellbore. During this period, oil productivity decreases as the pressures of the wellbore and reservoir become lower due to lower relative permeability to oil as more gas is liberated from the oil phase. The productivity can be greatly affected by oil production rate since higher drawdown will result in more liberated gas.

Figures 5.4 and 5.5 explain the drive mechanism by showing oil and gas saturation profiles with time. At the condition when the reservoir pressure remains above the bubble point pressure, oil expands with constant saturation as the pressure becomes lower. So, this period is dominated by fluid expansion drive. Later, when gas saturation in the reservoir increases with time, the production is dominated by solution gas drive mechanism as seen by large values of gas saturation in the reservoir. For volatile oil reservoir, a high amount of solution gas is liberated in the reservoir. Some liberated gas is drawn to the well bore but some moves upward to the upper part of the reservoir due to gravity force. This movement defined as gravity segregation and substantially contributes to total oil recovery efficiency. Figures 5.6 and 5.7 show the reservoir cross section in the Y-Z plane around well 1 of moderately and very volatile oil, respectively. These two figures demonstrate a gravity segregation mechanism at different pressure depletion stages. As the reservoir pressure decrease, liberated gas appears in the reservoir and moves upward due to difference in density between oil and solution gas. The liberated gas then accumulates at the upper part of the reservoir as a secondary gas cap. And when compared between moderately and very volatile oil, very volatile oil has a GOC located lower than moderately oil case at the same pressure depletion stage because very volatile oil yields higher amount of solution gas.

When considering the decline rate of oil productivity index and the average reservoir pressure between different degrees of oil volatility, very volatile oil has slower decline rate during the second period of production due to the higher amount of liberated gas in the reservoir which results in a better solution gas drive performance at the early time of second period (see Figures 5.2 to 5.5). However, for these base cases, the model has full to base perforation interval in which it is easier for free gas to flow into the wellbore. Therefore, we can observe that the decline rates of oil productivity and the reservoir pressure increase again due to high gas production rate from free gas or secondary gas cap in the reservoir.

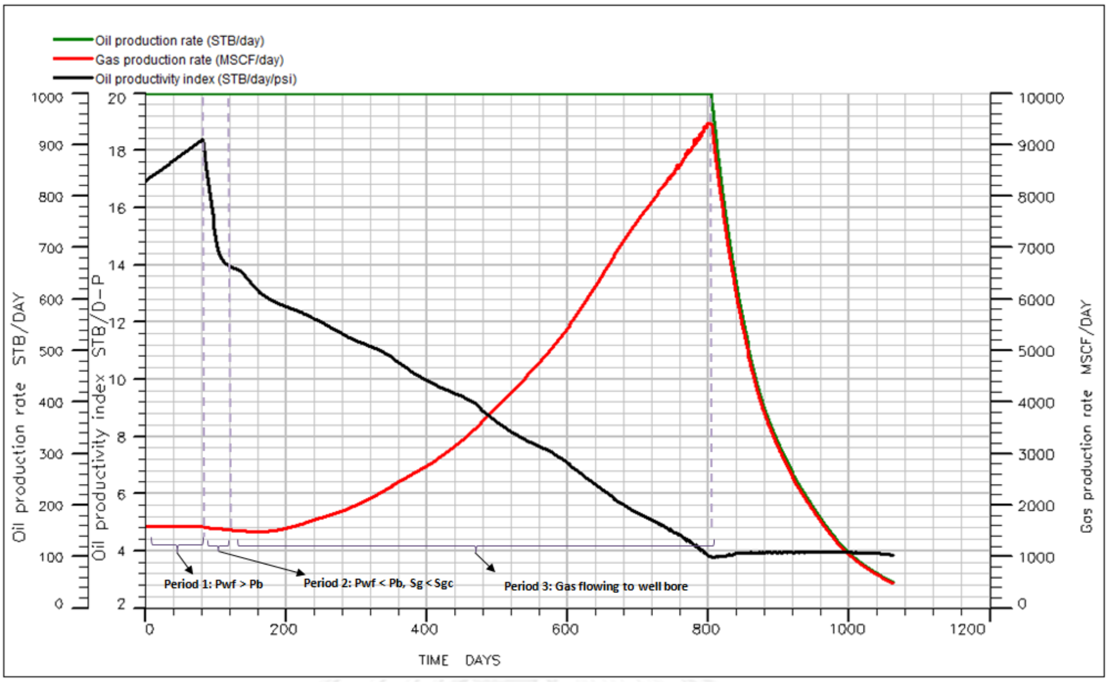


Figure 5. 2: Oil and gas production rate, oil productivity of moderately volatile oil.

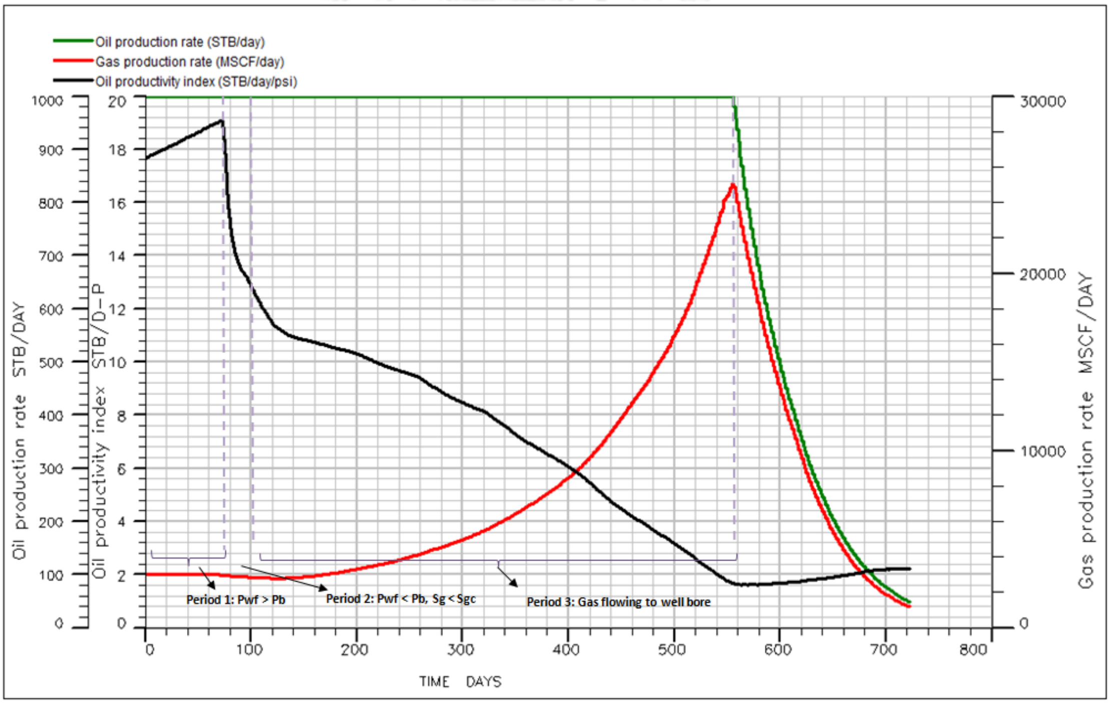


Figure 5. 3: Oil and gas production rate, oil productivity of very volatile oil.

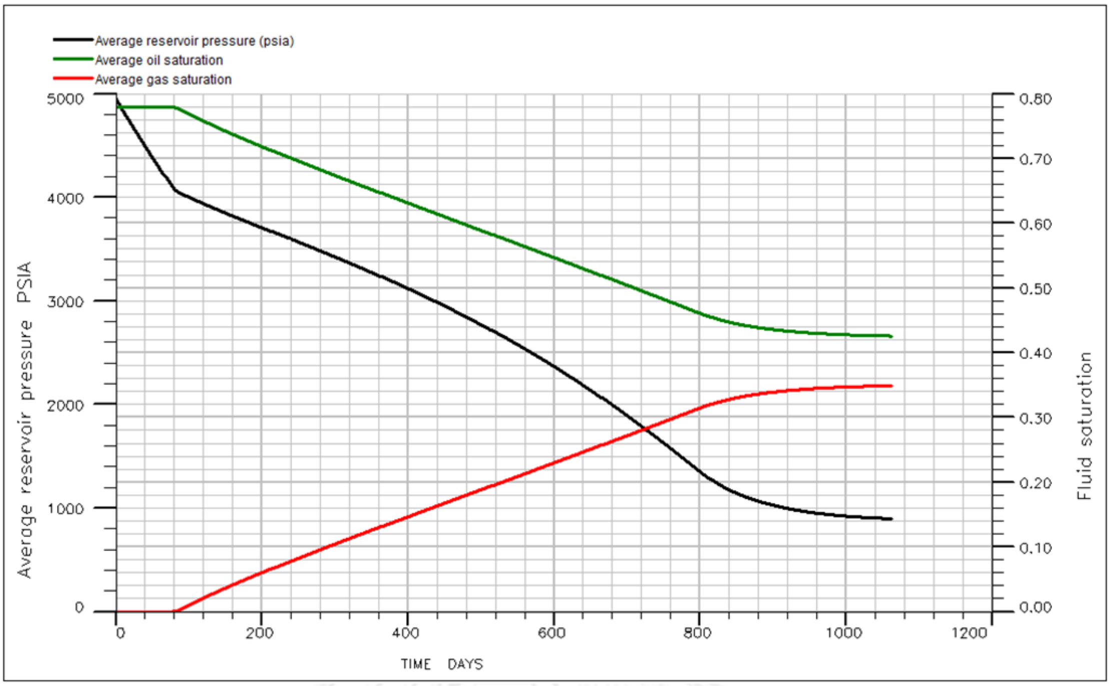


Figure 5. 4: Average reservoir pressure and hydrocarbon saturation profiles of moderately volatile oil.

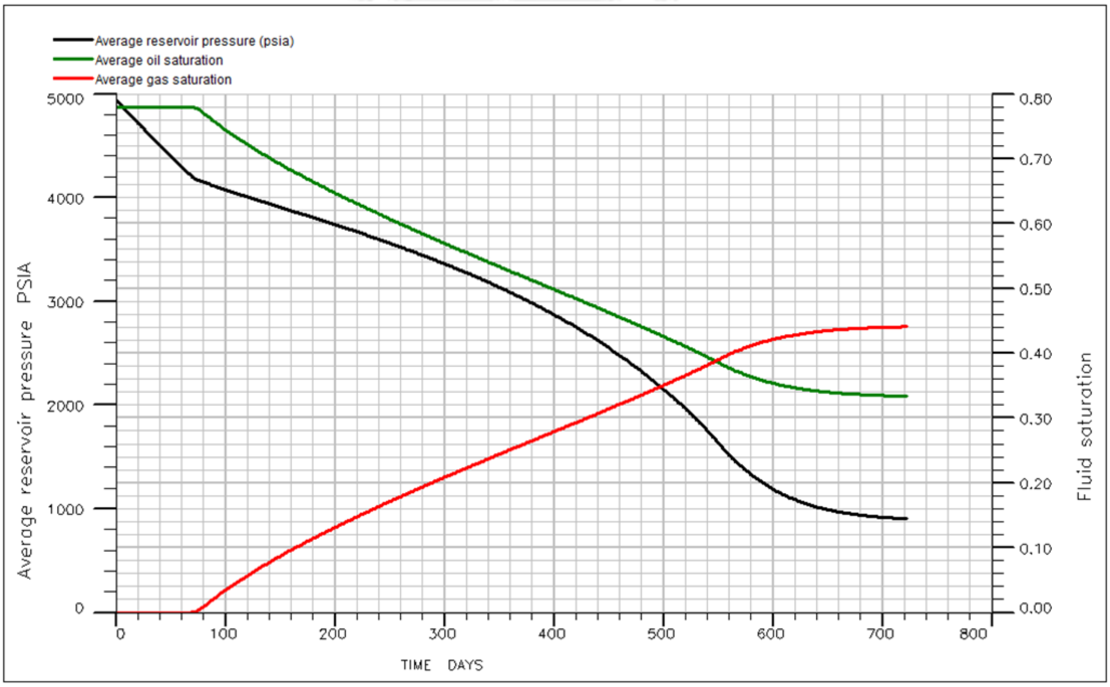
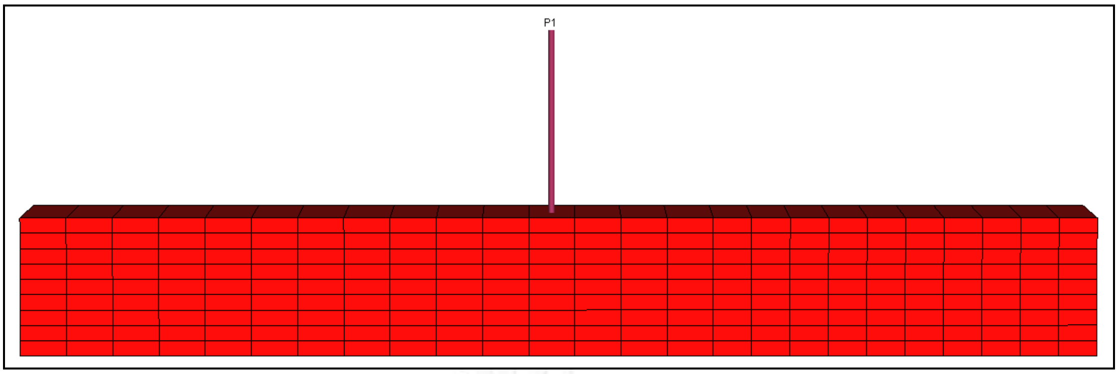
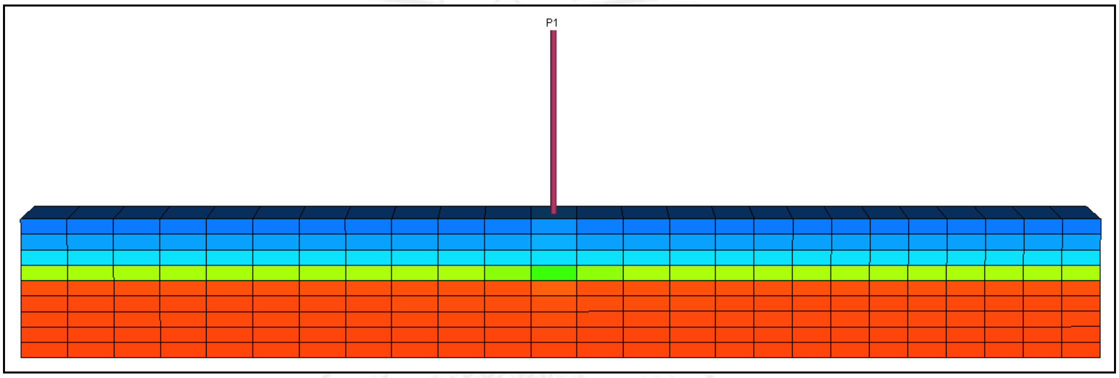


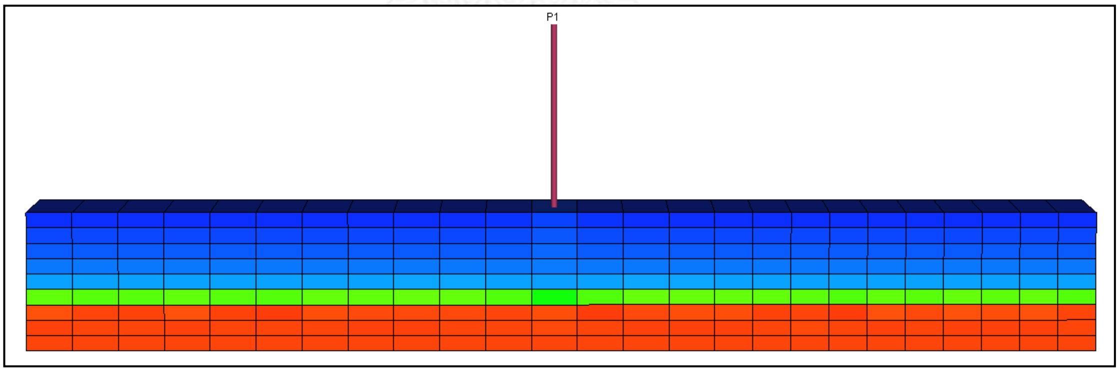
Figure 5. 5: Average reservoir pressure and hydrocarbon saturation profiles of very volatile oil.



(a) Average reservoir pressure equal to 4,087 psia (17 % pressure depletion).



(b) Average reservoir pressure equal to 3,111 psia (37 % pressure depletion).



(c) Average reservoir pressure equal to 2,128 psia (57 % pressure depletion).

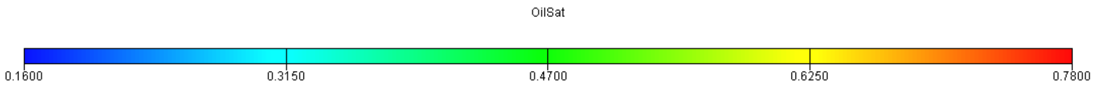
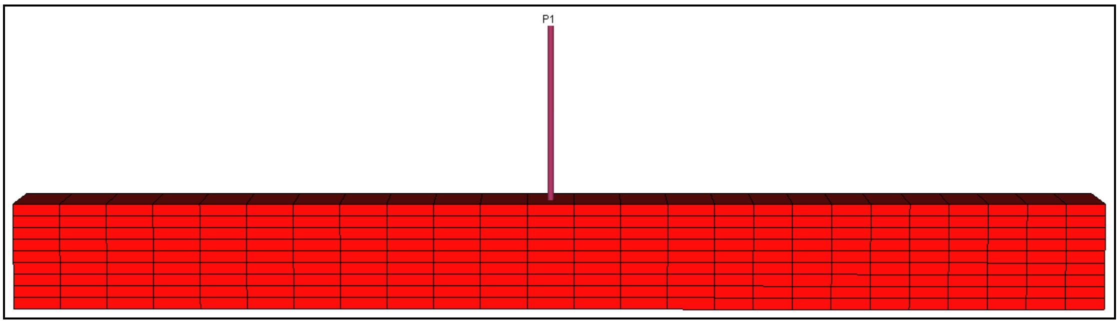
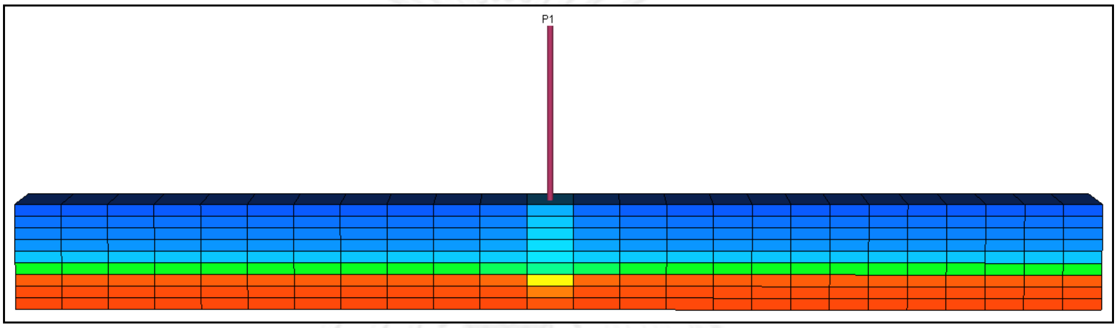


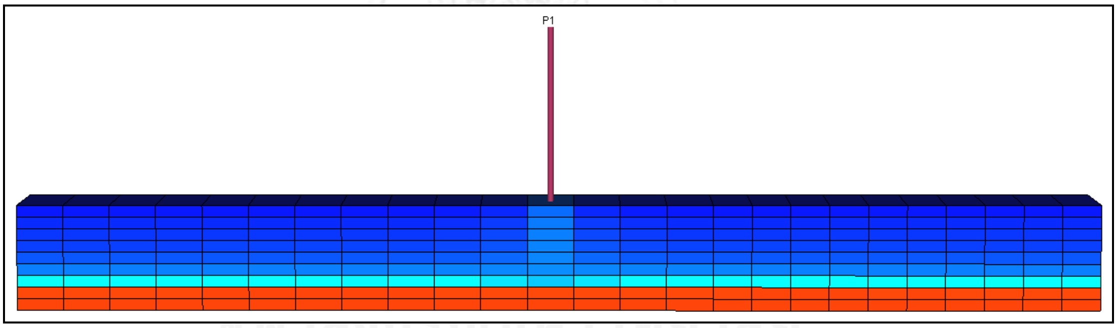
Figure 5. 6: Oil saturation profile of moderately volatile oil case in the Y-Z plane around well 1.



(a) Average reservoir pressure equal to 4,087 psia (17 % pressure depletion).



(b) Average reservoir pressure equal to 3,111 psia (37 % pressure depletion).



(c) Average reservoir pressure equal to 2,128 psia (57 % pressure depletion).

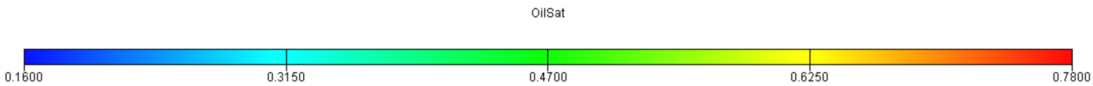


Figure 5. 7: Oil saturation profile of moderately volatile oil case in the Y-Z plane around well 1.

5.1.2 Effect of Well Configurations

The effect of pressure drawdown is quantified and studied in this section by trying different well configurations which are horizontal well and different well spacing for vertical wells. An oil production rate of 1,000 STB/Day is used as a constraint in the same manner as the base case. For horizontal well, the well is located at the bottom of the reservoir to enhance gravity segregation of liberated gas and to maximize standoff distance from secondary gas cap. Figure 5.8 shows the top view of the reservoir model with well locations for three producers while Figure 5.9 shows the side view in the X-Z plane of reservoir and location of horizontal well. Table 5.2 presents six cases of simulation results with different well configurations and degrees of oil volatility.

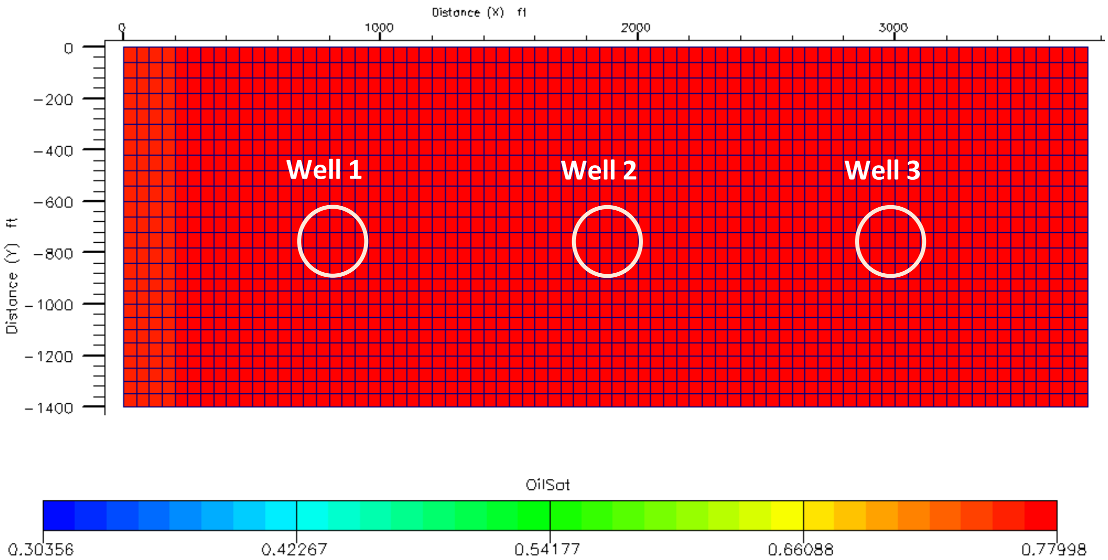


Figure 5. 8: Schematic of reservoir model with three production wells.

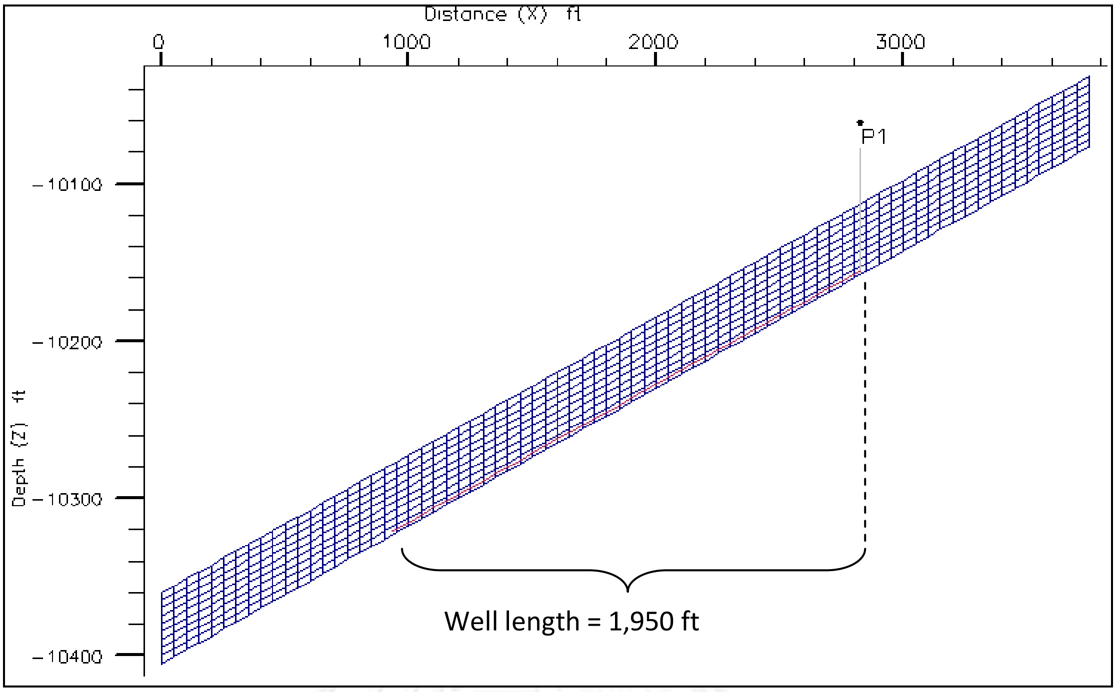


Figure 5. 9: Schematic of reservoir model with horizontal well.

Table 5. 2: Simulation results of the effect of well configurations.

Well configurations	Degree of oil volatility	N_p (MSTB)	G_p (BCF)	W_p (MSTB)	Oil RF (%)	Field life (days)
2 vertical wells	Moderately	884	3.82	0	24.09	1,063
3 vertical wells	Moderately	885	3.83	0	24.12	994
Horizontal well	Moderately	908	3.46	0	24.75	931
2 vertical wells	Very	612	5.48	0	23.34	722
3 vertical wells	Very	612	5.51	0	23.36	682
Horizontal well	Very	640	5.54	0	24.41	734

From results in Table 5.2, the difference of total oil recovery for each case is insignificant. However, we can still observe an increasing tendency of oil recovery factor when the well spacing was reduced. When we compare the results between vertical and horizontal wells, there is a slight improvement in total oil recovery from using horizontal well.

Figures 5.10 and 5.11 show oil and gas production profile of simulation cases that have different well configurations. All the cases are terminated at 50 STB/day of oil production rate expect the horizontal well case for moderately volatile oil which the run is stopped at 256 STB/day due to insufficient bottom hole pressure to lift the oil. We can see that for the horizontal well case, gas production rate rises up slower, and the well has longer plateau of oil production period when compared with the vertical well case. This is because the horizontal well is located at the bottom of the reservoir which is favorable to gravity segregation drives of solution gas. The gravity number, which is a dimensionless number, is a ratio between gravity force and viscous force (see Section 3.2 for details), can be used to quantify the effectiveness of gravity drainage mechanism. Tables 5.3 and 5.4 present variables used to calculate the gravity numbers and the oil properties at different conditions. The gravity numbers for each case are calculated at three different pressure stages as presented in Table 5.5.

Table 5. 3: Input parameters for gravity number calculation for different well configurations.

Well configurations	2 vertical wells	3 vertical wells	Horizontal well
k_v (md)	70	70	110
r_e (ft)	912	745	1,083
Q_o / well (STB/day)	500	333	1,000

Table 5. 4: Input parameters for gravity number calculation for different average reservoir pressure and degree of oil volatility.

Degree of oil volatility	Moderately			Very		
Pressure (psia)	1,500	2,500	3,500	1,500	2,500	3,500
ρ_o (lbm/ft^3)	44.0	41.7	39.6	43.5	40.2	36.8
ρ_g (lbm/ft^3)	5.41	9.18	12.7	5.84	10.2	14.6
μ_o (cp)	0.379	0.285	0.220	0.359	0.232	0.156
B_o (RB/STB)	1.33	1.48	1.66	1.49	1.74	2.12

Table 5. 5: Gravity number for different well configurations and average reservoir pressures.

Degree of oil volatility	Well configurations	At pressure = 1,500 psia	At pressure = 2,500 psia	At pressure = 3,500 psia
Moderately	2 vertical wells	219.30	220.85	211.00
	3 vertical wells	219.73	221.28	211.41
	Horizontal well	242.98	244.70	233.78
Very	2 vertical wells	201.68	212.88	192.28
	3 vertical wells	202.07	213.30	192.66
	Horizontal well	223.45	235.87	213.05

From the gravity number shown in Table 5.5, the horizontal well case has the highest gravity number because the well is located at the highest absolute permeability layer and the well also has the largest drainage radius when compared with two and three vertical wells cases. Figures 5.12 and 5.13 are plots between reservoir pressure and oil recovery factor which demonstrate depletion performance for moderately and very volatile oil, respectively. From these two figures, the horizontal well has a better depletion performance compared to the other cases corresponding with the large gravity number shown in Table 5.5.

Therefore, we can conclude that lowering pressure drawdown by using tighter vertical well spacing and horizontal well for this study results in a lower viscous force acting on liberated gas. Hence, liberated gas is dominated by gravitational force and consequently flows upward to the upper part of the reservoir rather than flowing to the wellbore. This movement enhances gravity segregation gas drive mechanism and consequently improves oil recovery during pressure depletion.

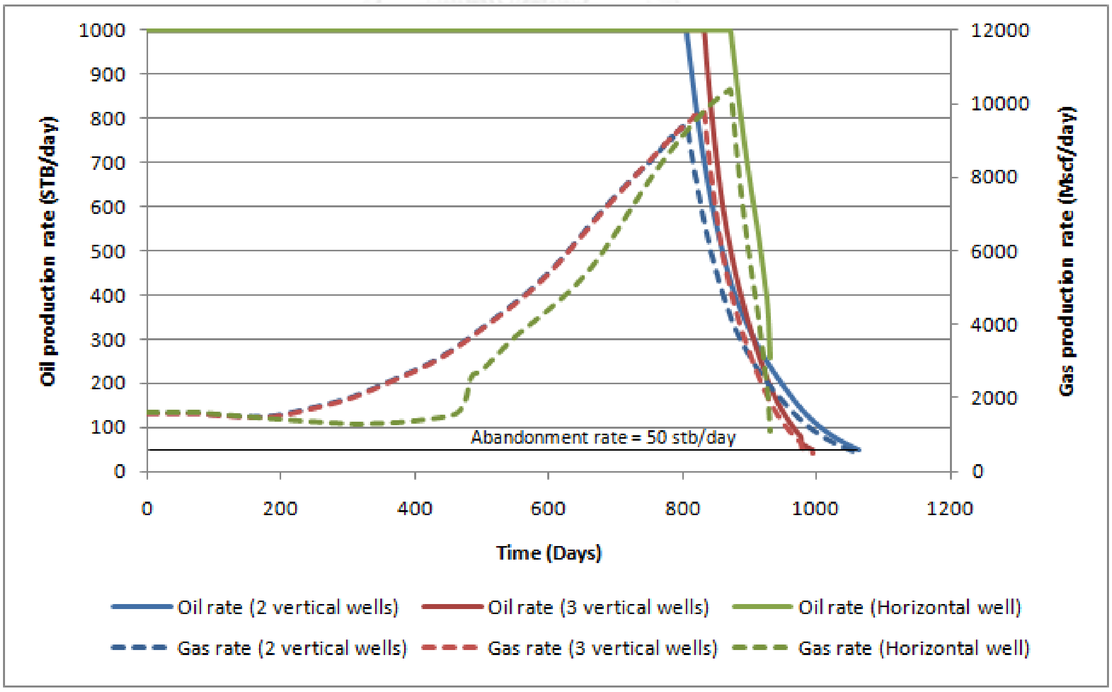


Figure 5. 10: Oil and gas production profiles of moderately volatile oil with different cases of well configurations.

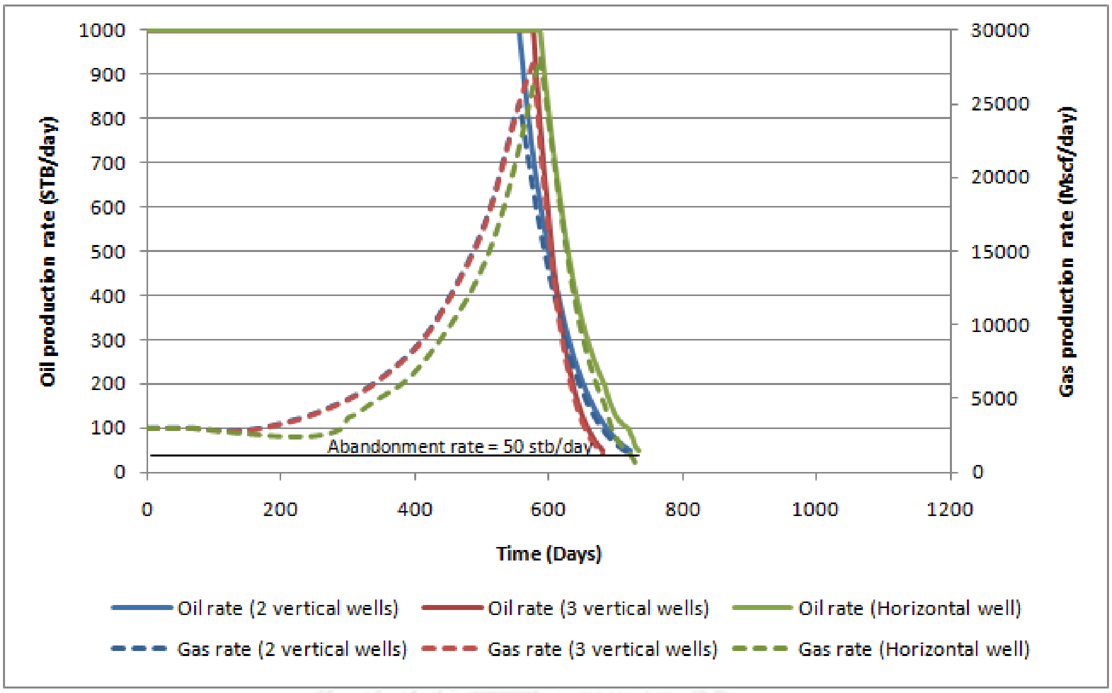


Figure 5. 11: Oil and gas production profiles of very volatile oil with different cases of well configurations.

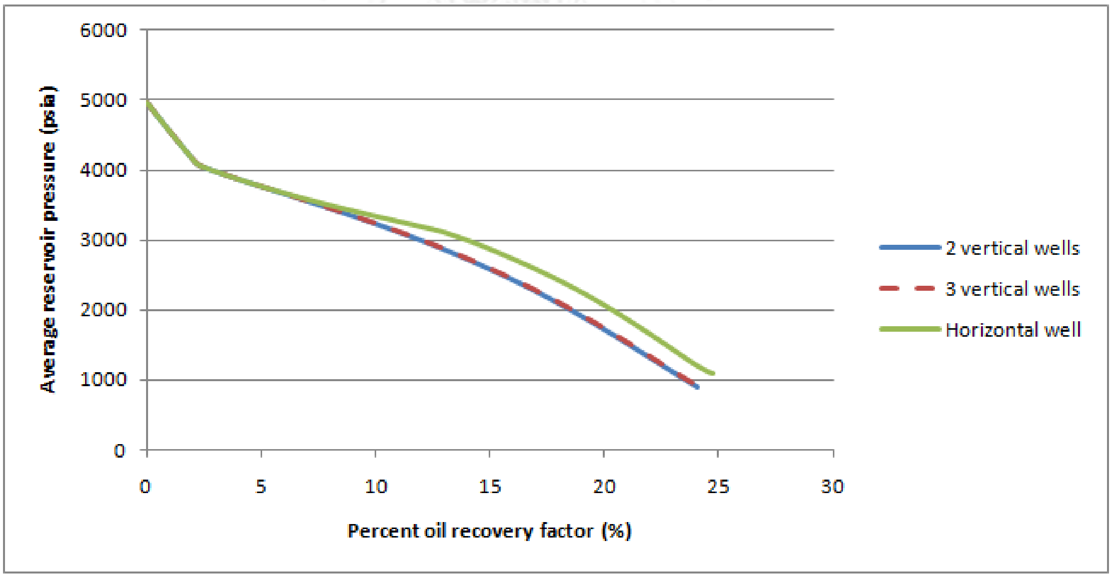


Figure 5. 12: Depletion performance of moderately volatile oil for different cases of well configurations.

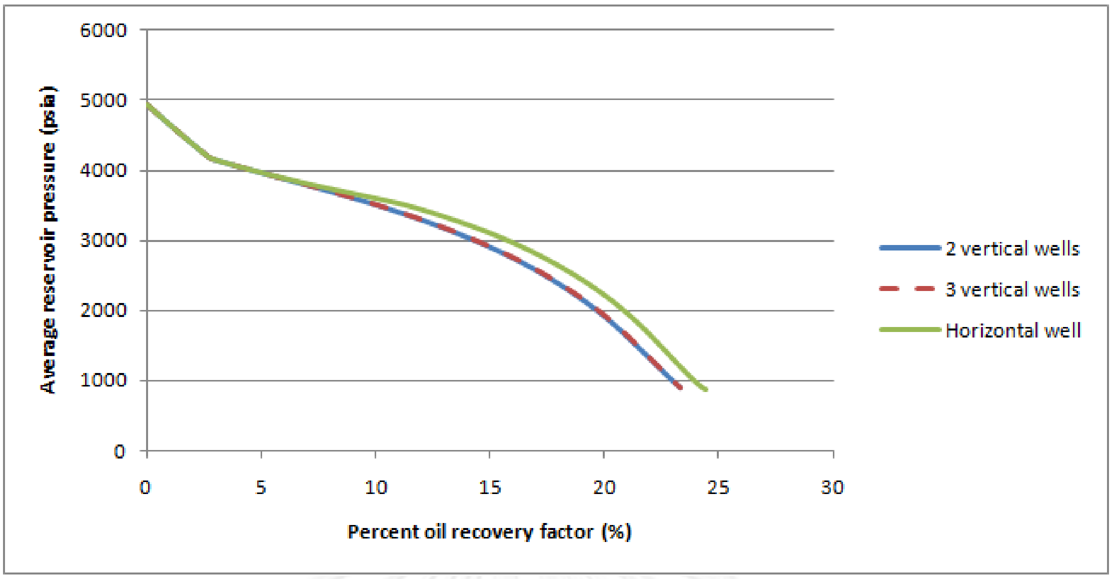


Figure 5. 13: Depletion performance of very volatile oil for different cases of well configurations.

5.1.3 Effect of Oil Production Rate

Since the production rate is directly related to pressure drawdown, higher oil production rate requires a high pressure drawdown which results in faster accumulation of liberated gas near the well bore. Therefore, we suspect that two phase flow near well bore may affect total amount of free gas production and reservoir abandonment pressure.

All simulation results conducted for different production rates are tabulated in Table 5.6. The model has two vertical wells as producers in the same fashion as the base case. From the table, oil recovery factor increases slightly with high production rate for moderately volatile oil but has a reverse trend for very volatile oil. And we can see that values of oil productivity index at the final time step increases correspondingly with the oil recovery factor.

Table 5. 6: Simulation results of the effect of oil production rate.

Degree of oil volatility	Q_o (STB/day)	N_p (MSTB)	G_p (BCF)	W_p (MSTB)	Oil RF (%)	Field life (days)	Oil PI at final time step (STB/day/psi)
Moderately	500	882	3.80	0	24.03	1,862	3.90
Moderately	1,000	884	3.82	0	24.09	1,063	3.90
Moderately	2,000	885	3.82	0	24.12	676	3.91
Moderately	4,000	888	3.83	0	24.21	506	3.92
Moderately	6,000	891	3.83	0	24.28	461	3.92
Very	500	619	5.48	0	23.62	1,309	2.19
Very	1,000	612	5.48	0	23.34	722	2.17
Very	2,000	600	5.48	0	22.88	445	1.86
Very	4,000	584	5.49	0	22.27	325	1.58
Very	6,000	574	5.50	0	21.91	292	1.46

From Table 5.6, the effect of different oil production rate on moderately volatile oil can be considered as insignificant due to very small difference in oil recovery factor but the for very volatile oil cases, the percent oil recovery factor are slightly different and have an increasing trend as oil production rate decreases. Figures 5.14 and 5.15 show depletion performance which are plots of oil recovery factor with reservoir pressure for moderately and very volatile oil, respectively. From the plot, we can see that for moderately volatile oil, we obtain a similar performance for different oil production rates but for very volatile oil, we can observe that the difference of depletion performance can be seen after the reservoir pressure drops below 3,000 psia. This implies that the effect of oil production on depletion performance starts to dominate the depletion performance as the amount of liberated gas increases when the reservoir pressure decreases.

From the previous section on the effect of well configurations, we know that gravity segregation of liberated gas is a key mechanism that enhances recovery performance and the gravity number is used as a key parameter representing the gravity segregation performance. From the equation of gravity number (see Section 3.2), increasing of oil production rate consequently increase viscous force that draws liberated gas to the well bore. To quantify this effect, Figures 5.16 and 5.17, show plots between average reservoir pressure and average gas saturation for moderately and very volatile oil, respectively. From Figure 5.17, we can see that average gas saturation slightly increases as oil production rate decreases. This trend aligns with the depletion performance plotted in Figure 5.15. Therefore, we may conclude that when the oil production rate increases, more liberated gas is pulled to the well bore by the viscous force. For the low oil production rate cases, gravity force relatively dominates the movement of liberated gas. So, we can observe more gas accumulated in the reservoir as shown in Figure 5.17.

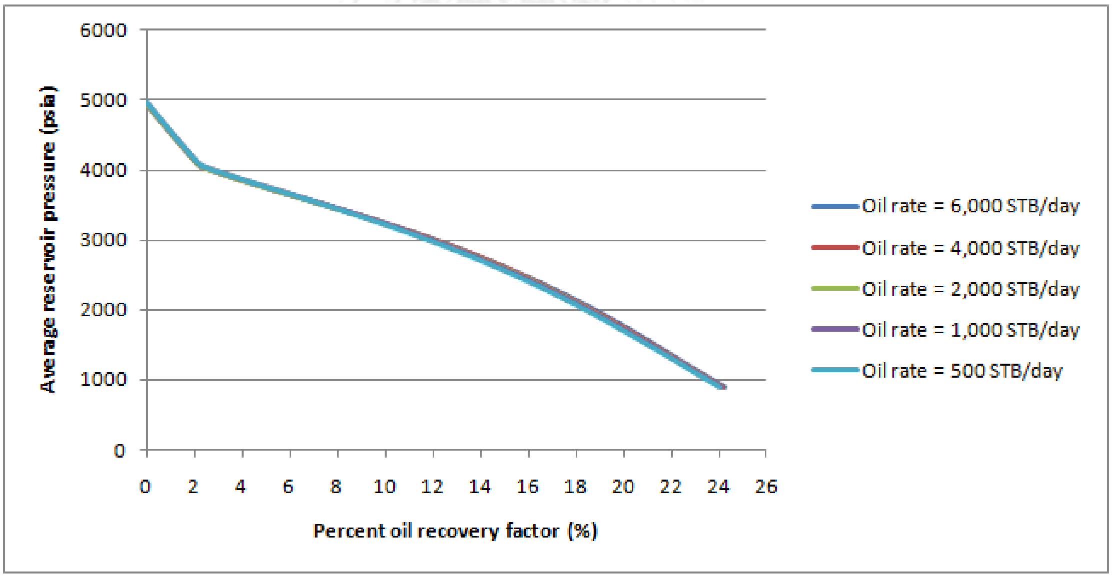


Figure 5. 14: Depletion performance of moderately volatile oil for different oil production rates.

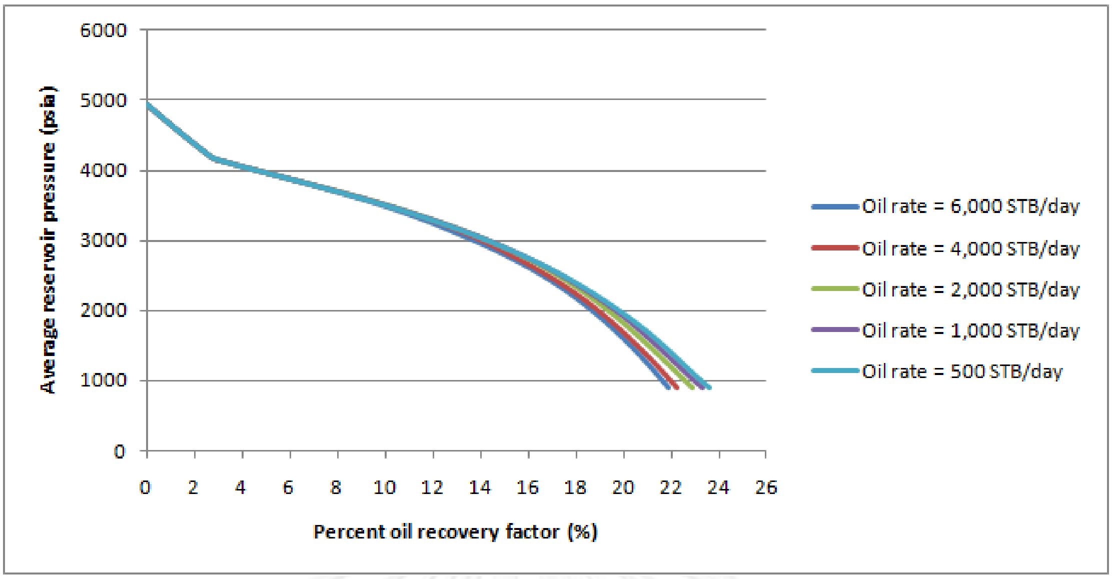


Figure 5. 15: Depletion performance of very volatile oil for different oil production rates.

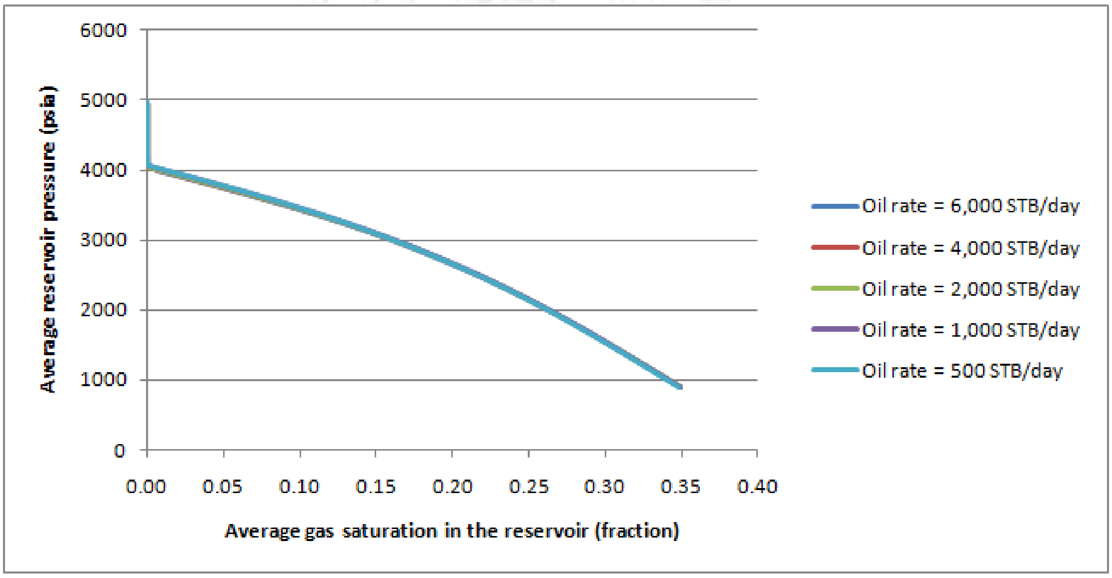


Figure 5. 16: Relationship between average reservoir pressure and average gas saturation of moderately volatile oil for different oil production rates.

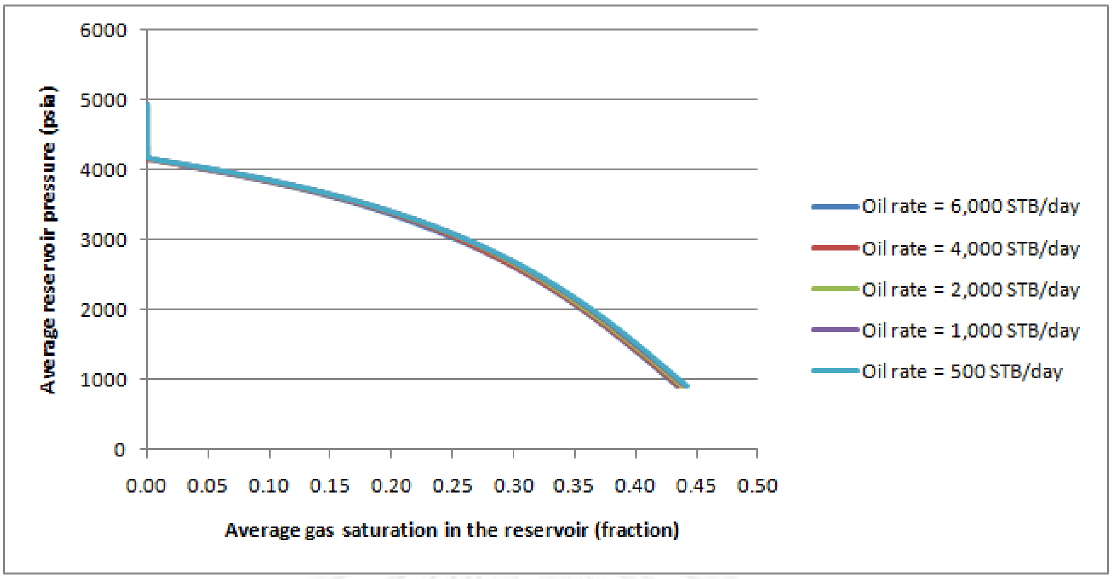


Figure 5. 17: Relationship between average reservoir pressure and average gas saturation of very volatile oil for different oil production rates.

5.1.4 Effect of Perforation Interval

The effect of perforation interval is investigated together with the effect of production rate in this section because high pressure drawdown causes an advert effect through gas coning. And we expect to see improvement in total oil recovery from partial perforation for the high production rate cases when compared with fully perforation cases.

For partial perforation interval cases, wells are perforated for one third of the total thickness at the bottom of the reservoir in order to avoid coning of secondary gas cap. All simulation results are tabulated in Table 5.7. There are slightly differences in recovery factors between full and partial perforation cases but partial perforation cases have longer production time especially for the high production rate cases.

Table 5. 7: Simulation results of the effect of perforation interval.

Degree of oil volatility	Q_o (STB/day)	100 % Perforation interval			33 % Perforation interval		
		Np	Oil RF (%)	Field life (days)	Np	Oil RF (%)	Field life (days)
Moderately	500	882	24.03	1,862	888	24.20	1,976
Moderately	1,000	884	24.09	1,063	888	24.20	1,202
Moderately	2,000	885	24.12	676	891	24.28	860
Moderately	4,000	888	24.21	506	897	24.44	731
Moderately	6,000	891	24.28	461	902	24.56	695
Very	500	619	23.62	1,309	623	23.75	1,418
Very	1,000	612	23.34	722	616	23.50	866
Very	2,000	600	22.88	445	607	23.17	614
Very	4,000	584	22.27	325	599	22.87	502
Very	6,000	574	21.91	292	598	22.82	475

Figures 5.18 and 5.19 show total oil recovery of simulation cases listed in Table 5.7. From the plot, we can see that there is a trend of improvement in total oil recovery from partial perforation. Furthermore, the improvement will be higher as oil production rate increases.

The production and pressure profile of six thousand stock tank barrel per day cases is selected to investigate the difference in production performance between full and partial perforation interval cases. From Figures 5.20 and 5.21, we can apparently see that gas production rate of partial perforation cases is less than that of the full perforation case but the plateau of oil production is shorter. Figures 5.22 and 5.23 also show that limited perforation cases have lower pressure depletion rate from a better gravity segregation of solution gas drive even through the pressure drawdown is higher from partial penetration skin. This increasing of skin is more evidenced when comparing oil productivity index between fully and partially perforation cases as shown in Figures 24 and 25.

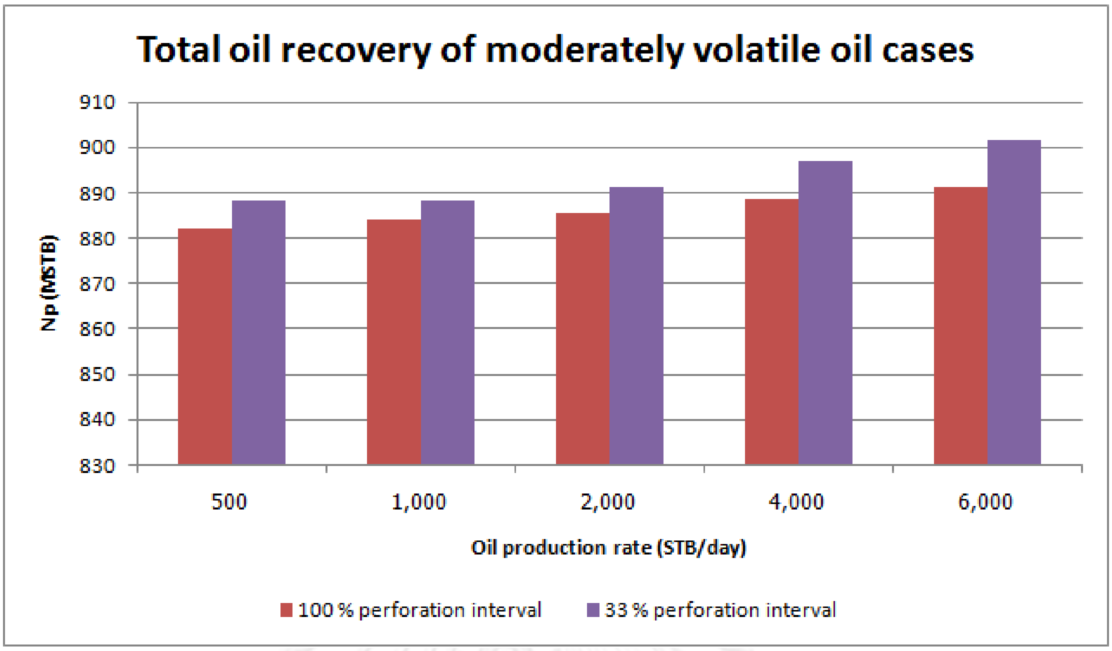


Figure 5. 18: Comparison of total oil recovery for different perforation intervals (moderately volatile oil).

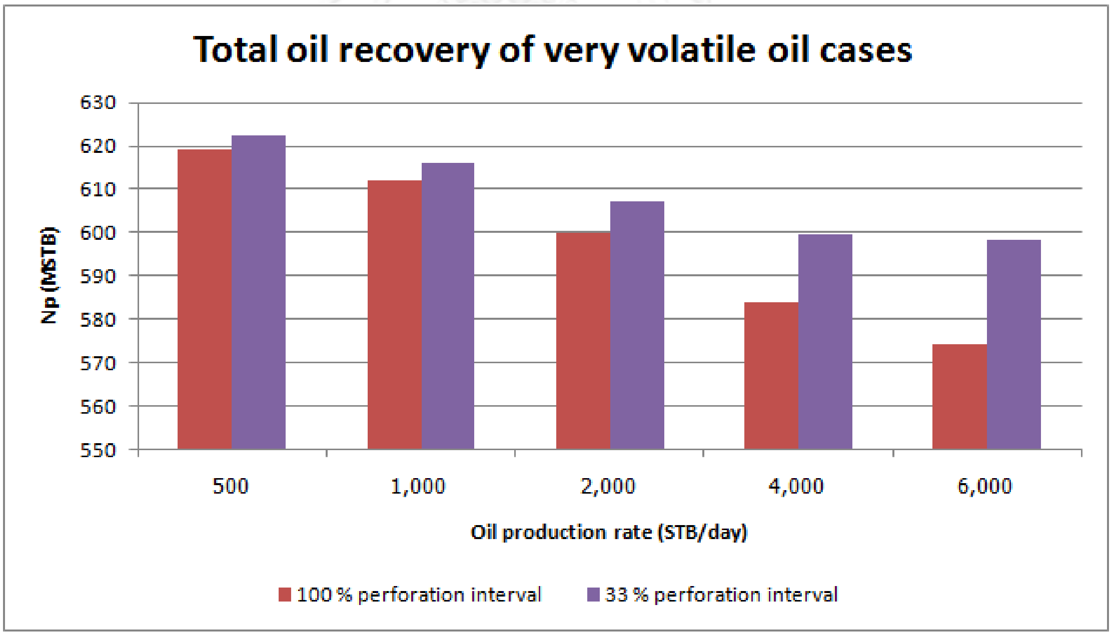


Figure 5. 19: Comparison of total oil recovery for different perforation intervals (very volatile oil).

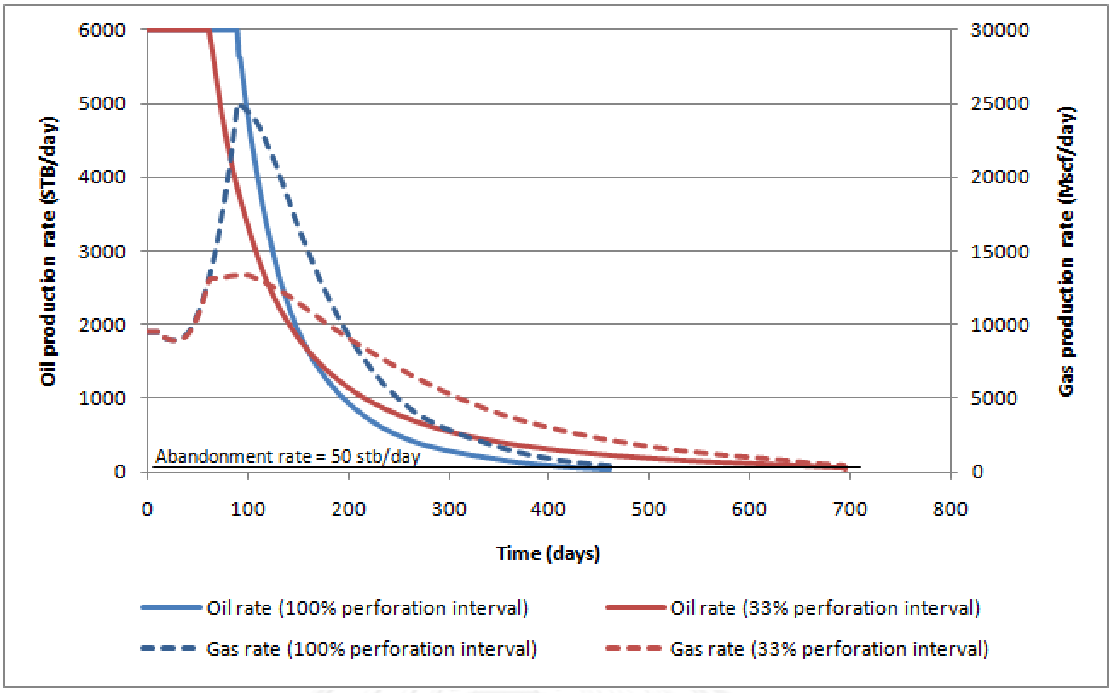


Figure 5. 20: Oil and gas production profiles of moderately volatile oil for different perforation intervals (Q_o = 6,000 STB/day).

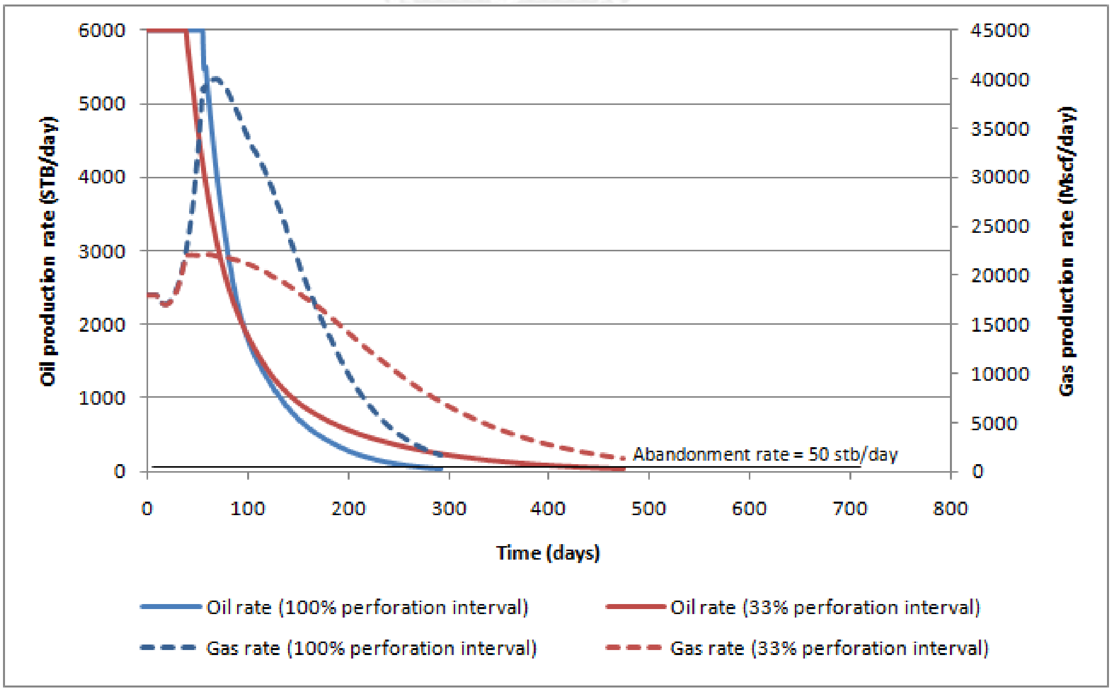


Figure 5. 21: Oil and gas production profiles of very volatile oil for different perforation intervals (Q_o = 6,000 STB/day).

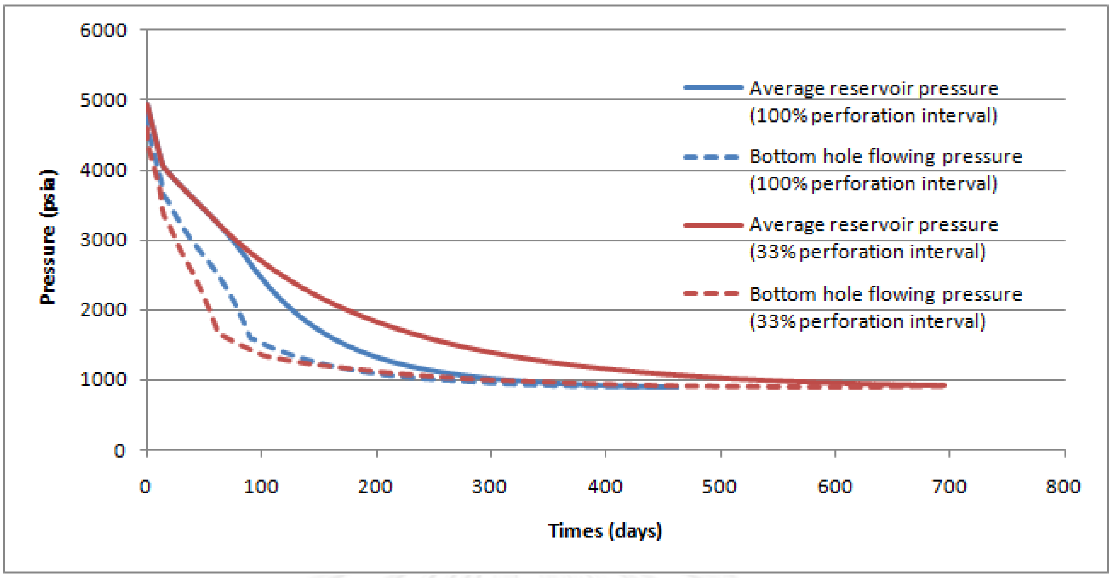


Figure 5. 22: Average reservoir and bottom hole pressure of moderately volatile oil for different perforation intervals (Q_o = 6,000 STB/day).

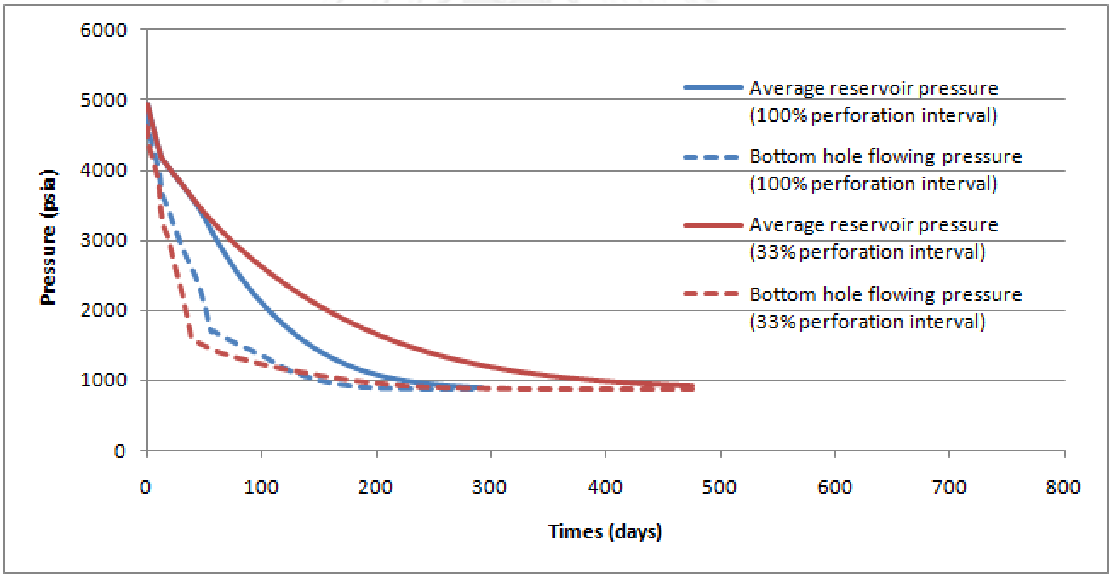


Figure 5. 23: Average reservoir and bottom hole pressure of very volatile oil for different perforation intervals (Q_o = 6,000 STB/day).

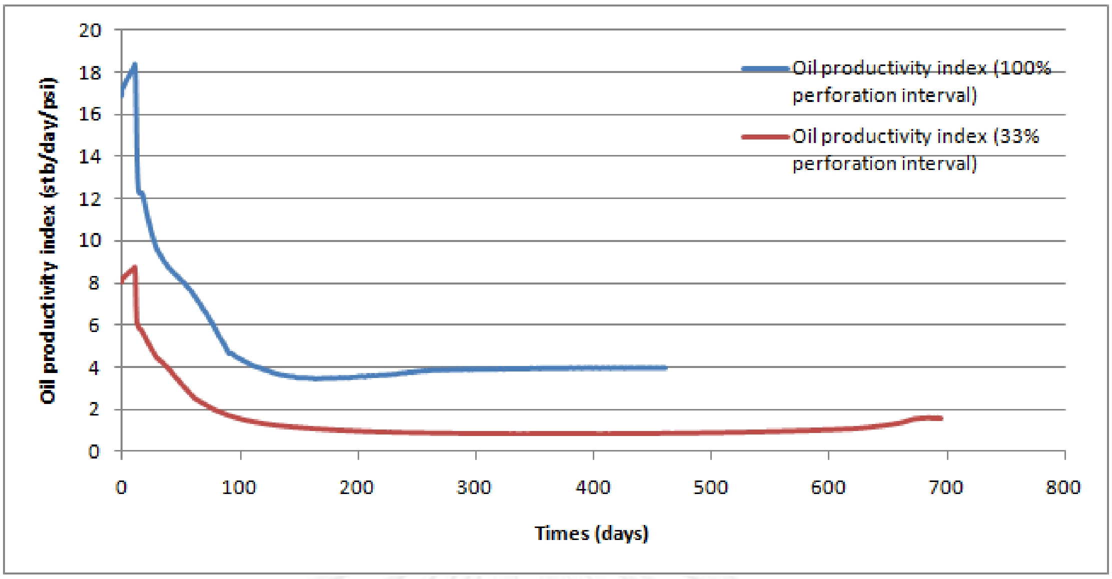


Figure 5. 24: Oil productivity index of moderately volatile oil for different perforation intervals (Q_o = 6,000 STB/day).

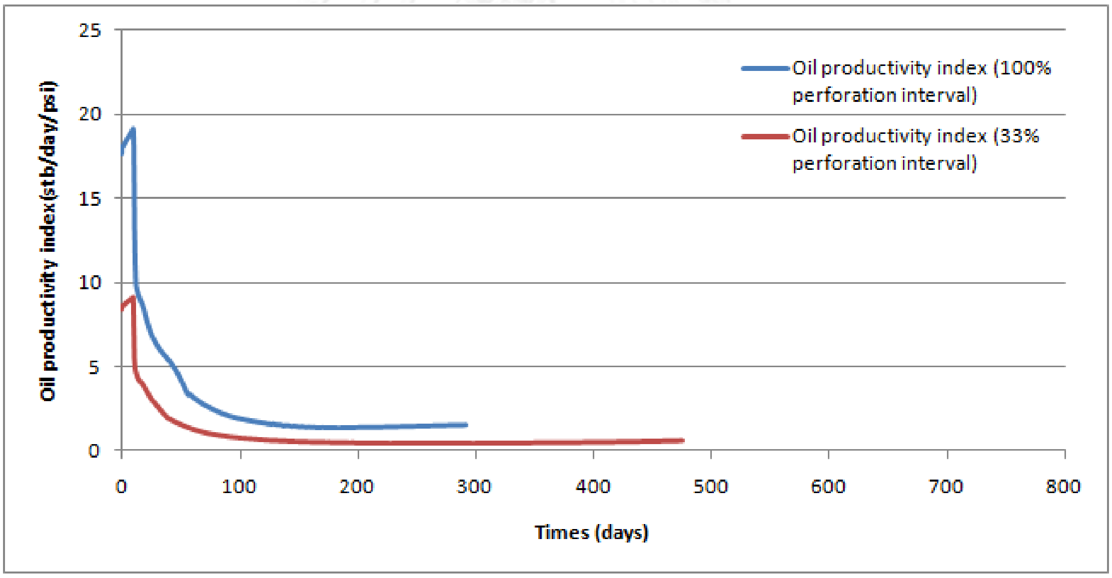


Figure 5. 25: Oil productivity index of very volatile oil for different perforation intervals (Q_o = 6,000 STB/day).

5.2 Waterflooding Performance

This part is an investigation of waterflooding performance in volatile oil reservoirs. First, the case of maintaining the average reservoir pressure above the bubble point pressure is discussed and compared between moderately and very volatile oil. This case is the base case for waterflooding. Second, we investigate the effect of time to start waterflood by assigning the start date at different percentage of pressure depletion from the initial reservoir pressure. Finally, effects of oil production rate on displacement and sweep efficiencies are addressed in order to maximize the total oil recovery.

A reservoir schematic of waterflooding scheme is shown in Figures 5.26 and 5.27. The vertical injector well is at the downdip position of reservoir while the vertical producer well is at the updip position. This injection pattern helps maintain stable waterflood front from a gravitational effect.

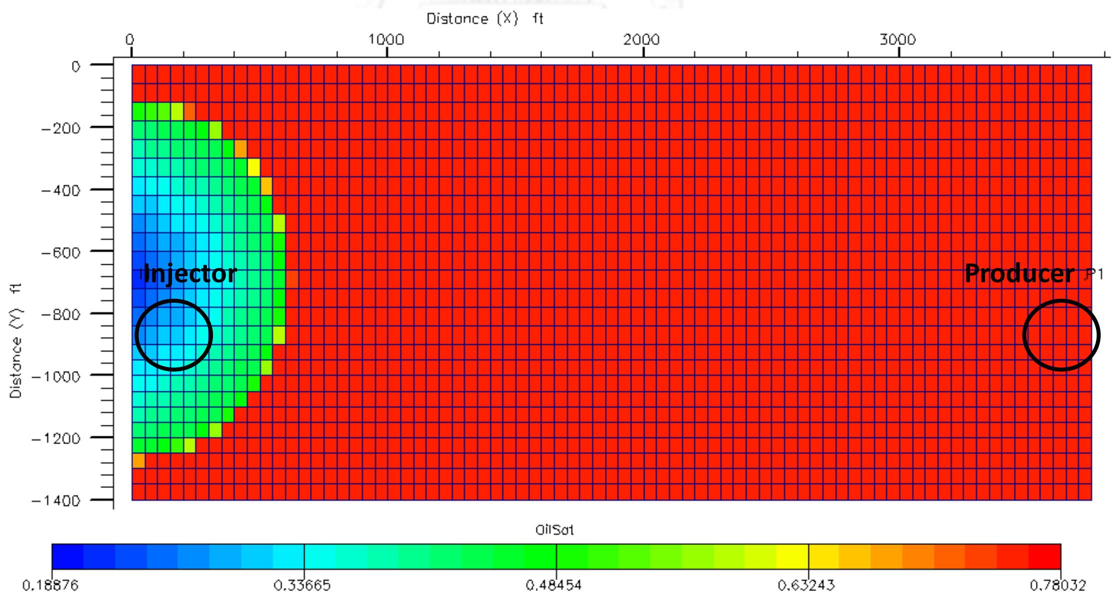


Figure 5. 26: Schematic of reservoir model of waterflooding scheme in the X-Y plane.

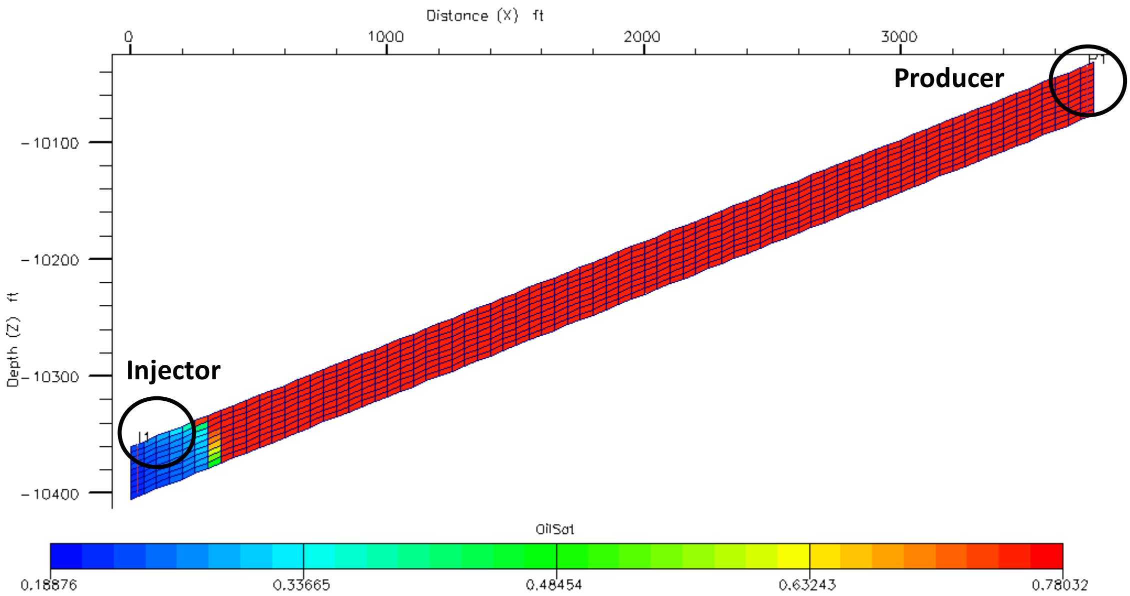


Figure 5. 27: Schematic of reservoir model of waterflooding scheme in the X-Z plane.

5.3.1 Base Case of Waterflooding

Water injection is implemented since the first day of production to maintain the reservoir pressure above the bubble point. In the base case, voidage replacement ratio (VRR) is kept around one by controlling water injection and total reservoir volume production rate to be equal at reservoir condition but the injection pressure is limited at estimated formation fracture pressure. Table 5.8 lists constraints for waterflooding base case. Simulation results of moderately and very volatile oil are presented in Table 5.9. Since both cases have the same reservoir volume production rate, very volatile oil yields less surface production rate due to higher shrinkage factor. Both cases have a similar percent oil recovery but very volatile oil produces more gas due to higher solution gas oil ratio. Very volatile oil case also has shorter recovery time with less cumulative water production when compared to moderately volatile oil case.

Table 5. 8: Constraints for waterflooding base case.

Maximum reservoir volume production rate (RB/day)	Maximum water injection rate (RB/day)	Maximum water injection pressure (psia)	Abandonment oil production rate (STB/day)	Minimum THP (psia)
1,800	1,800	7,037	50	514.7

Table 5. 9: Simulation results of waterflooding base case.

Degree of oil volatility	Q_o (STB/day)	W_i (STB/day)	N_p (MSTB)	G_p (BCF)	W_p (MSTB)	Oil RF (%)	Field life (days)
Moderately	989	1,824	2,532.06	4.02	1,095.83	68.98	3,179
Very	706	1,824	1,832.24	5.48	486.44	69.89	2,879

Figures 5.28 and 5.29 present production profiles of moderately and very volatile oil, respectively. Oil production rate can be maintained at the designed rate until injected water reaches the producer. The reservoir also produces constant gas rate because the reservoir pressure is maintained above the bubble point pressure. This is beneficial to gas handling facilities design and utilization unlike natural depletion in which we need to handle peak gas production during late time of field life. After water breakthrough, the oil rate declines drastically especially for very volatile oil case which has faster oil decline rate than moderately volatile oil.

Figures 5.30 and 5.31 show similar pressure profiles of waterflooding base cases for moderately and very volatile oil. The average reservoir pressure decline a little bit during production but is still above the bubble point pressure. And once injected water breaks through the producer, the flowing bottomhole pressure of the producer drops because water saturation values around the well bore become higher. And at the time the oil production rate drops from the plateau level, the reservoir cannot maintain the target reservoir volume production rate, but we still keep water injection at constant rate, then VRR is a bit higher than one for a short period of time until the reservoir can produce total liquid at target rate, then VRR is equal to one again. Therefore, we can see from the pressure plot that the reservoir pressure builds up and remains constant.

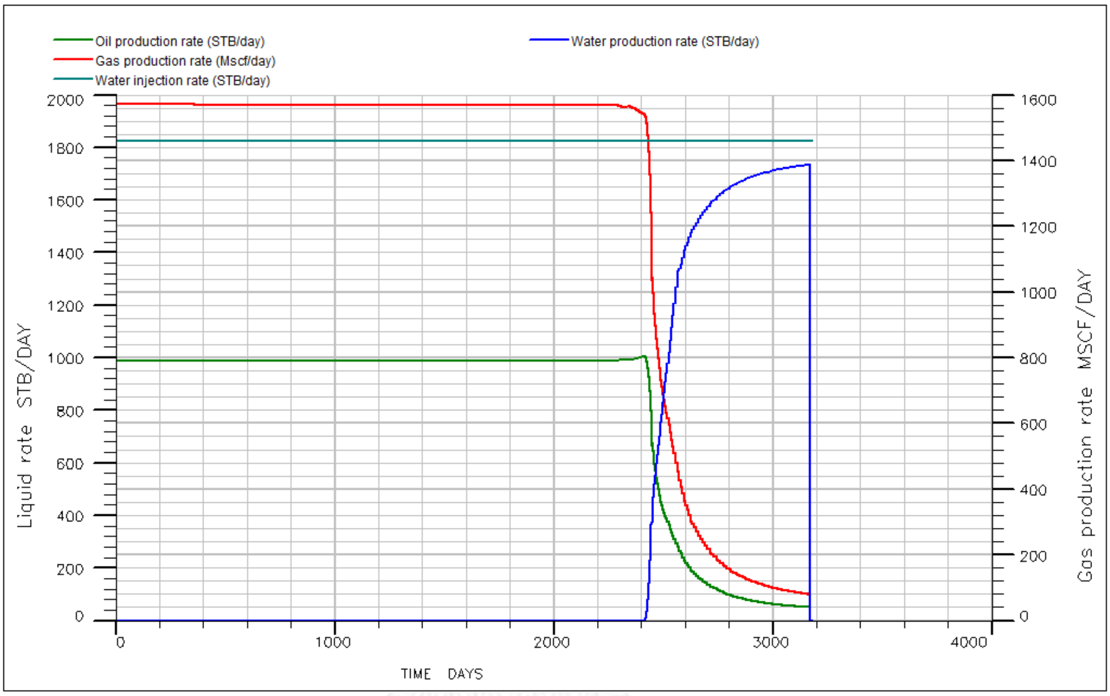


Figure 5. 28: Oil, gas and water production profiles of moderately volatile oil (waterflooding base case).

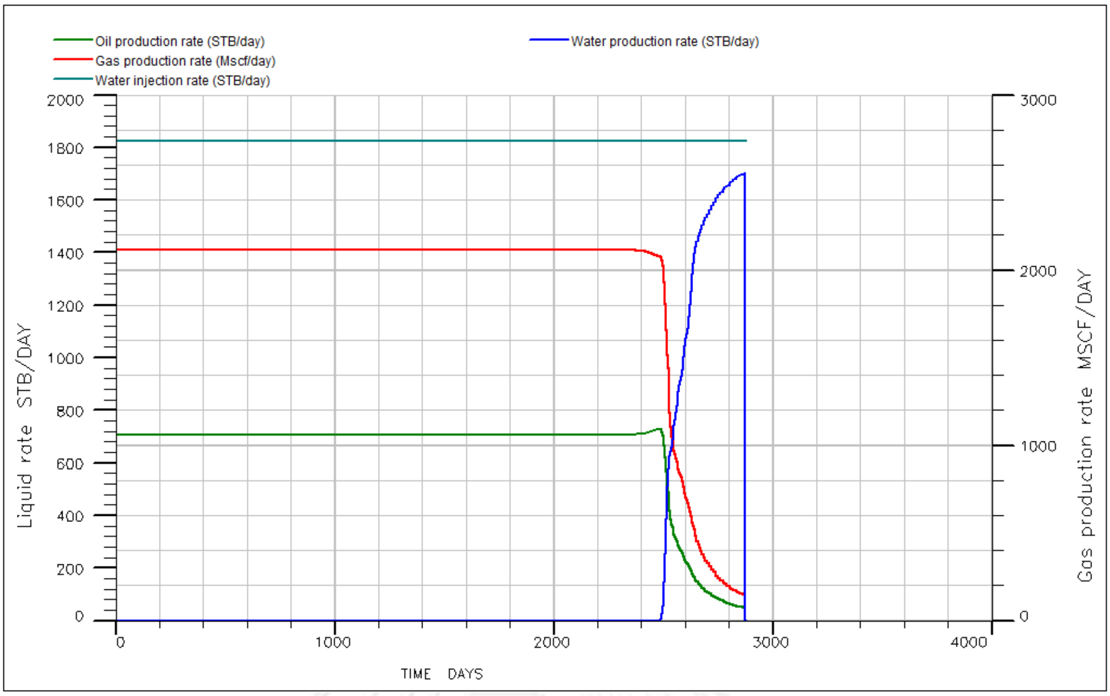


Figure 5. 29: Oil, gas and water production profiles of very volatile oil (waterflooding base case).

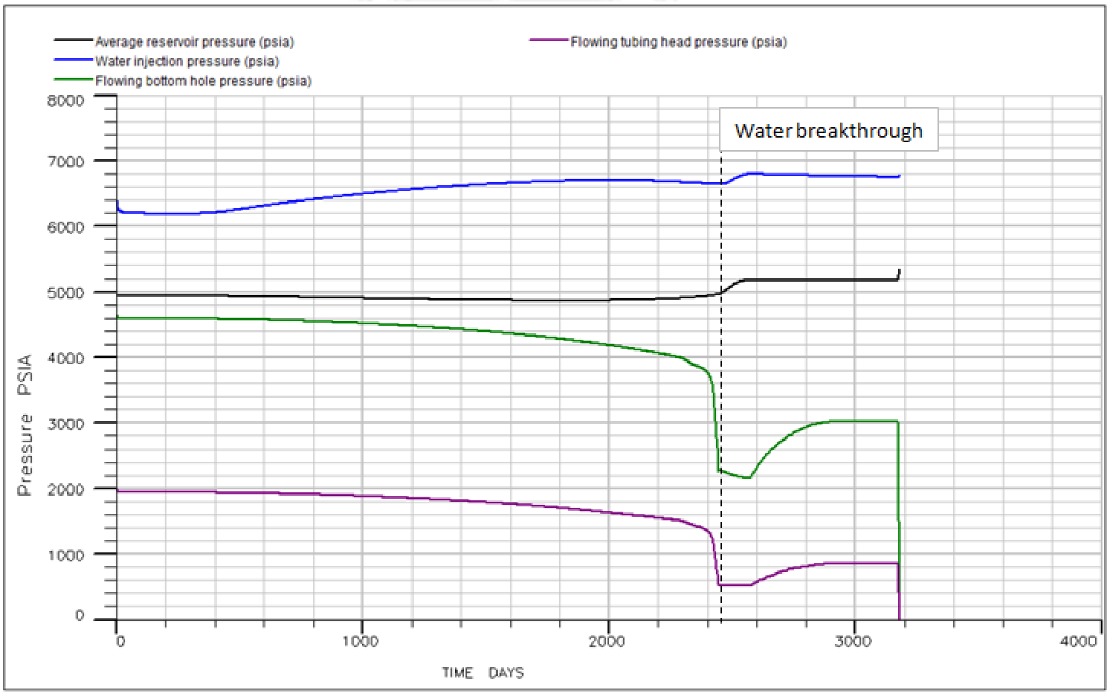


Figure 5. 30: Pressure profiles of moderately volatile oil (waterflooding base case).

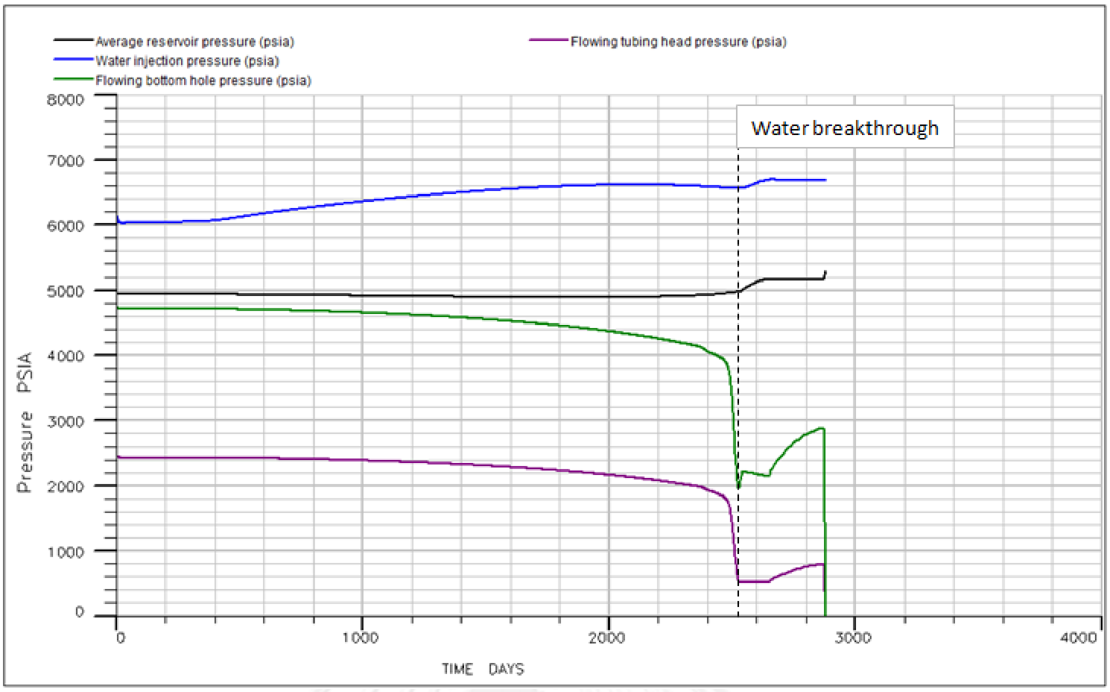


Figure 5. 31: Pressure profiles of very volatile oil (waterflooding base case).

The displacement and areal sweep efficiency can be estimated by using formula described in Section 3.9 based on average fluid saturation at breakthrough and final conditions. Input parameters and estimated efficiency values are presented in Tables 5.10 and 5.11, respectively.

From the calculation results, displacement efficiency is the most influential factor to oil recovery factor in this study. Very high areal sweep efficiency values are correspondent to homogeneous reservoir model and direct line drive flooding pattern used in this study. Moreover, the flooding condition is unconditionally stable displacement for a dipping reservoir (see Section 3.10). Figure 5.32 confirms this with a stable waterflood front at a particular time.

Figure 5.33 illustrates the oil recovery efficiency before and after breakthrough. We can see that there is a small improvement in recovery factor after the breakthrough but to achieve this small improvement, a significant amount of water injection volume is required. From economic perspective, spending high operating cost after water breakthrough is not practical if the revenue from oil during that period is small. Hence, for volatile oil reservoir, if sweep efficiency is high (homogeneous reservoir), we should terminate water injection after the breakthrough to avoid water pumping, treatment, and disposal cost.

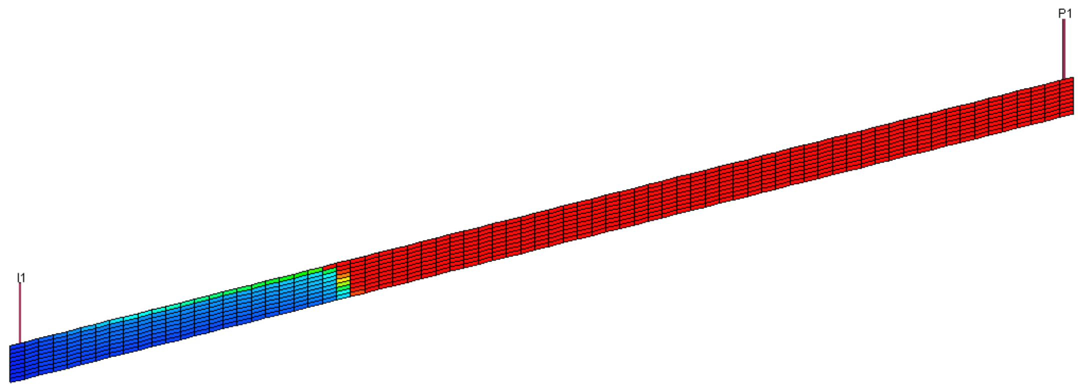
Table 5. 10: Input parameters for displacement and areal sweep efficiency calculation (waterflooding base case).

Degree of oil volatility	Avg. S_w at breakthrough condition	Avg. S_w at final condition	Cum. W_{inj} at breakthrough condition (MRB)	Cum. W_{inj} at final condition (MRB)	Cum. W_p at final condition (MSTB)
Moderately	0.7258	0.7581	4,341	5,723	1,096
Very	0.7408	0.7656	4,469	5,183	486

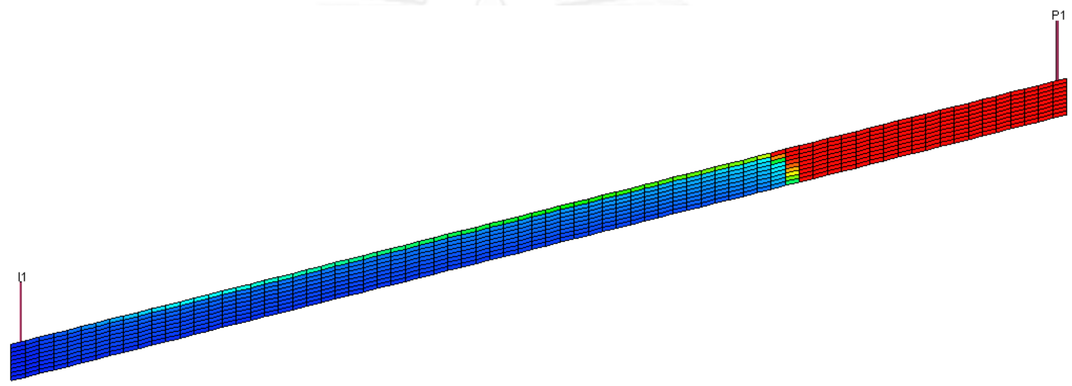
Note: For waterflooding base case, average gas saturation and cumulative water production at breakthrough are equal to zero.

Table 5. 11: Estimation of displacement and areal sweep efficiency (waterflooding base case).

Degree of oil volatility	E_D @BT (%)	E_A @BT (%)	E_D @final (%)	E_A @final (%)	E_V @final (%)	RF (%)
Moderately	64.85	99.07	68.99	99.10	1.00	68.98
Very	66.77	99.05	69.95	99.06	1.00	69.89



(a) 1 year after waterflood is started.



(b) 4 years after waterflood is started.

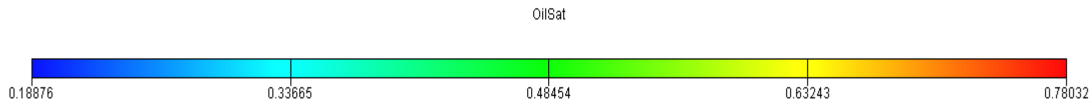


Figure 5. 32: Oil saturation profile in the X-Z plane (waterflooding base case).

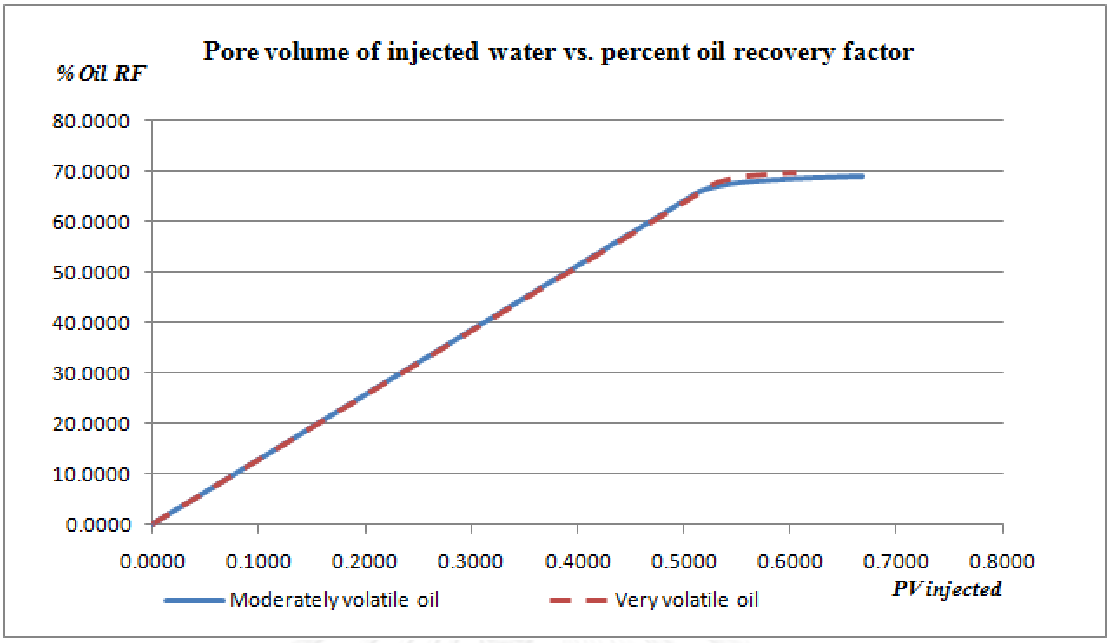


Figure 5. 33: Oil recovery factor vs. pore volume of injected fluid (waterflooding base case).

5.3.2 Effect of Time to Start Waterflood

Since volatile oil reservoir has a fast decline in reservoir pressure due to high amount of solution gas leaving the liquid phase, understanding of appropriate timing to maintain the reservoir energy will lead to effective water flood management plan. In general, water flood project may be started after oil has been produced naturally for a while due to many constraints of surface and subsurface facilities such as injection well, injection pump, and etc. Thus, it is worthwhile to find effect of time on waterflood performance which is also related to presence of gas while flooding (above or below the bubble point pressure). In this study, we investigate this effect by varying different percentages of pressure depletion from the initial reservoir pressure. Details and constraints of eight simulation cases are depicted in Tables 5.12 and 5.13 while Table 5.14 summarizes simulations results. Figures 5.34 and 5.35 illustrate the average reservoir pressure and time when waterflooding is started for the cases listed in Table 5.12. Note that the abandonment tubing head pressure of cases III, IV, VII, and VIII were lower to 64.7 psia in order to reach the same abandonment oil rate at 50 STB/day, because for these four cases waterflooding were implemented at relatively low reservoir pressure. So, to be able to compare all the cases at the same abandonment rate condition, we assume that if we installed a surface pump, we can reduce the back pressure to be at 64.7 psia.

From the results in Table 5.14, we obtain a similar total oil recovery for the cases which waterflooding is started at above thirty five percent of pressure depletion from the initial reservoir pressure. However, when waterflooding is started at 50 percent pressure depletion, the recovery factor drastically drops as the injected water has still not broken through the producer yet. For very volatile oil, the reduction in recovery factor is more serious than moderately volatile oil, as can be seen when we compare cases IV and VIII. This effect will be further investigated by comparing the displacement and areal sweep efficiency.

Figures 5.36 and 5.37 show oil production profiles for moderately and very volatile oil, respectively. For the cases which start water flooding at lower than twenty percent depletion from the initial reservoir pressure, the reservoir cannot maintain plateau oil rate and takes a longer time to get back to the target oil production rate. For cases IV and VIII, the simulation run does not reach the minimum oil production target because the well is loaded up due to insufficient reservoir pressure when the injected water reaches the producer.

Table 5. 12: Case details for different starting times to waterflood.

Case	Degree of oil volatility	Average reservoir pressure when waterflooding is started (psia)	Percentage of pressure depletion when waterflooding is started	Production period before waterflooding is started (days)
Case I (Base case)	Moderately	4,950	0	0
Case II	Moderately	3,990	20	117
Case III	Moderately	3,218	35	420
Case IV	Moderately	2,475	50	914
Case V (Base case)	Very	4,950	0	0
Case VI	Very	3,990	20	183
Case VII	Very	3,218	35	580
Case VIII	Very	2,475	50	1,172

Table 5. 13: Case constraints for different starting times to waterflood.

Case	Maximum oil production rate (RB/day)	Maximum water injection rate (RB/day)	Maximum water injection pressure (psia)	Abandonment oil production rate (STB/day)	Minimum THP (psia)
Case I (Base case)	1,800	1,800	7,037	50	514.7
Case II	1,800	1,800	7,037	50	514.7
Case III	1,800	1,800	7,037	50	64.7
Case IV	1,800	1,800	7,037	50	64.7
Case V (Base case)	1,800	1,800	7,037	50	514.7
Case VI	1,800	1,800	7,037	50	514.7
Case VII	1,800	1,800	7,037	50	64.7
Case VIII	1,800	1,800	7,037	50	64.7

Table 5. 14: Simulation results for different starting times to waterflood.

Case	Q_o (STB/day)	W_i (STB/day)	N_p (MSTB)	G_p (BCF)	W_p (MSTB)	Oil RF (%)	Field life (days)
Case I (Base case)	989	1,824	2,532	4.02	1,096	68.98	3,179
Case II	989	1,820	2,589	3.95	1,488	70.53	3,507
Case III	989	1,815	2,505	4.15	2,216	68.24	4,212
Case IV	989	1,812	1,990	4.14	0	54.21	3,041
Case V (Base case)	706	1,824	1,832	5.48	486	69.90	2,879
Case VI	706	1,820	1,832	5.36	904	69.88	3,179
Case VII	706	1,816	1,694	5.76	1,541	64.62	3,996
Case VIII	706	1,812	1,342	5.91	0	51.21	3,444

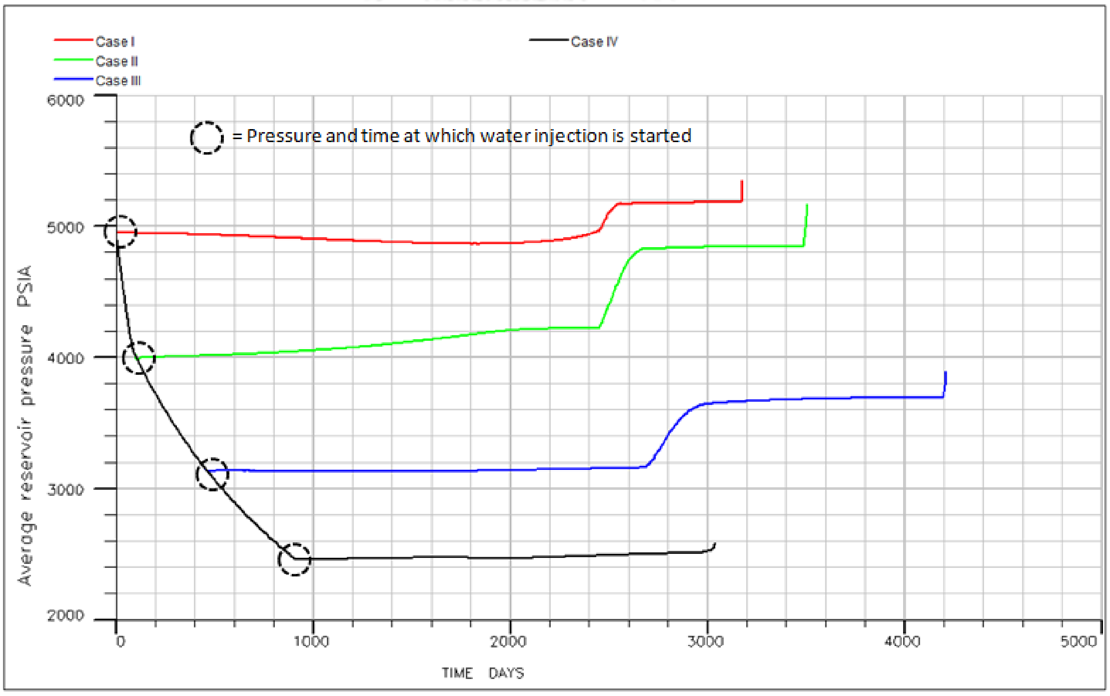


Figure 5. 34: Average reservoir pressure for different starting times to waterflood (moderately volatile oil).

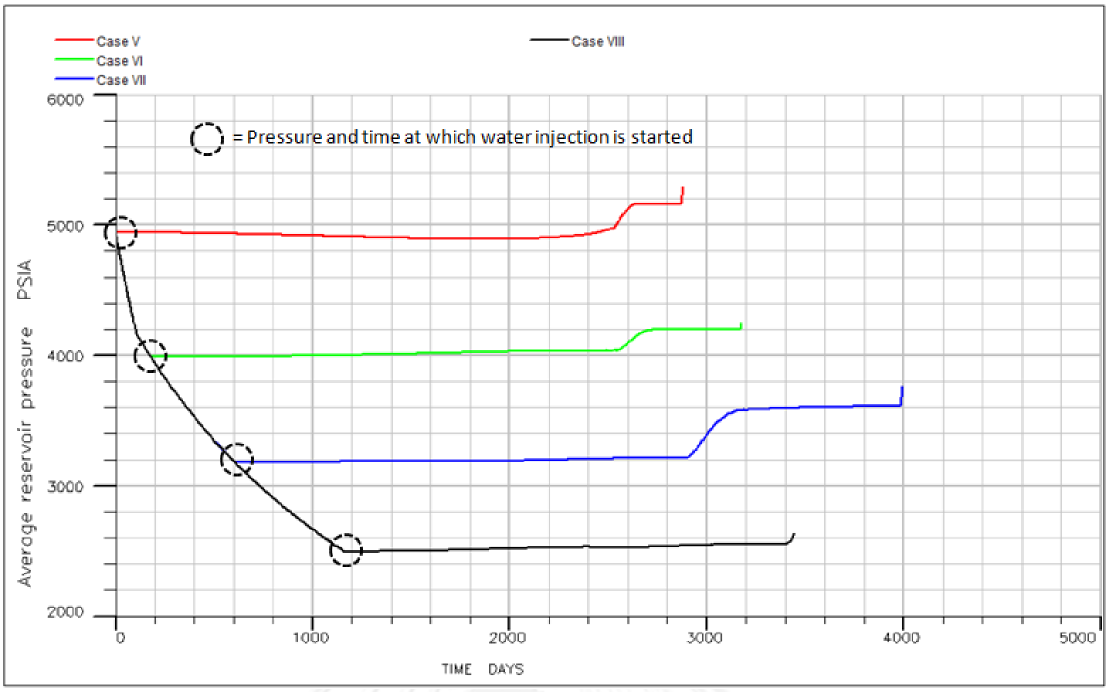


Figure 5. 35: Average reservoir pressure for different starting times to waterflood (very volatile oil).

Table 5.15 presents parameters used for displacement and sweep efficiencies estimation and the values for all cases are shown in Table 5.16. It is obvious that for the cases when waterflooding is started at high percent pressure depletion from the initial pressure such as cases V and VIII, displacement efficiency is quite low because the most influential factor in this study is the reservoir pressure level during the flooding. At a lower reservoir pressure level especially below the bubble point pressure, oil viscosity increases sharply and presence of gas in the reservoir reduces displacement and sweep efficiency of waterflooding. Figure 5.38 is a plot of oil viscosity at different reservoir pressures. We can observe that oil viscosity value changes a little when the reservoir pressure ranges between 2,000 and 4,000 psi. Therefore, this evidence answers our question why the effect of pressure on waterflooding performance is minimal for studied range of flooding pressure.

To differentiate different effect of oil viscosity from presence of gas during waterflooding, four difference fractional flow curves are plotted to compare curve position at different oil viscosity values which are listed in Table 5.17. Oil viscosity value at each reservoir pressure is calculated using an equation of state. Figures 5.39 and 5.40 show fractional flow curves which neglect the effect of gas saturation on oil relative permeability, for moderately and very volatile oil, respectively. While Figures 5.41 and 5.42 show the curves which include the effect of the presence of gas saturation in which value for each case is listed in Table 5.15. From the four curves, we can see that there is a small difference in the curve position when ignoring the effect of gas saturation on oil relative permeability. Therefore, we may conclude that for volatile oil, a reduction in oil viscosity is relatively small and has less effect on mobility ratio between water and oil while the presence of gas saturation reduces oil relative permeability and has more impact on the mobility ratio.

In brief, in order to select an optimum condition for waterflooding of volatile oil, we should study PVT properties at each condition of interest before running a simulation model. This can help save time for a large and complex reservoir model. Thorough understanding of PVT parameters also helps us on quality checking of simulation results.

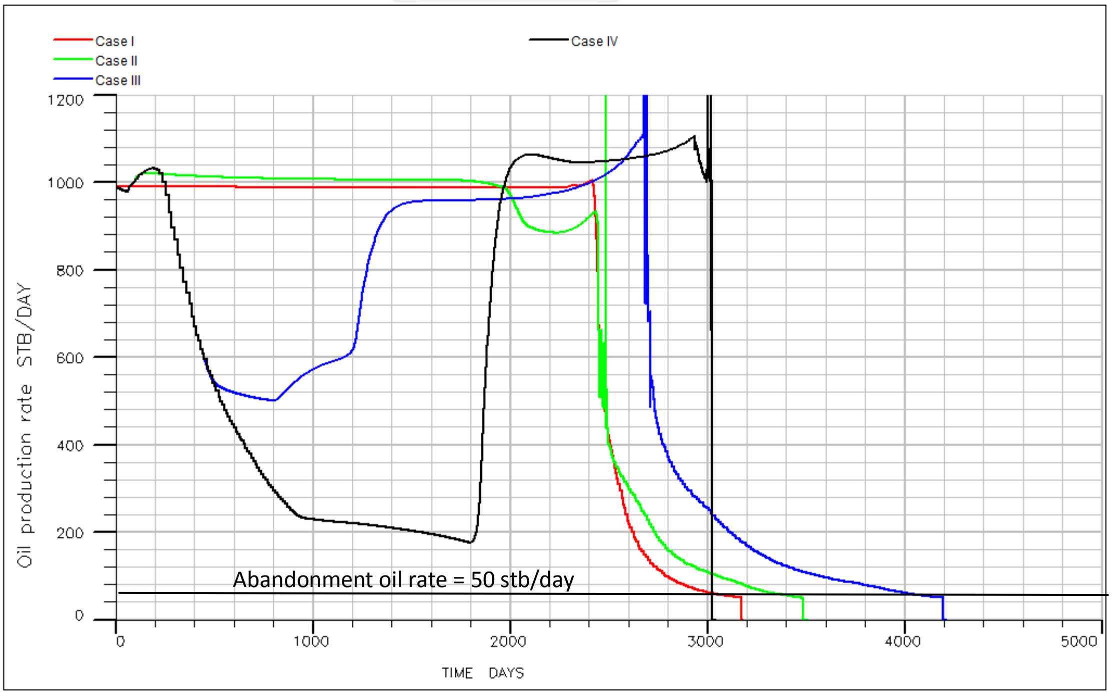


Figure 5. 36: Oil production rate for different starting times to waterflood (moderately volatile oil).

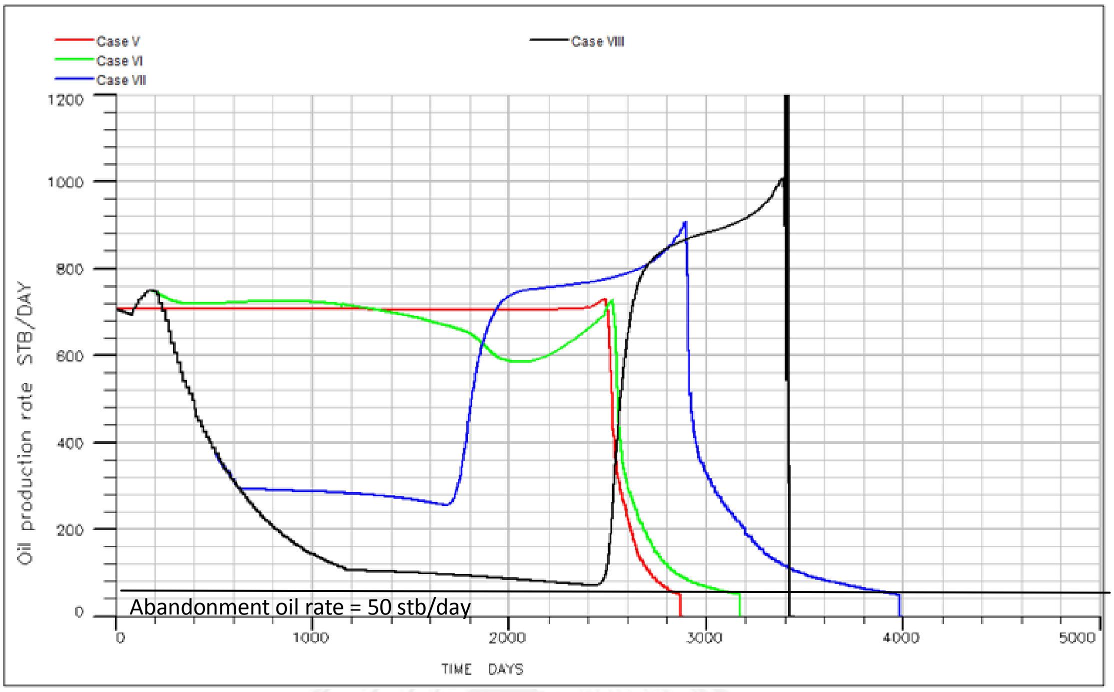


Figure 5. 37: Oil production rate for different starting times to waterflood (very volatile oil).

Table 5. 15: Input parameters for displacement and areal sweep efficiency calculation (different starting times to waterflood study).

Case	S_{wi}	Avg. S_w at breakthrough condition	Avg. S_w at final condition	Avg. S_g during water flooding	Cum. W_{inj} at breakthrough condition (MRB)	Cum. W_{inj} at final condition (MRB)
Case I (Base case)	0.22	0.7258	0.7581	0.000	4,341	5,723
Case II	0.22	0.7083	0.7581	0.025	4,177	6,115
Case III	0.22	0.6888	0.7511	0.065	3,983	6,746
Case IV	0.22	0.6723	0.6723	0.080	3,830	3,830
Case V (Base case)	0.22	0.7408	0.7656	0.000	4,469	5,183
Case VI	0.22	0.7124	0.7454	0.063	4,207	5,400
Case VII	0.22	0.7029	0.7545	0.098	4,104	6,102
Case VIII	0.22	0.7046	0.7046	0.140	4,104	4,104

Table 5. 16: Estimation of displacement and areal sweep efficiency (different starting times to waterflood study).

Case	E_D @BT (%)	E_A @BT (%)	E_D @final (%)	E_A @final (%)	E_V @final (%)	Oil RF (%)
Case I (Base case)	64.85	99.07	68.99	99.10	1.00	68.98
Case II	61.37	98.75	67.96	98.79	1.00	70.53
Case III	56.48	98.07	65.19	98.14	1.00	68.24
Case IV	53.18	97.76	53.18	97.76	1.00	54.21
Case V (Base case)	66.77	99.05	69.95	99.06	1.00	69.90
Case VI	59.90	98.61	64.50	98.64	1.00	69.88
Case VII	56.44	98.10	64.01	98.15	1.00	64.62
Case VIII	53.85	97.75	53.85	97.75	0.97	51.21

Table 5. 17: Average oil viscosity during waterflooding (different starting times to waterflood study).

Case	Degree of oil volatility	Average reservoir pressure when waterflooding is started (psia)	Average oil viscosity during waterflooding (cp)
Case I (Base case)	Moderately	4,950	0.212
Case II	Moderately	3,990	0.199
Case III	Moderately	3,132	0.237
Case IV	Moderately	2,456	0.279
Case V (Base case)	Very	4,950	0.131
Case VI	Very	3,990	0.127
Case VII	Very	3,179	0.171
Case VIII	Very	2,494	0.219

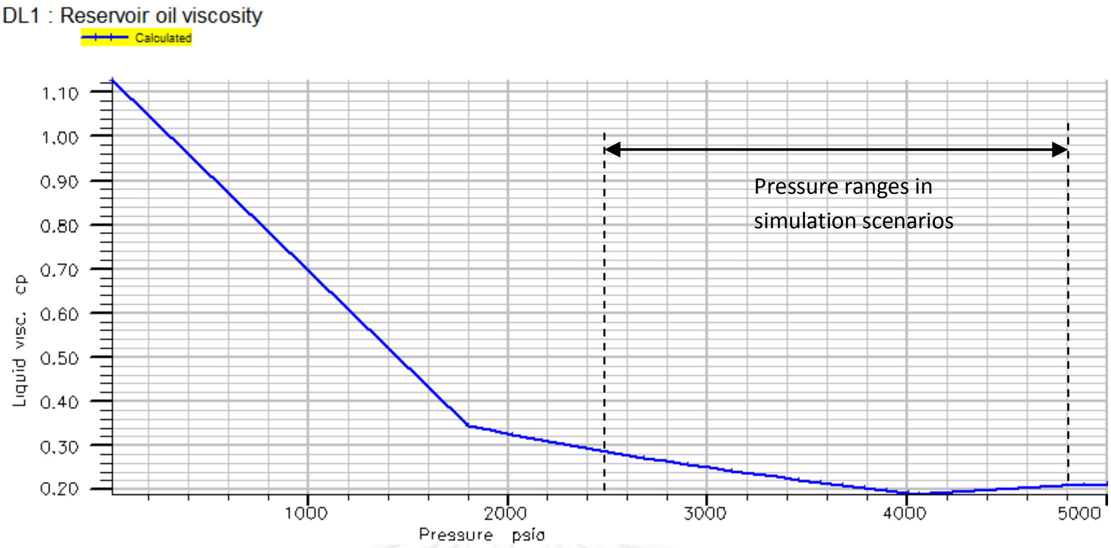


Figure 5. 38: Oil viscosity at different reservoir pressures.

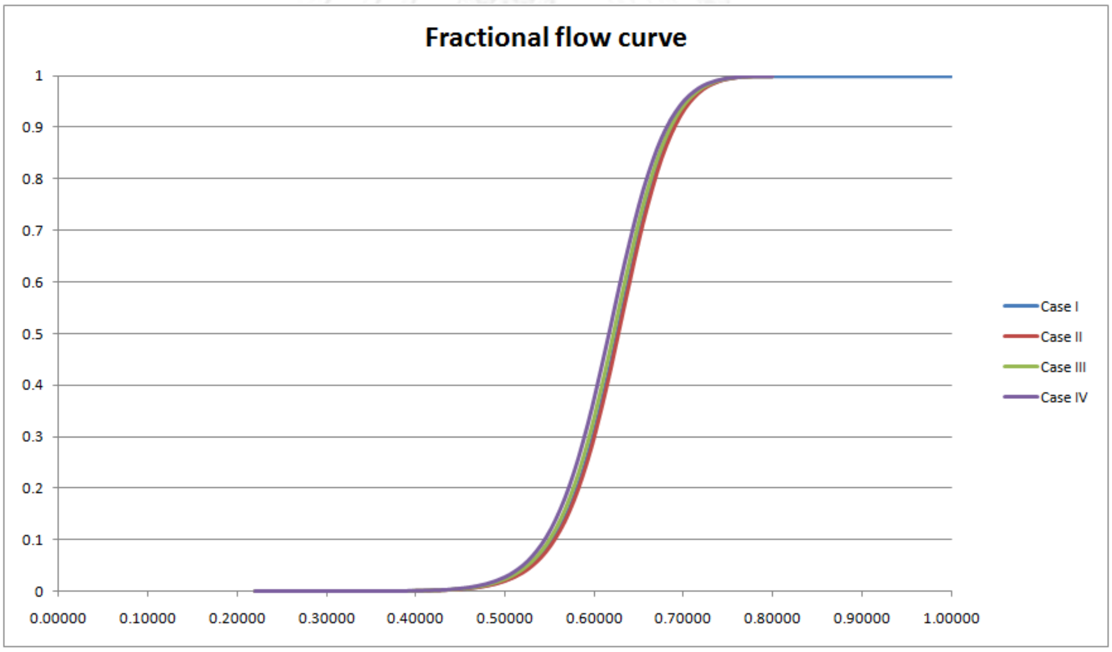


Figure 5. 39: Fractional flow curve of moderately volatile oil without the effect of gas saturation (different starting times to waterflood study).

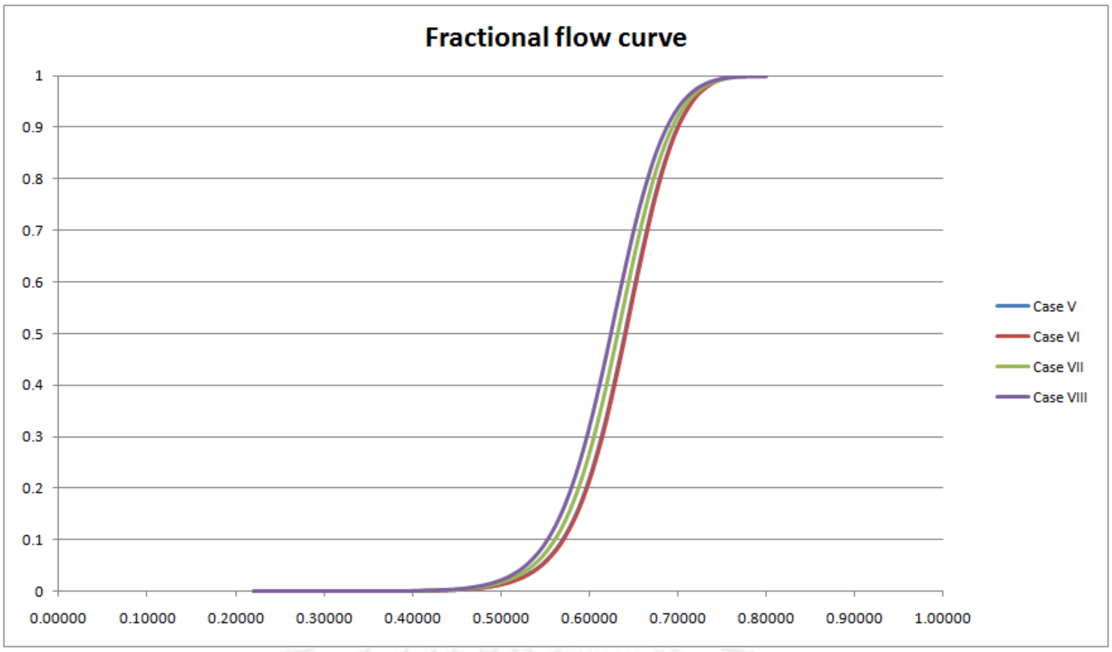


Figure 5. 40: Fractional flow curve of very volatile oil without the effect of gas saturation (different starting times to waterflood study).

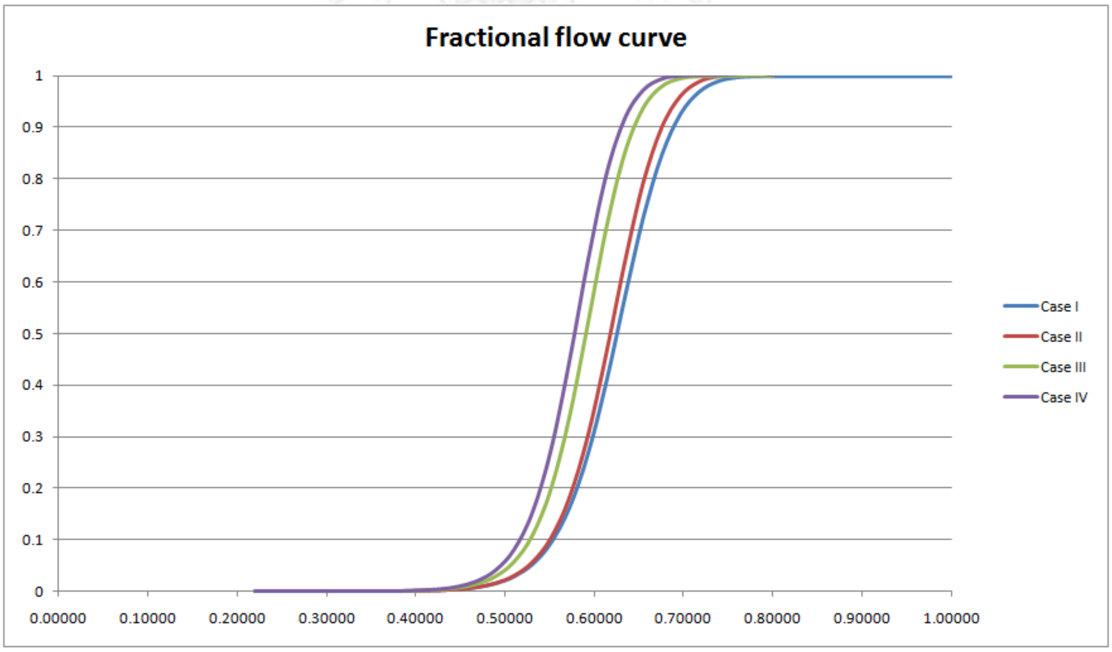


Figure 5. 41: Fractional flow curve of moderately volatile oil with the effect of gas saturation (different starting times to waterflood study).

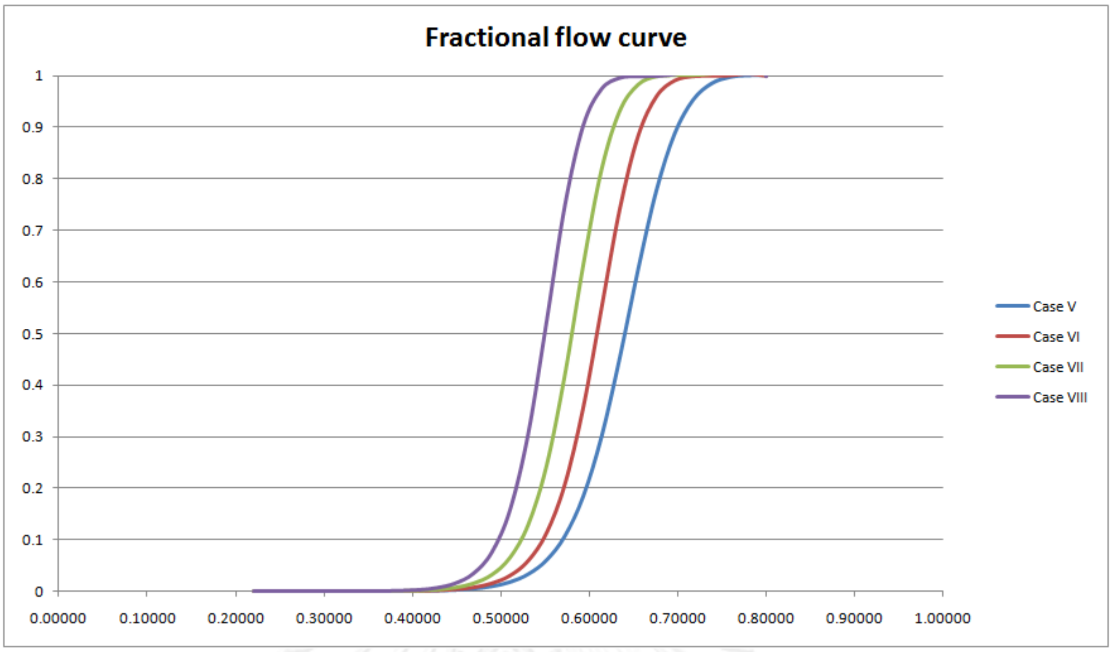


Figure 5. 42: Fractional flow curve of very volatile oil with the effect of gas saturation (different starting times to waterflood study).

5.3 Gasflooding Performance

This part is an investigation of gasflooding performance in volatile oil reservoirs, when considering effect of timing of injection and associated injection pressure. We begin gas flooding at different times by maintaining the reservoir pressure at different levels because we suspect that different timing and flooding pressure may have an effect on miscibility condition during gasflooding. The very and moderately volatile oil types are studied and compared to identify sensitivity of oil volatility to gasflooding performance.

A reservoir schematic of gasflooding scheme is shown in Figure 5.43 and 5.44. The vertical injector well is at the updip position of reservoir while the vertical producer well is at the downdip position. This injection pattern helps maintain stable gasflood front from a gravitational effect.

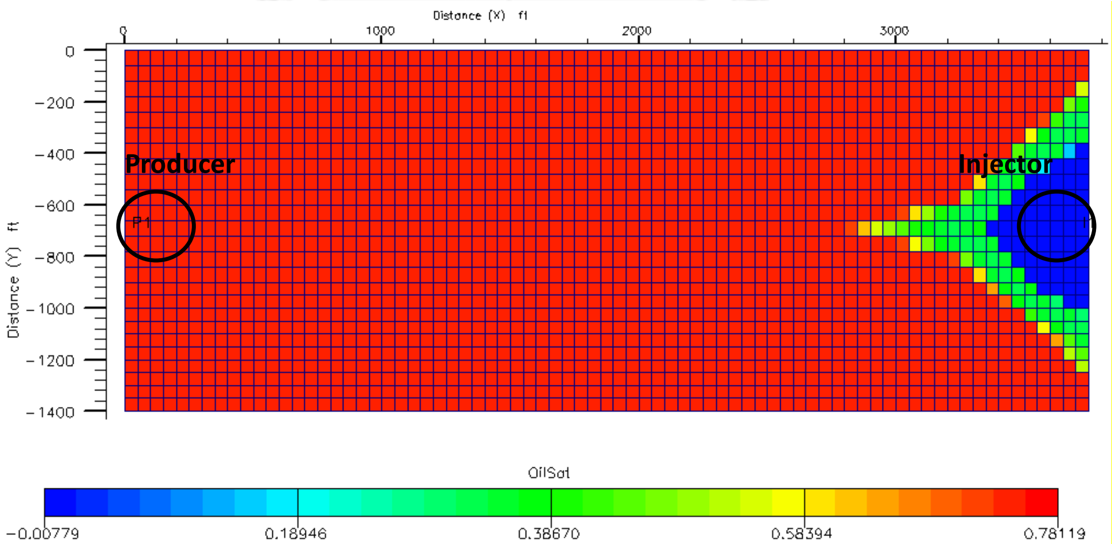


Figure 5. 43: Schematic of reservoir model of gasflooding scheme in the X-Y plane.

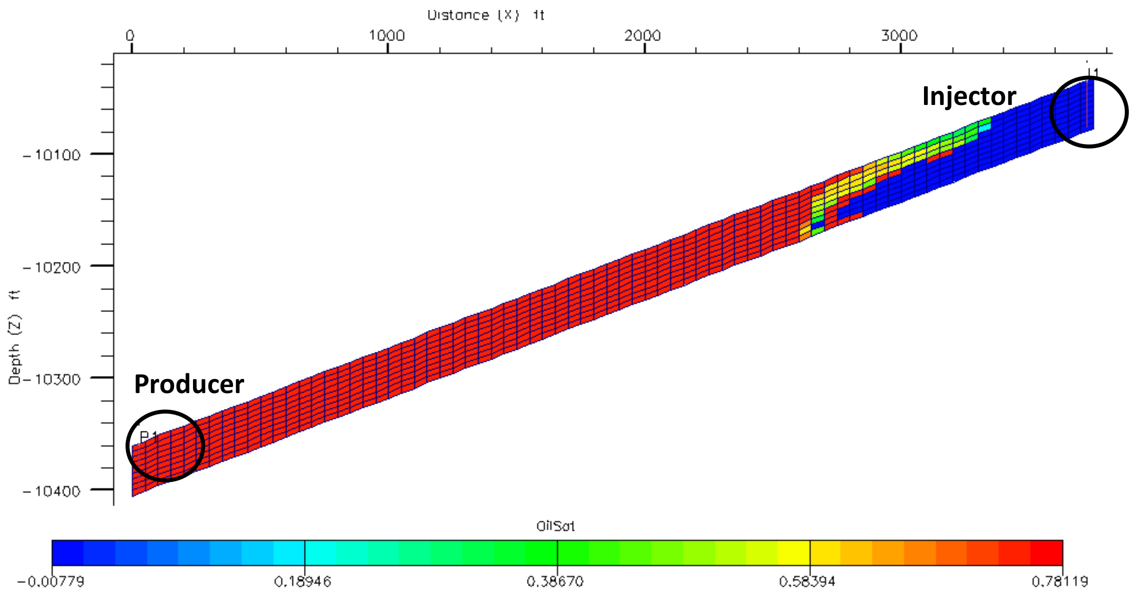


Figure 5. 44: Schematic of reservoir model of gasflooding scheme in the X-Z plane.

5.3.3 Base Case of Gasflooding

Gas injection is implemented since the first day of production so the injected gas (CO_2) is completely miscible with oil since the reservoir pressure is maintained above the bubble point pressure. Table 5.18 lists constraints for gasflooding base case simulation. For gasflooding, abandonment oil production rate is 200 STB/day because operating cost for gasflooding is normally higher than that for waterflooding. Simulation results are presented in Table 5.19, showing that oil recovery factor of very volatile oil is slightly higher than moderately volatile oil due to the fact that the higher oil volatility can achieve miscibility condition easier than the lower oil volatility.

Table 5. 18: Constraints for gasflooding base case.

Maximum reservoir volume production rate (RB/day)	Maximum gas injection rate (RB/day)	Maximum gas injection pressure (psia)	Abandonment oil production rate (STB/day)	Minimum THP (psia)
1,800	1,800	7,037	200	514.7

Table 5. 19: Simulation results of gasflooding base case.

Degree of oil volatility	Q_o (STB/day)	G_i (MMscfd)	N_p (MSTB)	G_p (BCF)	Cum G_i (BCF)	Oil RF (%)	Field life (days)
Moderately	989	2.85	3,174	9.3	12.86	86.47	4,745
Very	706	2.85	2407	10.99	13.37	91.83	4,676

From Figures 5.45 and 5.46, we can maintain plateau of oil rate until gas break through the producer, which is very fast compared to water flooding. From Figures 5.47 and 5.48, the reservoir pressure declines gradually during gas flooding despite the control of injection and production volume to be equal at reservoir condition. This is because we replace the oil with gas which is more compressive. Another observation is the reservoir requires less pressure drawdown even after the breakthrough of injected gas unlike the case of waterflooding.

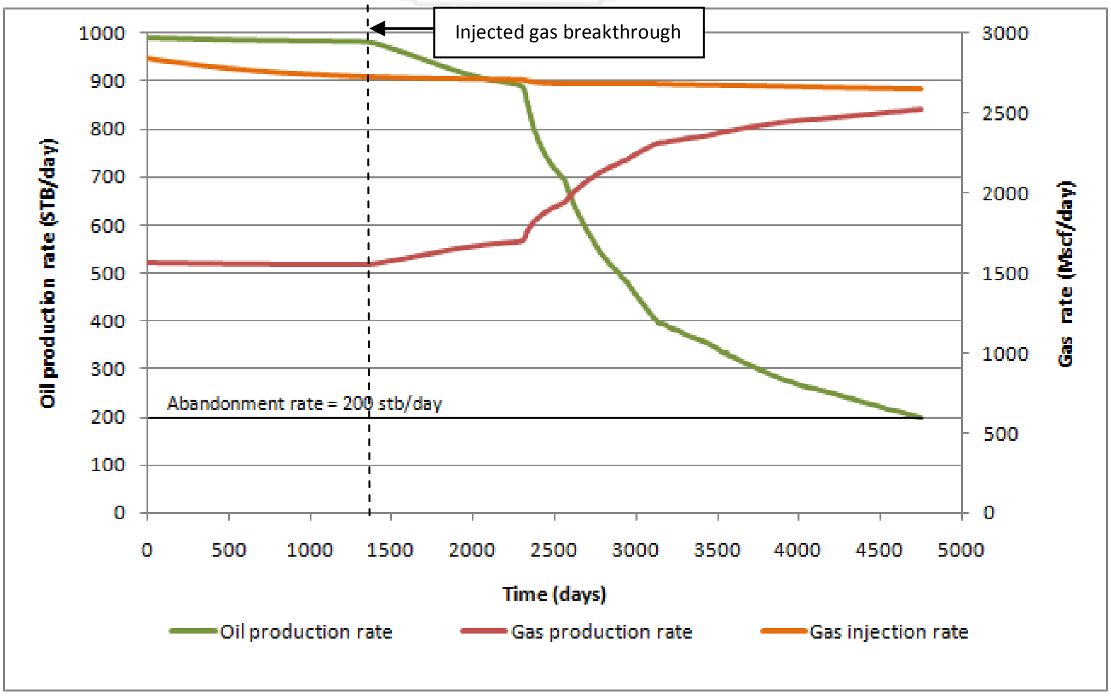


Figure 5. 45: Oil and gas production profile of moderately volatile oil case.

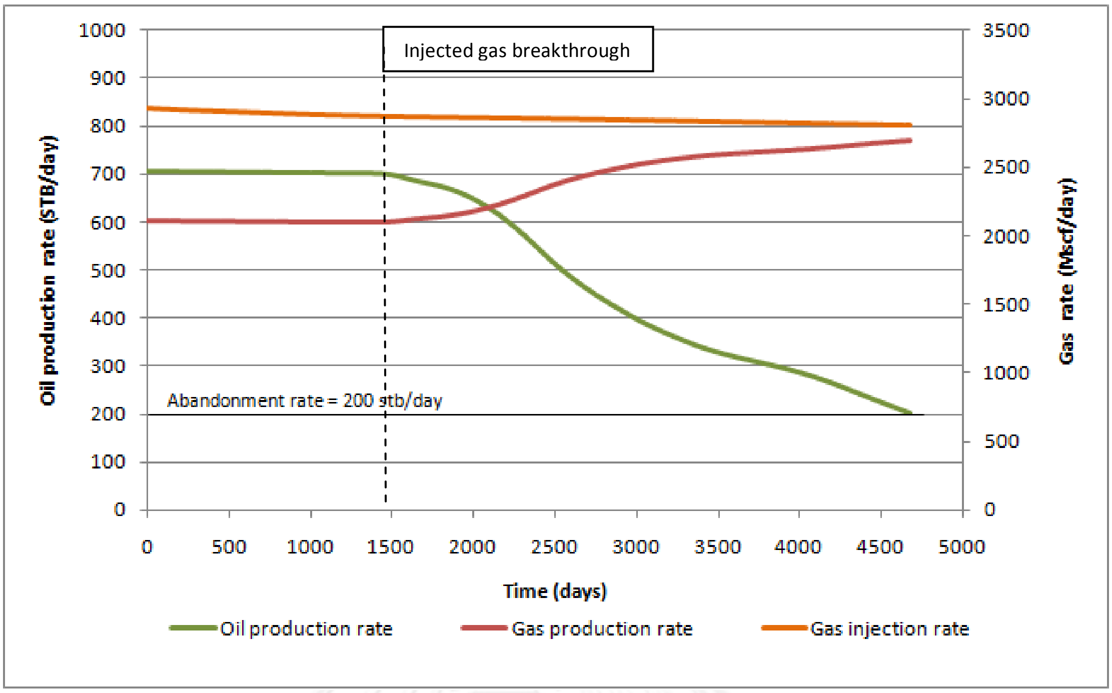


Figure 5. 46: Oil and gas production profile of very volatile oil case.

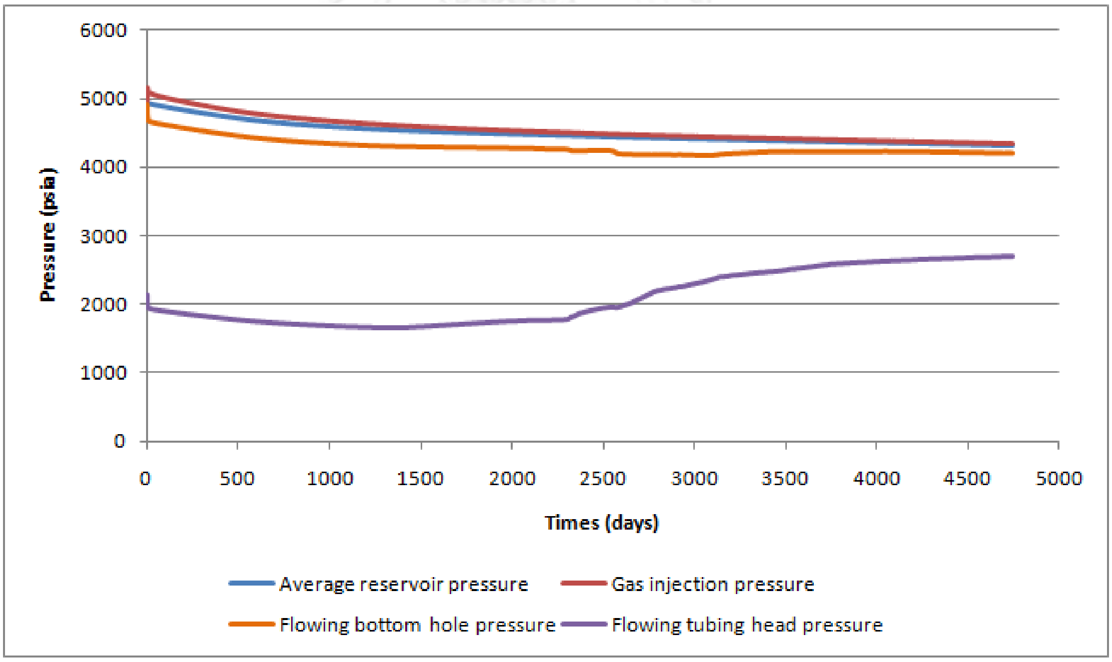


Figure 5. 47: Pressure profile of moderately volatile oil case.

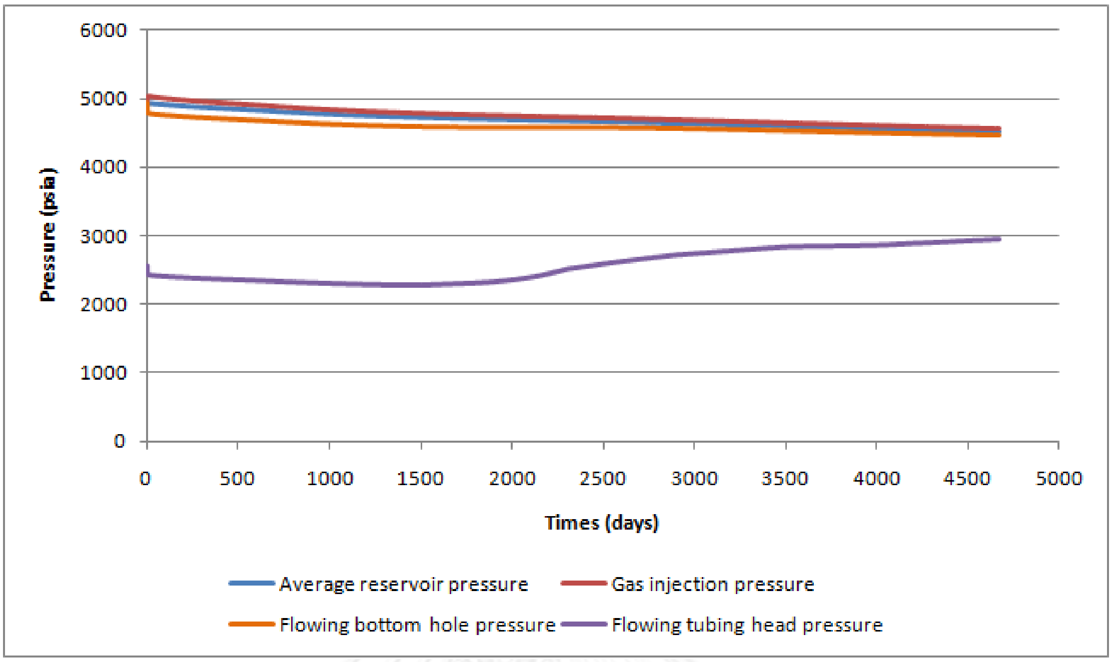


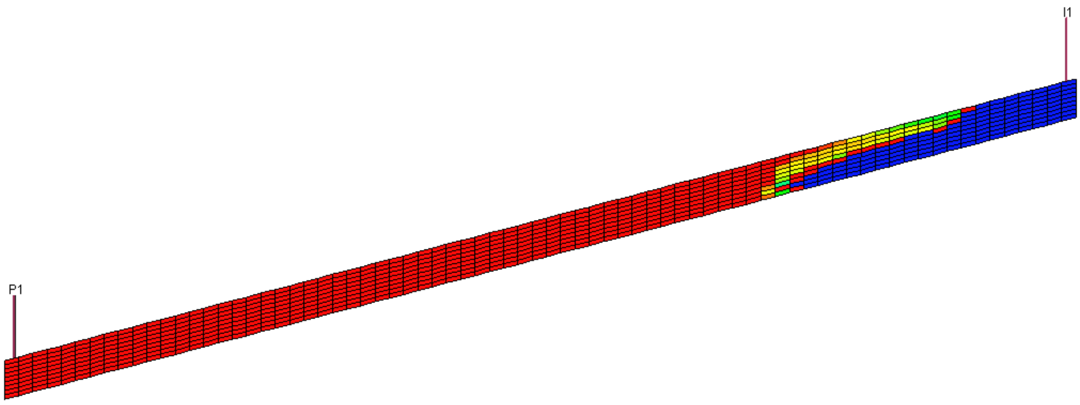
Figure 5. 48: Pressure profile of very volatile oil case.

For miscible gasflooding, we can achieve very high displacement efficiency up to a hundred percent if gas is totally miscible with oil, but the sweep efficiency of gas flooding is a lot poorer than that for the case of waterflooding because injected gas density and viscosity are much lower than those for the oil. For gasflooding study, we do not quantify displacement and sweep efficiency as in the case of waterflooding because we cannot separately track the gas saturation value that is directly related to injected gas mixes with the oil in the miscible process. So, an attempt to estimate those efficiency numbers may mislead the understanding of simulation results. However, we can still calculated oil recovery factor at breakthrough condition as presented in Table 5.20. The oil recovery factors at the breakthrough condition are relatively low when compared with the values at the abandonment condition. And the utilization of injected gas is become lower after the breakthrough which can be observed from relative high of cumulative gas production.

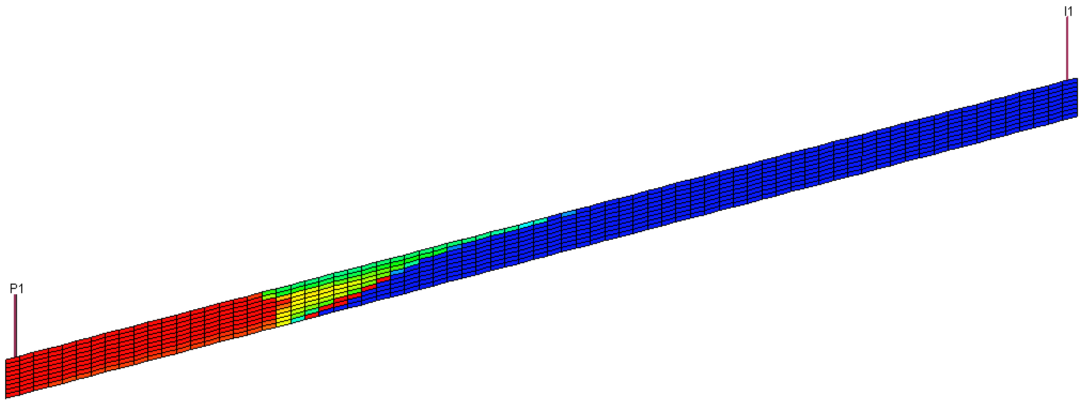
Furthermore, we qualitatively track the displacement and sweep efficiency of gasflooding by tracking the oil saturation profile in the reservoir. Figures 5.49 and 5.50 indicate that poor areal sweep efficiency is the main cause of early breakthrough of injected gas while the effect of vertical heterogeneity to vertical sweep efficiency is insignificant. Therefore, if we can improve sweep efficiency of gas flooding by delaying a breakthrough of injected gas, the economics of gas flooding project will be very attractive.

Table 5. 20: Simulation results of gasflooding base case at breakthrough and abandonment conditions.

Degree of oil volatility	Conditions	N_p (MSTB)	G_p (BCF)	Cum G_i (BCF)	Oil RF (%)	Times (days)
Moderately	At breakthrough	1,314	2.08	3.70	35.79	1,334
	At abandonment	3,174	9.3	12.86	86.47	4,745
Very	At breakthrough	1,017	3.05	4.12	38.80	1,445
	At abandonment	2,407	10.99	13.37	91.83	4,676



(a) 1 year after gasflood is started.



(b) 4 years after gasflood is started.

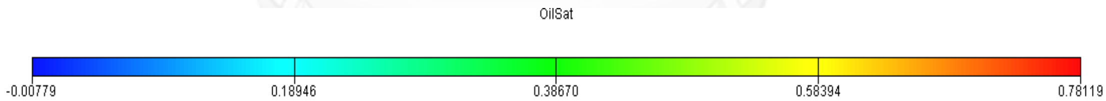
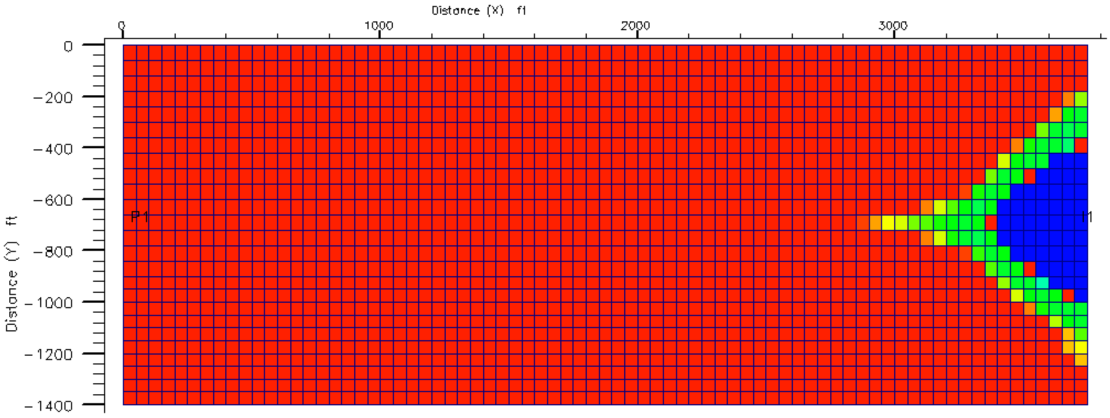
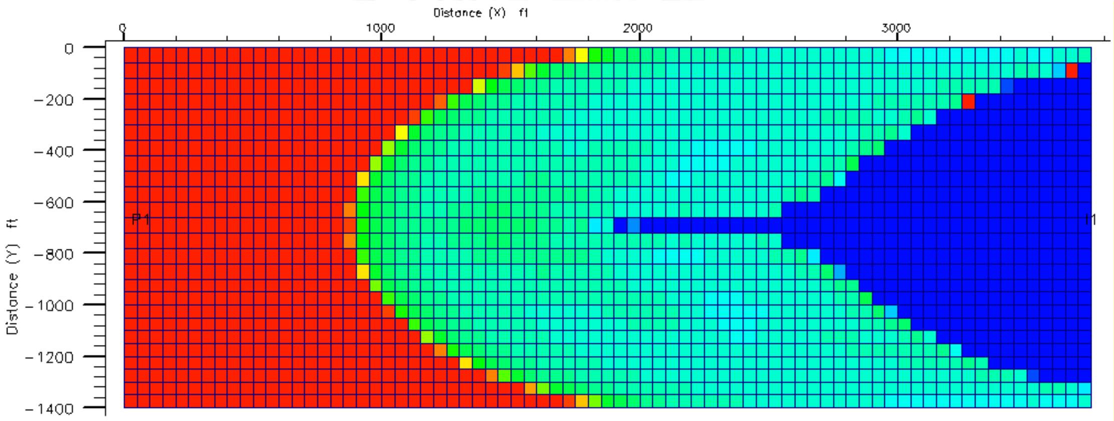


Figure 5. 49: Oil saturation profile in the X-Z plane (gasflooding base case).



(a) 1 year after gasflood is started.



(b) 4 years after gasflood is started.

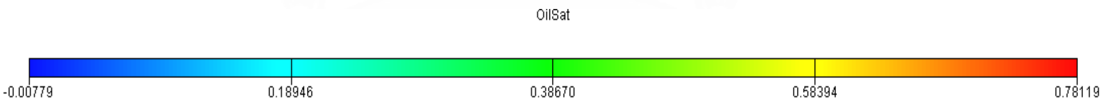


Figure 5. 50: Oil saturation profile in the X-Y plane (gasflooding base case).

5.3.4 Effect of Time to Start Gasflood

The investigation pattern for gas flooding is the same as that in the waterflooding section. Understanding of appropriate timing to maintain the reservoir energy will lead to effective gasflood management plan. In general, preparation of gas related surface and subsurface facilities such as gas compressor, gas injection pipeline and etc, usually take a longer period of time than liquid handing facilities. Therefore, the effect of starting time and pressure to gasflooding performance is very crucial to project economic. We study this effect by varying gasflood starting date at different percentages of pressure depletion from the initial reservoir pressure. Details and constraints of eight simulation cases are depicted in Tables 5.21 and Table 5.22 while Table 5.23 summarizes simulations results. Figures 5.51 and 5.52 illustrate the average reservoir pressure and time when gasflooding is started for the cases listed in Table 5.21.

Table 5. 21: Case details for different starting times to gasflood.

Case	Degree of oil volatility	Average reservoir pressure when gasflooding is started (psia)	Percentage of pressure depletion when gasflooding is started	Production period before gasflooding is started (days)
Case I (Base case)	Moderately	4,950	0	0
Case II	Moderately	3,990	20	106
Case III	Moderately	3,218	35	457
Case IV	Moderately	2,460	50	922
Case V (Base case)	Very	4,950	0	0
Case VI	Very	3,990	20	187
Case VII	Very	3,218	35	637
Case VIII	Very	2,460	50	1,207

Table 5. 22: Case constraints for different starting times to gasflood.

Case	Maximum reservoir volume production rate (RB/day)	Maximum gas injection rate (RB/day)	Maximum gas injection pressure (psia)	Abandonment oil production rate (STB/day)	Minimum THP (psia)
Case I (Base case)	1,800	1,800	7,037	200	514.7
Case II	1,800	1,800	7,037	200	514.7
Case III	1,800	1,800	7,037	200	514.7
Case IV	1,800	1,800	7,037	200	514.7
Case V (Base case)	1,800	1,800	7,037	200	514.7
Case VI	1,800	1,800	7,037	200	514.7
Case VII	1,800	1,800	7,037	200	514.7
Case VIII	1,800	1,800	7,037	200	514.7

Table 5. 23: Simulation results for different starting times to gasflood.

Case	Q_o (STB/day)	G_i (MMscfd)	N_p (MSTB)	G_p (BCF)	Cum. G_i (BCF)	Oil RF (%)	Field life (days)
Case I (Base case)	989	2.85	3,174	9.3	12.86	86.47	4,745
Case II	989	2.55	3,001	8.26	11.01	81.75	4,529
Case III	989	2.14	2,540	8.76	9.87	69.19	5,164
Case IV	989	1.68	2,181	8.68	8.33	59.42	5,872
Case V (Base case)	706	2.85	2,407	10.99	13.37	91.83	4,676
Case VI	706	2.64	2,065	8.6	9.78	78.79	3,972
Case VII	706	2.19	1,747	9.47	9.14	66.65	4,859
Case VIII	706	1.75	1,226	7.77	5.87	46.77	4,549

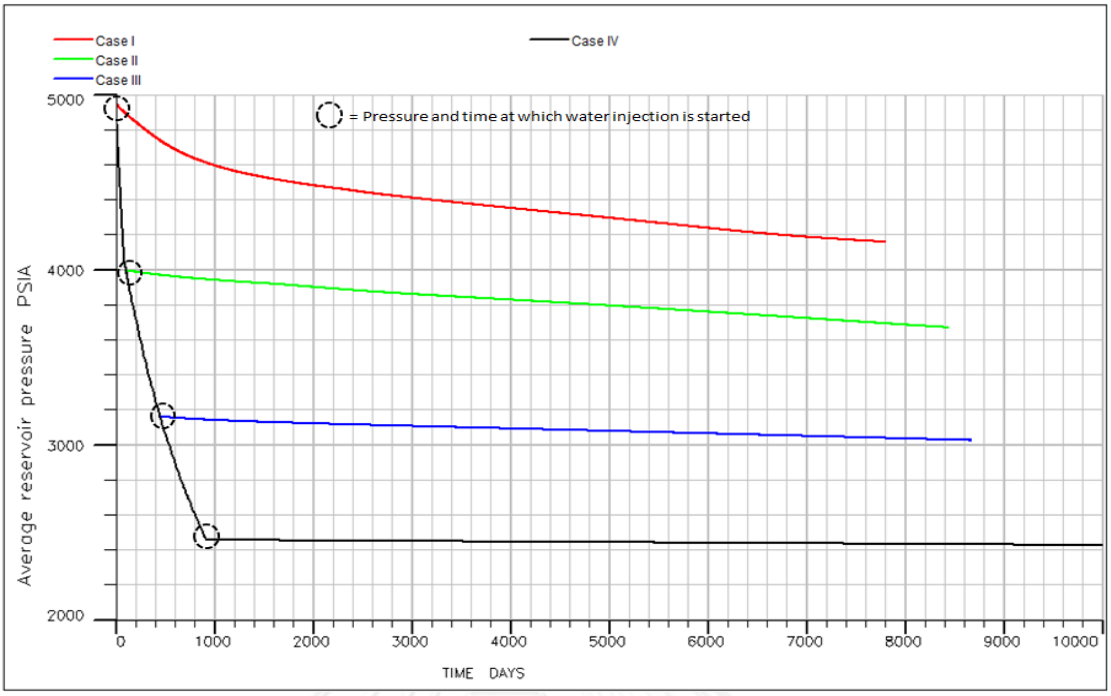


Figure 5. 51: Average reservoir pressure for different starting times to gasflood (moderately volatile oil).

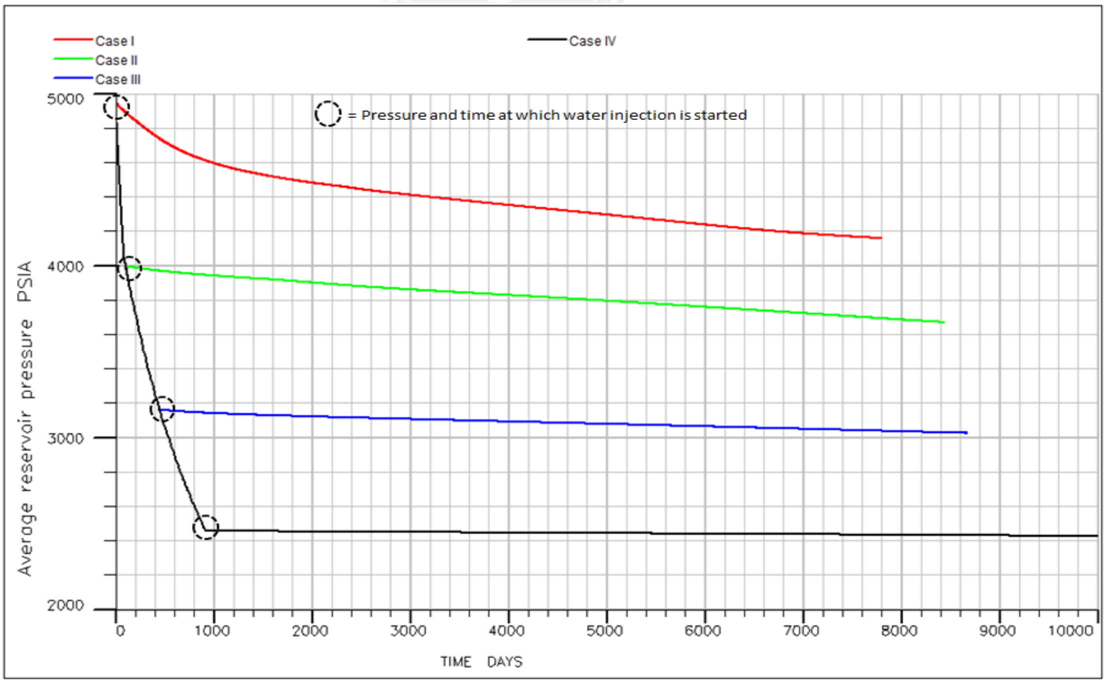


Figure 5. 52: Average reservoir pressure for different starting times to gasflood (very volatile oil).

From the results in Table 5.23, the later the time that gasflooding is started, the smaller the oil recovery. In addition, percent oil recovery factor of very volatile oil is more sensitive to timing and pressure level than that for moderately volatile. Low oil recovery factors obtained in cases IV and VIII, in which gasflooding is started at a low reservoir pressure level, are related to miscibility condition during gasflooding. As a result, greater amounts of residual oil are left behind gasflood front than that the cases which have higher reservoir pressure. So, we track the interfacial tension profiles along the reservoir grid in the X-Z plane at the final time step of all cases as presented in Figures 5.53 to 5.60 in order to confirm our assumption. These figures show the interfacial tension between oil and gas in dyne/cm unit. And we can observe that the interfacial tension increases as the reservoir pressure decreases for both types of oil volatility. We can see that for cases IV and VIII, interfacial tensions are much higher than those for other cases. This is correspondence with low oil recovery factors obtained in these two cases.

In summary, achievement of miscible condition during gasflooding is crucial to both displacement and sweep efficiency. In term of displacement efficiency, the higher miscibility the lower residual oil saturation after the gasflood front. When considered mobility ratio between gas and oil, gas viscosity is much lower than oil, and this causes poor sweep efficiency, because injected gas move faster than oil. However, if the reservoir can achieve miscible condition, relative permeability to oil increases as single phase flow. Therefore, higher miscibility results in higher oil relative permeability at miscible flood front, so mobility ratio between gas and oil is improved. And if we start gasflooding after free gas exist in the reservoir, interfacial tension between gas and oil increases and results in lower miscibility.

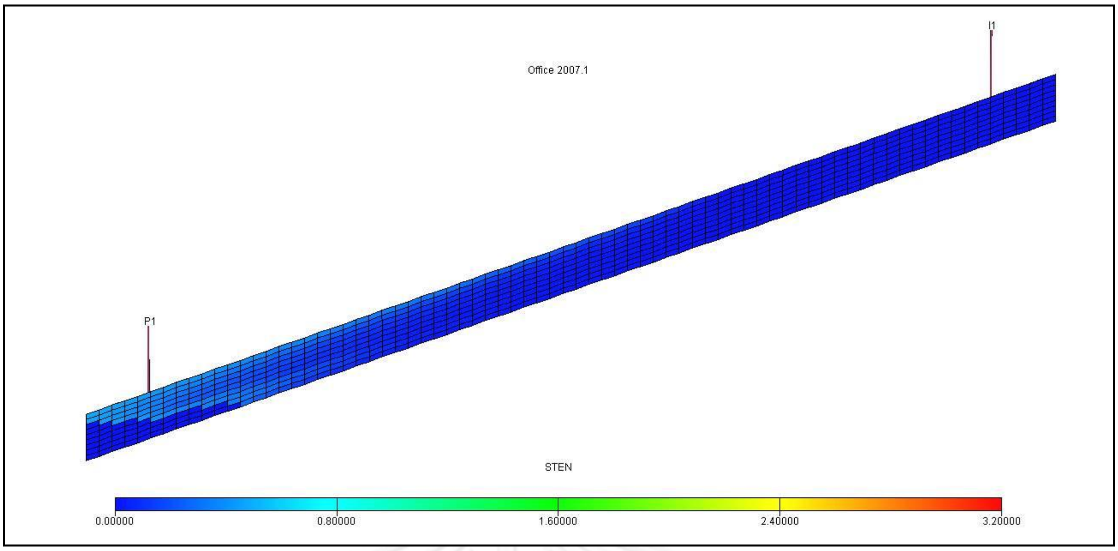


Figure 5. 53: Interfacial tension (dyne/cm) between oil and gas phase of Case I.

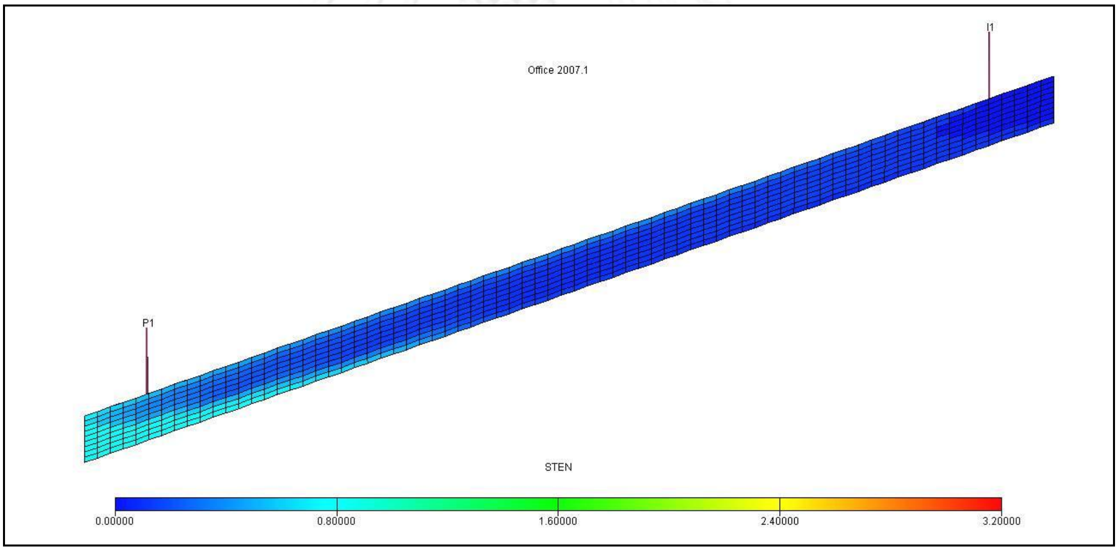


Figure 5. 54: Interfacial tension (dyne/cm) between oil and gas phase of Case II.

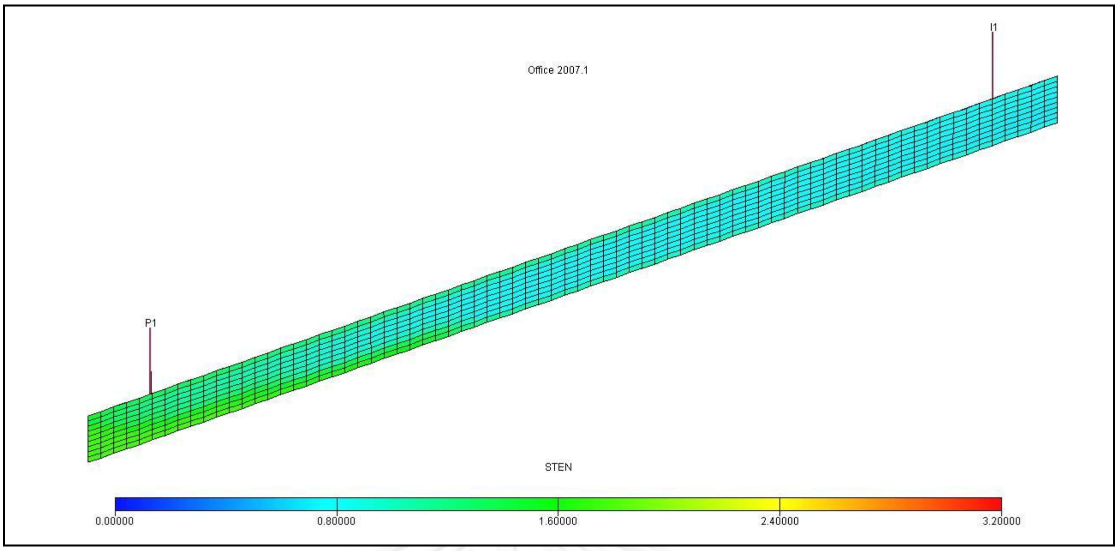


Figure 5. 55: Interfacial tension (dyne/cm) between oil and gas phase of Case III.

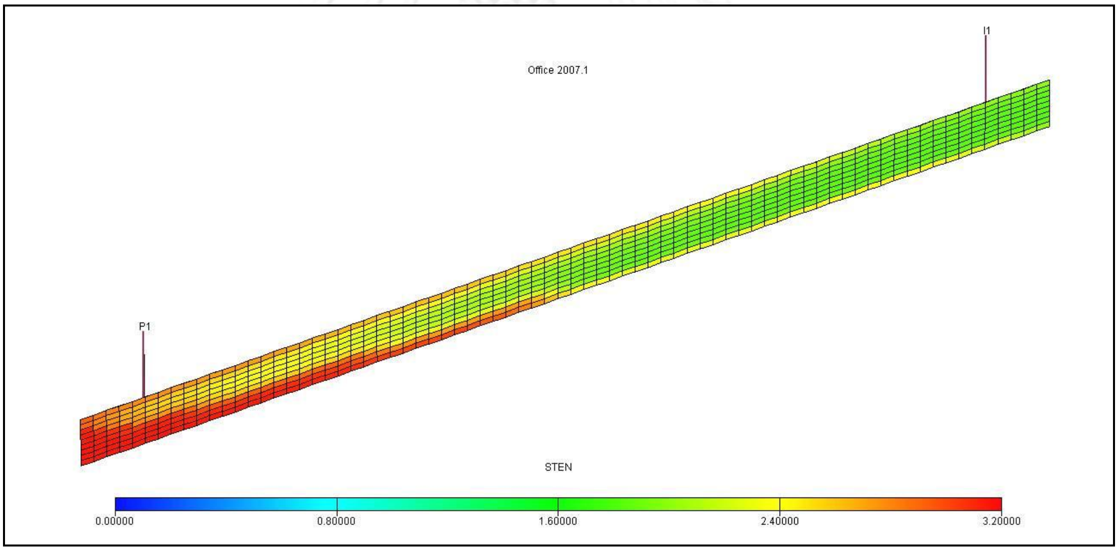


Figure 5. 56: Interfacial tension (dyne/cm) between oil and gas phase of Case IV.

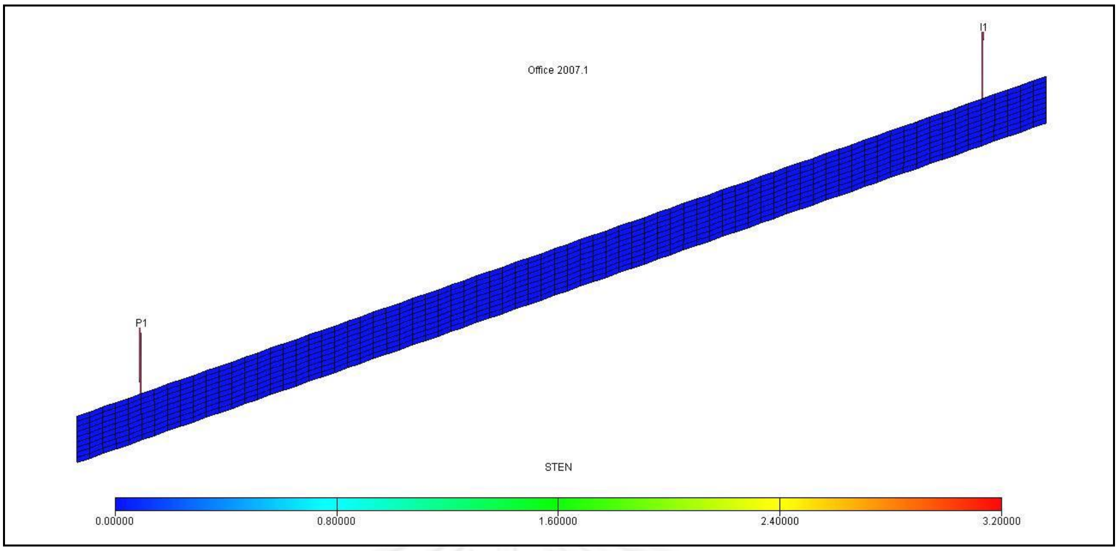


Figure 5. 57: Interfacial tension (dyne/cm) between oil and gas phase of Case V.

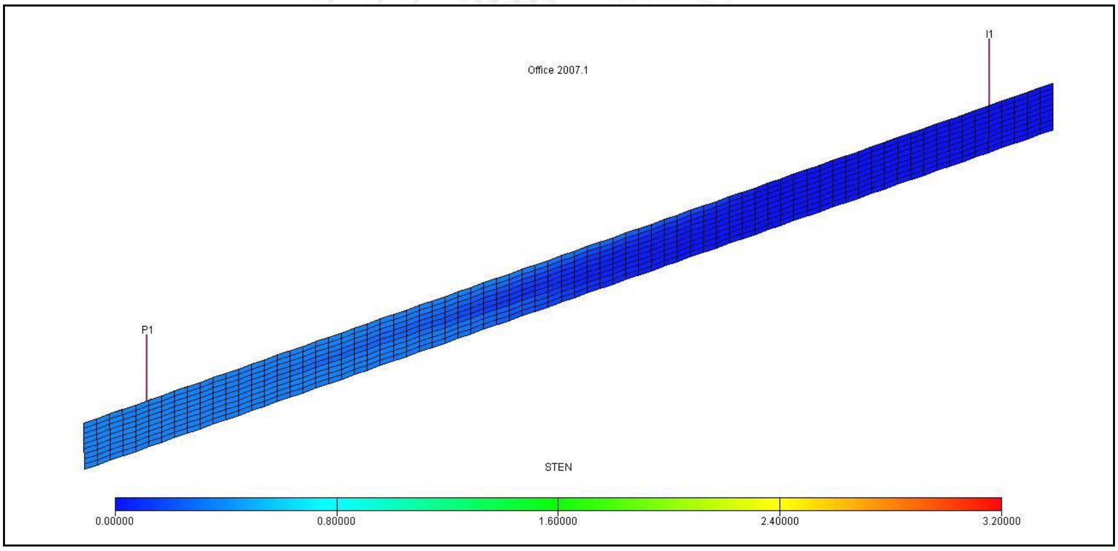


Figure 5. 58: Interfacial tension (dyne/cm) between oil and gas phase of Case VI.

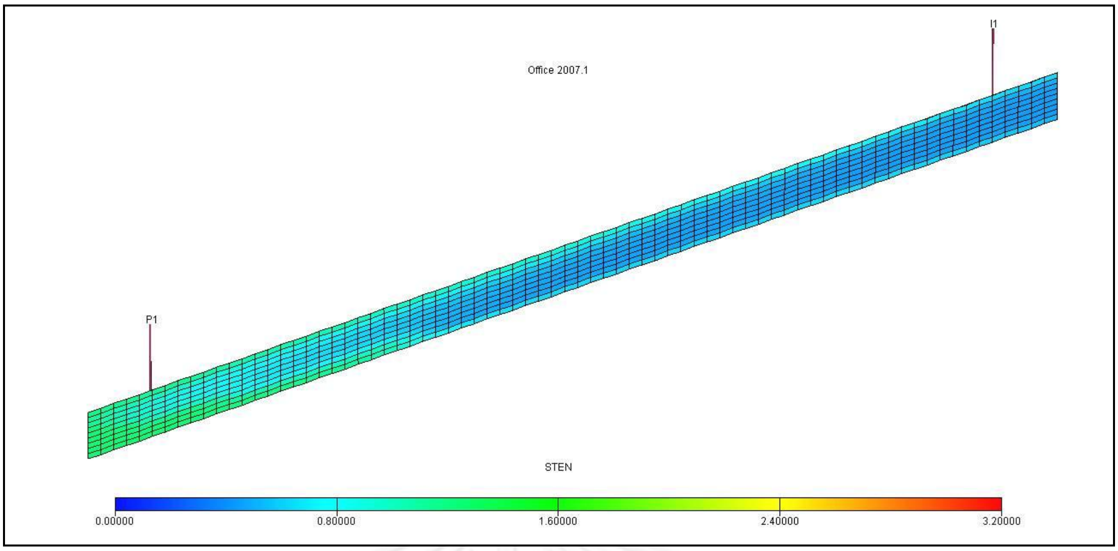


Figure 5. 59: Interfacial tension (dyne/cm) between oil and gas phase of Case VII.

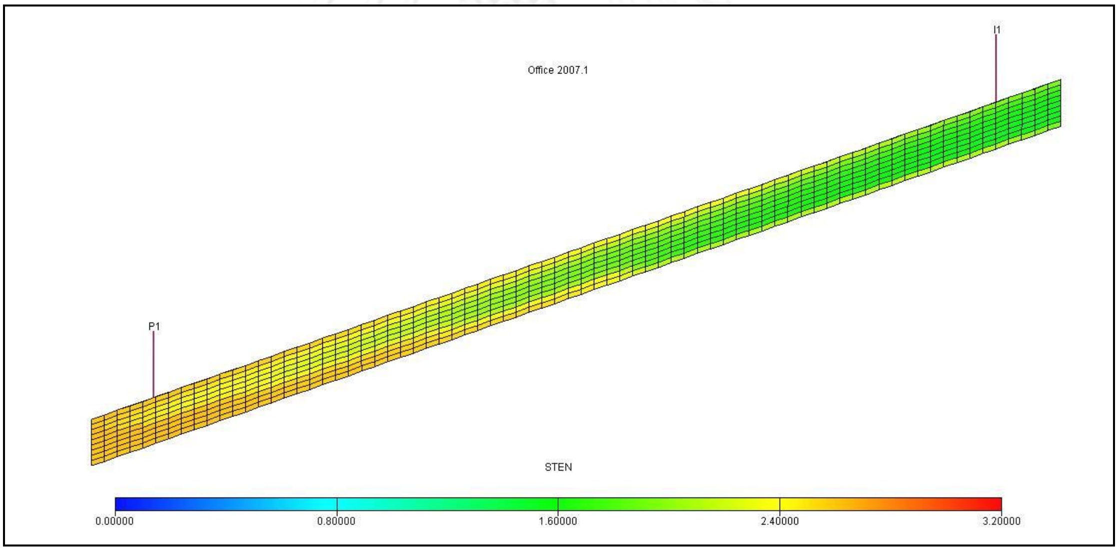


Figure 5. 60: Interfacial tension (dyne/cm) between oil and gas phase of Case VIII.

5.3.5 Partial Pressure Maintenance by Re-Injection of Produced Gas

For a marginal oil field, recovered solution gas at the surface may not be enough to create a long term sales contract with a local buyer. Therefore, produced gas is used to inject back into the reservoir for pressure maintenance.

In this study section, we assume that twenty percent of produced gas rate is loss in the gas processing system, so eighty percent of produced gas rate is re-injected at the updip injector. Thus, the injection rate depends on the production rate. Recycling of produced gas is actually a non-steady stage gasflooding because the reservoir pressure continuously declines, unlike fully pressure maintenance cases in which we try to keep the reservoir pressure constant throughout the production life. We simulate two cases of moderately and very volatile oil by assigning initial oil production rate equal to thousand barrels per day in order to compare with natural depletion and full pressure maintenance schemes in term of recovery performance. Table 5.24 shows simulation constraints while Table 5.25 shows simulation results.

From results in Table 5.25, very volatile oil case can recover oil faster and a little greater than moderately volatile oil but required higher gas injection rate and amount. This is because higher oil volatility has a better performance for solution gas expansion, secondary gas cap drive, and achieving miscibility condition. Figures 5.61 and 5.62 show a production and injection profiles. Figures 5.63 and 5.64 demonstrate recovery performance by showing oil saturation profiles in the X-Z plane of moderately and very volatile oil, respectively. For both moderately and very volatile oil, we can see that after three years of production, secondary gas cap occurs in the reservoir and is connected with gasflood front, which results in a preferred flow channel of injected gas to reach the producer faster than expected. Thus, this is a disadvantage of not controlling reservoir pressure to be above the bubble point pressure.

Table 5. 24: Constraints for partial pressure maintenance.

Maximum reservoir volume production rate (STB/day)	Maximum gas injection rate	Maximum gas injection pressure (psia)	Abandonment oil production rate (STB/day)	Minimum THP (psia)
1,000	80 % of gas production rate	7,037	50	514.7

Table 5. 25: Simulation results of partial pressure maintenance.

Degree of oil volatility	Q_o (STB/day)	Avg. G_i (MMscfd)	N_p (MSTB)	G_p (BCF)	Cum G_i (BCF)	Oil RF (%)	Field life (days)
Moderately	1,000	3.15	2,408	16.90	13.52	65.60	4,289
Very	1,000	6.38	1,777	23.19	18.56	67.78	2,909

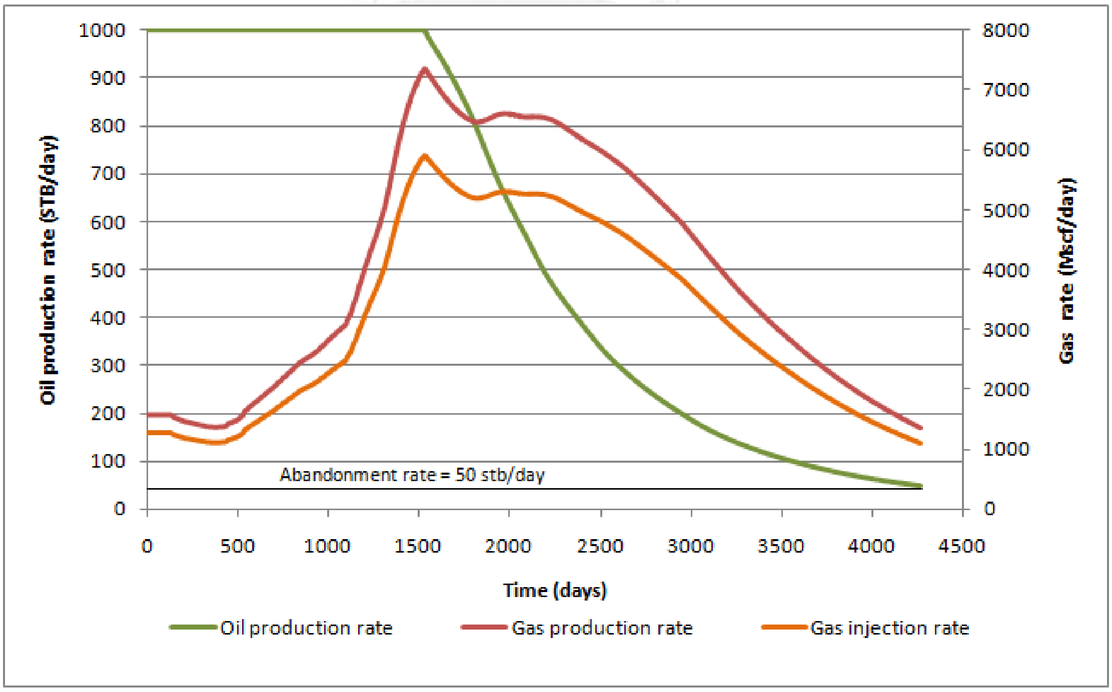


Figure 5. 61: Oil and gas production profile of moderately volatile oil case (PPM).

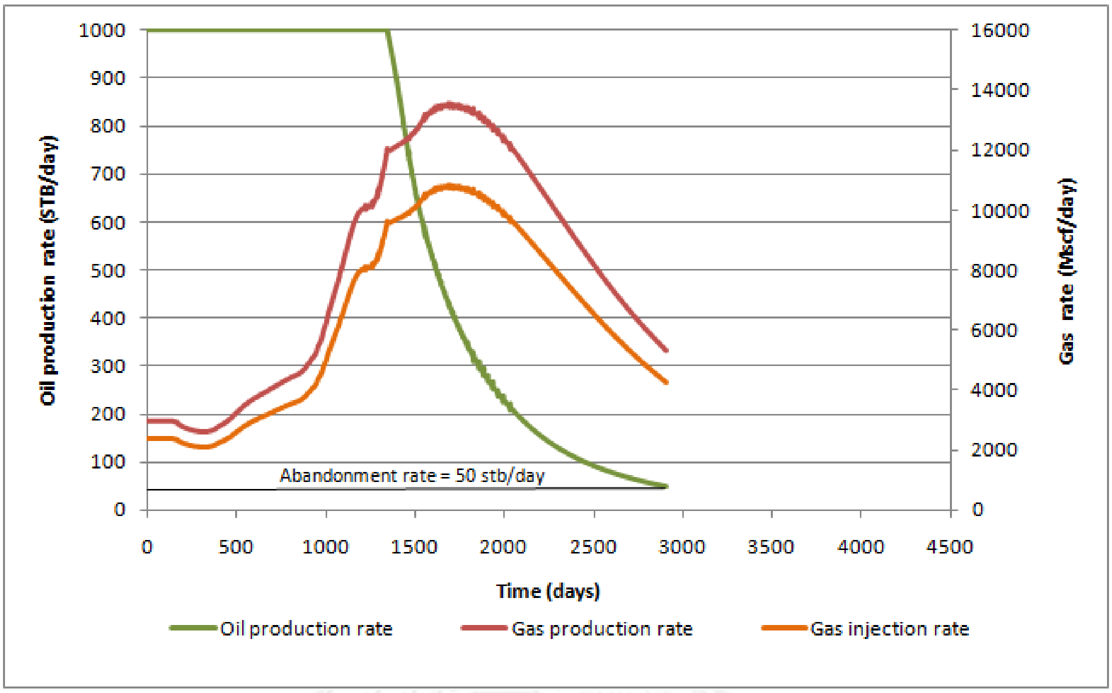
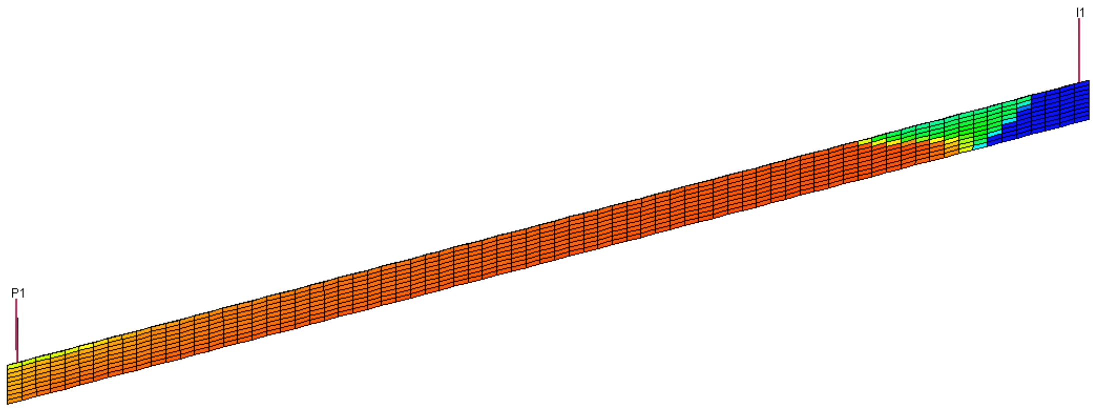
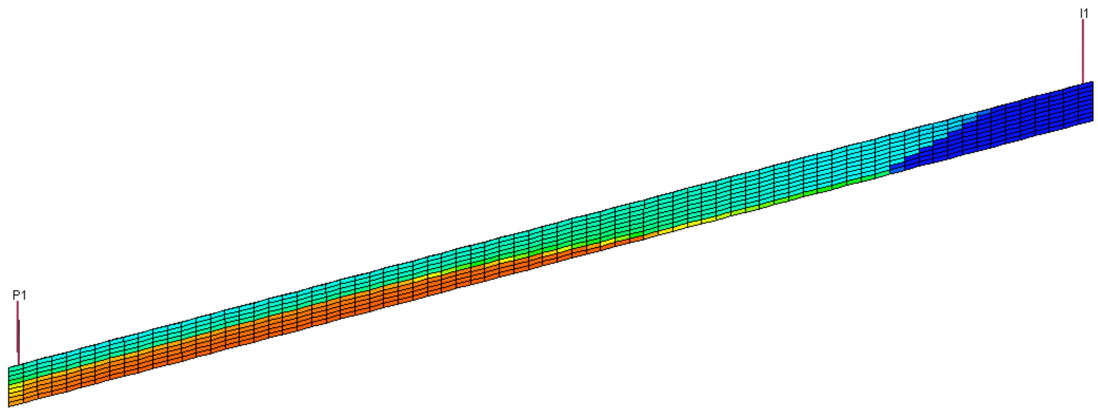


Figure 5. 62: Oil and gas production profile of very volatile oil case (PPM).



(a) 1 year after production.



(b) 3 years after production.

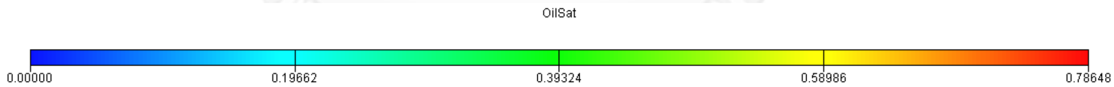
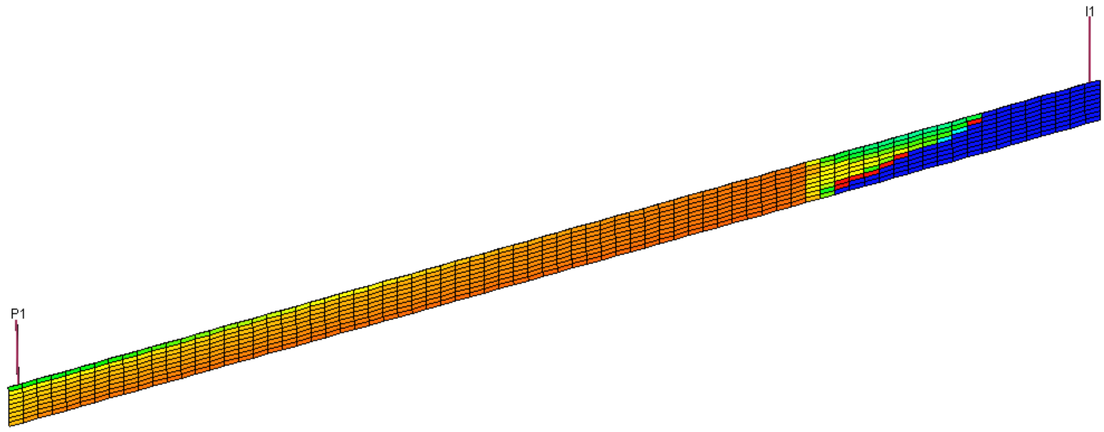
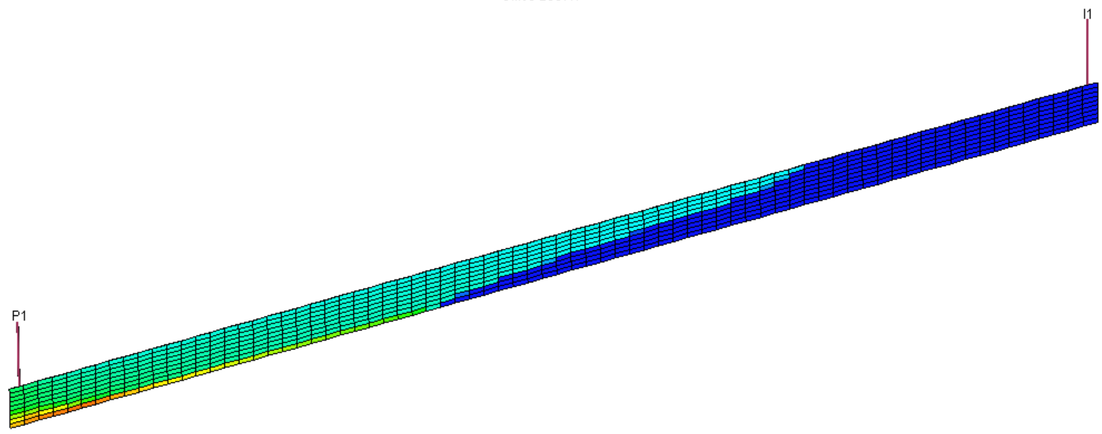


Figure 5. 63: Oil saturation profile in the X-Z plane for partial pressure maintenance (moderately volatile oil).



(a) 1 year after production.



(b) 3 years after production.

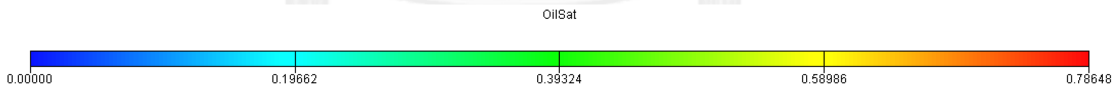


Figure 5. 64: Oil saturation profile in the X-Z plane for partial pressure maintenance (very volatile oil).

5.4 Water Alternating Gas (WAG) Flooding Performance

From simulation results of waterflooding and gasflooding, we know that gasflooding can yield very high displacement efficiency while water flooding has a better sweep efficiency. Therefore, in order to improve oil recovery efficiency of full pressure maintenance scheme, water alternating gas injection is studied.

5.3.6 Effect of Different WAG Ratio

In this study, we vary injection ratio of gas and water so called WAG ratio. In ECLIPSE, this ratio can be controlled by injection period of gas and water in days, months or years. After obtaining the optimum WAG ratio, we further investigate time to initiate WAG at different percentages of pressure depletion, similar to water and gasflooding sections.

Details and constraints of water alternating gas study are depicted in Tables 5.26 and Table 5.27. For WAG study, we assume the cut-off for economic oil production rate to be 200 STB/day due to high operating cost. Table 5.28 summarizes simulation results which indicate that when using WAG ratio of 1:1, we obtain the highest oil recovery. We can see from Table 5.28, Figures 5.65 and 5.66 that if the WAG ratio is high, the production performance behaves like water flooding, and on the contrary, production performance behaves like gasflooding when WAG ratio is small. For high WAG ratio (cases I, II, VI and VII), injected gas breakthrough time is greatly delayed compared to standalone gas injection. However, waterflood front still breaks through quickly after the injected gas has reached the producer due to high portion of water injection duration. So these cases have higher cumulative water production and able to hold longer plateau of oil production rate. For low WAG ratio (cases III, IV, IX and X), injected gas breaks through quite early but still slower than standalone gas injection. So these cases have higher cumulative gas production with shorter plateau of oil production rate. However, for low WAG ratio cases, if we are able to lower economic cut-off of oil rate, using low WAG ratio will recover more oil production due to more miscible gas dissolving residual oil after the flood front.

Figures 5.65 and 5.66 present the production profiles for WAG ratio of 1:1 case. We can see that the oil production rate fall off from plateau level when injected gas breakthrough and the oil production rate drop again when injected water breakthrough at late time. Figure 5.67 shows injection profile. Water and gas are injected alternatively at the same injection period for this case. Figures 5.68 and 5.69 show the pressure profiles. The reservoir pressure is maintained above the bubble point pressure. The injection pressure profiles look like saw-tooth geometry because water injection requires higher injection pressure than gas injection at the same injected pore volume.

In summary, implementation of water alternating gas helps improve oil recovery and delay the breakthrough time of injected fluid. The optimum WAG ratio depends on an economic cut-off of oil production rate. Low WAG ratio tends to yield higher oil recovery but injected gas breaks through early which causes an oil rate to decline rapidly while the high WAG ratio helps delay early breakthrough of injected gas and prolong a plateau of oil production rate as can be seen from Figures 5.70 and 5.71.

Table 5. 26: Case details for different WAG ratios.

Case	Degree of oil volatility	WAG ratio (water:gas, months)	W_i (STB/day)	G_i (MMscfd)
Case I	Moderately	2:1	1,824	2.85
Case II	Moderately	3:1	1,824	2.85
Case III	Moderately	1:1	1,824	2.85
Case IV	Moderately	1:2	1,824	2.85
Case V	Moderately	1:3	1,824	2.85
Case VI	Very	2:1	1,824	2.85
Case VII	Very	3:1	1,824	2.85
Case VIII	Very	1:1	1,824	2.85
Case IX	Very	1:2	1,824	2.85
Case X	Very	1:3	1,824	2.85

Table 5. 27: Case constraints for different WAG ratios.

Degree of oil volatility	Maximum reservoir volume production rate (RB/day)	Maximum oil production rate at standard condition (STB/day)	Maximum injection pressure (psia)	Abandonment oil production rate (STB/day)	Minimum THP (psia)
Moderately	1,800	989	7,037	200	514.7
Very	1,800	706	7,037	200	514.7

Table 5. 28: Simulation results for different WAG ratios.

Case	N_p (MSTB)	G_p (BCF)	W_p (MSTB)	Cum. W_i (MSTB)	Cum. G_i (BCF)	Oil RF (%)	Field life (days)
Case I	3,106	6.36	27.47	4,449	3.48	84.61	3,659
Case II	2,974	5.44	40.99	4,487	2.35	81.03	3,284
Case III	3,378	9.9	7.38	4,518	7.17	92.05	4,992
Case IV	3,159	10.31	0	3,097	9.42	86.05	5,002
Case V	3,129	10.56	0	2,349	10.83	85.26	5,088
Case VI	2,340	8.7	39.86	4,802	3.65	89.27	3,913
Case VII	2,221	7.35	37.58	4,656	2.45	84.71	3,411
Case VIII	2,455	12.32	6	4,737	7.38	93.67	5,185
Case IX	2,266	10.79	0	2,774	8.69	86.43	4,571
Case X	2,347	12.2	0	2,349	10.83	89.53	5,086

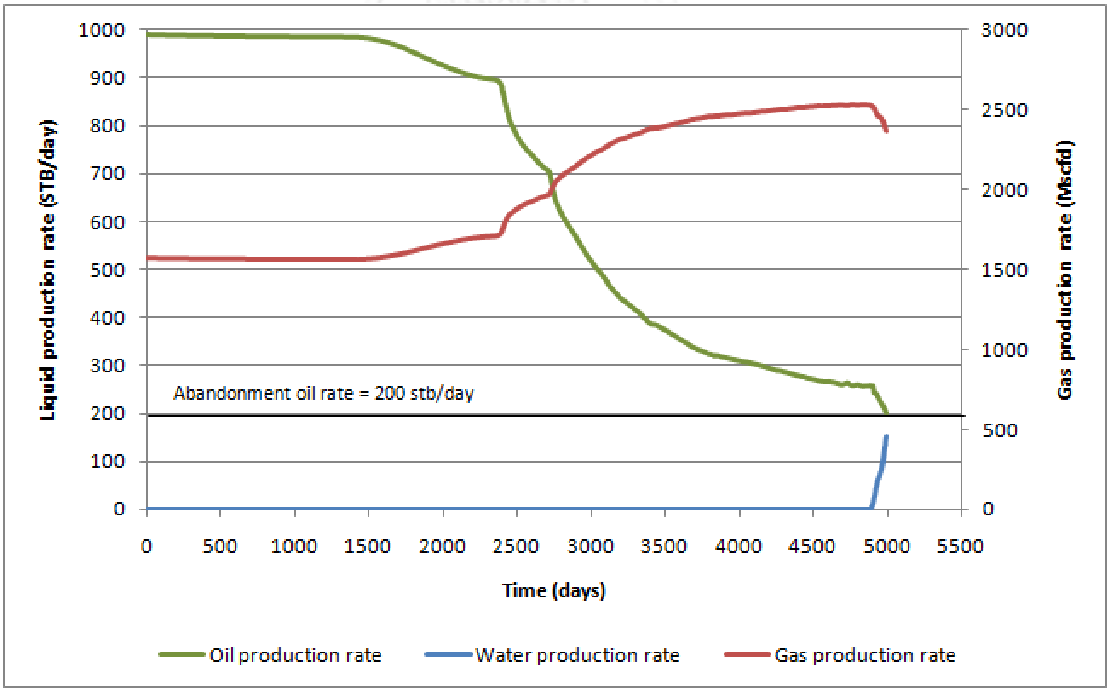


Figure 5. 65: Oil, gas and water production profiles of moderately volatile oil (WAG ratio =1:1).

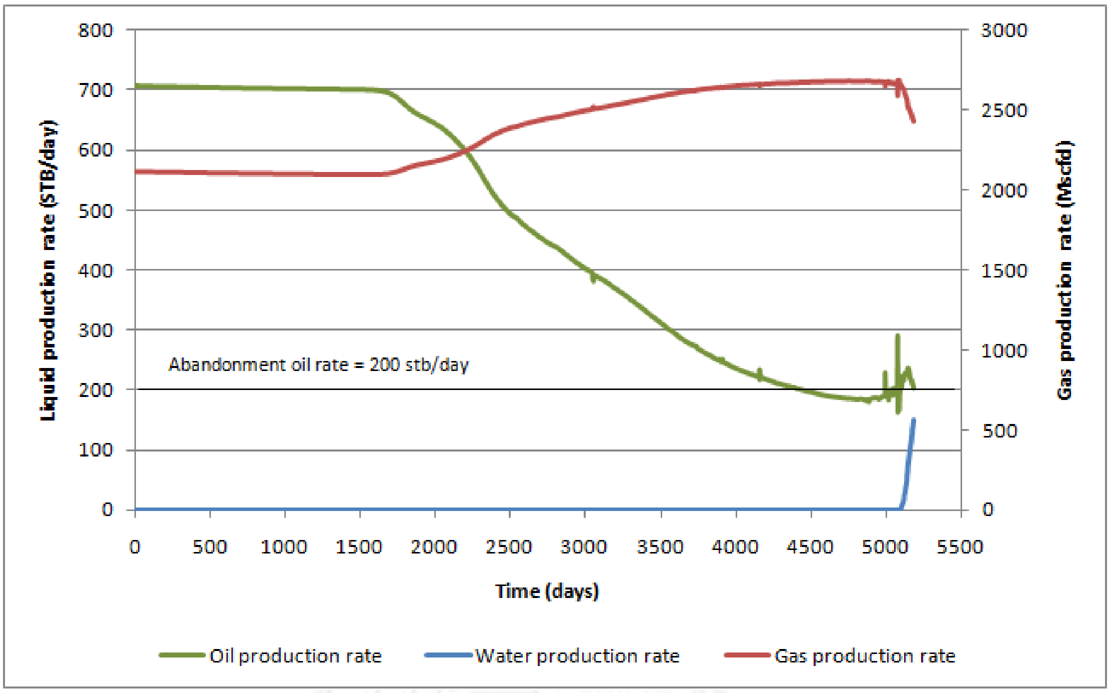


Figure 5. 66: Oil, gas and water production profiles of very volatile oil (WAG ratio =1:1).

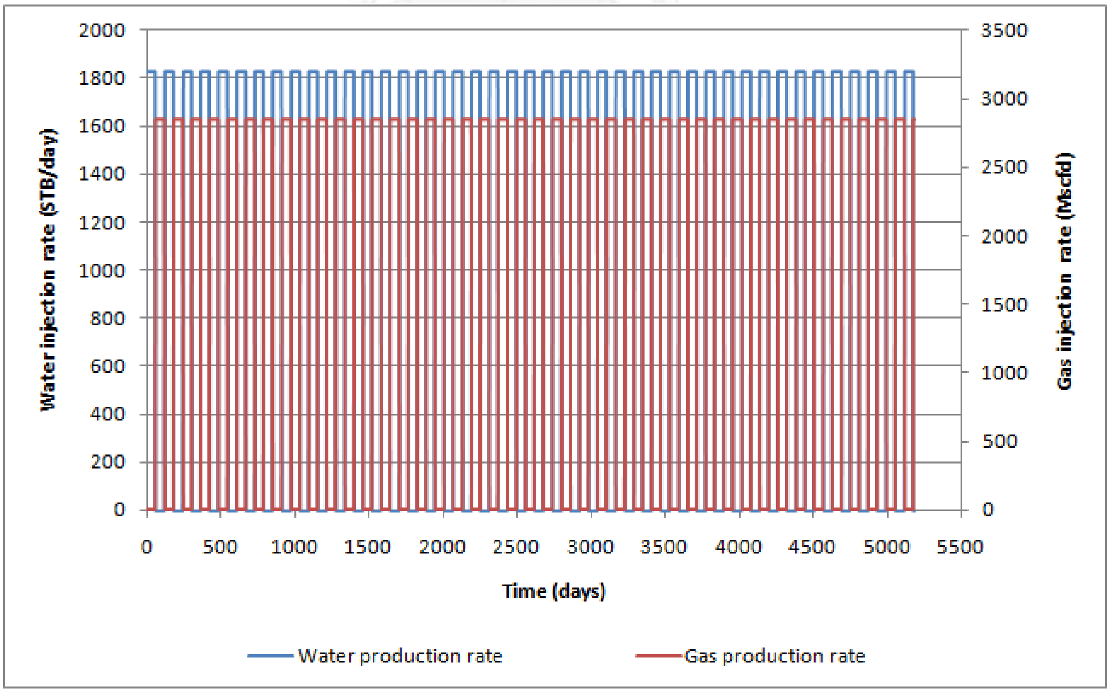


Figure 5. 67: Water and gas injection profiles (WAG ratio = 1:1).

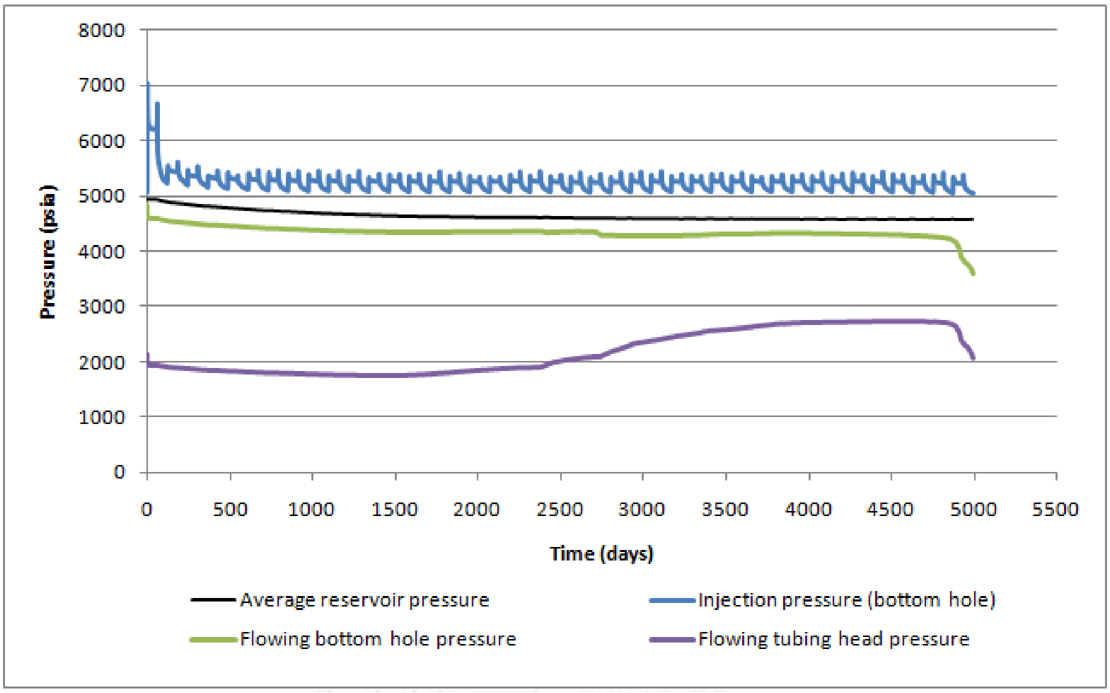


Figure 5. 68: Pressure profiles of moderately volatile oil (WAG ratio =1:1).

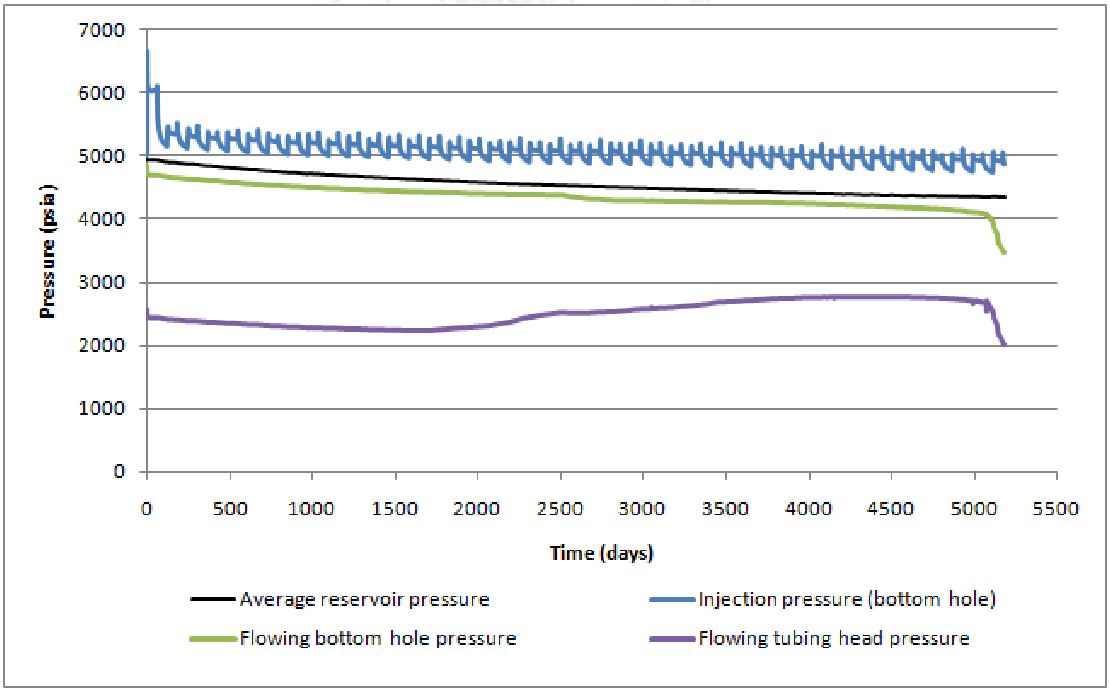


Figure 5. 69: Pressure profiles of very volatile oil (WAG ratio =1:1).

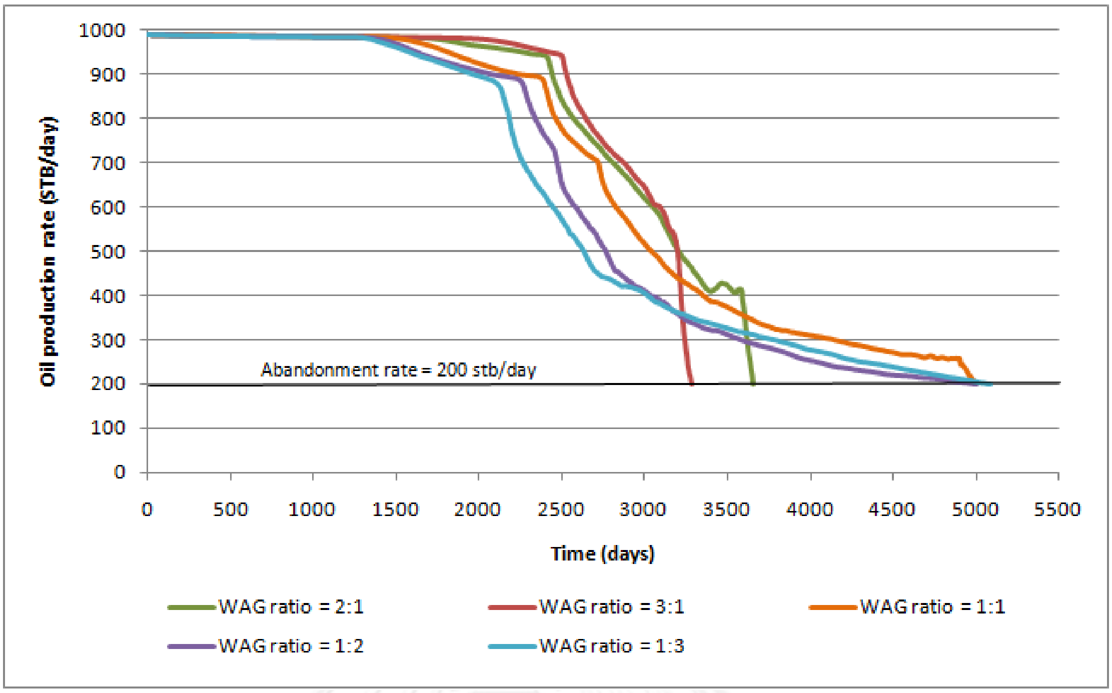


Figure 5. 70: Oil production rate for different WAG ratios (moderately volatile oil).

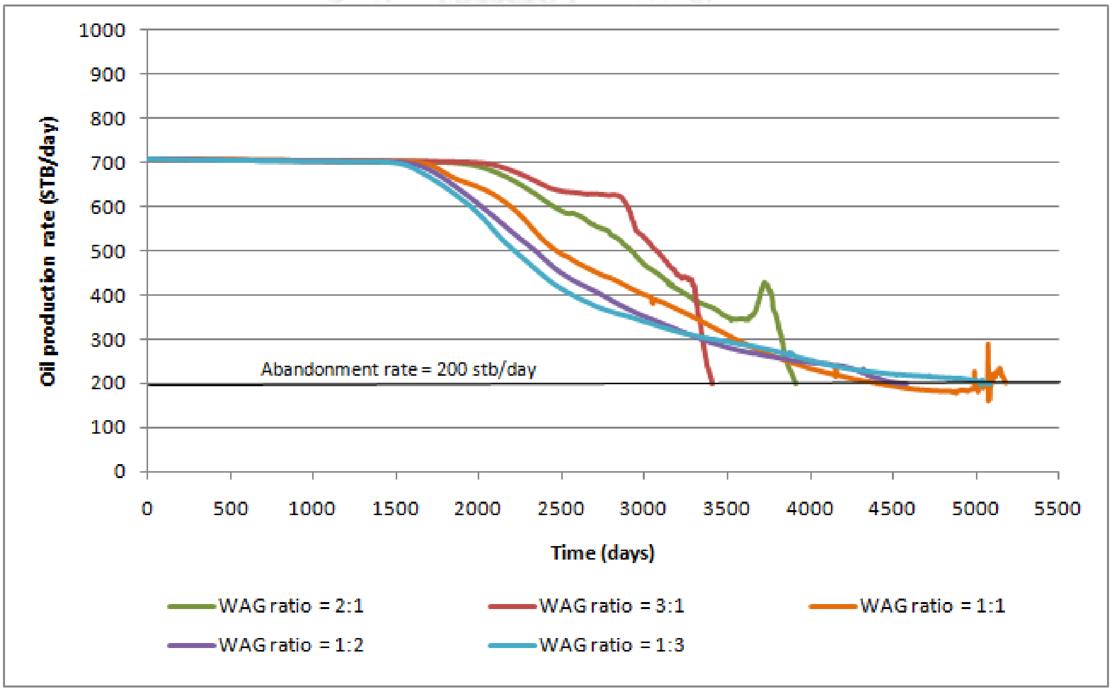


Figure 5. 71: Oil production rate for different WAG ratios (very volatile oil).

5.3.7 Effect of Time to Initiate WAG

In this section, effect of time to initiate WAG is studied by using WAG ratio equal to 1:1, which yields the highest oil recovery factor as studied in Section 5.4.1. The production constraints still remain the same as shown in Table 5.27. Table 5.29 presents cases for different percentages of pressure depletion from the initial reservoir pressure.

Table 5.30 shows the simulation results. In term of total oil recovery, the case which we start WAG since the first production day yields the highest oil recovery. This aligns with the results from water and gasflooding study. The main cause of this behavior is from early breakthrough of injected fluid due to lower oil mobility (higher oil viscosity, lower relative permeability to oil) at lower reservoir pressure when flooding is started. However, from this investigation, we found that all cases have similar values of cumulative gas and water injection. This implies that we require similar operating cost for injection even though we start the flooding late but if we include the cost for handling and processing of produced gas and water, the case when we have late starting time, has to spend more money to deal with higher amount of produced injected fluid. In summary, we should start doing WAG as soon as possible to maximize oil recovery.

Table 5. 29: Case details for different times to start WAG.

Case	Degree of oil volatility	Average reservoir pressure when WAG is started (psia)	Percentage of pressure depletion when WAG is started	Production period before WAG is started (days)
Case XI	Moderately	4,950	0	0
Case XII	Moderately	3,990	20	117
Case XIII	Moderately	3,218	35	420
Case XIV	Moderately	2,475	50	914
Case XV	Very	4,950	0	0
Case XVI	Very	3,990	20	183
Case XVII	Very	3,218	35	580
Case XVIII	Very	2,475	50	1,172

Table 5. 30: Simulation results for different times to start WAG.

Case	N_p (MSTB)	G_p (BCF)	W_p (MSTB)	Cum. W_i (MSTB)	Cum. G_i (BCF)	Oil RF (%)	Field life (days)
Case XI	3,379	9.9	7.38	4,518	7.17	92.05	4,992
Case XII	3,196	8.36	0	4,027	6.14	87.07	4,474
Case XIII	2,959	9.48	1.38	4,199	6.64	80.63	5,052
Case XIV	2,752	9.24	67.8	4,117	6.21	74.97	5,346
Case XV	2,456	12.32	6	4,737	7.38	93.67	5,185
Case XVI	2,322	10.92	0	4,189	6.60	88.56	4,793
Case XVII	2,118	10.38	0	4,020	6.02	80.82	4,898
Case XVIII	1,927	11.30	5.372	4,190	6.37	73.50	5,698

5.5 Comparison of IOR Schemes

Oil recovery performance and economic perspective are considered together in this section. The representative cases from natural depletion, waterflooding, gas flooding, partial pressure maintenance, and water alternating gas, are selected for comparison as shown in Table 5.31. For natural depletion, a thousand barrel per day of oil production rate case is selected in order to compare with the others cases that use similar range of oil production rate. For pressure maintenance production schemes, the case which we start pressure maintenance since first day of production are selected because they yield the highest oil recovery.

Table 5. 31: Case details for each production scheme from the studies..

Cases	**Production scheme**	**Description**
Case I	Natural depletion	Using 2 producers with 1,000 STB/day of oil production rate.
Case II	Waterflooding	Base case of waterflooding with production rate equal to 1,800 RB/day or 989 STB/day and 706 STB/day for moderately and very volatile oil, respectively.
Case III	Gasflooding	Base case of gasflooding using CO_2 as injected gas with production rate equal to 1,800 RB/day or 989 STB/day and 706 STB/day for moderately and very volatile oil, respectively.
Case IV	Partial pressure maintenance (PPM) by re-injection of produced gas	Using 80% of produced gas rate as an injected gas rate in order to partially maintain the reservoir pressure. Oil production rates are the same as those in water and gas flooding.
Case V	Water alternating gas (WAG)	Injection of gas (CO_2) and water alternately with 1:1 ratio. Oil production rates are the same as those in water and gas flooding.

5.3.8 Recovery Performance Comparison

Tables 5.32 and 5.33 present the simulation results for each production scheme. It is obvious that when using pressure maintenance production schemes, oil recovery can be increased up to approximately four times from natural depletion. For partial pressure maintenance, we obtained total oil recovery close to the one in waterflooding case but it takes a little bit longer time for production life. So, if we don't have a gas sales opportunity, doing PPM by re-injection of produced gas is an attractive option to manage gas production at surface and reduce gas treatment facility cost. When we compare between water and gas flooding, gasflooding can recover more oil in this study because displacement efficiency is higher. However, gasflooding has poorer sweep efficiency and can cause a premature breakthrough faster than waterflooding especially when the reservoir has a high permeability steak. And in this study, when using numerical simulation, we can only simulate macroscopic displacement of oil using relative permeability tables. If we consider microscopic displacement efficiency of gasflooding, we may not obtain a very low or zero residual oil saturation after gasflood front. Hence, recovery performance of gas flooding can be overestimated from numerical simulation and we need to have actual lab results and core flooding to QC a simulation results. For WAG production scheme, it yields the highest oil recovery when compared with the other schemes since it combines an advantage of gas and water flooding together.

Table 5. 32: Simulation results for different production schemes of moderately volatile oil.

Production schemes	N_p (MSTB)	G_p (BCF)	W_p (MSTB)	Cum. W_i (MSTB)	Cum. G_i (BCF)	Oil RF (%)	Field life (days)
Natural depletion	884	3.82	0	0	0	24.09	1,063
Waterflooding	2,532	4.02	1,096	5,723	0	68.98	3,179
Gasflooding	3,174	9.3	0	0	12.86	86.47	4,745
PPM	2,408	16.90	0	0	13.52	65.60	4,289
WAG	3,379	9.9	7.38	4,518	7.17	92.05	4,992

Table 5. 33: Simulation results for different production schemes of very volatile oil.

Production schemes	N_p (MSTB)	G_p (BCF)	W_p (MSTB)	Cum. W_i (MSTB)	Cum. G_i (BCF)	Oil RF (%)	Field life (days)
Natural depletion	612	5.48	0	0	0	23.34	722
Waterflooding	1,832	5.48	486	5,183	0	69.89	2,879
Gasflooding	2,407	10.99	0	0	13.37	91.83	4,676
PPM	1,777	23.19	0	0	18.56	67.78	2,909
WAG	2,456	12.32	6	4,737	7.38	93.67	5,185

Oil recovery factor is plotted versus cumulative volume of injected fluid for each production scheme as shown in Figures 5.72 and 5.73. The objective of such comparison is to mainly compare flooding efficiency (displacement and sweep) at the same pore volume of injected fluid. We can see that before the injected fluid reaches the producer (before the slope changes from linear to curvature) and the average reservoir pressure is still above the bubble point pressure, water and gas flooding have similar displacement and sweep efficiency. This is because mobility ratio for miscible gas and water flooding is less than 1. For water flooding, low oil viscosity from characteristic of volatile oil causes favorable mobility ratio while gas flooding creates a miscibility condition which results in a positive effect from altered oil relative permeability curve (k_{ro} is approximately equal to 1).

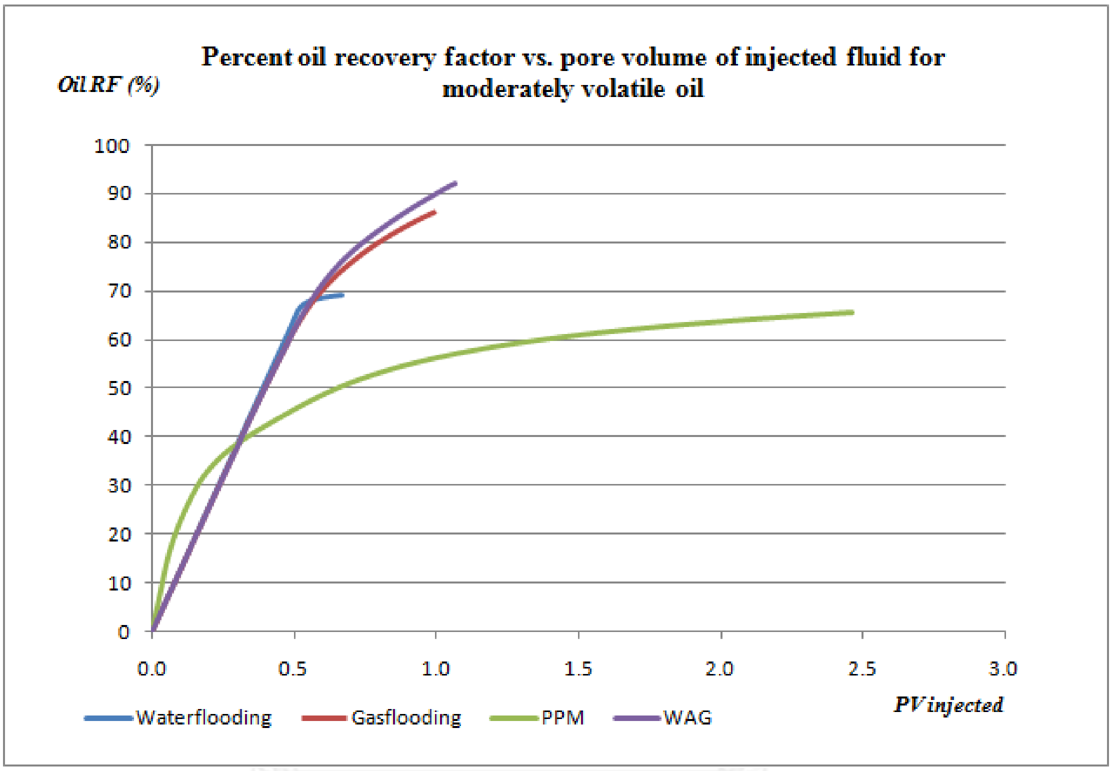


Figure 5. 72: Oil recovery factor vs. pore volume of injected fluid for moderately volatile oil.

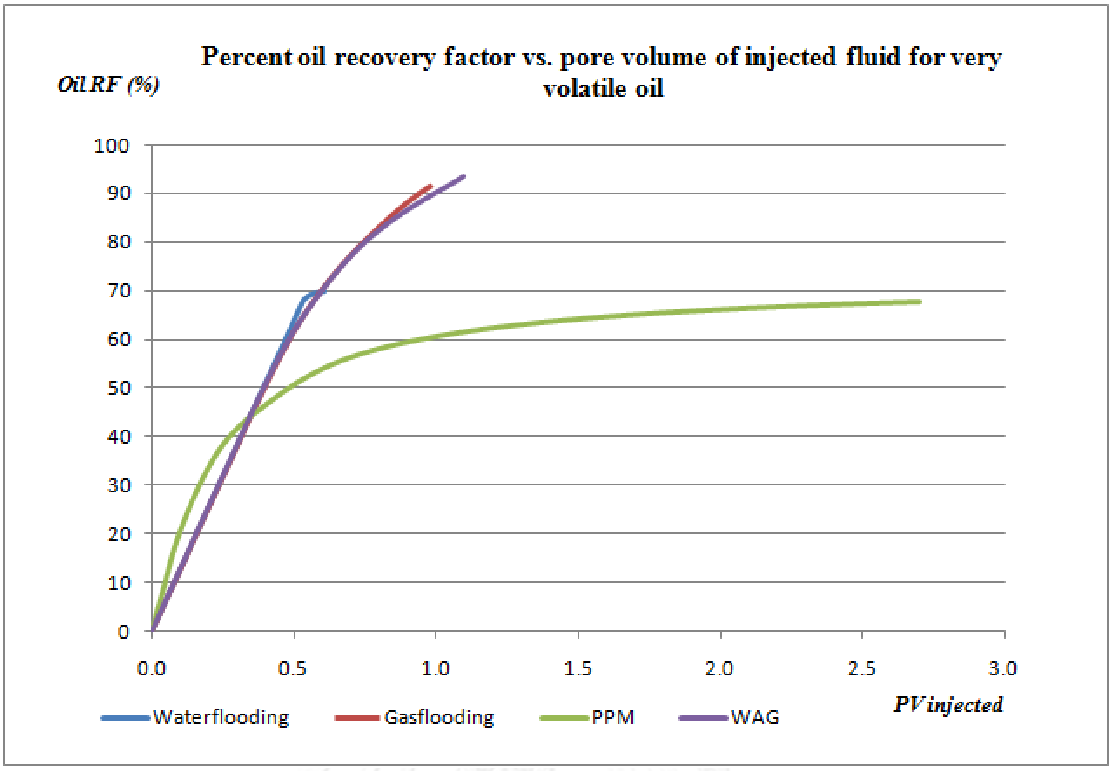


Figure 5. 73: Oil recovery factor vs. pore volume of injected fluid for very volatile oil.

5.3.9 Economic Comparison

The economic point of view is an important part for every decision making related to oil and gas development. Many times an alternative which provides the best recovery performance does not yield the best financial performance.

In this section, we estimate and compare project economic for each production scheme listed in Table 5.31 for both moderately and very volatile oil. Since we mainly focus on oil, we won't include the benefit of solution gas production in this study. We assume that our oil field is too marginal to have a gas sales contract with a local buyer. Cost assumptions are listed in Tables 5.34 and 5.35. All cases are calculated using Thai-I (PITA III) fiscal and tax regime which is currently an active law for several operating area in Gulf of Thailand. The oil price is assumed to be $100/STB.

Table 5. 34: Assumption of Capital Expenditure (CAPEX).

Item	CAPEX		Note & Reference
	Water flood	Gas flood	
Platform	20 \$MM	20 \$MM	Estimated based on GOT standard cost
Pipeline	10 \$MM	10 \$MM	Estimated based on GOT standard cost
CO_2 processing facilities (824,767\$/MMscfd capacity)	-	2.47 \$MM (from 3 MMscfd capacity)	Wyoming's Miscible CO_2 Enhanced Oil Recovery Potential from Main Pay Zones: An economic Scoping Study [32]
Gas compressor	-	3 \$MM	Estimated based on GOT standard cost
CO_2 Metering station	-	0.25 \$MM	Wyoming's Miscible CO_2 Enhanced Oil Recovery Potential from Main Pay Zones: An economic Scoping Study [32]
Well cost (3.5 \$MM/well)	10.5 \$MM	7 \$MM	Estimated based on GOT standard cost Waterflood: 3 wells (1 injector, 1 producer and 1 disposal well) Gasflood: 2 wells (1 injector, 1 producer well)
Water pumping equipments	1 \$MM	-	EIA (2010). "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009". [33]

Table 5. 35: Assumption of Operational Expenditure (OPEX).

Item	OPEX		Note & Reference
	Water flood	Gas flood	
CO_2 cost	-	\$2.17/Mscf	The Economic Contribution of CO_2 Enhanced Oil Recovery in Wyoming's Economy [34]
Processing cost	> Oil: \$3.75/barrel > Gas \$1.61/Mscf	> Oil: \$3.75/barrel > Gas \$1.61/Mscf	EIA (2010). "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009". [33]
Produced water handling cost	\$3/barrel	-	Estimated
Fixed cost: man power and etc.	\$ 300 k /yr	\$ 300 k /yr	Estimated based on GOT standard cost

5.5.2.1 Economic Analysis for Natural Depletion of Moderately Volatile Oil Case

For this case, oil flows naturally with 1,000 STB/day with 2 production wells. The field life is approximately 3 years. Table 5.36 shows a net cash flow for each year. Investment starts in year zero and production starts in the first year. Economic parameters are presented in Table 5.37. From the results, natural depletion case is considered as economically viable option. For the next IOR cases, we will consider incremental value from this natural flow case.

Table 5. 36: Cash flow table for natural depletion of moderately volatile oil case (million $).

Year	CAPEX	OPEX	Sale revenue	Royalty (12.5%)	Income tax (35%)	Remit. tax (23.08%)	Domestic sales tax credit	Net cash flow
0	37.00	-	-	-	-	-	-	(37.00)
1	-	2.67	36.50	(4.56)	(7.65)	(3.28)	2.28	20.62
2	-	4.51	36.50	(4.56)	(7.01)	(3.01)	2.28	19.70
3	-	3.17	15.43	(1.93)	(1.02)	(0.44)	0.44	9.30

Table 5. 37: Economic parameters for natural depletion of moderately volatile oil case.

As of year zero		
Parameter	Discount rate	Discounted value
NPV	10%	$4.77 million
DPI	10%	1.14
IRR	N/A	18.5%
NPI	10%	$35.28 million

5.2.2.2 Economic Analysis for Natural Depletion of Very Volatile Oil Case

For this case, oil flow naturally with 1,000 STB/day with 2 producer wells. The field life is approximately 2 years. Table 5.38 shows a net cash flow for each year. Investment starts in year zero and production starts in the first year. Economic parameters are presented in Table 5.39. From the results, natural depletion of very volatile oil case is not economic if we use a discount rate of 10 %. This is because total amount of oil recovered is too small for this project scale.

Table 5. 38: Cash flow table for natural depletion of very volatile oil case (million $).

Year	CAPEX	OPEX	Sale revenue	Royalty (12.5%)	Income tax (35%)	Remit. tax (23.08%)	Domestic sales tax credit	Net cash flow
0	37.00	-	-	-	-	-	-	(37.00)
1	-	3.82	36.50	(4.56)	(7.25)	(3.11)	2.28	20.04
2	-	7.83	24.70	(3.09)	(2.24)	(0.96)	0.96	11.55

Table 5. 39: Economic parameters for natural depletion of very volatile oil case.

As of year zero		
Parameter	Discount rate	Discounted value
NPV	10%	$(8.80) million
DPI	10%	0.75
IRR	N/A	(10.8)%
NPI	10%	$35.28 million

5.5.2.3 Economic Analysis for Waterflooding of Moderately Volatile Oil Case.

For waterflooding, we require a pump and water disposal well as an incremental CAPEX. And from cash flow table, we stop waterflooding at the end of year eight since the net cash flow becomes negative in year nine as presented in Table 5.40. When we compare with natural depletion case, we gain more profit from doing waterflood with attractive increment in NPV as shown in Tables 5.41 and 5.42.

Table 5. 40: Cash flow table for waterflooding of moderately volatile oil case (million $).

Year	CAPEX	OPEX	Sale revenue	Royalty (12.5%)	Income tax (35%)	Remit. tax (23.08%)	Domestic sales tax credit	Net cash flow
0	41.50	-	-	-	-	-	-	(41.50)
1	-	2.58	36.11	(4.51)	(7.25)	(3.11)	2.26	20.91
2	-	2.58	36.09	(4.51)	(7.25)	(3.11)	2.26	20.91
3	-	2.58	36.08	(4.51)	(7.24)	(3.10)	2.25	20.90
4	-	2.57	36.06	(4.51)	(7.24)	(3.10)	2.25	20.89
5	-	2.57	36.05	(4.51)	(7.24)	(3.10)	2.25	20.89
6	-	2.57	36.05	(4.51)	(10.14)	(4.35)	2.25	16.74
7	-	2.49	32.84	(4.11)	(9.19)	(3.94)	2.05	15.18
8	-	2.06	5.51	(0.69)	(0.97)	(0.41)	0.34	1.73

Table 5. 41: Economic parameters for waterflooding of moderately volatile oil case.

As of year zero		
Parameter	Discount rate	Discounted value
NPV	10%	$53.18 million
DPI	10%	2.34
IRR	N/A	46.0%
NPI	10%	$39.57 million

Table 5. 42: Incremental benefit from natural depletion case when investing for waterflooding (moderately volatile oil case).

Parameter	Discounted value
Incremental NPV	$48.41 million
Incremental Cost	$4.29 million
DPI	12.28

5.5.2.4 Economic Analysis for Waterflooding of Very Volatile Oil Case

Similar to moderately volatile oil case, doing a waterflood adds more incremental value from natural depletion case. And when we compare with moderately volatile oil case, the benefit in term of money is less because of smaller amount of oil is recovered. But in term of recovery performance, moderately and very volatile oil has similar range of percent oil recovery as mentioned in Section 5.5.1.

Table 5. 43: Cash flow table for waterflooding of very volatile oil case (million $).

Year	CAPEX	OPEX	Sale revenue	Royalty (12.5%)	Income tax (35%)	Remit. tax (23.08%)	Domestic sales tax credit	Net cash flow
0	41.50	-	-	-	-	-	-	(41.50)
1	-	2.51	25.78	(3.22)	(4.11)	(1.76)	1.61	15.79
2	-	2.51	25.77	(3.22)	(4.11)	(1.76)	1.61	15.78
3	-	2.51	25.77	(3.22)	(4.11)	(1.76)	1.61	15.78
4	-	2.51	25.75	(3.22)	(4.10)	(1.76)	1.61	15.77
5	-	2.51	25.75	(3.22)	(4.10)	(1.76)	1.61	15.77
6	-	2.51	25.75	(3.22)	(7.01)	(3.00)	1.61	11.62
7	-	2.48	25.08	(3.14)	(6.81)	(2.92)	1.57	11.30
8	-	1.80	4.96	(0.62)	(0.89)	(0.38)	0.31	1.58

Table 5. 44: Economic parameters for waterflooding of very volatile oil case.

As of year zero		
Parameter	Discount rate	Discounted value
NPV	10%	$29.94 million
DPI	10%	1.76
IRR	N/A	31.4%
NPI	10%	$39.57 million

Table 5. 45: Incremental benefit from natural depletion case when investing for waterflooding (very volatile oil case).

Parameter	Discounted value
Incremental NPV	$38.75 million
Incremental Cost	$4.29 million
DPI	10.03

5.5.2.5 Economic Analysis for Gasflooding of Moderately Volatile Oil Case.

For gas flooding, we simply assume that CO_2 is used continuously during the injection and the CO_2 cost is part of the OPEX. From Table 5.46, we stop gasflooding after sixteen years; otherwise the sale revenue won't cover the operating cost. When we compare economic parameters listed in Table 5.47 with waterflooding case, we found that gasflooding project has similar financial benefit but has lower incremental gain from natural depletion case because in this study, gasflooding yields higher oil recovery but requires higher CAPEX (gas compressor is more expensive than water injection pump).

Table 5. 46: Cash flow table for gasflooding of moderately volatile oil case (million $).

Year	CAPEX	OPEX	Sale revenue	Royalty (12.5%)	Income tax (35%)	Remit. tax (23.08%)	Domestic sales tax credit	Net cash flow
0	42.72	-	-	-	-	-	-	(42.72)
1	-	4.82	36.07	(4.51)	(6.37)	(2.73)	2.25	19.90
2	-	4.77	35.94	(4.49)	(6.35)	(2.72)	2.25	19.86
3	-	4.74	35.88	(4.48)	(6.34)	(2.72)	2.24	19.84
4	-	4.72	35.77	(4.47)	(6.31)	(2.71)	2.24	19.80
5	-	4.70	34.69	(4.34)	(5.99)	(2.57)	2.17	19.26
6	-	4.68	33.25	(4.16)	(8.55)	(3.66)	2.08	14.29
7	-	4.60	29.46	(3.68)	(7.41)	(3.18)	1.84	12.43
8	-	4.44	21.02	(2.63)	(4.88)	(2.09)	1.31	8.29
9	-	4.34	15.29	(1.91)	(3.16)	(1.36)	0.96	5.48
10	-	4.29	12.69	(1.59)	(2.39)	(1.02)	0.79	4.20
11	-	4.24	10.60	(1.32)	(1.76)	(0.76)	0.66	3.18
12	-	4.20	9.16	(1.15)	(1.34)	(0.57)	0.57	2.48
13	-	4.17	7.91	(0.99)	(0.96)	(0.41)	0.41	1.79
14	-	4.14	6.80	(0.85)	(0.63)	(0.27)	0.27	1.17
15	-	4.12	5.97	(0.75)	(0.39)	(0.17)	0.17	0.72
16	-	4.09	5.15	(0.64)	(0.15)	(0.06)	0.06	0.27

Table 5. 47: Economic parameters for gasflooding of moderately volatile oil case.

As of year zero		
Parameter	Discount rate	Discounted value
NPV	10%	$54.71 million
DPI	10%	2.34
IRR	N/A	42.1%
NPI	10%	$40.73 million

Table 5. 48: Incremental benefit from natural depletion case when investing for gasflooding (moderately volatile oil case).

Parameter	Discounted value
Incremental NPV	$49.94 million
Incremental Cost	$5.45 million
DPI	10.16

5.5.2.6 Economic Analysis for Gasflooding of Very Volatile Oil Case.

This case field life is shorter than that for moderately volatile oil case due to lower total amount of oil recovered. When compared with waterflooding, NPV values of this case are a lot lower than those in waterflooding case of very volatile oil despite of higher oil recovery factor obtained, since gasflooding case has longer production time, then the value of money gain from oil production is lower and the operating cost is also higher when production life of the field is longer.

Table 5. 49: Cash flow table for gasflooding of very volatile oil case (million $).

Year	CAPEX	OPEX	Sale revenue	Royalty (12.5%)	Income tax (35%)	Remit. tax (23.08%)	Domestic sales tax credit	Net cash flow
0	42.72	-	-	-	-	-	-	(42.72)
1	-	4.83	25.77	(3.22)	(3.21)	(1.38)	1.38	14.51
2	-	4.81	25.71	(3.21)	(3.20)	(1.37)	1.37	14.49
3	-	4.79	25.67	(3.21)	(3.19)	(1.37)	1.37	14.48
4	-	4.78	25.63	(3.20)	(3.19)	(1.37)	1.37	14.46
5	-	4.76	25.08	(3.14)	(3.02)	(1.30)	1.30	14.16
6	-	4.74	23.58	(2.95)	(5.56)	(2.39)	1.47	9.42
7	-	4.68	20.21	(2.53)	(4.55)	(1.95)	1.26	7.76
8	-	4.62	16.51	(2.06)	(3.44)	(1.47)	1.03	5.95
9	-	4.56	13.85	(1.73)	(2.64)	(1.13)	0.87	4.64
10	-	4.52	12.08	(1.51)	(2.12)	(0.91)	0.76	3.78
11	-	4.49	10.94	(1.37)	(1.78)	(0.76)	0.68	3.23
12	-	4.45	9.56	(1.19)	(1.37)	(0.59)	0.59	2.54
13	-	4.40	7.81	(0.98)	(0.85)	(0.36)	0.36	1.58
14	-	4.35	6.16	(0.77)	(0.36)	(0.16)	0.16	0.67

Table 5. 50: Economic parameters for gasflooding of very volatile oil case.

As of year zero		
Parameter	Discount rate	Discounted value
NPV at	10%	$28.67 million
DPI	10%	1.70
IRR	N/A	27.5%
NPI	10%	$40.73 million

Table 5. 51: Incremental benefit from natural depletion case when investing for gasflooding (very volatile oil case).

Parameter	Discounted value
Incremental NPV	$37.47 million
Incremental Cost	$5.45 million
DPI	7.87

5.5.2.7 Economic Analysis for PPM of Moderately Volatile Oil Case

For produced gas re-injection, gas compressor cost is added to CAPEX. From the results in Table 5.53, NPV and DPI values are lower than those for water and gas flooding. We know that this scheme yields comparable oil recovery with waterflooding case but this case has lower NPV because this scheme takes longer production time. However, from Table 5.54, we found that incremental NPV and DPI values are the highest among the selected IOR in this study because this scheme need a small additional investment cost.

Table 5. 52: Cash flow table for PPM of moderately volatile oil case (million $).

Year	CAPEX	OPEX	Sale revenue	Royalty (12.5%)	Income tax (35%)	Remit. tax (23.08%)	Domestic sales tax credit	Net cash flow
0	40.00	-	-	-	-	-	-	(40.00)
1	-	2.59	36.50	(4.56)	(7.47)	(3.20)	2.28	20.95
2	-	2.68	36.50	(4.56)	(7.44)	(3.19)	2.28	20.91
3	-	3.23	36.50	(4.56)	(7.25)	(3.11)	2.28	20.64
4	-	4.69	36.50	(4.56)	(6.74)	(2.89)	2.28	19.90
5	-	5.61	33.58	(4.20)	(5.52)	(2.37)	2.10	17.99
6	-	5.02	23.00	(2.88)	(5.29)	(2.27)	1.44	8.99
7	-	4.51	14.55	(1.82)	(2.88)	(1.23)	0.91	5.02
8	-	3.83	9.38	(1.17)	(1.53)	(0.66)	0.59	2.78
9	-	3.02	6.14	(0.77)	(0.82)	(0.35)	0.35	1.53
10	-	2.26	4.09	(0.51)	(0.46)	(0.20)	0.20	0.86
11	-	1.66	2.77	(0.35)	(0.27)	(0.11)	0.11	0.50
12	-	0.96	1.36	(0.17)	(0.08)	(0.03)	0.03	0.15

Table 5. 53: Economic parameters for PPM of moderately volatile oil case.

As of year zero		
Parameter	Discount rate	Discounted value
NPV at	10%	$44.57 million
DPI	10%	2.17
IRR	N/A	45.1%
NPI	10%	$38.14 million

Table 5. 54: Incremental benefit from natural depletion case when investing for PPM (moderately volatile oil case).

Parameter	Discounted value
Incremental NPV	$39.80 million
Incremental Cost	$2.86 million
DPI	14.91

5.5.2.8 Economic Analysis for PPM of Very Volatile Oil Case.

Similar to moderately volatile oil, very volatile oil yields a little bit lower values of NPV and DPI than those for water and gas flooding cases. However this does not means that economic of very volatile oil project is poorer with gas injection option. Since higher oil volatility has lower minimum miscibility pressure, we may need smaller compressor size to fully or partially maintain the reservoir pressure at lower level than moderately volatile oil.

Table 5. 55: Cash flow table for PPM of very volatile oil case (million $).

Year	CAPEX	OPEX	Sale revenue	Royalty (12.5%)	Income tax (35%)	Remit. tax (23.08%)	Domestic sales tax credit	Net cash flow
0	40.00	-	-	-	-	-	-	(40.00)
1	-	3.38	36.50	(4.56)	(7.20)	(3.08)	2.28	20.56
2	-	3.68	36.50	(4.56)	(7.09)	(3.04)	2.28	20.41
3	-	5.02	36.50	(4.56)	(6.62)	(2.84)	2.28	19.74
4	-	7.99	34.90	(4.36)	(5.09)	(2.18)	2.18	17.45
5	-	8.74	17.78	(2.22)	0.42	0.18	0.18	7.58

Table 5. 56: Economic parameters for PPM of very volatile oil case.

As of year zero		
Parameter	Discount rate	Discounted value
NPV at	10%	$25.76 million
DPI	10%	1.68
IRR	N/A	37.1%
NPI	10%	$38.14 million

Table 5. 57: Incremental benefit from natural depletion case when investing for PPM (very volatile oil case).

Parameter	Discounted value
Incremental NPV	$34.56 million
Incremental Cost	$2.86 million
DPI	13.08

5.5.2.9 Economic Analysis for WAG of Moderately Volatile Oil Case

From Table 5.58, WAG has a longer production time than that for waterflooding but shorter than that for gasflooding. For this scheme, abandonment oil production rate is also higher than water and gas flooding cases due to higher CAPEX and OPEX. NPV value from WAG is the highest among selected production schemes in this study. Lower DPI value than water and gas flooding case means that additional investment for WAG in this study may not attractive enough when compared to water and gas flooding option.

Table 5. 58: Cash flow table for WAG of moderately volatile oil case (million $).

Year	CAPEX	OPEX	Sale revenue	Royalty (12.5%)	Income tax (35%)	Remit. tax (23.08%)	Domestic sales tax credit	Net cash flow
0	47.22	-	-	-	-	-	-	(47.22)
1	-	3.36	36.08	(4.51)	(6.57)	(2.82)	2.25	21.08
2	-	3.54	36.00	(4.50)	(6.48)	(2.78)	2.25	20.95
3	-	3.52	35.95	(4.49)	(6.47)	(2.77)	2.25	20.94
4	-	3.46	35.92	(4.49)	(6.48)	(2.78)	2.24	20.95
5	-	3.53	35.38	(4.42)	(6.29)	(2.70)	2.21	20.65
6	-	3.48	33.78	(4.22)	(9.13)	(3.91)	2.11	15.15
7	-	3.45	31.31	(3.91)	(8.38)	(3.59)	1.96	13.93
8	-	3.36	24.31	(3.04)	(6.27)	(2.69)	1.52	10.47
9	-	3.20	17.56	(2.19)	(4.26)	(1.83)	1.10	7.18
10	-	3.02	14.63	(1.83)	(3.42)	(1.47)	0.91	5.81
11	-	3.10	11.81	(1.48)	(2.53)	(1.09)	0.74	4.36
12	-	3.10	10.78	(1.35)	(2.22)	(0.95)	0.67	3.84
13	-	2.98	9.79	(1.22)	(1.96)	(0.84)	0.61	3.41
14	-	2.97	8.14	(1.02)	(1.45)	(0.62)	0.51	2.58

Table 5. 59: Economic parameters for WAG of moderately volatile oil case.

As of year zero		
Parameter	Discount rate	Discounted value
NPV at	10%	$59.51 million
DPI	10%	2.32
IRR	N/A	40.3%
NPI	10%	$45.02 million

Table 5. 60: Incremental benefit from natural depletion case when investing for WAG (moderately volatile oil case).

Parameter	Discounted value
Incremental NPV	$54.73 million
Incremental Cost	$9.74 million
DPI	6.62

5.5.2.10 Economic Analysis for WAG of Very Volatile Oil Case

For very volatile oil case, Table 5.62 shows that both NPV and DPI values are higher than those for water and gas flooding case which similar to moderately volatile oil case.

Table 5. 61: Cash flow table for WAG of very volatile oil case (million $).

Year	CAPEX	OPEX	Sale revenue	Royalty (12.5%)	Income tax (35%)	Remit. tax (23.08%)	Domestic sales tax credit	Net cash flow
0	47.22	-	-	-	-	-	-	(47.22)
1	-	3.26	25.76	(3.22)	(3.44)	(1.48)	1.48	15.84
2	-	3.47	25.68	(3.21)	(3.35)	(1.43)	1.43	15.66
3	-	3.43	25.63	(3.20)	(3.34)	(1.43)	1.43	15.65
4	-	3.41	25.59	(3.20)	(3.34)	(1.43)	1.43	15.64
5	-	3.38	25.34	(3.17)	(3.27)	(1.40)	1.40	15.52
6	-	3.33	23.41	(2.93)	(6.00)	(2.57)	1.46	10.04
7	-	3.30	19.58	(2.45)	(4.84)	(2.07)	1.22	8.14
8	-	3.22	16.40	(2.05)	(3.90)	(1.67)	1.02	6.59
9	-	3.16	14.08	(1.76)	(3.21)	(1.37)	0.88	5.46
10	-	3.10	11.66	(1.46)	(2.48)	(1.07)	0.73	4.28
11	-	3.09	9.44	(1.18)	(1.81)	(0.78)	0.59	3.18
12	-	3.04	7.97	(1.00)	(1.38)	(0.59)	0.50	2.46
13	-	3.04	7.05	(0.88)	(1.10)	(0.47)	0.44	2.01
14	-	3.08	6.91	(0.86)	(1.04)	(0.45)	0.43	1.92
15	-	3.03	5.28	(0.66)	(0.56)	(0.24)	0.24	1.03

Table 5. 62: Economic parameters for WAG of very volatile oil case.

As of year zero		
Parameter	Discount rate	Discounted value
NPV at	10%	$30.81 million
DPI	10%	1.68
IRR	N/A	26.8%
NPI	10%	$45.02 million

Table 5. 63: Incremental benefit from natural depletion case when investing for WAG (very volatile oil case).

Parameter	Discounted value
Incremental NPV	$39.61 million
Incremental Cost	$9.74 million
DPI	5.06

5.5.2.11 Summary of Economic Comparison

Tables 5.64 and 5.65 present economic parameters for all cases of moderately and very volatile oil, respectively. From the overall results, WAG option yields the highest NPV for both moderately and very volatile oil. For moderately volatile oil, gasflooding has a little higher NPV than waterflooding. In contrast, for very volatile oil, waterflooding has higher NPV than gasflooding. For discounted profitability index perspective, PPM scheme has highest DPI value because this scheme requires low additional investment but still yields high oil recovery and NPV.

In summary, economic evaluation results suggests that full pressure maintenance schemes have a very high incremental gain from natural depletion. From a comparison between waterflooding and gasflooding, both schemes have a similar financial benefit despite of higher oil recovery amount when implement gasflooding. However, if we can lower CAPEX and OPEX required for gasflooding when compared to waterflooding, this scheme will yield higher benefit. Therefore, if oil in place is large enough to justify high investment cost, WAG and gasflooding are more attractive while waterflooding seems more appropriate for a marginal field since water flooding required lower investment cost.

Table 5. 64: Economic parameters for all cases of moderately volatile oil.

Production schemes	NPI @10 (million $)	NPV@10 (million $)	DPI@10 (million $)	Incremental from natural depletion case	
				NPV@10	DPI@10
Natural depletion	35.28	4.77	1.14	-	-
Waterflooding	39.57	53.18	2.34	48.41	12.28
Gasflooding	40.73	54.71	2.34	49.94	10.16
PPM	38.14	44.57	2.17	39.80	14.91
WAG	45.02	59.51	2.32	54.73	6.62

Table 5. 65: Economic parameters for all cases of very volatile oil.

Production schemes	NPI @10 (million $)	NPV@10 (million $)	DPI@10 (million $)	Incremental from natural depletion case	
				NPV@10	DPI@10
Natural depletion	35.28	(8.80)	0.75	-	-
Waterflooding	39.57	29.44	1.76	38.75	10.03
Gasflooding	40.73	28.67	1.70	37.47	7.87
PPM	38.14	25.76	1.68	34.56	13.08
WAG	45.02	30.81	1.68	39.61	5.06

CHAPTER VI

CONCLUSIONS AND RECOMMENDATIONS

This chapter captures all conclusions from simulation results in Chapter five and points out important matters of volatile oil recovery for natural depletion, waterflooding, gasflooding, partial pressure maintenance, and water alternating gas production schemes.

6.1 Conclusions

Base case of natural depletion shows that depletion performance of volatile throughout production life can be divided into 3 periods. The first period occurs when the bottom hole flowing pressure (BHFP) remains above the bubble point pressure. During this period, average oil productivity index is the highest due to the single phase flow. Hence, any IOR implementation should start within this period. The reservoir approaches the second period when the BHFP drops lower than the bubble point pressure but the gas saturation near the well bore has not reached the critical gas saturation yet. The second period disappears quickly once gas starts to liberate out and enters the third period, which has a drastic drop in oil productivity index. This period is not favorable for volatile oil production because high pressure drawdown will result in gas coning or cresting from accumulated free gas in the reservoir.

For natural depletion performance, we found out that gravity segregation of solution gas is a key drive mechanism during pressure depletion for this study. From an investigation of well configuration, we quantified the effectiveness of this drive mechanism by using gravity number, and found that using a tighter well spacing results in lower oil production rate per well and consequently reduces the viscous force that pulls liberated gas to the well bore. Thus, more liberated gas can segregate upward and helps support the reservoir pressure. For horizontal well case, the gravity segregation of liberated gas is even improved since well is placed at the bottom of the reservoir which has the highest absolute permeability. So the viscous force acting on liberated gas is relatively low compared to vertical well cases. When we further investigate the effect of oil production rate and perforation interval, the same concept of gravity segregation is applied. Lower oil production rate is more favorable to gravity segregation than higher rate due to lower free gas production. For a partial perforation study, as we limit perforation interval at the 3 bottom layers of reservoir model which have relative high absolute permeability compared with the shallow layers, limited perforation cases have higher recovery performance due to a better gravity segregation drive of liberated gas.

Next, for full pressure maintenance schemes, we try to identify appropriate starting time for maintaining the reservoir pressure with waterflooding, gasflooding and water alternating gas. We compare the cases when the flooding is started after the reservoir pressure has depleted by 0%, 20%, 35% and 50% of the initial reservoir pressure. Simulation results yield similar value of oil recovery factors for all three cases except a 50 % depletion case which has oil recovery significantly less than the other cases because, the reservoir pressure already drops below the bubble point pressure and gas phase already exists along the reservoir. For waterflooding, the existence of free gas in the reservoir has higher impact on displacement efficiency than a reduction of oil viscosity. This is because volatile oil has very low viscosity already and even though pressure has depleted to some level. For gasflooding, we found that the main cause of poorer oil recovery is from poorer miscibility condition achievement when the reservoir pressure already drops to a certain level below the bubble point pressure.

In the last section, water and gas flooding are compared in term of performance and project economic. Due to the fact that volatile oil has low oil viscosity, then flooding performances before breakthrough when using water and miscible gas are identical. However, after the breakthrough of injected fluid, gas flooding provides higher incremental recovery compared to water flooding. Based on economic data assumed in this study, WAG provides the highest financial benefit as expected. Waterflooding has similar economic performance to gasflooding but required less investment than gasflooding and WAG options.

Important conclusion points are as follows:

1. Maintaining the average reservoir pressure to be above the bubble point pressure is recommended to maximize volatile oil recovery.

2. For natural depletion of volatile oil reservoir, if the reservoir does not connected with aquifer, a gravity segregation of liberated gas is a key mechanism. And enhancement of this drive mechanism is a key optimization for well placement, completion design, production target and etc.

3. For waterflooding, suitable injection pressure can be selected from oil PVT data by selecting pressure that yields suitable oil viscosity in order to have favorable mobility ratio for waterflooding.

4. Waterflooding in volatile oil reservoir has high performance before water breakthrough but very low after the breakthrough. Therefore, from economic point of view, if the reservoir has low areal heterogeneity or has a high sweep efficiency, waterflooding should be terminated after water has reached the producer to avoid cost of produced water treatment and handling.

5. For both water and gas flooding, we should avoid starting the flooding after free exists in the reservoir. For waterflooding, if free gas exists, displacement efficiency is reduced due to gas blockage effect. For gasflooding, existing of free gas is lower capability in miscibility condition achievement because the intermediate components in oil phase already flash to gas phase and cannot be used to develop miscible flood front.

6. Economic analysis shows that full pressure maintenance production schemes have a very high incremental financial gain from natural depletion of volatile oil reservoir. Selection of suitable production scheme depends on investment cost required and amount of targeted oil recovery amount.

6.2 Recommendations

Recommendations for further study are as follows:

1. To make the study more practical, fluid properties should be measured and entered into the simulation model rather than using thermodynamic model to calculate PVT properties.

2. The effect of areal heterogeneity and others flooding patterns may be taken into account for further study.

3. A thicker reservoir which has initial compositional gradient along the depth may be taken into account for further study.

4. Others EOR performance in volatile oil reservoir should be investigated to compare with normal gas and water flooding.

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APPENDIX

APPENDIX

ECLIPSE 300 INPUT DATA

Reservoir model

The reservoir simulation model is constructed by inputting the required data in ECLIPSE simulator. The geological model comprises of number of cells or blocks in the directions of *X*, *Y* and *Z*. The number of blocks in this study is 75 x 25 x 9. Block permeability is varied between layers from low to high.

1. Case Definition

Simulator : Compositional

Model dimensions

Number of grid in x direction : 75

Number of grid in y direction : 25

Number of grid in z direction : 9

Grid type : Cartesian

Geometry type : Corner Point

Oil-gas-water properties: Water, oil, gas and dissolved gas

Solution type : Fully Implicit

2. Grid

Properties

Active Grid Block	X(1-75)	= 1
	Y(1-25)	= 1
	Z(1-9)	= 1

X Average permeability : 70 md

Y Average permeability : 70 md

Z Average permeability : 70 md

Porosity : 0.201

Dip angle : 5 degrees

Grid block sizes

x direction : 50 ft

y direction : 56 ft

z direction : 5 ft

Geometry

Grid Block Coordinate Lines

Grid Block Corners

Grid data units

3. PVT

Reservoir temperature

Moderately volatile oil : 189 F

Very volatile oil : 176 F

Equation of state : Modified Peng-Robinson 3

Number of components : 12

4. SCAL

Wate/oil saturation functions

S_w	k_{rw}	k_{ro}	P_c (psia)
0.2200	0.0000	0.9000	0
0.2407	0.0000	0.8069	0
0.2614	0.0000	0.7205	0
0.2821	0.0000	0.6406	0
0.3028	2.5499E-6	0.5667	0
0.3235	9.7273E-6	0.4988	0
0.3442	2.9045E-5	0.4365	0
0.3650	7.3242E-5	0.3796	0
0.3857	0.0001	0.3279	0
0.4064	0.0003	0.2812	0
0.4271	0.0006	0.2391	0
0.4478	0.0011	0.2014	0
0.4685	0.0018	0.1679	0
0.4892	0.0030	0.1383	0
0.5100	0.0046	0.1125	0
0.5307	0.0070	0.0900	0
0.5514	0.0104	0.0708	0
0.5721	0.0150	0.0545	0
0.5928	0.0211	0.0409	0

Wate/oil saturation functions (cont.)

S_w	k_{rw}	k_{ro}	P_c (psia)
0.6135	0.0292	0.0298	0
0.6342	0.0398	0.0209	0
0.6550	0.0533	0.0140	0
0.6757	0.0705	0.0088	0
0.6964	0.0921	0.0051	0
0.7171	0.1189	0.0026	0
0.7378	0.1519	0.0011	0
0.7585	0.1923	0.0003	0
0.7792	0.2411	4.0998E-5	0
0.8000	0.3000	0.0000	0
1.0000	1.0000	0.0000	0

Gas/oil saturation functions

S_l	k_{rg}	k_{ro}	Pc (psia)
0.2200	0.9000	0	0
0.3000	0.8677	0	0
0.3248	0.7957	0	0
0.3496	0.7258	0	0
0.3744	0.6583	1E-5	0
0.3992	0.5933	5E-5	0
0.4240	0.5310	0.0001	0
0.4488	0.4716	0.0003	0
0.4737	0.4153	0.0008	0
0.4985	0.3624	0.0016	0
0.5233	0.3129	0.0029	0
0.5481	0.2670	0.0050	0
0.5729	0.2250	0.0081	0
0.5977	0.1868	0.0125	0
0.6225	0.1525	0.0187	0
0.6474	0.1221	0.0271	0
0.6722	0.0957	0.0382	0
0.6970	0.0731	0.0528	0
0.7218	0.0542	0.0715	0
0.7466	0.0387	0.0952	0

Gas/oil saturation functions (cont.)

S_g	k_{rg}	k_{ro}	P_c (psia)
0.7714	0.0264	0.1247	0
0.7963	0.0171	0.1612	0
0.8211	0.0103	0.2057	0
0.8459	0.0056	0.2596	0
0.8707	0.0027	0.3243	0
0.8955	0.0010	0.4012	0
0.9203	0.0002	0.4920	0
0.9451	4E-5	0.5986	0
0.9700	0	0.7229	0
1	0	0.9	0

5. Initialization

Equilibration data specification

Datum depth : 10,034 ft
Pressure at datum depth : 4,900 psia

6. Regions : N/A

7. Schedule

In reservoir simulation model, each production well setting is described as follows (vertical well case):

7.1 Oil production well

Well specification

Well name	: P1
Group	: P
I location	: 19
J location	: 12
Preferred phase	: OIL
Inflow equation	: STD
Automatic shut-in instruction	: SHUT
Crossflow	: YES
Density calculation	: SEG

Well connection data

Well connection data	: P
K upper	: 1
K lower	: 9
Open/shut flag	: OPEN
Well bore ID	: 0.729 ft
Direction	: Z

Group production control

Group : P
Open/shut flag : OPEN
Control : ORAT
Oil rate : 2000 stb/day

Production well economic limits

Group : P
Minimum oil rate : 50 stb/day
Workover procedure : NONE
End run : YES

There are a few differences in setting the production and injection wells. In setting the production well, well specification and well connection data are the same as previous but we need to change the keyword from production well control to be injection well control. When we start gas injection, we change only the preferred phase and injection rate in injection well control.

7.2 Water injection well

Well specification

Well name : I1
Group : I
I location : 1
J location : 12
Preferred phase : WATER
Inflow equation : STD
Automatic shut-in instruction : SHUT
Crossflow : YES
Density calculation : SEG

Well connection data

Well connection data	: I1
K upper	: 1
K lower	: 9
Open/shut flag	: OPEN
Well bore ID	: 0.729 ft
Direction	: Z

Injection well control

Well	: I1
Injector type	: WATER
Open/shut flag	: OPEN
Control mode	: RATE
Liquid surface rate	: 2000 stb/day
BHP target	: 7,037 psia

7.3 Gas injection well

Well specification

Well name	: I1
Group	: I
I location	: 1
J location	: 12
Preferred phase	: GAS
Inflow equation	: STD
Automatic shut-in instruction	: SHUT
Crossflow	: YES
Density calculation	: SEG

Well connection data

Well connection data : I1
K upper : 1
K lower : 9
Open/shut flag : OPEN
Well bore ID : 0.729 ft
Direction : Z

Injection well control

Well : I1
Injector type : GAS
Open/shut flag : OPEN
Control mode : RATE
Liquid surface rate : 3,000 Mscf/day
BHP target : 7,037 psia

VITA

Wasin Saengnumpong was born on March 30, 1988 in Bangkok, Thailand. He graduated from Department of Mechanical Engineering in Mechanical Engineer from the Faculty of Engineering, Chulalongkorn University in 2010. After graduating, he continued his study in the Master of Petroleum Engineering program at the Department of Mining and Petroleum Engineering Faculty of Engineering in 2010.