Evaluation and Optimization of Double Displacement Process

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การประเมินและการหาค่าที่เหมาะสมของกระบวนการแทนที่สองครั้ง

นายวิศรุต สาธิตคณิตกุล

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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การแทนที่สองครั้งเป็นการผสมผสานกันระหว่างการฉีดอัดน้ำและการฉีดอัดแก๊ส โดยเมื่อเสร็จสิ้นการฉีดน้ำแล้วจะมีน้ำมันเหลืออยู่ในแหล่งกักเก็บจำนวนมากเนื่องจากน้ำไม่สามารถดันน้ำมันที่อยู่ในช่องว่างระหว่างเนื้อหินออกมาได้ดังนั้นเราจะฉีดอัดแก๊สที่ส่วนบนของแหล่งกักเก็บเพื่อที่จะนำน้ำมันขึ้นมาได้มากยิ่งขึ้น โดยการแทนที่น้ำมันด้วยแก๊ส

ในการศึกษานี้ เราจะศึกษาผลกระทบของ ความลาดเอียง เวลาสำหรับการหยุด การฉีดอัดน้ำ อัตราการฉีดอัดน้ำ อัตราการฉีดอัดแก๊ส และรูปแบบการวางหลุมเพื่อที่จะหาวิธีที่ดีที่สุดของการแทนที่สองครั้ง ยิ่งไปกว่านั้นเราจะศึกษาการวิเคราะห์ค่าเชิงละเอียดซึ่งมีผลมาจากการใช้ความสัมพันธ์ที่ต่างกันของค่าความซึมผ่านสัมพัทธ์ระหว่างของเหลว อัตราส่วนในแนวตั้งต่อแนวนอนของค่าความซึมผ่าน และชนิดของความสามารถของการเปียก โดยที่แหล่งกักเก็บที่มีความลาดเอียงมากกว่าให้ประสิทธิภาพมากกว่า การหยุดการฉีดอัดน้ำเมื่ออัตราส่วนการผลิตน้ำที่ 60 เปอร์เซ็นต์ให้ประสิทธิภาพดีที่สุด ในด้านอัตราการฉีดอัดน้ำและแก๊สพบว่าใช้อัตราการฉีดอัดที่ 8000 RB/D จะได้ปริมาณน้ำมันที่นำขึ้นมาได้มากที่สุด สำหรับรูปแบบการวางหลุมนั้นใช้หลุมแนวนอนเป็นหลุมผลิตที่ส่วนล่างสุดของ แหล่งกักเก็บจะให้ประสิทธิภาพการผลิตดีที่สุด จากการวิเคราะห์ค่าเชิงละเอียดพบว่าผลจากการใช้ความสัมพันธ์ที่ต่างกันของค่าความซึมผ่านสัมพัทธ์ระหว่างของเหลวนั้นมีความแตกต่างกันเพียงเล็กน้อย ด้านอัตราส่วนในแนวตั้งและแนวนอนของค่าความซึมผ่านพบว่าหากแหล่งกักเก็บอัตราส่วนที่มากกว่าจะให้ประสิทธิภาพที่ดีกว่าเนื่องจากของเหลวจะสามารถไหลในแนวตั้งได้ดีกว่า ในด้านของความสามารถของการเปียก แบบเปียกน้ำจะให้ประสิทธิภาพที่ดีกว่าในช่วงแรก แต่แบบเปียกน้ำมันจะให้ประสิทธิภาพที่ดีกว่าในระยะหลัง

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Double Displacement Process or DDP is the combination between water injection and gas injection. At the end of water injection, there is still a certain amount of oil remaining in the reservoir. Therefore, we can inject gas on top of the reservoir in order to recover more oil by displacing the oil with gas.

In this study, we investigate the effect of dip angles, stopping time for water injection, water injection rate, gas injection rate, and well pattern to determine the best strategy for DDP. Moreover, the sensitivity due to uncertainty in relative permeability, vertical to horizontal permeability ratio, and type of wettability is also included. The more the dip angle, the better the DDP performance. Using the water cut of 60% as the stopping criteria for water injection yields the best production performance. In term of water and gas injection rate, using the rate of 8,000 RB/D yields the best oil recovery factor. For well pattern, using horizontal well as the producer at the bottommost of the reservoir yields the best performance. For sensitivity analysis, the results show that different relative permeability correlations provide insignificant different results. Regarding the effect of vertical to horizontal permeability ratio, it can be concluded that the higher the ratio, the higher the oil recovery due to higher ability to flow in the vertical direction. Type of wettability has a large effect on the performance of DDP. Each type of wettability has a good potential for different periods. Water-wet is better at the early time of DDP while oil-wet shows the better performance at the late time.

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List of Abbreviations

DDP	Double displacement process
mD	Millidarcy
MMscf/d	Million standard cubic feet per day
Mscf/d	Thousand standard cubic feet per day
OOIP	Original oil in place
Psi	Pounds per square inch
Psia	Pounds per square inch absolute
PVT	Pressure-volume-temperature
RF	Recovery factor
SCAL	Special core analysis
Scf	Standard cubic foot
Stb	Stock-tank barrel
STB/D	Stock-tank barrel per day
BOE	Barrel of oil equivalent
W_p	Amount of water production
W_{inj}	Amount of water injection
G_p	Amount of gas production
G_{inj}	Amount of gas injection
N_P	Cumulative oil production
RB/D	Reservoir barrel per day

Nomenclature

$\Delta\rho$	Water-oil sensity different
μ_{o}	Oil viscosity
μ_w	Water viscosity
C_o	Corey-oil exponent
C_w	Corey-water exponent
k	Absolute 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
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)

CHAPTER I

INTRODUCTION

1.1 Background

The world oil reserves are very fast depleting. With the current rate of consumption, the oil reserves will be available for just only another 40 years. Global oil companies are engaged in devising new ways to sustain the available amount of oil. Improved oil recovery is one of the techniques that holds a significant key to future supply of oil. Gas injection is one of the popular strategies that can improve oil recovery and maintain the reservoir pressure. Carbon-dioxide and natural gas are good candidate for injection source because of its favorable properties and substantial availability.

Double displacement process (DDP) is the combination between water injection and gas injection. It starts with injecting water into the reservoir to improve oil recovery. However, there is still a certain amount of oil remaining in the reservoir which water cannot displace. So, after we finish injecting water, we can inject gas up-dip into a water-invaded oil column in order to mobilize and produce remaining oil. DDP uses gas injection to provide high pressure gas to the reservoir after water flooding to displace the remaining oil. As a result, we gain additional oil from such process.

In this study, ECLIPSE reservoir simulator is used to investigate the performance of double displacement method. Four important design parameters which are 1) Stopping time for water injection 2) water injection rate 3) gas injection rate and 4) well pattern are studied in order to determine the best strategy for double displacement via water and gas injection for different dip angles of the reservoir. The effects of three system parameters which are 1) relative permeability 2) vertical to horizontal permeability ratio 3) type of wettability are investigated as well.

1.2 Objectives

1. To determine the best conditions in terms of stopping time for water injection, water injection rate, gas injection rate, and well pattern for double displacement strategy.
2. To study the effect of different system parameters, i.e., relative permeability, vertical to horizontal permeability ratio, and type of wettability, on double displacement process.

1.3 Outline of thesis

This thesis consists of 6 chapters as listed below:

Chapter 1 introduces the inspiration and concept of this study.

Chapter 2 shows the previous studies that are related to this study.

Chapter 3 describes theories used in this study.

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

Chapter 5 presents results and discussions.

Chapter 6 concludes all of the cases study.

CHAPTER II

LITERATURE REVIEW

This chapter summarizes previous studies related to the improved oil recovery by using double displacement process.

An oil recovery improvement method uses sophisticated techniques to improve oil displacement or fluid flow in the reservoir. For double displacement process, we start with water flooding. Water flooding is a widely used technique for increasing oil recovery. The principle behind the technique is to displace the oil and at the same time maintain pressure in a reservoir by injecting water. A water flooding process can only recover 40% – 60% of the original oil in place of the oil reservoirs. However, experimental results have shown that nearly 100% of the original oil in place can be recovered by gas injection in the presence of connate water. Recoveries around 85% of original oil in place via gas injection have been reported from field tests. In order to increase oil recovery in a waterflooded oil field, gas may be injected up dip to displace the remaining oil. This process is known as the Double Displacement Process (DDP) because it involves the use of gas to displace the oil remaining in the reservoir after water displaces the oil in the initial phase of production.

Singhal et al. [1] studied the screening criteria that can provide favorable conditions for water flooding to be economically successful which are summarized as follows:

- thickness > 6 m, porosity > 10% and near well oil saturation > 50%
- transmissibility () of the reservoir > 0.1darcy.metre/mPa.s
- reserves life index of ongoing water flooding of over 10 years
- low value of skin factors for producers and injectors required

Fassihi and Gillham [2] studied the DDP by using air injection to improve oil recovery. They said that injection and production rates are very important parameters which affect performance of DDP. So, it is very important to choose the optimum injection and production rates. They also pointed out the gravity drainage effect on the DDP performance as well. Gravity drainage has two aspects. First, the displaced oil drains downward at a rate given by Darcy's law. Second, the accumulated oil at the bottom of the reservoir flows down to join the oil column. The authors studied the effect of permeability on the gravity drainage rate by using centrifuge tests. After the test, they concluded that gravity drainage rate increases with higher oil permeability and higher density difference between the oil and the injected gas.

Gachuz-Muro et al. [3] studied the efficiency of oil recovery using DDP and SCWD of fractured reservoir. Second contact water displacement process (SCWD) is a modification of DDP by injection of water after DDP. There were two types of gas that the authors used for injection: Nitrogen and natural gas. Their results indicate that injection of natural gas in naturally fractured reservoirs with light oils can significantly recover more oil than using nitrogen. They also said that temperature and ion composition (calcium, magnesium, sulfate) in brine that they used to inject were extremely important to alter wettability. Sulfate ion seems to play a key rule due to the affinity to carbonate formations. After the experiment on sulfate ion, they concluded that the sulfate may be a wettability modifier in chalk, limestone and dolomite. For comparison the efficiency between DDP and SCWD, they conclude that SCWC can slightly increase oil recovery. So, they suggest to choose DDP instead of SWCD.

Langenberg [4] studied the possibility of double-displacement process (DDP) for immiscible tertiary gas displacement of a watered-out oil reservoir in Hawkins field of east Texas. They concluded that the effectiveness of immiscible nitrogen injection process is strongly driven by favorable gravity-drainage characteristics and leads to improved sweep and displacement efficiencies for the gas/oil system relative to the water/oil system.

Carlson [5] proposed that a test of Double Displacement Process can be economically accomplished in the East Fault Block, Hawkins Field by monitoring the growth of the oil column, using GR/N and PNC logs.

Kantzas et al [6] estimated DDP using glass bed columns. Experiments were carried out with “continuous oil”, i.e., oil was the continuous phase in presence of irreducible water, and “discontinuous oil”, i.e., residual oil after waterflooding. Oil displacement was performed under “free drainage” and “controlled drainage” conditions. These terms refer to drainage of oil due to its own weight and due to the hindrance of a semipermeable membrane, respectively. Using controlled displacement, the recovery of continuous oil approached 100% of the original oil-in-place while the recovery of continuous oil was 85-95%. Under free drainage conditions, recoveries of continuous oil were lower and ranged from 73-79% of the original oil-in-place.

Ren et al [7] studied the DDP and SWCD by using a transparent sandpack micromodel which allowed them to investigate the microscopic mechanisms of the DDP and the SCWD processes. They concluded that a reservoir with high degree dip angle is favorable condition for DDP. Injection and production rates play a very important role in controlling the oil drainage rate. For the SCWD, they concluded that it is suited in the condition that the reservoir has high irreducible gas saturation.

Stone [8] studied three-phase relative permeabilities by using combinations of two phase relative permeabilities which are oil/water and oil/gas relative permeabilities. He explained that relative permeabilities are essentially dependent on pore geometry, wettability, fluid saturation, reservoir temperature, reservoir pressure, overburden pressure, rock lithology and porosity. He came up with a correlation to determine oil relative permeability when oil, water and gas are present in the system.

Nakornthap et al [9] derived the relationship between temperature and relative permeability using mathematical model. His model expressed that the relative permeability is a function of water saturation and temperature.

Xiao [10] studied the effect of reservoir temperature and pressure on relative permeability. He concluded that the temperature and pressure at experimental conditions do not affect the relative permeability curves of water but affect the relative permeability of gas dramatically.

CHAPTER III

THEORY AND CONCEPTS

3.1 Double displacement process

Double displacement process (DDP) is a process of injecting gas into waterflooded oil zones. When residual oil is in contact with injected gas, it forms a thin film. Subsequent drainage of the oil film creates a bank which flows down-dip and could be produced. The objective of injecting gas into waterflooded oil zone is to improve oil recovery by generating a gas cap and thereby allowing gravity drainage of the liquids to occur. Two displacement processes which are oil being displaced by water and water flooded oil involved when double displacement is performed. So, double displacement process can be defined as the gas displacement of a previously water displaced oil column as shown in Figure 3.1. In the operation of gas injection, gas will help mobilize oil until the oil-water contact is lowered to its initial position at the beginning of reservoir production. Under favorable conditions, improved oil recovery can be achieved effectively.

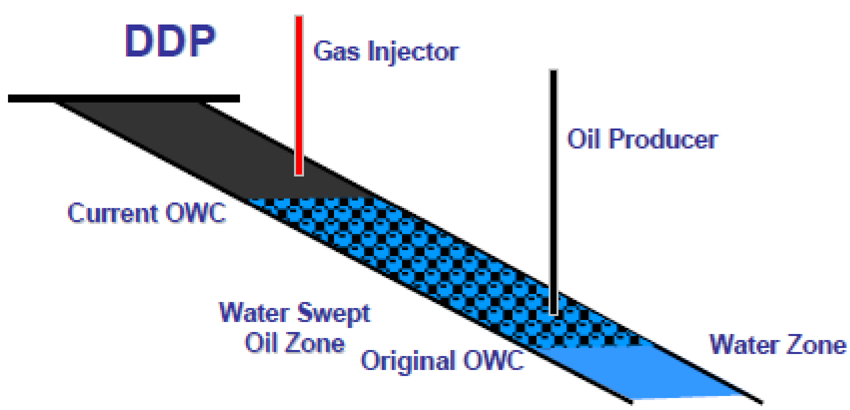

Figure 3.1 : Double displacement process (after [3])

Gravity drainage drive mechanism plays very important role in DDP. The mechanism of gravity drainage occurs in the reservoirs when there is difference in densities of the reservoir fluids. To make this more simplified, we can experiment by mixing a quantity of crude oil and a quantity of water in a jar and agitating the contents. After agitation, resting the jar for a few minutes, and the denser fluid (normally water) will settle to the bottom of the jar while the less dense fluid (normally oil) will rest on top of the denser fluid. This phenomenon is a result of the gravitational forces acting on them.

In order to take maximum advantage of the gravity-drainage-producing mechanism, production wells should be located as structurally low as possible. Important parameters that affect the performance of DDP are summarized as follows:

- permeability in the direction of dip
- dip of the reservoir
- reservoir producing rates
- oil viscosity
- relative permeability

If permeability in the direction of the dip is high, it allows fluids to flow more easily. In term of dip angle, a reservoir with high dip angle allows us to recover more oil due to assistance of gravity drainage force [7]. The oil production rate is important parameter because if we use too high production rate at the early time, oil rate may poor at late time. Oil viscosity is also important. If the viscosity is too high, it is hard to recover the oil.

3.2 Gravity drainage

Basically, fluids in the reservoirs are affected by the force of gravity, as evidenced by the relative positions of the fluids, i.e., gas on top, oil underlying the gas, and water underlying the oil. There are many equations that can be used to estimate the performance of DDP. One of the popular equations which provide a good estimation the oil displaced rate during the DDP was introduced by Hall [14] as shown in Equation 3.1:

$$\boldsymbol{e_o = -6.33(k_{ro})\frac{kA}{\mu_o}\left\{\frac{1}{(k_{ro})\frac{kA}{\mu_o}+(k_{rg})\frac{kA}{\mu_g}}\left[(k_{rg})\frac{kA}{\mu_g}(\alpha_g-\alpha_o)-\frac{e}{6.33}\right]\right\}} \qquad \textbf{(3.1)}$$

where

e_o	=	oil influx rate, cu ft/day
e	=	toal influx rate, cu ft/day
k	=	absolute permeability, darcies
k_{ro}	=	relative permeability to oil
A	=	cross-sectional are, sq ft
μ_o	=	oil viscosity, cp
μ_g	=	gas viscosity, cp
α_o	=	gravity gradient due to oil density, psi/ft
α_g	=	gravity gradient due to gas density, psi/ft

In term of reservoir pressure, there are variable rates of pressure decline that depends principally upon the amount of gas being injected into the reservoir. Strictly speaking, the more the amount of gas, the more the reservoir pressure is maintained.

3.3 Wettability

Interaction between the rock surface and the fluids in the reservoir will determine the distribution of the fluids and also affect the flow of fluids in pore spaces. When two immiscible fluids are located in contact with a rock surface, one of them prefers to attract to the rock surface than another one. The preferred fluid is identified as the wetting phase while the other phase is the non-wetting phase. Wettability is a function of rock and fluid properties.

Basically, there are 3 methods that can be used to identify the type of wettability which are contact-angle, Amott method, and USMB method. The contact-angle is a technique to determine the wettability of a pure mineral surface such as calcite and quartz while Amott and USMB techniques measure the average wettability of a core sample.

Type of wettability

Basically, there are 3 types of wettability which are described as follows:

- Water-wet is a surface that prefers to adhere water when there is a presence of oil phase. It is generally considered as a favorable condition for oil production.

- Oil-wet is a surface that tends to attach oil in the presence water phase. The condition is unfavorable for oil production.

- Neutral-wet is a surface having either water-wet or oil-wet characters or a surface without wettability preference. Several studies concluded that neutral-wet is the most favorable condition for oil production.

3.4 Relative Permeability

Effective permeability data are generally presented as relative permeability data. The relative permeability is defined as the ratio of the effective permeability of a phase to a base permeability.

<u>Two-phase relative permeability model</u>

Basically, the way to measure relative permeability directly on actual core samples from the reservoir is very difficult. Therefore, several correlations have been developed in order to determine relative permeability as a function of fluid saturation.

3.4.1 Corey's correlation

Corey [11] developed the equation to determine two-phases relative permeabilities. In ECLIPSE reservoir simulator, Corey's correlation can be used to generate the relative permeability curves. Equations 3.2-3.3 are used for calculate the relative permeability to oil and water. The relative permeability to oil and gas can be calculated by using Equations 3.4-3.5.

<u>For oil-water</u>

$$k_{ro} = \left(\frac{1-S_w-S_{or}}{1-S_{wi}-S_{or}}\right)^{N_o} \quad \textbf{(3.2)}$$

$$k_{rw} = k_{rwend}\left(\frac{S_w-S_{wi}}{1-S_{wi}-S_{or}}\right)^{N_w} \quad \textbf{(3.3)}$$

<u>For oil-gas</u>

$$k_{ro} = \left(\frac{1-S_g-S_{wi}-S_{or}}{1-S_{wi}-S_{or}}\right)^{N_o} \quad \textbf{(3.4)}$$

$$k_{rg} = \left(\frac{S_g-S_{gc}}{1-S_{wi}-S_{or}-S_{gc}}\right)^{N_g} \quad \textbf{(3.5)}$$

where

S_w	=	water saturation,
S_{or}	=	residual oil saturation,
S_{wi}	=	initial water saturation (or connate water),
S_{gc}	=	critical gas saturation,
S_g	=	gas saturation
k_{ro}	=	relative permeability to oil at any water saturation,
k_{rw}	=	relative permeability to water at any water saturation,
k_{rg}	=	relative permeability to gas at any water saturation,
k_{rwend}	=	relative permeability to water at minimum water saturation,
N_w	=	Corey water exponent,
N_o	=	Corey oil exponent,
N_g	=	Corey gas exponent.

Three phase relative permeability

In general, it is very difficult and complex to determine three-phase relative permeability. So, it is more common to measure two-phase relative permeabilities and expand them to determine three-phase relative permeabilities.

There are several correlations that can be used to estimate three-phase relative permeabilities such as

3.4.2 ECLIPSE Model

The default model for the 3-phase oil relative permeability is based on an assumption of complete segregation of the water and gas within the reservoir. The model provides a simple but effective formula which avoids the problems associated with other methods. The ECLIPSE Model is shown in Figure 3.2. The oil saturation is assumed to be constant and equal to the block average value, S_o, throughout the cell. The gas and water are assumed to be completely segregated, except that the water saturation in the gas zone is equal to the connate saturation, S_{wco} . So, assuming the block average saturations are S_o, S_w, and S_g, (with $S_o + S_w + S_g = 1$), we can write the fractional for the water zone and gas zone as the following.

For gas zone

In a fraction $S_g/(S_g + S_w - S_{wco})$ of the cell,

the oil saturation is S_o ,

the water saturation is S_{wco} ,

the gas saturation is $S_g + S_w - S_{wco}$,

For water zone

In a fraction $(S_w - S_{wco})/(S_g + S_w - S_{wco})$ of the cell,

the oil saturation is S_o ,

the water saturation is $S_g + S_w$,

the gas saturation is 0,

The oil relative permeability is than given by

$$k_{ro} = \frac{S_g k_{rog} + (S_w - S_{wco})k_{row}}{(S_g + S_w - S_{wco})} \tag{3.6}$$

where

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

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

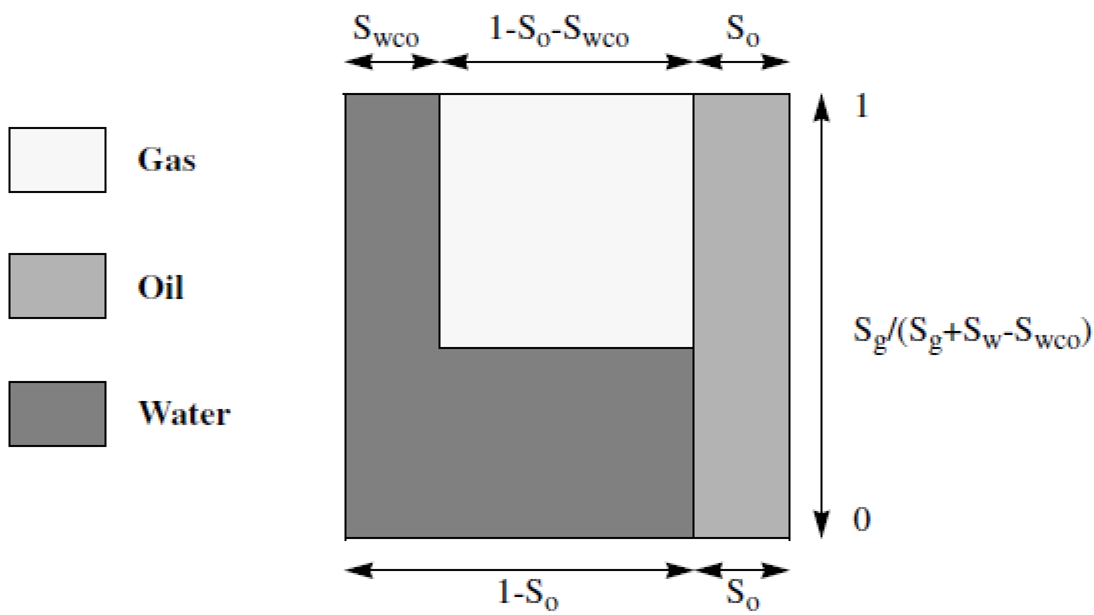

Figure 3.2 : The default 3-phase oil relative permeability model assumed by ECLIPSE

3.4.3 Stone's Model 1

Stone [7] developed a correlation to determine three-phase relative permeability when the values of two-phase relative permeability are available. Channel flow theory was used in developing the correlation. The correlation accounts for hysteresis effects when water and gas saturations are changing in the same direction. The use of the channel flow theory implies that water-relative permeability and water-oil capillary pressure in the three-phase system are functions of water saturation alone, irrespective of the relative saturations of oil and gas. Moreover, they are the same function in the three-phase system as in the two-phase water-oil system. Similarly, the gas-phase relative permeability and gas-oil capillary pressure are the same functions of gas saturation in the three-phase system as in the two-phase gas-oil system. Stone suggested that a nonzero residual oil saturation, called minimum oil saturation, S_{om}, exists when oil is displaced simultaneously by water and gas. It should be noted that this minimum oil saturation is different from the critical oil saturation in the oil-water system i.e., $S_{orw}$and the residual oil saturation in the gas-oil system, i.e.,S_{org}. Stone introduced the following normalized saturations:

$$S_o^* = \frac{S_o - S_{om}}{(1 - S_{wc} - S_{om})} \quad \textbf{(3.7)}$$

$$S_w^* = \frac{S_w - S_{wc}}{(1 - S_{wc} - S_{om})} \quad \textbf{(3.8)}$$

$$S_g^* = \frac{S_g}{(1 - S_{wc} - S_{om})} \quad \textbf{(3.9)}$$

The oil-relative permeability in a three-phase system is then defined as:

$$k_{ro} = S_o^* \beta_w \beta_g \quad \textbf{(3.10)}$$

The two multipliers β_w and β_g are determined from:

$$\beta_w = \frac{k_{row}}{1 - S_w^*} \quad \textbf{(3.11)}$$

$$\beta_g = \frac{k_{rog}}{1 - S_g^*} \quad \textbf{(3.12)}$$

where

S_{om} = minimum oil saturation

k_{row} = oil relative permeability as determined from the oil-water two-phase relative permeability at S_w

k_{rog} = oil relative permeability as determined from the gas-oil two-phase relative permeability at S_g

3.4.4 Stone's Model 2

A modified form of Stone's model l was suggested to avoid the difficulties in choosing S_{om}. The equation of this model is

$$k_{ro} = (k_{row} + k_{rw})(k_{rog} + k_{rg}) - k_{rw} - k_{rg} \quad \textbf{(3.13)}$$

This equation can be rearranged in normalized form as:

$$k_{ro} = k_{rocw}[(\frac{k_{row}}{k_{rocw}} + k_{rw})(\frac{k_{rog}}{k_{rocw}} + k_{rg}) - k_{rw} - k_{rg}] \quad \textbf{(3.14)}$$

3.5 Suitable injection rate

In a dipping reservoir, Essley [12] constructed the model that allows the calculation of the critical injection rate that provides a stable displacement for waterflooding process. He uses 2 parameters that are dimensionless gravity number (G) and the end-point mobility ratio (M^*) to identify the stability of displacement.

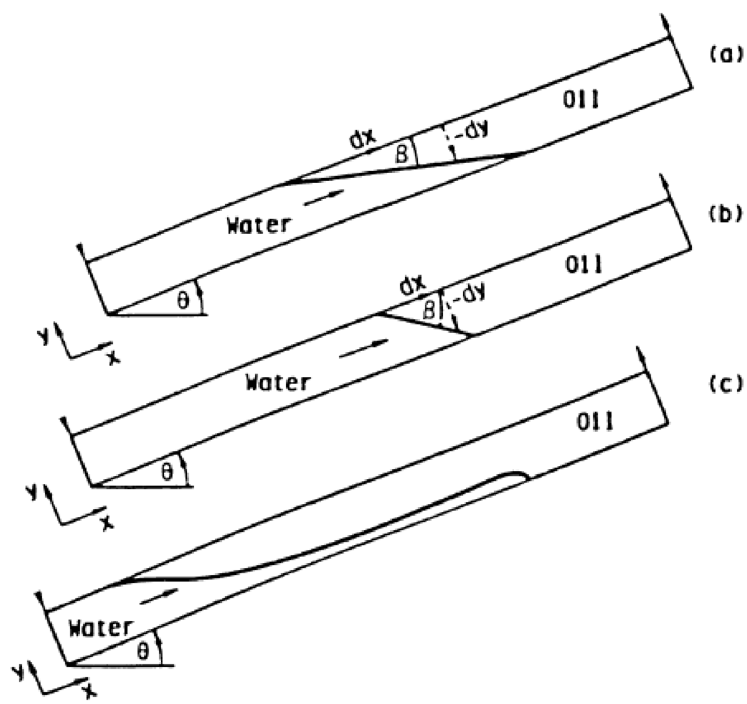

Figure 3.3 : Stable and unstable displacement in gravity segregated displacement: (a) stable: $G > M - 1$, $M > 1$, (b) stable: $G > M - 1$, $M < 1$, (c) unstable: $G < M - 1$ (after [15])

The dimensionless gravity number (G) is defined as:

$$G = \frac{7.853x10^{-6} k k_{rw} A(\rho_w - \rho_o) \sin\theta}{i_w \mu_w} \tag{3.15}$$

where

k	=	absolute permeability, md
k_{rw}	=	relative permeability to water as evaluated at S_{or}
A	=	cross-sectional area
ρ_w	=	water density, lb/ft3
Θ	=	dip angle

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

$$M^* = \frac{k_{rw}@S_{or}\mu_o}{k_{ro}@S_{wi}\mu_w} \tag{3.16}$$

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

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

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

The critical flow rate, i_{crit} is

$$i_{crit} = \frac{7.853x10^{-6} k k_{rw} A(\rho_w - \rho_o) \sin\alpha}{\mu_w (M^* - 1)} \tag{3.17}$$

where

i_{crit}	=	critical water-injection rate, bbl/day
k_{rw}	=	relative permeability to water @ S_{or}
μ_w	=	water viscosity, cp
K	=	absolute permeability, md
α	=	dip angle

3.6 Fracturing pressure

The injection pressure should not be high enough to cause any fracture in the reservoir. The formation fracturing pressure can be calculated using an available correlation for the M field which located in gulf of Thailand [13] as follows:

$$Fracturing\ pressure(bar) = \frac{FRAC.S.G.x\ TVD}{10.2} \quad \textbf{(3.18)}$$

while

$$FRAC.S.G. = 1.22 + (TVDx1.6x10^{-4}) \quad \textbf{(3.19)}$$

where

FRAC.S.G	=	fracturing pressure gradient (bars/meter)
TVD	=	true vertical depth below rotary table (meters)

3.7 Barrel of oil equivalent

The barrel of oil equivalent (BOE) is a unit of energy based on the approximate energy released by burning one barrel of crude oil. The value is necessarily approximate as various grades of oil have slightly different heating values. Equation 3.23 [16] is used to approximate the barrel of oil equivalent is this study.

NET BOE = Cumulative oil production(BBL) + (Cumulative gas production(MMSCF) x 166.7) **–** (Cumulative gas injection(MMSCF) x 166.7) **(3.20)**

CHAPTER IV

MODEL DESCRIPTION

This chapter explains the construction of reservoir models and reservoir properties. We use 30 degree dip angle reservoir as the base case. Corner point grid is used to construct dipping reservoir.

4.1 Reservoir model

The size of the reservoir is 6,000ftx2,000ftx210ft which consists of 73x31x21 corner point grid blocks as shown in Figures 4.1-4.3. When we focus on waterflood period, well 1 is producer while well 2 is injector. On the contrary, in the period of gas injection, well 1 becomes injector while well 2 becomes producer. The reservoir is assumed to be homogenous and table 4.1 is shown the details of the reservoir model.

Table 4.1 : Summary of reservoir model

Parameters	Values	Unit
Number of grids	73x31x21	block
Size of reservoir	6,000x2,000x210	ft
Porosity	15.09	%
X permeability	32.529	mD
Y permeability	32.529	mD
Z permeability	3.2529	mD
Top of reservoir	5,000	ft
Initial pressure @ 5,000 ft	2,377	psia
Bubble point pressure	2,242	psia
Dip angle	30	degree
Initial oil saturation	0.7	

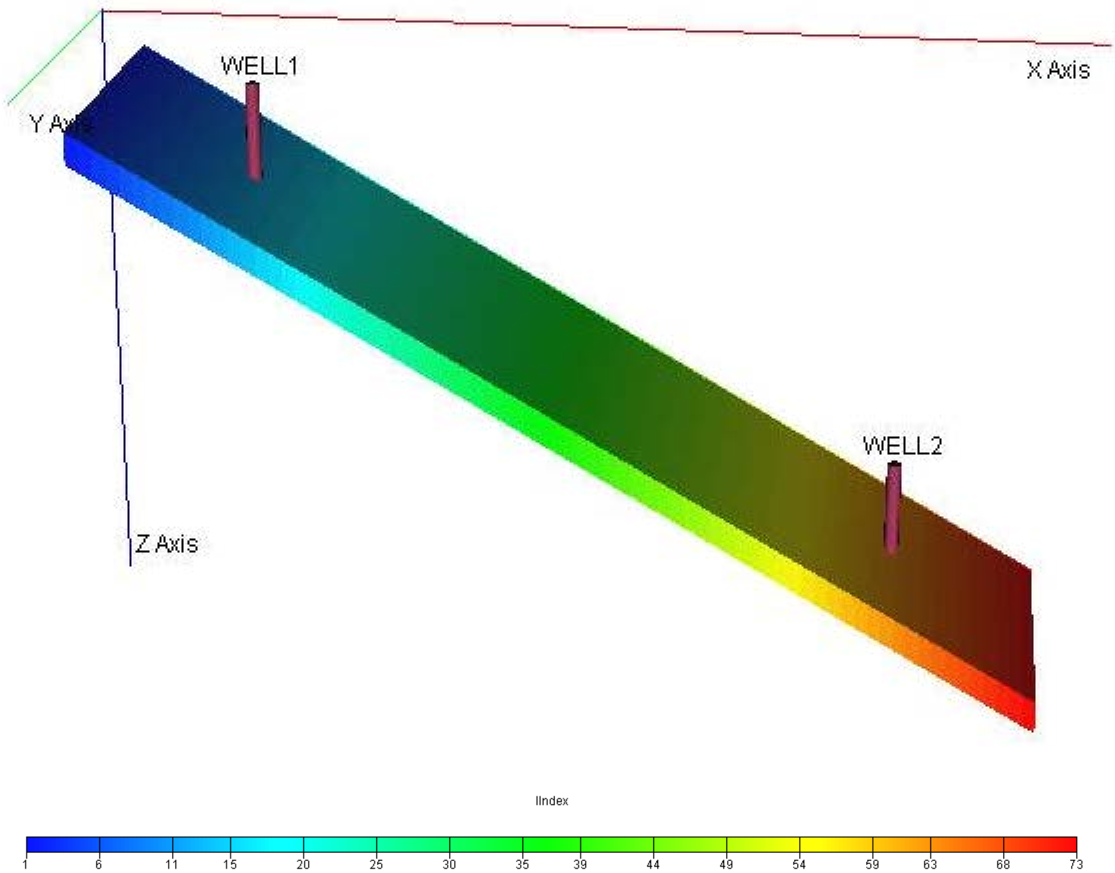

Figure 4.1 : Position of cells in the x-direction in the reservoir model

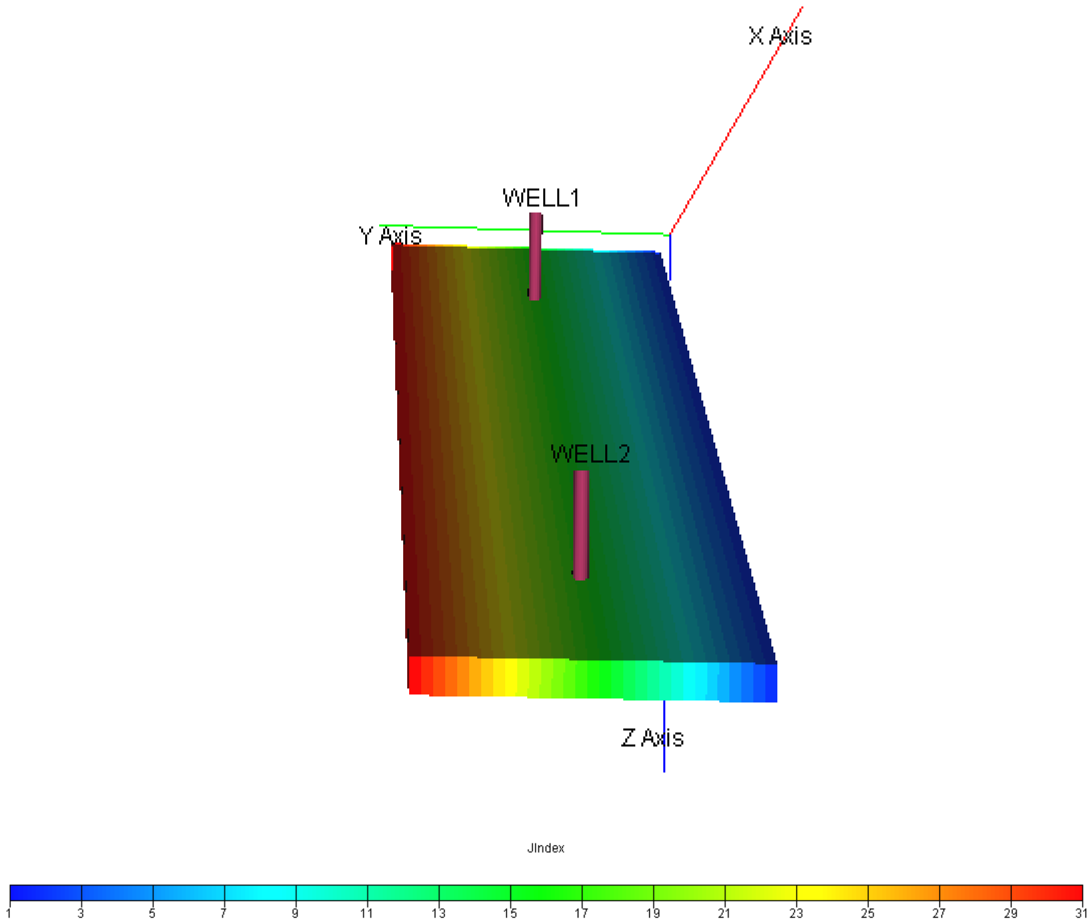

Figure 4.2 : Position of cells in the y-direction in the reservoir model

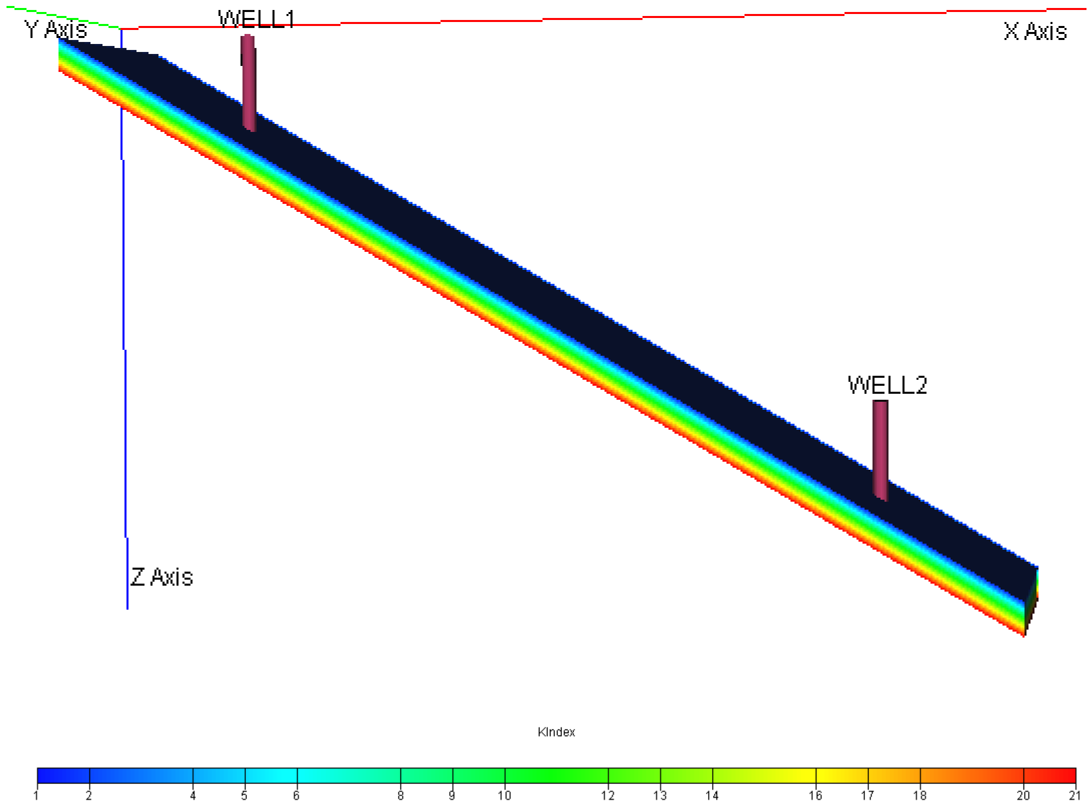

Figure 4.3 : Position of cells in the z-direction in the reservoir model

4.2 General fluid properties

The fluid and rock properties are generated from ECLIPSE correlation. Table 4.2 is the required value for ECLIPSE correlation. Figures 4.4-4.5 show PVT properties that are generated from ECLIPSE.

Table 4.2 : Summary of input data for ECLIPSE correlation

Input parameter	Value	Units
Oil gravity	39	API
Gas gravity	0.7	
R_s	650	scf/stb
Reservoir temperature	200	°F
Porosity	15.09	%
Rock type	Consolidated Sandstone	

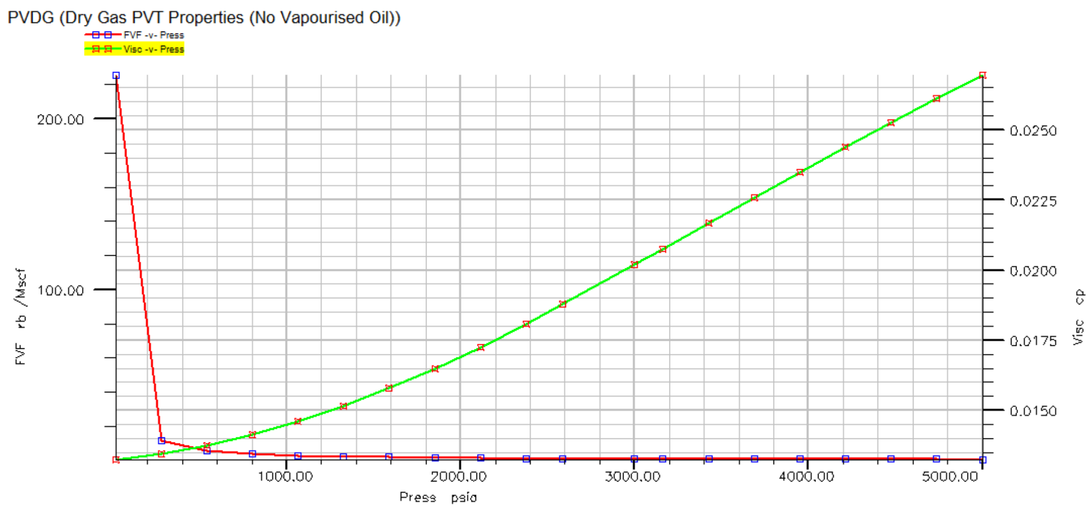

Figure 4.4 : Dry gas PVT properties (no vaporized oil)

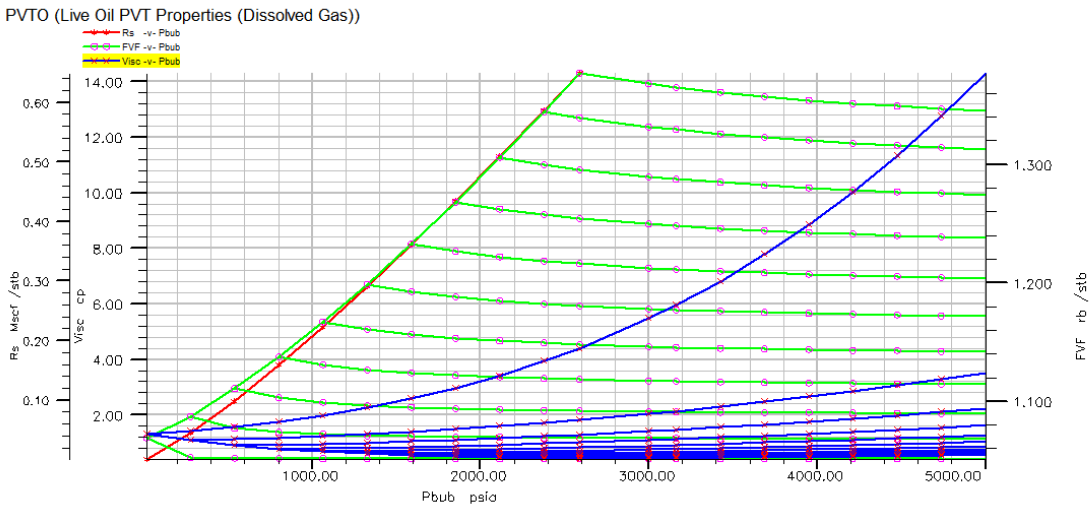

Figure 4.5 : Live oil PVT properties (dissolved gas)

4.3 SCAL properties

Corey's correlation is used to generate relative permeability curves for the base case. The parameters used to generate the relative permeability curves are shown in Table 4.3. The generated relative permeability curves are shown in Figures 4.6-4.7.

Table 4.3 : Parameters for Corey's correlation

Corey water	2	**Corey Gas/Oil**	3	**Corey Oil/Water**	3
S_{wmin}	0.3	S_{gmin}	0	**Corey Oil/Gas**	3
S_{wcr}	0.3	S_{gcr}	0.15	S_{org}	0.1
S_{wi}	0.3	S_{gi}	0.15	S_{orw}	0.3
S_{wmax}	1	$k_{rg}(S_{org})$	0.8	$k_{ro}(S_{wmin})$	0.8
$k_{rw}(S_{orw})$	0.8	$k_{rg}(S_{gmax})$	0.8	$k_{ro}(S_{gmin})$	0.8
$k_{rw}(S_{wmax})$	0.8				

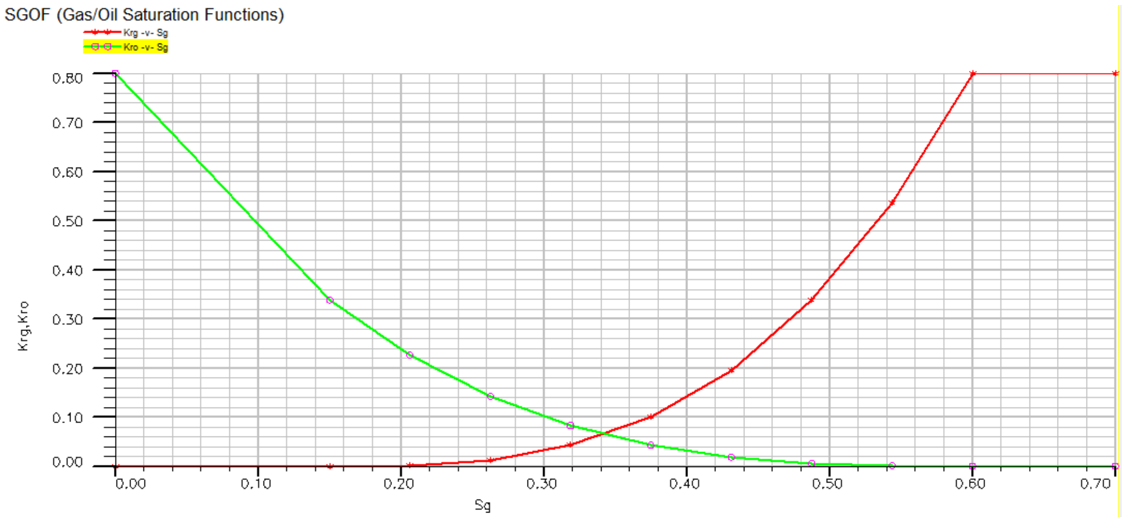

Figure 4.6 : Gas/oil saturation functions

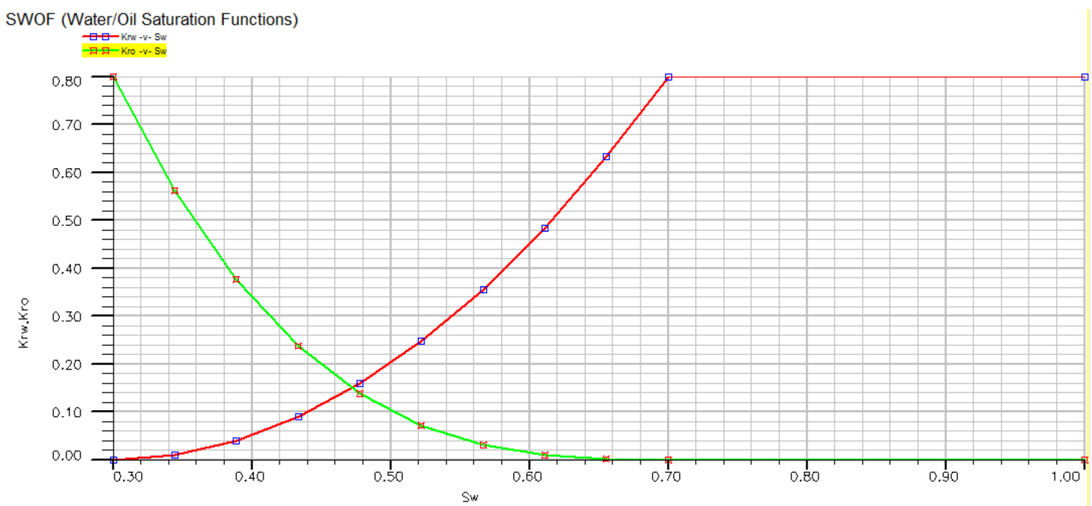

Figure 4.7 : Water/oil saturation functions

4.4 Well schedules

Figure 4.8 (z-plane = 1) shows the location of the wells for the base case. The data associated with this well pattern are shown in Tables 4.4.

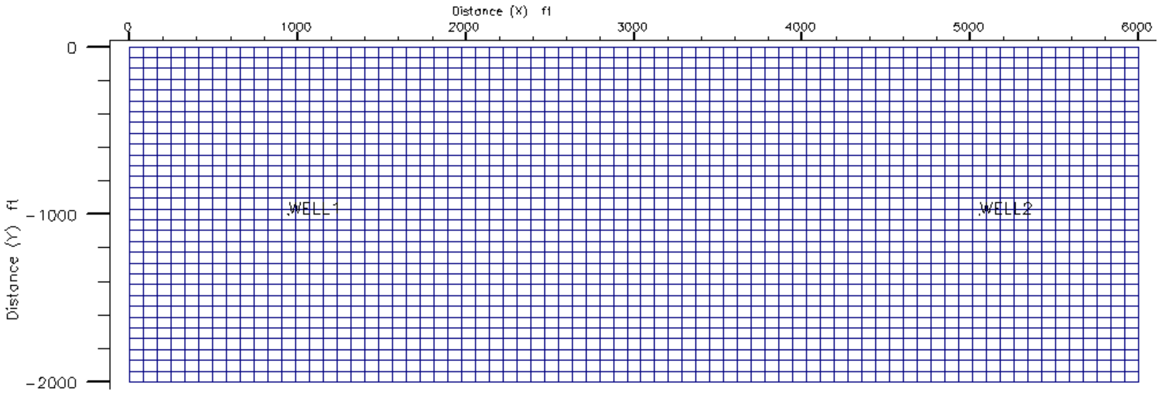

Figure 4.8 : Pattern of 2 vertical wells

Table 4.4 : Well schedule for pattern of 2 vertical wells

Parameter	**Value**
Position for Well 1	i=12, j=16
Position for Well 2	i=62, j=16
Fracture pressure for Well 1	3,500 psia
Fracture pressure for Well 2	4,305 psia
Water injection rate	4,000/6,000/8,000 RB/D
Production rate during injecting water	4,000/6,000/8,000 RB/D
Gas injection rate	4,000/6,000/8,000 RB/D
Production rate during injecting gas	4,000/6,000/8,000 RB/D
Economic constraint	Oil rate < 100 STB/D

CHAPTER V

RESULT AND DISCUSSION

In this chapter, the results of all study parameters and sensitivities are illustrated and discussed. DDP starts with water injection until water cut reaches the criteria. After that, we inject gas up-dip to displace the remaining oil. In the first section of this chapter, the effect of 4 main parameters which are stopping time for water injection, water injection rate, gas injection rate and well pattern are discussed. Then, the sensitivity of results due to uncertainty in relative permeability correlation, vertical to horizontal permeability ratio and type of wettability is discussed. The injection constraint for every case is fracture pressure calculated from Equations 3.18-3.19. Figures 5.1-5.7 (z-plane = 1) show how water and gas displaces trapped oil in DDP for the base case. Figure 5.1 is the initial oil saturation of this reservoir model. Next, we start to inject water down-dip (well2) into the reservoir until the produced water reaches the criteria. After waterflooding, there is still quite an amount of oil remaining in the reservoir as shown in Figure 5.3. To displace the remaining oil, we inject gas up-dip (well1) into the reservoir until the reservoir reaches the economic constraint. The process that gas displaces the remaining oil is illustrated in Figures 5.4-5.7 via the change in oil saturation from the first few days of gas injection until the economic constraint.

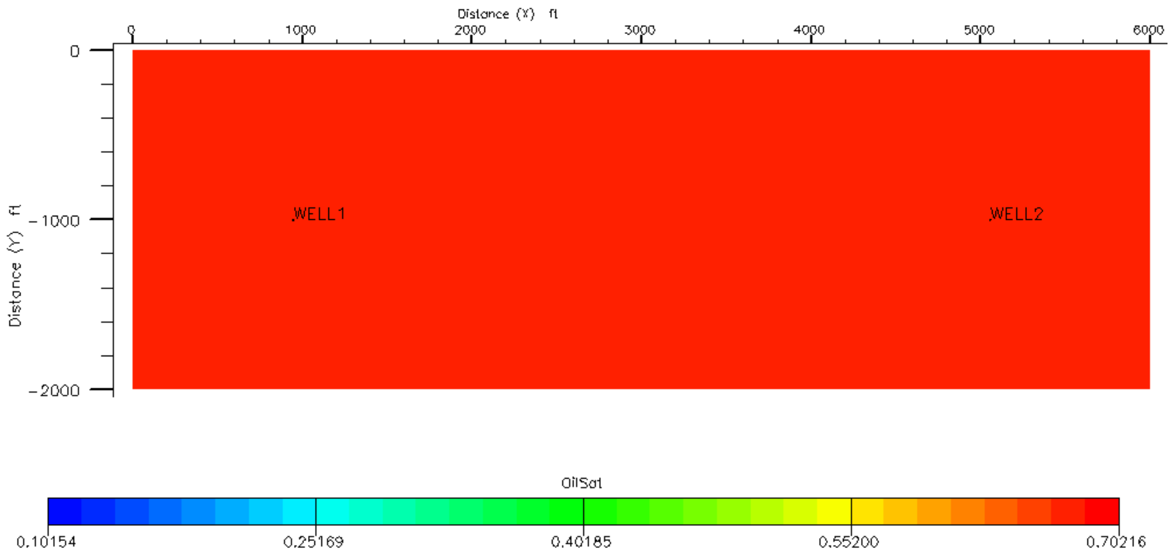

Figure 5.1 : Initial oil saturation

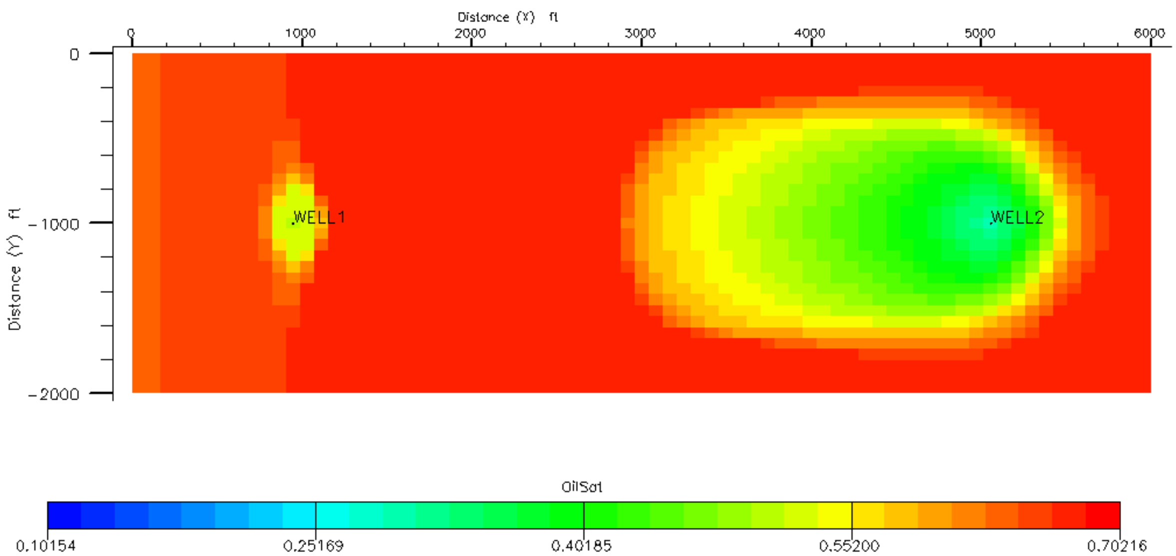

Figure 5.2 : Oil saturation at the early time of water injection (1,825 days of water injection)

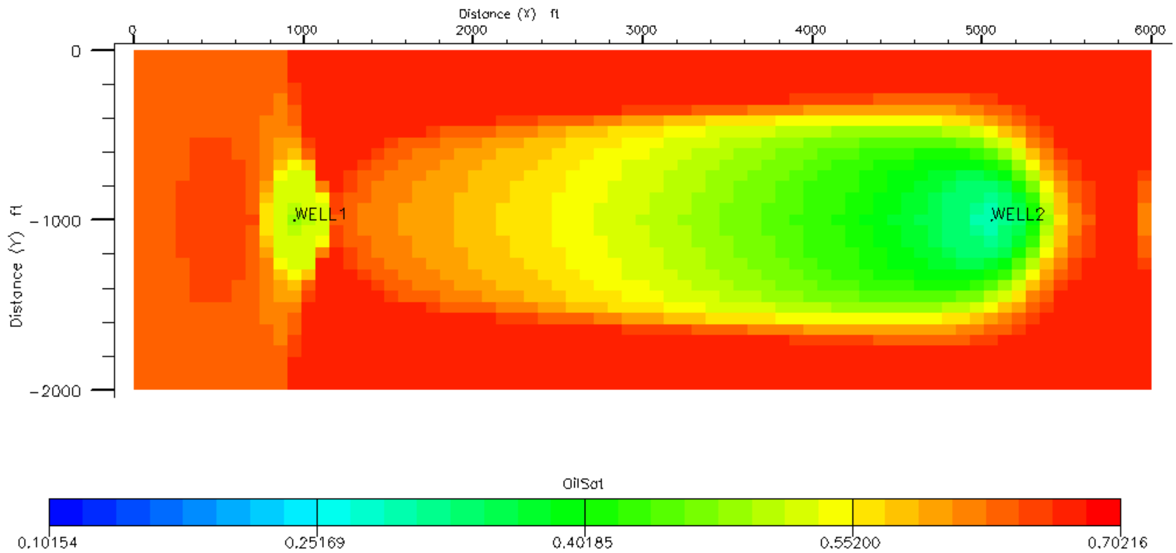

Figure 5.3 : Oil saturation when WCT reaches 60% (3,650 days of water injection)

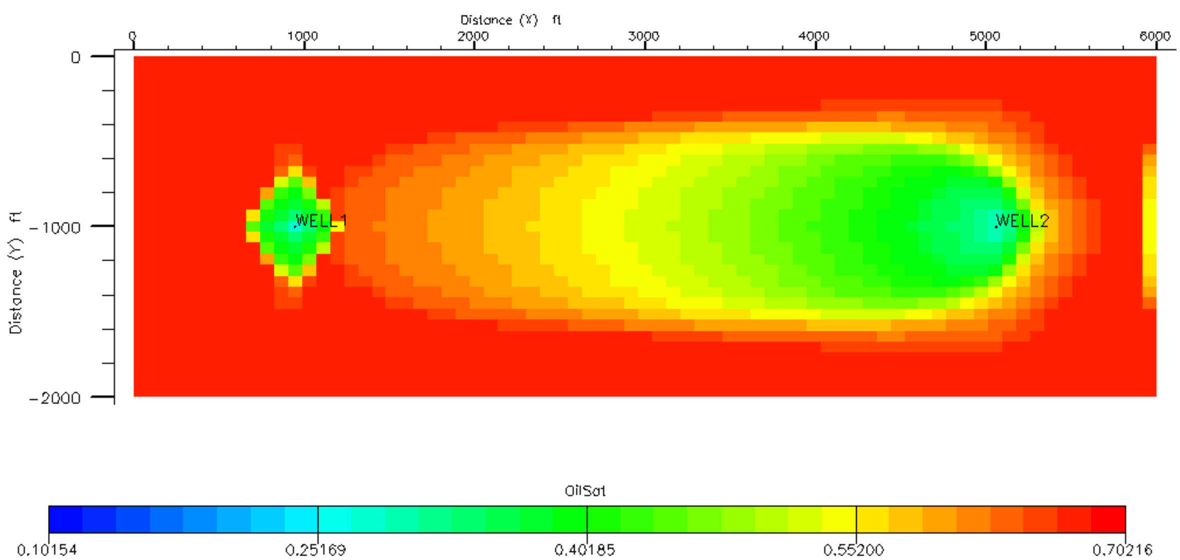

Figure 5.4 : Oil saturation at the early time of gas injection (5 days of gas injection)

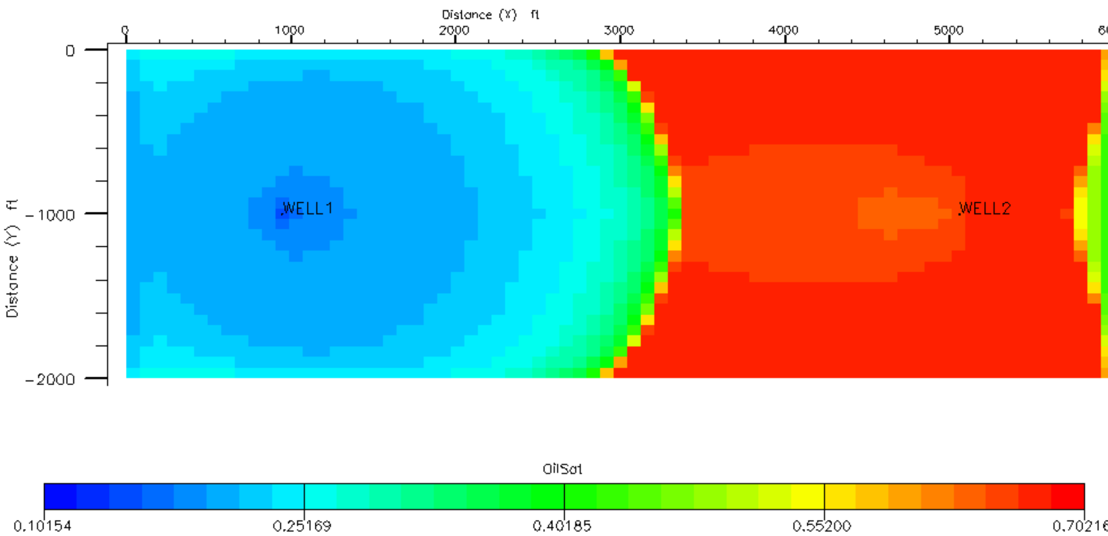

Figure 5.5 : Oil saturation after 5 years of gas injection (2,007 days of gas injection)

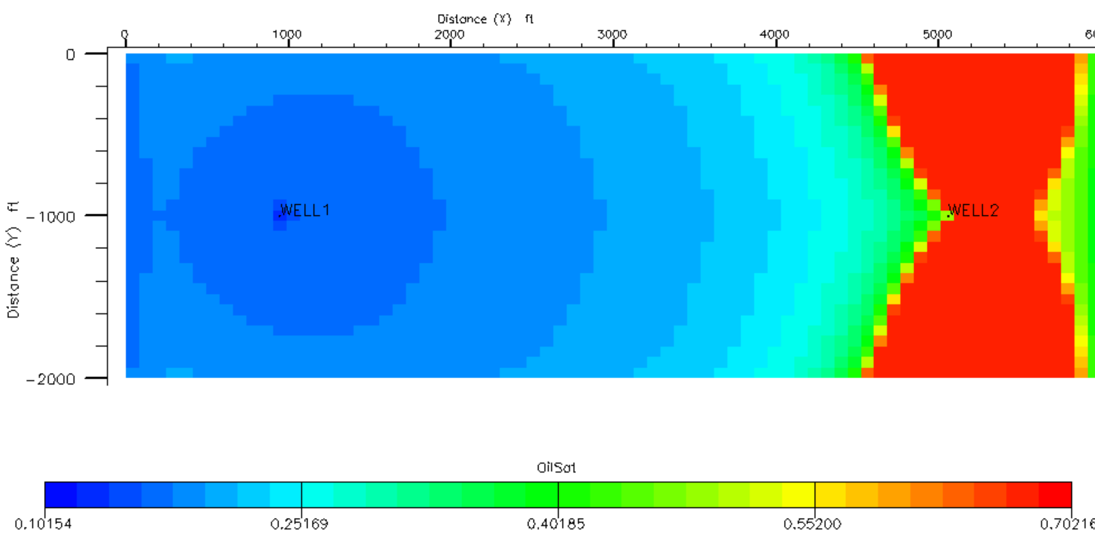

Figure 5.6 : Oil saturation when gas breaks through the producer (2,920 days of gas injection)

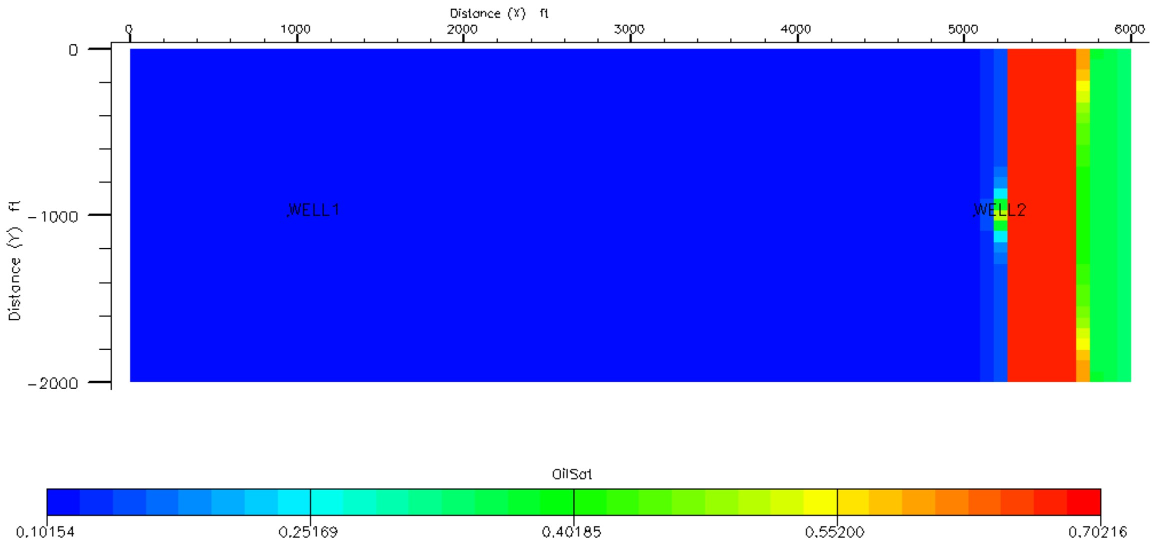

Figure 5.7 : Oil saturation at economic constraint (25,550 days of gas injection)

Figures 5.8-5.13 illustrate the oil production rate, WCT, gas production rate, reservoir pressure, water injection rate, gas injection rate during DDP, respectively.

As shown in Figure 5.8, the oil rate is constant for the first 8 years and dramatically drops afterwards as the water breaks through the producer (see Figure 5.9). After that, we shut in all wells for 6 months in order to stabilize the reservoir pressure. Next, we perform gas injection. The oil rate at the early time of gas injection is not good because there are a lot of water surrounding the producer. However, it gradually increases due less amount of water around the wellbore as gas injection continues.

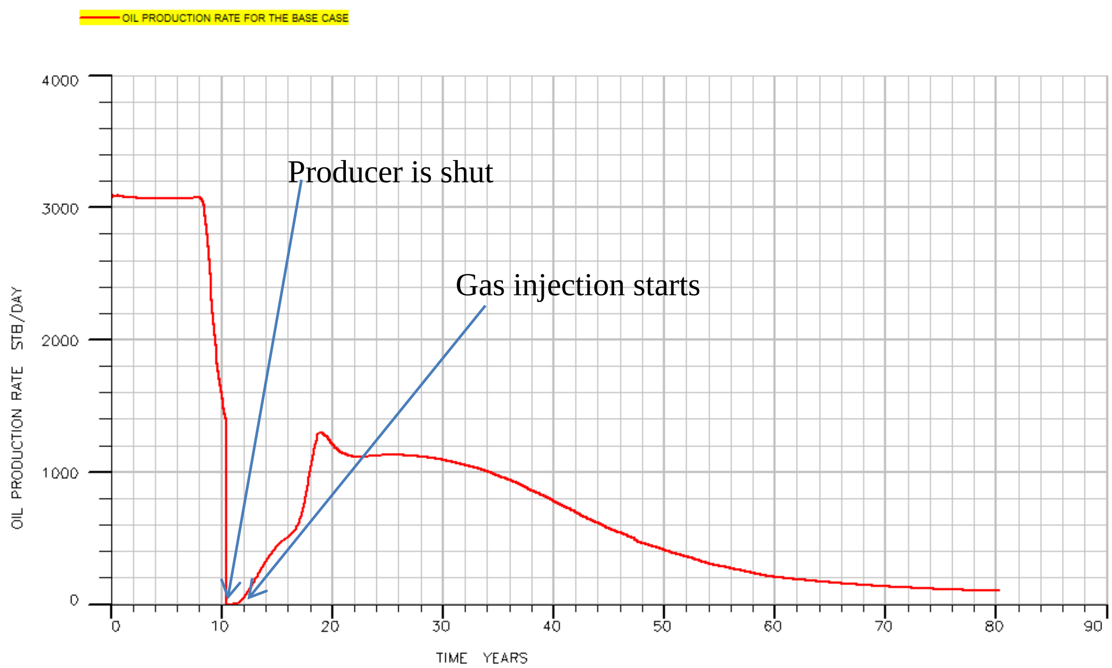

Figure 5.8 : Oil production rate for the base case

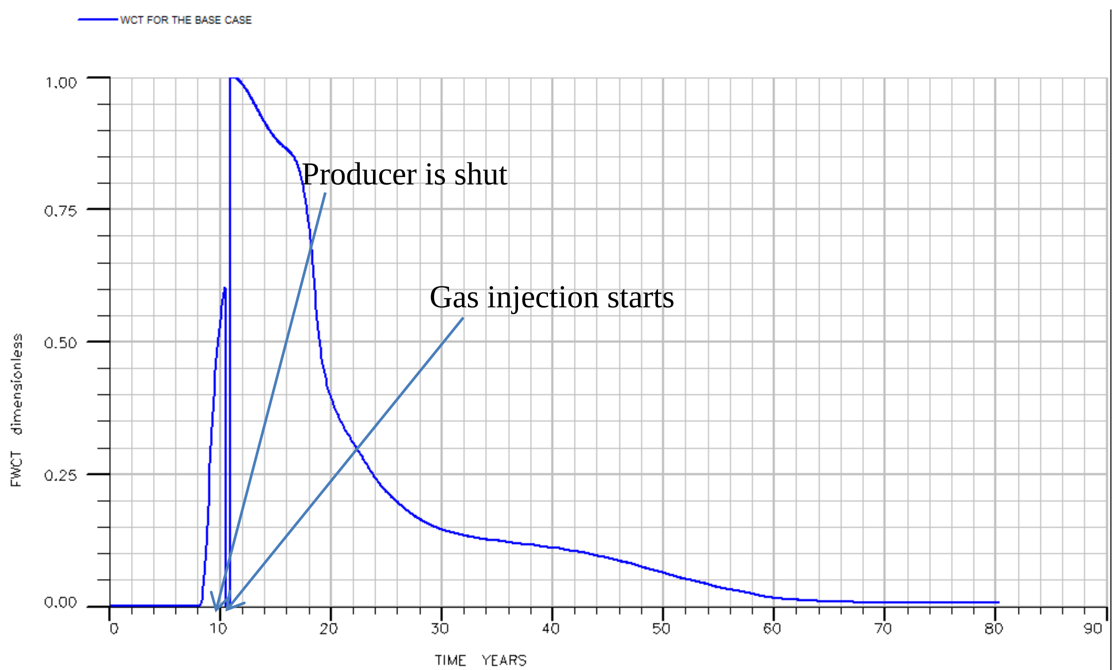

Figure 5.9 : WCT for the base case

At the early time, gas production rate is approximately around 1600 MSCF/D. This gas comes from dissolved gas in the reservoir. We shut in the all wells after 10 years of production. So, the gas rate drops to zero. Then, well 2 is open for production and the gas rate gradually increases. Gas rate dramatically increases again when injected gas breaks through the producer as shown in Figure 5.10.

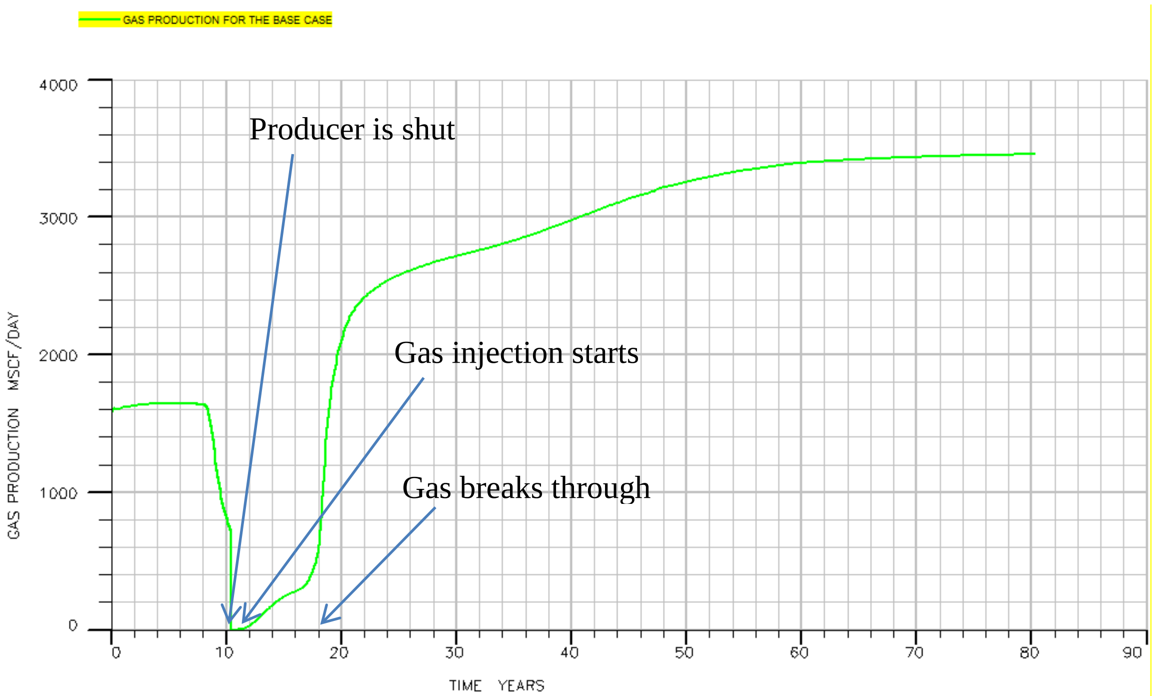

Figure 5.10 : Gas production rate for the base case

In term of the reservoir pressure as shown in Figure 5.11, the initial reservoir pressure is around 2,784 psia. When we perform waterflooding, the reservoir pressure builds up to 3160 psia. However, during gas injection period, the reservoir pressure drops to around 2540 psia, and we can maintain the reservoir pressure at this value until reaching the economic constraint.

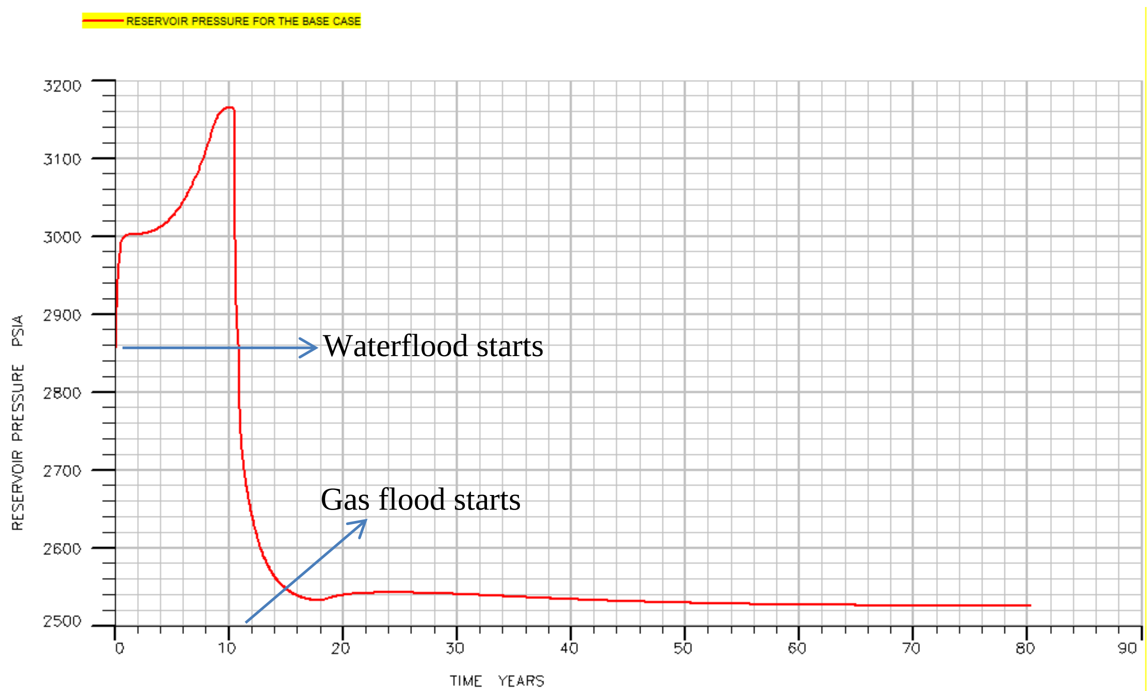

Figure 5.11 : Reservoir pressure for the base case

In term of water injection rate, we can keep water injection rate at 4,000 RB/D which is equivalent to 3,920 STB/D all the time that we perform waterflooding without exceeding fracture pressure of the reservoir as shown in Figure 5.12.

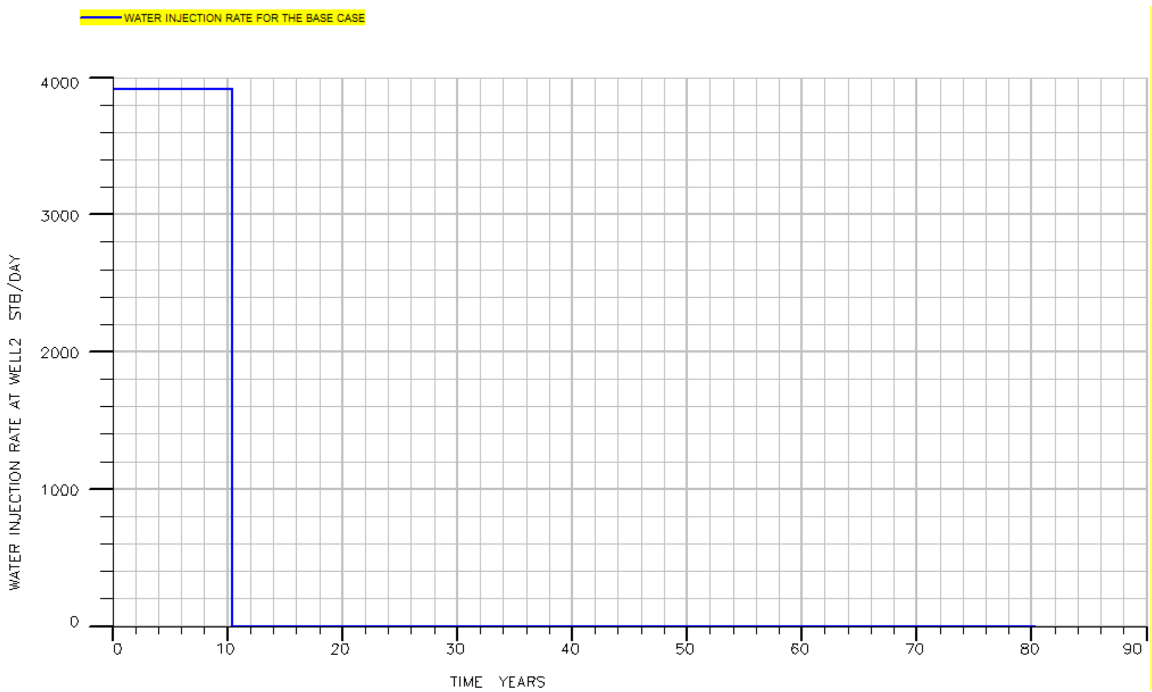

Figure 5.12 : Water injection rate for the base case

Figure 5.13 shows the gas injection rate. We can keep gas injection rate at 4,000 RB/D which is equivalent to 3,590 MSCF/D all the time that we perform gas flooding.

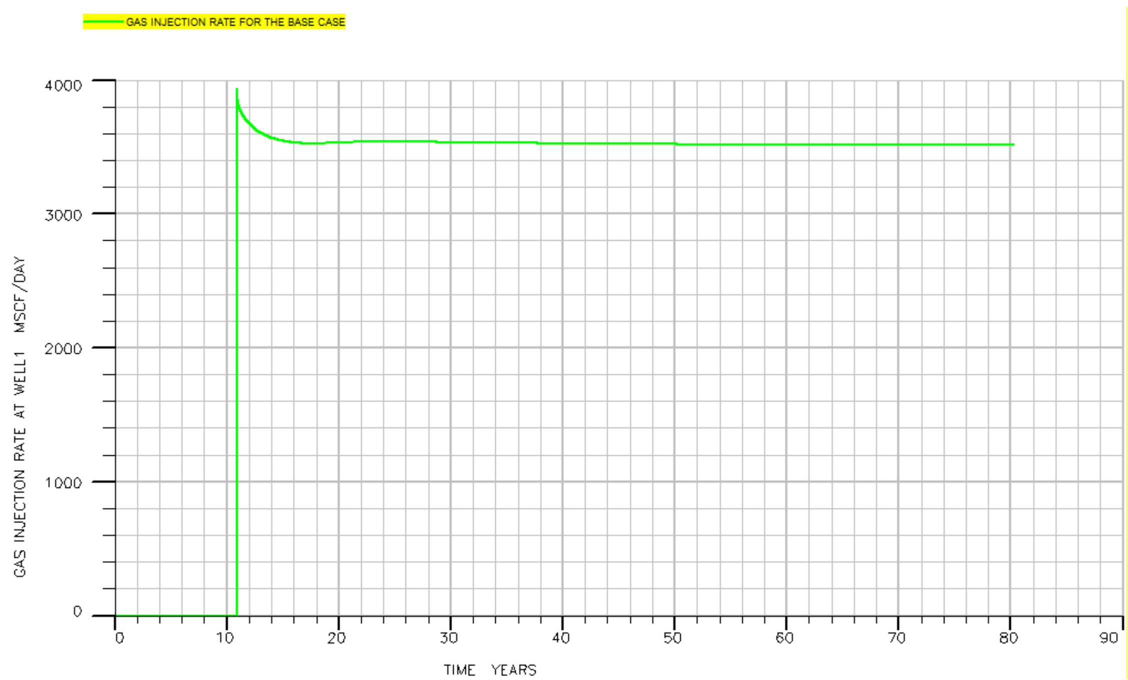

Figure 5.13 : Gas injection rate for the base case

5.1 Effect of stopping time for water injection

Water cut criteria are used to investigate the effect of duration of waterflood on DDP performance. In this study, four values of water cut which are 20%, 40%, 60%, and 80% are selected. The wells are located as shown in Figure 5.14 in a reservoir with 30 degree dip angle. Table 5.1 shows the injection and production sequence.

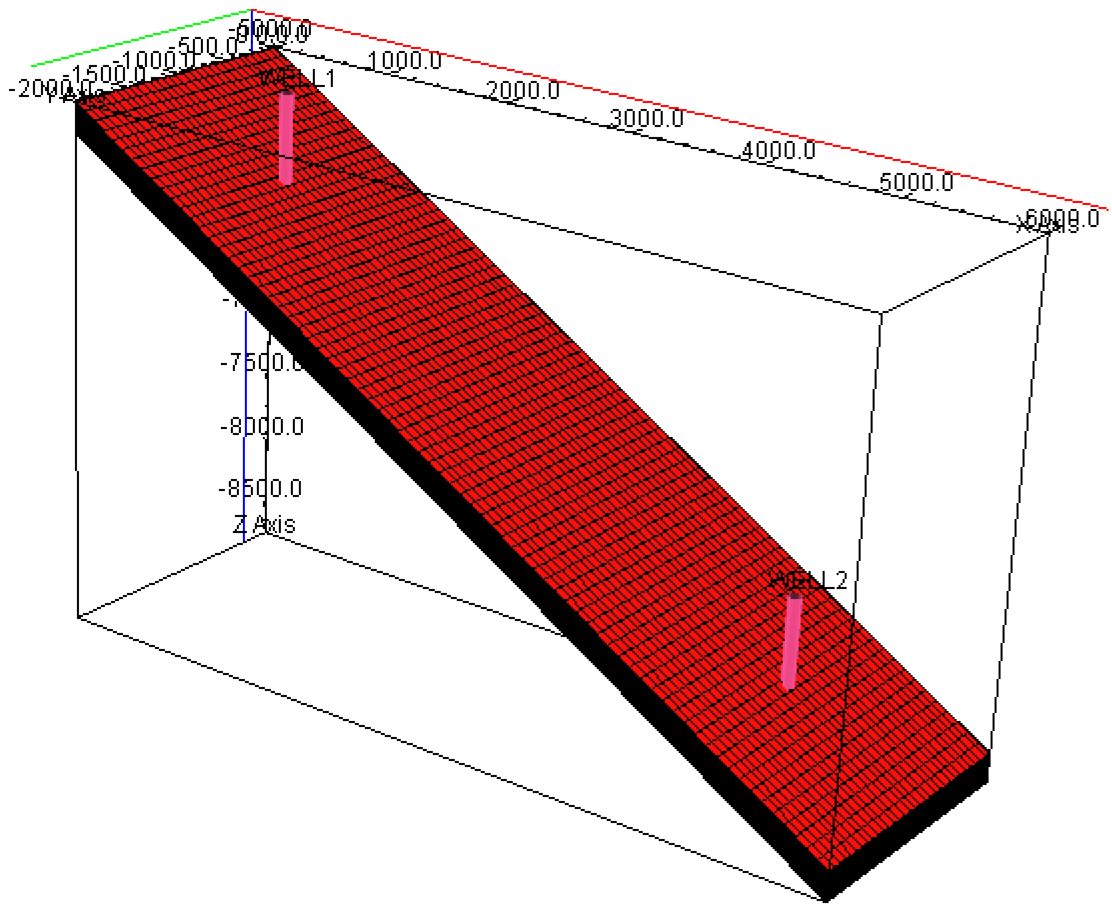

Figure 5.14 : Well locations

Table 5.1 : Injection and production sequence in double displacement process.

Stage	Well1	Well2
Waterflood	Producer	Water injector
WCT reaches preset criteria	Shut in for 6 months	Shut in for 6 months
Gas injection	Gas injector	Producer

During waterflooding stage, well 1 is the injector and well 2 is the producer. We inject water at rate of 4,000 RB/D which is equivalent to 3,920 STB/D until the water cut reaches the preset criteria. After water injection, we shut in all wells for 6 months in order to stabilize the reservoir pressure. After that, we inject gas at well 1 at rate of 4,000 RB/D which is equivalent to 3,590 MSCF/D until the oil production rate drops to 100 STB/D which is the economic limit. The oil production profile, oil recovery factor and WCT from the simulation are shown in Figures 5.15-5.17.

As shown in Figure 5.15, the oil rate is initially the same and becomes zero at different times due to different stopping criteria for water injection. During gas flooding, the case in which water injection is stopped when the water cut is 20% yields the best oil production rate at the early period of gas injection. However, the oil rate is the lowest among the cases at late period of gas injection.

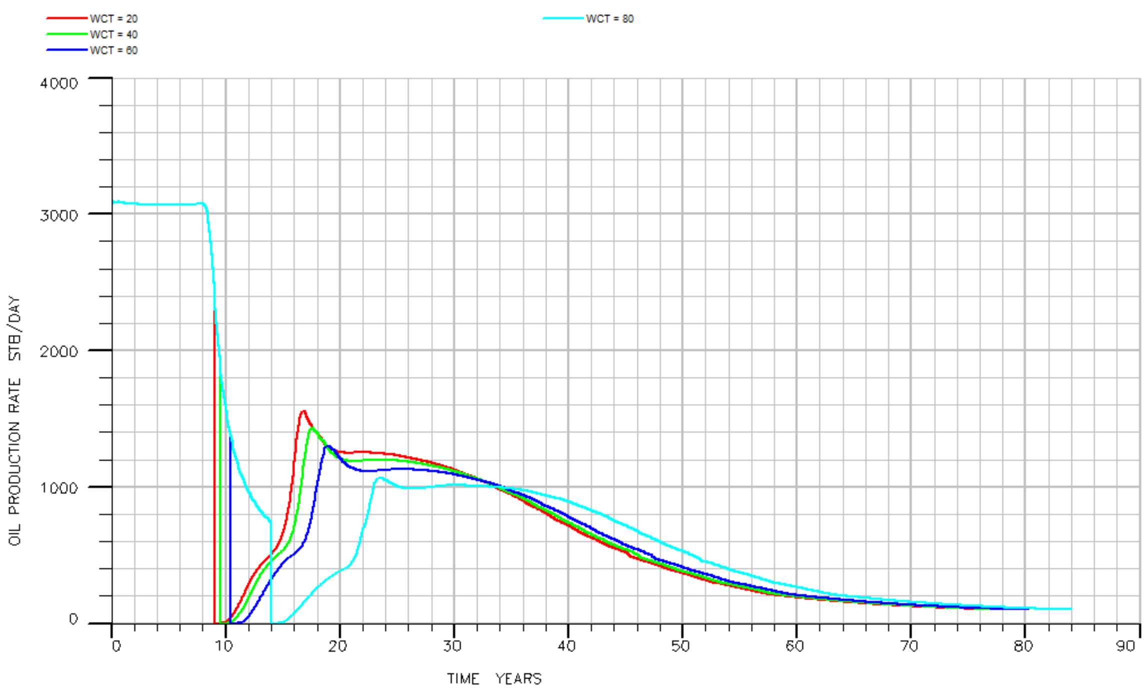

Figure 5.15 : Oil production profile for each WCT criteria

As shown in Figure 5.16, during the first 9 years of production, there is no difference in oil recovery factor for each stopping criteria of water injection. During the 10th and 20th year, which is the early time of gas flooding, the case with 80% WCT criteria yields more oil recovery than other cases. After 20 years of production, the oil recovery factor is highest when the water cut criteria is 20% and becomes subsequently lower as the water cut criteria increases to 40%, 60%, and 80%, respectively. However, at economic constraint, the case with WCT = 80% provides the highest oil recovery factor.

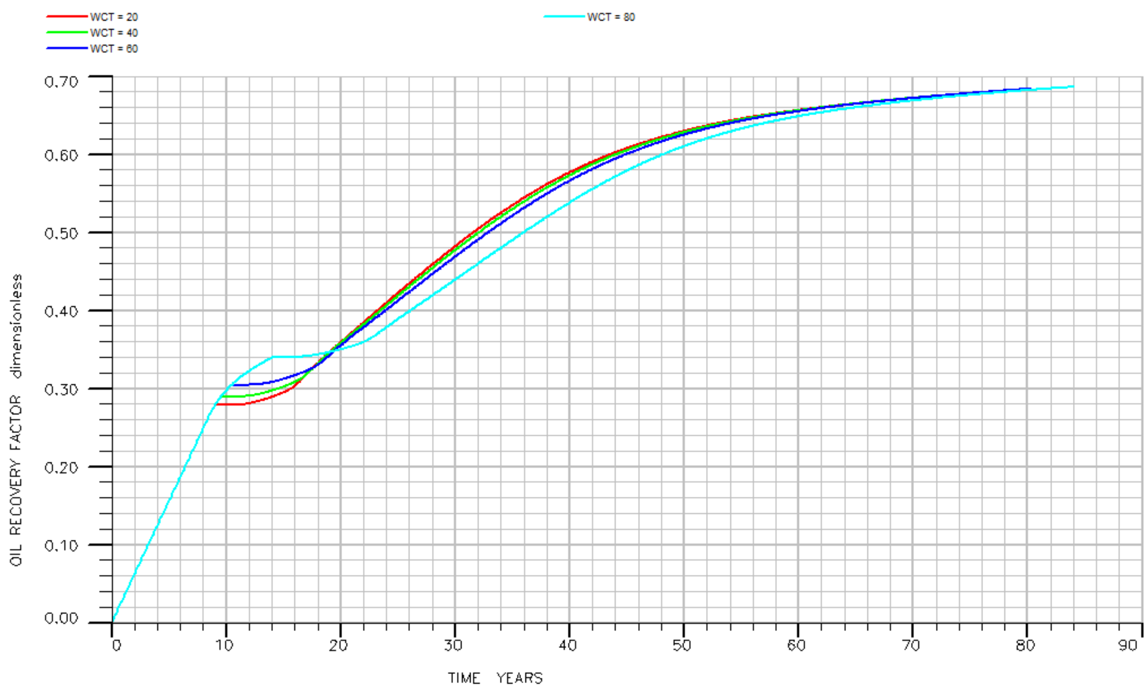

Figure 5.16 : Oil recovery factor for each WCT criteria

Figure 5.17 shows the WCT profile of each stopping criteria. The less the WCT criteria, the less the time that we perform waterflooding.

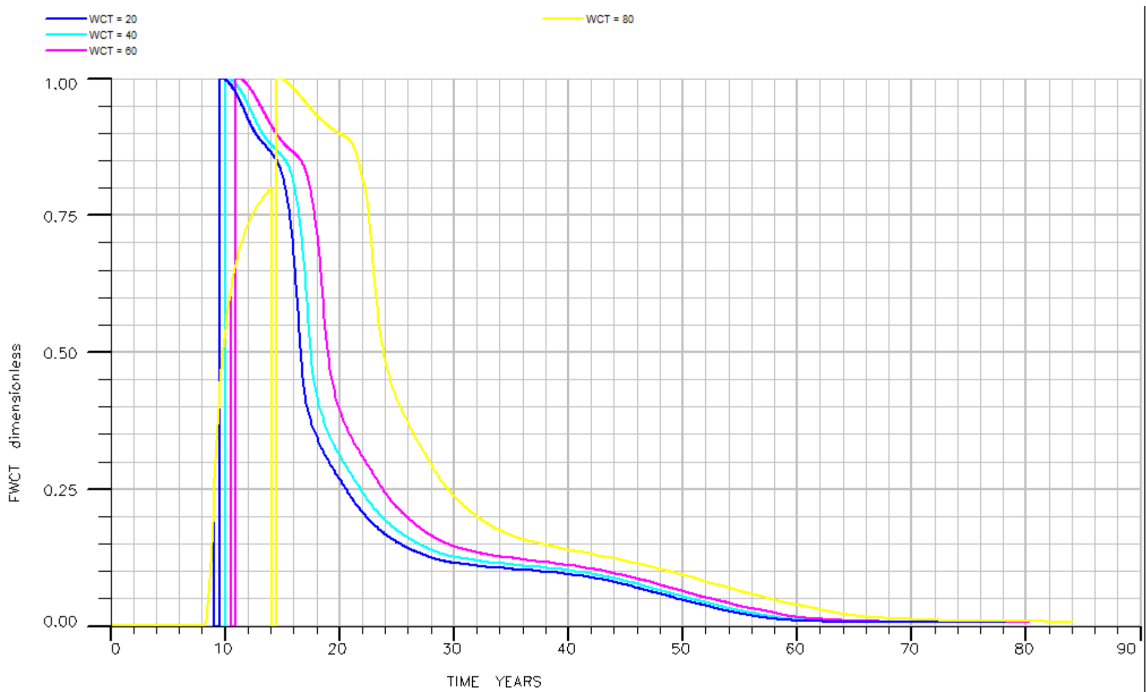

Figure 5.17 : WCT for each WCT criteria

The summary for cases with different stopping times for water injection are shown in Table 5.2.

Table 5.2 : Summarizes results related to DDP for different stopping criteria.

Case	Stopping criteria for waterflood	Production life (years)	RF (%)	Wp (MMSTB)	Gp (BSCF)	Winj (MMSTB)	Ginj (BSCF)	Waterflood duration (years)	Np during Waterflood (MMSTB)	Gas flood duration (years)	Np during Gas flood (BSCF)
1	20 % WCT	78.14	68.09	11.05	74.83	12.87	88.1	9	10.04	69.14	24.56
2	40 % WCT	79.05	68.22	11.72	75.46	13.58	88,.76	9.5	10.43	69.55	24.6
3	60 % WCT	80.21	68.56	12.97	75.95	14.89	89.3	10.42	10.97	69.79	24.66
4	80 % WCT	84.05	68.61	17.99	76.69	20.03	90.18	14.01	12.25	70.01	24.75

As shown in Table 5.2, cases 1-3 yield similar values of production life, water production, water injection, waterflood duration, and oil recovery factor during waterflood period except for case 4. The values in case 4 are quite high because the time and the amount of water used for water injection are higher than those in other cases. However, the recovery factor, gas production, gas injection, gas flood duration and oil production during gas flood for the four cases are more or less the same.

In term of oil recovery factor, the results show that higher value of water cut that is used as stopping criteria for water injection yields slightly more oil recovery factor. As we increase the water cut criteria from 60% to 80%, we have a slight gain in oil recovery factor but it takes a long time to gain this slight amount of additional oil recovery factor. Moreover, the amount of water and gas that are used to inject in this criteria is essentially higher than those in the other cases. So, we choose the water cut criteria of 60% to perform waterflood in this study.

5.2 Effect of water and gas injection rate on DDP

In theory, water and gas injection rates are important parameters that affect the performance of DDP. If the water injection rate during the initial waterflooding period is too high, water may underride the oil leading to poor sweep efficiency. If gas injection rate during the double displacement process is high, gas may override the remaining oil, causing an early break through. If the injection rates are too low, the reservoir pressure cannot be maintained. Therefore, we have to use suitable injection rates. Three different water and gas injection rates are used in this study.

In this study, three different dip angles which are 15, 30, and 60 degrees are considered because each dip angle may has its optimum injection rate. So, it is essential to choose a suitable injection rate for each dip angle. The water and gas injection rates are divided into 9 strategies as shown in Table 5.3. The maximum injection pressure is calculated by using Equations 3.18-3.19.

Table 5.3 : Water and gas injection rates for each strategy

Case	Water injection rate (RB/D)	Gas injection rate (RB/D)
1	4,000	4,000
2	4,000	6,000
3	4,000	8,000
4	6,000	4,000
5	6,000	6,000
6	6,000	8,000
7	8,000	4,000
8	8,000	6,000
9	8,000	8,000

5.2.1 Dip angle of 15 degrees

As shown in Figure 5.18, cases 1-3 can keep the water injection rate to the preset criteria. However, cases 4-6 and 7-9 cannot keep the injection rate to 6,000 RB/D and 8,000 RB/D, respectively, because the injection pressure exceeds the fracture pressure of the reservoir.

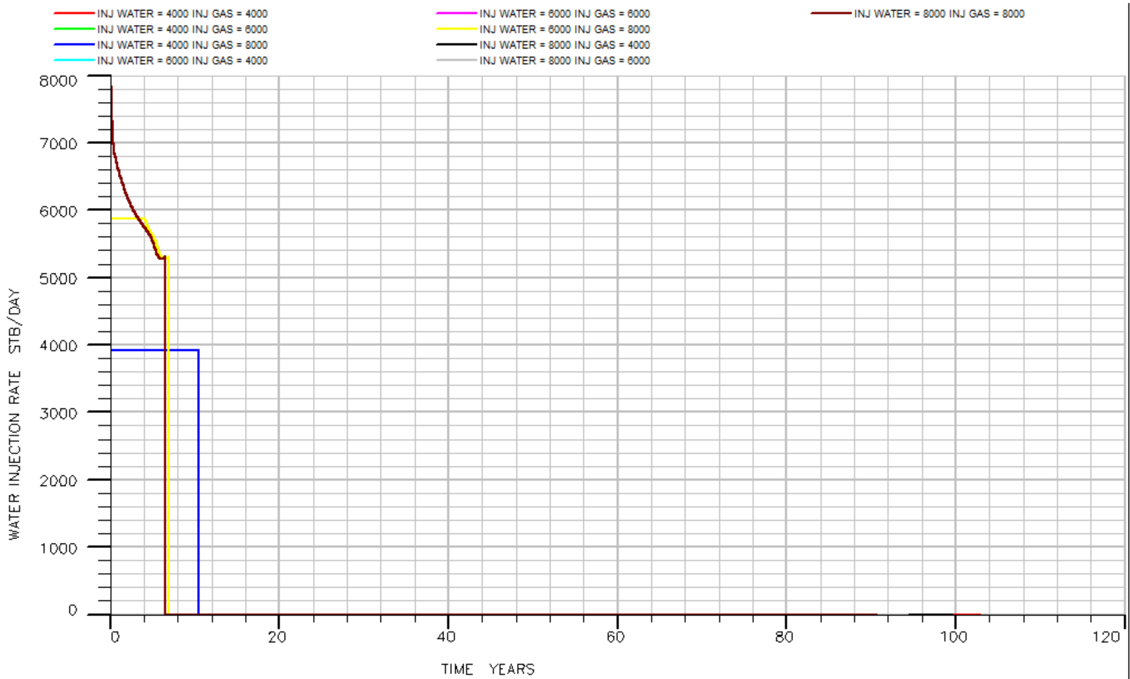

Figure 5.18 : Water injection rate for combinations of different water and gas injection rate (15-degree dip angle)

As shown in Figure 5.19, the gas injection rate for each case is different because the reservoir pressure at the time that we perform gas injection is different. So, the range of injection pressure used for each case is different. Case 9 uses the highest injection rate while case 1 uses the lowest injection rate.

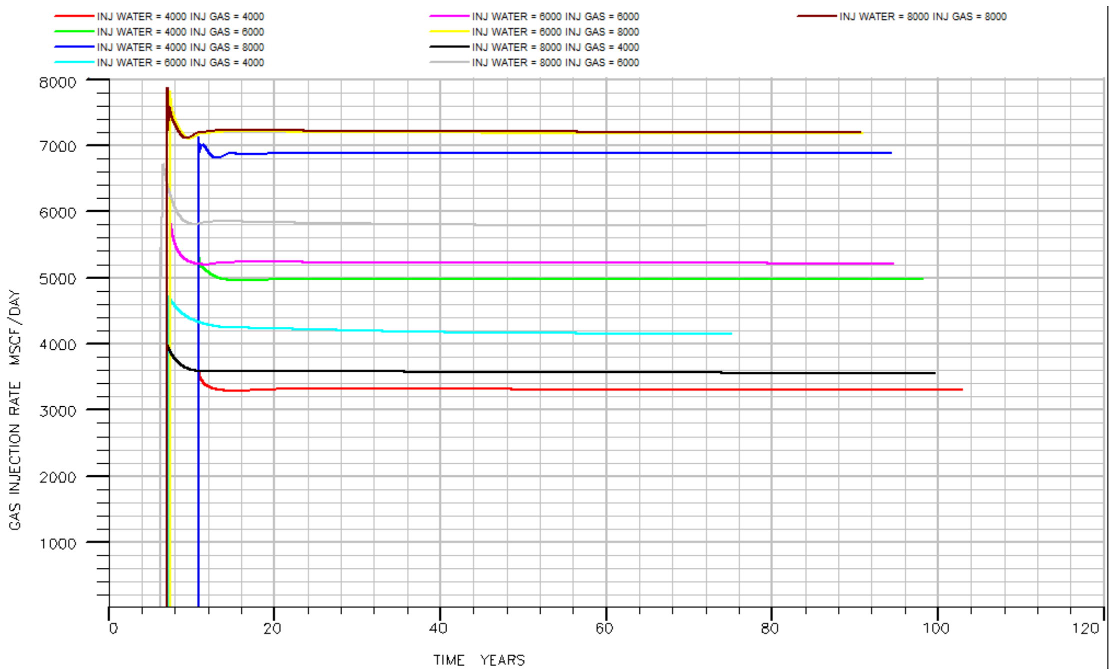

Figure 5.19 : Gas injection rate for combinations of different water and gas injection rates (15-degree dip angle)

During water injection period as shown in Figure 5.20, the oil rates for cases 1-3 are constant around 3,100 STB/D. The oil rates for cases 4-6 vary between 4,400 STB/D and 4,700 STB/D. The oil rates for cases 7-9 vary between 4,400 STB/D and 5,600 STB/D. During gas injection period, cases 3, 6, and 9 yield the higher oil rates than those in other cases.

The oil rate starts to decline when the water cut increases as shown in Figure 5.21. After the water cut reaches 60%, we shut in the production well for 6 months in order to prepare for gas injection and stabilize the reservoir pressure. Since we switch the producer from the top of the reservoir (well1) to the bottom of the reservoir (well2) which has a lot of surrounding water as shown in Figure 5.22, oil production rate in the early period of gas injection is not good but gradually increases as a result of smaller amount of water around the wellbore. For gas flooding, oil production rate starts dramatically drops again when gas breaks through the producer.

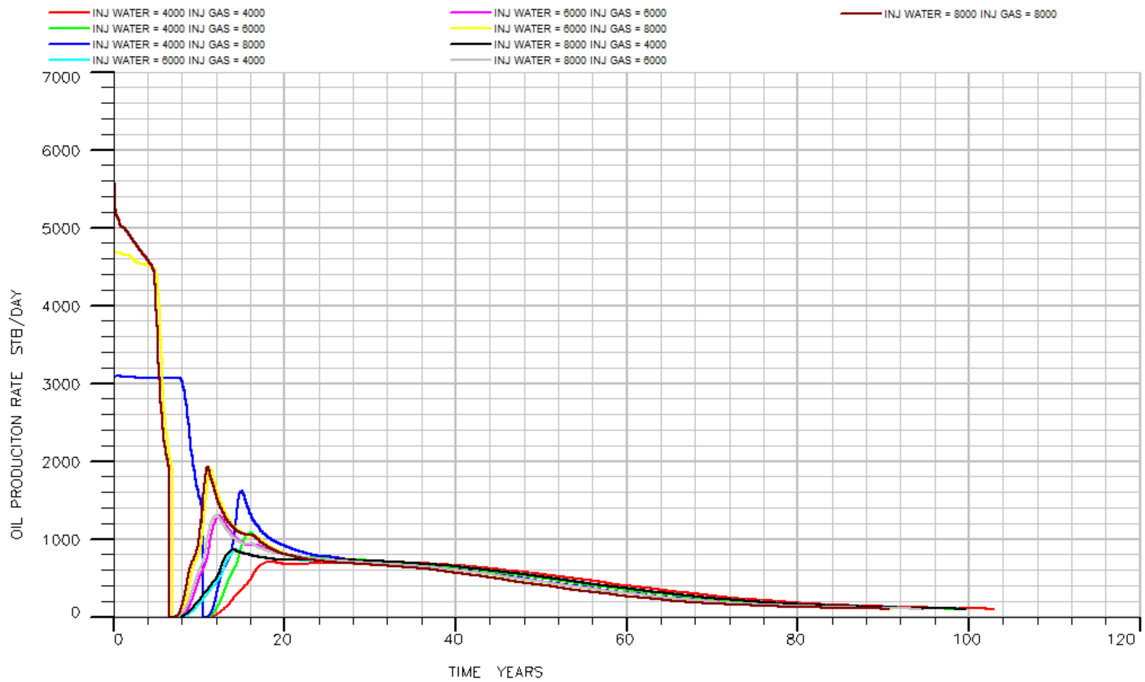

Figure 5.20 : Oil production rate for combinations of different water and gas injection rate (15-degree dip angle)

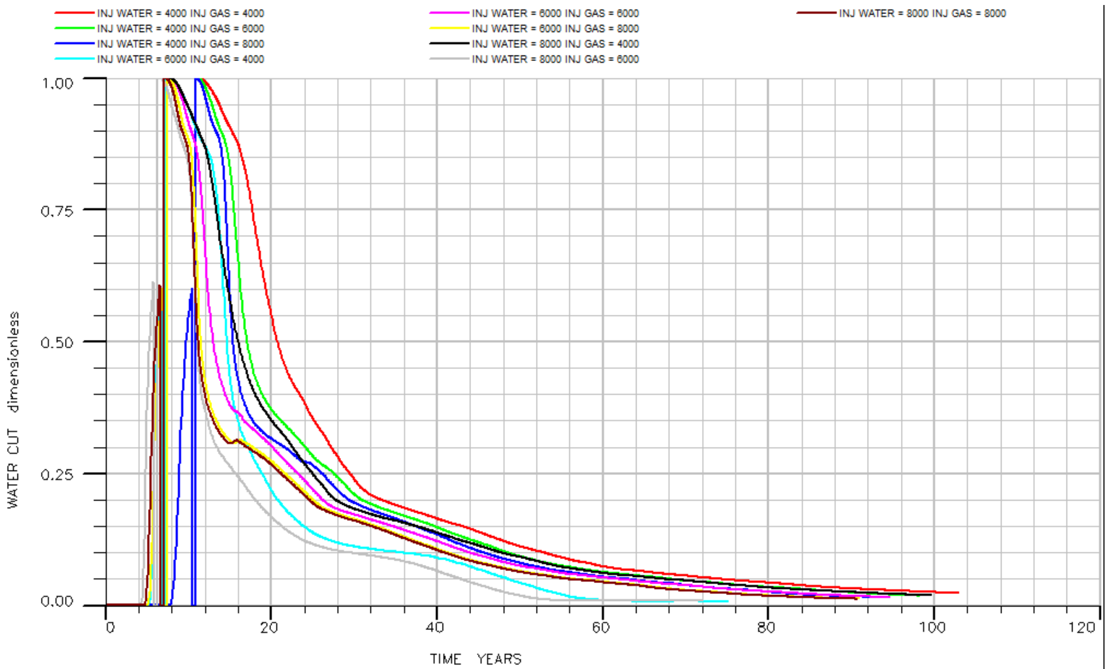

Figure 5.21 : Water cut for combinations of different water and gas injection rates (15-degree dip angle)

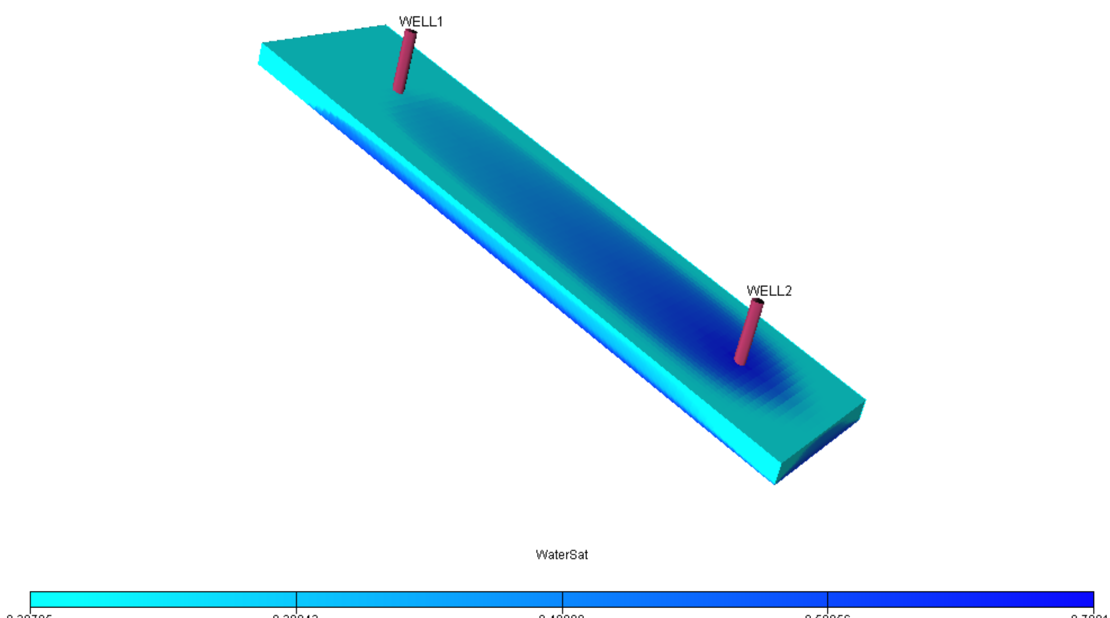

Figure 5.22 : Water saturation at the early time of gas injection (15-degree dip angle)

In term of cumulative oil production and oil recovery factor as shown in Figures 5.23-5.24, during waterflood period, cases 4-9 yield the higher cumulative oil production and oil recovery factor than those in cases 1-3. During gas injection period, cases 6 and 9 which use high gas injection rate yield the high cumulative oil production and oil recovery factor. Case 1 used the lowest water and gas injection rate yields the lowest cumulative oil production and oil recovery factor.

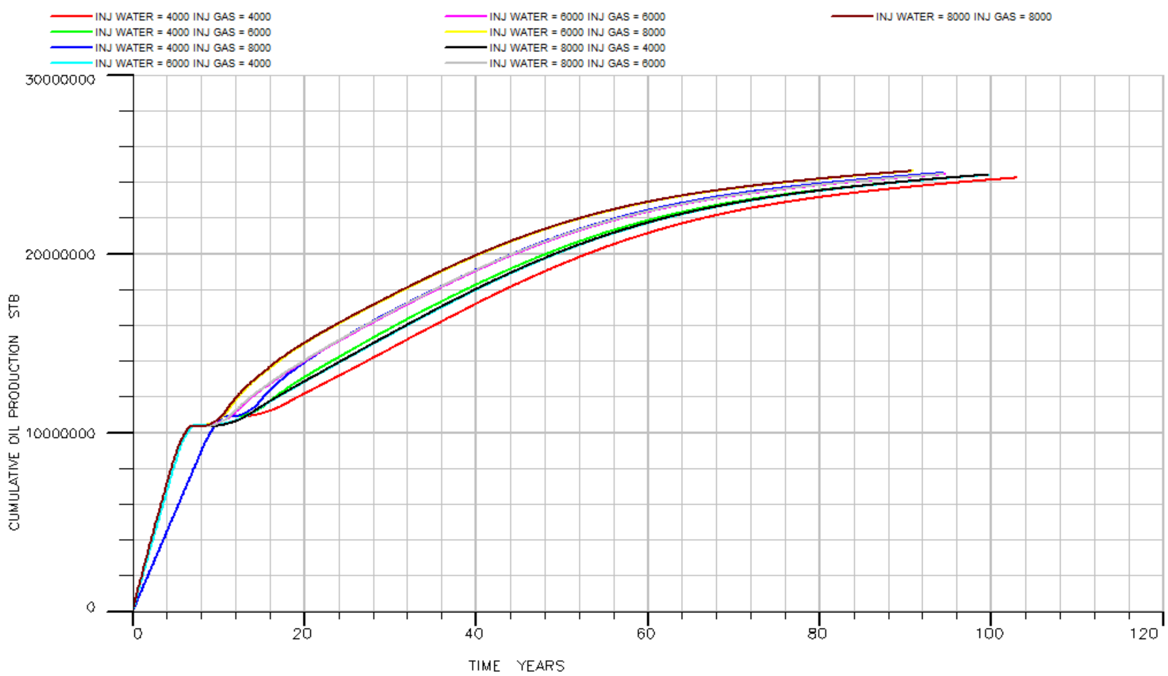

Figure 5.23 : Cumulative oil production for combinations of different water and gas injection rates (15-degree dip angle)

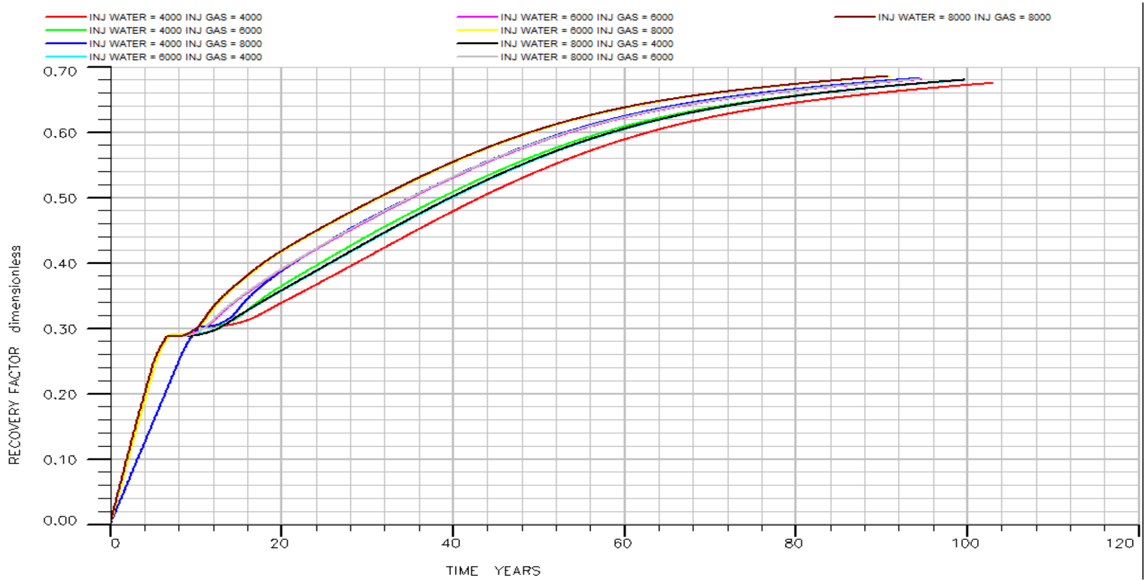

Figure 5.24 : Oil recovery factor for combinations of different water and gas injection rates (15-degree dip angle)

As shown in Figures 5.25-5.27, the amount of gas production mainly depends on the amount of gas that we inject into the reservoir. Gas production, gas-oil ratio, and cumulative gas production will significantly increase when gas break through the producer. For cases 6 and 9, gas breaks through times are shorter than those in the other cases because both cases use high gas injection rates.

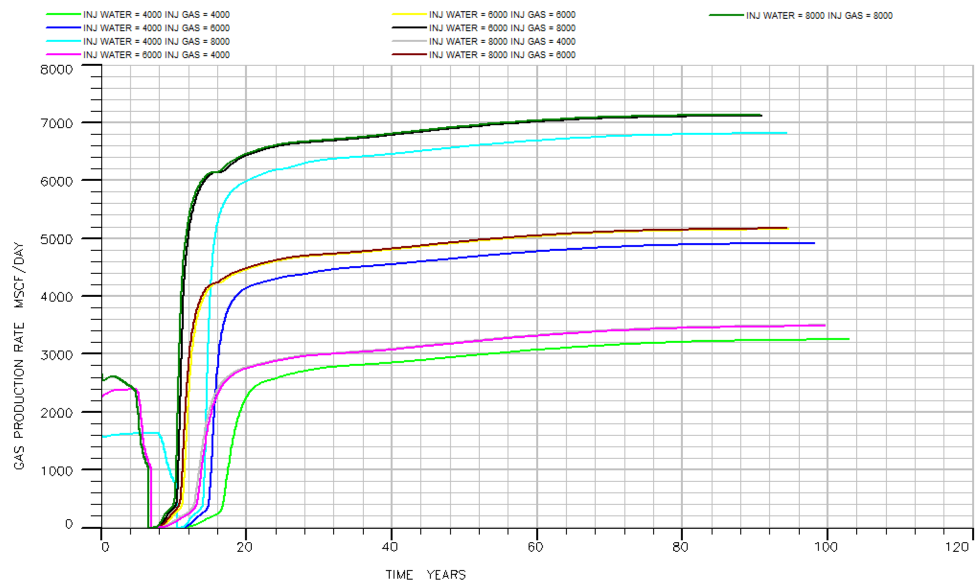

Figure 5.25 : Gas production rate for combinations of different water and gas injection rates (15-degree dip angle)

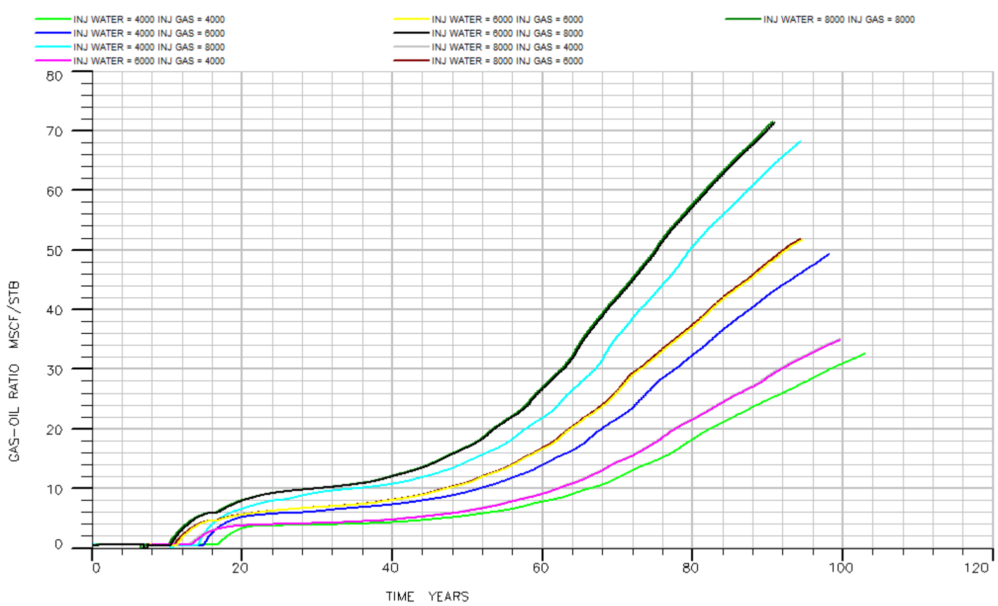

Figure 5.26 : Gas-oil ratio for combinations of different water and gas injection rates (15-degree dip angle)

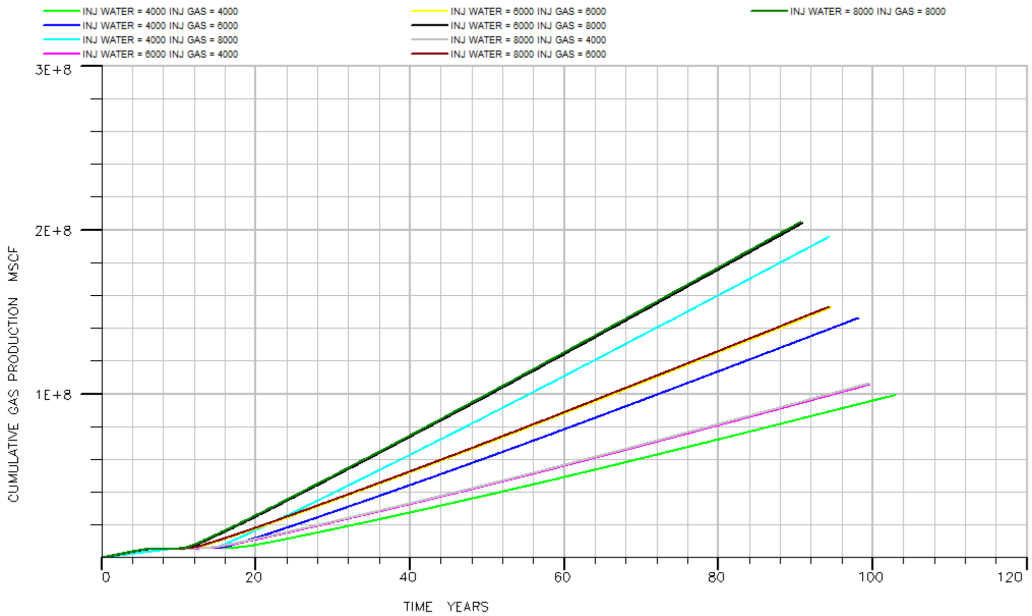

Figure 5.27 : Cumulative gas production for combinations of different water and gas injection rates (15-degree dip angle)

As shown in Figure 5.28, the reservoir pressure for all cases pretty is stable because we try to balance voidage of the reservoir. So, the fluid volumes that are removed from the reservoir equal to the fluid volumes that are injected to the reservoir. Cases 6 and 9 are the best strategy to maintain the reservoir pressure while the ability of cases 1-2 to maintain the reservoir pressure are not be good because the reservoir pressure is dramatically drops to 2,380 psia.

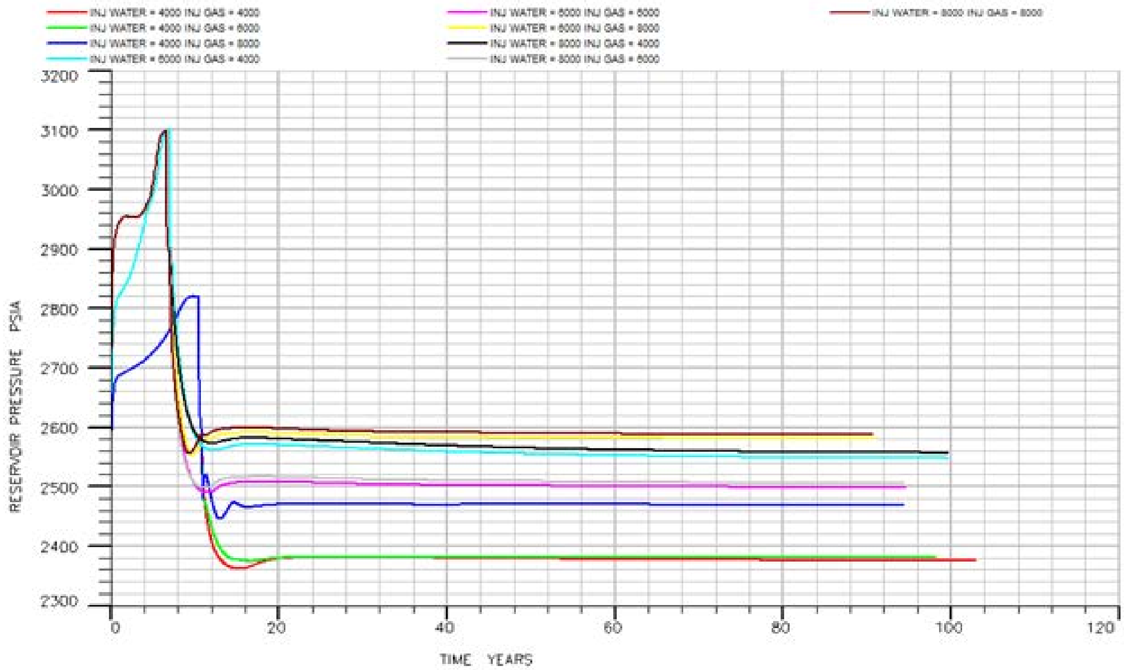

Figure 5.28 : Reservoir pressure for combinations of different water and gas injection rate (15-degree dip angle)

The summary of cumulative oil production, oil recovery factor, cumulative water production, cumulative water injection, cumulative gas production, cumulative gas injection, BOE and oil production period of the reservoir with 15 degree dip angle for each injection strategy are shown in the Table 5.4. Tables 5.5-5.6 show the duration of waterflood and gas flood at first 30 years and abandonment.

Table 5.4 : Summary for 15 degree dip angle

Case no.	Water injection rate (RB/D)	Gas injection rate (RB/D)	At 30 years							At Abandonment							
			Np (MMSTB)	RF (%)	Wp (MMSTB)	Winj (MMSTB)	Gp (BSCF)	Ginj (BSCF)	BOE (MMSTB)	Tp (years)	Np (MMSTB)	RF (%)	Wp (MMSTB)	Winj (MMSTB)	Gp (BSCF)	Ginj (BSCF)	BOE (MMSTB)
1	4,000	4,000	14.7	40.94	12.23	14.88	17.25	23.13	13.72	102.9	24.23	67.49	13.53	14.88	99.12	111.2	22.22
2	4,000	6,000	15.84	44.12	13.68	14.88	27.84	34.77	14.69	98.08	24.34	67.79	13.68	14.88	146.1	158.46	22.28
3	4,000	8,000	16.76	46.69	13.79	14.88	39.42	47.95	15.34	94.32	24.51	68.25	13.79	14.88	195.82	209.49	22.23
4	6,000	4,000	15.48	43.12	12.45	14.44	21.59	29.63	14.14	99.64	24.4	67.95	12.45	14.44	105.61	119.9	22.01
5	6,000	6,000	16.68	46.45	13.29	14.44	34.59	43.31	15.22	94.49	24.44	68.06	13.29	14.44	152.4	166.29	22.12
6	6,000	8,000	17.6	49	13.4	14.44	49.17	59.47	15.88	90.83	24.61	68.54	13.4	14.44	204	219.12	22.09
7	8,000	4,000	15.53	43.25	13.12	14.42	22.02	30.18	14.17	99.49	24.41	67.98	13.12	14.42	106.26	120.68	22
8	8,000	6,000	16.73	46.59	12.55	14.42	35.24	44.08	15.25	94.31	24.44	68.07	12.55	14.42	152.95	166.94	22.11
9	8,000	8,000	17.65	49.15	13.89	14.42	50.05	60.45	15.91	90.58	24.61	68.55	13.39	14.42	204.66	219.87	22.08

Table 5.5 : Waterflood and gas flood duration for the first 30 years.

Case number	Waterflood duration (years)	Gas flood duration (years)
1	10.42	19.58
2	10.42	19.58
3	10.42	19.58
4	6.91	23.09
5	6.91	23.09
6	6.91	23.09
7	6.58	23.42
8	6.58	23.42
9	6.58	23.42

Table 5.6 : Waterflood and gas flood duration at economic constraint

Case number	Waterflood duration (years)	Gas flood duration (years)
1	10.42	92.48
2	10.42	87.66
3	10.42	83.90
4	6.91	92.73
5	6.91	87.58
6	6.91	83.92
7	6.58	92.91
8	6.58	87.73
9	6.58	84.00

As shown in Table 5.4, the water production for each case is slightly different. During waterflood period, when we increase the water injection rate from 4,000 RB/D to 6,000 RB/D, it can significantly reduce the waterflood period from 10.42 to 6.91 years. However, when we increase water injection rate from 6,000 RB/D to 8,000 RB/D, it can slightly reduce the waterflood period which is 6.91 to 6.58 years as shown in Tables 5.5-5.6. During gas injection period, the more the gas injection rate, the smaller the overall production period.

In term of cumulative oil production, oil recovery factor, and BOE for the first 30 years of production period, cases 6 and 9 provide good oil recovery factor that are around 49% and BOE around 15.88 and 15.91 MMSTB, respectively. So, the injection and production strategies for both cases are the best DDP performance for first 30 years. At economic constraint, all cases give almost the same oil recovery factor and BOE. However, there are differences in time to reach the economic constraint. From the results, if we want to accelerate the production period, we should choose cases 6 and 9 because they give the lower production period than those in the other cases which is around 90 years.

5.2.2 Dip angle of 30 degrees

We apply water and gas injection strategies in Table 5.3 to a reservoir with 30 degree dip angle. As shown in Figure 5.29, cases 1-6 can keep water injection rate equal to preset value. However, cases 7-9 cannot keep injection rate equal to 8,000 RB/D because the injection pressure exceeds the fracture pressure.

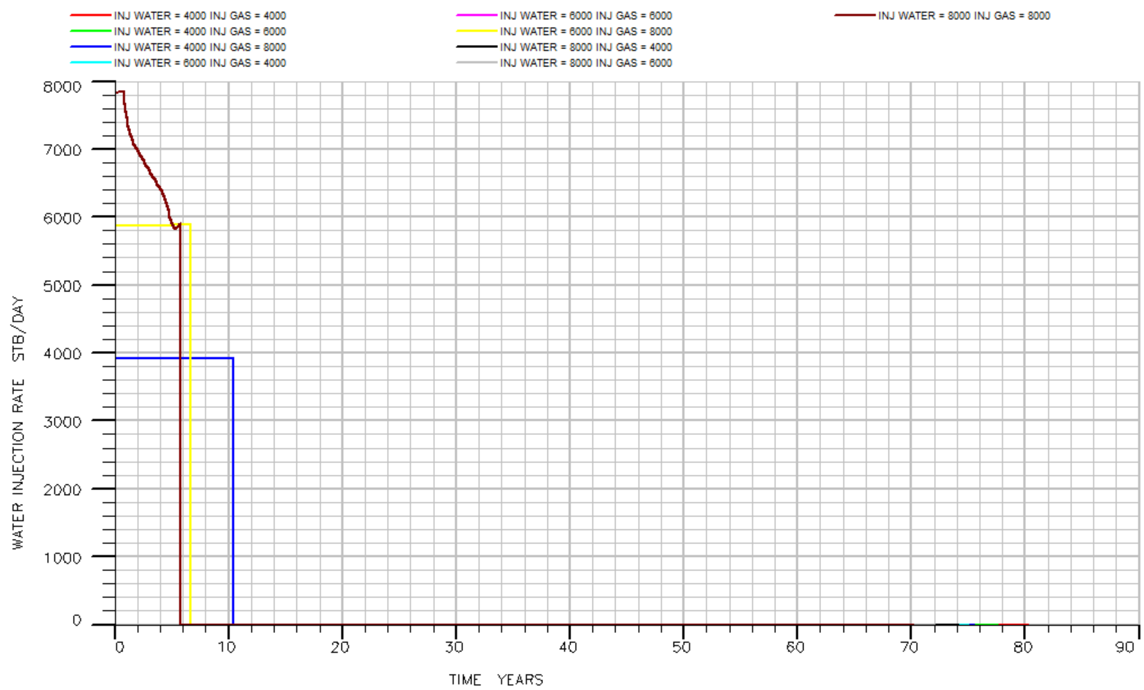

Figure 5.29 : Water injection rate for combinations of different water and gas injection rates (30-degree dip angle)

As shown in Figure 5.30, the gas injection rate for each case is different because the reservoir pressure at the time that we perform gas injection is different. Case 9 uses the highest injection rate while case 1 uses the lowest injection rate.

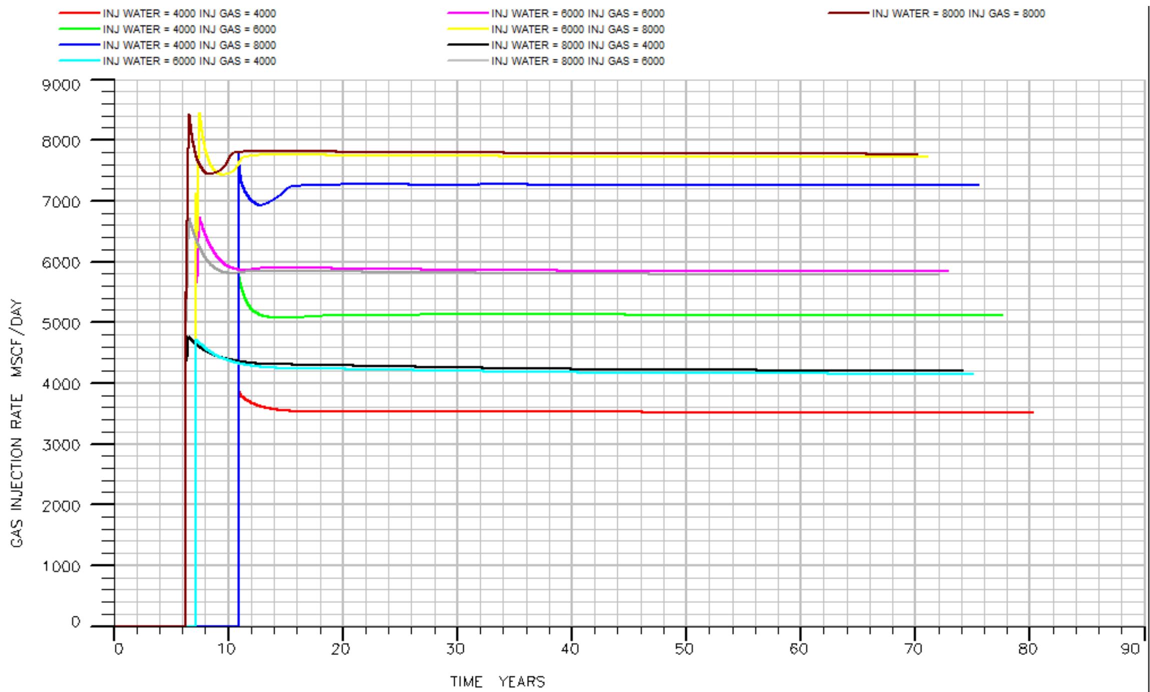

Figure 5.30 : Gas injection rate for combinations of different water and gas injection rates (30-degree dip angle)

During water injection period as shown in Figure 5.31, the oil rates for cases 1-3 are constant that around 3,100 RB/D. For cases 4-6, the oil rates are pretty constant. However, the oil rates for cases 7-9 are not constant which between 5,200 and 5,800 STB/D. During gas injection period, cases 3, 6, and 9 yield the higher oil rate when compare with those in the other cases. Oil rate starts to decline when the water cut increases as shown in Figure 5.32. After the water cut reaches 60%, we shut in the production well for 6 months in order to prepare gas injection and stabilize the reservoir pressure. Oil production rate starts dramatically drop again when gas break through the producer.

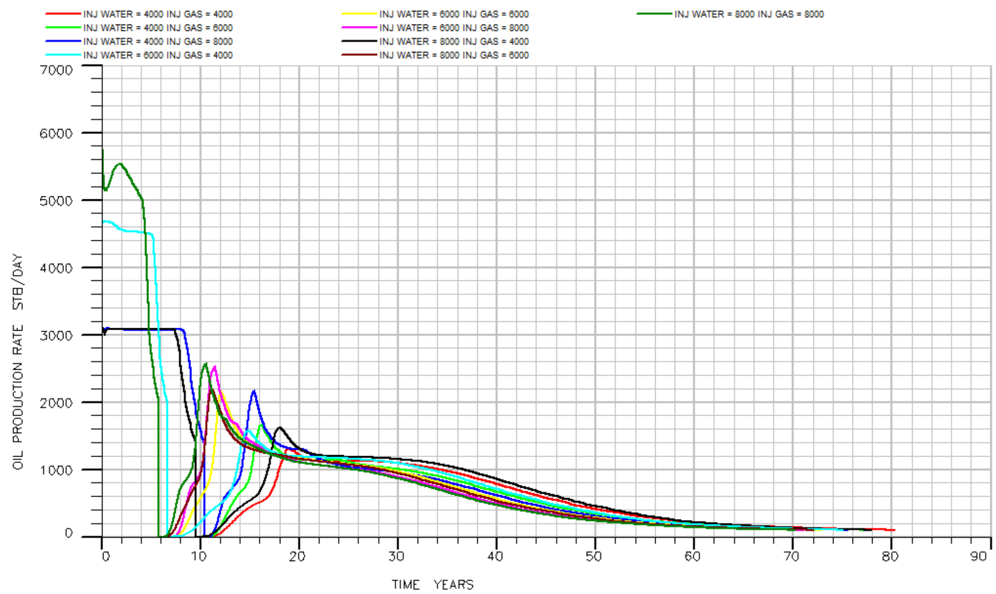

Figure 5.31 : Oil production rate for combinations of different water and gas injection rates (30-degree dip angle)

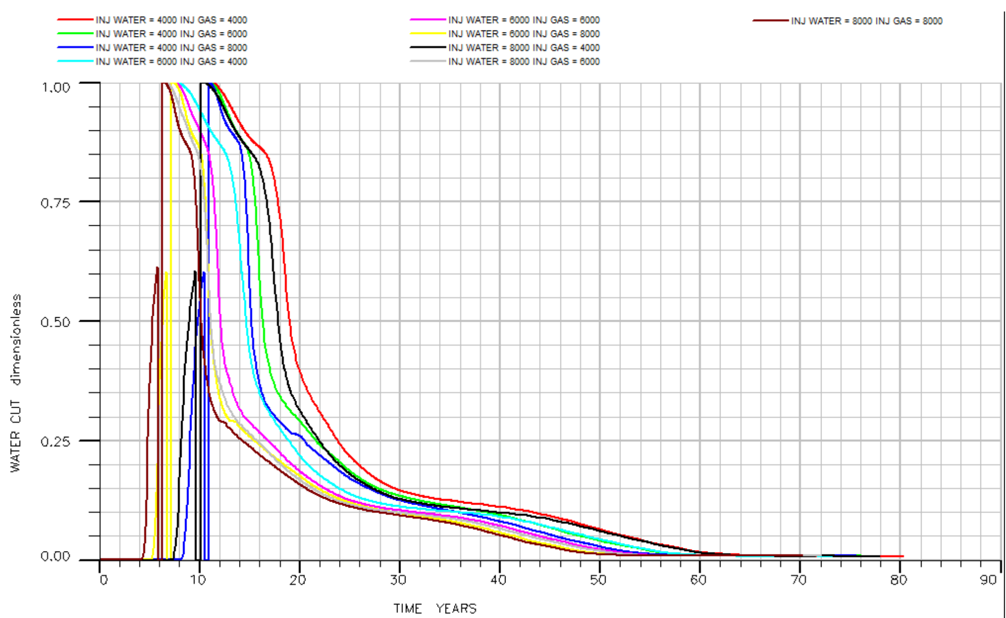

Figure 5.32 : Water cut for combinations of different water and gas injection rates (30-degree dip angle)

In term of cumulative oil production and oil recovery factor as shown in Figures 5.33-5.34, using high water injection rate yield higher cumulative oil production and oil recovery factor in waterflood period. During gas injection period, the higher gas injection rate yields the higher cumulative oil production and oil recovery factor. After 50 years of production, all cases yield the slightly increase for cumulative oil production and oil recovery factor.

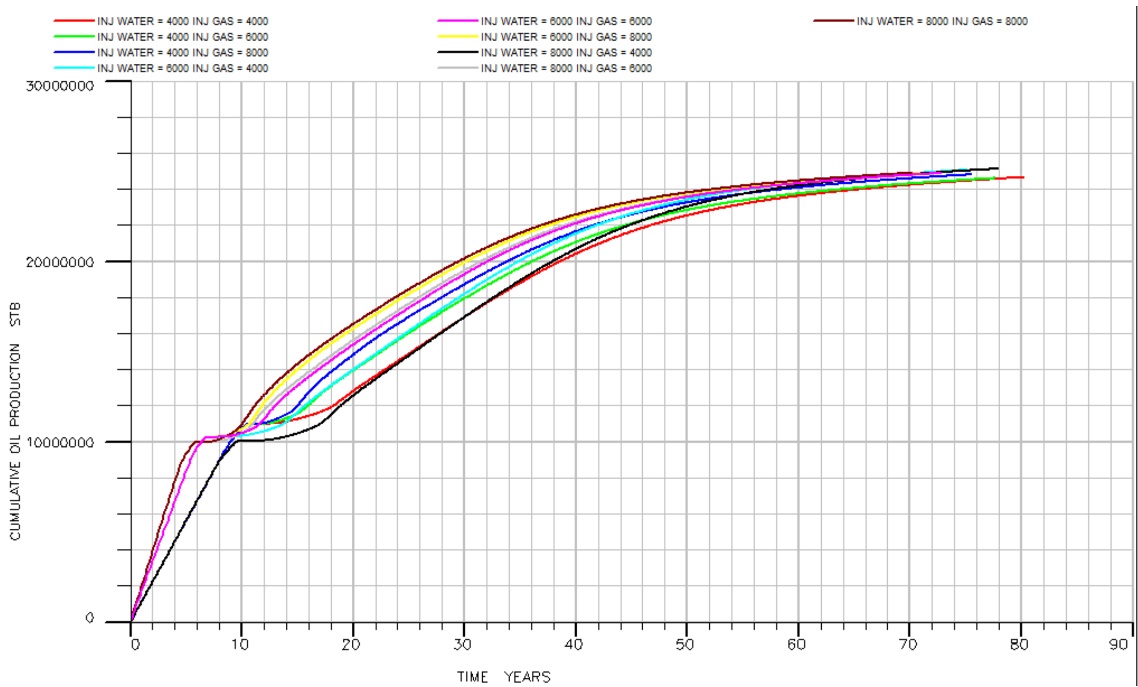

Figure 5.33 : Cumulative oil production for combinations of different water and gas injection rates (30-degree dip angle)

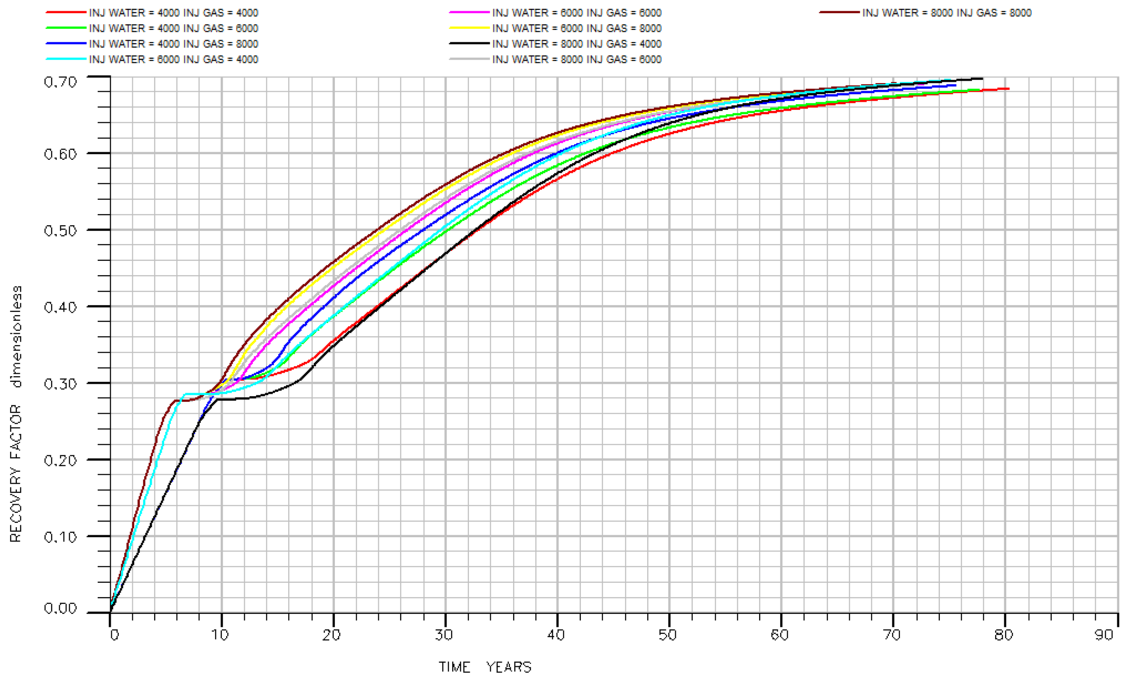

Figure 5.34 : Oil recovery factor for combinations of different water and gas injection rates (30-degree dip angle)

As shown in Figures 5.35-5.37, the amount of gas production mainly depends on the amount of gas that we inject into the reservoir. Gas production, gas-oil ratio, and cumulative gas production will significantly increase when gas breaks through the producer. For cases 6 and 9, gas breaks through times are shorter than those in the other cases because both cases use high gas injection rates.

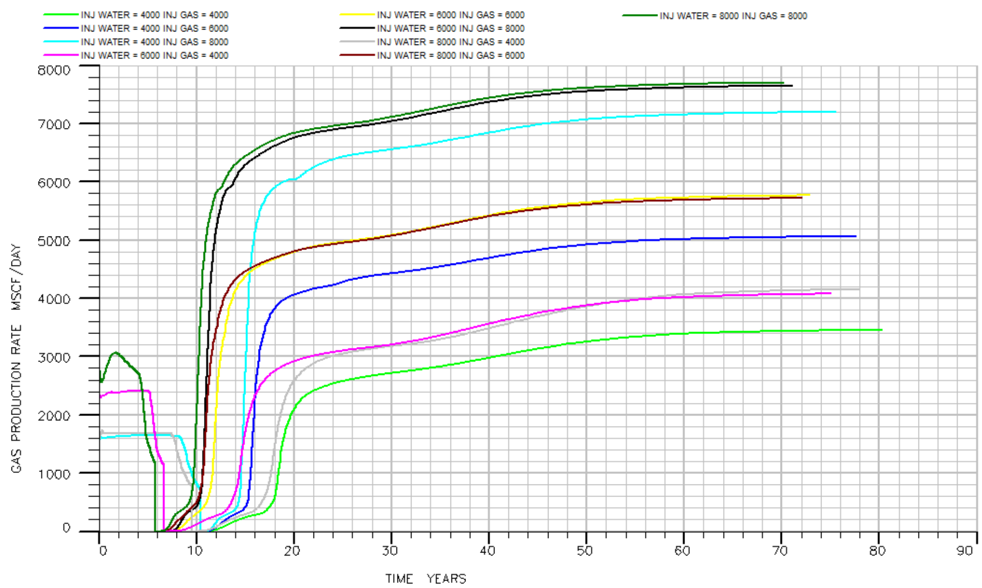

Figure 5.35 : Gas production rate for combinations of different water and gas injection rates (30-degree dip angle)

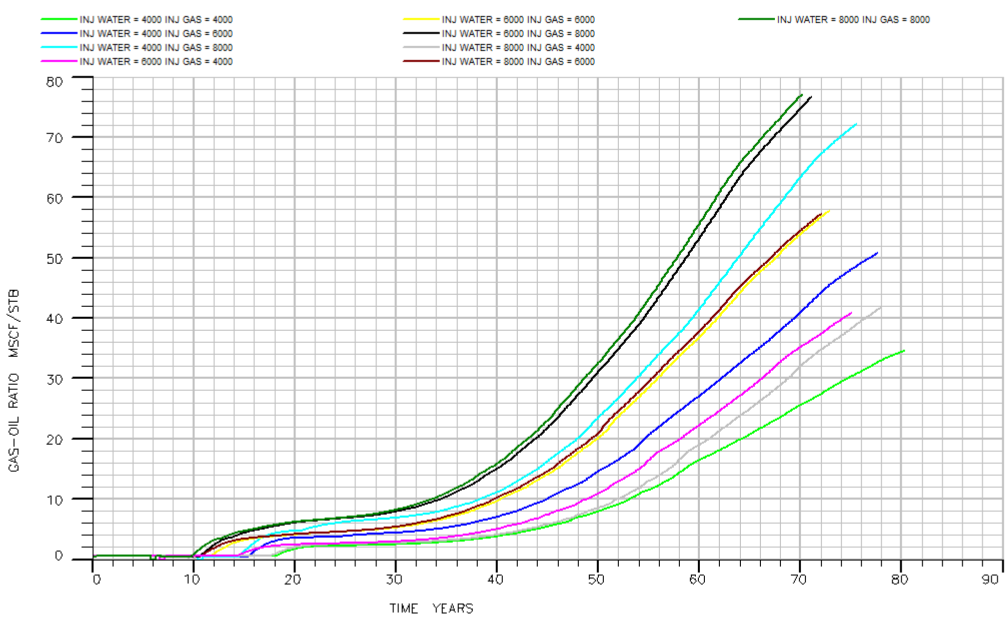

Figure 5.36 : Gas-oil ratio for combinations of different water and gas injection rates (30-degree dip angle)

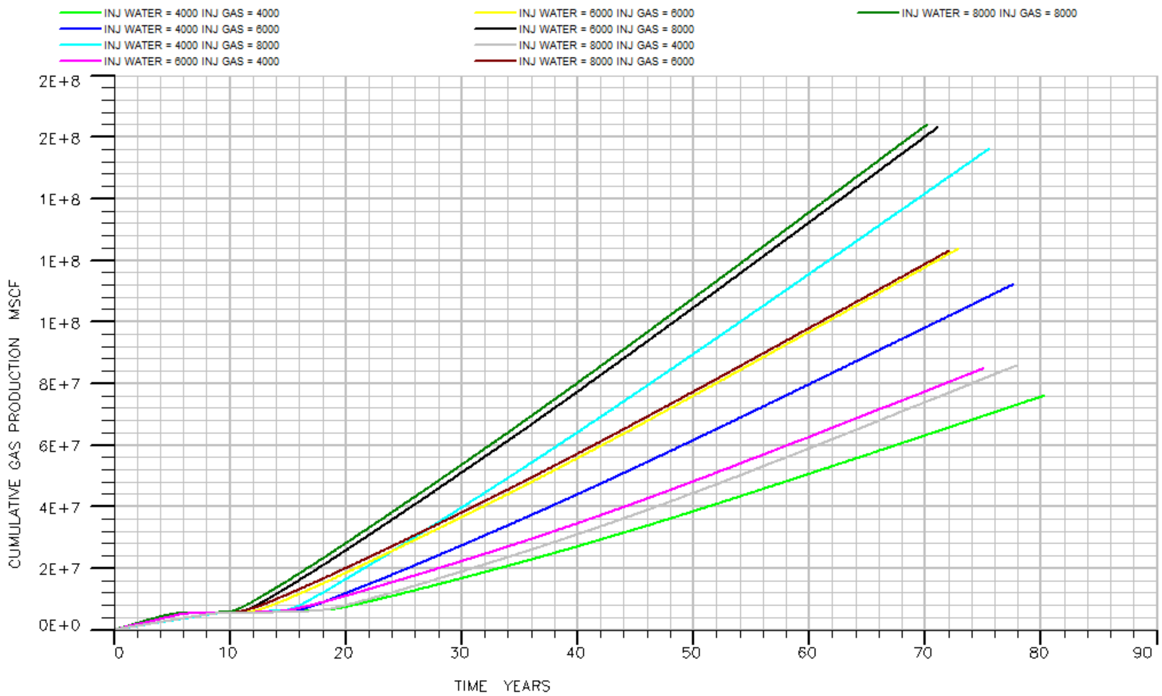

Figure 5.37 : Cumulative gas production for combinations of different water and gas injection rates (30-degree dip angle)

As shown in Figure 5.38, the reservoir pressure for all cases is pretty stable. Case 7 is the best strategy to maintain the reservoir pressure. The ability of case 2 to maintain the reservoir pressure is not good because the reservoir pressure is dramatically drops to 2,440 psia.

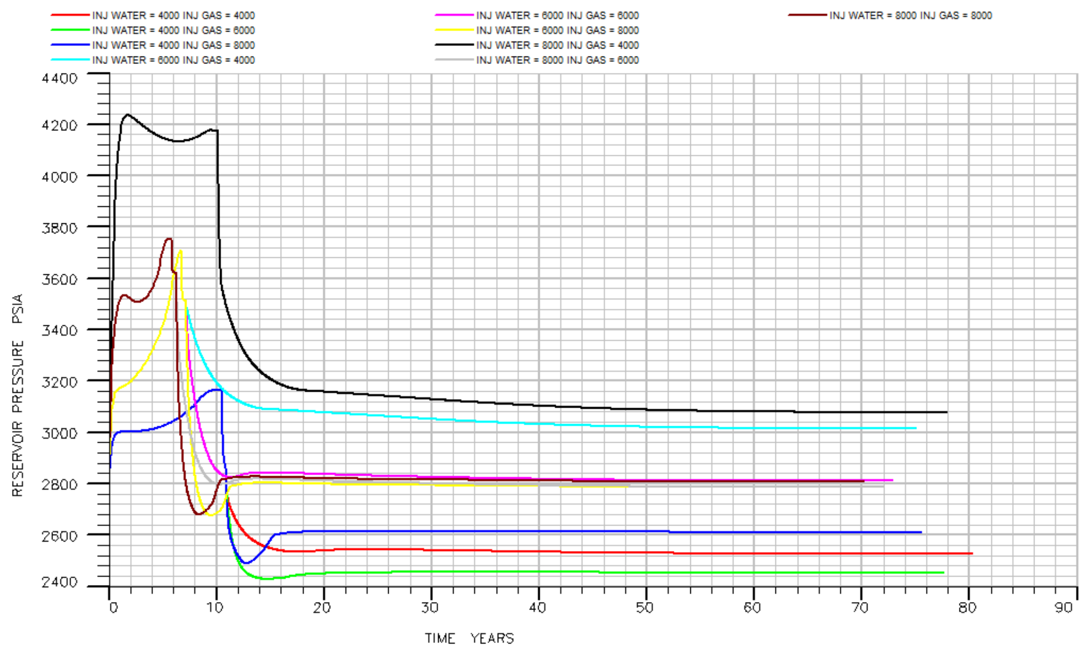

Figure 5.38 : Reservoir pressure for combinations of different water and gas injection rates (30-degree dip angle)

The summary of cumulative oil production, oil recovery factor, cumulative water production, cumulative water injection, cumulative gas production, cumulative gas injection, BOE and oil production period of a reservoir with 30 degree dip angle for each injection strategy are shown in Table 5.7. Tables 5.8-5.9 show the duration of waterflood and gas flood at first 30 years and abandonment.

Table 5.7 : Summary for 30 degree dip angle

Case number	Water injection rate (RB/D)	Gas injection rate (RB/D)	At 30 years							At abandonment							
			Np (MMSTB)	RF (%)	Wp (MMSTB)	Winj (MMSTB)	Gp (BSCF)	Ginj (BSCF)	BOE (MMSTB)	Tp (years)	Np (MMSTB)	RF (%)	Wp (MMSTB)	Winj (MMSTB)	Gp (BSCF)	Ginj (BSCF)	BOE (MMSTB)
1	4,000	4,000	16.92	46.92	12.19	14.89	16.71	24.8	15.58	80.22	24.66	68.36	12.97	14.89	75.95	89.3	22.43
2	4,000	6,000	17.95	49.77	12.53	14.89	27.42	35.78	16.56	77.54	24.6	68.21	13.09	14.89	112.07	124.65	22.5
3	4,000	8,000	18.74	51.96	12.74	14.89	39.98	50.35	17.01	75.46	24.8	68.77	13.19	14.89	156.11	170.82	22.35
4	6,000	4,000	18.2	50.48	11.9	14.31	22.28	35.64	15.98	75.05	25.06	69.47	12.45	14.31	84.93	104.1	21.86
5	6,000	6,000	19.3	53.52	12.23	14.31	36.61	49.4	17.17	72.74	24.89	69.00	12.6	14.31	123.65	140.63	22.06
6	6,000	8,000	19.95	55.31	12.43	14.31	51.11	64.36	17.74	71.00	24.9	69.00	12.71	14.31	163.14	180	22.09
7	8,000	4,000	16.93	47.32	12.1	14.69	18.9	31.49	14.83	77.88	25.13	69.67	12.81	14.69	85.82	105.68	21.82
8	8,000	6,000	19.51	54.10	12.22	14.69	38.12	50.9	17.38	72.04	24.84	68.88	12.55	14.69	123.1	139.8	22.06
9	8,000	8,000	20.17	55.94	12.41	14.69	53.68	67.33	17.9	70.16	24.9	69.03	12.66	14.69	164.3	181.4	22.04

Table 5.8 : Waterflood and gas flood duration for the first 30 years.

Case number	Waterflood duration (years)	Gas flood duration (years)
1	10.41	19.59
2	10.41	19.59
3	10.41	19.59
4	6.66	23.34
5	6.66	23.34
6	6.66	23.34
7	5.75	24.25
8	5.75	24.25
9	5.75	24.25

Table 5.9 : Waterflood and gas flood duration at economic constraint

Case number	Waterflood duration (years)	Gas flood duration (years)
1	10.41	69.81
2	10.41	67.13
3	10.41	65.05
4	6.66	68.39
5	6.66	66.08
6	6.66	64.34
7	5.75	72.13
8	5.75	66.29
9	5.75	64.41

For water production as shown in Table 5.7, there are slightly differences in water production for each criteria. During waterflooding, increasing the water injection rate from 4,000 RB/D to 6,000 RB/D can significantly reduce the waterflood duration from 10.41 to 6.66 years. However, when we increase water injection rate from 6,000 RB/D to 8,000 RB/D, it slightly reduces the waterflood duration as shown in Tables 5.8-5.9. During gas flooding, the more the gas injection rate, the less the time that is used to perform DDP.

In term of cumulative oil production, oil recovery factor and BOE for the first 30 years of production period, cases 6 and 9 provide good oil recovery factor of 55.31% and

55.94%, respectively and BOE of 17.84 and 17.9 MMSTB, respectively. So, the injection and production strategies in both cases are the best performance for the first 30 years of production. At economic constraint of 100 STB/D, all cases give almost the same oil recovery factor and BOE. However, there are differences in time to reach the economic constraint. From the simulation result, if we want to accelerate the production period, we should choose cases 6 and 9 because they need shorter production period which is around 71 and 72.04 years, respectively.

5.2.3 Dip angle of 60 degrees

Finally, we apply injection strategies in Table 5.3 to a reservoir with 60 degree dip angle. As shown in Figure 5.39, cases 1-3 can keep the water injection rate to the preset criteria. However, cases 4-6 and 7-9 cannot keep the injection rate to 6,000 RB/D and 8,000 RB/D, respectively, because the injection pressure exceeds the fracture pressure of the reservoir.

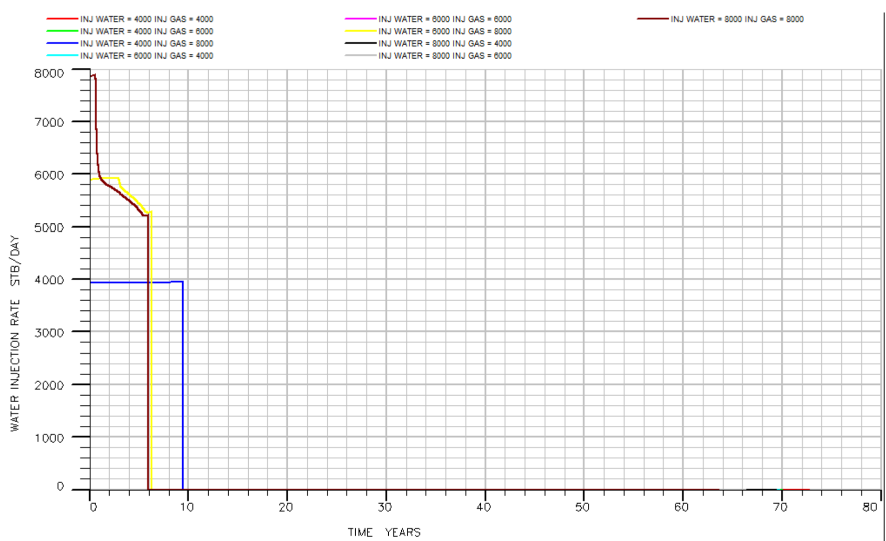

Figure 5.39 : Water injection rate for combinations of different water and gas injection rates (60-degree dip angle)

As shown in Figure 5.40, the gas injection rate for each case is different because the reservoir pressure at the time that we perform gas injection is differences. So, the range of injection pressure used for each case is difference. Cases 3, 6, and 9 use the highest injection rate while case 1 uses the lowest injection rate.

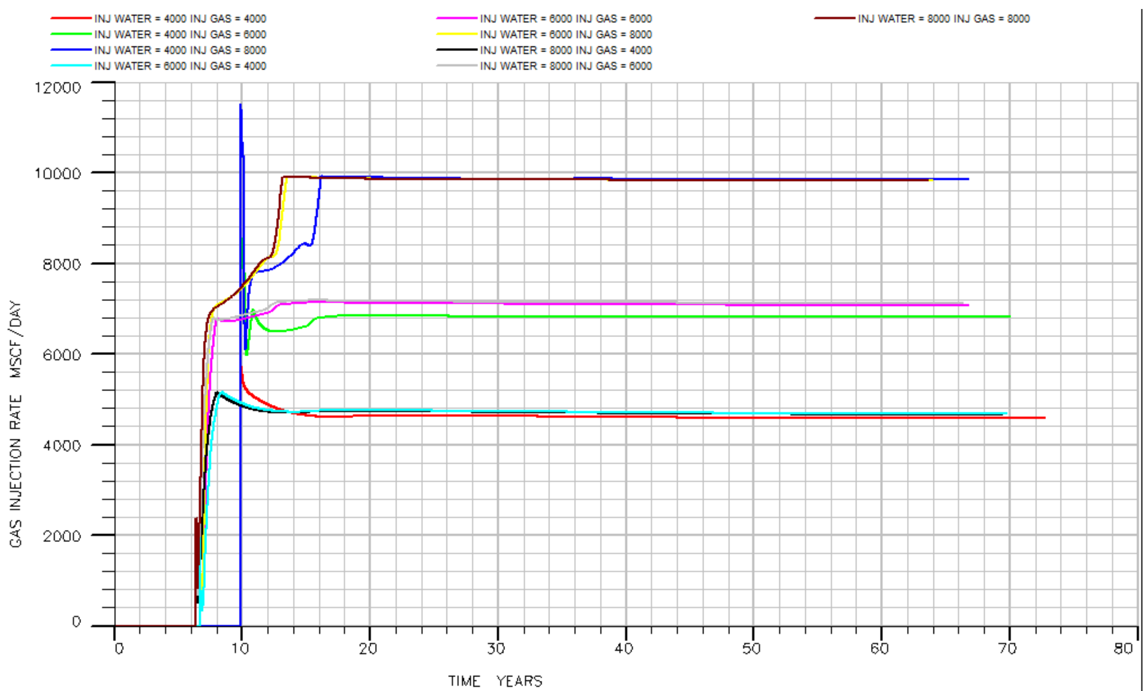

Figure 5.40 : Gas injection rate for combinations of different water and gas injection rates (60-degree dip angle)

During water injection period as shown in Figure 5.41, the oil rates for cases 1-3 are constant of 3,100 RB/D. For cases 4-9, the oil rates are not stable. During gas injection period, cases 3, 6, and 9 yield the higher the oil rates when compare with those in the other cases. The oil rate starts to decline when the water cut increases as shown in Figure 5.42. The oil production rate starts dramatically drop again when gas breaks through the producer.

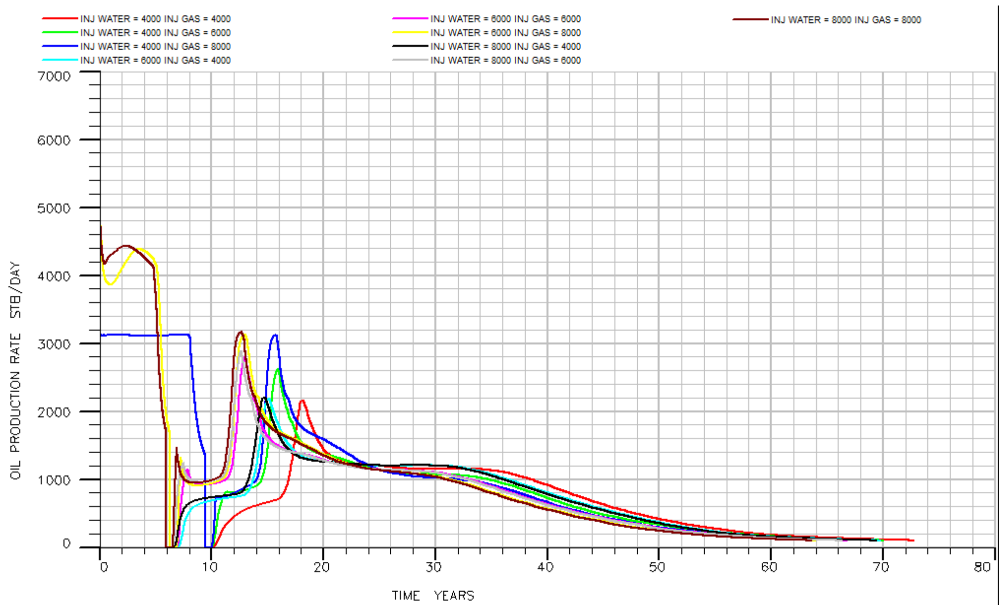

Figure 5.41 : Oil production profile for combinations of different water and gas injection rates (60-degree dip angle)

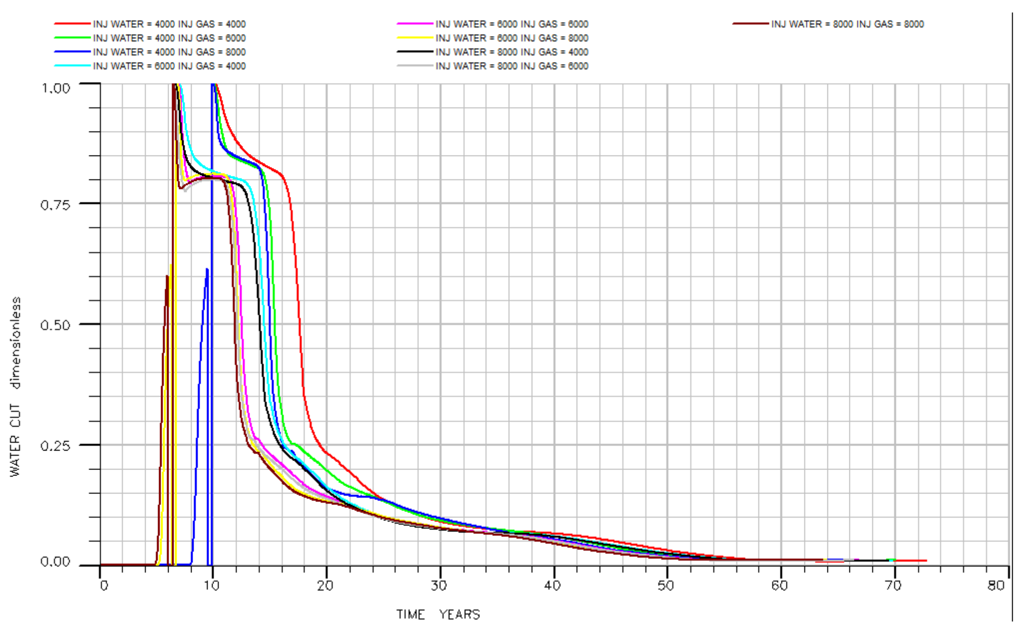

Figure 5.42 : Water cut for combinations of different water and gas injection rates (60-degree dip angle)

In term of cumulative oil production and oil recovery factor as shown in Figures 5.43-5.44, during waterflood period, cases 4-9 yield the higher cumulative oil production and oil recovery factor than those in cases 1-3. During gas injection period, cases 6 and 9 which use high gas injection rate yield the high cumulative oil production and oil recovery factor. Case 1 used the lowest water and gas injection rate yields the lowest cumulative oil production and oil recovery factor.

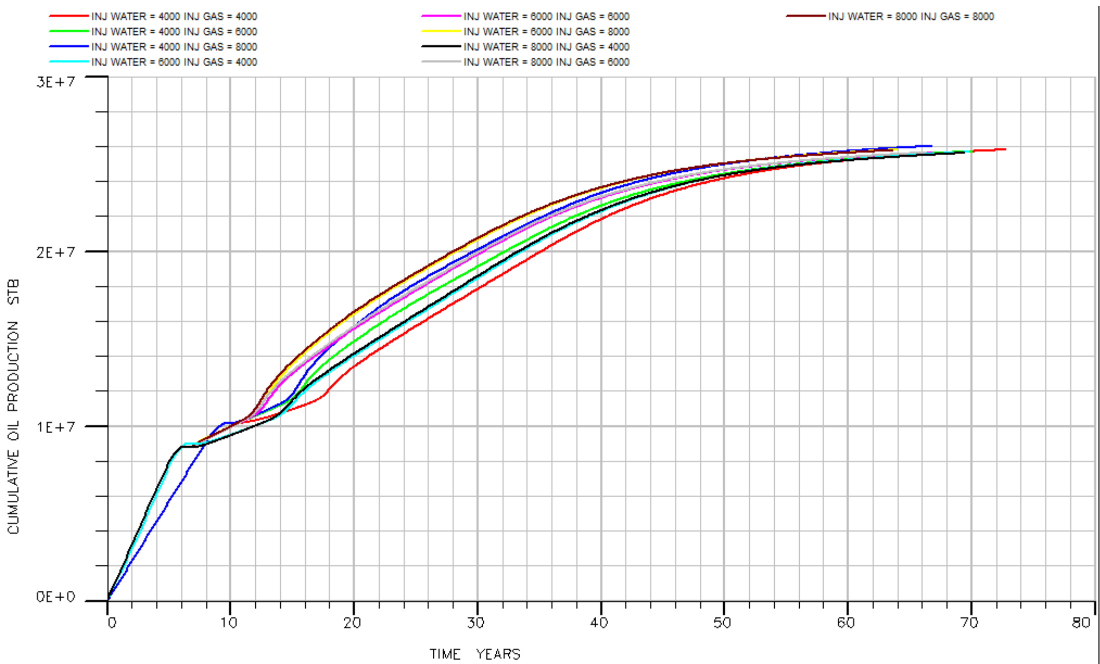

Figure 5.43 : Cumulative oil production for combinations of different water and gas injection rates (60-degree dip angle)

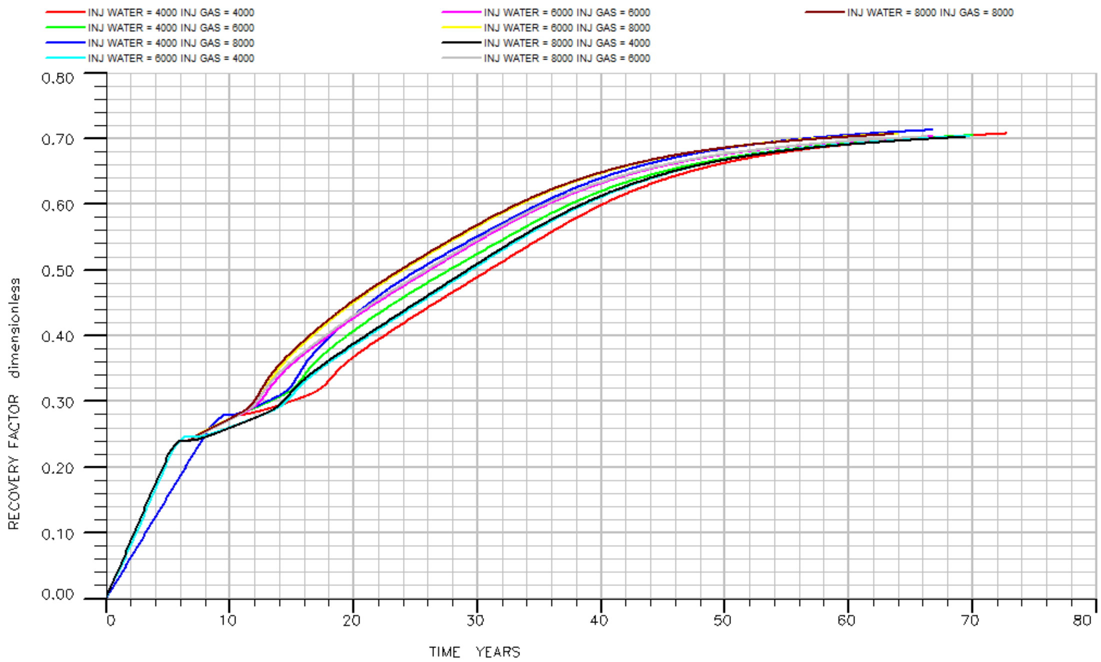

Figure 5.44 : Oil recovery factor for combinations of different water and gas injection rates (60-degree dip angle)

As shown in Figures 5.45-5.47, the amount of gas production mainly depends on the amount of gas that we inject into the reservoir. Gas production, gas-oil ratio, and cumulative gas production will significantly increase when gas break through the producer. For cases 6 and 9, gas breaks through times are shorter than those in the other cases because both cases use high gas injection rates.

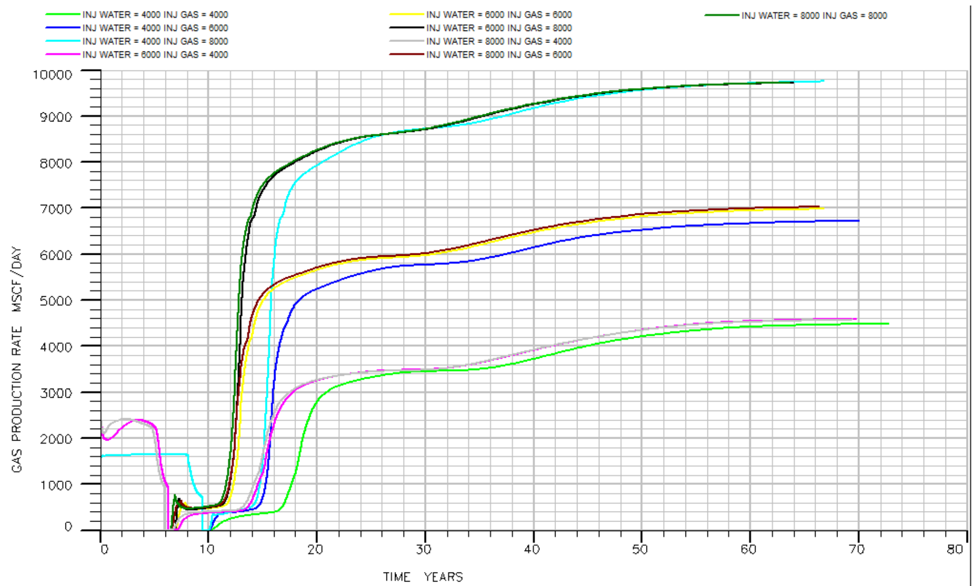

Figure 5.45 : Gas production rate for combinations of different water and gas injection rates (60-degree dip angle)

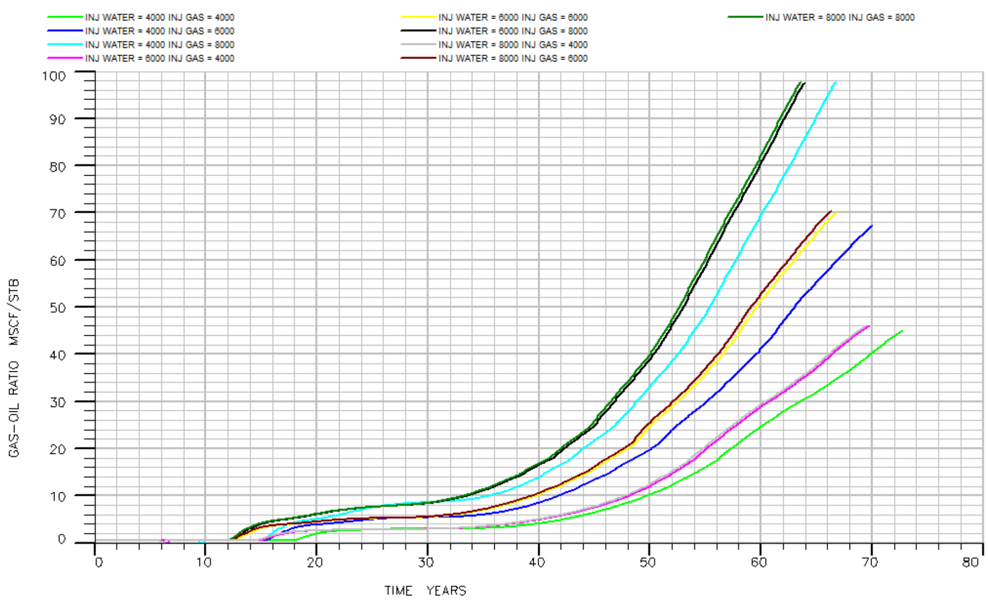

Figure 5.46 : Gas-oil ratio for combinations of different water and gas injection rates (60-degree dip angle)

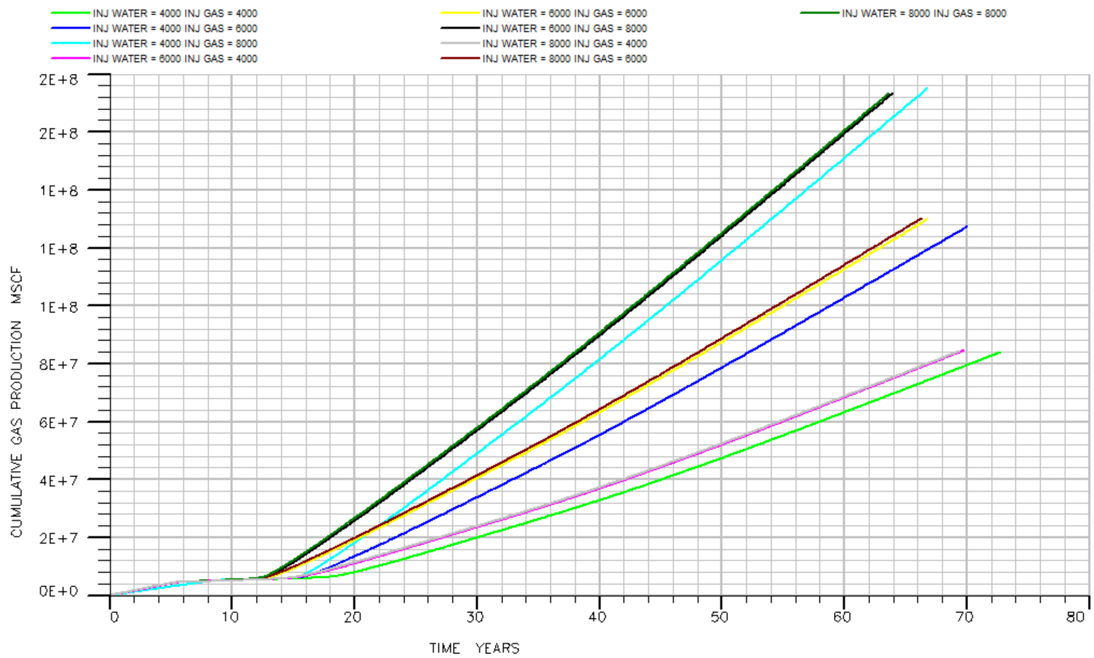

Figure 5.47 : Cumulative gas production for combinations of different water and gas injection rates (60-degree dip angle)

As shown in Figure 5.48, during water injection period, cases 7-9 can maintain the reservoir pressure better than other cases while cases 1-3 are not good. During gas injection period, cases 3, 6, and 9 provide the good performance to maintain the reservoir pressure while case 2 shows the lowest performance.

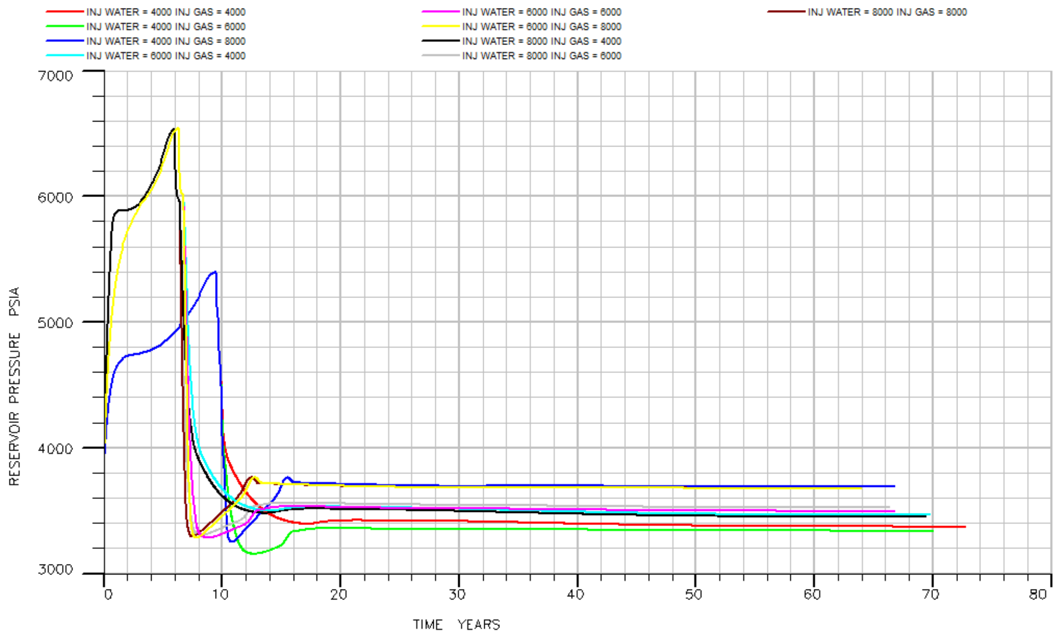

Figure 5.48 : Reservoir pressure for combinations of different water and gas injection rates (60-degree dip angle)

The summary of cumulative oil production, oil recovery factor, cumulative water production, cumulative water injection, cumulative gas production, cumulative gas injection, BOE and oil production period of 60 degree of dip angle for each injection strategy are shown in Table 5.10. Tables 5.11-5.12 show the duration of waterflood and gas flood at first 30 years and abandonment.

Table 5.10 : Summary for 60 degree dip angle

Case no.	Water injection rate (RB/D)	Gas injection rate (RB/D)	At 30 years							At Abandonment							
			Np (MMSTB)	RF (%)	Wp (MMSTB)	Winj (MMSTB)	Gp (BSCF)	Ginj (BSCF)	BOE (MMSTB)	Tp (years)	Np (MMSTB)	RF (%)	Wp (MMSTB)	Winj (MMSTB)	Gp (BSCF)	Ginj (BSCF)	BOE (MMSTB)
1	4,000	4,000	17.85	48.93	10,.94	13.54	19.94	34.44	15.44	72.71	25.81	70.73	11.42	13.54	83.9	106	22.13
2	4,000	6,000	19.13	52.44	11.25	13.54	33.9	49.79	16.49	70	25.71	70.47	11.63	13.54	127.37	149.39	22.04
3	4,000	8,000	20.1	55.1	11.39	13.54	49.1	68.59	16.86	66.74	26.01	71.29	11.73	13.54	175.2	200.89	21.73
4	6,000	4,000	18.48	50.64	10.8	13.01	23.55	39.65	15.8	69.79	25.67	70.35	11.19	13.01	84.68	107.85	21.81
5	6,000	6,000	19.83	54.35	11.07	13.01	40.54	58.55	16.83	66.74	25.65	70.3	11.36	13.01	129.92	153.63	21.7
6	6,000	8,000	20.67	56.64	11.19	13.01	57.04	77.36	17.28	63.91	25.8	70.72	11.45	13.01	173.48	199.13	21.53
7	8,000	4,000	18.59	50.96	10.51	12.67	23.92	40.09	15.9	69.32	25.62	70.21	10.9	12.67	84.29	107.32	21.78
8	8,000	6,000	19.93	54.64	10.78	12.67	41.46	59.82	16.88	66.29	25.64	70.27	11.07	12.67	130.2	154.21	21.64
9	8,000	8,000	20.76	56.88	10.9	12.67	57.96	78.43	17.34	63.58	25.77	70.63	11.15	12.67	173.34	199	21.49

Table 5.11 : Waterflood and gas flood duration for the first 30 years.

Case number	Waterflood duration (years)	Gas flood duration (years)
1	9.42	20.58
2	9.42	20.58
3	9.42	20.58
4	6.25	23.75
5	6.25	23.75
6	6.25	23.75
7	5.91	24.09
8	5.91	24.09
9	5.91	24.09

Table 5.12 : Waterflood and gas flood duration at economic constraint

Case number	Waterflood duration (years)	Gas flood duration (years)
1	9.42	63.29
2	9.42	60.58
3	9.42	57.32
4	6.25	63.54
5	6.25	60.49
6	6.25	57.66
7	5.91	63.41
8	5.91	60.38
9	5.91	57.67

As shown in Table 5.10, the water production for each case is slightly difference.

During waterflood period, when we increase the water injection rate from 4000 RB/D to 6000 RB/D, it can significantly reduce the waterflood period from 9.42 to 6.25 years. However, when we increase water injection rate from 6000 RB/D to 8000 RB/D, it can slightly reduce the waterflood period which is 6.25 to 5.91 years as shown in Tables 5.11-5.12. During gas injection period, the more the gas injection rate, the smaller the overall production period.

In term of cumulative oil production, oil recovery factor, and BOE during first 30 years of production period, cases 6 and 9 provide good oil recovery factor of 56.64% and 56.88%, respectively. For BOE, the values are 17.28 and 17.34 MMSTB, respectively. So, the injection and production strategies for both cases are the best DDP performance for first 30 years. At economic constraint, all cases give almost the same oil recovery factor and BOE. However, there are differences in time to reach the economic constraint. From the results, if we want to accelerate the production period, we should choose cases 6 and 9 because they give the lower production period than those in the other cases which is around 63 years.

After performing studies for all injection strategies and all dip angles, we got injection strategies that provide the best production performance for each dip angle. Table 5.13 is list of the best injection strategy for each dip angle. For all reservoir dip angles, using water and gas injection rate of 8000 RB/D provides the best DDP performance.

Table 5.13 : Best injection strategy for each dip angle

Dip angle (Degree)	**Water injection rate (RB/D)**	**Gas injection rate (RB/D)**
15	8,000	8,000
30	8,000	8,000
60	8,000	8,000

Figure 5.49 illustrates oil production rate for each dip angle. During waterflood period, a reservoir with more dip angle has less oil production rate because it is more difficult to inject water up a steep reservoir in order to sweep the oil. During gas injection period, a reservoir with more the dip angle provides better oil production rate because we can inject gas more easily when gas moves down-dip in a steep reservoir. When we

consider the entire DDP process, a higher dip angle yields better performance in term of oil recovery as shown in Figures 5.50-5.51.

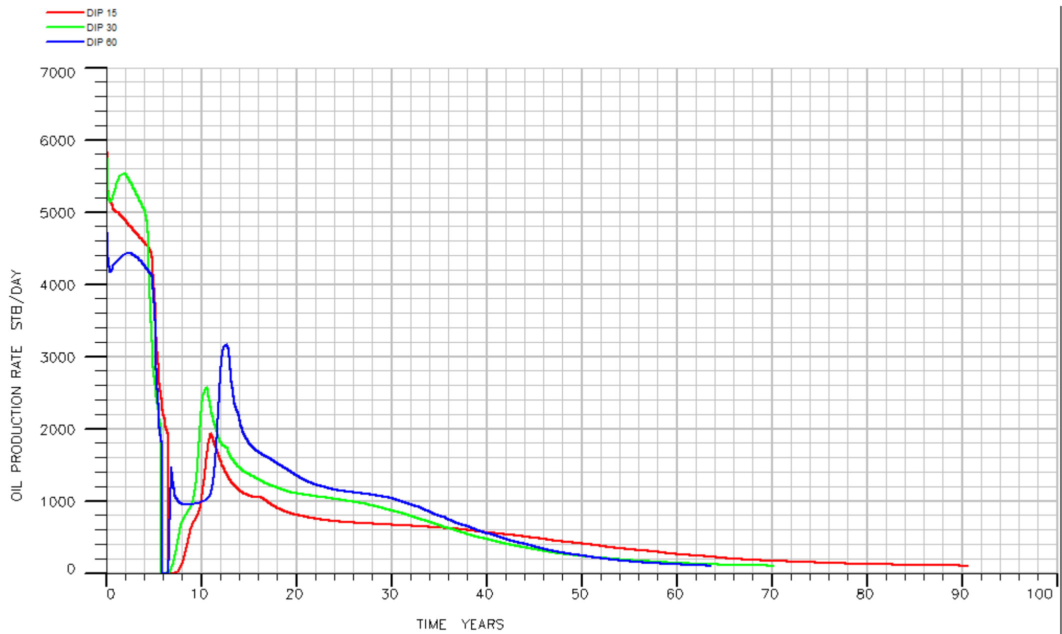

Figure 5.49 : Oil production profile for each dip angle

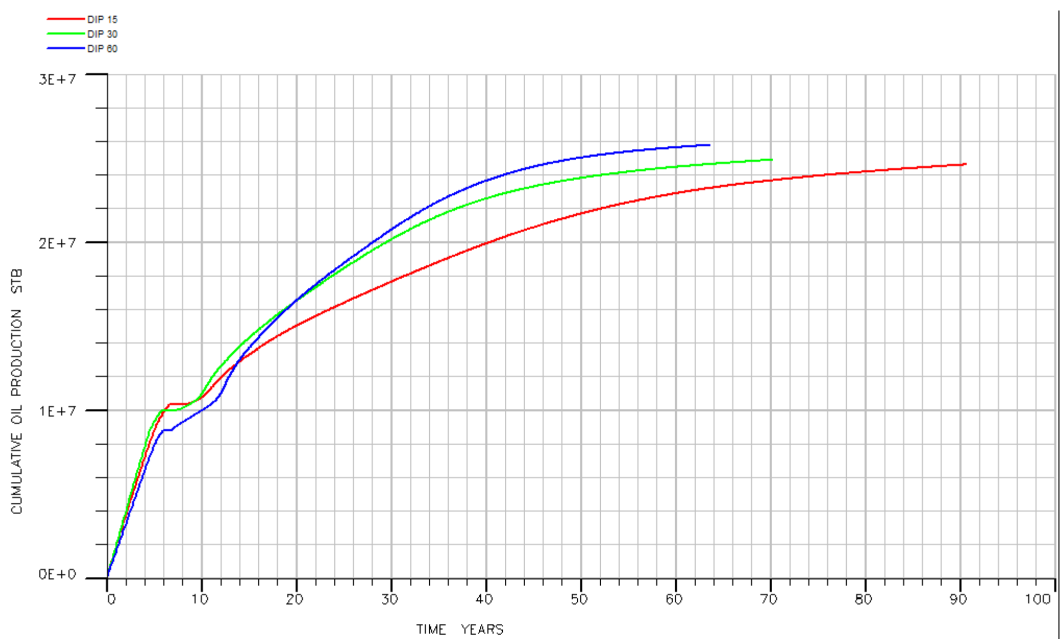

Figure 5.50 : Cumulative oil production for each dip angle

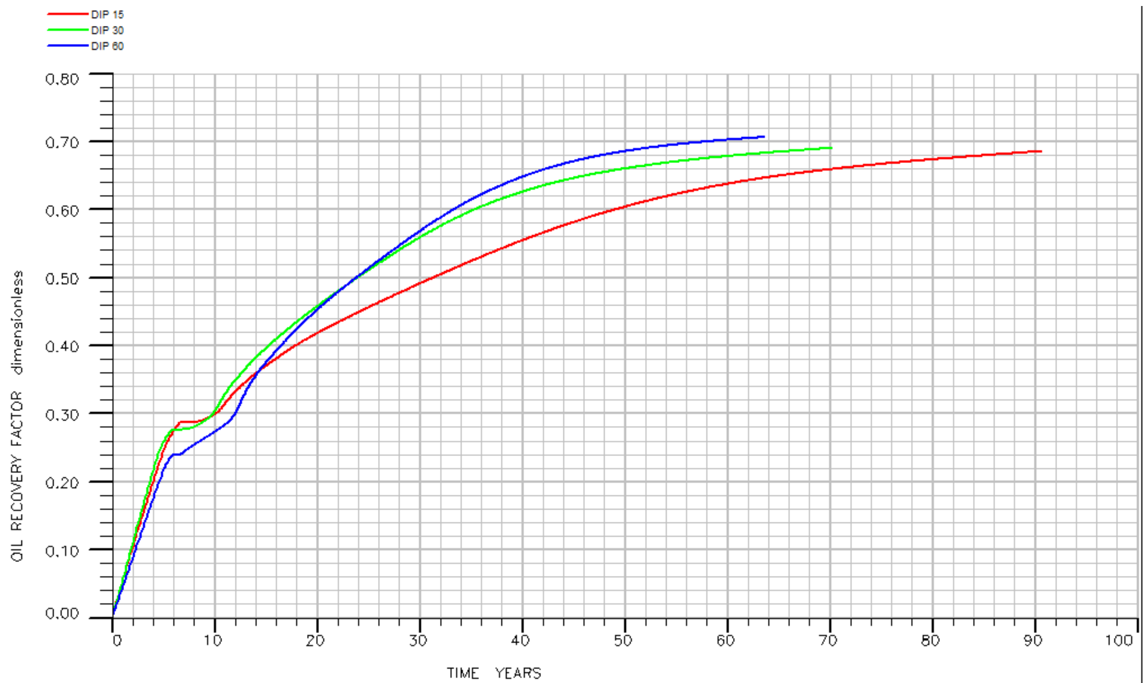

Figure 5.51 : Oil recovery factor for each dip angle

Table 5.14 : Summary the best injection strategy for each dip angle.

Dip angle (°)	Water injection rate (RB/D)	Gas injection rate (RB/D)	At 30 years							At Abandonment							
			Np (STB)	RF (%)	Wp (STB)	Winj (STB)	Gp (MSCF)	Ginj (MSCF)	BOE (STB)	Tp (years)	Np (STB)	RF (%)	Wp (STB)	Winj (STB)	Gp (MSCF)	Ginj (MSCF)	BOE (STB)
15	8,000	8,000	17.65	49.15	13.89	14.42	50.05	60.45	15.91	90.58	24.61	68.55	13.39	14.42	204.66	219.87	22.08
30	8,000	8,000	20.17	55.94	12.41	14.69	53.68	67.33	17.9	70.16	24.9	69.03	12.66	14.69	164.3	181.4	22.04
60	8,000	8,000	20.76	56.88	10.9	12.67	57.96	78.43	17.34	63.58	25.77	70.63	11.15	12.67	173.34	199	21.49

Table 5.15 : Waterflood and gas flood duration for the first 30 years.

Dip angle (°)	Water injection rate (RB/D)	Gas injection rate (RB/D)	Waterflood duration (years)	Gas flood duration (years)
15	8,000	8,000	6.58	23.42
30	8,000	8,000	5.75	24.25
60	8,000	8,000	5.91	24.09

Table 5.16 : Waterflood and gas flood duration at economic constraint.

Dip angle (°)	Water injection rate (RB/D)	Gas injection rate (RB/D)	Waterflood duration (years)	Gas flood duration (years)
15	8,000	8,000	6.58	84.00
30	8,000	8,000	5.75	64.41
60	8,000	8,000	5.91	57.67

As shown in Table 5.14, water production rate for a reservoir with 15 degree dip angle yields the highest amount of water because it is more easily to inject water up a shallow reservoir. On the other hand, a reservoir with 60 degree dip angle yields the lowest water production rate. In term of gas production, a reservoir with 60 degree dip angle yields the highest amount of gas production because we can inject gas more easily when gas moves down-dip in a steep reservoir during the first 30 years. At economic constraint, the water production and gas production for a reservoir with 15 degree dip angle are quite high because the time that we use to perform DDP is a lot higher than those with other dip angles.

During the first 30 years, a reservoir with 15 degree dip angle takes the highest time to perform water injection while a reservoir with 30 degree dip angle uses the lowest time. At economic constraint, a reservoir with 15 degree dip angle uses significantly more time than those with other dip angles.

In term of cumulative oil production, oil recovery factor, and BOE during the first 30 years, a reservoir with 60 degree dip angle provides good cumulative oil production and oil recovery factor which around 20.76 MMSTB and 56.88%, respectively. At economic constraint of 100 STB/D, a reservoir with 60 degree dip angle still yields the highest cumulative oil production, oil recovery factor, and BOE.

5.3 Effect of well pattern

In this section, different well patterns are used to investigate DDP performance. Different dip angles are also included in this section because we would like to know which well pattern is suited for each reservoir.

Six different well patterns are used in this study. The locations of the wells for various patterns are shown in Figures 5.52-5.57. In addition, the production and injection sequences are shown in Tables 5.17-5.22. We use the formation fracture pressure as the injection constraint.

For well pattern 1, the locations and the fracturing pressure of the wells are shown in Figure 5.52 and Table 5.17. As shown in Table 5.18, we start with waterflooding at well 2. After the WCT reaches the stopping criteria, we shut in all wells for six months to stabilize the reservoir pressure. After that, we inject gas at well 1. Well 2 then becomes a producer until the reservoir reaches the economic constraint.

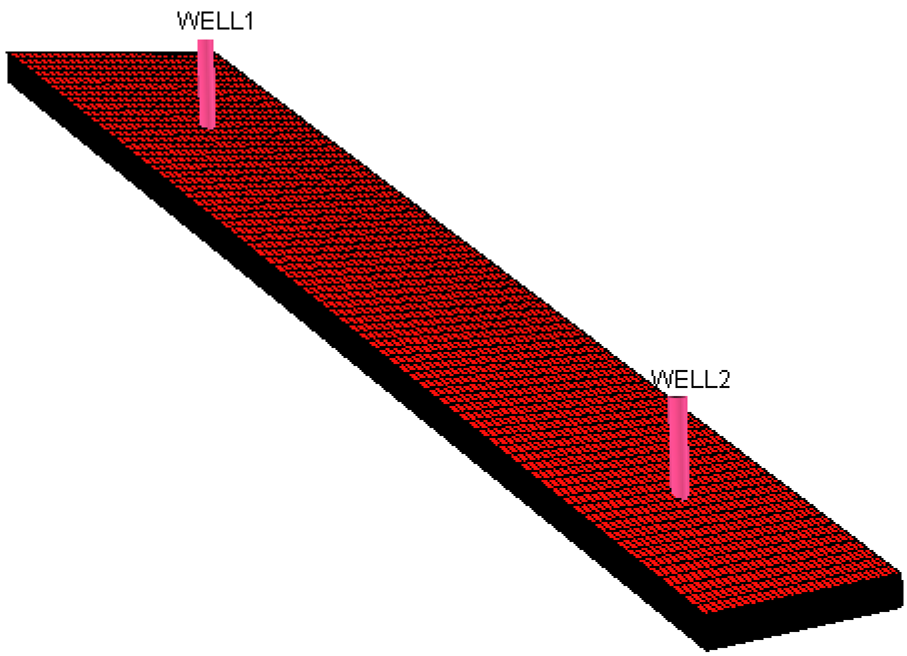

Figure 5.52 : Schematic of well pattern 1

Table 5.17 : Locations and constraints of well pattern 1

Parameter	Value	Unit
Position for Well 1	i=12, j=16	
Position for Well 2	i=62, j=16	
Formation fracture pressure of well 1(Reservoir with 15 degree dip angle)	3,400	psia
Formation fracture pressure of well 2(Reservoir with 15 degree dip angle)	4,250	psia
Formation fracture pressure of well 1(Reservoir with 30 degree dip angle)	3,720	psia
Formation fracture pressure of well 2(Reservoir with 30 degree dip angle)	5,500	psia
Formation fracture pressure of well 1(Reservoir with 60 degree dip angle)	4,400	psia
Formation fracture pressure of well 2(Reservoir with 60 degree dip angle)	11,200	psia

Table 5.18 : Injection and production sequence for well pattern 1

Stage	Well 1	Well 2
Waterflood	Producer (8,000 RB/D)	Water injector (8,000 RB/D)
WCT at well 2 = 0.6	Shut in for 6 months	Shut in for 6 months
Gas injection	Gas injector (8,000 RB/D)	Producer (8,000 RB/D)

For well pattern 2, the locations and the fracturing pressure of the wells are shown in Figure 5.53 and Table 5.19. As shown in Table 5.20, we start with injecting water at well 4 while wells 1-3 are the producer. After the WCT of well 3 reaches the stopping criteria, we shut in well 3 while wells 1-2 still produce the oil until the WCT of well 2 reaches the stopping criteria. Then, we shut in well 2. Well 1 continues to produce the oil until WCT reaches the stopping criteria. Then, we shut in all wells for six months to stabilize the reservoir pressure. After that, we open wells 1-2. Well 1 is gas injector and well 2 is the producer. Well 2 continuously produce the oil until gas production rate reaches 8000 RB/D. Then, we shut in well 2 and open well 3 as a producer. Well 3 continuously produces the oil until gas breaks through at well 3. Then, we shut in well 3 while well 4 is opened to be a producer until oil rate reaches the economic constraint.

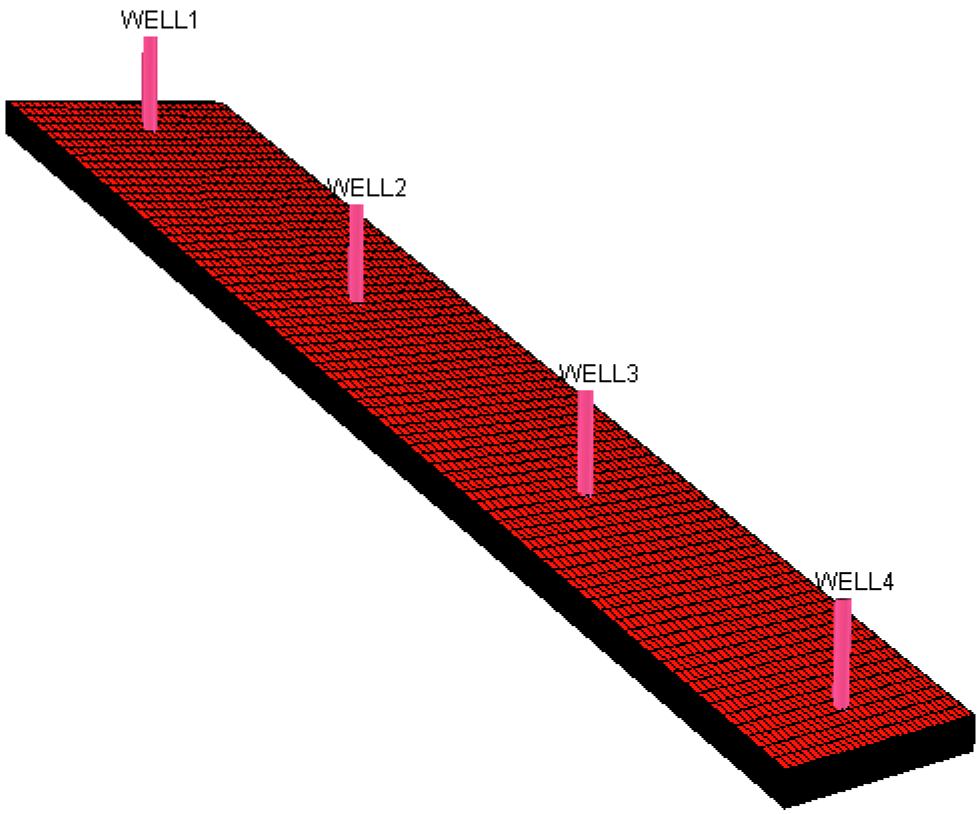

Figure 5.53 : Schematic of well pattern 2

Table 5.19 : Locations and constraints of well pattern 2

Parameter	Value	Unit
Position for Well 1	i=4, j=16	
Position for Well 2	i=26, j=16	
Position for Well 3	i=48, j=16	
Position for Well 4	i=70, j=16	
Formation fracture pressure of well 1(Reservoir with 15 degree dip angle)	3,300	psia
Formation fracture pressure of well 2(Reservoir with 15 degree dip angle)	3,600	psia
Formation fracture pressure of well 3(Reservoir with 15 degree dip angle)	3,960	psia
Formation fracture pressure of well 4(Reservoir with 15 degree dip angle)	4,400	psia
Formation fracture pressure of well 1(Reservoir with 30 degree dip angle)	3,300	psia
Formation fracture pressure of well 2(Reservoir with 30 degree dip angle)	4,079	psia
Formation fracture pressure of well 3(Reservoir with 30 degree dip angle)	4,927	psia
Formation fracture pressure of well 4(Reservoir with 30 degree dip angle)	5,830	psia
Formation fracture pressure of well 1(Reservoir with 60 degree dip angle)	3,500	psia
Formation fracture pressure of well 2(Reservoir with 60 degree dip angle)	6,074	psia
Formation fracture pressure of well 3(Reservoir with 60 degree dip angle)	9,069	psia
Formation fracture pressure of well 4(Reservoir with 60 degree dip angle)	11,000	psia

Table 5.20 : Injection and production sequence for well pattern 2

Stage	Well 1	Well 2	Well 3	Well 4
Waterflood	Producer (2,666 RB/D)	Producer (2,666 RB/D)	Producer (2,666 RB/D)	Water injector (8,000 RB/D)
WCT at well 3 = 0.6	Producer (4,000 RB/D)	Producer (4,000 RB/D)	Shut-in	Water injector (8,000 RB/D)
WCT at well 2 = 0.6	Producer (8,000 RB/D)	Shut-in	Shut-in	Water injector (8,000 RB/D)
WCT at well 1 = 0.6	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months
Gas injection	Gas injector (8,000 RB/D)	Producer (8,000 RB/D)	Shut-in	Shut-in
Gas breakthrough at well 2	Gas injector (8,000 RB/D)	Shut-in	Producer (8,000 RB/D)	Shut-in
Gas breakthrough at well 3	Gas injector (8,000 RB/D)	Shut-in	Shut-in	Producer (8,000 RB/D)

For well pattern 3, the locations and the fracturing pressure of the wells are shown in Figure 5.54 and Table 5.21. As shown in Table 5.22, we start with injecting water at well 4 while wells 1-3 are the producer. After the WCT of well 3 reaches the stopping criteria, we shut in well 3 while wells 1-2 still produce the oil until the WCT of well 2 reaches the stopping criteria. Then, we shut in well 2. Well 1 continuously produces the oil until WCT reaches the stopping criteria. Then, all wells have to shut in for six months to stabilize the reservoir pressure. After that, we open wells 1-2, well 1 is the gas injector and well 2 is the producer. Well 2 continuously produces the oil until gas production rate reaches 8000 RB/D. Then, we shut in well 2 and open well 3. We continuously produce the oil at well 3 until gas breaks through. After that, we shut in well 3 while well 4 is opened. We continuously produce the oil at well 4 until it reaches the economic constraint.

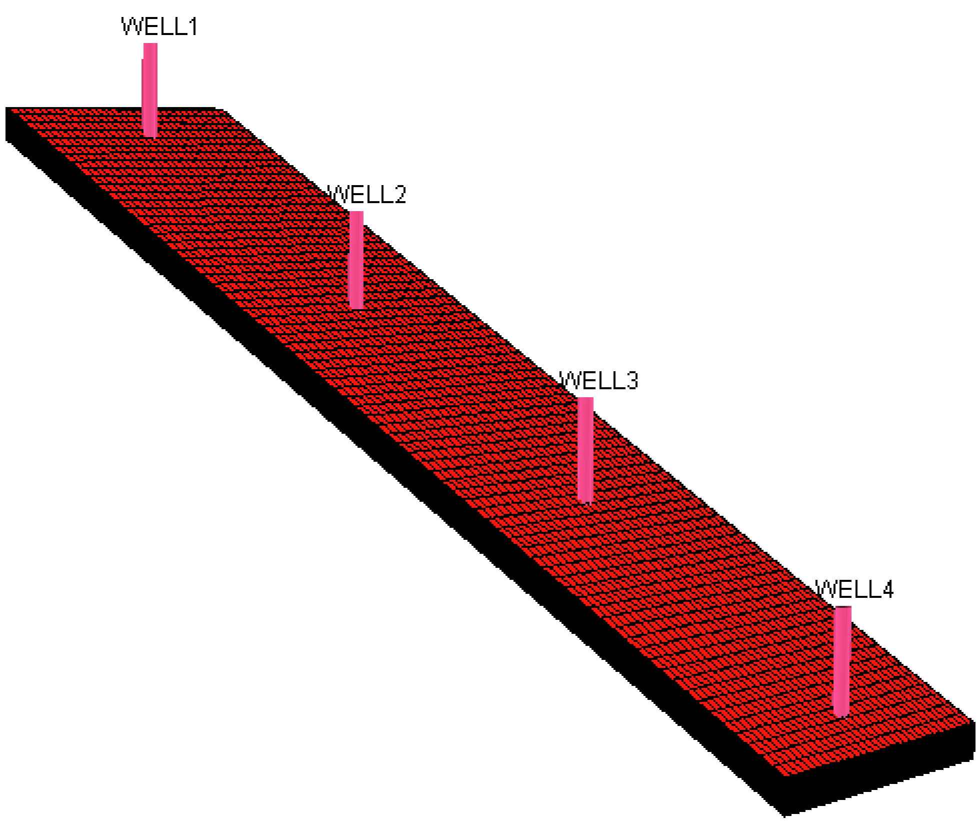

Figure 5.54 : Schematic of well pattern 3

Table 5.21 : Locations and constraints of well pattern 3

Parameter	Value	Unit
Position for Well 1	i=4, j=16	
Position for Well 2	i=26, j=16	
Position for Well 3	i=48, j=16	
Position for Well 4	i=70, j=16	
Formation fracture pressure of well 1(Reservoir with 15 degree dip angle)	3,300	psia
Formation fracture pressure of well 2(Reservoir with 15 degree dip angle)	3,600	psia
Formation fracture pressure of well 3(Reservoir with 15 degree dip angle)	3,960	psia
Formation fracture pressure of well 4(Reservoir with 15 degree dip angle)	4,400	psia
Formation fracture pressure of well 1(Reservoir with 30 degree dip angle)	3,300	psia
Formation fracture pressure of well 2(Reservoir with 30 degree dip angle)	4,079	psia
Formation fracture pressure of well 3(Reservoir with 30 degree dip angle)	4,927	psia
Formation fracture pressure of well 4(Reservoir with 30 degree dip angle)	5,830	psia
Formation fracture pressure of well 1(Reservoir with 60 degree dip angle)	3,500	psia
Formation fracture pressure of well 2(Reservoir with 60 degree dip angle)	6,074	psia
Formation fracture pressure of well 3(Reservoir with 60 degree dip angle)	9,069	psia
Formation fracture pressure of well 4(Reservoir with 60 degree dip angle)	11,000	psia

Table 5.22 : Injection and production sequence for well pattern 3

Stage	Well 1	Well 2	Well 3	Well 4
Waterflood	Producer (2,666 RB/D)	Producer (2,666 RB/D)	Producer (2,666 RB/D)	Water injector (8,000 RB/D)
WCT at well 3=0.6	Producer (4,000 RB/D)	Producer (4,000 RB/D)	Shut-in	Water injector (8,000 RB/D)
WCT at well 2=0.6	Producer (8,000 RB/D)	Shut-in	Shut-in	Water injector (8,000 RB/D)
WCT at well 1=0.6	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months
Gas injection	Gas injector (8,000 RB/D)	Producer (8,000 RB/D)	Shut-in	Shut-in
Gas breakthrough at well 2	Shut-in	Gas injector (8,000 RB/D)	Producer (8,000 RB/D)	Shut-in
Gas breakthrough at well 3	Shut-in	Gas injector (8,000 RB/D)	Shut-in	Producer (8,000 RB/D)

For well pattern 4, the locations and the fracturing pressure of the wells are shown in Figure 5.55 and Table 5.23. As shown in Table 5.24, we start with injecting water at well 8 while other wells are opened for production. After WCT of the production wells reach the stopping criteria. Then, we close the production well as sequence from well 7 to well 1. Now, all wells have to shut for six months to stabilize the reservoir pressure. Next, we perform gas injection at well 1. We sequentially open the wells for production which start from well 2 to well 8.

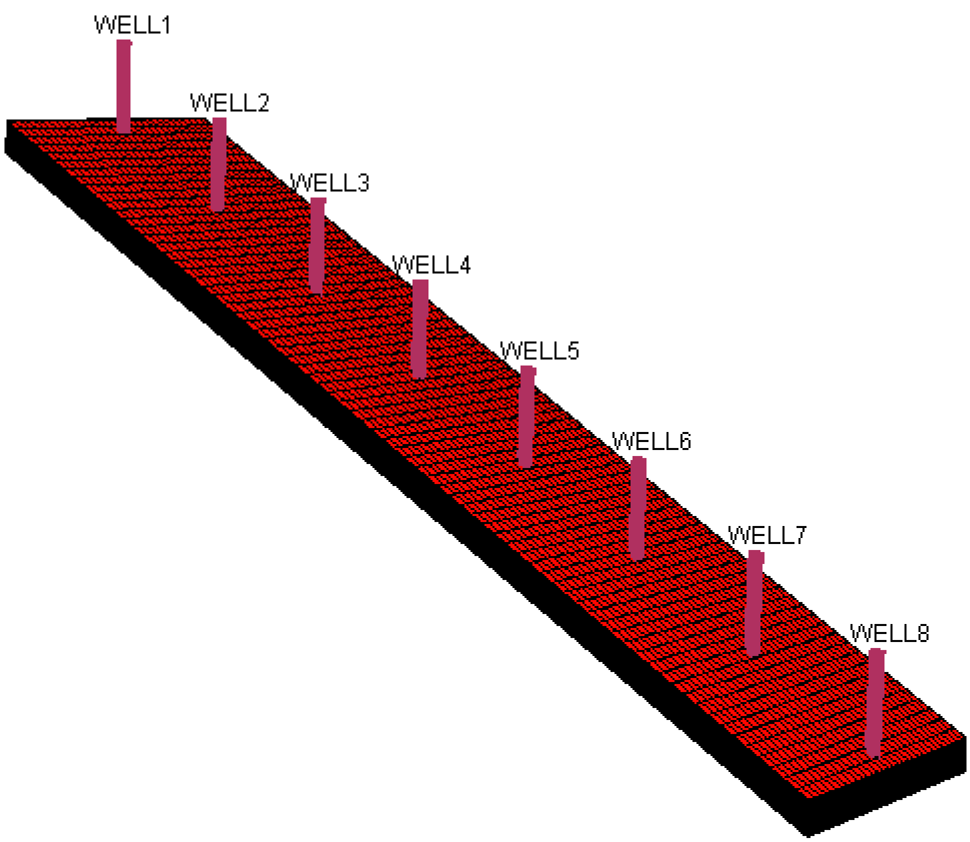

Figure 5.55 : Schematic of well pattern 4

Table 5.23 : Locations and constraints of well pattern 4

Parameter	Value	Unit
Position for Well 1	i=2, j=16	
Position for Well 2	i=12, j=16	
Position for Well 3	i=22, j=16	
Position for Well 4	i=32, j=16	
Position for Well 5	i=42, j=16	
Position for Well 6	i=52, j=16	
Position for Well 7	i=62, j=16	
Position for Well 8	i=72, j=16	
Formation fracture pressure of well 1(Reservoir with 15 degree dip angle)	3,200	psia
Formation fracture pressure of well 2(Reservoir with 15 degree dip angle)	3,352	psia
Formation fracture pressure of well 3(Reservoir with 15 degree dip angle)	3,518	psia
Formation fracture pressure of well 4(Reservoir with 15 degree dip angle)	3,686	psia
Formation fracture pressure of well 5(Reservoir with 15 degree dip angle)	3,856	psia
Formation fracture pressure of well 6(Reservoir with 15 degree dip angle)	4,030	psia
Formation fracture pressure of well 7(Reservoir with 15 degree dip angle)	4,204	psia
Formation fracture pressure of well 8(Reservoir with 15 degree dip angle)	4,400	psia
Formation fracture pressure of well 1(Reservoir with 30 degree dip angle)	3,210	psia
Formation fracture pressure of well 2(Reservoir with 30 degree dip angle)	3,563	psia
Formation fracture pressure of well 3(Reservoir with 30 degree dip angle)	3,930	psia
Formation fracture pressure of well 4(Reservoir with 30 degree dip angle)	4,306	psia
Formation fracture pressure of well 5(Reservoir with 30 degree dip angle)	4,691	psia
Formation fracture pressure of well 6(Reservoir with 30 degree dip angle)	5,087	psia
Formation fracture pressure of well 7(Reservoir with 30 degree dip angle)	5,491	psia
Formation fracture pressure of well 8(Reservoir with 30 degree dip angle)	5,910	psia
Formation fracture pressure of well 1(Reservoir with 60 degree dip angle)	3,300	psia
Formation fracture pressure of well 2(Reservoir with 60 degree dip angle)	4,382	psia
Formation fracture pressure of well 3(Reservoir with 60 degree dip angle)	5,573	psia
Formation fracture pressure of well 4(Reservoir with 60 degree dip angle)	6,981	psia
Formation fracture pressure of well 5(Reservoir with 60 degree dip angle)	8,211	psia
Formation fracture pressure of well 6(Reservoir with 60 degree dip angle)	9,659	psia
Formation fracture pressure of well 7(Reservoir with 60 degree dip angle)	11,192	psia
Formation fracture pressure of well 8(Reservoir with 60 degree dip angle)	12,811	psia

Table 5.24 : Injection and production sequence for well pattern 4

Stage	Well 1	Well 2	Well 3	Well 4	Well 5	Well 6	Well 7	Well 8
Waterflood	Producer (1,142 RB/D)	Producer (1,142 RB/D)	Producer (1,142 RB/D)	Producer (1,142 RB/D)	Producer (1,142 RB/D)	Producer (1,142 RB/D)	Producer (1,142 RB/D)	Water injector (8,000 RB/D)
WCT at well 7=0.6	Producer (1,333 RB/D)	Producer (1,333 RB/D)	Producer (1,333 RB/D)	Producer (1,333 RB/D)	Producer (1,333 RB/D)	Producer (1,333 RB/D)	Shut-in	Water injector (8,000 RB/D)
WCT at well 6=0.6	Producer (1,600 RB/D)	Producer (1,600 RB/D)	Producer (1,600 RB/D)	Producer (1,600 RB/D)	Producer (1,600 RB/D)	Shut-in	Shut-in	Water injector (8,000 RB/D)
WCT at well 5=0.6	Producer (2,000 RB/D)	Producer (2,000 RB/D)	Producer (2,000 RB/D)	Producer (2,000 RB/D)	Shut-in	Shut-in	Shut-in	Water injector (8,000 RB/D)
WCT at well 4=0.6	Producer (2,666 RB/D)	Producer (2,666 RB/D)	Producer (2,666 RB/D)	Shut-in	Shut-in	Shut-in	Shut-in	Water injector (8,000 RB/D)
WCT at well 3=0.6	Producer (4,000 RB/D)	Producer (4,000 RB/D)	Shut-in	Shut-in	Shut-in	Shut-in	Shut-in	Water injector (8,000 RB/D)
WCT at well 2=0.6	Producer (8,000 RB/D)	Shut-in	Shut-in	Shut-in	Shut-in	Shut-in	Shut-in	Water injector (8,000 RB/D)
WCT at well 1=0.6	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months	Shut in for 6 months
Gas injection	Gas injector (8,000 RB/D)	Producer (8,000 RB/D)	Shut-in	Shut-in	Shut-in	Shut-in	Shut-in	Shut-in
Gas breakthrough at well 2	Gas injector (8,000 RB/D)	Shut-in	Producer (8,000 RB/D)	Shut-in	Shut-in	Shut-in	Shut-in	Shut-in
Gas breakthrough at well 3	Gas injector (8,000 RB/D)	Shut-in	Shut-in	Producer (8,000 RB/D)	Shut-in	Shut-in	Shut-in	Shut-in
Gas breakthrough at well 4	Gas injector (8,000 RB/D)	Shut-in	Shut-in	Shut-in	Producer (8,000 RB/D)	Shut-in	Shut-in	Shut-in
Gas breakthrough at well 5	Gas injector (8,000 RB/D)	Shut-in	Shut-in	Shut-in	Shut-in	Producer (8,000 RB/D)	Shut-in	Shut-in
Gas breakthrough at well 6	Gas injector (8,000 RB/D)	Shut-in	Shut-in	Shut-in	Shut-in	Shut-in	Producer (8,000 RB/D)	Shut-in
Gas breakthrough at well 7	Gas injector (8,000 RB/D)	Shut-in	Shut-in	Shut-in	Shut-in	Shut-in	Shut-in	Producer (8,000 RB/D)

For well pattern 5, the locations and the fracturing pressure of the wells are shown in Figure 5.56 and Table 5.25. As shown in Table 5.26, we start with perform waterflood at well 2. After the WCT reaches the stopping criteria, we shut in all wells for six months to stabilize the reservoir pressure. After that, we inject gas at well 1 and well 2 becomes a producer until the reservoir reaches the economic constraint.

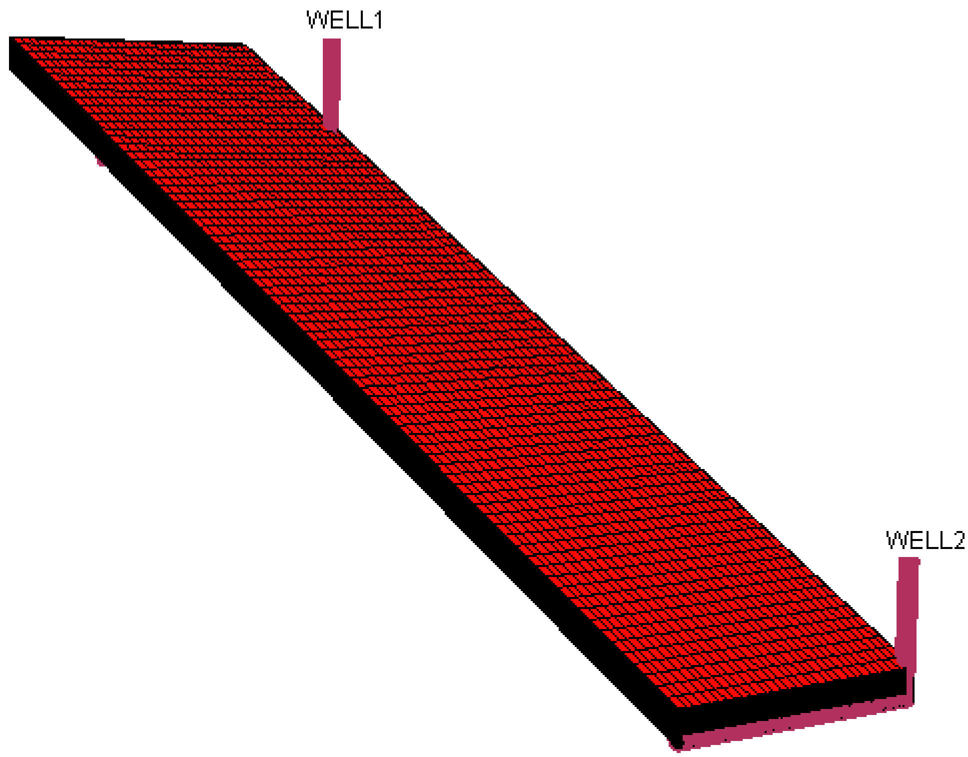

Figure 5.56 : Schematic of well pattern 5

Table 5.25 : Locations and constraints of well pattern 5

Parameter	Value	Unit
Position for Well 1	i=12, j=1-31	
Position for Well 2	i=72, j=1-31	
Formation fracture pressure of well 1(Reservoir with 15 degree dip angle)	3,400	psia
Formation fracture pressure of well 2(Reservoir with 15 degree dip angle)	4,400	psia
Formation fracture pressure of well 1(Reservoir with 30 degree dip angle)	3,720	psia
Formation fracture pressure of well 2(Reservoir with 30 degree dip angle)	5,500	psia
Formation fracture pressure of well 1(Reservoir with 60 degree dip angle)	4,400	psia
Formation fracture pressure of well 2(Reservoir with 60 degree dip angle)	13,000	psia

Table 5.26 : Injection and production sequence for well pattern 5

Stage	Well 1	Well 2
Waterflood	Producer (8,000 RB/D)	Water injector (8,000 RB/D)
WCT at well 2 = 0.6	Shut in for 6 months	Shut in for 6 months
Gas injection	Gas injector (8,000 RB/D)	Producer (8,000 RB/D)

For well pattern 6, the locations and the fracturing pressure of the wells are shown in Figure 5.57 and Table 5.27. As shown in Table 5.28, we start with perform waterflood at well 2. After the WCT reaches the stopping criteria, we shut in all wells for six months to stabilize the reservoir pressure. After that, we inject gas at well 1 and well 2 becomes a producer until the reservoir reaches the economic constraint.

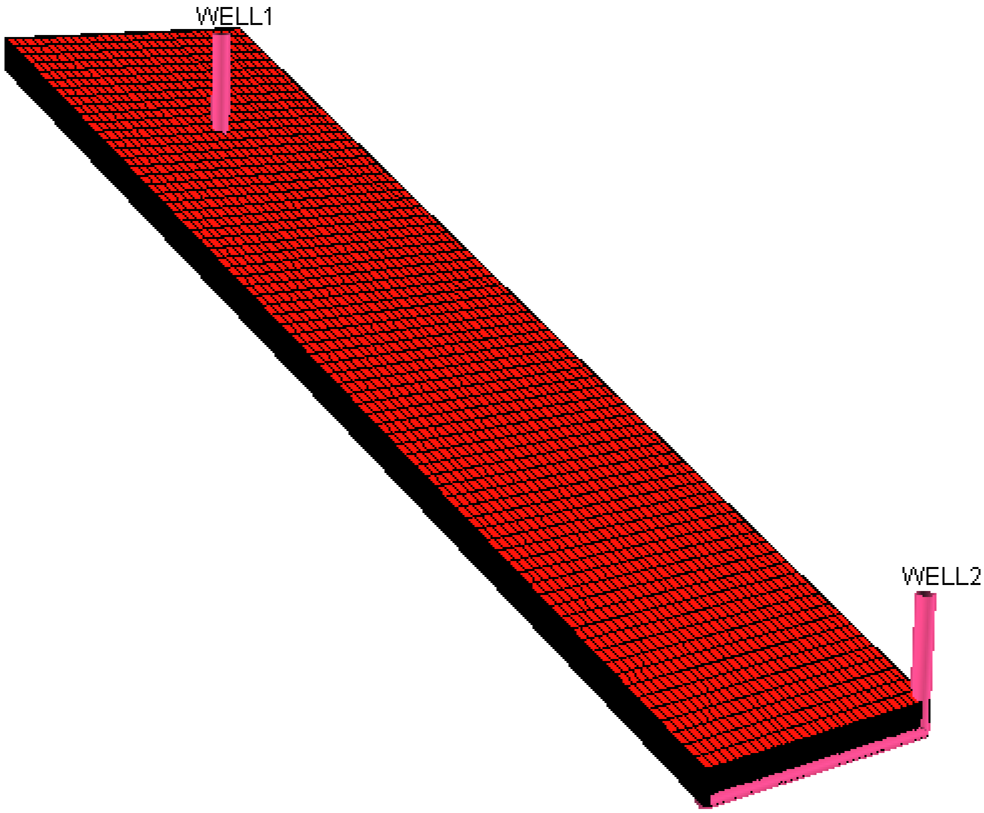

Figure 5.57 : Schematic of well pattern 6

Table 5.27 : Locations and constraints of well pattern 6

Parameter	Value	Unit
Position for Well 1	i=12, j=16	
Position for Well 2	i=72, j=1-31	
Formation fracture pressure of well 1(Reservoir with 15 degree dip angle)	3,400	psia
Formation fracture pressure of well 2(Reservoir with 15 degree dip angle)	4,400	psia
Formation fracture pressure of well 1(Reservoir with 30 degree dip angle)	3,720	psia
Formation fracture pressure of well 2(Reservoir with 30 degree dip angle)	5,500	psia
Formation fracture pressure of well 1(Reservoir with 60 degree dip angle)	4,400	psia
Formation fracture pressure of well 2(Reservoir with 60 degree dip angle)	13,000	psia

Table 5.28 : Injection and production sequence for well pattern 6

Stage	Well 1	Well 2
Waterflood	Producer (8,000 RB/D)	Water injector (8,000 RB/D)
WCT at well 2 = 0.6	Shut in for 6 months	Shut in for 6 months
Gas injection	Gas injector (8,000 RB/D)	Producer (8,000 RB/D)

5.3.1 Dip angle of 15 degrees

Figure 5.58 shows the water injection profile for each well pattern. For pattern of 4 vertical wells, 4 vertical wells with 2 injector, and 8 vertical wells, the injection rate is the highest at the beginning but dramatically drop within 2 years. Pattern of 2 horizontal wells shows rather stable water injection rate. Pattern of 2 vertical wells and vertical with horizontal well have closely water injection profile that yield the lowest water injection rate.

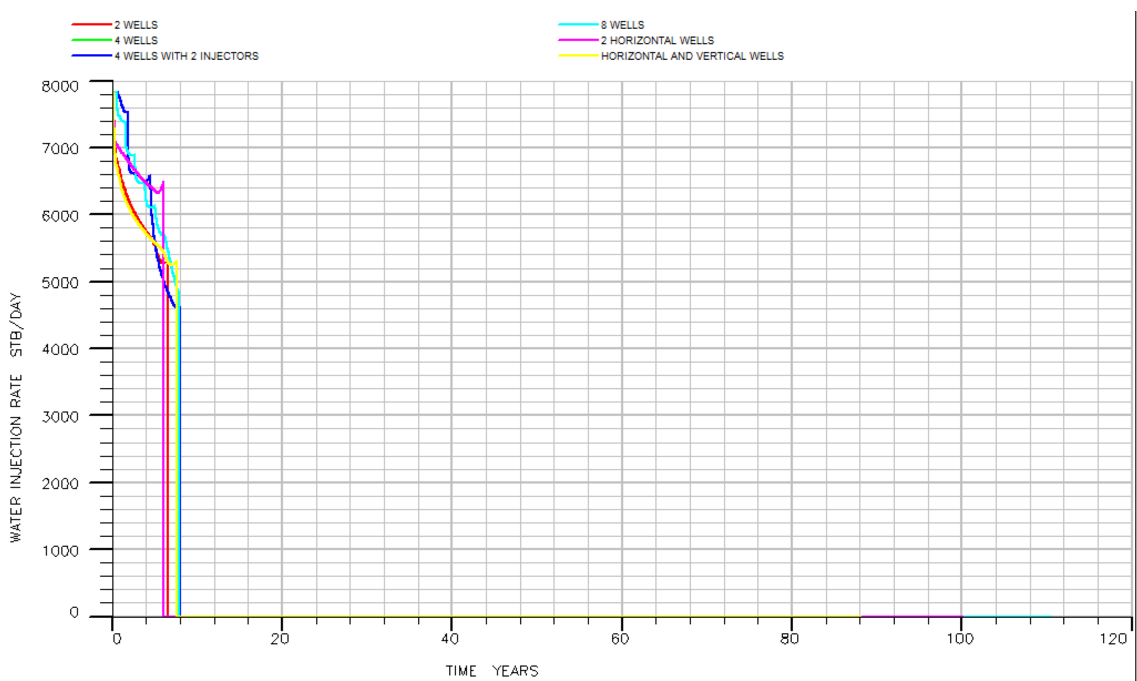

Figure 5.58 : Water injection for each well pattern

(15-degree dip angle)

As shown in Figure 5.59, all well patterns have closely gas injection profile except pattern of 2 horizontal wells. The water injection rate in pattern of 2 horizontal wells is quite low.

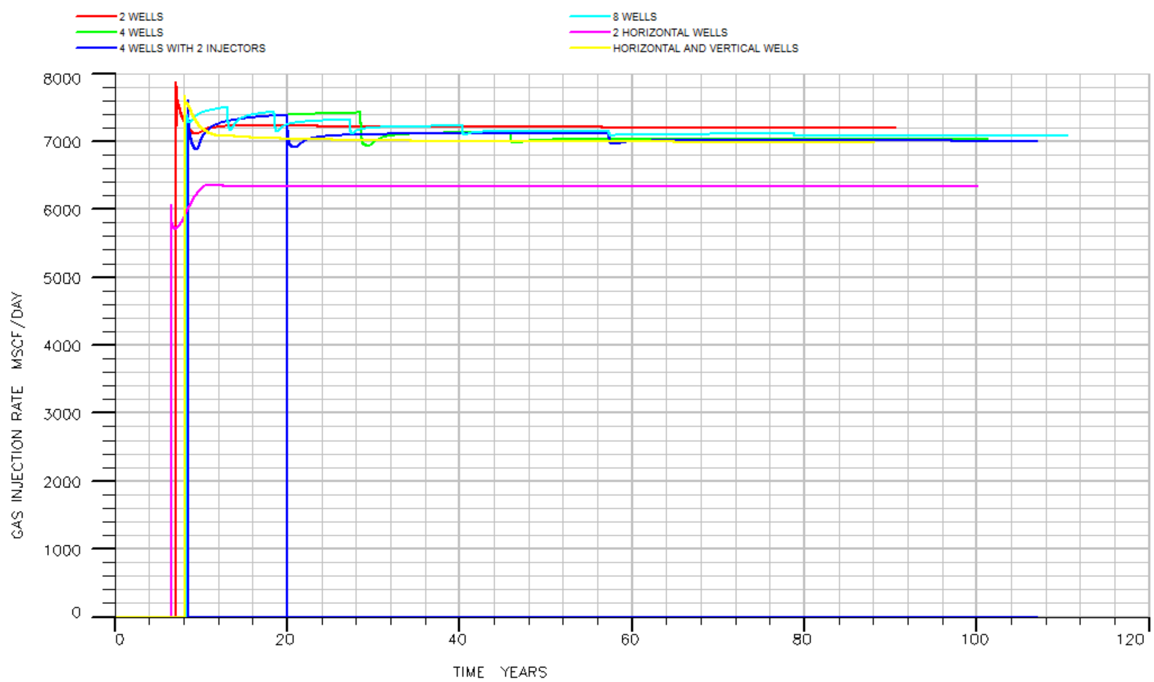

Figure 5.59 : Gas injection rate for each well pattern
(15-degree dip angle)

As shown in Figure 5.60, the oil rate in pattern of 2 horizontal wells yields a stable oil production rate during waterflood period. But, during gas injection period, pattern of vertical with horizontal well provides the best oil rate. Oil rate starts to decline when the water cut increases. Oil production rate starts dramatically drop again when gas break through the producer.

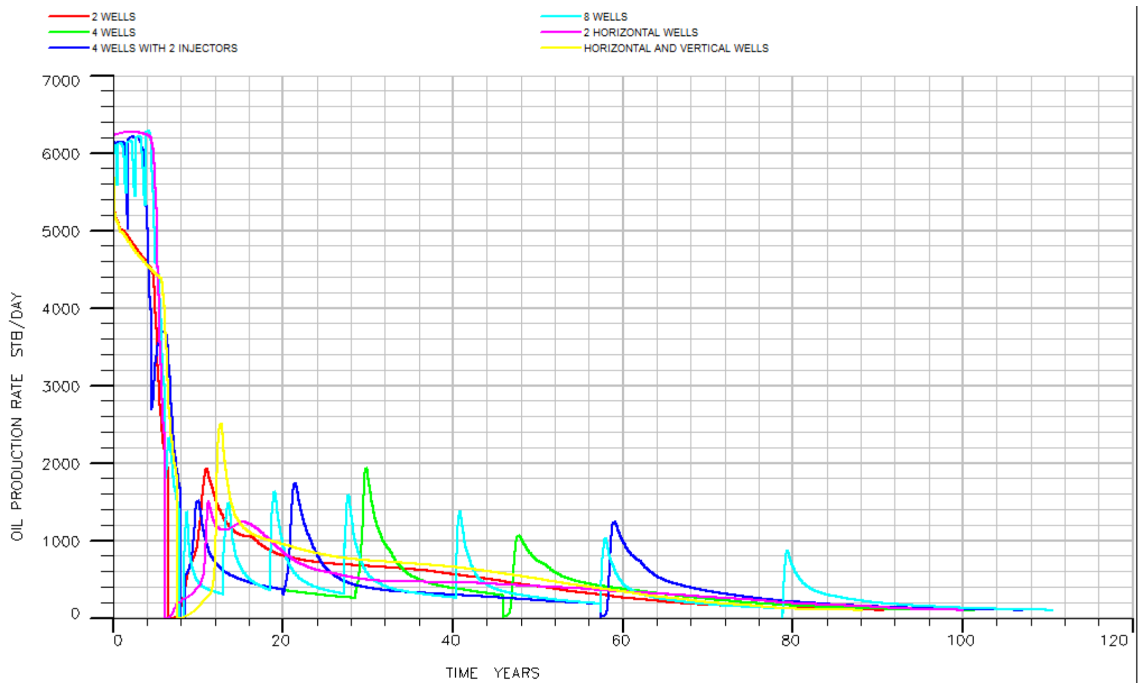

Figure 5.60 : Oil production rate for each well pattern
(15-degree dip angle)

As shown in Figures 5.61-5.63, gas production, gas-oil ratio, and cumulative gas production will significantly increase when gas breaks through the producer. Gas breaks through time is the shortest in pattern of 8 wells because the distance between the gas injector and the first producer is closer than those in the other patterns. Pattern of horizontal with vertical wells yields the highest gas breaks through time.

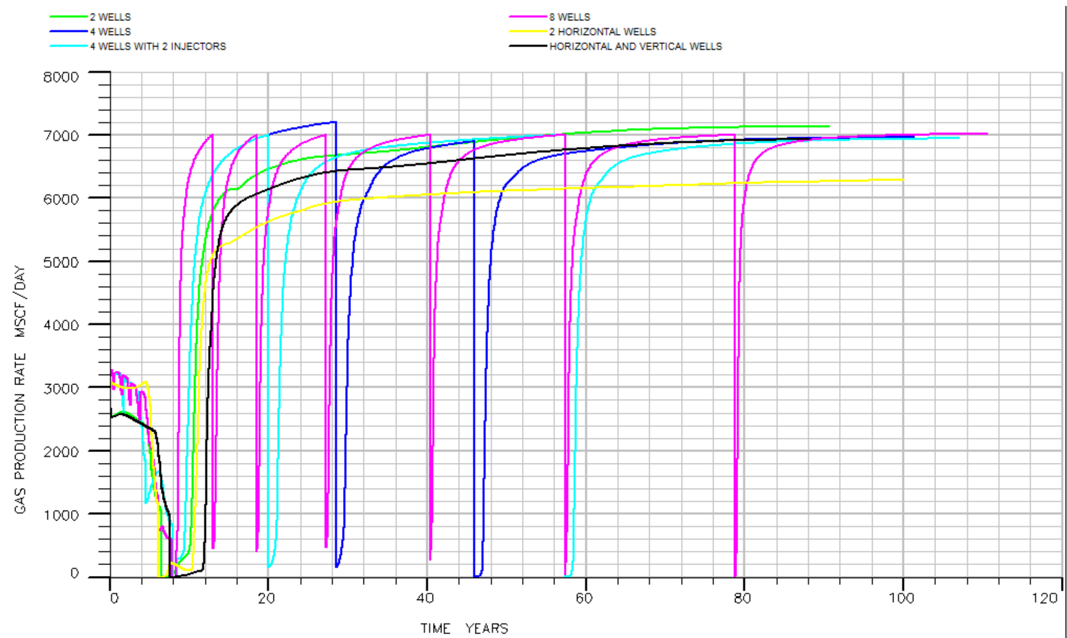

Figure 5.61 : Gas production rate for each well pattern

(15-degree dip angle)

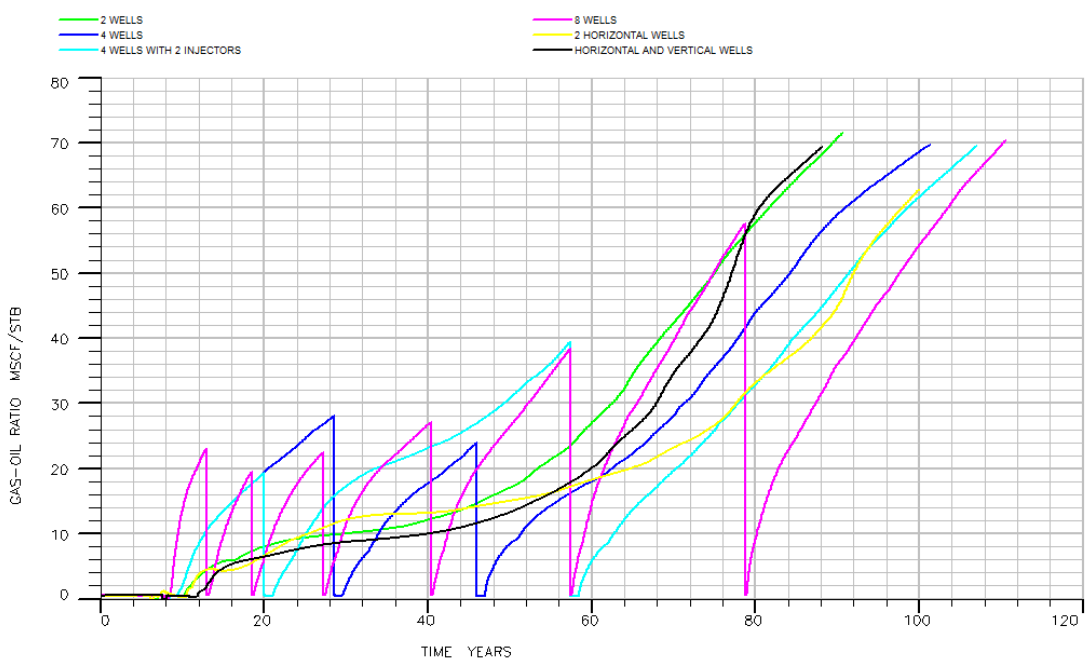

Figure 5.62 : Gas-oil ratio for each well pattern

(15-degree dip angle)

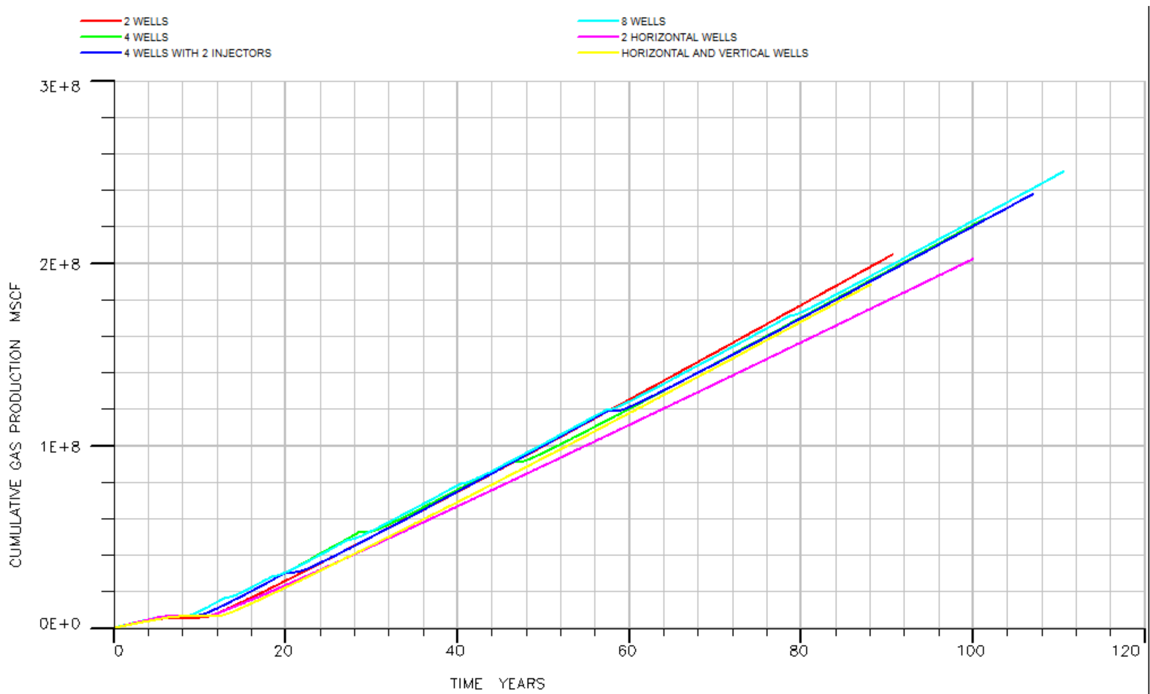

Figure 5.63 : Cumulative gas production for each well pattern
(15-degree dip angle)

In term of cumulative oil production and oil recovery factor as shown in Figures 5.64 and 5.65, pattern of 2 horizontal wells provides the best value during water injection period. But, for the entire period, pattern of vertical with horizontal wells yields the best value of cumulative oil production and oil recovery factor.

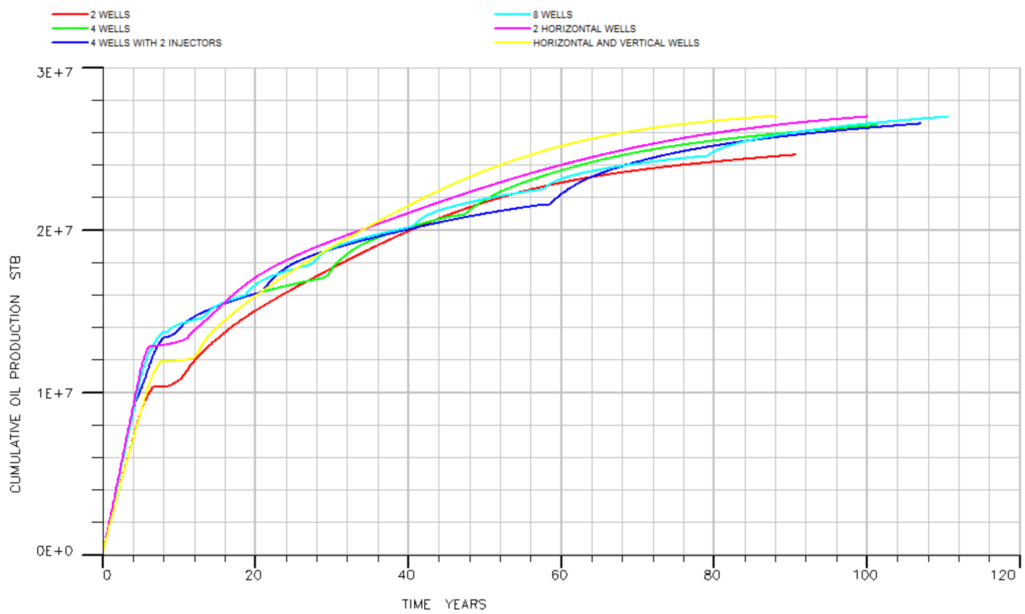

Figure 5.64 : Cumulative oil production for each well pattern

(15-degree dip angle)

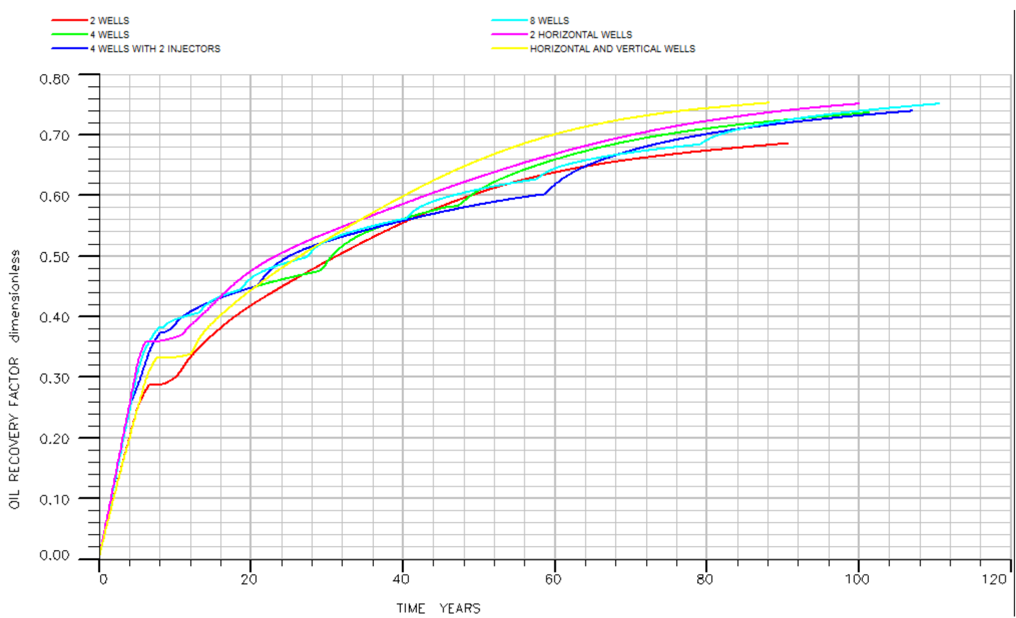

Figure 5.65 : Oil recovery factor for each well pattern

(15-degree dip angle)

In term of reservoir pressure, most patterns have similar level of pressure maintenance except pattern of 2 horizontal wells which can maintain the reservoir pressure worse than other patterns as shown in Figure 5.66.

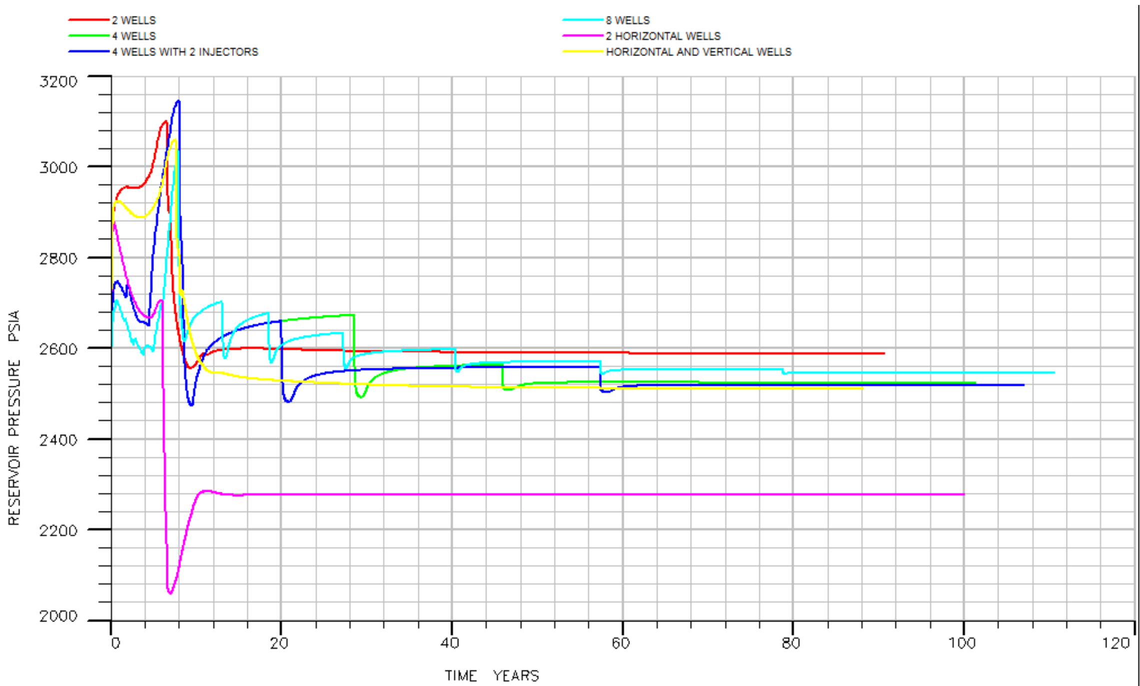

Figure 5.66 : Reservoir pressure for each well pattern
(15-degree dip angle)

The summary of cumulative oil production, oil recovery factor, cumulative water production, cumulative water injection, cumulative gas production, cumulative gas injection, BOE and oil production period of the reservoir with 15 degree dip angle for each well pattern are shown in the Table 5.29. Tables 5.30-5.31 show the duration of waterflood and gas flood at first 30 years and abandonment.

Table 5.29 : Summary of results for each well pattern for a reservoir with 15 degree dip angle

Case	At 30 years							At Abandonment							
	Np (MMSTB)	RF (%)	Wp (MMSTB)	Winj (MMSTB)	Gp (BSCF)	Ginj (BSCF)	BOE (MMSTB)	Tp (years)	Np (MMSTB)	RF (%)	Wp (MMSTB)	Winj (MMSTB)	Gp (BSCF)	Ginj (BSCF)	BOE (MMSTB)
2 vertical wells	17.65	49.15	13.39	14.42	50.05	60.45	15.91	90.58	24.61	68.55	13.38	14.42	204.66	219.87	22.08
4 vertical wells	17.6	49.01	10.35	18.07	52.93	57.36	16.86	101.24	26.43	73.61	17.99	18.07	224.2	240.65	23.69
4 vertical wells with 2 injectors	18.82	52.4	11.78	18.07	49.95	56.32	17.76	107.07	26.54	73.9	17.98	18,.07	238.02	254.43	23.8
8 vertical wells	18.86	52.52	9.85	18.18	53.21	57.93	18.07	110.57	26.96	75.09	18.12	18.18	250.18	267.24	24.12
2 horizontal wells	19.33	53.82	14.14	14.86	44.76	53.76	17.83	99.98	26.96	75.08	14.84	14.86	202.37	215.52	24.77
A horizontal with a vertical well	18.95	52.77	15.43	16.29	45.35	56.65	17.06	88	27	75.23	16.24	16.29	188.38	204.79	24.28

Table 5.30 : Waterflood and gas flood duration for the first 30 years for different well patterns for a reservoir with 15 degree dip angle.

Case	Waterflood duration (years)	Gas flood duration (years)
2 vertical wells	6.58	23.42
4 vertical wells	8.00	22.00
4 vertical wells with 2 injectors	8.00	22.00
8 vertical wells	7.83	22.17
2 horizontal wells	6.08	23.92
A horizontal with a vertical well	7.58	22.42

Table 5.31 : Waterflood and gas flood duration at economic constraint for different well patterns for a reservoir with 15 degree dip angle.

Case	Waterflood duration (years)	Gas flood duration (years)
2 vertical wells	6.58	84.00
4 vertical wells	8.00	93.24
4 vertical wells with 2 injectors	8.00	99.07
8 vertical wells	7.83	102.74
2 horizontal wells	6.08	93.90
A horizontal with a vertical well	7.58	80.42

From Table 5.29, for water production during first 30 years, pattern of 2 vertical wells, 2 horizontal wells, and vertical with horizontal wells yield the high amount of water production which are around 13.39 14.14 and 15.43 MMSTB, respectively. At the economic constraint, pattern of 4 vertical wells, 4 vertical wells with 2 injector and 8 vertical wells provide the high water production as a result of large amount of water that we injected.

Gas production for pattern of 4 vertical wells and 8 vertical wells which are around 52.93 MSCF and 53.21 BSCF is quite high during first 30 years. At economic constraint, pattern of 8 vertical wells shows the largest amount of gas production which is around 250.18 BSCF. So, if we have high gas production, it has to use the surface facilities for handle them.

Four patterns that are 4 vertical wells with 2 injectors, 8 vertical wells, 2 horizontal wells and vertical with horizontal wells provide high cumulative oil production, oil recovery factor and BOE during first 30 years. At economic constraint, there are 3 cases that yield the good cumulative oil production, oil recovery factor and BOE that are pattern of 8 vertical wells, 2 horizontal wells and vertical with horizontal wells. However, the difference between each case is time because the reservoir used vertical well with horizontal well pattern gives the shortest period which is around 88 years.

5.3.2 Dip angle of 30 degrees

The studies of well patterns in a reservoir with 30 degree dip angle are introduced.

Figure 5.67 shows the water injection profile for each well pattern. The injection rates for all cases are not constant depending on the reservoir pressure.

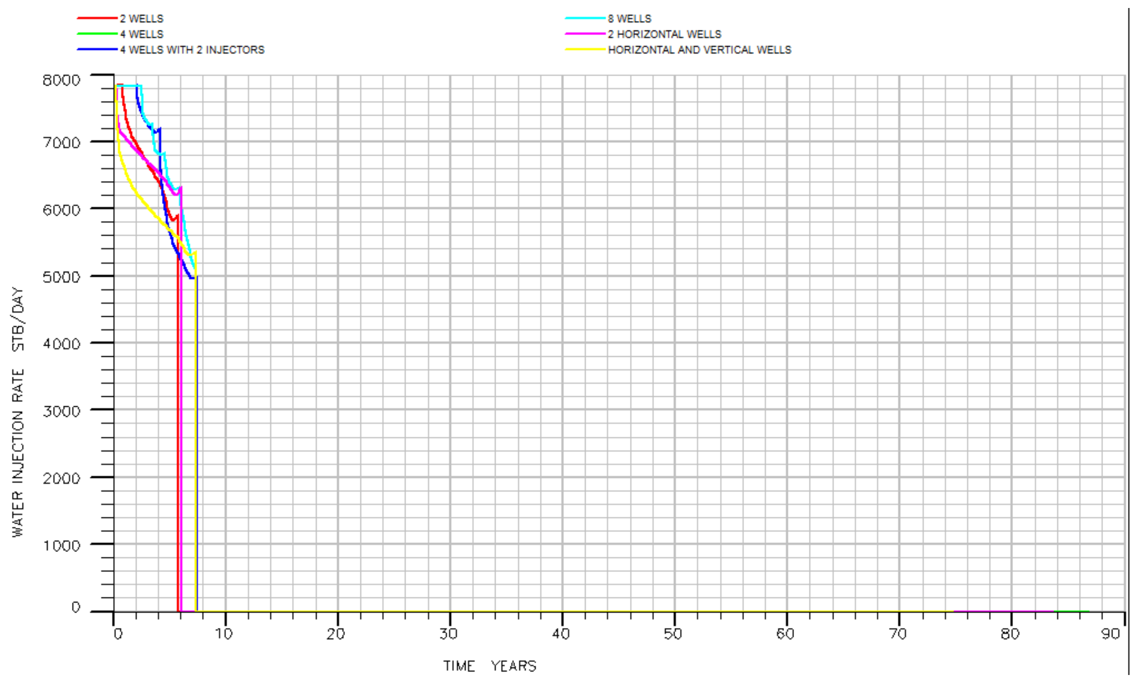

Figure 5.67 : Water injection rate for each well pattern
(30-degree dip angle)

As shown in Figure 5.68, each well pattern has different gas injection profile due to different in reservoir pressure and formation fraction pressure. The gas injection rate for pattern of 8 vertical wells is quite high when compare with those in the other patterns. The injection for pattern of 4 vertical wells is quite low.

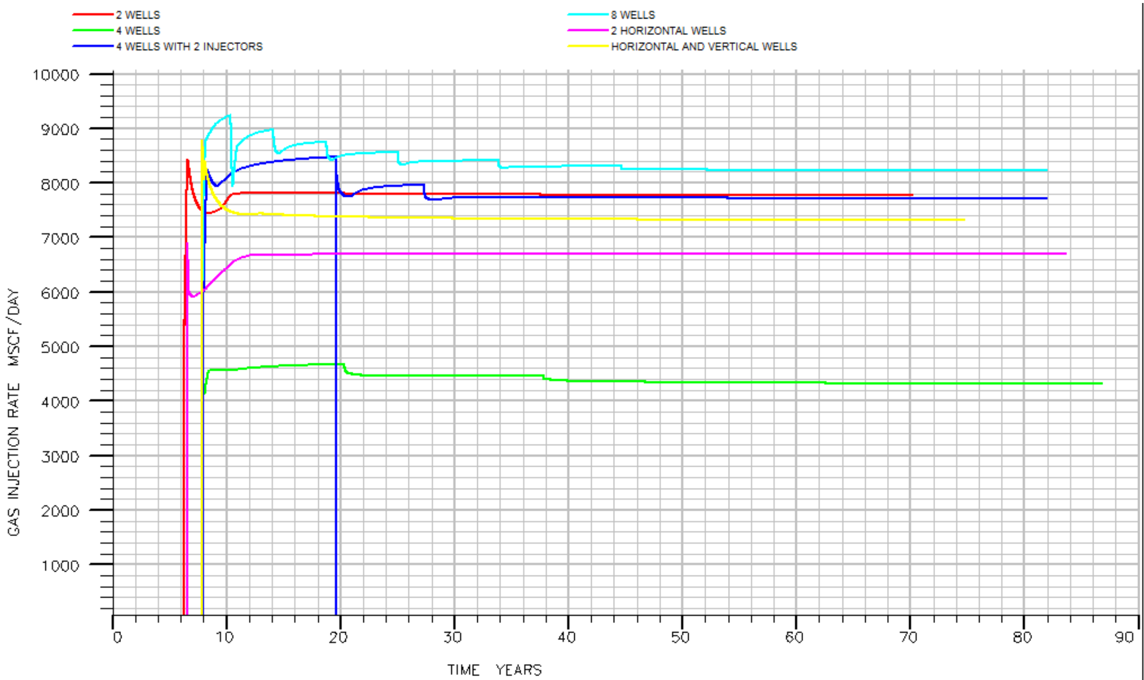

Figure 5.68 : Gas injection rate for each well pattern

(30-degree dip angle)

As shown in Figure 5.69, pattern of 2 horizontal wells yields the most stable oil production rate during water injection pertiod. During gas injection period, pattern of vertical with horizontal wells yields the highest oil production rate. For gas production, gas production rate becomes high when gas break through the producer leading high gas-oil ratio as shown in Figures 5.57-5.58.

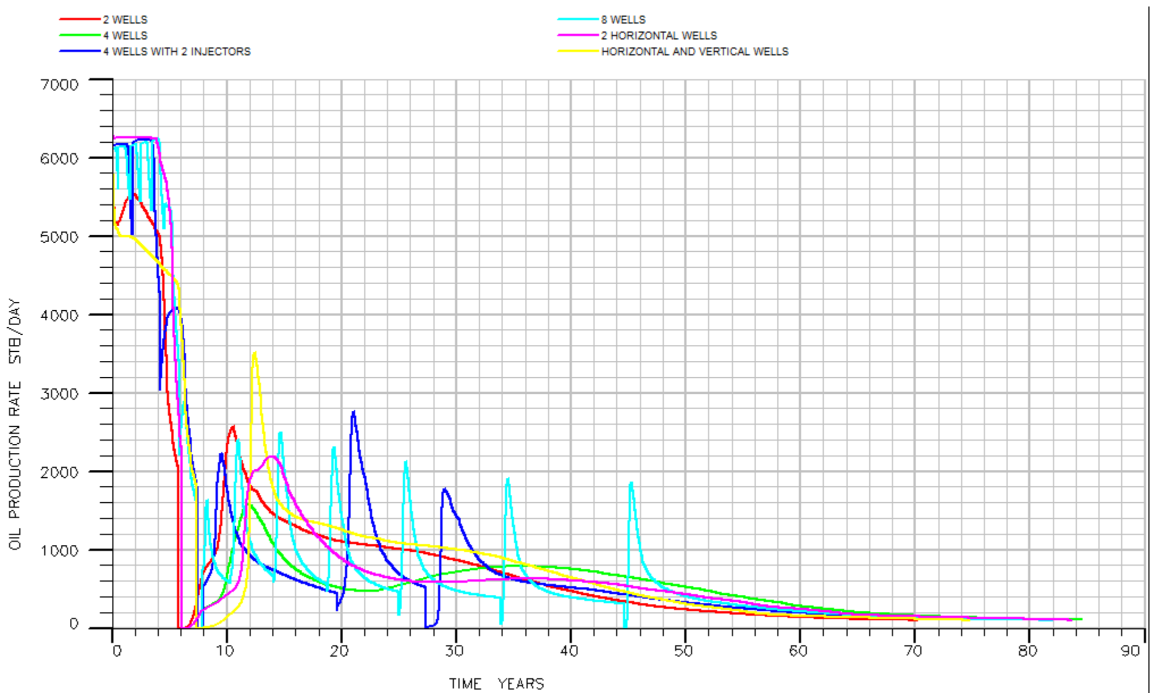

Figure 5.69 : Oil production rate for each well pattern

(30-degree dip angle)

As shown in Figures 5.70-5.72, gas production, gas-oil ratio, and cumulative gas production will significantly increase when gas breaks through the producer. Gas breaks through time is the shortest in pattern of 8 wells because the distance between the gas injector and the first producer is closer than those in the other patterns. Pattern of horizontal with vertical wells yields the highest gas breaks through time.

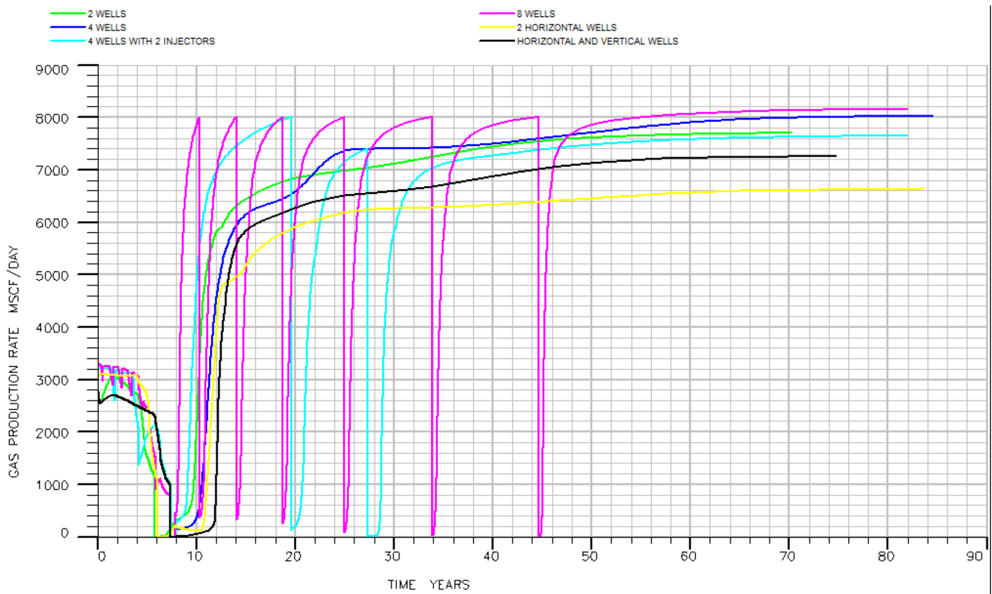

Figure 5.70 : Gas production rate for each well pattern

(30-degree dip angle)

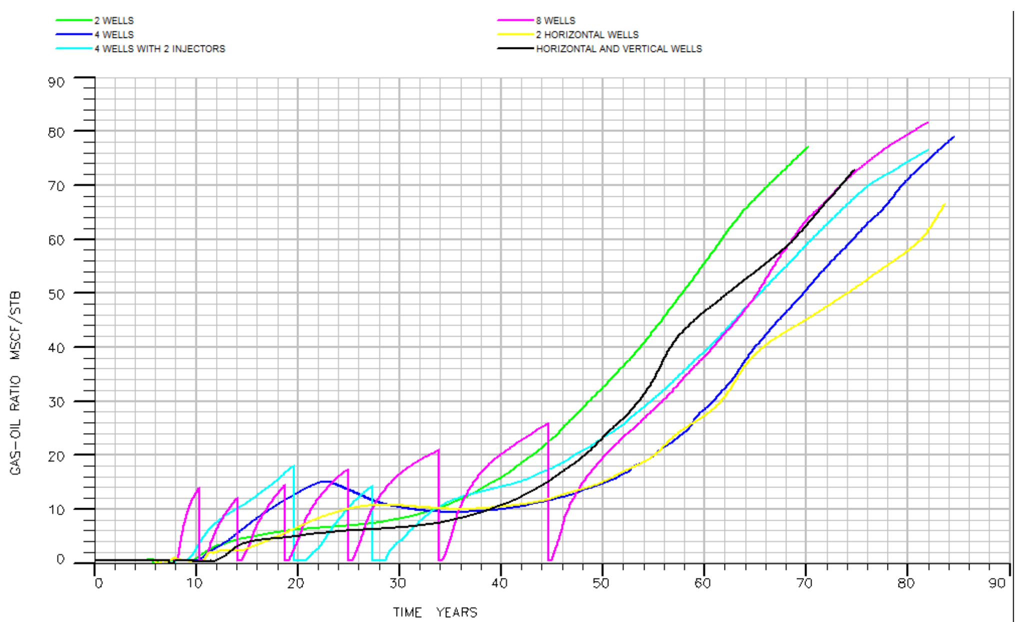

Figure 5.71 : Gas-oil ratio for each well pattern

(30-degree dip angle)

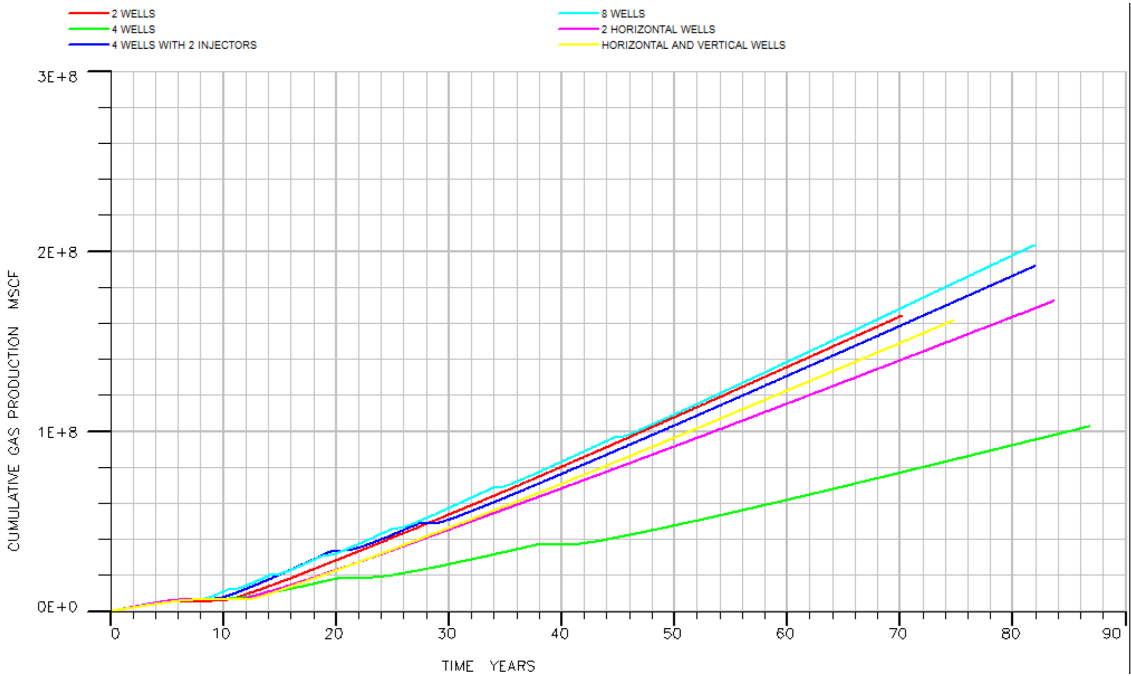

Figure 5.72 : Cumulative gas production for each well pattern (30-degree dip angle)

In term of cumulative oil production and oil recovery factor as shown in Figures 5.73-5.74, pattern of 2 horizontal wells provide the high values during water injection period. During gas injection period, pattern of vertical with horizontal wells yields the best values of cumulative oil production and oil recovery factor.

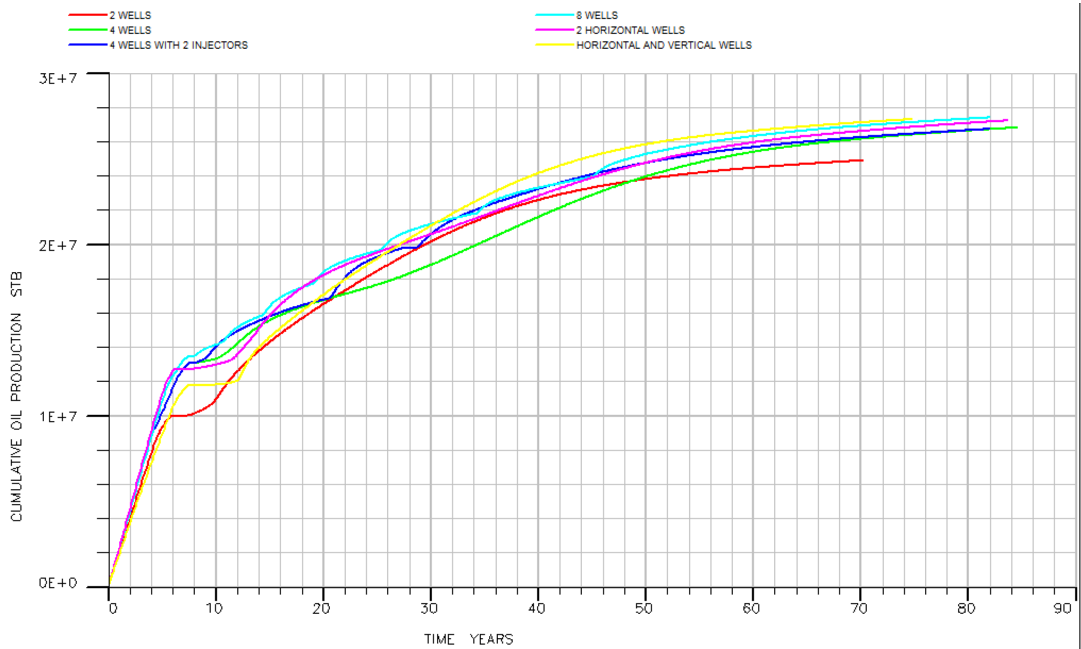

Figure 5.73 : Cumulative oil production for each well pattern

(30-degree dip angle)

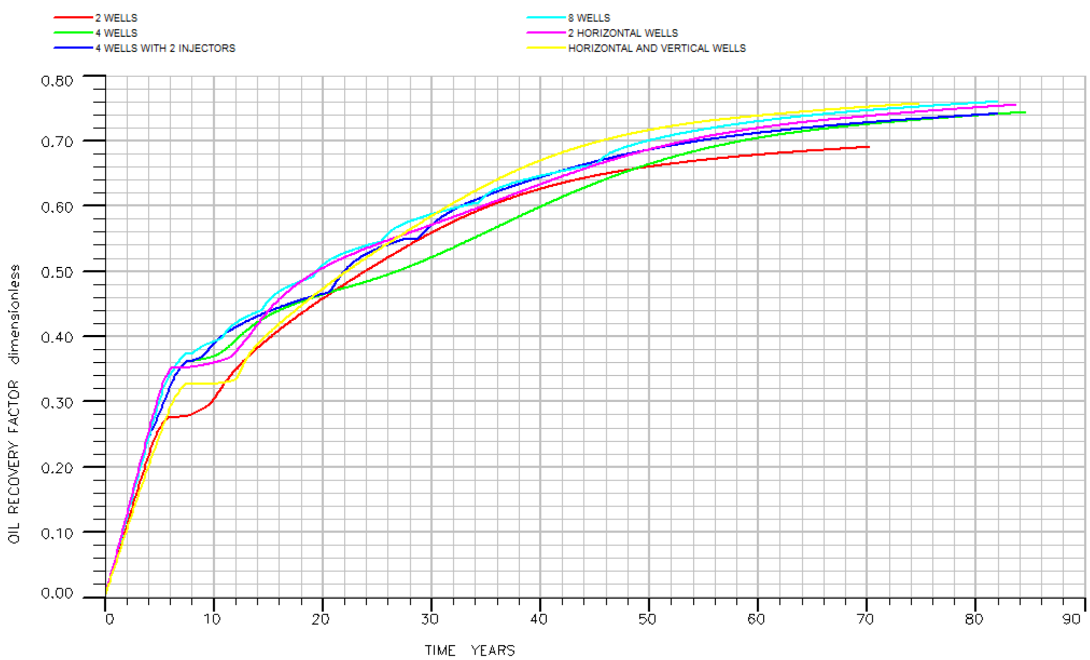

Figure 5.74 : Oil recovery factor for each well pattern

(30-degree dip angle)

As shown in Figure 5.75, pattern of 4 vertical wells can maintain the reservoir pressure better than those in the other patterns. The ability for pattern of 2 horizontal wells to maintain the reservoir pressure is quite poor because the reservoir pressure drops to 2,400 psia.

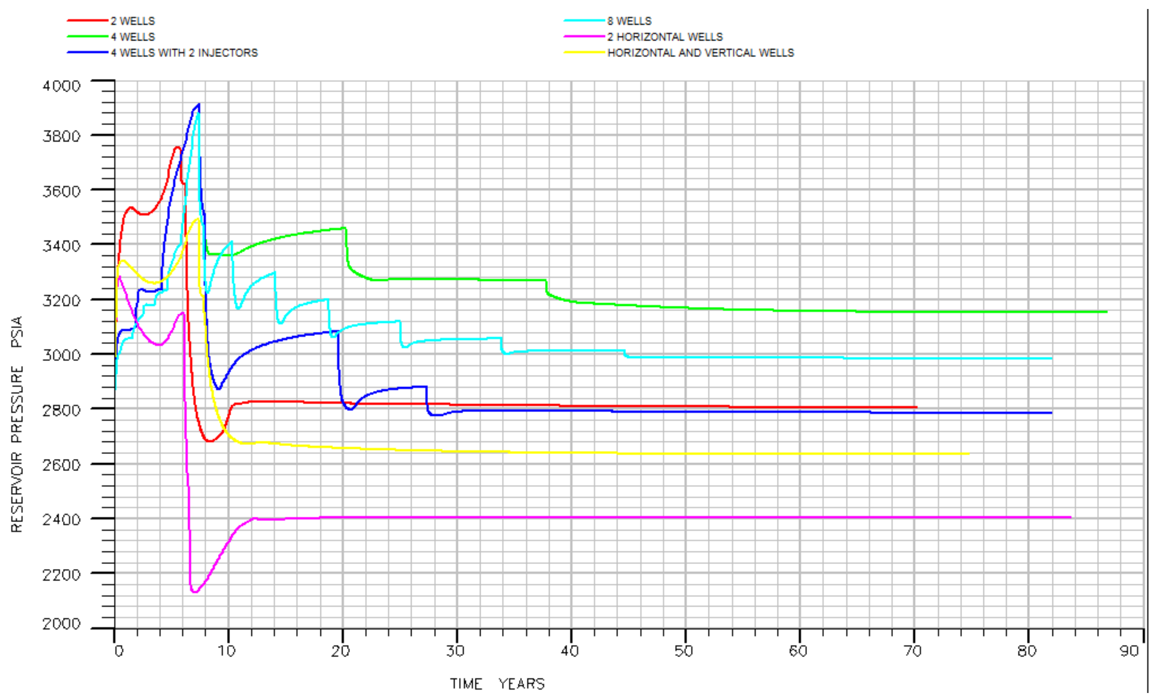

Figure 5.75 : Reservoir pressure for each well pattern
(30-degree dip angle)

The summary of cumulative oil production, oil recovery factor, cumulative water production, cumulative water injection, cumulative gas production, cumulative gas injection, BOE and oil production period of the reservoir with 15 degree dip angle for each well pattern are shown in the Table 5.32. Tables 5.33-5.34 show the duration of waterflood and gas flood at first 30 years and abandonment.

Table 5.32 : Summary of results for each well pattern for a reservoir with 30 degree dip angle

Case	At 30 years							At Abandonment								
	Np (MMSTB)	**RF (%)**	**Wp (MMSTB)**	**Winj (MMSTB)**	**Gp (BSCF)**	**Ginj (BSCF)**	**BOE (MMSTB)**	**Tp (years)**	**Np (MMSTB)**	**RF (%)**	**Wp (MMSTB)**	**Winj (MMSTB)**	**Gp (BSCF)**	**Ginj (BSCF)**	**BOE (MMSTB)**
2 vertical wells	20.17	55.94	12.4	14.69	53.68	67.33	17.9	70.16	24.9	69.03	12.66	14.68	164.3	181.4	22.04
4 vertical wells	20.37	56.48	11.17	17.98	55.75	65.25	18.79	81.47	26.73	74.1	17.78	17.98	190.77	210.56	23.43
4 vertical wells with 2 injectors	20.61	57.16	16.42	17.98	50.84	65.14	18.23	81.97	26.73	74.12	17.87	17.98	191.82	211.59	23.44
8 vertical wells	21.49	59.6	12.93	18.53	67.72	65.9	21.8	80.38	25.48	70.65	18.45	18.53	219.52	212.96	26.57
2 horizontal wells	20.6	57.11	14.52	14.98	45.28	56.44	18.74	83.58	27.22	75.48	15	14.98	172.26	187.39	24.7
A horizontal with a vertical well	21.1	58.49	15.48	16.13	46.26	60.19	18.77	74.66	27.3	75.69	16.12	16.13	161.45	179.76	24.25

Table 5.33 : Waterflood and gas flood duration for the first 30 years for different well patterns for a reservoir with 30 degree dip angle.

Case	Waterflood duration (years)	Gas flood duration (years)
2 vertical wells	5.75	24.25
4 vertical wells	7.41	22.59
4 vertical wells with 2 injectors	7.41	22.59
8 vertical wells	7.33	22.67
2 horizontal wells	6.09	23.91
A horizontal with a vertical well	7.32	22.68

Table 5.34 : Waterflood and gas flood duration at economic constraint for different well patterns for a reservoir with 30 degree dip angle.

Case	Waterflood duration (years)	Gas flood duration (years)
2 vertical wells	5.75	64.41
4 vertical wells	7.41	74.06
4 vertical wells with 2 injectors	7.41	74.56
8 vertical wells	7.33	73.05
2 horizontal wells	6.09	77.49
A horizontal with a vertical well	7.32	67.34

From Table 5.32, in term of water production during the first 30 years, pattern of 4 vertical wells with 2 injectors, 2 horizontal wells and vertical with horizontal wells yield the high amount of water production which are around 16.42 MMSTB, 14.52 MMSTB, and 15.48 MMSTB, respectively. At economic constraint, pattern of 4 vertical wells, 4 vertical wells with 2 injectors, and 8 vertical wells produce high water due to the large amount of water that we injected into the reservoir.

Pattern of 8 vertical wells yields the cumulative gas production of 67.78 BSCF that quite high during the first 30 years. When we consider at economic constraint, pattern of 8 vertical wells still shows the largest amount of cumulative gas production which is around 219.52 BSCF.

During the first 30 years, the highest oil recovery factor is around 59 percent. Two patterns yield this value which are pattern of 8 vertical wells and vertical with horizontal wells. However, at economic constraint, there are 2 cases that yield high oil recovery factors which are pattern of 2 horizontal wells and pattern of horizontal with vertical wells. They provide oil recovery factor of 75 percent. However, using pattern of horizontal with vertical wells is better because it uses the shorter time which is around 74.66 years.

Moreover, in case of 4 vertical wells pattern, we further investigate the effect of injector location. In the original case, we inject gas at well 1. But in this investigation, we change gas injector from well 1 to well 2 and 3, respectively, to study the effect of injector location. The results shown in Figures 5.76-5.77 show that if we select well 1 as the gas injector, oil production rate will be good at early time but poor at late time. We get opposite result when we inject gas at well 3.

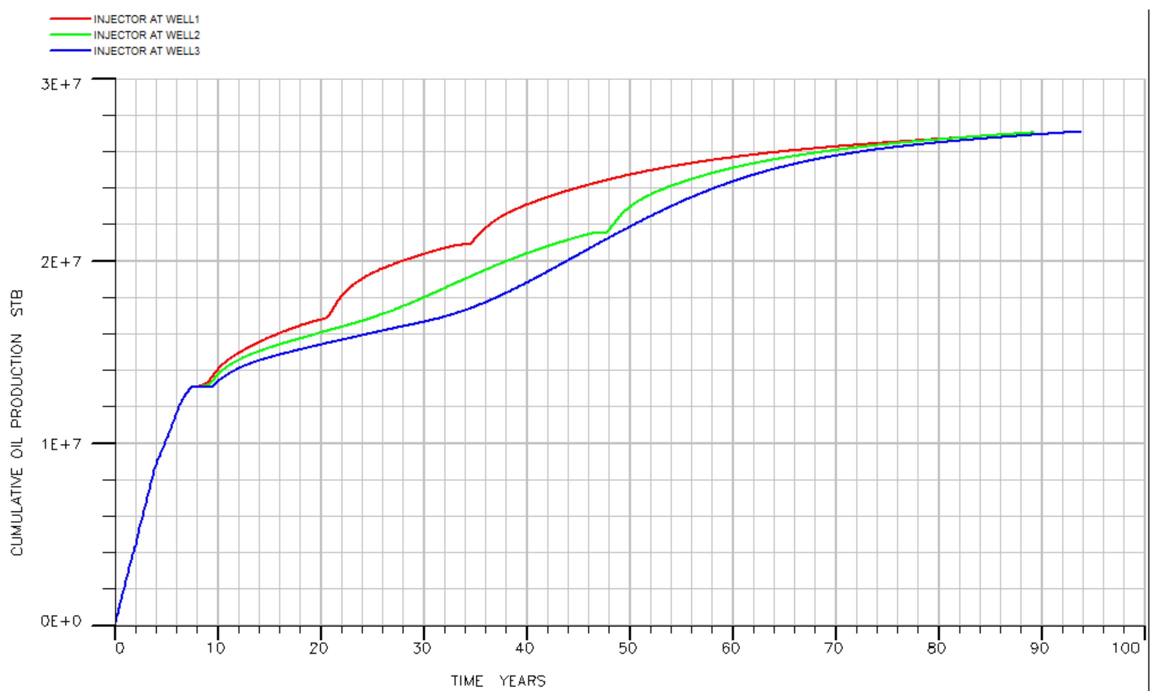

Figure 5.76 : Cumulative oil production for each gas injector location

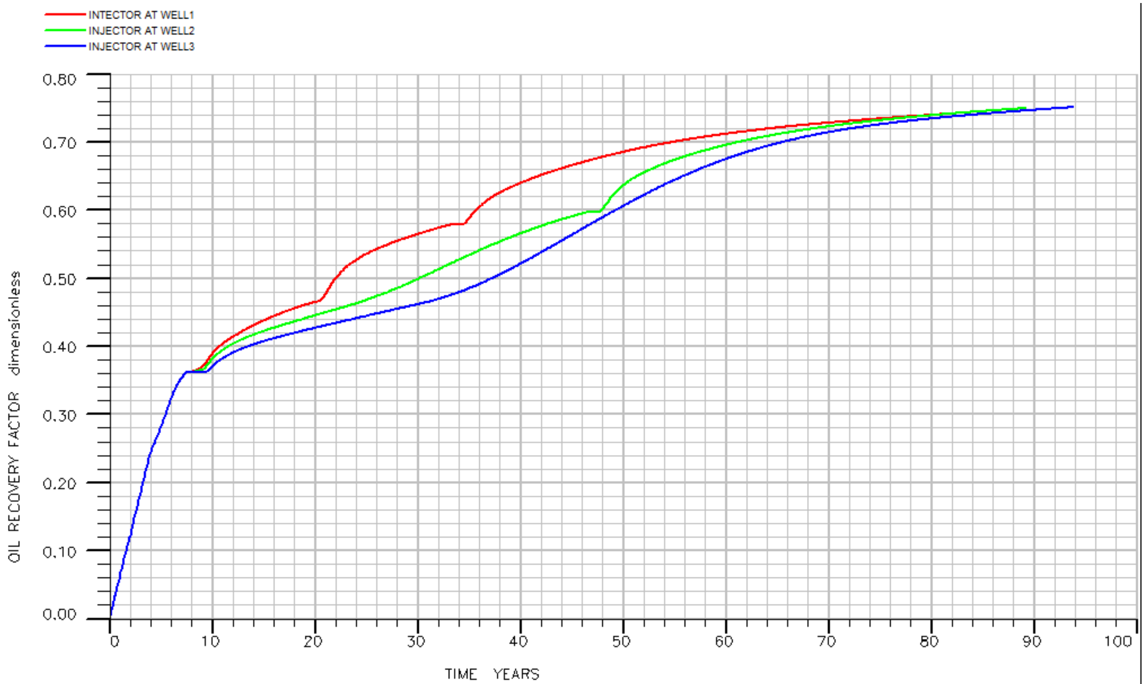

Figure 5.77 : Oil recovery for each gas injector location

Table 5.35 : Summary of results for each gas injector location

Case	At 30 years							At Abandonment							
	Np (MMSTB)	RF (%)	Wp (MMSTB)	Winj (MMSTB)	Gp (BSCF)	Ginj (BSCF)	BOE (MMSTB)	Tp (years)	Np (MMSTB)	RF (%)	Wp (MMSTB)	Winj (MMSTB)	Gp (BSCF)	Ginj (BSCF)	BOE (MMSTB)
INJECT AT WELL 1	20.37	56.48	11.17	17.98	55.75	65.25	18.79	81.47	26.73	74.1	17.78	17.98	190.77	210.56	23.43
INJECT AT WELL 2	18	49.91	11.26	17.98	59.19	67.4	16.63	89.16	27.03	74.95	17.84	17.98	221.74	243.35	23.43
INJECT AT WELL 3	16.65	46.17	15.98	17.98	54.27	66.21	14.66	93.74	27.08	75.09	17.88	17.98	232.16	253.51	23.52

Table 5.36 : Waterflood and gas flood duration for the first 30 years for different gas injector location.

Case	Waterflood duration (years)	Gas flood duration (years)
INJECT AT WELL 1	7.41	22.59
INJECT AT WELL 2	7.41	22.59
INJECT AT WELL 3	7.41	22.59

Table 5.37 : Waterflood and gas flood duration at economic constraint for different gas injector location.

Case	Waterflood duration (years)	Gas flood duration (years)
INJECT AT WELL 1	7.41	74.06
INJECT AT WELL 2	7.41	81.75
INJECT AT WELL 3	7.41	86.33

Tables 5.35-5.37 are the summary for each injector location. During the first 30 years, cumulative water production for the case that we inject gas at well 3 is higher than those in the other cases. At the economic constraint, all cases yield similar cumulative water production.

The amount of gas production during the first 30 years for the case that we inject gas at well 2 is quite high while the values are no difference at the economic constraint.

For the first 30 years, injected gas at well 1 yields significantly higher cumulative oil production, oil recovcery factor and BOE. At the economic constraint, all cases have similar values of cumulative oil production, oil recovcery factor and BOE but the difference is time. For waterflooding, all cases have the same period around 7.41 years as shown in Table 5.27. However, during gas injection period, injecting gas at well 1 yields the lowest duration around 74.06 years.

At the end of production period, all 3 cases provide almost the same for cumulative oil production. So, we can conclude that location of gas injector slightly affect DDP performance. Although the 3 cases yield similar oil recovery factor at economic constraint, but in real situation, we should choose well 1 to be a gas injector because its performance for the first 30 years is significantly better than those in other cases.

5.3.3 Dip angle of 60 degrees

Finally, the studies of well patterns in a reservoir with 60 degree dip angle are introduced. Figure 5.78 shows the water injection profile for each well pattern. The injection rates for all cases are not constant depending on the reservoir pressure. The water injection rates for pattern of 2 horizontal wells and pattern of horizontal with vertical wells are quite stable.

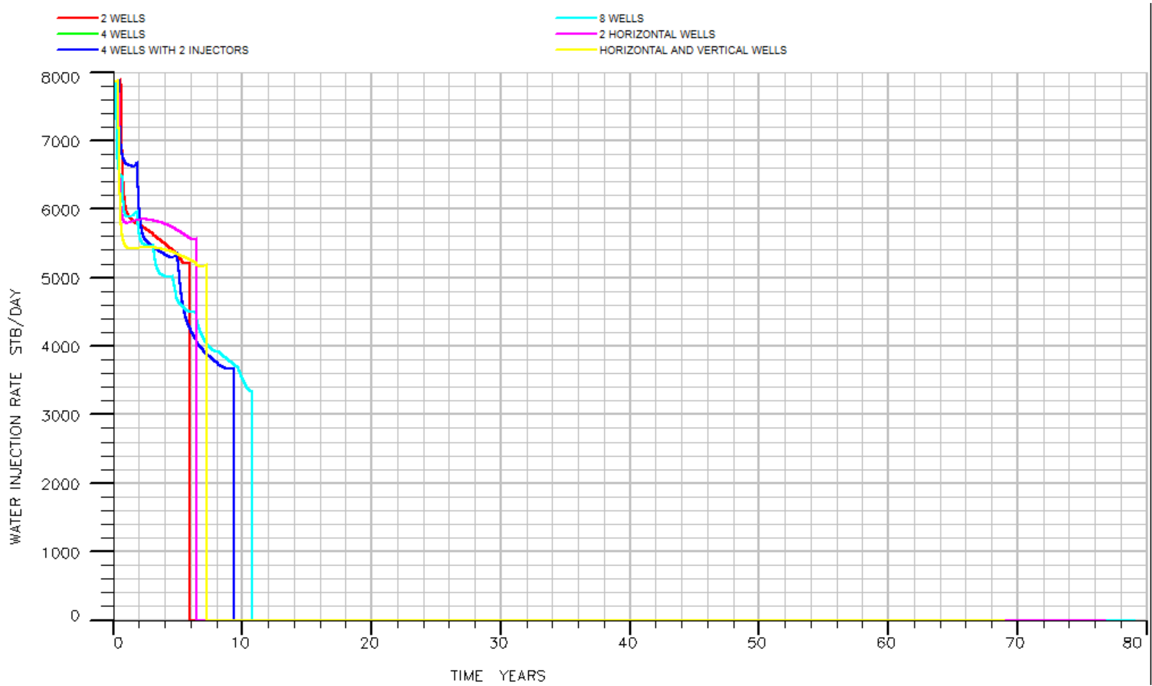

Figure 5.78 : Water injection rate for each well pattern
(60-degree dip angle)

As shown in Figure 5.79, each well pattern has different gas injection profile due to different in reservoir pressure and formation fraction pressure. The gas injection rate for pattern of 2 vertical wells is quite high when compare with those in the other patterns. The injection for pattern of 8 vertical wells is quite low.

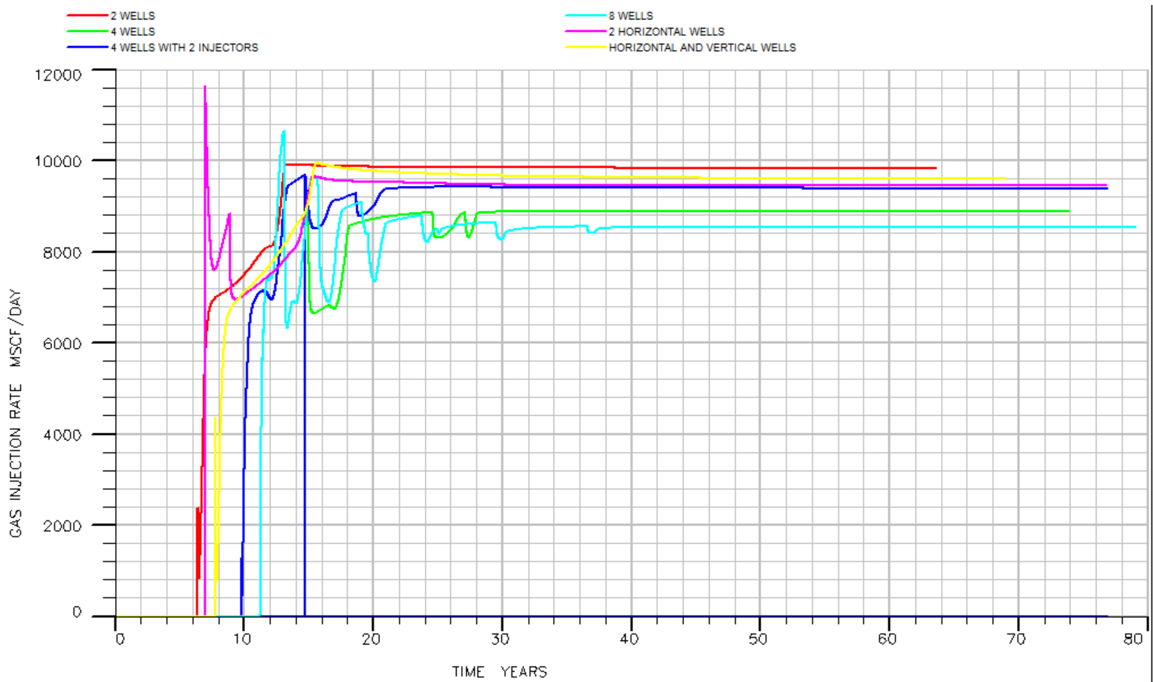

Figure 5.79 : Gas injection rate for each well pattern
(60-degree dip angle)

As shown in Figure 5.80, pattern of 2 vertical wells and pattern of 2 horizontal wells yield pretty stable oil production rate during water injection period. During gas injection, pattern of vertical with horizontal wells yields the highest oil production rate. For gas production, gas production rate becomes high when gas breaks through the producer which around 12th years leading high gas-oil ratio as shown in Figures 5.81-5.83.

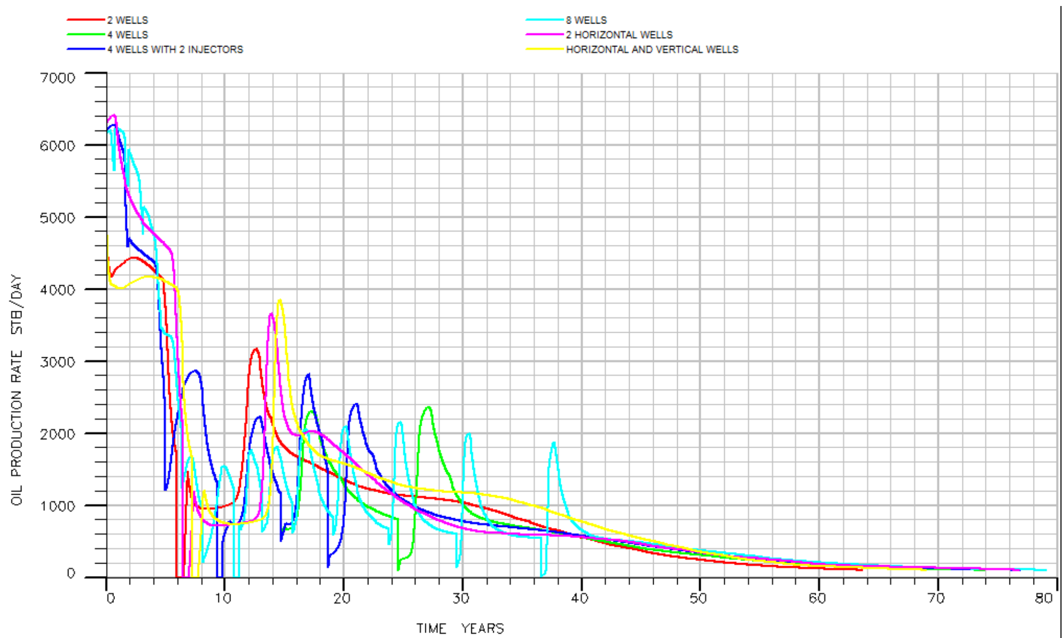

Figure 5.80 : Oil production rate for each well pattern

(60-degree dip angle)

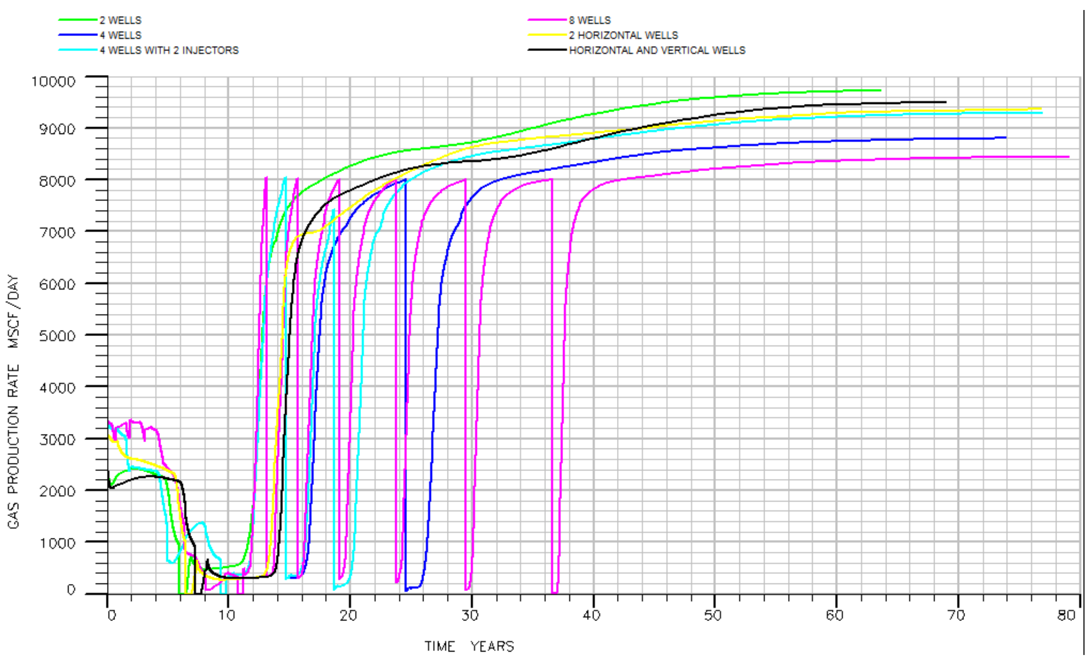

Figure 5.81 : Gas production rate for each well pattern

(60-degree dip angle)

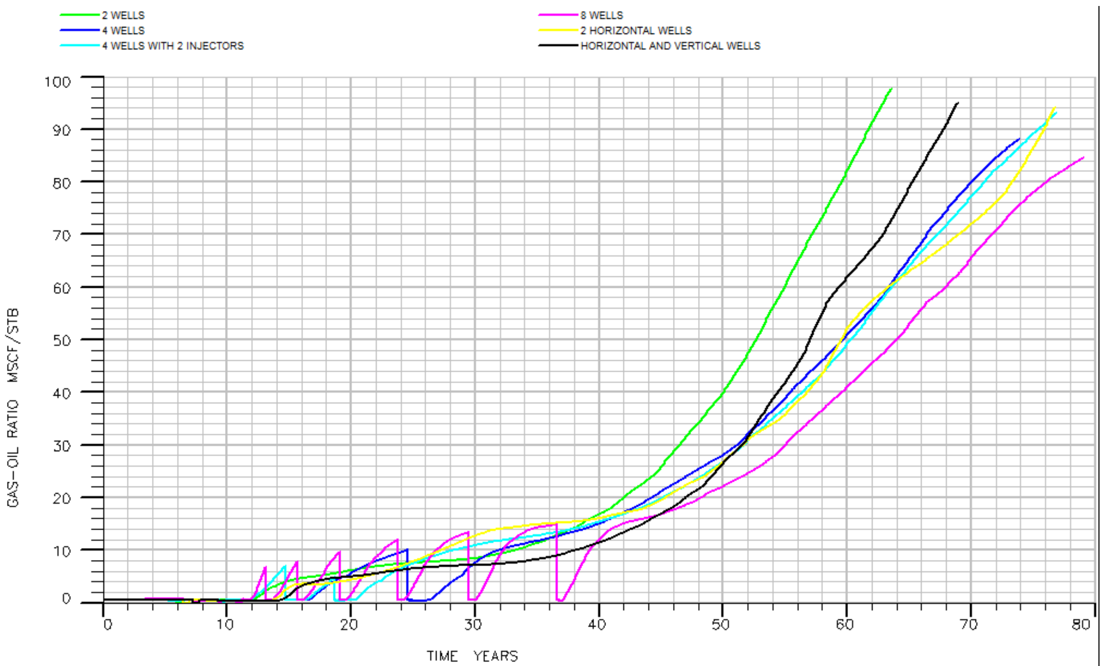

Figure 5.82 : Gas-oil ratio for each well pattern

(60-degree dip angle)

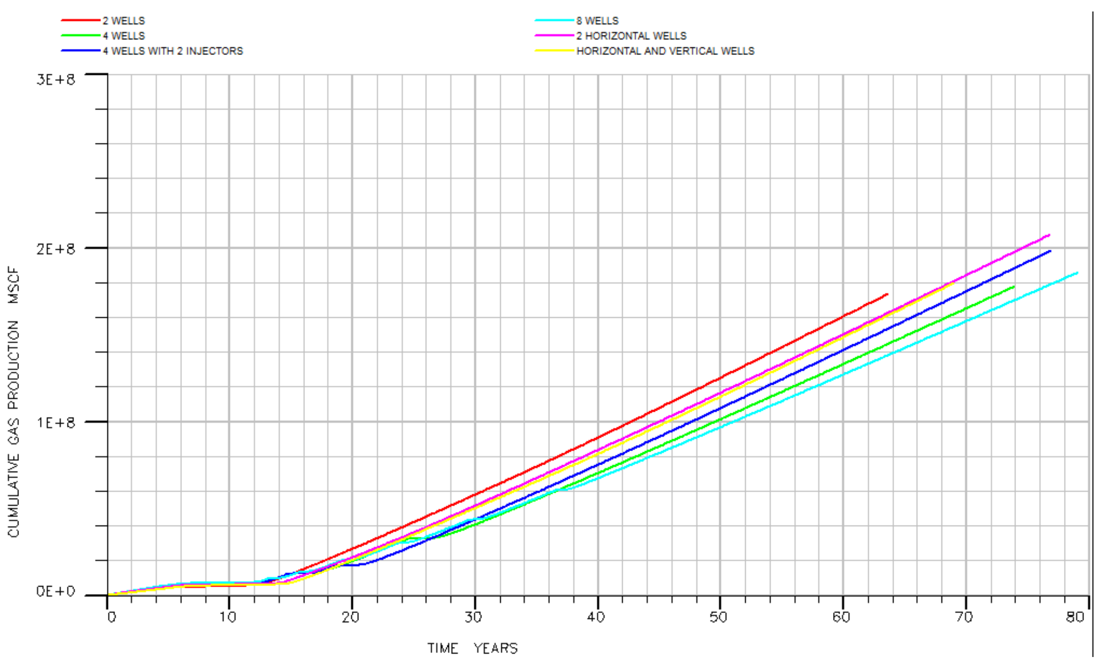

Figure 5.83 : Cumulative gas production for each well pattern

(60-degree dip angle)

Pattern of two horizontal wells yields outstanding oil recovery factor and cumulative oil production during water injection. However, at late time, pattern of vertical with horizontal wells provides remarkable oil recovery factor and cumulative oil production as shown in Figures 5.84-5.85.

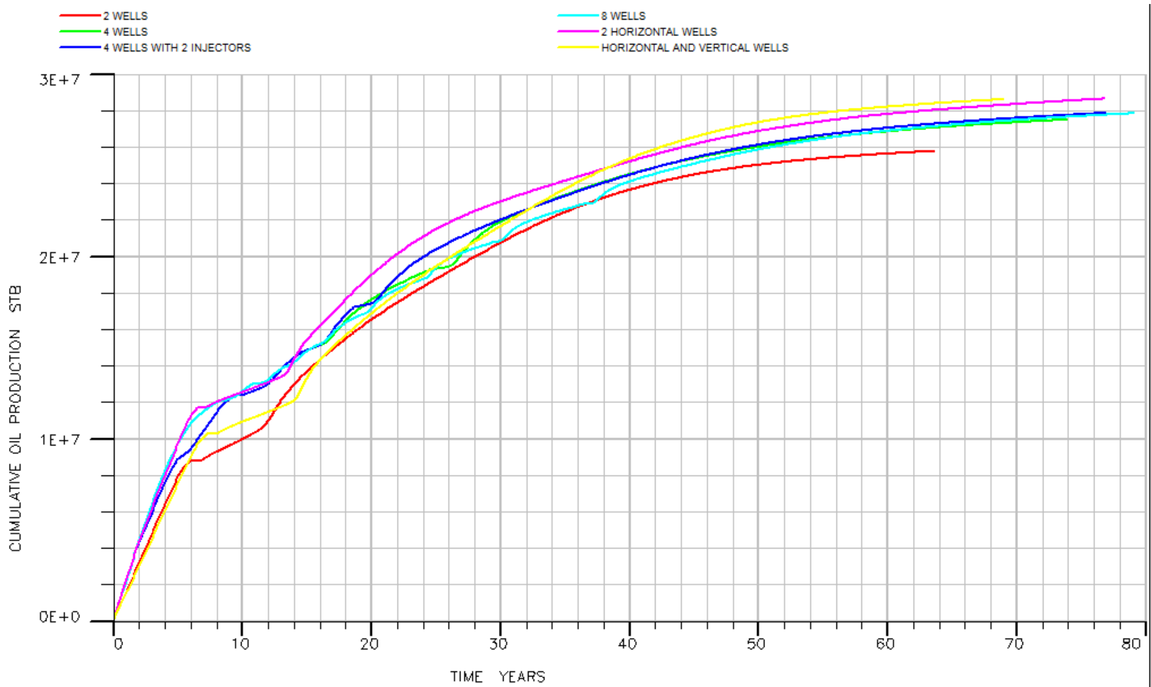

Figure 5.84 : Cumulative oil production for each well pattern

(60-degree dip angle)

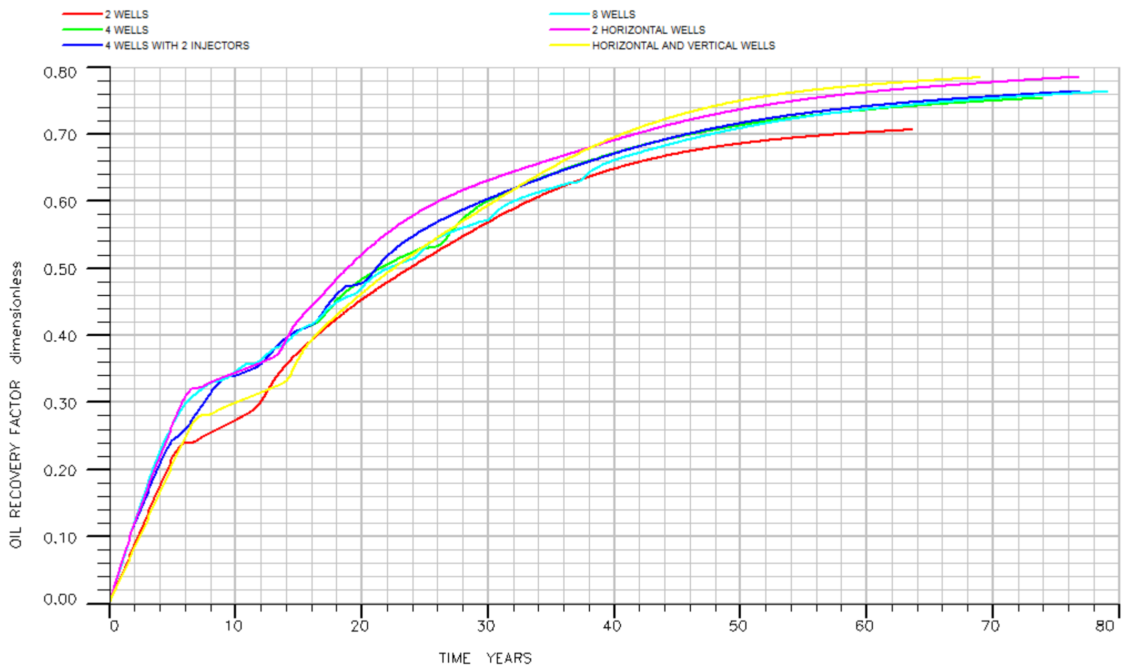

Figure 5.85 : Oil recovery factor for each well pattern
(60-degree dip angle)

As shown in Figure 5.86, pattern of 2 vertical wells can maintain the reservoir pressure better than those in the other patterns. The ability for pattern of 8 vertical wells to maintain the reservoir pressure is quite poor because the reservoir pressure drops to 3,100 psia.

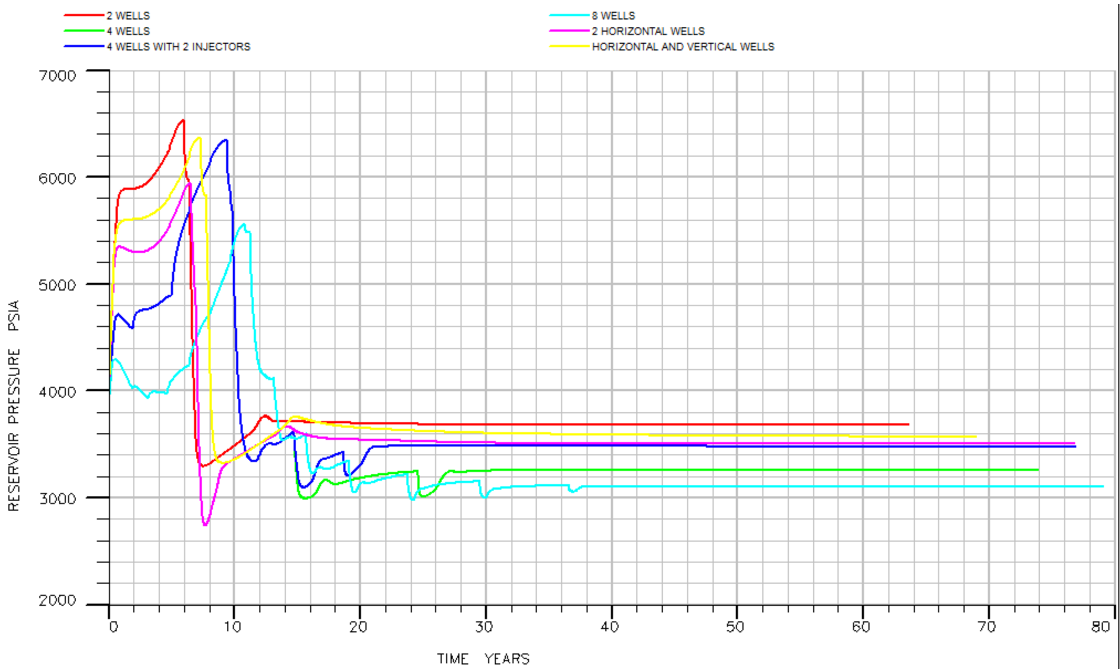

Figure 5.86 : Reservoir pressure for each well pattern

(60-degree dip angle)

Table 5.38 : Summary of each pattern for 60 degree of dip angle

Case	At 30 years							At Abandonment							
	Np (MMSTB)	RF (%)	Wp (MMSTB)	Winj (MMSTB)	Gp (BSCF)	Ginj (BSCF)	BOE (MMSTB)	Tp (years)	Np (MMSTB)	RF (%)	Wp (MMSTB)	Winj (MMSTB)	Gp (BSCF)	Ginj (BSCF)	BOE (MMSTB)
2 vertical wells	20.76	56.88	10.9	12.67	57.96	78.43	17.34	63.58	25.77	70.63	11.15	12.67	173.34	199	21.49
4 vertical wells	21.92	60.07	16.36	17.43	40.75	60.32	18.66	73.83	27.5	75.36	17.18	17.43	177.53	202.59	23.32
4 vertical wells with 2 injectors	22.02	60.34	16.38	17.43	43.67	65.15	18.44	76.88	27.86	76.35	17.14	17.43	198.23	225.85	23.26
8 vertical wells	20.86	57.16	14.57	18.74	43.5	56.98	18.61	79	27.84	76.31	18.77	18.74	185.56	209.55	23.84
2 horizontal wells	23.02	63.09	13.46	14,.05	51.62	74.98	19.13	76.66	28.64	78.48	14.05	14.05	207.11	236.22	23.78
A horizontal with a vertical well	21.64	59.4	13.92	14.66	50.2	72.58	17.9	68.83	28.6	78.4	14.66	14.66	179.22	208.96	23.65

Table 5.39 : Waterflood and gas flood duration for first 30 years.

Case	Waterflood duration (years)	Gas flood duration (years)
2 vertical wells	5.91	24.09
4 vertical wells	9.33	20.67
4 vertical wells with 2 injectors	9.32	20.68
8 vertical wells	10.74	19.26
2 horizontal wells	6.50	23.50
A horizontal with a vertical well	7.25	22.75

Table 5.40 : Waterflood and gas flood duration at economic constraint.

Case	Waterflood duration (years)	Gas flood duration (years)
2 vertical wells	5.91	57.67
4 vertical wells	9.33	64.50
4 vertical wells with 2 injectors	9.32	67.56
8 vertical wells	10.74	68.26
2 horizontal wells	6.50	70.16
A horizontal with a vertical well	7.25	61.58

From Table 5.29, the water production during the first 30 years for pattern of 4 vertical wells and 4 vertical wells with 2 injectors yield the high amount of cumulative water production which are around 16.36 MMSTB and 16.38 MMSTB, respectively. At the economic constraint, pattern of 8 vertical wells provides the highest water production due to large amount of water that we inject into the reservoir.

Pattern of 2 vertical wells yields cumulative gas production around 57.96BSCF which quite high during the first 30 years. When we consider at economic constraint, pattern of 2 horizontal wells shows the largest amount of gas production which is 219.52 BSCF.

In term of cumulative oil production, oil recovery factor and BOE, pattern of 2 horizontal wells gives the highest values during the first 30 years. Pattern of vertical with horizontal wells give the best value at the economic constraint.

In term of time used to perform waterflood, pattern of 2 vertical wells uses the lowest duration which is 5.91 years while pattern of 8 vertical wells yields the longest duration. For the entire period, pattern of 2 wells shows the shortest time.

After simulating the cases for all well patterns and all dip angles, we choose the best pattern for each dip angle to study the effect of dip angle. The best pattern for each dip angle is shown in Table 5.41. Oil production rate, cumulative oil production and oil recovery factor are shown in Figures 5.87-5.89, respectively. During water injection period, there is slight different in oil recovery factor among different dip angles. The higher the dip angle, the less the oil recovery because it is difficult to inject water up the reservoir in order to sweep the oil. During gas injection period, there is significant difference among different dip angles. As depicted in Figure 5.89, a reservoir with higher dip angle has outstandingly more oil recovery factor because the steeply dip angle reservoir allows gravity drainage force play an important role in recovering oil.

Table 5.41 : List of the best well pattern for each dip angle

Dip angle	**Best well pattern**
15	Two horizontal wells
30	Eight vertical wells
60	Two horizontal wells

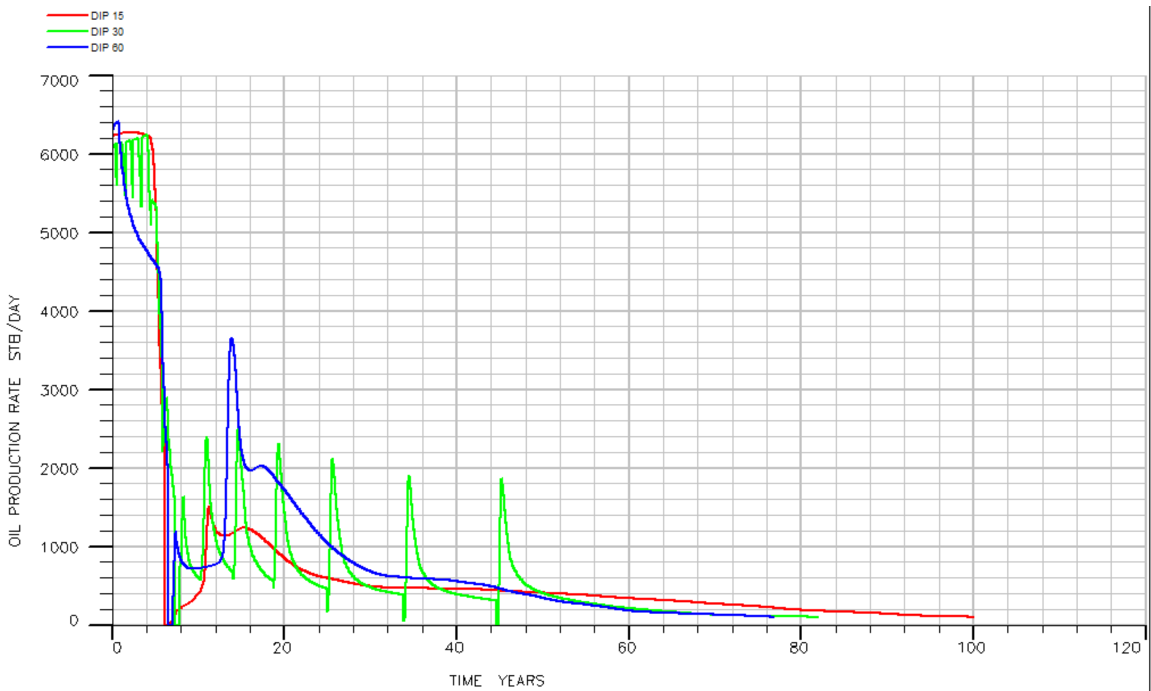

Figure 5.87 : Oil production rate for each dip angle

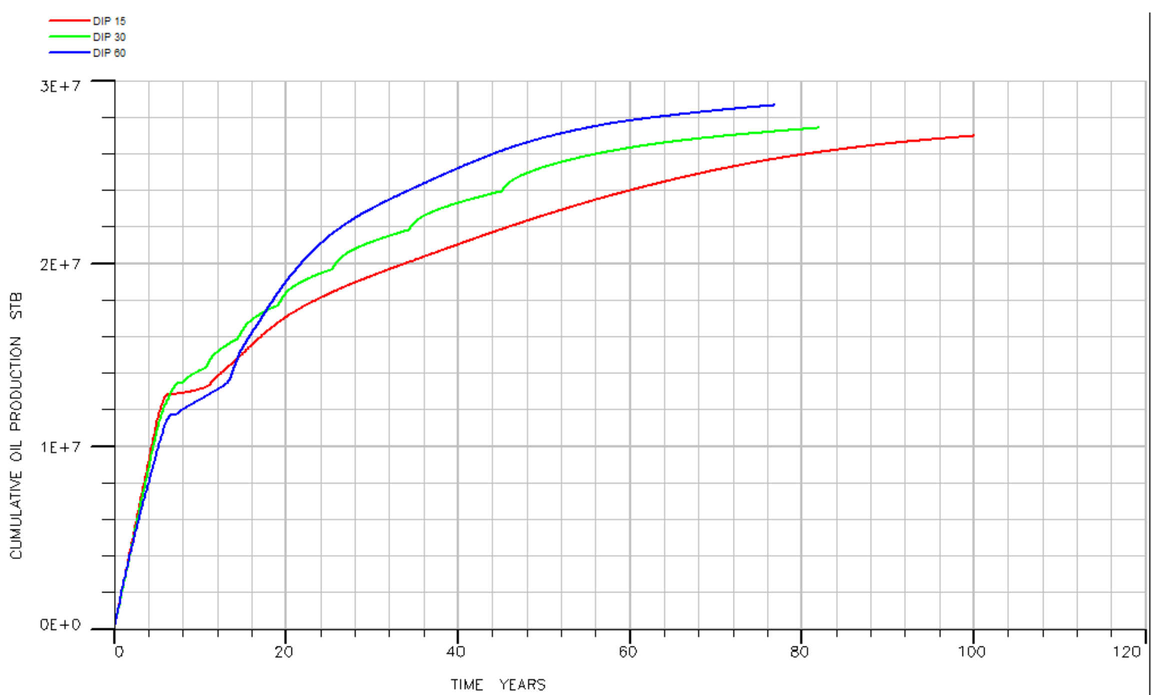

Figure 5.88 : Cumulative oil production for each dip angle

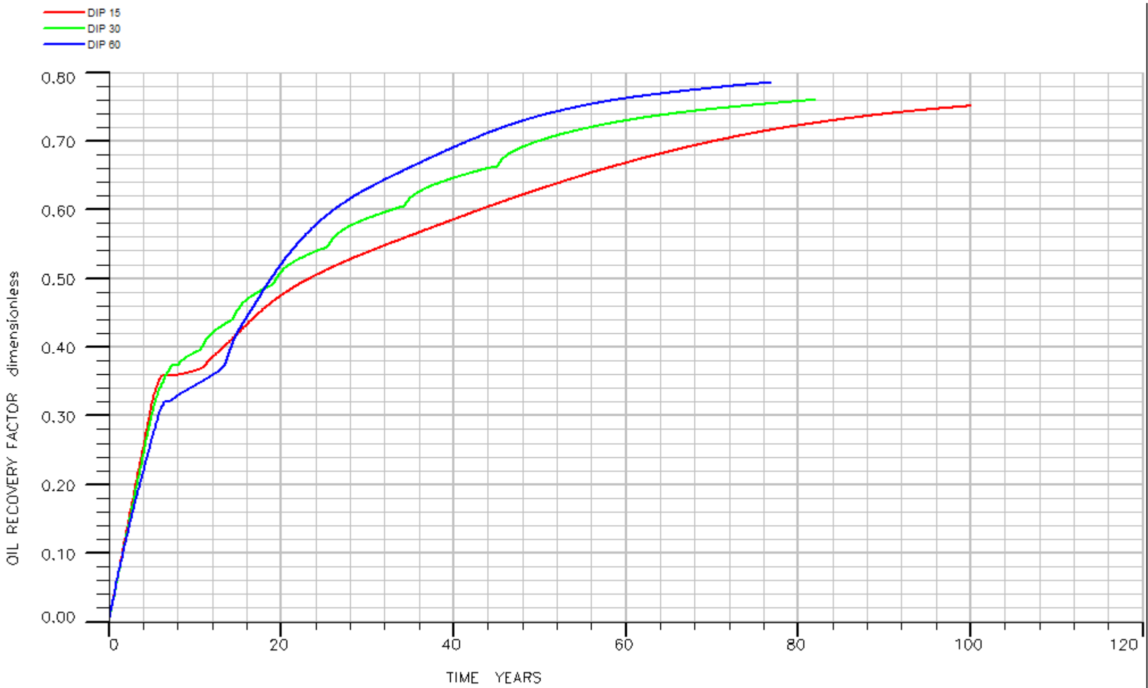

Figure 5.89 : Oil recovery factor for each dip angle

Table 5.42 : Summary of the best well pattern for each dip angle

Dip angle (°)	Case	At 30 years							At Abandonment							
		Np (MMSTB)	RF (%)	Wp (MMSTB)	Winj (MMSTB)	Gp (BSCF)	Ginj (BSCF)	BOE (MMSTB)	Tp (years)	Np (MMSTB)	RF (%)	Wp (MMSTB)	Winj (MMSTB)	Gp (BSCF)	Ginj (BSCF)	BOE (MMSTB)
15	**Two horizontal wells**	19.33	53.82	14.14	14.86	44.76	53.76	17.83	99.98	26.96	75.08	14.84	14.86	202.37	215.52	24.77
30	**Eight vertical wells**	21.49	59.60	12.93	18.53	67.78	65.9	21.81	80.38	25.48	70.65	18.45	18.53	219.52	212.96	26.57
60	**Two horizontal wells**	23.02	63.09	13.46	14.05	51.62	74.98	19.13	76.66	28.64	78.48	14.05	14.05	207.11	236.22	23.78

Table 5.43 : Waterflood and gas flood duration for first 30 years.

Dip angle (°)	Case	Waterflood duration (years)	Gas flood duration (years)
15	**Two horizontal wells**	6.08	23.92
30	**Eight vertical wells**	7.33	22.67
60	**Two horizontal wells**	6.50	23.50

Table 5.44 : Waterflood and gas flood duration at economic constraint.

Dip angle (°)	Case	Waterflood duration (years)	Gas flood duration (years)
15	**Two horizontal wells**	6.08	93.90
30	**Eight vertical wells**	7.33	73.05
60	**Two horizontal wells**	6.50	70.16

As shown in Table 5.42, during the first 30 years, the cumulative water production for reservoir with 15 dip angles yield quite high. While a reservoir with 30 degree dip angle yields the lowest amount of water production. In term of gas production, a reservoir with 30 degree dip angle yields the highest amount of gas. At economic constraint, the water production and gas production for a reservoir with 30 degree dip angle are quite high.

In term of cumulative oil production, oil recovery factor, and BOE during the first 30 years, a reservoir with 60 degree dip angle provides good cumulative oil production and oil recovery factor which around 23.02 MMSTB and 63.09 %, respectively. At economic constraint of 100 STB/D, a reservoir with 60 degree dip angle yields the highest cumulative oil production and oil recovery factor.

During the first 30 years as shown in Table 5.43, a reservoir with 30 degree dip angle consumes the highest time to perform water injection while a reservoir with 15 degree dip angle uses the lowest time. At economic constraint as shown in Table 5.44, a reservoir with 15 degree dip angle uses significantly more times than those in the other dip angles.

5.4 Sensitivity analysis

5.4.1 Effect of relative permeability correlation

In this section, we use 3 types of relative permeability correlations which are ECLIPSE default, Stone 1 and Stone 2 in order to see the effects on production performance.

5.4.1.1 Dip angle of 15 degrees

The results of the study to a reservoir with 15 degree dip angle are shown in Figures 5.90-5.91 and Tables 5.45-5.46.

As shown in Tables 5.45-5.46, ECLIPSE default model shows the highest water production while Stone 2 model yield the lowest water production during waterflood period. However, the difference is rather small. At economic constraint, Stone 1 model shows the highest water production while Stone 2 model yields the lowest water production.

For gas production during waterflood period, Stone 1 model gains a little bit higher gas production than the other models. At economic constraint, ECLIPSE default model provides the higher gas production than the other models.

All the cases provide no significantly difference in time, cumulative oil production, and oil recovery factor for both waterflood period and gas injection period. In summary, the three models of relative permeability provide similar results in a reservoir with 15 degree dip angle.

Table 5.45 : Summary of results for different methods of three-phase relative permeabilities. (waterflood period)

Model	Time (year)	Cumulative water production (MMSTB)	Cumulative gas production (BSCF)	Cumulative oil production (MMSTB)	Oil recovery factor (%)
Eclipse default	6.08	0.7	6.25	12.85	35.78
Stone 1	6.09	0.73	6.3	12.93	36.01
Stone 2	6	0.59	6.22	12.76	35.54

Table 5.46 : Summary of results for different methods of three-phase relative permeabilities. (at economic constraint)

Model	Time (year)	Cumulative water production (MMSTB)	Cumulative gas production (BSCF)	Cumulative oil production (MMSTB)	Oil recovery factor (%)
Eclipse default	99.98	14.84	202.37	26.96	75.08
Stone 1	99	14.89	198.3	26.92	74.9
Stone 2	99	14.63	200.23	26.94	75.03

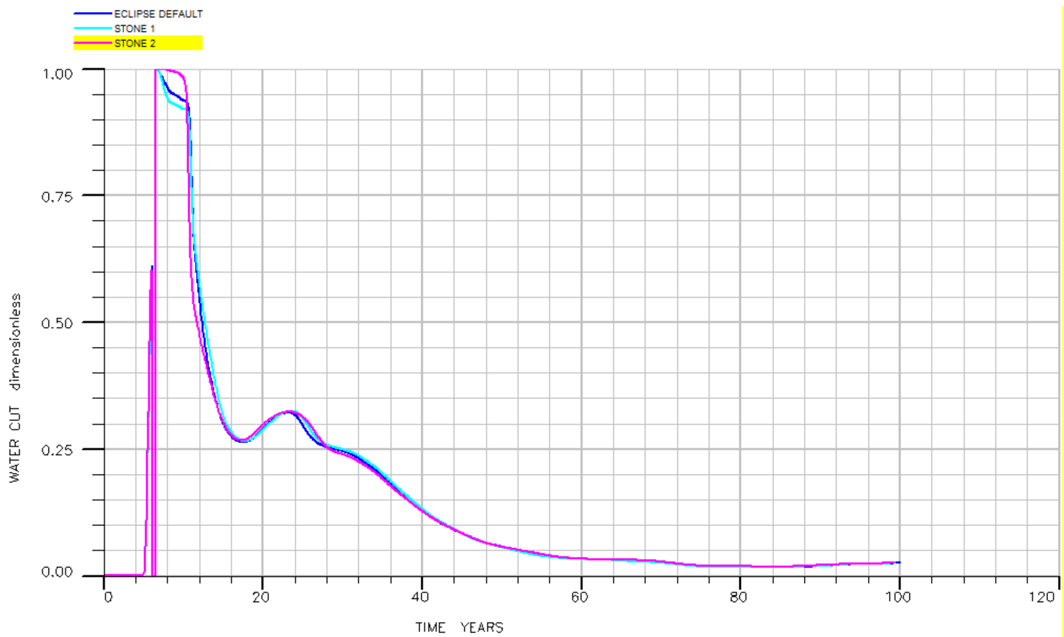

Figure 5.90 : Water cut for different methods of three-phase relative permeabilities (15-degree dip angle)

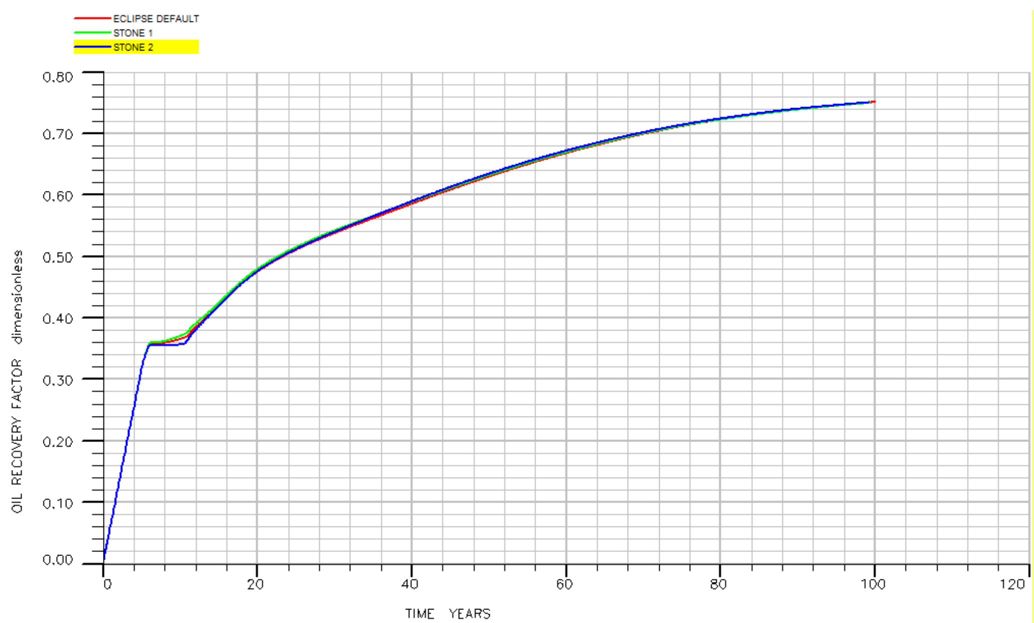

Figure 5.91 : Oil recovery factor for different methods of three-phase relative permeabilities (15-degree dip angle)

5.4.1.2 Dip angle of 30 degrees

The results of the study to a reservoir with 30 degree dip angle are shown in Figures 5.92-5.93 and Tables 5.47-5.48.

As shown in Tables 5.47-5.48, Stone 1 default model shows the highest water production while Stone 2 model yield the lowest water production during waterflood period. At economic constraint, Stone 1 model shows the highest water production while Stone 2 model yields the lowest water production. However, the difference is rather small.

For gas production during waterflood period, Stone 1 model gains a little bit higher gas production than the other models. At economic constraint, Stone 2 model provides a little bit higher gas production than the other models.

All the cases provide no significantly difference in time, cumulative oil production, and oil recovery factor for both waterflood period and gas injection period. In summary, the three models of relative permeability provide similar results in a reservoir with 30 degree dip angle.

Table 5.47 : Summary of results for different methods of three-phase relative permeabilities in a reservoir with 30 degree dip angle. (waterflood period)

Model	Time (year)	Cumulative water production (MMSTB)	Cumulative gas production (BSCF)	Cumulative oil production (MMSTB)	Oil recovery factor (%)
Eclipse default	7.32	1.2	6.69	13.44	37.27
Stone 1	7.33	1.23	6.72	13.51	37.46
Stone 2	7.24	1.15	6.66	13.37	37.07

Table 5.48 : Summary of results for different methods of three-phase relative permeabilities in a reservoir with 30 degree dip angle. (at economic constraint)

Model	Time (year)	Cumulative water production (MMSTB)	Cumulative gas production (BSCF)	Cumulative oil production (MMSTB)	Oil recovery factor (%)
Eclipse default	81.97	18.45	203.59	27.4	75.98
Stone 1	80.89	18.49	201.03	27.4	75.96
Stone 2	82.24	18.3	204.57	27.4	75.95

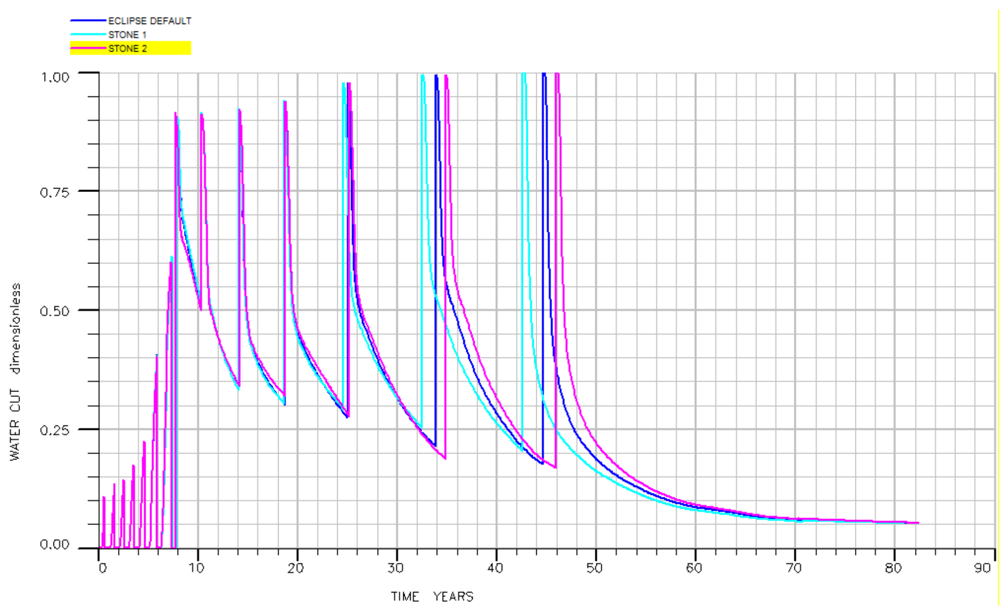

Figure 5.92 : Water cut for different methods of three-phase relative permeabilities (30-degree dip angle)

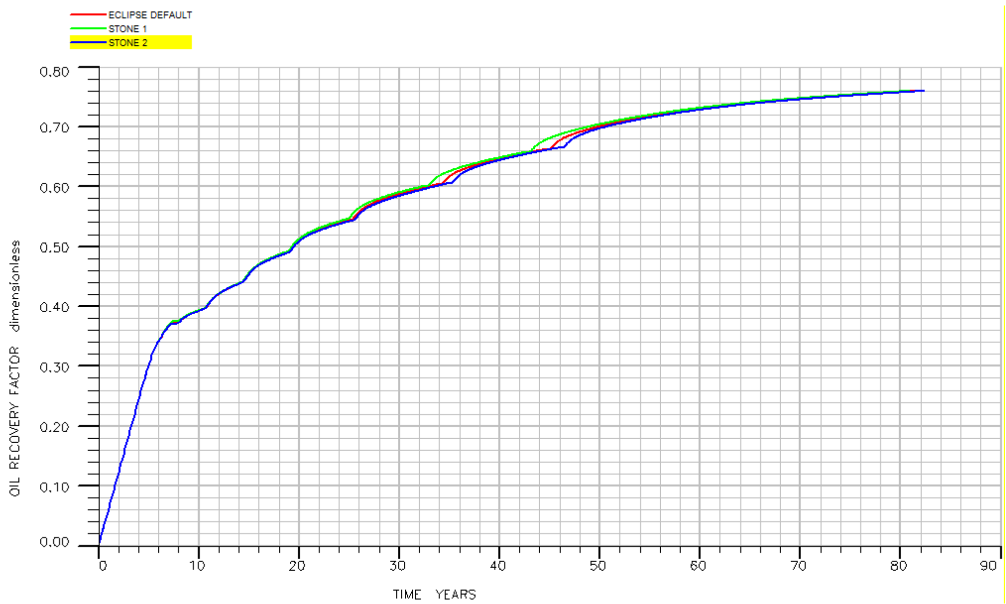

Figure 5.93 : Oil recovery factor for different methods of three-phase relative permeabilities (30-degree dip angle)

5.4.1.3 Dip angle of 60 degrees

The results of the study to a reservoir with 60 degree dip angle are shown in Figures 5.94-5.95 and Tables 5.49-5.50.

As shown in Tables 5.49-5.50, Stone 1 default model shows the highest water production while Stone 2 model yield the lowest water production during waterflood period. At economic constraint, Stone 1 model shows the highest water production while ECLIPSE default model yields the lowest water production. However, the difference is rather small.

For gas production during waterflood period, Stone 1 model gains a little bit higher gas production than the other models. At economic constraint, ECLIPSE default model provides a little bit higher gas production than the other models.

All the cases provide no significantly difference in time, cumulative oil production, and oil recovery factor for both waterflood period and gas injection period. In summary, the three models of relative permeability provide similar results in a reservoir with 60 degree dip angle.

Table 5.49 : Summary of results for different methods of three-phase relative permeabilities in a reservoir with 60 degree dip angle. (waterflood period)

Model	**Time (year)**	**Cumulative water production (MMSTB)**	**Cumulative gas production (BSCF)**	**Cumulative oil production (MMSTB)**	**Oil recovery factor (%)**
Eclipse default	6.49	0.45	5.82	11.72	32.13
Stone 1	6.58	0.57	5.88	11.83	32.42
Stone 2	6.5	0.45	5.83	11.73	32.14

Table 5.50 : Summary of results for different methods of three-phase relative permeabilities in a reservoir with 60 degree dip angle. (at economic constraint)

Model	**Time (year)**	**Cumulative water production (MMSTB)**	**Cumulative gas production (BSCF)**	**Cumulative oil production (MMSTB)**	**Oil recovery factor (%)**
Eclipse default	76.66	14.05	207.11	28.64	78.48
Stone 1	76.46	14.24	206.42	28.63	78.47
Stone 2	76.05	14.05	203.8	28.59	78.35

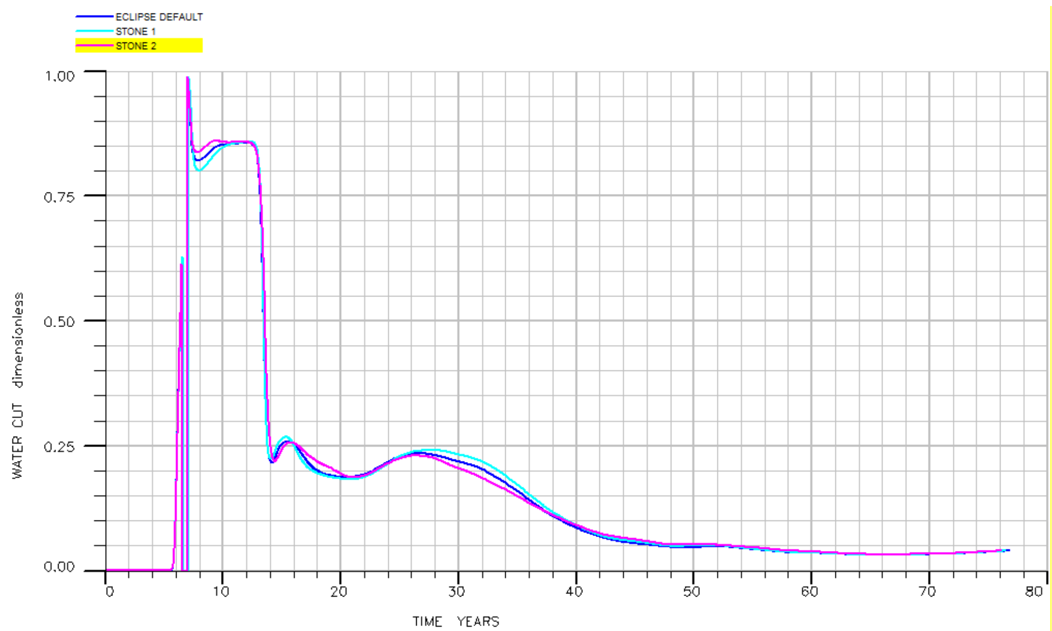

Figure 5.94 : Water cut for different methods of three-phase relative permeabilities (60-degree dip angle)

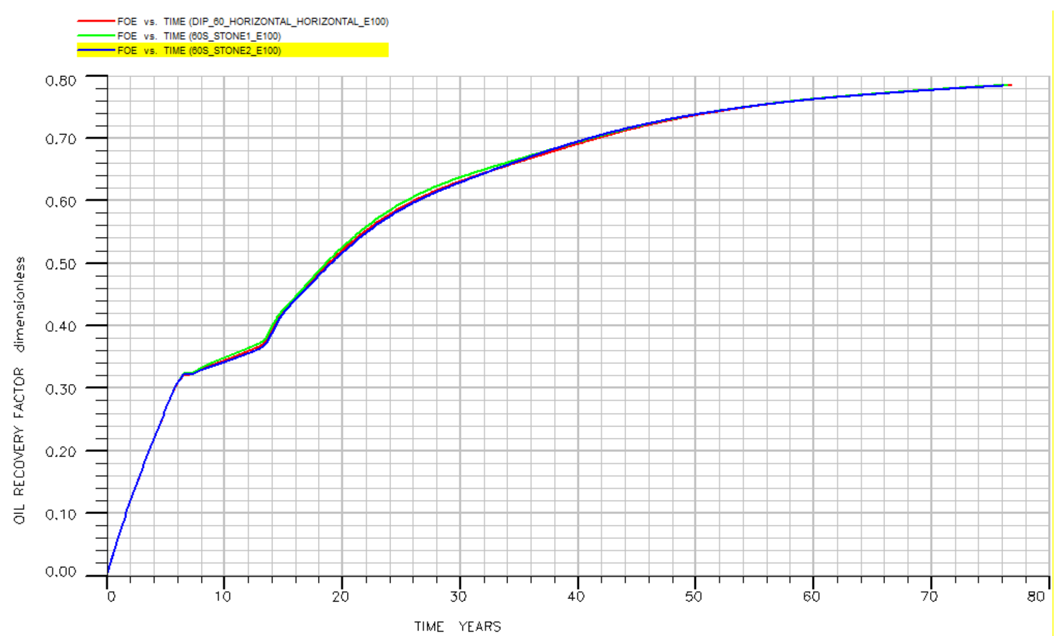

Figure 5.95 : Oil recovery factor for different methods of three-phase relative permeabilities (60-degree dip angle)

5.4.2 Effect of vertical to horizontal permeability ratio

In this section, three different vertical to horizontal permeability ratios which are 0.01, 0.1 and 1 are considered. For all cases, we fix the value of horizontal permeability and change the value of vertical permeability as shown in Table 5.51.

Table 5.51 : Vertical and horizontal permeabilities for different anisotropy ratio

Case	**Vertical to horizontal permeability ratio**	**Vertical permeability (md)**	**Horizontal permeability (md)**
1	0.01	0.32529	32.529
2	0.1	3.2529	32.529
3	1	32.529	32.529

5.4.2.1 Dip angle of 15 degrees

In term of oil production rate during waterflood period as shown in Figure 5.96, there is significant difference in oil production among the three cases. In cases 2-3, the oil production rate is quite constant than those in the other cases. Oil rate starts to decline when the water cut increases. During gas injection period, case 3 provides the best oil rate.

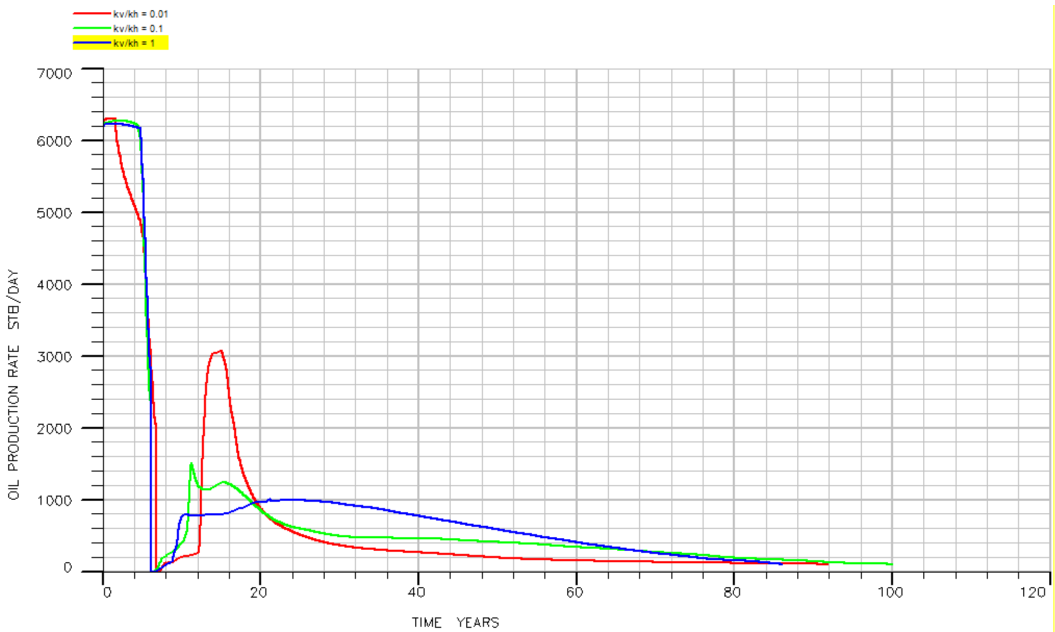

Figure 5.96 : Oil production rate for different vertical to horizontal ratios (15-degree dip angle)

As shown in Figure 5.97, all cases gain a little bit different in oil recovery factor during the first 6 years of production. For 6th-15th years, case 3, in which k_v/k_h is 1, yields significant higher oil recovery when compared with other cases. However, during the 15th-34th years, case 1 gains the highest oil recovery. At 32th year and 48th year, oil recovery for case 3 and 2 catches up with oil recovery factor for case 1, respectively. After 48 years, oil recovery factor of case 3, in which k_v/k_h is 1, is the best while case 1, in which k_v/k_h is 0.01, has the lowest oil recovery.

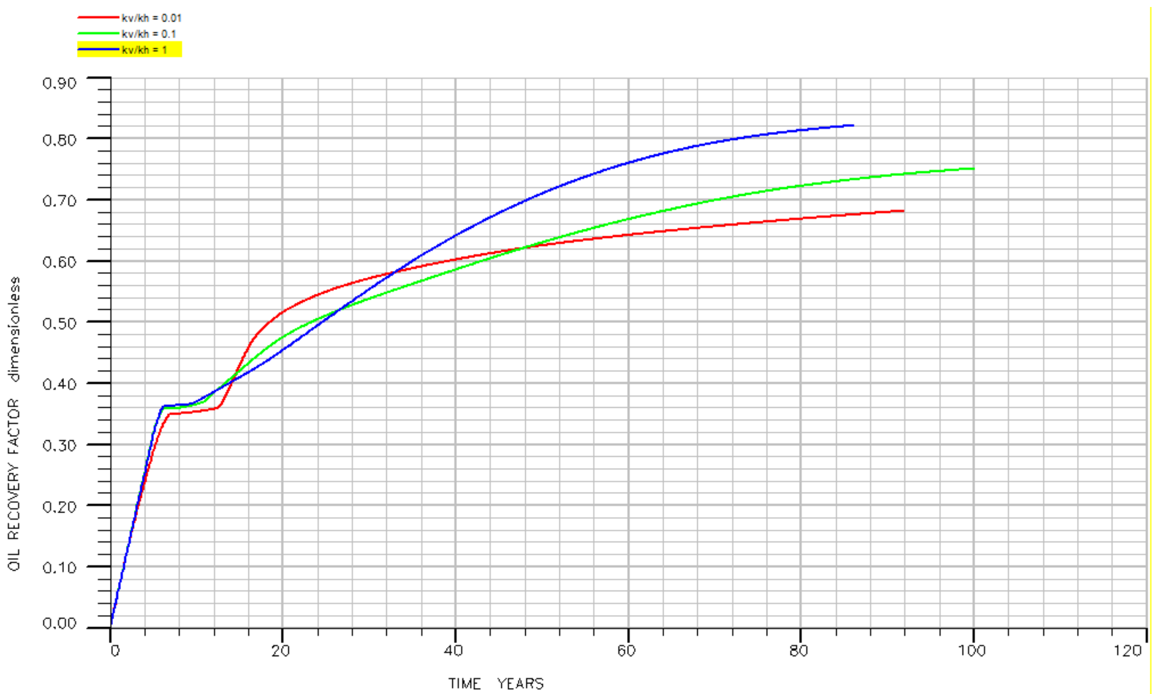

Figure 5.97 : Oil recovery factor for different vertical to horizontal ratio (15-degree dip angle)

For reservoir pressure, cases 1 yields quite high reservoir pressure. The reservoir pressure for cases 2 and 3 are quite low.

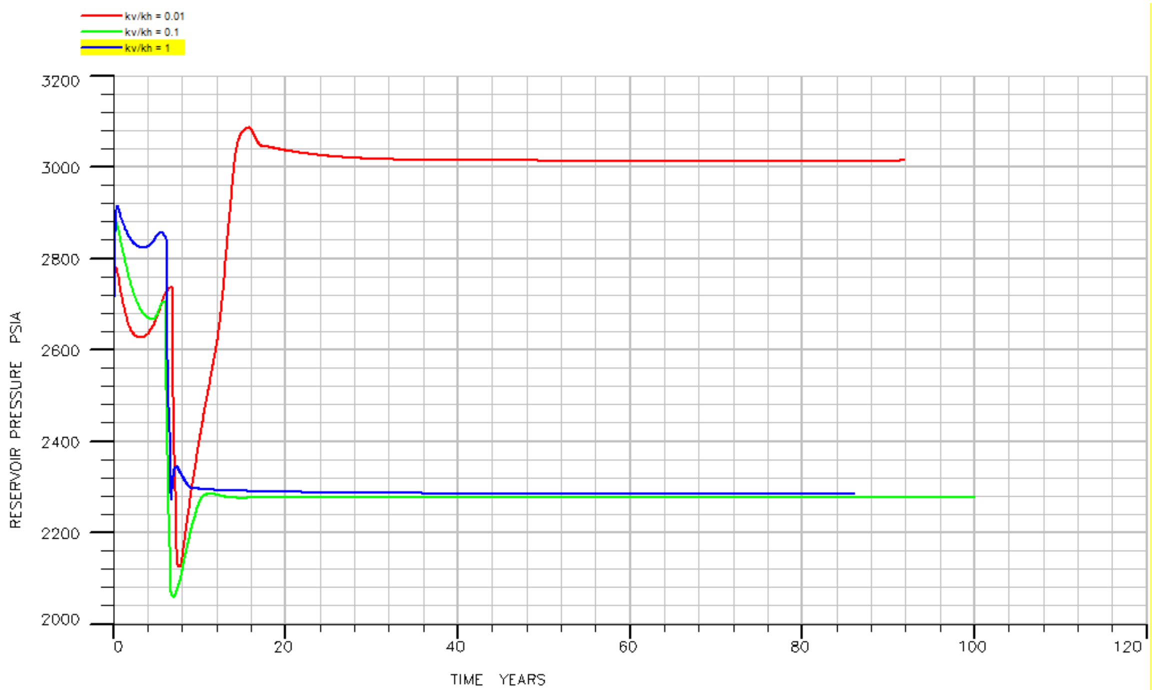

Figure 5.98 : Reservoir pressure for different vertical to horizontal ratio (15-degree dip angle)

Table 5.52 : Summary of results for different vertical to horizontal permeability ratios (waterflood period)

Case	Time (year)	Cumulative water production (MMSTB)	Cumulative gas production (BSCF)	Cumulative oil production (MMSTB)	Oil recovery factor (%)
1	6.83	0.9	5.95	12.56	34.97
2	6.08	0.7	6.25	12.85	35.78
3	6.16	1.16	6.6	13.04	36.31

Table 5.53 : Summary of results for different vertical to horizontal permeability ratios (at economic constraint)

Case	Time (year)	Cumulative water production (MMSTB)	Cumulative gas production (BSCF)	Cumulative oil production (MMSTB)	Oil recovery factor (%)
1	91.81	14.74	230.03	24.48	68.17
2	99.98	14.84	202.37	26.96	75.08
3	86	17.1	169.74	29.49	82.12

During waterflood period as shown in Table 5.52, case 3, in which k_v/k_h is 1, gives significantly higher water production when compared with other cases because water can more easily to flow up in a reservoir with high vertical permeability. Case 3 also yields quite high cumulative gas production. At economic constraint as shown in Table 5.53, case 3 still yield the highest cumulative water production. However, when we consider cumulative gas production, case 1 has the highest cumulative gas production.

In term of cumulative oil production and oil recovery factor, case 3 yields the highest values for both waterflood and gas flood durations due to the high k_v which allows oil in the reservoir can flow more easily.

5.4.2.2 Dip angle of 30 degrees

In term of oil production rate during waterflood period as shown in Figure 5.99, there is significant difference in oil production among the three cases. In case 3, the oil production rate is quite high than those in the other cases. Oil rate starts to decline when the water cut increases. During gas injection period, case 1 and case 2 yield the high oil rate for a while. Then, they dramatically drop because of low permeability. Oil rate in case 3 is quite stable than those in the other cases.

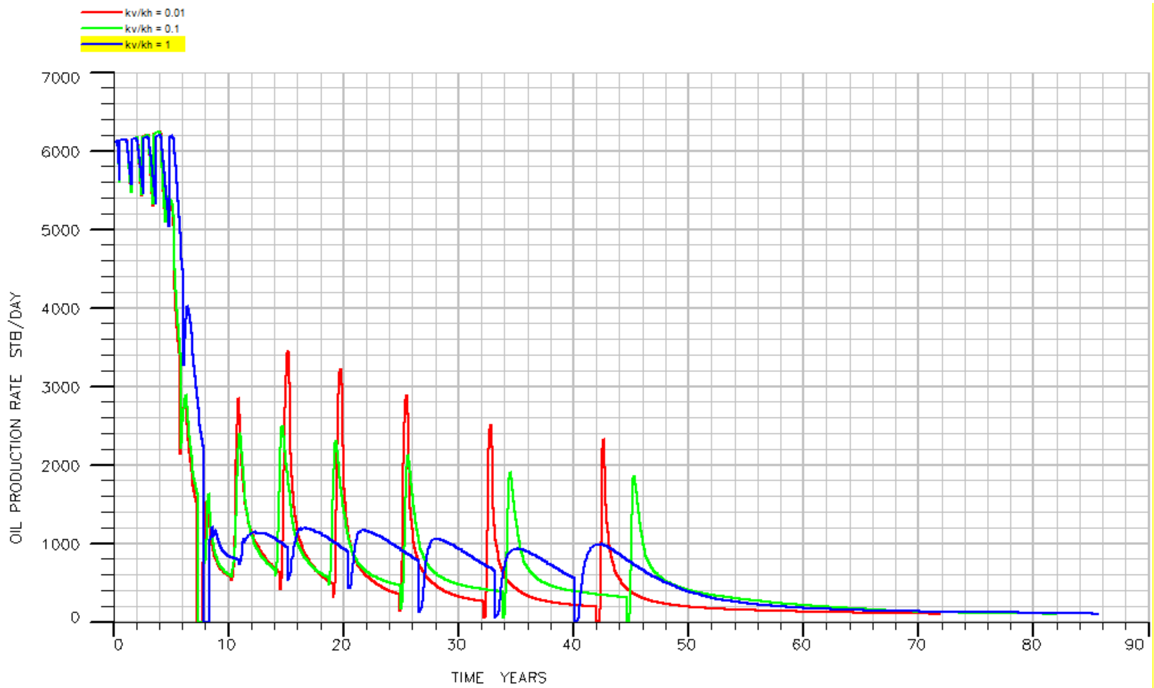

Figure 5.99 : Oil production rate for different vertical to horizontal ratios (30-degree dip angle)

As shown in Figure 5.100, all cases gain a little bit different in oil recovery factor during the first 6 years of production. After that, oil recovery factor of case 3, in which k_v/k_h is 1, is the best while case 1, in which k_v/k_h is 0.01, has the lowest oil recovery.

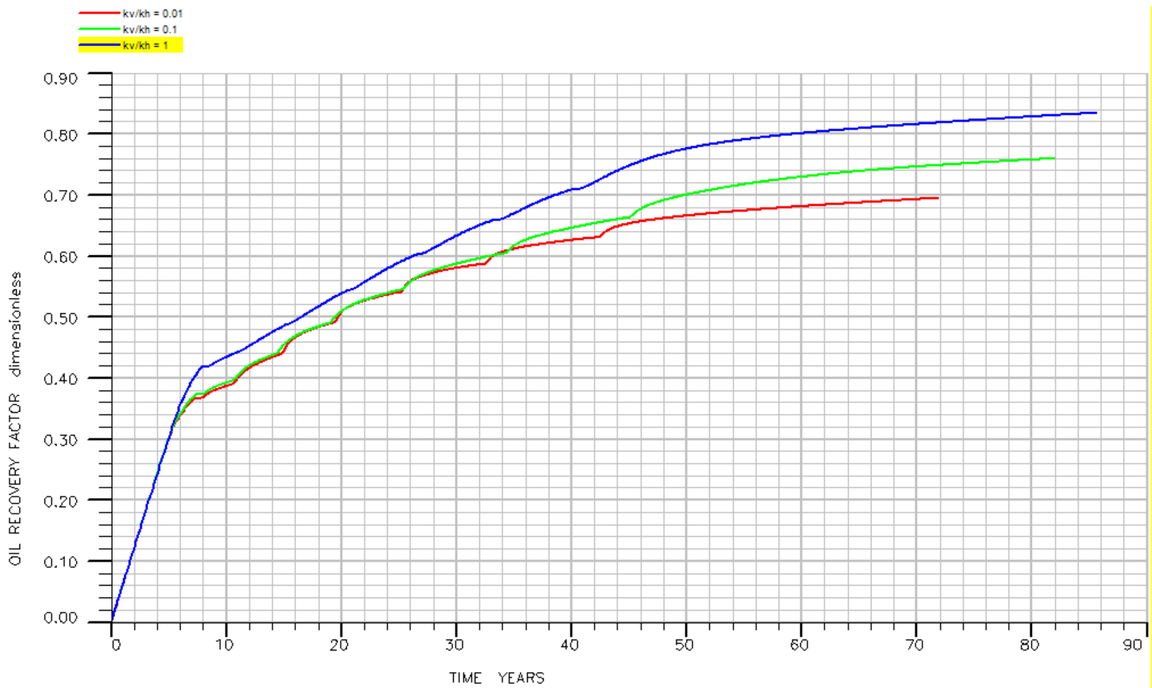

Figure 5.100 : Oil recovery factor for different vertical to horizontal ratios (30-degree dip angle)

The reservoir pressure in case 3 is quite high due to the high permeability. So, we can more easily to inject water or gas to maintain the reservoir pressure as shown in Figure 101.

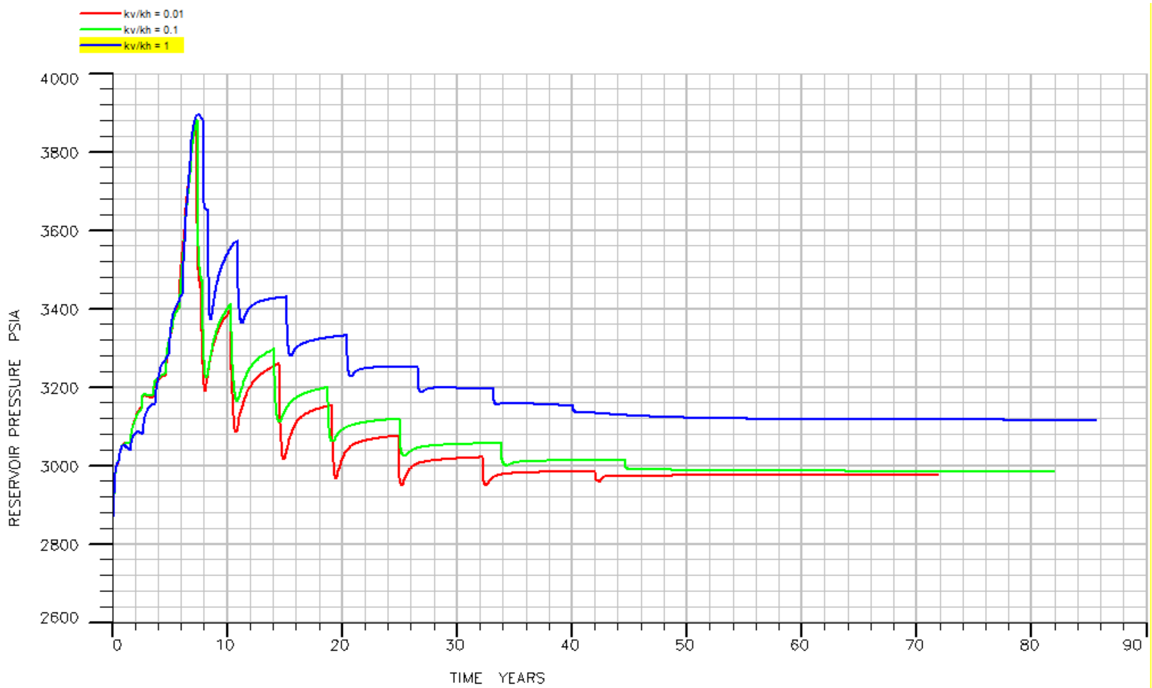

Figure 5.101 : Reservoir pressure for different vertical to horizontal ratios (30-degree dip angle)

Table 5.54 : Summary of results for different vertical to horizontal permeability ratios (waterflood period)

Case	Time (year)	Cumulative water production (MMSTB)	Cumulative gas production (BSCF)	Cumulative oil production (MMSTB)	Oil recovery factor (%)
1	7.25	1.07	6.57	13.23	36.68
2	7.32	1.2	6.69	13.44	37.27
3	7.83	1.87	7.85	15.06	41.75

Table 5.55 : Summary of results for different vertical to horizontal permeability ratios (at economic constraint)

Case	Time (year)	Cumulative water production (MMSTB)	Cumulative gas production (BSCF)	Cumulative oil production (MMSTB)	Oil recovery factor (%)
1	71.88	17.82	173.75	25.06	69.48
2	81.97	18.45	203.59	27.4	75.98
3	85.58	21.43	218.7	30.1	83.44

During waterflood period as shown in Table 5.54, case 3, in which k_v/k_h is 1, gives significantly higher water production when compared with other cases because water can more easily to flow up in a reservoir with high vertical permeability. Case 3 also yields quite high cumulative gas production. At economic constraint as shown in Table 5.55, case 3 still yield the highest cumulative water production. However, when we consider cumulative gas production, case 1 has the highest cumulative gas production because the more duration of DDP.

In term of cumulative oil production and oil recovery factor, case 3 yields the highest values for both waterflood and gas flood durations due to the high k_v which allows oil in the reservoir can flow more easily.

5.4.2.2 Dip angle of 60 degrees

As shown in Figure 5.102, there is difference in oil production among the three cases during waterflood period. In case 3, the oil production rate is quite higher than those in the other cases. Oil rate starts to decline when the water cut increases. During gas injection period, case 3 provides pretty good oil rate.

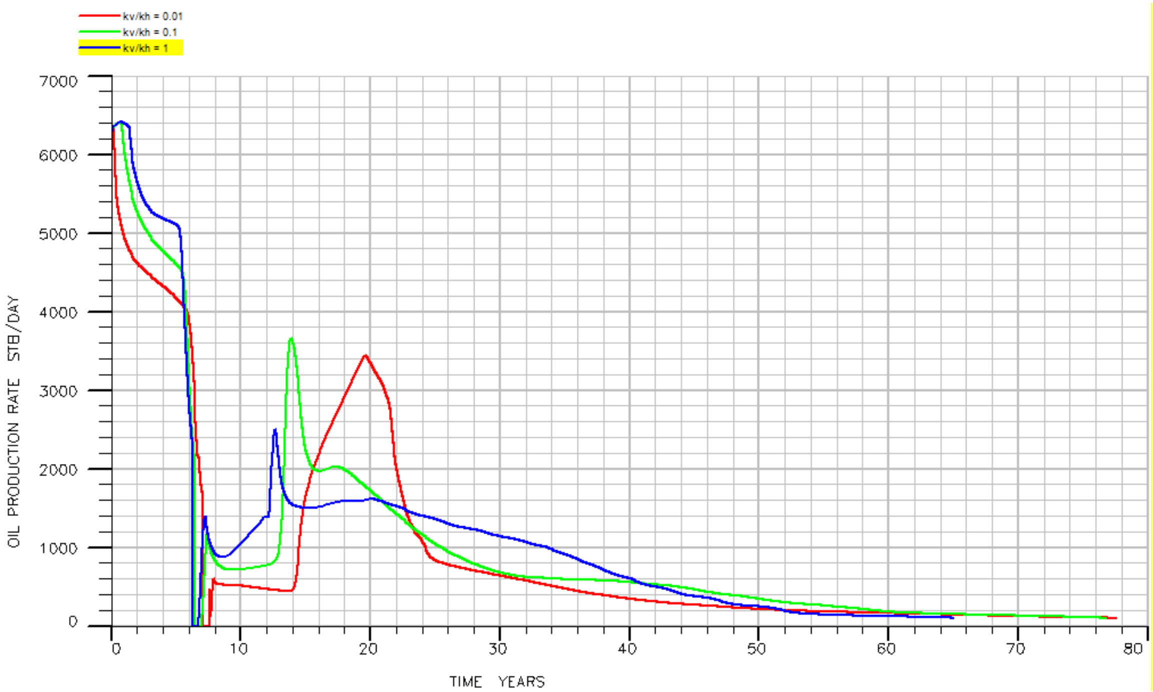

Figure 5.102 : Oil production rate for different vertical to horizontal ratios (60-degree dip angle)

As shown in Figure 5.103, oil recovery factor shows the same trend with 2 previous dip angle.

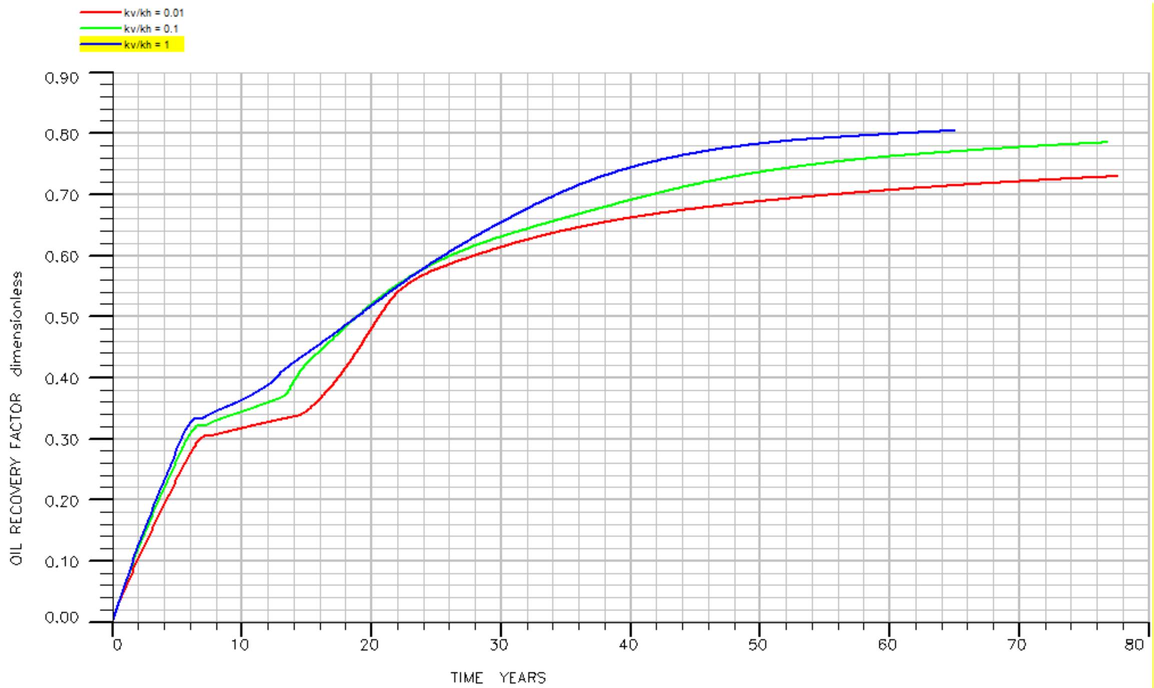

Figure 5.103 : Oil recovery factor for different vertical to horizontal ratios (60-degree dip angle)

In term of reservoir pressure as shown in Figure 5.104, all cases have a little bit different level of pressure maintenance.

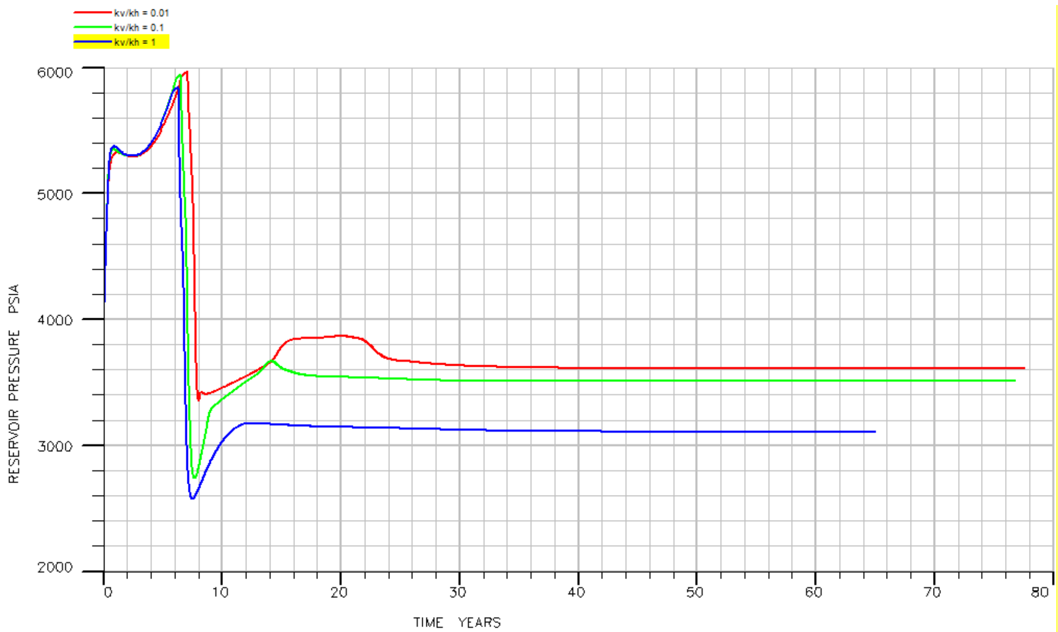

Figure 5.104 : Reservoir pressure for different vertical to horizontal ratios (60-degree dip angle)

Table 5.56 : Summary of results for different vertical to horizontal permeability ratios (waterflood period)

Case	Time (year)	Cumulative water production (MMSTB)	Cumulative gas production (BSCF)	Cumulative oil production (MMSTB)	Oil recovery factor (%)
1	7.09	0.5	5.61	11.13	30.51
2	6.49	0.45	5.82	11.72	32.13
3	6.25	0.55	6.03	12.14	33.28

Table 5.57 : Summary of results for different vertical to horizontal permeability ratios (at economic constraint)

Case	Time (year)	Cumulative water production (MMSTB)	Cumulative gas production (BSCF)	Cumulative oil production (MMSTB)	Oil recovery factor (%)
1	77.54	14.07	199.17	26.62	72.94
2	76.66	14.05	207.11	28.64	78.48
3	65.04	14.43	156.38	29.35	80.43

During waterflood period as shown in Table 5.56, case 3, in which k_v/k_h is 1, gives significantly higher water production when compared with other cases because water can more easily to flow up in a reservoir with high vertical permeability. Case 2 yields quite high cumulative gas production because the long time and high permeability. The results are the same trend at economic constraint.

5.4.3 Effect of wettability

In this section, we set up the relative permeability curve corresponding to the type of wettability. To simplify the configuration, we set up the relative permeability curve base on rule of thumb that shows in Table 5.58. Tables 5.59-5.60 show the input parameter of Corey's correlation for water-wet and oil-wet, respectively. Figures 5.105-5.108 show relative permeability curve for each type of wettability. The original oil in place for oil-wet system is much more than water-wet system as shown in Table 5.61.

Table 5.58 : Classification of rock wettability from relative permeability curve

Property	Water-wet	Oil-wet
Irreducible water saturation	Usually greater than 20 to 25 % PV	Generally less than 15% PV
Cross over saturation	Greater than 50% water saturation	Less than 50% water saturation
Relative permeability to water at residual oil saturation	Generally less than 30%	Greater than 50% and can approach 100%

Table 5.59 : List of input parameter for Corey's correlation (Water-wet system)

Corey Water	2	**Corey Gas**	3	**Corey Oil/Water**	3
Swmin	0.4	**Sgmin**	0	**Corey Oil/Gas**	3
Swcr	0.4	**Sgcr**	0.15	**Sorg**	0.1
Swi	0.4	**Sgi**	0.15	**Sorw**	0.3
Swmax	1	**Krg(Sorg)**	0.8	**Kro(Swmin)**	0.8
Krw(Sorw)	0.3	**Krg(Sgmax)**	0.8	**Kro(Sgmin)**	0.8
Krw(Swmax)					

Table 5.60 : List of input parameter for Corey's correlation (Oil-wet system)

Corey Water	2	**Corey Gas**	3	**Corey Oil/Water**	3
Swmin	0.1	**Sgmin**	0	**Corey Oil/Gas**	3
Swcr	0.1	**Sgcr**	0.15	**Sorg**	0.1
Swi	0.1	**Sgi**	0.15	**Sorw**	0.3
Swmax	1	**Krg(Sorg)**	0.8	**Kro(Swmin)**	0.8
Krw(Sorw)	0.8	**Krg(Sgmax)**	0.8	**Kro(Sgmin)**	0.8
Krw(Swmax)	0.8				

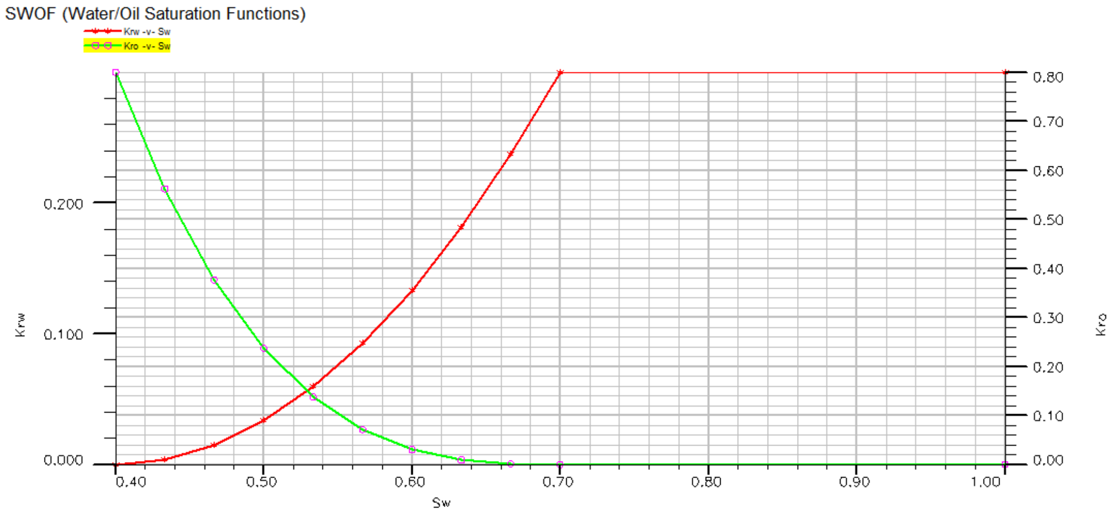

Figure 5.105 : Relative permeability curve for water-wet system (Water-Oil)

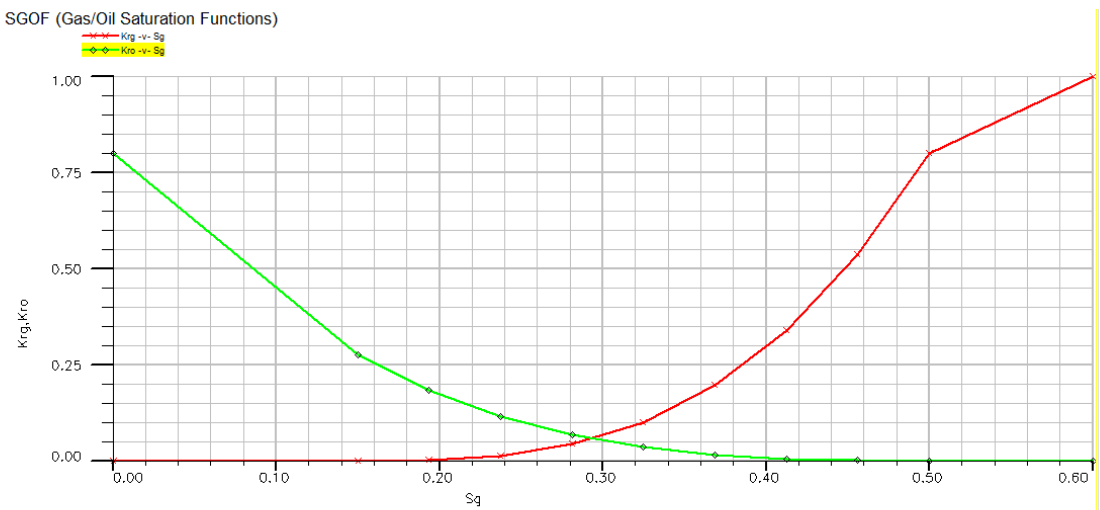

Figure 5.106 : Relative permeability curve for water-wet system (Gas-Oil)

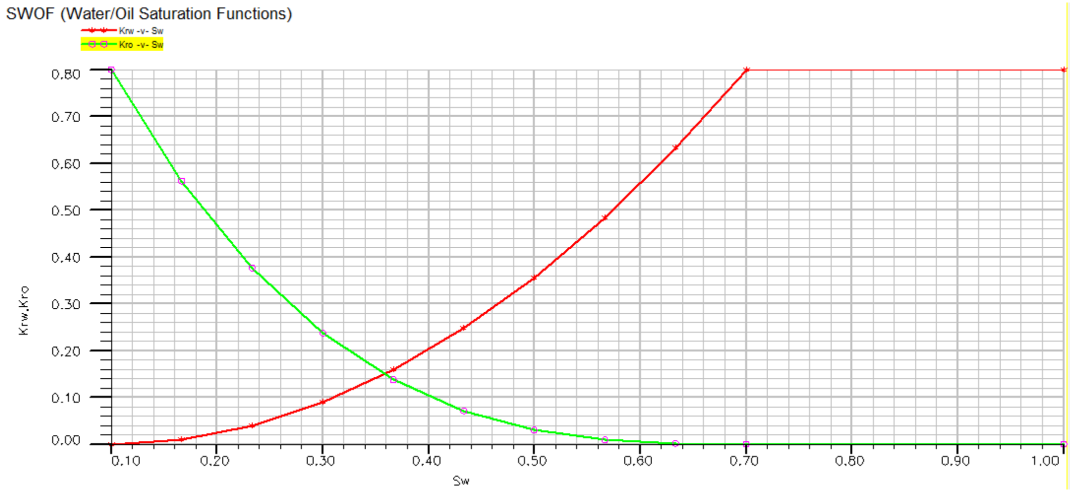

Figure 5.107 : Relative permeability curve for oil-wet system (Water-Oil)

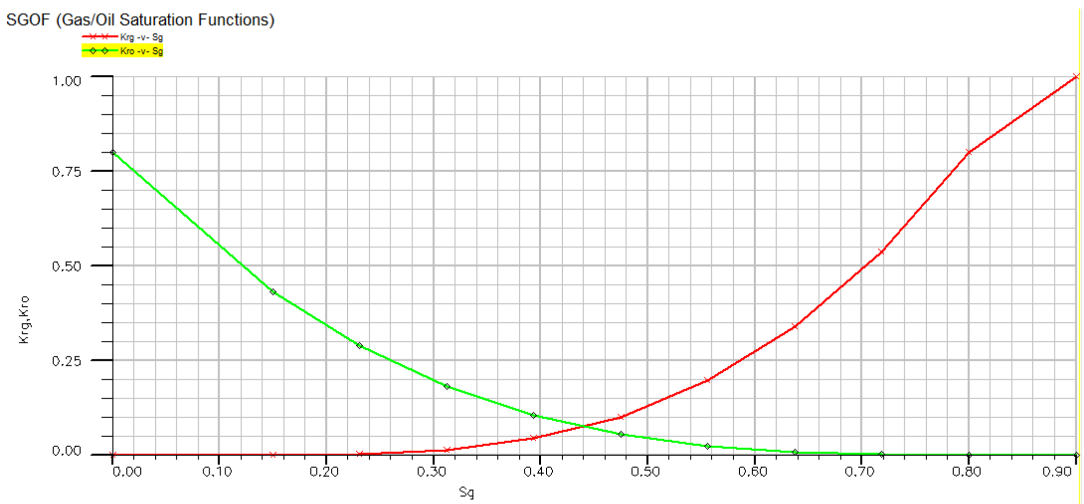

Figure 5.108 : Relative permeability curve for oil-wet system (Gas-Oil)

Table 5.61 : Original oil in place for each type of wettability

Case	Original oil in place (STB)
Water-wet	30,912,154
Oil-wet	46,368,232

5.4.3.1 Dip angle of 15 degrees

As shown is Figure 5.109, oil recovery factor is the same for the first 8 years. For 8th-16th years, oil-wet yields more oil recovery factor. For 16th-84th years, there is significant difference in oil recovery factor among the two cases. Water-wet shows the higher oil recovery. In 85th years, case, in which type of wettability is water-wet, reaches the economic constraint while case, in which type of wettability is oil-wet continue produces the oil. In 92th years, the oil recovery factor in the case, in which type of wettability is oil-wet, catches up with oil recovery factor for case, in which type of wettability is water-wet.

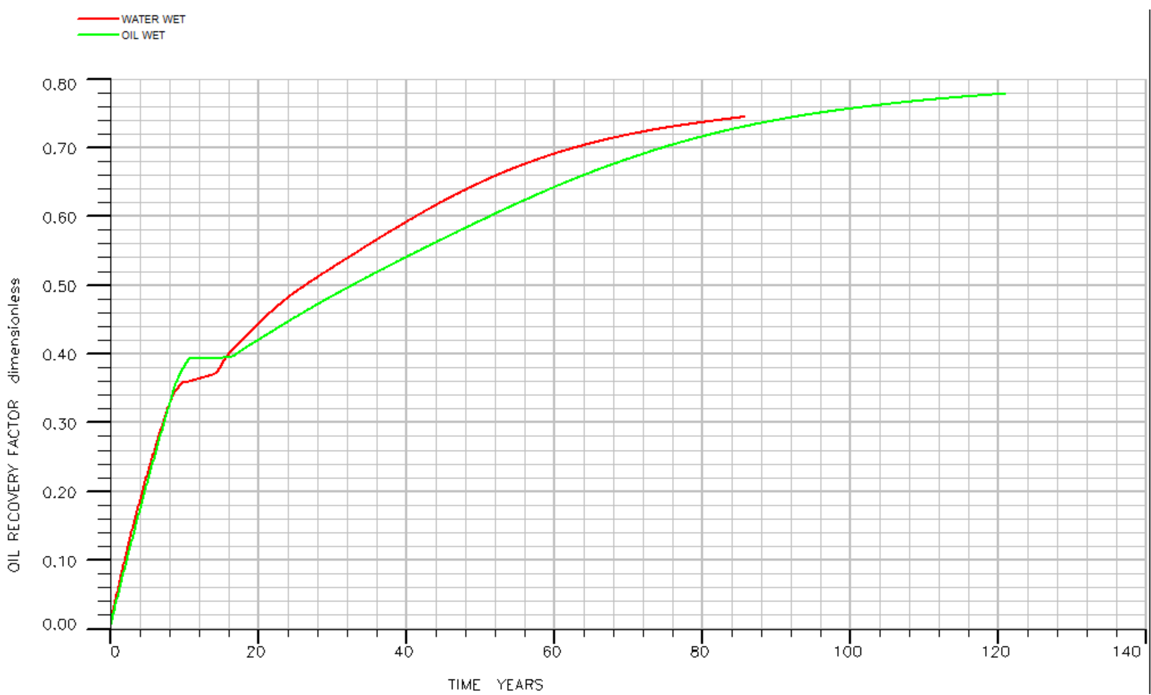

Figure 5.109 : Oil recovery factor for each type of wettability

(15-degree dip angle)

Table 5.62 : Summary for each type of wettability (waterflood period)

Case	Time (year)	Cumulative water production (MMSTB)	Cumulative gas production (BSCF)	Oil recovery factor (%)
Water-wet	9.84	0.47	5.35	35.9
Oil-wet	10.66	1.25	9.27	39.26

Table 5.63 : Summary for each type of wettability (at economic constraint)

Case	Time (year)	Cumulative water production (MMSTB)	Cumulative gas production (BSCF)	Oil recovery factor (%)
Water-wet	85.8	13.41	198.84	74.45
Oil-wet	120	23.84	246.91	77.83

As shown in Tables 5.62-5.63, oil-wet yields significant higher cumulative water production for both waterflood and gas flood period because the formation prefers to adhere oil more than water. For cumulative gas production, oil-wet provides higher gas production for both eaterflood and gas flood period.

Although oil-wet yields more oil recovery factor than water-wet, but it consumes much more times than water-wet.

5.4.3.2 Dip angle of 30 degrees

As shown is Figure 5.102, oil recovery factor is the same trend with a reservoir with 15 degree dip angle but the production period is shorter.

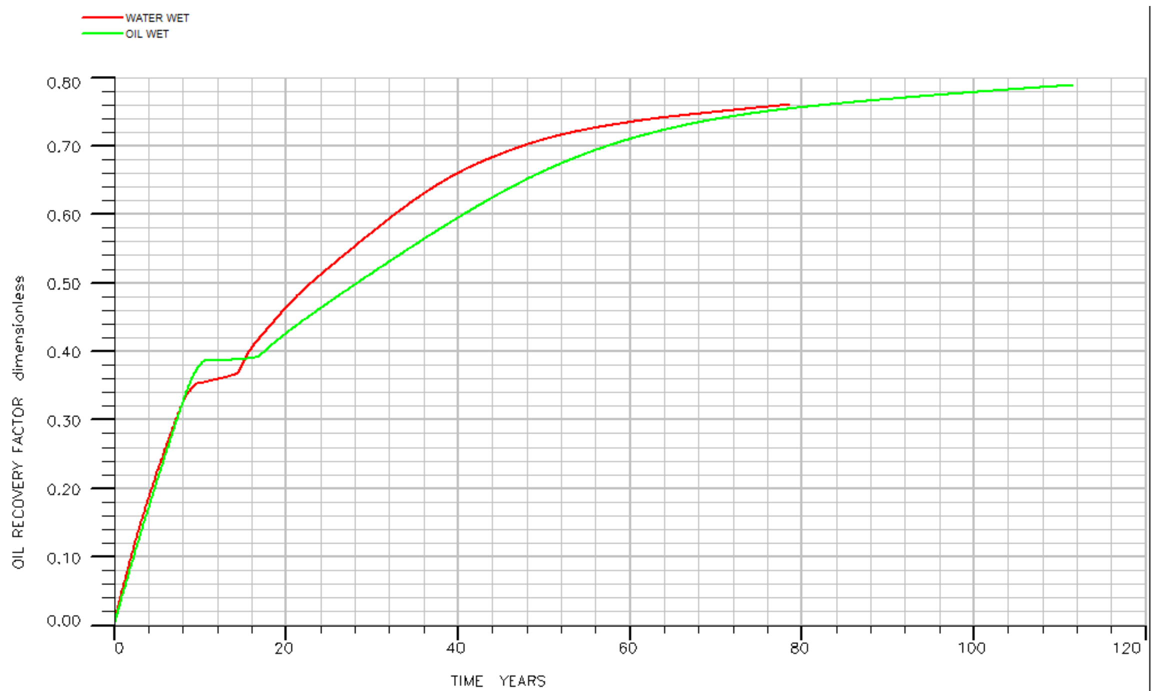

Figure 5.110 : Oil recovery factor for each type of wettability (30-degree dip angle)

Table 5.64 : Summary for each type of wettability (waterflood period)

Case	**Time (year)**	**Cumulative water production (MMSTB)**	**Cumulative gas production (BSCF)**	**Oil recovery factor (%)**
Water-wet	9.66	0.46	5.43	35.42
Oil-wet	10.41	1.1	9.33	38.71

Table 5.65 : Summary for each type of wettability (at economic constraint)

Case	**Time (year)**	**Cumulative water production (MMSTB)**	**Cumulative gas production (BSCF)**	**Oil recovery factor (%)**
Water-wet	78.41	13.57	191.4	76
Oil-wet	111	23.72	230.89	78.82

As shown in Tables 5.64-5.65, oil-wet yields significant higher cumulative water production for both waterflood and gas flood period. For cumulative gas production, oil-wet provides higher gas production for both waterflood and gas flood period.

Although oil-wet yields more oil recovery factor than water-wet, but it consumes much more times than water-wet.

5.4.3.3 Dip angle of 60 degrees

As shown is Figure 5.103, oil recovery factor is the same trend with a reservoir with 15 degree dip angle but the production period is shorter.

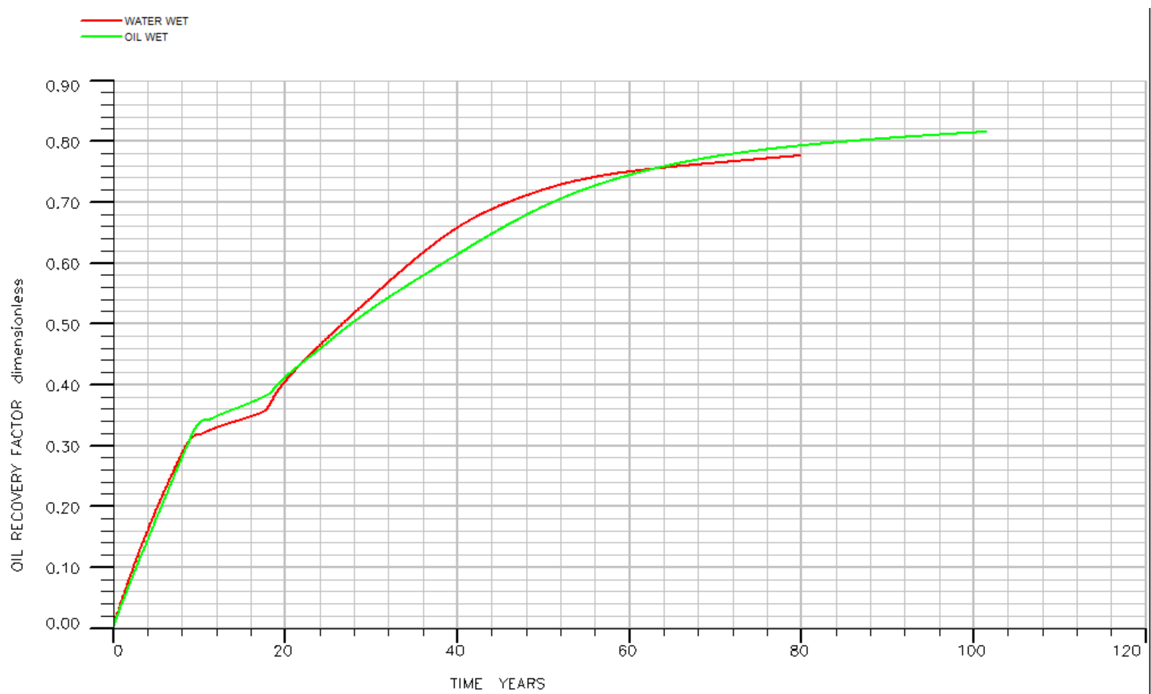

Figure 5.111 : Oil recovery factor for each type of wettability

(60-degree dip angle)

Table 5.66 : Summary for each type of wettability (waterflood period)

Case	Time (year)	Cumulative water production (MMSTB)	Cumulative gas production (BSCF)	Oil recovery factor (%)
Water-wet	9.62	0.29	5.15	31.83
Oil-wet	10.35	0.59	8.37	34.15

Table 5.67 : Summary for each type of wettability (at economic constraint)

Case	Time (year)	Cumulative water production (MMSTB)	Cumulative gas production (BSCF)	Oil recovery factor (%)
Water-wet	79.74	13.28	202.33	77.61
Oil-wet	101	20.98	271.04	81.53

As shown in Tables 5.66-5.67, oil-wet yields significant higher cumulative water production for both waterflood and gas flood period because the formation prefers to adhere oil more than water. For cumulative gas production, oil-wet provides higher gas production for both eaterflood and gas flood period.

Although oil-wet yields more oil recovery factor than water-wet, but it consumes much more times than water-wet.

When we compared the oil recovery factor for the reservoir with all dip angle, a reservoir with 60 degree dip angle yields the highest oil recovery factor and it also consumes the shortest time of production period.

CHAPTER VI

CONCLUSION AND RECOMMENDATION

In this chapter, we conclude DDP performance under different conditions. Five important parameters which are dip angle of the reservoir, stopping criteria for waterflooding, water injection rate, gas injection rate and well pattern are discussed in this chapter that allow us to identify the best condition for DDP. The results of sensitivity studies allow us to know the effect of uncertainty in relative permeability, vertical to horizontal permeability ratio, and wettability on DDP performance. Several recommendations are also provided.

6.1 Conclusion

For simulations based on water cut criteria used to determine the stopping time for water injection, we perform 4 simulation based different WCT which are 20%, 40%, 60%, and 80%. The more the WCT that we use as the stopping time for water injection, the more the oil recovery factor. Although WCT criteria of 80% gains the highest oil recovery factor, the oil recovery factor is not much higher than the one with 60% WCT criteria. However, the amount of water production and the production life are quite high when compared with those in the other cases. So, the case in which water injection is stopped when the water cut is 60% is selected because it provides good oil recovery factor while the amount of water production and the production life are not too high.

In term of water and gas injection rate, injecting with water rate of 8000 RB/D and gas rate of 8000 RB/D yields the best oil recovery and the shortest production period among the injection criteria. If we use the injection rate more than 8000 RB/D, the injection pressure will exceed the formation fracture pressure.

In this study, we perform a study for 6 different well patterns which are pattern of 2 vertical wells, 4 vertical wells, 4 vertical wells with 2 injectors, 8 vertical wells, 2 horizontal wells and vertical with horizontal wells to identify the most appropriate well pattern. For the first 30 years of production, the results show that using the pattern of horizontal injector up dip with horizontal producer down dip yields the highest oil recovery factor in a reservoir with 15 and 60 degree dip angle. For a reservoir with 30 degree dip angle, pattern of 8 vertical wells provides the highest oil recovery factor. However, the pattern of 2 horizontal wells yields only a slightly lower recovery factor than the pattern of 8vertical wells.

When we consider reservoir dip angle, a reservoir with 60 degree dip angle yields the best DDP performance. We can conclude that the more the dip angle, the more the oil recovery factor and the less production period due to more effect from gravity drainage.

For three-phase relative permeability correlations, the oil recovery factors from ECLIPSE default, Stone I, and Stone II models are slightly different. This is because the three correlations yield similar oil production profiles.

In term of vertical to horizontal permeability ratio, the case in which k_v/k_h is 1, shows significantly higher oil recovery factor and less production period than other cases because fluids in the reservoir have higher ability to flow in the vertical direction.

The effects of wettability type are also investigated. The results show that type of wettability has a large effect on the performance of DDP. Each type of wettability has a good potential for different periods. Water-wet is better at the early time of DDP while oil-wet shows the better production performance at the late time.

6.2 Recommendations

1. To verify the relative permeability correlation, we have to perform DDP in pilot test that will allow us to know which correlation provides correct result in the real situation.
2. Besides DDP, there are other methods that can improved oil recovery such as GAGD, SWCD. We should study the performance of those methods and compared them with DDP that will allow us to identify the best strategy to improved oil recovery in this reservoir.
3. In this study, we assume our reservoir to be homogenous. Our suggestion is to study the effect of heterogeneity on the performance of DDP.

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APPENDIX

APPENDIX

ECLIPSE 100 INPUT DATA FOR MODELS

Reservoir model

The reservoir simulation model is constructed by inputting the required data in Eclipse simulator. The geological model comprises of number of cells or blocks in the direction of *X*, *Y* and *Z*. The number of block in this study is 73 x 31 x 21.

1. Case Definition

Simulator : BlackOil

Model dimensions

Number of grid in x direction : 73

Number of grid in y direction : 31

Number of grid in z direction : 21

Simulation start date : 1 Jan 2000

Grid type : Cartesian

Geometry type : Corner Point

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

Solution type : Fully Implicit

2. Grid

Properties

Active Grid Block	X(1-73) = 1
	Y(1-31) = 1
	Z(1-21) = 1
X Permeability	: 32.529 md

Y Permeability : 32.529 md

Z Permeability : 32.529 md

Porosity : 0.1509

Dip angle : 30 degree in base case

Grid block sizes : based on calculation with dip angle

Geometry

Grid Block Coordinate Lines

Grid Block Corners

Grid data units

Grid Axes wrt Map Coordinatesr

3. PVT

Fluid densities at surface conditions

Oil density : 51.6375 lb/ft3

Water density : 62.42841 lb/ft3

Gas density : 0.04981752 lb/ft3

Water PVT properties

Reference pressure (Pref) : 3000 psia

Water FVF at Pref : 1.021057 rb/stb

Water compressibility : 3.083002 x 10-6 psi-1

Water viscosity at Pref : 0.3051548 cp

Water viscosity : 3.350528 x 10-6 psi-1

Live oil PVT properties (dissolved gas)

Rs (Mscf /stb)	Pbub (psia)	FVF (rb /stb)	Visc (cp)
0.00128	14.7	1.06912	1.32774
	277.084	1.05225	1.40853
	539.468	1.0518	1.55204
	801.853	1.05164	1.74084
	1064.24	1.05156	1.97375
	1326.62	1.05151	2.25323
	1589.01	1.05148	2.58341
	1851.39	1.05145	2.96939
	2113.77	1.05144	3.41702
	2376.16	1.05142	3.93262
	2588.57	1.05141	4.40441
	3000	1.0514	5.47133
	3163.31	1.0514	5.95564
	3425.69	1.05139	6.8122
	3688.08	1.05138	7.77152
	3950.46	1.05138	8.84017
	4212.85	1.05138	10.0243
	4475.23	1.05137	11.3293
	4737.62	1.05137	12.7599
	5000	1.05137	14.3197
0.04402	277.084	1.0872	1.08195
	539.468	1.07724	1.11364
	801.853	1.07382	1.1627
	1064.24	1.07209	1.22551
	1326.62	1.07104	1.30047
	1589.01	1.07034	1.38683
	1851.39	1.06984	1.48424
	2113.77	1.06947	1.59259
	2376.16	1.06917	1.71191
	2588.57	1.06898	1.81657
	3000	1.06868	2.04008
	3163.31	1.06859	2.13647
	3425.69	1.06845	2.30053
	3688.08	1.06833	2.47597
	3950.46	1.06823	2.6628

	4212.85	1.06815	2.86095
	4475.23	1.06807	3.07031
	4737.62	1.068	3.29068
	5000	1.06794	3.52178
0.09824	539.468	1.11076	0.89844
	801.853	1.10292	0.92289
	1064.24	1.09897	0.95678
	1326.62	1.09659	0.99861
	1589.01	1.095	1.04756
	1851.39	1.09386	1.10313
	2113.77	1.093	1.16503
	2376.16	1.09234	1.23305
	2588.57	1.0919	1.29252
	3000	1.09122	1.41871
	3163.31	1.091	1.47276
	3425.69	1.09069	1.56428
	3688.08	1.09043	1.66147
	3950.46	1.0902	1.76423
	4212.85	1.09	1.87247
	4475.23	1.08982	1.98603
	4737.62	1.08967	2.10475
	5000	1.08953	2.22845
0.15837	801.853	1.13761	0.77039
	1064.24	1.13071	0.79085
	1326.62	1.12657	0.81733
	1589.01	1.1238	0.84905
	1851.39	1.12182	0.88552
	2113.77	1.12034	0.92642
	2376.16	1.11918	0.97151
	2588.57	1.11842	1.01098
	3000	1.11725	1.09467
	3163.31	1.11687	1.13047
	3425.69	1.11633	1.19096
	3688.08	1.11587	1.25505
	3950.46	1.11548	1.32263
	4212.85	1.11513	1.39359
	4475.23	1.11482	1.46782
	4737.62	1.11455	1.54519

	5000	1.11431	1.62555
0.22273	1064.24	1.16708	0.67734
	1326.62	1.16066	0.69511
	1589.01	1.15639	0.71706
	1851.39	1.15333	0.74274
	2113.77	1.15104	0.77182
	2376.16	1.14926	0.80408
	2588.57	1.14809	0.8324
	3000	1.14628	0.89259
	3163.31	1.1457	0.91835
	3425.69	1.14488	0.96188
	3688.08	1.14417	1.00796
	3950.46	1.14356	1.05651
	4212.85	1.14303	1.10742
	4475.23	1.14255	1.1606
	4737.62	1.14214	1.21594
	5000	1.14176	1.27334
0.29047	1326.62	1.19883	0.60688
	1589.01	1.19266	0.62266
	1851.39	1.18825	0.64151
	2113.77	1.18496	0.66313
	2376.16	1.18239	0.68732
	2588.57	1.1807	0.70865
	3000	1.17811	0.75416
	3163.31	1.17727	0.77368
	3425.69	1.17609	0.80668
	3688.08	1.17508	0.84164
	3950.46	1.1742	0.87847
	4212.85	1.17343	0.91709
	4475.23	1.17276	0.9574
	4737.62	1.17215	0.99933
	5000	1.17162	1.04278
0.36102	1589.01	1.23262	0.55164
	1851.39	1.22655	0.56586
	2113.77	1.22202	0.58243
	2376.16	1.21849	0.60114
	2588.57	1.21617	0.61775
	3000	1.21262	0.65335

	3163.31	1.21146	0.66867
	3425.69	1.20984	0.69462
	3688.08	1.20846	0.72213
	3950.46	1.20725	0.75113
	4212.85	1.2062	0.78156
	4475.23	1.20528	0.81332
	4737.62	1.20445	0.84636
	5000	1.20371	0.88059
0.434	1851.39	1.26827	0.50711
	2113.77	1.26223	0.52007
	2376.16	1.25755	0.53487
	2588.57	1.25447	0.54811
	3000	1.24975	0.57666
	3163.31	1.24822	0.589
	3425.69	1.24607	0.60993
	3688.08	1.24423	0.63217
	3950.46	1.24264	0.65565
	4212.85	1.24124	0.68029
	4475.23	1.24002	0.70603
	4737.62	1.23892	0.73282
	5000	1.23795	0.76057
0.50915	2113.77	1.30566	0.47039
	2376.16	1.29959	0.4823
	2588.57	1.2956	0.49303
	3000	1.28949	0.51636
	3163.31	1.28751	0.52649
	3425.69	1.28474	0.54371
	3688.08	1.28236	0.56206
	3950.46	1.2803	0.58145
	4212.85	1.2785	0.60184
	4475.23	1.27692	0.62316
	4737.62	1.27551	0.64535
	5000	1.27425	0.66836
0.58623	2376.16	1.34468	0.43954
	2588.57	1.3396	0.44836
	3000	1.33186	0.4677
	3163.31	1.32936	0.47613
	3425.69	1.32584	0.49053

	3688.08	1.32283	0.50591
	3950.46	1.32023	0.5222
	4212.85	1.31795	0.53934
	4475.23	1.31595	0.5573
	4737.62	1.31417	0.57601
	5000	1.31258	0.59542
0.64993	2588.57	1.37739	0.41793
	3000	1.36812	0.43468
	3163.31	1.36512	0.44202
	3425.69	1.36092	0.45459
	3688.08	1.35732	0.46804
	3950.46	1.35421	0.48232
	4212.85	1.35149	0.49738
	4475.23	1.3491	0.51316
	4737.62	1.34697	0.52962
	5000	1.34507	0.54671

Dry gas PVT properties (no vapourised oil)

Pressure (psia)	FVF (rb /stb)	Visc (cp)
14.7	225.771	0.01325
277.084	11.6844	0.01344
539.468	5.86041	0.01374
801.853	3.85571	0.01413
1064.24	2.84654	0.0146
1326.62	2.24321	0.01515
1589.01	1.84548	0.01578
1851.39	1.56657	0.01648
2113.77	1.36258	0.01725
2376.16	1.20883	0.01808
2588.57	1.11063	0.01878
3000	0.96701	0.02019
3163.31	0.92258	0.02076
3425.69	0.86218	0.02168
3688.08	0.81251	0.02259
3950.46	0.77111	0.0235
4212.85	0.73619	0.02439

4475.23	0.70639	0.02527
4737.62	0.6807	0.02613
5000	0.65832	0.02696

Rock properties (For ECLIPSE 100)

Reference pressure : 3000 psia

Rock compressibility : 3.013923 x 10-6 psi^{-1}

4. SCAL

Water/oil saturation functions

S_w	k_{rw}	k_{ro}	P_c (psia)
0.3	0	0.8	0
0.344444	0.009877	0.561866	0
0.388889	0.039506	0.376406	0
0.433333	0.088889	0.237037	0
0.477778	0.158025	0.137174	0
0.522222	0.246914	0.070233	0
0.566667	0.355556	0.02963	0
0.611111	0.483951	0.008779	0
0.655556	0.632099	0.001097	0
0.7	0.8	0	0
1	0.8	0	0

Gas/oil saturation functions

Sg	Krg	Kro	Pc (psia)
0	0	0.8	0
0.15	0	0.3375	0
0.20625	0.001563	0.226099	0
0.2625	0.0125	0.142383	0
0.31875	0.042188	0.082397	0
0.375	0.1	0.042188	0
0.43125	0.195313	0.017798	0
0.4875	0.3375	0.005273	0

0.54375	0.535938	0.000659	0
0.6	0.8	0	0
0.7	0.8	0	0

5. Initialization

Equilibration data specification

Datum depth : 5,000 ft

Pressure at datum depth : 2,242 psia

WOC depth : 12000 ft

GOC depth : 5000 ft

6. Regions : N/A

7. Schedule

In reservoir simulation model, each production well setting is described as follows:

7.1 Oil production well

Well specification

Well name : WELL1

Group : 1

I location : 12

J location : 16

Preferred phase : OIL

Inflow equation : STD

Automatic shut-in instruction : SHUT

Crossflow : YES

Density calculation : SEG 106

Well connection data

Well connection data : WELL1

K upper : 1

K lower : 21

Open/shut flag : OPEN

Well bore ID : 0.5522083 ft

Direction : Z

Production well control

Well : WELL1

Open/shut flag : OPEN

Control : RESV

Liquid rate : Depend on injection rate

BHP target : 500 psia

Production well economic limits

Well : WELL1

Workover procedure : NONE

End run : YES

Quantity for economic limit : RATE

Secondary workover procedure : NONE

There is a few difference in setting between production well and injection well. The first two setting, well specification and well connection data, are the same as previous but we need to change the keyword from production well control to be injection well control. When we start gas injection we change only the preferred phase and injection rate in injection well control.

7.2 Water injection well

Well specification

Well name	: WELL2
Group	: WELL
I location	: 62
J location	: 16
Preferred phase	: WATER
Inflow equation	: STD
Automatic shut-in instruction	: SHUT
Crossflow	: YES
Density calculation	: SEG

Well connection data

Well connection data	: WELL2
K upper	: 1
K lower	: 21
Open/shut flag	: OPEN
Well bore ID	: 0.5522083 ft
Direction	: Z

Injection well control

Well	: WELL2
Injector type	: WATER
Open/shut flag	: OPEN
Control mode	: RESV
Liquid surface rate	: Depend on injection strategies
BHP target	: Depend on formation fracture pressure

7.3 Gas injection well

Well specification

Well name	: WELL1
Group	: WELL
I location	: 12
J location	: 16
Preferred phase	: GAS
Inflow equation	: STD
Automatic shut-in instruction	: SHUT
Crossflow	: YES
Density calculation	: SEG

Well connection data

Well connection data	: WELL1
K upper	: 1
K lower	: 21
Open/shut flag	: OPEN
Well bore ID	: 0.5522083 ft
Direction	: Z

Injection well control

Well	: WELL1
Injector type	: GAS
Open/shut flag	: OPEN
Control mode	: RESV
Liquid surface rate	: Depend on injection strategies
BHP target	: Depend on formation fracture pressure

VITAE

Wisarut Satitkanitkul was born on April 18, 1987 in Bangkok, Thailand. He graduated from Department of Computer Engineering from the Faculty of Engineering, Kasetsart University in 2009. After graduating, he worked for Bisnews AFE Thailand for one year and then he started his to study in the Master of Petroleum Engineering program at the Department of Mining and Petroleum Engineering Faculty of Engineering in 2010.