EVALUATION OF GAS DUMPFLOOD IN WATER-FLOODED RESERVOIR

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การประเมินกระบวนการแทนที่แบบถ่ายเทของก๊าซในแหล่งกักเก็บน้ำมันที่ถูกแทนที่ด้วยน้ำ

นายณัฐดนัย อุไรรัตน์

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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กระบวนการแทนที่แบบถ่ายเทของก๊าซในแหล่งกักเก็บน้ำมันที่ถูกแทนที่ด้วยน้ำคือวิธีการเพิ่มการผลิตปริมาณน้ำมันอย่างหนึ่ง โดยการถ่ายเทของก๊าซจากแหล่งกักเก็บก๊าซที่อยู่ต่ำกว่าแหล่งกักเก็บน้ำมันที่สนใจในช่วงเวลาหลังจากเริ่มขบวนการฉีดอัดน้ำ ในการศึกษานี้หกตัวแปรที่กำหนดถูกพิจารณาเพื่อตัดสินกลยุทธ์ที่เหมาะสมสำหรับวิธีการนี้ การจัดเรียงตำแหน่งหลุมที่ดีที่สุดสำหรับแหล่งกักเก็บไม่ลาดเอียงคือสองหลุมผลิตในแนวนอนที่มีระยะห่าง 2000 ฟุตระหว่างหลุมผลิตและหลุมฉีดอัดแบบแนวตั้ง สำหรับแหล่งกักเก็บที่มีความเอียง 15 และ 30 องศา การจัดเรียงตำแหน่งหลุมที่ดีที่สุดคือหนึ่งหลุมผลิตในแนวนอนที่มีระยะห่าง 4000 ฟุต การใช้เกณฑ์อัตราส่วนการผลิตน้ำที่ 1 เปอร์เซ็นต์เป็นกลยุทธ์การผลิตที่ดีที่สุด ช่วงการเจาะหลุมของแหล่งกักเก็บก๊าซที่ไม่ลาดเอียงคือ 20 เปอร์เซ็นต์จากล่างสุด สำหรับแหล่งกักเก็บที่มีความเอียง 15 และ 30 องศา ช่วงการเจาะหลุมของแหล่งกักเก็บก๊าซไม่สามารถเปลี่ยนแปลงได้เนื่องจากความดันทำให้หลุมแตก ค่าที่เลือกสำหรับอัตราการฉีดอัดน้ำและอัตราการผลิตของเหลวของแหล่งกักเก็บไม่ลาดเอียงคือ 3000 และ 7000 บาร์เรลสแตนดาร์ดต่อวันตามลำดับ สำหรับแหล่งกักเก็บเอียง 15 และ 30 องศา การจัดกลุ่มของอัตราการฉีดอัดน้ำและอัตราการผลิตของเหลวที่แตกต่างกันจะให้ผลคล้ายคลึงกัน

สำหรับการวิเคราะห์การแปรผัน เมื่ออัตราส่วนความสามารถในการซึมผ่านแนวตั้งต่อแนวนอนของแหล่งกักเก็บไม่ลาดเอียงมีค่าน้อยลง จะสามารถผลิตน้ำมันเพิ่มขึ้นได้เล็กน้อย แต่ในกรณีที่อัตราส่วนน้อยเกินไป จะทำให้ลดการผลิตปริมาณน้ำมันได้ปานกลางเนื่องมาจากน้ำมันไม่สามารถเคลื่อนตัวลงมายังหลุมผลิตได้ สำหรับแหล่งกักเก็บเอียง 15 องศา ไม่มีความแตกต่างของปริมาณน้ำมันที่ผลิตได้ท่ามกลางการเปลี่ยนแปลงอัตราส่วนความสามารถในการซึมผ่านแนวตั้งต่อแนวนอน สำหรับแหล่งกักเก็บเอียง 30 องศา เมื่ออัตราส่วนเพิ่มขึ้น จะสามารถเพิ่มการผลิตปริมาณน้ำมันได้เล็กน้อย ในแง่ของความหนาของแหล่งกักเก็บก๊าซ เมื่อความหนาเพิ่มขึ้น จะสามารถเพิ่มการผลิตปริมาณน้ำมันได้เล็กน้อยในแหล่งกักเก็บไม่ลาดเอียงและแหล่งกักเก็บที่มีความเอียง 30 องศา สำหรับแหล่งกักเก็บเอียง 15 องศา การผลิตปริมาณน้ำมันเพิ่มขึ้นปานกลาง การเพิ่มขึ้นของความแตกต่างของความลึกระหว่างแหล่งกักเก็บน้ำมันและก๊าซช่วยเพิ่มการผลิตปริมาณน้ำมันได้เล็กน้อย ยกเว้นแต่ในกรณีที่มีความต่างของความลึก 3000 ฟุต สำหรับแหล่งกักเก็บไม่ลาดเอียงเนื่องจากค่าสกิน ในแง่ของสัดส่วนน้ำมันต่ำสุดจากการแทนที่ด้วยน้ำ การลดลงของน้ำมันตกค้างทำให้ปริมาณน้ำมันที่ผลิตได้มีค่าเพิ่มขึ้น ยกเว้นในกรณีของแหล่งกักเก็บเอียง 30 องศา ผลที่ได้ไม่ได้แสดงแนวโน้มใดๆ การลดลงของสัดส่วนน้ำมันต่ำสุดจากการแทนที่ด้วยก๊าซสามารถเพิ่มการผลิตปริมาณน้ำมันได้ปานกลางมากกว่าการลดลงของสัดส่วนน้ำมันต่ำสุดจากการแทนที่ด้วยน้ำ ปริมาณน้ำมันที่ได้มาลดลงเมื่อความหนืดของน้ำมันดั้งเดิมเพิ่มขึ้น

ภาควิชา วิศวกรรมเหมืองแร่และปิโตรเลียม ลายมือชื่อนิสิต ....

สาขาวิชา วิศวกรรมปิโตรเลียม ลายมือชื่อ อ.ที่ปรึกษาหลัก ....

ปีการศึกษา 2557

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Gas dumpflood in water-flooded reservoir is a method to increase oil recovery by dumping gas from a gas reservoir underneath into the subject oil reservoir after initial period of water flooding. In this study, six design parameters are investigated to determine the suitable strategy of this method. The best well arrangement for 0 dip angle is two horizontal producers with 2,000 ft distance between producers and the vertical injector. For 15° and 30° dip angle, the best well arrangement is one horizontal producer with 4,000 ft distance. Using of 1% water cut criteria yields the best production strategy. The perforation interval of gas reservoir of 0 dip angle is 20% interval from bottom. For 15° and 30° dip angle, perforation interval cannot be varied due to fracture pressure. The best water injection and production rates of 0 dip angle are 3,000 and 7,000 STB/D, respectively. For 15° and 30° dip angle, different combinations of both water injection and liquid production rates yield comparable results.

For sensitivity analysis, lower k_v/k_h ratio of 0° dip angle slightly increases oil recovery but too low ratio moderately reduces oil recovery due to the fact that oil cannot move down to producers. For 15° dip angle, there is insignificant difference of oil recovery among different anisotropy ratios. For 30° dip angle, higher ratio slightly increases oil recovery. In term of gas thickness, higher gas thickness slightly increases oil recovery for 0° and 30° dip angle. For 15° dip angle, oil recovery moderately increases. Higher depth difference between oil and gas reservoir slightly increases oil recovery except for the case of 3,000 ft depth difference of 0° dip angle due to skin factor. In term of S_{orw}, the lower the residual oil, the higher the oil recovery except for the case of 30° dip angle that the results show no trend. The reduction of S_{org} shows moderately higher oil recovery than the reduction of S_{orw}. Lower oil recovery is obtained when original oil viscosity increases.

Department:	Mining and Petroleum Engineering	Student's Signature	....
		Advisor's Signature	....
Field of Study:	Petroleum Engineering		
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CONTENTS

Page

Page

Page

List of Tables

Page

List of Figures

List of Abbreviations

BSCF	Billion standard cubic feet
DDP	Double displacement process
cp	Centipoise
FRAC.S.G.	Fracturing pressure gradient
ft	Feet
GOR	Gas-oil ratio
lb/ft^3	Pound per cubic foot
md	Millidarcy
MMSCF/D	Million standard cubic feet per day
MMSTB	Million stock tank barrel
MSCF/STB	Thousand standard cubic feet per stock tank barrel
OOIP	Original oil-in-place
psi	Pound per square inch
psia	Pound per square inch absolute
PV	Pore volume
PVT	Pressure-Volume-Temperature
RB/D	Reservoir barrel per day
RB/STB	Reservoir barrel per stock tank barrel
SCAL	Special core analysis
SCF/STB	Standard cubic feet per stock tank barrel
STB	Stock tank barrel
STB/D	Stock tank barrel per day
TVD	True vertical depth

Nomenclatures

μ_g	Viscosity of gas
μ_o	Viscosity of oil
μ_w	Viscosity of water
ρ_w	Density of water
ρ_o	Density of oil
θ, α	Dip angle of the reservoir
A	Cross sectional area
f_g	Fractional flow of gas in reservoir
f_w	Fractional flow of water in reservoir
g	Acceleration due to gravity
k	Absolute permeability
k_h	Horizontal permeability
k_{rg}	Relative permeability to gas
k_{ro}	Relative permeability to oil
k_{rocw}	Oil relative permeability in the presence of connate water only
k_{rog}	Oil relative permeability for a system with oil, gas, and connate water
k_{row}	Oil relative permeability for a system with oil and water only
k_{rw}	Relative permeability to water
k_v	Vertical permeability
P_c	Capillary pressure
$q_{g,crit}$	Critical rate for gas by-passing
q_i	Water injection rate

q_o	Oil flow rate
q_t	Total flow rate
q_w	Water flow rate
$q_{w,crit}$	Critical rate for water by-passing
R_s	Solution gas-oil ratio
S_g	Gas saturation
S_o	Oil saturation
S_{om}	Minimum residual oil saturation
S_w	Water saturation
S_{wco}	Connate water saturation

CHAPTER I

INTRODUCTION

1.1 Background

According to the increasing demand on energy consumption, increasing oil recovery from depleted reservoir becomes significant. One of the methods that can be used to increase oil recovery is gas injection. The idea of using gas is to maintain reservoir pressure, improve the properties of oil and displace some trapped oil inside pore space. Gas injection with carbon dioxide and natural gas is proved to be effective with its availability and favorable properties. In Gulf of Thailand, most of gas reservoirs have high methane content and some have high carbon dioxide content (non-commercial gas reservoirs). In order to make these gas reservoirs useful without much of additional investment is to perform gas dumpflood into target oil reservoir.

Gas dumpflood in water flooded reservoir is based on the same concept as double displacement (DDP), the method of injecting immiscible gas to water invaded oil reservoir. Instead of injecting gas from surface, gas is flowed from high pressure gas formation to the lower pressure water-flooded reservoir, allowing gas to cross-flow between two zones of interest. By this method, there's no need of having surface facility for injecting gas into the target oil reservoir. Therefore, additional oil gain can be produced without much capital investment.

In this study, hypothetical reservoir models are created via reservoir simulation. ECLIPSE 100 is used as reservoir simulator to investigate the performance of different gas dumpflood recovery processes. There are six design parameters: 1) well types which are vertical and horizontal 2) well location 3) completion interval 4) water injection rate 5) liquid production rate 6) starting time for gas dumpflood process which are all determined to provide the best performance. Also, the effect of reservoir and fluid properties such as dip angle, vertical/horizontal permeability, thickness of gas reservoir, depth difference between gas and oil reservoir, residual oil saturation and oil viscosity are investigated.

1.2 Objectives

1. To determine the best conditions for gas dumpflood strategy in water-flooded reservoir.

2. To study the effect of different design parameters which are well type, well location, completion interval, water injection rate, oil production rate, starting time for gas dumpflood on gas dumpflood process in water-flooded reservoir

3. To study the effect of reservoir and different fluid properties which are dip angle, vertical to horizontal permeability, thickness of gas reservoir, depth difference between gas and oil reservoirs, residual oil saturation, oil viscosity on gas dumpflood process in water-flooded reservoir.

1.3 Outline of methodology

The methodology is summarized into flow chart as shown in Figure 1.1. The detailed methodology is described in Chapter 4.

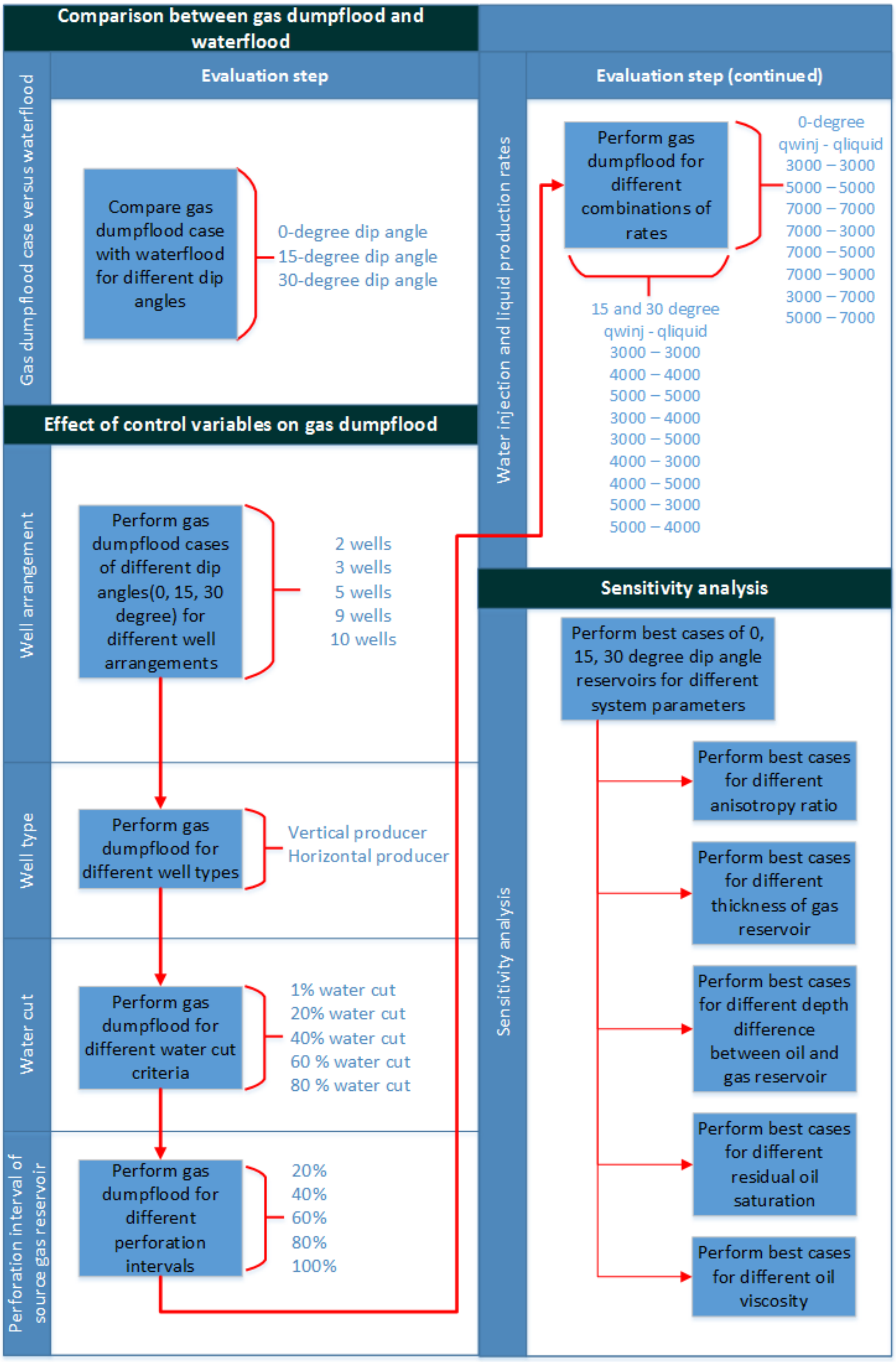


Figure 1. 1 Outline methodology in flow chart

1.4 Thesis outline

This thesis consists of six chapters as listed below:

Chapter I introduces the background, objectives and methodology of this study.

Chapter II presents some previous works that related to this study.

Chapter III provides some general concepts and relevant theory to this study.

Chapter IV illustrates reservoir model details including fluid properties, rock properties and well schedule which are used in this study.

Chapter V discusses and summarizes the simulation results on design parameters and system parameters.

Chapter VI provides conclusion and recommendation on this study.

CHAPTER II
LITERATURE REVIEW

2.1 Double displacement process

Al Sumaiti el al. [1] performed experiment and numerical modeling of double displacement process (DDP) in tight fractured carbonate reservoirs. They stated that DDP has been successful in single-porosity sandstone. Thus, we can expect similar results in vertical fractured reservoir. The core samples are obtained from offshore carbonate reservoir in Middle East. The scopes of this study are 1) experimentation of DDP in fractured cores using a high-speed centrifuge, 2) numerical simulation of DDP experiment using two different approaches which are a multi-node fine grid method and a single-node transfer function method, 3) upscaling of laboratory result to field application. They concluded based on experimental and numerical simulation results that DDP could be an effective tertiary oil recovery method in fractured carbonate cores and we could expect similar results in the field provided that fractured reservoir section is thick enough gravity drainage to occur.

Carlson [2] studied the performance of Hawkins field unit under gas drive-pressure maintenance operations and development of EOR project. He defined the term DDP which means the process of gas displacement of a water invaded oil column. From his in-depth studies, he stated that Hawkins field unit can have 80% recovery efficiency from gas-drive gravity drainage and only 60% recovery efficiency from water drive. He did the three-phase centrifuge tests which indicate that average residual oil saturation can be reduced from 35% to 12% for gas driving the water invaded oil column which represents a potential recovery of 65% of oil in place after water drive. The injected gases were produced gas and inert gas. He concluded that DDP can be economically accomplished in this field by monitoring the growth of oil column using GR/N and PNC logs.

Langenberg et al. [3] studied the performance and expansion plans for double displacement process in Hawkins Field Unit. This paper documented the first

6 years of DDP project in East Fault Block as depicted in Figure 2.1. The authors described how oil gravity drainage occurring slower than expected and the optimization during gas injection. They concluded that DDP can reduce the residual oil saturation thus leading to additional oil recovery. The oil gravity drainage was occurring slower than expected because higher viscosity oil is found in bypassed-oil zones and the reason of lower oil relative permeability. Due to the slower oil gravity drainage, the rate of gas injection must be reduced for optimization in order to reduce the chance of outrunning (draining oil cannot catch up with advancing oil columns). With slower gravity drainage, it provides enough time for oil to drain by gravity to the oil column.

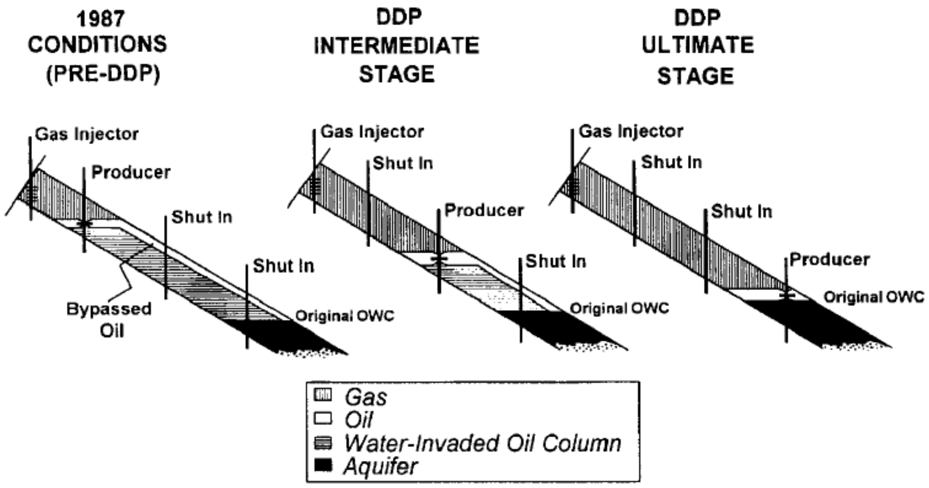


Figure 2. 1 Hawkins East fault block DDP schematic (after Langenberg et al. [3])

2.2 Dumpflood

2.2.1 Water dumpflood

Osharode et al. [4] studied application of natural water dumpflood in depleted reservoir in Egbema West. At the beginning, the production rate reduced from 32 Mbopd to an average rate of 5 Mbopd due to the pressure reduction from 3,452 to 2,650 psig. This is because of the weak aquifer support. Then, they executed the pilot water dumpflood to maintain pressure support which leads to an increase in oil recovery. By this process, previously shut-in wells can be brought back to production. The natural water dumpflood can sustain reservoir pressure at the current level of 2650 psig. After 12 years of steady production, the average reservoir pressure increased 8 psi. They concluded that pilot water dumpflood scheme in Egbema West can prove to be effective and can be applied on a full field scale.

Quttainah et al. [5] performed water dumpflood pilot project in Umm Guidair field to enhance sweep efficiency and maintain reservoir pressure. From historical data, the reservoir pressure declined from 4,050 to 3,200 psi and had low oil recovery factor. The authors performed pilot project for water dumpflood by perforating source water zone above the target zone which has higher pressure. By the concept of gravity and pressure difference, the target zone was dumped by water. The authors also designed two options of well completion as shown in Figure 2.2. They said that casing completion was more preferable than straddle completion because of lower pressure loss and very low chance of casing collapse. The authors concluded that water dumpflood could be used as a full field project in order to support falling of reservoir pressure and improve sweep efficiency with low operating cost.

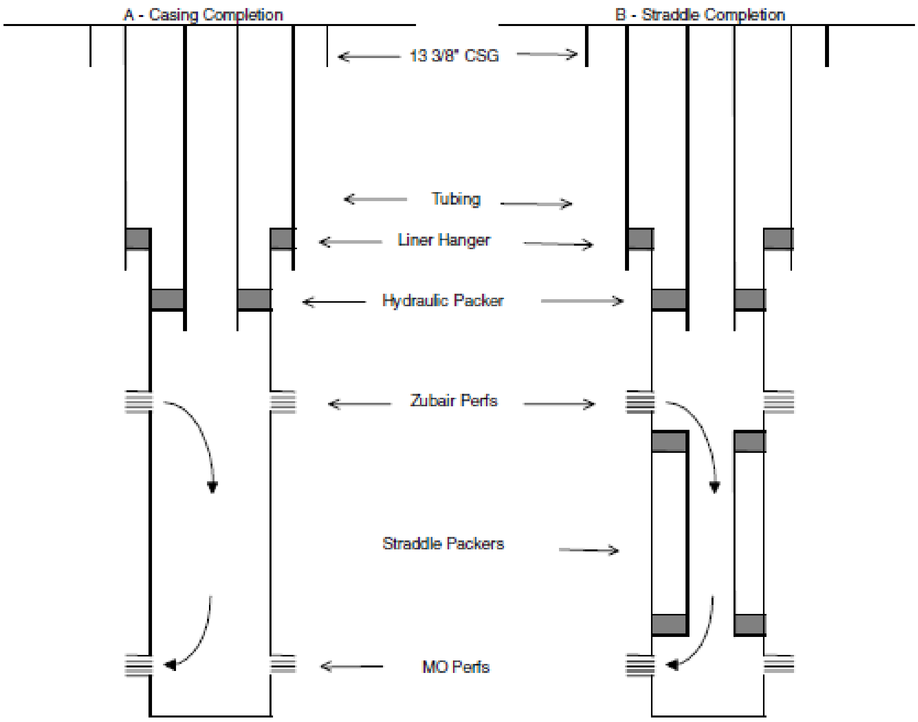


Figure 2. 2 Schematic of basic components of most popular used dumpflood well completions (after Quttainah et al. [5])

Helaly et al. [6] performed water dumpflood to overcome typical operation problems and cost of water injection. Meleiha, North East oil field had been produced for 4 years, before applying water injection due to natural depletion of pressure from 2300 to 1000 psi. However, the nearest water source is about 10 km away which can cause the problems of long length line leakage, corrosion and water blockage. And also, it would incur the cost of the maintenance of ESP and casing. Thus, they attempted to improve the production performance by water dumpflood project. From RFT measurements of the three oil zones, they indicated that the average pressure was around 400 psi. The water zone was found to be 2,250 psi and it provided the dumping rate of 1,100 BWPD contributing to three recipient zones. This project could avoid surface leakage and provided minimum cost when compared with water injection. The authors recommended that dumpflood project should have smart well completions which can control rate or increase the pressure of the injection rate, for example, down hole valves and pressure booster. They also said that water dumpflood saves the cost for facilities and suitable for remote area that requires fluid source.

Shizawi et al. [7] performed an enhancement of oil recovery through water dumpflood in satellite field. They used ESP as injector and producer in the same wellbore for allowing cross flow between two zones. For this field, it is not economic to perform a conventional water flood project. So, water dumpflood concept was used. They injected water for 10 months and kept the minimum injection rate to avoid the fracture pressure. After injection, they could observe pressure response and the oil gain was about 40%. They concluded that dumpflood is effective means and has reasonable cost. It can eliminate the requirement of surface facilities. This paper also showed that dumpflood concept is suitable for small field projects.

Fujita [8] studied a formation water dumping for the Ratawi Limestone in order to maintain pressure from natural depletion. The reservoir consists of light and heavy oil, 33 API and 28 to 9 API of which the heavy part is located under the light oil, and the bottommost is an aquifer. During depletion period, the peak of production rate was 66,000 B/D. It later declined to 33,000 B/D. The pressure was 1000 psi below the original value. After 5 years of production, water dumping can maintain the reservoir pressure. The preliminary reservoir studies stated that other methods such as gas injection for the field were not suitable. This is because of low permeability of reservoir rock about 4.6 md and low dip angle. Other artificial lifts such as subsurface pumps or gas lift were rejected because the bottom hole pressure was not below 1500 psig. He also showed some designs of water dumping wells as shown in Figure 2.3. Type A and Type B can control the shutting of dumping well by retrievable wire line bridge plug but later on, it would not be necessary because we can work over. Type C and D can cause corrosion or scale problem inside casing. So, they must be monitored frequently. In conclusion, dumping water is proved to be successful for maintaining reservoir pressure.

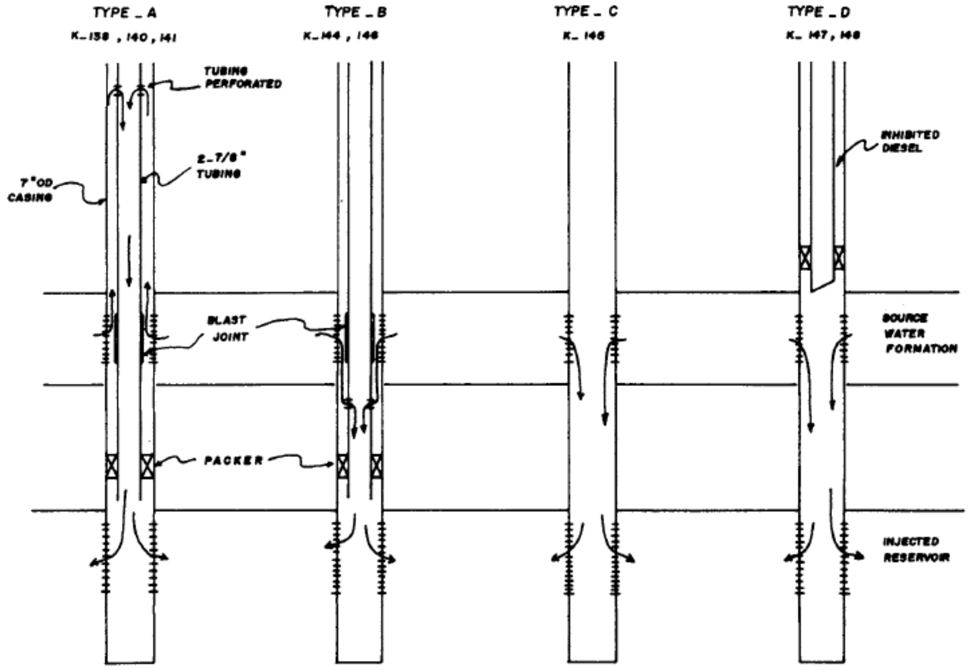


Figure 2. 3 Schematic of deepwater injectors (after Fujita [8])

2.2.2 Gas dumpflood

Rinadi et al. [9] performed a study for in-situ gas lift and gas dumpflood to improve oil recovery from a partially depleted oil reservoir at North Arthit Field, Gulf of Thailand. The authors performed the simulation to understand reservoir characteristic which leads to the method of allowing high pressure gas from underneath gas reservoir to cross flow with tubing into oil reservoir. The authors introduced two methods. The first method is in-situ gas lift as shown in Figure 2.4. They perforated gas zone in Arthit No.1 and allowed gas to flow up to increase the GOR of the well. The second method is in-situ gas dumpflood as shown in Figure 2.5. They perforated gas zone in Arthit No.2 and allowed the gas to cross flow into the oil reservoir. The distance between Arthit No.1 and Arthit No.2 is 0.3 km. These two methods provided the same results that Arthit No. 1 was reactivated again. For in-situ gas dumpflood, it caused the reservoir pressure to increase by 110 psia (from 1750 to 1860 psia) which was close to the initial pressure and later depleted as gas rate decreased. The authors expected that one of the dominant factors to successfully improve oil recovery is gas segregation due to the fact that this reservoir has a lateral homogeneity and permeability ranging from 270-570 md. The highest permeability layer at the bottom and the lowest permeability layer at the top of oil sand are suitable condition for a gravity segregation mechanism. These methods incur low cost and they have simple operation to provide suitable GOR to the well and maintain the reservoir pressure in order to improve oil recovery.

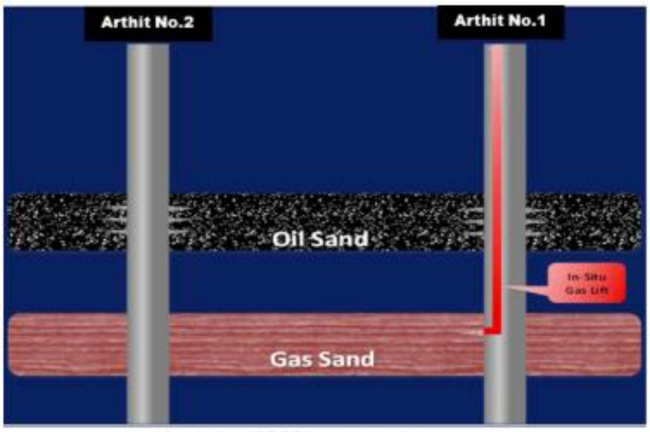


Figure 2. 4 In situ gas lift process (after Rinadi et al [9].)

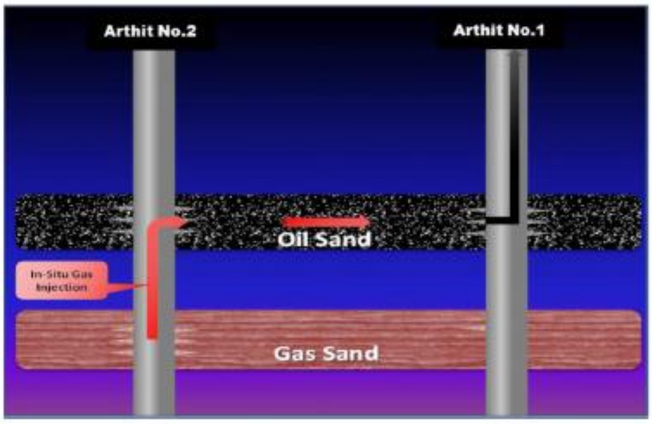


Figure 2. 5 In situ gas dumpflood process (after Rinadi et al. [9])

2.3 Gas flooding

Sohrabi and Emadi [10] studied novel insights into the pore-scale mechanisms of enhanced oil recovery by CO_2 injection. They performed an experiment of CO_2 injection into micromodel with three different oil samples and three conditions of CO_2 injection. They did the secondary recovery for water flooding and tertiary recovery for CO_2 injection. The three condition of CO_2 injection into the micromodel are 1) low pressure CO_2 injecton, 2) high pressure immiscible CO_2 injection, and 3) high pressure miscible CO_2 injection. For the first condition, they injected low pressure vapor CO_2 to displace residual oil after waterflooding. They stated that viscosity reduction and oil swelling were the mechanisms happened during CO_2 injection. The CO_2-diluted oil was displaced by film flow mechanism at very slow rate. For the second condition, they injected high pressure CO_2 above the critical point but not high enough to create miscibility. The mechanisms are CO_2 dissolution, CO_2 extraction, swelling of trapped oil and the growth of new phase within separated oil ganglia as shown in Figure 2.6. They stated that swelling of trapped oil could reduce residual oil but it did not significantly reduce like the enlargement of new phase. This new phase happened when high pressure CO_2 in liquid phase was injected after water flooding without direct contact to residual oil. The new phase occurred inside isolated oil ganglia. The enlargement of this new phase could help residual oil to reconnect again with the CO_2 stream during CO_2 injection. They also stated that this new phase had not been seen because CO_2 always had direct contact with oil even in three phases. With the gravity force, water accumulated at the bottom of the cell, leaving CO_2 and oil in direct contact. For the third condition of CO_2 injection, it created miscibility and new phase which increased recovery of oil more than the previous two conditions. In conclusion, the authors said that high pressure CO_2 could provide additional oil recovery by both immiscible and miscible.

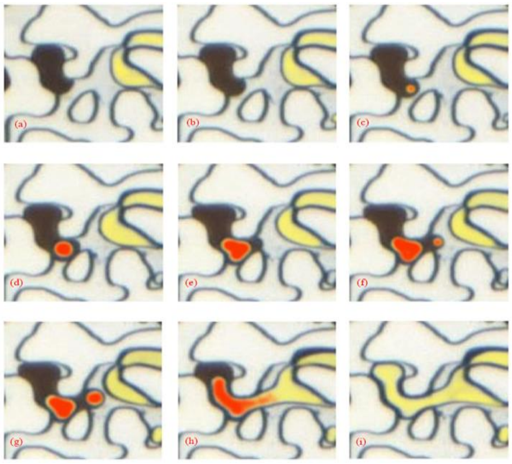


Figure 2. 6 A magnified section of the micromodel during the super-critical CO2 flood in which enlargement of the isolated oil blob as a result of formation of new phase (after Sohrabi et al. [10])

Zhang et al. [11] performed experiment on core flooding to investigate immiscible gas process performance for medium oil in south-western Saskatchewan reservoir. They stated that this reservoir had high pressure to provide good oil swelling and gas dissolution but not enough to create miscibility. They also performed experiment on phase behavior of fluid which we could see great reduction of viscosity and high swelling factor after CO_2 injection. For the core flooding experiment, they compared three different methods which are single slug CO_2 injection, simultaneous water and CO_2 injection and water alternating gas injection. They concluded that injected with pure CO_2 was better than flue gas (70%N_2, 30%CO_2) and injection of single slug CO_2 and WAG gave good result of oil recovery. For simultaneous injection method that gave lower oil recovery, they said that it may be caused by water shielding the oil from injected gas.

CHAPTER III

THEORY AND CONCEPT

3.1 Double displacement process (DDP)

Gas dumpflood in water-flooded reservoir is based on concept of double displacement process (DDP) which is a method of gas displacing a previously water displaced oil column. Figure 3.1 shows the process of gas injection after water injection process. In this figure, the original OWC has moved upward to the current OWC by water flooding which has created the water swept oil zone. After the water cut reaches the criteria, gas injection is performed at updip location to sweep water-displaced oil to the oil producer at downdip location.

Due to the inclined plane, gravity drainage mechanism can occur to increase the performance of gas injection process. The gas and water-displaced oil at interface may or may not form a segregation due to gravity depending on many factors such as permeability in the direction of dip, vertical permeability, dip angle of reservoir, injection and production rates, oil viscosity and relative permeability. Thus, the performance of DDP depends on these properties.

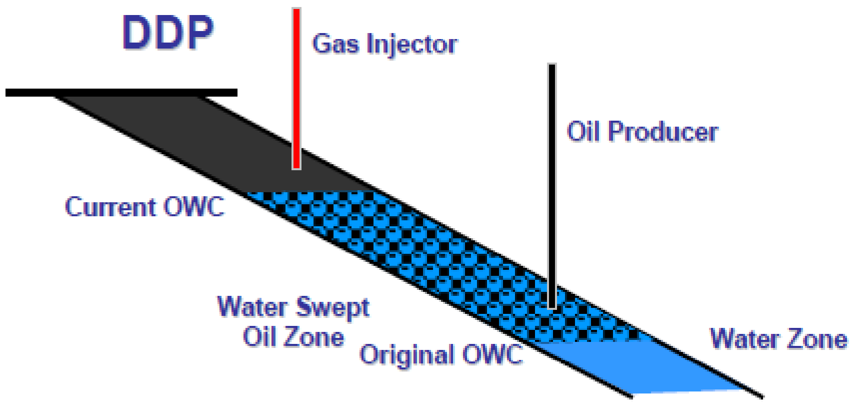


Figure 3. 1 Double displacement process (after Lepski [12])

3.2 Water flooding

Water flooding has been developed for over five decades. The use of injected water to increase oil recovery is known as secondary recovery process which is usually performed after primary recovery process or natural depletion (fluid and rock expansion, solution-gas drive, gravity drainage and aquifer influx). The primary recovery process is the use of natural reservoir energy which is pressure difference to produce oil from underground up to surface. As oil is produced, the reservoir pressure drops, and the production rate declines. With the use of water injection, the pressure of reservoir can be increased or maintained. This helps increase oil production rate and oil recovery. Water flooding not only maintains the reservoir pressure but also sweeps the oil toward the producer. The efficiency of water flooding depends mainly on mobility ratio and rock characteristics. A good waterflood should have a mobility ratio around 1 or less to reduce the fingering effect which happens when water bypasses the oil. Another beneficial factor water flooding can bring is it can mitigate the subsidence of surface formation.

There are some limitations which we should be concerned before performing water flooding.

1) Interaction between rock formation and injected water can occur; clay sensitivities, rock dissolution, rock precipitation.

2) Treatment of injected water by removing O_2, bacteria, undesirable chemicals, oil content, scale (Mg, Ca) to prevent environmental impact and production problem.

The performance of water flooding process depends on microscopic efficiency and macroscopic efficiency of immiscible displacement.

3.2.1 Microscopic displacement efficiency (E_D)

The microscopic displacement efficiency is a measure of how well the displacing fluid moves the oil once the fluid has contacted the oil. The water and oil interacts immiscibly when moving from one set of pores to another. The factors affecting microscopic efficiency are interfacial and surface tension forces, wettability, capillary pressure and relative permeability. These factors will be discussed in later section.

3.2.1.1 Residual oil saturation

Another factor affecting the performance of water flooding is residual oil saturation. There are two important numbers that can give the information of reservoir rock. The first one is S_{wc} connate-water saturation, and the second is S_{orw} residual oil saturation after water flooding process. Assuming oil formation volume factor is the same at the beginning and the end of water flood, the equation for unit-displacement efficiency is:

$$E_D = 1 - \frac{S_{orw}}{S_{oi}} \tag{3.1}$$

where S_{oi} = initial oil saturation $(1 - S_{wc})$.

Salathiel [13] showed the result of S_{orw} for water-wet and mixed-wet conditions. From Figure 3.2, the water-wet rocks are generally 10%PV higher than those for mixed-wet rocks.

Rock Sample	Permeability, md	Porosity, % BV	S_w at Time of "Contact," % PV	S_o After 25 PV of Waterflooding: Water-Wet	S_o After 25 PV of Waterflooding: Mixed-Wet
Boise (sandstone)	1,094	29.3	13.5	33.5	20.5
Upper Austin (sandstone)	596	28.0	20.0	30.0	22.9
Woodbine Outcrop (sandstone)	690	33.0	17.0	27.3	30.7
Upper Noodle (limestone)	620	21.2	18.9	40.5	28.1
Lissie (sandstone)	536	21.9	7.2	42.5	29.1

Figure 3. 2 Residual oil saturation after 25 PV of water flooding (after Salathiel [13])

3.2.2 Macroscopic displacement efficiency (E_V)

The macroscopic displacement efficiency is a measure of how well the displacing fluid has contacted the oil-bearing parts of the reservoir which is composed of two terms. E_a is the areal sweep efficiency, and E_i is the vertical sweep efficiency.

$$E_V = E_a \cdot E_i \tag{3.2}$$

There are some factors affecting macroscopic efficiency which are heterogeneities and anisotropy, mobility ratio and the arrangement of injection and production wells. Some of these factors will be discussed in later section.

3.2.2.1 Overall recovery efficiency

The overall recovery efficiency is calculated by the product of these efficiency factors:

$$E_R = E_D \cdot E_a \cdot E_i \tag{3.3}$$

The overall recovery efficiency is the product of microscopic displacement efficiency (E_D) which depends on the microscopic structure of porous medium and marcroscopic displacement efficiency (E_V) which is the product of areal sweep efficiency (E_a) and vertical sweep efficiency (E_i).

3.2.2.2 Location of injection and production wells

The arrangement of injection and production wells should be designed to: a) provide good oil productivity with suitable water injection rate and b) take advantage of reservoir characteristics such as dip, faults, and fractures. Generally, there are two kinds of flooding patterns that are used: peripheral flooding and pattern flooding.

Pattern flooding is used in reservoirs with a small dip and a large surface area. Figure 3.3 shows some of common pattern arrangements. It has been extensively studied that five-spot pattern is the most effective one. In some cases, if the reservoir can take lower injection rate than what we want, we can increase the injection wells per pattern to increase the rate by considering seven- or nine-spot pattern as shown in Table 3.1.

In peripheral flooding, the injectors are grouped together as shown in Figure 3.4. In Figure 3.4(a), the injectors are placed together so that they can inject water into aquifer or near aquifer-reservoir interface. It is like a ring of injectors circling around a group of producers. In Figure 3.4(b), injectors are grouped to inject water into reservoir or near the water-oil interface.

Table 3. 1 Ratio of producing wells to injection wells for several pattern arrangements (after Craft [14])

Pattern	Ratio of producing wells to injection wells
Four-spot	2
Five-spot	1
Seven-spot	1/2
Nine-spot	1/3
Direct-line-drive	1
Staggered-line-drive	1

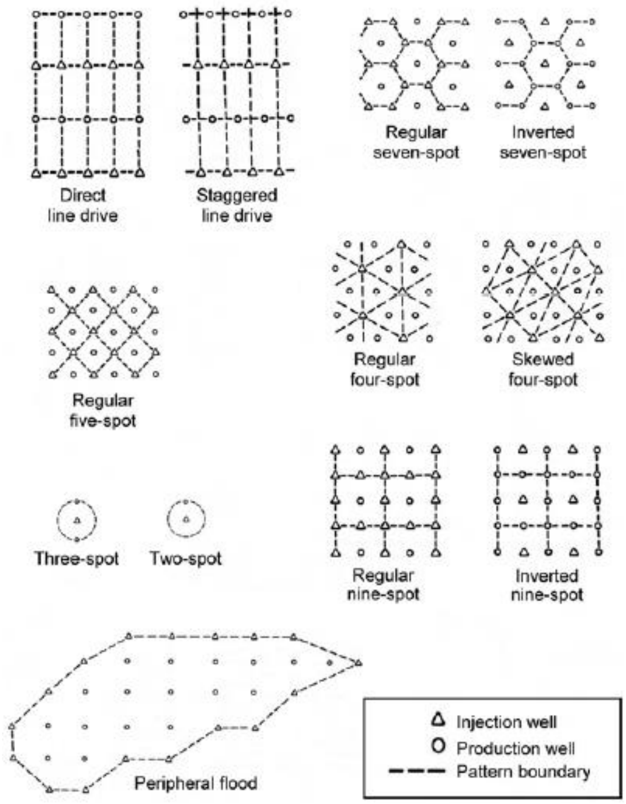


Figure 3. 3 Common waterflood-pattern configuration (after Craft [14])

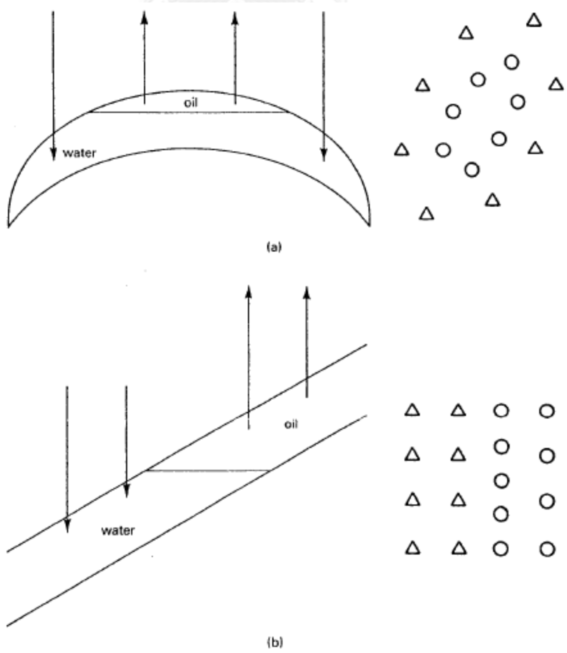


Figure 3. 4 Well arrangements for anticlinal (a) and monoclonal (b) reservoirs with underlying aquifers. (after Craft [14])

In order to understand the oil displacement efficiency by water, the mathematical aspect for homogeneous linear system is presented. The Buckley-Leverett equation or frontal advance theory is derived by the assumptions that fractional flow of water is only a function of water saturation and there is no mass transfer between oil and water phases. The general form of the water fractional flow is:

$$f_w = \frac{1 + \frac{k k_{ro}}{u_t \mu_o}(\frac{\partial P_c}{\partial L} - g\Delta\rho sin\alpha_d)}{1 + (\frac{\mu_w}{\mu_o})\left(\frac{k_o}{k_w}\right)} \tag{3.4}$$

where

f_w = fraction of water in flowing stream passing any point in the rock

k = formation permeability

k_{ro} = relative permeability to oil

k_o = effective permeability to oil

k_w = effective permeability to water

μ_o = oil viscosity

μ_w = water viscosity

u_t = total fluid velocity (i.e., q_t/A)

P_c = capillary pressure

L = distance along direction of movement

g = acceleration due to gravity

$\Delta\rho$ = water-oil density difference = $\rho_w - \rho_o$

α_d = angle of the formation dip to the horizontal

3.2.3 Water flooding in dipping reservoirs

When water flooding is performed in dipping reservoirs, there are some factors that need to be considered which are dip angle, location of injection well and injection rate because these factors directly affect the performance of water flooding process. Neglecting the effect of capillary pressure, the fractional flow of water can be written as

$$f_w = \frac{1 + \frac{kk_{ro}}{u_t\mu_o}(-g\Delta\rho sin\alpha_d)}{1 + (\frac{\mu_w}{\mu_o})\left(\frac{k_o}{k_w}\right)} \tag{3.5}$$

The sign convention of dip angle (α_d) is assigned to be positive when the water is displacing oil upward (inject downdip) and negative when displacing oil downward (inject updip). Equation (3.5), it is used to plot the fractional flow curve of water flooding as illustrated in Figure 3.5. The fractional flow curve shows that at the same water saturation, the water fractional flow of displacing oil updip is lower than that of displacing oil downdip but the average water saturation behind the flood front is higher. This result can imply that displacing oil updip has better performance than displacing oil downdip because more oil is swept by water. So, from this reason water injection well is located at downdip in this study.

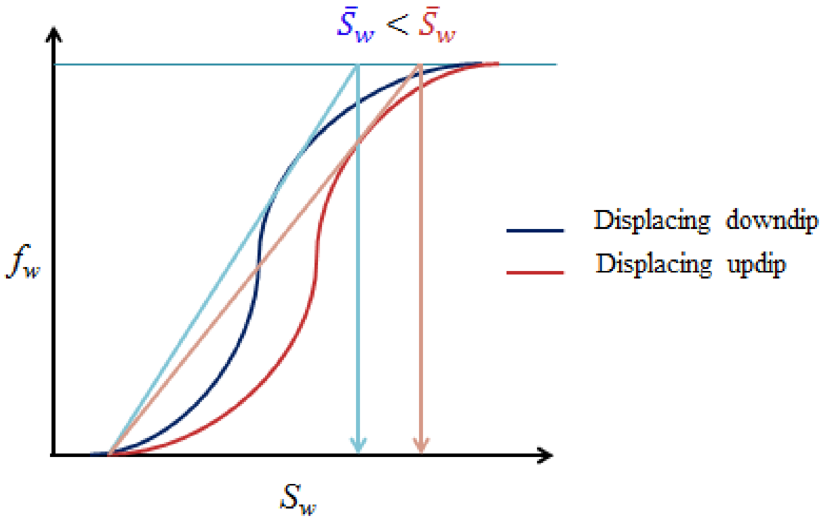


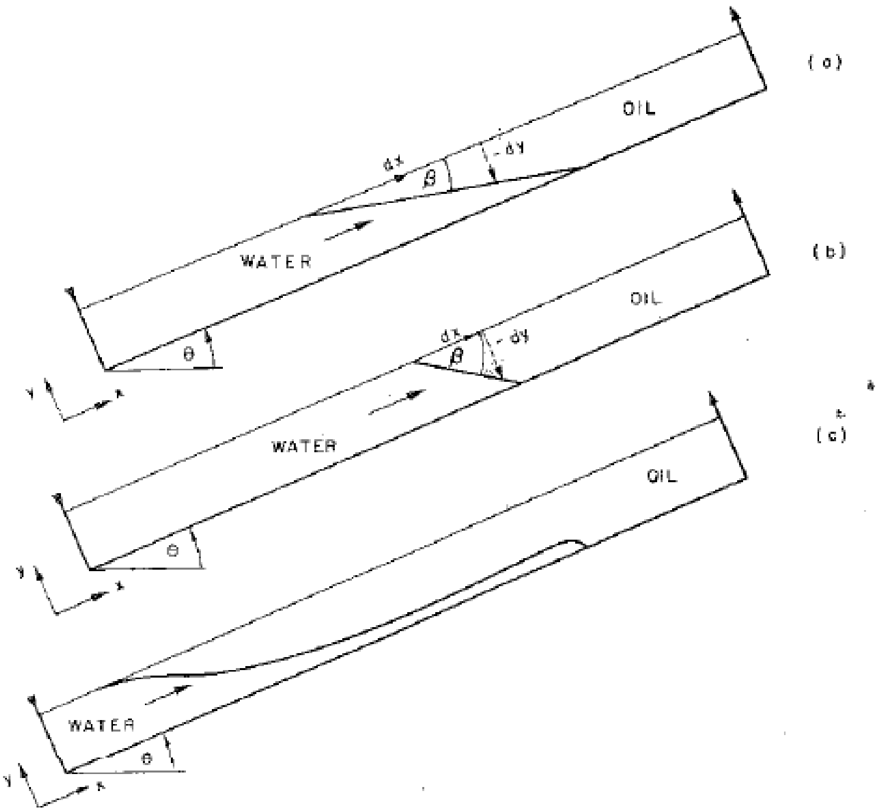
Figure 3. 5 Fractional flow curve of water flooding in both locations. (after Natchapon [15])

3.2.3.1 Injection rate

Craig [16] observed the influence of formation dip and rate. He stated that when water displaces oil updip, lower flow rate provides more efficiency since gravity force dominates. However, when water displaces oil downdip, higher rate provides more efficiency because there is less chance for water to percolates down through oil by gravity.

Another observation of Craig [16], at any flow rates when formation dip angle is increasing, the displacing of oil updip has better performance than displacing oil downdip.

Dietz [17] characterized the type of displacement into stable and unstable flow as shown in Figure 3.6. Figure 3.6 a) and b) show the cases of stable displacement. As water displaces oil in updip direction, the water and oil segregate and rise up horizontally forming smooth flood front. Figure 3.6 c) illustrates the case of unstable displacement. As water displaces oil, the water underruns the oil forming water tongue.



(a) stable: G > M – 1; M > 1; β < Ө

(b) stable: G > M – 1; M < 1; β > Ө

(c) unstable: G < M – 1

Figure 3. 6 Stable and unstable flow displacement (after Dake [18])

The dimensionless gravity number (*G*) is defined as:

$$G = \frac{kk'_{rw}A\Delta\rho g sin\theta}{\mu_w q_t} \tag{3.6}$$

where

k = absolute permeability

k'_{rw} = relative permeability to water at end point

A = cross-sectional area

$\Delta\rho$ = $\rho_w - \rho_o$

θ = dip angle

The end point mobility ratio M^* is defined as:

$$M^* = \frac{k'_{rw}\mu_o}{k'_{ro}\mu_w} \tag{3.7}$$

where

k'_{rw} = relative permeability to water at end point (S_{orw})

k'_{ro} = relative permeability to oil at end point (S_{wc})

If $M^* > 1$, the displacement is stable when $G > (M^* - 1)$, providing the fluid interface β < Θ. The displacement is unstable when $G > (M^* - 1)$.

If $M^* = 1$, the displacement is unconditionally stable, providing β = Θ. The fluid interface rises horizontally.

If $M^* < 1$, the displacement is unconditionally stable, providing β > Θ. The fluid interface rises at an angle.

When $G = (M^* - 1)$, water will underrun the oil, forming a water tongue. By this definition of G, we can solve the critical rate for by passing

$$q_{wcrit} = \frac{kk'_{rw}A\Delta\rho g sin\theta}{\mu_w(M-1)} \tag{3.8}$$

If the injection rate is maintained below the critical rate, the gravity force will stabilize the flow.

3.3 Immiscible gas flooding

Gas flooding is usually performed when there is available supply of gas nearby. This supply of gas could come from produced solution gas or gas cap, gas from closing gas field or gas dump reservoir.

There are 4 physical mechanisms occur after gas injection

1) Reservoir pressure maintenance

2) Displacement of oil horizontally and vertically

3) Vaporization of liquid hydrocarbon

4) Oil swelling

3.3.1 Gas/oil linear displacement efficiency

In order to understand the mechanism of oil displacement by immiscible gas, the gas fractional flow equation is developed by Welge [19]. The assumptions in his work are steady-state flow, constant pressure, no compositional effects, no production of fluids behind the gas front and uniform cross-sectional flow. The fractional flow of gas at any gas saturation (S_g) is illustrated as follows:

$$f_g = \frac{1 + \frac{kk_{ro}}{u_t\mu_o}(\frac{\partial P_c}{\partial L} - g\Delta\rho sin\alpha_d)}{1 + (\frac{\mu_g}{\mu_o})\left(\frac{k_o}{k_g}\right)} \qquad (3.9)$$

where

f_g = fraction of gas in flowing stream passing any point in the rock

k_g = effective permeability to gas

P_c = capillary pressure = $p_0 - p_g$ = pressure in oil phase minus pressure in gas phase

$\Delta\rho$ = water-oil density difference = $\rho_g - \rho_o$

3.3.2 Gas flooding in dipping reservoirs

According to fractional flow of gas in equation (3.9), the sign convention of oil displaced updip (inject downdip) is positive while oil displaced downdip (inject updip) is negative. At the same gas saturation, displacing oil downdip will give lower gas fractional flow while the average gas saturation behind flood front is higher. This means that gas injection at updip location has better performance than gas injection at downdip.

Figure 3.7 shows the effect of gravity term which is directly related to the dip angle on fractional flow curve of gas. When the gravity term is included, the curve shifts to the right, resulting in better performance. This can be described in the same way as injection at updip location.

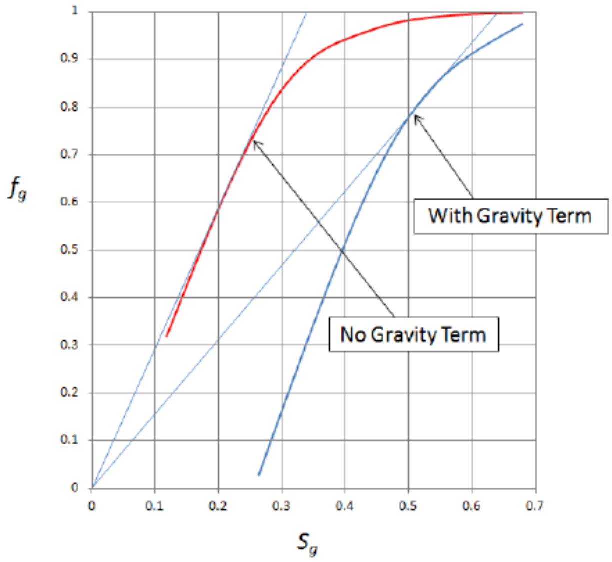


Figure 3. 7 Effect of gravity on fractional flow curve of gas flooding for updip gas injection (after Holstein [20])

The same analytical method that is derived for water displacing oil from downdip location can be applied for gas displacing oil from updip location. As shown in Figure 3.8, the unstable displacement case can cause gas overriding and result in premature gas breakthrough in the production well located at downdip location. For stable displacement case, the fluid interface between gas and oil provides the constant angle of inclination which happens when

$$G > (\mathrm{M} - 1)$$

where

$$G = \frac{kk'_{rg}A\Delta\rho g sin\theta}{\mu_g q_t}$$

$$M = \frac{k'_{rg}\mu_o}{k'_{ro}\mu_g}$$

$$\Delta\rho = \rho_o - \rho_g$$

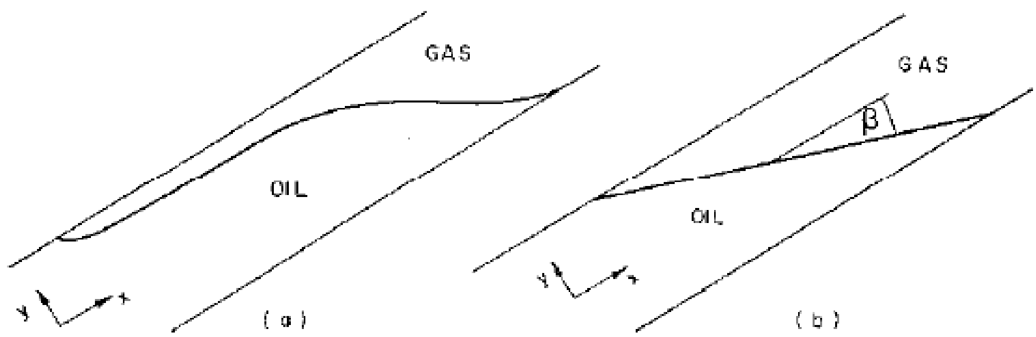
k'_{rg} = relative permeability to gas at end point (S_{org})

k'_{ro} = relative permeability to oil at end point (S_{wc})

The critical flow rate is expressed as:

$$q_{gcrit} = \frac{kk'_{rg}A\Delta\rho g sin\theta}{\mu_g(M-1)} \tag{3.10}$$

Since μ_g is very low when compared to μ_o, the mobility ratio will be very large. The condition of unconditionally stable (M ≤ 1) is impossible to occur. So, only the magnitude of *G* which leads to the dip angle determines the stability.



(a) unstable (b) stable

Figure 3. 8 Segregated downdip displacement of oil by gas at constant pressure [18]

3.4 Factors affecting fluid and rock interaction

3.4.1 Mobility ratio

Mobility of fluid is defined as its relative permeability divided by its viscosity which combines rock property with fluid property.

Mobility can be written as

$$\lambda_i = (\frac{k_{ri}}{\mu_i}) \tag{3.11}$$

where

λ_i = mobility of fluid phase i

k_{ri} = relative permeability of fluid phase i

μ_i = viscosity of fluid phase i

Mobility ratio is defined as mobility of the displacing phase (depends on flooding process can be water or gas) divided by the mobility of the displaced phase (oil) which can be written as

$$M = \frac{\lambda_i}{\lambda_o} = \left(\frac{k_{ri}}{k_{ro}}\right)\left(\frac{\mu_o}{\mu_i}\right) \tag{3.12}$$

If $M \leq 1$, oil is capable of traveling with a velocity equals to or greater than displacing fluid (gas or water). There is no tendency for oil to be by-passed which is favorable.

If $M > 1$, displacing fluid is capable of traveling faster than oil. Some of oil will be by-passed which usually happens in gas displacement. This case is unfavorable.

The viscosity ratio which is defined as viscosity of water divided by viscosity of oil can be used to determine the efficiency of water flooding. The more viscosity ratio, the more efficiency of water flooding is. A small viscosity ratio means oil is so viscous to be displaced by water, giving small efficiency.

3.4.2 Relative permeability

Laboratory studies concluded that the effective permeability of reservoir fluid depends on fluid saturation and the wetting characteristics of formation. The effective permeability is the property of porous medium and fluids measured by flowing fluid through the medium when two or more fluids flow. The ratio of effective permeability of each phase to the absolute permeability at specific saturation is called relative permeability.

$$k_{ro} = \frac{k_o}{k} \tag{3.13}$$

$$k_{rg} = \frac{k_g}{k} \tag{3.14}$$

where

k = absolute permeability

k_o = effective permeability of oil

k_g = effective permeability of gas

k_{ro} = relative permeability to oil

k_{rg} = relative permeability to gas

3.4.2.1 Corey's method for two-phase relative permeability.

Corey [21] proposed a mathematical expression to determine two-phases relative permeability.

For oil-water

$$k_{ro} = \left(\frac{1 - S_w - S_{orw}}{1 - S_{wc} - S_{orw}}\right)^{N_o} \quad (3.15)$$

$$k_{rw} = k_{rwend}\left(\frac{S_w - S_{wi}}{1 - S_{wc} - S_{orw}}\right)^{N_w} \quad (3.16)$$

For oil-gas

$$k_{ro} = \left(\frac{1 - S_g - S_{wi} - S_{org}}{1 - S_{wc} - S_{org}}\right)^{N_o} \quad (3.17)$$

$$k_{rg} = \left(\frac{S_g - S_{gc}}{1 - S_{wc} - S_{org} - S_{gc}}\right)^{N_g} \quad (3.18)$$

where

S_w = water saturation

S_{orw} = residual oil saturation in oil-water system

S_{wc} = initial water saturation (or connate water)

S_{gc} = critical gas saturation

S_g = gas saturation

S_{org} = residual oil saturation in oil-gas system

k_{ro} = relative permeability to oil

k_{rw} = relative permeability to water

k_{rg} = relative permeability to gas

k_{rwend} = relative permeability to water at end point

N_w = Corey water exponent

N_o = Corey oil exponent

N_g = Corey gas exponent

In ECLIPSE reservoir simulator, Corey-based method is used to generate the relative permeability curves.

3.4.2.2 Three-phase relative permeability

An experiment to determine three-phase relative permeability properties is difficult and complicated. Historically, two sets of calculated two-phase data are used to generate three-phase relative permeability.

3.4.2.2.1 ECLIPSE model

The ECLIPSE model is the default three-phase relative permeability calculation which can be used if no other model is selected. It is the weighted sum of two-phase relative permeabilities. This model as depicted in Figure 3.9 assumes oil saturation to be constant, S_o, throughout the cell. Water and gas has complete segregation, except for water saturation in the gas zone which is equal to the connate water, S_{wco}. The block average saturation are S_o, S_w and S_g ($S_o + S_w + S_g = 1$), the fraction of each phase can written as follows:

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 zero

The oil relative permeability is then given by

$$k_{ro} = \frac{S_g k_{rog} + (S_w - S_{wco})k_{row}}{S_g + S_w - S_{wco}} \tag{3.19}$$

where k_{rog} is oil relative permeability for a system with oil, gas and connate water (tabulated as a function of S_o) and k_{row} is oil relative permeability of a system with oil and water only (also tabulated as a function of S_o)

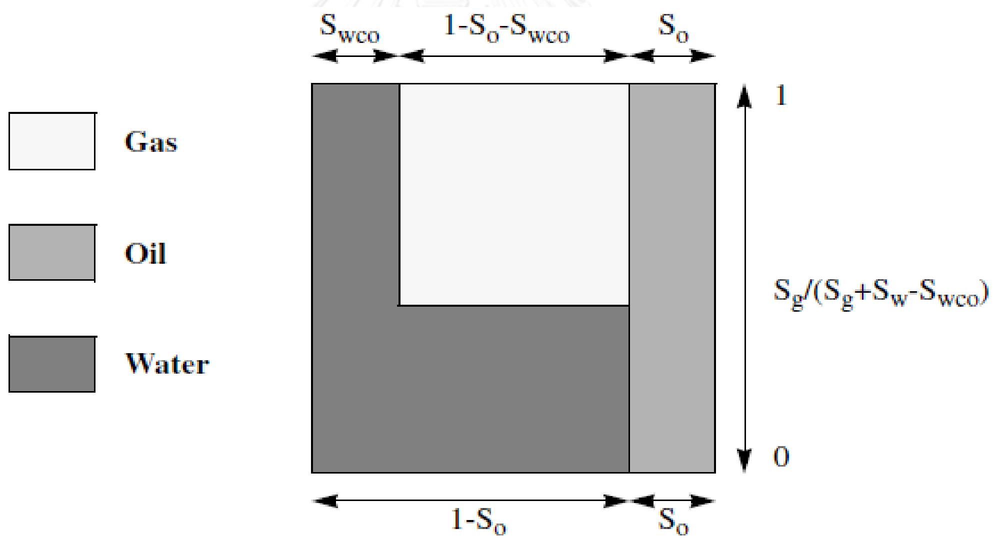


Figure 3. 9 Default model of three-phase relative permeability assumed by ECLIPSE (after Schlumberger [22])

3.4.2.2.2 Stone's model I

Another model available on ECLIPSE to estimate three-phase relative permeability data from two-phase data was developed by Stone [23]. The model combines channel flow theory in porous media with probability concept to obtain the relative permeability to oil in presence of water and gas flow.

Stone [23] suggested that nonzero residual oil saturation, called minimum oil saturation. (S_{om}) exists during oil displacement by water and gas. Stone [23] calculated relative permeability based normalized saturation as follows:

$$k_{ro} = \left[\frac{k_{row}k_{rog}}{(k_{ro})_{s_{wc}}}\right](\beta)^n \tag{3.20}$$

where

$$\beta = \frac{S_o^*}{(1-S_w^*)(1-S_g^*)}$$

$$S_o^* = \frac{S_o-S_{om}}{1-S_{wc}-S_{om}-S_{gc}}$$

$$S_g^* = \frac{S_g-S_{gc}}{1-S_{wc}-S_{om}-S_{gc}}$$

$$S_w^* = \frac{S_w-S_{wc}}{1-S_{wc}-S_{om}-S_{gc}}$$

k_{row} = oil relative permeability in oil-water two-phase system at S_w

k_{rog} = oil relative permeability in gas-oil two-phase system at S_g

S_{om} = minimum oil saturation

Frayers and Mathews [24] suggested that S_{om} used be determined by

$$S_{om} = \alpha S_{orw} + (1-\alpha)S_{org} \tag{3.21}$$

with

$$\alpha = 1 - \frac{S_g}{1-S_{wc}-S_{org}}$$

3.4.2.2.3 Stone's model II

The development of Stone's model II comes from the difficulty of choosing S_{om}. Stone [25] proposed normalized expression as follows:

$$k_{ro} = (k_{ro})_{S_{wc}} \left[\left(\frac{k_{row}}{(k_{ro})_{S_{wc}}} + k_{rw} \right) \left(\frac{k_{rog}}{(k_{ro})_{S_{wc}}} + k_{rg} \right) - (k_{rw} + k_{rg}) \right] \quad (3.22)$$

3.4.2.3 Wettability

Wettability is defined as the tendency of fluid to adhere on the solid surface in the presence of other immiscible fluids such as oil and water. Equation 3.23 shows the force balance of water drop on the solid surface which is surrounded by oil. The lower contact angle, the wetter the water phase is.

$$\sigma_{os} - \sigma_{ws} = \sigma_{ow} cos\theta \quad (3.23)$$

where

σ_{os} = interfacial tension between oil and solid phases

σ_{ws} = interfacial tension between water and solid phases

σ_{ow} = interfacial tension between oil and water phases.

Wettability is considered to control the flow and distribution of fluid which affects the properties of capillary pressure and relative permeability.

Types of wettability

-Water-wet is a rock surface that prefers to adhere water. So there is continuous water phase on rock surface. This is considered as a favorable condition.

-Oil-wet is a preference of rock surface to oil than water. It is considered as unfavorable condition.

-Neutral-wet or intermediate-wet is a rock surface that has no strong preference for either oil or water.

The rule of thumb for typical water-oil relative permeability characteristics for water-wet and oil-wet formations is presented in Table 3.2 by Craig [16].

Table 3. 2 Water-wet and oil-wet characteristics

Property	Water-Wet	Oil-Wet
Connate water saturation (Swc)	Usually > 20 to 25 % PV	Generally < 15 % PV, frequently > 10 %
Water saturation at cross over between oil and water relative permeability	> 50 % water saturation	< 50 % water saturation
krw at maximum water saturation or (Sor)	Generally < 30 %	> 50 % (can approach 100 %)

3.4.3 Permeability anisotropy

Permeability anisotropy is the difference in directional permeability measuring in parallel and perpendicular to the bedding plane. It is generally represented as the ratio of vertical to horizontal permeability (k_v/k_h). High k_v/k_h ratio means high vertical permeability which may cause the injected gas to override oil or move to the higher structural positions. This can cause vertical segregation of gas and oil, which may result in low or high efficiency of gas displacement depending on the bedding plane. If the reservoir lacks vertical permeability and gravity segregation, the frontal drive similar to water injection could occur to create efficient gas displacement in flat reservoir.

3.5 Fracturing pressure

In practical situation, the injection well pressure should not be higher than fracturing pressure in order to prevent the damage of the well when injecting fluids. The fracturing pressure is calculated by the equation below which is obtained from the correlation in the Gulf of Thailand [26].

$$\boldsymbol{Fracturing\ pressure\ (bar) = \frac{FRAC.S.G. \times TVD}{10.2}} \tag{3.24}$$

and

$$\boldsymbol{FRAC.S.G. = 1.22 + (TVD \times 1.6 \times 10^{-4})} \tag{3.25}$$

where

$\boldsymbol{FRAC.S.G.}$ = fracturing pressure gradient (bar/meter)

$\boldsymbol{TVD}$ = true vertical depth below rotary table (meter)

3.6 Partial penetration and limited entry

In some cases in this study, when allowing gas to cross flow to the oil reservoir, the high pressure gas may cause the flowing pressure to be higher than fracturing pressure. This situation occurs when the depth difference between oil and gas reservoirs is high which leads to high pressure inside the source gas reservoir. Perforation of fraction of the total formation of the gas reservoir can avoid the fracture of the well. Figure 3.10 represents the geometries of partial penetration.

Brons and Marting [27] suggested that the effect of partial penetration can be expressed as a skin factor.

$$S_c = \left(\frac{1}{b} - 1\right)[\ln(h_D) - G(b)] \tag{3.26}$$

where

b = h_p/h

h_D = dimensionless pay thickness, $\left(\frac{k}{k_v}\right)^{0.5}\left(\frac{h}{r_w}\right)$

h_p = limited interval open to flow (ft)

h = total formation thickness (ft)

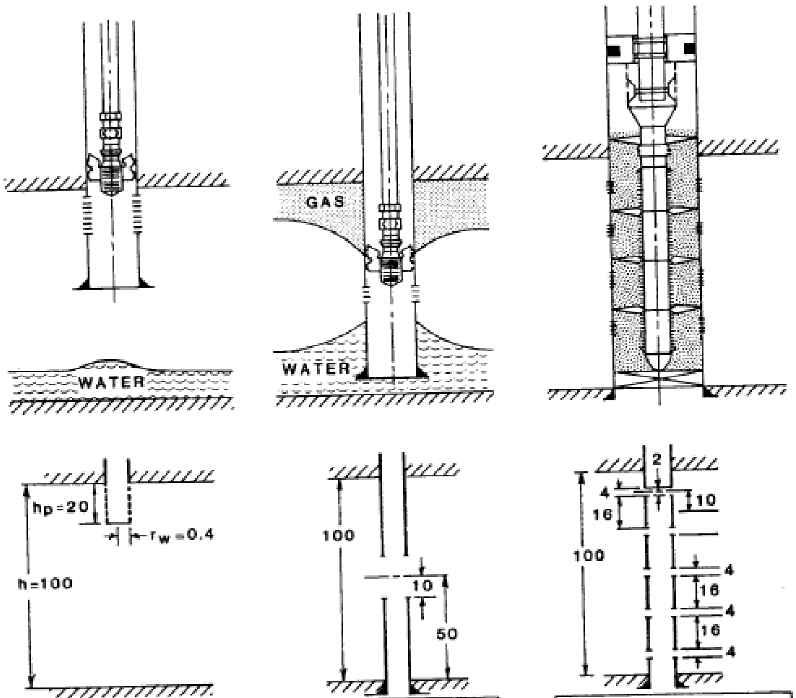
k = horizontal formation permeability (md)

k_v = vertical formation permeability (md)

$G(b)$ = is a function of the fractional penetration b

$$G(b) = 2.948 - 7.363b + 11.45b^2 - 4.675b^3 \tag{3.27}$$

In our simulation model, partial penetration skin factor is used to accommodate the partial perforation effect in the gas zone.



$b=\frac{h_p}{h}$	$\frac{20}{100}=0.2$	$\frac{20}{100}=\frac{10}{50}=0.2$	$\frac{20}{100}=\frac{2}{10}=0.2$
h_D	$\left(h/r_w\right)\left(\frac{K}{K_v}\right)^{0.5}$	$\left(\frac{h}{2Nr_w}\right)\left(\frac{K}{K_v}\right)^{0.5}$	$\left(\frac{h}{2Nr_w}\right)\left(\frac{K}{K_v}\right)^{0.5}$
	$\frac{K}{K_v}=1$	$N=1$ $\frac{K}{K_v}=1$	$N=5$ $\frac{K}{K_v}=1$
h_D	250	125	25
S_c	15	12	6.5

Figure 3. 10 Partial penetration and three geometries of limited entry (after Golan [28])

CHAPTER IV
RESERVOIR SIMULATION MODEL

In order to evaluate the performance of gas dumpflood in water-flooded reservoir, a reservoir model is constructed using reservoir simulator ECLIPSE100. This chapter explains the grid section, general PVT properties of fluid, relative permeability models and well schedules used in this study. Additional assumption made here is that immiscibility occurs throughout displacement mechanism due to the fact that reservoir temperature is too high, causing enlargement of di-phasic phase on ternary phase diagram.

4.1 Grid section

The details tabulated below in Table 4.1 are derived from a petroleum field in the Gulf of Thailand. The drainage area of oil and source gas reservoirs is 4500 ft x 1900 ft. The thickness of oil column is 50ft while that for the gas reservoir 100 ft. The oil reservoir is located at depth of 5,000ft and is 2,000ft above the gas reservoir. The reservoir model is constructed using block-centered grid type for no dipping reservoir and corner-point grid type for dipping reservoir. The reservoir is assumed to be homogenous with water wet reservoir properties.

Table 4. 1 Target oil and source gas reservoir properties.

Parameters	Oil reservoir	Gas reservoir	Units
Number of grid blocks	45x19x5	45x19x5	grid blocks
Size of reservoir	4500x1,900x50	4500x1,900x100	ft.
Effective porosity	21.5	21.5	%
Horizontal permeability	126	126	mD.
Vertical permeability	12.6	12.6	mD.
Top of reservoir	5,000	7,050, 8,215, 9,300	ft.
Datum depth	5,000	7,150, 8,315, 9,400	ft.

Parameters	Oil reservoir	Gas reservoir	Units
Initial pressure at datum depth	2,243	3,200, 3,683, 4,167	psia.
Reservoir temperature	232.33	302, 340, 375	°F
Initial water saturation	25	25	%
Dip angle	0, 15, 30	0, 15, 30	degree

4.2 Pressure-Volume-Temperature (PVT) properties section

The oil in the reservoir has API gravity of 35 degree and initial solution gas oil ratio of 200 SCF/STB while the gas in both oil and gas reservoirs is assumed to be of the same type with gas specific gravity of 0.6. Pressure dependent fluid properties such as viscosity, formation volume factor and solution gas oil ratios are based on correlation set II in ECLIPSE100. Tables 4.2 and 4.3 illustrate water PVT properties in oil and gas zone, respectively. Although there is no original mobile water in the reservoirs, these properties are needed since the connate water may become mobile as it expands due to pressure reduction. Tables 4.4 and 4.5 illustrate fluid densities in both zones at surface condition. Figures 4.1 and 4.2 illustrate dry gas and live oil PVT properties as a function of pressure.

Table 4. 2 Water PVT properties in oil reservoir.

Properties	Value	Units
Reference pressure (Pref)	2,243	psia
Water FVF at Pref	1.034847	rb/stb
Water compressibility	3.37148E-6	/psi
Water viscosity at Pref	0.2499959	cp
Water viscosibility	3.060077E-6	/psi

Table 4. 3 Water PVT properties in gas reservoir.

Properties	Value	Units
Reference pressure (Pref)	3,157	psia
Water FVF at Pref	1.063671	rb/stb
Water compressibility	3.998482E-6	/psi
Water viscosity at Pref	0.1849182	cp
Water viscosibility	5.775883E-6	/psi

Table 4. 4 Fluids densities in top reservoir (oil reservoir) at surface condition.

Properties	Value	Units
Oil density	53.00209	lb/cuft
Water density	62.42797	lb/cuft
Gas density	0.03745678	lb/cuft

Table 4. 5 Fluids densities in bottom reservoir (gas reservoir) at surface condition.

Properties	Value	Units
Water density	62.42797	lb/cuft
Gas density	0.03745678	lb/cuft

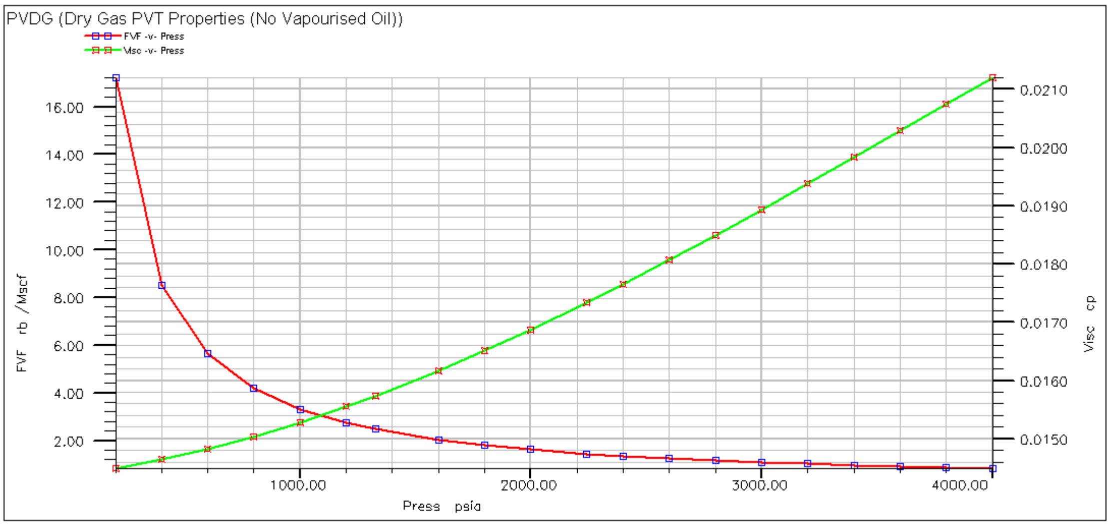


Figure 4. 1 Dry gas PVT properties in oil and gas reservoir (no vaporized oil).

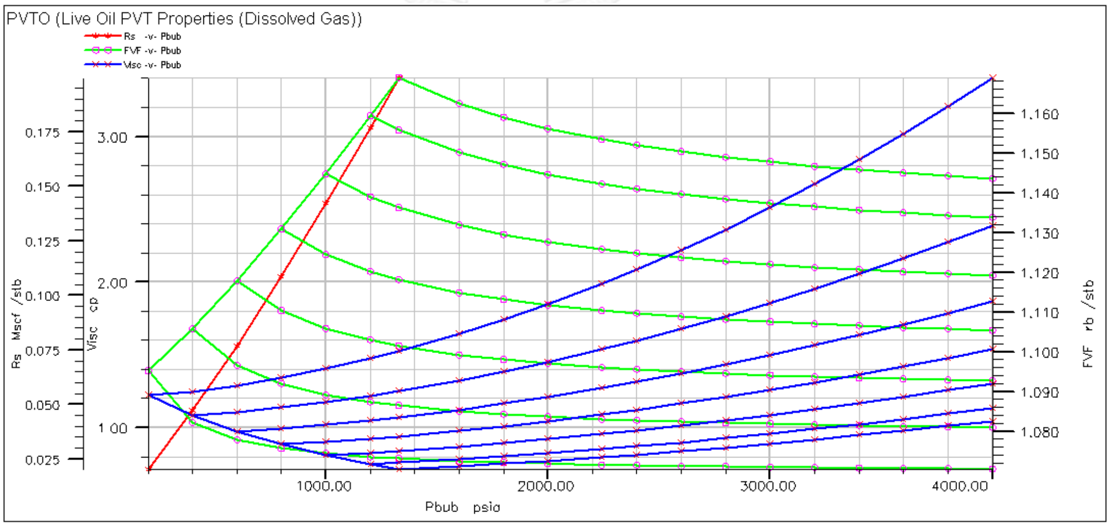


Figure 4. 2 Live oil PVT properties in oil reservoir (dissolved gas).

4.3 Special Core Analysis (SCAL) section

Three phase relative permeability is generated by ECLIPSE default model in order to construct the model for this study. Two sets of relative permeability are generated by inputting parameters in Corey’s correlation in both oil-water and oil-gas systems. This information is calculated based on information obtained from typical properties in Gulf of Thailand. The input parameters used to construct the relative permeability curves are illustrated in Table 4.6. The water/oil and gas/oil relative permeability values are tabulated in Tables 4.7 and 4.8, respectively. After the values are generated, the plotted curves are illustrated in Figures 4.3 and 4.4.

Table 4. 6 Input parameters for Corey's correlation.

Corey water	3	Corey gas/oil	3	Corey oil/water	1.5
Swmin	0.25	Sgmin	0	Corey oil/gas	1.5
Swcr	0.25	Sgcr	0.15	Sorg	0.1
Swi	0.25	Sgi	0.15	Sorw	0.3
Swmax	1	Krg(Sorg)	0.4	Kro(Swmin)	0.8
Krw(Sorw)	0.3	Krg(Sgmax)	0.4	Kro(Sgmin)	0.8
Krw(Swmax)	1				

Table 4. 7 Water and oil relative permeability.

Sw	Krw	Kro
0.25	0	0.8
0.30	0.0004	0.6704
0.35	0.0033	0.5487
0.40	0.0111	0.4355
0.45	0.0263	0.3313
0.50	0.0514	0.2370
0.55	0.0889	0.1540
0.60	0.1412	0.0838
0.65	0.2107	0.0296
0.7	0.3	0
1	1	0

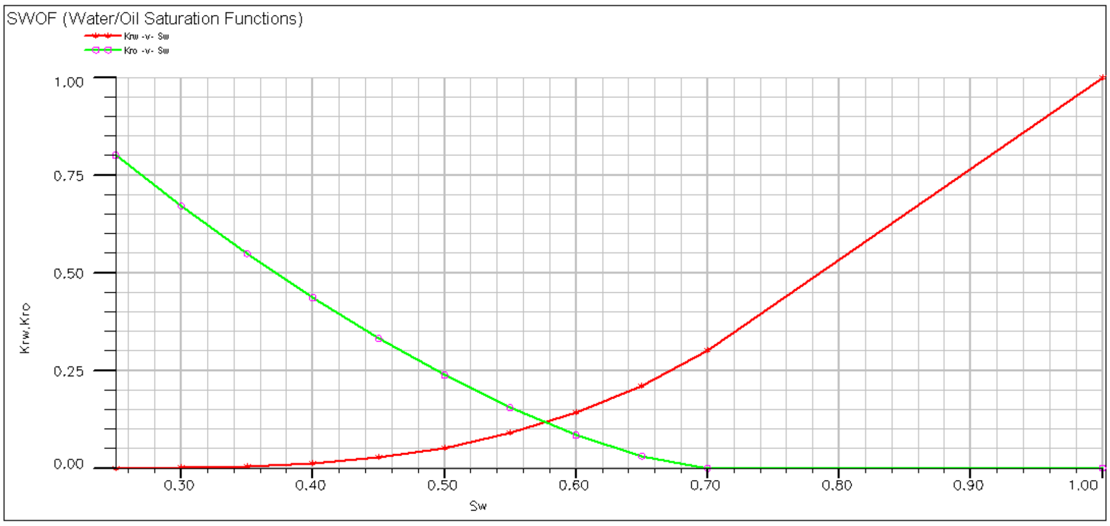


Figure 4. 3 Water/oil saturation function.

Table 4. 8 Gas and oil relative permeability.

Sg	Krg	Kro
0	0	0.8
0.1500	0	0.5397
0.2125	0.0008	0.4418
0.2750	0.0063	0.3506
0.3375	0.0211	0.2667
0.4000	0.0500	0.1908
0.4625	0.0977	0.1239
0.5250	0.1688	0.0675
0.5875	0.2680	0.0239
0.65	0.4	0
0.75	1	0

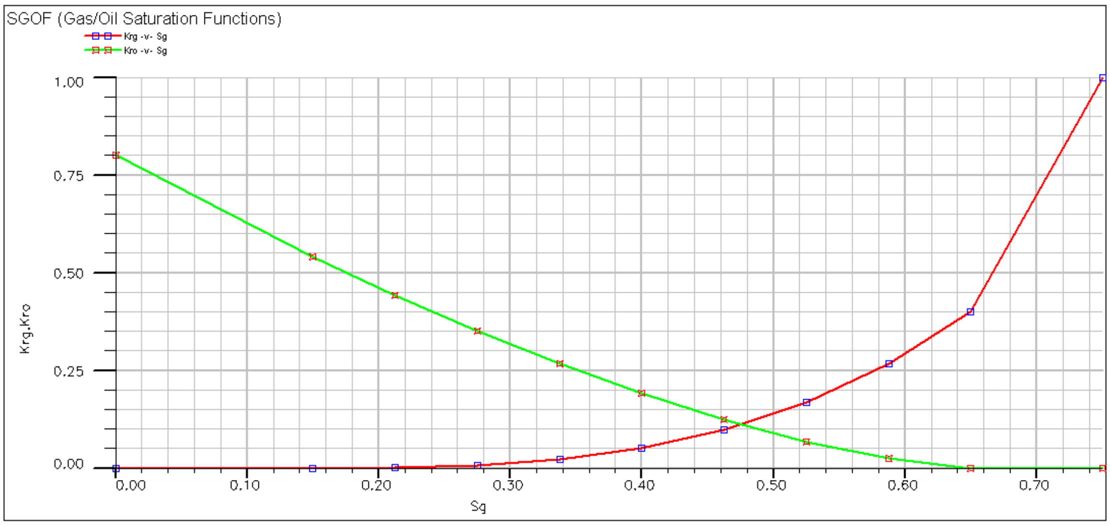
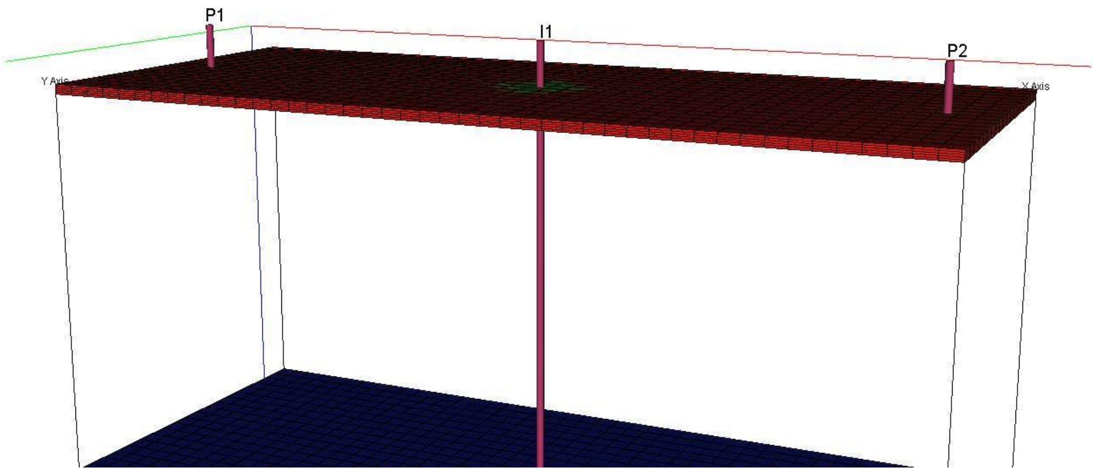


Figure 4. 4: Gas/oil saturation function.

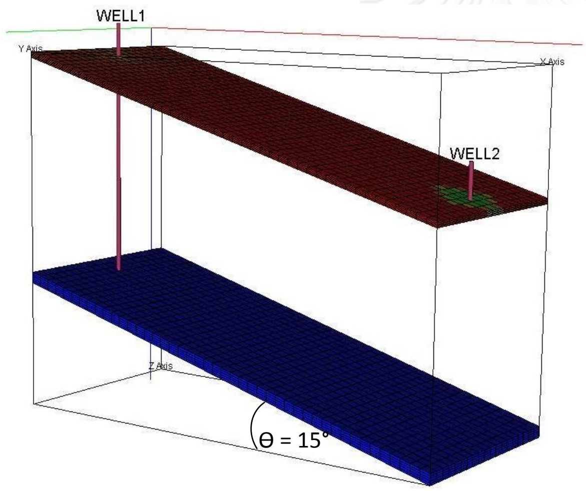
4.4 Well schedules

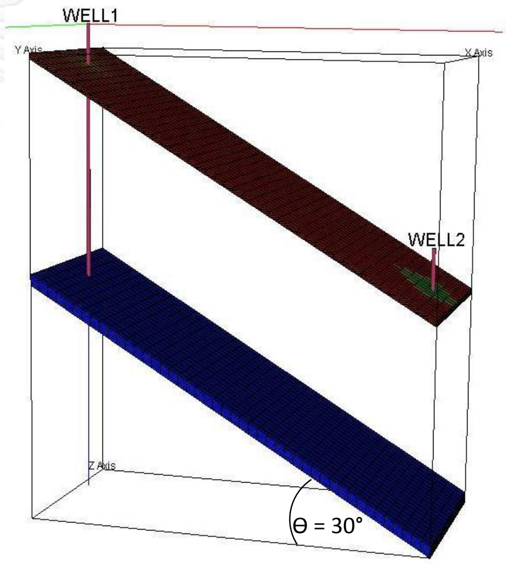
Figure 4.5 shows the constructed reservoir models for 0°, 15° and 30° dip angle reservoirs. For 0° dip angle, there are three vertical wells in which wells P1 and P2 are production wells and well I1 is an injection well. Since the injection well serves as water injector during initial water flooding but as gas dumpflood well during gas flooding, it must be drilled through the gas reservoir underneath. For 15° and 30° dip angles, there are two wells. During the water flooding, well1 located updip is production well and well 2 located downdip is injection well. During gas dumpflood process, well 1 is dumpflood well and well 2 is production well. As well1 is later used to dump gas from a reservoir below the oil reservoir, it needs to be drilled until reaching the lower gas reservoir. The wellbore diameter of each well is 6-1/8 inches. The maximum production period is set at 30 years which is a typical concession period. Well details and schedule constraints are summarized in Table 4.9.



a) 0-degree dip angle

P1, P2 = production well I1 = injector, dumpflood well





b) 15-degree dip angle c) 30-degree dip angle

Well1 = producer, dumpflood well Well2 = injector, producer

Figure 4. 5 Well location set for gas dumpflood and water flooding process

Table 4. 9 Well details and schedule constraints

Parameters	0° Dip	15° Dip	30° Dip	Units
Position for I1	i=23, j=10			
Position for P1, Well1	i=3, j=10	i=3, j=10	i=3, j=10	
Position for P2, Well2	i=43, j=10	i=43, j=10	i=43, j=10	
Maximum liquid production rate	1,500	5,000	5,000	STB/D/Well
Economic oil rate for production well	50	50	50	STB/D/Well
Minimum BHP for production well	200	200	200	psia
Maximum BHP for water injection well	3,000	3,900	4,700	psia
Maximum BHP for gas dumpflood injection well	3,172	3,220	3,265	psia
Maximum water injection rate	3,000	5,000	5,000	STB/D
Fracturing pressure (dumpflood well)	3,172	3,220	3,265	psia
Fracturing pressure (water injection well)	3,172	4,012	4,840	psia
Production period	30	30	30	years
Maximum water cut for abandoning water flooding	95%	95%	95%	

4.5 Thesis methodology

The details of thesis methodology are described as follows:

1. Construct simulation models for a reservoir with 0, 15 and 30 degree dip angle using ECLIPSE 100 with corner point geometry type for grid blocks.

2. Simulate conventional water flooding with 95% water cut criteria and compare with the base case of gas dumpflood with 80% water cut criteria for a reservoir with 0, 15, and 30 degree dip angle in order to see the benefit of this process.

3. Simulate gas dumpflood case with 80% water cut criteria for a reservoir with 0, 15, and 30 degree dip angle in order to observe the performance of different well arrangements which are: (note that the distance is between production and injection well)

- 2 wells (4000-ft distance)
- 3 wells (2000-ft distance)
- 5 wells (1000-ft distance)
- 9 wells (500-ft distance)
- 10 wells (1000-ft distance with two alignments of five wells)

4. Select suitable well arrangement in order to study the performance of different well types (vertical and horizontal) and identify appropriate starting point for gas dumpflood by varying water cut criteria (1%, 20%, 40%, 60%, and 80%).

5. Suitable well type and water cut criteria case is selected to study the production performance with different parameters including

- Perforation interval of source well
    - 20% perforation from bottom
    - 40% perforation from bottom
    - 60% perforation from bottom

- 80% perforation from bottom

- 100% perforation from bottom

- Water injection rate

- 0-degree dip angle (3000, 5000, and 7000 STB/D)

- 15 and 30 degree dip angle (3000, 4000, and 5000 STB/D)

- Liquid production rate

- 0-degree dip angle (3000, 5000, and 7000 STB/D)

- 15 and 30 degree dip angle (3000, 4000, and 5000 STB/D)

6. Compare and analyze results to determine the most appropriate design parameters for each dip angle.

7. Choose the optimum case for investigating the effect of system parameters which include

- Vertical to horizontal permeability ratio (0.001, 0.01, 0.1 and 0.3)

- Thickness of gas reservoir (50, 100 and 150 ft)

- Depth difference between gas and oil reservoirs (1000, 2000, and 3000 ft)

- Residual oil saturation

- (S_{orw} = 0.2, 0.3, and 0.4)

- (S_{org} = 0.05, 0.1, and 0.15)

- Oil viscosity (0.5, 2, and 5 cp.)

8. Compare and analyze the results on the effect of system parameters for production performance.

CHAPTER V
RESULTS AND DISCUSSION

In this chapter, the result of study parameters and sensitivity are shown and discussed in order to investigate the effects on this proposed method. Gas dumplflood in water-flooded reservoir is the process beginning with water injection until water cut reaches the criteria, then gas is dumped from a gas reservoir into the subject oil reservoir. Firstly, the case of conventional water flooding and base case are compared. Then, the proposed method is simulated under different conditions of six design parameters which are well arrangement, stopping time for water flooding, well type, perforation interval of source well, water injection rate, and oil production rate for reservoirs with 0, 15, and 30 degree dip angle. Lastly, the sensitivity of results due to the variations in reservoir parameters which are dip angle, vertical to horizontal permeability ratio, thickness of source gas reservoir, depth difference between gas and oil reservoirs, residual oil saturation and oil viscosity are discussed.

5.1 Dip angle of 0 degree

5.1.1 Gas dumpflood in waterflooded reservoir versus conventional water flooding

In order to establish the benefits of gas dumpflood in water-flooded reservoir, its performance needs to be compared with conventional water flooding. In this case, gas dumpflood and water flooding cases consist of two production wells and one injection well as shown in Figure 5.1. In the gas dumpflood case, water cut of 80% is set as stopping criteria for water flooding before starting gas dumpflood. The abandonment criteria assumed for both processes is the economic rate of 50 STB/D/well. For conventional water flooding case, 95% of water cut is used as additional abandonment criteria. This water cut limit is not needed for the case of gas dumpflood since the amount of water production decreases with time as gas dumpflood takes place.

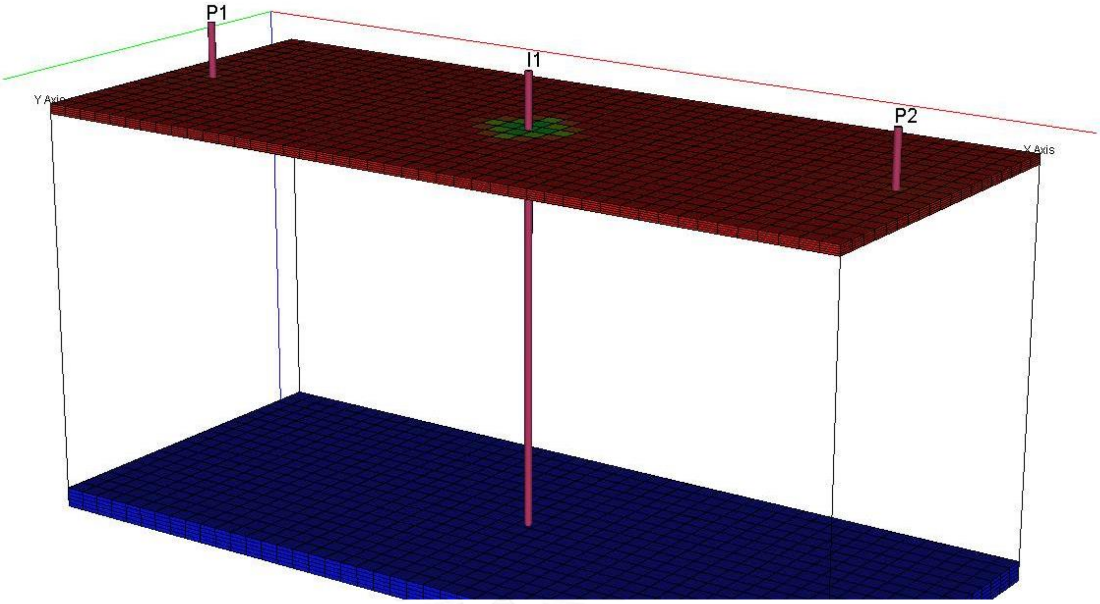


Figure 5. 1 Well placement of gas dumpflood case
(0-degree dip angle)

Table 5. 1 Injection and production sequence of gas dumpflood in water-flooded reservoir (0-degree dip angle)

Stage	P1, P2	I1
Waterflood	Producer	Water injector
WCT reaches criteria	Shut in for 60 days	Shut in for 60 days
Gas dumpflood	Producer	Gas dumpflood well

Figures 5.2-5.6 illustrate the oil production rate, water cut, water injection rate, gas production rate and reservoir pressure of gas dumpflood case and conventional water flooding.

In Figure 5.2, the total oil rates obtained from two producers for both cases are constant at 3,000 STB/D for about 3 years and sharply drop down as water breaks through the producer. For the gas dumpflood case, oil production is stopped at the time a little bit before 8 years because the water cut criteria of 80% is reached as shown in Figure 5.3. The wells are shut in for 60 days in order to perforate the gas reservoir before dumping gas into the target oil zone. After 60 days of shut in the wells, the oil production rate shoots up due to the fact that when water injection is suspended, oil is still moving to production well dynamically which later some amount of oil accumulates around wellbore. Then, oil rate drastically drops down for a short period of time and then stays constant at rate around 400 STB/D until year 9th due to production of water around wellbore prior to water flooding process. At this time, gas from underneath reservoir does not breakthrough yet until year 9th as shown in Figure 5.5. After year 9th, the oil rate starts to increase and reaches the peak at 800 STB/D as gas chases oil to the producer. After 800 STB/D peak, oil rate starts to decrease until it reaches 50 STB/D economic constraint and shut the wells. This is because gas rate flows into target oil zone is depleted. For the conventional water flooding case, the oil rate gradually drops down as more water approaches the producer until water cut reaches the 95% economic limit as shown in Figure 5.3.

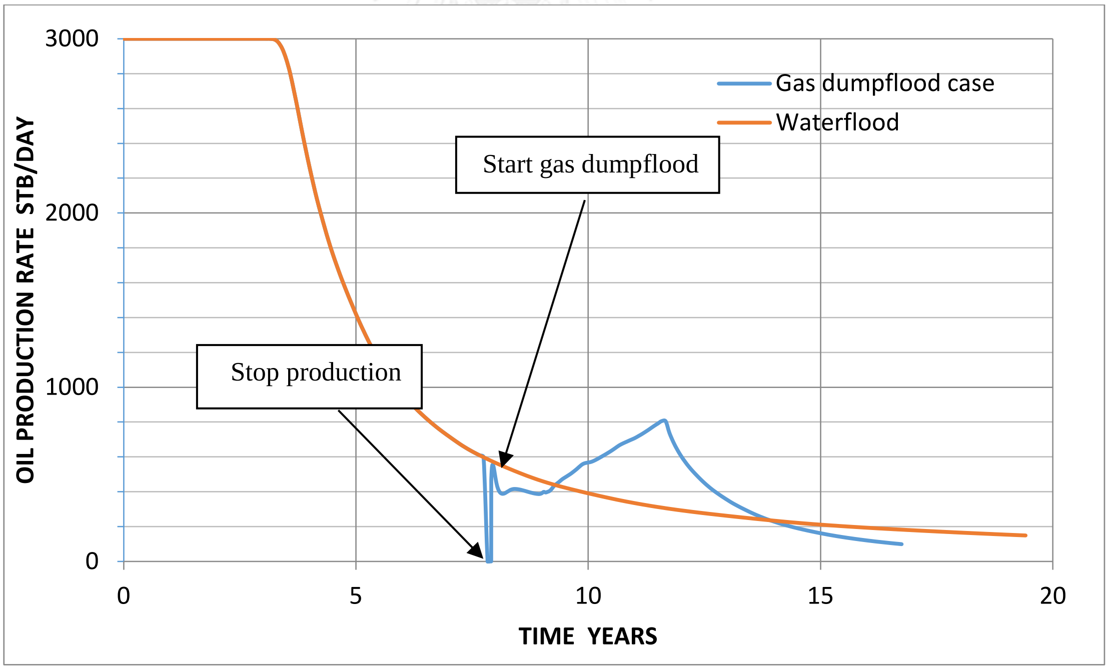


Figure 5. 2 Oil production rate comparison between gas dumpflood case and water flooding (0-degree dip angle)

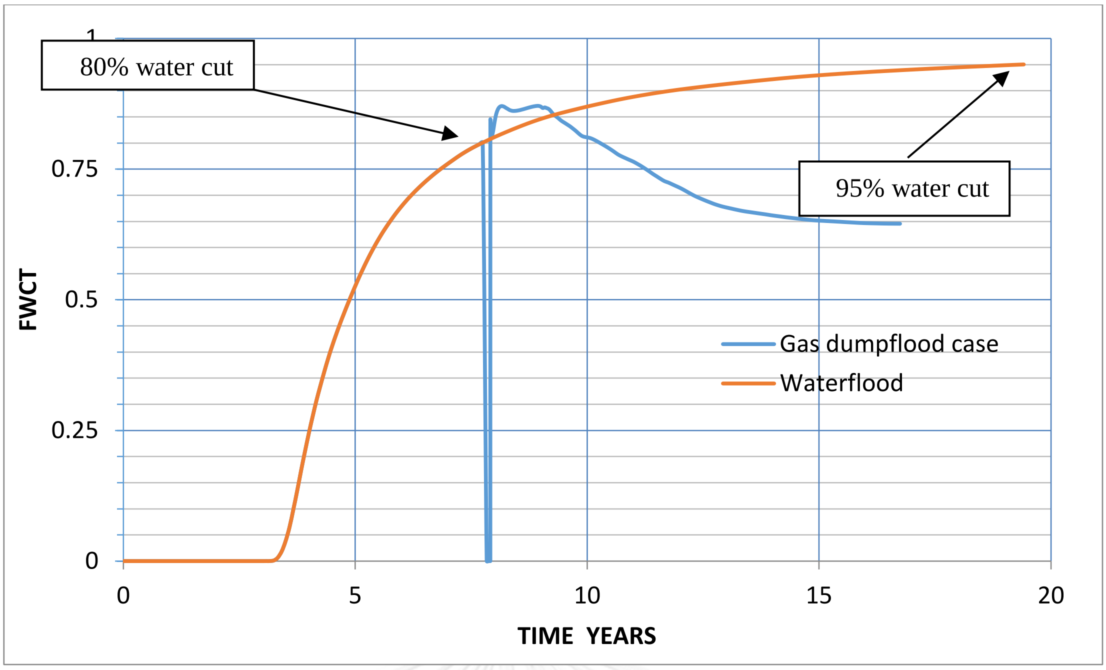


Figure 5. 3 Water cut comparison between gas dumpflood case and water flooding (0-degree dip angle)

Figure 5.4 illustrates that water injection rate can be kept at 3,000 STB/D for both cases. However, conventional water flooding takes longer time for water injection as the injection is continued until abandonment whereas water injection is discontinued when gas is dumped from the gas reservoir into the target oil reservoir in the gas dumpflood case.

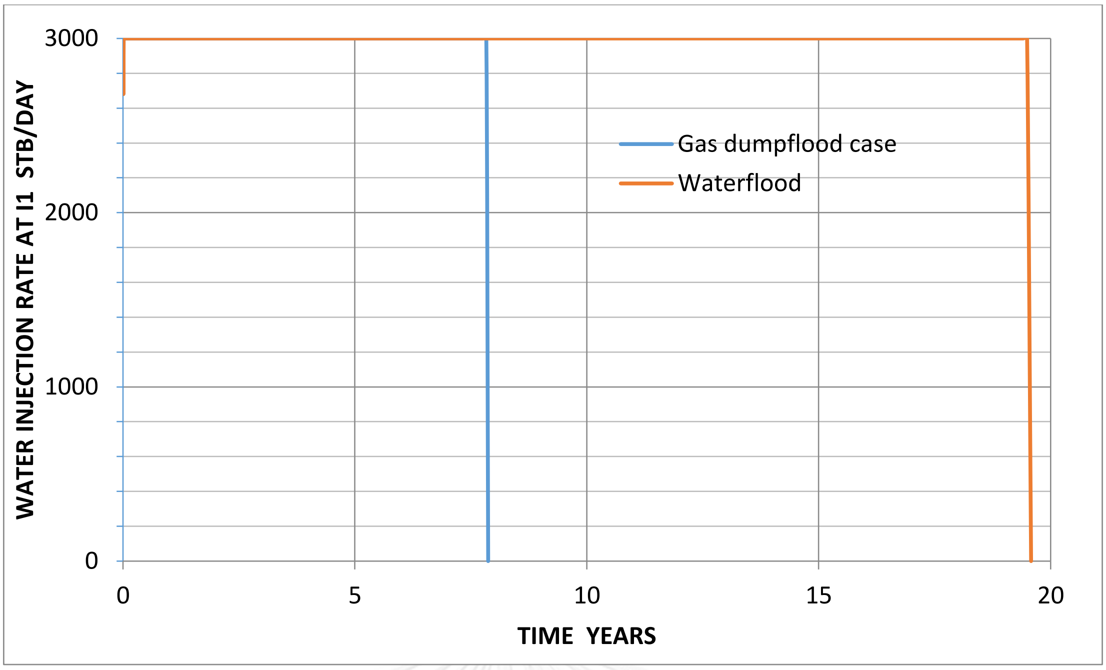


Figure 5. 4 Water injection rate comparison between gas dumpflood case and water flooding (0-degree dip angle)

As shown in Figure 5.5, gas production of gas dumpflood case during gas dumpflood period is significantly higher than that of water flooding process as gas from the source reservoir is produced after it has flooded the upper part of the oil reservoir. This gas also helps sweep parts of the residual oil left by water flooding which results in higher recovery factor as shown in Table 5.2.

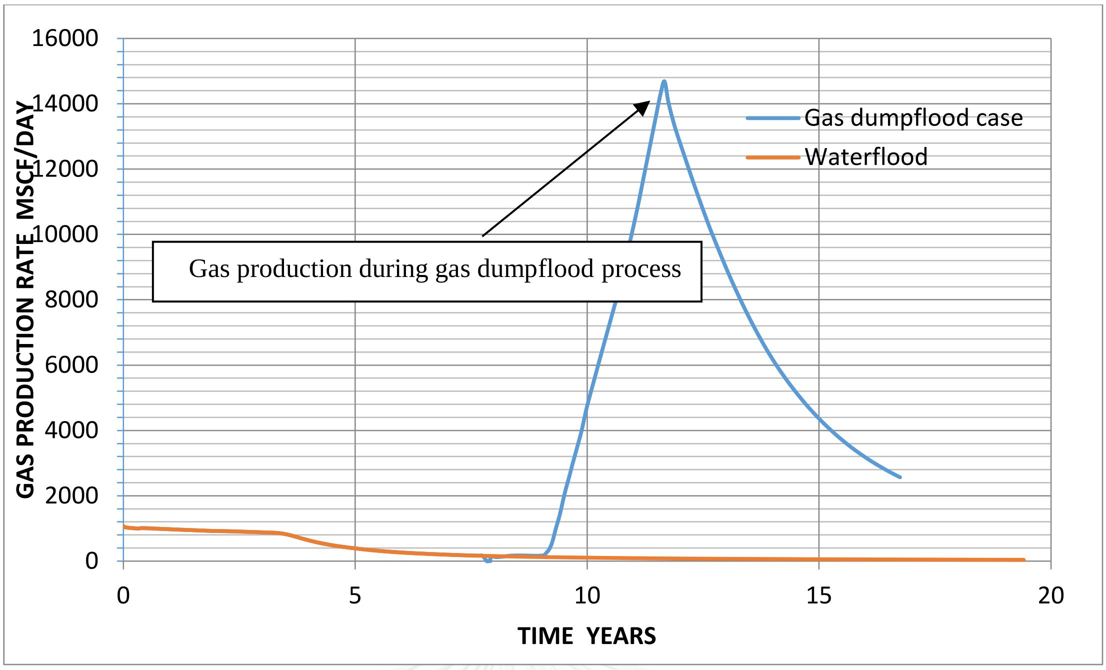


Figure 5. 5 Gas production rate comparison between gas dumpflood case and water flooding (0-degree dip angle)

Gas that flows from the source reservoir to the target oil zone can help maintain the reservoir pressure. During gas dumpflood period as shown in Figure 5.6, the reservoir pressure of gas dumpflood case increases and then drops down as oil is continuously produced. At the end, the reservoir pressure of conventional waterflood is higher than that of gas dumpflood case because water is continuously injected at the same rate while gas rate from the gas reservoir declines as gas is running out.

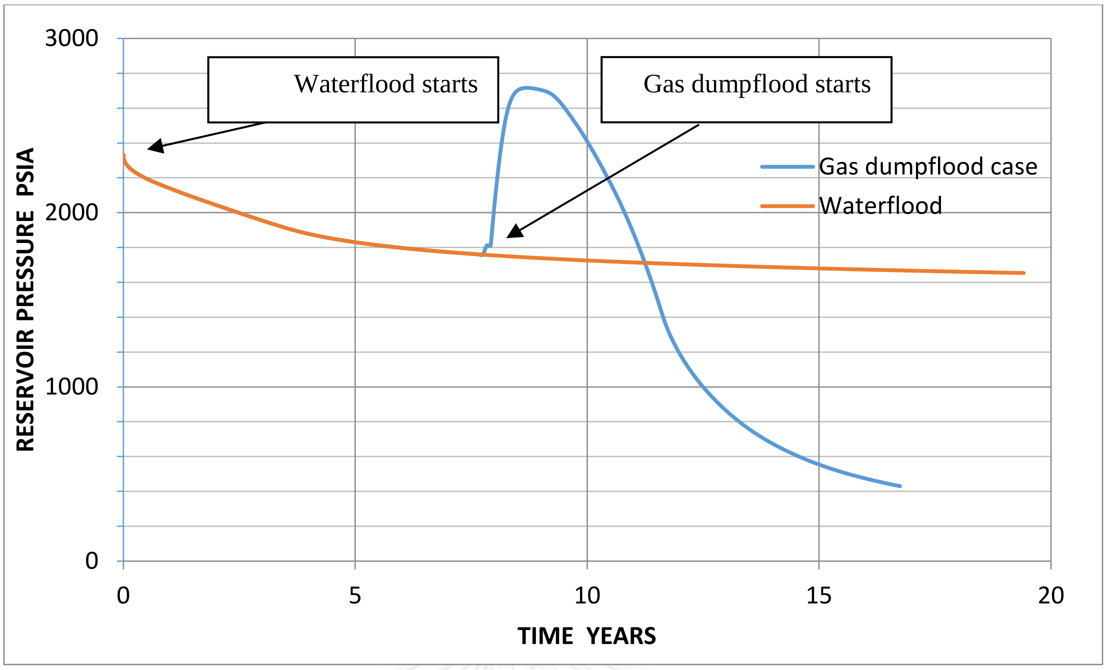


Figure 5. 6 Reservoir pressure comparison between gas dumpflood case and water flooding (0-degree dip angle)

During the beginning of gas dumpflood, gas from underneath reservoir flows into the oil reservoir with a peak in gas rate of 10,000 MSCF/DAY as shown in Figure 5.7 and then dramatically drops down until the 9th year. At the 9th year, gas breaks through the producer which makes gas rate from underneath reservoir starts to increase again. After the gas rate from underneath reservoir reaches another peak around 10,000 MSCF/DAY, it drops down as gas reservoir is depleted.

Figure 5.8 shows saturation profiles of gas dumpflood case at the beginning of gas dumpflood process until gas breakthrough.

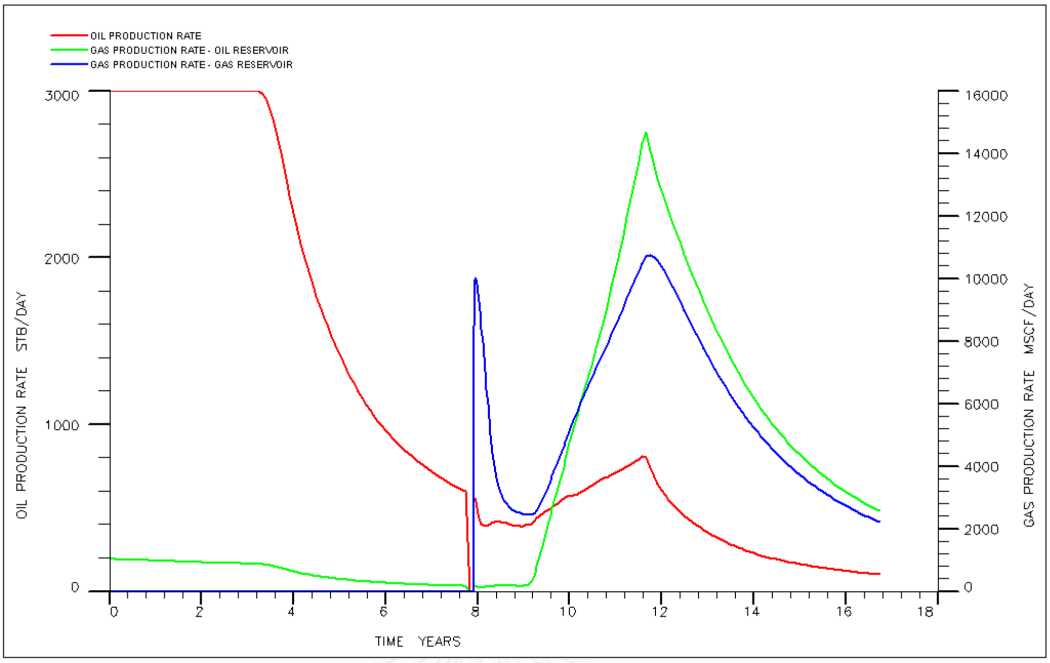
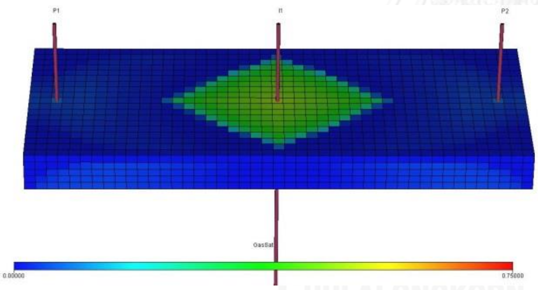
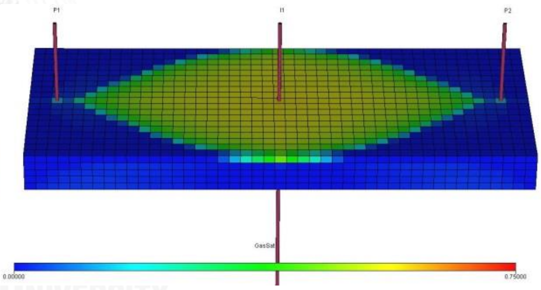


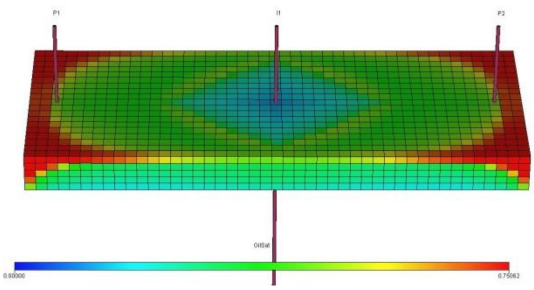
Figure 5. 7 Oil production rate, gas production rate of oil reservoir, and gas production rate of gas reservoir for gas dumpflood case (0-degree dip angle)



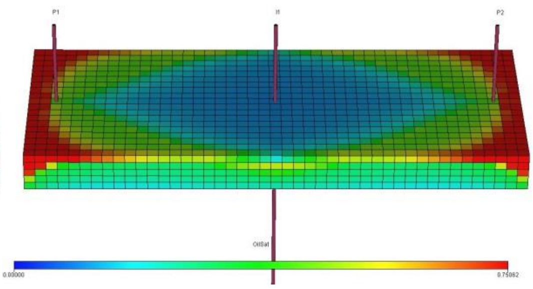
a) gas saturation (starting gas dumpflood)



b) gas saturation (gas breakthrough)



c) oil saturation (starting gas dumpflood)



d) oil saturation (gas breakthrough)

Figure 5. 8 Saturation profiles of gas dumpflood case (0-degree dip angle)

From the results shown in Table 5.2, the recovery factor and total oil production of gas dumpflood case and conventional water flooding are more or less the same. The production life of the gas dumpflood case is almost three years shorter. The gas dumpflood case has much lower water production and water injection. The cost of pumping water and treatment of produced water from conventional water flooding process will be much higher. In term of gas production, the cumulative volume of gas produced in the case of gas dumpflood is much higher than the one obtained from conventional water flooding. However, this should not be taken into account when judging the two cases because gas can be produced separately in the case of conventional water flooding. Due to the fact that gas dumpflood requires shorter time and needs less water handling, gas dumpflood in water-flooded reservoir is more attractive than conventional water flooding process.

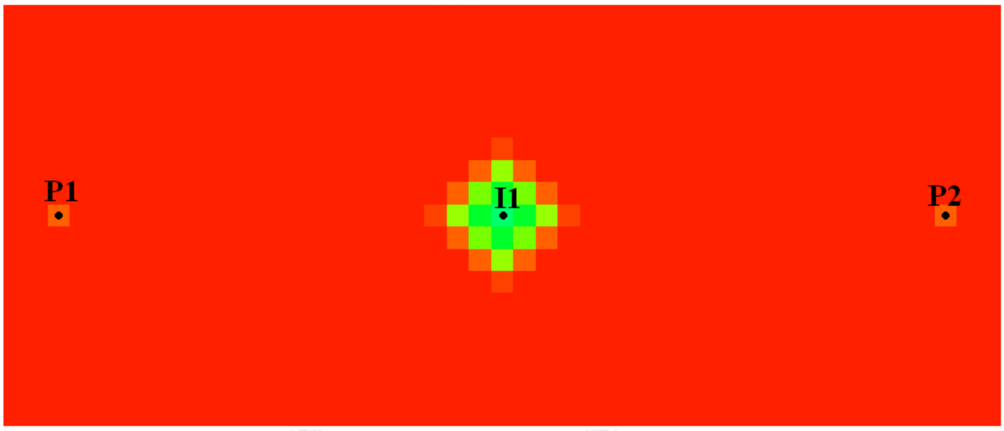
Table 5. 2 Summarized results for gas dumpflood in water-flooded reservoir & conventional waterflood (0-degree dip angle)

Case	Production life (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
Gas dumpflood case	16.75	71.87	7.087	8.583	7.075	20.700
Waterflood	19.41	71.21	7.022	21.361	14.251	2.066

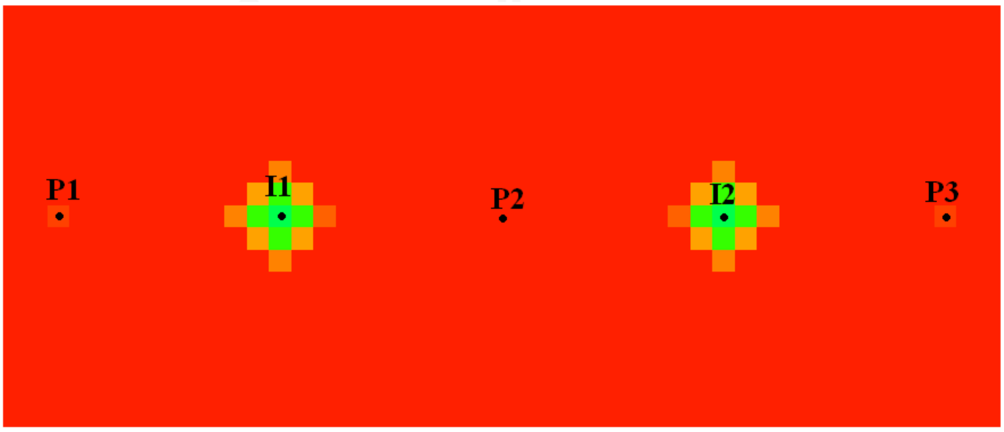
5.1.2 Effect of well arrangement

The effectiveness of water flooding and gas flooding depends on the locations of injectors and producers as appropriate locations can help sweep the oil in the reservoir toward the producers better. In this section, five cases of well arrangement with different distances between each injector and producer are investigated as shown in Figure 5.9. The position of all wells, formation fracture pressure and injection and production sequence for all well arrangements are depicted in Tables 5.3-5.8.

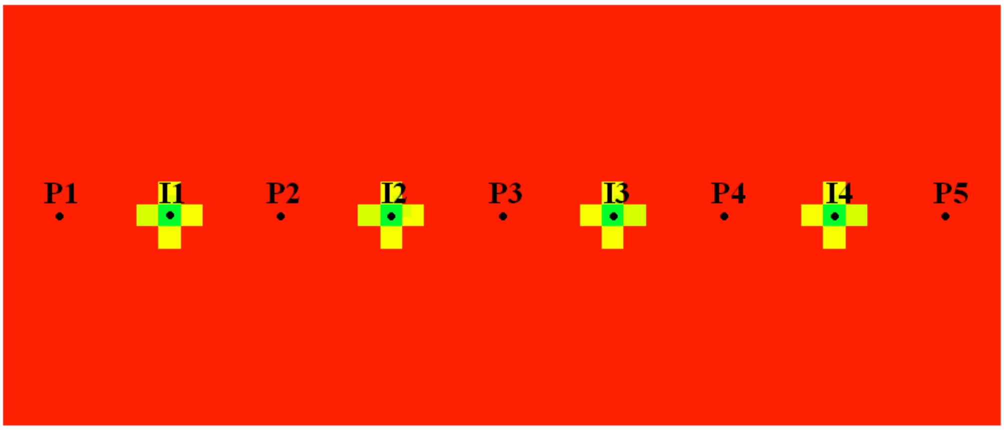
a. two wells (1 injector and 1 producer)



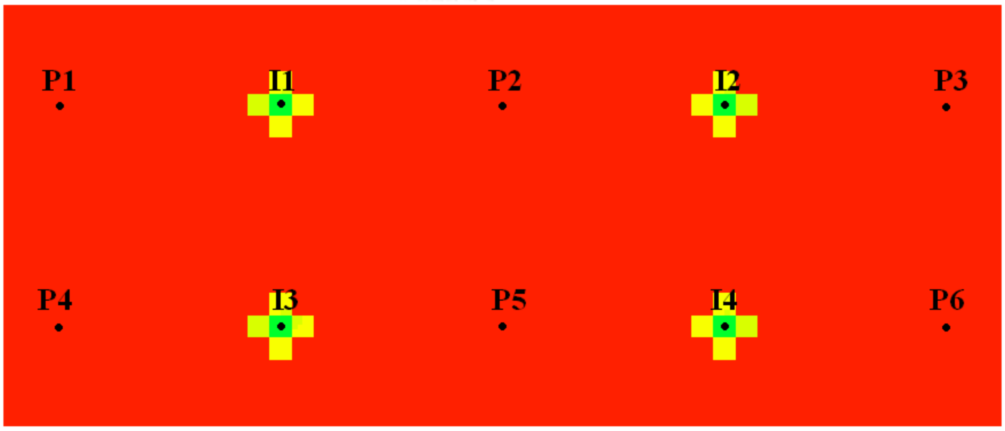
b. three wells (1 injector and 2 producers)



c. five wells (2 injectors and 3 producers)



d. nine wells (4 injectors and 5 producers)



e. ten wells (4 injectors and 6 producers)

Figure 5. 9 Schematics of different well arrangements (0-degree dip angle)

Table 5. 3 Locations and constraints of two wells for reservoir with 0-degree dip angle

Well	i^{th} position	j^{th} position	Fracture pressure (psia)
I1	43	10	3,172
P1	3	10	3,172

Table 5. 4 Locations and constraints of three wells for reservoir with 0-degree dip angle

Well	i^{th} position	j^{th} position	Fracture pressure (psia)
I1	23	10	3,172
P1	3	10	3,172
P2	43	10	3,172

Table 5. 5 Locations and constraints of five wells for reservoir with 0-degree dip angle

Well	i^{th} position	j^{th} position	Fracture pressure (psia)
I1	13	10	3,172
I2	33	10	3,172
P1	3	10	3,172
P2	23	10	3,172
P3	43	10	3,172

Table 5. 6 Locations and constraints of nine wells for reservoir with 0-degree dip angle

Well	i^{th} position	j^{th} position	Fracture pressure (psia)
I1	8	10	3,172
I2	18	10	3,172
I3	28	10	3,172
I4	38	10	3,172
P1	3	10	3,172

P2	13	10	3,172
P3	23	10	3,172
P4	33	10	3,172
P5	43	10	3,172

Table 5. 7 Locations and constraints of ten wells for reservoir with 0-degree dip angle

Well	i^{th} position	j^{th} position	Fracture pressure (psia)
I1	13	5	3,172
I2	33	5	3,172
I3	13	15	3,172
I4	33	15	3,172
P1	3	5	3,172
P2	23	5	3,172
P3	43	5	3,172
P4	3	15	3,172
P5	23	15	3,172
P6	43	15	3,172

Table 5. 8 Injection and production sequence for all well arrangements for reservoir with 0-degree dip angle

Well arrangements	Stage	P1	I1
two wells	Waterflood	Producer (3,000* STB/D)	Water injector (3000** STB/D)
	WCT reaches criteria	Shut in for 60 days	
	Gas dumpflood	Producer (3,000* STB/D)	Gas dumpflood well

*liquid production rate, **water injection rate

Well arrangements	Stage	P1	I1	P2
three wells	Waterflood	Producer (1,500* STB/D)	Water injector (3000** STB/D)	Producer (1,500* STB/D)
	WCT reaches criteria	Shut in for 60 days		
	Gas dumpflood	Producer (1,500* STB/D)	Gas dumpflood well	Producer (1,500* STB/D)

*liquid production rate, **water injection rate

Well arrangements	Stage	P1	I1	P2	I2	P3
five wells	Waterflood	Producer (1,000* STB/D)	Water injector (1,500** STB/D)	Producer (1,000* STB/D)	Water injector (1,500** STB/D)	Producer (1,000* STB/D)
	WCT reaches criteria	Shut in for 60 days				
	Gas dumpflood	Producer (1,000* STB/D)	Gas dumpflood well	Producer (1,000* STB/D)	Gas dumpflood well	Producer (1,000* STB/D)

*liquid production rate, **water injection rate

Well arrangements	Stage	P1	I1	P2	I2	P3	I3	P4	I4	P5
nine wells	Waterflood	Producer (600* STB/D)	Water injector (750** STB/D)	Producer (600* STB/D)	Water injector (750** STB/D)	Producer (600* STB/D)	Water injector (750** STB/D)	Producer (600* STB/D)	Water injector (750** STB/D)	Producer (600* STB/D)
	WCT reaches criteria	Shut in for 60 days								
	Gas dumpflood	Producer (600* STB/D)	Gas dumpflood well	Producer (600* STB/D)	Gas dumpflood well	Producer (600* STB/D)	Gas dumpflood well	Producer (600* STB/D)	Gas dumpflood well	Producer (600* STB/D)

*liquid production rate, **water injection rate

Well arrangements	Stage	P1	P4	I1	I3	P2	P5	I2	I4	P3	P6
ten wells	Waterflood	Producer (500* STB/D)		Water injector (750** STB/D)		Producer (500* STB/D)		Water injector (750** STB/D)		Producer (500* STB/D)	
	WCT reaches criteria	Shut in for 60 days									
	Gas dumpflood	Producer (500* STB/D)		Gas dumpflood well		Producer (500* STB/D)		Gas dumpflood well		Producer (500* STB/D)	

*liquid production rate, **water injection rate

Figures 5.10 and 5.11 demonstrate the oil production profile and water cut in each case of well arrangement, respectively. As depicted in Figure 5.11, case of nine wells takes longer time than other cases for water flooding to reach the water cut criteria. This is due to the early water breakthrough of wells P2, P3 and P4, making these wells to be shut in early and leaving only wells P1 and P5 still on production. As there are two wells left for production, longer time is needed before the water cut of these two wells to reach the criteria. The distance between injector and producer of nine wells is too narrow to have good sweep efficiency of oil toward the producers. For other cases, water flooding period duration is not so much different.

The total water injection rate of nine wells case in Figure 5.12 shows the reduction of injection rate from 3,000 STB/D to about 1,250 STB/D at around the fourth year. This is the result of simulator adjusting the rate not to exceed the maximum bottomhole target pressure for injection well which is set at 3,000 psia according to the fracturing pressure of 3,172 psia.

Figures 5.13 and 5.14 show that during gas dumpflood, there is some high amount of gas production and an increase in pressure of the reservoir. As the case of nine wells reaches the criteria to start gas dumpflood at the latest, gas production is delayed. The reservoir pressure for the case of nine wells is constant at 3,000 psia which is the same as the maximum BHP for water injection well. This is because water is still being injected until year 18th. During this time, the water cut has not reached the criteria yet.

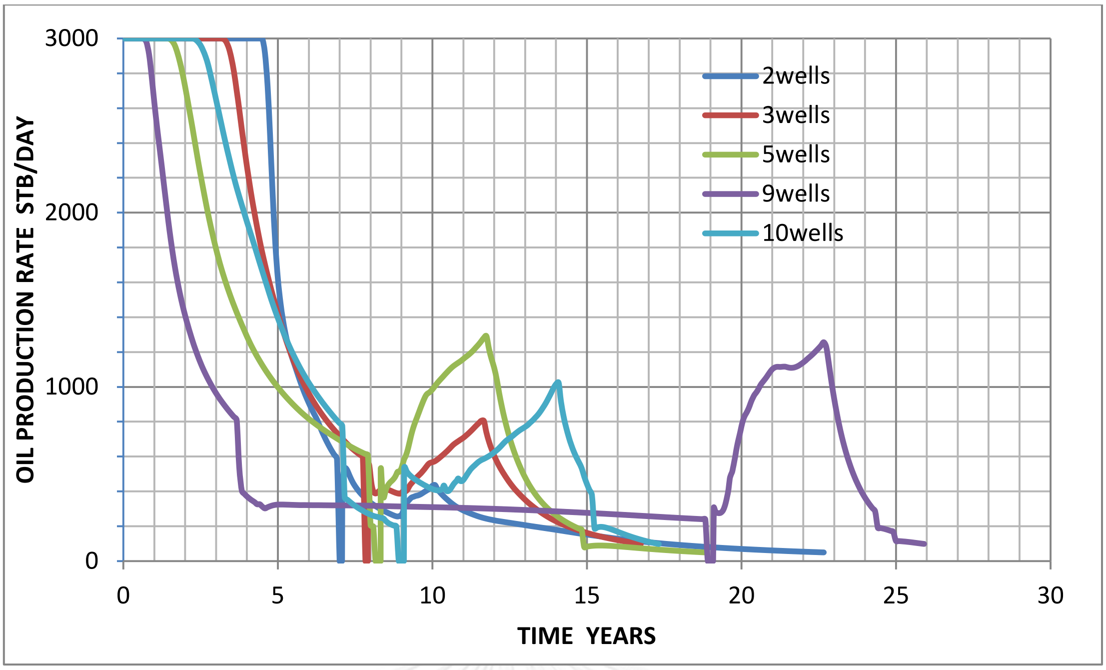


Figure 5. 10 Oil production rates for different well arrangements.

(0-degree dip angle)

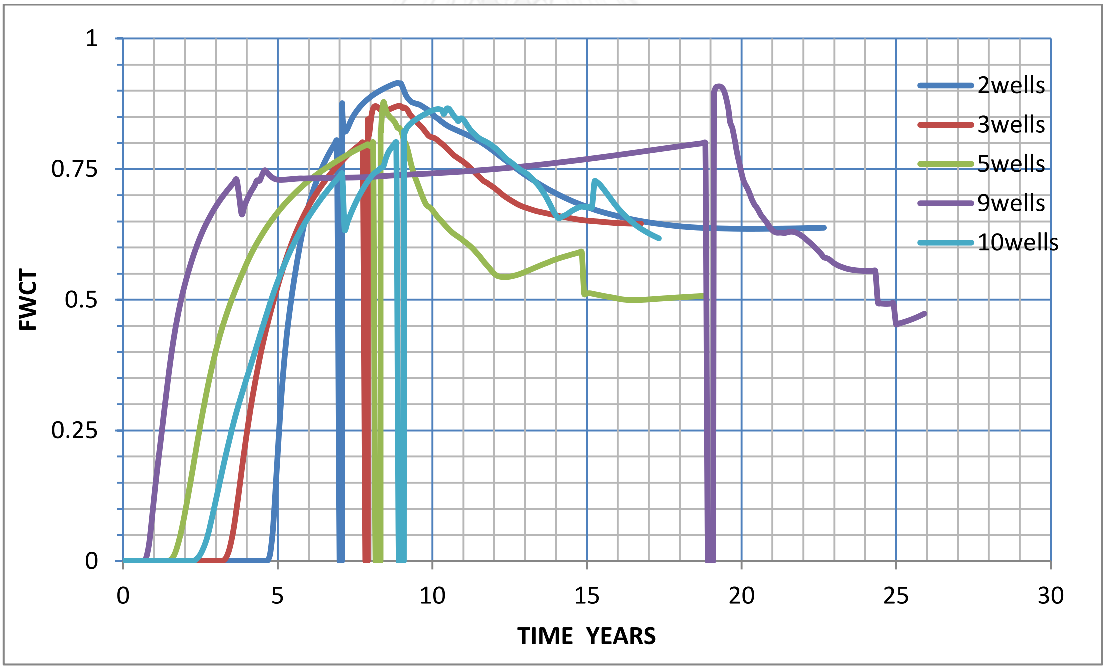


Figure 5. 11 Water cuts for different well arrangements.

(0-degree dip angle)

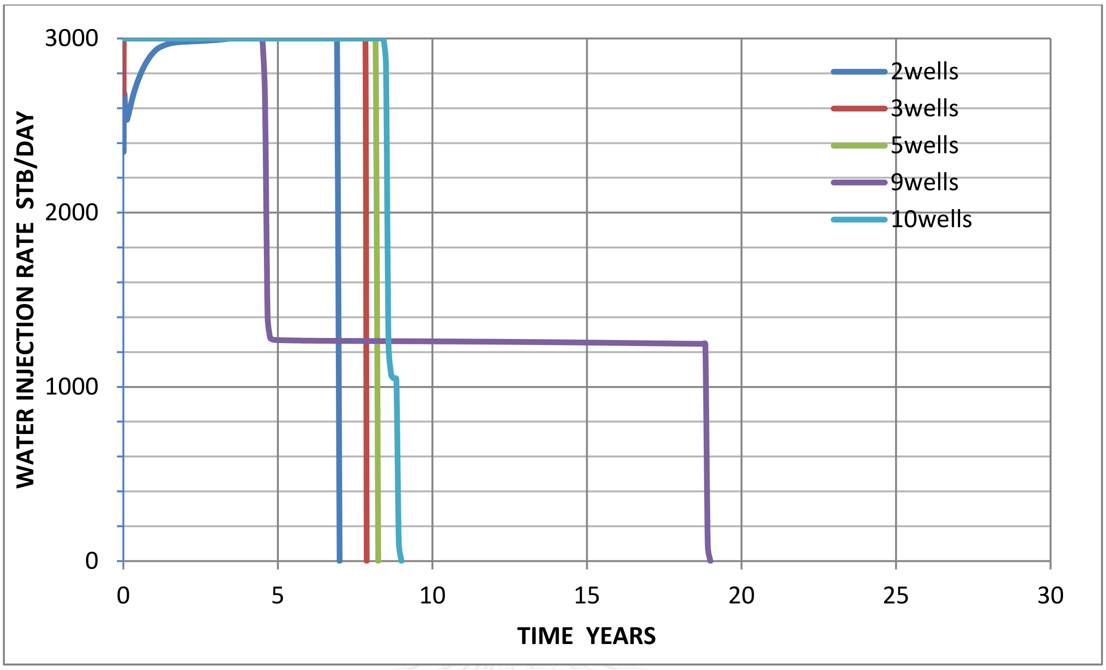


Figure 5. 12 Water injection rates for different well arrangements.

(0-degree dip angle)

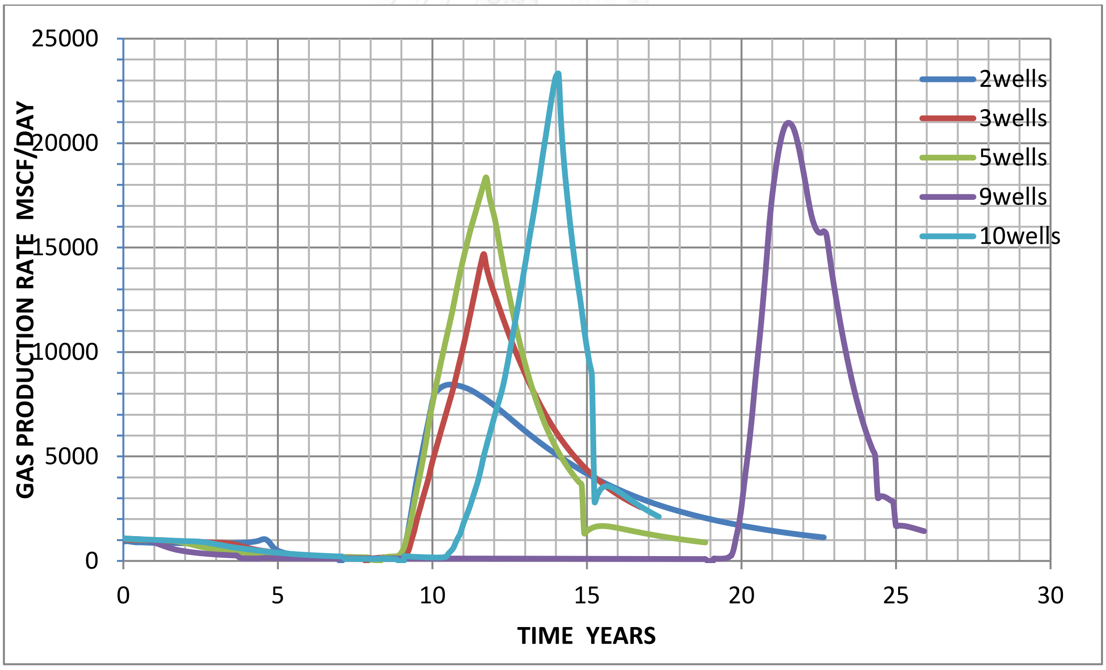


Figure 5. 13 Gas production rates for different well arrangements.

(0-degree dip angle)

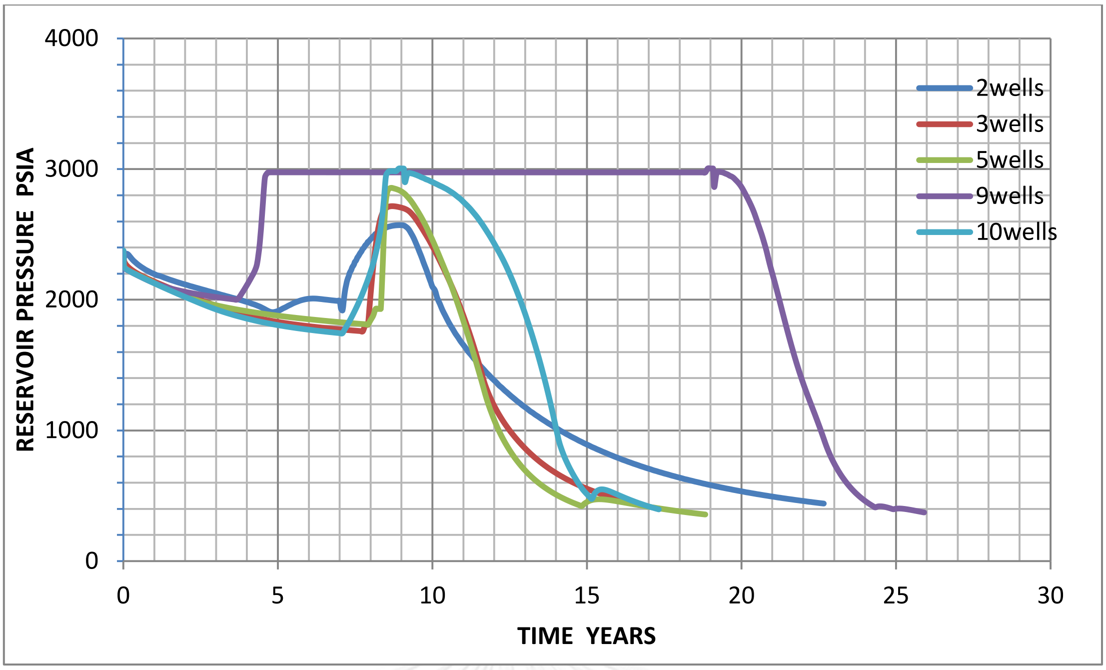


Figure 5. 14 Reservoir pressures for different well arrangements.

(0-degree dip angle)

Comparing between the cases of two and three wells in Table 5.9, the case of two wells obtains 21,308 STB lower total oil production and takes longer production time than the case of three wells. In term of water, it requires 1.115 million barrels less amount of injected water and 951,971 barrels less amount of produced water. As mentioned before, the total oil production between two cases show insignificant difference. However, the production time of three wells case takes about six years shorter. Thus, three wells case is more attractive than two wells case.

From the results shown in Table 5.9, as the number of wells is increased from three to nine, the recovery factor and total oil production decrease quite significantly. When the distance between injector and producer in the x-direction gets closer, there is more area in the y-direction left unswept. Thus, drilling more wells in the same alignment is not a good idea. However, when we increase the number of wells from five to ten by drilling another set of five wells in another alignment as shown in Figure 5.7, the recovery factor increases from 66.50% to 72.11%. This is because the better balance between the distances in the x- and y-directions. When comparing all cases, the case with three wells is the best performer. Although it yields 23,782 barrels of oil less than the case of ten wells, the cost of drilling and completing three wells is much less.

For gas production, the cases of two and three wells have low gas production since they have only one well that connects with the gas reservoir underneath. The other three cases have comparable amounts of gas production.

Table 5. 9 Summarized results for different well arrangements (0-degree dip angle)

Case	Water cut (%)	Production life (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
2 wells	80	22.66	71.65	7.065	7.468	6.123	21.652
3 wells	80	16.75	71.87	7.087	8.583	7.075	20.700
5 wells	80	18.83	66.50	6.558	8.943	7.399	23.493
9 wells	80	25.91	57.81	5.700	11.566	9.920	23.497
10 wells	80	17.34	72.11	7.111	9.444	7.868	22.990

5.1.3 Effect of stopping time for water flooding

Water cut criteria are used to investigate the stopping time for water flooding in order to start gas dumpflood. Five values of water cut used in this study are 1%, 20%, 40%, 60% and 80%. As the case of three wells is the best performer, it is used throughout the study. However, the investigation is expanded to cover both vertical and horizontal well types.

5.1.3.1 Vertical producers

Oil production rate of each water cut case is shown in Figure 5.15. From the beginning, the oil production is constant at 3000 STB/D for about 4 years. Then, it dramatically drops down. The well is later shut in due to the water cut criteria of each case. The lower the water cut criteria, the earlier the gas dumpflood starts. Thus, 1% water cut is the case that gas dumpflood is started soonest and abandoned at the earliest because the oil production reaches the economic rate of 50 STB/D soonest.

During the first 3.5 years in Figure 5.16, there is no difference in oil recovery for different water cut criteria. During early gas dumpflood process in the 4th and 6th year, the case of 1% water cut criteria yields the highest oil recovery but at the end of production, the case of 80% water cut criteria yields the highest value. The oil recovery factor slightly increases as the water cut criteria increases.

Figure 5.17 illustrates water cut profiles for different water cut criteria used to start gas dumpflood. During the beginning of gas dumpflood process, the result of water cut is high since water is still around the production well as a result of prior water flooding. After that, the water cut gradually reduces but it is still higher than 50%.

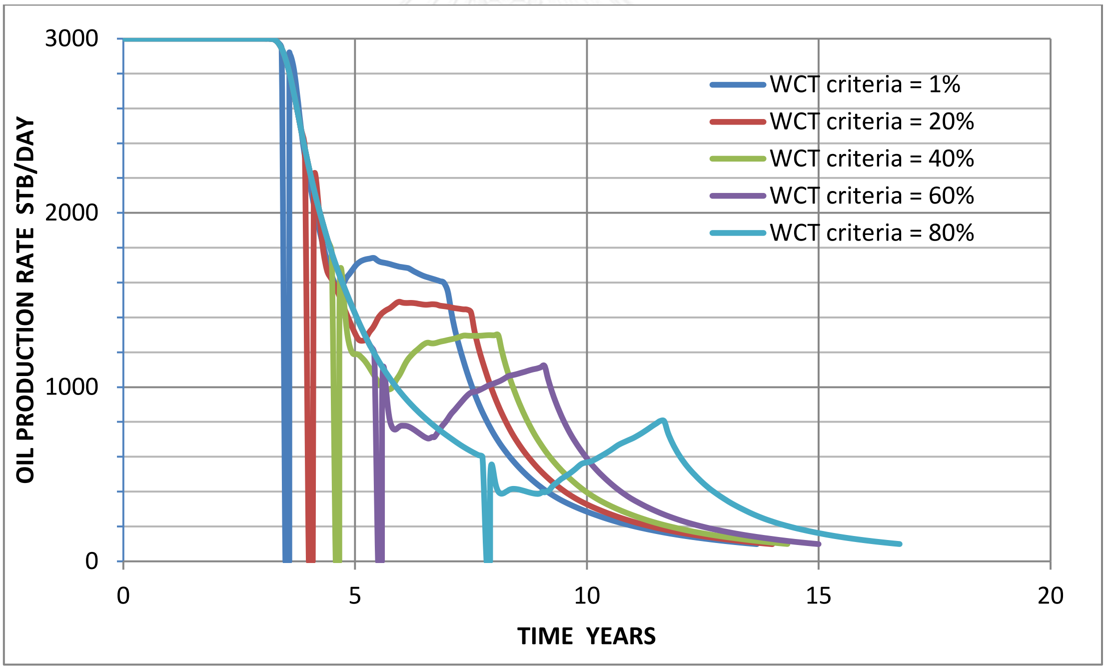


Figure 5. 15 Oil production rates for different water cut criteria (0-degree dip angle)

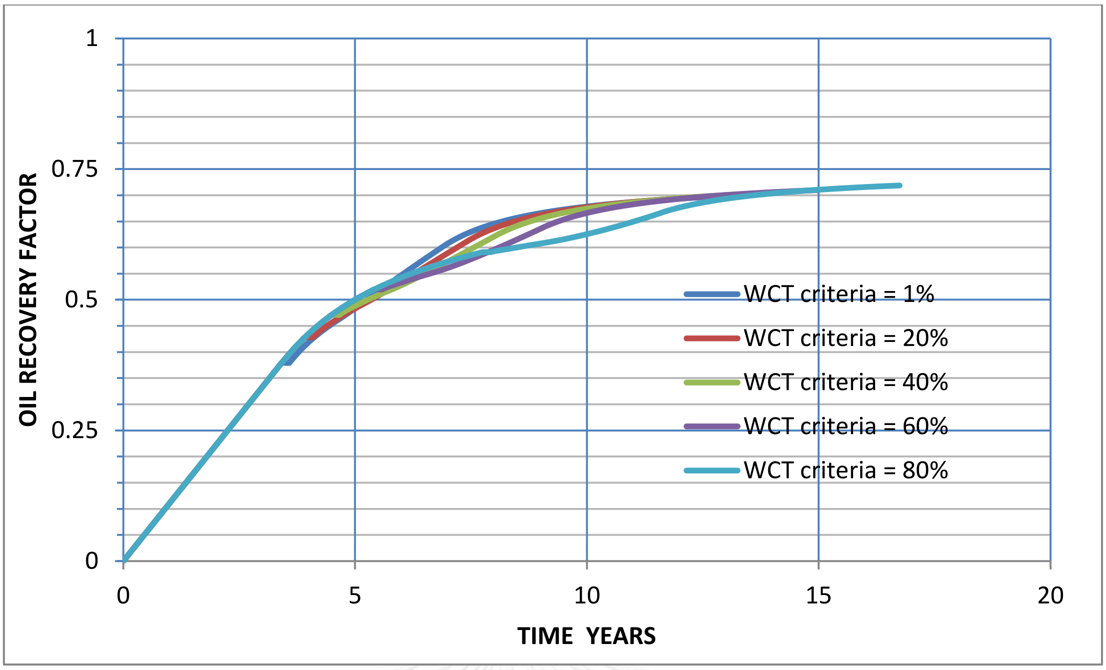


Figure 5. 16 Oil recovery factors for different water cut criteria

(0-degree dip angle)

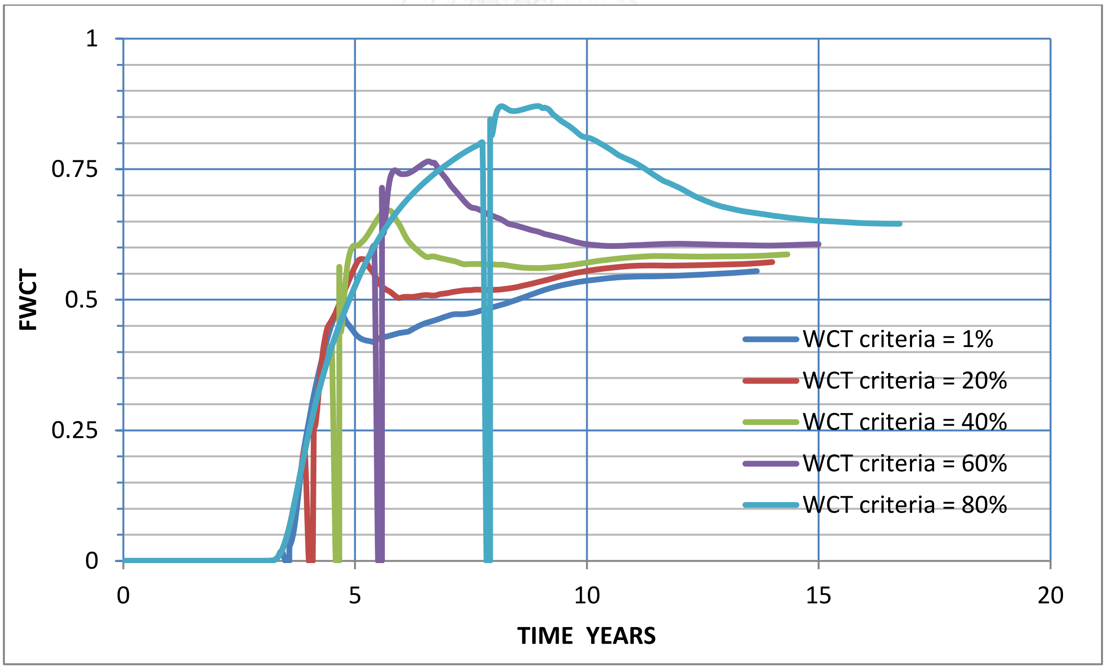


Figure 5. 17 Water cut profiles for different water cut criteria

(0-degree dip angle)

Summarized results tabulated in Table 5.10 illustrate that the oil recovery factor and total oil production slightly increases as the water cut criteria is increased but the amounts of water production and water injection increase quite significantly. In particular, when we increase the water cut criteria from 1% to 80%, oil recovery increases by 173,687 STB while requiring 4.754 million barrels more water injection and producing additional 4.637 million barrels of water. In normal circumstance, this small increment in oil production does not pay off the additional water injection and production. In term of production life and gas production, there is no significant difference among different cases.

Table 5. 10 Summarized results for different water cuts criteria of vertical producers (0-degree dip angle)

Case	Water cut (%)	Production life (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
3 wells	1	13.67	70.11	6.913	3.829	2.438	21.668
	20	13.99	70.36	6.938	4.382	2.964	21.550
	40	14.37	70.61	6.962	5.018	3.574	21.379
	60	14.99	70.99	7.001	6.019	4.551	21.199
	80	16.75	71.87	7.087	8.583	7.075	20.700

5.1.3.2 Horizontal producers

In this section, we investigate different water cut criteria used to start gas dumpflood when the producers are horizontal wells. According to the previous section, three vertical wells provide good result on oil recovery with good sweep efficiency in the x- and y-directions. Thus, we try the locations of these three wells for this case in an attempt to get better performance from horizontal producers. Note that the middle well which is used to dump gas from the source reservoir is still a vertical well. Two horizontal producers are placed in layer 5 of the oil reservoir in the y-direction (bottom most layer) with the length of 1900 ft. Figures 5.18-5.19

illustrate the schematics of horizontal well type. Five values of water cut criteria are investigated: 1%, 20%, 60%, 40% and 80%.

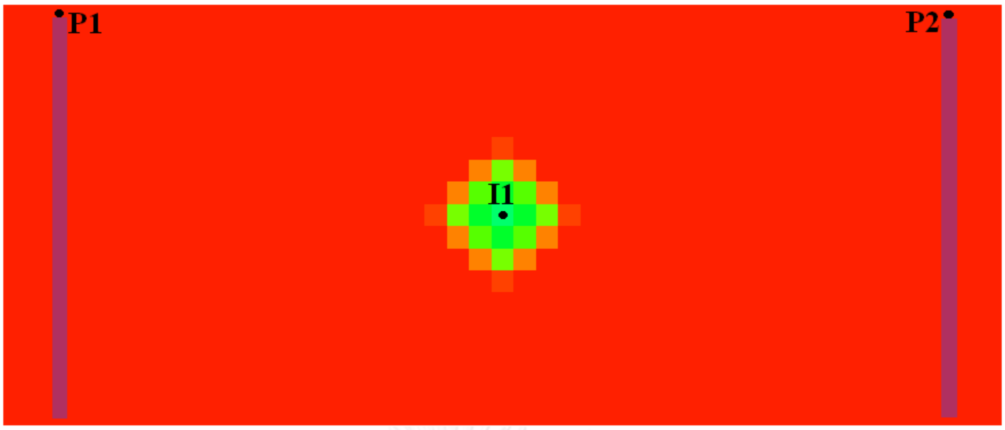


Figure 5. 18 Schematic of two horizontal producers and one vertical well used for gas dumpflood (0-degree dip angle)

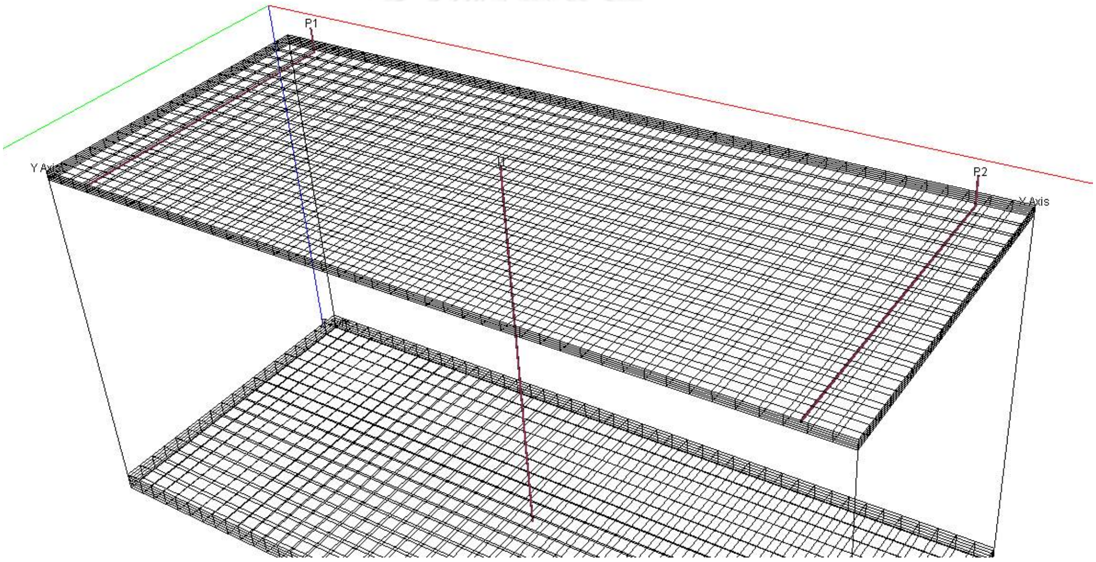


Figure 5. 19 Well placement of two horizontal producers and one vertical well used for gas dumpflood (0-degree dip angle)

Table 5. 11 Locations and constraints of two horizontal producers and one vertical well used for gas dumpflood (0-degree dip angle)

Well	i^{th} position	j^{th} position	Fracture pressure (psia)
I1	23	10	3,172
P1	3	1-19	3,172
P2	43	1-19	3,172

Higher water cut criteria delays the time to start gas dumpflood and abandon the process as shown in Figure 5.20. Oil recovery factor during the first four years in Figure 5.21 shows no difference among different water cut criteria as it is still the water flooding period. As gas dumpflood is started, the highest oil recovery factor is obtained in the case of 1% water cut and becomes gradually lower as the water cut criteria increases to 20%, 40%, 60% and 80%. However, at the economic constraint, the case with 80% water cut criteria yields the highest oil recovery factor.

Water cut criteria in each case is reached at different times as shown in Figure 5.22. During the early time of gas dumpflood process, water cut is so high since water around wellbore from water flooding process is produced.

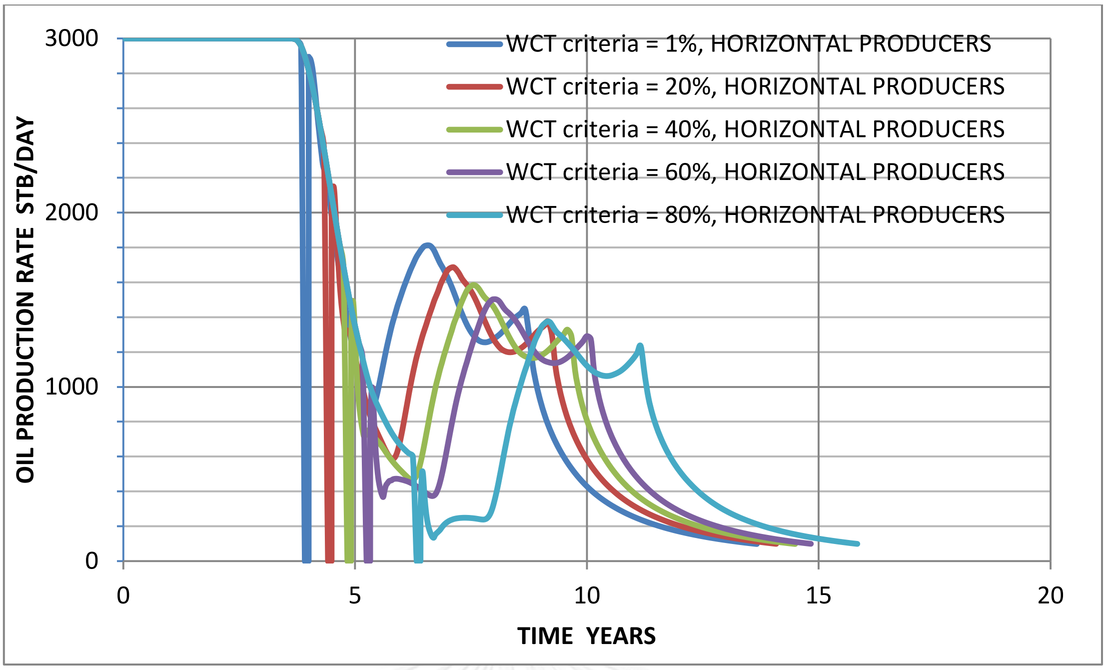


Figure 5. 20 Oil production rates for different water cut criteria

(0-degree dip angle)

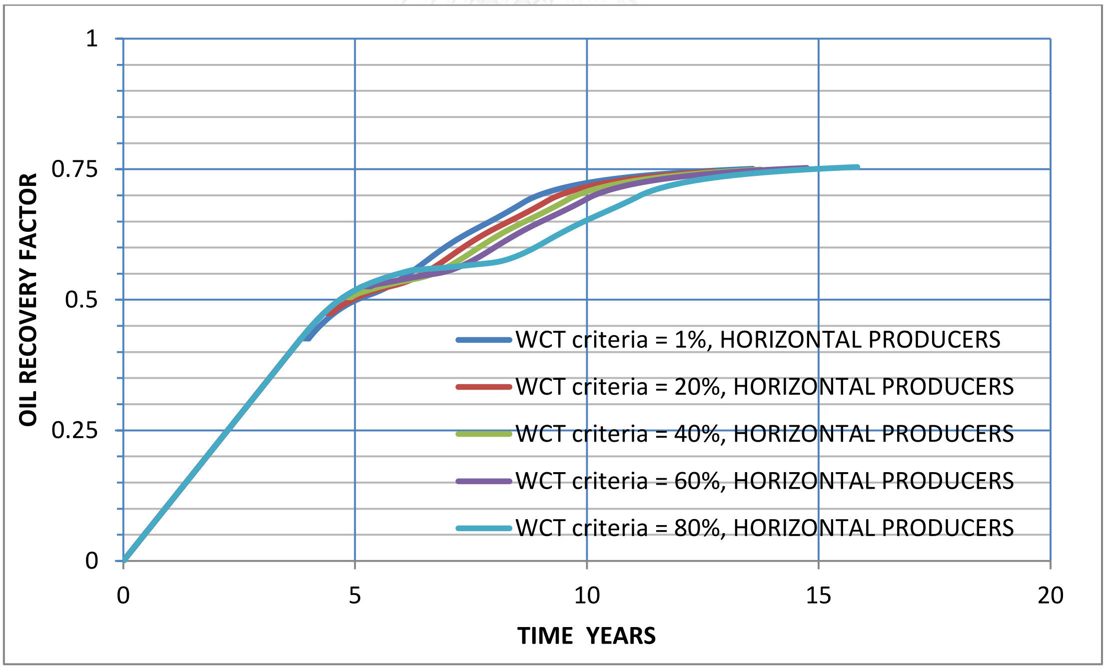


Figure 5. 21 Oil recovery factors for different water cut criteria

(0-degree dip angle)

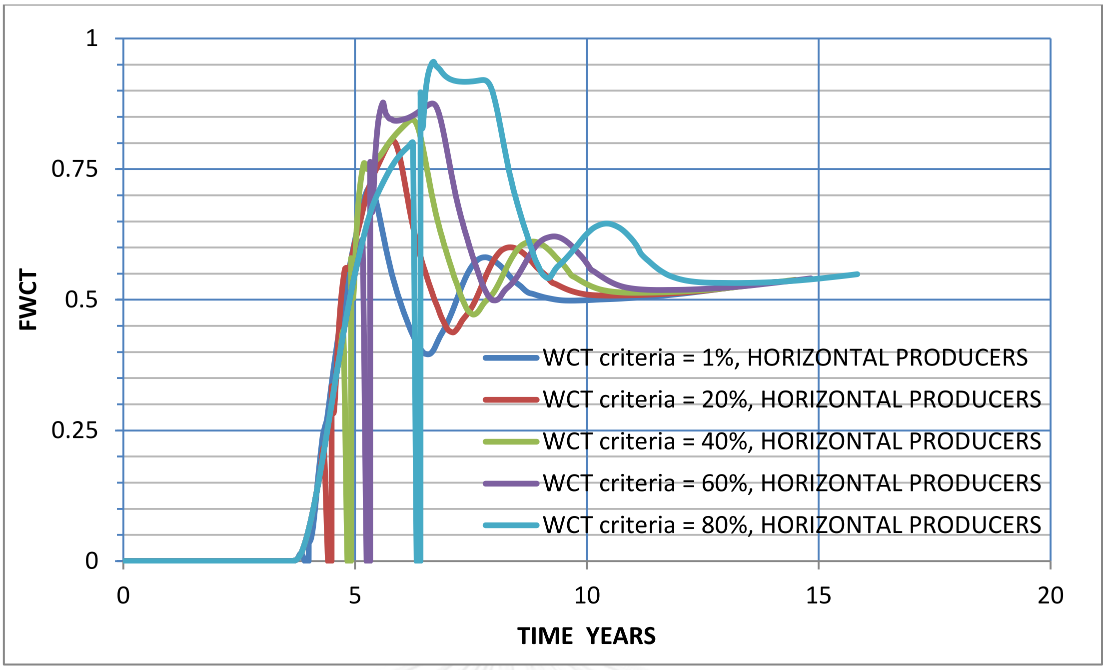


Figure 5. 22 Water cut profiles for different water cut criteria (0-degree dip angle)

Summarized results provided in Table 5.12 demonstrate that the oil recovery factor and total oil production insignificantly increases as the water cut criteria is increased but the amounts of water injection and water production considerably increase. When the water cut criteria is increased from 1% to 80%, oil production is increased by 29,967 STB with the 2.643 million barrels more of injected water and 2.616 million barrels more of produced water. This small increment of oil recovery does not pay off for the additional water injection and water production. In term of gas production, all the cases produce approximately the same amount.

Table 5. 12 Summarized results for different water cut criteria of gas dumpflood using horizontal producers (0-degree dip angle).

Case	Water cut (%)	Production life (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
2 horizontal producers for gas dumpflood	1	13.67	75.12	7.407	4.288	3.169	21.991
	20	14.08	75.18	7.413	4.836	3.707	21.925
	40	14.49	75.25	7.420	5.295	4.162	21.908
	60	14.84	75.28	7.423	5.748	4.610	21.846
	80	15.84	75.42	7.437	6.931	5.785	21.766

5.1.4 Effect of perforation interval of source gas reservoir

The perforation interval of source well at the depth of gas reservoir is investigated to see the effect of gas dumpflood into the subject oil zone. The case of two horizontal producers with 1% water cut criteria is performed to see the results. The total gas thickness is 100 ft. The perforation interval is varied from 20% to 40%, 60%, 80% and 100% of the total thickness.

Figures 5.23-5.25 illustrate the oil production rate, oil recovery factor and water production rate for different production intervals. Oil and water production profiles for different perforation intervals look very slightly different. The oil recovery factors for different cases follow the same line.

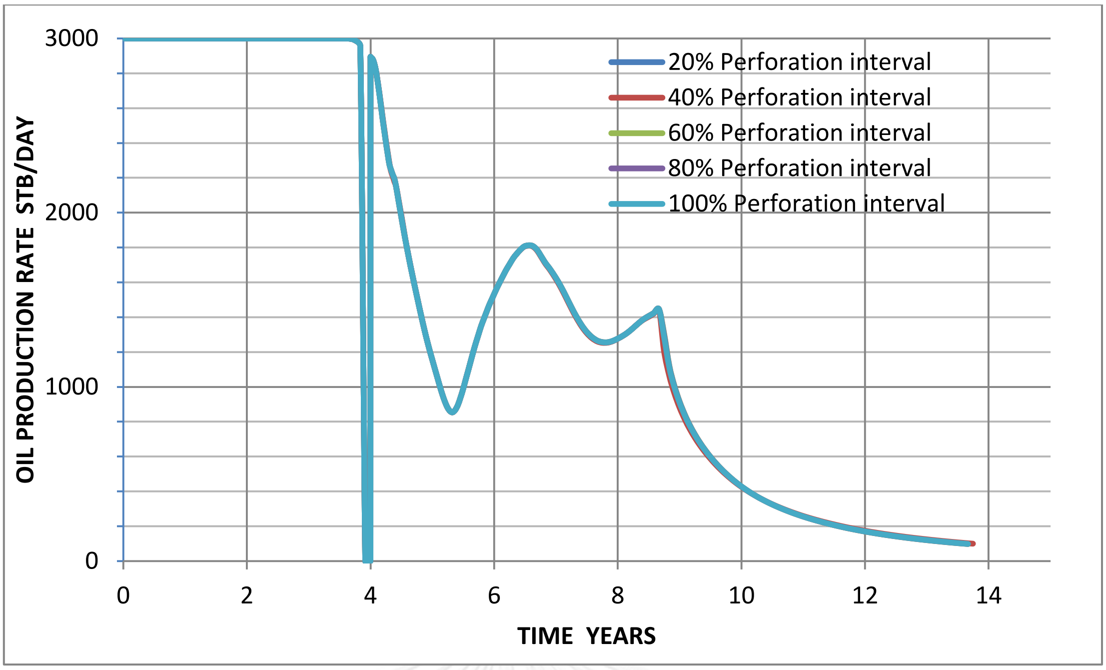


Figure 5. 23 Oil production rate for different perforation intervals (0-degree dip angle)

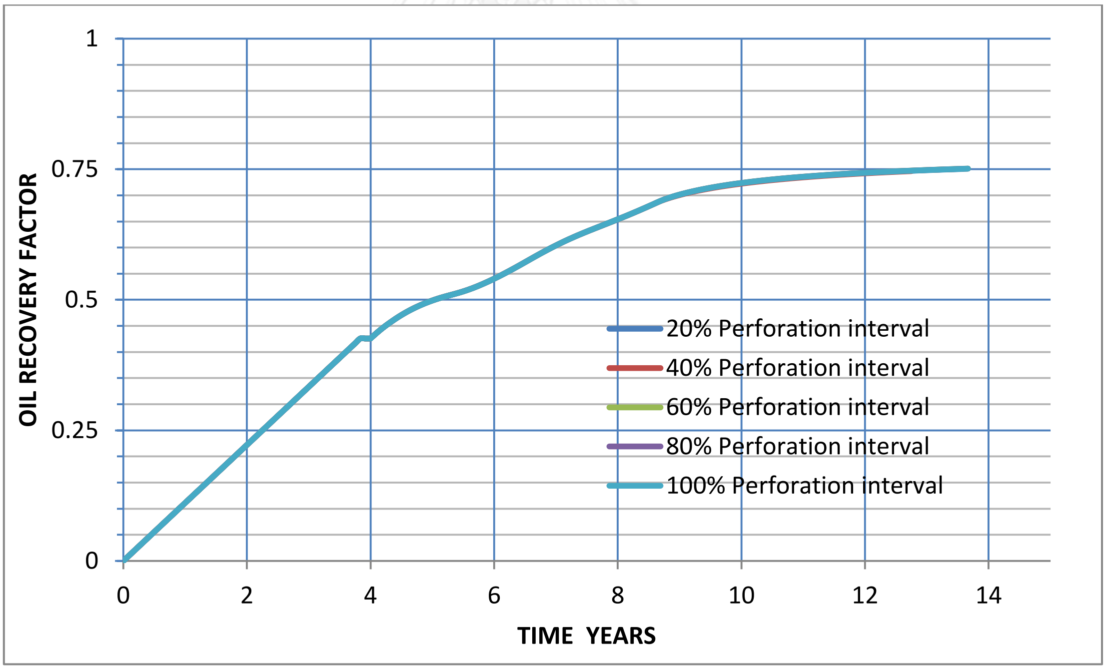


Figure 5. 24 Oil recovery factor for different perforation intervals (0-degree dip angle)

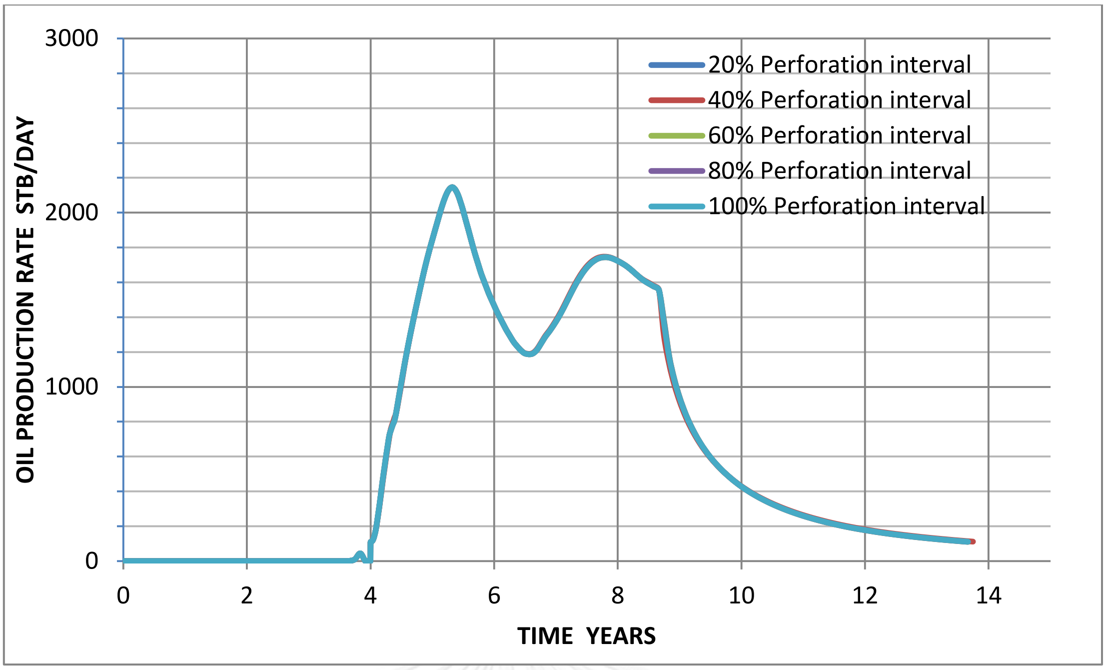


Figure 5. 25 Water production rate for different perforation intervals (0-degree dip angle)

From the results tabulated in Table 5.13, as the percentage of perforation interval increases, the oil recovery factor and total oil production slightly increases. As perforation interval of the gas zone does not affect water injection from surface, the amount of water injection is the same for all cases. However, there is a slight difference in water production as the amount of gas flowing from the gas reservoir into the oil zone which depends on perforation interval affects oil and water production. When we perforate more intervals from 20% to 100%, 6,048 barrels of oil is gained while producing 3,234 barrels less water. According to these results, the perforation interval does not affect much on the performance. Thus, we would rather choose to perforate only 20% than all the thickness due to lower cost of perforation and lower risk of fracturing the target zone.

Table 5. 13 Summarized results for different perforation intervals (0-degree dip angle)

Case	Production life (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
20% perforation (from bottom)	13.76	75.06	7.401	4.288	3.172	21.678
40% perforation (from bottom)	13.67	75.08	7.404	4.288	3.169	21.841
60% perforation (from bottom)	13.67	75.10	7.406	4.288	3.169	21.923
80% perforation (from bottom)	13.67	75.11	7.407	4.288	3.169	21.966
100% perforation	13.67	75.12	7.407	4.288	3.169	21.991

5.1.5 Effect of water injection rate and liquid production rate

The case with two horizontal production wells with 20% perforation of gas zone from bottom and 1% water cut criteria is used for investigating the effect of water injection and liquid production rate. Note that water injection rate in this case is limited by fracture pressure that should not allow bottomhole pressure be higher than 3,172 psia.

Table 5.14 shows different combinations of target water injection and target liquid production rate that have been studied in this section.

Table 5. 14 Target water injection and liquid production rates (0-degree dip angle)

Case	Target water injection rate (STB/D)	Target liquid production rate (STB/D)
1	3,000	3,000
2	5,000	5,000
3	7,000	7,000
4	7,000	3,000
5	7,000	5,000
6	7,000	9,000
7	3,000	7,000
8	5,000	7,000

As shown in Figure 5.26, the target water injection rate of 3,000 and 5,000 STB/D can be achieved until the end of water flooding. But for cases with 7,000 STB/D target, only case 6 can reach that rate for some period of time but cases 3, 4 and 5 cannot reach the target rate at all. The target rate cannot be reached because of the limit in the bottom pressure due to fracturing pressure.

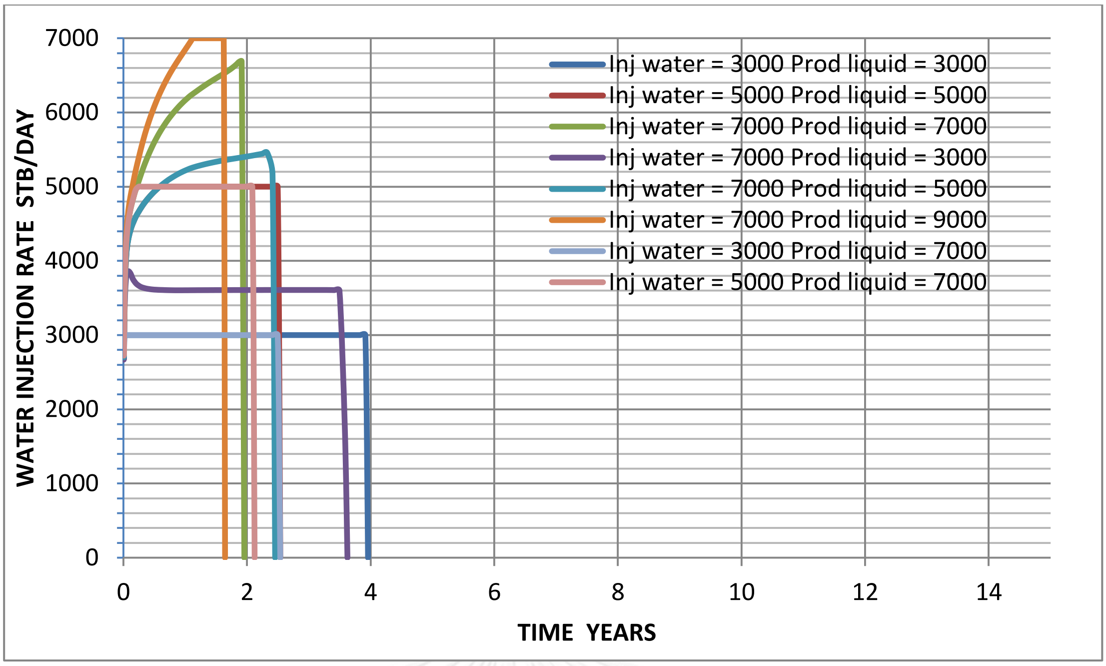


Figure 5. 26 Water injection profiles for different target water injection and liquid production rates (0-degree dip angle)

Figure 5.27 illustrates oil production rate for different combinations of target rates. The oil production rate of 3,000, 5,000, 7,000 and 9,000 STB/D can be all reached and kept constant for some period of time until it dramatically drops down due to water breakthrough. When the water cut criteria of 1% is reached, the wells are shut in and gas dumpflood begins. The higher the target liquid production rate, the sooner the water cut reaches the criteria, thus; the sooner gas dumpflood starts. During gas dumpflood process, the oil rate increases and drops down again due to the increase in water cut as shown in Figure 5.28.

In term of oil recovery factor (Figure 5.29), during the early period, case 6 has the highest amount of oil recovery but at the end of production, case 7 has the highest oil recovery and case 4 has the lowest.

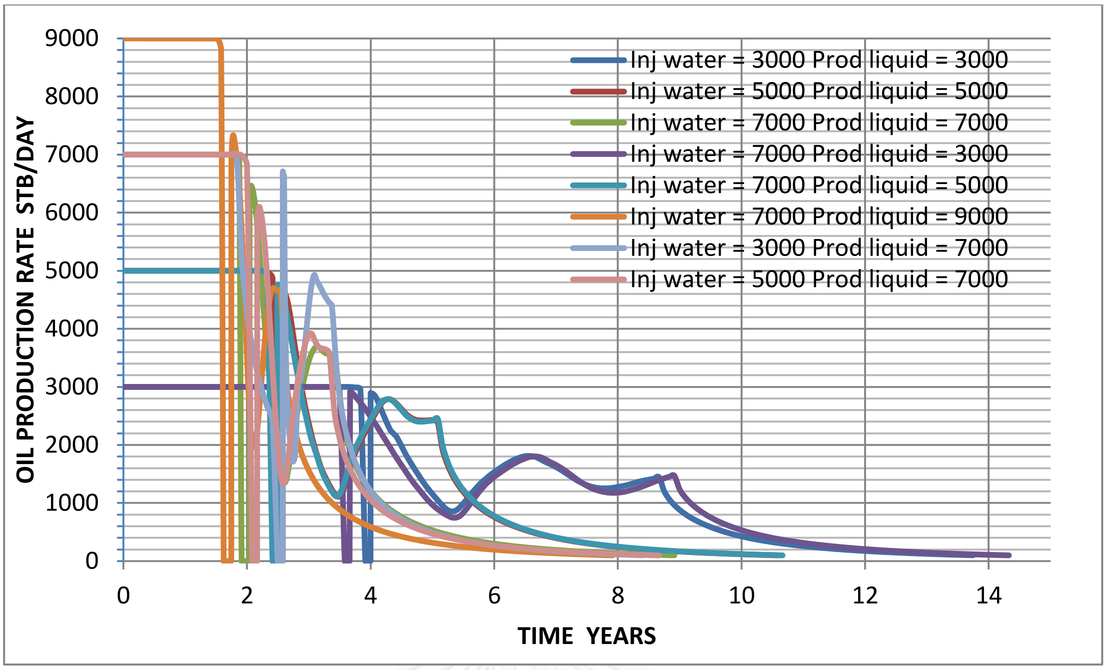


Figure 5. 27 Oil production profiles for different target water injection and liquid production rates (0-degree dip angle)

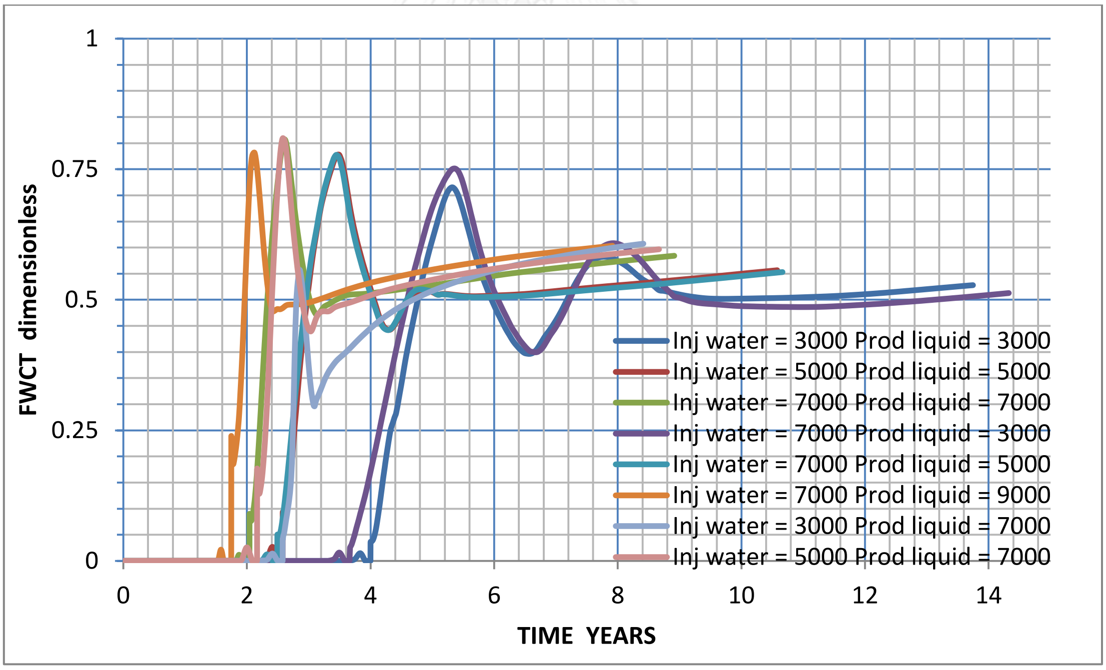


Figure 5. 28 Water cuts for different target water injection and liquid production rates (0-degree dip angle)

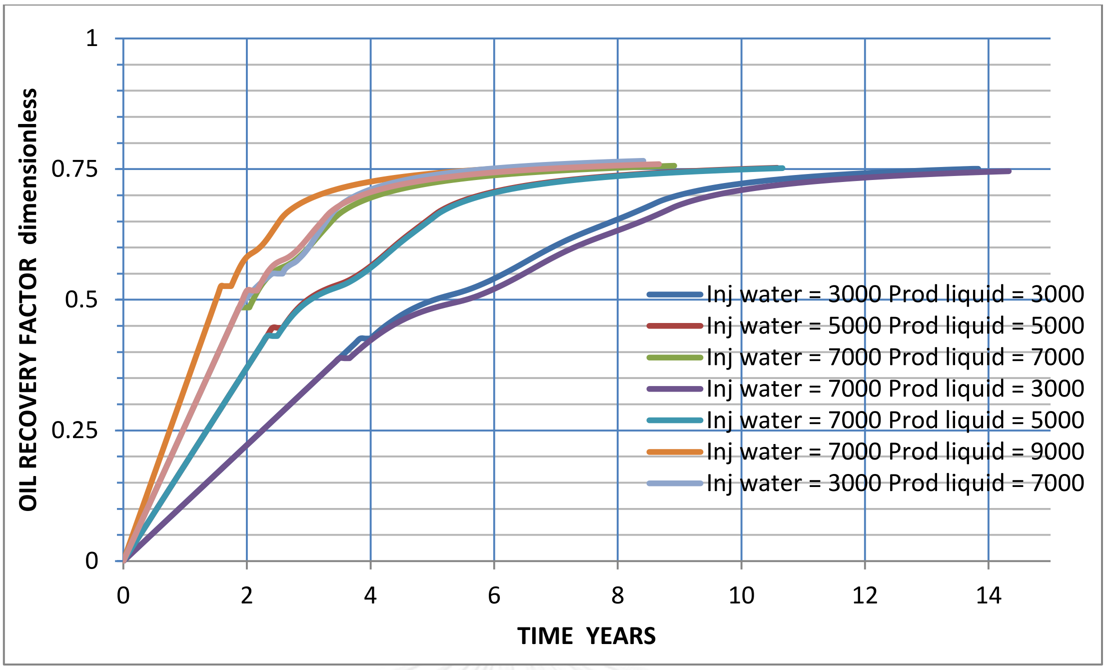


Figure 5. 29 Oil recovery factors for different target water injection and liquid production rates (0-degree dip angle)

Cases 1, 2, 4 and 5 show better maintenance of reservoir pressure than cases 6 and 7 which have the lowest reservoir pressure profiles among all cases as shown in Figure 5.30. This is because the oil production rates of cases 1, 2, 4 and 5 are less than or equal to the water injection rates.

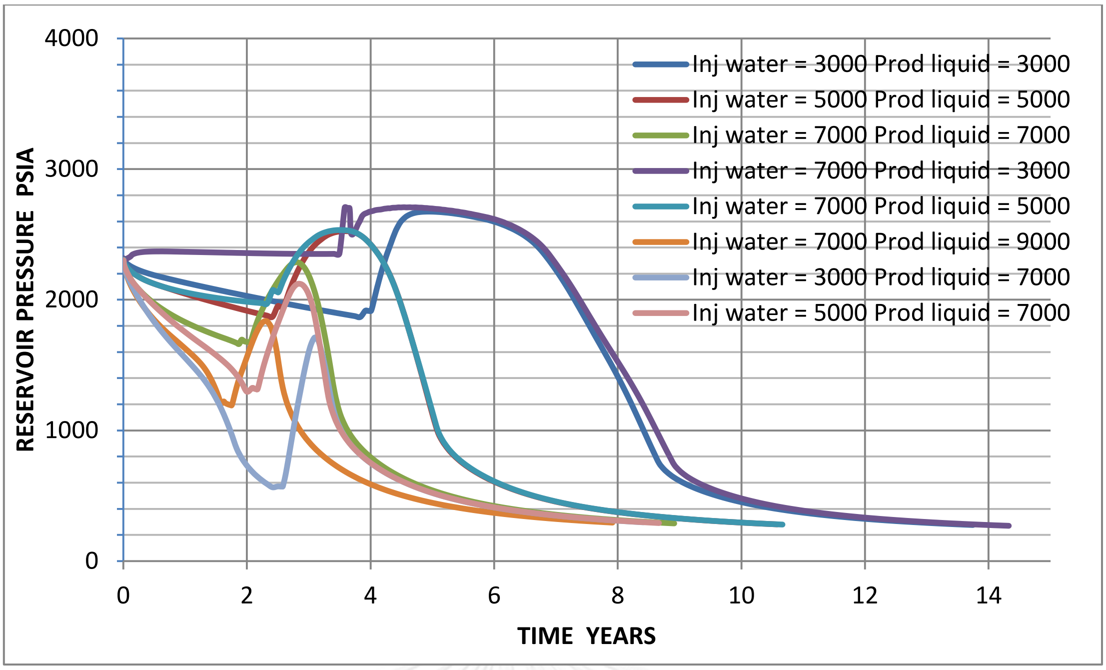


Figure 5. 30 Reservoir pressures for different target water injection and liquid production rates (0-degree dip angle)

The results for different combinations of rates are summarized in Table 5.15. In cases 1-3, the same injection and production rate are selected in order to balance the reservoir pressure. Then, the rate in case 3 is selected for further investigation of unequal injection and production rates. Case 3 has been selected because of higher oil recovery, less water injection and production, and less time for production life among the three cases.

For different combinations of target water injection rate and target liquid production rate, it has been found that a higher target liquid production rate provides better oil recovery. For example, as we increase the target liquid rate from 3,000 to 9,000 STB/D (from case 4 to case 6), the oil recovery increases by 141,852 barrels with 914,625 barrels less water injection and 1.03 million barrels less water production. In the same way, when lowering water injection rate by keeping oil production rate constant as conducted in cases 7 and 8, oil recovery increases by 62,612 barrels with 1.04 million barrels less water injection and 1.01 million barrels less water production.

Case 7 is considered to be the best performer. The total oil production and oil recovery are the highest with the least amount of water injection and water production among all cases. In term of gas production, the numbers are quite similar for all cases.

Table 5. 15 Summarized results for different combinations of target water injection rate and liquid production rates (0-degree dip angle).

Case	Waterflood duration (years)	Production life (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
1	3.84	13.75	75.06	7.401	4.288	3.172	21.678
2	2.41	10.58	75.25	7.420	4.481	3.310	21.497
3	1.87	8.91	75.64	7.459	4.150	2.944	21.189
4	3.49	14.33	74.60	7.356	4.670	3.560	21.975
5	2.33	10.66	75.19	7.414	4.530	3.361	21.563
6	1.58	7.91	76.04	7.498	3.755	2.529	20.906
7	2.41	8.41	76.59	7.552	2.734	1.540	20.693
8	1.99	8.67	75.95	7.489	3.771	2.554	21.042

5.2 Dip angle of 15 degrees

Oil and gas reservoirs with 15 degree dip angle are simulated to determine the effect of different operating parameters on gas dumpflood after initial water flooding. This section starts by comparing gas dumpflood after water flooding with conventional long-termed water flooding. Then, the effects of well arrangement, stopping criteria for water flooding, perforation interval of gas zone, target water injection rate and liquid production rate on performance of the gas dumpflood case are investigated.

5.2.1 Gas dumpflood in waterflooded reservoir versus conventional water flooding

The gas dumpflood case and conventional water flooding are compared to see the benefits of gas dumpflood in water-flooded reservoir. Our gas dumpflood case and water flooding case consist of one production well and one injection well as shown in Figure 5.31. In the gas dumpflood case, water cut of 80% is set as stopping criteria for water flooding before starting gas dumpflood and oil production rate of 50 STB/D is set as the abandonment criteria. For conventional water flooding, 95% of water cut is set before abandoning the process.

Table 5.16 shows the injection and production sequence. During the water flooding period, well 2 located downdip is used to inject water and sweep oil towards well 1 located updip. At this initial stage, well 1 serves as a producer. After water cut reaches the criteria, wells 1 and 2 are shut in for 60 days. Well 1 is then perforated at the gas zone. Then, gas dumpflood is performed by dumping gas through well 1 to sweep oil toward well 2. Thus, during gas dumpflood, well 2 serves as a producer.

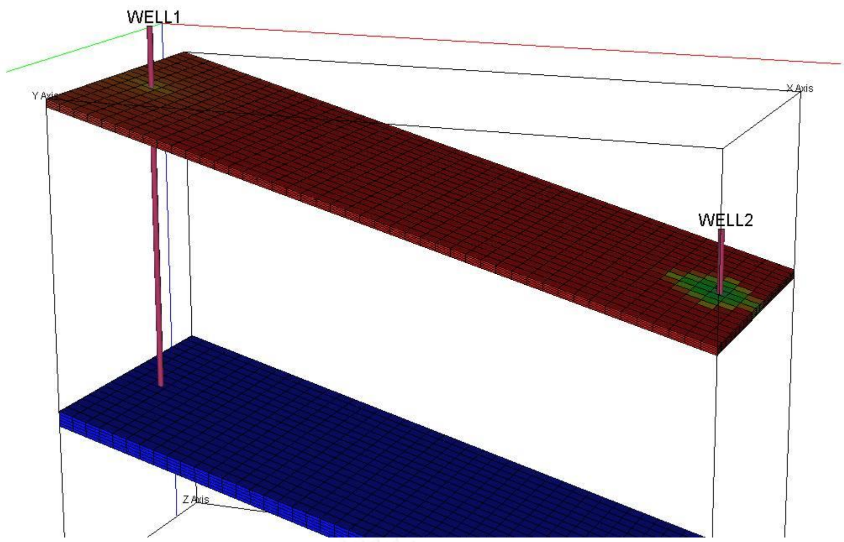


Figure 5. 31 Well placement of gas dumpflood case
(15-degree dip angle)

Table 5. 16 Injection and production sequence of gas dumpflood in water-flooded reservoir (15-degree dip angle)

Stage	Well1	Well2
Waterflood	Producer	Water injector
WCT reaches criteria	Shut in for 60 days	Shut in for 60 days
Gas dumpflood	Gas dumpflood well	Producer

During gas dumpflood period, gas from the underneath reservoir may have high pressure that can cause fracture pressure in the target oil reservoir if gas is allowed to flow freely with no restriction. In order to reduce the pressure of the gas, the gas zone should be partially perforated. Since the well may need to be perforated with an interval smaller than the grid dimension in the z-direction in order to reduce the gas pressure to be lower than the fracturing pressure of the oil reservoir, partial penetration skin needs to be incorporated into the simulator. Based on trial and error, skin value of 1,165 is required for the well completed in the gas zone. This skin value is equivalent to the perforation interval of 0.36 ft out of 100 ft of gas reservoir as shown in Table 5.17.

Table 5. 17 Perforation interval and skin of source gas reservoir (15-degree dip angle)

Case	Perforation interval(ft)	Skin
Gas dumpflood case	0.36	1,165

The oil production rates for both cases start at 5,000 STB/D as shown in Figure 5.32 and then dramatically drop down. For conventional water flooding case, oil is produced until water cut reaches 95% as abandonment criteria. For gas dumpflood case, the production stops when it reaches the water cut criteria of 80% and gas dumpflood process is then started. The oil rate starts with no shoot up rate after production as observed in the case of 0-degree dip angle due to changing of injection and production well sequence. The oil rate stays at 200 STB/D for 1.5 year and starts to increase due to gas breakthrough.

During gas dumpflood period shown in Figure 5.35, the amount of gas production increases. Gas dumpflood in water-flooded reservoir can prolong the oil production due to the fact that gas sweeps oil toward the producer. The oil is produced until it reaches the economic rate of 50 STB/D.

The water cut for both cases are shown in Figure 5.33 while water injection rate is shown in Figure 5.34. For reservoir pressure of gas dumpflood case, it sharply declines due to oil production as depicted in Figure 5.36.

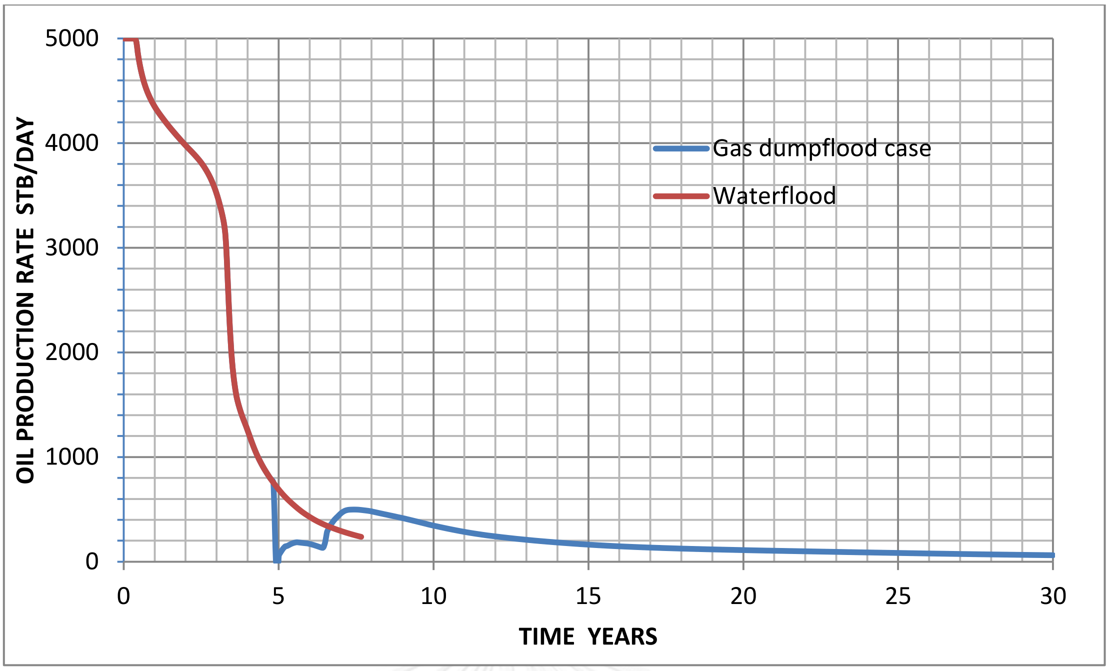


Figure 5. 32 Oil production rate comparison between gas dumpflood case and water flooding (15-degree dip angle)

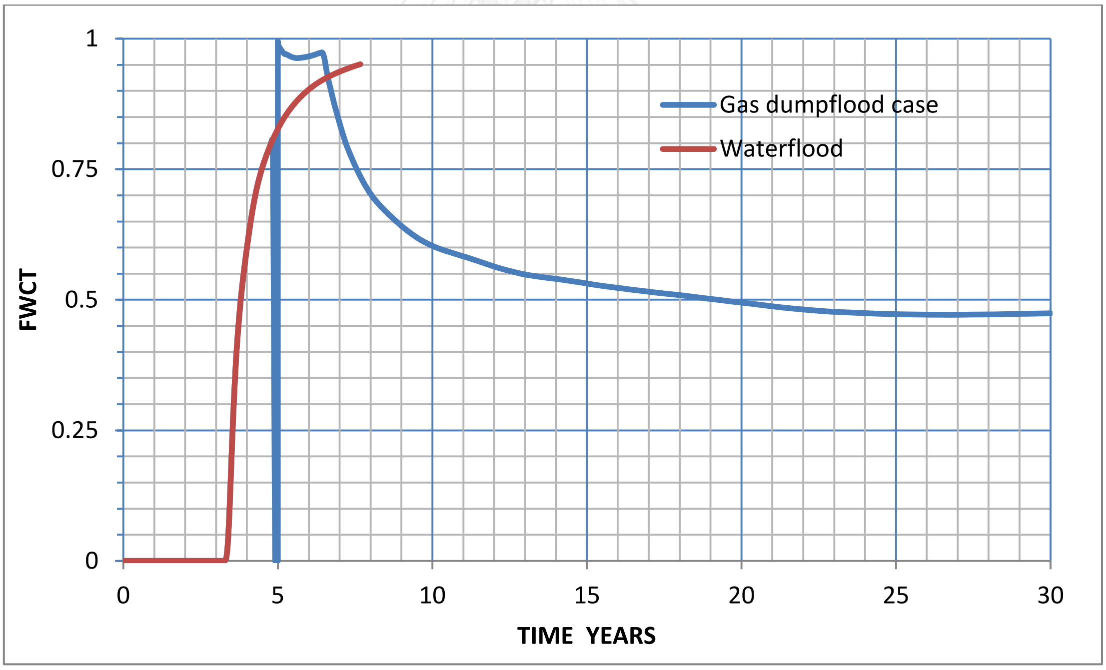


Figure 5. 33 Water cut comparison between gas dumpflood case and water flooding (15-degree dip angle)

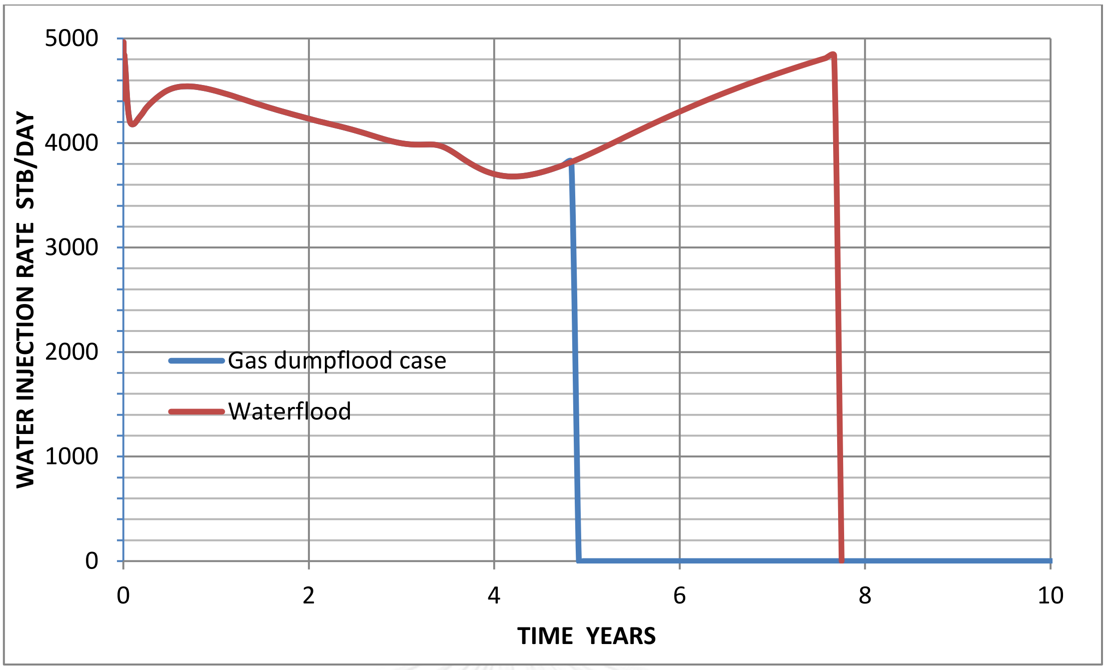


Figure 5. 34 Water injection rate comparison between gas dumpflood case and water flooding (15-degree dip angle)

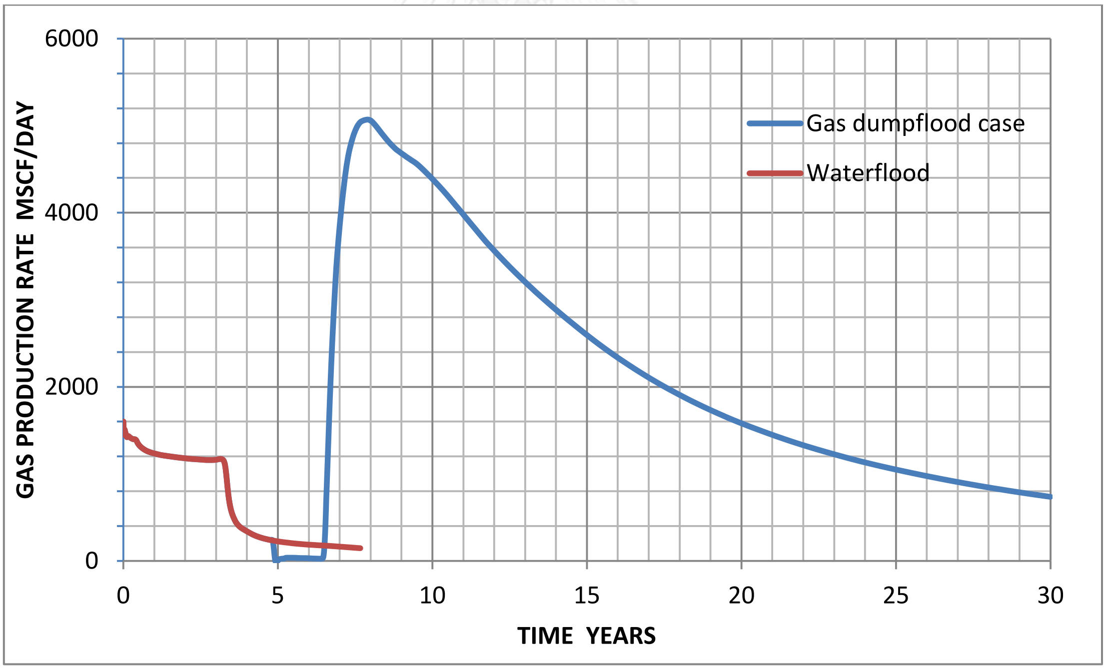


Figure 5. 35 Gas production rate comparison between gas dumpflood case and water flooding (15-degree dip angle)

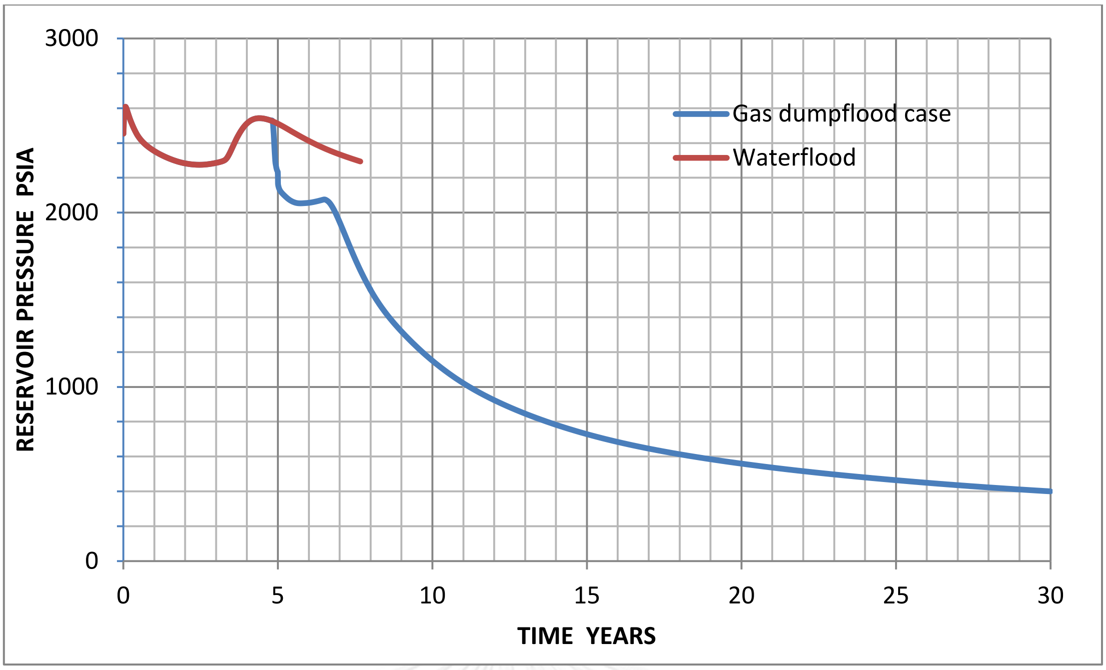


Figure 5. 36 Reservoir pressure comparison between gas dumpflood case and water flooding (15-degree dip angle)

Gas from underneath gas reservoir starts to flow into target oil zone at the 5th year with gas rate around 3,400 MSCF/D as shown in Figure 5.37 and stays at this rate until the 6.5th year which is gas breakthrough. After that, gas rate rises up to a peak around 4,000 MSCF/D and then drops down as gas from underneath gas reservoir is depleted.

Figure 5.38 shows saturation profiles of gas dumpflood case at the beginning of gas dumpflood and gas breakthrough.

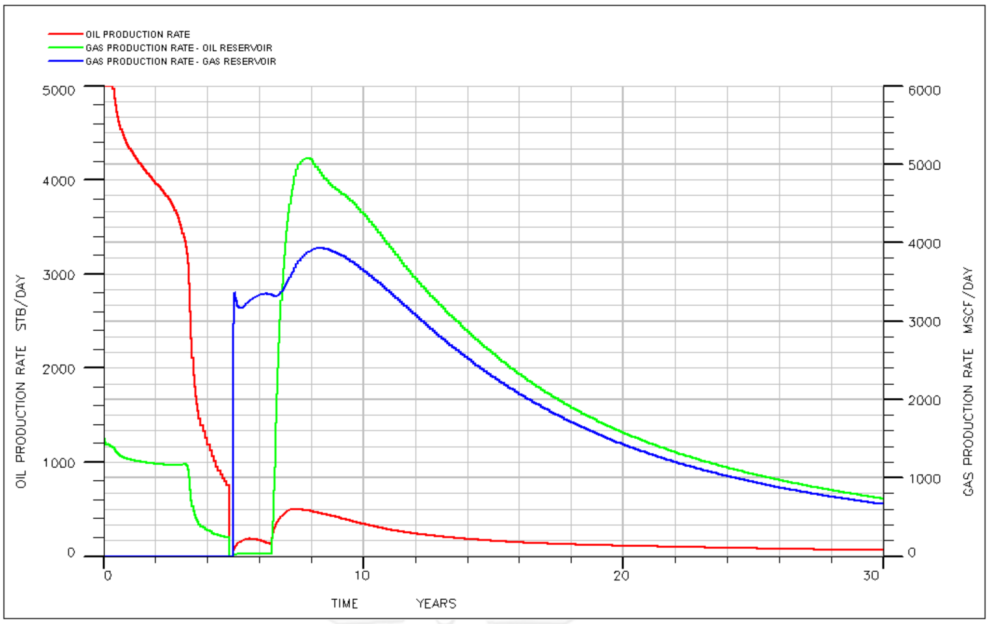
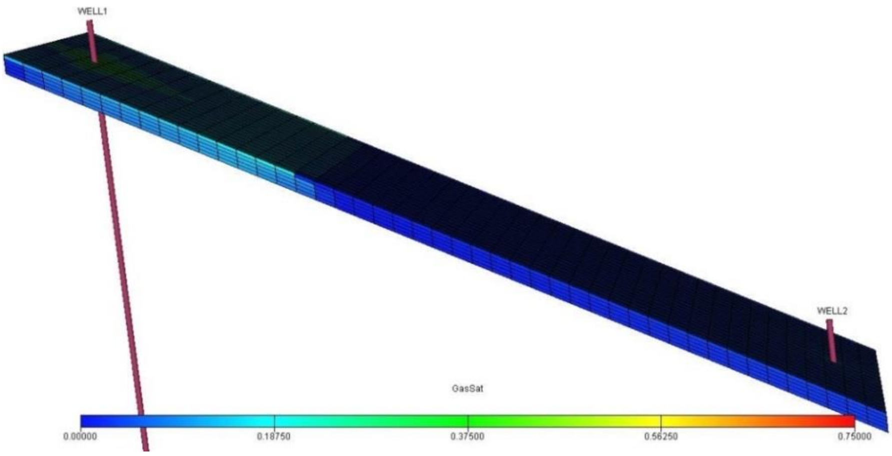
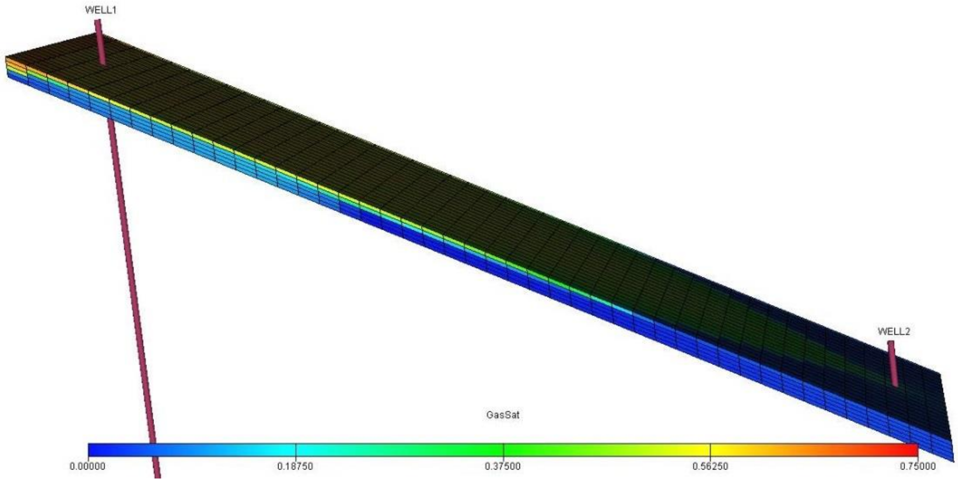


Figure 5. 37 Oil production rate, gas production rate of oil reservoir, and gas production rate of gas reservoir for gas dumpflood case (15-degree dip angle)



a) gas saturation (starting gas dumpflood)



b) gas saturation (gas breakthrough)

Figure 5. 38 Saturation profiles of gas dumpflood case (15-degree dip angle)

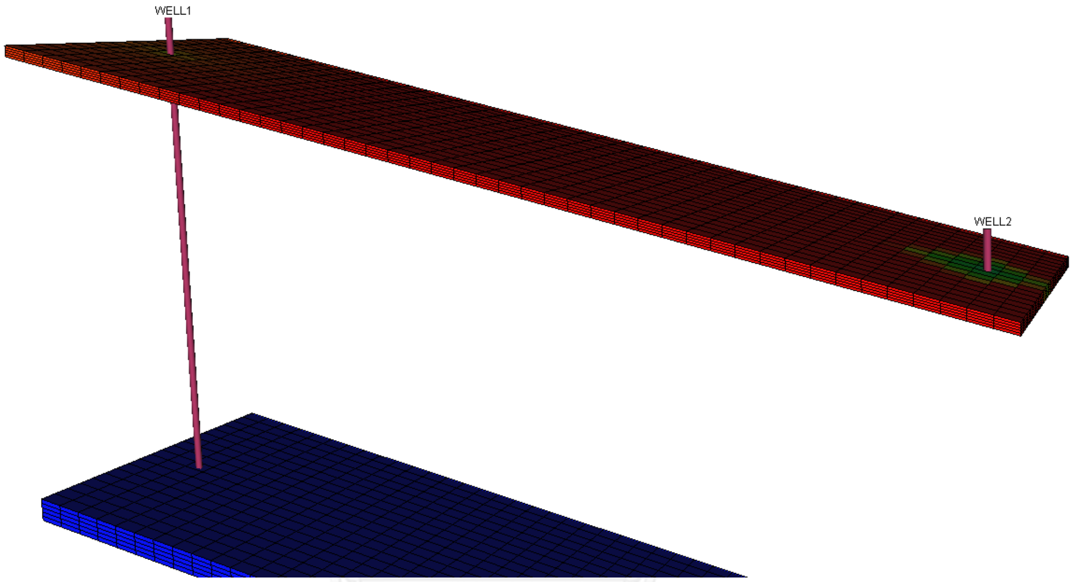
Summarized results in Table 5.18 illustrate that gas dumpflood case has better performance due to additional total oil production of 1.174 million STB and 4.538 million barrels lower total water injection while 1.282 million barrels higher total water production. Although total water injection of conventional waterflood case is higher, the total water production is lower. This is because injected water is still left inside reservoir since there is no gas to chase oil and water toward the producer like the gas dumpflood case. However, due to higher oil production and less water injection, gas dumpflood case is more attractive than conventional water flooding.

Table 5. 18 Summarized results for gas dumpflood in water-flooded reservoir & conventional waterflood (15-degree dip angle)

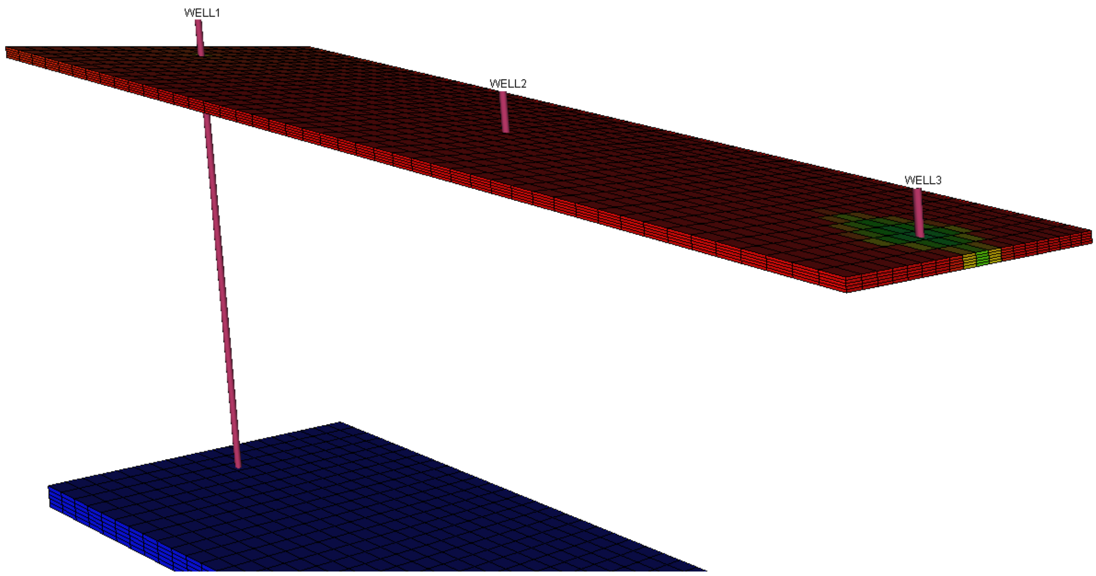
Case	Production life (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
Gas dumpflood case	30	76.50	7.313	7.272	6.539	21.197
Waterflood	7.67	64.21	6.139	11.810	5.257	1.878

5.2.2 Effect of well arrangements

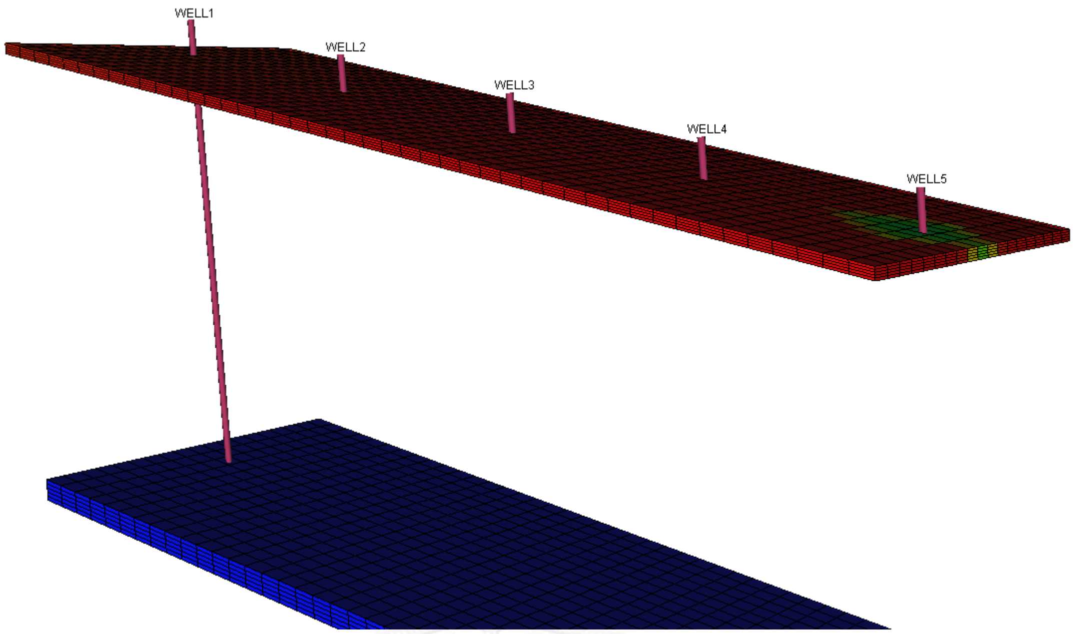
The different well arrangements of 15 degree dip angle reservoir are shown in Figure 5.39. The wells spacing between injector and producer is studied in order to find appropriate locations. The higher dip angle can drain more oil toward the producer due to gravity drainage. There are five cases of well arrangement in this section as shown in Figure 5.39.



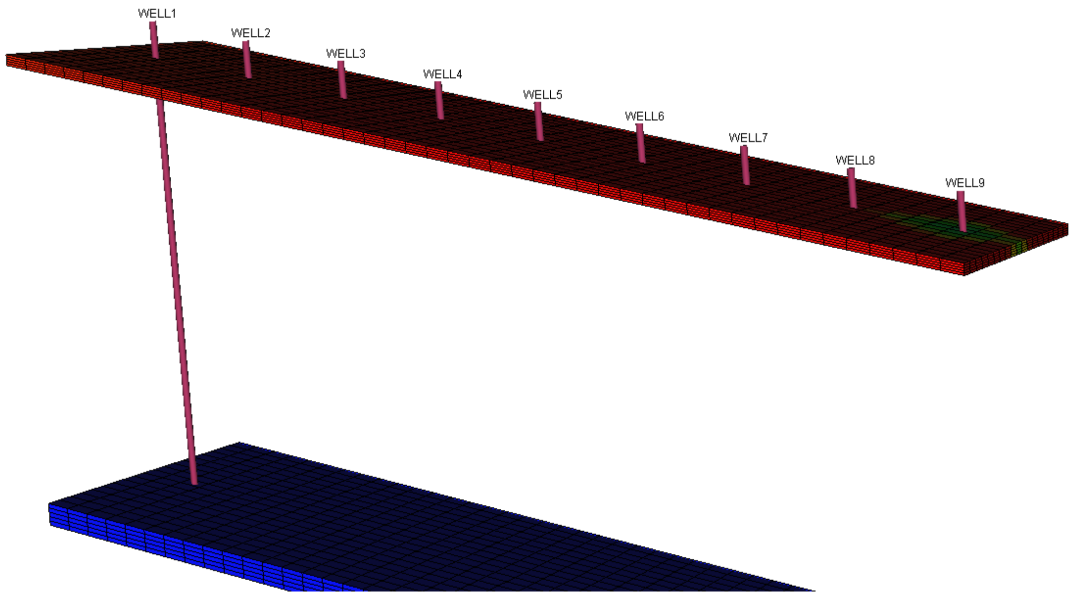
a. two wells (1 injector and 1 producer)



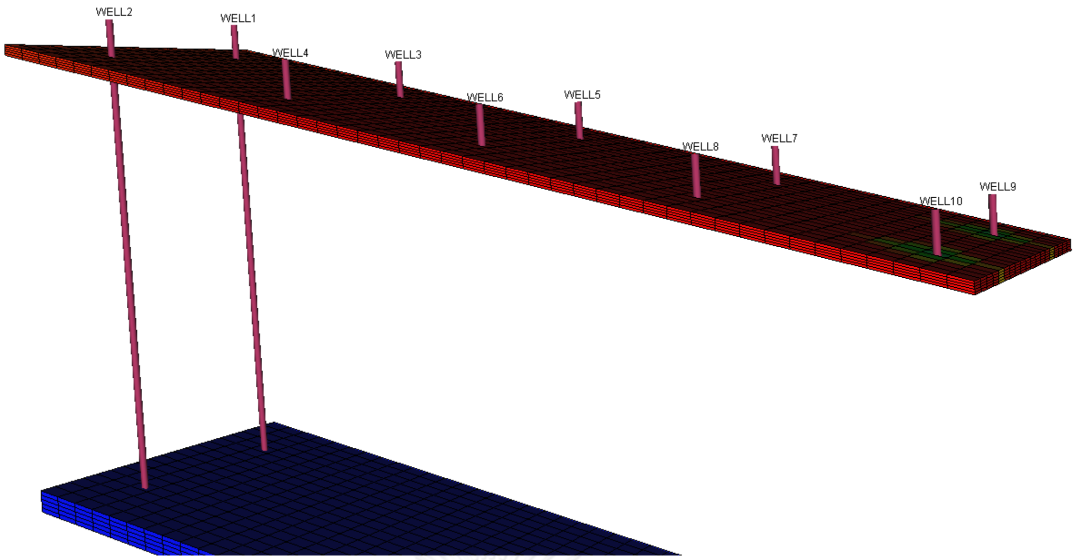
b. three wells (1 injector and 2 producers)



c. five wells (2 injectors and 3 producers)



d. nine wells (4 injectors and 5 producers)



e. ten wells (4 injectors and 6 producers)

Figure 5. 39 Schematics of different well arrangements (15-degree dip angle)

Tables 5.19-5.23 tabulate the locations and constraints of each well in different well arrangements. We set the water injector located downdip and gas dump well located updip in order to maximize the performance of both water injection and gas dumpflood process. For downdip water injection, the effect of gravity can help sweeping oil without fingering effect toward the producer. For updip gas dump injection, segregation helps stabilize the flood front and also helps drain oil by gravity force. The gas dump well is always set as well 1 at the most updip location with the fracture pressure of 3,220 psia and water injector is always set at the most downdip well location.

Table 5. 19 Locations and constraints of two wells for reservoir with 15-degree dip angle

Well	i^{th} position	j^{th} position	Fracture pressure (psia)
Well 1	3	10	3,220
Well 2	43	10	4,011

Table 5. 20 Locations and constraints of three wells for reservoir with 15-degree dip angle

Well	i^{th} position	j^{th} position	Fracture pressure (psia)
Well 1	3	10	3,220
Well 2	23	10	3,610
Well 3	43	10	4,011

Table 5. 21 Locations and constraints of five wells for reservoir with 15-degree dip angle

Well	i^{th} position	j^{th} position	Fracture pressure (psia)
Well 1	3	10	3,220
Well 2	13	10	3,413
Well 3	23	10	3,610
Well 4	33	10	3,810
Well 5	43	10	4,011

Table 5. 22 Locations and constraints of nine wells for reservoir with 15-degree dip angle

Well	i^{th} position	j^{th} position	Fracture pressure (psia)
Well 1	3	10	3,220
Well 2	8	10	3,316
Well 3	13	10	3,413
Well 4	18	10	3,511

Well 5	23	10	3,610
Well 6	28	10	3,709
Well 7	33	10	3,809
Well 8	38	10	3,910
Well 9	43	10	4,011

Table 5. 23 Locations and constraints of ten wells for reservoir with 15-degree dip angle

Well	i^{th} position	j^{th} position	Fracture pressure (psia)
Well 1	3	5	3,220
Well 2	3	15	3,220
Well 3	13	5	3,413
Well 4	13	15	3,413
Well 5	23	5	3,610
Well 6	23	15	3,610
Well 7	33	5	3,809
Well 8	33	15	3,809
Well 9	43	5	4,011
Well 10	43	15	4,011

The injection and production sequence is illustrated in Table 5.24. For the cases that the number of wells is more than two, production wells have to shut in when gas breaks through after gas dumpflood has been started to avoid losing energy from gas flooding process. Note that, oil has solution gas oil ratio of 0.2 MSCF/STB. When wells reach such GLR criteria of 1 MSCF/STB, the wells are shut in except for the last well located downdip which is set to shut in by abandonment criteria of 50 STB/D economic rate.

Table 5. 24 Injection and production sequence for all wells arrangements for reservoir with 15 degree di angle

Well arrangements	**Stage**	**Well 1**	**Well 2**
two wells	Waterflood	Producer (5,000* STB/D)	Water injector (5,000** STB/D)
	WCT reaches criteria	Shut in for 60 days	
	Gas dumpflood	Gas dumpflood well	Producer (5,000* STB/D)

*liquid production rate, **water injection rate

Well arrangements	**Stage**	**Well 1**	**Well 2**	**Well 3**
three wells	Waterflood	Producer (2,500* STB/D)		Water injector (5,000** STB/D)
	WCT reaches criteria	Shut in for 60 days		
	Gas dumpflood	Gas dumpflood well	Producer (2,500* STB/D)	
	GLR reaches 1 MSCF/STB		Shut-in	Producer (2,500* STB/D)

*liquid production rate, **water injection rate

<table>
<tr><th>Well arrangements</th><th>Stage</th><th>Well 1</th><th>Well 2</th><th>Well 3</th><th>Well 4</th><th>Well 5</th></tr>
<tr><td rowspan="4">five wells</td><td>Waterflood</td><td colspan="4">Producer (1,250* STB/D)</td><td>Water injector (5,000** STB/D)</td></tr>
<tr><td>WCT reaches criteria</td><td colspan="5">Shut in for 60 days</td></tr>
<tr><td>Gas dumpflood</td><td rowspan="2">Gas dumpflood well</td><td colspan="4">Producer (1,250* STB/D)</td></tr>
<tr><td>GLR reaches 1 MSCF/STB</td><td colspan="3">Shut-in</td><td>Producer (1,250* STB/D)</td></tr>
</table>

*liquid production rate, **water injection rate

Well arrangements	Stage	Well 1	Well 2	Well 3	Well 4	Well 5	Well 6	Well 7	Well 8	Well 9
nine wells	Waterflood	Producer (625* STB/D)								Water injector (5,000** STB/D)
	WCT reaches criteria	Shut in for 60 days								
	Gas dumpflood	Gas dumpflood well	Producer (625* STB/D)							
	GLR reaches 1 MSCF/STB		Shut-in							Producer (625* STB/D)

*liquid production rate, **water injection rate

Well arrangements	Stage	Well 1	Well 2	Well 3	Well 4	Well 5	Well 6	Well 7	Well 8	Well 9	Well 10
ten wells	Waterflood	Producer (625* STB/D)								Water injector (2,500** STB/D)	
	WCT reaches criteria	Shut in for 60 days									
	Gas dumpflood	Gas dumpflood well		Producer (625* STB/D)							
	GLR reaches 1 MSCF/STB			Shut-in						Producer (625* STB/D)	

*liquid production rate, **water injection rate

Perforation interval is converted into skin for different well arrangements as shown in Table 5.25. For the cases of nine and ten wells, even the lowest of perforation interval cannot reduce the pressure lower than the fracture pressure of well 1 which is 3,220 psia. So, we delay the shut in of production well by stopping water injection when the water cut reaches the criteria but still keep on production for 1 day. Then, shut in the well.

Table 5. 25 Perforation interval and skin of source gas reservoir for reservoir with 15-degree dip angle

Case	Perforation interval(ft)	Skin	Delay in shut-in (day)
2 wells	0.36	1,165	no delay
3 wells	0.3	1,396	no delay
5 wells	0.18	2,325	no delay
9 wells	0.06	6,966	1
10 wells	0.06	6,966	1

Figure 5.40 shows the bottom hole pressure of well 1 in the nine-well cases. Well 1 should not have pressure more than fracture pressure which is 3,220 psia. The bottom hole pressure of well 1 for 1 day delayed shut-in in the nine-well case has pressure less than fracture pressure at the beginning of gas dumpflood period.

Figure 5.41 shows the bottom hole pressure of well 1 and well 2 in the ten-well case. These two wells of ten-well case have the same x-location but different in y-locations because ten-well case is the drilling of another five wells in another alignment. Thus, the behavior of well 1 and well 2 are the same for this homogeneous reservoir. When well 1 and well 2 of ten-well case have higher pressure than fracture pressure during gas dumpflood, the delayed shut-in can lower pressure of ten-well case than fracture pressure.

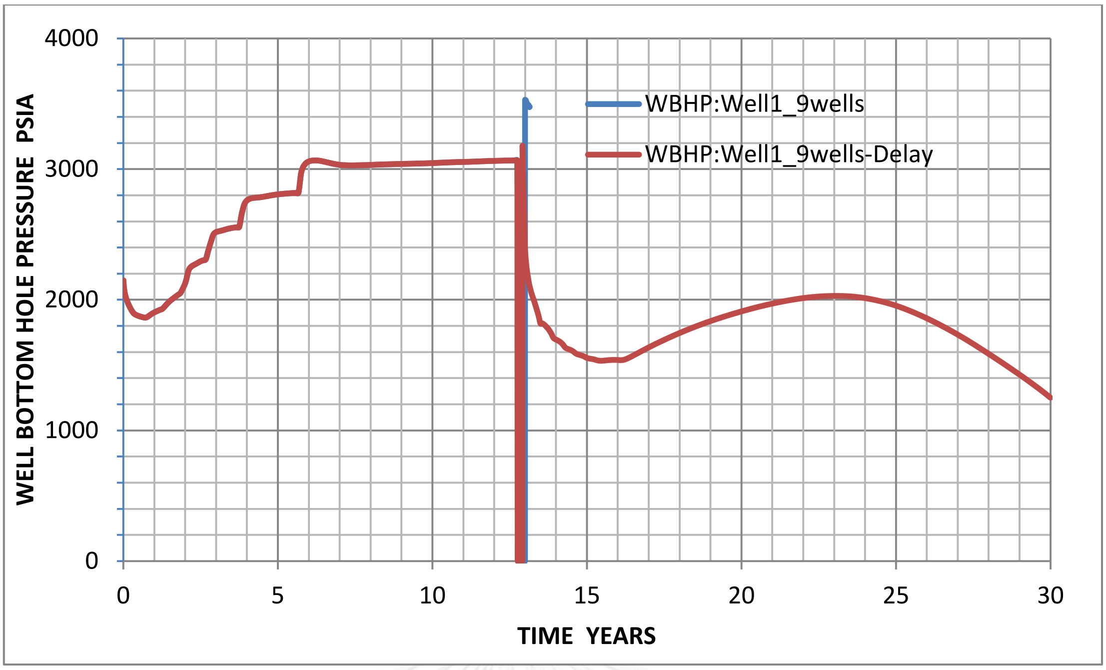


Figure 5. 40 Bottom hole pressure of well 1 for nine-well case and nine-well case with delayed shut in (15-degree dip angle)

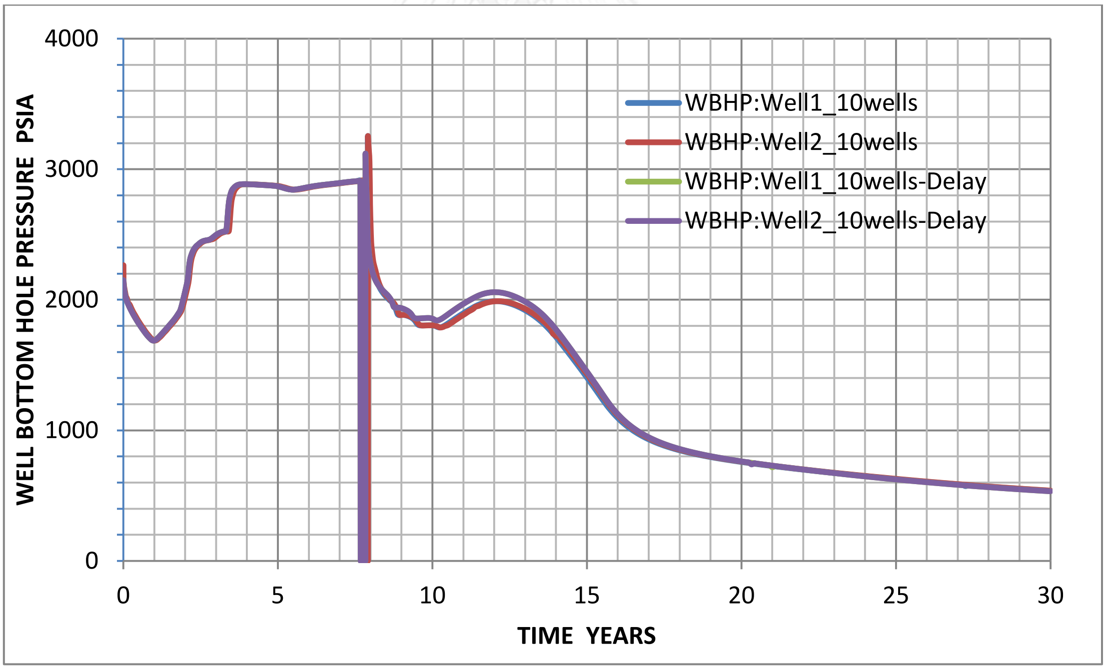


Figure 5. 41 Bottom hole pressure of well 1 and well 2 for ten-well and ten-well case with delayed shut in (15-degree dip angle)

Figures 5.42-5.46 illustrate oil production rate, water cut, water injection rate, gas production rate and reservoir pressure of different well arrangements. Oil production rate of nine- well case has the shortest time of constant rate of 5,000 STB/D. This is because of the sequence of shutting in the producers as water cut reaches the criteria. For the cases of two wells, three wells, five wells and ten wells, they have similar production profiles. The case of nine wells performs the longest water flooding period as shown in Figure 5.43. Figure 5.43, water cut for each well has to reach 80% criteria before starting gas dumpflood. Figure 5.44 shows that injection rate for two wells case does not reach the target rate of 5,000 STB/D because of the constraint of fracture pressure. As shown in Figure 5.45, for the case of nine wells, the gas production rate is not yet at the peak but oil production has to stop due to limited production period. Reservoir pressure for the case of nine wells is constant around 3,200 psia due to the fact that water is being injected until the 13th year. After that, the pressure rises up due to gas dumpflood.

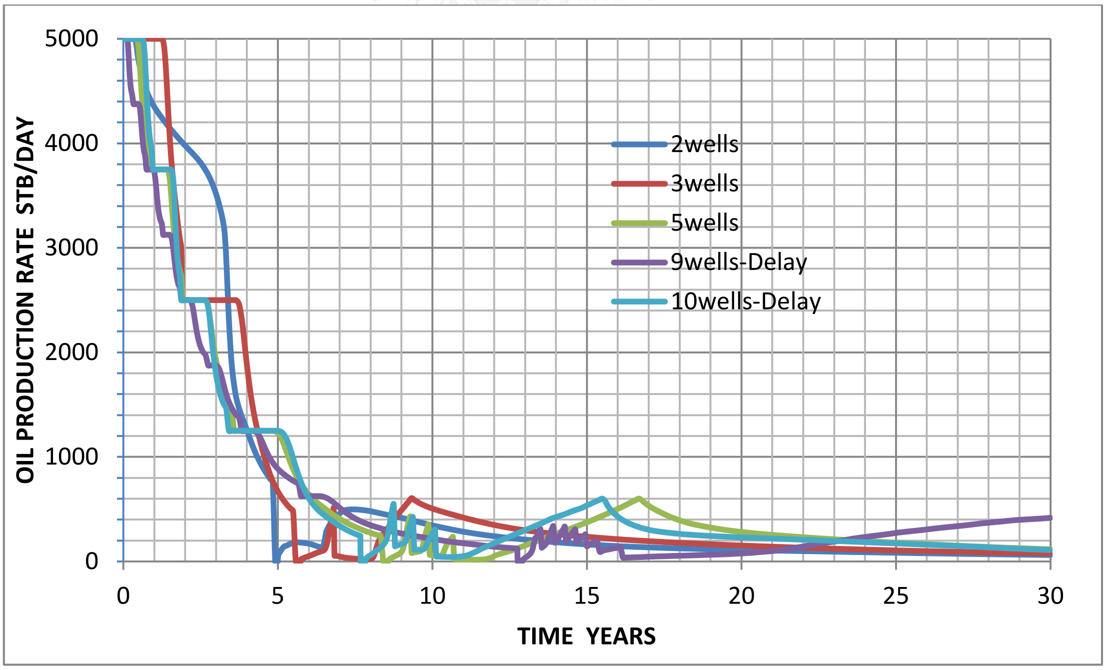


Figure 5. 42 Oil production rates for different well arrangements.

(15-degree dip angle)

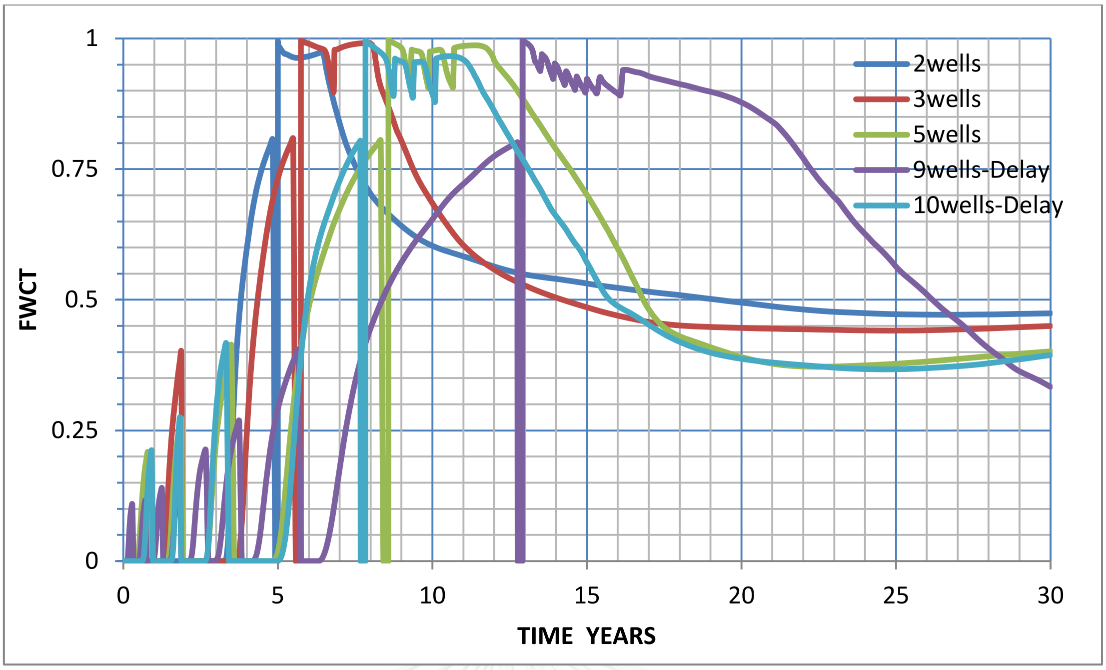


Figure 5. 43 Water cuts for different well arrangements.

(15-degree dip angle)

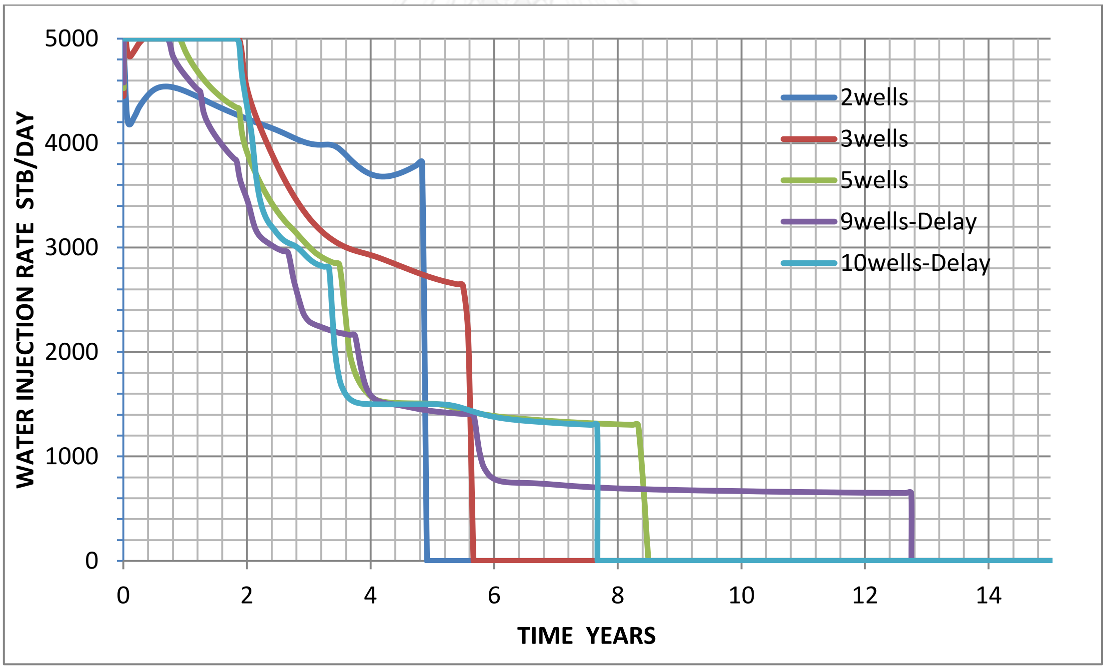


Figure 5. 44 Water injection rates for different well arrangements.

(15-degree dip angle)

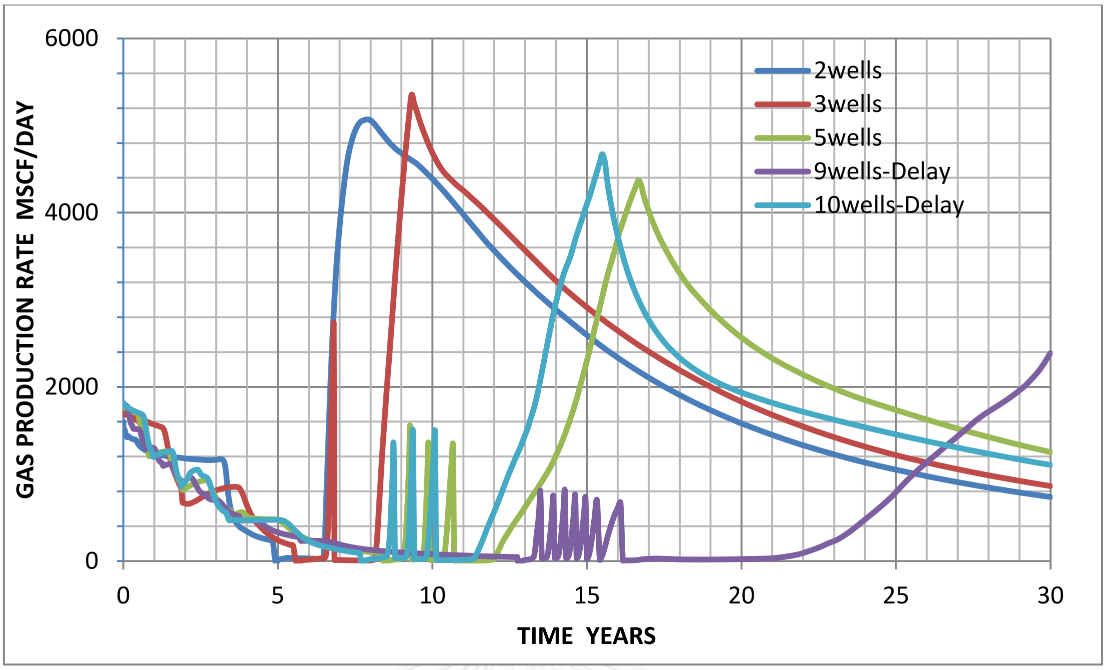


Figure 5. 45 Gas production rates for different well arrangements.

(15-degree dip angle)

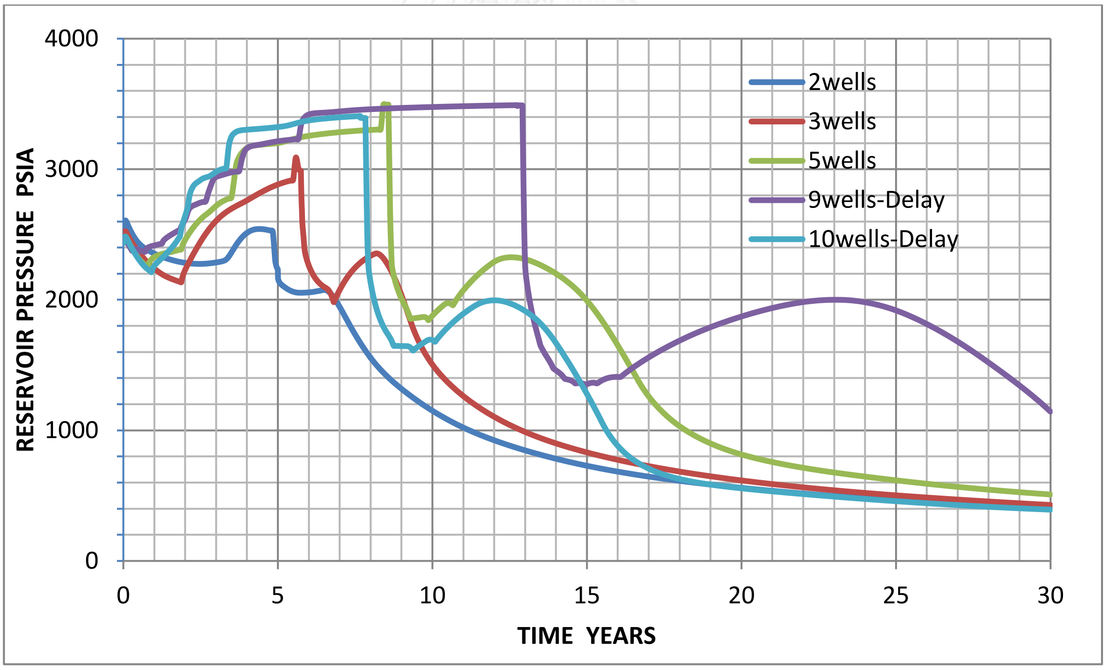


Figure 5. 46 Reservoir pressures for different well arrangements.

(15-degree dip angle)

Summarized results in Table 5.26 show that as we increase the number of wells from two to three, the total oil production and oil recovery decrease insignificantly while the amount of water injection and water production increase significantly. Thus, two-well case is more favorable than three-well case. When the number of wells increases from three to nine, the total oil production and oil recovery decrease significantly. So, drilling more wells in the same alignment does not help increase oil recovery. In the previous section of 0 dip angle, by drilling another set of wells from five wells to ten wells, oil recovery increases significantly. However, for this 15 degree dip angle reservoir, the oil recovery slight increases as the recovery factor for the case of five wells is already high. This is because the gravity force which helps drain oil toward the producer located downdip.

In term of gas production, nine wells case has the lowest total amount of gas production due to the fact that gas dumpflood has just been started and it has not reached the economic rate yet.

When comparing all the cases, the case with two wells is the best performer as it yields the highest amount of total oil production and gas production and the lowest amount of total water injection and water production.

Table 5. 26 Summarized results for different well arrangements (15-degree dip angle)

Case	Water cut (%)	Production life (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
2 wells	80	30	76.50	7.313	7.272	6.539	21.197
3 wells	80	30	76.18	7.283	7.698	6.936	20.028
5 wells	80	30	74.90	7.161	7.785	6.937	15.759
9 wells	80	30	69.05	6.601	7.784	6.701	5.625
10 wells	80	30	75.08	7.178	7.436	6.637	15.225

5.2.3 Effect of stopping time for water flooding

Water cut criteria is used to investigate the stopping time for water flooding in order to start gas dumpflood. Five values of water cut used in this study are 1%, 20%, 40%, 60% and 80%. As the case of two wells is the best performer, it is used throughout the study for 15-degree dip angle. However, the investigation is expanded to cover both vertical and horizontal well types. As the bottom hole pressure of well 1 exceeds the fracture pressure during gas dumpflood, partial penetration is performed as depicted in Table 5.27.

Table 5. 27 Perforation interval and skin of source gas reservoir for reservoir with 15-degree dip angle

Case	Water cut (%)	Perforation interval(ft)	Skin
2 wells	1	0.3	1,396
	20	0.36	1,165
	40	0.24	1,744
	60	0.36	1,165
	80	0.36	1,165

5.2.3.1 Vertical producer

Figures 5.47-5.49 show oil production rate, oil recovery factor and water cut profiles. The oil production rates are all the same for the first 3 years. Then, after water cut reaches the criteria, gas dumpflood process is started. The 80% water cut criteria in Figure 5.47 has the longest waterflood duration. Show in Figure 5.48, oil recovery factor at late time shows no difference among the cases but at the beginning of gas dumpflood process in the 5th year, the case with 80% water cut criteria has the highest oil recovery. In Figure 5.49, water cuts of different cases reach the criteria at different times. During the beginning of gas dumpflood process, water cut is high since water is still around the production well as a result of prior water flooding.

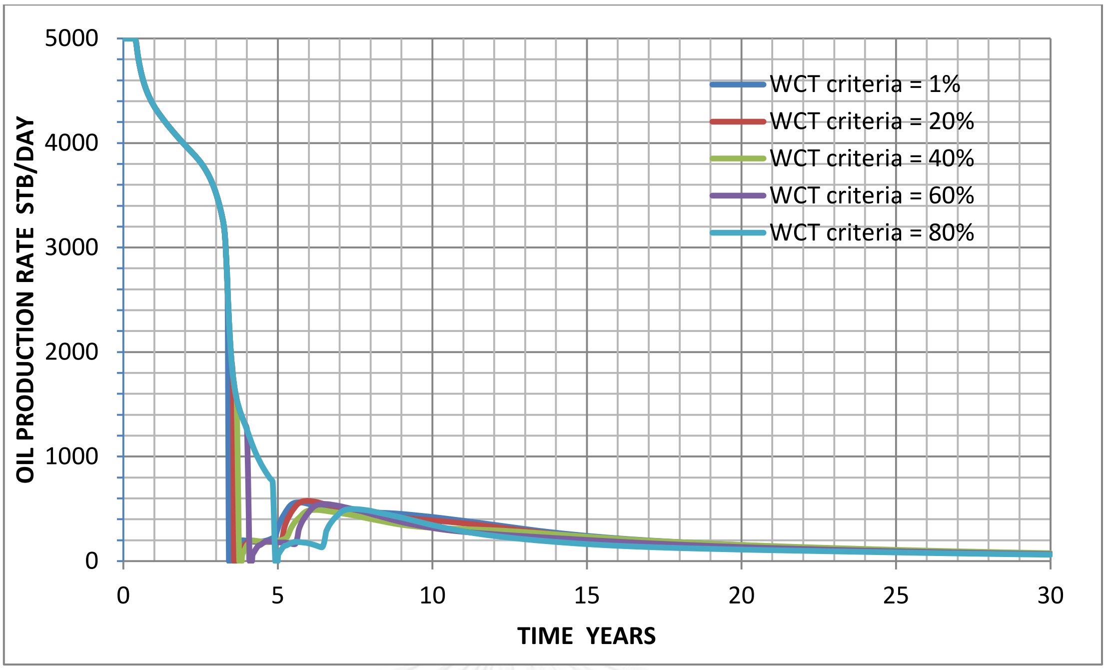


Figure 5. 47 Oil production rates for different water cut criteria
(15-degree dip angle)

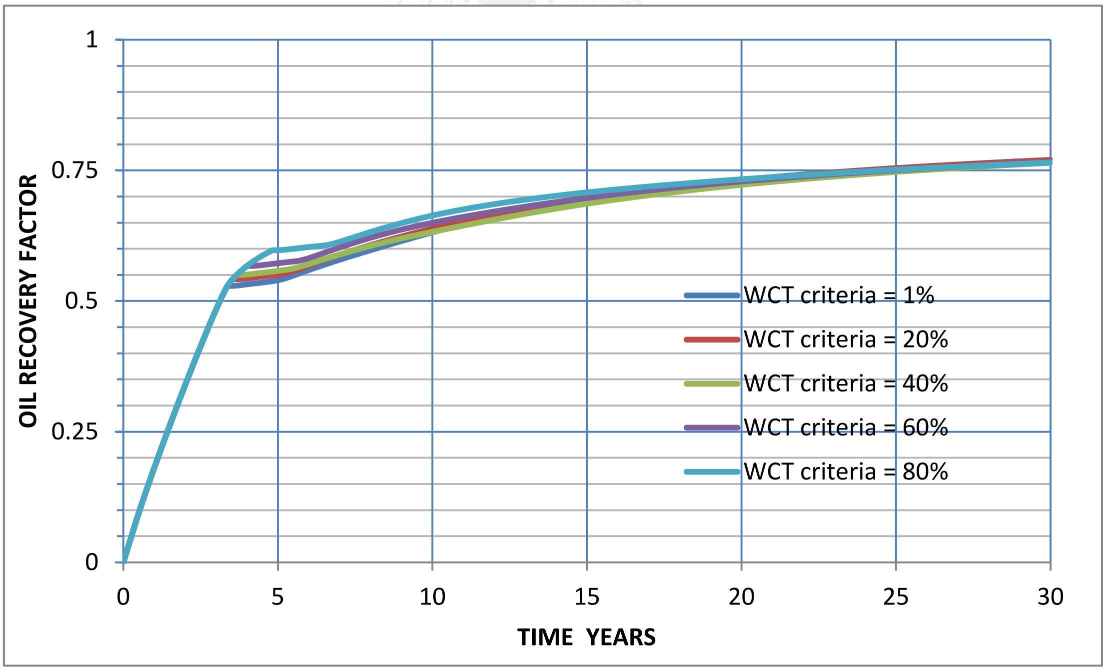


Figure 5. 48 Oil recovery factor for different water cut criteria
(15-degree dip angle)

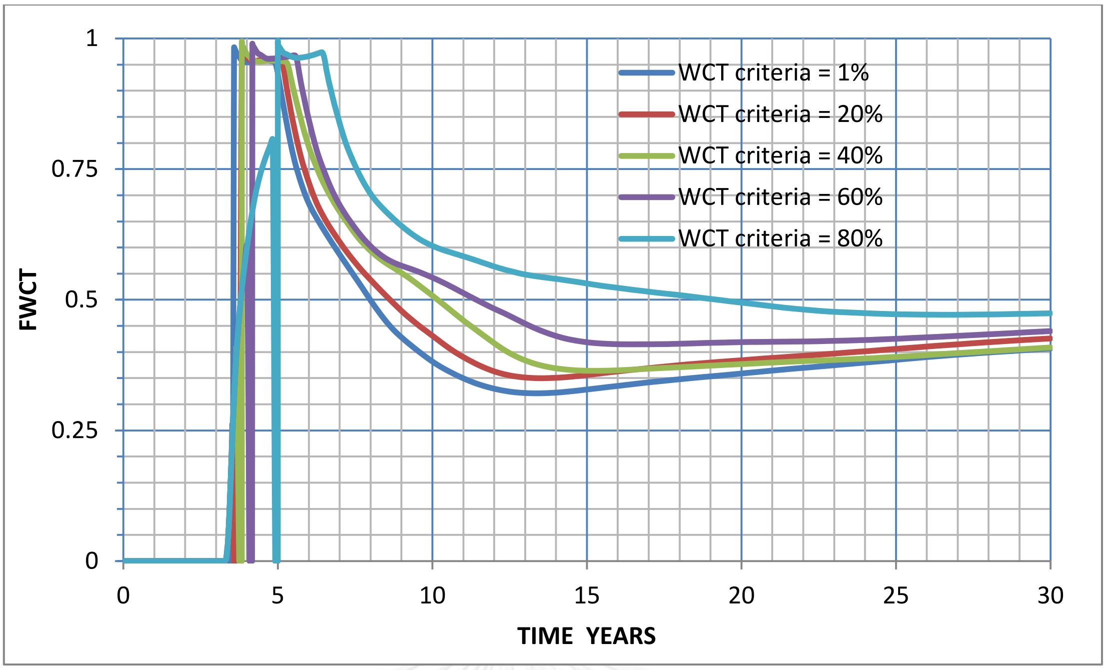


Figure 5. 49 Water cut profiles for different water cut criteria
(15-degree dip angle)

The results in Table 5.28 illustrate that as water cut criteria is increased, oil recovery factor and total oil production slightly decrease while the amounts of water injection and water production increase significantly. When we increase water cut criteria from 1% to 80%, oil recovery gets lowered by 49,728 STB and requires 2.012 million barrels more water injection and produces more 1.908 million barrels of water. Thus, 1% water cut criteria is the best performer as it produces more oil while requires and produces less water. In term of production life and gas production, there is no significant difference among the cases.

Table 5. 28 Summarized results for different water cut criteria of vertical producers for reservoir with 15-degree dip angle

Case	Water cut (%)	Production life (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
2 wells	1	30	77.02	7.363	5.260	4.631	20.773
	20	30	76.95	7.356	5.501	4.842	21.388
	40	30	76.43	7.306	5.683	5.008	19.825
	60	30	76.54	7.317	6.139	5.438	21.333
	80	30	76.50	7.313	7.272	6.539	21.197

5.2.3.2 Horizontal producer

In this section, we investigate different water cut criteria used to start gas dumpflood when the producers are horizontal wells. According to the previous section, two vertical wells provide good result on oil recovery. Thus, we try the locations of these two wells for this case in an attempt to get better performance from horizontal producers. Note that well 1 which is used to dump gas from the source reservoir is still vertical. One horizontal well is placed in layer 5 of the oil reservoir in the y-direction (bottom most layer) with the length of 1900 ft. Figures 5.50-5.51 illustrate the schematics of horizontal well type. Five values of water cut criteria are investigated: 1%, 20%, 40% and 80%. As the full-to-base perforation causes the bottom hole pressure during gas dumpflood to exceed the fracture pressure of well 1, partial perforation is performed as shown in Table 5.30.

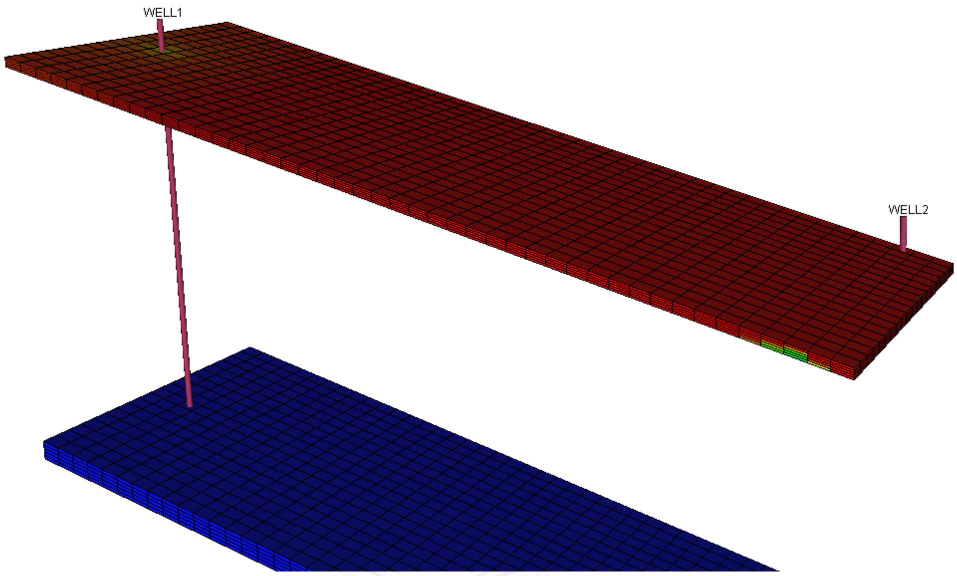


Figure 5. 50 Well locations for the horizontal producer and vertical well connecting the source and target reservoirs. (15-degree dip angle)

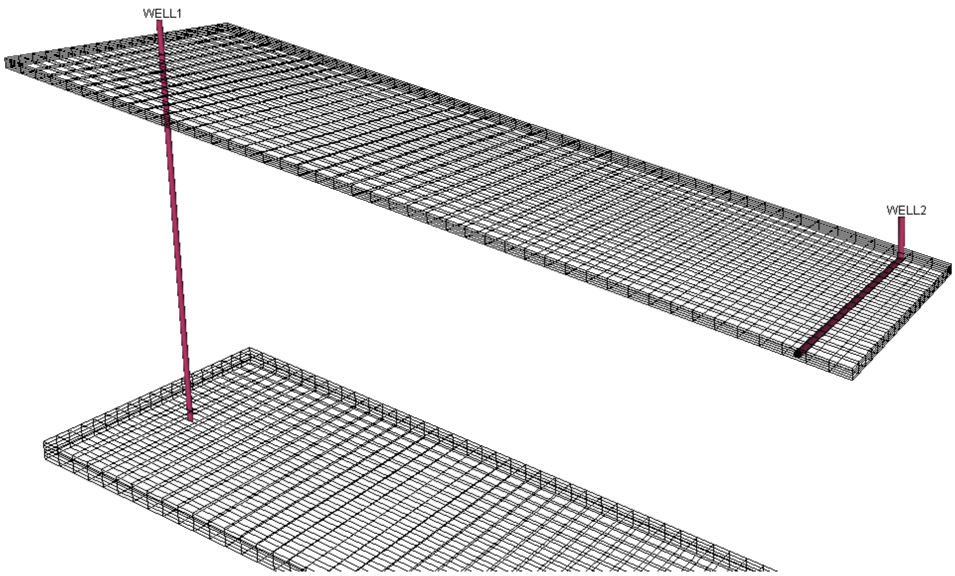


Figure 5. 51 Well locations for the horizontal producer and vertical well connecting the source and target reservoirs. (15-degree dip angle)

Table 5. 29 Locations and constraints of the horizontal producer and vertical well connecting the source and target reservoirs for reservoir with 15-degree dip angle

Well	i^{th} position	j^{th} position	Fracture pressure (psia)
Well 1	3	10	3,220
Well 2	43	1-19	4,011

Table 5. 30 Perforation interval and skin of source gas reservoir for reservoir with 15-degree dip angle

Case	Water cut (%)	Perforation interval(ft)	Skin
1 horizontal producer for gas dumpflood	1	0.36	1,165
	20	0.36	1,165
	40	0.36	1,165
	60	0.36	1,165
	80	0.36	1,165

Figures 5.52-5.54 show oil production rate, oil recovery factor and water cut profiles. Oil production rate for all cases in the first 3 years are all the same until water cut reaches the criteria. For the case of 1% water cut criteria, during the first period of starting gas dumpflood, oil production rate is at the highest peak. Case of 80% water cut criteria takes the longest time of water flooding process. At late time, oil production rates of all cases drop down to nearly 50 STB/D. During early gas dumpflood process, oil recovery factor of the case with 80%water cut criteria is the highest as shown in Figure 5.53 but at late time, oil recovery factor of the case with 1% water cut criteria is the highest. Water cuts reach criteria as shown in Figure 5.54

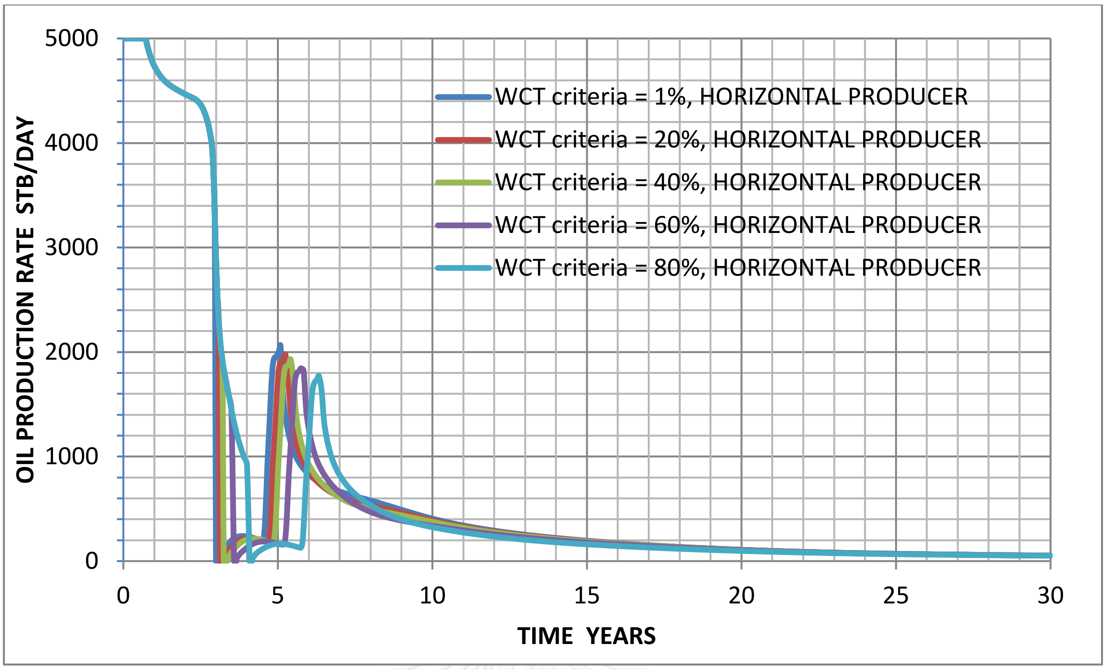


Figure 5. 52 Oil production rates for different water cut criteria

(15-degree dip angle)

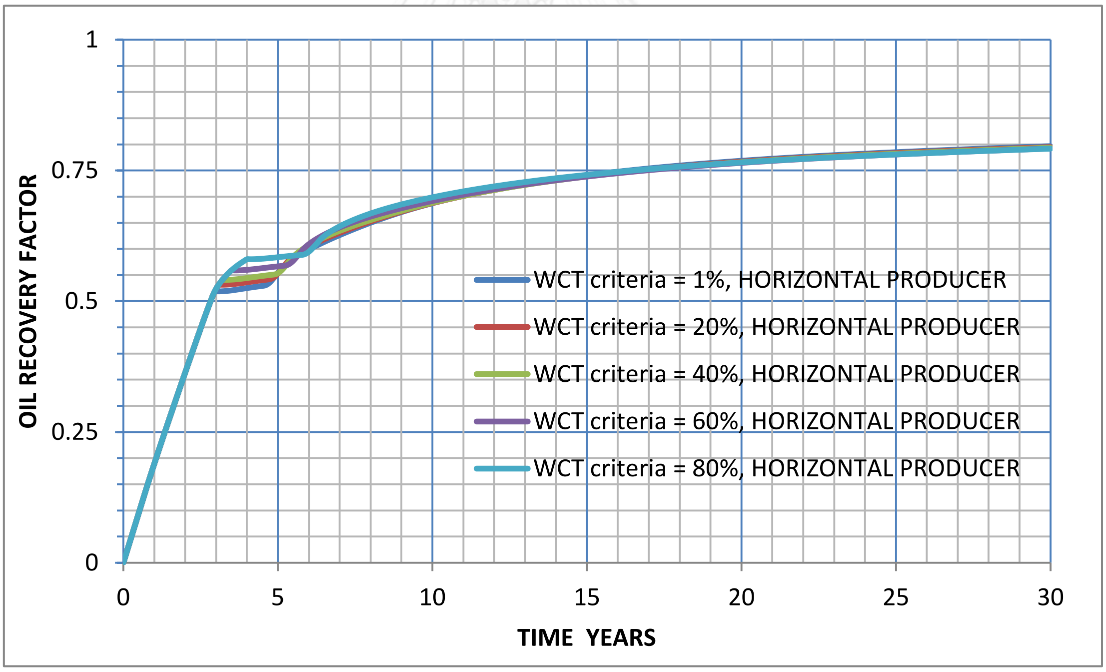


Figure 5. 53 Oil recovery factors for different water cut

(15-degree dip angle)

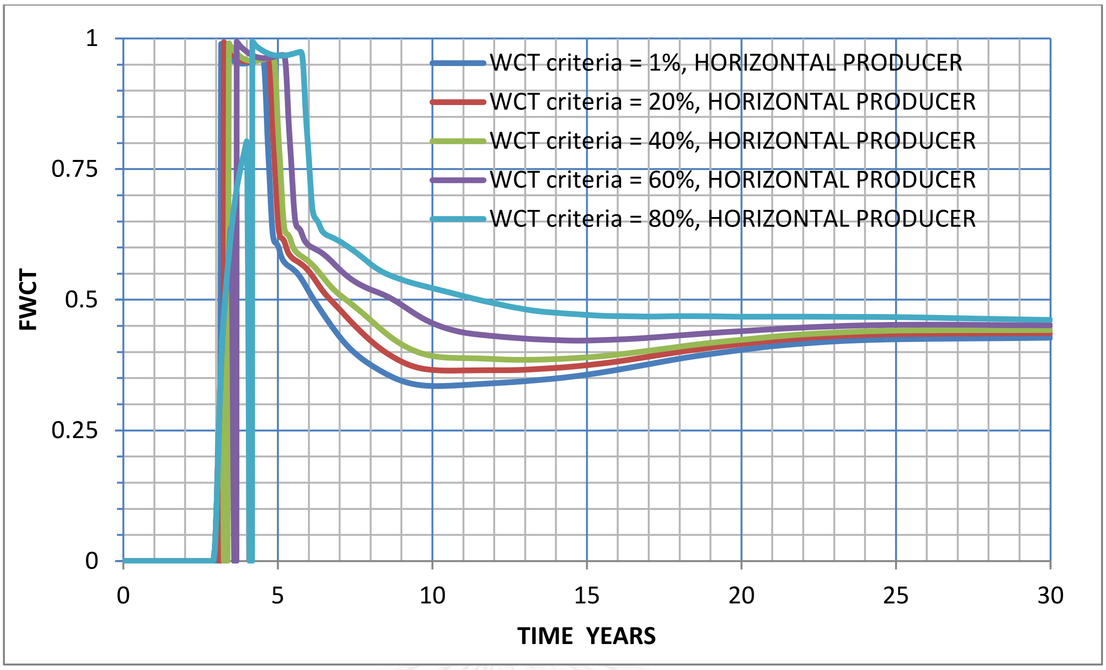


Figure 5. 54 Water cut profiles for different water cut criteria
(15-degree dip angle)

From the summarized results tabulated in Table 5.31, as the water cut criteria increases, the oil recovery factor and total oil production slightly decreases while the amounts of water injection and water production increase quite significantly. When the water cut criteria increases from 1% to 80%, oil production gets lowered by 45,757 STB, requiring 1.735 million barrels more water injection and producing 1.654 million barrels more water. Thus, 1% water cut criteria for one horizontal producer case is the best performer. In term of production life and gas production, all cases have comparable results.

Table 5. 31 Summarized results for different water cut criteria of horizontal producer and vertical well connecting the source and target reservoirs for reservoir with 15-degree dip angle

Case	Water cut (%)	Production life (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
1 horizontal producer for gas dumpflood	1	30	79.65	7.614	5.396	4.829	23.103
	20	30	79.47	7.597	5.626	5.034	23.073
	40	30	79.36	7.586	5.832	5.225	23.049
	60	30	79.20	7.571	6.303	5.673	23.001
	80	30	79.17	7.568	7.131	6.483	22.914

5.2.4 Effect of perforation interval of source gas reservoir

According to the fracture pressure of gas dump well (well 1), it is not possible to vary the perforation interval in order to see the effect of gas dumpflood process. We can only do partial penetration to limit the entry of high pressure gas into the target oil reservoir which does not exceed the fracture pressure.

5.2.5 Effect of water injection rate and liquid production rate

One horizontal production well with 1% water cut criteria is used throughout the study of 15-degree dip angle for investigating the effect of water injection and liquid production rates. Note that water injection rate in this case is limited by fracture pressure that should not allow the bottomhole pressure higher than 4,011 psia. Table 5.32 shows different combinations of target water injection and target liquid production rates that have been studied in this section.

Table 5. 32 Target water injection and liquid production rates for reservoir with 15-degree dip angle

Case	Target water injection rate (STB/D)	Target liquid production rate (STB/D)
1	3,000	3,000
2	4,000	4,000
3	5,000	5,000
4	3,000	4,000
5	3,000	5,000
6	4,000	3,000
7	4,000	5,000
8	5,000	3,000
9	5,000	4,000

As shown in Figure 5.55, cases 6, 8 and 9 cannot maintain constant rate during water flooding process. This is because injection rate is more than production rate which leads to the accumulation of pressure inside the reservoir. For the rest of the cases, we can inject at the target water rate until the end of water flooding process. As depicted in Figure 5.56, for the cases of 5,000 STB/D of target liquid production rate, the rate can be maintained only for some short period of time and then drops down dramatically. However, the cases of target liquid production rate of 3,000 and 4,000 STB/D show longer periods of constant rate than the cases of target liquid production rate of 5,000 STB/D. Figure 5.57 shows the water cut profiles for different cases. The profiles look different when the water starts to break through the producer. However, at the end, the water cuts are between 0.42-0.44 for all cases. Regarding recovery factor shown in Figure 5.58, case 3 has the highest oil recovery factor during the beginning of gas dumpflood process but at late time of production, all cases show no significant difference of oil recovery factor. The cases with higher or equal rate between target water injection rate and target liquid production rate tend to have better maintenance of reservoir pressure as shown in Figure 5.59.

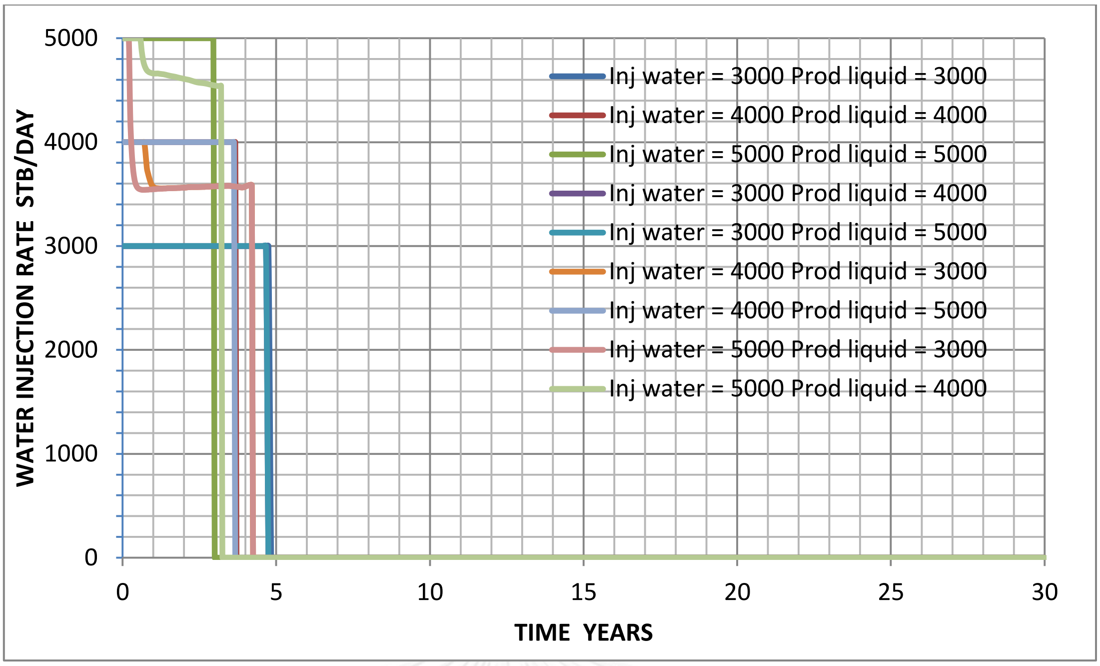


Figure 5. 55 Water injection rate profiles for different target water injection and liquid production rates (15-degree dip angle)

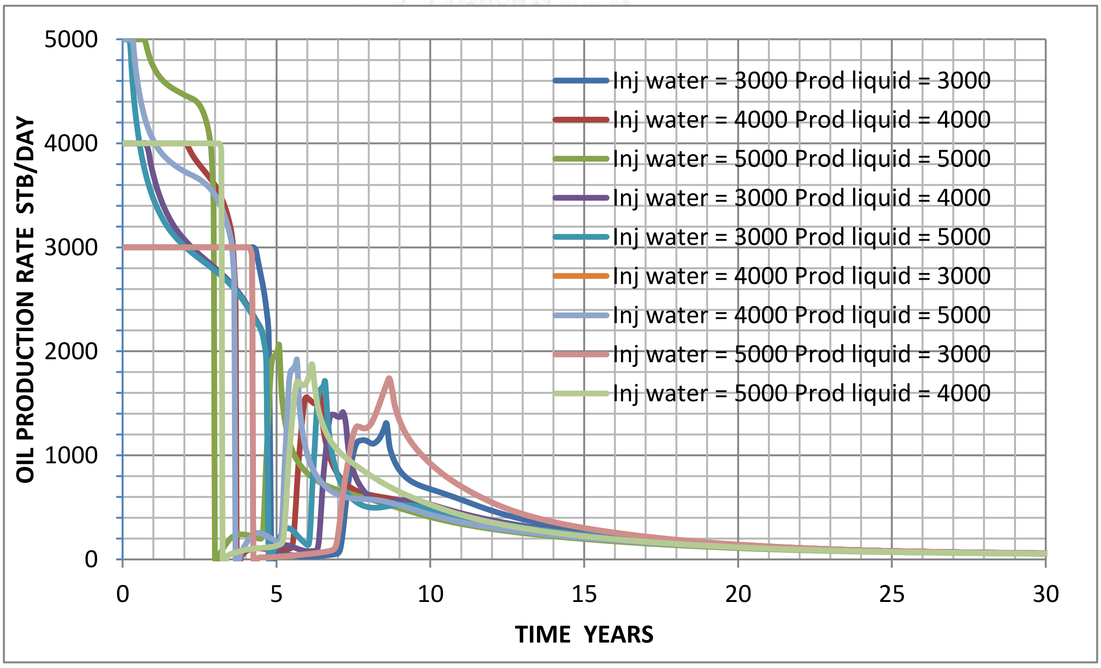


Figure 5. 56 Oil production profiles for different target water injection and liquid production rates (15-degree dip angle)

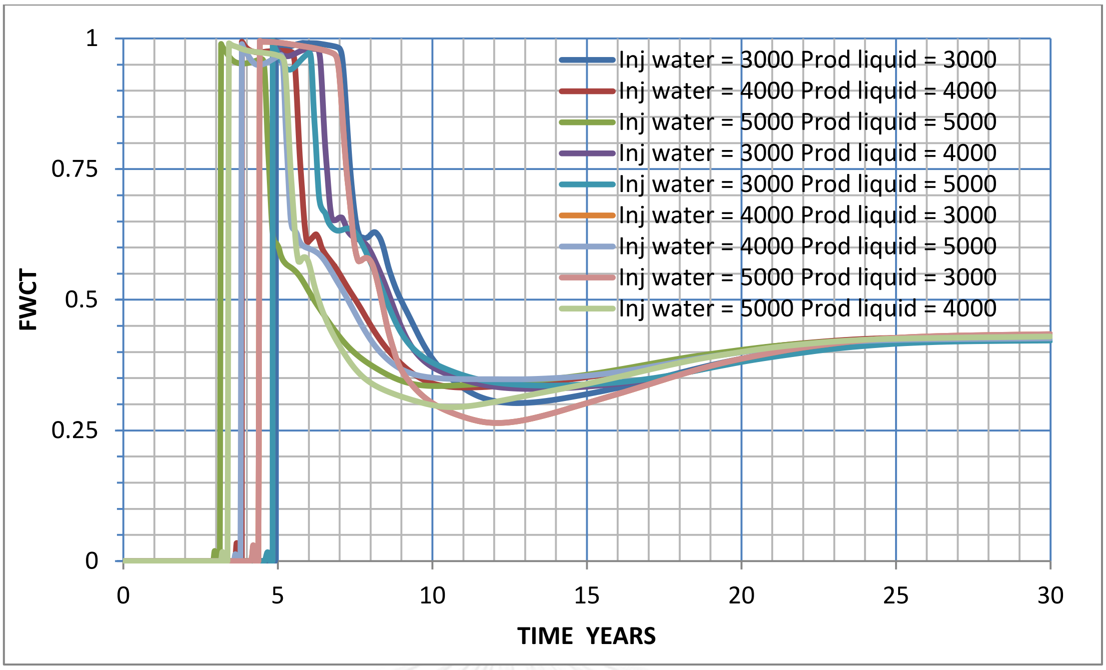


Figure 5. 57 Water cuts for different target water injection and liquid production rates (15-degree dip angle)

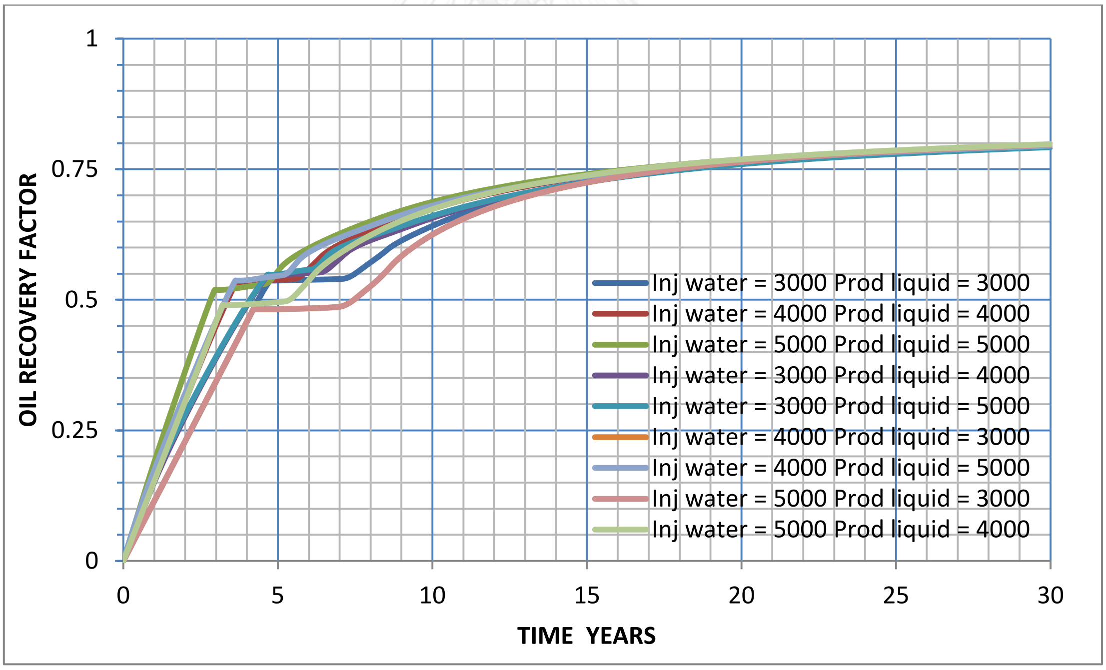


Figure 5. 58 Oil recovery factors for different target water injection and liquid production rates (15-degree dip angle)

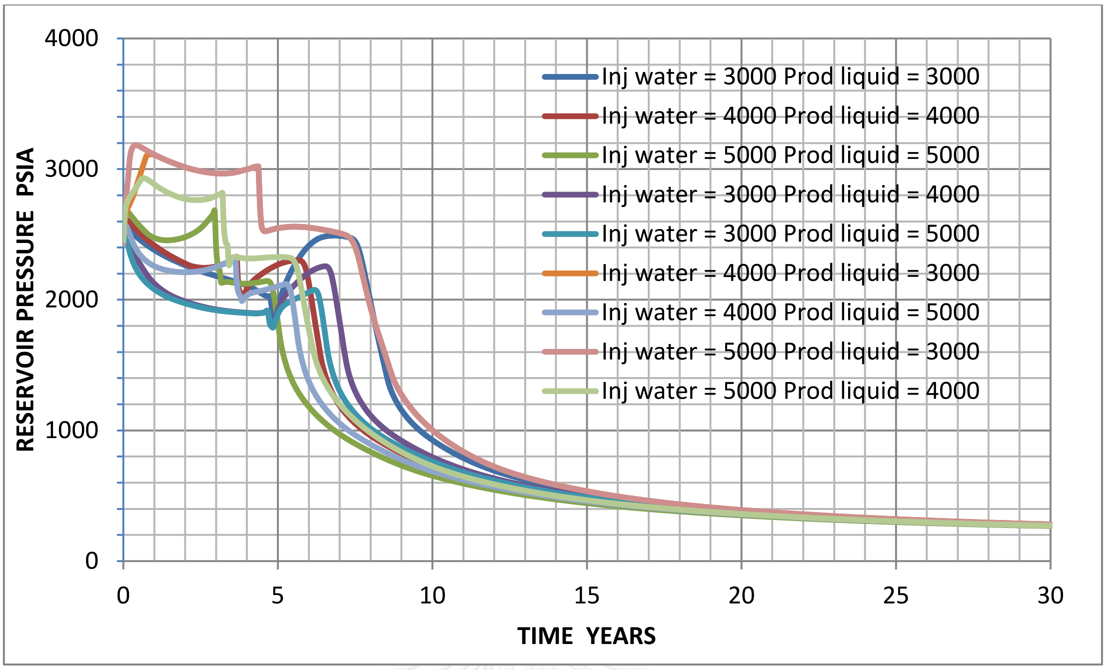


Figure 5. 59 Reservoir pressures for different target water injection and liquid production rates (15-degree dip angle)

The results as tabulated in Table 5.33 show that as we vary the target rates, oil recovery factor, total oil production, total water injection, total water production and total gas production are not significantly different among all cases. Case 3 is chosen due to the least waterflood duration which it can reduce operating cost from water injection.

Table 5. 33 Summarized results for different combinations of target water injection rate and liquid production rates for reservoir with 15-degree dip angle

Case	Waterflood duration (years)	Production life (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
1	4.75	30	79.59	7.608	5.201	4.609	22.565
2	3.67	30	79.57	7.607	5.357	4.774	22.916
3	2.96	30	79.65	7.614	5.396	4.829	23.103
4	4.67	30	79.31	7.582	5.113	4.522	22.737
5	4.67	30	79.22	7.573	5.113	4.523	22.796
6	4.20	30	79.70	7.619	5.602	5.011	21.110
7	3.62	30	79.52	7.602	5.295	4.719	22.887
8	4.20	30	79.70	7.619	5.602	5.012	22.520
9	3.21	30	79.80	7.628	5.488	4.922	22.946

5.3 Dip angle of 30 degrees

Oil and gas reservoirs with 30 degree dip angle are simulated to determine the effect of different operating parameters on gas dumpflood after initial water flooding. This section starts by comparing gas dumpflood after water flooding with conventional long-termed water flooding. Then, the effects of well arrangement, stopping criteria for water flooding, perforation interval of gas zone, water injection rate and liquid production rate on performance of the gas dumpflood case are investigated.

5.3.1 Gas dumpflood in waterflooded reservoir versus conventional water flooding

The gas dumpflood and conventional water flooding cases are compared to see the benefits of gas dumpflood in waterflooded reservoir. The gas dumpflood and water flooding cases consist of one production well and one injection well as previously shown in Figure 5.31. In the gas dumpflood case, water cut of 80% is set as stopping criteria for water flooding before starting gas dumpflood. The economic oil rate for both cases is set at 50 STB/D. For conventional water flooding, 95% of water cut is set before abandoning the process.

Table 5.34 shows the injection and production sequence. During the water flooding period, well 2 located downdip is used to inject water, sweeping oil towards well 1 located updip. At this initial stage, well 1 serves as a producer. After water cut reaches the criteria, wells 1 and well 2 are shut in for 60 days. Well 1 is then perforated at the gas zone. Then, gas dumpflood is performed by dumping gas through well 1 to sweep oil toward well 2. Thus, during gas dumpflood, well 2 serves as a producer. Note that during gas dumpflood process, the bottom hole pressure of gas dump well (well 1) at the target oil zone is higher than the fracture pressure of the oil reservoir if the well is perforated full to base. Thus, partial perforation is performed to reduce the amount of gas flow. As shown in Table 5.35, skin value of 2,090 is needed to account for the perforation interval of 0.2 ft out of 100 ft of gas reservoir.

Table 5. 34 Injection and production sequence of gas dumpflood in water-flooded reservoir for reservoir with 30-degree dip angle

Stage	Well1	Well2
Waterflood	Producer	Water injector
WCT reaches criteria	Shut in for 60 days	Shut in for 60 days
Gas dumpflood	Gas dumpflood well	Producer

Table 5. 35 Perforation interval and skin of source gas reservoir for reservoir with 30-degree dip angle

Case	Perforation interval(ft)	Skin
Gas dumpflood case	0.2	2,090

Figures 5.60-5.64 show oil production rate, water cut, water injection rate, gas production rate and reservoir pressure of 30 degree dip angle reservoir. Figure 5.60 shows that the oil production of gas dumpflood case has longer production time than waterflood case. The waterflood case has the same oil production rate with gas dumpflood case until the water cut reaches 80% criteria. The waterflood case continues producing until the water cut reaches 95% criteria as shown in Figure 5.61.

During the beginning of gas dumpflood, the water cut of gas dumpflood case reaches 100% for short period of time because injected water around the producer as a result of prior water flooding is produced back to surface. Then, the amount of water production decreases with time as gas dumpflood is progressing.

Gas production rate is at the highest peak when gas breaks through at about two years after gas dumpflood process. Then, it gradually drops down with time as lower amount of gas flows into the target zone as shown in Figure 5.63. At the end of production, the reservoir pressure of gas dumpflood case is lower than waterflood case due to more fluid withdrawal as shown in Figure 5.64.

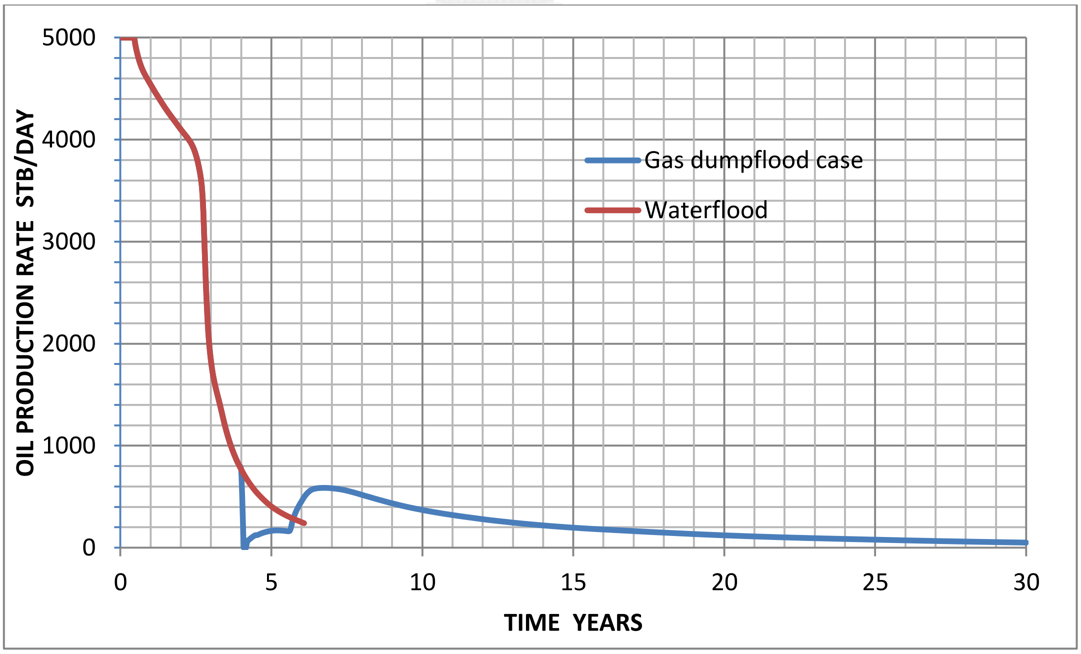


Figure 5. 60 Oil production rate comparison between gas dumpflood case and water flooding (30-degree dip angle)

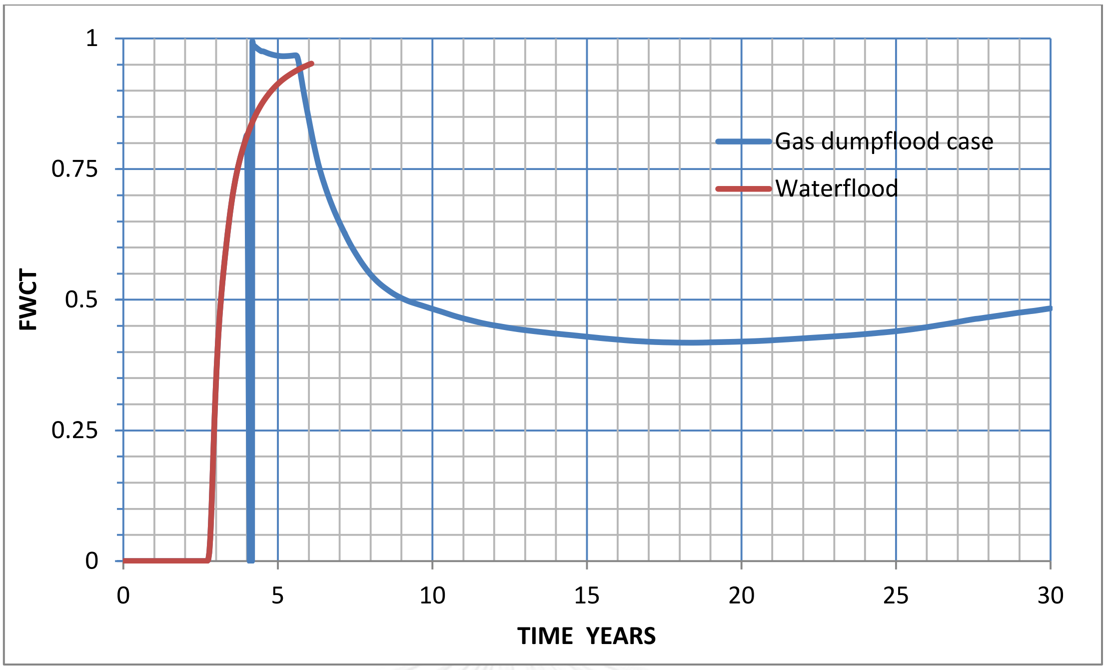


Figure 5. 61 Water cut comparison between gas dumpflood case and water flooding (30-degree dip angle)

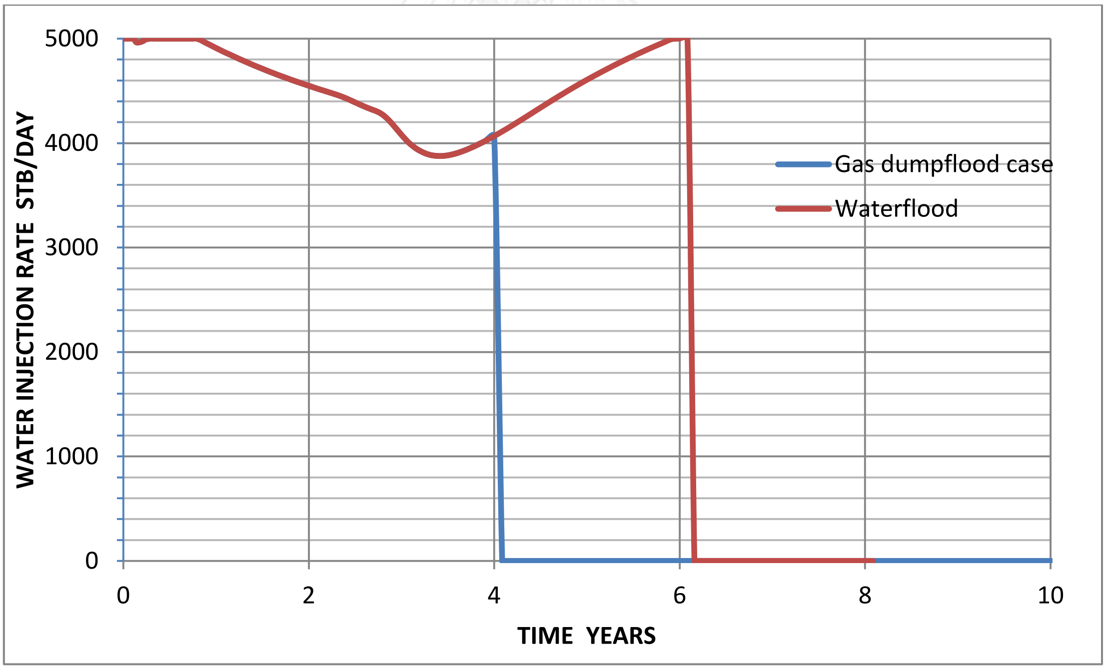


Figure 5. 62 Water injection rate comparison between gas dumpflood case and water flooding (30-degree dip angle)

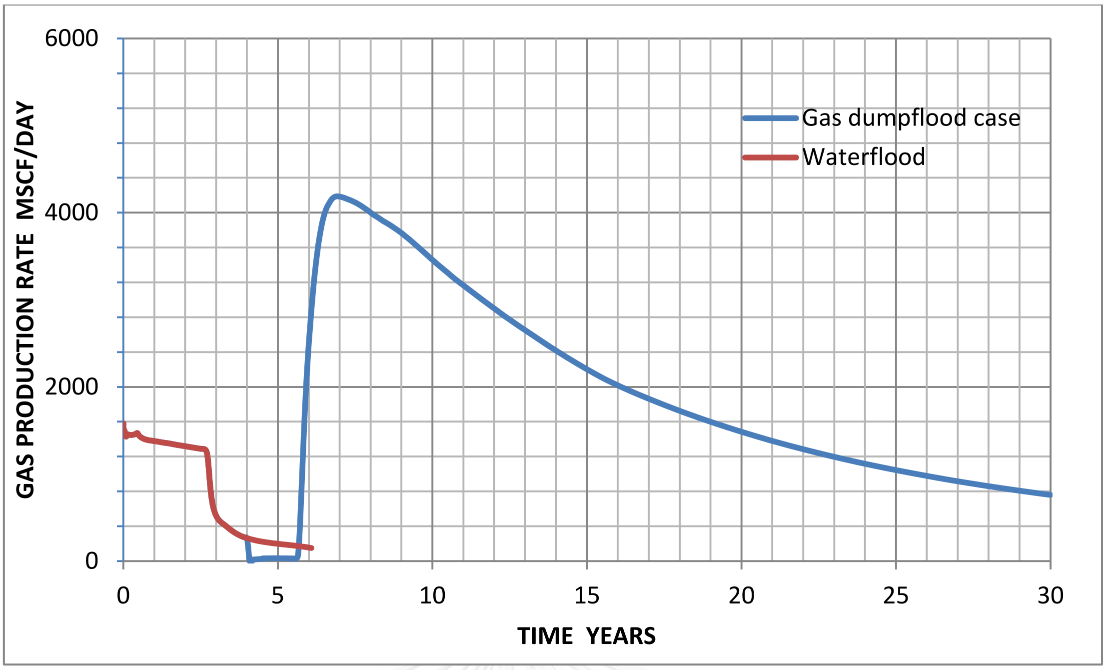


Figure 5. 63 Gas production rate comparison between gas dumpflood and water flooding (30-degree dip angle)

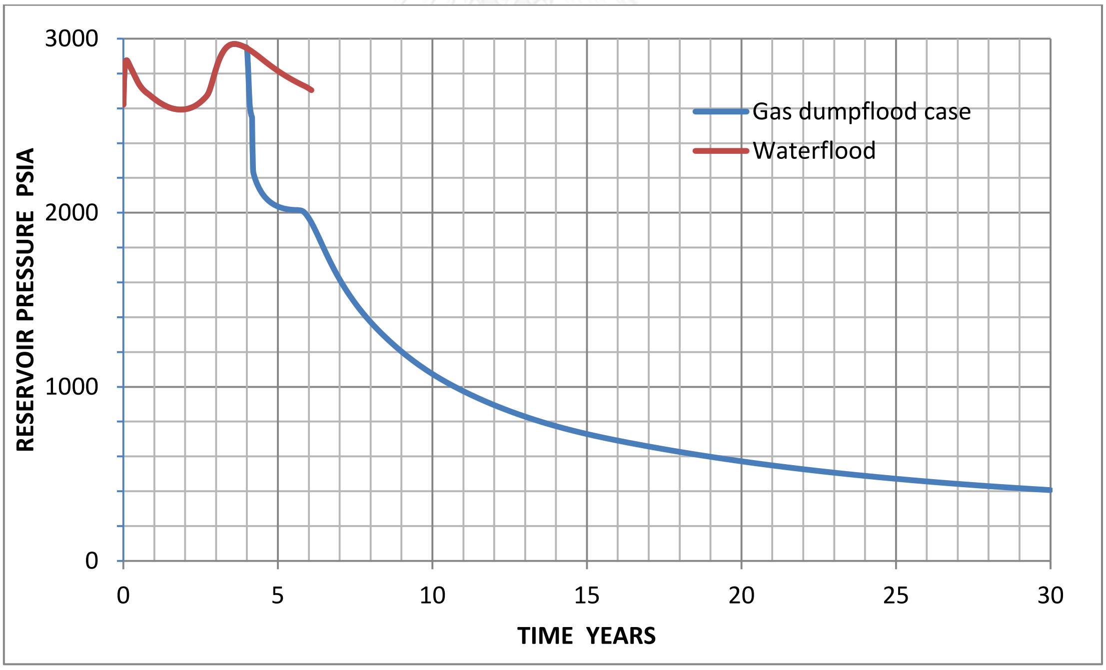


Figure 5. 64 Reservoir pressure comparison between gas dumpflood case and water flooding (30-degree dip angle)

Gas from gas reservoir starts to flow into target oil reservoir at the 4th year as depicted in Figure 5.65. At the beginning of gas dumpflood process, gas rate rises up to 3,000 MSCF/D and stays at that rate for about two years until gas breakthrough. After gas breakthrough, the gas rate rises up to a peak of 3,300 MSCF/D and then drops down as gas from gas reservoir is depleted.

Figure 5.66 shows saturation profiles of gas dumpflood case at different period of time during gas dumpflood process.

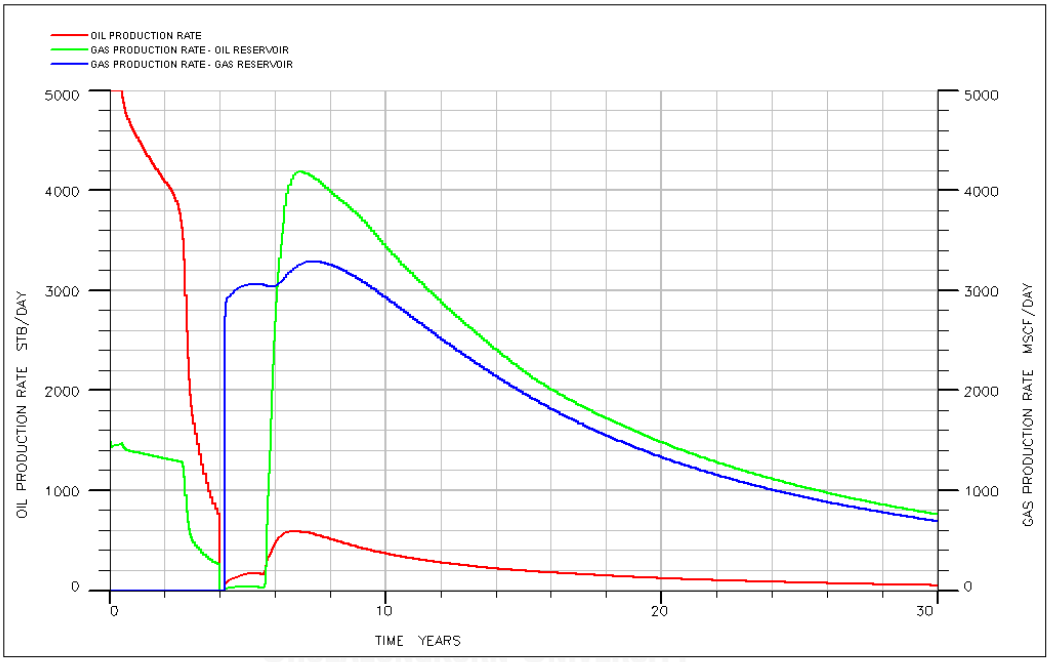
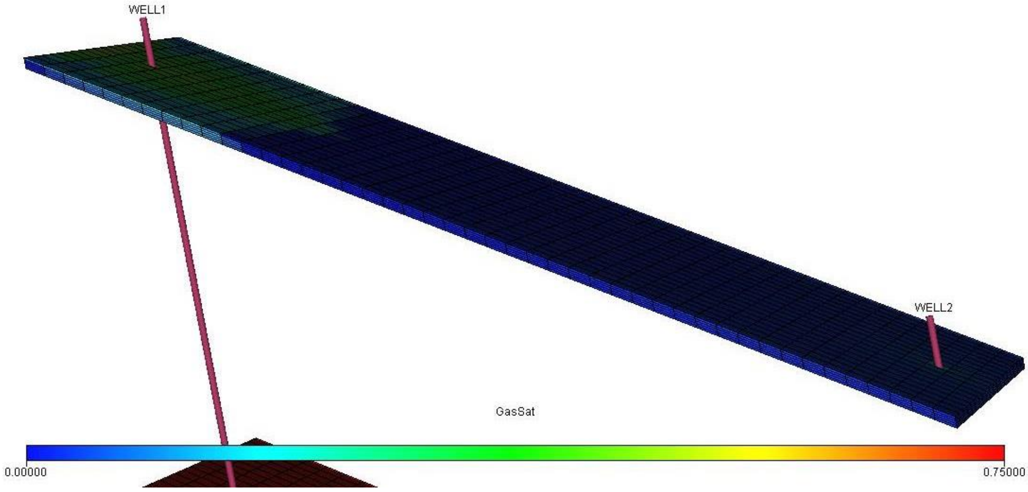
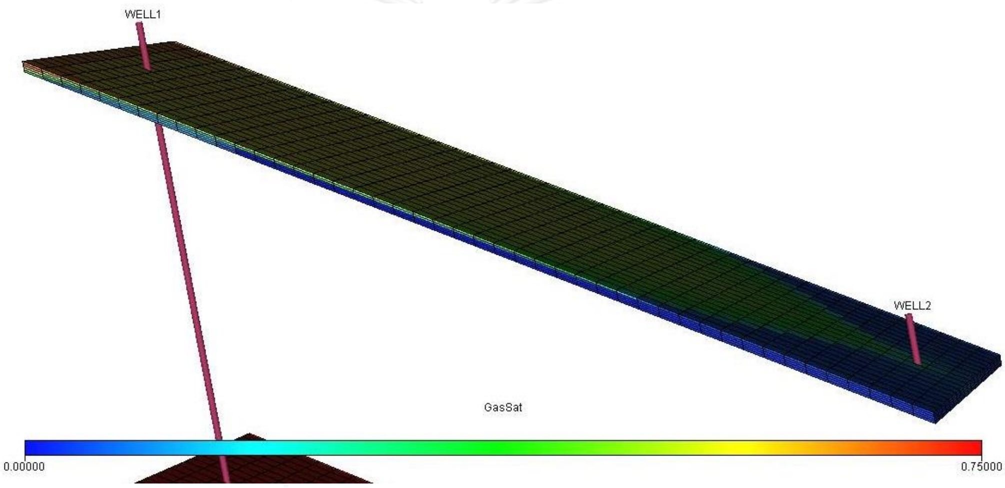


Figure 5. 65 Oil production rate, gas production rate of oil reservoir, and gas production rate of gas reservoir for gas dumpflood case (30-degree dip angle)



a) gas saturation (starting gas dumpflood)



b) gas saturation (gas breakthrough)

Figure 5. 66 Saturation profiles of gas dumpflood case (30-degree dip angle)

The summarized results in Table 5.36 show that gas dumpflood case has better performance than conventional water flooding because of producing 1.6 million STB more oil and injecting 3.5 million barrels less water but producing 1.86 million barrels more water. The cost of pumping water of waterflood case is higher but lower cost of water treatment process. However, the oil recovery factor of gas dumpflood case is remarkably higher than that for conventional water flooding. This makes gas dumpflood more favorable to perform.

Table 5. 36 Summarized results for gas dumpflood in water-flooded reservoir & conventional waterflood for reservoir with 30-degree dip angle

Case	Production life (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
Gas dumpflood case	30	80.80	6.943	6.577	6.048	19.640
Waterflood	6.08	62.22	5.346	10.093	4.186	1.706

5.3.2 Effect of well arrangements

Five different schematics of well arrangement are investigated to see the effect in 30 degree dip angle reservoir. The distance between injector and producer is varied in order to observe the appropriate distance which can provide good sweep efficiency. The schematics of well arrangements are the same as the ones in 15 degree dip angle reservoir as shown in Figure 5.39. Tables 5.37-5.41 summarize details of well locations and constraints for all well arrangements.

Table 5. 37 Locations and constraints of two wells for reservoir with 30-degree dip angle

Well	i^{th} position	j^{th} position	Fracture pressure (psia)
Well 1	3	10	3,265
Well 2	43	10	4,840

Table 5. 38 Locations and constraints of three wells for reservoir with 30-degree dip angle

Well	i^{th} position	j^{th} position	Fracture pressure (psia)
Well 1	3	10	3,265
Well 2	23	10	4,031
Well 3	43	10	4,840

Table 5. 39 Locations and constraints of five wells for reservoir with 30-degree dip angle

Well	i^{th} position	j^{th} position	Fracture pressure (psia)
Well 1	3	10	3,265
Well 2	13	10	3,643
Well 3	23	10	4,043
Well 4	33	10	4,430
Well 5	43	10	4,840

Table 5. 40 Locations and constraints of nine wells for reservoir with 30-degree dip angle

Well	i^{th} position	j^{th} position	Fracture pressure (psia)
Well 1	3	10	3,265
Well 2	8	10	3,452
Well 3	13	10	3,643
Well 4	18	10	3,835

Well 5	23	10	4,031
Well 6	28	10	4,229
Well 7	33	10	4,430
Well 8	38	10	4,634
Well 9	43	10	4,840

Table 5. 41 Locations and constraints of ten wells for reservoir with 30-degree dip angle

Well	i^{th} position	j^{th} position	Fracture pressure (psia)
Well 1	3	5	3,265
Well 2	3	15	3,265
Well 3	13	5	3,643
Well 4	13	15	3,643
Well 5	23	5	4,031
Well 6	23	15	4,031
Well 7	33	5	4,430
Well 8	33	15	4,430
Well 9	43	5	4,840
Well 10	43	15	4,840

The injection and production sequence of 30 degree dip angle reservoir is the same as those in 15 degree dip angle reservoir which is repeatedly shown in Table 5.42. The GLR (gas liquid ratio) criterion is set at the same value as the one used in 15 degree dip angle reservoir which is 1 MSCF/STB for shutting in the well.

Table 5. 42 Injection and production sequence for all wells arrangements for reservoir with 30-degree dip angle

<table>
<tr><th>Well arrangements</th><th>Stage</th><th>Well 1</th><th>Well 2</th></tr>
<tr><td rowspan="3">two wells</td><td>Waterflood</td><td>Producer (5,000* STB/D)</td><td>Water injector (5,000** STB/D)</td></tr>
<tr><td>WCT reaches criteria</td><td colspan="2">Shut in for 60 days</td></tr>
<tr><td>Gas dumpflood</td><td>Gas dumpflood well</td><td>Producer (5,000* STB/D)</td></tr>
</table>

*liquid production rate, **water injection rate

<table>
<tr><th>Well arrangements</th><th>Stage</th><th>Well 1</th><th>Well 2</th><th>Well 3</th></tr>
<tr><td rowspan="4">three wells</td><td>Waterflood</td><td colspan="2">Producer (2,500* STB/D)</td><td>Water injector (5,000** STB/D)</td></tr>
<tr><td>WCT reaches criteria</td><td colspan="3">Shut in for 60 days</td></tr>
<tr><td>Gas dumpflood</td><td rowspan="2">Gas dumpflood well</td><td colspan="2">Producer (2,500* STB/D)</td></tr>
<tr><td>GLR reaches 1 MSCF/STB</td><td>Shut-in</td><td>Producer (2,500* STB/D)</td></tr>
</table>

*liquid production rate, **water injection rate

<table>
<tr><th>Well arrangements</th><th>Stage</th><th>Well 1</th><th>Well 2</th><th>Well 3</th><th>Well 4</th><th>Well 5</th></tr>
<tr><td rowspan="4">five wells</td><td>Waterflood</td><td colspan="4">Producer (1,250* STB/D)</td><td>Water injector (5,000** STB/D)</td></tr>
<tr><td>WCT reaches criteria</td><td colspan="5">Shut in for 60 days</td></tr>
<tr><td>Gas dumpflood</td><td rowspan="2">Gas dumpflood well</td><td colspan="4">Producer (1,250* STB/D)</td></tr>
<tr><td>GLR reaches 1 MSCF/STB</td><td colspan="3">Shut-in</td><td>Producer (1,250* STB/D)</td></tr>
</table>

*liquid production rate, **water injection rate

<table>
<tr><th>Well arrangements</th><th>Stage</th><th>Well 1</th><th>Well 2</th><th>Well 3</th><th>Well 4</th><th>Well 5</th><th>Well 6</th><th>Well 7</th><th>Well 8</th><th>Well 9</th></tr>
<tr><td rowspan="4">nine wells</td><td>Waterflood</td><td colspan="8">Producer (625* STB/D)</td><td>Water injector (5,000** STB/D)</td></tr>
<tr><td>WCT reaches criteria</td><td colspan="9">Shut in for 60 days</td></tr>
<tr><td>Gas dumpflood</td><td rowspan="2">Gas dumpflood well</td><td colspan="8">Producer (625* STB/D)</td></tr>
<tr><td>GLR reaches 1 MSCF/STB</td><td colspan="7">Shut-in</td><td>Producer (625* STB/D)</td></tr>
</table>

*liquid production rate, **water injection rate

<table>
<tr><th>Well arrangements</th><th>Stage</th><th>Well 1</th><th>Well 2</th><th>Well 3</th><th>Well 4</th><th>Well 5</th><th>Well 6</th><th>Well 7</th><th>Well 8</th><th>Well 9</th><th>Well 10</th></tr>
<tr><td rowspan="4">ten wells</td><td>Waterflood</td><td colspan="9">Producer (625* STB/D)</td><td>Water injector (2,500** STB/D)</td></tr>
<tr><td>WCT reaches criteria</td><td colspan="10">Shut in for 60 days</td></tr>
<tr><td>Gas dumpflood</td><td colspan="2" rowspan="2">Gas dumpflood well</td><td colspan="8">Producer (625* STB/D)</td></tr>
<tr><td>GLR reaches 1 MSCF/STB</td><td colspan="7">Shut-in</td><td>Producer (625* STB/D)</td></tr>
</table>

*liquid production rate, **water injection rate

During gas dumpflood process, gas from the underneath reservoir has higher pressure than the fracture pressure of the target reservoir. Thus, the partial perforation of the gas zone is performed. However, the lowest perforation interval still incurs fracture of the oil zone. By continuing the production without additional water injection after water cut reaches the criteria, it can reduce the bottom hole pressure lower than the fracture pressure. The longer the period of delaying the shut in of the producer, the lower the bottom hole pressure will be.

Table 5. 43 Perforation interval and skin of source gas reservoir for reservoir with 30-degree dip angle

Case	Perforation interval(ft)	Skin	Delay in shut-in(day)
2 wells	0.2	2,090	no delay
3 wells	0.05	8,351	no delay
5 wells	0.05	8,351	3
9 wells	0.05	8,351	5
10 wells	0.06	6,966	1

Figures 5.67 and 5.68 show the bottom hole pressure of the dumpflood well for the case of five, nine and ten wells arrangements without and with delaying the shut in, respectively. The fracture pressure of 30 degree dip angle reservoir of well 1 is 3,265 psia. Figure 5.67 shows that the bottome hole pressure of each case is beyond the fracture pressure during the beginning of gas dumpflood when there is no delay. However, for the cases of delayed shut in as shown in Figure 5.68, the pressure does not go beyond the fracture pressure.

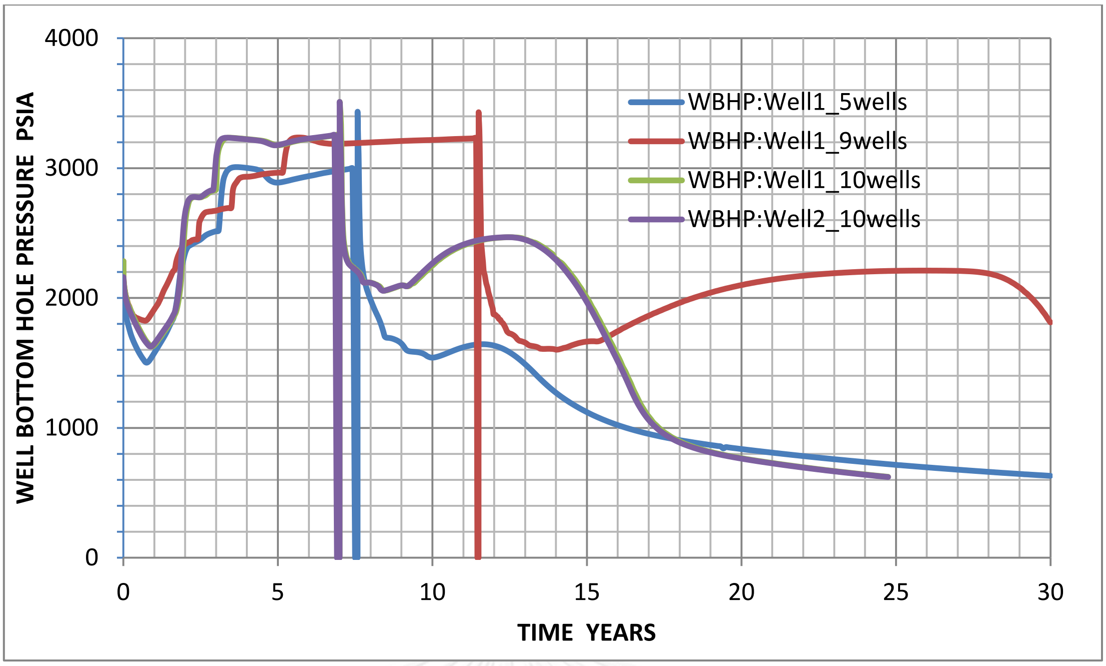


Figure 5. 67 Bottom hole pressure of the dumpflood well for the case of five, nine and ten wells without delay shut in (30-degree dip angle)

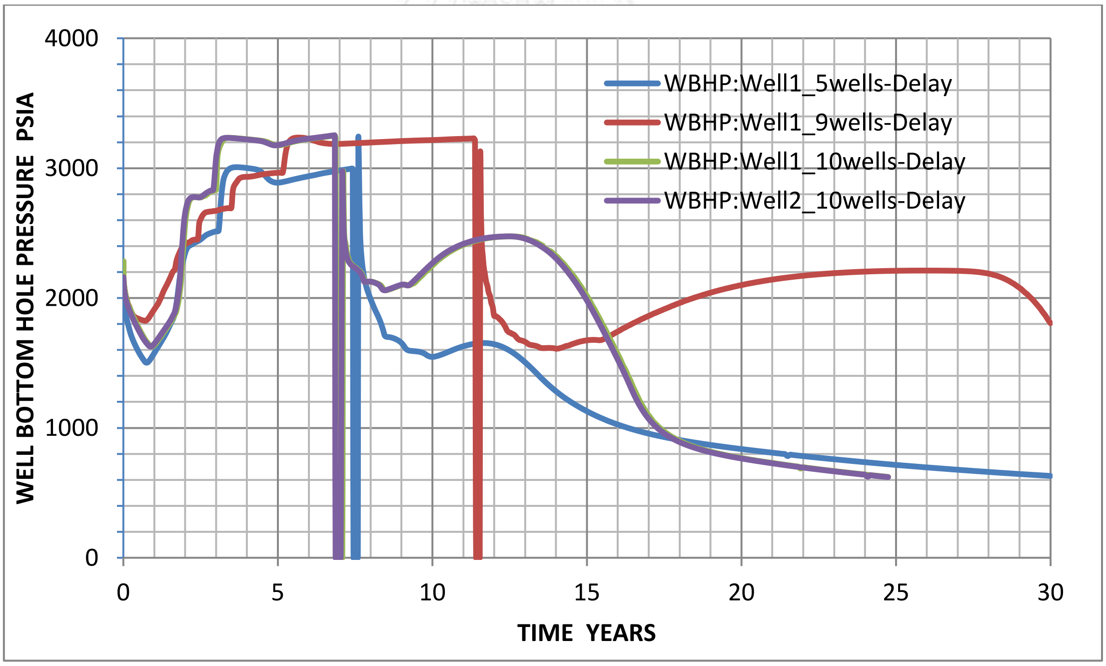


Figure 5. 68 Bottom hole pressure of the dumpflood well for the case of five, nine and ten wells with delay shut in (30-degree dip angle)

Figures 5.69-5.73 illustrate oil production rate, water cut, water injection rate, gas production rate and reservoir pressure for different well arrangements. Field oil production rate maintained constant at 5,000 STB/D until each well for different well arrangements reaches 80% can be water cut criteria. Then, those wells are shut in, leading the field oil rate to drop down. For the case of nine wells, it has the shortest time of constant oil production rate compared to other cases. Also, the nine-well case has the longest water flooding period due to low oil production rate as most of the wells are shut in. The case of two wells starts gas dumpflood the soonest due to the shortest water flooding period as depicted in Figure 5.70 and Figure 5.71. This leads to the highest oil recovery factor as shown in Table 5.43. As depicted in Figure 5.72, cases of two, three, five, ten and nine well arrangements have gas breakthrough at different times. The case of nine wells is the last to start gas dumpflood process. According to this, the nine-well case has the shortest gas dumpflood duration which leads to the lowest oil recovery. For the case of nine wells, the reservoir pressure during water flooding is constant at around 3,800 psia as shown in Figure 5.73 due to the fact that water is injected until the 11.5th year.

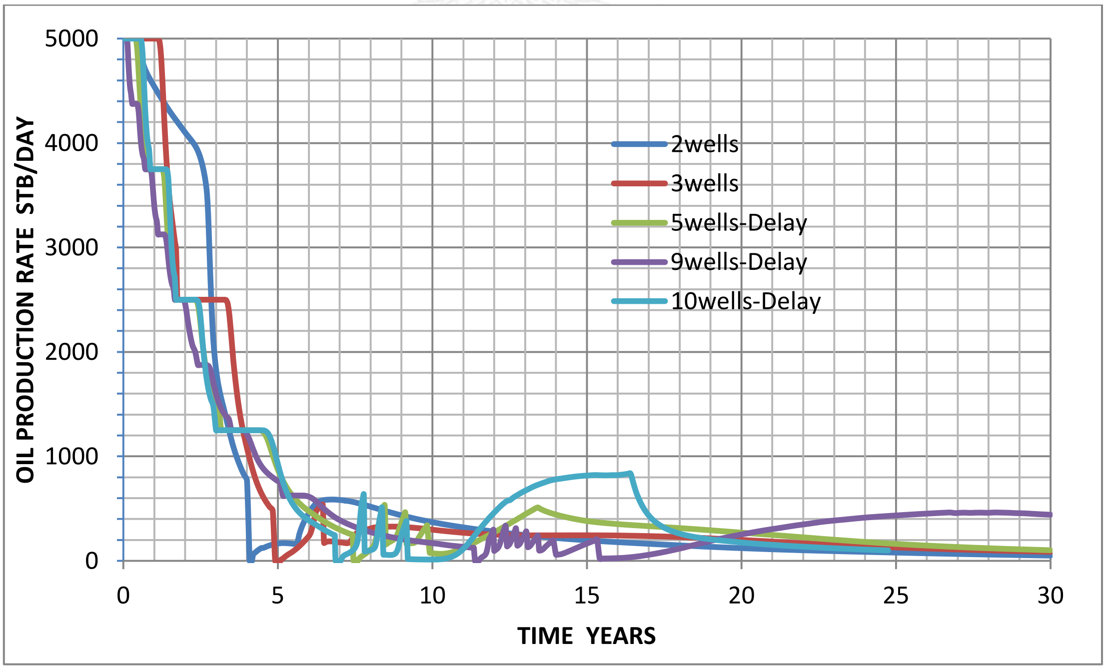


Figure 5. 69 Oil production rates for different well arrangements.

(30-degree dip angle)

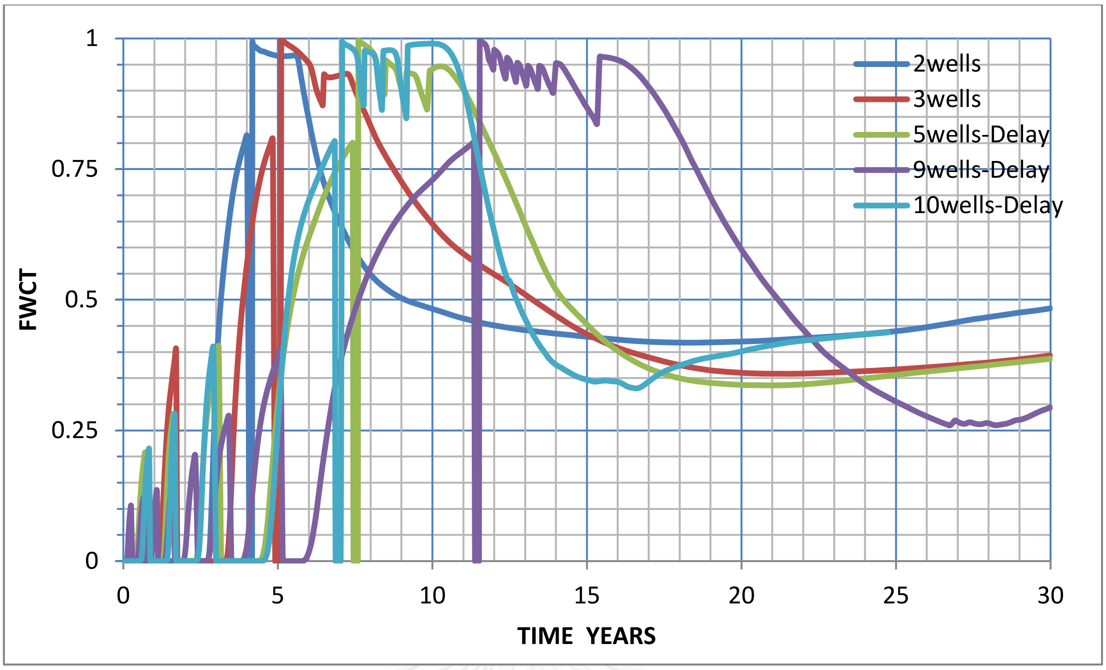


Figure 5. 70 Water cuts for different well arrangements.

(30-degree dip angle)

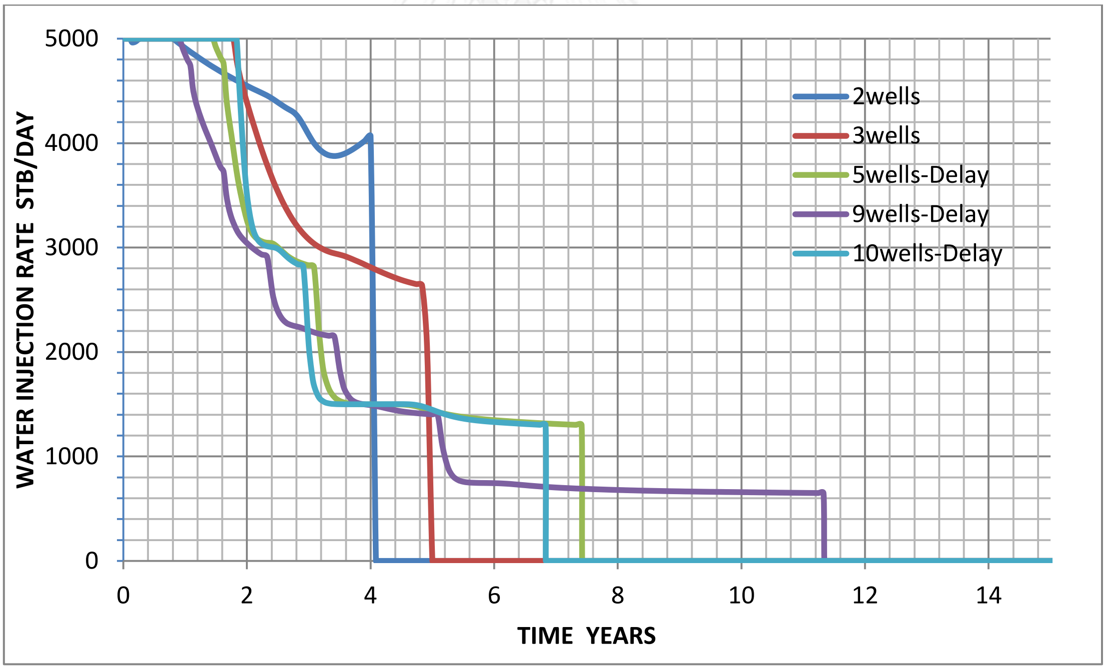


Figure 5. 71 Water injection rates for different well arrangements.

(30-degree dip angle)

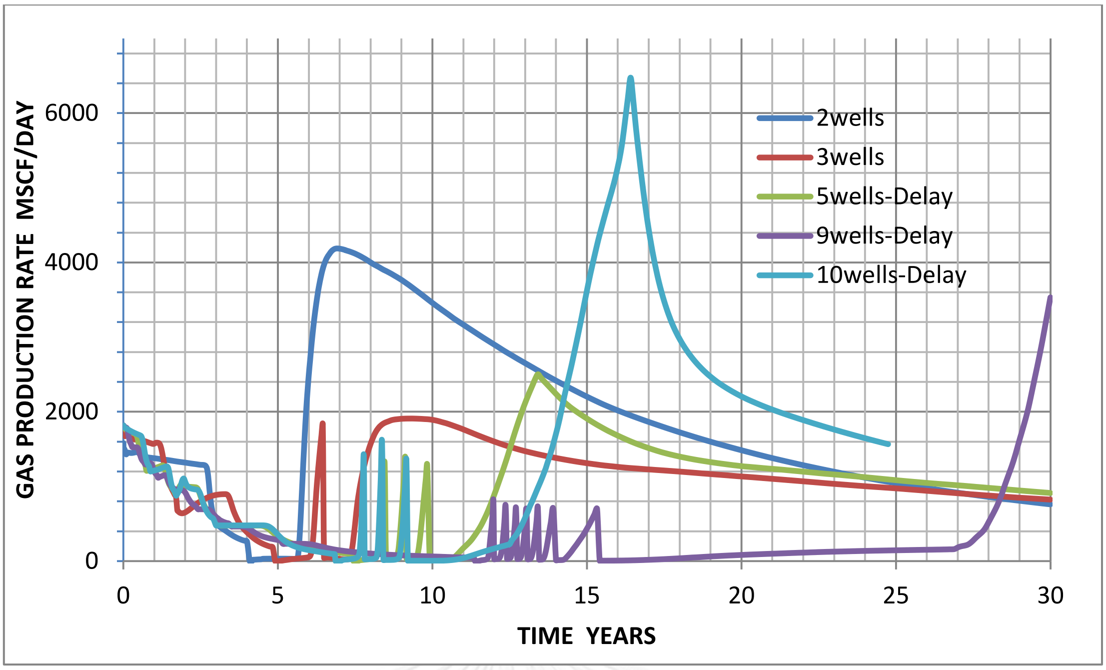


Figure 5. 72 Gas production rates for different well arrangements.

(30-degree dip angle)

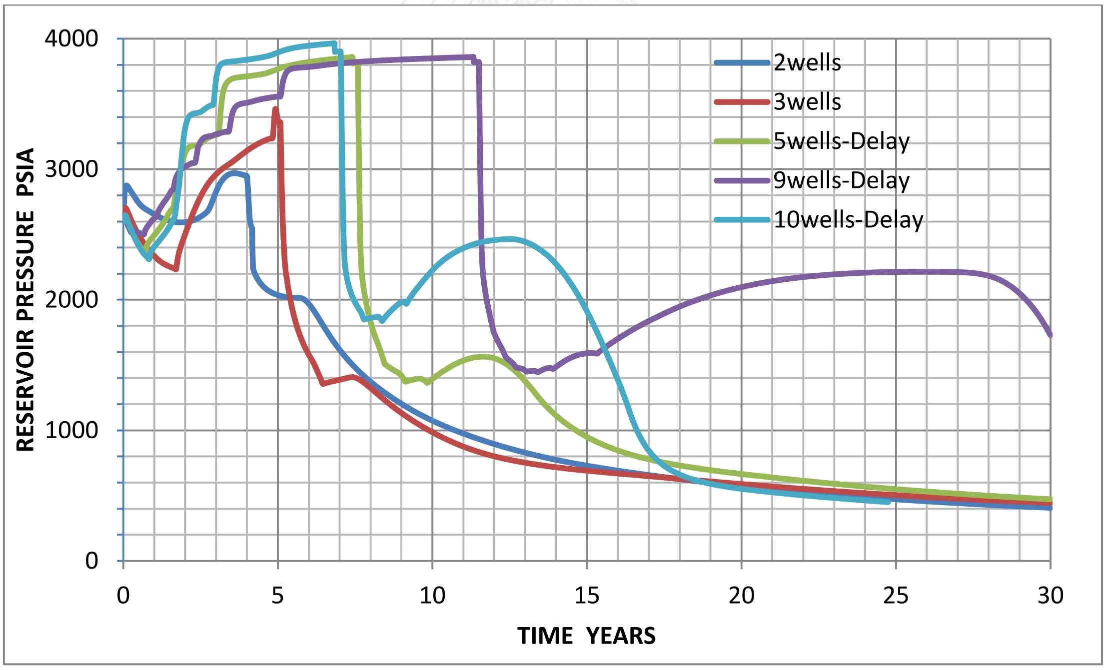


Figure 5. 73 Reservoir pressures for different well arrangements.

(30-degree dip angle)

Summarized results in Table 5.44 show that as we increase the number of wells from two to nine wells, oil recovery factor slightly decreases. So, drilling more wells in the same alignment does not increase the oil recovery. Then, we try to increase the wells from five to ten wells by drilling another five wells in another alignment. The oil recovery factor slightly increases as the recovery factor for the case of five wells is already high. This is because the effect of gravity drainage drains more oil toward the producers located downdip. When comparing all the cases, the best performer is two wells case which gain the best oil recovery, the lowest water injection and the highest gas production.

Table 5. 44 Summarized results for different well arrangements for reservoir with 30-degree dip angle

Case	Water cut (%)	Production life (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (MSCF)
2 wells	80	30	80.80	6.943	6.577	6.048	19.640
3 wells	80	30	79.10	6.796	6.878	6.317	11.994
5 wells	80	30	78.53	6.748	6.919	6.302	11.037
9 wells	80	30	78.17	6.716	6.956	6.179	3.914
10 wells	80	24.75	79.88	6.863	6.652	5.946	13.446

5.3.3 Effect of stopping time for water flooding

Similar to the previous cases, the starting of gas dumpflood period is determined by water cut criteria. Five values of water cut which are 1%, 20%, 40%, 60% and 80% are used in this study. As the case of two wells is the best performer, it is used throughout the study of 30-degree dipping reservoir. However, the investigation is expanded to cover both vertical and horizontal well types. As the bottom hole pressure of well 1 exceeds the fracture pressure during gas dumpflood, partial penetration is needed as depicted in Table 5.45.

5.3.3.1 Vertical producer

Table 5. 45 Perforation interval and skin of source gas reservoir for reservoir with 30-degree dip angle

Case	Water cut (%)	Perforation interval(ft)	Skin
2 wells	1	0.25	1,673
	20	0.36	1,165
	40	0.10	4,177
	60	0.10	4,177
	80	0.20	2,090

Figure 5.74 shows that during the first three years, all water cut criteria cases provide the same oil production rates until they reach the criteria. The higher the water cut criteria, the longer the water flooding period. The case with water cut of 80% criteria has the longest period. During gas dumpflood period, the case of 20% water cut criteria has the highest peak in oil production rate and oil recovery factor (Figure 5.75) and it is the first case reaching the abandonment criteria. At late time, oil recovery factors of all cases are not significantly different.

Figure 5.76 shows that the water cut reach the criteria at different times. During the beginning of gas dumpflood process, water cut reaches 100% since water is still around the production well as a result of prior water flooding. Then, water cut decreases with time as gas dumpflood progresses.

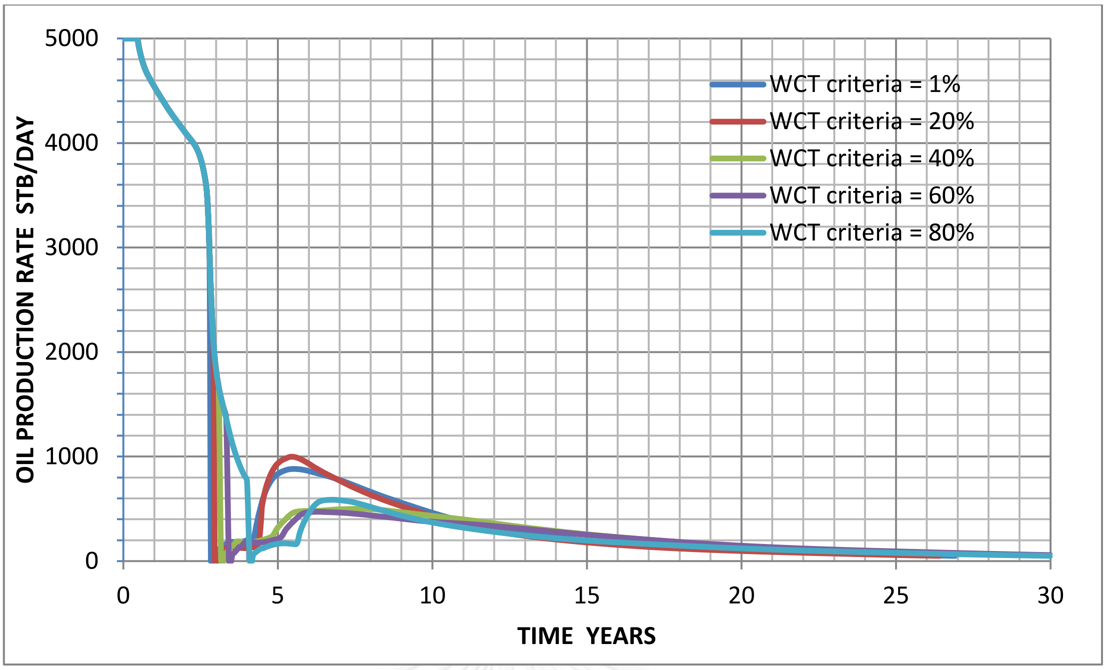


Figure 5. 74 Oil production rates for different water cut criteria (30-degree dip angle)

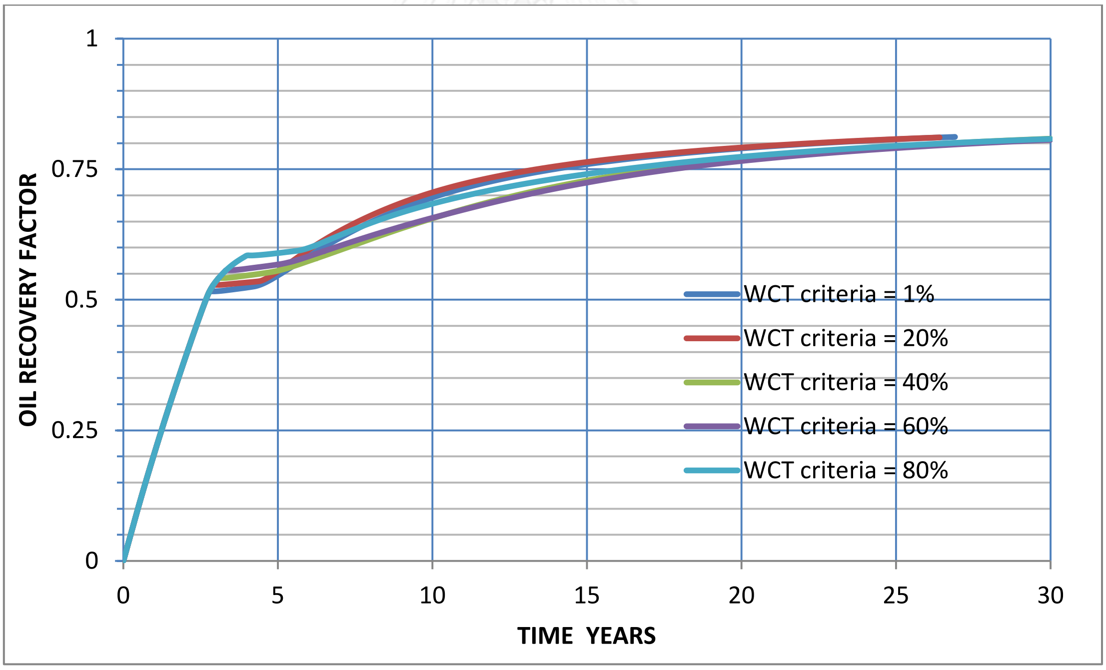


Figure 5. 75 Oil recovery factors for different water cut criteria (30-degree dip angle)

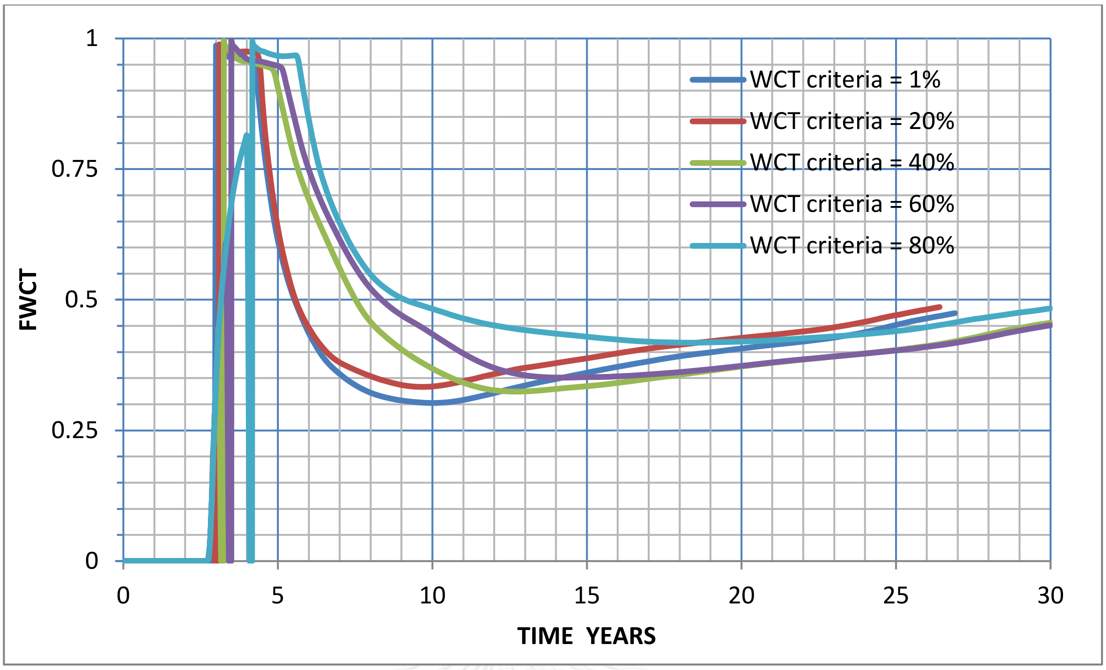


Figure 5. 76 Water cut profiles for different water cut criteria

(30-degree dip angle)

Summarized results in Table 5.46 show that as the water cut criteria is increased from 1% to 80%, total oil production decreases by 32,985 STB while the water injection and production increases by 1.764 million barrels and 1.73 million barrels, respectively. So, increasing of water cut criteria is not a good way to increase oil recovery. When comparing all the cases, 1% water cut criteria is the best performer with the highest oil recovery and the lowest water injection and production.

Table 5. 46 Summarized results for different water criteria of vertical wells for reservoir with 30-degree dip angle

Case	Water cut (%)	Production life (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
2 wells	1	26.91	81.19	6.976	4.813	4.317	19.977
	20	26.41	81.09	6.968	5.003	4.476	21.110
	40	30	80.85	6.947	5.258	4.768	16.433
	60	30	80.62	6.927	5.607	5.101	16.374
	80	30	80.80	6.943	6.577	6.048	19.640

5.3.3.2 Horizontal producer

In this section, we investigate different water cut criteria used to start gas dumpflood when the producer is horizontal wells. According to the previous section, two vertical wells provide good result on oil recovery with good sweep efficiency in the x- and y-directions. Thus, we try the locations of these two wells for this case in an attempt to get better performance from horizontal producer. Note that the well 1 which is used to dump gas from the source reservoir is still a vertical well. One horizontal producer is placed in layer 1 of oil reservoir in the y-direction (top most layer) with the length of 1900 ft. Figure 5.77 illustrates the schematic of horizontal well type. Locations and constraints of horizontal producer and vertical gas dump well are tabulated in Table 5.47. Five values of water cut criteria are investigated: 1%, 20%, 40%, 60% and 80%. Note that during gas dumpflood process, the bottom hole pressure of gas dump well (well 1) exceeds fracture pressure. Thus, partial perforation is performed as detailed in Table 5.48.

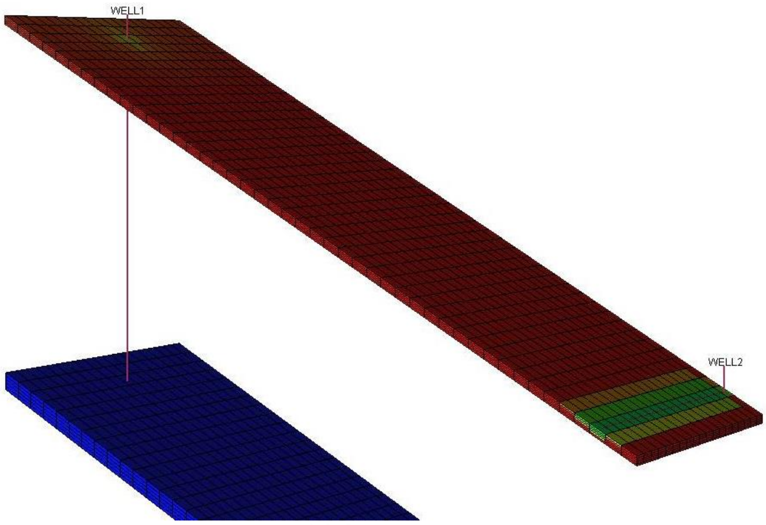


Figure 5. 77 well locations for the horizontal producer and vertical well connecting the source and target reservoirs (30-degree dip angle).

Table 5. 47 Locations and constraints of the horizontal producer and vertical well connecting the source and target reservoirs for reservoir with 30-degree dip angle

Well	ith position	jth position	Fracture pressure (psia)
Well 1	3	10	3,265
Well 2	43	1-19	4,840

Table 5. 48 Perforation interval and skin of source gas reservoir for reservoir with 30-degree dip angle

Case	Water cut (%)	Perforation interval(ft)	Skin
1 horizontal producer for gas dumpflood	1	0.36	1,165
	20	0.36	1,165
	40	0.36	1,165
	60	0.24	1,742
	80	0.24	1,742

As shown in Figure 5.78, the case of 1% water cut criteria is the first one starting gas dumpflood and it has the highest peak of oil production rate during gas dumpflood. During the beginning of gas dumpflood, the case with 80% water cut criteria has the highest oil recovery factor but at late time the case with 1% water cut criteria gives the highest value as shown in Figure 5.79. The Water cut reaches its criteria as shown in Figure 5.80.

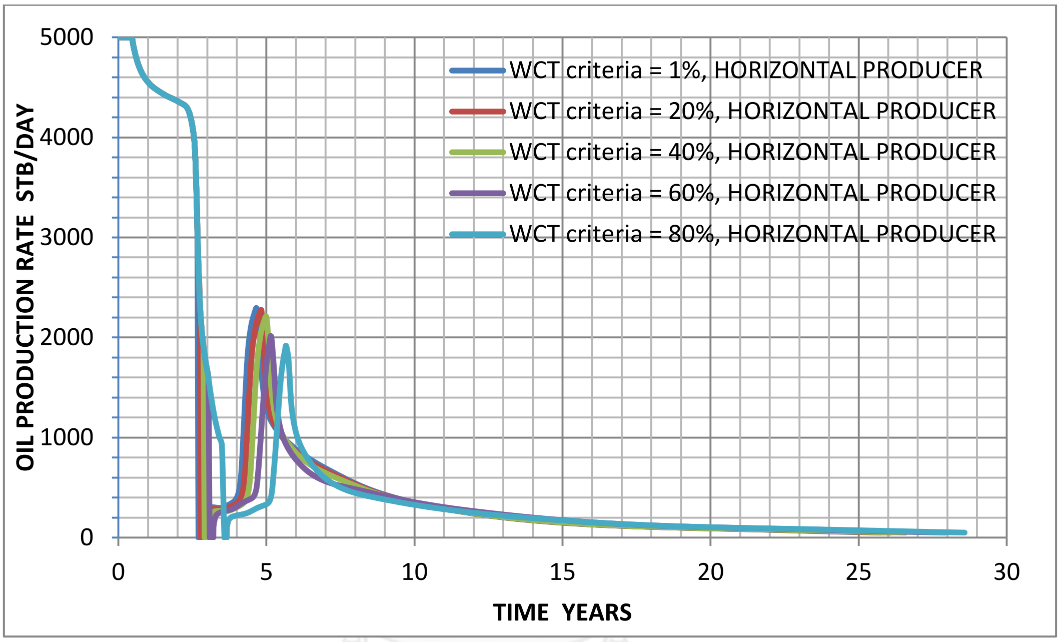


Figure 5. 78 Oil production rates for different water cut criteria
(30-degree dip angle)

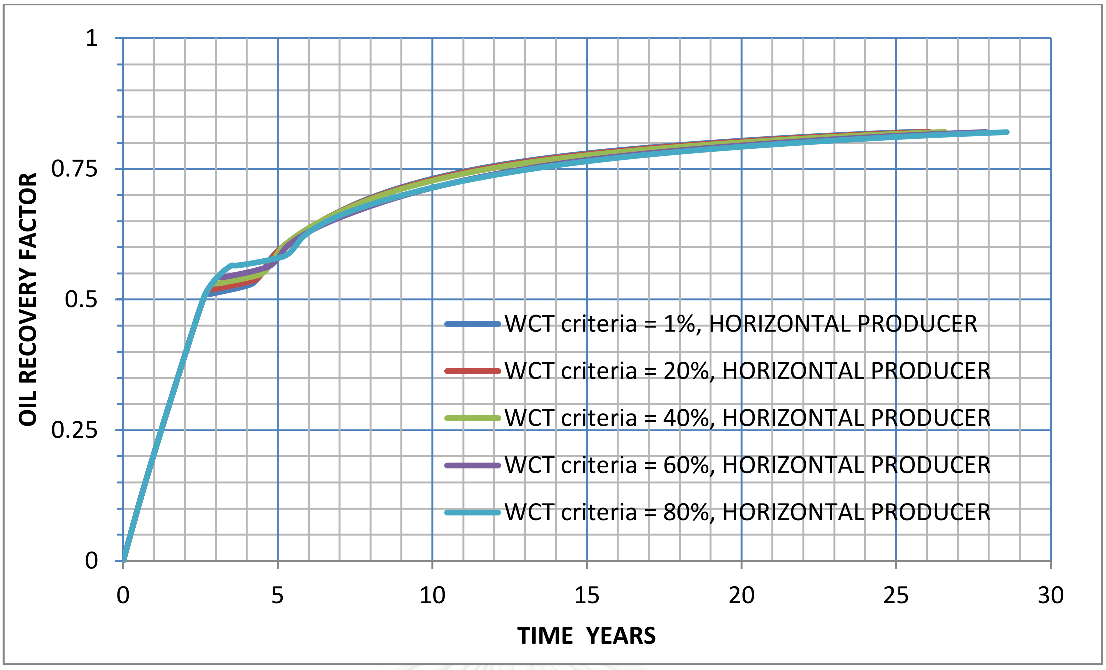


Figure 5. 79 Oil recovery factors for different water cut criteria

(30-degree dip angle)

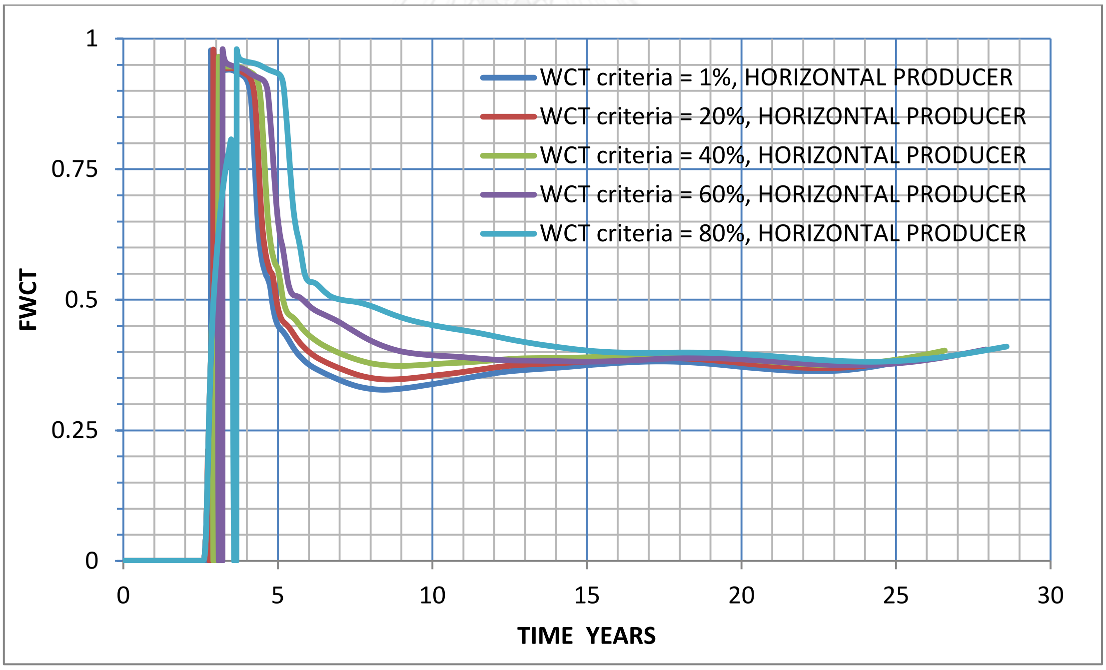


Figure 5. 80 Water cut profiles for different water cut criteria

(30-degree dip angle)

According to summarized results in Table 5.49, as the water cut criteria is increased, oil recovery factor slightly decreases while water injection and production significantly increases. The total oil production gets lowered by 9,000 STB with 1.43 million barrels increase in water injection and 1.412 million barrels increase in water production. So, increasing water cut criteria does not increase oil recovery. When comparing all the cases, the case with 1% water cut criteria is the best performer with the highest amount of oil production, the lowest water injection and water production, and the shortest production life time among all cases. In term of gas production, all cases have comparable results.

Table 5. 49 Summarized results for different water cut criteria of horizontal producer and vertical well connecting the source and target reservoirs for reservoir with 30-degree dip angle.

Case	Water cut (%)	Production life (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
1 horizontal producer for gas dumpflood	1	25.75	82.12	7.056	4.867	4.185	22.617
	20	26.08	82.09	7.053	5.014	4.322	22.667
	40	26.58	82.06	7.051	5.240	4.540	22.743
	60	27.91	82.05	7.050	5.527	4.836	21.541
	80	28.58	82.02	7.047	6.297	5.597	21.602

5.3.4 Effect of perforation interval of source gas reservoir

According to the fracture pressure of gas dump well (well 1), it is not possible to vary the perforation interval in order to see the effect of gas dumpflood process. We can only use partial penetration to limit the entry of high pressure gas into the target oil reservoir which does not exceed the fracture pressure.

5.3.5 Effect of water injection rate and liquid production rate

One horizontal production well with 1% water cut criteria are used throughout this study for investigating the effect of water injection and liquid production rate. Note that water injection rate in this case is limited by fracture pressure that should not allow the bottom hole pressure higher than 4,840 psia.

The different combinations of target water injection and target liquid production rate that have been studied in this section are shown in Table 5.50. The rates between 3,000 and 5,000 STB/D are studied.

Table 5. 50 Target water injection and liquid production rates for reservoir with 30-degree dip angle

Case	Target water injection rate (STB/D)	Target liquid production rate (STB/D)
1	3,000	3,000
2	4,000	4,000
3	5,000	5,000
4	3,000	4,000
5	3,000	5,000
6	4,000	3,000
7	4,000	5,000
8	5,000	3,000
9	5,000	4,000

As shown in Figure 5.81, the cases with target water injection rate higher than target liquid production rate (cases 6, 8 and 9) cannot maintain the target injection rate until they reach the water cut criteria. This is because the bottom hole pressure accumulates and exceeds the fracture pressure as less fluid is withdrawn out from reservoir in comparison to injected water. The rest of the cases can maintain stable target rate until they reach the criteria. Figure 5.82 illustrates oil production profiles.

The cases with target liquid production rate of 5,000 STB/D can maintain constant rate shorter than the cases with target liquid production rate of 3,000 and 4,000 STB/D which can maintain constant rate until the beginning of gas dumpflood. Water cut reaches 1% criteria at different times for different cases as shown in Figure 5.83. At the beginning of gas dumpflood, there is high water cut due to prior water injection. The oil recovery factors of all the cases show comparable results as illustrated in Figure 5.84. Figure 5.85 shows reservoir pressures of all cases which have the same profiles at late time. For cases 6, 8 and 9, the reservoir pressures rise up higher than other cases during the water injection period.

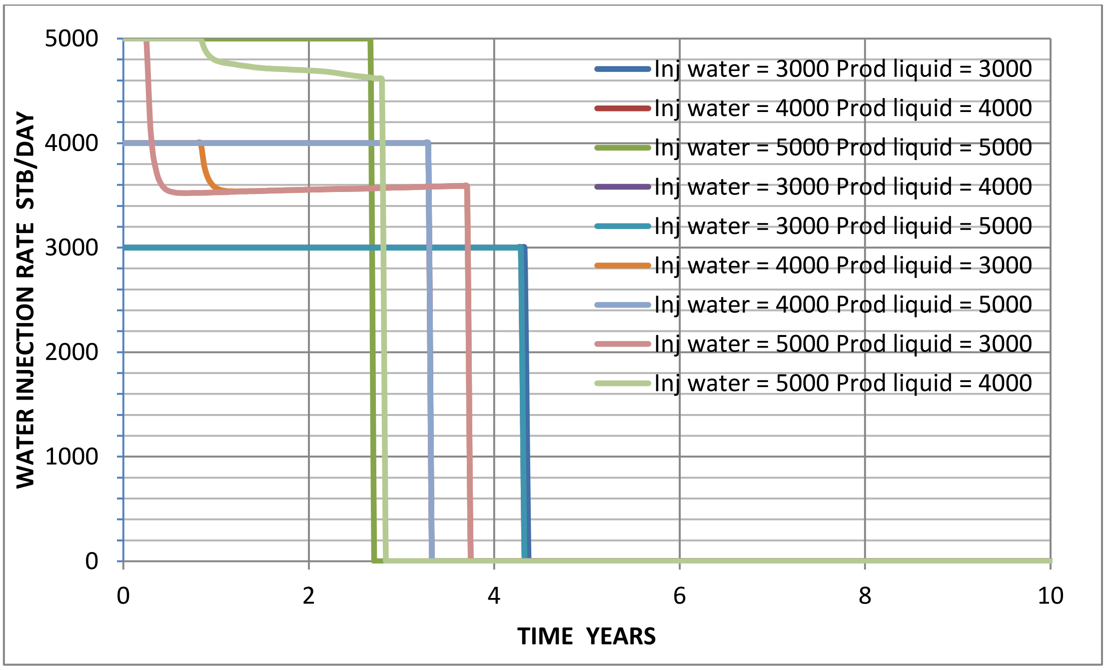


Figure 5. 81 Water injection profiles for different target water injection and liquid production rates (30-degree dip angle)

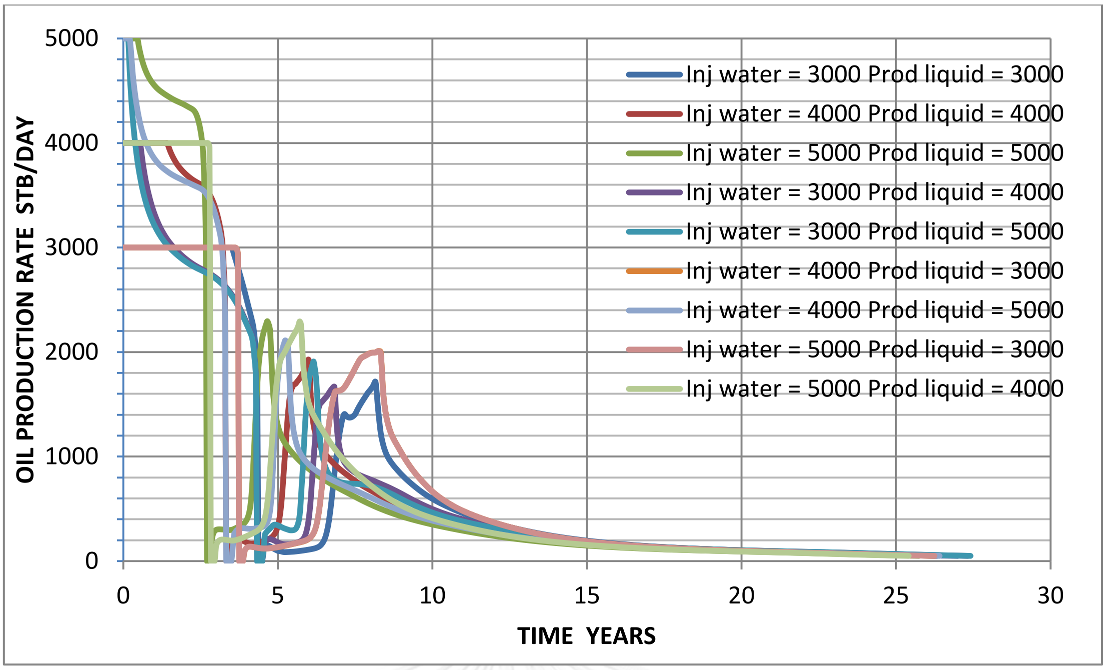


Figure 5. 82 Oil production profiles for different target water injection and liquid production rates (30-degree dip angle)

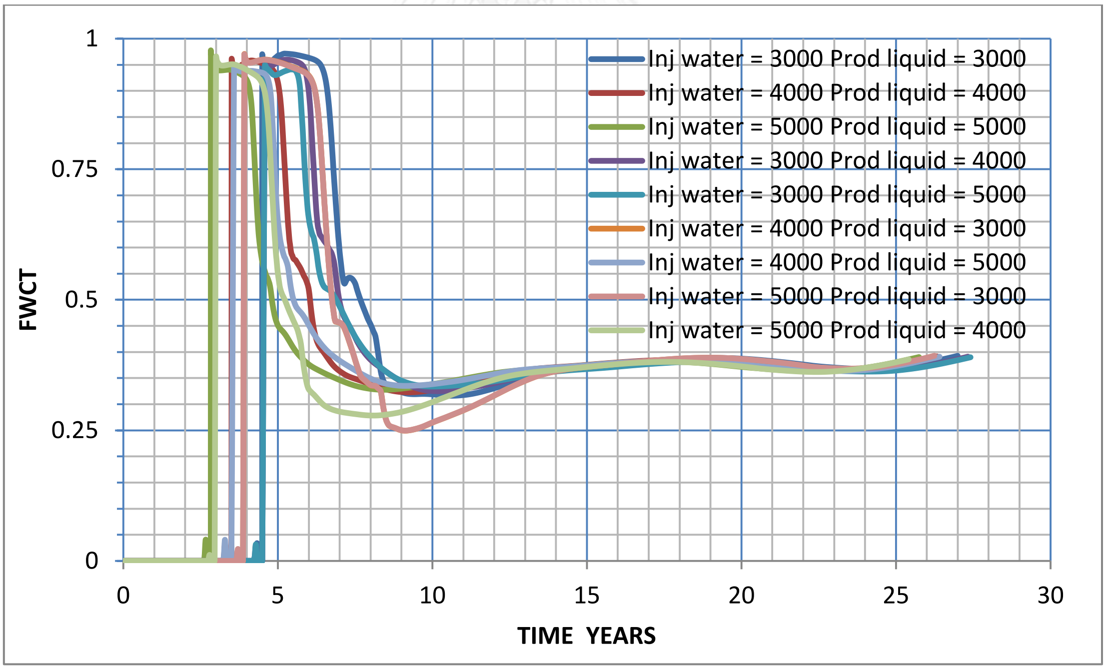


Figure 5. 83 Water cuts for different target water injection and liquid production rates (30-degree dip angle)

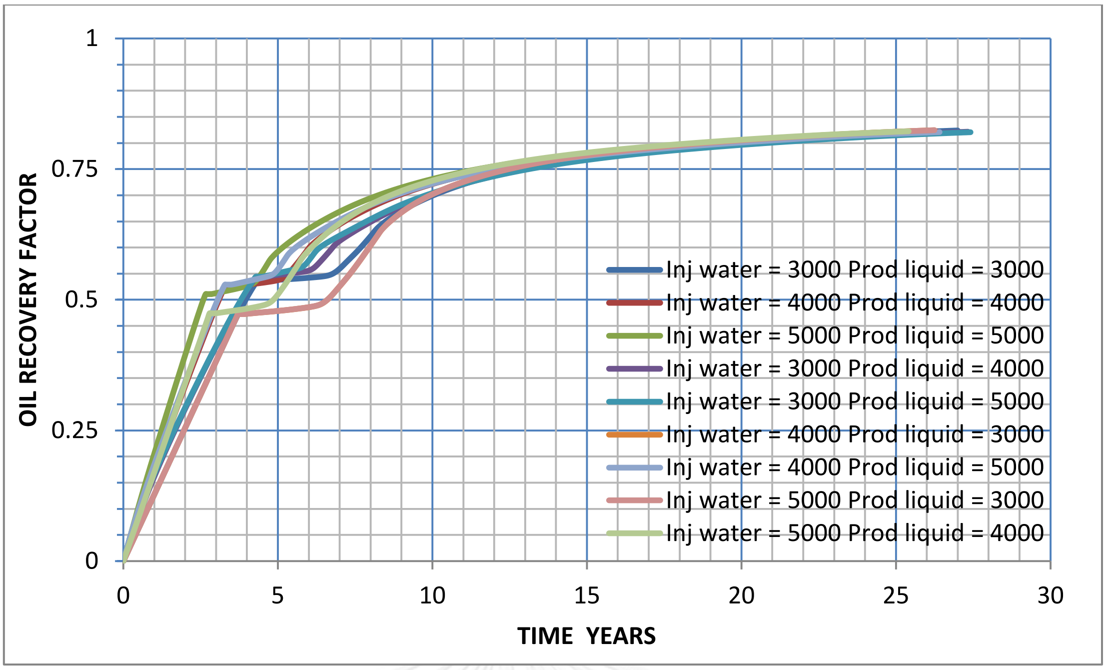


Figure 5. 84 Oil recovery factors for different target water injection and liquid production rates (30-degree dip angle)

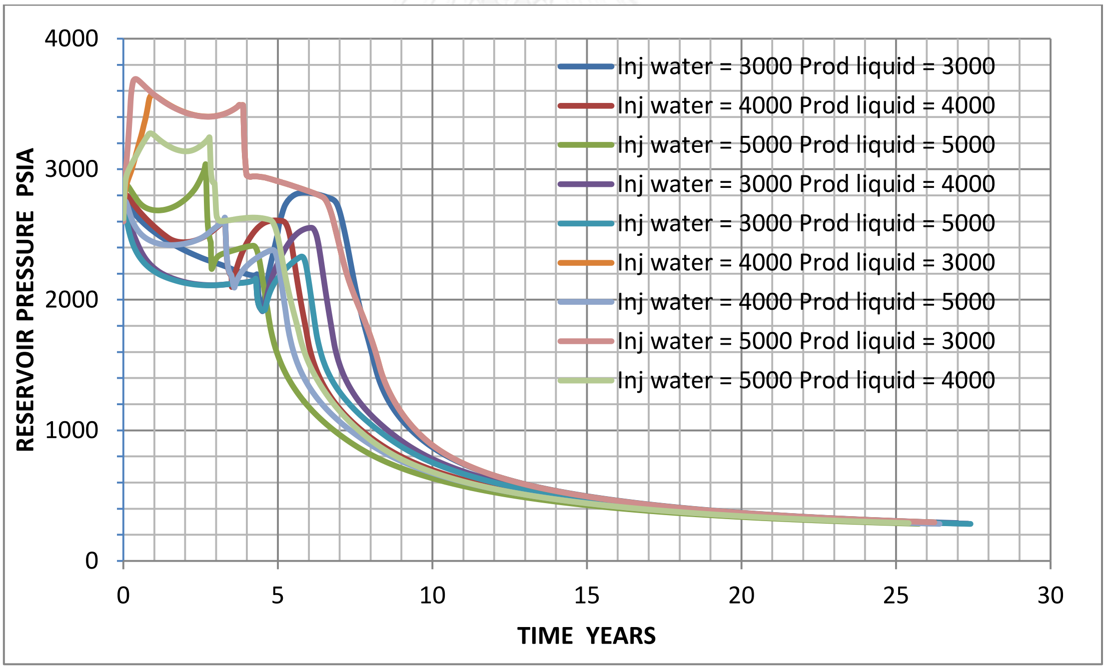


Figure 5. 85 Reservoir pressures for different target water injection and liquid production rates (30-degree dip angle)

Summarized results in Table 5.51 show that as the rate is varied from 3,000 to 5,000 STB/D for both target water injection and target liquid production, the oil recovery factor, total water injection, total water production and total gas production show no significant difference among all cases. Case 3 is selected due to the lowest operating cost of water injection.

Table 5. 51: Summarized results for different combinations of target water injection rate and liquid production rate for reservoir with 30-degree dip angle

Case	Waterflood duration (years)	Production life (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
1	4.33	27.00	82.40	7.080	4.742	4.056	22.353
2	3.29	26.33	82.21	7.064	4.804	4.121	22.553
3	2.66	25.75	82.12	7.056	4.867	4.185	22.617
4	4.29	27.33	82.15	7.059	4.698	4.015	22.580
5	4.29	27.41	82.06	7.051	4.698	4.016	22.655
6	3.71	26.25	82.45	7.084	4.963	4.276	22.163
7	3.29	26.41	82.09	7.053	4.804	4.121	22.636
8	3.71	26.25	82.44	7.084	4.963	4.275	22.163
9	2.79	25.41	82.24	7.067	4.883	4.203	22.397

After simulating all the cases, the results of well arrangements for each dip angle can be summarized in Table 5.52 and 5.53. These selected well arrangements will be further studied in the sensitivity analysis section. The results shown in Figures 5.86-5.89 are oil production rate, oil recovery factor, original oil in place and gas in place. For oil production rate, 0-degree dip angle reservoir has the maximum oil rate at 7,000 STB/D, 15 and 30 degree dip angle reservoirs have the same maximum oil rate at 5,000 STB/D. This because of zero degree dip has two horizontal production wells in which each well produces at 3,500 STB/D and can still maintain maximum rate longer than the other two dip angle reservoirs which have only one production well. The production life time of 0-degree dip angle reservoir is shorter than those for 15 and 30 degree dip angle reservoirs because two horizontal producers can withdraw higher amount of fluid with shorter time. For 30 degree dip angle reservoir, it has the highest oil recovery factor due to gravity force as segregation helps improve the efficiency of gas flooding and also helps drain oil toward the producer.

Table 5. 52 List of selected well arrangement cases for each dip angle

Dip angle	Selected well arrangement
0	Two horizontal producers for gas dumpflood (layer 5)
15	One horizontal producer for gas dumpflood (layer 5)
30	One horizontal producer for gas dumpflood (layer 1)

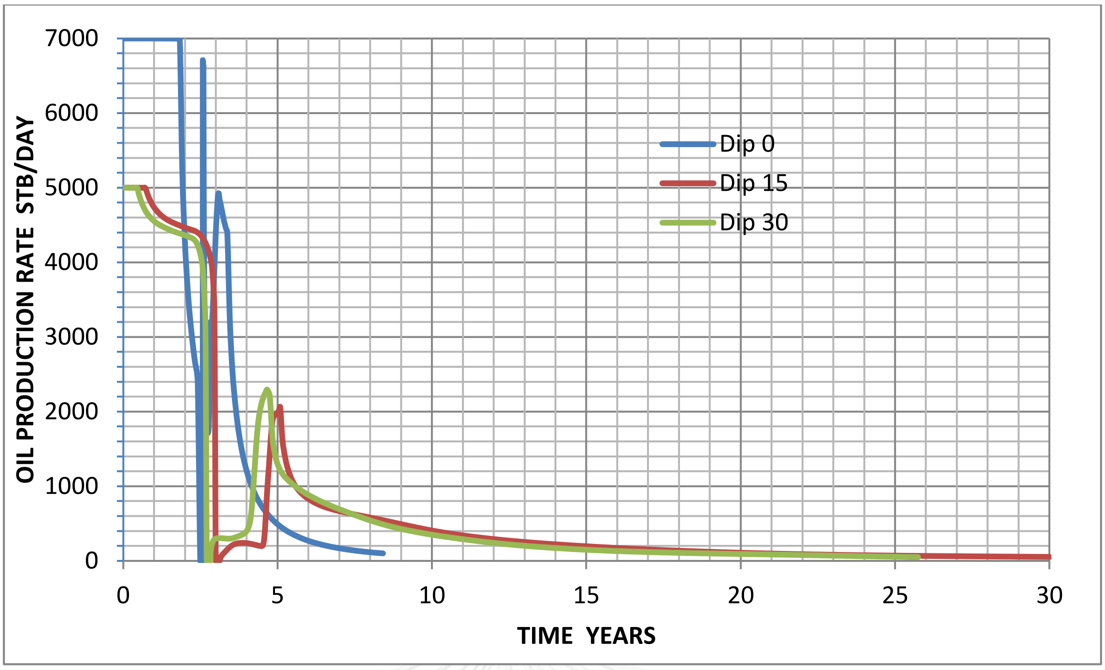


Figure 5. 86 Oil production rates of different well arrangements for different dip angle reservoirs

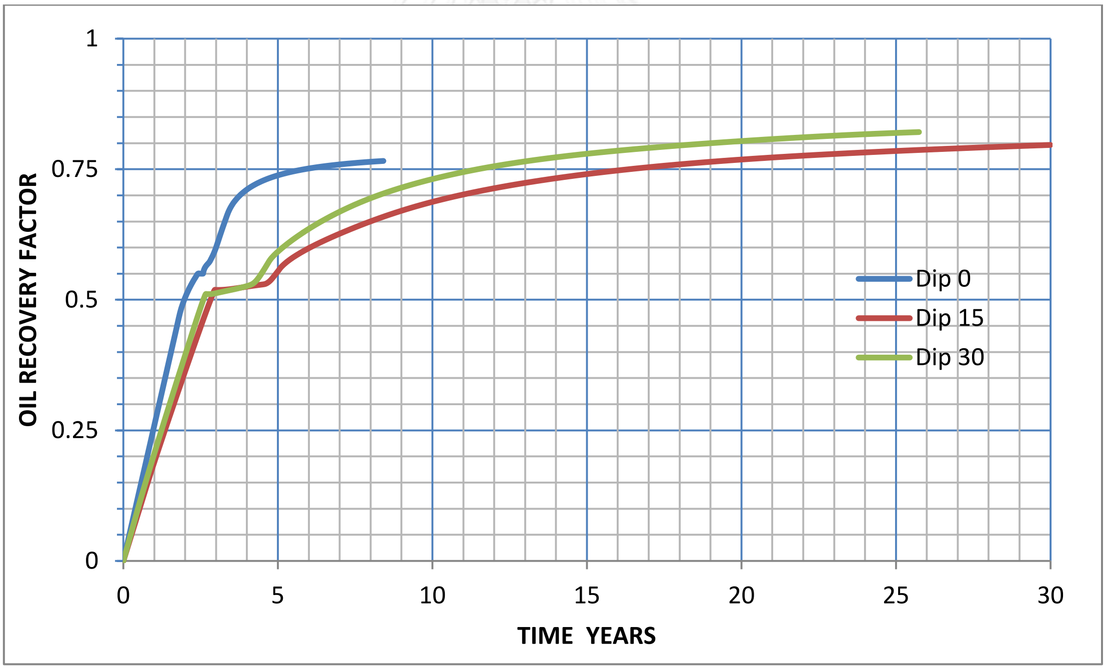


Figure 5. 87 Oil recovery factors of different well arrangements for different dip angle reservoirs

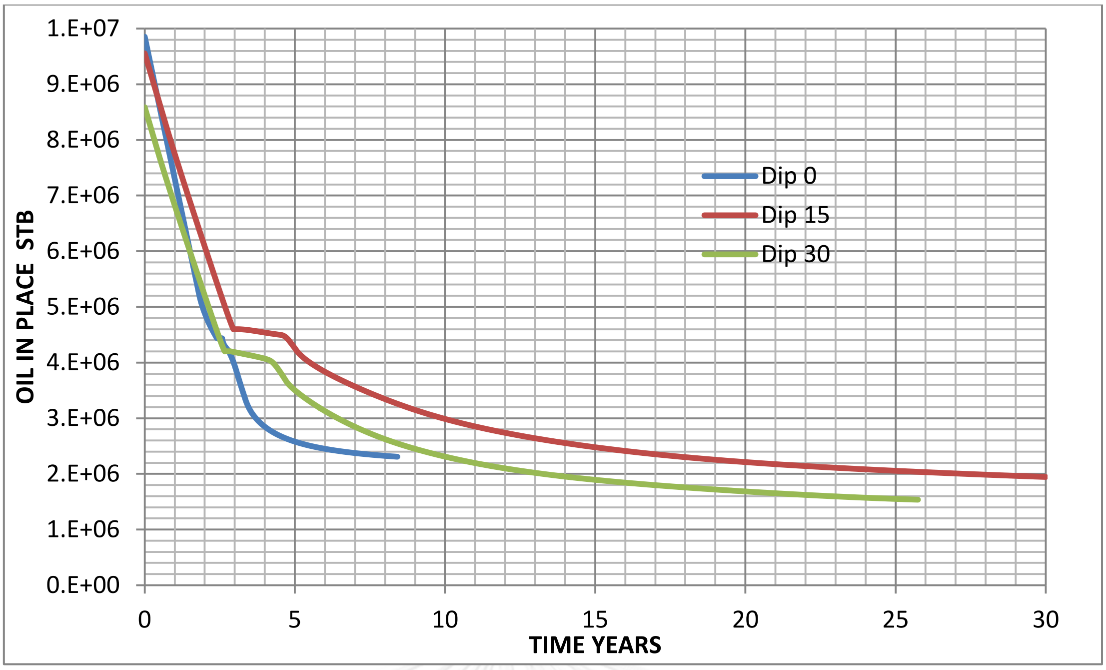


Figure 5. 88 Oil in place for different dip angle reservoirs

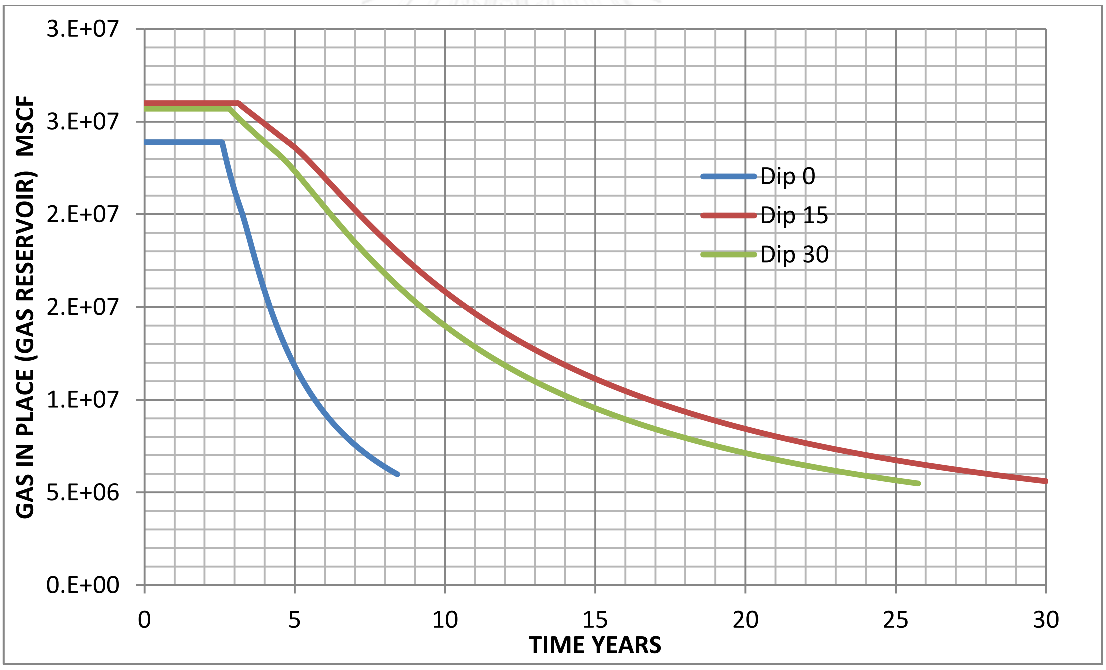


Figure 5. 89 Gas in place of gas reservoir for different dip angle reservoirs

Table 5. 53 Summarized results of selected well arrangement cases for each dip angle

Dip angle (°)	Case	Target water injection rate (STB/D)	Target liquid production rate (STB/D)	Waterflood duration (years)	Production life (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
0	Two horizontal producers for gas dumpflood	3,000	7,000	2.41	8.41	76.59	7.552	2.734	1.540	20.693
15	One horizontal producers for gas dumpflood	5,000	5,000	2.96	30	79.65	7.614	5.396	4.829	23.103
30	One horizontal producers for gas dumpflood	5,000	5,000	2.66	25.75	82.12	7.056	4.867	4.185	22.617

5.4 Sensitivity analysis

According to variations in reservoir parameters, the system parameters are investigated to see the effect on each optimized case for different dip angle reservoirs. The system parameters investigated include vertical to horizontal permeability ratio, thickness of gas reservoir, depth difference between gas and oil reservoir, residual oil saturations of oil-gas system and oil-water system, and oil viscosity. The selected optimized cases illustrated in Table 5.51 are used to investigate the effects of such parameters in this section

5.4.1 Effect of vertical to horizontal permeability ratio

Four cases of vertical to horizontal ratio which are 0.001, 0.01, 0.1 and 0.3 are investigated. The horizontal permeability is fixed while the vertical permeability is varied as shown in Table 5.54.

Table 5. 54 Vertical and horizontal permeability for different anisotropy ratios

Case	Vertical to horizontal permeability ratio (k_v/k_h)	Vertical permeability (md)	Horizontal permeability (md)
1	0.001	0.126	126
2	0.01	1.26	126
3	0.1	12.6	126
4	0.3	37.8	126

5.4.1.1 Dip angle of 0 degree

The oil production profile, oil recovery factor and reservoir pressure of zero degree dip angle are shown in Figures 5.90-5.92. The oil production is abandoned before twelve years in all cases due to high production rate. In Figure 5.90, cases 2, 3, and 4 show longer plateau period than case 1. For oil recovery factor in Figure 5.91, case 2, which has k_v/k_h = 0.01, yields the highest oil recovery factor and case1, which has k_v/k_h = 0.001, yields the lowest oil recovery factor. Reservoir pressures shown in Figure 5.90 indicate that case 1 can maintain reservoir pressure better than other cases.

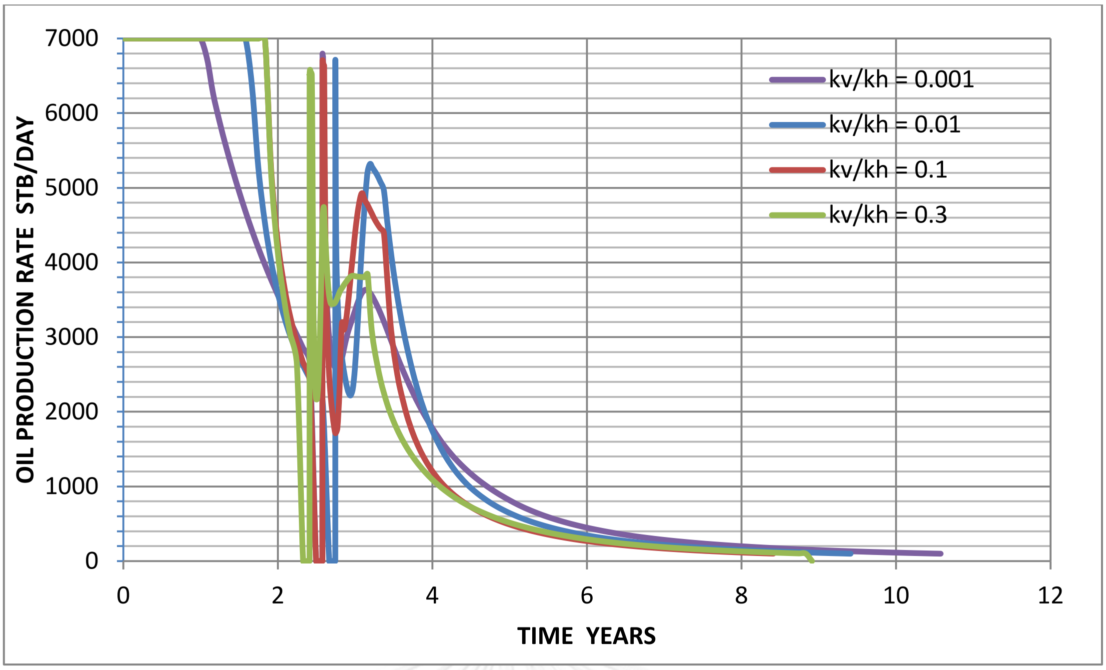


Figure 5. 90 Oil production rate for different vertical to horizontal ratios (0-degree dip angle)

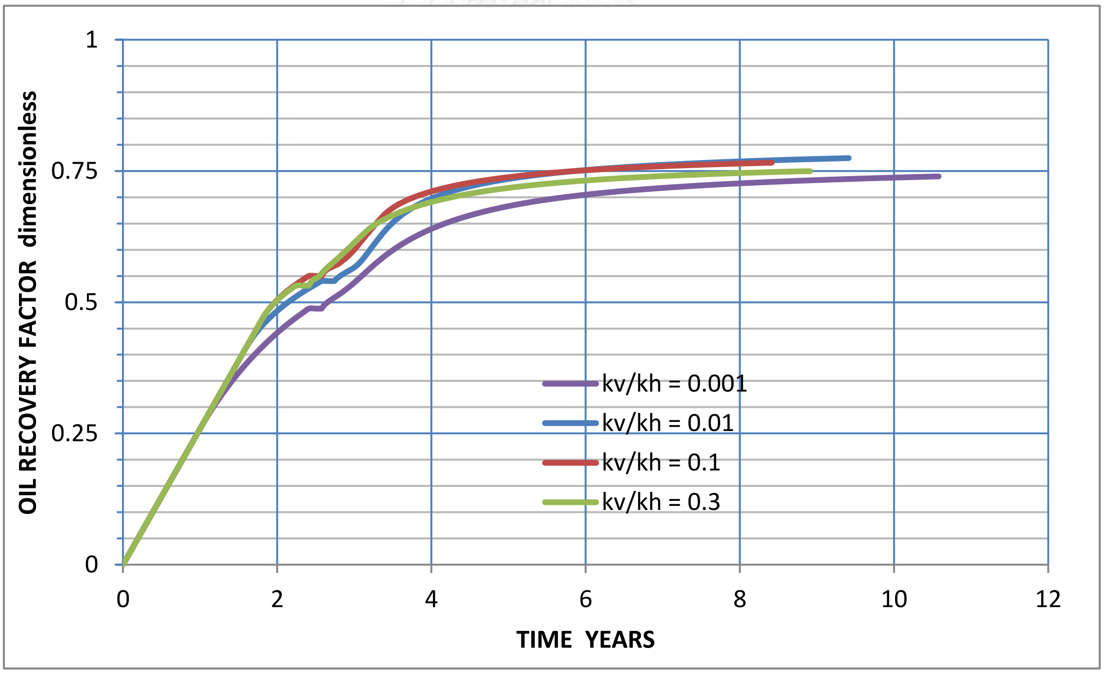


Figure 5. 91 Oil recovery factor for different vertical to horizontal ratios (0-degree dip angle)

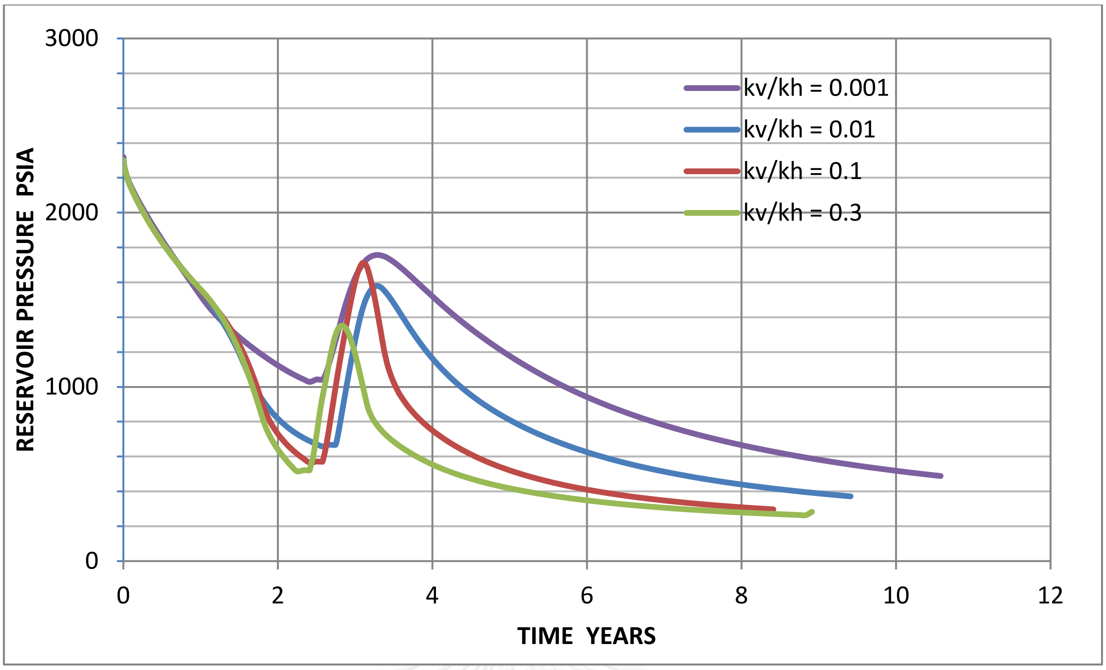


Figure 5. 92 Reservoir pressure for different vertical to horizontal ratios (0-degree dip angle)

The summarized results of all cases are shown in Table 5.55. The case of k_v/k_h = 0.001 has the least oil recovery factor and the longest production life due to the fact that it has the least vertical permeability among all cases which hinders oil from flowing down to the producers which are located at the bottommost layer (layer 5). For cases 2 to 4, as k_v/k_h ratio increases, the oil recovery factor decreases. This is because high vertical permeability causes higher degree of segregation between gas, oil, and water. As a result, more water flows to the producers located at the bottommost layer while less oil can be drained. The better the vertical communication is, the lower the oil recovery factor will be for the flat plane reservoir.

In term of water, the lowest k_v has the lowest amount of water production because less communication in vertical direction makes water hard to move toward the producer located at the bottommost layer.

Table 5. 55 Summarized results of different vertical to horizontal permeability ratios for 0-degree dip angle

kv/kh	Production life(years)	Waterflood period(years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
0.001	10.58	2.41	73.98	7.294	2.734	0.856	19.524
0.01	9.41	2.58	77.46	7.638	2.920	1.299	20.248
0.1	8.41	2.41	76.59	7.552	2.734	1.540	20.693
0.3	8.83	2.25	74.96	7.392	2.549	1.685	21.508

5.4.1.2 Dip angle of 15 degrees

Shown in Figures 5.93-5.95 are oil production rate, oil recovery factor and reservoir pressure of 15 degree dip angle reservoir for different anisotropy ratios. The oil production profiles during the water flooding process are quite the same for all cases. However, during gas dumpflood, case 2 which has k_v/k_h of 0.01 gives the highest peak in oil rate, followed by cases 1, 3 and 4, respectively. Case 1 is the first one that reaches the abandonment criteria. For oil recovery factor in Figure 5.94, the recovery factors of the four cases are approximately the same. The reservoir pressure of case 1 is less depleted than the other three cases, meaning that there is better pressure maintenance.

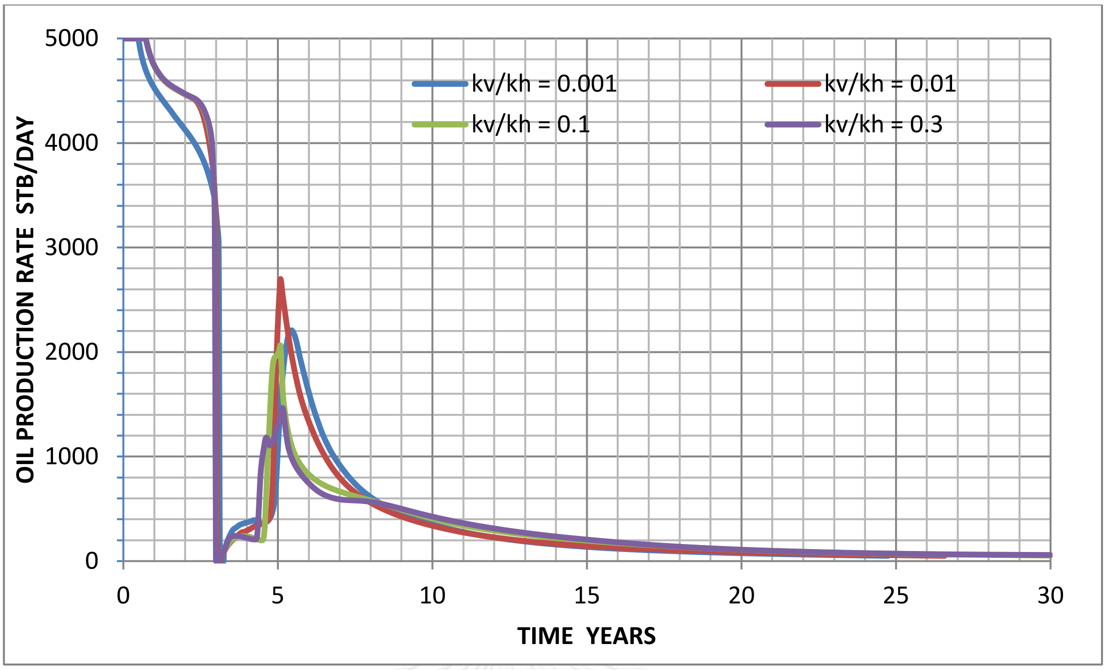


Figure 5. 93 Oil production rate for different vertical to horizontal ratios (15-degree dip angle)

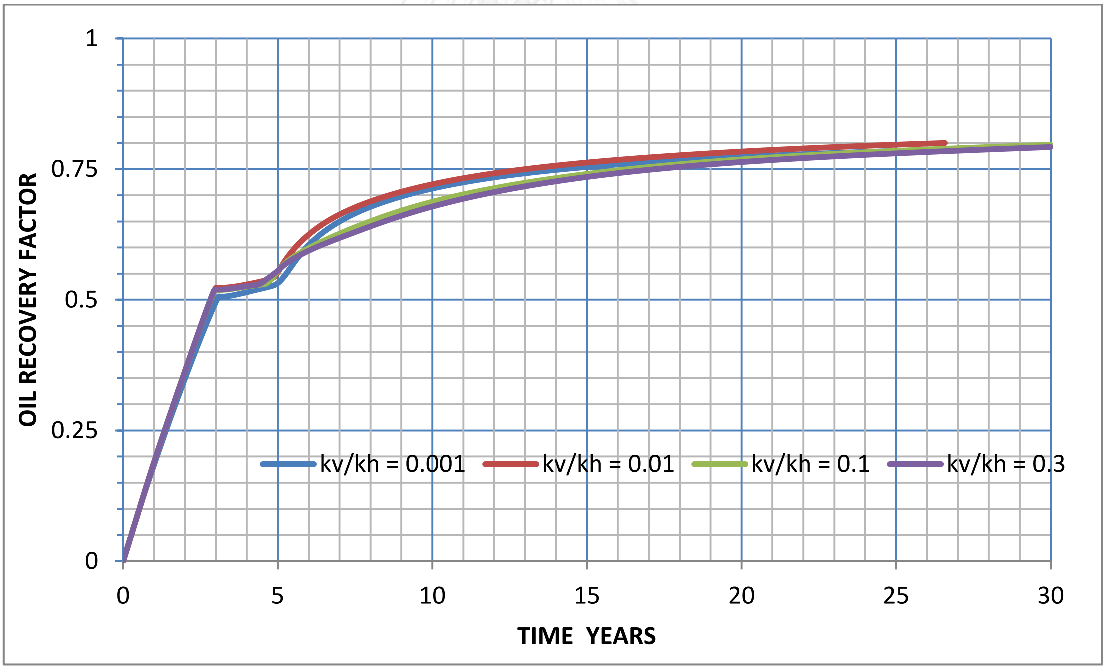


Figure 5. 94 Oil recovery factor for different vertical to horizontal ratios (15-degree dip angle)

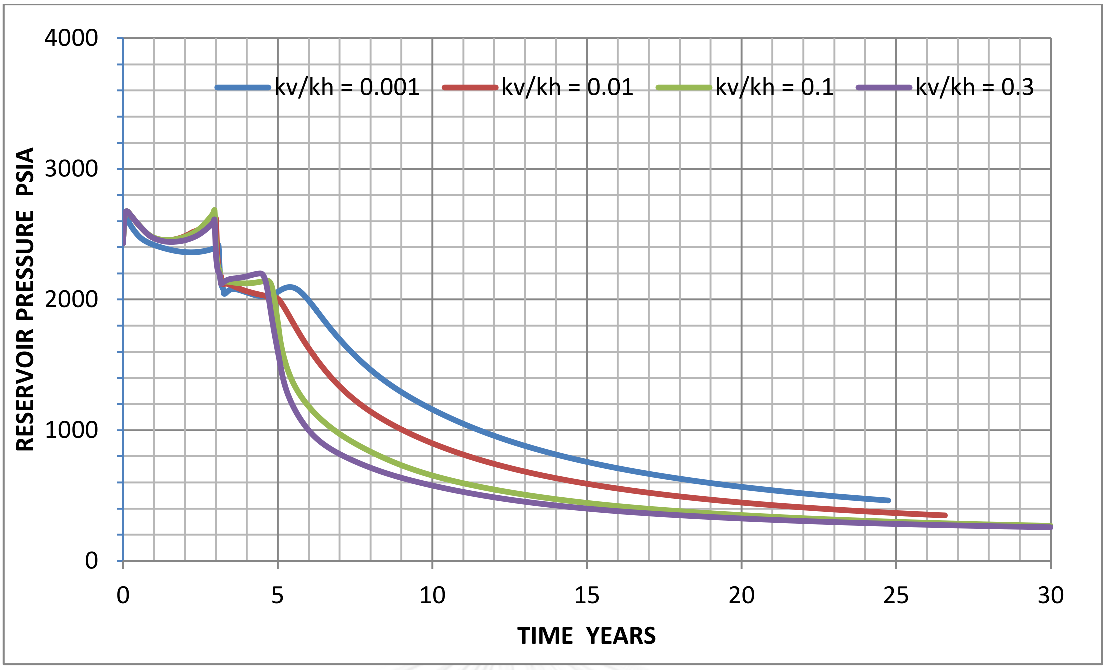


Figure 5. 95 Reservoir pressure for different vertical to horizontal ratios (15-degree dip angle)

Summary of results in Table 5.56 of 15 degree dip angle reservoir shows that there is no significant difference among the amounts of total oil production and oil recovery factor of the four cases. Due to the fact that 15 degree dip angle reservoir has steepness in between 0 and 30 degree dip angle which is not flat and steep enough to see clearly whether of gravity or viscous forces dominate the flow. Thus, there is no trend of oil recovery factor shown in the results. For the total amount of water injection, there is also no obvious distinction among the four cases. On the other hand, the amount of water injection and production for k_v/k_h of 0.001 are moderately less than those for the other cases. This is because water does not flow as easily in the case of low k_v. Due to the same reason, gas production for the case of low k_v/k_h is lower than that for the case of high k_v/k_h.

Table 5. 56 Summarized results of different vertical to horizontal permeability ratios for 15-degree dip angle

kv/kh	Production life(years)	Waterflood period(years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
0.001	24.75	3.08	78.43	7.498	5.061	4.007	19.969
0.01	26.58	3.00	79.99	7.647	5.400	4.416	21.499
0.1	30	2.95	79.65	7.614	5.396	4.829	23.103
0.3	30	2.95	79.23	7.574	5.396	4.995	23.314

5.4.1.3 Dip angle of 30 degrees

Figures 5.96-5.98 demonstrate oil production rate, oil recovery factor and reservoir pressure. The oil production profile shows that at the beginning all cases have the same profiles until gas dumpflood process is performed. Case 2 with k_v/k_h = 0.01 has the highest rate after about 2 years of gas flooding period. After that, the oil rate of case 2 dramatically declines and becomes less than other cases until reaching the abandonment criteria. For oil recovery factor in Figure 5.97, during the gas dumpflood period, case 2 has the highest oil recovery profile until the graph becomes flat at the late time making case 3 and 4 have higher oil recovery factor. The reservoir pressure in Figure 5.98 shows that case 1 has the best pressure maintenance compared to other cases.

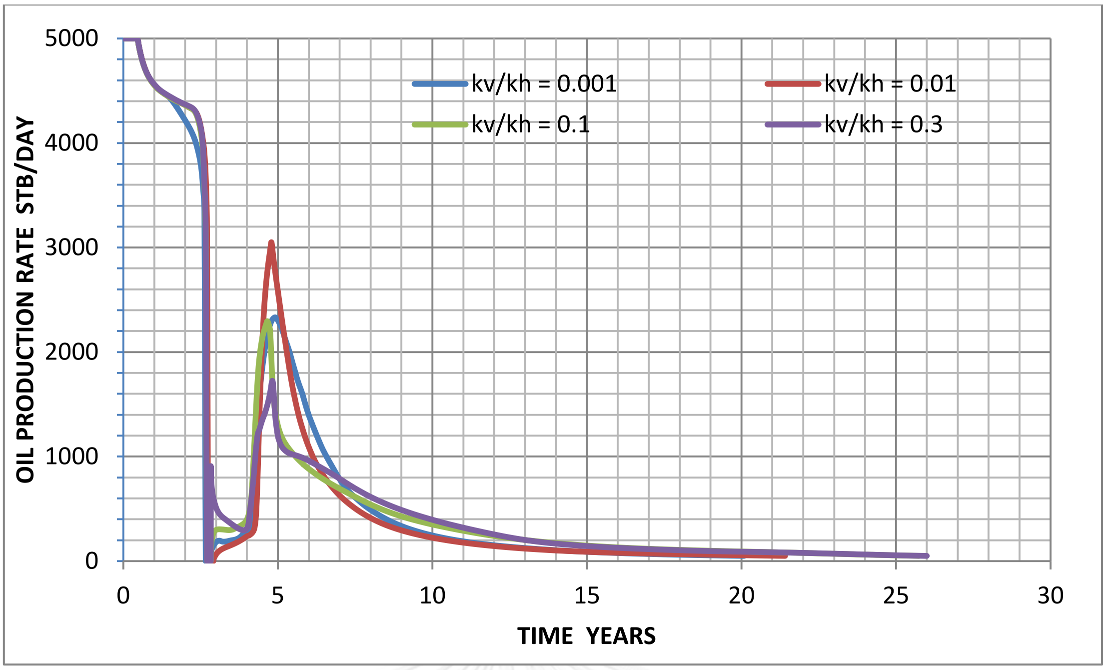


Figure 5. 96 Oil production rate for different vertical to horizontal ratios
(30-degree dip angle)

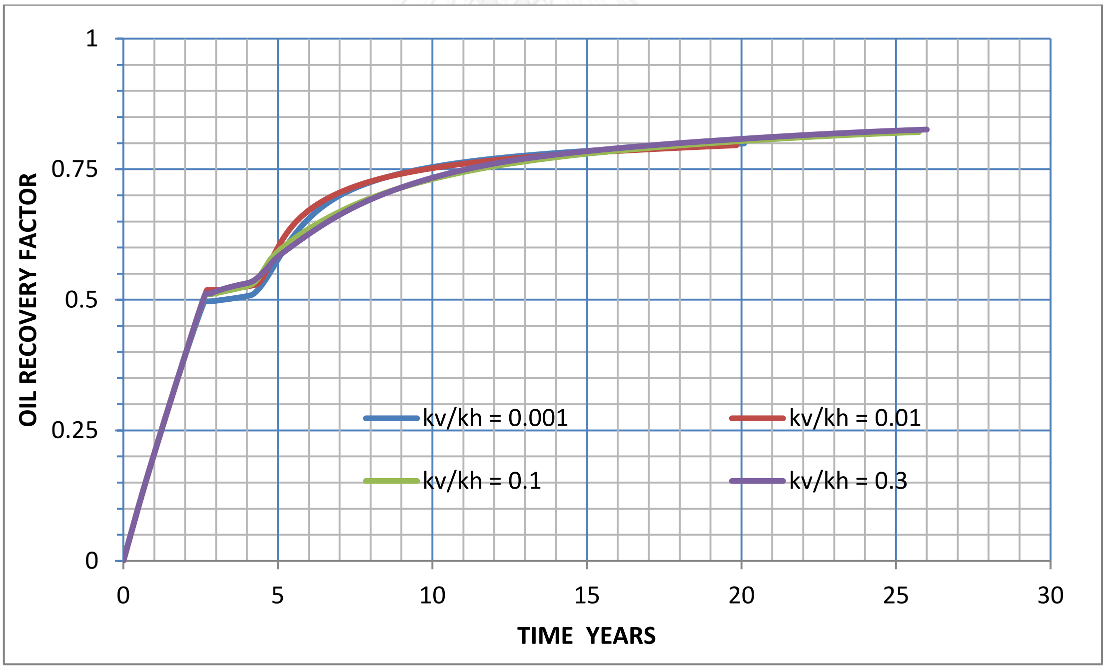


Figure 5. 97 Oil recovery factor for different vertical to horizontal ratios
(30-degree dip angle)

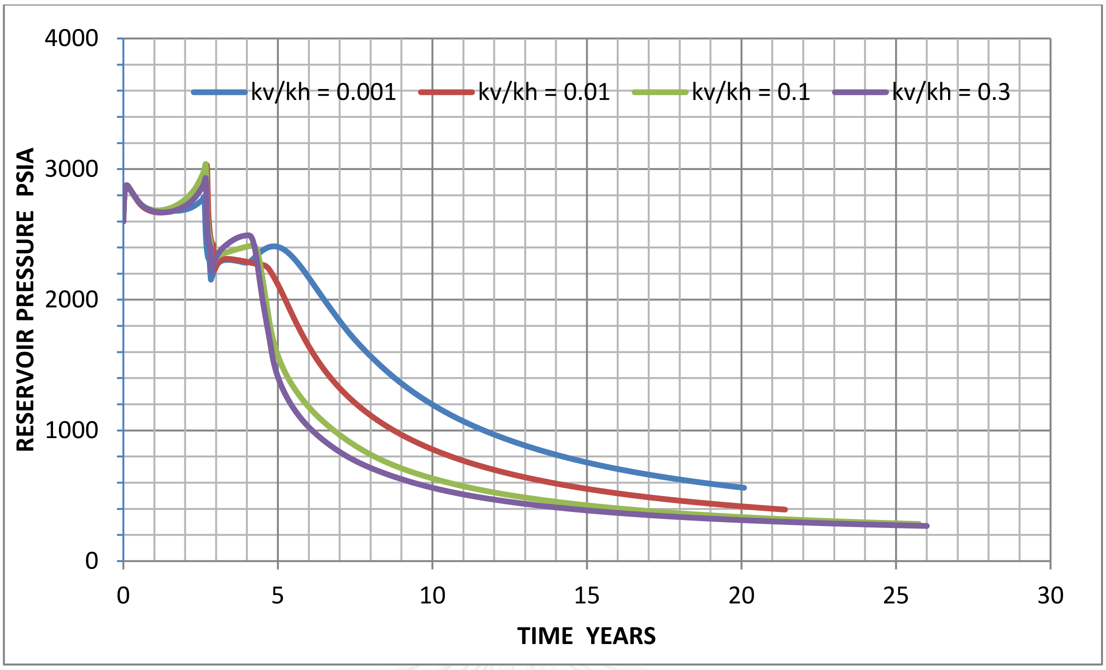


Figure 5. 98 Reservoir pressure for different vertical to horizontal ratios (30-degree dip angle)

Summary of results in Table 5.57 indicates that as anisotropy ratio increases, the total oil production, water production, gas production and water injection increase except for the water injection of the last case in which k_v/k_h = 0.3. The oil recovery factor and total oil production increase because there is more segregation occurred by gravity force as k_v increases. The segregation can provide stable flood front for gas flooding which leads to better sweep efficiency. In addition, segregation causes water to stay at the bottom and oil in the middle. This results in more amount of oil flowing to the horizontal producer located at the topmost layer. In term of water production, high k_v causes water easily move down to the producer as a result of high amount of water to be produced during the middle time of gas dumpflood process. Gas production increases because higher k_v allows gas to move easily in vertical direction.

Table 5. 57 Summarized results of different vertical to horizontal permeability ratios for 30-degree dip angle

kv/kh	Production life(years)	Waterflood period(years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
0.001	20.09	2.62	79.92	6.867	4.643	3.696	18.691
0.01	26.58	2.71	79.94	6.868	4.937	3.977	20.495
0.1	30	2.66	82.12	7.056	4.937	4.185	22.617
0.3	30	2.66	82.60	7.099	4.867	4.333	22.877

5.4.2 Effect of the thickness of gas reservoir

In this section, the thickness of 50 ft, 100 ft, and 150 ft of gas reservoir are investigated in order to determine its effect on performance of gas dumpflood after water flooding.

5.4.2.1 Dip angle of 0 degree

As shown in Table 5.58, the top of gas reservoir is fixed at 7,050 ft while the bottom depth is varied according to the thickness. The higher gas thickness provides more original gas in place. Note that the gas reservoir pressure is the pressure at datum depth. For case 3 with gas thickness of 150 ft, the bottom hole pressure of gas dumpflood well exceeds the fracture pressure if the gas zone is fully perforated as a lot of gas flows into the target zone. In order to keep the bottom hole pressure of the target zone to be lower than the fracture pressure, we need to partially perforate the gas zone or equivalently adding partial penetration skin to the well. In case 3, a skin of 89 or penetration interval of 8 feet from 150 feet keeps the gas rate to be low enough not to create fracture in the target reservoir. The skin of 89 is found by trial and error, i.e., running the simulation with guessed value of skin until the bottomhole pressure of the target zone is below the fracture pressure. So, perforating only 8 ft in the gas zone can reduce the bottom hole not to reach the fracture pressure.

Table 5. 58 Gas reservoir details and skin for 0-degree dip angle

Case	Gas thickness (ft)	Top depth of gas reservoir (ft)	Bottom depth of gas reservoir (ft)	Original gas in place (BSCF)	gas reservoir pressure (psia)	Skin	Perforation interval (ft)
1	50	7050	7100	11.875	3,178	no skin	10
2	100	7050	7150	23.888	3,200	no skin	20
3	150	7050	7200	36.052	3,223	89	8

Figure 5.99 shows oil production profile for different gas thicknesses. At the beginning during water flooding, the oil production profiles are all the same. During the time of gas dumpflood, the case with higher gas thickness can maintain higher rate than the case with smaller gas thickness. Case 3 with the highest amount of gas can prolong the longest time of oil production. Figure 5.100 demonstrates that oil recovery factor profiles are different at the late time of gas dumpflood process. Figure 5.101 shows that case 3 has the best pressure maintenance due to the highest amount of original gas in place.

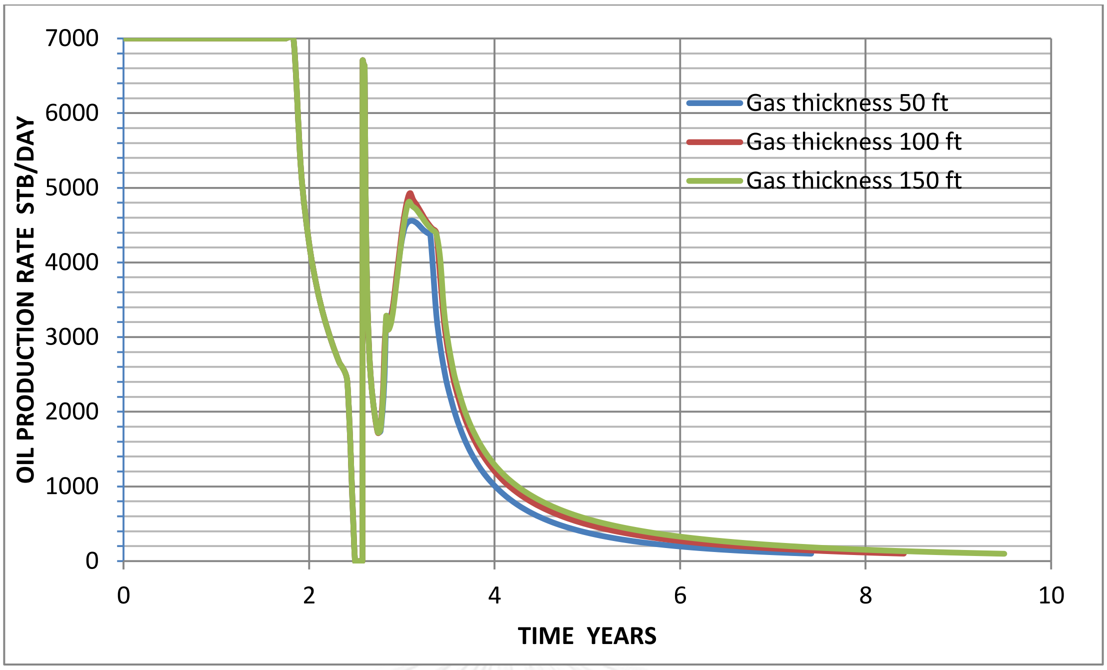


Figure 5. 99 Oil production rate for different gas reservoir thicknesseses (0-degree dip angle)

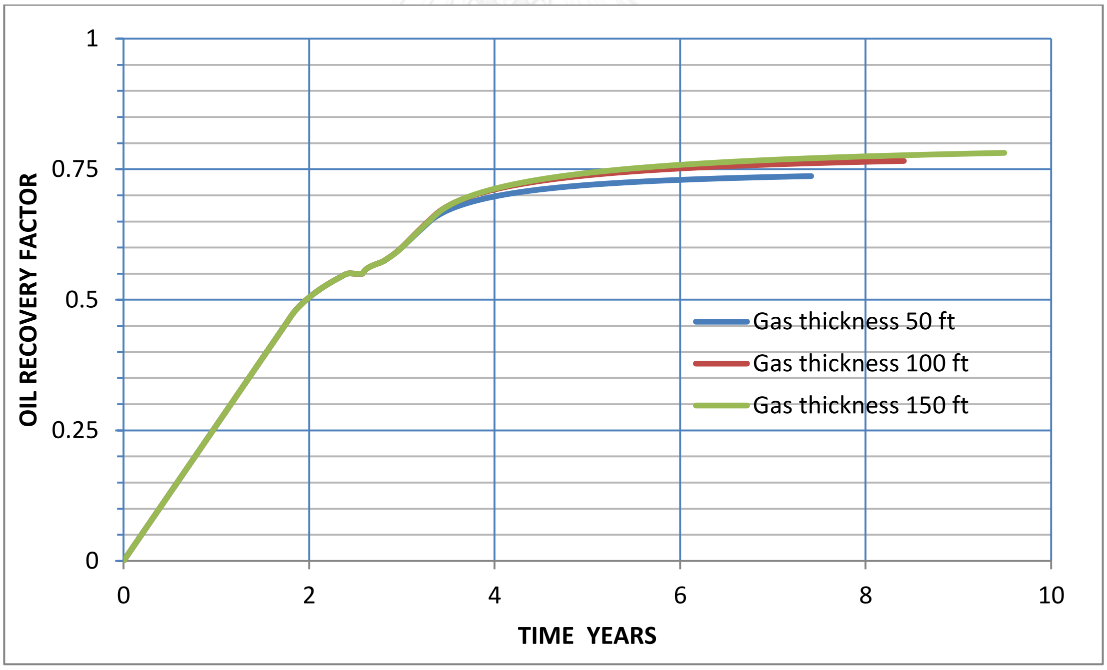


Figure 5. 100 Oil recovery factor for different gas reservoir thicknesses (0-degree dip angle)

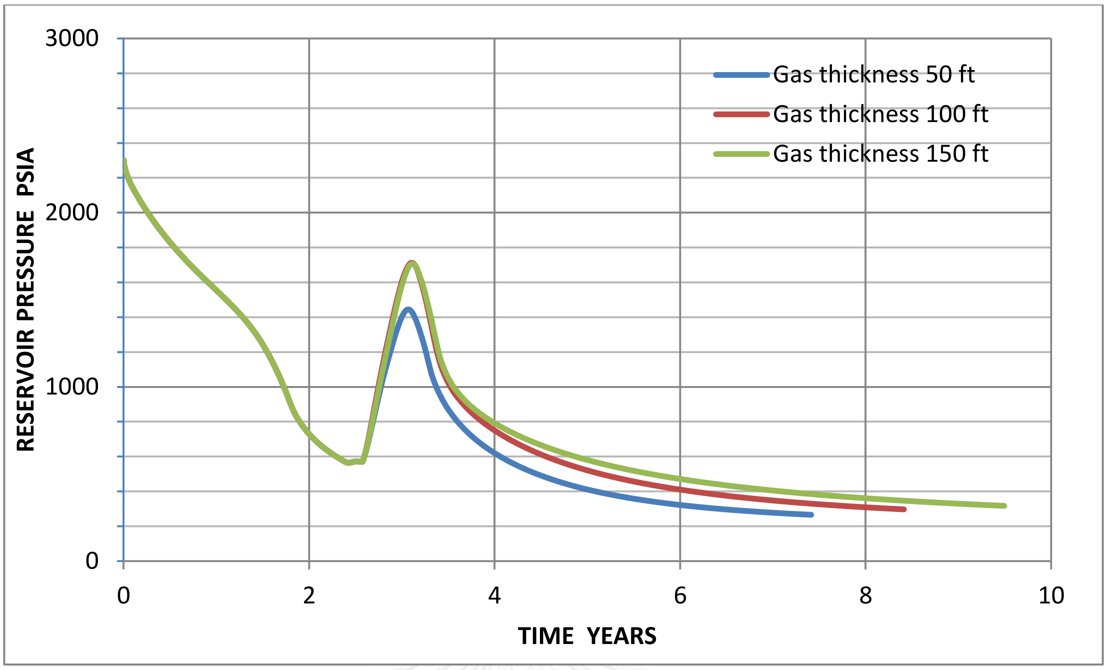


Figure 5. 101 Reservoir pressure for different gas reservoir thicknesses (0-degree dip angle)

Summary of results in Table 5.59 illustrates that as gas thickness increases, the oil recovery factor increases. This is because the higher amount of gas can flood more oil to the producer. At the same time, higher gas thickness also increases the total water production. Water injection is the same for all the cases because increasing the gas thickness does not affect the process of water flooding.

Table 5. 59 Summarized results of different gas thicknesses for 0-degree dip angle

Gas thickness (ft)	Production life(years)	Waterflood period(years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
50	7.41	2.41	73.68	7.266	2.734	1.320	12.533
100	8.41	2.41	76.59	7.552	2.734	1.540	20.693
150	9.50	2.41	78.13	7.704	2.734	1.683	27.263

5.4.2.2 Dip angle of 15 degrees

Table 5.60 demonstrates different top depths and bottom depths of gas reservoir at updip and downdip locations. The original gas in place is increased by the larger gas thickness. The pressure of gas reservoir depends on depth. The gas reservoir pressure tabulated in the table is the pressure at depth of 8,265, 8,315, 8,365 ft, respectively. For cases 1, 2, and 3 with gas thickness of 50, 100, 150 ft, respectively, the bottom hole pressure of gas dumpflood well exceeds the fracture pressure if the gas zone is fully perforated as a lot of gas flows into the target zone. In order to keep the bottom hole pressure of the target zone to be lower than the fracture pressure, we need to partially perforate the gas zone or equivalently adding partial penetration skin to the well. In cases 1, 2, and 3, skin of 1,165 or penetration of 0.15, 0.36 and 0.59 feet from 50, 100, and 150 feet, respectively, keep the gas rate to be low enough not to create fracture in the target reservoir.

Table 5. 60 Gas reservoir details and skin for 15-degree dip angle

Case	Gas thickness (ft)	Updip top and bottom depths (ft)	Downdip top and bottom depths (ft)	Original gas in place (BSCF)	gas reservoir pressure (psia)	Skin	Perforation interval (ft)
1	50	7050/7100	8215/8265	12.852	3,679	1,165	0.15
2	100	7050/7150	8215/8315	25.993	3,683	1,165	0.36
3	150	7050/7200	8215/8365	39.015	3,687	1,165	0.59

Figures 5.102-5.104 illustrate oil production rate, oil recovery factor and reservoir pressure. The case with gas thickness of 150 ft performs the best in oil production rate profiles, oil recovery factor and pressure maintenance. This is due to the high amount of gas and pressure which can increase the oil rate during gas dumpflood and sustain the pressure of the reservoir from fluid withdrawal.

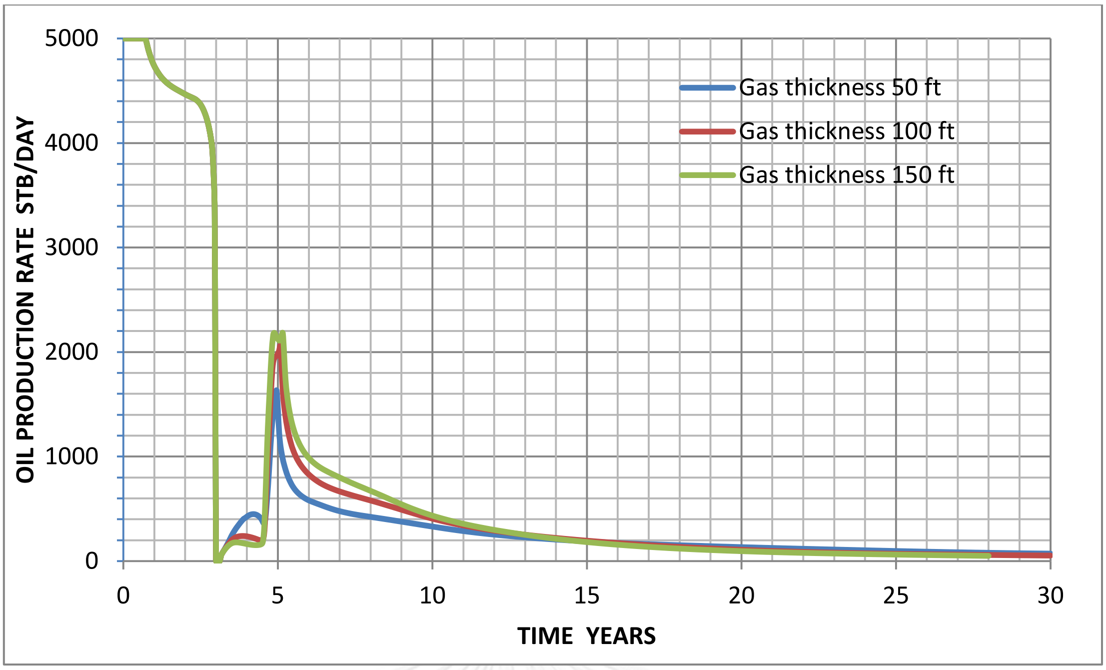


Figure 5. 102 Oil production rate for different gas reservoir thicknesses (15-degree dip angle)

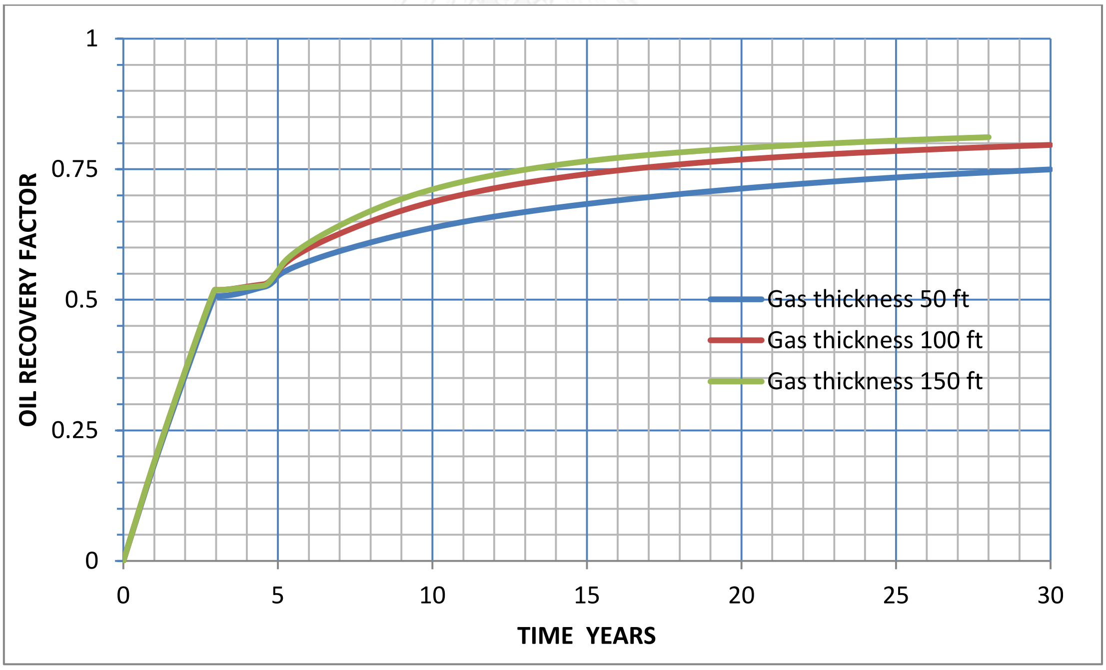


Figure 5. 103 Oil recovery factor for different gas reservoir thicknesses (15-degree dip angle)

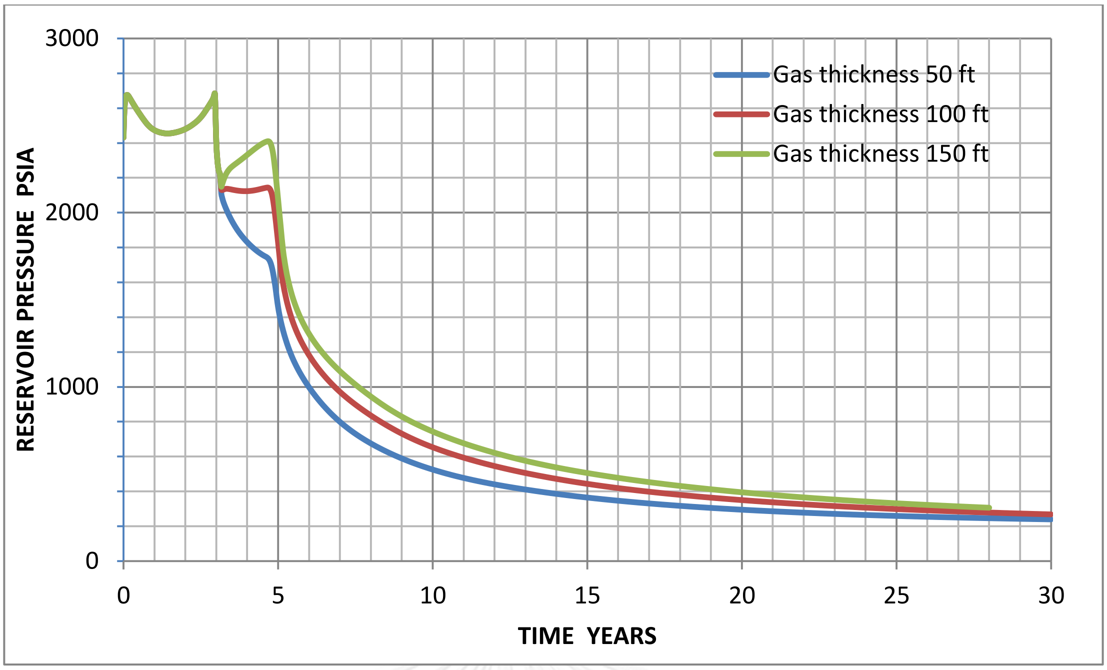


Figure 5. 104 Reservoir pressure for different gas reservoir thicknesses (15-degree dip angle)

According to results tabulated in Table 5.61, as gas thickness increases, the oil recovery factor, water production and gas production increase while the water injection is the same. This is because higher amount of gas and pressure have higher force to sweep more oil and water toward the production well during gas dumpflood since it is located at layer 5.

Table 5. 61 Summarized results of different gas thicknesses for 15-degree dip angle

Gas thickness (ft)	Production life(years)	Waterflood period(years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
50	30	2.95	74.96	7.308	5.396	4.767	13.153
100	30	2.95	79.65	7.614	5.396	4.829	23.103
150	28	2.95	81.14	7.756	5.396	4.844	31.905

5.4.2.3 Dip angle of 30 degrees

Table 5.62 shows different top depths and bottom depths of gas reservoir at updip and downdip locations, original gas in place and skin for each 30 degree dip angle gas thickness. The gas reservoir pressure tabulated in the table is the pressure at depth of 9,350, 9,400 and 9,450, respectively. For cases 1, 2, and 3 with gas thickness of 50, 100, 150 ft, respectively, the bottom hole pressure of gas dumpflood well exceeds the fracture pressure if the gas zone is fully perforated. In order to keep the bottom hole pressure of the target zone to be lower than the fracture pressure, we need to partially perforate the gas zone or equivalently adding partial penetration skin to the well. In cases 1, 2, and 3, skin of 1,165, 1,165, and 1,377 or penetration of 0.15, 0.36, and 0.5 feet from 50, 100, and 150 feet, respectively, keep the gas rate to be low enough not to create fracture in the target reservoir.

Table 5. 62 Gas reservoir details and skin for 30-degree dip angle

Case	Gas thickness (ft)	Updip top and bottom (ft)	Downdip top and bottom (ft)	Gas reservoir pressure (psia)	Original gas in place (BSCF)	Skin	Perforation interval (ft)
1	50	7050/7100	9300/9350	4,163	12.842	1,165	0.15
2	100	7050/7150	9300/9400	4,167	25.697	1,165	0.36
3	150	7050/7200	9300/9450	4,171	38.565	1,377	0.5

Figures 5.105-5.107 show oil production rate, oil recovery factor and reservoir pressure. During water flooding, all profiles are the same since the amount of gas does not affect waterflood process. During gas dumpflood period, case 3 with the highest amount of gas and pressure provides the highest peak in oil rate and oil recovery factor. Case 3 is the best in term of pressure maintenance compared to the others.

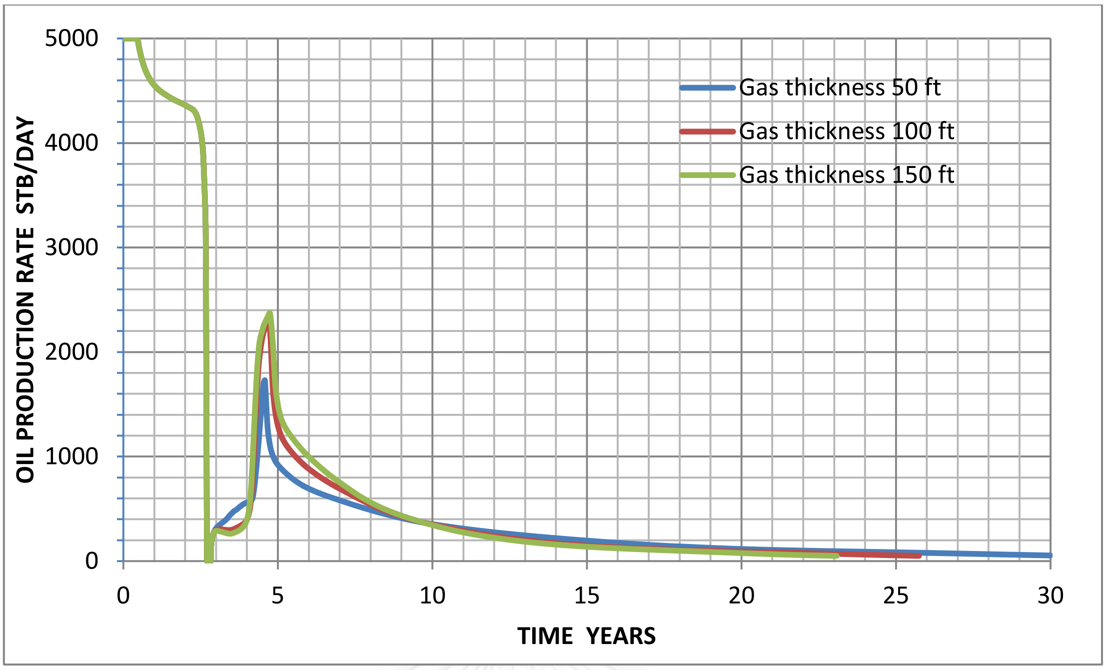


Figure 5. 105 Oil production rate for different gas reservoir thicknesses (30-degree dip angle)

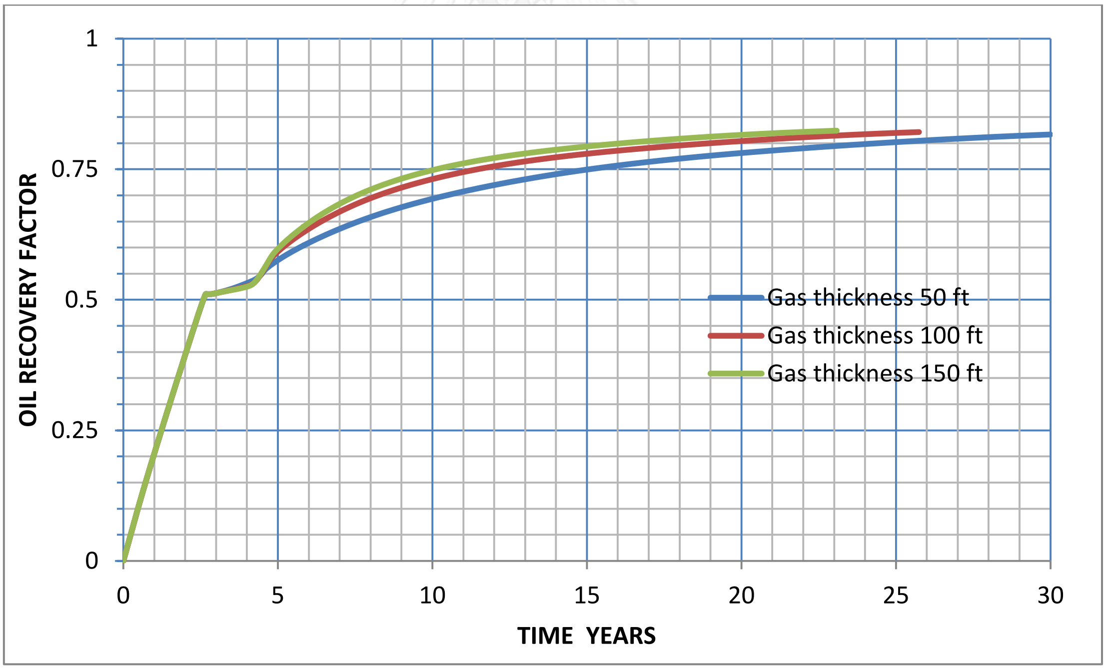


Figure 5. 106 Oil recovery factor for different gas reservoir thicknesses (30-degree dip angle)

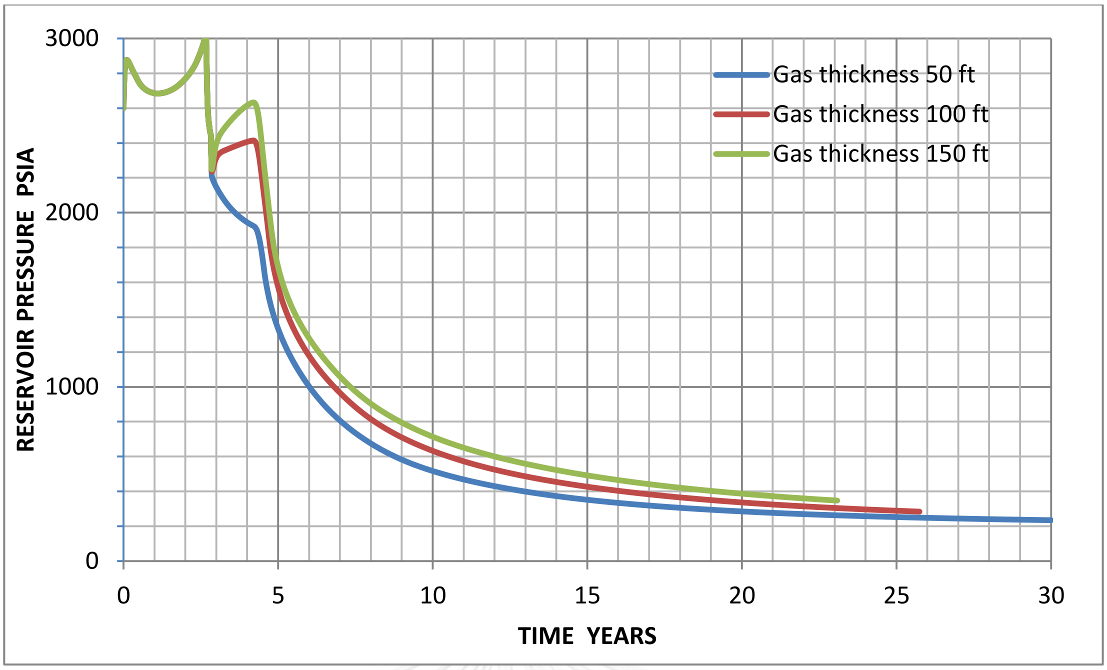


Figure 5. 107 Reservoir pressure for different gas reservoir thicknesses (30-degree dip angle)

According to Table 5.63, as gas thickness increases, total oil production and gas production become higher while water production becomes lower and water injection does not change. Oil and gas production increase because the high amount of gas with high pressure floods the oil toward the producer. Water production slightly decreases since gas thickness increases due to gravity segregation which is dominant in this particular dip angle reservoir. The production well is located at layer 1. As gas and oil with low density segregate above the water and more gas moves toward the production well in the case of large gas reservoir thickness, less water flows to the producers. The water flooding process is not affected by the variation of gas thickness which leads to the result of the same water injection.

Table 5. 63 Summarized results of different gas thicknesses for 30-degree dip angle

Gas thickness (ft)	Production life(years)	Waterflood period(years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
50	30	2.66	81.65	7.016	4.867	4.200	13.257
100	25.75	2.66	82.12	7.056	4.867	4.185	22.617
150	23.08	2.66	82.39	7.079	4.867	4.178	29.921

5.4.3 Effect of depth difference between oil and gas reservoir

The depth difference between oil reservoir and gas reservoir which is 1000 ft, 2000 ft and 3000 ft are investigated to determine its effect on the performance of gas flooding.

5.4.3.1 Dip angle of 0 degree

The pressures at the top and the bottom of gas reservoirs located at different depths are shown in Table 5.64. The original gas in place varies with depth of the gas reservoir due to different initial pressures. Note that case 3 has skin equal to 838 which is equivalent to 0.5 ft perforation interval of gas zone for preventing the bottom hole pressure at the oil zone from exceeding fracturing pressure due to high pressure as a result of large depth difference between the gas and the oil reservoirs.

Table 5. 64 Top and bottom reservoir pressure for each depth difference of 0-degree dip angle

Case	Depth difference (ft)	Gas reservoir pressure at top depth (psia)	Gas reservoir pressure at bottom depth (psia)	Original gas in place (BSCF)	Skin	Perforation interval (ft)
1	1000	2,711	2,755	20.760	no skin	20
2	2000	3,156	3,200	23.888	no skin	20
3	3000	3,602	3,647	26.819	838	0.5

Figures 5.108-5.110 illustrate oil production rate, oil recovery factor and reservoir pressure. The oil production rate of case 2 which has depth difference of 2,000 ft is higher than those for the other cases most of the time. However, case 3 yields the longest period of oil production. During gas dumpflood, case 2 has the highest oil recovery factor, followed by case1 and case 3. For reservoir pressure profile, case 2 has the highest peak. In general, case 3 which has higher pressure and amount of gas should yield higher oil recovery factor. The reason that we do not see such behavior is because case 3 needs a skin factor to limit the amount of gas flow during the early time of gas dumpflood not to exceed the fracture pressure of the oil zone. During late time, gas rate from the gas reservoir flowing into the subject oil reservoir is lower than it should be due to skin effect. As less gas can flow into the oil reservoir, the oil recovery decreases.

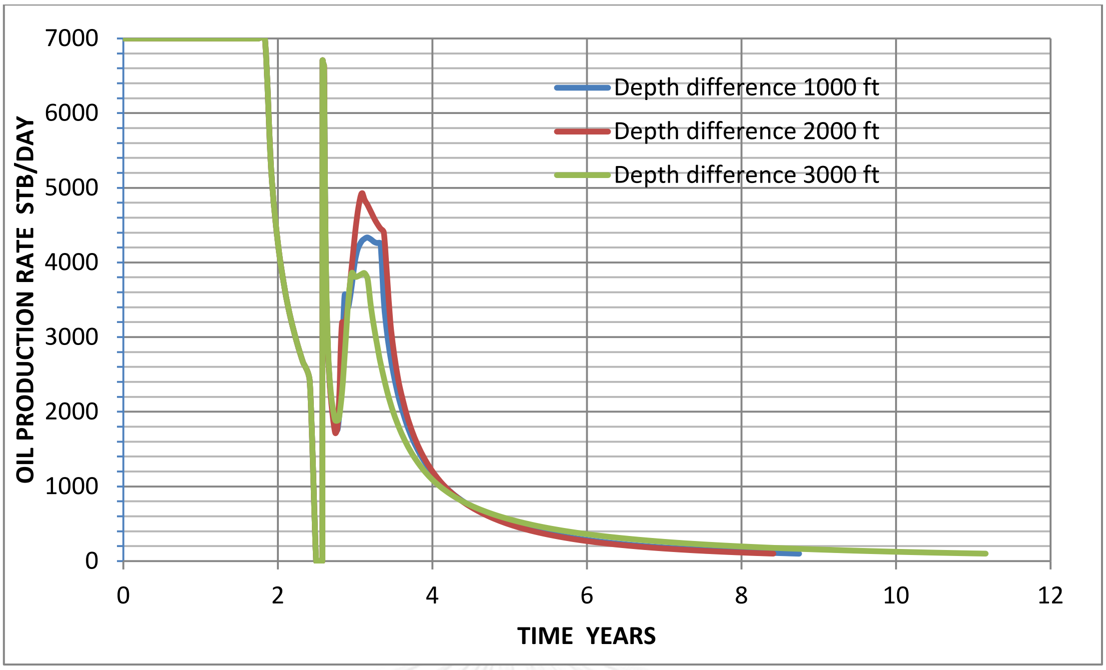


Figure 5. 108 Oil production rate for each depth difference cases (0-degree dip angle)

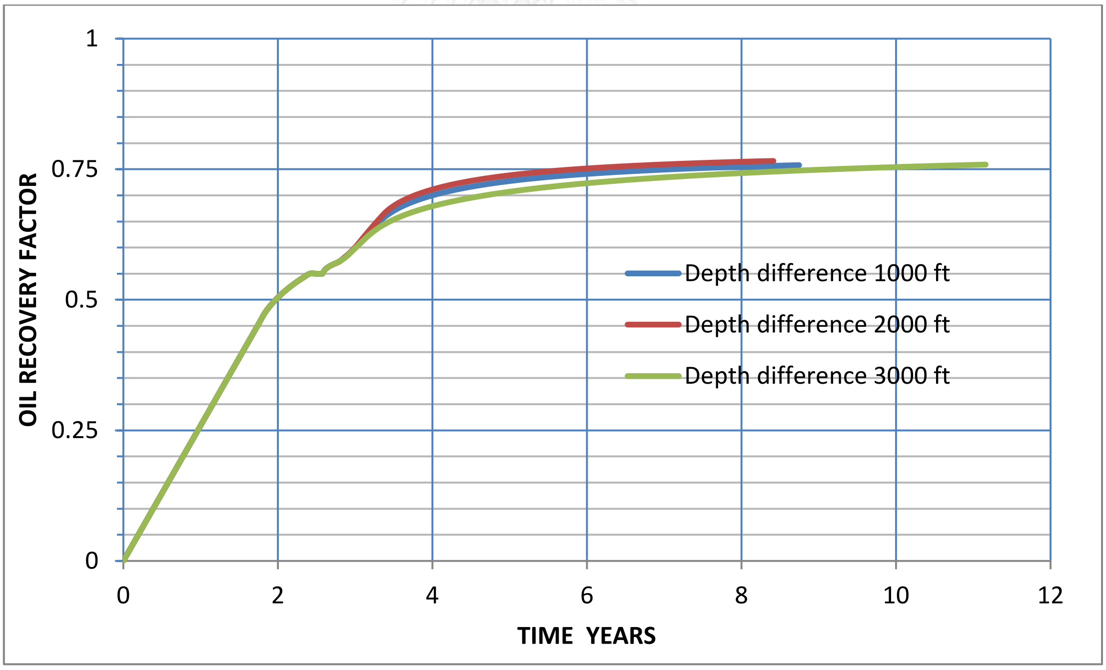


Figure 5. 109 Oil recovery factor for each depth difference cases (0-degree dip angle)

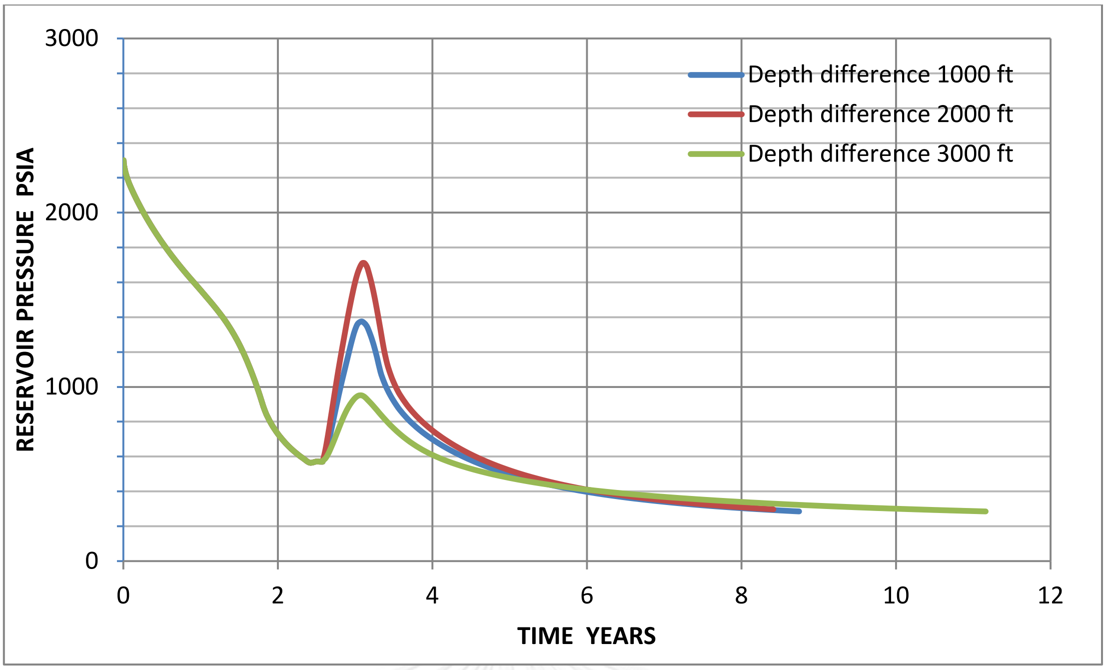


Figure 5. 110 Reservoir pressure for each depth difference cases
(0-degree dip angle)

According to Table 5.65, an increase in depth difference from 1000 ft to 2000 ft slightly increases the recovery factor but increasing the depth difference from 2000 ft to 3000 ft decreases the oil recovery factor. The same trend can be seen in water production and gas production. This is because partial penetration of the gas zone to avoid fracturing the oil zone reduces performance of gas flooding process, limiting gas from flowing into the target oil reservoir.

Table 5. 65 Summarized results of depth difference between gas and oil reservoirs for 0-degree dip angle

Depth difference (ft)	Production life(years)	Waterflood period(years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
1000	8.75	2.41	75.79	7.473	2.734	1.544	18.148
2000	8.41	2.41	76.59	7.552	2.734	1.540	20.693
3000	11.16	2.41	75.89	7.483	2.734	1.700	18.215

5.4.3.2 Dip angle of 15 degrees

The pressures at the top and bottom of gas reservoir located at downdip are tabulated in Table 5.66. All cases have the same skin factor for reducing the bottom hole pressure. Note that skin factor of 1,165 is equivalent to 0.36 feet of perforation interval.

Table 5. 66 Top and bottom reservoir pressures for each depth difference of 15-degree dip angle

Case	Depth difference (ft)	Gas reservoir pressure at top depth (psia)	Gas reservoir pressure at bottom depth(psia)	Original gas in place (BSCF)	Skin	Perforation interval (ft)
1	1000	3,230	3,238	23.192	no skin	20
2	2000	3,675	3,683	25.993	1,165	0.36
3	3000	4,121	4,129	28.617	1,165	0.36

Figure 5.111 shows that case 1 with the lowest depth difference has the highest peak in oil production rate during gas dumpflood followed by case 3 and case 2. This is because case 1 has no skin effect to restrict gas flows into target oil reservoir. Oil recovery factors are shown in Figure 5.112. The variations of gas thickness do not affect the water flooding process. Thus, recovery factors during initial water flooding are the same for all cases. They begin to behave a little bit differently during gas dumpflood. The reservoir pressure profiles of cases 2 and 3 in Figure 5.113 are quite the same but only at the beginning of gas dumpflood that case 3 shows higher peak than case 2. However, case 1 has the highest peak in reservoir pressure due to no effect from skin factor.

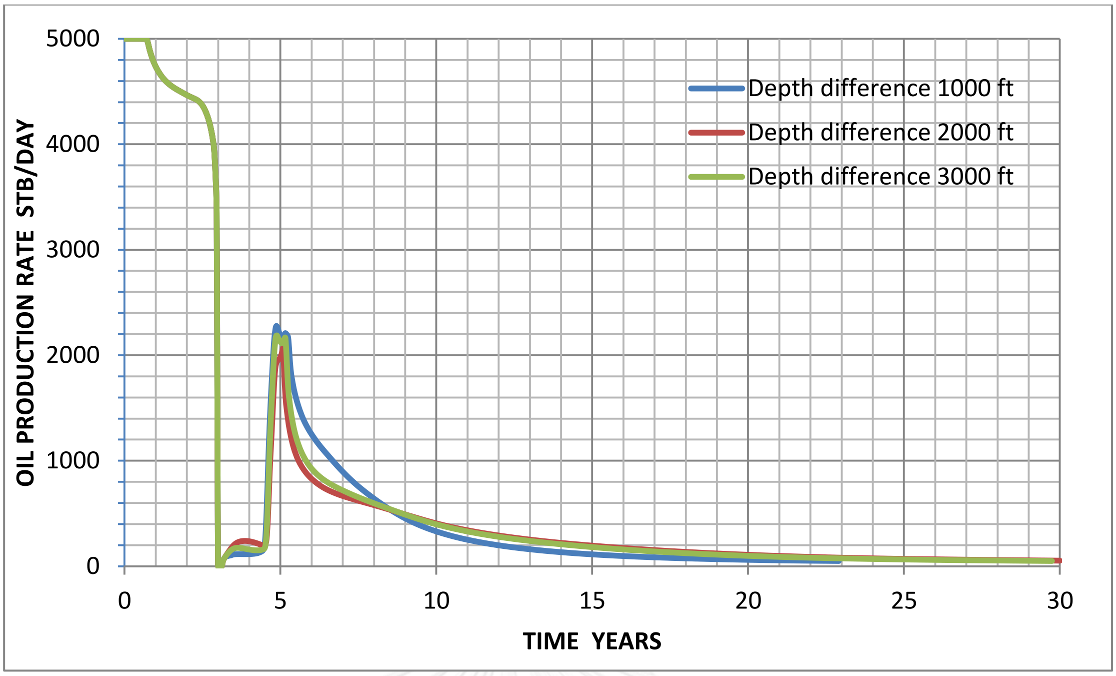


Figure 5. 111 Oil production rate for each depth difference cases (15-degree dip angle)

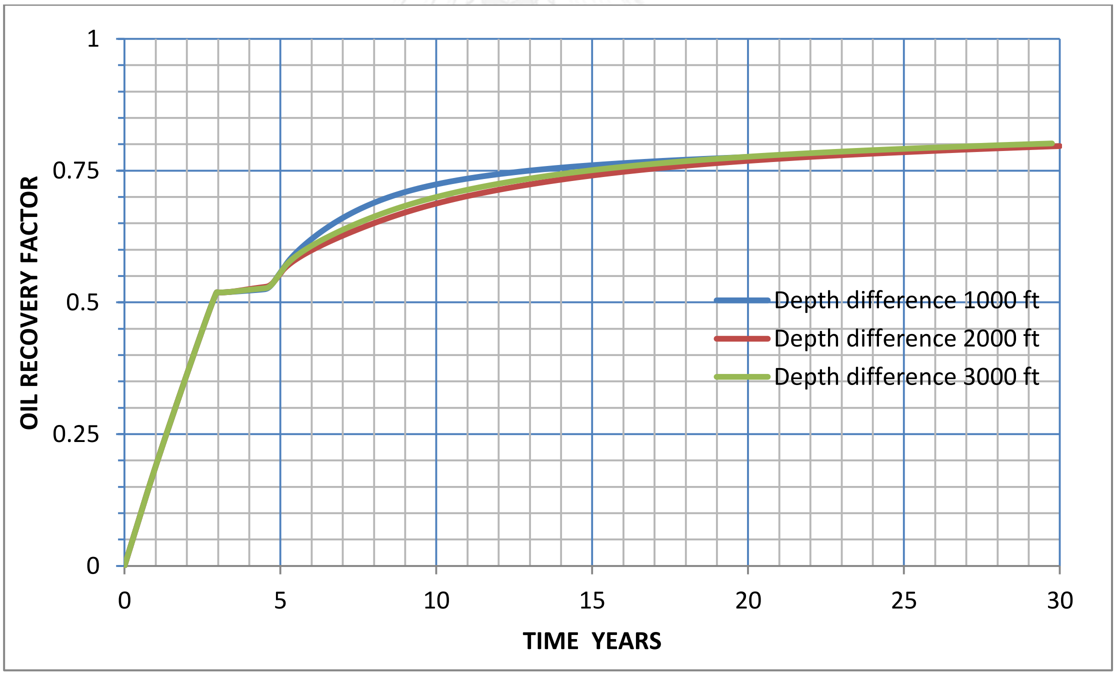


Figure 5. 112 Oil recovery factor for each depth difference cases (15-degree dip angle)

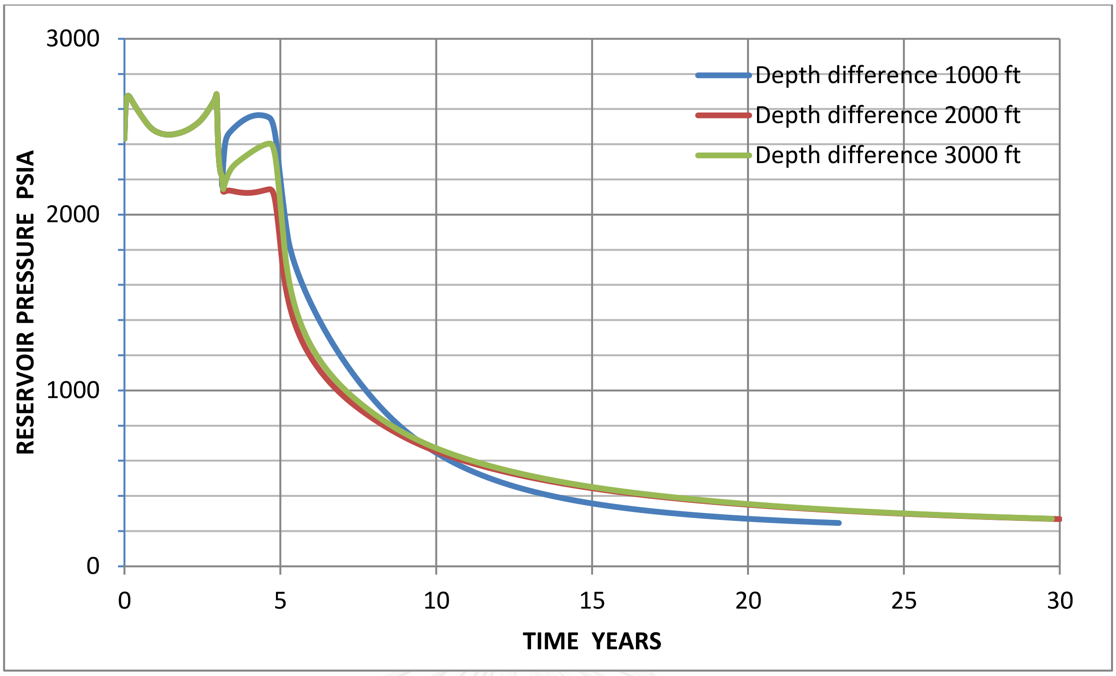


Figure 5. 113 Reservoir pressure for each depth difference cases
(15-degree dip angle)

As depth difference increases, the pressure of the gas zone also increases. As shown in Table 5.67, a slightly higher oil recovery factor and total oil production are obtained in case of higher depth difference. The increase in gas production (case 2 to case 3) is due to higher amount of gas flowing from a deeper reservoir. Case 2 has lower gas production than case 1 because skin factor restricts the flow of gas. For total water production, the amount of water increases as depth different increases is due to the fact that higher amount of gas from the gas reservoir with high initial pressure not only chase oil towards the producer but also drive the water there as well since the location of production well is at the bottom layer which high density water usually stays below oil and gas. So, water production increases in a similar manner as oil production.

Table 5. 67 Summarized results of depth difference between gas and oil reservoirs for 15-degree dip angle

Depth difference (ft)	Production life(years)	Waterflood period(years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
1000	22.91	2.95	78.18	7.474	5.396	4.680	23.846
2000	30	2.95	79.65	7.614	5.396	4.829	23.103
3000	29.75	2.95	80.15	7.662	5.396	4.834	25.535

5.4.3.3 Dip angle of 30 degrees

The pressures at the top and bottom of gas reservoir located at downdip are tabulated in Table 5.68 together with original gas in place, skin factor and perforation interval for different depth differences.

Table 5. 68 Top and bottom reservoir pressures for each depth difference of 30-degree dip angle

Case	Depth difference (ft)	Top gas reservoir pressure (psia)	Bottom gas reservoir pressure (psia)	Original gas in place (BSCF)	Skin	Perforation interval (ft)
1	1000	3,713	3,721	23.360	420	1
2	2000	4,159	4,167	25.697	1,165	0.36
3	3000	4,605	4,613	28.009	1,395	0.3

Figure 5.114 shows that during gas dumpflood all cases have comparable peak in oil production rate. Although case 3 has the highest skin compared to the others, the oil recovery factor is the highest as depicted in Figure 5.115. Case 3 which has the highest pressure for the gas reservoir can provide gas to the oil reservoir at higher pressure. For reservoir pressure, during the beginning of gas dumpflood, cases 1 and 3 have comparable peak in pressure as shown in Figure 5.116. This is because there is less skin effect on case 1 which allows high amount of gas flowing into the oil reservoir.

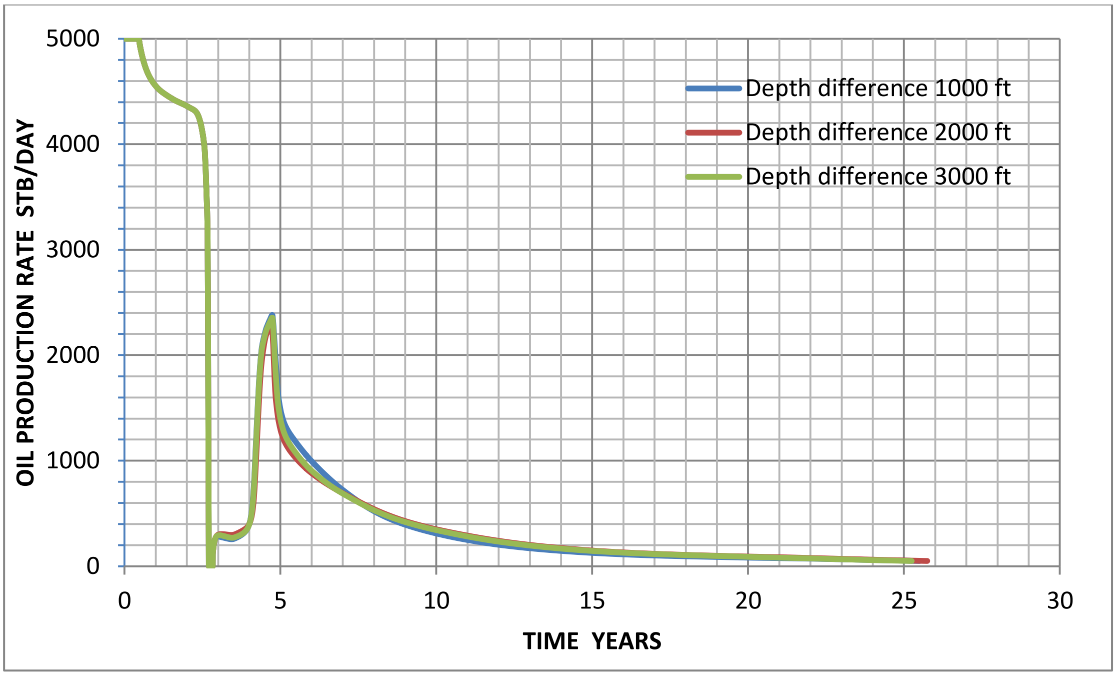


Figure 5. 114 Oil production rate for each depth difference cases

(30-degree dip angle)

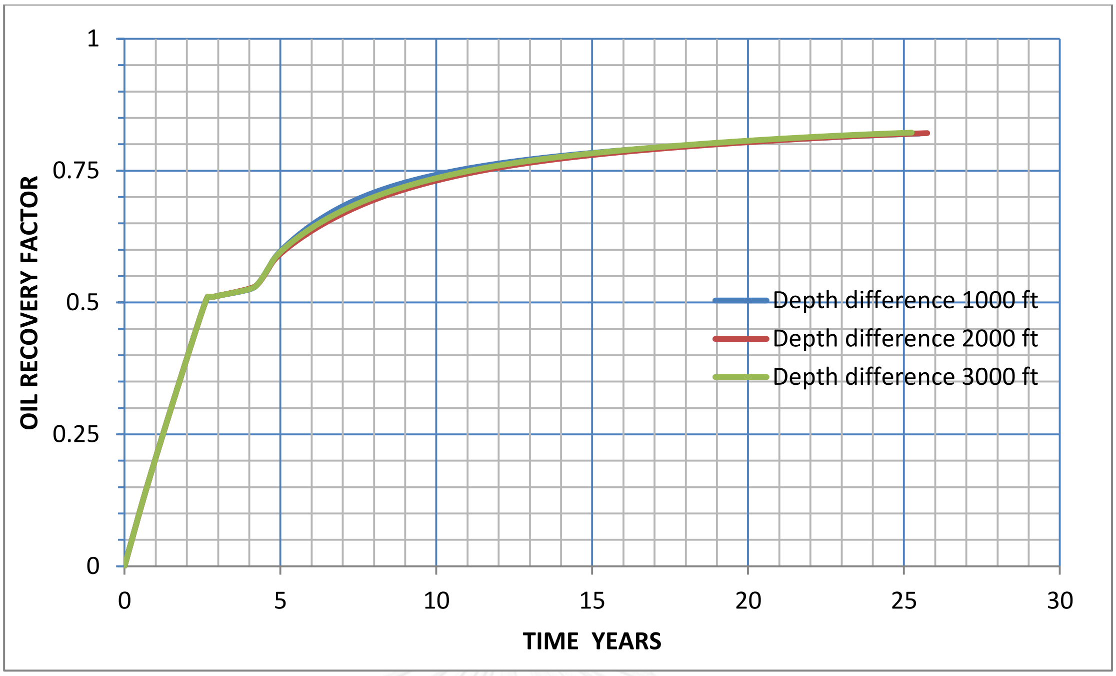


Figure 5. 115 Oil recovery factor for each depth difference cases

(30-degree dip angle)

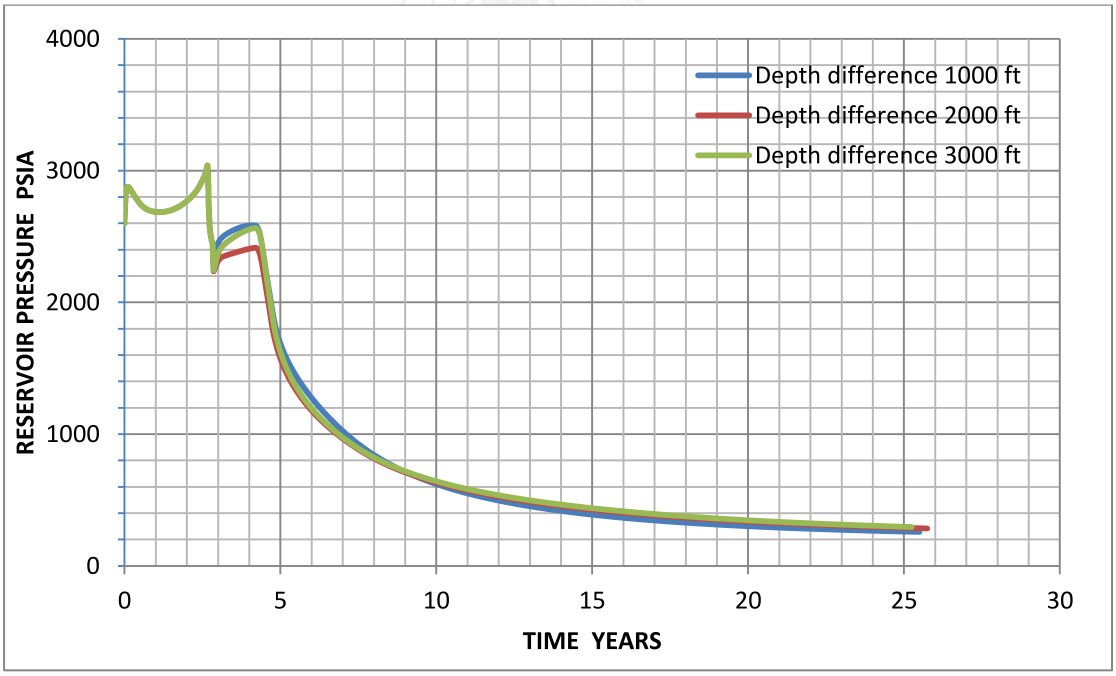


Figure 5. 116 Reservoir pressure for each depth difference cases

(30-degree dip angle)

As depicted in Table 5.69, as the depth difference increases, the total oil production and water production increase since gas with higher pressure chase more oil and water toward the production well. The total water injection is not affected by the changing of depth difference. In term of gas production, case 3 has the highest gas production because it has the highest original gas in place and pressure. However, case 2 has lower gas production than case 1 due to more skin effect.

Table 5. 69 Summarized results of depth difference between gas and oil reservoirs for 30-degree dip angle

Depth difference (ft)	Production life(years)	Waterflood period(years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
1000	25.49	2.66	82.03	7.048	4.867	4.165	22.705
2000	25.75	2.66	82.12	7.056	4.867	4.185	22.617
3000	25.25	2.66	82.21	7.063	4.867	4.185	23.999

5.4.4 Effect of residual oil saturation

In practice, residual oil saturation is obtained from special core analysis method. Due to the uncertainties of system parameter, the variation in residual oil saturation is examined to see the effect on the performance of gas dumpflood in water-flooded reservoir for each dip angle. The residual oil saturations for oil-water system and oil-gas systems are varied in this study.

5.4.4.1 Effect of residual oil saturation in oil-water system

The relative permeability curves as shown in Figure 5.117 are plotted based on Corey's correlation. The residual oil saturation in oil-water system (S_{orw}) is varied in three different values which are 0.2, 0.3 and 0.4 while other parameters are kept constant.

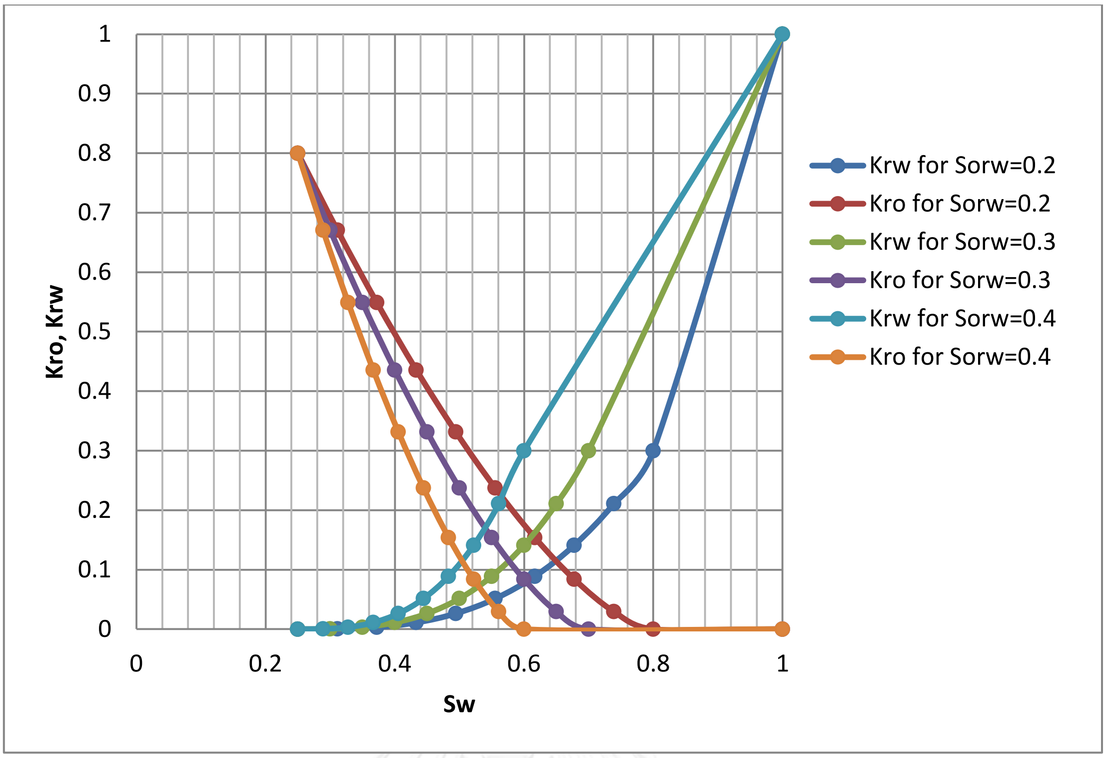


Figure 5. 117 Oil-water functions for different residual oil saturations in oil-water system

5.4.4.1.1 Dip angle of 0 degree

Reservoir of 0-degree dip angle is investigated to see the effect of different residual oil saturation. According to Figure 5.118, the highest oil recovery factor is 78.85% for the case with S_{orw} equals to 0.2, and it gets lowered by 2.26% and 4.13% when S_{orw} equals to 0.3 and 0.4, respectively. At the beginning of oil production, all the cases have the same recovery factor until each case reaches the water cut criteria for shutting in the well. A longer water flood period is observed in the case of lower S_{orw} due to more mobile oil for waterflood process to sweep toward the production well. Thus, a higher amount of water injection is needed for lower S_{orw}, and so does the total water production as shown in Table 5.70.

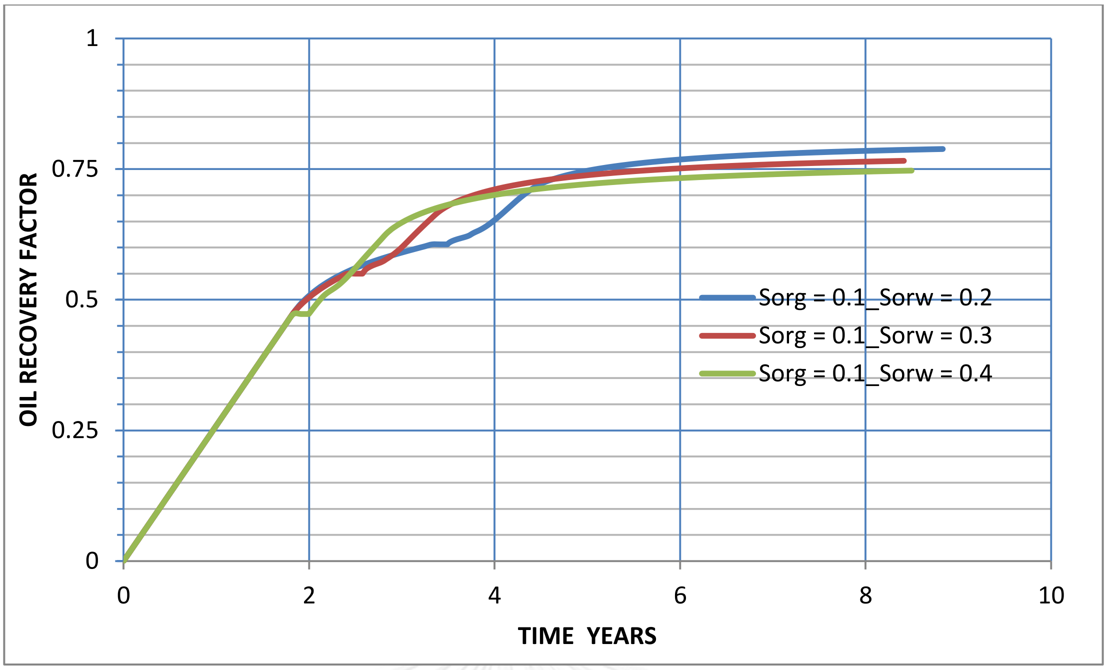


Figure 5. 118 Oil recovery factors for different residual oil saturations in oil-water system (0-degree dip angle)

Table 5. 70 Summarized results of different residual oil saturations in oil-water system for 0-degree dip angle

Residual oil saturation S_{org} = 0.1	Production life(years)	Waterflood period (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
S_{orw} = 0.2	8.83	3.33	78.85	7.775	3.741	2.084	19.261
S_{orw} = 0.3	8.41	2.41	76.59	7.552	2.734	1.540	20.693
S_{orw} = 0.4	8.50	1.83	74.72	7.368	2.095	1.298	21.358

5.4.4.1.2 Dip angle of 15 degrees

Reservoir of 15 degree dip angle is simulated to study the effect of S_{orw}. According to Figure 5.119, the case with S_{orw} of 0.2 has the highest oil recovery factor of 80.4% due to the longest time of water flooding process. And the oil recovery factor gets lowered by 0.75% and 1.15% when S_{orw} equals to 0.3 and 0.4, respectively. The decrease in oil recovery factor is not as much as in the case of 0-degree reservoir. This is because of segregation of gas and water-flooded oil zone. In the zone near gas injection, the oil saturation is close to S_{org} while the oil saturation near the downdip producer is close to S_{orw}. As most of the upper part of the reservoir is occupied by gas, the variation in S_{orw} has smaller effect on oil recovery. As S_{orw} decreases, there is more mobile oil that can be recovered. Thus, a more amount of injected water is needed to flood the oil. This increases the waterflood period as depicted in Table 5.71.

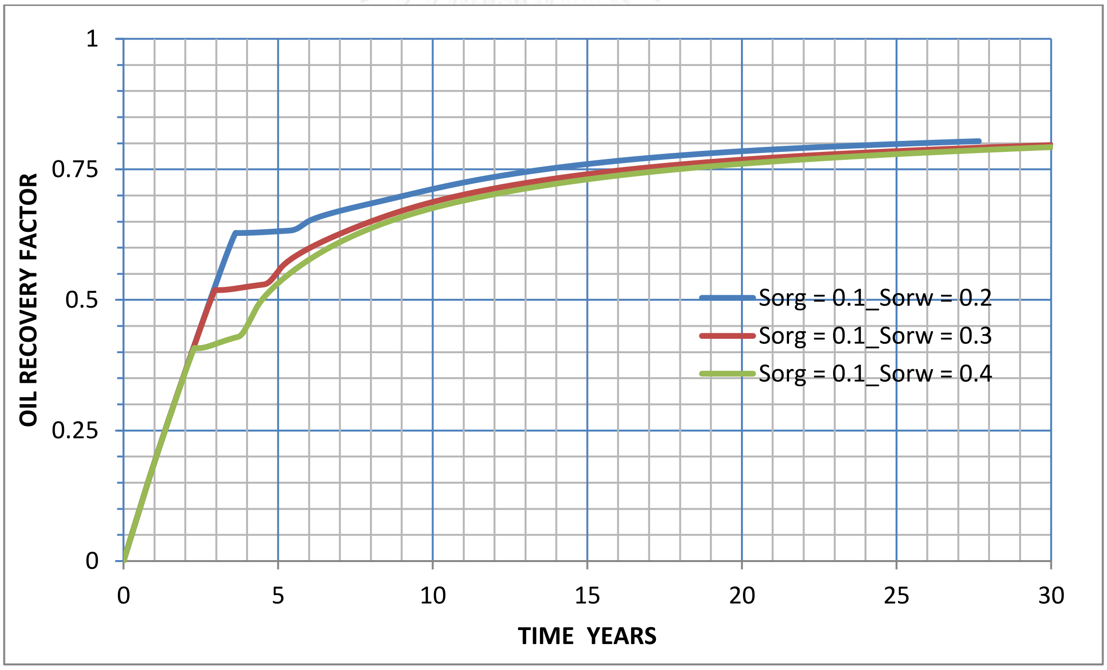


Figure 5. 119 Oil recovery factor for different residual oil saturations in oil-water system (15-degree dip angle)

Table 5. 71 Summarized results of different residual oil saturations in oil-water system for 15-degree dip angle

Residual oil saturation S_{org} = 0.1	Production life(years)	Waterflood period (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
S_{orw} = 0.2	27.67	3.62	80.40	7.686	6.604	5.746	22.379
S_{orw} = 0.3	30	2.95	79.65	7.614	5.396	4.829	23.103
S_{orw} = 0.4	30	2.29	79.25	7.576	4.175	3.829	23.294

5.4.4.1.3 Dip angle of 30 degrees

The oil recovery factor of 30 degrees dip angle reservoir is shown in Figure 5.120. At the beginning of oil production, all cases have the same oil recovery factor until they reach water cut criteria. The case with S_{orw} of 0.4 is the first case shutting in the well before gas dumpflood process is performed. As S_{orw} increases, the duration of water flooding decreases. This is because there is less mobile oil that can be recovered. The highest oil recovery factor is 82.49% for the case with S_{orw} of 0.2 and it gets lowered by 0.37% and 0.21% for the case with S_{orw} of 0.3 and 0.4, respectively as depicted in Table 5.72. The decrease in oil recovery factor is not as much as in the case of 0-degree reservoir. This is because of segregation of gas and water-flooded oil zone which affects higher than 15-degree reservoir due to higher steepness. In the zone near gas injection, the oil saturation is close to S_{org} while the oil saturation near the downdip producer is close to S_{orw}. As major part of the reservoir is occupied by gas, the variation in S_{orw} has very smaller effect on oil recovery. Due to the fact that simulator has the variations of numerical error, this error might be larger than the small increment in the recovery factor. There is no trend of oil recovery factor that can be seen clearly. The increase in total water injection and water production as S_{orw} decreases is because water flooding process takes longer time.

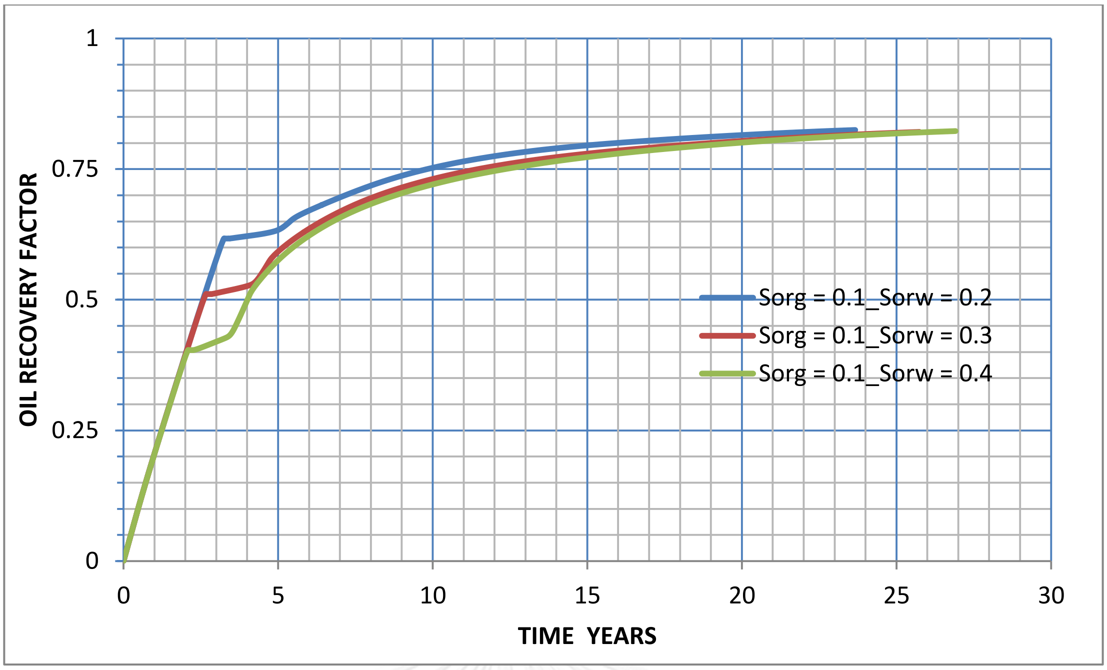


Figure 5. 120 Oil recovery factor for different residual oil saturations in oil-water system (30-degree dip angle)

Table 5. 72 Summarized results of different residual oil saturations in oil-water system for 30-degree dip angle

Residual oil saturation S_{org} = 0.1	Production life(years)	Waterflood period (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
S_{orw} = 0.2	23.67	3.25	82.49	7.087	5.931	4.999	21.832
S_{orw} = 0.3	25.75	2.66	82.12	7.056	4.867	4.185	22.617
S_{orw} = 0.4	26.91	2.09	82.28	7.070	3.807	3.325	23.070

5.4.4.2 Effect of residual oil saturation in oil-gas system

The relative permeability curves demonstrated in Figure 5.121 are constructed based on Corey's correlation by varying the residual oil saturation in oil-gas system (S_{org}) from 0.05 to 0.1 and 0.15.

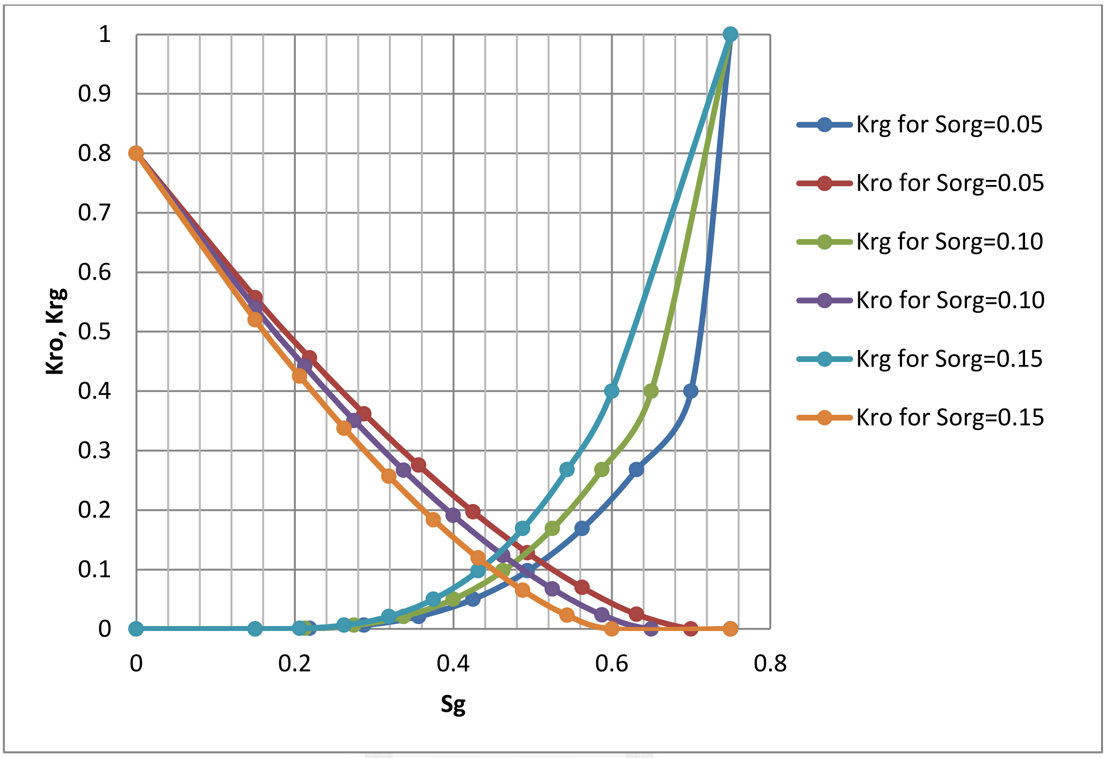


Figure 5. 121 Oil-gas functions for different residual oil saturations in oil-gas system

5.4.4.2.1 Dip angle of 0 degree

As shown in Figure 5.122, the oil recovery factors of 0-degree dip angle reservoir for all S_{org} are similar during water flooding since there is no gas flowing from the gas reservoir into the oil zone yet. After gas dumpflood is started, the case with lower S_{org} has higher recovery factor than the other cases. The highest oil recovery factor is 81.84% for the case with S_{org} of 0.05. The recovery factor becomes lower by 5.25% and 10.53% for the case with S_{org} of 0.1 and 0.15, respectively. This number is significantly reduced as S_{org} increases. The reason is that the higher the value of S_{org}, the higher the unrecoverable oil is from gas dumpflood process. The case of high S_{org} takes shorter production time since less oil can be recovered. The change of this system parameter does not affect much on waterflood process, as you can see from Table 5.73. The waterflood period of each case is slightly different and so do total water injection and total water production.

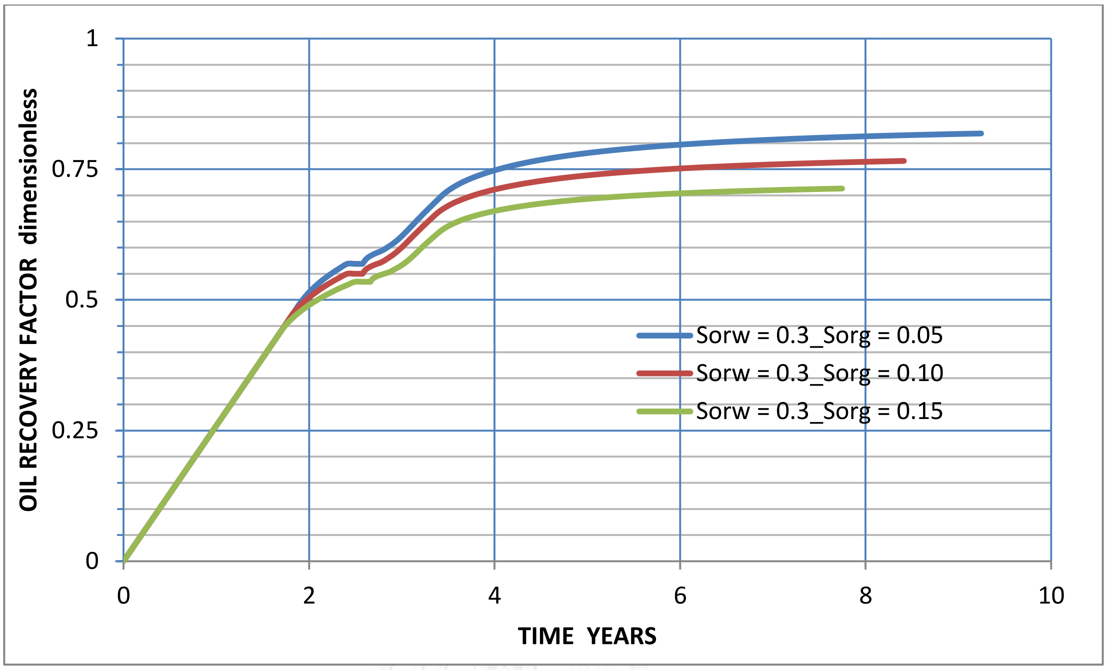


Figure 5. 122 Oil recovery factor for different residual oil saturations in oil-gas system (0-degree dip angle)

Table 5. 73 Summarized results of different residual oil saturations in oil-gas system for 0-degree dip angle

Residual oil saturation S_{orw} = 0.3	Production life(years)	Waterflood period (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
S_{org} = 0.05	9.25	2.41	81.84	8.070	2.734	1.576	21.323
S_{org} = 0.10	8.41	2.41	76.59	7.552	2.734	1.540	20.693
S_{org} = 0.15	7.75	2.50	71.31	7.031	2.825	1.586	19.932

5.4.4.2.2 Dip angle of 15 degrees

Figure 5.123 shows oil recovery factor of 15 degree dip angle reservoir. At the beginning of water flooding, all the cases have the same profiles until they reach water cut criteria. During the gas dumpflood period, the oil recovery factors are significantly different. The highest oil recovery factor is 85.33% for the case with S_{org} of 0.05 and it gets lowered by 5.68% and 12.05% for the case with S_{org} of 0.1 and 0.15, respectively. The oil recovery factor becomes lower as S_{org} increases due to less amount of recoverable oil.

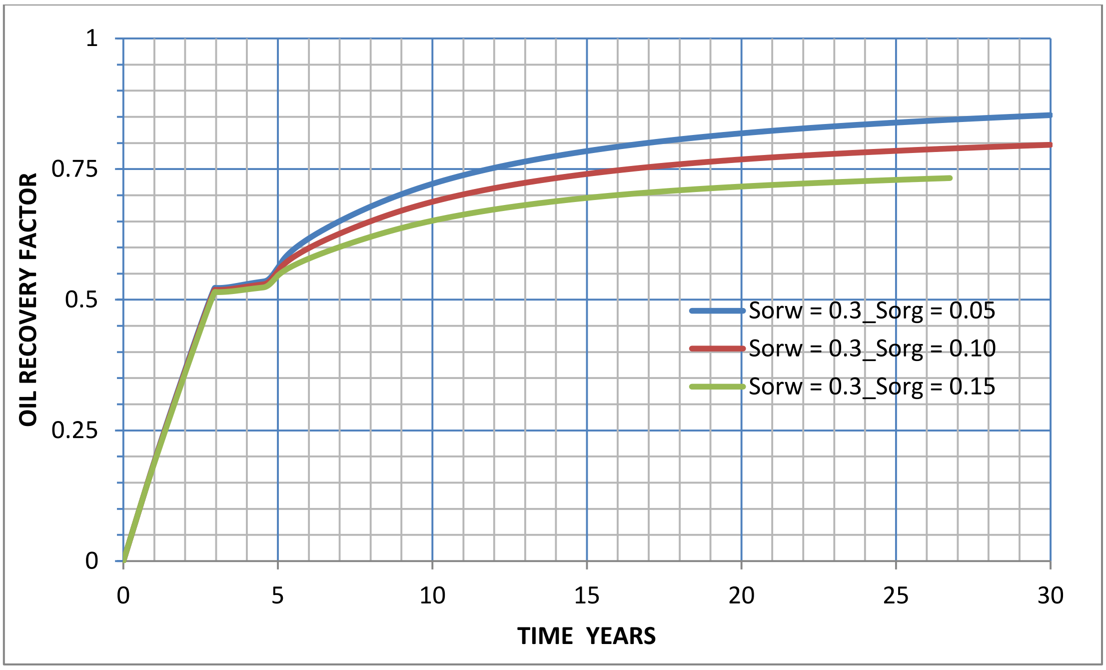


Figure 5. 123 Oil recovery factor for different residual oil saturations in oil-gas system (15-degree dip angle)

Summary of results in Table 5.74, as you can see the waterflood period is the same for all cases and total water injection and total water production show slightly different.

Table 5. 74 Summarized results of different residual oil saturations in oil-gas system for 15-degree dip angle

Residual oil saturation S_{orw} = 0.3	Production life(years)	Waterflood period (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
S_{org} = 0.05	30	2.95	85.33	8.157	5.396	4.826	22.987
S_{org} = 0.10	30	2.95	79.65	7.614	5.396	4.829	23.103
S_{org} = 0.15	26.75	2.95	73.28	7.005	5.387	4.776	22.458

5.4.4.2.3 Dip angle of 30 degrees

At the beginning of water flooding, all cases perform the same until gas dumpflood process starts as seen in Figure 5.124. The oil recovery factor shows significant difference among all cases of different S_{org}. The highest oil recovery factor is 89.03% for the case with S_{org} of 0.05 and it gets lowered by 6.91% and 13.68% for the case with S_{org} of 0.1 and 0.15, respectively. The higher oil recovery case takes longer time of production.

According to Table 5.75, the duration of water flooding process is the same for all cases and so does the total water injection. The total water production is slightly different among all cases.

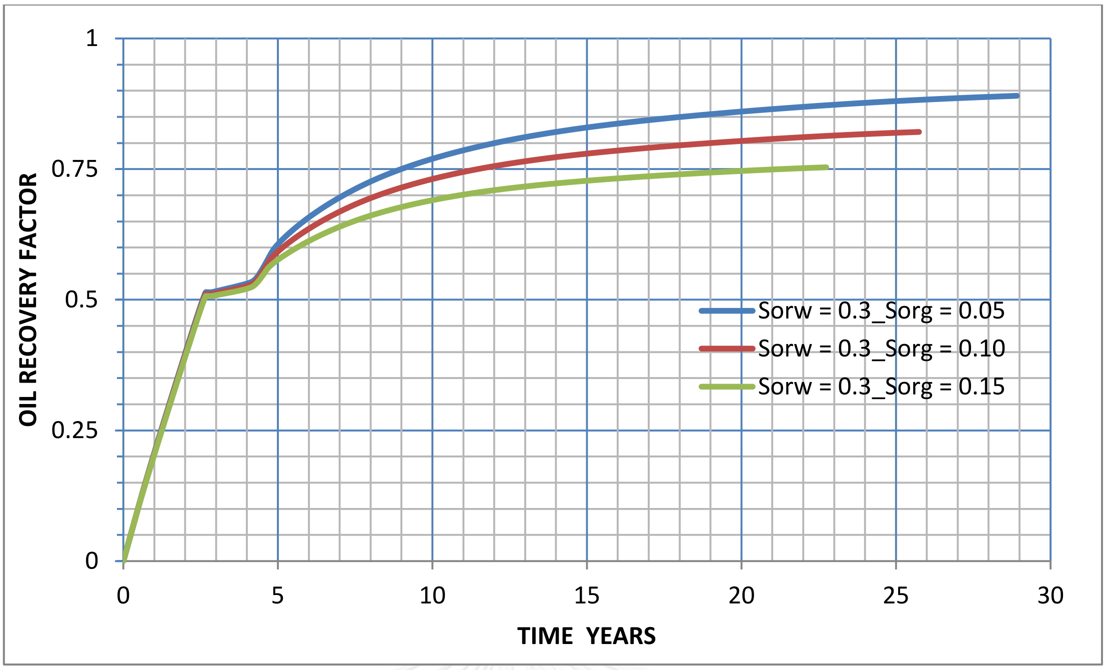


Figure 5. 124 Oil recovery factor for different residual oil saturations in oil-gas system (30-degree dip angle)

Table 5. 75 Summarized results of different residual oil saturations in oil-gas system for 30-degree dip angle

Residual oil saturation S_{orw} = 0.3	Production life(years)	Waterflood period (years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
S_{org} = 0.05	28.91	2.66	89.03	7.649	4.867	4.205	23.169
S_{org} = 0.10	25.75	2.66	82.12	7.056	4.867	4.185	22.617
S_{org} = 0.15	22.75	2.66	75.35	6.474	4.867	4.161	21.898

5.4.5 Original oil viscosity

Viscosity is a measure of a fluid's internal resistance to flow which is directly related to the movement of fluid. It is affected by temperature, pressure and the amount of gas in solution in a liquid. For the same system of effective permeability and oil saturation, high viscosity oil is less mobile than low viscosity oil. Viscosity influences the rate of oil production and the ultimate oil recovery. So, different viscosities of oil are considered to observe the performance of gas dumpflood in water-flooded reservoir. Three values of original oil viscosity (0.5, 2, and 5 cp.) are generated by ECLIPSE100 correlation set II by varying oil API gravity and solution gas oil ratio. The input PVT properties in ECLIPSE100 are illustrated in Table 5.76

Table 5. 76 Input parameters for different values of original oil viscosity

Case	Oil gravity (API)	Gas gravity	Rs (SCF/STB)	Oil viscosity at 2,243 psia (cp.)	Bubble point pressure (psia)
1	40	0.6	300	0.5	1,609
2	25	0.6	100	2	996
3	15	0.6	80	5	1,103

5.4.5.1 Dip angle of 0 degree

From the beginning of water flooding process, different original oil viscosities provide different oil recovery profiles as shown in Figure 5.125. The case with lower original oil viscosity can produce more oil due to easier oil movement. In this figure, the highest oil recovery factor is 78.39% for the case with original oil viscosity of 0.5 cp. The original oil recovery for the cases with oil viscosity of 2 cp. and 5 cp. is 71.03% and 61.79%, respectively.

At the beginning, oil production rate for the case with original oil viscosity of 5 cp. can maintain the maximum oil production rate for the shortest time while the cases with original viscosity of 2 and 0.5 cp. can maintain the plateau production for longer time as shown in Figure 5.126. The case of 5 cp. original oil viscosity has the longest total production time but has the lowest oil recovery factor. The difference in oil recovery factors between high original viscosity and low original viscosity oil is quite significant.

In Table 5.77, the total water injection and total water production are quite different. As original oil viscosity decreases, the injected water and produced water increase. This is because during the water flooding process, the water has more efficiency to sweep lower viscosity oil.

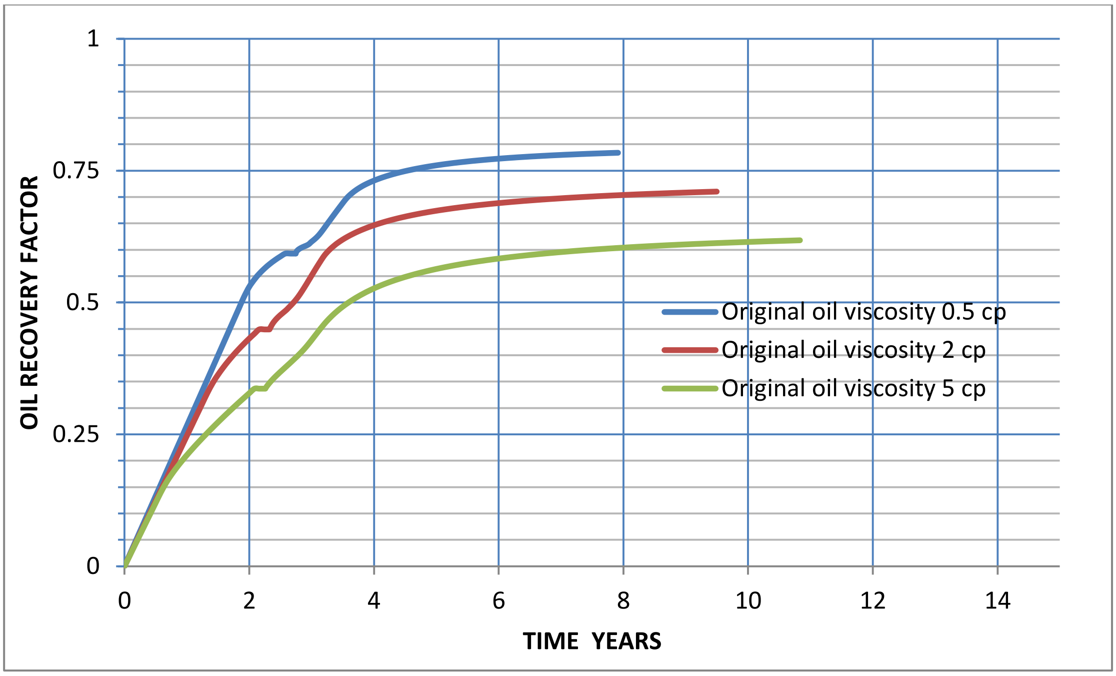


Figure 5. 125 Oil recovery factor for different original oil viscosities

(0-degree dip angle)

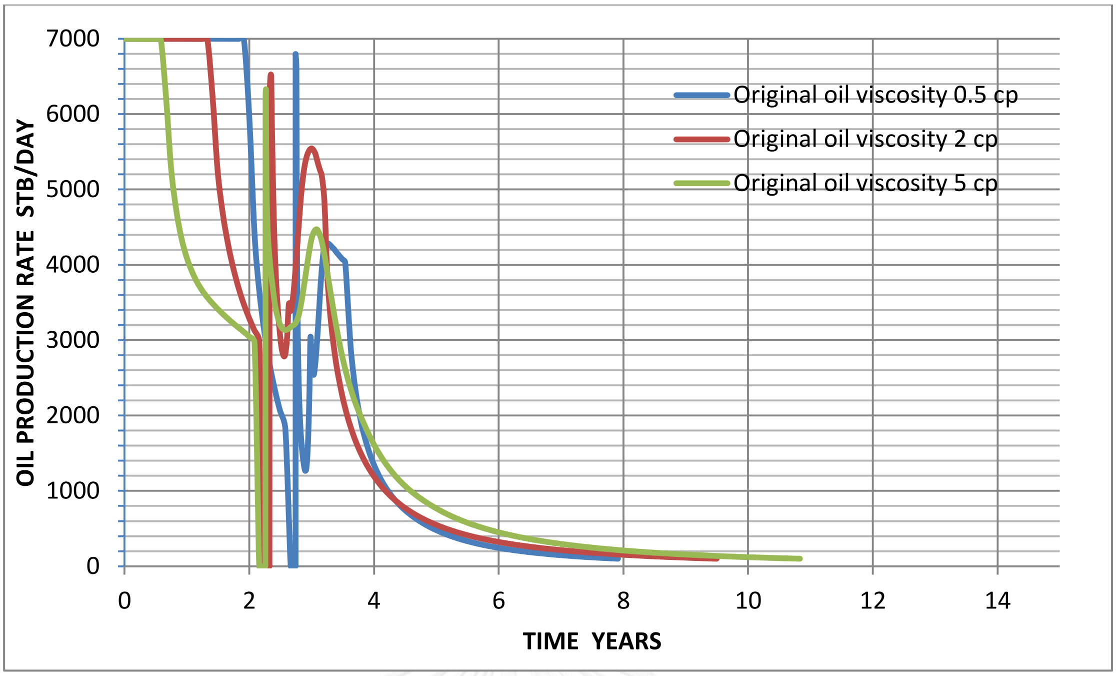


Figure 5. 126 Oil production rate for different original oil viscosities (0-degree dip angle)

Table 5. 77 Summarized results of different original oil viscosities for 0-degree dip angle

Original oil viscosity (cp.)	Production life(years)	Waterflood period(years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
0.5	7.91	2.58	78.39	7.517	2.920	1.679	20.795
2	9.50	2.16	71.03	7.340	2.452	1.332	20.371
5	10.83	2.08	61.79	6.565	2.285	1.295	19.808

5.4.5.2 Dip angle of 15 degrees

Oil recovery factors for different values of original oil viscosity are illustrated in Figure 5.127 for 15 degree dip angle reservoir. As illustrated, the difference in oil recovery factor is quite significant among the cases. The highest oil recovery is 81.04% with the case of 0.5 cp. original oil viscosity. The cases with original viscosity of 2 and 5 cp. have 10% and 25.97% lower oil recovery factor, respectively.

At the beginning of oil production in Figure 5.128, case of 0.5 cp. original oil viscosity can maintain maximum production rate at 5,000 STB/D while the other cases have lower rate. At late times, the cases of 2 and 5 cp. original oil viscosity is still producing as the amount of oil recovery at that time is still low while the case of 0.5 cp. original oil viscosity stops production at the 27th year as the recovery factor is very high.

The summary of results in Table 5.78 shows that the case of 0.5 cp. original oil viscosity requires the highest amount of total water injection for sweeping oil during waterflood process and also has the highest total water production. However, it spends the least duration of waterflood due to low viscosity oil that can move easier than high viscosity oil.

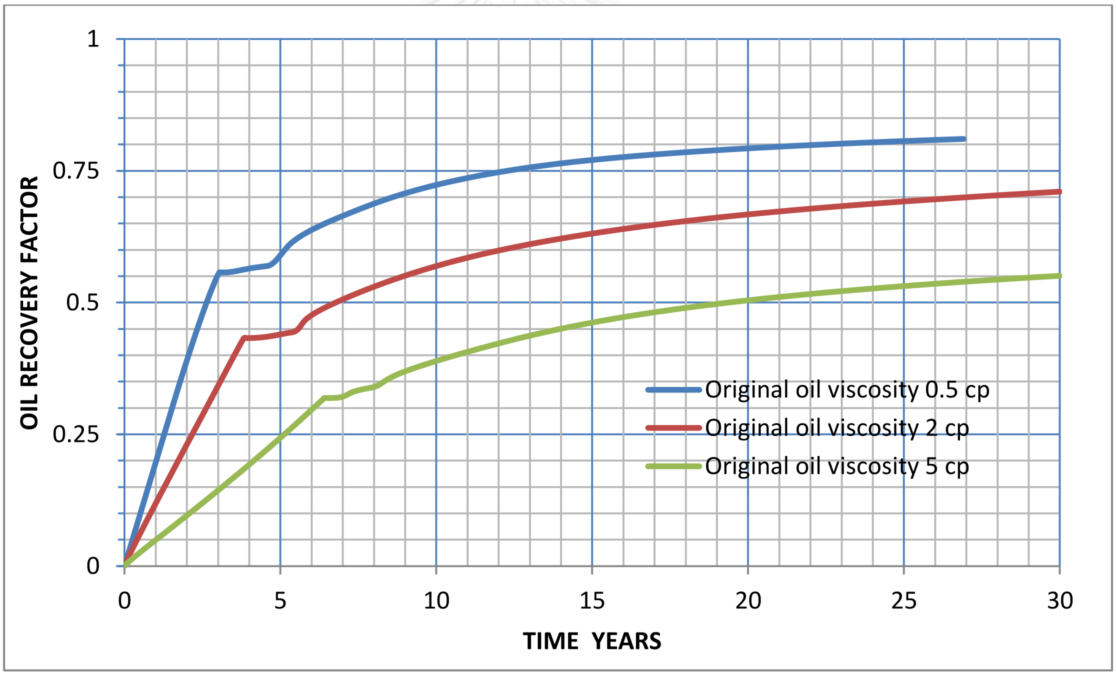


Figure 5. 127 Oil recovery factor for different original oil viscosities (15-degree dip angle)

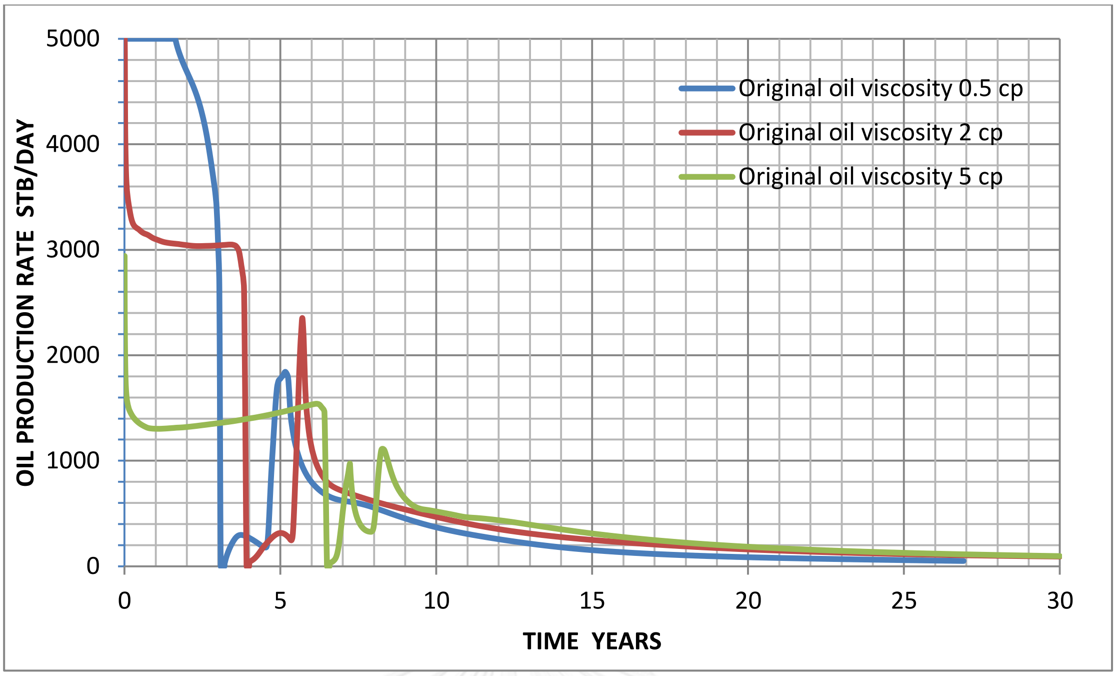


Figure 5. 128 Oil production rate for different original oil viscosities (15-degree dip angle)

Table 5. 78 Summarized results of different original oil viscosities for 15-degree dip angle

Original oil viscosity (cp.)	Production life(years)	Waterflood period(years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
0.5	26.91	3.04	81.04	7.530	5.554	4.938	23.133
2	30	3.83	71.04	7.097	4.772	4.156	21.509
5	30	6.41	55.07	5.661	3.590	3.026	19.105

5.4.5.3 Dip angle of 30 degrees

The 30 degree reservoir dip angle is observed for different original oil viscosities. Due to the higher pressure of gas reservoir, partial penetration of gas reservoir is needed to prevent fracturing the dumpflood well in oil reservoir. The perforation intervals are tabulated in Table 5.79.

Table 5. 79 Skin and perforation interval of different original oil viscosities for 30-degree dip angle

Case	Original oil viscosity (cp.)	Skin	Perforation interval of gas zone (ft)
1	0.5	1,165	0.36
2	2	1,395	0.30
3	5	2,786	0.15

Oil recovery factors for different values of original oil viscosity are significantly different among the cases as depicted in Figure 5.129. The oil recovery profiles look different since the beginning of oil production. In case of original oil viscosity of 2 and 5 cp., the oil recovery factor is 58.9% and 76.73%, respectively. During the beginning of oil production rate in Figure 5.130, the lowest original oil viscosity of 0.5 cp. can maintain the maximum oil rate of 5,000 STB/D but the others cannot. At late times, the cases of 2 and 5 cp. original oil viscosity is still producing as the amount of oil recovery at that time is still low while the case of 0.5 cp. original oil viscosity stops production at the 22th year as the recovery factor is very high.

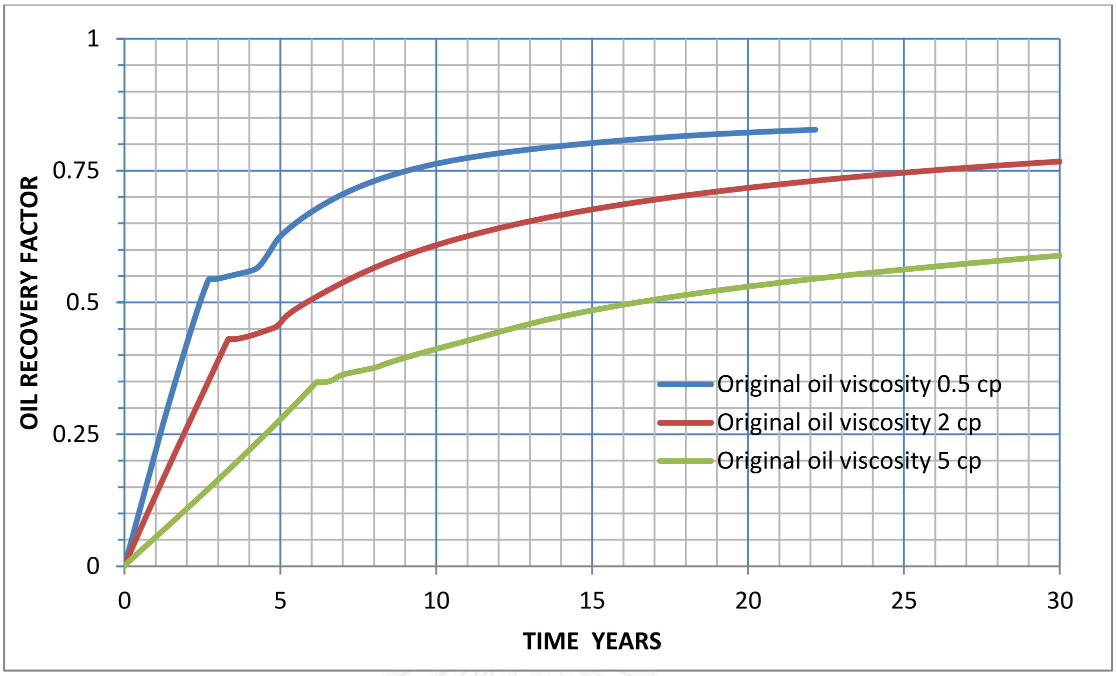


Figure 5. 129 Oil recovery factor for different oil viscosities

(30-degree dip angle)

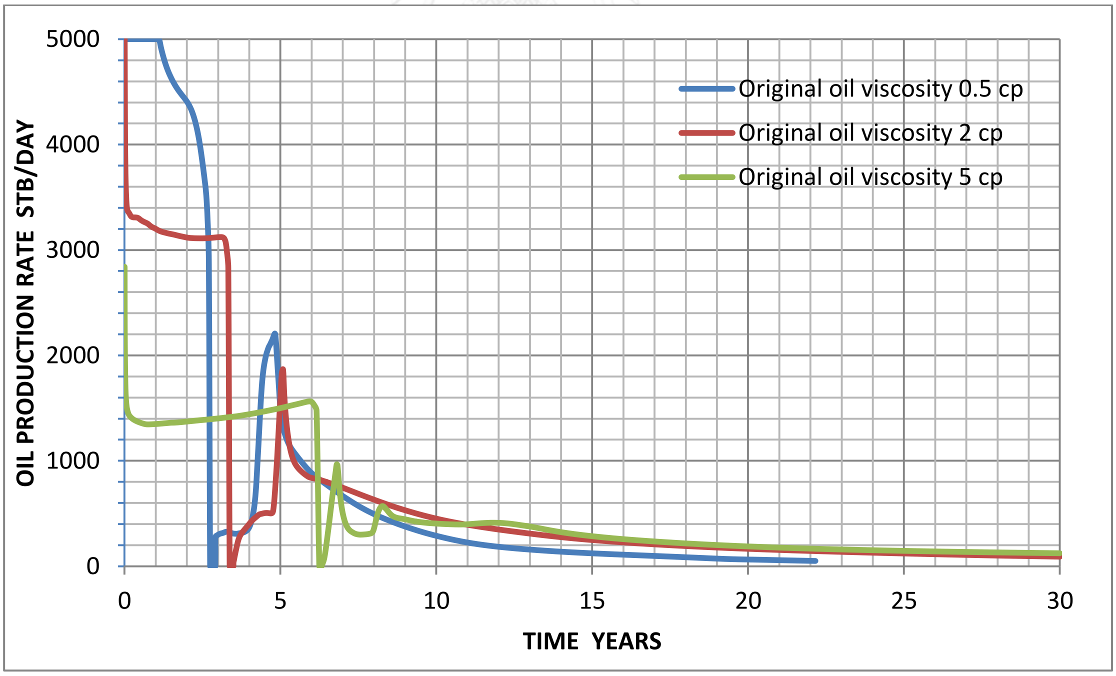


Figure 5. 130 Oil production rate for different original oil viscosities

(30-degree dip angle)

Summary of results in Table 5.80 show that as original oil viscosity increases, the total water injection and total water production decrease. However, the waterflood period of 5 cp. original oil viscosity has the longest time, and the amount of total injected water and total produced water are the least. This is because high viscosity oil is hard to move. It needs more time to move toward the producer than the low viscosity oil.

Table 5. 80 Summarized results of different original oil viscosities for 30-degree dip angle

Original oil viscosity (cp.)	Production life(years)	Waterflood period(years)	RF (%)	Total oil production (MMSTB)	Winj (MMSTB)	Wp (MMSTB)	Gp (BSCF)
0.5	22.16	2.71	82.76	6.913	4.940	4.186	22.289
2	30	3.33	76.73	6.889	4.343	3.734	21.524
5	30	6.16	58.90	5.437	3.577	2.939	16.150

CHAPTER VI
CONCLUSION AND RECOMMENDATION

Gas dumpflood in water-flooded reservoir can perform to obtain high amount of oil recovery with less capital investment and operating cost from gas injection facility. This process is the use of non-commercial gas reservoir (high CH_4 and high CO_2 content) to increase oil recovery from residual oil after water flooding process. The dip angle of reservoir can help increase oil recovery due to gravity drainage and segregation. The appropriate well arrangement for this study can reduce the cost of drilling and completing the well and at the same time gains high amount of oil recovery. Water cut criteria for this study performs the lowest cost due to the shortest water injection duration.

In this chapter, conclusion from the result of all design parameters and sensitivity analysis are concluded. Several recommendations which might be useful for future study are also shown.

6.1 Conclusion

The results from six design parameters on gas dumpflood in waterflooded reservoir which are well arrangements, water cut, well types, perforation interval, water injection, and liquid production rates and the results obtained from sensitivity analysis in order to observe the effect of variations of reservoir parameters which are vertical to horizontal permeability ratio, gas thickness, depth difference between oil and gas reservoir, residual oil saturation in oil-water and oil-gas systems and original oil viscosity are concluded as follows:.

1. When comparing between gas dumpflood in waterflooded reservoir and conventional water flooding, for 0-degree dip angle reservoir, gas dumpflood case has no significant difference on oil recovery while the amount of total water production and water injection are significantly lower than water flooding case. For 15-degree and 30-degree dip angle reservoirs, gas dumpflood cases have a remarkably higher oil recovery and remarkably lower requirement for water injection.

2. Appropriate distance between injector and producers is an important factor on oil recovery mechanism of gas dumpflood process. For 0-degree dip angle reservoir, three vertical wells with 2,000-ft distance between vertical producers and vertical injector can recover high amount of oil with the shortest production time while the ten vertical wells with 1,000-ft distance between producers and injectors can recover the highest amount of oil. However, the case of three wells is more attractive as it incurs much lower cost for drilling and completing. For 15 and 30 degree dip angle reservoirs, two vertical wells with 4,000-ft distance between producers and injectors have the highest oil recovery and the least requirement for water injection. After the appropriate distance between injector and producers is investigated, the horizontal producers well type which are used in an attempt to get better performance. For 0-degree dip angle reservoir, two horizontal producers with 2,000 ft between producers and the vertical injector is the best well arrangement. For 15 and 30 degree dip angle reservoirs, the best well arrangement is one horizontal producer with 4,000-ft distance.

3. The most suitable time for beginning gas dumpflood process is 1% water cut criteria for both vertical and horizontal well types for the three dip angles studied. As water cut criteria increases, the oil recovery is not significantly changed while total water injection and total water production are much higher.

4. The best perforation interval of gas zone is 20% of total interval for 0-degree dip angle reservoir because there is insignificant increase in oil recovery as perforation interval increases but we may incur the risk of fracturing the oil formation. For 15 and 30 degree dip angle reservoirs, the perforation interval has to be very small in order to prevent high pressure gas from dipping reservoirs from fracturing the oil zone.

5. Regarding target water injection and liquid production rates, for 0-degree dip angle reservoir, the cases with target water injection rate higher than target liquid production rate and the cases with the same target rates can provide good pressure maintenance. However, the cases with target liquid production rate higher than target water injection rate have high oil recovery with lower amount of total water injection

and total water production. For 15 and 30 degree dip angle reservoir, there is no significant difference on oil recovery.

6. The case with very low vertical to horizontal permeability ratio of 0.001, for 0-degree dip angle reservoir, causes moderately lower oil recovery because oil cannot flow down toward the producers located at the bottommost of the reservoir. As vertical to horizontal permeability ratio increases from 0.01 to 0.3, there are more chances of fluids moving along the vertical direction. Thus, water flows more easily to the bottommost layer, causing less production of oil which has lower density. For 15 degree dip angle reservoir, there is insignificant difference in oil recovery as vertical to horizontal permeability increases. For 30 degree dip angle, as vertical to horizontal permeability increases, the oil recovery slightly increases because of better segregation among gas, oil and water. For the case with the highest vertical permeability, water segregates to the bottom, allowing oil to flow better to the producer located at the topmost layer.

7. Different thicknesses of source gas reservoir provide different initial gas reservoir pressures and amounts of original gas in place. For all dip angles, as gas thickness increases, the oil recovery increases because there is higher gas pressure and higher amount of gas that can sweep more oil.

8. Depth difference between the oil and source gas reservoirs directly affects the pressure and original gas in place. For 0-degree dip angle reservoir, as depth difference increases, the oil recovery slightly increases except for the last case of 3,000 ft depth difference due to skin factor which affects the flow of gas into the target reservoir. For 15 and 30 degree dip angles, oil recovery factor slightly increases as depth difference increases.

9. The lower the residual oil saturation for oil-water and oil-gas systems, the higher the oil recovery factor. For 0 and 15 degree dip angle reservoirs, as residual oil saturation for oil-water system decreases, the oil recovery factor slightly increases while as residual oil saturation for oil gas system decreases, oil recovery remarkably increases. For 30 degree dip angle reservoir, as residual oil saturation for oil-water

system decreases, oil recovery shows no trend due to the fact that the variations of error have larger effect on the increment of the results. However, for oil-gas system, oil recovery significantly increases as residual oil saturation decreases.

10. The oil recovery factor becomes much smaller as the original oil viscosity increases.

6.2 Recommendation

1. In this study, partial penetration is performed to restrict the flow of gas into target oil reservoir which reduces the performance of gas flooding. Other methods of reducing gas pressure during gas dumpflood process should be investigated such installing valve to control the gas rate, producing gas from gas reservoir first in order to reduce pressure below fracture reservoir before performing gas dumpflood process.

2. This study is performed by using ECLIPSE 100 black oil reservoir simulation in which the effect of compositional is not included. The study on the effect of miscibility should be investigated by ECLIPSE 300 compositional reservoir simulator.

3. The production performance of gas dumpflood in a heterogeneous reservoir is different from that of homogeneous one. Thus, a detailed study should be performed.

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APPENDIX

APPENDIX

This section provides details for reservoir model construction by use of ECLIPSE100 reservoir simulator. The parameters input in base case condition for gas dumpflood is as follows:

1. Reservoir model

1.1 Case definition

Simulator	Black oil
Model dimension	Number of grid blocks in the x-direction = 45
	Number of grid blocks in the y-direction = 19
	Number of grid blocks in the x-direction = 12
Grid type	Cartesian
Geometry type	Block Centered
Oil-Gas-Water properties	Water, oil, gas and dissolved gas
Solution type	Fully Implicit

1.2 Grid

1.2.1 Properties

Active Grid Block	(1:45, 1:19, 1:5) = 1
	(1:45, 1:19, 6:7) = 0
	(1:45, 1:19, 8:12) = 1
X Permeability	126 md
Y Permeability	126 md
Z Permeability	12.6 md
Porosity	0.215

1.2.2 Geometry

Grid block sizes	x grid block size = 100
	y grid block size = 100
	z grid block size 1:5 = 10, 6:7 = 1000, 8:12 = 20
Depth of top face	5,000 ft. at top of reservoir model

1.3 PVT

Fluid densities at surface conditions

Oil density	53.00209	lb/ft^3
Water density	62.42797	lb/ft^3
Gas density	0.03745678	lb/ft^3

Water PVT properties

Reference pressure (P_{ref})	2243	psia
Water FVF at P_{ref}	1.034847	rb/stb
Water compressibility	3.37148E-6	psi^{-1}
Water viscosity at Pref	0.2499959	cp
Water viscosibility	3.060077E-6	psi^{-1}

Live oil PVT properties (dissolved gas)

Rs (Mscf /stb)	Pbub (psia)	FVF (rb/stb)	Visc (cp)
0.020439	200.000	1.095227	1.221221
	400.000	1.082170	1.247540
	600.000	1.077853	1.288608
	800.000	1.075700	1.341135

Rs (Mscf /stb)	Pbub (psia)	FVF (rb/stb)	Visc (cp)
	1000.000	1.074411	1.403610
	1200.000	1.073552	1.475258
	1327.951	1.073139	1.525714
	1600.000	1.072480	1.644699
	1800.000	1.072123	1.742259
	2000.000	1.071837	1.848394
	2243.000	1.071559	1.989010
	2400.000	1.071409	2.086758
	2600.000	1.071244	2.219238
	2800.000	1.071103	2.360768
	3000.000	1.070981	2.511485
	3200.000	1.070874	2.671515
	3400.000	1.070779	2.840971
	3600.000	1.070695	3.019942
	3800.000	1.070620	3.208494
	4000.000	1.070553	3.406662
0.047113	400.000	1.105854	1.086154
	600.000	1.096558	1.107902
	800.000	1.091941	1.138234
	1000.000	1.089180	1.175735
	1200.000	1.087343	1.219596
	1327.951	1.086459	1.250757

Rs (Mscf /stb)	Pbub (psia)	FVF (rb/stb)	Visc (cp)
	1600.000	1.085051	1.324610
	1800.000	1.084288	1.385255
	2000.000	1.083679	1.451136
	2243.000	1.083084	1.538121
	2400.000	1.082764	1.598335
	2600.000	1.082413	1.679582
	2800.000	1.082112	1.765905
	3000.000	1.081851	1.857294
	3200.000	1.081623	1.953740
	3400.000	1.081421	2.055229
	3600.000	1.081242	2.161740
	3800.000	1.081082	2.273243
	4000.000	1.080938	2.389695
0.076789	600.000	1.117825	0.975290
	800.000	1.110358	0.994436
	1000.000	1.105903	1.019349
	1200.000	1.102943	1.049268
	1327.951	1.101520	1.070802
	1600.000	1.099254	1.122331
	1800.000	1.098027	1.164920
	2000.000	1.097047	1.211310
	2243.000	1.096091	1.272624

Rs (Mscf /stb)	Pbub (psia)	FVF (rb/stb)	Visc (cp)
	2400.000	1.095577	1.315059
	2600.000	1.095013	1.372264
	2800.000	1.094529	1.432948
	3000.000	1.094110	1.497063
	3200.000	1.093744	1.564568
	3400.000	1.093420	1.635420
	3600.000	1.093133	1.709576
	3800.000	1.092876	1.786989
	4000.000	1.092645	1.867604
0.108598	800.000	1.130822	0.885256
	1000.000	1.124416	0.902511
	1200.000	1.120168	0.923941
	1327.951	1.118127	0.939621
	1600.000	1.114880	0.977619
	1800.000	1.113122	1.009315
	2000.000	1.111719	1.044004
	2243.000	1.110352	1.089994
	2400.000	1.109616	1.121872
	2600.000	1.108809	1.164873
	2800.000	1.108117	1.210490
	3000.000	1.107518	1.258667
	3200.000	1.106994	1.309351

Rs (Mscf /stb)	Pbub (psia)	FVF (rb/stb)	Visc (cp)
	3400.000	1.106532	1.362492
	3600.000	1.106121	1.418040
	3800.000	1.105754	1.475947
	4000.000	1.105424	1.536158
0.142095	1000.000	1.144681	0.811451
	1200.000	1.138957	0.827213
	1327.951	1.136211	0.838979
	1600.000	1.131845	0.867940
	1800.000	1.129484	0.892378
	2000.000	1.127599	0.919290
	2243.000	1.125764	0.955130
	2400.000	1.124777	0.980040
	2600.000	1.123694	1.013690
	2800.000	1.122766	1.049425
	3000.000	1.121962	1.087184
	3200.000	1.121260	1.126912
	3400.000	1.120640	1.168556
	3600.000	1.120090	1.212068
	3800.000	1.119598	1.257400
	4000.000	1.119155	1.304501
0.177002	1200.000	1.159302	0.750120
	1327.951	1.155751	0.759117

Rs (Mscf /stb)	Pbub (psia)	FVF (rb/stb)	Visc (cp)
	1600.000	1.150116	0.781667
	1800.000	1.147071	0.800963
	2000.000	1.144641	0.822372
	2243.000	1.142277	0.851046
	2400.000	1.141005	0.871044
	2600.000	1.139610	0.898120
	2800.000	1.138416	0.926923
	3000.000	1.137381	0.957392
	3200.000	1.136477	0.989471
	3400.000	1.135680	1.023110
	3600.000	1.134972	1.058261
	3800.000	1.134339	1.094879
	4000.000	1.133769	1.132916
0.199981	1327.951	1.169022	0.716090
	1600.000	1.162486	0.735461
	1800.000	1.158958	0.752201
	2000.000	1.156143	0.770878
	2243.000	1.153405	0.795997
	2400.000	1.151934	0.813562
	2600.000	1.150319	0.837385
	2800.000	1.148936	0.862763
	3000.000	1.147739	0.889635

Rs (Mscf /stb)	Pbub (psia)	FVF (rb/stb)	Visc (cp)
	3200.000	1.146693	0.917947
	3400.000	1.145771	0.947649
	3600.000	1.144952	0.978695
	3800.000	1.144219	1.011040
	4000.000	1.143561	1.044641

Dry gas PVT properties (no vapourised oil)

Press (psia)	FVF (rb /Mscf)	Visc (cp)
200.000	17.240317	0.014499
400.000	8.5306875	0.014644
600.000	5.632052	0.014825
800.000	4.1864466	0.015039
1000.000	3.322295	0.015282
1200.000	2.7490737	0.015552
1327.951	2.4743644	0.015738
1600.000	2.0395984	0.016167
1800.000	1.8064563	0.016510
2000.000	1.6220474	0.016873
2243.000	1.4448151	0.017340
2400.000	1.3507989	0.017655
2600.000	1.2489387	0.018070
2800.000	1.1631155	0.018497

Press (psia)	FVF (rb /Mscf)	Visc (cp)
3000.000	1.0900717	0.018934
3200.000	1.0273509	0.019380
3400.000	0.9730655	0.019832
3600.000	0.92574174	0.020288
3800.000	0.88421332	0.020747
4000.000	0.84754667	0.021207

1.4 SCAL

Water/oil saturation functions

S_w	K_{rw}	K_{ro}
0.25	0	0.8
0.30	0.0004	0.6704
0.35	0.0033	0.5487
0.40	0.0111	0.4355
0.45	0.0263	0.3313
0.50	0.0514	0.2370
0.55	0.0889	0.1540
0.60	0.1412	0.0838
0.65	0.2107	0.0296
0.7	0.3	0
1	1	0

Gas/oil saturation functions

S_g	K_{rg}	K_{ro}
0	0	0.8
0.15	0	0.5397
0.2125	0.0008	0.4418
0.2750	0.0063	0.3506
0.3375	0.0211	0.2667
0.4000	0.0500	0.1908
0.4625	0.0977	0.1239
0.5250	0.1688	0.0675
0.5875	0.2680	0.0239
0.65	0.4	0
0.75	1	0

1.5 Initialization

1.5.1 Equilibration region 1

Equilibration data specification

Datum depth	5,000	ft
Pressure at datum depth	2243	psia
WOC depth	10000	ft
GOC depth	5000	ft

1.5.2 Equilibration region 2

Equiligration data specification

Datum depth	7150	ft

Pressure at datum depth	3200	psia
WOC depth	10000	ft
GOC depth	7150	ft

1.6 Region

Equilibration region numbers	1 at (1:19, 1:45, 1:7)
	2 at (1:19, 1:45, 8:12)
FIP region numbers	1 at (1:19, 1:45, 1:7)
	2 at (1:19, 1:45, 8:12)
PVT region numbers	1 at (1:19, 1:45, 1:12)

1.7 Schedule

1.7.1 Gas dumpflood case

1.7.1.1 Production well 1

Well specification

Well name	P1
Group	1
I location	3
J location	10
Datum depth	5000
Preferred phase	OIL
Inflow equation	STD
Automatic shut-in instruction	SHUT
Crossflow	YES
PVT property table	1

Well connection data

Well	P1
K upper	1
K lower	5
Open/shut flag	OPEN
Well bore ID	0.51042 ft.
Direction	Z

Production well control

Well	P1
Open/shut flag	OPEN
Control	LRAT
Liquid rate	1500 stb/day
BHP target	200 psia

Production well economic limits

Well	P1
Minimum oil rate	50 stb/day
Workover procedure	None
WELL End run	NO
Quantity for economic limit	RATE

1.7.1.2 Production well 2

Well specification

Well name	P2
Group	1
I location	43
J location	10

Datum depth	5000
Preferred phase	OIL
Inflow equation	STD
Automatic shut-in instruction	SHUT
Crossflow	YES
PVT property table	1

Well connection data

Well	P2
K upper	1
K lower	5
Open/shut flag	OPEN
Well bore ID	0.51042 ft.
Direction	Z

Production well control

Well	P2
Open/shut flag	OPEN
Control	LRAT
Liquid rate	1500 stb/day
BHP target	200 psia

Production well economic limits

Well	P2
Minimum oil rate	50 stb/day
Workover procedure	None
WELL End run	NO

Quantity for economic limit	RATE

1.7.1.3 Water injection well

Well specification

Well name	I1
Group	2
I location	23
J location	10
Datum depth	5000
Preferred phase	WATER
Inflow equation	STD
Automatic shut-in instruction	SHUT
Crossflow	YES
Density calculation	SEG

Well connection data

Well	I1
K upper	1
K lower	5
Open/shut flag	OPEN
Well bore ID	0.51042 ft.
Direction	Z

Well connection data

Well	I1
K upper	8
K lower	12

Open/shut flag SHUT

Well bore ID 0.51042 ft.

Direction Z

Injection well control

Well I1

Injector type WATER

Open/shut flag OPEN

Control RATE

Liquid surface rate 3000 stb/day

BHP target 3000 psia

1.7.1.4 Well action control condition

Well action condition

Action A01

Well Name P1

Quantity WWCT

Operator >

No. of times 1

Water cut 0.8

Production well control

Well P1

Open/Shut flag SHUT

End of action

Well action condition

Action A02

Well Name	P2
Quantity	WWCT
Operator	>
No. of times	1
Water cut	0.8

Production well control

Well	P2
Open/Shut flag	SHUT

End of action

Action condition

Action	AF01
Quantity	FOPR
Operator	<
Rate	0.1 stb/day

Injection well control

Well	I1
Injector Type	WATER
Open/shut flag	SHUT
Control	RATE
Liquid surface rate	0

End of action

1.7.1.5 Initiates a set of keywords to be processed

After water cut reaches 80% criteria, all the wells shut in for 60 days for perforation of gas zone through well I1.

Initiates a set of keywords to be processed

Action name	D01
Action name that triggers this action	A01
Time delay	60

Well connection data

Well	I1
K upper	8
K lower	12
Open/shut flag	OPEN
Well bore ID	0.51042 ft.
Direction	Z

Well connection data

Well	I1
K upper	1
K lower	4
Open/shut flag	SHUT
Well bore ID	0.51042 ft.
Direction	Z

Production well control

Well	I1
Open/shut flag	STOP
VFP pressure table	3

Production well control

Well	P1

Open/shut flag	OPEN
Control	LRAT
Liquid rate	1500 stb/day
BHP target	200 psia

Production well control

Well	P2
Open/shut flag	OPEN
Control	LRAT
Liquid rate	1500 stb/day
BHP target	200 psia

Production well economic limits

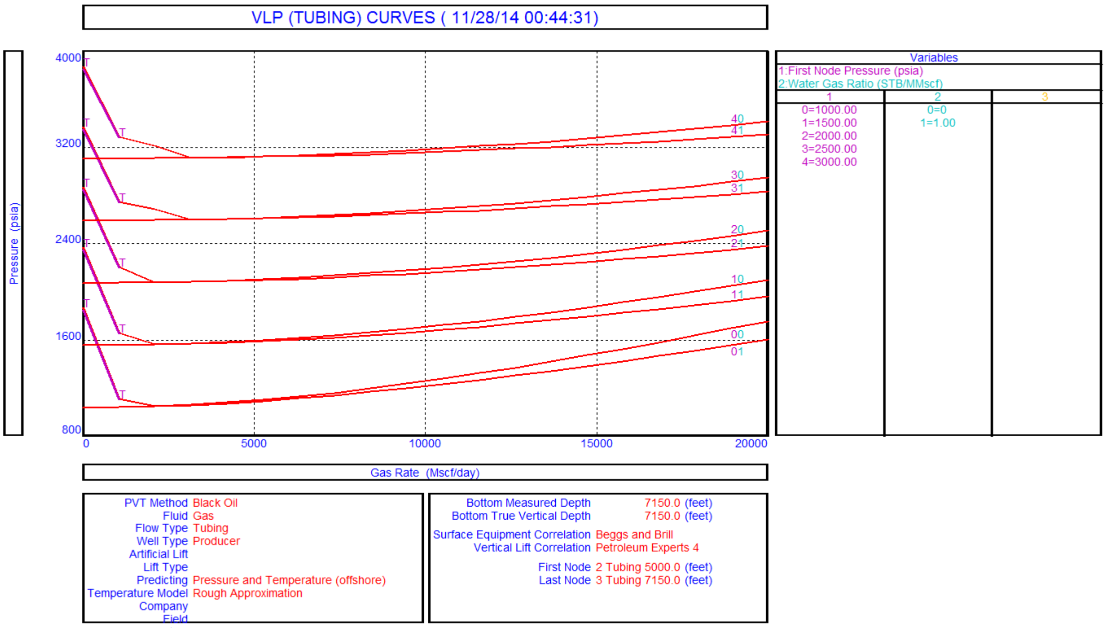
Well	P1
Minimum oil rate	50 stb/day
Workover procedure	None
WELL End run	NO
Quantity for economic limit	RATE

Production well economic limits

Well	P2
Minimum oil rate	50 stb/day
Workover procedure	None
WELL End run	NO
Quantity for economic limit	RATE

End of action

For pressure traverse curve calculation, vertical flow performance curve generated by using PROSPER is plotted as shown below.



VITA

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