COMPARATIVE PRODUCTION PERFORMANCE BETWEEN CONVENTIONAL WATER ALTERNATING GAS FLOODING AND WATER INJECTION ALTERNATING GAS DUMPFLOOD

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วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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รวินท์ พิทักษ์วัชระ : การเปรียบเทียบสมรรถนะการผลิตระหว่างการอัดน้ำสลับแก๊สแบบธรรมดากับการอัดน้ำสลับแก๊สที่ไหลมาจากแหล่งกักเก็บอื่น. (COMPARATIVE PRODUCTION PERFORMANCE BETWEEN CONVENTIONAL WATER ALTERNATING GAS FLOODING AND WATER INJECTION ALTERNATING GAS DUMPFLOOD) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร. สุวัฒน์ อธิชนากร , 137 หน้า.

แม้ว่ากระบวนการอัดน้ำสลับแก๊สแบบธรรมดามีส่วนช่วยในการเพิ่มปริมาณการผลิตน้ำมัน วิธีการนี้ต้องอาศัยค่าใช้จ่ายจำนวนมากสำหรับเครื่องมือเพื่อใช้ในการอัดฉีดน้ำและแก๊ส การศึกษานี้นำเสนอกระบวนการที่งดการใช้งานของเครื่องอัดฉีดแก๊สด้วยการปล่อยแก๊สให้ไหลมาจากแหล่งกักเก็บอื่น และเปรียบเทียบประสิทธิภาพของกระบวนการอัดน้ำสลับแก๊สที่ไหลมาจากแหล่งกักเก็บอื่นกับกระบวนการอัดน้ำสลับแก๊สแบบธรรมดาโดยใช้แบบจำลองแหล่งกักเก็บน้ำมันโดยที่มีแหล่งกักเก็บแก๊สด้านล่าง พร้อมทั้งศึกษาผลกระทบที่เกิดจากความผันแปรของค่าคุณสมบัติทั้งของแหล่งกักเก็บและของเหลวที่อยู่ในแหล่งกักเก็บนั้น

จากกรณีศึกษาที่ให้ค่าการผลิตน้ำมันดีที่สุดในสองวิธีพบว่ากระบวนการอัดน้ำสลับแก๊สแบบธรรมดาให้ค่าการผลิตน้ำมันมากว่ากระบวนการการอัดน้ำสลับแก๊สที่ไหลมาจากแหล่งกักเก็บอื่น อีกทั้งใช้น้ำเพื่อการอัดฉีดในปริมาณที่น้อยกว่าภายใต้ระยะเวลาการผลิตที่สั้นกว่า แต่ใช้แก๊สในปริมาณมาก เงื่อนไขในการดำเนินการที่ดีที่สุดของทั้งสองวิธีคือ ให้หลุมผลิตและหลุมอัดอยู่ห่างกัน 2,000 ฟุต โดยหยุดอัดน้ำเมื่อน้ำจากหลุมอัดเคลื่อนมาถึงหลุมผลิต การเพิ่มขึ้นของอัตราการอัดน้ำส่งผลเพียงเล็กน้อยต่อการลดของค่าการผลิตน้ำมันด้วยกระบวนการอัดน้ำสลับแก๊สแบบธรรมดา แต่เพิ่มค่าการผลิตน้ำมันเล็กน้อยถึงปานกลางภายใต้กระบวนการอัดน้ำสลับแก๊สที่ไหลมาจากแหล่งกักเก็บอื่น การเปลี่ยนแปลงของขนาดและระยะเวลาการอัดฉีดน้ำและแก๊สส่งผลเล็กน้อยต่อค่าการผลิตน้ำมันในทั้งสองกระบวนการ

จากผลการศึกษาค่าความผันแปรแสดงให้เห็นถึงการเพิ่มขึ้นปานกลางของค่าสัดส่วนการผลิตในกระบวนการอัดน้ำสลับแก๊สแบบธรรมดา และเพิ่มขึ้นอย่างมากในกระบวนการอัดน้ำสลับแก๊สที่ไหลมาจากแหล่งกักเก็บอื่นเมื่อสัดส่วนของค่าความซึมผ่านระหว่างแนวตั้งและแนวนอนลดลง การลดลงของค่าสัดส่วนการผลิตของทั้งสองกระบวนการเป็นผลมาจากการเพิ่มขึ้นของค่าความหนืดและค่าอิ่มตัวของน้ำมัน ที่ระยะความหนาของแหล่งกักเก็บแก๊สที่เพิ่มขึ้น ส่งผลให้ค่าสัดส่วนการผลิตเพิ่มขึ้นปานกลาง ในขณะที่การเพิ่มขึ้นของค่าระยะความแตกต่างของความลึกระหว่างแหล่งกักเก็บน้ำมันและแหล่งกักเก็บแก๊สส่งผลต่อการเพิ่มขึ้นของค่าการผลิตน้ำมันเพียงเล็กน้อยในวิธีการอัดน้ำสลับแก๊สที่ไหลมาจากแหล่งกักเก็บอื่น

ภาควิชา	วิศวกรรมเหมืองแร่และปิโตรเลียม	ลายมือชื่อนิสิต	....
สาขาวิชา	วิศวกรรมปิโตรเลียม	ลายมือชื่อ อ.ที่ปรึกษาวิทยานิพนธ์หลัก	....
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RAWIN PITAKWATCHARA: COMPARATIVE PRODUCTION PERFORMANCE BETWEEN CONVENTIONAL WATER ALTERNATING GAS FLOODING AND WATER INJECTION ALTERNATING GAS DUMPFLOOD. ADVISOR: ASST. PROF. SUWAT ATHICHANAGORN, Ph.D., 137 pp.

Although water alternating gas (WAG) injection provides incremental oil recovery, this process requires high expenditure for water and gas surface facilities. This study proposes a method that eliminates the use of gas injection facility via the process of gas dumpflood compares the performance of the proposed method of water injection alternating gas dumpflood with conventional WAG. Reservoir simulation is performed for a hypothetical oil reservoir with another gas reservoir underneath. In addition, the sensitivity of reservoir and fluid parameters on performance are investigated.

The best case of conventional WAG gives slightly higher oil production than the best case of the proposed water injection alternating gas dumpflood. Conventional WAG requires slightly lower water injection and less production time but needs tremendous amount of gas injection. In terms of operating conditions for both methods, the most suitable time to stop water injection is when water breaks through the producer. Well location at which injector to producer distance is 2,000 ft. gives the best results. In addition, increasing water injection rate slightly decreases total oil production in conventional WAG but slightly to moderately increases oil recovery in the proposed method. And, variation in slug size and ratio of water to gas injection duration has a minor impact on total oil recovery in both methods.

The sensitivity study shows that a decrease in k_v/k_h ratio moderately increases the recovery factor in the case of conventional WAG but highly increases the recovery factor in the case of the proposed method. Lower recovery factor is obtained when oil viscosity and residual oil saturation increases in both methods. As the thickness of source gas reservoir increases, the recovery factor moderately increases in the proposed method. The increase in depth difference between the oil and gas reservoir slightly increases the oil recovery in the proposed method.

Department:	Mining and Petroleum Engineering	Student's Signature	....
		Advisor's Signature	....
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List of Abbreviations

BCF	Billion cubic feet
BHP	Bottomhole pressure
BOE	Barrel of oil equivalent
CO_2	Carbon dioxide
cp	Centipoise
EOR	Enhanced oil recovery
F or °F	Degree Fahrenheit
FRAC.S.G	Fracturing pressure gradient
ft	feet
GOR	Gas-oil ratio
ID	Inner diameter
IFT	Interfacial tension
IOR	Improved oil recovery
IWS	Irreducible water saturation
lb/cuft	Pound per cubic foot
M	Mobility ratio
mD	Millidarcy
MMSCF	Million standard cubic feet
MMSCF/D	Million standard cubic feet per day
MSCF/STB	Thousand standard cubic feet per stock tank barrel
MSm^3	Mega standard cubic meter
OOIP	Original oil in place
psi	Pound per square inch
psia	Pound per square inch absolute
psi/ft	Pound per square inch per foot
psig	Pound per square inch gauge

PV	Pore volume
PVT	Pressure-Volume-Temperature
rb/stb	Reservoir barrel per stock tank barrel
SCAL	Special core analysis
SCF/STB	standard cubic feet per stock tank barrel
STB	Stock tank barrel
STB/D	Stock tank barrel per day
TVD	True vertical depth
VGR	Viscous to gravity ratio
WAG	Water alternating gas

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Nomenclatures

ρ_g	Density of gas
ρ_w	Density of water
$\Delta\rho$	Density difference between water and gas
σ_{SN}	Interfacial tension between solid and non-wetting phase fluids
σ_{SW}	Interfacial tension between solid and wetting phase fluids
σ_{WN}	Interfacial tension between wetting and non-wetting phase fluids
θ	Contact angle on solid interface measured to water phase
λ_{rt}^{m}	Total relative mobility in the mixed zone
μ_o	Oil viscosity
μ_w	Water viscosity
E_A	Areal sweep efficiency
E_D	Displacement efficiency
E_I	Vertical sweep efficiency
g	Gravitational acceleration
k	Absolute permeability
k_h	Horizontal permeability
k_{rg}	Relative permeability to gas
k_{ro}	Relative permeability to oil

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k_{row}	Relative permeability to oil (Oil/water function)
k_{rog}	Relative permeability to oil (Gas/liquid function)
k_{rw}	Relative permeability to water
k_v	Vertical permeability
L_g	Distance in flow direction required for complete segregation
N_c	Capillary number
n_g	Corey gas exponent
n_o	Corey oil exponent
n_{og}	Corey oil/gas exponent
n_w	Corey water exponent
Q	Total volumetric injection rate of gas and water
q_t	Total flow rate
R_g	Radius at which segregation is complete
R_s	Solution gas-oil ratio
S_g	Gas saturation
S_{gc}	Critical gas saturation
S_l	Liquid saturation
S_{om}	Minnimum oil saturation (to gas)
S_{org}	Residual oil saturation (to gas)
S_{orw}	Residual oil saturation (to water)
S_w	Water saturation
$\bar{S}_w$	Average water saturation behind floodfront
S_{wc}	Connate water saturation

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S_{wcr}	Critical water saturation
S_{wi}	Initial water saturation (connate water saturation)
W	Thickness of the rectangular reservoir perpendicular to flow

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CHAPTER I
INTRODUCTION

1.1 Background

Water alternating gas (WAG) injection is considered to be a potential method of oil recovery improvement. As it combines the benefits of water and gas injection, this method yields effective performances over single application of water or gas injection. In immiscible WAG injection [1], gas injection helps improve microscopic oil displacement by vaporization, viscosity reduction and oil phase swelling while water injection can improve macroscopic sweep of flood front. Thus, injecting slug of water alternating with gas slug apparently gives advantages in mobility control (reduction in viscous fingering effect from gas injection that causes early breakthrough [2]) and better oil contact in unswept regions that helps improve displacement and sweep efficiency. WAG has been applied in several types of field under various reservoir conditions. Many of those have proved to be success with approximate incremental oil recovery around 5-13% [2], [3].

To save cost of improving oil recovery in a system which has a gas reservoir below the target oil zone, the method of water injection alternating gas dump flood is proposed in which gas is flowed from the gas zone underneath via a well connecting to the oil reservoir instead of injecting gas from surface. Although water injection alternating gas dump flood may not be as effective as conventional WAG injection since the gas flow rate is not controlled during the operation, the benefit in cost reduction for surface gas facilities and operating cost can be a rational compensation

In order to compare the performance between conventional WAG injection and water injection alternating gas dumpflood, production scenarios are conducted by ECLIPSE100 reservoir simulator. The most suitable condition in term of well location and injection techniques for each scenario are determined from simulation results. Moreover, sensitivity analysis for both methods can indicate influential parameters that strongly affect the two processes. Reservoir and fluid properties such as vertical and horizontal permeability ratio, thickness of source gas reservoir, depth difference between gas and oil reservoirs, residual oil saturation and oil viscosity are varied in the sensitivity analysis.

1.2 Objectives

1. To compare the performance in terms of oil recovery, cumulative water and gas injection between conventional water alternating gas injection and water injection alternating gas dump flood.
2. To determine suitable well location and injection conditions for implementation of conventional water alternating gas injection and water injection alternating gas dumpflood.
3. To evaluate the sensitivity of reservoir and fluid properties on conventional water alternating gas injection and water injection alternating gas dumpflood. The varied reservoir and fluid properties are vertical and horizontal permeability ratio, thickness of source gas reservoir, depth difference between gas and oil reservoirs, residual oil saturation and oil viscosity.

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1.3 Outline of methodology

1. Study various published literatures and gather required data relevant to the topic.
2. Construct a homogeneous reservoir model to be a base case for conventional WAG injection and water injection alternating gas dump flood.
3. Simulate both models with different flooding parameters to study the effects on production performance. Flooding parameters focus on
    - Water injection stopping criteria
    - Well location
    - Water and gas injection rates
    - Injection duration and slug size
4. Compare the recovery performance in terms of oil recovery, cumulative water and gas injection and cumulative water and gas production for conventional WAG injection and water injection alternating gas dumpflood.
5. Simulate the conventional WAG injection and water injection alternating gas dumpflood model with different reservoir parameters to see the sensitivity of oil recovery. The reservoir parameters are compose of
    - Vertical and horizontal permeability ratio (0.01, 0.1, 0.3)
    - Thickness of source gas reservoir (50, 100, 150 ft.)
    - Depth difference between gas and oil reservoirs (1,000, 2,000, 4,000 ft.)
    - Residual oil saturation (S_{org} = 0.05, 0.1, 0.15 and S_{orw} = 0.2, 0.3, 0.4)
    - Oil viscosity (0.5, 2, 5 cp.)
6. Analyze the results obtained from simulation and discuss on rational thought.
7. Summarize the most suitable criteria for both conventional WAG and water injection alternating gas dump flood which yields the optimum production.

1.4 Outline of thesis

This thesis is divided into six chapters as outlined below:

Chapter I introduces the background of water alternating gas injection and indicates the objectives and methodology of this study.

Chapter II introduces various published literatures related to water alternating gas injection and gas dumpflood.

Chapter III introduces important concepts related to water alternating gas injection and petrophysical properties.

Chapter IV describes reservoir details, rock properties, fluid properties and production condition set in simulation.

Chapter V presents simulation results and discussion on study parameters. The investigated results by conventional WAG and water injection alternating gas dumpflood methods are compared and summarized. The discussion on the sensitivity of several parameters is also included in this chapter.

Chapter VI provides conclusions of this study.

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CHAPTER II

LITERATURE REVIEW

Several studies in the literature about WAG injection are reviewed in this chapter. The discussions and summary based on experiments, simulation results and real field application reveal the potential of WAG injection in recovering more oil. Furthermore, the review of gas dumpflood reservoir simulation is also discussed in term of flow behavior that aids in recovery improvement.

2.1 Studies of water alternating gas injection

Caudle and Dyes [4] proposed the method of simultaneous gas-water injection with the objective to reduce the mobility of miscible gas displacement and obtain higher sweep efficiency. A conducted laboratory model showed an increase in sweep efficiency up to 90% for five spot flooding pattern by injecting water and gas simultaneously. Water as a higher viscous fluid plays a major role in reducing effective gas permeability. The authors recommended that the injected gas should not be too high to enlarge the gas zone (makes flooding condition approaching general gas displacement) and too low to let water flow faster (makes flooding condition approaching water displacement).

Huang and Holm [5] studied the effect of rock wettability on CO_2 water alternating gas injection by observing the amount of oil trapped by water during the flood. Their experiment used three type different reservoir core samples from different formations. They are water-wet, mixed-wet and oil-wet cores. The results under 1 PV CO_2 water alternating gas injection at miscible condition of 120°F and 2,500 psig for water wet core showed 45% of residual oil after waterflood trapped by CO_2 WAG which is the highest compared to mixed-wet and oil-wet cores (20% and 5% of residual oil trapped in mixed-wet and oil-wet core).

Fatemi et al. [6] performed core flood experiments on both water-wet and mixed-wet cores in order to study the effect of wettability to oil recovery by water injection, gas injection and WAG. The results showed better recovery performance of WAG compared to water and gas injection. WAG performance in water-wet rock can be improved if WAG cycles begin with water injection. But for mixed-wet rock, beginning the injection cycle with gas can effectively improve WAG performance. Furthermore, increasing gas injection cycles in water-wet cores yields an increasing oil recovery compared to the preceding gas cycle while the first cycle of WAG effectively recovers residual oil in mixed-wet core compared to the later WAG cycle.

Zhongchun et al. [7] conducted simulation study on feasibility of natural gas flooding in Ansai field. Their study also extended to water-gas alternative injection. The design constraints of injection were categorized in three cases. The first case was set to start with gas injection followed by water injection until water cut reached 95%. In the second case, water injection for 500 days was set at the beginning followed by gas injection, then water injection was applied again until water cut reached 95%. For the third case, the injection constraint is similar to the second case except water injection was for 900 days instead of 500 days. The simulation results gave similar range of ultimate recovery that are in average 6% higher than water flooding with different production times. Injecting gas early takes less production time than starting gas injection later. This means the use of water injection in this case is also less compared to the others.

Surguchev et al. [8] used a three-phase black oil simulator to investigate the optimum WAG schemes for stratified Brent reservoir that is composed of Ness and Etive formation. Both formations have very low vertical to horizontal permeability ratios (K_v/K_h = 0.004). The Ness formation is thicker, less permeable and above the Etive formation. The simulation model of Brent reservoir was subdivided into six layers with twenty grid blocks in the x direction. The injection parameters such as water-gas ratio, injection rate and cyclic periods have strong influence on WAG and become the main factors in this study. Based on simulation results, the authors observed that the increase of gas and water injection rate only give little improvement in high permeability Etive formation. In the low permeability Ness formation, the oil recovery was getting less when injection rate increased. Moreover, the effect of water/gas ratio and cycle size were analyzed. The authors recommended 1:1 WAG ratio with 300 days injection cycles for the entire Brent reservoir in which the simulation result yield the highest oil recovery factor of 53.1%. The authors also summarized that the improvement of oil recovery is mainly from the lower permeability Ness Layer. They also suggested that the optimization on WAG injection schemes for each formation (Ness and Etive) should be done individually. The reason is that the difference in permeability directly affect the flow of fluid in formation.

Selamat and Samsuddin [9] performed immiscible WAG simulation for oil recovery of Tapis and Guntong fields which have previously been under water flood and about 40% OOIP were recovered by water flooding. Operation strategies such as imposing GOR limit, subsurface operating pressure targets, WAG cycle time and WAG ratio have been put into consideration. The results from reservoir simulation showed that the oil recovery from WAG implementation increased up to 7% over water flood within 20 years of production period. Note that the injector and producer are located in 3:1 line drive pattern with low WAG ratio and 6 months WAG cycle time. In addition to this, increasing GOR limit can directly lower reservoir pressure and make gas cap to expand which consequently help promote gas cap drive in updip region.

Ma and Youngren [10] investigated an immiscible WAG reservoir simulation incorporated with field operation and conducted a core flood experiment for supporting an improvement in oil recovery by immiscible WAG in Kuparuk field. For core flood experiment, they observed the effect of trapped gas on water and oil relative permeability and the mobilization of residual oil after waterflood. The results based on a wide range of maximum gas saturation showed 1-30% range of gas trapped by water when maximum gas saturation ranges from 1-30%. Over 30% maximum gas saturation, the amount of trapped gas remained constant around 30%. They concluded that the present of trapped gas showed positive role in lowering water relative permeability while oil relative permeability have no effect from trapped gas. Moreover, trapped gas aids in residual oil reduction after waterflood in mixed wettability reservoirs. The authors also conducted reservoir simulation based on field description at Kuparuk unit that accounted for the effect of trapped gas and three-phase relative permeability. The base case started with 3 years waterflooding, followed by immiscible WAG with unit WAG ratio. The simulation results showed 1-3% OOIP additional recovery from immiscible WAG over waterflooding. In real field operation, they observed that producing GOR can be properly controlled by adjusting WAG ratio and gas slug size. Higher WAG ratio with smaller gas slug can yield benefit in lowering GOR peak response.

Crough et al. [11] summarized success in immiscible WAG operation at Statfjord field of Brent reservoir started in 1997. By May 2002, 3.5 MSm^3incremental oil were recovered by WAG, in which 45% of injected gas has been reproduced. Moreover, the water cut of the oil producer decreased while the oil rate and GOR increased. These are typical response seen in WAG process. In term of incremental oil from each WAG cycle, the authors found the first WAG cycle is the most efficient compared to other cycles.

Christensen et al. [1] summarized WAG operation problems based on real field application from past experience. The following operations can take place as either unavoidable sequences or unexpected events:

1. Early gas breakthrough caused by overriding and channeling can reduce not only vertical sweep efficiency but also recovery efficiency. In some cases, the producing wells were shut before schedule due to excessive GOR.
2. Loss of miscibility (in case of miscible WAG) due to loss of pressure during the displacement can significantly reduce the oil recovery.
3. Low water injectivity after injecting a gas slug can lead to a rapid pressure drop inside the reservoir. This can directly affect the displacement mechanism of WAG.
4. Pipe and facility damage due to corrosion when using CO_2 as an injected gas. The use of coating pipe and high steel grade is the most common way to relieve this effect.
5. Asphaltenes precipitation that can cause plugging and damaging to downhole pump. Many solutions such as hot oil and methanol solvent treatment are normally used to solve this problem.

2.2 Study on gas dumpflood

Kridsanan [12] studied the mechanism of gas dumpflood in gas condensate reservoir associated with pressure maintenance and revaporization with an emphasis on both flow behavior analysis and condensate recovery. He used ECLIPSE 300 to simulate the process of gas dumpflood in which high CO_2 gas is flowed from a source reservoir to the target gas-condensate reservoir to increase the reservoir pressure which can prevent the forming of condensate by raising pressure to be above the dew point pressure.

His simulation study focused on the evaluation of gas dump flood performance in three main important points which are 1) dumpflood timing 2) composition variation of source gas 3) depth or pressure difference between the two reservoirs. The results can be summarized as follows:

1. Dumpflood timing. The difference in time to start gas dump flood yields different gas production and condensate recovery. Kridsanan concluded that the proper time to start gas dumpflood in a gas condensate reservoir is the

time before the reservoir pressure drops to the dew point. Otherwise, condensate recovery will become less.

2. Composition variation of source gas. The author studied the effect of CO_2 concentration of gas dumpflood. The results showed only a slight increase in condensate recovery with increasing CO_2 concentration in source gas.
3. Depth or pressure difference between two reservoirs. The conclusion is large pressure difference between the two reservoirs shortens the time of gas and condensate recovery but the amount of condensate recovery just slightly increases.

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CHAPTER III
THEORY AND CONCEPT

This chapter summarizes important theories on conventional WAG injection behavior. The characteristic of fluid flow, injection techniques, reservoir rock, and fluid properties are directly related to WAG performance in various situation.

3.1 Water alternating gas injection

In 1957, the water alternating gas injection (WAG) was proposed by Caudle and Dyes [4] as an oil recovery method aimed to improve sweep efficiency of gas injection by combining with water injection which gives advantages in stabilization, providing more contact to unswept zone, controlling displacement and mobility of the flood front. With gas injection mechanism, WAG yields better incremental oil recovery compared to water flooding.

The water alternating gas injection has been successfully applied in several fields as an improved process after a long production period or water flooding. WAG can be applied using many types of gas for both miscible and immiscible displacement. In the case of miscible WAG, high reservoir pressures are major requirements in miscibility generation and maintenance. From past experiences, the operation was mainly done by reservoir repressurization. The reservoir pressure was maintained above the minimum miscibility pressure of the fluids. The new miscible phase can be created in accordance with proper fluid composition in reservoir. This yields a higher amount of oil recovery than the case of immiscible WAG. Even though miscibility can be created, it might not be able to be maintained along the displacement during production life. The results in loss of miscibility and oscillation between miscible and immiscible front will take place if high pressure cannot be maintained.

Even the amount of oil recovery in immiscible WAG is less compared to miscible WAG, its main recovery mechanisms of using water are to improve frontal stability and gas displacement to provide more contact to oil. The displacement condition also causes the mass transfer between gas and oil in reservoir, resulting in IFT and capillary pressure reduction [10] which gives advantages over single gas or water injection. Furthermore, immiscible WAG can be applied in a wide range of reservoir conditions, and it does not require high reservoir pressure as in the case of miscible WAG.

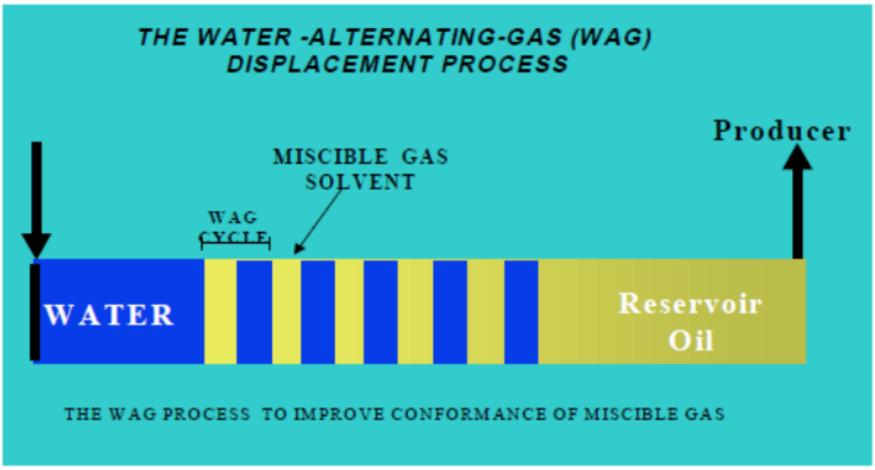

Figure 3. 1 Schematic view of miscible WAG process (after Sanchez [3])

Figure 3.1 represents a schematic view of miscible WAG which can also be used to describe immiscible WAG. Water and gas are injected into the reservoir via the same injection well and carried out in cycles. The amounts of water and gas injected depend on WAG ratio. In general, the total amount of injection and injection strategies are different for different reservoir conditions.

Surguchev et al. [8] suggested that the gas entrapment process is the major role in residual oil reduction by WAG in a stratified reservoir. The gas entrapment refers to the occurrence that gas which is not the wetting phase, is bypassed and trapped by the wetting phase water. The more the amount of gas trapped, the more chance to reduce both gas segregation and water relative permeability. When injecting water alternating with gas slug, the volume of gas for each cycle should be large enough to create higher gas saturation to the next injected water cycle. The higher the gas saturation, the higher the amount of gas that can be trapped. The residual oil can then be mobilized after a period of gas entrapment.

3.2 Gravity segregation

Even WAG can improve vertical conformance of flood front. This improvement only occurs in some region nearby the injector. The gravitational effect still cause gas and water to be segregate at certain distance away from the injector.

Stone [13] studied on the vertical conformance in WAG. He proposed that good vertical conformance and sweep efficiency only occur around the injector. Figure 3.2 shows the vertical conformance of WAG that the dispersed zone occurs near the injection well (which can be described in the case of water-gas alternating slug as long as the injection cycles are kept below two months). This region gas and water penetrate together along the pay zone, and its size is normally governed by fluid injection rate, water-gas density difference and vertical permeability. Beyond the dispersed zone, the gas having lower density overrides on top of water. Whenever this situation happens, the sweep efficiency becomes less. From this point, Stone and Jenkins [14], [15] proposed the complete gravity segregation distance formulae to calculate the distance that gas and water are completely segregated for transverse and radial systems. By considering steady state saturation distribution resulting from simultaneous injection of gas and water into a homogeneous reservoir, these formulae can be described as

$$L_g = \sqrt{\frac{Q}{k_z(\rho_w-\rho_g)gW\lambda_{rt}^m}} \tag{3.1}$$

$$R_g = \sqrt{\frac{Q}{\pi k_z(\rho_w-\rho_g)g\lambda_{rt}^m}} \tag{3.2}$$

Where

L_g = distance in flow direction required for complete segregation

R_g = radius at which segregation is complete

Q = total volumetric injection rate of gas and water

ρ_w = density of water

ρ_g = density of gas

g = gravitational acceleration

W = thickness of the rectangular reservoir perpendicular to flow

λ_{rt}^m = total relative mobility in the mixed zone

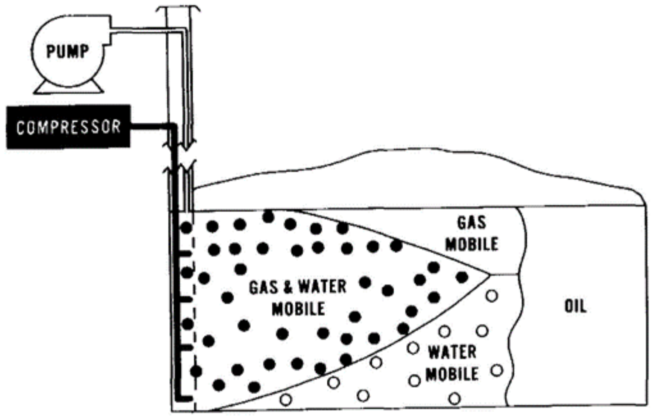

Figure 3. 2 Vertical conformance of WAG (after Stone [13])

In order to determine the efficiency of WAG, the ratio of viscous to gravity forces become a prime factor that determines sweep efficiency of gas and water to be completely segregated certain at distance L_g. The main variables for viscous to gravity ratio determination are flow rate, well spacing, density differences and permeability. High enough injection rate relative to well spacing can greatly increase this ratio. An increase of this ratio means an improvement in vertical conformance and sweep efficiency which also improve recovery factor. Stone [13] suggested the dimensionless viscous to gravity ratio for homogeneous reservoir which is defined as

$$VGR = \frac{q_t}{\Delta\rho k_v L_g W \left[\frac{k_{rw}}{\mu_w} + \frac{k_{rg}}{\mu_g}\right]} \tag{3.3}$$

where

q_t = total flow rate

$\Delta\rho$ = density difference between water and gas

k_v = permeability in vertical direction

$L_g W$ = the cross section area required for complete gravity segregation

k_{rw} = relative permeability to water evaluated at S_{wi}

μ_w = water viscosity

k_{rg} = relative permeability to gas evaluated at S_{wi}

μ_g = gas viscosity

3.3 Factors affecting distribution of fluids in porous media

Naturally, there are more than one type of immiscible fluids coexisting in the reservoir where water, oil and gas stay together in a system of reservoir rock whether flowing or spatially distributed. The interactions between fluids and rock are the governing parameters that describe the flow behavior in a porous system. Two principal interactions are 1) The interaction between fluids and rock surface which is described by the property called wettability and 2) the interaction between two types of fluid which can be quantified by interfacial tension [16] These two properties are mutually dependent to the movement of reservoir fluids that directly affects oil recovery by WAG.

3.3.1 Wettability

Craig [17] describes the definition of wettability as a preference of one fluid which can be either water or oil to adhere on rock surface in a presence of other immiscible fluids. The fluid with more tendency to adhere on rock surface is generally called wetting phase fluid while the rest are called non-wetting phase fluid. In petroleum reservoir, three main types of wettability can be categorized as follows:

1. Water-wet is the condition that the rock surface tends to adhere by water rather than other immiscible fluids. This condition reveals favorable condition when applying improved oil recovery (IOR) methods that yields lower residual oil saturation.
2. Oil-wet is the condition that the rock surface tends to adhere by oil when other immiscible fluids are present. The recovery performance in oil-wet reservoir are generally lower than the case of water-wet reservoir. To obtain that high recovery factor in oil-wet reservoir, the use of enhance the recovery (EOR) methods tend to give more favorable results than the use of improved oil recovery (IOR) methods.
3. Intermediate-wet is the condition that the rock surface is exposed to no special type preferential fluid. This type of wettability sometimes proves to be the most favorable condition in oil recovery.

Typically, there are three common methods to find the wettability of reservoir rock: 1) measurement of contact angle through water, 2) test procedure by Amott method and 3) the experiment under USMB method [18].

3.3.2 Interfacial tension

Two immiscible fluids remain separately by a well-defined interface [18]. Each type of fluid has its own inward force as molecular attraction. When they coexist, there is an interaction between fluid interfaces. The term called Interfacial Tension (IFT) is used to define the tension of fluid interface with the units of force per length (normally expressed as dynes/cm). General equation of IFT proposed by Young-Dupre [17] expresses the relationship between wetting and non-wetting fluids as follows

$$\sigma_{SN} - \sigma_{SW} = \sigma_{WN} cos\theta \tag{3.4}$$

where

σ_{SN} = interfacial tension between solid and non-wetting phase fluid (dynes/cm)

σ_{SW} = interfacial tension between solid and wetting phase fluid (dynes/cm)

σ_{WN} = interfacial tension between wetting and non-wetting phase fluids (dynes/cm)

θ = contact angle on solid interface measured to water phase (degrees)

3.4 Relative permeability

The relative permeability is the fluid conductivity in porous system when two or more fluids are present in pore. The relative permeability can be defined as the ratio of effective permeability to one specific fluid at a given saturation to the base permeability. Three types of base permeability that can be used are absolute water permeability, absolute air permeability, and effective permeability to oil at irreducible water saturation. There are several correlations developed for constructing two-phase and three-phase relative permeability curves which are discussed as follows:

3.4.1 Two - phase relative permeability

3.4.1.1 Corey's correlation

The relationship between two-phase relative permeability and fluid saturation can be generated by **Corey's correlation**. The Corey's correlation [19] for relative permeability calculation in oil/water system and oil/gas system can be defined as

Oil-water system

$$k_{ro} = k_{ro@S_{wc}} \left[\frac{1-S_{orw}-S_w}{1-S_{orw}-S_{wc}}\right]^{n_o} \tag{3.5}$$

$$k_{rw} = k_{rw@S_{orw}} \left[\frac{S_w-S_{wc}}{1-S_{orw}-S_{wc}}\right]^{n_w} \tag{3.6}$$

Oil-gas system

$$k_{ro} = k_{ro@S_{gc}} \left[\frac{1-S_{org}-S_g-S_{wc}}{1-S_{wc}-S_{org}-S_{gc}}\right]^{n_{go}} \tag{3.7}$$

$$k_{rg} = k_{rg@S_{or}} \left[\frac{S_g-S_{gc}}{1-S_{wc}-S_{org}-S_{gc}}\right]^{n_g} \tag{3.8}$$

where

S_w = water saturation

S_g = gas saturation

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

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

S_{wc} = connate water saturation

S_{gc} = critical gas saturation

k_{rg} = relative permeability to gas

k_{ro} = relative permeability to oil

k_{rw} = relative permeability to water

$k_{ro@Swc}$ = relative permeability to oil at connate water saturation

$k_{ro@Sgc}$ = relative permeability to oil at critical gas saturation

$k_{rg@Sor}$ = relative permeability to gas at residual oil saturation

$k_{rw@Sorw}$ = relative permeability to water at residual oil saturation

n_o = Corey oil exponent

n_{og} = Corey oil/gas exponent

n_g = Corey gas exponent

n_w = Corey water exponent

3.4.2 Three - phase relative permeability

3.4.2.1 ECLIPSE model

The ECLIPSE model generates the three-phase relative permeability by saturation weighing. For each block in the water zone, the oil saturation is assumed to be constant (S_o = constant) while gas and water are fully segregated. In gas zone, water saturation equals connate water saturation. For the assumption of each block that the total saturation for gas, oil and water is unity ($S_o + S_g + S_w = 1$), the fraction of fluid saturation in gas and water zone can be described by the following details with schematic diagram as shown in Figure 3.3.

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

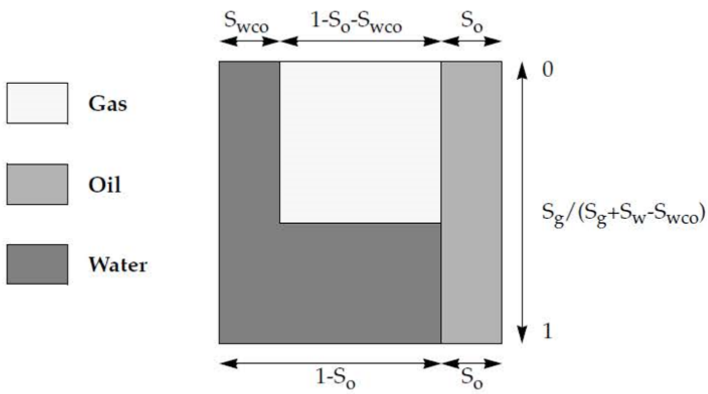

Figure 3. 3 The default model of three-phase relative permeability by ECLIPSE (after Schlumberger technical manual [20])

The oil relative permeability can be defined as

$$k_{ro} = \frac{S_g k_{rog} + k_{row}(S_w - S_{wco})}{S_g + S_w - S_{wco}} \tag{3.9}$$

where

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

k_{row}= the oil relative permeability for a system with oil and water only

(tabulated as a function of S_o)

3.4.2.2 Stone's model 1

Stone's model 1 [21] is an option for three-phase relative permeability correlation developed from the theory of channel flow in porous media. In a water wet system, the water relative permeability and water-oil capillary pressure in a three-phase system are only a function of water saturation. Furthermore, the gas-phase relative permeability and gas-oil capillary pressure are function of gas saturation. Stone [21] also suggested the existence of minimum oil saturation (nonzero residual oil saturation) S_{om} in a system where oil is displaced simultaneously by water and gas and marked that this minimum oil saturation is different from the critical oil saturation in the oil-water system (S_{orw}) and the residual oil saturation in gas-oil system (S_{org}).

The normalized saturation formulae for Stone's model are defined by considering connate water and irreducible residual oil as immobile fluids which are

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

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

$$S_g^* = \frac{S_g}{(1 - S_{wc} - S_{om})} \quad (\text{for } S_g \geq S_{om}) \tag{3.12}$$

where $S_g^* + S_w^* + S_o^* = 1$

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

$$k_{ro} = S_o^* \beta_w \beta_g \tag{3.13}$$

The two multipliers β_w and β_g that account for oil blockage by water and gas can be calculated from

$$\beta_w = \frac{k_{row}}{1-S_w^*} \tag{3.14}$$

$$\beta_g = \frac{k_{rog}}{1-S_g^*} \tag{3.15}$$

where

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

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

S_{om} = minimum oil saturation

3.4.2.3 Stone's model 2

Stone's model 2 [22] was developed from the Stone's model in 1973 with the objective in avoiding difficulties in choosing S_{om}. The equation of this model is then defined as

$$k_{ro} = (k_{row} + k_{rw})(k_{rog} + k_{rg}) - k_{rw} - k_{rg} \tag{3.16}$$

The above equation can be rearranged into normalized form as

$$k_{ro} = k_{rocw}[\left(\frac{k_{row}}{k_{rocw}} + k_{rw}\right)\left(\frac{k_{rog}}{k_{rocw}} + k_{rg}\right) - k_{rw} - k_{rg}] \tag{3.17}$$

3.5 Displacement phenomena

The effectiveness of displacing oil by any method can be described by efficiency factors as the following:

3.5.1 Displacement efficiency

In pore scale, the displacement efficiency (E_D) refers to the effectiveness of displacing fluid in oil recovery. This factor can be defined by the fraction of oil recovered from displacing agent to the oil initially in contacted behind the displacing front. General relationship between displacement efficiency and oil saturation [23] can be described as

$$E_D = \frac{1-S_{wi}-S_{or}}{1-S_{wi}} \tag{3.18}$$

where

E_D = displacement efficiency

S_{wi} = interstitial water saturation

S_{or} = residual oil saturation

The value of E_D is influenced by pore structure, oil-water interfacial tension and fluid viscosity.

3.5.2 Areal sweep efficiency

Areal sweep efficiency (E_A) is simply the fraction of reservoir area occupied by displacing fluid (viewed from top). This factor depends on many parameters such as flooding pattern, flow rate, mobility ratio and production constraint at the producer. The value of E_A decreases as mobility ratio increases or oil viscosity increases.

For immiscible displacement, mobility ratio can be defined locally at water-oil contacted region which water is the main displacing fluid [24].

$$M = \frac{k_{rw}}{\mu_w} * \frac{\mu_o}{k_{ro}} \tag{3.19}$$

where

M = mobility ratio

k_{rw} = water relative permeability

k_{ro} = oil relative permeability

μ_w = water viscosity

μ_o = oil viscosity

The favorable displacing condition refers to the condition that $M < 1$ and gives the stable displacement front. The injection by alternating water with gas reduces the displacing phase relative permeability which reduces the mobility ratio.

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3.5.3 Vertical sweep efficiency

Vertical sweep efficiency (E_I) is defined as the ratio of reservoir volumn invaded by the displacing fluid to the reservoir volume contained in the flooded area. This factor strongly depends on heterogeneity of the reservoir, viscous to gravity ratio and mobility ratio. An increase in mobility ratio together with formation heterogeneity can significantly cause a decrease of vertical sweep efficiency.

3.5.4 Overall sweep efficiency

The overall recovery efficiency is the product of three efficiency factors which can be calculated by

$$E_R = E_D \times E_A \times E_I \tag{3.20}$$

3.6 Fracturing pressure

Normally, recovery process involves with method of injection. The injection pressure should not be too high to create the fracture. Thus, the injection pressure should be less than the formation fracture pressure. In the Gulf of Thailand, the fracture pressure correlation [25] can be defined as

$$Fracture\ Pressure\ (bar) = \frac{FRAC.S.G \times TVD}{10.2} \tag{3.21}$$

and

$$FRAC.S.G = 1.22 + (TVD \times 1.6 \times 10^{-4}) \tag{3.22}$$

where

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

TVD = true vertical depth below rotary table (meter)

3.7 Barrel of oil equivalent

Barrel of oil equivalent (BOE) is a term used to summarize total produced amount of energy that is equivalent to the amount of energy in a barrel of crude oil.

[26] The amount of cumulative gas injection and production are converted into equivalent barrel unit by the following equation:

NET BOE (STB) = Cumulative Oil Production (STB) + Cumulative Gas Production (MMSCF) × 166.7 - Cumulative Gas Injection (MMSCF) × 166.7 (3.23)

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CHAPTER IV
RESERVOIR SIMULATION MODEL

Based on the objectives of this study, a reservoir model was created using reservoir simulator ECLIPSE 100 in order to simulate the performance of conventional WAG and water injection alternating gas dumpflood. This chapter describes the grid model, PVT properties, relative permeability models, and well schedules used in this study. For more detail, the parameters input in ECILPSE are illustrated in the Appendix.

4.1 Grid section

In order to predict the performance of conventional WAG injection and the proposed water injection alternating gas dumpflood, ECLIPSE 100 reservoir simulation software is used in this study. The reservoir model is constructed using rectangular coordinate and block-centered grid type. It consists of two separate zones. The upper zone is the target oil reservoir while the lower zone is the reservoir containing gas that will be dumped into the upper zone. An impermeable layer exists between the two reservoirs, isolating the two zones. Homogeneous water wet reservoir properties as listed in Table 4.1 are assumed for the target oil reservoir and source gas reservoir.

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

	Parameters	Oil Reservoir	Gas reservoir	Units
1	Number of grid blocks	19×45×5	19×45×5	grid blocks
2	Size of reservoir	1,900×4,500×50	1,900×4,500×100	ft.
3	Effective porosity	21.5	21.5	%
4	Horizontal permeability	126	126	mD.
5	Vertical permeability	12.6	12.6	mD.
6	Top of reservoir	5,000	7,050	ft.
7	Datum depth	5,000	7,150	ft.
8	Initial pressure at datum depth	2,243	3,201	psia.
9	Reservoir temperature	232	302	°F
10	Fracturing pressure	3,215	4,843	psia.
11	Initial water saturation	25	25	%

4.2 Pressure-Volume-Temperature (PVT) properties section

The PVT properties of reservoir fluid are categorized into two regions which are the oil reservoir located in the upper region and the gas reservoir located in the lower region. Reservoir fluid properties are generated using ECLIPSE correlation set II. For the oil reservoir, the surface oil properties are set as 35° API oil gravity, 200 SCF/STB initial GOR, 0.6 gas specific gravity. For the gas reservoir, the gas has a specific gravity of 0.7. Tables 4.2 and 4.3 demonstrate water PVT properties in the target oil zone and the gas reservoir, respectively while fluids densities at surface conditions for the two zones are presented in Tables 4.4 and 4.5. Live oil and dry gas PVT properties illustrated in relationship with pressure are shown in Figures 4.1 to 4.3.

Table 4. 2 Water PVT properties in oil reservoir.

Properties	Value	Units
Reference pressure (Pref)	2,243	psia
Water FVF at Pref	1.034716	rb/stb
Water compressibility	3.368884E-6	/psi
Water viscosity at Pref	0.2504328	cp
Water viscosibility	3.054844E-6	/psi

Table 4. 3 Water PVT properties in gas reservoir.

Properties	Value	Units
Reference pressure (Pref)	3,157	psia
Water FVF at Pref	1.063672	rb/stb
Water compressibility	3.998482E-6	/psi
Water viscosity at Pref	0.1849284	cp
Water viscosibility	5.857001E-6	/psi

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

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

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

Properties	Value	Units
Water density	62.42797	lb/cuft
Gas density	0.04369958	lb/cuft

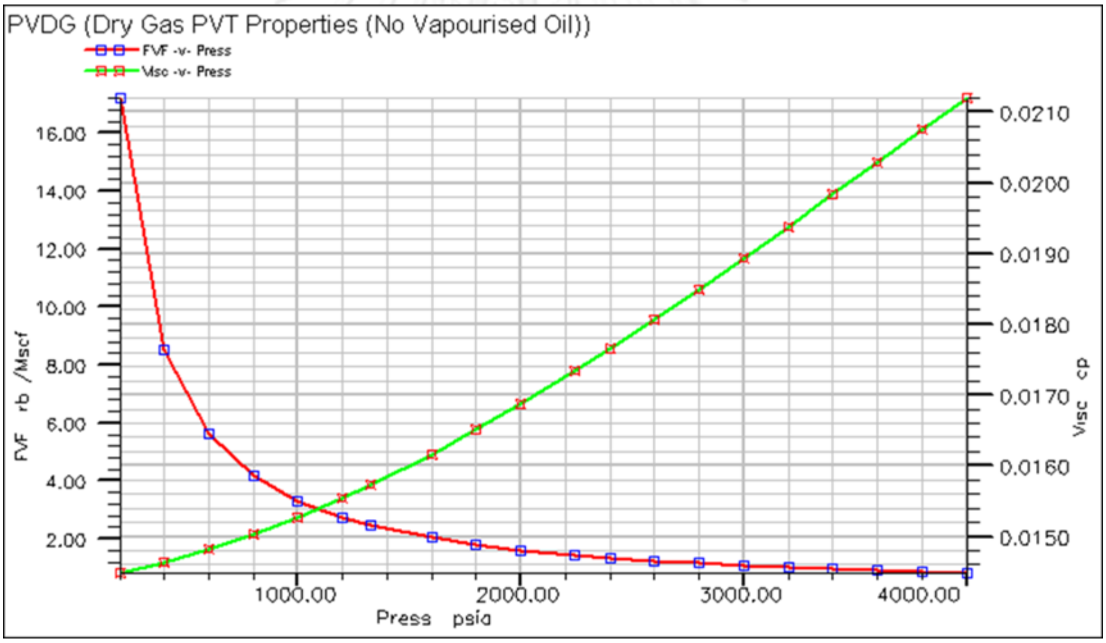


Figure 4. 1 Dry gas PVT properties in oil reservoir (no vaporized oil).

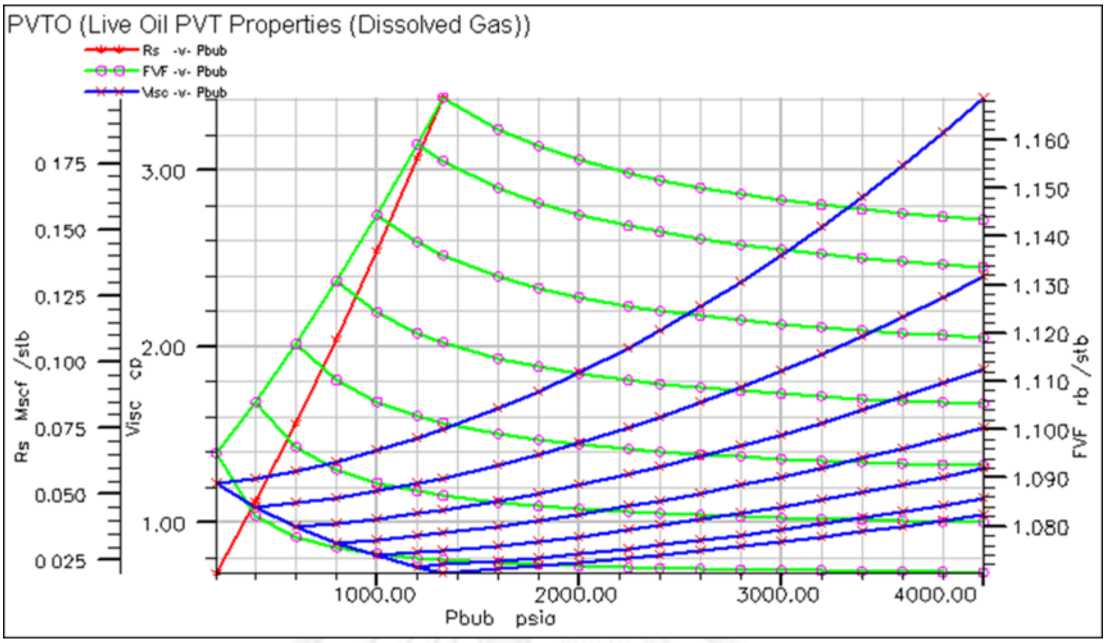


Figure 4. 2 Live oil PVT properties in oil reservoir (dissolved gas).

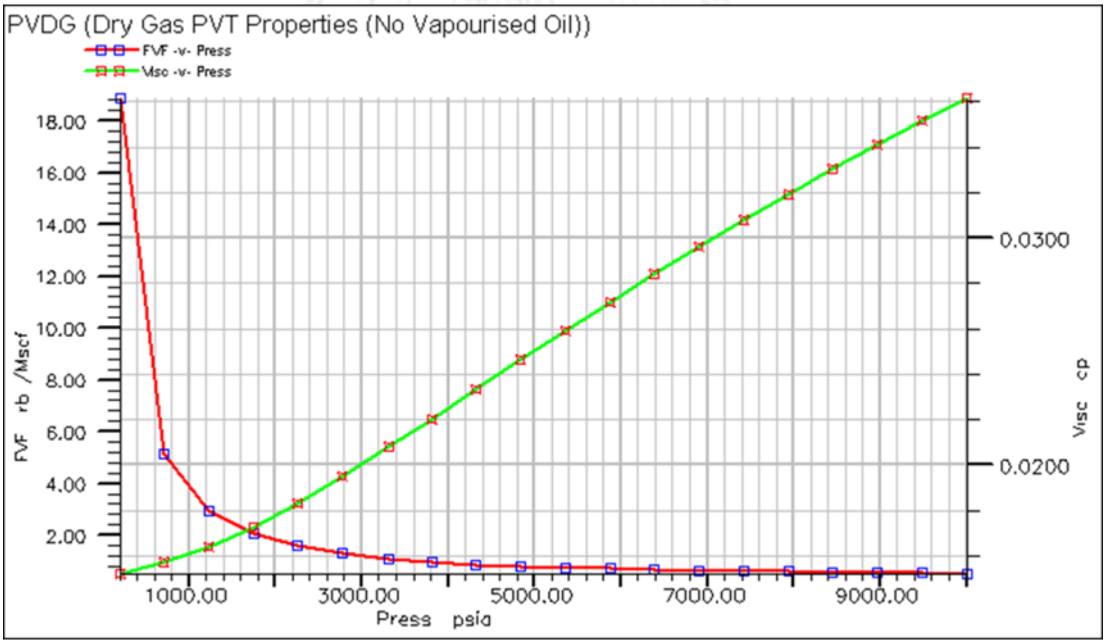


Figure 4. 3 Dry gas PVT properties in gas reservoir (no vaporized oil).

4.3 Special Core Analysis (SCAL) section

In order to generate three-phase relative permeability, Corey's correlation was used to create two sets of two-phase relative permeability first. The required parameters for two-phase relative permeability calculation based on a study conducted for a reservoir in Thailand are shown in Table 4.6. The relative permeability curves for water-oil and gas-oil systems were constructed as illustrated in Figures 4.4 and 4.5. Relative permeability values are tabulated in Tables 4.7 and 4.8. After the two-phase relative permeability relationships are established, ECLIPSE default model is used to determine three-phase relative permeability.

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

Corey Water	3	Corey Gas	3	Corey Oil/Water	1.5
S_{wmin}	0.25	S_{gmin}	0	Corey Oil/Gas	1.5
S_{wcr}	0.25	S_{gcr}	0.15	S_{org}	0.1
S_{wi}	0.25	S_{gi}	0.15	S_{orw}	0.3
S_{wmax}	1	$K_{rg}(S_{org})$	0.4	$K_{ro}(S_{wmin})$	0.8
$K_{rw}(S_{orw})$	0.3	$K_{rg}(S_{gmax})$	0.4	$K_{ro}(S_{gmin})$	0.8
$K_{rw}(S_{wmax})$	1				

Table 4. 7 Water and oil relative permeability.

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

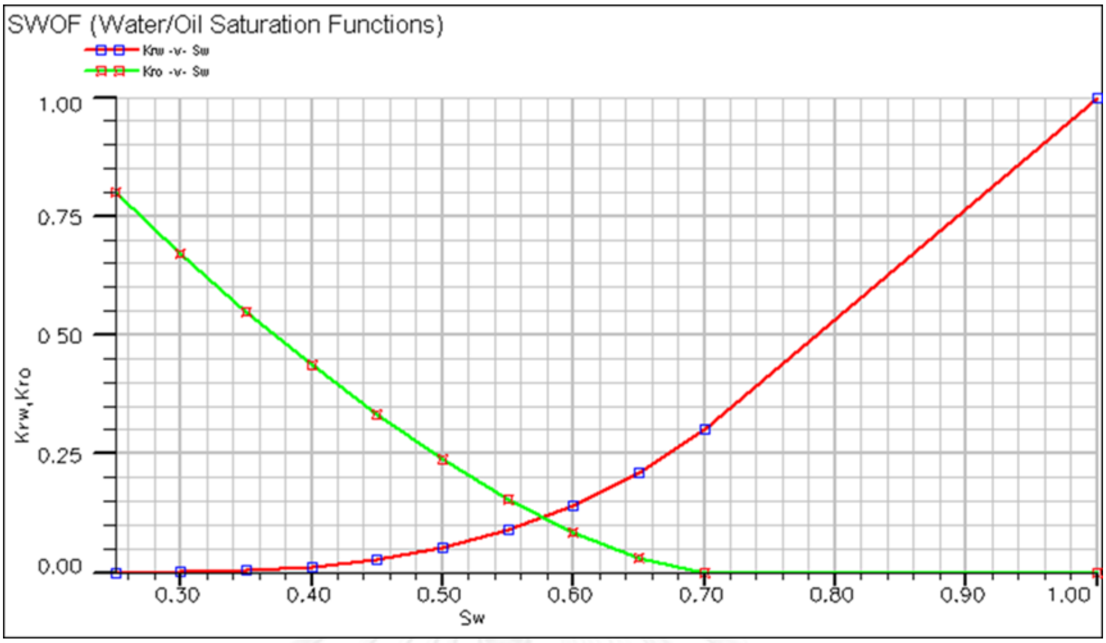


Figure 4. 4 Water/oil saturation function.

Table 4. 8 Gas and oil relative permeability.

S_g	K_{rg}	K_{ro}
0	0	0.8
0.1500	0.0000	0.5397
0.2125	0.0008	0.4418
0.2750	0.0063	0.3506
0.3375	0.0211	0.2667
0.4000	0.0500	0.1908
0.4625	0.0977	0.1239
0.5250	0.1688	0.0675
0.5875	0.2680	0.0239
0.65	0.4	0
0.75	0.8	0

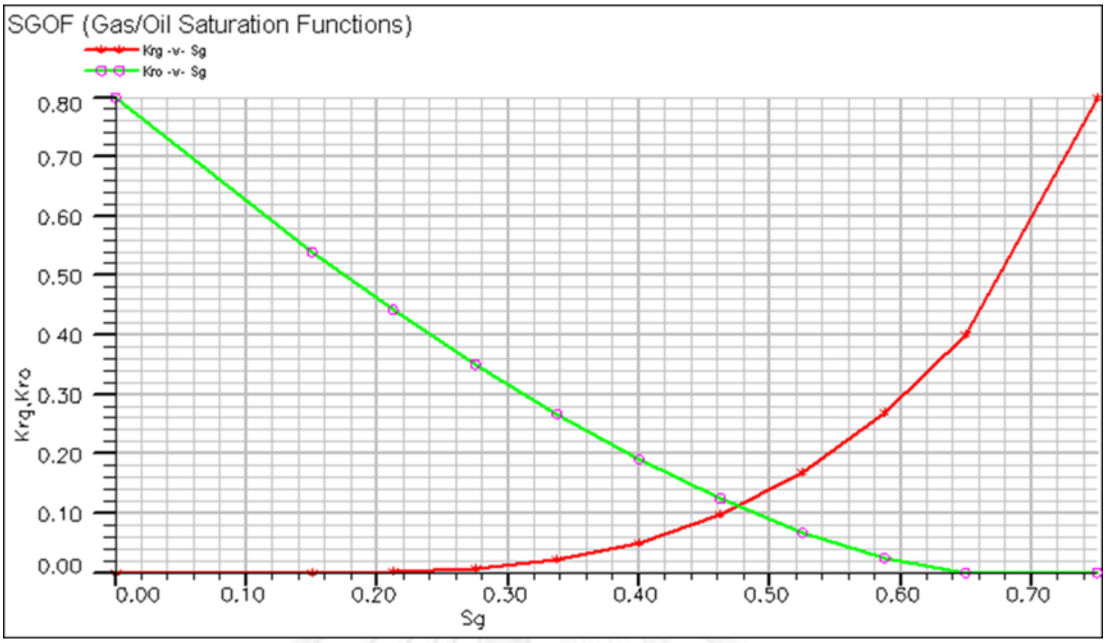
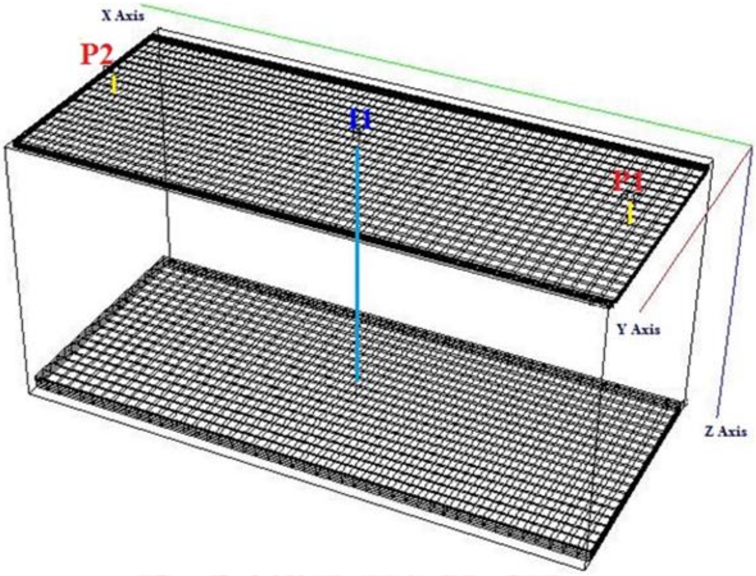


Figure 4. 5 Gas/oil saturation function.

4.4 Well schedules

In this study, both production and injection wells have the same wellbore ID of 6-1/8 inches. They are fully perforated for the entire thickness of the reservoir. Two vertical producers are located on both sides of the reservoir at coordinate (11, 3) and (11, 43) as shown in Figure 4.6. For conventional WAG, a vertical injector is placed at location (11, 23) in the middle of the reservoir. For water alternating gas dumpflood, this injector needs to be extended to connect the bottom reservoir with the target oil reservoir to allow gas to cross-flow.

For conventional WAG, the gas injection from surface is set to alternate with water injection via the same injection well in which the water and gas injection rates can be controlled. The replacement of gas injection by gas cross-flowing from the bottom gas reservoir via the same water injection well is set in water injection alternating gas dumpflood model in which the gas flow rate cannot be controlled. As gas flow from the bottom reservoir, the effect of pressure reduction along the flow path is accounted for via the use of vertical flow performance generated by using PROSPER software. Details are described in the Appendix section. Injection and production constraints of both methods are summarized in Table 4.9.



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

Figure 4. 6 Well locations set for water for conventional WAG and water injection alternating gas dumpflood.

Table 4. 9 Injection and production constraints.

	Parameters	Conventional WAG	Water injection alternating gas dumpflood	Units
1	Oil production rate	5,000	5,000	STB/D/Well
2	Economic oil rate for production well	50	50	STB/D/Well
3	Maximum GOR for production well	50	50	MSCF/STB
4	BHP control for production well	200	200	psia
5	Water injection rate	5,000	5,000	STB/D
6	Gas injection rate	15	-	MMSCF/D
7	BHP target for injection well	3,100	3,100	psia
8	Fracturing pressure	3,215	3,215	psia
9	Concession period	30	30	years

CHAPTER V
SIMULATION RESULTS AND DISCUSSIONS

The discussion on conventional water alternating gas injection and water injection alternating gas dumpflood performances are summarized in this chapter. Based on the created reservoir model and input parameters, each case of conventional WAG and water injection alternating gas dumpflood were individually simulated under similar constraints. The cases that show the best performance of those processes were compared. In addition, sensitivity of the performance of conventional WAG and water injection alternating gas dumpflood due to uncertainties in k_v/k_h ratio, thickness of source gas reservoir, depth difference between gas and oil reservoirs, residual oil saturation, and oil viscosity is discussed.

5.1 Base case

5.1.1 Conventional WAG injection

For conventional water alternating gas, water and gas are injected alternatively at a rate of 5,000 stock-tank barrels per day and 15 million cubic feet per day, respectively, for three months each. Water injection is stopped when injected water arrives at the producer (water cut of 1%) but gas is continuously injected until the oil rate reaches the economic limit.

The base case flooding characteristic of conventional WAG can be described by Figure 5.1. The first slug of water injection is injected since the first day. Three-month water injection rate at 5,000 STB/D alternating three-month gas injection rate at 15 MMSCF/D is carried out until water breaks through the producer (field water cut reaches at 1%). After that, gas injection is continued until GOR at the producer reaches 50 MSCF/STB. After gas injection is stopped for a while, the simulation run is terminated due to economic constraint on oil production rate.

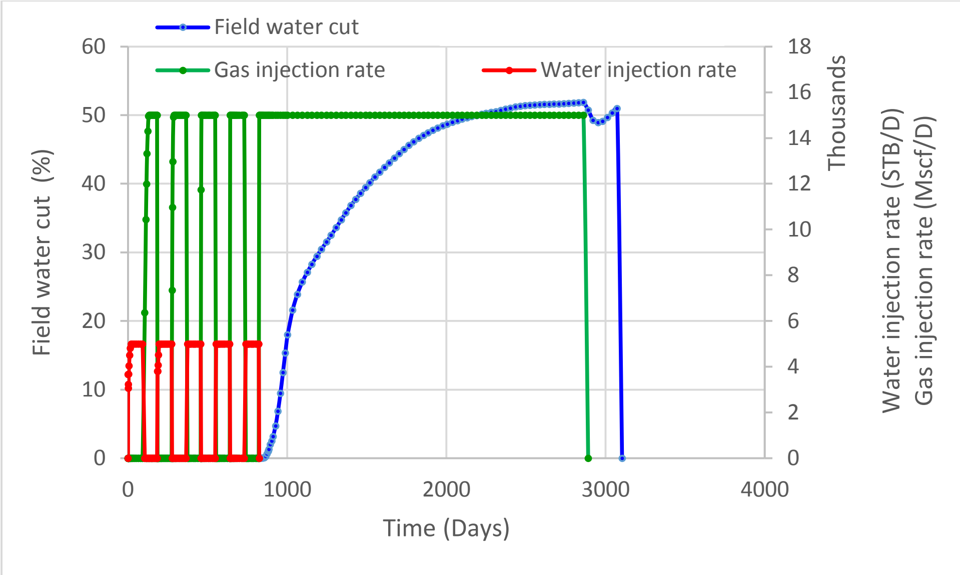


Figure 5. 1 Base case flooding characteristic by conventional WAG injection.

The field oil production rate for the base case of conventional WAG is shown in Figure 5.2. The field oil production rate from two producers remains more or less constant at 10,000 STB/D during the first year and gradually decline in the following years. Figure 5.3 illustrates the field oil, gas and water production rate during 3,073 production days. It can be noticed that gas production rate becomes higher since the early time due to gas early breakthrough. The gas production is maintained in the high range by continuous gas injection and suddenly drops when gas injection is stopped at the condition that the gas oil ratio at producer reaches the limit of 50 MSCF/STB.

Figure 5.4 represents the oil saturation profile at mid cross section after 1 year of production. The oil saturation around the injector in the middle of the reservoir is low since water and gas displace oil as they flow towards the producers. This figure also shows the effect of gas over ridding that occurs in the top part of the reservoir where oil saturation is low. At the end of production, the oil saturation profile at mid cross section becomes very low everywhere except around the edges in the bottom part of the reservoir as illustrated in Figure 5.5.

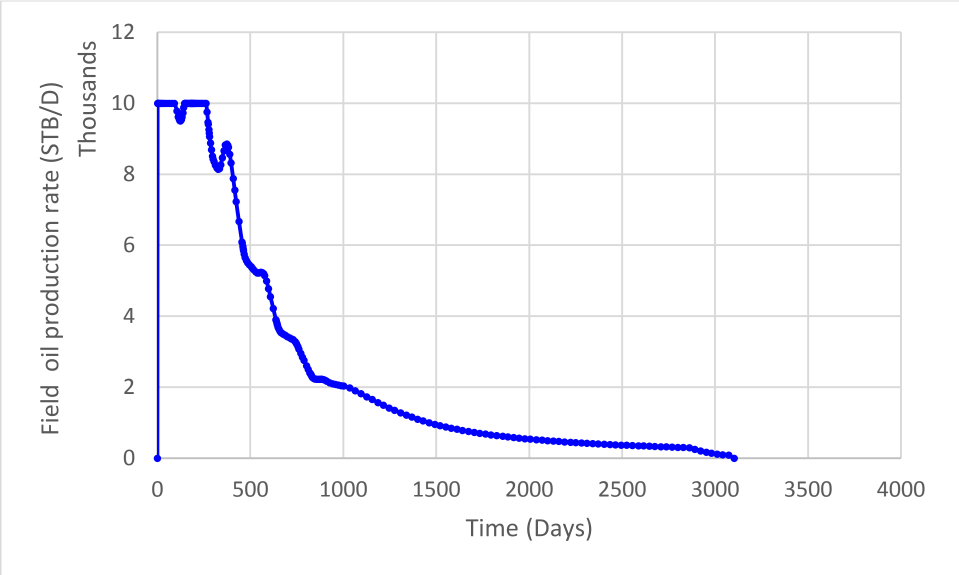


Figure 5. 2 Field oil production rate by conventional WAG under base case condition.

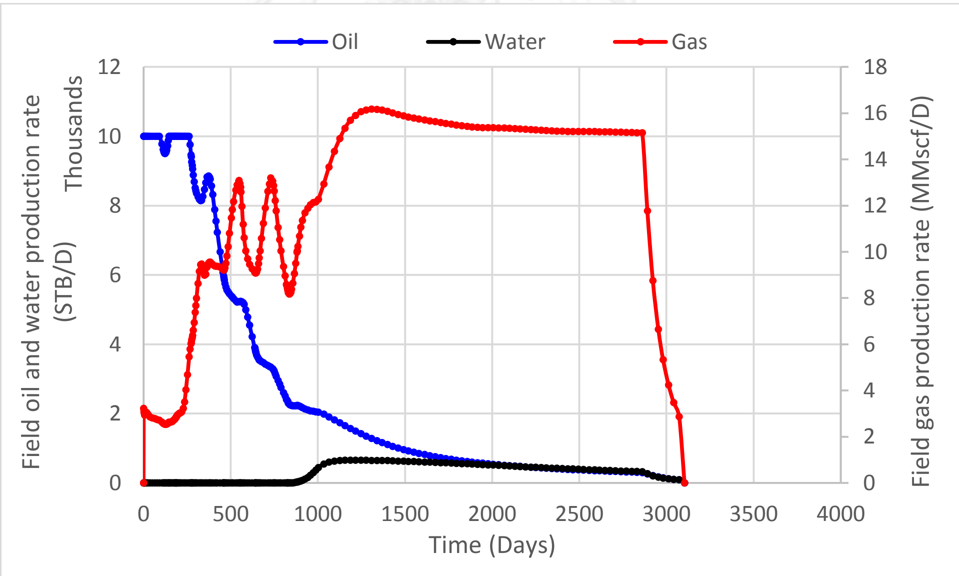


Figure 5. 3 Field oil, water and gas production rates by conventional WAG under base case condition.

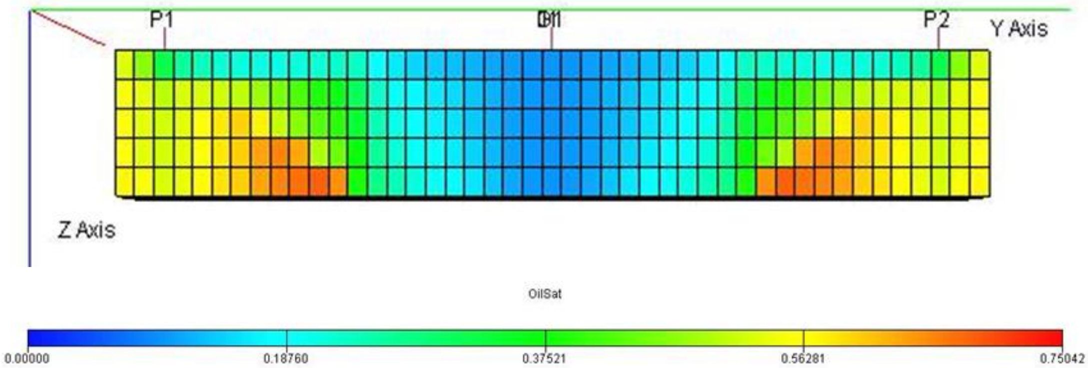


Figure 5. 4 Oil saturation profile (mid cross section) after 1 year production.

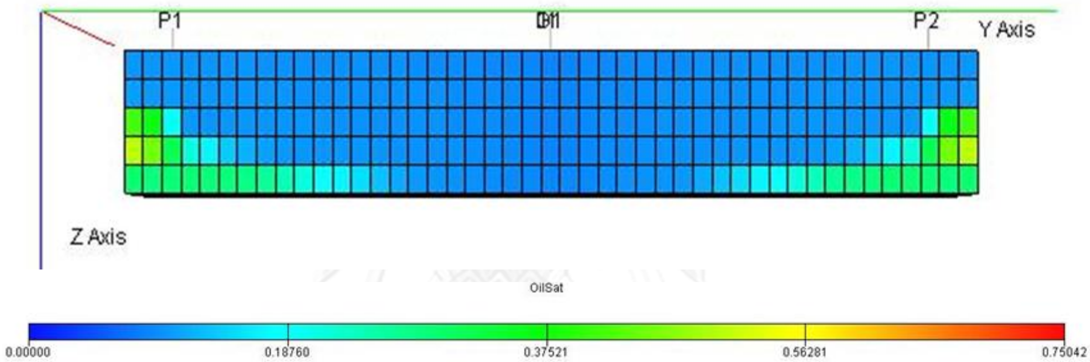


Figure 5. 5 Oil saturation profile (mid cross section) at the end of production.

5.1.2 Water injection alternating gas dumpflood

For water injection alternating gas dumpflood method, water is injected at 5,000 stock-tank barrels per day for three months alternatively with gas being dumped from the gas reservoir for the same duration. When injected water breaks through the producer (water cut of 1%), water injection is stopped and gas is continuously dumped from the gas reservoir to the target oil reservoir. This process of continuous gas dumpflood after water breakthrough lasts until the economic rate of oil production is reached.

Figure 5.6 illustrates the base case flooding characteristic of water injection alternating gas dumpflood in which the reservoir has been flooded by slugs of three-month 5,000 STB/D water injection alternating with slugs of three-month dumped gas until field water cut reaches 1% at the time 868 days. After that, water injection is stopped and gas dumpflood is continued. The oil production rate reaches the economic limit 50 STB/D at the time 3,165 days when the wells are already shut before the bottom gas reservoir is depleted.

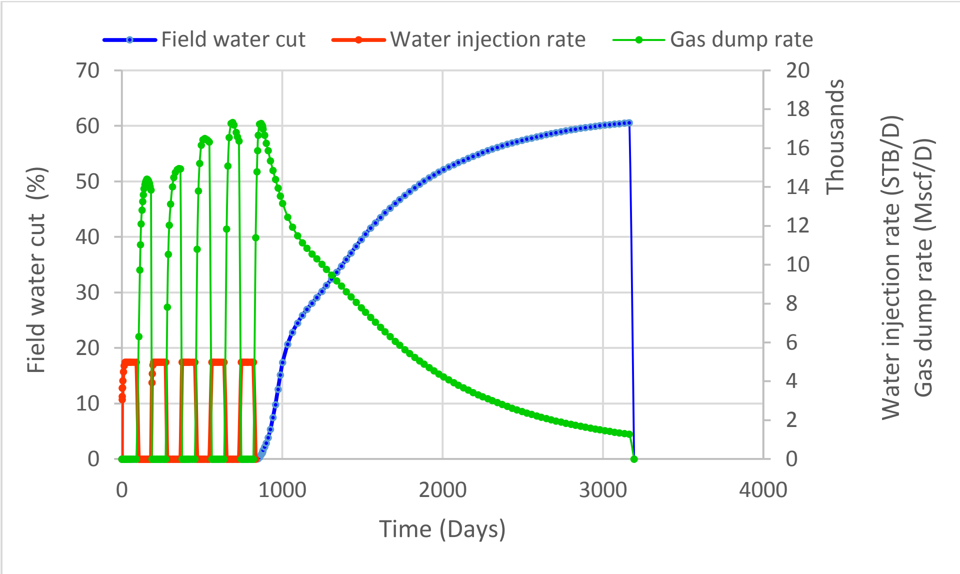


Figure 5. 6 Base case flooding characteristic by water injection alternating gas dumpflood.

The field oil production rate for the base case during 3,165 days is presented in Figure 5.7. The amount of field oil production obtained from two producing wells remains constant at 10,000 STB/D during the first year and continuously declines afterward. Figure 5.8 shows oil, water and gas production rates with time. From this graph, it clearly shows that gas can travel very fast from the dumpflood well to the producers due to its low viscosity and the effect of high pressure drawdown at the producing wells. The oil production rate starts to decline after water breakthrough at the producer.

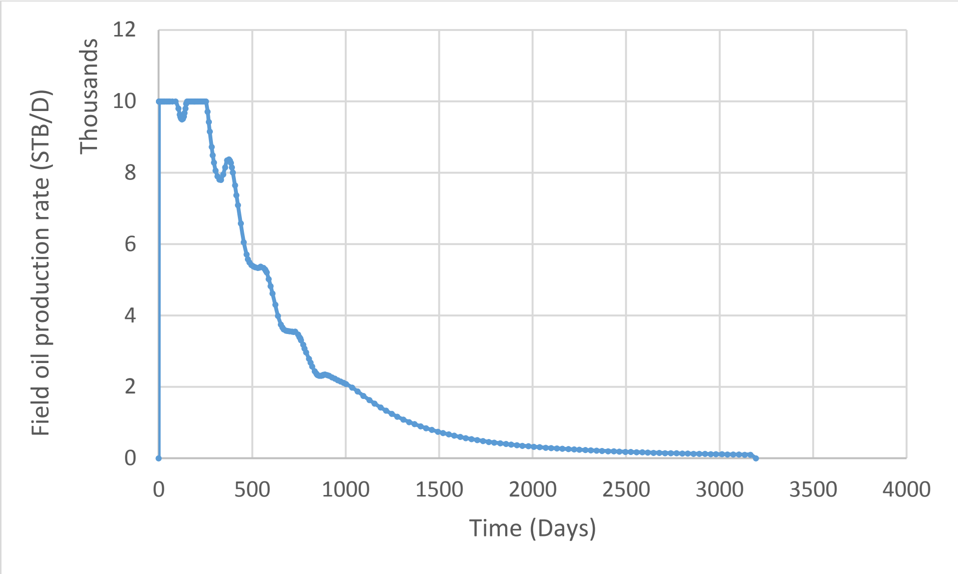


Figure 5. 7 Field oil production rate by water injection alternating gas dumpflood under base case condition.

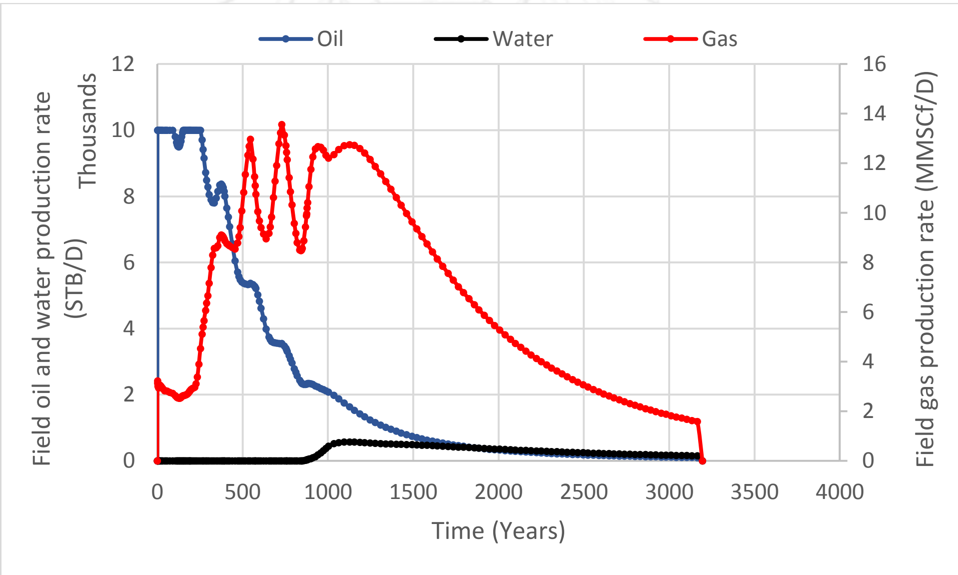


Figure 5. 8 Field oil, water and gas production rates water injection alternating gas dumpflood under base case condition.

The oil saturation profiles observed after 1 year of production and at the end of this process are displayed in Figures 5.9 and 5.10, respectively. Figure 5.9 depicts clear difference in oil saturation profile in the upper and lower parts of the oil reservoir due to gravity segregation. The oil around the injector is flooded by water alternating with gas while the oil in the upper part is flooded by gas which overrides the oil. At the end, most oil is displaced by alternating slugs of water and gas. The oil saturation is low everywhere except the bottom edges as shown in Figure 5.10.

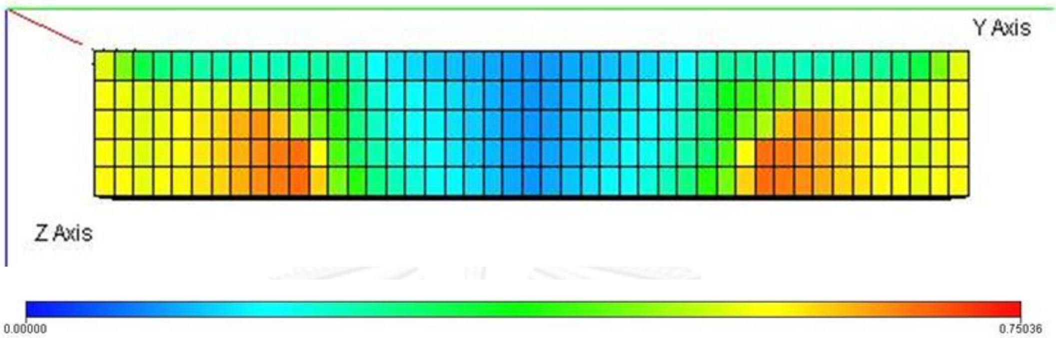


Figure 5. 9 Oil saturation profile (mid cross section) after 1 year production.

Figure 5. 10 Oil saturation profile (mid cross section) at the end of production.

As shown in Figure 5.11, recovery factor for both methods is quite similar during the first 1,500 days. At the end of the production, water injection alternating gas dumpflood yields oil recovery factor of 72.27% with 7.14 MMSTB of total oil production within 8.7 years while conventional WAG injection gives final recovery factor of 75.89% which is 3.62% higher than that of the proposed water injection alternating gas dumpflood. As summarized in Table 5.1, the conventional WAG method requires 35 billion standard cubic feet of gas injection while the proposed method does not require any gas injection from surface.

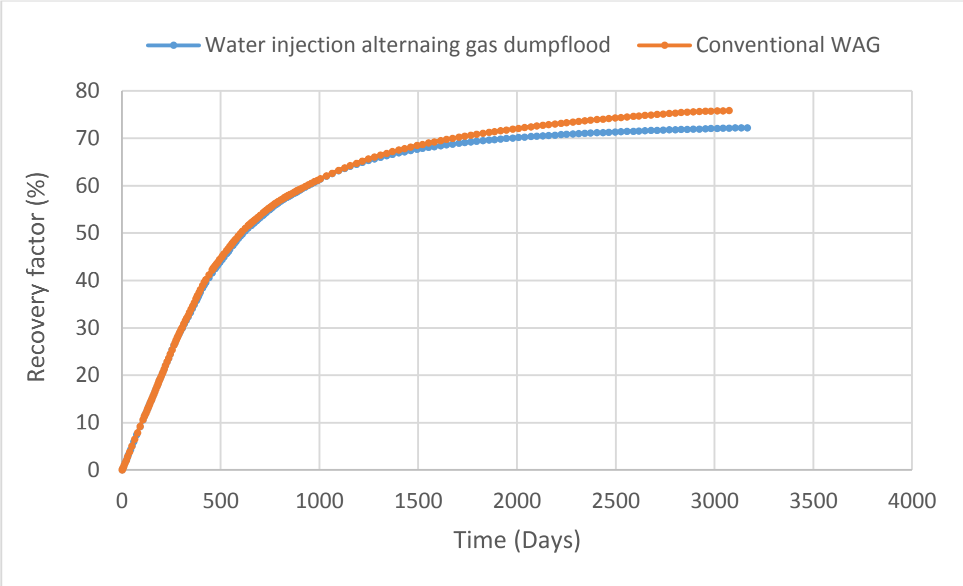


Figure 5. 11 Comparison of recovery factor by conventional WAG injection and water injection alternating gas dumpflood.

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Table 5. 1 Summary of results for conventional WAG injection and water injection alternating gas dumpflood under base case condition.

Base case by method	Recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative water production (MMSTB)	Cumulative water injection (MMSTB)	Cumulative gas production (BCF)	Cumulative gas injection (BCF)	Barrel of oil equivalent (MMSTB)	Production time (Years)
Conventional WAG	75.89	7.493	1.010	2.261	38.309	35.838	7.905	8.4
Water injection alternating gas dumpflood	72.27	7.136	0.775	2.252	21.137	-	10.659	8.7

5.2 Effect of different design parameters

Design parameters strongly affect the production performance. The investigation on each parameter is discussed and summarized in this section. Design parameters studied in this section are

- Water injection stopping criteria
- Well location
- Water and gas injection rates
- Injection duration and slug size

5.2.1 Effect of water injection stopping criteria

As the time to stop water injection may affect the performance of conventional WAG injection and the proposed water injection alternating gas dumpflood, three different criteria to stop water injection based on field water cut (1%, 40%, and 80%) are investigated.

5.2.1.1 Conventional WAG injection

The base case flooding characteristic is again depicted in Figure 5.12. Five slugs of water alternating with four slugs of gas have been injected until water breaks through the producer (field water cut set at 1%). After stopping the process of water injection, only continuous gas injection is continued until GOR at the producer reaches 50 MSCF/STB. The oil production can still be prolonged for a few more months after gas injection is stopped. The simulation is terminated when the field oil production rate drops to the economic limit of 50 STB/D. The total production duration is 3,073 days (8.42 years).

Higher water cut constraint can prolong the flooding process and let the oil to be flooded by more slugs of water and gas. Flooding characteristic at 40% water cut constraint can be depicted by Figure 5.13. The flooding process of conventional WAG injection is carried out until 1,232 days when the field water cut reaches 40% at the producers. After that, gas injection is continued at constant rate of 15 MMSCF/D and stopped when field GOR reaches the limit of 50 MSCF/STB. The production life for this case is prolonged to 3,165 days (8.8 years).

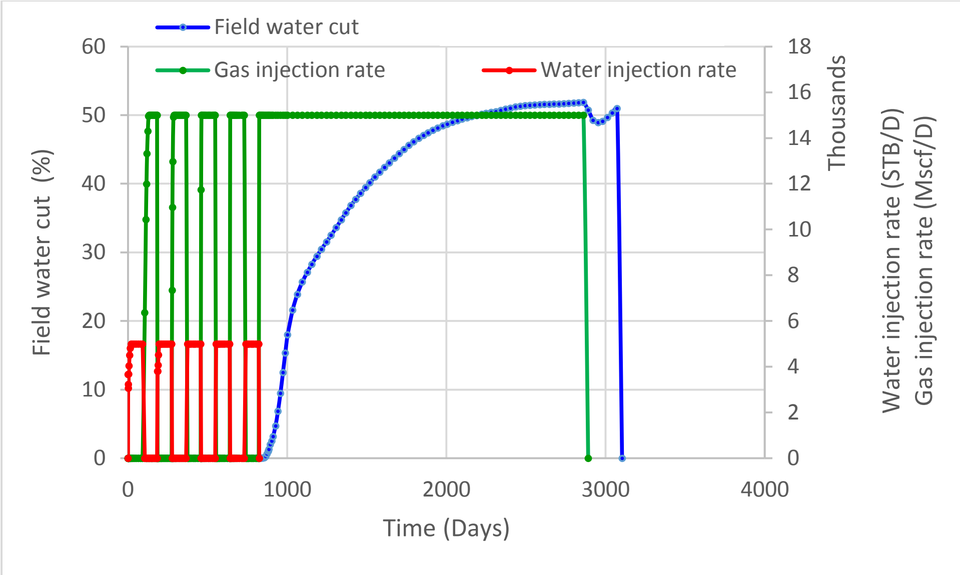

Figure 5. 12 Base case flooding characteristic by conventional WAG injection at 1% field water cut constraint.

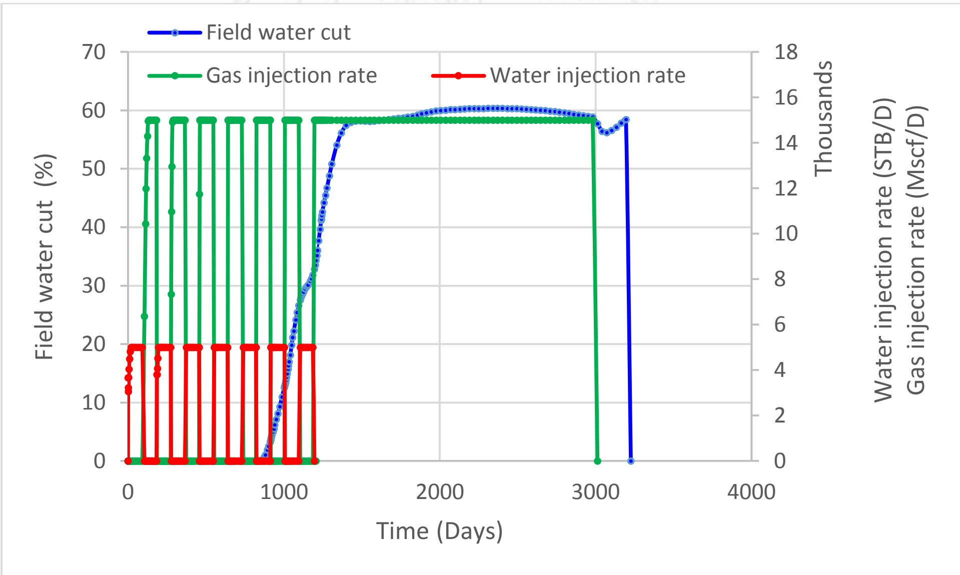

Figure 5. 13 Flooding characteristic by conventional WAG injection at 40% field water cut constraint.

Figure 5.14 represents the flooding characteristic under 80% water cut constraint. The process of water alternating gas flooding is performed from the first day to 2,139 days. After the field water cut reaches the constraint at 2,139 days, continuous gas injection proceeds and then ends at 3,287 days. The oil production finally ceases at 3,499 days (9.6 years).

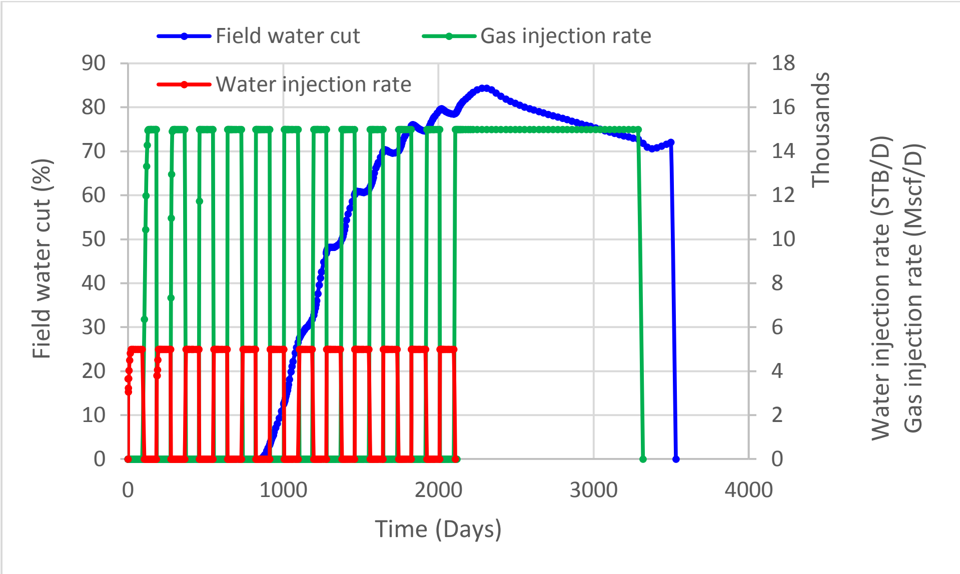

Figure 5. 14 Flooding characteristic by conventional WAG injection at 80% field water cut constraint.

The recovery factor obtained from the cases of 40% and 80% water cut criteria are only 0.12% and 0.54% respectively higher than that of the base case as shown in Table 5.2. Figure 5.15 shows field oil production from different water alternating gas injection stopping constraints. For 40% and 80% water cut criteria, the cumulative oil productions are slightly higher than that of the base case. The incremental oil production of 0.01 and 0.06 million barrels in the two cases is obtained with 0.91 and 3.19 million barrels of additional water injection. As a small gain in oil production must be sacrificed by a lot of water injection, it may not be worthwhile to change the water cut criteria from the base case. Thus, the base case with 1% field water cut is chosen as the optimal condition. Even the total gas injection for the base case is the highest, the injected gas is reproduced back to surface during the production life of the reservoir.

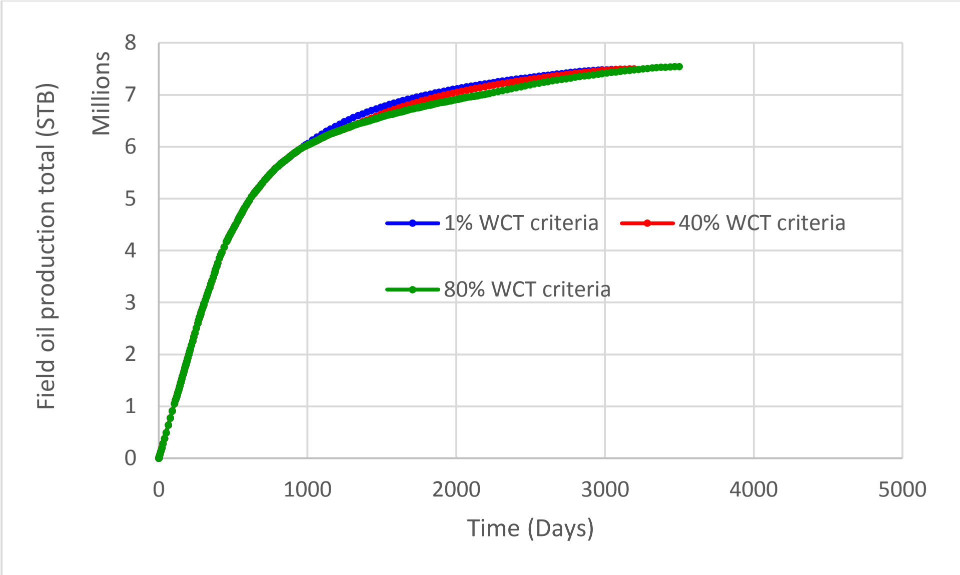

Figure 5. 15 Total field oil production by conventional WAG injection at different water injection stopping constraints.

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Table 5. 2 Summary of results for conventional WAG injection under the variation of water injection stopping criteria.

Case	Field WCT criteria (%)	Recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative water production (MMSTB)	Cumulative water injection (MMSTB)	Cumulative gas production (BCF)	Cumulative gas injection (BCF)	Barrel of oil equivalent (MMSTB)	Production time (Years)
1 (Base case)	1	75.89	7.493	1.010	2.261	38.309	35.838	7.905	8.4
2	40	76.01	7.504	1.763	3.174	37.335	34.895	7.911	8.8
3	80	76.43	7.546	3.690	5.455	35.022	32.644	7.942	9.6

5.2.1.2 Water injection alternating gas dumpflood

Figure 5.16 illustrates the base case flooding characteristic as previously shown in Section 5.1.2. The oil reservoir has been flooded by five slugs of water and four slugs of dumped gas when field water cut reaches 1% (water breaks through the producers) at time 868 days. Then, water injection is stopped, and gas is continuously dumped from the source gas reservoir until abandonment. It takes 3,165 days (8.7 years) for the oil production to reach the economic limit of 50 STB/D.

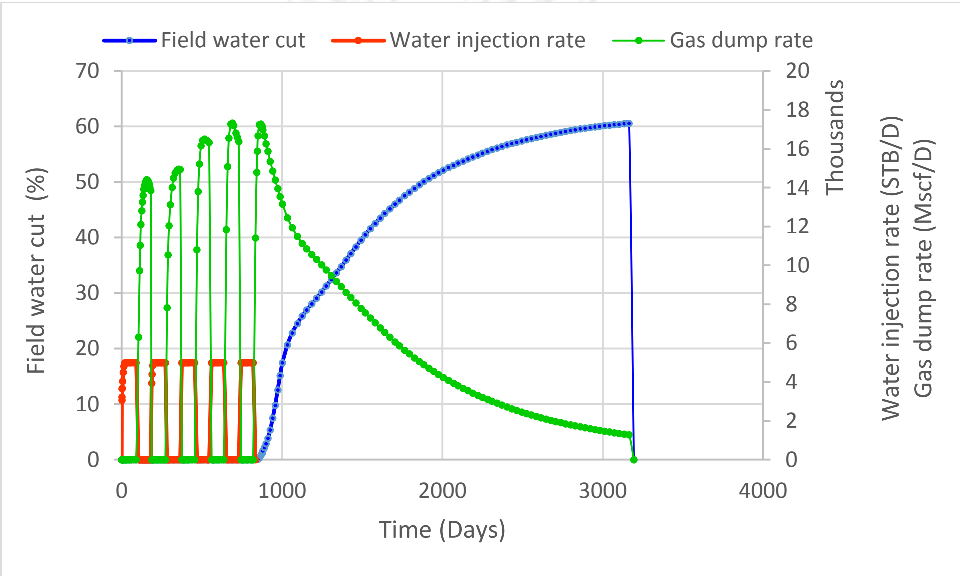

Figure 5. 16 Base case flooding characteristic by water injection alternating gas dumpflood at 1% field water cut constraint.

The case in which the field water cut criteria is set at 40% yields longer flooding duration as seven slugs of water and six slugs of dumped gas are needed (as presented in Figure 5.17). The duration of alternating slugs of injected water and dumped gas extends to 1,260 days. After that, gas dumpflood is continued until 3,469 days (9 years) at which the oil production rate reaches the economic limit of 50 STB/D.

From Figure 5.18, it is obvious that the oil in the case of 80% water cut criteria is flooded by more slugs of water and dumped gas than the previous two cases. The process of water injection alternating gas dumpflood goes on until 2,143 days, which is the time that field water cut reaches 80%. Then, continuous gas dumpflood proceeds until the field oil production rate reaches the economic limit at 4,048 days (11.0 years).

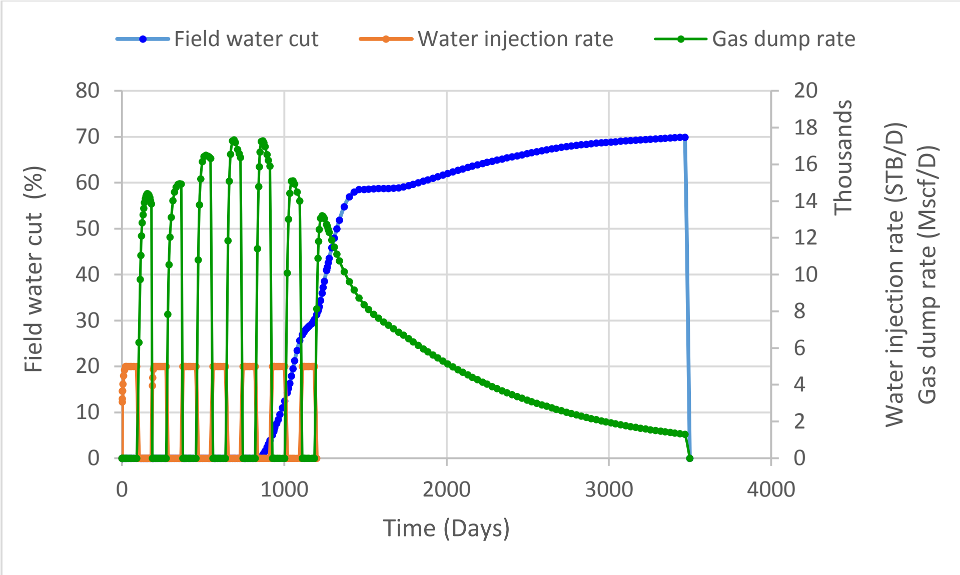

Figure 5. 17 Flooding characteristic by water injection alternating gas dumpflood at 40% field water cut constraint.

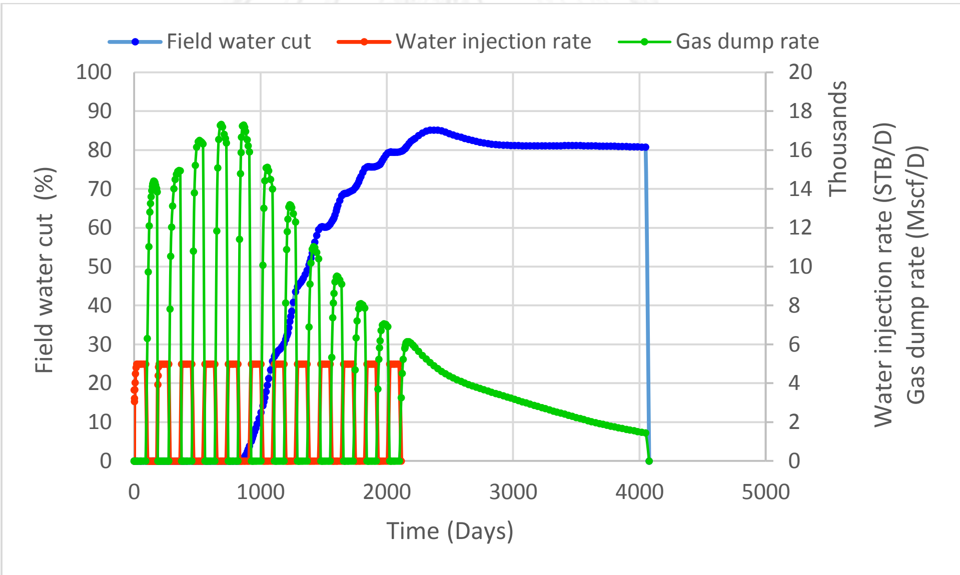

Figure 5. 18 Flooding characteristic by water injection alternating gas dumpflood at 80% field water cut constraint.

Figure 5.19 shows total field oil production from different water injection stopping constraints. The total oil productions obtained in the cases of higher water cut constraints are slightly higher than that for the base case. The reason is that the cases of higher water cut constraints have higher amounts of water injection and dumped gas flow from the gas reservoir to the oil reservoir, resulting in better oil displacement.

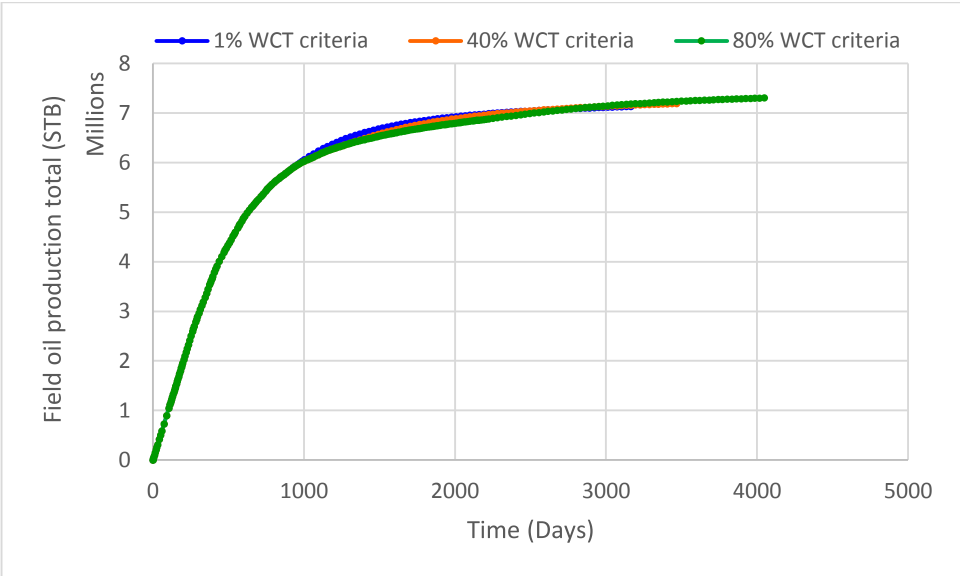

Figure 5. 19 Total field oil production by water injection alternating gas dumpflood at different water injection stopping constraints.

The recovery factor in the case of 40% and 80% field water cut is respectively 0.61% and 1.75% higher than that of the base case as summarized in Table 5.3. The oil production obtained from these two cases is 0.06 and 0.17 million barrels higher than that of the base case but they require additional 0.91 and 3.2 million barrels of water injection, respectively. These additional amounts of injected water are much higher than the incremental oil productions. Thus, field water cut of 1% is the optimal case for water injection alternating gas dumpflood.

Both conventional WAG injection and water injection alternating gas dumpflood is optimal when the condition to start the two processes is field water cut of 1%. The recovery factor of conventional WAG is 3.62% higher than that for water injection alternating gas dumpflood. However, a large amount of gas injection (35.84 BCF) is a major requirement in processing conventional WAG to attain total field oil of 0.357 MMSTB higher than that from the method of water injection alternating gas dumpflood.

Table 5. 3 Summary of results for water injection alternating gas dumpflood under the variation of water injection stopping criteria

Case	Field WCT (%)	Recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative water production (MMSTB)	Cumulative water injection (MMSTB)	Cumulative gas production (BCF)	Barrel of oil equivalent (MMSTB)	Production time (Years)
1 (Base case)	1	72.27	7.136	0.775	2.252	21.137	10.659	8.7
2	40	72.88	7.196	1.476	3.164	21.032	10.702	9.5
3	80	74.02	7.308	3.344	5.450	20.685	10.756	11.0

5.2.2 Effect of Well Location

Since locations of injector and producer influence flooding performance, different well patterns are investigated. When the injector and producer are placed at proper locations, sweep efficiency should be improved. In this study, the injector to producer spacing is varied. Well pattern 1 for the base case is sketched in Figure 5.20 It consists of one injector and two producers located 2,000 feet apart. Well pattern 2, shown in Figure 5.21, has four injectors placed in between producers with 500 ft. spacing. Well pattern 3 has two injectors and three producers as depicted in Figure 5.22. The distance between each pair of wells is 1,000 ft. Well pattern 4 has a total of ten wells in which there are two lines of wells as shown in Figure 5.23. These four well patterns are simulated individually by the application of conventional WAG and water injection alternating gas dumpflood under the same constraints as the base case. To be comparable with the base case, field water rate and field liquid production rate set for each case must add up to 5,000 STB/D and 10,000 STB/D, respectively. For the case of conventional WAG, field gas injection rate must equal to 15 MMSCF/D.

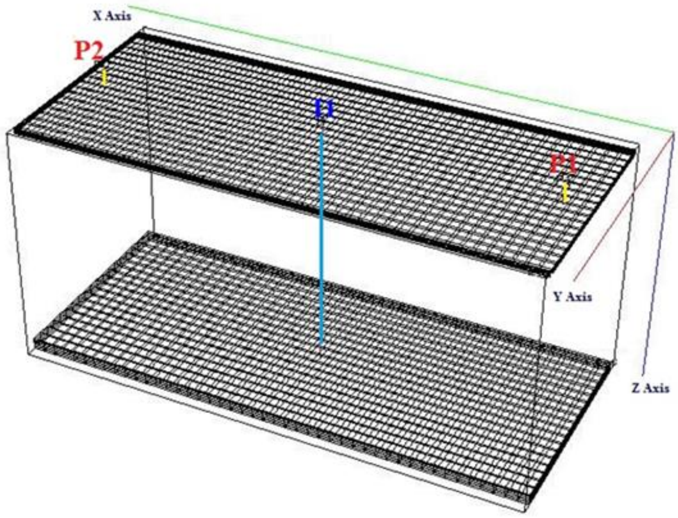

Figure 5. 20 Well pattern 1 as the base case well condition.

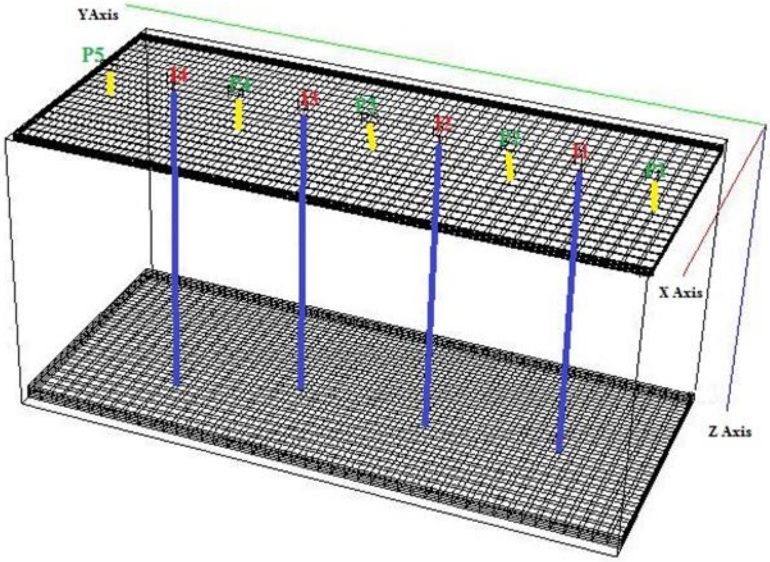

Figure 5. 21 Well pattern 2.

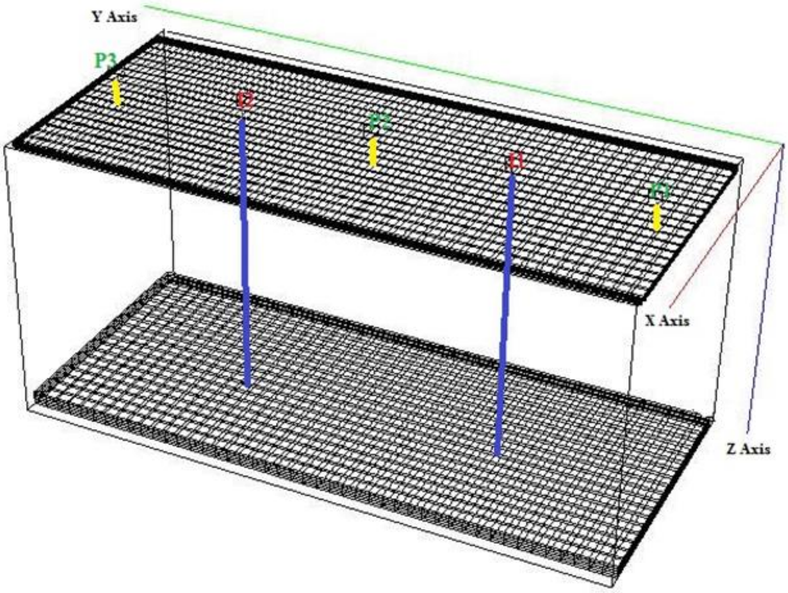

Figure 5. 22 Well pattern 3.

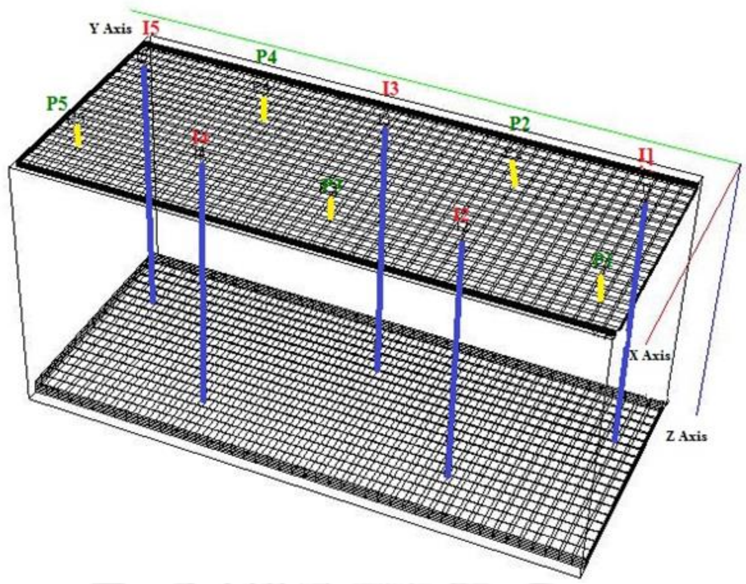

Figure 5. 23 Well pattern 4

5.2.2.1 Conventional WAG injection

In case of pattern 2, the well system is composed of four injectors and five producers located 500 ft. apart. Each of the injector is set to inject water at 1,250 STB/D. The summation of water injection rate from four injectors are equal to 5,000 STB/D. Gas injection rate is set for the method of conventional WAG at 3.75 MMSCF/D/well. The maximum liquid production rate is set at 2,000 STB/D to obtain a total of 10,000 STB/D from five producers.

For well pattern 3, two injectors are placed in between three producers at 1,000 ft. distance. The maximum water injection rate is set at 2,500 STB/D/well while the gas injection rate is set at 7.5 MMSCF/D/well. The liquid production rate at the producers is set at 3,333 STB/D which adds up to 10,000 STB/D from three producers.

In well pattern 4, the injectors and producers are placed in alternate pairs along the length of reservoir at 1,000 ft. distance. Water injection rate of 1,000 STB/D/well, and the maximum liquid production rate of 2,000 STB/D/well are applied at each injector and producer, respectively. The gas injection rate in this case is 3 MMSCF/D/well.

The injection and production schedules for each well pattern are summarized in Table 5.4. Each well pattern is simulated with the constraints mentioned in Chapter IV. The simulated results are summarized in Table 5.5.

Table 5. 4 Well schedules at different well patterns under the method of conventional WAG injection.

Well pattern	No. of wells	Well distance (ft.)	No. of injector	No. of producer	Water injection rate/well (STB/D)	Gas injection rate/well (MMSCF/D)	Liquid production rate/well (STB/D)
1 (Base case)	3	2,000	1	2	5,000	15.00	5,000
2	9	500	4	5	1,250	3.75	2,000
3	5	1,000	2	3	2,500	7.50	3,333
4	10	1,000	5	5	1,000	3.00	2,000

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Table 5. 5 Summary of results for conventional WAG injection for various well locations.

Well Pattern	Recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative water production (MMSTB)	Cumulative water injection (MMSTB)	Cumulative gas production (BCF)	Cumulative gas injection (BCF)	Barrel of oil equivalent (MMSTB)	Production time (Years)
1 (Base case)	75.89	7.493	1.010	2.261	38.309	35.838	7.905	8.4
2	60.95	6.017	0.230	0.456	54.597	52.013	6.448	10.1
3	71.20	7.030	0.423	0.913	55.881	53.380	7.447	10.5
4	75.87	7.491	0.514	1.419	38.862	36.324	7.914	7.7

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From Table 5.5, the base case yields 75.89% recovery factor which is the highest among the others. This case with well spacing of 2,000 ft. is considered to be the most suitable well pattern. Although well pattern 4 has a slightly less recovery factor (75.87%) with much lower amounts of water injection and production, it needs a total of ten wells. As pattern 4 requires twice capital investment on well cost, this pattern is not recommended. In pattern 1, the oil can flow toward producing wells along both edges of the reservoir without premature breakthrough of gas and water, resulting in high sweep efficiency. Low residual oil saturation in the base case well pattern can be observed at the end of production in Figure 5.24. However, the effect of gravity segregation still occurs. Layers k = 1, 2 and 3 are effectively swept by gas while layers k = 4 and 5 are less effectively swept by water.

The recovery factor of well pattern 2 is the lowest compared to the others due to the fact that well spacing between each pair of injector and producer is too short to drain the oil from the entire area. This small distance causes injected gas and water to arrive at the producers early without sweeping much of the area in the reservoir. The total gas injection of 52 BCF is quite high. This is due to early gas breakthrough. The distributions of oil saturation for different layers in Figure 5.25 clearly show there is a lot of by passed oil along the edges of the reservoir in the lower layers. The reason that upper layers are better swept is because successive slugs of gas in the upper layers flow faster than water in the lower layers and cover more area by the time the oil rate reaches the economic limit.

For well pattern 3, the recovery factor is 71.20%. The distributions of oil saturation in different layers are shown in Figure 5.26. Similar to the previous two patterns, the effect of gravity segregation still occurs. There is still some oil left in the lower layers at abandonment condition.

For well pattern 4, the amount of oil left in the lower layers at abandonment is quite low as shown in Figure 5.27 due to a more balance well distance in the x and y directions. Injected fluids can sweep the area quite well before they break through the producers.

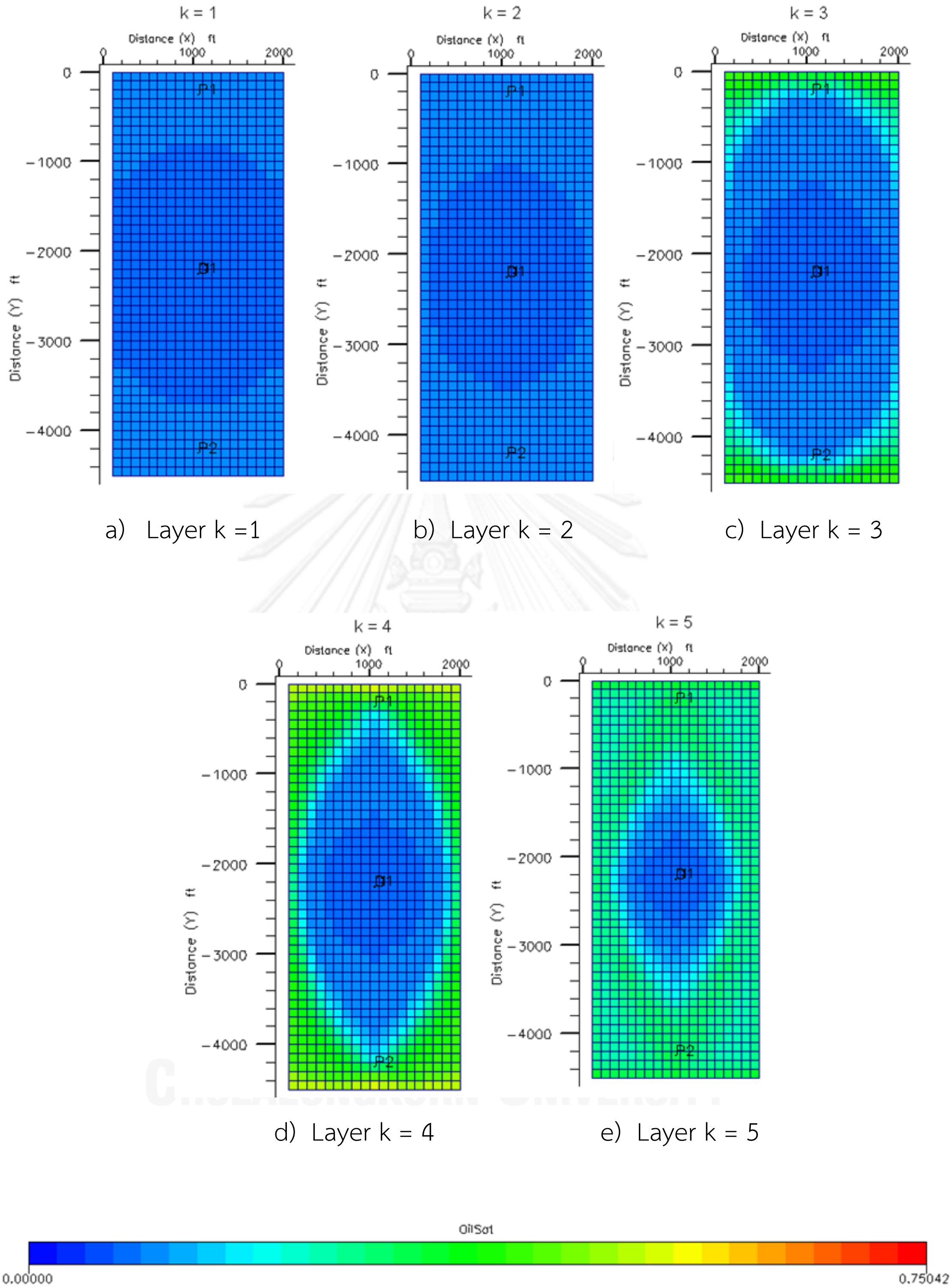


Figure 5. 24 Oil saturation profile at the end of production by conventional WAG under well arrangement pattern 1.

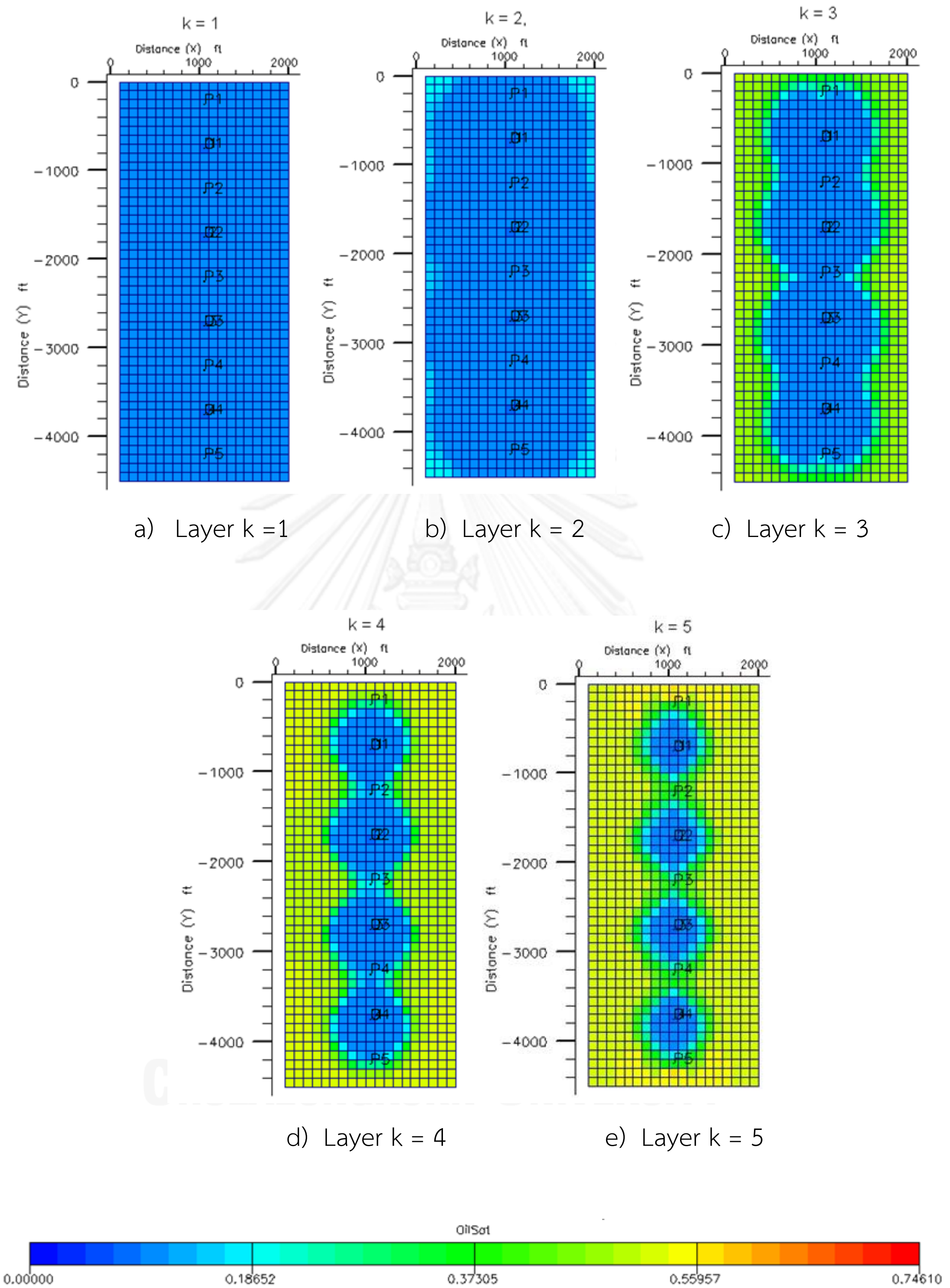
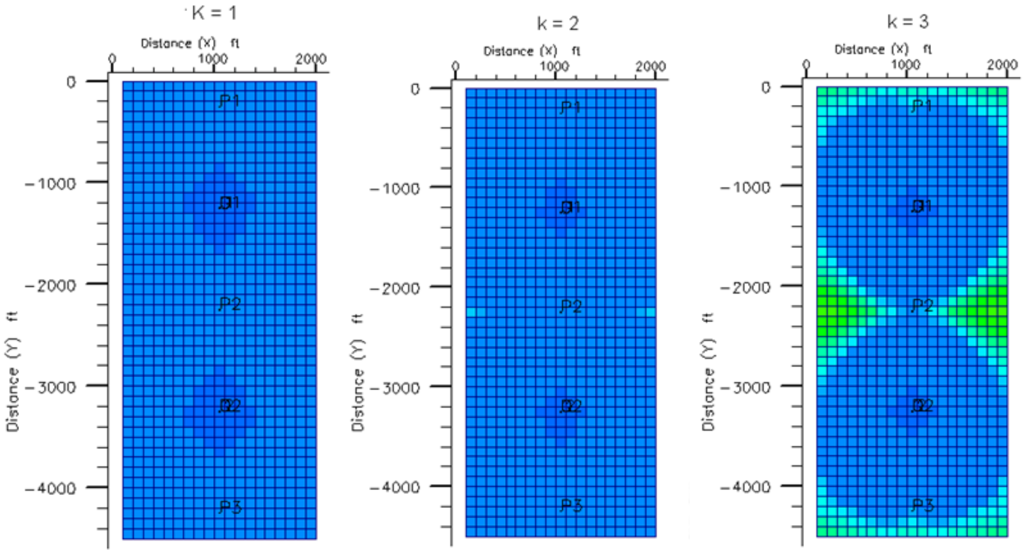
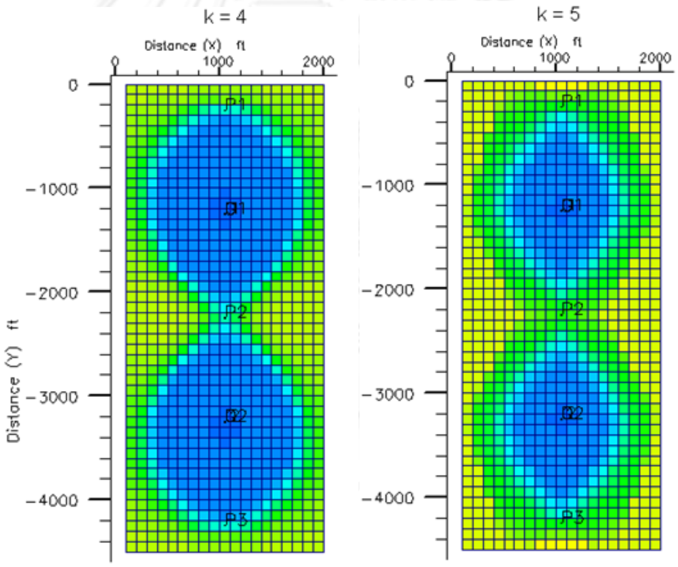


Figure 5. 25 Oil saturation profile at the end of production by conventional WAG under well arrangement pattern 2.



a) Layer k =1 b) Layer k = 2 c) Layer k = 3



d) Layer k = 4 e) Layer k = 5

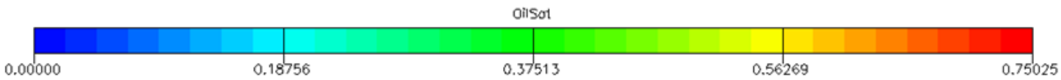


Figure 5. 26 Oil saturation profile at the end of production by conventional WAG under well arrangement pattern 3.

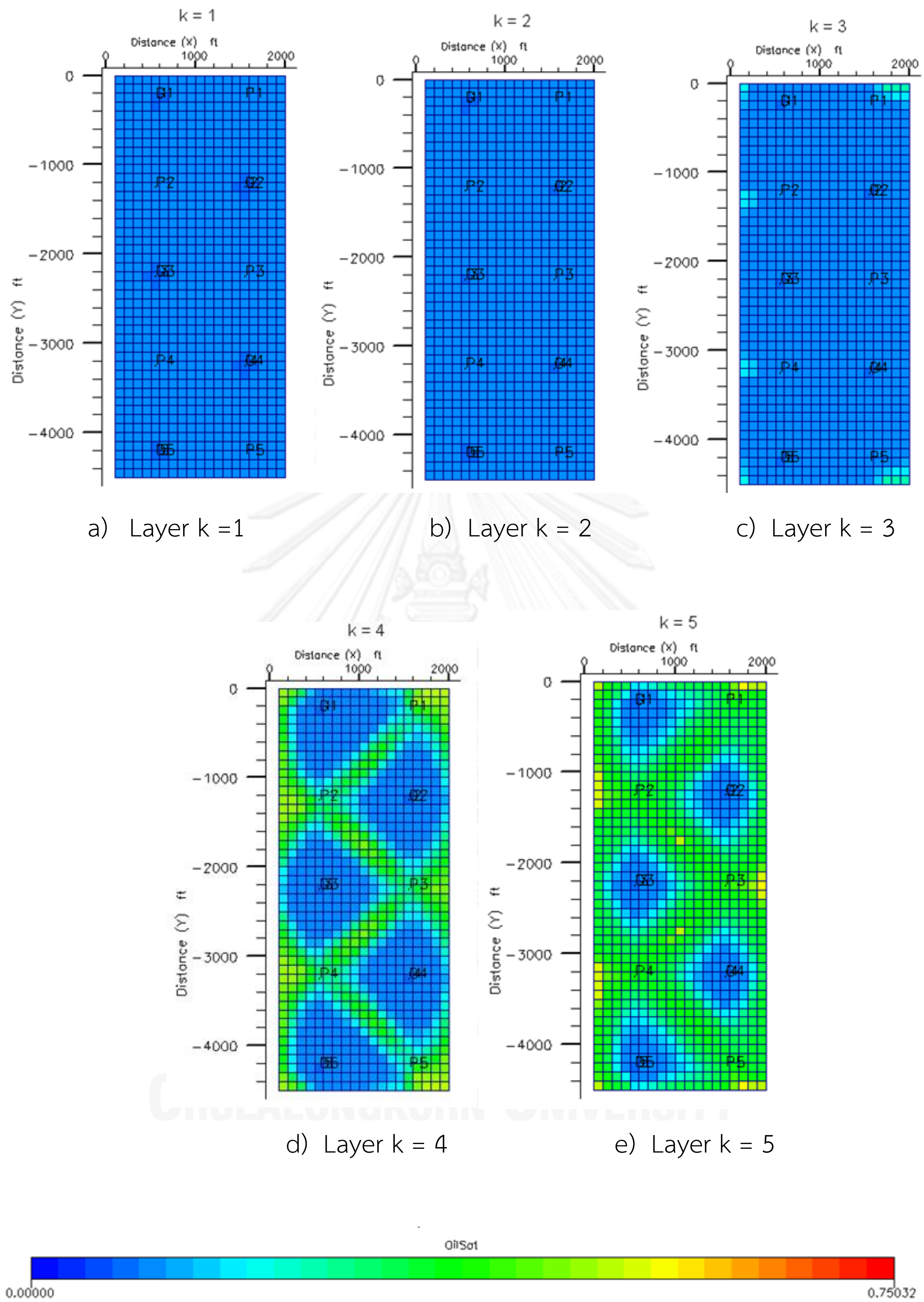


Figure 5. 27 Oil saturation profile at the end of production by conventional WAG under well arrangement pattern 4.

5.2.2.2 Water injection alternating gas dumpflood

According to injection and production constraints mentioned previously, well schedules for different well patterns by the method of water injection alternating gas dumpflood are determined and tabulated in Table 5.6.

Table 5. 6 Well schedules for different well patterns under the method of water injection alternating gas dumpflood.

Well pattern	No. of wells	Well distance (ft.)	No. of injector	No. of producer	Water injection rate/well (STB/D)	Liquid production rate/well (STB/D)
1 (Base case)	3	2,000	1	2	5,000	5,000
2	9	500	4	5	1,250	2,000
3	5	1,000	2	3	2,500	3,333
4	10	1,000	5	5	1,000	2,000

The simulated results from different well patterns are summarized in Table 5.7. The base case pattern gives the highest recovery factor of 72.27%. This case has low residual oil saturation at the end of production (as presented in Figure 5.29). In the case of well pattern 2, recovery factor is the lowest in comparison to other cases. The injector to producer distance in this case is too close so that gas and water break through very fast. This leaves some portion of oil remained unswept around the edges in the lower part reservoir. Figure 5.30 depicts oil saturation profile after 4 year of production in layers k = 1 to k = 5. In layers k = 1 and k = 2, most oil is flooded by dumped gas. However, high oil saturation still remains around the edges in layer k = 3, k = 4 and k = 5 after 4 years production because slow water movement in the lower layers can displace only a certain amount of oil before the field oil production rate reaches the economic limit.

For well patterns 3 and 4, they have the same well distance of 1,000 ft. The oil recovery factor of these two cases are less than that of the base case by 10.44% and 0.84%, respectively. It can be remarkably seen that the recovery factor of well pattern 4 is just slightly less than that of the base case with shorter production time. This type of well arrangement covers the flooding area that gives better sweep performance than the case of same well distance in single line arrangement. Even most of water still floods in the lower portion and gas overrides, low residual oil saturation apparently shows better oil drainage than the case of well pattern 3. The oil saturation profiles at the end of production under well placement patterns 3 and 4 are presented in Figures 5.31 and 5.32, respectively.

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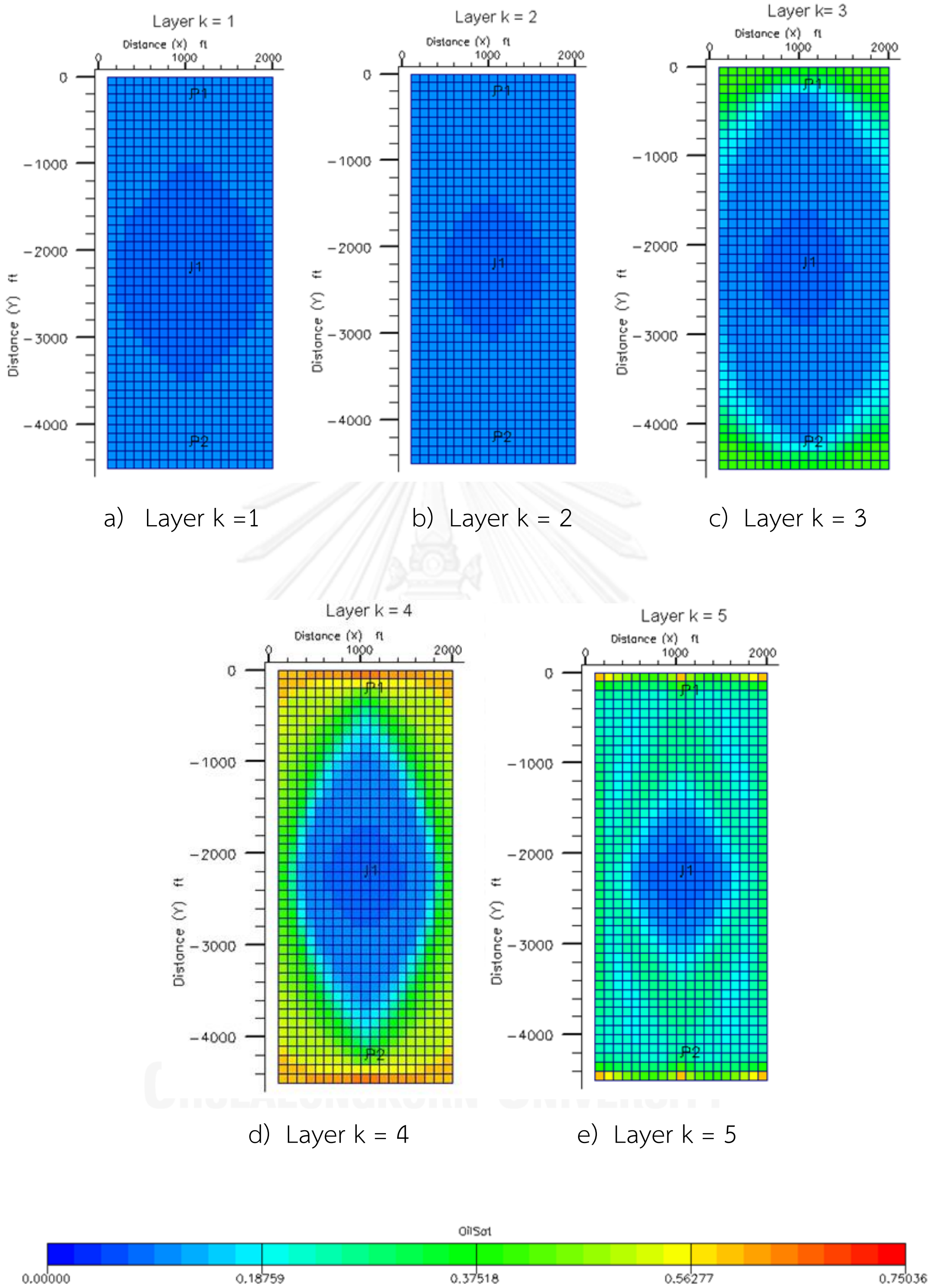
Table 5. 7 Summary of results for water injection alternating gas dumpflood for various well locations.

Well pattern	Recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative water production (MMSTB)	Cumulative water injection (MMSTB)	Cumulative gas production (BCF)	Barrel of oil equivalent (MMSTB)	Production time (Years)
1 (Base case)	72.27	7.136	0.775	2.252	21.137	10.659	8.7
2	49.67	4.904	0.134	0.451	22.366	8.632	4.0
3	61.83	6.104	0.237	0.908	22.239	9.812	7.5
4	71.43	7.052	0.147	1.359	22.245	10.760	4.8



a) Layer k =1 b) Layer k = 2 c) Layer k = 3

d) Layer k = 4 e) Layer k = 5

Figure 5. 28 Oil saturation profile at the end of production by water injection alternating gas dumpflood under well arrangement pattern 1.

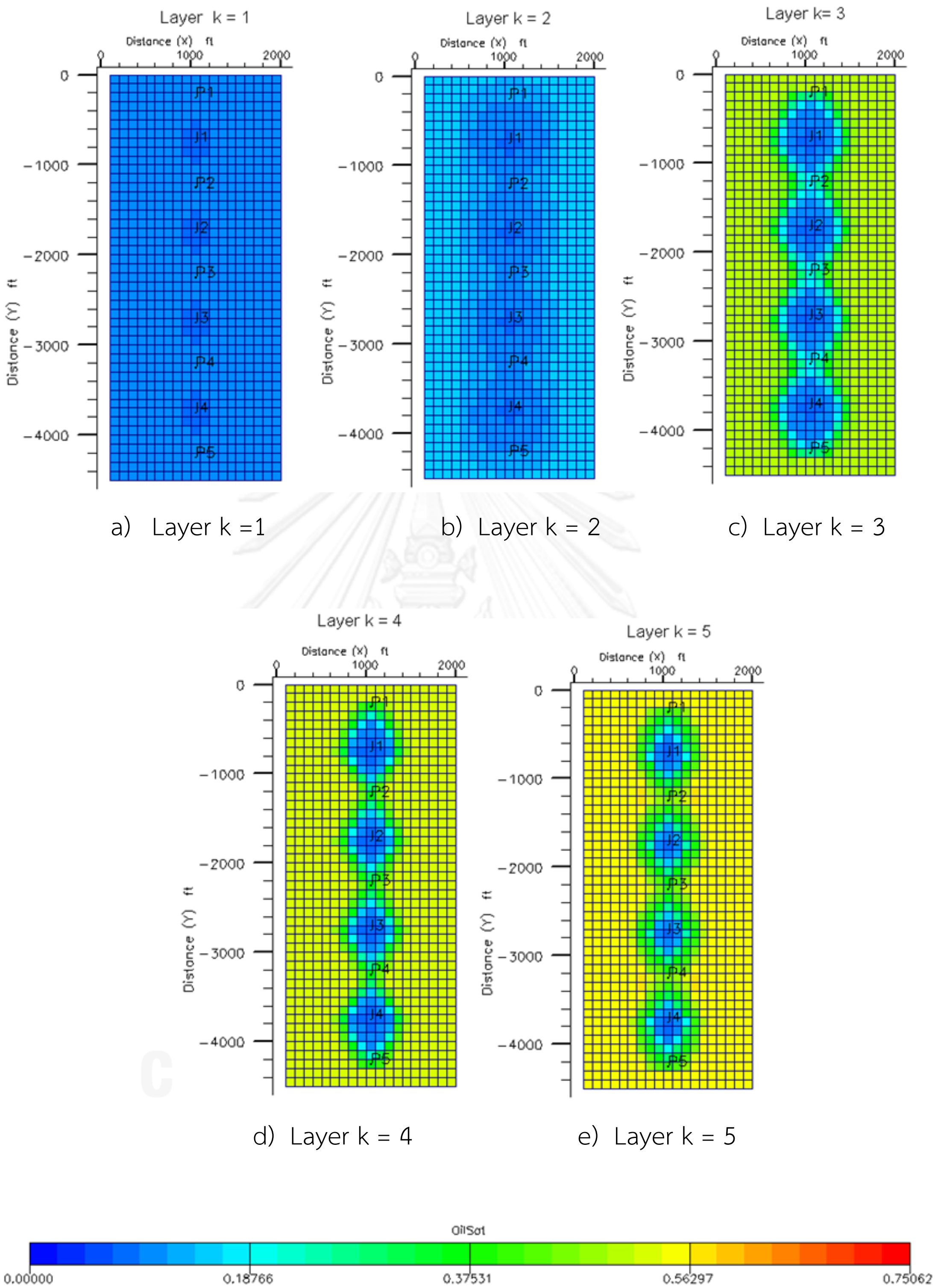
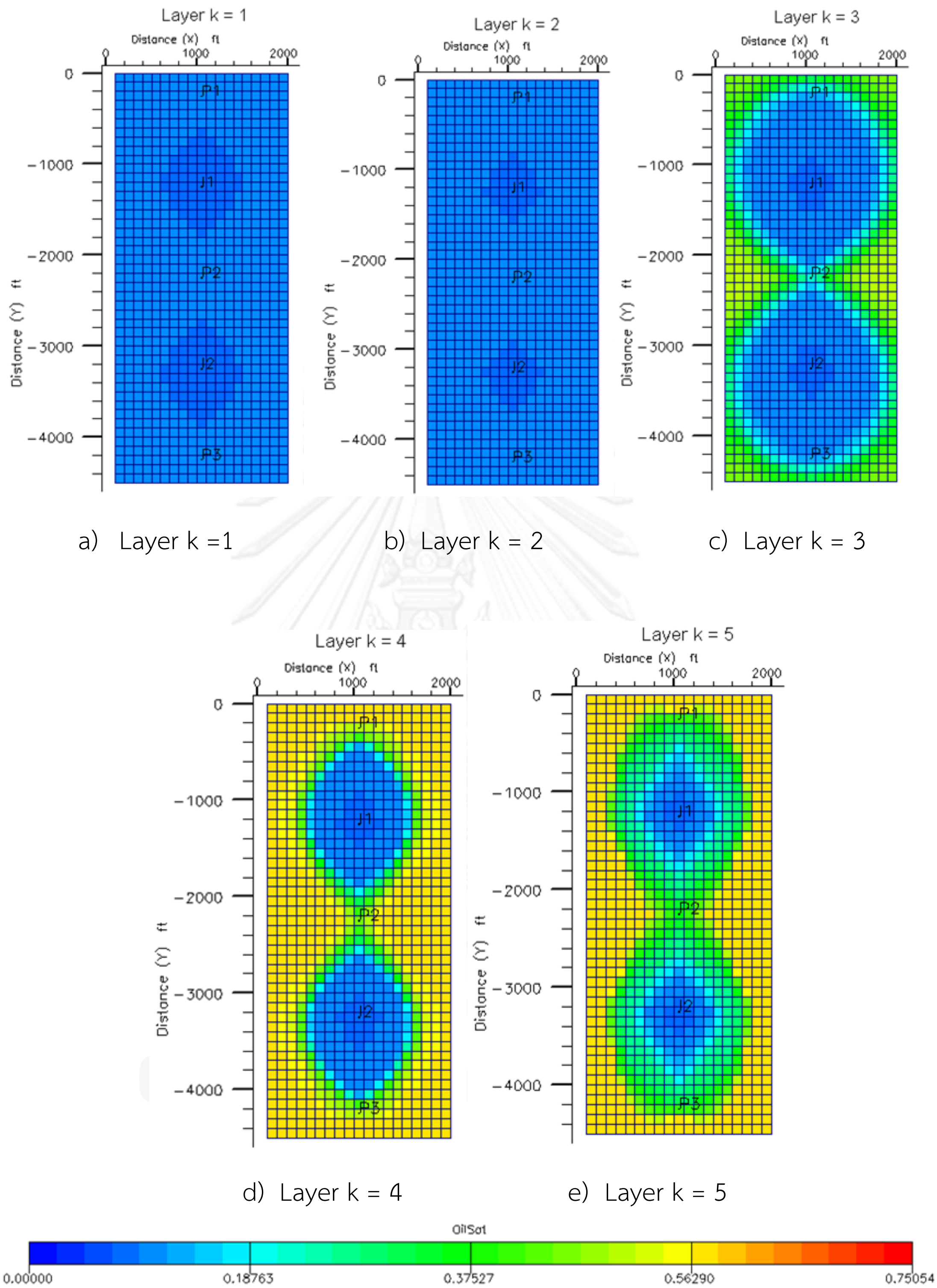


Figure 5. 29 Oil saturation profile at the end of production by water injection alternating gas dumpflood under well arrangement pattern 2.



a) Layer k =1 b) Layer k = 2 c) Layer k = 3

d) Layer k = 4 e) Layer k = 5

Figure 5. 30 Oil saturation profile at the end of production by water injection alternating gas dumpflood under well arrangement pattern 3.

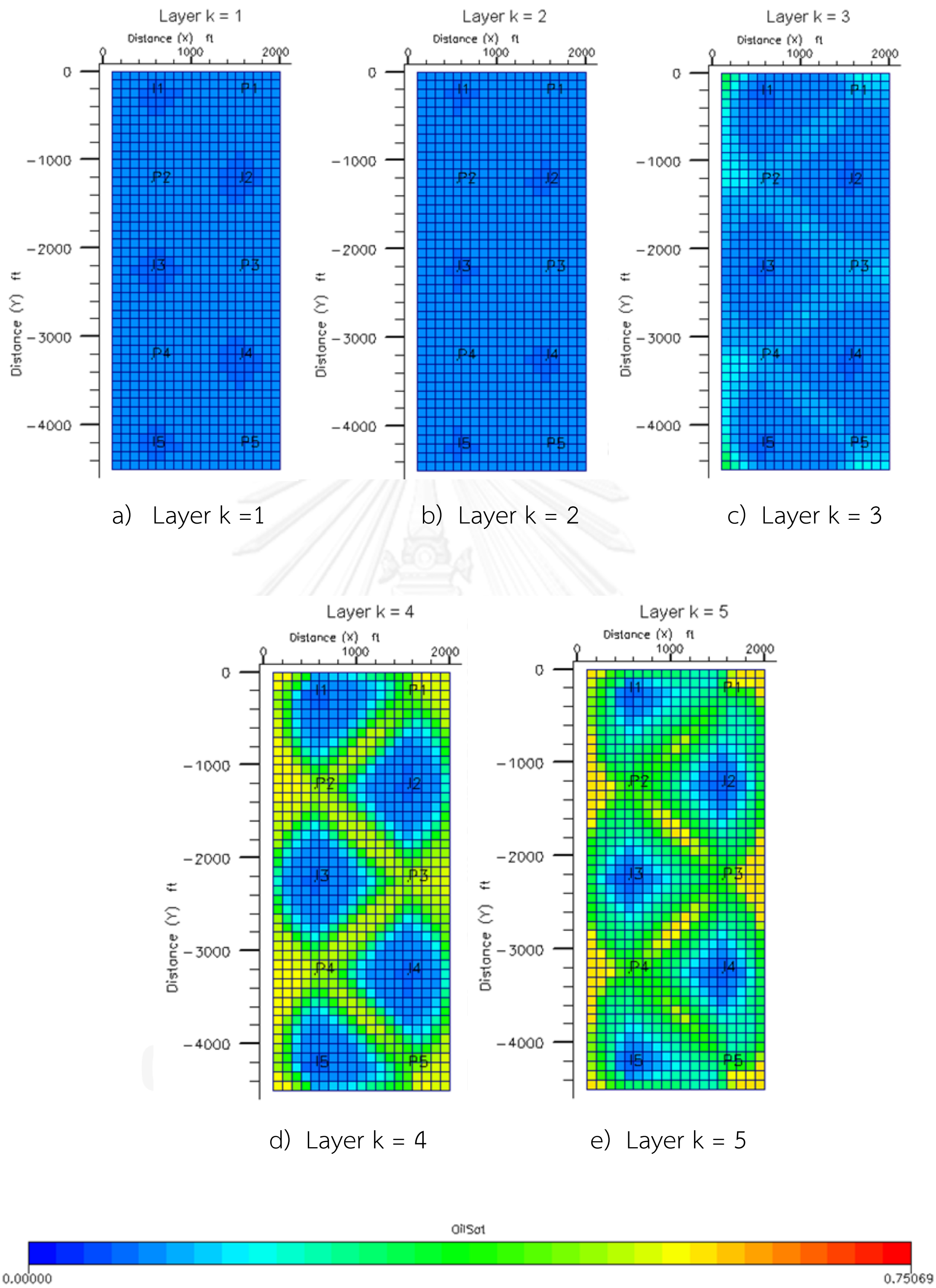


Figure 5. 31 Oil saturation profile at the end of production by water injection alternating gas dumpflood under well arrangement pattern 4.

Figure 5.28 shows oil production rate versus time. The oil production rate is constant at early time and starts to decline at different times for different well patterns. Comparing the case of well pattern 4 with the base case, the plateau production duration at total 10,000 STB/D from five producing well is longer than that for the base case. That is because of the oil production rate per well in this case is lower than the one for the base case (2,000 STB/D versus 5,000 STB/D). Production wells can keep producing at small pressure drawdown until the field oil production rate reaches the economic limit. In term of production life, well pattern 4 requires less amount of time to produce. However, the requirements of ten wells drilled resulting in high capital investment. Thus, the most suitable well pattern chosen in this study for water injection alternating gas dumpflood is the base case with three wells that are 2,000 ft. apart.

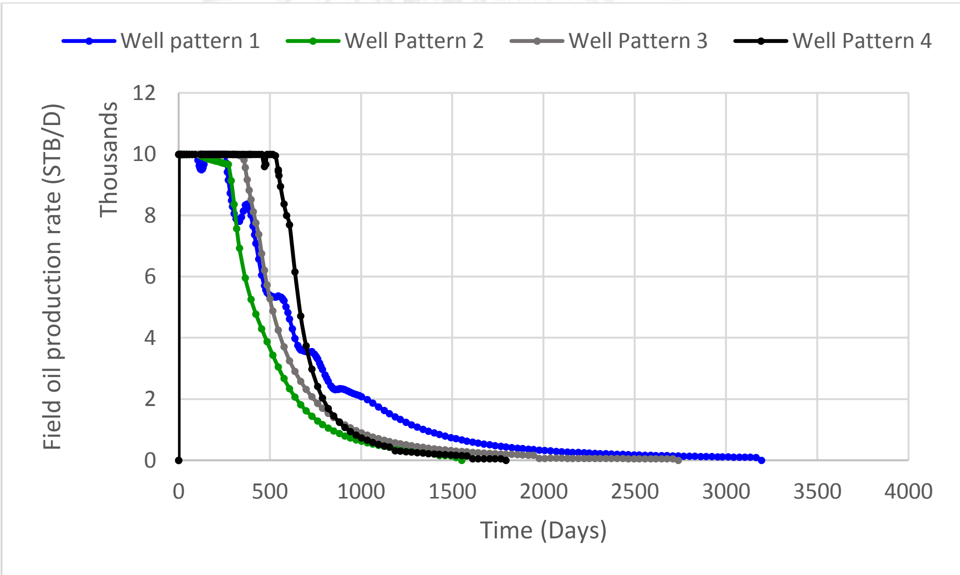


Figure 5. 32 Field oil production rate by water injection alternating gas dumpflood at different well patterns.

In summary, well pattern 1 is considered to be the most suitable well location under the method of water injection alternating gas dumpflood. The highest recovery factor of 72.27% requires 2.25 MMSTB of injected water to obtain 7.135 MMSTB total oil production. Comparison with the base case result by the method of conventional WAG, the requirement of total water injection and production time by both methods are not much different. The limited amount of gas in the dumpflood process results in 3.62% lower recovery factor (0.358 MMSTB of oil production) than the method of conventional WAG.

5.2.3 Effect of water and gas injection rates

As water and gas injection rates may have some effects on the recovery of oil, this study investigates different combinations of water and gas injection rates for conventional WAG and different water injection rates for water injection alternating gas dump flood.

5.2.3.1 Conventional WAG injection

Using the same injection and production constraints as the base case, well schedules with different water and gas injection rates in various cases are summarized as shown in Table 5.8. From the results summarized in Table 5.9, it can be referred that increasing water injection rate can speed up the recovery process but slightly decrease the cumulative oil production when compared with cases having the same gas injection rate. This higher rate of water injection allows higher amount of water to enter the reservoir, accelerating the displacement. Thus, an early water breakthrough is encountered. Besides, too high water injection rate cannot be fully operated during the early period of production since the bottomhole pressure must not exceed 3,100 psia. For gas injection rate, changing gas injection rate does not have much effect on the final oil recovery but it has a significant effect on production time. Higher gas injection rate speeds up the recovery process, thus takes a shorter time to produce. In addition, the cumulative water production is smaller as gas injection rate is increased due to shorter time to produce fluids at the producers.

Table 5. 8 Summary of well schedules simulated by conventional WAG injection under the variation of water and gas injection rates.

Case	Water injection rate (STB/D)	Gas injection rate (MMSCF/D)	Liquid production rate (STB/D)
1	5,000	5	5,000
2	6,000	5	5,000
3	7,000	5	5,000
4	5,000	10	5,000
5	6,000	10	5,000
6	7,000	10	5,000
7 (Base case)	5,000	15	5,000
8	6,000	15	5,000
9	7,000	15	5,000
10	5,000	20	5,000
11	6,000	20	5,000
12	7,000	20	5,000

Comparing the base case with case 1 and case 10 which have the same water injection rate but different gas injection rates. The cumulative oil production of case 10 as presented in Figure 5.33 shows higher increment of total field oil production during 1,000 – 2,000 days. Although case 10 (water injection rate of 5,000 barrels per day and gas injection rate of 20 million standard cubic feet per day) yields a slightly lower oil production than case 1, which gives the highest recovery factor, it takes a much shorter time to produce and has much less amounts of water injection and production. Thus, this case is considered as the optimal case for conventional WAG process.

Table 5. 9 Summary of results for conventional WAG injection under the variation of water and gas injection rate.

Case	Recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative water production (MMSTB)	Cumulative water injection (MMSTB)	Cumulative gas production (BCF)	Cumulative gas injection (BCF)	Barrel of oil equivalent (MMSTB)	Production time (Years)
1	76.42	7.545	1.477	2.270	37.638	35.440	7.911	20.7
2	76.29	7.532	1.727	2.565	36.047	33.727	7.919	19.8
3	76.27	7.530	1.689	2.510	36.658	34.461	7.896	19.9
4	75.85	7.489	1.205	2.270	37.634	35.197	7.895	11.3
5	75.78	7.482	1.365	2.480	36.155	33.721	7.887	10.8
6	75.67	7.471	1.341	2.444	36.026	33.587	7.878	10.7
7 (Base case)	75.89	7.493	1.010	2.261	38.309	35.838	7.905	8.4
8	75.82	7.486	1.113	2.397	37.034	34.557	7.899	8.1
9	75.70	7.474	1.125	2.425	36.139	33.665	7.886	7.8
10	75.98	7.502	0.859	2.249	38.832	36.366	7.913	7.0
11	75.90	7.493	0.941	2.367	37.161	34.696	7.904	6.7
12	75.73	7.477	0.926	2.372	35.900	33.438	7.887	6.4

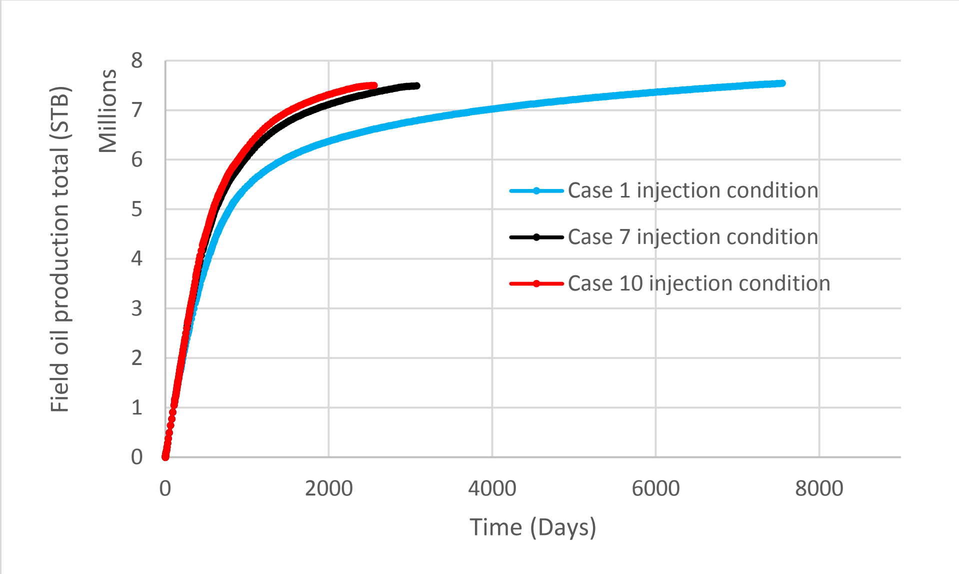


Figure 5. 33 Total field oil production by conventional WAG injection comparing case 1 and case 10 injection condition.

5.2.3.2 Water injection alternating gas dumpflood

In order to observe the effect of production performance from different water injection rates and maximize the cumulative oil production, selected water injection rates varying from 2,000 to 7,000 STB/D are simulated under the same constraints as the base case. Summary of well schedules investigated in this section are tabulated in Table 5.10.

Table 5. 10 Summary of well schedules simulated by the method of water injection alternating gas dumpflood under the variation of water injection rate.

Case	Water injection rate (STB/D)	Gas dump rate (MSCF/D)	Liquid production rate (STB/D)
1	2,000	uncontrolled	5,000
2	3,000	uncontrolled	5,000
3	4,000	uncontrolled	5,000
4 (Base case)	5,000	uncontrolled	5,000
5	6,000	uncontrolled	5,000
6	7,000	uncontrolled	5,000

The results in Table 5.11 shows that higher amount of oil recovery can be obtained in shorter production time from the case of higher water injection rate. As there is limited amount of gas flowing to the oil reservoir, the higher the amount of water injection, the better the oil displacement. The liquid production rate from each case remains constant at early time as presented in Figure 5.34. Higher water injection rate can slightly extend the plateau oil production. When the oil production rate starts to decline, the case with higher water injection rate can produce at higher oil rate compared to the case of low water injection rate. Figure 5.35 shows the reservoir pressure maintenance by water injection alternating gas dumpflood from different water injection rates. From this figure, the case of higher water injection rate has more ability to maintain reservoir pressure than the case of lower water injection rate.

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Table 5. 11 Summary of results for water injection alternating gas dumpflood under the variation of water injection rate.

Case	Recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative water production (MMSTB)	Cumulative water injection (MMSTB)	Cumulative gas production (BCF)	Barrel of oil equivalent (MMSTB)	Production time (Years)
1	68.37	6.750	0.377	1.823	21.693	10.367	10.8
2	70.11	6.922	0.583	2.005	21.538	10.513	10.0
3	71.41	7.050	0.717	2.180	21.339	10.607	9.3
4 (Base case)	72.27	7.136	0.775	2.252	21.137	10.659	8.7
5	72.49	7.157	0.905	2.402	21.018	10.661	8.4
6	72.50	7.158	0.935	2.421	20.946	10.650	8.3

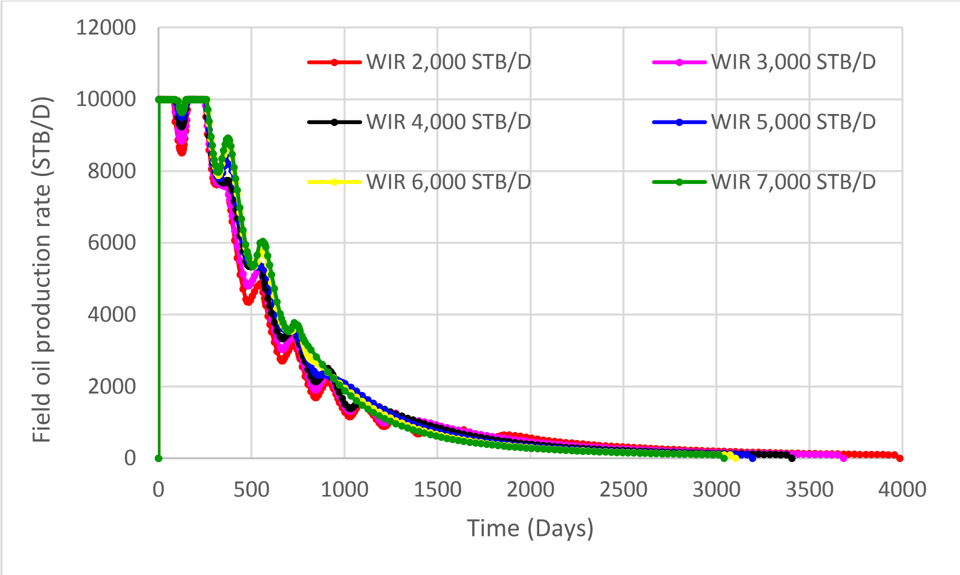

Figure 5. 34 Field oil production rate by water injection alternating gas dumpflood for different water injection rate.

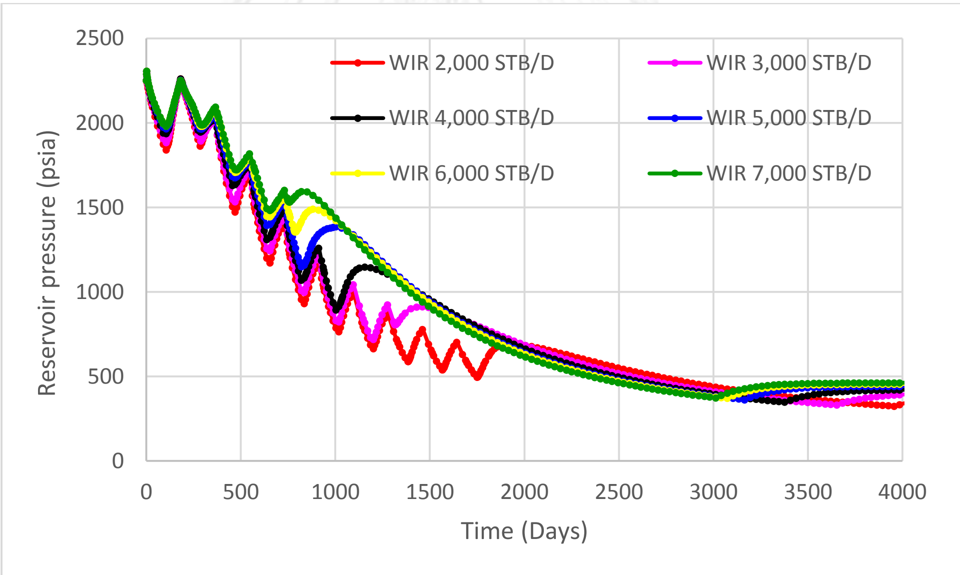

Figure 5. 35 Reservoir pressure by water injection alternating gas dumpflood for different water injection rate.

The total filed oil production presented in Figure 5.36 shows an increase in oil recovery from 6.750 to 7.158 MMSTB as water injection rate is increased from 2,000 to 7,000 STB/D. From the results shown in Table 5.11, the amount of additional oil gained from the case of 6,000 STB/D water injection rate is 21,693 STB higher than the base case while the additional injected water is 150,733 STB more than the base case. The case of 7,000 STB/D water injection rate yields 22,385 STB higher total oil production with 169,717 STB water injection more than the base case. If the amount of cumulative gas production is taken into account, the case of 6,000 STB/D water injection rate gives the highest BOE with a short production life. Thus, the case of water injection rate at 6,000 STB/D cooperated with 5,000 STB/D liquid production is likely to be the best condition of water injection alternating gas dumpflood.

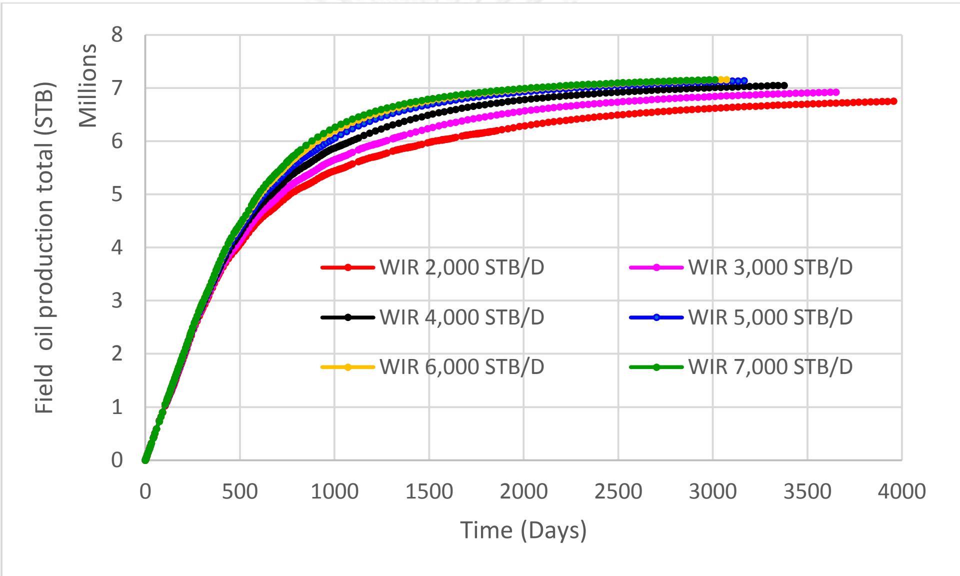

Figure 5. 36 Total field oil production by water injection alternating gas dumpflood at different water injection rate.

When comparing the best case of conventional WAG with the best case of the proposed water injection alternating gas dumpflood, conventional WAG has a slightly higher oil recovery (0.345 MMSTB) and slightly lower requirement for water injection and production time. However, it requires 36.37 billion cubic feet of gas injection while the proposed method does not.

5.2.4 Effect of injection duration and slug size

Since the slug size and ratio of water and gas injection duration may impact production performance of both processes, these parameters are examined in this study. Continuing from the best injection condition obtained from the previous part, the injection slug size of one month and three months are investigated under the variation of water to gas injection duration ratio.

5.2.4.1 Conventional WAG

This section continues from case 10 injection condition that yield the best performance over the others. The injection slug size of one month and three months are investigated under the variation of water to gas duration ratio.

Simulation results show that variation in slug size and ratio of water and gas injection duration has a small impact on total oil recovery as tabulated in Tables 5.12 and 5.13. Most of the cases in Table 5.12, which have small slug sizes give slightly higher recovery than the cases in Table 5.13, which have large slug sizes when compared with equal injection duration ratio. The injection with smaller slug size allows the displacing phase to flood in more cycles than the case with bigger slug size. Smaller slug can improve the displacement efficiency of the flooding process.

To investigate the effect of water injection duration, three cases operating with the same gas injection duration are compared. These are case 3 (1:3 injection duration ratio), case 5 (2:3 injection duration ratio) and case 8 (3:3 injection duration ratio). The results from simulation show that longer water injection duration can speed up the oil production as can be seen in Figure 5.37.

Figure 5.38 shows the effect of longer gas injection duration to the cumulative oil production. Case 3 with 1:3 injection duration takes the longest time on gas injection in each cycle. The total field oil production from this case is slightly lower than those for case 2 (1:2 injection duration ratio) and case 1 (1:1 injection duration ratio).

For conventional WAG, case 5 that is operated with 2:3 injection duration ratio yields the best recovery performance compared to the others. However, the recovery is not much different from those in other cases. The optimal duration to inject water and gas depends on the availability of the fluids for injection as well as the cost to inject them. As the water injection duration is longer, cumulative water injection increases while cumulative gas injection decreases.

Table 5. 12 Summary of results for conventional WAG injection for injection duration based on 1-month slug size.

Case	Slug size (months)	Water : gas duration ratio	Recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative water production (MMSTB)	Cumulative water injection (MMSTB)	Cumulative gas production (BCF)	Cumulative gas injection (BCF)	Barrel of oil equivalent (MMSTB)	Production time (Years)
1	1	1:1	76.07	7,511	0.956	2.235	42.163	39.692	7.923	7.50
2		1:2	75.91	7.495	0.737	1.917	47.606	45.103	7.912	8.09
3		1:3	75.79	7.483	0.529	1.625	50.399	47.960	7.889	8.25
4		2:1	75.68	7.472	1.096	2.500	35.901	33.445	7.881	6.75
5		2:3	76.12	7.516	0.821	2.087	44.164	41.674	7.931	7.67
6		3:1	75.42	7.447	1.220	2.699	34.038	31.595	7.854	6.58
7		3:2	75.78	7.481	0.966	2.365	36.535	34.075	7.892	6.75

Table 5. 13 Summary of results for conventional WAG injection for various injection duration based on 3-month slug size.

Case	Slug size (months)	Water : gas duration ratio	Recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative water production (MMSTB)	Cumulative water injection (MMSTB)	Cumulative gas production (BCF)	Cumulative gas injection (BCF)	Barrel of oil equivalent (MMSTB)	Production time (Years)
8 (Base case)	3	3:3	75.98	7.502	0.859	2.249	38.832	36.366	7.913	7.00
9		3:6	76.03	7.507	0.555	1.777	44.640	42.132	7.925	7.59
10		3:9	75.67	7.471	0.569	1.811	46.963	44.518	7.879	7.84
11		6:3	75.38	7442	1.023	2.476	35.083	32.632	7.851	6.58
12		6:9	75.58	7462	0.599	1.813	42.427	39.914	7.881	7.25
13		9:3	75.01	7.406	1.269	2.711	35.337	32.896	7.813	6.75
14		9:6	75.14	7.418	1.235	2.627	38.484	36.030	7.827	7.17

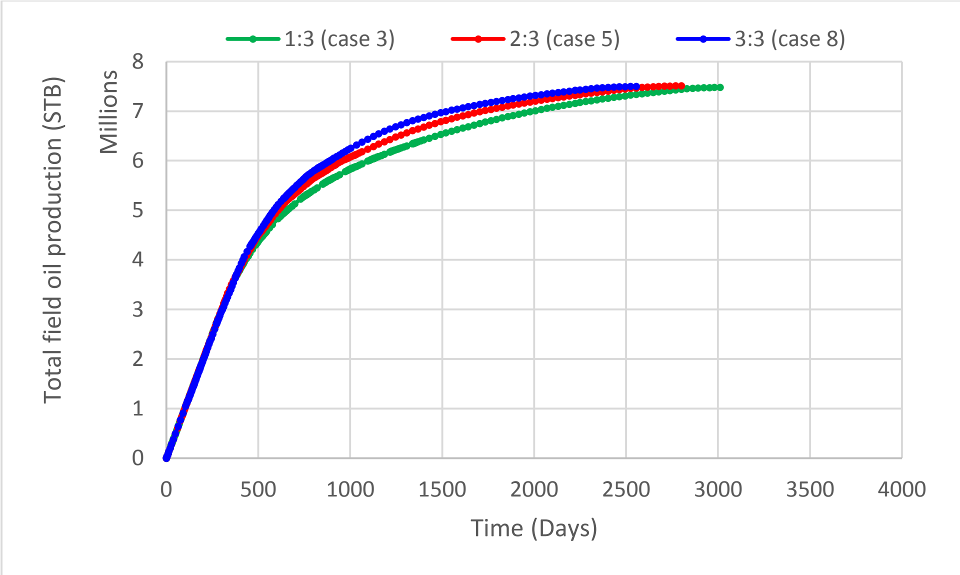

Figure 5. 37 Total field oil production by conventional WAG under the variation of water injection duration.

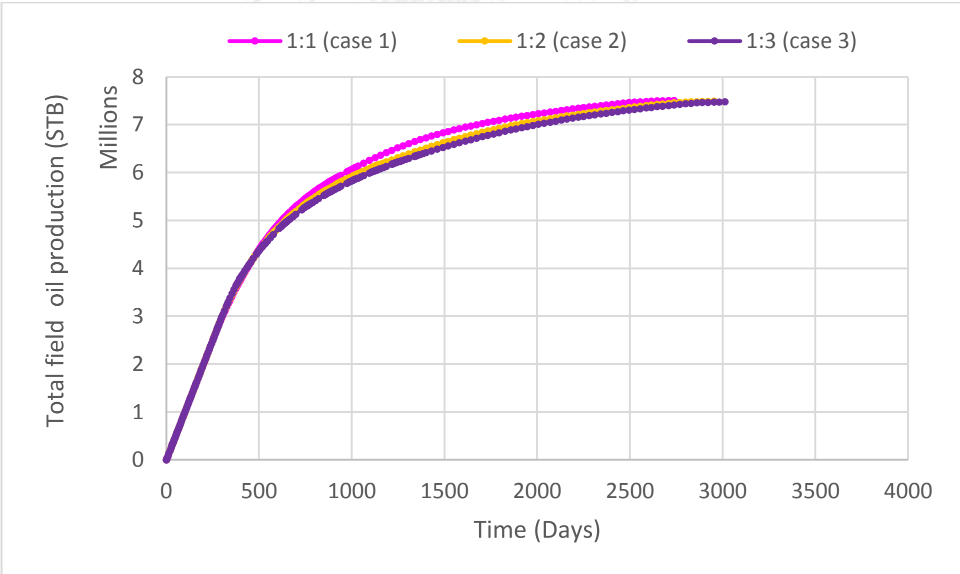

Figure 5. 38 Total field oil production by conventional WAG under the variation of gas injection duration.

5.2.4.2 Water injection alternating gas dumpflood

Table 5.14 and 5.15 show simulation results obtained from two different slug sizes with different water to gas injection duration ratio. In overall, they are not much different due to the limited amount of gas in the bottom reservoir.

The recovery factor from case 1 to 3 and case 8 to 10 decreases in the same trend due to an increase of gas dumpflood duration. A similar trend is observed in Figure 5.39 which illustrates the total field oil production for 1-month slug size with water to gas injection duration ratio varied from 1:1 to 1:3. Applying gas dumpflood in longer duration means letting gas flow into the oil reservoir with less amount of water. The gas is likely to flood only in the upper portion of oil reservoir.

In summary, the case of injecting water for 2 months and dumping gas into the oil reservoir for 1 month yields the highest recovery efficiency of 72.94 %. Similar to conventional WAG, as the water injection duration becomes longer, cumulative water injection increases.

Comparing between the best injection condition of conventional WAG and water injection alternating gas dumpflood, the highest recovery factor by both methods is obtained from the injection based on one-month slug size. At ratio 2:3 (water : gas injection duration) of conventional WAG results in 3.18% higher recovery factor than at ratio 2:1 of water injection alternating gas dumpflood. Total field gas and water injection of 41.674 BCF and 2.087 MMSTB, respectively are needed for the operation of conventional WAG while water injection alternating gas dumpflood requires slightly higher amount of injected water (2.807 MMSTB).

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Table 5. 14 Summary of results for water injection alternating gas dumpflood for various injection duration based on 1-month slug size.

Case	Slug size (months)	Water : gas duration ratio	Recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative water production (MMSTB)	Cumulative water injection (MMSTB)	Cumulative gas production (BCF)	Barrel of oil equivalent (MMSTB)	Production time (Years)
1	1	1:1	72.43	7.151	1.008	2.479	21.092	10.667	8.8
2		1:2	70.55	6.965	0.709	2.125	21.453	10.542	9.5
3		1:3	69.08	6.821	0.531	1.951	21.670	10.433	10.0
4		2:1	72.94	7.201	1.266	2.807	20.699	10.652	8.1
5		2:3	71.69	7.078	0.739	2.173	21.255	10.622	8.9
6		3:1	72.42	7.151	1.265	2.778	20.725	10.606	8.0
7		3:2	72.90	7.197	1.103	2.640	20.757	10.657	8.1

Table 5. 15 Summary of results for water injection alternating gas dumpflood for various injection duration based on 3-month slug size.

Case	Slug size (months)	Water : gas duration ratio	Recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative water production (MMSTB)	Cumulative water injection (MMSTB)	Cumulative gas production (BCF)	Barrel of oil equivalent (MMSTB)	Production time (Years)
8 (Base case)	3	3:3	72.49	7.157	0.905	2.402	21.018	10.661	8.4
9		3:6	71.48	7.057	0.637	2.120	21.378	10.621	9.1
10		3:9	70.06	6.917	0.481	1.994	21.515	10.504	9.4
11		6:3	72.37	7.145	1.058	2.565	20.799	10.613	8.0
12		6:9	71.22	7.031	0.697	2.127	21.255	10.575	8.6
13		9:3	72.15	7.124	1.458	3.013	20.634	10.564	8.1
14		9:6	71.53	7.062	0.838	2.297	20.957	10.556	8.1

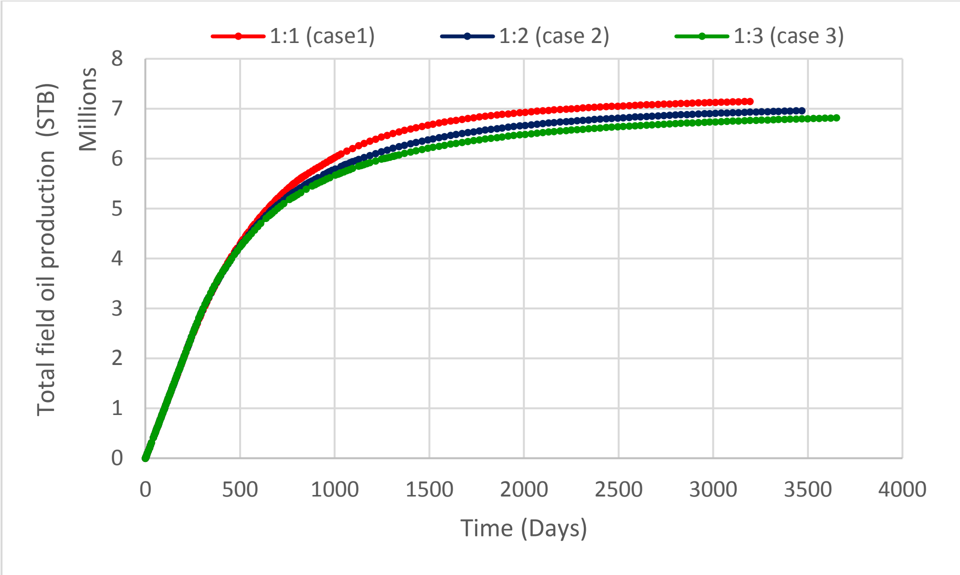


Figure 5. 39 Total field oil production by water injection alternating gas dumpflood based on 1-month slug size with water to gas duration ratio varied from 1:1 to 1:3.

5.3 Sensitivity analysis

Due to uncertainties of reservoir parameters, sensitivity analysis can indicate the effects that might occur in both processes of water injection alternating gas dumpflood and conventional WAG injection. The parameters investigated in this study include

- Vertical to horizontal permeability ratio
- Thickness of source gas reservoir
- Depth difference between gas and oil reservoirs
- Residual oil saturation
- Oil viscosity

Well location based on well pattern 1 with the most suitable injection and production conditions for both methods is still used when performing sensitivity analysis. For conventional WAG injection, two-month water injection at 5,000 STB/D alternating with three-month gas injection at 20 MMSCF/D is the injection condition studied. The injection scenario with two-month water injection at 6,000 STB/D alternating with one-month gas dumpflood is set as an injection condition in the method of water injection alternating gas dumpflood.

5.3.1 Effect of vertical to horizontal permeability ratio

Vertical permeability strongly affects the flow of fluid in the vertical direction. When changing this ratio, the recovery performance of the process may also change. The vertical to horizontal permeability ratios of 0.01, 0.1 and 0.3 are simulated to observe the sensitivity of production performance. The values of vertical and horizontal permeability for different anisotropy ratios used in reservoir simulation are summarized in Table 5.16.

Table 5. 16 Vertical and horizontal permeability used in reservoir simulation at different vertical to horizontal permeability ratios.

Case	Vertical to horizontal permeability ratio	K_v (md.)	K_h (md.)
1	0.01	1.26	126
2	0.1	12.6	126
3	0.3	37.8	126

For conventional WAG, the recovery factor obtained from the case of 0.01 vertical to horizontal permeability ratio is the highest (78.99%) as depicted in Figure 5.40. This is 2.87% and 3.71% higher than that for the case of 0.1 and 0.3 ratio, respectively. The reason is because low vertical permeability causes less gas overriding. As depicted in Figure 5.41, the oil can be thoroughly displaced by the stable front of water and gas in the horizontal direction and produced up to surface. In the case of higher permeability ratio, the high vertical permeability allows the injected gas to favorably flow in the upper portion rather than flooding the entire cross section (as illustrated in Figure 5.42 and 5.43 for the cases of 0.1 and 0.3 ratio, respectively). Even the case of 0.3 ratio has higher vertical permeability than the case of 0.1 ratio, the final recovery factor is in similar range to the one for the case of 0.1. However, the requirement of gas injection for case of 0.3 ratio is much higher than the one for the case of 0.1 (around 7.60 BCF). The summary of results by the method of conventional WAG are illustrated in Table 5.17.

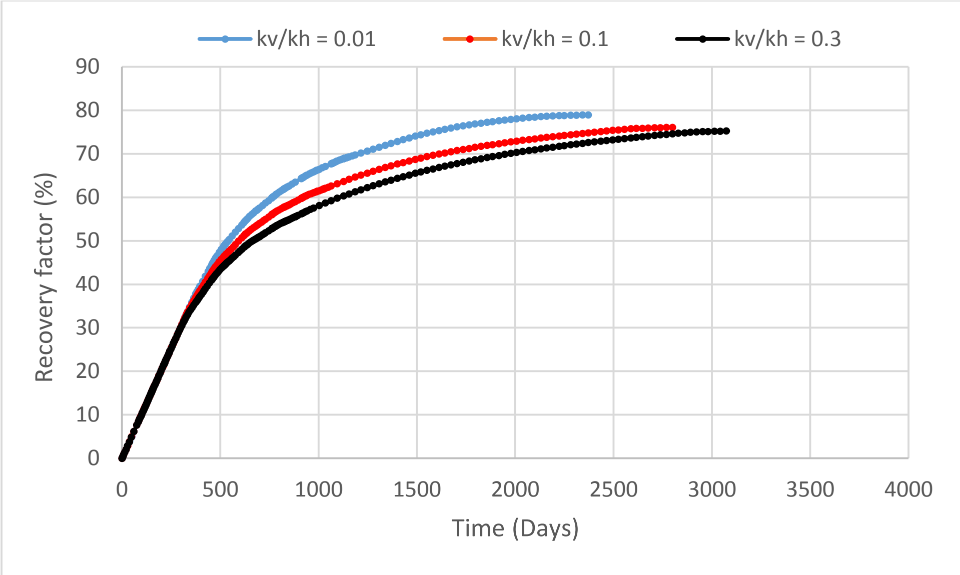
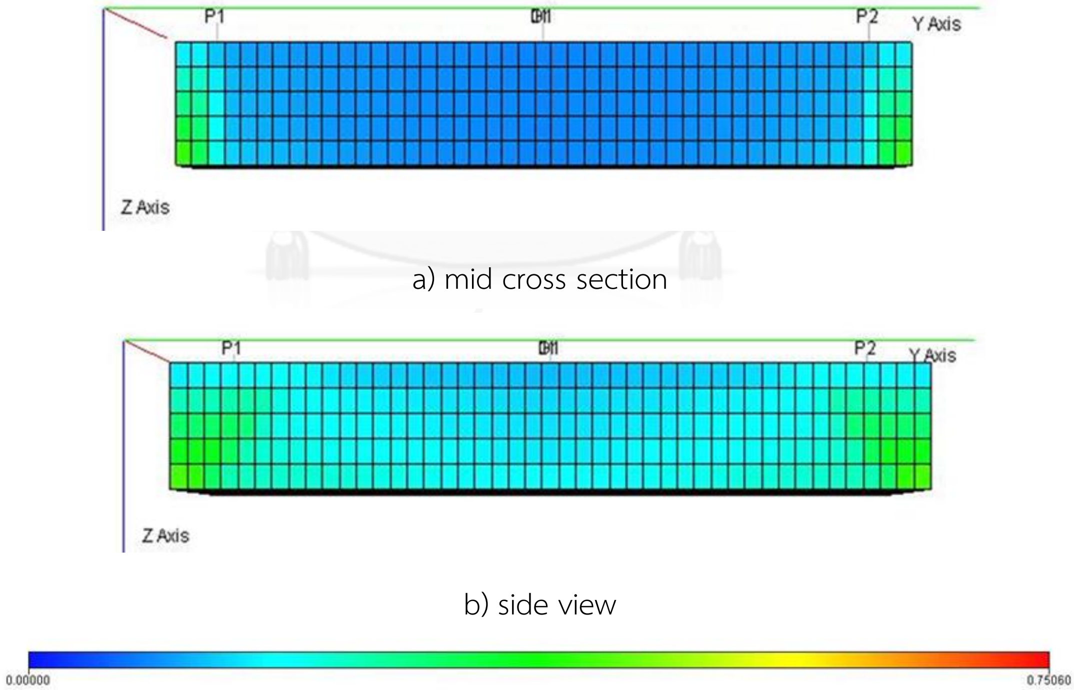


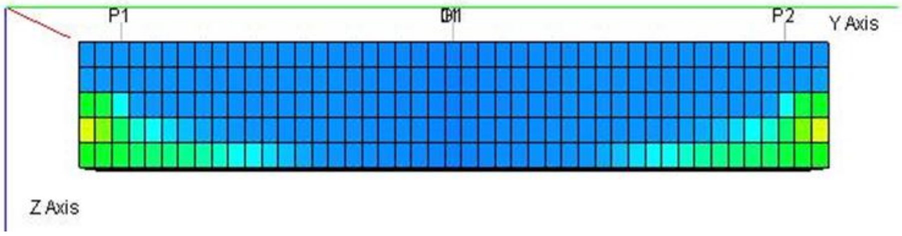
Figure 5. 40 Recovery factor by conventional WAG injection for various $\boldsymbol{k_v/k_h}$ ratios.



a) mid cross section

b) side view

Figure 5. 41 Oil saturation profile at the end of production for conventional WAG when $\boldsymbol{k_v/k_h}$ = 0.01.



a) mid cross section

b) side view

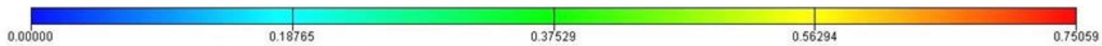
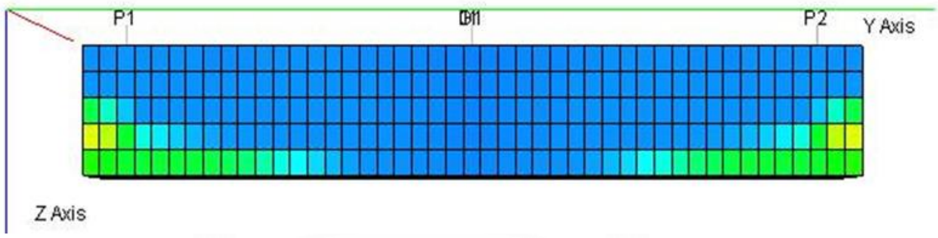


Figure 5. 42 Oil saturation profile at the end of production for conventional WAG when $\boldsymbol{k_v/k_h}$ = 0.1.



a) mid cross section

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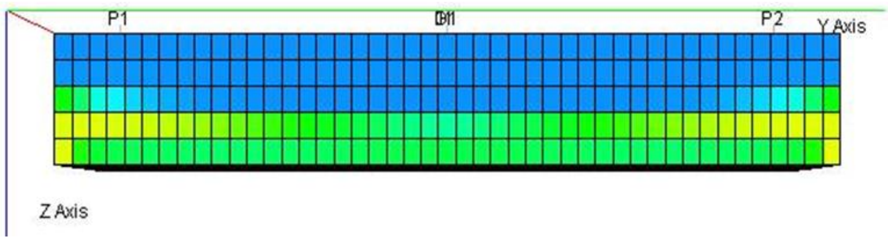

b) side view

Figure 5. 43 Oil saturation profile at the end of production for conventional WAG when $\boldsymbol{k_v/k_h}$ = 0.3.

Table 5. 17 Summary of results for conventional WAG for various $\boldsymbol{k_v/k_h}$ ratios.

Case	K_v/K_h	Recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative water production (MMSTB)	Cumulative water injection (MMSTB)	Cumulative gas production (BCF)	Cumulative gas injection (BCF)	Barrel of oil equivalent (MMSTB)	Production time (Years)
1	0.01	78.99	7.799	0.393	2.357	32.982	30.853	8.154	6.5
2	0.1	76.12	7.516	0.821	2.087	44.164	41.674	7.931	7.7
3	0.3	75.28	7.433	0.974	1.790	51.742	49.268	7.845	8.4

In the method of water injection alternating gas dumpflood, the case of low vertical to horizontal permeability ratio yields higher recovery factor than the case of high ratio as illustrated in Figure 5.44. From the results in Table 5.18, the case with 0.01 vertical to horizontal permeability ratio gives the highest recovery factor of 77 % which is 4.06% and 6.94% higher than the cases of 0.1 and 0.3, respectively.

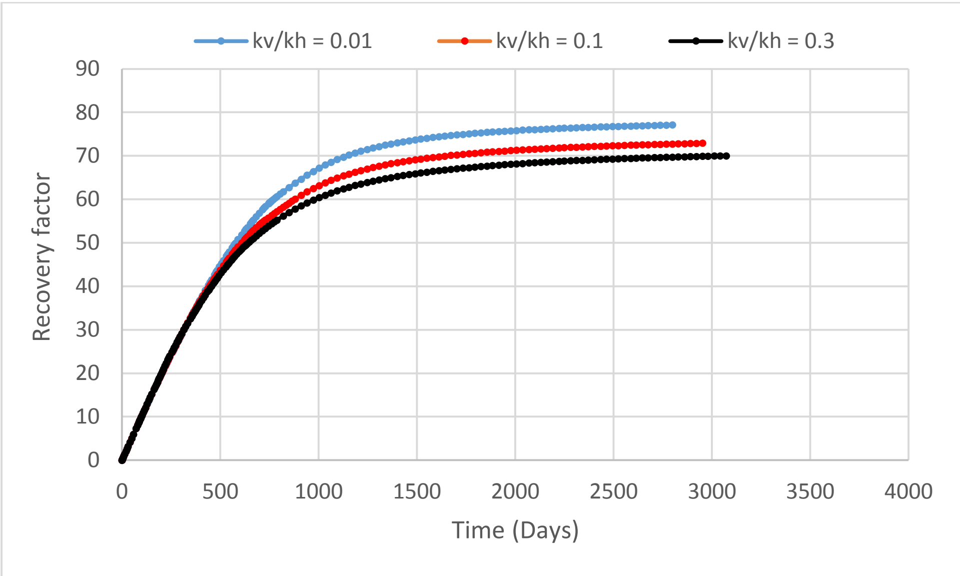

Figure 5. 44 Recovery factor by water injection alternating gas dumpflood for various k_v/k_h *ratios.*

Low vertical permeability can impede the flow of gas in the vertical direction and lessen the effect of gas overriding. Figures 5.45 to 5.47 display the oil saturation profiles at the end of production in different cases. The cases of 0.1 and 0.3 vertical to horizontal permeability ratio show the effect of gas overriding as can be observed from lower oil saturation in the upper part. At higher vertical permeability, the gas can easily flow upward. Very good displacement can be seen in the upper part. However, the lower part of the reservoir has high oil saturation because less amount of gas sweeps the area. Overall, the recovery factor becomes lower as a result of serious gas overriding problem.

Table 5. 18 Summary of results for water injection alternating gas dumpflood for various $\boldsymbol{k_v/k_h}$ *ratios.*

Case	K_v/K_h	Recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative water production (MMSTB)	Cumulative water injection (MMSTB)	Cumulative gas production (BCF)	Barrel of oil equivalent (MMSTB)	Production time (Years)
1	0.01	77.00	7.602	0.747	2.763	18.512	10.688	7.6
2	0.1	72.94	7.201	1.266	2.807	20.699	10.652	8.1
3	0.3	70.06	6.917	1.320	2.463	21.434	10.490	8.4

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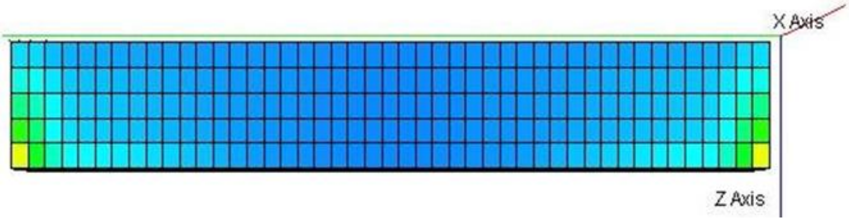
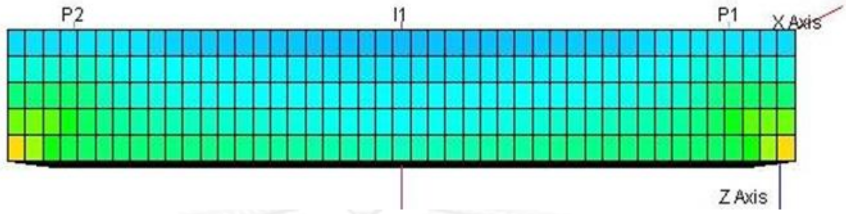


a) mid cross section



b) side view

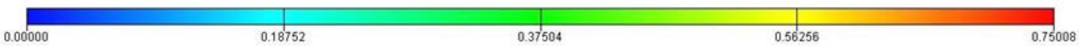
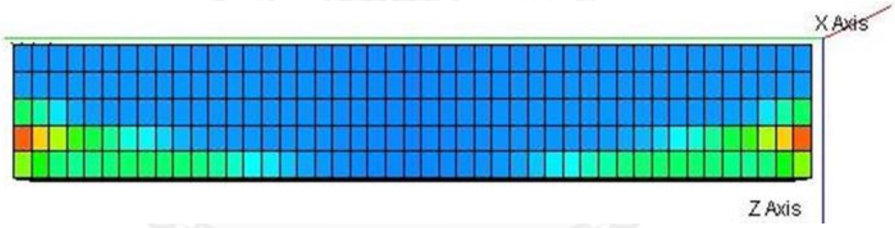
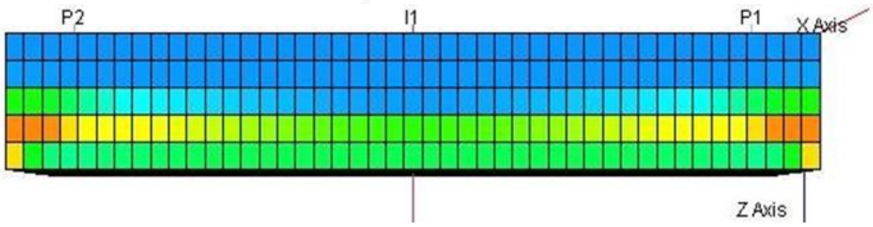


Figure 5. 45 Oil saturation profile at the end of production for water injection alternating gas dumpflood when $\boldsymbol{k_v/k_h}$ *= 0.01*

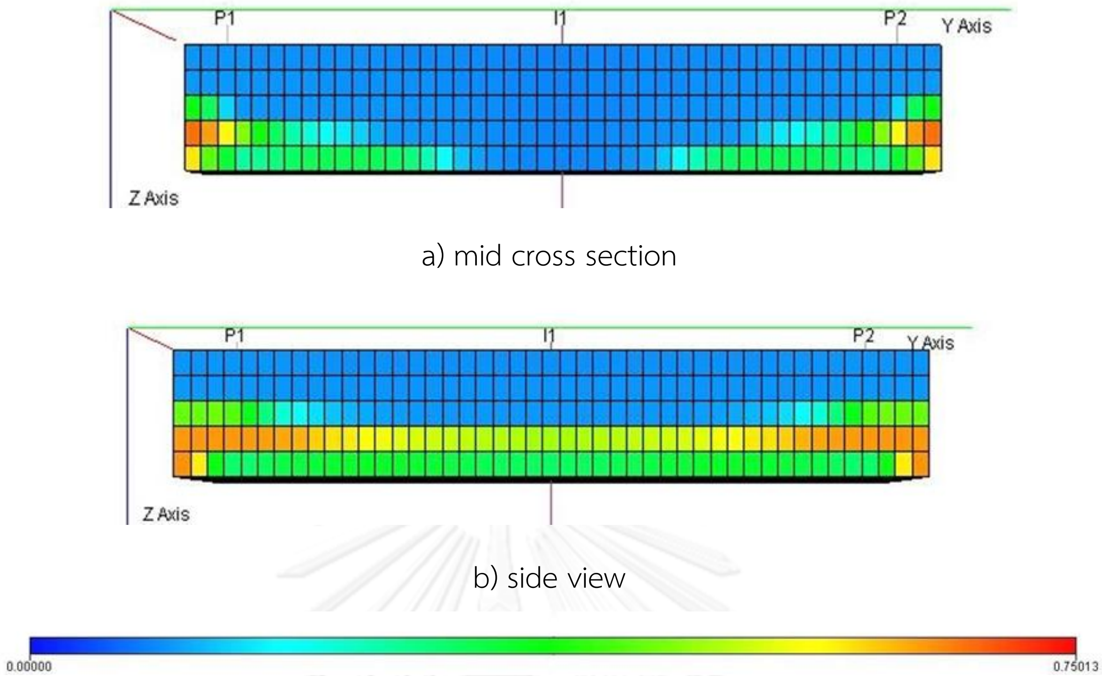


a) mid cross section



b) side view

Figure 5. 46 Oil saturation profile at the end of production for water injection alternating gas dumpflood when $\boldsymbol{k_v/k_h}$ *= 0.1.*



a) mid cross section

b) side view

Figure 5. 47 Oil saturation profile at the end of production for water injection alternating gas dumpflood when $\boldsymbol{k_v/k_h}$ *= 0.3.*

According to variation of vertical to horizontal permeability ratio in each case also applied in bottom gas reservoir, the flow of gas from bottom gas reservoir shows different behavior of gas dumpflood (as presented in Figure 5.48). In the case of low vertical permeability as observed from the case of 0.01 ratio, the gas in bottom reservoir tends to flow in horizontal direction rather than vertical toward the injector (cross-flowing well to target oil reservoir). This lessen the ease of gas to flow and hence shows a lower constant rate of gas dump compare to others cases. From Figure 5.49, the filed gas production rate results from this case not only yields in the lower range compared to the others but gas breakthrough also occurs afterward.

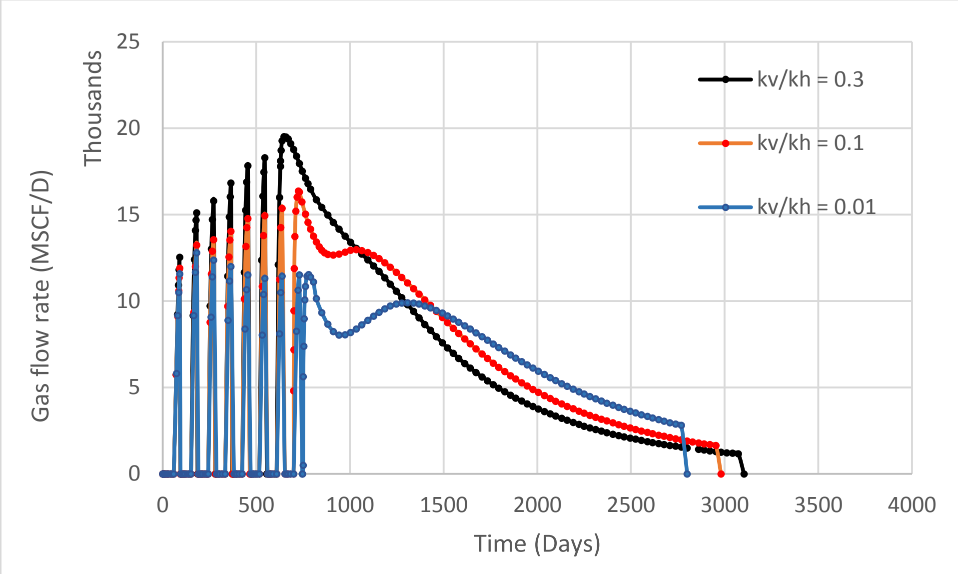


Figure 5. 48 Gas flow rate from the bottom gas reservoir in water injection alternating gas dumpflood for various $\boldsymbol{k_v/k_h}$ ratios.

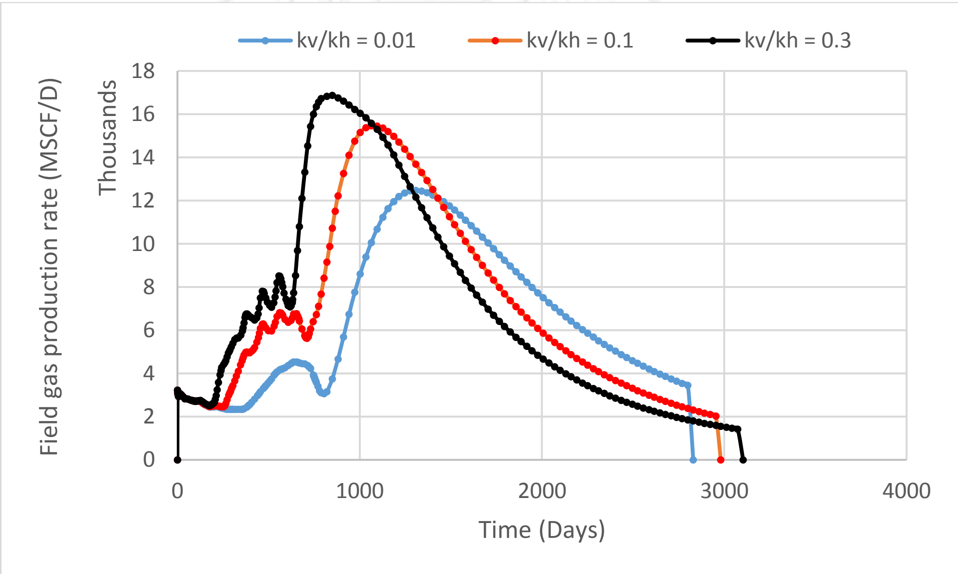


Figure 5. 49 Field gas production rate in water injection alternating gas dumpflood for various $\boldsymbol{k_v/k_h}$ ratios.

When comparing the results between conventional WAG and water injection alternating gas dumpflood, the recovery factor by conventional WAG is 1.99% higher than that by water injection alternating gas dumpflood (0.20 MMSTB higher) in the case of 0.01 vertical to horizontal permeability ratio. This higher oil recovery by conventional WAG requires around 0.41 MMSTB less amount of water injection but requires tremendous amount of gas injection (30.85 BCF). The difference in recovery factors by the two methods increases when the ratio of vertical to horizontal permeability increases. However, the requirement for gas injection also increases. At 0.1 ratio, recovery factor by conventional WAG is 3.19% higher than that by water injection alternating gas dumpflood. The total amount of gas injection in this case is 41 BCF. In addition, higher recovery factor around 5.26% by the method of conventional WAG can be obtained in the case of 0.3 ratio. This case requires the highest amount of total injected gas (49 BCF).

5.3.2 Effect of thickness of Source Gas Reservoir

As the amount of gas in the source gas reservoir may affect water injection alternating gas dumpflood, the influence of thickness of source gas reservoir is studied under the variation of 3 values. The selected 50, 100 and 150 ft. thicknesses of bottom gas reservoir are simulated to observe the oil recovery. Different thickness of source gas reservoir yields different storage capacity of gas reservoir. With the same fluid saturation, the increase in reservoir thickness directly increases the amount of original gas in place. The original gas in place for different cases are compared in Figure 5.50. Note that the thickness of gas reservoir does not affect conventional WAG injection as the process obtains gas from other source.

Not only the amount of original gas in place changes but also the initial reservoir pressure. Since the datum depth of gas reservoir in every case is set at the bottom most, changing the thickness causes change in initial pressure at the datum depth. These changes are tabulated in Table 5.19.

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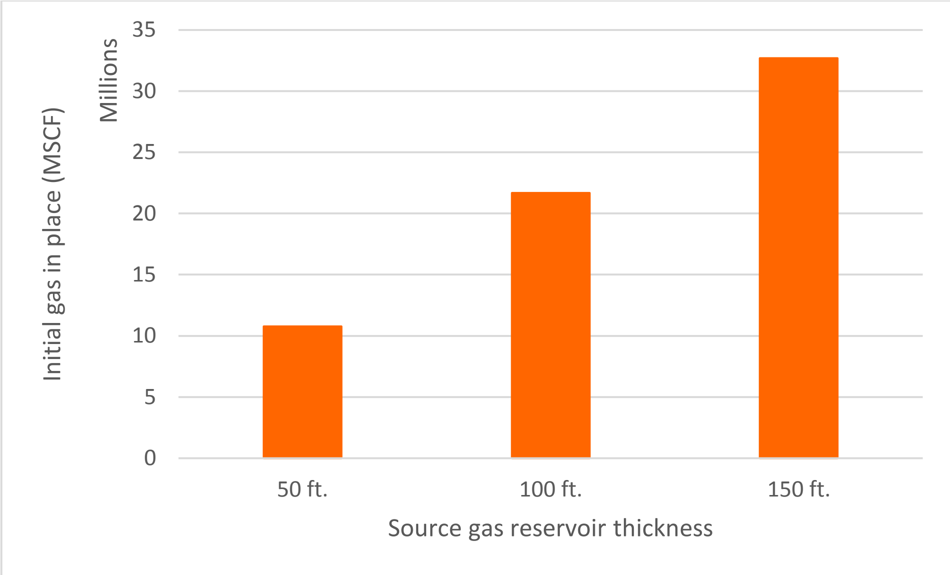

Figure 5. 50 Original gas in place for different source gas reservoir thicknesses.

Table 5. 19 Source gas reservoir properties at different reservoir thickness.

Case	Thickness (ft.)	Top reservoir (ft.)	Bottom reservoir (ft.)	Datum depth (ft.)	P_i at datum depth (psia)
1	50	7,050	7,100	7,100	3,179
2	100	7,050	7,150	7,150	3,201
3	150	7,050	7,200	7,200	3,223

As tabulated in Table 5.20, the simulation results show that the highest recovery factor of 74.95% is from case 3 in which the gas reservoir thickness is 150 ft. As can be seen in Figure 5.51, the recovery factors in case of 50 ft. and 100 ft. are 5.73% and 2.02% less than that for the case of 150 ft., respectively. Regarding the crossflow of gas, the gas dump rate as shown in Figure 5.52 shows the highest level in the case of 150 ft. Higher pressure and higher amount of source gas in place in the case of 150 ft. thickness are the main factors that improve the flooding performance. A decrease in the source gas reservoir thickness can reduce the recovery factor of this process.

Table 5. 20 Summary of results for water injection alternating gas dumpflood for various source gas reservoir thicknesses.

Case	Reservoir thickness (ft.)	Recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative water production (MMSTB)	Cumulative water injection (MMSTB)	Cumulative gas production (BCF)	Barrel of oil equivalent (MMSTB)	Production time (Years)
1	50	69.22	6.826	1.031	2.821	12.052	8.835	7.7
2	100	72.94	7.201	1.266	2.807	20.699	10.652	8.1
3	150	74.95	7.390	1.386	2.796	28.556	12.151	8.7

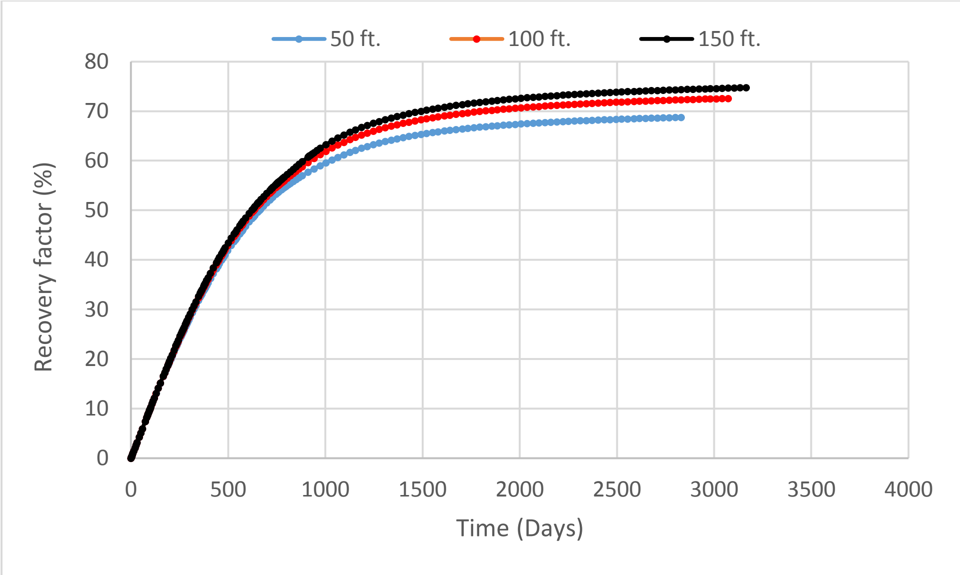

Figure 5. 51 Recovery factor by water injection alternating gas dumpflood at various source gas reservoir thicknesses.

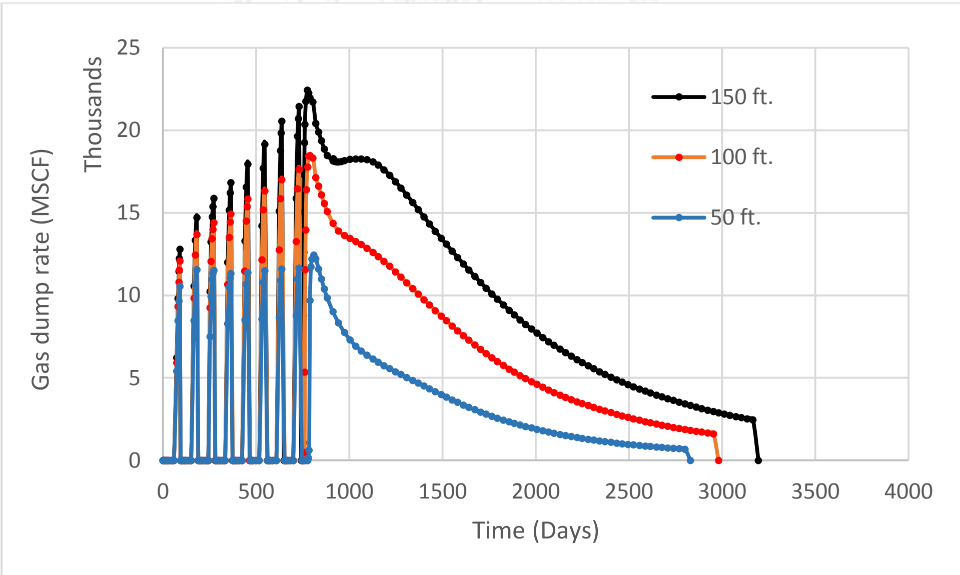

Figure 5. 52 Gas flow rate at various source gas reservoir thicknesses.

When thickness of the source gas reservoir is larger, the difference in recovery factors obtained from conventional WAG and water injection alternating gas dumpflood becomes smaller. Comparing the best result obtained from case 3 (150 ft. gas reservoir thickness) by water injection alternating gas dumpflood with the best result by conventional WAG from Section 5.2.4.1, recovery factor by conventional

WAG is 1.17% higher than that by water injection alternating gas dumpflood with 0.71 MMSTB lower amount of injected water. However, gas injection of 41.67 BCF is required to fulfill in the case of conventional WAG injection.

5.3.3 Effect of depth difference between gas and oil reservoirs

The reservoir system in this study is composed of the upper reservoir or the target oil reservoir and the source gas reservoir located below the target oil reservoir. The influence of depth difference between these two reservoirs on production performance is investigated by varying the value to be 1,000, 2,000 and 4,000 ft. Changing this depth requires the adjustment of initial pressure at the datum depth. At deeper depth, the initial pressure at datum is higher. These changes of initial pressure are tabulated in Table 5.21. In addition, the vertical flow performance curves applied for the cross flow in dumpflood well needs to be adjusted. Note that the depth difference between gas and oil reservoirs does not affect conventional WAG injection as the process obtains gas from other source.

Table 5. 21 Source gas reservoir properties for various depth differences between oil and gas reservoir.

Case	Depth difference (ft.)	Top reservoir (ft.)	Bottom reservoir (ft.)	Datum Depth (ft.)	P_i at datum depth (psia)
1	1,000	6,050	6,150	6,150	2,755
2	2,000	7,050	7,150	7,150	3,201
3	4,000	9,050	9,150	9,150	4,092

For water injection alternating gas dumpflood, the dumped gas flows from higher pressure to lower pressure. The deeper the depth difference between the oil and source gas reservoirs, the higher pressure difference between the two reservoirs and the higher the amount of original gas in place in the lower reservoir as shown in Figure 5.53. Although a higher rate of gas dump can be achieved in the case of 4,000 ft. depth difference, the higher pressure gas that flows into the oil reservoir can cause fracture, which can be noticed from the bottomhole pressure at the injector that exceeds the fracturing pressure of the oil reservoir (3,215 psia) as illustrated in Figures

5.54. To avoid the formation from being fractured, partial penetration is applied to the bottom gas zone in case of 4,000 ft. depth difference. A 10 ft. perforation rather than full-to-base perforation is implemented at the bottom most of the gas zone. The simulation result shows 72.78% recovery factor in the case of 4,000 ft. which is almost the same as the one for the case of 2,000 ft. as depicted in Figure 5.55. Due to the restriction of gas flow, the gas dump rate in the case of 4,000 ft. depth difference as illustrated in Figure 5.56 is lower than the one in the case of 2,000 ft. Hence, the total gas entering the oil zone is also less. Furthermore, this case of 4,000 ft. takes longer period of producing time than the others. Recovery results from different cases are summarized in Table 5.22.

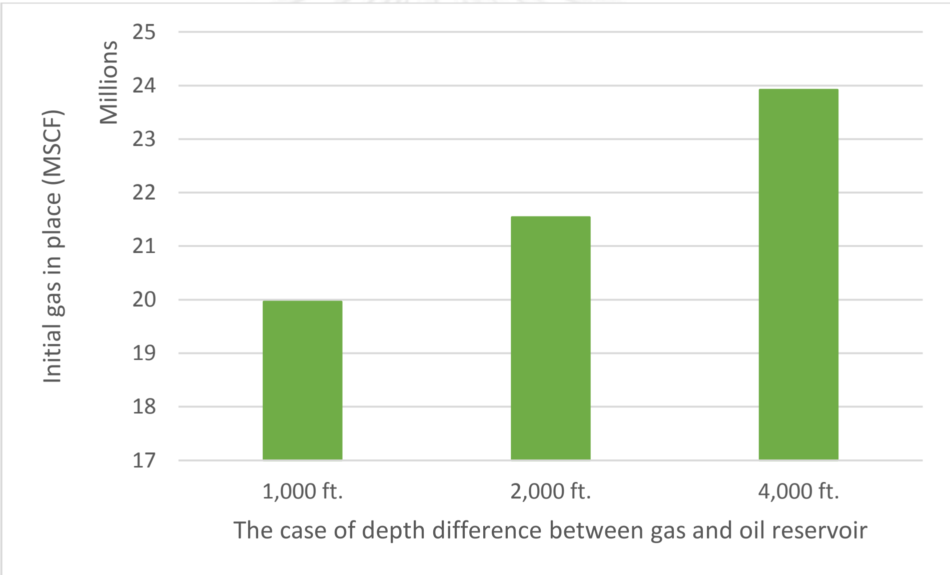

Figure 5. 53 Original gas in place for various depth differences between gas and oil reservoirs.

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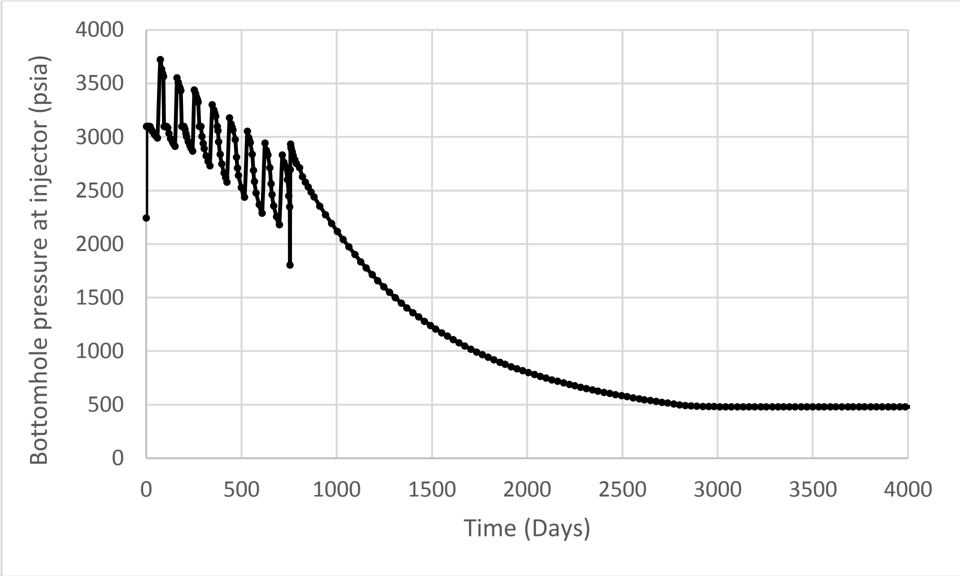

Figure 5. 54 Bottomhole pressure at the injector in the case of 4,000 ft. depth difference by water injection alternating gas dumpflood.

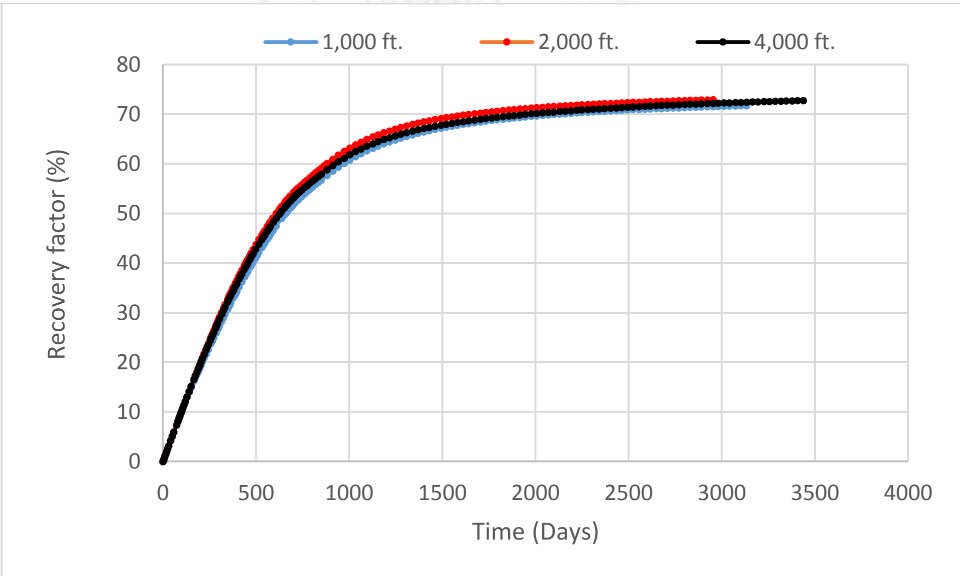

Figure 5. 55 Recovery factor by water injection alternating gas dumpflood under the variation of depth difference between oil and gas reservoirs.

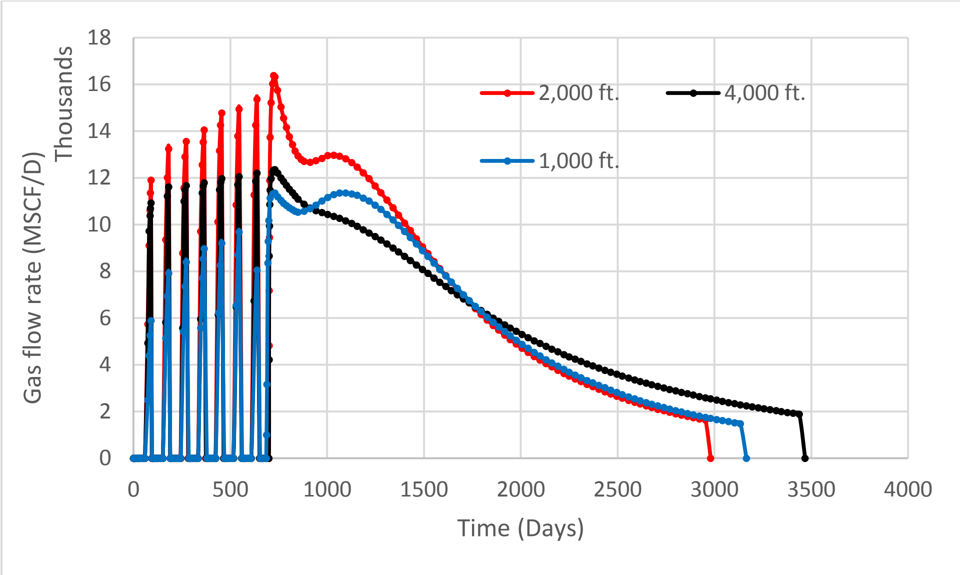

Figure 5. 56 Gas flow rate by water injection alternating gas dumpflood under the variation of depth difference between oil and gas reservoirs.

From the summary of results in Table 5.22, recovery factor in the case of 2,000 ft. depth difference is the highest at 72.94%. When comparing with the best case by conventional WAG obtained from Section 5.2.4.1, recovery factor by conventional WAG is 3.18% higher than that by water injection alternating gas dumpflood with lower amount of injected water. As high amount of gas injection yields better oil displacement, total gas injection of 41.67 BCF is required for conventional WAG injection.

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Table 5. 22 Summary of results for water injection alternating gas dumpflood for various depth differences between gas and oil reservoirs.

Case	Depth difference (ft.)	Recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative water production (MMSTB)	Cumulative water injection (MMSTB)	Cumulative gas production (BCF)	Barrel of oil equivalent (MMSTB)	Production time (Years)
1	1,000	71.74	7.078	1.273	2.753	19.088	10.260	8.6
2	2,000	72.94	7.201	1.266	2.807	20.699	10.652	8.1
3	4,000	72.78	7.168	1.399	2.819	20.353	10.561	9.4

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5.3.4 Effect of residual oil saturation

Typically, the residual oil saturations from water and gas displacement are obtained from special core analysis. However, these parameters still have uncertainties. To observe the effect of these parameters on production performance, six cases under the variation of residual saturations are simulated for both conventional WAG and water injection alternating gas dumpflood.

5.3.4.1 Effect of residual oil saturation in oil-gas system

By remaining the other parameters to be constant, the residual oil saturation in oil-gas system is varied among three values of 0.05, 0.1 and 0.15. The relative permeability curves constructed by Corey's correlation are illustrated in Figure 5.57.

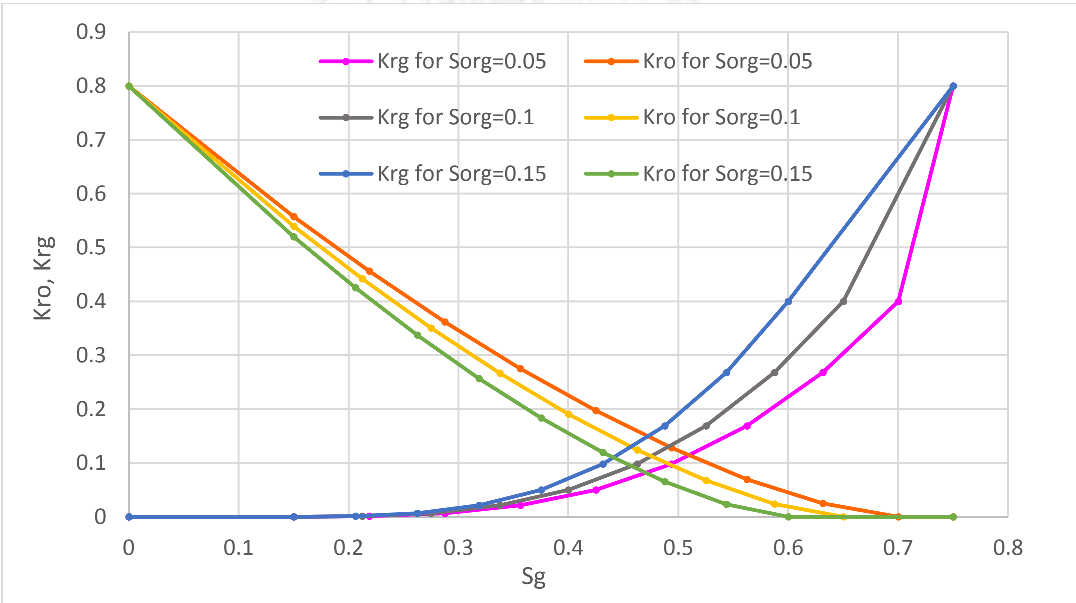

Figure 5. 57 Oil-gas saturation functions for different residual oil saturations.

For conventional WAG, the highest recovery factor of 81.74 % is obtained from the case of lowest residual oil saturation S_{org} = 0.05 as seen in Figure 5.58. The oil is recovered mainly by the displacement of injected gas. In the case of low S_{org}, a high amount of oil can be recovered in slightly longer production time. From the summary of results shown in Table 5.23, this condition requires the highest amount gas (47.23 BCF) injection compared to other cases. Regarding water production, the results for different cases are not much different.

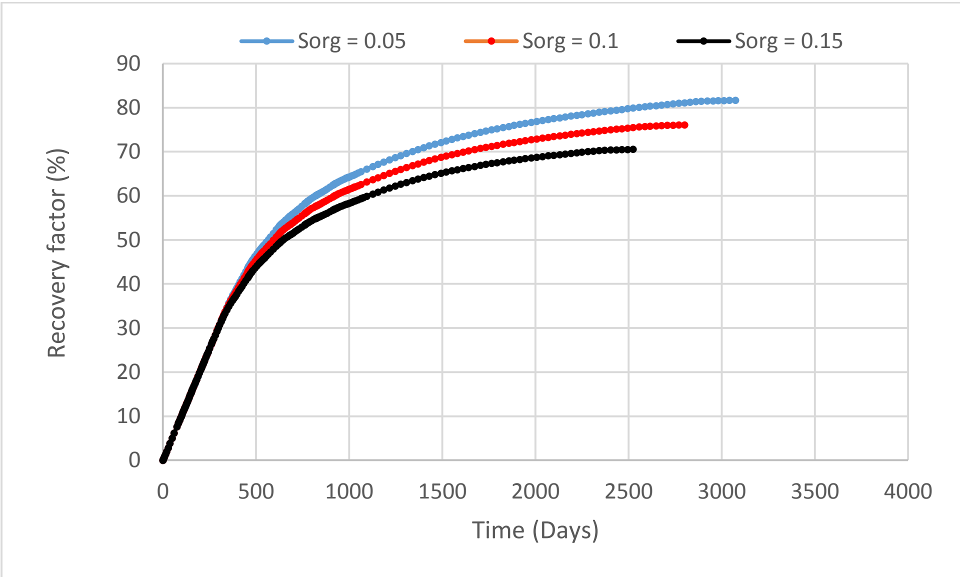

Figure 5. 58 Recovery factor by conventional WAG injection at different residual oil saturations in gas-oil system.

The oil recovery in the process of water injection alternating gas dumpflood is the highest at 76.66 % in case of the lowest residual oil saturation S_{org} = 0.05 as shown in Figure 5.59. This lowest residual oil saturation can be achieved by the alternating process of water injection and gas dumpflood which increases the amount of recovered oil in a little longer production period. However, water injection requirement in each case is not much different as can be observed from Table 5.23.

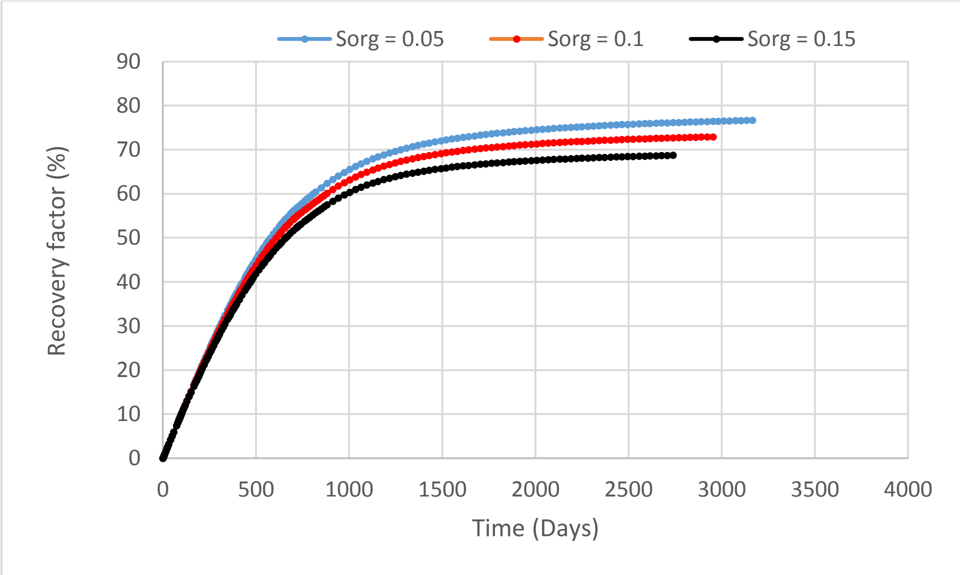

Figure 5. 59 Recovery factor by water injection alternating gas dumpflood at different residual oil saturations in gas-oil system.

Recovery results at different S_{org} by conventional WAG show significant higher recovery factor than those by water injection alternating gas dumpflood. The lower the value of S_{org}, the higher the difference in recovery factor between the two methods. Gas displacement shows a major role in oil recovery as long as it can be provided. With tremendous amount of injected gas in conventional WAG, gas can thoroughly recover the oil faster and more effective than dumpflood gas.

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Table 5. 23 Summary of results for conventional WAG and water injection alternating gas dumpflood for various residual oil saturation in oil-gas system.

Case	Method	Residual oil saturation	Recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative water production (MMSTB)	Cumulative water injection (MMSTB)	Cumulative gas production (BCF)	Cumulative gas injection (BCF)	Barrel of oil equivalent (MMSTB)	Production time (Years)
1	Conventional WAG	$S_{org} = 0.05$	81.74	8.071	0.941	2.100	49.678	47.233	8.478	8.4
2		$S_{org} = 0.1$	76.12	7.516	0.821	2.087	44.164	41.674	7.931	7.7
3		$S_{org} = 0.15$	70.59	6.969	0.667	2.053	39.171	36.720	7.378	6.9
4	Water injection alternating gas dumpflood	$S_{org} = 0.05$	76.68	7.571	1.287	2.755	21.050	-	11.080	8.7
5		$S_{org} = 0.1$	72.94	7.201	1.266	2.807	20.699	-	10.652	8.1
6		$S_{org} = 0.15$	68.73	6.786	1.064	2.659	20.307	-	10.171	7.5

5.3.4.2 Effect of residual oil saturation in oil-water system

The effect of residual oil saturation on production performance is observed based on 3 different values. At 0.05, 0.1 and 0.15 residual oil saturation in oil-water system, the relative permeability curves are constructed based on Corey's correlation which can be illustrated in Figure 5.60.

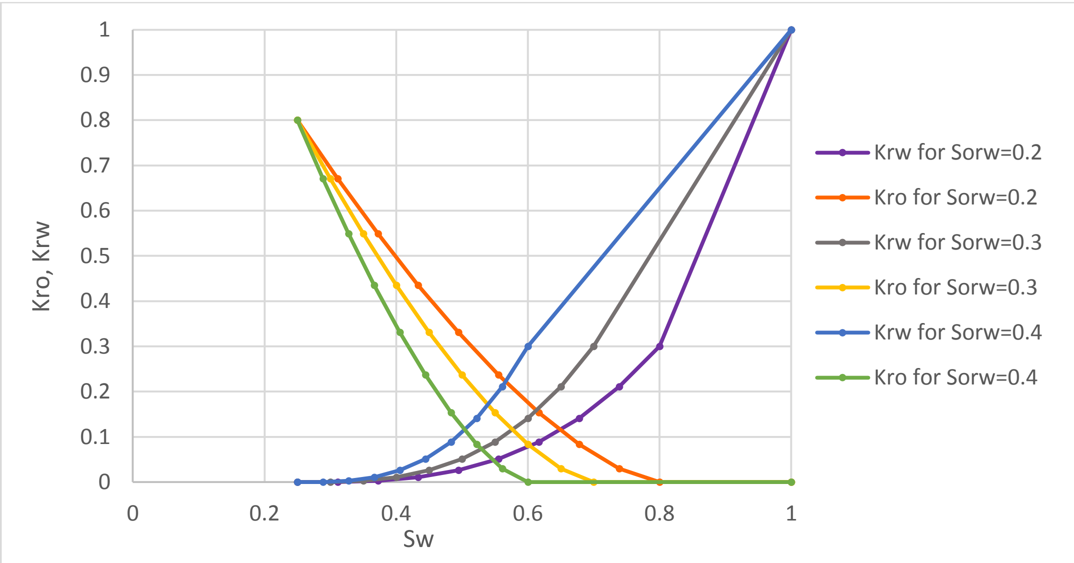

Figure 5. 60 Oil-water saturation functions for different residual oil saturations.

For conventional WAG, the recovery factors for various residual oil saturations are illustrated in Figure 5.61. The case of the lowest residual oil saturation S_{orw}= 0.2 shows the highest recovery factor 78.12 %. From the summary of results in Table 5.24, this case requires a higher amount of injected water and lower amount of gas injection than other cases. However, the recovery factor in the cases of higher S_{orw} at 0.3 and 0.4 is 2% and 3.50% lower than the case that S_{orw} = 0.2.

The recovery factors for cases of water injection alternating gas dumpflood process are illustrated in Figure 5.62. The recovery factor in the case of S_{orw} = 0.2 is the highest at 76.27 %. Since the initial water saturation of all cases are equal, this case requires higher amount of injected water (as summarized in Table 5.24) to attain that much recovery while the other two cases of higher S_{orw} requires lower amount of injected water. At higher S_{orw} at 0.3 and 0.4, the oil cannot be effectively displaced by water. Besides, the amount of dumped gas is limited. The recovery factor when S_{orw}= 0.3 and S_{orw} = 0.4 are 3.34% and 7.39% lower than the one when S_{orw} = 0.2.

Comparing recovery performance between two methods at different residual oil saturations in oil-water system, conventional WAG still gives higher recovery factor than water injection alternating gas dumpflood in every case. The higher the value of S_{orw}, the larger the gap in recovery factors obtained from conventional WAG and water injection alternating gas dumpflood. Furthermore, conventional WAG takes a shorter period of time and requires lower amount of water injection. However, large amount of gas injection is still required.

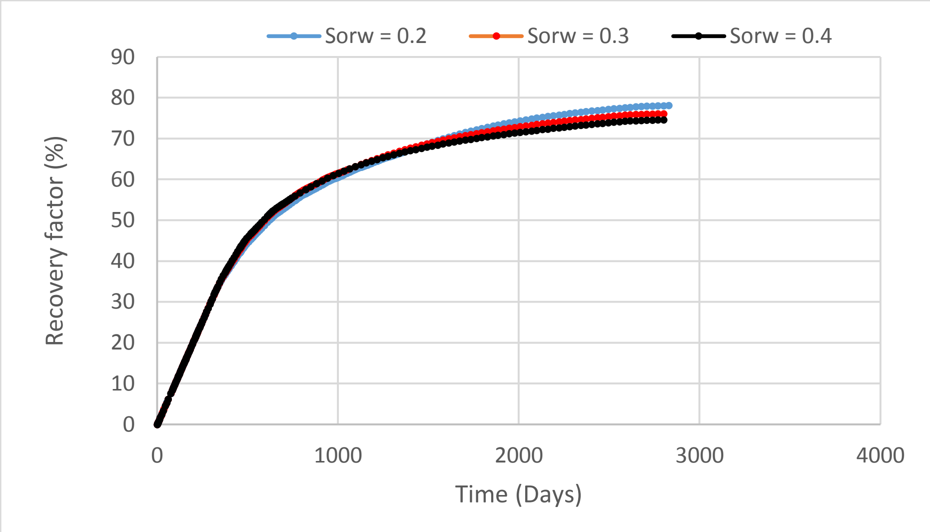

Figure 5. 61 Recovery factor by conventional WAG injection at different residual oil saturations in oil-water system.

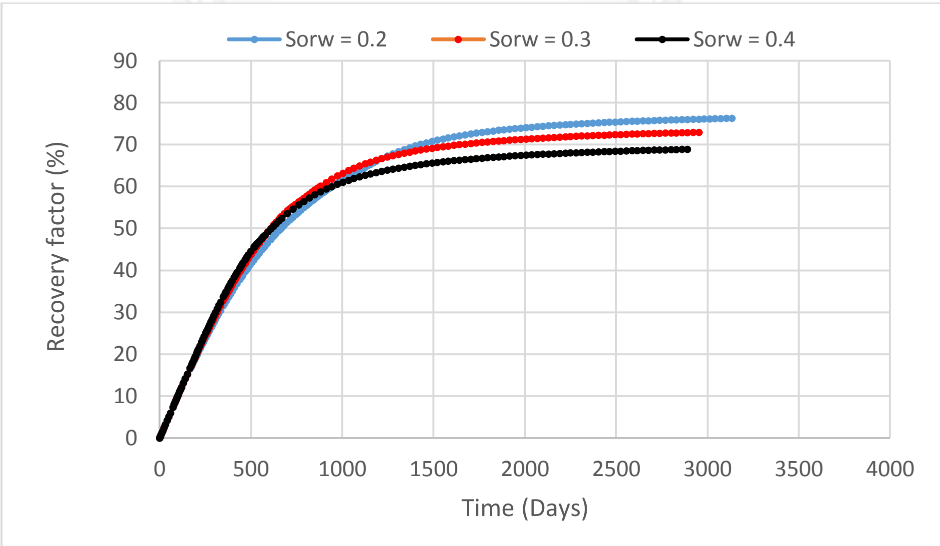

Figure 5. 62 Recovery factor by water injection alternating gas dumpflood at different residual oil saturations in oil-water system.

Table 5. 24 Summary of results for conventional WAG and water injection alternating gas dumpflood for various residual oil saturation in oil-water system.

Case	Method	Residual oil saturation	Recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative water production (MMSTB)	Cumulative water injection (MMSTB)	Cumulative gas production (BCF)	Cumulative gas injection (BCF)	Barrel of oil equivalent (MMSTB)	Production time (Years)
1	Conventional WAG	$S_{orw} = 0.2$	78.12	7.713	0.729	2.593	42.660	40.250	8.114	7.8
2		$S_{orw} = 0.3$	76.12	7.516	0.821	2.087	44.164	41.674	7.931	7.7
3		$S_{orw} = 0.4$	74.62	7.368	0.754	1.504	46.912	44.397	7.787	7.7
4	Water injection alternating gas dumpflood	$S_{orw} = 0.2$	76.28	7.532	1.162	3.319	20.360	-	10.926	8.6
5		$S_{orw} = 0.3$	72.94	7.201	1.266	2.807	20.699	-	10.652	8.1
6		$S_{orw} = 0.4$	68.89	6.802	1.111	2.116	21.125	-	10.323	7.9

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5.3.5 Effect of oil viscosity

Oil viscosity is directly related to oil mobility. At the same effective oil permeability and oil saturation, high viscosity oil yields low value of oil mobility. The effectiveness of both processes of conventional WAG and water injection alternating gas dumpflood in different cases of oil viscosity are considered in this section. Three values of oil viscosity (0.5, 2, and 5 cp.) are generated by ECLIPSE100 correlation set II. The parameters of PVT properties needed as input in ECLIPSE100 are tabulated in Table 5.25.

Table 5. 25 Input parameters for different values of oil viscosity.

Case	Oil gravity (API)	Gas gravity	GOR (SCF/STB)	Oil viscosity (cp.)
1	46	0.6	200	0.5
2	19	0.6	200	2
3	15	0.6	80	5

The immiscible displacement by conventional WAG gives the highest recovery factor in the case of lowest oil viscosity of 0.5 cp. as depicted in Figure 5.63. Because of its low viscosity, the ability of oil to be displaced by injected water and gas is easier than the case of higher oil viscosity. However, viscosity reduction aided by gas injection improves the recovery factor of those viscous oil which can rise up to 58.88% and 64.71%, respectively. In Figure 5.64, the oil production rate by the case of 2 and 5 cp. oil viscosity can only produce at lower rate when compared with the case of 0.5 cp. oil viscosity.

As illustrated in Figure 5.65 for the method of water injection alternating gas dumpflood, the recovery factor of case 0.5 cp. oil viscosity is much higher than those for the case of 2 and 5 cp. Even the production time in case of 2 and 5 cp. is much longer compared to the case of 0.5 cp., the recovery factor of those viscous oil can rise up to 56.67% and 50.14%, respectively. In Figure 5.66, the oil production rate from case of 0.5 cp. remains constantly at 10,000 STB/D during early production. But the case of 2 and 5 cp. oil viscosity can only produce at lower rate.

The effectiveness of both conventional WAG and water injection alternating gas dumpflood for various oil viscosity are summarized in Table 5.26. This table shows more favorable recovery factor by conventional WAG for all cases. However, only a slight difference in recovery factor for conventional WAG and water injection alternating gas dumpflood can be seen in the case that oil viscosity is 0.5 cp. The higher the viscosity, the more difference in recovery factors obtained from the two processes. When oil viscosity is 5 cp., the recovery factor by water injection alternating gas dumpflood is as large as 50.14%.

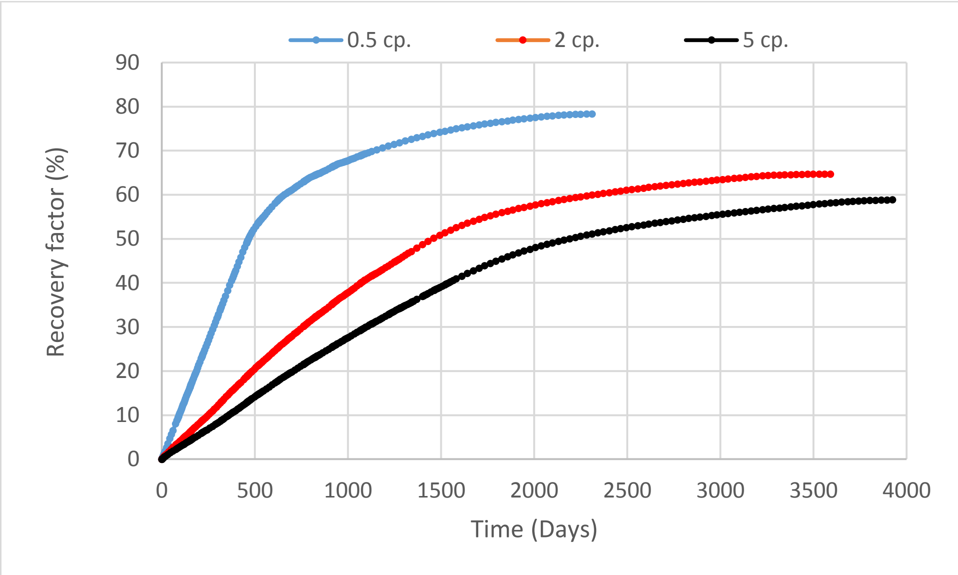

Figure 5. 63 Recovery factor by conventional WAG at different oil viscosities.

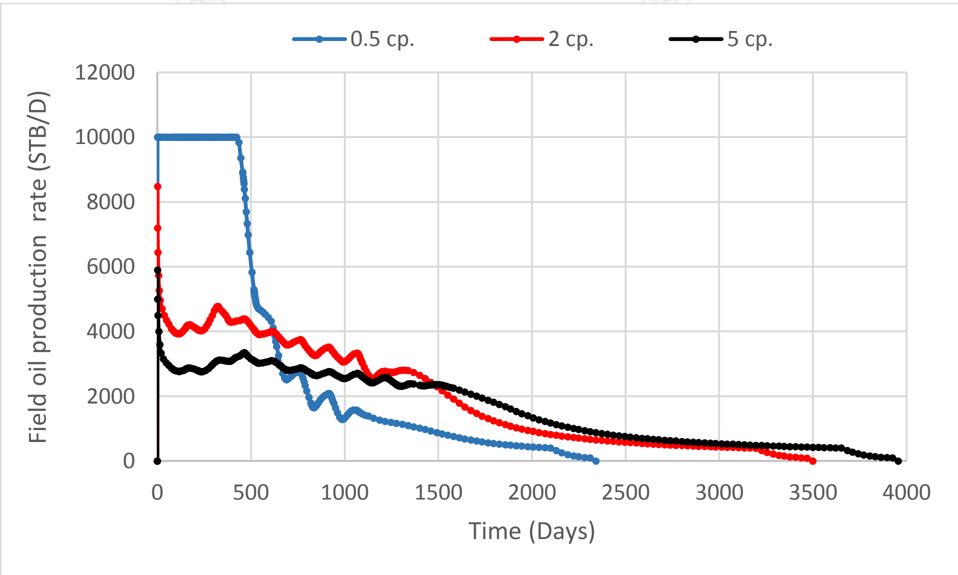

Figure 5. 64 Field oil production rate by conventional WAG injection at different oil viscosities.

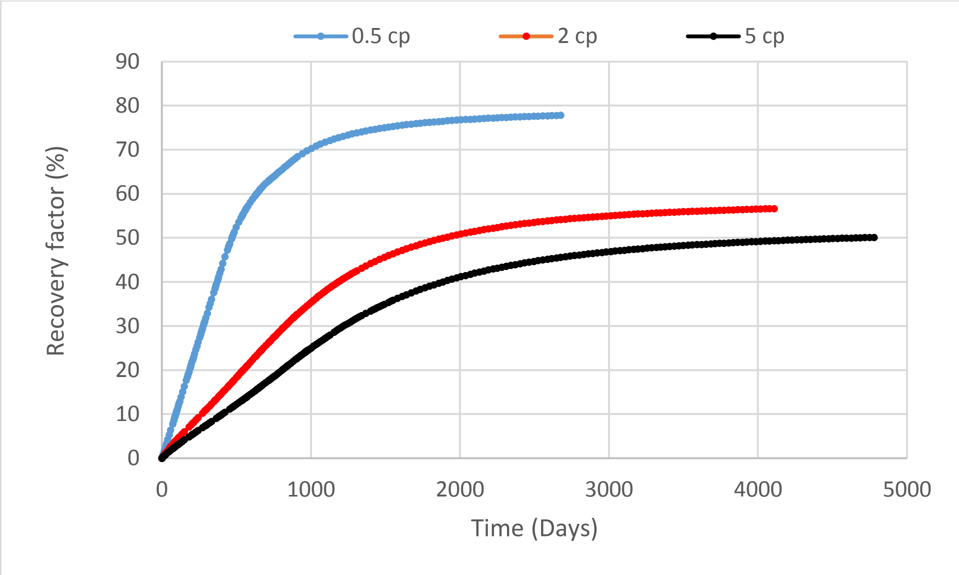

Figure 5. 65 Recovery efficiency by water injection alternating gas dumpflood at different oil viscosities.

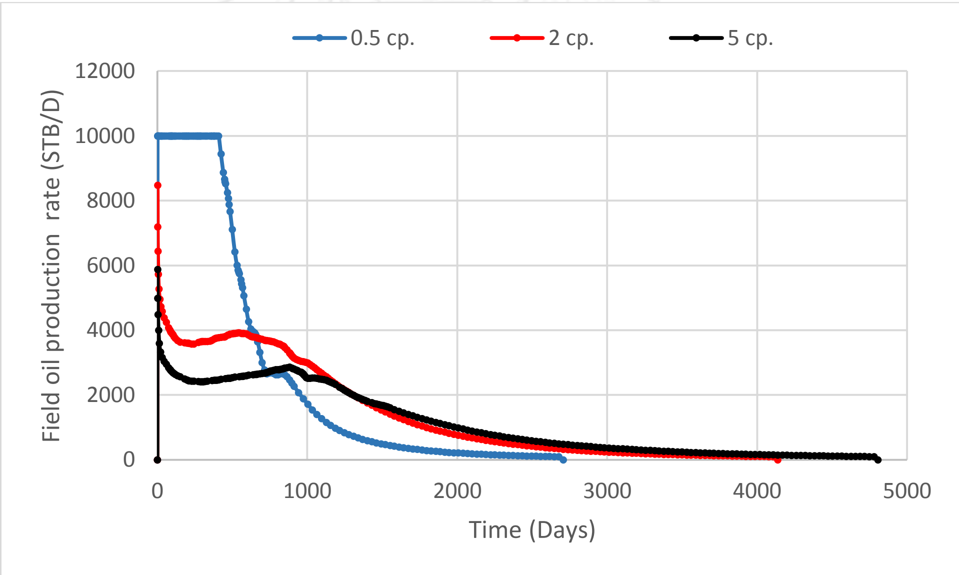

Figure 5. 66 Field oil production rate by water injection alternating gas dumpflood at different oil viscosities.

Table 5. 26 Summary of results for conventional WAG and water injection alternating gas dumpflood for various oil viscosities.

Case	Method	Oil viscosity (cp.)	Recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative water production (MMSTB)	Cumulative water injection (MMSTB)	Cumulative gas production (BCF)	Cumulative gas injection (BCF)	Barrel of oil equivalent (MMSTB)	Production time (Years)
1	Conventional WAG	0.5	78.41	7.247	0.680	2.092	36.460	32.897	7.840	6.3
2		2	64.71	6.785	0.716	1.777	47.744	46.641	6.969	9.5
3		5	58.88	6.259	0.615	1.538	49.458	48.818	6.365	10.8
7	Water injection alternating gas dumpflood	0.5	77.82	7.192	1.260	2.886	21.911	-	10.845	7.3
8		2	56.67	5.942	1.011	2.147	19.015	-	9.112	11.3
9		5	50.14	5.329	0.842	1.834	18.275	-	8.376	13.1

CHAPTER VI
CONCLUSIONS

From the study on production performance and sensitivity by conventional WAG and water injection alternating gas dumpflood, the following conclusions can be drawn.

1. When comparing the best case of conventional WAG with the best case of the proposed water injection alternating gas dumpflood, conventional WAG injection has a slightly higher oil recovery and slightly lower requirement for water injection and production time. However, it requires large amount of gas injection while water injection alternating gas dumpflood does not.
2. Proper well location in accordance with the reservoir area plays an important role in oil recovery mechanism. Better sweep efficiency yielding higher recovery efficiency can be obtained from the case of three wells with well distance of 2,000 ft. and ten wells that injectors are laid in alternate positions with well distance of 1,000 ft. However, the case of three wells is more suitable as it incurs lower expenditure for drilling and completion.
3. Based on the injection constraint used in this study, the most suitable time to stop water injection in both conventional WAG and water injection alternating gas dumpflood is when water breaks through the producer (water cut of 1% is used as a benchmark in this study). Stopping water injection at higher water cut constraint is not worthwhile in economic condition since it requires much higher barrels of injected water compared with the additional oil produced.
4. Regarding water injection rate, increasing water injection rate slightly decreases oil recovery and slightly reduces duration of the production time in conventional WAG. In addition, increasing gas injection rate can greatly hasten the oil production but slightly decreases oil recovery. For water injection alternating gas dump flood, increasing water injection rate slightly to moderately increases oil recovery but slightly reduces duration of the production time.
5. Variation in slug size and ratio of water and gas injection duration has a minor impact on total oil recovery in both conventional WAG injection and water injection alternating gas dumpflood. As water injection duration gets longer,

cumulative water injection increases in both processes while cumulative gas injection in conventional WAG decreases.

6. Low vertical to horizontal permeability ratio causes the difficulty for gas to flow upward. Less effect of gravity segregation occurs in both methods when the ratio equals 0.01. As the anisotropy ratio increases, the recovery factor decreases moderately in conventional WAG but highly decreases in the proposed method. Furthermore, the cumulative water production highly increases and cumulative water injection highly reduces in both methods.
7. Different thicknesses of source gas reservoir directly result in different initial reservoir pressures and amounts of original gas in place. The thicker the gas reservoir, the higher the amount of original gas in place available for dumpflood process. In the method of water injection alternating gas dumpflood, thicker gas reservoir moderately provides higher recovery factor with a bit longer period of production time.
8. By the variation of depth difference between the oil and source gas reservoirs, the recovery factor slightly increases as the difference of depth increases in the method of water injection alternating gas dumpflood. Due to the higher initial pressure and original gas in place in case of large depth difference, partial perforation is necessary to avoid formation fracture. The recovery factor under the condition of partial perforation is lower than the condition of full perforation. This restricted flow allows a smaller amount of gas to the oil zone resulting in a smaller rate of oil production and thus requires a longer production time.
9. The lowest residual oil saturation cases either by water or gas flood show remarkably high recovery factor in both methods. For conventional WAG injection, the case of S_{org} = 0.05 gives higher oil recovery factor than the case of S_{orw} = 0.2 which requires higher amount of gas injection. In the method of water injection alternating gas dumpflood, slightly higher recovery factor is attained from the case of S_{org} = 0.05 with the lower amount of injected water.
10. Recovery factors by both methods become smaller as the oil viscosity increases. At higher oil viscosity, the recovery performance by conventional WAG is much better than water injection alternating gas dumpflood method.

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APPENDIX

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APPENDIX

This section provides details for reservoir model construction by the use of ECLIPSE100 reservoir simulator. The parameters input in base case condition for conventional WAG and water injection alternating gas dumpflood are as follows:

1. Reservoir model

1.1 Case definition

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

1.2 Grid

1.2.1 Properties

Active Grid Block	(1:19, 1:21, 1:5) = 1
	(1:19, 1:21, 6:7) = 0
	(1:19, 1:21, 8:12) = 1
X Permeability	126 md
Y Permeability	126 md
Z Permeability	12.6 md
Porosity	0.215

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1.2.2 Geometry

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

1.3 PVT

1.3.1 PVT 1

Fluid densities at surface conditions

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

Water PVT properties

Reference pressure (Pref)	2243	psia
Water FVF at Pref	1.034716	rb/stb
Water compressibility	3.368884 x 10-6	psi-1
Water viscosity at Pref	0.2504328	cp
Water viscosity	3.054844 x 10-6	psi-1

Live oil PVT properties (dissolved gas)

Rs (Mscf/stb)	Pbub (psia)	FVF (rb/stb)	Visc (cp)
0.020456	200.000	1.095040	1.223986
	400.000	1.082015	1.250365
	600.000	1.077708	1.291526
	800.000	1.075561	1.344172
	1000.000	1.074275	1.406789
	1200.000	1.073419	1.478599
	1327.033	1.073009	1.528793

Rs (Mscf/stb)	Pbub (psia)	FVF (rb/stb)	Visc (cp)
	1600.000	1.072349	1.648424
	1800.000	1.071993	1.746205
	2000.000	1.071708	1.852579
	2243.000	1.071430	1.993515
	2400.000	1.071280	2.091484
	2600.000	1.071116	2.224264
	2800.000	1.070975	2.366114
	3000.000	1.070853	2.517172
	3200.000	1.070746	2.677565
	3400.000	1.070652	2.847404
	3600.000	1.070569	3.026781
	3800.000	1.070494	3.215760
	4000.000	1.070426	3.414377
0.047152	400.000	1.105673	1.088411
	600.000	1.096399	1.110205
	800.000	1.091792	1.140599
	1000.000	1.089038	1.178178
	1200.000	1.087205	1.222131
	1327.033	1.086329	1.253124
	1600.000	1.084918	1.327362
	1800.000	1.084157	1.388133
	2000.000	1.083549	1.454152
	2243.000	1.082956	1.541317
	2400.000	1.082637	1.601656
	2600.000	1.082286	1.683072
	2800.000	1.081986	1.769574
	3000.000	1.081725	1.861154

Rs (Mscf/stb)	Pbub (psia)	FVF (rb/stb)	Visc (cp)
	3200.000	1.081498	1.957800
	3400.000	1.081297	2.059500
	3600.000	1.081118	2.166232
	3800.000	1.080959	2.277967
	4000.000	1.080815	2.394661
0.076853	600.000	1.117652	0.977161
	800.000	1.110201	0.996344
	1000.000	1.105755	1.021305
	1200.000	1.102802	1.051281
	1327.033	1.101391	1.072695
	1600.000	1.099121	1.124484
	1800.000	1.097896	1.167155
	2000.000	1.096918	1.213634
	2243.000	1.095965	1.275066
	2400.000	1.095452	1.317582
	2600.000	1.094888	1.374897
	2800.000	1.094406	1.435697
	3000.000	1.093988	1.499935
	3200.000	1.093622	1.567570
	3400.000	1.093299	1.638558
	3600.000	1.093013	1.712857
	3800.000	1.092756	1.790417
	4000.000	1.092526	1.871187
0.108689	800.000	1.130657	0.886835
	1000.000	1.124265	0.904121
	1200.000	1.120024	0.925590
	1327.033	1.118001	0.941180

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Rs (Mscf/stb)	Pbub (psia)	FVF (rb/stb)	Visc (cp)
	1600.000	1.114747	0.979363
	1800.000	1.112993	1.011116
	2000.000	1.111592	1.045866
	2243.000	1.110228	1.091939
	2400.000	1.109494	1.123874
	2600.000	1.108688	1.166951
	2800.000	1.107997	1.212650
	3000.000	1.107399	1.260913
	3200.000	1.106877	1.311687
	3400.000	1.106415	1.364923
	3600.000	1.106006	1.420570
	3800.000	1.105639	1.478580
	4000.000	1.105309	1.538899
0.142214	1000.000	1.144526	0.812807
	1200.000	1.138812	0.828594
	1327.033	1.136089	0.840291
	1600.000	1.131713	0.869389
	1800.000	1.129357	0.893869
	2000.000	1.127475	0.920825
	2243.000	1.125643	0.956725
	2400.000	1.124658	0.981676
	2600.000	1.123577	1.015383
	2800.000	1.122651	1.051178
	3000.000	1.121849	1.089000
	3200.000	1.121147	1.128794
	3400.000	1.120529	1.170508
	3600.000	1.119980	1.214092

Rs (Mscf/stb)	Pbub (psia)	FVF (rb/stb)	Visc (cp)
	3800.000	1.119488	1.259499
	4000.000	1.119046	1.306679
0.177149	1200.000	1.159158	0.751299
	1327.033	1.155636	0.760241
	1600.000	1.149987	0.782896
	1800.000	1.146947	0.802222
	2000.000	1.144521	0.823665
	2243.000	1.142160	0.852384
	2400.000	1.140891	0.872414
	2600.000	1.139499	0.899532
	2800.000	1.138306	0.928380
	3000.000	1.137273	0.958897
	3200.000	1.136371	0.991026
	3400.000	1.135575	1.024718
	3600.000	1.134868	1.059925
	3800.000	1.134236	1.096600
	4000.000	1.133667	1.134697
0.199981	1327.033	1.168814	0.717408
	1600.000	1.162268	0.736887
	1800.000	1.158749	0.753670
	2000.000	1.155942	0.772393
	2243.000	1.153211	0.797573
	2400.000	1.151743	0.815181
	2600.000	1.150132	0.839061
	2800.000	1.148753	0.864500
	3000.000	1.147560	0.891436
	3200.000	1.146516	0.919816

Rs (Mscf/stb)	Pbub (psia)	FVF (rb/stb)	Visc (cp)
	3400.000	1.145596	0.949589
	3600.000	1.144779	0.980709
	3800.000	1.144049	1.013131
	4000.000	1.143392	1.046812

Dry gas PVT properties (no vapourised oil)

Press (psia)	FVF (rb/stb)	Visc (cp)
200.000	17.231699	0.014493
400.000	8.526228	0.014637
600.000	5.628980	0.014819
800.000	4.184071	0.015033
1000.000	3.320340	0.015276
1200.000	2.747401	0.015547
1327.033	2.474606	0.015732
1600.000	2.038286	0.016163
1800.000	1.805268	0.016506
2000.000	1.620960	0.016870
2243.000	1.443831	0.017337
2400.000	1.349872	0.017653
2600.000	1.248076	0.018067
2800.000	1.162311	0.018495
3000.000	1.089318	0.018933
3200.000	1.026644	0.019379
3400.000	0.972401	0.019831
3600.000	0.925115	0.020288
3800.000	0.883622	0.020747
4000.000	0.846987	0.021208

1.3.2 PVT 2

Fluid densities at surface conditions

Oil density	48.62175	lb/ft^3
Water density	62.42797	lb/ft^3
Gas density	0.04369958	lb/ft^3

Water PVT properties

Reference pressure (Pref)	3157	psia
Water FVF at Pref	1.063672	rb/stb
Water compressibility	3.998482 x 10-6	psi-1
Water viscosity at Pref	0.1849284	cp
Water viscosity	5.857001 x 10-6	psi-1

Dry gas PVT properties (no vapourised oil)

Press (psia)	FVF (rb/stb)	Visc (cp)
200.000	18.907626	0.015235
715.789	5.154928	0.015704
1231.579	2.939985	0.016399
1747.368	2.048050	0.017282
2263.158	1.575896	0.018322
2778.947	1.290021	0.019485
3318.418	1.095318	0.020790
3810.526	0.971978	0.022024
4326.316	0.877357	0.023333
4842.105	0.806144	0.024636
5357.895	0.750875	0.025921
5873.684	0.706835	0.027180
6389.474	0.670944	0.028410
6905.263	0.641122	0.029609

Press (psia)	FVF (rb/stb)	Visc (cp)
7421.053	0.615928	0.030777
7936.842	0.594336	0.031915
8452.632	0.575600	0.033024
8968.421	0.559165	0.034107
9484.211	0.544611	0.035164
10000.000	0.531615	0.036197

1.4 SCAL

Water/oil saturation functions

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

Gas/oil saturation functions

S_g	K_{rg}	K_{ro}
0	0	0.8
0.1500	0.0000	0.5397
0.2125	0.0008	0.4418
0.2750	0.0063	0.3506
0.3375	0.0211	0.2667
0.4000	0.0500	0.1908
0.4625	0.0977	0.1239
0.5250	0.1688	0.0675
0.5875	0.2680	0.0239
0.65	0.4	0
0.75	0.8	0

1.5 Initialization

1.5.1 Equilibration region 1

Equilibration data specification

Datum depth	5000	ft
Pressure at datum depth	2243	psia
WOC depth	8000	ft
GOC depth	5000	ft

1.5.1 Equilibration region 1

Equilibration data specification

Datum depth	7150	ft
Pressure at datum depth	3201	psia
WOC depth	8000	ft
GOC depth	7150	ft

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1.6 Region

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

1.7 Schedule

1.7.1 Conventional WAG base case

1.7.1.1 Production well 1

Well specification

Well name	P1
Group	1
I location	10
J location	3
Datum depth	5000
Preferred phase	OIL
Inflow equation	STD
Automatic shut-in instruction	SHUT
Crossflow	YES
PVT property table	2
Density calculation	SEG

Well connection data

Well	P1
K upper	1
K lower	5

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Open/shut flag	OPEN
Well bore ID	0.5104 ft.
Direction	Z

Production well control

Well	P1
Open/shut flag	OPEN
Control	LRAT
Liquid rate	5000 stb/day
BHP target	200 psia

Production well economic limits

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

1.7.1.2 Production well 2

Well specification

Well name	P2
Group	1
I location	10
J location	43
Datum depth	5000
Preferred phase	OIL
Inflow equation	STD
Automatic shut-in instruction	SHUT
Crossflow	YES
PVT property table	2
Density calculation	SEG

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Well connection data

Well	P2
K upper	1
K lower	5
Open/shut flag	OPEN
Well bore ID	0.5104 ft.
Direction	Z
Production well control	
Well	P2
Open/shut flag	OPEN
Control	LRAT
Liquid rate	5000 stb/day
BHP target	200 psia

Production well economic limits

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

1.6.1.3 Water injection well

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Well specification

Well name	I1
Group	2
I location	10
J location	23
Datum depth	5000
Preferred phase	WATER
Inflow equation	STD

Automatic shut-in instruction	SHUT
Crossflow	YES
Density calculation	SEG

Well connection data

Well	I1
K upper	1
K lower	5
Open/shut flag	OPEN
Well bore ID	0.5104 ft.
Direction	Z

Injection well control

Well	I1
Injector type	WATER
Open/shut flag	OPEN
Control	RATE
Liquid surface rate	5000 stb/day
BHP target	3100 psia

1.6.1.4 Gas injection well

Well specification

Well name	G1
Group	3
I location	10
J location	23
Datum depth	5000
Preferred phase	GAS
Inflow equation	STD
Automatic shut-in instruction	SHUT
Crossflow	YES

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PVT property table	2
Density calculation	SEG

Well connection data

Well	G1
K upper	1
K lower	5
Open/shut flag	OPEN
Well bore ID	0.5104 ft.
Direction	Z

Injection well control

Well	G1
Injector type	GAS
Open/shut flag	OPEN
Control	RATE
Gas surface rate	20000 Mscf/day
BHP target	3100 psia

1.7.2 Water injection alternating gas dumpflood base case

1.7.2.1 Production well 1

Well specification

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

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Crossflow	YES
PVT property table	2
Density calculation	SEG

Well connection data

Well	P1
K upper	1
K lower	5
Open/shut flag	OPEN
Well bore ID	0.5104 ft.
Direction	Z

Production well control

Well	P1
Open/shut flag	OPEN
Control	LRAT
Liquid rate	5000 stb/day
BHP target	200 psia

Production well economic limits

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

1.7.2.2 Production well 2

Well specification

Well name	P2
Group	1
I location	10
J location	43

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Datum depth	5000
Preferred phase	OIL
Inflow equation	STD
Automatic shut-in instruction	SHUT
Crossflow	YES
PVT property table	2
Density calculation	SEG

Well connection data

Well	P2
K upper	1
K lower	5
Open/shut flag	OPEN
Well bore ID	0.5104 ft.
Direction	Z

Production well control

Well	P2
Open/shut flag	OPEN
Control	LRAT
Liquid rate	5000 stb/day
BHP target	200 psia

Production well economic limits

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

1.7.2.3 Injection well

As water injection and gas crossflowing are conducted alternately in the same well, well setting is described as follow:

Well specification

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

Well specification

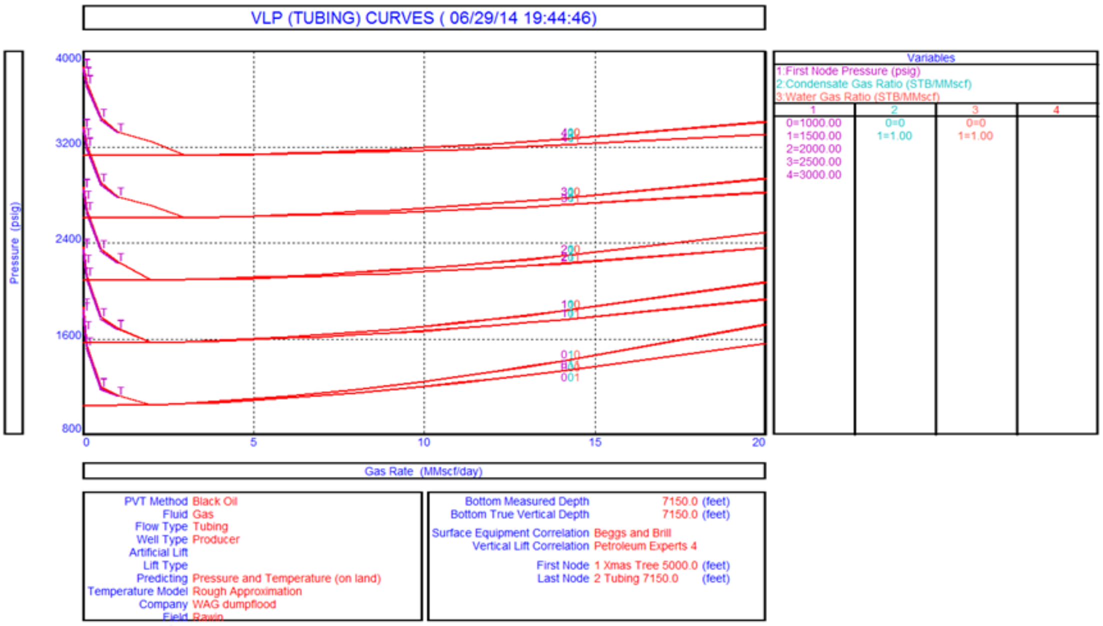
Well name	I1
Group	2
I location	10
J location	23
Datum depth	5000
Preferred phase	GAS
Inflow equation	STD
Automatic shut-in instruction	SHUT
Crossflow	YES
Density calculation	SEG

Well connection data

Well	I1
K upper	1
K lower	5
Open/shut flag	OPEN
Well bore ID	0.5104 ft.

Direction	Z
Well connection data	
Well	I1
K upper	8
K lower	12
Open/shut flag	OPEN
Well bore ID	0.5104 ft.
Direction	Z
Injection well control	
Well	I1
Injector type	WATER
Open/shut flag	OPEN
Control	RATE
Liquid surface rate	5000 stb/day
BHP target	3100 psia
Production well control	
Well	I1
Open/shut flag	STOP
VFP pressure table	1
Production vertical flow performance	
VFP table number	2
Datum depth	7150 ft.
Flow rate definition	GAS
Water fraction definition	WGR
Gas fraction definition	OGR
Fixed pressure definition	THP
Table units	FIELD
Tabulated quantity definition	BHP

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



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VITA

Rawin Pitakwatchara was born on January 13rd, 1987 in Samutprakarn, Thailand. She received a Bachelor degree in Civil Engineering from Faculty of Engineering, Chulalongkorn University in 2008. After obtaining her first degree, she spent 3 years working as a civil engineer on structural and architectural construction for Italian-Thai Development Plc, Bangkok, Thailand. After that, she continued her study in the Master’s Degree program in Petroleum Engineering at the Department of Mining and Petroleum Engineering, Faculty of Engineering, Chulalongkorn University since the academic year 2012.

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