EVALUATION OF COMBINED WATER AND GAS DUMPFLOOD INTO OIL RESERVOIR

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วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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วัฒนา มอม : การประเมินการไหลเทร่วมของน้ำและแก๊สไปยังแหล่งกักเก็บน้ำมัน (EVALUATION OF COMBINED WATER AND GAS DUMPFLOOD INTO OIL RESERVOIR) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร. สุวัฒน์ อธิชนากร, 102 หน้า.

การฉีดอัดด้วยน้ำ หรือแก๊ส เป็นกระบวนการที่นิยม เพื่อเพิ่มปริมาณการผลิตน้ำมัน อย่างไรก็ตาม กระบวนการดังกล่าวต้องใช้การลงทุนและค่าดำเนินการที่สูง สำหรับแหล่งกักเก็บหลายชั้นที่มีแหล่งน้ำอยู่เหนือชั้นน้ำมัน และมีชั้นแก๊สอยู่ชั้นล่าง น้ำจากแหล่งน้ำดังกล่าวสามารถไหลเทลงมายังแหล่งกักเก็บน้ำมัน อีกทั้ง แก๊สจากชั้นล่างสามารถไหลเทขึ้นมายังแหล่งกักเก็บน้ำมัน แทนการฉีดอัดด้วยน้ำหรือแก๊สจากพื้นผิวเพื่อเพิ่มการผลิตน้ำมันได้เช่นกัน การศึกษานี้เป็นการศึกษาเพื่อเปรียบเทียบความสามารถของกระบวนการไหลเทร่วมของน้ำและแก๊ส กับการบวนการไหลเทด้วยน้ำหรือแก๊สเพียงชนิดเดียว โดยใช้โปรแกรมแบบจำลองการไหลในแหล่งกักเก็บ เพื่อสร้างแบบจำลองแหล่งกักเก็กที่มีความลาดเอียงพอประมาณ โดยออกแบบให้หลุมสำหรับไหลเทน้ำอยู่บริเวณส่วนล่างและหลุมสำหรับไหลเทแก๊สอยู่บริเวณส่วนบนของแหล่งกักเก็บ ในขณะที่หลุมผลิตอยู่ระหว่างหลุ่มไหลเททั้งสอง ในขณะเดียวกัน ขนาดของแหล่งกักเก็บแก๊สและแหล่งน้ำถูกปรับเปลี่ยนเพื่อศึกษาผลกระทบที่มีต่อการผลิตน้ำมันเช่นกัน

ผลจากการศึกษาด้วยโปรแกรมแบบจำลองการไหลในแหล่งกักเก็บแสดงให้เห็นว่า การไหลเทร่วมของน้ำและแก๊สเป็นวิธีที่เหมาะสมในกรณีที่ขนาดของแหล่งน้ำมีขนาดใหญ่ และแหล่งกักเก็บแก๊สมีขนาดเล็ก นอกจากนี้ การไหลเทด้วยแก๊สเพียงชนิดเดียวเป็นกระบวนการที่เหมาะสมเมื่อแหล่งกักเก็บแก๊สมีขนาดใหญ่ ในทางกลับกัน กระบวนการเทด้วยน้ำเพียงชนิดเดียวให้ปริมาณการผลิตน้ำมันน้อยกว่าทุกๆกระบวนการ เพื่อที่จะหาวิธีการที่ให้ประสิทธิภาพสูงสุดต่อกระบวนการไหลเทร่วมของน้ำและแก๊สไปยังแหล่งกักเก็บน้ำมัน การวางหลุมผลิตควรวางใกล้หลุมไหลเทน้ำเพื่อหลีกเลี่ยงการผลิตแก๊สก่อนกำหนด มากไปกว่านั้น ผลการศึกษายังแสดงให้เห็นว่า เมื่อถ่ายเทน้ำและแก๊ส พร้อมทั้งผลิตน้ำมันในเวลาเดียวกัน เป็นวิธีการที่ดีที่สุดสำหรับกระบวนการไหลเทร่วมของน้ำและแก๊สไปยังแหล่งกักเก็บน้ำมัน ทั้งนี้เพราะระยะเวลาดังกล่าวช่วยรักษาความดันในแหล่งกักเก็บได้มากที่สุดสำหรับอัตราการผลิตที่มากที่สุดด้วยเช่นกัน

ภาควิชา วิศวกรรมเหมืองแร่และปิโตรเลียม ลายมือชื่อนิสิต ....

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Secondary recoveries such as water and gas flooding are commonly used in order to improve oil production. However, water and gas injection typically incurs high capital and operating costs. In multi-stacked reservoirs in which water aquifer is located above an oil reservoir with a gas reservoir underneath, water from the overlying aquifer and gas from the underlying gas reservoir can be dumped into the oil reservoir instead of injecting them from surface. In order to investigate the performance of combined water and gas dumpflood in comparison to stand-alone water dumpflood and stand-alone gas dumpflood, a hypothetical reservoir model with simple geometry having a moderate dip angle is constructed using a numerical reservoir simulator. Water dumping well is located in the downdip part of the reservoir system while the gas dumping well is located updip. The oil producer is located between the two wells. The sizes of gas reservoir and aquifer are varied in order to determine their effect on oil recovery.

Simulation results show combination dumpflood is more favorable than other methods when there is a presence of large aquifer size and small gas reservoir. In cases of large gas reservoir, stand-alone gas dumpflood is better a method. In all the cases, stand-alone water dumpflood is worse than stand-alone gas dumpflood and combination dumpflood. To optimize oil production in case of combination dumpflood, the oil producer should be located a little bit towards the water dumping well in order to avoid early gas breakthrough. The results from simulation also indicate that simultaneous dumpflood of water and gas at the beginning of the production is the best choice for combination dumpflooding schedule due to its ability to maintain higher oil reservoir pressure at higher oil production rate.

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LIST OF ABBREVIATIONS

bbl	Barrel
bbl/STB	Barrel per stock tank barrel
BWPD	Barrel of water per day
BSCF	Billion standard cubic feet
B/D	Barrel per day
cu ft	Cubic feet
ESP	Electrical submersible pump
ft	Feet
FVF	Formation volume factor
GOR	Gas oil ratio
LRAT	Liquid rate
m	Meter
mD	Millidarcy
MSTB	Thousand stock tank barrel
MMSTB	Million stock tank barrel
MBOPD	Thousand barrel of oil per day
OOIP	Oil originally in place
ppm	Part per million
psi	Pound per square inch
psia	Pound per square inch absolute
psig	Pound per square inch gauge
psi/ft.	Pound per square inch per foot
PV	Pore volume
PVT	Pressure-Volume-Temperature
rb /stb	Reservoir barrel per stock tank barrel
Sg	Specific gravity
SCF/STB	Standard cubic feet per stock tank barrel
STB	Stock tank barrel

STB/D	Stock tank barrel per day
TVD	True vertical depth

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NOMENCLATURES

B_o	Gas formation volume factor at a given time, bbl/SCF
B_{gi}	Initial gas formation volume, bbl/SCF
B_o	Oil formation volume at a given time, bbl/STB
B_{oi}	Initial oil formation volume, bbl/STB
^oC	Degree Celsius
cp	Centipoise
c_w	Compressibility of the water, psi^{-1}
E_A	Areal sweep efficiency, fraction
E_I	Vertical sweep efficiency, fraction
E_D	Displacement efficiency, fraction
E_V	Volumetric sweep efficiency, fraction
^oF	Degree Fahrenheit
$FRAC.S.G$	Fracturing pressure gradient
I	Injectivity index, BWPD/psi
I_w	Water producing rate into oil reservoir, BWPD
J	Productivity index, BWPD/psi
k	Absolute permeability
k_g	Effective permeability of gas
k_o	Effective permeability of oil
k_{rg}	Relative permeability to gas
k_{ro}	Relative permeability to oil
k_{rw}	Relative permeability to water
K_{rog}	Oil relative permeability as determined from the gas-oil two-phase relative permeability at S_w
K_{row}	Oil relative permeability as determined from the oil-water two-phase relative permeability at S_w
$K_{rw,end}$	Relative permeability to water at minimum water saturation

$(K_{ro})_{S_{wc}}$	Relative permeability to oil at the connate-water saturation as determined from the oil-water relative permeability system
k_w	Effective permeability of water
$lb\ /ft^3$	Pound per cubic foot
M	Mobility ratio
N	Initial oil in place at the start of flooding, STB
N_g	Corey gas exponent
N_o	Corey oil exponent
N_P	Cumulative oil production, STB
N_w	Corey water exponent
Δp_{fr}	Friction pressure drop, psi
p_{eo}	Boundary pressure in oil zone, psig
p_{ew}	Boundary pressure in water zone, psig
RF	Overall recovery factor, fraction
R_p	Cumulative gas oil ratio, SCF/STB
R_s	Dissolved gas oil ratio, SCF/STB
R_s	Initial dissolved gas oil ratio, SCF/STB
S_g	Gas saturation, fraction
S_{gc}	Critical gas saturation, fraction
$\bar{S}_o$	Average oil saturation at a given time, fraction
S_{oi}	Initial oil saturation at start of flood, fraction
S_w	Water saturation, fraction
S_{or}	Residual oil saturation, fraction
S_{wi}	Initial water saturation or connate water saturation, fraction
S_{om}	Minimum oil saturation, fraction
S_{row}	Residual oil saturation in the oil-water relative permeability system, fraction
S_{rog}	Residual oil saturation in the gas-water relative permeability system, fraction

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W_e	Water influx into the reservoir, bbl
W_{inj}	Water injection into the reservoir, bbl

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CHAPTER 1

INTRODUCTION

1.1 Background

During primary recovery, only certain amount of oil can be recovered. That is why secondary process can be used in order to maintain the reservoir pressure and prolong the reservoir's life. Conventional methods of secondary recovery include immiscible processes such as water flooding and gas flooding.

Water flooding is used for the main purpose of maintaining the reservoir pressure as well as displacing the oil toward the production wells in order to increase the oil recovery. With the same objectives as conventional water flooding, water dumpflood is conducted by dumping water or flowing water naturally from aquifer into the oil reservoir. Based on similar concepts as water flooding and water dumpflood, immiscible gas flooding and gas dumpflood are also used for reservoir pressure maintenance and displacement of oil from the pore spaces by injecting gas from surface or dumping gas from a gas reservoir according to its availability.

The availability of the water from an aquifer and gas from a gas reservoir in multi-layer reservoir system leads to an idea of studying the performance of the combination of dumpflooding of both water and gas into an oil reservoir in comparison with stand-alone water dumpflood and stand-alone gas dumpflood. In this study, investigation of performance of water dumpflood, gas dumpflood and the combination of both water and gas dumpflood are conducted by using reservoir simulator ECLIPSE 100 with different production scenarios. Reservoir system parameter and operational parameters that will be discussed later at the methodology part are evaluated on their performance based on oil recovery, gas production and water production.

1.2 Objectives

1. To determine the best conditions for combined water and gas dumpflood
2. To conduct comparative study among conventional water dumpflood, conventional gas dumpflood, and combined water and gas dumpflood
3. To study the effect of different reservoir system parameters and operational parameters on oil recovery obtained from combined water and gas dumpflood

1.3 Outline of methodology

1. Construct base case models for natural depletion, dumpflood, gas dumpflood and combined water and gas dumpflood at the same time into oil reservoir with 15° dip-angle. For natural depletion, three production wells are used to produce oil; one at updip, one at the middle and another one downdip. For water dumpflood, two wells are used: a dumping well downdip and a producer updip. For gas dumpflood a pair of updip dumping well and a downdip producer is used. The combined water and gas dumpflood requires three wells: gas dumping well updip, oil producer in the middle and water dumping well downdip.
2. Simulate and find recovery factor natural depletion, water dumpflood and gas dumpflood model in order to define whether there is an improvement when combining of water and gas dumpflood.
3. After obtaining base case results, simulate the model of combined water and gas dumpflood with different operational parameters and reservoir system parameters in order to study the effects of these parameters on oil recovery. The parameters are:
   - Reservoir system parameters:
     - i. Aquifer size
     - ii. Gas reservoir size
   - Operational parameters:
     - i. Production well location:

ii. Dumping schedule

4. Analyze the results from simulations and discuss the results
5. Summarize the effects of each parameter on performance of combination of water and gas dumpflood into oil reservoir and give the suggestion on the operational method from which optimum production can be obtained in term of oil recovery and production time.

1.4 Outline of thesis

This thesis contains six chapters including:

1. Chapter 1 introduces the background of combined water and gas dumpflood into dipping oil reservoir and demonstrates the objectives and outline of methodology of this study.
2. Chapter 2 discusses various publications related to water dumpflood and gas dumpflood into oil reservoir.
3. Chapter 3 summarizes some important theories and concepts that are related to water dumpflood and gas dumpflood into oil reservoir.
4. Chapter 4 demonstrates reservoir model details, fluid properties, rock properties and production conditions used in simulation.
5. Chapter 5 demonstrates reservoir simulation results, comparison and discussions of the result from studied parameters.
6. Chapter 6 provides conclusions and recommendations of this study.

CHAPTER 2

LITERATURE REVIEW

Previous studies related to gas and water dumpflood into oil reservoir are summarized in this chapter. These studies are divided into two sections: *water dumpflood* and *gas dumpflood*.

2.1 Water dumpflood

Fujita [2] studied pressure maintenance by dumping formation water into a partially depleted oil reservoir of limestone rock for improving the recovery. Water was dumped into the light oil part (33 ^{o}API) which is underlain by heavy oil mat (from 28 to 9 ^{o}API). In order to study the performance and effectiveness of the method, comparison between water dumpflood and natural depletion was conducted by a mean of reservoir simulation model. The regular oil production rate was 30,000 B/D at the beginning in August, 1969 and was then increased to 66,000 B/D when completing all the producers up to 15 wells. Later, the producing GOR increased rapidly due to the reduction of pressure about 1,000 to 2,600 psig from its original pressure. To maintain oil production by controlling GOR and improve the ultimate oil recovery, the pressure maintenance operation was implemented by dumping the shallow aquifer water into the oil zone. After 5 years of operations, the pressure had been maintained at around 2,600 psig and the oil production was maintained at 40,000 to 45,000 B/D as the GOR was controlled below 1,000 SCF/STB. In the operation, nine injectors were perforated into the oil zone not deeper than 30 ft. above the water/oil contact in the peripheral area of the reservoir. As a result of water-dumping scheme, an additional 19.58 MMSTB of oil has been added to the estimated natural-depletion oil recovery of 54.60 MMSTB during 5-year operation.

Osharode et al. [3] conducted a study on natural water dumpflood into a depleted oil and gas reservoir in Egbema West field. Oil production was reduced from a peak of 32 MBOPD to an average rate of 5 MBOPD due to the rapid pressure reduction from 3452 to 2650 psig caused by the insufficient support of the aquifer. As a result, production from primary recovery resulted in low recovery. Natural water dumpflood pilot test was then suggested for study to improve the recovery and sustain the reservoir pressure from dropping down. The pilot test showed that water dumpflood successfully maintained the reservoir pressure at 2650 psi. Moreover, the average reservoir pressure increased about 8 psi after 12 years of operation. Incremental recovery of 33% was added to natural depletion. So the pilot water dumpflood in Egbema West was proven to be effectively applicable on a full field scale.

Quttainah and Al-Hunaif [4] conducted a water dumpflood pilot test in Umm Gudair reservoir which received very little natural pressure support in some areas, thus, resulted in a declining reservoir pressure from 4050 to 3200 psi and low recovery factor. There are 3 main objectives of this pilot: (1) to prove the applicability and quantify sweep benefits of water dumpflood, (2) to prove and quantify pressure maintenance and observe reservoir response and (3) to observe production acceleration benefits of water dumpflood. The study consisted of process of selecting a well location for the dumpflood pilot purposes and the completion strategy that was chosen for this well. The best option for location is mid flank that had some production offtake and it had intermediate reservoir pressure due to this offtake. The completion strategy is to drill a water injection well at the desired location which included laying of pipeline from the gathering center to the desired well to supply it with enough water. Many tests were implemented which resulted in the increment from 26% to 54% of oil production rate.

Shizawi et al. [5] performed water dumpflood in W field, small satellite field, that already showed sign of pressure depletion. The concept of the project was to implement a single well which was used as a source of water supply and inject domain with different depths of perforation; in the deeper water zone and on the injection target reservoir. ESP was used to help producing and injecting water at different perforation depths. Surveillance program was implemented focusing on monitoring of reservoir pressure in the surrounding wells, production metering and periodical surface flow of dumpflood to assess its productivity and injectivity. Downhole gauges were installed in the dumpflood well across the aquifer and the target reservoir to monitor the reservoir pressure behavior and calibrate the injection rate. This concept was proved to be a success as the injection rate of water was achieved around 1200 BPD into the target zone and resulted in oil gain around 40%. The positive result of W field has to more implementations of this technique in two other trial fields.

2.2 Gas dumpflood

Kridsanan [6] conducted a study on the mechanism of gas dumpflood into a gas condensate reservoir with the purpose of pressure maintenance and enhancing condensate recovery. Compositional simulator, ECLIPSE 300, was employed to simulate the process in which high CO2 is flowed from the source reservoir into the target gas-condensate reservoir in order to increase the reservoir pressure to above dew point pressure which can prevent the forming of condensate. The simulation model focused on the gas dumpflood performance evaluated by three main factors: dumpflood timing, composition variation of source gas and depth or pressure difference between the two reservoirs. The study showed the difference in time to start gas dump flood yields different recoveries and the proper time to start the gas dumpflood in gas condensate reservoir is the time before the reservoir pressure drops to the dew point. The investigation on the effect of CO2 concentration of gas flood showed only a slight increase in condensate recovery with increasing CO2 concentration in source gas and on depth or pressure difference between two reservoirs that large pressure difference between the two reservoirs shortens the time of gas and condensate recovery but the amount of condensate recovery just slightly increases.

Welch [7] described a case history of an immiscible gas injection pilot which has similar principle as gas dumpflood in carbonation reservoir in the Middle East. The reservoir oil is understaturated, intermediate gravity oil. Production started in 1943 via natural depletion and 40 years later, only less than 5 percent of recovery had been achieved. The initial pressure was only 822 pisa and the pressure dropped quickly until 1950 when the decline slowed down a little bit due to the support of natural water drive. The production rate rarely exceeded 6,000 STB/D and before the gas

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injection started the production was 4,700 STB/D with 60% of water cut. After gas injection, reservoir pressure started to increase slightly and water cut began to decline as well due to the shift of support from water drive to gas cap drive and also due to the migration downward of oil pushed by gas. GOR also increased in the well as gas moved vertically downward to the completed production zone. However, the increase in GOR can be controlled by recompletions. Finally, the most important response of the technique is the increase in oil recovery.

CHAPTER 3

THEORY AND CONCEPT

Some important theories and concepts that are related to water dumpflood and gas dumpflood into oil reservoir are summarized in this chapter. This chapter is divided into four sections including: 1) *water and gas dumpflood*, 2) *mobility and mobility ratio*, 3) *sweep efficiency*, 4) *relative permeability* and 5) *fracture pressure*.

3.1 Dumpflood

3.1.1 Water dumpflood

Water Dumpflood is a process in which water flows from an aquifer to an oil reservoir naturally and sweeps the oil toward the producing well. In this process, water-bearing reservoir of high pressure potential feeds into an oil reservoir of lower fluid potential by placing the two zones in communication through a well so that reservoir is provided with pressure support and the oil will be displaced by water coming into the reservoir [1]. Water Dumpflood is often preferable for the economical reason due to the absence of cost of injection facilities at the surface and the cost of injection fluids. The process can be achieved by both underlying and overlying aquifer.

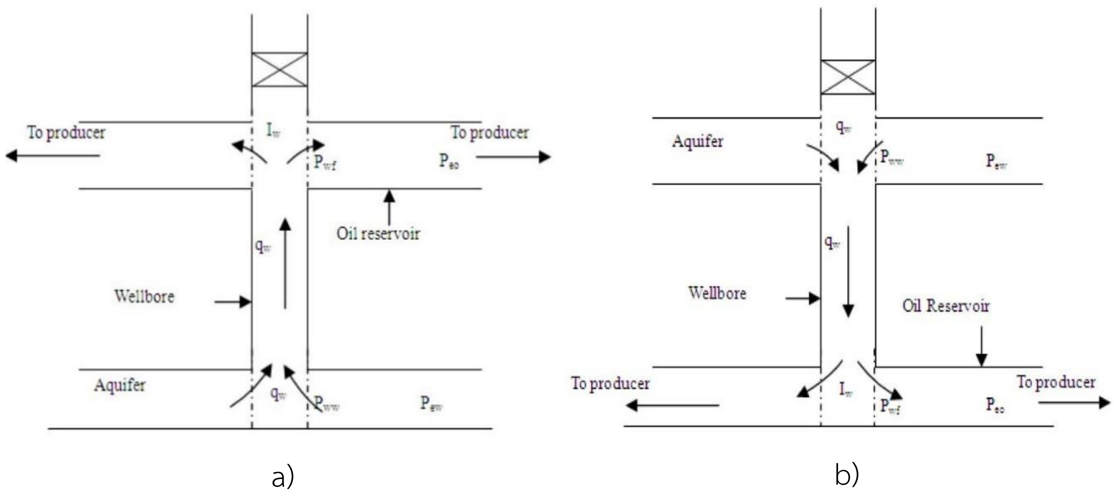

Figure 3-1: Upward flow mechanism (a) and downward flow mechanism (b) [1]

Davies [8] demonstrated that the rate at which fluid transfers from one zone to another is a constant value if the reservoir static pressure in both zones is maintained.

$$I_w = \left[\frac{1}{I} + \frac{1}{J} + \Delta p_{fr}\right] = p_{ew} - p_{eo} \qquad (1)$$

where

I_w = water producing rate into oil reservoir, BWPD

I = injectivity index, BWPD/psi

J = productivity index, BWPD/psi

Δp_{fr} = friction pressure drop, psi

p_{ew} = boundary pressure in water zone, psig

p_{eo} = boundary pressure in oil zone, psig

3.1.2 Gas dumpflood

Gas dumpflood also follows the same concept as water dumpflood with the same principle of reservoir pressure maintenance and oil displacement. Gas dumpflood or gas injection is usually conducted when there is already available source of gas nearby. When gas is injected or dumped into the reservoir, some mechanisms occurs such as:

i. reservoir pressure maintenance
ii. oil displacement of both horizontally and vertically
iii. vaporization of the liquid hydrocarbon components
iv. swelling of the oil in case of understarurated oil at the initial reservoir condition

Water and gas dumped into an oil reservoir can be calculated from the same equation as for conventional water or gas injection employing the general Material Balance Equation mentioned by Ahmed [9]:

$$
\begin{aligned}
&N_p[B_o + (R_p - R_s)B_g + W_pB_w \\
&= N[(B_o + B_{oi}) + (R_{si} - R_s)B_g] + mNB_{oi}\left(\frac{B_g}{B_{gi}} - 1\right) \\
&+N(1+m)B_{oi}\left[\frac{c_wS_{wi} + c_f}{1 - S_{wi}}\right]\Delta p + W_e + W_{inj}B_w \\
&+G_{inj}B_{ginj}
\end{aligned} \qquad (2)
$$

where

$N_p[B_o + (R_p - R_s)B_g$	represents the reservoir volume of cumulative oil and gas produced
$[W_e - W_pB_w]$	refers to the net water influx that is retained the reservoir
$[G_{inj}B_{ginj} + W_{inj}B_{winj}]$	is the pressure maintenance terms representing cumulative fluid injection or dump into the reservoir
$[mNB_{oi}(B_g/B_{gi} - 1)]$	represents the net expansion of the gas that occurs during the production of N_p stock tank barrels of oil

However, there are also challenges on monitoring the dumpflood wells and controlling the reservoir pressure. These include difficulties with flood front control, water and gas breakthrough, conformance management, and the inability to quantify the crossflow rate in each well.

3.2 Mobility and mobility ratio

The mobility of any fluid **λ** is defined as the ratio of the effective permeability of the fluid to the fluid viscosity.

$$
\lambda_o = \frac{k_o}{\mu_o} = \frac{kk_{ro}}{\mu_o} \qquad (3)
$$

`

$$\lambda_w = \frac{k_w}{\mu_w} = \frac{kk_{rw}}{\mu_w} \qquad (4)$$

$$\lambda_g = \frac{k_g}{\mu_g} = \frac{kk_{rg}}{\mu_g} \qquad (5)$$

The mobility ratio M is defined as the mobility of the displacing fluid to the mobility of the displaced fluid.

$$M = \frac{\lambda_{displacing}}{\lambda_{displaced}} \qquad (6)$$

where

$\lambda_o, \lambda_w, \lambda_g$	= mobility of oil, water and gas
k_o, k_w, k_g	= effective permeability of oil, water and gas
k_{ro}, k_{rw}, k_{rg}	= relative permeability to oil, water and gas
k	= absolute permeability
M	= mobility ratio

If $M \leq 1$, the displaced fluid is traveling with a velocity equals to or greater than the displacing fluid.

If $M > 1$, the displaced fluid traveling faster than displacing fluid which is unfavorable for oil displacement.

3.3 Sweep efficiency

3.3.1 Displacement efficiency

Displacement efficiency is the fraction of movable oil that has been recovered from the swept zone at any given time. Displacement efficiency is expressed as:

$$E_D = \frac{Volume\ of\ oil\ at\ the\ start\ of\ flood - Remaining\ oil\ Volume}{Volume\ of\ oil\ at\ the\ start\ of\ flood}$$

`

or

$$E_D = \frac{\frac{S_{oi}}{B_{oi}} - \frac{\bar{S}_o}{B_o}}{\frac{S_{oi}}{B_{oi}}} \quad (7)$$

where

E_D = displacement efficiency, fraction

S_{oi} = initial oil saturation at start of flood, fraction

B_{oi} = oil formation volume factor at start of flood, bbl/STB

$\bar{S}_o$ = average oil saturation at a given time, fraction

B_o = oil formation volume factor at a given time, bbl/STB

3.3.2 Volumetric sweep efficiency

Volumetric sweep efficiency is the percentage of the total reservoir contacted by the injected fluid. It is composed of areal (or pattern) sweep efficiency and vertical sweep efficiency.

The areal sweep efficiency E_A is the fractional area of the pattern that is swept by the displacing fluid. The major factors determining areal sweep are:

- fluid mobility
- pattern type
- areal heterogeneity
- total volume of fluid injected

The vertical sweep efficiency E_I is the fraction of the vertical section of the pay zone that is contacted by injected fluids. The vertical sweep efficiency is primarily a function of:

- Vertical heterogeneity
- Degree of gravity segregation
- Fluid mobility
- Total volume injection

$$E_V = E_A E_I \quad (8)$$

$$E_A = \frac{Area\ contacted\ by\ diplacing\ fluid}{Total\ area}$$

$$E_I = \frac{Cross\ sectional\ area\ contaced\ by\ diplacing\ fluid}{Total\ cross\ sectional\ area}$$

where

E_V = volumetric sweep efficiency, fraction

E_A = areal sweep efficiency, fraction

E_I = vertical sweep efficiency, fraction

3.3.3 Overall recovery efficiency

The overall recovery efficiency or recovery factor (RF) for any secondary or tertiary oil recovery method is the product of a combination of the three individual efficiency factors as:

$$RF = E_D E_V = E_D E_A E_I \quad (9)$$

In term of cumulative oil production, it can be written as:

$$N_P = N E_D E_A E_I \quad (10)$$

where

RF = overall recovery factor, fraction

E_D = displacement sweep efficiency, fraction

E_A = areal sweep efficiency, fraction

E_I = vertical sweep efficiency, fraction

E_V = volumetric sweep efficiency, fraction

N_P = cumulative oil production, STB

N = initial oil in place at the start of flooding, STB

3.4 Relative permeability

Relative permeability is the ability to flow of one fluid when there are more than one fluid flowing in the system. Mathematically, it is the ratio of the effective permeability of one fluid to a reference or base permeability of a rock. Relative permeability studies are usually conducted on two-phase and three-phase flow system.

3.4.1 Two-phase flow: Corey's correlation

Corey's correlation [10] is used in ECLIPSE reservoir simulator for generating relative permeability the two-phase flow as a function of fluid saturation. The Corey's correlation can be used in both oil-water system and oil-gas system.

- Oil-water system

$$K_{ro} = \left(\frac{1 - S_w - S_{or}}{1 - S_{wi} - S_{or}}\right)^{N_o} \quad (11)$$

$$K_{rw} = K_{rwend}\left(\frac{S_w - S_{wi}}{1 - S_{wi} - S_{or}}\right)^{N_w} \quad (12)$$

Oil-gas system

$$K_{ro} = \left(\frac{1 - S_{wg} - S_{wi} - S_{or}}{1 - S_{wi} - S_{or}}\right)^{N_o} \quad (13)$$

$$K_{rg} = \left(\frac{S_g - S_{gc}}{1 - S_{wi} - S_{or} - S_{gc}}\right)^{N_g} \quad (14)$$

where

S_w = water saturation

S_{or} = residual oil saturation

S_{wi} = initial water saturation or connate water saturation

S_{gc} = critical gas saturation

S_g = gas saturation

K_{ro} = relative permeability to oil at any water saturation

K_{rw} = relative permeability to water at any water saturation

`

K_{rg} = relative permeability to gas at any water saturation

$K_{rw,end}$ = relative permeability to water at minimum water saturation

N_w = corey water exponent

N_o = corey oil exponent

N_g = corey gas exponent

3.4.2 Three-phase flow

3.4.2.1 ECLIPSE model (default model)

ECLIPSE or default model for the three-phase oil relative permeability is based on an assumption of complete segregation of the water and gas within each grid cell. The model provides a simple but effective formula which avoids the problems associated with other methods (for example poor conditioning and negative values). The oil saturation is assumed to be constant and equal to the block average value, S_o, throughout the cell. The gas and water are assumed to be completely segregated, except that the water saturation in the gas zone is equal to the connate saturation, S_{wco}. the block average saturations are S_o, S_w and S_g (with $S_o + S_w + S_g = 1$) [11].

- Gas zone

Within the fraction $\frac{S_g}{S_g+S_w-S_{wco}}$ of the cell

- The oil saturation = S_o
- The water saturation = S_{wco}
- The gas saturation = $S_g + S_w - S_{wco}$

- Water zone

Within the fraction $\frac{S_w-S_{wco}}{S_g+S_w-S_{wco}}$ of the cell

- The oil saturation = S_o
- The water saturation = $S_g + S_w$
- The gas saturation = 0

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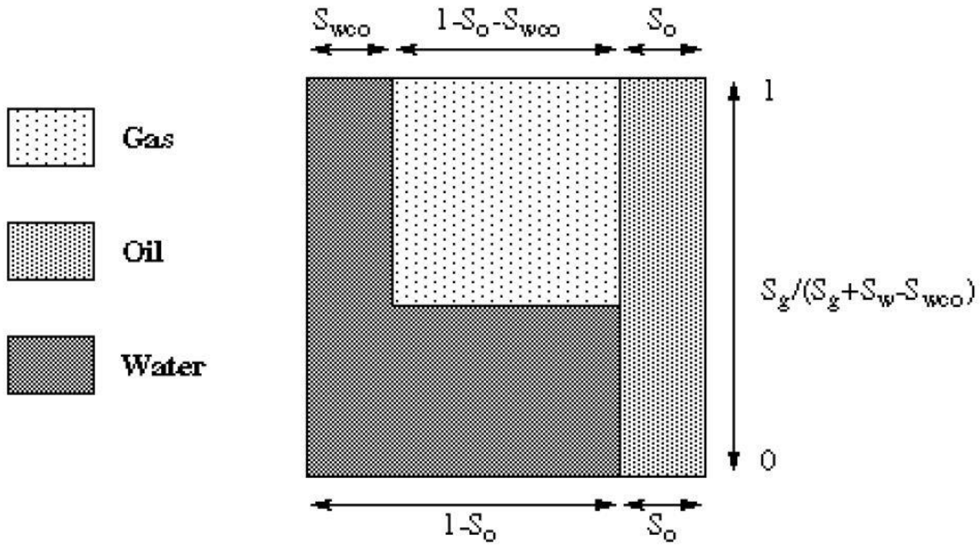


Figure 3-2: The default three-phase oil relative permeability model assumed by ECLIPSE [11]

The oil relative permeability is then given by:

$$K_{ro} = \frac{S_g K_{rog} + K_{row}(S_w - S_{wco})}{S_g + S_w - S_{wco}} \quad (15)$$

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 for a system with oil and water only, also tabulated as a function of S_o

3.4.2.2 Stone's model I

Another method for relative permeability correlative is Stone's I. This method can be regarded as a means of interpolating between the two sets of two-phase data in order to obtain the three-phase relative permeability. From the two phase system of water and oil, we can obtain both $K_{rw}$and K_{row} as a function of water saturation. Similarly, we can obtain K_{rg} and K_{rog} as a function of gas saturation in oil-gas system [12].

`

The normalized saturation are defined by treating connate water and irreducible residual oil as immobile fluids:

$$S_o^* = \frac{S_o - S_{om}}{(1 - S_{wc} - S_{om})} \quad (for\, S_o > S_{om}) \tag{16}$$

$$S_w^* = \frac{S_w - S_{wc}}{(1 - S_{wc} - S_{om})} \quad (for\, S_o > S_{om}) \tag{17}$$

$$S_g^* = \frac{S_g}{(1 - S_{wc} - S_{om})} \tag{18}$$

The relative permeability to in Stone's Model I can be defined as:

$$K_{ro} = S_o^* \beta_w \beta_g \tag{19}$$

The two multiplier β_w and β_g are determined from:

$$\beta_w = \frac{K_{row}}{1 - S_w^*} \tag{20}$$

$$\beta_g = \frac{K_{rog}}{1 - S_w^*} \tag{21}$$

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

The difficulty in using Stone's Model I is selecting the minimum oil saturation S_{om}. Fayers and Mathews [13] suggested an expression for determining S_{om}.

$$S_{om} = \alpha S_{orw} + (1 - \alpha) S_{org} \tag{22}$$

with

$$\alpha = 1 - \frac{S_g}{1 - S_{wc} - S_{org}} \tag{23}$$

`

where

S_{row} = residual oil saturation in the oil-water relative permeability system

S_{rog} = residual oil saturation in the gas-water relative permeability system

Aziz and Settari [14] pointed out that Stone's correlation could give K_{ro} value greater than the unity. That is why they suggest the following equation which is normalized from Stone's:

$$K_{ro} = \frac{S_o^*}{(1 - S_w^*)(1 - S_g^*)} \left(\frac{k_{row} k_{rog}}{(K_{ro})_{S_{wc}}} \right) \qquad (24)$$

where

$(K_{ro})_{S_{wc}}$ = relative permeability of the oil at the connate-water saturation as determined from the oil-water relative permeability system

3.4.2.3 Stone's model II

The Stone's model II is the modified version of the first model of Stone due to the difficulties in choosing S_{om} [15].

$$K_{ro} = (K_{ro})_{S_{wc}} \left[\left(\frac{k_{row}}{(k_{ro})_{S_{wc}}} + k_{rw} \right) \left(\frac{k_{rog}}{(k_{ro})_{S_{wc}}} + k_{rg} \right) - (k_{rw} + k_{rg}) \right] \qquad (25)$$

3.5 Fracture pressure

In the Gulf of Thailand, the fracture pressure correlation for the M field can be defined as from the correlation below:

$$Fracture\ Pressure\ (bar) = \frac{FRAC.S.G\ \times TVD}{10.2} \qquad (26)$$

and

$$FRAC.S.G = 1.22 + (TVD \times 1.6 \times 10^{-4}) \qquad (27)$$

where

$FRAC.S.G$ = fracture pressure gradient (bar/meter)

TVD = true vertical depth below rotary table (m)

This correlation of fracture pressure is used to constrain water and gas dumpflood in the simulation runs.

`

CHAPTER 4

RESERVOIR MODEL

4.1 Grid properties

In this study, the reservoir model is constructed using Cartesian coordinate, simple rectangular shape, homogeneous condition and a dip angle of 15°. There are three reservoirs in total namely; aquifer on top, oil reservoir in the middle and gas reservoir at the bottom as shown in Figure 4.1. The dimension of grids in this simulation is 57 x 45 x 28. Some grids are inactivated to adjust the size of different gas reservoirs and aquifers in different cases. The top depths of aquifer, oil reservoir and gas reservoir are 3,000, 5,000 and 7,050 ft., respectively. The properties of the reservoirs for this study are summarized in Table 4-1 for oil reservoir, Table 4-2 for aquifer and Table 4-3 for gas reservoir.

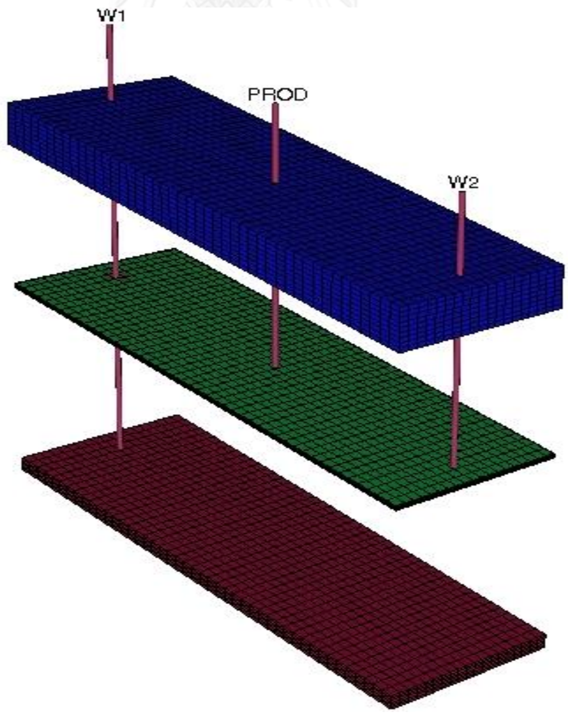


Figure 4-1: 3D view of reservoir model (top aquifer, middle oil reservoir and bottom gas reservoir)

Table 4-1: Target oil reservoir properties

No	Parameters	Values	Unit
1	Number of grids	19×45×10	Grid
2	Size of reservoir	1,900×4,500×50	cu ft.
3	Effective porosity	21.5	%
4	Horizontal permeability	126	mD.
5	Vertical permeability	12.6	mD.
6	Top of reservoir	5,000	ft.
7	Pressure at datum depth (top of reservoir)	2,130.1	psia
8	Reservoir temperature at datum depth	163.58	˚F
9	Fracturing pressure at datum depth	3,172	psia
10	Initial water saturation	25	%

Table 4-2: Aquifer properties

No	Parameters	Values	Unit
1	Number of grids	5PV : 9×45×10 10PV : 19×45×10 30PV : 57×45×10	Grid
2	Aquifer Dimension	5PV : 900×4,500×500 10PV : 1,900×4,500×500 30PV : 5,700×4,500×500	cu ft.
3	Effective porosity	21.5	%
4	Horizontal permeability	126	mD.
5	Vertical permeability	12.6	mD.
6	Top of aquifer	3,000	ft.
7	Pressure at datum depth (top of aquifer)	1,283.9	psia
8	Reservoir temperature at datum depth	136,15	˚F
9	Fracturing Pressure at datum depth	1,776	psia

Table 4-3: Gas reservoir properties

N°	Parameters	Values	Unit
1	Number of grids	1PV : 7×45×6 3PV : 19×45×6 9PV : 57×45×6	Grid
2	Size of reservoir	1PV : 700×4,500×150 3PV : 1,900×4,500×150 9PV : 5,700×4,500×150	cu ft.
3	Effective porosity	21.5	%
4	Horizontal permeability	126	mD.
5	Vertical permeability	12.6	mD.
6	Top of reservoir	7,050	ft.
7	Pressure at datum depth (at 8500 ft.)	2,997.46	psia
8	Reservoir temperature at datum depth	191.70	°F
9	Fracturing pressure at datum depth	4,778	psia
10	Initial water saturation	25	%

The sizes of gas reservoir and aquifer are varied in order to determine their effect on oil recovery. Note that three different aquifer sizes, namely, 5PV, 10PV and 30PV are used in this study. The schematic of the aquifers are shown in Figure 4-2, Figure 4-3 and Figure 4-4. The volumes of aquifer for this study are 5, 10 and 30 hydrocarbon pore volume (PV). In order to adjust the aquifer's size, some grids are set inactive in the xy plan in the x direction to avoid the effect on the aquifer's average pressure which depends on its depth and thickness.

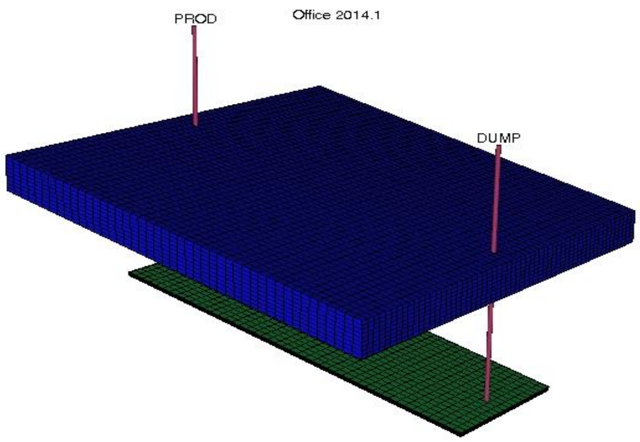


Figure 4-2: 3D view of 30PV aquifer size

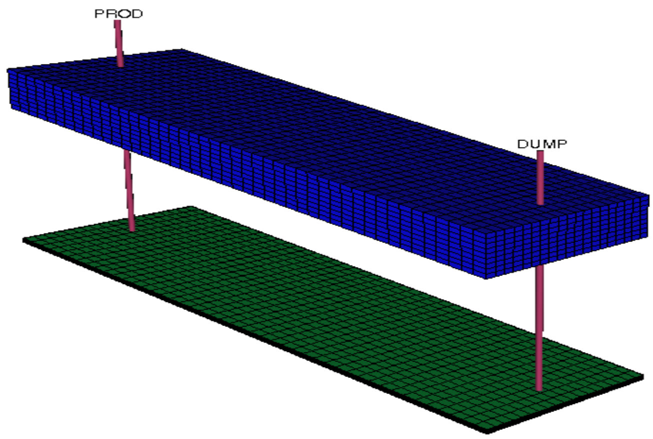


Figure 4-3: 3D view of 10PV aquifer size

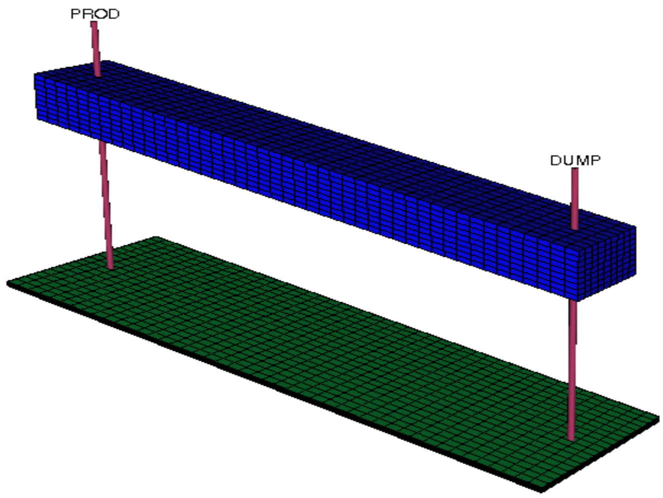


Figure 4-4: 3D view of 5PV aquifer size

For gas reservoir, three sizes of gas reservoir are studied. The size is varied from 1PV, 3PV to 9PV by changing the thickness of the gas zone as shown in Figure 4-5, Figure 4-6 and Figure 4-7. Like aquifer, gas reservoir is also adjusted by deactivating the grid in the xy plan in the x direction in order to avoid the effect in the average pressure change. The sizes of gas reservoir for this study are 1, 3 and 5 hydrocarbon pore volume (PV).

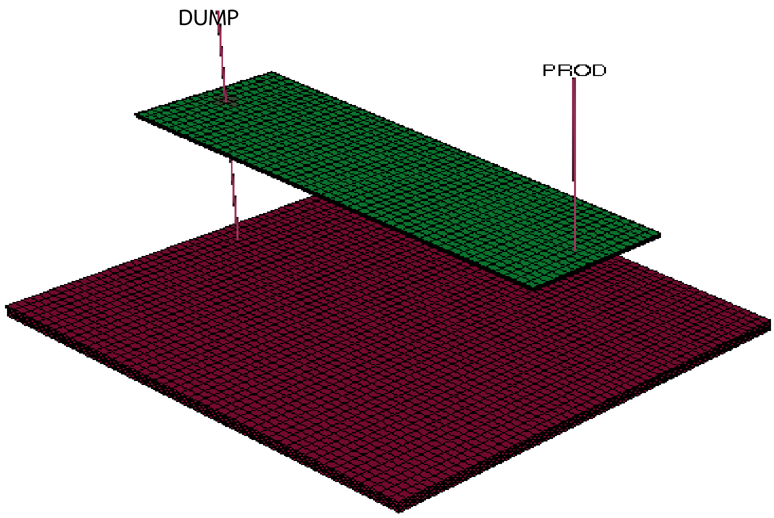


Figure 4-5: 3D view of 9PV gas reservoir size

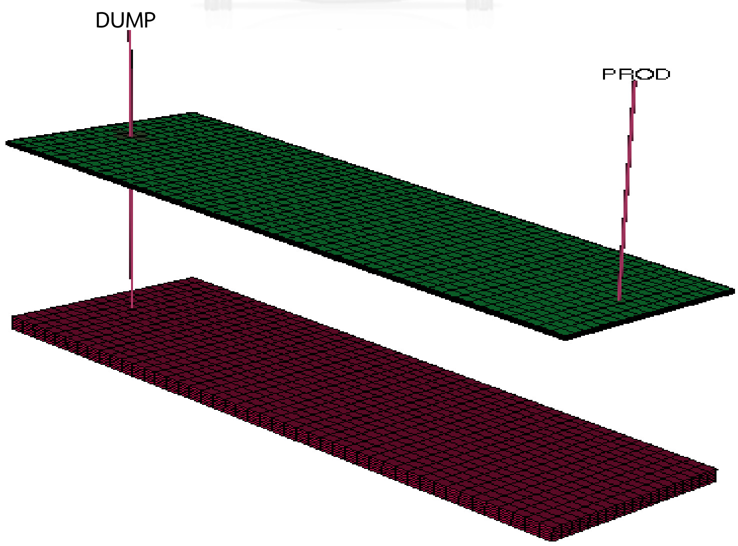


Figure 4-6: 3D view of 3PV gas reservoir size

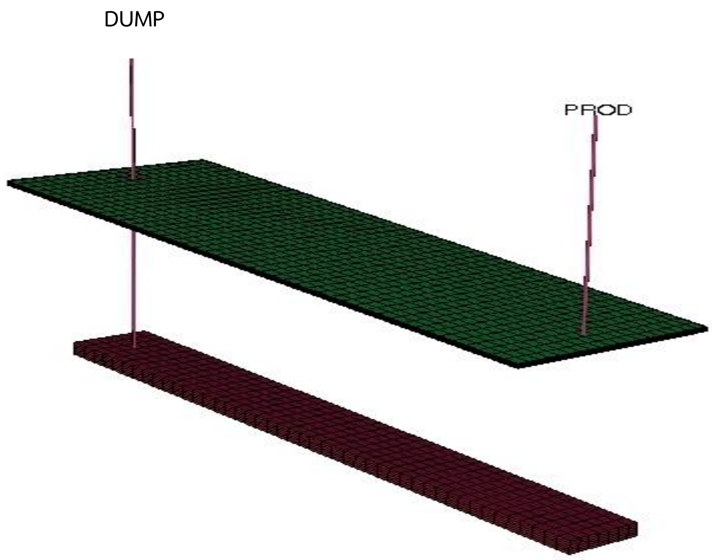


Figure 4-7: 3D view of 1PV gas reservoir size

4.2 PVT properties

PVT properties of aquifer, oil reservoir and gas reservoir are generated using provided correlation sets in ECLIPSE 100 simulator. The input data for correlation are given in Table 4-4 and the generated PVT properties are summarized in Table 4-5 and plotted in Figure 4-8, Figure 4-9 and Figure 4-10. Some assumption are made when generating the PVT properties for the reservoirs such as:

- Reservoir is consolidated sandstone
- Correlation Set 1 is used for calculation
- Salinity is 500 ppm
- Pressure gradient of 0.423 psi/ft. is used
- Temperature gradient 2.5 ^{o}C per 100 m is used with 35 oC surface temperature

Table 4-4: Input parameters for PVT properties correlation

Parameters	Aquifer	Oil Reservoir	Gas Reservoir	Unit
Oil gravity	-	25	-	^{o}API
Gas gravity	-	0.8	0.7	Sg (Air)
Gas-oil ratio	-	200	-	SCF/STB
Reservoir pressure	1524.81	2371.01	3238.36	psia
Reservoir Temperature	143.96	171.39	199.51	^{o}F
Salinity	5,000	5,000	5,000	ppm

Table 4-5: Generated PVT properties from PVT section

Properties	Aquifer	Oil reservoir	Gas reservoir	Unit
Fluid Properties at surface condition				
Oil density	-	56.38881	-	lb /ft3
Water density	62.4281	62.4281	62.4281	lb /ft3
Gas density	-	0.049942	0.0437	lb /ft3
Water PVT properties				
Reference pressure (Pref)	1524.81	2371.01	3238.36	psia
Water FVF at Pref	1.007518	1.013718	1.02135	rb /stb
Water compressibility	2.964254E-6	2.76166E-6	2.76166E-6	/psi
Water viscosity at Pref	0.4585623	0.374519	0.3131752	cp
Water viscosibility	3.447735E-6	4.566538E-6	5.571338E-6	/psi

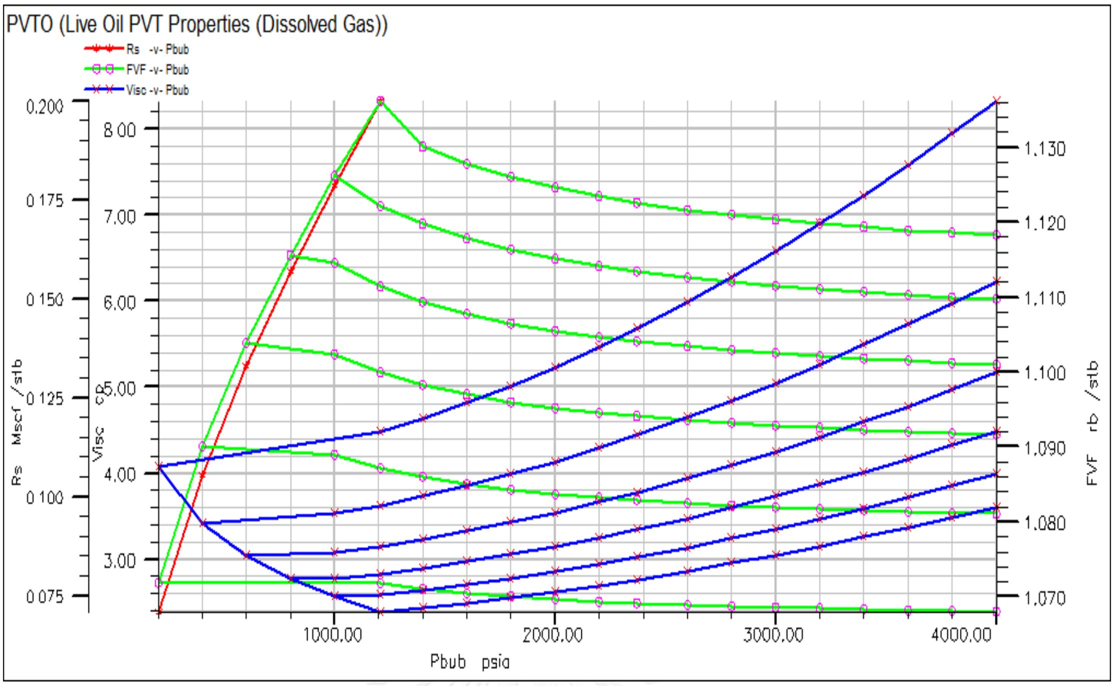


Figure 4-8: Live oil PVT properties in oil reservoir

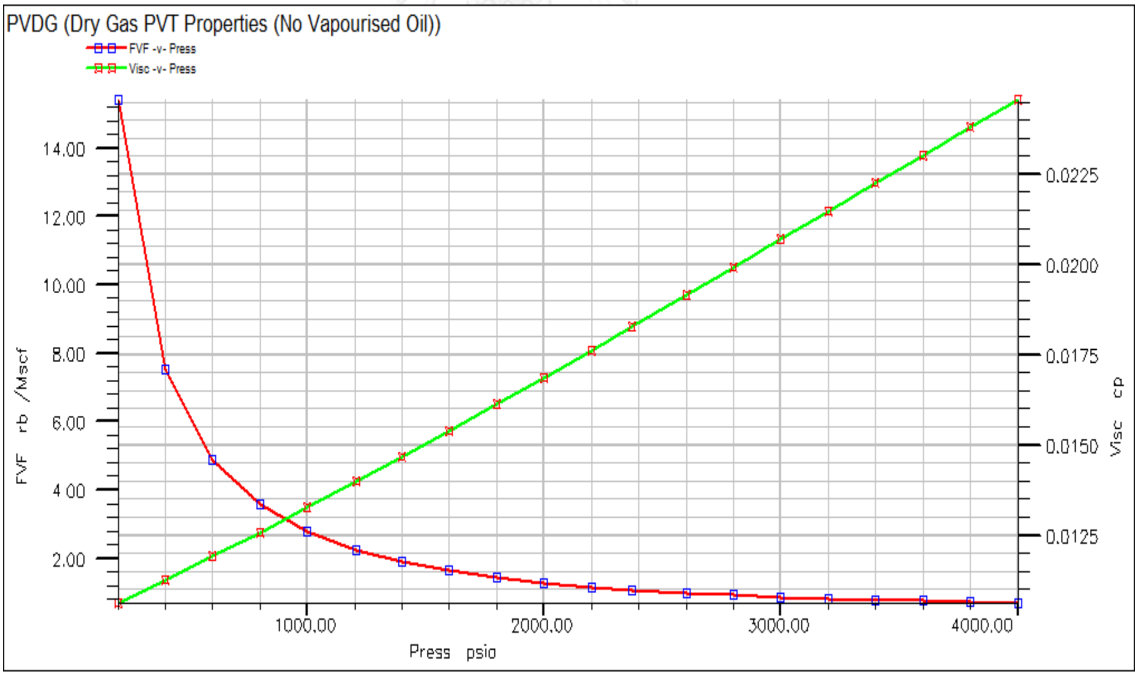


Figure 4-9: Dry gas PVT Properties in oil reservoir

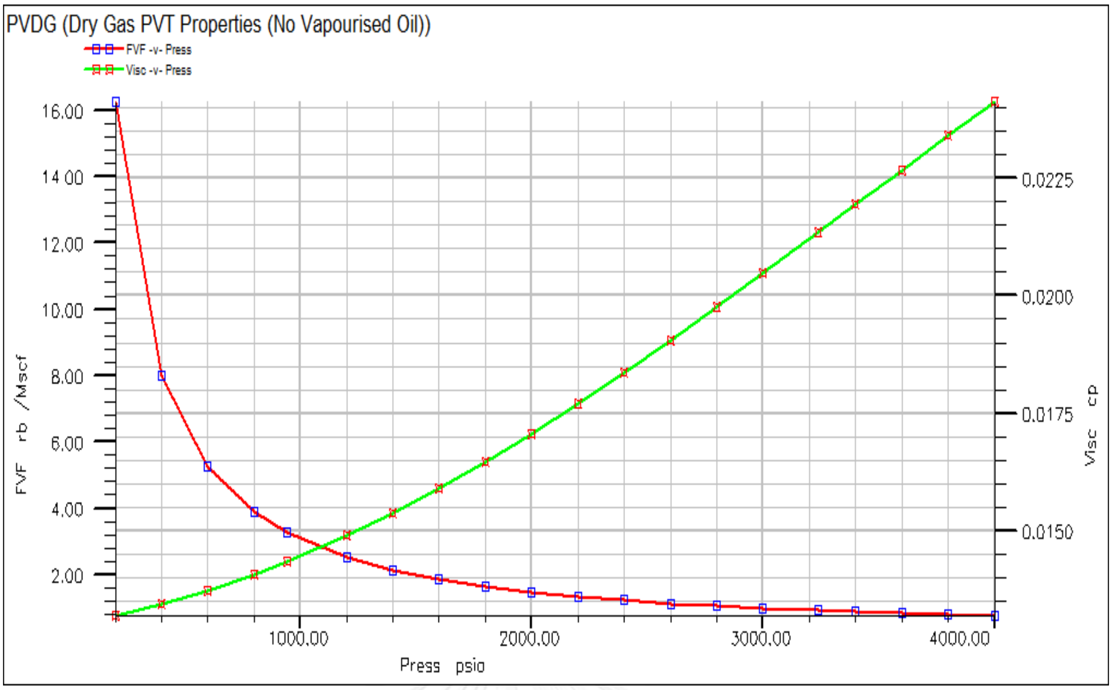


Figure 4-10: Dry gas PVT Properties in gas reservoir

4.3 Special core analysis (SCAL)

Relative permeability of the system is generated by Corey's correlation by creating two sets of two-phase relative permeability; oil-water and gas-oil. The input parameters for relative permeability calculation are shown in Table 4-6. The relative permeability curves are also shown in Figure 4-11 and Figure 4-12 along with their values shown in Table 4-7 and Table 4-8. Note that three-phase relative permeability value are evaluated based on ECLIPSE default model.

Table 4-6: Input parameters for relative permeability calculation with Corey's correlation

Corey Water	3	Corey Gas	3	Corey Oil/Water	0.15
S_{wmin}	0.25	S_{gmin}	0	Corey Oil/Gas	0.15
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
$K_{rw(S_{wmin})}$	0.3	$K_{rg(S_{gmax})}$	0.4	$K_{ro(S_{gmin})}$	0.8
$K_{rw(S_{wmax})}$	1				

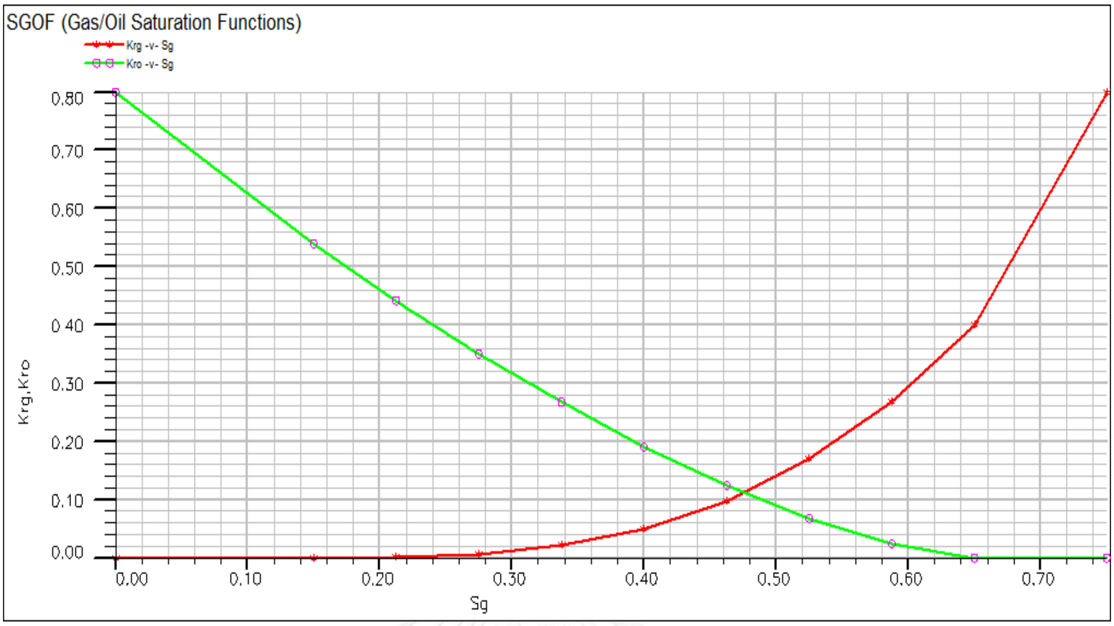


Figure 4-11: Gas/oil saturation function

Table 4-7: Gas-oil relative permeability

S_g	K_{rg}	K_{ro}
0	0	0.8
0.15	0	0.539728
0.2125	0.000781	0.441761
0.275	0.00625	0.350564
0.3375	0.021094	0.266683
0.4	0.05	0.190823
0.4625	0.097656	0.123943
0.525	0.16875	0.067466
0.5875	0.267969	0.023853
0.65	0.4	0
0.75	0.8	0

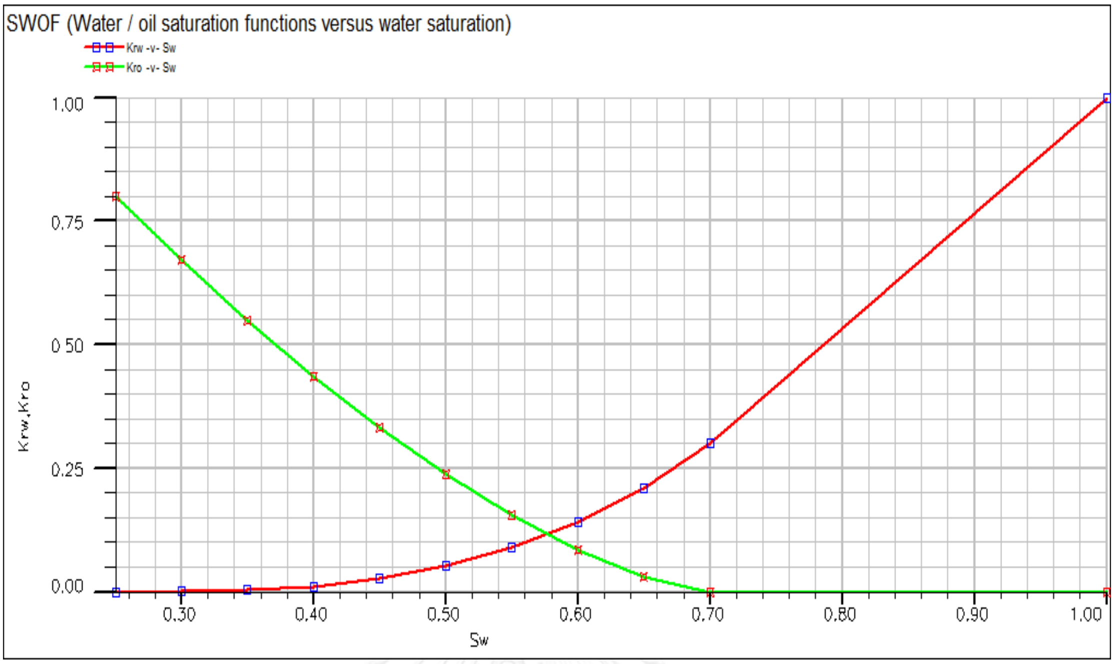


Figure 4-12: Water/oil saturation function

Table 4-8: Water-oil relative permeability

S_w	K_{rw}	K_{ro}
0.25	0	0.8
0.3	0.000412	0.670442
0.35	0.003292	0.548748
0.4	0.011111	0.435465
0.45	0.026337	0.331269
0.5	0.05144	0.237037
0.55	0.088889	0.15396
0.6	0.141152	0.083805
0.65	0.2107	0.02963
0.7	0.3	0
1	1	0

4.4 Detail methodology

1. Construct base case models for natural depletion, water dumpflood, gas dumpflood and combined water and gas dumpflood at the same time. For natural depletion, three production wells are used to produce oil; one at updip, one at the middle and another one downdip shown in Figure 4-13. For water dumpflood, two wells are used: a dumping well downdip and a producer updip as shown in Figure 4-14. For gas dumpflood a pair of updip dumping well and a downdip producer is used as illustrated in Figure 4-15. The combined water and gas dumpflood requires three wells: gas dumping well updip, oil producer in the middle and water dumping well downdip as depicted in Figure 4-16.

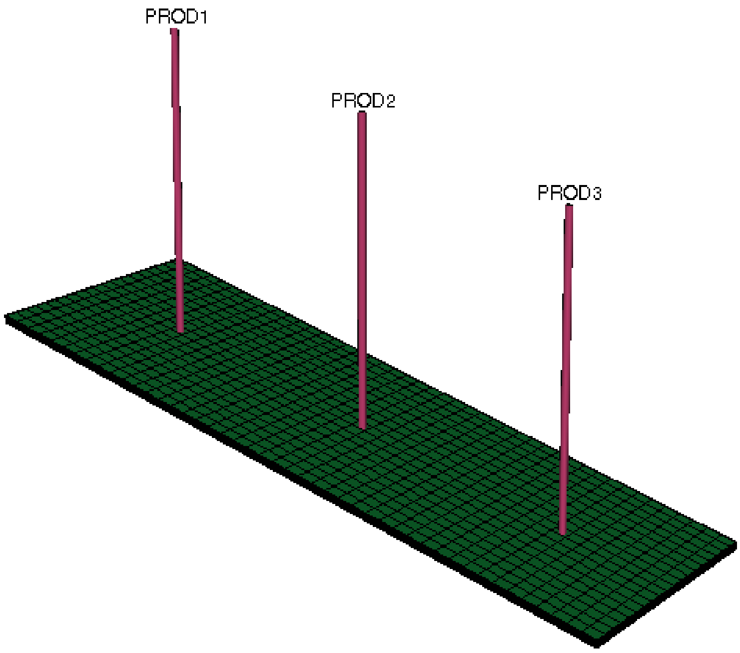


Figure 4-13: 3D view of oil reservoir with 3 production wells for natural depletion

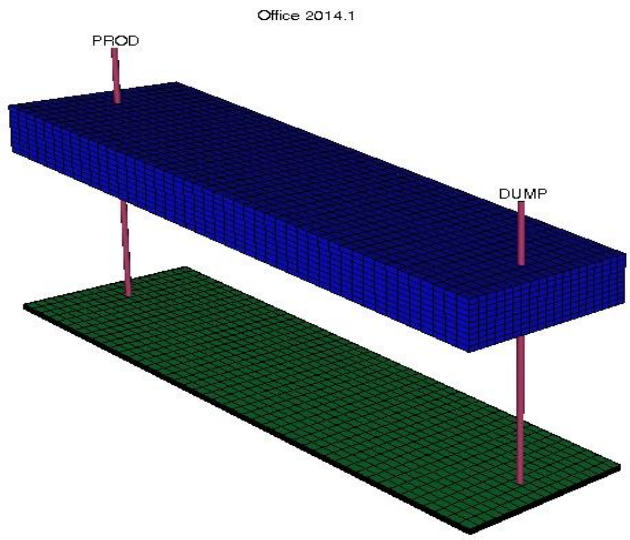


Figure 4-14: 3D view of oil reservoir and aquifer with one producer and one water dumping well in case of water dumpflood

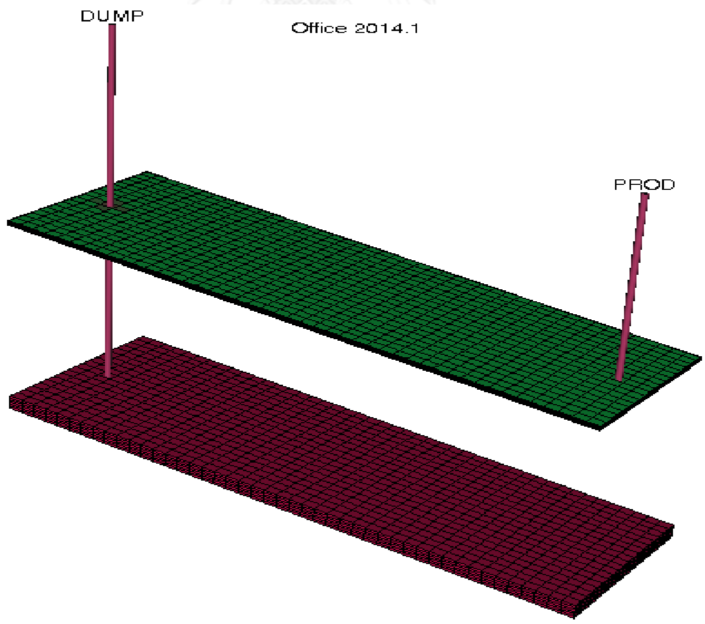


Figure 4-15: 3D view of oil reservoir and gas reservoir with one producer and one gas dumping well in case of gas dumpflood

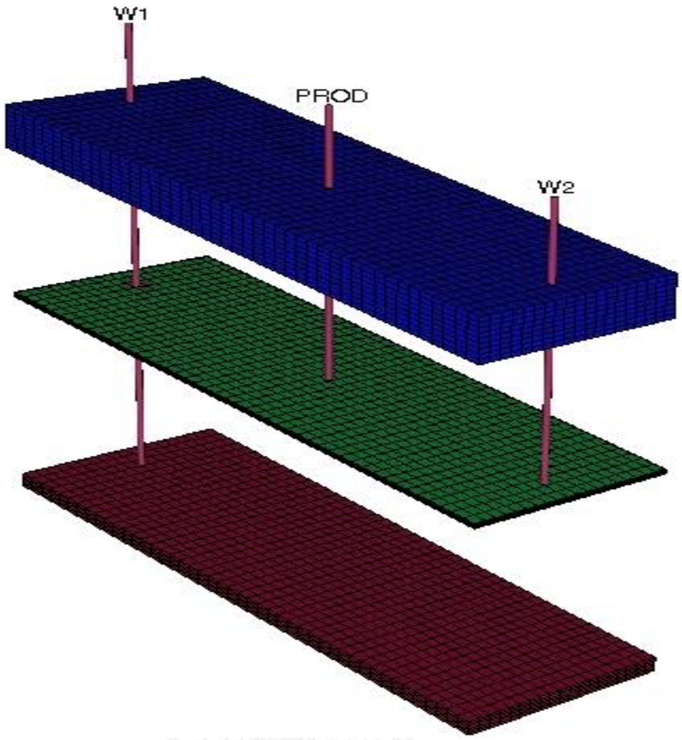


Figure 4-16: 3D view of oil reservoir, aquifer and gas reservoir with one producer, one water dumping well (W2) and one gas dumping well (W1) in case of combination dumpflood

2. Simulate and find recovery factor natural depletion, water dumpflood and gas dumpflood model in order to obtain results for comparison with the results from combination of water and gas dumpflood

3. After obtaining base case results, simulate the model of combined water and gas dumpflood with different operational parameters and reservoir system parameters in order to study the effects of these parameters on oil recovery. The parameters are:

   - Reservoir system parameters:

      iii. Aquifer size: 5PV, 10PV and 30PV

      iv. Gas reservoir size: 1PV, 3PV and 9PV

- Operational parameters:

    iii. Production well location:

    a) In the middle between the updip and downdip dumping wells as shown in Figure 4-17 (a).

    b) One-fourth of the distance between the original producer and water dumper downdip toward the water dumper as shown in Figure 4-17 (b).

    c) One-third of the distance between the original producer and water dumper downdip toward the water dumper as shown in Figure 4-17 (c).

    d) Half of the distance between the original producer and water dumper downdip toward the water dumper as shown in Figure 4-17 (d).

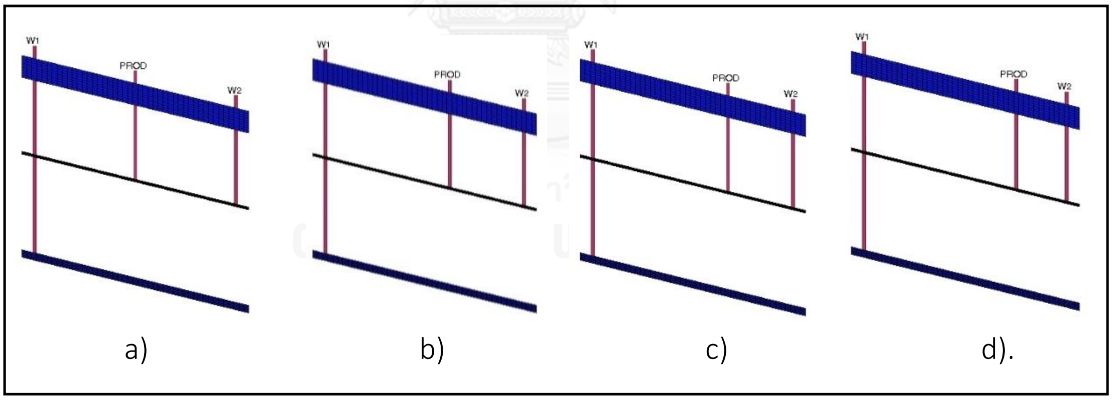


Figure 4-17: Production well locations

    iv. Dumping schedule: simultaneously, water first and gas first.

4. Analyze and discuss the results from simulations.
5. Summarize the effects of each parameter on performance of combination of water and gas dumpflood into oil reservoir and give the suggestion on the operational method from which optimum production can be obtained in term of oil recovery and production time.

All the scenarios are summarized in Figure 4-18 and Table 4-9.

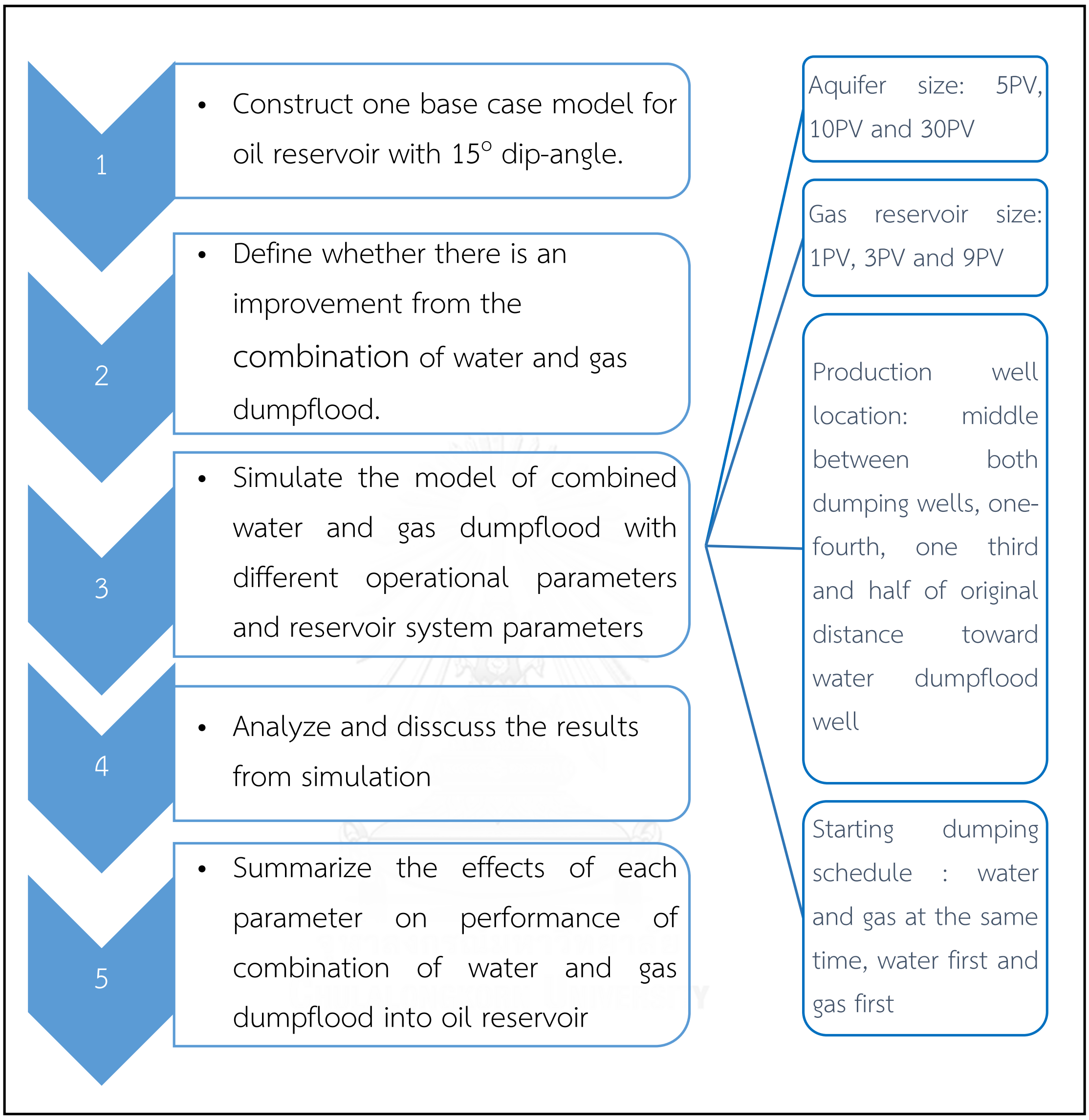


Figure 4-18: Summary of research procedure

Table 4-9: Detail of reservoir simulation cases

<table>
<tr><th>Strategy</th><th>Aquifer size</th><th>Gas Reservoir size</th><th>Production Well Location</th><th>Dumping schedule</th><th>N° of cases</th></tr>
<tr><td>Natural depletion</td><td>-</td><td>-</td><td>-</td><td>-</td><td>1</td></tr>
<tr><td rowspan="3">Water dumpflood</td><td>5PV</td><td rowspan="3">-</td><td rowspan="3">-</td><td rowspan="3">-</td><td rowspan="3">3</td></tr>
<tr><td>10PV</td></tr>
<tr><td>30PV</td></tr>
<tr><td rowspan="3">Gas dumpflood</td><td rowspan="3">-</td><td>1PV</td><td rowspan="3">-</td><td rowspan="3">-</td><td rowspan="3">3</td></tr>
<tr><td>3PV</td></tr>
<tr><td>9PV</td></tr>
<tr><td>Combined water and gas dumpflood</td><td>● 5PV
● 10PV
● 30PV</td><td>● 1PV
● 3PV
● 9PV</td><td>● middle between both dumping wells
● one-fourth
● one third
● half of original distance toward water dumpflood well</td><td>● water and gas at the same time
● water first
● gas first</td><td>3×3×4×3=108</td></tr>
<tr><td colspan="5">Total</td><td>115</td></tr>
</table>

4.5 Well schedules

The size of wellbore ID for this study is 6-1/8 inches for all wells. The perforation is conducted on the entire thickness of the reservoir. There are three production wells for natural depletion, one producers and one dumping well for stand-alone dumpflood and one producer and two dumping wells in case of combination dumpflood as mentioned in the methodology part.

Well production control and production constraints are summarized in Table 4-10, Table 4-11 and Table 4-12 for the case of simultaneous water and gas dumpflood, water dumpflood first followed by gas dumpflood and vice versa.

Table 4-10: Production control data for simultaneously dumping of water and gas

Well	Production Well	Water Dumpflood Well	Gas Dumpflood Well
Open/Shut flag	OPEN	STOP	STOP
Well completion data	OPEN	OPEN	OPEN
Control	LRAT	-	-
Liquid rate	2000 STB/D	-	-
BHP target	500 psia	-	-
Shut-in condition	Oil rate < 50 STB/D	Aquifer pressure < 650 psia	Gas reservoir pressure < 650 psia
Production life	30 years		

Table 4-11: Production control data for production well and dumping wells for water dumpflood first schedule followed by gas dumpflood

Well	Production Well	Water Dumpflood Well	Gas Dumpflood Well
Open/Shut flag	OPEN	STOP	STOP
Well completion data	OPEN	OPEN	SHUT
Control	LRAT	-	-
Liquid rate	2000 STB/D	-	-
BHP target	500 psia	-	-
Triggering condition for stopping water dumpflood and starting gas dumpflood	Aquifer pressure < 650 psia		
Well completion data	OPEN	SHUT	OPEN
Shut-in condition	Oil rate < 50 STB/D	-	Gas reservoir pressure < 650 psia
Production life	30 years		

Table 4-12: Production control data for production well and dumping wells for gas dumpflood first schedule followed by water dumpflood

Well	Production Well	Water Dumpflood Well	Gas Dumpflood Well
Open/Shut flag	OPEN	STOP	STOP
Well completion data	OPEN	SHUT	OPEN
Control	LRAT	-	-
Liquid rate	2000 STB/D	-	-
BHP target	500 psia	-	-
Triggering condition for stopping gas dumpflood starting water dumpflood	Set 1 : Gas reservoir pressure < 650 psia Set 2 : a) oil rate < 200 STB/D in the case of 5 and 10 PV aquifer b) oil rate < 400 STB/D in the case of 30 PV aquifer		
Well completion data	OPEN	OPEN	SHUT
Shut-in condition	Oil rate < 50 STB/D	Aquifer pressure < 650 psia	-
Production life	30 years		

CHAPTER 5

SIMULATION RESULTS AND DISCUSSIONS

This chapter summarizes the discussion on the result of all the simulation cases including natural depletion, water dumpflood, gas dumpflood and combination of water and gas dumpflood. The simulation cases are run in a full factorial pattern for all the parameters in case of combination dumpflood. The performance of combination dumpflood is evaluated based oil recovery for at the end of production.

The preliminary results of combination water and gas dumpflood compared with natural depletion, stand-alone water dumpflood and stand stand-alone gas dumpflood are discussed in the base case result section. The studied parameters such as aquifer size, gas reservoir size, and production well location and water and gas dumping schedule which have effects on the production performance are discussed in Sections 5.2 to 5.3.

5.1 Base case

In this section, the results from natural depletion, stand-alone water dumpflood, stand-alone gas dumpflood and combination of gas dumpflood are compared. As already mentioned, oil is produced with three producers via natural depletion with all wells having the same production control condition but with one well via dumpflood methods. In the base case, the aquifer size is 30 times (30PV) the reservoir and lays 2000 ft. over the oil reservoir. The gas reservoir is located 2000 ft. below the oil reservoir and has the same size as the oil reservoir (1PV).

Oil is produced with the rate of 2000 STB/D for each well, making the total production rate of 6000 STB/D for natural depletion and still 2000 STB/D for dumpflood cases. For all the dumpflood cases including water dumpflood, gas dumpflood and combination dumpflood, water or/and gas is/are dumped into the oil reservoir since the first of the production in order to maintain the plateau rate longer.

Water is dumped at the downdip edge of the reservoir while gas is dumped at updip edge in order to reduce the effect of water underrunning and gas overriding. The production life is limited to be 30 years. However, due to economic limit, some cases reach their economic limits before 30 years such as the case of natural depletion in which the total production rate is very high at the beginning due to the high number of wells and the case of water dumpflood as shown in Figure 5-1. Total field oil production from various methods are shown in Figure 5-2. Among all the methods, combination of water and gas dumpflood yields the highest increment of 27.28% compared to natural depletion method as shown in Table 5-1.

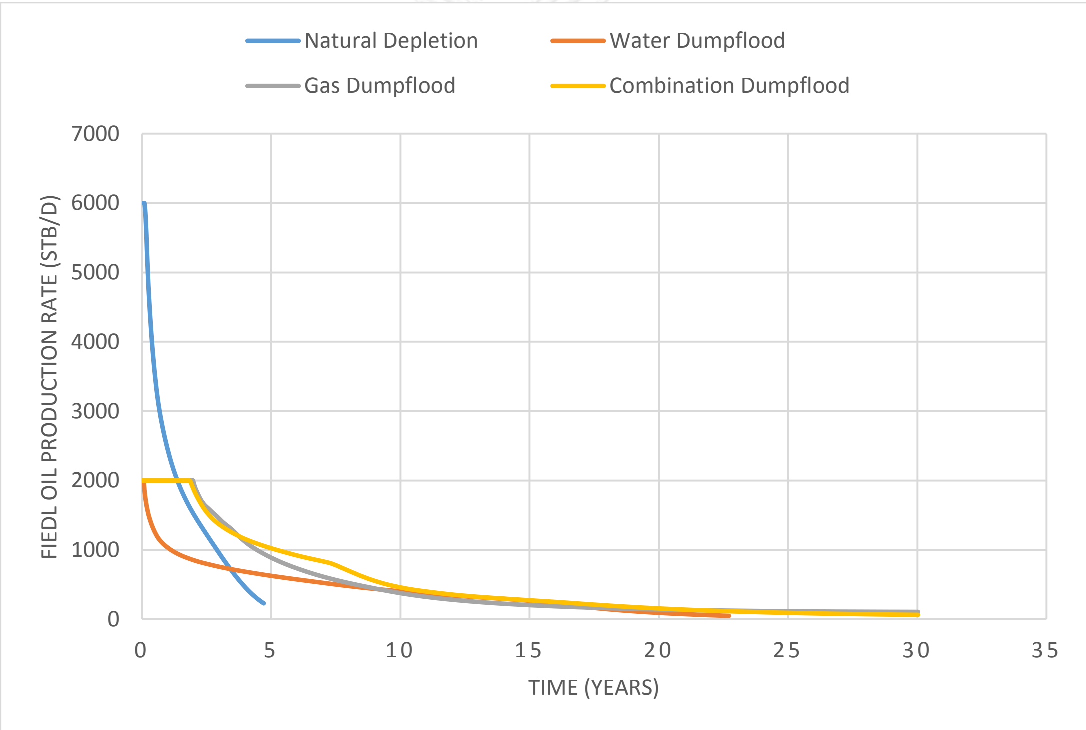


Figure 5-1: Field oil production rate for different production methods

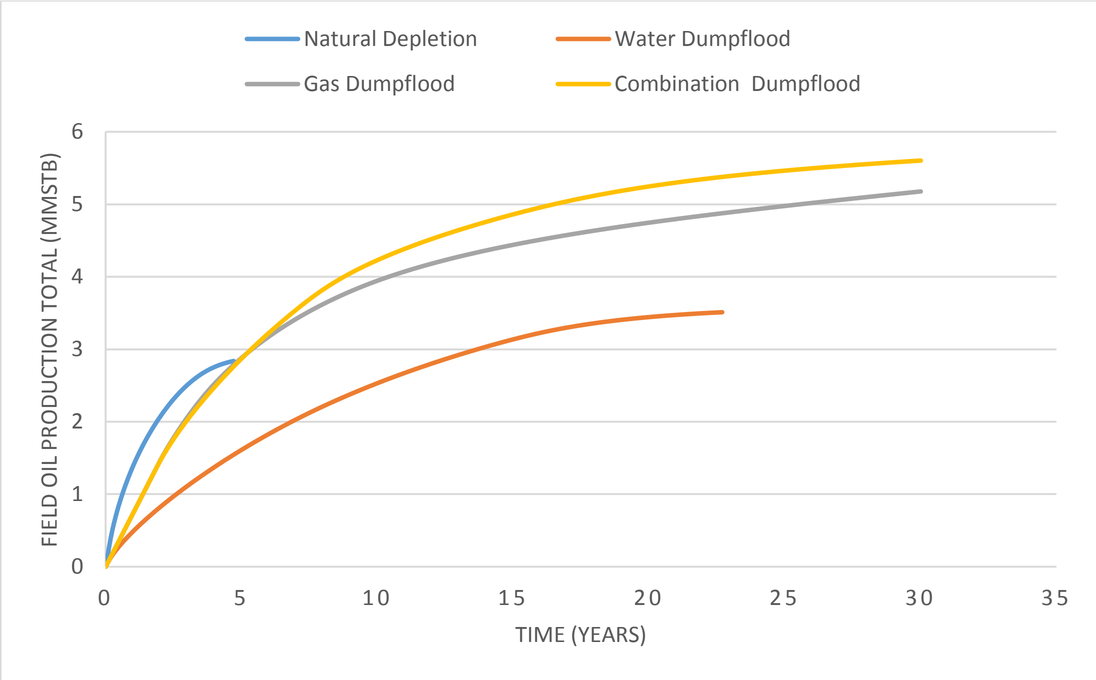


Figure 5-2: Total field oil productions from different methods

Pressures of the oil reservoir from different production methods are plotted in Figure 5-3. In natural depletion case, oil reservoir pressure decreases rapidly due to no support from other sources. Compared to natural depletion, water dumpflood helps support the reservoir pressure. However, the aquifer is not strong enough to maintain the plateau oil production rate, letting it drop since the first day of production. Gas dumpflood and combination dumpflood, on the other hand, do not only maintain the oil reservoir pressure but also increase the pressure from its original pressure making the oil production rate stay at the plateau rate, up to 2 years for both cases. Oil reservoir pressure from combination dumpflood rises faster at the beginning and drops faster than gas dumpflood at later time but it, however, sustains the oil reservoir pressure at higher values than gas dumpflood later due to the strong support from both aquifer and gas reservoir while gas dumpflood has only one support from gas reservoir.

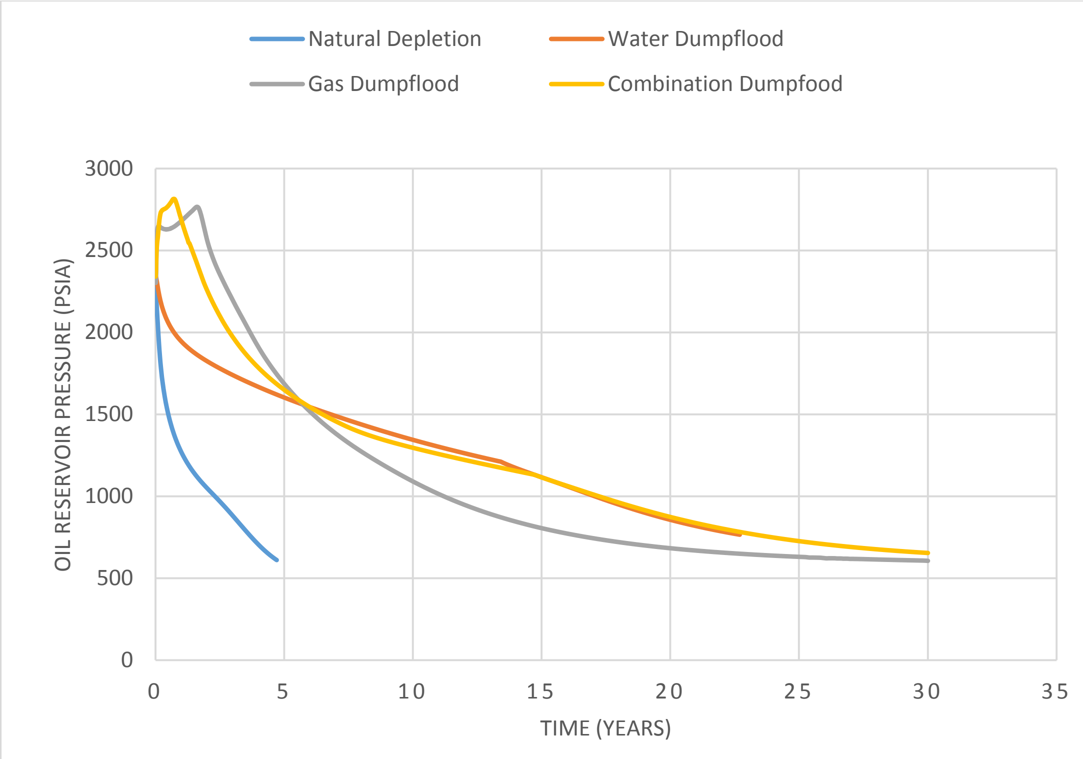


Figure 5-3: Oil reservoir pressures after production with different methods of production

Figure 5-4 shows comparison between the amount of water crossflowing from water aquifer into the oil reservoir in case of water dumpflood and combination dumpflood (natural depletion and gas dumpflood do not have water crossflow). From this figure, it can be seen that combination dumpflood allows more water to crossflow from aquifer into the oil reservoir. This is because the production well in the combination dumpflood case is located closer to the water dumping well than the one in water dumpflood case. The combination dumpflood case has lower pressure around the dumping well than water dumpflood and this allows more water to cross flow from aquifer. Similar to the comparison between water and combination dumpflood, the total amount of gas crossflowing into the oil reservoir in case of gas dumpflood is slightly higher than one in case of combination dumpflood at the end of production but tends to be slightly less at later time as can be seen in Figure 5-5 due to the equilibration in the system, i.e., all the gas that can crossflow into the oil reservoir has already crossflowed.

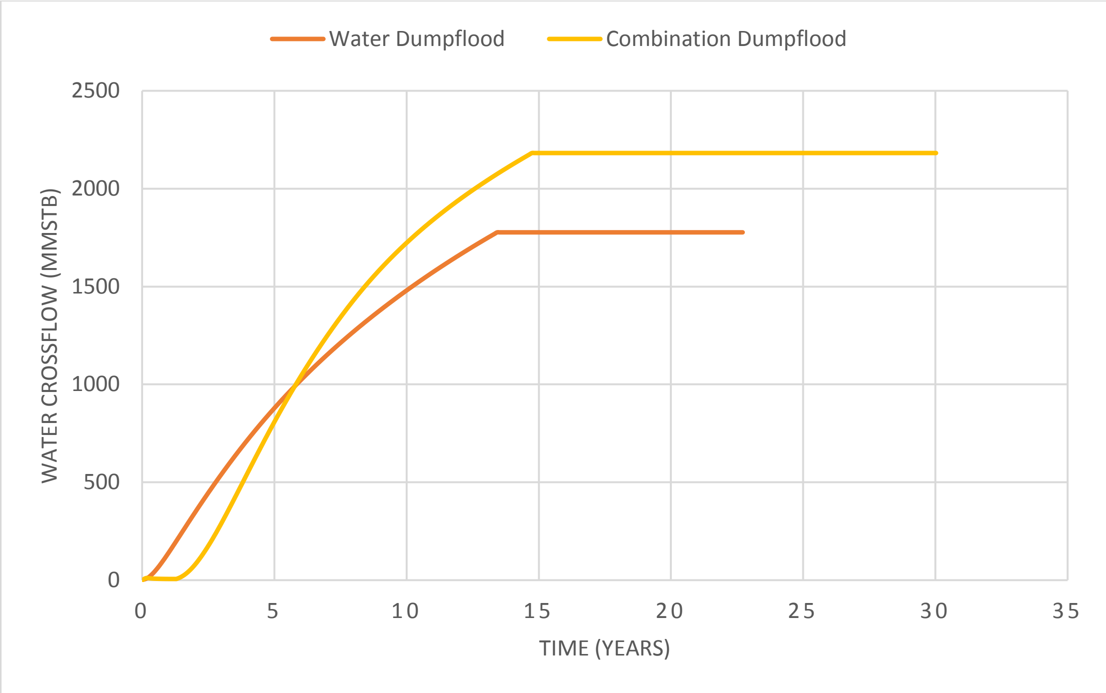


Figure 5-4: Water crossflow from aquifer into oil reservoir in case of water dumpflood and combination dumpflood.

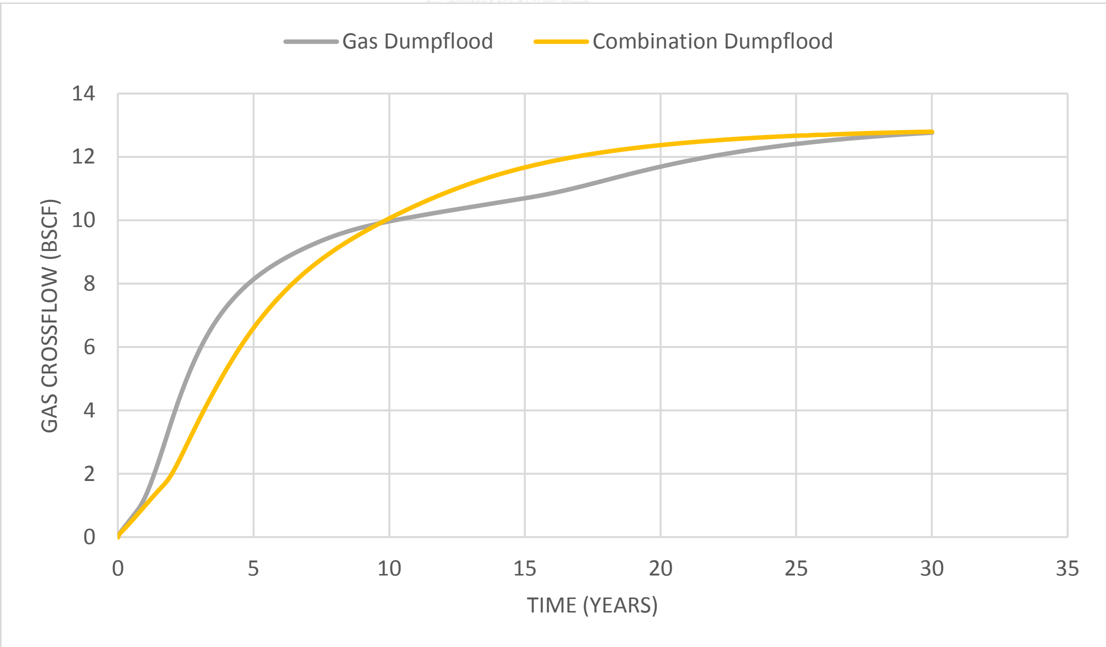


Figure 5-5: Gas crossflow from gas reservoir into oil reservoir in case of gas dumpflood and combination dumpflood.

The results from all the cases mentioned above are summarized in Table 5-1 in term of the oil recovery factor, total oil, gas and water production, water and gas crossflow, their production life and incremental recovery compared to natural depletion methods. Natural depletion can recover 28% of OOIP. In addition to natural depletion, other methods can give incremental recovery of 6.63%, 23.08% and 27.28% for the case of stand-alone water dumpflood, stand-alone gas dumpflood and combination dumpflood, respectively. So, it can be clearly seen that combination dumpflood gives the highest oil recovery. As already discussed, gas production from combination dumpflood is slightly higher than the one from stand-alone gas dumpflood. However, water production from combination dumpflood is much higher than other cases with amount of 593.68 MSTB. The reason behind this higher value of water production is because the producer becomes closer to the dumping wells which allows water to break through faster. Based on the amounts of water production from other cases beside combination dumpflood, we can say that there is no water breakthrough for stand-alone water dumpflood.

Table 5-1: Results of natural depletion, water dumpflood, gas dumpflood and combination dumpflood

Methods / Results	Natural Depletion	Water Dumpflood	Gas Dumpflood	Combination Dumpflood
Recovery factor (%)	28.00	34.64	51.08	55.29
Total oil production (MMSTB)	2.84	3.51	5.18	5.60
Gas production (BSCF)	1.23	1.28	13.81	13.97
Water production (MSTB)	0.42	0.48	0.69	593.68
Total gas crossflow (BSCF)	-	-	12.79	12.76
Total water crossflow (MMSTB)	-	1.78	-	2.18
Production life (Years)	4.71	22.70	30	30
Incremental recovery (%)	-	6.63	23.08	27.28

In Figure 5-6 to Figure 5-9, the distributions of oil saturation after production with all the studied methods are illustrated. In case of natural depletion, we can still see high oil saturation at topmost and intermediate oil saturation at bottommost part of the reservoir. Stand-alone water dumpflood can sweep oil quite well at the downdip part of the bottommost layer of the reservoir but fails to sweep the topmost layer of the reservoir due to gravity segregation. On the other hand, stand-alone gas dumpflood does a great job in sweeping oil at the top of reservoir by leaving only small area of oil behind, but fails to sweep the bottommost layer of the reservoir due to same reason as stand-alone water dumpflood. Finally, combination dumpflood compromises the weakness and strength of both and water dumpflood and gas dumpflood. It improves the swept area of oil in the topmost part of the reservoir but leaves more amount of unrecovered in the bottommost part of the reservoir. However, the gain and the loss are compromised and results in the incremental oil production compared to stand-alone water or gas dumpflood.

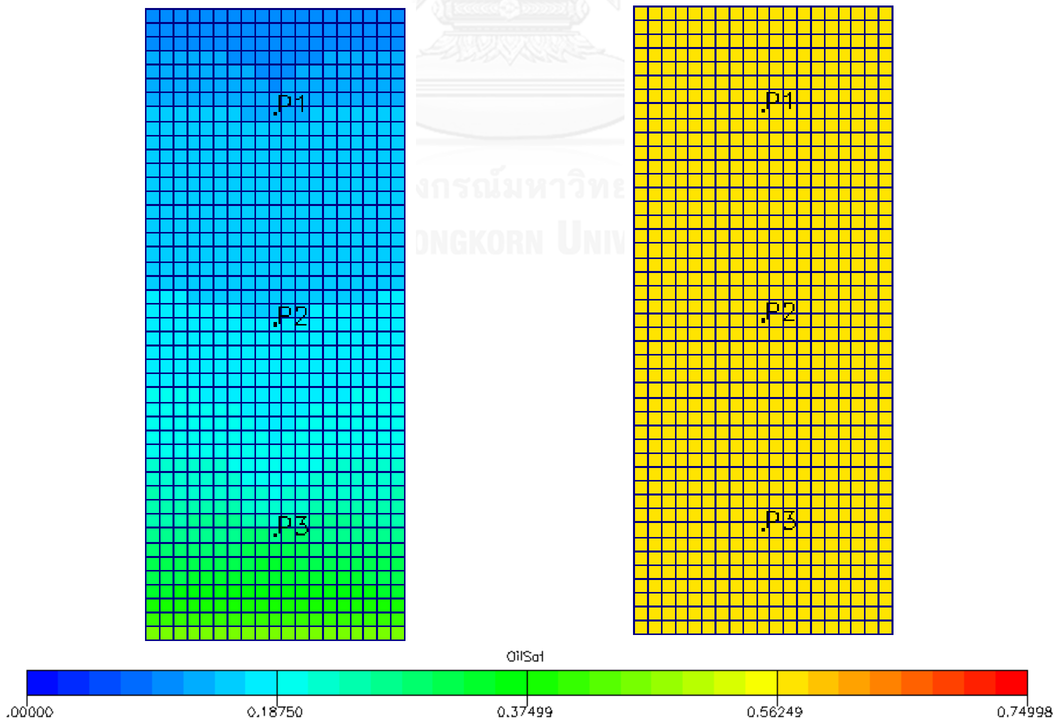


Figure 5-6: Oil saturation distribution of top layer (left) and bottom (right) of oil reservoir after natural depletion production

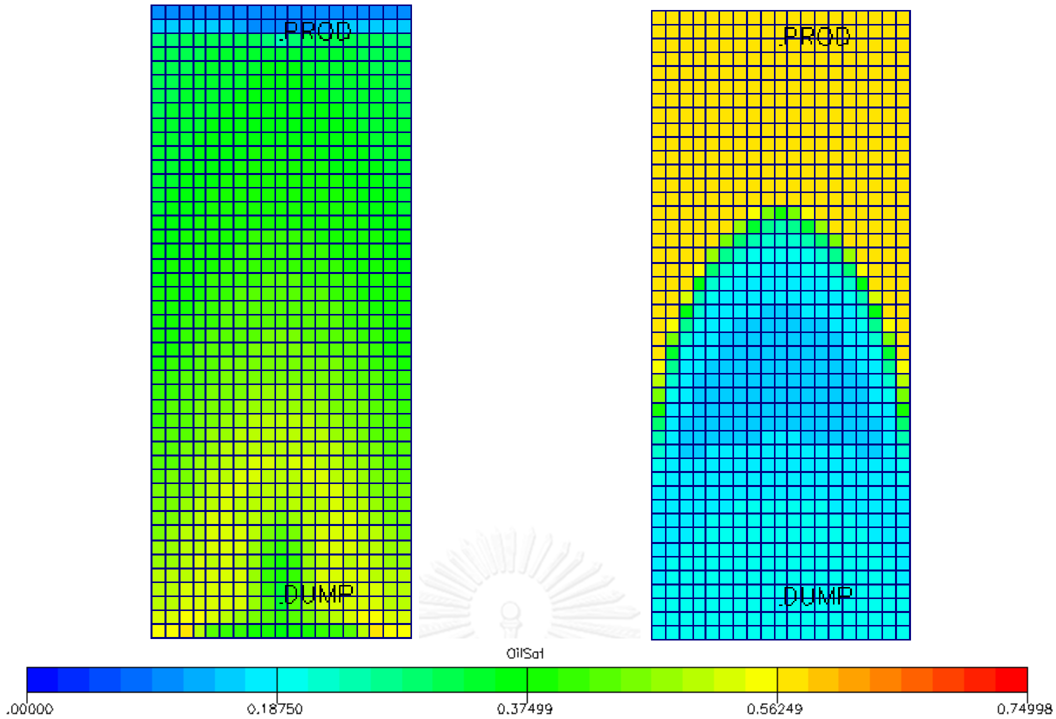


Figure 5-7: Oil saturation distribution of top layer (left) and bottom (right) of oil reservoir after water dumpflood

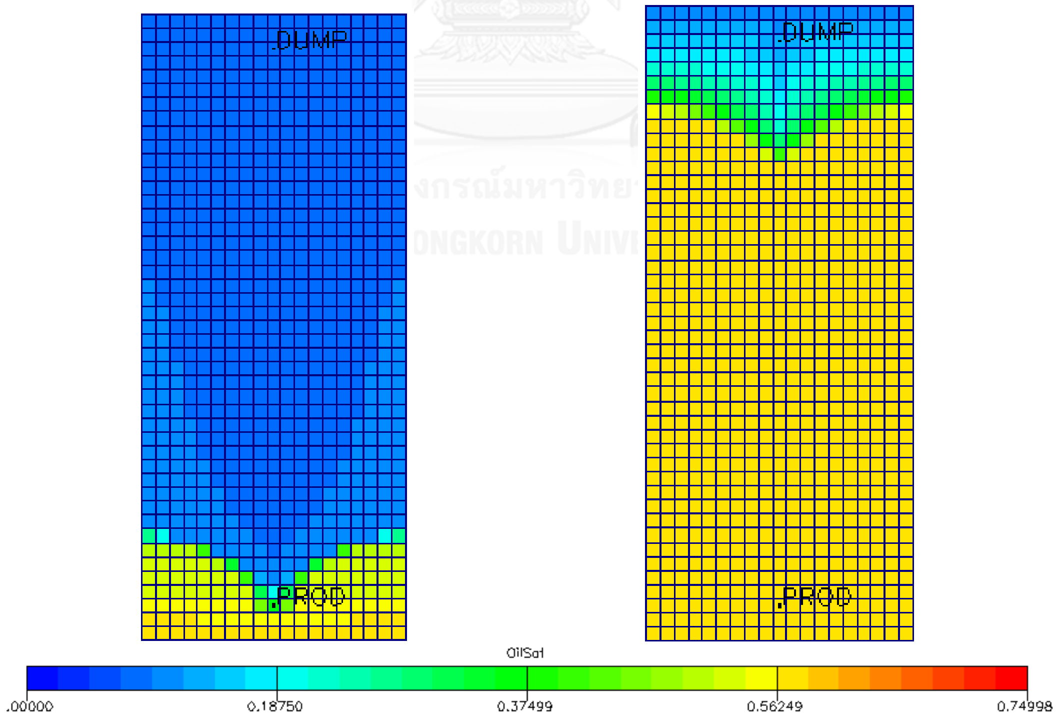


Figure 5-8: Oil saturation distribution of top layer (left) and bottom (right) of oil reservoir after gas dumpflood production

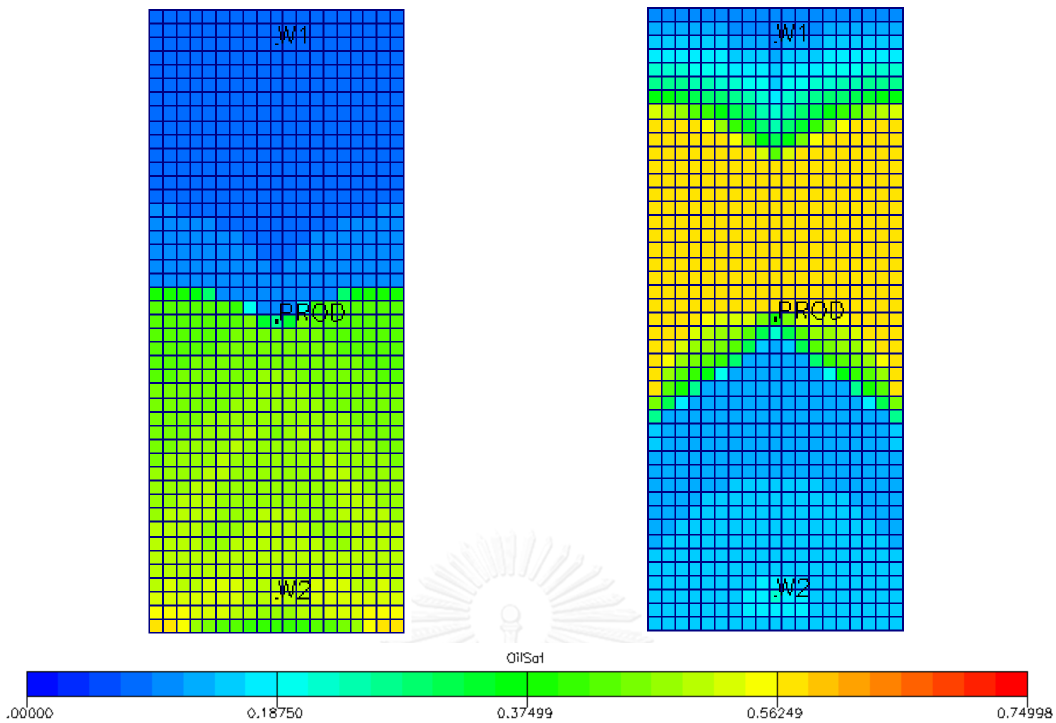


Figure 5-9: Oil saturation distribution of top layer (left) and bottom (right) of oil reservoir after combination dumpflood production

5.2 Effect of reservoir system parameters

Two reservoir system parameters, aquifer size and gas reservoir size, are studied in this section in order to evaluate their effects on production performance. Various values of aquifer size are used and their results are discussed in Section 5.2.1. Effects of gas reservoir size are discussed in Section 5.2.2. More results of various combinations of different aquifer sizes and gas reservoir sizes are discussed in Section 5.2.3.

5.2.1 Effect of aquifer size on water dumpflood and combination dumpflood

Aquifer size is studied in order to see its effect on the performance of stand-alone water dumpflood and combination of water and gas dumpflood. In addition to the aquifer size of 30PV which was previously studied in the base case section, 5P and 10PV aquifer size are introduced to the model. The gas reservoir size of 1PV, which was previously used in the combination dumpflood base case is used for the evaluation of the aquifer size. The results from the water dumpflood and combination dumpflood cases for different aquifer sizes are compared to the natural depletion case in order to see the incremental oil recovery. The results from simulation for various mentioned cases are shown and summarized in Figure 5-10 and Table 5-2.

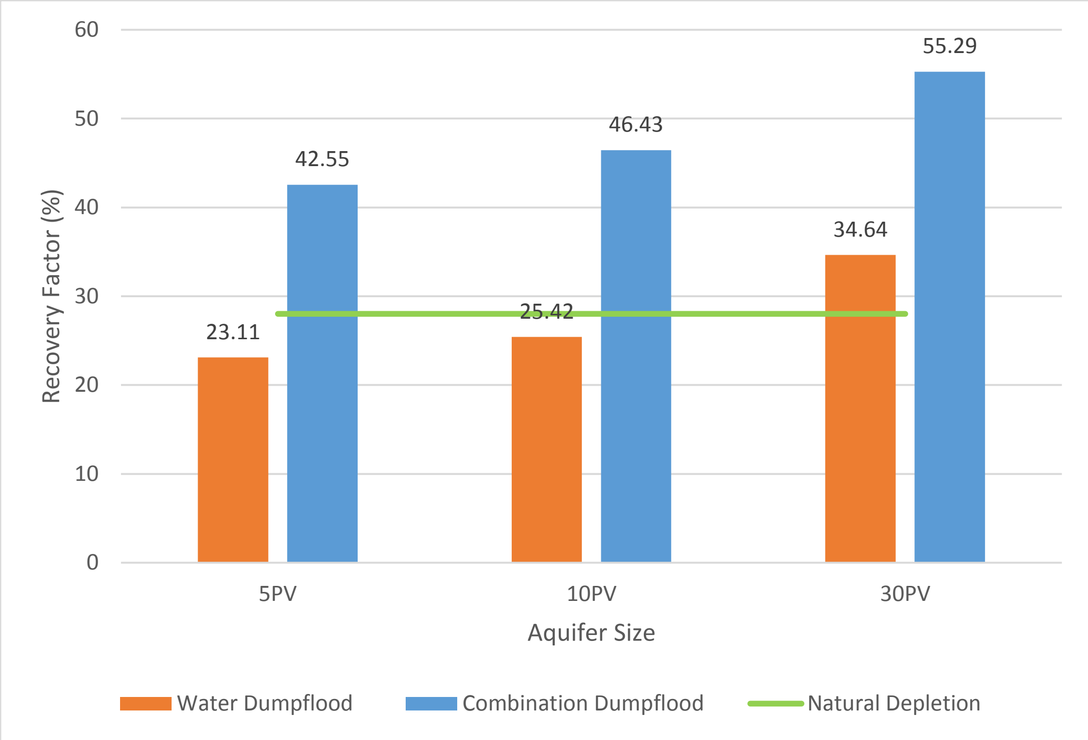


Figure 5-10: Recovery comparison between natural depletion, water dumpflood and combination dumpflood at different aquifer sizes

Table 5-2: Summarized results of natural depletion, water dumpflood and combination dumpflood at different aquifer sizes

Method	Aquifer Size	Recovery Factor	Total Oil Production	Total Gas Production	Total Water Production	Incremental Oil Production	Production life
		%	MMSTB	BSCF	MSTB	%	Years
Natural Depletion	-	28.00	2.84	1.23	0.42	-	4.71
Water Dumpflood	5PV	23.11	2.34	1.07	0.34	-4.89	19.34
	10PV	25.42	2.58	1.11	0.37	-2.58	19.59
	30PV	34.64	3.51	1.28	0.48	6.64	22.71
Combination Dumpflood	5PV	42.55	4.31	14.10	0.44	14.55	20.99
	10PV	46.43	4.71	14.20	4.32	18.43	24.36
	30PV	55.29	5.60	13.97	593.68	27.29	30.00

Natural depletion can recover 28% of OOIP which is equal to 2.84 MMSTB within 4.71 years. Oil recovery from water dumpflood is less than the one obtained from natural depletion for the first two cases of aquifer size (5PV and 10PV) due to two main reasons: (1) there is only one producer located updip in the case of water dumpflood in comparison to three producers distributed along the length of the reservoir in the case of natural depletion and (2) the water aquifer is relatively too small to provide enough water for the flooding. However, water dumpflood provides 6.64% higher recovery factor than natural depletion when the aquifer size becomes 30PV. In case of combination of water and gas dumpflood, the method can increase oil recovery factor from 14.55 to 27.29% in addition to the recovery of natural depletion case depending on the aquifer size. Larger aquifer size yields more oil recovery due to a higher amount of water crossflowing into the oil reservoir.

The water production in the cases of water dumpflood does not change much from one case of one aquifer size to another. The amount of water production changes from 0.34 to 0.48 MSTB which is similar to the one from natural depletion when the aquifer size changes from 5PV to 30PV. This is because there is no water breakthrough among these cases. The produced water are connate water which is produced along with oil. However, the results of water production from combination dumpflood cases do not follow the same trend. The amount of water production increased from 0.44 MSTB to 4.32 MSTB and finally to 593.68 MSTB when the aquifer size increases from 5PV to 30PV. For 5PV aquifer, the amount of water crossflow is too small to break through. For 10PV aquifer, water starts to break through but the amount of water production is still minimal. The amount of water increases strikingly when the aquifer size becomes 30PV due to the large amount water crossflowing into the oil reservoir.

Change in aquifer size does not have much effect on the amount of gas production. Even though the aquifer size changes, the amount of produced gas still stay in the same range. In Table 5-2, we see that the total gas production varies from 13.97 to 14.20 BSCF.

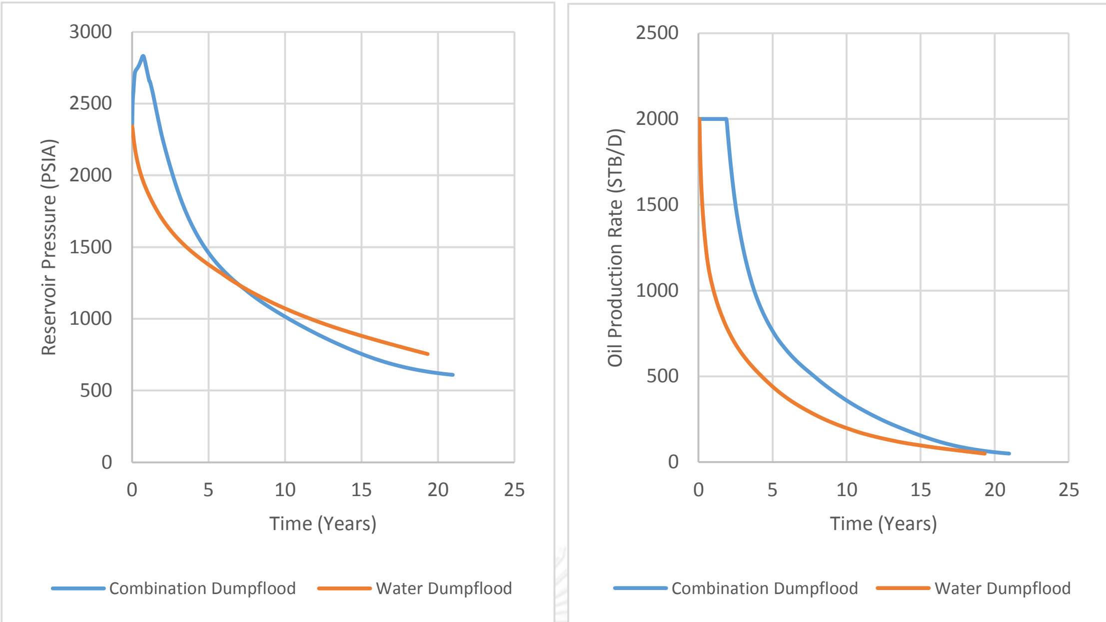


Figure 5-11: Oil reservoir pressure and oil production rate comparison between water dumpflood and combination dumpflood in case of 5PV aquifer

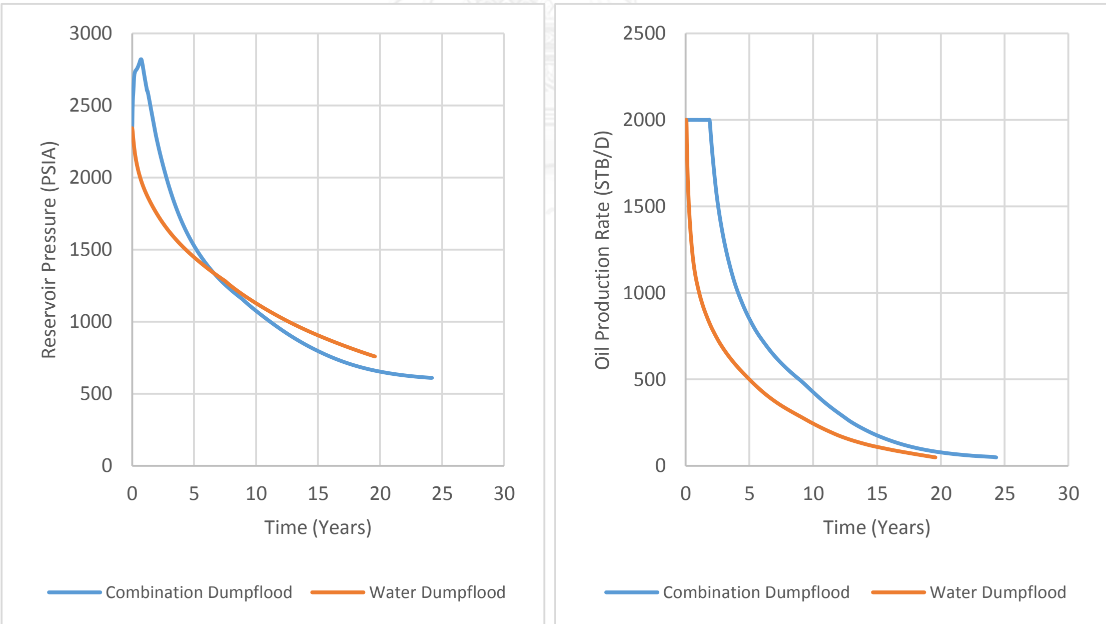


Figure 5-12: Oil reservoir pressure and oil production rate comparison between water dumpflood and combination dumpflood in case of 10PV aquifer

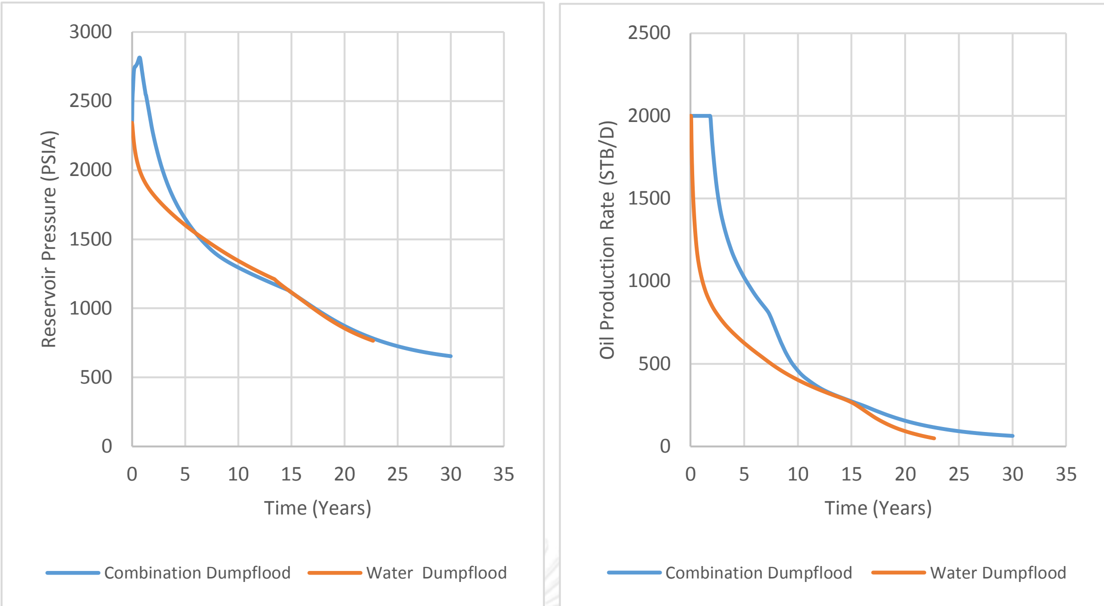


Figure 5-13: Oil reservoir pressure and oil production rate comparison between water dumpflood and combination dumpflood in case of 30PV aquifer

Comparison between water dumpflood and combination dumpflood in term of oil reservoir pressure and oil production rate shown in Figure 5-11 to Figure 5-13 reveals that combination dumpflood helps increase the oil reservoir pressure at the beginning of the production which in turn helps maintain the oil plateau production for longer periods of time. After the plateau production period, combination dumpflood still manages to produce higher oil rate compared to water dumpflood and can produce until lower oil reservoir pressure because the producer of the combination dumpflood is located in the middle allowing the oil to be produced more effectively while the producer of the water dumpflood case is located updip toward the boundary. When the aquifer becomes larger, the oil reservoir pressure declines slower in both cases of dumpflood, causing the oil production rate to drop more slowly as well.

In summary, when the aquifer size becomes bigger, the more it can improve the recovery in both water dumpflood and combination of water and gas dumpflood. It is expected that more improvement can be achieved when the aquifer is bigger than this.

5.2.2 Effect of gas reservoir size on gas dumpflood combination dumpflood

In this section, the effect of gas reservoir size on the performance of the production is discussed. To extend a deeper study from the base case, two more gas reservoir sizes are chosen for this study; 3PV and 9PV. 30PV of aquifer size is kept constant while changing gas reservoir size so that the changes in simulation results are only affected by the change of gas reservoir size. The results of cases with different gas reservoir sizes are compared to natural depletion to see the incremental recovery and to the gas dumpflood of the same gas reservoir size. The results from simulation cases are summarized in Figure 5-14 and Table 5-3.

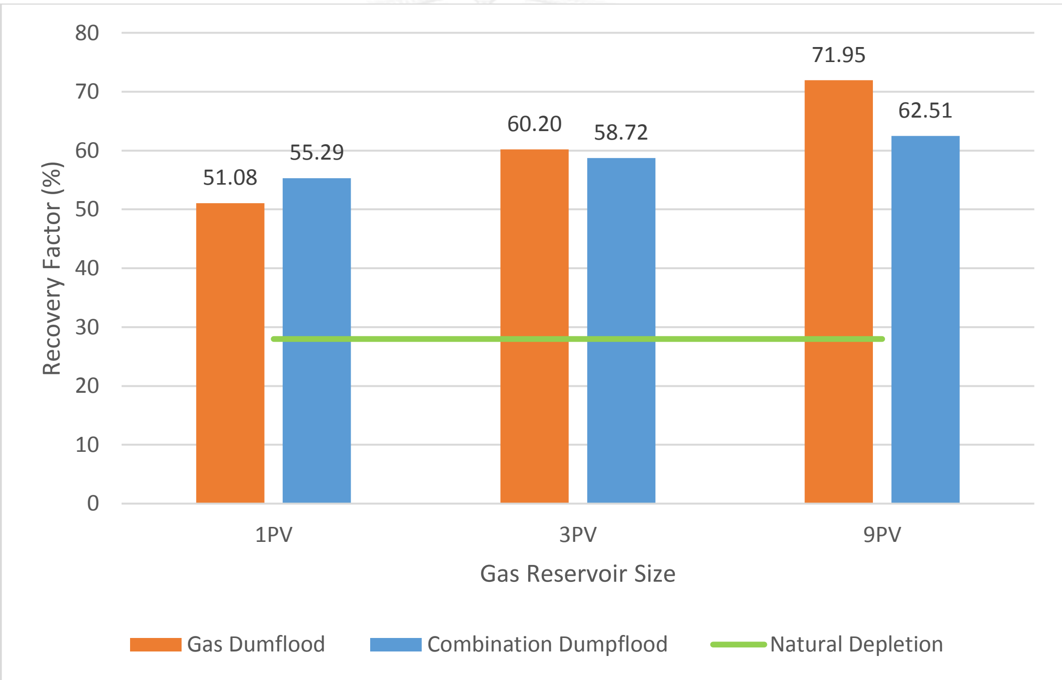


Figure 5-14: Recovery comparison between natural depletion gas dumpflood and combination dumpflood at different aquifer sizes

Table 5-3: Summarized results of natural depletion, gas dumpflood and combination dumpflood at different aquifer sizes

Method	Aquifer Size	Recovery Factor	Total Oil Production	Total Gas Production	Total Water Production	Incremental Oil Production	Production life
		%	MMSTB	BSCF	MSTB	%	Years
Natural Depletion	-	28.00	2.84	1.23	0.42	-	4.71
Gas Dumpflood	1PV	51.08	5.18	13.81	0.69	23.08	30
	3PV	60.20	6.10	34.94	0.76	32.20	30
	9PV	71.95	7.29	91.36	0.88	43.95	30
Combination Dumpflood	1PV	55.29	5.60	13.97	593.68	27.29	30
	3PV	58.72	5.95	34.83	620.88	30.72	30
	9PV	62.51	6.34	91.86	593.20	34.51	30

The results demonstrate that gas dumpflood can provide 23.08 to 43.95% incremental recovery factor compared to natural depletion as the gas reservoir size is increased from 1PV to 9PV while combination of water and gas dumpflood, seemingly good when the gas reservoir is small, can provide 27.29 to 34.51% incremental oil recovery factor when the gas reservoir size is increased. For 1PV gas reservoir, combination dumpflood is the best, being able to recover 5.60 MMSTB of oil compared to 5.18 MMSTB from stand-alone gas dumpflood. When the gas reservoir size is increased to 3PV and 9PV, stand-alone gas dumpflood provides better recovery factor than combination of water and gas dumpflood (recovery factor of 60.20% and 71.95% in case of gas dumpflood versus 58.72% and 62.51% in case combination dumpflood). The difference in oil recovery of gas dumpflood versus combination dumpflood becomes greater as the gas reservoir is bigger. In term of water production, combination dumpflood produces around six hundred thousands of water compared to less one thousand barrels for stand-alone gas dumpflood cases during the same period of production of 30 years due to the breakthrough of water at the producer located in the middle of the reservoir in the combination dumpflood scenario.

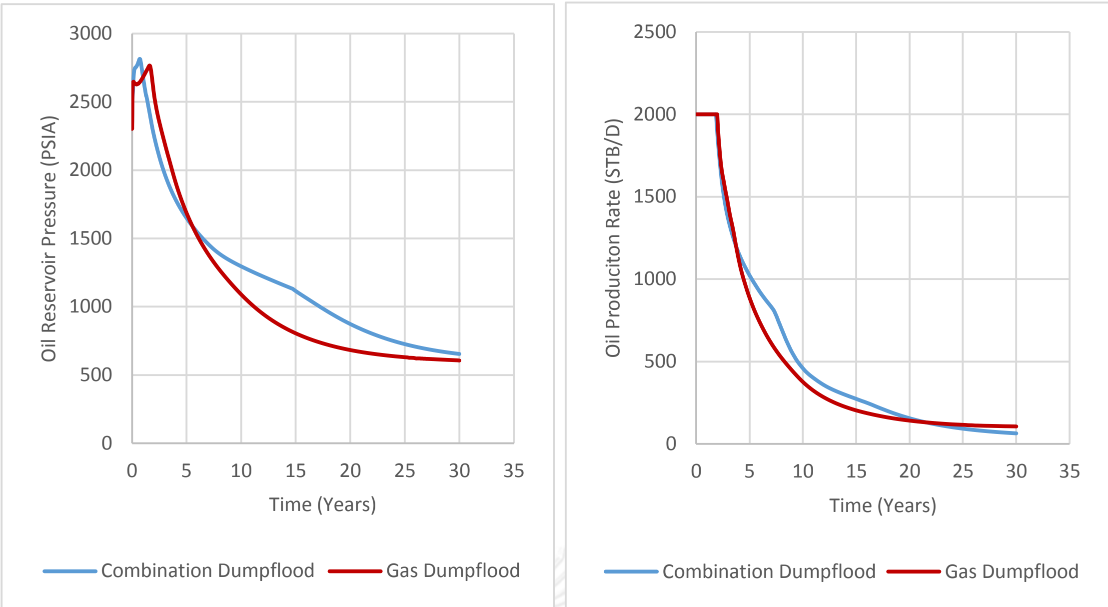


Figure 5-15: Oil reservoir pressure and oil production rate comparison between gas dumpflood and combination dumpflood in case of gas 1PV

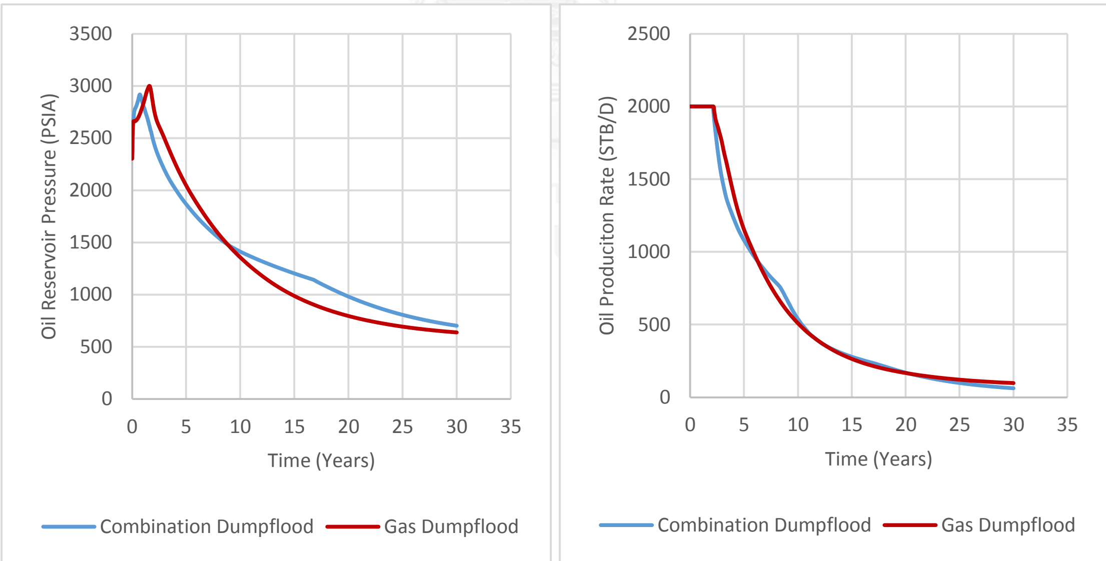


Figure 5-16: Oil reservoir pressure and oil production rate comparison between gas dumpflood and combination dumpflood in case of gas 3PV

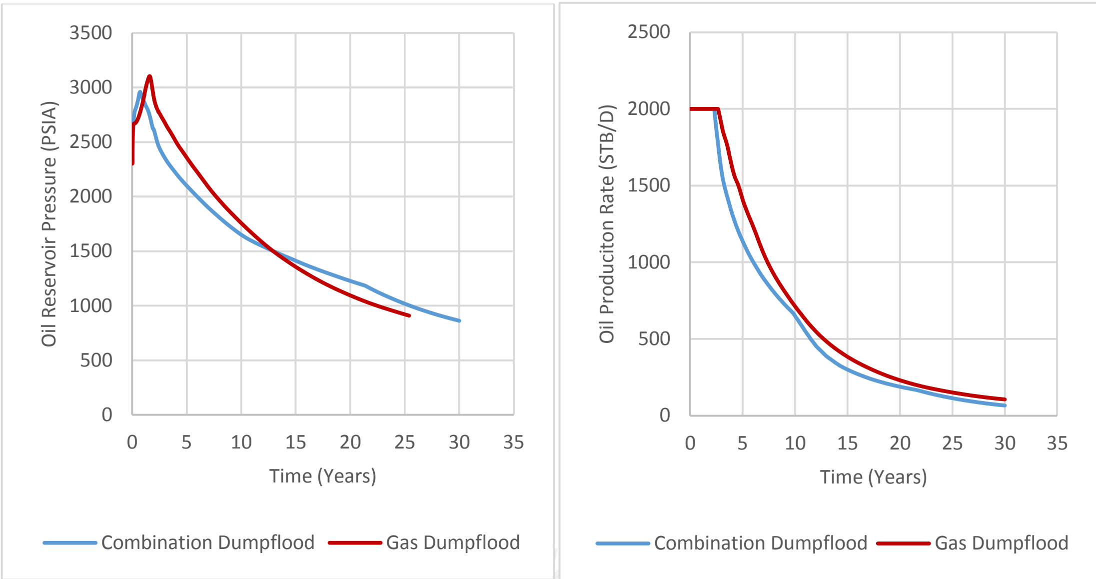


Figure 5-17: Oil reservoir pressure and oil production rate comparison between gas dumpflood and combination dumpflood in case of gas 9PV

Figure 5-15, Figure 5-16 and Figure 5-17 compare oil reservoir pressure and oil production rate between stand-alone gas dumpflood and combination of water and gas dumpflood. In case of small gas reservoir (1PV), combination dumpflood can lift oil reservoir pressure up higher than stand-alone gas dumpflood at the beginning of production (as well as most of the dumpflooding process) while keeping oil production rate slightly higher than the rate from stand-alone gas dumpflood most of the time. But when the gas reservoir size is increased to 3PV or 9PV, there are contradict results to the case of 1PV gas reservoir. The oil reservoir pressure in gas dumpflood is increased higher than the one in combination dumpflood at early times of the production and is also able to provide higher oil production rate. In case of 3PV gas reservoir, the difference between the two methods is not much noticeable. But the difference becomes more significant when the gas reservoir size is changed to 9PV. When the gas reservoir is 9PV, stand-alone gas dumpflood is far more efficient than combination dumpflood as can be clearly seen in both reservoir pressure and production rate comparison.

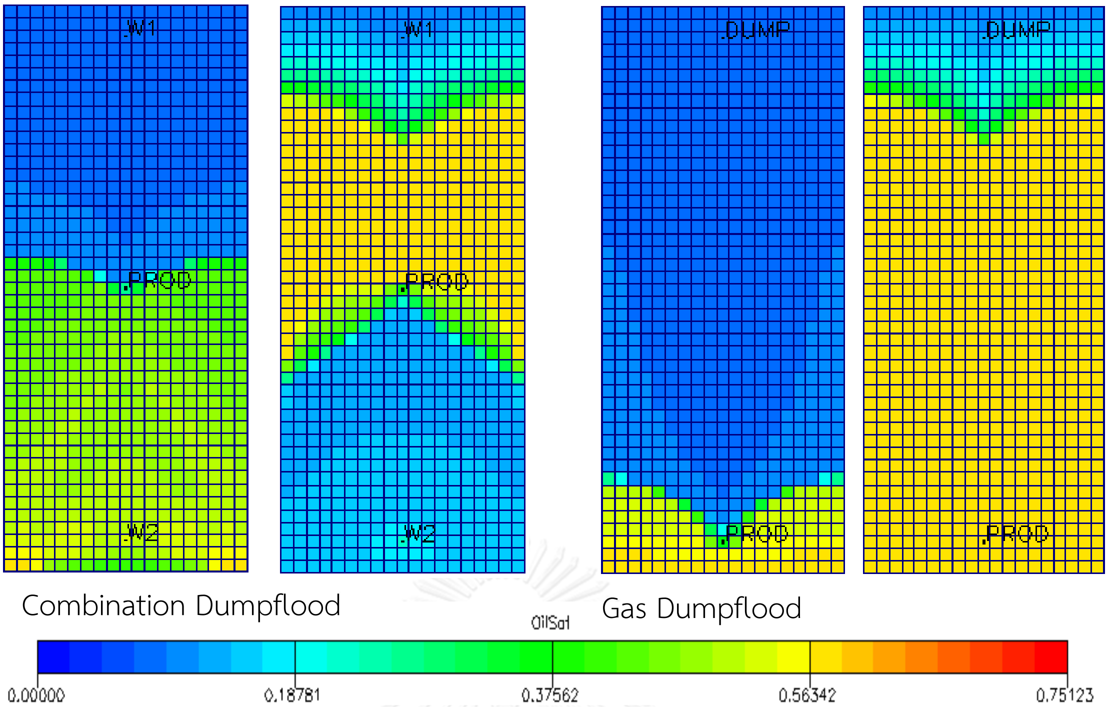


Figure 5-18: Oil saturation distribution of topmost layer (left) and bottommost layer (right) for each method after production for the case of 1PV gas reservoir

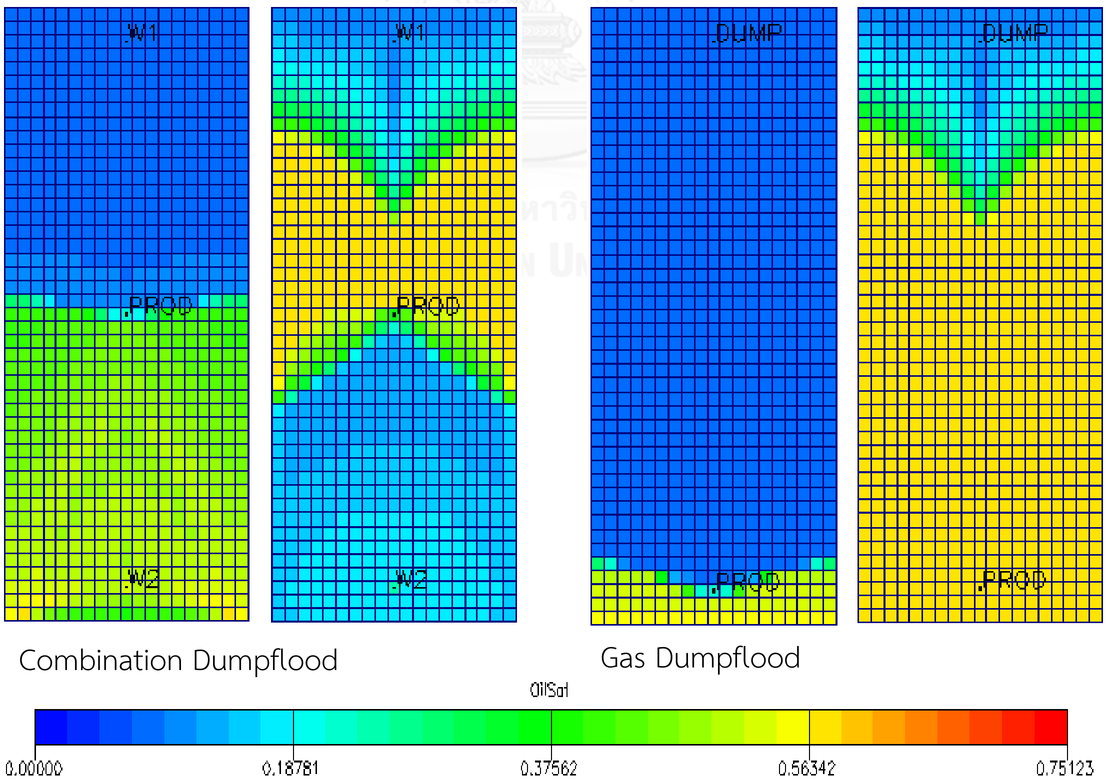


Figure 5-19: Oil saturation distribution of topmost layer (left) and bottommost layer (right) for each method after production for the case of 3PV gas reservoir

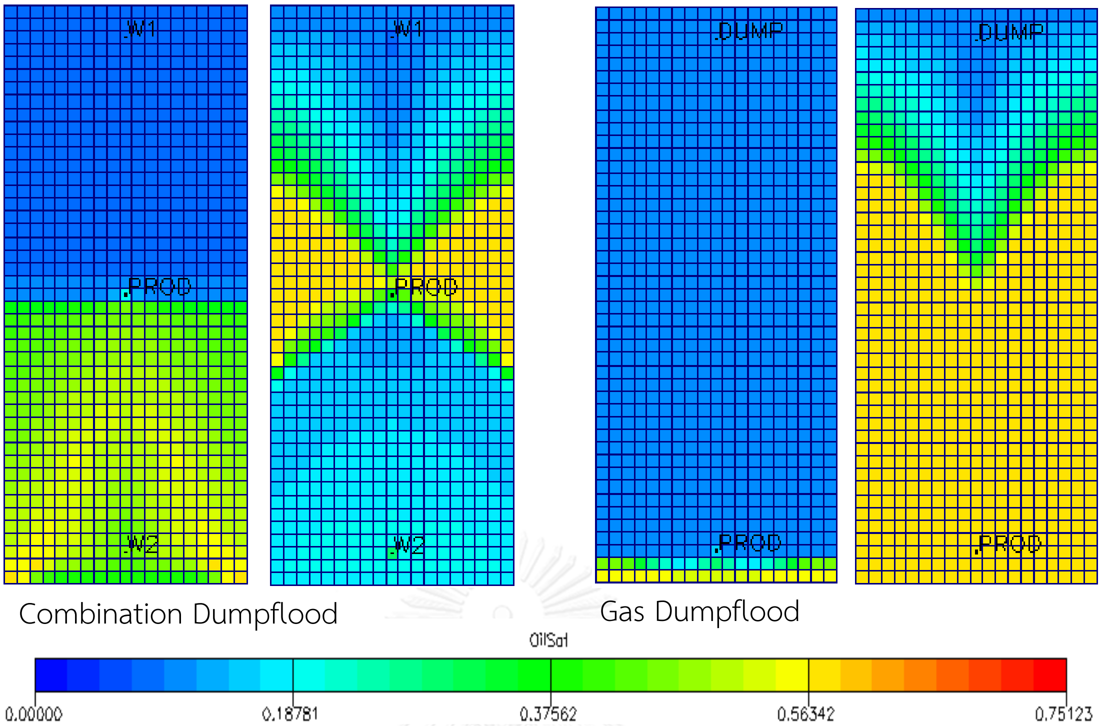


Figure 5-20: Oil saturation distribution of topmost layer (left) and bottommost layer (right) for each method after production for the case of 9PV gas reservoir

Figure 5-18, Figure 5-19 and Figure 5-20 show the distribution of the oil saturation after production with each method at the topmost and the bottommost layers of the reservoir in order to see the difference between the oil swept area from different production methods. As already briefly discussed in Section 5.1, gas dumpflood is proved to be a great technique to sweep oil in the uppermost area of the oil reservoir but poor in sweeping oil in the bottommost area. This can be improved by employing combination dumpflood instead of stand-alone gas dumpflood. However, when combination dumpflood is used, some part of the uppermost area, which can be swept by stand-alone gas dumpflood, has to be sacrificed due to change in production well location as it is moved from the upper edge of the reservoir (gas dumpflood) to the middle between dumpflood wells (combination dumpflood). As the change is applied, it is important to consider if the gain from the bottommost area can compensate the loss from the uppermost area. Figure 5-18 shows that combination dumpflood can sweep oil from large area of the bottommost layer while gas dumpflood leaves a lot of oil behind. Even though combination dumpflood leaves high oil saturation behind around half of the area of the uppermost layer, the gain from the bottommost layer overpowers this loss and makes combination dumpflood more effective than gas dumpflood. Despite the improvement from combination dumpflood in the case of small gas reservoir, opposite results in cases of medium and large gas reservoir size are observed. Gas dumpflood alone can recover a larger amount of oil than combination dumpflood. In Figure 5-19 and Figure 5-20, we can see that gas dumpflood sweep more oil in the uppermost and lowermost layers while combination dumpflood sweeps more oil only in the bottommost layer when compared to results from 1PV gas reservoir.

In brief, we can summarize that combination dumpflood is more effective in recovering oil than stand-alone gas dumpflood only when it comes to small gas reservoir size. Combination dumpflood is a poorer method compared to gas dumpflood when there is a presence of moderate to large gas reservoir.

5.2.3 Results of various combinations of different aquifer sizes and gas reservoir sizes

In the section, the results from various combinations of aquifer sizes and gas reservoir sizes are summarized in order to extend to more precise understanding of effect of aquifer and gas reservoir size on oil production. All gas reservoir sizes that are studied in Section 5.2.2 are combined in the factorial pattern with all aquifer sizes investigated in Section 5.2.1. The results of natural depletion, water dumpflood and gas dumpflood are also provided for comparison purpose. The results are summarized in Table 5-4 and illustrated in Figure 5-21 to Figure 5-23.

Table 5-4: Summarized results of the cases of natural depletion, water dumpflood, gas dumpflood and various combination dumpflood of aquifer sizes and gas reservoir sizes

Case			Recovery Factor	Total Oil Production	Total Gas Production	Total Water Production	Production Life
			%	MMSTB	BSCF	MSTB	Years
Natural Depletion			28.00	2.84	1.23	0.42	4.71
Water Dumpflood	5PV		23.11	2.34	1.07	0.34	19.34
	10PV		25.42	2.58	1.11	0.37	19.59
	30PV		34.64	3.51	1.28	0.48	22.71
Gas Dumpflood	1PV		51.08	5.18	13.81	0.69	30.00
	3PV		60.20	6.10	34.94	0.76	30.00
	9PV		71.95	7.29	91.36	0.88	30.00
Combination Dumpflood	G1PV	W5PV	42.55	4.31	14.10	0.44	20.99
		W10PV	46.43	4.71	14.20	4.32	24.36
		W30PV	55.29	5.60	13.97	593.68	30.00
	G3PV	W5PV	48.07	4.87	35.50	0.49	23.37
		W10PV	51.53	5.22	35.73	9.24	25.92
		W30PV	58.72	5.95	34.83	620.88	30.00
	G9PV	W5PV	54.23	5.50	96.26	0.59	27.48
		W10PV	57.13	5.79	96.72	13.32	28.79
		W30PV	62.51	6.34	91.86	593.20	30.00

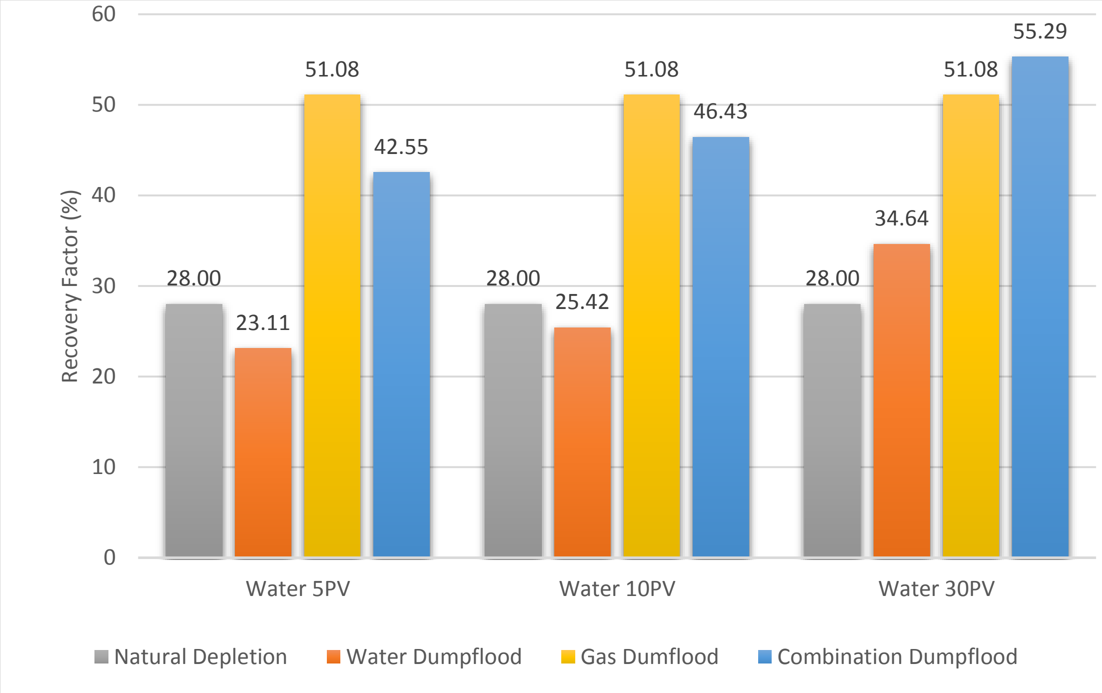


Figure 5-21: Recovery comparison between different production methods in case of 1PV gas reservoir

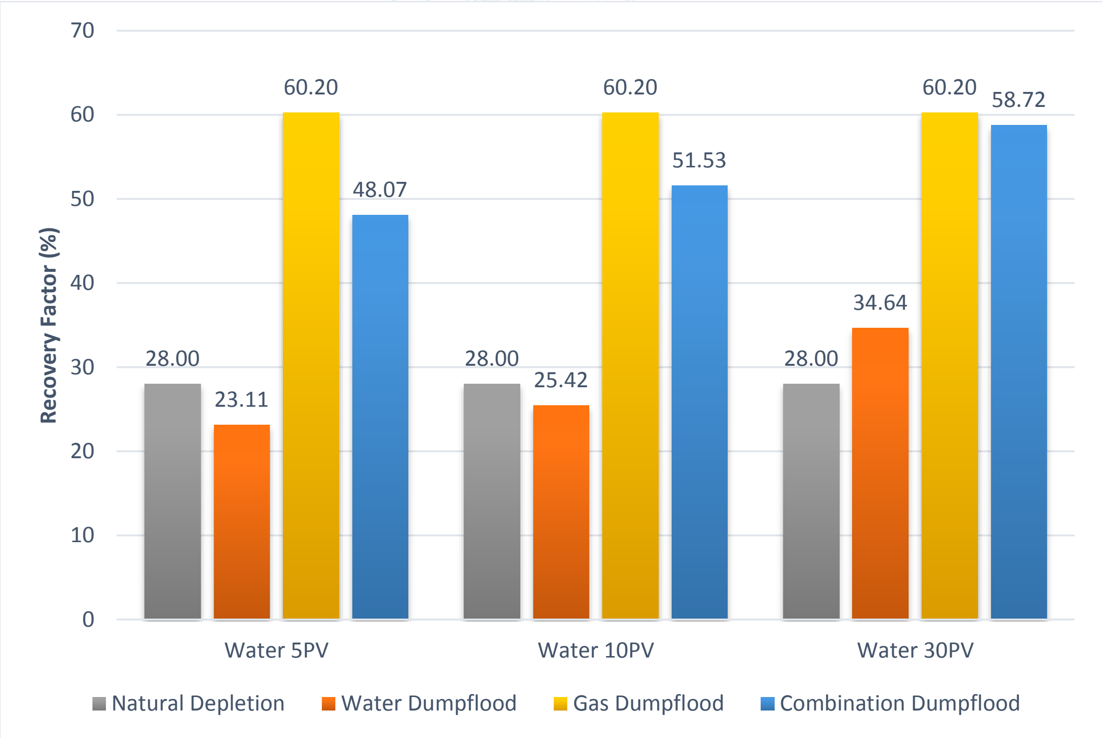


Figure 5-22: Recovery comparison between different production methods in case of 3PV gas reservoir

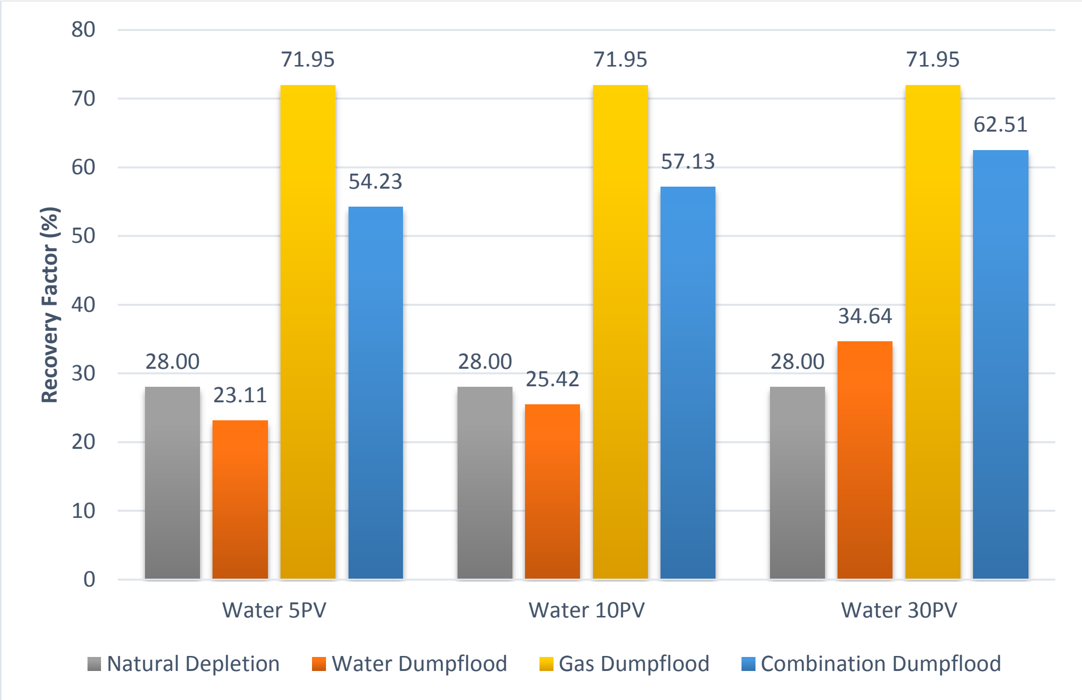
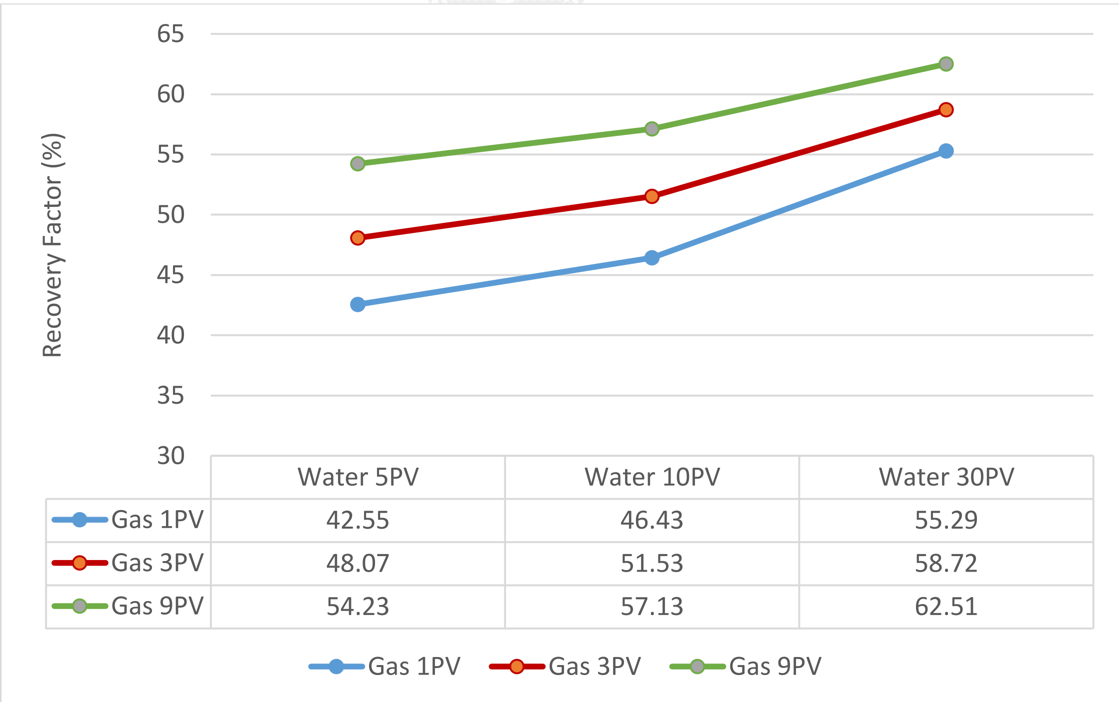


Figure 5-23: Recovery comparison between different production methods in case of 9PV gas reservoir

In the case of small gas reservoir (1PV), combination dumpflood does not show satisfying results when the aquifer size is 10PV or less as the recovery is less than stand-alone gas dumpflood. However, when the aquifer size is increased to large size (30PV), combination dumpflood yields higher oil recovery factor than stand-alone gas dumpflood (55.29% versus 51.08%).

For the case of medium and large gas reservoirs, the same trend can be observed that there is an improvement when the aquifer size is increased. However, the recovery of combination dumpflood never reaches the one of stand-alone gas dumpflood. For 3PV gas reservoir, the recovery factor increases from 48.07% to 58.72% when the aquifer size is changed from small (5PV) to large (30PV) for combination dumpflood while stand-alone gas dumpflood can recover about 60.20% of oil. When the gas reservoir is 9PV, the difference in the recovery factors between gas dumpflood and combination dumpflood becomes larger. While combination dumpflood can recover 54.23 to 62.51% of oil in place depending on the aquifer size, gas dumpflood provides the recovery factor of 71.95%. This is due to the fact that gas leaves less amount of residual oil behind when compared with water. When gas is big and strong enough, it does not require any help from water.

As already discussed in Sections 5.2.1 and 5.2.2, the change in aquifer size does not have much effect on the amount of gas production and vice versa. The amount of gas production increases when the gas reservoir size is increased for both stand-alone gas dumpflood and combination dumpflood. The amounts of gas production from both methods are almost the same for each case of gas reservoir size. Regarding water production, even though the size of gas reservoir does not have much effect on the amount of water production because the amount of water production does not change much in combination dumpflood case for the same aquifer size with different gas reservoir sizes, the small change is due to the production life of each production scenarios. The larger the gas reservoir, the longer the production. This allows water to be produced longer as well.



	Water 5PV	Water 10PV	Water 30PV
Gas 1PV	42.55	46.43	55.29
Gas 3PV	48.07	51.53	58.72
Gas 9PV	54.23	57.13	62.51

Figure 5-24: Recovery factor of combination of various gas reservoir sizes combined with different aquifer sizes

In brief, without considering the results from stand-alone water dumpflood and stand-alone gas dumpflood cases, we can see how the size of water and gas can affect the production. Oil recovery can be improved by increasing the gas reservoir size or aquifer size. Figure 5-24 shows around 13% improvement in recovery factor, from the case with the smallest gas reservoir size and the smallest aquifer size in recovery when increasing the aquifer to the largest one and around 12% increase in recovery when increasing the gas reservoir size to the largest one.

5.3 Effect of operational parameters

In this part, two operational parameters which are the location of production well and water and gas dumping schedule, are studied to evaluate their effects on the performance of the oil production and in order to improve the recovery obtained in Section 5.2. Various locations of production wells are studied and discussed in Section 5.3.1. The dumping schedule of water and gas into the oil reservoir is evaluated in Section 5.3.2.

5.3.1 Effect of production well location

The location of oil production well is studied in the purpose of improving the oil recovery. Since gas has higher mobility than oil, changing the production well location toward the water dumping well will postpone the gas breakthrough and improve the recovery. However, the location of production well has to be balanced between gas breakthrough and water breakthrough. In addition to the original location where the production well is in the middle between the two dumping wells, three more production well locations are investigated for the study by moving the well downdip toward the water dumping well for a distance of one-fourth, one-third and half of the distance between the original production well and water dumping well. Various positions of the production well are depicted in Figure 5-25 to Figure 5-28. W1 represents gas dumping well and W2 represents water dumping well in these figures.

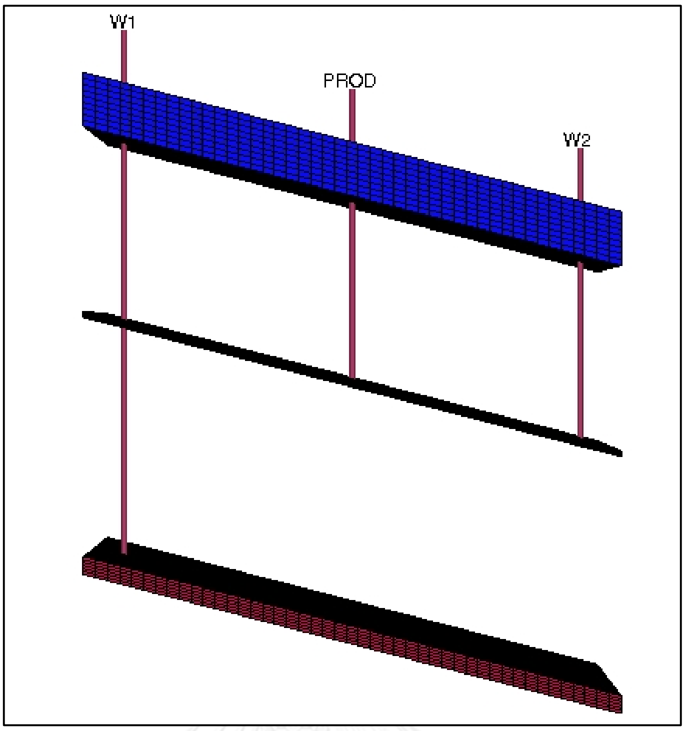


Figure 5-25: Production well at the middle between the two dumping wells (original location)

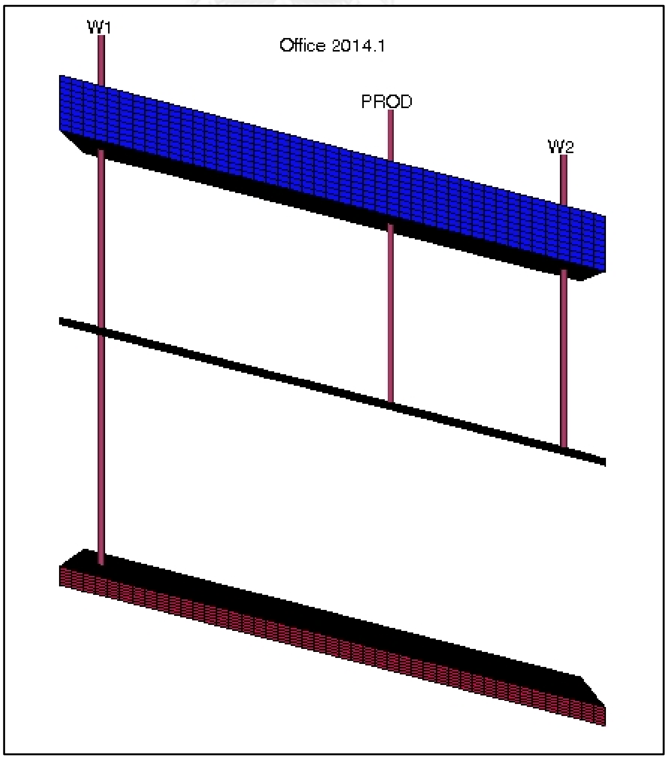


Figure 5-26: Production well located one-fourth of the original distance between the production well and dumping wells toward water dumping well (location 1)

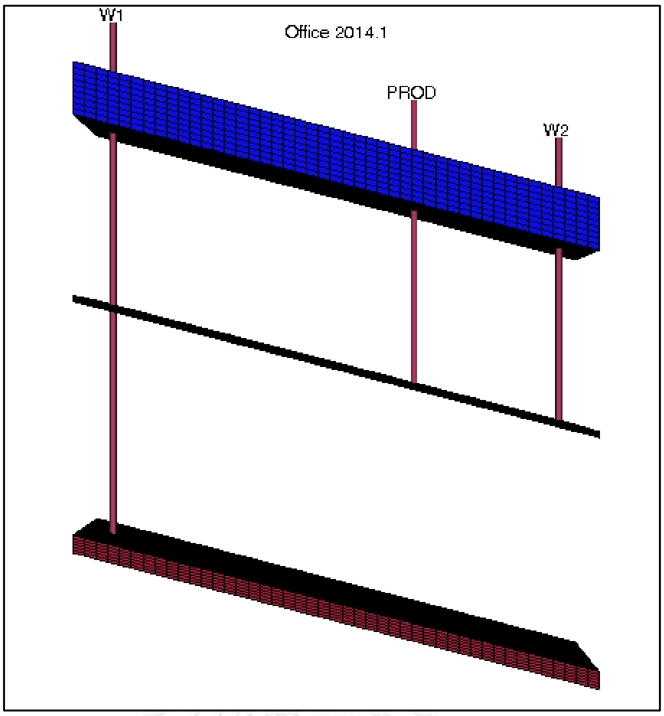


Figure 5-27: Production well located one-third of the original distance between the production well and dumping wells toward water dumping well (location 2)

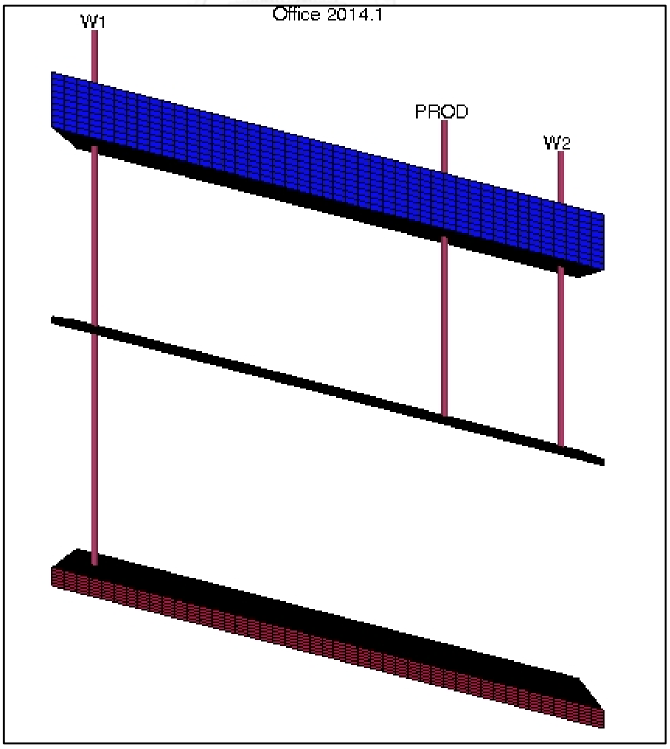


Figure 5-28: Production well located half of the original distance between the production well and dumping wells toward water dumping well (location 3)

The comparison between different well locations are discussed based on the recovery and the breakthrough time of water and gas. The amounts of produced water and gas are also the one of the main discussion in this section due to the fact that changing location will change the amount of produced water and produced gas which strongly has a direct impact on the production performance and the amount of the recoverable oil.

In this section, it is divided into three subsections: small gas reservoir, medium gas reservoir and large gas reservoir sizes where different locations of production well are evaluated while combining with different sizes of aquifer. The three parts are discussed respectively in Sections 5.3.1.1 to 5.3.1.3. For simplification, the location where the production well is moved one-fourth, one-third and half of the original distance between the production well and water dumping well will be called location 1, location 2 and location 3, respectively.

5.3.1.1 Effect of production well location in case of small gas reservoir size (1PV)

As already mentioned, three addition production well locations are studied and compared to the original location. Results from various cases of different production well locations are summarized in Table 5-5. Results are discussed from case to case in term of the aquifer size that is combined with 1PV gas reservoir size.

Table 5-5: Results for various well locations for the case of 1PV gas reservoir combined with different aquifer sizes

Combination		Location	Recovery Factor	Total Oil Production	Total Gas Production	Total Water Production	Production Life
Gas Reservoir Size	Aquifer Size		(%)	(MMSTB)	(BSCF)	(MSTB)	(Years)
1PV	5PV	Original	42.55	4.31	14.10	0.44	20.99
		Location 1	46.83	4.75	14.25	4.48	30
		Location 2	47.83	4.85	14.15	23.40	30
		Location 3	49.00	4.97	13.99	102.95	30
	10PV	Original	46.43	4.71	14.20	4.32	24.36
		Location 1	49.90	5.06	14.16	81.66	30
		Location 2	50.46	5.12	14.04	153.04	30
		Location 3	50.83	5.15	13.89	318.92	30
	30PV	Original	55.29	5.60	13.97	593.68	30
		Location 1	55.58	5.63	13.82	930.77	30
		Location 2	55.35	5.61	13.71	1,095.70	30
		Location 3	54.62	5.54	13.54	1,435.56	30

Table 5-5 demonstrates that the recovery of oil is improved when the production well is moved toward the water dumping well in the case of 5PV and 10PV aquifer. In the case of 1PV gas reservoir and 5PV aquifer, the recovery factory increases from 42.55% at the original location to 46.83% at location 1 and then 49% when the producer is moved to location 3 which is the furthest location from its original location in this study. The case of 1PV gas reservoir with 10PV aquifer also shows the same trend. The recovery factory increases from 46.43% to 50.83% when the producer is moved from the middle location to location 3. However, in the case of 1PV gas reservoir with 30PV aquifer, the result does not follow the trend of the first two cases. Moving from the original location to location 1, the recovery is slightly improved from 55.29% to 55.58%. But when the producer is moved further, we can spot a slight decrease in recovery factor to 55.35% and 54.62% at location 2 and location 3, respectively.

The difference in total gas production is not much significant among the cases. We can still see the gas production around 14 BSCF for almost every case. Among all the cases, there is only one case that gas production drops the most to 13.54 BSCF due to a huge amount of water crossflowing into the oil reservoir. Talking about water production, huge amount of water is produced along with oil when the producer is moved toward the water dumping well. The total water production increases from 0.44 MSTB to 102.95 MSTB, from 4.32 MSTB to 318.92 MSTB and from 593.68 MSTB to 1,435.6 MSTB when the producer is moved from original location to location 3 in case of combination with 5PV, 10PV and 30PV aquifer, respectively.

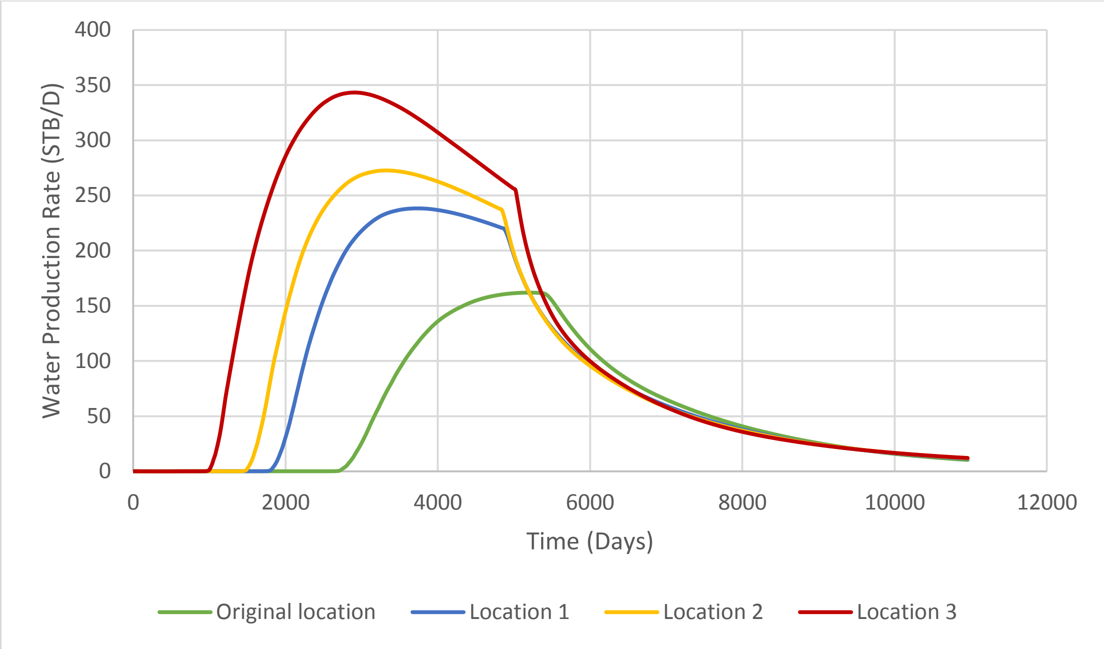


Figure 5-29: Water production rates for different production well locations in case of 1PV gas reservoir with 5PV aquifer

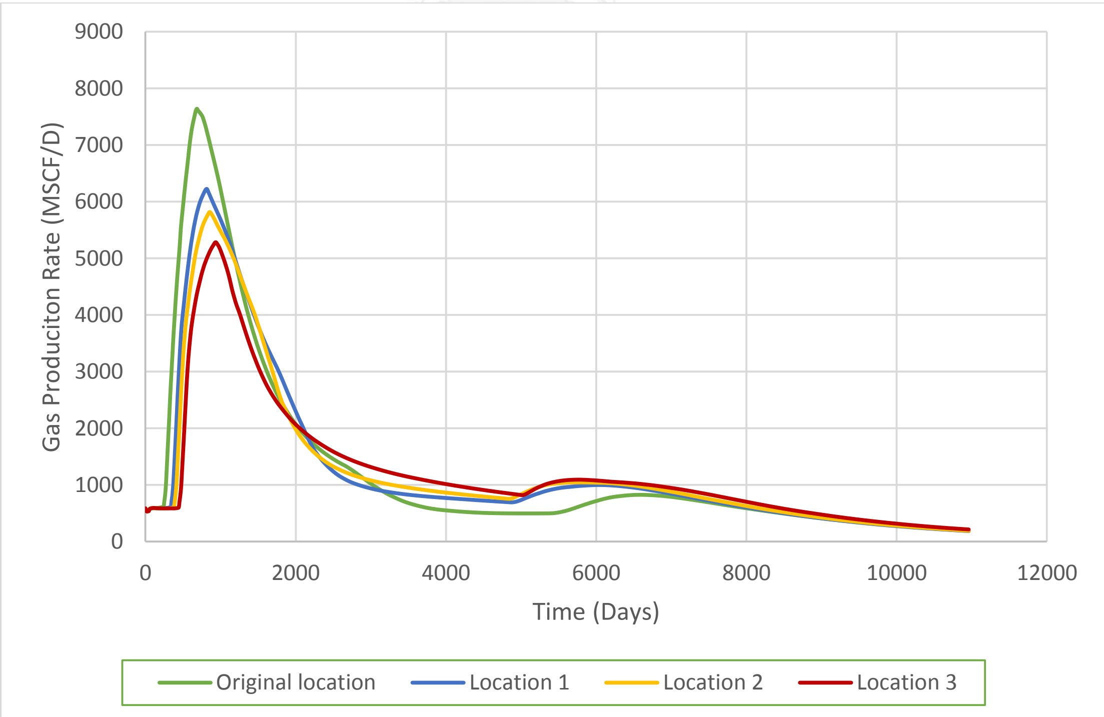


Figure 5-30: Gas production rates for different production well locations in case of 1PV gas reservoir with 5PV aquifer

Figure 5-29 and Figure 5-30 show the effect of production well location on the breakthrough time of water and gas in case of combination dumpflood of 1PV gas reservoir (small gas reservoir) with 5PV aquifer (small aquifer). Moving the producer well downdip causes early water breakthrough but, on the other hand, delays gas breakthrough. The breakthrough times of both fluids have to be balanced so that the recovery can be improved. If one of them has too early breakthrough time which causes excessive amount of that fluid to be produced, it will reduce oil production like the case of combination dumpflood of gas with large aquifer.

5.3.1.2 Effect of production well location in case of medium gas reservoir size (3PV)

This section discusses the effect of the location of oil producer on the production performance in case of medium gas reservoir size (3PV). Results from various cases of different production well locations are summarized in Table 5-6. Results are discussed for the cases in of combination with all aquifer sizes that are combined with 3PV of gas reservoir.

Table 5-6 shows that the recovery of oil is improved when the production well is moved further toward the water dumping well for the case of 5PV and 10PV aquifer. In the case of 5PV aquifer, the recovery factory increases from 48.07% at the original location to 56.07% when the producer is moved to the furthest location, location 3. The cases of 10PV aquifer also shows the same tendency. The recovery factory increases from 51.53% to 57.56% when the producer is moved to location 3. However, in the case of large aquifer size, the result does not follow the trend of the first two cases, just like the case of 1PV gas reservoir size. Moving from the original location to location 2, the recovery is improved but moving from location 2 to location 3, the recovery factor drops from 60.73% to 60.69%.

Table 5-6: Results for various well locations for the case of 3PV gas reservoir combined with different aquifer sizes

Combination		Location	Recovery Factor	Total Oil Production	Total Gas Production	Total Water Production	Production Time
Gas Reservoir Size	Aquifer Size		(%)	(MMSTB)	(BSCF)	(MSTB)	(Years)
3PV	5PV	Original	48.07	4.87	35.50	0.49	23.37
		Location 1	52.66	5.34	35.88	9.11	26.99
		Location 2	54.53	5.53	35.99	36.77	30
		Location 3	56.07	5.68	35.50	128.81	30
	10PV	Original	51.53	5.22	35.73	9.24	25.92
		Location 1	55.72	5.65	35.83	103.82	30
		Location 2	56.66	5.74	35.52	182.06	30
		Location 3	57.56	5.84	35.08	342.30	30
	30PV	Original	58.72	5.95	34.83	620.88	30
		Location 1	60.50	6.13	34.39	962.53	30
		Location 2	60.73	6.16	34.19	1,119.52	30
		Location 3	60.69	6.15	33.84	1,380.99	30

The total gas production from one case to another is not much different as well. The gas production is around 35.50 BSCF for almost every case. There is only one case that gas production drops the most to 33.84 BSCF due to a huge amount of water crossflowing into the oil reservoir. Talking about water production, huge amount of water is produced along with oil when the producer is moved toward the water dumping well. The total water production increases from 0.49 MSTB to 128.81 MSTB, from 9.24 MSTB to 342.30 MSTB and from 620.88 MSTB to 1,380.99 MSTB when the producer is moved from original location to location 3 in case of combination with 5PV, 10PV and 30PV aquifer, respectively.

5.3.1.3 Effect of production well location in case of large gas reservoir size (9PV)

This section discusses the effect of the location of oil producer on the production performance in case of large gas reservoir size (9PV). Results from various cases of different production well locations are summarized in Table 5-7. Results are discussed for the cases in of combination with all aquifer sizes that are combined with 9PV of gas reservoir.

Results in Table 5-7 shows that the recovery of oil is improved for all the cases when the production well was moved further toward the water dumping well. The recovery for the case with 9PV increases from 54.23% to 64.61% when the producer was moved to the furthest location. The cases with 10PV aquifer also show the same tendency. The recovery factory increases from 57.13% to 65.62% when the producer is moved to location 3. Similar to the 5PV and 10PV aquifer case, the recovery factor rises from 62.51% to 67.88% in case with 30PV of aquifer size when changing the location of the producer from the original one to location 3.

Table 5-7: Results for various well locations for the case of 9PV gas reservoir combined with different aquifer sizes

Combination		Location	Recovery	Total Oil	Total Gas	Total Oil	Production Time
Gas Reservoir Size	Aquifer size		(%)	(MMSTB)	(BSCF)	(MSTB)	(Years)
9PV	5PV	Original	54.23	5.50	96.26	0.59	27.48
		Location 1	60.35	6.12	96.58	12.99	29.37
		Location 2	62.34	6.32	96.11	46.98	30
		Location 3	64.61	6.55	93.87	145.42	30
	10PV	Original	57.13	5.79	96.72	13.32	28.79
		Location 1	62.33	6.32	95.52	116.29	30
		Location 2	63.82	6.47	94.17	194.91	30
		Location 3	65.62	6.65	92.01	356.37	30
	30PV	Original	62.51	6.34	91.86	593.20	30
		Location 1	65.89	6.68	89.54	926.44	30
		Location 2	66.90	6.78	88.49	1,084.12	30
		Location 3	67.88	6.88	86.44	1,353.61	30

Similar to the cases of 1PV and 3PV gas reservoir, the total gas production from one case to another is not much different as well. However, the gas production at location 3 is a little bit reduced compared to one at other locations due to a huge amount of water crossflowing into the oil reservoir. Talking about water production, huge amount of water is produced along with oil when the producer is moved toward the water dumping well. The total water production increases from 0.59 MSTB to 145.42 MSTB, from 13.32 MSTB to 356.37 MSTB and from 593.20 MSTB to 1,353.61 MSTB when the producer is moved from original location to location 3 in case of combination with 5PV, 10PV and 30PV aquifer, respectively.

In summary, from the study of the effect of changing location of producer, location 3 yields the highest oil recovery in most cases of gas reservoir and aquifer sizes except for the case of small gas reservoir (1PV) in combination with large aquifer (30PV) in which location 1 is the best and the case of medium gas reservoir (3PV) with large aquifer (30PV) in which location 2 is the best. As the producer is moved toward water dumping well, gas breakthrough is delayed but water breakthrough occurs faster as well. Gas and water dumpflooding need to be balanced with each other. If not, it can lead to less oil production with excessive water production like the case of combination of small and medium gas reservoir with large aquifer. In case of large gas reservoir size, location 3 is the most favorable for all aquifer size due to strong gas support which overpowers water strength.

5.3.2 Effect of dumping schedule of water and gas into oil reservoir

Dumping schedule of water and gas into the oil reservoir has a direct effect on production behavior. It is related to how the pressure support from water and gas is provided to the oil reservoir. The study in this section is intended to evaluate the effect which may be caused by the changing time the support from gas and water feeds into the oil reservoir. In previous sections, water and gas are dumped into the oil the reservoir simultaneously at the beginning of production. Two more cases of dumping schedule are added for the study:

1) Water is dumped at the beginning of the production until the aquifer pressure drops to 650 psia. Then water dumpflood is terminated and gas dumpflood is started.
2) Gas is dumped at the beginning of the production until:
   - The gas reservoir pressure drops to 650 psia. Then, gas dumpflood is replaced with water dumpflood.
   - Oil production drops to 200 STB/D for cases with small and medium aquifer and 400 STB/D for cases with large aquifer. Then, gas dumpflood is replaced with water dumpflood.

The cases of water dumpflood first followed by gas dumpflood versus gas dumpflood first followed by water dumpflood with gas reservoir pressure reduction criteria are discussed in Section 5.3.2.1.

The cases of water dumpflood first followed by gas dumpflood versus gas dumpflood first followed by water dumpflood with oil production rate reduction criteria are discussed in Section 5.3.2.2.

5.3.2.1 Effect of dumping schedule in case of gas dumpflood is stopped with gas reservoir pressure reduction criteria

In this section, two additional water and gas dumping schedules are added to make comparison with the preciously studied schedule, simultaneously dumpflood, in order to study the effect the scheduling of dumpflooding on the production performance. The two additional schedules are water dumpflood first followed by gas dumpflood and gas dumpflood first followed by water dumpflood. The triggering conditions to stop dumping one fluid and starting another dumpflood are shown in Table 4-11 and Table 4-12 in Section 4.4. In this section, in both cases of gas dumpflood first followed by water dumpflood and water dumpflood first followed by gas dumpflood, gas or water dumpflood is stopped when the gas reservoir or aquifer pressure drops to 650 psia. Results of each dumping schedule are summarized in Table 5-8 to Table 5-10 for the cases of combination of different sizes of gas reservoir with various aquifer sizes at different locations of the production well.

Table 5-8: Results for different dumping schedules in case of 1PV gas reservoir

Case				Recovery Factor	Total Oil Production	Total Gas Production	Total Water Production	Production Time
Gas	Aquifer	Location	Schedule	(%)	(MMSTB)	(BSCF)	(MSTB)	(Years)
1PV	5PV	Original	Simultaneously	42.55	4.31	14.10	0.44	20.99
			Water First	41.50	4.21	14.05	0.48	20.00
			Gas First	39.10	3.96	13.86	0.40	18.19
		1	Simultaneously	46.83	4.75	14.25	4.48	30.00
			Water First	44.60	4.52	14.20	2.45	22.88
			Gas First	44.80	4.54	13.95	0.51	30.00
		2	Simultaneously	47.83	4.85	14.15	23.40	30.00
			Water First	47.03	4.77	14.22	18.24	30.00
			Gas First	45.95	4.66	13.92	0.53	30.00
		3	Simultaneously	49.00	4.97	13.99	102.95	30.00
			Water First	48.38	4.90	14.08	83.20	30.00
			Gas First	47.69	4.83	13.87	1.77	30.00
	10PV	Original	Simultaneously	46.43	4.71	14.20	4.32	24.36
			Water First	44.13	4.47	14.14	0.86	21.64
			Gas First	39.10	3.96	13.86	0.40	18.19
		1	Simultaneously	49.90	5.06	14.16	81.66	30.00
			Water First	48.40	4.91	14.26	55.01	30.00
			Gas First	46.31	4.69	13.95	0.91	30.00
		2	Simultaneously	50.46	5.12	14.04	153.04	30.00
			Water First	49.18	4.99	14.14	117.01	30.00
			Gas First	47.11	4.78	13.92	9.27	30.00
		3	Simultaneously	50.83	5.15	13.89	318.92	30.00
			Water First	49.65	5.03	13.99	266.64	30.00
			Gas First	47.66	4.83	13.86	63.98	30.00
	30PV	Original	Simultaneously	55.29	5.60	13.97	593.68	30.00
			Water First	52.10	5.28	14.15	368.85	30.00
			Gas First	39.10	3.96	13.86	0.40	18.19
		1	Simultaneously	55.58	5.63	13.82	930.77	30.00
			Water First	52.32	5.30	13.94	733.87	30.00
			Gas First	46.61	4.73	13.95	433.12	30.00
		2	Simultaneously	55.35	5.61	13.71	1,095.70	30.00
			Water First	51.94	5.27	13.85	907.59	30.00
			Gas First	46.71	4.74	13.91	569.03	30.00
		3	Simultaneously	54.62	5.54	13.54	1,435.56	30.00
			Water First	51.04	5.17	13.74	1,192.80	30.00
			Gas First	46.98	4.76	13.85	797.82	30.00

Table 5-9: Results for different dumping schedules in case of 3PV gas reservoir

Case				Recovery Factor	Total Oil Production	Total Gas Production	Total Water Production	Production Time
Gas	Aquifer	Location	Schedule	(%)	(MMSTB)	(BSCF)	(MSTB)	(Years)
3PV	5PV	Original	Simultaneously	48.07	4.87	35.50	0.49	23.37
			Water First	47.03	4.77	35.32	0.54	22.96
			Gas First	44.89	4.55	35.17	0.46	21.48
		1	Simultaneously	52.66	5.34	35.88	9.11	26.99
			Water First	51.52	5.22	35.74	3.60	25.75
			Gas First	48.98	4.97	35.44	0.50	23.04
		2	Simultaneously	54.53	5.53	35.99	36.77	30.00
			Water First	53.60	5.43	36.04	23.08	29.53
			Gas First	52.21	5.29	35.66	0.56	30.00
		3	Simultaneously	56.07	5.68	35.50	128.81	30.00
			Water First	55.47	5.62	35.67	92.47	30.00
			Gas First	54.48	5.52	35.60	0.61	30.00
	10PV	Original	Simultaneously	51.53	5.22	35.73	9.24	25.92
			Water First	49.59	5.03	35.54	1.33	24.52
			Gas First	44.89	4.55	35.17	0.46	21.48
		1	Simultaneously	55.72	5.65	35.83	103.82	30.00
			Water First	54.26	5.50	35.95	62.36	29.53
			Gas First	48.98	4.97	35.44	0.50	23.04
		2	Simultaneously	56.66	5.74	35.52	182.06	30.00
			Water First	55.48	5.62	35.70	126.17	30.00
			Gas First	53.05	5.38	35.63	2.38	30.00
		3	Simultaneously	57.56	5.84	35.08	342.30	30.00
			Water First	56.48	5.73	35.26	280.49	30.00
			Gas First	54.61	5.54	35.56	28.24	30.00
	30PV	Original	Simultaneously	58.72	5.95	34.83	620.88	30.00
			Water First	56.52	5.73	35.23	370.90	30.00
			Gas First	44.89	4.55	35.17	0.46	21.48
		1	Simultaneously	60.50	6.13	34.39	962.53	30.00
			Water First	57.75	5.85	34.66	740.81	30.00
			Gas First	48.98	4.97	35.44	0.50	23.04
		2	Simultaneously	60.73	6.16	34.19	1,119.52	30.00
			Water First	57.80	5.86	34.43	919.37	30.00
			Gas First	52.67	5.34	35.62	430.71	30.00
		3	Simultaneously	60.69	6.15	33.84	1,380.99	30.00
			Water First	57.54	5.83	34.18	1,213.96	30.00
			Gas First	53.88	5.46	35.55	370.80	28.05

Table 5-10: Results for different dumping schedules in case of 9PV gas reservoir

Case				Recovery Factor	Total Oil Production	Total Gas Production	Total Water Production	Production Time
Gas	Aquifer	Location	Schedule	(%)	(MMSTB)	(BSCF)	(MSTB)	(Years)
9PV	5PV	Original	Simultaneously	54.23	5.50	96.26	0.59	27.48
			Water First	53.47	5.42	95.68	0.67	27.89
			Gas First	51.35	5.21	95.39	0.58	26.33
		1	Simultaneously	60.35	6.12	96.58	12.99	29.37
			Water First	59.65	6.05	96.28	3.79	29.53
			Gas First	57.45	5.82	95.44	3.27	27.56
		2	Simultaneously	62.34	6.32	96.11	46.98	30.00
			Water First	61.76	6.26	95.83	26.22	30.00
			Gas First	59.87	6.07	96.14	0.67	28.79
		3	Simultaneously	64.61	6.55	93.87	145.42	30.00
			Water First	64.26	6.51	93.96	101.77	30.00
			Gas First	63.37	6.41	96.31	0.72	30.00
	10PV	Original	Simultaneously	57.13	5.79	96.72	13.32	28.79
			Water First	55.90	5.67	95.96	0.91	28.88
			Gas First	51.35	5.21	95.39	0.58	26.33
		1	Simultaneously	62.33	6.32	95.52	116.29	30.00
			Water First	61.44	6.23	95.18	65.10	30.00
			Gas First	57.45	5.82	95.44	0.64	27.56
		2	Simultaneously	63.82	6.47	94.17	194.91	30.00
			Water First	63.04	6.39	93.82	132.01	30.00
			Gas First	59.87	6.07	96.14	0.67	28.79
		3	Simultaneously	65.62	6.65	92.01	356.37	30.00
			Water First	64.84	6.57	91.65	296.52	30.00
			Gas First	63.27	6.41	96.31	0.72	30.00
	30PV	Original	Simultaneously	62.51	6.34	91.86	593.20	30.00
			Water First	61.40	6.22	90.32	350.87	30.00
			Gas First	51.35	5.21	95.39	0.58	26.33
		1	Simultaneously	65.89	6.68	89.54	926.44	30.00
			Water First	63.98	6.49	87.87	735.68	30.00
			Gas First	57.45	5.82	95.44	0.64	27.56
		2	Simultaneously	66.90	6.78	88.49	1,084.12	30.00
			Water First	64.61	6.55	86.88	925.29	30.00
			Gas First	59.87	6.07	96.14	0.67	28.79
		3	Simultaneously	67.88	6.88	86.44	1,353.61	30.00
			Water First	65.26	6.62	85.66	1,237.29	30.00
			Gas First	63.27	6.41	96.31	0.72	30.00

As shown in Table 5-8 to Table 5-10, among the three dumping schedules, simultaneous dumpflood can yield the highest recovery for all the cases compared to other the two schedules. Almost all cases, water dumpflood first has higher recovery than gas dumpflood first as well. Similar to simultaneous dumpflood, water dumpflood first shows the same trend of the increase in oil recovery when the production well is moved further toward the water dumping well. In case of 1PV gas reservoir, water dumpflood first can yield the highest recovery factor of 52.32% at location 1 when the aquifer is 30PV. But this value is still lower than the one from simultaneous dumpflood that can yield 55.58%. For the case of 3PV and 9PV gas reservoirs, the highest recovery of water dumpflood first is 57.80% and 65.26%, respectively at location 2 and location 3 where the highest recovery is obtained from simultaneous dumpflood as well. On the other hand, gas dumpflood first can recover the highest oil recovery factor of 47.69%, 54.61% and 63.37% in the case of 1PV, 3PV and 9PV gas reservoir, respectively which is mostly from the combination with 5PV aquifer size when the production well is at location 3.

Gas production seems to be not much effected by the dumping schedule. The amount of produced gas does not change much when changing the dumping schedule because the amount of gas crosssflowing into the oil reservoir does not change much. Whether it is simultaneous dumpflood, gas dumpflood first or water dumpflood first, the amount of gas which is dumped into oil reservoir to increase the oil reservoir pressure is almost the maximum amount that can be dumped. Contradict to gas crossflow, the water crossflow displays different image. The amount of water production decreases from the case of simultaneous dumpflood to water dumpflood first and finally, gas dumpflood first schedule which produces the least amount of water. For the case of water dumpflood first, the oil reservoir pressure drops more quickly than one from simultaneous dumpflood which causes the reduction of water crossflow. In case of gas dumpflood first, the oil reservoir pressure almost decreases to its lowest point so that water dumpflood is not able to help, so that only small amount of water is dumped into the oil reservoir. The pressures of the oil reservoir from different dumping schedules are shown in Figure 5-31.

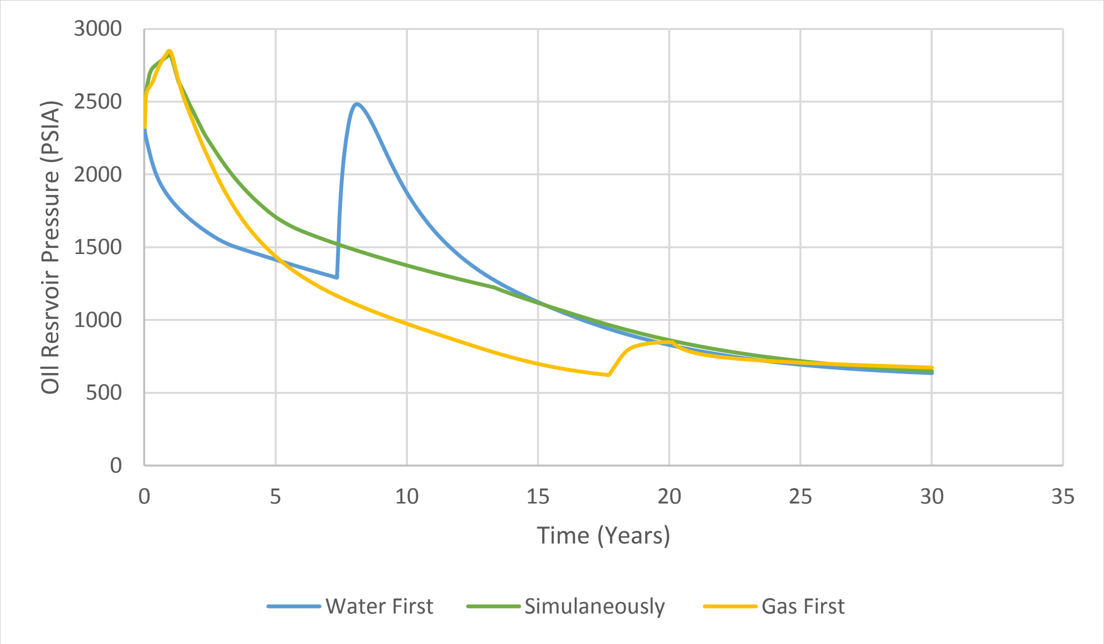


Figure 5-31: Oil reservoir pressure from different dumping schedules in case combination of 1PV gas reservoir and 30PV aquifer

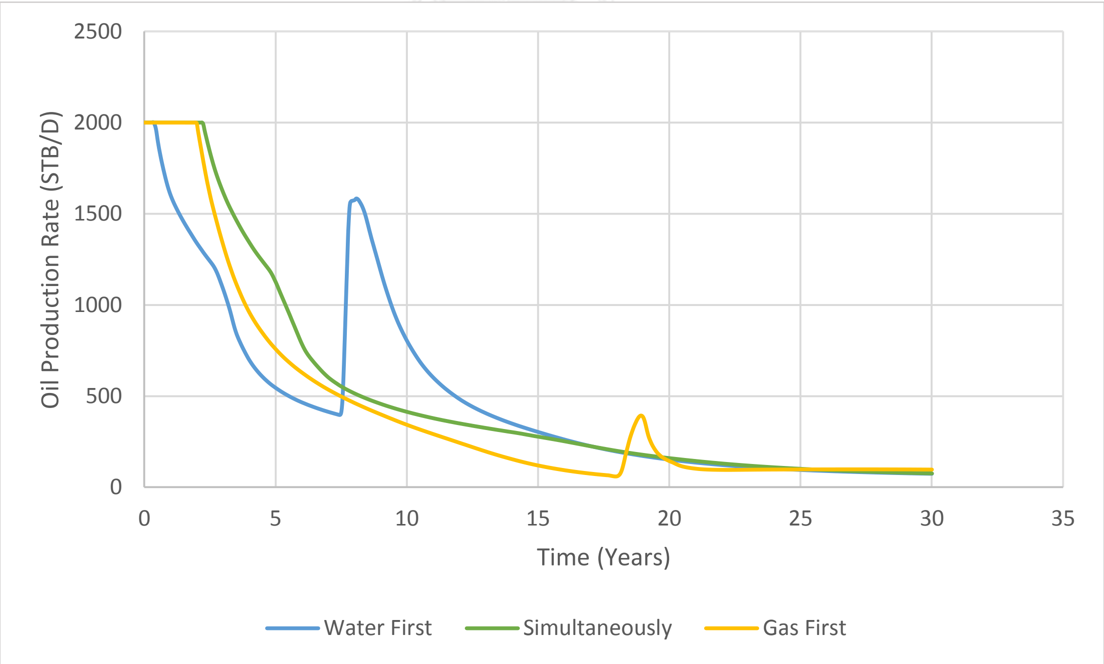


Figure 5-32: Oil production rates from different dumping schedules in case combination of 1PV gas reservoir and 30PV aquifer

Based on the oil reservoir pressure plots shown in Figure 5-31, we can see that simultaneous dumpflood can help maintain the oil reservoir pressure the highest, preventing it from drastic drop while other two cases let the reservoir pressure decrease strongly at one point of their production life. Simultaneous dumpflood can keep the oil rate higher than other cases most of the times as shown in Figure 5-32. That is why simultaneous dumpflood is still the most favorable schedule for oil production via combination dumpflood.

However, in the cases of 9PV gas reservoir with all the aquifer sizes, water is not dumped into the oil reservoir if gas dumpflood first is conducted. The reason behind this is that the oil production rate reaches its economic limit before the gas reservoir drops to 650 psia. Figure 5-33 and Figure 5-34 show that the oil production rate decreases to the rate lower than 50 STB/D while gas reservoir pressure still stays higher than 650 psia. This leads to another gas dumpflood stopping condition that is discussed in Section 5.3.2.2.

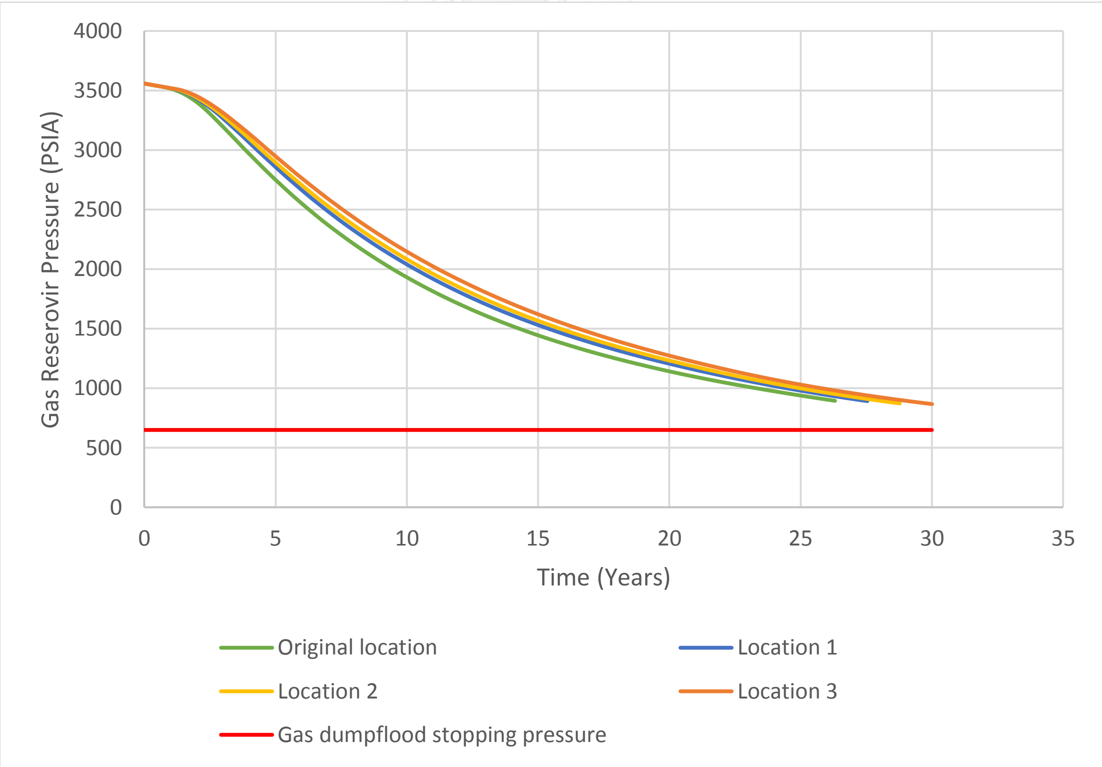


Figure 5-33: Gas reservoir pressure at different locations for gas dumpflood first for the case of 9PV gas reservoir and 30PV aquifer

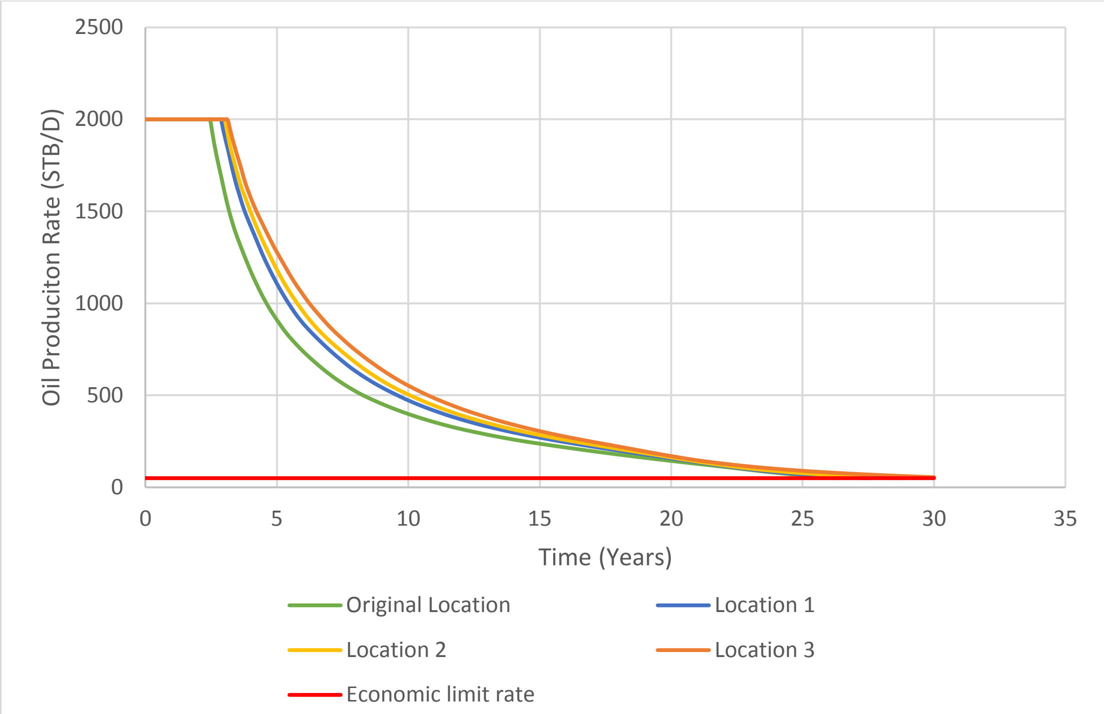


Figure 5-34: Oil production rate at different locations for gas dumpflood first for the case of 9PV gas reservoir and 30PV aquifer

5.3.2.2 Effect of dumping schedule in case of gas dumpflood is stopped with oil production rate reduction criteria

This section is an extended study from the previous section that is added later when water cannot be dumped since the dumping criteria is not reached in the case of large gas reservoir in which its pressure does not drop below 650 psia even when the oil production reaches the economic limit. That is the reason why new triggering condition for stopping gas dumpflood and starting water dumpflood is set.

The new condition for stopping gas dumpflood in order to start water dumpflood is controlled by oil production rate. Oil will be produced with only gas dumpflood at the beginning stage of production. When oil production rate drops to 200 STB/D for cases of with small and medium aquifer or 400 STB/D for cases with large aquifer, gas dumpflood will be terminated and water dumpflood is started. Other schedule cases are kept the same as the one in Section 5.3.2.1. Summary of all results is shown in Table 5-11 to Table 5-13.

Table 5-11: Results for different dumping schedules in case of 1PV gas reservoir

Case				Recovery Factor	Total Oil Production	Total Gas Production	Total Water Production	Production Time
Gas	Aquifer	Location	Schedule	(%)	(MMSTB)	(BSCF)	(MSTB)	(Years)
1PV	5PV	Original	Simultaneously	42.55	4.31	14.10	0.44	20.99
			Water First	41.50	4.21	14.05	0.48	20.00
			Gas First	41.16	4.17	13.22	0.45	22.22
		1	Simultaneously	46.83	4.75	14.25	4.48	30.00
			Water First	44.60	4.52	14.20	2.45	22.88
			Gas First	44.04	4.46	13.12	0.48	23.78
		2	Simultaneously	47.83	4.85	14.15	23.40	30.00
			Water First	47.03	4.77	14.22	18.24	30.00
			Gas First	45.76	4.64	13.03	0.52	30.00
		3	Simultaneously	49.00	4.97	13.99	102.95	30.00
			Water First	48.38	4.90	14.08	83.20	30.00
			Gas First	47.32	4.80	12.90	2.37	30.00
	10PV	Original	Simultaneously	46.43	4.71	14.20	4.32	24.36
			Water First	44.13	4.47	14.14	0.86	21.64
			Gas First	44.69	4.53	13.26	0.52	27.23
		1	Simultaneously	49.90	5.06	14.16	81.66	30.00
			Water First	48.40	4.91	14.26	55.01	30.00
			Gas First	48.09	4.88	13.12	2.95	30.00
		2	Simultaneously	50.46	5.12	14.04	153.04	30.00
			Water First	49.18	4.99	14.14	117.01	30.00
			Gas First	49.10	4.98	12.96	24.56	30.00
		3	Simultaneously	50.83	5.15	13.89	318.92	30.00
			Water First	49.65	5.03	13.99	266.64	30.00
			Gas First	49.86	5.05	12.75	117.10	30.00
	30PV	Original	Simultaneously	55.29	5.60	13.97	593.68	30.00
			Water First	52.10	5.28	14.15	368.85	30.00
			Gas First	51.87	5.26	12.12	307.16	30.00
		1	Simultaneously	55.58	5.63	13.82	930.77	30.00
			Water First	52.32	5.30	13.94	733.87	30.00
			Gas First	52.09	5.28	11.95	641.50	30.00
		2	Simultaneously	55.35	5.61	13.71	1,095.70	30.00
			Water First	51.94	5.27	13.85	907.59	30.00
			Gas First	51.82	5.25	11.82	797.32	30.00
		3	Simultaneously	54.62	5.54	13.54	1,435.56	30.00
			Water First	51.04	5.17	13.74	1,192.80	30.00
			Gas First	51.21	5.19	11.65	1,035.36	30.00

Table 5-12: Results for different dumping schedules in case of 3PV gas reservoir

Case				Recovery Factor	Total Oil Production	Total Gas Production	Total Water Production	Production Time
Gas	Aquifer	Location	Schedule	(%)	(MMSTB)	(BSCF)	(MSTB)	(Years)
3PV	5PV	Original	Simultaneously	48.07	4.87	35.50	0.49	23.37
			Water First	47.03	4.77	35.32	0.54	22.96
			Gas First	45.61	4.62	32.52	0.46	21.89
		1	Simultaneously	52.66	5.34	35.88	9.11	26.99
			Water First	51.52	5.22	35.74	3.60	25.75
			Gas First	49.11	4.98	32.08	0.48	21.32
		2	Simultaneously	54.53	5.53	35.99	36.77	30.00
			Water First	53.60	5.43	36.04	23.08	29.53
			Gas First	50.51	5.12	31.84	0.50	21.48
		3	Simultaneously	56.07	5.68	35.50	128.81	30.00
			Water First	55.47	5.62	35.67	92.47	30.00
			Gas First	52.16	5.29	31.46	1.26	21.48
	10PV	Original	Simultaneously	51.53	5.22	35.73	9.24	25.92
			Water First	49.59	5.03	35.54	1.33	24.52
			Gas First	48.00	4.87	32.55	0.51	24.36
		1	Simultaneously	55.72	5.65	35.83	103.82	30.00
			Water First	54.26	5.50	35.95	62.36	29.53
			Gas First	51.90	5.26	32.13	1.73	24.60
		2	Simultaneously	56.66	5.74	35.52	182.06	30.00
			Water First	55.48	5.62	35.70	126.17	30.00
			Gas First	53.31	5.40	31.87	15.08	26.08
		3	Simultaneously	57.56	5.84	35.08	342.30	30.00
			Water First	56.48	5.73	35.26	280.49	30.00
			Gas First	55.40	5.62	31.46	97.71	30.00
	30PV	Original	Simultaneously	58.72	5.95	34.83	620.88	30.00
			Water First	56.52	5.73	35.23	370.90	30.00
			Gas First	54.60	5.53	28.01	297.70	29.78
		1	Simultaneously	60.50	6.13	34.39	962.53	30.00
			Water First	57.75	5.85	34.66	740.81	30.00
			Gas First	56.06	5.68	27.88	626.35	30.00
		2	Simultaneously	60.73	6.16	34.19	1,119.52	30.00
			Water First	57.80	5.86	34.43	919.37	30.00
			Gas First	56.26	5.70	27.67	781.09	30.00
		3	Simultaneously	60.69	6.15	33.84	1,380.99	30.00
			Water First	57.54	5.83	34.18	1,213.96	30.00
			Gas First	56.28	5.71	27.33	1,024.09	30.00

Table 5-13: Results for different dumping schedules in case of 9PV gas reservoir

Case				Recovery Factor	Total Oil Production	Total Gas Production	Total Water Production	Production Time
Gas	Aquifer	Location	Schedule	(%)	(MMSTB)	(BSCF)	(MSTB)	(Years)
9PV	5PV	Original	Simultaneously	54.23	5.50	96.26	0.59	27.48
			Water First	53.47	5.42	95.68	0.67	27.89
			Gas First	50.29	5.10	80.22	0.49	22.88
		1	Simultaneously	60.35	6.12	96.58	12.99	29.37
			Water First	59.65	6.05	96.28	3.79	29.53
			Gas First	56.17	5.69	80.06	0.54	22.79
		2	Simultaneously	62.34	6.32	96.11	46.98	30.00
			Water First	61.76	6.26	95.83	26.22	30.00
			Gas First	58.28	5.91	79.86	0.56	22.88
		3	Simultaneously	64.61	6.55	93.87	145.42	30.00
			Water First	64.26	6.51	93.96	101.77	30.00
			Gas First	61.11	6.19	79.09	0.94	22.79
	10PV	Original	Simultaneously	57.13	5.79	96.72	13.32	28.79
			Water First	55.90	5.67	95.96	0.91	28.88
			Gas First	52.19	5.29	80.27	0.53	24.52
		1	Simultaneously	62.33	6.32	95.52	116.29	30.00
			Water First	61.44	6.23	95.18	65.10	30.00
			Gas First	58.03	5.88	80.11	1.33	24.44
		2	Simultaneously	63.82	6.47	94.17	194.91	30.00
			Water First	63.04	6.39	93.82	132.01	30.00
			Gas First	59.93	6.08	79.86	10.83	24.60
		3	Simultaneously	65.62	6.65	92.01	356.37	30.00
			Water First	64.84	6.57	91.65	296.52	30.00
			Gas First	62.26	6.31	79.06	72.14	25.26
	30PV	Original	Simultaneously	62.51	6.34	91.86	593.20	30.00
			Water First	61.40	6.22	90.32	350.87	30.00
			Gas First	56.65	5.74	57.19	289.07	26.90
		1	Simultaneously	65.89	6.68	89.54	926.44	30.00
			Water First	63.98	6.49	87.87	735.68	30.00
			Gas First	59.51	6.03	58.98	606.86	27.15
		2	Simultaneously	66.90	6.78	88.49	1,084.12	30.00
			Water First	64.61	6.55	86.88	925.29	30.00
			Gas First	60.35	6.12	59.44	759.98	27.15
		3	Simultaneously	67.88	6.88	86.44	1,353.61	30.00
			Water First	65.26	6.62	85.66	1,237.29	30.00
			Gas First	61.30	6.21	60.04	996.77	26.41

Results for simultaneous dumpflood and water dumpflood first are exactly the same as the ones in Section 5.3.2.1 since their schedules are the same. Results from different schedules still show a similar trend as the ones in Section 5.3.2.1. Simultaneous dumpflood is still the schedule that can yield the highest recovery for all the cases compared other the two schedules. The change in the schedule of gas dumpflood first does not change the results much. Water dumpflood first still has higher recovery than gas dumpflood first. Gas dumpflood first can recover the highest oil recovery factor of 52.09%, 56.28% and 62.26% in case of 1PV, 3PV and 9PV gas reservoir, respectively. In the case of 1PV and 3PV gas reservoir, gas dumpflood first with the new triggering condition for water dumpflood improves from the ones with the previous triggering condition but for the last case of 9PV gas reservoir, the recovery drops from 63.27% to 62.26% due to the presence of water while gas itself is strong enough to yield high recovery already (stand-alone gas dumpflood is better than combination dumpflood in case with large gas reservoir).

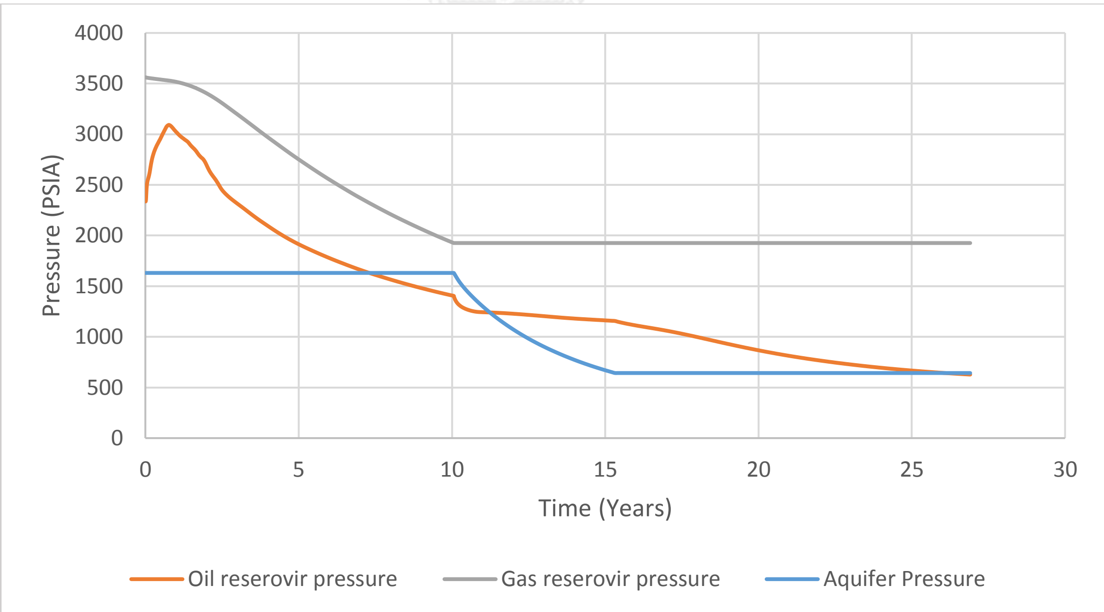


Figure 5-35: Pressures of oil reservoir, gas reservoir and aquifer in case of gas dumpflood first for 9PV gas reservoir with 30PV aquifer and producer at original location

Figure 5-38 shows the pressures of aquifer, oil and gas reservoir during the production with gas dumpflood first. We can see that gas reservoir pressure drops as gas is dumped into the oil reservoir and the pressure of oil reservoir starts to increase and drops later with production. At one point of the production, oil production rate decreases below the triggering rate, gas dumpflood is stopped and water dumpflood is started.

In any case, even though there are some changes in dumping schedule in order to make full combination of water and gas dumpflood happen in case of gas dumpflood first for large gas reservoir, the recovery from simultaneous dumpflood is still the most preferable schedule because of high recovery due to its ability to maintain oil reservoir pressure and oil production rate higher than other cases.

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

This chapter concludes all the effects of the reservoir system parameters and operational parameters on the performance of combination dumpflood of water and gas into oil reservoir having dip angle. The conclusion from one parameter to another can be an insight of how this method can be performed under a specific condition. At the end, recommendations of further studies which are related to this kind of production technique are proposed as well.

6.1 Conclusions

Combination of water dumpflood was investigated via reservoir simulation by comparing different techniques of production scenarios. Many parameters were investigated in order to determine conditions suited and not suited for combination dumpflood. From the results of the study, some conclusions can be drawn and summarized as follows:

1) Combination dumpflood can yield better recovery than stand-alone water dumpflood no matter how larger the aquifer is.
2) Combination dumpflood has better performance than stand-alone gas dumpflood only when small gas reservoir (1PV) and large aquifer (30PV) are available as gas and water sources for dumpflooding due to effective pressure support on the oil reservoir from the strong aquifer. In case of moderate and large gas reservoir sizes (3PV and 9PV), stand-alone gas dumpflood can recover more oil than combination gas dumpflood for all aquifer sizes due to its sufficient strength to support oil reservoir pressure and the better displacement efficiency of gas compared to water in a dipping reservoir.
3) Gas tends to breakthrough faster than water. In order to prevent this problem, production well location has to be carefully designed with the balance of gas and water breakthrough because none of them is desirable. The further away

from the gas dumping well, the later the gas breakthrough. But this can cause early water breakthrough. So, location of the producer should be designed by performing sensitivity analysis. Implementation of producer at unfavorable location can result in excessive amount of gas or water production. Different combinations of gas reservoir and aquifer sizes have their own best locations for the production wells.

4) In the case that combination dumpflood is the most suitable, simultaneous combination dumpflood is proved to be more effective than other dumping schedules due to its ability to maintain the oil reservoir pressure higher than other cases, leading to higher oil production rates and higher recovery.

6.2 Recommendations

Even though this study covers many important parts of oil production via combination dumpflood, there are still some more issues that need to be investigated in order to profoundly understand the mechanism of this production technique which is not able to be conducted due to the limit amount of time of the research. Some recommendations are suggested for further study of combination dumpflood technique to produce oil in dipping oil reservoir:

1) Sensitivity analysis of rock, gas and oil properties on the production performance should be conducted since they generally strongly affect the dumpflooding process.

2) Heterogeneous reservoir is also recommended for next step study. The result from homogenous reservoir can be very different from the one of heterogeneous reservoir. This point of study is very important in order to obtain the most reliable study result to implant in the real life reservoir.

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APPENDIX

Appendix A
Reservoir Model

This section gives more details on reservoir model constructed with ECLIPSE 100 reservoir simulator in addition the reservoir model section.

1. Case definition

Simulator	Black oil
Model dimension	Number of grid block in the x-direction = 57
	Number of grid block in the y-direction = 45
	Number of grid block in the z-direction = 28
Grid type	Cartesian
Geometry type	Corner point
Oil-Gas-Water properties	Water, oil, gas and dissolved gas
Solution type	Fully implicit

2. Grid properties

Active grid block	(25-33, 1-45, 1-10) = 1 (for aquifer 5PV)
	(20-38, 1-45, 1-10) = 1 (for aquifer 10PV)
	(1-57, 1-45, 1-10) = 1 (for aquifer 30PV)
	(1-57, 1-45, 11-11) = 0 (shale)
	(20-38, 1-45, 12-21) = 1 (oil reservoir)
	(26-32, 1-45, 23-28) = 1 (for gas reservoir 1PV)
	(20-38, 1-45, 23-28) = 1 (for gas reservoir 3PV)
	(1-57, 1-45, 23-28) = 1 (for gas reservoir 9PV)
X permeability	126 md
Y permeability	126 md
Z permeability	12.6 md
Porosity	0.215

3. Initialization

3.1. Equilibration region 1

Datum depth	3000	ft.
Pressure at datum depth	1284	psia
WOC depth	3000	ft. (no oil)
GOC depth	3000	ft. (no gas)

3.2. Equilibration region 2

Datum depth	5000	ft.
Pressure at datum depth	2130	psia
WOC depth	85000	ft. (no water)
GOC depth	5000	ft. (no gas)

3.3. Equilibration region 3

Datum depth	8500	ft.
Pressure at datum depth	3611	psia
WOC depth	9000	ft. (no water)
GOC depth	8500	ft. (no oil)

4. Region

4.1. FIP region numbers

(1:57, 1:45, 1:11) = 1

(1:57, 1:45, 12:22) = 2

(1:57, 1:45, 23:28) = 3

4.2. PVT region numbers

(1:57, 1:45, 1:11) = 1

(1:57, 1:45, 12:22) = 2

(1:57, 1:45, 23:28) = 3

4.3. Equilibration region numbers

(1:57, 1:45, 1:11) = 1

(1:57, 1:45, 12:22) = 2

(1:57, 1:45, 23:28) = 3

Appendix B
Schedule

There are one oil production well, PROD, one gas dumpflood well, W1, and one water dumpflood well, W2, in the case of combination dumpflood. Well specification, completion, segment and production control data are summarized in Tables A.1 – A.13.

1. <u>Well specification (keyword: WELSPECL)</u>

Table A - 1: Well specification data in case production well at original location

Parameters	Wells		
	PROD	W1	W2
J Location	29	29	29
I Location	23	3	43
Datum depth	5569.4	5051.76	6087.04
Preferred phase	Oil	Gas	Water

Table A - 2: Well specification data in case production well at location 1

Parameters	Wells		
	PROD	W1	W2
J Location	29	29	29
I Location	28	3	43
Datum depth	5725.69	5051.76	6087.04
Preferred phase	Oil	Gas	Water

Table A - 3: Well specification data in case production well at location 2

Parameters	Wells		
	PROD	W1	W2
J Location	29	29	29
I Location	30	3	43
Datum depth	5750.56	5051.76	6087.04
Preferred phase	Oil	Gas	Water

Table A - 4: Well specification data in case production well at location 3

Parameters	Wells		
	PROD	W1	W2
J Location	29	29	29
I Location	23	3	43
Datum depth	5828.22	5051.76	6087.04
Preferred phase	Oil	Gas	Water

2. <u>Completion data (keyword: COMPDATL)</u>

Table A - 5: Well completion data

Parameters	Wells			Unit
	PROD	W1	W2	
Wellbore ID	0.5104	0.5104	0.5104	ft.
K upper perforated zone	12	12, 23	12, 1	Grid number
K lower perforated zone	21	21, 23	21, 10	

3. Well segment definition (keyword: WELSEGS)

Table A - 6: Segmented well definition data for well W1

Parameters	Segments				Unit
	1	2	3	4	
Length	5000	50	2000	150	ft.
Depth	5000	50	2000	150	Grid number
Diameter	0.2032				
Roughness	0.00015				

4. Well segment completion (keyword: COMPSEGL)

Table A - 7: Segmented well completion data for well W1

Parameters	Segments		Unit
	1	2	
Start point	29, 3, 12	29, 3, 23	(i,j,k)
End point	29, 3, 21	29, 3, 28	
Start length	0	2050	ft.
End length	50	2300	

5. Production well control part (keyword: WCONPROD)

Table A - 8: Production control data for all wells

Parameter	Wells		
	PROD	W1	W2
Open/Shut flag	OPEN	STOP	STOP
Control	LRAT	-	-
Liquid rate	2000 STB/D	-	-
BHT target	500 psia	-	-
Preferred phase	Oil	Gas	Water

6. <u>Vertical flow performance (keyword: VFPPROD)</u>

Table A - 9: Input data of VFP table for tables 1 for gas dumping well

Parameter	Value	Unit
Fluid	Dry and wet gas.	
Method	Black oil	
Gas gravity	0.7	
Condensate to gas ratio	0	SCF/STB
Water salinity	5,000	ppm
Gas viscosity	Lee et al.	
Measure depth	7,101.76	ft
Tubing diameter	2.441	inch
Rate type	Liquid rate	
Vertical lift correlation	Petroleum Experts 2	
First node depth	5,101.76	ft
Last node depth	7,101.76	ft
Temperature	192.41	°F
Enter rate	0.01, 0.05, 0.1, 0.5, 1, 2, 3, 4, 5, 6, 7, 10, 12, 14, 16, 18, 20, 25, 30, 35, 40	MMSCF/D
Variable 1: First node pressure	100, 300, 500, 750, 100, 1250, 1500, 2000, 2500, 3000	psia
Variable 2: Water gas ratio	0, 0.5 1, 5, 10	STB/MMSCF

7. <u>Segment vertical flow performance table (keyword: WSEGTABL)</u>

Table A - 10: Segment VFP tables applied for gas dumpflood well

Well	Segment		VFP Table	P Drop Compnts	-ve Flow	Scale P Drop
	From	To				
W1	3	3	1	FH	FIX	LEN

Note:

- FH stands for "Friction and hydrostatic losses".
- FIX stands for "Fixing the lookup value of the flow rate at the first flow point in the table".
- LEN stands for "The interpolated pressure drop which is scaled in proportion to the length of the segment relative to the table's datum length."

VITA

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