การผลิตด้วยการอัดน้ำจากแหล่งกักเก็บหลายชั้นให้ได้ประสิทธิภาพสูงสุดโดยใช้หลุมอัดน้ำและหลุมผลิตอัจฉริยะ

นายรุ่งอรุณ จูงาม

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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OPTIMIZATION OF MULTILAYERED WATER FLOODING USING INTELLIGENT INJECTORS AND PRODUCERS

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A Thesis Submitted in Partial Fulfillment of the Requirements
for the Degree of Master of Engineering Program in Petroleum Engineering
Department of Mining and Petroleum Engineering
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Thesis Title	OPTIMIZATION OF MULTILAYERED WATER FLOODING USING INTELLIGENT INJECTORS AND PRODUCERS
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Field of Study	Petroleum Engineering
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รุ่งอรุณ จูงาม: การผลิตด้วยการอัดน้ำจากแหล่งกักเก็บหลายชั้นให้ได้ประสิทธิภาพสูงสุดโดยใช้หลุมอัดน้ำและหลุมผลิตอัจฉริยะ (OPTIMIZATION OF MULTILAYERED WATER FLOODING USING INTELLIGENT INJECTORS AND PRODUCERS) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร. สุวัฒน์ อธิชนากร, 89 หน้า.

แหล่งน้ำมันหลายแหล่งที่ประกอบด้วยชั้นของแหล่งกักเก็บกั้นด้วยชั้นของหินดินดาน บ่อยครั้งที่กระบวนการอัดน้ำแทนที่ได้ถูกนำมาใช้เพื่อเพิ่มประสิทธิภาพในการผลิตน้ำมัน ในหลายกรณีที่ชั้นผลิตหลักๆ มีความสามารถในการอัดน้ำแตกต่างกัน จะมีผลทำให้ประสิทธิภาพในการกวาดต่ำ

จุดมุ่งหมายของการศึกษานี้คือเพื่อศึกษาว่า การควบคุมทั้งหลุมอัดน้ำอัจฉริยะและหลุมผลิตอัจฉริยะจะสามารถเพิ่มประสิทธิภาพในการผลิตน้ำมันในแหล่งกักเก็บหลายชั้นได้มากน้อยเพียงใด โดยเปรียบเทียบกับประสิทธิภาพของการผลิตจากการควบคุมหลุมอัดน้ำอัจฉริยะเพียงหลุมเดียว และการควบคุมหลุมผลิตอัจฉริยะเพียงหลุมเดียว

ในการศึกษานี้ใช้โปรแกรมจำลองแหล่งกักเก็บที่ประกอบด้วยแหล่งน้ำมัน 3 ชั้นกั้นด้วยชั้นของหินดินดาน แบบจำลองหลุมแบบหลายส่วนและแบบจำลองอุปกรณ์ควบคุมการไหลได้ถูกจำลองไว้ทั้งหลุมอัดน้ำและหลุมผลิต จากนั้นกระบวนการอัดน้ำแทนที่จะถูกจำลองเพื่อหาปริมาณการผลิตน้ำมันสูงสุดตามแผนการควบคุมต่างๆ ผลจากการจำลองบ่งชี้ว่าในกรณีที่ความแตกต่างของความสามารถในการซึมผ่านของชั้นหินไม่ต่างกันมาก การใช้อุปกรณ์ควบคุมการไหลที่หลุมอัดน้ำและหลุมผลิตทั้งสองหลุมจะสามารถผลิตน้ำมันมากกว่าการผลิตจากการควบคุมเพียงหลุมอัดเพียงหลุมเดียว และการควบคุมเพียงหลุมผลิตเพียงหลุมเดียวเพียงเล็กน้อย แต่ปริมาณน้ำที่ผลิตมีค่าลดลงมาก ในกรณีที่ความแตกต่างของความสามารถในการซึมผ่านของชั้นหินต่างกันมาก การใช้อุปกรณ์ควบคุมการไหลสามารถเพิ่มประสิทธิภาพในการผลิตน้ำมันได้ถึง 9.33%

ภาควิชา วิศวกรรมเหมืองแร่และปิโตรเลียม ลายมือชื่อนิสิต

สาขาวิชา วิศวกรรมปิโตรเลียม ลายมือชื่ออ.ที่ปรึกษาวิทยานิพนธ์หลัก

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KEYWORDS: MULTI-LAYERED RESERVOIR/ WATER FLOODING/ WELL COMPLETION/ INTELLIGENT INJECTOR/ INTELLIGENT PRODUCER

RUNGARUN JUNGAM: OPTIMIZATION OF MULTILAYERED WATER FLOODING USING INTELLIGENT INJECTORS AND PRODUCERS. THESIS ADVISOR: ASST. PROF. SUWAT ATHICHANAGORN, Ph.D., 89 pp.

In many reservoirs, there are multiple sand layers separated by shale layers. Waterflooding is often applied to improve oil recovery. In many cases, the injectivity contrast between the major layer elements would result in poor sweep efficiency.

This thesis objective is to study that how much intelligent water injection and intelligent production wells control would improve oil recovery from multi-layer reservoirs in comparison to recovery from a single intelligent injection scheme and a single intelligent production strategy.

In this study, the reservoir consists of 3 layers pay zones separated by a shale layer is modeled. The multi-segment well model and choke model were selected to model both the producers and injectors. Then, waterflooding process simulations were performed to find the maximum oil production of each strategy. The simulation results indicate that using downhole flow control in both injector and producer well give a slightly higher oil recovery compared to recovery from a single intelligent injection and a single intelligent production if the permeability contrast is low. However, the approach significantly reduces the amount of water production. If the permeability contrast is high, utilization of downhole control valve can increase the oil recovery as much as 9.33%.

Department: Mining and Petroleum Engineering Student's Signature: ...
Field of Study: Petroleum Engineering Advisor's Signature: Suwat Athichanagorn
Academic Year: 2009

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LIST OF ABBREVIATIONS

BHP	bottomhole pressure
cp	centipoises
INJ	injector
IOR	initial oil recovery
LGR	local grid refinement
md	millidarcy
PVT	pressure-volume-temperature
PROD	producer
RB/D	reservoir barrel per day
RF	recovery factor
SCAL	special core analysis
STB	stock tank barrel
WCT	watercut
TVD	true vertical depth

NOMENCLATURES

$\frac{dp}{dL}$	pressure drop per unit length
k	absolute permeability
k_r	relative permeability
k_{ro}	relative permeability of oil
k_{rw}	relative permeability of water
k_w	permeability of water
L	distance between injector and producer
L_w	horizontal section length
M	mobility ratio
p	pressure
S_w	water saturation
S_{wc}	connate water saturation
W	pattern width

GREEK LETTERS

Φ	porosity
μ	viscosity
μ_o	oil viscosity
μ_w	water viscosity

CHAPTER I

INTRODUCTION

Production optimization is traditionally associated with maximizing the performance of a producing well by controlling the wellhead choke, ESP's, or gas-lift rate. Conversely, water or gas injectors have traditionally been employed to maintain reservoir pressure.

In many reservoirs, there are multiple sand layers separated by shale layers. Water flooding is often applied to improve oil recovery. In many cases, the injectivity contrast between the major layer elements would result in poor sweep efficiency.

Traditional solutions to this situation include:

- Completion of a separate injection well to each major layer
- Completion in one layer of the reservoir at a time, with subsequent intervention recompletions.
- Commingled injection into multiple layers with a later intervention to attempt to correct the injection profile.

In high operating cost environments, such as deepwater or remote locations, well interventions are very expensive. A simple reduction in the number of interventions saves a great amount of investment. The elimination of downtime while planning interventions, waiting on rigs, etc. accelerates production, adding further value. The ability to inject water where it is needed becomes essential to prevent early water breakthrough and to achieve effective oil sweep and recovery. This task is complicated due to variation in permeability and thickness among the pay sections. By using downhole flow control (DHFC), controlling water placement in multi-zone is possible. The ability to toggle between zones is seen as a valuable optimization feature. Intelligent injection completions have been proven to be an efficient technique for improving oil recovery.

Besides that, using DHFC to control the gas and water production at the producer can increase the total oil production. The value is clearer in wells where the gas or water constraint is reached early in the well life, causing cessation of production. The inflow control valve (ICV) provides ability to delay the gas/water breakthrough from each layer.

Therefore, introducing downhole flow control in both injector and producer well may be the best strategy to optimize the recovery.

1.1 Outline of Methodology

This thesis objective is to study that how much intelligent water injection and intelligent production wells control would improve oil recovery from multi-layer reservoirs in comparison to recovery from a single intelligent injection scheme and a single intelligent production strategy.

A waterflooding process with downhole flow controls at injectors and producers will be simulated using ECLIPSE 100 reservoir simulator. The multi-segment well model and choke model were selected to model both the producers and injectors. The procedure for this study is as follows:

1. Set up reservoir and well model to represent multilayered oil reservoir.
2. Run the simulation to determine the optimized recovery and strategy of following cases:
    - ***Base Case:*** the injector and producer are completed using conventional completion.
    - ***Injection Control Case:*** the injector will be controlled by using DHFC while the producer will not be controlled.
    - ***Production Control Case:*** the producer will be controlled by using DHFC while the injector will not be controlled.
    - ***Injection and Production Control Case:*** both the injector and producer will be controlled.
3. Evaluate all case productions to determine the best strategy to deal with the multilayered oil reservoirs.
4. The effects on oil recovery due to difference in reservoir characteristics are studied by changing what parameter, then repeat above processes from step 1 to step 3.

1.2 Thesis Outline

This thesis consists of 7 chapters as outlined below:

Chapter 1 introduces the main idea and concepts of this work

Chapter 2 reviews previous studies on waterflooding on multilayered oil reservoirs.

Chapter 3 describes the basic principles of waterflooding, choke model, well completion, and some reservoir simulation concept.

Chapter 4 explains the detail of model construction and reservoir conditions used in the simulation.

Chapter 5 shows the simulation results, discussion and the sensitivity study

Chapter 6 concludes the results obtained from the study and makes remarks for recommendation for future work.

CHAPTER II

LITERATURE REVIEW

Brouwer and Jansen [1] investigated the optimization of water flooding in one-layer reservoir with smart horizontal wells. They developed an algorithm capable of optimizing ICV settings over the life of the reservoir for both producers and injectors. They used a gradient-based dynamic optimization method, optimal control theory, building on the work of Asheim [2] and Sudaryanto and Yortsos [3]. The gradients were computed with an adjoint equation, which is computationally efficient but requires significant programming effort. One results show that, the optimization under rate constraints accelerate the production and also increase the cumulative oil recovery.

Sandoy *et al.* [4] applied the intelligent well completion at Statoil Veslefrikk Field in the North Sea, in May 2004. A 4-zone intelligent WAG injector system was installed. The completion includes one on/off and three variable downhole chokes for controlling injection rate into each of the four zones. The completion also includes three downhole optical flowmeters and three optical pressure and temperature gauges. Measurement of the surface injection rate and the rate from each of the three flow meters provides real-time measurement of injection rate into each zone, regardless of choke positions.

The well is on a Water Alternating Gas (WAG) cycle where one zone is primarily intended for gas injection and the other three zones are primarily intended for water injection. The combination of downhole chokes and flowmeters allow full control and monitoring of zonal injection rates and has proved to be a valuable tool in managing reservoir pressures and optimizing production.

Sun and Konopczynski [5] presented the prediction of injection-fluid distributions for multiple zones. It was developed to assist the control decision process for intelligent injection wells. For example,

- For a two-zone intelligent injection system and both zone ICVs in certain open positions, there is a minimum wellhead pressure ($P_{WH(min)}$) to control fluid allocation to the higher dynamic-pressure zone; when the wellhead pressure is below that pressure, most fluid will inject into one zone instead of two zones; above that pressure, fluid starts to inject into the higher dynamic-pressure zone.

- When the higher dynamic-pressure zone ICV choke setting is greater than the other, it is possible to establish a wellhead pressure ($P_{WH(e)}$) which will balance the fluid distribution for the two-zone intelligent well. If (P_{WH}) is below ($P_{WH(e)}$), injection rate to the lower dynamic-pressure zone will always be higher than the higher dynamic-pressure one; when increasing the (P_{WH}) above ($P_{WH(e)}$), the amount of injection rate to the higher dynamic-pressure zone begins to be higher.

Almutairi [6] investigated the impact of utilizing the downhole inflow control valves (ICVs) on the performance of horizontal wells and to quantify any increase in recovery achieved by controlling the production from various sections of the horizontal well completed in a thin oil column. The impacts of various factors controlling the intelligent well performance were investigated:

1. ICV arrangement within the wellbore
2. Permeability distribution
3. Production rate
4. Well position
5. Gas and water constraints

The study shows that using intelligent well completion can increase the total oil production from a well by controlling the gas and water production.

According to the number of literatures survey above, no articles have mentioned the performances of multi-layered oil reservoir from using both intelligent water injection and intelligent production wells control. The study by Brouwer and Jansen [1] was done on a one-layer reservoir. The works by Sandoy et. al. [4] and Sun and Konopczynski [5] concentrated on injection well only, while the work by Almutairi [6] concentrated on production well only.

It is interesting to study that how much intelligent water injection and intelligent production wells control would improve oil recovery from multi-layer reservoirs in comparison to recovery from a single intelligent injection scheme and a single intelligent production strategy.

CHAPTER III

THEORIES AND CONCEPTS

This chapter presents the basic principles and theories concerning multi-layered well application, waterflooding, and reservoir simulation. First, the basic concepts concerning intelligent well are introduced. Next, the mechanism of conventional waterflooding (vertical wells) is described for fundamental understanding. The multi-segment well model is selected to model the multi-layered wells in this work. Also the vertical flow performance program is used for modeled the pressure loss across a choke.

3.1 Intelligent Well

Waterflooding using intelligent well completions have been proven to be an efficient technique for improving oil recovery. The ability to control water placement in multi-zone provided effective oil sweep and recovery. By controlling water and gas production, increasing productivity in low permeability reservoir, and improving waterflood efficiency.

3.1.1 Intelligent Well Completions

An intelligent well completion is a system capable of collecting, transmitting and analyzing completion, production, and reservoir data, and taking action to better control well and production processes without physical intervention. The value of the intelligent well technologies comes from their capability to actively modify the well zonal completions and performance through downhole flow control, and to monitor the response and performance of the zones through real time downhole data acquisition, thereby maximizing the value of the asset. An Intelligent Completion combines a series of components that collect, transmit and analyse completion, production and reservoir data, and enable selective zone control to optimize the production process. The following devices are installed for above objectives.

- *Flow Control Devices.* Most current downhole flow control devices are based on or derived from sliding sleeve or ball-valve technologies. Flow control may be binary (on/off), discrete positioning (a number of preset fixed positions), or infinitely variable. The actuating motive force for these systems may be provided by hydraulic or electric systems. Current-generation hydraulically operated flow control devices have evolved to be more reliable, more resistant to erosion, provide greater flow control, and generate greater opening and closing forces.

- *Feedthrough Isolation Packers.* To realize individual zone control, each zone must be isolated from each other by packers incorporating feedthrough systems for control, communication, and power cables.
- *Control, Communication and Power Cables.* Current intelligent well technology requires one or more conduits to transmit power and data to downhole monitoring and control devices. These may be hydraulic control lines, electric power and data conductors, or fiber optic lines. For additional protection and ease of deployment, multiple lines are usually encapsulated and may be armored.
- *Downhole Sensors.* A variety of downhole sensors are available to monitor flow performance parameters from each zone of interest. Several single-point electronic quartz crystal pressure and temperature sensors may be multiplexed on a single electric conductor, thus allowing very accurate measurements at several zones.

A typical 3-zone intelligent well completion schematic is shown in Figure 3.1.

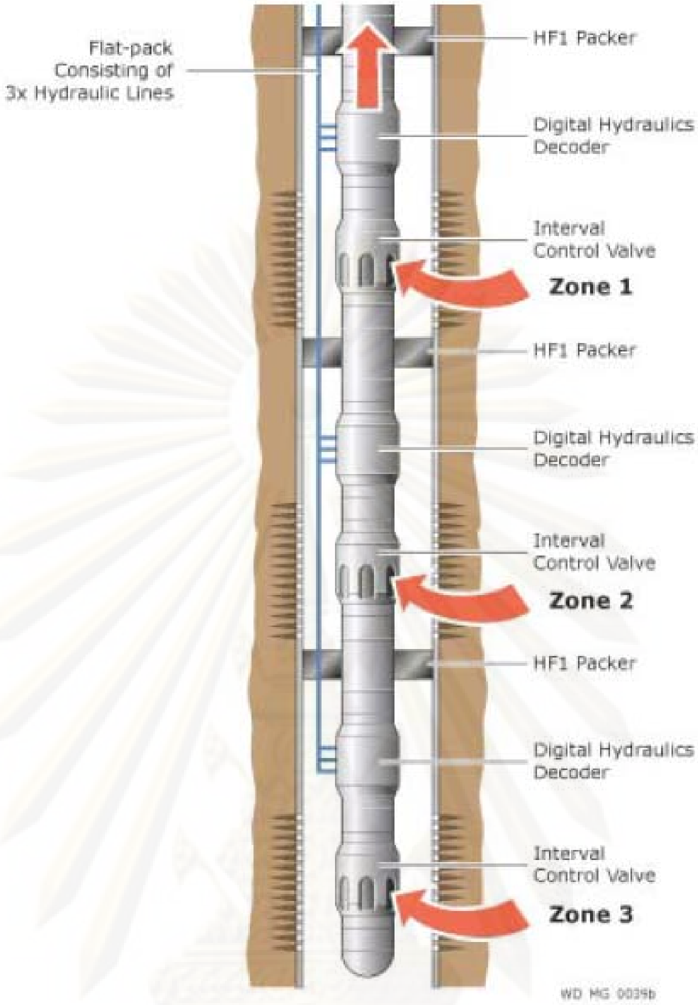

Figure 3.1: 3-zone intelligent well completion schematic

3.2 Waterflooding

Waterflooding is the most widely applied IOR process. Water is injected into the reservoir to displace and sweep oil towards the production well. It is necessary to understand the mechanism of fluid displacement in the reservoir and waterflooding process in order to optimize waterflooding performance.

3.2.1 Fluid displacement

During fluid displacement in the reservoir, both gravity and viscous forces play a major role in determining the shape of the displacement front. The viscous force will encourage water to flow through the reservoir faster than oil, while gravity forces will encourage water to remain at the lowest point in the reservoir.

In the reservoir, there is always connate water present; two fluids are competing for the same pore space. The permeability of one of the fluids is then described by its "relative permeability" (k_r), which is a function of saturation of the fluid as shown in Figure 3.2.

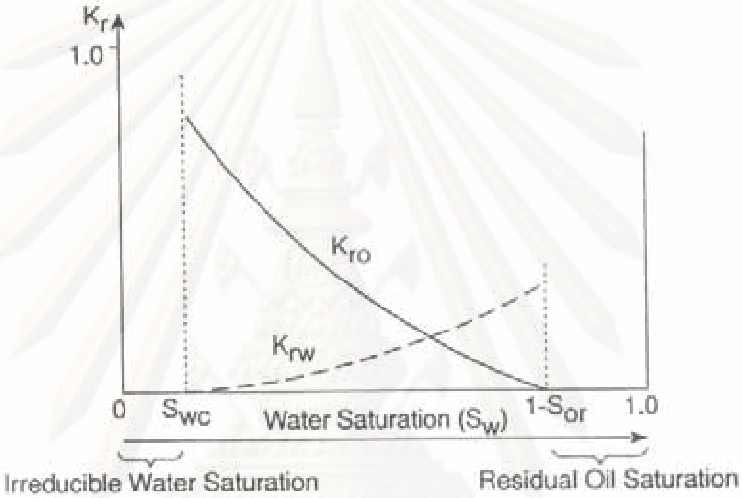

Figure 3.2: Relative permeability curve for oil and water [10]

For a given water saturation (S_w), the permeability to water (k_w) can be determined from the absolute permeability and the relative permeability as follows:

$$k_w = k \cdot k_{rw}$$

The mobility of a fluid is defined as the ratio of its permeability to viscosity:

$$\text{Mobility} = \frac{k \cdot k_r}{\mu}$$

When water is displacing oil in the reservoir, the mobility ratio determines which fluid can move more preferentially through the pore space. The mobility ratio for water displacing oil is defined as:

$$\text{Mobility ratio (M)} = \frac{k_{rw}/\mu_w}{k_{ro}/\mu_o}$$

If the mobility ratio is greater than 1.0, it means water can move faster than oil through the reservoir. This causes “Unstable Displacement” which can be described as viscous fingering as shown in Figure 3.3.

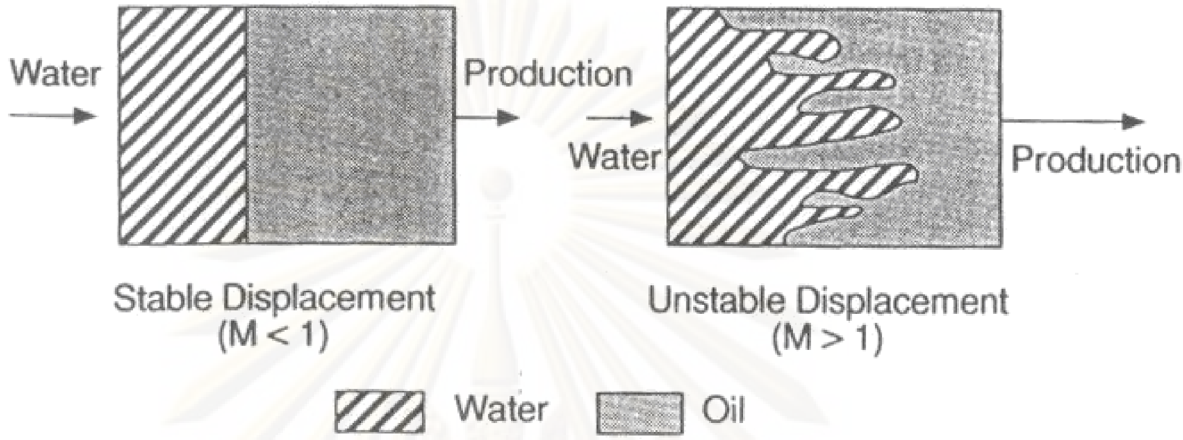

Figure 3.3: Stable and Unstable displacement in the horizontal plane [10]

Unstable displacement is clearly less preferable, since water reaches the producer much earlier than in stable situation, and some oil may be left unrecovered at abandonment.

Consider the water displacing oil in a dipping reservoir, at low injection rates the displacement is stable; the gravity force is dominating the viscous forces. At higher injection rates, the viscous forces dominates, and the water underruns the oil, forming a so-called “gravity tongue”. This is less favorable situation since water will break through early. The steeper the dip angle, the more influence the gravity force will have. Figure 3.4 compares between stable and unstable situation.

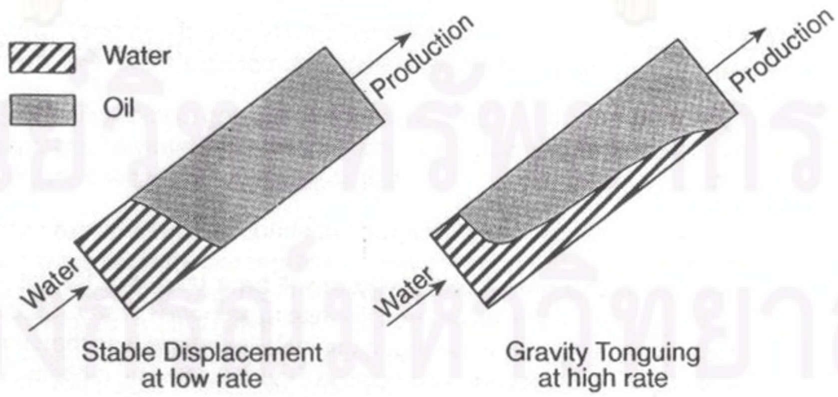

Figure 3.4: Gravity tonguing [10]

3.2.2 Conventional Waterflooding

The displacement process is typically conducted in patterns where specific configuration of injectors and producers is repeated across the field. Figure 3.5 illustrates common flooding patterns used in waterflooding.

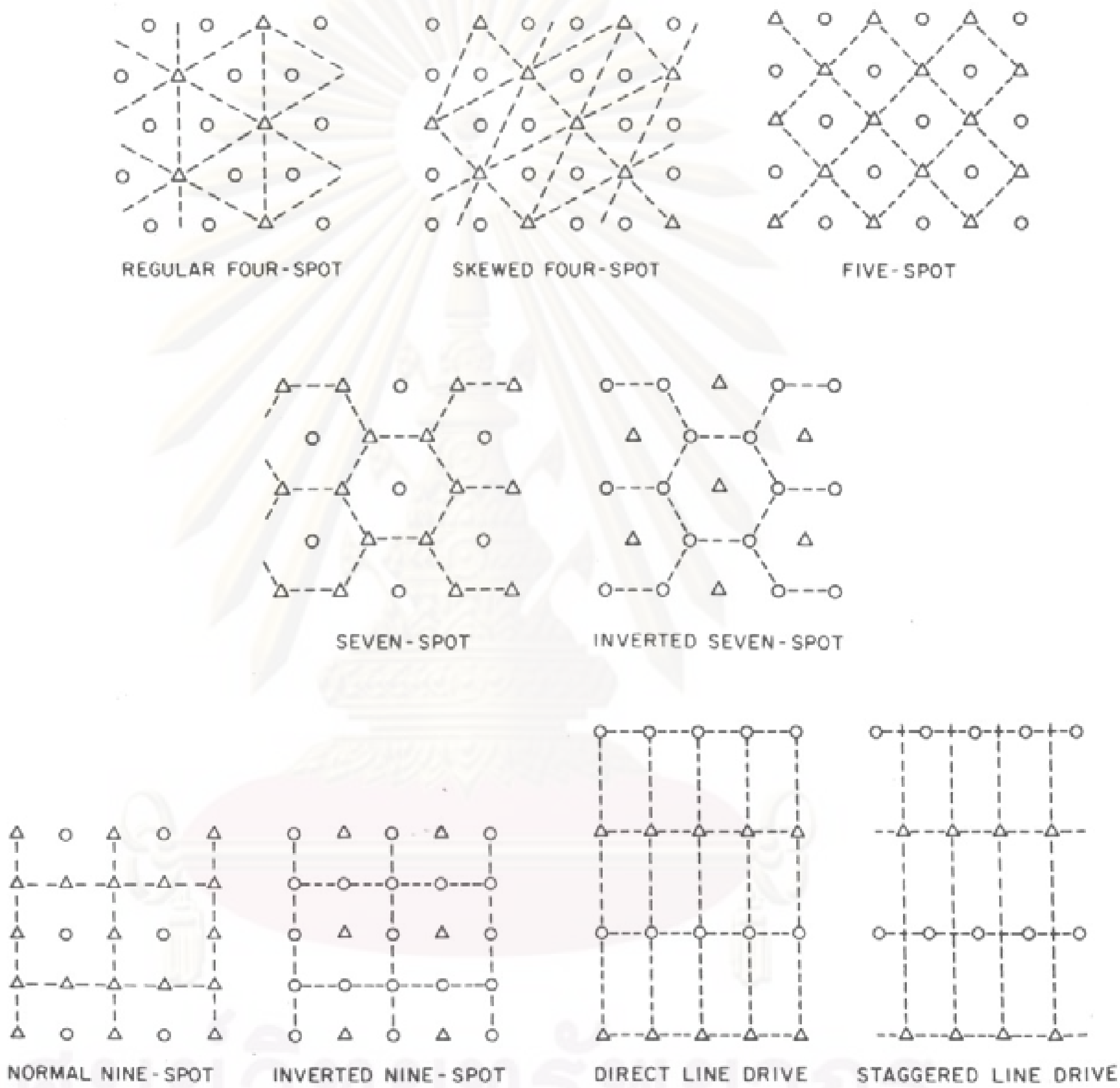

Figure 3.5: Flooding patterns [11]

The performance of waterflooding can be determined by the swept area between injectors and producers within the pattern. Pattern geometry and viscous forces are the main factors used to determine the sweep efficiency. Figure 3.6 compares the sweep efficiency at breakthrough of direct line drive pattern with various mobility ratios. A low mobility ratio gives more sweep efficiency than a high mobility ratio due to more displacement efficiency.

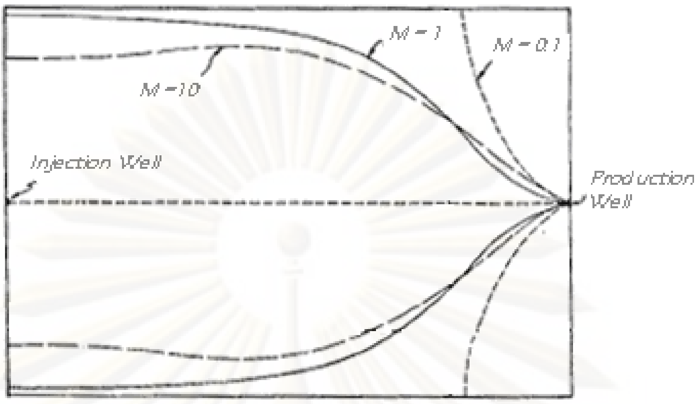

Figure 3.6: Comparison of flooded areas for M = 10, 1 and 0.1 for direct line drive pattern[12]

3.3 Reservoir Simulation

In order to study the behavior of waterflooding process, we used ECLIPSE 100 reservoir simulator[8] since it has the multi-segment well model and used VFPi program since it can generate the VFP table to represent choke model. These programs can handle specific requirements in this thesis.

3.3.1 Multi-segment Well Model

In order to determine the flow rate on injector and producer, we must be able to compute and adjust the flow rate in each layer. Thus, the well has to be divided into segments. The multi-segment well model is capable of handling this requirement.

1. *Segment Structure*: Each segment consists of a **node** and a **flowpath** to its parent segment's node. A segment's node is positioned at the end away from the wellhead (Figure 3.7). Each node lies at a specified depth and has a nodal pressure which is determined by the well model calculation. Flow from the formation through grid-block-to-well connections also enters the well at segment nodes (Figure 3.8). Each segment also has a specified length, diameter, roughness, and area. These attributes are properties of its flowpath and are used in the friction and acceleration pressure loss calculations. Also,

associated with each segment's flowpath are the flow rates of oil, water and gas, which are determined by the well model calculation.

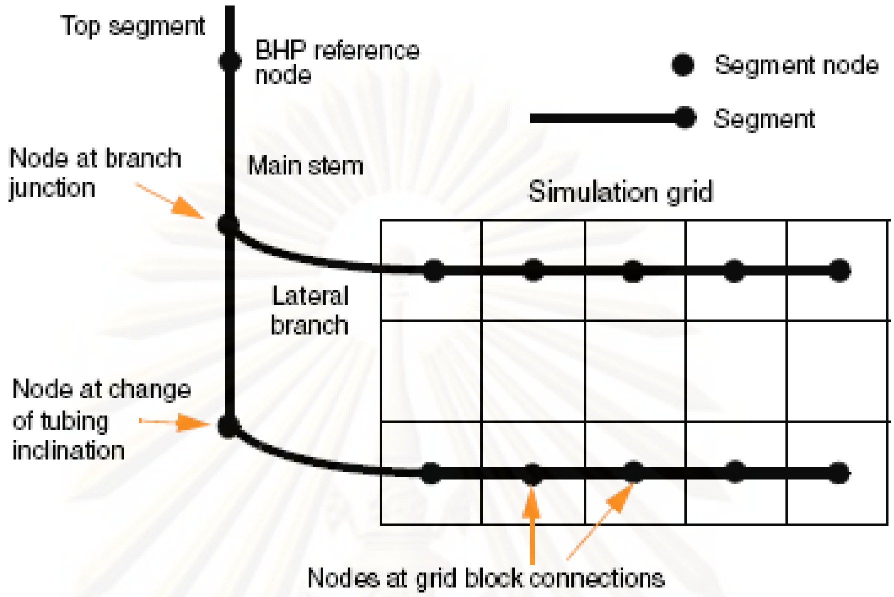

Figure 3.7: Structure of multi-segment well model (8)

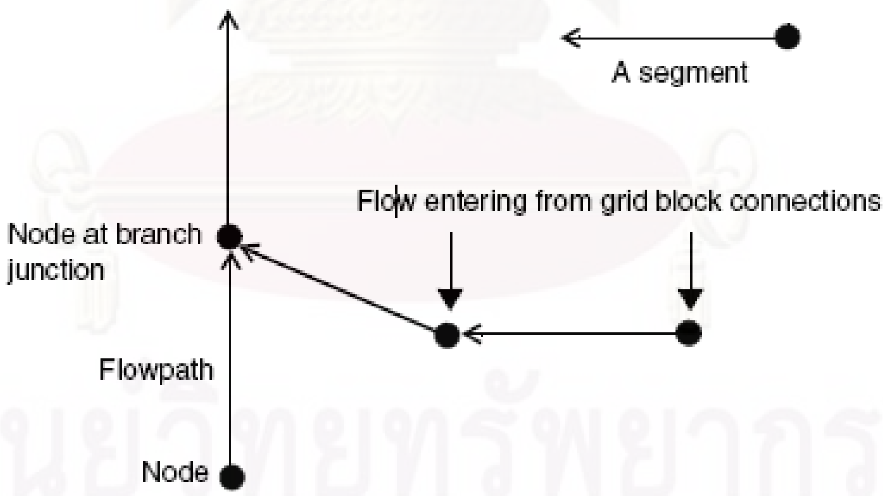

Figure 3.8: Flow components in multi-segment well model (8)

2. *Inflow Performance*: The flow of fluid between a grid block and its associated segment's node is given by the inflow performance relationship

$$q_{pj} = T_{wj} M_{pj} (P_j + H_{cj} - P_n - H_{nc})$$

where

q_{pj} = volumetric flow rate of phase p in connection j at stock tank condition.

T_{wj} = connection transmissibility factor

M_{pj} = phase mobility at the connection.

P_j = pressure in the grid block containing the connection.

H_{cj} = hydrostatic pressure head between the connection's depth and the center depth of the grid block.

P_n = pressure at the associated segment's node n.

H_{nc} = hydrostatic pressure head between the segment node n and the connection's depth.

3. *Frictional Pressure Loss Calculation*: The calculation of the frictional pressure loss is based on the correlation of Hagedorn and Brown.

$$\Delta P_f = \frac{C_f \, f \, L w^2}{A^2 D \rho}$$

where

f = Fanning friction factor

L = length of the segment

w = mass flow rate of the fluid mixture through the segment

A = segment's area of cross-section for flow

D = segment's diameter

ρ = in-situ density of the fluid mixture

C_f = unit conversion constant

2.679E-15 (METRIC), 5.784E-14 (FIELD)

4. Acceleration Pressure Loss Calculation: The acceleration pressure loss across a segment is the difference between the velocity head of the mixture flowing across the segment's outlet junction and the velocity heads of the mixture flowing through all its inlet junctions.

$$\Delta P_a = H_{vout} - \sum_{inlets} H_{vin}$$

The velocity head of the mixture flowing through a junction is

$$H_v = \frac{0.5 C_f w^2}{A^2 \rho}$$

For the outlet junction flow, *A* is the cross-sectional area of the segment. For inlet junction flows, *A* is the maximum of the cross-sectional areas of the segment and the inlet segment.

3.3.2 Choke Model

VFPi program can generate VFP table whose purpose is to model the pressure loss across a bean or choke for a variety of flowing conditions.

VFPi provide the choice of seven multi-phase flow correlations to calculate the pressure traverse:

- Aziz, Govier and Fogarasi
- Orkiszewski
- Hagedorn and Brown
- Beggs and Brill
- Mukherjee and Brill
- Gray
- Petalas and Aziz

VFP table can be used in the ECLIPSE Multi-Segment Well model whereby the effects of a variable choke at, say, the heel of a lateral may be modeled by assigning the pressure loss calculation for the appropriate segment to be taken from this VFP table. The choke will be placed in the middle of a short horizontal piece of smooth tubing. This will ensure that the pressure losses will be dominated by the choke and not by the hydrostatic and frictional effects of the fluid flow through the tubing.

We also can set the bean/choke diameter as the ALQ variable in the VFP table (Figure 3.9) to provide ability to adjust the choke diameter in ECLIPSE simulation.

OIL (stb/day)	THP (psia)	WOR	GOR (Mscf/stb)	BEAN (64ths in)
100	200	0.5	2	8
300	350			16
500	500			24
700	650			32
900				40
1200				48
1500				56
2000				64
2500				

Figure 3.9: VFP table data panel [8]

The behavior of the flow through bean can be predicted by this program, example as shown in *Figure 3.10*

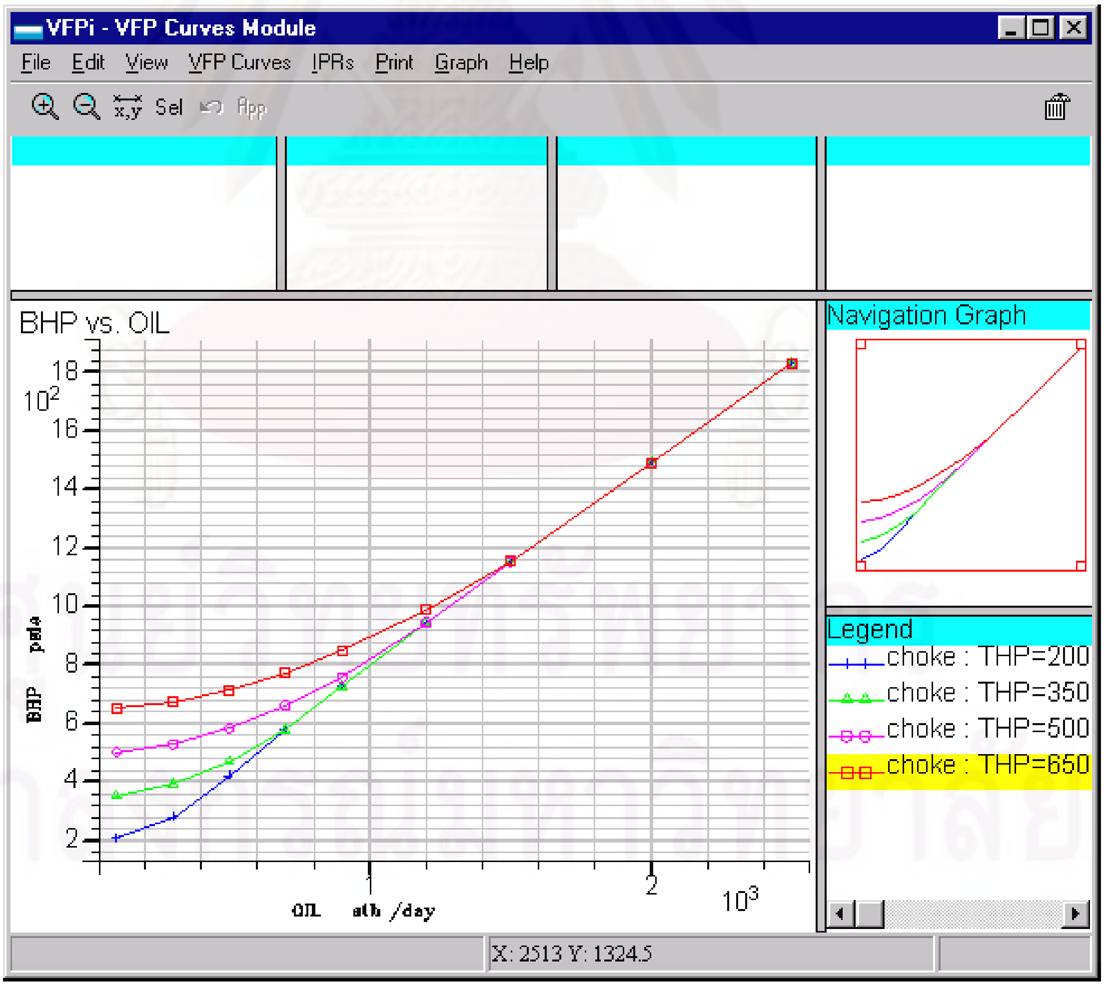

Figure 3.10: VFP table data panel [8]

CHAPTER IV

RESERVOIR MODEL

In order to optimize oil recovery from water flooding in multi-layered oil reservoirs using intelligent injection and production well control strategies. A hypothetically reservoir model was constructed in ECLIPSE 100 reservoir simulator. The model can handle several requirements such as

1. Completion in multi-layered pay zones with one well.
2. Ability to adjust chokes size in every layer.
3. Computation of inflow and outflow of each layer.

This chapter describes the construction of reservoir model, multi segment wells model and choke model.

The hypothetically model is selected for this study. A rectangular reservoir consists of 3 layers pay zones separated by a shale layer is modeled. The injector and producer were located at the end of both sides to represent the direct line drive pattern. Both injector and producer consist of adjustable choke at every layer. All chokes were fully opened in base case and were adjust the position according to the well control strategies. The ECLIPSE script for base case is provided in Appendix A.

4.1 Reservoir Model

The reservoir model consists of 15x25x11 grid blocks. For oil layers, grid blocks size are 100x200x20 ft. For shale layers, grid blocks size are 100x200x40 ft as shown in Table 4.1 and Figure 4.1 – 4.3. In the first 2 rows and the last 2 rows that the wells are placed, the y-grid sizes are reduced to 1 ft in order to locate each layered well segments (yellow color) as shown in Figure 4.1

Table 4.1: Reservoir model description

Reservoir width	1500 ft
Reservoir length	4204 ft
Reservoir thickness	260 ft
Number of grid	15 x 25 x 11
Oil grid size	100 x 200 x 20 ft
Shale grid size	100 x 200 x 40 ft

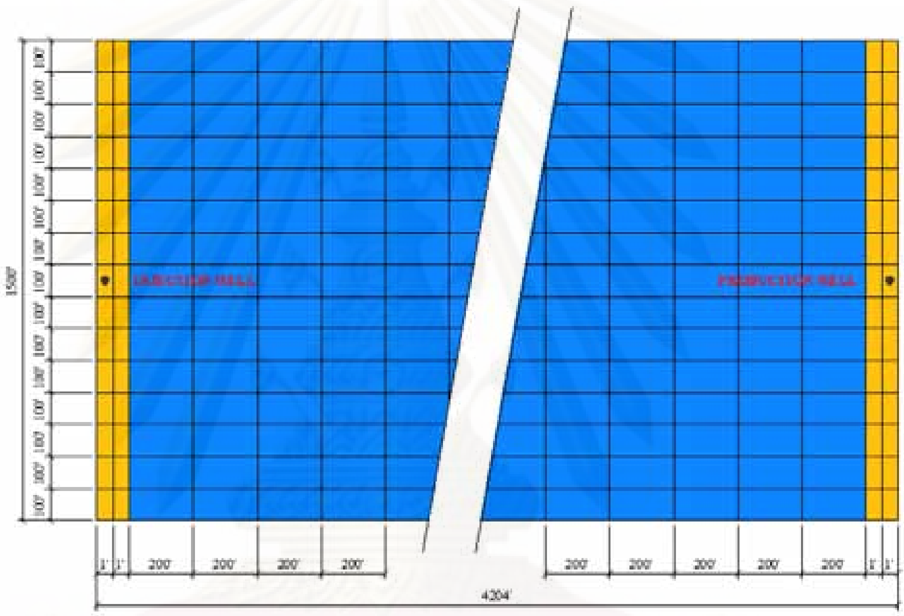

Figure 4.1: Reservoir top view

Figure 4.2: Reservoir side view

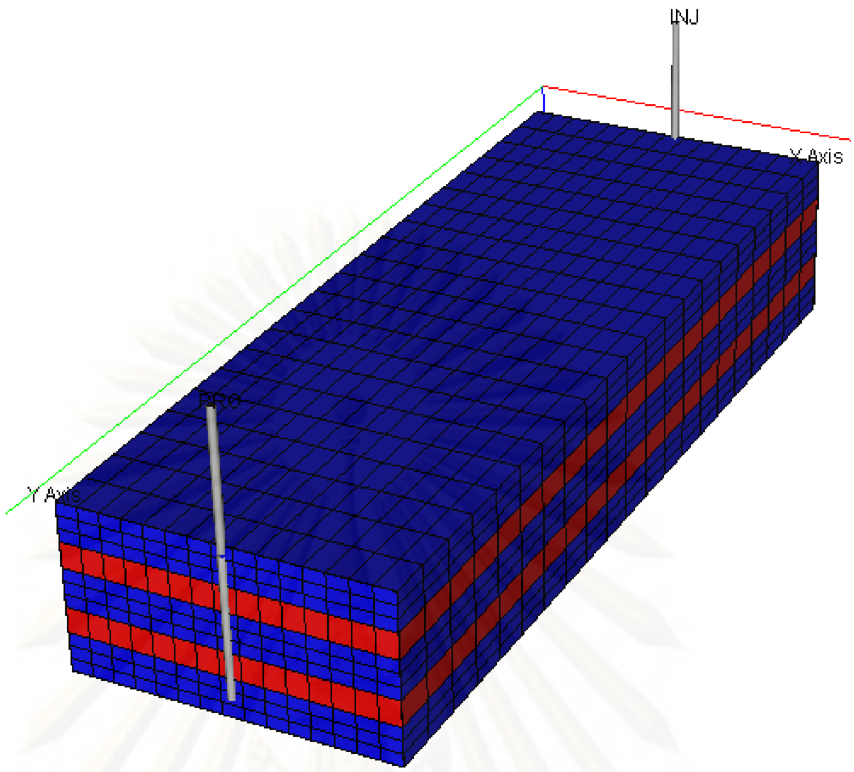

Figure 4.3: Reservoir model

The model is homogenous reservoir. The reservoir properties are shown in Table 4.2

Table 4.2: Reservoir properties

Reservoir Property	Layer 1	Layer 2	Layer 3
Horizontal permeability	500 md	300 md	150 md
Vertical permeability	50 md	30 md	15 md
Porosity	0.30	0.25	0.20
Initial pressure	2180 psia	2220 psia	2260 psia
Reservoir temperature	200 °F	200 °F	200 °F
Initial water saturation	0.25	0.25	0.25

4.2 Well Model

The well completion used in this simulation is shown in Figure 3.1. In order to realize individual zone control, each zone was isolated from each other by packers Discrete positioning downhole flow control devices are located at starter segment of every layer. Downhole sensors are installed to monitor flow performance parameters from each zone.

By using multi-segment well model, the wells are divided into 12 segments as shown in Figure 4.4. Segment 1 is the top segment. Segments 1-3 represent the main string while segment 4-6, 7-9 and 10-11 represent the individual branch in layer 1, 2 and 3 respectively.

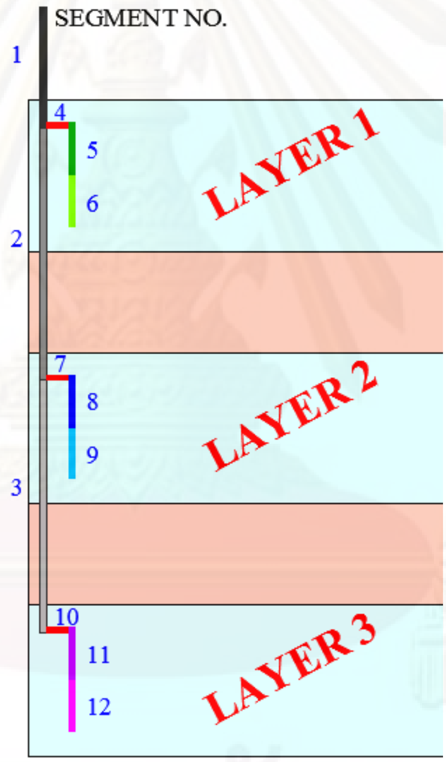

Figure 4.4: Well segment model

Segments 4, 7 and 10 are modeled to represent the ICV or DHFC. The next 2 segments represent the perforated interval of each layer as shown in Figure 4.5. The well conditions are described in Table 4.3.

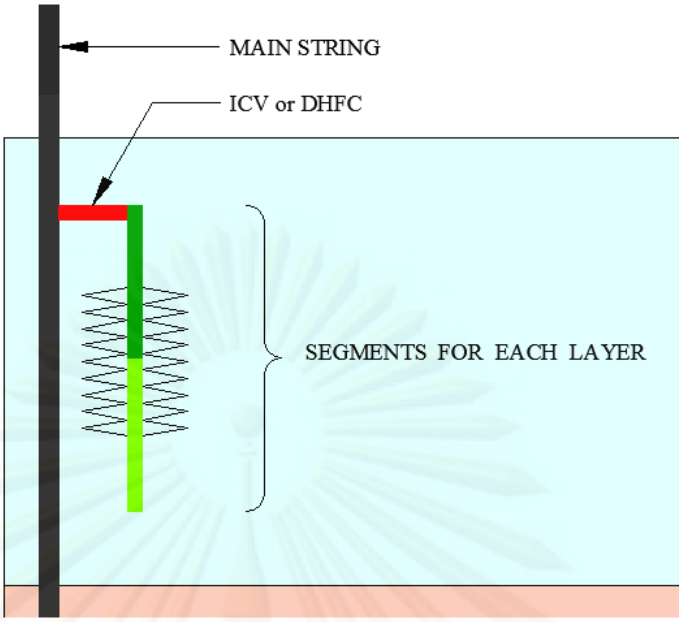

Figure 4.5: Well segment completion model

Table 4.3: Well conditions

No. of well segments	12
Tubing diameter	3.5 inch
Well bore ID.	0.24933 ft
Skin factor	0
Tubing roughness	0.000175

4.3 Choke Model

The VFP tables were generated from VFPi program. VFP tables were imported to ECLIPSE simulator for providing ability to adjust the liquid flow rate at every choke locations.

The intelligent well completion was modeled with 9 choke positions as shown in Table 4.4. For the base case, all choke were set at position 9 (fully open). The simulation behaves like there are no chokes in a model. For other cases, choke will be adjusted according to the well control strategies. Choke will be set at position 1 (closed) when we want to stop injection or production at specific layer.

Table 4.4: Choke position

Position	Choke position
1	0/64” (closed)
2	8/64”
3	16/64”
4	24/64”
5	32/64”
6	40/64”
7	48/64”
8	56/64”
9	64/64” (fully open)

4.4 Fluid and SCAL properties

The initial fluids in the reservoir consist of oil and water. The initial water saturation is equal to 0.3. Live oil was used in the simulation. The fluid properties are listed in Table 4.5.

Table 4.5: Fluid properties

Oil density	53.0 lb/ft^3
Oil viscosity	0.371 cp
B_o	1.49 Rb/STB
Water density	62.4 lb/ft^3
Water viscosity	0.307 cp
B_w	1.02 Rb/STB
Gas density	0.0624 lb/ft^3
Gas viscosity	0.022 cp
B_g	1.12 Rb/STB

To determine the relative permeability, Corey correlation is used. Assuming the following values:

Table 4.6: Relative permeability

Water - oil, residual oil saturation	0.2
Water - oil, relative oil permeability	1
Water - oil, corey exponent oil	3
Water - oil, residual water saturation	0.2
Water - oil, relative water permeability	0.55
Water - oil, corey exponent water	3
Gas - oil, residual gas saturation	0.05
Gas - oil, relative gas permeability	1
Gas - oil, corey exponent gas	2
Gas- oil, residual oil saturation	0.2
Gas - oil, relative oil permeability	1
Gas - oil, corey exponent oil	2

The relative permeability curve for *Water-Oil* and *Gas-Oil* are shown in Figure 4.6 and Figure 4.7.

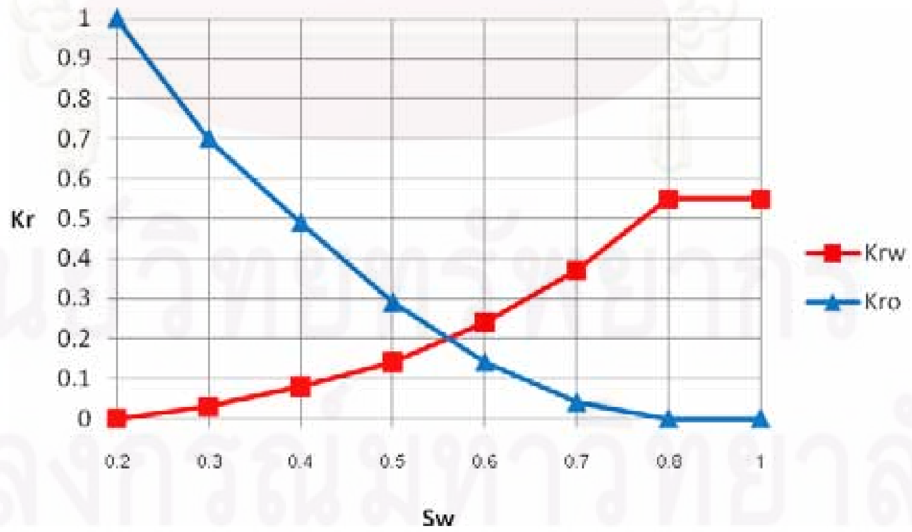

Figure 4.6: Relative permeability curve (Water-Oil)

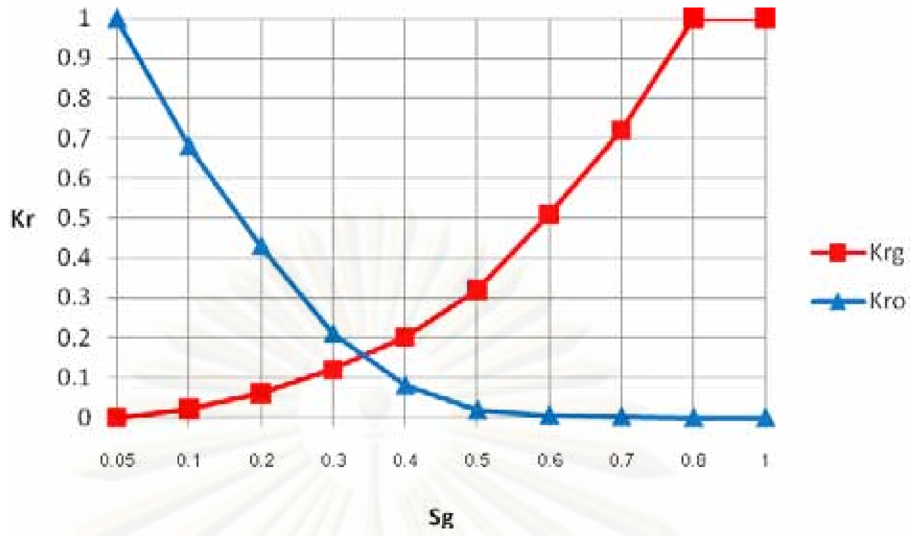

Figure 4.7: Relative permeability curve (Gas-Oil)

CHAPTER V

OPTIMIZATION

This chapter describes the simulation results from the well control strategies.

As mentioned before, this thesis aims to optimize oil recovery from water flooding in multi-layered oil reservoirs. The best strategy can be obtained by comparing the oil production from the following cases.

1. ***Base Case:*** the injector and producer are completed using conventional completion.
2. ***Injection Control Case:*** the injector is controlled by using DHFC, while the producer is not controlled.
3. ***Production Control Case:*** the producer is controlled by using ICV, while the injector is not controlled.
4. ***Injection and Production Control Case:*** both the injector and producer are controlled.

In order to compare the results, the operating condition and the production constraints were set as Table 5.1.

Table 5.1: Operating condition and production constraint

Constant injection rate	7,000 bpd
Maximum BHP (injector)	5000 psi
Minimum BHP (producer)	400 psi
Maximum GOR	10,000 ft^3/bbl
Maximum watercut	0.9
Maximum liquid rate	5,000 bpd
Minimum oil rate	200 bpd

5.1 Base Case

For this case, the injector and producer are completed using conventional completion. Commingled injection and production were applied without downhole flow control.

The simulation was performed to investigate the reservoir behavior. Figure 5.1 illustrates the flow distribution to each layer at the injector. Most of water is distributed to the highest injectivity layer (in this case is layer 1). That is the cause for an early breakthrough in layer 1 as shown in Figure 5.2. The production well starts to produce water at around day 2,000 as shown in Figure 5.2.

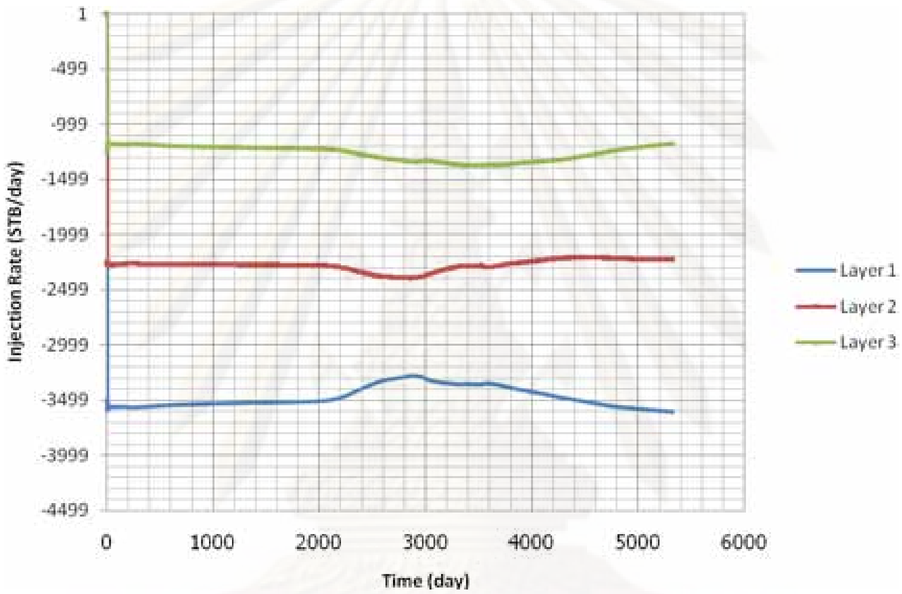

Figure 5.1: Base Case – Layer's water injection rate at injector

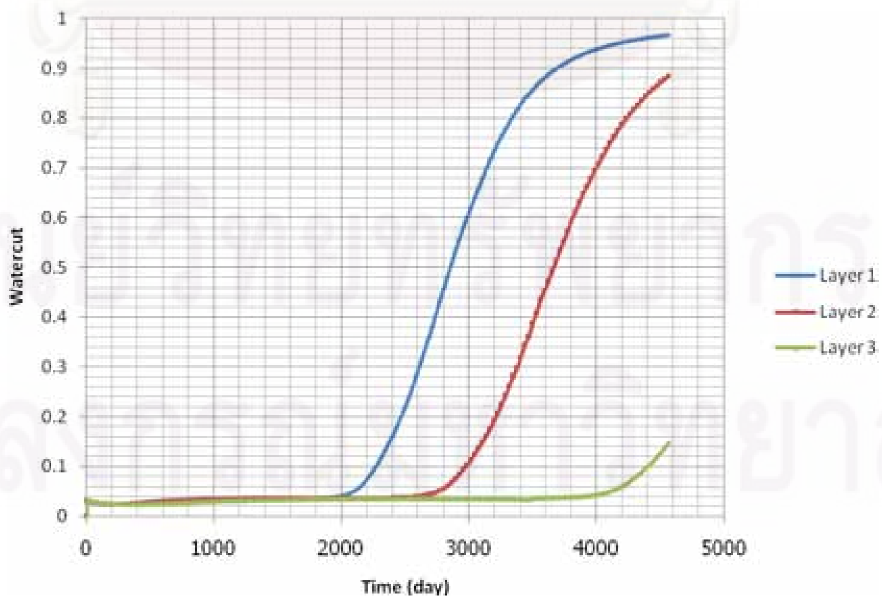

Figure 5.2: Base Case – Layer's watercut at producer

Figure 5.3 illustrates the watercut profile of the production well. The well is shut because the watercut reaches the maximum watercut. The oil production is 17.380 MMSTB and the water production is 11.363 MMSTB at day 5,322 as shown in Figure 5.4.

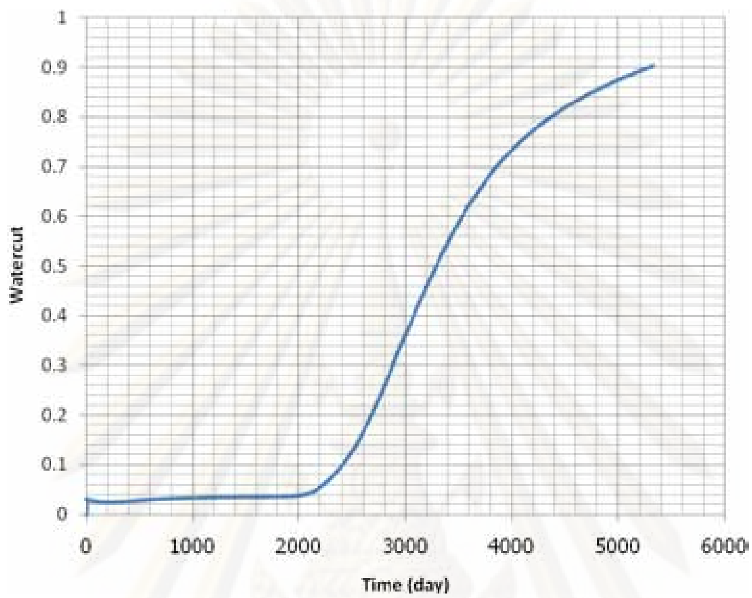

Figure 5.3: Base Case – Well watercut at producer

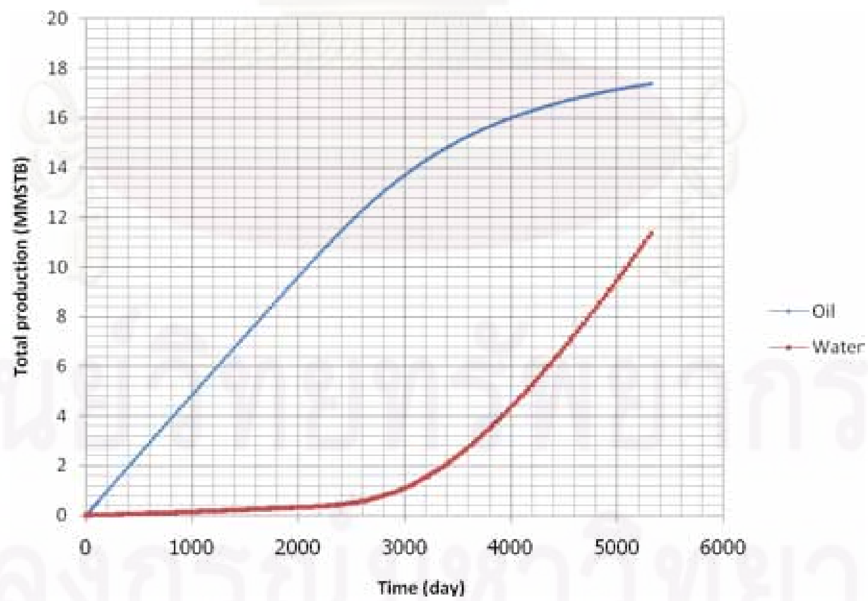

Figure 5.4: Base Case - Total oil and water production

5.2 Injection Control Case

For this case, the injector is controlled by using downhole flow control while the producer is not controlled. In order to find the best well control, several strategies were simulated as the following.

5.2.1 Injection Control Case 1

For this case, chokes of all layers were adjusted by trial and error until water of all layers breaks through at the same time (or almost the same). After appropriate choke sizes were obtained, the simulation was run until the production well is shut by keeping all choke sizes to be the same from the start to the end. Note that the production is shut when the watercut reaches 90%.

After many trial adjustments, the water of all layers breaks through at the same time when the choke size of layer 1, 2 and 3 is 24, 24 and 64, respectively. Figure 5.5 illustrates the flow distribution of each layer at the injector. Compared to the base case, the water distribution changes according to the choke sizes. All layers break through almost at the same time as shown in Figure 5.6. The production well starts producing water at around day 2,500 as shown in Figure 5.6. The oil production is 17.447 MMSTB and the water production is 5.983 MMSTB at day 4,563 as shown in Figure 5.7.

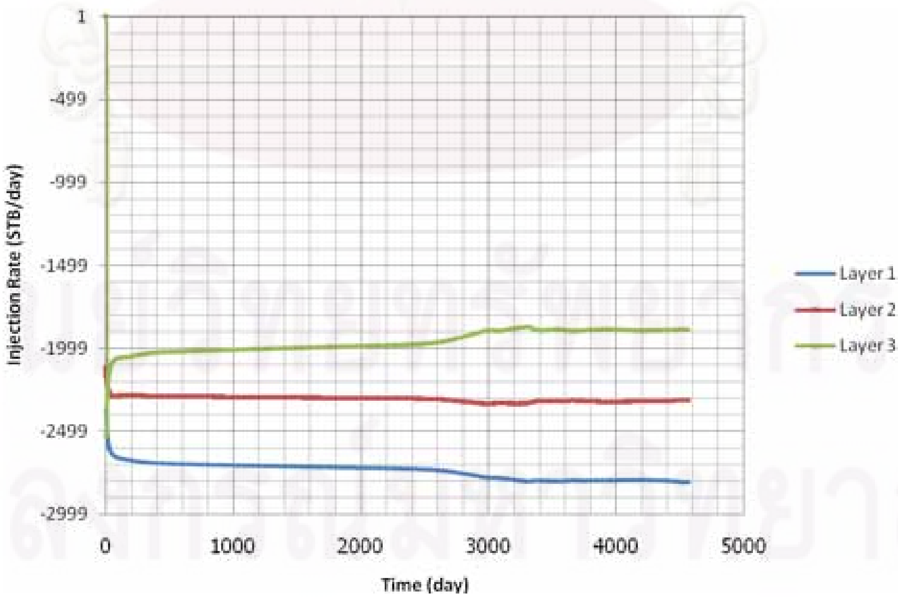

Figure 5.5: Case 5.2.1 – Layer's water injection rate at injector

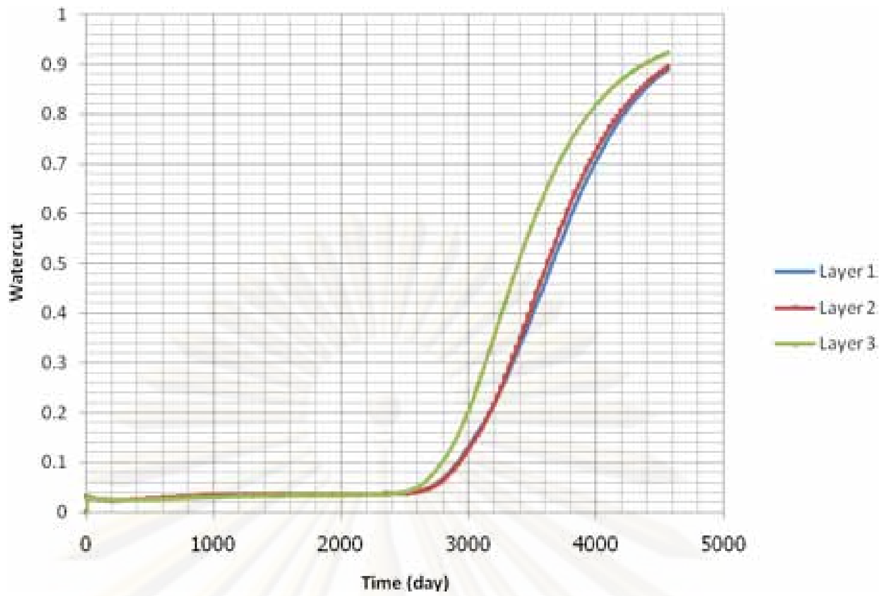

Figure 5.6: Case 5.2.1 – Layer's watercut at producer

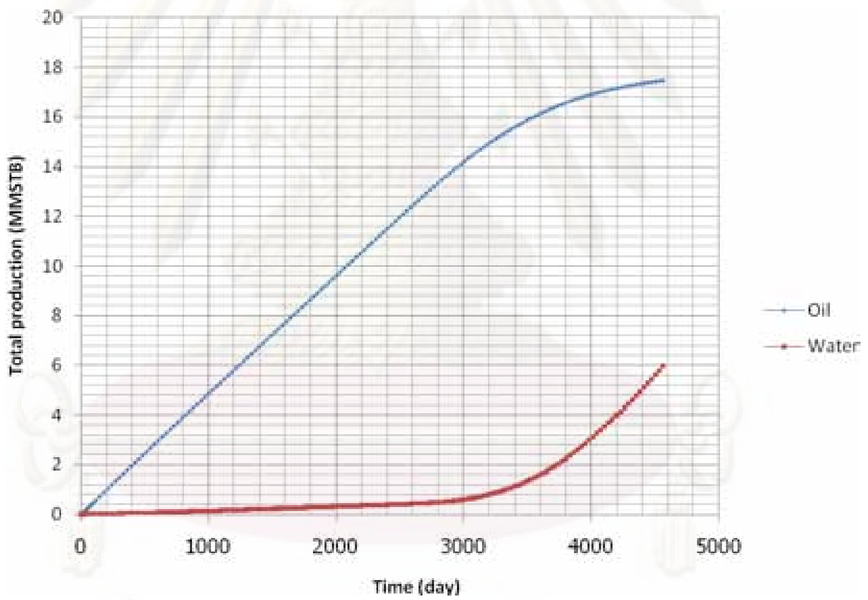

Figure 5.7: Case 5.2.1 - Total oil and water production

5.2.2 Injection Control Case 2

For this case, chokes of all layers were adjusted by trial and error until water of all layers was breaks through at the same time (or almost the same). After appropriate choke sizes were obtained, the simulation was run until water of all layers break through. Then, all chokes were set to size 64 (fully open). Chokes of the two layers that have higher watercut at the producer were adjusted in a stepwise manner according to the sequence shown in Table 5.2. Basically, every time the layer's watercut changes by 10%, the choke size is reduced.

Table 5.2: Choke adjustment 1

Layer's watercut at producer	Choke size
0.3	48
0.4	40
0.5	32
0.6	24
0.7	16
0.8	8
0.9	0

After trial adjustment, the water of all layers breaks through at the same time when the choke size of layer 1, 2 and 3 is 24, 24 and 64, respectively. After water of all layers breaks through, then all chokes were reset to size 64. The simulation was then continued. The layer's watercut were obtained and shown in Figure 5.8.

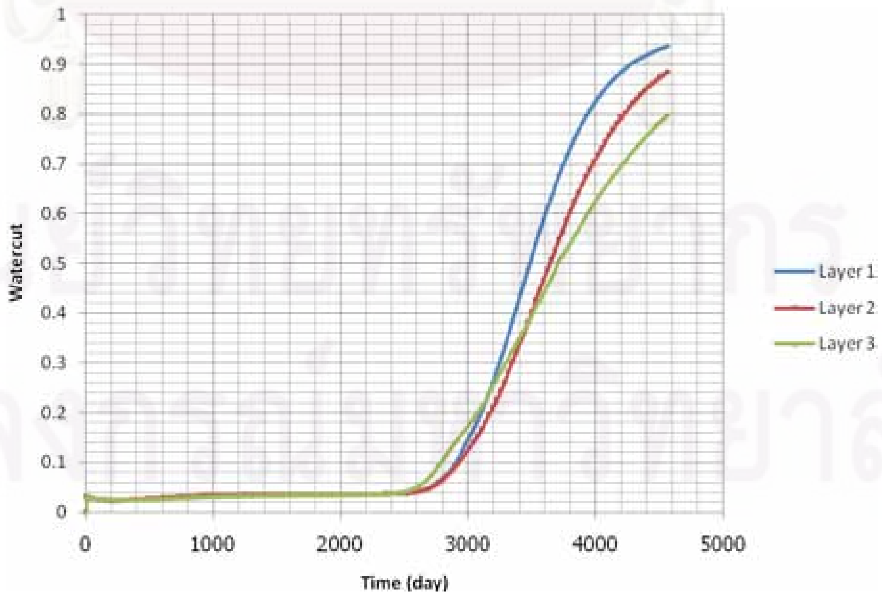

Figure 5.8: Case 5.2.2 – Layer's watercut at producer after fully open chokes

Several other adjustment patterns were tried. Chokes of layer 1 and 2 were adjusted in these trials in order to achieve the same break through time for all three layers. For example, in pattern 2, the chokes were adjusted to 48 for layers 1 and 2 as shown in Table 5.3.

Table 5.3: Result of case 5.2.2 (Injection Control Case 2)

Adjustment Pattern	Choke size Layer 1	Choke size Layer 2	Choke size Layer 3	Oil production (MMSTB)
1	64	64	64	17.430
2	48	48	64	**17.449**
3	40	40	64	17.443
4	32	32	64	17.439
5	24	24	64	17.424
6	16	16	64	17.409

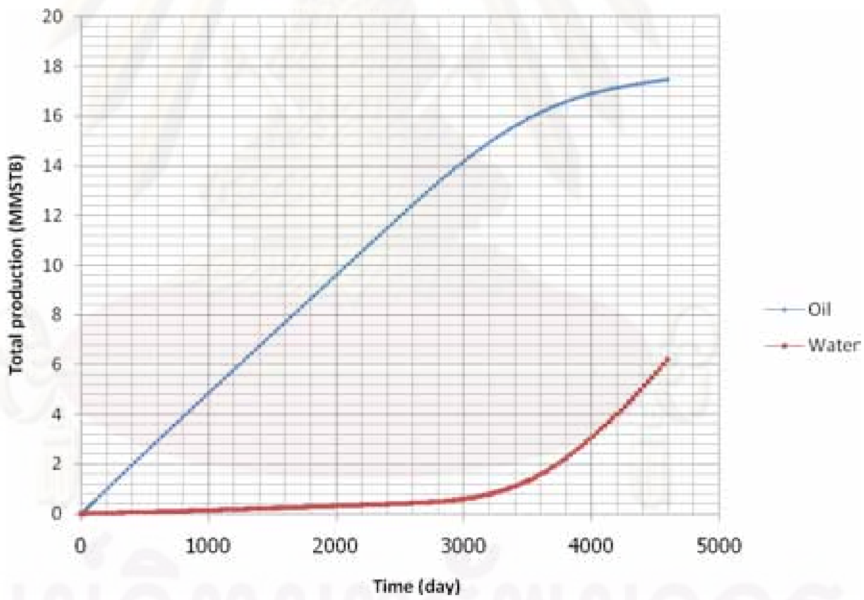

Figure 5.9: Case 5.2.2 - Total oil and water production for adjustment pattern 2

By using this strategy, we can see that the total oil production was increased after a certain adjustment. From Table 5.3 and Figure 5.9, the maximum oil production of 17.449 MMSTB is obtained in pattern 2. The water production in this case is 6.199 MMSTB at day 4,593. The production well starts producing water at around day 2,500 as shown in Figure 5.8.

5.2.3 Injection Control Case 3

For this case, chokes of all layers were adjusted by trial and error until water of all layers breaks through at the same time (or almost the same). After appropriate chokes sizes were obtained, the simulation was run until the water of all layers breaks through. Unlike Injection Control Case 2, all chokes were not set to size 64 (fully open). All chokes were adjusted immediately after breakthrough. At this condition, all chokes positions were set at specific sizes. Adjustments as shown in Table 5.2 are not suitable.

After comparing the layer's watercut profile in Figure 5.6 with Figure 5.2, we can observe that the more the layer's watercut are close to one another, the more the maximum oil production will be. As the layer's watercut profile shown in Figure 5.6, watercut of layer 1 and 2 are lower than watercut of layer 3. We have two adjustment methods to make the watercuts becoming closer: decreasing the choke size of layer 3 or increasing the choke sizes of layer 1 and 2. Decreasing the choke size of layer 3 will make the bottomhole pressure at the injector becoming higher. So, increasing choke sizes of layer 1 and 2 is more suitable. The choke sizes will be increased 1 step at every 0.1 increase of watercut. For example,

- When watercuts of layers 1 and 2 reach 0.3, the choke sizes were adjusted from size 24 to be size 32.
- And when watercuts of layers 1 and 2 reach 0.4, the choke sizes were adjusted from size 32 to be size 40.

After several simulations were run, the results are shown in Table 5.4 & Figure 5.10. The maximum oil production of 17.453 MMSTB is obtained in adjustment pattern 1. The water production in this case is 6.199 MMSTB at day 4,563. The production well starts producing water at around day 2,500 as shown in Figure 5.11.

Table 5.4: Result of case 5.2.3 (Injection Control Case 3)

Adjustment Pattern	Choke size Layer 1	Choke size Layer 2	Choke size Layer 3	Oil production (MMSTB)
0	24	24	64	17.447
1	32	32	64	**17.453**
2	40	40	64	17.451
3	48	48	64	17.449
4	56	56	64	17.445

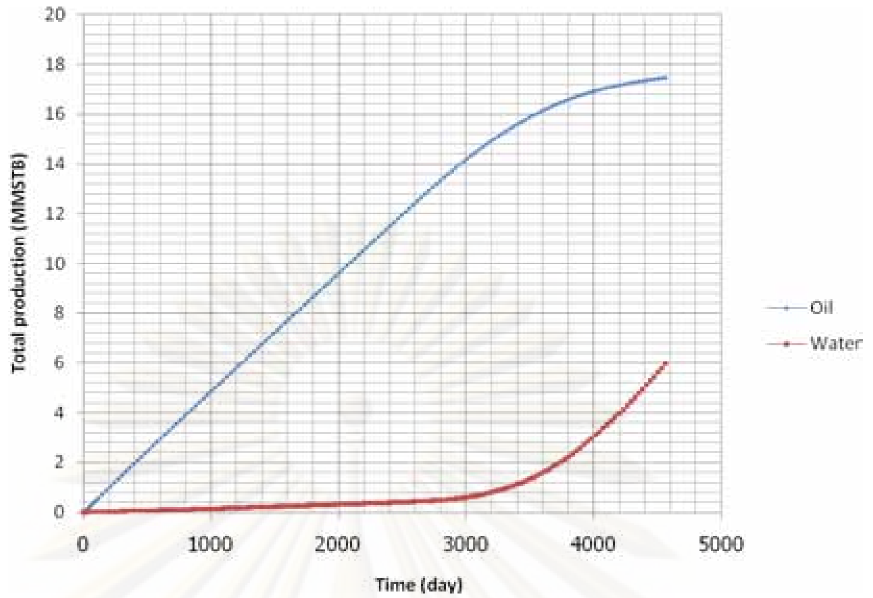

Figure 5.10: Case 5.2.3 - Total oil and water production (Adjustment pattern 1)

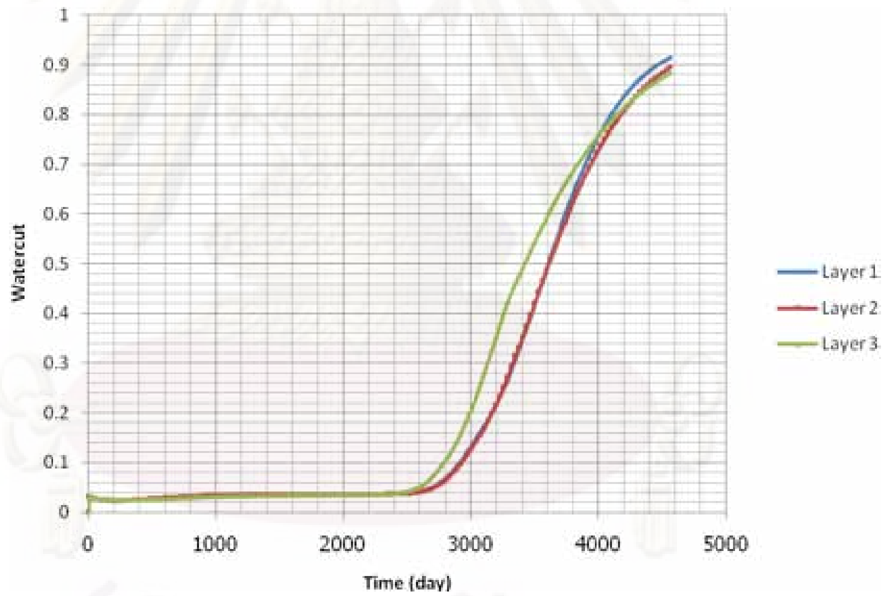

Figure 5.11: Case 5.2.3 – Layer’s watercut at producer (Adjustment pattern 1)

5.2.4 Injection Control Case 4

For this case, chokes of all layers were adjusted by trial and error with an objective to inject more water into the lowest injectivity layer. This may be the cause for a BHP at the injector to reach the well constraint. In doing so, the BHP at the injector has to be always observed. Then, the well control strategies are set similar to Injection Control Case 3.

The layer's watercut profiles are shown in Figure 5.13. Watercut of layer 1 is lower than watercut of layers 2 and 3. We have two adjustment methods to make the watercuts becoming closer: decreasing the choke sizes of layer 2 and 3 or increasing the choke size of layer 1. Decreasing the choke sizes of layer 2 and 3 will make the bottomhole pressure at the injector becoming higher. So, increasing choke sizes of layer 1 is more suitable. The choke size will be increased 1 step at every 0.1 increase of watercut. For example,

- When watercut of layer 1 reaches 0.3, the choke size was adjusted from size 16 to be size 24.
- And when watercut of layer 1 reaches 0.4, the choke size was adjusted from size 24 to be size 32.

After several simulations were run, the results are shown in Table 5.5 – Table 5.7 and Figure 5.12. The maximum oil production of 17.841 MMSTB and the water production of 19.829 MMSTB at day 6,632 are obtained in pattern 6 in Table 5.6. The production well starts producing water at around day 1,800 as shown in Figure 5.13.

Table 5.5: Result of case 5.2.4A (Injection Control Case 4)

Adjustment Pattern	Choke size Layer 1	Choke size Layer 2	Choke size Layer 3	Oil production (MMSTB)
0	16	24	64	17.512
1	24	24	64	17.710
2	32	24	64	17.744
3	40	24	64	17.761
4	48	24	64	17.764
5	56	24	64	17.766
6	64	24	64	17.767

Table 5.6: Result of case 5.2.4B (Injection Control Case 4)

Adjustment Pattern	Choke size Layer 1	Choke size Layer 2	Choke size Layer 3	Oil production (MMSTB)
0	16	32	64	17.494
1	24	32	64	17.748
2	32	32	64	17.782
3	40	32	64	17.810
4	48	32	64	17.826
5	56	32	64	17.837
6	64	32	64	**17.841**

Table 5.7: Result of case 5.2.4C (Injection Control Case 4)

Adjustment Pattern	Choke size Layer 1	Choke size Layer 2	Choke size Layer 3	Total oil production (MMSTB)
0	24	24	64	17.501
1	32	24	64	17.482
2	40	24	64	17.473

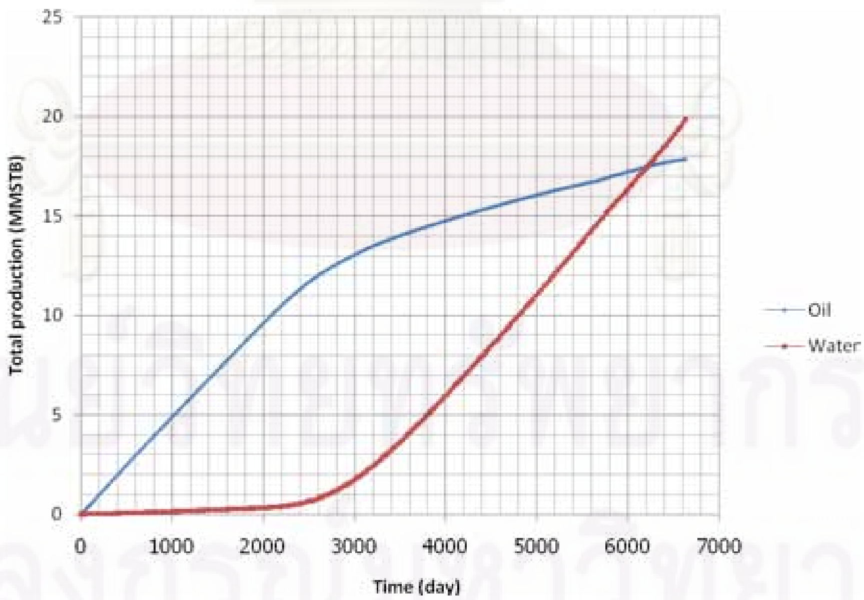

Figure 5.12: Case 5.2.4B - Total oil and water production (Adjustment pattern 6)

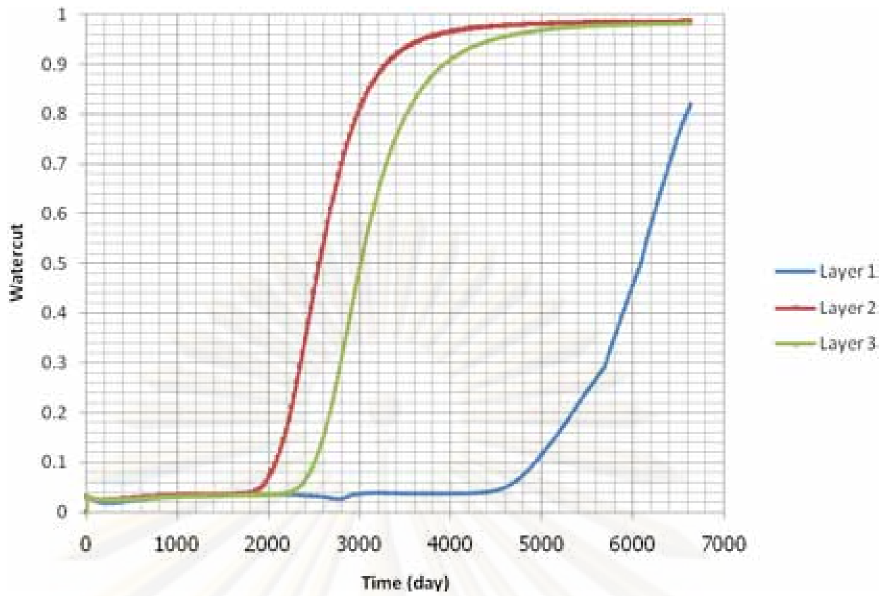

Figure 5.13: Case 5.2.4B – Layer's watercut at producer (Adjustment pattern 6)

5.2.5 Injection Control Case 5

For this case, all chokes were set at size 64 (fully open). The simulation was run to investigate the layer's watercut. All chokes were adjusted according to the sequence shown in Table 5.2.

After several simulations were run, the results are shown in Table 5.8 and Figure 5.14. The maximum oil production of 17.454 MMSTB and the water production of 8.238 MMSTB at day 4,896 are obtained in adjustment pattern 5. The production well starts producing water at around day 2,000 as shown in Figure 5.15.

Table 5.8: Result of case 5.2.5 (Injection Control Case 5)

Adjustment Pattern	Choke position Layer 1	Choke position Layer 2	Choke position Layer 3	Oil production (MMSTB)
0	64	64	64	17.381
1	48	64	64	17.399
2	40	64	64	17.407
3	32	64	64	17.418
4	24	64	64	17.433
5	16	64	64	**17.454**

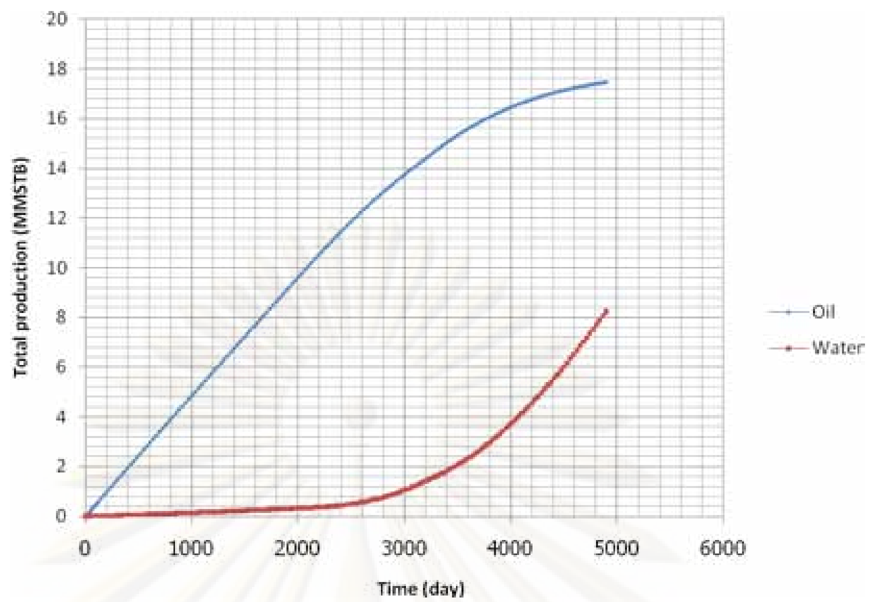

Figure 5.14: Case 5.2.5 - Total oil and water production (Adjustment pattern 5)

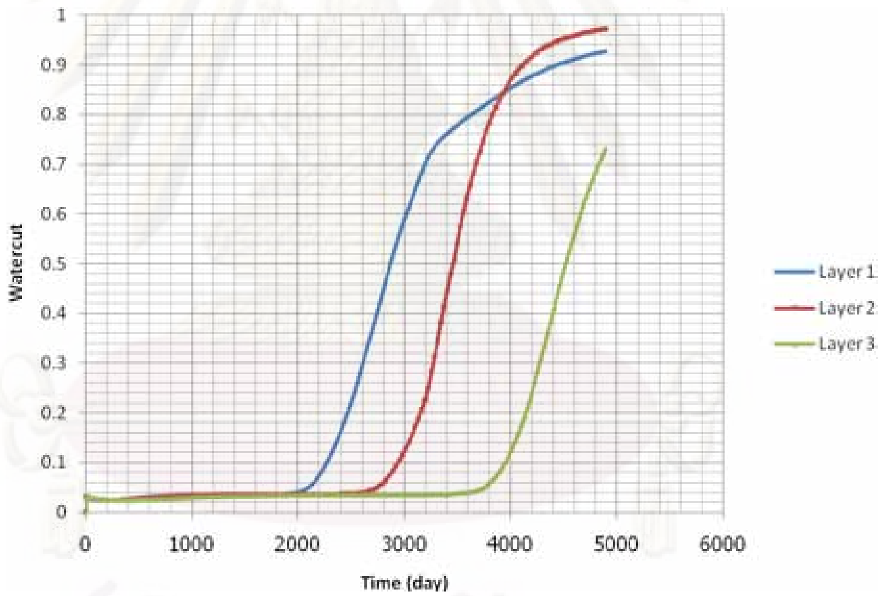

Figure 5.15: Case 5.2.5 – Layer's watercut at producer (Adjustment pattern 5)

From the results of all injection control strategies shown in Table 5.9, we found that case 4 give the maximum oil production but the water production is much higher than the other cases. The well starts producing water earlier than the other cases. And the production time is longer than the other cases. So, case 4 may not be the optimum strategy for injection well control because we have to invest for a large volume of water treatment and also have to start the water treatment process earlier than the other cases. Case 3 gives the oil production lower than case 4 but with a lower water production and longer time before water production starts. So, we use case 3 as the optimum strategy for injection well control.

Table 5.9: Result of case 5.2 (Injection Control Case)

Injection Control	Oil Prod. (MMSTB)	Water Prod. (MMSTB)	Start Water Prod. (Days)	Prod. Time (Days)
Case 1	17.447	5.983	2,500	4,563
Case 2	17.449	6.199	2,500	4,593
Case 3	**17.453**	**5.982**	**2,500**	**4,563**
Case 4	17.841	19.829	1,800	6,632
Case 5	17.454	8.238	2,000	4,896

5.3 Production Control Case

The producer will be controlled by using inflow control valve (ICV), while the injector will not be controlled. In order to find the best well control, several strategies were simulated as the following.

5.3.1 Production Control Case 1

For this case, chokes of all layers were adjusted by trial and error until water of all layers breaks through at the same time (or almost the same). After appropriate choke sizes were obtained, the simulation was run until the production well was shut by keeping all choke sizes to be the same from the start to the end.

After many trial adjustments, the water of all layers breaks through at the same time when choke size of layer 1, 2 and 3 is 24, 24 and 64, respectively. Figure 5.16 illustrates the flow distribution of each layer at the injector. Compared to the base case, the water distribution changes according to the choke sizes. All layers break through almost at the same time as shown in Figure 5.17. The oil production is 17.373 MMSTB, and the water production is 6.152 MMSTB at day 4,624 as shown in Figure 5.18. The production well starts producing water at around day 2,500 as shown in Figure 5.17.

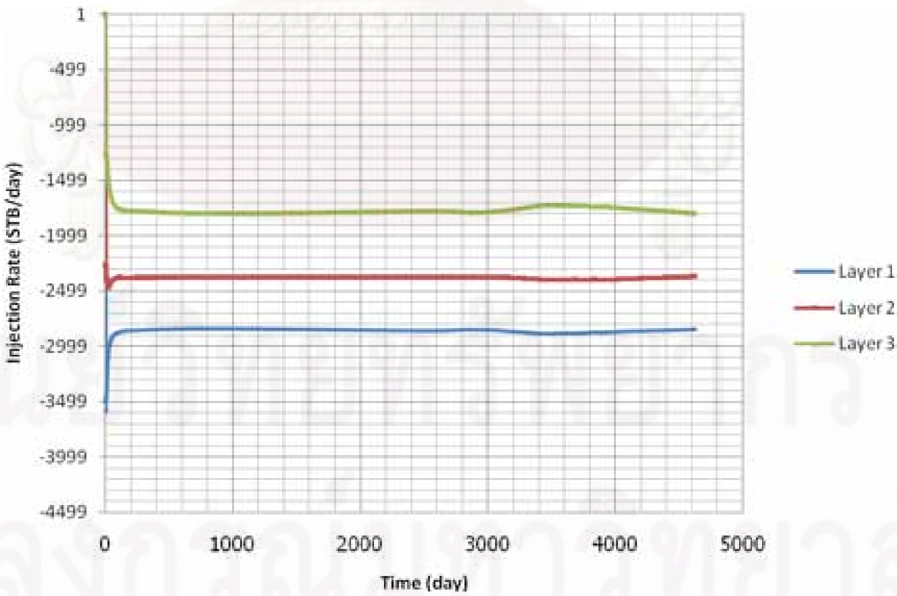

Figure 5.16: Case 5.3.1 – Layer's water injection rate at injector

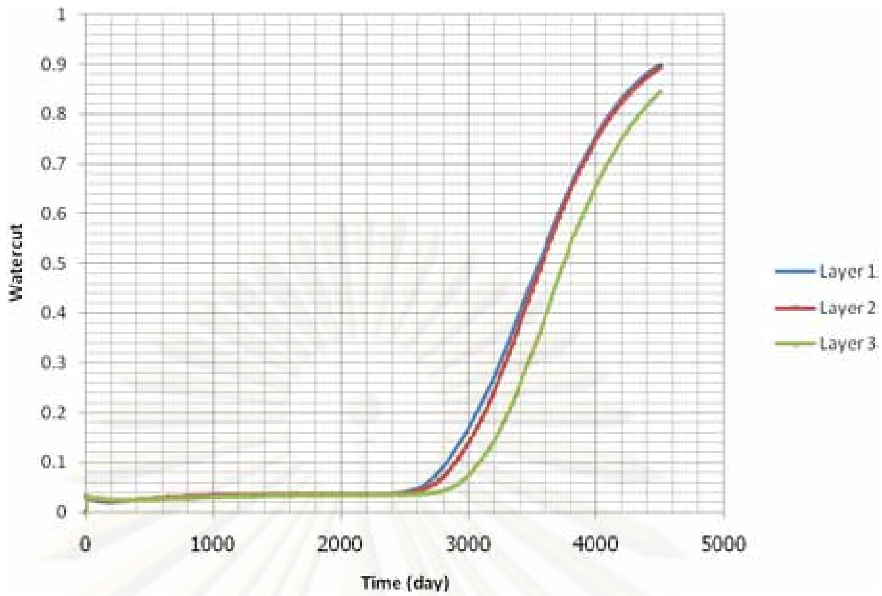

Figure 5.17: Case 5.3.1 – Layer's watercut at producer

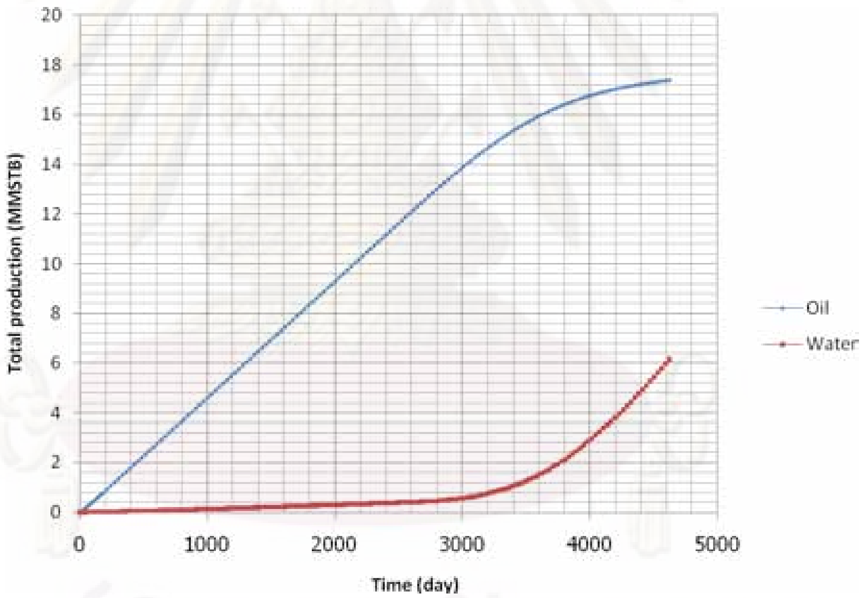

Figure 5.18: Case 5.3.1 - Total oil and water production

5.3.2 Production Control Case 2

For this case, chokes of all layers were adjusted by trial and error until water of all layers breaks through at the same time (or almost the same). After appropriate choke sizes were obtained, the simulation was run until water of all layers breaks through. Then all chokes were set at size 64 (fully open). All chokes were adjusted according to the sequence shown in Table 5.2.

After many trial adjustments, the water of all layers breaks through at the same time when choke size of layer 1, 2 and 3 is 24, 24 and 64, respectively. After water of all layers breaks through, then all chokes were set at size 64 (fully open). The simulation was run again. The layered watercut were obtained. All chokes were adjusted again according to Table 5.2.

After several simulation were run, the results are shown in Table 5.10

Table 5.10: Result of case 5.3.2 (Production Control Case 2)

Adjustment Pattern	Choke position Layer 1	Choke position Layer 2	Choke position Layer 3	Oil production (MMSTB)
1	64	64	64	17.319
2	48	64	64	17.334
3	40	64	64	17.345
4	40	48	64	17.348
5	32	48	64	17.356
6	32	40	64	17.357
7	24	40	64	17.385
8	24	32	64	**17.387**
9	16	24	64	17.371
10	16	16	64	17.355

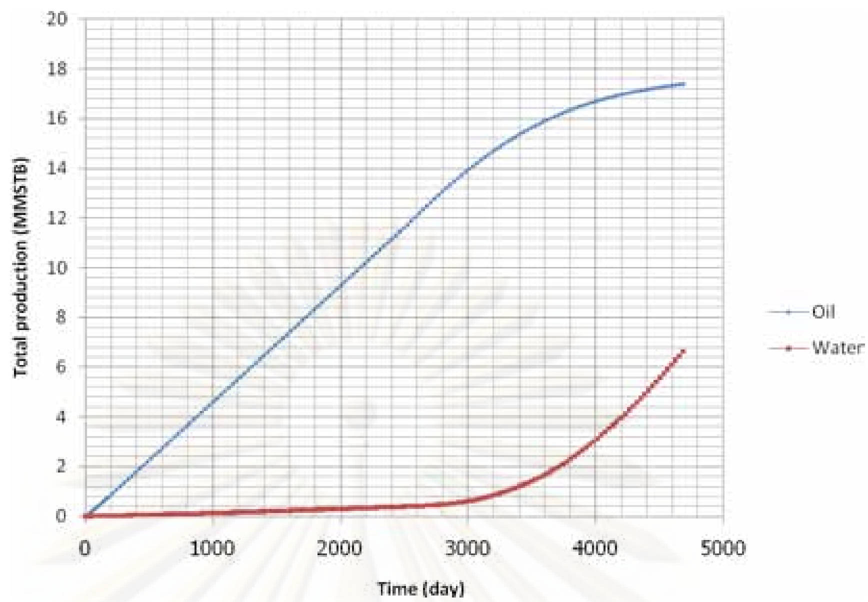

Figure 5.19: Case 5.3.2 - Total oil and water production (Adjustment pattern 8)

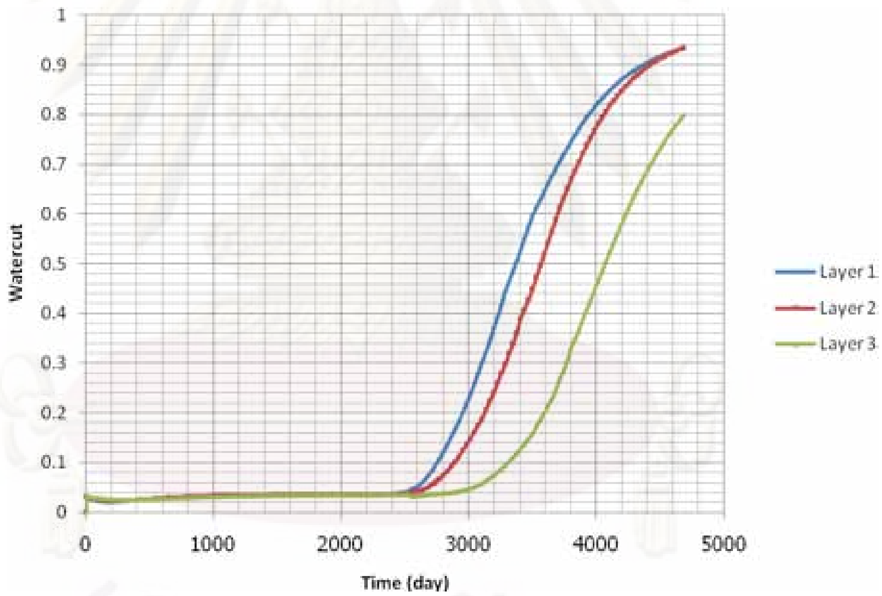

Figure 5.20: Case 5.3.2 – Layer's watercut at producer (Adjustment pattern 8)

By using this strategy, we can see that oil production was increased for a certain adjustment. From Table 5.10 and Figure 5.19, the maximum oil production of 17.387 MMSTB and the water production of 6.622 MMSTB at day 4,685 are obtained in pattern 8. The production well starts producing water at around day 2,500 as shown in Figure 5.20.

5.3.3 Production Control Case 3

For this case, chokes of all layers were adjusted by trial and error until water of all layers breaks through at the same time (or almost the same). After appropriate choke sizes were obtained, the simulation was run until water of all layers breaks through. Unlike production Control Case 2, all chokes were not set at size 64 (fully open). All chokes were adjusted immediately after breakthrough. At this condition, all chokes sizes were set at specific sizes. Adjustments as shown in Table 5.2 are not suitable. The well control strategies are set similar to Injection Control Case 3.

After many trial adjustments, the water of all layers breaks through at the same time when choke size of layer 1, 2 and 3 is 24, 24 and 64, respectively. As the layer's watercut profile shown in Figure 5.22, watercut of layer 1 and 2 are higher than watercut of layer 3. So, decreasing choke sizes of layer 1 and 2 is selected to make the watercuts becoming closer. The choke sizes will be decreased 1 step at every 0.1 increase of watercut. For this case,

- When watercuts of layers 1 & 2 reach 0.3, the choke sizes were adjusted from size 24 to be size 16.

After several simulations were run, the results are shown in Table 5.11. The maximum oil production of 17.373 MMSTB and the water production of 6.152 MMSTB at day 4,624 are obtained in pattern 0 in Table 5.11. The production well starts producing water at around day 2,500 as shown in Figure 5.22.

Table 5.11: Result of case 5.3.3 (Production Control Case 3)

Adjustment Pattern	Choke size Layer 1	Choke size Layer 2	Choke size Layer 3	Oil production (MMSTB)
0	24	24	64	**17.373**
1	16	16	64	17.293

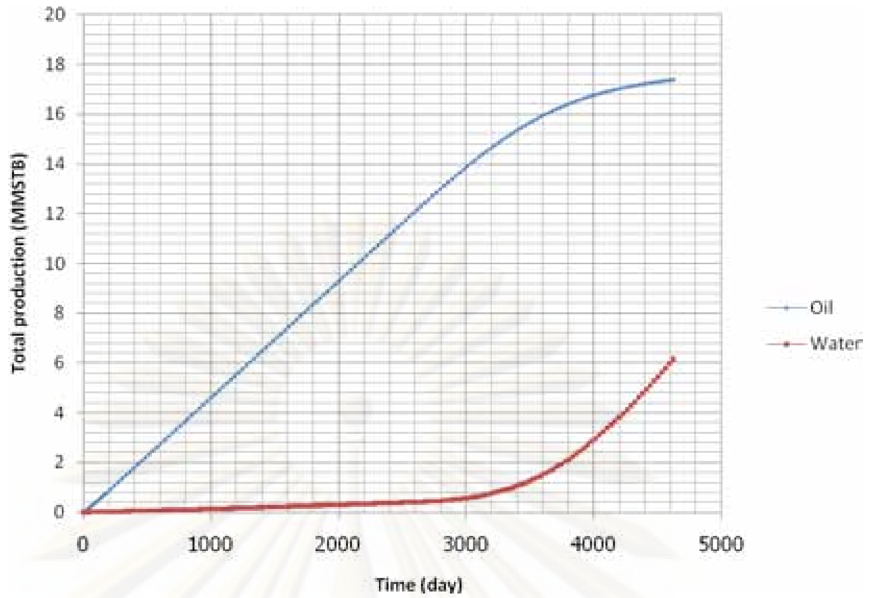

Figure 5.21: Case 5.3.3 - Total oil and water production (Adjustment pattern 0)

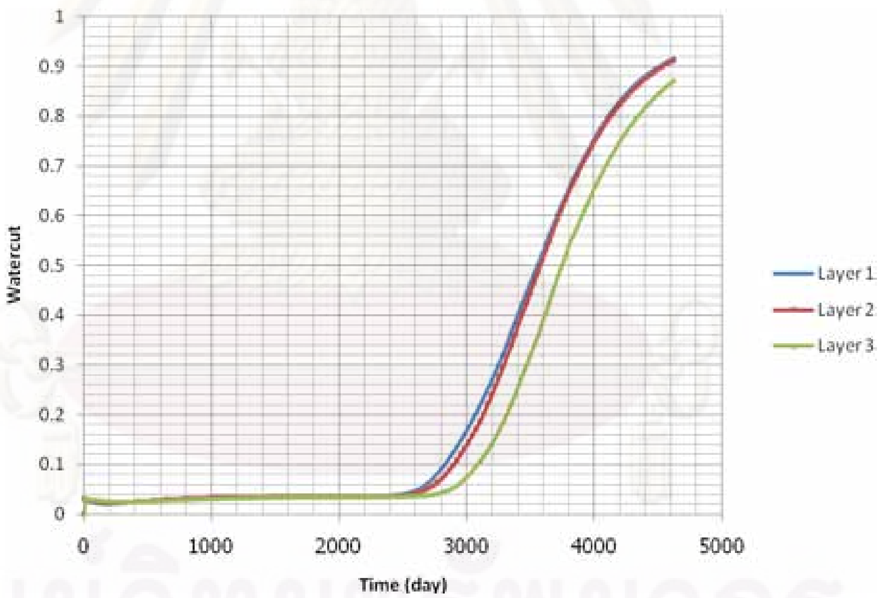

Figure 5.22: Case 5.3.3 – Layer's watercut at producer (Adjustment pattern 0)

5.3.4 Production Control Case 4

For this case, chokes of all layers were adjusted by trial and error with an objective to inject more water into the lowest injectivity layer. This may be the cause for a BHP at the injector to reach the well constraint. In doing so, the BHP at the injector has to be always observed. Then the well control strategies are set similar to Injection Control Case 3.

As the layer's watercut profile shown in Figure 5.24, watercut of layer 1 is lower than watercuts of layers 2 & 3. We have two adjustment methods to make the watercuts becoming closer: decreasing the choke sizes of layer 2 and 3 or increasing the choke size of layer 1. Decreasing the choke sizes of layer 2 and 3 will make the bottomhole pressure at the injector becoming higher. So, increasing choke sizes of layer 1 is more suitable. The choke size will be increased 1 step at every 0.1 increase of watercut. For example,

- When watercut of layer 1 reaches 0.3, the choke size was adjusted from size 16 to be size 24.
- And when watercut of layer 1 reach 0.4, the choke size was adjusted from size 24 to be size 32.

After several simulations were run, the results are shown in Table 5.12 – Table 5.13 and Figure 5.23. The maximum oil production of 17.608 MMSTB and the water production of 15.572 MMSTB at day 5,992 are obtained in pattern 6 in Table 5.13. The production well starts producing water at around day 1,800 as shown in Figure 5.24.

Table 5.12: Result of case 5.3.4A (Production Control Case 4)

Adjustment Pattern	Choke size Layer 1	Choke size Layer 2	Choke size Layer 3	Oil production (MMSTB)
0	16	24	64	17.292
1	24	24	64	17.486
2	32	24	64	17.544
3	40	24	64	17.555
4	48	24	64	17.563
5	56	24	64	17.570
6	64	24	64	17.576

Table 5.13: Result of case 5.3.4B (Production Control Case 4)

Adjustment Pattern	Choke size Layer 1	Choke size Layer 2	Choke size Layer 3	Total oil production (MMSTB)
0	16	32	64	17.294
1	24	32	64	17.519
2	32	32	64	17.563
3	40	32	64	17.573
4	48	32	64	17.581
5	56	32	64	17.605
6	64	32	64	**17.608**

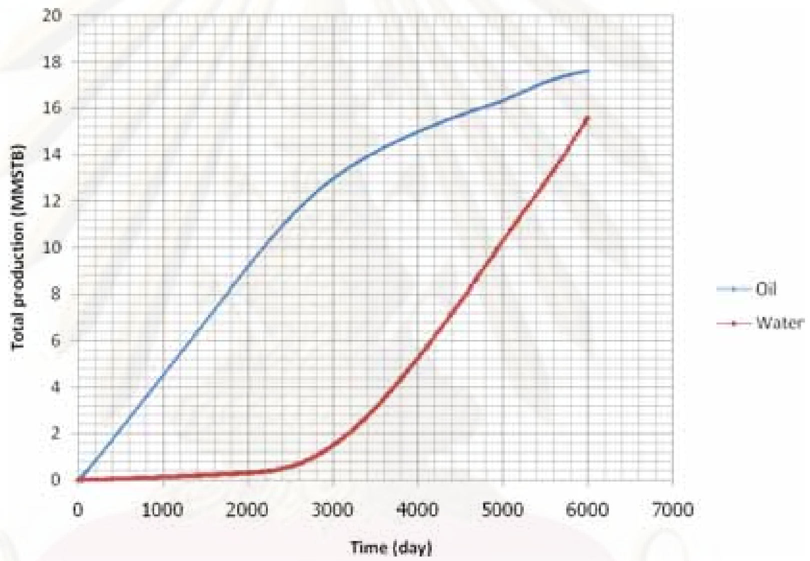

Figure 5.23: Case 5.3.4B - Total oil and water production (Adjustment pattern 6)

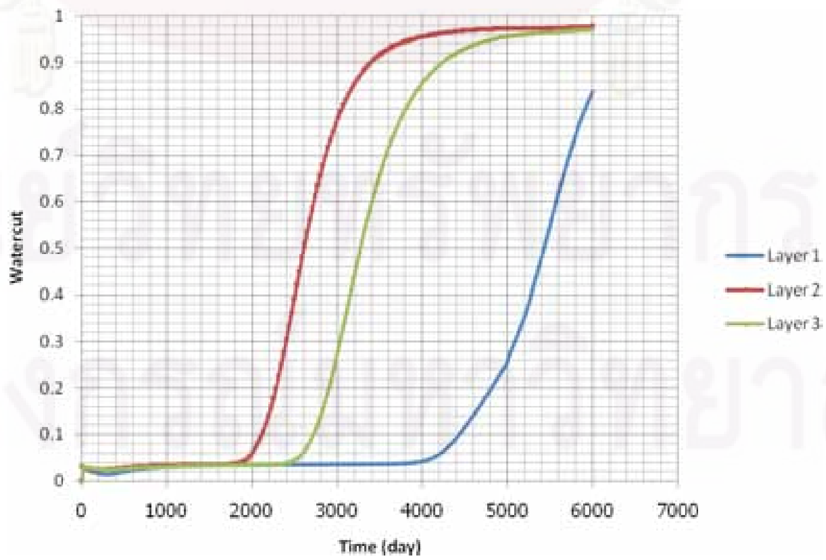

Figure 5.24: Case 5.3.4B – Layer's watercut at producer (Adjustment pattern 6)

5.3.5 Production Control Case 5

For this case, all chokes were set at size 64 (fully open). The simulation was run to investigate the layer's watercut. All chokes were adjusted according to the sequence shown in Table 5.2.

After several simulations were run, the results are shown in Table 5.14 and Figure 5.25. The maximum oil production of 17.480 MMSTB and the water production of 9.415 MMSTB at days 5,082 are obtained in adjustment pattern 4. The production well starts producing water at around day 2,000 as shown in Figure 5.26.

Table 5.14: Result of case 5.3.5 (Production Control Case 5)

Adjustment Pattern	Choke size Layer 1	Choke size Layer 2	Choke size Layer 3	Oil production (MMSTB)
0	64	64	64	17.381
1	48	64	64	17.416
2	40	64	64	17.425
3	32	64	64	17.433
4	24	64	64	**17.480**
5	16	64	64	17.402

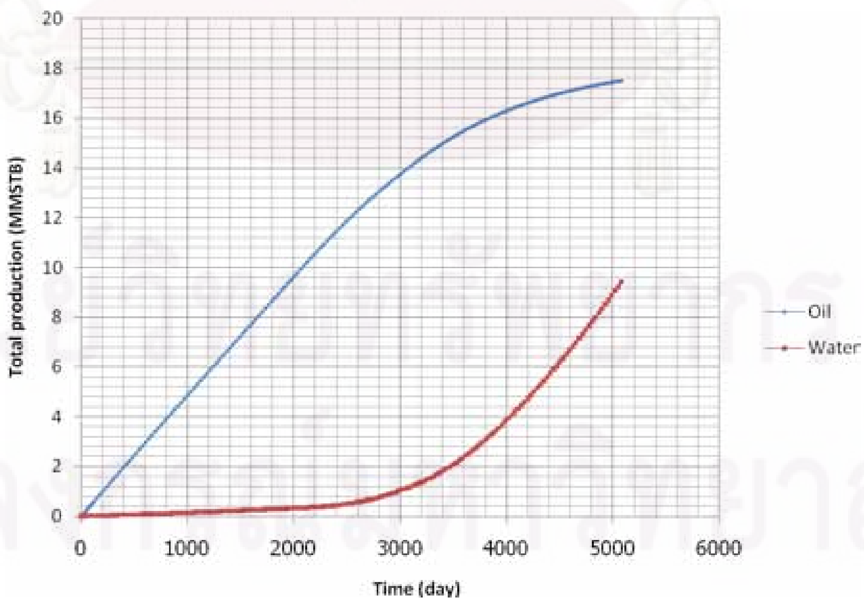

Figure 5.25: Case 5.3.5 - Total oil and water production (Adjustment pattern 4)

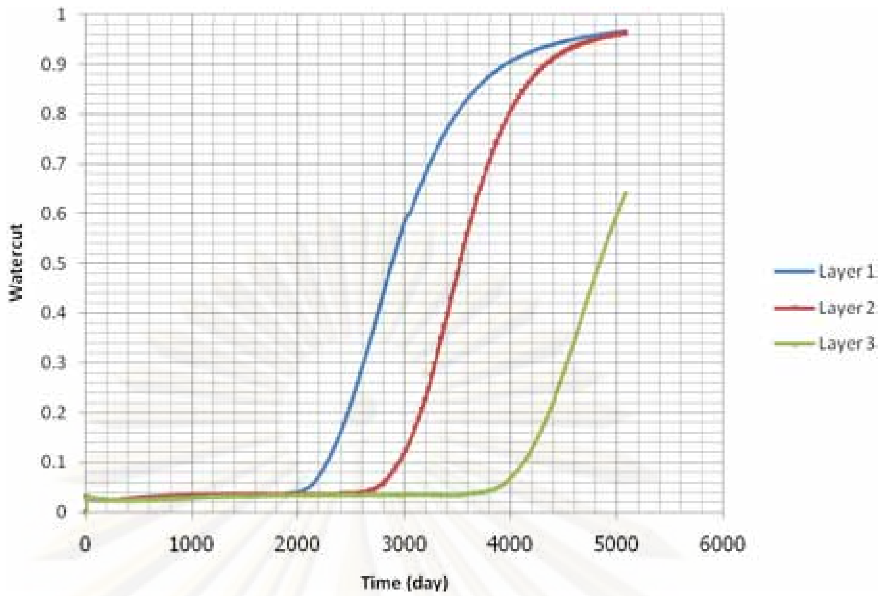

Figure 5.26: Case 5.3.5 – Layer's watercut at producer (Adjustment pattern 4)

From the results of all production control strategies shown in Table 5.15, we found that case 4 gives the maximum oil production but the water production is much higher than the other cases. The well starts producing water earlier than the other cases. And the production time is longer than the other cases. So, case 4 may not be the optimum strategy for injection well control because we have to invest for a large volume of water treatment and also have to start the water treatment process earlier than the other cases. Case 2 gives the oil production lower than case 4 but with a lower water production and longer time before water production starts. So, we use case 2 as the optimum strategy for production well control.

Table 5.15: Result of case 5.3 (Production Control Case)

Production Control	Oil Prod. (MMSTB)	Water Prod. (MMSTB)	Start Water Prod. (Days)	Prod. Time (Days)
Case 1	17.373	6.152	2,500	4,624
Case 2	**17.387**	**6.622**	**2,500**	**4,685**
Case 3	17.373	6.152	2,500	4,624
Case 4	17.608	15.572	1,800	5,992
Case 5	17.480	9.415	2,000	5,082

5.4 Injection and Production Control Case

Both the injector and producer will be controlled. The production will be optimized by using both well controls. In order to find the best well control, several strategies were simulated as the following.

5.4.1 Injection and Production Control Case 1

For this case, chokes of both wells were adjusted by trial and error. The simulations were run until the production well was shut by keeping all choke sizes to be the same from the start to the end.

After several simulations were run, the results are shown in Table 5.16 and Figure 5.27. The maximum total oil production of 17.561 MMSTB and the water production of 15.899 MMSTB at day 6,024 are obtained in adjustment pattern 15. The production well starts producing water at around day 2,000 as shown in Figure 5.28.

Table 5.16: Result of case 5.4.1 (Injection and Production Control Case 1)

Adjustment Pattern	Choke size at injector			Choke size at producer			Oil production (MMSTB)
	Layer1	Layer2	Layer3	Layer1	Layer2	Layer3	
1	24	32	64	64	64	64	17.434
2	24	32	64	64	64	48	17.444
3	24	32	64	64	64	32	17.435
4	24	24	64	64	64	64	17.447
5	24	24	64	64	64	48	17.446
6	24	24	64	64	64	32	17.445
7	16	32	64	64	64	64	17.493
8	16	32	64	64	64	48	17.494
9	16	32	64	64	64	32	17.497
10	16	32	64	64	64	24	17.502
11	16	32	64	64	64	16	17.500
12	16	24	64	64	64	64	17.512
13	16	24	64	64	64	48	17.525
14	16	24	64	64	64	32	17.541
15	16	24	64	64	64	24	**17.561**
16	16	24	64	64	64	16	17.538

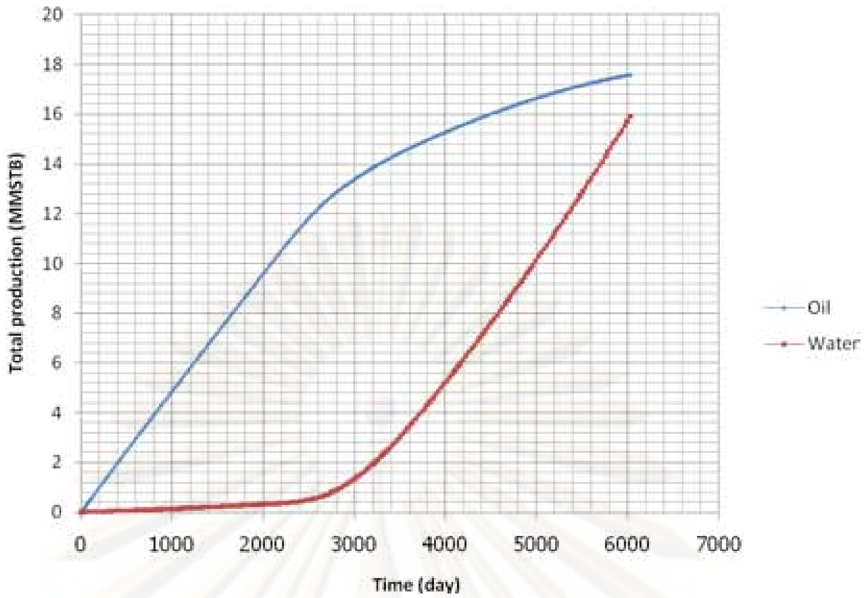

Figure 5.27: Case 5.4.1 - Total oil and water production (Adjustment pattern 15)

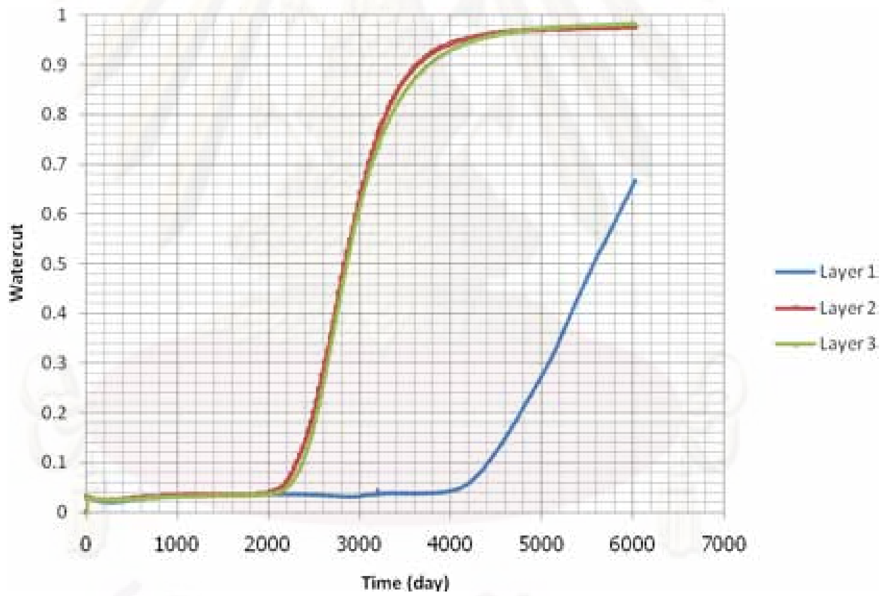

Figure 5.28: Case 5.4.1 – Layer's watercut at producer (Adjustment pattern 15)

5.4.2 Injection and Production Control Case 2

For this case, chokes at the injector were adjusted by trial and error until water of all layers breaks through at the same time (or almost the same). After appropriate choke sizes were obtained, the simulation was run until water of all layers breaks through. Then, chokes at the producer were adjusted immediately after breakthrough following Table 5.2.

After several simulations were run, the results are shown in Table 5.17 and Figure 5.29. The maximum total oil production of 17.447 MMSTB and the water production of 5.982 MMSTB at day 4,563 are obtained in adjustment pattern 0. The production well starts producing water at around day 2,500 as shown in Figure 5.30.

Table 5.17: Result of case 5.4.2 (Injection and Production Control Case 2)

Adjustment Pattern	Choke size at injector			Choke size at producer			Oil production (MMSTB)
	Layer1	Layer2	Layer3	Layer1	Layer2	Layer3	
0	24	24	64	64	64	64	**17.447**
1	24	24	64	64	64	48	17.446
2	24	24	64	64	64	40	17.446
3	24	24	64	64	64	32	17.446
4	24	24	64	64	64	24	17.413
5	24	24	64	64	64	16	17.355

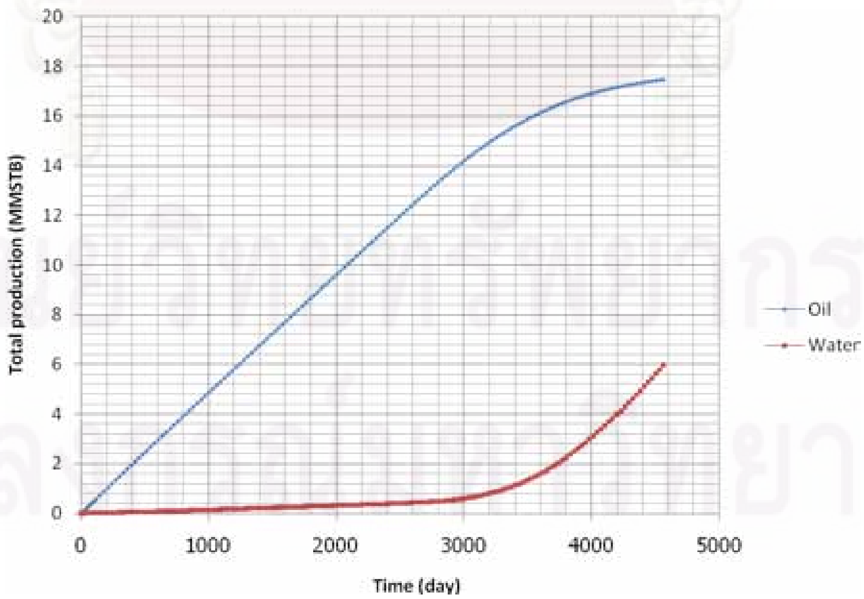

Figure 5.29: Case 5.4.2 - Total oil and water production (Adjustment pattern 0)

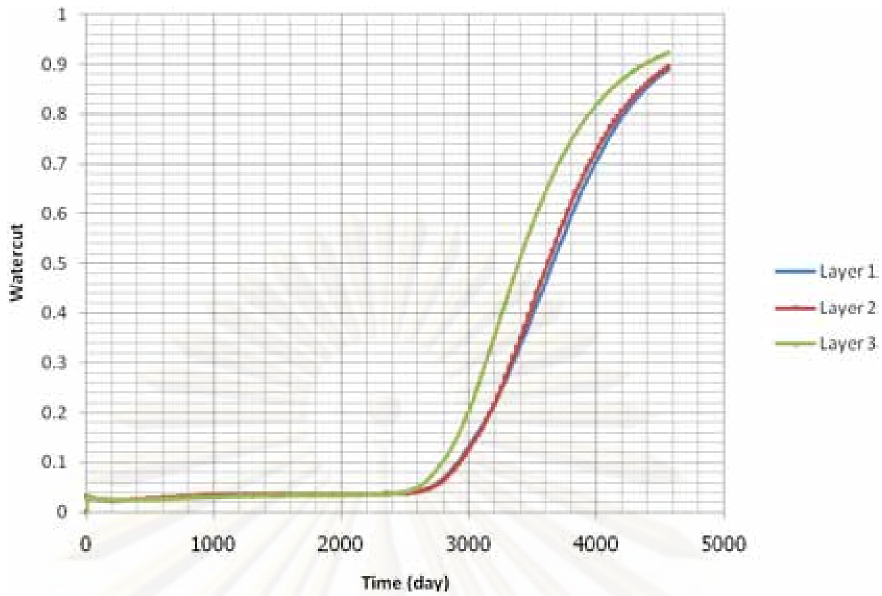

Figure 5.30: Case 5.4.2 – Layer's watercut at producer (Adjustment pattern 0)

5.4.3 Injection and Production Control Case 3

For this case, chokes at the producer were adjusted by trial and error until water of all layer breaks through at the same time (or almost the same). After appropriate choke sizes were obtained, the simulation was run until water of all layer breaks through. Then, chokes at the injector were adjusted immediately after breakthrough following Table 5.2.

After several simulations were run, the results are shown in Table 5.18 and Figure 5.31. The maximum total oil production of 17.376 MMSTB and the water production of 6.152 MMSTB at day 4,623 are obtained in adjustment pattern 1. The production well starts producing water at around day 2,500 as shown in Figure 5.32.

Table 5.18: Result of case 5.4.3 (Injection and Production Control Case 3)

Adjustment Pattern	Choke size at injector			Choke size at producer			Oil production (MMSTB)
	Layer1	Layer2	Layer3	Layer1	Layer2	Layer3	
0	64	64	64	24	24	64	17.373
1	48	48	64	24	24	64	17.376
2	40	40	64	24	24	64	17.358
3	32	32	64	24	24	64	17.357

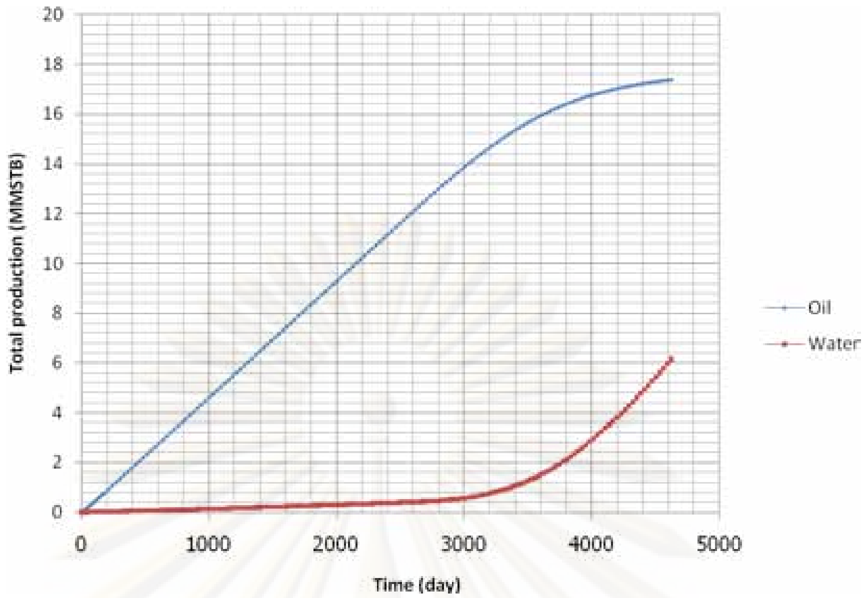

Figure 5.31: Case 5.4.3 - Total oil and water production (Adjustment pattern 1)

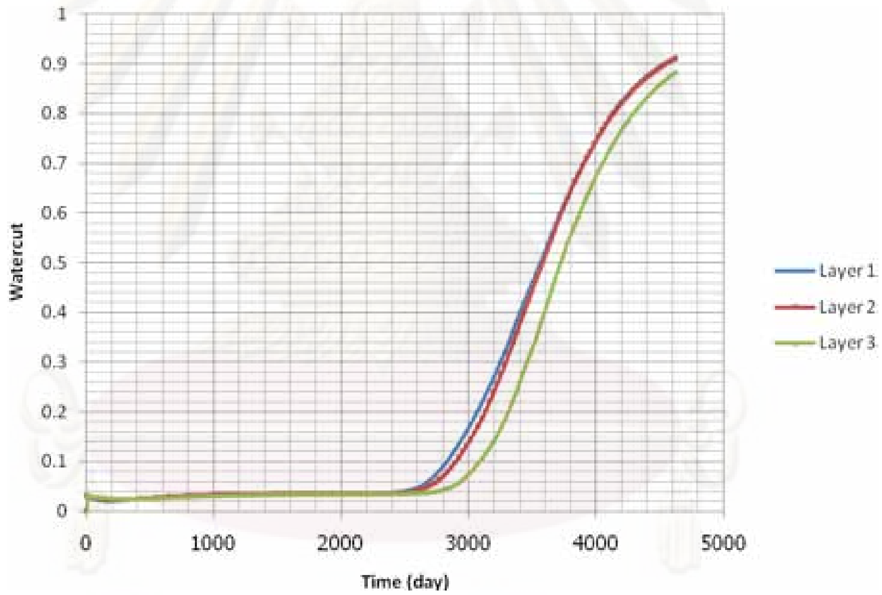

Figure 5.32: Case 5.4.3 – Layer's watercut at producer (Adjustment pattern 1)

5.4.4 Injection and Production Control Case 4

For this case, chokes at the injector were adjusted by trial and error with an objective to inject more water into the lowest injectivity layer. This may be the cause for a BHP at the injector to reach the well constraint. In doing so, the BHP at the injector has to be always observed. Then, chokes at the producer were adjusted by Table 5.2. After several simulations were run, the results are shown in Table 5.19 – 5.20 and Figure 5.33. The maximum total oil production of 17.891 MMSTB and the water production of 15.891 MMSTB at day 6,116 are obtained in pattern 7. The production well starts producing water at around day 1,800 as shown in Figure 5.34.

Table 5.19: Result of case 5.4.4A (Injection and Production Control Case 4)

Adjustment Pattern	Choke size at injector			Choke size at producer			Oil production (MMSTB)
	Layer1	Layer2	Layer3	Layer1	Layer2	Layer3	
0	16	24	64	64	64	64	17.512
1	16	24	64	64	64	48	17.518
2	16	24	64	64	64	40	17.527
3	16	24	64	64	64	32	17.539
4	16	24	64	64	64	24	17.573
5	16	24	64	64	56	24	17.587
6	16	24	64	64	48	16	17.649
7	16	24	64	64	40	16	17.661
8	16	24	64	64	32	16	17.623

Table 5.20: Result of case 5.4.4B (Injection and Production Control Case 4)

Adjustment Pattern	Choke size at injector			Choke size at producer			Oil production (MMSTB)
	Layer1	Layer2	Layer3	Layer1	Layer2	Layer3	
0	16	32	64	64	64	64	17.494
1	16	32	64	64	48	64	17.518
2	16	32	64	64	40	64	17.540
3	16	32	64	64	32	64	17.570
4	16	32	64	64	24	64	17.623
5	16	32	64	64	24	48	17.698
6	16	32	64	64	16	48	17.881
7	16	32	64	64	16	40	**17.891**
8	16	32	64	64	16	32	17.878

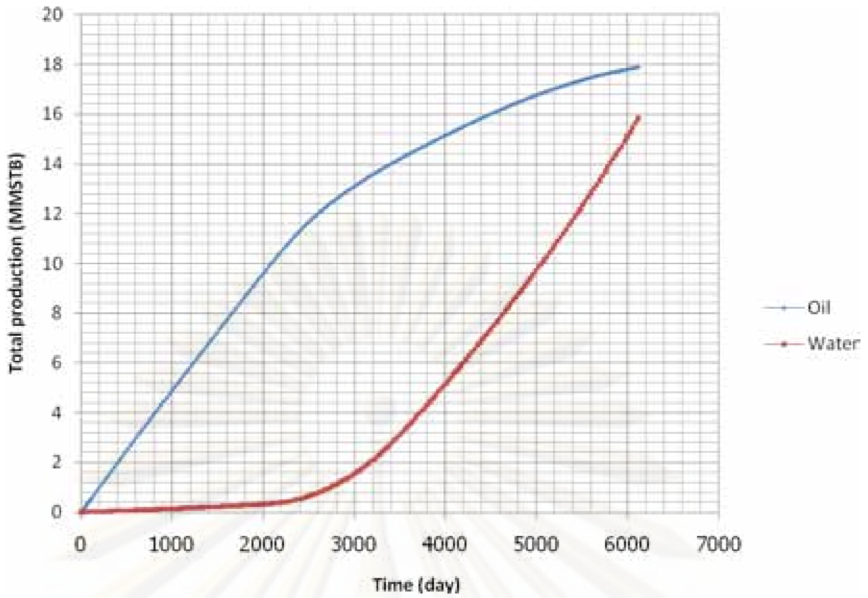

Figure 5.33: Case 5.4.4 - Total oil and water production (Adjustment pattern 7)

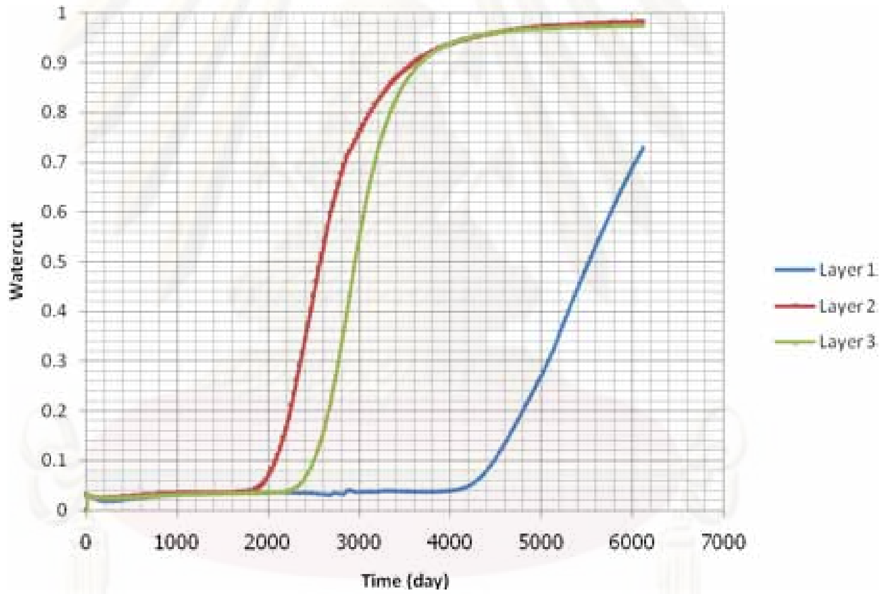

Figure 5.34: Case 5.4.4 – Layer’s watercut at producer (Adjustment pattern 7)

5.4.5 Injection and Production Control Case 5

For this case, chokes at the producer were adjusted by trial and error with an objective to inject more water into the lowest injectivity layer. This may be the cause for a BHP at the injector to reach the well constraint. In doing so, the BHP at the injector has to be always observed. Then, chokes at the injector were adjusted by followed Table 5.2.

After several simulations were run, the results are shown in Table 5.21 – Table 5.22 and Figure 5.35. The maximum total oil production of 17.556 MMSTB and the water production of 14.506 MMSTB at day 5,688 are obtained in adjustment pattern 7. The production well starts producing water at around day 1,800 as shown in Figure 5.36.

Table 5.21: Result of case 5.4.5A (Injection and Production Control Case 5)

Adjustment Pattern	Choke size at injector			Choke size at producer			Oil production (MMSTB)
	Layer1	Layer2	Layer3	Layer1	Layer2	Layer3	
0	64	64	64	16	24	64	17.292
1	64	48	48	16	24	64	17.311
2	64	40	40	16	24	64	17.318
3	64	32	32	16	24	64	17.325
4	64	24	24	16	24	64	17.393
5	64	16	16	16	24	64	17.502*

*The pressure at injector is over the limitation.

Table 5.22: Result of case 5.4.5B (Injection and Production Control Case 5)

Adjustment Pattern	Choke size at injector			Choke size at producer			Oil production (MMSTB)
	Layer1	Layer2	Layer3	Layer1	Layer2	Layer3	
0	64	64	64	16	32	64	17.294
1	64	48	64	16	32	64	17.303
2	64	40	64	16	32	64	17.319
3	64	32	64	16	32	64	17.342
4	64	24	64	16	32	64	17.396
5	64	16	64	16	32	64	17.545
6	64	16	48	16	32	64	17.547
7	64	16	40	16	32	64	**17.556**
8	64	16	32	16	32	64	17.543

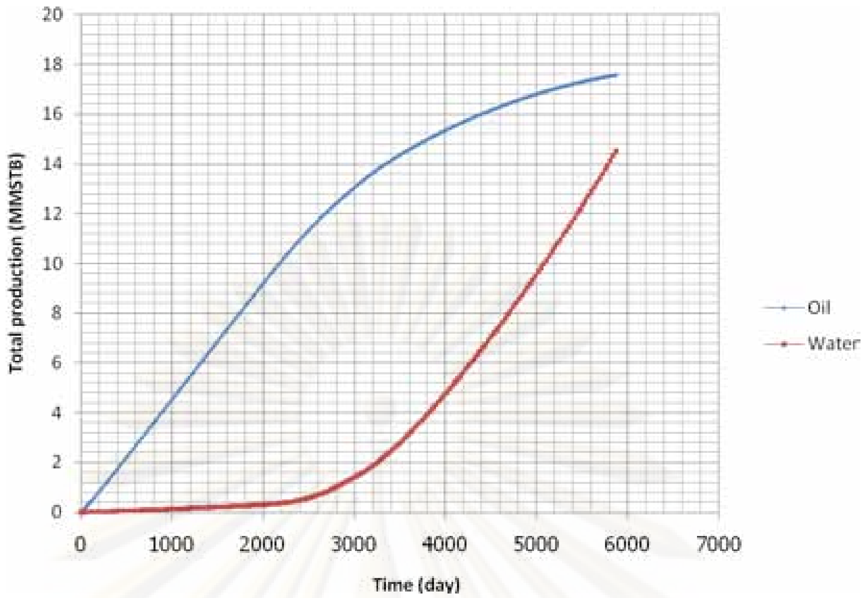

Figure 5.35: Case 5.4.5 - Total oil and water production (Adjustment Pattern 7)

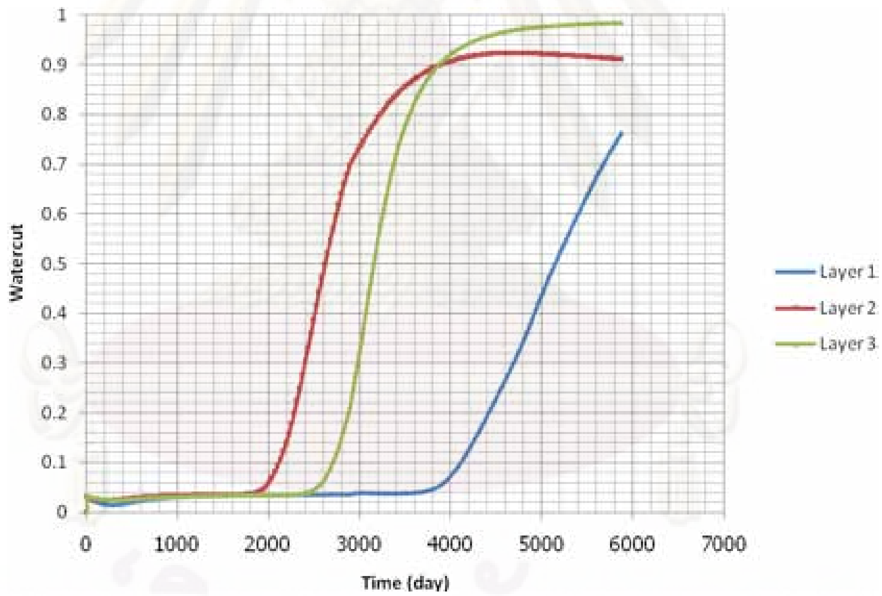

Figure 5.36: Case 5.4.5 – Layer's watercut at producer (Adjustment Pattern 7)

From the results of all injection and production control strategies shown in Table 5.23, we found that case 4 gives the maximum oil production but the water production is much higher than the other cases. The well starts producing water earlier than the other cases. And the production time is longer than the other cases. So, case 4 may not be the optimum strategy for injection well control because we have to invest for a large volume of water treatment and also have to start the water treatment process earlier than the other cases. Case 2 gives the oil production lower than case 4 but with a lower water production and longer time before water production starts. So, we use case 2 as the optimum strategy for production well control.

Table 5.23: Result of case 5.4 (Injection and Production Control Case)

Injection & Production Control	Oil Prod. (MMSTB)	Water Prod. (MMSTB)	Start Water Prod. (Days)	Prod. Time (Days)
Case 1	17.561	15.899	2,000	6,024
Case 2	**17.447**	**5.982**	**2,500**	**4,563**
Case 3	17.376	6.152	2,500	4,623
Case 4	17.891	15.891	1,800	6,116
Case 5	17.556	14.506	1,800	5,841

Finally, the oil productions of all cases are listed in Table 5.24. The results indicate that using downhole flow control does not really help increase the oil recovery because the watercut constraint is 90% which is quite high. However, downhole flow control help reduce water production by almost half as well as shorten the time to obtain the amount of oil production. The capability to control or reduce water production is the main advantage of downhole flow control.

*Table 5.24: Result of all case*s

Case	Oil Prod. (MMSTB)	Water Prod. (MMSTB)	Start Water	Prod. Time	Compare to Base Case
Base Case	17.380	11.363	2,000	5,322	+ 0.00%
Injection Case	17.453	5.982	2,500	4,563	+ 0.42%
Production Case	17.387	6.622	2,500	4,685	+ 0.04%
Injection & Production Case	17.447	5.982	2,500	4,563	+ 0.39%

5.5 Sensitivity Study

The sensitivity study describes the effects 0n oil recovery and water production when using downhole flow control in both injector and producer well due to difference in reservoir characteristics.

5.5.1 Effect of Permeability

In order to study the effect on oil and water production due to the permeability, the simulations were performed under the difference in permeability. We used the production obtained from the base case as a reference. Then, the effects were investigated in terms of how much oil and water productions are obtained by using well control strategy.

Table 5.25: Effect of Permeability

Permeability (md)			Base case Oil production (MMSTB)	Control case Oil production (MMSTB)	Compare to Base Case
Layer1	Layer2	Layer3			
400	250	150	17.373	17.412	+ 0.22%
500	300	150	17.380	17.453	+ 0.42%
600	400	150	17.257	17.472	+ 1.25%
800	500	150	16.919	17.481	+ 3.32%
1000	600	150	15.995	17.487	+ 9.33%

Table 5.26: Effect of Permeability

Permeability (md)			Base case Water production (MMSTB)	Control case Water production (MMSTB)
Layer1	Layer2	Layer3		
400	250	150	9.172	5.844
500	300	150	11.363	5.982
600	400	150	14.412	6.181
800	500	150	17.521	6.497
1000	600	150	14.008	6.947

Table 5.25 & 5.26 illustrate the effect on oil and water production due to permeability. For a small contrast in permeability, the well control strategy improved the oil production only by a small amount. For a high contrast in permeability, the

well control strategy improved the oil production a lot. For all contrast in permeability, the well control strategy reduces water production by almost half.

5.5.2 Effect of Porosity

In order to study the effect on oil and water production due to the porosity, the simulations were performed under the difference in porosity. We used the production obtained from the base case as a reference. Then, the effects were investigated in terms of how much oil and water productions are obtained by using well control strategy.

Table 5.27: Effect of Porosity

Porosity			Base case Oil production (MMSTB)	Control case Oil production (MMSTB)	Compare to Base Case
Layer1	Layer2	Layer3			
0.20	0.20	0.20	13.737	13.907	+ 1.24%
0.25	0.225	0.20	15.565	15.680	+ 0.74%
0.30	0.25	0.20	17.380	17.453	+ 0.42%
0.35	0.275	0.20	19.164	19.225	+ 0.32%
0.40	0.30	0.20	20.964	20.984	+ 0.10%

Table 5.28: Effect of Porosity

Porosity			Base case Water production (MMSTB)	Control case Water production (MMSTB)
Layer1	Layer2	Layer3		
0.20	0.20	0.20	14.358	5.045
0.25	0.225	0.20	12.755	5.593
0.30	0.25	0.20	11.363	5.982
0.35	0.275	0.20	10.049	7.191
0.40	0.30	0.20	9.332	8.637

Table 5.27 & 5.28 illustrate the effect on oil and water production due to porosity. For any contrast in porosity, the increases in oil production obtained by using well control strategy compared to conventional completion are nearly the same. It indicates that contrast in porosity seem to have a little effect on oil recovery. For a small contrast in porosity, the well control strategy reduces water production more than a high contrast in porosity.

CHAPTER VI

CONCLUSION

This chapter concludes the results obtained from this thesis in terms of oil and water production by using both intelligent injector and intelligent producer in multi-layered oil reservoir and the effects on oil and water production of this strategy due to difference in reservoir characteristics. Then, some remarks for this thesis are noted.

6.1 Conclusions

In this study, a multi-layered oil reservoir model, reservoir conditions, fluid properties, operating constraint were set up by using ECLIPSE 100 reservoir simulator. The multi-segment well model and choke model were selected to model both the producers and injectors. Then a waterflooding process with downhole flow controls at injectors and producers was simulated.

Many simulations were performed to find the maximum oil production with minimum water production of each strategy. From the results, we can concluded as the following

1. Using downhole flow control in both injector and producer well in multi-layer reservoirs give a slightly higher oil recovery compared to recovery from a single intelligent injection and a single intelligent production. For the base case in which the permeability of the most permeable layer is about three times larger than the permeability of the least permeable layer but the difference in the oil recovery factor is very small. However, there is significant difference in the amount of water production. Downhole flow control help reduce water production by almost half as well as shorten the time to obtain the amount of oil production.
2. In multi-layered oil reservoirs. Water flooding using well control strategy gives more effective if the permeability contrast of layers is high.
3. In multi-layered oil reservoirs. Any contrast in porosity seems to have a little effect on oil recovery by using well control strategy.

6.2 Remarks

1. This thesis considers only the maximum oil production. Economic evaluation should be performed to find the best strategy in term of NPV.
2. The other factors such as the thickness of reservoir, distance between the layer, reservoir pressure, injection rate, etc. should be investigated for their effects on the waterflooding performance.

References

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APPENDIX

APPENDIX

ECLIPSE script for the base case of well model.

<u>RUNSPEC Section</u>

```
TITLE
Multilayered Water Flooding
 START
 1 'JAN' 2001 /
 FIELD
 GAS
 OIL
 WATER
 DISGAS
 NSTACK
 150 /
 MONITOR
 RSSPEC
 NOINSPEC
 MSGFILE
 1 /
 WSEGDIMS
 2 12 4 /
 DISPDIMS
 1 2 1 /
```

DIMENS

15 25 11 /

EQLDIMS

1 100 100 1 20 /

REGDIMS

1 1 0 0 /

TABDIMS

1 1 20 20 1 20 20 1 /

VFPPDIMS

10 13 5 5 8 4 /

WELLDIMS

3 19 3 3 /

<u>Grid Section</u>

ECHO

GRIDUNIT

-- Grid data units

'FEET' /

MAPAXES

-- Grid Axes wrt Map Coordinates

0 0 0 0 0 0 /

--*BOX panel edit: DX set equal to 100 ft for box (1:15, 1:25, 1:11)

--*BOX panel edit: DY set equal to 1 ft for box (1:15, 1:2, 1:11)

--*BOX panel edit: DY set equal to 1 ft for box (1:15, 24:25, 1:11)

--*BOX panel edit: DY set equal to 200 ft for box (1:15, 3:23, 1:11)

--*BOX panel edit: DZ set equal to 20 ft for box (1:15, 1:25, 1:11)

--*BOX panel edit: DZ set equal to 40 ft for box (1:15, 1:25, 4:4)

--*BOX panel edit: DZ set equal to 40 ft for box (1:15, 1:25, 8:8)

--*BOX panel edit: TOPS set equal to 5000 ft for box (1:15, 1:25, 1:11)

--*BOX panel edit: TOPS set equal to 5020 ft for box (1:15, 1:25, 2:11)

--*BOX panel edit: TOPS set equal to 5040 ft for box (1:15, 1:25, 3:11)

--*BOX panel edit: TOPS set equal to 5060 ft for box (1:15, 1:25, 4:11)

--*BOX panel edit: TOPS set equal to 5100 ft for box (1:15, 1:25, 5:11)

--*BOX panel edit: TOPS set equal to 5120 ft for box (1:15, 1:25, 6:11)

--*BOX panel edit: TOPS set equal to 5140 ft for box (1:15, 1:25, 7:11)

--*BOX panel edit: TOPS set equal to 5160 ft for box (1:15, 1:25, 8:11)

--*BOX panel edit: TOPS set equal to 5200 ft for box (1:15, 1:25, 9:11)

--*BOX panel edit: TOPS set equal to 5220 ft for box (1:15, 1:25, 10:11)

--*BOX panel edit: TOPS set equal to 5240 ft for box (1:15, 1:25, 11:11)

--*BOX panel edit: PORO set equal to 0.3 for box (1:15, 1:25, 1:3)

BOX

1 15 1 25 1 3 /

EQUALS

PORO 0.3 /

/

ENDBOX

--*BOX panel edit: PORO set equal to 0.01 for box (1:15, 1:25, 4:4)

BOX

1 15 1 25 4 4 /

EQUALS

PORO 0.01 /

/

ENDBOX

--*BOX panel edit: PORO set equal to 0.25 for box (1:15, 1:25, 5:7)

BOX

1 15 1 25 5 7 /

EQUALS

PORO 0.25 /

/

ENDBOX

--*BOX panel edit: PORO set equal to 0.01 for box (1:15, 1:25, 8:8)

BOX

1 15 1 25 8 8 /

EQUALS

PORO 0.01 /

/

ENDBOX

--*BOX panel edit: PORO set equal to 0.2 for box (1:15, 1:25, 9:11)

BOX

1 15 1 25 9 11 /

EQUALS

PORO 0.2 /

/

ENDBOX

--*BOX panel edit: PERMI set equal to 500 mD for box (1:15, 1:25, 1:3)

BOX

1 15 1 25 1 3 /

EQUALS

PERMI 500 /

/

ENDBOX

--*BOX panel edit: PERMI set equal to 0.001 mD for box (1:15, 1:25, 4:4)

BOX

1 15 1 25 4 4 /

EQUALS

PERMI 0.001 /

/

ENDBOX

--*BOX panel edit: PERMI set equal to 300 mD for box (1:15, 1:25, 5:7)

BOX

1 15 1 25 5 7 /

EQUALS

PERMI 300 /

/

ENDBOX

--*BOX panel edit: PERMI set equal to 0.001 mD for box (1:15, 1:25, 8:8)

BOX

1 15 1 25 8 8 /

EQUALS

PERMI 0.001 /

/

ENDBOX

--*BOX panel edit: PERMI set equal to 150 mD for box (1:15, 1:25, 9:11)

BOX

1 15 1 25 9 11 /

EQUALS

PERMI 150 /

```
/
ENDBOX
--*BOX panel edit: PERMJ set equal to 500 mD for box (1:15, 1:25, 1:3)
BOX
 1 15 1 25 1 3 /
EQUALS
PERMJ 500 /
/
ENDBOX
--*BOX panel edit: PERMJ set equal to 0.001 mD for box (1:15, 1:25, 4:4)
BOX
 1 15 1 25 4 4 /
EQUALS
PERMJ 0.001 /
/
ENDBOX
--*BOX panel edit: PERMJ set equal to 300 mD for box (1:15, 1:25, 5:7)
BOX
 1 15 1 25 5 7 /
EQUALS
PERMJ 300 /
/
ENDBOX
--*BOX panel edit: PERMJ set equal to 0.001 mD for box (1:15, 1:25, 8:8)
BOX
 1 15 1 25 8 8 /
EQUALS
```

```
PERMJ 0.001 /
/
ENDBOX
--*BOX panel edit: PERMJ set equal to 150 mD for box (1:15, 1:25, 9:11)
BOX
 1 15 1 25 9 11 /
EQUALS
PERMJ 150 /
/
ENDBOX
--*BOX panel edit: PERMK set equal to 50 mD for box (1:15, 1:25, 1:3)
BOX
 1 15 1 25 1 3 /
EQUALS
PERMK 50 /
/
ENDBOX
--*BOX panel edit: PERMK set equal to 0.001 mD for box (1:15, 1:25, 4:4)
BOX
 1 15 1 25 4 4 /
EQUALS
PERMK 0.001 /
/
ENDBOX
 --*BOX panel edit: PERMK set equal to 30 mD for box (1:15, 1:25, 5:7)
BOX
 1 15 1 25 5 7 /
```

EQUALS

PERMK 30 /

/

ENDBOX

--*BOX panel edit: PERMK set equal to 0.001 mD for box (1:15, 1:25, 8:8)

BOX

1 15 1 25 8 8 /

EQUALS

PERMK 0.001 /

/

ENDBOX

--*BOX panel edit: PERMK set equal to 15 mD for box (1:15, 1:25, 9:11)

BOX

1 15 1 25 9 11 /

EQUALS

PERMK 15 /

/

ENDBOX

--*BOX panel edit: ACTNUM set equal to 1 for box (1:15, 1:25, 1:11)

EQUALS

ACTNUM 1 /

/

SCAL Section

SWOF

-- Water/Oil Saturation Functions

0.2 0 1 0

0.3	0.03	0.7	0
0.4	0.08	0.49	0
0.5	0.14	0.29	0
0.6	0.24	0.14	0
0.7	0.37	0.04	0
0.8	0.55	0	0

/

SGOF

-- Gas/Oil Saturation Functions

0.05	0	1	0
0.1	0.022	0.68	0
0.2	0.06	0.43	0
0.3	0.12	0.21	0
0.4	0.2	0.08	0
0.5	0.32	0.019	0
0.6	0.51	0.006	0
0.7	0.72	0.002	0
0.8	1	0	0

/

PVT Section

--Water PVT Properties

2220 1.022902057192 3.157443e-006 0.30718992803032 3.878459391911e-007

/

PVDG

-- Dry Gas PVT Properties (No Vapourised Oil)

500 6.05057697662133 0.0125805143193829

888.888888888889 3.17370154268853 0.0138265094037136

1277.77777777778 2.07462839072016 0.0156149717094262

1666.66666666667 1.52046548114705 0.0179926429736342

2220 1.11813714732967 0.0221602633477397

2444.44444444444 1.02162680273003 0.0239698257808928

2857.36947221467 0.898043063854413 0.0272733876223496

3222.22222222222 0.824965508158336 0.0300642342606966

3611.11111111111 0.769066784118572 0.0328607397910261

4000 0.727437456325579 0.0354718966634022

/

PVTO

-- Live Oil PVT Properties (Dissolved Gas)

0.318752843446323 500 1.2433701 0.57139548124819

888.888888888889 1.2423701279297 0.57139548124819

1277.77777777778 1.22886748157994 0.574024947065444

1666.66666666667 1.22105511092636 0.598186967185781

2220 1.21469408472096 0.643388637706936

2444.44444444444 1.21294073119543 0.66492126178779

2857.36947221467 1.21043890906181 0.708931531315597

3222.22222222222 1.20876481982589 0.752277685896212

3611.11111111111 1.20735469339338 0.80280755980168

4000 1.20621995463119 0.857553334745035 /

0.427465175212219 888.888888888889 1.3007872 0.501252615476809

1277.77777777778 1.29978717133244 0.501252615476809

1666.66666666667 1.28427747409263 0.506740213713875

2220 1.27422662351354 0.538637442650019

2444.44444444444 1.27146086374001 0.554096282910405

2857.36947221467 1.26751795080497 0.585932956921744

3222.22222222222 1.26488185206318 0.617458928964414

3611.11111111111 1.26266282933952 0.654308409148117

4000 1.26087811464401 0.69428108188097 /

0.531765494570311 1277.77777777778 1.356874 0.452658914151618

1666.66666666667 1.35487398500137 0.452658914151618

2220 1.33447787213236 0.470386508650336

2444.44444444444 1.33052793491517 0.482284591292268

2857.36947221467 1.32490224864029 0.506996312647629

3222.22222222222 1.3211446566754 0.531622799541484

3611.11111111111 1.31798379018728 0.560511235820835

4000 1.31544303717185 0.591915379407272 /

0.638582850599918 1666.66666666667 1.41129018606791 0.414537892796431

2220 1.39923695390935 0.419251119230426

2444.44444444444 1.39384932922272 0.428704333105438

2857.36947221467 1.38618434267214 0.448525961586957

3222.22222222222 1.3810700904896 0.468422947831028

3611.11111111111 1.37677140222962 0.491863391528435

4000 1.37331830242642 0.517415437126588 /

0.799322742053861 2220 1.4981859 0.371180433259534

2444.44444444444 1.49618588441459 0.371180433259534

2857.36947221467 1.48284999885806 0.385642948161978

3222.22222222222 1.47528171267027 0.400851451901559

3611.11111111111 1.46892865773889 0.418896340721674

4000 1.4638308206434 0.438660510979188 /

0.868005148752306 2444.44444444444 1.53246089261607 0.356208721907602

2857.36947221467 1.52567647118862 0.364816909902042

3222.22222222222 1.51690319006408 0.37857108978318

3611.11111111111 1.50954303681346 0.394942716245958

4000 1.50364000386355 0.412913080156891 /

1 2857.36947221467 1.60217473261857 0.331676515225752

3222.22222222222 1.59898211975021 0.343225377111527

3611.11111111111 1.58946237635174 0.357059144641964

4000 1.58183492775389 0.372309157730511 /

/

DENSITY

-- Fluid Densities at Surface Conditions

53.0020924544493 62.4279737253144 0.0624279737253144

/

ECHO

ROCK

-- Rock Properties

2220 1.52989636834116e-006

/

<u>Schedule Section</u>

ECHO

WELSPECS

'INJ' '1' 8 1 1* 'WATER' 1* 'STD' 'SHUT' 'YES' 1* 'SEG' 3* 'STD' /

/

COMPDAT

'INJ' 8 1 1 1 'SHUT' 2* 0.249333333333333 3* 'Z' 1* /

/

COMPDAT

```
'INJ' 8 1 1 1 'SHUT' 2* 0.2493333 3* 'X' 1* /
 /
 COMPDAT
'INJ' 8 2 1 1 'SHUT' 2* 0.2493333 3* 'X' 1* /
 /
COMPDAT
'INJ' 8 2 1 2 'OPEN' 2* 0.2493333 3* 'Z' 1* /
 /
COMPDAT
'INJ' 8 1 2 5 'SHUT' 2* 0.2493333 3* 'Z' 1* /
 /
COMPDAT
'INJ' 8 1 5 5 'SHUT' 2* 0.2493333 3* 'X' 1* /
 /
COMPDAT
'INJ' 8 2 5 5 'SHUT' 2* 0.2493333 3* 'X' 1* /
 /
COMPDAT
'INJ' 8 2 5 6 'OPEN' 2* 0.2493333 3* 'Z' 1* /
 /
COMPDAT
'INJ' 8 1 6 9 'SHUT' 2* 0.2493333 3* 'Z' 1* /
 /
COMPDAT
'INJ' 8 1 9 9 'SHUT' 2* 0.2493333 3* 'X' 1* /
 /
COMPDAT
```

```
'INJ' 8 2 9 9 'SHUT' 2* 0.2493333 3* 'X' 1* /
 /
COMPDAT
'INJ' 8 2 9 10 'OPEN' 2* 0.2493333 3* 'Z' 1* /
 /
WELSPECS
'PRO' '2' 8 25 1* 'OIL' 1* 'STD' 'SHUT' 'YES' 1* 'SEG' 3* 'STD' /
 /
COMPDAT
'PRO' 8 25 1 1 'SHUT' 2* 0.2493333 3* 'Z' 1* /
 /
COMPDAT
'PRO' 8 25 1 1 'SHUT' 2* 0.2493333 3* 'X' 1* /
 /
COMPDAT
'PRO' 8 24 1 1 'SHUT' 2* 0.2493333 3* 'X' 1* /
 /
COMPDAT
'PRO' 8 24 1 2 'OPEN' 2* 0.2493333 3* 'Z' 1* /
 /
COMPDAT
'PRO' 8 25 2 5 'SHUT' 2* 0.2493333 3* 'Z' 1* /
 /
COMPDAT
'PRO' 8 25 5 5 'SHUT' 2* 0.2493333 3* 'X' 1* /
 /
COMPDAT
```

```
'PRO' 8 24 5 5 'SHUT' 2* 0.2493333 3* 'X' 1* /
 /
COMPDAT
'PRO' 8 24 5 6 'OPEN' 2* 0.2493333 3* 'Z' 1* /
 /
COMPDAT
'PRO' 8 25 6 9 'SHUT' 2* 0.2493333 3* 'Z' 1* /
 /
COMPDAT
'PRO' 8 25 9 9 'SHUT' 2* 0.2493333 3* 'X' 1* /
 /
COMPDAT
'PRO' 8 24 9 9 'SHUT' 2* 0.2493333 3* 'X' 1* /
 /
COMPDAT
'PRO' 8 24 9 10 'OPEN' 2* 0.2493333 3* 'Z' 1* /
 /
WELSEGS
'INJ' 5010 2* 'INC' 'HFA' 'HO' 2* /
2 3 1 1 100 100 0.2493333 0.000175 4* /
4 4 2 1 1 0 0.2493333 0.000175 4* /
5 6 2 4 20 20 0.2493333 0.000175 4* /
7 7 3 2 1 1 0.2493333 0.000175 4* /
8 9 3 7 20 20 0.2493333 0.000175 4* /
10 10 4 3 1 1 0.2493333 0.000175 4* /
11 12 4 10 20 20 0.2493333 0.000175 4* /
 /
```

```
WELSEGS
'PRO' 5010 2* 'INC' 'HFA' 'HO' 2* /
2 3 1 1 100 100 0.2493333 0.000175 4* /
4 4 2 1 1 0 0.2493333 0.000175 4* /
5 6 2 4 20 20 0.2493333 0.000175 4* /
7 7 3 2 1 1 0.2493333 0.000175 4* /
8 9 3 7 20 20 0.2493333 0.000175 4* /
10 10 4 3 1 1 0.2493333 0.000175 4* /
11 12 4 10 20 20 0.2493333 0.000175 4* /
 /
COMPSEGS
'INJ' /
8 1 1 2 0 1 'Y' 2 2* /
8 2 1 2 1 41 'Z' 2 2* /
8 1 2 1 0 100 'Z' 5 2* /
8 1 5 3 100 101 'Y' 2 2* /
8 2 5 3 101 141 'Z' 6 2* /
8 1 6 1 100 200 'Z' 9 2* /
8 1 9 4 200 201 'Y' 2 2* /
8 2 9 4 201 241 'Z' 10 2* /
 /
COMPSEGS
'PRO' /
8 25 1 2 0 1 'Y' 24 2* /
8 24 1 2 1 41 'Z' 2 2* /
8 25 2 1 0 100 'Z' 5 2* /
8 25 5 3 100 101 'Y' 24 2* /
```

```
8 24 5 3 101 141 'Z' 6 2* /
8 25 6 1 100 200 'Z' 9 2* /
8 24 9 4 200 201 'Y' 24 2* /
8 24 9 4 201 241 'Z' 10 2* /
 /
WCONINJE
'INJ' 'WATER' 'OPEN' 'RATE' 7000 5* /
 /
WCONPROD
'PRO' 'OPEN' 'ORAT' 5000 5* 400 3 1* /
 /
WECON
'PRO' 200 1* 0.9 10 1* 'WELL' 'YES' 1* 'RATE' 1* 'NONE' 2* /
 /
VFPPROD
1 5210 'LIQ' 'WCT' 'GOR' 'THP' 'BEAN' 'FIELD' 'BHP' /
100 300 500 700 900 1200 1500 2000 2500 3000 /
200 500 1000 1200 1500 1700 1900 2100 2300 2500 3000 3500 4000 /
0.1 0.3 0.5 0.7 0.9 /
1 /
2 4 8 12 16 24 32 64 /
1 1 1 1 21479.6 184564 495754 971398 1000000 1000000 1000000 1000000
1000000 1000000 /
2 1 1 1 21777.2 184852 496054 971698 1000000 1000000 1000000 1000000
1000000 1000000 /
3 1 1 1 22273.1 185333 496554 972198 1000000 1000000 1000000 1000000
1000000 1000000 /
```

4 1 1 1 22471.5 185525 496754 972398 1000000 1000000 1000000 1000000 1000000 1000000 /

.

.

.

10 5 1 8 2500.25 2500.25 2500.35 2500.68 2501.13 2502.01 2503.14 2505.59

2508.73 2512.57 /

11 5 1 8 3000.3 3000.3 3000.35 3000.68 3001.13 3002.01 3003.14 3005.57

3008.71 3012.54 /

12 5 1 8 3500.35 3500.35 3500.35 3500.68 3501.13 3502 3503.13 3505.56 3508.69

3512.52 /

13 5 1 8 4000.4 4000.4 4000.4 4000.68 4001.12 4002 4003.12 4005.55 4008.68

4012.5 /

VFPPROD

2 5210 'LIQ' 'WCT' 'GOR' 'THP' 'BEAN' 'FIELD' 'BHP' /

100 300 500 700 900 1200 1500 2000 2500 3000 /

200 500 1000 1200 1500 1700 1900 2100 2300 2500 3000 3500 4000 /

1 /

1 /

2 4 8 12 16 24 32 64 /

1 1 1 1 13501.9 90934.3 170017 223682 257089 285679 301183 314457 321006

324679 /

2 1 1 1 13789.9 91152.6 170164 223780 257158 285722 301212 314474 321017

324687 /

3 1 1 1 14269.9 91516.4 170409 223945 257273 285793 301260 314502 321036

324700 /

4 1 1 1 14462 91662 170507 224011 257318 285822 301279 314514 321043 324705

/

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10 1 1 8 2500.25 2500.25 2500.33 2500.64 2501.06 2501.89 2502.95 2505.25 2508.21 2511.82 /

11 1 1 8 3000.3 3000.3 3000.33 3000.64 3001.06 3001.89 3002.95 3005.24 3008.19 3011.8 /

12 1 1 8 3500.35 3500.35 3500.35 3500.64 3501.06 3501.89 3502.95 3505.24 3508.18 3511.78 /

13 1 1 8 4000.4 4000.4 4000.4 4000.64 4001.06 4001.88 4002.94 4005.23 4008.17 4011.77 /

VFPPROD

3 5010 'LIQ' 'WCT' 'GOR' 'THP' 1* 'FIELD' 'BHP' /

100 500 1000 2000 3000 4000 5000 6000 7000 8000 /

200 500 800 1200 1500 2000 2500 3000 4000 5000 /

0.1 0.3 0.5 0.7 0.9 /

0.1 0.5 1 1.5 2 /

0 /

1 1 1 1 2053.45 2047.98 2043.12 2074.41 2118.24 2168.78 2233.61 2308.87 2394.16 2488.89 /

2 1 1 1 2356.88 2361.91 2368.21 2397.79 2442.18 2492.6 2555.42 2629.4 2713.38 2807.13 /

3 1 1 1 2657.09 2662.34 2668.9 2695.64 2743.42 2794.95 2857.91 2932.66 3017.51 3112.19 /

4 1 1 1 3057.38 3062.91 3069.83 3093.46 3145.01 3198.4 3261.13 3336.89 3422.85 3518.74 /

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7 5 5 1 4528.98 4520.78 4520.31 4532.52 4555.57 4587.28 4626.89 4673.97

4731.16 4792.27 /

8 5 5 1 5020.05 5018.82 5021.91 5036.84 5060.78 5092.72 5132.17 5178.88

5232.71 5293.46 /

9 5 5 1 6016.32 6018.15 6022.85 6039.04 6063.48 6095.62 6135.15 6181.84

6235.51 6296.05 /

10 5 5 1 7026.29 7028.13 7032.82 7048.97 7073.33 7105.36 7144.74 7191.26

7244.74 7305.05 /

VFPPROD

4 5010 'LIQ' 'WCT' 'GOR' 'THP' 1* 'FIELD' 'BHP' /

100 500 1000 2000 3000 4000 5000 6000 7000 8000 /

200 500 800 1200 1500 2000 2500 3000 4000 5000 /

1 /

1 /

0 /

1 1 1 1 2379.45 2381.08 2385.21 2399.45 2420.91 2449.13 2483.82 2524.79

2571.89 2625 /

2 1 1 1 2681.43 2683.05 2687.18 2701.41 2722.85 2751.05 2785.71 2826.64

2873.69 2926.76 /

3 1 1 1 2983.41 2985.03 2989.16 3003.37 3024.79 3052.96 3087.59 3128.49

3175.5 3228.52 /

4 1 1 1 3386.05 3387.68 3391.8 3405.99 3427.39 3455.53 3490.12 3530.96

3577.92 3630.87 /

5 1 1 1 3688.04 3689.66 3693.78 3707.96 3729.34 3757.45 3792.01 3832.82

3879.73 3932.64 /

6 1 1 1 4191.37 4192.98 4197.1 4211.26 4232.6 4260.67 4295.18 4335.92 4382.77 4435.59 /

7 1 1 1 4694.7 4696.32 4700.42 4714.56 4735.88 4763.9 4798.35 4839.04 4885.81 4938.56 /

8 1 1 1 5198.04 5199.66 5203.76 5217.87 5239.16 5267.14 5301.54 5342.17 5388.87 5441.53 /

9 1 1 1 6204.76 6206.37 6210.46 6224.53 6245.75 6273.65 6307.95 6348.45 6395.01 6447.51 /

10 1 1 1 7211.52 7213.12 7217.2 7231.23 7252.39 7280.2 7314.39 7354.77 7401.19 7453.54 /

WSEGTABL

'INJ' 4 4 2 'F-' 'REV' 'NO' 64 /

'INJ' 7 7 2 'F-' 'REV' 'NO' 64 /

'INJ' 10 10 2 'F-' 'REV' 'NO' 64 /

'PRO' 4 4 1 'F-' 'REV' 'NO' 64 /

'PRO' 7 7 1 'F-' 'REV' 'NO' 64 /

'PRO' 10 10 1 'F-' 'REV' 'NO' 64 /

'INJ' 1 1 4 'FH' 'FIX' 'DEP' 1* /

'PRO' 1 1 3 'FH' 'FIX' 'DEP' 1* /

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VITAE

Rungarun Jungam was born on September 2, 1977 in Kampaengpetch, Thailand. He received his B.Eng. in Civil Engineering from the Faculty of Engineering, Sirindhorn International Institute of Technology, Thammasat University in 2000. After graduated, he worked for Asia Aluminum and Glass Co., Ltd. in Head of Design Department for seven years, then, moved to ASI Asiatic Co., Ltd. in Structural Engineer for 2 years. Nowadays he works at AAG Corporation Co., Ltd. as the Project Engineer together with study in the Master of Petroleum Engineering at the Department of Mining and Petroleum Engineering, Faculty of Engineering, Chulalongkorn University.