Evaluation of Double Displacement Process via Water and Gas Dumpflood

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การประเมินกระบวนการแทนที่น้ำมันโดยการไหลเทของน้ำและก๊าซตามลำดับ

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วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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สิริวัฒนา ทัม : การประเมินกระบวนการแทนที่น้ำมันโดยการไหลเทของน้ำและก๊าซตามลำดับ (Evaluation of Double Displacement Process via Water and Gas Dumpflood) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร. สุวัฒน์ อธิชนากร, 134 หน้า.

กระบวนการแทนที่น้ำมันโดยการแทนที่สองครั้ง คือวิธีเพิ่มปริมาณน้ำมันที่ผลิตได้ซึ่งมีประสิทธิภาพมากสำหรับแหล่งกักเก็บที่มีความลาดเอียง ปกติแล้วกระบวนการนี้ใช้เงินลงทุนจำนวนมหาศาลในการดำเนินการ ค่าสิ่งก่อสร้าง ในการอัดน้ำและก๊าซเข้าไปในแหล่งกักเก็บ สำหรับแหล่งกักเก็บบางแหล่ง ค่าใช้จ่ายในการอัดน้ำและก๊าซสามารถตัดออกไปได้ โดยปล่อยให้น้ำจากชั้นหินอุ้มน้ำที่อยู่บริเวณใกล้เคียงไหลเข้ามาในแหล่งกักเก็บน้ำมันขณะปฏิบัติการไหลเทด้วยน้ำ และปล่อยก๊าซจากแหล่งกักเก็บใกล้เคียงไหลเข้ามาในแหล่งกักเก็บขณะปฏิบัติการไหลเทด้วยก๊าซ

ปริมาณน้ำมันที่ผลิตได้เพิ่มขึ้นจากกระบวนการแทนที่น้ำมันสองครั้งโดยการไหลเทของน้ำและก๊าซในอ่าวไทย ศึกษาได้จากการสร้างแบบจำลองแหล่งกักเก็บแบบง่าย แบบจำลองนี้จะใช้ตรวจสอบผลกระทบของปริมาณก๊าซ และขนาดชั้นหินอุ้มน้ำ เนื่องจากตัวแปรทั้งสองนี้มีความไม่แน่นอน และตรวจสอบผลกระทบของตารางการผลิตเพื่อหาปริมาณน้ำมันที่ผลิตได้มากที่สุดจากกระบวนการนี้

ผลการศึกษาจากแบบจำลองแหล่งกักเก็บบ่งชี้ว่าปริมาณน้ำมันที่ผลิตได้จากกระบวนการแทนที่น้ำมันโดยการไหลเทของน้ำและก๊าซมีปริมาณมากกว่าการผลิตจากวิธีพร่องความดันตามธรรมชาติ โดยแปรผันตามขนาดแหล่งกักเก็บก๊าซ และขนาดชั้นหินอุ้มน้ำ จากการตรวจสอบตารางการผลิตพบว่า การผลิตน้ำมันสลับกับการหยุดผลิตขณะปฏิบัติการไหลเทด้วยก๊าซเป็นระยะๆ จะผลิตน้ำมันได้เพิ่มมากถึง 14 เปอร์เซนต์เมื่อเทียบกับวิธีผลิตอย่างต่อเนื่อง ปริมาณน้ำมันที่ผลิตเพิ่มได้นี้ขึ้นอยู่กับระยะเวลาที่หยุดการผลิต เนื่องจากขณะที่หยุดผลิต ก๊าซส่วนหน้าที่ถูกอัดฉีดเข้ามาจะสร้างเสถียรภาพการแบ่งแยกชั้นระหว่างก๊าซกับของเหลวโดยแรงโน้มถ่วงมากขึ้น และลดการผลิตก๊าซก่อนเวลาที่หลุมผลิตด้านลาดต่ำของหลุมแหล่งกักเก็บ ทำให้เพิ่มปริมาณน้ำมันที่ผลิตได้ในที่สุด

ภาควิชา	วิศวกรรมเหมืองแร่และปิโตรเลียม	ลายมือชื่อนิสิต	....
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Double Displacement Process (DDP) is an improved oil recovery method which is very effective in dipping reservoirs. However, this process requires large investment on water and gas injection facilities as well as high operating cost. For a certain reservoir system, water and gas injection can be eliminated by allowing water to cross flow from the nearby aquifer into the reservoir during the waterflooding phase and neighbouring gas reservoir to cross flow during the gas flooding phase of DDP.

To determine how much more oil recovery can be obtained using DDP via water and gas dumpflood for an offshore oil field in the Gulf of Thailand, a simplified numerical reservoir model was constructed. The model was used to investigate effects of gas reservoir volume and aquifer size due to uncertainty in the determination of the two parameters and effects of production schedule in order to maximize oil recovery.

Simulation results indicate that oil recovered by the proposed DDP can be much higher than that from natural depletion, depending on gas reservoir volume and aquifer size. Regarding production schedule, it was found that alternating oil production period with shut-in period during gas dumpflood yields up to 14% increment in oil recovery factor when compared with continuous production. The increment level depends on the duration of no-production period which helps stabilize gas flood front through gravity segregation, avoiding early gas breakthrough at downdip wells and leading to higher oil recovery.

Department:	Mining and Petroleum Engineering	Student's Signature	....
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BSCF/D	Billion standard cubic feet per day
BHP	Bottomhole pressure
DDP	Double Displacement Process
GOR	Gas-oil ratio
GLR	Gas-liquid ratio
GAGD	Gravity Assisted Gravity Drainage
mD	Millidarcy
MMSTB	Million stock tank barrel
MMSCF/D	Million standard cubic feet per day
MSCF/D	Thousand standard cubic feet per day
OOIP	Original oil in place
PV	Pore volume
STB/D	Stock tank barrel per day
SCAL	Special core analysis
TVD	True vertical depth

NOMENCLATURES

A	Cross sectional area
α	Dip angle
$\Delta\rho$	Density difference $\rho_o - \rho_g$,
Δp_{fr}	Friction pressure drop, psi
f_g	Fractional flow of gas
f_w	Fractional flow of water, bbl/bbl
$FRAC.S.G$	Fracture pressure gradient (bar/meter)
g	Gravitational acceleration
I	Injectivity index, BWPD/psi
i_w	Water injection rate, bbl/day
Iw	Water crossflow rate into oil reservoir, BWPD
i_g	Gas injection rate, bbl/day
J	Productivity index, BWPD/psi
k	Absolute permeability, md
k_o, k_w, k_g	Effective permeability of oil, water and gas
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
k_{rog}	Oil relative permeability for a system with oil, gas and connate water tabulated as a function of s_o
k_{row}	Oil relative permeability for a system with oil and water only, also tabulated as a function of s_o
k_{rg}	Relative permeability to gas, md
k_{ro}	Relative permeability to oil, md
k_{rw}	Relative permeability to water, md
k_{rwend}	Relative permeability to water at minimum water saturation

$(k_{ro})s_{wc}$	Relative permeability of the oil at the connate-water saturation as determined from the oil-water relative permeability system
$\lambda_o, \lambda_w, \lambda_g$	Mobility of oil, water and gas
M	Mobility ratio, $\frac{k_{rg}\mu_o}{\mu_g k_{ro}}$
μ_g	Gas viscosity, cp
μ_o	Oil viscosity, cp
μ_w	Water viscosity, cp
N_g	Corey gas exponent
N_o	Corey oil exponent
N_w	Corey water exponent
p_{ew}	Boundary pressure in water zone, psig
p_{eo}	Boundary pressure in oil zone, psig.
q_t	Total volumetric flow rate through area A
ρ_g	Gas density, g/cm3
ρ_o	Density of oil, g/cm^3
ρ_w	Density of water, g/cm^3
s_{gc}	Critical gas saturation
s_o	Oil saturation
s_{om}	Minimum oil saturation
s_{or}	Residual oil saturation
s_{orw}	Residual oil saturation in the oil-water relative permeability system
s_{rog}	Residual oil saturation in the gas-water relative permeability system
s_w	Water saturation
s_{wi}	Initial water saturation or connate water saturation
TVD	True vertical depth below rotary table (meter)

Chapter 1
INTRODUCTION

1.1 Background

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

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

Double displacement process (DDP) is one of the efficient methods to increase oil recovery as it takes advantages of gravitational drainage from injection of gas into waterflooded dipping reservoir to improve recovery factor. For conventional method of DDP, water and gas are injected from surface to oil reservoir which requires surface operation units.

In order to reduce cost of water and gas injection units, the concept of water and gas dumpflood is utilized in this study. By means of dumpflood, water and gas layers are connected to the oil layer via so-called dumping wells in order to allow both fluids to cross flow into the oil reservoir instead of injecting them from the surface.

The availability of water from an aquifer and gas from a gas reservoir in multi-layer reservoir system leads to an idea of studying the performance of Double

Displacement Process (DDP) which water from water aquifer displaces oil followed by gas dumpflood into an oil reservoir in comparison with conventional DDP.

1.2 Scopes of Works

In this study, the investigation of performance and comparison the effectiveness of both conventional and proposed method of DDPs is conducted by using reservoir simulator “ECLIPSE 100” with different production scenarios in order to find the optimum parameters of this method. This study covers

- performance comparison between different conventional oil recovery methods (natural depletion, waterflooding, gas flooding and DDP)
- Investigation effect of liquid production/water injection rate and gas injection rate on performance of conventional DDP
- Investigation the effect from different aquifer and gas reservoir sizes along with production schedules on performance of Double Displacement Process via water and gas dumpflood.
- Comparison of conventional oil recovery methods to the proposed method.

1.3 Objectives

- To determine the most appropriate operating conditions in terms of liquid production rate and intermittent production schedule of double displacement via water and gas dumpflood for system having different aquifer and gas reservoir sizes available for dumpflooding.
- To compare performance of the proposed method for system having different aquifer and gas reservoir sizes to other conventional recovery methods and suggest the most appropriate method for such system.

1.4 Methodology

- Collect various related literature and required data for reservoir simulation model.

- Construct homogeneous reservoir model and simulate conventional oil recovery methods (natural depletion, waterflooding, gas flooding, DDP) and compare their performance.
- Simulate and determine operating conditions which yield the highest recovery for conventional DDP case to be compared with the DDP dumpflood case.
- Add two additional reservoirs (aquifer and gas reservoir) into the existing model and simulate water and gas dumpflood via double displacement process with different reservoir system and operational parameters. Those parameters are:
    + Aquifer and gas reservoir size.
    + Target liquid production rate and intermittent production schedule.
- Discuss and summarize effects of reservoir and operational parameters on production performance of DDP via water and gas dumpflood
- Compare and analyze performance of conventional methods to the proposed method is compared and analyze

Chapter 2

LITERATURE REVIEW

2.1 Double Displacement Process

Carlson [1] studied performance of enhanced oil recovery of Hawkins Field Unit by implementing gas displacement of water invaded oil column which has been termed Double Displacement Process. Laboratory studies of 12 core plugs had shown that gas-liquid drainage mechanism achieved mean final oil saturation of 8.3 percent compared to water imbibed core at 18.4 percent. After obtaining favorable result from laboratory, Double Displacement Process was initiated in East Fault Block. Throughout the application of the DDP, the author expected to lower oil saturation from 35 percent to 12 percent by gas injection.

Johnston [2] operated an immiscible gravity stable CO2 flood diluted with methane at Week Island Louisiana. Pilot test had been conducted in high permeability sand reservoir in a deep (13,000 ft.) and hot (225 °F) reservoir with 26 degree of dip angle. Result from cores analysis showed that average oil saturation was reduced from 22 percent to an average of 1.9 percent. Oil recovery from pilot test was 66 percent of the OOIP, about 60 percent of oil unrecovered by water displacement.

Fassihi et al. [3] performed a numerical simulation of DDP with air injection to study the effect of the gravity drainage enhancement in dipping reservoir due to heat obtained from the oxidation of oxygen with oil, and mobilized oil front in West Hackberry Field. Result from simulation indicated that oil recovery was estimated to be improved to 90 percent from 60 percent compared to waterdrive recovery. The author also suggested reservoir parameters which are crucial for DDP such oil viscosity, and dip angle of the reservoir.

Ran et al. [4] developed a sandpack micromodel to conduct a pore level observation to investigate the effect of the DDP and Second Contact Water Displacement (SCWD) processes. From investigation, it was confirmed that gas front entered center of pore and displaced residual oil. Those displaced oil droplets were joining together and formed oil bank, and it was pushed to the outlet. This result indicates that both of the processes are efficient to recover waterflood residual oil.

Gachuz-Muro et al. [5] investigated efficiency of DDP and SCWD in oil recovery for a group of fractured carbonate cores. Results from experiment indicated that DDP from natural gas injection yielded 64 percent oil recovery compared to that of water gravity imbibition which was 47 percent and that of DDP with nitrogen injection which was 51 percent. The author proved that DDP is capable of mobilizing light oil in naturally fractured reservoir and also suggested using natural gas as source of gas injection which can recover more of OOIP compared to nitrogen.

Suwannakul [6] performed numerical simulation and sensitivity analysis of DDP performed on a hypothetical reservoir. This study investigated the effect of several parameters such as criteria to stop water flooding and residual oil saturation of the formation. From results, the author found an optimal water cut to stop water injection of 85 percent compared to 90 and 95 percent due to very high reduction in production time with reasonable amount of recovery factor.

Satitkanitkul [7] investigated performance of DDP under different conditions via numerical simulation. Parameters which were investigated in this study are dip angle of the reservoir, stopping criteria for waterflooding, water injection rates, gas injection rates and well patterns. Results from simulation showed that waterflood stopping criteria of 60 percent water cut is the optimal point. Higher dip angle increased recovery factor and reduced production period. The author also suggested that injecting with water rate of 8000 RB/D and gas rate of 8000 RB/D yield the best oil recovery with the shortest production period. Results also proved that two horizontal producers, one down dip and one up dip, yield the highest recovery for reservoir with 60 degree dip angle.

Urairat [8] performed a numerical simulation and sensitivity analysis of various parameters to investigate the performance of gas dumpflood in waterflooded reservoir. Parameters such as dip angle, residual oil saturation, oil viscosity, effective vertical to horizontal permeability, thickness of gas reservoir and depth differences between oil and gas layers were investigated in this study. After performing numerical simulation, results showed that lower residual oil saturation yielded higher in recovery factor. When thickness of gas source increases, oil recovery also increases as high pressure and a large quantity of gas swept more oil.

Chetchaovalit [9] constructed a homogenous reservoir simulation model using black-oil ECLIPSE100 reservoir simulator to compare production performance between Water Alternating Gas (WAG) and Double Displacement Process (DDP). Results from simulator showed that water cut stopping criteria had minimal effect on oil production. Hence, lower water cut was considered better choice since it lowered production time and reduced cost of water treatment. Increasing injection rate also gave a good result but it was limited by fracture pressure of the formation. The author also pointed out that WAG yielded maximum BOE with moderate gas injection but for DDP, it occurred when gas was injected at the highest rate.

Rakjarit [10] conducted a numerical study to use multiple gas reservoirs as source of gas dumpflood into oil reservoir to maintain pressure and sweep oil toward the producer in Double Displacement Process. In this study, author investigated the effect of perforation program, operational liquid rate and characteristic of gas reservoir to Double Displacement Process. As numerical simulation had been conducted, result showed that full to base perforation of all gas layers provided the highest recovery factor than two batches of perforation since it raised more pressure to oil reservoir at the early stage and maintained plateau production. During water flood period, higher liquid rate was also recommended as it could speed up the production time while different rates of liquid injection did not affect much. Previous study had shown that lowering liquid production rate hence lowering gas inflow increased oil recovery factor but due to time constrain, moderate rate of liquid production rate was recommended. A moderate rate can yield greater amount of oil within time period but in higher liquid rate cause unsmooth flood front which leads to early gas breakthrough.

The previous studies proved that DDP is an effective oil recovery method. Results are not only obtained from the laboratory or the simulator, but also applied in real oil reservoirs. However, conventional DDP is a high cost method to produce the oil. To solve this issue, water and gas dumpflood are introduced to eliminate the cost of water and gas injection. Anyhow, operational and reservoir system parameters have a strong effect on the performance of oil production in DDP with water and gas dumpflood. Therefore, the investigation of each parameter is necessary to understand its effect to DDP dumpflood.

2.2 Water Dumpflood

Quttainah et al. [11] initiated water dumpflood pilot in Minagish Oolite reservoir at Umm Gudair Oil Field in Kuwait. The objective of this study was to prove the applicability, sweep benefit, pressure maintenance, observe reservoir response and production acceleration of water dumpflood. As this test showed a very good result in increasing reservoir pressure, improving sweep efficiency and avoiding bypassing oil, and its cost-effectiveness, water dumpflood would be expanded and be used for full field implementation to slow down the falling of reservoir pressure in Umm Gudair Oil Field.

Helaly et al. [12] initiated a water dumpflood project to slow down reservoir pressure decline which replaced from conventional water injection due to some operational problems caused by lengthy injection (the oil field is approximately 10 kilometer away from water-source). Problems such as line leakage, corrosion and blockage required regular maintenance. The author suggested that water source zone should have a relatively high pressure with good rock properties and the compatibility of water between both zones. Limitation of water dumpflood was also mentioned such as difficulty of controlling downhole injection rate, injection rate restriction to the productivity of source zone, injection rate change with pressure change. Result from pilot project showed that dumpflood saved cost, eliminated problems resulted from fluid transferring facilities to injection wells especially for remote area where fluid source was too far.

2.3 Gas Dumpflood

Rinadi et al. [13] performed a pilot test of in-situ gas lift and gas dumpflood in a partially depleted oil reservoir at North Arthit Field, Gulf of Thailand. This pilot test successfully increased recovery factor from this type of reservoir. The author had pointed out that this method was a very good solution to save capital investment and operational cost. There are also some operational parameters which impact chance of success such as perforation design and oil production restriction to prevent gas coning.

Chapter 3

THEORY AND CONCEPT

This chapter summarizes the essential theory and concept of Double Displacement Process via water and gas dumpflood. The discussion is divided into nine sections which are 1) waterflooding, 2) immicible gas flooding, 3) gavity assisted drainage, 4) double displacement process, 5) mobility and mobility ratio, 6) water dumpflood, 7) gas dumpflood, 8) relative permeability and 9) fracture pressure.

3.1 Waterflooding

Displacing efficiency of waterflooding is generally related to fractional flow equation which is provided by Leverett [14]. Fractional flow equation of a type of fluid is defined as that fluid flow rate divided by the total of flow rate. Eq. (3.1) is fractional flow of water in water displacement.

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

where

f_w	=	fractional of water, bbl/bbl
k	=	absolute permeability, md
k_{ro}	=	relative permeability to oil, md
k_{rw}	=	relative permeability to water, md
μ_o	=	viscosity of oil, cp
μ_w	=	viscosity of water, cp
ρ_o	=	density of oil, g/cm^3
ρ_w	=	density of water, g/cm^3

A = cross-sectional area, ft^2

i_w = water injection rate, bbl/day

α = dip angle

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

Oil recovery is usually more efficient with down-dip water injection due to the advantage of gravity drainage. Eq. 3.1 can be rewritten in simplified form to determine the effect of dip angle and injection rate.

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

where

$$X = \frac{(0.001127)(0.0433)(kk_{ro})A(\rho_w - \rho_o)}{\mu_o}$$

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

When other parameters are treated as constant, the fractional flow curve will depend on injection rate. When oil is displaced up-dip, a lower injection rate is desirable because $X \frac{\sin(\alpha)}{i_w}$ term increases. This leads to a downward shift of f_w curve, which indicates better displacement efficiency. This requirement is in the opposite direction with the down-dip flow, which requires a high injection rate by Ahmed [14].

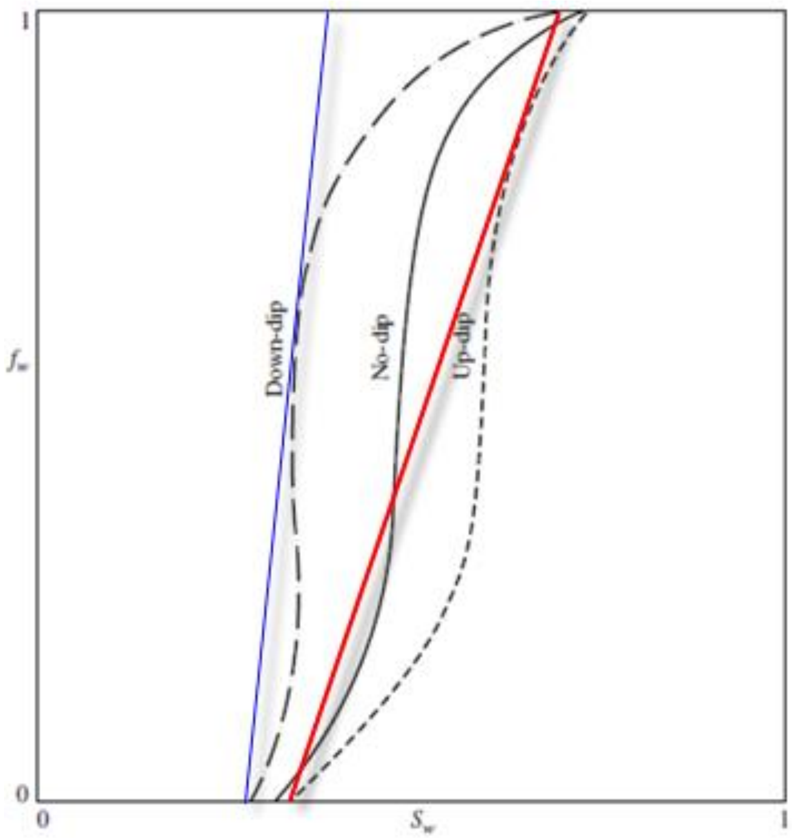


Figure 3.1 Effect of dip angle on fractional flow curve at the same injection rate [14].

Figure 3.1 shows that as water is injected to displace the oil toward up-dip location, it results in higher value of f_w and $\overline{S_w}$. This leads to a better displacement efficiency and results in a lower oil saturation left behind the flood front.

3.2 Immiscible Gas Flooding

Immiscible gas flooding operates at low pressure, which is not high enough to generate the miscible phase. The behavior of flooding process can also be described in fractional flow equation for gas/oil system as follows [14]:

$$f_g = \frac{1 - \left(\frac{[0.044(kk_{ro})(\rho_g - \rho_o)A\sin(\alpha)}{\mu_o i_g} \right)}{1 + \frac{k_{ro}}{k_{rg}} \frac{\mu_g}{\mu_o}} \qquad \text{Eq. (3.3)}$$

where

i_g = gas injection rate, ft^3/day

μ_g = gas viscosity, cp

ρ_g = gas density, lbm/ft^3

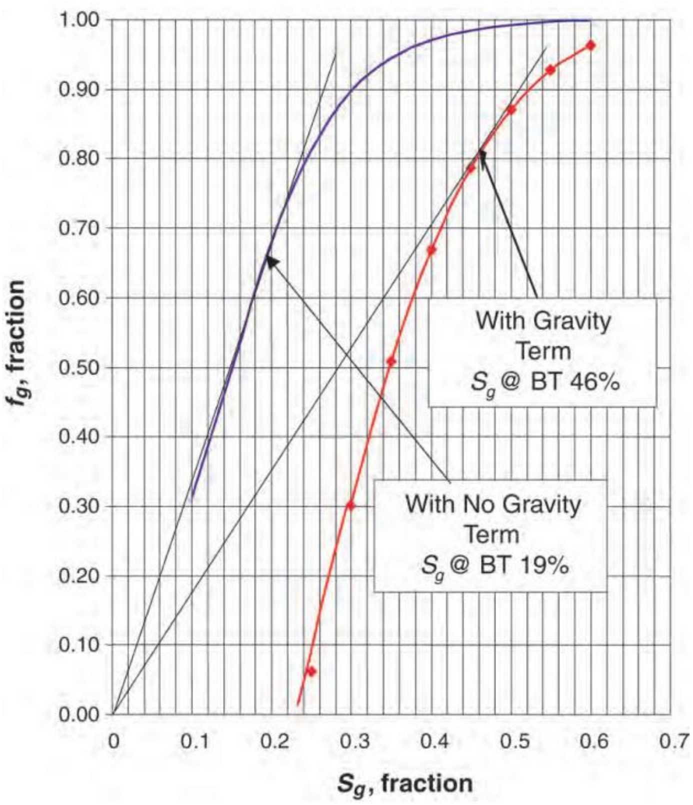


Figure 3.2 Effect of gravity on gas/oil fractional flow curve (after Lake [15])

The dip angle of the formation attributes in improving gas flooding process as shown in Figure 3.2. This figure shows an improvement in gas fractional flow and reduction in oil saturation left behind gas front resulted from gravity effect of gas injection. From Eq. (3.3), it clearly be seen that the gravity term becomes positive when gas is displacing oil from updip direction. The effect of gravity term is illustrated in Figure 3.2. The better displacement efficiency confirms that displacing oil updip (injecting gas at the top) is more favorable.

3.3 Gravity Assisted Drainage

Performance of Gas-Assisted Gravity Drainage (GAGD) process in dipping oil reservoir is significantly influenced by the dip angle of the reservoir and injection rates. Fractional flow of gas which was developed by Welge [16] will be taken into the discussion to understand the effect of the dip angle and injection rate. Assumptions used in his work are steady-state flow, constant pressure, no compositional effect, no capillary effect and uniform cross-sectional flow.

Injection rate is also an important parameter that strongly affects gas-oil interface. Two scenarios happen when gas is injected at the top, one where the injection rate is so low that interface is horizontal showing complete gravity stability as illustrated in Figure 3.3 (a) another where the injection rate is so high that the interface become unstable and thus gas advances along the top of the layer bypassing oil at the bottom (gas overriding effect) as illustrated in Figure 3.3 (b)

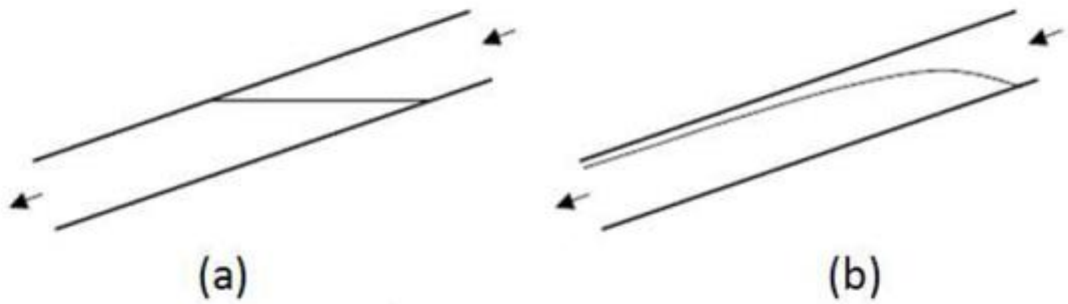


Figure 3.3 Effect of injection rate on gas flooding when displacing oil downdip [17] (a) Stable flood front with proper rate (b) Unstable flood front with too high rate

3.4 Double Displacement Process

Double displacement process (DDP) is defined as gas displacement of a previously water displaced oil column in order to mobilize and produce incremental oil. Additionally produced oil results from a difference in residual oil saturation in the presence of water as compared to that in the presence of gas. Gravity stable downward displacement of oil causes the creation of an oil bank, which accumulates progressively as gas migrates oil downward towards producing well. A simplified schematic of the Hawkins field unit of a dipping reservoir subjected to DDP is shown in Figure 3.4.

Before initiation of gas injection, residual oil is trapped by capillary retention forces that are greater than forces applied. Residual oil may be in contact with the surface of pore network (oil-wet rocks), trapped as globules surrounded by water contacting pore network surface (water-wet rocks) or a combination of the preceding may occur in the case of mixed wettability.

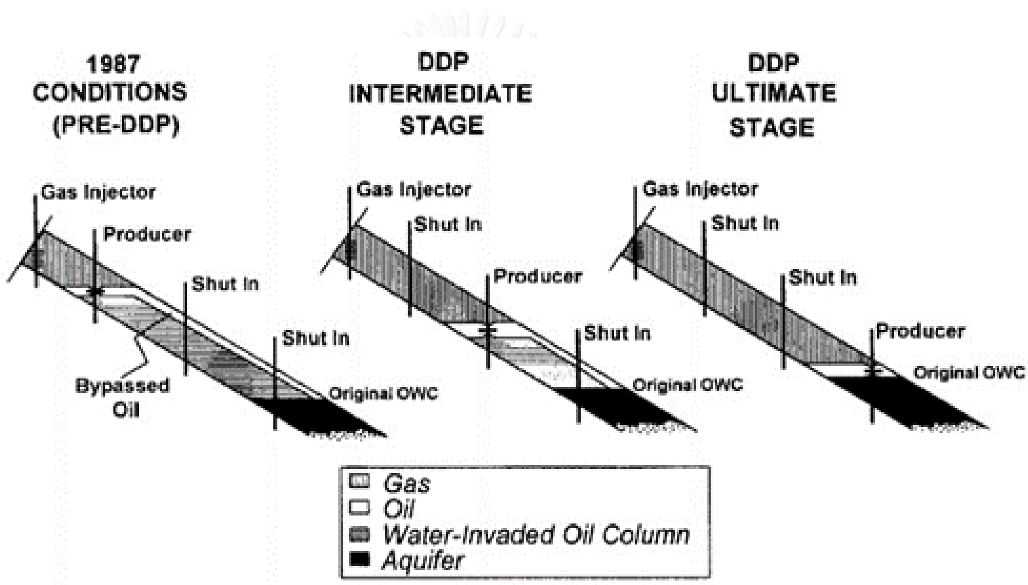


Figure 3.4 Double displacement process case study Hawkins field unit, Carlson [1]

By the introduction of a gas phase into the system creates conditions for three phase flow. When gas enters a pore space which contains residual oil globules, capillary forces cause oil to spread between water coating pore wall and gas bubble occupying the center of the pore, as shown in Figure 3.5. This condition allows oil phase to reconnect. The reconnected oil film flows downward due to gravity forces and creates an oil bank as shown in Figure 3.6. As more gas is injected, existing oil bank flows downwards encompassing residual oil blobs as it travels.

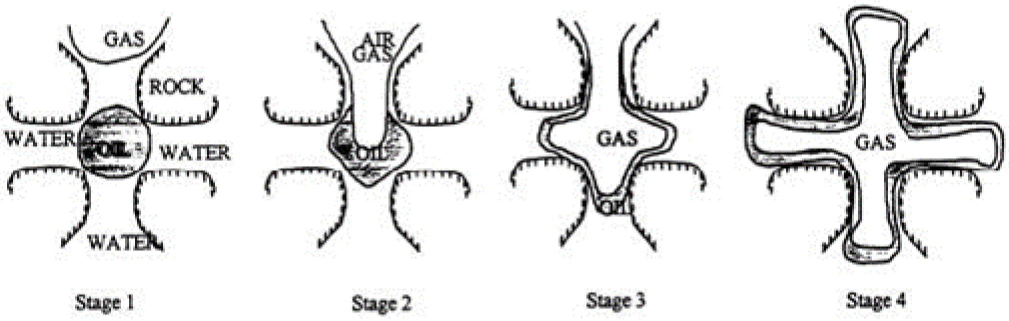


Figure 3.5 Pore scale of gas displacing remaining oil [6].

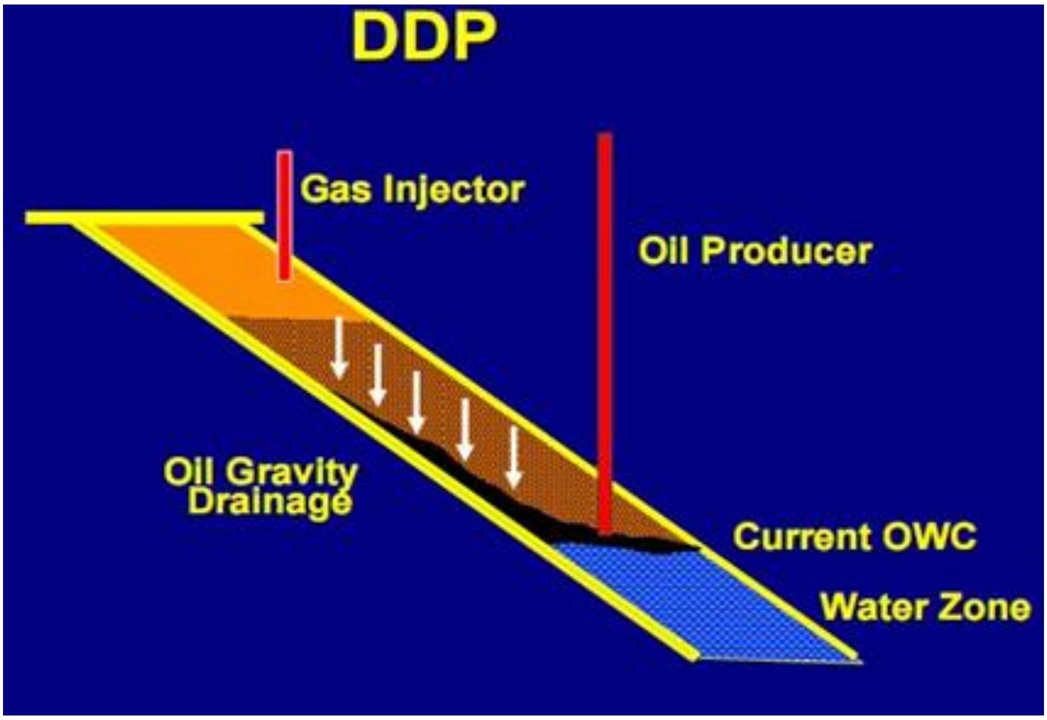


Figure 3.6 Oil gravity drainage after gas injection [6].

Oil production at the early stage has a very low rate because of the thickness of oil rim is still low. By given sufficient time, the flow of oil through the oil films can result in higher thickness. However, lengthy production time at a low rate is detrimental to the economic success of the process.

3.5 Mobility and Mobility Ratio

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

$$\lambda_o = \frac{k_o}{\mu_o} = \frac{kk_{ro}}{\mu_o} \qquad \text{Eq. (3.5)}$$

$$\lambda_w = \frac{k_{rw}}{\mu_w} = \frac{kk_{rw}}{\mu_w} \qquad \text{Eq. (3.6)}$$

$$\lambda_g = \frac{k_g}{\mu_g} = \frac{kk_{rg}}{\mu_g} \qquad \text{Eq. (3.7)}$$

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

$$M = \frac{\lambda_{displacing}}{\lambda_{displaced}} \qquad \text{Eq. (3.8).}$$

where

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

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

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

3.6 Water Dumpflood

Water Dumpflood is a process in which water flows from an aquifer to an oil reservoir naturally and sweeps the oil toward the producing well. This can be achieved by using water from overlying or underlying aquifer which has high water quantity and pressure potential feeding water into the oil reservoir of lower fluid potential by placing the two zones in communication through a well so that the oil reservoir is provided with pressure support and the oil is displaced by water coming into the reservoir [18] as illustrated in Figure 3.7.

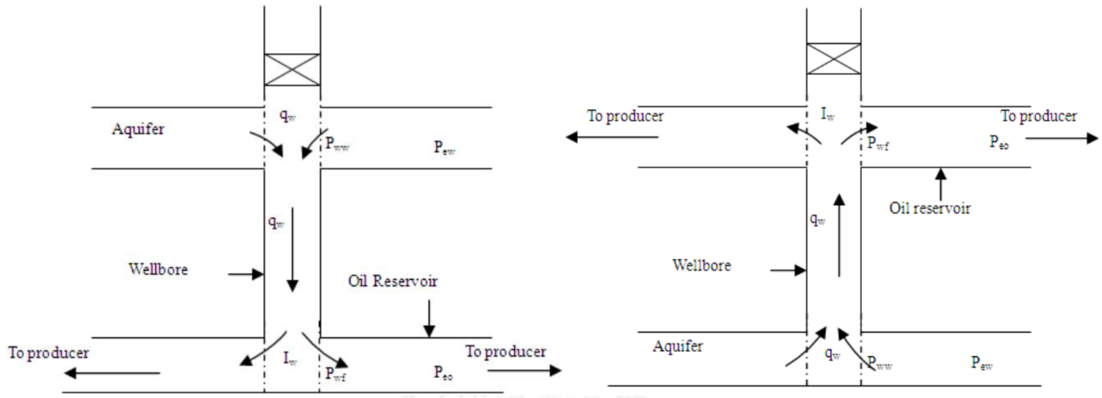


Figure 3.7 Upward and downward flow mechanism [18]

Davies [19] demonstrated that rate at which fluid transfers from one zone to another is a constant value if the reservoir static pressure in both zones is maintained.

$$I_w = \left[\frac{1}{I} + \frac{1}{J} + \Delta p_{fr}\right] = p_{ew} - p_{eo} \qquad \text{Eq. (3.9)}$$

where

I_w	=	water producing rate into oil reservoir, BWPD
I	=	injectivity index, BWPD/psi
J	=	productivity index, BWPD/psi
Δp_{fr}	=	friction pressure drop, psi
p_{ew}	=	boundary pressure in water zone, psig
p_{eo}	=	boundary pressure in oil zone, psig

3.7 Gas Dumpflood

Gas dumpflood also follows the same concept as water dumpflood with the same principle of reservoir pressure maintenance and oil displacement. Gas dumpflood or gas injection is usually conducted when there is already an available source of gas nearby. When gas is injected or dumped into the reservoir, several mechanisms happen such as reservoir pressure maintenance, oil displacement in both horizontal and vertical directions, vaporization of liquid hydrocarbon components, swelling of oil in case of undersaturated oil at initial reservoir condition.

Material Balance Equation can also be applied to water and gas dumped into an oil reservoir similarly to conventional water or gas injection:

$$N_p\left[B_o+\left(R_p-R_s\right)B_g+W_pB_w\right]=N\left[\left(B_o-B_{oi}\right)+\left(R_{si}-R_s\right)B_g\right]+mNB_{oi}\left(\frac{B_g}{B_{gi}}-1\right)+$$

$$N(1+m)B_{oi}\left[\frac{c_w s_w+c_f}{1-s_{wi}}\right]\Delta p+W_e+W_{inj}B_w+G_{inj}B_g \qquad \text{Eq. (3.10)}$$

where

$N_p\left[B_o+\left(R_p-R_s\right)B_g\right]$ Reservoir volume of cumulative oil and gas produced

$\left[W_e-W_pB_w\right]$ Net water influx that is retained the reservoir

$\left[W_{inj}B_w+G_{inj}B_g\right]$ Pressure maintenance terms representing cumulative fluid injection or dump into the reservoir

$N(1+m)B_{oi}\left[\frac{c_w s_w+c_f}{1-s_{wi}}\right]\Delta p$ Formation rock and water expansion

$\left[mNB_{oi}\left(\frac{B_g}{B_{gi}}-1\right)\right]$ Net expansion of the gas in the gas cap that occurs during the production of N_p stock tank barrels of oil

where

B_g = Gas formation volume factor

B_o = Oil formation volume factor

B_w = Water formation volume factor

c_w = Water compressibility

c_f = Formation compressibility

G_p = Cumulative gas production

G_{inj} = Cumulative gas injection

m = Ratio of initial volume gas to initial volume of oil

N = Original Oil in Place (OOIP)

N_p = Cumulative oil production

R_p = Producing GOR

R_s = Solution gas oil ratio

W_{inj} = Cumulative water injection

W_p = Cumulative water production

3.8 Relative Permeability

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

3.8.1 Corey's Correlation

Corey's correlation [20] is used in ECLIPSE reservoir simulator for generating relative permeability for two-phase flow as a function of fluid saturation. Corey's correlation can be used in both oil-water system and oil-gas system.

Oil-water system

$$k_{row} = \left(\frac{1 - s_w - s_{or}}{1 - s_{wi} - s_{or}} \right)^{N_o} \qquad \text{Eq. (3.11)}$$

$$k_{rw} = k_{rwend} \left(\frac{s_w - s_{wi}}{1 - s_{wi} - s_{or}} \right)^{N_w} \qquad \text{Eq. (3.12)}$$

Oil-gas system

$$k_{rog} = \left(\frac{1 - s_{wg} - s_{wi} - s_{or}}{1 - s_{wi} - s_{or}} \right)^{N_o} \quad \text{Eq. (3.13)}$$

$$k_{rg} = \left(\frac{s_g - s_{gc}}{1 - s_{wi} - s_{or} - s_{gc}} \right)^{N_g} \quad \text{Eq. (3.14)}$$

where

s_w	=	water saturation
s_{or}	=	residual oil saturation
s_{wi}	=	initial water saturation or connate water saturation
s_{gc}	=	critical gas saturation
s_g	=	gas saturation
k_{ro}	=	relative permeability to oil at any water saturation
k_{rw}	=	relative permeability to water at any water saturation
k_{rg}	=	relative permeability to gas at any water saturation
k_{rwend}	=	relative permeability to water at minimum water saturation
N_w	=	Corey water exponent
N_o	=	Corey oil exponent
N_g	=	Corey gas exponent

3.8.2 Three-phase Flow

ECLIPSE or default model for the three-phase oil relative permeability is based on an assumption that water and gas are completely segregated, except that the water saturation in the gas zone is equal to the connate saturation s_{wco} the block average saturations are s_o, s_w and s_g (with $s_o + s_w + s_g = 1$) [21]. Oil saturation is assumed to be constant and equal to the block average value, s_o throughout the cell.

Gas zone

Within the fraction $\frac{s_g}{s_g + s_w - s_{wco}}$ of the cell

where

s_o	=	oil saturation
s_{wco}	=	water saturation
$s_g + s_w - s_{wco}$	=	gas saturation

Water zone

Within the fraction $\frac{s_w - s_{wco}}{s_g + s_w - s_{wco}}$ of the cell

where

s_o	=	the oil saturation
$s_g + s_w$	=	the water saturation
Gas saturation	=	0

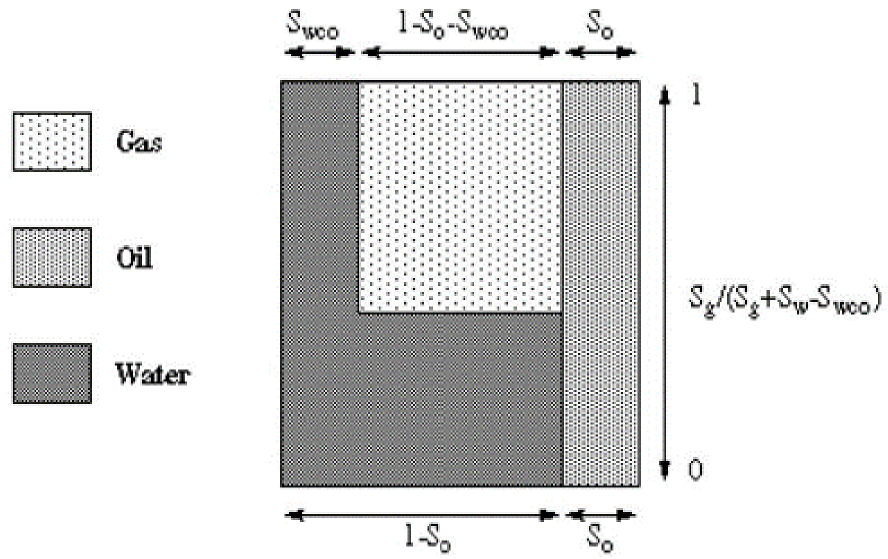


Figure 3.8 The default three-phase oil relative permeability model assumed by ECLIPSE [21]

Oil relative permeability is then given by:

$$k_{ro} = \frac{s_g k_{rog} + k_{row}(s_w - s_{wco})}{s_g + s_w - s_{wco}} \quad \text{Eq. (3.15)}$$

where

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

k_{row} = Oil relative permeability for a system with oil and water only, also tabulated as a function of s_o

3.8.3 Stone's Model I

Stone's technique requires two sets of data which are water-oil and gas-oil [22]. To use this method, those two sets of two-phase data are interpolated in order to obtain three-phase relative permeability. Normalized saturation are defined by treating connate water and irreducible residual oil as immobile fluids:

$$s_o^* = \frac{s_o - s_{om}}{(1 - s_{wc} - s_{om})} \quad (\text{for } s_o > s_{om}) \quad \text{Eq. (3.16)}$$

$$s_w^* = \frac{s_w - s_{wc}}{(1 - s_{wc} - s_{om})} \quad (\text{for } s_o > s_{om}) \quad \text{Eq. (3.17)}$$

$$s_g^* = \frac{s_g}{(1 - s_{wc} - s_{om})} \quad \text{Eq. (3.18)}$$

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

$$k_{ro} = s_o^* \beta_w \beta_g \quad \text{Eq. (3.19)}$$

The two multiplier β_w and β_g are determined from:

$$\beta_w = \frac{k_{row}}{1 - s_w^*} \quad \text{Eq. (3.20)}$$

$$\beta_g = \frac{k_{rog}}{1 - s_w^*} \quad \text{Eq. (3.21)}$$

where

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

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

s_{om} = Minimum oil saturation

The difficulty in using Stone's Model I is selecting the minimum oil saturation s_{om}. Fayers and Mathews [23] suggested an expression for determining s_{om}.

$$s_{om} = \alpha s_{orw} + (1-\alpha) s_{org} \qquad \text{Eq. (3.22)}$$

with

$$\alpha = 1 - \frac{s_g}{1 - s_{wc} - s_{org}} \qquad \text{Eq. (3.23)}$$

where

s_{orw} = residual oil saturation in the oil-water relative permeability system

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

Aziz and Settari [24] pointed out that Stone's correlation could give k_{ro} value which is greater than the unity. That is why the authors suggested the following equation which is normalized form Stone's:

$$k_{ro} = \frac{s_o^{*}}{(1-s_w^{*}) - (1-s_g^{*})} \left(\frac{k_{row} k_{rog}}{(k_{ro}) s_{wc}} \right) \qquad \text{Eq. (3.24)}$$

where

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

3.8.4 Stone's Model II

The Stone's model II is the modified version of the first model of Stone due to the difficulties in choosing S_{om} [25]

$$k_{ro} = (k_{ro})s_{wc}\left[\left(\frac{k_{row}}{(k_{ro})s_{wc}} + k_{rw}\right)\left(\frac{k_{rog}}{(k_{ro})s_{wc}} + k_{rg}\right) - \left(k_{rw} + k_{rg}\right)\right] \qquad \text{Eq. (3.25)}$$

3.9 Fracture Pressure

Practically, injection pressure should not be higher than the fracture pressure of the reservoir. By doing so, it prevents well damaging from happening. Rangponsumrit [26] used the following correlation to calculate fracturing pressure in the Gulf of Thailand:

$$\text{Fracture Pressure (bar)} = \frac{FRAC.\text{S.G}\times\text{TVD}}{10.2} \qquad \text{Eq. (3.26)}$$

And

$$FRAC.S.G = 1.22 + \left(TVD \times 1.6 \times 10^{-4}\right) \qquad \text{Eq. (3.27)}$$

where

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

Chapter 4
RESERVOIR SIMULATION MODEL

4.1 Grid Section

Simulation model of this study consists of three homogeneous water, oil and gas layers in rectangular shape as shown in Figure 4.1 with properties shown in Table 4.1, Table 4.2, and Table 4.3 for aquifer, oil reservoir and gas reservoir, respectively. Note that two different water aquifer sizes, namely, 10PV and 50PV are used in this study. The schematic of the aquifers are shown in Figure 4.1 and Figure 4.2. For gas reservoir, two sizes of gas reservoir 1PV and 5PV are also studied.

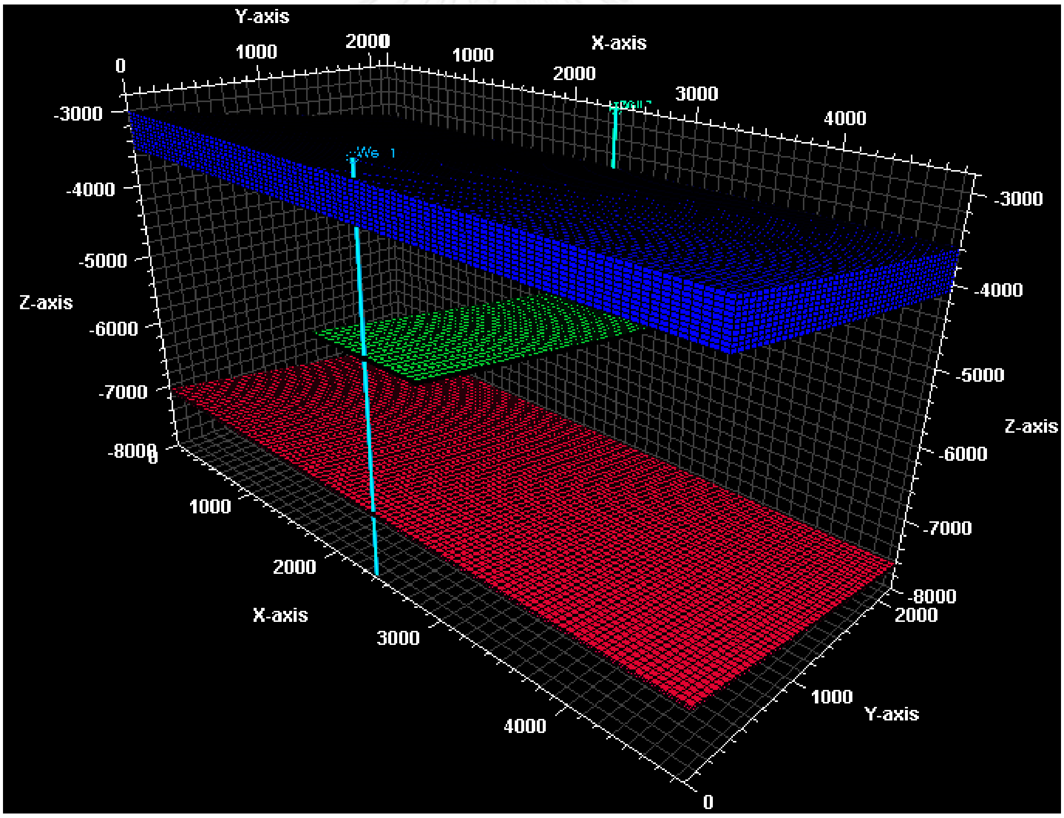


Figure 4.1 Reservoir model with 15° dip angle with overlying 50PV water aquifer & underlying 5PV gas

Table 4.1 Aquifer properties

Parameters	Values	Unit
Number of grid cells	10PV: 19 x 45 x 10 50PV: 95 x 45 x 10	cells
Aquifer Dimension	10PV: 950 x 2,250 x 500 50PV: 4,750 x 2,250 x 500	cu. ft.
Effective porosity	21.5	%
Horizontal permeability	126	mD
Vertical permeability	12.6	mD
Top of aquifer	3,000	ft.
Initial pressure at datum depth (top of aquifer)	1,284	psia
Average aquifer temperature	146	°F
Initial water saturation	25	%

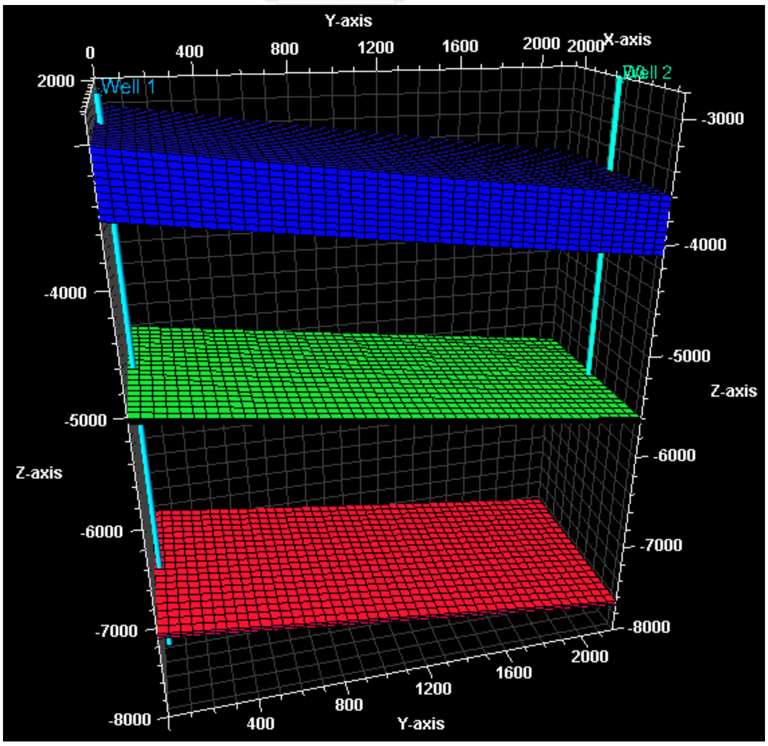


Figure 4.2 Reservoir model with 15° dip angle with overlying 10PV water aquifer & underlying 1PV Gas

Table 4.2 Oil reservoir properties

Parameters	Values	Unit
Number of grid cells	19 x 45 x 10	cells
Size of reservoir	950 x 2,250 x 50	cu. ft.
Effective porosity	21.5	%
Horizontal permeability	126	mD.
Vertical permeability	12.6	mD.
Top of reservoir	5,000	ft.
Initial pressure at datum depth (top of reservoir)	2,170	psia
Average reservoir temperature	172	°F
Fracturing pressure (updip)	3,150	psia
Fracturing pressure (downdip)	3,500	psia
Initial water saturation	25	%

Table 4.3 Gas reservoir properties

Parameters	Values	Unit
Number of grid cells	1PV: 19 x 45 x 2 5PV: 95 x 45 x 2	cells
Size of reservoir	1PV: 950 x 2,250 x 50 5PV: 4,750 x 2,250 x 50	cu. ft.
Effective porosity	21.5	%
Horizontal permeability	126	mD.
Vertical permeability	12.6	mD.
Top of reservoir	7,050	ft.
Initial pressure at datum depth (top of reservoir)	3,288	psia
Average Reservoir temperature	200	°F
Initial water saturation	25	%

4.2 PVT Properties

Table 4.4 Input parameters for PVT properties correlation

Parameters	Aquifer	Oil reservoir	Gas reservoir	Unit
Fluid Properties at surface condition				
Oil gravity	-	25	-	°API
Gas gravity	-	0.8	0.7	Sg (air)
Gas-oil ratio	-	200	-	SCF/STB
Reservoir pressure (Top formation)	1,274	2,170	3,288	psi
Average Reservoir Temperature	146	172	200	°F
Salinity	5000	5000	5000	ppm

4.3 Special Core Analysis (SCAL)

Parameters in Table 4.5 are used to input into simulator to create two-phase relative permeability by using Corey's correlation. ECLIPSE simulator default model is used to determine three-phase permeability. Parameters in Table 4.5 are based on a study conducted for a reservoir in Thailand.

Table 4.5 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_{grc}	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_{omax})	0.4	K_{ro} (S_{gmin})	0.8
K_{rw} (S_{wmax})	1				

4.4 Well Control

The lifetime of a well is set to 30 years due to the concession agreement in Thailand. Table 4.6 contains parameters which are used to input into the simulator as well control to set the up-dip well P1 as a production well and the down-dip well P2 as a water dumping well during the water dumpflood phase. The bottomhole target of the production well is set at 500 psia to represent the minimum pump intake pressure for the production well.

Table 4.7 illustrates the control parameters to set the up-dip well as gas dumping well and the downdip well as a production well during gas dumpflood. Similar to Table 4.6, the bottomhole pressure of 500 psia is used to set the minimum intake pressure of the pump required to produce the fluids from the reservoir to surface. After gas breakthrough, the production well is controlled by a vertical flow performance table with tubing head pressure of 300 psia as depicted in Table 4.8. Production tubing has an inner diameter of 2.992 inches with tubing roughness of 0.0006 inch.

Table 4.6 Production well control water dumping phase

Well	Well P1 (updip)	Well P2 (downdip)
Open/Shut Flag	OPEN	STOP
Liquid rate	500, 1000, 1500 STB/D	-
BHT target	500 psia	-
Shut-in condition	Oil rate < 50 STB/D	Aquifer pressure < 300 psia

Table 4.7 Production well control gas gas dumping phase before gas breakthrough (GLR < 1 Mscf/STB)

Well	Well P1 (updip)	Well P2 (downdip)
Open/Shut Flag	STOP	OPEN
Liquid rate	-	500, 1000, 1500 STB/D
BHT target	-	500 psia
Shut-in condition	-	Oil rate < 50 STB/D

Table 4.8 Production well control gas dumping phase after gas breakthrough (GLR > 1 Mscf/STB)

Well	Well P1 (updip)	Well P2 (downdip)
Open/Shut Flag	STOP	OPEN
Liquid rate	-	500, 1000, 1500 STB/D
THP target	-	300 psia
Shut-in condition	-	Oil rate < 50 STB/D

4.5 Methodology

The detail of thesis methodology is described as follows:

- Collect various related literature and required data for reservoir simulation model.
- Construct reservoir model with 15^{o} dip-angle, simulate conventional oil recovery methods according to simulation strategy in Table 4.9 and compare their performance.

Table 4.9 Simulation strategy for comparing between different recovery mechanisms

Strategy	Water injection rate *(STB/D)*	Target liquid rate (STB/D)	Gas injection rate MMSCF/D	Number of cases (cases)
Natural depletion	-	500	-	1
Water flooding	-	500	-	1
Gas flooding	-	500	8	1
DDP	500	500	8	1
Total				4

- Simulate production strategy shown in Table 4.10 and determine operating conditions which yields the highest recovery for conventional DDP case and select as a reference case to be compared with the DDP dumpflood case.

Table 4.10 Simulation strategies for conventional DDP

<table>
<tr><th>Water injection rate (STB/D)</th><th>Target liquid production rate (STB/D)</th><th>Gas injection rate MMSCF/D</th><th>Number of cases (cases)</th></tr>
<tr><td colspan="2" rowspan="3">500</td><td>8</td><td>1</td></tr>
<tr><td>12</td><td>1</td></tr>
<tr><td>16</td><td>1</td></tr>
<tr><td colspan="2" rowspan="3">1000</td><td>8</td><td>1</td></tr>
<tr><td>12</td><td>1</td></tr>
<tr><td>16</td><td>1</td></tr>
<tr><td colspan="2" rowspan="3">1500</td><td>8</td><td>1</td></tr>
<tr><td>12</td><td>1</td></tr>
<tr><td>16</td><td>1</td></tr>
<tr><td colspan="3">Total</td><td>9</td></tr>
</table>

- Add aquifer and gas reservoir into the existing model and simulate water and gas dumpflood via double displacement process with different operational parameters and reservoir system parameters in order to study the effect of those parameters on oil recovery as described in Table 4.11. Those parameters are:
    + Reservoir system parameters:
        - Aquifer size: 10PV and 50PV
        - Gas reservoir size: 1PV and 5PV

+ Operational parameters:

i. Different target liquid production rates in each production phase 500, 1000, 1500 STB/D

ii. Intermittent of the production schedule represented by off/on ratio: 0 (always on) , 1 (1 month off/1 month on), 2 (2 months off/1 month on)

Table 4.11 Detail of reservoir simulation strategies for water and gas dumpflood DDP

Strategy	Intermittent production	Water reservoir size	Gas reservoir Size	Target liquid production rate (STB/D)	Number of cases
Water and Gas dumpflood DDP	no off always on			500	3 x 2 x 2 x 3 = 36
	1 month off 1 month on	10 PV	1 PV	1000	
	2 months off 1 months on	50 PV	5 PV	1500	
Total					36

- Discuss and summarize effects of reservoir and operational parameters on production performance of DDP via water and gas dumpflood
- Compare performance of conventional methods to the proposed method and analyze
- Make conclusions

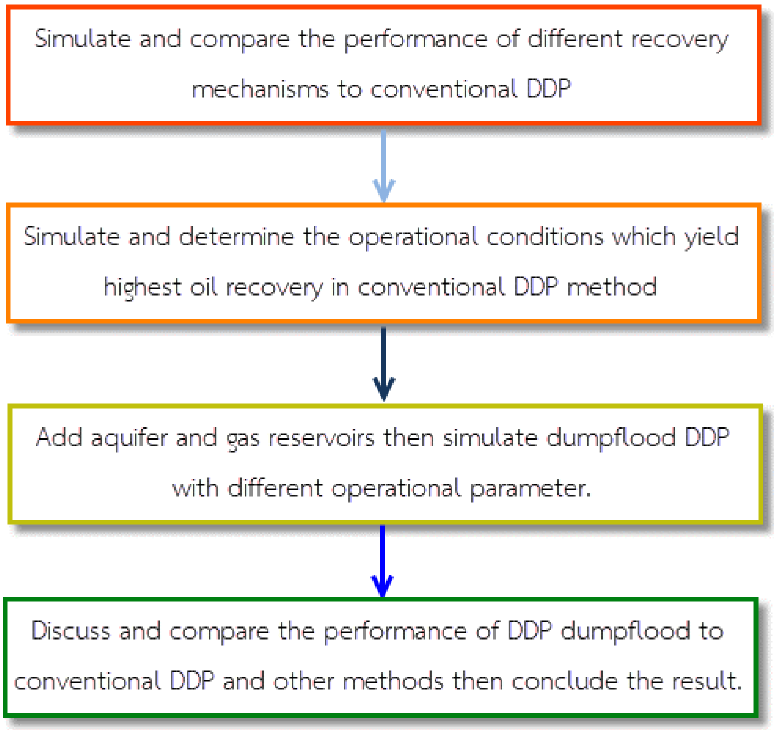


Figure 4.3 Flowchart of the methodology

Chapter 5
SIMULATION RESULTS AND DISCUSSION

This chapter discusses simulation results of DDP over other production methods such as natural depletion, waterflooding and gas flooding in term of recovery factor. Then, the maximum oil recovery in conventional DDP from varying the operational parameters obtained which is selected as a reference point to compare with the Double Displacement Process via Water and Gas Dumpflood. The results of Double Displacement Process via Water and Gas Dumpflood using the model described in Chapter 4 are analyzed and discussed. Then, the effect from each of different reservoir combinations are discussed in detail to determine the most favorable operational condition in each combination. Those operational parameters included the target liquid production rate and intermittent production. Finally, the optimum conditions are selected to compare with the reference of oil recovery obtained from other methods.

5.1 Performance of Different Recovery Mechanisms

This section discusses about the overall recovery comparison between DDP and other methods such as natural depletion, waterflooding and gas flooding to see whether if DDP should be implemented over conventional water or gas flooding. From Table 5.1, DDP shows the highest recovery followed by gas flooding, waterflooding and natural depletion of 82.54, 82.15, 54.89 and 27.12 percent, respectively. Performance of DDP is very remarkable compared to conventional waterflood and natural depletion as it increases oil recovery factor of 27.12 and 54.89 percent, respectively, to 82.54 percent. In addition to oil recovery, DDP reduces the amount of produced water and water injection by 0.6 and 2.1 MMSTB, respectively, compared to conventional waterflood. This will reduce both the costs of water treatment and water injection. On the other hand, the improvement of DDP over conventional gas flooding is insignificant in term of oil recovery factor, but DDP requires less volume of injected gas by approximately of 4 BSCF. However, the drawback of DDP is the amount produced water of 0.9 MMSTB and injected water of 1.035 MMSTB while conventional gas injection has none.

Table 5.1 Simulation results from different recovery methods

Case	Time [years]	Recovery Factor	Cumulative oil production (MMSTB)	Cumulative gas production (BCF)	Cumulative water production (MMSTB)	Cumulative gas injection (BSCF)	Cumulative water injection (MMSTB)
Natural depletion	6.25	27.12%	0.722	0.197	0	0	0
Water flooding	17.00	54.89%	1.535	0.282	1.513	0	3.105
Gas flooding	21.50	82.15%	2.188	52.040	0	53.465	0
DDP	26.33	82.54%	2.309	48.687	0.902	49.592	1.035

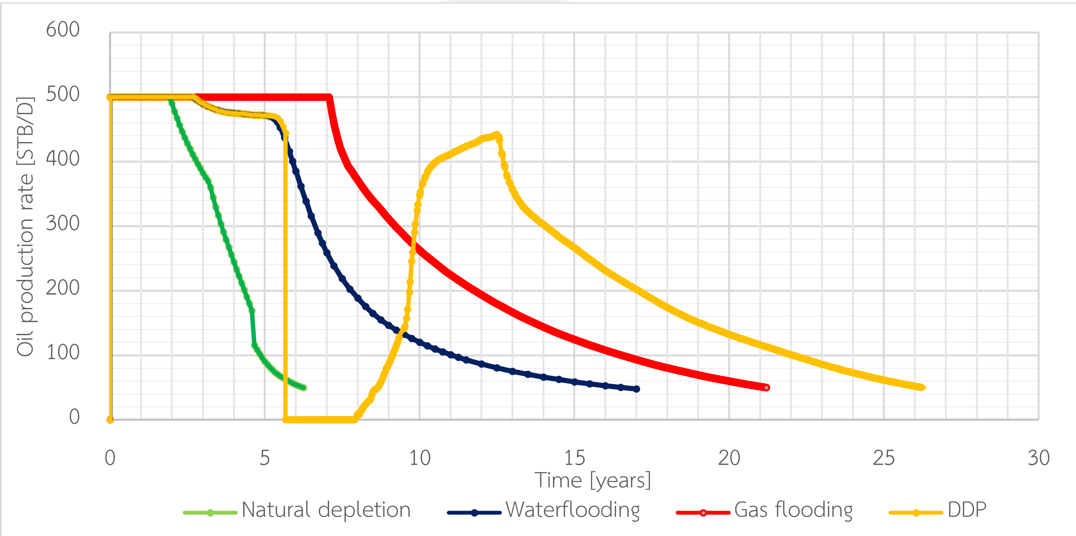


Figure 5.1 Oil production profile of different methods

Figure 5.1 shows oil production profiles from different recovery methods. For natural depletion, the oil production rate remains at the maximum plateau of 500 STB/D for 1.5 years and then sharply drops to the economic limit of 50 STB/D where waterflooding can maintain the plateau rate for 2 years, followed by a small drop in oil production rate due to decline in reservoir pressure. After water breakthrough, the oil production rate declines more sharply until reaching the economic limit. However, for the case of gas flooding, the production plateau can be maintained for 6.5 years before it declines due to good pressure support from gas injection. For DDP case, early production shows the characteristics of water flooding as a result of the same operation during the first phase of displacement. After water breakthrough occurs, the injection well at the downdip location is switched to production well and the updip production well is converted to gas injection well. This causes the downdip production well to produce previously injected water surrounding the downdip well back to the surface, making the oil production rate drop to 0 STB/D for 2 years before the oil rate increases again to a certain rate as a result of gas injection and then drops to the economic limit.

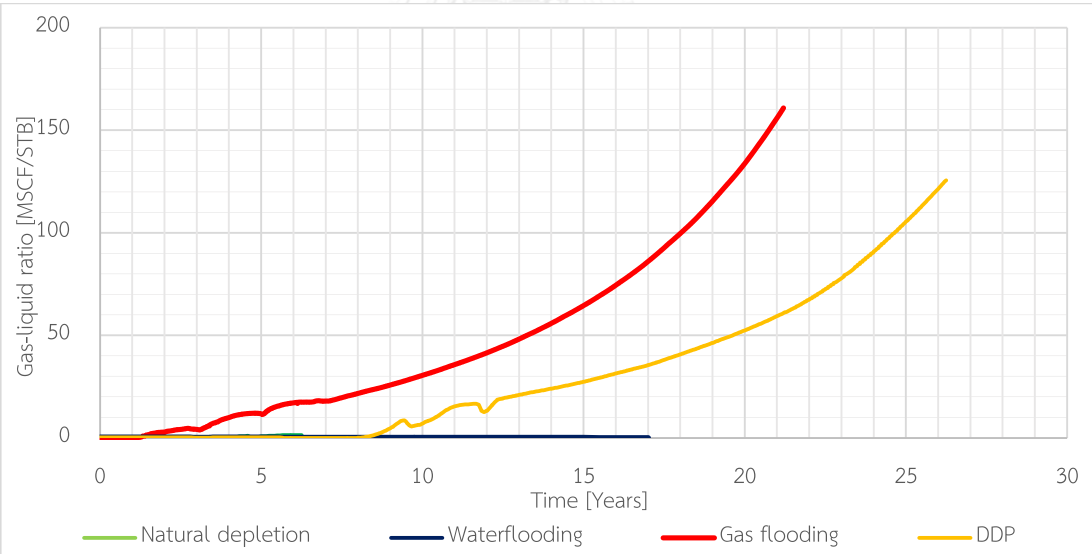


Figure 5.2 Gas to Liquid ratio of different recovery methods

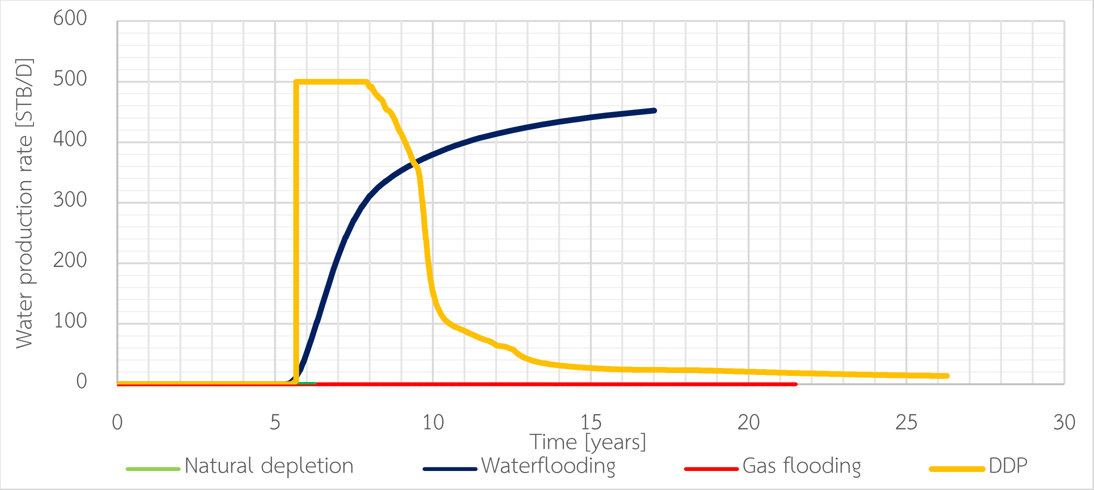
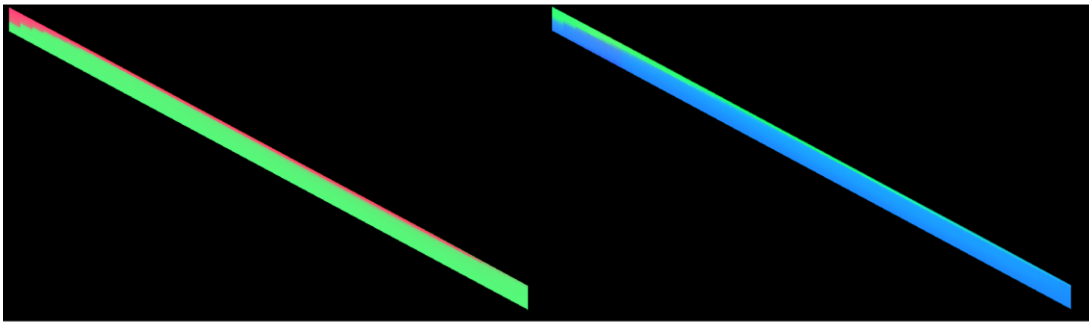


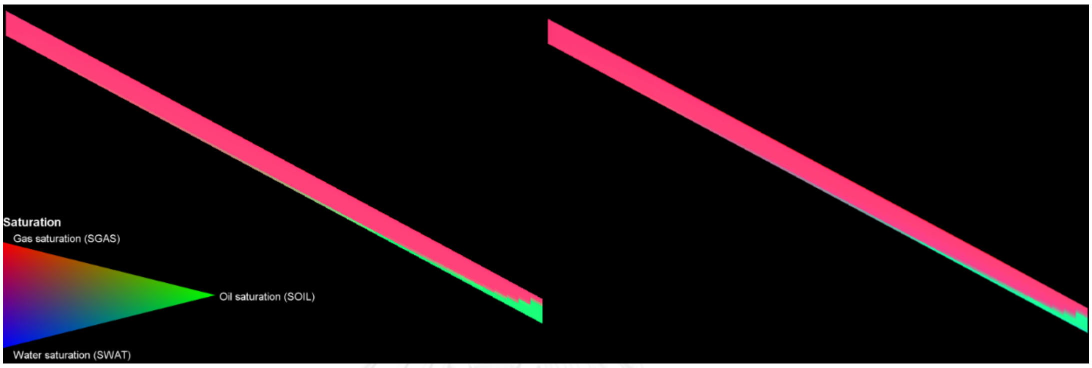
Figure 5.3 Water production profile of different recovery methods

Figure 5.2 and Figure 5.3 show gas-liquid ratio and water production rate, respectively. Gas-liquid ratio increases sharply in the case of gas injection and DDP after gas breaks through the producer located downdip. In DDP process, a plateau of water production of 500 STB/D is seen after the downdip water injection is switched to producer. However, water production rate drops as time progresses in contrast to increasing water production rate in the waterflood method due to continuous water injection until the end of production life. Figure 5.4 shows clearly the improvement of vertical sweep efficiency by implementing gas flooding and DDP as there is less amount of oil left in the reservoir compared to natural depletion and water flooding.

In summary, DDP is clearly a very attractive method among all methods due to the high oil recovery factor. However, it requires both water and gas injection facilities which increase the overall cost of oil production. DDP via water and gas dumpflood can help eliminate the undesirable cost.



(a) Natural Depletion (b) Waterflooding



(c) Gas flooding (d) DDP

Figure 5.4 Side view of saturation from different methods at the abandonment

5.2 Conventional DDP

Conventional DDP is performed by starting the water injection from the downdip well, displacing oil toward the producer at the updip location. When water breakthrough occurs, the water injection well at the downdip location is switched to production well while the updip well is converted to a gas injection well, displacing oil and water mixture toward the production well at the downdip location until reaching the economic limit of 50 STB/D. To obtain the optimal operating conditions for conventional DDP, various target liquid production and water injection rates along with different gas injection rates as described in Table 5.2 were investigated. Note that the target liquid production rate was set to be the same as the target water injection rate in all cases.

Table 5.2 Simulation strategies for conventional DDP

Case No	Target liquid production rate (STB/D)	Target water injection rate (STB/D)	Gas injection rate (MMSCF/D)
1	500	500	8
2			12
3			16
4	1000	1000	8
5			12
6			16
7	1500	1500	8
8			12
9			16

Table 5.3 Simulation results from conventional DDP

Case	Time [years]	Recovery Factor	Cumulative oil production (MMSTB)	Cumulative gas production (BCF)	Cumulative water production (MMSTB)	Cumulative gas injection (BSCF)	Cumulative water injection (MMSTB)
1	26.33	82.54%	2.189	48.687	0.902	49.592	1.035
2	25.16	84.23%	2.233	63.878	0.902	65.014	1.035
3	23.92	85.18%	2.259	73.452	0.899	75.096	1.035
4	22.00	82.36%	2.184	50.975	0.897	51.656	1.035
5	20.16	84.00%	2.227	66.014	0.895	67.173	1.035
6	18.75	85.01%	2.254	75.870	0.892	77.449	1.035
7	20.75	82.32%	2.183	50.667	0.912	51.362	1.055
8	18.92	83.98%	2.227	65.594	0.909	66.800	1.055
9	17.58	85.01%	2.254	75.535	0.906	77.384	1.055

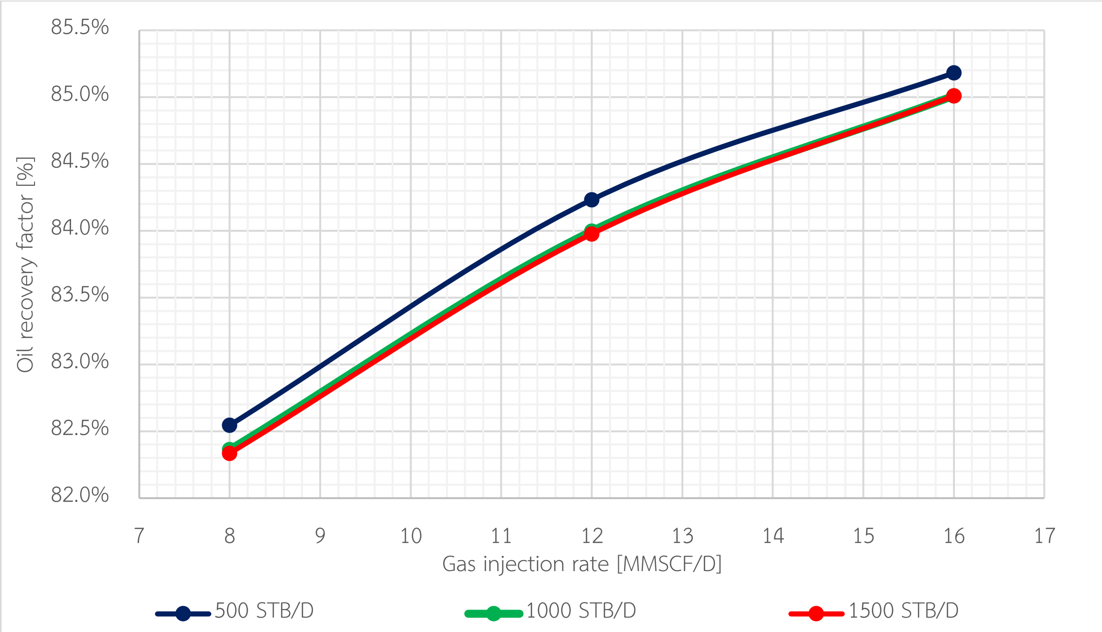


Figure 5.5 Oil recovery factor as function of gas injection rate at different target liquid production and water injection rates (STB/D)

Results from different production and injection strategies as mentioned in Table 5.2 are shown in Table 5.3 and Figure 5.5. Results show that there is a small improvement in term of oil recovery in all cases with higher gas injection rate. This additional recovery is due to the fact that more gas is being used to displace oil toward the producer, and higher gas injection rate helps keep the reservoir pressure higher than the case with lower gas injection as indicated in Figure 5.6. Figure 5.6 also shows that, reservoir pressure in all cases is equal to the early phase of production. This is due to the prevention of injection pressure to exceed the formation fracture pressure. As shown in Figure 5.7 and Figure 5.8, after the target injection rate is achieved, reservoir pressure drops as most of injected gas is reproduced back to the surface. During gas flooding period, the case with gas injection rate of 16 MMSCF/D reaches maximum oil production of 460 STB/D while the case with gas injection rate of 8 MMSCF/D reaches maximum of 440 STB/D before declining due to a slower decline in reservoir pressure as shown in Figure 5.9. Table 5.2 also shows that the amount of gas injection and gas production significantly increase with higher gas injection rate. However, cumulative water injection for the same injection rate is exactly the same for different gas injection rates, because waterflooding is implemented for the same duration. There is a very small difference in water injection in the case of 1500 STB/D water injection rate. The amount of produced water in different cases is approximately the same because of similar amounts of water are injected during waterflooding period.

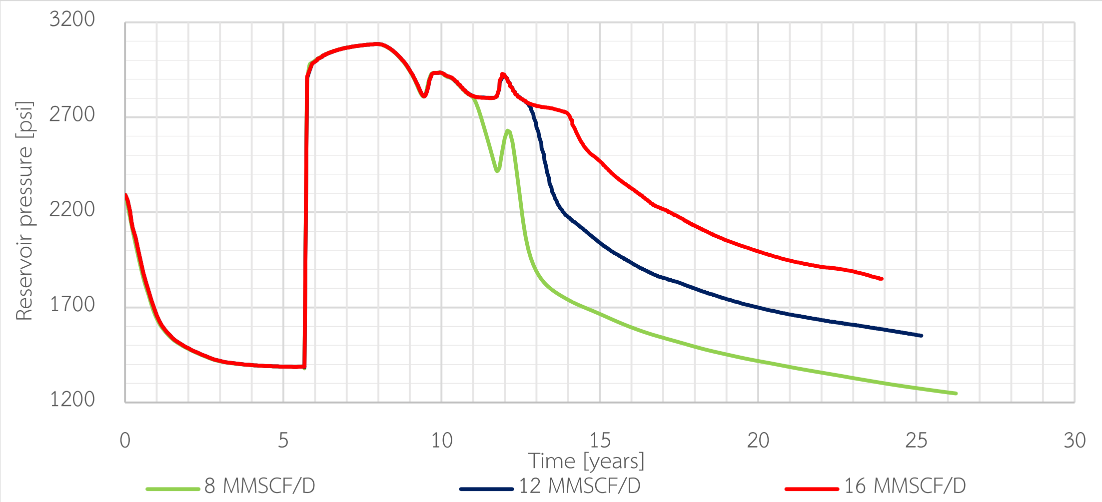


Figure 5.6 Reservoir pressure with different target gas injection rates (8,12,16) MMSCF/D at target liquid production and water injection rate of 500 STB/D

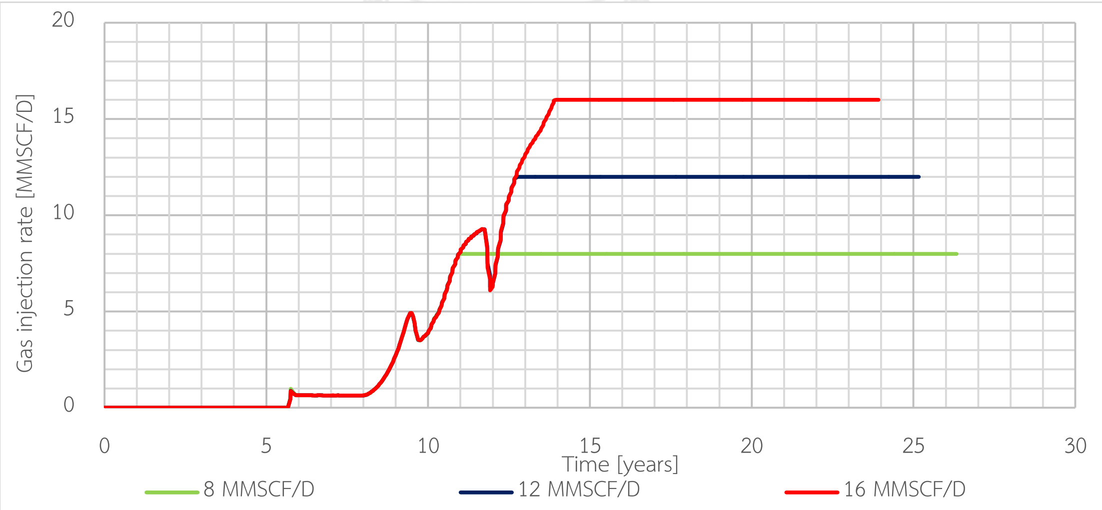


Figure 5.7 Gas injection rate with different target gas injection rates (8,12,16) MMSCF/D at target liquid production and water injection rate of 500 STB/D

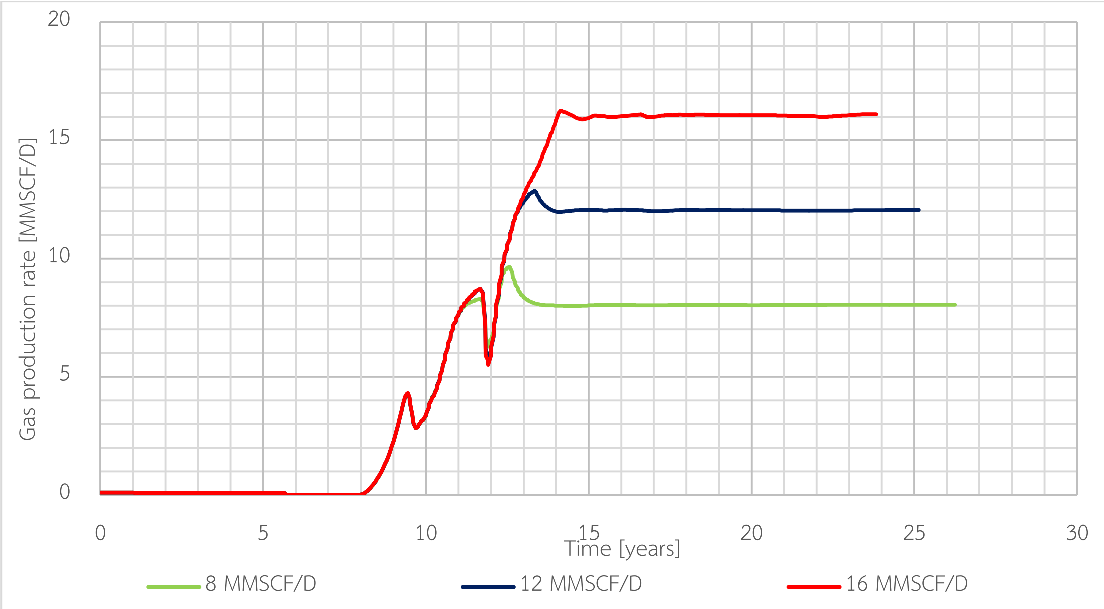


Figure 5.8 Gas production rate with different target gas injection rates (8, 12,16) MMSCF/D at target liquid production and water injection rate of 500 STB/D

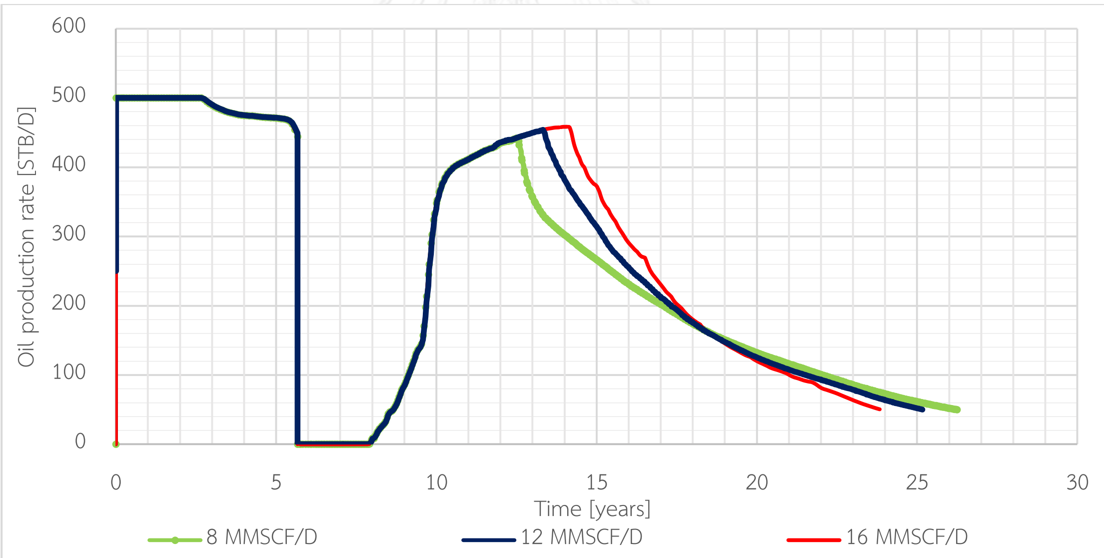


Figure 5.9 Oil production profile with different gas injection rates (8,12,16) MSCF/D at target liquid production and water injection rate of 500 STB/D

In terms of liquid production rate, Figure 5.5 shows that the case with 500 STB/D of target liquid production and water injection rate has a very small improvement of recovery factor over the cases with higher rates. Producing at a low liquid target rate allows oil and gas to segregate better while flowing into the production well at the downdip location during the gas flooding phase. As shown in Figure 5.10, the case with low target liquid production rate has higher gas saturation at the updip location of the reservoir while the case with high target liquid production rate has higher gas saturation at the downdip location. This shows that the case with low target liquid production rate, gas and liquid segregate better compared to the case with high target liquid production rate. With better segregation leads to a gradual decline in oil production rate which prolongs production life and improves the oil recovery.

However to obtain the optimal operating conditions, the target gas injection rate is further increased to observe its effect on the performance of DDP while target liquid production and target water injection rate are fixed at 500 STB/D as shown in Table 5.4.

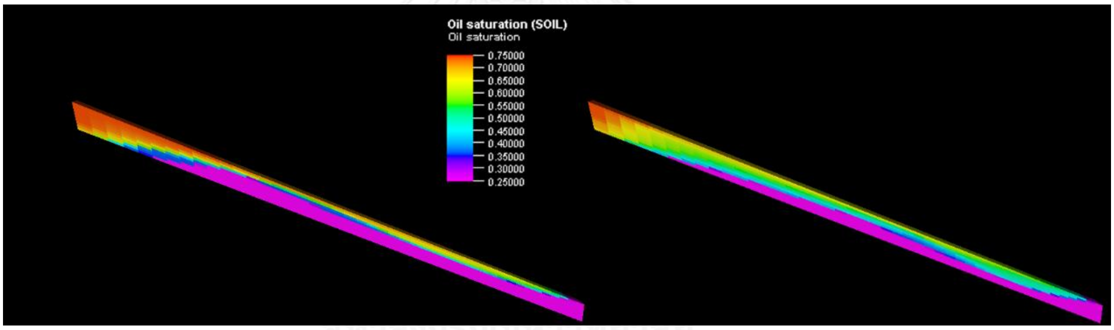


Figure 5.10 Gas saturation at the gas breakthrough with 8 MMSCF/D of gas injection and 500 STB/D (left), 1500 STB/D (right) of target liquid production and water injection rate.

Table 5.4 Additional simulation strategies for conventional DDP.

<table>
<tr><th>Case
No</th><th>Target liquid production rate
(STB/D)</th><th>Target water injection rate
(STB/D)</th><th>Gas injection rate
(MMSCF/D)</th></tr>
<tr><td>3</td><td colspan="2" rowspan="4">500</td><td>16</td></tr>
<tr><td>10</td><td>20</td></tr>
<tr><td>11</td><td>24</td></tr>
<tr><td>12</td><td>28</td></tr>
</table>

Table 5.5 Simulation results from additional strategies for conventional DDP

Case	Time [years]	Recovery factor	Cumulative oil production (MMSTB)	Cumulative gas production (BCF)	Cumulative water production (MMSTB)	Cumulative gas injection (BSCF)	Cumulative water injection (MMSTB)
3	23.92	85.18%	2.383	73.452	0.899	75.096	1.035
10	23.00	85.96%	2.404	79.707	0.897	81.857	1.035
11	22.83	86.56%	2.421	84.674	0.896	90.327	1.035
12	22.67	86.83%	2.429	87.767	0.898	87.147	1.035

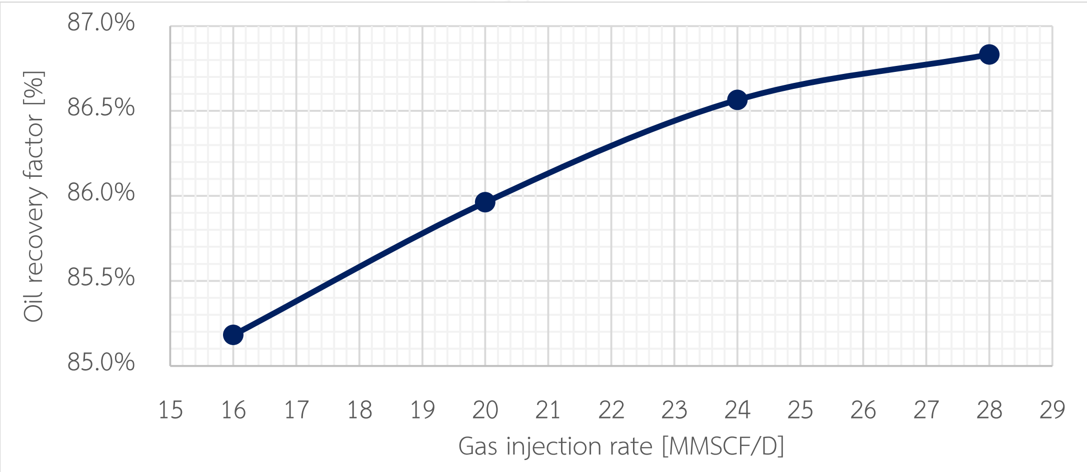


Figure 5.11 Oil recovery factor as function of gas injection rate at 500 STB/D of target liquid production and water injection rate

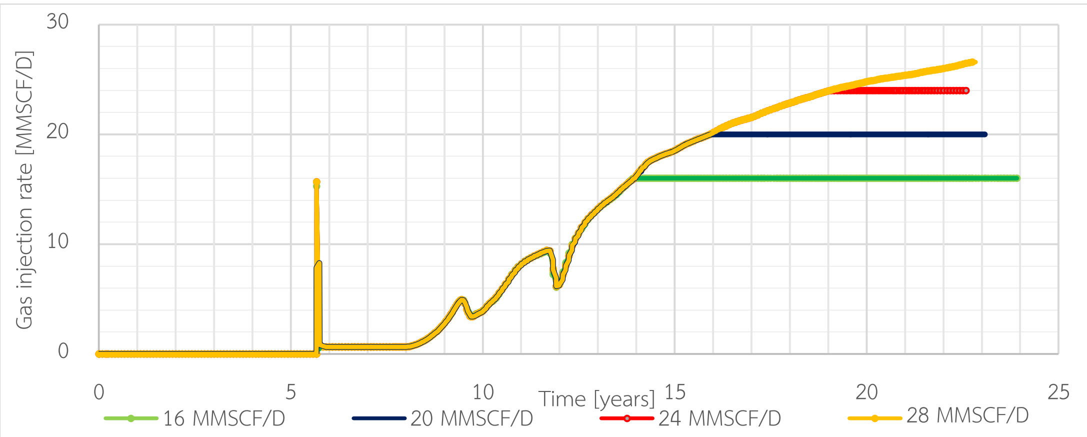


Figure 5.12 Actual gas injection rate at different target gas injection rates in 500 STB/D of target liquid production and water injection rate

Results from additional simulation strategies are shown in Table 5.5 and Figure 5.11. Results show that as the gas injection rate is increased, there is a slight increase in recovery factor. However, the gas injection rate could not reach the desired target in the case with target gas injection rate of 28 MMSCF/D or higher as illustrated in Figure 5.12. This is due to the prevention of injection pressure to exceed the formation fracture pressure. Thus, the maximum recovery factor of 86.83 % is obtained for the case of conventional DDP.

In this study, it is illustrated that liquid production and water injection rate has negligible effect on the cumulative amount of oil, gas and water production while a higher amount of oil can be recovered by injecting gas at higher rates. However, the downside of high gas injection rate is the total amount of gas required to inject is tremendously increased. By comparison, the case with 28 MMSCF/D of target gas injection rate has approximately 37.6 billion SCF of cumulative gas injection, higher than the case with gas injection rate of 8 MMSCF/D but this increment results in approximately 4.3 % improvement in oil recovery factor. Selection of operational parameters for conventional DDP needs to be further analyzed in term of economics where gas injection cost needs to be included to obtain the optimum profit.

5.3 Double Displacement Process via Water and Gas Dumpflood

This process is similar to conventional DDP except water and gas from overlying and underlying formations are used. This eliminates surface injection facilities, leading to a reduction in capital and operational cost to recover oil. The downside of this method is the availability of the water and gas source and how much fluid both types of reservoir can provide to implement this method.

At the beginning, oil is produced from the up-dip well till pressure in the oil reservoir is low enough to start water dumping. This prevents oil from back flowing from the oil reservoir to the aquifer. Backflow of oil will damage flow ability of aquifer water around the wellbore, due to increase of oil saturation and reduced relative permeability to water. This reduces performance of dumpflood from the aquifer. After pressure in the oil reservoir drops, water in the aquifer flows into the oil reservoir and sweeps oil toward the production well at updip location. When the sand face pressure of the aquifer in dumpflood well drops to 300 psi or water breakthrough at the updip producing well (watercut > 1%), water dumpflood is stopped. This sand face pressure was approximately selected to let as much water to be dumped as possible. In a sense, it is the abandonment bottomhole pressure condition. Then, the downdip well is switched from water dumpflood well to the production well and the updip well is switched to gas dumpflood. Unlike water dumping, gas dumping is started immediately since the pressure of the oil reservoir is already low. Since the production from the downdip well contains mainly oil and water before gas breakthrough, the downdip well is operated by ESP (electric submersible pump) during this period. This is done by setting the minimum bottomhole pressure equal to 500 psia. Once gas breakthrough occurs (gas-liquid ratio > 1MSCF/STB), there is no further need for ESP since gas will help lift fluids to surface. The well is then controlled by tubing head pressure of 300 psi via vertical lift performance (VLP). Production is continued till it reaches the oil economic limit of 50 STB/D or 30 years of production. To optimize DDP from water and gas dumpflood from different combinations of aquifer sizes and gas reservoir sizes, different target liquid production rates and intermittent production schedules were investigated as tabulated in Table 5.6. Note that the intermittent production schedule is only used during the gas dumpflood period only. The optimum production strategy for each water aquifer and gas reservoir combination are also obtained. The combinations are:

- Small aquifer and small gas reservoir (10PV aquifer and 1PV gas reservoir)
- Small aquifer and large gas reservoir (10PV aquifer and 5PV gas reservoir)
- Large aquifer and small gas reservoir (50PV aquifer and 1PV gas reservoir)
- Large aquifer and large gas reservoir (50PV aquifer and 5PV gas reservoir)

Table 5.6 Detail of simulation strategy

Water aquifer size	Gas reservoir size	Intermittent production	Target liquid production rate (STB/D)	Number of cases
10 PV	1 PV	no off Always on	500	3 x 2 x 2 x 3 = 36
50 PV	5 PV	1 month off 1 month on	1000	
		2 months off 1 month on	1500	
Total				36

5.3.1 Small Aquifer and Small Gas Reservoir (10PV aquifer and 1PV gas reservoir)

Effect of production strategy was investigated for this set of small aquifer and small gas reservoir combination in order to optimize oil recovery in such case. Table 5.7 shows production strategies of combined different target liquid rates and intermittent schedules of production well during gas dumpflood in 10 PV aquifer and 1PV gas reservoir as well as the results obtained from the simulation.

Table 5.7 Simulation results for 10 PV aquifer and 1 PV gas reservoir

Case No	Target liquid production rate (STB/D)	Intermittent production	Time [Years]	Oil recovery factor	Cumulative oil production [MMSTB]	Cumulative Gas production [BSCF]	Cumulative water production [MMSTB]	Cumulative cross-flow gas [BSCF]	Net cumulative gas production [BSCF]
Case 1.1	500	No off Always on	10.50	42.39%	1.124	1.999	0.175	2.172	0.173
Case 1.2	500	1 month off 1 month on	14.00	43.74%	1.159	1.593	0.176	1.935	0.342
Case 1.3	500	2 months off 1 month on	24.00	56.10%	1.487	1.332	0.182	1.846	0.514
Case 1.4	1000	No off Always on	9.66	42.47%	1.126	2.031	0.175	2.192	0.161
Case 1.5	1000	1 month off 1 month on	10.83	40.07%	1.062	1.629	0.173	1.937	0.308
Case 1.6	1000	2 months off 1 month on	13.08	40.97%	1.086	1.364	0.174	1.773	0.409
Case 1.7	1500	No off Always on	9.58	42.75%	1.133	2.042	0.175	2.196	0.154
Case 1.8	1500	1 month off 1 month on	10.50	40.06%	1.062	1.632	0.173	1.938	0.306
Case 1.9	1500	2 months off 1 month on	12.09	39.78%	1.054	1.339	0.174	1.749	0.410

Table 5.7 shows that as off/on ratio is increased, production period and the net cumulative gas production also rise. The net cumulative gas production is the amount of cumulative cross-flow subtracted by the cumulative gas production. In contrary to production period and net cumulative gas production, cumulative gas production is reduced as increasing off/on ratio. In terms of cumulative oil production, the oil production only increases with the increasing off/on ratio in the case of target liquid production rate of 500 STB/D, while cases with higher target production rate result in lower in cumulative oil production. However, for total water production, all cases show that there is insignificantly different between production schedules.

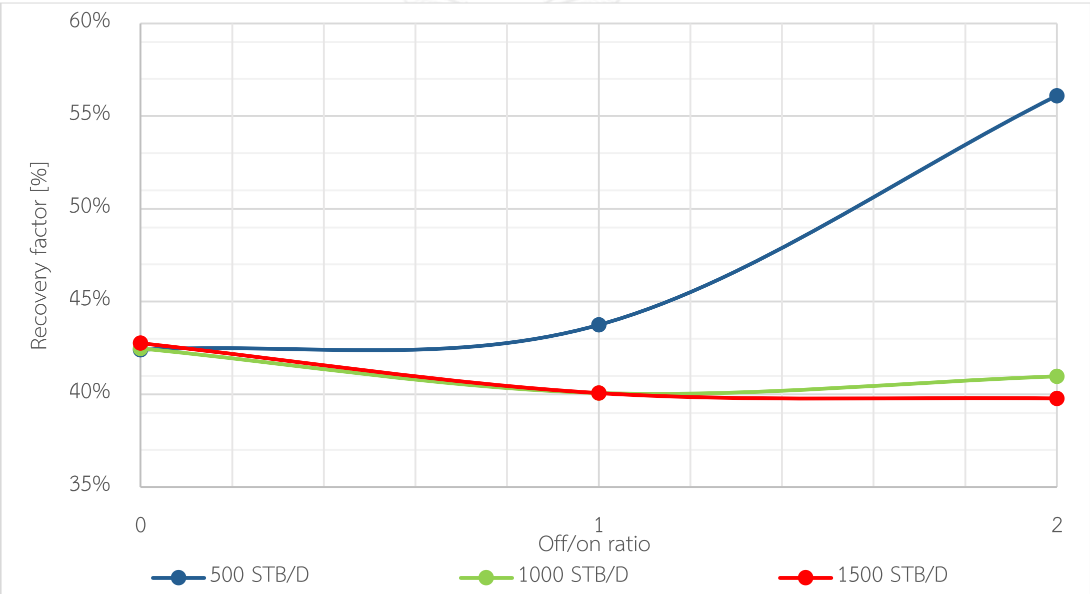


Figure 5.13 Recovery factor as function with off/on ratios with different target liquid production rates

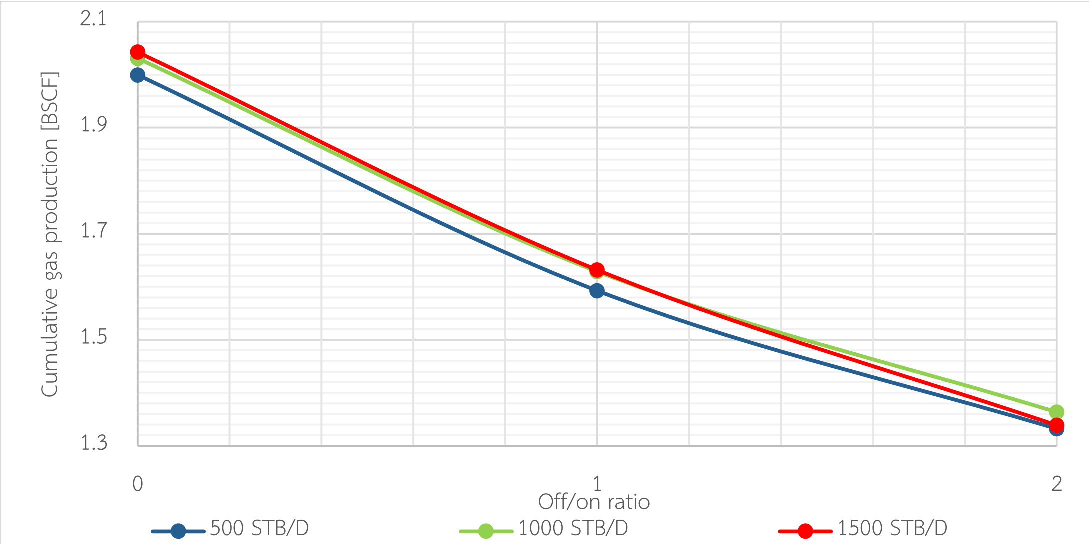


Figure 5.14 Cumulative gas production as function with off/on ratios with different target liquid production rates

In the case of target liquid production rate of 500 STB/D, liquid production rate remains at a plateau rate of 500 STB/D for a longer period of time in the case with higher off/on ratio during gas flooding period as shown in Figure 5.15. In this target liquid production rate, results show an upward trend of recovery factor in the case with liquid target production rate of 500 STB/D when off/on ratio is increased. The improvement in oil recovery factor after increasing off/on ratio is because of the segregation of injected gas and oil during the shut in period which helps retain injected gas inside the reservoir. This is confirmed by the increase in the amount of net gas influx in result table plus less gas production rate, with gradual increase in producing GLR and cumulative gas production as shown in Figure 5.16 to Figure 5.18 as off/on ratio is increased. By retaining more gas in the oil reservoir, the reservoir pressure declines at a slower rate as shown in Figure 5.19.

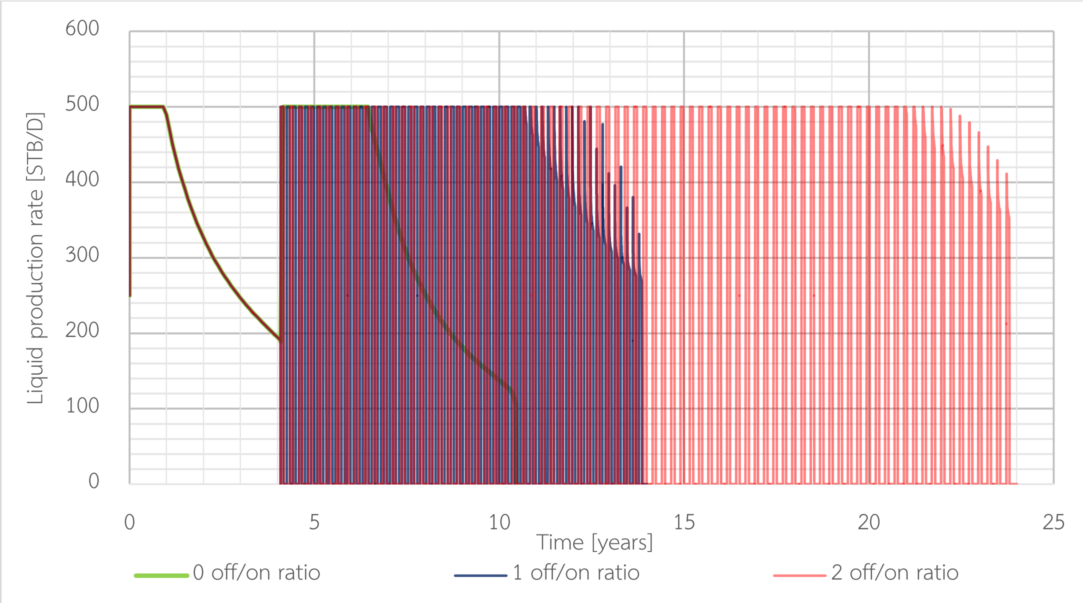


Figure 5.15 Liquid production rate at different off/on ratio at target liquid production rate of 500 STB/D

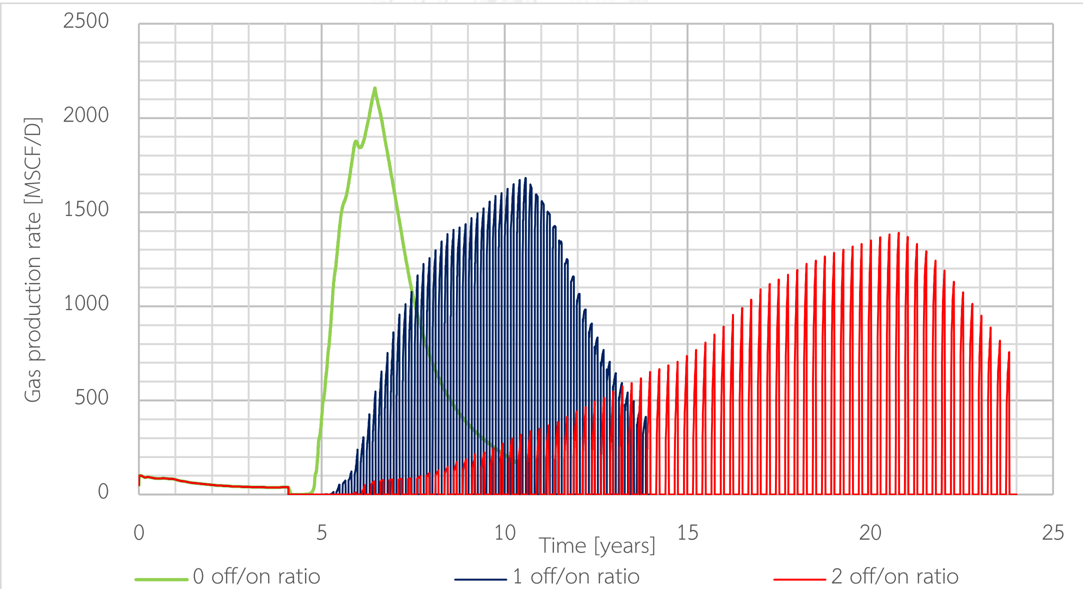


Figure 5.16 Gas production rate with different on/off ratios at target liquid production rate of 500 STB/D

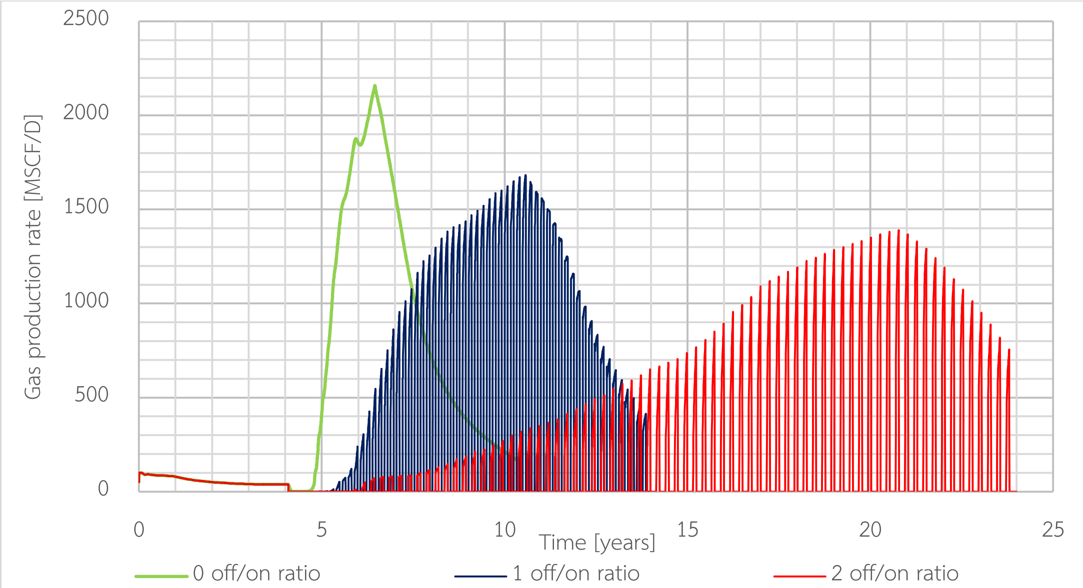


Figure 5.17 GLR with different on/off ratios at target liquid production rate of 500 STB/D

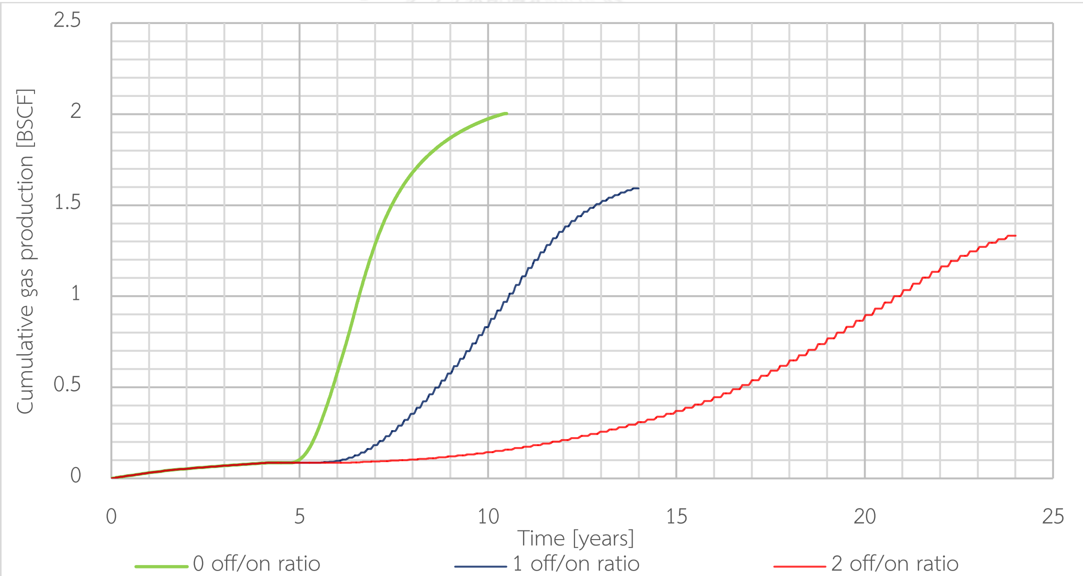


Figure 5.18 Cumulative gas production with different off/on ratios at target liquid production rate of 500 STB/D

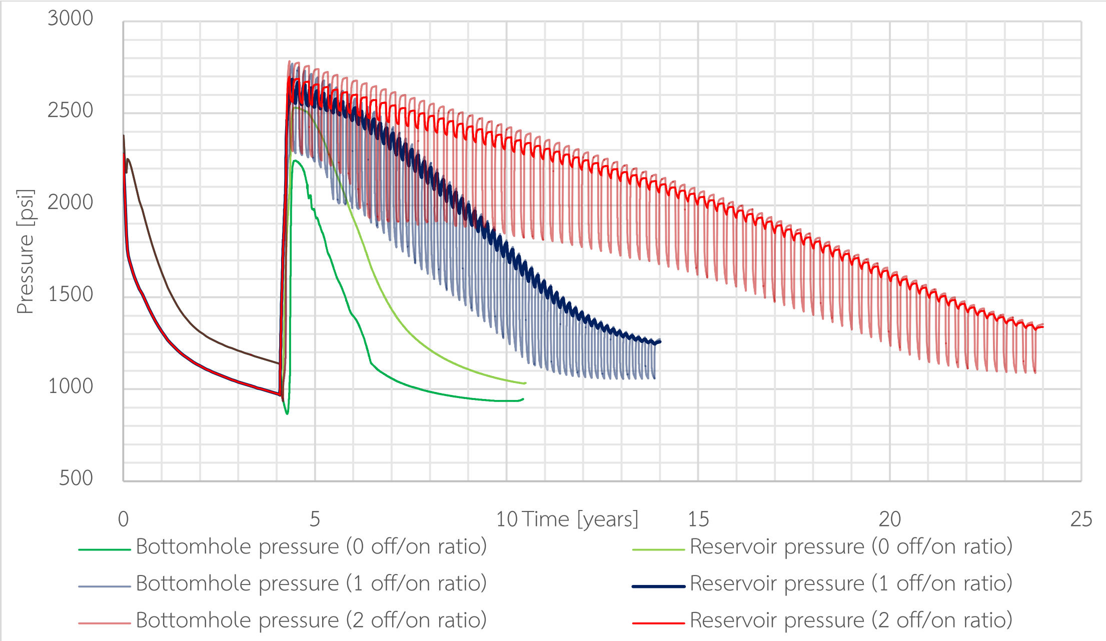


Figure 5.19 Bottomhole and average reservoir pressure with different off/on ratios at target liquid production rate of 500 STB/D

However, for the case of high off/on ratio, there is more liquid fraction near the producer than the cases with low off/on ratio due to better segregation. This affects the abandonment pressure as shown in Figure 5.19. As off/on ratio is increased, pressure loss which is the differences between average reservoir pressure and bottomhole pressure is increased because of two main reasons. First, as liquid segregation causes gas saturation around the production well to drop, reduces the relative permeability to oil (k_{ro}) from Eq. (5-1) decrease since $k_{rog} > k_{row}$ (Figure 5.20). Second, average fluid viscosity ($\bar{\mu}$) is increased as gas saturation is reduced. These two parameters increase pressure losses in porous media as shown in Eq. (5-2).

$$k_{ro} = \frac{s_g k_{rog} + k_{row} - s_{wco})}{s_g + s_w - s_{wco}} \qquad \text{Eq. (5 1)}$$

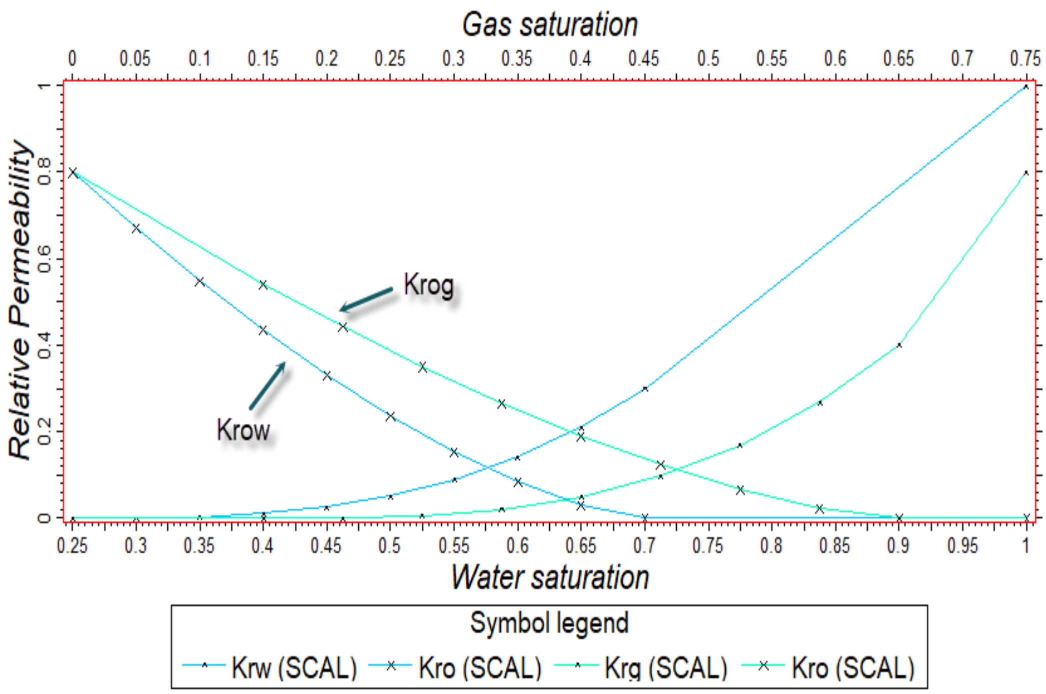


Figure 5.20 Three phases relative permeability

$$p_e - p_{wf} = \frac{q_o B\mu}{2\pi k_{ro} kh}\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{1}{2}\right] \qquad \text{Eq. (5-1)}$$

The bottomhole pressure of production well fluctuates as producing GLR changes. Figure 5.21 shows that as the production well still operates above the economic limit, the case with high off/on ratio maintains higher oil production rates at late times of the production due to better segregation of oil and gas compared to the case with low off/on ratio. At the end, the reservoir pressure is too low to produce and lift oil up to the surface, causing production well to be prematurely die. Similarly to target liquid production rate, high off/on ratio allows oil production rate to decline at a gradual rate compared to the case with low off/on ratio.

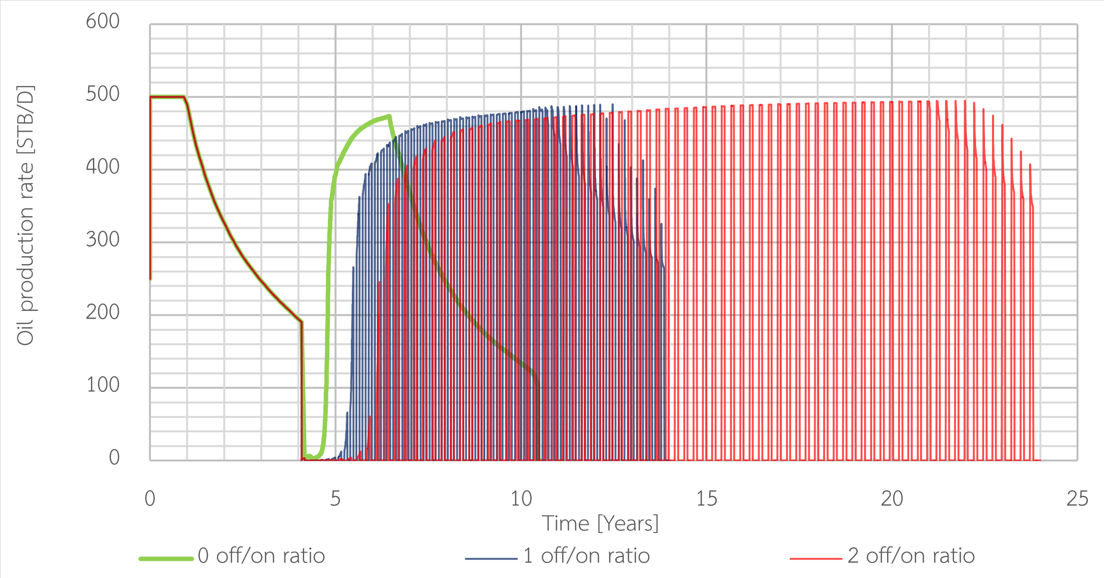


Figure 5.21 Oil production rate with different off/on ratios at target liquid production rate of 500 STB/D

In the case of target liquid production rate of 1000 STB/D, liquid production maintains maximum plateau for a smaller period of time (Figure 5.22) compare to case with target liquid production rate of 500 STB/D (Figure 5.15). Oil recovery efficiency is noticeably decreased as the off/on ratio is increased as seen in Figure 5.13. This reduction is due to the fact that gas is not effectively retained in the reservoir when increasing the shut-in period. Unlike the case of 500 STB/D in which gas production rate, gas-liquid ratio and cumulative gas production decrease in the case of longer shut-in period, the case of target liquid production rate of 1000 STB/D shows insignificant different between various off/on ratios as shown in Figure 5.23 - Figure 5.25, respectively. Since gas is produced and not effectively retained in the reservoir during gas dumpflood in the case of high off/on ratio, there is small difference in the way the reservoir pressure decline as shown in Figure 5.26, in comparison to what happens in the case of 500 STB/D (Figure 5.19). Although in terms of cumulative gas production, Figure 5.24 shows that as off/on ratio is increased, it lowers total gas production compared to cases with low off/on ratio. This is because the abandonment pressures are significantly different between different off/on ratio. In addition, the case with high off/on ratio has a lower amount of gas cross-flow from the gas reservoir to the oil reservoir (Table 5.7), causing the total gas production to be lower compared to cases with low off/on ratio. Even though high off/on ratio causes the reservoir pressure to decline gradually compared to low off/on ratio, the effect of pressure loss in porous media due to low gas saturation around the production well is dominant as shown in Figure 5.26. Hence, for the target liquid production rate of 1000 STB/D, high off/on ratio is not recommended as high pressure loss around wellbore overcomes the benefit of the gradual decline of the reservoir pressure results in a lower oil recovery factor. In the case of 1000 STB/D of target liquid production rate, there is an insignificantly different in oil production rate at between different off/on ratio as shown in Figure 5.27 compared to the case of 500 STB/D (Figure 5.21) since high off/on ratio does not yield any benefit at this rate since the gas production rate is still high with increasing off/on ratio.

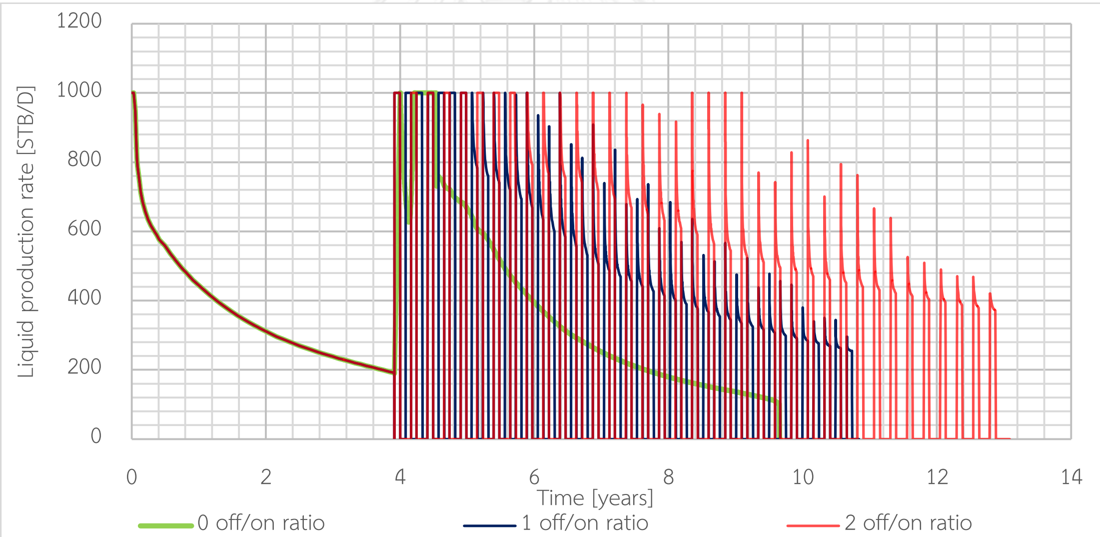


Figure 5.22 Liquid production rate with different off/on ratios at target liquid production rate of 1000 STB/D

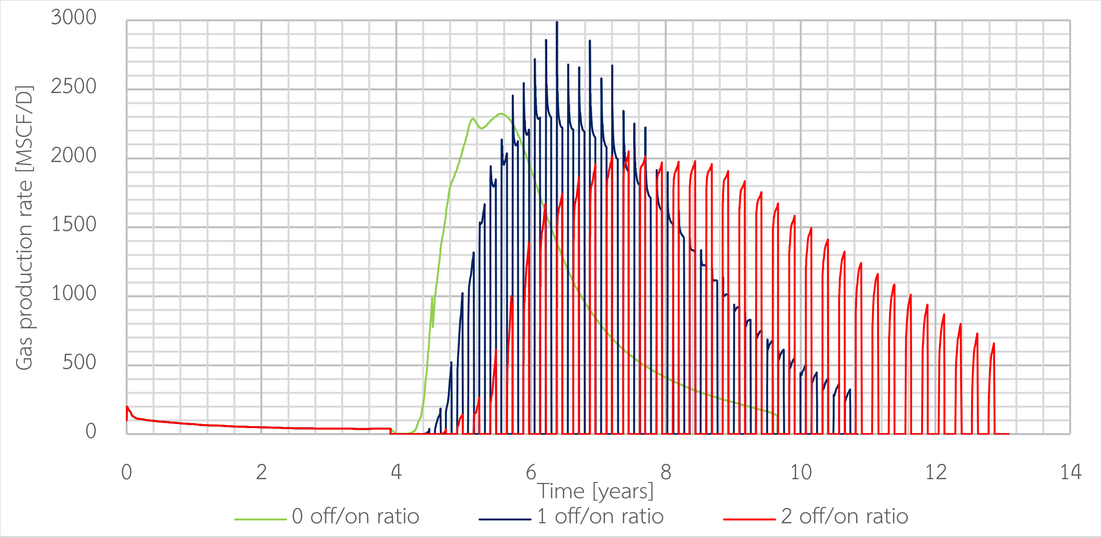


Figure 5.23 Gas production rate at different off/on ratios at 1000 STB/D target liquid production rate

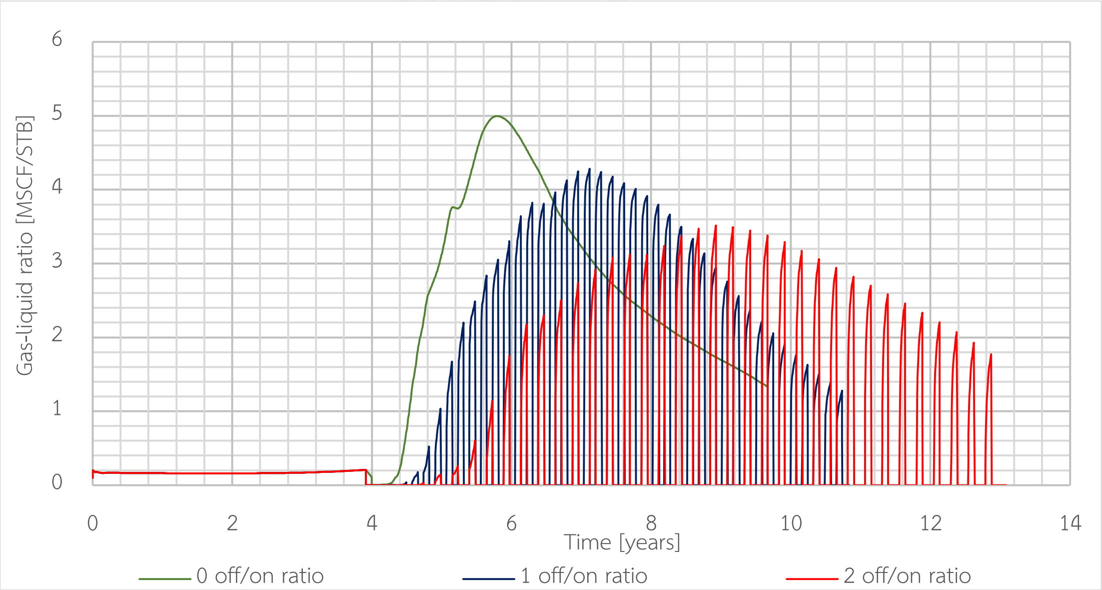


Figure 5.24 Gas liquid ratio at different off/on ratios at 1000 STB/D target liquid production rate

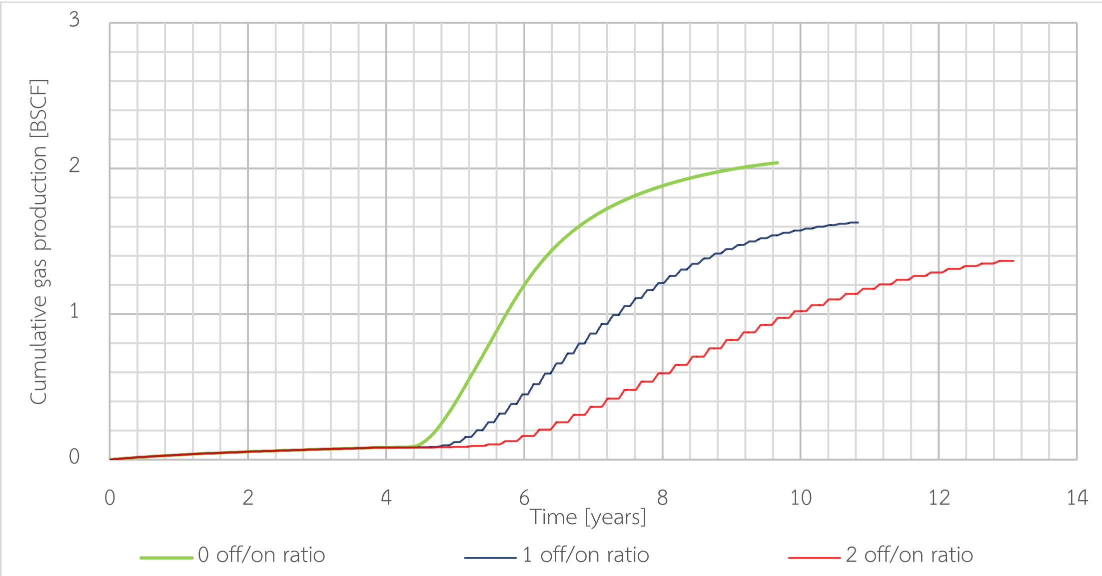


Figure 5.25 Cumulative gas production at different off/on ratios at 1000 STB/D target liquid production rate

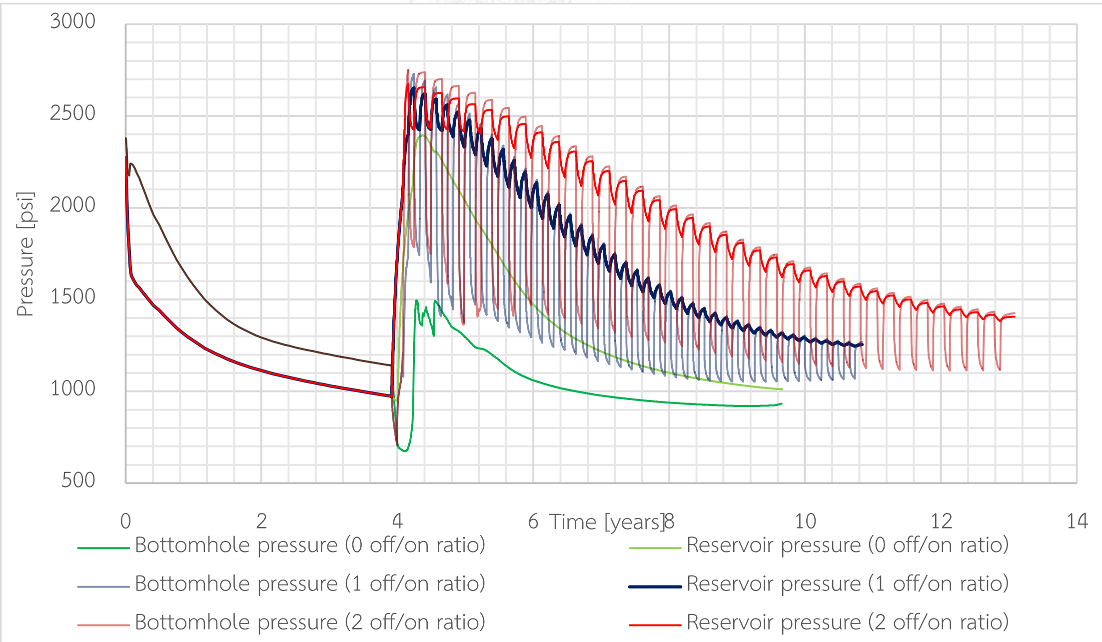


Figure 5.26 Bottomhole and average reservoir pressure with different off/on ratios at target liquid production rate of 1000 STB/D

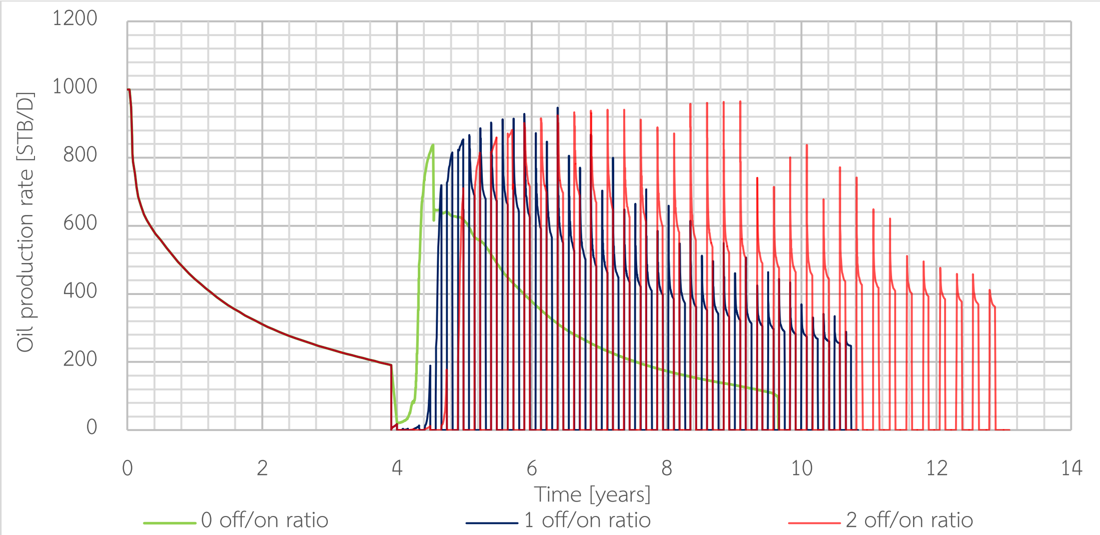


Figure 5.27 Oil production rate with different off/on ratios at target liquid production rate of 1000 STB/D

In the case with target liquid production rate of 1500 STB/D, Figure 5.28 shows that the liquid production rate maintains maximum plateau for a smaller period of time compare to case with lower target liquid production rate. In this target rate, similar behaviors to the cases with target liquid production rate of 1000 STB/D are observed in term of gas production rate, cumulative gas production, gas-liquid ratio, reservoir pressure and as shown in Figure 5.29 - Figure 5.32, respectively.

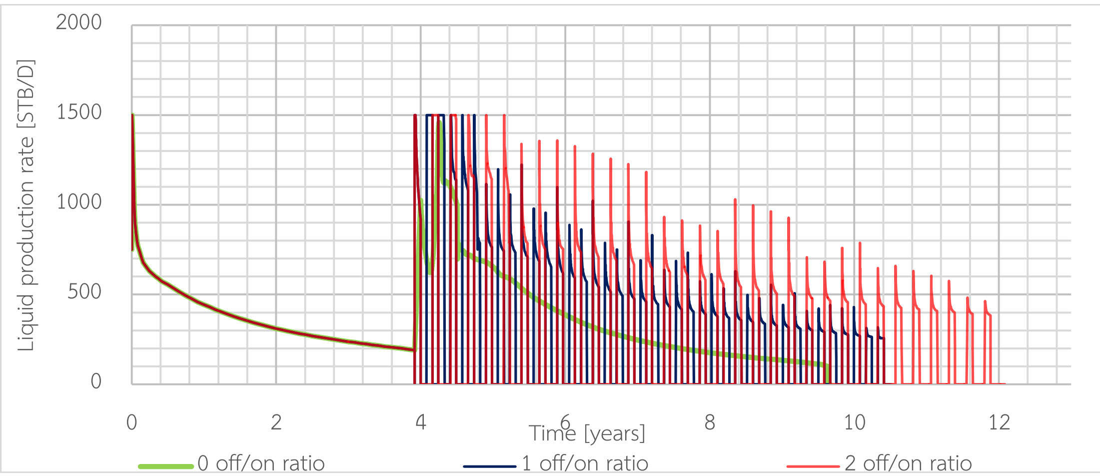


Figure 5.28 Liquid production rate with different off/on ratios at target liquid production rate of 1500 STB/D

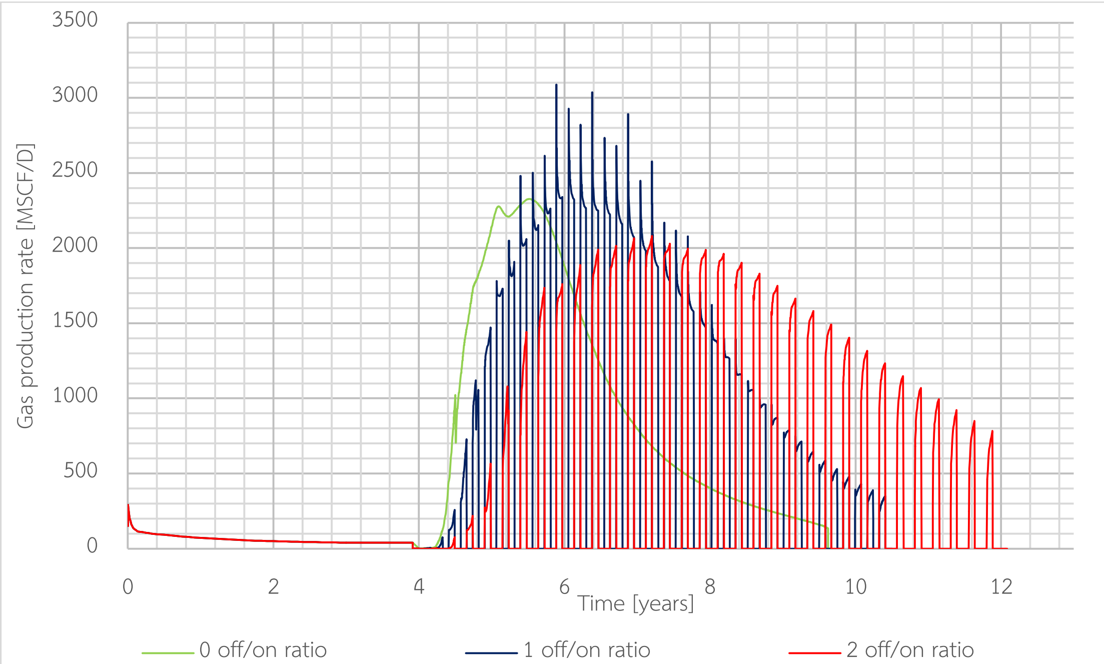


Figure 5.29 Gas production rate at different off/on ratios at 1500 STB/D target liquid production rate

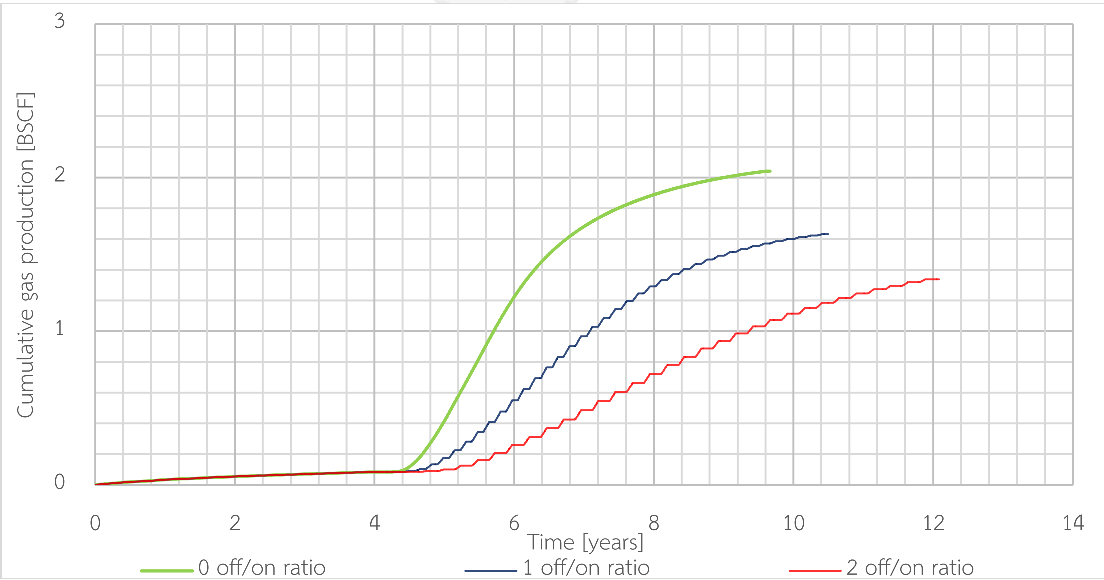


Figure 5.30 Cumulative gas production at different off/on ratios at 1500 STB/D target liquid production rate

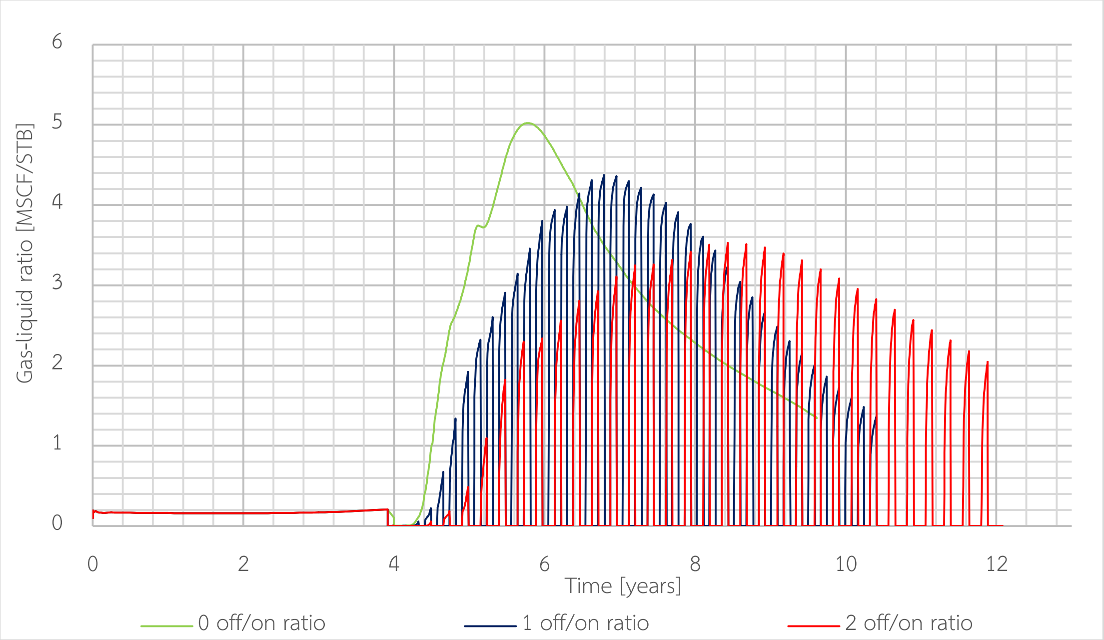


Figure 5.31 Gas-liquid ratio at different off/on ratios at 1500 STB/D target liquid production rate

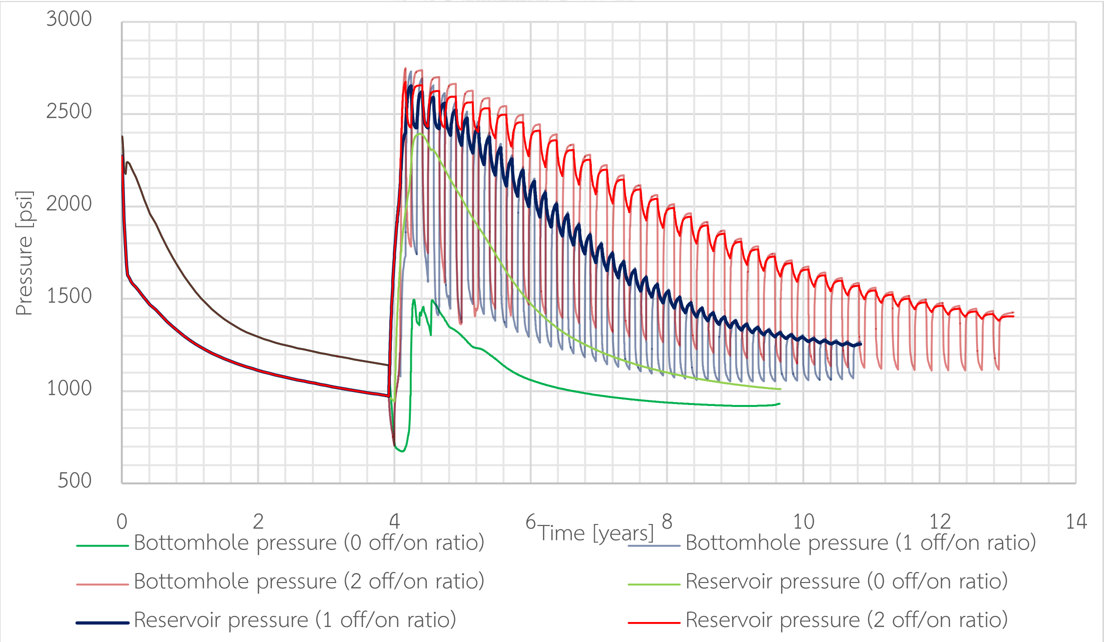


Figure 5.32 Bottomhole and average reservoir pressure with different off/on ratios at target liquid production rate of 1500 STB/D

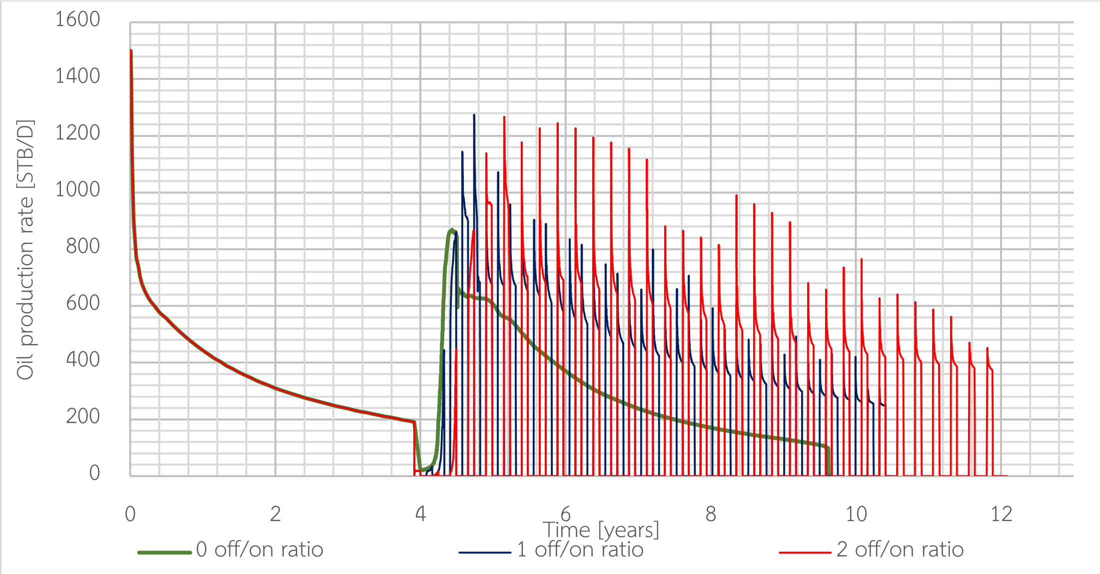


Figure 5.33 Oil production rate with different off/on ratios at target liquid production rate of 1500 STB/D

Due to the fact that gas is not effectively retained in the reservoir with this target liquid production rate, this causes the pressure inside the reservoir to decline at a faster rate when compared to cases with 500 STB/D (Figure 5.19). Similarly to the case of 1000 STB/D of target liquid production rate, the disadvantage from pressure loss in porous media as gas saturation is reduced around the wellbore is greater than the benefit of gradual pressure loss by implementing intermittent production. This causes reduction in oil recovery when increasing off/on ratio as indicated in Figure 5.13, while oil production profile in the case of target liquid production rate of 1500 STB/D is insignificantly different with different off/on ratio.

Simulation results clearly show that decreasing liquid target production rate to 500 STB/D with 2 off/on ratio provides the optimum operating condition to improve oil recovery for this reservoir combination. However, this strategy decreases total gas production compared to cases with high target liquid production rates and low off/on ratios. The drawback of this method is that it takes longer time to produce. If a high target liquid production rate is chosen in order to shorten production time, intermittent production is not recommended since it does not help retain the gas in the reservoir and introduces high pressure loss in porous media as gas saturation decreases from liquid segregation. As a result, it does not help improve the oil recovery.

5.3.2 Large Aquifer and Small Gas Reservoir (50PV aquifer, 1PV gas reservoir)

Effect of production strategy was investigated for this set of big aquifer and small gas reservoir combination in order to optimize oil recovery in such case. Table 5.8 shows production strategies of combined different target liquid production rates and intermittent schedules of production well during gas dumpflood in 50 PV aquifer and 1PV gas reservoir as well as the results obtained from the simulation.

Table 5.8 shows that by increasing off/on ratio, production period and net cumulative gas production are also increasing. In contrary to production period and net cumulative gas production, cumulative gas production is reduced as increasing off/on ratio. In terms of cumulative oil production, oil production only increases with the increasing off/on ratio in the case of target liquid production of 500 STB/D while cases with higher target injection rate result in lower in oil production. In addition, the results also show that increasing off/on ratio also increases cumulative water production for the cases with 500 STB/D and 1000 STB/D. For cases with 1500 STB/D of target liquid production rate, cumulative water production is insignificantly different between off/on ratios. Oil recovery factor and cumulative gas production from result table are plotted in Figure 5.34 and Figure 5.35, respectively.

Table 5.8 Simulation results for 50 PV aquifer and 1 PV gas reservoir

Case No	Target liquid production rate (STB/D)	Intermittent production	Time [Years]	Oil recovery factor	Cumulative oil production [MMSTB]	Cumulative Gas production [BSCF]	Cumulative water production [MMSTB]	Cumulative cross-flow gas [BSCF]	Net cumulative gas production [BSCF]
Case 2.1	500	No off Always on	15.25	49.35%	1.309	2.175	0.678	2.259	0.084
Case 2.2	500	1 month off 1 month on	19.16	49.69%	1.318	1.674	0.697	1.963	0.290
Case 2.3	500	2 months off 1 month on	26.08	54.34%	1.441	1.274	0.724	1.752	0.478
Case 2.4	1000	No off Always on	13.16	48.47%	1.285	2.200	0.664	2.268	0.068
Case 2.5	1000	1 month off 1 month on	15.00	47.39%	1.256	1.817	0.671	2.033	0.216
Case 2.6	1000	2 months off 1 month on	17.25	47.64%	1.263	1.518	0.682	1.851	0.333
Case 2.7	1500	No off Always on	12.67	48.63%	1.289	2.217	0.661	2.277	0.060
Case 2.8	1500	1 month off 1 month on	14.08	47.14%	1.250	1.866	0.665	2.060	0.194
Case 2.9	1500	2 months off 1 month on	14.83	46.25%	1.226	1.604	0.665	1.870	0.266

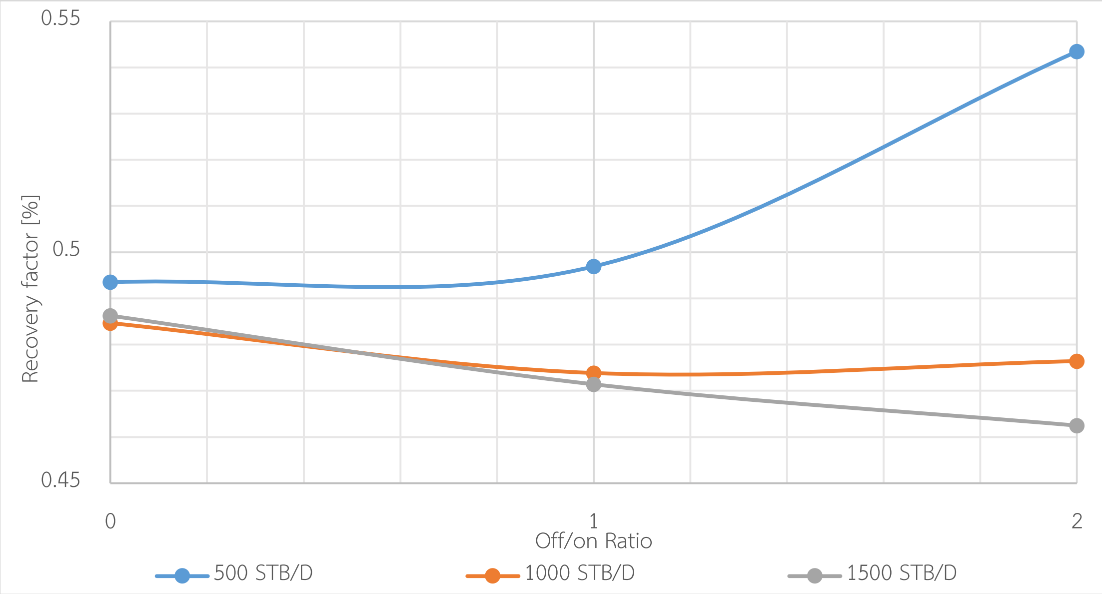


Figure 5.34 Recovery factor as function with off/on ratios with different target liquid production rate in 50 PV aquifer with 1 PV gas reservoir combination.

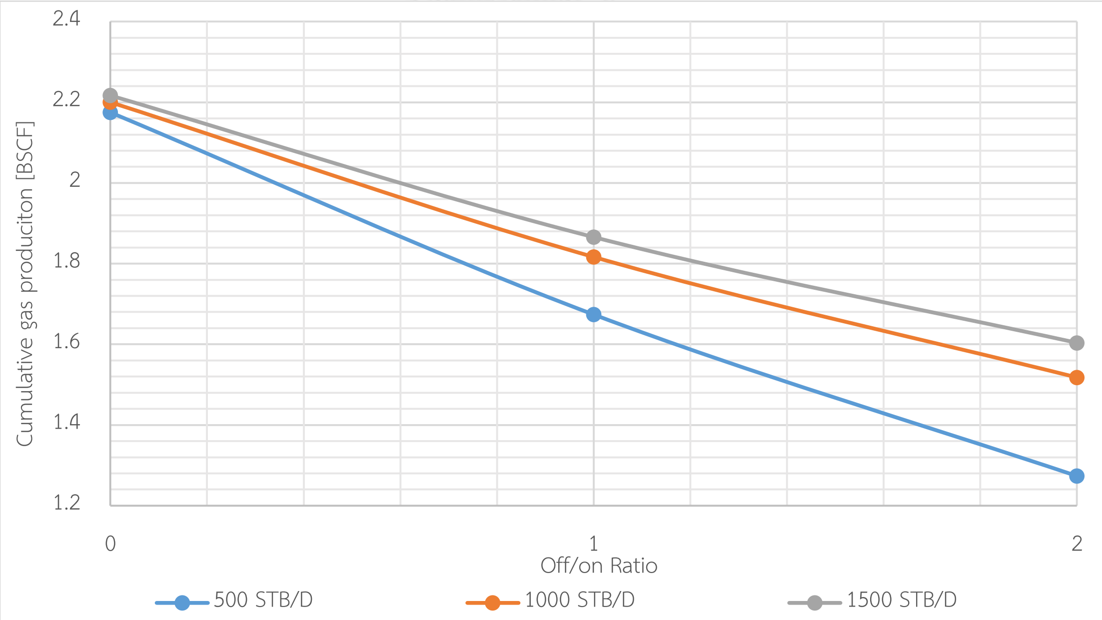


Figure 5.35 Cumulative gas production as function with off/on ratios with different TLPR in 50 PV aquifer with 1 PV gas reservoir combination.

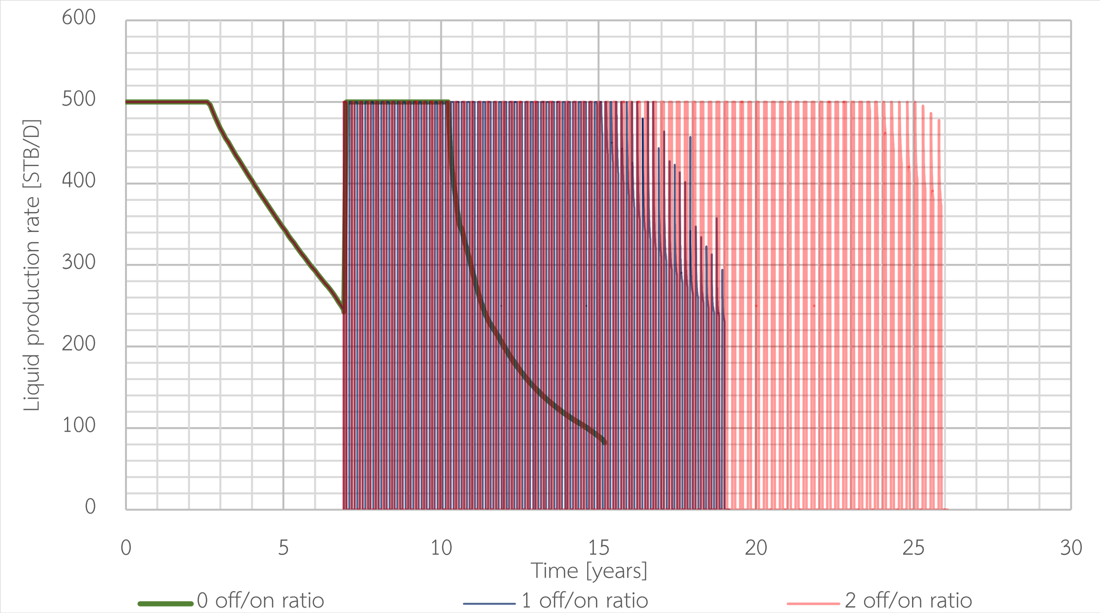


Figure 5.36 Liquid production rate at different off/on ratios at target liquid production rate of 500 STB/D

For target liquid production rate of 500 STB/D, Figure 5.36 shows that the case with higher off/on ratio remains at a plateau rate of 500 STB/D for a longer period of time compared to the case with lower off/on ratio during gas flooding period. This same figure also shows that liquid production rate is higher as off/on ratio increase in near abandonment period. Oil recovery factor is noticeably increased with increasing off/on ratio of the target liquid production rate of 500 STB/D. This improvement in oil recovery factor after increasing off/on ratio is because of the liquid and gas segregate during the shut-in period which helps retain injected gas inside the reservoir. As shown in Table 5.8, the amount of net gas influx is higher in the case of larger off/on ratio. This is further confirmed by less gas production rate as shown in Figure 5.37. By retaining more gas in the oil reservoir, the reservoir pressure declines at a slower rate. However, the abandonment pressure is higher in the case of high off/on ratio. As off/on ratio increase, gas saturation around the production well decreases as gas and liquid segregate. This causes higher pressure loss in the reservoir as relative permeability to oil decreases while average fluid viscosity increases. However, the advantage from gas retention is greater than the downside from the pressure loss in the reservoir when implementing high off/on ratio as shown in Figure 5.39. Thus, at target liquid production rate of 500 STB/D, higher off/on ratio yields higher oil recovery factor than the case with low off/on ratio. The oil production rate in this target liquid production rate is different between different off/on ratios as shown in Figure 5.40. The case with high off/on ratio shows a gradual decline in oil production rate, this further confirm the advantage of implementing intermittent production in this target liquid production rate.

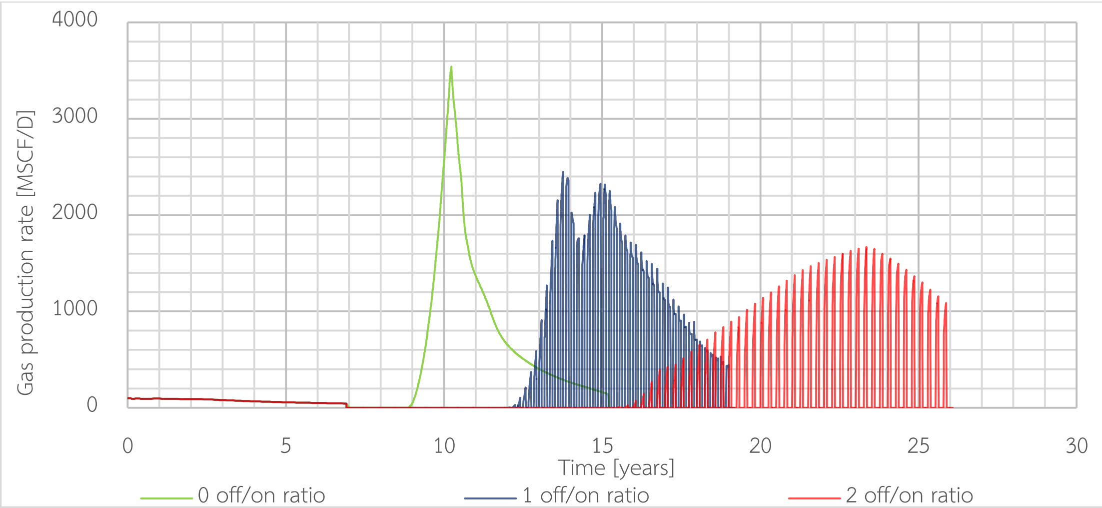


Figure 5.37 Gas production rate at different off/on ratios at 500 STB/D target liquid production rate

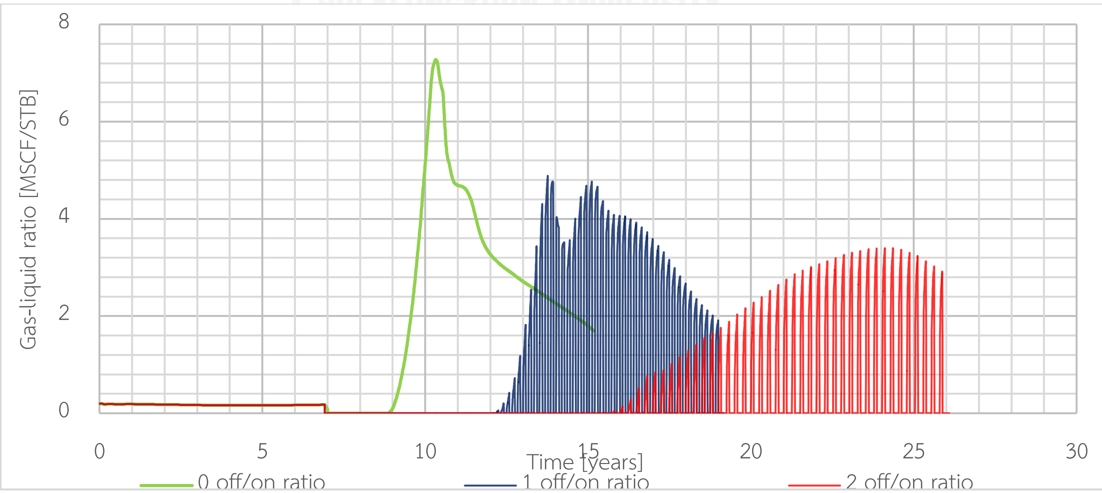


Figure 5.38 Gas-liquid ratio at different off/on ratios at 500 STB/D target liquid production rate

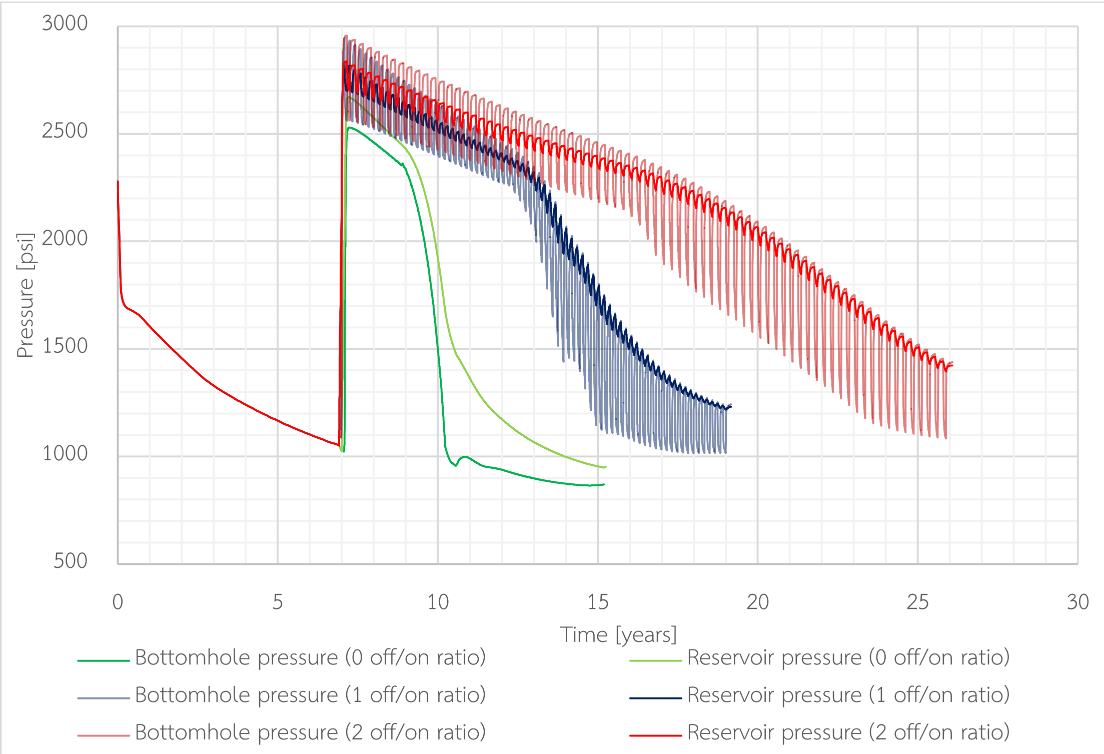


Figure 5.39 Bottomhole and average reservoir pressure with different off/on ratio at target liquid production rate of 500 STB/D

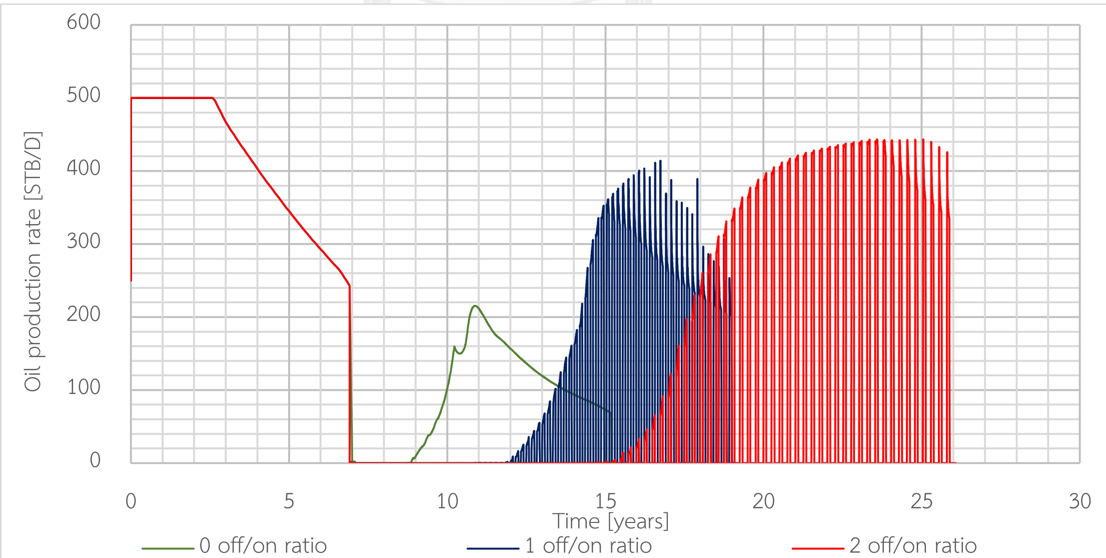


Figure 5.40 Oil production rate with different off/on ratios at target liquid production rate of 500 STB/D

In the case with target liquid production rate of 1000 STB/D, Figure 5.41 shows that liquid production rate maintains maximum plateau for a smaller period of time compared to the case with target liquid production rate of 500 STB/D. In contrast to the case with 500 STB/D, the target liquid production rate of 1000 STB/D slightly has a decrease in oil recovery efficiency as off/on ratio is increased as seen in Figure 5.34. This reduction is due to the fact that gas is not effectively retained in the reservoir when increasing the shut-in period. Unlike the case of 500 STB/D in which gas rate and cumulative gas production and GLR noticeably decrease, gas production rate, cumulative gas production and producing GLR for the case of 1000 STB/D are insignificantly different between various off/on ratios as shown in Figure 5.42 and Figure 5.43, respectively. For this target rate, intermittent production shows small differences in the in the way the reservoir pressure declines as shown in Figure 5.45, in comparison to what happens in the case of 500 STB/D (Figure 5.39). The downside of the pressure loss in the reservoir as liquid and gas segregation remains the same. This results in more disadvantage from high off/on ratio than benefit from maintaining reservoir pressure in this target liquid production rate. Thus, intermittent production should not be implemented in the case with target liquid production rate of 1000 STB/D.

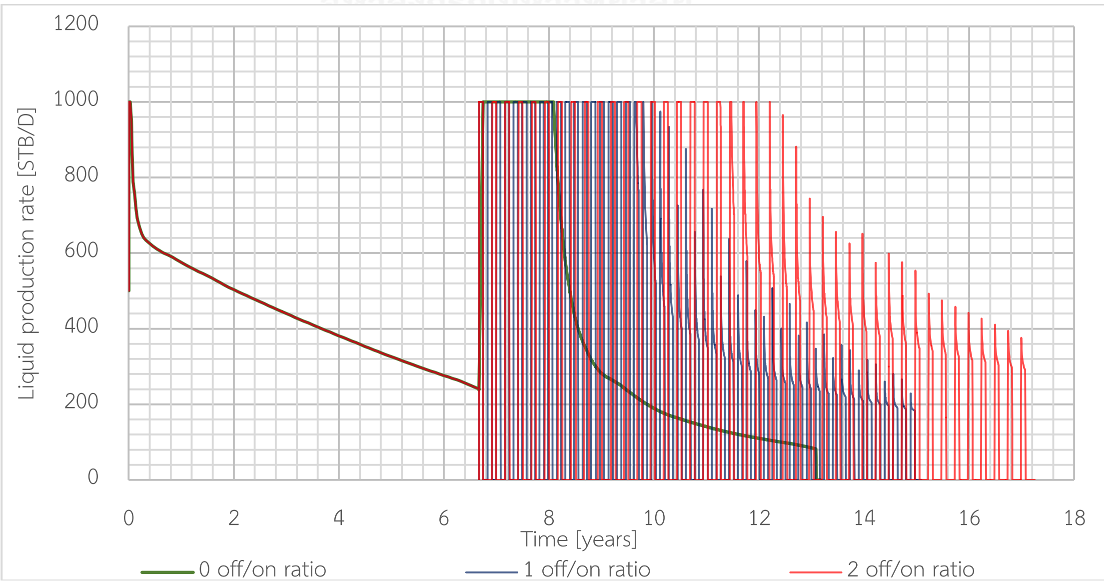


Figure 5.41 Liquid production rate with different off/on ratios at target liquid production rate of 1000 STB/D

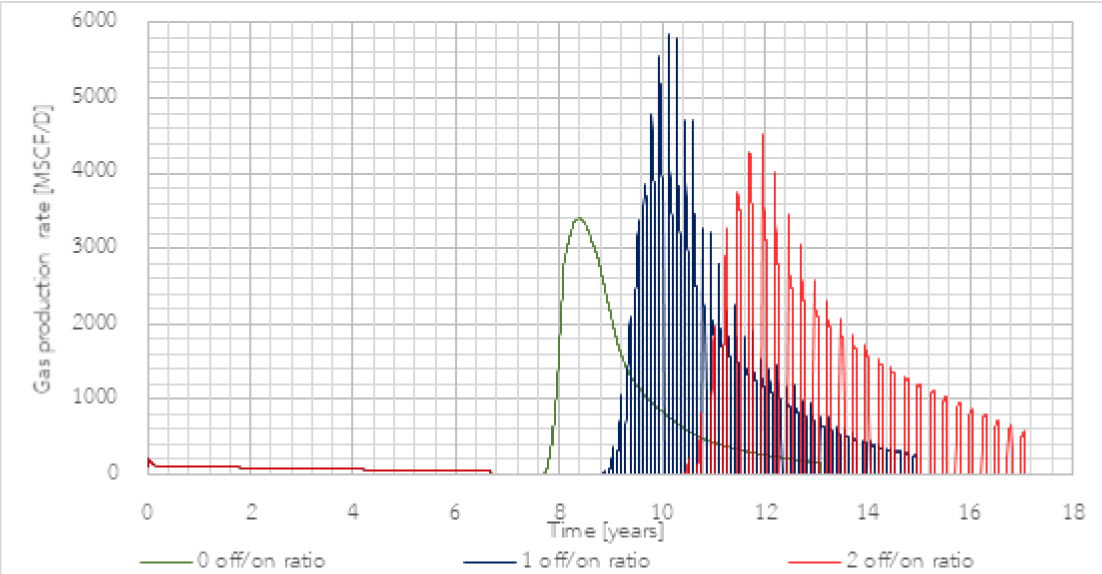


Figure 5.42 Gas production rate with different off/on ratios at target liquid production rate of 1000 STB/D

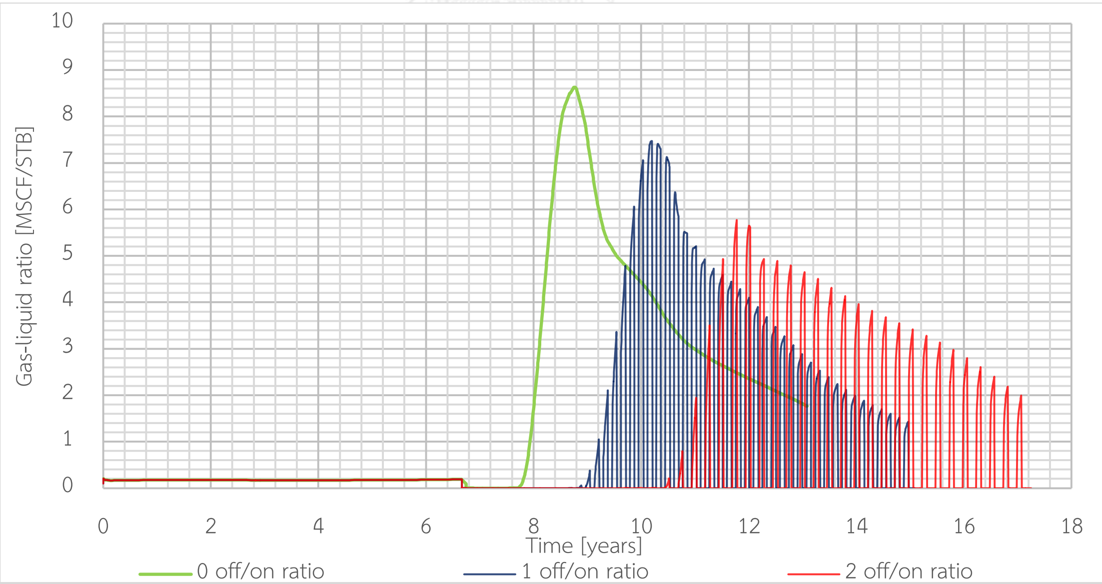


Figure 5.43 Gas-liquid ratio with different off/on ratios at target liquid production rate of 1000 STB/D

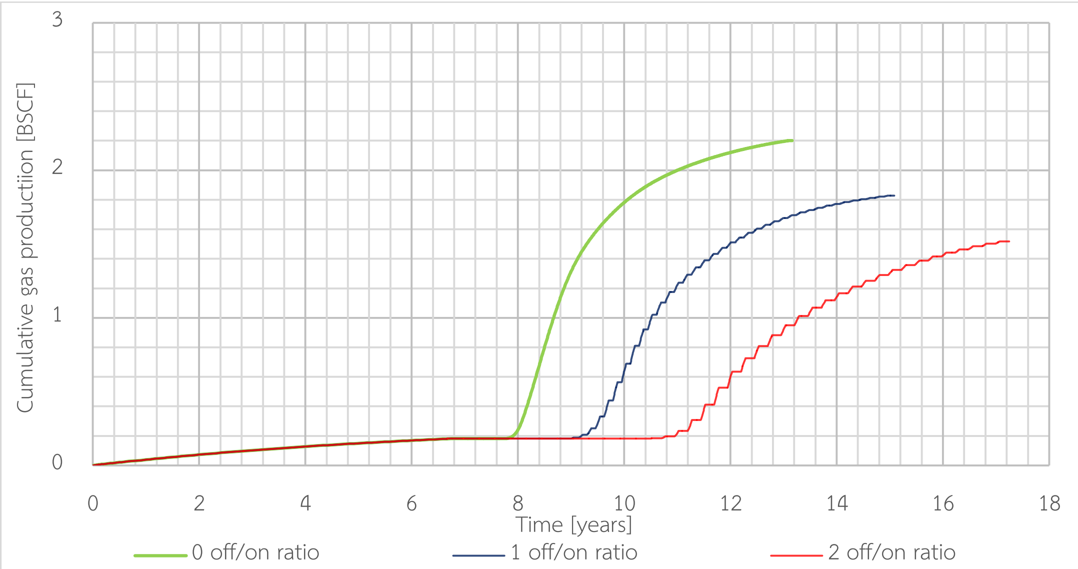


Figure 5.44 Cumulative gas production with different off/on ratios at target liquid production rate of 1000 STB/D

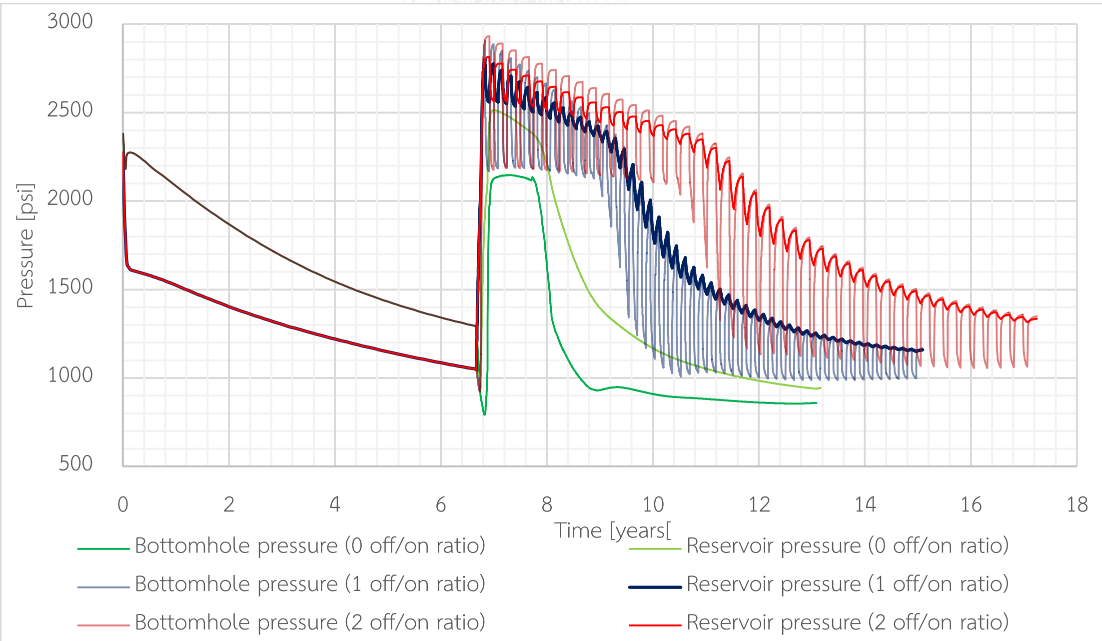


Figure 5.45 Bottomhole and average reservoir pressure with different off/on ratios at target liquid production rate of 1000 STB/D

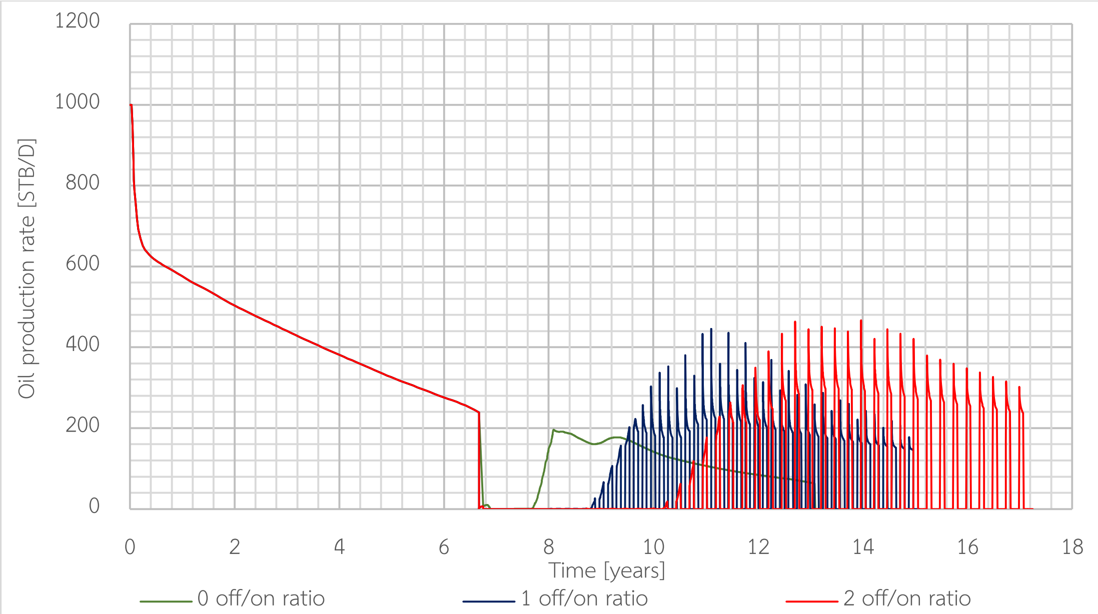


Figure 5.46 Oil production rate with different off/on ratios at target liquid production rate of 1000 STB/D

In the case of target liquid production rate of 1500 STB/D, Figure 5.47 shows that the liquid production rate can be maintained at the maximum plateau for a smaller period of time compared to cases with lower target liquid production rate. In this target rate, similar behaviors to the cases with target liquid production rate of 1000 STB/D are observed in term of gas production rate, cumulative gas production, gas-liquid ratio and reservoir pressure as shown in Figure 5.48 to Figure 5.51. In terms of gas production rate, intermittent production does not effectively reduce gas production rate compared to the case without intermittent production unlike the case with target liquid production rate of 500 STB/D. As the gas is not effectively retained in the oil reservoir, the reservoir pressure declines at a faster rate (Figure 5.51) compared with cases with 500 STB/D (Figure 5.34). Similarly to the case of 1000 STB/D of target liquid production rate, the disadvantage from pressure loss in porous media as gas saturation reduces around wellbore is greater than the benefit of the gradual pressure loss by implementing intermittent production. This confirms the reduction in oil recovery efficiency as intermittent production is implemented in this target liquid production rate as shown in Table 5.8.

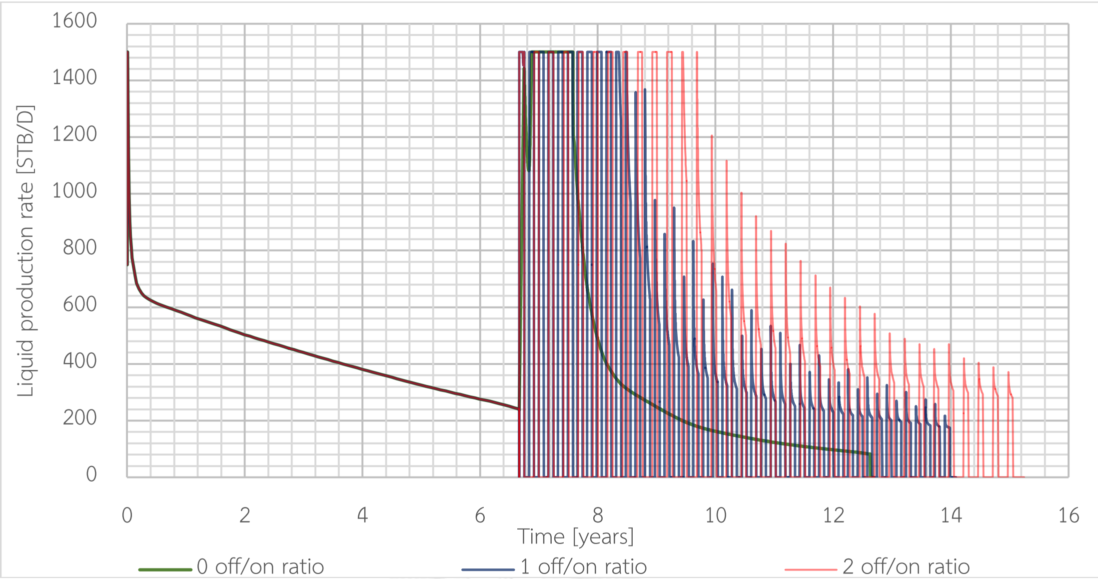


Figure 5.47 Liquid production rate with different off/on ratios at target liquid production rate of 1500 STB/D

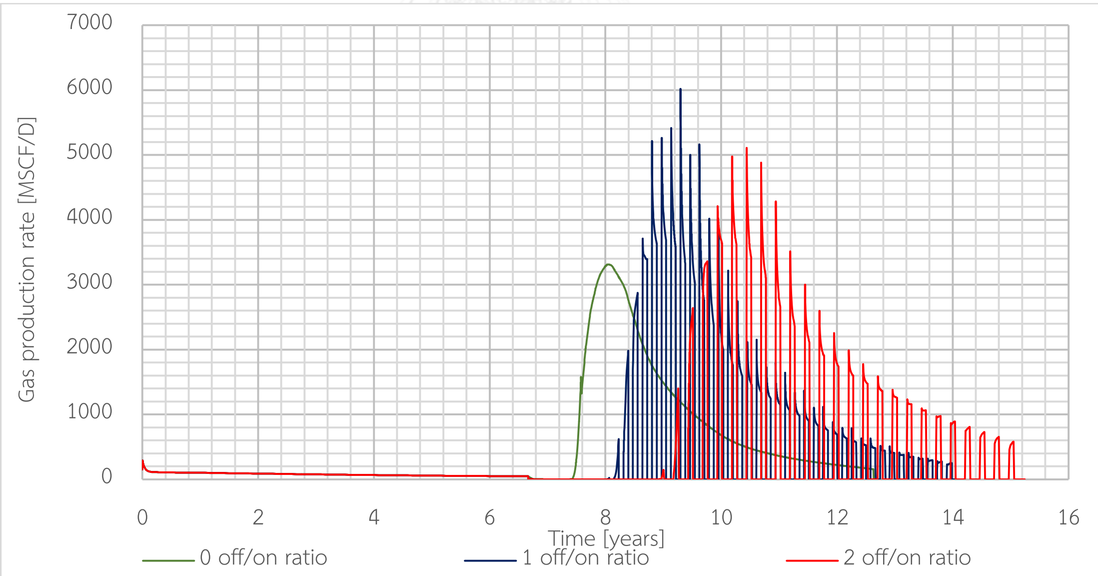


Figure 5.48 Gas production rate with different off/on ratios at target liquid production rate of 1500 STB/D

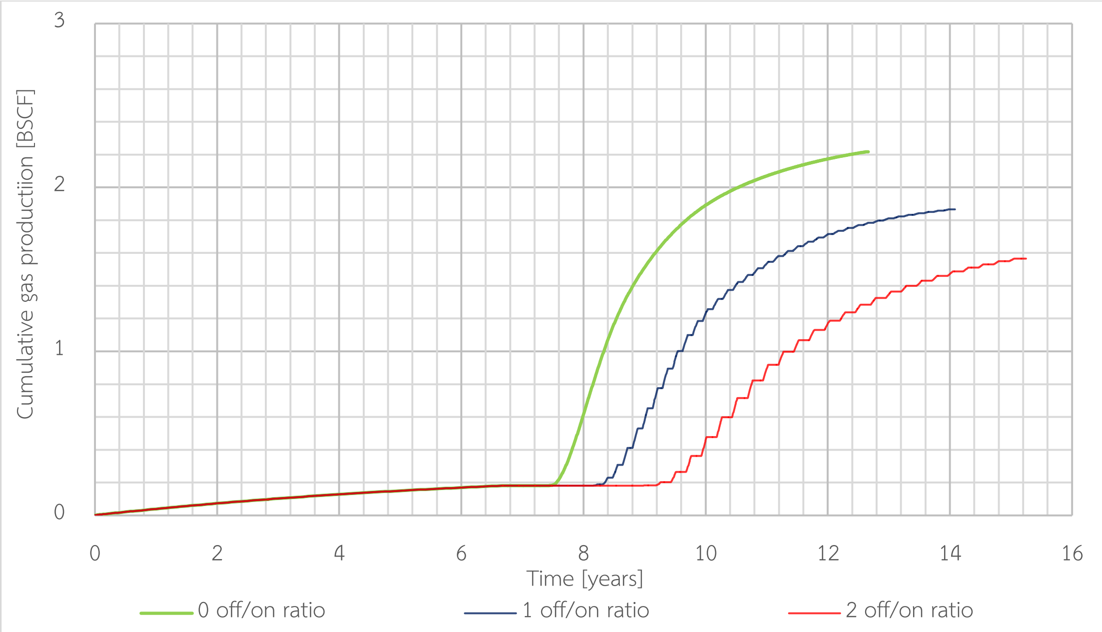


Figure 5.49 Cumulative gas production with different off/on ratios at target liquid production rate of 1500 STB/D

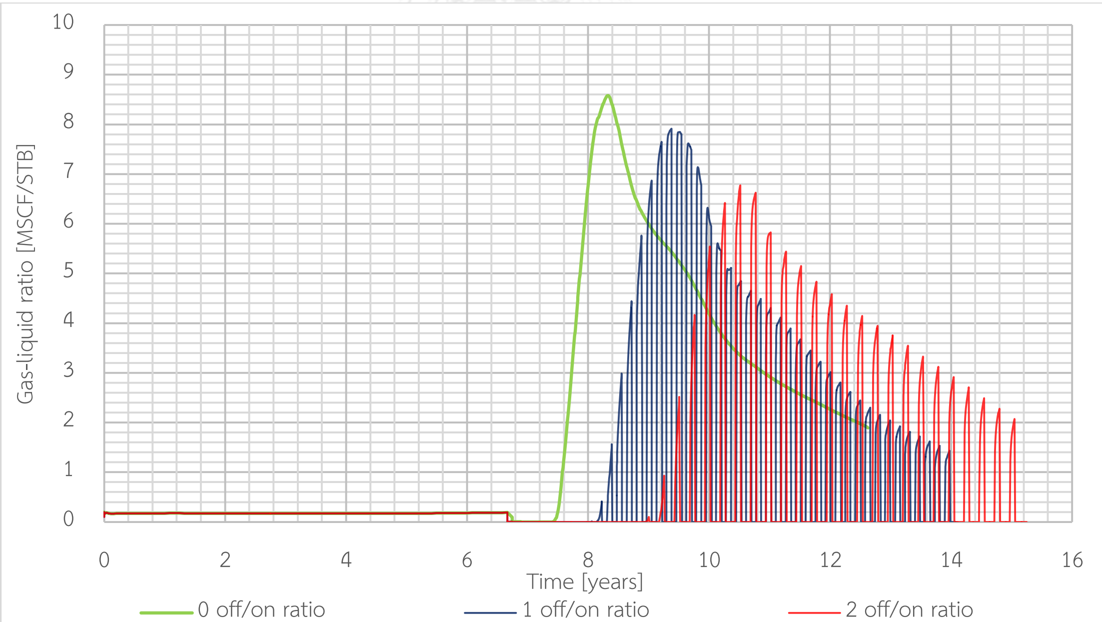


Figure 5.50 Gas-liquid ratio with different off/on ratios at target liquid production rate of 1500 STB/D

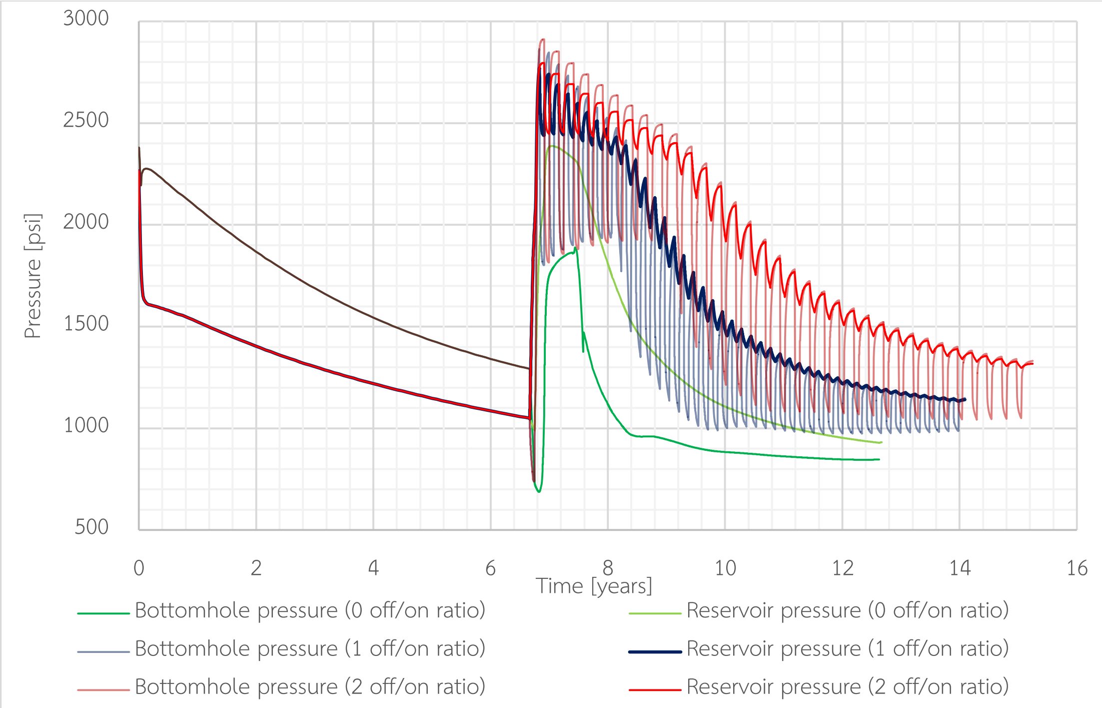


Figure 5.51 Bottomhole and average reservoir pressure with different off/on ratios at target liquid production rate of 1500 STB/D

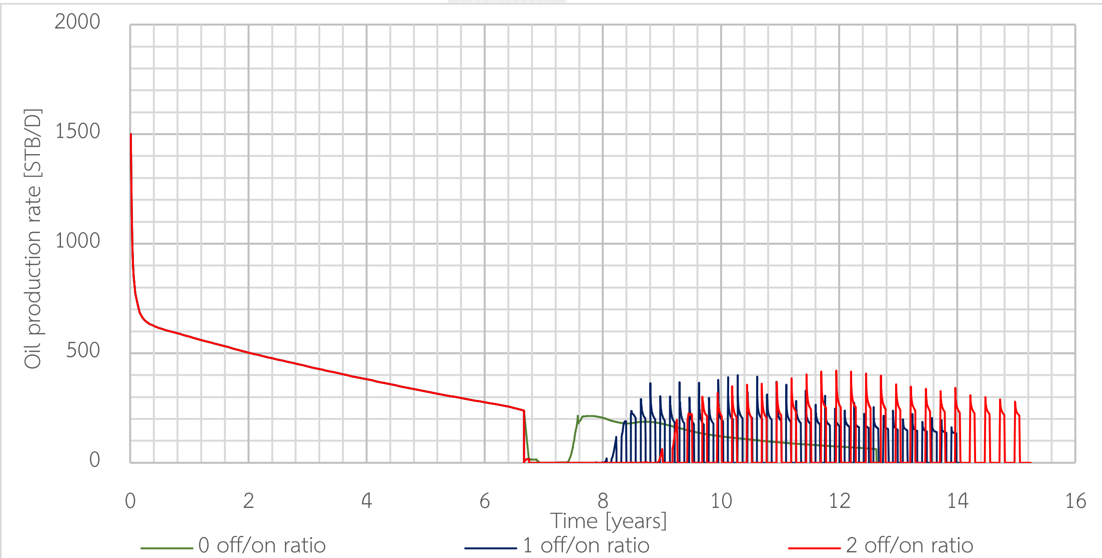


Figure 5.52 Oil production rate with different off/on ratios at target liquid production rate of 1500 STB/D

In this reservoir combination, target liquid production rate of 500 STB/D with 2 off/on ratio is recommended to obtain maximum recovery. This set of production schedule effectively limits gas production and maintains reservoir pressure better than the other cases. The advantage of maintaining high reservoir pressure overcomes the effect of higher pressure loss in the reservoir from liquid gas segregation. If the case of high target liquid rate is chosen to shorten production time, intermittent production is not recommended since the downside of pressure loss in the reservoir as liquid and gas segregate will overcome the advantage of maintaining the reservoir pressure. Thus, high rate with intermittent production yields no improvement in oil recovery.

5.3.3 Small Aquifer and Large Gas Reservoir (10PV aquifer, 5PV gas reservoir)

Effect of production strategy was investigated for this set of small aquifer and large gas reservoir combination in order to optimize oil recovery in such case. Table 5.9 shows production strategies of combined different target liquid rates and intermittent schedules of production well during gas dumpflood in 10 PV aquifer and 5PV gas reservoir as well as the results obtained from the simulation.

Table 5.9 shows that by increasing off/on ratio, production period and net cumulative gas production also increase. In opposite to production period, cumulative gas production decreases as increasing off/on ratio. In terms of cumulative oil production, oil production only increases with the increasing off/on ratio in the cases with target liquid production of 1000 STB/D and 1500 STB/D while cases with 500 STB/D target injection rate result in lower in oil production as shown in Figure 5.53. This shows a reverse trend compared to the result in cases with 1PV gas reservoir. However, all cases with intermittent production are limited of 30 year period, according to the Thailand fiscal regime. In addition, the results are insignificantly different in term of cumulative water production among different production schedules.

At target liquid production rate of 500 STB/D, Figure 5.54 shows that the case with higher off/on ratio remains at a plateau rate of 500 STB/D for a long period of time compared to the case with lower off/on ratio during gas flooding period. This same figure also shows that liquid production rate is higher near abandonment period as off/on ratio is increased.

Table 5.9 Simulation results for 10 PV aquifer and 5 PV gas reservoir

Case No	Target liquid production rate (STB/D)	Intermittent production	Time [Years]	Oil recovery factor	Cumulative oil production [MMSTB]	Cumulative Gas production [BSCF]	Cumulative water production [MMSTB]	Cumulative cross-flow gas [BSCF]	Net cumulative gas production [BSCF]
Case 3.1	500	No off Always on	18.16	67.68%	1.794	12.384	0.186	12.431	0.046
Case 3.2	500	1 month off 1 month on	30.00	75.69%	2.006	11.968	0.189	12.108	0.140
Case 3.3	500	2 months off 1 month on	30.00	71.32%	1.891	6.973	0.186	7.792	0.818
Case 3.4	1000	No off Always on	16.41	66.71%	1.769	12.379	0.186	12.429	0.050
Case 3.5	1000	1 month off 1 month on	30.00	74.82%	1.983	12.180	0.188	12.302	0.122
Case 3.6	1000	2 months off 1 month on	30.00	75.44%	1.999	10.880	0.188	11.198	0.318
Case 3.7	1500	No off Always on	16.25	66.70%	1.768	12.380	0.186	12.432	0.052
Case 3.8	1500	1 month off 1 month on	30.00	74.77%	1.981	12.187	0.189	12.308	0.121
Case 3.9	1500	2 months off 1 month on	30.00	75.46%	2.000	10.936	0.188	11.246	0.310

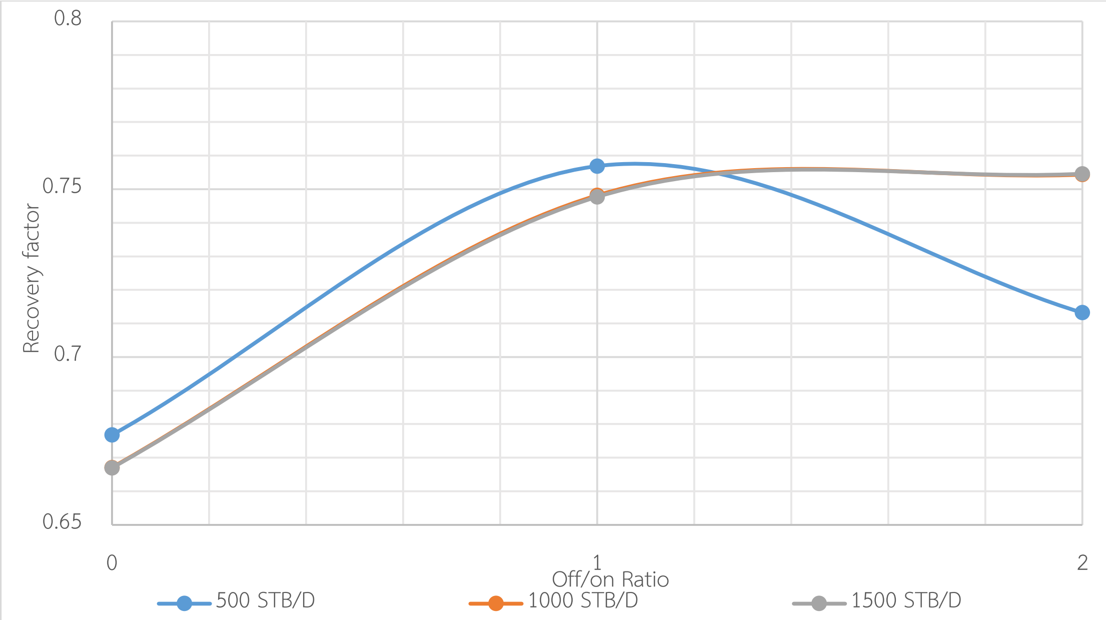


Figure 5.53 Recovery factor as function with off/on ratios with different target liquid production rate in 10 PV aquifer with 5 PV gas reservoir combination.

As off/on ratio is increased from 0 to 1, the oil recovery factor increases significantly from 67.68 % to 75.69 %. However, as the ratio is increased from 1 to 2, the oil recovery factor decreases from 75.69 % to 71.32 %. High oil recovery efficiency is obtained in the case of 1 off/on ratio due to the fact that liquid and gas segregate better with increasing off/on ratio compared to the case without intermittent production. This causes liquid production rate to decline gradually and allows the production well to produce at a higher oil rate before getting to the 30-year limit. Low gas production rate and gradual increase in cumulative gas production (Figure 5.55 and Figure 5.56) cause the reservoir pressure to decline at a slower rate as shown in Figure 5.57. This figure also shows that the case with 2 off/on ratio is terminated at relatively high pressure compared to the case with 1 off/on ratio. This confirms the reduction in oil recovery efficiency in such case. Oil production before the production ends is still high in the case with high off/on ratio as shown in Figure 5.58. This can be concluded that wells are terminated only because of time constraint, not according to the productivity of the production well at all.

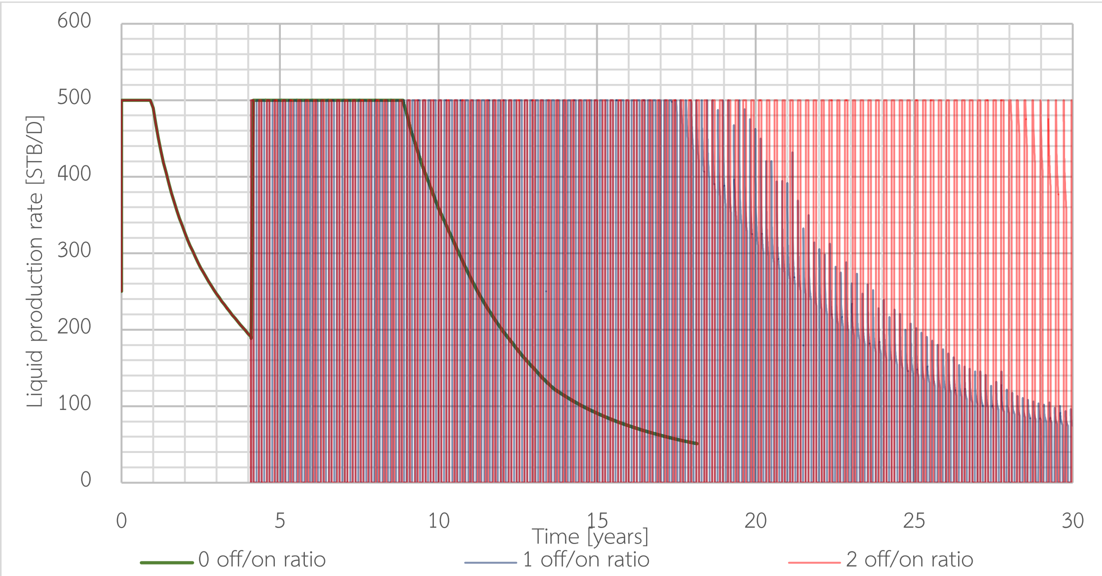


Figure 5.54 Liquid production rate at different off/on ratios at target liquid production rate of 500 STB/D

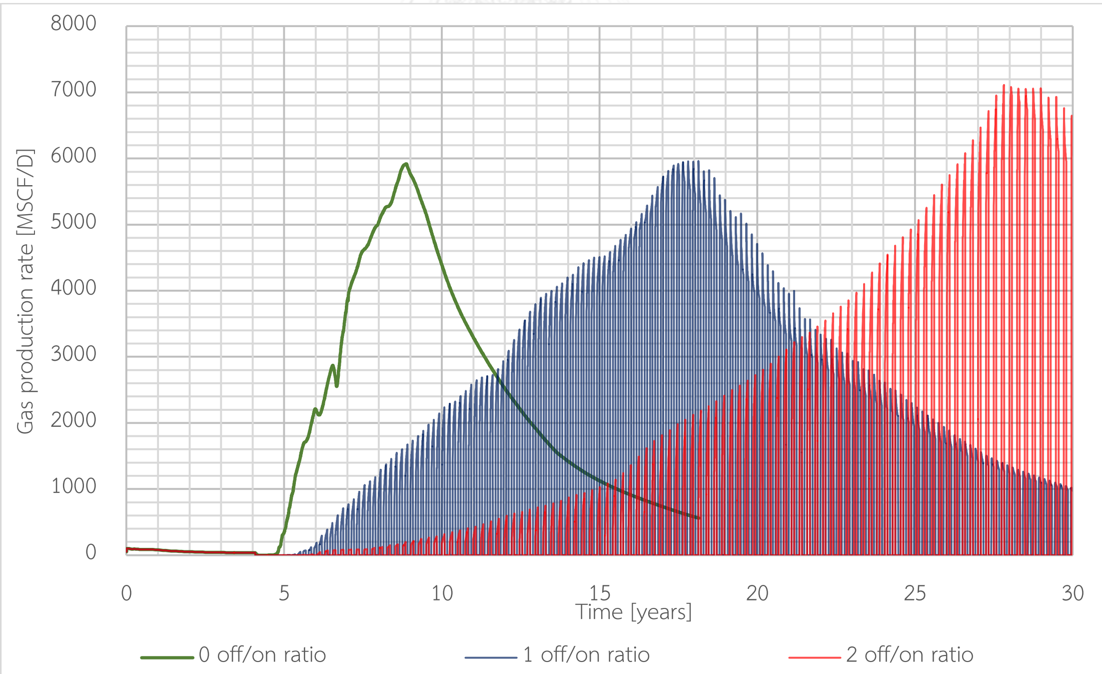


Figure 5.55 Gas production rate at different off/on ratios at target liquid production rate of 500 STB/D

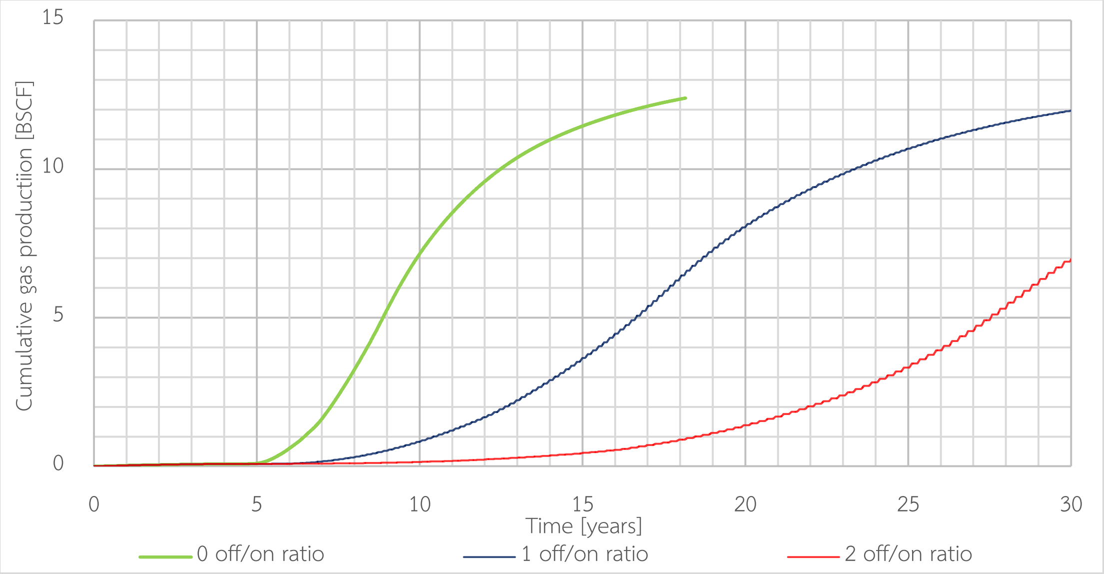


Figure 5.56 Cumulative gas production at different off/on ratios at target liquid production rate of 500 STB/D

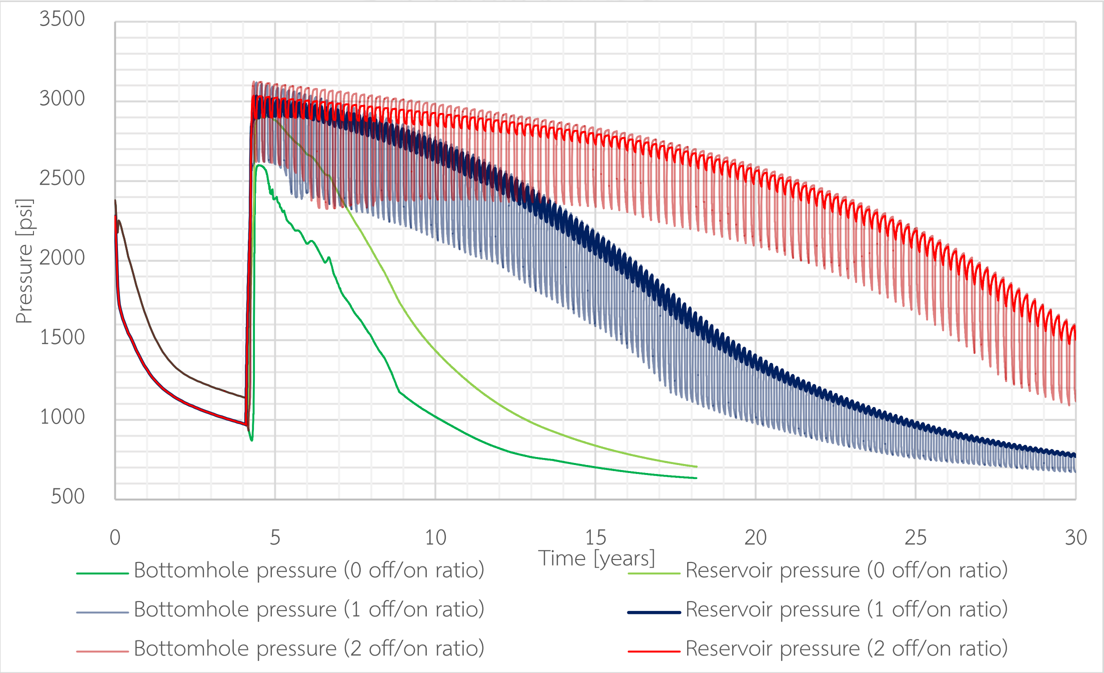


Figure 5.57 Bottomhole and average reservoir pressure with different off/on ratios at target liquid production rate of 500 STB/D

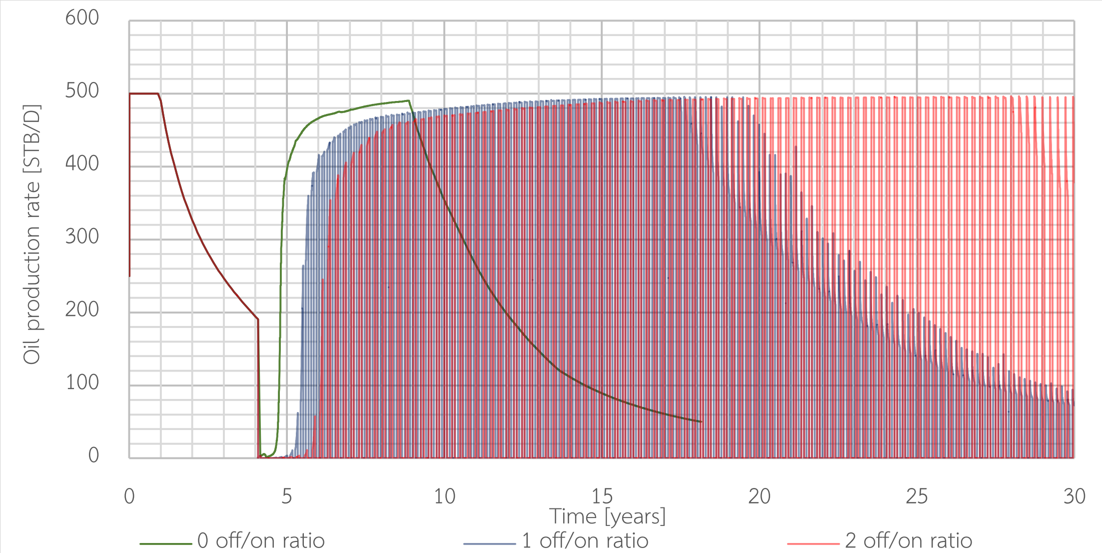


Figure 5.58 Oil production at different off/on ratios at target liquid production rate of 500 STB/D

In the case with target liquid production rate of 1000 STB/D, liquid production rate maintains maximum plateau for a smaller period of time compared to case with target liquid production rate of 500 STB/D as shown in Figure 5.60. Unlike the case with 500 STB/D, the target liquid production rate of 1000 STB/D yields a high recovery factor as off/on ratio is increased. This increment in oil recovery is due to better segregation between liquid and gas, enabling the production well to produce above the economic rate. As shown in Figure 5.59, high off/on ratio case shows a better segregation of liquid and gas which results in high gas saturation at the updip location and high oil saturation at the downdip location. In addition to a better segregation, the drawback of abandoning the production well due to time constraint is lower than the benefit of liquid segregation from low target production rate. Less gas production rate and gradual increase in cumulative gas production (Figure 5.61 and Figure 5.62) cause reservoir pressure to decline at a slower rate as indicated in Figure 5.63. This confirms the benefit from the increasing off/on ratio of this target liquid production rate. For this target production rate with 2 off/on ratio, the oil production rate at the end of the production is approximately 150 STB/D while the case of target liquid production rate of 500 STB/D with 2 off/on ratio has the oil production rate at the end of production around 350 STB/D as shown in Figure 5.64 and Figure 5.58. This explains the reason why the case with target liquid production rate of 1000 STB/D yields more oil recovery than the case of target liquid production rate of 500 STB/D.

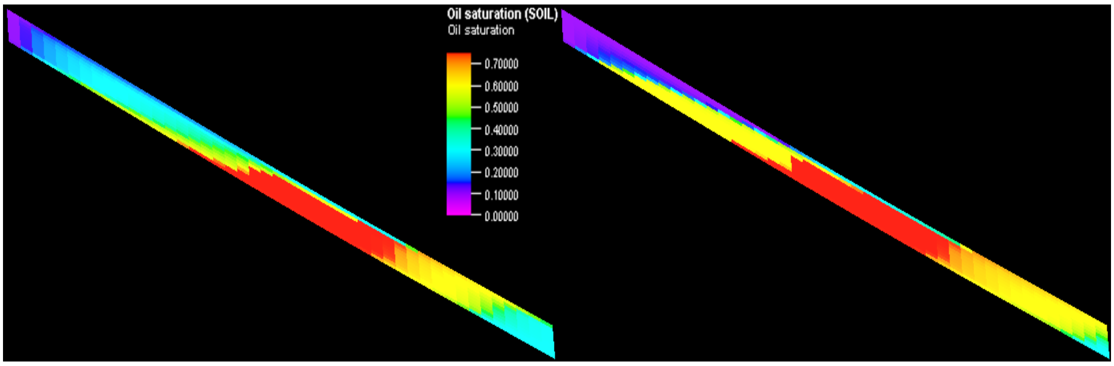


Figure 5.59 Oil saturation at the gas breakthrough with 1000 STB/D target liquid production rate and 0 off/on ratio (left), 2 off/on ratio (right).

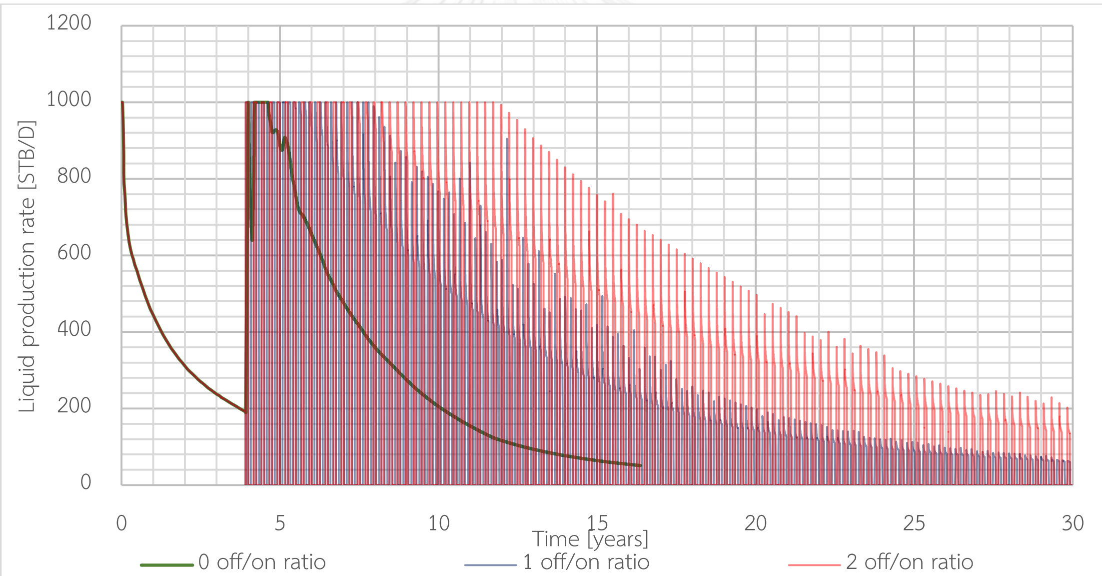


Figure 5.60 Liquid production rate at different off/on ratios at target liquid production rate of 1000 STB/D

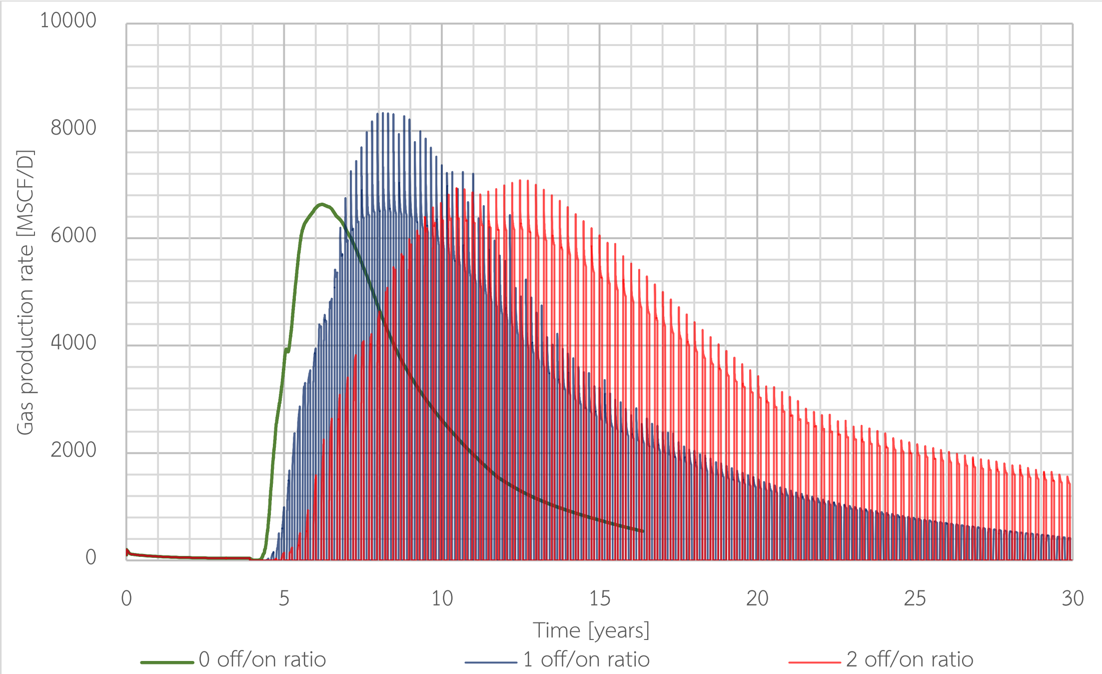


Figure 5.61 Gas production rate at different off/on ratios at target liquid production rate of 1000 STB/D

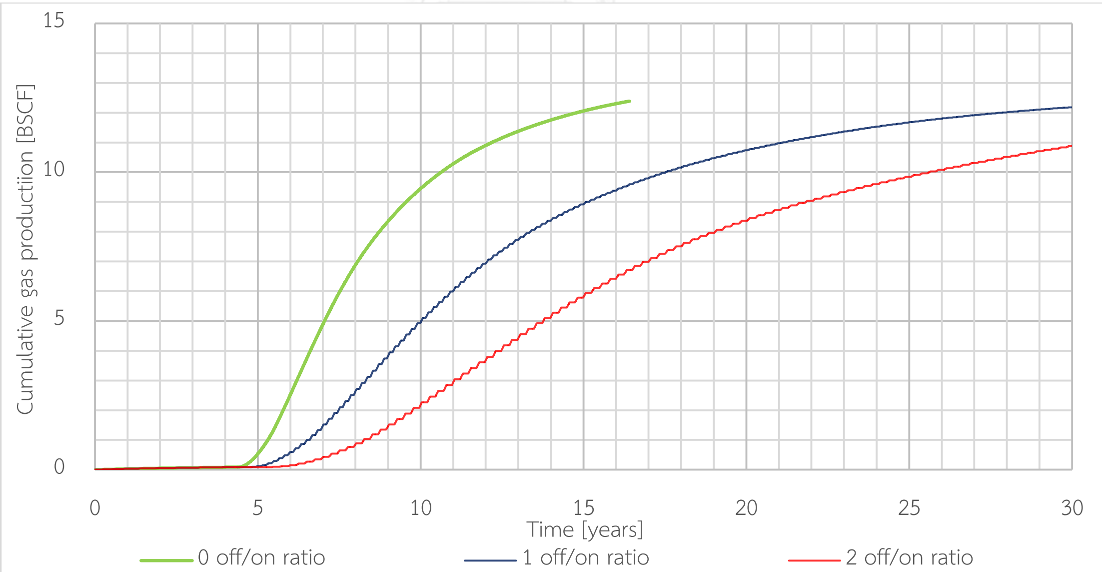


Figure 5.62 Cumulative gas production at different off/on ratios at target liquid production rate of 1000 STB/D

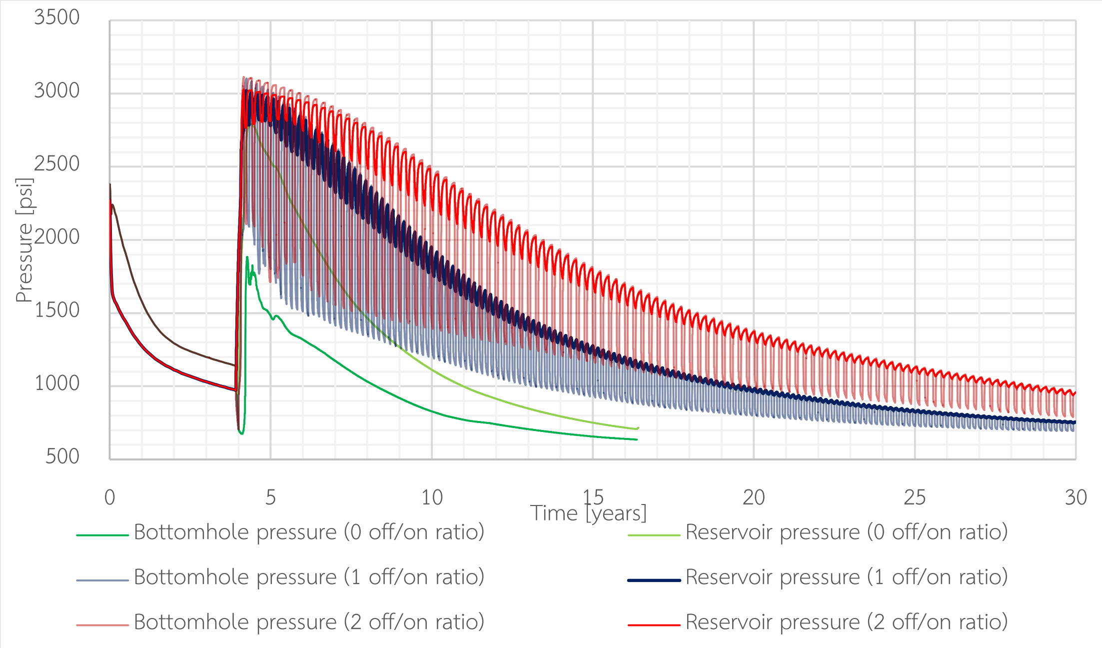


Figure 5.63 Bottomhole and average reservoir pressure with different off/on ratios at target liquid production rate of 1000 STB/D

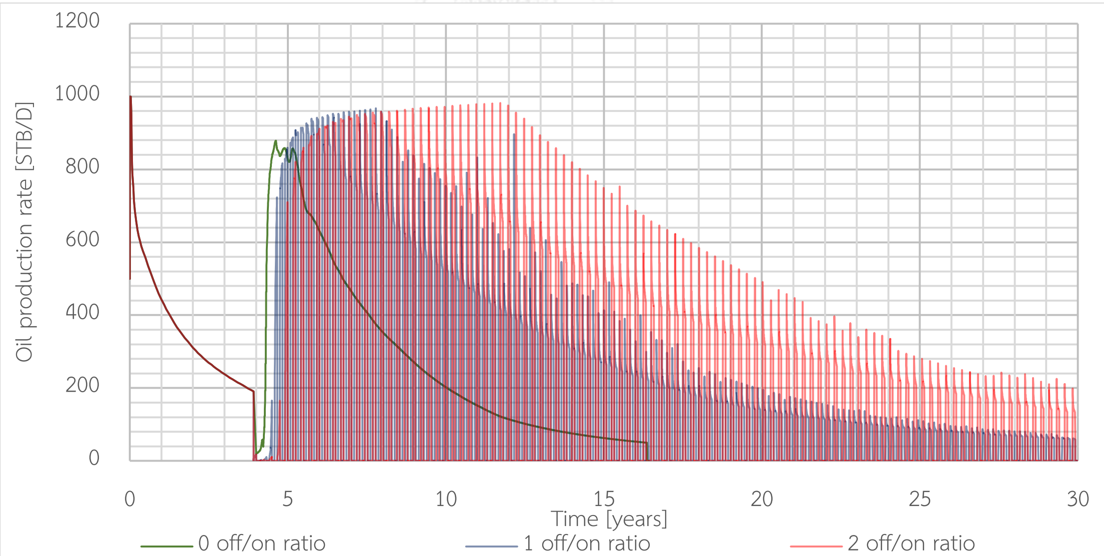


Figure 5.64 Oil production rate at different off/on ratios at target liquid production rate of 1000 STB/D

For the case of target liquid production rate of 1500 STB/D, Figure 5.65 shows that the liquid production rate maintains maximum plateau for smaller period of time compared to case with lower target liquid production rate. For this target rate, similar behaviors to the cases with target liquid production rate of 1000 STB/D are observed in term of gas production rate, cumulative gas production, reservoir pressure as shown in Figure 5.66 to Figure 5.68. By increasing off/on ratio, liquid and gas segregate better similar to the case of target liquid production rate of 1000 STB/D as shown in Figure 5.59. This helps maintain the decline of oil production at a gradual rate. In addition to this, the reservoir pressure declines at a gradual rate and higher liquid production rate from liquid segregation causes the overall recovery factor to increase by increasing off/on ratio.

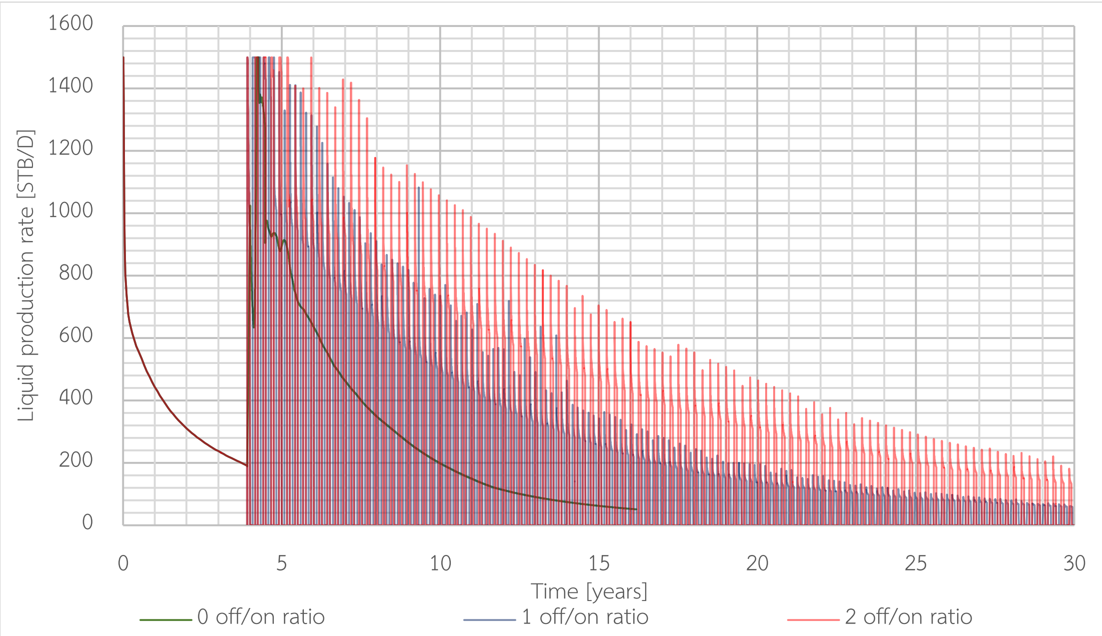


Figure 5.65 Liquid production rate at different off/on ratios at target liquid production rate of 1500 STB/D

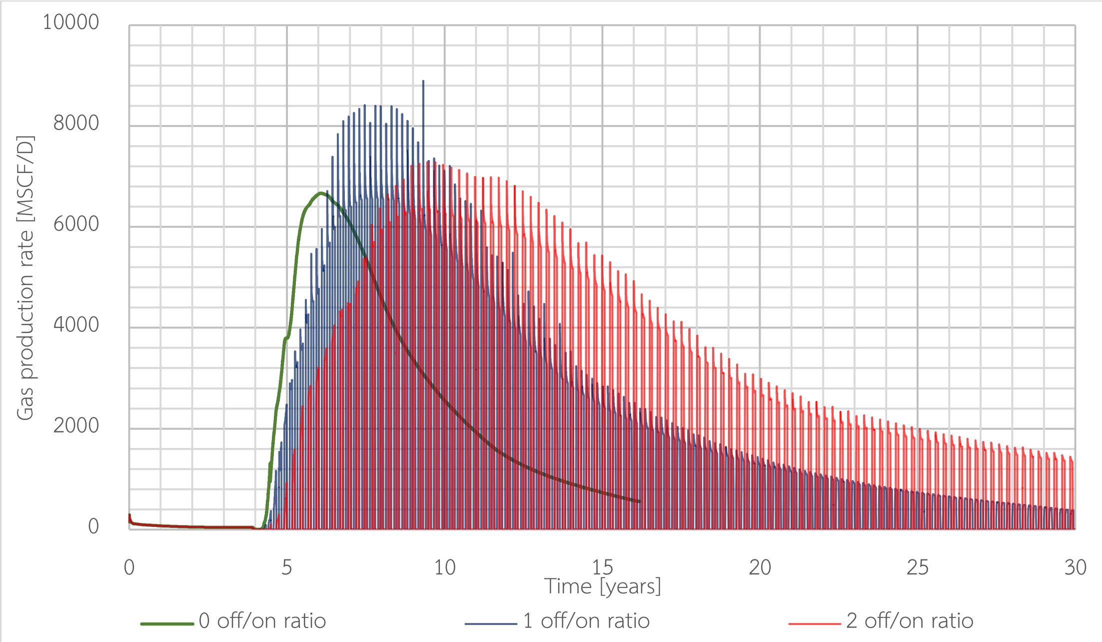


Figure 5.66 Gas production rate at different off/on ratios at target liquid production rate of 1500 STB/D

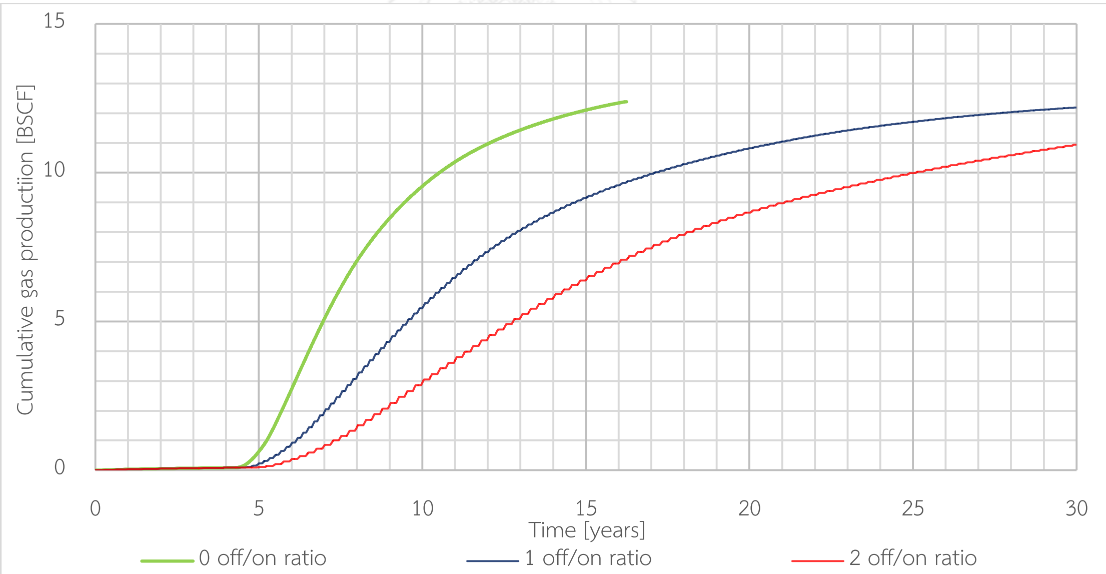


Figure 5.67 Cumulative gas production at different off/on ratios at target liquid production rate of 1500 STB/D

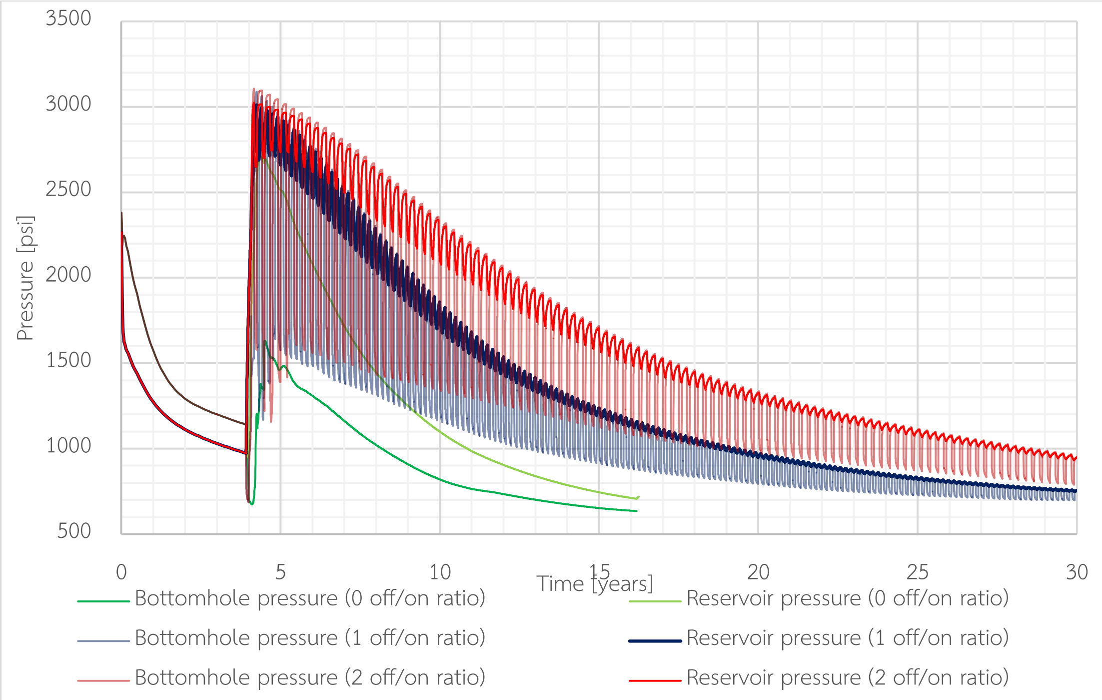


Figure 5.68 Bottomhole and average reservoir pressure with different off/on ratios at target liquid production rate of 1500 STB/D

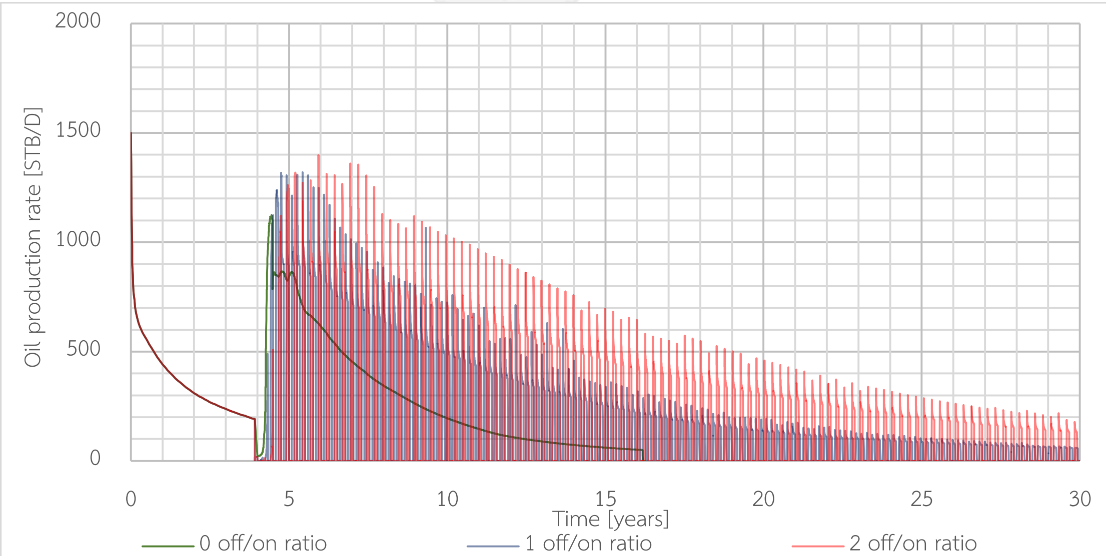


Figure 5.69 Oil production rate at different off/on ratios at target liquid production rate of 1500 STB/D

However, to fully conclude the effect of production schedule to oil recovery efficiency in this reservoir combination, production period limitation of 30 years is eliminated in all cases in this reservoir combination. The results are summarized in Table 5.10 which shows that by increasing off/on ratio, production period and net cumulative gas production also increase. In opposite to production period, cumulative gas production is insignificantly different with increasing off/on ratio. In terms of cumulative oil production, oil production shows a remarkable increase with increasing off/on ratio. In addition, the results also show insignificant difference in term of cumulative water production among the cases.

All target liquid production rates show an increasing trend of oil recovery with increasing off/on ratio. This is due to the fact that as off period is increased, the liquid and gas segregate better (Figure 5.59), with the added benefit from a gradual decrease in reservoir pressure. This causes the production well in a downdip location, to produce a greater amount of oil before reaching the economic limit, resulting in an improvement in oil recovery with increasing off/on ratio.

Table 5.10 Simulation results for 10 PV aquifer and 5 PV gas reservoir without time limit

Case No	Target liquid production rate (STB/D)	Intermittent production	Time [Years]	Oil recovery factor	Cumulative oil production [MMSTB]	Cumulative Gas production [BSCF]	Cumulative water production [MMSTB]	Cumulative cross-flow gas [BSCF]	Net cumulative gas production [BSCF]
Case 3.1	500	No off Always on	18.16	67.68%	1.794	12.384	0.186	12.431	0.046
Case 3.2	500	1 month off 1 month on	35.25	77.43%	2.052	12.510	0.190	12.597	0.087
Case 3.3	500	2 months off 1 month on	42.08	81.64%	2.163	12.163	0.191	12.286	0.123
Case 3.4	1000	No off Always on	16.41	66.71%	1.769	12.379	0.186	12.429	0.050
Case 3.5	1000	1 month off 1 month on	30.92	75.15%	1.991	12.236	0.189	12.354	0.118
Case 3.6	1000	2 months off 1 month on	43.16	80.85%	2.141	12.540	0.191	12.620	0.080
Case 3.7	1500	No off Always on	16.25	66.70%	1.768	12.380	0.186	12.432	0.052
Case 3.8	1500	1 month off 1 month on	30.25	74.84%	1.983	12.198	0.189	12.320	0.122
Case 3.9	1500	2 months off 1 month on	43.16	80.82%	2.140	12.538	0.192	12.619	0.081

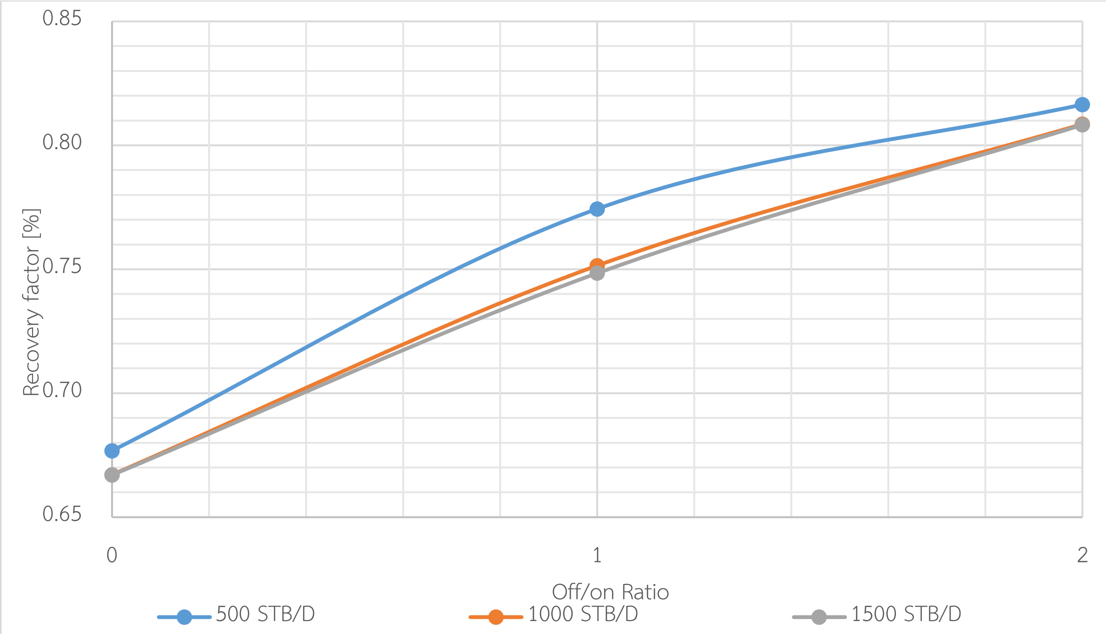


Figure 5.70 Recovery factor as function with off/on ratios with different target liquid production rates in 10 PV aquifer with 5 PV gas reservoir combination without time limitation.

By increasing off/on ratio, the reservoir pressure declines at a lower rate for all target liquid production rate as shown in Figure 5.71, Figure 5.73 and Figure 5.75. In terms of oil production rate, high off/on ratio results in a gradual decrease in oil production rate as shown in Figure 5.72, Figure 5.74 and Figure 5.76. This confirms the improvement in oil recovery with increasing off/on ratio.

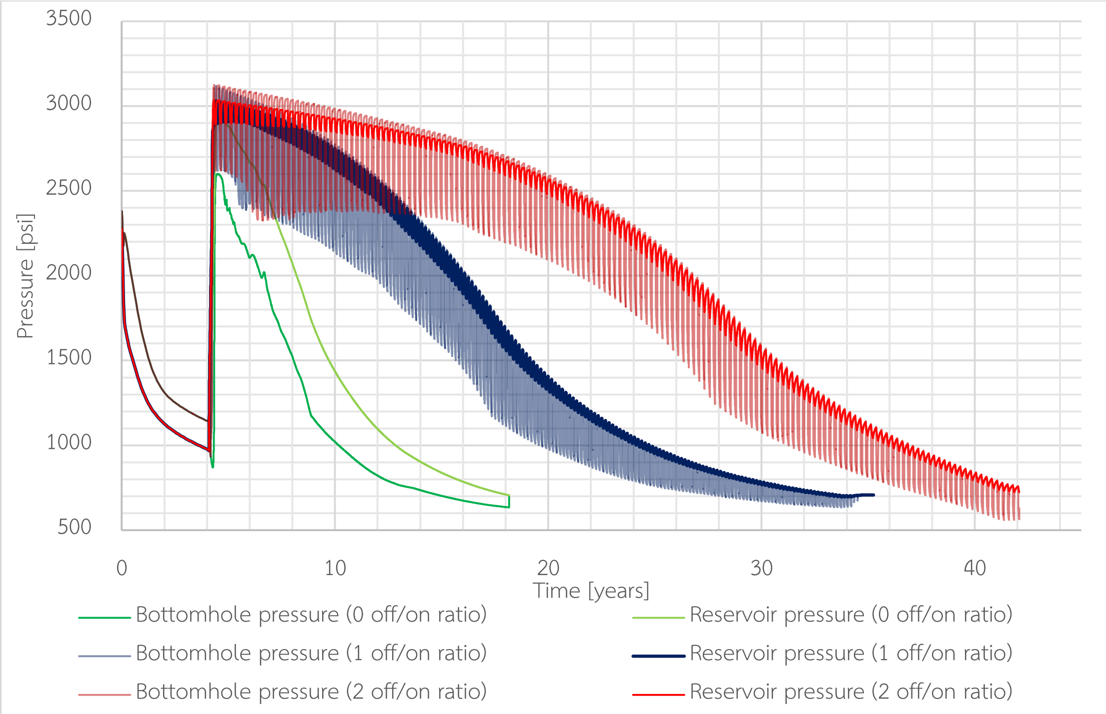


Figure 5.71 Bottomhole and average reservoir pressure with different off/on ratios at target liquid production rate of 500 STB/D

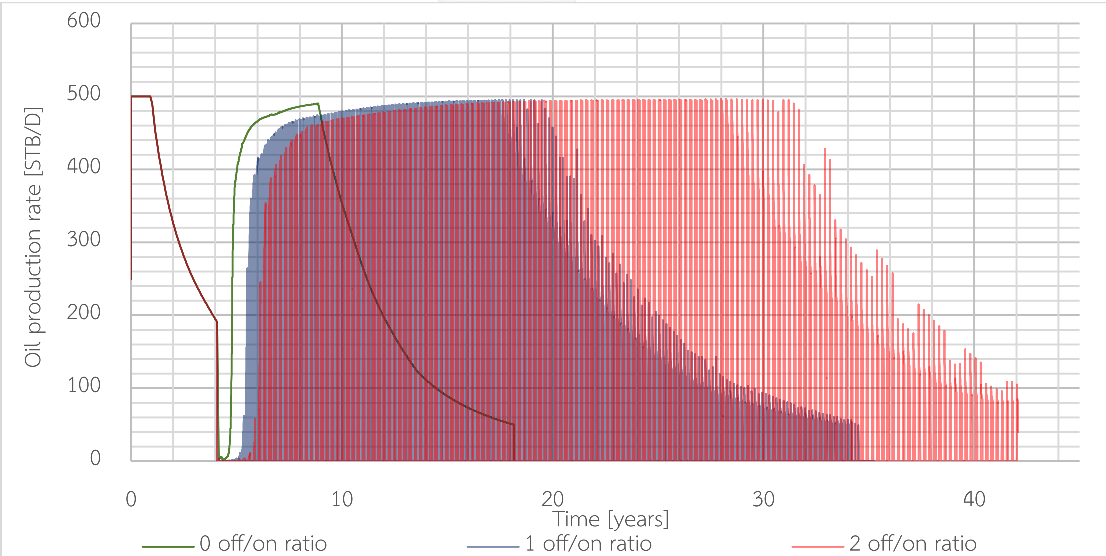


Figure 5.72 Oil production rate at different off/on ratios at target liquid production rate of 500 STB/D

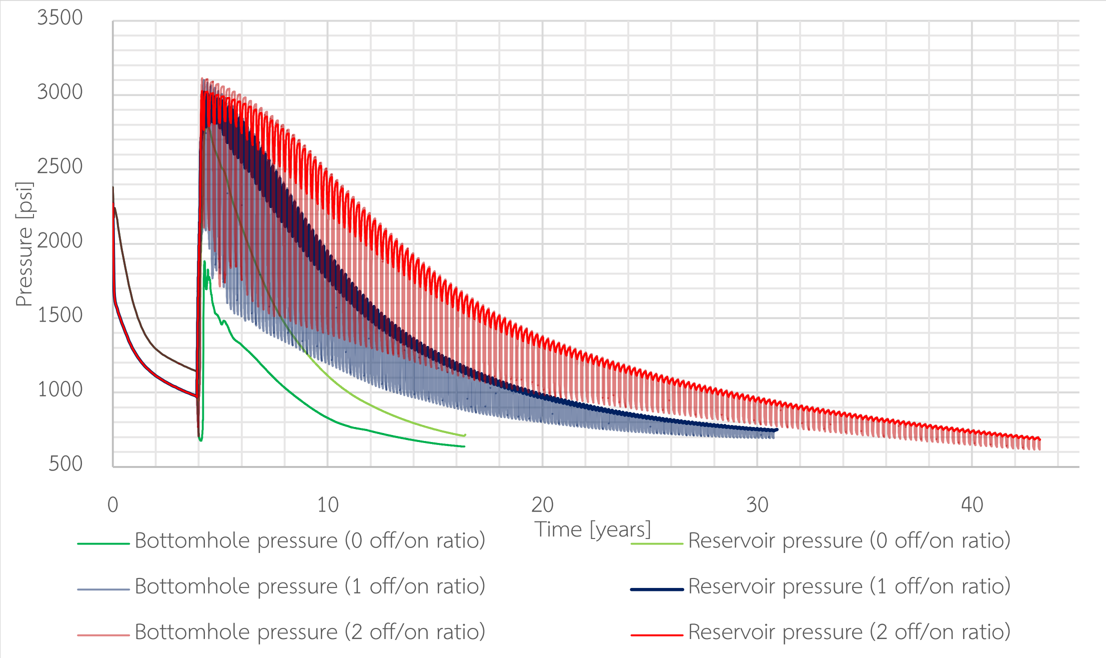


Figure 5.73 Bottomhole and average reservoir pressure with different off/on ratios at target liquid production rate of 1000 STB/D

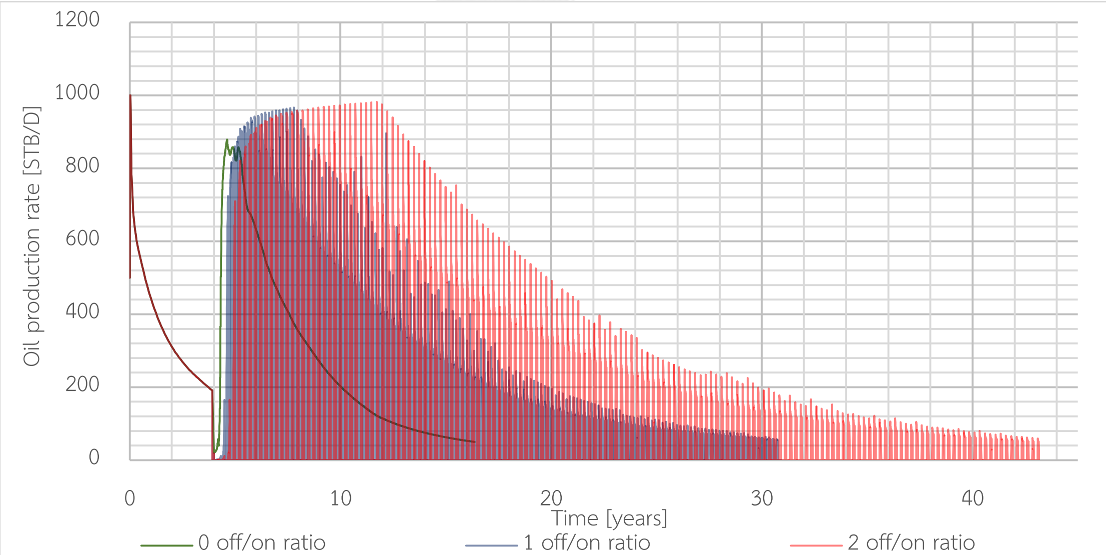


Figure 5.74 Oil production rate at different off/on ratios at target liquid production rate of 1000 STB/D

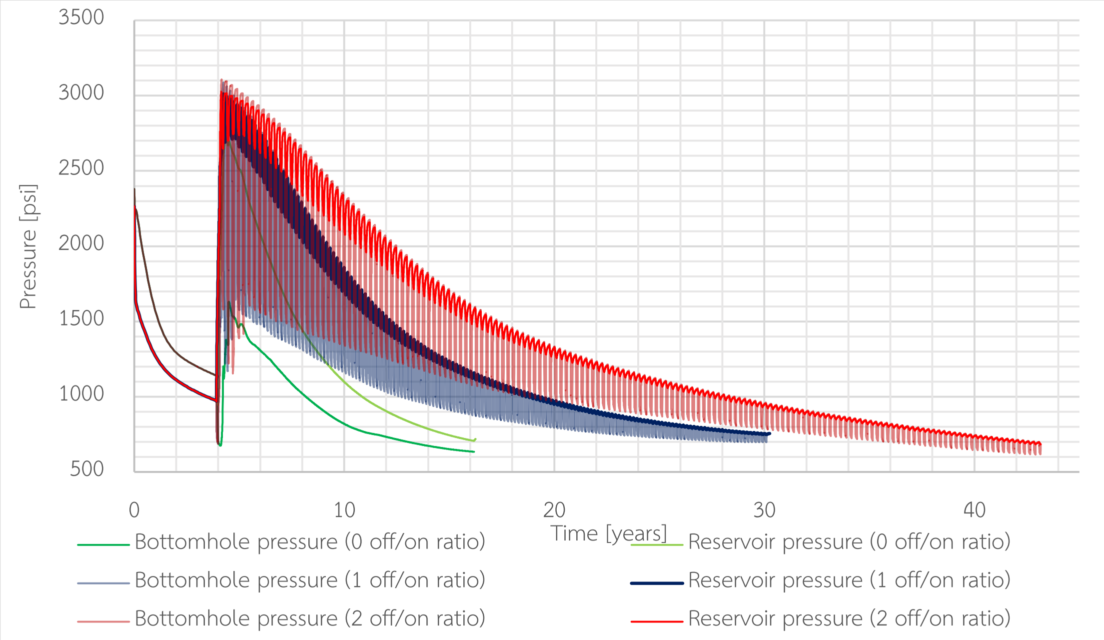


Figure 5.75 Bottomhole and average reservoir pressure with different off/on ratios at target liquid production rate of 1500 STB/D

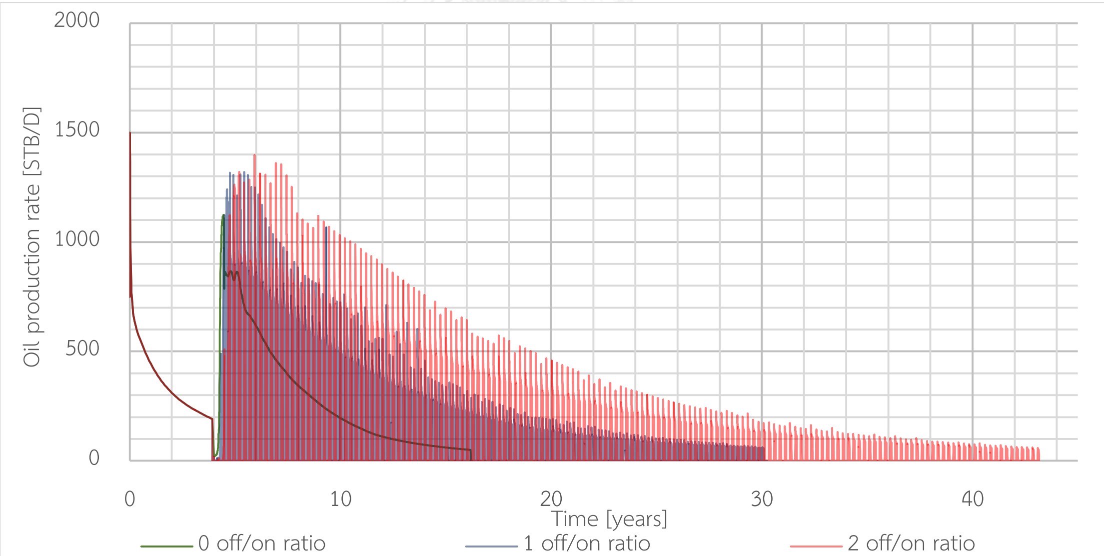


Figure 5.76 Oil production rate at different off/on ratios at target liquid production rate of 1500 STB/D

In summary, if the case of time constraint of 30 years is imposed on this reservoir combination, target liquid production rate of 500 STB/D with 1 off/on ratio is recommended to obtain maximum recovery. As this set of production schedule is effectively balancing the advantages of gradual decline in the oil rate as liquid and gas segregation from the off period and disadvantage from abandoning reservoir at high pressure. However, if the time constraint is not a concern, 500 STB/D with 2 off/on ratio of production schedule is recommended to obtain the maximum oil recovery. Since low target liquid production rate combined with the high off period causes the maximum segregation of liquid and gas, allowing the production well to produce at a rate above the economic limit for a longer period of time compared to the other cases.

5.3.4 Large Aquifer and Large Gas Reservoir (50PV aquifer, 5PV gas reservoir)

Effect of production strategy was investigated for this set of large aquifer and large gas reservoir combination in order to optimize oil recovery in such case. Table 5.11 shows production strategies of combined different target liquid rates and intermittent schedules of production well during gas dumpflood in 50 PV aquifer and 5PV gas reservoir as well as the results obtained from the simulation.

Table 5.11 shows that by increasing off/on ratio, production period and net cumulative gas production also increase. In opposite to production period, cumulative gas production decreases with increasing off/on ratio. In terms of cumulative oil production, oil production increases with increasing off/on ratio in the cases with target liquid production of 1000 STB/D and 1500 STB/D but decreases with increasing off/on ratio in the cases with 500 STB/D as shown in Figure 5.77. However, all intermittent production schedules are terminated by of production period of 30 years. For cumulative water production, they are insignificantly different between different off/on ratios and the target liquid production rates for all cases.

The oil recovery factor from all simulation cases are plotted in Figure 5.77. At target liquid production rate of 500 STB/D, the case with high off/on ratio remains at a plateau rate of 500 STB/D for a long period of time compared to the case with lower off/on ratio during gas flooding period as shown in Figure 5.78. This figure also shows that liquid production rate near abandonment condition is higher as off/on ratio increases.

This improvement in oil recovery efficiency in the case of 1 off/on ratio is due to better segregation of liquid and gas, which causes liquid production rate to decline at a gradual rate. This allows the production well to produce additional oil before reaching the economic limit compared to the case without intermittent production. In addition to the extension in production period, increasing off/on ratio does increase the amount of net gas influx in the case of larger off/on ratio. This is further confirmed by less gas production rate and gradual increase in cumulative gas production as shown in Figure 5.79 and Figure 5.80. By retaining gas inside the reservoir, the reservoir pressure declines at a slower rate compared to the case with low off/on ratio as shown in Figure 5.81. Due to limitation in production period, case with high off/on ratio is abandoned at a higher pressure compared to the case with low off/on ratio as shown in Figure 5.81. This explains the reason why the case with 2 off/on ratio yields less oil recovery compared to the case with 1 off/on ratio. As the reservoir is abandoned at a high reservoir pressure, the oil production rate is still higher in the case of high off/on ratio at the moment before the abandonment as shown in Figure 5.81. However, in Figure 5.79, there is an odd behavior happened in the case of 0 off/on ratio at the year of 10.5 as there is a sudden drop and rise of gas production rate. This is due to the fact that the producing well faced a sudden drop in watercut which causes a reduction in pressure loss in the production well. To maintain liquid production rate at 500 STB/D tubing head pressure is adjusted which leads to a gradual decline in bottomhole pressure results in a smaller pressure drawdown cause a decline of gas production rate as shown in Figure 5.83. Since, liquid saturation around production well declines, after a while, tubing head pressure needed to be lowered to maintain its liquid production rate which resulted in higher pressure drawdown leads to increasing of gas production rate at the year 11.

Table 5.11 Simulation results for 50 PV aquifer and 5 PV gas reservoir

Case No	Target liquid production rate (STB/D)	Intermittent production	Time [Years]	Oil recovery factor	Cumulative oil production [MMSTB]	Cumulative Gas production [BSCF]	Cumulative water production [MMSTB]	Cumulative cross-flow gas [BSCF]	Net cumulative gas production [BSCF]
Case 4.1	500	No off Always on	20.33	68.54%	1.817	12.082	0.739	12.128	0.046
Case 4.2	500	1 month off 1 month on	30.00	73.25%	1.942	11.100	0.764	11.330	0.230
Case 4.3	500	2 months off 1 month on	30.00	63.09%	1.673	4.097	0.747	5.165	1.068
Case 4.4	1000	No off Always on	18.42	67.59%	1.792	12.064	0.734	12.123	0.059
Case 4.5	1000	1 month off 1 month on	30.00	73.12%	1.937	11.918	0.769	12.037	0.119
Case 4.6	1000	2 months off 1 month on	30.00	72.48%	1.921	10.089	0.765	10.468	0.379
Case 4.7	1500	No off Always on	17.91	67.45%	1.788	12.056	0.733	12.112	0.056
Case 4.8	1500	1 month off 1 month on	30.00	73.04%	1.935	12.066	0.770	12.168	0.102
Case 4.9	1500	2 months off 1 month on	30.00	72.87%	1.931	10.489	0.768	10.813	0.324

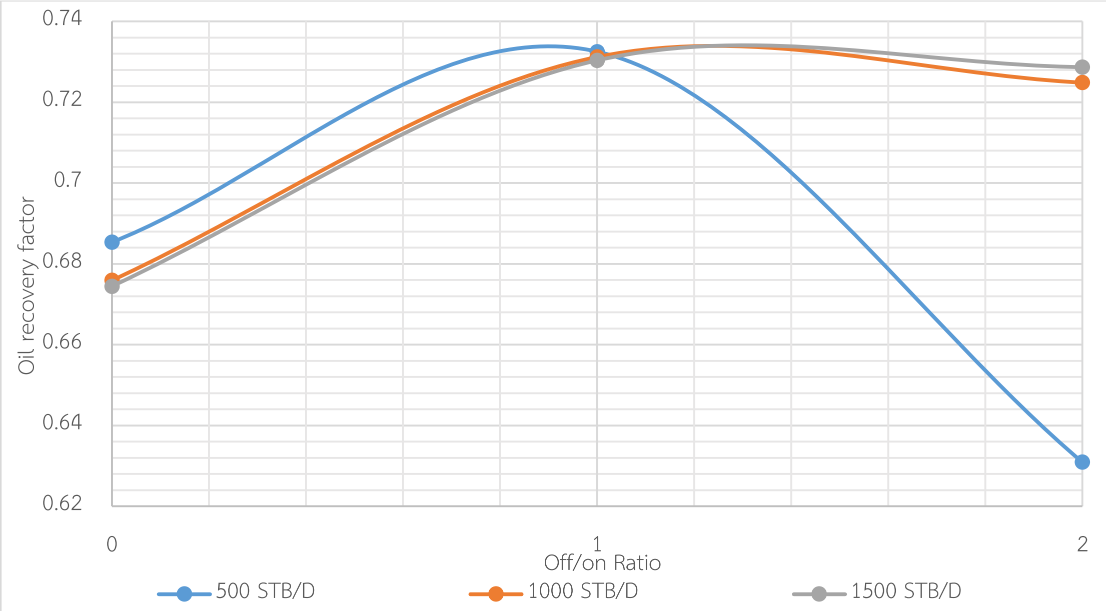


Figure 5.77 Recovery factor as function with off/on ratios with different target liquid production rate in 50 PV aquifer with 5 PV gas reservoir combination

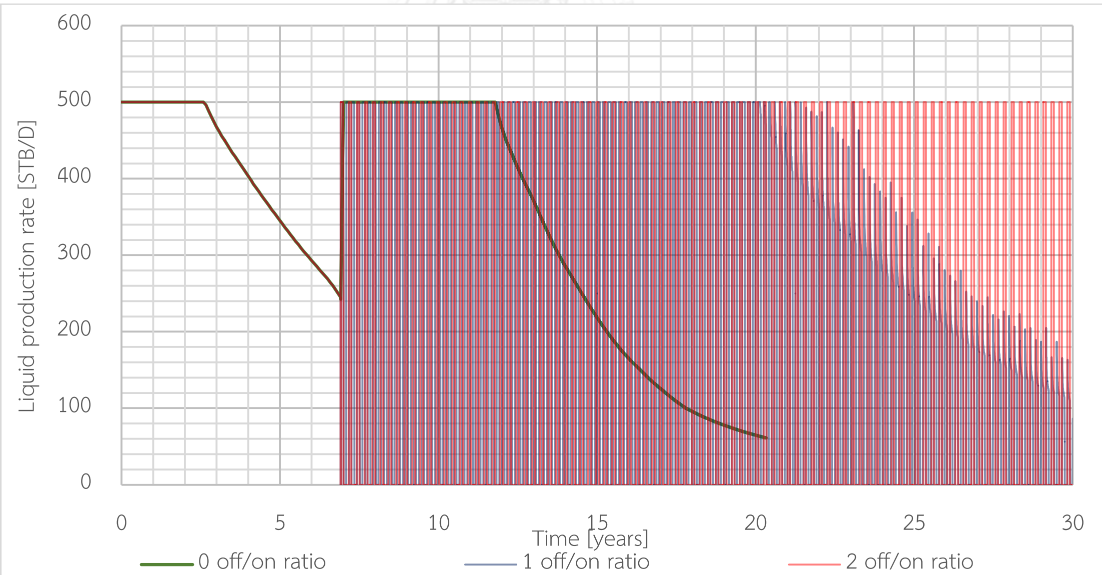


Figure 5.78 Liquid production rate at different off/on ratios at target liquid production rate of 500 STB/D

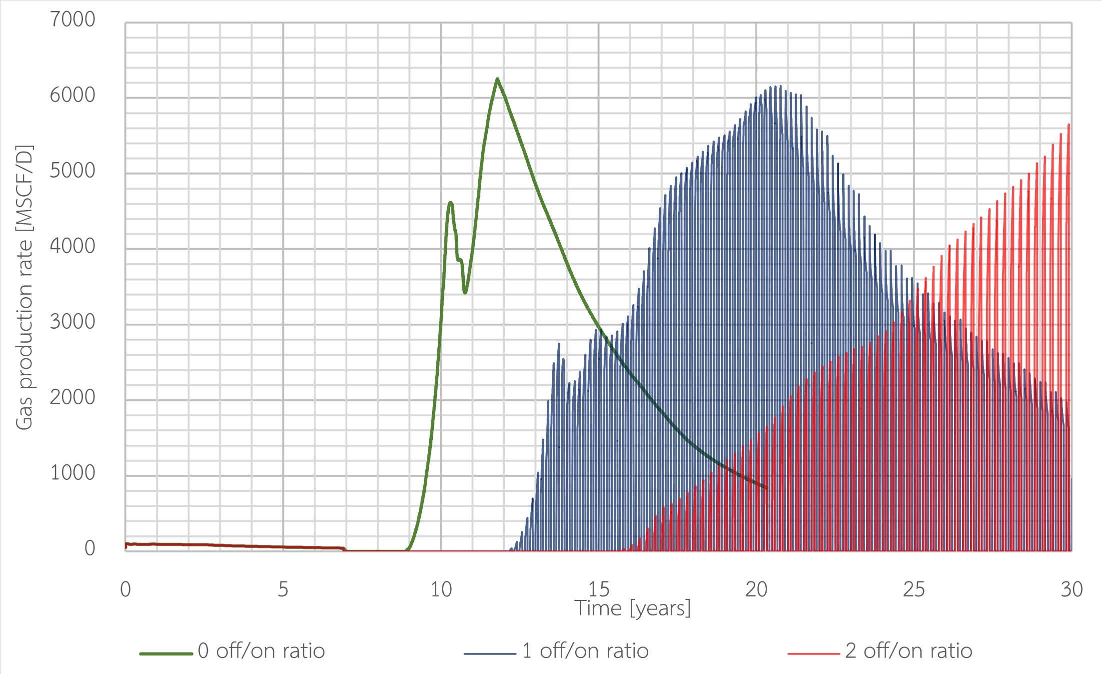


Figure 5.79 Gas production rate at different off/on ratios at target liquid production rate of 500 STB/D

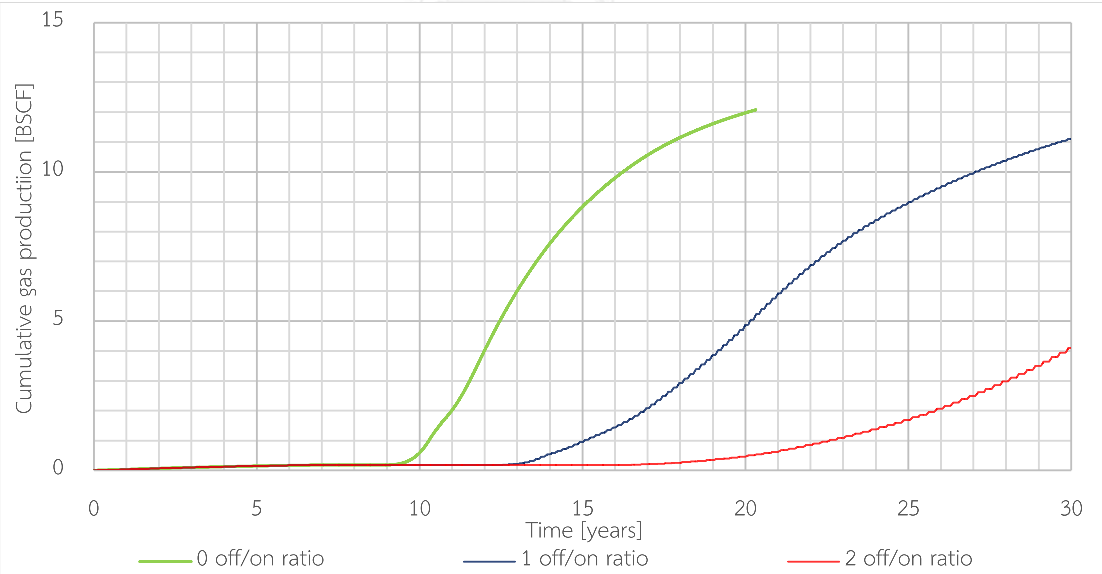


Figure 5.80 Cumulative gas production at different off/on ratios at target liquid production rate of 500 STB/D

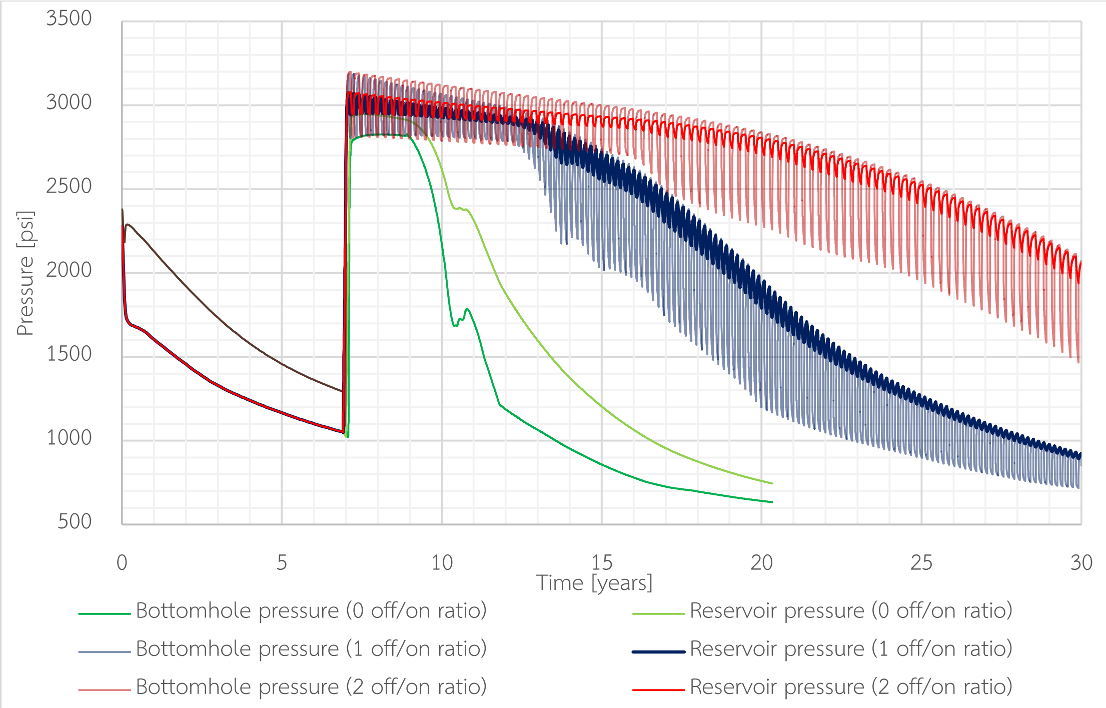


Figure 5.81 Bottomhole and average reservoir pressure with different off/on ratios at target liquid production rate of 500 STB/

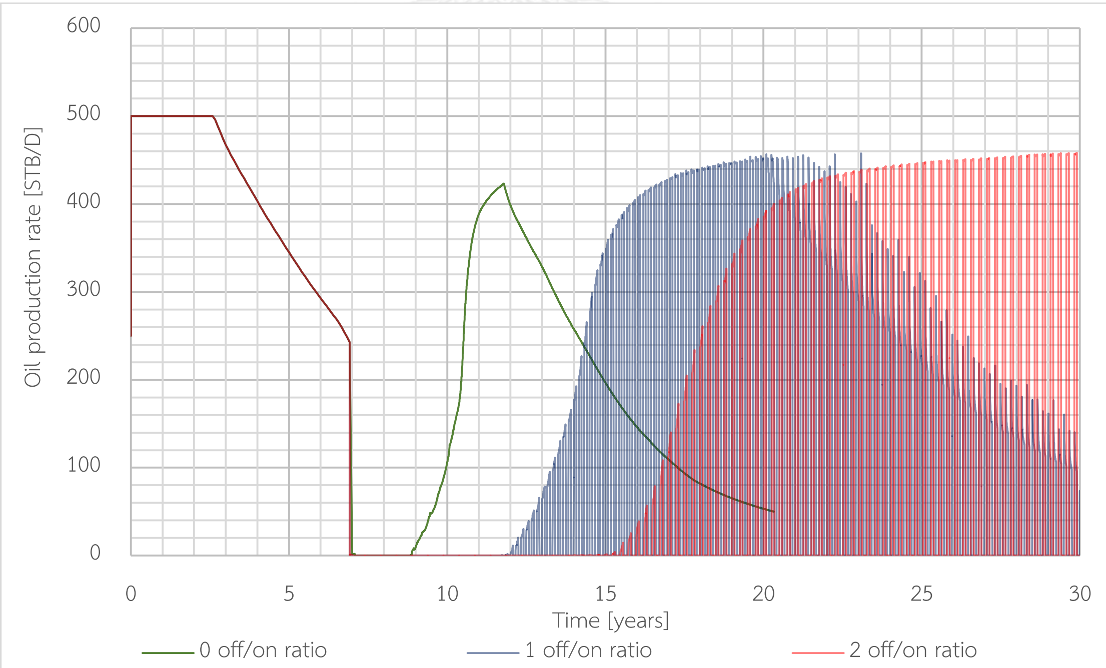


Figure 5.82 Oil production rate at different off/on ratios at target liquid production rate of 500 STB/D

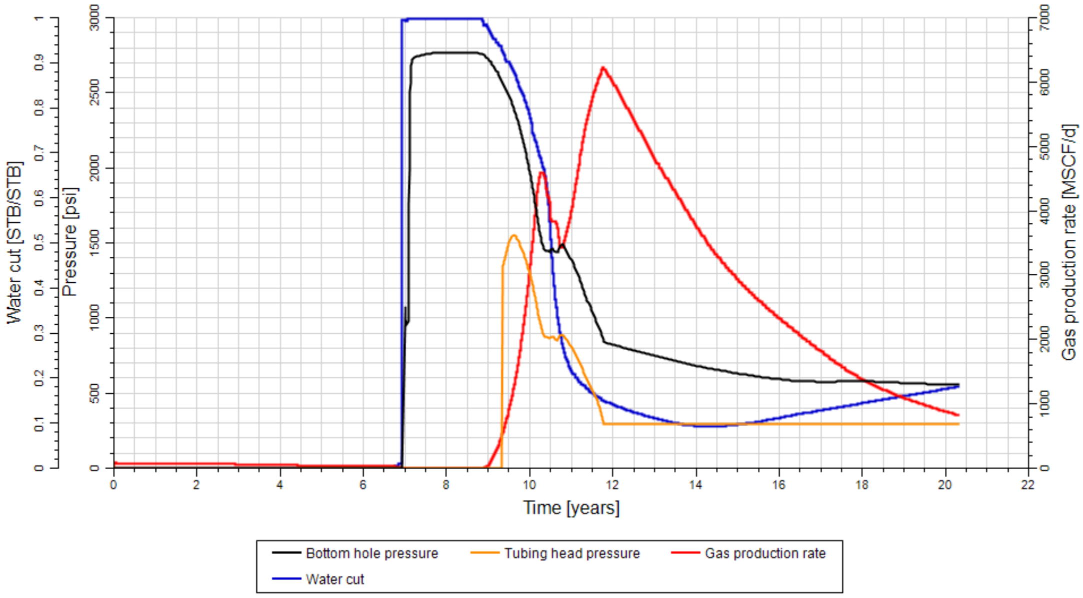


Figure 5.83 Bottomhole and tubing head pressure with gas production rate and water cut of the Case 4.1

In the case with target liquid production rate of 1000 STB/D, liquid production rate maintains maximum plateau for a smaller period of time compared to case with target liquid production rate of 500 STB/D as shown in Figure 5.84. Less gas production rate and gradual increases in cumulative gas production (shown in Figure 5.85 and Figure 5.86) cause reservoir pressure to decline at a slower rate as shown in Figure 5.87. Unlike the case with 500 STB/D, the case with target liquid production rate of 1000 STB/D and 2 off/on ratio yields higher recovery. This is due to the fact that large volume of fluid is produced from high target liquid production rate, causing the reservoir pressure before abandonment to be lower while maintaining the benefit from liquid and gas segregation. This confirms the benefit from the increasing off/on ratio of this target liquid production rate. However, the oil production rate of the case with intermittent production is still high at abandonment as shown in Figure 5.88.

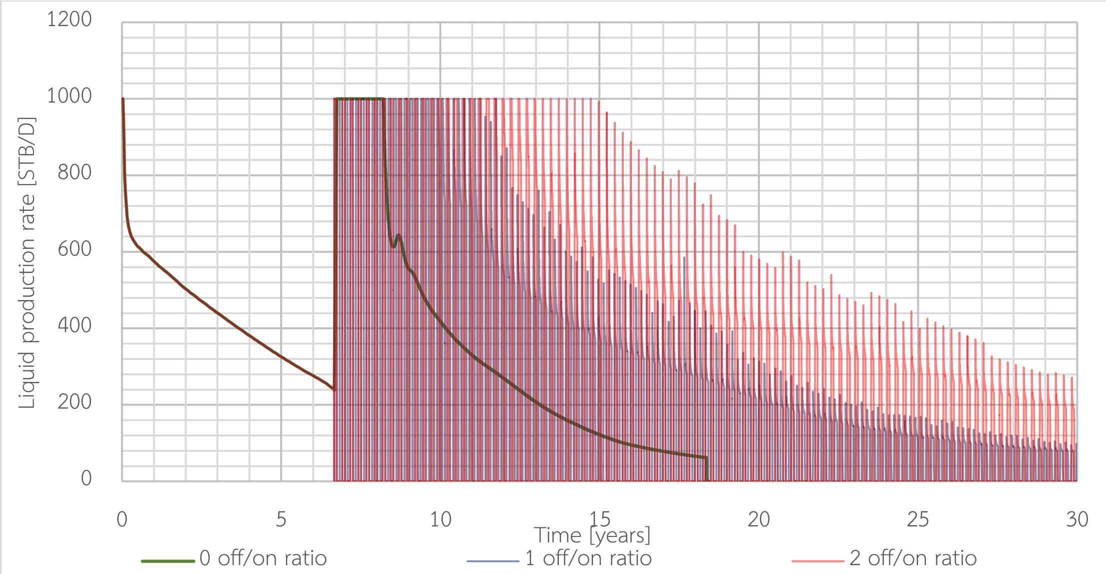


Figure 5.84 Liquid production rate at different off/on ratios at target liquid production rate of 1000 STB/D

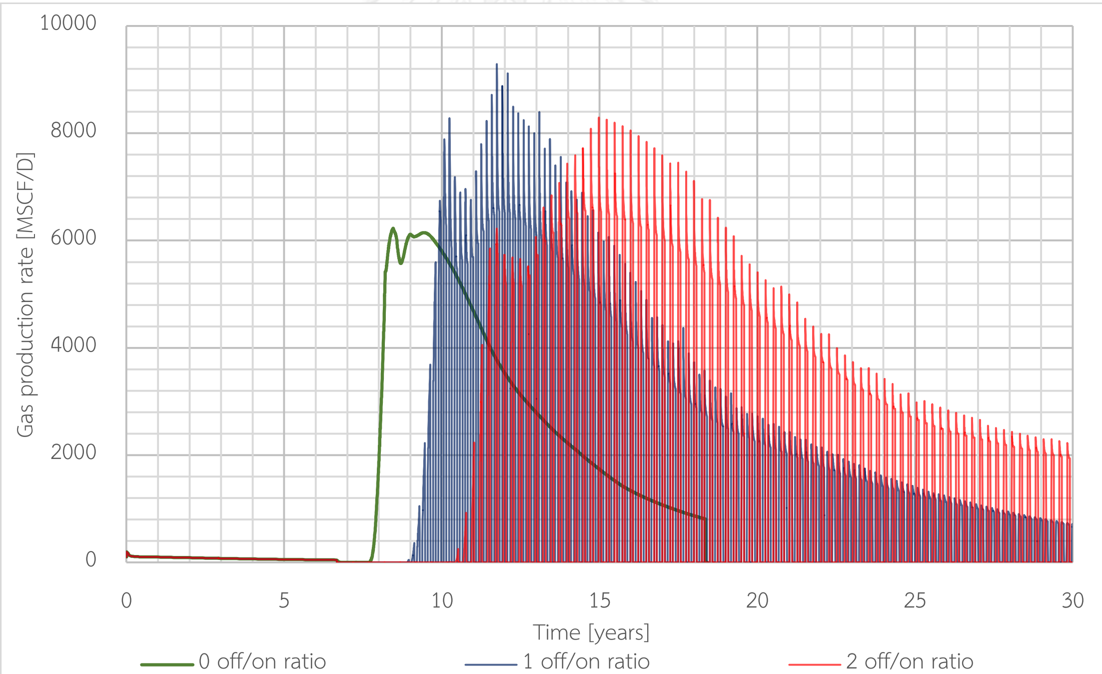


Figure 5.85 Gas production rate at different off/on ratios at target liquid production rate of 1000 STB/D

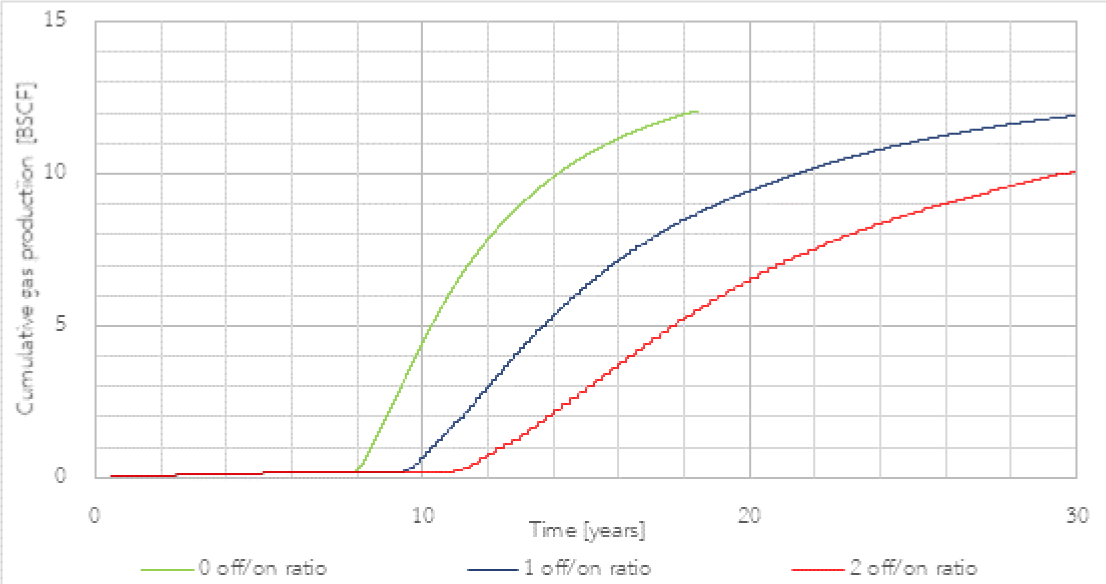


Figure 5.86 Cumulative gas production at different off/on ratios at target liquid production rate of 1000 STB/D

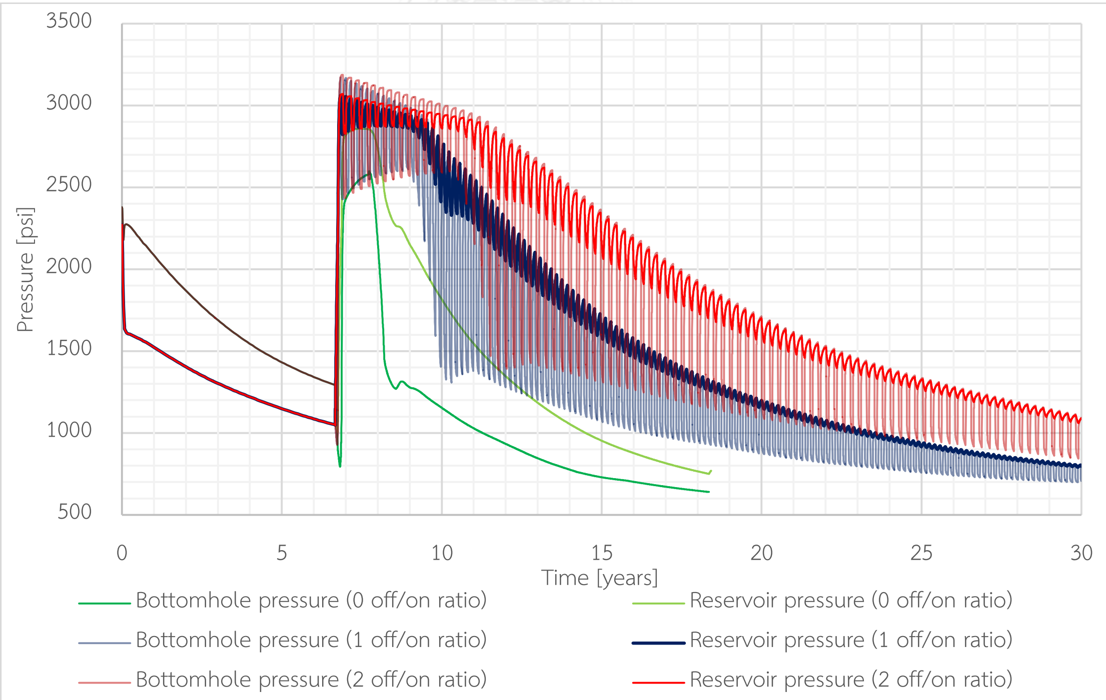


Figure 5.87 Bottomhole and average reservoir pressure with different off/on ratios at target liquid production rate of 1000 STB/D

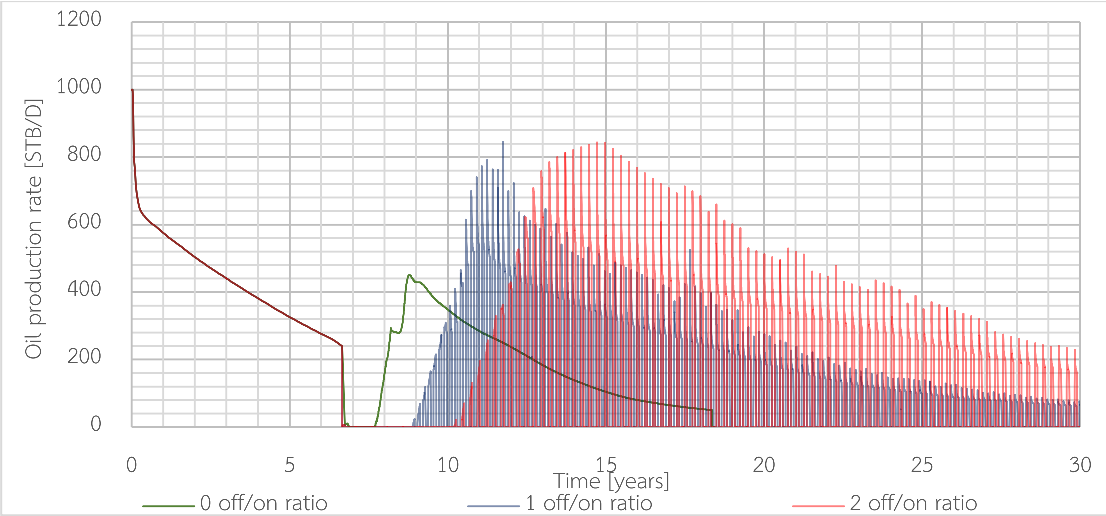


Figure 5.88 Oil production rate at different off/on ratios at target liquid production rate of 1000 STB/D

In the case of target liquid production rate of 1500 STB/D, the liquid production rate maintains maximum plateau for a smaller period of time (Figure 5.89) compared to case with lower target liquid production rate (Figure 5.84 and Figure 5.78). For this target rate, similar behaviors to the cases with target liquid production rate of 1000 STB/D are observed in term of gas production rate, cumulative gas production, reservoir pressure as shown in Figure 5.90 to Figure 5.92. Increasing off/on ratio causes liquid and gas segregation which helps the oil production rate to stay above the producing economic limit. In addition to this, the reservoir pressure which declines at a gradual rate and high liquid production rate resulted from liquid segregation cause the overall recovery factor to increase when increasing off/on ratio.

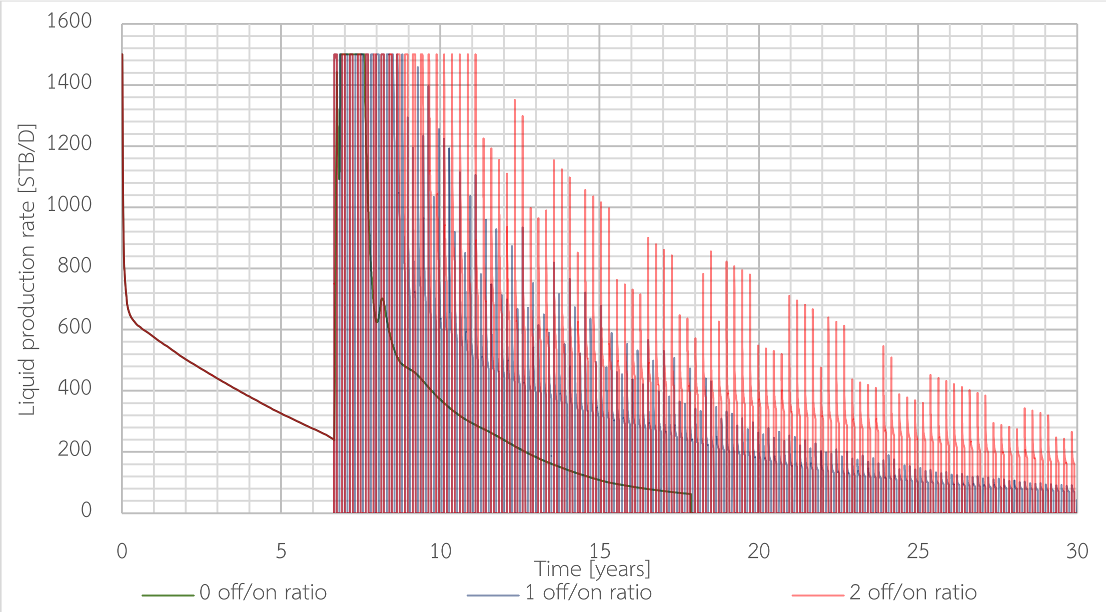


Figure 5.89 Liquid production rate at different off/on ratios at target liquid production rate of 1500 STB/D

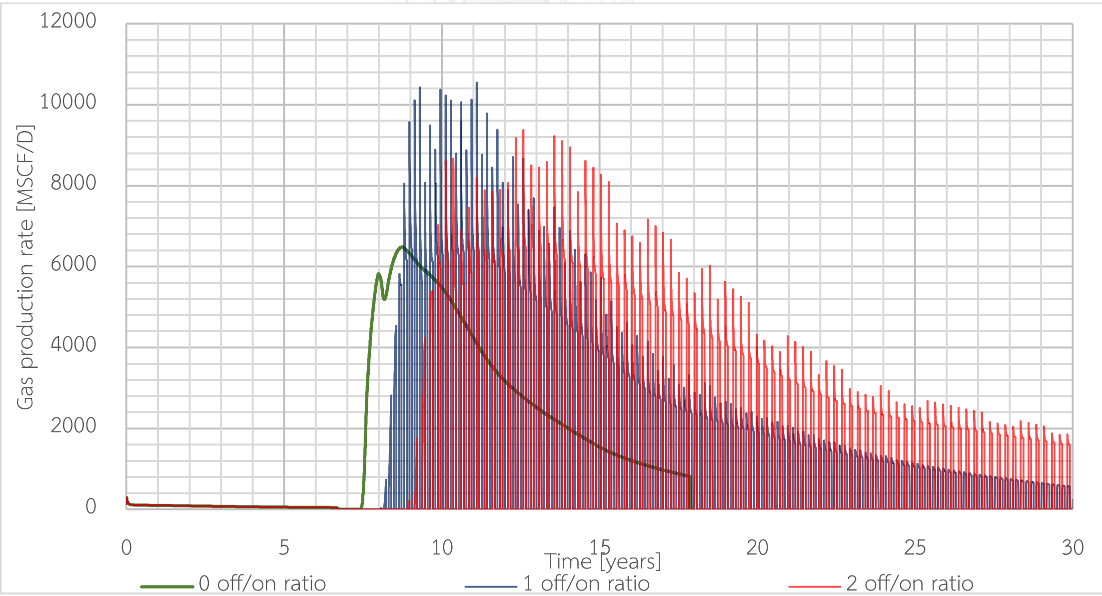


Figure 5.90 Gas production rate at different off/on ratios at target liquid production rate of 1500 STB/D

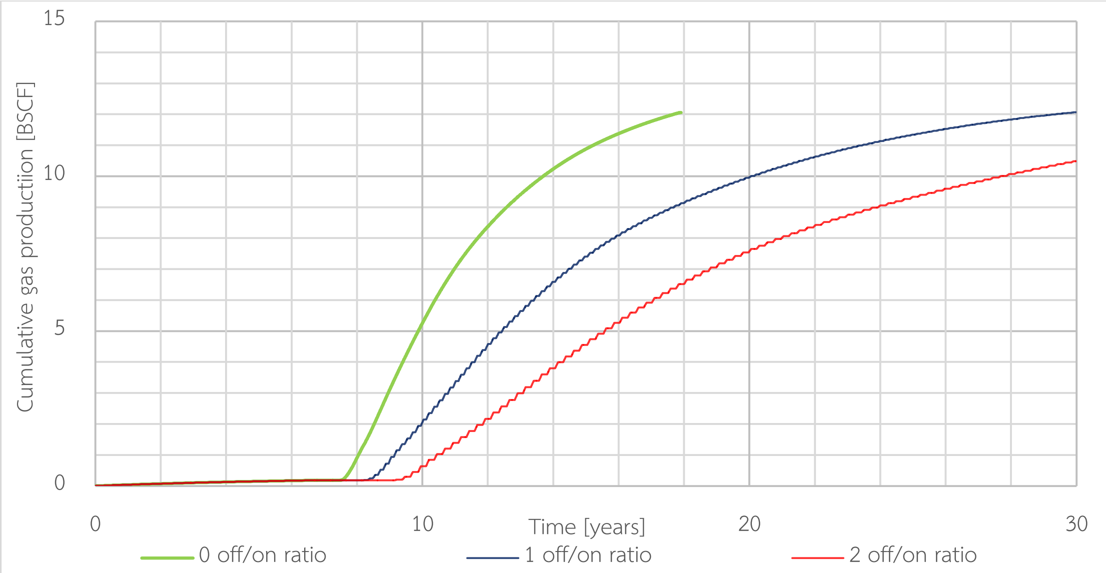


Figure 5.91 Cumulative gas production at different off/on ratios at target liquid production rate of 1500 STB/D

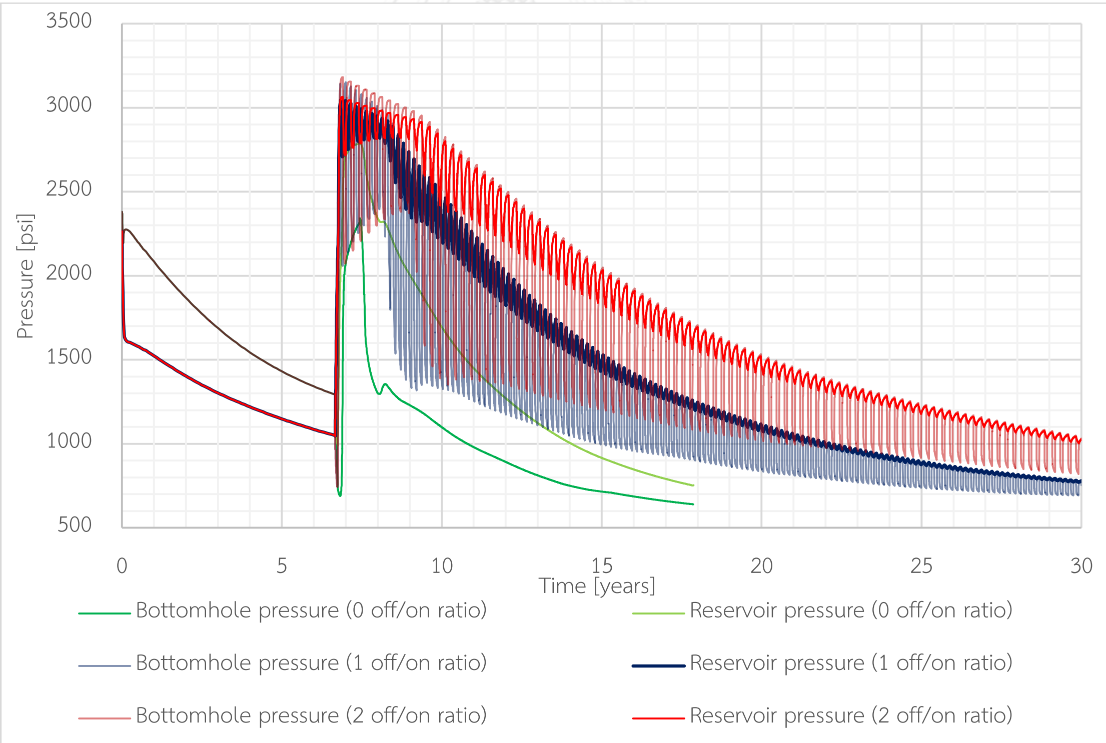


Figure 5.92 Bottomhole and average reservoir pressure with different off/on ratios at target liquid production rate of 1500 STB/D

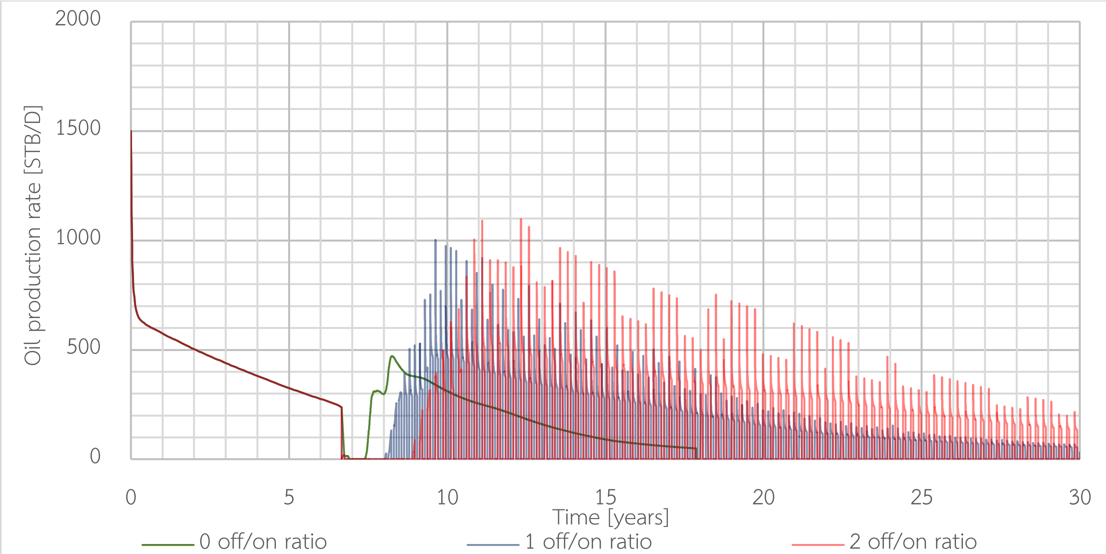


Figure 5.93 Oil production rate at different off/on ratios at target liquid production rate of 1500 STB/D

However, to fully conclude the effect of production schedule to oil recovery efficiency in this reservoir combination, production period limitation of 30 years is eliminated in all cases. Table 5.12 shows that by increasing off/on ratio, production period and net cumulative gas production also increase. Cumulative gas production increases with increasing off/on ratio for most cases except the case with target liquid production rate of 500 STB/D with 2 off/on ratio. In terms of cumulative oil production, oil production shows a remarkable increase with increasing off/on ratio for all target liquid production rates as shown in Figure 5.94. In addition, the results also show an increasing trend with increasing off/on ratio of cumulative water production for all cases.

All target liquid production rates show an increasing trend of oil recovery with increasing off/on ratio. This is due to the fact that as off period is increased, the liquid and gas segregate better, plus a gradual decrease in reservoir pressure. This causes the production well in the downdip location to produce a greater amount of oil before reaching the economic limit. This results in an improvement in oil recovery by increasing off/on ratio.

Table 5.12 Simulation results for 50 PV aquifer and 5 PV gas reservoir without time limit

Case No	Target liquid production rate (STB/D)	Intermittent production	Time [Years]	Oil recovery factor	Cumulative oil production [MMSTB]	Cumulative Gas production [BSCF]	Cumulative water production [MMSTB]	Cumulative cross-flow gas [BSCF]	Net cumulative gas production [BSCF]
Case 4.1	500	No off Always on	20.33	68.54%	1.817	12.082	0.739	12.128	0.046
Case 4.2	500	1 month off 1 month on	36.41	76.15%	2.017	12.318	0.779	12.400	0.082
Case 4.3	500	2 months off 1 month on	45.41	80.19%	2.125	11.937	0.797	12.075	0.138
Case 4.4	1000	No off Always on	18.42	67.59%	1.792	12.064	0.734	12.123	0.059
Case 4.5	1000	1 month off 1 month on	33.25	74.14%	1.964	12.190	0.776	12.288	0.098
Case 4.6	1000	2 months off 1 month on	44.16	78.85%	2.088	12.202	0.807	12.310	0.108
Case 4.7	1500	No off Always on	17.91	67.45%	1.788	12.056	0.733	12.112	0.056
Case 4.8	1500	1 month off 1 month on	31.67	73.72%	1.953	12.157	0.775	12.245	0.089
Case 4.9	1500	2 months off 1 month on	44.16	78.72%	2.085	12.199	0.810	12.313	0.113

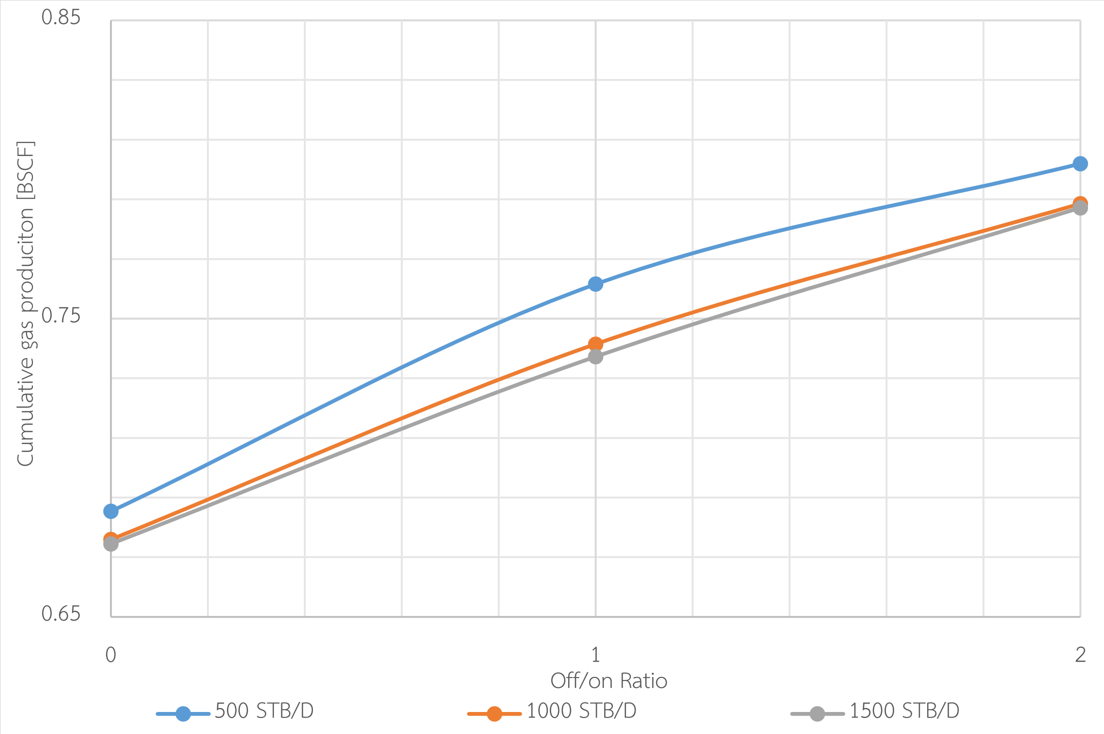


Figure 5.94 Recovery factor as function with off/on ratios with different target liquid production rate in 50 PV aquifer with 5 PV gas reservoir combination without time limitation

Cumulative gas production increases with increasing off/on ratio. This is due to the fact that high off/on ratio allows oil production rate to decrease at a gradual rate. As the oil production rate drops steadily, it allows the production well to operate to lower reservoir pressure without getting below the economic limit. Since the reservoir pressure is lower, more gas is produced. However, in the case of target liquid production rate of 500 STB/D and 2 off/on ratio, pressure loss around the wellbore is dominant, causing the abandonment pressure to be higher than the cases with lower off/on ratio. This reduces the amount of gas expansion in the reservoir as well as gas crossflow from the gas reservoir, causing reduction in cumulative gas production. By increasing off/on ratio, the reservoir pressure declines at a lower rate in for all target liquid production rate as shown in Figure 5.95, Figure 5.97 and Figure 5.99. In terms of oil production rate, high off/on ratio results in a gradual decrease in oil production rate as shown in Figure 5.96, Figure 5.98 and Figure 5.100. This confirms the improvement in oil recovery with increasing off/on ratio.

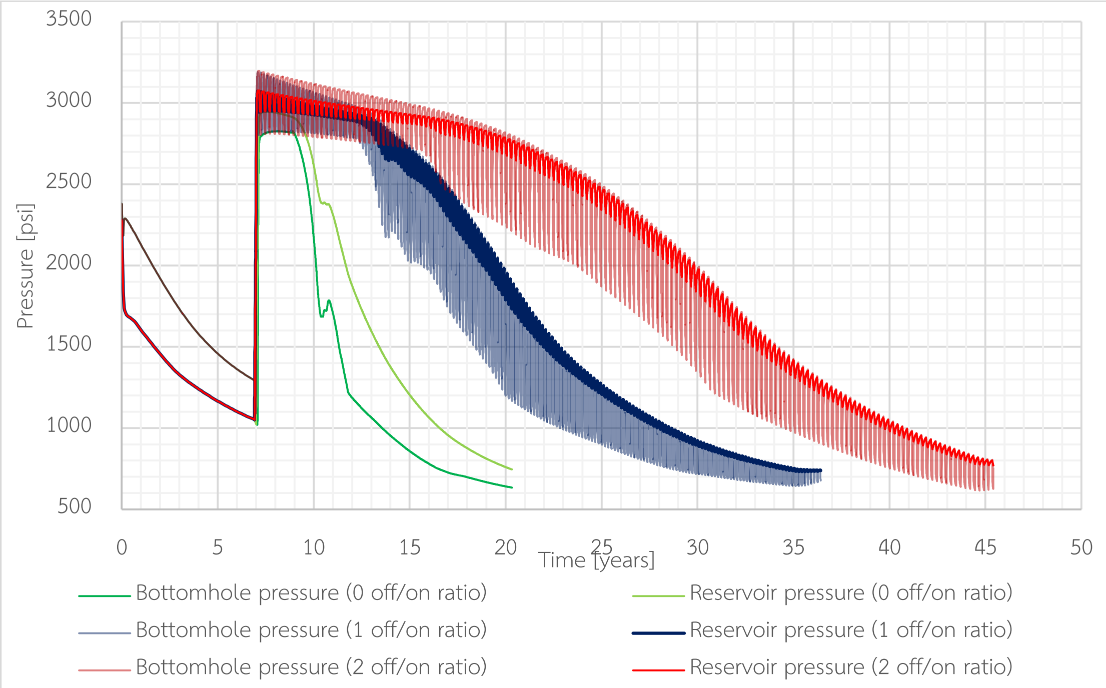


Figure 5.95 Bottomhole and average reservoir pressure with different off/on ratios at target liquid production rate of 500 STB/D

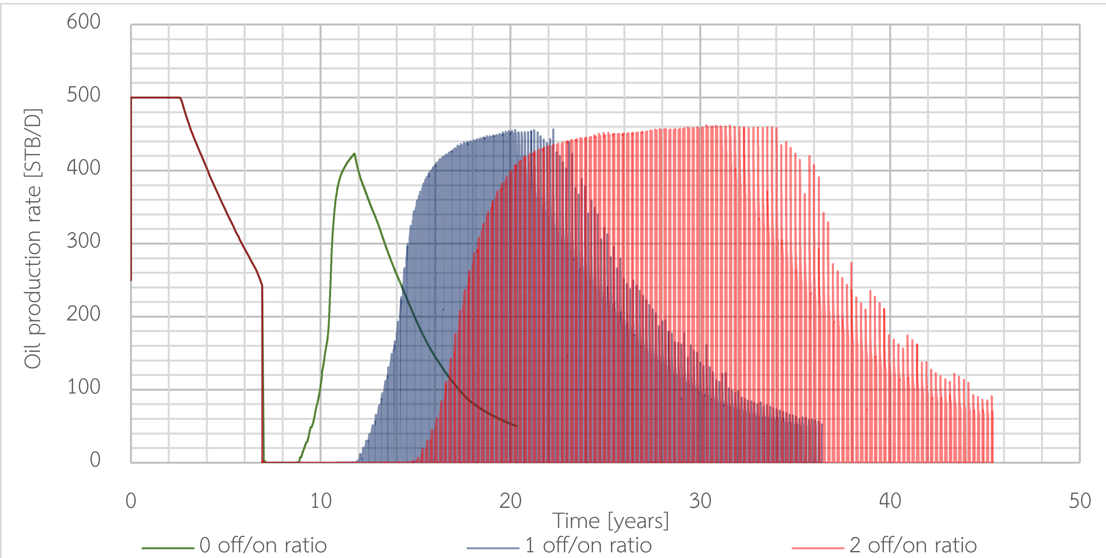


Figure 5.96 Oil production rate at different off/on ratios at target liquid production rate of 500 STB/D

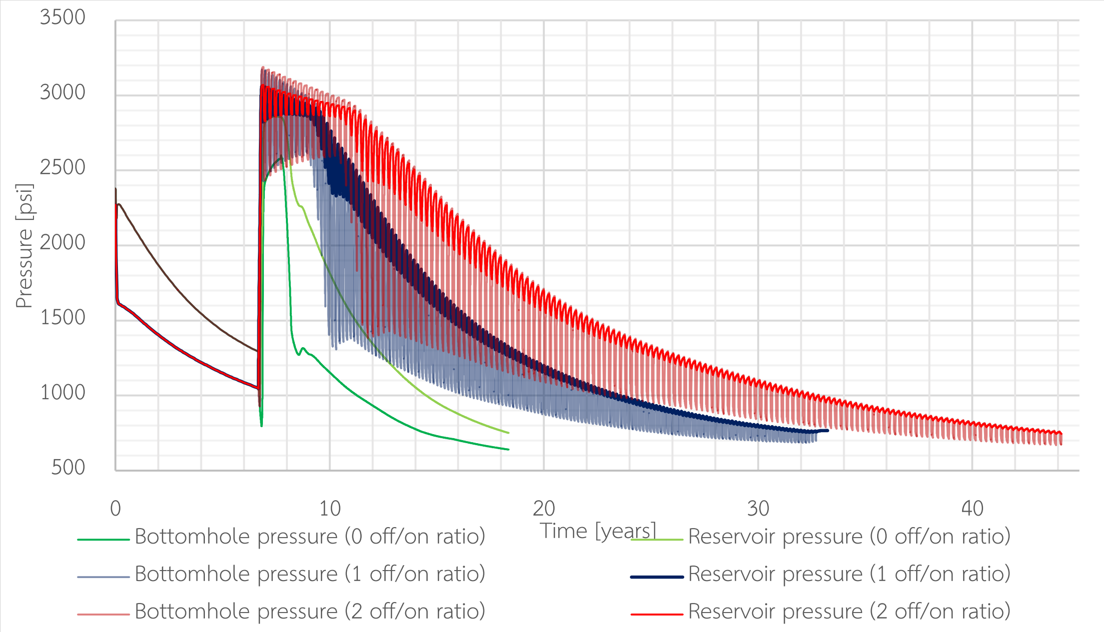


Figure 5.97 Bottomhole and average reservoir pressure with different off/on ratios at target liquid production rate of 1000 STB/D

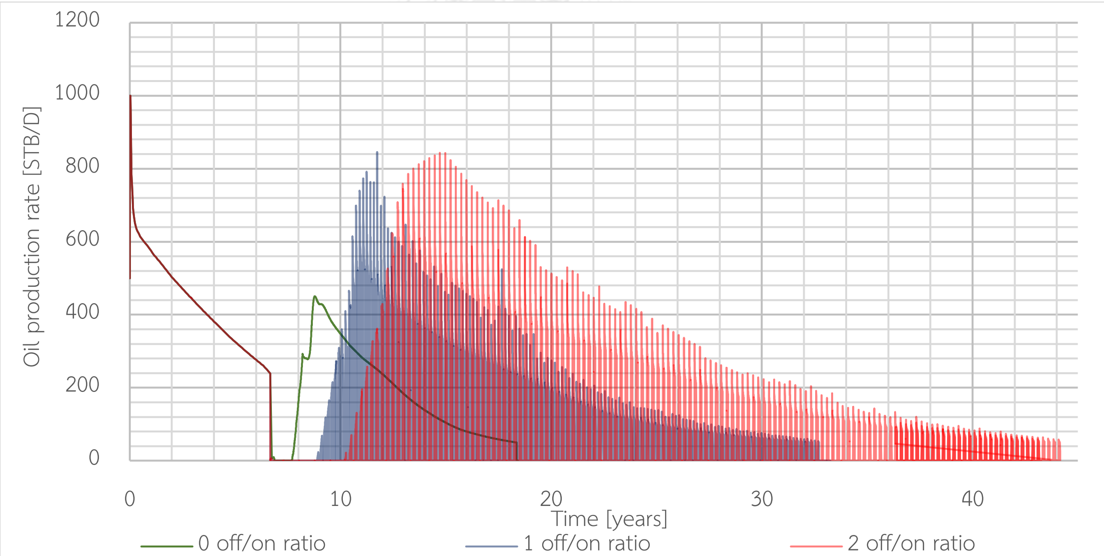


Figure 5.98 Oil production rate at different off/on ratios at target liquid production rate of 1000 STB/D

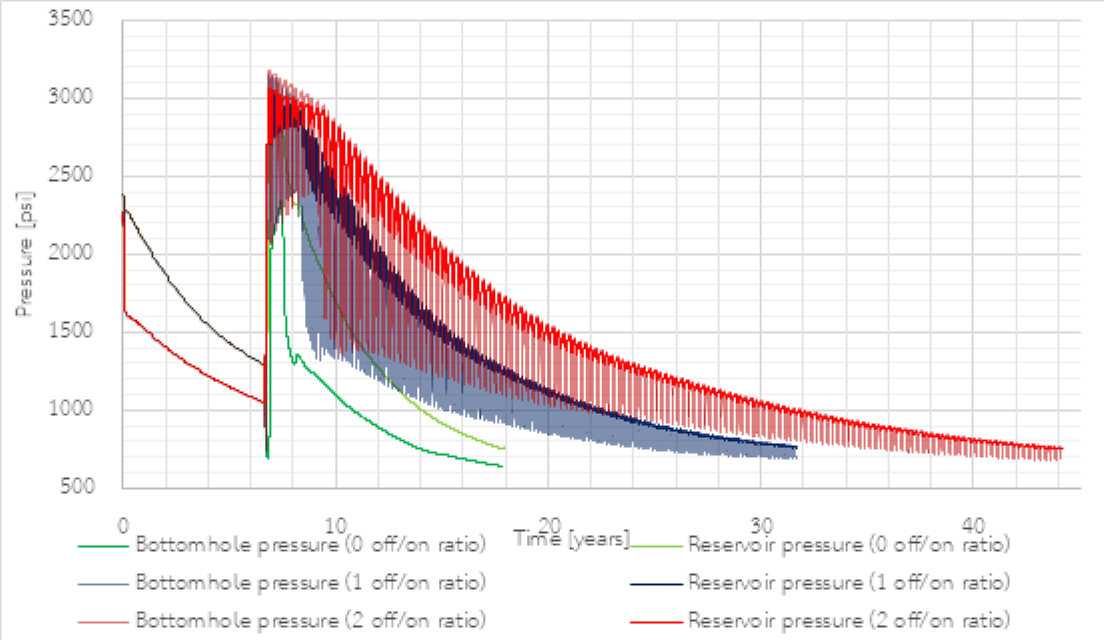


Figure 5.99 Bottomhole and average reservoir pressure with different off/on ratios at target liquid production rate of 1500 STB/D

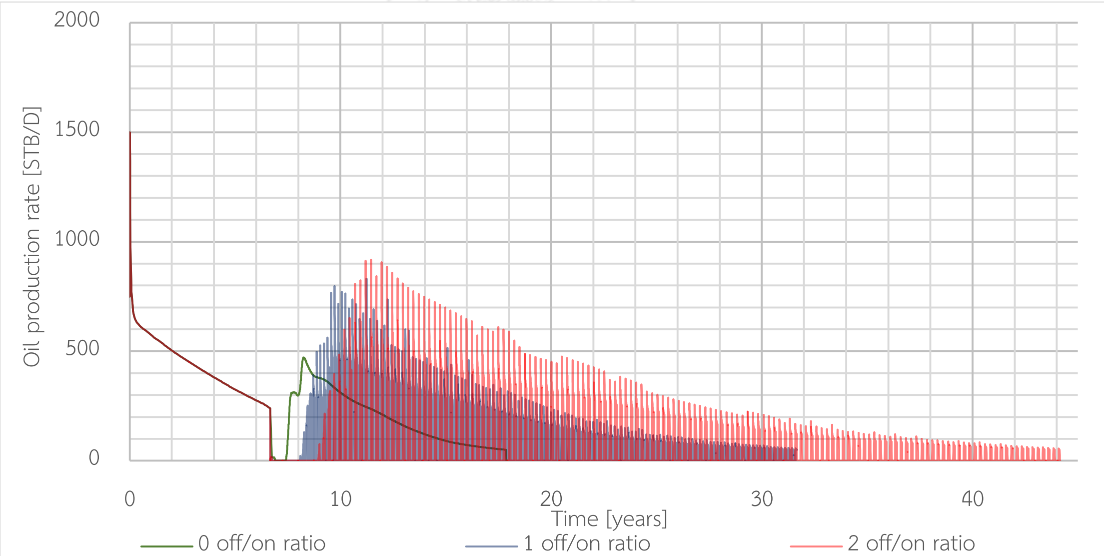


Figure 5.100 Oil production rate at different off/on ratios at target liquid production rate of 1500 STB/D

In summary, if the time constraint is imposed on this reservoir combination, target liquid production rate of 500 STB/D with 1 off/on ratio is recommended to obtain the maximum recovery. This set of production schedule effectively maintains the oil rate at a rate above the economic limit as gas and liquid segregate during off periods, plus the benefit of gradual pressure decline from limiting the liquid production rate. However, if the time constraint is not a concern, 500 STB/D with 2 off/on ratio of production schedule is recommended to obtain the maximum oil recovery as low target liquid production rate combined with the high off period causes the maximum segregation of liquid and gas, allowing production well to be produced at a rate above the economic limit for a longer period of time.

5.3.5 Comparison between Reservoir Combinations

- Effect of aquifer size with 1PV gas reservoir size

Effect of aquifer size was investigated to see the benefit of increasing the aquifer size in the case of 1 PV gas. Table 5.13 shows both simulation results of 10 PV aquifer with 1 PV gas reservoir and 50 PV aquifer with 1 PV gas reservoir combinations. The results show that as aquifer size increases, production period and cumulative water production increase because more water can be dumped into the oil reservoir and reproduced back to the surface. Cumulative crossflow gas increases with increasing size of the aquifer since the case with large aquifer has lower reservoir pressure compared to the case with smaller aquifer. The reduction in reservoir pressure is due to the fact that, as aquifer size increases, more water is dumped into oil reservoir, and water tends to stay at the lower portion of the reservoir as shown in Figure 5.101. Thus, the relative permeability of gas in the lower part of the oil reservoir increases. This boosts gas overriding effect as gas is dumped into the oil reservoir. This causes high gas production rates in the case of large aquifer as shown in Figure 5.102. Hence, the case with large aquifer has high GLR compared to the case with small aquifer. This phenomenon also explains the reduction in net cumulative gas production. As aquifer size increases, there is higher gas production. As a result, less gas is retained in the oil reservoir.

Table 5.13 Simulation results for 10 PV and 50 PV aquifer with 1 PV gas reservoir

Case No	Aquifer size (PV)	Target liquid production rate (STB/D)	Intermittent production	Time [Years]	Oil recovery factor	Cumulative oil production [MMSTB]	Cumulative Gas production [BSCF]	Cumulative water production [MMSTB]	Net cumulative gas production [BSCF]
Case 1.1	10	500	No off	10.50	42.39%	1.124	1.999	0.175	0.173
Case 2.1	50		Always on	15.25	49.35%	1.309	2.175	0.678	0.084
Case 1.2	10		1 month off	14.00	43.74%	1.159	1.593	0.176	0.342
Case 2.2	50		1 month on	19.16	49.69%	1.318	1.674	0.697	0.290
Case 1.3	10		2 months off	24.00	56.10%	1.487	1.332	0.182	0.514
Case 2.3	50		1 month on	26.08	54.34%	1.441	1.274	0.724	0.478
Case 1.4	10	1000	No off	9.66	42.47%	1.126	2.031	0.175	0.161
Case 2.4	50		Always on	13.16	48.47%	1.285	2.200	0.664	0.068
Case 1.5	10		1 month off	10.83	40.07%	1.062	1.629	0.173	0.308
Case 2.5	50		1 month on	15.00	47.39%	1.256	1.817	0.671	0.216
Case 1.6	10		2 months off	13.08	40.97%	1.086	1.364	0.174	0.409
Case 2.6	50		1 month on	17.25	47.64%	1.263	1.518	0.682	0.333
Case 1.7	10	1500	No off	9.58	42.75%	1.133	2.042	0.175	0.154
Case 2.7	50		Always on	12.67	48.63%	1.289	2.217	0.661	0.060
Case 1.8	10		1 month off	10.50	40.06%	1.062	1.632	0.173	0.306
Case 2.8	50		1 month on	14.08	47.14%	1.250	1.866	0.665	0.194
Case 1.9	10		2 months off	12.09	39.78%	1.054	1.339	0.174	0.410
Case 2.9	50		1 month on	14.83	46.25%	1.226	1.604	0.665	0.266

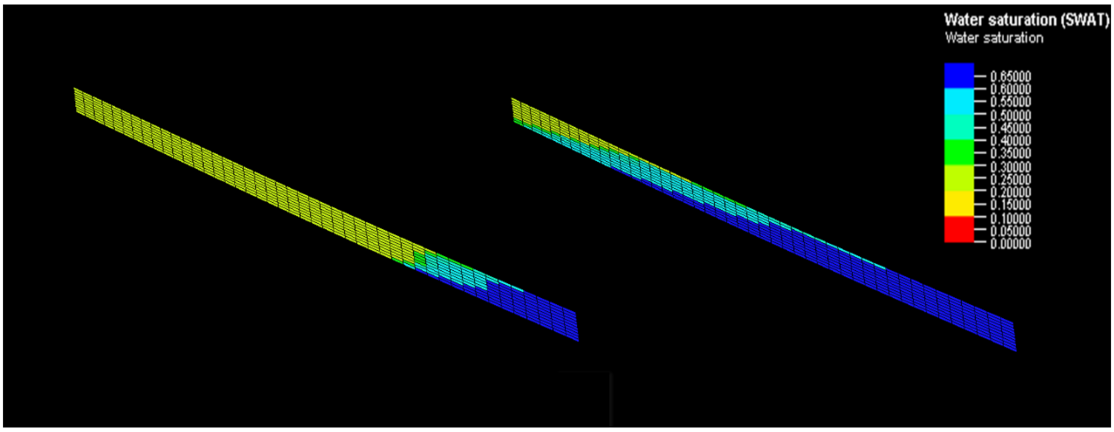


Figure 5.101 Water saturation at the end of water dumping phase of cross sectional area between the two wells. 10 PV aquifer (left), 50 PV aquifer (right)

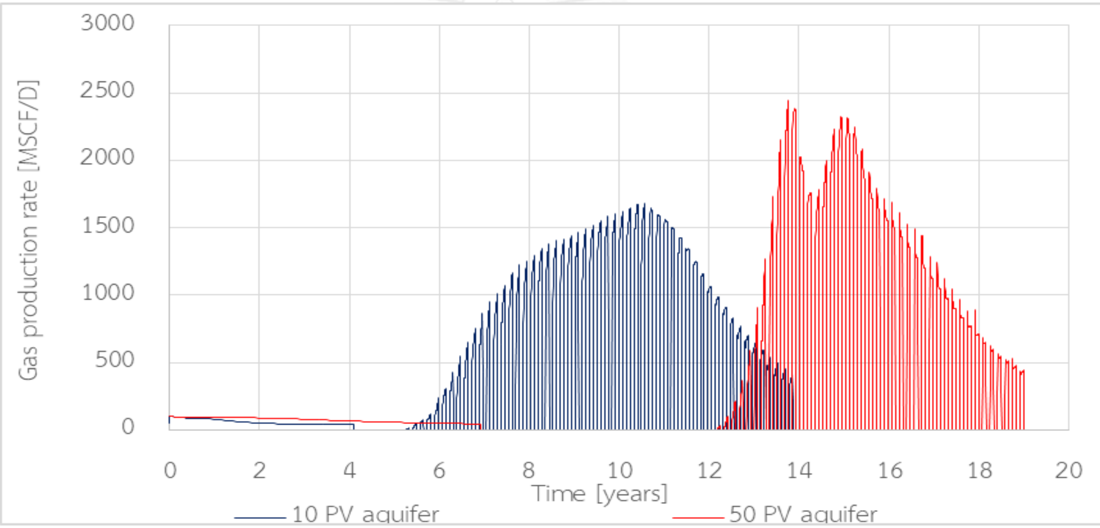


Figure 5.102 Gas production rate for different aquifer sizes with 1 PV gas reservior at 500 STB/D target liquid production rate with 1 off/on ratio

Most cases of 50 PV aquifer have improvement in oil recovery compared to case with 10 PV aquifer. This is due to the fact that, as aquifer size is bigger, there is a larger amount of water to displace oil in the oil reservoir. However, the case of 500 STB/d target liquid production rate with 2 off/on ratio shows a reverse trend in oil recovery. As aquifer size is increased, oil recovery is less. In such case, the benefit obtained from effective gas retention is greater than the drawback of dumping water from a smaller aquifer. As shown in Table 5.14, case 1.3 shows high oil recovery from gas dumpflood compared to other cases. This shows a great benefit from gas retention from low liquid target production rate with high off/on period, eliminating the need of large aquifer to produce a large amount of oil. However, cases with large aquifer have high oil recovery from water dumpflood but small amount of oil recovered from the gas dumpflood period.

Table 5.14 Oil recovery efficiency at different phases of DDP in the case of 10PV and 50 PV aquifer with 1 PV gas reservoir

Case	Aquifer size (PV)	Time (years)	Overall oil recovery factor	Recovery factor from water dumpflood	Recovery factor from gas dumpflood
Case 1.1	10	10.50	42.39%	19.13%	23.26%
Case 2.1	50	15.25	49.35%	39.20%	10.16%
Case 1.2	10	14.00	43.74%	19.13%	24.61%
Case 2.2	50	19.16	49.69%	39.20%	10.49%
Case 1.3	10	24.00	56.10%	19.13%	36.97%
Case 2.3	50	26.08	54.34%	39.20%	15.15%
Case 1.4	10	9.66	42.47%	19.08%	23.39%
Case 2.4	50	13.16	48.47%	39.38%	9.09%
Case 1.5	10	10.83	40.07%	19.08%	20.99%
Case 2.5	50	15.00	47.39%	39.38%	8.01%
Case 1.6	10	13.08	40.97%	19.08%	21.89%
Case 2.6	50	17.25	47.64%	39.38%	8.27%
Case 1.7	10	9.58	42.75%	19.09%	23.66%
Case 2.7	50	12.67	48.63%	39.39%	9.23%
Case 1.8	10	10.50	40.06%	19.09%	20.97%
Case 2.8	50	14.08	47.14%	39.39%	7.75%
Case 1.9	10	12.09	39.78%	19.09%	20.68%
Case 2.9	50	14.83	46.25%	39.39%	6.85%

In summary, increasing aquifer size yields benefit from oil recovery in water dumpflood; however, it reduces the benefit from gas dumpflood. At the same time, a big drawback from large aquifer size is high cumulative water production. The results clearly show that large aquifer size is not necessary to increase oil recovery if gas is effectively retained in the oil reservoir as pressure maintenance. At the same time, small aquifer yields a smaller amount of produced water onto the surface which reduce, the cost of water treatment and disposal.

- Effect of aquifer size with 5 PV gas reservoir

Effect of aquifer size was investigated to see the benefit of increasing the aquifer size in the case of 5 PV gas. Table 5.15 shows both simulation results of 10 PV aquifer with 5 PV gas reservoir and 50 PV aquifer with 5 PV gas reservoir combination. The results show that oil recovery for the case with high aquifer size yield better recovery without intermittent production. This is due to the fact that, as aquifer size gets bigger, there is a larger amount of water to displace oil in the oil reservoir. However, all intermittent production cases are abandoned because of production period constraint of 30 years.

To see the full improvement in the production schedule to these reservoir combinations, constraint of production period is eliminated. Table 5.16 shows simulation results for reservoir combination of 10 PV and 50 PV aquifer with 5 PV gas without constraint of production period. Results show that, as intermittent production is implied, small aquifer yields more improvement in oil recovery than the case with large aquifer size. As aquifer size increases, oil recovery from gas dumpflood phase decreases as shown in Table 5.17. This reduction in oil recovery results from the increasing of gas overriding effect due to low gas relative permeability in the lower portion of the reservoir as water saturation is high as shown in Figure 5.101. Hence, small aquifer size yields higher benefit from gas retention, and gas sweep efficiency is greater than the drawback obtained from dumping water from a smaller aquifer.

Table 5.15 Simulation results for 10 PV and 50 PV aquifer with 5 PV gas reservoir

Case No	Aquifer size (PV)	Target liquid production rate (STB/D)	Intermittent production	Time [Years]	Oil recovery factor	Cumulative oil production [MMSTB]	Cumulative Gas production [BSCF]	Cumulative water production [MMSTB]	Net cumulative gas production [BSCF]
Case 3.1	10	500	No off	18.16	67.68%	1.794	12.384	0.186	0.046
Case 4.1	50		Always on	20.33	68.54%	1.817	12.082	0.739	0.046
Case 3.2	10		1 month off	30.00	75.69%	2.006	11.968	0.189	0.140
Case 4.2	50		1 month on	30.00	73.25%	1.942	11.100	0.764	0.230
Case 3.3	10		2 months off	30.00	71.32%	1.891	6.973	0.186	0.818
Case 4.3	50		1 month on	30.00	63.09%	1.673	4.097	0.747	1.068
Case 3.4	10	1000	No off	16.41	66.71%	1.769	12.379	0.186	0.050
Case 4.4	50		Always on	18.42	67.59%	1.792	12.064	0.734	0.059
Case 3.5	10		1 month off	30.00	74.82%	1.983	12.180	0.188	0.122
Case 4.5	50		1 month on	30.00	73.12%	1.937	11.918	0.769	0.119
Case 3.6	10		2 months off	30.00	75.44%	1.999	10.880	0.188	0.318
Case 4.6	50		1 month on	30.00	72.48%	1.921	10.089	0.765	0.379
Case 3.7	10	1500	No off	16.25	66.70%	1.768	12.380	0.186	0.052
Case 4.7	50		Always on	17.91	67.45%	1.788	12.056	0.733	0.056
Case 3.8	10		1 month off	30.00	74.77%	1.981	12.187	0.189	0.121
Case 4.8	50		1 month on	30.00	73.04%	1.935	12.066	0.770	0.102
Case 3.9	10		2 months off	30.00	75.46%	2.000	10.936	0.188	0.310
Case 4.9	50		1 month on	30.00	72.87%	1.931	10.489	0.768	0.324

Table 5.16 Simulation results for 10 PV and 50 PV aquifer with 5 PV gas reservoir without time constraint

Case No	Aquifer size (PV)	Target liquid production rate (STB/D)	Intermittent production	Time [Years]	Oil recovery factor	Cumulative oil production [MMSTB]	Cumulative Gas production [BSCF]	Cumulative water production [MMSTB]	Net cumulative gas production [BSCF]
Case 3.1	10	500	No off	18.16	67.68%	1.794	12.384	0.186	0.173
Case 4.1	50		Always on	20.33	68.54%	1.817	12.082	0.739	0.084
Case 3.2	10		1 month off	35.25	77.43%	2.052	12.510	0.190	0.342
Case 4.2	50		1 month on	36.41	76.15%	2.017	12.318	0.779	0.290
Case 3.3	10		2 months off	42.08	81.64%	2.163	12.163	0.191	0.514
Case 4.3	50		1 month on	45.41	80.19%	2.125	11.937	0.797	0.478
Case 3.4	10	1000	No off	16.41	66.71%	1.769	12.379	0.186	0.161
Case 4.4	50		Always on	18.42	67.59%	1.792	12.064	0.734	0.068
Case 3.5	10		1 month off	30.92	75.15%	1.991	12.236	0.189	0.308
Case 4.5	50		1 month on	33.25	74.14%	1.964	12.190	0.776	0.216
Case 3.6	10		2 months off	43.16	80.85%	2.141	12.540	0.191	0.409
Case 4.6	50		1 month on	44.16	78.85%	2.088	12.202	0.807	0.333
Case 3.7	10	1500	No off	16.25	66.70%	1.768	12.380	0.186	0.154
Case 4.7	50		Always on	17.91	67.45%	1.788	12.056	0.733	0.060
Case 3.8	10		1 month off	30.25	74.84%	1.983	12.198	0.189	0.306
Case 4.8	50		1 month on	31.67	73.72%	1.953	12.157	0.775	0.194
Case 3.9	10		2 months off	43.16	80.82%	2.140	12.538	0.192	0.410
Case 4.9	50		1 month on	44.16	78.72%	2.085	12.199	0.810	0.266

Table 5.17 Oil recovery factor at different phases of DDP in the case of 10 PV and 50 PV aquifer with 5 PV gas reservoir

Case	Aquifer size (PV)	Time (years)	Overall oil recovery factor	Recovery factor from water dumpflood	Recovery factor from gas dumpflood
Case 3.1	10	18.16	67.68%	19.13%	48.55%
Case 4.1	50	20.33	68.54%	39.20%	29.34%
Case 3.2	10	35.25	77.43%	19.13%	58.30%
Case 4.2	50	36.41	76.15%	39.20%	36.95%
Case 3.3	10	42.08	81.64%	19.13%	62.51%
Case 4.3	50	45.41	80.19%	39.20%	40.99%
Case 3.4	10	16.41	66.71%	19.08%	47.63%
Case 4.4	50	18.42	67.59%	39.38%	28.21%
Case 3.5	10	30.92	75.15%	19.08%	56.07%
Case 4.5	50	33.25	74.14%	39.38%	34.76%
Case 3.6	10	43.16	80.85%	19.08%	61.77%
Case 4.6	50	44.16	78.85%	39.38%	39.47%
Case 3.7	10	16.25	66.70%	19.09%	47.61%
Case 4.7	50	17.91	67.45%	39.39%	28.06%
Case 3.8	10	30.25	74.84%	19.09%	55.75%
Case 4.8	50	31.67	73.72%	39.39%	34.33%
Case 3.9	10	43.16	80.82%	19.09%	61.73%
Case 4.9	50	44.16	78.72%	39.39%	39.33%

In summary, increasing aquifer size yields benefit of oil recovery from water dumpflood phase; however, it reduces benefit from gas dumpflood. At the same time, very high amount of produced water production is obtained. This increases the operational cost for the production while at the same time reduces the overall oil recovery. Results clearly shows that large aquifer size is not necessary to improve oil recovery if gas is effectively retained in the oil reservoir.

- Effect of gas reservoir size with 10PV aquifer size

Effect of gas size was investigated to see the benefit of increasing the gas reservoir size in the case of 10 PV aquifer. Table 5.18 shows simulation results of 10 PV aquifer with 1 PV gas reservoir and 10 PV aquifer with 5 PV gas reservoir combinations.

Table 5.18 shows that all cases with 5 PV gas reservoir have high improvement in oil recovery. As the gas reservoir gets bigger, it provides very good pressure maintenance with a large volume of gas to displace fluids in the oil reservoir. The same trend can also be seen in cumulative gas production. More gas is produced to the surface as gas reservoir is larger. However, there is a slight increase in cumulative water production due to the fact that more liquid is displaced toward the producer as gas reservoir size increases. However, cases with large gas reservoir size show a big increase in production period as well. All cases with intermittent production with 5 PV gas reservoir are abandoned because of production period constraint of 30 years.

To see the full improvement in the production schedule to these reservoir combinations, constraint from production period is eliminated. Table 5.19 shows simulation results for reservoir combination of 1 PV and 5 PV gas reservoir with 10 PV aquifer without constraint of the production period. For 1 PV gas reservoir, there is no change in the result because the production times are less than 30 years in all cases. For 5 PV gas reservoir, the production time for the cases with off periods are extended beyond 30 years. By eliminating the time constraint, a decrease in net cumulative gas production with increasing gas reservoir size can be seen clearly. Since gas reservoir size increases, there is less liquid saturation around the producer, causing less pressure loss in porous media. Plus, high GLR in production well lowers the pressure loss in the wellbore. Both lower the abandonment pressure of the reservoir, hence more gas can be produced.

In summary, a large gas reservoir is preferred since it yields remarkable improvement in oil recovery and cumulative gas production. However, the downside from increasing gas reservoir size is the increasing in production period with a slight increase in cumulative water production.

Table 5.18 Simulation results for 1 PV and 5 PV gas reservoir with 10 PV aquifer with time constraint

Case No	Gas reservoir size (PV)	Target liquid production rate (STB/D)	Intermittent production	Time [Years]	Oil recovery factor	Cumulative oil production [MMSTB]	Cumulative Gas production [BSCF]	Cumulative cross-flow gas [BSCF]	Net cumulative gas production [BSCF]
Case 1.1	1	500	No off	10.50	42.39%	1.124	1.999	2.172	0.173
Case 3.1	5		Always on	18.16	67.68%	1.794	12.384	12.431	0.046
Case 1.2	1		1 month off	14.00	43.74%	1.159	1.593	1.935	0.342
Case 3.2	5		1 month on	30.00	75.69%	2.006	11.968	12.108	0.140
Case 1.3	1		2 months off	24.00	56.10%	1.487	1.332	1.846	0.514
Case 3.3	5		1 month on	30.00	71.32%	1.891	6.973	7.792	0.818
Case 1.4	1	1000	No off	9.66	42.47%	1.126	2.031	2.192	0.161
Case 3.4	5		Always on	16.41	66.71%	1.769	12.379	12.429	0.050
Case 1.5	1		1 month off	10.83	40.07%	1.062	1.629	1.937	0.308
Case 3.5	5		1 month on	30.00	74.82%	1.983	12.180	12.302	0.122
Case 1.6	1		2 months off	13.08	40.97%	1.086	1.364	1.773	0.409
Case 3.6	5		1 month on	30.00	75.44%	1.999	10.880	11.198	0.318
Case 1.7	1	1500	No off	9.58	42.75%	1.133	2.042	2.196	0.154
Case 3.7	5		Always on	16.25	66.70%	1.768	12.380	12.432	0.052
Case 1.8	1		1 month off	10.50	40.06%	1.062	1.632	1.938	0.306
Case 3.8	5		1 month on	30.00	74.77%	1.981	12.187	12.308	0.121
Case 1.9	1		2 months off	12.09	39.78%	1.054	1.339	1.749	0.410
Case 3.9	5		1 month on	30.00	75.46%	2.000	10.936	11.246	0.310

Table 5.19 Simulation results for 1 PV and 5 PV gas reservoir with 10 PV aquifer without time constraint

Case No	Size of gas reservoir (PV)	Target liquid production rate (STB/D)	Intermittent production	Time [Years]	Oil recovery factor	Cumulative oil production [MMSTB]	Cumulative Gas production [BSCF]	Cumulative cross-flow gas [BSCF]	Net cumulative gas production [BSCF]
Case 1.1	1	500	No off	10.50	42.39%	1.124	1.999	2.172	0.173
Case 3.1	5		Always on	18.16	67.68%	1.794	12.384	12.431	0.046
Case 1.2	1		1 month off	14.00	43.74%	1.159	1.593	1.935	0.342
Case 3.2	5		1 month on	35.25	77.43%	2.052	12.510	12.597	0.087
Case 1.3	1		2 months off	24.00	56.10%	1.487	1.332	1.846	0.514
Case 3.3	5		1 month on	42.08	81.64%	2.163	12.163	12.286	0.123
Case 1.4	1	1000	No off	9.66	42.47%	1.126	2.031	2.192	0.161
Case 3.4	5		Always on	16.41	66.71%	1.769	12.379	12.429	0.050
Case 1.5	1		1 month off	10.83	40.07%	1.062	1.629	1.937	0.308
Case 3.5	5		1 month on	30.92	75.15%	1.991	12.236	12.354	0.118
Case 1.6	1		2 months off	13.08	40.97%	1.086	1.364	1.773	0.409
Case 3.6	5		1 month on	43.16	80.85%	2.141	12.540	12.620	0.080
Case 1.7	1	1500	No off	9.58	42.75%	1.133	2.042	2.196	0.154
Case 3.7	5		Always on	16.25	66.70%	1.768	12.380	12.432	0.052
Case 1.8	1		1 month off	10.50	40.06%	1.062	1.632	1.938	0.306
Case 3.8	5		1 month on	30.25	74.84%	1.983	12.198	12.320	0.122
Case 1.9	1		2 months off	12.09	39.78%	1.054	1.339	1.749	0.410
Case 3.9	5		1 month on	43.16	80.82%	2.140	12.538	12.619	0.081

- Effect of gas reservoir size with 50PV aquifer size

Effect of gas size was investigated to see the benefit of increasing the gas reservoir size in the case of 50 PV aquifer. Table 5.20 shows simulation results of 50 PV aquifer with 1 PV gas reservoir and 50 PV aquifer with 5 PV gas reservoir combinations.

Table 5.20 shows that all cases with 5 PV gas reservoir yield higher oil recovery than the case with 1 PV gas reservoir. As the gas reservoir gets bigger, it provides very good pressure maintenance with a large volume of gas to displace fluids in the oil reservoir. At the same time, cumulative gas production increases as gas reservoir gets larger. However, cases with large gas reservoir size show a big increase in production period as well. For all cases with intermittent production, the reservoir is abandoned because of production period constraint of 30 years.

To see the full improvement in the production schedule to these reservoir combinations, constraint from production period is eliminated. Table 5.21 shows simulation results for reservoir combination of 1 PV and 5 PV gas reservoir with 50 PV aquifer without constraint of the production period. For 1 PV gas reservoir, there is no change in the result because the production times are less than 30 years in all cases. For 5 PV gas reservoir, the production time for the cases with off periods are extended beyond 30 years. By eliminating the time constraint, a further improvement in oil recovery with increasing gas reservoir size can be seen. Since production period is eliminated, reservoir can be produced to the abandonment condition. As shown in Table 5.21 , an improvement of 16 percent in oil recovery is obtained by increasing the gas reservoir size from 1 PV to 5 PV.

In summary, a large gas reservoir is favored since it yields great improvement in oil recovery and cumulative gas production. However, the drawback from increasing gas reservoir size is the increasing in production period with a slight increase in cumulative water production.

Table 5.20 Simulation results for 1 PV and 5 PV gas reservoir with 50 PV aquifer

Case No	Size of gas reservoir (PV)	Target liquid production rate (STB/D)	Intermittent production	Time [Years]	Oil recovery factor	Cumulative oil production [MMSTB]	Cumulative Gas production [BSCF]	Cumulative cross-flow gas [BSCF]	Net cumulative gas production [BSCF]
Case 2.1	1	500	No off	15.25	49.35%	1.309	2.175	2.259	0.084
Case 4.1	5		Always on	20.33	68.54%	1.817	12.082	12.128	0.046
Case 2.2	1		1 month off	19.16	49.69%	1.318	1.674	1.963	0.290
Case 4.2	5		1 month on	30.00	73.25%	1.942	11.100	11.330	0.230
Case 2.3	1		2 months off	26.08	54.34%	1.441	1.274	1.752	0.478
Case 4.3	5		1 month on	30.00	63.09%	1.673	4.097	5.165	1.068
Case 2.4	1	1000	No off	13.16	48.47%	1.285	2.200	2.268	0.068
Case 4.4	5		Always on	18.42	67.59%	1.792	12.064	12.123	0.059
Case 2.5	1		1 month off	15.00	47.39%	1.256	1.817	2.033	0.216
Case 4.5	5		1 month on	30.00	73.12%	1.937	11.918	12.037	0.119
Case 2.6	1		2 months off	17.25	47.64%	1.263	1.518	1.851	0.333
Case 4.6	5		1 month on	30.00	72.48%	1.921	10.089	10.468	0.379
Case 2.7	1	1500	No off	12.67	48.63%	1.289	2.217	2.277	0.060
Case 4.7	5		Always on	17.91	67.45%	1.788	12.056	12.112	0.056
Case 2.8	1		1 month off	14.08	47.14%	1.250	1.866	2.060	0.194
Case 4.8	5		1 month on	30.00	73.04%	1.935	12.066	12.168	0.102
Case 2.9	1		2 months off	14.83	46.25%	1.226	1.604	1.870	0.266
Case 4.9	5		1 month on	30.00	72.87%	1.931	10.489	10.813	0.324

Table 5.21 Simulation results for 1 PV and 5 PV gas reservoir with 50 PV aquifer without time constraint

Case No	Size of gas reservoir (PV)	Target liquid production rate (STB/D)	Intermittent production	Time [Years]	Oil recovery factor	Cumulative oil production [MMSTB]	Cumulative Gas production [BSCF]	Cumulative cross-flow gas [BSCF]	Net cumulative gas production [BSCF]
Case 2.1	1	500	No off	15.25	49.35%	1.309	2.175	0.678	0.084
Case 4.1	5		Always on	20.33	68.54%	1.817	12.082	0.739	0.084
Case 2.2	1		1 month off	19.16	49.69%	1.318	1.674	0.697	0.290
Case 4.2	5		1 month on	36.41	76.15%	2.017	12.318	0.779	0.290
Case 2.3	1		2 months off	26.08	54.34%	1.441	1.274	0.724	0.478
Case 4.3	5		1 month on	45.41	80.19%	2.125	11.937	0.797	0.478
Case 2.4	1	1000	No off	13.16	48.47%	1.285	2.200	0.664	0.068
Case 4.4	5		Always on	18.42	67.59%	1.792	12.064	0.734	0.068
Case 2.5	1		1 month off	15.00	47.39%	1.256	1.817	0.671	0.216
Case 4.5	5		1 month on	33.25	74.14%	1.964	12.190	0.776	0.216
Case 2.6	1		2 months off	17.25	47.64%	1.263	1.518	0.682	0.333
Case 4.6	5		1 month on	44.16	78.85%	2.088	12.202	0.807	0.333
Case 2.7	1	1500	No off	12.67	48.63%	1.289	2.217	0.661	0.060
Case 4.7	5		Always on	17.91	67.45%	1.788	12.056	0.733	0.060
Case 2.8	1		1 month off	14.08	47.14%	1.250	1.866	0.665	0.194
Case 4.8	5		1 month on	31.67	73.72%	1.953	12.157	0.775	0.194
Case 2.9	1		2 months off	43.16	80.82%	2.140	12.538	0.192	0.410
Case 4.9	5		1 month on	14.83	46.25%	1.226	1.604	0.665	0.266

5.4 Comparison between Water and Gas Dumpflood DDP to Conventional Methods

This section compares the performance of DDP via water and gas dumpflood to other methods such as natural depletion, waterflooding, gas flooding and conventional DDP. By comparing results from conventional recovery methods to water and gas dumpflood via DDP (Table 5.22 and Table 5.23), most water and gas dumpflood DDP cases yield higher oil recovery factor in comparison with conventional waterflooding. If the gas reservoir is small (1PV), oil recovery factor of DDP dumpflood from 10 PV aquifer is 1.21% higher than the one obtained from conventional waterflood while DDP dumpflood from 50 PV aquifer yields 0.55% lower recovery factor due to the reduction is gas retention as water saturation in reservoir increases. For a large gas reservoir (5PV), DDP dumpflood provides 18.36 to 26.75 percent additional recovery factor when compared with conventional waterflood. The success of DDP dumpflood over conventional waterflood is from gas dumpflooding. In any case, DDP dumpflood requires no water injection and yields less the amounts of cumulative water production. This may be significant factor in decision making if the costs of water injection, water treatement and water disposal are high.

When comparing DDP dumpflood with conventional gas flooding, all DDP dumpflood case yield lower oil recovery factor as to gas flooding. For small gas reservoir (1 PV), oil recovery factor decreases from 82.15 percent obtained by gas flooding to 54.34 – 56.20 percent as DDP dumpflood is implemented. For large gas reservoir (5 PV), oil recovery factor drops just 8.9 to 0.51 percent when compared with conventional gas flooding. However, the proposed method requires no injection facilities which lowers the production cost while gas flooding method needs 53.46 BSCF of injected gas. While, the drawback of the proposed method is a higher in cumulative water production and production period.

By comparing DDP dumpflood to conventional DDP, all DDP dumpflood cases yield lower oil recovery factor in comparison with conventional DDP. For small gas reservoir (1PV), oil recovery factor decreases up to 30.73 to 32.49 percent compared to the conventional DDP case. However, for large gas reservoir (5PV), the reduction in oil recovery by performing DDP dumpflood decreases down to 5.19 – 13.08 percent while at the same time increases production period from 7.33 to 22.74 years. Set aside from the drawback, the proposed method requires no injection facilities and yields lower in cumulative water production which lower the overall cost of oil production.

In summary, water and gas dumpflood via DDP process is a very good method to produce oil from perforating water and gas zones to allow fluids to displace the oil toward the production well when the gas reservoir size is big (5PV). If the gas reservoir is small (1PV), conventional DDP is the most attractive method in term of oil recovery factor. However the most suitable method needs to include economic analysis in the decision making process.

Table 5.22 Simulation results from conventional methods (* optimized case)

Case	Time [years]	Recover Factor	Cumulative oil production (MMSTB)	Cumulative gas production (BCF)	Cumulative water production (MMSTB)	Cumulative gas injection (BSCF)	Cumulative water injection (MMSTB)
Natural depletion	6.25	27.12%	0.719	0.197	0	0	0
Water flooding	17.00	54.89%	1.455	0.282	1.513	0	3.105
Gas Flooding	21.50	82.15%	2.178	52.040	0	53.465	0
DDP*	22.67	86.83%	2.302	87.767	0.898	87.147	1.035

Table 5.23 Highest recovery obtained from water and gas dumpflood via DDP (* cases without time constraint)

Case	Aquifer size	Gas reservoir size	Time [years]	Recover Factor	Cumulative oil production (MMSTB)	Cumulative gas production (BCF)	Cumulative water production (MMSTB)
Case 1.3	10 PV	1 PV	24.00	56.10%	1.487	1.332	0.182
Case 2.3	50 PV	1 PV	26.08	54.34%	1.441	1.274	0.724
Case 3.2	10 PV	5 PV	30.00	75.69%	2.006	11.968	0.189
Case 4.2	50 PV	5PV	30.00	73.25%	1.942	11.100	0.764
Case 3.3*	10 PV	5 PV	42.08	81.64%	2.163	12.163	0.191
Case 4.3*	50 PV	5PV	45.41	80.19%	2.125	11.937	0.797

Chapter 6

CONCLUSIONS AND RECOMMENDATIONS

In this chapter, conclusions of the study of the reservoir simulation on double displacement via water and gas dumpflood which investigates the effect from different aquifer and gas reservoir sizes with different production schedules such as target liquid production rate and intermittent production are presented. Then, a recommendation for future study is also included.

6.1 Conclusions

1) Regarding aquifer size, large aquifer size is not necessary to improve the oil recovery. Even though there is more water to displace oil toward the producer, as water saturation in the oil reservoir increases, the benefit from gas displacement is lower. By just retaining gas effectively in the oil reservoir, it can surpass the benefit from large aquifer size while at the same time lowers the amount of cumulative water production and production period.

2) The size of gas reservoir is a major influence to oil recovery efficiency in this process. Larger gas reservoir provides better pressure support to the oil reservoir as well as better effect of gravity drainage. Oil recovery and cumulative gas production generally increase with increasing gas reservoir size.

3) For target liquid production rate, a slight increase in oil recovery is observed in all cases as target liquid production rate is lower. A high target liquid production rate causes unsmooth flood front, leading to early gas breakthrough. Early gas breakthrough causes a steeper decline in reservoir pressure and low oil recovery. There is a decrease in cumulative gas production and increase in cumulative water production as the target liquid production rate is increased.

4) Regarding intermittent production, the improvement in oil recovery efficiency can be seen in most cases. Since intermittent production enhances the segregation of the liquid and gas, gas can be better retained in the reservoir. This causes pressure in the reservoir to decline at a more gradual rate

compared to the case without the intermittent production. Additionally, for the case with 5 PV reservoir size, liquid and gas segregation in case with intermittent production keeps oil production rate to stay above the economic limit, which prolong the production. However, the case of 1 PV gas and high target liquid production rate, intermittent production is not recommended as gas is not effectively retained in the reservoir. At the same time, it introduces additional pressure loss in the reservoir due to high water and oil saturation around the production well.

5) Water and gas dumpflood via DDP is a promising method when the gas reservoir is large (5 PV) compared to other conventional methods. For example, with 10 PV aquifer and 5 PV gas reservoir, DDP via water and gas dumpflood can yield 26 percent higher oil recovery factor compared to waterflooding and shows an insignificantly difference in oil recovery to gas flooding. However, it yields just 5 percent lower than the conventional DDP but it requires no injection facilities.

6.2 Recommendations

1) A further study should be performed to determine the best condition to terminate the water dumping for the case of large aquifer to maximize the oil recovery and reduce the amount of produced water.

2) The performance of DDP with intermittent production schedule should be further investigated to understand its effect and maximize the oil recovery with a lower production period.

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