DOWNHOLE WATER DRAIN FROM BOTTOM WATER-DRIVE GAS RESERVOIR INTO PARTIALLY DEPLETED GAS RESERVOIR

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การระบายน้ำใต้ดินจากแหล่งกักเก็บก๊าซที่ขับเคลื่อนด้วยน้ำข้างใต้เข้าสู่แหล่งกักเก็บก๊าซที่มีการผลิตบางส่วน

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วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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วีรพล กมลขันติกุล : การระบายน้ำใต้ดินจากแหล่งกักเก็บก๊าซที่ขับเคลื่อนด้วยน้ำข้างใต้เข้าสู่แหล่งกักเก็บก๊าซที่มีการผลิตบางส่วน (DOWNHOLE WATER DRAIN FROM BOTTOM WATER-DRIVE GAS RESERVOIR INTO PARTIALLY DEPLETED GAS RESERVOIR) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร.สุวัฒน์ อธิชนากร, 117 หน้า.

หนึ่งในปัญหาสำคัญในการผลิตก๊าซ จากแหล่งกักเก็บก๊าซที่ขับเคลื่อนด้วยน้ำข้างใต้คือ การโหลดของของเหลวในหลุมผลิต สำหรับระบบแหล่งกักเก็บที่มีหลายชั้นซึ่งประกอบด้วย แหล่งกักเก็บก๊าซที่ขับเคลื่อนด้วยน้ำข้างใต้ และ แหล่งกักเก็บก๊าซซึ่งอยู่ลึกลงไปข้างล่าง วิธีการผลิตที่เรียกว่า “การระบายน้ำใต้ดินจากแหล่งกักเก็บก๊าซที่ขับเคลื่อนด้วยน้ำข้างใต้เข้าสู่แหล่งกักเก็บก๊าซที่มีการผลิตบางส่วน” สามารถช่วยลด ปรากฏการณ์ที่ระดับน้ำสูงขึ้นมาเป็นรูปกรวย และดังนั้นจึงสามารถช่วยเพิ่มการนำก๊าซขึ้นมาจากแหล่งกักเก็บก๊าซชั้นบน ในขณะเดียวกัน น้ำที่ระบายออกมาสามารถถูกถ่ายไปยังแหล่งกักเก็บก๊าซที่มีการผลิตไปแล้วบางส่วน เพื่อช่วยเพิ่มการนำก๊าซขึ้นมาจากแหล่งกักเก็บก๊าซชั้นล่าง วัตถุประสงค์ของการศึกษาครั้งนี้คือ การบ่งบอกสภาวะที่เหมาะสมสำหรับการนำวิธีการผลิตดังกล่าวไปใช้ เมื่อเทียบกับเทคนิคการผลิตแบบอื่นๆ โปรแกรมจำลองแหล่งกักเก็บชื่อว่า ECLIPSE100 ถูกใช้เพื่อประเมินสมรรถนะของวิธีการผลิตสามแบบ ได้แก่ การผลิตแบบผสมผสาน การผลิตแบบล่างขึ้นบน และ การผลิตด้วยวิธีการระบายน้ำใต้ดินจากแหล่งกักเก็บก๊าซที่ขับเคลื่อนด้วยน้ำข้างใต้เข้าสู่แหล่งกักเก็บก๊าซที่มีการผลิตบางส่วน คุณสมบัติตัวอย่างของหินและของไหลจากอ่าวไทยถูกใช้ในการสร้างแบบจำลองแหล่งกักเก็บ ผลจากการจำลองแสดงให้เห็นว่า วิธีการผลิตดังกล่าวให้ผลที่ดีกว่าวิธีการผลิตแบบเดิมในแง่ของการเพิ่มการนำก๊าซขึ้นมา และการลดการผลิตน้ำ เมื่อทดสอบด้วยสภาวะการผลิตที่เหมาะสมภายใต้สภาวะของแหล่งกักเก็บต่างๆกัน ผลปรากฏว่า วิธีการการระบายน้ำใต้ดินจากแหล่งกักเก็บก๊าซที่ขับเคลื่อนด้วยน้ำข้างใต้เข้าสู่แหล่งกักเก็บก๊าซที่มีการผลิตบางส่วนสามารถช่วยเพิ่มการนำก๊าซขึ้นมามากสุดถึง 16% จากการผลิตแบบผสมผสาน และ 13% จากการผลิตแบบล่างขึ้นบน ในขณะเดียวกันยังช่วยลดการผลิตน้ำมากสุดถึง 155 MSTB จากการผลิตแบบผสมผสาน และ 110 MSTB จากการผลิตแบบล่างขึ้นบน

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One of the most important problems in producing gas from a water-drive gas reservoir is liquid loading. For a multi-layered system consisting of a bottom water-drive gas reservoir and a dry-gas reservoir located at a deeper location underneath, a method called “Downhole Water Drain from Bottom Water-Drive Gas Reservoir into Partially Depleted Gas Reservoir” (DWD) can help reduce water coning effect and thus increase gas recovery of the upper reservoir. At the same time, the water can be dumped into a partially-depleted gas reservoir to help increase gas recovery of the lower reservoir. The objective of this study is to determine appropriate conditions for applying DWD method in comparison with other production scenarios. ECLIPSE100 reservoir simulator was used to evaluate the performance of three production scenarios: commingled production, bottom-up production and DWD. Typical rock and fluid properties from Gulf of Thailand gas fields were used to create the reservoir model. The result from simulation showed that DWD performs better than conventional commingled method and bottom-up production methods in terms of increasing gas recovery and reducing water production. Tested with proper operating conditions among various reservoir conditions, DWD can help enhance gas recovery upto 16% from commingled and 13% from bottom-up production meanwhile DWD can help reduce water production by upto 155 MSTB from commingled and 110 MSTB from bottom-up production

Department:	Mining and Petroleum Engineering	Student's Signature	....
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API	American Petroleum Institute gravity
BCF	billion standard cubic feet
BHP	bottom hole pressure
BTU	British thermal unit
˚C	degree Celsius
CGR	condensate to gas ratio
cm	centimeter
COMPDAT	well completion specification data
COMPSEGS	segmented well completion
cP	centipoise
cu.ft.	cubic feet
EOR	enhance oil recovery
˚F	degree Fahrenheit
FH	Friction and hydrostatic losses
FIX	Fixing the lookup value of the flow rate at the first flow point in the table
ft.	feet
ft.ss.	feet subsea
GOR	gas to oil ratio
hr	hour
ID	internal diameter
i.e.	id est
in.	inch
LEN	The interpolated pressure drop is scaled in proportion to the length of the segment relative to the table’s datum length
m	meter
M	thousand
MBOPD	thousand barrel of oil per day

MBWPD	thousand barrel of water per day
mD	millidarcy
MM	million
MMSCF	million standard cubic feet
MMSCF/day	million standard cubic feet per day
MMSTB	million stock tank barrel
MSCF	thousand standard cubic feet
MSTB	thousand stock tank barrel
OGIP	original gas in place
ppm	parts per million
psi	pound force per square inch
psia	pound force per square inch absolute
psig	pound force per square inch gauge
PVT	pressure volume temperature
°R	degree Rankine
RB	reservoir barrel
SCAL	special core analysis
SCF	standard cubic feet
sec	second
STB	stock tank barrel
THP	tubing head pressure
TVD	true vertical depth
VFP	vertical flow performance
VFPPROD	vertical flow performance table for production wells
VLP	vertical lift performance
WCONPROD	production well control
WGR	water to gas ratio
WELSEGS	segmented well definition
WELSPECS	well specification
WSEGTABL	segment vertical flow performance table
%	percent

NOMENCLATURES

c_w	aquifer water compressibility, psi^{-1}
c_f	aquifer rock compressibility, psi^{-1}
B_g	gas formation volume factor, bbl/SCF
B_{ga}	gas formation volume factor at abandonment pressure, bbl/SCF
B_{gi}	initial gas formation volume factor, bbl/SCF
B_w	water formation volume factor, RB/STB
E	overall sweep efficiency
E_A	areal sweep efficiency
E_D	displacement efficiency
E_I	vertical sweep efficiency
E_V	volumetric sweep efficiency
$FRAC.S.G.$	fracture pressure gradient
G	gas in place before water dumpflood, SCF
G_p	cumulative gas production during water dumpflood, SCF
h	reservoir thickness, ft.
k	absolute permeability, mD
k_g	effective gas permeability, mD
k_o	effective oil permeability, mD
k_w	effective water permeability, mD
k_{rg}	relative permeability to gas
k_{ro}	relative permeability to oil
k_{rw}	relative permeability to water
M	mobility ratio
n_g	Corey gas exponent
n_w	Corey water exponent
P	current reservoir pressure (pressure at GWC), psi
P_i	initial reservoir pressure, psi

P_{inj}	well injection pressure, psi
P_f	fracture pressure, psia
P_p	pore pressure
P_r	reservoir pressure, psia
P_0	reference pressure, psia
$\bar{P}_r$	average reservoir pressure, psi
Q_{inj}	water injection rate, bbl/D
Q_{curve}	hypothetical rates as determined from the Chaney et al. curves
Q_g	gas flow rate, MSCF/day
Q_{gc}	critical gas flow rate, MSCF/day
r_e	well's drainage radius, ft.
r_w	wellbore radius, ft.
S	skin
S_g	gas saturation
S_{gi}	initial gas saturation
S_{gr}	residual gas saturation
$S_{g,cr}$	critical gas saturation
$S_{g,min}$	minimum gas saturation
S_w	water saturation
$S_{w,cr}$	critical water saturation
S_{wi}	initial water saturation
$S_{w,max}$	maximum water saturation
$S_{w,min}$	minimum water saturation
T	temperature, °R
T_r	reservoir temperature, ˚F
W_e	cumulative water influx, bbl
W_i	initial volume of water in the aquifer, bbl
W_p	cumulative water production, STB
z	gas compressibility factor

Greek symbol

Δ	Difference
ρ_g	gas density, lb/ft^3
ρ_w	water density, lb/ft^3
μ_g	gas viscosity, cp
β_g	gas FVF, bbl/MSCF
μ_w	water viscosity, cp
ψ_p	pseudopressure calculated at pressure p, PSI^2/cp
ψ_{wf}	pseudopressure computed at flowing sand face pressure, PSI^2/cp
$\overline{\psi_r}$	pseudopressure computed at average reservoir pressure, PSI^2/cp
γ	Poisson's ratio
σ_o	vertical overburden stress, psi
$\overline{\sigma_H}$	average horizontal matrix stress, psi
σ_v	vertical matrix stress, psi

CHAPTER 1
INTRODUCTON

1.1 Background

One of the most important problems in producing gas from a water-drive gas reservoir is liquid loading which is caused by invasion of water into the wellbore and eventually the well stops producing. On the other hands, one of the most important problems that stops a volumetric gas reservoir from producing gas is insufficient reservoir pressure to allow gas from the reservoir flowing into the wellbore and to lift the gas from bottom hole to surface. In addition, waterflooding in partially depleted volumetric gas reservoir which has low reservoir pressure was proved to further increase gas recovery by simply increasing the reservoir pressure.

For a multi-layered system consisting of a bottom water-drive gas reservoir located at shallow depth and a volumetric gas reservoir located at a deeper location underneath, a method called Downhole Water Drain from Bottom Water-Drive Gas Reservoir into Partially Depleted Gas Reservoir (DWD) can help reduce water coning effect in the upper reservoir as well as increasing pressure of the lower reservoir which has been producing by dumping the water from the upper reservoir into the lower partially produced reservoir. This technique requires the well to be perforated in three intervals which are upper gas zone, water aquifer at the bottom of the gas zone, and lower gas reservoir underneath. Water is allowed to flow from the upper reservoir into the lower reservoir. Gas from the deeper zone can be produced from another well located further away from the dumping well. Thus, this method can help increase gas recovery of both the upper reservoir and the lower reservoir at the same time.

In order to evaluate the performance of the proposed strategy, a simple representative system of reservoirs having characteristics as described earlier was created using ECLIPSE100 reservoir simulator. Typical rock and fluid properties from Gulf of Thailand gas fields were used in the study. Conventional production practices in Gulf of Thailand were evaluated in parallel with the proposed strategy in all stages for comparison purposes. Several reservoir parameters and operational constraints were investigated such as perforation intervals, initial production rates, timing of dumpflood operation, reservoir thickness, reservoir depth and reservoir permeability. The performance of each study case was evaluated based on gas recovery and water production.

1.2 Objectives

1) To determine appropriate operating conditions for applying "Downhole Water Drain from Bottom Water-Drive Gas Reservoir into Partially Depleted Gas Reservoir" method in comparison with other production scenarios.
2) To examine the effects of reservoir parameters on "Downhole Water Drain from Bottom Water-Drive Gas Reservoir into Partially Depleted Gas Reservoir".

1.3 Outline of methodology

1) Construct static base case model to simulate a system of reservoirs in a field. The upper reservoir is bottom water-drive gas reservoir. The lower reservoir is dry gas reservoir.
2) Simulate three production scenarios with the same system of reservoirs created in the first step but vary operational parameters in order to examine their effects
    a) Upper gas perforation interval
    b) Upper water perforation interval
    c) Initial production rate
    d) Timing of dumpflood operation
3) Select three best cases, one from each production scenario, prioritizing from highest R.F., lowest water production and shortest production time, respectively. Then, simulate the three selected cases under each of the following reservoir conditions in order to evaluate the performance.
    a) Thickness of water column in the upper reservoir
    b) Thickness of gas column in the lower reservoir
    c) Top depth of the lower reservoir

d) Vertical to horizontal permeability ratio

e) Horizontal permeability

4) Analyze the results from simulations and discuss the results.

1.4 Outline of thesis

There are six chapters in this thesis consisting of:

Chapter 1 introduces the background of thesis, common obstacles of gas production by conventional techniques and the basic concept how the proposed strategy can theoretically improve gas production from conventional practices. The objectives and the outline of methodology are included in this chapter as well.

Chapter 2 summarizes reviews of previously published literatures related to methods to reduce water coning and methods to increase gas recovery.

Chapter 3 summarizes essential theories and concepts that explain phenomena involved in downhole water drain and water dumpflood.

Chapter 4 illustrates the details of the reservoir model including case definition, grid, fluid properties, special core analysis, and production parameters used in the simulation.

Chapter 5 discusses the results of the reservoir simulations obtained from different production scenarios and reservoir parameters.

Chapter 6 provides conclusions for this research and recommendations for further study.

CHAPTER 2
LITERATURE REVIEW

Previous studies related to the thesis topic are reviewed and summarized in this chapter. There are several studies about reduction of water conning effect in water-drive reservoirs by draining the water as much as possible from the reservoir. Furthermore, there are several studies discussing about uncommon mechanisms of how waterflooding can help increase gas recovery in low-pressure reservoirs. Various approaches were used for these studies including real field implementation, field observation, reservoir simulation and technical analysis.

2.1 Methods to reduce water coning effect

Water coning in gas reservoirs often results in excessive water production which can kill a well due to liquid loading or severely shorten its economic life due to water handling cost. In Gulf of Thailand, most of the wells are shut in early because of this problem. There were several techniques that have been proposed to reduce water coning in the literature such as coproduction, downhole water sink and downhole water loop.

2.1.1 Coproduction

Rogers [1] initiated an attempt to reproduce gas from a watered-out gas reservoir. Mt. Selman Field was abandoned for about 12 years before this test. At time of abandonment, gas rate was lower than 0.5 MMSCFD which was not economic to continue production. Also, no gas cap was found; the remaining gas was trapped as an immobile dispersed phase in water. A few techniques to determine the remaining gas volume including p/z plot, volumetric estimation and numerical simulation showed that there was about 4.5 BCF of gas left in the reservoir in form of dissolved gas bubbles and pockets of trapped free gas inside sandstone matrix with the overall gas to water ratio of 7 SCF/STB. Rogers proposed to produce water from another well to reduce reservoir pressure so that the trapped free gas could be released up dip and thus, could be reproduced. The result showed that this method could increase gas to water ratio to 3 times the amount of dissolved gas which is about 21 SCF/STB. Even though the result was very successful in terms of research but the gas to water ratio could not reach the economical producing point of 80 SCF/STB.

Arcaro and Bassiouni [2] employed basic material-balance analysis, tank-model simulation, and a preliminary economic analysis to demonstrate the technical and economic feasibility of coproduction technique for a case study of the Louisiana gulf coast Eugene Island Block 305 10,300-ft-sand gas reservoir. They proposed to convert the watered-out down dip well into high-rate water production well in order to produce gas from another well up dip. Removing water at down dip would create three benefits. First, the production of water lowers reservoir pressure, and more gas is produced because of expansion. Second, water production slows the advance of the water front. And third, previously immobile gas in the swept zone might become mobile again as the pressure is lowered. However, this project focused on the application of the process to water-drive gas reservoirs which was not totally watered out. The technical result showed that coproduction technique in an actual case of the Eugene Island Block 305 10,300-ft-sand water-drive gas reservoir had the expected recovery of 83 % compared with only 62% for the conventional production approach or equaled to an increase of 56 BCF of gas recovery.

2.1.2 Downhole water sink

Marcano and Wojtanowicz [3] suggested the method to control water coning called Downhole Water Sink (DWS) in an oil reservoir. The design was composed of two tubing strings, one for oil and one for water, installed in a production casing. This method can delay water coning in dual-completed wells by concurrently producing water from the bottom completion below the oil-water contact and oil from another completion at the top of the oil sand. A simulation study was conducted using data from actual wells in Louisiana Gulf Coast. The authors proved that this method can increase oil recovery and well productivity.

Shirman and Wojtanowicz study [4] supported the result from Marcano and Wojtanowicz [3] that DWS could reduce water cut and increase oil recovery. Their study was based on both experiment and field observations. Experimental results showed that a 38% reduction of the total water cut was possible with DWS for an optimum combination of top production and bottom drainage rates. Field observations indicate that after DWS recompletions, production of oil increased and the water cut at the top completion was reduced though there was no reduction in the total production water cut.

2.1.3 Downhole water loop

Wojtanowicz [5] studied the method to reduce total water production in oil reservoir connected to bottom aquifer called Downhole Water Loop (DWL). The idea was to pump water back into the aquifer itself at deeper perforation. A submersible pump was required to provide the pressure difference against aquifer pressure at deeper depth. Packer was set just below oil water contact to isolate water reinjection system with oil production. This method also provided additional benefit in terms of safe disposal of produced water. Results from simulation study revealed that oil production rate can increase two to four folds compared with conventional completions with minimal water cut. However, this method was effective when (1) the oil production by strong water drive was delayed by water coning; (2) the bottom section of the well, in the water zone, was deviated such that the water source can be set below and aside water sink; (3) the water zone needed to be thick enough to allow sufficient lateral departure of the water loop without unnecessary curvature of the bottom section.

Later, Jin and Wojtanowicz [6] developed a nodal analysis model to find the operational range of DWL for a given reservoir system and compared the model performance to conventional completion. The design parameters included depth of the three completions, oil production rate, drainage rate and injection rate. Simulation model consisting of radial-cylindrical reservoir was created by ECILPSE100 to simulate DWL system. Top completion was located at the top of oil zone to lift the oil by ESP.

The other two completions, for water drainage and water injection, were located in the aquifer zone; one was just below OWC; the other was located deep down but still in the aquifer zone. A packer was set between the completions in order to separate their flowing pressures. The results showed that for each DWL system, there existed such a combination of three parameters mentioned above and drainage-injection distance that resulted in water-free oil production. Above certain drainage-injection spacing, doubling water drainage rate could increase critical oil production rate by 80%. Moreover, it was found that minimum drainage-injection spacing was relatively small. Thus, DWL can also be implemented in reservoirs with thin bottom water.

2.2 Waterflood mechanisms that increase gas recovery in low-pressure reservoir

Generally, waterflooding is not a normal practice for enhancing gas recovery in volumetric gas reservoir because its main drive mechanism is gas expansion. Waterflooding traps the gas in aqueous phase and creates higher reservoir pressure which compresses gas, reducing gas expansion. However, there were some studies in the past presenting that waterflooding in low-pressure gas reservoir creates inverse effect which favorably increases gas recovery. There are mainly two mechanisms that waterflood help increase gas recovery in low-pressure reservoirs which are gas displacement and reservoir re-pressurization.

2.2.1 Waterflooding in gas reservoir

Cason [7] showed that waterflooding in nearly abandoned gas reservoir can help displacing left-over gas and increase recovery. He showed by examining the theory and reported the results of a water-flooded gas reservoir in southern Louisiana. Duke Lake gas field in southern Louisiana had undergone water injection for 11 years after the reservoir pressure had fallen below 1,000 psi. An incremental recovery of 25 BCF was credited to water injection. Finally, the author concluded that waterflooding increased recovery by 5-16% of OGIP in gas reservoir that never experienced water influx and 3.6% of OGIP in a gas reservoir that experienced water influx.

Valjak et al. [8] studied physical and economic feasibility of waterflooding in low-pressure gas reservoirs. The economic feasibility of the well was indicated by the amount of water injected which can be increased significantly in the case of depleted gas reservoir. Alternatively, water can be cross-flowed from large aquifer down to a depleted gas reservoir which reduced cost of providing sufficient amount of water. The authors investigated NPV and PVR of different production scenarios, consisting of pressure maintenance, pressure support and waterflooding followed by compression. By using actual data from low-pressure Godchaux Reservoir A, waterflooding performance was estimated using material balance. The result showed that waterflooding followed by compression yielded the highest NPV and PVR. Additionally, a hypothetical reservoir model was simulated based on data from depletion-drive Reservoir X. Waterflooding performance was predicted by the simulation using one well as a water injector in order to compare with the compression option. The result showed that waterflooding extended well duration, recovery and yielded higher NPV and PVR. This paper finally concluded that waterflooding of low-pressure volumetric gas reservoirs is a feasible improved recovery method.

Geffen et al. [9] showed that waterflooding can displace gas and thus increase gas recovery. A study was made through simulation, laboratory and field tests to determine any differences in residual gas saturation. The factors studied include flooding rate, static pressure, temperature, sample size and saturation conditions before flooding. It had been shown that there was no difference between the flow characteristics of oil and water or gas and water in water wet porous rocks. The residual gas saturation that can be expected following waterflooding of a gas reservoir then would be in the same range as the residual oil saturation normally expected after waterflooding an oil reservoir, i.e., in the range of 15% - 50% pore space.

2.2.2 Pressure maintenance via water dumpflood

Fujita [10] presented 5-year-operation results of successful pressure maintenance by formation water dumping into a partially depleted limestone oil reservoir, Ratawi oil reservoir. Water was dumped from a shallower zone to a deeper depleted oil reservoir. Before dumping, the oil production rate had dropped to 33 Mbopd, the reservoir pressure had dropped to 2,650 psig and GOR had increased to 1,550 SCF/STB. Water dumping operation was developed in the 5-year period which finally dumped the water at the rate of 29 MBWPD. During 5 years of dumpflood operation, the oil production rate was maintained at 40-45 MBOPD, the reservoir pressure was maintained at 2,600 psig and GOR dropped below 1,000 SCF/STB. Thus, it was obvious that remarkable improvement was achieved in reservoir pressure maintenance and GOR reduction by water dumping.

Osharode et al. [11] explored benefits of implementing water dumpflood in a depleted reservoir and also suggested other operation criteria for optimal recovery by using dynamic modelling. The D reservoir in Egbema West Field originally had 12 producers producing at 32 MBOPD. After 7 years, the oil production rate dropped to 5 MBOPD due to rapid pressure decline in the reservoir from 3,452 to 2,650 psig. The pressure decline was due to lower aquifer supply than reservoir withdrawal. Shallower water source at 4,000 ft.ss. was at normal hydrostatic pressure while the target reservoir at 8,000 ft.ss had been depleted by 800 psi. The difference in pressures and gravity allowed water to fall from the source to the target reservoir to maintain the pressure and swept the remaining oil. After water dumpflood was applied for 12 years, further pressure decline was stopped, and cumulative oil production was 33% higher than the case without dumpflood. The authors also proposed that dumpflooding can be achieved either by drilling a fewer number of high-rate dumpers or a higher number of average-rate dumpers. Though, the former is better in term of wider well spacing and performance monitoring.

Water dumpflood is considered relatively new techniques incorporating both ideas of reducing water coning effect and waterflooding in low-pressure gas reservoir together. This technique delays water coning by draining water from source reservoir and dumpflood sink reservoir increasing its hydrocarbon recovery.

Buratanavonsom [12] further modified DWS technique by dumping water to a lower oil reservoir instead of pumping water up to the surface which is the technique called Downhole Water Dumpflood (DWDF). A hypothetical reservoir model was created by using ECLIPSE100. There were two layers of reservoirs composing of an upper gas-water reservoir and a lower oil reservoir. Result from reservoir simulation showed that this method can reduce a significant amount of total water production when perforating more than 60% of the gas column and obtained the highest equivalent barrel of oil production when 80% of gas column was perforated. Gas recovery from the upper reservoir was higher compared to conventional method when more than 50% of gas column was perforated. In addition, dumping water into the lower oil reservoir improved oil recovery to 41% compared with 12% in conventional production. He also suggested that gas perforation interval was the main factor that affected cumulative gas production and cumulative water production.

Quttanair and Al-Maraghi [13] tried to develop the strategy to maximize production plateau based on data from Umm Gudair oil field. They suggested that the major cause of decline rate was lack of reservoir pressure support such as water injection. Surface water injection and water dumpflood were compared. The result showed that water dumpflood was more economic. Thus, a simulation study was conducted to design the best water dumpflood scenario. Three categories of wells were drilled: production infill, water-dumping and water disposal. The optimized numbers of each kind were found to be 38 infill wells, 16 water-dumping wells and 6 disposal wells which extended oil plateau length to 11 years from 4.5 years for conventional production. From simulation runs, the author obtained the optimum dumpflood injection rate required to maintain the reservoir pressure and efficiently swept the oil to be 450-550 MBWPD. The surveillance plan was implemented in order to monitor the water injection rate with PLTs installed in the dumpflood injection well.

Lertsakulpasuk [14] studied a new method to increase gas recovery in multiple low-pressure reservoirs by dumping water from a large aquifer located above and below target reservoirs. The author studied several parameters hypothesized to affect the gas recovery by performing reservoir simulation using ECLIPSE100. The parameters are water dumpflood triggering condition, minimum wellhead pressure, well pattern, depth difference between gas reservoirs and aquifer, size of water aquifer and dip angle. The result shows that water dumpflood can yield the incremental recovery factor compared to natural depletion in the range of 0.9% – 10.5%. when the minimum well head pressure of 500 psia is set. On the other hand, setting the minimum well head pressure at 150 psia results in small incremental recovery or negative increment compared with natural depletion case. In addition, dumping water when gas rate starts to drop from the plateau rate can shorten production time while yielding the same recovery factor with the case that water is dumped when the gas rate approaches the economic rate.

CHAPTER 3
THEORY AND CONCEPT

Important theories and concepts related to the thesis topic are summarized in this chapter. The content is mainly about the explanation of phenomenon and discussion of concerns in performing the proposed method, Downhole Water Drain from Bottom Water-Drive Gas Reservoir into Partially Depleted Gas Reservoir (DWD).

3.1 Water influx

For bottom water-drive gas reservoirs, water influx occurs when the reservoir pressure reduces after being produced for some time due to expansion of aquifer water into the reservoir. The simplest model used to estimate the water influx is called "Pot Aquifer Model". This model is based on the basic definition of compressibility. Reduction in the reservoir pressure, due to the production of fluids, causes the aquifer water to expand and flow into the reservoir. Volumetric expansion due to compressibility can be written as Equation (3.1)

$$\Delta V = cV\Delta P \tag{3.1}$$

Applying the above basic compressibility definition to the aquifer gives:

$$W_e = \left(c_w + c_f\right)W_i(P_i - P) \tag{3.2}$$

where

W_e = cumulative water influx, bbl

c_w = aquifer water compressibility, psi^{-1}

c_f = aquifer rock compressibility, psi^{-1}

W_i = initial volume of water in the aquifer, bbl

P_i = initial reservoir pressure, psi

P = current reservoir pressure (pressure at GWC), psi

In this equation, W_i is the critical parameter that requires an appropriate adjustment until a unit slope is obtained in material balance plot. Note that this equation is applicable to small aquifers where expansion of water is more or less instantaneous such as the thin bottom aquifer assumed in our case. The DWD method proposed in this study can drain out the water from bottom aquifer in the upper reservoir which reduces total amount of water or W_i in Equation (3.2)

3.2 Water coning

As mentioned in Section 2.1, water coning is the major problem in Gulf of Thailand gas well operation. One method to avoid this problem is to partially perforate above the GWC to delay water production. The other method is to produce gas below "critical rate" such that the water cone can steadily exist below the nearest gas perforation in which desired single-phase gas production could be extended. At rates equal to or greater than the critical rate, the water will eventually be produced, and the water rate will increase with time. The calculated critical rate is valid only for a certain fixed gap between the fluid contact and the perforations which is eventually reduced with time. Though there are several proposed equations for calculating critical rate, the most popular method was proposed by Chaney et al. [15] in 1956. For vertical wells in gas-water system, he proposed the method to calculate the critical gas rate as Equation (3.3)

$$Q_{gc} = 0.5288 \times 10^{-4} \left[\frac{k_g(\rho_w - \rho_g)}{\mu_g B_g}\right] Q_{curve} \tag{3.3}$$

where

ρ_g = gas density, lb/ft3

ρ_w = water density, lb/ft3

Q_{gc} = critical gas flow rate, MSCF/D

μ_g = gas viscosity, cp

B_g = gas FVF, bbl/MSCF

k_g = effective gas permeability, md

Q_{curve} = hypothetical rates as determined from the Chaney et al. [15] curves

Note that Q_{curve} has to be corrected to account for the actual reservoir rock and fluid properties. From the above correlation, whether a cone will move toward perforations depends on the relative impact of viscous and gravitational forces near the well. The pressure drawdown as a result of viscous force at the perforations is likely to cause the water to move toward the perforations while gravitational force is likely to cause the water to stay away from the perforations. Coning occurs when the viscous forces dominate.

The variables that could affect coning are:

- Density (gravitational forces) differences between water and oil, gas and oil, or gas and water
- Fluid viscosities and relative permeability
- Vertical and horizontal permeability
- Distances from contacts to perforations

3.3 Water dumpflood

Water dumpflood requires active aquifer as a source of underground water. If the source aquifer is located above the target gas reservoir, gravity is the main driving force to push water into the gas reservoir. If the source aquifer is below target gas reservoir, pore pressure is the main driving force instead, due to overburden pressure gained with depth. The increase in gas recovery from water dumpflood could be explained by modified material balance equation as shown in Equation (3.4)

$$G_p B_g + W_p B_w = G\left(B_g - B_{gi}\right) + W_e \tag{3.4}$$

where

B_g = gas formation volume factor, RB/SCF

B_{gi} = initial gas formation volume factor before water dumpflood, RB/SCF

B_w = water formation volume factor, RB/STB

G = gas in place before water dumpflood, SCF

G_p = cumulative gas production during water dumpflood, SCF

W_e = water influx into the reservoir, bbl

W_p = cumulative water production, STB

In this case, W_e represents water injected into gas reservoir from water dumpflood. As a consequence, cumulative gas production can be increased. Water dumpflood can enhance gas recovery by two mechanisms: pressure maintenance and gas displacement. However, the invasion of water also causes a negative effect on gas recovery as a certain amount of gas is trapped in the water-flooded zone.

3.4 Water injectivity

The success of water dumpflood depends on aquifer size and aquifer pressure which should have potential to supply enough pressure for water to flow into the gas reservoir. In our case, water is dumpflooded into a nearly depleted gas reservoir which is at low pressure already. Equation (3.5) expresses the relationship between injection pressure and injection flowrate.

$$P_{inj} - \overline{P_r} = 141.2 \frac{q_{inj} B_w \mu_w}{k k_{rw} h} \left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s \right] \tag{3.5}$$

where

$\overline{P_r}$ = average reservoir pressure, psi

P_{inj} = well injection pressure, psi

k = absolute permeability, mD

k_{rw} = relative permeability to water

q_{inj} = water injection rate, bbl/D

μ_w = water viscosity, cp

r_e = well's drainage radius, ft.

S = skin

B_w = water formation volume factor, RB/STB

h = reservoir thickness, ft.

3.5 Mobility ratio

Mobility ratio has strong influence on waterflooding in gas reservoir due to difference in mobility between water and gas. The mobility of a fluid is defined as its relative permeability divided by its viscosity. Mobility combines a rock property, permeability, with a fluid property, fluid viscosity. Gas-water relative permeability is dependent on the saturations of the two fluid phases and assumed to be independent of fluid viscosity. A fluid mobility relates to its flow resistance in a reservoir rock at a certain saturation of that fluid. For our case, gas has high mobility relative to water because gas viscosity is relatively low. Mobility ratio is defined in Equation (3.6)

$$M = \left(\frac{k_{rw}}{k_{rg}}\right)\left(\frac{\mu_g}{\mu_w}\right) \tag{3.6}$$

where

M = mobility ratio

k_{rw} = relative permeability to water

k_{rg} = relative permeability to gas

μ_g = gas viscosity, cp

μ_w = water viscosity, cp

If $M \leq 1$, gas is traveling with a velocity equal to or greater than water. There is no tendency for viscous fingering which is favorable.

If $M > 1$, water is traveling faster than gas. Some gas will be by-passed by viscous fingering which is unfavorable. However, this condition is not likely because gas viscosity is much lower than water viscosity.

3.6 Gas displacement efficiency

One of the mechanisms that increase gas recovery by waterflooding is water displacing gas. Displacement efficiency indicates how efficient water can displace gas in the reservoir. The displacement efficiency is a portion of movable gas that is displaced from the swept zone at any given time or pore volume injected. Displacement efficiency can be calculated as shown in Equation (3.7)

$$E_D = \frac{\frac{S_{gi}}{B_{gi}} - \frac{S_g}{B_g}}{\frac{S_{gi}}{B_{gi}}} \tag{3.7}$$

where

E_D = displacement efficiency

S_{gi} = initial gas saturation

S_g = current gas saturation

B_g = gas formation volume factor, RB/SCF

B_{gi} = initial gas formation volume factor before water dumpflood, RB/SCF

3.7 Volumetric sweep efficiency

Volumetric sweep efficiency is ability of injected fluid to displace fluid in the reservoir which depends on the contact volume between reservoir and the injected fluid. The volumetric sweep efficiency is a general result depending on many variables: injection pattern, off-pattern wells, fractures in the reservoir, position of gas-oil and oil/water contacts, reservoir thickness, permeability and areal and vertical heterogeneity, mobility ratio, density difference between the displacing and the displaced fluid, and flow rate. Volumetric sweep efficiency can be calculated as shown in Equations (3.8) - (3.10)

$$E_V = E_I \times E_A \tag{3.8}$$

$$E_A = \frac{Area\ contact\ by\ displacing\ phase}{Total\ area} \tag{3.9}$$

$$E_I = \frac{Cross\ section\ area\ connected\ by\ displacing\ agent}{Total\ cross\ section\ area} \tag{3.10}$$

where

E_A = areal sweep efficiency

E_I = vertical sweep efficiency

E_V = volumetric sweep efficiency

3.8 Pressure maintenance by waterflooding

Waterflooding can decelerate reservoir pressure depletion due to water injected into the reservoir. Gas production rate can be maintained at a plateau level for a longer time or decelerated the declining rate. In our case, the lower dry gas reservoir is partially depleted prior to dumpflood from the upper aquifer. Thus, the pressure in the reservoir can vary from time to time. The proper solution for any range of pressure is to use pseudo-pressure approach. According to Equation (3.11), as average reservoir pseudo pressure increases, gas flow rate increases correspondingly.

$$Q_g = \frac{kh(\bar{\psi}_r - \psi_{wf})}{1422T\left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right]} \tag{3.11}$$

where

Q_g = gas flow rate, MSCF/day

k = permeability, md

$\overline{\psi_r}$ = pseudopressure computed at average reservoir pressure, PSI^2/cp

ψ_{wf} = pseudopressure computed at flowing sand face pressure, PSI^2/cp

T = temperature, °R

s = skin factor

h = thickness, ft.

r_e = drainage radius, ft.

r_w = wellbore radius, ft.

Note that pseudopressure can be calculated from Equation (3.12)

$$\psi_p = 2\int_{p_0}^{p} \frac{p}{\mu_g z} dp \tag{3.12}$$

where

ψ_p = pseudopressure calculated at pressure p, PSI^2/cp

p_0 = reference pressure, psi

p = current pressure, psi

μ_g = gas viscosity, cp

z = gas compressibility factor

3.9 Gas recovery

In most of the dry gas reservoirs, bulk volume of gas underground is not known during pre-production period. The best method prevalently used to predict gas in place is volumetric estimation. Equation (3.13) shows how to calculate initial gas in place in the unit of SCF/acre-ft.

$$G = \frac{43{,}560\phi(1 - S_w)}{B_{gi}} \tag{3.13}$$

For reservoirs under volumetric control, there is no change in the interstitial water, the gas volume at reservoir condition remains the same. Thus, at abandonment pressure, gas in place in the unit of SCF/acre-ft. can be expressed as Equation (3.14)

$$G_a = \frac{43{,}560\phi(1 - S_w)}{B_{ga}} \tag{3.14}$$

The unit recovery, in unit of SCF/acre-ft., is the difference between gas in place at initial condition and gas in place at abandoned condition which is expressed in equation (3.15)

$$Unit\ recovery = 43{,}560\phi(1 - S_w)\left[\frac{1}{B_{gi}} - \frac{1}{B_{ga}}\right] \tag{3.15}$$

The unit recovery is also called initial unit reserve which is generally lower than initial unit gas in place. At any stage in the production period, initial unit reserve is different depending on the current reservoir pressure. The recovery factor is then the ratio between unit recovery and initial unit reserve as shown in Equation (3.16)

$$recovery\ factor = \frac{\left[\frac{1}{B_{gi}} - \frac{1}{B_{ga}}\right]}{\frac{1}{B_{gi}}} \tag{3.16}$$

Recovery factor in the water-drive gas reservoir is a bit different from dry gas reservoir though they are derived in the same manner. The formula for calculating recovery factor for water-drive gas reservoir is derived as shown in equation (3.17)

$$recovery\ factor = \frac{\left[\frac{1-S_{wi}}{B_{gi}} - \frac{S_{gr}}{B_{ga}}\right]}{\frac{1-S_{wi}}{B_{gi}}} \tag{3.17}$$

where

B_{gi} = initial formation volume factor of gas, RB/SCF

B_{ga} = abandoned formation volume factor, RB/SCF

S_{wi} = initial water saturation in gas reservoir

S_{gr} = residual gas saturation in gas reservoir

3.10 Relative permeability

Relative permeability is the ability of fluid to flow in porous media in the environment of multi-fluid system. For example, in the reservoir containing gas, water and oil, relative permeability of each fluid is not the same as absolute permeability of each fluid in single-fluid system. Relative permeability to the fluid starts from zero at low fluid saturation and keeps increasing to one as the fluid saturation approaches 100%. Relative permeability is defined as the ratio of effective permeability to any particular fluid at a given saturation to the absolute permeability. In the gas-oil-water system, relative permeability to each fluid is defined as Equation (3.18) - (3.20)

$$k_{rg} = \frac{k_g}{k} \tag{3.18}$$

$$k_{ro} = \frac{k_o}{k} \tag{3.19}$$

$$k_{rw} = \frac{k_w}{k} \tag{3.20}$$

There are several correlations developed for gas reservoir which has two-phase permeability, gas and water. Corey [16] is one of the famous correlations used for generating data of the gas-water system which is also used in ECLIPSE100. Corey [16] proposed that the gas-water relative permeability can be calculated as shown in Equations (3.21) - (3.22)

$$k_{rw} = k'_{rw}\left(\frac{S_w - S_{wc}}{1 - S_{gr} - S_{wc}}\right)^{n_w} \tag{3.21}$$

$$k_{rg} = k'_{rg}\left(\frac{S_g - S_{gr}}{1 - S_{gr} - S_{wc}}\right)^{n_g} \tag{3.22}$$

where

k_{rg} = relative permeability to gas

k_{rw} = relative permeability to water

k'_{rg} = relative permeability to gas at connate water saturation

k'_{rw} = relative permeability to water at residual gas saturation

S_g = gas saturation

S_w = water saturation

S_{gr} = residual gas saturation

S_{wc} = connate water saturation

n_g = Corey gas exponent

n_w = Corey water exponent

3.11 Fracture pressure

One important consideration for water injection or water dumpflood is fracture pressure. The injecting water pressure should not exceed formation fracture pressure in order to avoid fracture propagation in the target reservoir. Fracture pressure can be calculated using Eaton's approach [17] as shown in Equations (3.23) - (3.25)

$$P_p = \sigma_o - \sigma_v \tag{3.23}$$

$$\overline{\sigma_H} = \left(\frac{\gamma}{1+\gamma}\right)\sigma_v \tag{3.24}$$

$$P_f = \overline{\sigma_H} + p_p \tag{3.25}$$

where

P_p = pore pressure, psi

P_f = fracture pressure, psi

γ = Poisson's ratio

σ_o = vertical overburden stress, psi

$\overline{\sigma_H}$ = average horizontal matrix stress, psi

σ_v = vertical matrix stress, psi

In Gulf of Thailand, the fracture pressure of the M field can be calculated using correlations [18] defined in Equations (3.26) - (3.27).

$$Fracture\ pressure = \frac{FRAC.S.G.\times TVD}{10.2} \tag{3.26}$$

$$FRAC.S.G. = 1.22 + (TVD \times 1.6 \times 10^{-4}) \tag{3.27}$$

where

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

TVD = true vertical depth below rotary table, meter

3.12 Liquid loading

Liquid loading is one of the main causes that terminates gas production from water-drive gas reservoir. In dry gas reservoir, gas is produced with zero WGR throughout the production period. Thus, its tubing performance relationship (TPR) is the increasing function for the whole range of flow rate as characterized by the red line in Figure 3.1.

In water-drive gas reservoir, gas is produced with zero WGR at first but WGR keeps increasing after water breakthrough due to decreasing proportion of gas to water inside the reservoir and rising of GWC around the wellbore. Producing with WGR>0, TPR is shifted higher because water-gas mixture column is heavier than pure gas column which results in higher BHP requirement at the same flow rate. Moreover, the TPR behaves as decreasing function at the range of low flow rate because some water is not carried up to the surface and partially loads up the well. In the decreasing trend, the lower the flow rate, the lower lifting velocity, the higher amount of water accumulates and thus, the higher BHP is required. The explained TPR is characterized by the blue line in Figure 3.1. In this case, the well dies at relatively high rate when the IPR crosses at the minimum point of TPR in which the phenomenon is so called “liquid loading”.

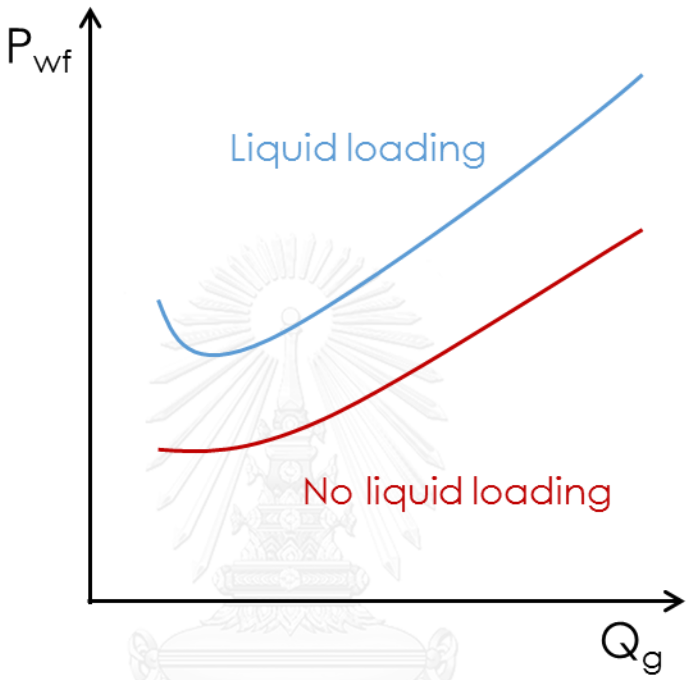

Figure 3.1 Tubing performance curve (TPR) with/without liquid loading

3.13 Minimum lifting velocity

In a gas well producing with some WGR, water usually accumulates at bottom hole when the gas flow rate drops to a certain value. The point at which liquid begins to accumulate or the minimum gas-producing rate required to keep the well unloaded is called “minimum lifting velocity”. Turner et al. [19] presented the well-known equation used to estimate “minimum lifting velocity” in a well producing gas with some water as shown in Equation (3.28). The Turner method was originally suggested to be applicable for LGR less than 130 bbl/MMSCF, but has been found to provide good result for rate as high as 250 bbl/MMSCF.

$$v_{min} = \frac{5.62(67 - 0.0031P_{wh})^{0.25}}{(0.0031P_{wh})^{0.5}} \quad (3.28)$$

where

v_{min} = minimum lifting velocity, ft./sec

P_{wh} = wellhead flowing pressure, psia

3.14 Multiphase flow in vertical pipe

During petroleum production, it is common to encounter multiphase flow in production tubing and surface pipelines. In the study, water and gas are produced simultaneously in some cases which is considered as upward multiphase phase flow in vertical pipe.

In order to determine pressure drop inside the tubing correctly, flow regime must be identified first. Flow regime is the qualitative description of the phase distribution inside tubing. For gas-liquid vertical upward flow, there are 4 flow regimes which are generally accepted among the two-phase flow literatures: bubble flow, slug flow, churn flow and annular flow. A brief description of these flow regime is provided in the textbook [20] as follows:

1) Bubble flow: dispersed bubble of gas in a continuous liquid phase
2) Slug flow: At higher gas rates, the bubbles coalesce into larger bubbles, called Taylor bubbles that eventually fill the entire pipe cross section, between the large gas bubbles are slugs of liquid that contain smaller bubbles of gas entrained in the liquid.
3) Churn flow: With a further increase in gas rate, the larger gas bubbles become unstable and collapse, resulting in churn flow, a highly turbulent flow pattern with both phase dispersed. Churn flow is characterized by oscillatory, up-and-down motions of liquid.
4) Annular flow: At higher gas rates, gas becomes the continuous phase, with liquid flowing in an annulus coating the surface of the pipe and with liquid droplets entrained in the gas phase.

Determination of flow regime mainly depends on its liquid and gas superficial velocities. Each flow regime is illustrated in Figure 3.2.

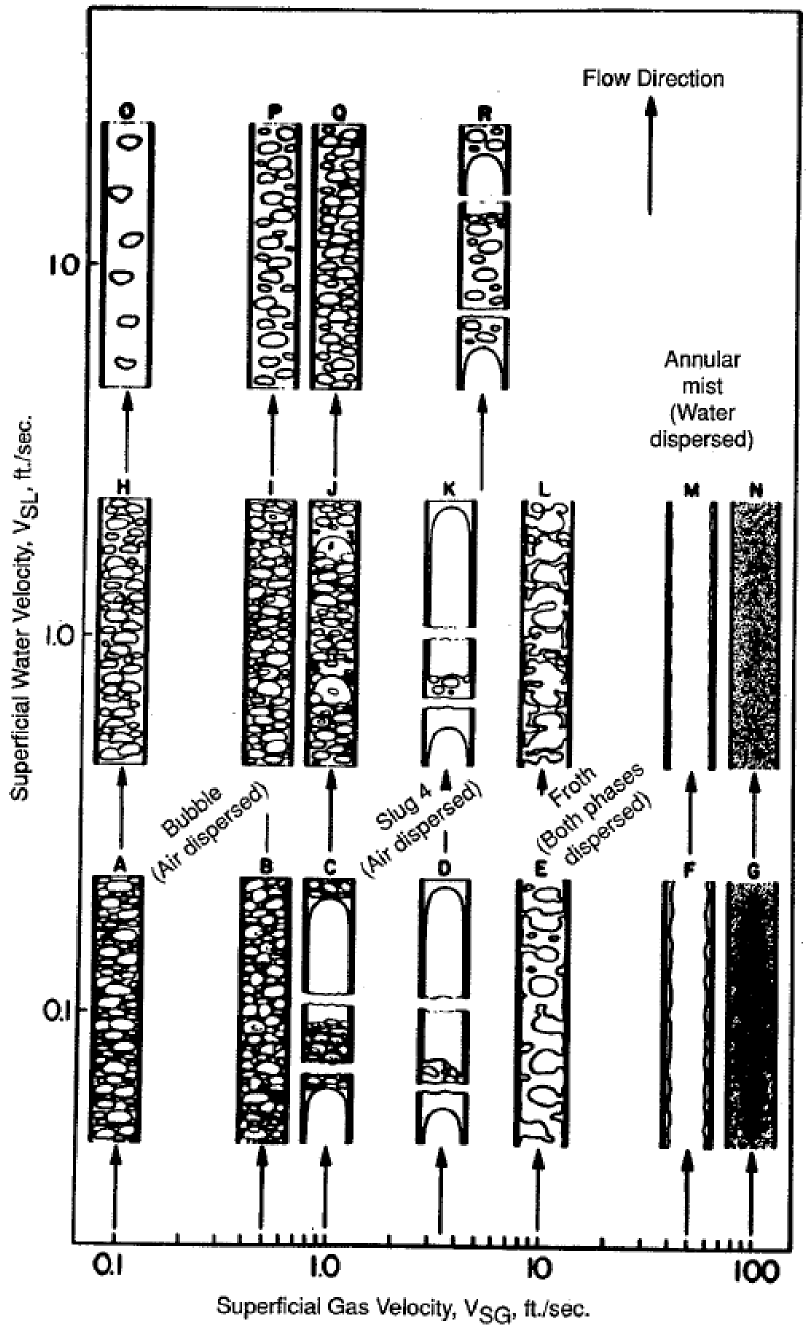

Figure 3.2 Flow regime in gas-liquid flow [20]

CHAPTER 4
RESERVOIR SIMULATION MODEL

The static hypothetical reservoir model was created using a reservoir simulator. ECLIPSE100 or “Black Oil Model” was used to evaluate the performance of different production scenarios of the water-gas reservoir system. The ECLIPSE reservoir model can be defined within five main sections: case definition, grid section, fluid properties, Special Core Analysis and production schedule. All the setting parameters belong to the three base case models: commingled production, bottom-up production and Downhole Water Drain from Bottom Water-Drive Gas Reservoir into Partially Depleted Gas Reservoir (DWD). Setting parameters for other cases are explained in words in detail of methodology in this chapter.

4.1 Case definition

Simulator	Black Oil (ECLIPSE100)
Unit	Field
Simulation start date	1 Jan 2015
Number of cells in the x-direction	25
Number of cells in the y-direction	50
Number of cells in the z-direction	55
Grid type	Cartesian, Block-centered
Fluid properties:	Water and gas

4.2 Grid

A hypothetical model was created using Cartesian coordinate under simple rectangular shape and homogeneous conditions. The model consists of 50 ft. of bottom water-drive gas reservoir located at shallow depth and 20 ft. of dry gas reservoir located at a deeper location underneath. Drainage area of each reservoir is 4.5 million sq. ft. resulting from 1,500 ft. in width and 3,000 ft. in length. Top depths of the upper and lower reservoirs are 6,000 ft. and 7,000 ft., respectively. The thickness of shale layer located between the two reservoirs is 950 ft. The picture of reservoir model is illustrated in *Figure 4.1*. Porosity and permeability were obtained from typical values of a gas field in the Gulf of Thailand.

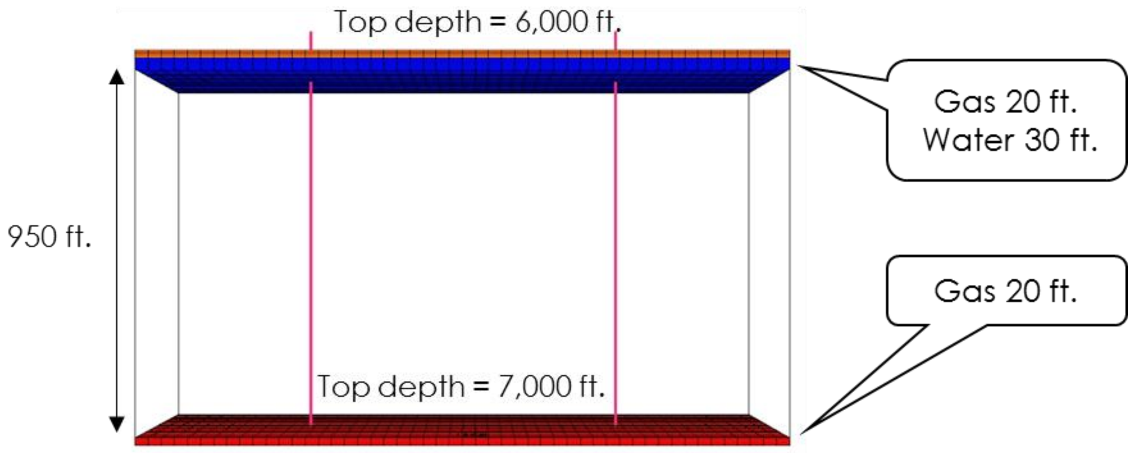

Figure 4.1 The picture of reservoir model

Grid sizes in the x-direction and y-direction were set at 60 ft. equally for both upper and lower reservoirs. Grid size in the z-direction was set at 5 ft. for the lower reservoir but it was set at 1 ft. for the upper reservoir in order to capture movement of GWC and water coning phenomenon. Porosity and permeability for both reservoirs were assumed to be homogeneous. Details of grid properties and geometry are summarized in *Table 4.1*.

Table 4.1 Grid properties and geometry

Parameters	Bottom water-drive gas reservoir		Dry gas reservoir
	Gas column	Water column	
Top depth (ft.)	6,000	6,020	7,000
Number of grids in x,y,z	25 x 50 x 20	25 x 50 x 30	25 x 50 x 4
Grid size in x,y,z (ft.)	60 x 60 x 1	60 x 60 x 1	60 x 60 x 5
Dimension in x,y,z (ft.)	1500 x 3000 x 20	1500 x 3000 x 30	1500 x 3000 x 20
Porosity (%)	20	20	20
Horizontal permeability (mD)	150	150	150
Vertical permeability (mD)	15	15	15
Initial water saturation (%)	53	100	49.1
Shale thickness (ft.)	950		
Drainage area (ft.^{2})	4,500,000		

4.3 PVT

In this study, there are only two fluids, water and gas, flowing in the system. Gas specific gravity was set at 0.92 which is the average value from a gas field in Gulf of Thailand. Consolidated sandstone was chosen as reservoir rock type. Fluid properties were calculated at different pressures and temperatures using a set of correlations integrated inside ECLIPSE itself. Formation pressure and temperature were manually calculated. Normal pressure gradient of 0.433 psi/ft. was used in formation pressure calculation. Temperature gradient was taken from a gas field in Gulf of Thailand as shown in Equation (4.1).

$$T = 5.755\left(\frac{D}{100}\right) + 30 \tag{4.1}$$

where

T = temperature at certain depth D, °C

D = depth, m

Fluid properties for each reservoir are summarized in *Table 4.2*. The generated gas viscosity and formation volume factor for each reservoir are plotted in *Figure 4.2* and *Figure 4.3*.

Table 4.2 Fluid properties

Parameters	Bottom water-drive gas reservoir	Dry gas reservoir
Properties at surface condition		
Gas specific gravity	0.92	
Gas density (lb./cu.ft.)	0.0574	
Water density (lb./cu.ft.)	62.4	
Pressure (psia)	14.7	
Temperature (°F)	60	
Properties at reservoir conditions		
Water FVF (RB/STB)	1.053	1.068
Water compressibility (psi^{-1})	3.693×10^{-6}	3.755×10^{-6}
Water viscosity (cp)	0.208	0.184
Water viscosibility (psi^{-1})	8.508×10^{-6}	9.529×10^{-6}
Pressure (psia)	2612.7	3045.7
Temperature (°F)	275.45	307.02

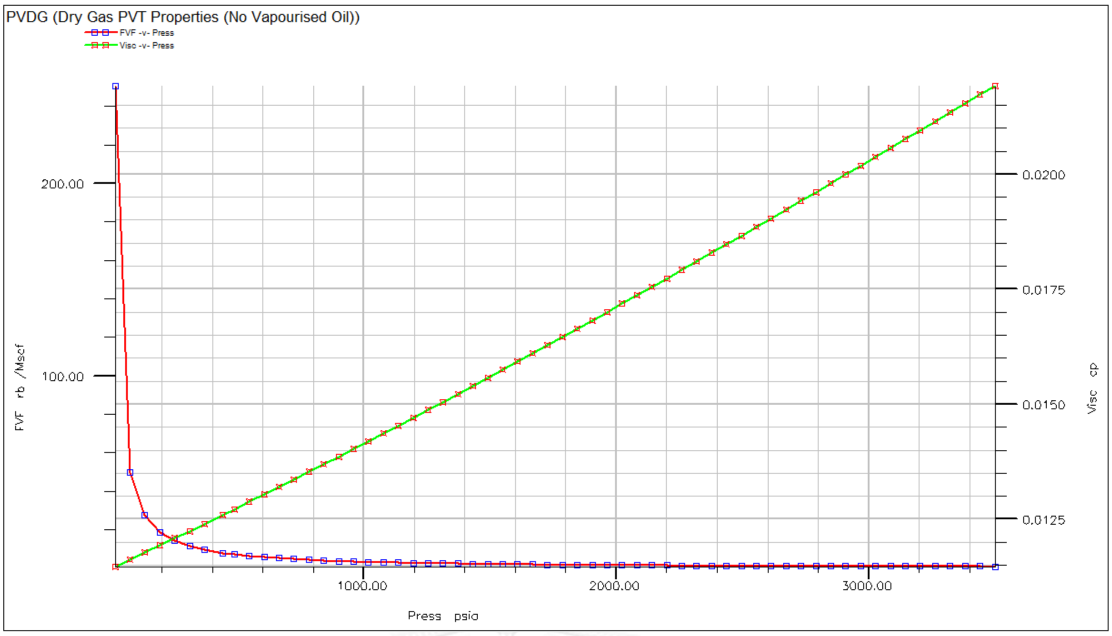

Figure 4.2 FVF and viscosity plots of the upper water-drive gas reservoir

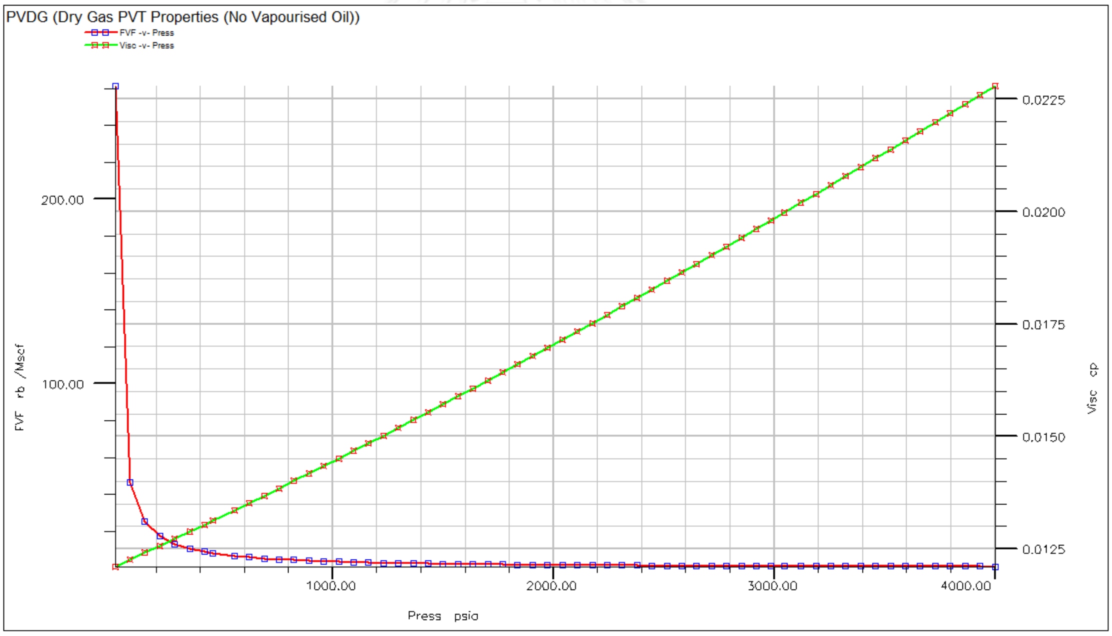

Figure 4.3 FVF and viscosity plots of the lower dry gas reservoir

4.4 Special Core Analysis

Special Core Analysis (SCAL) section allows users to construct relative permeability between reservoir fluids which are water and gas in this case. Corey's correlation embedded inside ECLIPSE was used to generate relative permeability curves as shown in Equation (3.21) and Equation (3.22). Both upper and lower reservoirs share the same set of relative permeability curves. Input parameters used in generating the relative permeability curves are shown in *Table 4.3*. The plots of relative permeability as a function of gas saturation for each reservoir are depicted in *Figure 4.4*.

Table 4.3 Input parameters for Corey's Correlation

Parameters	Value
Corey Gas exponent	3
Corey Water exponent	3
$S_{g,min}$	0.1
$S_{w,min}$	0.5
$S_{w,cr}$	0.5
S_{wi}	0.5
k_{rw}@$S_{g,min}$	0.3
k_{rg}@$S_{g,max}$	0.6
k_{rw}@100%S_w	1

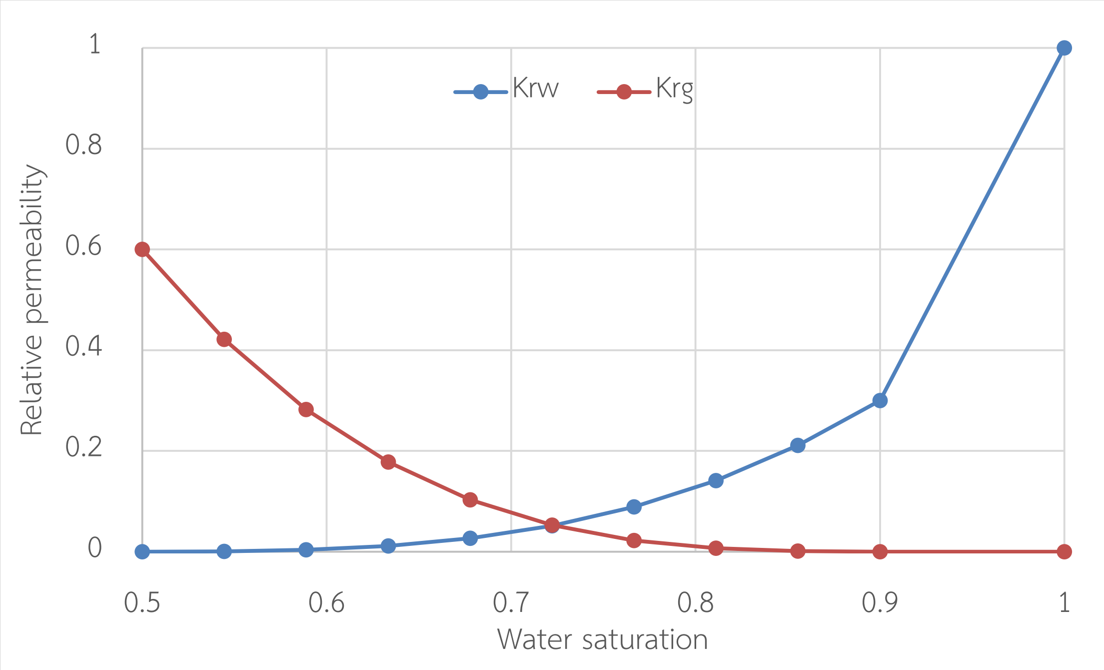

Figure 4.4 Gas/water relative permeability curve

4.5 Production schedule

Three production scenarios were simulated: commingled production, bottom-up production and DWD. The first two conventional methods were created for comparison purpose. Both conventional methods are popular production methods which are currently used in Gulf of Thailand. All three scenarios share the same reservoir model described in Section 4.1 - Section 4.4. Two vertical production wells, PROD1 and PROD2, are drilled at (13,13) and (13,38) respectively for all production scenarios as shown in *Figure 4.5*.

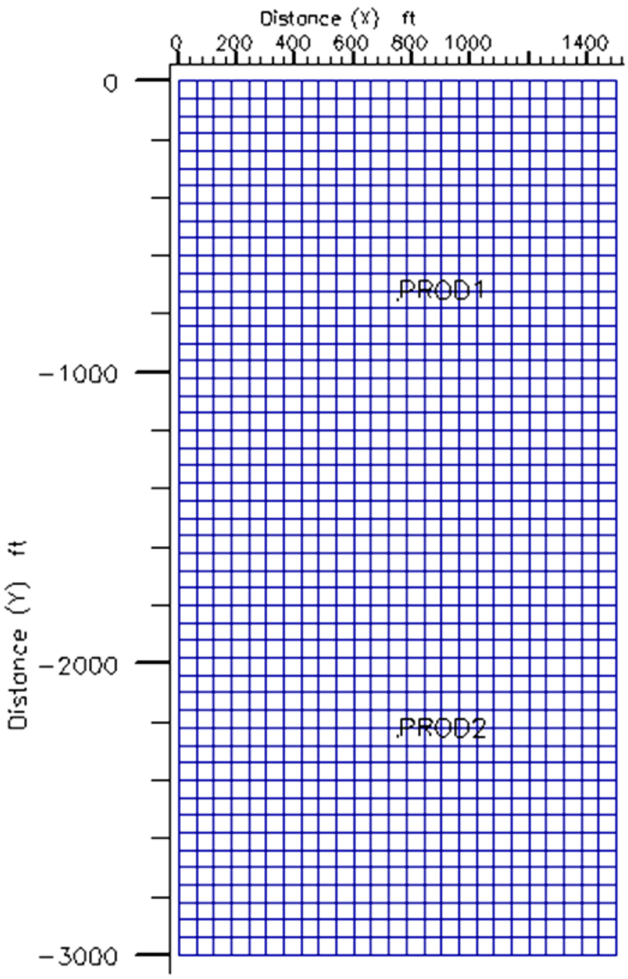

Figure 4.5 Locations of well PROD1 and well PROD2

The minimum THP was controlled at 500 psia assuming that no booster compressor was installed on the platform. Wellbore ID of 6 1/8 in. and tubing ID of 2.441 in. were used with cased-hole completion. Tubing roughness of 0.00015 ft. was used. Gas production rate is controlled at the beginning until minimum THP of 500 psia is reached. The economic limit of each well was set at 500 MSCF/day. PROSPER software was used to model vertical flow performance (VFP) of PROD1 and PROD2 by providing table of BHP values at various production rates under varying THP and WGR in which Gray's correlation was selected because it generally gives practical results for gas wells. In addition, there is an imaginary well named DUMP1 added at the same x and y location as PROD1 for the purpose of simulating dumflood action in DWD only. DUMP1 serves as part of the tubing which connects water column of the upper reservoir to the lower reservoir which is physically the same well with PROD1. Well specification and well control data are summarized in *Table 4.4*.

Table 4.4 Well specification and well control data

Parameters	Well PROD1	Well PROD2
I Location	13	13
J Location	13	38
Well production control	Gas rate	Gas rate
Minimum THP (psia)	500	500
Wellbore ID (ft.)	0.5104	0.5104
Well economic limit (MSCF/day)	500	500

4.5.1 Commingled production

In commingled production, the two reservoirs are perforated at the same time, and gas is produced from the two wells until the economic rate is reached. Producing from multiple reservoirs at the same time can deplete reservoirs with less time, thus reducing operating cost and also boosting up the flow rate. However, its drawback is crossflow of gas from the higher-pressure reservoir into the lower-pressure reservoir. Thus, a low overall recovery factor may be obtained.

4.5.2 Bottom-up production

. In bottom-up production, the lower reservoir is perforated and gas is produced from the two wells until the economic limit. Then, the lower zone is plugged, and the upper reservoir is perforated for both wells. Gas is produced until the economic rate is reached. In general for gas fields, producing from a lower reservoir first can help reduce crossflow of gas such that overall R.F. increases and offer better water control by plugging lower reservoir after water breakthrough if the lower reservoir is water-drive. However, its drawback is longer time to deplete all the reservoirs.

4.5.3 DWD

DWD is the new method proposed as a better alternative to produce from a gas field with multiple stacks of gas reservoirs like Gulf of Thailand. In this method, no additional well is required but only some modifications of completion, perforation sequence and well intervention are needed. In DWD scenario set in this study, two wells are used to produce from the lower reservoir until a certain rate is reached. Then, one well is shut in for additional completion. The upper gas column is partially perforated as well as the water zone. The perforation of the water zone allows water to crossflow into the lower partially depleted gas reservoir. Then, that well is re-opened to produce from the upper reservoir until both wells reach the economic rate. Schematic diagram of DWD is shown in *Figure 4.6*.

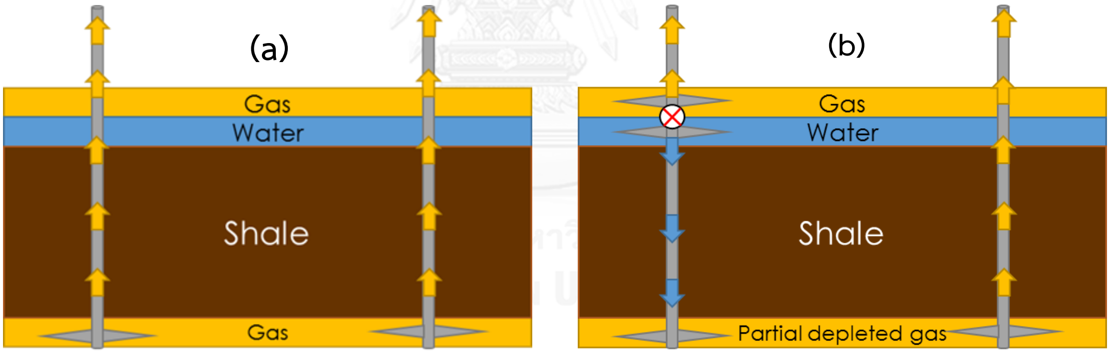

Figure 4.6 Schematic diagram of DWD. (a) In the first phase, production comes from both wells completed in the lower gas reservoir. (b) In the second phase, the well on the left is perforated in the upper reservoir in both gas and water zones for water draining and dumpflood.

4.6 Detail of methodology

1) Construct static base case model to simulate system of reservoirs in a field. The upper reservoir is bottom water-drive gas reservoir. The lower reservoir is dry gas reservoir.

2) Simulate three production scenarios with the same system of reservoirs created in the first step but vary operational parameters in order to examine their effects
   a) Commingled production as displayed in *Table 4.5*
   b) Bottom-up production as displayed in *Table 4.6*
   c) DWD as displayed in *Table 4.7 - Table 4.9*

Table 4.5 Varied operational parameters for commingled production

Gas perforation interval from top (ft.)	**Controlled initial production rate (MMSCF/day)**
15	Max potential
	10
	5
10	Max potential
	10
	5
5	Max potential
	10
	5

Table 4.6 Varied operational parameters for bottom-up production

Gas perforation interval from top (ft.)	**Controlled initial production rate (MMSCF/day)**
15	Max
	10
	5
10	Max
	10
	5
5	Max
	10
	5

Table 4.7 Varied operational parameters for DWD (1)

Gas perforation interval from top (ft.)	**Water perforation interval (ft.)**	**Controlled initial production rate (MMSCF/day)**	**Well trigger rate for dumpflood**
15	20	Max potential	Half of initial rate
			1 MMSCF/day
		10	Below plateau rate
			Half of initial rate
			1 MMSCF/day
		5	Below plateau rate
			Half of initial rate
			1 MMSCF/day
	10	Max potential	Half of initial rate
			1 MMSCF/day
		10	Below plateau rate
			Half of initial rate
			1 MMSCF/day
		5	Below plateau rate
			Half of initial rate
			1 MMSCF/day

Table 4.8 Varied operational parameters for DWD (2)

Gas perforation interval from top (ft.)	**Water perforation interval (ft.)**	**Controlled initial production rate (MMSCF/day)**	**Well trigger rate for dumpflood**
10	20	Max potential	Half of initial rate
			1 MMSCF/day
		10	Below plateau rate
			Half of initial rate
			1 MMSCF/day
		5	Below plateau rate
			Half of initial rate
			1 MMSCF/day
	10	Max potential	Half of initial rate
			1 MMSCF/day
		10	Below plateau rate
			Half of initial rate
			1 MMSCF/day
		5	Below plateau rate
			Half of initial rate
			1 MMSCF/day

Table 4.9 Varied operational parameters for DWD (3)

Gas perforation interval from top (ft.)	**Water perforation interval (ft.)**	**Controlled initial production rate (MMSCF/day)**	**Well trigger rate for dumpflood**
5	20	Max potential	Half of initial rate
			1 MMSCF/day
		10	Below plateau rate
			Half of initial rate
			1 MMSCF/day
		5	Below plateau rate
			Half of initial rate
			1 MMSCF/day
	10	Max potential	Half of initial rate
			1 MMSCF/day
		10	Below plateau rate
			Half of initial rate
			1 MMSCF/day
		5	Below plateau rate
			Half of initial rate
			1 MMSCF/day

3) Select three best cases, one from each production scenario, prioritizing from highest R.F., lowest water production and shortest production time, respectively. Then, simulate the three selected cases under various reservoir conditions in order to evaluate the performance as displayed in *Table 4.10*

Table 4.10 Varied reservoir parameters for simulating the three selected cases

Varied reservoir parameter	**Value**
Thickness of water column of the upper reservoir	15 ft.
	30 ft. (base case)
	60 ft.
Thickness of gas column of the lower reservoir	10 ft.
	20 ft. (base case)
	40 ft.
Top depth of the lower reservoir	6,500 ft.
	7,000 ft. (base case)
	9,000 ft.
Vertical to horizontal permeability ratio	0.01
	0.1
	0.5
Horizontal permeability	75 mD
	150 mD (base case)
	300 mD

4) Analyze the results from simulations and discuss the results

CHAPTER 5
SIMULATION RESULTS AND DISSUSION

This chapter discusses results from all the 96 cases described in Chapter 4. The order of discussion will follow the methodology: 1) effects from operational parameter and 2) effects from reservoir parameters.

For the discussion on effects from operational parameters, each production scenario is first discussed one by one. After that, comparison among different production scenarios is discussed. In the first part, a total of 66 simulation cases were run: 9 cases for commingled production, 9 cases for bottom-up production, and 48 cases for DWD. Then, the logic in selecting the best case from each production scenario, which is carried on to be used in the next part, is mentioned.

For the discussion on effects from reservoir parameters, each production scenario is first discussed one by one. After that, the discussion is comparison among different production scenarios. In the second part, a total of 30 simulation cases were run: 10 cases for each production scenario. At the end, favorable reservoir conditions for performing DWD technique are summarized.

5.1 Base cases for the three production scenarios

Examples of gas production profiles of the three production scenarios are illustrated in Figure 5.1 and Figure 5.2, respectively. For all the scenarios, 15 ft. out of 20 ft. of the gas zone is perforated, and the well initial production rate is controlled at 10 MMSCF/day. For DWD, the water column is perforated for 20 ft. out of 30 ft. and dumpflood starts when the field gas rate falls below the field plateau rate of 20 MMSCF/day.

The plateau gas rate in the commingled production case can be maintained for the shortest period compared to the other two cases because of early water invasion into the wells (as shown in Figure 5.2). Then, the gas rate declines with a consistent trend until abandonment due to liquid loading. For water production, water breaks through the producers after 10 days of production and keeps increasing due to increasing water saturation around the wells. After a while, water production rate decreases as the reservoir has less energy (lower pressure) to produce fluids to surface. The total amount of water production in this case is 148,726 STB.

In the case of bottom-up production, gas is produced by two wells initially penetrating the lower reservoir until the economic rate is reached. Then, the two wells are shut in for 10 days for additional perforations in the upper reservoir. After the two wells are back to production, the two wells begin to produce water because the upper reservoir is water driven and only 31 days of plateau gas rate can be achieved. Eventually, gas production stops when each well reaches the economic rate. At the end, 161,616 STB of water has been produced.

In the case of DWD, the plateau period is equal to that of bottom-up production as the first phase of production is from the lower reservoir only. In this particular case, the criterion to start dumpflood is when the gas rate drops below the plateau rate. As only one well is shut in for 10 days for additional perforations in the upper reservoir (dumping well), there is still gas production from the other well during the intervention period. After additional perforations, the dumping well produces fluids from the upper reservoir, causing gas production rate to shoot up at 42^{nd} day. Then, gas production declines with a smooth trend for 40 days. In fact, the production from the dumping well producing from the upper reservoir is actually constant but the production from the other well producing from the lower reservoir is declining. After 82^{nd} day, gas production changes to another declining trend as the dumping well cannot sustain its plateau rate anymore. At 196^{th} day, the trend changes again when the production from the lower reservoir stops due to economic limit. Thus, from this point on, gas production only comes from the dumping well. Finally, the production stops at 500 MSCF/day because the dumping well reaches the economic rate. Regarding water production rate, it is quite small and hardly seen in Figure 5.2 because water is drained and dumped into the lower reservoir. In this selected case, only 3,750 STB of water is produced which is relatively small compared to the other cases.

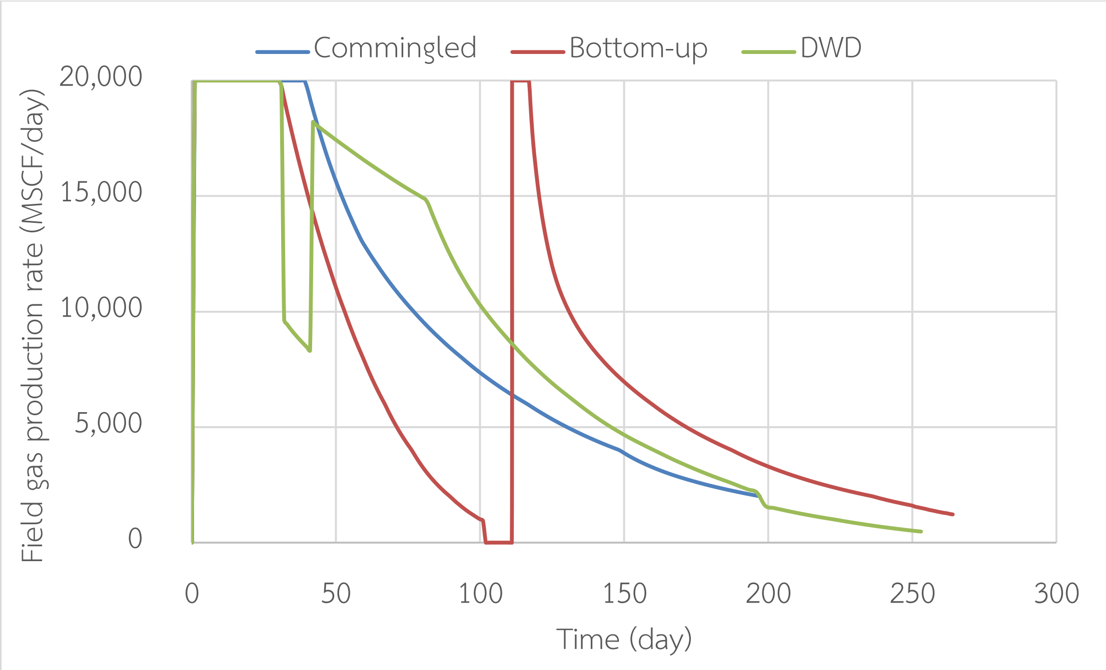

Figure 5.1 Field gas production rate of the three different production scenarios

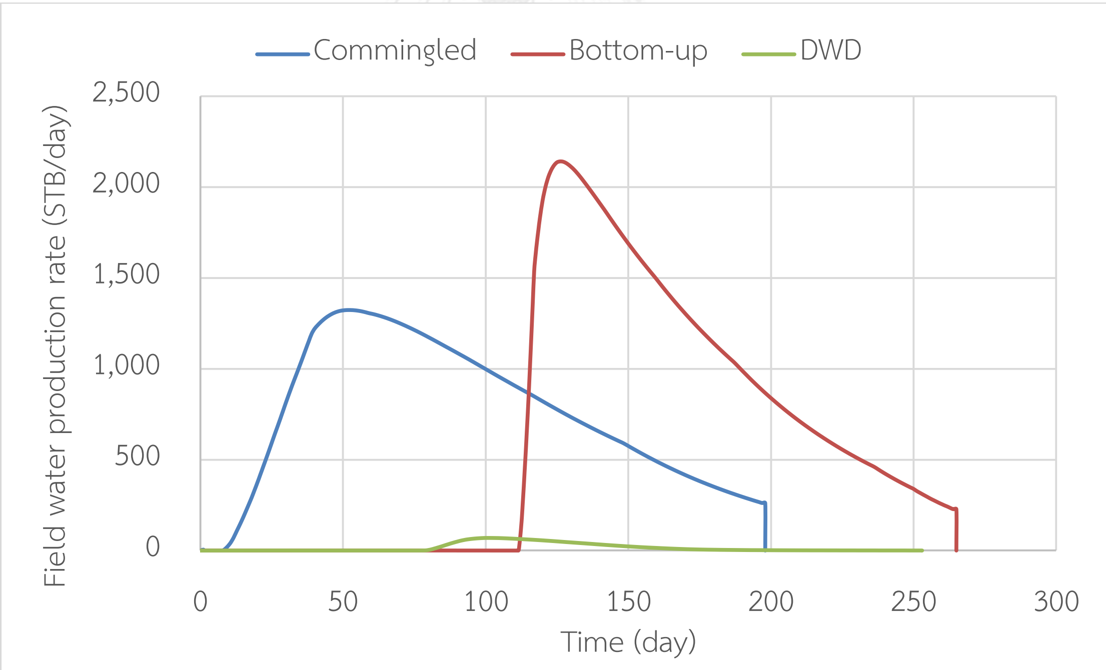

Figure 5.2 Field water production rate of the three different production scenarios

5.2 Effects from operation parameters

According to the reservoir model mentioned in Chapter 4, the lower dry gas column can be perforated full to base in order to obtain the maximum production in the shortest period. However, the upper water-drive gas reservoir should not be perforated at the maximum length of gas column because water will invade into the wellbore very early, causing high water production and eventually loads up the well. General practice for reducing this problem is to partially perforate the gas column above the gas-water contact and/or producing at a low flow rate. Therefore, in the upper reservoir, gas perforation interval was varied at 5, 10 and 15 ft. from the top of the reservoir out of 20-ft. gas column, and the controlled initial production rate was varied at maximum possible rate, 10 MMSCF/day and 5 MMSCF/day.

In DWD method, two additional parameters which are water perforation interval and time to start draining and dumping water, were varied. In general, the thicker the water perforation interval, the higher water volume could be dumpflooded which can displace a larger volume of gas and provide better support pressure in the lower reservoir as well as reducing water coning effect in the upper reservoir. However, thicker water perforation interval increases the chance of gas cross flowing from the upper reservoir into the lower reservoir which decreases gas recovery from the upper reservoir. Therefore, water perforation interval needs to be investigated. In this study, it was varied at 10 and 20 ft. from the bottom shale.

Time to start dumpflood affects directly the pressure of the lower reservoir. The later the time to drain and dump water, the more gas is produced from the lower reservoir, the less pressure left in the reservoir, and the easier the water can flow into the lower reservoir. However, the earlier the dumpflood starts, the faster we can produce from the upper reservoir and the longer time water can flow into the lower reservoir. Therefore, starting time should be investigated in details to identify when to start water draining and dumpflooding. In this study, the draining and dumping action was set to trigger when the well gas production rate drops either below the initial rate, half of the initial rate, or close to the economic rate (1 MMSCF/day). There is an exception for the case of maximum initial production rate where dumping and draining water when the rate drops below the initial rate was not simulated because the pressure in the lower reservoir is still at virgin pressure which is too high for natural crossflow to happen.

As the change in one parameter will affect gas production from either the upper or the lower reservoir at a time, gas recovery will be considered separately for the two reservoirs. RF1 represents gas recovery from the upper reservoir; RF2 represents gas recovery from the lower reservoir, and RF represents overall gas recovery from the field.

5.2.1 Commingled production

According to simulation results, varied operational parameters have some impact on commingled production performance. As summarized in Table 5.1, gas recovery ranges from 65.43% to 70.26%. Recovery factor of the lower layer is higher than that of the upper layer since the lower one is volumetric depletion while the upper one is water drive. All the cases yield high water production (67-149 MSTB) but relatively short life (155-251 days) as shown in Table 5.2. Every case dies because of water loading. Lower initial production rate slightly improves gas recovery and moderately reduces water production but the production time becomes longer. As the perforation interval of the gas zone is increased, the gas recovery moderately increases with a significant increase in water production. The increase in gas recovery predominantly comes from the upper layer (see RF1 in Table 5.1). The production periods for different gas perforation intervals are approximately the same for cases with the same initial production rate but they are longer with lower initial production rates. Among all the cases, the scenario yielding the highest gas recovery of 70.26% (with 128,826 STB of produced water) is 15-ft gas perforation with 5-MMSCF/day initial rate, and the case that results in the least water production of 67,097 STB (with gas recovery of 66.14%) is 5-ft gas perforation with 5-MMSCF/day initial rate.

Table 5.1 Gas recovery for commingled production for various gas perforation intervals and initial production rates

Gas perforation interval (ft.)	IP rate (MMSCF/day)	RF (%)	RF1 (%)	RF2 (%)
15	Max	67.55%	62.18%	72.56%
	10	69.94%	65.50%	74.08%
	5	70.26%	66.11%	74.13%
10	Max	65.43%	57.81%	72.54%
	10	67.67%	61.25%	73.64%
	5	67.94%	61.83%	73.63%
5	Max	65.85%	56.23%	74.81%
	10	65.89%	56.31%	74.81%
	5	66.14%	56.80%	74.85%

Table 5.2 Water production and production period for commingled production for various gas perforation intervals and initial production rates

Gas perforation interval (ft.)	IP rate (MMSCF/day)	Water production (STB)	Time (days)
15	Max	146,392	161
	10	148,726	197
	5	128,826	248
10	Max	113,821	155
	10	117,785	187
	5	101,945	235
5	Max	80,973	199
	10	77,932	208
	5	67,097	251

5.2.2 Bottom-up production

According to simulation results, for bottom-up production, varied operational parameters have little impact on gas recovery but some impact on water production and production period. As summarized in Table 5.3, gas recovery ranges from 72.39% to 72.92%. Similar to commingle production, recovery factor of the lower layer is higher than that of the upper layer due to the fact that the lower one is volumetric depletion while the upper one is water drive. All the cases yield high water production (96-162 MSTB) but moderate life (253-421 days) as detailed in Table 5.4. Every case dies because of water loading except for the cases with 5-ft. gas perforation which dies because of economic limit since the perforation interval in these cases is limited, water coning is not a serious problem. Initial production rate has a minimal effect on gas recovery and water production but lower rate requires longer production time. Longer gas perforation interval slightly increases the gas recovery but significantly increases water production. Longer gas perforation interval also results in shorter production time. Overall, the case yielding the highest gas recovery of 72.92% (with 97,147 STB of water) is 5-ft gas perforation with 10-MMSCF/day initial rate, and the case producing the least water of 96,364 STB (with 72.89% gas recovery) is 5-ft gas perforation with 5-MMSCF/day initial rate.

Table 5.3 Gas recovery for bottom-up production for various gas perforation intervals and initial production rates

Gas perforation interval (ft.)	IP rate (MMSCF/day)	RF (%)	RF1 (%)	RF2 (%)
15	Max	72.62%	63.69%	80.93%
	10	72.67%	63.75%	80.98%
	5	72.61%	63.65%	80.96%
10	Max	72.39%	63.21%	80.93%
	10	72.49%	63.38%	80.98%
	5	72.39%	63.20%	80.96%
5	Max	72.89%	64.27%	80.93%
	10	72.92%	64.28%	80.98%
	5	72.90%	64.26%	80.96%

Table 5.4 Water production and production period for bottom-up production for various gas perforation intervals and initial production rates

Gas perforation interval (ft.)	IP rate (MMSCF/day)	Water production (STB)	Time (day)
15	Max	161,628	253
	10	161,616	264
	5	158,742	313
10	Max	135,935	277
	10	136,124	289
	5	134,090	335
5	Max	97,220	366
	10	97,147	376
	5	96,364	421

5.2.3 Downhole Water Drain from Bottom Water-Drive gas reservoir into partially depleted gas reservoir (DWD)

According to simulation results, for DWD, varied operational parameters have small impact on gas recovery but some impact on water production and production period. As summarized in Table 5.5 -Table 5.10, gas recovery ranges from 77.49% to 79.21%. Both gas and water perforation intervals of the upper reservoir have small effects on gas recovery where longer perforation interval of the two factors slightly help increase gas recovery. Longer gas perforation enlarges flow channel for gas and longer water perforation interval drains more water, thus delaying the water invasion and prolonging the well life. For operational parameters of the lower reservoir, only water perforation interval has a small effect on gas recovery. The longer water perforation interval, the higher amount of water being dumpflooded, thus more gas is displaced. Initial production rate has little impact on gas recovery of both the upper and the lower reservoirs. Gas recovery of the water-drive reservoir is slightly increased when initial production rate is lower due to less water-coning effect. On the other hand, gas recovery of the dry gas reservoir is slightly increased when initial production rate is higher due to less pressure loss at well head during plateau production period since accelerated production results in lower reservoir pressure which enables more gas expansion.

Furthermore, all the cases produce minimal water (0-17 MSTB) compared to the other two conventional cases. Water production is mainly from the upper water-drive reservoir and only slightly from the lower reservoir. Note that the water production from the lower reservoir comes from the connate water expansion. Most of the high-water-production cases are those with 10-ft. water perforation because of insufficient capacity to drain water out from the upper water-drive reservoir except for the cases with 5-ft. gas perforation interval where gas column is partially perforated far above the GWC such that water coning happens at later time. Initial production rate has two-sided effects on water production. Higher initial production rate induces more water coning effect in the upper water-drive reservoir whereas it depletes the lower dry gas reservoir faster which leads to more water crossflowing into the lower reservoir, thus less water is produced up to the surface. Trigger rate for starting dumpflood operation also has two-sided effects on water production. Starting dumpflood at later time helps in dropping the pressure of the lower reservoir such that higher amount of water is dumpflooded into the lower reservoir which results in lower water production. However, it extends the production period, and thus total water production is higher. Overall, the case yielding the highest gas recovery of 79.21% (with 3,010 STB of water) is 15-ft. gas perforation, 20-ft. water perforation with maximum initial rate and starting dumpflooding at half initial rate. The case producing the least water of 96,364 STB (with 72.89% gas recovery) is 5-ft. gas perforation, 20-ft. water perforation with maximum initial rate and starting dumpflooding at half initial rate.

Table 5.5 Gas recovery for DWD at 15-ft. gas perforation for various water perforation intervals, initial production rates and triggering rates to start dumpflood

Gas perforation interval (ft.)	Water perforation interval (ft.)	IP rate (MMSCF /day)	Trigger rate	RF (%)	RF1 (%)	RF2 (%)
15	20	Max	Half	79.21%	73.07%	84.94%
15	20	Max	1,000 MSCF/day	78.88%	73.30%	84.09%
15	20	10	Plateau	79.17%	73.09%	84.83%
15	20	10	Half	79.13%	73.23%	84.62%
15	20	10	1,000 MSCF/day	78.91%	73.33%	84.10%
15	20	5	Plateau	79.02%	73.35%	84.30%
15	20	5	Half	78.92%	73.31%	84.15%
15	20	5	1,000 MSCF/day	78.86%	73.33%	84.01%
15	10	Max	Half	79.20%	73.01%	84.97%
15	10	Max	1,000 MSCF/day	78.36%	73.10%	83.27%
15	10	10	Plateau	78.83%	72.96%	84.30%
15	10	10	Half	78.73%	73.06%	84.01%
15	10	10	1,000 MSCF/day	78.20%	73.10%	82.96%
15	10	5	Plateau	78.58%	73.12%	83.66%
15	10	5	Half	78.44%	73.19%	83.34%
15	10	5	1,000 MSCF/day	78.35%	73.18%	83.17%

Table 5.6 Water production and production period for DWD at 15-ft. gas perforation for various water perforation intervals, initial production rates and triggering rates to start dumpflood

Gas perforation interval (ft.)	Water perforation interval (ft.)	IP rate (MMSCF /day)	Trigger rate	Water production (STB)	Time (days)
15	20	Max	Half	3,010	235
			1,000 MSCF/day	124	280
		10	Plateau	3,746	253
			Half	737	265
			1,000 MSCF/day	271	299
		5	Plateau	205	349
			Half	222	364
			1,000 MSCF/day	235	385
	10	Max	Half	5,939	241
			1,000 MSCF/day	7,905	319
		10	Plateau	16,633	286
			Half	10,796	301
			1,000 MSCF/day	8,656	337
		5	Plateau	3,300	380
			Half	3,592	400
			1,000 MSCF/day	3,773	421

Table 5.7 Gas recovery for DWD at 10-ft. gas perforation for various water perforation intervals, initial production rates and triggering rates to start dumpflood

Gas perforation interval (ft.)	Water perforation interval (ft.)	IP rate (MMSCF /day)	Trigger rate	RF (%)	RF1 (%)	RF2 (%)
10	20	Max	Half	79.00%	72.70%	84.86%
			1,000 MSCF/day	78.66%	72.97%	83.96%
		10	Plateau	79.01%	72.80%	84.79%
			Half	78.91%	72.86%	84.54%
			1,000 MSCF/day	78.74%	73.05%	84.04%
		5	Plateau	78.89%	73.13%	84.25%
			Half	78.79%	73.09%	84.10%
			1,000 MSCF/day	78.79%	73.13%	84.07%
	10	Max	Half	79.07%	72.67%	85.04%
			1,000 MSCF/day	78.16%	72.71%	83.24%
		10	Plateau	78.67%	72.59%	84.34%
			Half	78.55%	72.67%	84.02%
			1,000 MSCF/day	78.01%	72.68%	82.98%
		5	Plateau	78.43%	72.81%	83.67%
			Half	78.17%	72.66%	83.31%
			1,000 MSCF/day	78.11%	72.79%	83.07%

Table 5.8 Water production and production period for DWD at 10-ft. gas perforation for various water perforation intervals, initial production rates and triggering rates to start dumpflood

Gas perforation interval (ft.)	Water perforation interval (ft.)	IP rate (MMSCF /day)	Trigger rate	Water production (STB)	Time (days)
10	20	Max	Half	754	244
10	20	Max	1,000 MSCF/day	49	286
10	20	10	Plateau	1,077	262
10	20	10	Half	137	271
10	20	10	1,000 MSCF/day	50	302
10	20	5	Plateau	52	352
10	20	5	Half	54	367
10	20	5	1,000 MSCF/day	56	388
10	10	Max	Half	1,419	250
10	10	Max	1,000 MSCF/day	2,646	325
10	10	10	Plateau	7,825	295
10	10	10	Half	4,176	307
10	10	10	1,000 MSCF/day	3,070	341
10	10	5	Plateau	1,078	386
10	10	5	Half	1,213	400
10	10	5	1,000 MSCF/day	1,317	425

Table 5.9 Gas recovery for DWD at 5-ft. gas perforation for various water perforation intervals, initial production rates and triggering rates to start dumpflood

Gas perforation interval (ft.)	Water perforation interval (ft.)	IP rate (MMSCF /day)	Trigger rate	RF (%)	RF1 (%)	RF2 (%)
5	20	Max	Half	78.58%	72.06%	84.66%
			1,000 MSCF/day	78.10%	72.17%	83.62%
		10	Plateau	78.32%	71.68%	84.51%
			Half	78.39%	72.08%	84.27%
			1,000 MSCF/day	78.13%	72.19%	83.67%
		5	Plateau	78.35%	72.24%	84.04%
			Half	78.26%	72.21%	83.90%
			1,000 MSCF/day	78.10%	72.00%	83.79%
	10	Max	Half	78.40%	71.52%	84.81%
			1,000 MSCF/day	77.61%	71.63%	83.17%
		10	Plateau	78.20%	71.48%	84.46%
			Half	78.05%	71.65%	84.01%
			1,000 MSCF/day	77.49%	71.67%	82.92%
		5	Plateau	77.86%	71.67%	83.63%
			Half	77.73%	71.75%	83.30%
			1,000 MSCF/day	77.61%	71.72%	83.09%

Table 5.10 Water production and production period for DWD at 5-ft. gas perforation for various water perforation intervals, initial production rates and triggering rates to start dumpflood

Gas perforation interval (ft.)	Water perforation interval (ft.)	IP rate (MMSCF /day)	Trigger rate	Water production (STB)	Time (days)
5	20	Max	Half	47	259
			1,000 MSCF/day	48	316
		10	Plateau	104	277
			Half	48	289
			1,000 MSCF/day	49	328
		5	Plateau	52	370
			Half	54	385
			1,000 MSCF/day	55	400
	10	Max	Half	172	274
			1,000 MSCF/day	238	334
		10	Plateau	1,381	307
			Half	507	319
			1,000 MSCF/day	276	349
		5	Plateau	172	394
			Half	187	413
			1,000 MSCF/day	194	433

5.3 Selection of the three best cases

In order to study the effect from reservoir parameters, the field should be operated under the same conditions. The results from Section 5.2 show that none is the best in every aspect; some cases yield high RF, some cases produce low water and some cases require less production time. Economic analysis needs to be done in order to identify the “optimized” case for each production scenario. However, cost and revenue keep changing from time to time, thus making analysis to be complicated and unpractical to be performed. Instead, it was decided to select “best” case based on three criteria prioritizing from highest RF, lowest water production and shortest production time in order to use them in reservoir-parameter study in the Section 5.4 - Section 5.6.

For commingled production scenario, three candidate cases are shown in Figure 5.3. Based on the selecting criteria, the case with the highest RF is selected because of its highest RF. This case is perforating 15 ft. of gas column with initial production rate of 5 MMSCF/day.

For bottom up production scenario, three candidate cases are shown in Figure 5.4. By looking at R.F. as the first priority and water production as the second priority, although the case with the highest RF has the highest RF, incremental difference from the case with the lowest water production is only 0.02% meanwhile the case with the lowest water production produces 1,000 STB of water less than the case with the highest RF. Therefore, the case with the lowest water production is selected because of less water production. The selected case is perforating 5 ft. of gas column with initial production rate of 5 MMSCF/day.

For DWD scenario, two candidate cases are shown in Figure 5.5. DWD has only two candidates because the case with the highest RF possesses both good points which are highest R.F. and shortest production time. The case with the highest RF is selected because of its highest R.F. This case is 15-ft. gas perforation, 20-ft. water perforation with maximum initial rate and starting dumpflood at half initial rate.

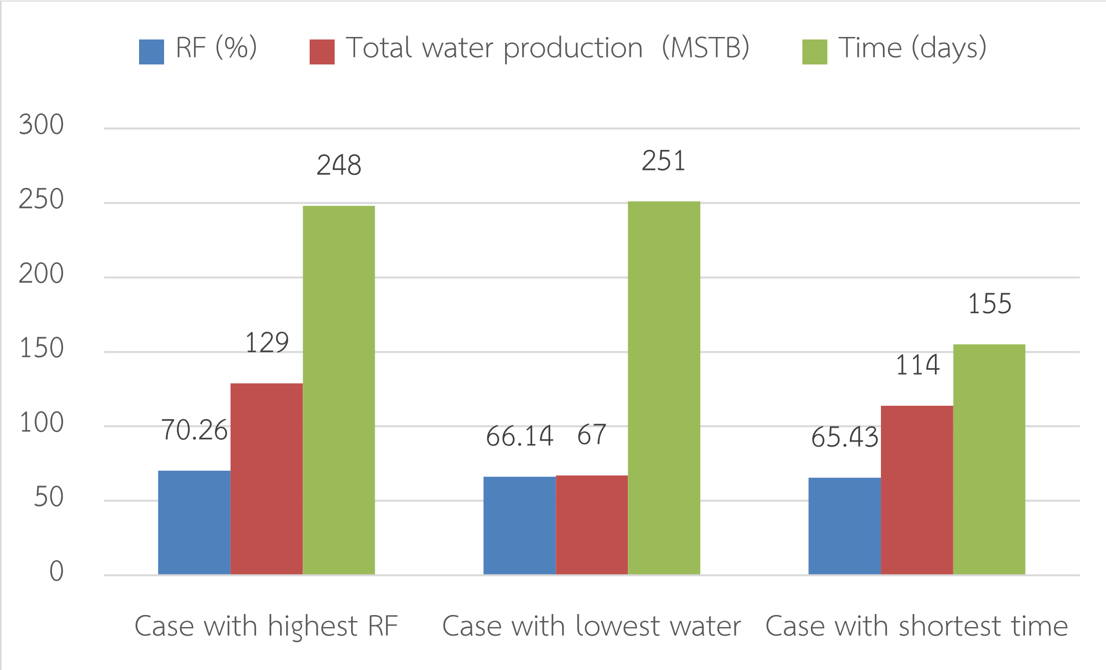

Figure 5.3 Three candidate cases for commingled production

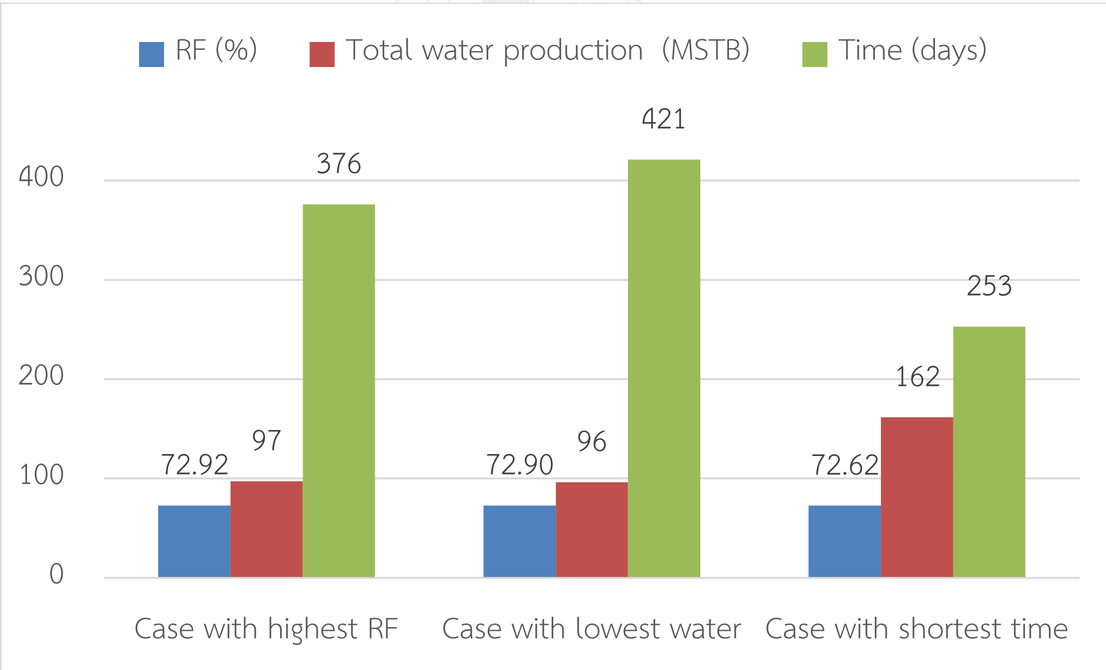

Figure 5.4 Three candidate cases for bottom-up production

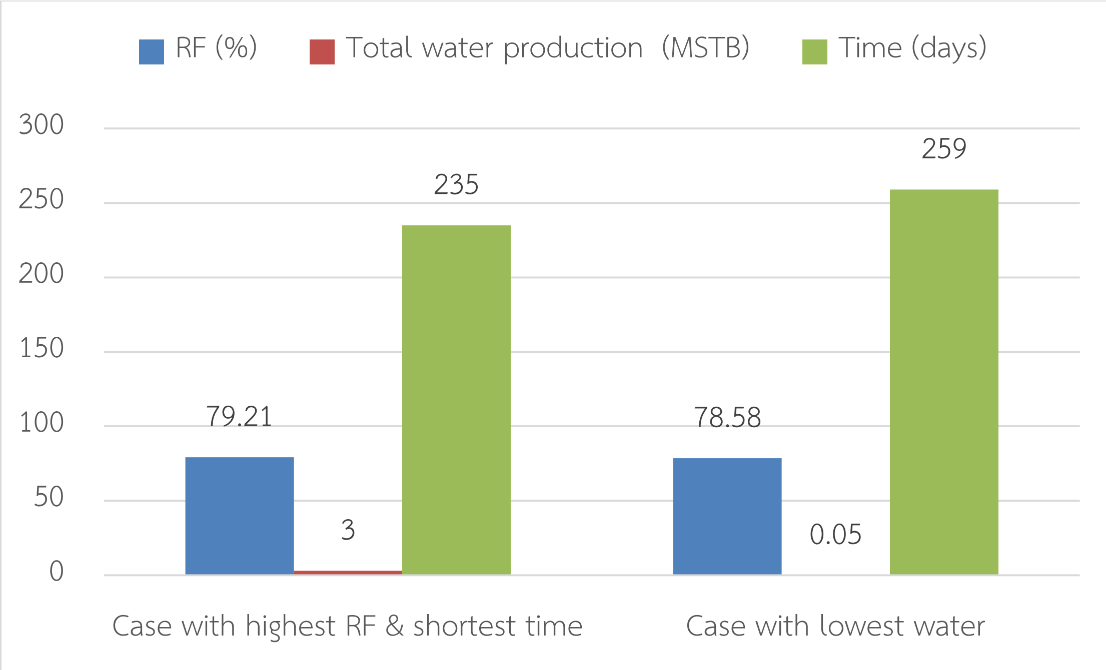

Figure 5.5 Two candidate cases for DWD

5.4 Effects from reservoir parameters

Different production scenarios perform differently under different reservoir characters. One may perform better in a certain reservoir character while the other perform worse. Therefore, effects from varied reservoir parameters should be studied for determining favorable reservoir conditions for each production scenario and in turn determine the case with highest incremental profit for performing DWD.

In Section 5.4 - Section 5.6, the reservoir model that has been used previously is considered as “base case”. If a parameter value is increased from the base case, it is called “high case”, and if a parameter value is decreased from the base case, it is called “low case”. Total of five reservoir parameters are studied including thickness of water column of the upper reservoir, thickness of gas column of the lower reservoir, top depth of the lower reservoir, vertical to horizontal permeability ratio and horizontal permeability.

5.4.1 Commingled production

The first studied parameter is thickness of water column in the upper reservoir. As shown in Figure 5.6, gas recover factor of the base case is slightly higher than that of the low case but it is significantly higher than that of the high case. In the case of 60-ft. water, the well dies at early time because of water loading. In this case, it produces with the highest WGR, as illustrated in Figure 5.7, such that hydrostatic pressure inside tubing is increased and thus, water loading occurs at the earliest time. In the low case, non-convergence problem in reservoir simulation was encountered, causing gas production to stop earlier than it should be, at 215th day as depicted in Figure 5.8. The problem results in low RF, RF1 and RF2. If there is no such problem, gas production is expected to continue after 215th day. Besides, since WGR is lower than that of the base case as shown in Figure 5.7, water loading is expected to occur at a later time, and thus gas production is expected to last longer. As a result, RF, RF1 and RF2 are expected to be higher than those of the base case if there were no non-convergence problem.

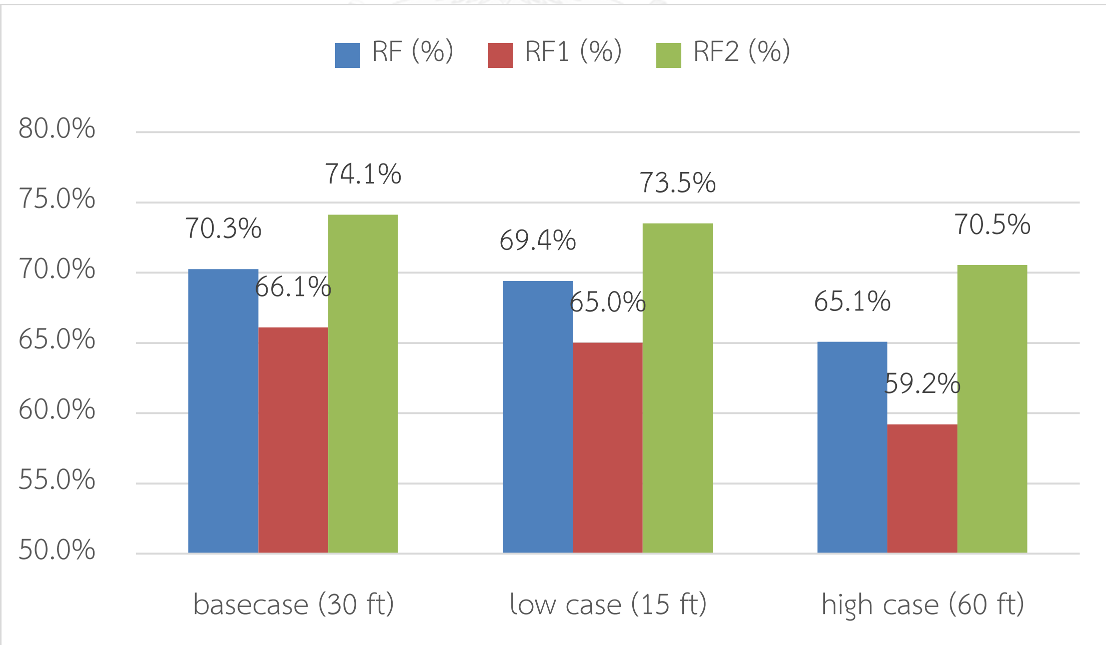

Figure 5.6 Gas recovery comparison among different thickness of water column of the upper reservoir with commingled production

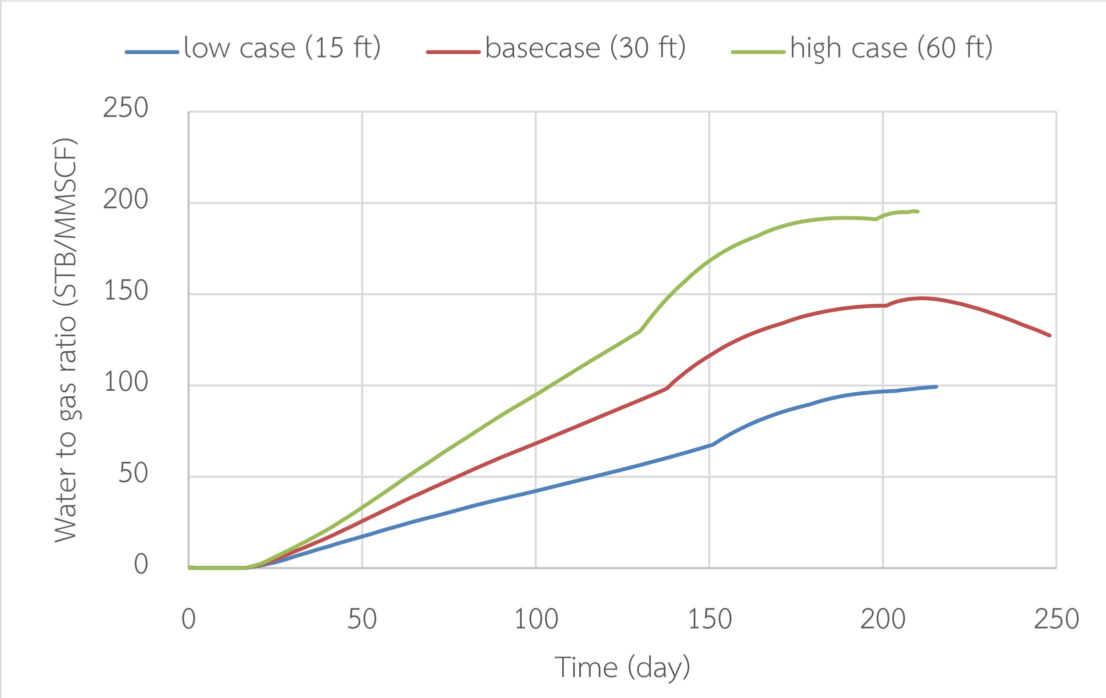

Figure 5.7 Water to gas ratio among different thickness of water column of the upper reservoir with commingled production

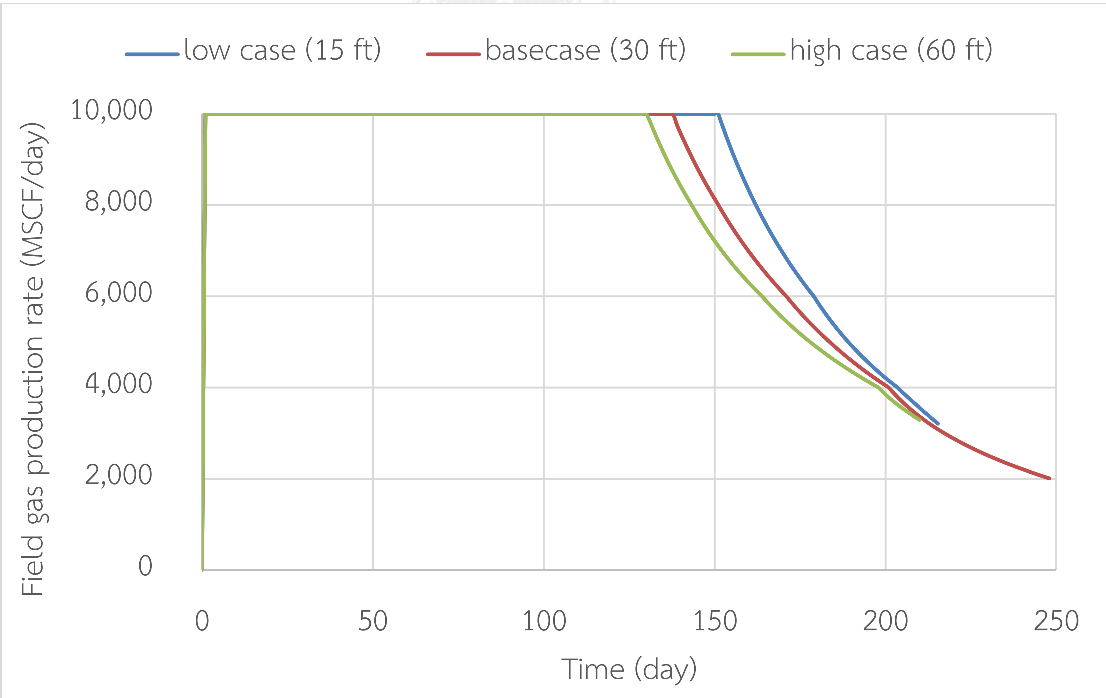

Figure 5.8 Field gas production rate among different thickness of water column of the upper reservoir with commingled production

The second studied parameter is thickness of the lower dry gas reservoir. As shown in Figure 5.9, RF, RF1 and RF2 of the low case are the lowest whereas those of the high case and the base case are about the same. Total flow rate of the low case has relatively high contribution from the upper reservoir compared to the other two cases because its gas column in the lower reservoir is thinner than gas column in the upper reservoir. With the bottom aquifer underlying, water breakthrough occurs very early and water production increases the fastest as shown in Figure 5.10. In the high case, gas crossflows from the upper to the lower reservoir occurs just before its abandonment which causes a drop in total flow rate resulting in water loading.

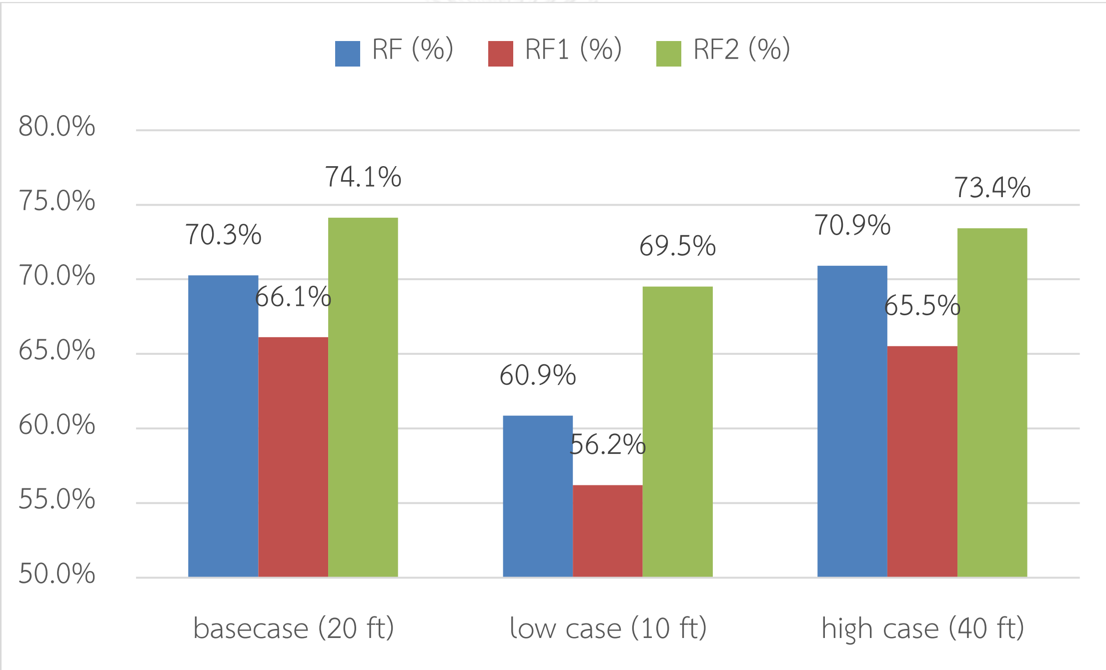

Figure 5.9 Gas recovery comparison among different thickness of the lower dry gas reservoir with commingled production

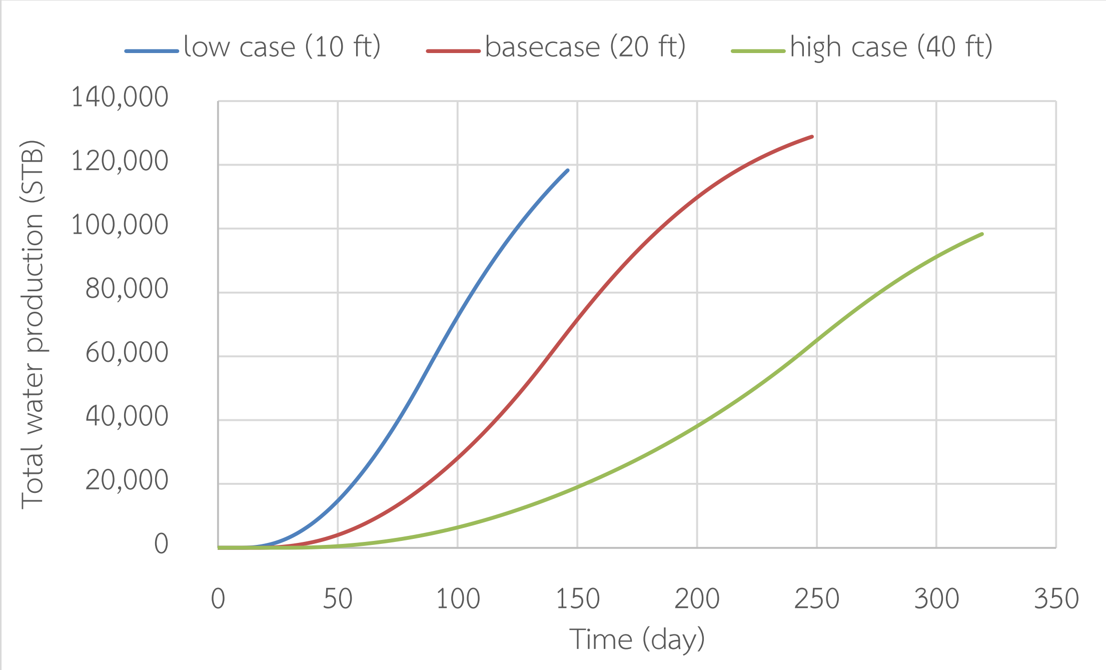

Figure 5.10 Total water production profile comparison among different thickness of the lower dry gas reservoir with commingled production

The third studied parameter is top depth of the lower reservoir. As shown in Figure 5.11, RF of the base case is higher than the low case but lower than the high case. In normal pressure gradient, the deeper the reservoir, the higher the reservoir pressure. Deeper lower reservoir causes higher amount of gas crossflowing into the upper reservoir during early production time. This is represented by more negative contribution from the upper reservoir as shown in Figure 5.12. Thus, the low case has the highest contribution from the upper reservoir while the high case has the lowest contribution from the upper reservoir. As the low case has the highest gas rate from the upper reservoir, its water production rate is also the highest among the three cases. This results in early water loading and thus reducing RF1 & RF2. For the high case, RF1 is the same with the base case but RF2 is higher than the base case because of the higher pore pressure and overburden pressure. As a result, the total RF of the high case is higher than that of the base case.

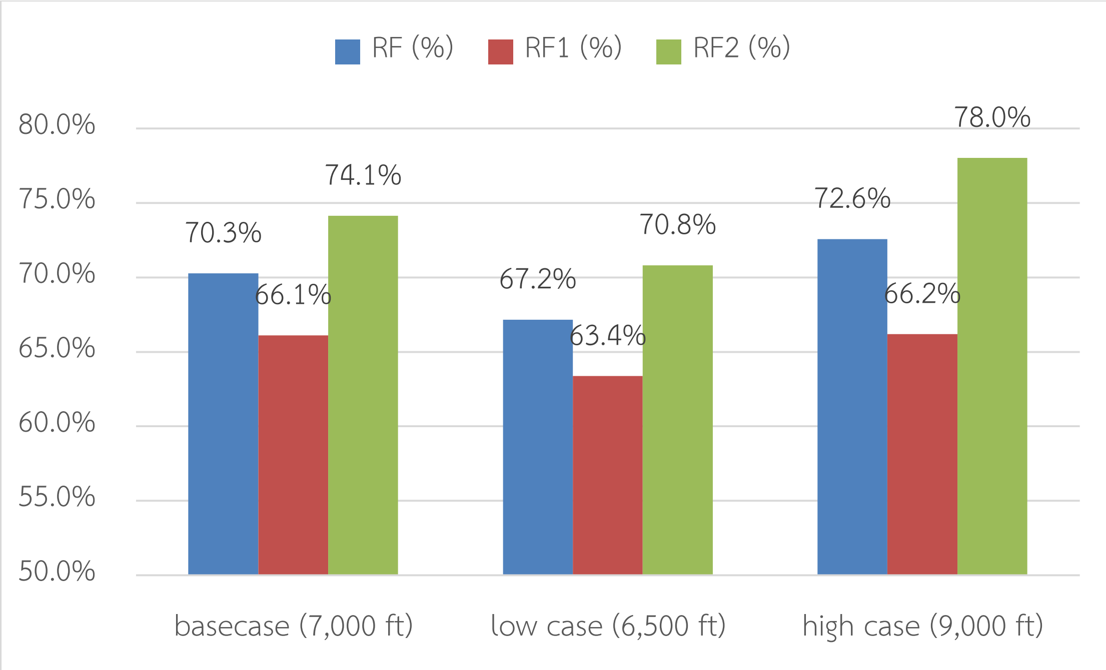

Figure 5.11 Gas recovery comparison among different top depth of the lower reservoir with commingled production

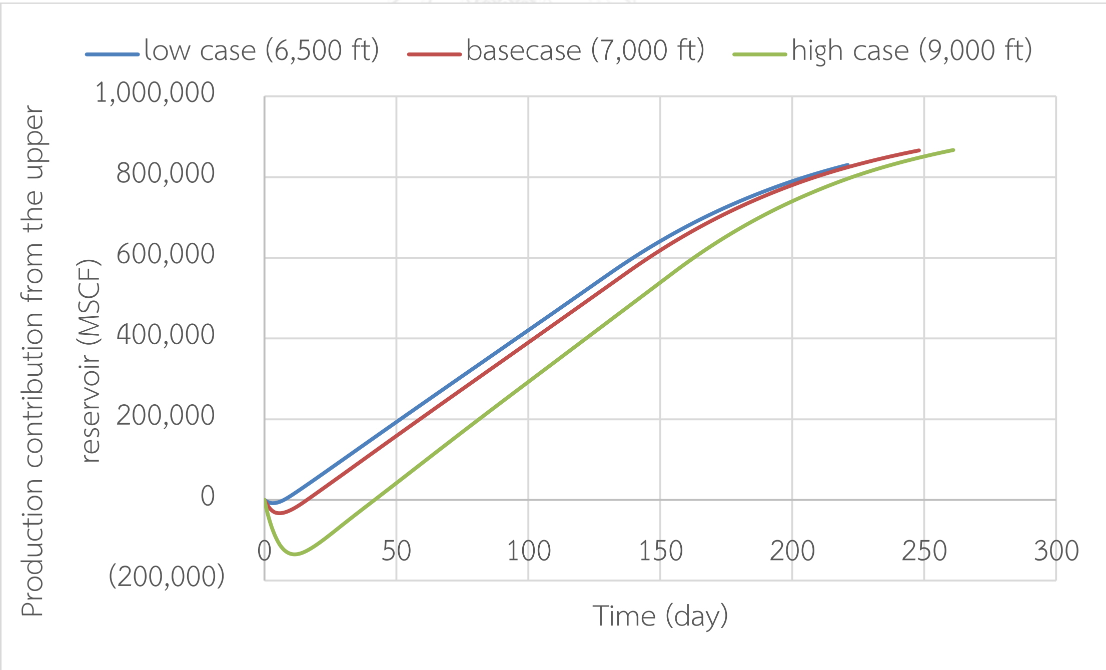

Figure 5.12 Production contribution from the upper reservoir among different top depths of the lower reservoir with commingled production

The fourth studied parameter is Kv/Kh ratio. As shown in Figure 5.13, RF, RF1 and RF2 of the base case are all lower than those of the low case but higher than those of the high case. In another word, the lower the vertical permeability, the higher the values of RF1, RF2 and RF. Vertical permeability affects directly to the rising of GWC and water coning especially in bottom water-drive reservoir. In this case, vertical permeability affects directly to the upper reservoir where underlying aquifer exists. The difference in RF1 between the low and high cases is around 14%. Although there is no water coning in the lower reservoir, vertical permeability still has an effect on RF2 due to commingled production. In the high case, as the vertical permeability becomes higher, there is more water flowing from the upper perforation, creating higher hydrostatic pressure. This reduces amount of gas flowing from the lower reservoir into the wellbore, thus reducing RF2. In the low case, the opposite happens.

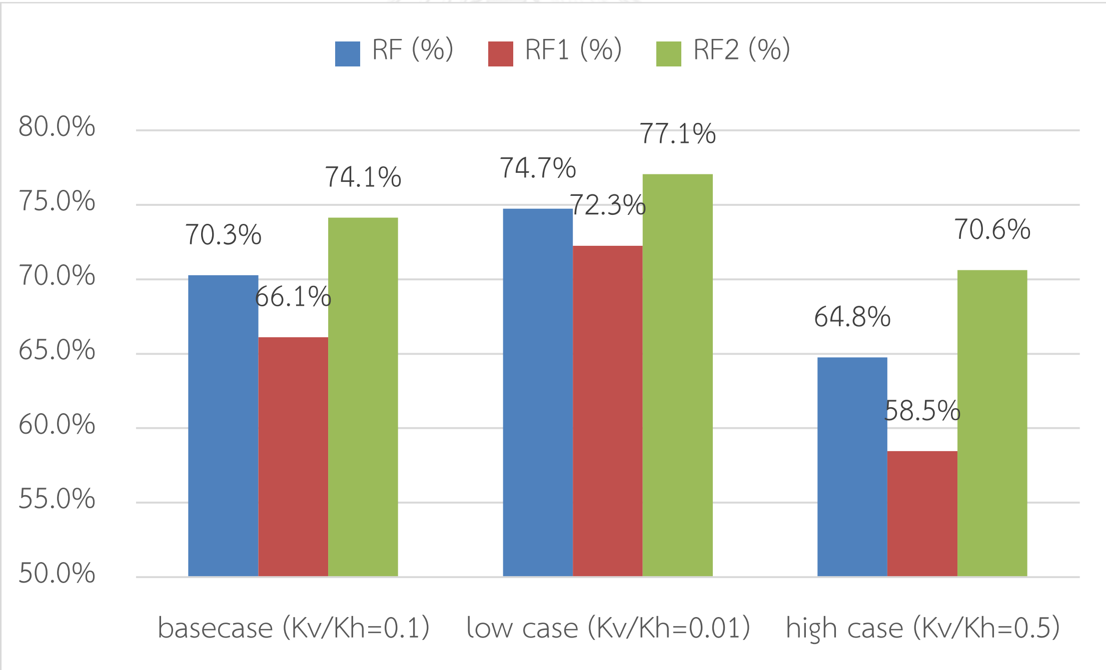

Figure 5.13 Gas recovery comparison among different vertical to horizontal permeability ratio with commingled production

The fifth studied parameter is horizontal permeability. Note that the Kv/Kh ratio is still kept the same at 0.1 as the horizontal permeability is varied. As shown in Figure 5.14, RF of the high case is slightly higher than that of the base case because of lower drawdown pressure meanwhile RF of the low case is around 7% lower than those of the other two. The well BHP does not need to be reduced to low values when the horizontal permeability is high. As a result, a longer plateau period is observed as shown in Figure 5.15. However, the low case dies earliest because of early water loading as a consequence of highest WGR as depicted in Figure 5.16. Thus, its RF is much lower than the other two cases.

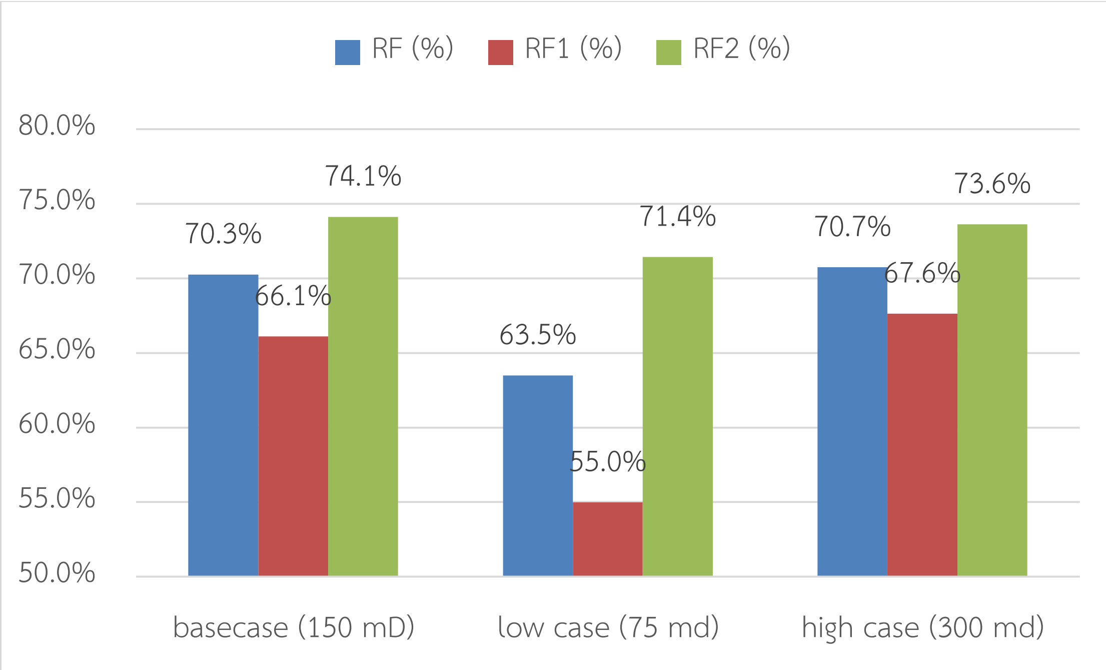

Figure 5.14 Gas recovery comparison among different horizontal permeability with commingled production

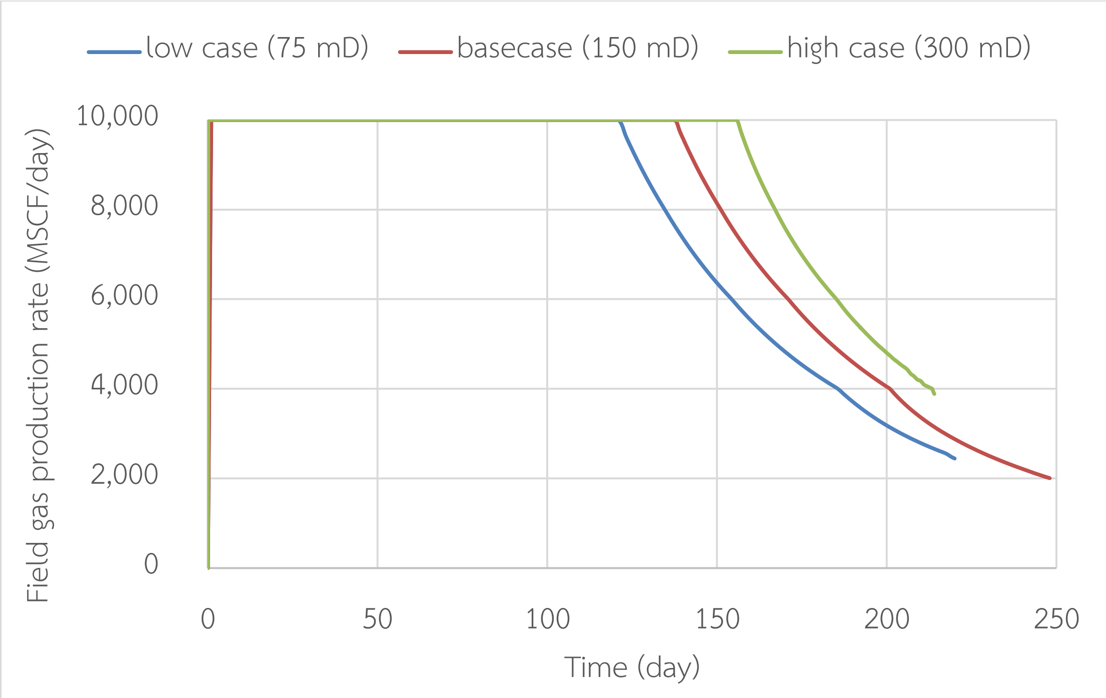

Figure 5.15 Field gas production rate among different horizontal permeability with commingled production

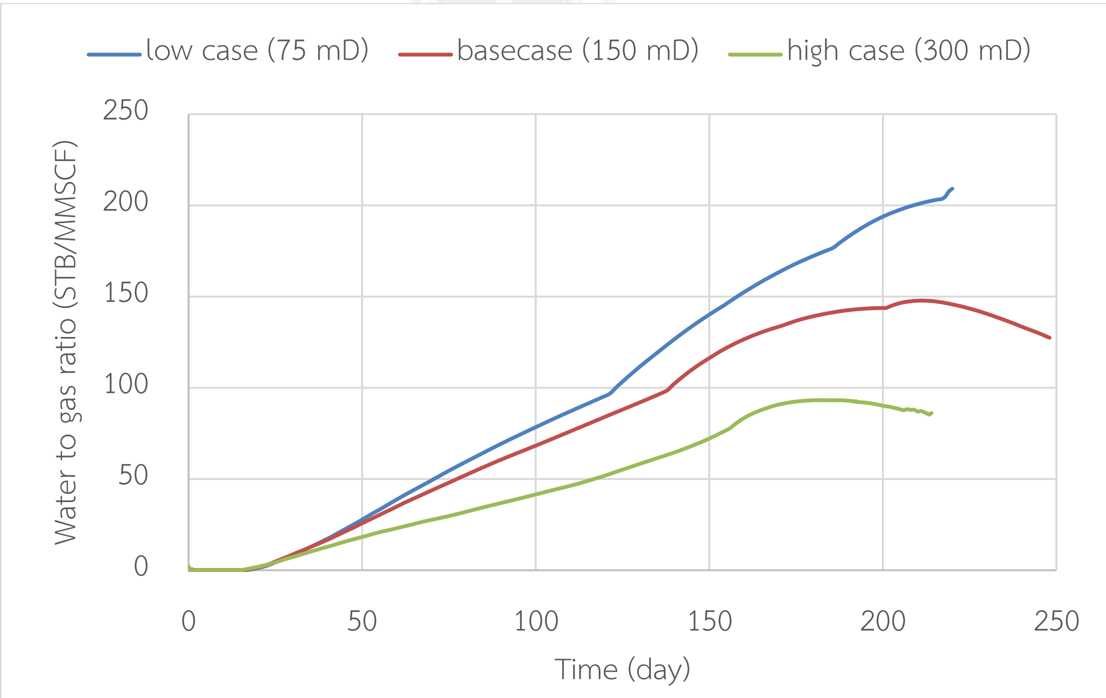

Figure 5.16 Water to gas ratio among different horizontal permeability with commingled production

All in all, different values of reservoir properties have significant impact on the performance of commingled production. As illustrated in Figure 5.17, RF can be altered from minimum of -9.41% to maximum of +4.48% from the base case under scope of the varied parameters. The reservoir parameter that has the highest negative impact on RF is thickness of the lower reservoir. When the value is changed from 20 ft. to 10 ft., RF decreases from 70.26% to 60.85%, a 9.41% reduction. On the other hand, the reservoir parameter that has the highest positive impact on RF is Kv/Kh. When Kv/Kh is changed from 0.1 to 0.01, RF increases by 4.48% from 70.26% to 74.74%.

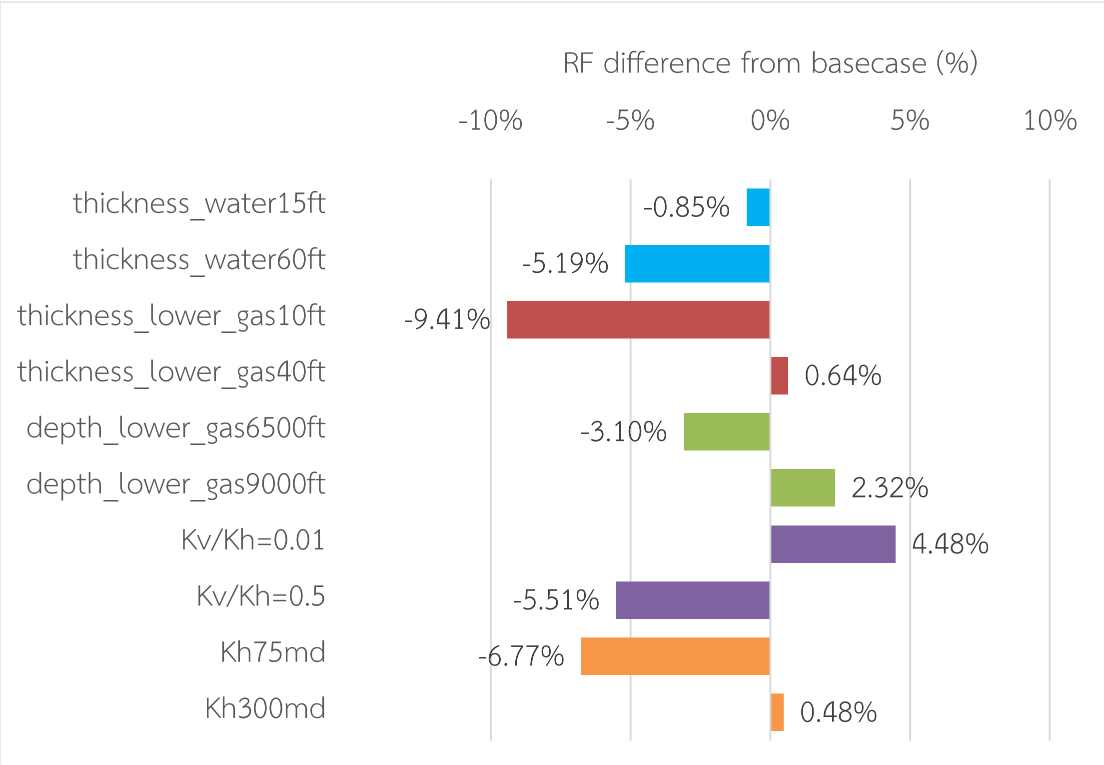

Figure 5.17 RF difference from the base case with commingled production

5.4.2 Bottom-up production

The first studied parameter is thickness of water column of the upper reservoir. As shown in Figure 5.18, RF2 of every case is the same meanwhile RF1 improves as water column is thinner so that RF increases along with RF1. Since bottom-up production produces each reservoir separately, the change in the upper reservoir does not have any effect to the lower reservoir. As water column is thicker, more water invades into the wellbore, and the well produces with higher WGR as shown in Figure 5.19. Hence, plateau rate of the cases with thicker water column can be sustained for a shorter period, as shown in Figure 5.20, because of heavier hydrostatic column inside the tubing. As a result, RF1 and RF decrease as thickness of water column increases.

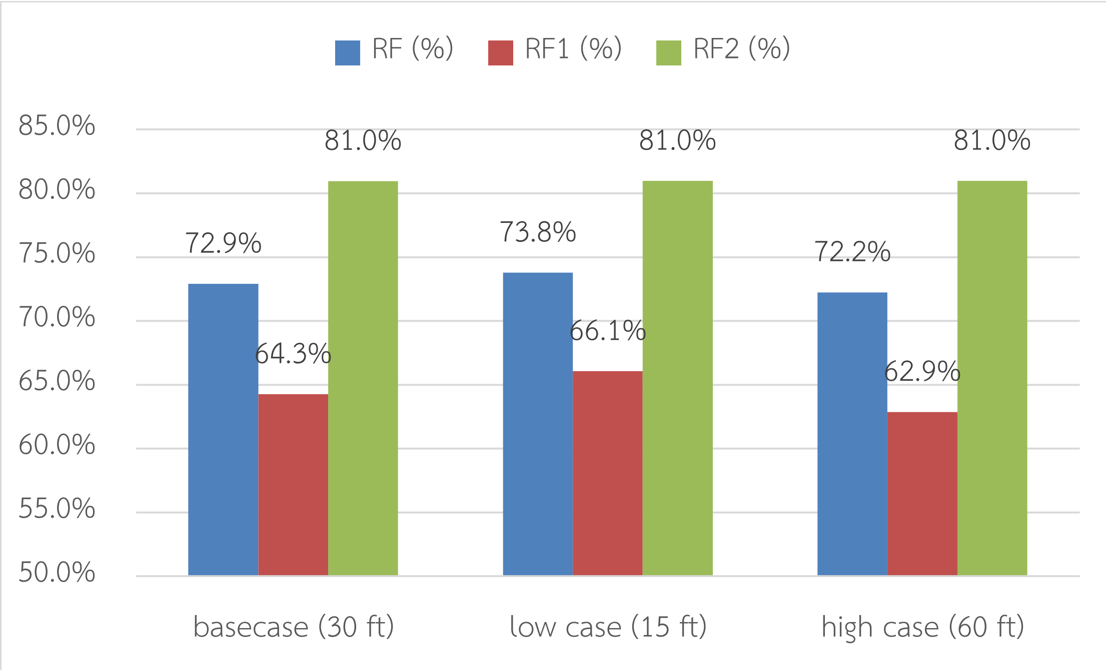

Figure 5.18 Gas recovery comparison among different thickness of water column of the upper reservoir with bottom-up production

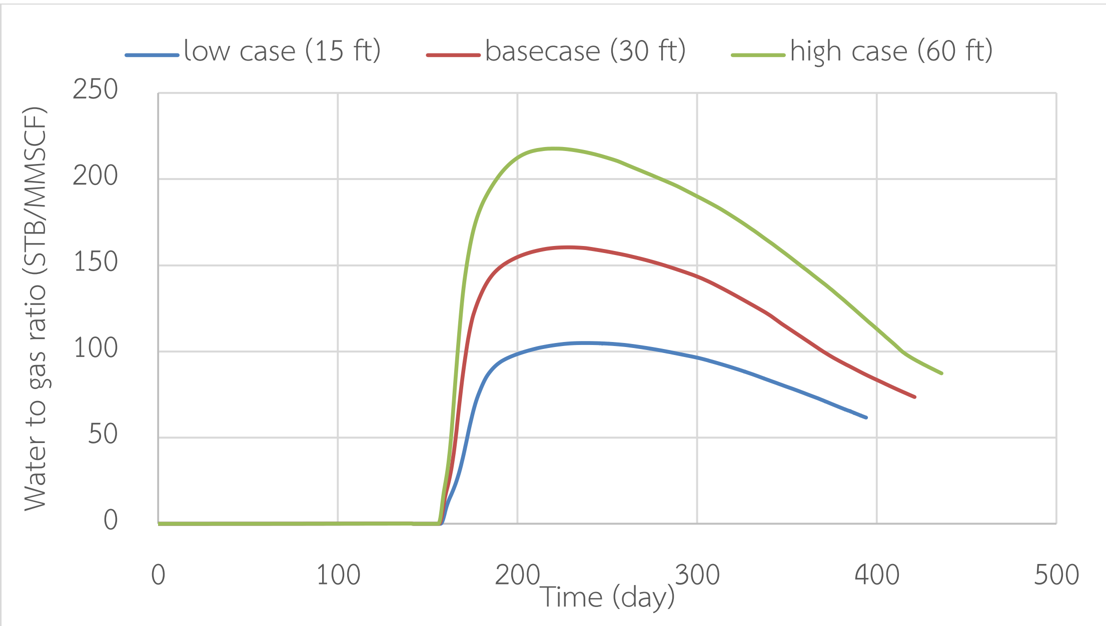

Figure 5.19 Water to gas ratio among different thickness of water column of the upper reservoir with bottom-up production

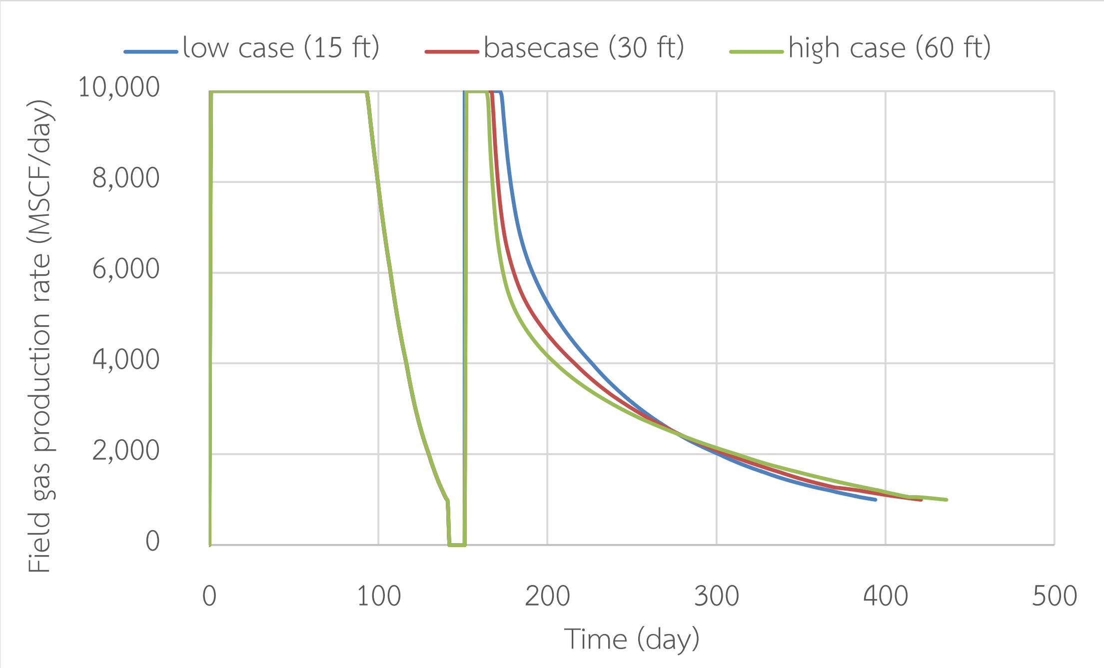

Figure 5.20 Field gas production rate among different thickness of water column of the upper reservoir with bottom-up production

The second studied parameter is thickness of gas column of the lower reservoir. As shown in Figure 5.21, RF1 of every case is the same meanwhile RF2 slightly improves as gas column is thicker due to slightly higher average reservoir pressure. However, that is not the reason for significant improvement in RF. In the case of thicker reservoir, RF increases because of larger contribution of gas production from the lower reservoir as a result of higher OGIP. OGIP of the low case, the base case and the high case are 703, 1,406 and 2,812 respectively. Hence, RF is more biased toward RF2 in the case of thicker gas column. Overall, thicker lower gas column results in a little slightly higher RF.

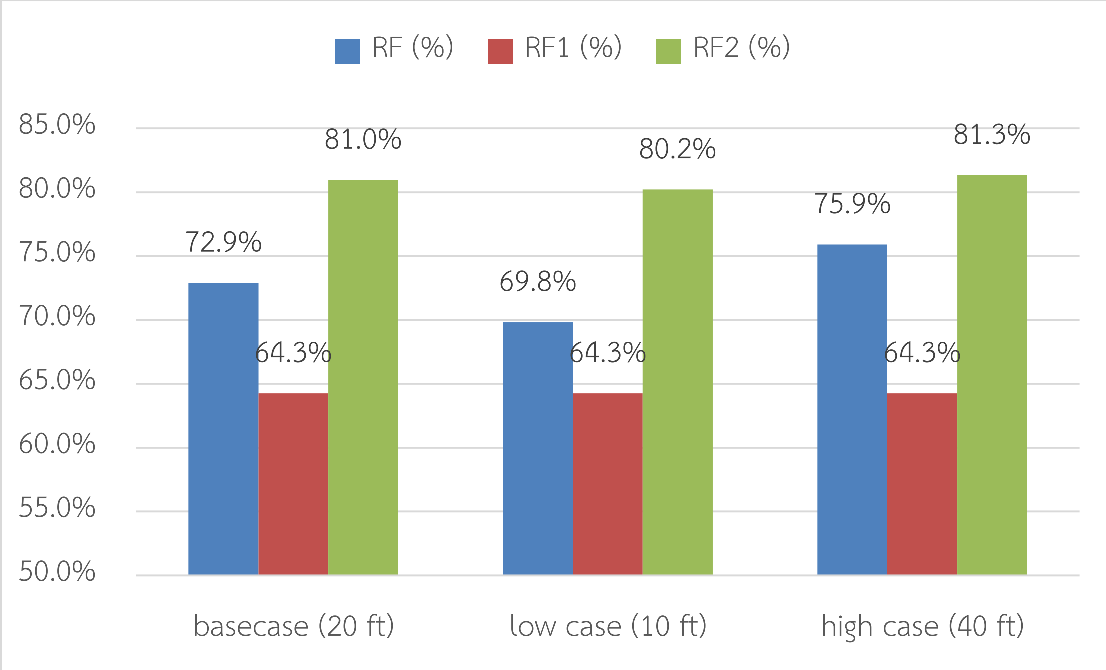

Figure 5.21 Gas recovery comparison among different thickness of gas column of the lower reservoir with bottom-up production

The third studied parameter is top depth of the lower reservoir. As shown in Figure 5.22, RF1 of every case is equal meanwhile RF2 as well as RF increases a little as top depth of the lower reservoir goes deeper. The deeper the reservoir, the higher the OGIP because gas will expand more once it reaches the surface. As shown in Figure 5.23, the plateau rate before well intervention can be maintained longer in the case of deeper lower reservoir due to higher reservoir pressure. Eventhough there is an additional pressure drop from flowing through longer tubing section, it has only small effect relative to the increase in reservoir pressure.

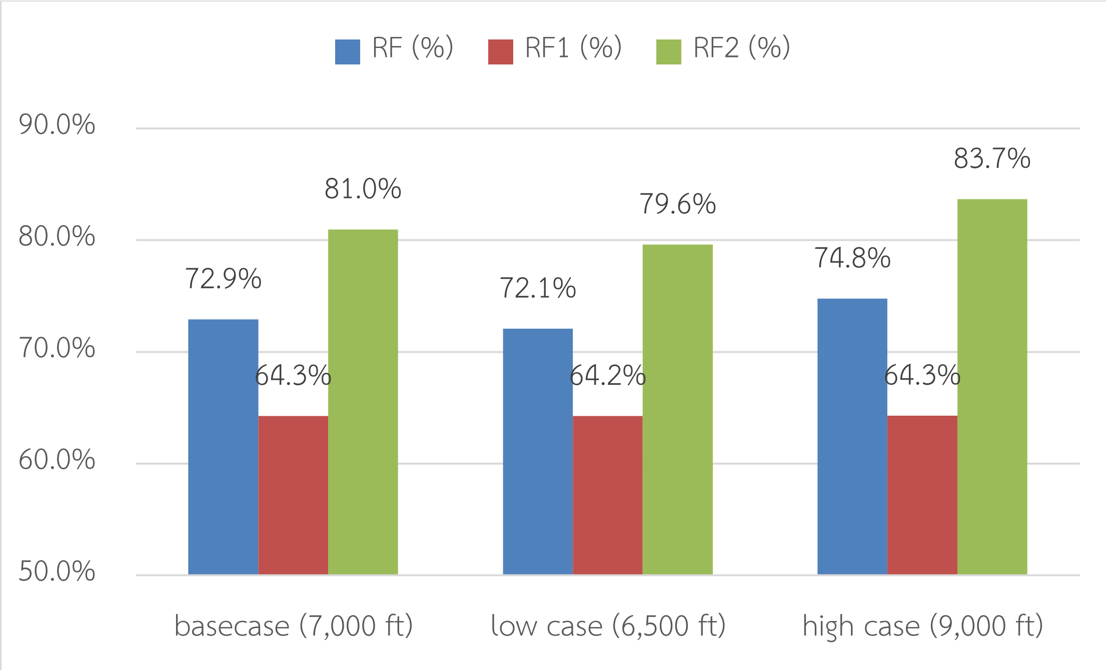

Figure 5.22 Gas recovery comparison among different top depth of the lower reservoir with bottom-up production

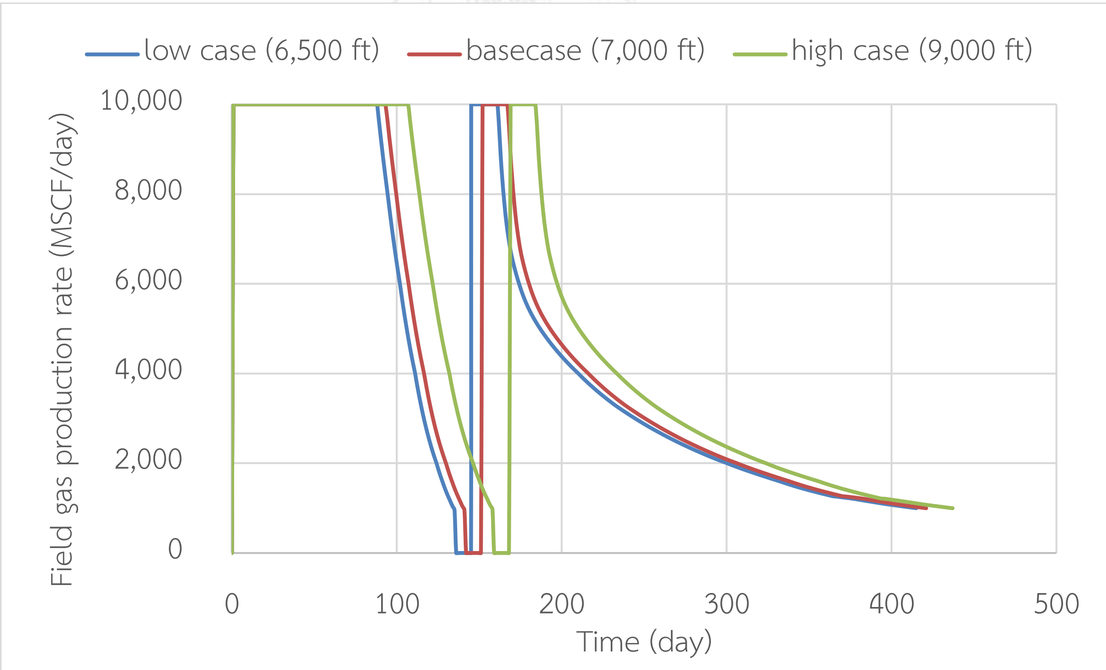

Figure 5.23 Field gas production rate among different top depth of the lower reservoir with bottom-up production

The fourth studied parameter is vertical to horizontal permeability ratio. As shown in Figure 5.24, RF2 is the same for every case whereas RF1 is affected significantly by vertical permeability. In general, higher vertical permeability facilitates the rising of GWC which results in water coning. The lower reservoir contains only dry gas without underlying aquifer, thus it is not affected. On the other hand, the upper reservoir is substantially affected by vertical permeability since it has underlying aquifer such that water coning happens earlier as vertical permeability increases. According to the simulation results, only the high case was abandoned because of water loading. At the abandonment, the gas flow rate is 862 MSCF/day with the WGR of 165 STB/MMSCF. The other two cases were abandoned at economic limit of 500 MSCF/day. At their abandonment, WGR for the low case and the base case were 37 and 74 STB/MMSCF, respectively.

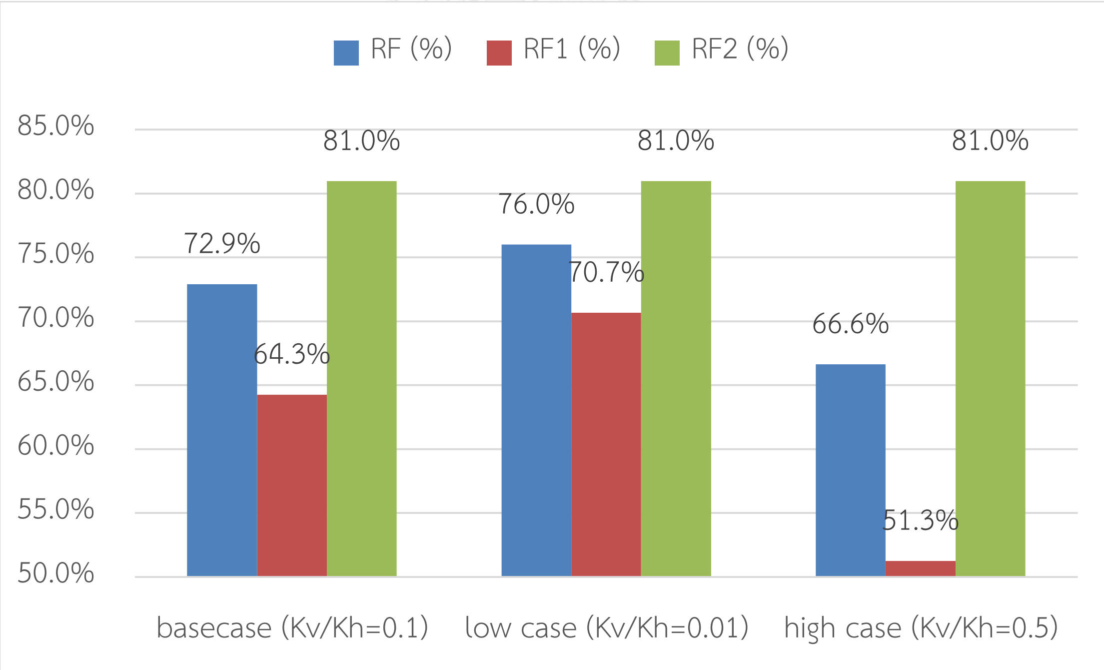

Figure 5.24 Gas recovery comparison among different vertical to horizontal permeability ratio with bottom-up production

The fifth studied parameter is horizontal permeability. As shown in Figure 5.25, RF increases as horizontal permeability increases which is mainly contributed from RF1 and trivially from RF2. In general, higher horizontal permeability eases any fluid in flowing through porous media which means either volumetric or water-drive gas reservoir benefits from that. However, the benefit in the case of water-drive gas reservoir is much higher than the one in volumetric depletion. Higher horizontal permeability also helps maintain high BHP such that the plateau rate can be sustained longer. As shown in Figure 5.26, higher horizontal permeability causes a longer plateau period for both upper reservoir (0^{th} to 100^{th} day) and lower reservoir (145^{th} to 172^{nd} day).

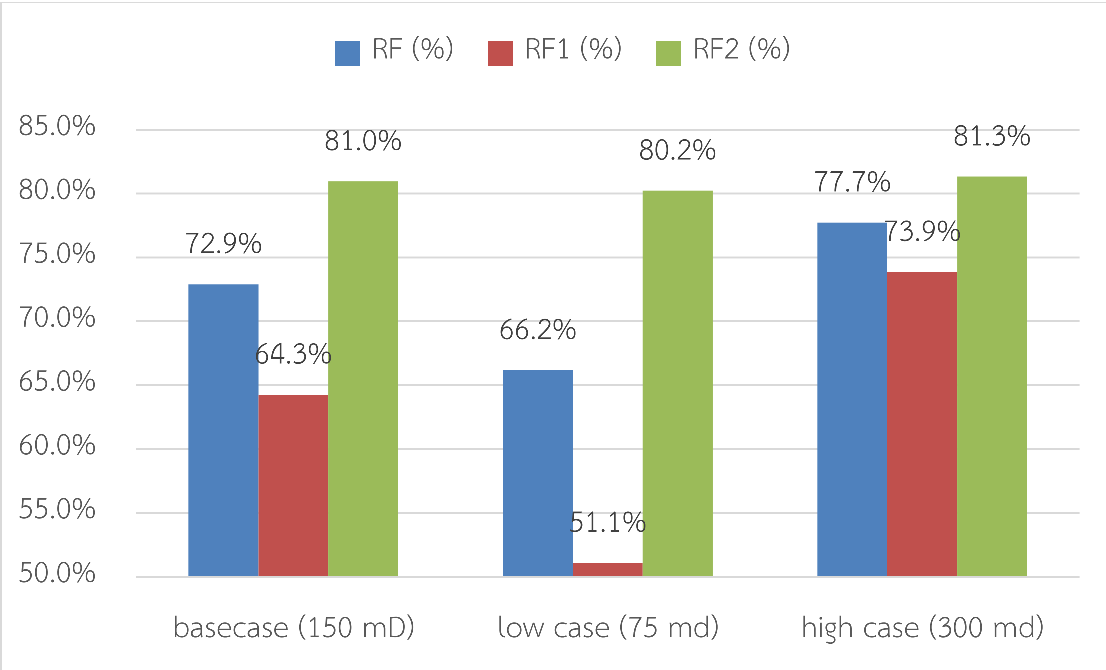

Figure 5.25 Gas recovery comparison among different horizontal permeability with bottom-up production

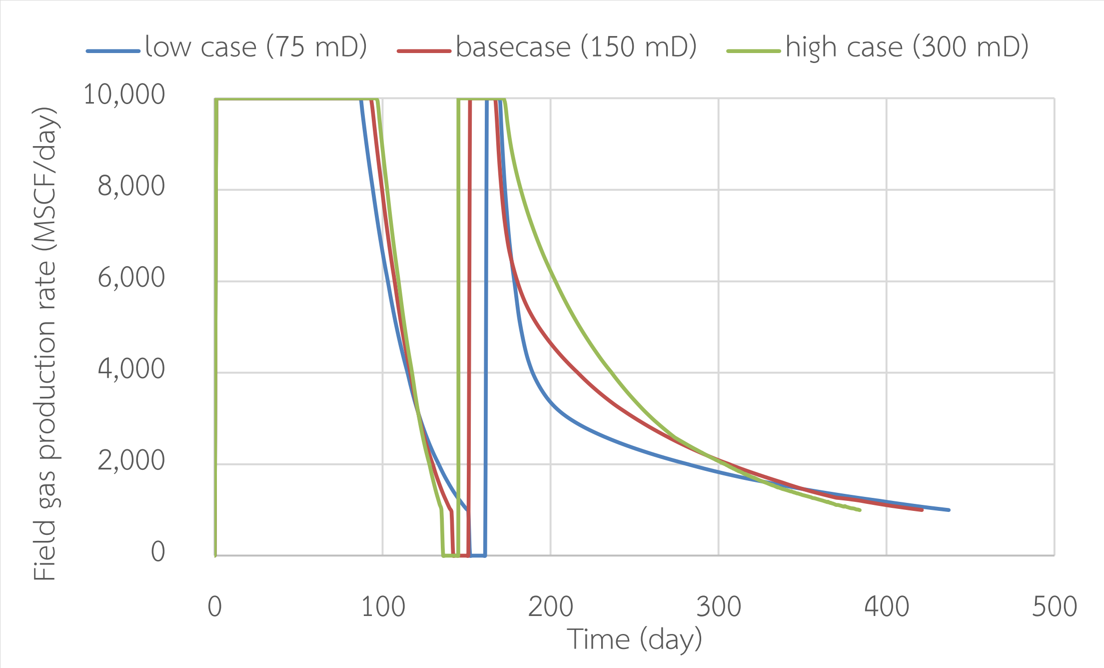

Figure 5.26 Field gas production rate among different horizontal permeability with bottom-up production

All in all, different values of reservoir properties have moderate impact on the performance of bottom-up production. As illustrated in Figure 5.27, RF can be altered from minimum of -6.73% to maximum of +4.82% from the base case under scope of the varied parameters. The two reservoir parameters that have the highest negative impact on RF are Kv/Kh and Kh. Increasing Kv/Kh from 0.1 to 0.5 decreases RF by 6.26% from 72.90% to 66.64% and decreasing Kh from 150 mD to 75 mD decreases RF by 6.73% from 72.90% to 66.17%. On the other hand, the reservoir parameter that has the highest positive impact on RF is Kh in which increasing Kh from 150 mD to 300 mD increases RF by 4.82% from 72.90% to 77.72%.

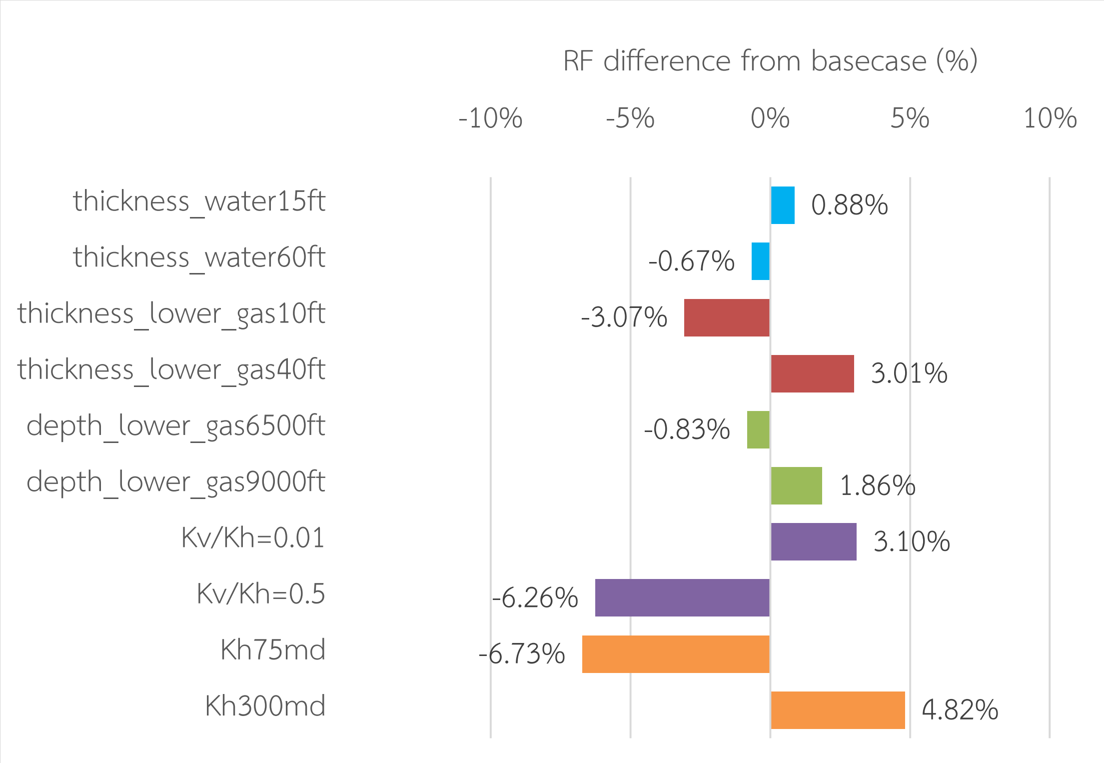

Figure 5.27 RF difference from the base case with bottom-up production

5.4.3 DWD

The first studied parameter is thickness of water column of the upper reservoir. Note that perforation interval of water column in the upper reservoir is changed from 15 ft. out of 20 ft. for the basecase to 40 ft. out of 60 ft. for the high case and 10 ft. out of 15 ft. for the low case in order to keep the ratio of perforated fraction to 2/3 of the total water column thickness. As shown in Figure 5.28, thicker water column causes RF1 to decrease but RF2 to increase, resulting in nearly the same RF in every case. Thicker water column holds back the performance of the upper reservoir by introducing higher WGR during production from the upper reservoir as shown in Figure 5.29. In the meantime, it allows more water to be dumpflooded into the lower reservoir which is represented by greater negative values as shown in Figure 5.30. As a result, higher gas displacement and more reservoir re-pressurization can be achieved which in turn, increases RF2.

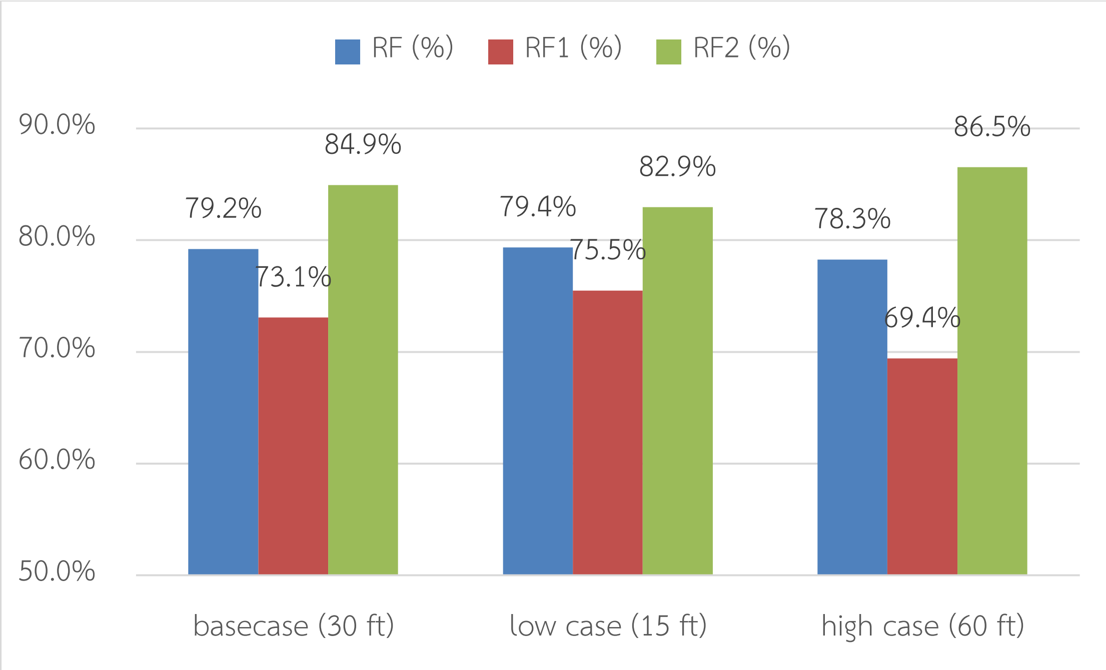

Figure 5.28 Gas recovery comparison among different thickness of water column of the upper reservoir with DWD

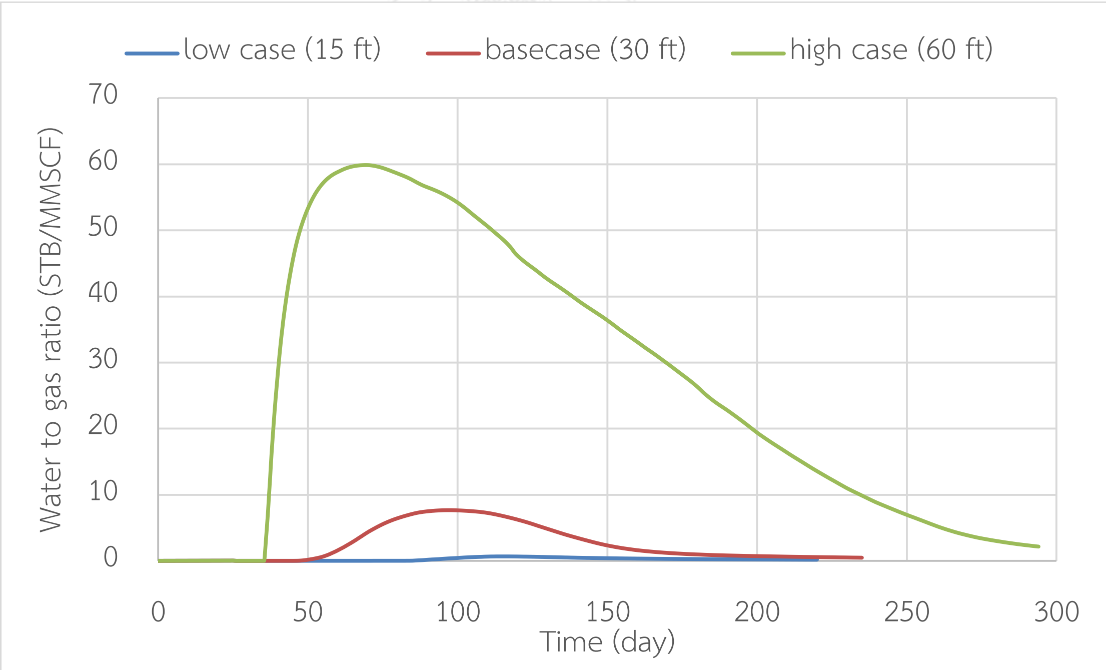

Figure 5.29 Water to gas ratio of PROD1 among different thickness of water column of the upper reservoir with DWD

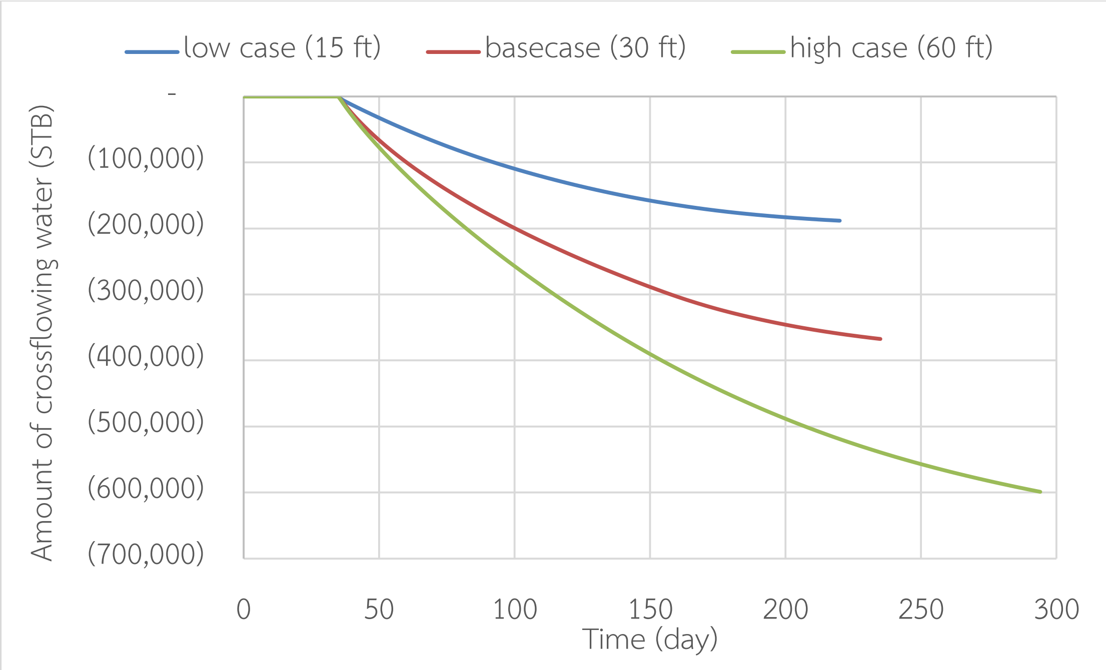

Figure 5.30 Amount of crossflowing water from the upper reservoir to the lower reservoir among different thickness of water column of the upper reservoir with DWD

The second studied parameter is thickness of gas column of the lower reservoir. As shown in Figure 5.31, RF1 slightly increases as gas thickness becomes thicker meanwhile RF2 in every case is about the same. Thicker gas column allows more water to be drained from the upper reservoir into the lower reservoir, thus less amount of water invades into the well penetrating the upper reservoir. According to the simulation results, WGR at the abandonment is higher in the case of thinner gas column. As shown in Figure 5.32 , the total amount of crossflowing water in the low case, the base case and the high case increases by 302 MSTB, 367 MSTB and 405 MSTB, respectively.

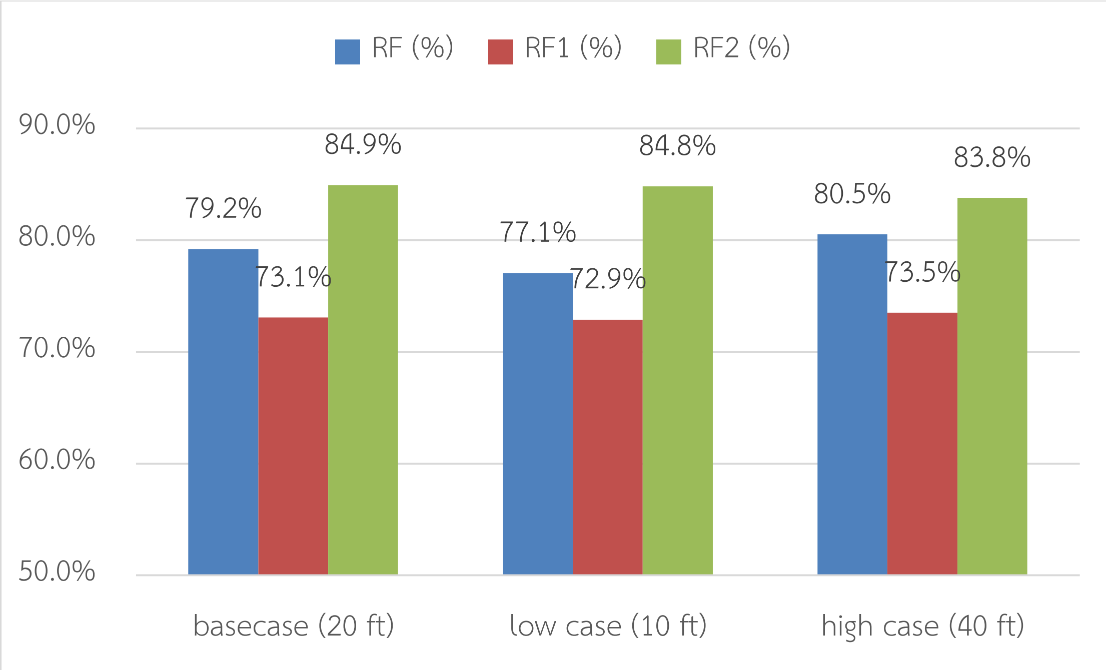

Figure 5.31 Gas recovery comparison among different thickness of gas column of the lower reservoir with DWD

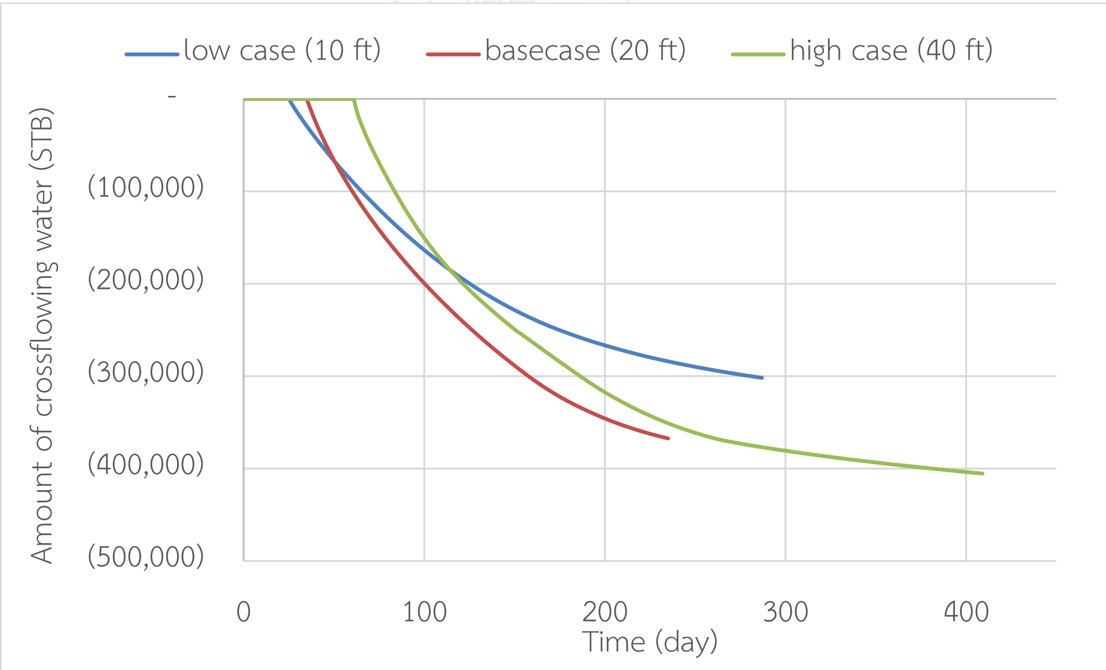

Figure 5.32 Amount of crossflowing water from the upper reservoir to the lower reservoir among different thickness of gas column of the lower reservoir with DWD

The third studied parameter is top depth of the lower reservoir. As shown in Figure 5.33, RF1 of all the cases are close to each other meanwhile RF2 as well as RF increases as the lower reservoir is located deeper. Change in depth of the lower reservoir has two-sided effect on water dumping. Average reservoir pressure of the deeper lower reservoir at the time of dumpflood is higher, thus decreasing water injectivity. According to the simulation result, average reservoir pressure of the lower reservoir at the time of dumpflood operation are 1,417 psia, 1,474 psia and 1,780 psia for the low case, the basecase and the high case, respectively.

However, hydrostatic pressure at the inlet of the deeper lower reservoir is higher as tubing extends to a deeper depth, thus increasing water injectivity. If the dumping fluid is water and the producing fluid is gas, pressure overcomes the effect from reservoir pressure. As a result, the deeper the lower reservoir, the higher water injectivity, and the higher amount of water can be drained. As shown in Figure 5.34, amount of crossflowing water in the low case, the base case and the high case increases by 340 MSTB, 367 MSTB and 384 MSTB, respectively. Therefore, higher amount of gas in the lower is displaced in deeper lower reservoir, resulting in higher RF2.

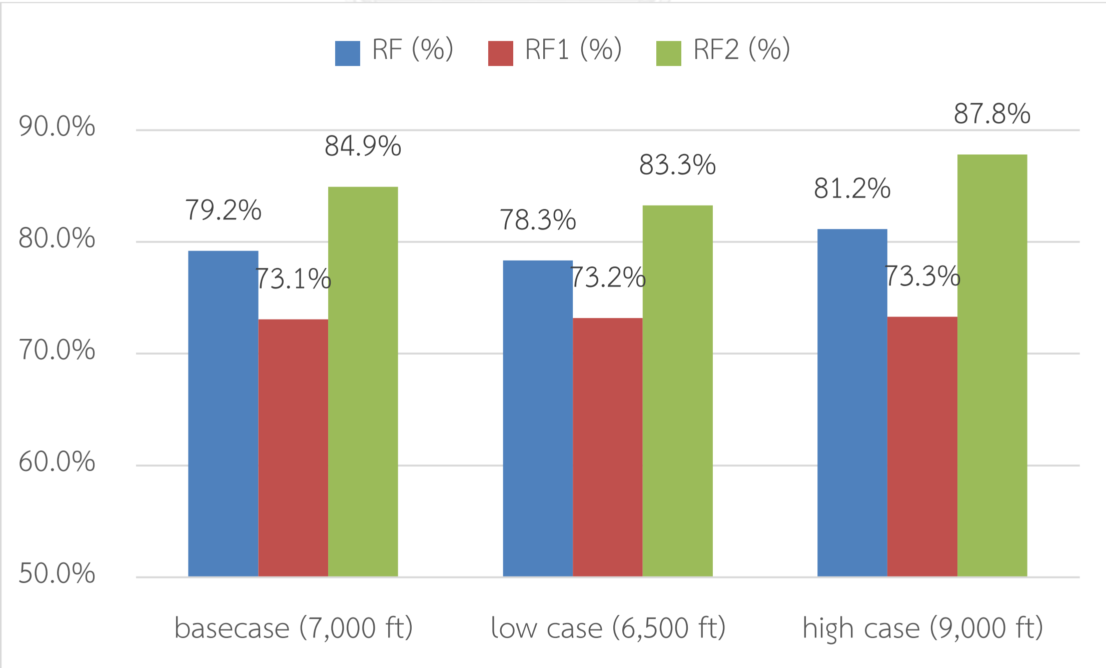

Figure 5.33 Gas recovery comparison among different top depth of the lower reservoir with DWD

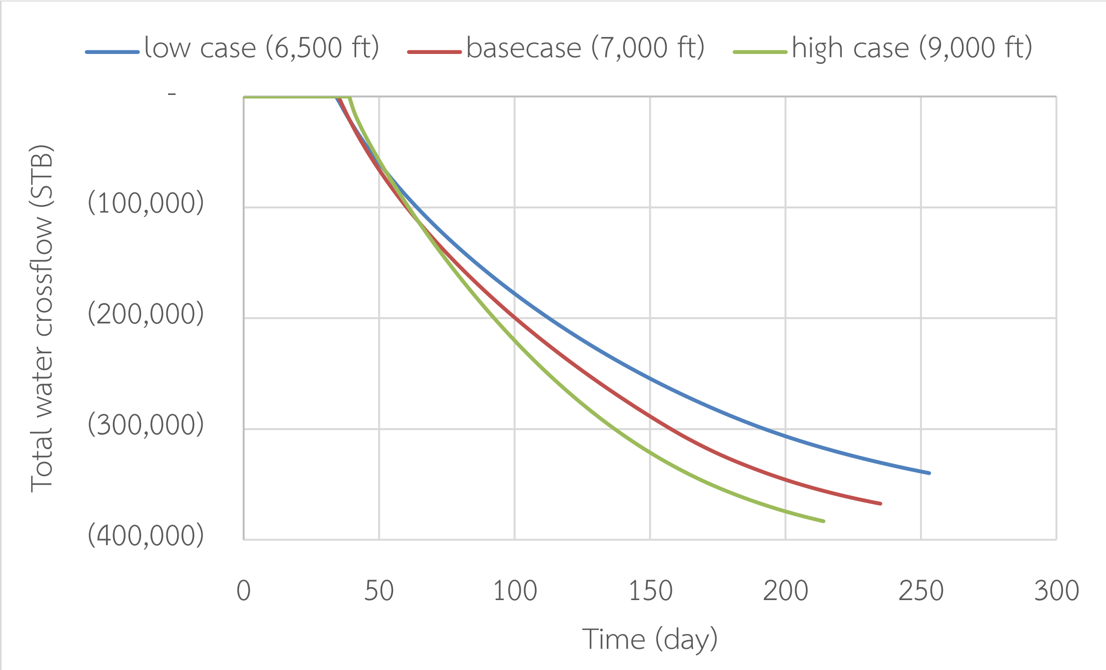

Figure 5.34 Amount of crossflowing water from the upper reservoir to the lower reservoir among different top depth of the lower reservoir with DWD

The fourth studied parameter is vertical to horizontal permeability ratio. As shown in Figure 5.35, RF, RF1 and RF2 of all the cases are very close to each other. However, RF1 slightly increases as vertical permeability increases. Possible reason for this might be pressure sustaining of the upper reservoir. Due to the fact that all the cases produce with very low WGR (<1 STB/MMSCF), water loading is not the major concern for these cases, instead the reservoir pressure is. As the Kv/Kh ratio is high, there is small pressure drawdown.

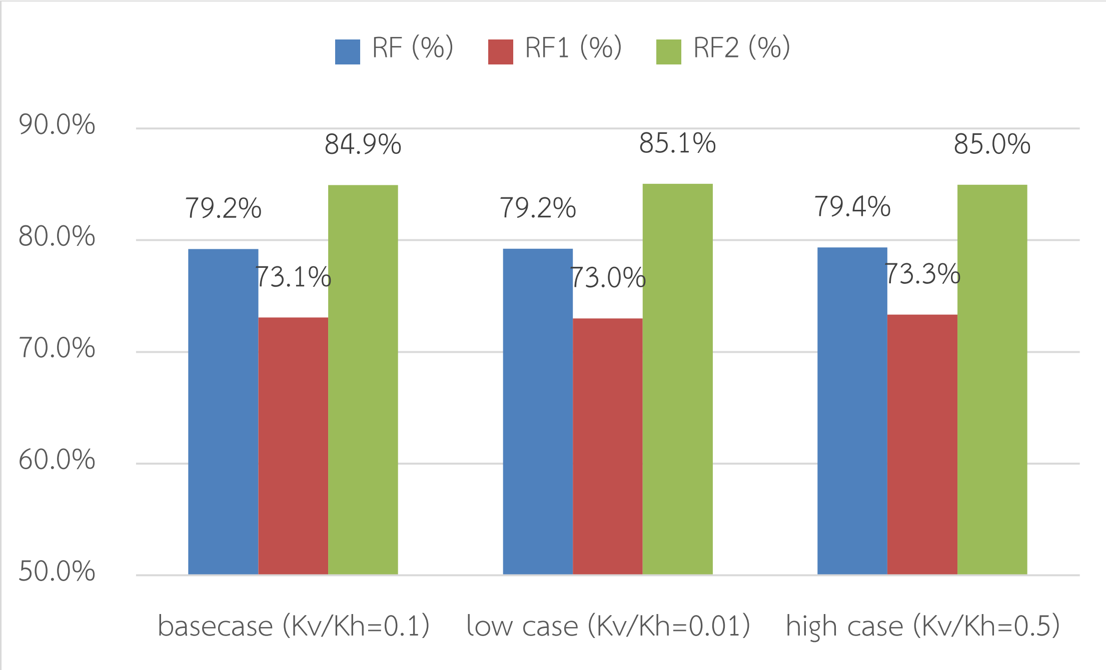

Figure 5.35 Gas recovery comparison among different vertical to horizontal permeability ratio with DWD

The fifth studied parameter is horizontal permeability. As shown in Figure 5.36, RF1 and RF2 increase as horizontal permeability increases. Both the upper and the lower reservoirs benefit from higher horizontal permeability. As shown in Figure 5.37, cases with higher horizontal permeability yield the higher initial maximum rate before and after dumpflood. Furthermore, after dumpflood, flow rate drops slower due to less drawdown pressure, and shorter production period is required due to faster gas production.

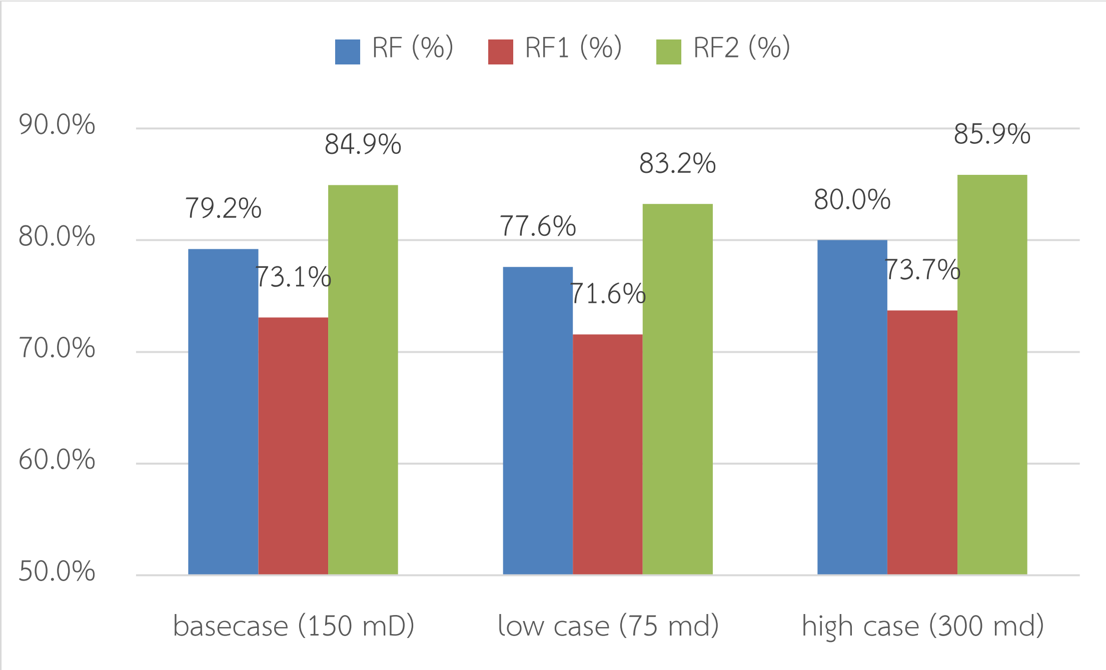

Figure 5.36 Gas recovery comparison among different horizontal permeability with DWD

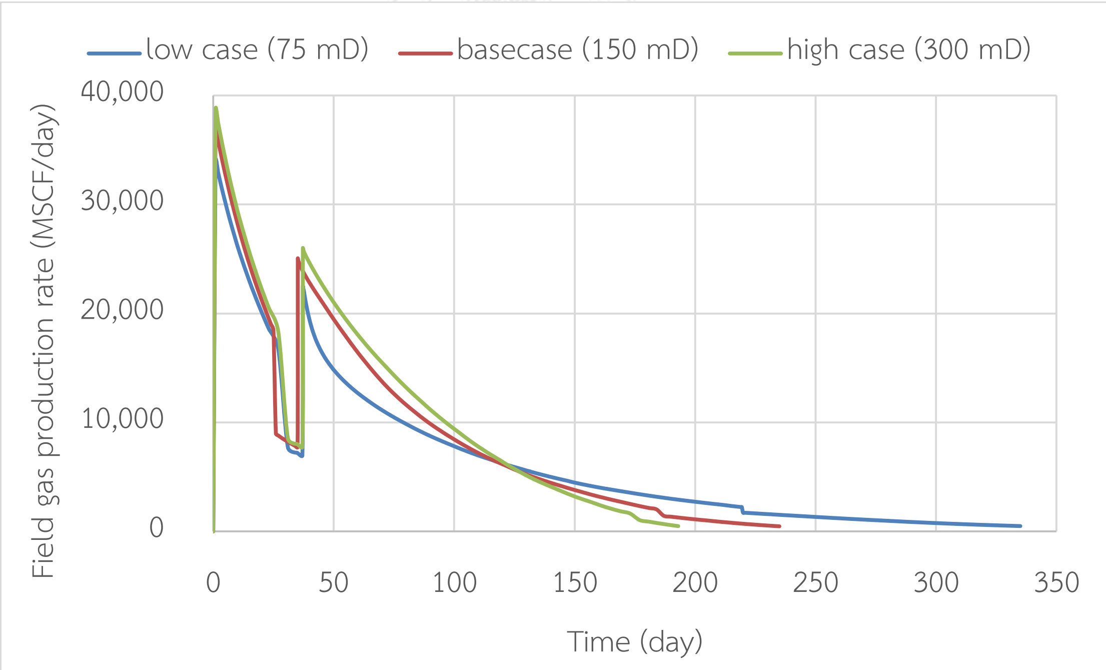

Figure 5.37 Field gas production rate among different horizontal permeability with DWD

All in all, different values of reservoir properties have little impact on the performance of DWD. As illustrated in Figure 5.38, RF can be altered from minimum of -2.16% to maximum of +1.95% from the base case under scope of the varied parameters. The reservoir parameter that has the highest negative impact on RF is thickness of the lower reservoir. When the value is changed from 20 ft. to 10 ft., RF is decreases from 79.21% to 77.06%, 2.16% reduction. On the other hand, the reservoir parameter that has the highest positive impact on RF is top depth of the lower reservoir. When the value is changed from 7,000 ft. to 9,000 ft., RF is increased from 79.21% to 81.16%, 1.95% reduction.

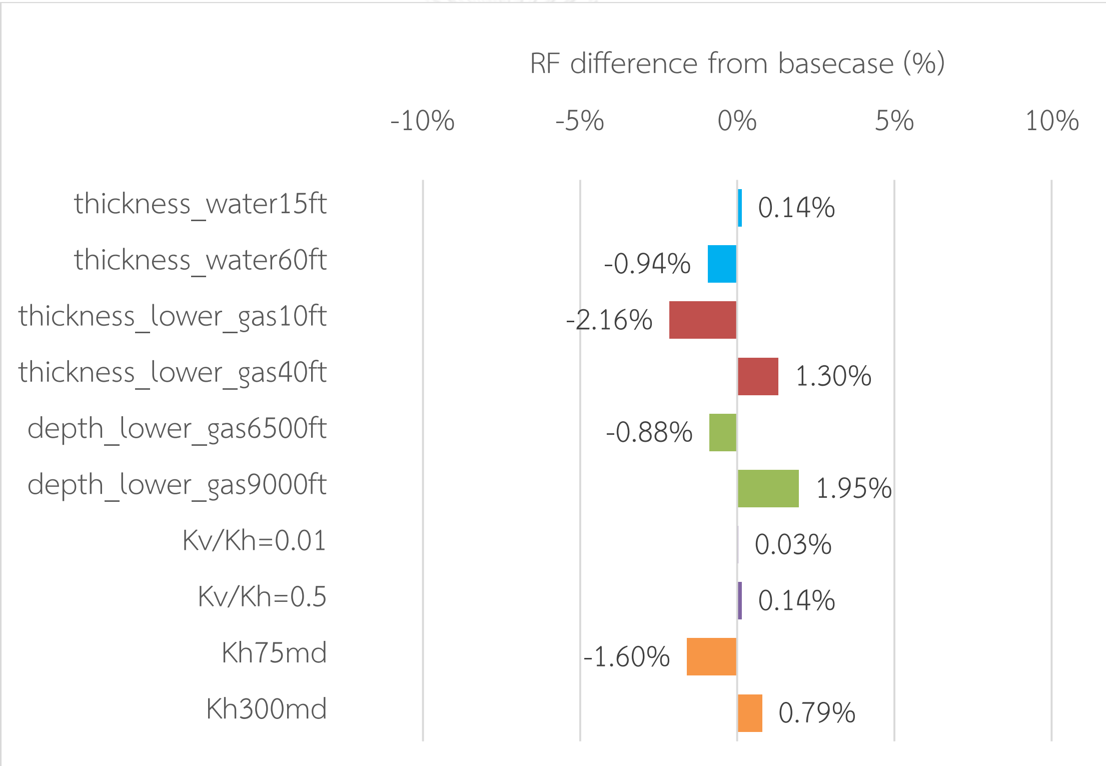

Figure 5.38 RF difference from the base case with DWD

5.5 Comparison between conventional production scenarios and DWD

All the cases are compared across production scenarios under the same reservoir conditions. In the base case, the best operational parameters previously selected are used depending on each production scenario. For other varied reservoir conditions, the same set of operational parameters are used for each production scenario. Eventhough they are not essentially the best conditions for different reservoir conditions, they can be used to demonstrate the results for each production scenario such that it is acceptable in terms of comparing across different production scenarios.

5.5.1 Basecase

In the base case, DWD performs the best in all aspects: RF, water production and production time. RF increases by 8.95% from commingled production and 6.31% from bottom-up production as depicted in Figure 5.39. The total water production reduces by 43 times from commingled strategy and 32 times from bottom-up production. Production period reduces by 13 days from commingled scenario and 186 days from bottom-up production.

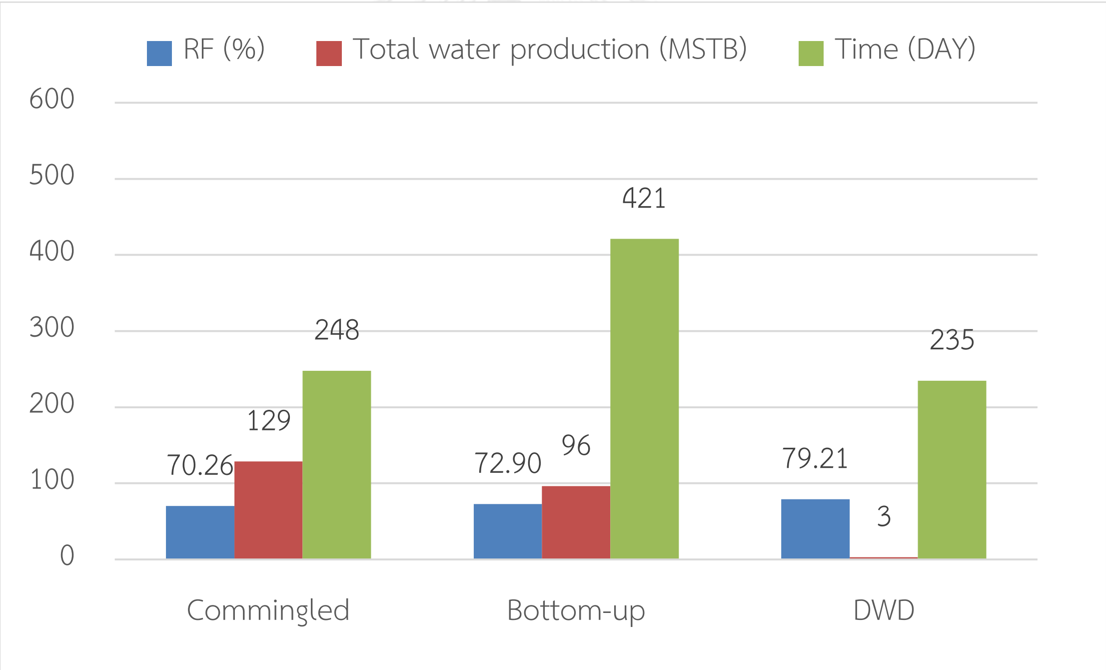

Figure 5.39 Performance comparison between the three production scenarios under basecase reservoir conditions

5.5.2 Thickness of water column of the upper reservoir

In the case of 15-ft water, DWD performs the best in terms of RF and water production, yet it requires a little longer production period than commingled production as shown in Figure 5.40. RF increases by 11.22% from commingled and 5.57% from bottom-up production. The total water production reduces from 75 MSTB in commingled strategy and 64 MSTB in bottom-up production to none. Production period reduces by 274 days from bottom-up production but increases by 14 days from commingled production.

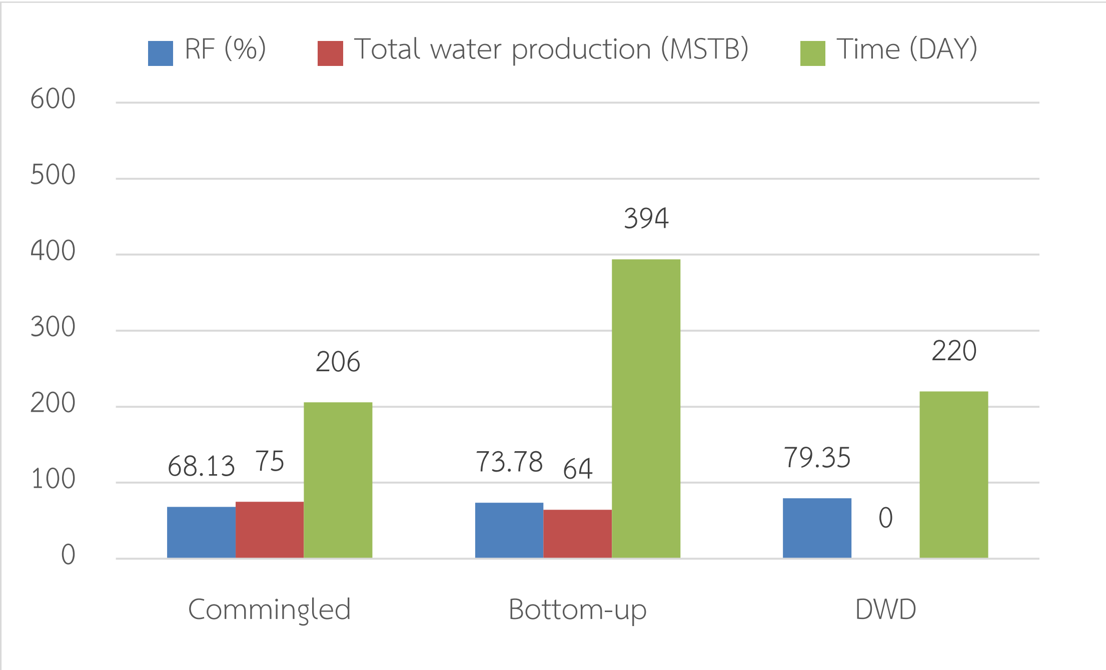

Figure 5.40 Performance comparison between the three production scenarios with water column thickness of the upper reservoir varied to 15 ft.

. In the case of 60-ft water as illustrated in Figure 5.41, DWD performs the best in terms of RF and water production but requires a longer production period than commingled production. RF increases by 13.19% from commingled method and 6.03% from bottom-up production. The total water production reduces by 4.14 times from commingled technique and 3.43 times from bottom-up production. Production period reduces by 142 days from bottom-up strategy but increases by 184 days from commingled production.

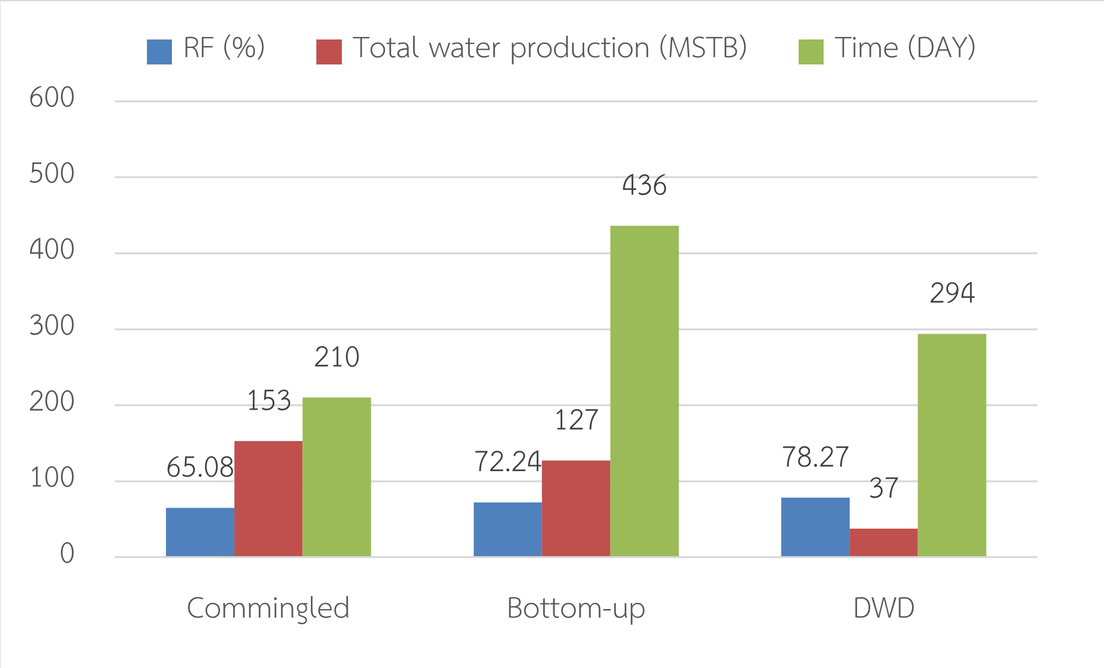

Figure 5.41 Performance comparison between the three production scenarios with water column thickness of the upper reservoir varied to 60 ft.

5.5.3 Thickness of gas column of the lower reservoir

In the case of 10-ft gas, DWD performs the best in terms of RF and water production but requires about two times longer production period from commingled production (see in Figure 5.42). RF increases by 16.21% from commingled strategy and 7.23% from bottom-up production. The total water production reduces by 4.54 times from commingled production and 3.73 times from bottom-up production. Production period reduces by 69 days from bottom-up method but increases by 141 days from commingled production.

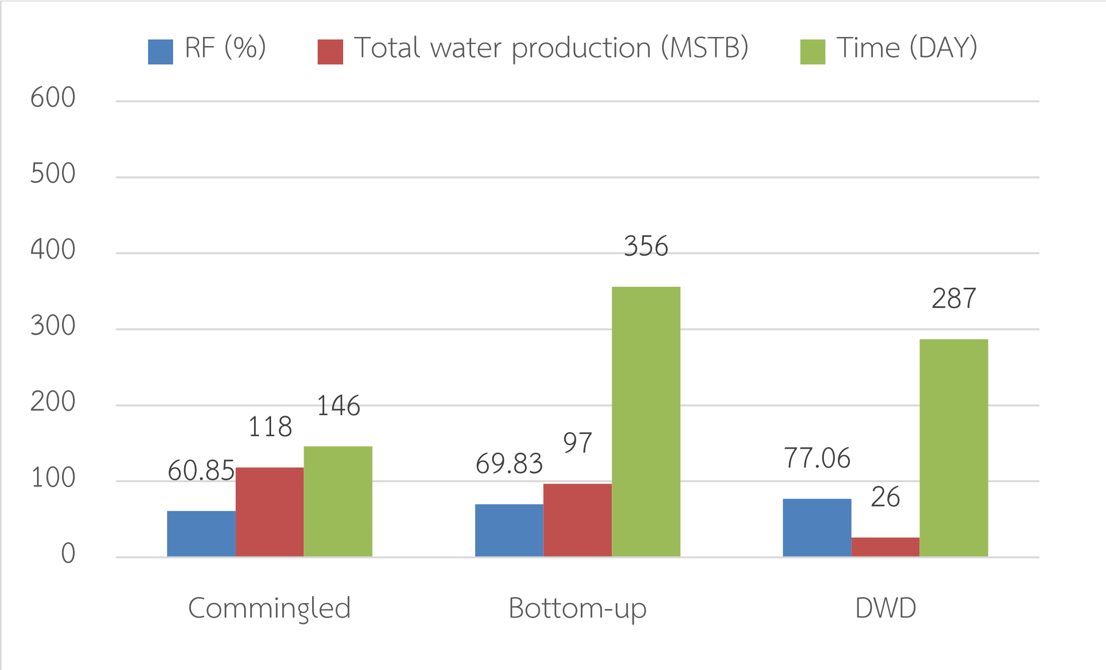

Figure 5.42 Performance comparison between the three production scenarios with gas column thickness of the lower reservoir varied to 10 ft.

In the case of 60-ft gas, DWD performs the best in all aspects: RF, water production and production period as displayed in Figure 5.43. RF increases by 9.61% from commingled technique and 4.60% from bottom-up production. The total water production reduces by 49 times from commingled strategy and 48.5 times from bottom-up production. Production period reduces by 10 days from commingled method and 240 days from bottom-up production.

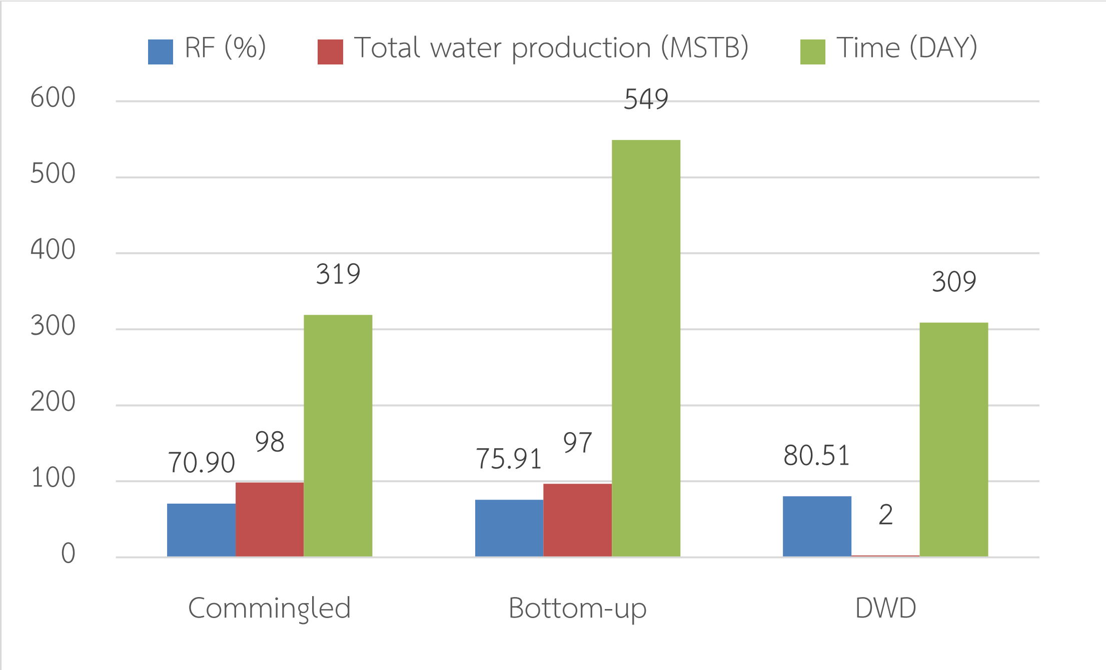

Figure 5.43 Performance comparison between the three production scenarios with gas column thickness of the lower reservoir varied to 40 ft.

5.5.4 Top depth of the lower reservoir

In the case of 6,500-ft top depth, DWD performs the best in terms of RF and water production but requires a longer production period than commingled production as shown in Figure 5.44. RF increases by 11.16% from commingled strategy and 6.26% from bottom-up production. The total water production reduces by 12.8 times from commingled production and 9.6 times from bottom-up production. Production period reduces by 162 days from bottom-up method but increases by 32 days from commingled production.

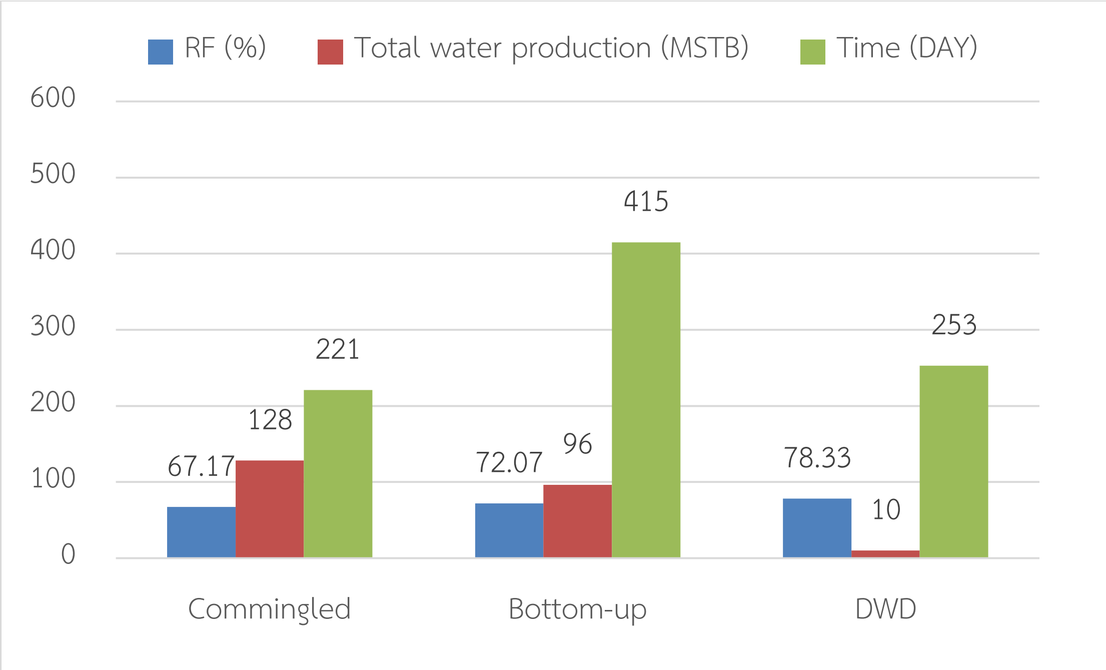

Figure 5.44 Performance comparison between the three production scenarios with top depth of the lower reservoir varied to 6,500 ft.

In the case of 9,000-ft top depth, DWD performs the best in all aspects: RF, water production and production period as illustrated in Figure 5.45. RF increases by 8.58% from commingled strategy and 6.39% from bottom-up production. The total water production reduces from 120 MSTB in commingled production and 99 MSTB in bottom-up production to none. Production period reduces by 46 days from commingled method and 222 days from bottom-up production.

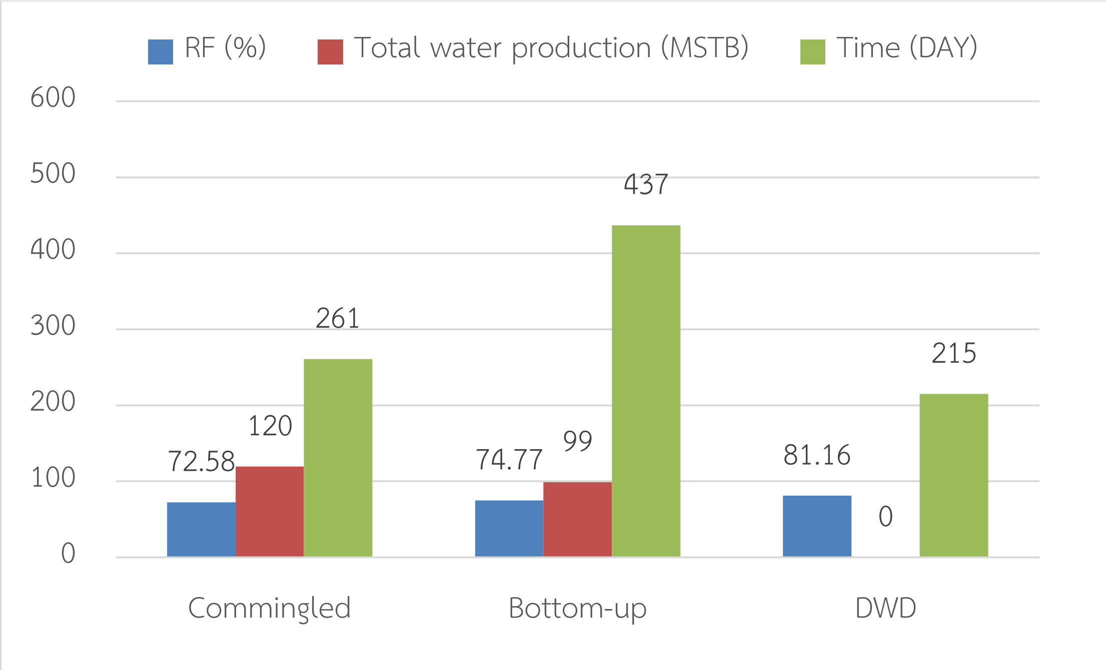

Figure 5.45 Performance comparison between the three production scenarios with top depth of the lower reservoir varied to 9,000 ft.

5.5.5 Vertical to horizontal permeability ratio

In the case of Kv/Kh of 0.01, DWD performs the best in terms of RF and water production but its production period is equal to commingled production as displayed in Figure 5.46. RF increases by 4.5% from commingled production and 3.24% from bottom-up production. The total water production reduces by 26 times from commingled strategy and 10 times from bottom-up production. Production period reduces by 95 days from bottom-up production and is equal to commingled production.

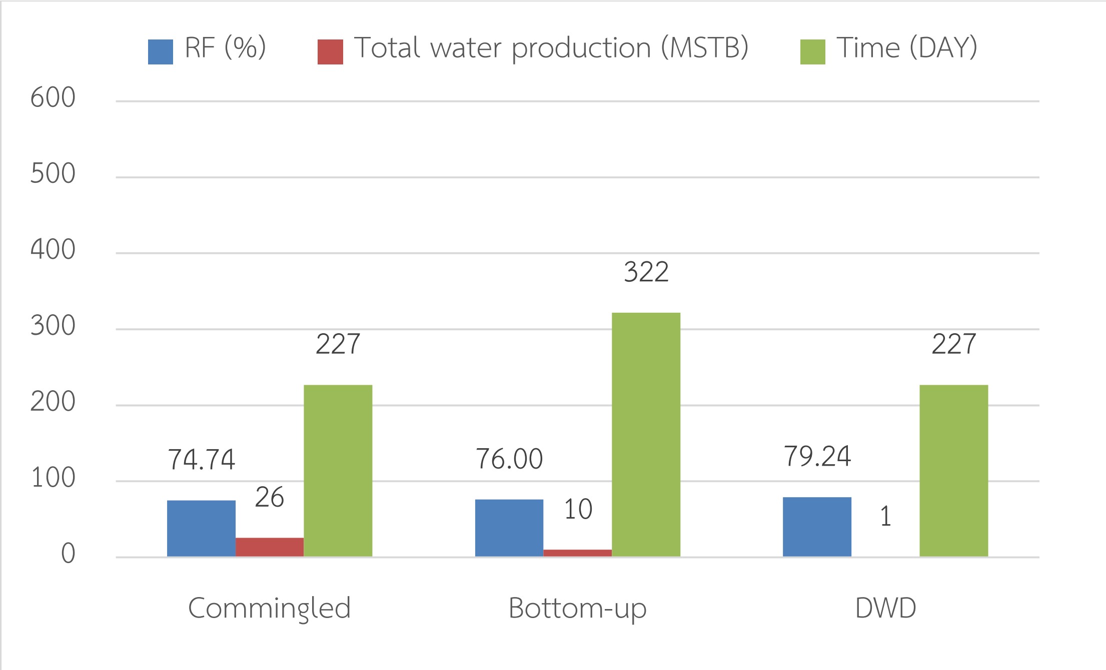

Figure 5.46 Performance comparison between the three production scenarios vertical to horizontal permeability ratio varied to 0.01

In the case of Kv/Kh of 0.5, DWD performs the best in terms of RF and water production but it requires a longer production time than commingled production as depicted in Figure 5.47. RF increases by 14.61% from commingled technique and 12.72% from bottom-up production. The total water production reduces by 39.75 times from commingled method and 28.5 times from bottom-up production. Production period reduces by 97 days from bottom-up production but increases by 32 days from commingled production.

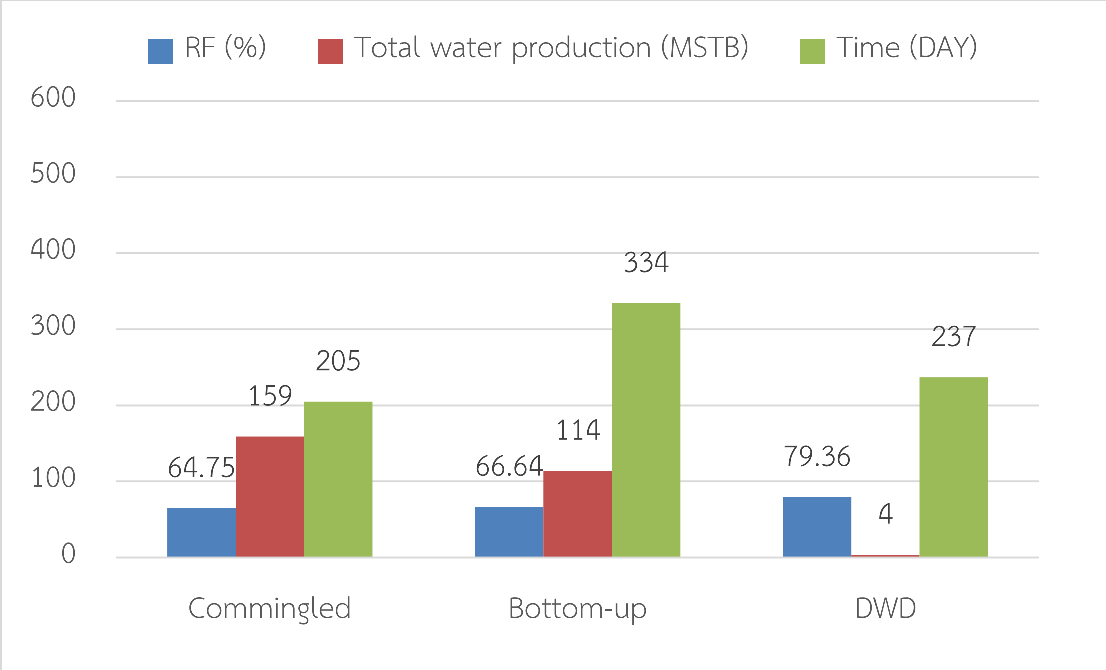

Figure 5.47 Performance comparison between the three production scenarios with vertical to horizontal permeability ratio varied to 0.5

5.5.6 Horizontal permeability

In the case of 75-mD horizontal permeability, DWD performs the best in terms of RF and water production but it requires a longer production period than commingled production as shown in Figure 5.48. RF increases by 14.11% from commingled method and 11.44% from bottom-up production. The total water production reduces by 6 times from commingled technique and 3.86 times from bottom-up production. Production period reduces by 102 days from bottom-up strategy but increases by 115 days from commingled production.

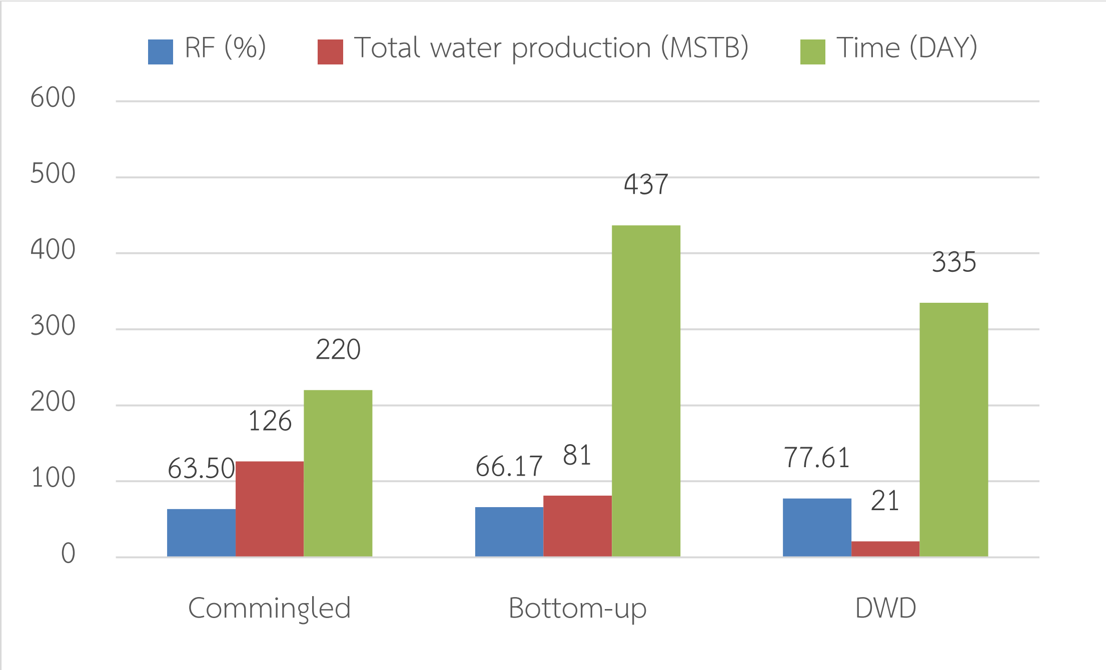

Figure 5.48 Performance comparison between the three production scenarios with horizontal permeability varied to 75 mD

In the case of 300-mD horizontal permeability, DWD performs the best in all aspects: RF, water production and production period as illustrated in Figure 5.49. RF increases by 9.56% from commingled production and 2.27% from bottom-up production. The total water production reduces from 83 MSTB in commingled strategy and 91 MSTB in bottom-up production to none.

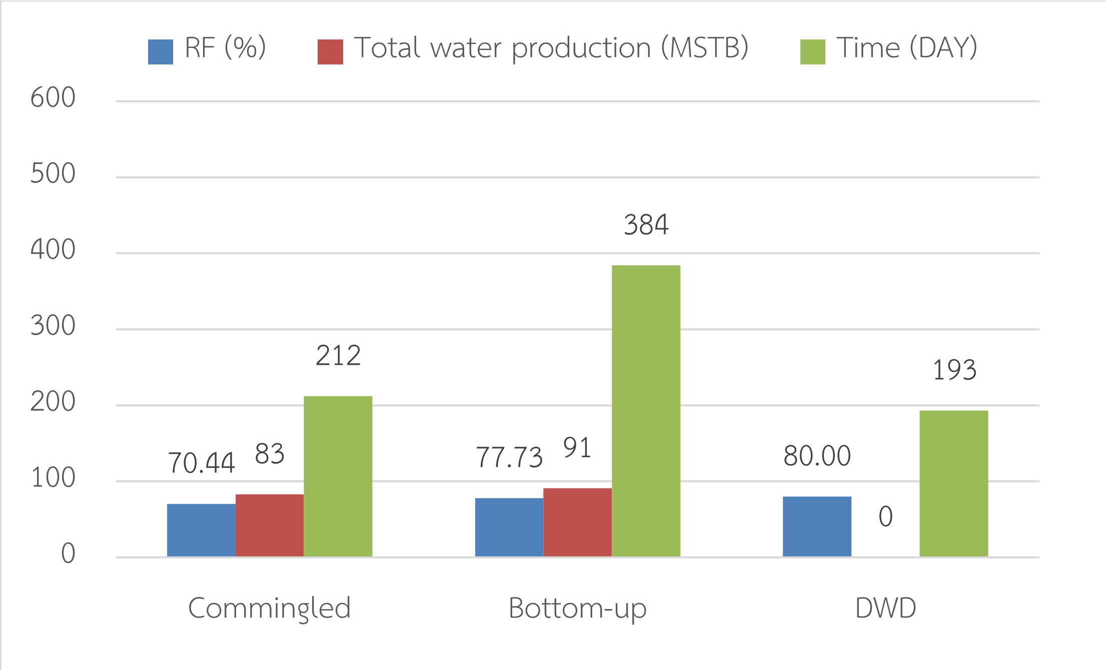

Figure 5.49 Performance comparison between the three production scenarios with horizontal permeability varied to 300 mD

5.6 Improvement of DWD from conventional production scenarios under various reservoir conditions

In this section, DWD is compared to commingled production and bottom-up production under different varied reservoir parameters in order to determine the favorable reservoir conditions to perform DWD. RF increment, production time reduction and total water reduction are determined based on the difference in results between DWD and commingled/bottom-up production. A negative value in production time reduction means that DWD requires more production time.

Figure 5.50 illustrates the improvement when performing DWD instead of commingled production. As shown in Figure 5.50, RF increment is at least 5% and at most 16%. In terms of RF gain, the most benefited case is the case with 10-ft of the lower reservoir where 16% of RF gain can be achieved. Thinner lower gas reservoir tremendously worsens the performance of commingled strategy but slightly worsens the performance of DWD. For commingled production, thinner lower reservoir decreases the gas production from the lower layer to lift up fluid column and allows higher contribution from the upper water-drive reservoir which results in high WGR. For DWD, thinner lower gas reservoir affects less to downhole gas production to lift fluid column because dry gas reservoir is produced separately from the water-drive gas reservoir where production WGR is very low. Moreover, the same amount of crossflowing water can displace higher pore volume of remaining gas in the thinner lower reservoir which results in higher RF2. The least benefited case is the case with 0.01 of Kv/Kh ratio where only 5% of RF gain can be obtained. Lower Kv/Kh ratio slows down water coning which is the main production problem in commingled production. Thus, commingled production can perform quite well under this reservoir condition. One of the purposes of DWD is also to reduce water coning by draining water out from the water-drive reservoir. Therefore, the benefit gained from DWD in reducing water coning is less under this reservoir condition.

In terms of water reduction, DWD is able to reduce water production in the range of 25 MSTB to 155 MSTB or 75% to 100% as shown in Figure 5.51. In terms of volume of water reduction, the most benefited case is the case of Kv/Kh of 0.05 where 155 MSTB (98% of water) reduction can be achieved. The least benefited case is the case of Kv/Kh of 0.01 where 25 MSTB (98% of water) reduction can be obtained. In terms of percentage of water reduction, the three most benefited cases are the cases with Kh of 300 mD, top depth of the lower reservoir of 9,000 ft. and water thickness of 15 ft. where 100% of water reduction can be achieved. The least benefited case is the case with water thickness of 60 ft. where 75% of water reduction can be obtained.

However, the production time of DWD in most cases are longer than commingled production because 1) DWD does not produce from the two reservoirs simultaneously since the beginning, 2) DWD requires time for well intervention between the first batch and the second batch of perforation and 3) DWD produces with lower WGR until economic limit rate. In contrast, commingled production mostly dies because of water loading before reaching the economic limit.

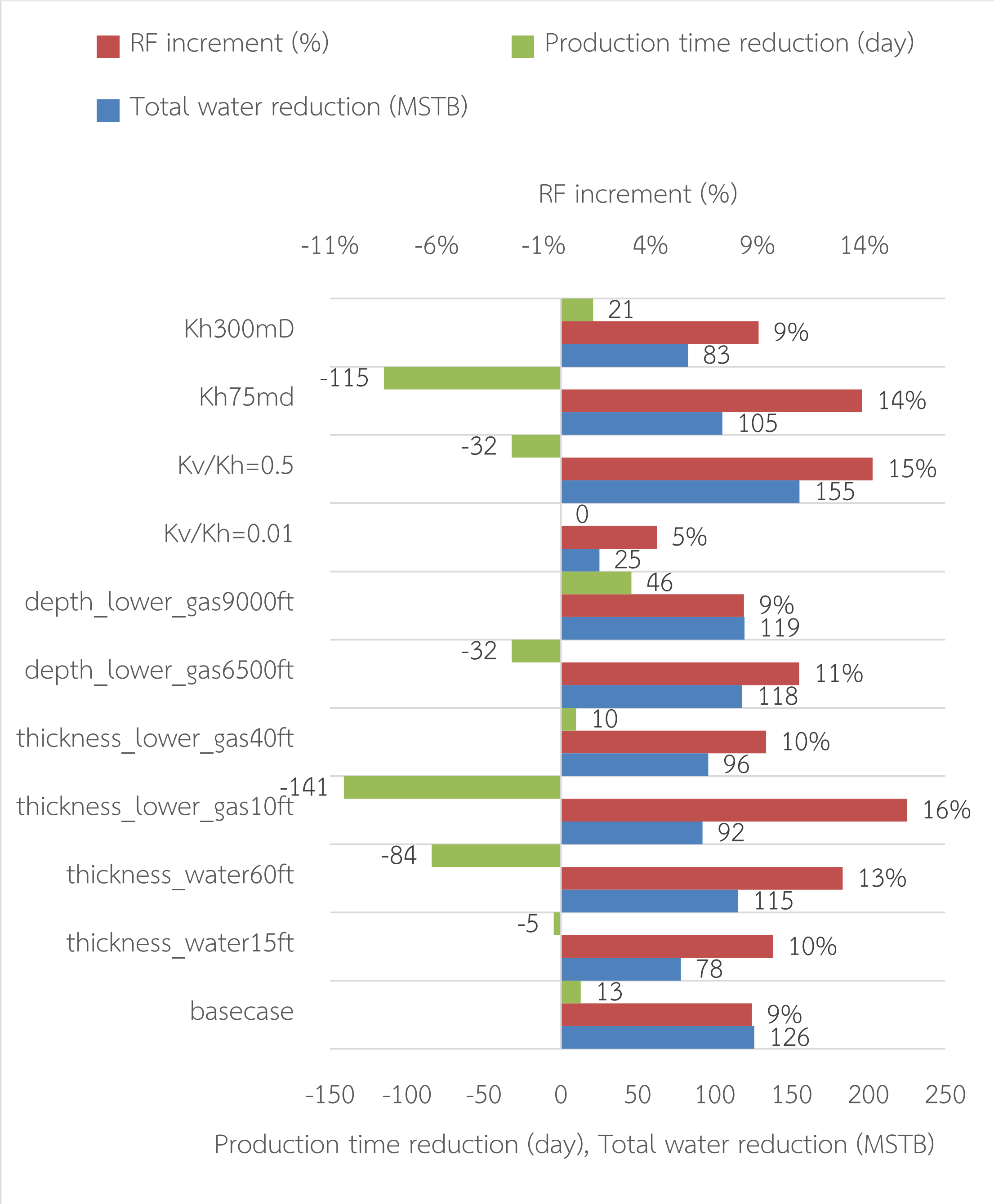

Figure 5.50 Performance improvement of DWD from commingled production

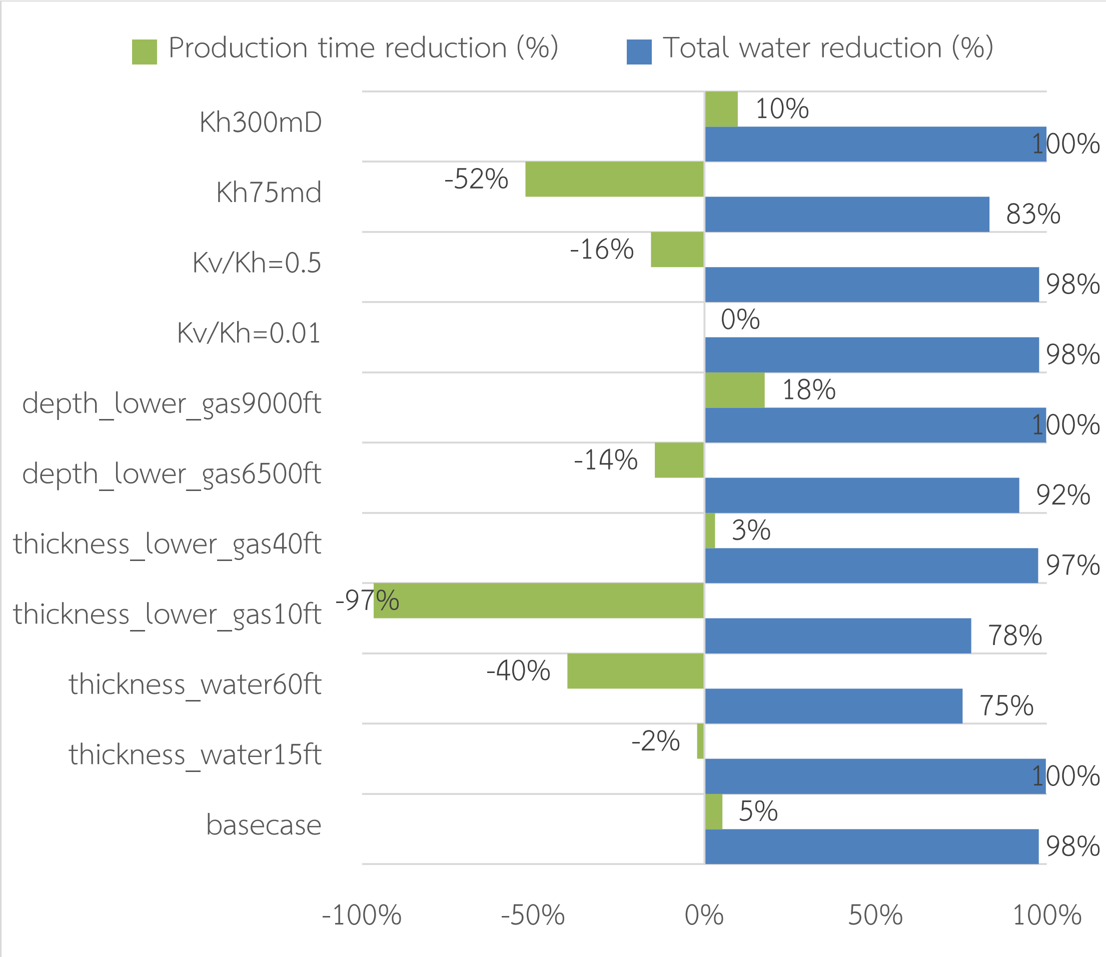

Figure 5.51 Performance improvement of DWD from commingled production in terms of % reduction in total water production and % reduction in production time

Figure 5.52 illustrates the improvement when performing DWD instead of bottom-up production. As shown in Figure 5.52, RF increment ranges from 2% to 13%. In terms of RF gain, the most benefited case is the case of Kv/Kh of 0.5 where 13% of RF gain can be achieved. Both bottom-up and DWD produce from the two reservoirs separately but the difference is that water is drained during the production from the upper water-drive reservoir in DWD. Under high Kv/Kh condition, water cones very fast in bottom-up production but this is not the problem in DWD since most of the water is dumpflooded into the lower reservoir. The least benefited case is the case of Kh of 300 mD where only 2% of RF gain can be obtained. Higher horizontal permeability helps maintain high BHP by reducing drawdown. This high BHP can maintain high gas flow rate without water loading problem. This results in about the same gas recovery from the water-drive reservoir in both bottom-up and DWD cases. Thus, the main benefit only comes from dumpflooding the lower dry gas reservoir.

In terms of water reduction, DWD is able to reduce water production in the range of 9 MSTB to 110 MSTB or 71% to 100% as shown in Figure 5.53. In terms of volume of water reduction, the most benefited case is the case of Kv/Kh of 0.5 where 110 MSTB (97% of water) reduction can be achieved. The least benefited case is the case of Kv/Kh of 0.01 where only 9 MSTB (97% of water) reduction can be obtained. In terms of percentage of water reduction, the three most benefited cases are the cases with Kh of 300 mD, top depth of the lower reservoir of 9,000 ft. and water thickness of 15 ft. where 100% of water reduction can be achieved. The least benefited case is the case with water thickness of 60 ft. where 71% of water reduction can be obtained.

In addition, DWD also helps shorten the production time from bottom-up production under the scope of varied reservoir conditions. It can reduce upto 240 days or 44% of production time, still with 6% of RF gain and 94 MSTB or 97% of water reduction in the case of lower reservoir thickness of 40 ft.

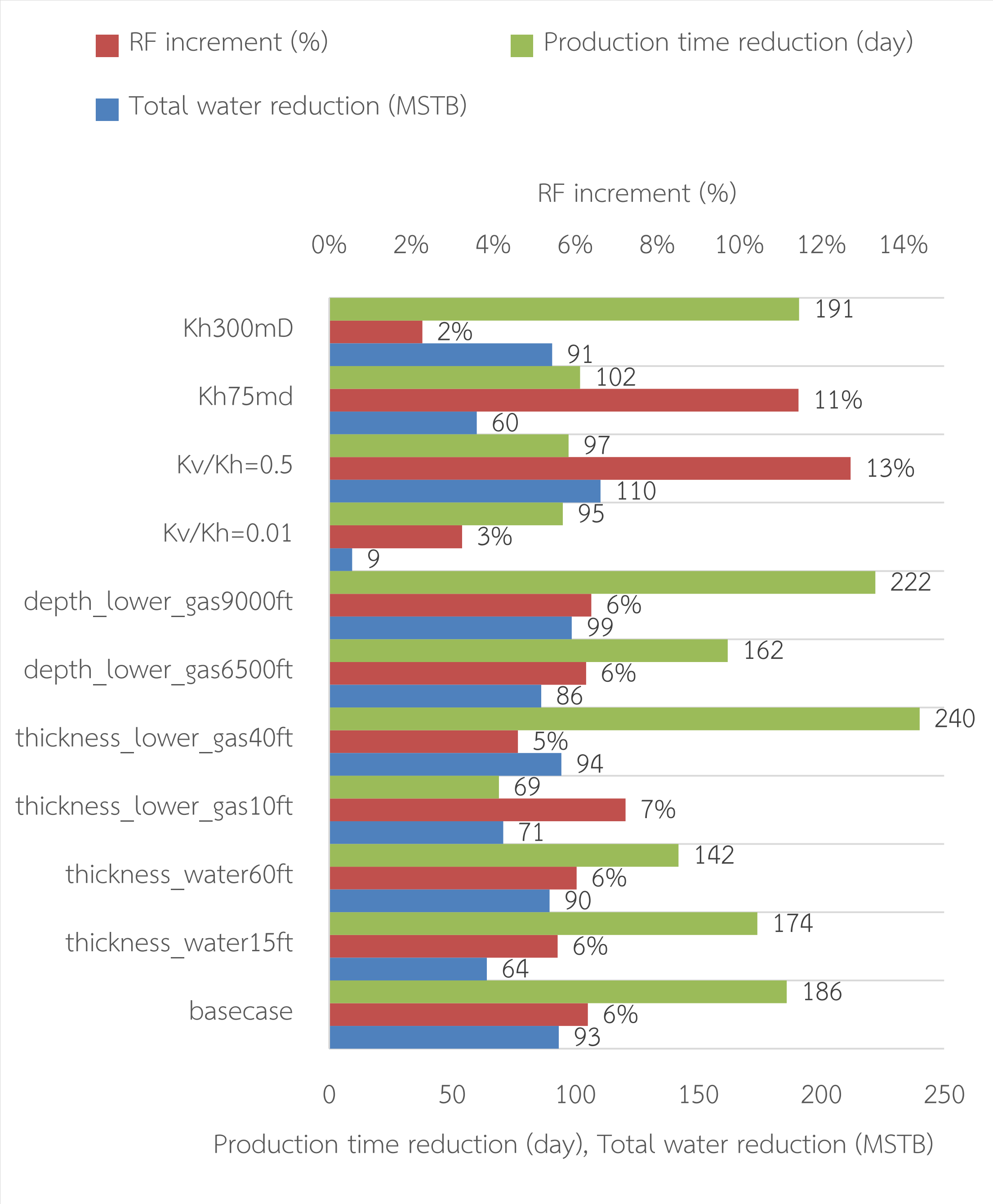

Figure 5.52 Improvement of DWD from bottom-up production

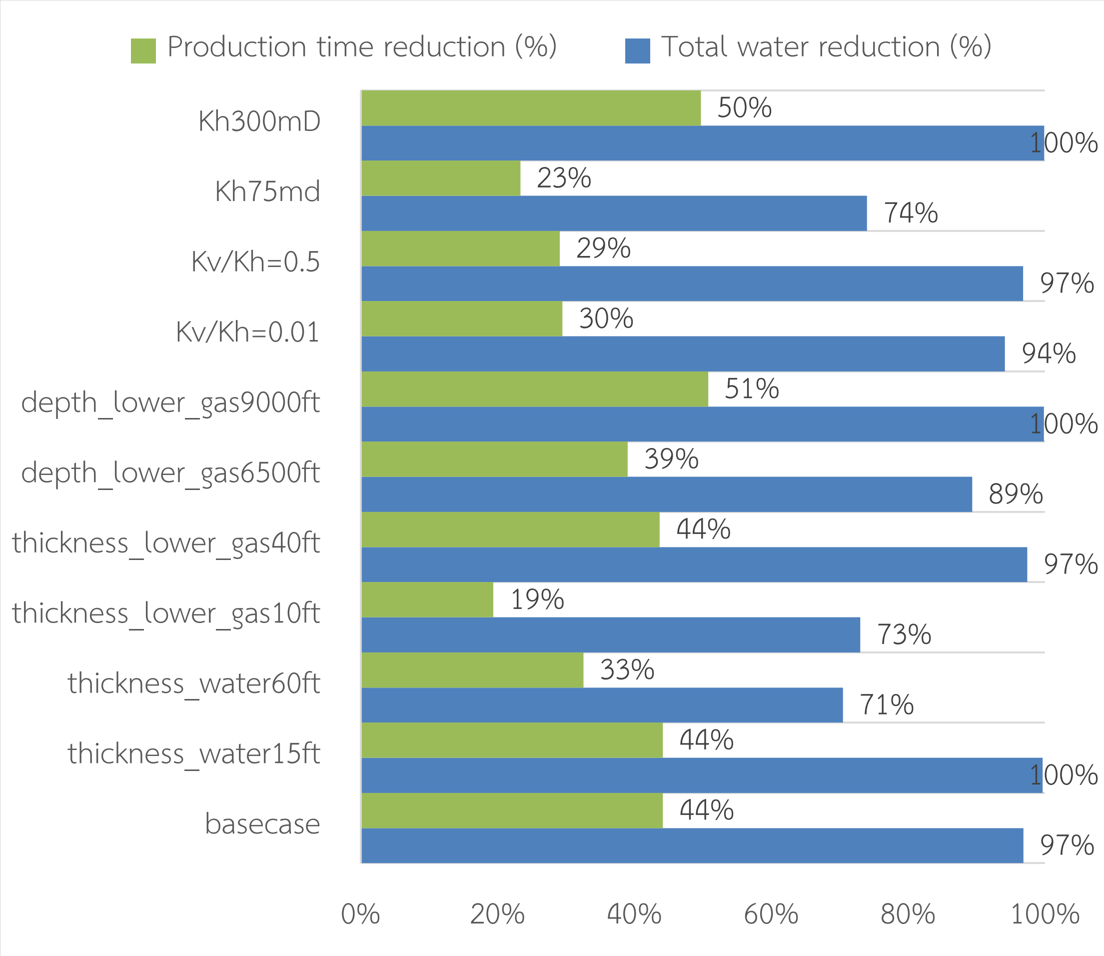

Figure 5.53 Performance improvement of DWD from bottom-up production in terms of % reduction in total water production and % reduction in production time

CHAPTER 6
CONCLUSIONS AND RECOMMENDATIONS

This chapter concludes the key findings obtained in Chapter 5. The conclusion are mainly for preliminary determining favorable reservoir conditions for performing the proposed technique, Downhole Water Drain from Bottom Water-Drive Gas Reservoir into Partially Depleted Gas Reservoir (DWD). In addition, the impact from each studied parameters on the two conventional production scenarios are mentioned.

6.1 Conclusions

1) For commingled production, lower initial production rate slightly improves gas recovery and moderately reduces water production. Longer perforation interval of the gas zone moderately increases the gas recovery factor with a significant increase in water production.
2) For bottom-up production, all the studied operational parameters have minimal effect on gas recovery. However, longer gas perforation interval significantly increases water production and higher initial production rate moderately increases water production.
3) For DWD, longer gas and water perforation intervals slightly improve gas recovery. Water production depends mainly on water and gas perforation intervals. Initial rate and time to start dumpflood do not have obvious relationship with gas and water production. In any cases, the difference in gas production among the cases lies within small range.
4) Comparing among the same production scenario, thickness of water column of the upper reservoir has a moderate impact on gas recovery for commingled production but small impact on bottom-up production and DWD.
5) Comparing among the same production scenario, thickness of gas column of the lower reservoir has significant impact on commingled production, moderate impact on bottom-up production and small impact on DWD.

6) Comparing among the same production scenario, top depth of the lower reservoir has moderate impact on commingled production but small impact on bottom-up production and DWD.
7) Comparing among the same production scenario, vertical permeability has significant impact on commingled and bottom-up production but no impact on DWD.
8) Comparing among the same production scenario, horizontal permeability has moderate impact on commingled production, significant impact on bottom-up production and small impact on DWD.
9) Comparing among the same reservoir conditions, performing DWD instead of commingled production can improve gas recovery from 5% upto 16% and reduce total water production from 25 MSTB upto 155 MSTB or from 75% upto 100% but DWD generally requires more production time.
10) Comparing among the same reservoir conditions, performing DWD instead of bottom-up production can improve gas recovery from 2% upto 13%, reduce total water production from 9 MSTB upto 110 MSTB or from 71% upto 100%, and reduce total production time for the maximum of 240 days (with 6% of RF gain and 94 MSTB or 97% of water reduction).
11) Under the scope of studied reservoir parameters, the highest gain in RF compared to commingled production belongs to the case in which thickness of water column of the upper reservoir is 30 ft., thickness of the lower reservoir is 10 ft., top depth of the lower reservoir is 7,000 ft., vertical to permeability ratio is 0.1, and horizontal permeability is 150 mD.
12) Under the scope of studied reservoir parameters, the highest gain in RF compared to bottom-up production belongs to the case in which thickness of water column of the upper reservoir is 30 ft., thickness of the lower reservoir is 20 ft., top depth of the lower reservoir is 7,000 ft., vertical to permeability ratio is 0.5, and horizontal permeability is 150 mD.

6.2 Recommendations

1) Operational parameters should be optimized for each specific reservoir conditions in order to achieve maximum RF, minimum water production or minimum production time depending on the purpose.
2) The tubing size used in this study is 2 7/8 in. which can handle a large amount of WGR. If another tubing size is used, different results may be obtained.
3) IP rate should be optimized differently when producing from different drive-mechanism gas reservoirs, e.g., higher IP rate is good for dry gas reservoir in terms of more gas recovery and production period meanwhile lower IP rate is good for water-drive gas reservoir in terms of less water production.

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APPENDIX

APPENDIX A
PRODUCTION SCHEDULE

In the thesis, all the simulation cases have two production wells which are PROD1 and PROD2. Perforations of K-layer in the upper reservoir are not the same depending upon each case.

Segmented well model is only required for commingled production which are described in Section A.3 - Section A.5. ACTION keyword is required for bottom-up production and DWD when additional perforations are needed which is described in Section 4.5.

In the segmented well model, VFP table can be used to calculate pressure drop across particular segment of the tubing. VFP table 1 is responsible for tubing segment from the surface to top depth of the upper reservoir. VFP table 2 is used for tubing segment from the end point of gas perforation interval in the upper reservoir to top depth of the lower reservoir. VFP table 3 is created for tubing segment from the surface to top depth of the lower reservoir. The detailed input data for each keyword are summarized in the following sections.

A.1 Well Specification (keyword: WELSPECS)

Table A.1 Data for well specification (keyword: WELSPECS)

Parameters	PROD1	PROD2	DUMP1
I Location	13	13	13
J Location	13	38	13
Preferred phase	Gas	Gas	Water

A.2 Well Completion Specification Data (keyword: COMPDAT)

Table A.2 Data for well completion specification (keyword: COMPDAT)

Parameters	PROD1	PROD2	DUMP1
Wellbore ID (ft.)	0.5104	0.5104	0.5104
Perforated K-layer in the upper reservoir	1-5, 1-10, 1-15	1-5, 1-10, 1-15	41-50, 31-50
Perforated K-layer in the lower reservoir	52-55	52-55	52-55

A.3 Segmented Well Definition (keyword: WELSEGS)

Table A.3 Data for segmented well definition (keyword: WELSEGS)

Parameters	Segments (PROD1 & PROD2)			
	1	2	3	4
Length	6000	15	985	20
Depth	6000	15	985	20
Tubing ID (ft.)	0.2034			
Roughness (ft.)	0.00015			

A.4 Segmented Well Completion (keyword: COMPSEGS)

Table A.4 Data for segmented well completion (keyword: COMPSEGS)

Parameters	Segments (PROD1 & PROD2)	
	2	**4**
Starting K-layer	1	52
Ending K-layer	5, 10, 15	55
Starting length (ft.)	0	1000
Ending length (ft.)	5, 10, 15	1020

A.5 Segment Vertical Flow Performance Table (keyword: WSEGTABL)

Table A.5 Data for segment vertical flow performance table (keyword: WSEGTABL)

Parameters	PROD1 & PROD2
First segment	3
Last segment	3
VFP table	2
Components of the pressure drop	FH *
Handling negative flow	FIX **
Scaling the interpolated pressure drop	LEN ***

Note: * FH stands for "Friction and hydrostatic losses."

** FIX stands for "Fixing the lookup value of the flow rate at the first flow point in the table."

*** LEN stands for "The interpolated pressure drop is scaled in proportion to the length of the segment relative to the table's datum length."

A.6 Production Well Control (keyword: WCONPROD)

Table A.6 Data for production well control

Parameters	PROD1	PROD2	DUMP1
Commingled production			
Open/Shut flag	OPEN	OPEN	-
Control	Gas rate	Gas rate	-
Gas rate (MMSCF/day)	5, 10, Max *	5, 10, Max *	-
THP target (psia)	500	500	-
VFP table number	1	1	-
Bottom-up production			
Open/Shut flag	OPEN	OPEN	-
Control	Gas rate	Gas rate	-
Gas rate (MMSCF/day)	5, 10, Max *	5, 10, Max *	-
THP target (psia)	500	500	-
VFP table number	3 (1^{st} phase **) 1 (2^{nd} phase **)	3 (1^{st} phase **) 1 (2^{nd} phase **)	-
DWD			
Open/Shut flag	OPEN	OPEN	STOP
Control	Gas rate	Gas rate	-
Gas rate (MMSCF/day)	5, 10, Max *	5, 10, Max *	-
THP target (psia)	500	500	-
VFP table number	3 (1^{st} phase **) 1 (2^{nd} phase **)	3	-

Note: * Max is full-choke rate where the well produces with maximum possible rate under specified minimum THP target

** 1st phase is the period before triggering condition is met and 2nd phase is the period after well intervention

A.7 Vertical Flow Performance (keyword: VFPPROD)

Table A.7 Input data for generating VFP tables

Parameters	Table		
	1	2	3
Fluid	Dry and wet gas		
Method	Black oil		
Gas gravity	0.92		
CGR (STB/MMSCF)	0		
Water salinity (ppm)	5000		
Gas viscosity correlations	Lee et al		
Dip angle (degree)	0		
Tubing ID (in.)	2.441		
Vertical lift correlation	Gray		
Overall heat transfer coefficient (BTU/hr/ft^2/°F)	7.98		
First node depth (ft.)	0	6015	0
Last node depth (ft.)	6000	6500, 7000, 9000	6500, 7000, 9000
Temperature at first node (°F)	86	275.91	86
Temperature at last node (°F)	275.44	291.22, 307.01, 370.15	291.22, 307.01, 370.15
Enter rate (MMSCF/day)	0.000001, 0.1, 0.2, 0.4, 0.6, 0.8, 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 20, 30, 40, 50		
Variable 1: water gas ratio (STB/MMSCF)	0, 100, 120, 140, 160, 180, 200, 220, 240, 260		
Variable 2: first node pressure (psia)	14.7, 300, 500, 750, 1000, 1250, 1500, 2000, 3000, 4000		

A.8 Well economic limit (keyword: WECON)

Table A.8 Data for well economic limit

Parameters	PROD1	PROD2
Minimum gas rate per well (MSCF/day)	500	500

A.9 Well triggering conditions (keyword: ACTION)

Table A.9 Triggering conditions for well intervention

Operation	Conditions
Bottom-up production	
Adding perforations in the upper reservoir	Field gas production rate < 1000 MSCF/day
DWD	
Starting dumpflood	Field gas production rate < Plateau rate Field gas production rate < Half of plateau rate Field gas production rate < 2000 MSCF/day

VITA

Werapon Kamonkhantikul was born on April 28th, 1991 in Bangkok, Thailand. He pursued the bachelor's degree in Nano Engineering from Chulalongkorn University in 2013. After that, he had been working as a Failure Analysis Engineer at Seagate Technology Thailand for 1 year. Then, he got a scholarship for tuition fee and monthly stipend from Chevron Thailand Exploration and Production Limited to pursue his master’s degree study in Petroleum Engineering at Chulalongkorn University since 2014.