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OPTIMAL PRODUCTION AND WATER FLOODING STRATEGY FOR MULTI-LAYERED RESERVOIRS

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for the Degree of Master of Engineering Program in Petroleum Engineering
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แหล่งกักเก็บหลายชั้นประกอบด้วยชั้นทรายสลับกับชั้นหินดินดาน ซึ่งเกิดขึ้นจากการทับถมของตะกอนในลำดับเวลาและสภาวะแวดล้อมที่แตกต่างกัน เป็นผลให้ชั้นทรายแต่ละชั้นมีคุณสมบัติของหินที่ต่างกัน และคุณสมบัติของของไหลในแต่ละชั้นอาจแตกต่างกันด้วย

วิทยานิพนธ์เล่มนี้มีจุดมุ่งหมายในการศึกษากลยุทธ์ที่เหมาะสมในการผลิตน้ำมันของแหล่งกักเก็บน้ำมันหลายชั้นแหล่งหนึ่งในประเทศไทย แหล่งกักเก็บน้ำมันแหล่งนี้ประกอบด้วยแหล่งกักเก็บน้ำมันเล็กๆ ทั้งที่ถูกผลิตแล้วและยังถูกไม่ผลิต ซึ่งประกอบด้วยชั้นทรายบางๆถูกแยกจากกันด้วยชั้นหินดินดาน ชั้นทรายส่วนใหญ่มีความหนาในช่วง 1 ถึง 5 เมตร โดยคุณสมบัติของของไหลและคุณสมบัติของหินอาจมีความแตกต่างกันมากในแต่ละชั้นทราย

เนื่องด้วยความหลากหลายในคุณสมบัติของของไหลและคุณสมบัติของหินซึ่งมีผลต่อประสิทธิภาพในการอัดน้ำแทนที่ การศึกษาถึงกลยุทธ์ที่เหมาะสมจึงมีความจำเป็นเพื่อให้สามารถผลิตน้ำมันได้ในปริมาณมากที่สุดภายในเวลาน้อยที่สุด โดยโปรแกรมสร้างแบบ จำลองแหล่งกักเก็บ 3 มิติ ได้ถูกนำมาใช้ในการหาศึกษาอิทธิพลของตัวแปรต่างๆที่มีต่อความสามารถในการผลิตน้ำมันและการอัดน้ำแทนที่ ตัวแปรที่ถูกพิจารณาได้แก่ จุดระเหยของน้ำมัน ปริมาณก๊าซที่ละลายในน้ำมัน ความหนืดของน้ำมัน ความหนาของชั้นทราย และความสามารถในการไหลของชั้นทราย

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CHATRAWEE PAIRATANA: OPTIMAL PRODUCTION AND WATER F LOODING STRATEGY FOR MULTI-LAYERED RESERVOIRS. THESIS ADVISOR : JIRAWAT CHEWAROUNGROAJ, Ph.D., THESIS CO-ADVISOR : YOTHIN TONGPENYAI, Ph.D., 120 pp.

Multi-layered reservoirs comprise several sands interbedding with shale, which are laid down in a variety of depositional environments and subsequent events. As a result, rocks properties and fluids properties in different layers are likely to be different.

This thesis intends to investigate the optimal strategy in the oil production of multi-layered reservoirs in a field in Thailand. The reservoirs of interest include new and depleted reservoir compartments, which consist of series of thin sand layers completely separated by impermeable shales. Sand thickness generally ranges from 1 to 5 meters and it is possible that characteristics of reservoir fluids and the rock properties are significantly largely different in each layer.

Because it is not simple to effectively and efficiently produce from sand with such a wide variation in fluid and rock properties, it is necessary to investigate strategy to optimize the oil production from this system. The optimal production and waterflooding criterion is the maximum oil recovery within the minimum production time. In this study, a 3D reservoir simulator is used to observe the effects of several parameters on production and waterflooding performance. The parameters which are considered are the bubble point pressure, the oil viscosity, the solution gas-oil ratio, the layer thickness, and the layer permeability.

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Thanks to my classmates and friends with whom I had the opportunity to learn, share and enjoy. It has been a pleasure.

This work is dedicated to the most important people in my life, my mother and father, my husband, and my little daughter, who have always been my life, my inspiration, and every happiness. You are sincerely the main reason I had the commitment and strength to accomplish this goal.

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LIST OF ABBREVIATIONS

BHP	bottomhole flowing pressure
cp	centipoises
cu ft	cubic feet
d	days
F	Fahrenheit
ft	feet
ft^2	square feet
lb	pound
m	meters
md	millidarcies
rb	reservoir barrels
scf	standard cubic feet
stb	stock tack barrels
WOR	water-oil ratio

NOMENCLATURE

A	cross section area
B_o	oil formation volume factor
B_w	water formation volume factor
d	differential
f_w	fractional flow of water
k	permeability
k_o	oil permeability
k_r	relative permeability
k_{ro}	relative permeability to oil
k_{rw}	relative permeability to water
k_w	water permeability
L	flowing distance
M	mobility ratio
p_b	bubble point pressure
p_i	initial reservoir pressure
p_o	oil pressure
p_r	average reservoir pressure
p_{sgc}	critical gas saturation pressure
p_w	water pressure
p_{wh}	wellhead pressure
Δp	pressure drop
P_c	capillary pressure
q	fluid flow rate
q_o	oil flow rate
q_w	water flow rate
q_{wi}	water injection rate
q_{wp}	water production rate
q_t	total flow rate
R_s	solution gas oil ratio
S_g	gas saturation

S_{gc}	critical gas saturation
S_{or}	residual oil saturation
S_w	water saturation
t	time
v_{Sw}	flood front velocity
x	flowing distance

GREEK LETTER

γ	specific gravity
Δ	difference
θ	dip angle of the reservoir
ρ	density
μ	viscosity
ϕ	porosity

SUBSCRIPTS

b	*bubble point*
c	capillary
g	gas
i	initial condition
o	oil
r	relative
sgc	critical gas saturation
s	solution gas
t	total
w	water
wh	wellhead
wi	water injection
wp	water production

CHAPTER 1
INTRODUCTION

1.1 Introduction and Problem Statement

Most reservoirs are laid down in a variety of depositional environments and subsequent events, resulting in geologic variations. Multi-layered reservoir here is defined as a reservoir comprising several sands interbedding with shale. Because of the variation in the depositional environments, rocks properties in different layers are likely to be different.

If oil reservoirs are not connected to aquifers, the principle producing mechanism is a solution-gas drive, which is the expansion of the oil and the liberated gas. This kind of reservoir drive mechanism can yield a recovery factor in the range if 15-30%. There are several secondary recovery techniques to improve the oil recovery in this type of reservoir. However, waterflooding is the recovery process responsible for most of the oil production by secondary recovery.

This thesis intends to study the oil production of multi-layered reservoirs in a field in Thailand. Most reservoirs in this field consist of thin sand layers alternated with shale. Sand layers are completely separated by impermeable shale barriers so the connection occurs hydraulically only at injectors and producers. Sand thickness generally ranges between 1 to 5 meters and each sand is different in areal extent. The continuities between injector(s) and producer(s) are consequently different. Sand layers which are continuous in a large coverage always connect to both producer(s) and injector(s) while the others may connect to only producer(s). In addition, it is possible that characteristics of reservoir fluids and the rock properties are significantly largely different in each layer.

Because it is not simple to effectively and efficiently produce from sand with such a wide variation in fluid and rock properties, it is necessary to investigate strategy to optimize the oil production from this system. The study focuses on the observation of waterflooding in layers which connect to both producer(s) and injector(s). The effects of several parameters on waterflooding performance will be studied and various production scenarios will be simulated by reservoir simulation runs. The results from these runs will be compared, analyzed and discussed. Recommendation for optimal production strategies will be given.

1.2 Objective

This study is aimed to investigate, by numerical reservoir simulation, the optimal strategy to produce oil from a multi-layered reservoir that has different oil and rock properties in each layer. The appropriate procedure of the producing and the waterflooding operations will be determined to optimize the oil recovery from each layer.

1.3 Review of Targeted Reservoirs

The reservoirs of interest comprise series of thin sand layers completely separated by impermeable shales. Sand thickness generally ranges between 1 to 5 meters and each sand is different in areal extent. A thick sand is generally continuous in a large coverage while a thin sand may not. In the waterflooding operation, some of these thin sand layers are not continuous between injectors and producers. This leads to two different production characteristics,

1. Primary depletion drive in discontinuous sand layers, which connect to only the producer(s)

2. Secondary recovery by waterflooding in sand layers which are continuous between injector(s) and producer(s).

Most reservoirs in this field have been produced. However, some new compartments have not depleted. The oil gravity ranges between 35-45^{o}API, where solution gas-oil ratio possibly varies between 400 and 1500 scf/stb. The sand possibly varies from highly permeable (up to 2000 md) to low permeable (20 md). The averaged values of porosity and initial water saturation of 0.20 and 0.30 are adopted, respectively.

CHAPTER 2

WATERFLOODING THEORY

In an oil reservoir, which is closed from any outside source of energy, the principle drive mechanism is the solution-gas drive. If the reservoir pressure is initially above bubble point pressure, no free gas exists, hence, the only source of energy is the expansion of oil in the reservoir. In the first period of solution gas drive system, the reservoir pressure will decline rapidly with production until it equals to the bubble point pressure. Once the reservoir pressure declines below the bubble point pressure, free gas will expand and the reservoir pressure will decline much slower. Recovery at the abandonment condition of this type of reservoir will range between 15% to 30% of original oil in place. [1]

The main purposes of secondary recovery are to displace oil by displacing fluid and maintain the reservoir energy by the energy source outside the reservoir. Water is the most popular fluid for this technique. It is injected through the reservoir in order to displace oil from injectors towards the producer. When pressure in the solution gas drive reservoir has been depleted and reached the design condition, the waterflooding operation should be implemented in order to provide the energy to drive additional oil out of the reservoir.

2.1 Production and Waterflooding in a Homogeneous Reservoir

Darcy's law states that in a steady-state condition, the flow rate of homogeneous fluid is proportional to the fluid mobility, k/μ, the pressure gradient, cross section area and flowing distance.

$$q = -\frac{kA\Delta p}{\mu L} \tag{2.1}$$

By the definition, the formation permeability, or absolute permeability, is the ability to pass a fluid through its interconnected pore. A reservoir with higher permeability will be produced at higher flow rate, resulting in higher depletion. The oil viscosity has an opposite effect to the permeability, that is the oil with higher oil viscosity will be produced at lower flow rate, resulting in lower depletion.

If there are two fluids, such as oil and water, flowing simultaneously through a porous medium, the permeability measurement yields one permeability value for each fluid in presence, which are permeability to oil and permeability to water. These measurements are called the effective permeability to each fluid. The effective permeability to any fluid is always less than the absolute permeability of the rock, because of the disturbing effect of the presence of a fluid to the flow of the other.

The relative permeability, k_r, corresponds to the ratio of the effective permeability to the absolute permeability. The relative permeability of a rock to a fluid is unity when only that fluid is present. When other fluids are also present, the relative permeabilities are less than 1, and sometimes as low as zero.

The ease of flow of water relative to oil is measured by the mobility ratio, which is defined by:

$$M = \frac{k_w}{\mu_w}\frac{\mu_o}{k_o} = \frac{k_{rw}}{\mu_w}\frac{\mu_o}{k_{ro}} \tag{2.2}$$

The mobility ratio is the ratio of the mobility of water in the water-contacted portion of the reservoir to the mobility of oil in the unswept portion of the reservoir. If $M \leq 1$, it means that the oil is capable to travel with a velocity equal or greater than that of the water. Under this circumstance, there is no tendency for oil to be by-passed. This is the ideal displacement and the most attractive condition. On the other hand, if $M > 1$ or the mobility ratio is greater than unity, the water is capable of flowing faster than the oil. The oil will be by-passed and water fingering or water tongues develop, leading to the unfavorable water injection profile.

In a solution-gas drive reservoir, no free gas initially exists or is formed during production while the reservoir pressure is above the bubble point. The solution gas-oil ratio will remain constant whereas the oil viscosity will decrease as the reservoir pressure decreases. Once the reservoir pressure falls below the bubble point pressure, solution gas starts to liberate from oil. The oil viscosity will increase as pressure decreases due to the liberation of gas that leaves the heavier molecule in the liquid phase. The reservoirs of which the oil has higher bubble point pressure will generate free gas earlier, resulting in slower pressure declines. Therefore, they are likely to flow longer and yield higher primary recoveries.

If the waterflooding starts after the reservoir pressure has fallen below the bubble point, the increment in oil viscosity will result in poorer displacement and the injected water in the reservoir must fill-up and push the free gas back into the oil before pushing the oil ahead into production wells. It is also likely that implementation of waterflooding when the reservoir pressure is above the bubble point pressure will result in higher oil recovery due to lower oil viscosity and no free gas to obstruct the flow of oil. However, when the reservoir pressure is above the bubble point, it is likely that flooding in the earlier time while the reservoir pressure is high does not give higher oil recovery as higher oil viscosity, lower mobility ratio, and harder for water to push the oil. A good rule of thumb to maximize oil recovery is to start water injection at the time the reservoir reaches the bubble point, where the reservoir reaches the most favorable mobility ratio condition. [2]

In practice, at the time the average reservoir pressure reaches the bubble point, the well flowing pressure will always fall below the bubble point due to a drawdown behavior. The difference between average reservoir pressure and well flowing pressure depends on reservoir permeability and oil production rate. Once the well flowing pressure falls below the bubble point, gas bubbles evolve from solution in the vicinity of wellbore. Initially, these small gas bubbles are separated in individual pore spaces and do not move because they lodge in the small openings between pore spaces. As oil withdrawal continues, further pressure decline takes place and more free gas is formed around the wellbore. These small bubbles will enlarge sufficiently to connect together and once the thread of gas is continuous through pore channels, the gas will begin to flow and the reservoir will start producing free gas.

The critical gas saturation pressure (p_{sgc}) is defined as the maximum pressure at which gas becomes mobile within the well drainage radius. When this point is reached, gas saturation is maximized without being produced at the well. Some previous studies have shown that start waterflooding at the critical gas saturation pressure can maximize oil displacement due to the reduction in the volume of residual oil left in the reservoir. Therefore, the critical gas saturation pressure can be the lowest pressure at which waterflood should be initiated in order to maximize the oil recovery. The related literatures will be mentioned in Chapter 3, the literature review.

In the simulation work, p_{sgc} can be indicated by using producing gas-oil ratio as a trigger when the reservoir pressure achieves the target. As production proceeds, producing gas-oil ratio will remain at its solution value while the reservoir operating pressure is higher than p_{sgc}. Once the well flowing pressures is lower than p_{sgc}, free gas will begin to be movable and the well will start to produce free gas, resulting in an increment in producing gas-oil ratio.

The fundamental of waterflooding operation to obtain the maximum oil recovery is to maintain the reservoir pressure at the suitable operating conditions. Generally, producers produce under primary depletion recovery from the initial reservoir pressure until a designed reservoir pressure has been reached. Once this pressure is reached, water injection will start with voidage replacement to displace oil at a constant pressure. In case that no gas is present, the voidage replacement or underground material balance can be expressed by,

$$q_{wi} = q_o B_o + q_{wp} B_w \quad (\text{rb/d}) \tag{2.3}$$

in which the rates are those measured at the surface and it is assumed that the injected water contains no gas or air (B_w = 1.0 rb/stb). [3]

Buckley-Leverett One Dimensional Displacement [4]

When two fluids, e.g., water and oil, flow simultaneously through a porous medium, we are interested in knowing what fraction of the total fluid is water and what fraction is oil. Actually, if we know one of the fractions, then the other can be obtained by subtracting the known value from one. Consequently, we focus on the calculation of only one, i.e., the water fraction, f_w. If q_w and q_o represent the water and oil flow rates, respectively, then the fractional flow of water is given by

$$f_w = \frac{q_w}{q_o + q_w} = \frac{q_w}{q_t} \tag{2.4}$$

If we employ Darcy's law for the two phase-flow rates, it can be shown that the fractional flow equation for water can be expressed in field units as

$$f_w = \frac{1 + 1.127\times10^{-3}\dfrac{kk_{ro}A}{q_t\mu_o}\left(\dfrac{\partial P_c}{\partial x} - 0.4335\Delta\gamma\, sin\,\theta\right)}{1 + \dfrac{\mu_w}{k_{rw}}.\dfrac{k_{ro}}{\mu_o}} \tag{2.5}$$

where $$\frac{\partial P_c}{\partial x} = \frac{\partial p_o}{\partial x} - \frac{\partial p_w}{\partial x} \tag{2.6}$$

the capillary pressure gradient in the direction of flow

$$\Delta\gamma = \gamma_w - \gamma_o \tag{2.7}$$

the difference in fluids specific gravities

and θ is the angle measured from the horizontal to the line indicating the direction of flow.

Buckley and Leverett presented the basic equation for describing immiscible displacement in one dimension. For water displacing oil, the equation determines the velocity of a plane of constant water saturation traveling through a linear system. In Fig.2-1, the conversion of mass of water flowing through volume element $A\phi dx$ may be expressed as

$$q_w\rho_w\big|_x - q_w\rho_w\big|_x = A\phi dx\frac{\partial}{\partial t}(\rho_w S_w) \tag{2.8}$$

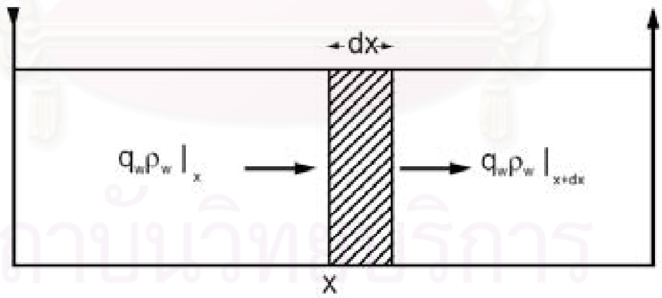


Figure 2-1: Mass flow rate of water through a linear volume element $A\phi dx$

For the assumption of incompressible displacement ($\rho_w \approx$ constant), we derive

$$\left.\frac{\partial q_w}{\partial S_w}\right|_t = A\phi\left.\frac{dx}{dt}\right|_{S_w} \tag{2.9}$$

If q_t is constant and $q_w = q_t f_w$, Eq. (2.9) may be expressed as

$$v_{S_w} = \left.\frac{dx}{dt}\right|_{S_w} = \frac{q_t}{A\phi}\left.\frac{df_w}{dS_w}\right|_{S_w} \tag{2.10}$$

The left-hand side of the equation refers to a fixed plane of water saturation that moves with a speed of *dx/dt*. The derivative on the right-hand side is evaluated from a fractional flow curve at this saturation. Thus, given the total flow rate, the cross-sectional area of the l-D system, the porosity, and a fractional flow curve, one can determine the speed of a specific saturation plane passing through the porous system using Eq. (2.10).

Flooding Patterns and Sweep Efficiency [5]

In waterflooding, water is injected into injectors and produced from producers. The amount of oil recovered is dependent upon the percentage of oil in place that is contacted and moved by water. In an areal sense, injectors and producers take place at points. As a result, pressure distributions and corresponding streamlines are developed between injectors and producers. In symmetrical well patterns, a straight line connecting the injector and producer is the shortest streamline between these two wells. As a result, the pressure gradient along this line is the highest. So, injected water moving areally along this shortest streamline reaches the producer before water moving along any other streamline. Therefore, at a time of water breakthrough, only a portion of the reservoir area lying between these two wells is contacted by water. This contacted fraction is the pattern areal sweep efficiency at breakthrough. Fig.2-2 shows the sweep of a five-spot model as the injected fluid moves to breakthrough.

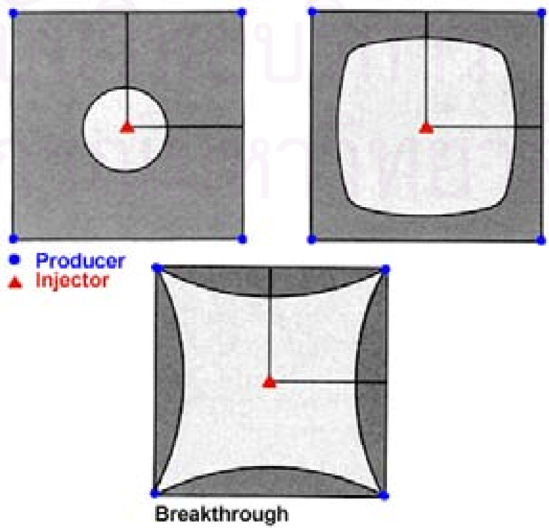


Figure 2-2: Areal sweep of a five-spot model

A wide variety of flooding patterns have been designed in different producers and injectors arrangements. The most common patterns are as shown in Fig.2-3.

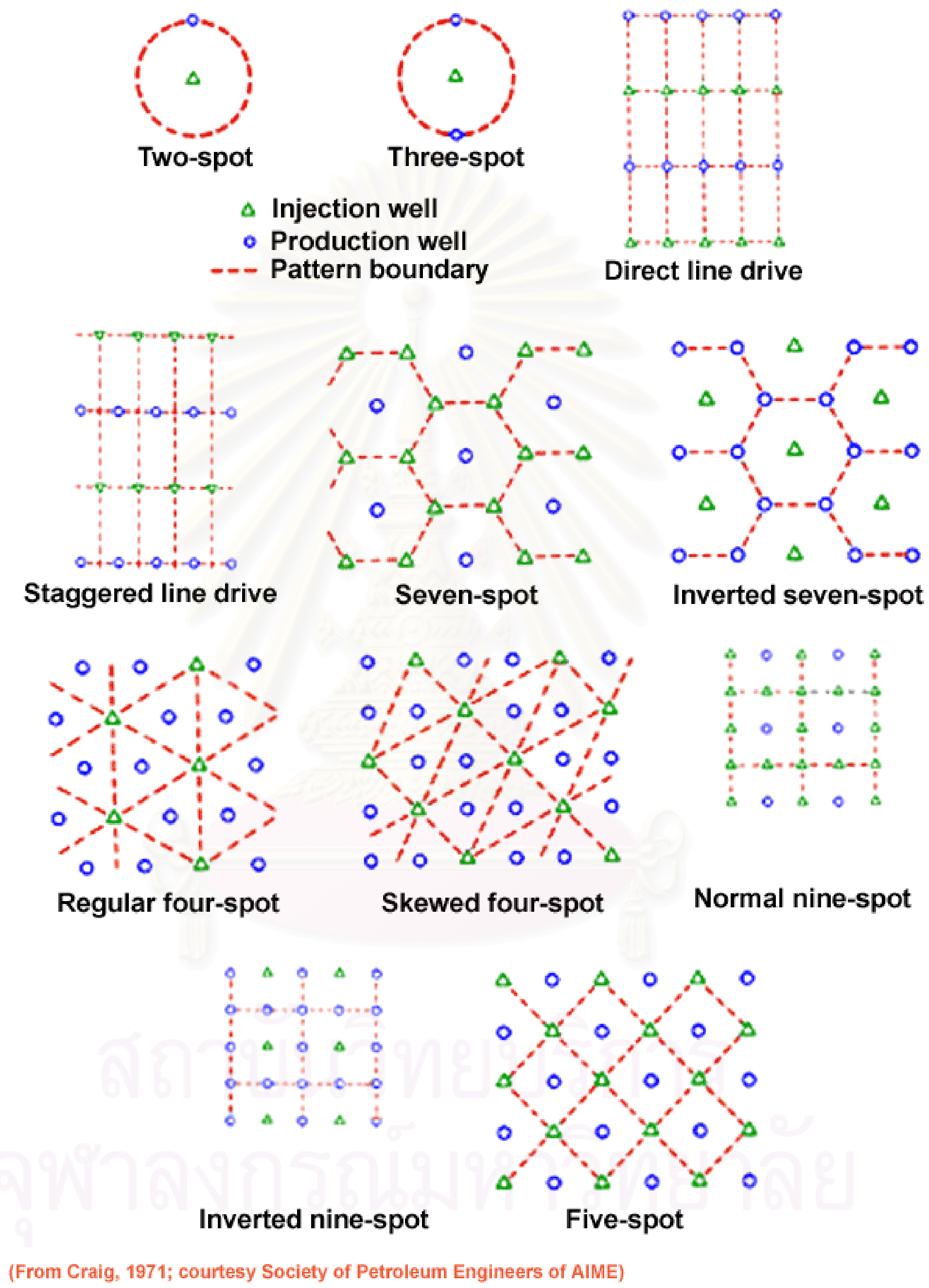


Figure 2-3: Flooding patterns

Various areal sweep efficiencies at breakthrough have been reported for a variety of flooding patterns. For the condition that mobility ratio is 1.0 or less, there is satisfactory agreement among most investigators that the five-spot flooding pattern gives the highest sweep efficiency.

In the oil field, the five-spot waterflood pattern has been used more frequently than any other. Second to the five-spot in popularity is the peripheral or line drive flood pattern. Because of well spacing regulations, primary wells are usually drilled on a square pattern, which lends itself easily to conversion to a five-spot waterflood.

2.2 Production and Waterflooding in a Multi-layered Reservoir

A multi-layered reservoir, which consists of series of sands with different fluids and rock properties, becomes a very complicated model for an efficient displacement process. The complexity of multi-layered operations requires optimal planning for each production and injection. Parameters from the Darcy's law and mobility ratio such as layer permeability, oil viscosity, bubble point pressure, solution gas-oil ratio, and layer thickness; possibly influence different degree of the complexity. However, the bubble point pressure and the oil viscosity are generally well correlated with the solution gas-oil ratio. Oils with high solution gas-oil ratio always have high bubble point pressure and low viscosity. Therefore, the variation in the bubble point pressure and the oil viscosity will be studied via the variation in the solution gas-oil ratio.

Effect of layer permeability

Referring to Darcy's law, the fluid flow rate is proportional to the absolute permeability, or formation permeability. The layers with higher permeability will be produced at higher flow rate, therefore, higher depletion of reservoir energy. Different depletion rates cause different pressure drops. As a result, the layers with higher permeability will have lower pressure and more liberated gas. When waterflooding starts, large amount of water will go into these high permeability layers due to 1) water displacing liberated gas (more liberated gas in high permeability layers) and 2) water can flow easier in these layers. This can lead to early water breakthrough in these layers and producers may have to be shut-in due to high water cut.

Effect of the oil viscosity

The effect of oil viscosity can also be described by Darcy’s law. Its effect is opposite to the layer permeability, which is the layers with higher oil viscosities will be produced at lower flow rates. In the waterflooding operation, as described previously, the mobility ratio implies the efficiency of water pushing oil. The viscosity of oil in each layer affects the performance of the waterflooding. Higher oil viscosity, higher mobility ratio, and harder for water to push the oil. Therefore, the oil recovery is low.

Effect of bubble point pressure

The bubble point pressure regulates condition of formation fluids, i.e. the amount of liberated gas and oil viscosity. As mentioned earlier, it directly affects the optimal time to start waterflooding. The best time to initiate waterflooding in order to get optimal oil seems to be at the time the reservoir reaches the bubble point pressure, at which the oil viscosity is the most favorable and the residual oil saturation is the lowest. However, due to the differences in oil and rock properties in a multi-layered reservoir system, each layer generates free gas at different times due to different bubble point pressures and different depletion rates.

Effect of solution gas-oil ratio

The energy for producing the oil is stored up in the solution gas. The oil which has greater solution gas is lighter and less viscous, which moves easily toward the well. When formation pressure falls below bubble point pressure, it will generate more liberated gas. Because of effect of gas expansion on maintaining reservoir pressure and effect of decreased liquid column weight as it is produced at the well, the reservoir tends to flow longer, resulting in higher primary recovery.

If waterflooding starts when the reservoir pressure is less than the bubble point pressure, solution gas-oil ratio will affect amount of free gas in the reservoir. More free gas will delay oil recovery due to the longer fill-up period.

Effect of layer thickness

Once there is the difference in fluids densities, fluid with higher density will move downward while fluid with lower density moves upward, resulting in segregation. In a thick layer, fluids can segregate because of high density difference and gravity effect. When water displaces oil in a thick layer, water tongue will be developed, resulting in early water breakthrough at the bottom part of the layer. After breakthrough, the water cut will increase substantially because water prefers moving at the bottom part of the layer, where the relative permeability to water is low. As a result, oil at the upper part of the layer will be bypassed and the recovery will be low.

All the likely impacts of various parameters on primary and secondary (waterflooding) recoveries for a multi-layered system discussed above will be quantitatively shown in the later chapters. It will be pointed out in details how and why these impacts affect the oil recovery. Recommendations on optimization of oil recovery will also be given.

CHAPTER 3
LITERATURE REVIEW

Several applications of optimization schemes have been developed and these techniques have been proved to be beneficial in various reservoir developments. This chapter reviews these optimization techniques and their results. The related works will be discussed and applied in the simulation studies.

3.1 Previous Works on Optimal Operating Pressure

Predicting of the optimal operating pressure in waterflooding operation is a very complex problem because it depends on many factors. Although most of the waterflooding projects resulted in large increases in oil recovery, the idea that starting water injection as soon as possible can maximize the oil recovery is not always correct. The following literatures discuss some related works on optimal operating pressure.

Tarr and Heuer [6] presented that the factors which are dependent upon pressure, i.e., formation volume factor, oil viscosity, free gas space, etc., will indicate that water injection should start at near “bubble point” pressure for maximum recovery. Other factors which are not dependent upon pressure, such as permeability, recovery mechanisms, fractures, reservoir geometry, etc., may indicate that water injection should start ranging from immediately to never. They gave the reason that when the reservoir is at the bubble point, oil viscosity will be the lowest and less stock tank oil will be left as residual oil by the injected water.

Chik *et al.* [7] presented the Guntong Field development studies. One of their aspects is to operate the waterflood at an optimum pressure to maximize the oil displacement. Their studies indicate that reducing reservoir pressure to the pressure of critical gas saturation and then maintain at this level can maximize the oil displacement and minimize percentage of residual oil saturation. Residual oil saturation (S_{or}) that generally formed in the middle of the pore spaces in water-wet reservoirs, being reduced due to the presence of trapped gas saturation resulting in the increment of oil recovery. The simulation work shows a 3.8% incremental recovery when operating at p_{sgc} compared to operating at p_b.

Kyte *et al.* [8] presented experimental studies which described that the presence of a gas phase was found to have a beneficial effect in reducing residual oil saturations. Their results supported the idea that the recovery from waterflooding will be maximized when the reservoir pressure reaches the critical gas saturation pressure.

3.2 Previous Works on High Water Cut Management

Waterflooding operations always encounter the problem of high water cut from high permeable sands, which would decrease oil recovery and result in early well shut-in due to excessive high water cut limit. Many previous studies have been attempted to improve the oil recovery by managing uneconomic water production. Some related field problems are raised and their solving techniques are presented in this section.

Starley *et al.* [9] presented a simulation work for Kuparuk River Field development planning. The reservoir in this field is made up of two distinct sandstone horizons which reservoir properties are contrast to each other. The technique of shutting-off high WOR interval was applied to solve the problem of uneconomic water production in high permeable sand. When the high permeable sand produces oil with WOR reach the limitation, the interval was shut-off for control water breakthrough. As a result, the injected water was shifted to the low permeable sand, accelerating low permeable sand oil production. A low WOR shut-off criteria shortens flooding duration in high permeable sand, resulting in significant oil left in the reservoir. As WOR shut-off limit increased, ultimate recovery also increased. However, low permeable sand oil production was decelerated (relative to low WOR shut-off limit) because shifting water injection from high permeable sand to low permeable sand was delayed. The sensitivity studies suggested that ultimate recovery may be optimized by producing the field to a WOR shut-off limit which maximize oil recovery in high permeable sand and minimize deceleration of oil recovery in low permeable sand.

Zengxiong *et al.* [10] presented a field study of Daqing, a large multi-layered heterogeneous sandstone reservoir. In cross section, there are up to over 100 single layers with great variations in layer thickness and permeability. Waterflooding was initiated at an early stage of development. After the oilfield development reached the high water cut stage, the layers re-grouping technique with its own injection and production system was introduced to improve the oil recovery. In this technique, thickness and productivity of each group were considered. Infill wells were drilled to form an independent system for the new development of medium-low permeable layers, which have low productivity and low water cut. In this way, there is no interference from high permeable layers and water intake capacity of the low permeable layers has been improved. As a result, the middle and lower permeable layers are becoming more and more active in oil production.

Mamgai *et al.* [11] managed waterflood in Cambay Basin of India by shift of injection row and selective injection in low permeable layers. Implementation of study in the field has resulted in an improvement of oil production from 1400 stb/d to 2000 stb/d from only one sand.

Bhushan *et al.* [12] proposed their study in various options of redevelopment stage for Mumbai High North, a highly heterogeneous multi-layered carbonate reservoir which is located on the continental shelf of Western India in Arabian Sea. One of their beneficial techniques to improve the overall oil recovery is to combine the layers of similar productivity by the use of dual completions in many injectors and producers with optimizing injection rate. Many scenarios which use this technique were studied and result in additional oil recoveries through improving the field performance.

From literatures review above, two major concerns in waterflooding are optimal operating pressure and unrecovered oil in tight layers as a result of early well shut-in from excessive water cut from high permeable layers. Many techniques have been proposed to improve oil recovery. These techniques are summarized and can be guidelines for the study.

1) Operating pressure optimization

Operating waterflooding at the critical gas saturation pressure yields optimal oil recovery. In practice, operating waterflooding at least above critical gas saturation pressure would prevent free gas from moving and avoid long fill-up period which would delay and reduce oil recoveries.

2) Shutting-off high WOR interval

By shutting-off high permeable sands which have high WOR from premature water breakthrough, the injected water will be shifted to recover more oil in low permeable sands. The oil recovery can be optimized by setting WOR shut-off limit high enough to maximize high permeable sand recovery but low enough to minimize deceleration of low permeable sand recovery.

3) Selective water injection in low permeable layers

By targeting water injection into low permeable layers would also recover remaining oil, thus improve oil recovery.

4) Separate-layer injection and production in a well

By the use of dual completions technique, layers of similar oil and rock properties could be grouped and operated at their optimal conditions. Oil could be recovered efficiently from existing injectors and producers.

5) The layers re-grouping technique and infill drilling

This technique is similar to the separate-layer injection and production in a well except for drilling an infill well to access each group. Beside the use in the waterflooded layers, this technique can be used in the system which consists of layers which do not connect to the existing injector. This can be done by drilling new injectors pass through layers which do not connect to the existing injector, to commence waterflooding to these layers.

CHAPTER 4
METHODOLOGY

In order to identify an effective strategy for a multi-layered reservoir system, influences of several parameters on production and waterflooding performance should be realized. In this study, a hypothetical model is constructed for reservoir simulation trial. Several simulated cases will be run to observe the influences of each parameter and evaluate the effectiveness of each strategy. Then, the simulation results will be analyzed and the recommendations for recovery improvement will be provided.

The workflow of reservoir simulation is organized into 2 main steps, which are reservoir model construction, and reservoir study and optimization. A rough detail of each step is described as follows:

4.1 Reservoir Model Construction

To construct a reservoir model, the following tasks are performed:

1. Select an appropriate simulation model. In this study, the reservoir simulator ECLIPSE 100, black oil simulator, is used.
2. Describe the physical properties of the reservoir such as reservoir structure, gross and net thickness, well location, and perforation interval.
3. Design reservoir grid such as grid dimension, and define reservoir and fluid properties for each grid such as porosity, permeability, fluid properties, initial fluid saturation, and initial pressure.

The details of reservoir model construction will be described in Chapter 5.

4.2 Reservoir Study and Optimization

After obtaining the hypothetical model with the desired properties, the reservoir model can now be used to simulate the behavior of different scenarios. The study is divided into two parts, which are (1) waterflooding in a homogeneous reservoir and (2) waterflooding in a multi-layered reservoir. The procedure of each part will be described in this section. The result and analysis of the first part will be presented in Chapter 6, whereas the result and analysis of the second part will be presented in Chapter 7.

(1) Waterflooding in a homogeneous reservoir

A single-layer reservoir model is constructed to represent a homogeneous reservoir. The base reservoir and fluid properties (R_s = 700 scf/stb, k = 100 md and h = 5 m) are assigned to the model. Several simulation runs are performed with an objective of better understanding the behavior of homogeneous reservoir under waterflooding.

The simulation work starts from operating pressure optimization. Several simulation cases are performed so that we can see the reservoir behavior under different waterflooding conditions. The operating pressure which gives optimal oil recovery will be defined as an optimal operating pressure.

After observing the optimal operating conditions, an attempt to improve the oil recovery by the partial shut-off technique is performed. If this strategy effectively improves the displacement process, its application will be included in the multi-layered reservoir study.

(2) Waterflooding in a multi-layered reservoir

For the multi-layered reservoir study, a two-layer model is used to observe the influence of variation in properties between layers. A reservoir model with two layers completely separated by an impermeable shale barrier in between, and the layers connected hydraulically only at a producer and an injector, is constructed. Reservoir and oil properties, which are under observation, are listed as follows:

- Layer thickness
- Oil viscosity
- Bubble point pressure
- Solution gas-oil ratio
- Layer permeability

As two major concerns are the premature water breakthrough and the free gas production when the reservoir pressure falls below the bubble point, the simulation is conducted to observe the effect of each parameter in two conditions. The first condition is a condition that the waterflooding can start any time to optimize the oil recovery. For this condition, waterflooding will be initiated at an optimal time and the reservoir pressure will be maintained at an optimal pressure which is proved from the studying of waterflooding in a homogeneous reservoir that can maximize the oil recovery. The second condition focuses on a condition that waterflooding is initiated after primary recovery in some time due to the economic reason. For this condition, free gas has liberated and produced out of the reservoir prior to waterflooding.

Then, the simulation results will be compared and analyzed. The optimal strategies will be recommended. The idea of optimal production and waterflooding strategy between two layers will be beneficially applied to more complicated multi-layered reservoir.

CHAPTER 5
RESERVOIR MODEL CONSTRUCTION

5.1 General Descriptions

The reservoir simulation is a very effective tool for reservoir engineers to seek the best production strategy for a reservoir. Simulation of petroleum reservoir performance needs construction of a model whose rock and fluid properties are defined or assigned. Because the objective of this study is to observe the behavior of the oil production in different production and waterflooding scenarios, a hypothetical model has been constructed. A good model should be accurate enough to study effects of changing parameters on displacement mechanisms in a reservoir.

In this study, the reservoir simulation is carried out with the use of Eclipse 100 (black oil simulator). A reservoir with a quarter of a five-spot pattern waterflood scheme and no-flow boundaries on all sides is considered. This system, in fact, represents behavior of a quarter of a five-spot flood pattern and the results can be used for any five-spot flood pattern. A 30 x 30 blocks model represents a 33-acre drainage area (approximately 1200 ft x 1200 ft) with two permeable sand layers separated by an impermeable shale barrier. Each layer has total thickness of 5 meters. The top view of the model is shown by Fig.5-1.

The optimal number of vertical sub-layers per layer is raised to observe vertical movement of reservoir fluids. Two models with 5 and 25 vertical sub-layers (3.28 and 0.656 meters thickness per sub-layer) representing single layer models will be compared in section 5.3. The optimal numbers of vertical sub-layers will be selected to represent the reservoir in this study.

Homogeneous properties have been assigned to the individual layers and sand thickness is assumed to be uniform across the entire reservoir. A shale layer divides the model into two independent pressure regions which are connected hydraulically only at a producer and an injector. A vertical producer and a vertical injector are located on the opposite corners of the model (in grid blocks 1:1:1 and 30:30:1, respectively). The depth of top surface of the reservoir is 9,000 ft. The 3-dimensional reservoir model for an example of 5 vertical sub-layers per layer is shown in Fig.5-2.

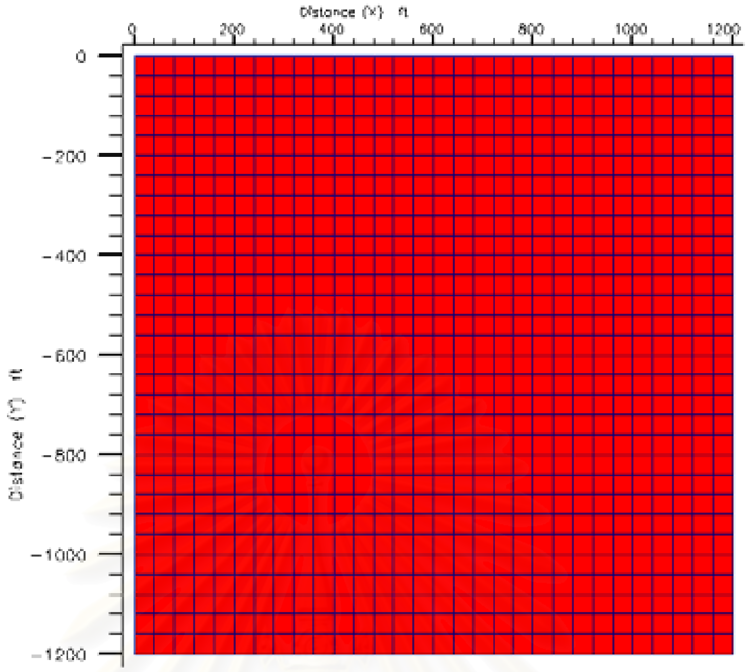


Figure 5-1: Top view of the reservoir model

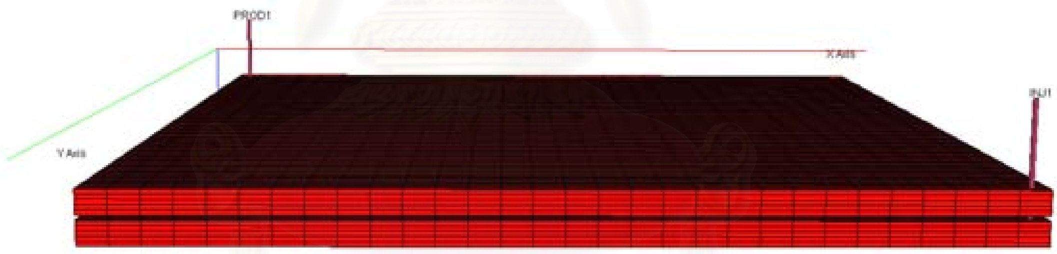


Figure 5-2: 3-dimension reservoir model of 5 vertical sub-layers per layer

5.2 Input data for model construction

5.2.1 Grid

The basic geometry of the simulation grid and various rock properties, i.e., porosity, absolute permeability in each grid cell are specified in the grid section. In this case, the Cartesian, block-centered geometry option is defined in the case definition section. All grid blocks has X and Y dimensions of 40 x 40 ft^2. True vertical depth of top face is 9000 ft. An average horizontal permeability for the base case is 100 md and the vertical permeability depends on the horizontal permeability with the value of 1/10 of horizontal permeability. Active grid blocks are assigned in permeable sands whereas inactive ones are assigned in impermeable shale barriers.

5.2.2 PVT Properties of the Reservoir Fluids

The reservoir fluids consist of oil, gas, and water. On the first day of production, the reservoir is undersaturated. Therefore, the gas is initially dissolved in the oil and initial gas saturation is zero. In this study, most PVT properties of the reservoir fluids are estimated by using the defaulted correlations supplied by the simulator as shown in Table 5-1. Input surface and reservoir properties for the base case are shown in Table 5-2.

Table 5-1: Correlations used to calculate PVT properties

Property	Correlation
Oil	
Solution gas-oil ratio	Standing
Bubble Point Pressure	Standing
Viscosity	Beggs
Formation Volume Factor	Standing
Compressibility	Vasquez
Gas	
Z Factor	Hall and Yarborough
Viscosity	Lee
Critical properties	Thomas *et al.*
Formation Volume Factor	Ideal Gas
Water	
Viscosity	Meehan
Formation Volume Factor	Meehan
Compressibility	Meehan
Reservoir density	From FVF
Rock	
Compressibility	Newman

Table 5-2: Input Data for Surface and Reservoir Properties and Conditions

Description	Value
Surface Properties and Conditions	
Oil gravity (^oAPI)	40
Gas gravity	0.798
Gas oil ratio (scf/stb)	700
Salinity	0
Temperature (^oF)	60
Pressure (psia)	14.7
Reservoir Properties and Conditions	
Temperature (^oF)	200
Pressure (psia)	4000
Porosity	0.2
Rock Type	Consolidated sandstone

At surface conditions, the oil has a calculated density of 51.46 lb/cuft while the density of water is 62.43 lb/cuft and the density of gas is 0.0498 lb/cuft. Water compressibility is 3.03 x 10^{-6} psi^{-1}, water formation volume factor is 1.02 rb/stb and viscosity is 0.3 cp at a reference pressure of 4000 psi. The bulk compressibility of the rock is 1.53 x 10^{-6} psi^{-1}. The plots of dry gas and live oil properties calculated by correlations are shown in Fig.5-3 and Fig.5-4.

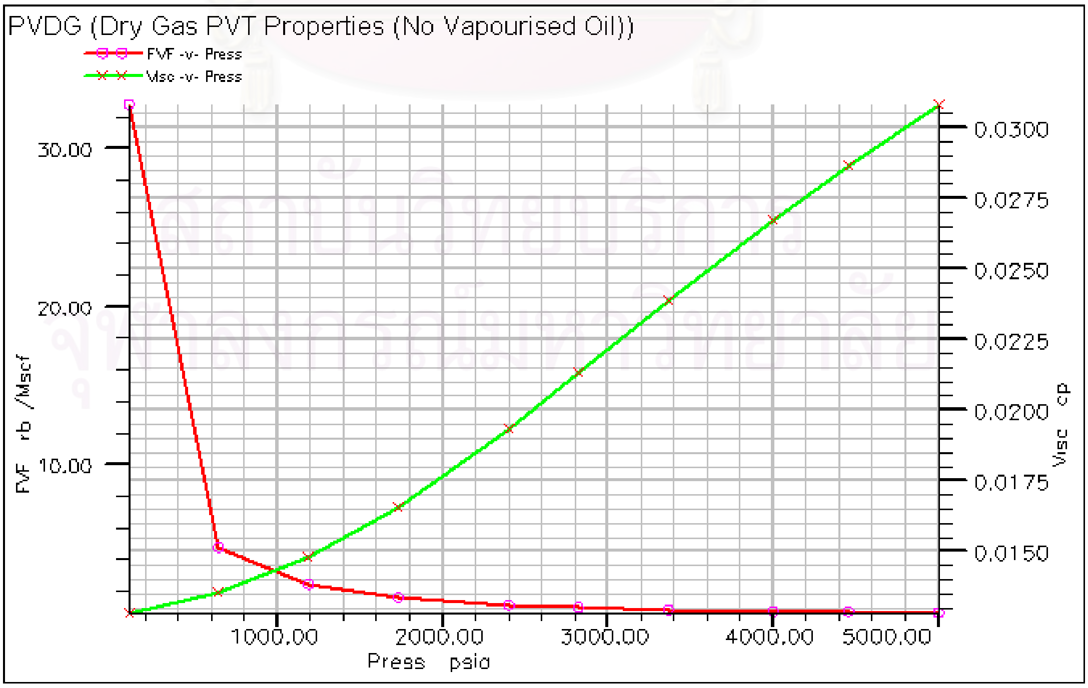


Figure 5-3: Dry gas PVT properties of the base case

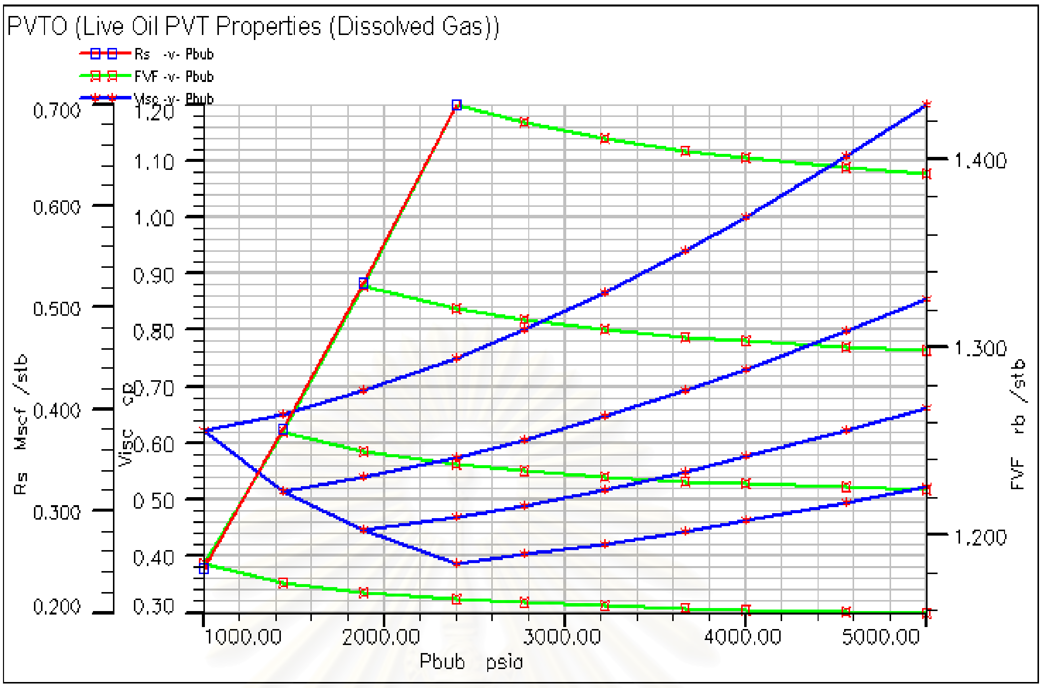


Figure 5-4: Live oil PVT properties of the base case

5.2.3 SCAL Properties of the Reservoir Fluids

For rock-fluid interaction, plots of fluids relative permeability functions are shown in Fig.5-5 and Fig.5-6.

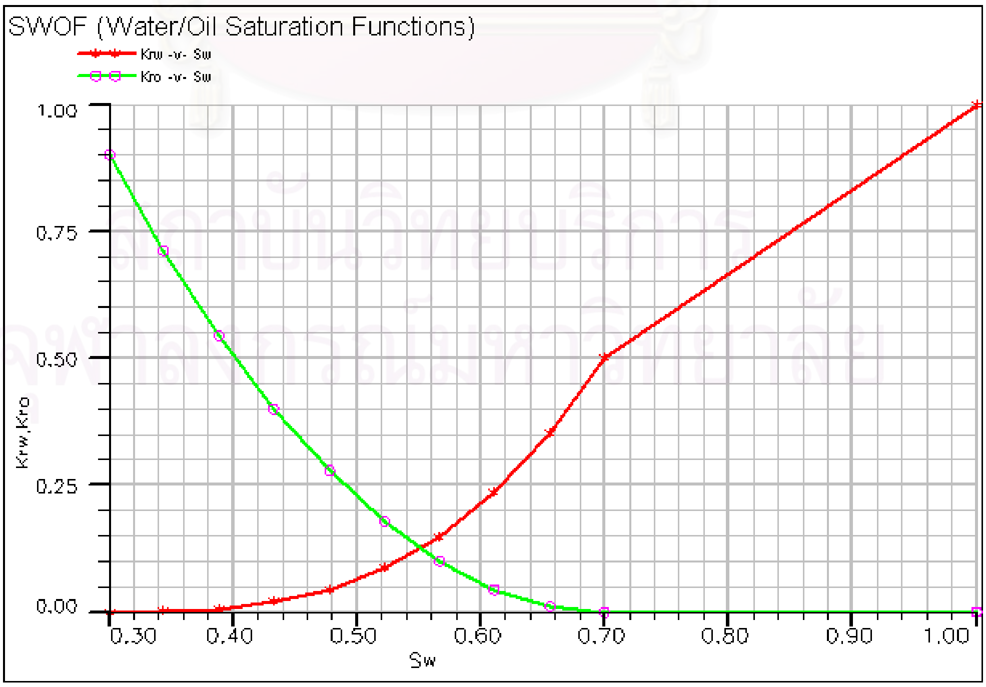


Figure 5-5: Water-oil relative permeability function

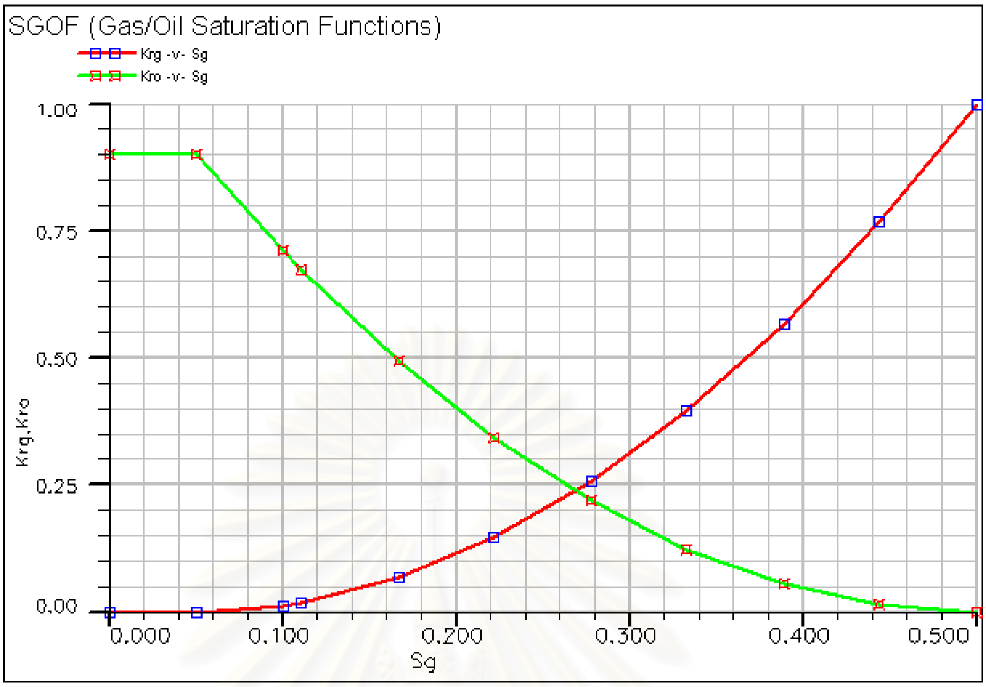


Figure 5-6: Gas-oil relative permeability function

5.2.4 Initialization

The initial conditions in every grid block are defined in the initialization section. The conditions used in this study consist of initial pressure, initial water saturation, initial gas saturation, and initial solution gas-oil ratio. The initial pressure is assumed to be 4000 psia at the upper most grid blocks of the reservoir (9000 ft depth) and the pressures in lower grid blocks are assumed to increase with the pressure gradient of water (0.433 psi/ft). Initial gas saturation is zero for the assumed undersaturated oil reservoir. The initial water saturation is assumed to be uniform for the entire reservoir. The oil contains a constant and uniform concentration of dissolved gas with a base value of 700 scf/stb.

5.2.5 Region

Because an impermeable shale barrier dividing the model into two independent pressure regions, the region number 1 and 2 are assigned to the upper layer and lower layer, respectively.

5.2.6 Schedule

A pair of an injector and a producer is located on the opposite corners of the model (coordinate of producer is in grid block 1:1:1 and injector is in grid block 30:30:1). Both wells have the hole size of 0.583 ft and are fully perforated in sand layers. The production rate is fixed at the liquid rate of 500 stb/day while the injection rate is varied to maintain the reservoir pressure at designed conditions.

The minimum allowable well head pressure was set to be 250 psi and the vertical flow performance curve is used to predict pressure drops along the well to the surface. The maximum available water injection rate was set to be 2000 stb/d. The economic limits of the producers were set using the maximum water cut fraction of 0.90 or the minimum oil rate of 20 stb/d. In the case of this study, if the production condition exceeds one of the economic limits that have been set, the producer will automatically shut-in.

5.3 Optimal Number of Vertical Sub-layers per Layer

As mentioned in section 5.1, the optimal number of vertical sub-layers per layer for simulation work is concerned. Theoretically, the more grid blocks that model contains, the more precision that the simulated result should have. However, a model with more grid blocks spends more simulated time to obtain the results. If two models with different grid blocks give very close results, it should be sufficient to use fewer grid blocks model to represent the reservoir we are studying. In this section, two single models with an equal thickness of 5 meters are constructed for comparison. The first model consists of 5 vertical sub-layers with the sub-layer thickness of 1 meter (3.28 ft). The other model consists of 25 vertical sub-layers with the sub-layer thickness of 0.2 meter (0.656 ft). The cross sections of both models are shown in Fig.5-7.

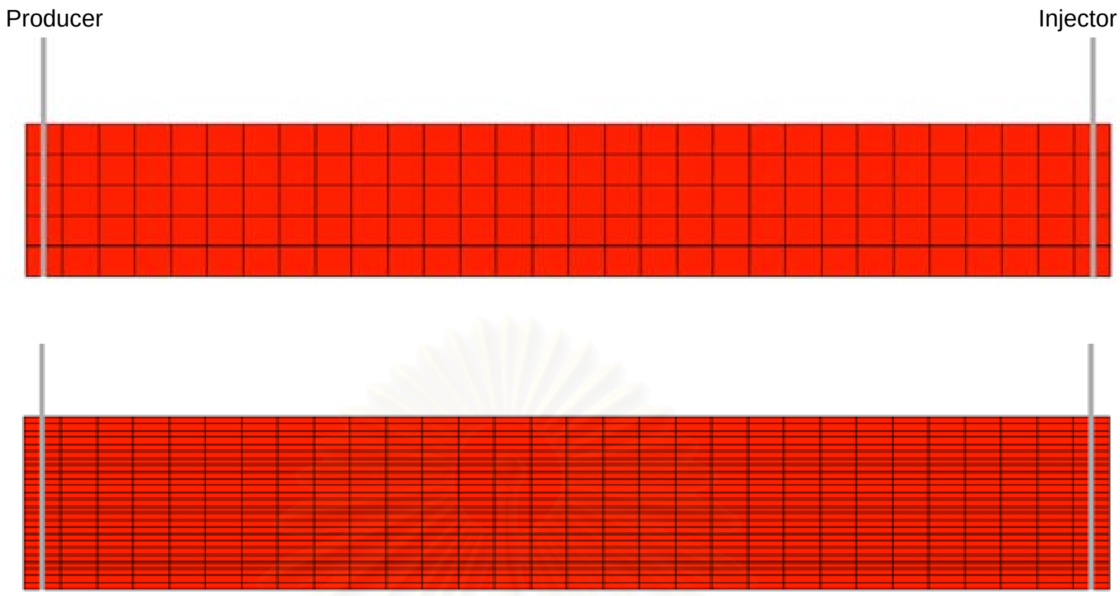


Figure 5-7: Cross sections of 5 vertical sub-layers model (above) and 25 vertical sub-layers model (below) presenting oil saturation **before** production and waterflooding

The simulation is carried out by injecting water in the first day of production and maintaining the reservoir pressure at the initial condition until the economic limit is reached. Then the recovery factors and flood front obtained from both models are observed and compared. The results are shown in Fig.5-8 and Fig.5-11.

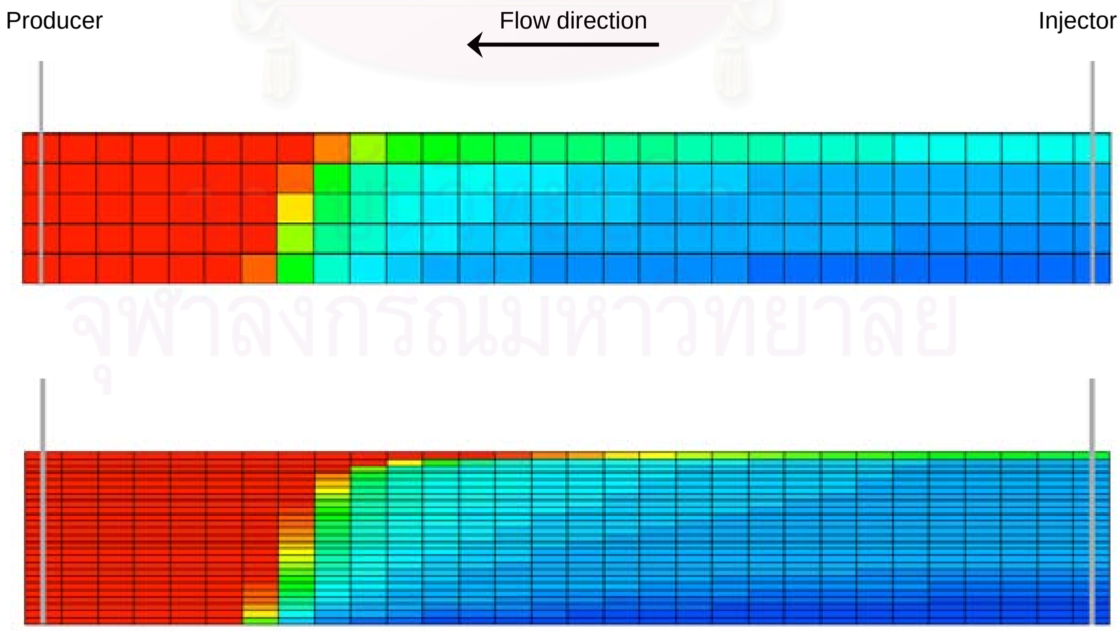


Figure 5-8: Cross sections of 5 vertical sub-layers model (above) and 25 vertical sub-layers model (below) presenting oil saturation **during** production and waterflooding

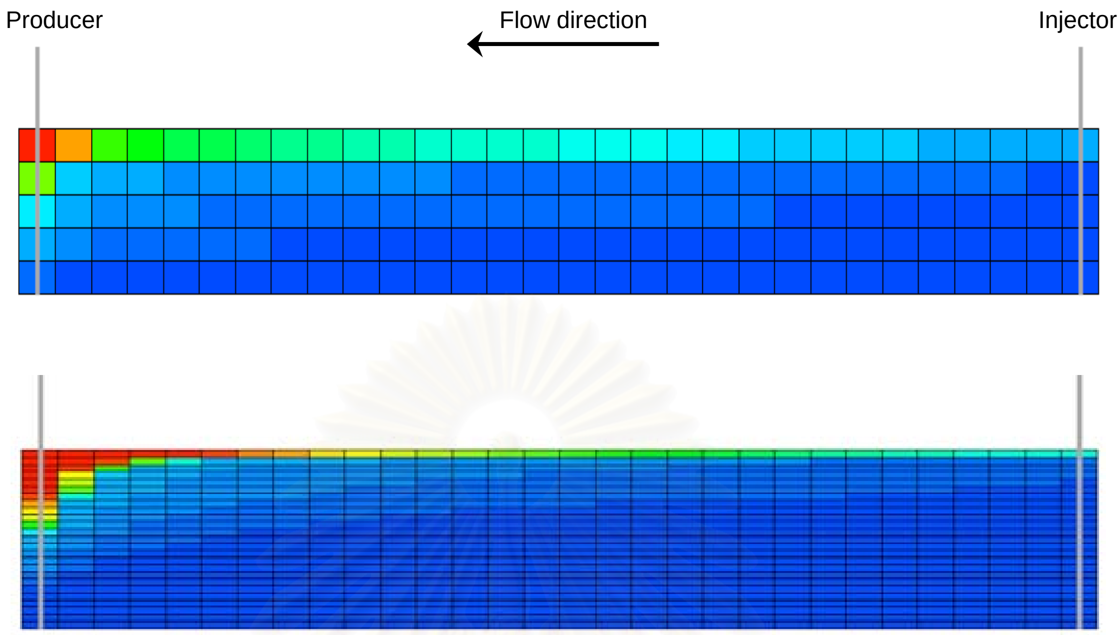


Figure 5-9: Cross sections of 5 vertical sub-layers model (above) and 25 vertical sub-layers model (below) presenting oil saturation **after** production and waterflooding

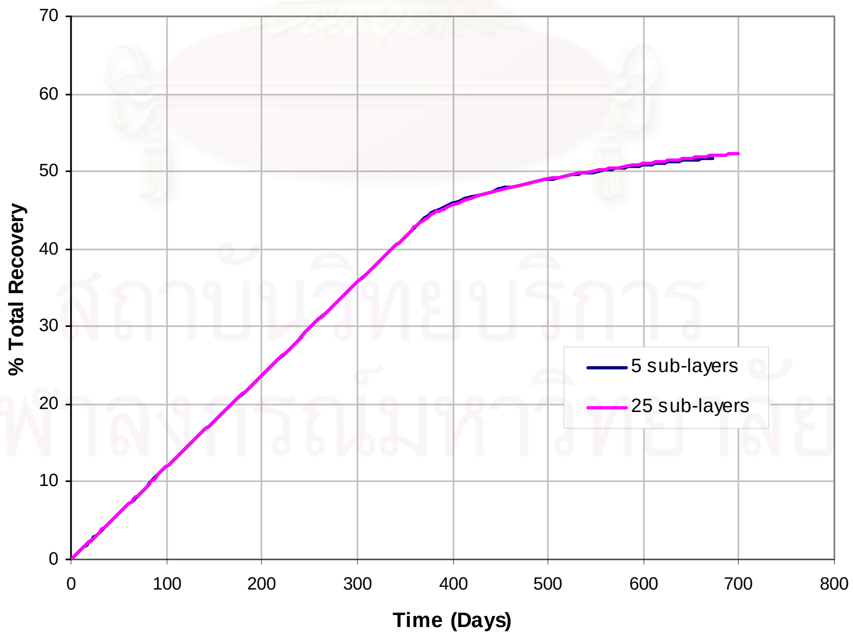


Figure 5-10: % Total recoveries from 5 vertical sub-layers and 25 vertical sub-layers models

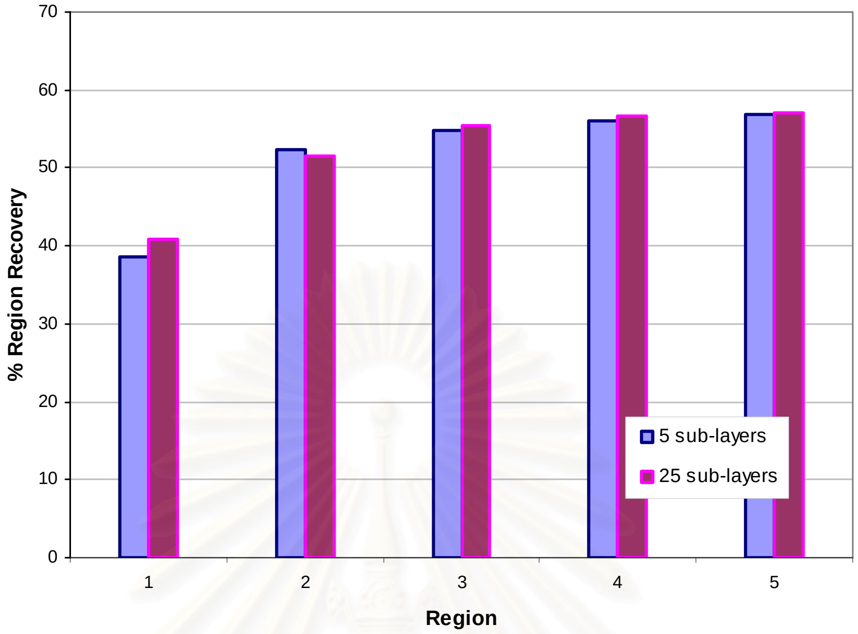


Figure 5-11: % Region recoveries from 5 vertical sub-layers and 25 vertical sub-layers models

It is noted that in order to compare oil saturations at the end of operation, five regions are defined in the simulations as shown in Table 5-3. Oil saturation in each region is presented in terms of region recovery factor as shown in Fig.5-11, where total oil recoveries are shown in Fig.5-10.

Table 5-3: Groups of Vertical Sub-layers Represented by Regions

Region	Vertical Sub-layer (from top)	
	5 sub-layers	25 sub-layers
1	1	1-5
2	2	6-10
3	3	11-15
4	4	16-20
5	5	21-25

It can be seen from Fig.5-8 and Fig.5-9 that with higher vertical resolution, the 25 vertical sub-layers reservoir model is better representing the real reservoir behavior. However, when comparing the region recovery factors, which the oil saturations are the average values, very slightly difference in region recovery factor is observed. When considering the total recovery factors, the results obtained from both models are almost the same. Therefore, it should be sufficient to use 5 vertical sub-layers per layer model to represent the reservoir in this study.

After obtaining the optimal vertical sub-layers per layer, the representative reservoir model will be used for entire simulation studies. Chapter 6 focuses on a homogeneous reservoir by using one-layer reservoir model, while Chapter 7 focuses on a multi-layered reservoir by using two-layer reservoir model.

CHAPTER 6
WATERFLOODING IN
A HOMOGENEOUS RESERVOIR

Recovery optimization in a multi-layered reservoir would be obtained from thoroughly understanding how the waterflooding behaves in a homogeneous reservoir. This chapter deals with attempts to improve oil recoveries in a homogeneous reservoir with the properties in the range of interest by using a single-layer reservoir model. There are two sections discussing two improvement strategies. The first section focuses on operating pressure optimization. The second section deals with an attempt to improve vertical displacement efficiency by the use of partial shut-off technique.

In this chapter, the base properties are used for observation. A single-layer model is used to represent a homogeneous reservoir. The simulation results will be compared and analyzed. The optimal techniques will be applied in the multi-layered model in Chapter 7.

6.1 Operating Pressure Optimization

This section has an objective to determine the operating pressure which gives the maximum oil recovery in the waterflooding operation. In order to maintain the reservoir pressure at a designed level, the voidage replacement technique is applied. The water will be injected to increase the reservoir pressure to a designed level. Once the reservoir pressure reaches the designed level, it will be maintained by volume balancing between underground produced fluid and injected water.

By using the Eclipse simulator, the GPMAINT keyword is beneficially used to adjust the production or injection rate so as to maintain the average pressure in a particular fluid-in-place region at a specified target. In this study, since the oil production rate is fixed, the water injection rate will be automatically adjusted until the region pressure is maintained at a designed level.

To investigate the optimal maintaining pressure, four simulation cases are designed as follows.

Case 1A: Maintaining the reservoir pressure at the initial pressure (p_i)

Case 1B: Maintaining the reservoir pressure at which the bottomhole flowing pressure at the producer equals to the bubble point pressure (p_b)

Case 1C: Maintaining the reservoir pressure at the critical gas saturation pressure (p_{sgc})

Case 1D: Start water injection after an amount of free gas was produced and maintaining the reservoir pressure at the critical gas saturation pressure (p_{sgc})

Case 1A represents pressure maintenance at the initial pressure, which is performed by starting water injection in the first day of production and maintaining reservoir pressure at the initial pressure (p_i).

Case 1B represents the operating condition at which the bottomhole flowing pressure at the producer decreases to the bubble point pressure. Since the bottomhole flowing pressure at the producer is lower than the pressure at any point in the reservoir, maintaining the bottomhole flowing pressure at the producer at the bubble point pressure would ensure that the reservoir pressure is maintained above the bubble point pressure.

In Case 1C, an amount of free gas is allowed to take place in the reservoir. Since the critical gas saturation pressure is the pressure at which free gas starts to flow, the waterflooding is initiated once the first free gas was produced from the wellbore. Then, the reservoir pressure would be maintained at this level to prevent more free gas production and remain this amount of gas saturation throughout the operation.

In the simulation work, the determination of p_{sgc} is done by observing the production gas-oil ratio at the surface. Before the bottomhole flowing pressure reaches p_{sgc}, free gas may liberate but was not produced so the production gas-oil ratio should equal to or less than the solution gas-oil ratio. Just above p_{sgc}, the production gas-oil ratio slightly drops because gas saturation liberates in the reservoir but does not move, so amount of solution gas in the oil decrease, hence decrease the residual oil saturation. At p_{sgc}, the liberated gas saturation is maximum while the solution gas is minimum, resulting in the minimum production gas-oil ratio and if bottomhole flowing pressure falls below this pressure level, free gas will start to flow and the production gas-oil ratio will sharply increase.

For Case 1D, the reservoir pressure is designed to deplete until the well head pressure at the producer reaches the lowest level. This condition is similar to producing under the primary recovery process before starting waterflooding or a secondary recovery process. Waterflooding will be initiated with the maximum allowable rate to fill-up the gas space and increase the production rate to the designed level again. Once the fill-up period ends and oil production increases to the desired level, the water injection rate will be adjusted to maintain the reservoir pressure at the critical gas saturation pressure, which is obtained from Case 1C.

Table 6-1 summarizes the injecting time and maintaining pressure level for each case. The values of bottomhole flowing pressure at the producer and average reservoir pressure when water injection starts are also included. It is noted that for the base properties used in this section, the bubble point pressure estimated by correlation was 2400 psia.

Table 6-1: Summary of Times and Operating Pressures for Cases 1A to 1D

Case	Starting Time	Target Pressure Maintenance (psia)	*BHP* @ Producer When Water Injection Starts (psia)	p_r When Water Injection Starts (psia)
1A	1^{st} day	p_i	3210	4000
1B	*BHP* @ producer = p_b	*BHP* = p_b	2400	2830
1C	*BHP* = p_{sgc}	*BHP* = p_{sgc}	1660	2230
1D	p_{wh} @ producer = 250 psia	*BHP* = p_{sgc}	1040	1730

Remarks: *BHP* = bottomhole flowing pressure

p_b = bubble point pressure (2400 psia)

p_i = initial reservoir pressure

p_r = average reservoir pressure

p_{sgc} = critical gas saturation pressure

p_{wh} = wellhead pressure

By maintaining the reservoir pressure using the voidage replacement strategy, the reservoir pressures of all cases remain constant during a period of controlling production at the producer as shown in Fig.6-1 and Fig.6-2. In all cases except case 1D, the oil production was maintained at the plateau rate without free gas production as shown in Fig.6-3 and Fig.6-4. For case 1D, the reservoir was allowed to deplete until the wellhead pressure at the producer reaches the lowest limit, leading to the decline of oil production from the plateau rate. Once the oil production rate started to decline, waterflood was initiated in order to increase the oil rate up to the desired level again. A large amount of injected water was needed to push free gas back into the oil (Fig.6-5). After the fill-up period ended, oil production increased to the plateau rate again. However, production gas-oil ratio was lower than from the initial value, which indicated the decrease in solution gas-oil ratio resulting from free gas production prior to waterflooding. This is clearly shown in Fig.6-4.

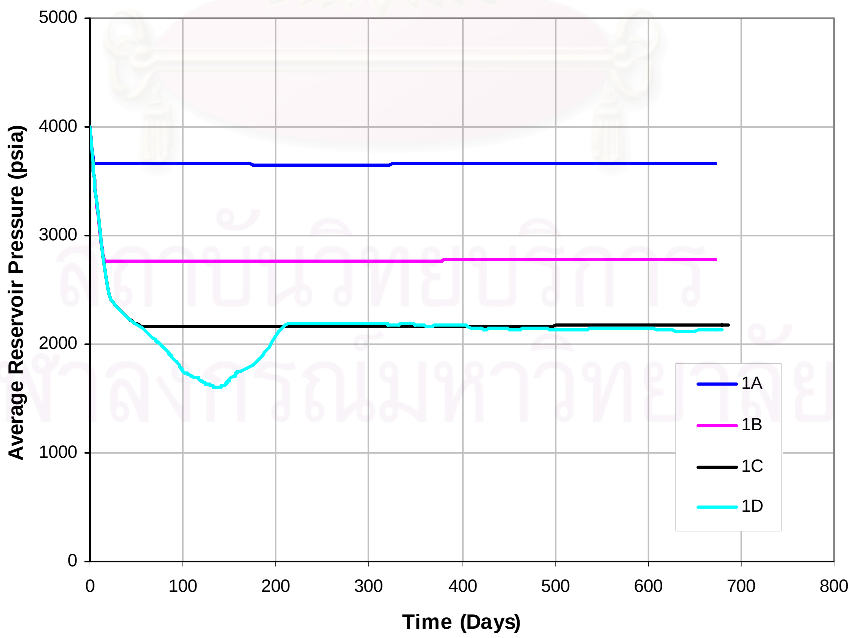


Figure 6-1: Average reservoir pressures for Cases 1A, 1B, 1C, and 1D

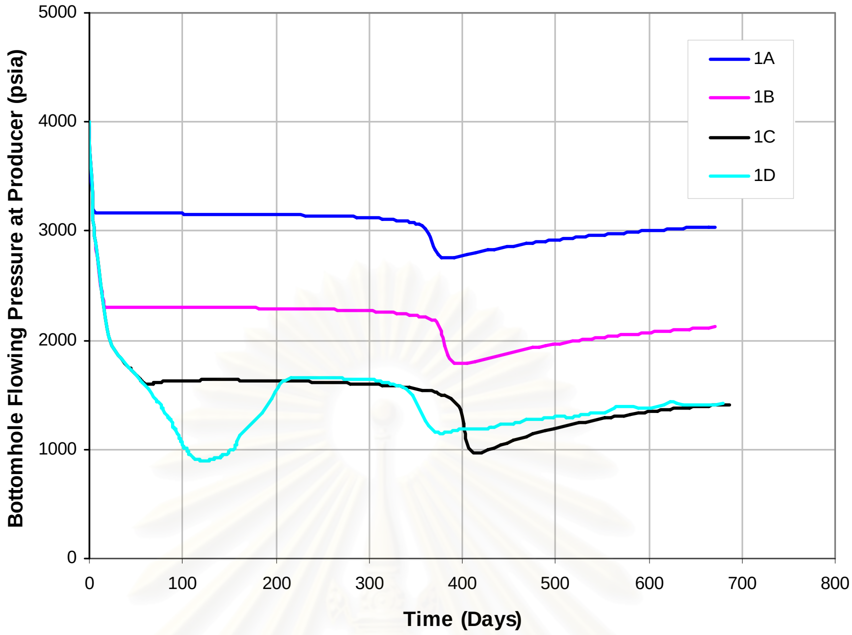


Figure 6-2: Bottomhole flowing pressures at the producer for Cases 1A, 1B, 1C, and 1D

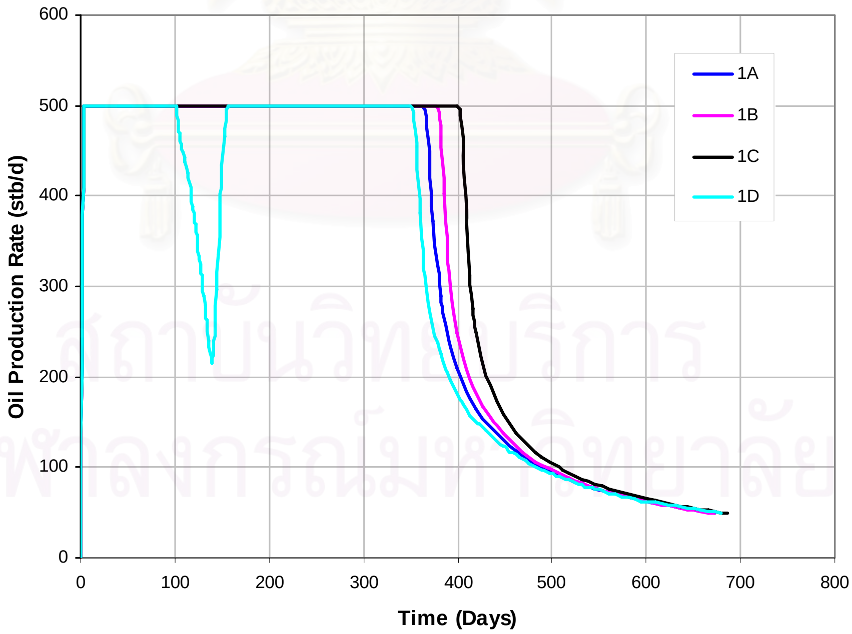


Figure 6-3: Oil production rates for Cases 1A, 1B, 1C, and 1D

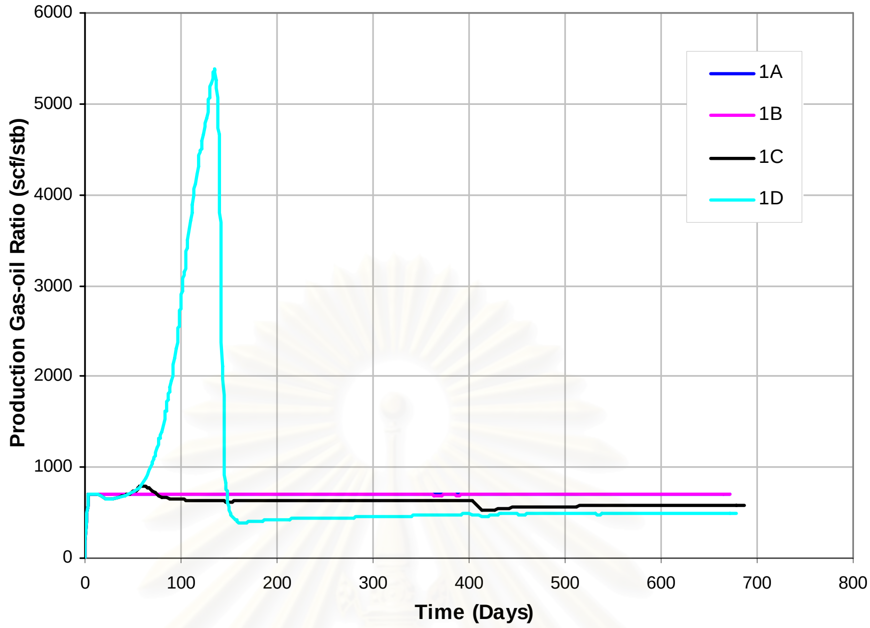


Figure 6-4: Production gas-oil ratios for Cases 1A, 1B, 1C, and 1D

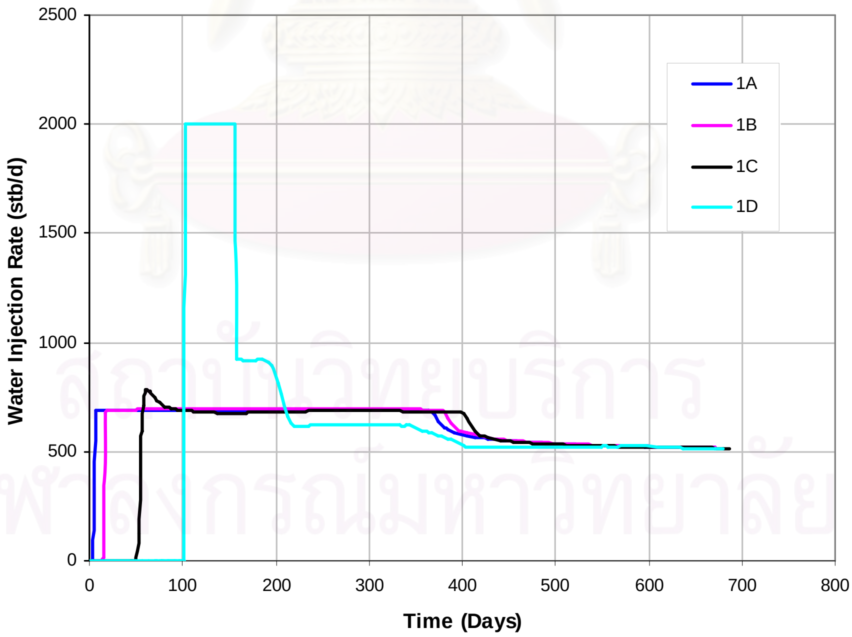


Figure 6-5: Water injection rates for Cases 1A, 1B, 1C, and 1D

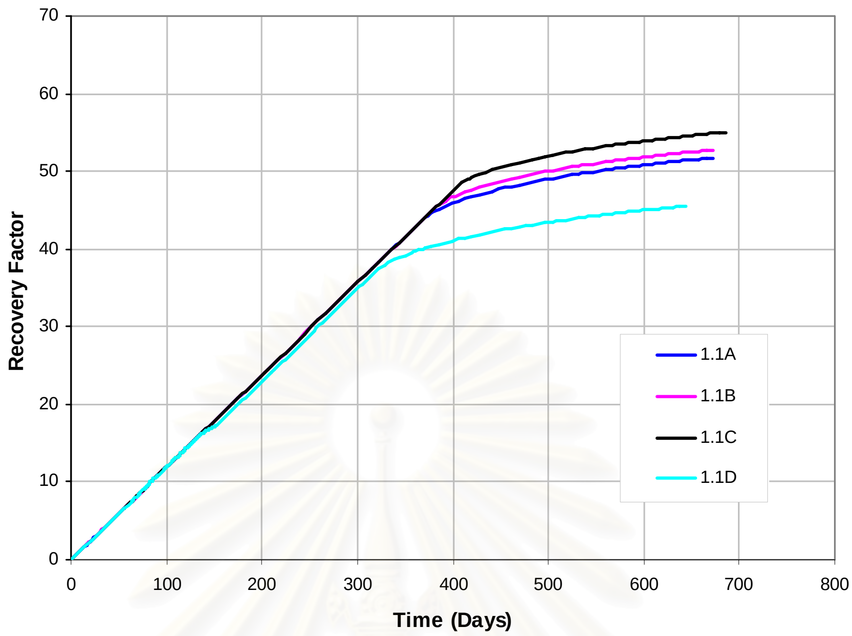


Figure 6-6: % Oil recoveries for Cases 1A, 1B, 1C, and 1D

Fig. 6-6 shows a comparison of recovery factors for all cases. From the plot, recovery factors obtained from Cases 1A, 1B, 1C, and 1D are 51.7%, 52.8%, 55.0%, and 48.9%, respectively, within the same production time. It can be seen that lowering reservoir pressure below the initial pressure increases oil recoveries. The highest oil recovery was obtained from maintaining reservoir pressure at its p_{sgc}, which is as high as 2.2% and 3.3% above those obtained from maintaining the bottomhole flowing pressure at p_b and p_i, respectively.

However, when the reservoir pressure is allowed to fall lower than p_{sgc} and some free gas has been produced, the oil recovery dramatically decreases. As seen from Case 1D, the recovery factor is 6.1% lower than Case 1C although the average reservoir pressure was maintained at p_{sgc} after the fill-up period. This case gives the lowest oil recovery compared to other cases although the water injection started as soon as the wellhead pressure at the producer reached the limit.

Fig.6-7 and Fig.6-8 show the distributions of oil and gas saturations at the end of production. Oil and gas saturations are presented in top views of the top sub-layer and top views of the bottom sub-layer, so the minimum and maximum remaining saturations can be observed. For oil saturation, top views of the top sub-layer show an amount of remaining oil, particularly at the drainage boundaries which are far away from the injector. In top views of the bottom sub-layer, small amount of oil was left, which is close to the residual oil saturation. Top views of the bottom sub-layer demonstrate that the highest displacement of oil is taken place at the bottom of the reservoir. The difference between oil saturations at the top and the bottom of the reservoir implies the fluids segregation, which is the result of difference in fluid densities during displacement process.

For gas saturation, though no significant difference between the top sub-layer and the bottom sub-layer is observed, free gas is clearly present in Case 1C. However, the gas saturation is still very low, i.e. lower than S_{gc}. The free gas present in the reservoir for Case 1C is believed to be the one of the supporting factor that help improve oil recovery by waterflooding. The other point that should be noted is that no significant difference of gas saturation between the top sub-layer and the bottom sub-layer leads to the conclusion that fluids segregation taking place in Fig.6-7 is mainly between water and oil phases.

When comparing among all cases, Case 1C has the lowest oil saturation and the highest gas saturation. Since free gas is allowed to liberate but not allowed to be produced, the residual oil saturation is minimized. Hence, oil recovery is maximized.

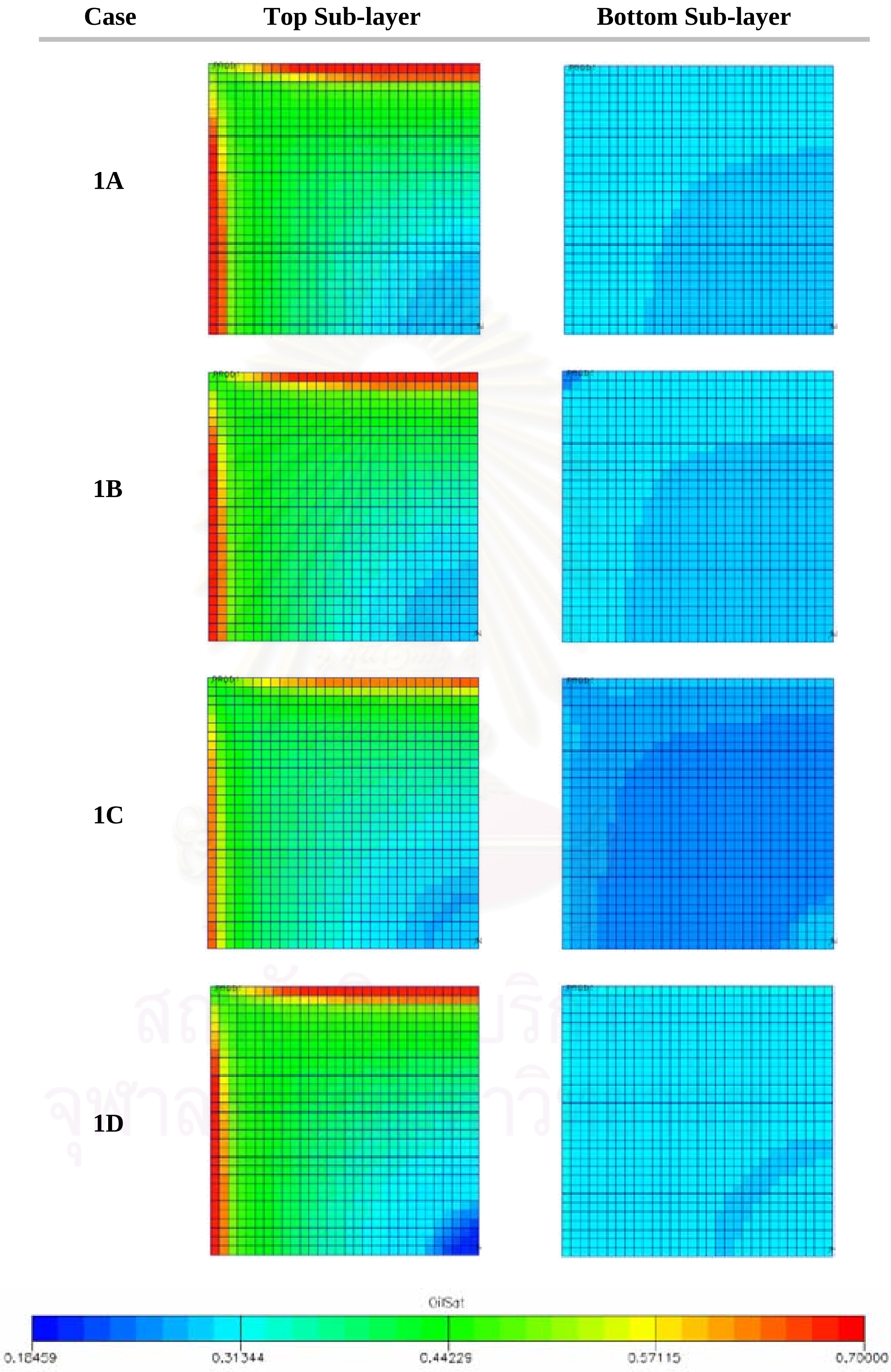


Figure 6-7: Oil saturation at the end of production for Cases 1A, 1B, 1C, and 1D

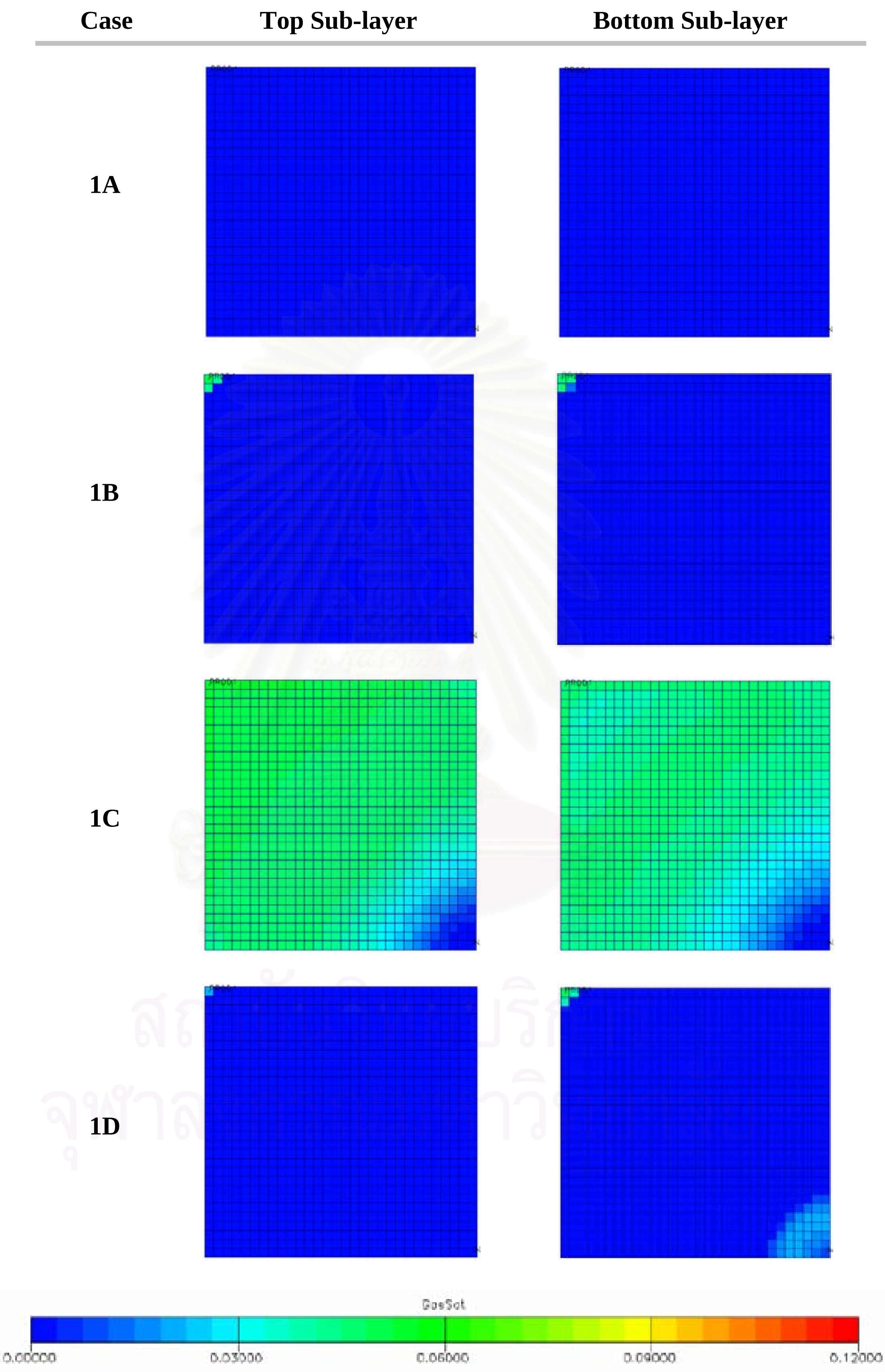


Figure 6-8: Gas saturation at the end of production for Cases 1A, 1B, 1C, and 1D

Coming back to Case 1D, which yields the lowest oil recovery, Fig.6-6 shows that the % oil recovery of this case increases at lower rate at about 100 days until about 160 days. This is inline with the behaviors shown in Fig.6-3 and Fig.6-4 where oil rate drops below the plateau rate and free gas is produced. In addition, after the % oil recovery for Case 1D deviated from the main trend of the % oil recovery of other cases (Fig.6-6), it cannot come back and join the main trend again, causing the % oil recovery to be lower than other cases at all times. This partly causes the recovery factor of Case 1D to be lower than that of other cases. It is, therefore, clearly demonstrated that producing of free gas from the reservoir has large impact on oil recovery.

In addition, it should be noted that though the bottomhole flowing pressure of Case 1D is close to that of Case 1C (Fig.6-2), and the average reservoir pressures are approximately the same (Fig.6-1), gas saturation of Case 1D is lower than that of Case 1C. This implies the phase system of Case 1D has changed and leads to a conclusion that with less solution gas, Case 1D yields less recovery factor than other cases because it is more difficult to displace higher viscous oil (Case 1D) than lower viscous oil (other cases) by water.

However, there is another interesting phenomenon that should be discussed here. Comparing Case 1A, 1B, and 1C, one can conclude that the presence of free gas in the reservoir has more positive impact on the recovery factor than increase in oil viscosity due to liberation of the free gas (Fig.6-6). With this conclusion, it is interesting to investigate if more free gas is allowed for Case 1D (referring to Fig.6-8), will oil recovery for this case be higher?

Case 1E is designed for this purpose. In this case, the average reservoir pressure will be maintained at the level when fill-up completes, which is observed by the time at which the production gas-oil ratio sharply drops to the level lower than the original solution gas-oil ratio. In Fig.6-4, the production gas-oil ratio drops at day 147 and the average reservoir pressure at that time is 1730 psia. The simulation results are as shown in Fig.6-9 to Fig.6-12.

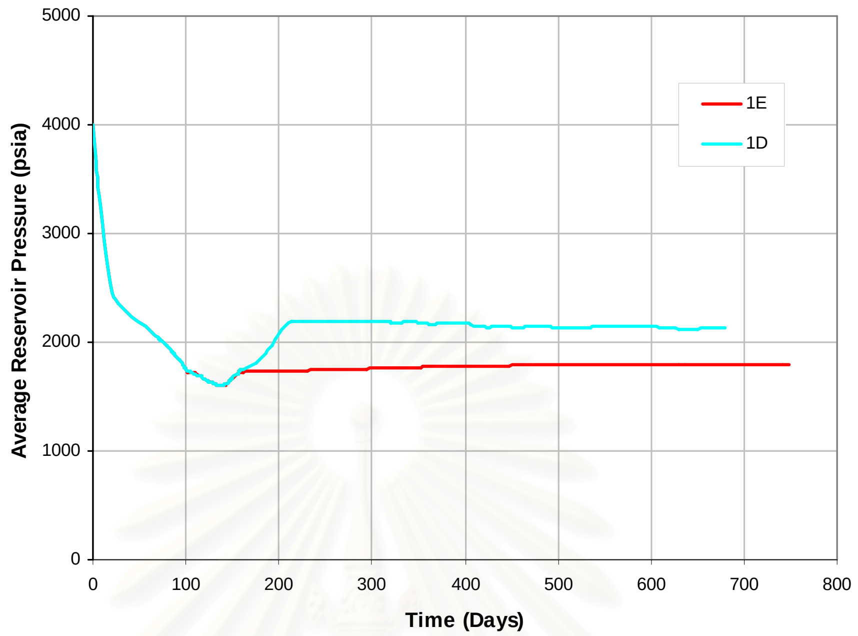


Figure 6-9: Average reservoir pressures comparison between Cases 1D and 1E

Fig.6-9 shows the comparison of average reservoir pressures between Cases 1D and 1E. It can be seen that the average reservoir pressure was decreased from approximately 2100 psia to 1730 psia. By maintaining the average reservoir pressure at this level, more gas saturation in the reservoir is observed in Fig.7-10. As a result, less oil saturation remains in the reservoir as shown in Fig.7-11. It can be said that since this pressure is the pressure which liberated gas was completely pushed back into the oil bank, it is likely that it should be the critical gas saturation pressure of the new system.

Fig.6-12 shows % recovery comparison between both cases. It can be seen that the % recoveries are slightly different at the same time. However, the production time extends and the recovery factor increases around 1% in 100 days. Therefore, this should be the most preferable operating pressure for the new reservoir system.

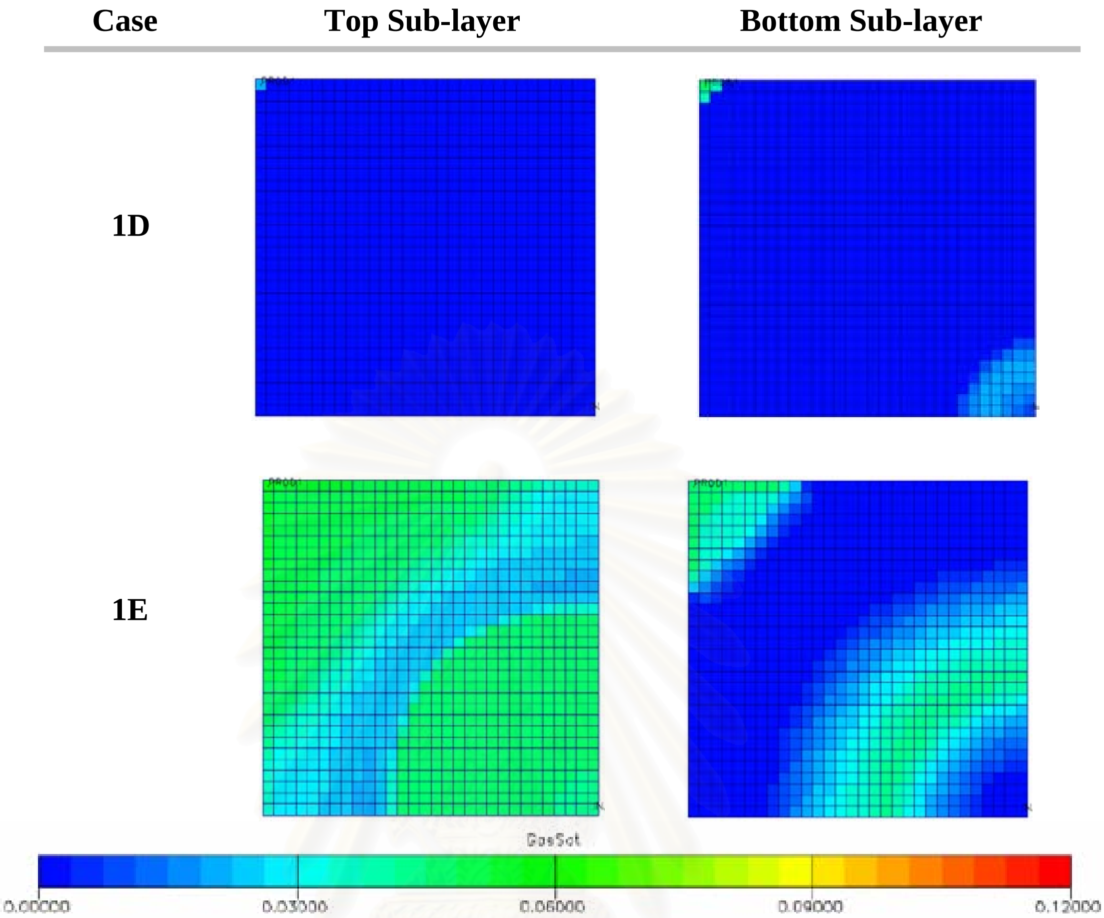


Figure 6-10: Gas saturation comparison between Cases 1D and 1E

Case **Top Sub-layer** **Bottom Sub-layer**

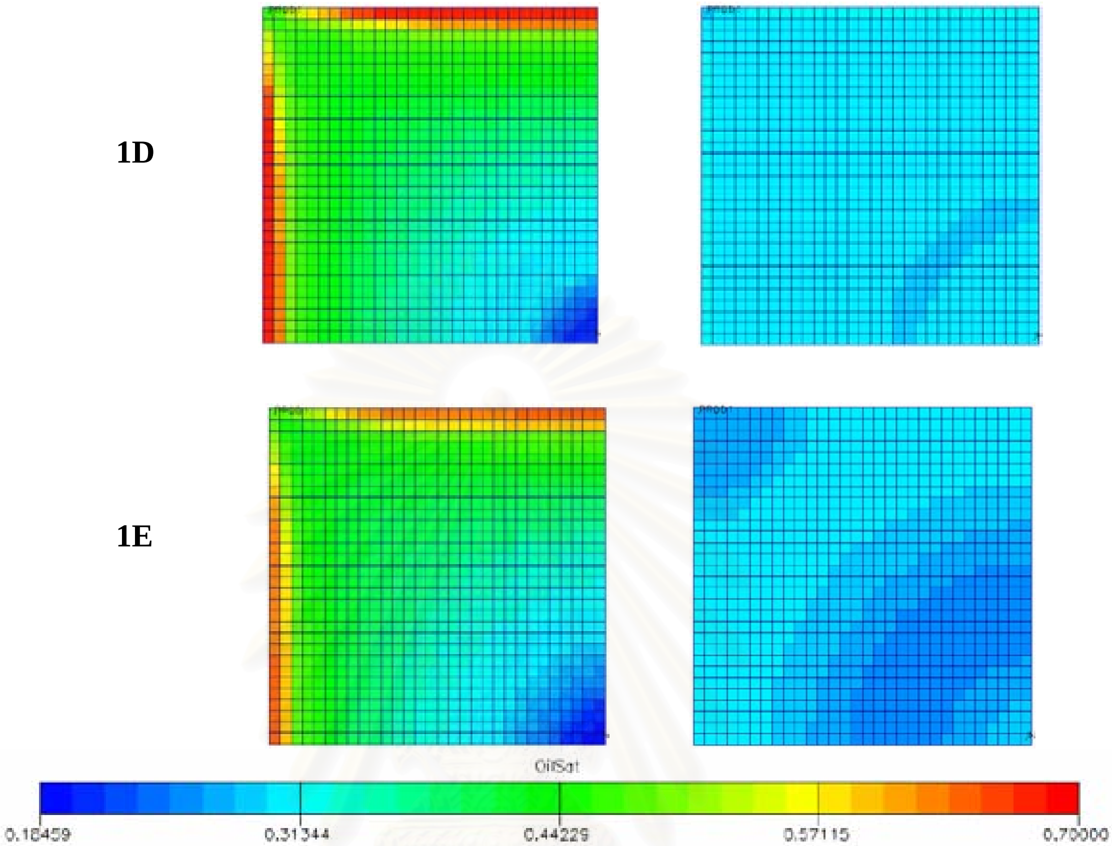


Figure 6-11: Oil saturation comparison between Cases 1D and 1E

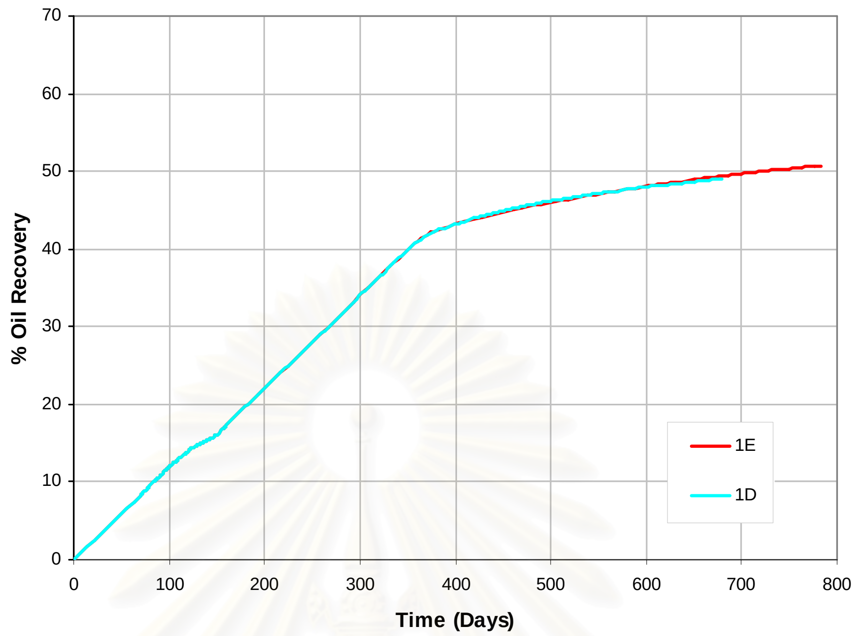


Figure 6-12: % Oil recovery comparison between Cases 1D and 1E

In conclusion, the maximum oil recovery can be obtained when starting waterflooding after letting reservoir pressure reduce until free gas liberates but does not move and maintaining reservoir pressure at this level. If the reservoir is produced until significant amount of free gas is produced, oil recovery due to waterflooding method will be less than the other cases. The result obviously agrees with the previous studies in the literature review sections described in Chapter 3.

With the observation that the top of the reservoir still contains considerable amount of oil, as illustrated by high oil saturation in Fig.6-7, it was decided to investigate if partial shut-off (at the wall of the production well) in the vicinity of the lower section of the reservoir would help improve oil recovery. The investigation on this matter will be described in the next section.

6.2 Partial Shut-off Technique

As seen in the previous section that the gravity segregation takes place in the reservoir, resulting in bypassed oil which cannot be recovered by purely water injection. In this section, the partial shut-off technique is introduced with an attempt to recover the bypassed oil at the top of the reservoir. This technique can be performed by setting patch at the wall of the production well. The patch will be set at the bottom of the layer with variations in its height of 1, 2, 3 and 4 meters. With these patch sizes, partial shut-off will be 20%, 40%, 60% and 80% of layer thickness. In order to compare fluid saturations at the end of operation, the model is divided into 5 vertical regions as shown in Table 6-2.

As we intend to improve oil recovery from the optimal pressure maintenance scenario, Case 1C is considered. Simulation work is performed by injecting water to maintain reservoir pressure at p_{sgc}. The patch will be set at the same time for all cases when the water breaks through at the producer.

Table 6-2: Vertical Sub-layers Represented by Regions

Region	Vertical Sub-layer (from top)
1	1
2	2
3	3
4	4
5	5

Simulation results are presented in Fig.6-13 to Fig.6-17. Fig.6-13 shows total recovery factors, whereas Fig.6-14 shows region recovery factors. It can be seen that there is very slightly difference in recoveries obtained from all partial shut-off jobs, even in total sense or region by region. The results can be explained by saturation distributions shown in Fig.6-15 to Fig.6-17.

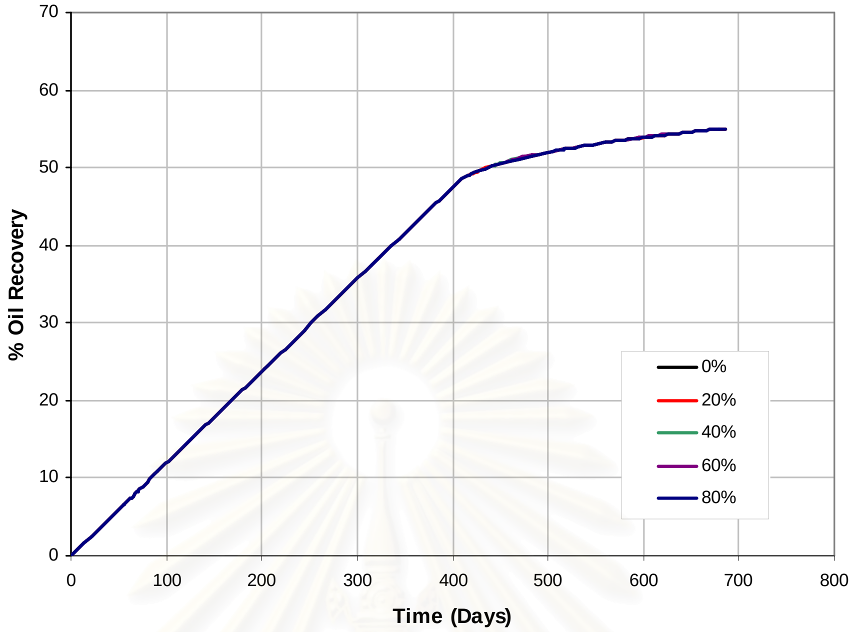


Figure 6-13: % Total recoveries for 20%, 40%, 60% and 80% partial shut-off

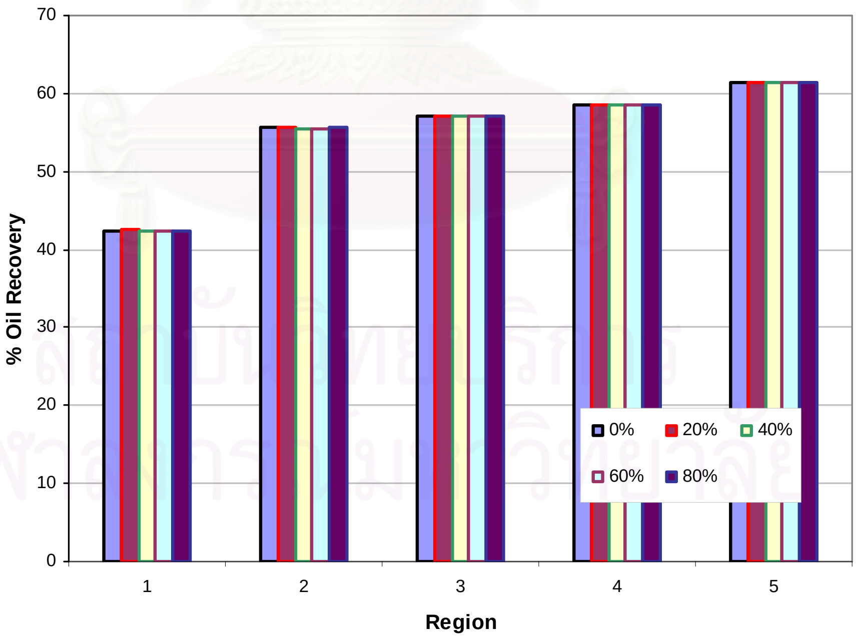


Figure 6-14: % Region recoveries for 20%, 40%, 60% and 80% partial shut-off

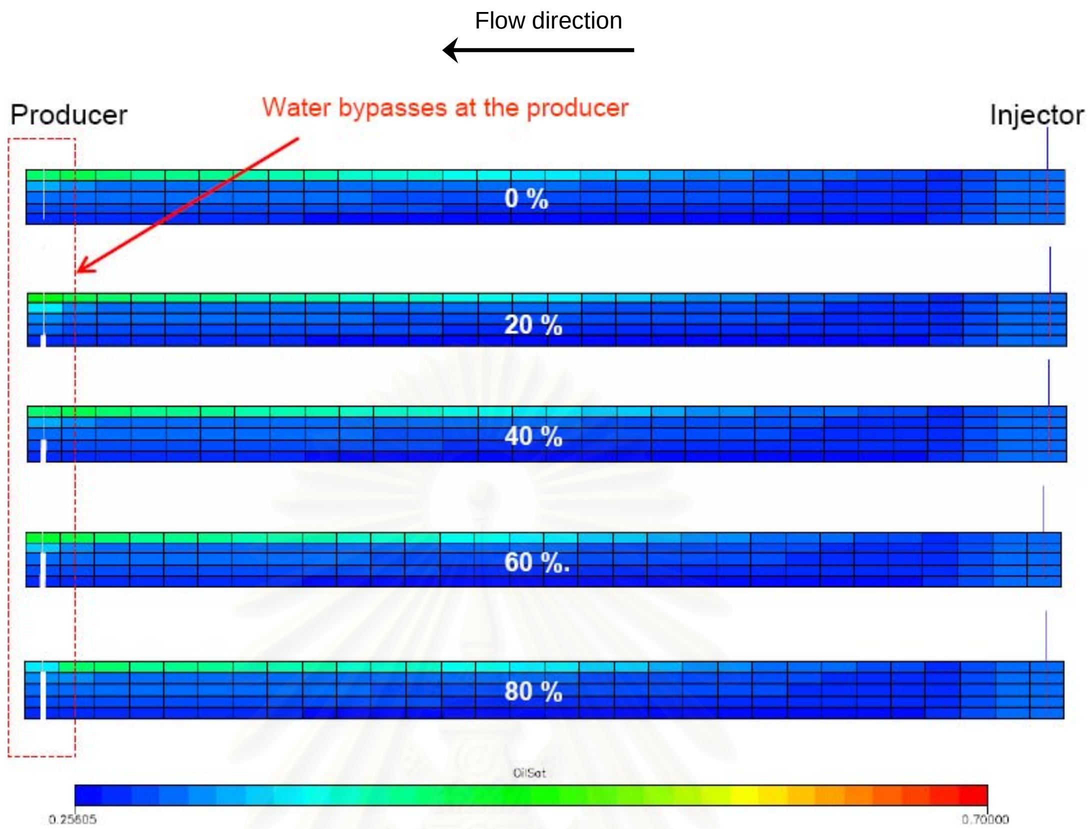


Figure 6-15: Cross section of oil saturation distribution of variations in partial shut-off at the end of production

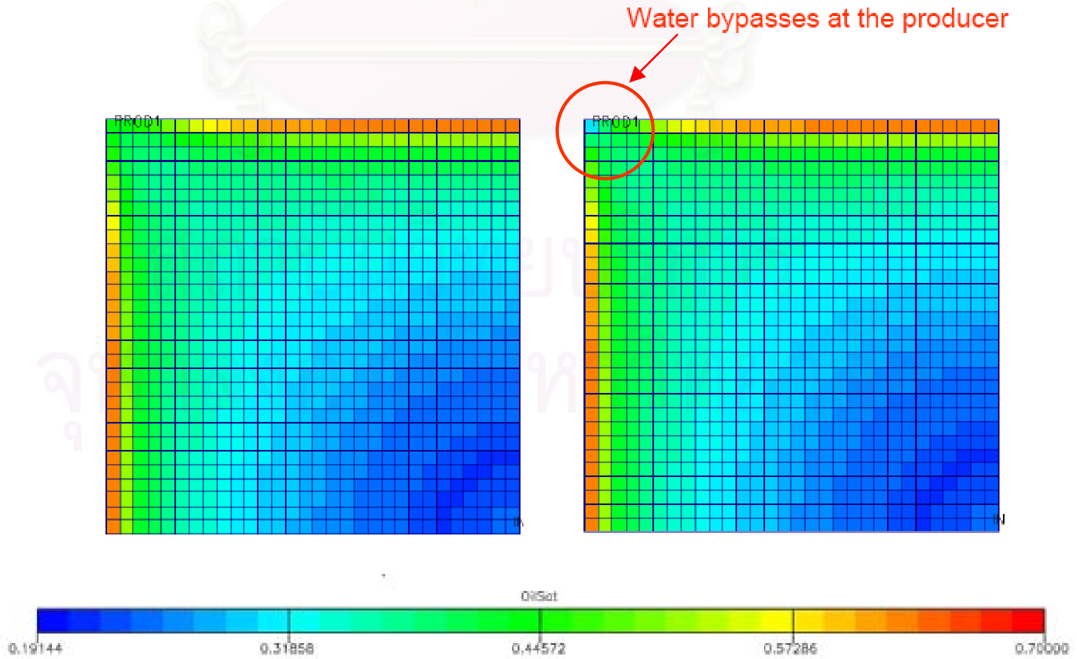


Figure 6-16: Top view of oil saturation distribution without any patch (left) and with 80% partial shut-off (right) at the end of production

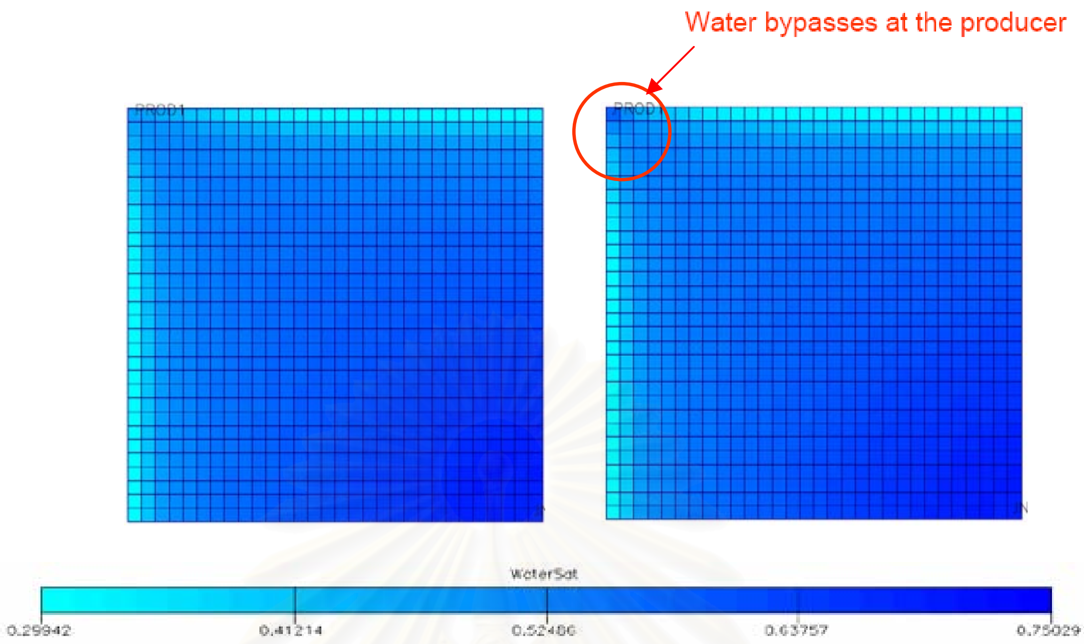


Figure 6-17: Top view of water saturation distribution without any patch (left) and with 80% partial shut-off (right) at the end of production

From cross section and top views, it is obviously seen that the change in oil saturation took place only around the producing well. Once the flood front reached the producer, patch job was performed to obstruct water producing region. In stead of shifting the existing water path upward, water still moved on the same horizontal path. Water would not change its direction until it reached the patch. Once it was obstructed, the water front would move upward and then entered the producing well, bypassing the oil in the above region behind. As a result, the remaining oil was still unrecovered.

The results are the same for all patch sizes. It is presumed that it is the effect of difference between vertical and horizontal permeabilities. Water still moves horizontally since the horizontal permeability is 10 times of vertical permeability. When it comes to the end, then it will move upward where pressure gradient is the lowest. Therefore, this technique cannot improve the oil recovery for the conditions under study.

In summary, we see that operating the waterflooding at p_{sgc} gives the maximum oil recovery. Operating pressure above this level gives lower the oil recovery. However, operating pressure below this level significantly impairs the oil recovery because of free gas production. Therefore, it is recommended that waterflooding should be initiated in the early stage of production to prevent the free gas production. If possible, the reservoir pressure should be as low as free gas will not produce from the reservoir to maximize the oil recovery.

After an attempt to improve the oil recovery, we also see that the partial shut-off technique does not improve vertical oil displacement for the conditions under study, i.e. thin layers (less than 5 meters thick) and k_v/k_h = 0.1, because of water bypassing at the producing well.

In reality, most reservoirs are heterogeneous. Due to the differences in oil and rock properties in a multi-layered reservoir system, maintaining pressure at the optimal level for every region becomes impossible. The optimization plans for this kind of reservoir will be studied in the following chapter.

CHAPTER 7
WATERFLOODING IN
A MULTI-LAYERED RESERVOIR

After we derived better understanding in displacement process in one layer, the influence of variation in properties between layers will be studied in this chapter. For this purpose, a pair of layers is used for observation. The simulation results from 2-layer model will describe production and waterflooding behavior between layers, leading to better understanding of the displacement process in more complicated multi-layered reservoir.

In a combination of layers with different fluid and rock properties, two major concerns are the premature water breakthrough and the free gas production from the reservoir, which impair the recovery factor. With the vertical heterogeneities of multi-layered reservoirs, the properties which we concern are layer thickness, oil viscosity, bubble point pressure, solution gas-oil ratio, and layer permeability. However, as the bubble point pressure and the oil viscosity are functions of the solution gas-oil ratio, the variation in both properties will be studied via the variation in solution gas-oil ratio.

In this chapter, the displacement process by waterflooding under the influence of the variations in oil and rock properties are studied. Two conditions will be considered here. The first condition is a condition that waterflooding can start any time while the second condition is a condition that the reservoir has been produced under primary recovery for some time before waterflooding can start. The first condition represents the condition that the operator of the field tries to optimize oil recovery since the beginning with available technical and economical support. The second condition represents the condition that the operator of the field has no choice but has to produce under the primary recovery condition first. This is usually mainly due to the economical reason. However, sometimes the reservoir condition is very complicated and planning for waterflooding is unlikely due to high uncertainty of various estimated properties. This can lead to the production strategy of producing under primary recovery first. After reservoir characteristic is known through addition information from drilling of development wells and production data, waterflooding can be planned accordingly.

- **The condition when waterflooding can begin at any time**

From the result of the study discuss in the previous chapter, it is concluded that start of waterflooding when the reservoir is at the condition of critical gas saturation pressure will yield highest recovery factor. This condition is, therefore, selected for consideration of the influence of variations in oil and rock properties.

- **The condition when waterflooding can begin after production under primary recovery**

In this case waterflooding starts after the reservoir has been produced under the primary recovery condition for some time. Water injection will be initiated with the maximum available rate to fill-up the free gas. Once filling-up is completed or almost completed, water injection rate will be controlled to maintain the bottom hole flowing pressure at the producer as close as the critical gas saturation pressure as possible. This condition is maintained due to the belief that it can give highest recovery factor.

For both conditions, several simulation cases will be performed to observe the influence of layer thickness, solution gas-oil ratio, and layer permeability on flood front movement and fill-up behavior. The strategy to improve the recovery factor will be simulated. Recommendations for optimization of oil recovery will also be provided.

7.1 Effect of Layer Thickness

The simulation work was conducted to observe the depletion between layers, water distribution between layers, and flood front movements when two layers have different thicknesses. The reservoir model consisted of two layers with 5 meters thick for the upper layer and 1 meter thick for the lower layer. In this case, 0.2 meter grid block height was used for better resolution for 1 meter thickness. Therefore, there were 5 vertical sub-layers for 1 meter thickness and 25 vertical sub-layers for 5 meters thickness.

Firstly, a simulation case without waterflooding was run to observe the depletion between layers. The simulation results are as shown in Fig.7-1 and Fig.7-2.

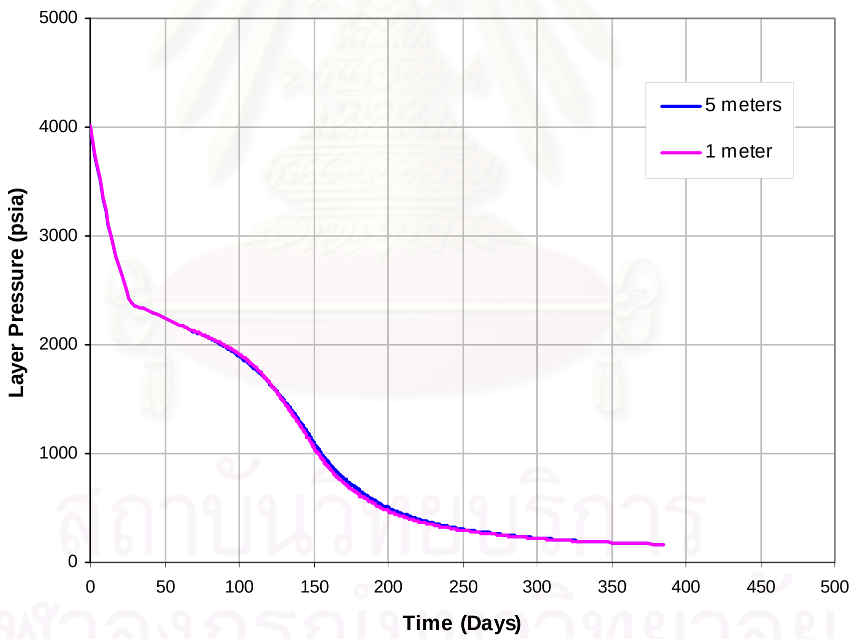


Figure 7-1: Layer pressures of 2-layer model with 5 meters thick for upper layer and 1 meter thick for lower layer in case of primary depletion

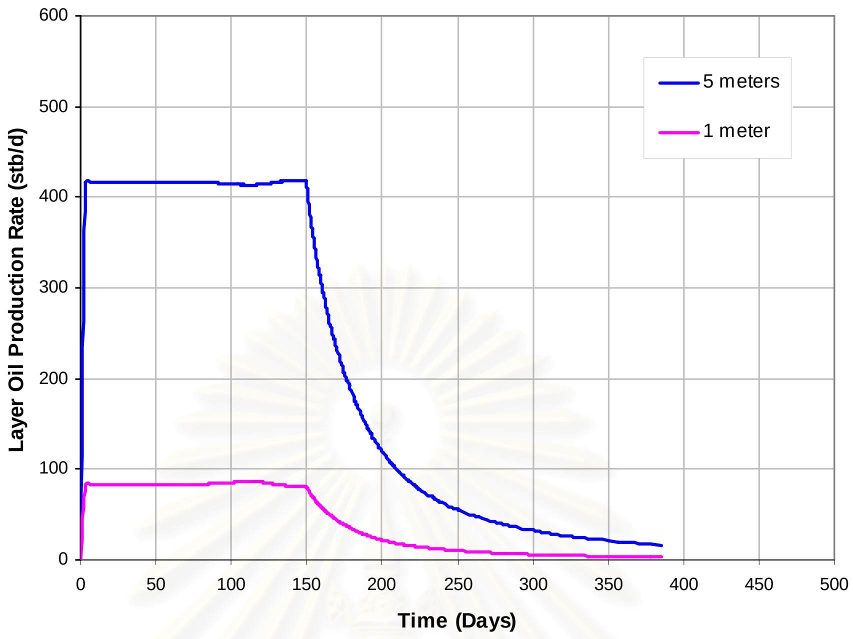


Figure 7-2: Layer oil production rates of 2-layer model with 5 meters thick for upper layer and 1 meter thick for lower layer in case of primary depletion

From Fig.7-1, it can be seen that both layers depletes simultaneously. This is because the layers are producing with the rates proportion to their thicknesses, which could be observed from Fig.7-2. Due to the same depletion rate, both layers produce free gas simultaneously. However, it is noted that because the two layers are not too far from each other, hence the layer pressures are not much different. If the layers are far apart, the layer pressures will be much different, and free gas will be produced at different times.

(i) The condition when waterflooding can begin at any time

As mentioned earlier, the water injection is selected to start at reservoir pressure equal to p_{sgc} and maintain the reservoir pressure at this level during water injection so that the highest recovery factor can be achieved. However, with a 2-layer system, maintaining the reservoir pressure at p_{sgc} can be accomplished for only one layer while the reservoir pressure of the other layer will be higher than its p_{sgc}. This condition will be applied for simulation runs with the case that the reservoir pressure is maintained at p_{sgc}.

Fig.7-3 to Fig.7-6 show simulation results of this case. Fig.7-3 shows how pressure in each layer behaves. The pressure in 5-meter layer is controlled such that no free gas is produced. Because the two layers are close to each other, the pressures in each layer are close. This implies that the fluid behavior in each layer should be only slightly different.

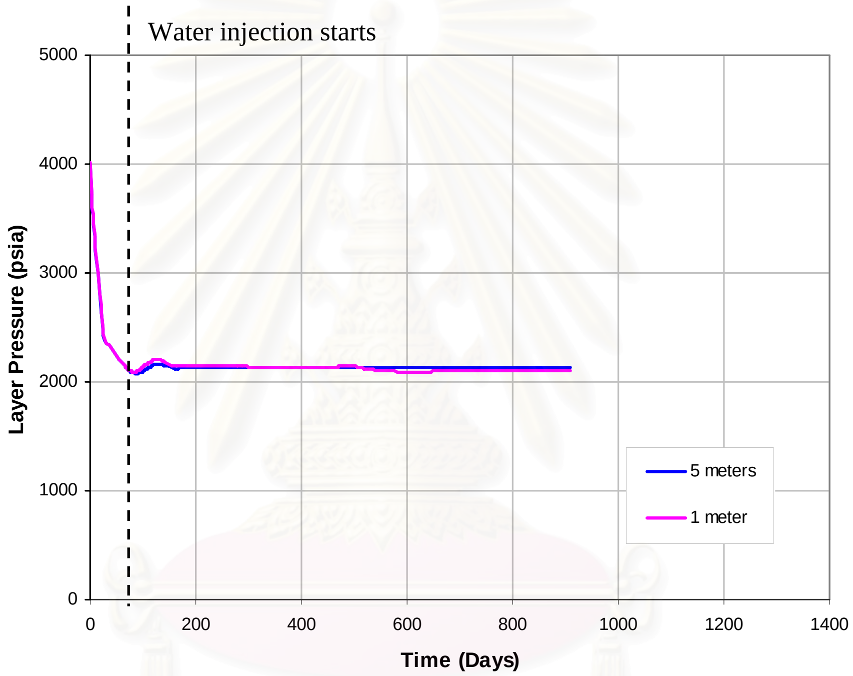
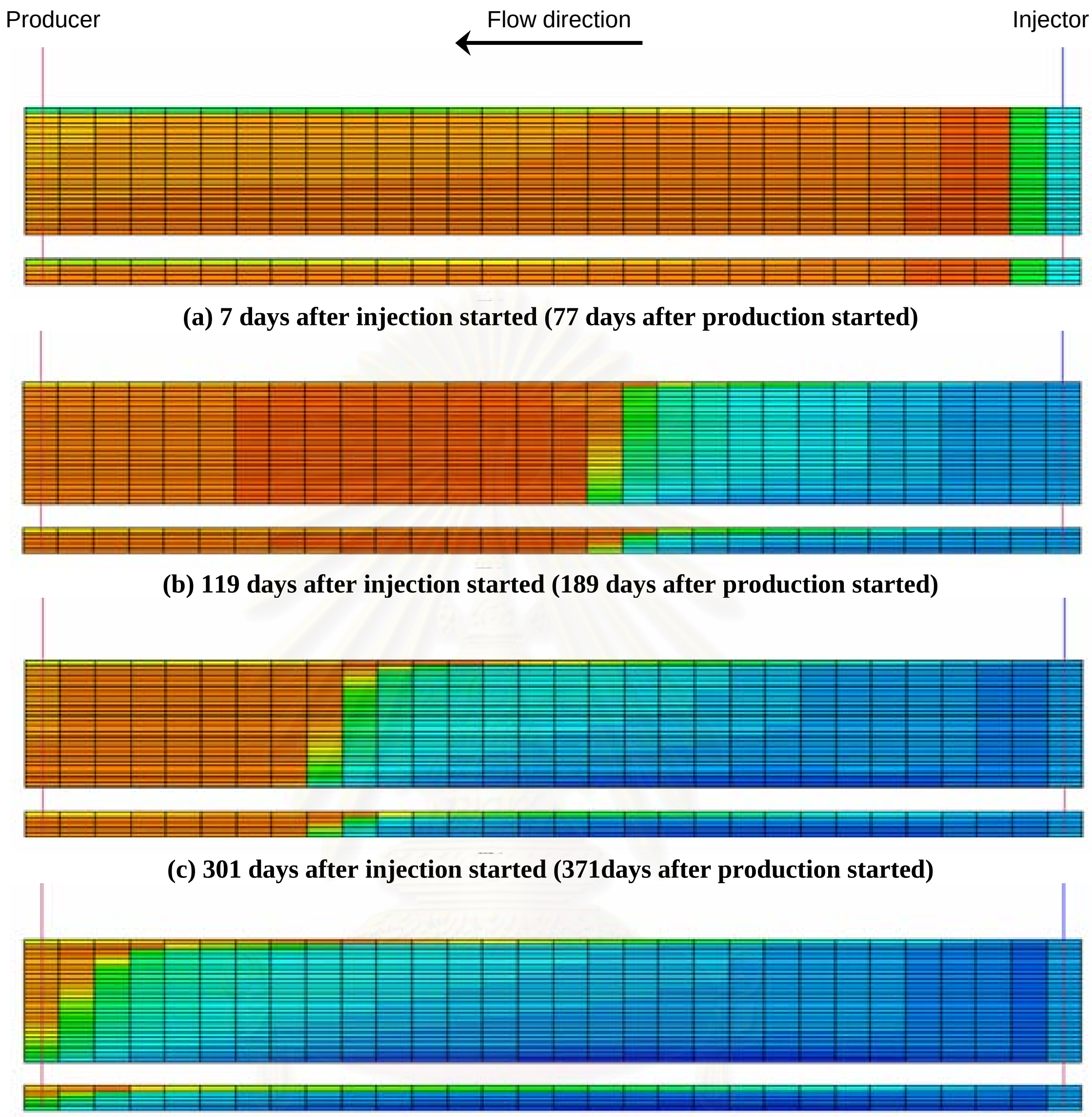


Figure 7-3: Layer pressures of 2-layer model with 5 meters thick for upper layer and 1 meter thick for lower layer of the case which waterflooding is initiated at p_{sgc}



(a) 7 days after injection started (77 days after production started)

(b) 119 days after injection started (189 days after production started)

(c) 301 days after injection started (371days after production started)

(d) 413 days after injection started (483 days after production started)

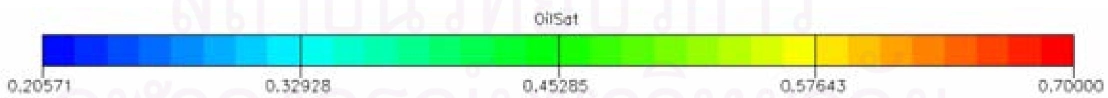
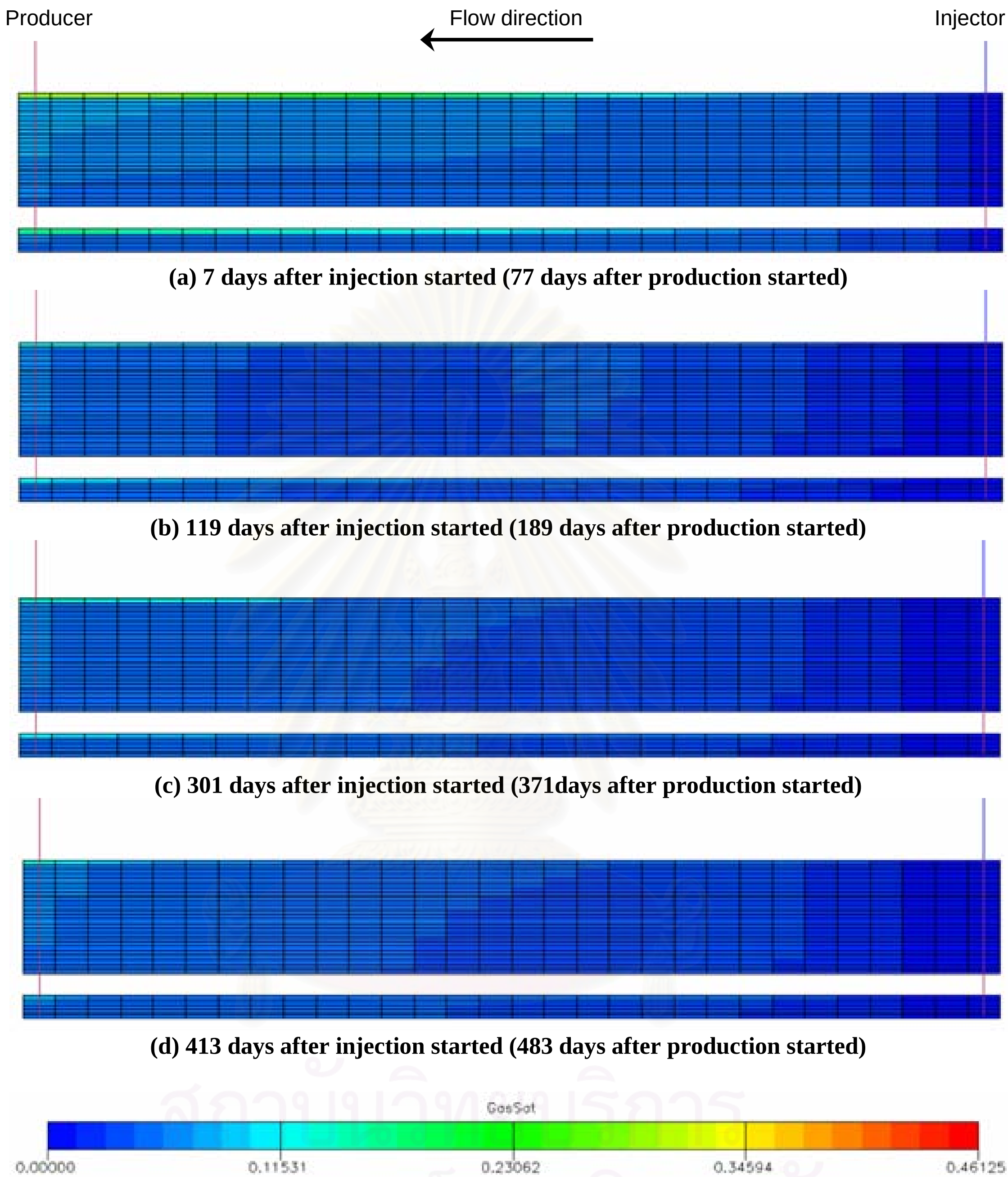


Figure 7-4: Cross section of 2-layer model with 5 meters thick for upper layer and 1 meter thick for lower layer showing oil saturation of the case which waterflooding is initiated at p_{sgc}



(a) 7 days after injection started (77 days after production started)

(b) 119 days after injection started (189 days after production started)

(c) 301 days after injection started (371days after production started)

(d) 413 days after injection started (483 days after production started)

Figure 7-5: Cross section of 2-layer model with 5 meters thick for upper layer and 1 meter thick for lower layer showing gas saturation of the case which waterflooding is initiated at p_{sgc}

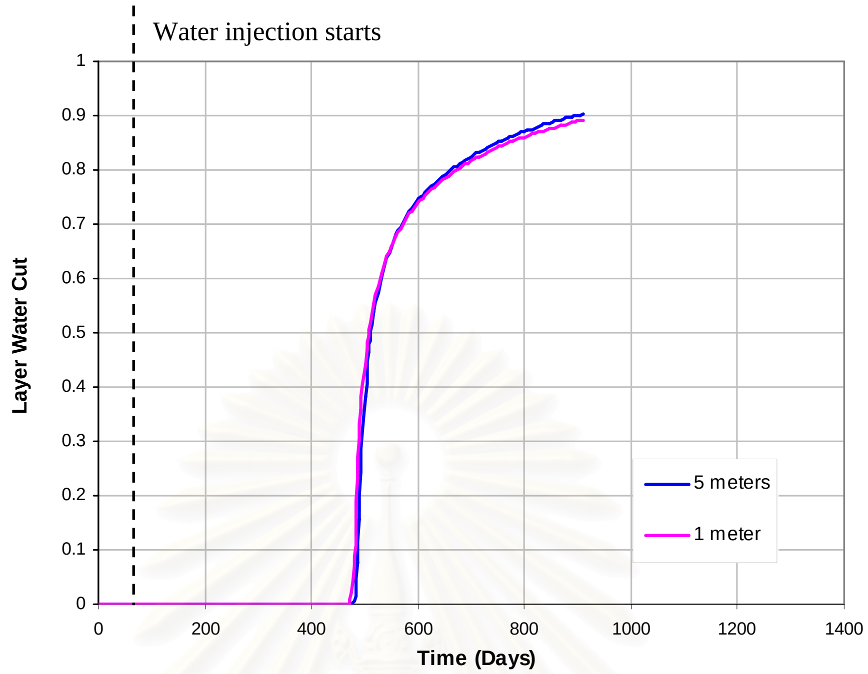


Figure 7-6: Layer water cuts of 2-layer model with 5 meters thick for upper layer and 1 meter thick for lower layer of the case which waterflooding is initiated at p_{sgc}

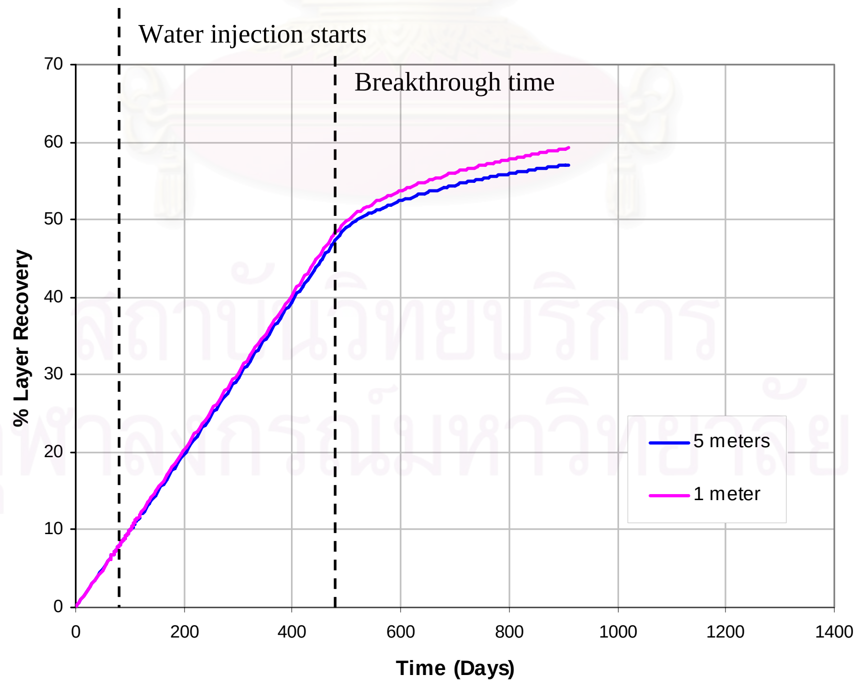


Figure 7-7: % Layer recoveries of 2-layer model with 5 meters thick for upper layer and 1 meter thick for lower of the case which waterflooding is initiated at p_{sgc}

From the oil and gas saturation profiles (Fig.7-4 and Fig.7-5), it can be said that flood front of both layers are similar up to breakthrough time. In turn, breakthrough time is almost at the same time for each layer (Fig.7-6). This implies that different thicknesses have no impact on waterflooding behavior. This is confirmed by the layer recoveries which are almost the same up to the breakthrough time (483 days) shown in Fig.7-7.

However, after breakthrough, the layer recovery curves start to diverge an about 2% difference in recovery factor (57.1% for 5 meters thick layer and 59.2% for 1 meter thick layer). It should be said that thickness has some effect on the recovery factor of each layer. This, in fact, should be expected because water tongue or gravity segregation effect in thinner layer should be less than that for thicker layer with less gravity segregation effect. With less gravity segregation effect, waterflooding performance should be better, hence better recovery factor. With larger contrast of the layer thickness, it is expected that differences in layer recovery factor should be more significant.

(ii) The condition when waterflooding can begin after production under primary recovery

After production under primary recovery process, there is free gas present in the reservoir and some free gas will be produced. If water injection starts at this condition, it is shown in Chapter 6 that the recovery factor for this case will be less than the case with water injection starting at the time the layer pressure equals to p_{sgc}. In this section, the effect of layer thickness on the performance of waterflooding is investigated.

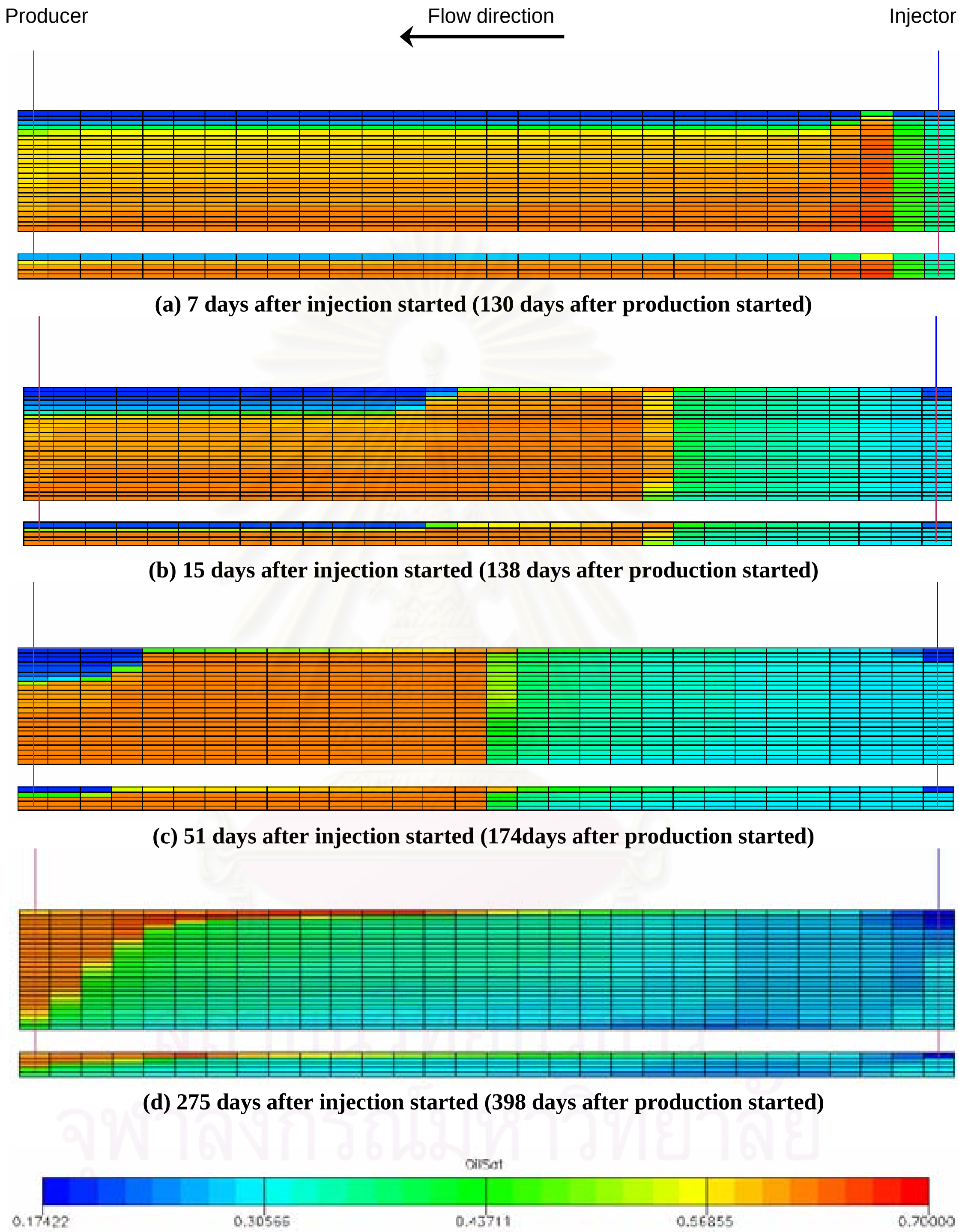
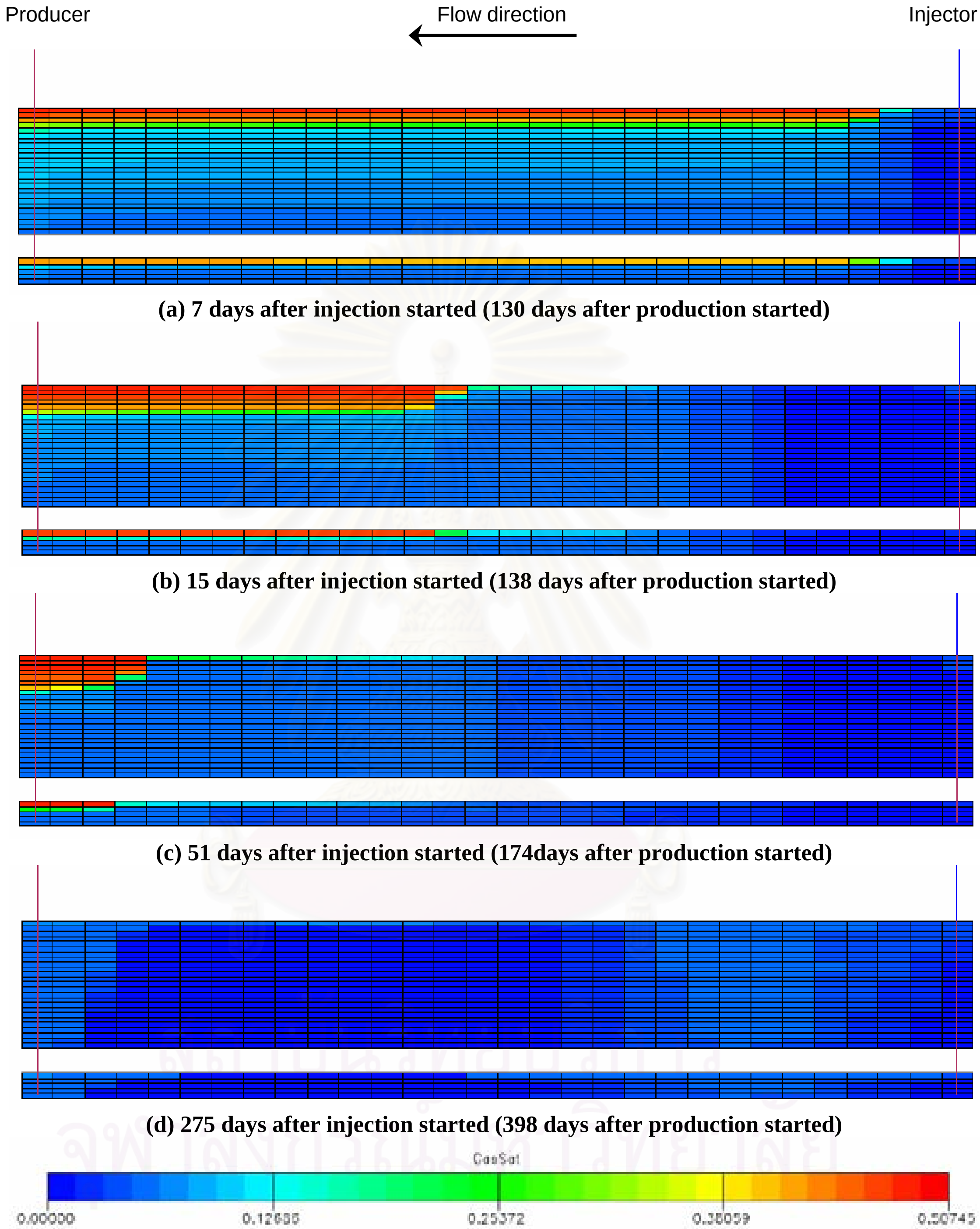


Figure 7-8: Cross section of 2-layer model with 5 meters thick for upper layer and 1 meter thick for lower layer showing oil saturation of the case which waterflooding is initiated after production under primary recovery



(a) 7 days after injection started (130 days after production started)

(b) 15 days after injection started (138 days after production started)

(c) 51 days after injection started (174days after production started)

(d) 275 days after injection started (398 days after production started)

Figure 7-9: Cross section of 2-layer model with 5 meters thick for upper layer and 1 meter thick for lower layer showing gas saturation of the case which waterflooding is initiated after production under primary recovery

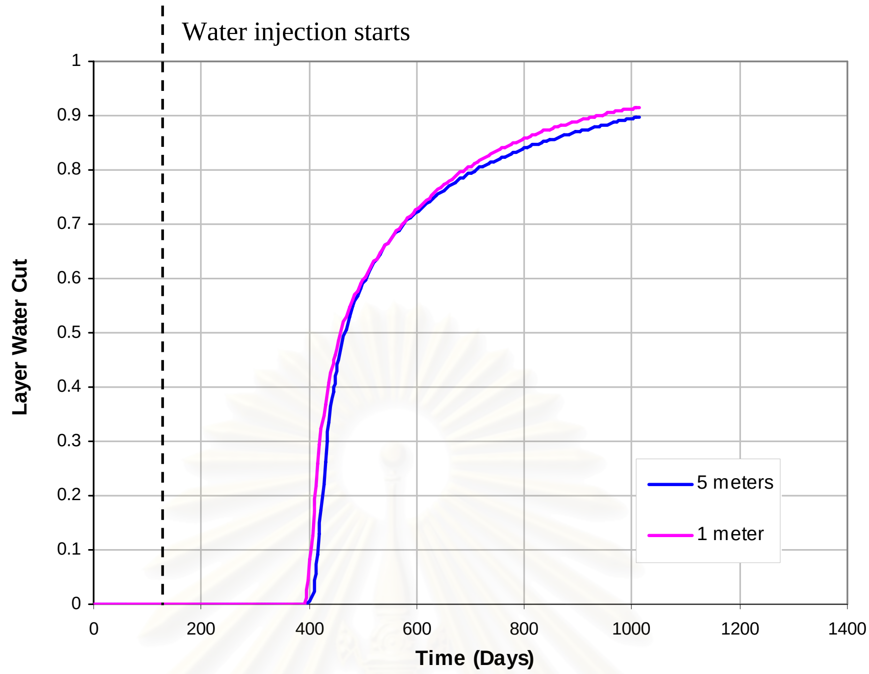


Figure 7-10: Layer water cuts of 2-layer model with 5 meters thick for upper layer and 1 meter thick for upper layer of the case which waterflooding is initiated after production under primary recovery

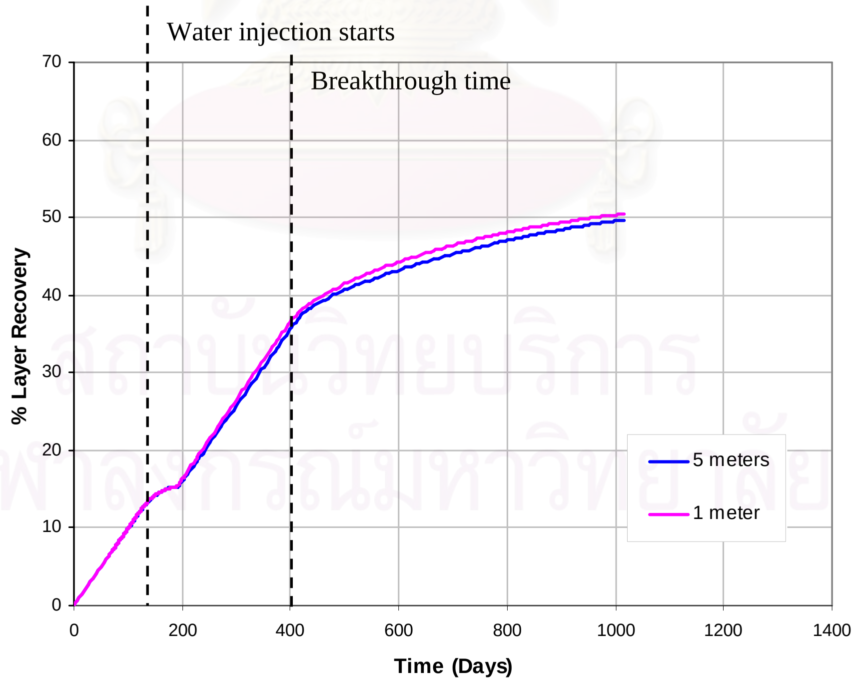


Figure 7-11: % Layer recoveries of 2-layer model with 5 meters thick for upper layer and 1 meter thick for upper layer of the case which waterflooding is initiated after production under primary recovery

Fig.7-8 and Fig.7-9 show the oil saturation and gas saturation during displacement process of this case, respectively. It can be said that flood fronts in both layers are in similar shape and move with the same velocity to the producer. As a result, water breaks through from both layers simultaneously and water cut profiles are similar as shown in Fig.7-10.

In Fig.7-11, the oil recovery profiles of both layers are only slightly different (49.72% and 50.44% recovery factors for 5 meters thick layer and 1 meter thick layer, respectively). This is slight different from the previous case, where the difference in thickness has some effect on layer recovery factor. Here, the difference in layer thickness of this case has almost no effect on recovery factor. This is probably due to the effect of the presence of free gas in the reservoir. However, it should be noted that before water breakthrough, the effect on layer recovery is almost none. This is true for both cases.

It is also observed that in case that waterflood was initiated after free gas was produced from the reservoir, the flood front will move faster to displace free gas during the fill-up period. After free gas was pushed into the oil, the flood front moves slower until it reaches the producer. It is noticed that in this case, the water moves very fast and breaks through in 275 days after injection started (Fig.7-8(d)) compared to the case of injection at p_{sgc}, which requires 413 days for break through (Fig.7-4(d)). Therefore, it should be expected that the earlier water production will occur in the system which has larger amount of free gas saturation.

It is noted that in this study, the layers are not far apart. In case the layers are too far from each other, the difference in layer pressures and injection pressures should be taken into account. The layers will deplete with different rates, and flood front will move with different velocities.

Fig.7-12 and Fig.7-13 show comparison of layer recoveries of both layers. From these two figures, it is confirmed again that water injection at p_{sgc} is much better than injection after primary depletion even for two-layer system.

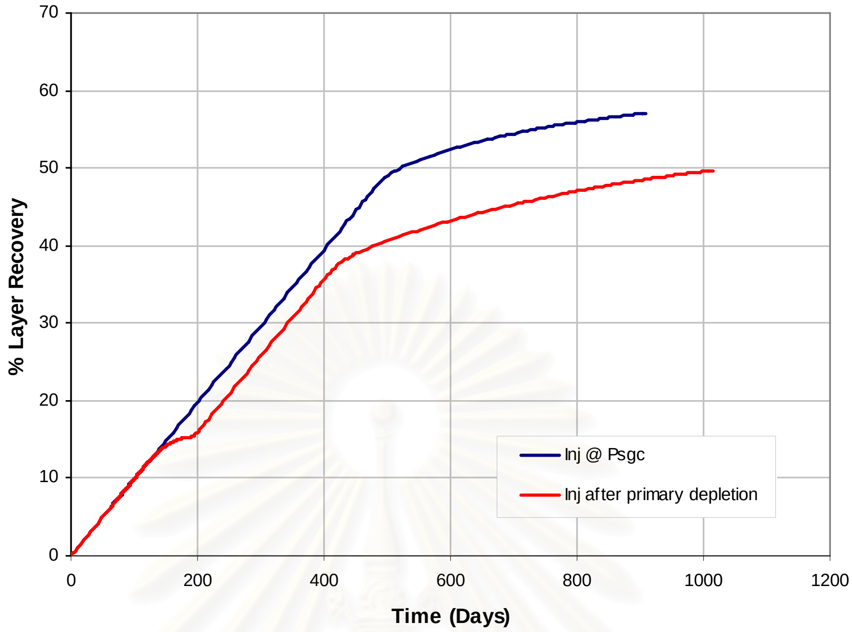


Figure 7-12: % Recovery of 5 meters thick layer of 2-layer model with 5 meters thick for upper layer and 1 meter thick compared between the cases which waterflooding is initiated at p_{sgc} and waterflooding is initiated after production under primary recovery

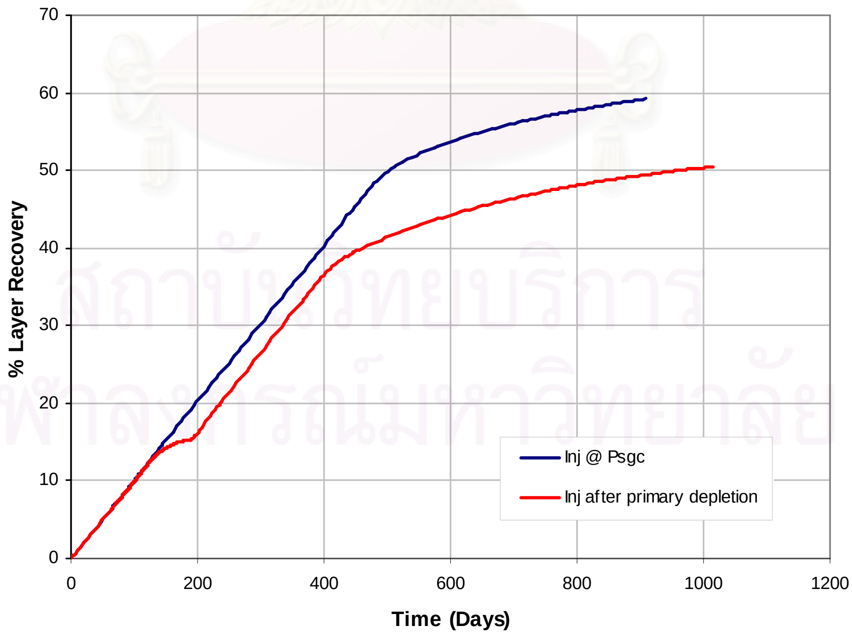


Figure 7-13: % Recovery of 1 meter thick layer of 2-layer model with 5 meters thick for upper layer and 1 meter thick compared between the cases which waterflooding is initiated at p_{sgc} and waterflooding is initiated after production under primary recovery

7.2 Effect of Solution Gas-oil Ratio

As mentioned in Chapter 2, the solution gas-oil ratio has effects on oil viscosity, bubble point pressure, and amount of free gas when the reservoir pressure falls below the bubble point pressure. Oil viscosity affects the oil depletion in terms of oil flow rate, which affects depletion rate. In waterflooding operation, oil viscosity affects ability of water to push oil, which affects flood front movement. Therefore, layers with different oil viscosities will have water breakthrough at different times. Since oil viscosity is a function of solution gas-oil ratio, the influence of oil viscosity in the range of proposed solution gas-oil ratio will be investigated.

In case the waterflooding is initiated to displace the oil when no or only minor free gas present in the reservoir, oil viscosity is the parameter which mainly has influence on waterflooding operation in terms of flood front movement in each layer. If water injection starts after the free gas has been produced, beside the effect of oil viscosity on flood front movement, the amount of free gas will affect the fill-up behavior in each layer.

In order to observe the influence of solution gas-oil ratio on waterflooding between two layers, two extreme solution gas-oil ratios was used in simulation work. By using the correlations with possible range of oil gravity and solution gas-oil ratio, p_b and oil viscosity at p_b are estimated as shown in Table 7-1. The plots of live oil properties for R_s 400 and 1500 scf/stb calculated by correlations are included in appendix A.

Table 7-1: Summary of Oil Properties Used in Simulations

Oil Gravity (API)	R_s (scf/stb)	p_b (psia)	Viscosity at p_b (cp)
35	400	1740	0.63
40	700	2400	0.39
45	1500	3910	0.23

From Table 7-1, we see that the estimated oil viscosities at the bubble point pressures in the range of R_s 400 to 1500 scf/stb are slightly higher than the water viscosity (0.3 cp). Therefore, waterflooding in this reservoir is likely to be in the favorable condition, i.e. mobility ratio less than 1.

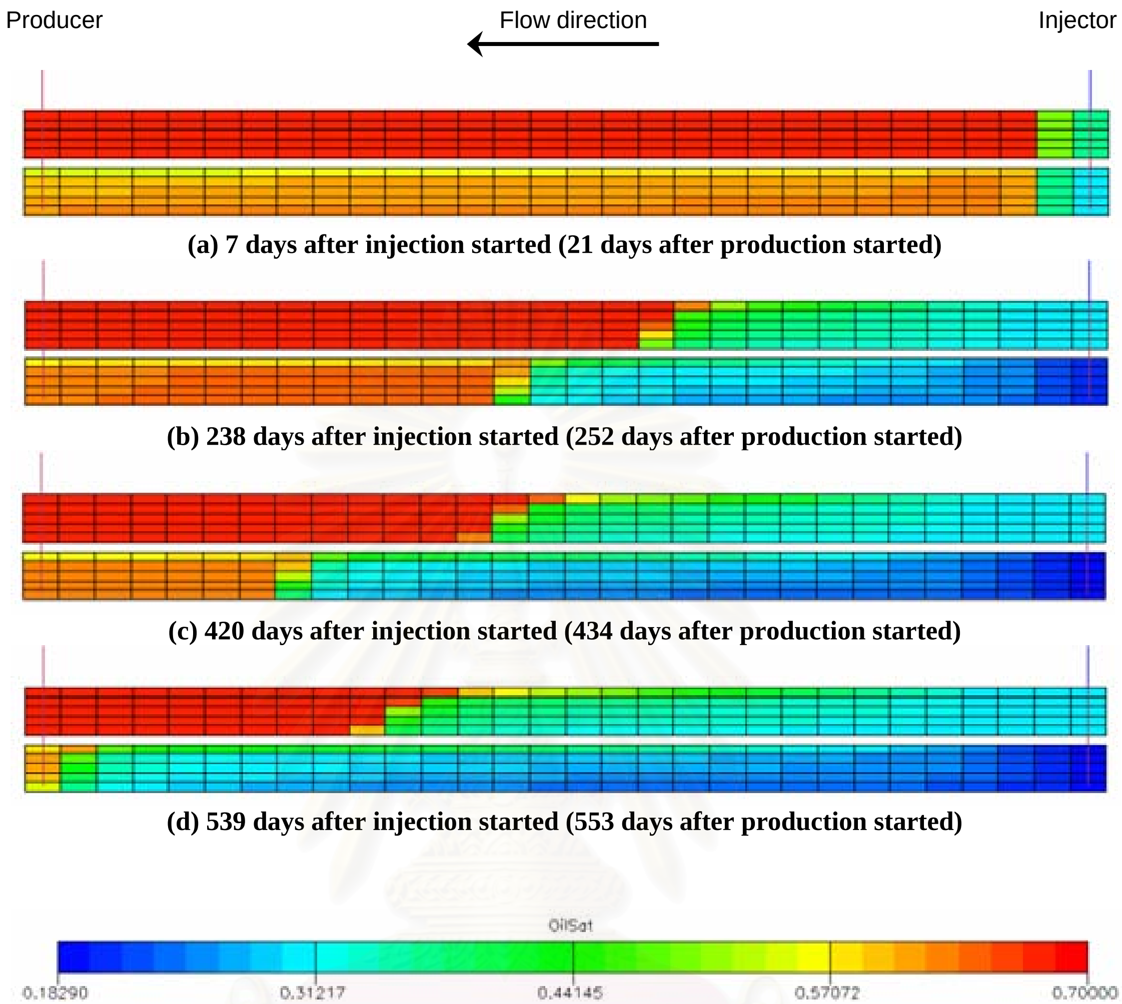
In the reservoir model, lower R_s (400 scf/stb) was assigned to the upper layer, leading to more viscous oil with lower p_b, whereas higher R_s (1500 scf/stb) was assigned to the lower layer, leading to less viscous oil with higher p_b. The simulation work was run for two cases, which are the condition when waterflooding can begin at any time and the condition when waterflooding can begin after production under primary recovery, as mentioned earlier.

(i) The condition when waterflooding can begin at any time

As mentioned earlier, the water injection is selected to start at reservoir pressure equal to p_{sgc} and maintain the reservoir pressure at this level during water injection so that the highest recovery factor can be achieved. For a 2-layer system which has different R_s, hence different p_b, maintaining the pressure of higher R_s layer at its p_{sgc} would have the other layer operated at the pressure higher than its p_{sgc}. This condition will be applied for simulation runs as it is the lowest operating pressure without free gas production from the reservoir.

Fig.7-14 and Fig.7-15 show oil saturation and gas saturation during displacement process of this case, respectively. It is observed in Fig.7-15 that there is no liberated gas in the upper layer. This is because upper layer has low R_s oil, hence low p_b. As the pressure in higher R_s layer is controlled such that no free gas is produced, bottomhole flowing pressure of the lower R_s layer is still above its p_b, so no free gas exists.

It can be seen that water moves faster in the lower layer of which the oil is less viscous. As a result, premature water breakthrough occurs at the lower layer. After a while, water breaks through at the upper layer. The well water cut increases substantially and finally the well was shut-in due to an excessive water cut. The water cut profiles are shown in Fig 7-16 and the % recovery obtained from each layer is shown in Fig.7-17.



(a) 7 days after injection started (21 days after production started)

(b) 238 days after injection started (252 days after production started)

(c) 420 days after injection started (434 days after production started)

(d) 539 days after injection started (553 days after production started)

Figure 7-14: Cross section of 2-layer model with R_s 400 scf/stb for upper layer and 1500 scf/stb for lower layer showing oil saturation of the case which waterflooding is initiated at p_{sgc}

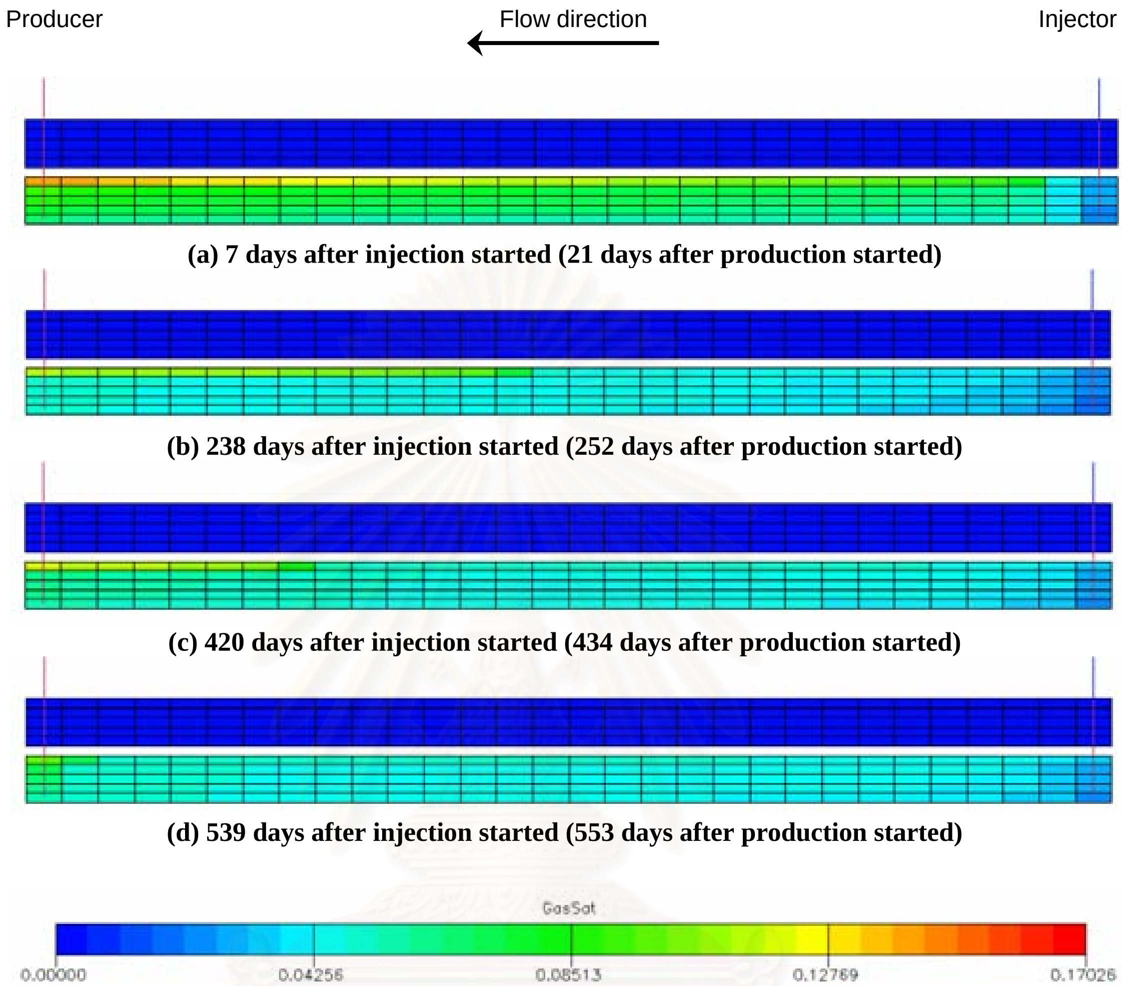


Figure 7-15: Cross section of 2-layer model with R_s 400 scf/stb for upper layer and 1500 scf/stb for lower layer showing gas saturation of the case which waterflooding is initiated at p_{sgc}

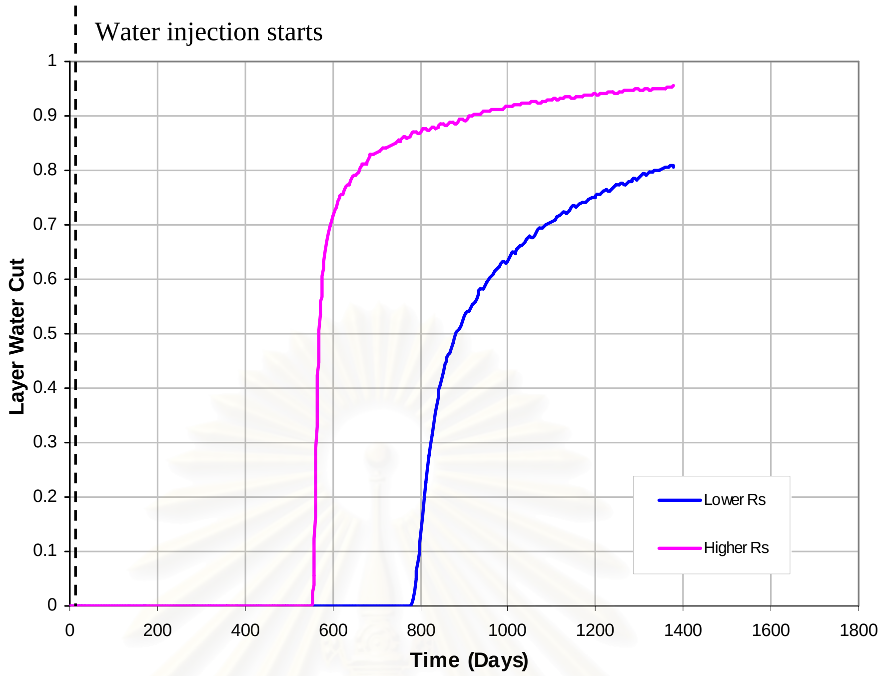


Figure 7-16: Layer water cuts of 2-layer model with R_s 400 scf/stb for upper layer and 1500 scf/stb for lower layer of the case which waterflooding is initiated at p_{sgc}

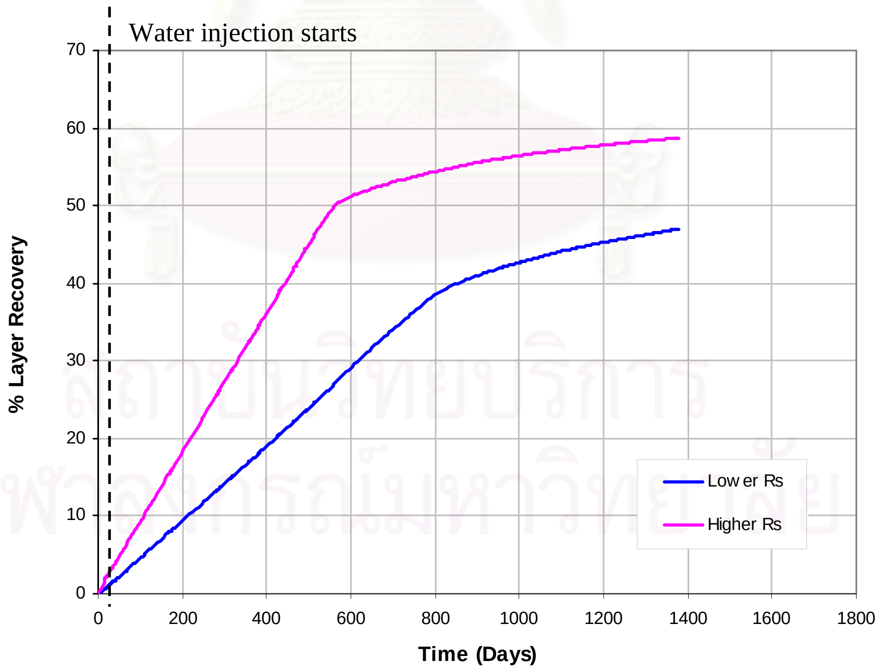


Figure 7-17: % Layer recoveries of 2-layer model with R_s 400 scf/stb for upper layer and 1500 scf/stb for lower layer of the case which waterflooding is initiated at p_{sgc}

From Fig.7-17, it is observed that at the same time, the less viscous oil layer (higher R_s) has higher % oil recovery compared to the more viscous oil layer (lower R_s). This is because the less viscous oil layer has better favorable condition, i.e. mobility ratio is more favorable, resulting in higher oil production rate as shown in Fig.7-18. This leads to a largely diverge between layer recovery curves since water injection was initiated (14 days after production) in Fig.7-17.

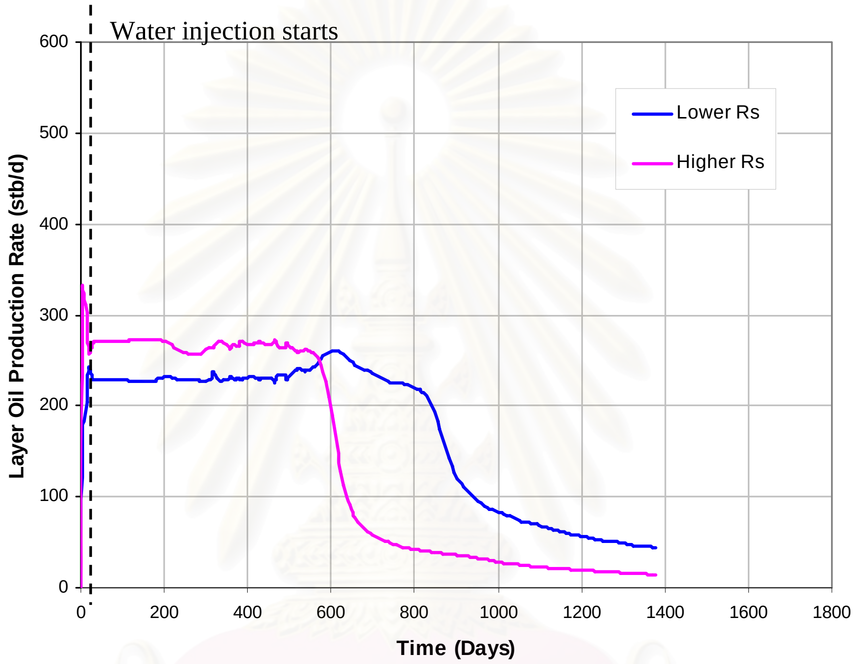


Figure 7-18: Layer oil production rates of 2-layer model with R_s 400 scf/stb for upper layer and 1500 scf/stb for lower layer of the case which waterflooding is initiated at p_{sgc}

By observing oil saturations when waterflooding ends as shown in Fig.7-19, we see that the upper layer has much more oil saturation than the lower layer. Fig.7-19 (a) and (c) show that most of bypassed oil of the upper layer is near the drainage boundaries. Because high viscous oil is hard for water to push towards the production well, the injected water moves along the water channel connecting between injector and producer, where the pressure gradient is the highest. When the well water cut reaches the economic limit, the oil at the drainage boundaries is bypassed. As a result, the recovery factor of the upper layer is low.

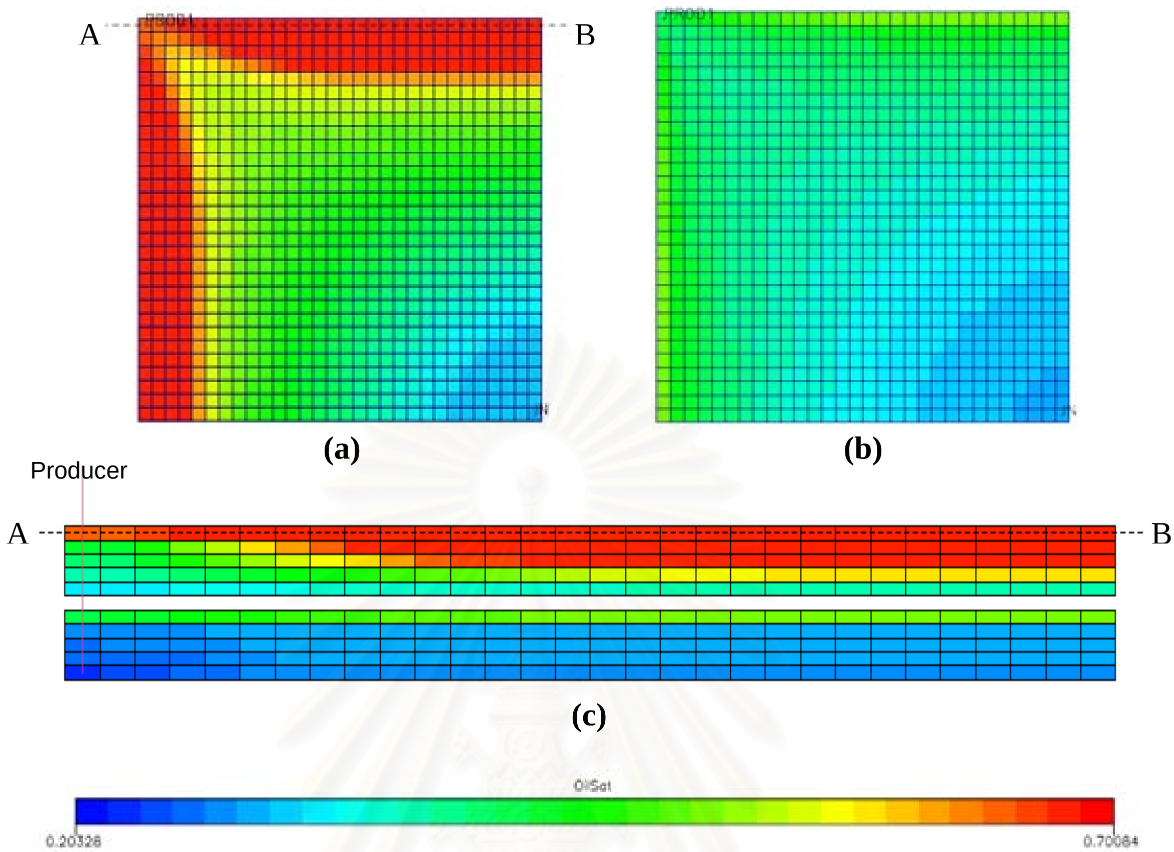


Figure 7-19: Oil saturation distributions of 2-layer showing the top view of upper layer (R_s 400 scf/stb, upper right), lower layer (R_s 1500 scf/stb, upper left) and cross section at the drainage boundary (below) at the end of the case which waterflooding is initiated at p_{sgc}

Since the layer with lower viscous oil has premature water breakthrough and higher water cut, the layer with low viscous oil was shut-off when the well water cut reaches the economic limit to extend oil production and recover more oil in the other layer.

Fig.7-20 shows the comparison of % recovery of each layer before and after shutting-off layer with less viscous oil, which has premature water breakthrough. It can be seen that after shutting-off premature water breakthrough layer, the other layer producing for a while. As a result, the recovery factor of the layer with higher oil viscosity increases from 46.96% to 50.26%. It is noted that this result is obtained from a model with some oil viscosity contrast (R_s 400 and 1500 scf/stb). For other R_s values within this range, the increment in recovery factor by this strategy may be lower due to less contrast in oil viscosities.

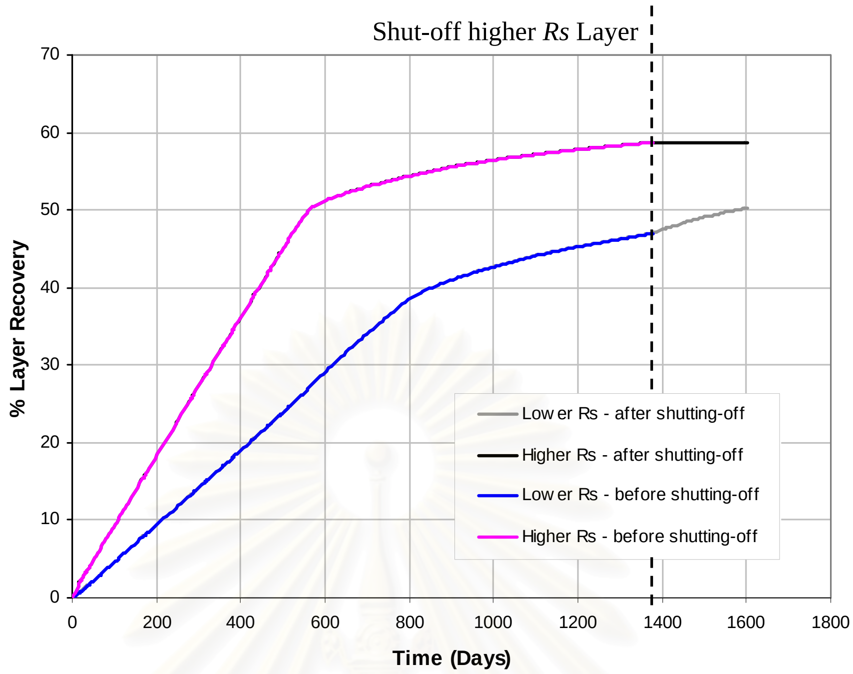


Figure 7-20: % Layer recoveries from 2-layer model with R_s 400 scf/stb for upper layer and 1500 scf/stb for lower layer before and after shutting-off premature water breakthrough layer of the case which waterflooding is initiated at p_{sgc}

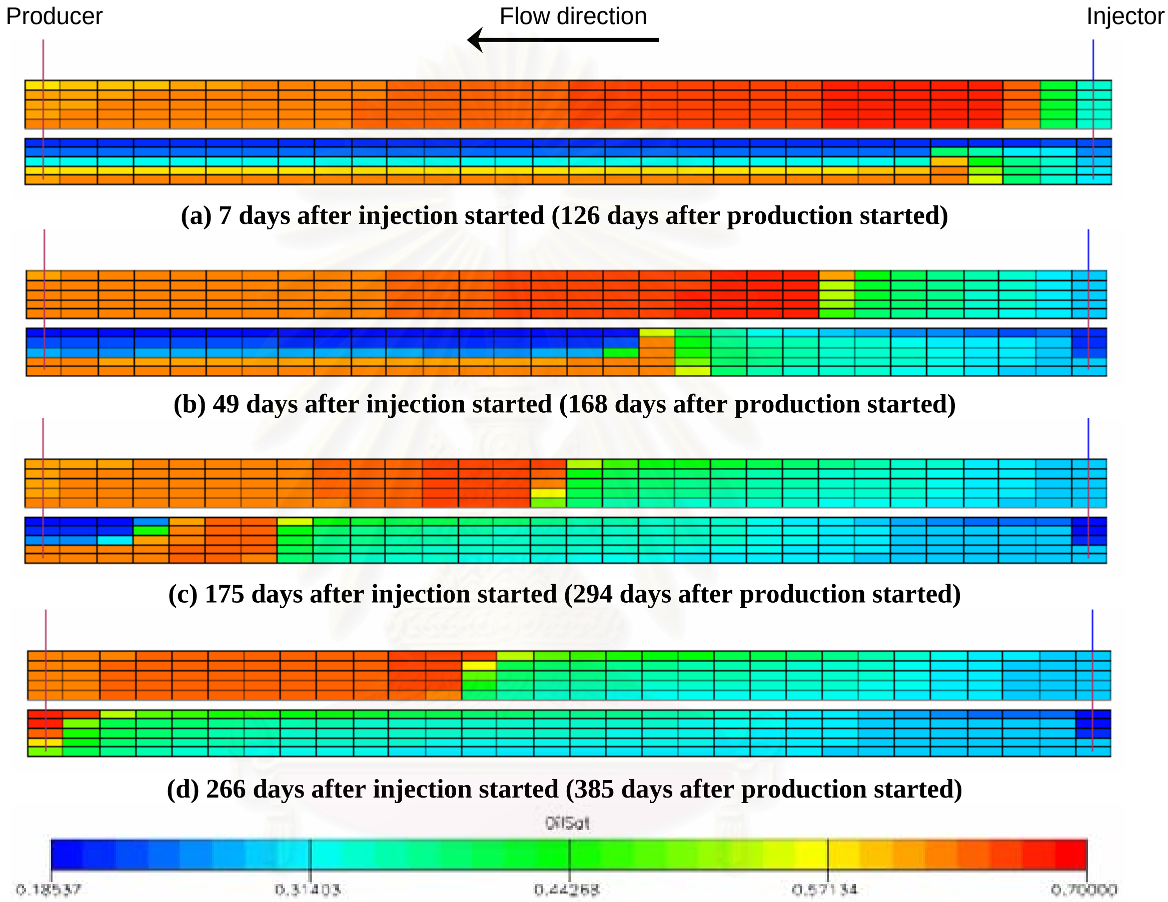
In conclusion, we see that oil viscosity within this range has an effect on premature water breakthrough. Oil recovery in layer with more viscous oil is low because the mobility ratio is high, so it is harder for water to push oil towards the producer, leading to lower oil production rate. Shutting-off premature water breakthrough is recommended as it improves recovery factor.

(ii) The condition when waterflooding can begin after production under primary recovery

After free gas was produced from the reservoir, there will be the effect of free gas in addition to the effect of oil viscosity. The effect of both parameters under this waterflooding condition will be investigated in this section. Two waterflooding issues are considered, the flood front movement and the fill-up behavior.

a) The flood front movement

Since the waterflooding was operated when large amount of free gas is present, the flood front movement is affected by the oil viscosity and amount of free gas. The simulation results are as shown in Fig. 7-21 to Fig.7-24.



(a) 7 days after injection started (126 days after production started)

(b) 49 days after injection started (168 days after production started)

(c) 175 days after injection started (294 days after production started)

(d) 266 days after injection started (385 days after production started)

Figure 7-21: Cross section of 2-layer model with R_s 400 scf/stb for upper layer and 1500 scf/stb for lower layer showing oil saturation of the case which waterflooding is initiated after production under primary recovery

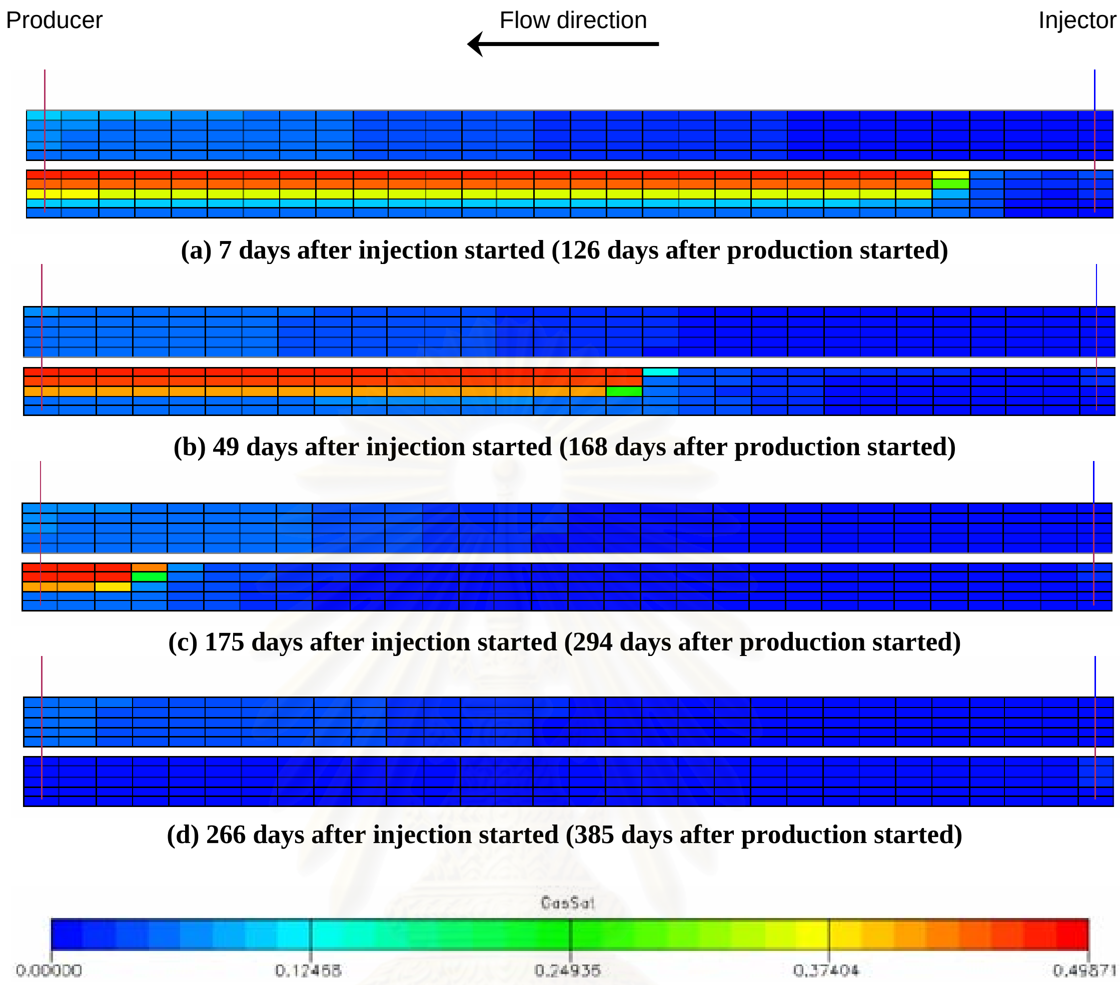


Figure 7-22: Cross section of 2-layer model with R_s 400 scf/stb for upper layer and 1500 scf/stb for lower layer showing gas saturation of the case which waterflooding is initiated after production under primary recovery

Fig.7-21 and Fig.7-22 show the oil saturation and gas saturation during displacement process the case which waterflooding is initiated after production under primary recovery, respectively. It can be seen that the upper layer, which has lower R_s, has small amount of liberated free gas due to very low p_b. On the other hand, the lower layer, which has higher R_s, has higher p_b and large amount of liberated free gas when the layer pressure falls below p_b.

In the early stage of waterflooding, flood front in the lower layer move so fast to displace the liberated gas. It is noticed that in Fig.7-21 (a) and (b), the flood front in upper sub-layers moves faster than the flood front in lower sub-layers. When refer to the gas saturation in Fig.7-22 (a) and (b), it can be seen that large amount of liberated gas segregates and presents in the upper sub-layers. Because free gas is much easier displaced by water, flood front in upper sub-layers moves faster. Once most of free gas was displaced by water, water moves slower and the flood front in lower sub-layers tends to move faster than the upper ones.

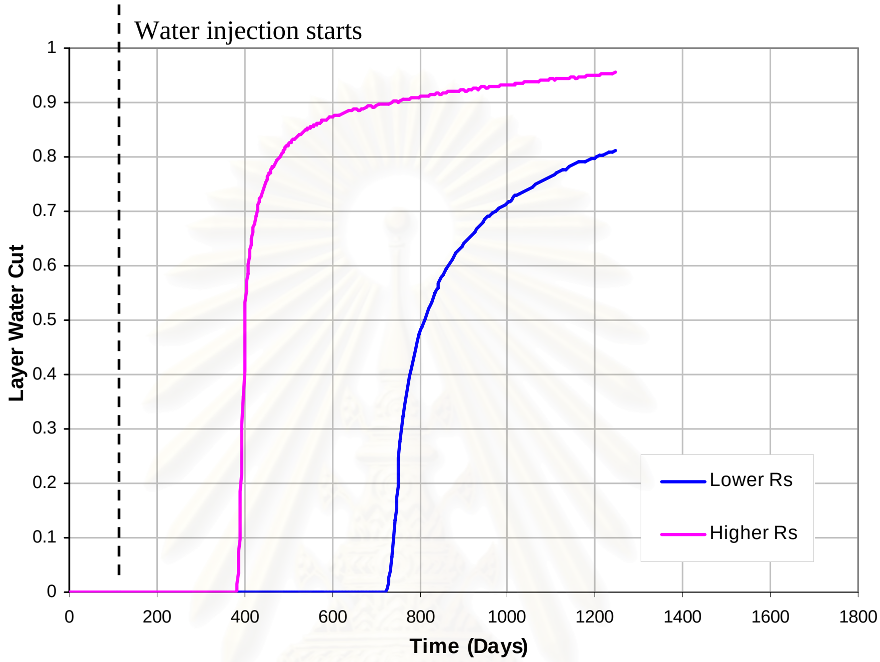


Figure 7-23: Layer water cuts of 2-layer model with R_s 400 scf/stb for upper layer and 1500 scf/stb for lower layer of the case which waterflooding is initiated after production under primary recovery

From Fig.7-23, in case which waterflooding is initiated after production under primary recovery, water breaks through faster in the layer with higher R_s and the duration until water breaks through at layer with low R_s is longer than in case waterflooding at p_{sgc}. This is because much more free gas in lower layers let water move much faster than in the upper layer. Therefore, it can be concluded that the amount of free gas has predominantly effect on the flood front movement than the oil viscosity. It is noticed that in this case, the water moves very fast and breaks through in 266 days after injection started (Fig.7-21 (d)), compared to the case waterflooding at p_{sgc} which requires 539 days to break through (Fig.7-14 (d)). Therefore, it should be expected that the earlier water production will occur in the system which has larger amount of free gas saturation.

When observing % recovery from each layer in Fig.7-24, % recovery from higher R_s layer is much lower than % recovery from lower R_s layer. The lost in % recovery of higher R_s layer is due to free gas production. It is noted that the recovery factor of the lower R_s layer is still high because no free gas was produced due to very low p_b. The effect of free gas on the fill-up period will be studied in the following section.

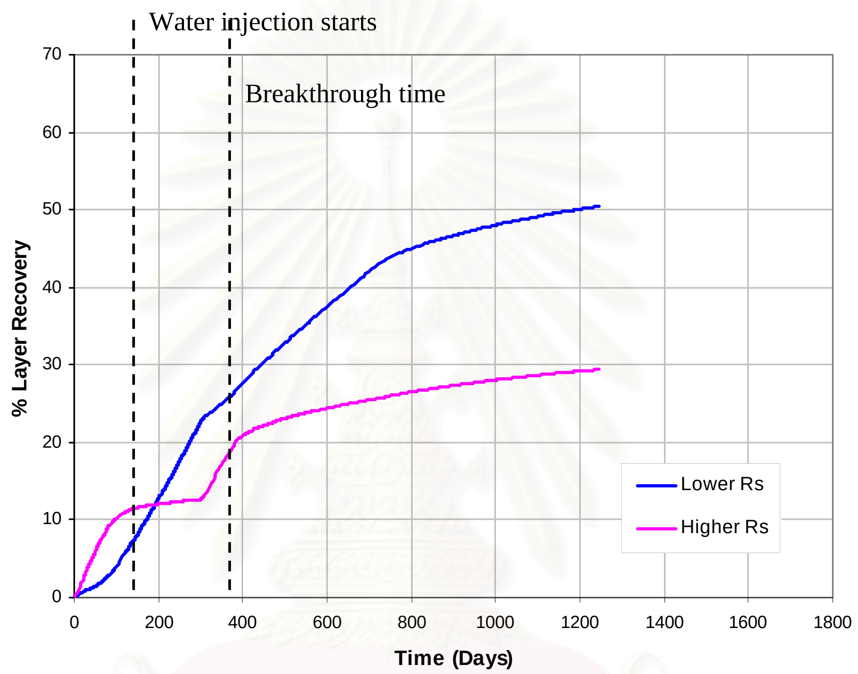


Figure 7-24: % Layer recoveries of 2-layer model with R_s 400 scf/stb for upper layer and 1500 scf/stb for lower layer of the case which waterflooding is initiated after production under primary recovery

As seen in Fig.7-23 that the layer with higher R_s has premature water breakthrough and higher water cut, the layer with higher R_s was shut-off when the well water cut reaches the economic limit to extend oil production to recover more oil in another layer.

Fig.7-25 shows the comparison of recovery factor of each layer before and after shutting-off layer with higher R_s, which has premature water breakthrough. Similarly to the case waterflooding at p_{sgc}, the recovery factor of layer with lower R_s increases from 50.44% to 53.39% by the use of this strategy. Therefore, this strategy is recommended to improve the oil recovery of this system.

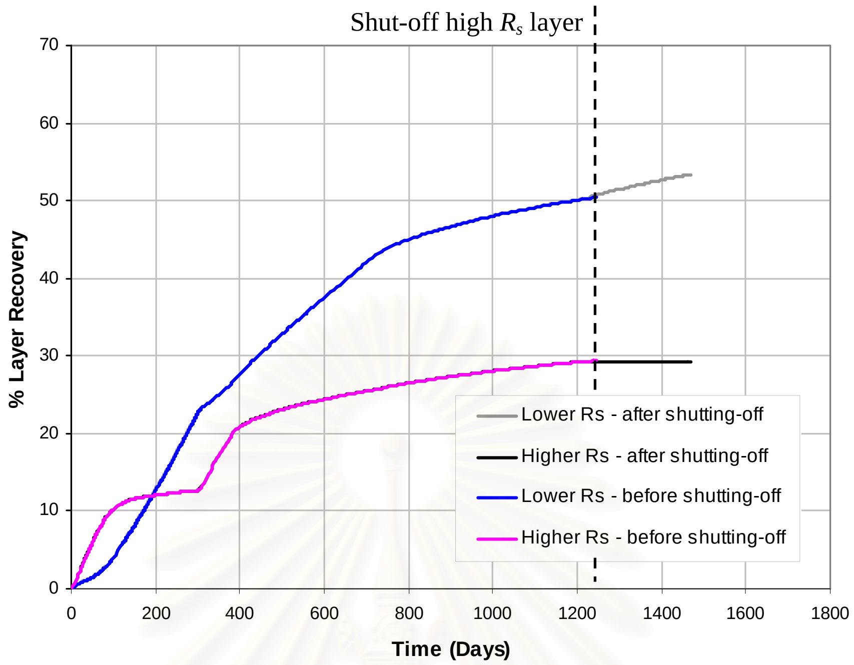


Figure 7-25: % Layer recoveries from 2-layer model with R_s 400 scf/stb for upper layer and 1500 scf/stb for lower layer before and after shutting-off premature water breakthrough layer of the case which waterflooding is initiated after production under primary recovery

b) The fill-up behavior

As seen in Fig.7-24 that the recovery obtained from higher R_s layer is very low, the detailed study is performed to observe the cause and investigate the strategy to improve the oil recovery in this section. Fig.7-26 to 28 show production gas-oil ratio, oil production rate, and solution gas-oil ratio from each layer, respectively.

It can be seen that the higher R_s layer produced a large amount of free gas prior to waterflooding. Although water injection was initiated, this free gas is still produced, leading to a dramatically drop of layer oil rate. The simulation results demonstrate that in stead of pushing the gas back into the oil, the waterflooding drives the free gas out of the reservoir. As a result, the layer R_s decreases from 1500 scf/stb to 400 scf/stb as shown in Fig.7-28, and recovery factor is extremely low.

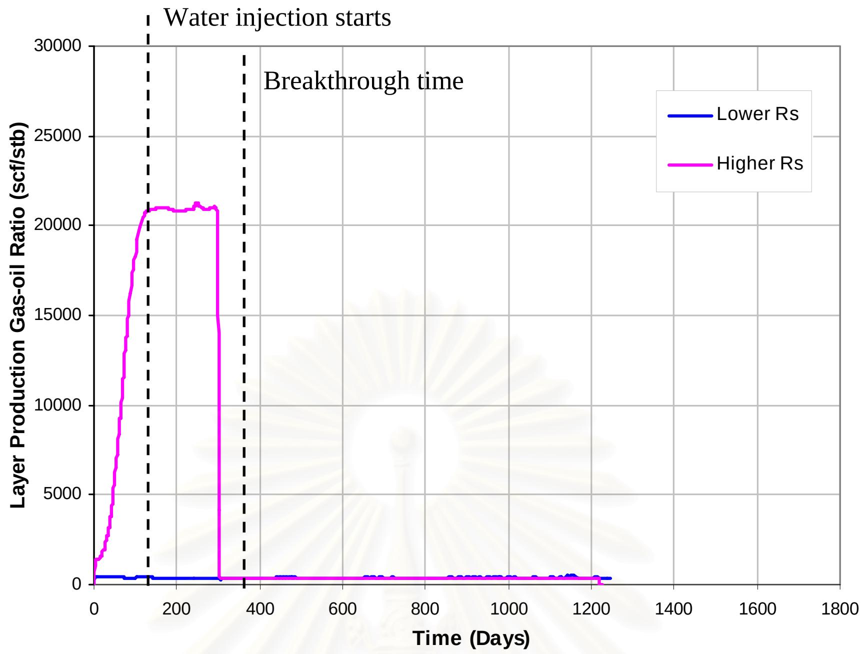


Figure 7-26: Layer production gas-oil ratios of 2-layer model with R_s 400 scf/stb for upper layer and 1500 scf/stb for lower layer of the case which waterflooding is initiated after production under primary recovery

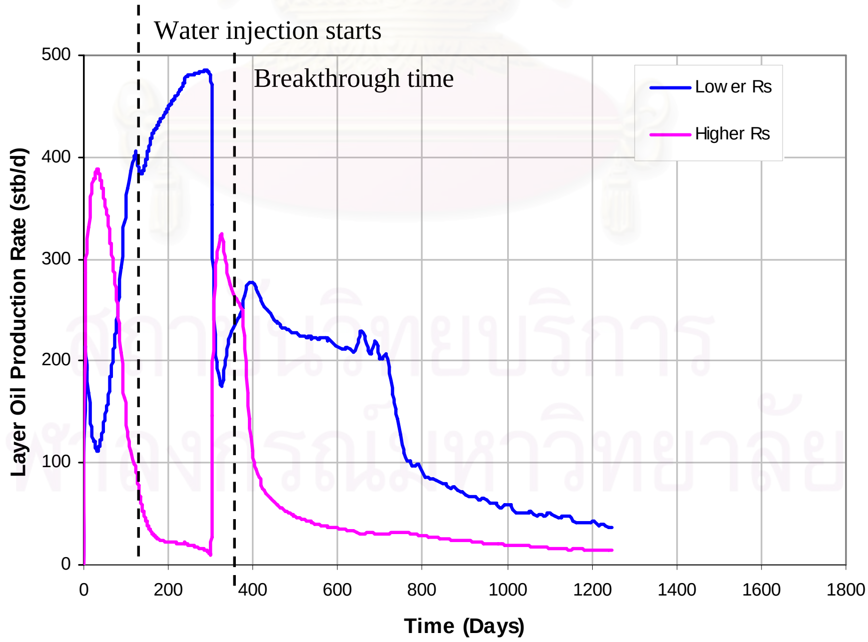


Figure 7-27: Layer oil production rates of 2-layer model with R_s 400 scf/stb for upper layer and 1500 scf/stb for lower layer of the case which waterflooding is initiated after production under primary recovery

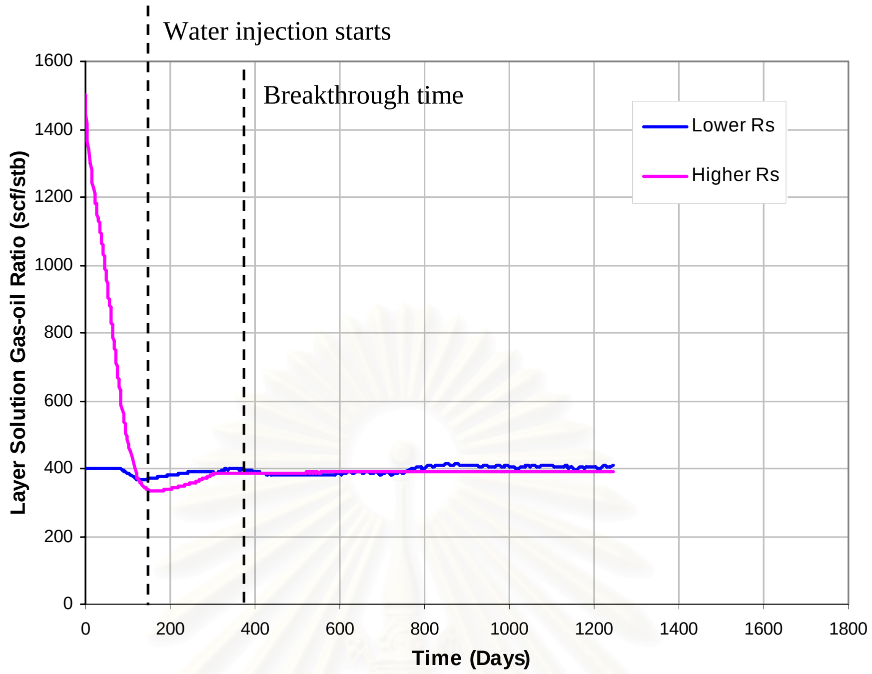
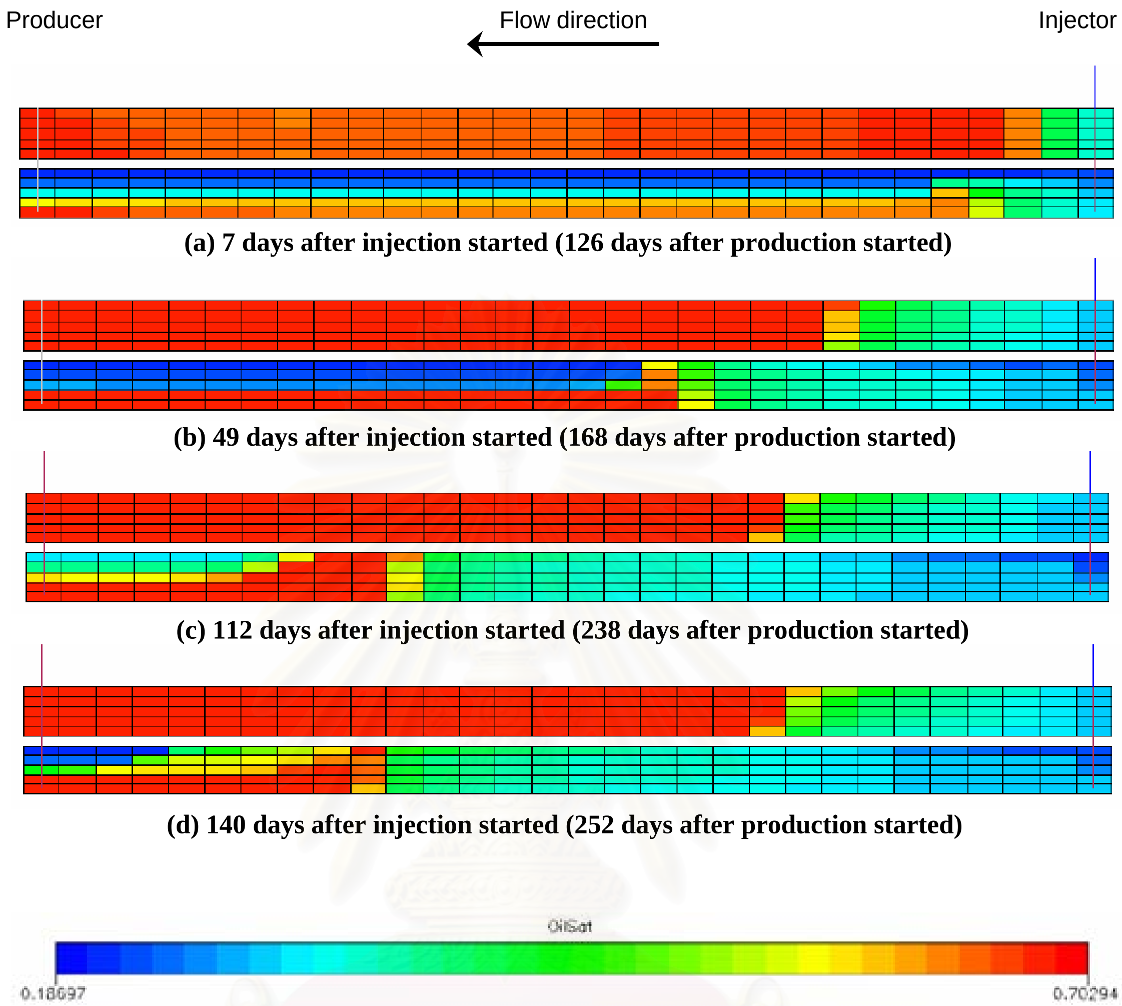


Figure 7-28: Layer solution gas-oil ratios of 2-layer model with R_s 400 scf/stb for upper layer and 1500 scf/stb for lower layer of the case which waterflooding is initiated after production under primary recovery

The attempt to improve the fill-up process was made by shutting-in the production well during the fill-up period. This strategy has an objective to hold the production until most free gas is pushed back into the oil for better fill-up efficiency. The simulation results are as shown in Fig.7-29 to Fig.7-34.



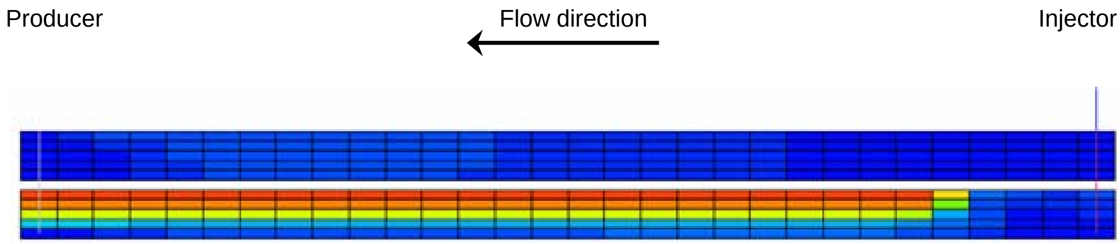
(a) 7 days after injection started (126 days after production started)

(b) 49 days after injection started (168 days after production started)

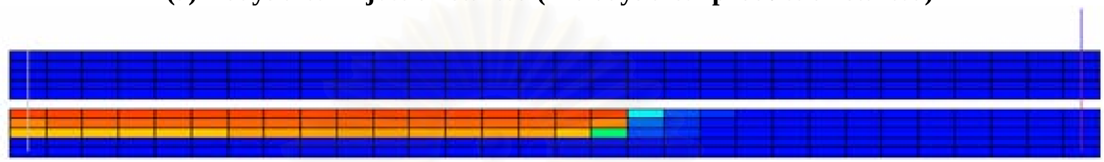
(c) 112 days after injection started (238 days after production started)

(d) 140 days after injection started (252 days after production started)

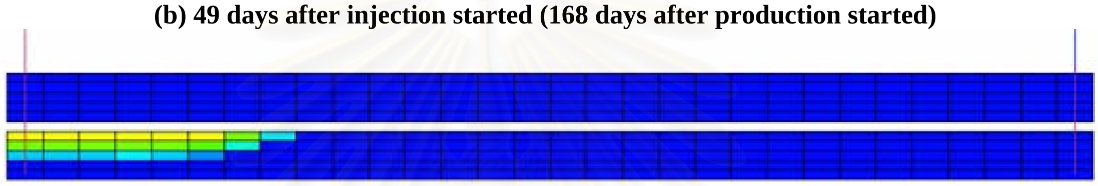
Figure 7-29: Cross section of 2-layer model with R_s 400 scf/stb for upper layer and 1500 scf/stb for lower layer showing oil saturation in case shutting-in production well during fill-up period



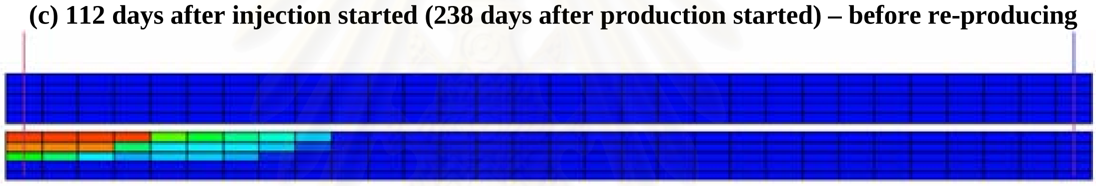
(a) 7 days after injection started (126 days after production started)



(b) 49 days after injection started (168 days after production started)



(c) 112 days after injection started (238 days after production started) – before re-producing



(d) 140 days after injection started (252 days after production started) – after re-producing

Figure 7-30: Cross section of 2-layer model with R_s 400 scf/stb for upper layer and 1500 scf/stb for lower layer showing gas saturation in case shutting-in production well during fill-up period

Fig.7-29 and Fig.7-30 show the oil saturation and gas saturation in case shutting-in the production well during the fill-up period, respectively. Note that the production well was shut-in since waterflooding was initiated (126 days after production started) and re-produce at 113 days after waterflooding was initiated (239 days after production started). It can be seen in Fig.7-29 (c) and Fig.7-30 (c) that in the day before re-producing (112 days after injection started) most free gas was pushed back into the oil. However, when the production starts, abruptly pressure drop in the well (Fig.7-31) causes free gas liberation around the well, resulting in large amount of fee gas production for a short period as seen in Fig.7-32.

After filling-up completed and the well is producing, oil production from higher R_s layer starts to increase. However, its oil production rate is not so high compared to the lower R_s layer. By observing Fig.7-34, the solution gas-oil ratio decreases to around 500 scf/stb after filling-up. As too much free gas was produced prior to the waterflooding, the remaining solution gas is not so high.

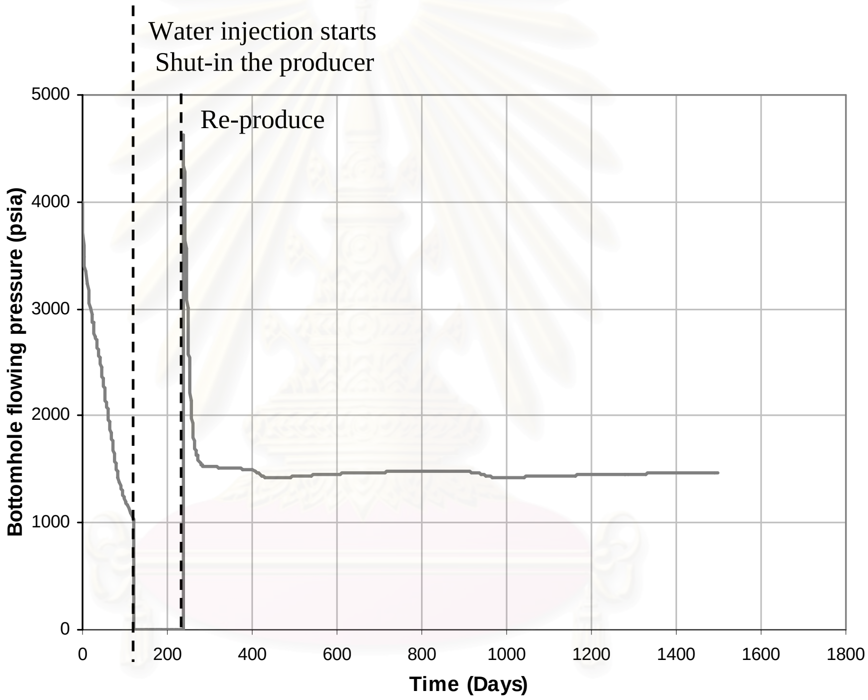


Figure 7-31: Bottomhole flowing pressure of 2-layer model with R_s 400 scf/stb for upper layer and 1500 scf/stb for lower layer in case shutting-in production well during fill-up period

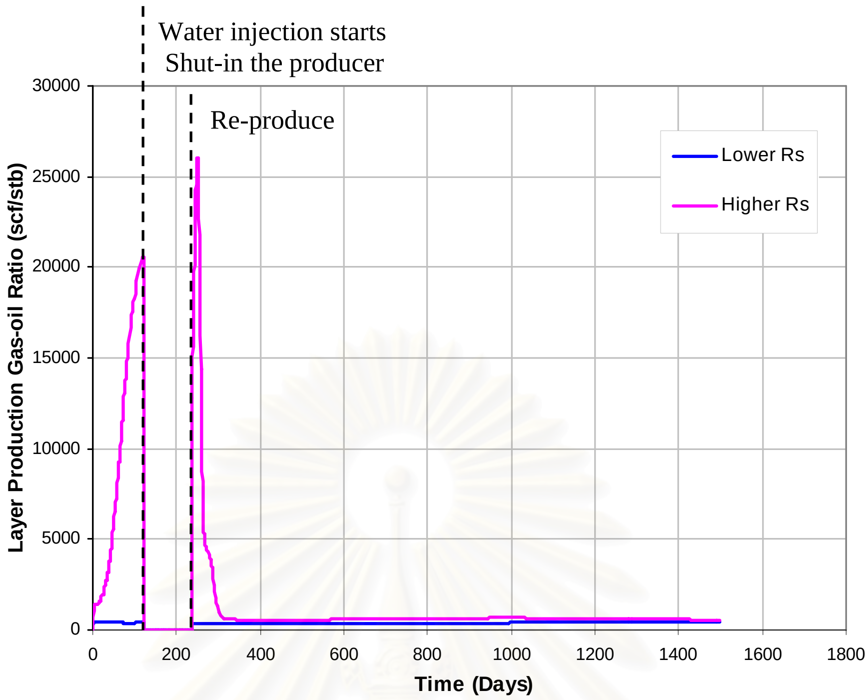


Figure 7-32: Layer production gas-oil ratios of 2-layer model with R_s 400 scf/stb for upper layer and 1500 scf/stb for lower layer in case shutting-in production well during fill-up period

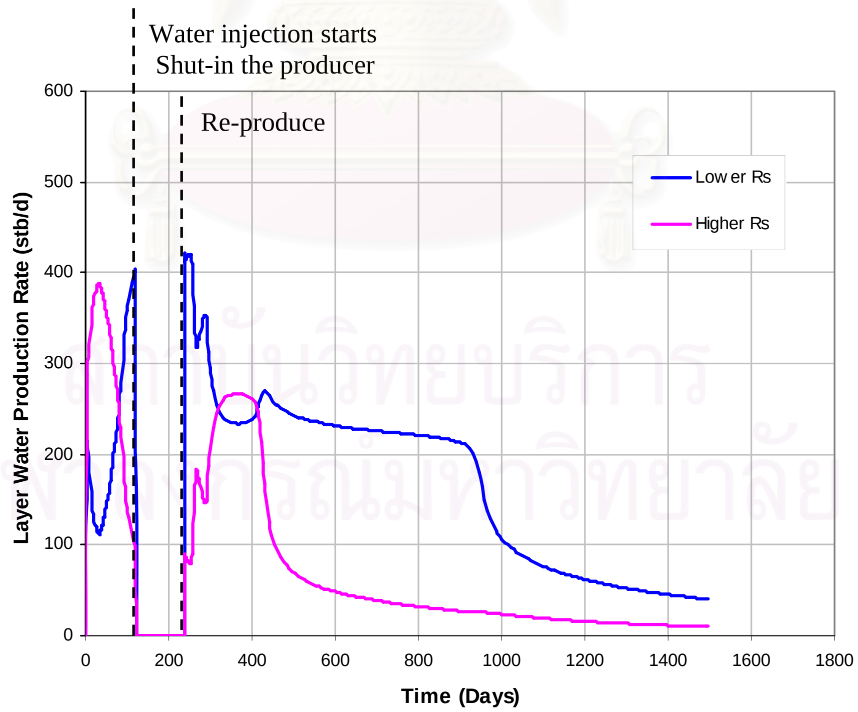


Figure 7-33: Layer oil production rates of 2-layer model with R_s 400 scf/stb for upper layer and 1500 scf/stb for lower layer in case shutting-in production well during fill-up period

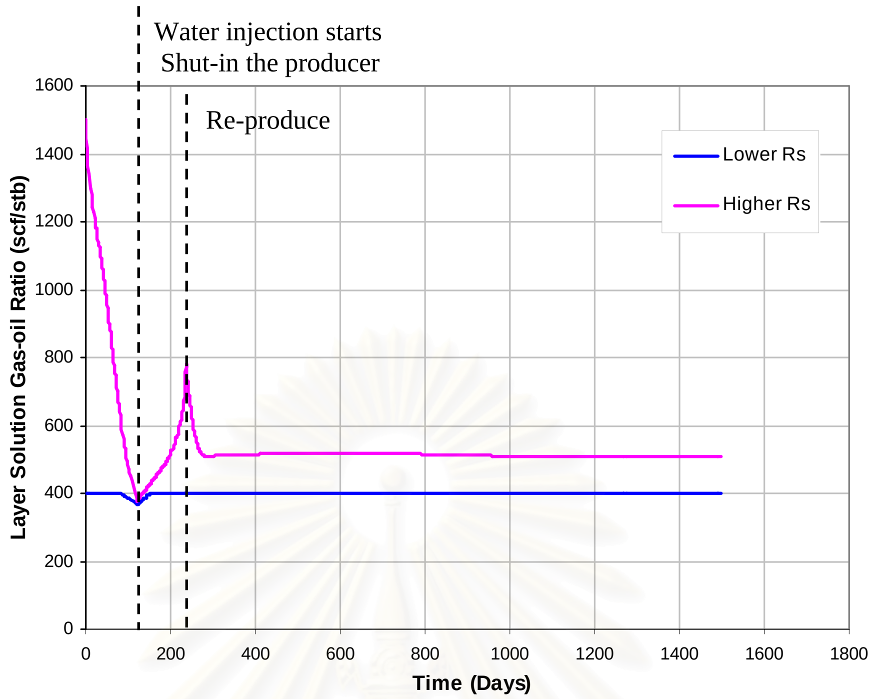


Figure 7-34: Layer solution gas-oil ratios of 2-layer model with R_s 400 scf/stb for upper layer and 1500 scf/stb for lower layer in case shutting-in production well during fill-up period

Fig.7-35 and Fig.7-36 show the comparison of % layer recoveries of the cases which waterflooding is initiated at p_{sgc}, waterflooding is initiated after production under primary recovery, and waterflooding is initiated after production under primary recovery with shutting-in the producer during the fill-up period. It is noted that since the lower R_s layer has very low p_b, no free gas is present in this layer in all cases as seen in Fig.7-15, Fig7-22, and Fig7-30.

In Fig.7-36, for the layer with lower R_s, the recovery factor of the case that waterflooding is initiated at p_{sgc} (of the higher R_s layer) is the lowest. This confirms the behavior illustrated in Chapter 6 that for the reservoir pressure above p_{sgc}, higher waterflooding pressure gives lower recovery factor. Because free gas does not exist in the lower R_s layer, it is operating above p_b. Operating waterflooding at p_{sgc} of the higher R_s layer leads to highest operating pressure of lower R_s layer compared to other cases. As a result, the recovery factor of this case is the lowest.

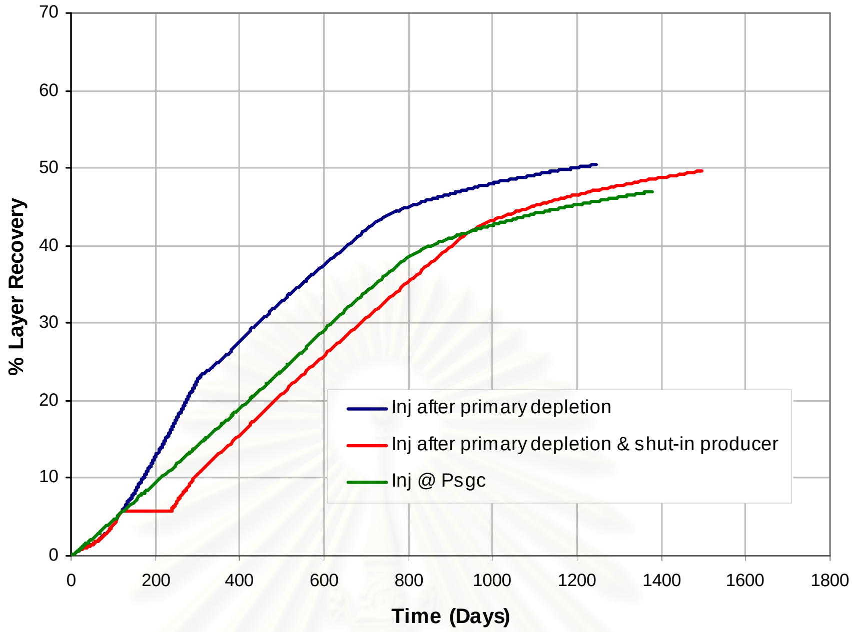


Figure 7-35: % Recovery of lower R_s layer compared between the cases which waterflooding is initiated at p_{sgc}, waterflooding is initiated after production under primary recovery, and waterflooding is initiated after production under primary recovery with shutting-in in the producer during fill-up period

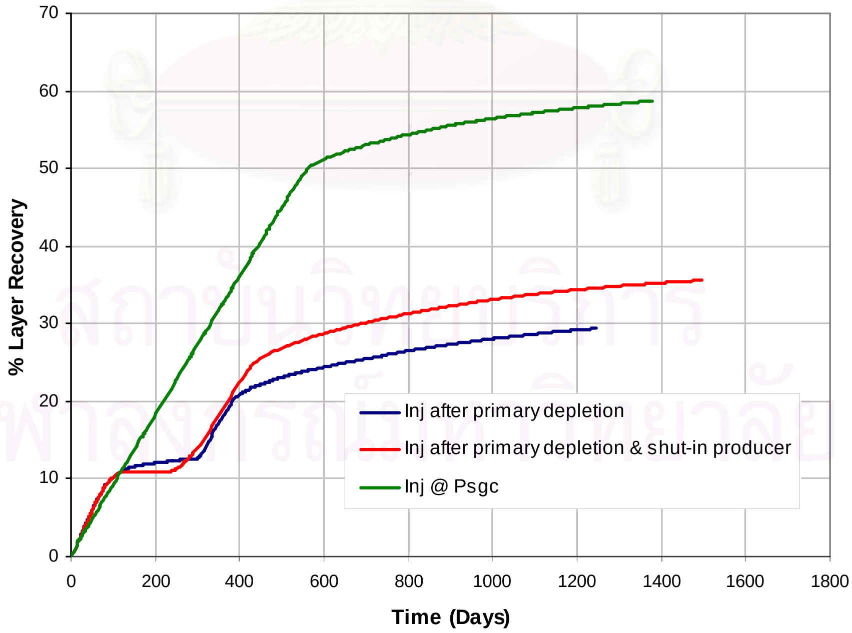


Figure 7-36: % Recovery of higher R_s layer compared between the cases which waterflooding is initiated at p_{sgc}, waterflooding is initiated after production under primary recovery, and waterflooding is initiated after production under primary recovery with shutting-in in the producer during fill-up period

For the layer with higher R_s, injecting at its p_{sgc} gives much higher recovery factor than other cases (Fig.7-36). In case of injecting water after production under primary recovery, a significant increment in recovery factor is obtained from shutting-in the production well during fill-up period. However, its recovery factor is much lower than in case injecting water at its p_{sgc} because too much free gas was produced prior to waterflooding as described earlier.

To maximize the oil recovery, it is recommended that water injection should be initiated before free gas was produced from the reservoir. However, in case free gas has been produced, minimizing free gas production and maintaining solution gas at the highest level is required for recovery maximization. Therefore, start water injection as soon as possible with shutting-in the production well during fill-up period is recommended.

In summary, R_s has effects on oil viscosity, bubble point pressure, and amount of free gas when the reservoir pressure falls below the bubble point pressure. Oil with higher R_s will be less viscous, which will flow easier and deplete faster. It is also easier for water to displace. As a result, flood front will move faster and break through earlier. Amount of free gas has predominantly effect than oil viscosity on the flood front movement. More liberated free gas lets flood front move faster, leading to earlier water breakthrough at the producer. So, early water production should be expected for a reservoir which produce large amount of free gas. The strategy of shutting-off premature water breakthrough layer can improve the recovery factor so it is recommended.

Because high R_s layer has high p_b and generates large amount of free gas when the layer pressure falls below p_b, its recovery factor will be extremely low if too much free gas was produced prior to waterflooding. It is recommended that waterflooding should be initiated at p_{sgc} of the higher R_s layer to optimize the oil recovery. In case that waterflooding is initiated after free gas was produced, shutting-in the production well during fill-up period is recommended to minimize free gas production, hence maximize oil recovery at that condition.

7.3 Effect of Layer Permeability

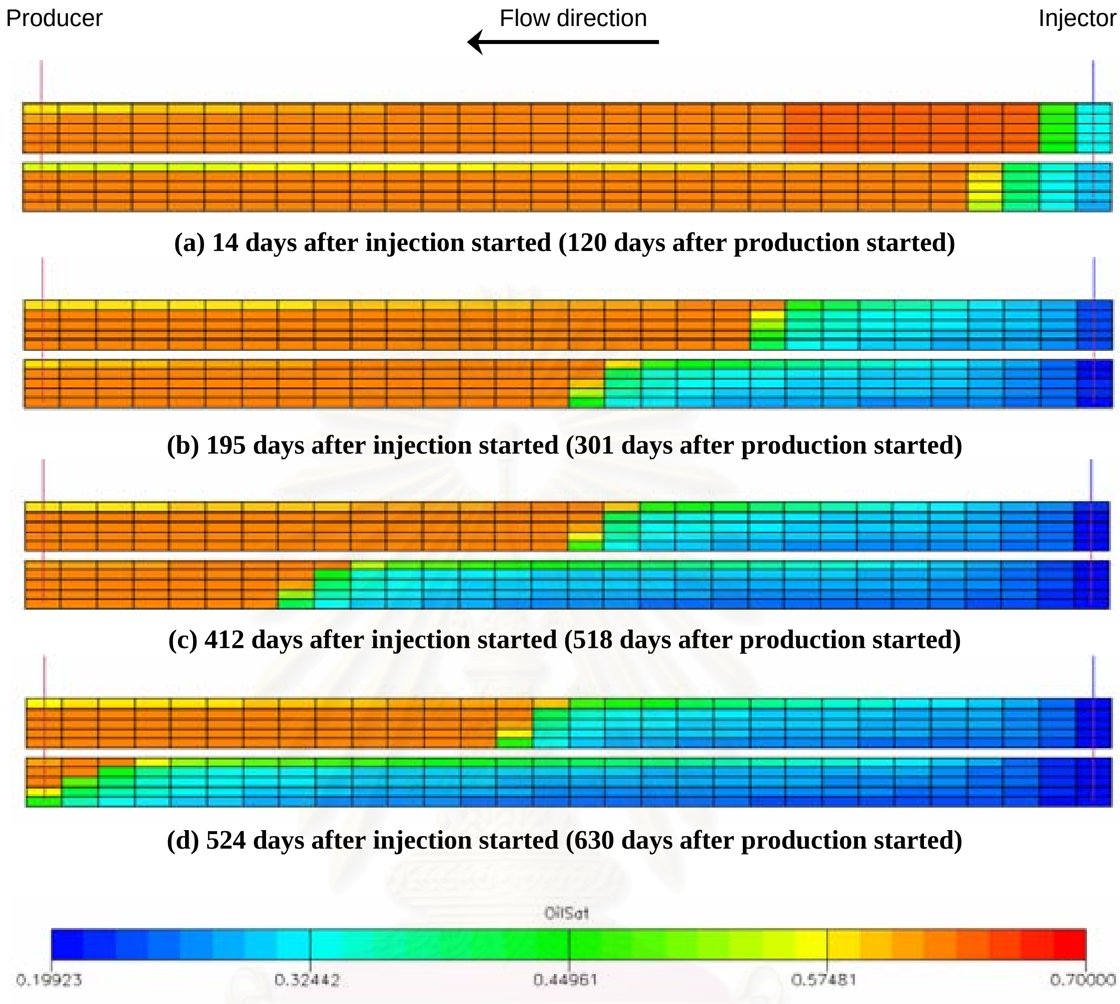
Being a component in Darcy's Equation, permeability has a significant effect on oil production rate and water injection rates in each layer as it has a wide variation (20 to 2000 md). The difference in permeabilities between layers could be very small or as large as 1000 times within this range. Therefore, this parameter is likely to have a great impact on different layer depletions and water distributions, which cause premature water breakthrough.

To observe the influence of layer permeability on waterflooding performance, the simulation work starts from a reservoir model which has small difference in layer permeabilities. Two times permeability contrast is selected for observation. In this case, lower k (100 md) was assigned to the upper layer, whereas higher k (200 md) was assigned to the lower layer. After investigating the effect of this small permeability contrast, larger contrast will be further studied.

a) 2 times permeability contrast

(i) The condition when waterflooding can begin at any time

As mentioned earlier, the water injection is selected to start at reservoir pressure equal to p_{sgc} and maintain the reservoir pressure at this level during water injection so that the highest recovery factor can be achieved. For a 2-layer system which has different k, hence different depletion rates. A layer with higher k will deplete faster due to higher production rate, leading to faster pressure drop and earlier free gas liberation. Therefore, maintaining the pressure of higher k layer at its p_{sgc} would have the other layer operated at the pressure higher than its p_{sgc}. This condition will be applied for simulation runs as it is the lowest operating pressure without free gas production from the reservoir. The simulation results are as shown in Fig.7-37 to Fig.7-41.



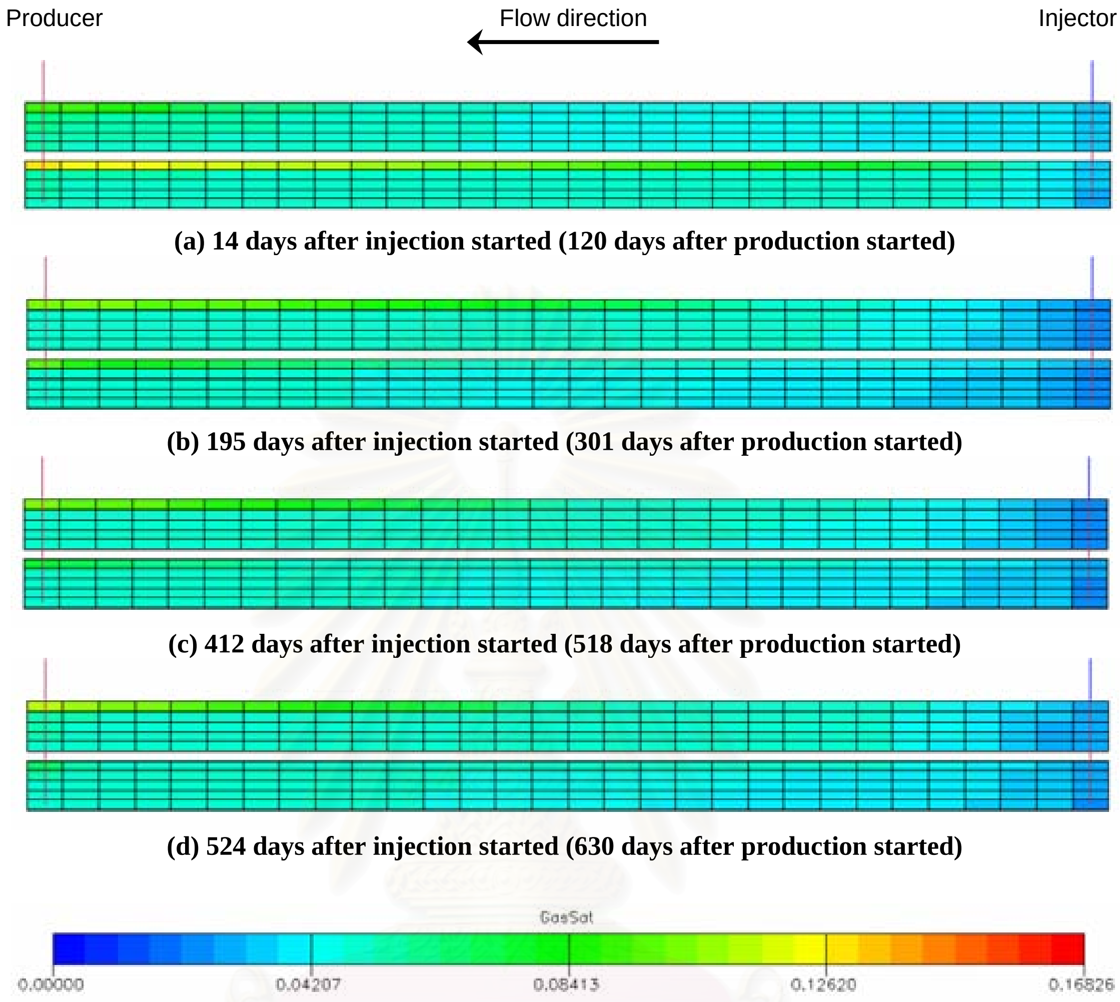
(a) 14 days after injection started (120 days after production started)

(b) 195 days after injection started (301 days after production started)

(c) 412 days after injection started (518 days after production started)

(d) 524 days after injection started (630 days after production started)

Figure 7-37: Cross section of 2-layer model with *k* 100 md for upper layer and 200 md for lower layer showing oil saturation of the case which waterflooding is initiated at p_{sgc}



(a) 14 days after injection started (120 days after production started)

(b) 195 days after injection started (301 days after production started)

(c) 412 days after injection started (518 days after production started)

(d) 524 days after injection started (630 days after production started)

Figure 7-38: Cross section of 2-layer model with *k* 100 md for upper layer and 200 md for lower layer showing gas saturation of the case which waterflooding is initiated at p_{sgc}

Fig.7-37 and Fig.7-38 show the oil saturation and gas saturation during displacement process for this case, respectively. It can be seen that only 2 times difference in layer permeability can cause a large different in water breakthrough times between layers. After water breaks through at the lower *k* layer, the well water cut substantially increases and finally the well was shut-in due to an excessive water cut. The layer water cut profile is shown in Fig.7-39 and the recovery factor obtained from each layer is shown in Fig.7-40.

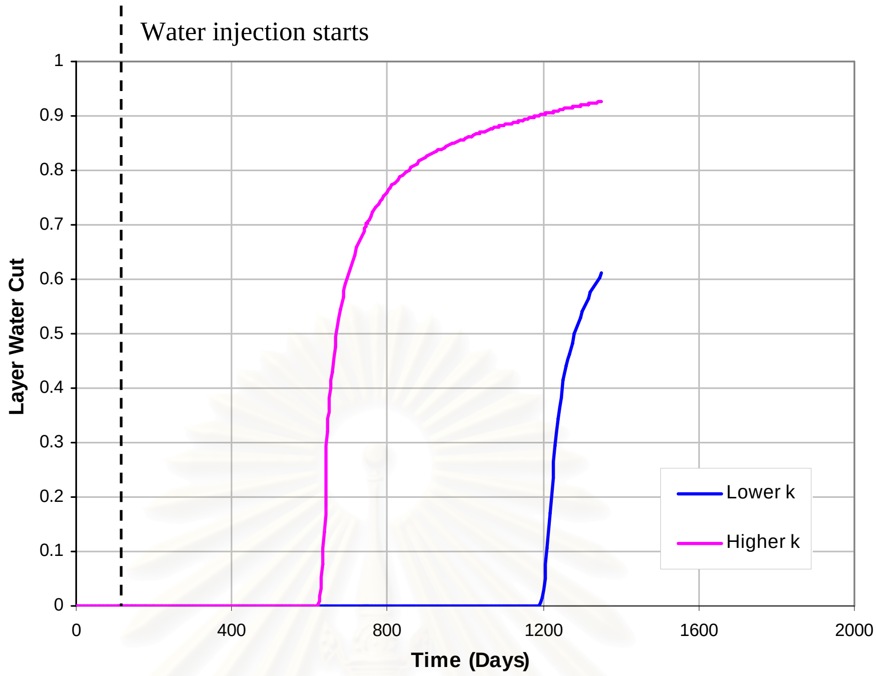


Figure 7-39: Layer water cuts of 2-layer model with *k* 100 md for upper layer and 200 md for lower layer of the case which waterflooding is initiated at p_{sgc}

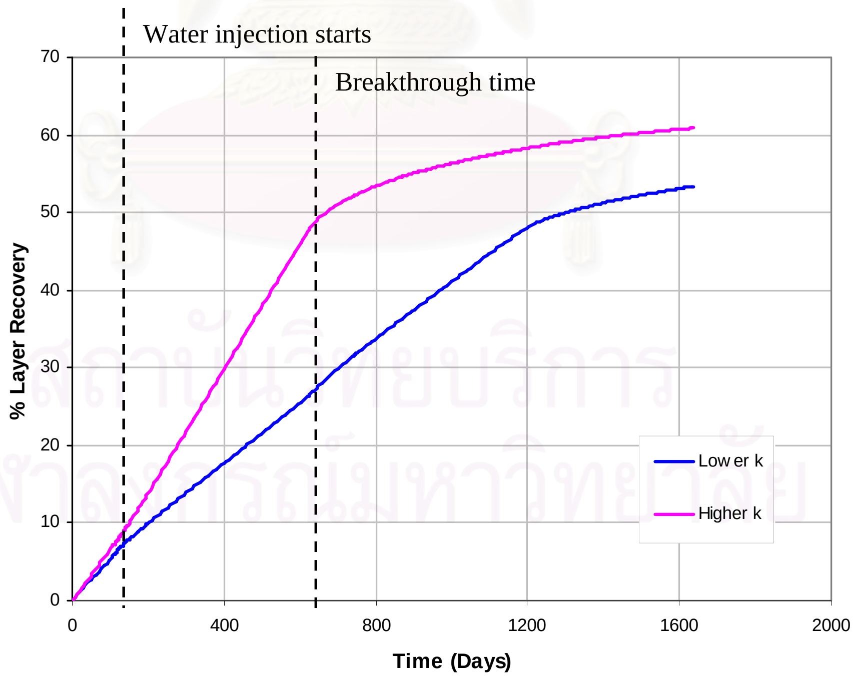


Figure 7-40: % Layer recoveries of 2-layer model with *k* 100 md for upper layer and 200 md for lower layer of the case which waterflooding is initiated at p_{sgc}

From Fig.7-40, it is observed that at the same time, the higher k layer has higher % oil recovery compared to the lower k layer. This is because higher k layer can be produced at higher flow rate as shown in Fig.7-41.

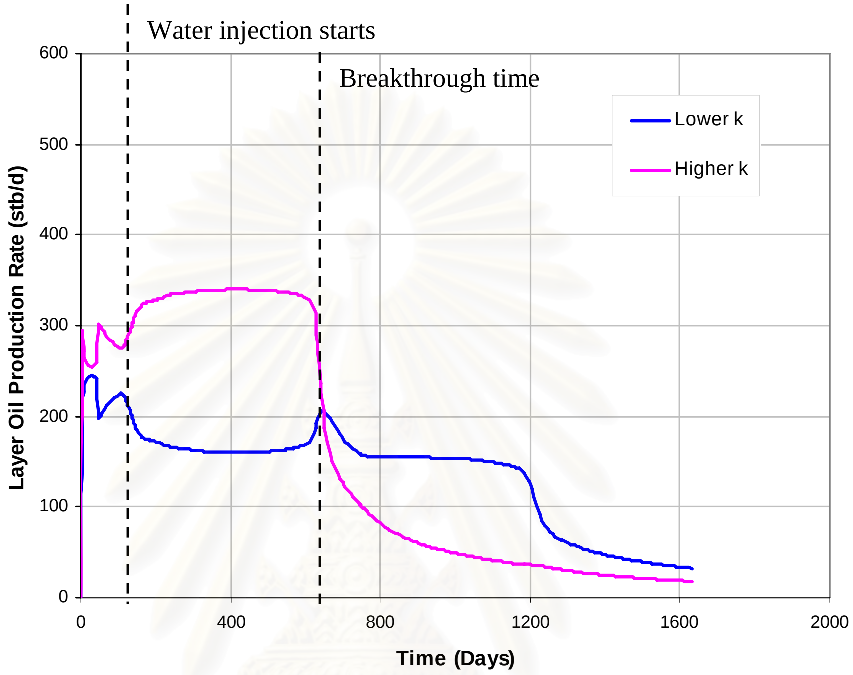


Figure 7-41: Layer oil production rates of 2-layer model with k 100 md for upper layer and 200 md for lower layer of the case which waterflooding is initiated at p_{sgc}

Because the higher k layer has premature water breakthrough and higher water cut as seen in Fig.7-39, the higher k layer was shut-off when the well water cut reaches the economic limit to extend oil production and recover more oil in another layer. The simulation results are as shown in Fig.7-42.

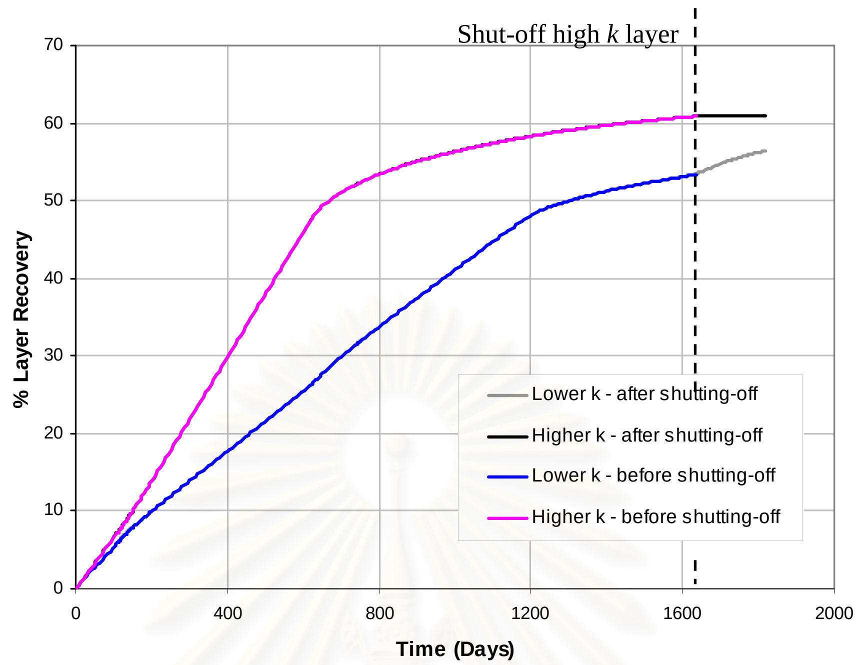


Figure 7-42: % Layer recoveries from 2-layer model with k 100 md for upper layer and 200 md for lower layer before and after shutting-off premature water breakthrough layer of the case which waterflooding is initiated at p_{sgc}

Fig.7-42 shows the comparison of recovery factor of each layer before and after shutting-off higher *k* layer, which has premature water breakthrough. It can be seen that after shutting-off higher *k* layer, the lower *k* layer continues producing, hence recovery factor increases from 53.39% to 56.46%. As seen that only small difference in layer permeabilities affects premature water breakthrough and shutting-off premature water breakthrough can effectively improve the recovery factor. Therefore, the strategy is recommended even in small difference in permeabilities.

(ii) The condition when waterflooding can begin after production under primary recovery

After production under primary recovery process, there is free gas present in the reservoir and some free gas will be produced. The simulation results for this case are shown in Fig.7-43 to Fig.7-49.

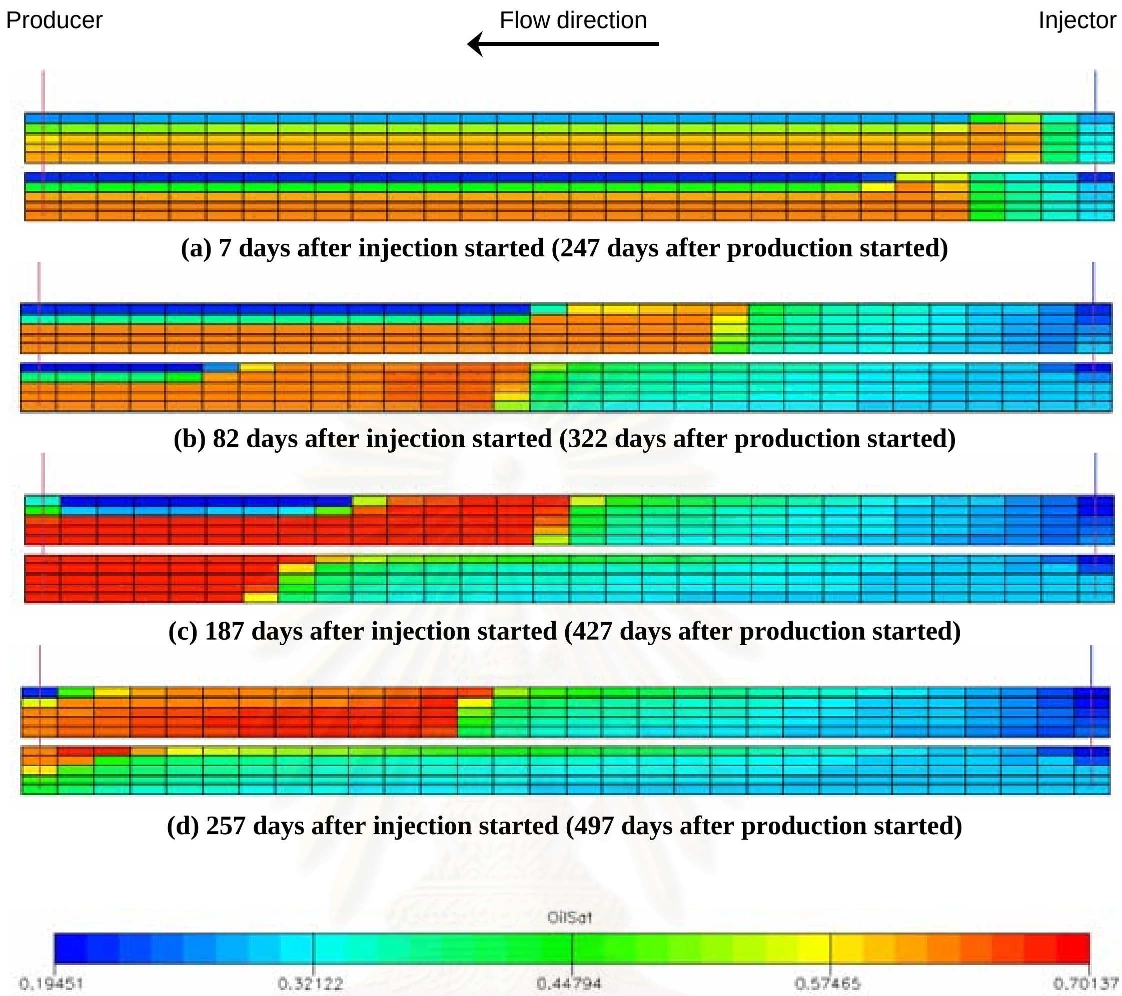
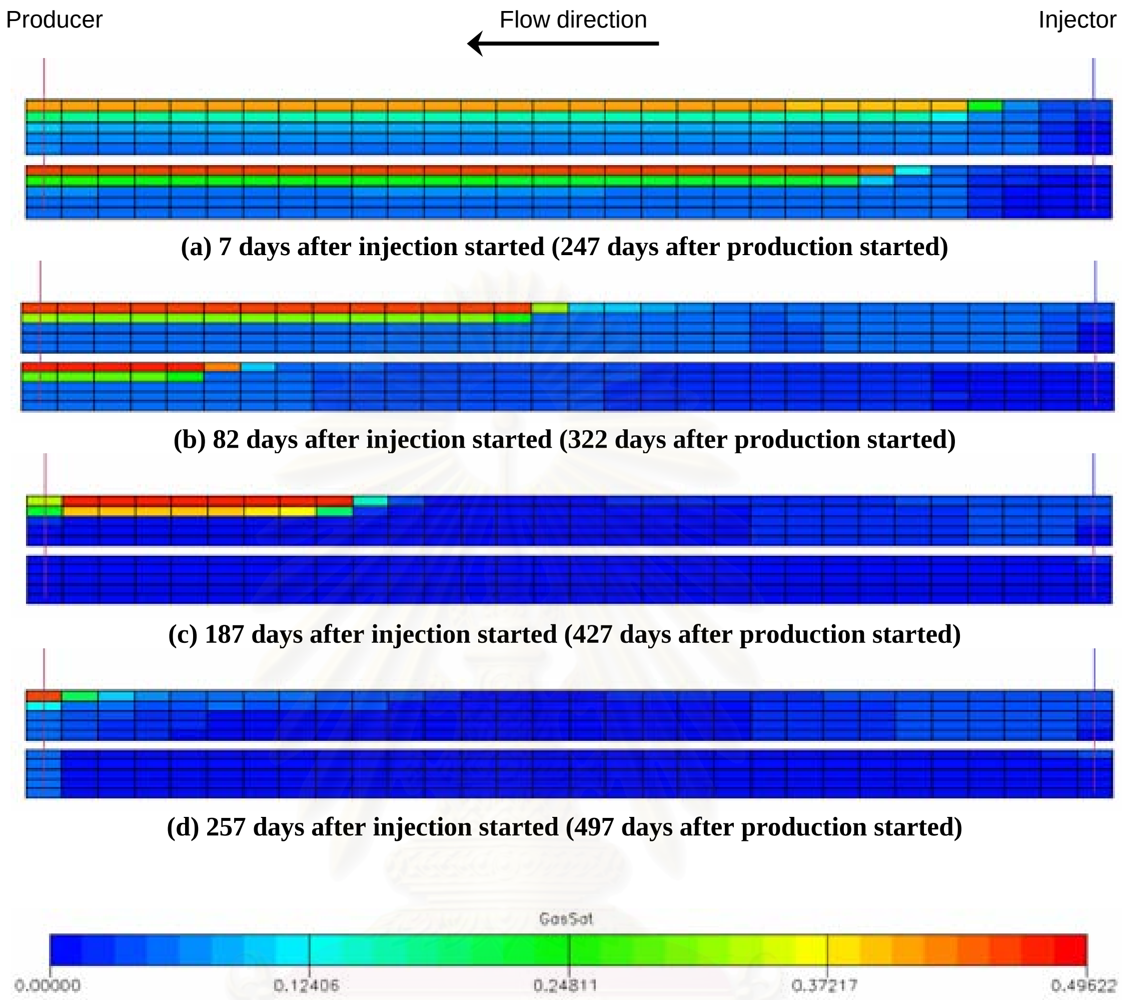


Figure 7-43: Cross section of 2-layer model with *k* 100 md for upper layer and 200 md for lower layer showing oil saturation of the case which waterflooding is initiated after production under primary recovery



(a) 7 days after injection started (247 days after production started)

(b) 82 days after injection started (322 days after production started)

(c) 187 days after injection started (427 days after production started)

(d) 257 days after injection started (497 days after production started)

Figure 7-44: Cross section of 2-layer model with *k* 100 md for upper layer and 200 md for lower layer showing gas saturation of the case which waterflooding is initiated after production under primary recovery

Fig.7-43 and Fig.7-44 show the oil saturation and gas saturation during displacement process for this case, respectively. It can be seen that in the early stage of waterflooding, water moves so fast and flood front in upper sub-layers almost moves as fast as flood front in lower sub-layers, as shown in Fig.7-43 (a) and (b). This is because segregating gas in upper sub-layers is easier for water to displace, referring to Fig.7-44 (a) and (b). As filling-up continues and more free gas was filled-up, water moves slower and the flood front shape changes to be the normal shape finally, as shown in Fig.7-43 (c) and (d).

Fig.7-45 shows water cut profile of this case. It can be seen that in case that waterflooding is initiated after production under primary recovery, the water moves very fast and breaks through in 257 days after injection started (Fig.7-43 (d)), compared to the case that waterflooding is initiated at p_{sgc} which requires 524 days to break through (Fig.7-37 (d)). Therefore, earlier water production should be expected for the reservoir with higher amount of free gas.

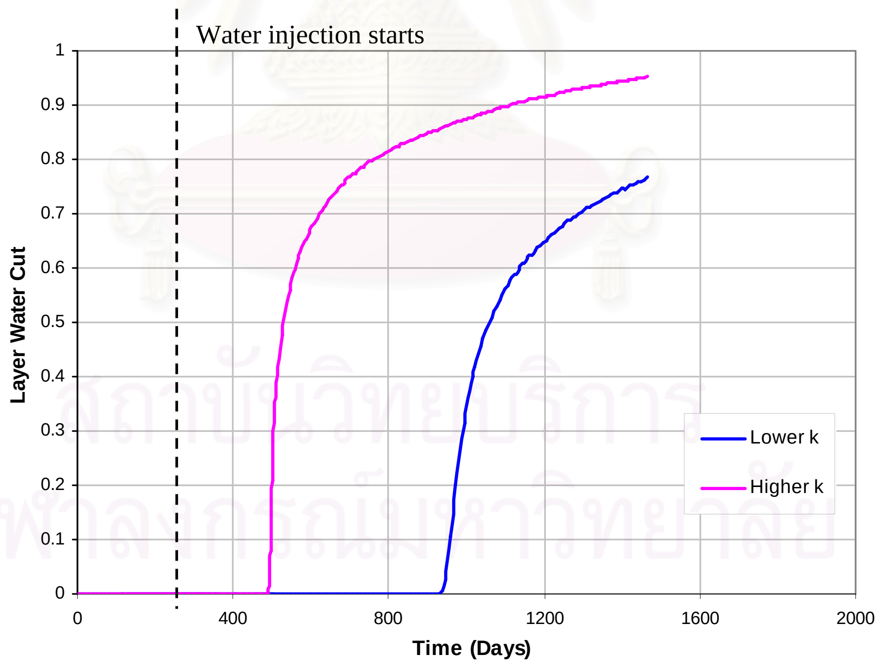


Figure 7-45: Layer water cuts of 2-layer model with *k* 100 md for upper layer and 200 md for lower layer of the case which waterflooding is initiated after production under primary recovery

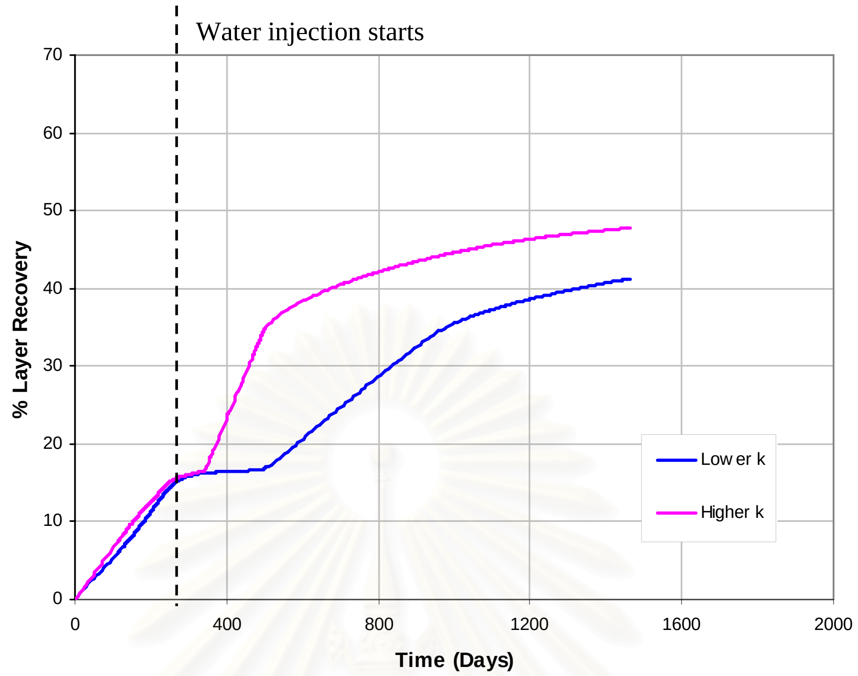


Figure 7-46: % Layer recoveries of 2-layer model with *k* 100 md for upper layer and 200 md for lower layer of the case which waterflooding is initiated after production under primary recovery

Fig.7-46 shows recovery profile obtained from each layer. It can be seen that the recovery factor obtained from both layers are much lower than in case that waterflooding is initiated at p_{sgc}. This is because large amount of free gas was produced prior to waterflooding, as seen in Fig.7-47. During the fill-up period, free gas was still producing. This behavior is the same as the case in section 7.2 b (the fill up behavior), which recommends that the producer should be shut-in during the fill-up period. Though the result of this strategy is not mentioned for this section, it should be noted that this strategy is also recommended for all reservoirs which has produced free gas prior to waterflooding.

Fig.7-48 shows oil production rate for each layer. At the time that waterflooding started the oil rates in both layers still decreased. This is because free gas flows easier than oil, so gas production rate increased as oil production rate decreased. As larger amount of free gas and the easier for water to travel in higher *k* layer, more injected water was distributed as shown in Fig.7-49.

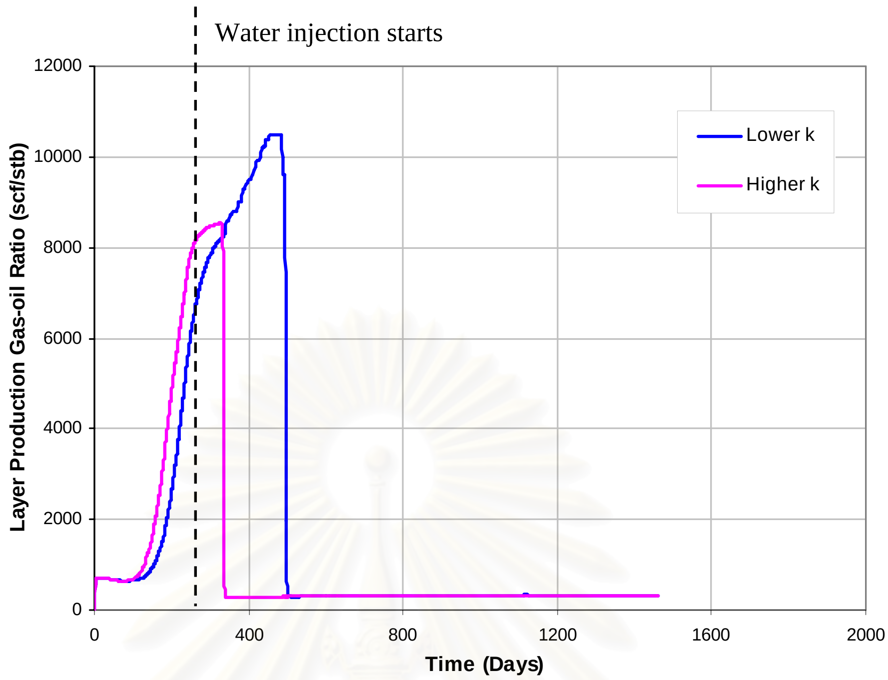


Figure 7-47: Layer production gas-oil ratios of 2-layer model with *k* 100 md for upper layer and 200 md for lower layer of the case which waterflooding is initiated after production under primary recovery

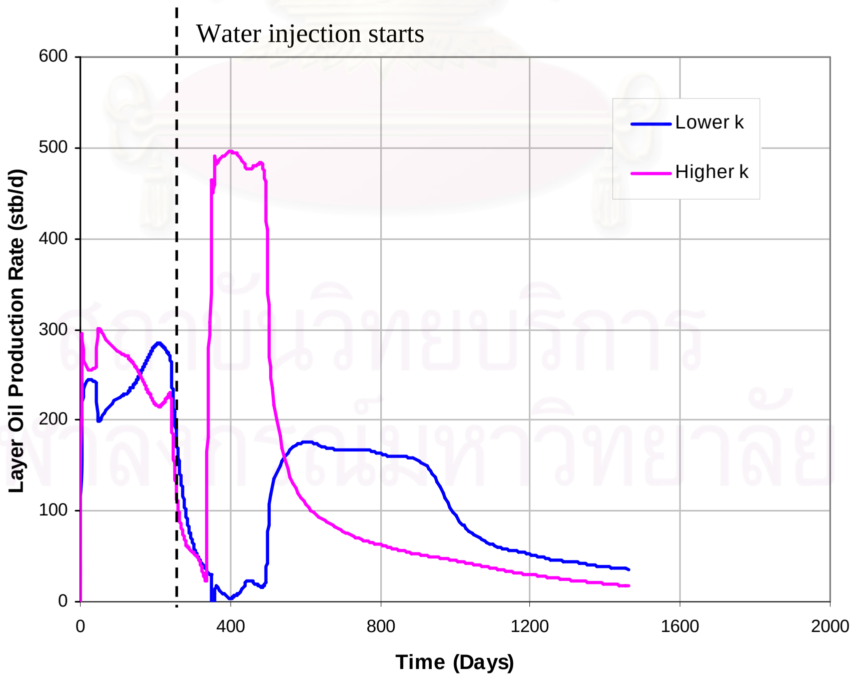


Figure 7-48: Layer oil production rates of 2-layer model with *k* 100 md for upper layer and 200 md for lower layer of the case which waterflooding is initiated after production under primary recovery

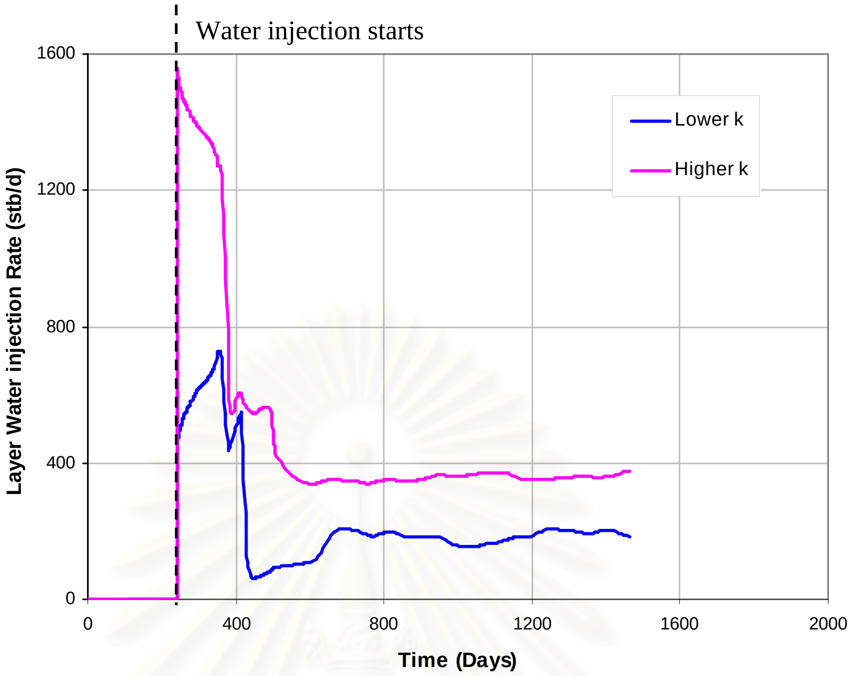


Figure 7-49: Layer water injection rates of 2-layer model with *k* 100 md for upper layer and 200 md for lower layer of the case which waterflooding is initiated after production under primary recovery

As seen in Fig.7-47 and Fig.7-48, there is an abruptly drop in production gas-oil ratio and an abruptly increase in oil production rate of higher *k* layer around 350 days after production started. The abruptly drop in production gas-oil ratio implies that most free gas was either pushed into the production well or pushed back to dissolve in the oil by the injected water. Water also pushes the oil bank ahead, resulting in an increment in oil production rate when the oil bank reaches the producer, which implies that the fill-up period of the higher *k* layer completes. As a result, the % recovery of the higher *k* layer increases at a higher rate than the lower *k* layer (Fig.7-46).

Because lower *k* layer has lower water injection rate (Fig.7-46), its fill-up period is longer, which could be observed by longer period of high production gas-oil ratio in Fig.7-47. The abruptly dropped in production gas-oil ratio around 500 days implies that its fill-up period completes so the oil production rate abruptly increases in Fig.7-48, leading to the increment in % recovery in Fig.7-46.

Though both layers were completely filled-up, their recovery factor is low since too much free gas was produced prior to the waterflooding, as discussed in Chapter 6.

Because premature water breakthrough occurs at the higher *k* layer and its water cut is higher, the layer is decided to shut-off when the well water cut reaches the economic limit to extend oil production and improve recovery factor in lower *k* layer.

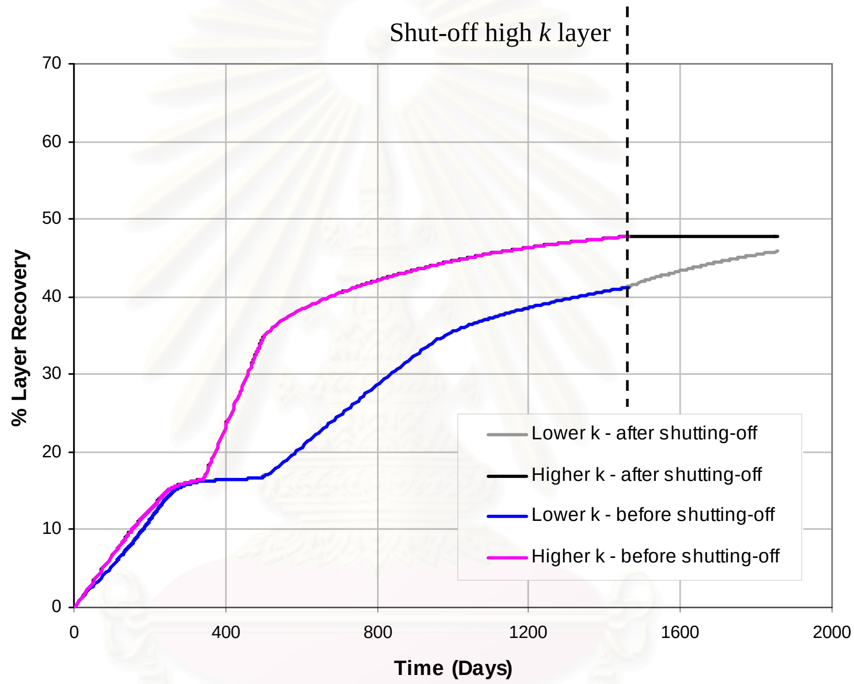


Figure 7-50: % Layer recoveries from 2-layer model with *k* 100 md for upper layer and 200 md for lower layer before and after shutting-off premature water breakthrough layer of the case which waterflooding is initiated after production under primary recovery

Fig.7-50 shows the comparison of recovery factor of each layer before and after shutting-off higher *k* layer, which has premature water breakthrough. In this case, the recovery factor of the lower *k* layer increases from 41.24% to 45.85%. Similarly to the case that waterflooding is initiated at p_{sgc}, we see that shutting-off premature water breakthrough layer can improve recovery factor even permeability difference is small. So the strategy of shutting of premature breakthrough later is recommended in even a small permeability difference.

In summary, the layer with higher k is easier for water to flow, so the oil is better displaced and its recovery factor is higher. However, as the water velocity is higher, premature water breakthrough occurs. The higher k layer also has higher depletion, so more free gas liberates than the lower k. In case that waterflooding is initiated after production under primary recovery, more gas lets flood front move faster, leading to much earlier water breakthrough at the producer. In this study, we used 2 times permeability contrast for observation. With this small permeability contrast, shutting-off premature water breakthrough layer can improve the recovery. As this strategy is very efficient for the variation in permeability, it is recommended even in small permeability difference.

With the observation that only 2 times k contrast has significant impact on the recovery factor in each layer. It is interesting to observe the effect of larger k contrasts. In the next section, 10 times k contrast is selected for observation. In this case, lower k (20 md) was assigned to the upper layer, whereas higher k (200 md) was assigned to the lower layer.

b) 10 times permeability contrast

(i) The condition when waterflooding can begin at any time

Again for this level of k contrast, the higher k layer (200 md) will be maintained at its p_{sgc} to have the other layer operated at the pressure higher than its p_{sgc}. The simulation results are as shown in Fig.7-51 to Fig.7-57.

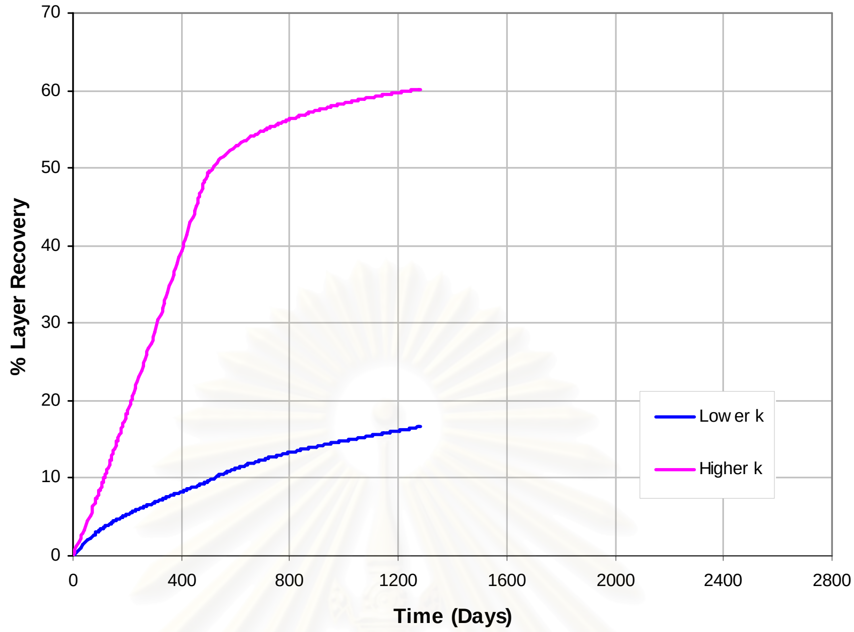
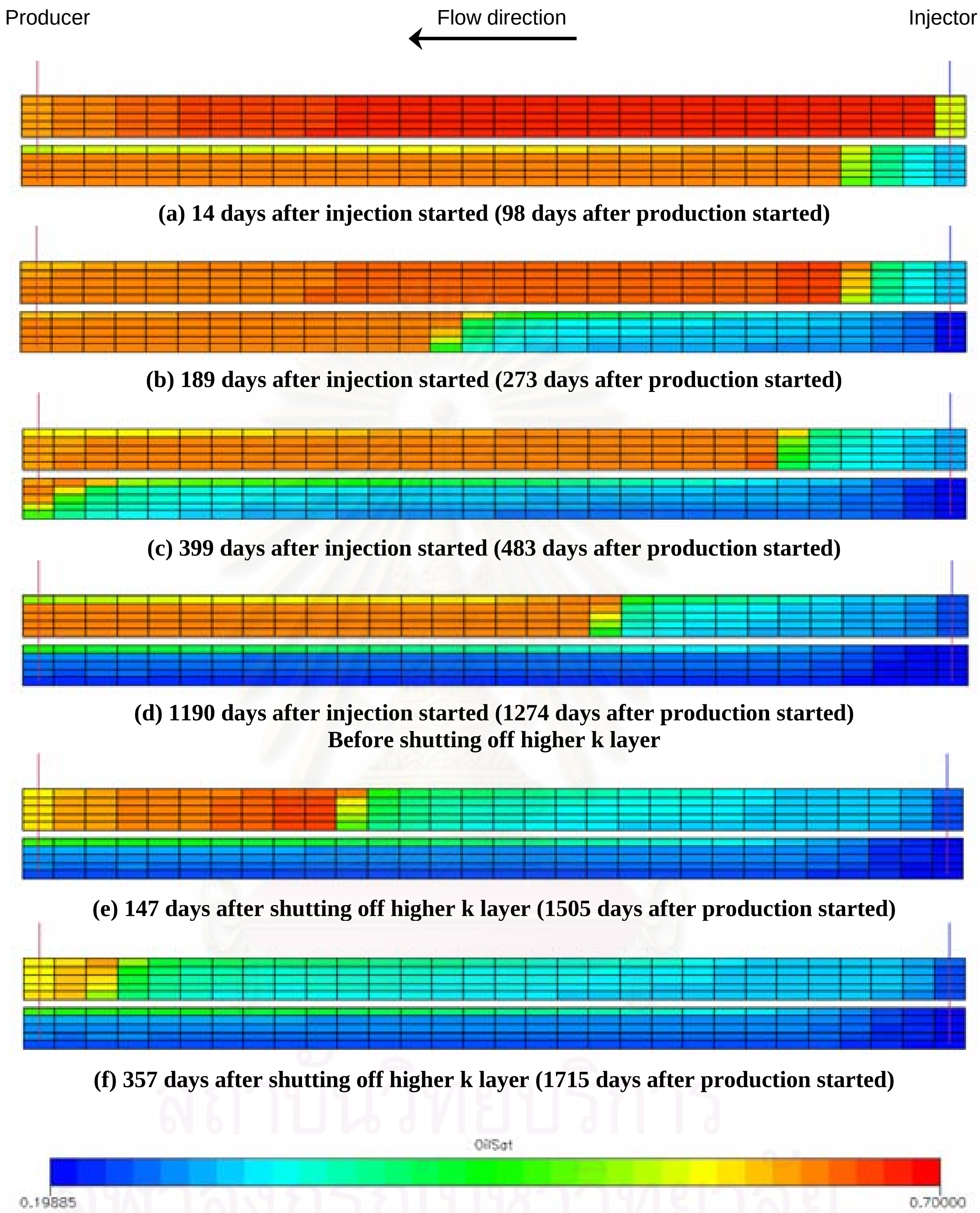


Figure 7-51: % Layer recoveries of 2-layer model with k 20 md for upper layer and 200 md for lower layer of the case which waterflooding is initiated at p_{sgc}

Fig.7-51 shows % layer recovery of each layer. As we discussed in previous section that higher k layer has higher % recovery due to better displacement by water. It is noticed that the permeability contrast has a great impact on the recovery factor of the lower k layer. The effect of permeability contrast will be discussed in this section.

Fig.7-52 and Fig.7-53 show the oil saturation and gas saturation during displacement process for this case, respectively. In Fig.7-52 (a) to (c), we see that the injected water is very low distributed to the lower k layer. At the breakthrough times at the higher k layer, the injected water into lower k layer is extremely low (Fig.7-52 (d)) and the water in lower k layer will never breakthrough until the well was shut-in when water cut from higher k layer reaches the economic limit (Fig7-53). The water injection rate into each layer is shown in Fig.7-55.



(a) 14 days after injection started (98 days after production started)

(b) 189 days after injection started (273 days after production started)

(c) 399 days after injection started (483 days after production started)

(d) 1190 days after injection started (1274 days after production started)
Before shutting off higher k layer

(e) 147 days after shutting off higher k layer (1505 days after production started)

(f) 357 days after shutting off higher k layer (1715 days after production started)

Figure 7-52: Cross section of 2-layer model with *k* 20 md for upper layer and 200 md for lower layer showing oil saturation of the case which waterflooding is initiated at p_{sgc}

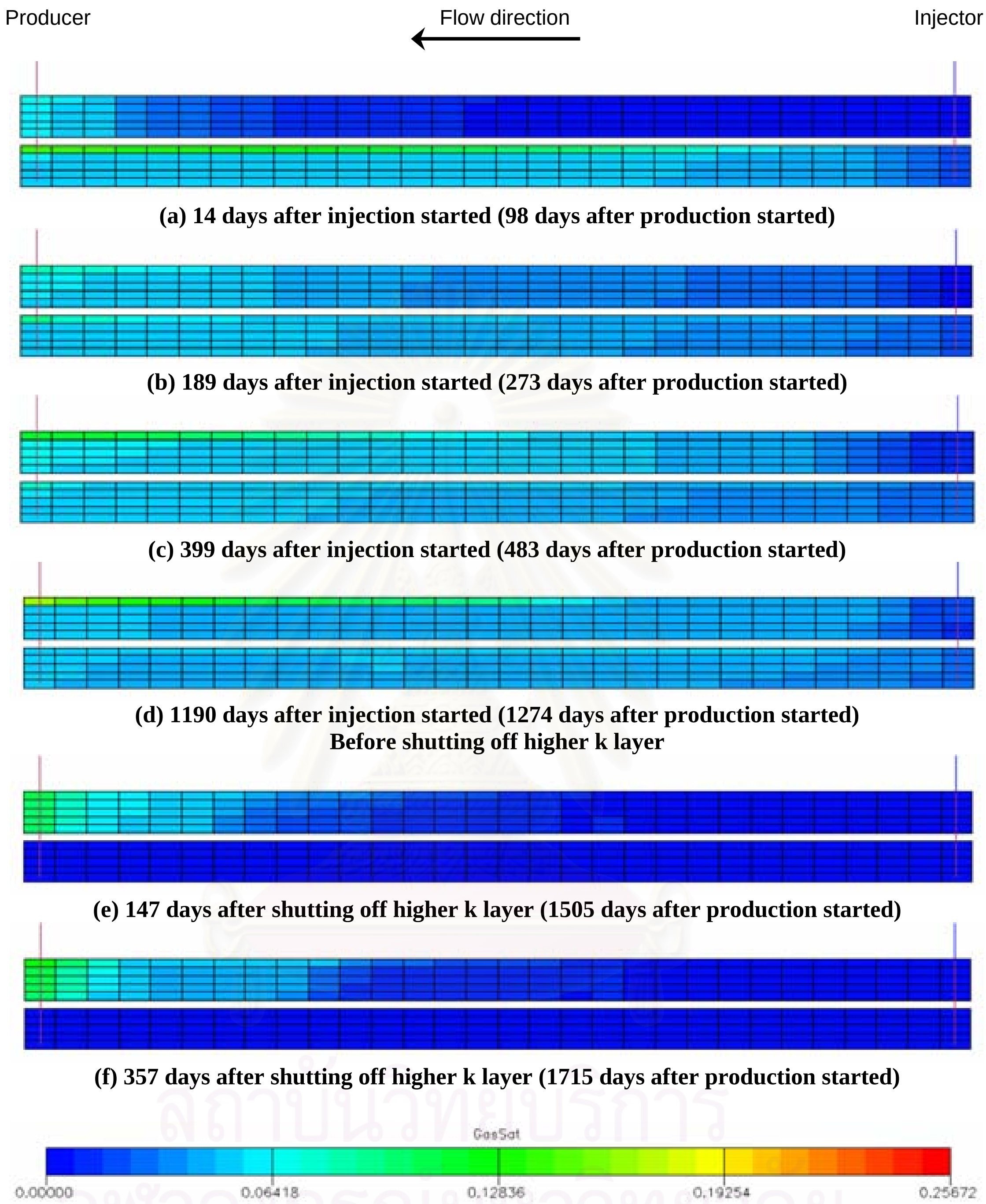


Figure 7-53: Cross section of 2-layer model with k 20 md for upper layer and 200 md for lower layer showing gas saturation of the case which waterflooding is initiated at p_{sgc}

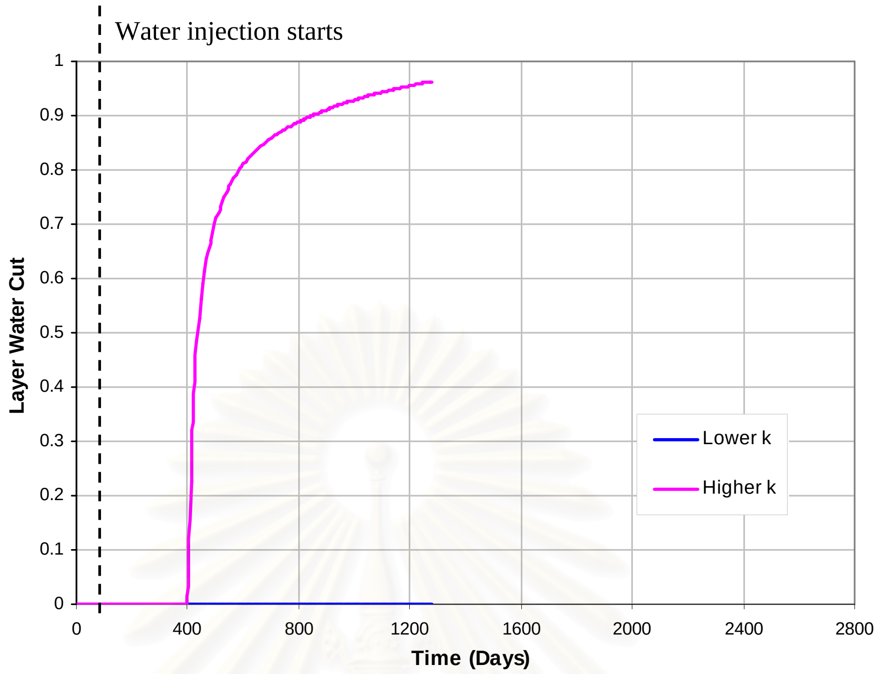


Figure 7-54: % Layer water cuts of 2-layer model with *k* 20 md for upper layer and 200 md for lower layer of the case which waterflooding is initiated at p_{sgc}

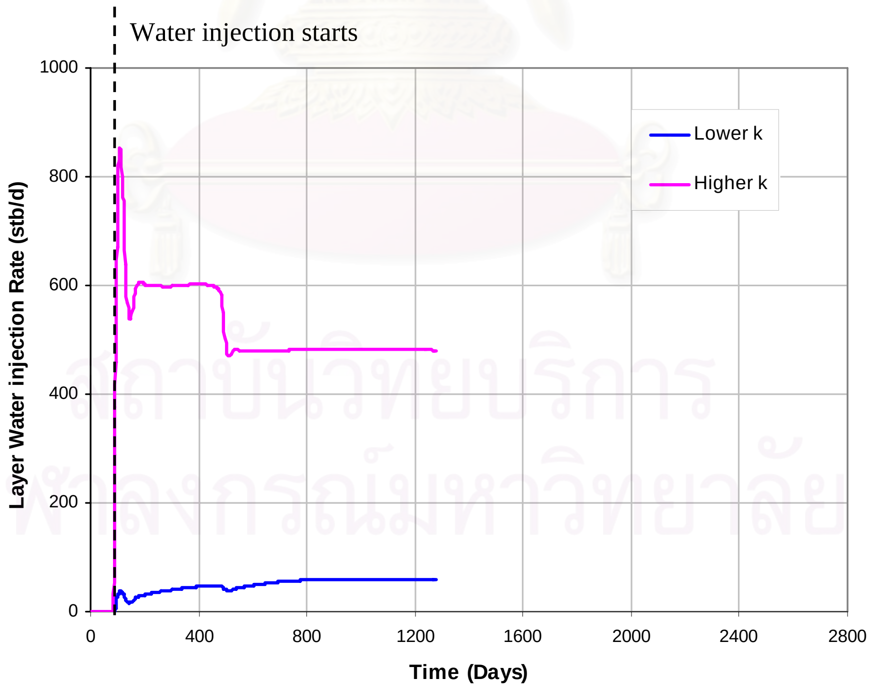


Figure 7-55: % Layer water injection rates of 2-layer model with *k* 20 md for upper layer and 200 md for lower layer of the case which waterflooding is initiated at p_{sgc}

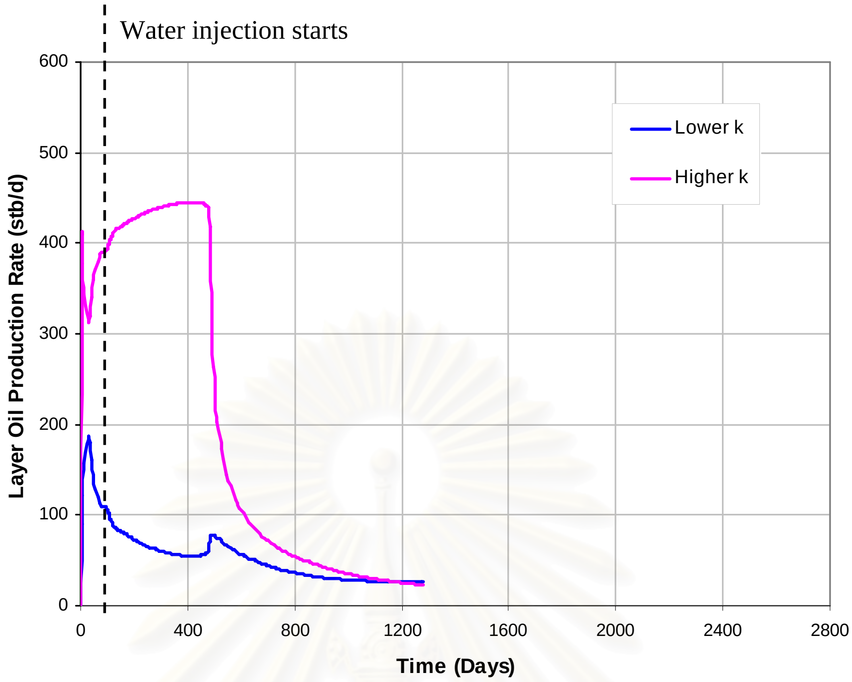


Figure 7-56: % Layer oil production rates of 2-layer model with *k* 20 md for upper layer and 200 md for lower layer of the case which waterflooding is initiated at p_{sgc}

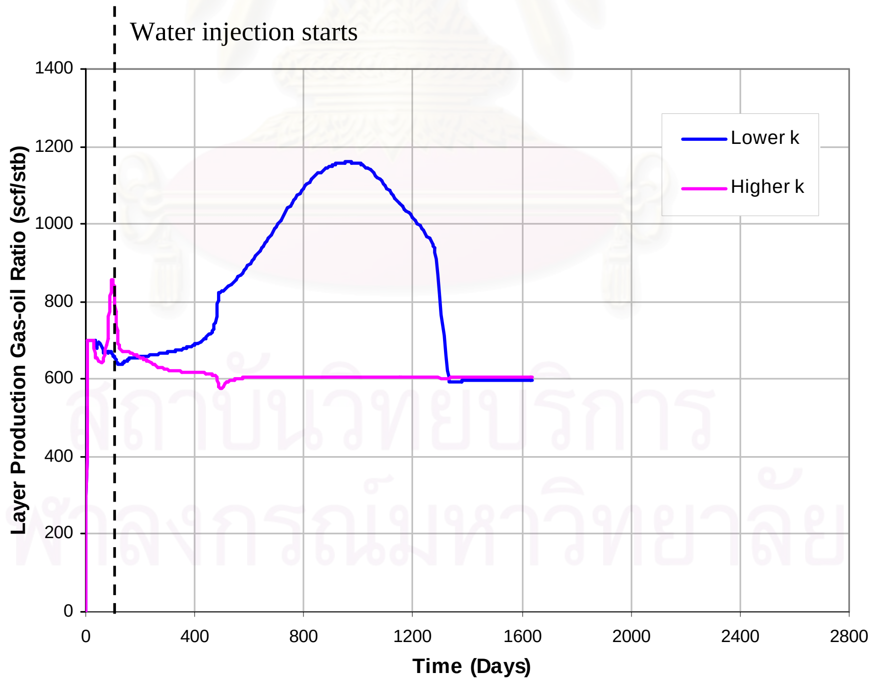


Figure 7-57: % Layer oil production rates of 2-layer model with *k* 20 md for upper layer and 200 md for lower layer of the case which waterflooding is initiated at p_{sgc}

Two main reasons that cause extremely low recovery factor in lower *k* layer are observed. The first one is the much higher oil rate in higher *k* layer as a result of more amount of injected water as shown in Fig.7-55 and Fig.7-56. The second reason can be observed from the production gas-oil ratio profile in Fig.7-57. It can be seen that due to extremely low water support, the lower *k* layer produces free gas. As a result, its recovery factor is low.

To improve the recovery factor of the system, the higher *k* layer was shut-off when the water cut reaches the economic limit. Fig.7-58 shows the comparison of % recoveries between before and after shutting-off higher *k* layer.

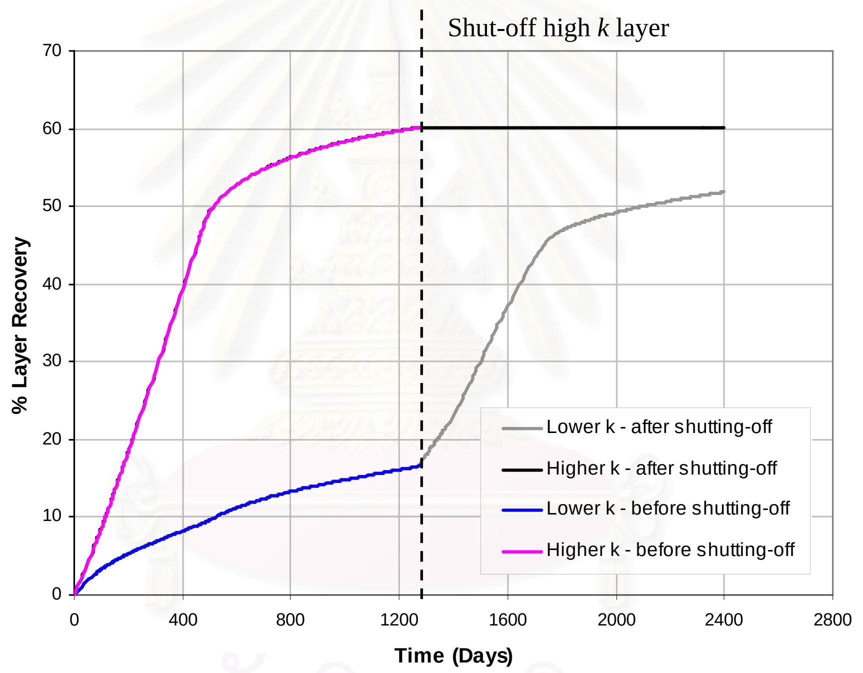


Figure 7-58: % Layer recoveries from 2-layer model with *k* 20 md for upper layer and 200 md for lower layer before and after shutting-off premature water breakthrough layer of the case which waterflooding is initiated at p_{sgc}

After shutting-off the higher *k* layer, a rapidly increase in % recovery of lower *k* layer is observed. However, we see that it is still much lower than the recovery factor of lower *k* layer in 2 times *k* contrast system. This is partly a result of free gas production in lower *k* layer as discussed above. Therefore, delay in oil recovery from lower *k* layer and low recovery factor should be expected when dealing with a reservoir system with higher permeability contrast.

(ii) The condition when waterflooding can begin after production under primary recovery

After production under primary recovery process, there is free gas present in the reservoir and some free gas will be produced. The simulation results for this case are shown in Fig.7-59 to Fig.7-65.

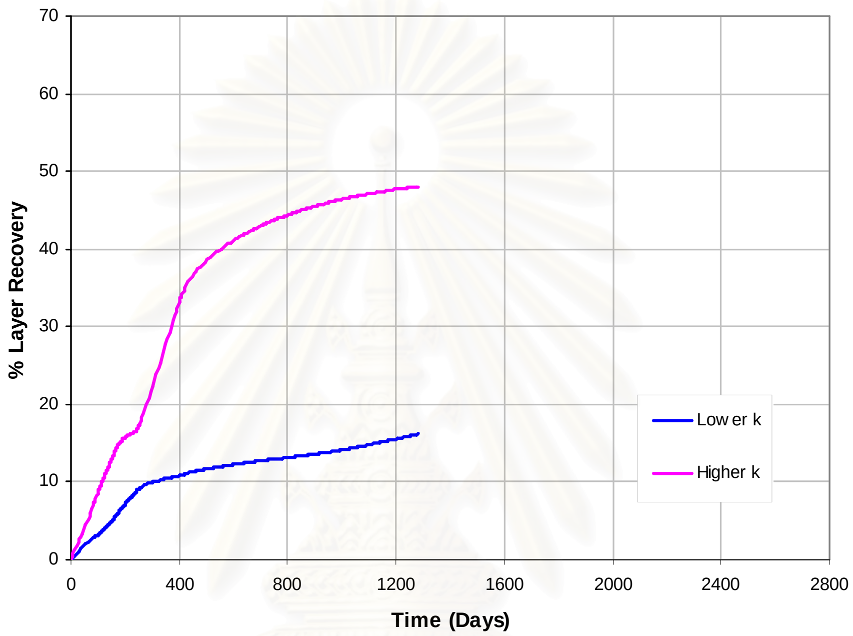


Figure 7-59: % Layer recoveries of 2-layer model with k 20 md for upper layer and 200 md for lower layer of the case which waterflooding is initiated after production under primary recovery

For this case, we see that the recovery profile of lower k layer is the similar to the case which waterflooding is initiated at p_{sgc}. For higher k layer, the recovery factor is lower than the case which waterflooding is initiated at p_{sgc} because of the free gas production prior to waterflooding.

Fig.7-60 and Fig.7-61 show oil saturation and gas saturation for this case, respectively. The result is similar to the previous case except for the earlier water breakthrough from high k layer as a result of more free gas space. Fig.7-62 shows the water cut profile while Fig.7-63 shows the water injection rate into each layer. It is noticed that just after waterflooding starts, water injection into higher k layer abruptly increases to the highest allowable rate. This is because large amount of water is needed to fill-up the free gas in higher *k* layer, which has highly depleted and generates large amount of free gas as seen in Fig. 7-61 (a) and (b).

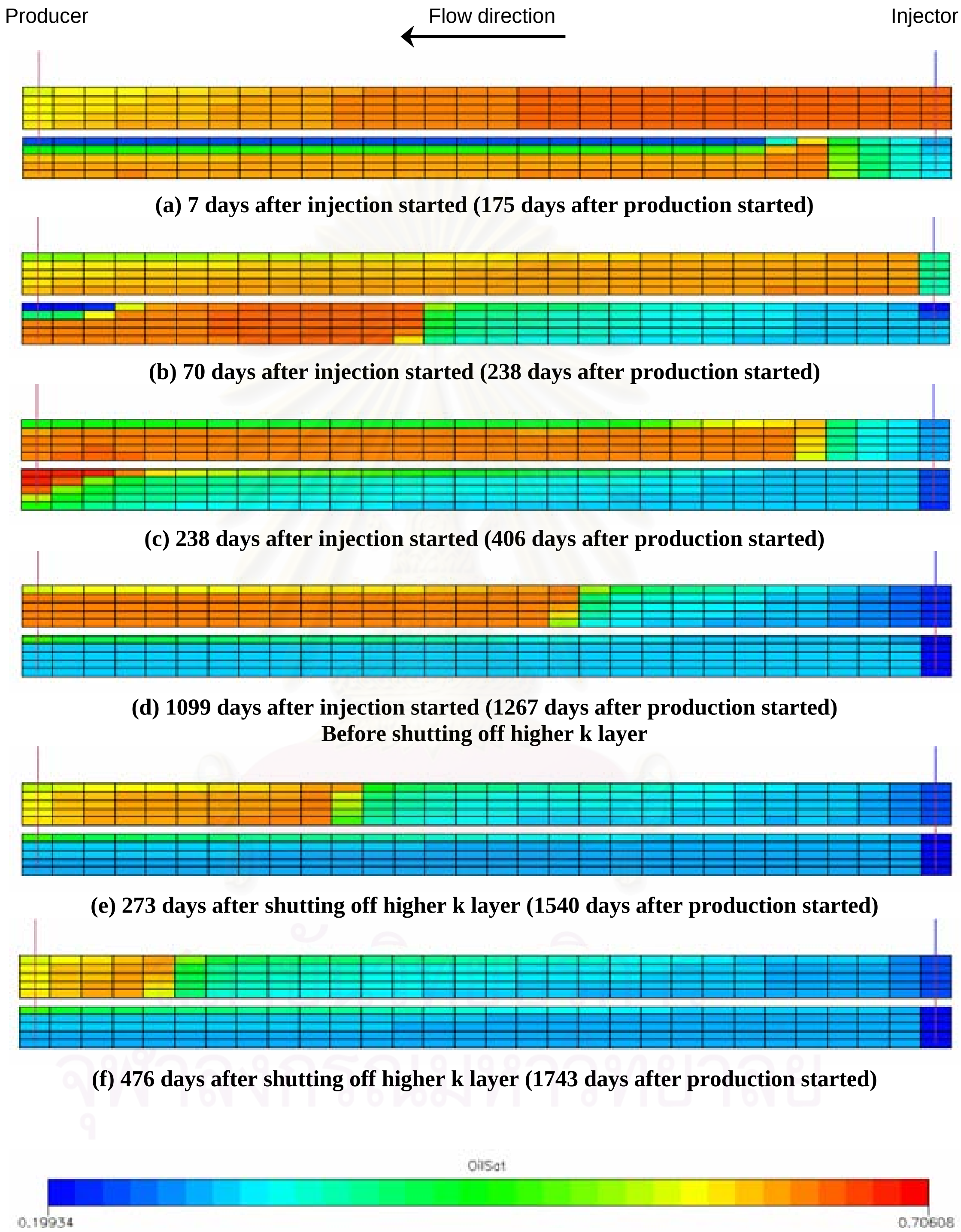
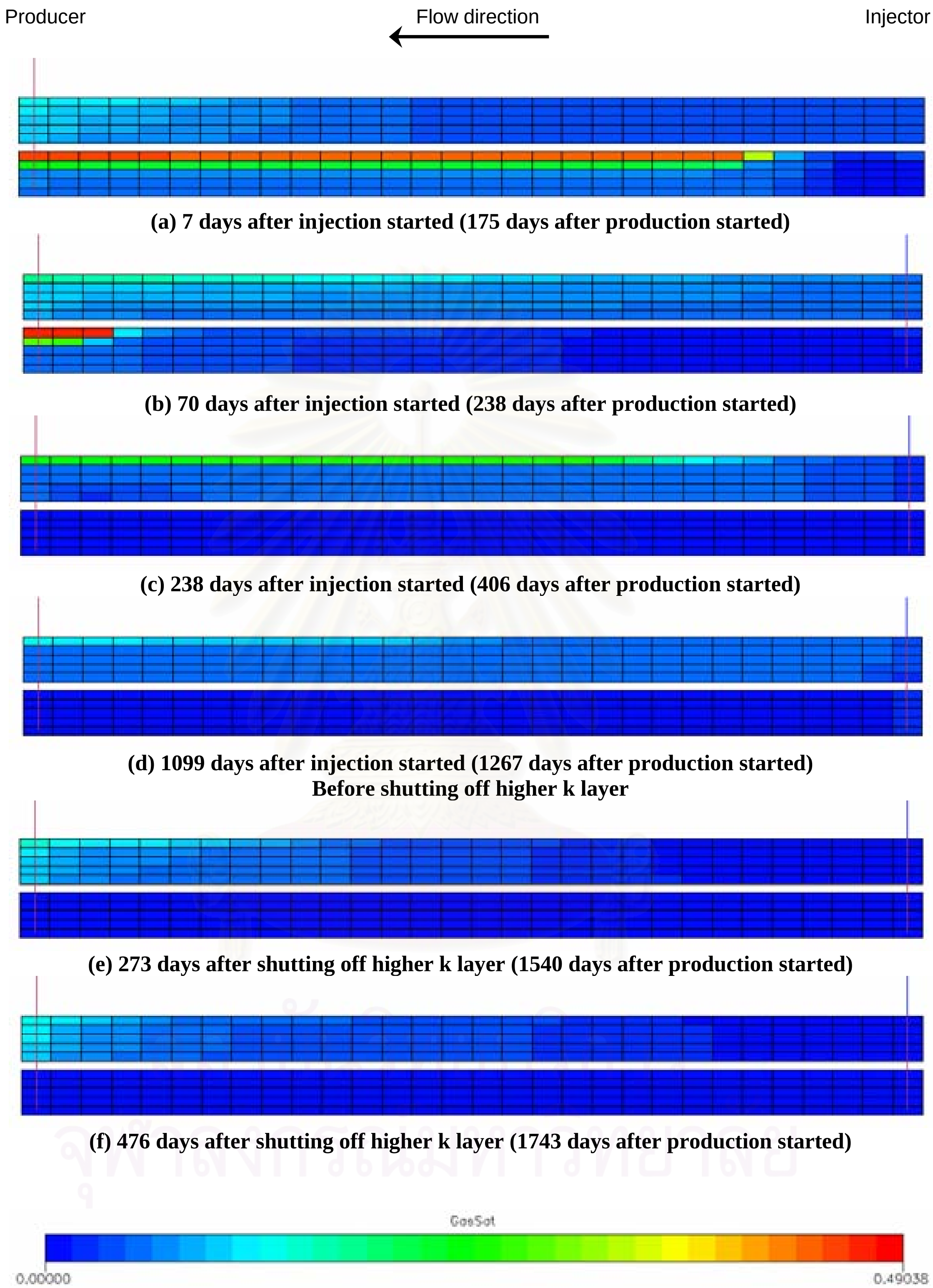


Figure 7-60: Cross section of 2-layer model with *k* 100 md for upper layer and 200 md for lower layer showing oil saturation of the case which waterflooding is initiated after production under primary recovery



(a) 7 days after injection started (175 days after production started)

(b) 70 days after injection started (238 days after production started)

(c) 238 days after injection started (406 days after production started)

(d) 1099 days after injection started (1267 days after production started)
Before shutting off higher k layer

(e) 273 days after shutting off higher k layer (1540 days after production started)

(f) 476 days after shutting off higher k layer (1743 days after production started)

Figure 7-61: Cross section of 2-layer model with *k* 20 md for upper layer and 200 md for lower layer showing oil saturation of the case which waterflooding is initiated after production under primary recovery

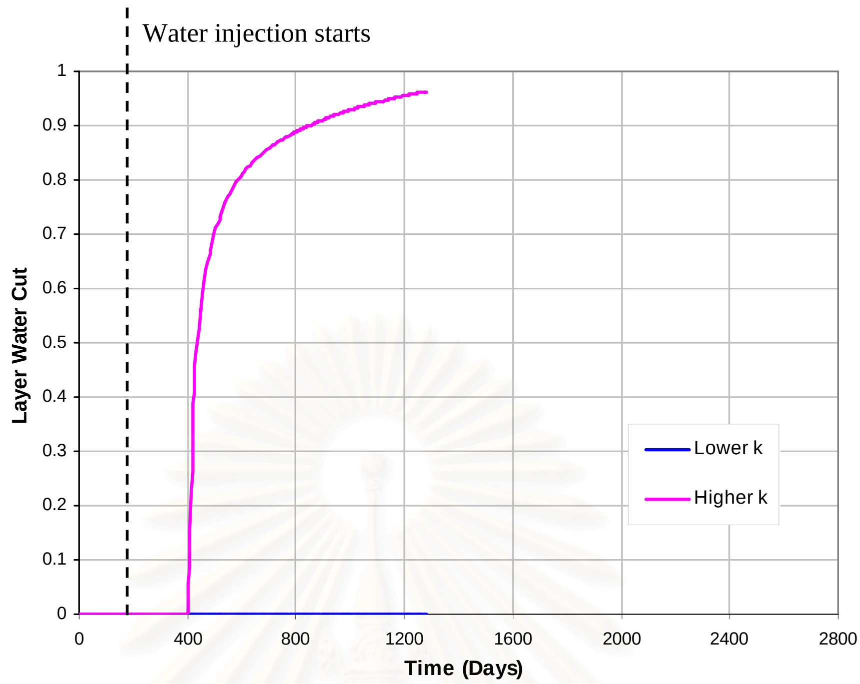


Figure 7-62: % Layer water cuts of 2-layer model with *k* 20 md for upper layer and 200 md for lower layer of the case which waterflooding is initiated after production under primary recovery

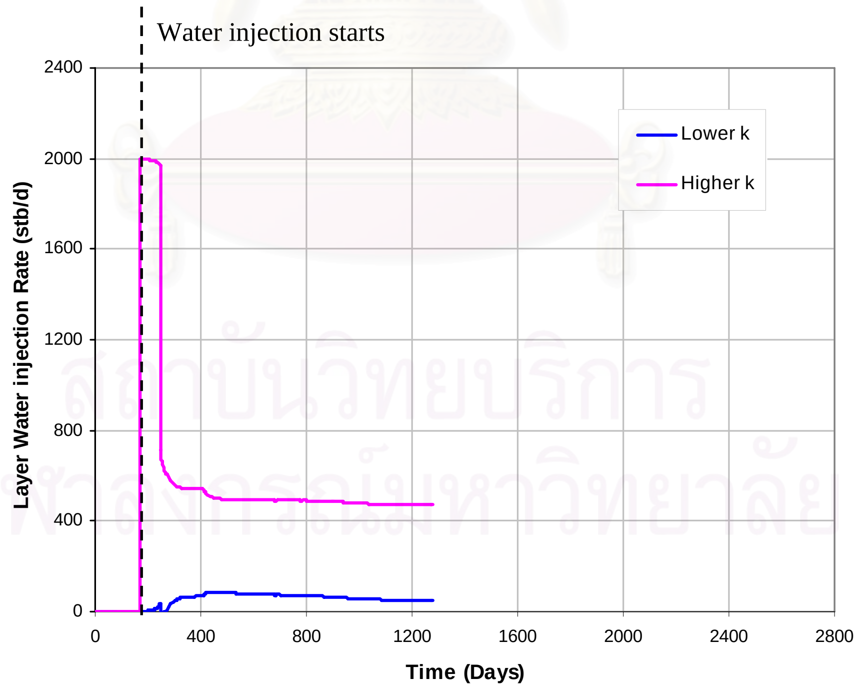


Figure 7-63: % Layer water injection rates of 2-layer model with *k* 20 md for upper layer and 200 md for lower layer of the case which waterflooding is initiated after production under primary recovery

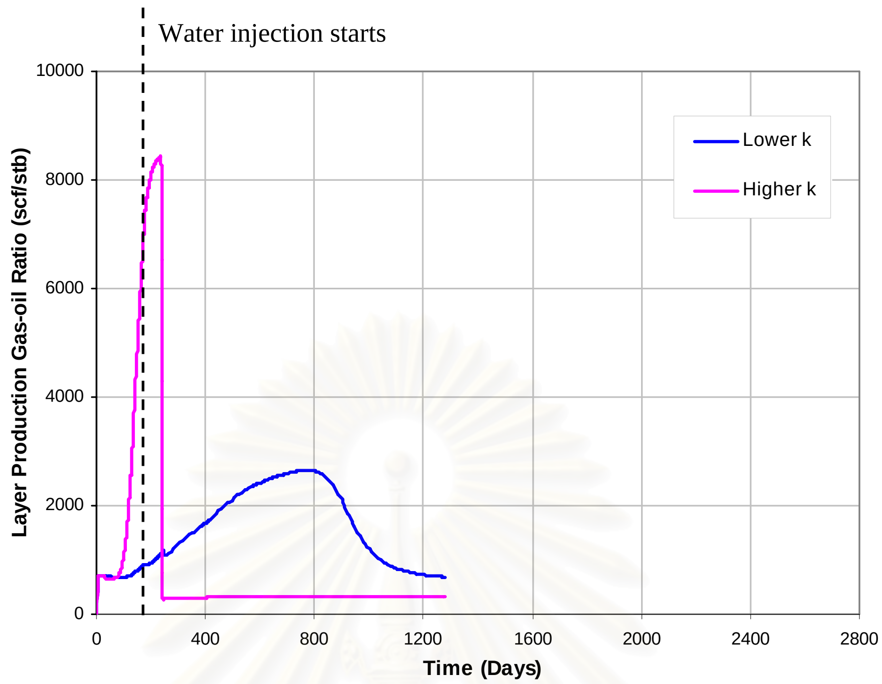


Figure 7-64: % Layer production gas-oil ratio of 2-layer model with *k* 20 md for upper layer and 200 md for lower layer of the case which waterflooding is initiated after production under primary recovery

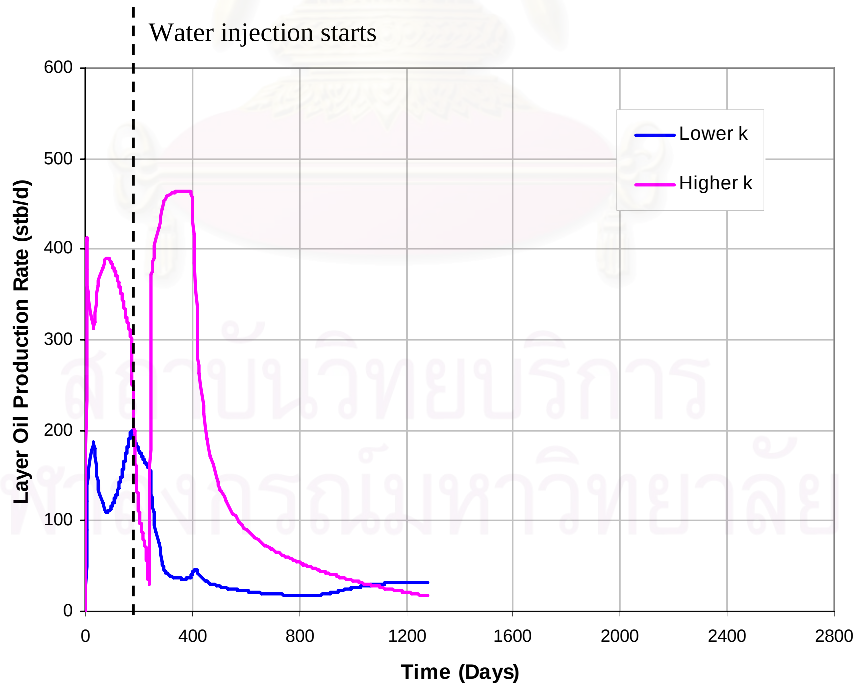


Figure 7-65: % Layer oil production rates of 2-layer model with *k* 20 md for upper layer and 200 md for lower layer of the case which waterflooding is initiated after production under primary recovery

Fig.7-64 and Fig.7-65 show the production gas-oil ratio and oil production rate of each layer, respectively. It is observed that higher *k* layer produced free gas prior to waterflooding while lower *k* layer produced free gas after water injection was initiated. It is noted that the lower *k* layer did not produce free gas prior to waterflooding because its pressure is still higher than p_{sgc}. In Fig.7-65, we see that before fill-up period (about 200 days), oil rate in higher k layer dramatically drops because free gas flows easier. As a result, oil rate in lower *k* layer increases. After fill-up period, the oil rate in higher *k* layer abruptly increases again. Since the maximum well oil rate is limited, oil rate in lower *k* layer decreases. After a while, the lower *k* layer starts to produce free gas due to small water support, similarly to the case which waterflooding is initiated at p_{sgc}.

To improve the recovery factor of the system, the higher *k* layer was shut-off when the water cut reaches the economic limit. Fig.7-66 shows the comparison of % recoveries between before and after shutting-off higher *k* layer.

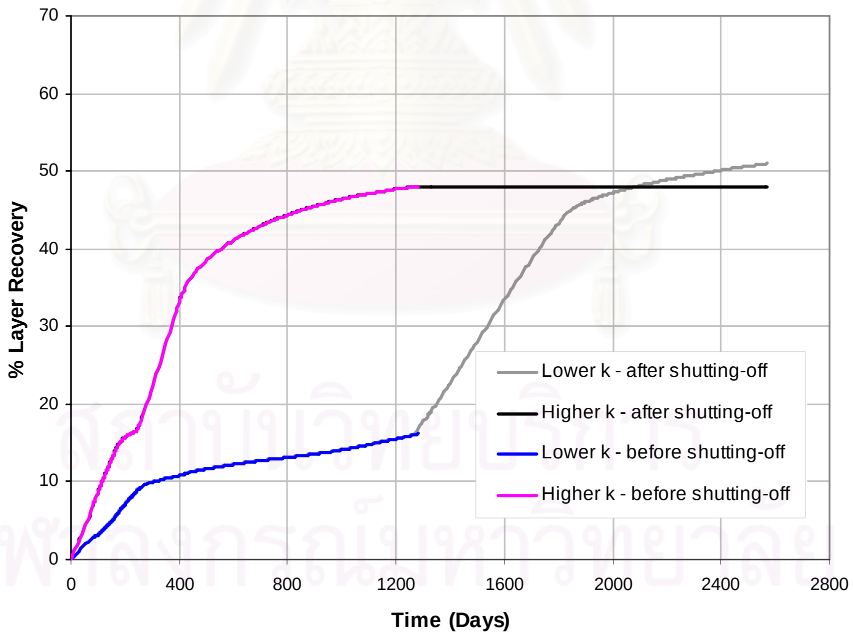


Figure 7-66: % Layer recoveries from 2-layer model with *k* 20 md for upper layer and 200 md for lower layer before and after shutting-off premature water breakthrough layer of the case which waterflooding is initiated after production under primary recovery

After shutting-off the higher *k* layer, a rapidly increase in % recovery of lower *k* layer is observed. It can be seen that the recovery factor of the lower k layer is higher than that of the higher *k* layer, which is the result of higher free gas production from higher *k* layer. Therefore, beside the low recovery factor which will be obtained by initiating water injection after production under primary recovery, the delay in oil recovery from lower *k* layer should be expected when dealing with a reservoir system with higher permeability contrast.

From the simulation results, we see that for 10 times *k* contrasts, recovery from lower *k* layer obviously delays because the injected water is very low distributed to the lower *k* layer. Low oil recovery from lower *k* layer should also be expected because it produces free gas as a result of low water support. The impact is likely to be greater for any system with larger *k* contrasts. It is recommended that waterflooding should be initiated at p_{sgc} of the layer which will produce free gas first. However, if free gas has been produced prior to waterflooding, the shutting-in producer during fill-up period will improve the recovery factor, as described in Section 7.2. Other strategies mentioned in the literature review can be candidates to improve oil recovery from lower *k* layer. However, the range of permeabilities should be appropriately grouped in order to optimize the production.

CHAPTER 8
CONCLUSIONS AND RECOMMENDATIONS

An understanding in the displacement process taking place by waterflooding in various conditions, including the influence of the variations in oil and rock properties, is required in oil recovery optimization in a multi-layered reservoir. This study demonstrates the response between two layers under waterflooding when the layers have different oil and rock properties. These properties include layer thickness, oil viscosity, bubble point pressure, solution gas-oil ratio, and layer permeability.

For the purpose of the study, a hypothetical reservoir model was simulated by using a 3-D reservoir simulator. Simulation work was divided into two parts. The first part deals with the optimal displacement conditions in a homogeneous reservoir. The second part focuses on the influence of each parameter between layers by using a 2-layer reservoir model.

For a homogeneous reservoir, we derived that the waterflooding condition which maximizes the oil recovery is to displace the oil at the critical gas saturation pressure. At this pressure, the highest amount of free gas liberates but does not mobilize. For higher operating pressure, oil recovery decreases as a result of higher oil viscosity. However, produced free gas has greater effect in the decrease in oil recovery. Therefore, it is recommended that the waterflooding should be initiated in early stage of production, when free gas has not been produced. The lowest allowable operating pressure to optimize the oil recovery should be when the free gas starts to be produced from the reservoir.

The attempt to improve the oil recovery in a homogeneous reservoir was performed by applying the partial shut-off technique. The simulation results show that for the conditions under study, i.e. thin layers (less than 5 meters thick) and k_v/k_h = 0.1, this technique cannot improve the oil recovery as water does not change its direction until it reached the patch. Once it reaches the patch, the water front moves upward and then entered the producing well, bypassing the oil in the above region behind.

Next, the simulation study was conducted by using a 2-layer reservoir model. The simulation results from 2-layer model will describe the influence of variation in properties between layers, leading to better understanding the displacement process in more complicated multi-layered reservoir. The simulation cases include condition which waterflooding was initiated at its p_{sgc} and condition which waterflooding can begin after production under primary recovery. The influence of each parameter on waterflooding performance is summarized as follows:

- **Layer thickness within 1 – 5 meters**

Different layer thicknesses within the range of interest have no effect on waterflooding behavior up to breakthrough time for both waterflooding conditions. After breakthrough, layer thickness has some effect on the recovery factor due to the effect of gravity segregation. In reservoirs which have large amount of free gas prior to waterflooding, earlier water production should be expected because flood front moves faster to displace free gas space.

- **Solution gas-oil ratio within 400 – 700 scf/stb**

The solution gas-oil ratio has effects on oil viscosity, bubble point pressure, and amount of free gas when the reservoir pressure falls below the bubble point pressure. Amount of free gas has a large impact on fill-up period and predominantly affects flood front velocity than the oil viscosity. Water will move much faster when free gas saturation is high. In this range of R_s, the oil viscosity is slightly higher than the water viscosity so waterflooding is in the favorable condition ($M < 1$). The shutting-off premature breakthrough layer when the well water cut reaches the economic limit is recommended to either case with or without the presence of free gas since it improves the recovery factor.

It is also recommended to shut-in the production well during fill-up period if gas production is high. By using this strategy, the oil recovery increased as free gas production was minimized.

- **Layer permeability within 20 – 2000 md**

The layer permeability has a large impact on premature water breakthrough and pressure depletion because the permeability contrast between layers could be very high in the range of interest. Higher permeable layer will deplete faster, so more free gas liberates, and earlier breakthrough occurs. Shutting-off premature breakthrough is an effective strategy to improve the oil recovery even in a small difference in permeability contrast.

In a reservoir system with high permeability contrast, the delay in oil recovery of the lower permeable layer should be expected as a result of low water distribution to push oil towards the producer. In addition, with low pressure support by water, the oil recovery of lower permeable layer may be low as a result of free gas production.

The following points are recommended for future study:

(1) The effect of distance between layers was not included in this study. If the layers are far from each other, the difference in layer pressures and injection pressures should be taken into account. The layers will deplete with different rates, and flood front will move with different velocities. To optimize the oil recovery, the effect of distance between layers should be accounted for.

(2) In this study, the reservoir was assumed to be horizontal. In reality, the reservoir may incline so that the displacement process is impacted by the gravity force. Its effect is interested and should be taken into account for future studies.

(3) In real multi-layered reservoirs, layers are always continuous in different coverage. As a result, some layers are not continuous between injectors and producers. This leads to two different production characteristics,

- Primary depletion drive in discontinuous layers, which connect to only the producer(s)
- Secondary recovery by waterflooding in layers which are continuous between injector(s) and producer(s).

The optimal production and waterflooding strategy for layers with primary depletion drive is beyond the scope of this study. However, the oil recovery will be more optimized if the layers with primary depletion drive are taken into account.

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APPENDIX A

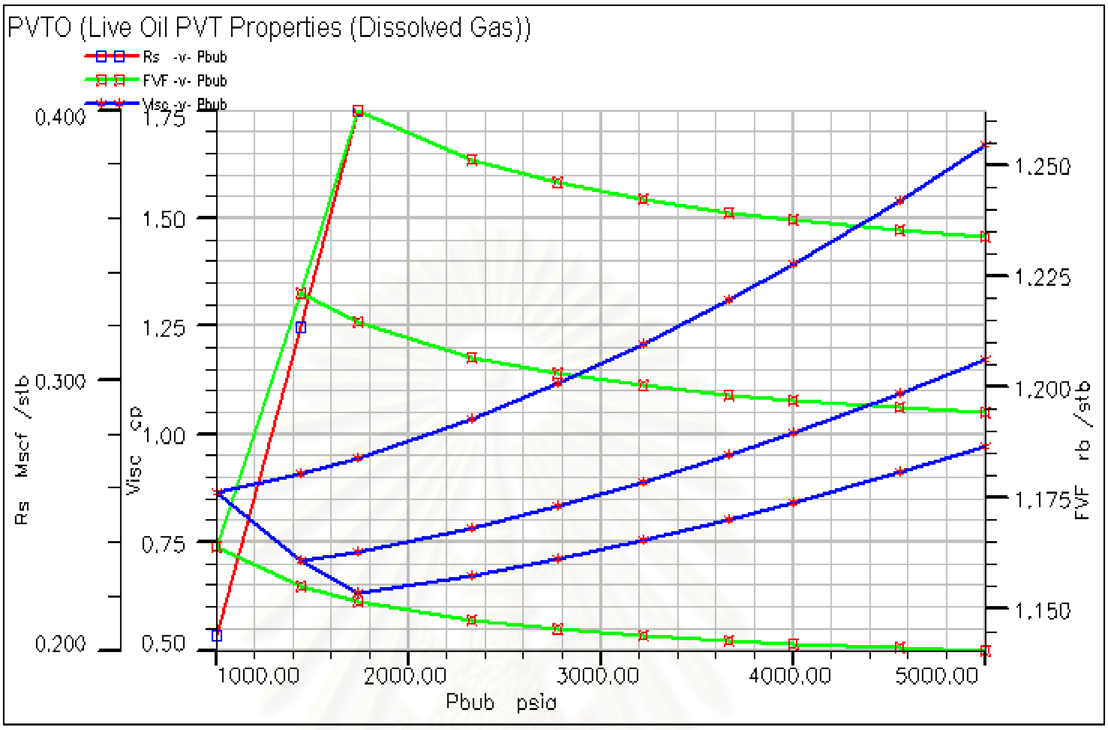

Figure A-1: Live oil PVT properties of the oil with R_s 400 scf/stb

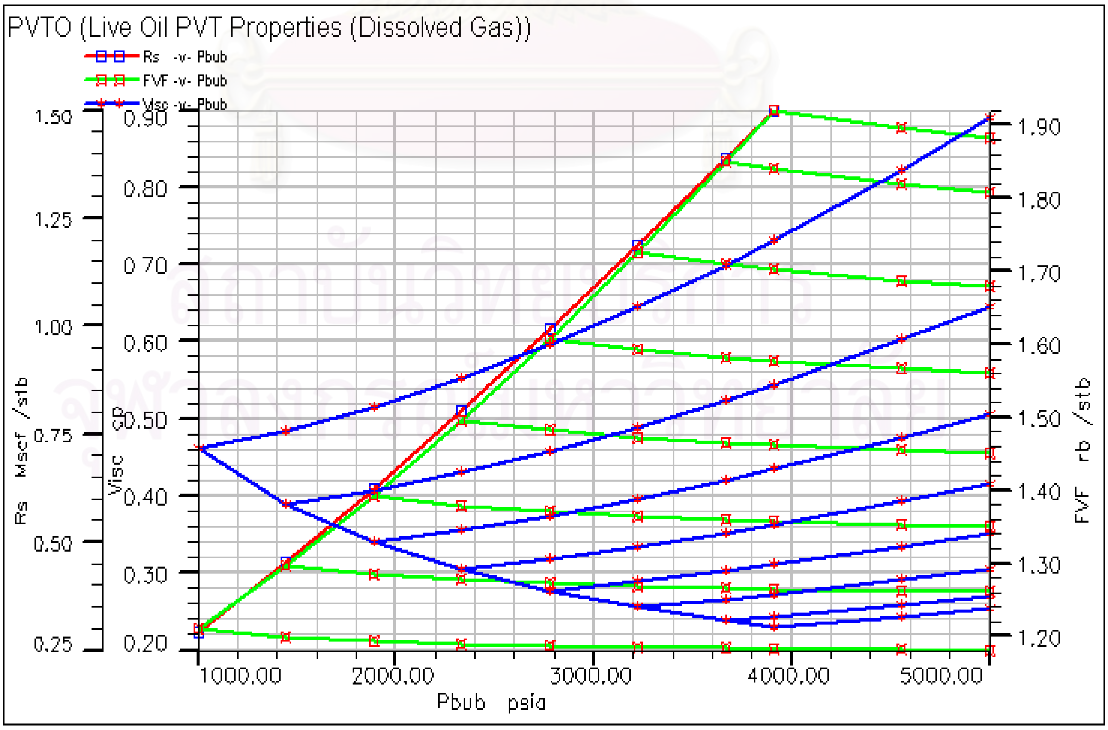

Figure A-2: Live oil PVT properties of the oil with R_s 1500 scf/stb

VITAE

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