EVALUATION OF DOUBLE DISPLACEMENT PROCESS VIA GAS DUMPFLOOD FROM MULTIPLE GAS RESERVOIRS

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การประเมินกระบวนการแทนที่สองครั้งโดยการแทนที่แบบถ่ายเทด้วยแก๊สจากแหล่งกักเก็บแก๊สหลายชั้น

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กระบวนการแทนที่สองครั้งโดยการแทนที่แบบถ่ายเทด้วยแก๊สจากแหล่งกักเก็บแก๊สหลายชั้นเป็นวิธีการที่มีประสิทธิภาพในการผลิตน้ำมันวิธีหนึ่งซึ่งกระทำด้วยการอัดน้ำและตามด้วยการอัดแก๊ส ทั้งนี้เพื่อเป็นการลดต้นทุนของอุปกรณ์ในการอัดแก๊ส กระบวนการถ่ายเทแก๊สได้ถูกนำมาใช้โดยใช้แก๊สจากแหล่งกักเก็บแก๊สหลายชั้นในการอัดแก๊ส ซึ่งในการศึกษานี้ได้ทำการศึกษาผลของตัวแปรต่างๆ ได้แก่ การยิงท่อกรุ อัตราไหลของของเหลว และลักษณะของแหล่งกักเก็บแก๊ส โดยอาศัยแบบจำลองแหล่งกักเก็บในการศึกษา

รูปแบบการยิงท่อกรุในชั้นแก๊สแบบพร้อมกันทุกชั้นในครั้งเดียว มีประสิทธิภาพการผลิตน้ำมันที่สูงกว่ารูปแบบการยิงท่อกรุสองครั้งในชั้นแก๊ส เพราะมีปริมาณแก๊สที่ไหลเข้าสู่ชั้นน้ำมันในช่วงเริ่มต้นของการถ่ายเทแก๊สมาก ส่วนการผลิตของเหลวด้วยอัตราการผลิตที่สูงในช่วงของการอัดน้ำช่วยให้เวลาในการผลิตน้ำมันสั้นลง แต่อย่างไรก็ตามประสิทธิภาพของการผลิตโดยรวมไม่มีความแตกต่างกันในแต่ละอัตราการผลิตที่แตกต่างกันในช่วงของการอัดน้ำ แต่อัตราการผลิตในช่วงถ่ายเทแก๊สพบว่าต้องมีค่าที่เหมาะสมเพื่อการชะลอการไหลของแก๊สสู่หลุมผลิตเพื่อให้ได้ประสิทธิภาพสูงในช่วงระยะเวลาอันจำกัดของการผลิต ส่วนการเพิ่มขึ้นของระยะระหว่างด้านล่างสุดของชั้นน้ำมันกับชั้นบนสุดของชั้นแก๊สนั้น มีผลช่วยเพิ่มประสิทธิภาพการผลิตน้ำมันขึ้นเล็กน้อยเนื่องจากความดันที่สูงในระยะนานขึ้น สำหรับปริมาณแก๊สเริ่มต้นนั้น ถ้ามีปริมาณที่มากขึ้นจะสามารถเพิ่มความดันได้นานขึ้นและช่วยให้ประสิทธิภาพการผลิตน้ำมันดีขึ้น

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Double displacement process (DDP) is an efficient method to increase oil recovery by starting with water injection and followed by gas injection. In order to reduce the cost of gas injection units, the concept of gas dumpflood is utilized by using multiple thin gas layers as the gas source. In this study, the effects of the perforation program, operational liquid rates and characteristics of gas reservoirs are evaluated using reservoir simulation.

Perforating full to base in all gas layers at the same time provides a higher recovery factor than two-batch perforation because larger amount of gas flows into the oil reservoir at early time. Higher target liquid production rates during waterfood require shorter time to produce oil than lower ones. However, there is not much difference in recovery factors obtained from different target liquid production rates during waterflood. Nevertheless, the target liquid production rate during gas dumpflood needs to be properly selected in order to delay the gas breakthrough and still get high recovery within the time constraint. Larger depth difference between the bottom of the oil zone and the top of gas reservoirs slightly increases the oil recovery factor due to higher pressure and longer support. Regarding original gas in place, higher amount of gas results in higher oil recovery owing to longer pressure support.

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List of Abbreviations

BCF	Billion cubic feet
DDP	Double displacement process
cp	Centipoise
FRAC.P.G.	Fracturing pressure gradient
ft	Feet
GOR	Gas-oil ratio
lb/ft^3	Pound per cubic foot
md	Millidarcy
OGIP	Original gas in place
ppm	Parts per million
psi	Pound per square inch
psia	Pound per square inch absolute
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

Nomenclature

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
ρ_g	Density of gas
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
Gp	Gas production total
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
i_g	Gas injection rate
i_w	Water injection rate
MMSCF/D	Million standard cubic feet per day
MMSTB	Million stock tank barrel
MSCF/STB	Thousand standard cubic feet per stock tank barrel
n_o	Corey's oil exponent
Np	Oil production total

n_g	Corey's gas exponent
n_w	Corey's water exponent
n_{go}	Corey's gas-oil exponent
R_s	Solution gas-oil ratio
S_g	Gas saturation
S_{gc}	Critical gas saturation
S_o	Oil saturation
S_{om}	Minimum residual oil saturation
S_{org}	Residual oil saturation in the gas oil system
S_{orw}	Residual oil saturation in the water-oil system
S_w	Water saturation
S_{wc},	Connate water saturation
S_{wco}	Connate water saturation
Wi	Water injection total
Wp	Water production total

CHAPTER I
INTRODUCTION

1.1 Background

Double displacement process (DDP) is one of the efficient methods to increase the oil recovery as it can take advantages of gravitational drainage to improve recovery factor. This method consists of two steps which is started by waterflooding at down-dip location and followed by immiscible gas injection at up-dip location. Conventional method of DDP is injecting water and gas from surface to the reservoir which requires surface operation units.

In order to reduce the cost of gas injection units, the concept of gas dumpflood is utilized in this study. By means of gas dumpflood, the gas layers are connected to the oil layer in order to allow gas to cross flow into the oil reservoir instead of injecting gas from the surface. Since most gas layers found in the Gulf of Thailand are thin layers, these layers need to be completed together in order to yield enough gas for dumpflood.

In this study, ECLIPSE 100 reservoir simulator is used to create a homogeneous oil reservoir located above multi-layered thin gas reservoirs to study the commingled flow of gas from multiple layers to perform gas dumpflood in a double displacement process. Design parameters which are perforation programs of gas layers, target liquid production rates during waterflood and gas dumpflood are investigated to determine oil recovery via double displacement process with limitation of gas source. The characteristics of gas reservoirs in terms of depth difference between gas layers and oil zone, gas layer thickness, and gas quantity in terms of number of gas layers are varied in order to study their effect on the performance of gas dumpflood in double displacement process.

1.2 Objectives

1. To determine the best operational parameters for gas dumpflood process from multiple gas reservoirs into a water flooded reservoir which are perforation sequence of gas layers, target liquid production rate during waterflood and target liquid production rate during gas dumpflood.
2. To investigate the effect of characteristics of gas reservoirs which are used as source for gas dumpflood. These parameters are depth difference between oil and gas reservoirs, thicknesses of gas layers and number of gas layers.

1.3 Outline of methodology

1. Construct homogeneous reservoir model for using as the base case in a double displacement process via gas dumpflood.
2. Compare the effect of perforation program on the gas layers of the base case model as follows:
    - Full to base on all layers
    - Full to base on upper layers then lower layers
    - Full to base on lower layers then upper layers
3. Select the optimum program for perforation program and use it throughout the study
4. Investigate the effects of operational parameters which are
    - Target liquid production rate during waterflood
    - Target liquid production rate during gas dumpflood
5. Determine the characteristics of gas reservoirs system that affect the recovery process as follows:
    - Thickness of gas layers (25, 50 ft)
    - Number of gas layers (2, 4 layers)
    - Depth difference between oil and gas layers (500, 1,000, 2,000 ft)
6. Analyze the results obtained from the simulation
7. Summarize the results

1.4 Thesis outline

Chapter I introduces the background and primary concepts of the thesis study on double displacement process and provides the thesis objectives and outline of methodology.

Chapter II presents some of previous works and studies which are related to double displacement process, water and gas flooding and commingled production from multi-layers.

Chapter III discusses relevant theory of double displacement process which combines the effect of water and gas flooding and commingled production.

Chapter IV describes the detailed reservoir model and reservoir properties.

Chapter V discusses the results of simulation study on both the operational parameters and system parameters.

Chapter VI concludes the results of thesis study and provides recommendation for future work.

CHAPTER II

LITERATURE REVIEW

2.1 Double displacement process

Carlson [1] studied the enhanced oil recovery performance of Hawskins field by performing gas displacement into the water invaded oil column, termed as double displacement process. From the experiment on core sample, the residual oil saturation after injecting gas is reduced to about 12 % from the previous waterflood which is 35%. After favorable result had been obtained in the laboratory, this technique of double displacement was initiated in the field test at the East fault block and showed the effectiveness of the process in a relatively short period of time. The author suggested that gas injection rate should be below the critical rate, the rate that gas completely overruns the oil column because it will lower the sweep efficiency of the double displacement process.

Ren et al. [2] performed numerical simulation and sensitivity analysis of gravity-assisted tertiary gas-injection processes. The adaptive-implicit numerical simulator, IMEX, was used throughout this study. The study investigated the effect of several parameters on double displacement process (DDP) in the stage of gas injection to optimize the amount of produced oil. Moreover, second contact water displacement (SCWD) process was performed in order to compare the results with DDP. Injection rate and production rate were found to be significant variables in controlling the formation of oil bank, shape of gas flood front, gas sweep efficiency and oil drainage. At too high rate, gas overrides oil, leaving a large amount of reservoir unswept. The reservoir dip angle increases the gravity effect which assists the performance of gas flooding process. Accurate three phase oil relative permeability and three phase capillary pressure are also important in prediction of oil production rate. The simulation on SCWD process illustrated the benefit in the high irreducible gas saturation, and this process also reduces the amount of injected gas.

Satitkanitkul [3] studied several conditions that affect double displacement process which are stopping time for water injection, injection rate, and well pattern. Water cut was used as a criteria for stopping time for water injection in order to switch to gas injection. Water cut of 60% is a good criteria to optimize oil recovery on the level of water production is not too high when compared with cases with higher water cut criteria. For the injection rate, the gas rate has to be optimized to maintain the reservoir pressure and obtain good sweep efficiency. The water rate should not be too high as this creates water underrun and should not be too low as the pressure becomes unstable. The higher dip angle of the reservoir leads to shorter production period.

Urairat [4] studied gas dumpflood in water-flooded reservoir by using a single thick gas reservoir as the gas source for dumpflood process. The optimum well arrangement was investigated for several reservoir dip angles, and the most suitable one for 15^{o} dip angle is to use a horizontal well to be the production well and a vertical well to be gas dumping well with the well distance of 4,000 ft. The water cut criteria for switching from water injection to gas dumpflood that gets the optimum results is 1% which is different from study of Satitkanitkul [3] on conventional DDP because limitation of gas source that comes from underneath gas layer. If the water cut criteria is high, gas dumpflood will not effectively sweep high volume of injected water after switching to gasflooding phase.

2.2 Waterflooding

Singhal et al. [5] proposed the screening criteria of infill wells for successful waterflooding process as follows:

- Thickness > 6 m, porosity > 10% and near well oil saturation > 50% (water-cut < 75%)
- Transmissibility (kh/μ_o) of the reservoir >0.1darcy.metre/mPa.s
- Remaining reserve over 10 years
- Appropriate completion of the well to lower the skin effect.

2.3 Gas flooding

Rinadi et al. [6] studied the improvement of oil recovery using an in-situ gas lift and gas dumpflood in North Arthit field in Gulf of Thailand for an oil well that stopped producing due to low gas oil ratio and insufficient lifting capacity. Many methods had been used to reactivate the well such as blowing down the well and re-perforation but the outcome was not successful. The simulation study shows that the implementation of in-situ gas lift will enable the well to produce the oil at high rate. Further improvement of oil production in this well can be achieved by using gas dumpflood from gas sand layer located below the oil sand layer. Another well located nearby has to be shut in to allow gas to cross flow into the oil sand and increase the reservoir pressure. The results from simulation and pilot work indicate the success of reactivating the oil well and producing oil at high rate.

Jadhawar et al. [7] studied the effect of irregular and regular well patterns. Vertical and horizontal CO_2 gas injection wells were investigated using a full 3D compositional reservoir simulation model for both secondary immiscible and tertiary miscible modes under the conditions of voidage balance, constant injection and production pressure and injection rate below the critical rate. For the comparison of well patterns, as shown in Figure 2.1. Regular well pattern of direct line drive has longer production period than irregular well patterns because the reservoir pressure declines slower and has later breakthrough time of the injected CO_2. The type of injection well (vertical versus horizontal) does not show significant difference in the result for both miscible and immiscible processes of CO_2 assisted gravitational drainage.

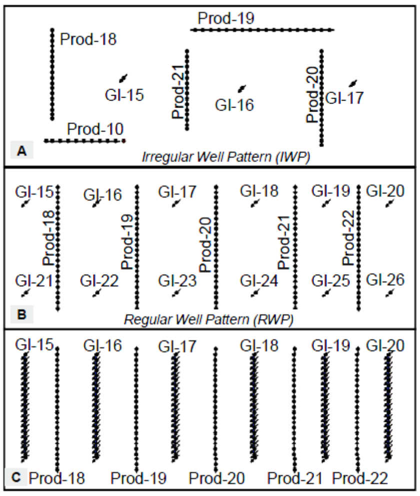


Figure 2.1 (A) Irregular well pattern (IWP) with vertical gas injection (VGI) and horizontal oil production well (HZPW); (B) Regular well pattern (RWP): Well are rearranged to from direct line drive pattern; (C) RWP: Direct line drive from horizontal wells (after Jadhawar et al. [7])

2.4 Commingled production

Al-Shehri et al. [8] studied the effect of commingled production of carbonate gas reservoir which consists of four correlative gas layers named Khuff-A, B, C and D as shown in Figure 2.2. The Khuff-B and C are major reservoirs while Khuff-A exhibits some of good quality and Knuff-D is poor quality. At early period of field development, Khuff-C is already produced. The strategy of adding Knuff-A and B in producing shows good results in extending the life of the well. Permeability, porosity and reservoir pressure are the important parameters that indicate the potential of each zone and the requirement of development plans to create the success in commingled production.

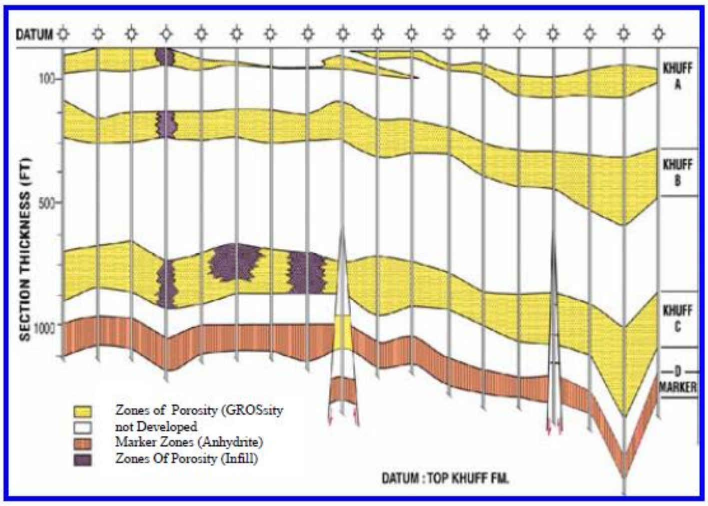


Figure 2.2 Crossection of Knuff zones (after Al-Shehri [8])

Fernando et al. [9] studied commingled production wells in Lake Maracaibo, Venezuela. This reservoir was producing at a nearly abandonment rate and was aimed to recover by commingled production process. Prior to implementing this method in real production well, a pilot test was performed to see the benefit of commingled production and evaluate the proposed method for calculating IPR. The pilot test shows good result from commingled production which is the increment of the production rate and production capacity. In addition, combining two zones with large difference in water cut might create an unsatisfied result because the water increases the hydraulic column. The shape of the composite IPR curve depends on both individual IPR and the depth of commingled zone.

CHAPTER III

THEORY AND CONCEPT

Double displacement process generally contains two main steps in oil recovery process: water injection followed by gas injection. This process takes the advantage of gravitational effects by flooding water from the down-dip side. As the water is injected down-dip, it pushes the oil toward the production well located up-dip until the water cut reaches the constrained criteria. Then, we switch to the gas flooding process from the up-dip side of the reservoir. Gas prefers to stay on the top side and pushes the oil toward the down-dip well, which is now a production well. The schematic of DDP is illustrated in Figure 3.1.

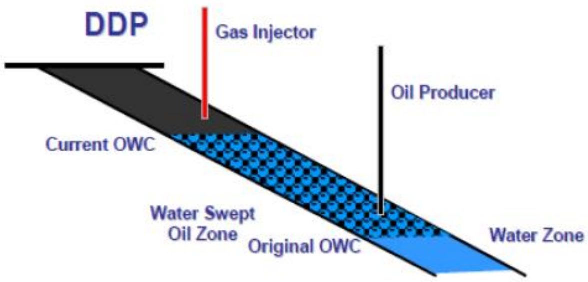


Figure 3.1 Double displacement process (after lepski [10])

3.1 Waterflooding

Displacing efficiency of waterflooding is generally defined in term of fractional flow equation which is provided by Leverett [11]. Equation 3.1 is the fractional flow of water in water displacement.

$$f_w = \frac{1 - \left(\dfrac{0.001127(kk_{ro})A}{\mu_o i_w}\right)\left[0.0433(\rho_w - \rho_o)\sin(\alpha)\right]}{1 + \dfrac{k_{ro}}{k_{rw}}\dfrac{\mu_w}{\mu_o}} \qquad (3.1)$$

where

f_w = fractional of water, bbl/bbl

k = absolute permeability, md

k_{ro} = relative permeability to oil, md

k_{rw} = relative permeability to water, md

μ_o = viscosity of oil, cp

μ_w = viscosity of water, cp

ρ_o = density of oil, g/cm^3

ρ_w = density of water, g/cm^3

A = cross-sectional area, ft^2

i_w = water injection rate, bbl/day

α = dip angle

$sin(\alpha)$ = positive for up-dip flow, negative for down-dip flow

Figure 3.2 shows the effect of water displacing oil up-dip (injection well located at down-dip), without dip and down-dip (injection well located up-dip). We obtain more efficient performance with down-dip injection. Equation 3.1 can be rewritten in simplified form to determine the effect of dip angle and injection rate.

$$f_w = \frac{1 - \left[X \frac{\sin(\alpha)}{i_w} \right]}{1 + Y} \qquad (3.2)$$

where

$$X = \frac{(0.001127)(0.433)(kk_{ro})A(\rho_w - \rho_o)}{\mu_o}$$

$$Y = \frac{k_{ro}}{k_{rw}} \frac{\mu_w}{\mu_o}$$

Since other parameters are treated as constant, the fractional flow curve will depend on the injection rate. When the oil is displaced up-dip, a lower injection rate is desirable because sin(α) is positive when the flow is from up-dip. So, decreasing injection rate will decrease fractional flow curve which indicates better displacement efficiency. This requirement is in opposite direction with down-dip flow which requires high injection rate. [11]

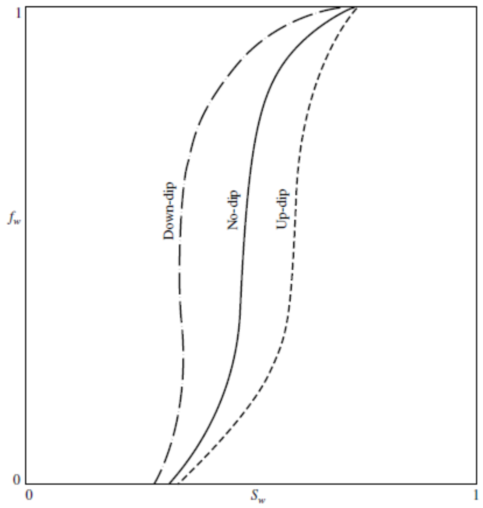


Figure 3.2 Effect of dip angle on fractional flow curve at the same injection rate (after Ahmed [11])

3.2 Immiscible gas flooding

Immiscible gas flooding is operated at low pressure which is not high enough to generate the miscible phase. The behavior of flooding process can be described in fractional flow equation for gas/oil system as follows [11]:

$$f_g = \frac{1 - \left(\dfrac{0.001127(kk_{ro})A}{\mu_o i_g}\right)\left[0.433(\rho_g - \rho_o)\sin(\alpha)\right]}{1 + \dfrac{k_{ro}}{k_{rg}}\dfrac{\mu_g}{\mu_o}} \tag{3.3}$$

where

i_g = gas injection rate, bbl/day

μ_g = gas viscosity, cp

ρ_g = gas density, g/cm^3

The dip angle of the formation attributes in improving gas flooding process as showed in Figure 3.3 in term of fractional flow which area under the curves represents the gas-invaded zone, if permeability is high enough and withdrawal rate does not exceed gravity-stable conditions. From Equation 3.3, as increasing of the dip angle (α), the fractional flow will increase and results in better sweep efficiency.

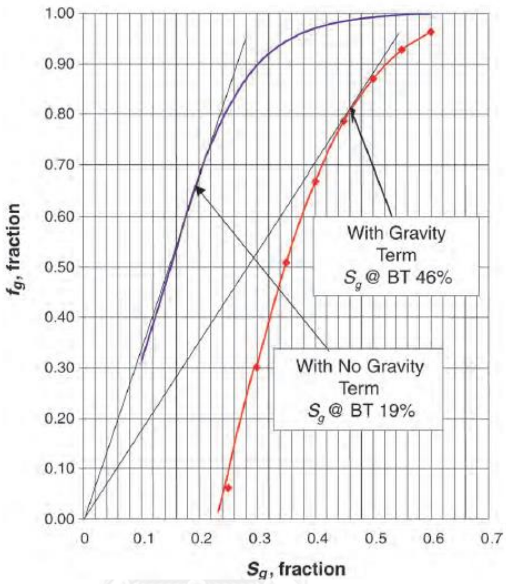


Figure 3.3 Effect of gravity on gas/oil fractional flow curve (after Lake [12])

3.3 Commingled production

Production of reservoir fluid from multi-layered zones is mostly applied when each layer produces at low flow rate. In some cases, commingled production is applied for other functions such as [9]

- Reservoir production is close to economic limit.
- Delaying water or gas breakthrough without reducing production rate in water or gas drive reservoir.
- Controlling the fluid velocity without reducing production rate in order to avoid sand production.
- Requiring higher production rate.
- Accelerating the recovery of remaining reserves which leads to increase in NPV.

- The economic life of reservoir is extended by improvement of lifting efficiency.

There are some limitations that have to be taken into account when planning to produce with many layered zones:

- Fluid may not compatible with other zones. So, we should perform fluid compatibility test before starting comingled production.
- Different pressures for separate zones might initiate cross flow within the well.
- Requiring close monitoring while producing with commingled system.
- Difficult to allocate the production from the individual zones.

3.4 Fracturing pressure

Injection of fluid to the reservoir should operate at pressure below the fracturing pressure to avoid creating fracture in the reservoir. The fracturing pressure of one of the field in Gulf of Thailand is estimated by the following correlation [13].

$$\text{Fracture Pressure (bar)} = \frac{\text{Frac.P.G.} \times \text{TVD}}{10.2} \tag{3.4}$$

and

$$\text{Frac.P.G.} = 1.22 + (\text{TVD} \times 1.6 \times 10^{-4}) \tag{3.5}$$

where

Frac.P.G. = fracturing pressure gradient, bar/meter

TVD = true vertical depth below rotary table, meter

3.5 Relative permeability

Relative permeability is the ability of the porous system to conduct one fluid when more than one fluid are present. These flow properties are the composite effect of pore geometry, wettability, fluid distribution, and saturation history. The relative permeability is the ratio of effective permeability of each phase to the absolute permeability at a specific saturation. In the case that relative permeability data from actual samples from the reservoir are not available, the relative permeability can be obtained from correlations.

3.5.1 Corey's method

Corey [11] [14] proposed simple mathematical expressions for generating the relative permeability data of the gas-oil and water-oil systems. The approximation is good for drainage processes.

In ECLIPSE reservoir simulator, relative permeability curves are calculated by Corey's correlation.

For oil-water system

$$k_{ro} = (k_{ro})_{S_{wc}} \left[\frac{1 - S_w - S_{orw}}{1 - S_{wc} - S_{orw}} \right]^{n_o} \tag{3.6}$$

$$k_{rw} = (k_{rw})_{S_{orw}} \left[\frac{S_w - S_{wc}}{1 - S_{wc} - S_{orw}} \right]^{n_w} \tag{3.7}$$

For oil-gas system

$$k_{ro} = (k_{ro})_{S_{gc}} \left[\frac{1 - S_g - S_{wc} - S_{org}}{1 - S_{gc} - S_{wc} - S_{org}} \right]^{n_{go}} \tag{3.8}$$

$$k_{rg} = (k_{rg})_{S_{wc}} \left[\frac{S_g - S_{gc}}{1 - S_{wc} - S_{org} - S_{gc}} \right]^{n_g} \tag{3.9}$$

where

S_g = gas saturation

S_w = water saturation

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

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

S_{gc} = critical gas saturation

S_{wc} = connate water saturation

k_{ro} = relative permeability to oil

k_{rg} = relative permeability to gas

k_{rw} = relative permeability to water

$(k_{ro})_{Swc}$ = oil relative permeability at connate water saturation

$(k_{ro})_{Sgc}$ = oil relative permeability at critical gas condensate

$(k_{rw})_{Sorw}$ = water relative permeability at the residual oil saturation

$(k_{rg})_{Sgc}$ = gas relative permeability at the critical gas saturation

n_o = Corey's oil exponent

n_g = Corey's gas exponent

n_w = Corey's water exponent

n_{go} = Corey's gas-oil exponent

3.5.2 Three-phase relative permeability

Three-phase relative permeability requires a complex method to obtain from experiments. Therefore, the general method to calculate it is based on two-phase relative permeability.

3.5.2.1 Stone's first model

Stone's technique requires two sets of two-phase data which are water-oil and gas-oil [15]. Then, we interpolate between these two sets of two-phase data to get the three phase relative permeability. This model defines the normalized fluid saturation by treating connate water and irreducible residual oil as immobilized fluid.

$$S_o^* = \frac{S_o - S_{om}}{(1 - S_{wc} - S_{om})} \qquad \text{for } (S_o \geq S_{om}) \tag{3.10}$$

$$S_w^* = \frac{S_w - S_{wc}}{(1 - S_{wc} - S_{om})} \qquad \text{for } (S_w \geq S_{wc}) \tag{3.11}$$

Note that Sg* + Sw* + So* = 1

The oil relative permeability to the oil saturation can be written as

$$k_{ro} = S_o^* \beta_w \beta_g \tag{3.12}$$

The two multipliers β_w and β_g can be calculated from

$$\beta_w = \frac{k_{row}}{1 - S_w^*} \quad \text{(oil and water phase data)} \tag{3.13}$$

$$\beta_g = \frac{k_{rog}}{1 - S_g^*} \quad \text{(gas and oil phase data)} \tag{3.14}$$

where

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

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

S_{om} = minimum oil saturation

3.5.2.2 Stone's second model

This model is modified from the first model to improve the estimation of three-phase relative permeability, and it also yields better agreement with the experiment data. The equation of this model is defined as [16]

$$k_{ro} = k_{rocw}\left[\left(\frac{k_{row}}{k_{rocw}} + k_{rw}\right)\left(\frac{k_{rog}}{k_{rocw}} + k_{rg}\right) - k_{rw} - k_{rg}\right] \tag{3.15}$$

where

k_{rocw} = oil relative permeability in the presence of connate water only

3.5.2.3 ECLIPSE's model

This model is the default model in ECLIPSE simulation program. It assumes that gas and water are completely segregated, except that water saturation in the gas zone is equal to the connate saturation. The block average saturations are S_o, S_w and S_g ($S_o + S_w + S_g = 1$) [17].

The oil relative permeability is then given by

$$k_{ro} = \frac{S_g k_{rog} + (S_W - S_{wco}) k_{row}}{S_g + S_w - S_{wco}} \tag{3.10}$$

where

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

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

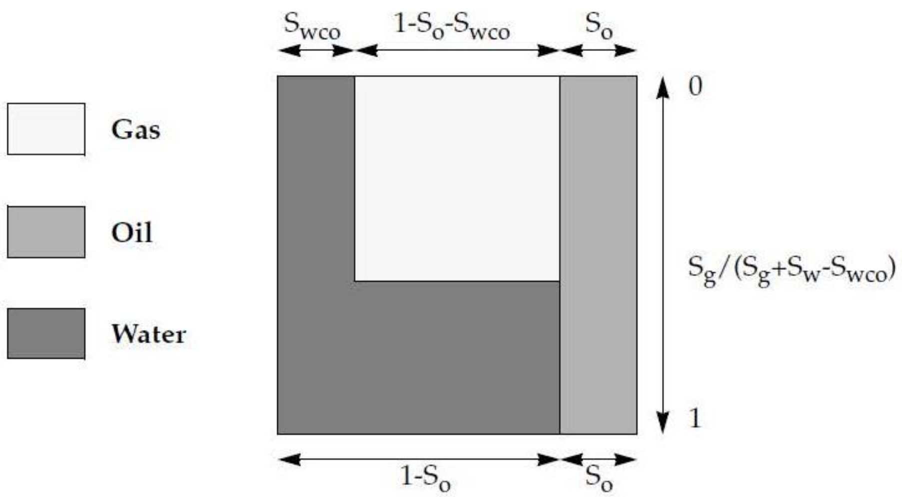


Figure 3.4 The default three-phase oil relative permeability model assumed by ECLIPSE [17]

CHAPTER IV
RESERVOIR SIMULATION MODEL

The reservoir model was constructed via ECLIPSE100 reservoir simulator with homogeneous properties in order to consider the process of gas dumpflood from multi-gas reservoirs to a water flooded oil reservoir. In this chapter, the grid section, PVT properties, relative permeability model and well schedule are described. More details of each input parameter are provided in Appendix A.

4.1 Grid section

The reservoir model is constructed based on black oil simulation model by using Cartesian coordinate and corner point to create inclined reservoirs with 15^{o} dip angle. The base case model consists of one oil layer located at 5,000 ft and 4 layers of gas which are separated by an impermeable layer in between as shown in Figure 4.1. The detail of grid section is tabulated in Table 4.1 and Table 4.2.

Table 4.1 Grid parameters of oil reservoir

	Parameters	Oil reservoir	Units
1.	Number of grid blocks	45×19×10	grid blocks
2.	Size of reservoir	4,500×1,900×50	ft
3.	Effective porosity	21.5	%
4.	Horizontal permeability	126	mD.
5.	Vertical permeability	12.6	mD.
6.	Top of reservoir (up-dip)	5,000	ft
7.	Top of reservoir (down-dip)	6,165	ft
8.	Datum depth	5,000	ft
9.	Initial pressure at datum depth	2,243	psia.
10.	Reservoir temperature	252	°F
11.	Initial water saturation	25	%

Table 4.2 Grid parameters of gas reservoirs

Parameters	Gas reservoirs				Units
	1	2	3	4	
1. Number of grid blocks	45×19×10	45×19×10	45×19×10	45×19×10	grid blocks
2. Size of reservoir	4,500×1,900×25	4,500×1,900×25	4,500×1,900×25	4,500×1,900×25	ft^3
3. Effective porosity	21.5	21.5	21.5	21.5	%
4. Horizontal permeability	126	126	126	126	mD.
5. Vertical permeability	12.6	12.6	12.6	12.6	mD.
6. Top of reservoir (up-dip)	6,050	6,175	6,300	6,425	ft.
7. Top of reservoir (down-dip)	7,215	7,340	7,465	7,590	ft.
8. Datum depth	6,050	6,175	6,300	6,425	ft.
9. Reservoir temperature	285	289	293	297	°F
10. Initial pressure at datum depth	2,711	2,766	2,822	2,878	psia.
11. Initial water saturation	25	25	25	25	%

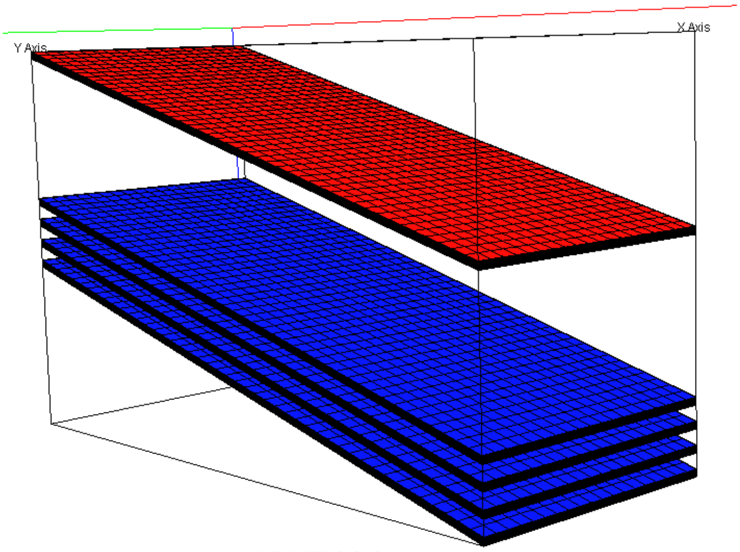


Figure 4.1 Reservoir model

4.2 Pressure-Volume-Temperature (PVT) properties section

PVT properties are generated by using ECLIPSE correlation set 2 for the fluid that is contained in each layer (oil for the topmost layer and gas for the remaining 4 layers). The fluid properties used to generate PVT properties are provided in Table 4.3. The generated data are provided in Table 4.4 and Table 4.5. Live oil and dry gas properties for both oil and gas layers are illustrated as a function of pressure in Figure 4.2 to Figure 4.7.

Table 4.3 Oil and gas fluid properties

	Parameters	Oil reservoir	Gas reservoir 1	Gas reservoir 2	Gas reservoir 3	Gas reservoir 4	Unit
1.	Oil gravity	30	-	-	-	-	°API
2.	Gas gravity	0.8	0.6	0.6	0.6	0.6	
3.	Bubble point pressure	2,002	-	-	-	-	psia
4.	Water salinity	2,500	2,500	2,500	2,500	2,500	ppm

Table 4.4 Water PVT properties

Properties	Oil reservoir	Gas reservoir				Units
		1	2	3	4	
Reference pressure (Pref)	2,243	2,711	2,766	2,822	2,878	psia
Reservoir temperature	252	285	289	293	297	^{o}F
Water FVF at Pref	1.043	1.057	1.059	1.061	1.063	rb/stb
Water compressibility	3.539E-6	3.855E-6	3.899E-6	3.944E-6	3.990E-6	/psi
Water viscosity at Pref	0.226	0.195	0.192	0.189	0.186	cp
Water viscosibility	3.386E-6	4.679E-6	4.858E-6	5.039E-6	5.222E-6	/psi

Table 4.5 Fluid densities at surface condition

Properties	Oil reservoir	Gas reservoir				Units
		1	2	3	4	
Oil density	54.643	-	-	-	-	lb/cuft
Water density	62.428	62.428	62.428	62.428	62.428	lb/cuft
Gas density	0.050	0.037	0.037	0.037	0.037	lb/cuft

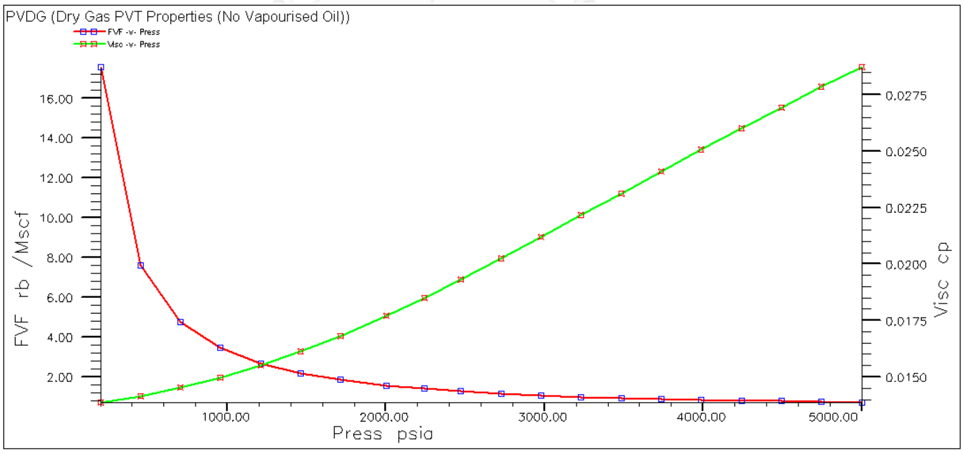


Figure 4.2 Dry gas PVT properties (No vaporized oil) of oil reservoir

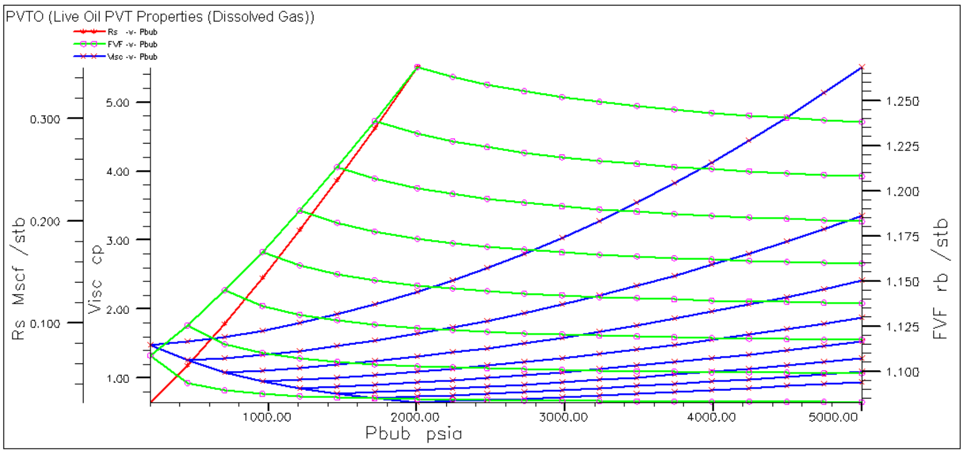


Figure 4.3 Live oil PVT properties in oil reservoir (dissolved gas)

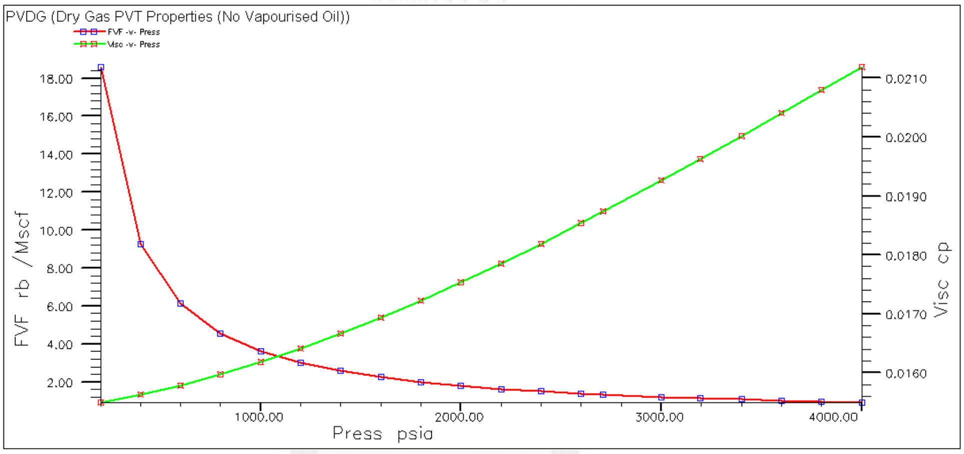


Figure 4.4 Dry gas PVT properties (No vaporized oil) of the first gas reservoir

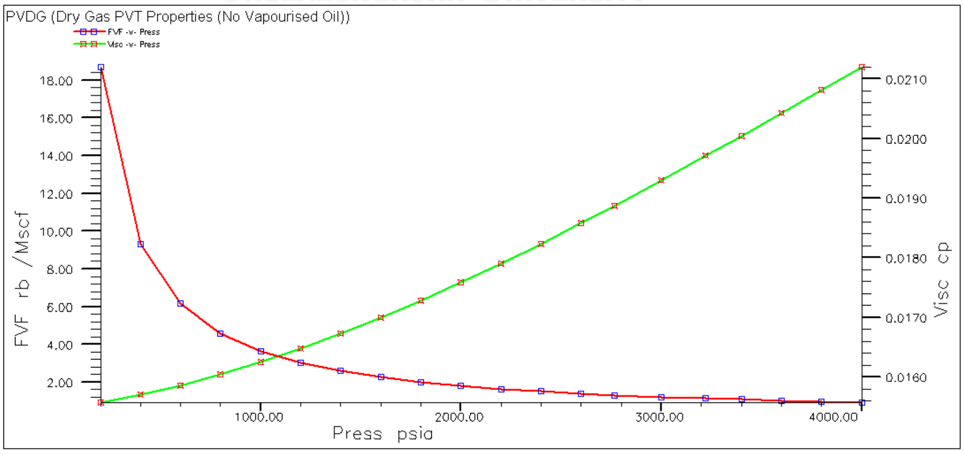


Figure 4.5 Dry gas PVT properties (No vaporized oil) of the second gas reservoir

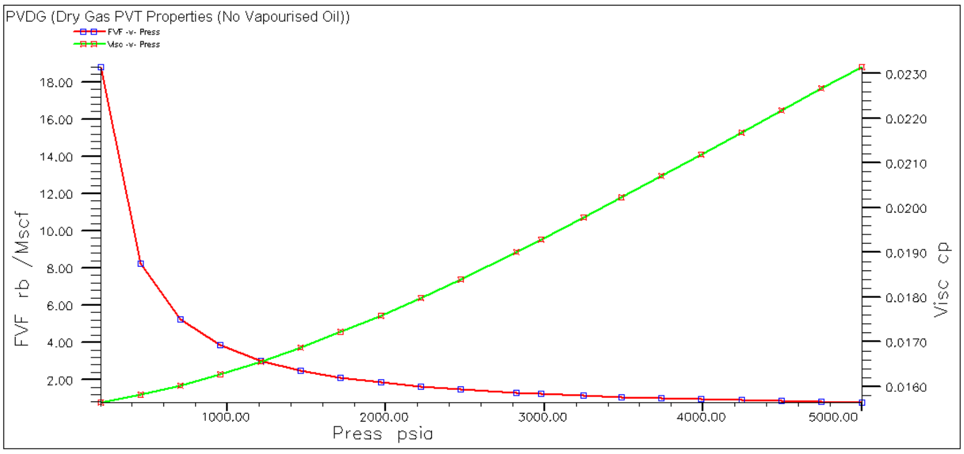


Figure 4.6 Dry gas PVT properties (No vaporized oil) of the third gas reservoir

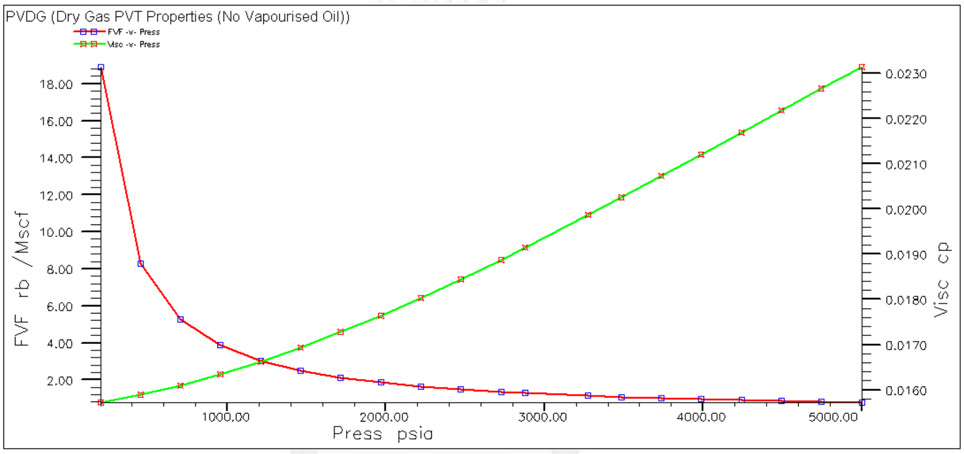


Figure 4.7 Dry gas PVT properties (No vaporized oil) of the fourth gas reservoir

4.3 Special Core Analysis (SCAL) section

Three-phase relative permeability of this reservoir system is generated by ECLIPSE default model by using two sets of relative permeability which are oil-water and gas-oil at connate water. The required data for the correlation are determined from the study of a reservoir in Gulf of Thailand as provided in Table 4.6. Relative permeability data of oil-water and gas-oil system are tabulated in Table 4.7 and Table 4.8 and also plotted in Figure 4.8 and Figure 4.9.

Table 4.6 Required data for Corey's correlation

Corey Water	2	Corey Gas	2	Corey Oil/Water	2
S_{wmin}	0.25	S_{gmin}	0	Corey Oil/Gas	2
S_{wcr}	0.25	S_{gcr}	0.15	S_{org}	0.1
S_{wi}	0.25	S_{gi}	0.15	S_{orw}	0.3
S_{wmax}	1	$K_{rg}(S_{org})$	0.4	$K_{ro}(S_{wmin})$	0.8
$K_{rw}(S_{orw})$	0.3	$K_{rg}(S_{gmax})$	0.4	$K_{ro}(S_{gmin})$	0.8
$K_{rw}(S_{wmax})$	1				

Table 4.7 Water and oil relative permeability

S_w	K_{rw}	K_{ro}
0.25	0	0.8
0.3	0.003704	0.632099
0.35	0.014815	0.483951
0.4	0.033333	0.355556
0.45	0.059259	0.246914
0.5	0.092593	0.158025
0.55	0.133333	0.088889
0.6	0.181481	0.039506
0.65	0.237037	0.009877
0.7	0.3	0
1	1	0

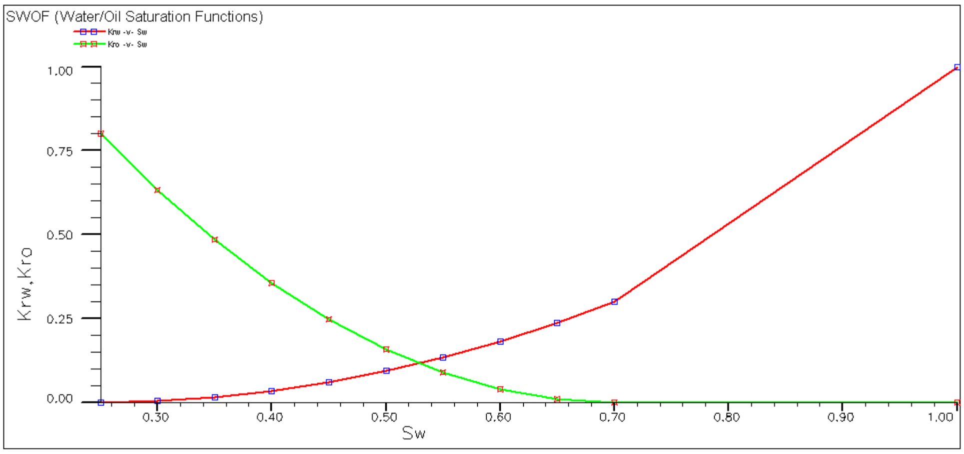


Figure 4.8 Water/Oil saturation function

Table 4.8 Gas and oil relative permeability

S_g	K_{rg}	K_{ro}
0	0	0.8
0.15	0	0.473373
0.2125	0.00625	0.362426
0.275	0.025	0.266272
0.3375	0.05625	0.184911
0.4	0.1	0.118343
0.4625	0.15625	0.066568
0.525	0.225	0.029586
0.5875	0.30625	0.007396
0.65	0.4	0
0.75	0.8	0

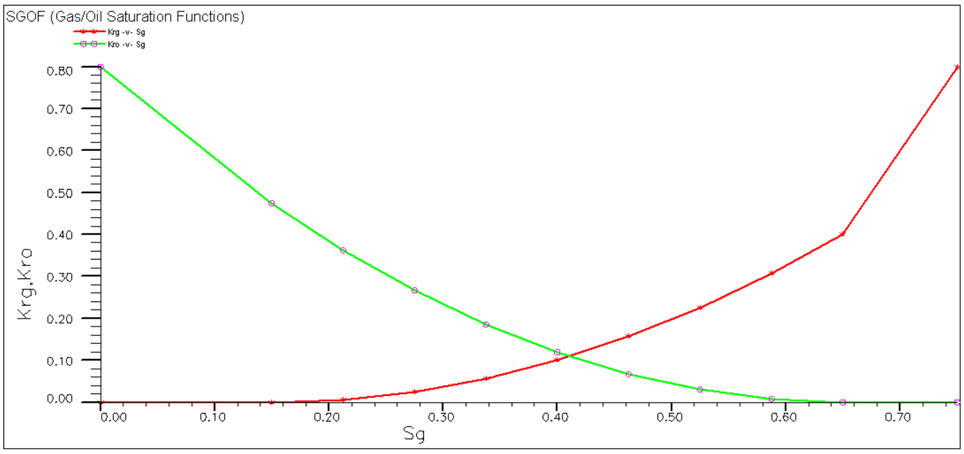


Figure 4.9 Gas/Oil saturation function

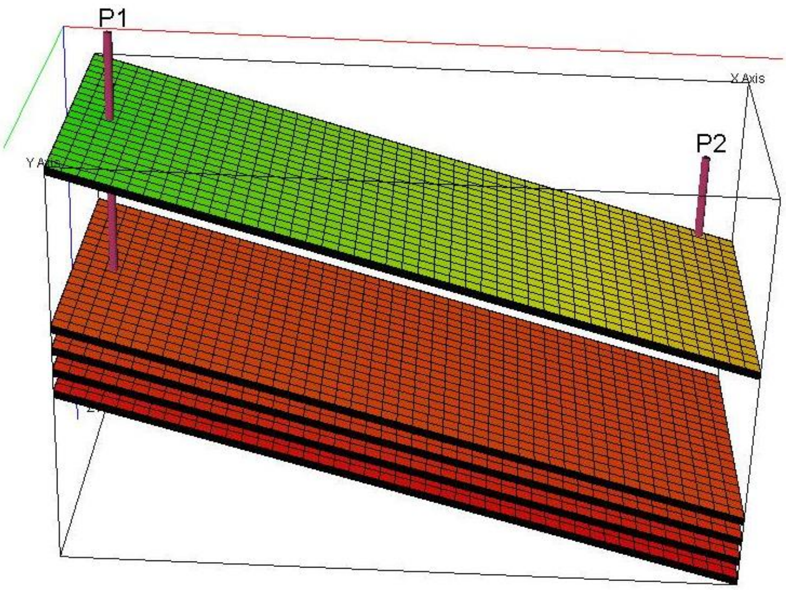
4.4 Well schedule

According to Urairat's study of evaluation of gas dumpflood in water flooded reservoir [4], the optimum well arrangement for DDP in an oil reservoir with 15^{o} dip angle is two wells: down-dip water injection using horizontal well and up-dip gas dumpflood using vertical well. Thus, this well arrangement is then chosen for this study. Table 4.9 and Figure 4.10 depict the location of the two wells in the simulation model.

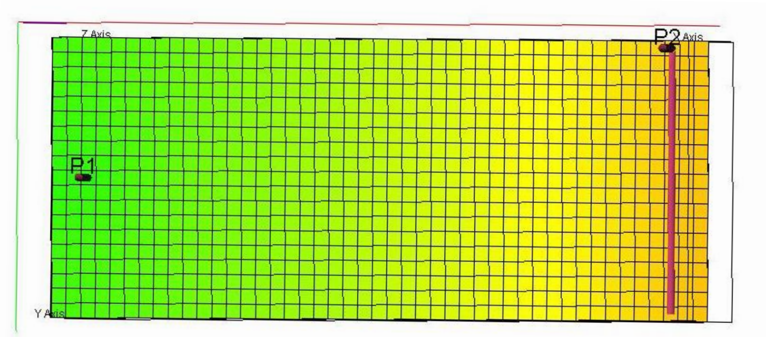
In this study, both production and injection wells have wellbore diameter of 6-1/8 inches and tubing diameter of 3-1/2 inches with 2.992-inch inner diameter. The down-dip water injection well which is horizontal well is fully perforated along the horizontal length, and this well will be converted to a production well during gas dumpflood process. For the vertical production well located up-dip, full perforation along the entire thickness of oil reservoir is initially applied. The perforation of underlying gas reservoirs in order to allow gas to cross flow during gas dumpflood process is carried out when the water cut of the producer reaches 1%, as suggested in Urairat's study [4]. In addition, multi-segment keywords are applied in the gas dumping well in order to get more accurate calculation of pressure drop along the tubing segments by using vertical flow performance which is generated by PROSPER software. Production and injection constraints are summarized in Table 4.10. Details of well scheduled are described in Appendix A.

Table 4.9 Well location

Well	I	J	K	Well type
P1	3	10	1-10, 12-21, 23-32, 34-43, 45-54	Vertical well
P2	43	1-19	10	Horizontal well



Side view



Top view (at bottom layer of oil zone to show location of the horizontal well)

Figure 4.10 3D model of oil and multi-layers of gas reservoirs

Table 4.10 Constrained parameters for production and injection wells

	Parameters	Values	Units
1.	Economic oil rate for production well	100	STB/D/Well
2.	Maximum water cut for production well	0.9	
3.	BHP control for production well	500	psia
4.	BHP target for water injection well (based on fracturing pressure of 4,012 psia)	3,900	psia
5.	BHP target for gas dumpflood well (based on fracturing pressure of 3,220 psia)	3,100	psia
6.	Concession period	30	years

4.5 Thesis methodology

The details of thesis methodology is described as follows:

1. Construct a homogeneous reservoir model with 15° dip angle in ECLIPSE 100 as shown in Figure 4.1.
2. Perform simulation of double displacement process via gas dumpflood starting with conventional wateflood in which water is injected from the surface. After the water cut reaches the criteria of 1%, gas dumpflood is performed by using gas from multiple gas reservoirs.
3. Investigate the effect of perforation sequence on the gas reservoirs that are used as the gas source which are:
    - Full to base on all layers
    - Full to base on upper layers then lower layers
    - Full to base on lower layers then upper layers

After that, use the optimum perforation program throughout this study to determine the effect of other parameters.

4. Perform the simulation for different target liquid production rates during waterflood and production rates during gas dumpflood as follows:

Liquid production rate during waterflood (STB/D)	Liquid production rate during gas dumpflood (STB/D)
1,500	1,500
	1,000
	500
3,000	1,500
	1,000
	500
4,500	1,500
	1,000
	500

The simulation runs are performed for the following gas reservoirs characteristics:

- 2 layers of 25-ft gas reservoirs
- 4 layers of 25-ft gas reservoirs
- 2 layers of 50-ft gas reservoirs
- 4 layers of 50-ft gas reservoirs

5. Use the optimum target liquid production rates during waterflood and target liquid production rate during gas dumpflood to simulate for different reservoir models shown in No. 4 in order to investigate the effect of depth difference between the bottommost of oil and the topmost of gas layers (500 ft, 1,000 ft, and 2,000 ft) and original gas in place due to difference in gas layer thickness and number of gas layers.
6. Evaluate and analyze the results.

CHAPTER V
SIMULATION RESULTS AND DISSCUSSION

This chapter discusses the results of performing gas dumpflood in water flooded reservoir using the model described in Chapter IV. The base case of double displacement process via gas dumpflood is constructed in order to illustrate its performance in details. Then, the effect of perforation sequence of the gas reservoirs is determined for selecting the most suitable perforation program for gas dumpflood from multi-layer gas reservoirs. After that, effects of target liquid production rates before and during gas dumpflood are discussed. In addition, results for different characteristics of gas layers in term of number of gas layers, gas layer thicknesses and depth from the oil reservoir are discussed.

5.1 Base case

The model containing four gas layers having thickness of 25 ft each and 1,000 ft depth below the oil reservoir is selected to perform gas dumpflood into water flooded reservoir in order to illustrate the process of the proposed method. The operation criteria is summarized in Table 5.1.

Table 5.1 Operation criteria for gas dumpflood into water flooded reservoir base case

Stage	Well P1 (up-dip)	Well P2 (down-dip)
Water injection	Producer	Water injector
Water cut is over 1%	Shut in for 30 days	Shut in for 30 days
Gas dumpflood	Gas dumpflood well	Producer

At the beginning, water is injected at the down-dip well while oil is produced from the up-dip well. Target water injection rate and liquid production rate are kept the same at 3,000 STB/D during the initial waterflooding (see Figure 5.1) until the water cut of the up-dip producer is over 1% as shown in Figure 5.2. Then, both wells are shut for 30 days before dumping gas from underlying gas reservoirs by perforating all four gas reservoirs full to base, allowing the gas to cross flow to the oil layer. The gas flow rates of the upper layers initially have negative sign as shown in Figure 5.3 because of gas cross flowing from deeper gas layers. This happens because the initial pressures of deeper gas reservoirs are high due to formation pressure gradient. When gas flows upwards, its pressure becomes smaller due to hydrostatic, friction and acceleration losses. However, the pressure of gas coming from deeper location is still higher than the pressure of the upper gas reservoirs. Thus, this gas flows into the upper gas reservoirs. This cross-flow happens for only a short period of time until pressure of the gas reservoirs are in equilibrium. After this short periods, the gas flow rates from all gas reservoirs are positive, meaning that gas flows out of these reservoirs (into the oil reservoir). The pressure of oil reservoir dramatically declines as gas starts to flow out of the oil reservoir which indicates the gas breakthrough at the production well.

After gas dumpflood is started, pressure of the oil zone initially increases as gas flows from the gas reservoirs but later declines due to production of liquid at down-dip of the oil reservoir while pressures of the gas reservoirs continually decline as gas flows out of the reservoirs as shown in Figure 5.4. At the early period of gas dumpflood oil production rate is low because injected water flows back to the down-dip well. During the gas dumpflood, target liquid production rate is kept at 1,000 STB/D. When gas breaks through the down-dip well, the oil production rate decreases slightly and then slightly increases again while the liquid production rate remains constant at its target rate. As gas cones towards the producer (see Figure 5.6 c), d), g)), it blocks the flow of oil into the well, causing the oil rate to drop slightly. As oil rate drops, water can flow better into the well. Thus, there is a slight increase in water production. Soon after that, oil rate increases again because new slugs of gas push the oil towards the producer as shown in Figure 5.6 f). As the oil rate increases, water production decreases. At around year 24, the oil rate and water rate both decline due to decline in reservoir pressure. At this time, gas-oil ratio still has an increasing trend. However, at the end, gas-oil ratio finally decreases due to low value of gas formation volume factor at low reservoir pressure (low ability for reservoir gas to expand at surface conditions).

A sharp increase of gas production rate at around year 20 in Figure 5.5 is due to gas breakthrough, causing the decline of oil reservoir pressure. Figure 5.6 shows that the gas overrides and cones into the production well as there is high gas saturation around the production well when gas breaks through.

From the results shown in Table 5.2, the recovery from this recovery method is 79.14% within 28 years of production. Gas production has reached 15.787 BCF with 4.211 MMSTB of water production and 4.289 MMSTB of water injection. This recovery method will be evaluated on the operation parameters and the effects of gas reservoirs in following sections to verify the optimum recovery criteria.

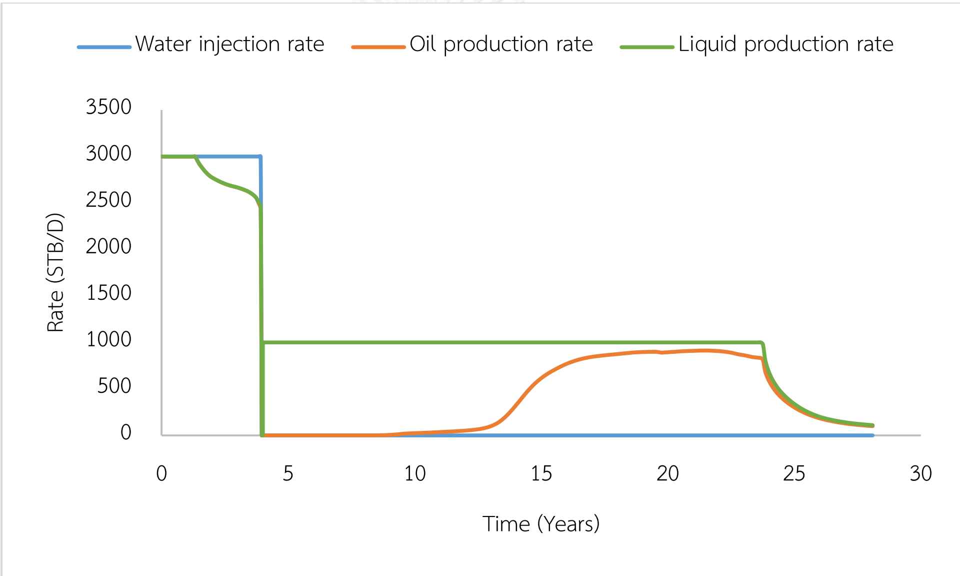


Figure 5.1 Liquid production rate, oil production rate and water injection rate under base case condition

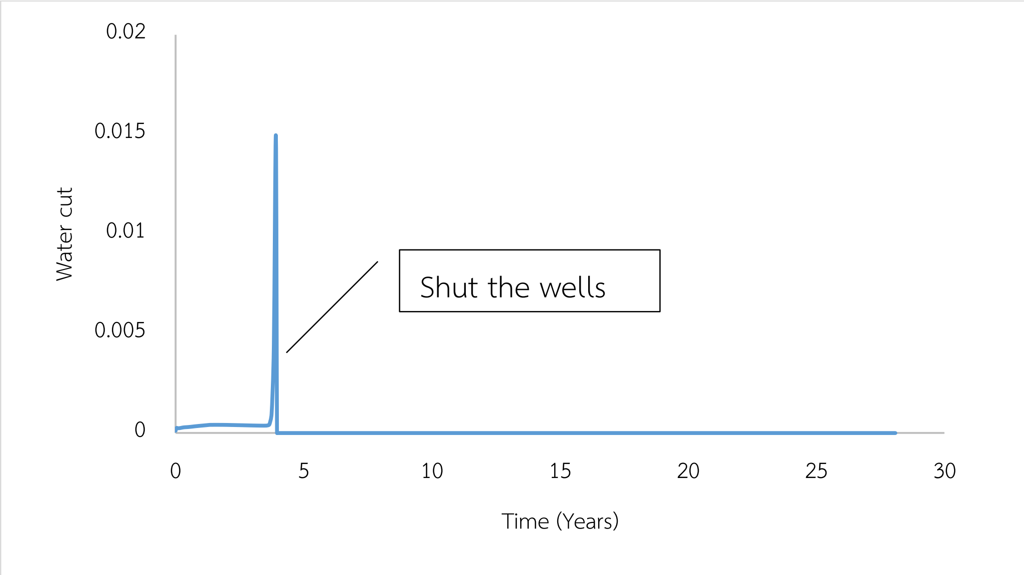


Figure 5.2 Water cut of up-dip oil production well

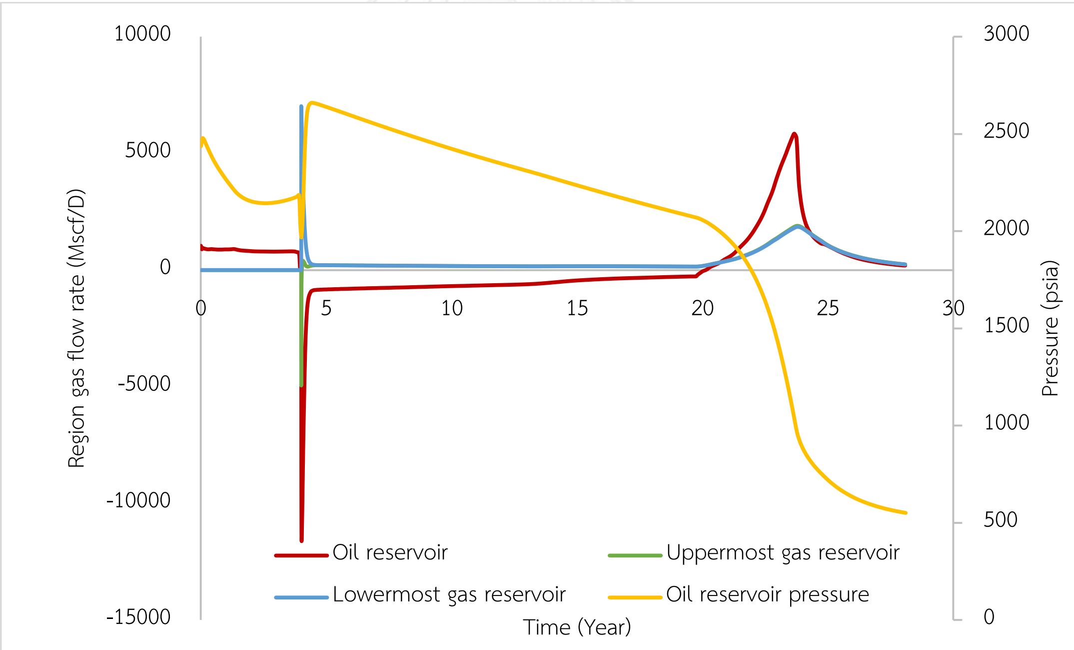


Figure 5.3 Region gas flow rate of each layer and oil reservoir pressure under base case condition

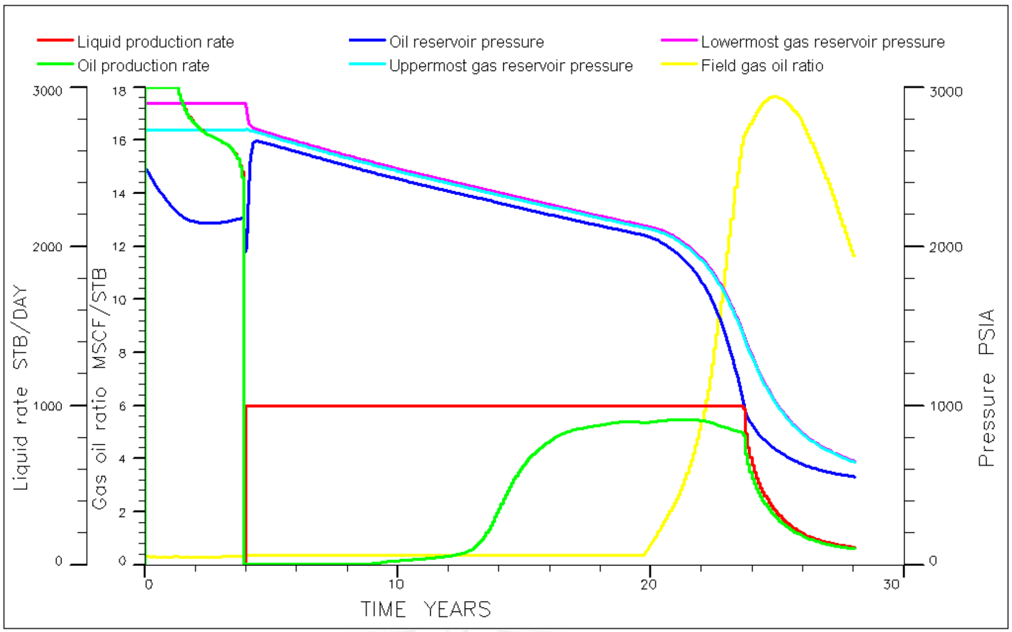


Figure 5.4 Region pressure of each layer under base case condition

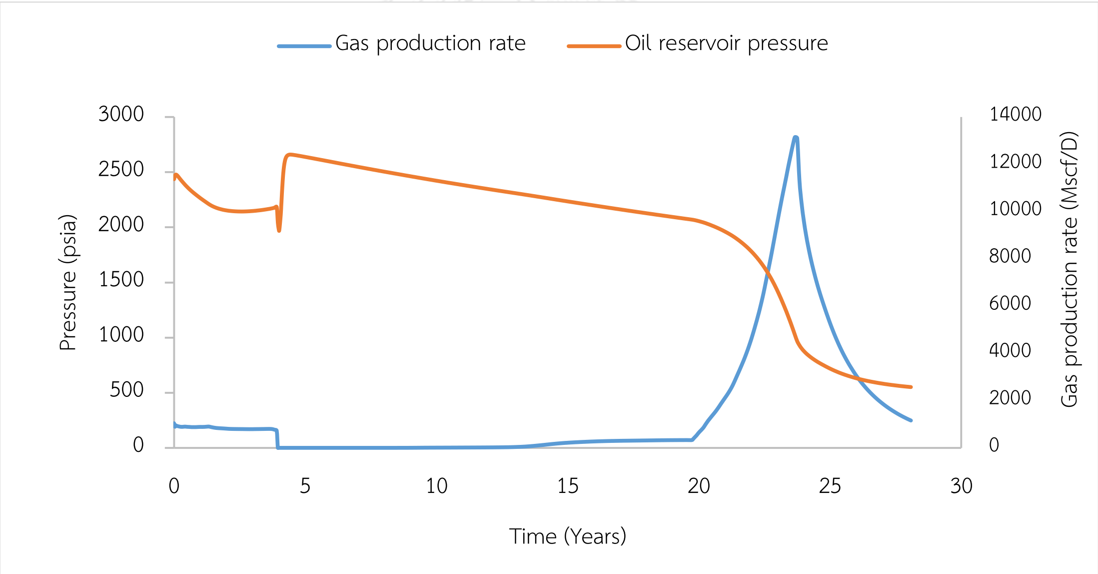
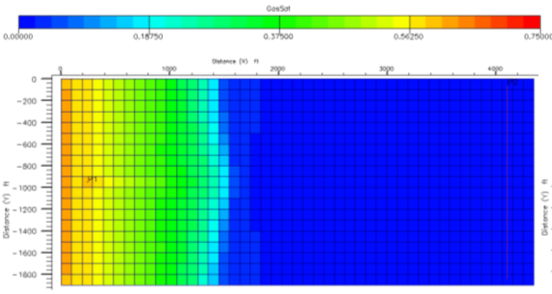
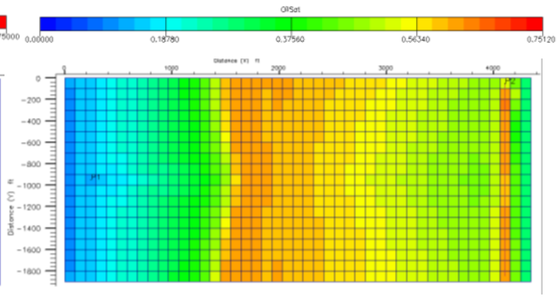


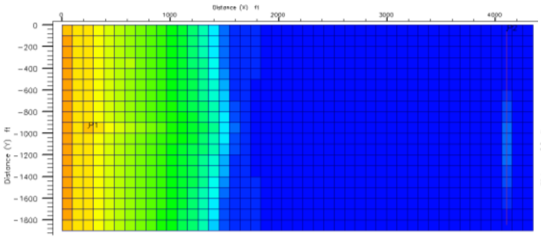
Figure 5.5 Field gas production rate and oil reservoir pressure under base case condition



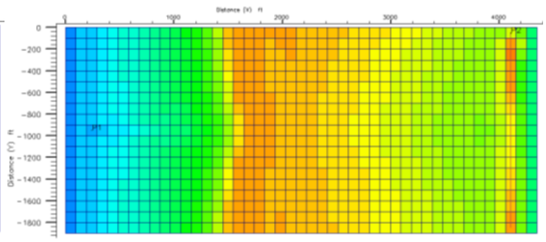
a) Gas saturation profile before gas breakthrough (at year 19)



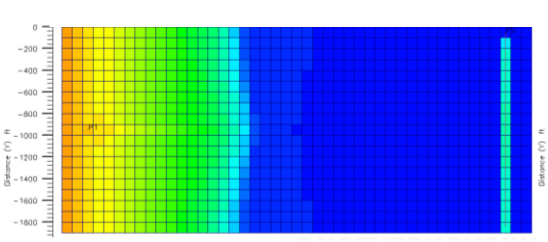
b) Oil saturation profile before gas breakthrough (at year 19)



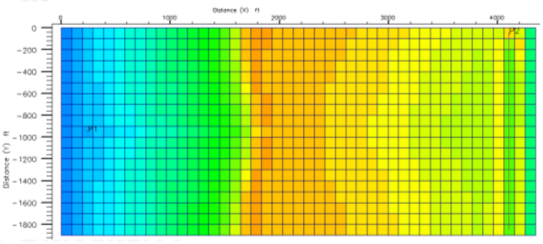
c) Gas saturation profile at gas breakthrough (around year 20)



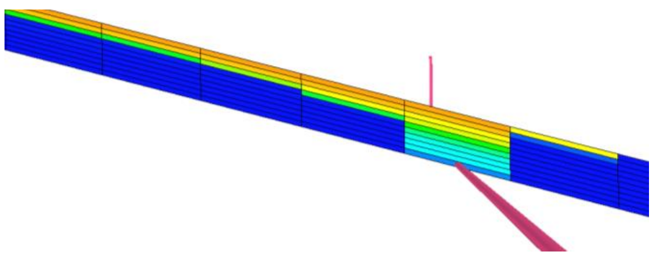
d) Oil saturation profile at gas breakthrough (around year 20)



e) Gas saturation profile after gas breakthrough (at year 22)



f) Oil saturation profile after gas breakthrough (at year 22)



g) Gas saturation profile of the middle of horizontal well at gas breakthrough

Figure 5.6 Saturation profile at the bottom layer of oil reservoir after perform gas dumpflood

Table 5.2 Summary of results for base case condition

Parameters	Value	Units
Recovery factor	79.14	%
Total oil production	7.448	MMSTB
Total gas production	15.787	BCF
Total water production	4.211	MMSTB
Production time	28	Years
Total water injection	4.289	MMSTB
Injection time	4	Years

5.2 Effect of perforation sequence of gas layers

The effect of perforation sequence of gas zones on gas dumpflood operation is investigated by using three perforation sequences which are (1) perforating all layers at the same time, (2) perforating upper layers then lower layers, and (3) perforating lower layers then upper layers. In scenarios 2 and 3, the second batch of perforation is performed when the liquid rate drops below the plateau rate. For the case of four gas layers, target water injection rate and liquid production rate during waterflood of 3,000 STB/D and target liquid production rate during gas dumpflood of 1,000 STB/D is selected to study the effect of each perforation criteria.

After perforation in the gas zones, net gas rate in the oil reservoir behaves differently according to the perforation sequence as seen in Figure 5.7. The case of perforating full to base on all layers lets the gas flow to the oil reservoir from all layers at the same time. Thus, there is only one peak in the net gas rate entering the oil reservoir (negative rate in Figure 5.7). For the other two cases, there are two peaks in net gas flow rate as the perforation is done in two batches. Gas production rate is positive when gas breaks through the down-dip production well and later declines due to gas depletion and pressure depletion. Net gas flow rate of the uppermost and bottommost gas reservoirs can be seen in Figures 5.8 and 5.9. For Single batch perforation on all layers, there is a small amount of gas crosses flow into the uppermost gas reservoir at the beginning of gas dumpflood. For the case that the lower layers are perforated first, gas initially crosses flow into the bottommost layer in the second batch of perforation because the bottommost layer has smaller pressure at that time. For the case that the upper layers are perforated first, gas initially crosses flow into the uppermost layer in the second batch of perforation due to lower pressure.

Dumped gas brings pressure into the oil zone as shown in Figure 5.10. The case of one batch has initially the highest pressure after gas dumpflood because it has the highest amount of gas that is dumped into the oil reservoir than other cases, and this effect of pressure is also the same when comparing the case of perforating on lower then upper layers as the gas is initially flowing from the high pressure region.At late time, all perforation cases have similar pressure of the oil reservoir as a similar amount cumulative gas flows into the oil reservoir.

Figure 5.11 illustrates the oil production rate from each perforation program. The cases of two perforation batches have to be shut in for 30 days to allow the perforation to take place. For two-batch perforation programs, the oil production profiles look very much similar while single batch has slightly longer plateau oil production rate due to less effect of gas cross-flow at late time compared to the cases of two-batch perforation. Figure 5.12 compares the recovery factors of each perforation case. The case of perforating all layers at the same time gives slightly higher recovery factor (about 1% more) than other cases as it provides higher and longer pressure support to the oil reservoir than the other cases. Table 5.3 compares results for all cases. The single batch perforation gives approximately 0.1 MMSTB higher oil production compared to other cases while the perforation on lower then upper layers gives a slightly higher production (approximately 0.01 MMSTB more) compared to perforation on upper then lower case. The gas production is increased as the initially dumped gas has higher pressure. For the water production, as the dumped gas has higher pressure, it tends to override, causing inefficient displacement of water towards the producer. Regarding production time, the case of single batch requires shorter period as it has longer plateau oil production rate.

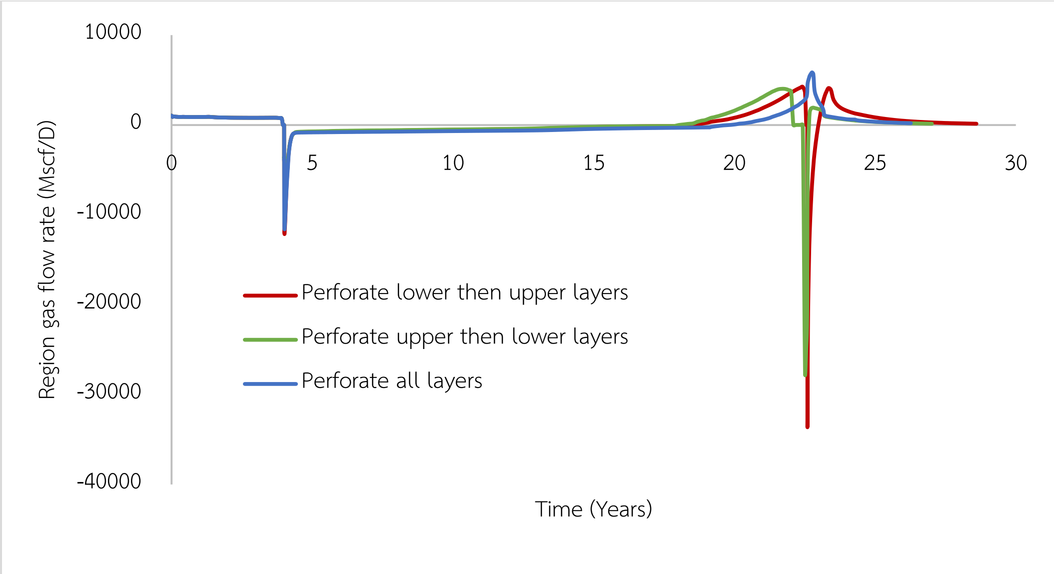


Figure 5.7 Region gas flow rate of oil reservoir for different perforation programs

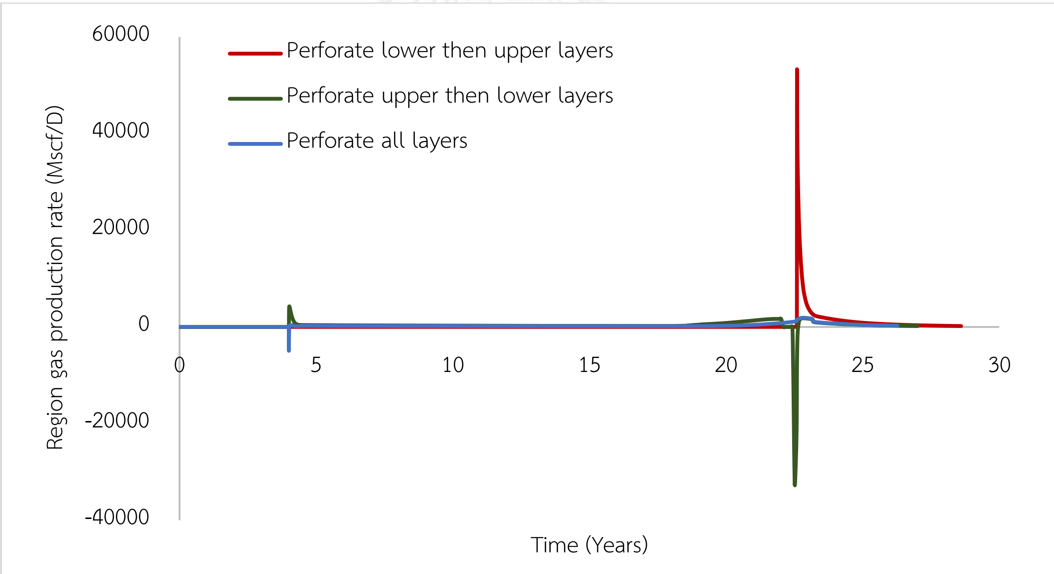


Figure 5.8 Region gas flow rate of the uppermost gas reservoir for different perforation programs

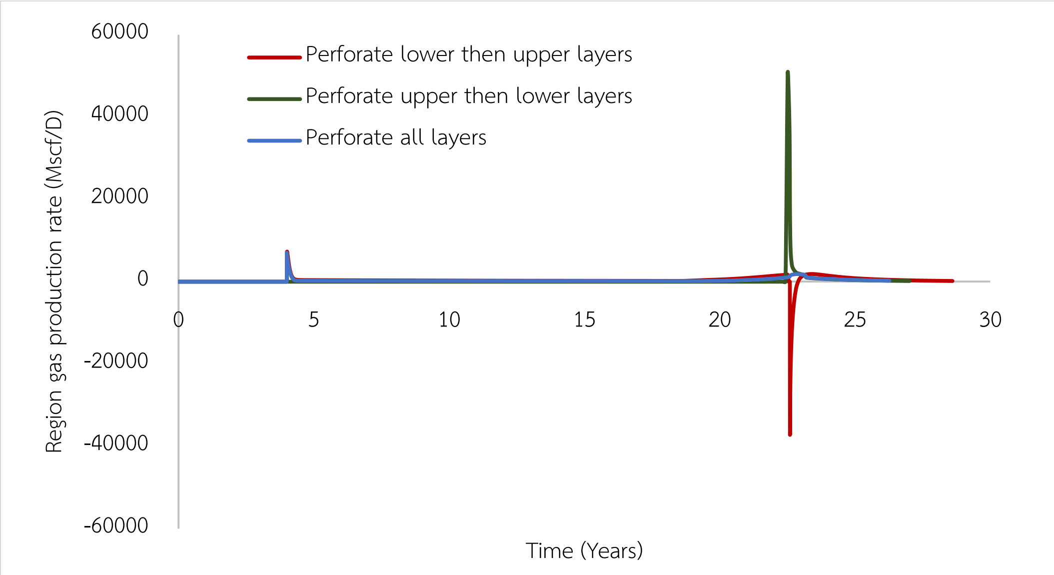


Figure 5.9 Region gas flow rate of the bottommost gas reservoir for different perforation programs

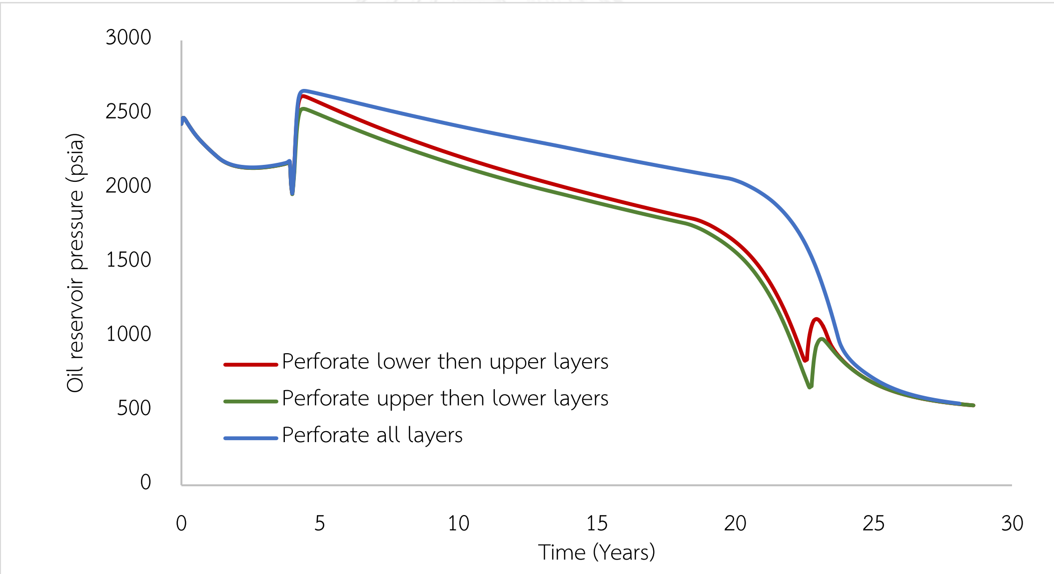


Figure 5.10 Oil reservoir pressure for different perforation programs

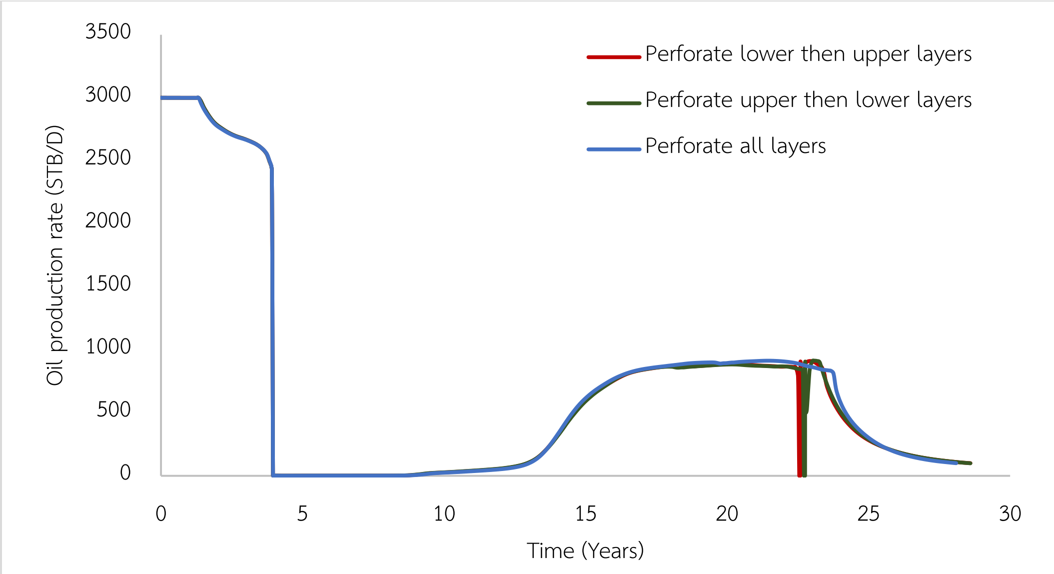


Figure 5.11 Oil production rate for different perforation programs

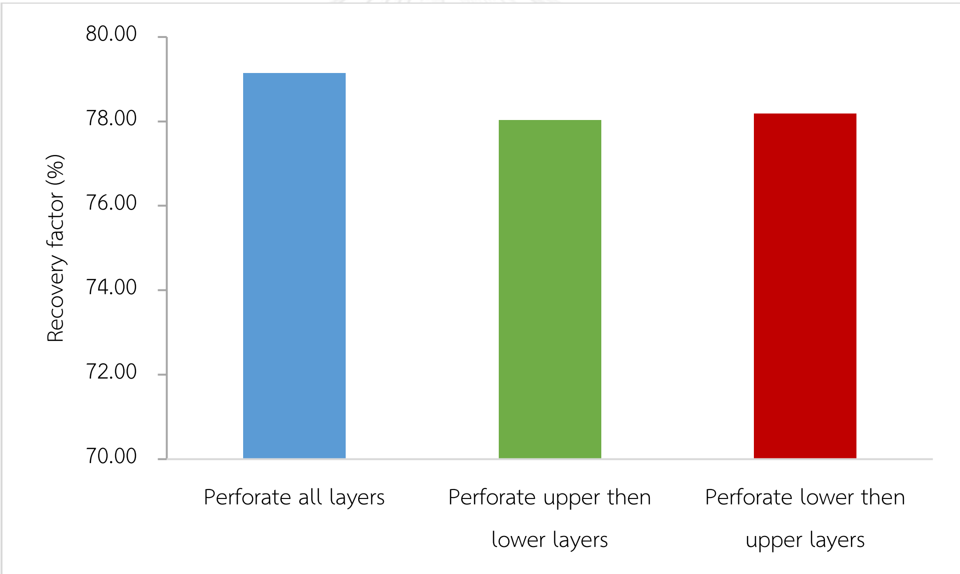


Figure 5.12 Recovery factor of each perforation programs

Table 5.3 Summary of results for different perforation programs in gas layers

Case	Recovery factor (%)	Np (MMSTB)	Gp (BCF)	Wp (MMSTB)	Production time (years)
Perforate all layers	79.14	7.448	15.787	4.211	28
Perforate upper then lower layers	78.04	7.344	16.039	4.227	29
Perforate lower then upper layers	78.18	7.357	16.046	4.225	29

Since perforation on all layers at the same time gives slightly higher of recovery factor (about 1% more) than other cases and also has lesser steps in operation, this perforation program is selected to perform the study on other parameters.

5.3 Selection of target liquid production rate during waterflood

During the waterflood phase of double displacement process, liquid production rate from the up-dip producer might affect the total oil recovery as it might help speed up the entire process. This section discusses the simulation results for three cases of target liquid production rate during waterflood phase: 1,500, 3,000, and 4,500 STB/D for four different reservoir systems having different numbers and thicknesses of gas layers. Note that the target water injection rates are the same as target liquid production rate in these cases in order to maintain the reservoir pressure to close to the initial pressure as much as possible.

5.3.1 Two layers of 25-ft gas reservoirs

Oil recovery factors for three cases of target liquid production rate during waterflood operation (1,500, 3,000 and 4,500 STB/D) are plotted for three different cases of target liquid production rates during gas dumpflood (500, 1000, and 1500 STB/D) as shown in Figure 5.13. The oil recovery factors among the three target liquid production rates during waterflood are approximately the same for all target liquid production rates during gas dumpflood. As depicted in Figures 5.14 - 5.16, oil productions have slightly different profiles during the waterflood period for different target liquid production rates of waterflooding. The oil rates in all cases are initially the same as the target rates but later decline to lower values in the cases that the target rates are too high to achieve. During gas dumpflood, oil productions have similar profiles among three different cases of initial target liquid production rates, although the oil rate starts to increase at different time. Since there are not distinctive differences in the overall production profile among the three cases of initial target rates, the oil recovery factors for the three cases are not much different. Only the case with 1,500 STB/D initial target liquid rate together with the target liquid rate of gas dumpflood of 500 STB/D yields a distinctive recovery factor than its respective cases. This is because the oil production in this particular case is still at its peak period when the time limit of 30 years is reached.

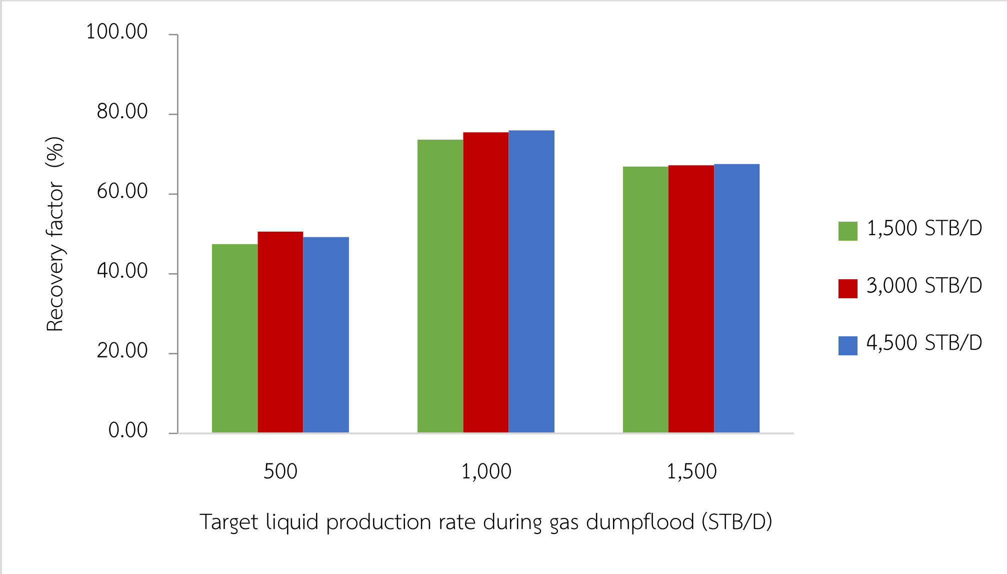


Figure 5.13 Recovery factors for different target liquid production rates during waterflood for 2 layers of 25-ft gas reservoirs

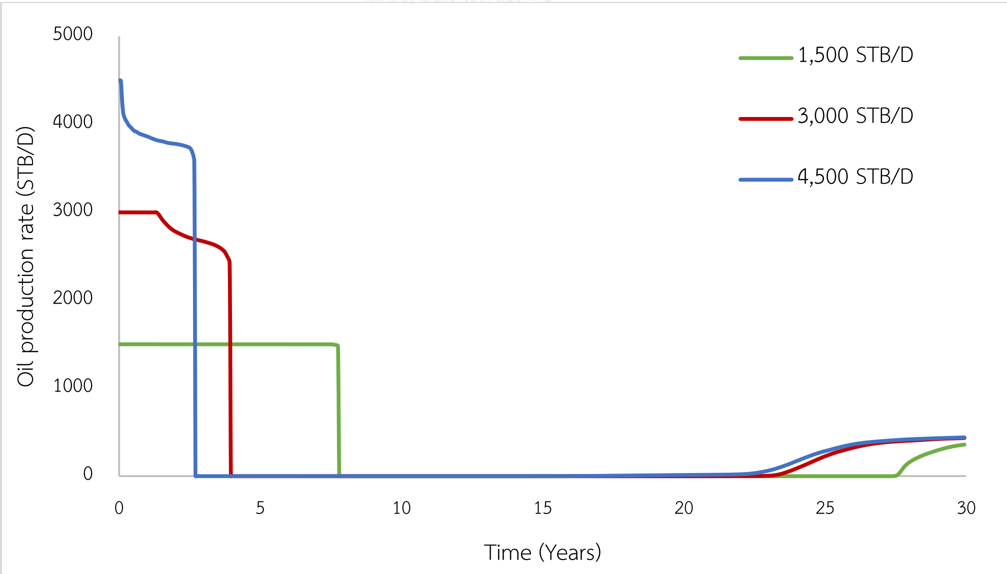


Figure 5.14 Oil production rate for different target liquid production rates during waterflood when the target liquid production rate during gas dumpflood is 500 STB/D (2 layers of 25-ft gas reservoirs)

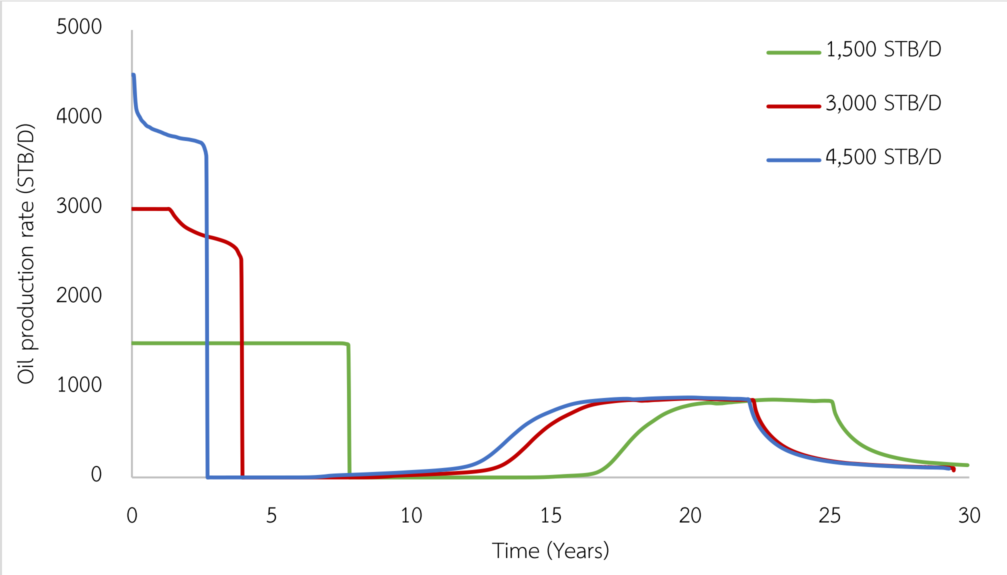


Figure 5.15 Oil production rate for different target liquid production rates during waterflood when the target liquid production rate during gas dumpflood is 1,000 STB/D (2 layers of 25-ft gas reservoirs)

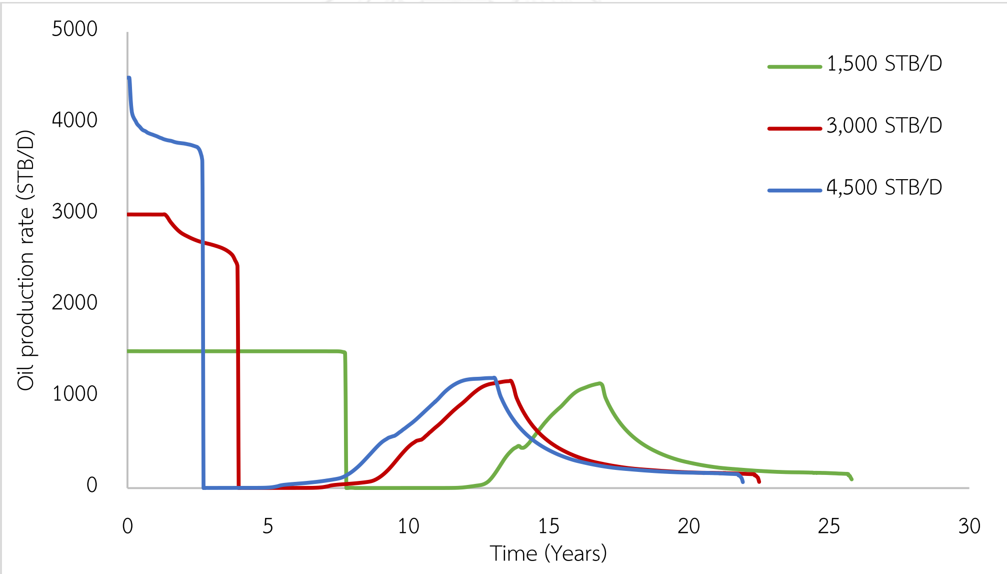


Figure 5.16 Oil production rate for different target liquid production rates during waterflood when the target liquid production rate during gas dumpflood is 1,500 STB/D (2 layers of 25-ft gas reservoirs)

Results from the simulation runs in terms of oil production, gas production, water production and injection, the time it takes to inject water are summarized in Table 5.4. The gas production slightly increases when the target liquid production rate during waterflood is increased in the cases of 500 STB/D target liquid rate during gas dumpflood while they are approximately the same in the cases of 1,000 and 1,500 STB/D target liquid rate during gas dumpflood. In terms of water production, it increases as the target liquid production rate during waterflood is increased. Regarding time, there is no difference in total time required to produce oil in the cases of 500 STB/D liquid rate during gas dumpflood since the time limit is reached in all cases. For 1,000 and 1,500 STB/D target rate during gas dumpflood, the cases with a larger target liquid production rate during waterflood have shorter production time than those with a smaller liquid rate due to more rapid withdrawal of injected water and oil from the reservoir. Regarding water injection, the cases with a larger water injection rate have a slightly higher amount of cumulative water injection while the time required to inject water is lower.

Table 5.4 Summarized results for different target liquid production rates during waterflood for 2 layers of 25-ft gas reservoirs

Target liquid rate during waterflood (STB/D)	Target liquid rate during dumpflood (STB/D)	Recovery factor (%)	Np (MMSTB)	Gp (BCF)	Wp (MMSTB)	Production time (Year)	Wi (MMSTB)	Injection time (Year)
1,500		47.43	4.463	1.393	3.815	30	4.245	8
3,000	500	50.62	4.763	1.450	3.984	30	4.289	4
4,500		49.25	4.635	1.508	4.083	30	4.376	3
1,500		73.66	6.932	9.053	4.139	30	4.245	8
3,000	1,000	75.47	7.103	9.154	4.199	29	4.289	4
4,500		75.95	7.148	9.167	4.290	29	4.376	3
1,500		66.88	6.294	9.221	4.113	26	4.245	8
3,000	1,500	67.24	6.328	9.217	4.169	23	4.289	4
4,500		67.57	6.359	9.213	4.263	22	4.376	3

5.3.2 Four layers of 25-ft gas reservoirs

Oil recovery factors for three cases of target liquid production rate during waterflood operation (1,500, 3,000 and 4,500 STB/D) are plotted for three different cases of target liquid production rates during gas dumpflood (500, 1000, and 1500 STB/D) as shown in Figure 5.17. Similar to the results in Section 5.3.1, the oil recovery factors among the three target liquid production rates during waterflood are approximately the same for all target liquid production rates during gas dumpflood because there are not distinctive differences in the overall production profile among the three cases of initial target rates. Only the case with 1,500 STB/D initial target liquid rate with the target liquid rate of gas dumpflood of 500 STB/D yields a distinctive recovery factor than its respective cases because the oil production in this particular case is still at its peak period when the time limit of 30 years is reached.

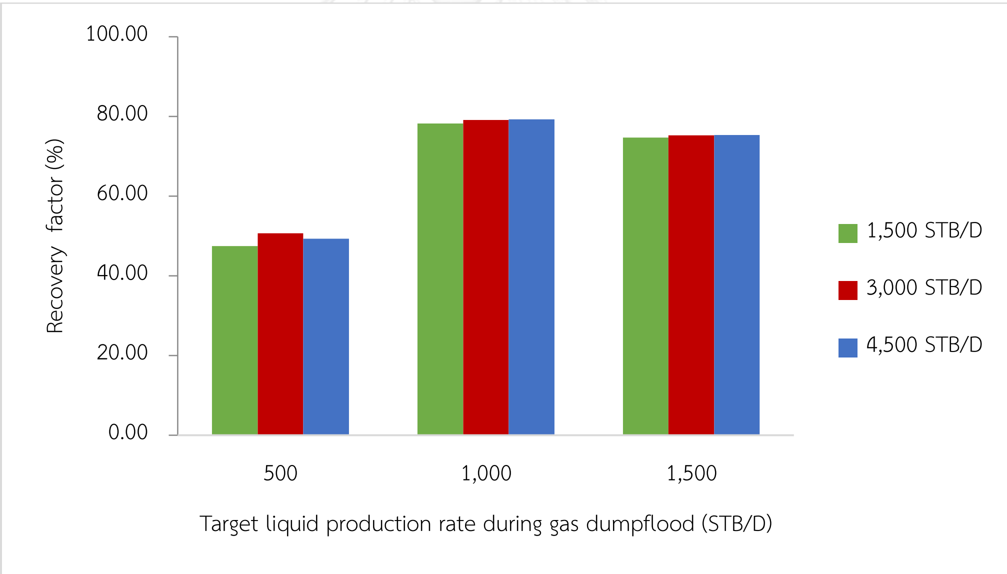


Figure 5.17 Recovery factors for different target liquid production rates during waterflood for 4 layers of 25-ft gas reservoirs

Results from the simulation runs in terms of oil production, gas production, water production and injection, the time it takes to inject water are summarized in Table 5.5. The gas production slightly increases when the target liquid production rate during waterflood is increased in the cases of 500 STB/D target liquid rate during gas dumpflood while they are approximately the same in the cases of 1,000 and 1,500 STB/D target liquid rate during gas dumpflood. In terms of water production, it increases as the target liquid production rate during waterflood is increased. Regarding time, there is no difference in total time required to produce oil in the cases of 500 STB/D liquid rate during gas dumpflood since the time limit is reached in all cases. For 1,000 and 1,500 STB/D target rate during gas dumpflood, the cases with a larger target liquid production rate during waterflood have shorter production time than those with a smaller liquid rate due to more rapid withdrawal of injected water and oil from the reservoir. Regarding water injection, the cases with a larger water injection rate have a slightly higher amount of cumulative water injection while the time required to inject water is lower.

Table 5.5 Summarized results for different target liquid production rates during waterflood for 4 layers of 25-ft gas reservoirs

Target liquid rate during waterflood (STB/D)	Target liquid rate during dumpflood (STB/D)	Recovery factor (%)	Np (MMSTB)	Gp (BCF)	Wp (MMSTB)	Production time (Year)	Wi (MMSTB)	Injection time (Year)
1,500		47.50	4.470	1.397	3.809	30	4.245	8
3,000	500	50.72	4.773	1.461	3.975	30	4.289	4
4,500		49.33	4.642	1.518	4.075	30	4.376	3
1,500		78.24	7.363	15.227	4.159	30	4.245	8
3,000	1,000	79.14	7.448	15.787	4.211	28	4.289	4
4,500		79.27	7.460	15.770	4.300	28	4.376	3
1,500		74.74	7.033	16.728	4.167	30	4.245	8
3,000	1,500	75.32	7.088	16.758	4.223	28	4.289	4
4,500		75.38	7.094	16.754	4.313	27	4.376	3

5.3.3 Two layers of 50-ft gas reservoirs

Oil recovery factors for three cases of target liquid production rate during waterflood operation (1,500, 3,000 and 4,500 STB/D) are plotted for three different cases of target liquid production rates during gas dumpflood (500, 1000, and 1500 STB/D) as shown in Figure 5.18. Similar to the results in Sections 5.3.1 - 5.3.2, the oil recovery factors among the three target liquid production rates during waterflood are approximately the same for all target liquid production rates during gas dumpflood because there are no significant difference in the overall production profile of each initial target rate. For the case with 1,500 STB/D initial target liquid rate and the target liquid rate of gas dumpflood is 500 STB/D, it yields a distinctive recovery factor because of time limit while oil production is still at its peak period.

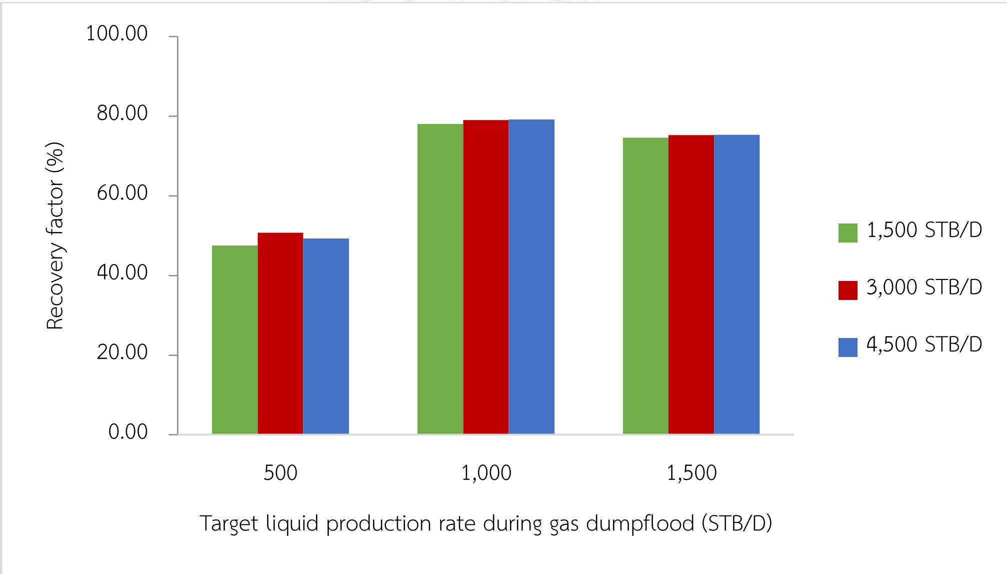


Figure 5.18 Recovery factors for different target liquid production rates during waterflood for 2 layers of 50 ft-gas reservoirs

Results from the simulation runs in terms of oil production, gas production, water production and injection, the time it takes to inject water are summarized in Table 5.8. The gas production slightly increases when the target liquid production rate during waterflood is increased in the cases of 500 STB/D target liquid rate during gas dumpflood while they are approximately the same in the cases of 1,000 and 1,500 STB/D target liquid rate during gas dumpflood. Regarding time, there is no difference in total time required to produce oil in the cases of 500 STB/D liquid rate during gas dumpflood since the time limit is reached in all cases. For 1,000 and 1,500 STB/D target rate during gas dumpflood, the cases with a larger target liquid production rate during waterflood have shorter production time than those with a smaller liquid rate due to more rapid withdrawal of injected water and oil from the reservoir. Regarding water injection, the cases with a larger water injection rate have a slightly higher amount of cumulative water injection while the time required to inject water is lower.

Table 5.6 Summarized results for different target liquid production rates during waterflood for 2 layers of 50 ft-gas reservoirs

Target liquid rate during waterflood (STB/D)	Target liquid rate during dumpflood (STB/D)	Recovery factor (%)	Np (MMSTB)	Gp (BCF)	Wp (MMSTB)	Production time (Year)	Wi (MMSTB)	Injection time (Year)
1,500		47.50	4.469	1.397	3.809	30	4.245	8
3,000	500	50.71	4.772	1.460	3.975	30	4.289	4
4,500		49.33	4.642	1.517	4.076	30	4.376	3
1,500		78.08	7.347	15.070	4.158	30	4.245	8
3,000	1,000	79.02	7.435	15.646	4.211	28	4.289	4
4,500		79.17	7.450	15.619	4.300	28	4.376	3
1,500		74.57	7.017	16.516	4.167	30	4.245	8
3,000	1,500	75.21	7.077	16.550	4.223	28	4.289	4
4,500		75.31	7.086	16.545	4.313	27	4.376	3

5.3.4 Four layers of 50-ft gas reservoirs

Oil recovery factors for three cases of target liquid production rate during waterflood operation (1,500, 3,000 and 4,500 STB/D) are plotted for three different cases of target liquid production rates during gas dumpflood (500, 1000, and 1500 STB/D) as shown in Figure 5.19. Similar to the results in Sections 5.3.1 - 5.3.3, the oil recovery factors among the three target liquid production rates during waterflood are approximately the same for all target liquid production rates during gas dumpflood. Only the case of 1,500 STB/D initial target liquid rate with 500 STB/D target liquid rate yields a distinctive recovery factor than its respective cases because the oil production in this particular case is still at its peak period when the time limit of 30 years is reached.

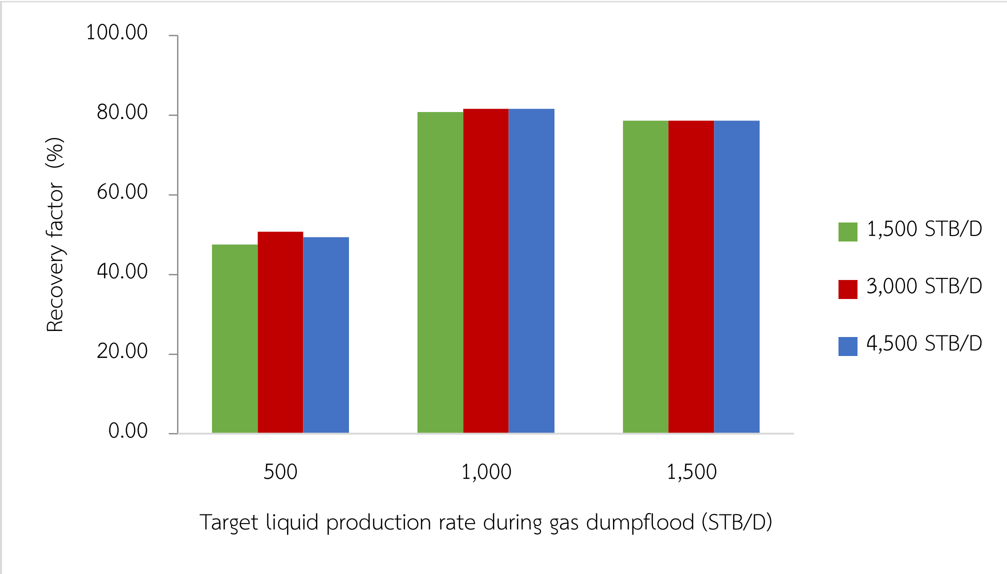


Figure 5.19 Recovery factors for different target liquid production rates during waterflood for 4 layers of 50 ft-gas reservoirs

Results from the simulation runs in terms of oil production, gas production, water production and injection, the time it takes to inject water are summarized in Table 5.7. The gas production slightly increases when the target liquid production rate during waterflood is increased in the cases of 500 STB/D target liquid rate during gas dumpflood while they are approximately the same in the cases of 1,000 and 1,500 STB/D target liquid rate during gas dumpflood. Regarding time, there is no difference in total time required to produce oil in the cases of 500 STB/D liquid rate during gas dumpflood since the time limit is reached in all cases. For 1,000 and 1,500 STB/D target rate during gas dumpflood, the cases with a larger target liquid production rate during waterflood have shorter production time than those with a smaller liquid rate due to more rapid withdrawal of injected water and oil from the reservoir. Regarding water injection, the cases with a larger water injection rate have a slightly higher amount of cumulative water injection while the time required to inject water is lower.

Table 5.7 Summarized results for different target liquid production rates during waterflood for 4 layers of 50 ft-gas reservoirs

Target liquid rate during waterflood (STB/D)	Target liquid rate during dumpflood (STB/D)	Recovery factor (%)	Np (MMSTB)	Gp (BCF)	Wp (MMSTB)	Production time (Year)	Wi (MMSTB)	Injection time (Year)
1,500		47.53	4.473	1.398	3.806	30	4.245	8
3,000	500	50.74	4.775	1.461	3.973	30	4.289	4
4,500		49.34	4.643	1.518	4.074	30	4.376	3
1,500		80.81	7.604	23.464	4.175	30	4.245	8
3,000	1,000	81.57	7.676	25.831	4.228	28	4.289	4
4,500		81.55	7.674	25.902	4.316	28	4.376	3
1,500		78.61	7.397	29.807	4.183	28	4.245	8
3,000	1,500	78.64	7.400	29.649	4.229	24	4.289	4
4,500		78.64	7.400	29.660	4.317	23	4.376	3

5.4 Selection of target liquid production rate during gas dumpflood

When dumping gas to the oil zone, liquid production rate is one of the parameters that affects the oil recovery. If the target rate is too high, gas will break through at the producer early, leading to rapid decline in reservoir pressure and oil production rate. If the target rate is too low, the amount of total oil recovery is low at the end of the 30-year period of the time constraint. As there is limited amount of gas flowing from the gas reservoirs into the oil reservoir, the liquid production rate from the oil reservoir needs to be properly balanced.

5.4.1 Two layers of 25-ft gas reservoirs

Oil recovery factors for three cases of target liquid production rate during gas dumpflood (500, 1000, and 1500 STB/D) are plotted for three different cases of initial target liquid production rates during waterflood operation (1,500, 3,000 and 4,500 STB/D) as shown in Figure 5.20. Note that the target water injection rate is set to be the same as the target liquid production rate during the waterflood phase in order to maintain the reservoir pressure as close to the initial pressure as much as possible.

From Figure 5.20, oil recovery factor increases as the target liquid production rate during gas dumpflood is increased from 500 STB/D to 1,000 STB/D but decreases when the target liquid production rate during gas dumpflood is increased from 1,000 STB/D to 1,500 STB/D for all target liquid rates during waterflood. As there is a lot of water up-dip of the producer when gas dumpflood is started, this water needs to be produced back to surface before oil can actually be produced. When the target liquid production rate during gas dumpflood is as small as 500 STB/D, it takes several years before oil can be produced again from the down-dip well as depicted in Figures 5.21 - 5.23. Then, oil production is continued for a few more years and terminated due to the time constraint of 30 years, giving rise to low values of oil recovery factor. When the target liquid production rate during gas dumpflood is increased to 1,000 and 1,500 STB/D, it takes shorter time for the production well to start producing oil again. As oil can be produced for longer time before the time constraint is reached, oil recovery factors in the cases of 1,000 and 1,500 STB/D are higher than those for 500 STB/D. However, as the cases of 1,000 STB/D can sustain oil production better than the cases with 1,500 STB/D, the recovery factors for the cases of 1,000 STB/D are better. This is because the oil reservoir pressures of the cases with 1,500 STB/D decline faster than any other cases as they produce a lot of liquid out of the reservoir as shown in Figures 5.24 - 5.26. As a result, the oil production in the cases of 1,500 STB/D cannot be sustained for long periods of time. Figure 5.27 illustrated the flood front of different target liquid production rates during gas dumpflood. The gas flood front is unfavorable as increment of target liquid production rate, leading to early gas breakthrough and rapidly decline of oil reservoir pressure. Consequently, the cases with 1,000 STB/D target liquid production rate during gas dumpflood provide the highest recovery factors in all cases of different target liquid production rates during waterflood.

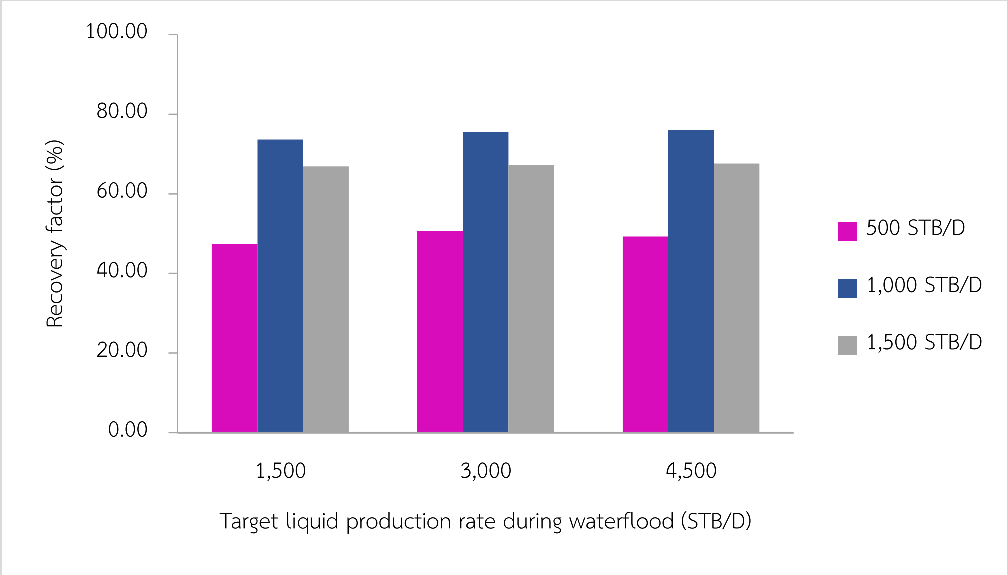


Figure 5.20 Recovery factors for different target liquid production rates during gas dumpflood for 2 layers of 25-ft gas reservoirs

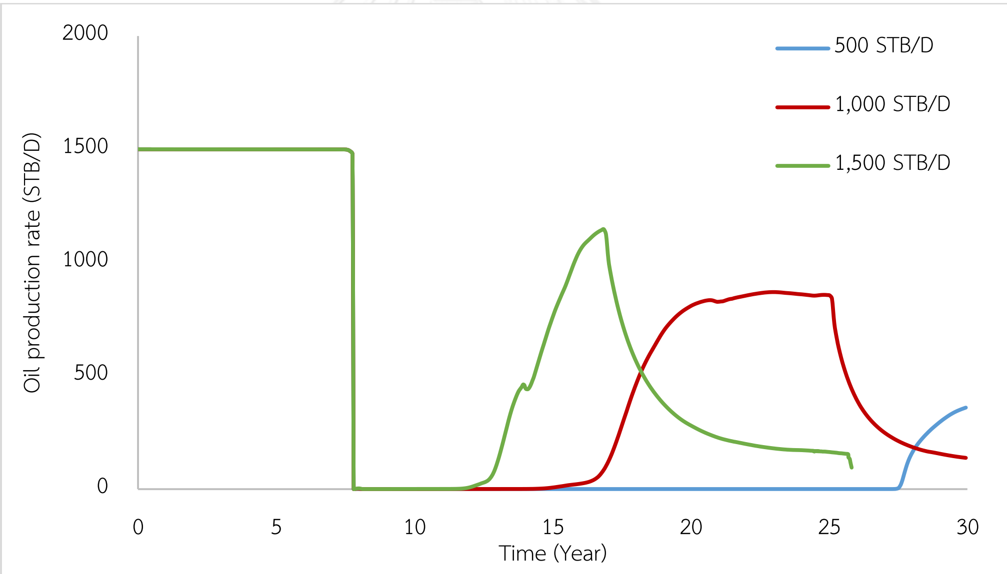


Figure 5.21 Oil production rate for different target liquid production rates during gas dumpflood when the target liquid production rate during waterflood is 1,500 STB/D (2 layers of 25-ft gas reservoirs)

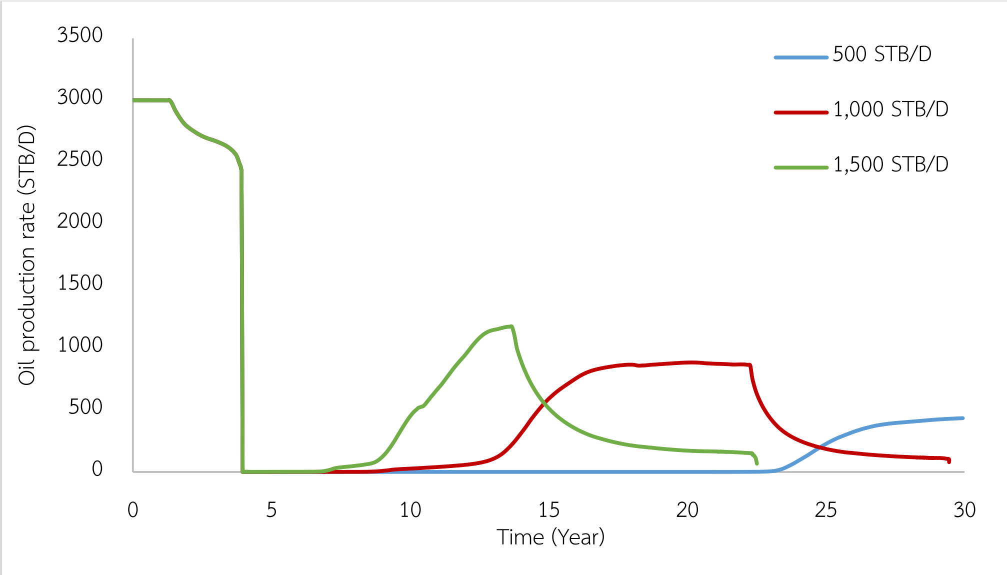


Figure 5.22 Oil production rate for different target liquid production rates during gas dumpflood when the target liquid production rate during waterflood is 3,000 STB/D (2 layers of 25-ft gas reservoirs)

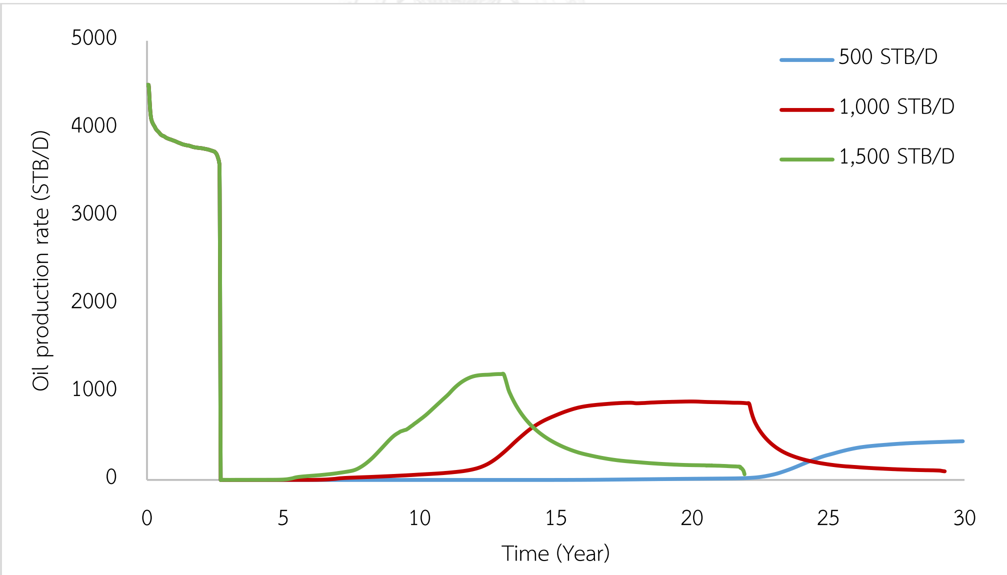


Figure 5.23 Oil production rate for different target liquid production rates during gas dumpflood when the target liquid production rate during waterflood is 4,500 STB/D (2 layers of 25-ft gas reservoirs)

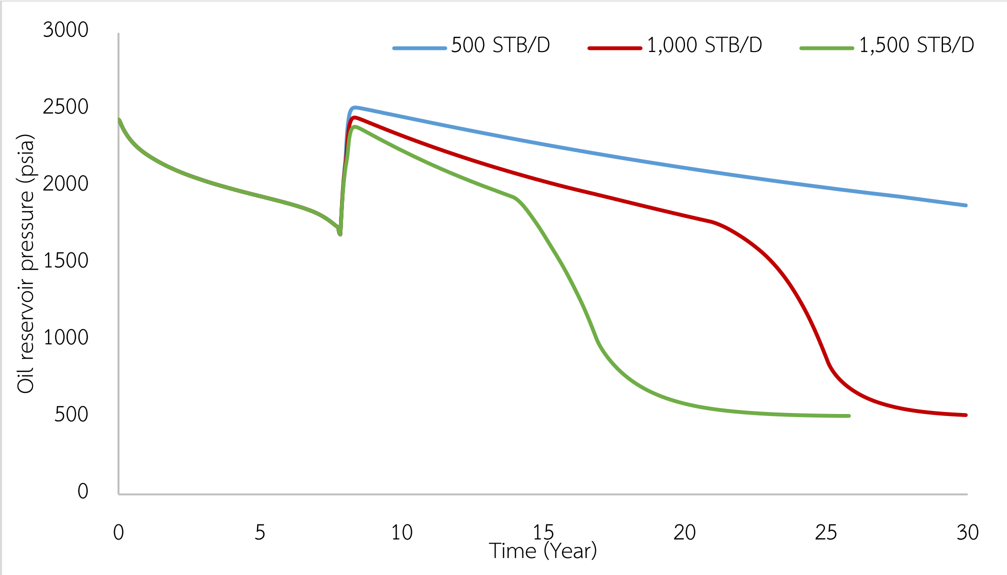


Figure 5.24 Oil reservoir pressure for different target liquid production rates during gas dumpflood when the target liquid production rate during waterflood is 1,500 STB/D (2 layers of 25-ft gas reservoirs)

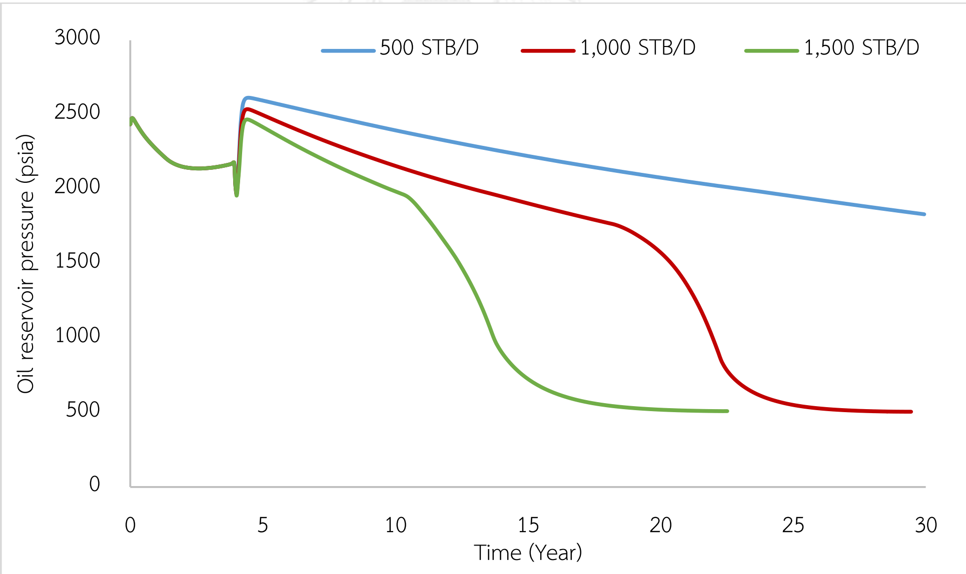


Figure 5.25 Oil reservoir pressure for different target liquid production rates during gas dumpflood when the target liquid production rate during waterflood is 3,000 STB/D (2 layers of 25-ft gas reservoirs)

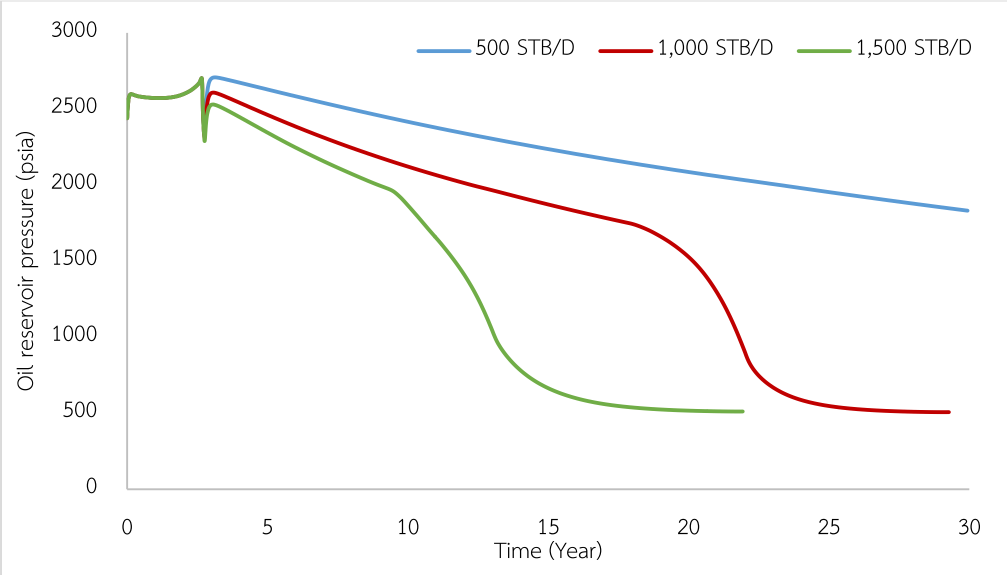


Figure 5.26 Oil reservoir pressure for different target liquid production rates during gas dumpflood when the target liquid production rate during waterflood is 4,500 STB/D (2 layers of 25-ft gas reservoirs)

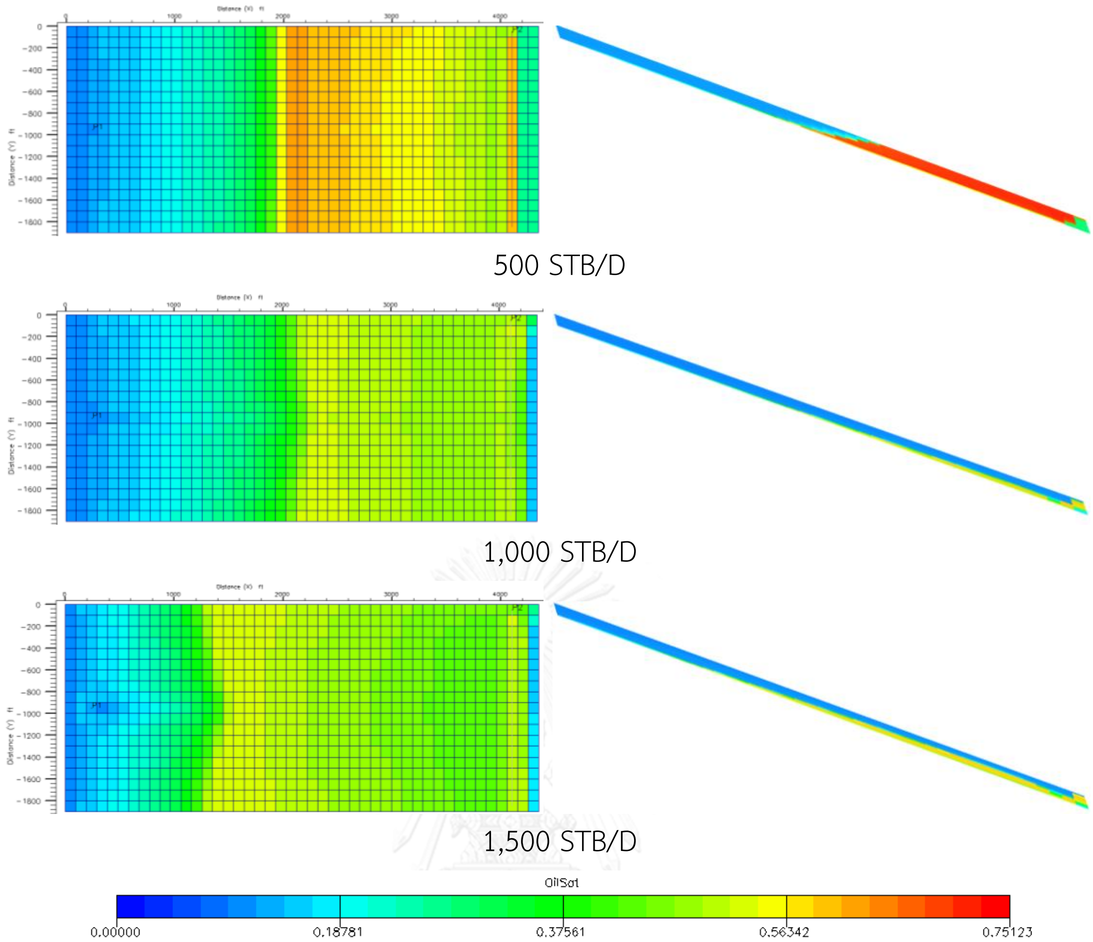


Figure 5.27 Oil saturation profile of bottom layer and side view of the oil reservoir at last time step for difference target liquid production rates during gas dumpflood for the rate during waterflood of 3,000 STB/D (2 layers of 25ft-gas reservoir)

Results from the simulation runs in terms of oil production, gas production, water production and injection, the time it takes to inject water are summarized in Table 5.8. The gas productions in the cases with 1,500 and 1,000 STB/D target liquid production rate during gas dumpflood are high (above 9 BCF) since gas already breaks through the producer in these cases but the gas production in the cases of 500 STB/D are low (less than 1.6 BCF) because there is no gas breakthrough at the producer.

In terms of water production, the cases with 1,500 and 1,000 STB/D target liquid production rate during gas dumpflood have higher water production than the case with 500 STB/D because the rates of 1,000 STB/D or more are high enough to produce back most of the water injected during the waterflood phase. In terms of production time, the cases with a larger liquid production rate during gas dumpflood have shorter production time than those with a smaller liquid rate due to more rapid withdrawal of injected water and oil from the reservoir. Regarding water injection, the cases with a larger water injection rate have a slightly higher amount of cumulative water injection while the time required to inject water is lower.

Table 5.8 Summarized results for different target liquid production rates during gas dumpflood for 2 layers of 25-ft gas reservoirs

Target liquid rate during waterflood (STB/D)	Target liquid rate during dumpflood (STB/D)	Recovery factor (%)	Np (MMSTB)	Gp (BCF)	Wp (MMSTB)	Production time (Year)	Wi (MMSTB)	Injection time (Year)
1,500	1,500	66.88	6.294	9.221	4.113	26	4.245	8
	1,000	73.66	6.932	9.053	4.139	30	4.245	8
	500	47.43	4.463	1.393	3.815	30	4.245	8
3,000	1,500	67.24	6.328	9.217	4.169	23	4.289	4
	1,000	75.47	7.103	9.154	4.199	29	4.289	4
	500	50.62	4.763	1.450	3.984	30	4.289	4
4,500	1,500	67.57	6.359	9.213	4.263	22	4.376	3
	1,000	75.95	7.148	9.167	4.290	29	4.376	3
	500	49.25	4.635	1.508	4.083	30	4.376	3

5.4.2 Four layers of 25-ft gas reservoirs

Oil recovery factors for three cases of target liquid production rate during gas dumpflood (500, 1000, and 1500 STB/D) are plotted for three different cases of initial target liquid production rates during waterflood operation (1,500, 3,000 and 4,500 STB/D) as shown in Figure 5.28 These results are also tabulated in Table 5.9. Similar to the results in Section 5.4.1 in which there are two layers of 25-ft gas reservoirs, oil recovery factor increases as the target liquid production rate during gas dumpflood is increased from 500 STB/D to 1,000 STB/D but decreases when the target liquid production rate during gas dumpflood is increased from 1,000 STB/D to 1,500 STB/D for all target liquid rates during waterflood. The explanation for this behavior is the same as the one in Section 5.4.1. As the production rate is increased, the injected water left inside the reservoir from the waterflood phase can be produced back to surface faster, allowing oil to be produced longer. However, if the production rate is too high, oil recovery factor decreases due to fast depletion of reservoir pressure. As a result, the liquid production rate of 1,000 STB/D still provides the highest oil recovery factors.

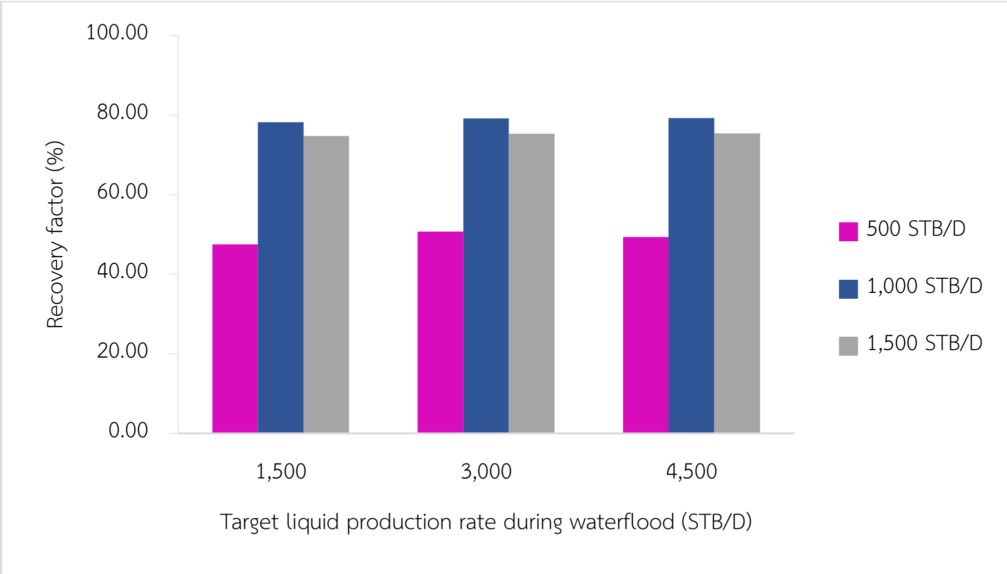


Figure 5.28 Recovery factors for different target liquid production rates during gas dumpflood for 4 layers of 25-ft gas reservoirs

Results from the simulation runs in terms of oil production, gas production, water production and injection, the time it takes to inject water are summarized in Table 5.9.The total oil productions for all cases in this section are higher than those for their respective cases in Section 5.4.1 due to the fact that there are two more layers of 25-ft gas reservoirs in this section. Thus, more gas can be dumped to displace the oil in the double displacement process. The gas productions in the cases with 1,500 and 1,000 STB/D target liquid production rate during gas dumpflood are high (above 15 BCF) since gas already breaks through the producer in these cases but the gas productions in the cases of 500 STB/D are low (less than 1.6 BCF) because there is no gas breakthrough at the producer. Note that the gas productions in the cases of 1,500 and 1,000 STB/D in this section in which gas comes from 4 layers of 25-ft gas reservoirs are higher than those in Section 5.4.1 in which gas comes from 2 layers of 25-ft gas reservoirs.

Similar to the results in Section 5.4.1, the cases with 1,500 and 1,000 STB/D target liquid production rate during gas dumpflood have higher water production than the cases with 500 STB/D because the rates of 1,000 STB/D or more are high enough to produce back most of the water injected during the waterflood phase. In terms of production time, the cases with a larger liquid production rate during gas dumpflood have shorter production time than those with a smaller liquid rate due to more rapid withdrawal of injected water and oil from the reservoir. Regarding water injection, the cases with a larger water injection rate have a slightly higher amount of cumulative water injection while the time required to inject water is lower.

Table 5.9 Summarized results for different target liquid production rates during gas dumpflood for 4 layers of 25-ft gas reservoirs

Target liquid rate during waterflood (STB/D)	Target liquid rate during dumpflood (STB/D)	Recovery factor (%)	Np (MMSTB)	Gp (BCF)	Wp (MMSTB)	Production time (Year)	Wi (MMSTB)	Injection time (Year)
1,500	1,500	74.74	7.033	16.728	4.167	30	4.245	8
	1,000	78.24	7.363	15.227	4.159	30	4.245	8
	500	47.50	4.470	1.397	3.809	30	4.245	8
3,000	1,500	75.32	7.088	16.758	4.223	28	4.289	4
	1,000	79.14	7.448	15.787	4.211	28	4.289	4
	500	50.72	4.773	1.461	3.975	30	4.289	4
4,500	1,500	75.38	7.094	16.754	4.313	27	4.376	3
	1,000	79.27	7.460	15.770	4.300	28	4.376	3
	500	49.33	4.642	1.518	4.075	30	4.376	3

5.4.3 Two layers of 50-ft gas reservoirs

Oil recovery factors for three cases of target liquid production rate during gas dumpflood (500, 1000, and 1500 STB/D) are plotted for three different cases of initial target liquid production rates during waterflood operation (1,500, 3,000 and 4,500 STB/D) as shown in Figure 5.29. Simulation results also tabulated in Table 5.10. Similar to the results in Sections 5.4.1 – 5.4.2, oil recovery factor increases as the target liquid production rate during gas dumpflood is increased from 500 STB/D to 1,000 STB/D but decreases when the target liquid production rate during gas dumpflood is increased from 1,000 STB/D to 1,500 STB/D for all target liquid rates during waterflood. The explanation for this behavior is the same as the one in Section 5.4.1. As the production rate is increased, the injected water left inside the reservoir from the waterflood phase can be produced back to surface faster, allowing oil to be produced longer. However, if the production rate is too high, oil recovery factor decreases due to fast depletion of reservoir pressure. As a result, the liquid production rate of 1,000 STB/D still provides the highest oil recovery factors.

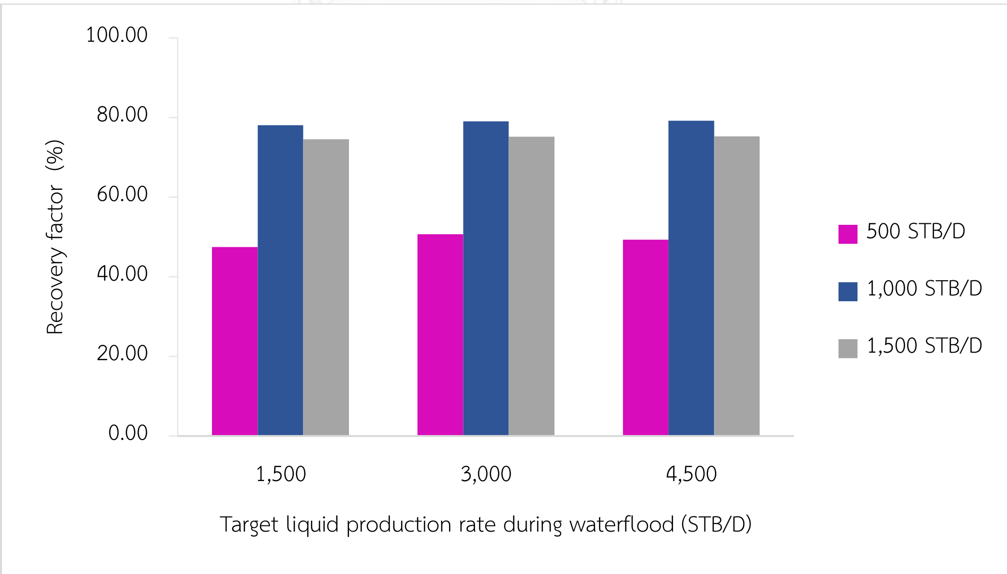


Figure 5.29 Recovery factors for different target liquid production rates during gas dumpflood for 2 layers of 50ft-gas reservoirs

Results from the simulation runs in terms of oil production, gas production, water production and injection, the time it takes to inject water are summarized in Table 5.10. The total oil productions for all cases in this section are higher than those for their respective cases in Section 5.4.1 due to the fact that the gas layers is thicker than the case of 25-ft gas reservoirs in this section but they are similar to the ones in Section 5.4.2 due to similar amount of original gas in place. The gas productions in the cases with 1,500 and 1,000 STB/D target liquid production rate during gas dumpflood are high (above 15 BCF) since gas already breaks through the producer in these cases but the gas productions in the cases of 500 STB/D are low (less than 1.6 BCF) because there is no gas breakthrough at the producer. Note that the gas productions in the cases of 1,500 and 1,000 STB/D in this section in which gas comes from 2 layers of 50-ft gas reservoirs are higher than those in Section 5.4.1 in which gas comes from 2 layers of 25-ft gas reservoirs.

Similar to the results in Sections 5.4.1 – 5.4.2, the cases with 1,500 and 1,000 STB/D target liquid production rate during gas dumpflood have higher water production than the cases with 500 STB/D because the rates of 1,000 STB/D or more are high enough to produce back most of the water injected during the waterflood phase. In terms of production time, the cases with a larger liquid production rate during gas dumpflood have shorter production time than those with a smaller liquid rate due to more rapid withdrawal of injected water and oil from the reservoir. Regarding water injection, the cases with a larger water injection rate have a slightly higher amount of cumulative water injection while the time required to inject water is lower.

Table 5.10 Summarized results for different target liquid production rates during gas dumpflood for 2 layers of 50ft-gas reservoirs

Target liquid rate during waterflood (STB/D)	Target liquid rate during dumpflood (STB/D)	Recovery factor (%)	Np (MMSTB)	Gp (BCF)	Wp (MMSTB)	Production time (Year)	Wi (MMSTB)	Injection time (Year)
1,500	1,500	74.57	7.017	16.516	4.167	30	4.245	8
	1,000	78.08	7.347	15.070	4.158	30	4.245	8
	500	47.50	4.469	1.397	3.809	30	4.245	8
3,000	1,500	75.21	7.077	16.550	4.223	28	4.289	4
	1,000	79.02	7.435	15.646	4.211	28	4.289	4
	500	50.71	4.772	1.460	3.975	30	4.289	4
4,500	1,500	75.31	7.086	16.545	4.313	27	4.376	3
	1,000	79.17	7.450	15.619	4.300	28	4.376	3
	500	49.33	4.642	1.517	4.076	30	4.376	3

5.4.4 Four layers of 50-ft gas reservoirs

Oil recovery factors for three cases of target liquid production rate during gas dumpflood (500, 1000, and 1500 STB/D) are plotted for three different cases of initial target liquid production rates during waterflood operation (1,500, 3,000 and 4,500 STB/D) as shown in Figure 5.30. These results are tabulated in Table 5.11. Similar to the results in Sections 5.4.1 - 5.4.3, oil recovery factor increases as the target liquid production rate during gas dumpflood is increased from 500 STB/D to 1,000 STB/D but decreases when the target liquid production rate during gas dumpflood is increased from 1,000 STB/D to 1,500 STB/D for all target liquid rates during waterflood. As the production rate is increased, the injected water left inside the reservoir from the waterflood phase can be produced back to surface faster, allowing oil to be produced longer. However, if the production rate is too high, oil recovery factor decreases due to fast depletion of reservoir pressure. As a result, the liquid production rate of 1,000 STB/D still provides the highest oil recovery factors.

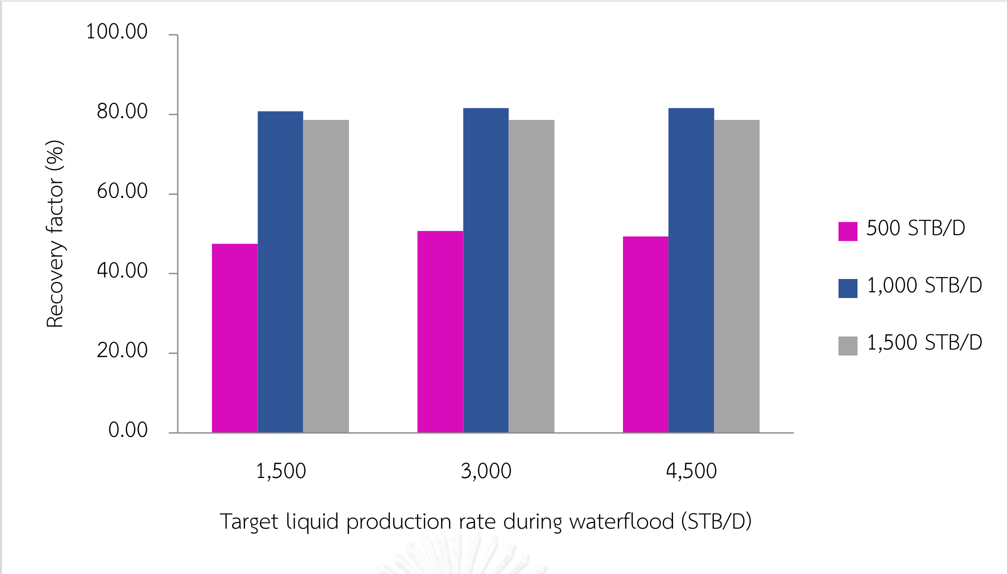


Figure 5.30 Recovery factors for different target liquid production rates during gas dumpflood for 4 layers of 50ft-gas reservoirs

Results from the simulation runs in terms of oil production, gas production, water production and injection, the time it takes to inject water are summarized in Table 5.11. The total oil productions for all cases in this section are higher than those for their respective cases in Sections 5.4.1 – 5.4.3 due to the fact that there are more amount of gas. The gas productions in the cases with 1,500 and 1,000 STB/D target liquid production rate during gas dumpflood are high (above 23 BCF) since gas already breaks through the producer in these cases but the gas productions in the cases of 500 STB/D are low (less than 1.6 BCF) because there is no gas breakthrough at the producer. Note that the gas productions in the cases of 1,500 and 1,000 STB/D in this section in which gas comes from 4 layers of 50-ft gas reservoirs are higher than those in Sections 5.4.1 – 5.4.3.

Similar to the results in Sections 5.4.1 - 5.4.3, the cases with 1,500 and 1,000 STB/D target liquid production rate during gas dumpflood have higher water production than the cases with 500 STB/D because the rates of 1,000 STB/D or more are high enough to produce back most of the water injected during the waterflood phase. In terms of production time, the cases with a larger liquid production rate during gas dumpflood have shorter production time than those with a smaller liquid rate due to more rapid withdrawal of injected water and oil from the reservoir. Regarding water injection, the cases with a larger water injection rate have a slightly higher amount of cumulative water injection while the time required to inject water is lower.

Table 5.11 Summarized results for different target liquid production rates during gas dumpflood for 4 layers of 50 ft-gas reservoirs

Target liquid rate during waterflood (STB/D)	Target liquid rate during dumpflood (STB/D)	Recovery factor (%)	Np (MMSTB)	Gp (BCF)	Wp (MMSTB)	Production time (Year)	Wi (MMSTB)	Injection time (Year)
	1,500	78.61	7.397	29.807	4.183	28	4.245	8
1,500	1,000	80.81	7.604	23.464	4.175	30	4.245	8
	500	47.53	4.473	1.398	3.806	30	4.245	8
	1,500	78.64	7.400	29.649	4.229	24	4.289	4
3,000	1,000	81.57	7.676	25.831	4.228	28	4.289	4
	500	50.74	4.775	1.461	3.973	30	4.289	4
	1,500	78.64	7.400	29.660	4.317	23	4.376	3
4,500	1,000	81.55	7.674	25.902	4.316	28	4.376	3
	500	49.34	4.643	1.518	4.074	30	4.376	3

5.5 Effect of depth difference between oil and gas reservoirs

The depth between oil and gas layers is one of the parameters that affect the performance of oil recovery in the double displacement process via gas dumpflood process as deeper gas reservoirs have higher pressures and temperatures. The depth differences between the bottom of the oil zone and the top of the topmost gas reservoirs investigated in this study are 500, 1000, and 2000 ft. Note that the target liquid production rates during waterflooding and gas dumpflood are 3,000 and 1,000 STB/D, respectively.

5.5.1 Two layers of 25-ft gas reservoirs

This reservoir contains two layers of 25-ft gas reservoirs located underneath the oil reservoir. Table 5.12 tabulates the pressures at top depths of the gas reservoirs for the cases investigated in this section. Recovery factors from reservoir simulation runs for different depths of gas reservoirs are depicted in Figure 5.31. As the gas reservoirs are located deeper, the oil recovery factor from double displacement process via gas dumpflood slightly increases. Due to higher and longer pressure support from deeper gas reservoirs (see Figure 5.32), the oil production rate during gas dumpflood from deeper gas reservoirs is slightly prolonged as illustrated in Figure 5.33.

As tabulated in Table 5.13, oil recovery factor increases from 74.41 to 76.74% when the depth difference increases from 500 to 2,000 ft. The gas production also increases with depth difference due to higher pressures of gas reservoirs and higher amount of total original gas in place. Water production and the length of time required to produce the oil are approximately the same for all cases.

Table 5.12 Gas reservoir pressure at top depth of each gas layer for various depth differences between oil and topmost gas layers for 2 layers of 25-ft gas reservoirs

Depth difference (ft)	Pressure at top depth (psia)			
	1	2	3	4
500	2,508	2,564	-	-
1,000	2,732	2,787	-	-
2,000	3,179	3,235	-	-

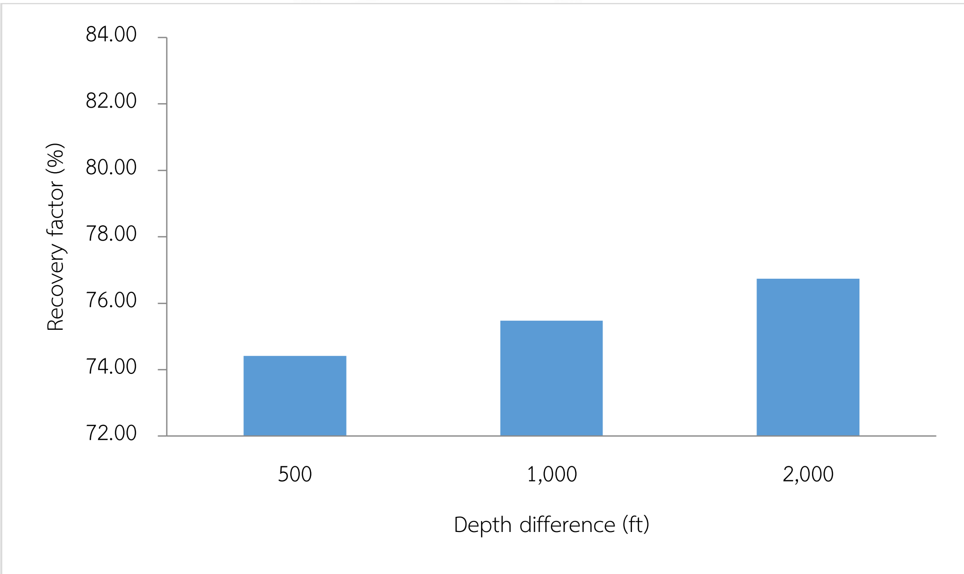


Figure 5.31 Recovery factors for three depth differences between oil and topmost gas layers for 2 layers of 25-ft gas reservoirs

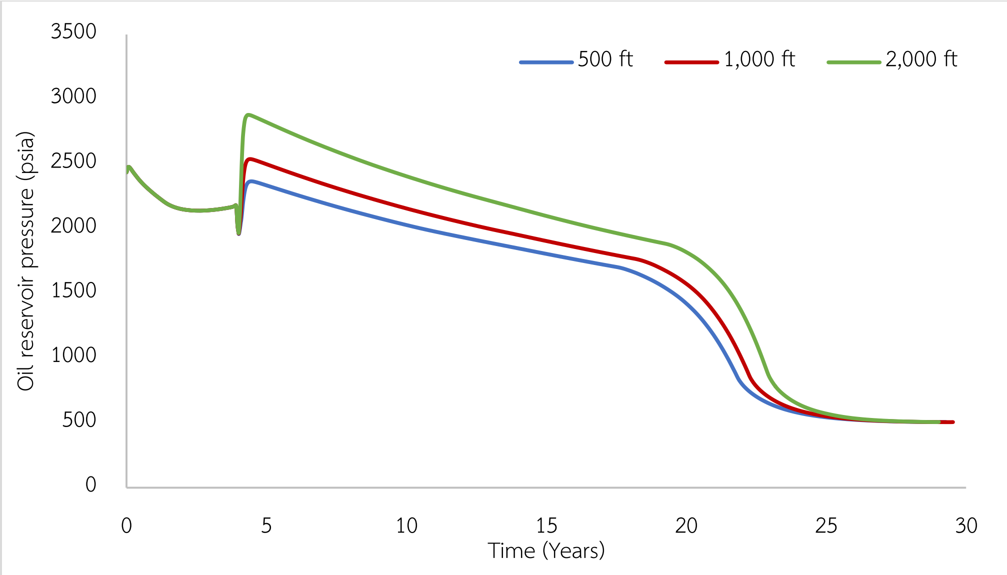


Figure 5.32 Oil reservoir pressures for three depth differences between oil and topmost gas layers for 2 layers of 25-ft gas reservoirs

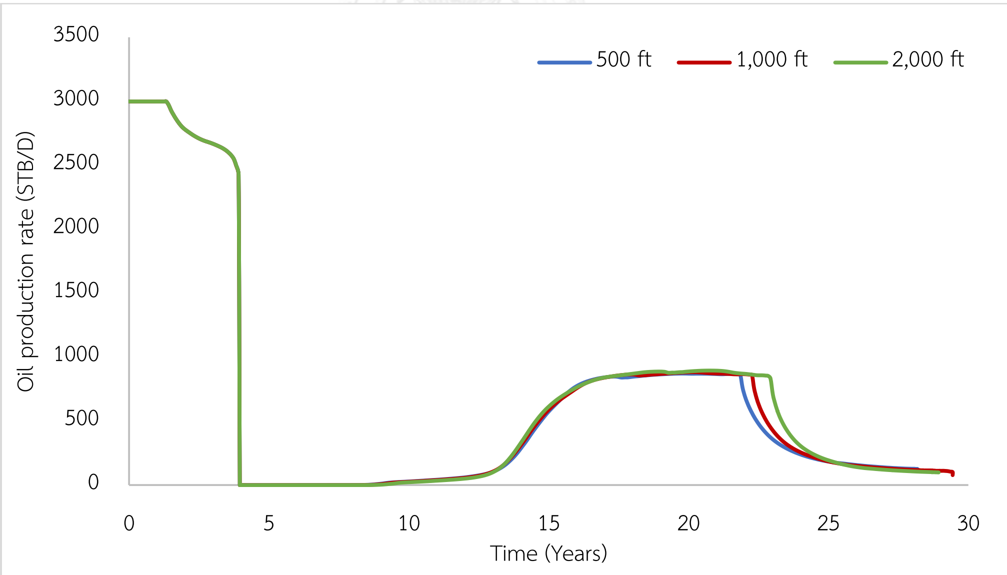


Figure 5.33 Oil production rate for three depth differences between oil and topmost gas layers for 2 layers of 25-ft gas reservoirs

Table 5.13 Summarized results for various depth differences between oil and topmost gas reservoirs for 2 layers of 25-ft gas reservoirs

Depth difference (ft)	Recovery factor (%)	Np (MMSTB)	Gp (BCF)	Wp (MMSTB)	Production time (Year)
500	74.41	7.008	8.695	4.198	29
1,000	75.47	7.103	9.154	4.199	29
2,000	76.74	7.227	9.936	4.196	29

5.5.2 Four layers of 25-ft gas reservoirs

This reservoir contains four layers of 25-ft gas reservoirs located underneath the oil reservoir. Table 5.14 tabulates the pressures at top depths of the gas reservoirs for the cases investigated in this section. Recovery factors from reservoir simulation runs for different depths of gas reservoirs are depicted in Figure 5.34. As the gas reservoirs are located deeper, the oil recovery factor from double displacement process via gas dumpflood slightly increases. Due to higher and longer pressure support from deeper gas reservoirs (see Figure 5.35), the oil production rate during gas dumpflood from deeper gas reservoirs is slightly prolonged as illustrated Figure 5.36.

As tabulated in Table 5.15, oil recovery factor increase from 78.50 to 80.11% when the depth difference increases from 500 to 2,000 ft. These values are higher than the ones in Section 5.5.1 in which there are only two layers of 25-ft gas reservoirs. As the number of gas layers is higher (more amount of gas in place), larger amounts of gas can flow from the gas reservoirs to the oil reservoir, enabling the double displacement process to be more efficient. In term of gas production, it still increases with depth difference. The gas productions for four layers of 25-ft gas reservoirs in Table 5.15 are much higher than the gas productions for two layers of 25-ft gas reservoirs in Table 5.13 due to a larger amount of total original gas in place in the gas layers. Water production and the length of time required to produce the oil are approximately the same for all cases and are of the same magnitudes as the ones in the cases of two layers of 25-ft gas reservoirs.

Table 5.14 Gas reservoir pressure at top depth of each gas layer for various depth differences between oil and topmost gas layers for 4 *layers of 25-ft gas reservoirs*

Depth difference (ft)	Pressure at top depth (psia)			
	1	2	3	4
500	2,508	2,564	2,619	2,676
1,000	2,732	2,787	2,843	2,900
2,000	3,179	3,235	3,291	3,346

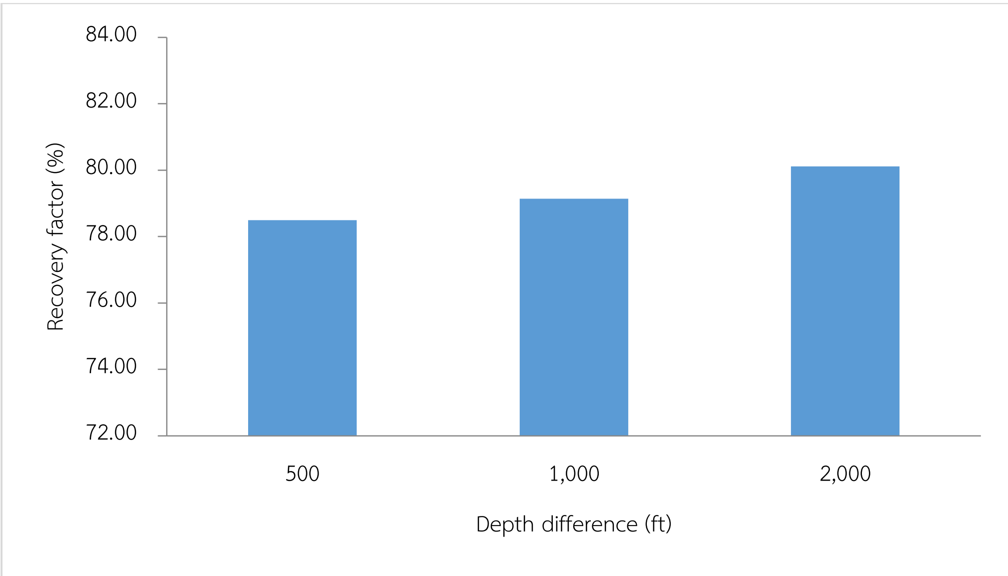


Figure 5.34 Recovery factors for three depth differences between oil and topmost gas layers for 4 layers of 25-ft gas reservoirs

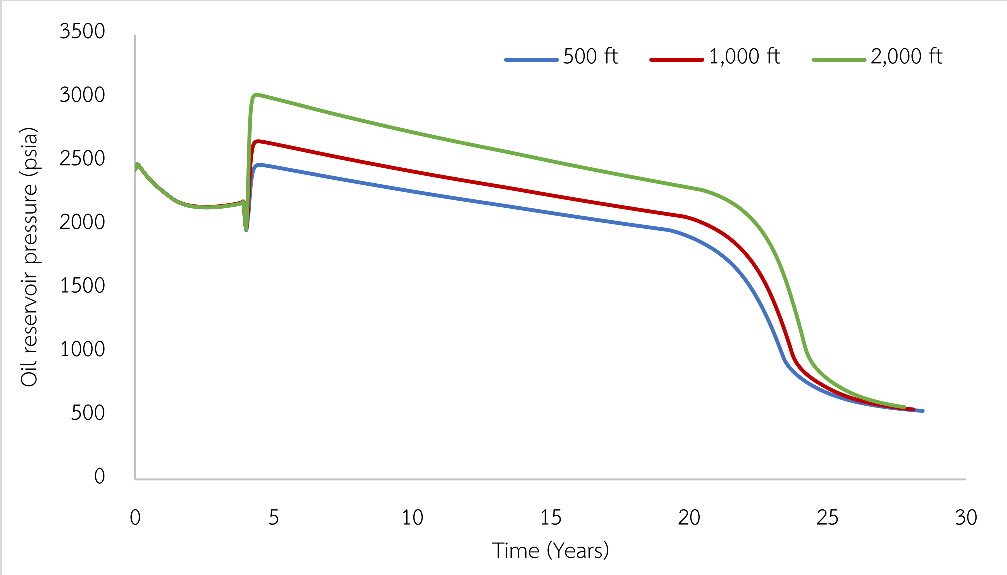


Figure 5.35 Oil reservoir pressures for three depth differences between oil and topmost gas layers for 4 layers of 25-ft gas reservoirs

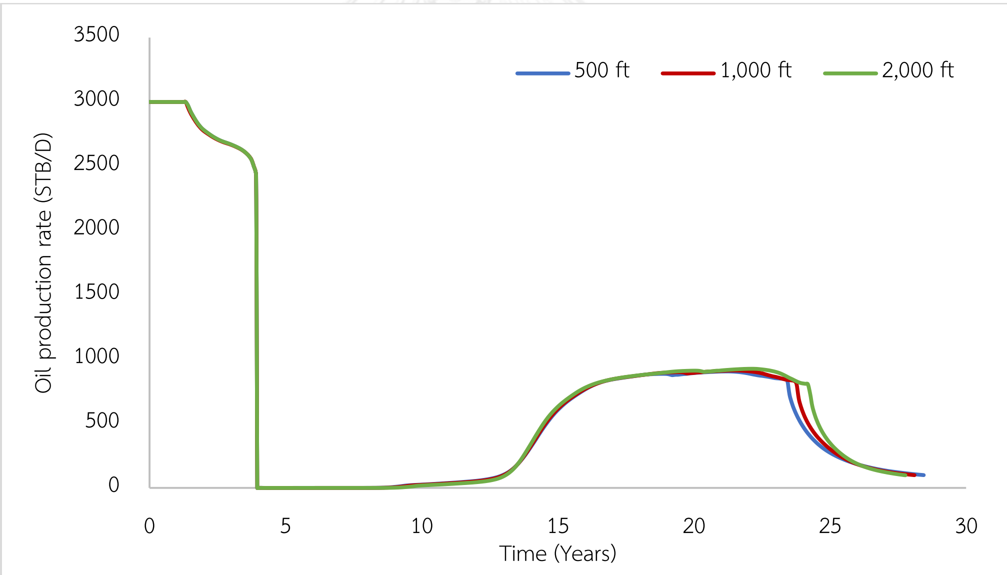


Figure 5.36 Oil production rate for three depth differences between oil and topmost gas layers for 4 layers of 25-ft gas reservoirs

Table 5.15 Summarized results for various depth differences between oil and topmost gas reservoirs for 4 layers of 25-ft gas reservoirs

Depth difference (ft)	Recovery factor (%)	Np (MMSTB)	Gp BCF)	Wp (MMSTB)	Production time (Year)
500	78.50	7.392	15.078	4.212	28
1,000	79.14	7.448	15.787	4.211	28
2,000	80.11	7.544	17.052	4.207	28

5.5.3 Two layers of 50-ft gas reservoirs

This reservoir contains two layers of 50-ft gas reservoirs located underneath the oil reservoir. Table 5.16 tabulates the pressures at top depths of the gas reservoirs for the case investigated in this section. Recovery factors from reservoir simulation runs for different depths of gas reservoirs are depicted in Figure 5.37. As the gas reservoirs are located deeper, the oil recovery factor from double displacement process via gas dumpflood slightly increases. Due to higher and longer pressure support from deeper gas reservoirs (see Figure 5.38), the oil production rate during gas dumpflood from deeper gas reservoirs is slightly prolonged as illustrated in Figure 5.38.

As tabulated in Table 5.17, oil recovery factor increases from 78.37 to 80.01% when the depth difference increases from 500 to 2,000 ft. These values are higher than the ones in Section 5.5.1 in which there are two layers of 25-ft gas reservoirs. As the thickness of gas reservoirs is higher (more amount of gas in place), larger amounts of gas can flow from the gas reservoirs to the oil reservoir, enabling the double displacement process to be more efficient. In term of gas production, it still increases with depth difference. The gas productions for two layers of 50-ft gas reservoirs in Table 5.17 are much higher than the gas productions for two layers of 25-ft gas reservoirs in Table 5.13 due to a larger amount of total original gas in place in the gas layers. Water production and the length of time required to produce the oil are approximately the same for all cases and are of the same magnitudes as the ones in the cases of two layers of 25-ft gas reservoirs.

Table 5.16 Gas reservoir pressure at top depth of each gas layer for various depth differences between oil and topmost gas layers for 2 layers of 50-ft gas reservoirs

Depth difference (ft)	Pressure at top depth (psia)			
	1	2	3	4
500	2,508	2,575	-	-
1,000	2,732	2,800	-	-
2,000	3,179	3,246	-	-

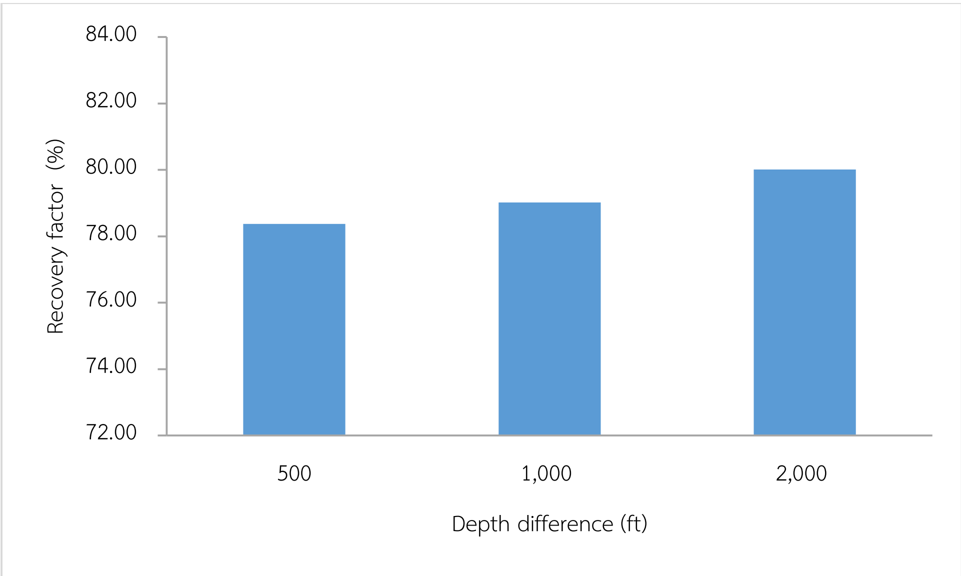


Figure 5.37 Recovery factors for three depth differences between oil and topmost gas layers for 2 layers of 50-ft gas reservoirs

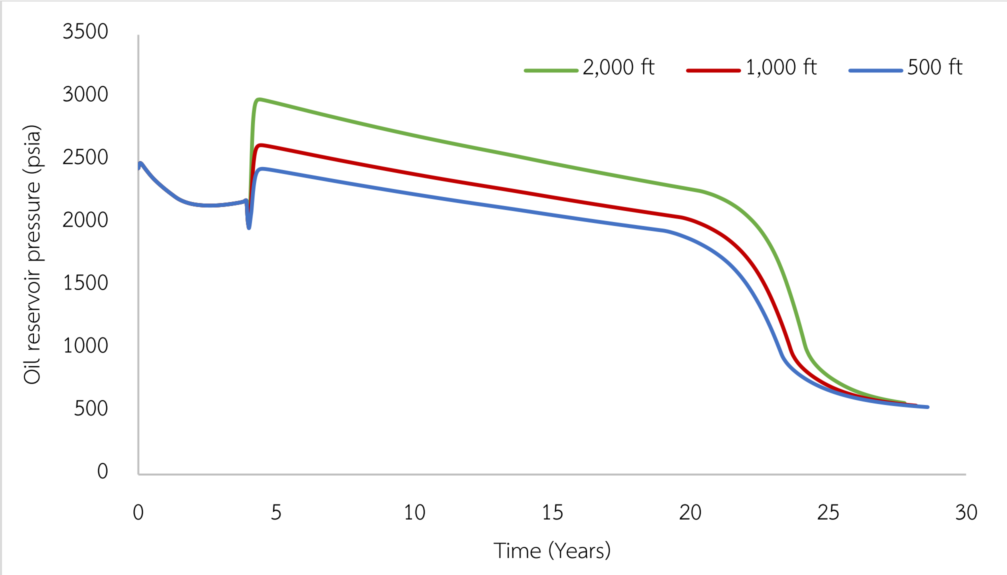


Figure 5.38 Oil reservoir pressures for three depth differences between oil and topmost gas layers for 2 layers of 50-ft gas reservoirs

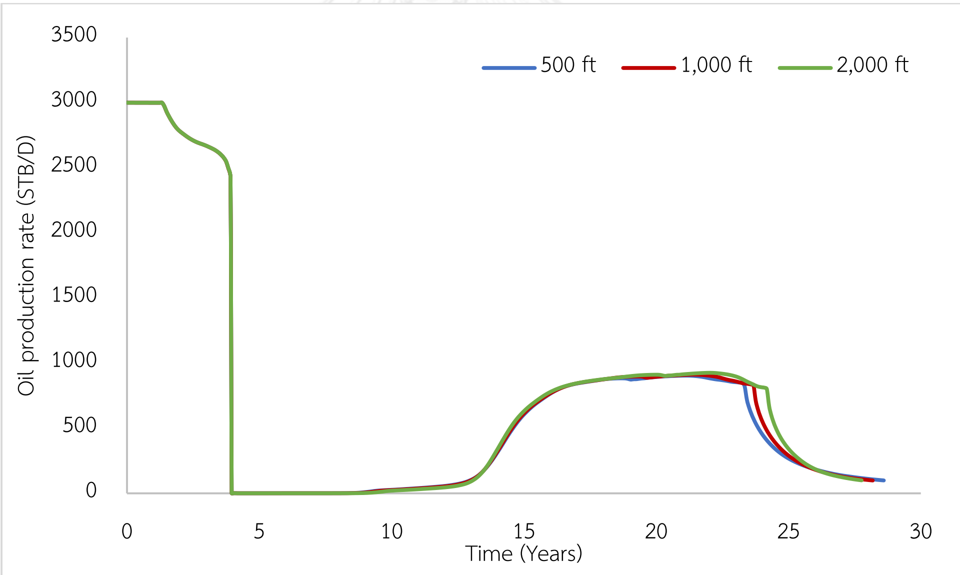


Figure 5.39 Oil production rate for three depth differences between oil and topmost gas layers for 2 layers of 50-ft gas reservoirs

Table 5.17 Summarized results for various depth differences between oil and topmost gas reservoirs for 2 layer of 50-ft gas reservoirs

Depth difference (ft)	Recovery factor (%)	Np (MMSTB)	Gp (BCF)	Wp (MMSTB)	Production time (Year)
500	78.37	7.377	14.920	4.213	29
1,000	79.02	7.435	15.646	4.211	28
2,000	80.01	7.535	16.900	4.208	28

5.5.4 Four layers of 50-ft gas reservoirs

This reservoir contains four layers of 50-ft gas reservoirs located underneath the oil reservoir. Table 5.18 tabulates the pressures of the gas reservoirs at top depths for the cases investigated in this section. Recovery factors from reservoir simulation runs for different depths of gas reservoirs are depicted in Figure 5.40. As the gas reservoirs are located deeper, the oil recovery factor from double displacement process via gas dumpflood slightly increases. Due to higher and longer pressure support from deeper gas reservoirs (see Figure 5.41), the oil production rate during gas dumpflood from deeper gas reservoirs is slightly prolonged as illustrated in Figure 5.42.

As tabulated in Table 5.19, oil recovery factor increases from 81.08 to 82.35% when the depth difference increases from 500 to 2,000 ft. These values are higher than the ones in Section 5.5.1 in which there are only two layers of 25-ft gas reservoirs. As the number of gas layers is higher and the thickness of each layer also bigger (more amount of gas in place), larger amounts of gas can flow from the gas reservoirs to the oil reservoir, enabling the double displacement process to be more efficient. In term of gas production, it still increases with depth difference. The gas productions for four layers of 50-ft gas reservoirs in Table 5.19 are much higher than the gas productions for two layers of 25-ft gas reservoirs in Table 5.13 due to a larger amount of total original gas in place in the gas layers. Water production and the length of time required to produce the oil are approximately the same for all cases and are of the same magnitudes as the ones in the cases of two layers of 25-ft gas reservoirs.

Table 5.18 Gas reservoir pressure at top depth of each gas layer for various depth differences between oil and topmost gas layers for 4 layers of 50-ft gas reservoirs

Depth difference (ft)	Pressure at top depth (psia)			
	1	2	3	4
500	2,508	2,575	2,643	2,709
1,000	2,732	2,800	2,866	2,933
2,000	3,179	3,246	3,314	3,381

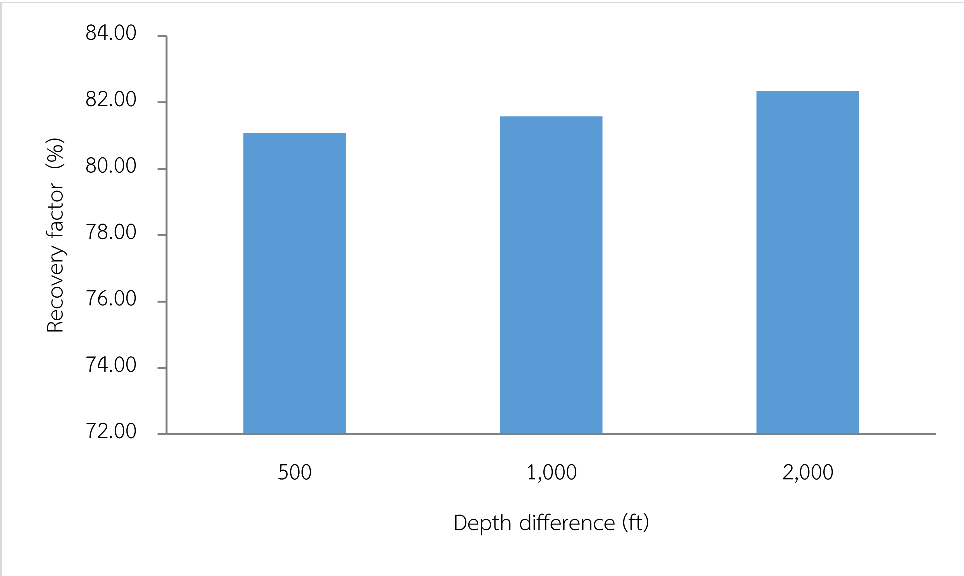


Figure 5.40 Recovery factors for three depth differences between oil and topmost gas layers for 4 layers of 50-ft gas reservoirs

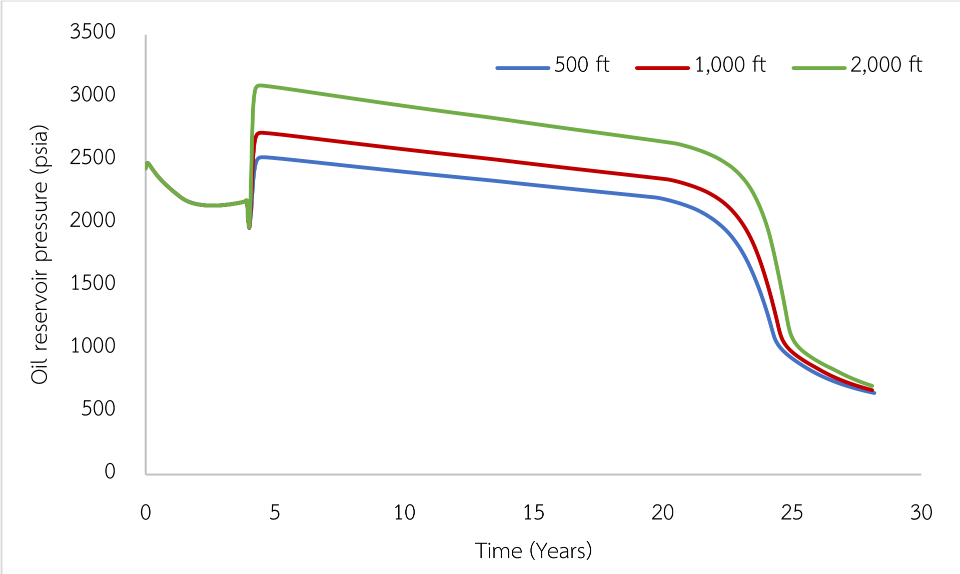


Figure 5.41 Oil reservoir pressures for three depth differences between oil and topmost gas layers for 4 layers of 50-ft gas reservoirs

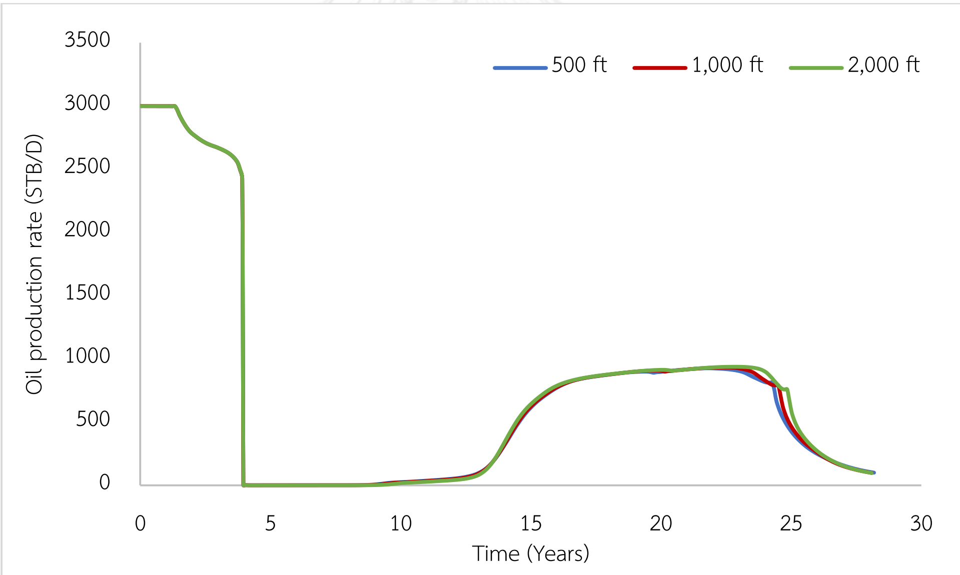


Figure 5.42 Oil production rate for three depth differences between oil and topmost gas layers for 4 layers of 50-ft gas reservoirs

Table 5.19 Summarized results for various depth differences between oil and topmost gas reservoirs for 4 layers of 50-ft gas reservoir

Depth difference (ft)	Recovery factor (%)	Np (MMSTB)	Gp (BCF)	Wp (MMSTB)	Production time (Year)
500	81.08	7.632	24.674	4.230	28
1,000	81.57	7.676	25.831	4.228	28
2,000	82.35	7.755	27.948	4.226	28

Note that dumping gas from underlying reservoirs into an overlying oil reservoir may cause a fracture in the oil layer if the entrance pressure into the oil layer exceeds the fracturing pressure. In this study, the entrance pressure at the dumping well is kept below 3,100 psi in all cases as provided in Figures 5.43 – 5.45.

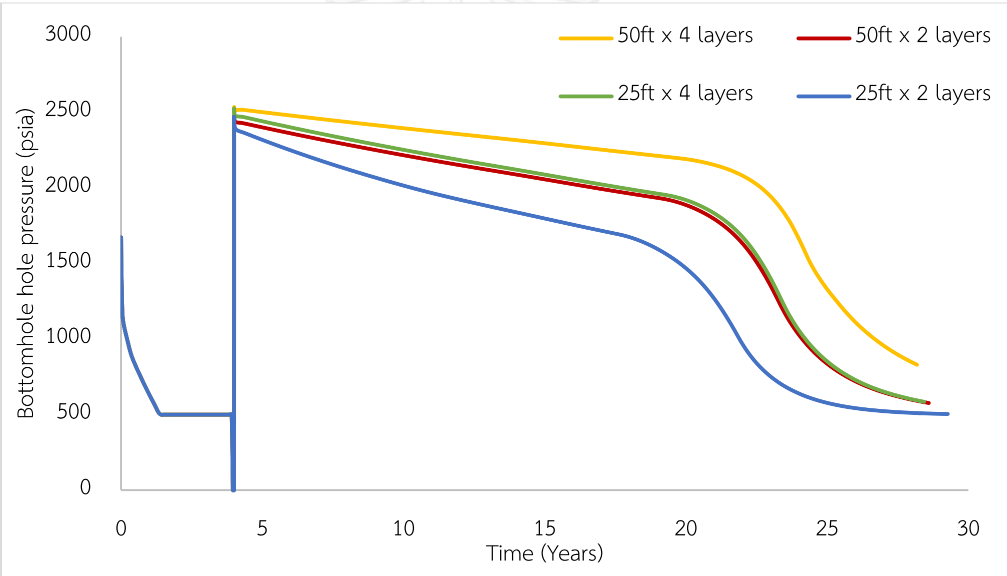


Figure 5.43 Bottomhole pressure of dumping well for 500-ft depth difference between oil and topmost gas layers

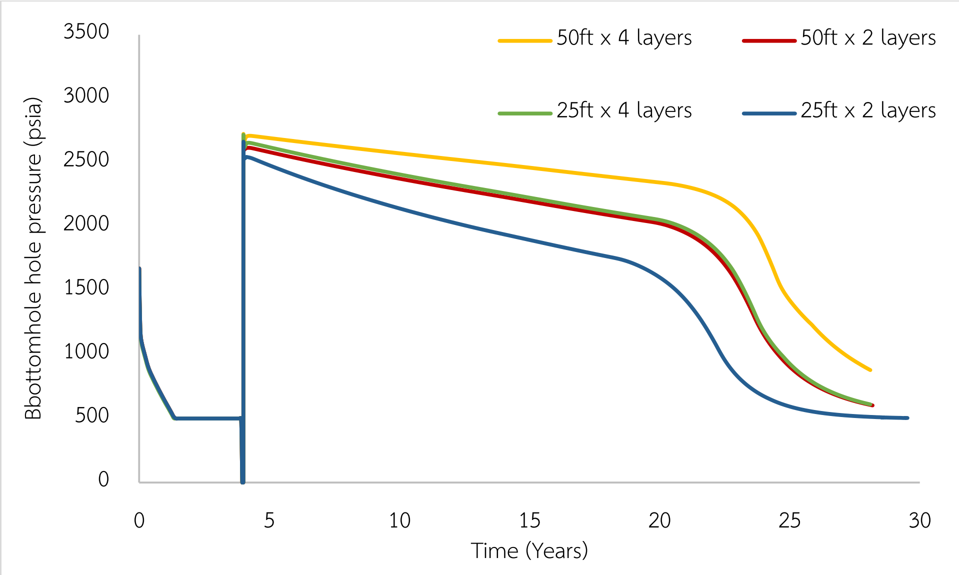


Figure 5.44 Bottomhole pressure of dumping well for 1,000-ft depth difference between oil and topmost gas layers

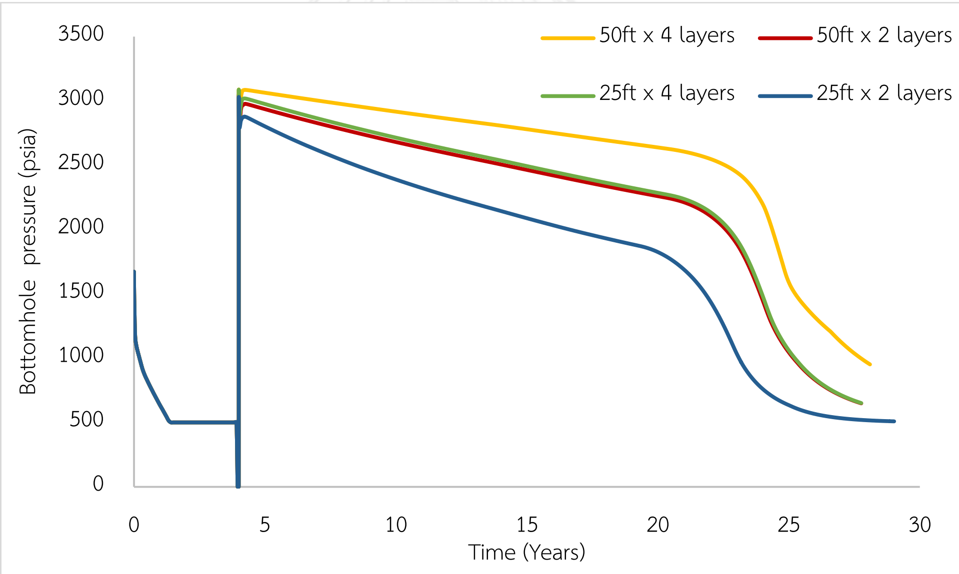


Figure 5.45 Bottomhole pressure of dumping well for 2,000-ft depth difference between oil and topmost gas layers

5.6 Effect of original gas in place in multi-layer gas reservoirs

In each reservoir model, it has its own amount of gas owing to difference in the number of gas layers and gas layer thickness. This section provides the data of original gas in place in each model as shown in Tables 5.20 - 5.22 and compares the recovery performance among the different models at the same target production rate of 3,000 STB/D during waterflood phase and 1,000 STB/D in gas dumpflood phase.

Table 5.20 Reservoir model composition

Model	Description
1	2 layers of 25-ft gas reservoirs
2	4 layers of 25-ft gas reservoirs
3	2 layers of 50-ft gas reservoirs
4	4 layers of 50-ft gas reservoirs

Table 5.21 Original gas in place in each gas layer for various depth differences between oil and topmost gas reservoirs and different gas thicknesses

Depth difference (ft)	Gas thickness (ft)	OGIP in each gas layer (BCF)			
		1	2	3	4
500	25	4.270	4.322	4.380	4.437
	50	8.526	8.666	8.802	8.932
1,000	25	4.494	4.547	4.601	4.653
	50	8.972	9.117	9.238	9.358
2,000	25	4.888	4.935	4.980	5.022
	50	9.778	9.885	9.988	10.106

Table 5.22 Total original gas in place of different reservoir models

Depth difference (ft)	OGIP in each reservoir model (BCF)			
	1	2	3	4
500	8.593	17.410	17.192	34.927
1,000	9.041	18.295	18.089	36.686
2,000	9.823	19.825	19.663	39.757

As the amount of original gas in place increases, oil recovery is better as shown in Figure 5.46 due to longer pressure maintenance as described in Section 5.5.

As tabulated in Table 5.23, the gas and water productions slightly increase with larger amount of gas in place. For production time, increasing gas in place slightly reduces production time. However, for too high amount of gas in place, the production time is approximately the same due to high gas production which leads to lower oil production rate at late time.

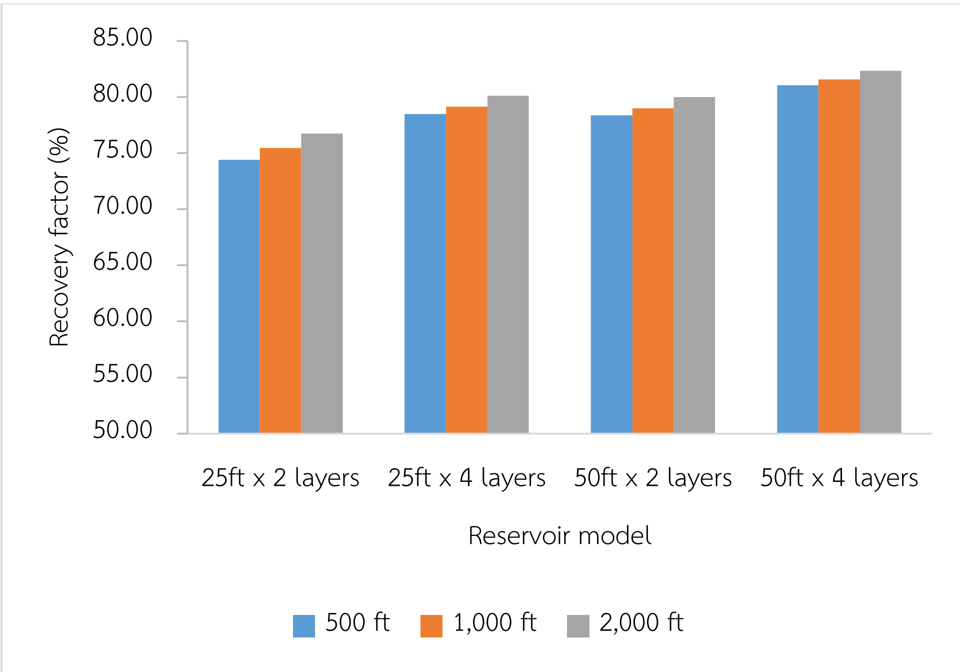


Figure 5.46 Recovery factor of each reservoir model and various depth differences between oil and topmost gas reservoirs

Table 5.23 Summarized results of different reservoir models at various depth differences between oil and topmost gas layers

Model	Depth difference (ft)	Recovery factor (%)	Np (MMSTB)	Gp (BCF)	Wp (MMSTB)	Production time (Year)
1	500	74.41	7.008	8.695	4.198	29
	1,000	75.47	7.103	9.154	4.199	29
	2,000	76.74	7.227	9.936	4.196	29
2	500	78.50	7.392	15.078	4.212	28
	1,000	79.14	7.448	15.787	4.211	28
	2,000	80.11	7.544	17.052	4.207	28
3	500	78.37	7.377	14.920	4.213	29
	1,000	79.02	7.435	15.646	4.211	28
	2,000	80.01	7.535	16.900	4.208	28
4	500	81.08	7.632	24.674	4.230	28
	1,000	81.57	7.676	25.831	4.228	28
	2,000	82.35	7.755	27.948	4.226	28

CHAPTER VI

CONCLUSIONS AND RECCOMENDATIONS

In this chapter, the conclusion from the study of reservoir simulation on double displacement process by using multiple gas reservoirs as the gas source for gas dumpflood process which investigates perforation program of gas layers, target liquid production rates during waterflood and gas dumpflood and characteristics of gas reservoirs are provided. Then, recommendations for future study are also included.

6.1 Conclusions

1) Regarding perforation program, perforating full to base in all gas layers at the same time provides a slightly larger recovery factor than two-batch perforation schemes (about 1% higher). This is because perforating all layers at the same time yields a large amount of gas flowing into the oil reservoir at early time, raising the pressure of the oil reservoir better than other cases. This high reservoir pressure helps prolong the plateau period of oil production.

2) Higher target liquid production rate during waterflood can speed up the entire double displacement process as a higher rate requires a short production time than a lower one. However, oil recovery factors for different target liquid production rates during waterflood are more or less the same. In term of water and gas production, higher target production rate during waterflood gives 0.2 MMSTB higher water production as increasing the liquid rate during waterflood from 1,500 to 4,500 STB/D while the gas production increases by a small amount (0.1 BCF). After comparing the overall advantages and disadvantages, the target liquid rate of 3,000 STB/D during waterflood should be used as it requires short production time approximately the same as the rate of 4,500 STB/D, but it uses less injected water (0.087 MMSTB lesser).

3) When the target liquid production rate during gas dumpflood is too low (500 STB/D in this study), the amount of total oil recovery is low (approximately lower to 47%) since its reaches the time constraint while the oil production is still at its peak period. When the target rate is increased to a moderate rate (1,000 STB/D) recovery factor increases. However, when the target rate is too high (1,500 STB/D) the recovery factor decreases since too high liquid production rate causes unsmooth flood front, leading to early gas breakthrough. Although the high rate results in low total oil recovery, oil can be produced much sooner than the case of moderate rate. In order to determine which case is more profitable, a detailed economic analysis needs to be performed. Total water production and total gas production also increase as the target liquid production rate during gas dumpflood is increased.

4) Larger depth difference between the bottom of the oil zone and the topmost gas reservoirs results in higher and longer pressure support from underlying gas reservoirs, leading to slightly better oil recovery (approximately up to 2% as the depth difference increases from 500 ft to 2,000 ft). In addition, gas production also increases as the depth difference is larger while the total water production and production period are approximately the same.

5) Different gas layer thicknesses and numbers of gas layers result in different values of original gas in place. Higher amount of original gas in place in reservoirs used as the gas source for gas dumpflood provides better recovery factor due to longer pressure maintenance. The gas production and water production are higher with the increase in original gas in place.

6.2 Recommendations

1) This study is based on the assumption that there is no miscibility effect in the recovery process of this method. A further study on the miscibility should be performed to investigate its effects as it helps reducing oil viscosity and density.

2) The properties of each gas layer are the same in this study. A further study may focus on the different characteristic of gas reservoirs such as permeability and porosity which influence cross-flow within the wellbore.

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APPENDIX

APPENDIX A

This section provides the details of input parameters for the base case of double displacement process via gas dumpflood from multiple gas reservoirs which constructed on ECLIPSE100 reservoir simulator.

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 z-direction = 54
Grid type	Cartesian
Geometry type	Corner point
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, 1:10) = 1
	(1:45, 1:19, 11) = 0
	(1:45, 1:19, 12:21) = 1
	(1:45, 1:19, 22) = 0
	(1:45, 1:19, 23:32) = 1
	(1:45, 1:19, 33) = 0
	(1:45, 1:19, 34:43) = 1
	(1:45, 1:19, 44) = 0
	(1:45, 1:19, 45:54) = 1

1.2.2 Geometry

Grid block sizes	x grid block size = 100
	y grid block size = 100
	z grid block size 1:10 = 5,
	11,22,33,44 = 1,000,
	12:21, 23:32, 34:43, 45:54 = 2.5
Depth of top face	5,000 ft at top of reservoir model

1.3 Initialization

1.3.1 Equilibration region 1

Equilibration data specification

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

1.3.2 Equilibration region 2

Equilibration data specification

Datum depth	6050 ft
Pressure at datum depth	2711 psia
WOC depth	10000 ft
GOC depth	7240 ft

1.3.3 Equilibration region 3

Equilibration data specification

Datum depth	6175 ft
Pressure at datum depth	2766 psia
WOC depth	10000 ft
GOC depth	7365 ft

1.3.4 Equilibration region 4

Equilibration data specification

Datum depth	6300 ft
Pressure at datum depth	2822 psia
WOC depth	10000 ft
GOC depth	7490 ft

1.3.5 Equilibration region 5

Equilibration data specification

Datum depth	6425 ft
Pressure at datum depth	2878 psia
WOC depth	10000 ft
GOC depth	7615 ft

1.6 Region

Equilibration region numbers	1 at	(1:19, 1:45, 1:11)
	2 at	(1:19, 1:45, 12:22)
	3 at	(1:19, 1:45, 23:33)
	4 at	(1:19, 1:45, 34:44)
	5 at	(1:19, 1:45, 45:54)

FIP region numbers	1 at	(1:19, 1:45, 1:11)
	2 at	(1:19, 1:45, 12:22)
	3 at	(1:19, 1:45, 23:33)
	4 at	(1:19, 1:45, 34:44)
	5 at	(1:19, 1:45, 45:54)

PVT region numbers	1 at	(1:19, 1:45, 1:11)
	2 at	(1:19, 1:45, 12:22)
	3 at	(1:19, 1:45, 23:33)
	4 at	(1:19, 1:45, 34:44)
	5 at	(1:19, 1:45, 45:54)

1.7 Schedule

1.7.1 Up-dip well

Well specification

Well name	P1
Group	1
I location	3
J location	10
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	10
Open/shut flag	OPEN
Well bore ID	0.51042 ft
Direction	Z

Production well control (during waterflood)

Well	P1
Open/shut flag	OPEN
Control	LRAT
Liquid rate	3000 stb/day
BHP target	500 psia

Production well control (during gas dumpflood)

Well	P1
Open/shut flag	STOP

Segmented well definition

Well	P1
Depth to top seg node	5051.76 ft
Length to top seg node	0
Length & depth	INC
Pressure drop	HF-
Flow model	HO

Table A.1 Well segments of P1

First Seg	Last Seg	Branch	Outlet Seg	Length (ft)	Depth (ft)	Diameter (ft)	Roughness (ft)
2	2	1	1	50	50	0.2493333	0.00015
3	3	1	2	1000	1000	0.2493333	0.00015
4	4	1	3	25	25	0.2493333	0.00015
5	5	1	4	100	100	0.2493333	0.00015
6	6	1	5	25	25	0.2493333	0.00015
7	7	1	6	100	100	0.2493333	0.00015
8	8	1	7	25	25	0.2493333	0.00015
9	9	1	8	100	100	0.2493333	0.00015
10	10	1	9	25	25	0.2493333	0.00015

Segmented well completions

Table A.2 Well completion of P1

I	J	K	Branch	Start Length (ft)	End Length (ft)	Direction	End
3	10	1	1	0	50	K	10
3	10	12	1	1050	1075	K	21
3	10	23	1	1175	1200	K	32
3	10	34	1	1300	1325	K	43
3	10	45	1	1425	1450	K	54

Segment VFP tables

Table A.3 VFP table of each segment for well P1

Well Names	First Seg	Last Seg	VFP Table	P drop components	Neg flow	Scale P drop
P1	3	3	1	FH	FIX	LEN
P1	5	5	2	FH	FIX	LEN
P1	7	7	3	FH	FIX	LEN
P1	9	9	4	FH	FIX	LEN

Note: FH stands for “Friction and Hydrostatic”.

HF stands for “Friction and Hydrostatic”.

FIX stands for “Fix the lookup value of the flow rate at the first flow point in the table”.

LEN stands for “The interpolated pressure drop is scaled in proportion to the length of the segment relative to the table’s datum length.”

INC stands for “Incremental changes of these quantities along each segment”.
HO stands for “Homogeneous flow; the phases all flow with the same velocity”.

<u>Vertical flow performance</u>

VFP tables are generated by software named Prosper 10.3 by using input parameters as tabulated in table A.4 and table A.5.

Table A.4 Input parameter for VFP table

Parameters	Table				Unit
	1	2	3	4	
Fluid	Dry and wet gas				
Method	Black oil				
Flow type	Tubing flow				
Well type	Producer				
Gas gravity	0.6				
Condensate to gas ratio	0				
Water salinity	2,500				ppm.
Gas viscosity	Carr et al				
Vertical lift correlation	Gray				
Enter rate	1E-6 to 100				MMscf/D
Variable 1: first node pressure	50 to 5000				psi
Variable 2: Water gas ratio	0 to 1				STB/MMscf
First node	5101.76	6126.76	6251.76	6376.76	ft
Last node	6101.76	6226.76	6351.76	6476.76	ft

Table A.5 Equipment data for VFP Table

Type	True vertical depth (ft)	Measure depth (ft)	Tubing ID (inches)	Tubing inside roughness (ft)	Formation temperature (^oF)
Tubing	0	0	2.992	0.0018	100
Tubing	5101.76	5101.76	2.992	0.0018	236
Tubing	6101.76	6101.76	2.992	0.0018	208
Tubing	6126.76	6126.76	2.992	0.0018	269
Tubing	6226.76	6226.76	2.992	0.0018	272
Tubing	6251.76	6251.76	2.992	0.0018	273
Tubing	6351.76	6351.76	2.992	0.0018	276
Tubing	6376.76	6376.76	2.992	0.0018	277
Tubing	6476.76	6476.76	2.992	0.0018	280

1.7.2 Down-dip well

Well specification

Well name	P2
Group	1
I location	43
J location	1
Preferred phase	OIL
Inflow equation	STD
Automatic shut-in instruction	SHUT
Crossflow	YES
PVT property table	1

Well connection data

Well	P2
I location	43
J location	1
K upper	1
K lower	10
Open/shut flag	SHUT

Well bore ID	0.51042 ft
Direction	Z

Well connection data

Well	P2
I location	43
J location	2 to 19
K upper	10
K lower	10
Open/shut flag	OPEN
Well bore ID	0.51042 ft
Direction	Y

Injection well control (during waterfloood)

Well	P2
Injector type	WATER
Open/shut flag	OPEN
Control	RATE
Liquid surface rate	3000 stb/day
BHP target	3900 psia

Production well control (during gas dumpflood)

Well	P1
Open/shut flag	OPEN
Control	LRAT
Liquid rate	3000 stb/day
BHP target	500 psia

Production well economic limits

Well	P2
Minimum oil rate	100 stb/day
Workover procedure	None
WELL End run	YES
Quantity for economic limit	RATE

VITA

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