PLACEMENT OF INFLOW CONTROL VALVES FOR HORIZONTAL OIL WELL IN HETEROGENEOUS RESERVOIRS

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เสริมสุข ธนบรรเจิดสิน : การจัดวางวาล์วควบคุมการไหลในหลุมน้ำมันแนวนอนในแหล่งกักเก็บแบบวิวิธพันธ์ (PLACEMENT OF INFLOW CONTROL VALVES FOR HORIZONTAL OIL WELL IN HETEROGENEOUS RESERVOIRS) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: อ. ดร. ฟ้าลั่น ศรีสุริยชัย, อ.ที่ปรึกษาวิทยานิพนธ์ร่วม: ผศ. ดร. จิรวัฒน์ ชีวรุ่งโรจน์, 111 หน้า.

หลุมผลิตปิโตรเลียมแบบแนวนอนมีข้อได้เปรียบหลายประการเมื่อเปรียบเทียบกับหลุมผลิตแบบแนวตั้ง การเพิ่มพื้นที่สัมผัสของหลุมผลิตต่อแหล่งกักเก็บน้ำมันอาจจะนับได้ว่าเป็นเหตุผลแรกในการตัดสินใจเจาะหลุมประเภทนี้ อย่างไรก็ดีการเจาะหลุมผลิตแนวนอนในแหล่งกักเก็บน้ำมันที่มีค่าวิวิธพันธ์สูงจะส่งผลเสียคือการเข้ามาอย่างรวดเร็วของน้ำจากชั้นน้ำข้างใต้แหล่งกักเก็บ โดยน้ำจะซึมผ่านชั้นหินที่มีค่าความสามารถในการซึมผ่านสูงอย่างรวดเร็ว ทำให้เกิดการผลิตน้ำในปริมาณมากในบางช่วงของหลุมผลิต การติดตั้งวาล์วควบคุมการไหลในช่วงของหลุมผลิตแนวนอนสามารถบรรเทาปัญหาการเข้ามาอย่างรวดเร็วของน้ำได้ การปรับแต่งหลุมผลิตน้ำมันแนวนอนโดยการปรับค่าพารามิเตอร์ที่เกี่ยวข้องกับการผลิตให้เหมาะสม สามารถทำให้เกิดผลประโยชน์ทั้งในด้านของการเพิ่มการผลิตน้ำมันและการลดการผลิตน้ำ

ในการศึกษานี้ส่วนต้นของหลุมผลิตควรถูกวางในตำแหน่งที่มีค่าความสามารถในการซึมผ่านต่ำเพื่อชดเชยการเข้ามาของน้ำอย่างรวดเร็วซึ่งเกิดจากแรงเสียดทานของที่ผนังหลุม ภายหลังการเลือกตำแหน่งหลุมผลิตโดยเลือกเจาะผ่านด้านบนสุดของชั้นหินแหล่งกักเก็บเพื่อเพิ่มปริมาตรที่สามารถถูกผลิตของแหล่งกักเก็บ และเลือกอัตราการผลิตของเหลวทั้งหมดที่เหมาะสม หลุมน้ำมันจะถูกปรับแต่งเพื่อระบุวิธีคำนวนการแบ่งช่วงของการติดวาล์วจำนวนวาล์ว และตั้งค่าการปิดวาล์วจากสัดส่วนการผลิตน้ำที่เข้าสู่หลุมสูงสุด ตามลำดับ

ผลจากการจำลองการไหลในแหล่งกักเก็บแสดงให้เห็นว่า การแบ่งช่วงของการติดตั้งวาลว์ด้วยวิธีการคำนวณให้ค่าความสามารถในการส่งผ่านเฉพาะชั้นหินที่หลุมผ่านเท่าๆกันต่อวาล์วแต่ละตัว และติดตั้งวาล์วจำนวนมาก ก่อให้เกิดประโยชน์ทั้งการเพิ่มผลผลิตน้ำมันและลดการผลิตน้ำ นองจากนี้การตั้งค่าให้วาล์วปิดการทำงานจากสัดส่วนการผลิตน้ำที่เข้าสู่หลุมควรปรับแต่งให้อยู่ประมาณ 90 ถึง 95 เปอร์เซนต์ เทียบกับสัดส่วนการผลิตน้ำสูงสุดด้วยการใช้ค่าการปรับแต่งหลุมผลิตที่ดีที่สุดจะสามารถเพิ่มผลผลิตน้ำมันได้ถึง 11 เปอร์เซ็นต์ และสามารถลดปริมาณการผลิตน้ำถึง 16 เปอร์เซ็นต์ ในกรณีของแหล่งกักเก็บน้ำมันที่มีค่าวิวิธพันธ์ต่ำ ประโยชน์จากการติดตั้งวาล์วควบคุมการไหลจะไม่เด่นชัดเมื่อเทียบกับกรณีแหล่งกักเก็บน้ำมันที่มีค่าวิวิธพันธ์สูง เนื่องจากปัญหาการเข้ามาของน้ำในแหล่งกักเก็บที่มีค่าวิวิธพันธ์ต่ำนั้นไม่รุนแรงมากนัก

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SERMSUK THANABANJERDSIN: PLACEMENT OF INFLOW CONTROL VALVES FOR HORIZONTAL OIL WELL IN HETEROGENEOUS RESERVOIRS. ADVISOR: FALAN SRISURIYACHAI, Ph.D., CO-ADVISOR: ASST. PROF. JIRAWAT CHEWAROUNGROAJ, Ph.D., 111 pp.

Horizontal well yields several advantages compared to vertical well. Increasing exposure area is probably one of the first reasons to drill this type of well. However, when horizontal well is implemented in highly heterogeneous reservoir; water encroachment from underneath aquifer will permeate through high permeability zone, causing locally high water production. Installation of Inflow Control Valve (ICV) in particular sections can mitigate this early water production. Configuring horizontal well with proper operating parameters could yield benefits on both increment of oil recovery and reduction of produced water.

In this study, the heel side of horizontal section should be placed at low permeability region to compensate water encroachment due to friction loss inside production string. After placing horizontal well location on top layer of reservoir to increase as much as possible the drainage volume and fixing appropriate total liquid production rate, the well is configured to identify segment partitioning method, number of ICV, and pre-set water cut, respectively.

From simulation results, partitioning well segment by using well contact transmissibility with the highest number of ICV segments yields benefit on both oil and water productions. Moreover, pre-set watercut of each valve should be configured to terminate the operation at 90 to 95 percent of the maximum watercut value. By using the best ICV configuration, increment of 11% total oil produced can be obtained. At the same time, this configuration can reduce water production by 16%. In case of reservoir containing small value of heterogeneity, benefits from ICV installation is not as well-pronounced as reservoir with high heterogeneity as water encroachment problem is not severe in case of low heterogeneous reservoir.

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		Advisor's Signature	....
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List of Abbreviations

bbl/day	Barrel per day
BHP	Bottomhole pressure
cP	Centipoise
F or °F	Degree Fahrenheit
ft	Feet
ft^3/bbl	Cubic feet per barrel
GOR	Gas-Oil ratio
ICV	Inflow Control Valve
IWS	Irreducible water saturation
mD	Millidarcy
MMSTB	Million stock-tank barrel
OOIP	Original oil in place
psia	Pound per square inch absolute
psi/ft	Pound per square inch per feet
ppm	Part per million
PV	Pore Volume
PVT	Pressure-Volume-Temperature
ROS	Residual oil saturation
SCAL	Special core analysis
scf/stb	Standard cubic feet per stock-tank barrel
SGOF	Relative permeability of gas/oil system
STB/d	Stock-tank barrel per day

SWOF	Relative permeability of water/oil system

Nomenclatures

β	Reservoir anisotropy
$\Delta\rho$	Density difference
ΔP	Pressure drop from reservoir boundary to well bore
δ	Horizontal well eccentricity
μ_o	Oil viscosity
μ_w	Water viscosity
ρ	Density
B_g	Formation volume factor of gas
B_o	Formation volume factor of oil
c	Empirical constant for erosional velocity calculation
C_o	Corey-oil exponent
C_w	Corey-water exponent
h	Reservoir thickness
k	Absolute permeability
k_h	Horizontal permeability
k_{rg}	Relative permeability to gas
k_{ro}	Relative permeability to oil (Oil/Water function)
k_{rog}	Relative permeability to oil (Gas/Liquid function)
k_{rw}	Relative permeability to water
L	Horizontal well length
P	Pressure
p_m	Gas/liquid mixture density at flowing condition

q_o	Oil flow rate
q_{co}	Critical oil flow rate
r_{eh}	Drainage radius of horizontal well
R_s	Solution gas-oil ratio
r_w	Well bore radius
S_w	Water saturation
S_{wc}	Connate water saturation
S_{wcr}	Critical water saturation
S_{wi}	Initial water saturation (connate water saturation)
S_{wmin}	Minimum water saturation (irreducible water saturation)
S_{wmax}	Maximum water saturation
S_{orw}	Residual oil saturation (to water)
V_e	Fluid erosional velocity
y_e	Half drainage length

CHAPTER I

INTRODUCTION

1.1 Background

Intelligent completion is a leap frog development in petroleum industry. Technology of intelligent completion refers to down-hole measurement and control of down-hole production. This technology mainly uses to improve oil and gas recovery [1]. Together with intelligent completion, horizontal well technology is co-utilized since this type of well increases petroleum production by enhancing well/reservoir exposure [2]. In reservoir containing bottom water drive, horizontal well combined with intelligent completion technology is also used to prevent water cresting effect, a severe problem that does not cause only lowering of oil recovery but also environmental effect due to water disposal.

Water coning or water cresting (in horizontal well) is considered as a tremendous problem when reservoir pressure is inferiorly supported by strong aquifer. Initial production period obtains a great benefit from constant pressure from inferior boundary. However, as production period goes in long term, Oil-Water Contact (OWC) tends to approach wellbore, decreasing oil production rate remarkably by suddenly change to high water production, resulting in higher water cut.

As fluid flow in reservoir is due to pressure difference between reservoir pressure and wellbore pressure, in horizontal well, reservoir fluid in high transmissibility zone enters wellbore with higher flow rate compared to low transmissibility location. Heterogeneity of reservoir therefore contributes transmissibility variation.

Several preventions for water cresting phenomenon have been studied. Shut-in well is a simple choice that is totally safe but creates loss of oil production as time with no production is involved [3]. One of the modernized methods is installation Inflow Control Valve or so-called ICV. This tool has ability to control fluid flow rate in particular section of the well. At certain well configuration, this valve can be used to smoothen OWC. By this way, oil production can be extended without early water encroachment problem. ICV functions by downhole sensor; transferring downhole signals to surface. Surface decision is then made to trigger ICV through hydraulic control line. To date, maximum number of ICV installation are limited at 6 [2]. ICV can be subdivided in several types according to controlling steps 1) one/off or 2-step 2) 4 to10-step and 3) infinite-step. For the latter type of ICV, control can be made at any flow rate in any section of wellbore. However, simplification is made in this study and first type of ICV is utilized in this reservoir simulation study.

Installation of ICV in particular section of horizontal well results in several parameters required for adjustment such as number of ICV, water cut constrain of each valve, length of each section. In this study, the main focus is on optimization of ICV configuration to minimize water production and at the same time, to enhance oil production if possible. Study is performed by the use of black oil reservoir simulator ECLIPSE®100 commercialized by GeoQuest Schlumberger. Reservoir models are constructed to have heterogeneity involved. Proper length of horizontal well is calculated first based on reservoir parameters as well as designed operational parameters. Openhole horizontal well is first simulated and the best case resulting in highest oil recovery is defined as a reference case for comparison with ICV equipped cases. Three parameters related to operating of ICV are studied which are number of ICV, water cut constrain, length of each section, respectively. Oil recovery factor and total water production are mainly used as judgment criteria. Oil production rate, water production rate, water cut ratio, reservoir pressure, oil saturation profile and water saturation profile are also used to assist in discussion and analyzing phases.

1.2 Objectives

1. To propose appropriate suggestions for ICV installation including number of valves, segment length and individual pre-set water cut for each section.

2. To study effects of reservoir heterogeneity on effectiveness of horizontal well equipped with ICV installation.

1.3 Outline of Methodology

Outline methodology is summarized below. Details on thesis methodology are explained in Chapter 4.

1. Construct three reservoir models with low, moderate and high heterogeneities.

2. Perform reservoir simulation first on model with moderate heterogeneity case and select base horizontal well with appropriate flow rate together with well location (off-centered distance). The selected production rate and well location will be applied also for cases with low and high heterogeneity models.

3. Simulate each reservoir model, varying ICV operational parameters including segment length partitioning method, number of segment and pre-setting watercut.

4. Discuss results obtained from reservoir simulations for each studied parameter.

5. Summarize and conclude new findings from the study.

1.4 Outline of Thesis

This thesis is divided into six chapters as shown in the following outlines.

Chapter I introduces background of oil production in horizontal well with strong aquifer support and also objectives and study framework.

Chapter II reviews various literatures related to prevention of water cresting in horizontal well as well as literatures related intelligence completion.

Chapter III presents important concepts related to practical length and completion techniques of horizontal, performance of horizontal well, and configuration of intelligence completion.

Chapter IV provides details of physical properties of reservoir model, pressure-volume-temperature (PVT) properties of reservoir fluids, special core analysis data, and well data.

Chapter V presents results and discussion of simulation study for each interest parameters. The results are primarily focused on oil recovery factor and total water production. Within this section, 3D results such as oil and water saturation profiles are also included to assist discussion.

Chapter VI summarizes results into conclusions and also recommendations of further study.

CHAPTER II
LITERATURE REVIEW

This chapter reviews previous studies related to water encroachment problem into horizontal well. Moreover, improvement of horizontal well performance by means of installation of inflow control valve is also stated.

2.1 Application of Horizontal Well

Several investigators studied performance of horizontal well compared to vertical well in different ways.

Malekzadeh and Abdelgawad [4] performed an analytical method to determine well performance for both horizontal and vertical wells by using model with only one drainage area and three wells: active vertical well, active horizontal well and observation well. They evaluated this study by varying several parameters such as shape of drainage, total drainage area, ratio between vertical permeability and horizontal permeability and location of both active wells. The result indicated that horizontal well performed with higher performance compared to vertical well in certain situations such as low value of ratio of vertical to horizontal permeability, small drainage area, rectangular drainage shape with horizontal well placed along long side, thin and isotropic reservoir.

Rahim et al. [5] determined optimal well configuration to maximize productivity index by using simple analytical method to determine result between several scenarios such as horizontal well, vertical well and hydraulic fracturing well performed in oil or tight gas reservoir. After results were interpreted, they concluded that horizontal well was an optimum solution when reservoir is thin and isotropic. However, in case of tight gas reservoir, hydraulic fracturing was suggested to perform instead of other choices.

Wang et al. [6] studied horizontal well design and predicted well performance by using numerical simulator called "HVWELL" together with real field data. This study is performed in four different fields including heavy oil reservoir, thin oil rim with gas cap on top and aquifer at bottom, water injection in tight oil reservoir and water injection in high permeability gas reservoir with bottom aquifer. They concluded that horizontal well was advantageous over vertical well for example, productivity in oil reservoir was highly improved, coning effects of both gas and water phases were substantially reduced, gas rate was increased as well as period of plateau rate was extended in case of gas reservoir with short horizontal well. However, in case of oil reservoir, decline rate of oil production was higher in horizontal well compared to vertical well.

2.2 Water Encroachment Problem in Conventional Horizontal Well

Aquifer is one of the best pressure sources to support reservoir in oil production. However, water encroachment through cresting can occur. When this water reaches productive well, production of water can be in serious problem, causing shut in due to abundant of produced water in short period. Some studies were performed with an attempt to eliminate this problem during the situation is going on. An outstanding research was performed in Minagish field in West Kuwait.

The field was suffering from water encroachment problem from strong bottom aquifer. Al-Enezi et al. [7] therefore conducted a study to resolve this problem for a horizontal well which was located in this field. This study was performed by an analytical method to determine critical drawdown rate, critical production rate, size of coning, breakthrough time and shut-in time to wait until coning retreated back. Critical production rate which is the maximum rate that can still stabilize coning interface was too low, causing production to be lower than economical limit. Determination of the shut-in period was then accomplished and still, results did not improve well performance as shut-in period was too long. The optimal solution was then aimed for Inflow Control Device (ICD) completion. This method effectively controlled severe water cresting and also greatly improved oil recovery in this field.

2.3 Intelligent Completion in Horizontal Well

Nowadays, intelligent completion is mainly adopted to multilaterals well and also horizontal well. This completion technique has several applications varied in reservoir type and production strategy. In this section, several studies expressing major application of intelligent completion are summarized.

Ebadi et al. [8] studied optimization of intelligent completion in several reservoir types such as homogeneous reservoir, heterogeneous reservoir, reservoir containing faults, inclined reservoir with multiple layers, and heterogeneous reservoir with channeling systems. This study was conducted by numerical method to simulate reservoir models and all models were supported by strong bottom aquifer. This study summarized that intelligent completion added values to every reservoir type and it can be endured with geological uncertainty. However, in case of heterogeneous reservoir with channeling systems, they expressed the limitation to determine optimal placement of ICV because ICV must separately control the flow rate channel by channel. Due to heterogeneity and channeling, the way to locate ICV in exact position is impractical aspect.

Almutairi et al. [9] studied intelligent completion in thin oil rim reservoir with a gas cap and bottom aquifer. They utilized reservoir simulator to evaluate dynamic study of reservoir models exploited with three different completion schemes: openhole, intelligent completion without control of ICV and intelligent completion with 10-step ICV control. Parameters such as ICV arrangement, permeability distribution, choking procedure and distance between wellbore and oil-water contact were investigated. This work indicated that intelligent completion provided effective improvement in both production rate and management capability in thin oil rim reservoir with a gas cap and bottom aquifer, by using a strategy that aims to control water and gas breakthrough. The relative size and connectivity of both gas cap and aquifer must be determined to maximize effectiveness of intelligent well.

Jansen et al. [10] also studied intelligent well in thin homogeneous oil reservoir with gas cap and bottom aquifer by using numerical method. This study focused on comparison between two intelligent completion schemes which were a Smart Stinger Completion (SSC) and an Inflow Switching Process (ISP). The SSC was only one ICV at heel section and tubing was connected to ICV and extended to approximately middle of wellbore length. The ISP instead was series of ICVs along horizontal wellbore length and these valves were separated into sections by packers. In this reservoir simulation study, not only conventional horizontal well was simulated to be a base case but also ideal cases without friction loss along well length were used in comparison for both SSP and ISP cases. The result showed that, the case of wellbore with series of ICVs or ISP yielded higher long term well performance than ideal case. This well completion produced less both gas and water. Moreover, this study was performed on an economic analysis and the results showed that at the reservoir condition, ISP with three ICVs installed was an optimum intelligent completion scheme.

Ebadi and Davies [11] performed an optimization study on ICV placement in variety of reservoir heterogeneity, expressing in terms of correlation length for several well types such as vertical well, deviated well and horizontal well. The study showed several interesting results such as higher number of ICV was required in reservoir with high value of heterogeneity. Fewer added values to well were observed when only one ICV was installed along production segment. However, this study also suggested that optimum number of ICV in homogeneous should be only one.

According to these literature reviews, several interests concerning configuration of intelligent completion applied to horizontal well lead to further study, especially on appropriate number and spacing of sub-segment in heterogeneous reservoir. Moreover, additional configuration of each valve in terms of pre-set water-cut ratio results in more specification of this study.

CHAPTER III
THEORY AND CONCEPT

In this chapter, general information of parameters concerned in horizontal well design and its completion systems are provided. Concept of intelligent completion is explained in the last section in this chapter.

3.1 Practical Length of Horizontal Well

One of the most important practical factors in horizontal well design is well length. Horizontal well length can be varied from a few feet to several thousand feet. In case where the length is very long, cost per foot will be very high. In case of very short length, this could turn into uneconomical situation.

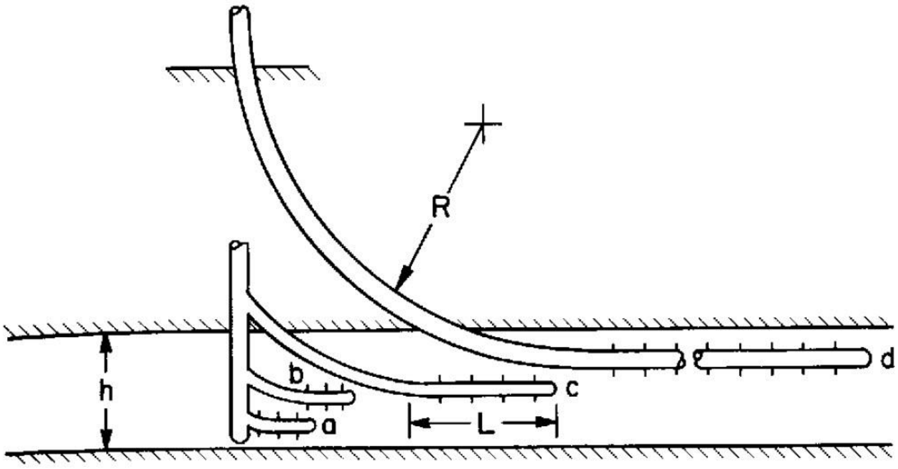


Figure 3.1 A schematic of difference drilling techniques [12] a) Ultra short radius, R = 1 – 2 ft, L = 100 – 200 ft, b) Short radius, R = 20 – 40 ft, L = 100 – 800 ft, c) Medium radius, R = 300 – 800 ft, L = 1,000 – 4,000 ft, and d) Long radius, R > 1,000 ft, L = 1,000 – 4,000 ft

Horizontal well that is drilled by medium turning radius is nowadays the most popular. Medium turning radius is around 300 ft to 800 ft as this turning radius is easy to perform by basic turning drilled tools and it is enable several conventional downhole tools to set in the well [12]. Several turning radius and practical horizontal length are shown in Figure 3. 1.

3.2 Completion Techniques for Horizontal Well

Horizontal well can be completed by several completion techniques. Most commonly used completion techniques are illustrated in Figure 3.2. However, not every radius of horizontal well that is possible to be completed with these completion techniques. There are just two radius types that are possible to be completed for every completion techniques which are medium and long turning radius [12].

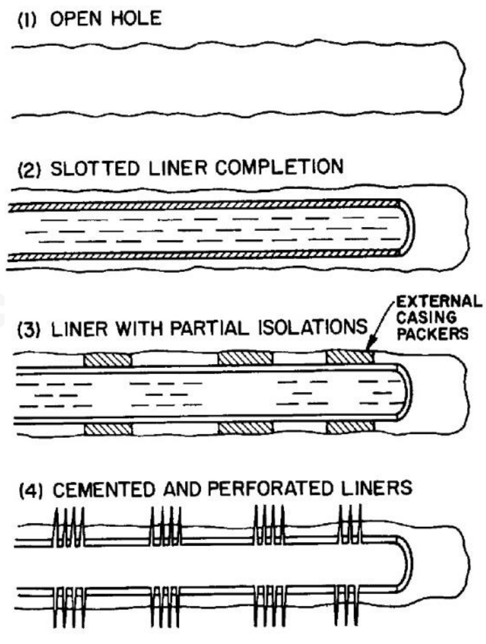


Figure 3.2 A schematic of various completion techniques for horizontal well [12]

From Figure 3.2, completion techniques for horizontal wells can be sub-divided into four types which are:

1) Openhole: this technique is the cheapest solution but it is strictly used in soft formation. Also controlling of production rate or injection rate along well length is not possible and it is not easy to perform well stimulation.

2) Slotted liner: this is more safe solution than the previous one as liner can prevent well collapse. Inside liner, various downhole tools can be set. A wire wrapped liner is very effective for sand control technique. However, controlling rate along the well length is not possible and also it is still difficult to stimulate the well.

3) Liner with partial isolation: this pattern is similar to slotted liner except it has external casing packer (ECP) set between liner and sand face. This method is used when separating well length into segments is required. However ECP is not easy to be set in the well length as practical horizontal well is bended or curvaceous.

4) Cemented and perforated liner: this method is suitable for various types of formation but it may be economical only for medium to long turning radius wells.This type of completion must be performed with less free water cement because high free water cement can cause poor cement job from effects of gravity segregation.

3.3 Steady-state Flow in Horizontal Well

In this study, reservoir pressure is supported by water drive that enables a simple analytical solution or steady-state flow, this solution describes flow rate from reservoir pressure at particular time. The steady-state occurs when pressure boundary reaches the aquifer and pressure boundary does not take long time to reach supporting pressure in thin reservoir, resulting in most of time production life to rely on steady-state flow regime.

Joshi reports his equation to predict the steady-state flow rate as shown below[12]

$$q_o = \frac{0.007078 k_h h \Delta p}{\mu_o B_o}\left[\frac{1}{ln\left(\frac{a+\sqrt{a^2-(L/2)^2}}{L/2}\right)+(h/L)ln(h/2r_w)}\right] \qquad (1),$$

$$a = \frac{L}{2}\left[0.5 + \sqrt{0.25 + (2r_{eh}/L)^4}\right] \quad (2),$$

where q_o= oil flow rate in STB/d,

k_h= horizontal permeability in mD,

h= reservoir thickness in ft,

Δp= pressure drop from reservoir boundary to wellbore in psi,

μ_o= oil viscosity in cP,

B_o= oil formation volume factor in RB/STB,

L= horizontal well length in ft,

r_w = wellbore radius in ft, and

r_{eh}= drainage radius of horizontal well in ft.

Note that this equation is suitable only for case of implementation in an isotropic reservoir (k_v= k_h), and horizontal well is drilled at the middle of formation bed.

However, in case of reservoir supported by water drive aquifer, changing location of well in vertical location results in different oil cut in long term which is affected from water crest phenomenon.

Placement of well upward or downward (in vertical direction) is called well eccentricity. Figure 3.3 illustrates diagram for eccentric well or off-centered well. Oil recovery can be gained or cut by changing well eccentricity value to be negative and positive respectively. However, in one time frame, either positive or negative well eccentricities result in reduction of oil production rate.

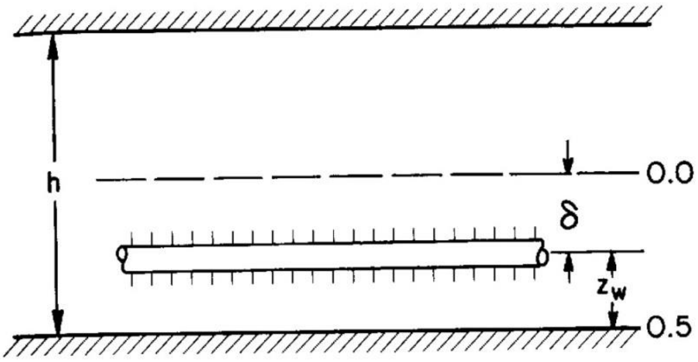


Figure 3.3 A schematic view of an off-centered horizontal well [12]

Oil flow rate is not only reduced by off-centered placement but also from reservoir anisotropy. That is reduction of vertical permeability from rock compaction, making difficulty for oil to permeate in vertical direction.

Two parameters which are off-centered well and reservoir anisotropy are included and reported in equation (3) [12]

$$q_h = \frac{0.007078 k_h h \Delta p}{\mu_o B_o}\left[\frac{1}{ln\left(\frac{a+\sqrt{a^2-(L/2)^2}}{L/2}\right)+(\beta h/L)ln\left(\frac{(\beta h/2)^2+\beta^2\delta^2}{\beta h r_w/2}\right)}\right] \quad (3),$$

where δ= horizontal well eccentricity in ft,

β= reservoir anisotropy or $\beta = k_v/k_h$.

Figure 3.4 compares productivities obtained from off-centered horizontal wells and centered well. Considering any value of eccentricity, longer horizontal well is less affected from water crest compared to shorter well. It can be concluded that at sufficiently long well, productivity is not significantly affected from well eccentricity.

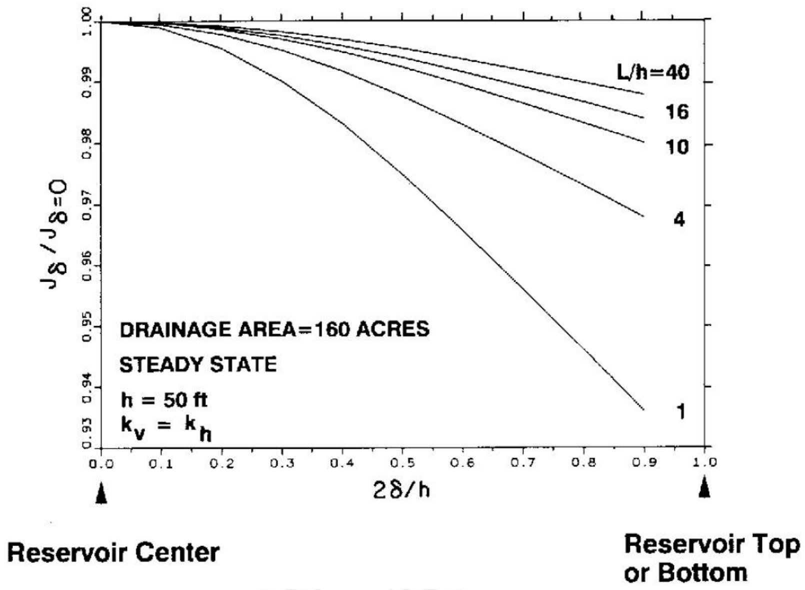


Figure 3.4 Influent of horizontal well eccentricity on productivity [12]

3.4 Water Cresting in Horizontal Well

Water cresting is mainly caused by pressure drawdown. Even horizontal well is less affected from water coning problem compared to vertical well, water encroachment problem is still severe in case of strongly water drive reservoir.

An interesting concept that can be used to mitigate water cresting effect is related to the critical rate. The critical rate is a flow rate that is sufficiently low enough to maintain fluid contact. Several studies of critical rate in horizontal well were performed. The Chaperon method is shown in following equations [12]

$$q_{co} = 4.888 \times 10^{-4} \frac{L}{y_e} \Delta\rho \frac{(k_h h)^2}{\mu_o B_o} F \quad for 1 \leq \alpha'' < 70 \; and \; 2y_e < 4L \tag{5),}$$

$$\alpha'' = (y_e/h)\sqrt{k_v/k_h} \tag{6),}$$

$$F = 3.9624955 + 0.0616438\alpha'' - 0.000540(\alpha'')^2 \tag{7),}$$

where q_{co} = critical rate in STB/d,

y_e = half drainage length (perpendicular to the horizontal well) in ft,

$\Delta\rho$ = density difference in g/cc, and

F = dimensionless function tabulated.

3.5 Intelligent Completion

As literature reviews mention that intelligent completion relies on petrophysical information around the wellbore from a downhole sensor. The downhole sensor can be divided in many types such as pressure sensor, temperature sensor, phase sensor and flow meter [13].

Information of petrophysical properties and downhole sensor are like a "soft tool", using to acquire necessary information for productive decision. An execution is a step after decision, working by a "hard tool" which is mainly related to controlling flow rate in each section of the wellbore. Zonal isolation packer acts like a wall to divide wellbore into several sections and each Inflow Control Valve (ICV) acts like a door to control flow rate between inside and outside tubing. The configuration of zonal isolation packer and the ICVs are shown in Figure 3.5.

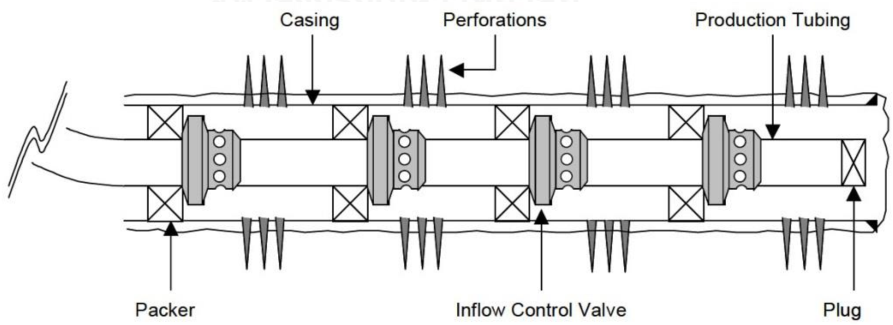


Figure 3.5 A schematic view of the intelligent completion [13]

The ICVs have various types of controlling step. In this study, two-step (on/off) ICV is placed in each zone, working in a two-phase downhole sensor to acquire water cut value zone by zone.

3.6 Reservoir Heterogeneity

Permeability is a property that is mostly concerned for calculation of heterogeneity. Heterogeneity index can be calculated in Lorenz coefficient proposed by Schmalz and Rahme or coefficient of variation proposed by Dykstra and Parson. Coefficient of variation of permeability is a statistical parameter defined to indicate level of heterogeneity in terms of permeability of the formation. To obtain this parameter, the log-normal plot between permeability and cumulative frequency of each permeability data is required and straight line that fit the most to the data set is drawn [14]. After acquiring fitting trend line, coefficient of variation of permeability is calculated from

$$V = \frac{k_{50} - k_{84.1}}{k_{50}} \tag{8},$$

where V = The Dykstra and Parson coefficient of variation of permeability,

k_{50} = Average permeability from fitting line, and

$k_{84.1}$ = Permeability above average by one standard deviation.

This coefficient ranges from zero for homogeneous reservoir to unity for extreme heterogeneous reservoir. Range of heterogeneity in log-normal plot is depicted in Figure 3.6.

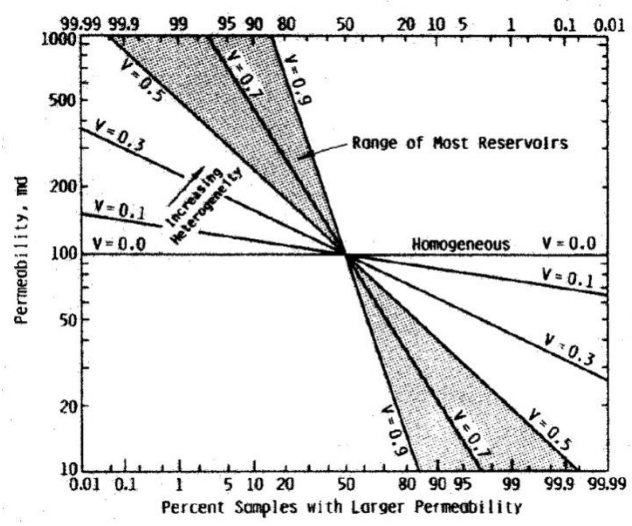


Figure 3.6 The variation of coefficient of variation of permeability shown on a plot between permeability as a function of percent samples with larger permeability [14]

It is observe that magnitude of permeability is interrelated with effective porosity when grain size is the same. Relationships of porosity and permeability of sandstone reservoir are investigated during study of the petrography and diagenetic history in Bassfield, Hosston [15]. This reservoir consists of thick red sandstone and some of shale sequence at 3,300 feet depth and deposition was occurred in alluvial environment.

The plot illustrating relationships between porosity and permeability is illustrated in Figure 3.7. Cores were taken from three different sands.

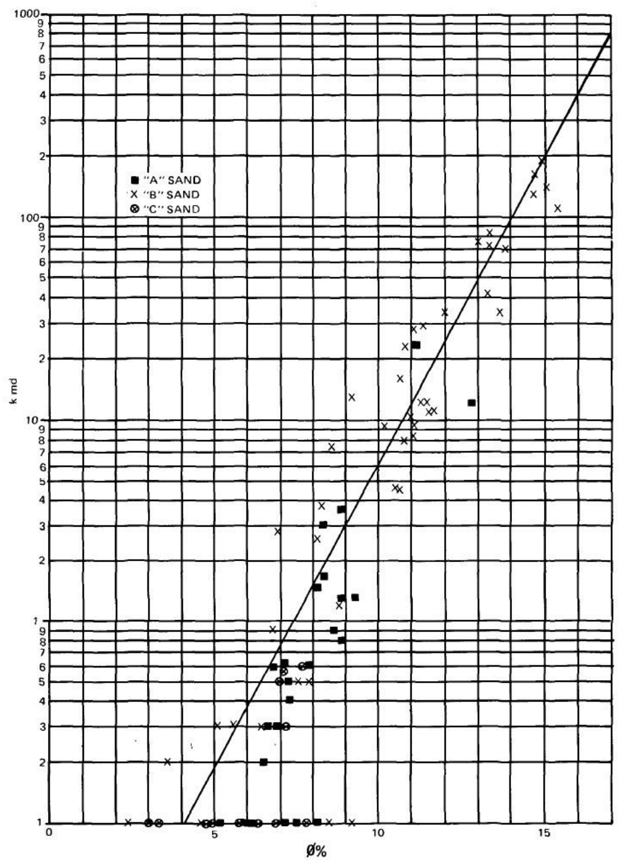


Figure 3.7 Plot illustrating relationships between porosity and permeability [15]

Correlation of these two parameters was calculated by fitting into Log-function and shown in equation 8

$$\phi = \frac{2.252094 + logk}{30.3246} \quad (9),$$

where ϕ = porosity (fraction), and

k = permeability (mD).

CHAPTER IV
RESERVOIR SIMULATION MODEL

Details of reservoir model are described in this chapter. Simulation of all study cases is conducted using black oil simulator ECLIPSE®100, commercialize by GeoQuest, Schulumberger. Horizontal well drilled in reservoir supported by strong aquifer is studied.

This chapter also contains details of base case model, rock properties, fluid properties, and petrophysical properties. Moreover, completion model for horizontal well as well as friction inside tubing are explained in this chapter.

4.1 Reservoir Physical Models

Reservoir model is constructed into three different patterns, characterized by reservoir heterogeneity. Reservoir heterogeneity of these models is mainly aimed on permeability and porosity.

4.1.1 Physical Properties of Reservoir Model

Reservoir models are constructed as shown in Figure 4.1, illustrating side view of model which is oil bearing zone with dimensions of 625×6,000×100 feet and number of blocks of 25×120×20 blocks in x, y and z direction, respectively. Each grid is block-centered with Cartesian coordinate. The datum depth is set at top surface of the model at 6,000 ft. The oil bearing zone is set along the topmost layer to the 20^{th} layer which is in contact with supporting aquifer from 21^{st} to 26^{th} layers. Size of aquifer is fixed at 50 times of pore volume in oil bearing zone. Table 4.1 concludes several physical parameters required for constructing physical model. Based on the grid block size, inclination of permeable layers is 11.3° to horizontal plane. As reservoir model is constructed as heterogeneous model, permeability increases along Y-direction from the minimum value of 22.6 to maximum of 870 mD. Method used for constructing heterogeneous model is explained in the following section. In this study, supporting aquifer is served as source of drive mechanism for oil bearing zone and details of aquifer block dimension are summarized in Table 4.2.

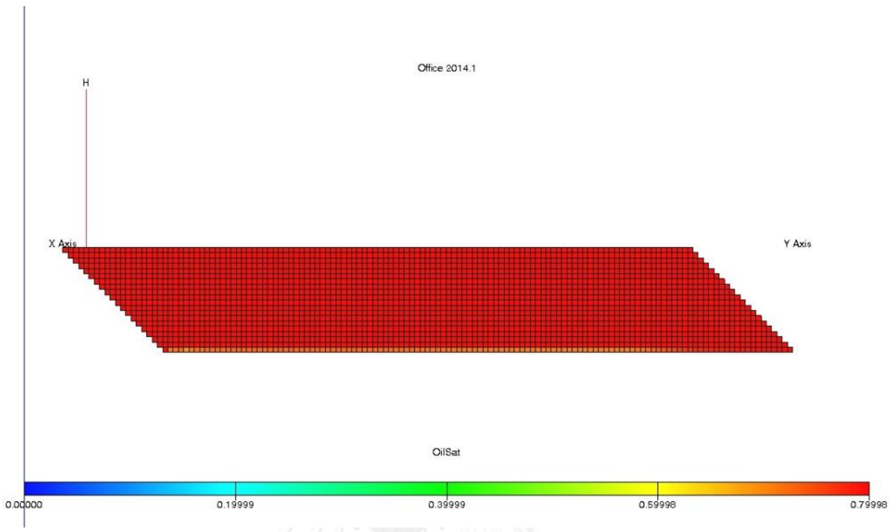


Figure 4.1 Side view of reservoir model

Table 4.1 Summary of important physical reservoir properties

Parameters	Values	Unit
Grid dimension of oil bearing zone	25×120×20	Block
Grid size of oil bearing zone	25×50×5	ft
Average porosity (ϕ_{eff})	14.327	%
Horizontal permeability (k_h)	Vary from 22.6 to 870	mD
Vertical permeability (k_v)	$0.1\times k_h$	mD
Top of reservoir (Reference depth)	6,000	ft
Thickness of oil bearing zone	100	ft

Table 4.1 Summary of important physical reservoir properties (continued)

Parameters	Values	Unit
Initial oil saturation (S_{oi})	80	%
Initial Pressure at datum depth	2,600	psia
Reservoir temperature	200	^{o}F
Initial bubble point pressure (P_b)	450	psia
Total production time	20	years

Table 4.2 Physical properties of supporting aquifer

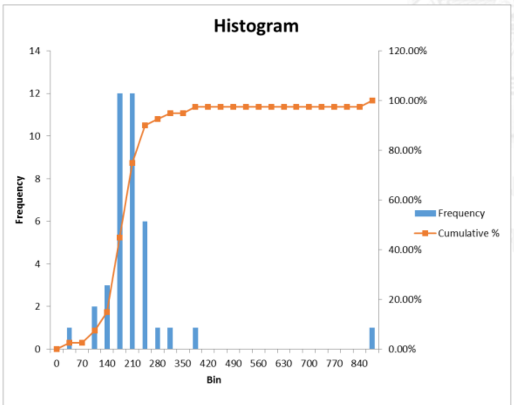
Parameters	Values	Unit
Aquifer volume (compared to oil bearing zone)	50	PV
Overall aquifer bearing size	625×6,000×5,000	ft
Aquifer layer	21^{st} – 26^{th}	layer

4.1.2 Variation of Permeability and Porosity

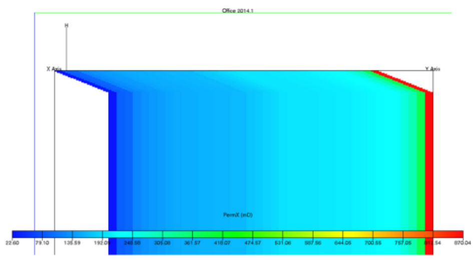
As heterogeneity is varied this study so both of permeability and porosity which are interrelated to each other, are assigned for each model. And in order to make all three cases comparable to each other, total flow capability and total liquid storage are kept constant by maintaining average porosity and permeability. To achieve the equivalent total flow capability, each model is constructed with 40 permeability layers, by using the log-normal distribution. Average horizontal permeability is fixed at 200 mD and permeability values range from 22.6 to 870 mD. Table 4.3 displays input parameters for each case and distributions of 40 permeability values are illustrated in Figures 4.2, 4.3 and 4.4 for three models with different heterogeneities.

Table 4.3 Input parameters for generating variation of permeability for model with different heterogeneities

Parameters	Moderate	Low	High
Average horizontal permeability	200 mD		
Permeability Max, Min	870 and 22.6 mD		
SD	250 mD	50 mD	400 mD

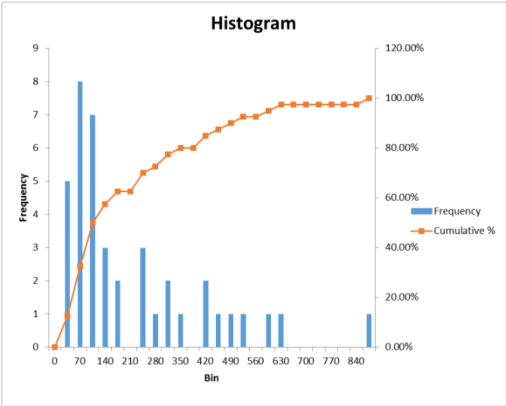


a)

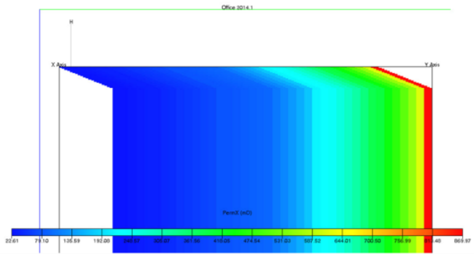


b)

Figure 4.2 Permeability data of reservoir model with low value of heterogeneity: a) distribution of permeability values and b) Variation of permeability assigned in reservoir model

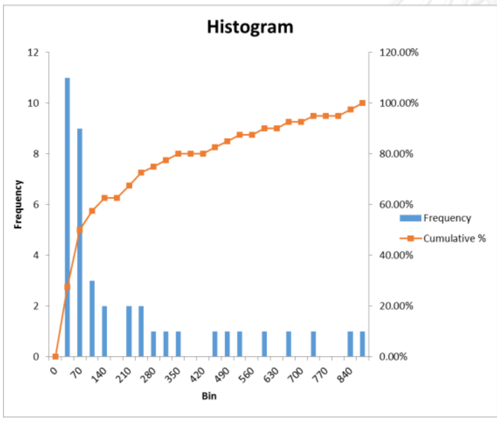


a)

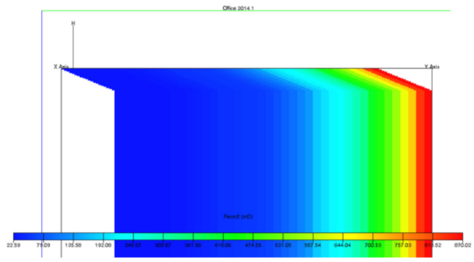


b)

Figure 4.3 Permeability data of reservoir model with moderate value of heterogeneity: a) distribution of permeability values and b) Variation of permeability assigned in reservoir model



a)



b)

Figure 4.4 Permeability data of reservoir model with high value of heterogeneity: a) distribution of permeability values and b) Variation of permeability assigned in reservoir model

From previous chapter in section 3.6, porosity is calculated based on value of permeability by log – function. In case of moderate heterogeneity, porosity of each block is calculated from this relationship:

$$\phi = {}^{(-a + \log k)}/_{b} \,.$$

However, for other two cases (low and high values of heterogeneities) where this relationship will result in difference liquid storages, modification of log-function is required. Table 4.3 summarizes modified values of constant –*a* and *b* for all cases to maintain average porosity to be constant.

Table 4.4 Summary of constants required to maintain average porosity in all cases

Parameters	Moderate	Low	High
-a	2.252094	2.197245	2.335535
B	30.3246	31.03755	30.21543
Average porosity		0.1432735	

Heterogeneity value is calculated from both porosity and permeability in each case by using the Dykstra-Parsons coefficient to demonstrate level of heterogeneous. Figure 4.5 depicts the plots of heterogeneity of these three cases. The heterogeneity values are 0.380, 0.697 and 0.753 for low, moderate and high heterogeneity case, respectively.

From the plot, Y-axis of each data point is determined as a single permeability value from specified permeability layer, whereas X-axis is acquired from percentage of number permeability layers that have higher permeability than permeability at specified data point. As each heterogeneous model has 40 permeability layers, the data points in each model are also as same as number of permeability layer. Three data set of each heterogeneous model are mapped in the same plot, and then equation that is able to draw the most fitted straight line to each model is identified.

After equation for each model is obtained, the coefficient of variation of permeability is being calculated from equation 8.

$$V = \frac{k_{50} - k_{84.1}}{k_{50}} \tag{8}$$

Equation fitted to each plot is illustrated in Figure 4.5. Together with these equations, the coefficients of variation of permeability of each heterogeneous model are also calculated and displayed.

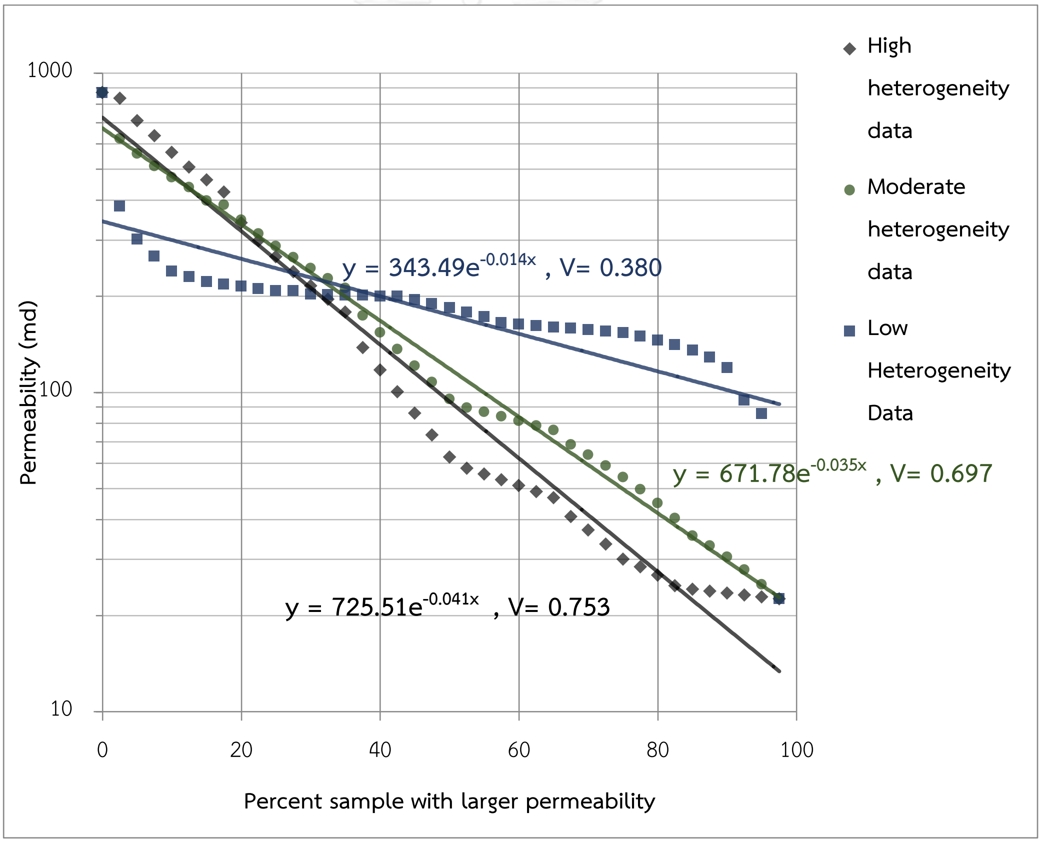


Figure 4.5 Relationship between permeability values as a function of percent sample with lager permeability for determination of Dykstra-Parson coefficient of variation

4.2 Pressure-Volume-Temperature (PVT) Properties

PVT properties of reservoir models are indicated by selecting appropriate correlations provided in PVT section of Eclipse simulator. List of correlation used is summarized in Table 4.5.

Table 4.5 Summary of PVT correlations used in the study

PVT Properties	Correlations by type of reservoir component			
	Oil	**Water**	**Gas**	**Rock**
Viscosity	Beggs	Meehan	Lee	-
FVF	Standing	Meehan	Ideal gas	-
Compressibility	$>P_b$ Vasquez $\leq P_b$ MacCain	Meehan	-	Newman
R_s	Standing	-	-	-
P_b	Standing	-	-	-
Z factor	-	-	Hall and Yarborough	-
Critical properties	-	-	Thomas et alia	-

In order to construct PVT properties, reasonably input data are required. These required data are summarized in Table 4.6.

Table 4.6 Input data required for generating PVT properties

Parameter	Values	Unit
Oil gravity	45	°API
Gas gravity	0.7	fraction
Bubble point (P_b)	450	Psia
Water salinity	1,000	ppm
Reservoir temperature	200	°F
Reference pressure (P_{ref})	2,600	psia

Since most PVT properties are function with pressure, Figures 4.6 and 4.7 illustrating oil and gas properties are there for plotted as a function of pressure, repectively. PVT properties of water together with compressibility of rock formation are summarized in Table 4.7.

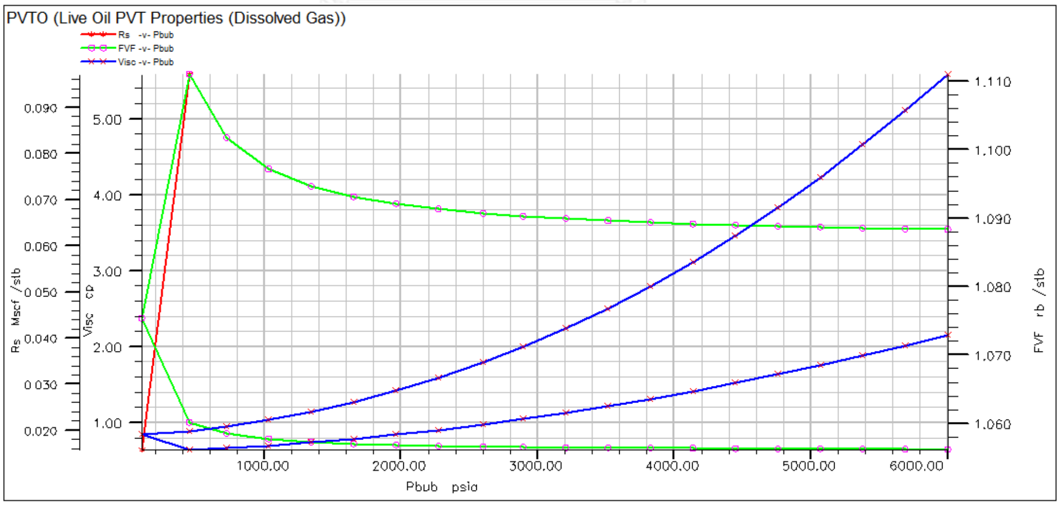


Figure 4.6 PVT properties of live oil including solution gas-oil ratio, oil viscosity and formation volume factor as a function of bubble point pressure

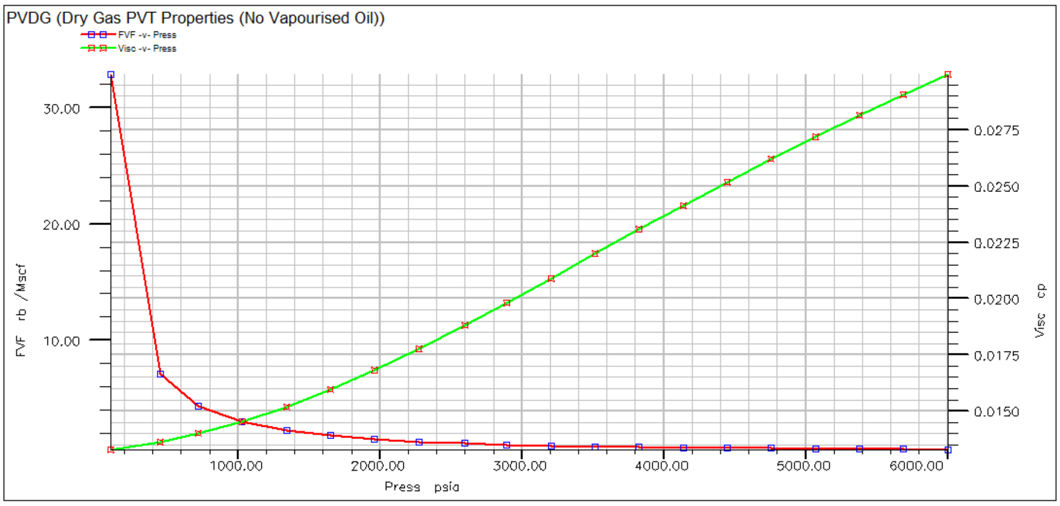


Figure 4.7 PVT properties of dry gas including formation volume factor and viscosity as a function of reservoir pressure

Table 4.7 PVT properties of water and formation

Properties	Values	Unit
Water FVF at P_{ref}	1.02233	Rb/STB
Water viscosity at P_{ref}	0.3009445	cP
Water compressibility	3.128539×10^{-6}	psi^{-1}
Water viscosibility	2.969812×10^{-6}	psi^{-1}
Rock compressibility	3.653216×10^{-6}	psi^{-1}

4.3 Petrophysical Properties

Relative permeability plays an important role in fluid flow ability as well as fluid distribution inside reservoir. The flow through each grid block of each phase is defined by effective permeability, this value varies by oil/water/gas saturation in those blocks. Thus, the aim of this section is to develop relative permeability for individual phase in a presence of other immiscible phases.

Relative permeability function of this model is generated from Corey's correlation. This correlation requires end point data of each fluid phase inside reservoir and the exponent value called Corey's exponent to describe the curvature between each pair of end point data.

As sandstone formation is mostly found water-wet in nature and it is selected in this study, the SCAL data is therefore based on ordinary sandstone petrophysical properties. Since this model does not emphasize on transition of fluid contact, therefore effects from capillary pressure is neglected. Table 4.8 summarizes input data, used for generating relative permeability curves by means of Corey's correlation.

Table 4.8 Required data for constructing relative permeability curve by Corey's correlation

Water		Gas		Oil	
Properties	Values	Properties	Values	Properties	Values
Corey water	2	Corey gas	2	Corey oil/water	2
S_{wmin}	0.2	S_{gmin}	0	Corey oil/gas	2
S_{wcr}	0.2	S_{gcr}	0.05	S_{org}	0.15
S_{wi}	0.2	S_{gi}	0	S_{orw}	0.2
S_{wmax}	1	k_{rg} at S_{org}	0.45	k_{ro} at S_{wmin}	0.45
k_{rw} at S_{orw}	0.3	S_{rg} at S_{gmax}	1	k_{ro} at S_{gmin}	0.45
$k_{rw}stS_{wmax}$	1				

Two sets of relative permeability functions are generated from data in Table 4.6 which are relative permeability curves of water/oil system (SWOF) and gas/oil system (SGOF). SWOF sampling data point and plot are shown in Table 4.9 and Figure

4.8 respectively, whereas SGOF sampling data point and plot are illustrated in Table 4.10 and Figure 4.9 respectively.

Table 4.9 Sampling data point of relative permeability curves of water/oil system

S_w	k_{rw}	k_{ro}
0.2000	0	0.4500
0.2667	0.0037	0.3556
0.3333	0.0148	0.2722
0.4000	0.0333	0.2000
0.4667	0.0593	0.1389
0.5333	0.0926	0.0889
0.6000	0.1333	0.0500
0.6667	0.1815	0.0222
0.7333	0.2370	0.0056
0.8000	0.3000	0
1.0000	1.0000	0

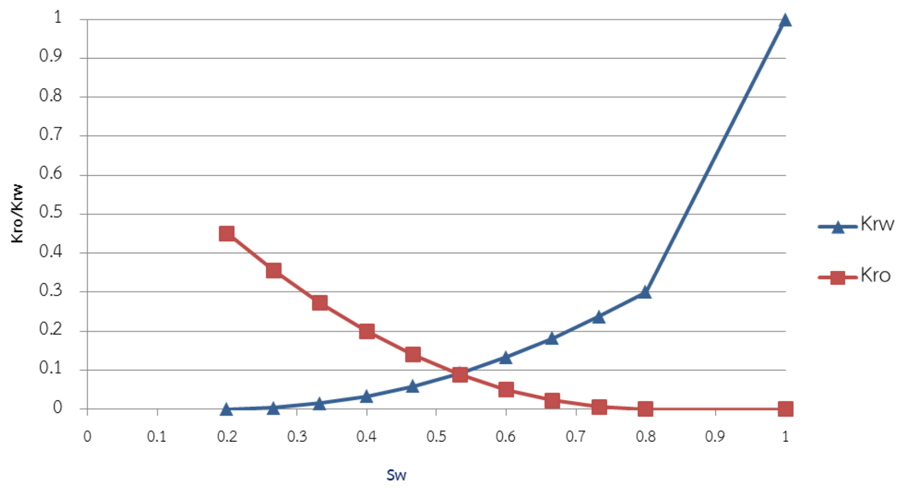


Figure 4.8 Relative permeability curves of water/oil system

Table 4.10 Sampling data point of relative permeability curves of gas/oil system

S_g	k_{rg}	k_{ro}
0	0	0.4500
0.0500	0	0.3834
0.1250	0.0070	0.2936
0.2000	0.0281	0.2157
0.2750	0.0633	0.1498
0.3500	0.1125	0.0959
0.4250	0.1758	0.0539
0.5000	0.2531	0.0240
0.5750	0.3445	0.0060
0.6500	0.4500	0
0.8000	1.0000	0

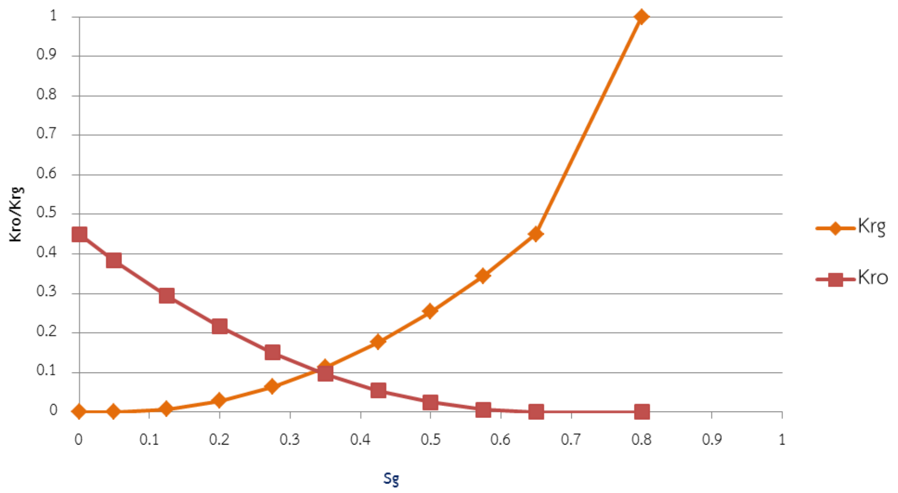


Figure 4.9 Relative permeability curves of gas/oil system

4.4 Well Geometry and Well Completion

Wellbore radius is set at 6-1/8 inch or 0.51 feet and tubing is run from surface through the length of horizontal well with diameter of 5 inch (N-80). For pay zone, completions between simple horizontal well case and case equipped with ICV are differentiated. Well length is set at 5,500 feet.

Friction along well length is crucial in this study as it may cause non-uniform pressure drawdown and consecutively local water cresting. The absolute roughness of liner is set to be 0.0072 feet. Friction is calculated segment by segment during flow of fluid inside production string. Segment length is assigned equally one grid block size in y-direction or 50 feet. Flow model inside segment is set to be homogeneous mode, and pressure loss during fluid flow consists of hydrostatic loss, friction loss and acceleration loss.

Maximum production rate allowed of this completion is 10,000 STB/d. Minimum bottomhole pressure is fixed at 500 psia. The economic limit of well are minimum oil rate of 100 STB/d or 95% watercut. Concession period is fixed at 20 years but simulation could terminate before if one of economic limits is attained.

4.4.1 Openhole with Perforated String Completion

From aerial view, horizontal section is drilled parallel to the long side of reservoir or y-direction. Initially, the well is set as central as possible in x-z direction. Drill path of horizontal well is shown in Figure 4.10. For the simplest base case, 5-inch outside diameter perforated string with 4.0126-inch or 0.334383 feet inside diameter is completed along the well.

The input data for numerical model are in the form of keywords. The keyword itself has several groups and methods for inserting data. Details of simulation keywords related to this section are summarized in appendix. Table 4.11 summarizes list of keywords associated with this case and Figure 4.11 shows diagram of well connection inside simulator.

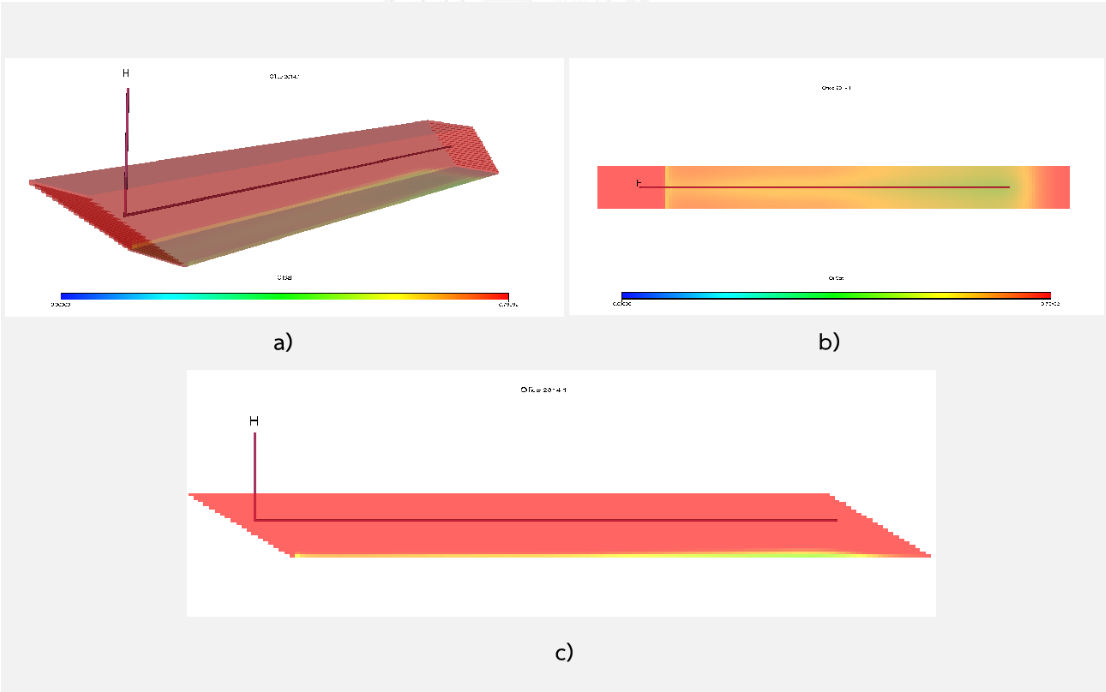


Figure 4.10 Horizontal well path in a) 3-D view, b) top view and c) side view

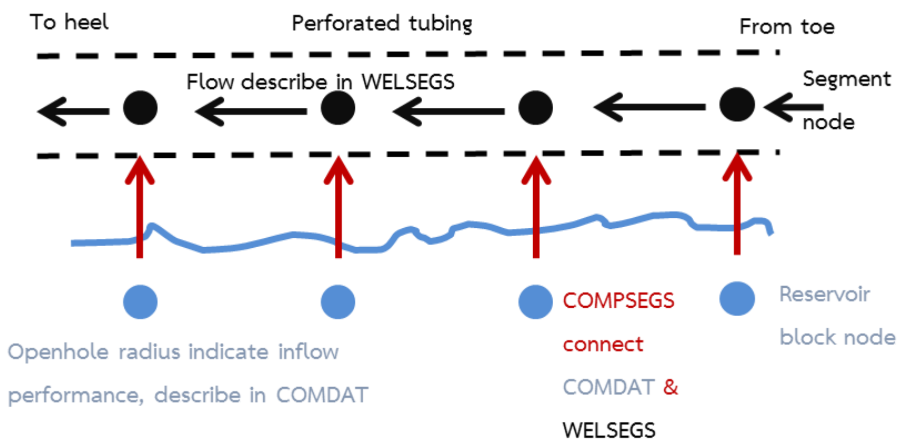


Figure 4.11 Well connection inside simulator for openhole well completed with perforated string

Table 4.11 Well completion keywords associated with openhole well completed with perforated tubing

Keywords	Properties	Main parameters
WELSPECS	State well name and well start location	Well name H Location (I, J) = 13, 5 Datum depth = 6,000 ft Allow cross flow Density by segment
COMPDAT	Describe well connection for fluid flow into completion system	Well length 5,500 ft, Well off-centered distance = vary See more on Appendix
WELCONPROD	State production policy	Control by liquid rate Maximum rate = vary BHP target constant at 500 psia
WECON	State production economic limit	Minimum oil rate 100 STB/d Maximum water cut 0.95 STB/STB
WELSEGS	Define cord of well segment	Multi segments with friction along each segment See more on Appendix
COMPSEGS	Connect WELSEGS to COMDAT	See more on Appendix

4.4.2 Openhole with Production String Equipped with ICV

Completion with ICV is deviated from previous case. However, connection from reservoir is not directly connected with production string but separated by ICV. Instead of flowing passes through perforated tubing and then flow inside tubing to heel section, the model requires fluids to flow inside annulus before ICV and then tubing.

The keywords are more complicated compared to previous case. First, two new keywords WSEGVALV and WELSEGLINK are introduced to this section. Also in WELSEGS, amount of segment is increased to be longer than two times of base case due to half of this has to be preserved for flow in annulus between borehole and tubing. In COMPSEGS, instead of connecting every segment from WELSEGS to COMPDAT, pairing will complete only annulus segment in case of ICV. Table 4.12 shows updated list of keywords associated with installation of ICV and Figure 4.12 shows the diagram of well connection inside simulator.

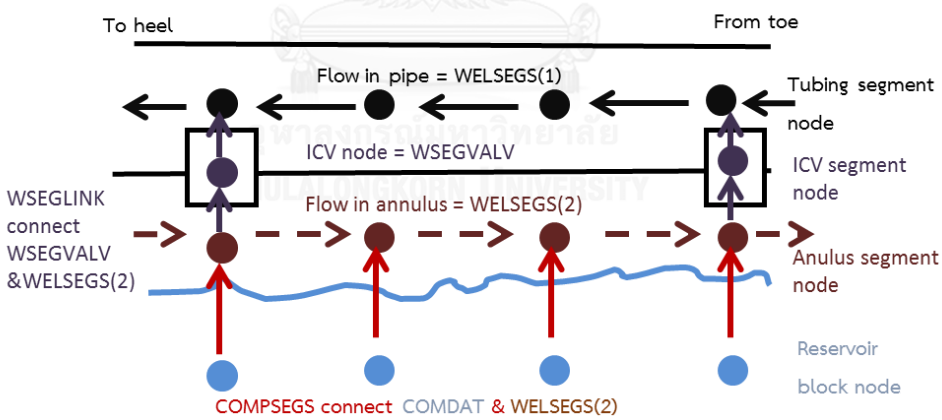


Figure 4.12 Well connection inside simulator for openhole well completed with tubing equipped with ICV

ICVs are automatically operated by setting of three input values; 1) initial watercut, 2) increment of watercut for re-opening in percentage, and 3) final watercut. ICVs are shut-in and re-opened based on these three parameters.

Operation flow chart of each ICV in Figure 4.13 illustrates production policy of ICV in each time step.

Table 4.12 Well completion keywords associated with openhole well completed tubing equipped with ICV

Keywords	**Properties**	**Main parameters**
WELSPECS	State well name and well start location	Same as previous case
COMPDAT	Describe well connection for fluid flow into completion system	Well length 5,500 ft, Selected off-centered distance from previous case, See more on Appendix
WELCONPROD	State production policy	Control by liquid rate Maximum rate is selected from previous case, BHP target same as previous case
WECON	State production economic limit	Same as previous case
WELSEGS	Define cord of well segment	More multi segments with friction along each segment See more on Appendix
COMPSEGS	Connect WELSEGS to COMDAT	See more on Appendix
WSEGVALV	Define ICV inside range of WELSEGS	See more on Appendix
WSEGLINK	Connect WELSEGS, contain ICV, to another WELSEGS	See more on Appendix

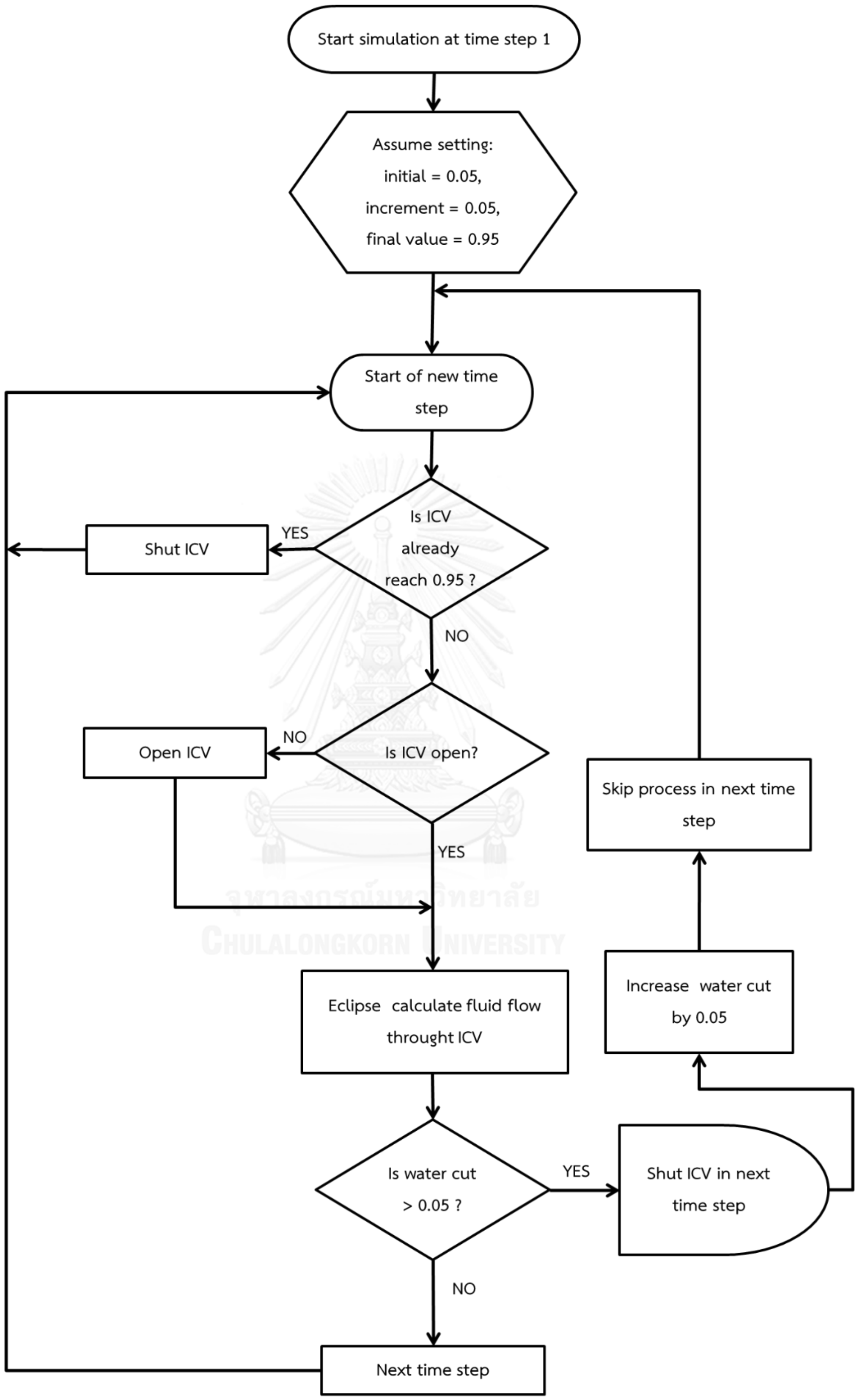


Figure 4.13 Individual ICV production policies

4.5 Thesis Methodology

This study is divided into three major parts. The first part involves with selection of base case model where production rate and well location are determined. Selected case is used in the second process in which adjustment of ICV is performed. The last part is to study effect of heterogeneity where all first and second processes will be repeated in every case. Comparison is made to conclude effects of heterogeneity on horizontal well equipped with ICV.

4.5.1 Well Geometry and Production Policy

1. Construct homogeneous reservoir model with rectangular shape supported by bottom aquifer with a size of 50 pore volume compared to size of oil bearing zone.

2. Perform reservoir simulation on horizontal well completed with perforated tubing. Total well length is fixed at 5,500 ft and number of case is generated from combination of two varying parameters which are:

   2.1 Well off-centered distance: 7.5 ft, 17.5 ft, 27.5 ft, 37.5 ft and 47.5ft

   2.2 Maximum liquid production rates from maximum rate of 10,000 STB/d to 7,500, 5,000 and 2,500 STB/d.

3. Select base case from simulation results by considering two simulation outcomes which are total oil production and total water production. Comparison is based on the effective oil produced that comes from net oil gained which is obtained from subtraction equivalent amount of oil to cover water disposal cost.

4.5.2 Placements of ICV

1. Develop ICV cases from selected well location and production rate. This section is separately performed to all reservoir models with various heterogeneities. Initially, ICV is operated by fixing pre-set watercut starting from 0.05 with 0.05 increments and 95% of maximum watercut of each segment. This watercut will trigger the closure of installed valves. Number of ICV segment is set at 2 and

comparison between two partitioning segment policy of every block transmissibility and well contact transmissibility are made. The policy for reservoir model that yields the highest benefit based on effective oil produced as similar as previous section will be selected.

2. From previous step, using selected relative segment length policy to perform further ICV installation of 4 ICVs and 6 ICVs. Selected the case from each reservoir model that provides the highest effective oil produced.

3. The selected case is chosen to study effects of pre-set watercut by changing value of final watercut by calculating from percentage of maximum watercut from each segment. The percentage is changed from 95% to 90% and 85%.

Reservoir simulation results are discussed in each section based on effective oil produced. Moreover, oil and water saturation profiles, oil and water production rates are sometimes used to assist explanation. Conclusion and further recommendation are stated after discussion. Summary of thesis methodology is illustrated in Figure 4.14.

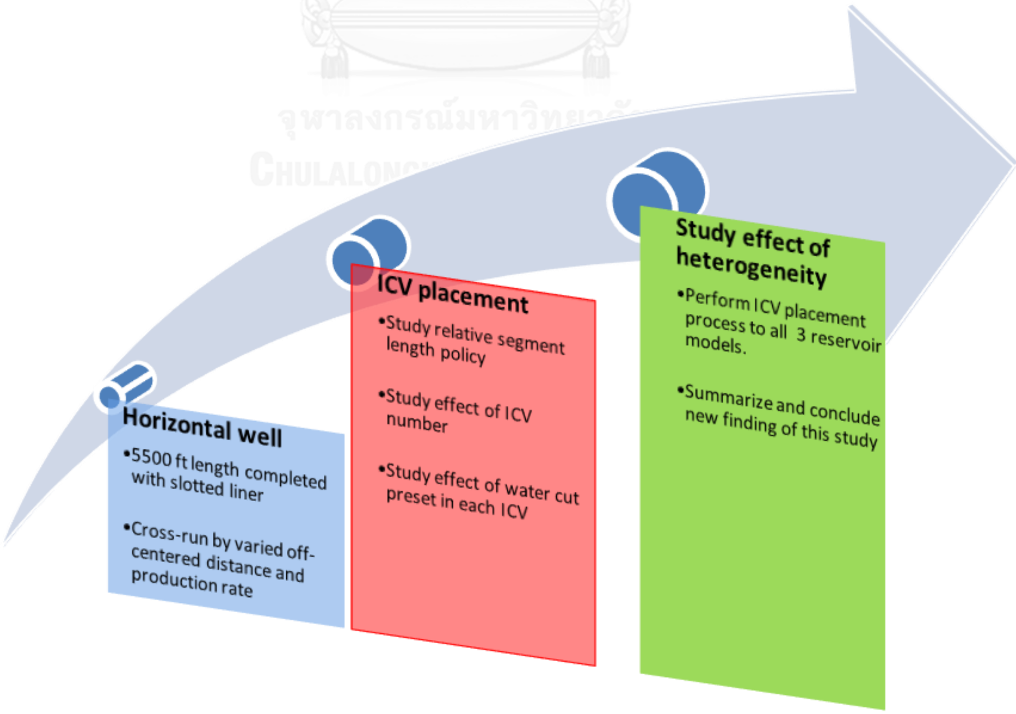


Figure 4.14 Summary of thesis methodology

CHAPTER V
RESULTS AND DISCUSSION

Initially, reservoir simulation study is performed to study parameters on simple horizontal well with details stated in previous chapter. First, comparison among all cases is accomplished to obtain base case of simple horizontal well by varying maximum liquid production rate together with well location (so-called off-centered distance) in moderate heterogeneous model which is chosen for initial study. After these two parameters are identified, further simulation study continues to configure ICV onto obtained all three reservoir models with various heterogeneity values. The study parameters include number of ICV, segment length and pre-set watercut. Selection of the best ICV configuration among all cases is acquired by comparing total oil production and total water production.

5.1 Dynamicity of Oil Production in Horizontal Well with Aquifer Support

As explained previously in methodology in Chapter 4, horizontal well is initially placed at nearly mid depth of oil bearing strata. Since water cresting phenomenon is expected to occur and to be mitigated by using ICV in high permeability region, high liquid production rate is chosen at 10,000 STB/d. Table 5.1 summarizes simulation outcomes from this case study.

Table 5.1 Summary of simulation outcomes of initialized case

Result Vectors	Values
Oil recovery factor (fraction)	0.4118
Total oil production (MMSTB)	2.94
Total water production (MMSTB)	3.63
Water cut at shut-in (fraction)	0.914
Liquid production rate at shut-in (STB/d)	1,128
Total production period (Years)	2.15

From Tables 5.1 it can be observed that at this high total liquid production rate, total water production is approximately 1.2 times compared to total oil production. Termination of production occurs because the well is unable to sustain oil rate above economic limit together with short production period could be interpreted that this well suffered from water cresting phenomena as well as quickly pressure depletion.

Bottom aquifer is the source of supporting pressure, resulting in different pressure to drive oil recovery mechanism. However, high water production also comes together with water influx especially in high permeability region. Water influx does not only sweep oil upward to toe section of horizontal well but it causes bypass of oil bearing zone, resulting in poor sweep efficiency. Figure 5.1 illustrates water saturation profile observed from side view of the model at 0.125 year from this cases with very high total liquid production rate.

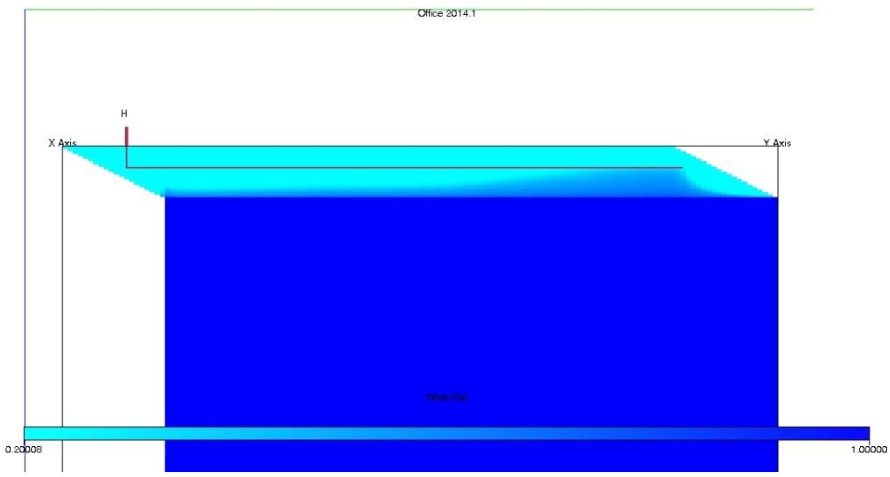


Figure 5.1 Water saturation profile obtained from a case with total liquid rate of 10,000 and off-centered distance 7.5 ft at time of 0.125 years

At very early stage of production, liquid production is almost 100% oil since the well is not surrounded by water from bottom aquifer yet. At the time around 0.125 years it can be seen from Figure 5.1 that water breakthrough occurs at the toe location as can be seen from dark blue color at the tip of horizontal section. Watercut rapidly increases from the moment of water breakthrough, resulting in great reduction of oil production rate. After that, water continues to be produced and exposure of water crest to wellbore expands to heel side.

At the production period of around 0.75 years, increment of watercut is subtle as shown in Figure 5.2. This indicates that water cresting phenomenon expands to cover throughout the whole length of horizontal well. From the figure, it can be seen that oil production rate shows the reverse trend as of watercut. In order to observe effect of water cresting phenomenon, cross-section in x-z direction if performed along y direction as shown in Figure 5.3 at this production period of 0.75 years.

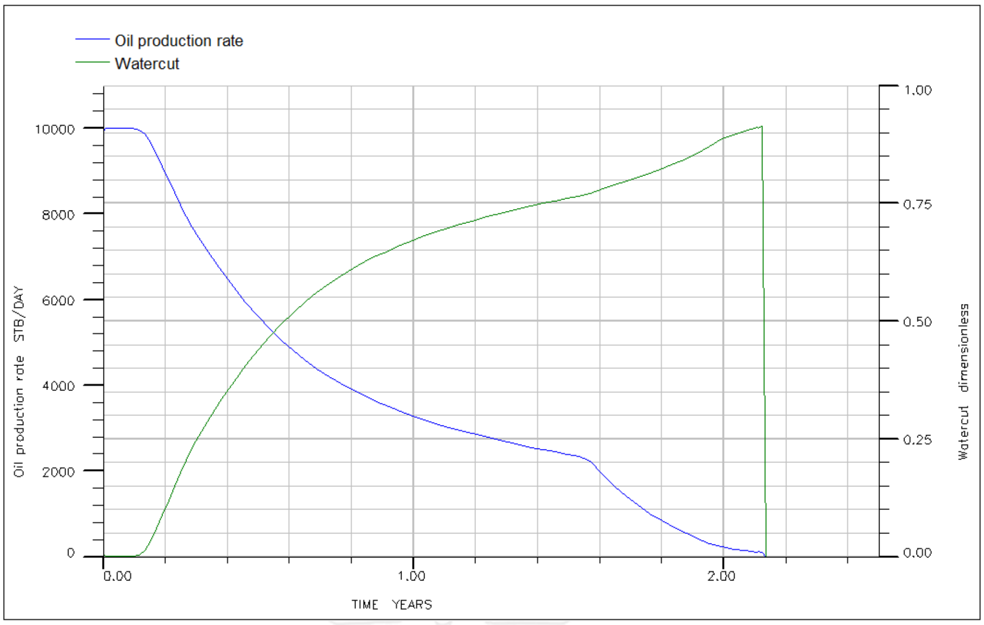


Figure 5.2 Oil production rate and watercut as a function of time

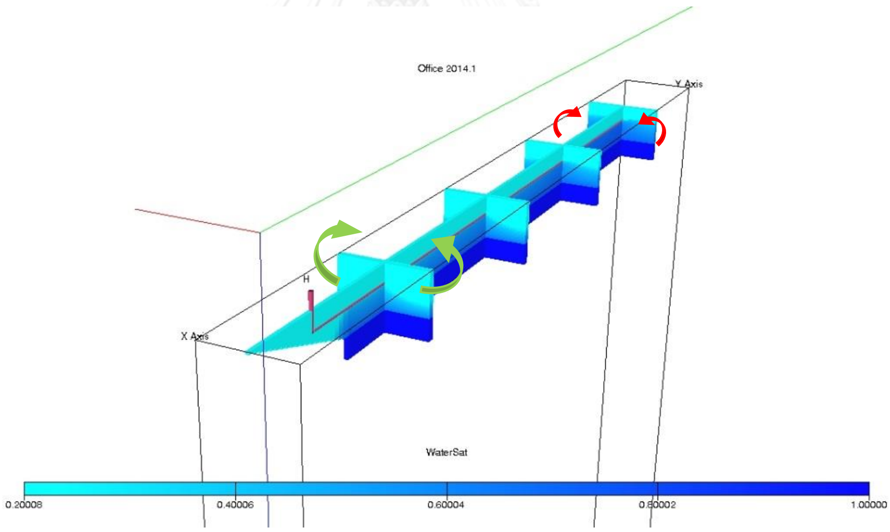


Figure 5.3 Water saturation profile in cross-section planes, illustrating water cresting phenomenon that occurred throughout horizontal well at time of 0.75 years

From Figure 5.3, water at the toe side does not only breakthrough from the bottom part of the wellbore but it starts encroaching the well in all circumferences, indicated by red arrows. At the heel side, water cresting phenomena is just at initial stage to occupy wellbore perimeter, starting from bottom side, indicated by green arrows.

At later stage, water encroachment continues and watercut constantly increases due to increment of water production from all circumferences in any location of horizontal section. As water starts to arrive first to this location, toe segment suffers the most from this phenomenon.

Not only water that is being produced, causing high amount of water disposal, reservoir starts to deplete its pressure drive. Once reservoir pressure is too low to drive liquid into wellbore, the well can no longer sustain the production due to economic limit of oil production rate. Part of oil is not recovered in the area above the well. Termination of the well occurs at time of 2.15 years and location of oil remained un-recovered can be observed from oil saturation profile (red color) as shown in Figure 5.4.

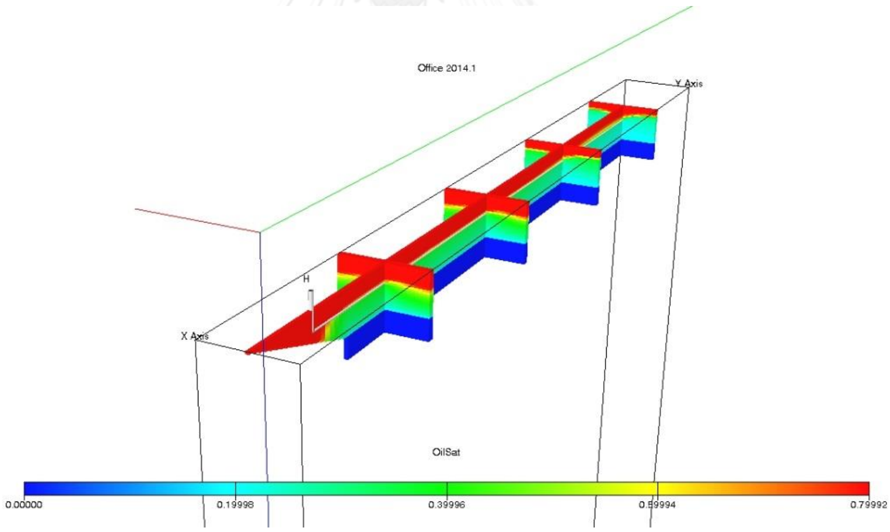


Figure 5.4 Oil saturation profile in cross-section planes, illustrating un-recovered oil in area above horizontal section at the end of production (2.15 years)

From the results obtained from initialized case, it can be seen that oil cannot be efficiently recovered due to too high liquid production that induces an arrival of early water breakthrough. From several literature reviews, the simplest way to avoid water cresting phenomenon in early stage is by stabilizing fluid front with reducing total liquid production rate. However, this mitigation has negative effect to profitability of the well and may affect to ultimate total oil produced if limiting total production rate is too conservative. The well may reach the end of concession period before attaining economic limit of watercut.

Also from initialized simulation result, improvement of total oil production can be remarkably performed since remaining oil is left-over mainly above horizontal section in Figure 5.4. Therefore, changing distance away from OWC would result in higher oil gain. Nevertheless, this method has a negative consequence to well productivity as indicated in Equation 3 in Chapter 3.

In conclusion, study the combination of two parameters which are maximum liquid production rate together with well off-centered distances by varying both parameters in the same time would yield the optimal result. Further details are described in the next section.

5.2 Selection of Liquid Production Rate and Well location

In this section, horizontal well length and economic limits are set as same as previous section. The study is mainly focused on selection of total liquid production rate and well location by varying both parameters at the same time in reservoir containing moderate heterogeneity. Total liquid production rates are varied from the smallest rate of 2,500 STB/day to the highest rate of 10,000 STB/day. Increment from the lower rate to higher rate is 2,500 STB/day, resulting in four different liquid rates of 2,500, 5,000, 7,500 and 10,000 STB/day. Well location is represented by off-centered distance which is the distance in vertical direction from central location of oil bearing zone. The nearest off-centered location starts from 7.5 feet with incremental step of 10 feet up to the maximum value of 47.5 feet, resulting in five different off-centered locations; 7.5, 17.5, 27.5, 37.5 and 47.5 feet from central location of oil bearing zone.

After obtaining the most suitable well location and total liquid production rate for reservoir with moderate heterogeneity, this setting values are also applied to others two reservoir models with lower and higher heterogeneities. For each reservoir heterogeneity value, the whole combination therefore results in 20 cases.

5.2.1 Effect of Total Liquid Production Rate

Total liquid production rate of the well is varied throughout base case. Reduction of total liquid flow rate results in lowering disturbance of oil-water contact. Fluid influx into wellbore is more uniformed at lower total liquid production rate. So that water cresting phenomenon is less pronounced.

Total oil production obtained from various total liquid production rates from different well locations are summarized in Figure 5.5. Oil recovery is maximized when total liquid production rate is set as low as 2,500 STB/d. This result is similar in most well locations except 7.5 and 17.5 feet. At this low liquid production rate with well location of 7.5 feet, total oil production is the smallest due to sensitivity to fluid front which is critical factor in this well location. As horizontal well is drilled from low permeability to high permeability region, the main purpose is to compensate drawdown from friction by good transmissibility from high permeability region. Even though lower liquid production rate helps preventing an arrival of water crest in high permeability zone, too low production rate does not create enough friction loss inside production string to balance fluid influx along well length. Oppositely, in this well location of 7.5 feet maximum liquid rate of 10,000 STB/d yields the highest oil recovery as it is able to balance both drawdown from friction and transmissibility.

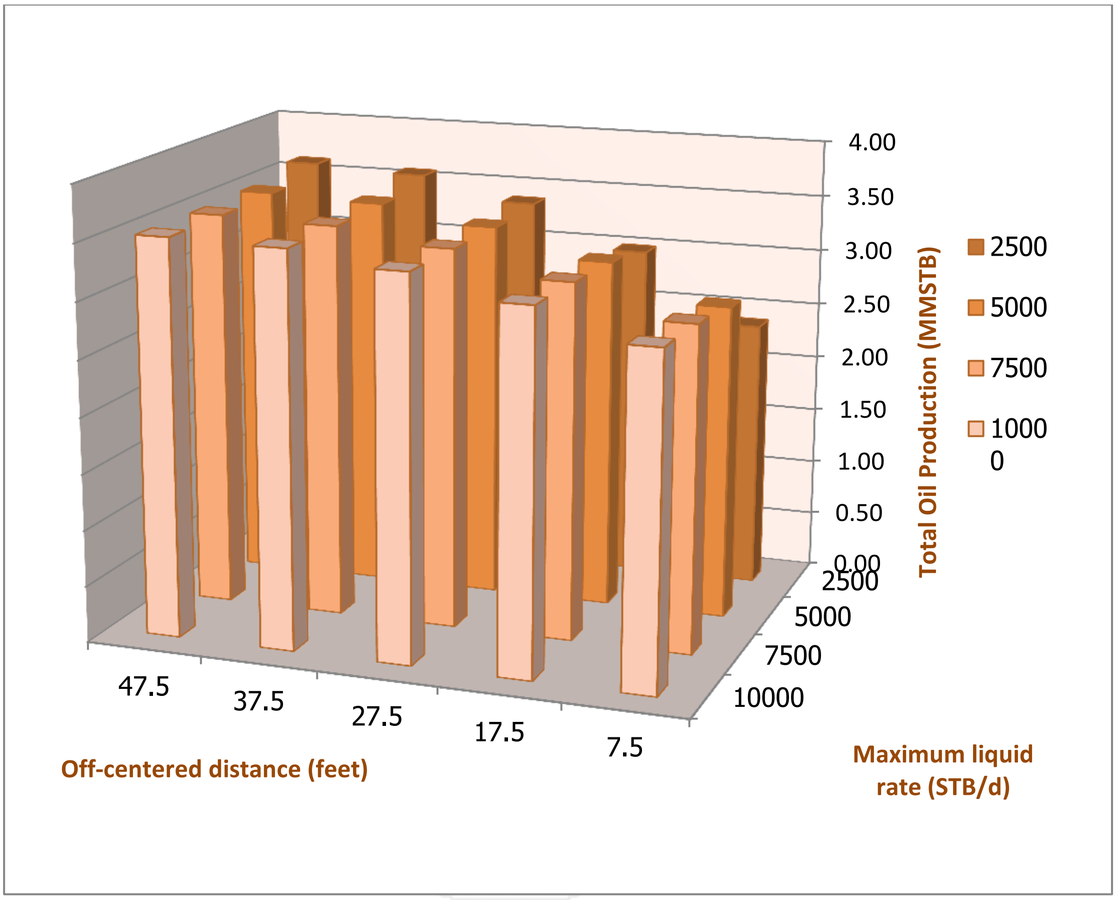


Figure 5.5 Total oil production obtained from various well locations and various total liquid production rates

Not only total oil production should be considered for designing a horizontal well, high water production that could lead to water disposal cost is also an essential consideration for project achievability. From the initialized case, overall water production is equal to oil gain. Figure 5.6 presents total water production of various cases. Total liquid production rate slightly influences water production in most of well locations as higher production rate accelerates an arrival of water crest, however from simulation result it is insignificantly. The difference in amount of produced water is obviously seen in cases where horizontal well is placed closer to oil-water contact as this location extremely depends on balancing between drawdown from friction and transmissibility. For total liquid production rate of 2,500

STB/day, not only total oil production is the lowest, water production is also the highest one. Undoubtedly, this is the worst case among all the results.

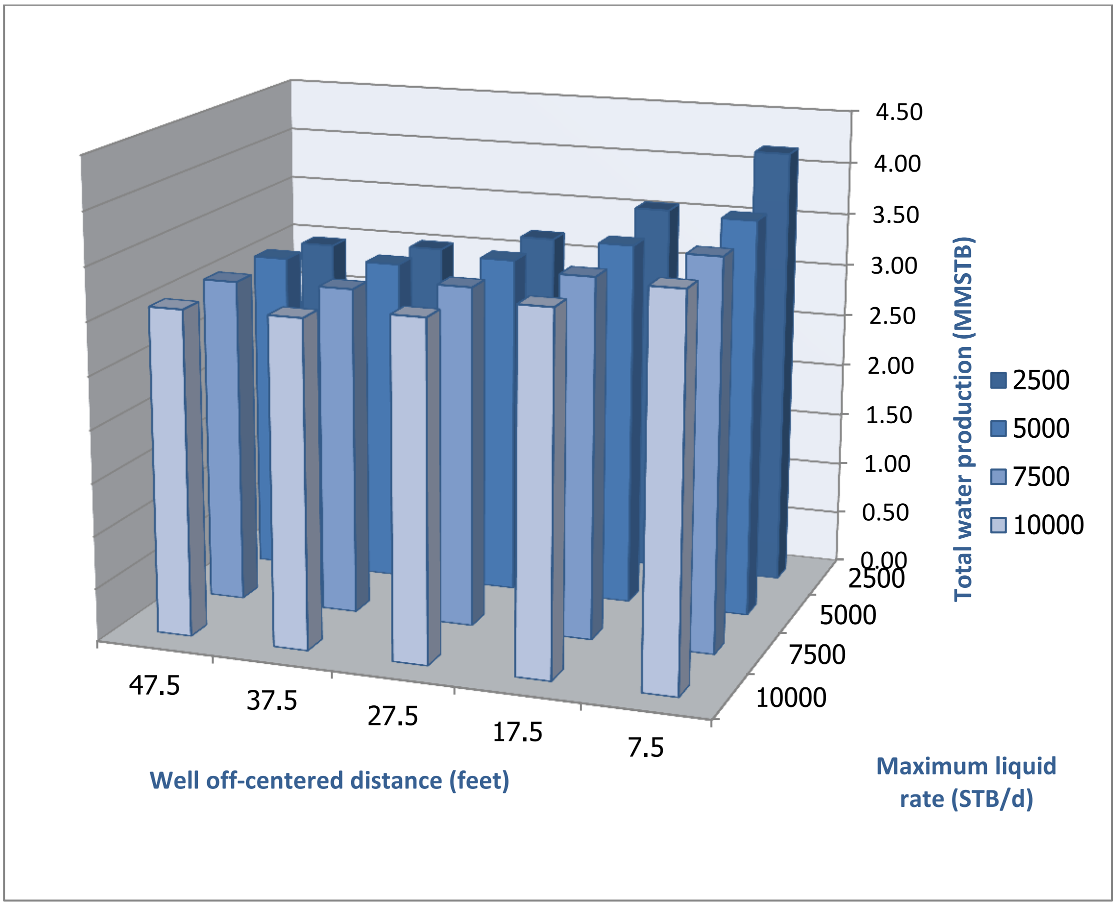


Figure 5.6 Total water production obtained from various well locations and various total liquid production rates

Total liquid production rate is one of the parameters controlling effectiveness of horizontal well. In most cases, lower liquid production rate is desirable due to ability to increase of oil recovery from fewer disturbances to oil-water contact. However, when the well is located at lower position, reduction of total liquid production might yield adverse result.

5.2.2 Effect of Well Location

In this study, well location is represented by off-centered distance or so-called well eccentricity in several literatures. This distance is measured from the middle location of oil bearing zone. Off-centered distance must be pre-determined before initiating drilling operation. Benefit of locating well far from oil-water contact can be foreseen when considering effects from oil-water contact deformation. However, this could lead to reduction of well productivity.

Oil production is firstly discussed. When a horizontal well is drilled into the uppermost layers it can be observed from Figure 5.5 that oil recovery is the highest in every total liquid production rate. As the well is shut when water occupies around wellbore circumference, oil from the zone above the well is nearly undisturbed from influx water. Therefore, locating the well at uppermost location can recover maximally oil recovery. Productivity of horizontal well at this location is expected to be low due to far most location from the pressure source. However, since aquifer strength is adequate, this low productivity is therefore compensated.

Total water production from changing off-centered distance can be observed from a trend shown Figure 5.6. Produced water is increased when well off-centered distance is reduced. As the well in every case is unable to maintain total liquid production until the end of concession as depicted in Figure 5.7, every well is terminated from shortening of reservoir pressure due to loss of pressurized fluid. Within the same pressure source, the well will either produce oil or water until the termination. The well that produces high amount of water will produce low amount of oil production and oppositely, the well that produces high amount of oil will produce less amount of water. The latter case is therefore a more favorable condition.

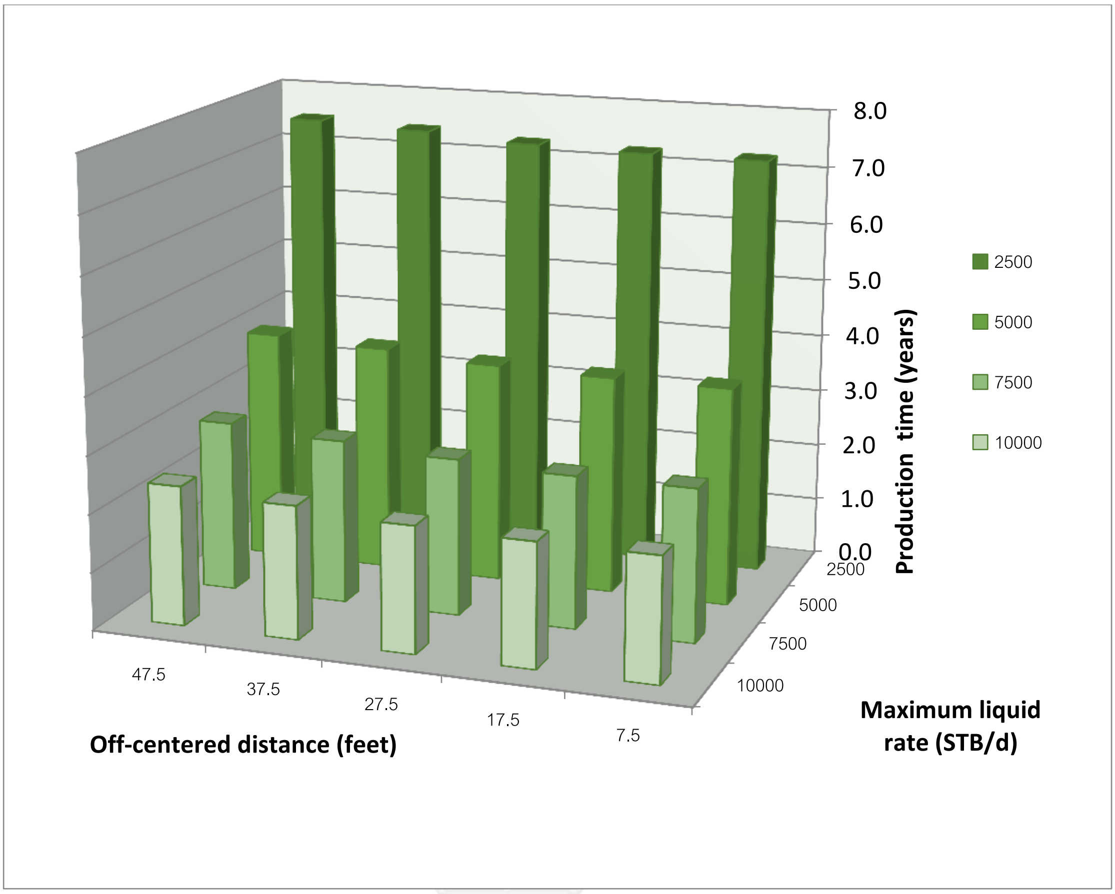


Figure 5.7 Total production time from cases with various well locations and total liquid production rates

From this section it can be obviously seen that off-centered location affects both oil recovery and total water production. The further distance away from supporting aquifer results in higher oil recovery for this reservoir model.

5.2.3 Selection of Base Case Model

The simulation cases from previous section are compared both to select the best well location and the best total liquid production rate. Selection of base case is explained in this section and the selected case will be used for further study of ICV placement.

The main criterion to justify horizontal well performance is total oil production. Nevertheless, total water production is also concerned in this section since reservoir is supported by aquifer and high amount of water will be produced. As disposal of water may result in excessive cost to the project, high amount of water is therefore undesirable.

The process to judge obtained results is acquired from the cost of water disposal in unit of profit from net oil at wellhead. In another word, cost of water disposal is converted into amount of oil with an equivalent cost to subtract out from total oil production. From the equation:

$$\forall_w \times c_w = \forall'_o \times s_o,$$

it can be rewritten as:

$$\forall'_o = \frac{\forall_w \times c_w}{s_o},$$

where

$\forall_w$ = Volume of water disposal (STB),

c_w = Water disposal cost per barrels of water ($/STB),

$\forall'_o$ = Volume of oil which is equivalent to water disposal cost (STB),

s_o = Profit of oil per barrels of oil ($/STB).

Easton [16] stated that water disposal by re-injecting of produced water back into deep well costs in average around 3-7 $/STB. For this study, water disposal cost is set as 4 $/STB and from World Economic Outlook (WEO) report 2015 of International Monetary Fund (IMF) [17], operational oil production cost per barrel around the globe varies depending on location of producer. In this study, the value of 15 $/STB which is used as this is mode and median of the whole data [17]. In the year of 2015, oil price which is quite fluctuated is assumed to be around 55 $/STB. And hence,

$$\forall'_o = \frac{\forall_w \times 4}{55-15} = 0.1\ \forall_w.$$

Net oil produced or effective oil produced is defined as volume of total oil production subtracted by volume of oil that is required to cover the cost of water disposal and it can be written as

$$\forall_{oeff} = \forall_o - \forall'_o\ ,$$

$$\forall_{oeff} = \forall_o - 0.1\forall_w \qquad (10),$$

where

$\forall_{oef}$ = Effective oil produced (STB),

$\forall_o$ = Total oil production (STB).

In this study, total oil and water production are determined through effective oil produced by comparing these parameters between cases. Tables 5.2 and 5.3 summarize total oil and water production, respectively for all cases.

Table 5.2 Total oil production of simulation cases with various liquid production rates and well locations

Total oil production (MMSTB)	Off-centered distance (ft)				
Total liquid production rate (STBPD)	**7.5**	**17.5**	**27.5**	**37.5**	**47.5**
2,500	2.400	3.008	3.386	3.585	3.633
5,000	2.805	3.124	3.363	3.504	3.536
7,500	2.892	3.165	3.374	3.498	3.524
10,000	2.936	3.195	3.391	3.508	3.529

Table 5.3 Total water production of simulation cases with various liquid production rates and well locations

Total water production (MMBBL)	**Off-centered distance (ft)**				
Total Liquid production rate (BBL/d)	**7.5**	**17.5**	**27.5**	**37.5**	**47.5**
2,500	4.186	3.569	3.205	3.021	2.975
5,000	3.769	3.456	3.230	3.106	3.075
7,500	3.672	3.403	3.219	3.111	3.090
10,000	3.632	3.382	3.198	3.099	3.083

From Tables 5.2 and 5.3, effective oil produced of each simulation case is calculated from equation 10 and calculated data are summarized in Table 5.4.

Table 5.4 Effective oil produced of simulation cases with various liquid production rates and well locations

Effective oil produced (MMSTB)	**Off-centered distance (ft)**				
Total liquid production rate (STB/d)	**7.5**	**17.5**	**27.5**	**37.5**	**47.5**
2,500	1.981	2.651	3.065	3.283	3.335
5,000	2.428	2.778	3.040	3.194	3.228
7,500	2.525	2.825	3.052	3.187	3.215
10,000	2.573	2.857	3.071	3.198	3.221

From Table 5.4, horizontal well with off-centered distance of 42.5 feet and liquid production rate of 2,500 STB/d meets requirements in terms of yielding the highest effective oil produced.

However, this well configuration might not be the most favorable as the horizontal well could have better result if well path is drilled in the opposite direction. The current case is drilled from low permeability zone at heel location into high permeability zone at toe location. The opposite direction is drilled from high permeability zone at heel location into low permeability zone. The simulation results of opposite well path are shown in Figure 5.8 and simulation outcomes are summarized in Table 5.5.

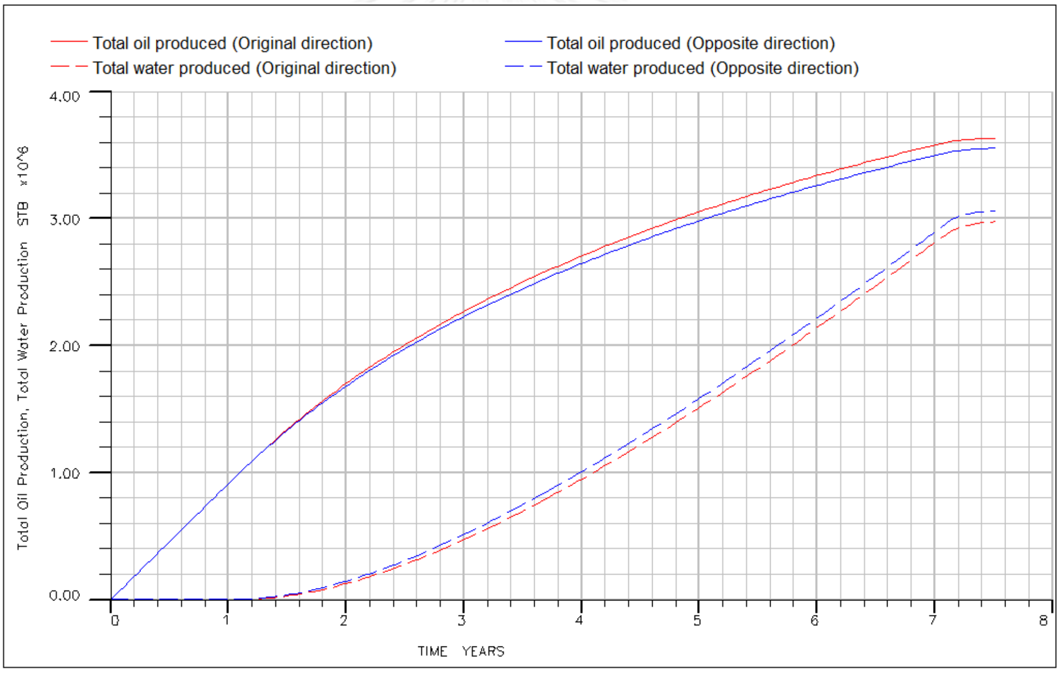


Figure 5.8 Total oil production and total water production from horizontal well placement of original well path and opposite well path as a function of time

Table 5.5 Simulation outcomes obtained from original well path and opposite well direction path

Well placement in Y-direction	Total oil production (MMSTB)	Total water production (MMSTB)	Effective oil produced (MMSTB)
Original	3.633	2.975	3.335
Opposite	3.554	3.061	3.248

From simulation outcomes in Table 5.5, it suggests that configuring horizontal well with the opposite direction or drilling the well from high permeability zone to lower permeability zone is not favorable compared to original well case. The explanation is simple that is horizontal well always comes with higher tendency of water, encroaching at heel location due to friction loss inside horizontal production string. If horizontal well is placed for the heel location in high permeability zone, effect from water cresting will be enlarged from transmissibility of reservoir itself. Hence, it is more favorable to place well with heel location in lower permeability zone as in original case.

This selected case is used for the following sections in every reservoir model. Table 5.6 summarizes effective oil produced from selected well configuration in three reservoir models with different reservoir heterogeneities.

Table 5.6 Summary of effective oil produced from selected well configuration applied in various reservoir models with different values of heterogeneity

Heterogeneity Models	**Total oil production (MMSTB)**	**Total water production (MMSTB)**	**Effective oil produced (MMSTB)**
Low	3.921	2.667	3.655
Moderate	3.633	2.975	3.335
High	3.442	3.177	3.125

5.3 Dynamicity of Oil Production in Horizontal Well Completed with ICVs

Inflow Control Valve or ICV is operated individually based on policy as mentioned in previous section. In this study, ICV policy consists of three pre-setting values. The first is initial watercut where ICV starts to trigger the closure to prevent influx of water into the wellbore. In this study, initial watercut is set at 5%. The second value is the increment of watercut in the following closure. Increment of watercut will help to slow down and encroachment of water and at the same time, it still allow the well to continue to produce oil. In this study, increment value is fixed at 5% watercut or 0.05 in fraction in every ICV. The last value required is final watercut where it will cause a permanent shut in of ICV. Since final watercut of each ICV is varied and encroachment of water is not uniform throughout the well length, final watercut therefore is not fixed at one value but it is determined from actual maximum watercut of each individual ICV segment.

The maximum watercut from each segment is the most important parameter needed to identify. As water encroachment might be controlled through adjustment of these pre-setting values, so this section is divided into two topics. First, the open/shut effect of each ICV to well performance is studied and second, the final watercut together with adjustment method is evaluated.

5.3.1 Effect of Open/Shut of ICV

The moderate heterogeneous model with four ICV segments without final watercut is initially used in this discussion. After ICV starts to shut in, it is re-opened in two weeks and triggering watercut is added by value of 0.05 for the following closure. Oil production rate obtained from this setting is illustrated in Figure 5.9. From the figure, oil production rate can be divided into two important periods representing by blue and red zones. The first period is the period where oil production rate is constant due to adequate reservoir pressure and high value of oil saturation around wellbore. The second period represents period where water starts to breakthrough which can be seen from reduction of oil production rate together with short-period peaks when each valve starts to sense first 5% of watercut.

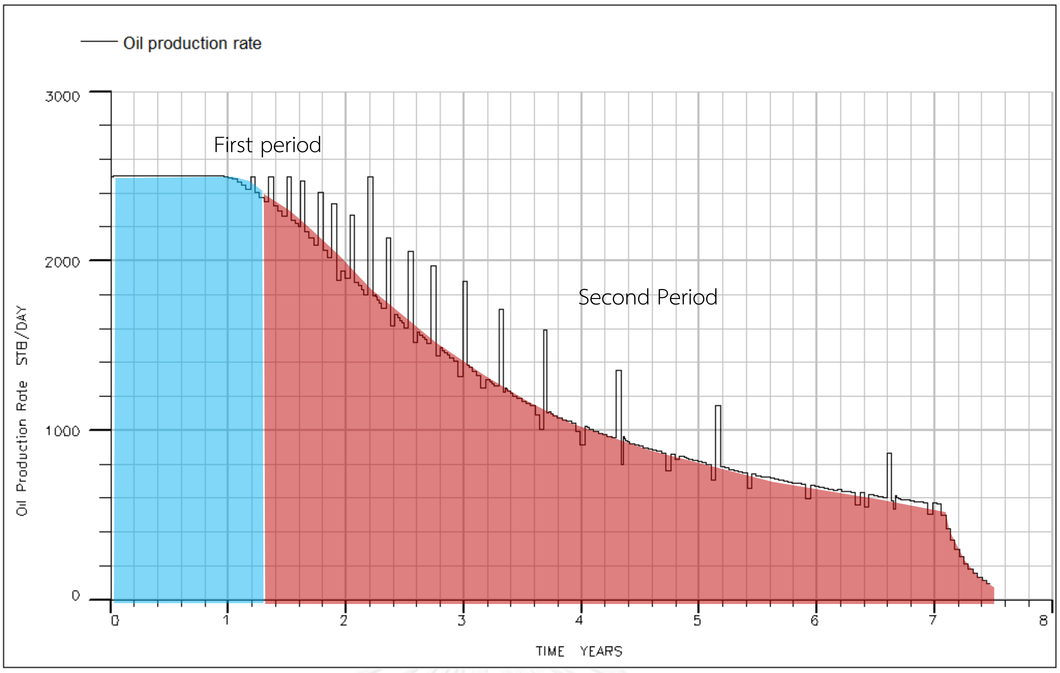


Figure 5.9 Oil production rates as a function of time for case with four ICV segments

The first period lasts approximately 1.2 years before water encroachment and after that, second period starts. ICV installed in segment facing the quickest water movement starts to operate. Oil production during this period is more complicated than first one as each ICV is activated from pre-set watercut individually. However, this mechanism can be described as the combination effect from alteration of two parameters.

The first parameter is oil production rate in all segments along the well length which is more uniform during the late period. The oil production at toe side segment where ICV number 4 is placed is higher than the toe side segment throughout production life due to higher permeability. Once any ICV is shut in, liquid production rates in other segments are abruptly increased in order to maintain total liquid production rate constant. As liquid production rate at other segments or ICV number 1, 2 and 3 always contains higher portion of oil or less watercut, oil production at from other segments is sharply increased every time the ICV at toe side segment is shut as indicated in Figure 5.10. After ICV at toe side segment operates for several times, oil production rate from ICV number 1, and 3 are mostly identical after 3.5 years. This phenomenon also occurs later, when ICV at other segments are shut, causing oil production rate at other segments to sharply increased. However, increment of oil production rate is not as obvious as previous explanation due to ICV at heel side segment starts to operate at later time.

Second parameter to consider is watercut. Once ICV is temporary shut, watercut from the segment is suddenly reduced as it has time to settle fluid contact below the segment due to gravity segregation. On the other hand, watercut of other opening ICVs is slightly increased as liquid production is highly increased from changing direction of water cresting. Change of watercut from different four segments as a function of time is demonstrated in Figure 5.11 and from the figure it can be observed that alternation of both oil production rate and watercut can maintain production efficiency by reducing non-uniform water encroachment along the well.

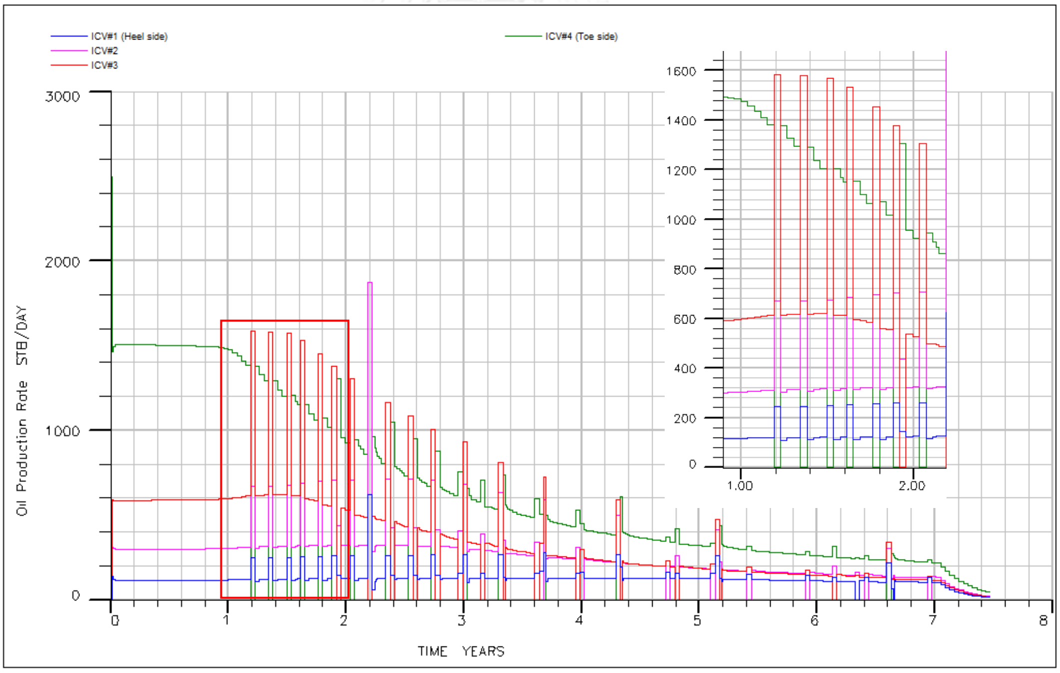


Figure 5.10 Oil production rates obtained from four different ICVs as a function of time

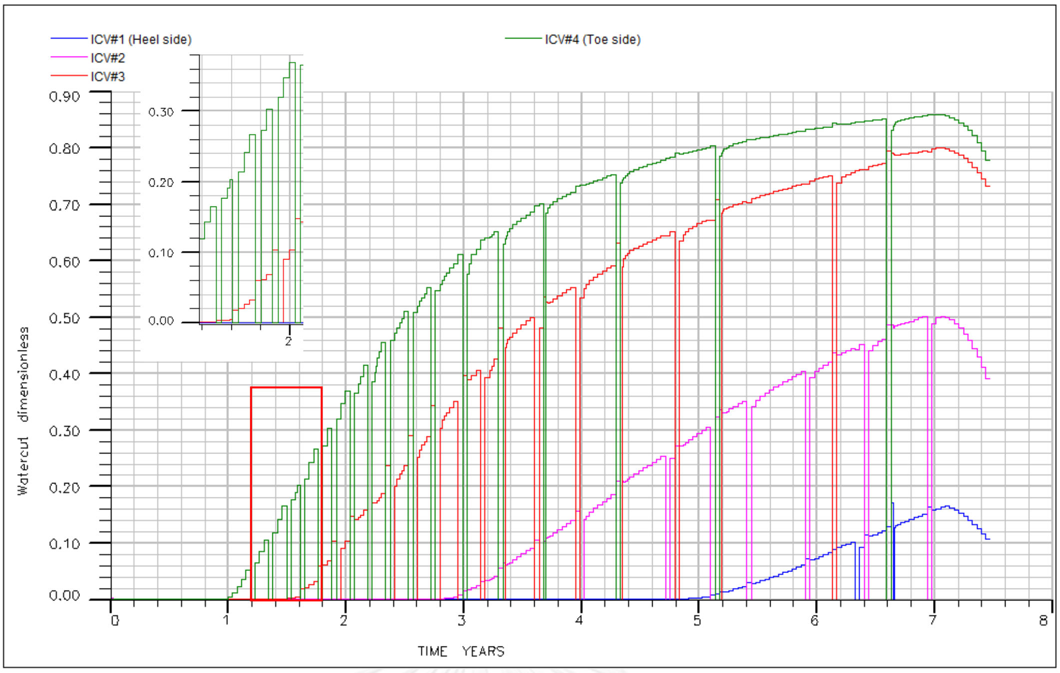


Figure 5.11Watercut obtained from four different ICVs as a function of time

The improvement from the installation of ICV becomes more obvious when considering Figure 5.12. Even final watercut is not adjusted yet, case with ICVs also yields greater oil recovery compared to base case and moreover, reduction of water disposal is also obtained. This further improvement from installation ICV is further investigated by appropriately setting final watercut to shut in some segments that produce too much of water.

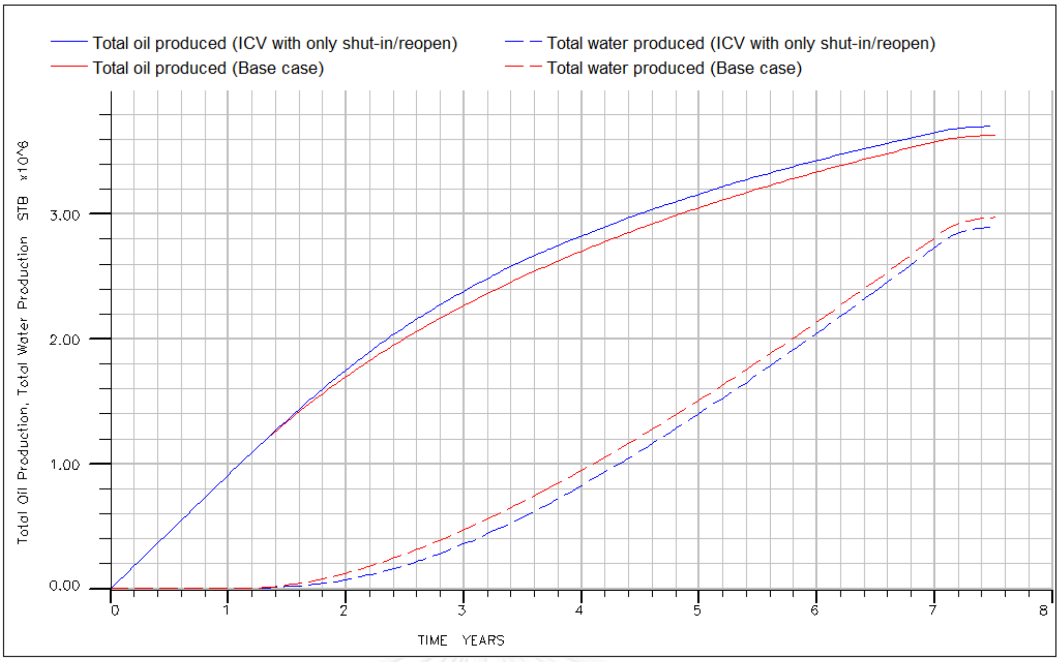


Figure 5.12 Total oil production and total water production from ICV installation case with shut-in/reopen action and case without ICV as a function of time

5.3.2 Effect of Permanent Closure of ICV Segment

The main purpose of installing of ICV is not only to shut in and re-open temporarily particular segment of the well but also to permanently terminate entire segment at appropriate timing. The good timing is therefore the key in this section. As indicated in Figure 5.11, each segment possesses its own watercut profile. For example, a segment of ICV number 4 which produces a lot of water at late time due to well location in high permeability zone, this segment therefore should be permanently shut in first. In this study, termination of each ICV is performed by inserting a value of final watercut to each ICV. The final watercut of each ICV is fixed at 95% of the maximum watercut surrounding each segment. According to this, configuration starts with ICV number 4 at the toe side of the well. The maximum watercut surrounding this segment of the well is around 0.859, hence; final watercut of this ICV is set at 0.816. Since this ICV is programmed to automatically shut in with an increment of watercut of 0.05 from previous step, this ICV will hence permanently shut in at the watercut of 0.80.

Table 5.7 Summary of maximum watercut of each segment during final watercut configuration

ICV number	Maximum watercut			
	Without final watercut	With final watercut setting		
		1st	2nd	3rd
1	0.17	0.37	0.57	0.72
2	0.50	0.70	0.83	0.75
3	0.80	0.86	0.80	0.80
4	0.86	0.80	0.80	0.80

Table 5.7 summarizes maximum watercut in each segment by highlighting closure watercut in orange color and the highest maximum watercut in yellow color. In the first run, maximum watercut without configuring permanent closure of ICV of each segment is shown in column 1 in Table 5.7. Then, the highest maximum watercut is obtained and closure watercut is calculated by multiplying 0.95 to the obtained value. The result of 0.80 is then used in the second run as a closure watercut for ICV number 4. The maximum watercut in the second run are 0.37, 0.7 and 0.86 for ICV number 1, 2 and 3, respectively. Then, the highest maximum watercut of 0.86 which is obtained from ICV number 3 is again multiplied by 0.95 to determine the closure watercut for ICV number 3. The same process is conducted until the closure watercut is obtained for ICV next to the last one.

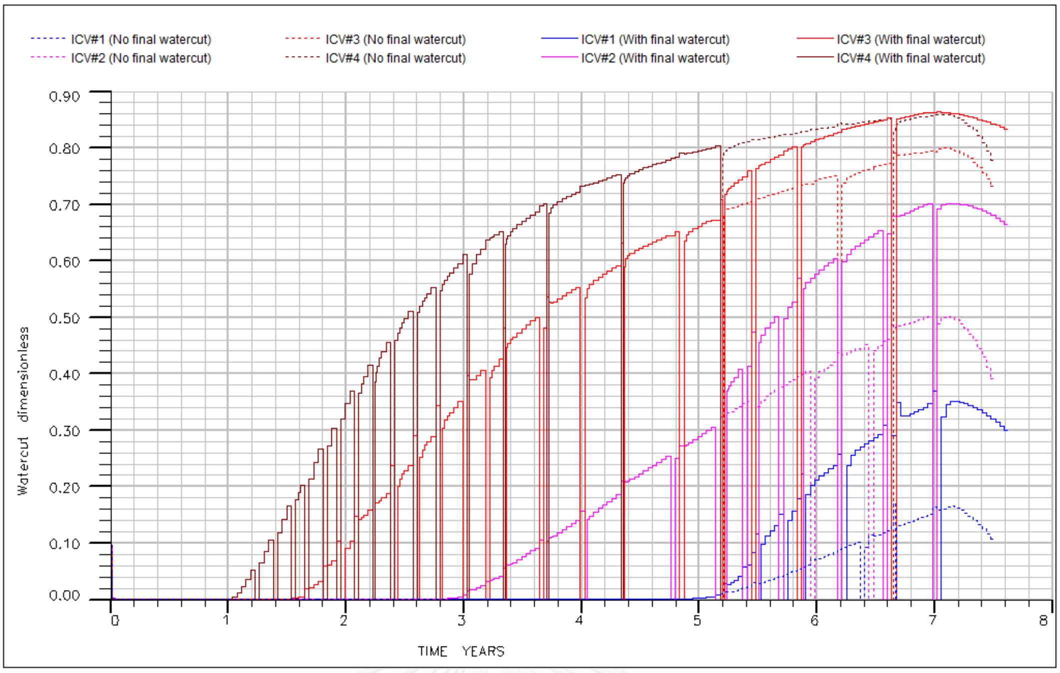


Figure 5.13 Watercut from ICVs before (dash line) and after (solid line) setting final watercut to ICV number 4 as a function of time

Figure 5.13 illustrates final watercut of all four ICVs from both cases, with and without configuring the final watercut on ICV number 4. Before ICV number 4 terminates, watercut of every segment is identical in both cases until around 5.2 years of production. ICV number 4 which is located at the toe side reaches 95% of maximum watercut of 0.86 and permanently shut in at watercut of 0.80. Then, watercut from other segments are gradually increased. According to permanently shut in of ICV number 4, watercut around the segment of ICV number 3 increases from 0.80 to 0.863. This indicates that this segment will produce more water, so the final watercut of this ICV number 3 needs to be adjusted to its 95% of maximum watercut around the segment. As this process is repeated also for the next ICV (ICV number 2), however, the last ICV which is ICV number 1 will not be adjusted for its final watercut as performed for ICV number 4, 3 and 2 because this segment will terminate by economic limit of the well.

This process results in less different value of maximum watercut of all four ICVs. In another word, maximum watercut is quite similar throughout all well segments as shown in Table 5.7 after setting the final watercut. Adjustment of final watercut yields a favorable result by greatly reducing of produced water and moreover, slightly increasing oil recovery as depicted in Figure 5.14.

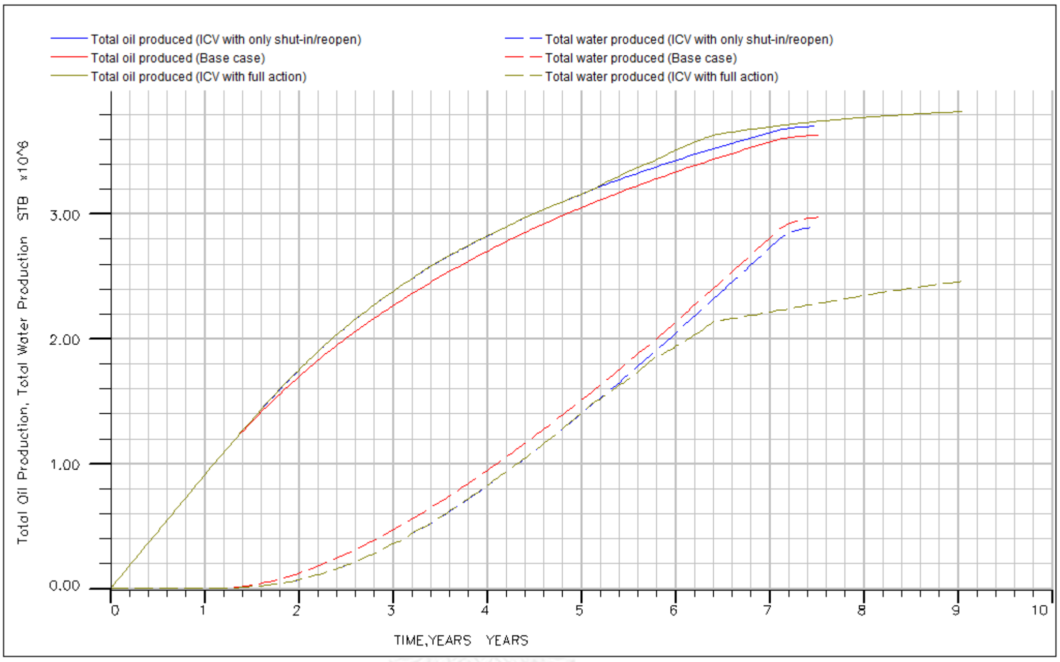


Figure 5.14 Total oil production and total water production from different three cases, base case, ICV installed case without setting final watercut, ICV installed case with setting final watercut as a function of time.

It can be seen that, when horizontal well is equipped with ICV together with specifying final watercut to each valve, this yields advantages over base case by combining shut-in/re-open process in early stage of production and final watercut adjustment via managing to use well pressure as efficient as possible.

5.4 Effect of Segment Length

In this section, effects of segment length are studied by fixing final watercut at 95% of maximum watercut as explained in previous section. The judgment criteria in this section are as same as for base case section, considering the effective oil produced which is a term associated with both total oil production and total water production.

Every heterogeneous model in this study has high permeability as well as high porosity located at toe location. This causes instability of oil-water contact at this location. As mentioned in section 5.3, ICVs are able to manage both oil production and water production along the well length. However, the toe location requires the utmost care by more ICV action to reduce unstable fluid contact. Therefore, increasing ICV density around this location should be implemented and hence, valve density adequate to manage oil-water contact at toe location must be identified to reasonably control production. In order to locate more ICV at the toe section, transmissibility is used in this study by calculating summation the products between horizontal length and vertical permeability in each block and after that divide by number of ICV. Different segment length can be therefore, created as shown in Figure 5.15.

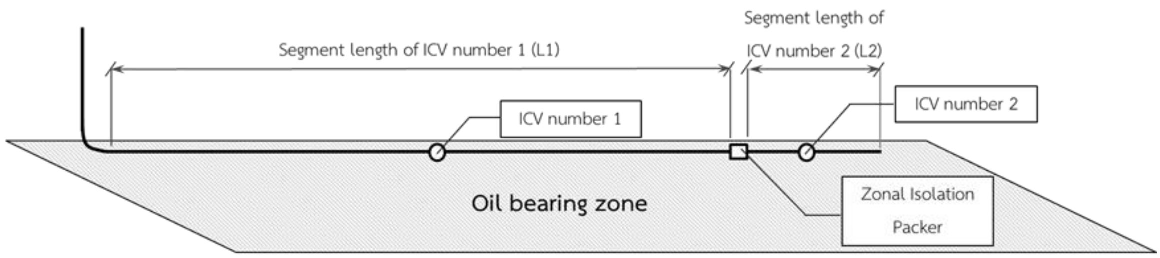


Figure 5.15 Partitioning of segment length in case of 2-ICV installation

Nevertheless, calculation of segment length as mentioned above can be done in two different ways. First, the summation is taken only from transmissibility calculated from blocks of well length. The second method includes all blocks in Y direction. The first way results in total length of 5,500 ft, whereas the calculated length is 6,000 ft in second case. In this section, six simulation cases are performed using only two installed valves to select the more effective way to calculate the segment length as mentioned above. Study is performed in all three reservoir models with different values of heterogeneity. Table 5.8 summarizes length of each segment for different two valves in three reservoir model by two different techniques.

Table 5.8 Transmissibility and length of each segment for three reservoir models calculated by two different techniques

Heterogeneity Models	Every permeability layers method				Well contact method			
	ICV No. 1 (heel)		ICV No. 2 (toe)		ICV No. 1 (heel)		ICV No. 2 (toe)	
	Transmissibility (x10^4md·ft)	L1 (ft)	Transmissibility (x10^4md·ft)	L2 (ft)	Transmissibility (x10^4md·ft)	L1 (ft)	Transmissibility (x10^4md·ft)	L2 (ft)
Low	5.93	3,650	5.97	1,800	4.95	3,200	4.99	2,250
Moderate	5.80	4,650	6.00	800	4.73	4,350	4.83	1,100
High	6.32	4,900	5.42	550	4.44	4,600	4.75	850

Partitioning each segment length might not cause a perfect equality of transmissibility value due to number of grid occupied. However, adjustment is needed to yield as equal as possible for the transmissibility in both segments. Locations of ICVs in each segment are located as central as possible. In case that transmissibility is calculated from every block in Y-direction, toe segment length becomes shorter than calculating only from well contact. As the method using entire block includes very high permeability layer located in a few block after the bottomhole. Moreover, horizontal well completed in reservoir with higher heterogeneity yields much shorter toe segment length compared to lower heterogeneity because reservoir with higher heterogeneous model has greater average permeability around toe location than lower heterogeneous model. Simulation result is presented in Table 5.9 including total oil production, total water production, effective oil produced and the difference from base case in each reservoir heterogeneity.

Table 5.9 Simulation outcomes from the study of segment length including total oil production, total water production, effective oil produced and difference from base case

Heterogeneity Models	Method of Transmissibility Calculation	Total Oil Production (MMSTB)	Total Water Production (MMSTB)	Effective Oil Produced (MMSTB)		
				Effective Oil Produced	Base case	Different from base case
Low	Every block	3.866	2.705	3.596	**3.655**	-0.059
	Well contact	3.869	2.688	3.601		-0.054
Moderate	Every block	3.657	2.935	3.364	**3.335**	0.029
	Well contact	3.698	2.886	3.410		0.075
High	Every block	3.489	3.114	3.178	**3.125**	0.053
	Well contact	3.570	3.024	3.267		0.143

From Table 5.9, calculating segment length yields higher oil production and lower water production than calculating from every block in every heterogeneous model. Therefore, calculating transmissibility well contact clearly yields more satisfactory. This can be explained by considering flow characteristics of oil and water inside each ICV segment of moderate heterogeneous model. From Figure 5.16 depicts oil production rates obtained from two ICVs from two different transmissibility calculation techniques, whereas Figure 5.17 illustrates watercut from two different methods. From Figure 5.16, oil flow rate through each ICV segment are quite balanced in both calculation methods as can be seen from mostly identical oil flow rate in early time. However, segment lengths of toe and heel calculated from well contact are less different compared to the method using every block and so, oil production rates from both ICVs (solid blue and black) are more uniformed (less different between rates) than calculating transmissibility from ever block (dash red and green) as displayed in Figure 5.16.

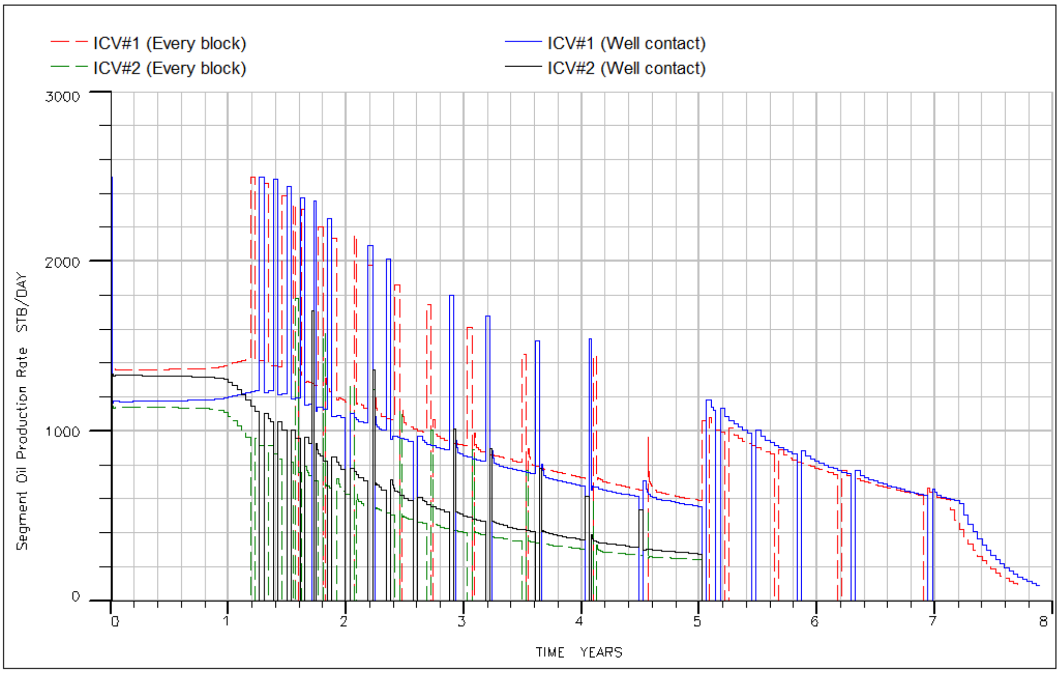


Figure 5.16 Oil production rates of each ICV obtained from two different calculations for segment length in moderate heterogeneous reservoir model as a function of time

The uniform fluid influx obtained from calculating transmissibility using well contact method disturbs oil-water contact less than another one so that, liquid production in each ICV contains less watercut throughout almost of production life as shown in Figure 5.17.

Nevertheless, from Table 5.9 positive different of effective oil produced is obtained only from reservoir models with moderate to high heterogeneity value. Even though the horizontal well is configured with the most favorable segment partitioning, the well without ICV installed yields better result in low heterogeneous reservoir. This can be interpreted that two segments are probably not enough. Therefore, in next section, all three models are configured with more ICVs by using segment length or transmissibility calculated from well contact method.

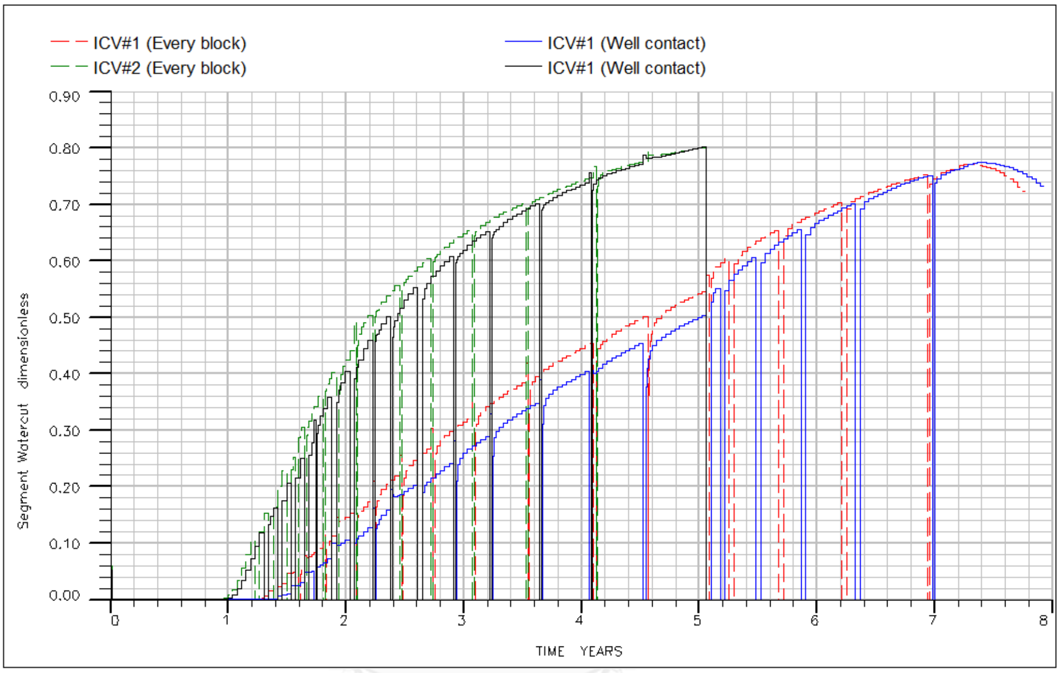


Figure 5.17 Watercut of each ICV obtained from two different calculations for segment length in moderate heterogeneous reservoir model as a function of time

5.5 Effect of ICV Number

After obtaining results from configuring the horizontal well with 2 ICVs in previous section, installing 4 and 6 ICVs are conducted to all three reservoir models in this section by using relative segment length calculated from well contact method. Final watercut of ICV is fixed at 95% of maximum watercut. Comparisons of result also include case of 2 ICVs from previous section.

Table 5.10 displays transmissibility and segment length to be used for cases with 4 and 6 ICVs. Cases with higher number of ICV have higher density of ICV placement at toe side location as well as cases with higher degree of heterogeneity.

Simulation results are summarized in Table 5.11. From the table, it can be seen that increasing number of ICV in horizontal well yields higher effective oil produced compared to cases with less ICV installed. Even this modification of ICVs number yields improvement on effective oil produced however, none of ICV configuration case in reservoir model with low heterogeneity value yields benefit better than base case configuration which is similar as in section 5.4.

Table 5.10 Transmissibility and length of each segment for cases with various ICV numbers and reservoir heterogeneities

<table>
<tr><th>Heterogeneity Models</th><th>Number of ICVs</th><th>Segment properties</th><th colspan="12">ICV segment from heel to toe location</th></tr>
<tr><td rowspan="4">Low</td><td rowspan="2">4</td><td>Transmissibility ($\times 10^4$ md·ft)</td><td colspan="3">2.48</td><td colspan="3">2.40</td><td colspan="3">2.35</td><td colspan="3">2.54</td></tr>
<tr><td>L (ft)</td><td colspan="3">1,800</td><td colspan="3">1,350</td><td colspan="3">1,150</td><td colspan="3">1,050</td></tr>
<tr><td rowspan="2">6</td><td>Transmissibility ($\times 10^4$ md·ft)</td><td colspan="2">1.61</td><td colspan="2">1.60</td><td colspan="2">1.58</td><td colspan="2">1.51</td><td colspan="2">1.60</td><td colspan="2">1.67</td></tr>
<tr><td>L (ft)</td><td colspan="2">1,250</td><td colspan="2">1,000</td><td colspan="2">850</td><td colspan="2">750</td><td colspan="2">750</td><td colspan="2">650</td></tr>
<tr><td rowspan="4">Moderate</td><td rowspan="2">4</td><td>Transmissibility</td><td colspan="3">2.38</td><td colspan="3">2.38</td><td colspan="3">2.29</td><td colspan="3">2.31</td></tr>
<tr><td>L (ft)</td><td colspan="3">3,350</td><td colspan="3">950</td><td colspan="3">600</td><td colspan="3">450</td></tr>
<tr><td rowspan="2">6</td><td>Transmissibility</td><td colspan="2">1.58</td><td colspan="2">1.41</td><td colspan="2">1.58</td><td colspan="2">1.46</td><td colspan="2">1.33</td><td colspan="2">1.61</td></tr>
<tr><td>L (ft)</td><td colspan="2">2,700</td><td colspan="2">950</td><td colspan="2">600</td><td colspan="2">400</td><td colspan="2">300</td><td colspan="2">300</td></tr>
<tr><td rowspan="4">High</td><td rowspan="2">4</td><td>Transmissibility</td><td colspan="3">2.20</td><td colspan="3">2.20</td><td colspan="3">2.16</td><td colspan="3">2.30</td></tr>
<tr><td>L (ft)</td><td colspan="3">3,750</td><td colspan="3">800</td><td colspan="3">450</td><td colspan="3">350</td></tr>
<tr><td rowspan="2">6</td><td>Transmissibility</td><td colspan="2">1.51</td><td colspan="2">1.39</td><td colspan="2">1.36</td><td colspan="2">1.37</td><td colspan="2">1.42</td><td colspan="2">1.38</td></tr>
<tr><td>L (ft)</td><td colspan="2">3,300</td><td colspan="2">750</td><td colspan="2">450</td><td colspan="2">300</td><td colspan="2">250</td><td colspan="2">200</td></tr>
</table>

Table 5.11 Summary of simulation results from cases with various ICV number and reservoir heterogeneities

Heterogeneity Models	Number of ICV	Total Oil Production (MMSTB)	Total Water Production (MMSTB)	Effective Oil Produced (MMSTB)	Effective Oil Produced (MMSTB)	
					Base case	Difference from base case
Low	2	3.869	2.688	3.601		-0.054
	4	3.858	2.631	3.595	**3.655**	-0.059
	6	3.894	2.544	3.640		-0.015
Moderate	2	3.698	2.886	3.410		0.075
	4	3.795	2.752	3.519	**3.335**	0.184
	6	3.831	2.673	3.564		0.229
High	2	3.570	3.024	3.267		0.143
	4	3.722	2.836	3.438	**3.125**	0.313
	6	3.805	2.722	3.533		0.408

When ICV number is increased, the maximum liquid production rate of the whole well remained unchanged. So that, actual oil flow rate through each valve in case of 6 ICVs is lower than that of case with 4 ICVs. Figure 5.18 illustrates oil production rates of two chosen segments which are ICVs from the nearest (heel side location) and the farthest (toe side location) segments from vertical well. This figure reveals that even the farthest segments at toe location are considerably different in transmissibility values from 4.83×10^4 md·ft in 2 ICVs case to 1.61×10^4 md·ft in 6 ICVs case, shutting-in of the valves results in oil production rates through every segment is converted to each other after approximately 4^{th} years after production.

Even though the case with larger transmissibility can obtain higher oil production rate compared to smaller transmissibility, at late time water production becomes more severe. Case with larger transmissibility segment suffers more from water production. Shutting-in of ICV results in convergence of oil flow rate at toe segment location at late time. Nevertheless, case with larger transmissibility segment produces high amount of water before it is permanently shut. The produced water from high permeability zone is therefore comingled to lower permeability zone in case of larger transmissibility segment, causing excessive produced water and low oil gain. Oppositely, the case with lower transmissibility segment is able to refine the shutting-in or re-opening by having more selective zones.

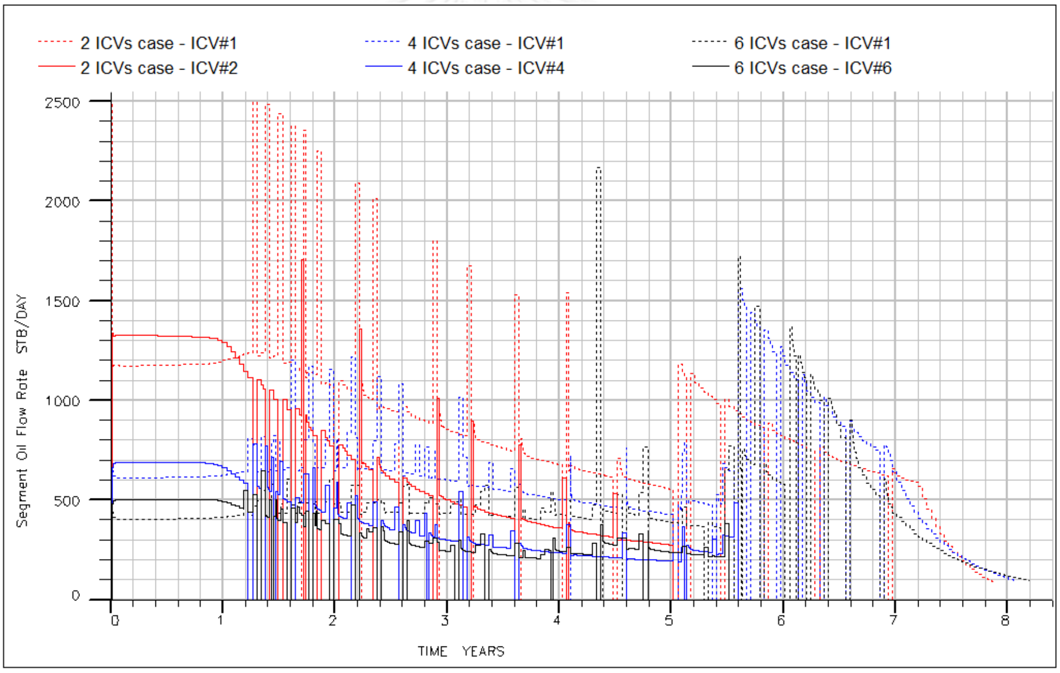


Figure 5.18 Oil production rates as function of time from heel side location and toe side location in cases of two, four and six ICVs in moderate heterogeneous case (ICV No.1 refers to heel side location)

Result from Table 5.11 also indicates that every ICVs configuration case in reservoir model with low heterogeneity yields lower total oil production than the base case. Even ICV installation in this model yields lower produced water but after calculating effective oil produced, the result is still worse than that of base case. This can be explained by considering Figures 5.19, 5.20 and 5.21, representing oil production rates through every ICV from case of 6 ICVs, emphasizing on ICV number 1 at the heel side location which is the key in this discussion together with total oil and water productions of ICV installed case compared to base case in three reservoir model with low, moderate and high value of heterogeneity, respectively.

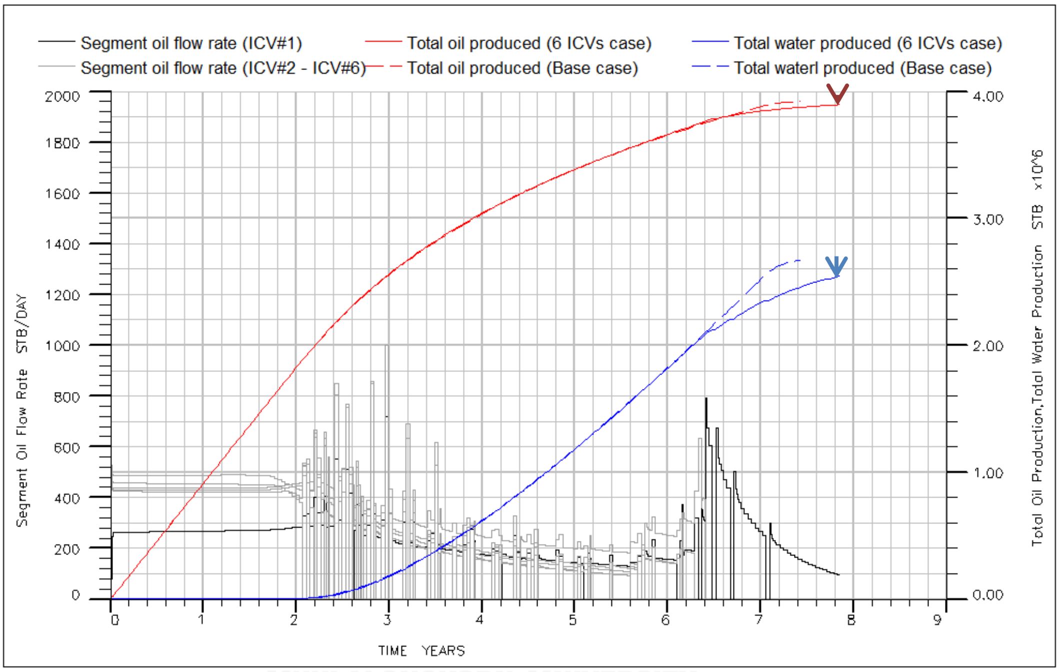


Figure 5.19 Oil production rates of various segments together with total oil and water production of six ICVs configured case compared to base case in low heterogeneous model

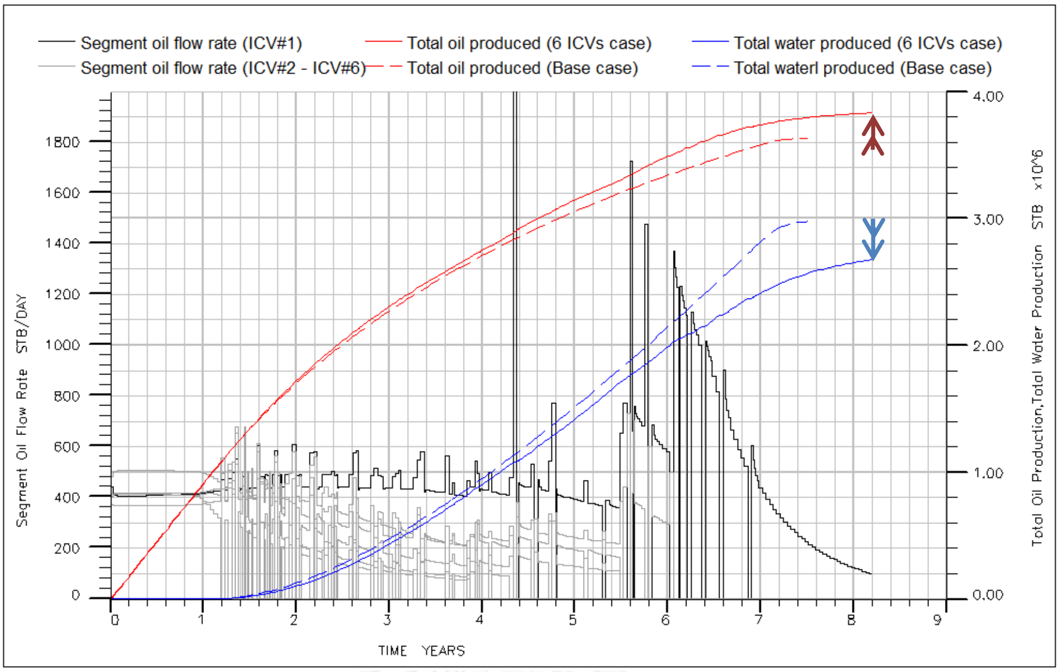


Figure 5.20 Oil production rates of various segments together with total oil and water production of six ICVs configured case compared to base case in moderate heterogeneous model

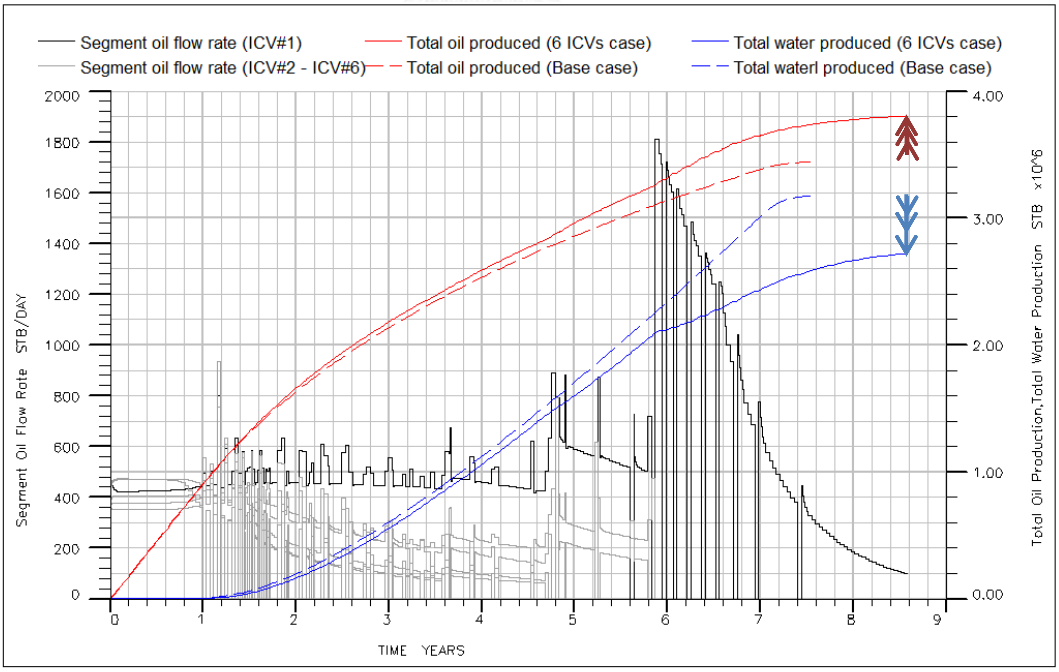


Figure 5.21 Oil production rates of various segments together with total oil and water production of six ICVs configured case compared to base case in high heterogeneous model

Figures 5.19 to 5.21 share one thing in common which is at late time after 5.5 years of production, only ICV in first segment or ICV number 1 operates as seen in solid black line. As can be seen in both total oil and water productions represented by red and blue color lines respectively that they both start to divert from dash line which is base case at this time. So, benefits from increase of oil production and reduction of produced water occur during this period. This implies that improvement from ICV installation is controlling water cresting from high permeability segments or ICV number 2 to ICV number 6 and maintaining reservoir pressure for ICV number 1 to produce remaining oil with relatively low watercut at late period.

In cases of reservoir models with moderate and high heterogeneities shown in Figure 5.20 and 5.21, respectively, the first segment has higher potential at late time compared to reservoir model with low heterogeneity. This can be explained that, during ICVs are operating in these model water cresting occurs very fast at toe segments. So, when ICVs number 2 to 6 mainly act to selectively produce between water and oil, often shut-in results in remaining reservoir pressure for the last segment which is segment of ICV number 1 at the heel side. Together with lower water-cut from low permeability zone, ICV number 1 can operate for much longer time, causing much higher in total oil production and much lower in water production compared to case with low reservoir heterogeneity.

On the other hands, reservoir model with low heterogeneity has relatively low contrast between high and low transmissibility. Base case of this model does not suffer much of water cresting. Also in ICV configured case, ICV number 2 to ICV number 6 do not experience high watercut from water encroachment. These ICVs can be operated for long period, terminated permanently after 6.5 years of production time which is latter time compared to other two heterogeneous models. This causes shorter period of ICV number 1 to obtain benefit before reservoir pressure is depleted. From this point, the case with 6 ICVs configuration is selected for the next section to study effects of pre-set watercut in each valve.

From the study in this section it shows that, installation higher number of ICV in high permeability zone yields benefit in oil production as well as it can control amount of produced water. This causes reduction of water encroachment and improves total oil production in segment located in low permeability zone. In reservoir with higher degree of heterogeneity, benefit of ICV installation is clearly shown compared to base case. Reservoir with low heterogeneity value where water encroachment is not severe does not yield benefit from ICV installation.

5.6 Effect of Pre-set Watercut

Pre-set watercut is percentage of maximum watercut and it is used as the pre-determined value of each valve to stop operating. In this study this value is regulated by acquiring maximum watercut surrounding each segment from simulation result before each valve is terminated and then calculating the pre-set watercut which is final watercut from 95% of maximum watercut as mentioned in section 5.3.2.

The 95% of maximum watercut is maximum value of watercut of each ICV. After each time ICV encounters high watercut, the valve will automatically shut-in. After 14 days, the valve will be re-opened with new pre-set watercut which is previous watercut plus 0.05 or 5%. This value of increment of watercut is assumed to be constant throughout this study. The valve will operate in this manner until watercut reaches the maximum pre-set water as explained previously. Lowering the value of final watercut might infer to narrowing down the operation range of ICV in high permeability region. In another word, this might give more operation range to ICV in low permeability region especially ICV number 1 at the heel side location which is very important valve in late time as it is less suffered from water cresting.

The simulations are conducted by varying pre-set watercut from 95% of maximum watercut as previous section into the values of 90% and 85% in 6 ICVs configured with all three heterogeneous models. Further explanations are begun with considering Table 5.12 where closure watercut of each valve in summarized in all three reservoir models.

Table 5.12 Closing sequence and watercut values and from cases with various pre-set watercut and reservoir heterogeneities

Heterogeneity Models	ICV number	Pre-set Watercut					
		Pre-set 85%		Pre-set 90%		Pre-set 95%	
		Sequence	Closure watercut	Sequence	Closure watercut	Sequence	Closure watercut
High	1	6	-	6	-	6	-
	2	4	0.70	4	0.75	4	0.80
	3	3	0.75	3	0.80	3	0.85
	4	1	0.80	1	0.85	1	0.90
	5	2	0.75	2	0.80	2	0.85
	6	5	0.70	5	0.75	5	0.80
Moderate	1	6	-	6	-	6	-
	2	5	0.75	5	0.80	5	0.80
	3	3	0.75	3	0.80	3	0.85
	4	1	0.80	1	0.85	1	0.85
	5	2	0.75	2	0.80	2	0.85
	6	4	0.70	4	0.70	4	0.75
Low	1	6	-	5	0.75	6	-
	2	4	0.70	3	0.75	4	0.80
	3	2	0.70	4	0.75	3	0.80
	4	3	0.70	2	0.75	2	0.80
	5	1	0.70	1	0.75	1	0.80
	6	5	0.70	6	-	5	0.75

Table 5.12 illustrates closure watercut of each ICV during operating under each pre-set watercut. Lowering pre-set watercut affects closure watercut by lowering closure watercut in every ICV. In most cases, ICV number 1 or ICV at heel side where permeability is low has no pre-set applied as this ICV are the last ICV that

still operates and hence, the final watercut is equal to well economic limit (95% watercut).

However, in reservoir model with low heterogeneity together with 90% pre-set watercut, ICV number 6 or segment at toe side of horizontal well is the last ICV segment that still operates. This can be simply explained that installed ICVs in reservoir with low heterogeneity are exposed to a uniform distribution of water cresting and therefore, every segment has relatively identical closure watercut as indicated in Table 5.12. Most ICVs are terminated in relatively the same watercut. Water cresting is induced also to lower permeability region as same as high permeability region and this can cause termination of ICV number 1 before other ICVs.

Simulation results are summarized in Table 5.13. From the table, it can be seen that pre-setting watercut at 95% yields the most favorable result compared to other pre-setting values in low and moderate heterogeneous models. However, lowering pre-set watercut to 90% provides higher effective oil produced over 95% and 85% of pre-set watercut in case of reservoir with high heterogeneity. Comparing effective oil produced within the same reservoir model it shows that varying final watercut between 90 and 95% has less impact in case of moderate and high heterogeneous models as values are not much different compared to case of low reservoir heterogeneity.

Table 5.13 Summary of simulation results from cases with various ICV watercut pre- and reservoir heterogeneities

Heterogeneity Models	ICV Watercut Pre-set (%from maximum)	Total Oil Production (MMSTB)	Total Water Production (MMSTB)	Effective Oil Produced (MMSTB)	Effective Oil Produced (MMSTB)	
					Base case	Difference from base case
	85	3.720	2.634	3.456		-0.198
Low	**90**	3.877	2.639	3.613	**3.655**	-0.041
	95	3.894	2.544	3.640		-0.015
	85	3.775	2.684	3.507		0.172
Moderate	**90**	3.805	2.674	3.537	**3.335**	0.202
	95	3.831	2.673	3.564		0.229
	85	3.795	2.677	3.528		0.403
High	**90**	3.824	2.664	3.558	**3.125**	0.433
	95	3.805	2.722	3.533		0.408

The effects of pre-set watercut on operation of ICV in different reservoir models with various heterogeneities are quite similar. Reduction of final watercut affects oil production shortly after shutting-in and final watercut in long term in the last operated segment as shown in Figure 5.22, 5.23 and 5.24 where oil production rates together with watercut of last operated segment are plotted with time for reservoir models with low, moderate and high heterogeneity, respectively.

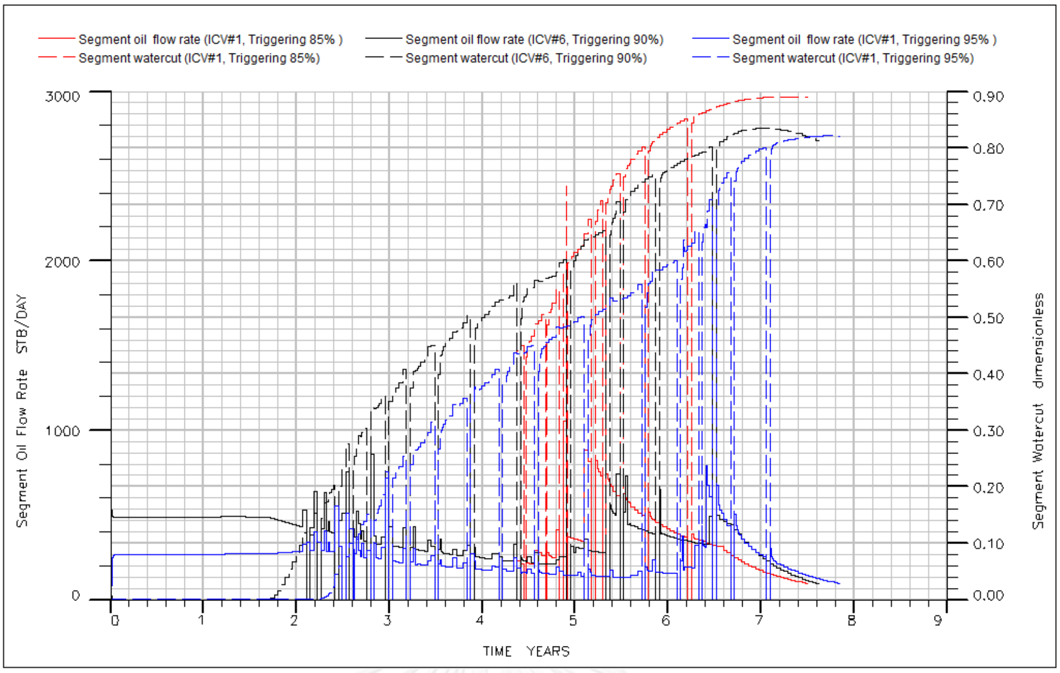


Figure 5.22 Oil production rates and watercut of last operated segment configured with various pre-set watercut values in low heterogeneity model as a function of time

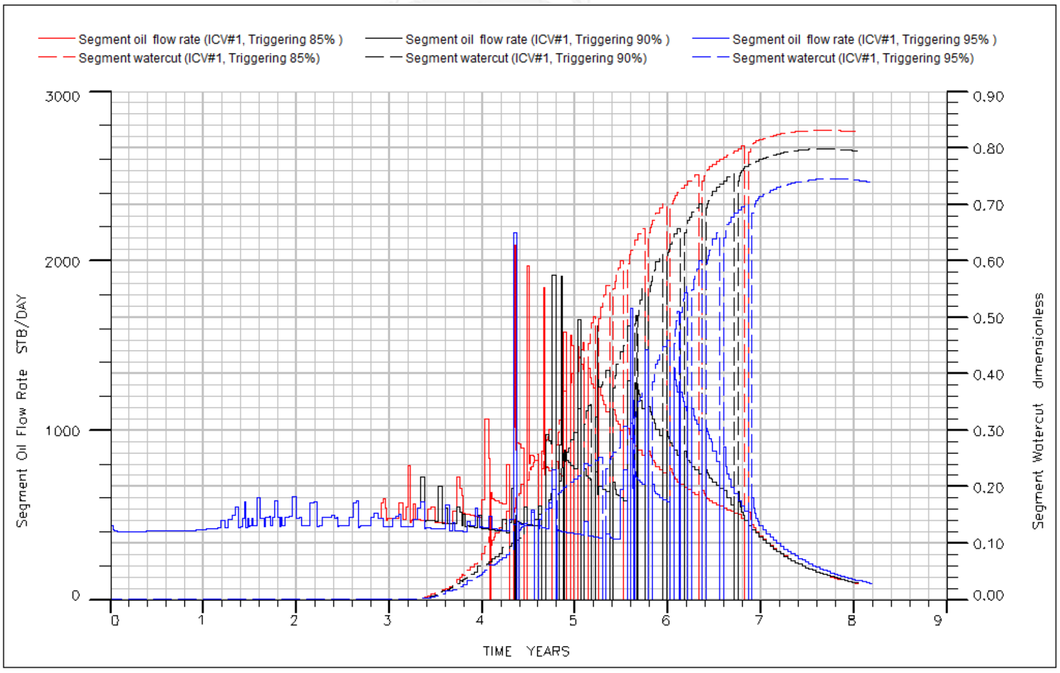


Figure 5.23 Oil production rates and watercut of last operated segment configured with various pre-set watercut values in moderate heterogeneity model as a function of time

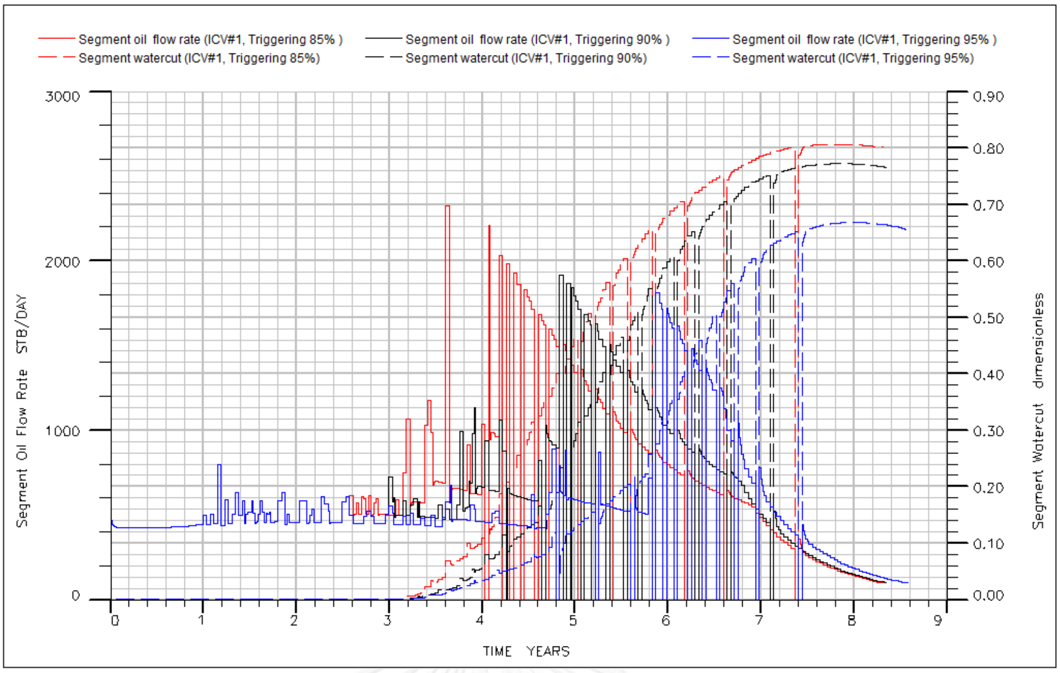


Figure 5.24 Oil production rates and watercut of last operated segment configured with various pre-set watercut values in high heterogeneity model as a function of time

Modifying pre-set watercut to lower value yields higher oil production rate to the last operated segment because other segments are earlier terminated so the well does not produce much liquid and more pressure is still remained inside the reservoir. The last operated ICV therefore, obtains benefit from this higher pressure support. However, this effect is not sustainable and watercut through the last segment is increased with time. Compensation of short term increasing of oil production with higher watercut at late time results in not much benefit of this modification. In case of low heterogeneous model, modification of ICV pre-set watercut still does not yield any improvement on effective oil produced.

In this study, even though modification of pre-set watercut which is performed in the last step does not yield an outstanding improvement to 6 ICVs case, at least simulation results suggest that it might be more secure to configure pre-set watercut around 90% to 95% or higher value if heterogeneity is not precisely recognized due to reservoir uncertainty.

5.7 Effect of Reservoir Heterogeneity

Most favorable parameters including number of ICV, segment partitioning method and pre-set watercut are almost the same for all heterogeneous models as show in Table 5.14. However, reservoir heterogeneity has significant effect on benefit of ICV installation. Effect of heterogeneity is discussed by considering simulation results from previous sections.

Table 5.14 Summary of the most favorable ICV configuration and benefit obtained from ICV installation compared to base cases for different heterogeneity models

Heterogeneity Models	**Most favorable configuration of ICV**			**Percent of difference between ICV case vs. base case**		**Benefit from installing ICV**
	Partitioning Method	**No. of ICV**	**Pre-set Watercut (%)**	**Increment of Oil Production (%)**	**Reduction of Water Production (%)**	
Low	Every Blocks	6	95	-0.7	4.6	No
Moderate	Every Blocks	6	95	5.5	10.2	Yes
High	Every Blocks	6	90	11.1	16.1	Yes

Comparing between case with ICV installation and base configuration case or case with perforated production string, case with ICV installed yields several advantages such as shut-in/re-open during early stage of production and also selectively production from each segment in late stage of production. However, ICV installation tends to trade off some of flow performance from frictional pressure loss between wellbore annulus and production string as ICV nozzle is much less opening area compared to perforated string.

This explanation can be extended to clarify the benefit of ICV in variation of reservoir heterogeneity. Installing ICV in reservoir with low heterogeneity does not achieve any improvement than base case by the way reservoir with low heterogeneity relatively suffers less from water encroachment from underneath aquifer compared to other cases with higher heterogeneities. Therefore, loss of flow performance from ICV nozzle in this case dominates benefit from ICV. In this study, ICV is therefore not suggested to be installed in reservoir with low heterogeneity. From Table 5.14, in case of moderate and high heterogeneous reservoirs, benefit of ICV is much more pronounced by increasing oil gain 5.5% and 11% in case of moderate and high heterogeneous reservoirs compared to that of base cases, respectively. And at the same time, water production is reduced by 10% and 16% in case of moderate and high heterogeneous reservoirs compared to that of base cases, respectively. These benefits are evidences explaining that ICV is capable to deliver effectiveness in control of water cresting and moreover, loss of flow performance from small opening area of ICV nozzle in these cases is suppressed by benefit obtained from ICV installation.

CHAPTER VI
CONCLUSIONS AND RECOMMENDATIONS

The influence of horizontal well location, several configurations of ICV and effects of non-operational parameters are finally concluded in this chapter. Moreover, this section also provides several recommendations for further studies.

6.1 Conclusions

Results from this study indicate that base case with proper choosing of horizontal well location and total liquid production rate are the most basic design parameters to increase well effectiveness. Improvement of oil recovery and reduction of total water production by installing ICV with proper segment division method and pre-setting watercut are very important stage to elevate performance of horizontal well. The following statements are conclusions from this study.

1. In case of horizontal well completed with perforated string, oil might be inefficiently recovered due to two phenomena, water cresting in early period and pressure depleting at later stage of production. Maximum liquid rate or total liquid production rate of the well is one of the most important factors affecting effectiveness of horizontal well. Lower total liquid production rate is desirable in this study as it can prevent water cresting, prolonging oil production. Too high of total liquid production rate yields benefit in early period but it induces early water breakthrough which consecutively causes high watercut and early termination of production. The off-centered location of horizontal well also affects both oil recovery factor and total water production. The further distance away from beneath aquifer results in higher oil recovery. If production constraints are not considered, location closer to aquifer will result in higher water production.

2. Placement of horizontal with heel side on low permeability zone and toe side on high permeability zone yields more favorable result than the opposite well placement. This is because friction inside production string is induced water cresting to heel location, if well placement heel location in low permeability region, water cresting from friction loss is compensated. Contrast between low and high permeability zone results in degree of heterogeneity of reservoir. And from the study, high heterogeneity of high permeability contrast results in earlier water encroachment.
3. Installing ICV yields benefit on the performance of horizontal well. Configuration of ICV is based on combination of two beneficial consequent. First, shutting-in and reopening of ICV yields an increment of oil production and reduces total water production. Second, termination of high watercut ICV yields more favorable result as this occurrence provides selectivity of production zone.
4. Dividing segment length using calculation method affects both oil and water productions. Calculation of segment length using well-contact transmissibility yields more favorable result compared to using transmissibility summation of every block.
5. In this study configuration horizontal well with 6 ICVs, which is the highest number of ICV segments, results in increasing of total oil production and reduction of total water production compared to cases equipped with lower number of ICV. As higher ICV numbers result in more ability to stabilize oil-water contact. However, increment of oil production and reduction of produced water tend to be smaller with an increase of ICV number.
6. Benefit from increasing ICV numbers is obvious in reservoir models with moderate and high heterogeneity. Improvement obtained from installing ICV in reservoir with high heterogeneity case is the most pronounced. However,

modification of ICV numbers does not show significant improvement in reservoir with low heterogeneity.

7. Pre-setting watercut by varying percentage of maximum watercut has small impact on oil and water productions compared to varying other parameters. Nevertheless, modifying pre-set watercut to medium or high value (90-95%) yields very similar and favorable result compared to lower value (85%). So, pre-setting watercut for ICV with medium to high value would be able to sustain beneficial results.
8. Benefit from ICV configuration in reservoir with low heterogeneity is obscure in this study since the well is not affected much from water encroachment problem.

6.2 Recommendations

Several recommendations are provided for further improvement of the ICV placement simulation study.

1. This case is simulated with quite large time step of 2 weeks. Each ICV is operated in opening or closure position at least with duration of 2 weeks. Therefore, time step might affect configuration of other parameters. Hence, further study on this parameter might yield advancement on ICV placement.
2. For this reservoir model, dimensions of grid blocks in X-Y-Z are 25, 50, and 5 feet, respectively. As the well is completed along Y-direction, this indicates minimum node length in multi-segment model used to develop flow model inside tubing and annulus. Due to zonal isolation packer is set in annulus; each zonal isolation packer node is restricted to the length of 50 feet dimension. This might cause excessively blocking of flow path inside annulus particularly in case of high ICV number, requiring many zonal isolation packers.
3. This study only focuses on large aquifer support reservoir. The study of ICV placement in other drive mechanisms might yield difference results.

4. The horizontal well in this study is developed in multi-segments well model. Due to 110 numerical segments in base case and more than 220 numerical segments in ICV configuration case, high amount of segment might result in iteration problem. Setting appropriate iteration parameters in multi-segments well model is required with assistance from simulation software support.
5. In case that permeability data is exactly known, a comparative study with zonal perforation should be performed.

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APPENDIX

APPENDIX

RESERVOIR MODEL CONSTRUCTION BY ECLIPSE SIMULATOR

Reservoir simulation model is developed by entering the required section in Eclipse office simulator including Case definition, Grid, PVT, SCAL, Initialization, Regions and Schedule

1. Case Definition

Simulator: Black Oil Model dimensions

Number of grid in x direction: 25

Number of grid in y direction: 140

Number of grid in z direction: 26

Simulation start date: 1 Jan 2014

Grid type: Cartesian

Geometry type: Block centered

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

2. Grid

Active Grid Block at	Z(1)	= Y(1-120)
	Z(2)	= Y(2-121)
	Z(3)	= Y(3-122)
	.	.
	.	.
	.	.
	Z(20)	= Y(20-139)
	Z(21-26)	= Y(21-140)

Permeability in X-Direction

Permeability Layers	Heterogeneity Cases		
	Low	Moderate	High
1	22.60013	22.61226	22.589657
2	85.84646	25.04473	22.905518
3	94.36226	27.86923	23.222049
4	119.4414	30.53167	23.539281
5	129.033	33.08255	23.857244
6	135.687	35.55434	24.175967
7	141.0349	40.34415	24.815804
8	145.6326	45.01942	26.756382
9	149.7427	49.65234	28.400652
10	153.5123	54.29265	30.072698
11	155.2995	58.97809	33.511034
12	157.0334	63.73957	37.092433
13	158.7208	68.60421	40.837489
14	160.3677	76.14922	46.808229
15	161.9791	78.74252	48.903829
16	163.5594	81.38005	51.057082
17	165.1124	84.06496	53.271177
18	172.5745	86.80044	55.549471
19	178.3213	89.58979	57.895505
20	183.9953	95.34394	62.805996

Permeability Layers	Heterogeneity Cases		
	Low	Moderate	High
21	189.6904	107.6601	73.621331
22	195.4946	121.288	86.039964
23	199.9739	136.5799	100.49454
24	200.5819	154.0082	117.58568
25	201.1928	174.2359	138.17999
26	201.8066	212.0975	178.70213
27	202.4235	227.5335	195.89843
28	203.0437	244.899	215.67741
29	207.8097	264.6704	238.72734
30	207.8097	287.5114	266.02203
31	211.1192	314.3811	298.99409
32	214.5579	346.7339	339.85745
33	218.1496	386.915	424.64915
34	221.9238	398.6048	462.7615
35	230.1737	439.0394	508.49124
36	239.7392	471.8425	564.75341
37	266.9343	511.2645	636.32915
38	301.622	560.1073	710.14005
39	382.1786	623.275	834.8567
40	870.0369	869.9729	870.01708

Permeability in Y-Direction = Permeability in X-Direction

Permeability in Z-Direction = 0.1* Permeability in X-Direction

3. PVT

PVT properties of formation water

Properties	Values	Unit
Water FVF at P_{ref}	1.02233	Rb/STB
Water viscosity at P_{ref}	0.3009445	cP
Water compressibility	3.128539×10^{-6}	psi^{-1}
Water viscosibility	2.969812×10^{-6}	psi^{-1}
Rock compressibility	3.653216×10^{-6}	psi^{-1}

Fluid densities at surface condition

Properties	Values (lb/cuft)
Oil density	49.99914
Water density	62.428
Gas density	0.04369958

Dry gas PVT properties (No vapourised oil)

Pressure (psia)	FVF (rb /Mscf)	Visc (cp)
100	32.918984	0.013295297
450	7.0817707	0.013626204
721.05263	4.3165568	0.013998609
1031.5789	2.9437355	0.014534889
1342.1053	2.2151984	0.015184785
1652.6316	1.769068	0.015944258
1963.1579	1.4722432	0.016804709
2273.6842	1.2640088	0.017751486
2600	1.1058809	0.018817757
2894.7368	0.99900348	0.0198228
3205.2632	0.91207433	0.020904309
3515.7895	0.84405515	0.021991719
3826.3158	0.78979537	0.023071702
4136.8421	0.74572998	0.024135097
4447.3684	0.70934859	0.025176164
4757.8947	0.67885579	0.026191714
5068.4211	0.65294803	0.027180319
5378.9474	0.63066465	0.028141717
5689.4737	0.61128714	0.029076373
6000	0.59427031	0.029985182

Live Oil PVT properties (Dissolved gas)

R_s (Mscf /stb)	P_{bub} (psia)	*FVF* (rb /stb)	*Visc* (cp)
0.015877135	100	1.0753578	0.83971238
	450	1.060178	0.88539178
	721.05263	1.0585605	0.94566502
	1031.5789	1.0577531	1.0347197
	1342.1053	1.0573196	1.143556
	1652.6316	1.057049	1.2720589
	1963.1579	1.0568641	1.4208091
	2273.6842	1.0567298	1.5907215
	2600	1.0566231	1.7932503
	2894.7368	1.0565475	1.9983563
	3205.2632	1.0564829	2.2382735
	3515.7895	1.0564297	2.5036024
	3826.3158	1.0563851	2.7951785
	4136.8421	1.0563472	3.1136411
	4447.3684	1.0563146	3.4593914
	4757.8947	1.0562863	3.8325569
	5068.4211	1.0562615	4.2329606
	5378.9474	1.0562395	4.6600973
	5689.4737	1.0562199	5.1131176
	6000	1.0562023	5.5908179

Live Oil PVT properties continued

R_s (Mscf /stb)	P_{bub} (psia)	*FVF* (rb /stb)	*Visc* (cp)
0.097221555	450	1.1110617	0.64654854
	721.05263	1.1017668	0.66514844
	1031.5789	1.0971517	0.69637514
	1342.1053	1.0946802	0.73628235
	1652.6316	1.0931403	0.78389679
	1963.1579	1.0920888	0.83872082
	2273.6842	1.0913252	0.90049389
	2600	1.0907196	0.97274657
	2894.7368	1.0902902	1.0443991
	3205.2632	1.0899234	1.1264015
	3515.7895	1.0896215	1.2150308
	3826.3158	1.0893686	1.3102129
	4136.8421	1.0891537	1.4118419
	4447.3684	1.0889689	1.5197717
	4757.8947	1.0888082	1.6338092
	5068.4211	1.0886673	1.7537098
	5378.9474	1.0885426	1.879175
	5689.4737	1.0884315	2.0098511
	6000	1.088332	2.14533

4. SCAL

Calculate from Corey's exponent of 2

Water/ Oil Saturation Functions (SWOF)

S_w	K_{rw}	K_{ro}	P_c (psia)
0.2	0	0.44999999	0
0.26666668	0.0037037036	0.35555556	0
0.33333334	0.014814815	0.27222222	0
0.40000001	0.033333335	0.2	0
0.46666667	0.059259258	0.1388889	0
0.53333336	0.09259259	0.088888891	0
0.60000002	0.13333334	0.050000001	0
0.66666669	0.18148148	0.022222223	0
0.73333335	0.23703703	0.0055555557	0
0.80000001	0.30000001	0	0
1	1	0	0

Gas/ Oil Saturation Functions (SGOF)

S_g	K_{rg}	K_{ro}	P_c (psia)
0	0	0.44999999	0
0.050000001	0	0.38343194	0
0.125	0.0070312498	0.29356509	0
0.2	0.028124999	0.21568048	0
0.27500001	0.063281253	0.14977811	0
0.34999999	0.1125	0.095857985	0
0.42500001	0.17578125	0.05392012	0
0.5	0.25312501	0.023964496	0
0.57499999	0.34453124	0.0059911241	0
0.64999998	0.44999999	0	0
0.80000001	1	0	0

5. Initialization

Equilibration data specification

Datum depth : 6,000 ft

Pressure at datum depth : 2,600 psia

OWC depth : 6,100 ft

No Gas Cap

6. Regions

N/A

7. Schedule

Well Specification (WELSPEGS)

Well Name	H
Group	1
I location	13
J location	5
Datum Depth	6000 ft
Preferred Phase	Oil
Inflow Equation	STD
Automatic Shut-In Instruction	SHUT
Crossflow	YES
PVT Property Table	1
Density Calculation	SEG

Well Connection Data (COMPDAT)

Well location on top most layer

I	J	K Upper	K Lower	Open/Shut Flag	Well Bore ID	Direction
13	5	1	1	OPEN	0.510417	Y
13	6	1	1	OPEN	0.510417	Y
13	7	1	1	OPEN	0.510417	Y
13	8	1	1	OPEN	0.510417	Y
13	9	1	1	OPEN	0.510417	Y
13	10	1	1	OPEN	0.510417	Y
.	.	.	.	.	.	.
.	.	.	.	.	.	.
.	.	.	.	.	.	.
13	112	1	1	OPEN	0.510417	Y
13	113	1	1	OPEN	0.510417	Y
13	114	1	1	OPEN	0.510417	Y

Production Well Control (WCONPLOD)

Well	H
Open/Shut Flag	OPEN
Liquid Rate	10,000 STB/d, 7,500 STB/d, 5,000 STB/d, 2,500 STB/d
BHP Target	500 psia

Production Well Economic Limit (WECON)

Well	H
Minimum Oil Rate	100 STB/d
Maximum Water Cut	0.95
End run	YES

Segment Well Definition (WELSEGS)

First Seg	Last Seg	Branch	Outlet Seg	Length (ft)	Depth (ft)	Diameter (ft)	Roughness (ft)
2	2	1	1	50	0	0.33438333	0.0072
3	3	1	2	50	0	0.33438333	0.0072
4	4	1	3	50	0	0.33438333	0.0072
5	5	1	4	50	0	0.33438333	0.0072
6	6	1	5	50	0	0.33438333	0.0072
.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.
108	108	1	107	50	0	0.33438333	0.0072
109	109	1	108	50	0	0.33438333	0.0072
110	110	1	109	50	0	0.33438333	0.0072

Segment Well Completion (COMPSEG)

***In ECL 2014, this keyword required input method to be only text file.

```
COMPSEGS
'H' /
13 5 1 1 2* 'J' 3* /
13 6 1 1 2* 'J' 3* /
13 7 1 1 2* 'J' 3* /
13 8 1 1 2* 'J' 3* /
13 9 1 1 2* 'J'3* /
13 10 1 1 2* 'J' 3* /
        .
        .
        .
13 112 1 1 2* 'J' 3* /
13 113 1 1 2* 'J' 3* /
13 114 1 1 2* 'J' 3* /
/
```

8. ICV Configuration Schedule

Several keyword input in ICV placement case is identical to base case however some keyword is added or change follow list below.

In this appendix, configuration of 4 ICVs with uniform segment length and ICV operational range of 0.05-0.95 is displays.

Segment Well Definition (WELSEGS)

First Seg	Last Seg	Branch	Outlet Seg	Length (ft)	Depth (ft)	Diameter (ft)	Roughness (ft)	Area (ft^2)
2	2	1	1	50	0	0.33438333	0.0072	
3	3	1	2	50	0	0.33438333	0.0072	
4	4	1	3	50	0	0.33438333	0.0072	
.	.	.	.	.	.	.	.	
.	.	.	.	.	.	.	.	
.	.	.	.	.	.	.	.	
109	109	1	108	50	0	0.334383	0.0072	
110	110	1	109	50	0	0.334383	0.0072	
111	111	1	110	50	0	0.0001	0.0072	
112	112	1	111	50	0	0.176034	0.0072	0.063479
113	113	1	112	50	0	0.176034	0.0072	0.063479
114	114	1	113	50	0	0.176034	0.0072	0.063479
.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.
136	136	1	135	50	0	0.176034	0.0072	0.063479
137	137	1	136	50	0	0.176034	0.0072	0.063479
138	138	1	137	50	0	0.176034	0.0072	0.063479
139	139	1	138	50	0	0.0001	0.0072	
140	140	1	139	50	0	0.176034	0.0072	0.063479
141	141	1	140	50	0	0.176034	0.0072	0.063479
142	142	1	141	50	0	0.176034	0.0072	0.063479
.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.
163	163	1	162	50	0	0.176034	0.0072	0.063479
164	164	1	163	50	0	0.176034	0.0072	0.063479

First Seg	Last Seg	Branch	Outlet Seg	Length (ft)	Depth (ft)	Diameter (ft)	Roughness (ft)	Area (ft^2)
165	165	1	164	50	0	0.176034	0.0072	0.063479
166	166	1	165	50	0	0.0001	0.0072	
167	167	1	166	50	0	0.176034	0.0072	0.063479
168	168	1	167	50	0	0.176034	0.0072	0.063479
169	169	1	168	50	0	0.176034	0.0072	0.063479
.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.
190	190	1	189	50	0	0.176034	0.0072	0.063479
191	191	1	190	50	0	0.176034	0.0072	0.063479
192	192	1	191	50	0	0.176034	0.0072	0.063479
193	193	1	192	50	0	0.0001	0.0072	
194	194	1	193	50	0	0.176034	0.0072	0.063479
195	195	1	194	50	0	0.176034	0.0072	0.063479
196	196	1	195	50	0	0.176034	0.0072	0.063479
.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.
218	218	1	217	50	0	0.176034	0.0072	0.063479
219	219	1	218	50	0	0.176034	0.0072	0.063479
220	220	1	219	50	0	0.176034	0.0072	0.063479
221	221	2	15	700	0	0.35681	5.00E-05	0.1
222	222	3	42	2050	0	0.35681	5.00E-05	0.1
223	223	4	69	3400	0	0.35681	5.00E-05	0.1
224	224	5	96	4750	0	0.35681	5.00E-05	0.1

Segment Well Completion (COMPSEGS)

***In ECL 2014, this keyword required input method to be only text file.

```
COMPSEGS
'H' /
13 5 1 1 2* 'J' 3* 220 /
13 6 1 1 2* 'J' 3* 219 /
13 7 1 1 2* 'J' 3* 218 /
        .
        .
        .
13 110 1 1 2* 'J' 3* 115 /
13 111 1 1 2* 'J' 3* 114 /
13 112 1 1 2* 'J' 3* 113 /
13 113 1 1 2* 'J' 3* 112 /
13 114 1 1 2* 'J' 3* 111 /
/
```

Sub-critical Valve Segment (WSEGVALV)

***In ECL 2014, this keyword required input method to be only text file.

```
WSEGVALV
'H' 221 1 0.1 2* 0.00005 1* OPEN /
'H' 222 1 0.1 2* 0.00005 1* OPEN /
'H' 223 1 0.1 2* 0.00005 1* OPEN /
'H' 224 1 0.1 2* 0.00005 1* OPEN /
/
```

Defines The Chord Segment Links for Specifying Looped Flowpaths (WSEGLINK)

***In ECL 2014, this keyword required input method to be only text file.

```
WSEGLINK
H 206 221 /
H 179 222 /
H 152 223 /
H 125 224 /
/
```

Set of keyword to govern the ICV policies (set of ACTIONX)

***In ECL 2014, this keyword required input method to be only text file.

```
ACTIONX
SHUTWATER 100000 /
SWCT 'H' 1 >= 0.95 /
/
END
/


ENDACTIO


ACTIONX
SHUTOFR 1 /
SOFR 'H' 1 < 100 AND/
SOFR 'H' 221 > 0 /
```

```
/
END
/

ENDACTIO

ACTIONX
OPEN221 25 /
SWCT 'H' 221 = 0 /
/
WSEGVALV
'H' 221 1 0.1 2* 0.00005 1* OPEN /
/

ENDACTIO

ACTIONX
SHUT221 100000 14 /
SWCT 'H' 221 >= 0.05 0.05 /
/
WSEGVALV
'H' 221 1 0.1 2* 0.00005 1* SHUT /
/
```

```
ENDACTIO

ACTIONX
OPEN222 14 /
SWCT 'H' 222 = 0 /
/
WSEGVALV
'H' 222 1 0.1 2* 0.00005 1* OPEN /
/

ENDACTIO

ACTIONX
SHUT222 100000 14 /
SWCT 'H' 222 >= 0.05 0.05 /
/
WSEGVALV
'H' 222 1 0.1 2* 0.00005 1* SHUT /
/

ENDACTIO

ACTIONX
OPEN223 15 /
```

```
SWCT 'H' 223 = 0 /
/
WSEGVALV
'H' 223 1 0.1 2* 0.00005 1* OPEN /
/

ENDACTIO

ACTIONX
SHUT223 100000 14 /
SWCT 'H' 223 >= 0.05 0.05 /
/
WSEGVALV
'H' 223 1 0.1 2* 0.00005 1* SHUT /
/

ENDACTIO

ACTIONX
OPEN224 15 /
SWCT 'H' 224 = 0 /
/
WSEGVALV
'H' 224 1 0.1 2* 0.00005 1* OPEN /
```

```
/

ENDACTIO

ACTIONX
SHUT224 100000 14 /
SWCT 'H' 224 >= 0.05 0.05 /
/
WSEGVALV
'H' 224 1 0.1 2* 0.00005 1* SHUT /
/

ENDACTIO
```

VITA

Sermsuk Thanabanjerdsin was born on October 19th, 1989 in Bangkok, Thailand. He received his Bachelor degree in Mechanical Engineering from Faculty of Engineering, Chulalongkorn University in 2011. After obtaining first degree, he continued his study in the Master's Degree program in Petroleum Engineering at the Department of Mining and Petroleum Engineering, Faculty of Engineering, Chulalongkorn University since the academic year 2014.