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EVALUATION OF DOWNHOLE WATER SINK IN BOTTOM WATER DRIVE GAS RESERVOIR

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ปวิช ศรีพงศ์วรกุล: การประเมินเทคนิคการผลิตน้ำก้นหลุมจากแหล่งกักเก็บก๊าซที่ขับเคลื่อนด้วยน้ำชั้นล่าง (EVALUATION OF DOWNHOLE WATER SINK IN BOTTOM WATER DRIVE GAS RESERVOIR) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร. สุวัฒน์ อธิชนากร, 89 หน้า.

การขึ้นรูปกรวยของน้ำ เป็นปัญหาใหญ่สำหรับหลุมผลิตก๊าซเนื่องจากเป็นสาเหตุหลักทำให้เกิดการกักตัวของของไหลในหลุมผลิตและยับยั้งผลผลิตก๊าซ มีเทคนิคหลายอย่างที่ช่วยป้องกันปัญหานี้ เช่น การใช้ปั๊มปี การอัดก๊าซเพื่อช่วยการผลิต, พลั้งเจอร์ลิฟท์ ใช้ท่อผลิตขนาดเล็ก ฯลฯ หนึ่งในเทคนิคที่น่าสนใจนั้นก็คือ วิธีการผลิตน้ำก้นหลุม หรือ ดีดับเบิ้ลยูเอส ซึ่งช่วยลดผลกระทบของ การขึ้นรูปกรวยของน้ำโดยการผลิตน้ำที่อยู่ใต้ผิวสัมผัสของไฮโดรคาร์บอนและน้ำ

ในการศึกษานี้ วิธีการผลิตน้ำก้นหลุมถูกนำมาใช้ในหลุมผลิตสำหรับแหล่งกักเก็บก๊าซที่ขับเคลื่อนด้วยน้ำชั้นล่างเพื่อช่วยเพิ่มการผลิต การวิเคราะห์ความอ่อนไหวของตัวแปรถูกดำเนินการโดยการเปลี่ยนแปลงเงื่อนไขการผลิต เพื่อดูผลกระทบของตัวแปรเหล่านี้ต่อประสิทธิภาพการผลิต ตัวแปรที่ได้ทำการศึกษาเหล่านี้ได้แก่ อัตราการกำจัดน้ำออก อัตราการผลิตก๊าซ ตำแหน่งที่ทำการยิงท่อกรุและช่วงระยะท่อกรุที่ยิง

ผลการศึกษาแสดงให้เห็นว่า เทคนิคการผลิตน้ำก้นหลุมสามารถทำให้ผลิตก๊าซได้จำนวนมากขึ้นเมื่อเทียบกับการผลิตทั่วไป และยังสามารถลดปริมาณน้ำที่เกิดจากการขึ้นรูปกรวยของน้ำ

การวิเคราะห์ความอ่อนไหวของตัวแปรแสดงให้เห็นว่าอัตราการกำจัดน้ำออกและตำแหน่งการยิงท่อกรุของชั้นก๊าซมีผลกระทบอย่างมากต่อปริมาณก๊าซที่ผลิตได้และปริมาณน้ำที่ลดลง การเพิ่มอัตราการกำจัดน้ำออกและการยิงท่อกรุที่ตำแหน่งด้านบนสุดของแหล่งกักเก็บทำให้ได้ผลผลิตก๊าซเพิ่มขึ้นและช่วยลดปริมาณน้ำที่เข้ามาจากชั้นก๊าซ ในทางตรงกันข้าม อัตราการผลิตก๊าซและช่วงระยะท่อกรุที่ยิงมีผลไม่มากต่อการผลิตก๊าซ

ภาควิชา....วิศวกรรมเหมืองแร่และปิโตรเลียม.... ลายมือชื่อนิสิต..

สาขาวิชา...วิศวกรรมปิโตรเลียม.................... ลายมือชื่อ อ.ที่ปรึกษาวิทยานิพนธ์หลัก...................

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PAWICH SRIPONGWARAKUL: EVALUATION OF DOWNHOLE WATER SINK IN BOTTOM WATER DRIVE GAS RESERVOIR. ADVISOR: ASST. PROF. SUWAT ATHICHANAGORN, Ph.D., 89 pp.

Water coning is a major problem for gas wells since it causes liquid loading in the well and obstructs gas production. There are different techniques to eliminate this problem such as using pumping unit, gas lift, plunger lift, small tubing ID, etc. One interesting technique is Downhole Water Sink (DWS) method which reduces water coning effect by producing water below the contact of hydrocarbon and water.

In this study, Downhole Water Sink method is applied to a well drilled in a bottom-drive gas reservoir to enhance production performances. Sensitivity analysis is conducted by varying operating conditions in order to observe the effect of these parameters on production performance. The operating conditions studied are water withdrawal rate, gas production rate, position of perforation and its interval.

The results show that DWS technique can improve recovery more than conventional technique and also reduce water production from water coning.

Sensitivity analysis shows that water withdrawal rate and position of perforation in the gas zone have important effects on gas recovery factor and reduction of water production. Increasing water withdrawal rate and perforating the gas zone at the topmost results in more gas production and less water production from the gas zone. On the other hand, gas production rate and perforation interval have slight effects on gas production.

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CONTENTS

Page

CHAPTER **Page**

LIST OF TABLES

LIST OF FIGURES

Page

LIST OF ABBREVIATIONS

°API	degree (American Petroleum Institute)
BHP	bottomhole pressure
BTU	British Thermal Unit
DWS	downhole water sink
ID	inner diameter
mD	millidarcy
MMscf/d	million standard cubic feet per day
Mscf/d	thousand standard cubic feet per day
ppm	part per million\
psi	pounds per square inch
psia	pounds per square inch absolute
PVT	pressure-volume-temperature
SCAL	special core analysis
scf	standard cubic foot
stb	stock-tank barrel
stb/d	stock-tank barrels per day
stb/MMscf	stock-tank barrels per million standard cubic feet
THP	tubing head pressure
VLP	vertical lift performance
XSA	cross-section area

NOMENCLATURES

b	fractional penetration
B_g	gas formation volume factor
dp	differential pressure
h_D	dimensionless pay thickness
h	reservoir thickness (ft)
h_p	perforated thickness (ft)
k	reservoir horizontal permeability, k_h
k_g	effective gas permeability
k_{rg}	gas relative permeability
k_{rw}	water relative permeability
k_v	reservoir vertical permeability
p_c	capillary pressure
p_i	initial reservoir pressure
p_{wf}	well flowing pressure
Q_c	critical gas flow rate
Q_{curve}	hypothetical critical production rate
r_w	wellbore radius
s_c	partial penetration skin
S_g	gas saturation
S_w	water saturation
v	fluid velocity

GREEK LETTERS

β	high velocity coefficient
γ	gas gravity
ρ	density
μ	viscosity
Σ	summation

CHAPTER I
INTRODUCTION

Producing gas in reservoir with aquifer presents a challenging problem. The main reason is water coning effect. In conventional completion, gas is produced from reservoir above gas-water contact. When gas is produced, differential pressure occurs around completion, causing aquifer water to cone into completion. After production is continued to some specific point, water reaches and enters into the completion, i.e., water breaks through the producer. Water production increases hydrostatic pressure that results in water loading in the well. This effect decreases production performance of the well.

One of solutions for this problem is Downhole Water Sink (DWS). In this technique, water coning can be prevented by producing water below gas-water contact interface to create a differential pressure in the water zone. This differential pressure can counter the effect of the one in the hydrocarbon zone and, thus, prevent water coning. In this scenario, there are two producing (completion) zones. The top completion produces gas from the reservoir and bottom completion produces water from the aquifer. These completions are separated by a packer. Gas and water are produced in separate flow paths. Gas is produced through the annulus between casing and tubing while water is produced through tubing.

The purpose of this study is to evaluate the performance of Downhole Water Sink in improving gas production from bottom water-drive dry gas reservoirs using a reservoir simulation software as a mean to mimic reservoir responses under different circumstances.

1.1 Methodology

1. Gather and prepare data for simulation model.
2. Create base case model in which conventional technique and DWS (Downhole Water Sink) model are applied.
3. Run simulation for both models to compare the production performance.
4. Conduct sensitivity on operating conditions for both models to observe the effect

of these conditions on production performance.

5. Analyze the results and conclude.

1.2 Thesis Outline

This thesis consists of six chapters. The outlines of each chapter are listed below:

Chapter II reviews previous studies related to water coning problem and Downhole Water Sink technique.

Chapter III describes theory and concepts related to this study.

Chapter IV describes the methodology for this study.

Chapter V describes production performance of conventional technique and Downhole Water Sink technique from simulation results.

Chapter VI provides conclusion and recommendation of the study.

CHAPTER II
LITERATURE REVIEW

Water coning is a problem for gas well since it causes liquid loading in the well and prevents gas production. Armenta and Wojtanowicz [1] have studied about mechanism of water coning in gas reservoir. Combining the results from numerical simulation with analytical models, they concluded that early water breakthrough and largely increase in water production may result from effects of increased vertical permeability, low density of perforation and high velocity gas flow (non-Darcy flow) around the wellbore.

The easiest way to avoid water coning effect is producing reservoir fluid at low rate, i.e., below the critical rate. The critical rate is the rate above which the flowing pressure gradient at the well can cause water or gas to cone into the well. Therefore, it is the maximum allowable flow rate that can be imposed on the well to avoid breakthrough from coning effect. Producing more than this rate can cause high pressure gradient that results in coning instability and breaks through will occur.

Although there are several empirical correlations for critical rate estimation, most of them are applied for oil reservoir, i.e., critical oil rate estimation. Only a few of them can be applied for gas-water system. One of them is Chaney *et al.* correlation.

Chaney *et al*. [2] developed a set of working curves for determining critical rate. These curves were generated by using a potentiometric analyzer study and applying the water coning mathematic theory developed by Muskat-Wychoff [3]. Each graph is used for a specific reservoir model based on the types of fluid in the system (oil-water, gas-water, gas-oil), sand thickness, drainage area, perforation interval and distance from top perforation to top of sand (for oil-water or gas-water system) or gas-oil contact (for gas-oil system).

Beside from producing at low rate, there are many other methods to eliminate or reduce this problem with different production techniques such as using pumping unit, gas lift, plunger lift, small tubing ID, etc [4]. One of interesting technique is Downhole Water Sink technique.

Downhole Water Sink technique reduces water coning effect by producing water below gas-water or oil-water contact to create a differential pressure in the water zone. This differential pressure can counter the effect of the one in the hydrocarbon zone and, thus, prevent water coning. Downhole Water Sink technique was first introduced for oil reservoir model. Inikori [5] studied water coning control in oil reservoir using this technique. Fluid flow behavior was studied for both vertical and horizontal wells. The results indicated that this technique can increase production rate.

Armenta and Wojtanowicz [4] later applied this technique in a gas reservoir. They investigated the production performance of this technique comparing to conventional completion and well with Downhole Gas Water Separator (DGWS). DGWS is equipment that separates gas and water at the bottom of gas wells in which separated water is re-injected into a non-productive interval while gas is produced to the surface. They also researched for reservoir candidates for which have the best conditions for DWS technique.

The results show that DWS well gives higher recovery than recovery from a conventional well but almost the same as that from a DGWS well. However, DWS is better than DGWS that it requires less production time for the same production recovery. In addition, they concluded that the best conditions for DWS technique is low-permeability low-pressure gas reservoir, i.e., low productivity gas reservoir for which DWGS technique is not suitable.

Later, Armenta and Wojtanowicz [6] applied DWS technique in low productivity gas reservoir model again. This time, they varied design parameters such as the water withdrawal rate, perforation position, perforation interval and time to start water withdrawal operation in order to maximize production performance for this type of reservoir. They concluded that the top completion should be shorter than 30 percent of gas zone. Water withdrawal rate should be maximized to keep the top completion water free.

CHAPTER III
THEORY AND CONCEPTS

3.1 Water coning in gas wells

Water coning is a phenomenon created by the rise of bottom water through the pore volume near the wellbore to the perforation. In gas reservoir with aquifer, when the well is perforated above the gas-water contact (GWC), the gas production creates a differential pressure and causes the gas-water interface to deform into a cone shape.

When the production rate increases, the cone height rises from the original contact. If the production rate is too high (higher than the critical rate), the cone becomes unstable causing water to breaks through into the wellbore. If the production is continued, water will finally load the well and prevent further production.

As mentioned in Chapter 2, Chaney *et al.* [2] developed an analytical correlation in order to determine the critical production rate for gas well. The procedure consists of a set of graphs that is used to determine hypothetical critical production rate and mathematical formula that fluid and rock properties are taken into account to correct the hypothetical flow rate for actual reservoir rock and fluid properties. The correlation was developed such that it can be used for oil-water, gas-water and gas-oil systems. For this study, we will focus only on a gas-water system.

In order to determine critical gas rate, the hypothetical rate must be determined from the set of graphs. Several graphs are constructed for different models. In these graphs, reservoir drainage area, formation thickness and well characteristics (perforation position and its interval) are take into account to determine the critical rate. For example, Figure 3.1 shows the hypothetical rate for the model having sand thickness of 100 ft, well radius of 3 inch, and drainage area of 1000 ft.

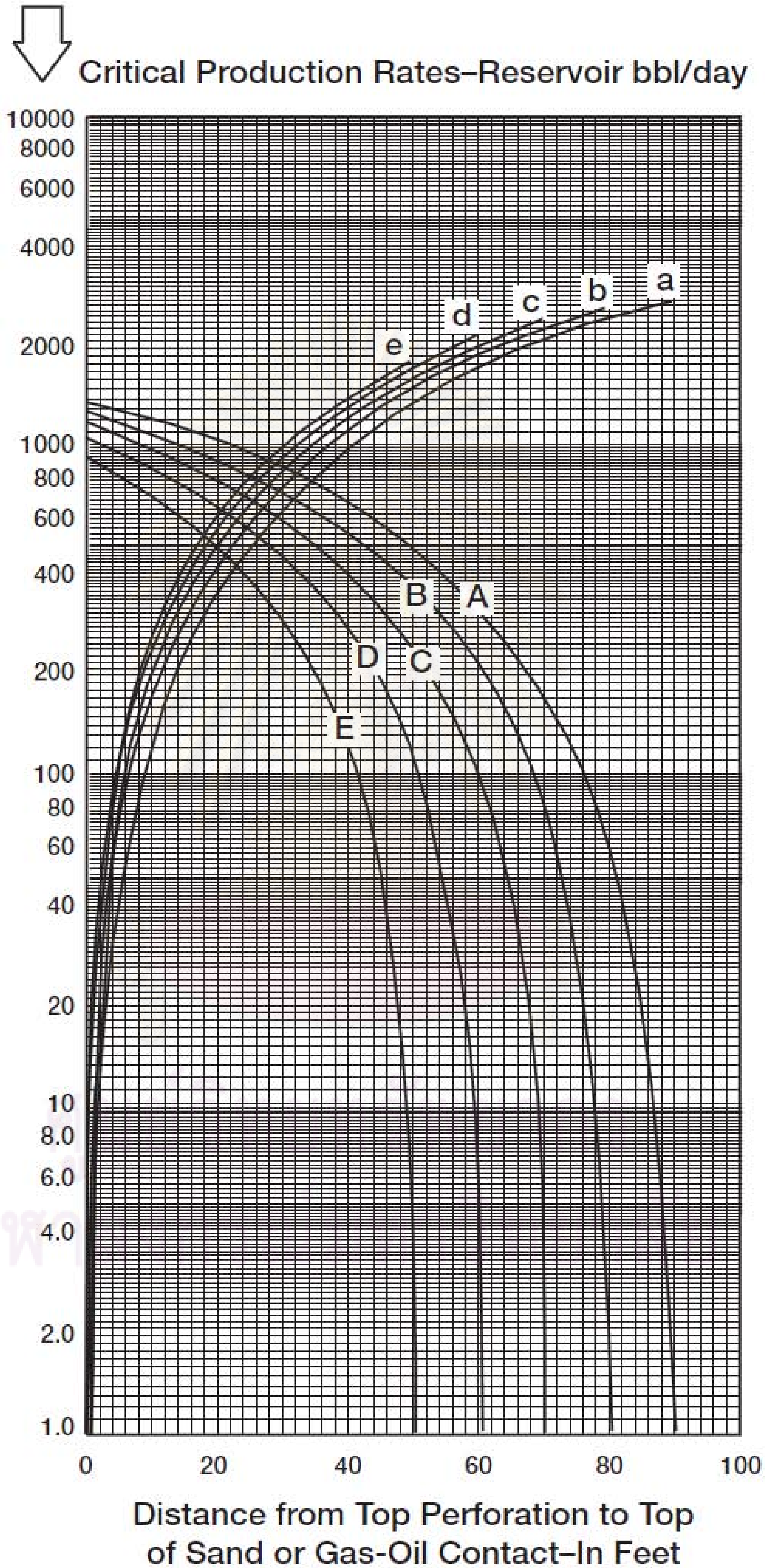

Figure 3.1: Critical production rate curves for sand thickness of 100 ft [2].

After the hypothetical critical rate is determined from the graph, this rate is corrected for actual reservoir and fluid properties by mathematical formula. For gas-water system, the critical gas rate can be calculated as follows:

$$Q_{gc} = 0.5288 \times 10^{-4} \left[\frac{k_g(\rho_w - \rho_g)}{\mu_g B_g} \right] Q_{curve} \tag{3.1}$$

where Q_{gc} = critical gas flow rate (Mscf/d)

Q_{curve} = hypothetical critical production rate (bbl/day)

k_g = effective gas permeability (md)

ρ_g = gas density (lb/cu ft)

ρ_w = water density (lb/cu ft)

μ_g = gas viscosity (cp)

B_g = gas formation volume factor (bbl/Mscf)

In Downhole Water Sink technique, this correlation cannot be used because both gas and water are produced at the same time. However, it is still useful for verifying that the model is set in proper manner when it is constructed. If the model is valid, the correlation should be able to verify simulation results.

As gas production causes water to cone around the wellbore, this study focuses on the effect of production rate on production performance. This includes gas rate and water rate in Downhole Water Sink technique.

3.2 Partial penetration skin

Partial penetration is also one of the techniques used to delay water breakthrough. Normally, the completion in gas well with aquifer is perforated from top of pay sand to somewhere in the pay zone above the gas-water contact to prevent water to cone into completion. However, the production performance may decrease due to partial penetration skin. In this case, the fluid cannot enter the well over the entire reservoir thickness. As a result, the well will experience a large pressure drop.

In several studies, correlations were developed to determine the skin resulted from partial penetration. Brons and Marting [7] develop the relation expressed in term of permeability, reservoir thickness and perforation interval.

$$s_c = \left(\frac{1}{b} - 1\right)\left[\ln(h_D) - G(b)\right] \tag{3.2}$$

where s_c = partial penetration skin

b = fractional penetration, h_p / h

h_D = dimensionless pay thickness, $(k/k_v)^{0.5}(h/r_w)$

h = reservoir thickness (ft)

h_p = perforated thickness (ft)

k = horizontal formation permeability (md)

k_v = vertical formation permeability (md)

r_w = wellbore radius (ft)

$G(b)$ is a function of fractional penetration and can be calculated from

$$G(b) = 2.948 - 7.363b = 11.45b^2 - 4.675b^3$$

Odeh [8] developed an empirical relation for skin due to an arbitrarily located open interval:

$$s_c = 1.35\left(\frac{1}{b} - 1\right)^{0.825}\left\{\ln(r_w h_D + 7) - 1.95 - [0.49 + 0.1\ln(r_w h_D)]\ln(r_{wc})\right\} \tag{3.3}$$

where

$$r_{wc} = \begin{cases} r_w \exp\left[0.2126\left(2.753 + z_m / h\right)\right], & 0 < z_m / h < 0.5 \\ r_w & , y = 0 \end{cases} \tag{3.4}$$

$$z_m = y + \frac{h_p}{2} \tag{3.5}$$

y = distance from the top of the formation to the top of the perforation

Many correlations have perforation interval and position of perforation taken into account. Effect of perforation interval and its position on production performance are also included in the scope of this study.

3.3 High velocity flow

When fluid flows at very high rate, there is additional pressure drop around the wellbore that increases in non-linear trend. This kind of effect is defined as Non-Darcy effect since this non-linear trend is against general form of Darcy's linear relation. There are many authors who developed the correlation to express this effect. Forchheimer [9] expressed the equation for high velocity flow

$$\frac{dp}{dr} = av + bv^2 \tag{3.6}$$

where $\frac{dp}{dr}$ = pressure drop across a cylindrical wall

a, b = constant

v = fluid velocity

Later, Green and Duwez [10] and Cornell and Katz [11] developed the equation and expressed in terms of fluid and rock properties.

$$\frac{dp}{dr} = \frac{\mu}{k}v + \beta\rho v^2 \tag{3.7}$$

where μ = gas viscosity

ρ = gas density

β = high velocity coefficient

Normally, Forchheimer equation is expressed as the radial Darcy flow equation with a rate-dependent skin Dq. For gas reservoir with uniform permeability, this rate-dependent skin can be expressed as below:

$$D_{Rg} = 2.222 \times 10^{-18} \frac{\gamma_g kh}{\mu_g r_w h_p^2} \beta_R \tag{3.8}$$

where γ_g = gas gravity

μ_g = gas viscosity

β_R = property of reservoir rock

β_R can be calculated from

$$\beta_R = 2.73 \times 10^{10} k^{-1.1045} \tag{3.9}$$

Beside from causing extra pressure drop in the wellbore, Non-Darcy effect also increases the effect of water coning [1]. In this study, gas rate is varied in sensitivity analysis to observe the performance of DWS well. Because of this, Non-Darcy effect may also take the part in performance of this technique.

CHAPTER IV
METHODOLOGY

As mentioned before, the objective of this thesis is to evaluate production performance of DWS (Downhole Water Sink) technique applied in a bottom water-drive gas reservoir under different operating conditions. To accomplish this task, numerical simulation models are constructed using ECLIPSE 100 reservoir simulator. The models are divided into 3 types for different purpose in order to fulfill the objective. These are verification model, base case model for conventional well and DWS (Downhole Water Sink) well. Then, sensitivity analysis is conducted to observe the performance of DWS technique under different operating conditions.

4.1 Reservoir Simulation model

The model is constructed with a conventional well in a gas reservoir with bottom water drive. Since this study is related to coning effect that occurs around the wellbore, the reservoir model is built with 3-D cylinder grid, and the well is located at the center as shown in Figure 4.1.

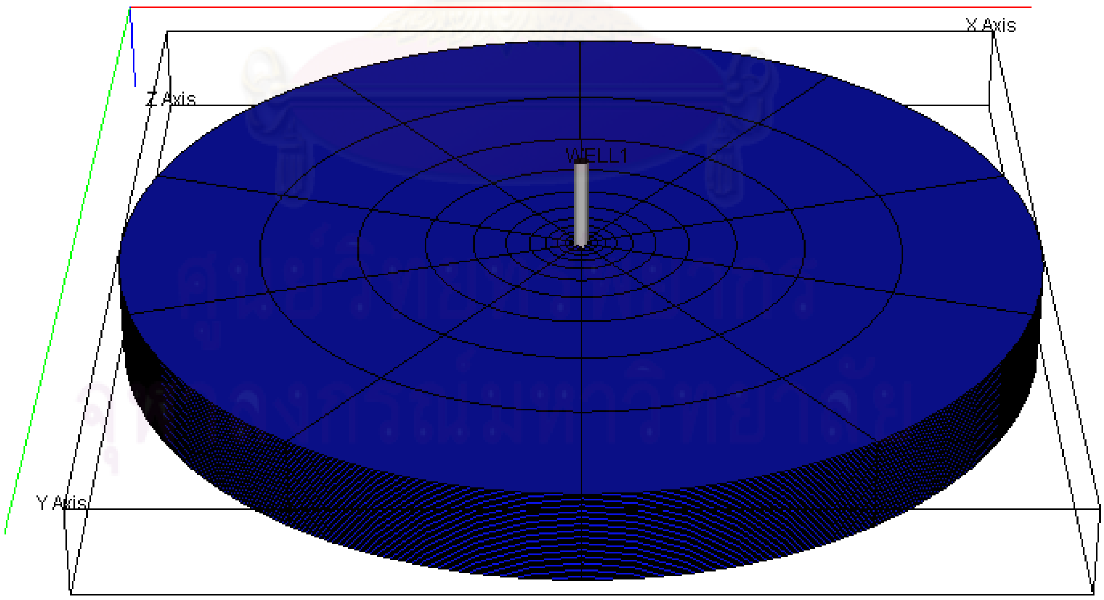

Figure 4.1: Reservoir model.

The reservoir model consists of 15, 10, and 40 radial grid blocks in the radial (r), theta (θ) and vertical (z) direction, respectively. In the radial direction, the grid block closet to the wellbore has the smallest size. Adjacent grid blocks become larger as the distance from the wellbore increases. Sizes of grid blocks in the radial direction for the model are shown in Table 4.1. The purpose of using refined grids near the wellbore is that reservoir properties affected by water coning such as reservoir pressure, fluid saturation, and fluid properties can be estimated with more accuracy and coning shape can be illustrated in more details around the wellbore. However, all grid blocks have the same size in theta and vertical direction. Grid sizes for theta and vertical direction are 36 degree and 5 ft, respectively.

Table 4.1: Size of grid blocks in the radial direction for reservoir model

Radial (r) direction		Radial (r) direction	
No. grid	Grid size (ft)	No. grid	Grid size (ft)
1	2	9	28.78755
2	2.79127	10	40.17691
3	3.895594	11	56.0723
4	5.436827	12	78.25645
5	7.587825	13	109.2174
6	10.58983	14	152.4277
7	14.77954	15	212.7334
8	20.62685	Σ	745.3795

The model used in this study is a homogeneous reservoir. Reservoir fluid consists of gas in the pay zone and water in the aquifer. Vertical grid blocks are divided into 2 zones evenly for gas and water, i.e., 20 grids for gas zone and 20 grids for water zone. There are 100 ft of total pay thickness and 100 ft of aquifer water in the model. There is also 4900 ft of numerical aquifer that is included as a source of water using ECLIPSE’s keyword. Figure 4.2 shows the reservoir with gas and water zone separated by gas-water contact.

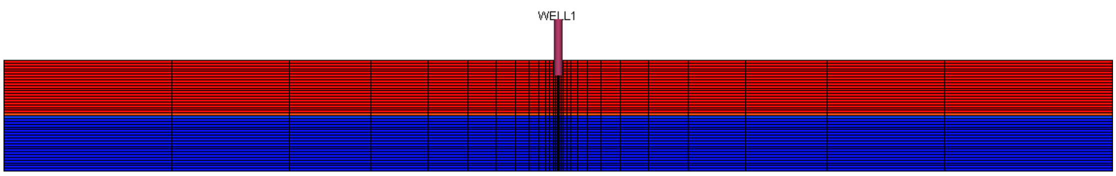

Figure 4.2: Reservoir with gas and water zone (red color indicates gas zone, blue color indicates water zone).

Most of reservoir rock properties are taken from a gas field in Gulf of Thailand. Tables 4.2 and 4.3 show reservoir properties and SCAL data taken from field data, respectively. Relative permeabilities are also plotted in Figure 4.3.

Table 4.2: Reservoir properties

Parameters	Values	Unit
Number of grids	15×10×40	Grid
Drainage area	3140022	sq ft
Gas zone thickness	100	ft
Water zone thickness	100	ft
Aquifer thickness (excluding water zone)	4900	ft
Porosity	21.5	%
Horizontal permeability	126	mD
Vertical permeability	10	mD
Top of reservoir	4950	ft
Datum depth	5000	ft
Initial pressure @ datum depth	2500	psia
Initial temperature @ datum depth	175	°F
Initial water saturation in gas zone	25	%
Initial water saturation in water zone	100	%

Table 4.3: SCAL properties – water saturation functions

Water saturation (S_w)	Water relative permeability (k_{rw})	Gas relative permeability (k_{rg})
0.25	0	0.8
0.3	0.006	0.444
0.35	0.027	0.228
0.4	0.0675	0.105
0.45	0.126	0.042
0.5	0.2055	0
0.55	0.3075	0
0.6	0.432	0
0.65	0.579	0
0.7	0.75	0
1	1	0

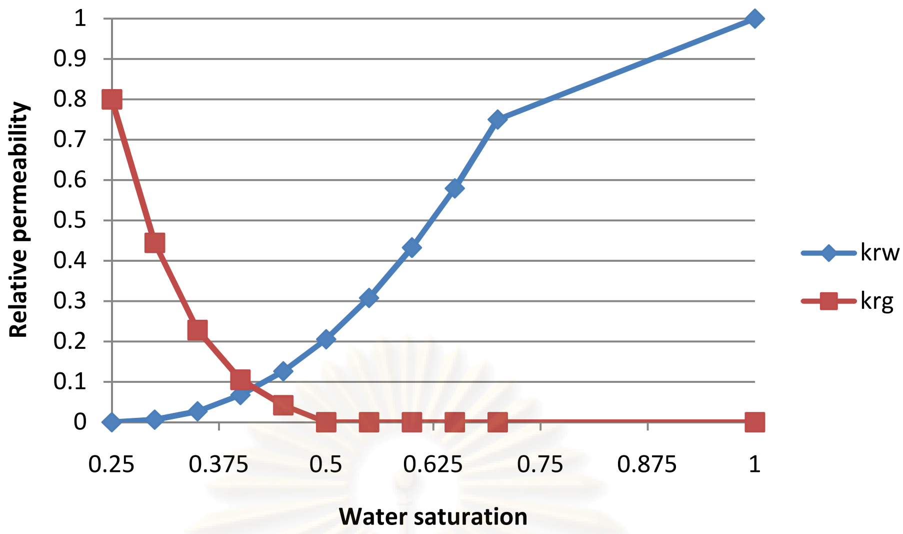

Figure 4.3: Relative permeability curves.

Reservoir fluid consists of dry gas and aquifer water. Their properties are assumed with reasonable values. Dry gas contains no water and impurities. Table 4.4 summarizes fluid properties for this model.

Table 4.4: Gas and water properties

Parameters	Value	Unit
Gas specific gravity	0.92	-
Water salinity	100000	ppm
Water specific gravity	1	-

Other gas properties that change with pressure and temperature such as gas density and gas formation volume factor are calculated in PROSPER. For gas viscosity, Lee *et al*. correlation [12] is used to estimate this property in PROSPER. All data used to generate the model in ECLIPSE 100 are listed in Appendix A.

4.2 Conventional well

For a conventional gas well, only the gas zone is perforated, and gas is produced through tubing. Figure 4.4 shows well schematic for this model. The sizes of tubing, casing and wellbore are listed in Table 4.5. All data used to generate the model in ECLIPSE 100 are listed in Appendix B.

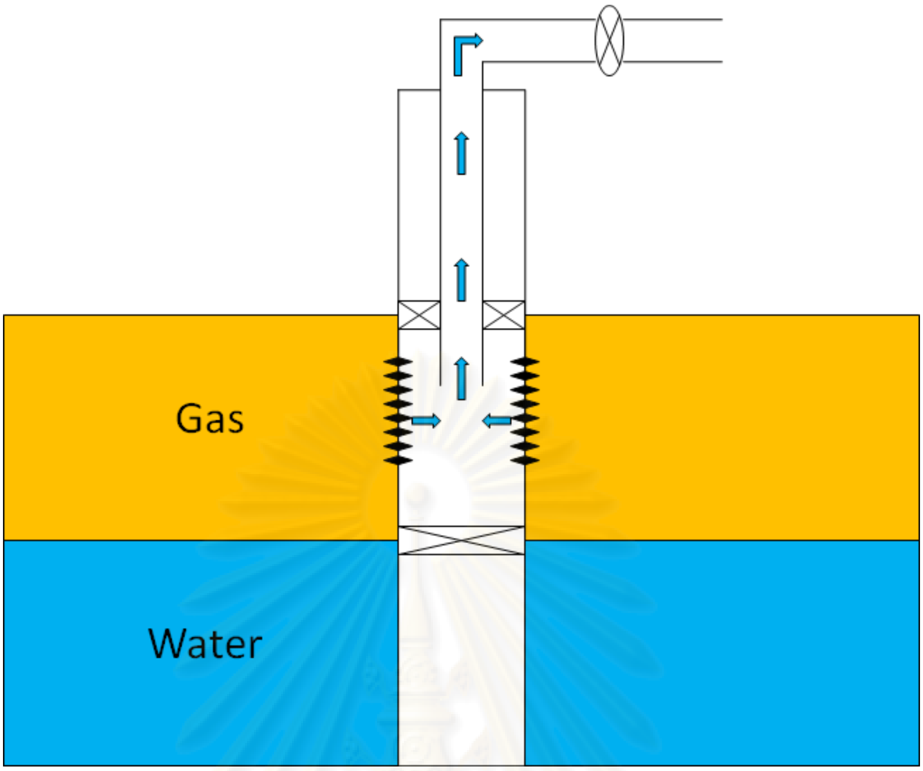

Figure 4.4: Schematic of conventional well for conventional model.

Table 4.5: Size of tubing, casing and wellbore

Parameter	Value (inch)
Tubing I.D.	2.75
Tubing O.D.	3.5
Casing I.D.	6.276
Casing O.D.	7
Wellbore diameter	8.75

4.3 Downhole water sink well

DWS model is used to evaluate production performance of gas well with DWS technique, in which water zone is also perforated and produced to reduce coning effect. Water is produced through tubing while gas is produced through the annulus between casing and tubing. Gas and water zones are separated by a packer in order to avoid multiphase flow. Figure 4.5 shows the schematic of DWS model. All data used to generate the model in ECLIPSE 100 are listed in Appendix C.

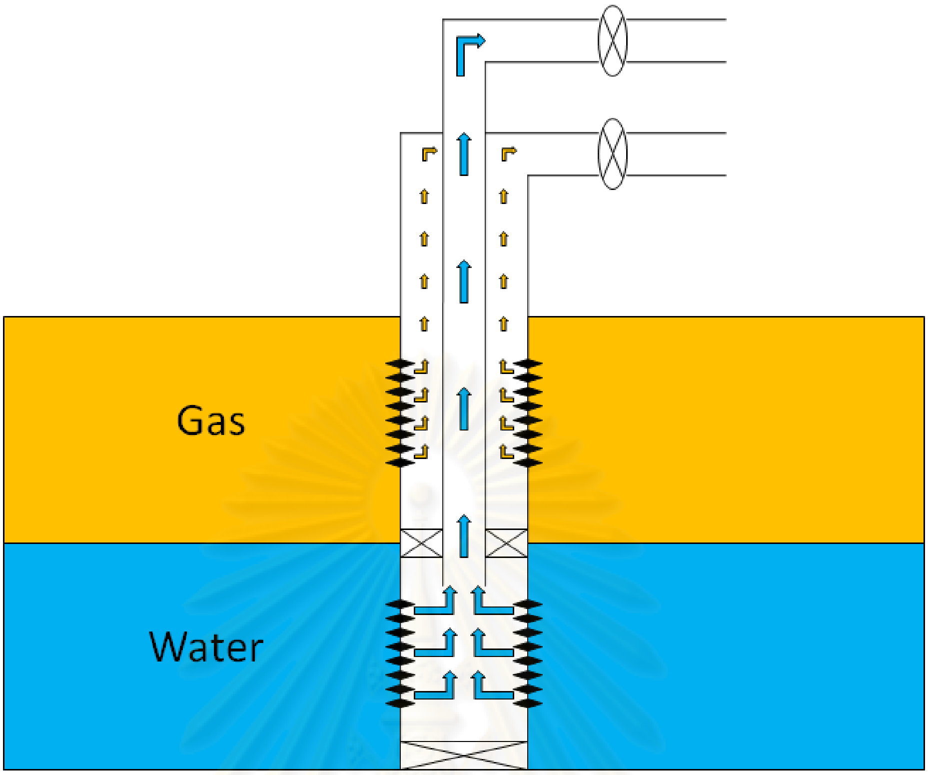

Figure 4.5: Schematic of DWS well.

In order to implement DWS technique in ECLIPSE 100, 2 wells are defined and located at the same place which is the center of the reservoir. One well, named “WELL1”, acts as gas production path from the top completion to wellhead through the annulus between casing and tubing. The other well, named “WELL2”, acts as water production path from the bottom completion to the wellhead through tubing. Vertical Lift Curves for both wells are created with PROSPER and defined in different ways. Flow type setting is tubing flow for WELL1 and annular flow for WELL2. Other rock and fluid properties are the same as in the conventional model.

4.4 Simulation condition

After all cases are established, they are simulated as the reservoir is produced with constant gas and water rate until the gas rate becomes lower than 0.5 MMscf/d. The minimum tubing head pressure is set at 450 psia for gas well, and the minimum bottomhole pressure is 500 psia for water well. When the simulation ends and results are generated, the main factors used as performance criteria for these models are recovery factor and cumulative gas and water production.

4.5 Sensitivity analysis

Several cases with varying operating parameters from the base case model are simulated for sensitivity analysis in order to observe their effects on production performance. These parameters are gas rate, water rate, position of perforation and perforation interval. Table 4.6 summarizes the varied parameters for sensitivity analysis.

Table 4.6: Varied parameters for sensitivity analysis

No.	Parameters	Values	Unit
1	Perforation interval	10, 20, 30, 40, 50, 60, 70, 80, 90, 100	ft
2	Gas rate	5, 10, 15	MMscf/d
3	Water rate	0, 250, 500, 750, 1000, 1500, 2000	stb/d

For perforation positions, there are 4 cases of different combinations as described below:

a) The top completion is perforated at the top of the gas zone while the bottom completion is perforated in the middle of the water zone
b) The top completion is perforated at the top of the gas zone while the bottom completion is perforated at the bottom of the water zone
c) The top completion is perforated in the middle of the gas zone while the bottom completion is perforated in the middle of the water zone
d) The top completion is perforated at the middle of gas zone while the bottom completion is perforated at the bottom of the water zone
e) The top completion is perforated at the bottom of the gas zone while the bottom completion is perforated at the top of the water zone

Figure 4.6 shows the position of perforation for these different cases.

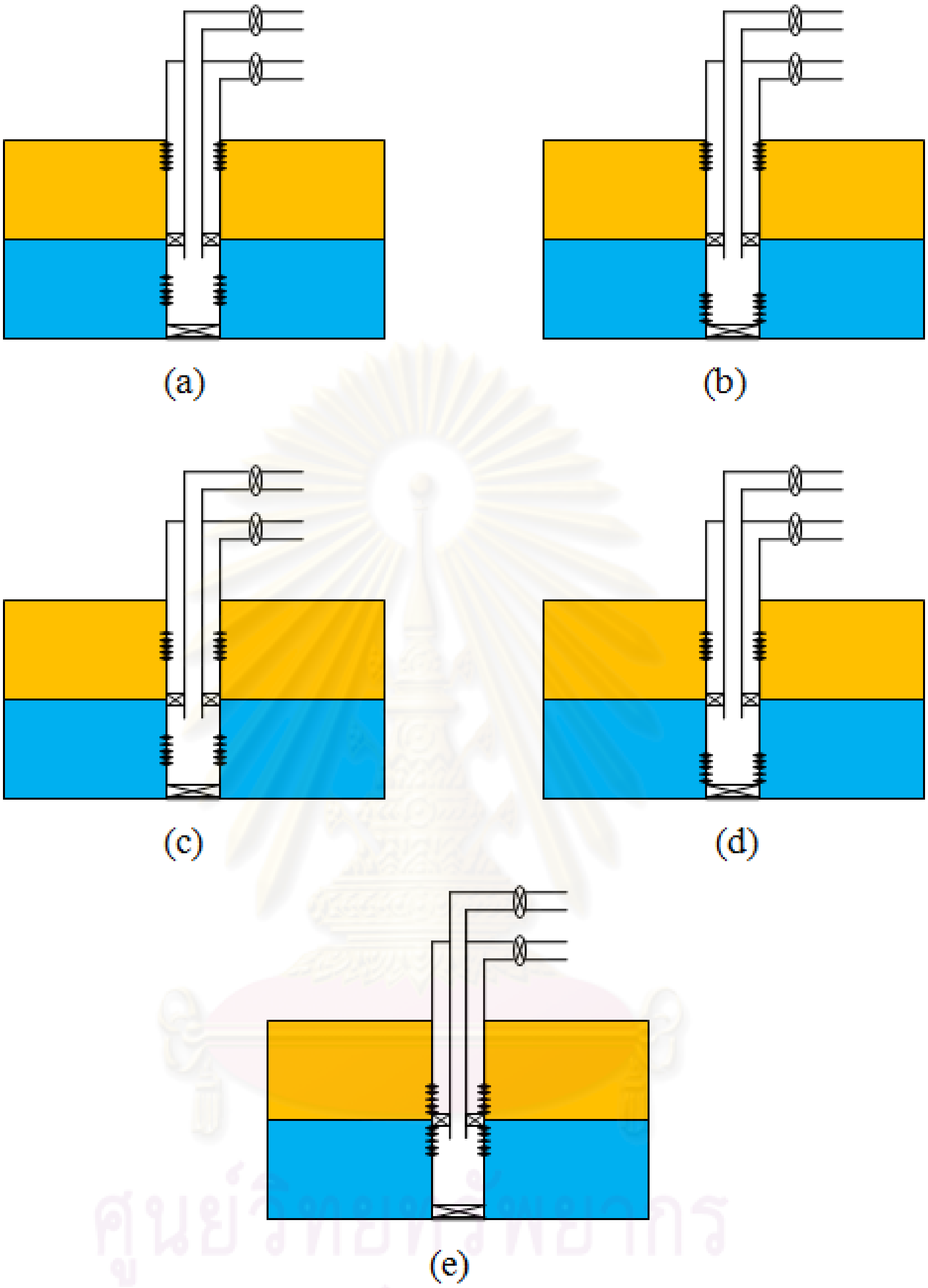

Figure 4.6: Varied position of perforation in sensitivity analysis.

This sensitivity analysis is conducted for 2 different reservoir models. The first model represents the reservoir with vertical permeability (10 mD from assumption) that is equal to 8% of horizontal permeability (126 mD from field data). The second model represents the reservoir with vertical that is equal to horizontal permeability (126 mD). All four operating parameters are varied for both types of reservoir.

CHAPTER V

PRODUCTION PERFORMANCE

In this chapter, results generated from simulation are analyzed after simulations of all cases have been run. The production performances for different operating conditions such as different gas rates, water rates, perforation positions and intervals are observed. The effects of these conditions on recovery factor and economic feasibility are investigated.

5.1 Evaluation of production performance

The main aspects of this evaluation are improvement of recovery factor and reduction of water produced from the gas zone. First, the production performances of base case models for conventional well and DWS well with the same gas rate, perforation position and perforation interval are described and compared. Next, the results of sensitivity analysis are analyzed to see the effect of gas rate, water rate, perforation position and perforation interval on production performance.

5.1.1 Conventional well

In this case, the reservoir consists of 100 ft of gas zone and 100 ft of water zone. Numerical aquifer with 4900 ft thickness is included using ECLIPSE's keywords as mentioned previously in Chapter 4. The well is perforated for 30 ft from top of gas zone. Figure 5.1 shows well schematic of the conventional case.

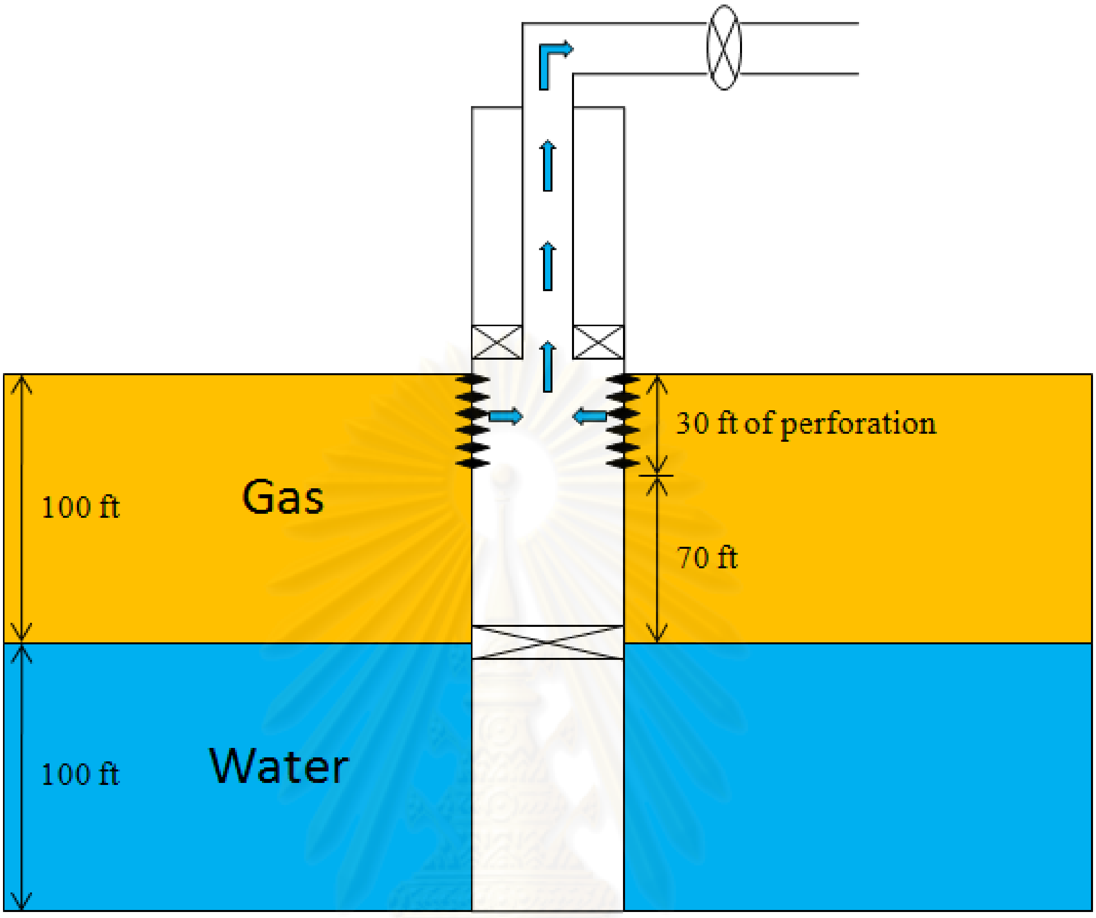

Figure 5.1: Well schematic for conventional well.

Figure 5.2 shows gas production rate from simulation results. In the figure, gas is produced at a plateau rate of 5 MMscf/d until gas rate cannot be maintained at 682 days due to low reservoir pressure. The production rate drops below the economic limit rate of 0.5 MMscf/d at 1036 days.

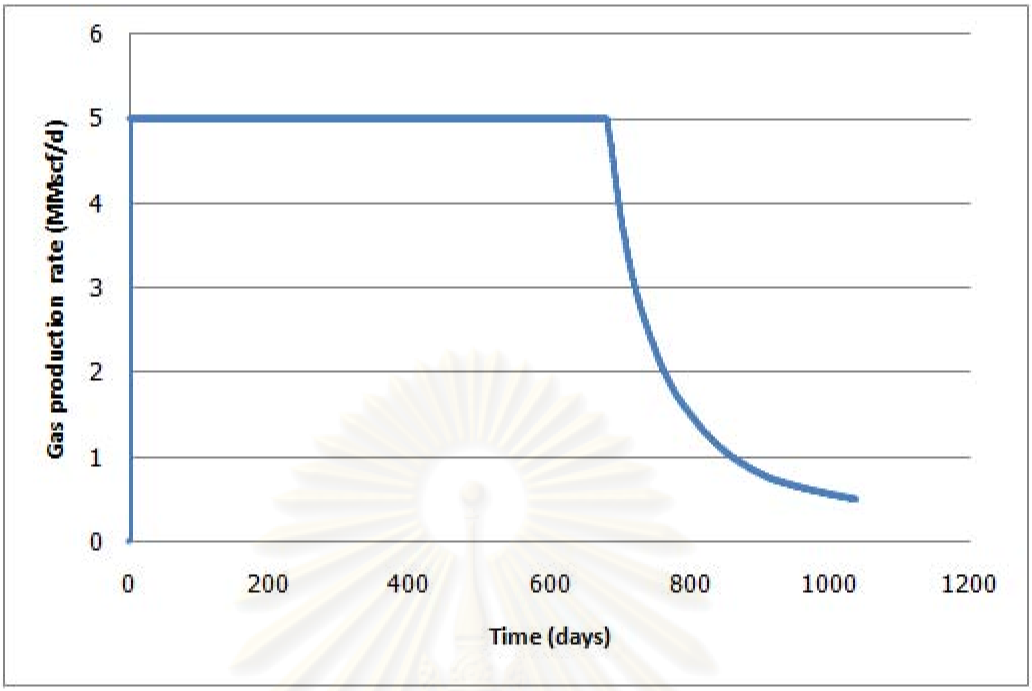

Figure 5.2: Gas production profile for conventional well.

Figure 5.3 shows the reservoir pressure dropping as a function of time. At the beginning, the pressure drops at a constant rate as the gas rate is maintained constant. After 682 days, the production rate declines due to low reservoir pressure and small amount of gas remained in the reservoir. At this point, the decline rate of reservoir pressure is slower as the production rate decreases.

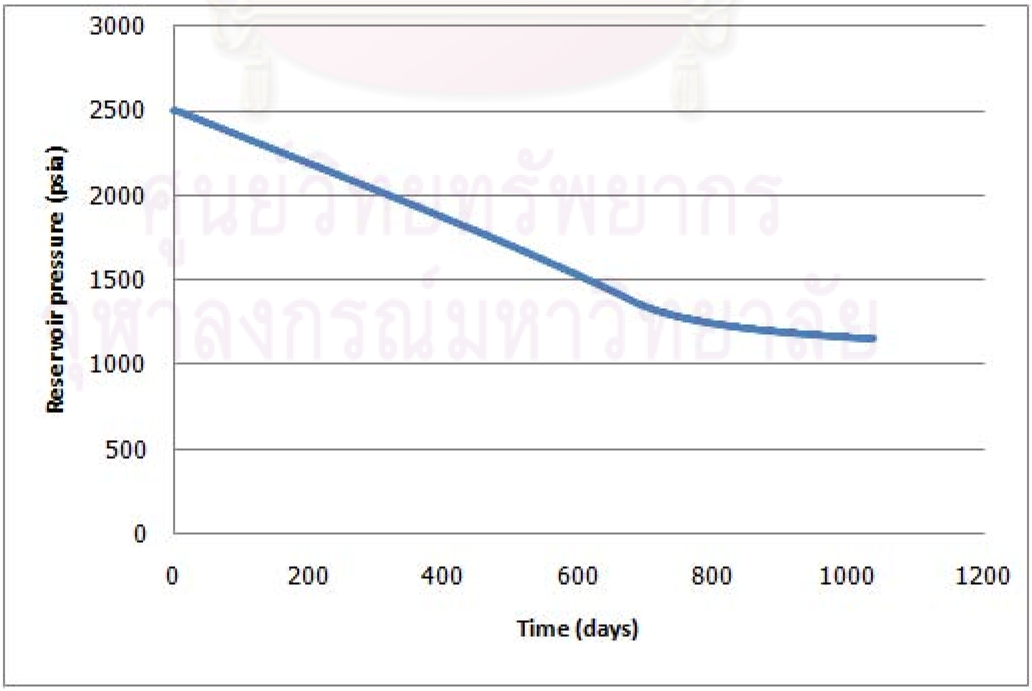

Figure 5.3: Reservoir pressure for conventional well.

Figure 5.4 shows water production profile, and Figures 5.5 to 5.8 show water coning effect that results in water production. Initially, gas-water contact rises as gas is being produced. At this point, the contact doesn't reach the perforation. Hence, no water is produced during this period. After 500 days of production, the contact reaches the perforation as shown in Figure 5.7, resulting in water breakthrough. Gas rate begins to drop below a constant rate at 682 days while water production rate still increase until 750 days. Finally, water overwhelms the perforated interval as shown in Figure 5.8 and causes a large pressure drop from hydrostatic gradient, resulting decline in gas and water production rate.

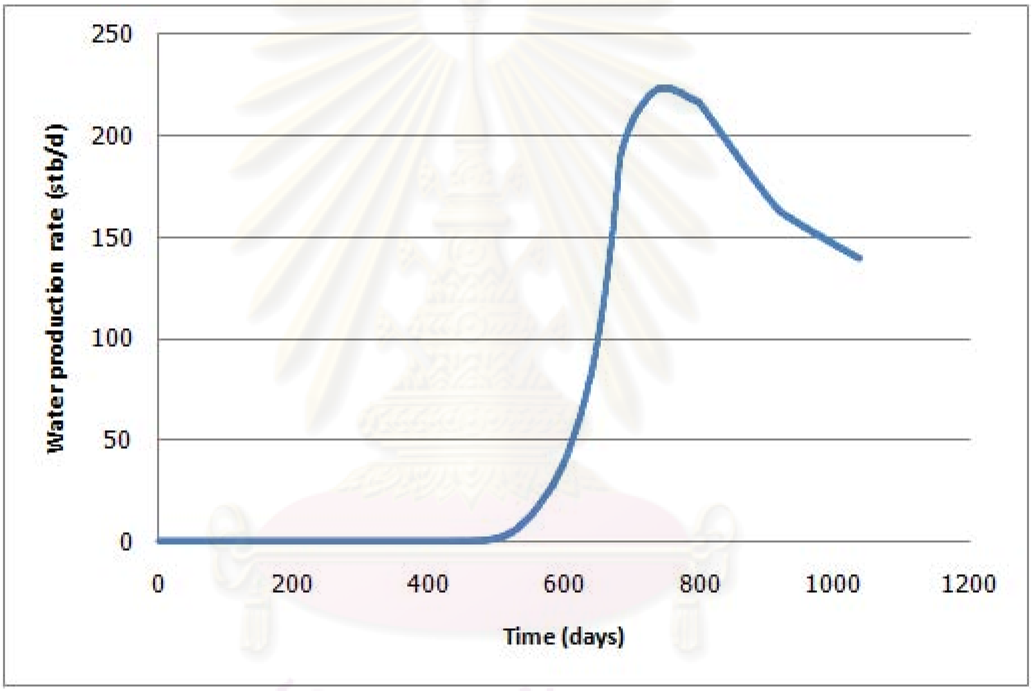

Figure 5.4: Water production profile for conventional well.

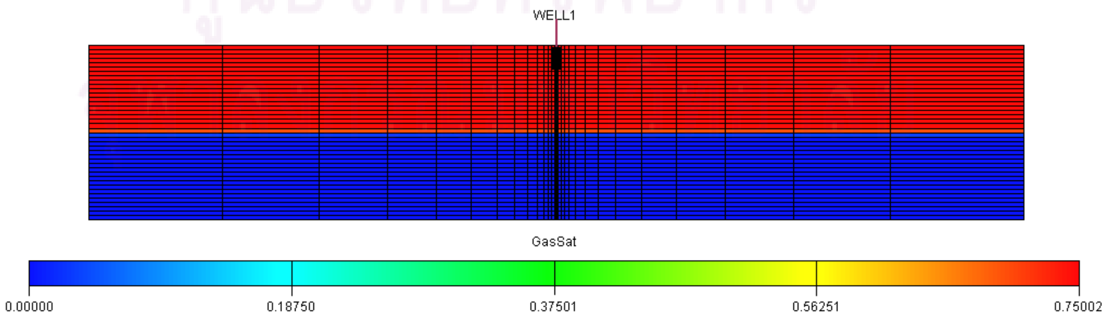

Figure 5.5: Reservoir fluid saturation before production for conventional well (red indicates gas and blue indicates water).

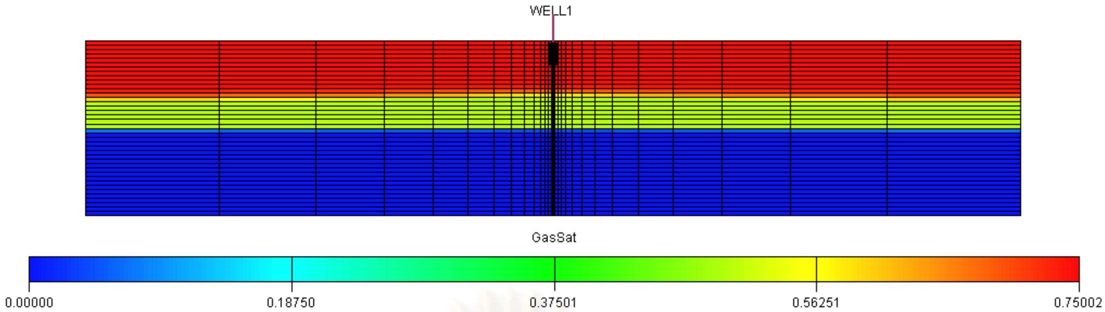

Figure 5.6: Water coning effect after 300 days of production for conventional well.

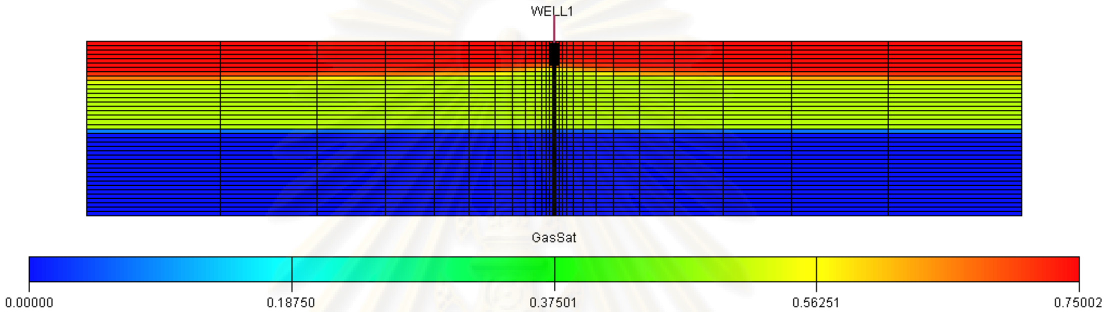

Figure 5.7: Water coning effect after 500 days of production for conventional well.

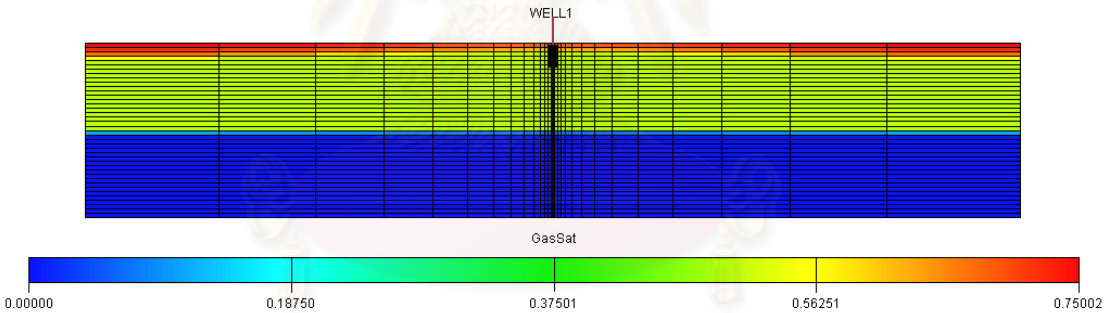

Figure 5.8: Water coning effect after 750 days of production for conventional well.

Figure 5.9 shows bottomhole pressure or BHP and tubing head pressure or THP. At the beginning, the bottomhole pressure reduces as the reservoir pressure decreases in order to keep gas rate constant. Tubing head pressure also reduces for the same reason. After 682 days, the tubing head pressure reaches minimum criteria of 450 psia and cannot be reduced further. At this point, gas rate cannot be maintained and eventually drops. The tubing head pressure is still kept at minimum value so that gas can be produced at the highest possible rate.

In contrast, the bottomhole pressure increases after 682 days. Because of water breakthrough, the hydrostatic pressure in the tubing increases. So, a higher pressure is required in order to flow the fluid from bottomhole to surface.

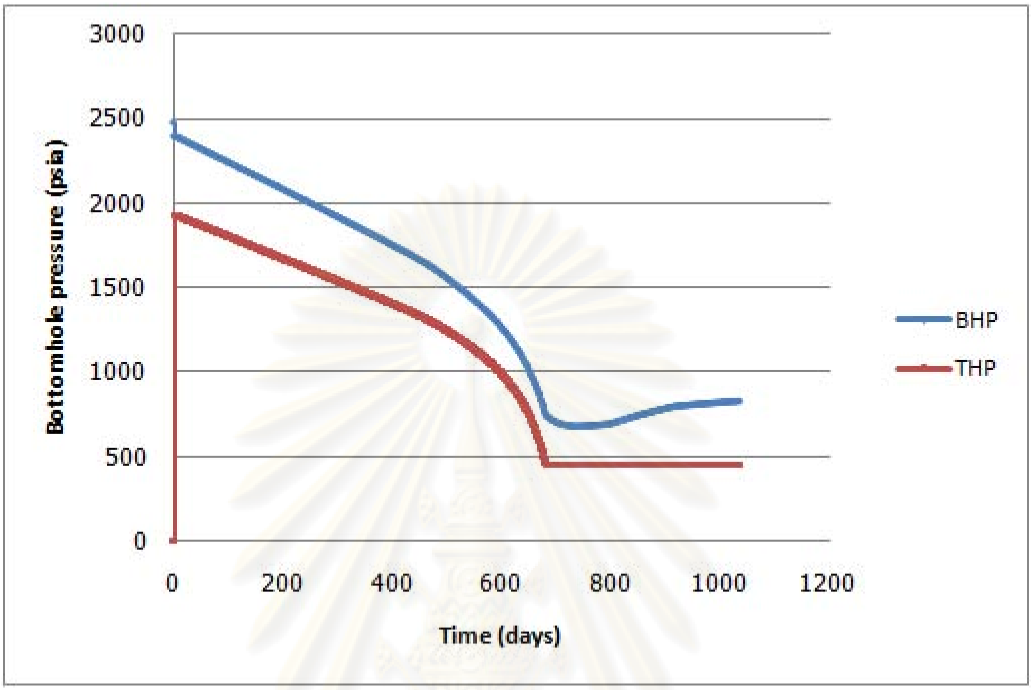

Figure 5.9: Bottomhole pressure and tubing head pressure for conventional well.

5.1.2 DWS well

DWS well is constructed in order to compare production performance with the conventional well. Similar to the conventional well, the reservoir consists of 100 ft of gas zone and 100 ft of water zone. Numerical aquifer with 4900 ft thickness is also included in the model. In this case, water is also perforated and produced through tubing while gas is produced through the annulus between casing and tubing instead. The top completion produces gas while the bottom completion produces water. Both completions are perforated for 30 ft in the middle of each zone. Figure 5.10 shows well schematic of DWS case.

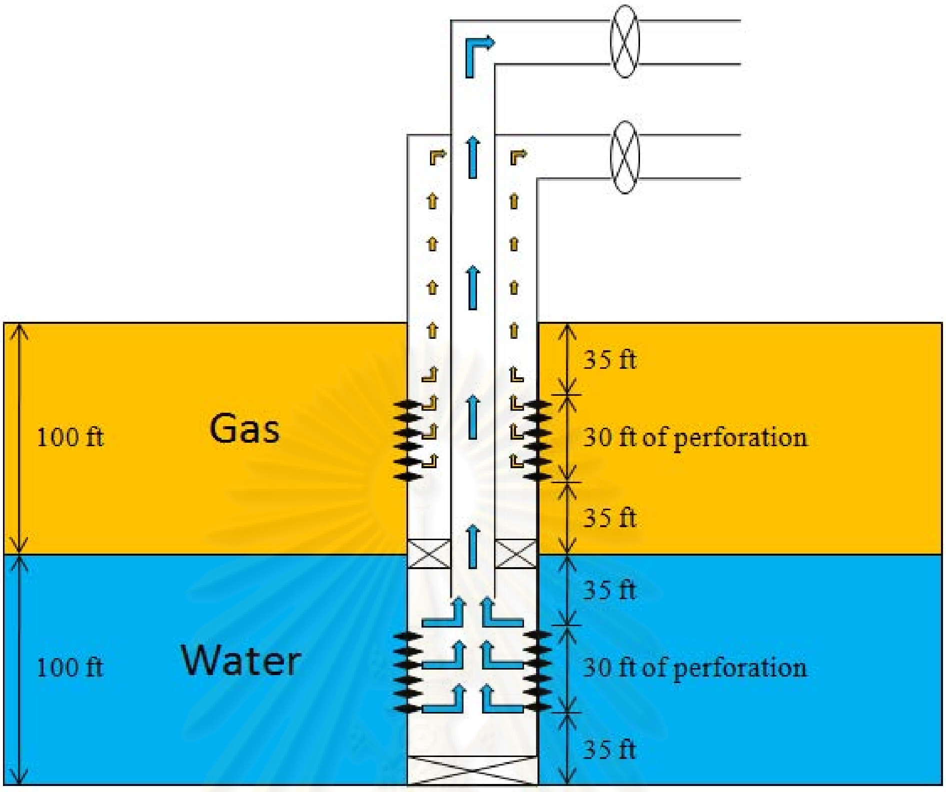

Figure 5.10: Well schematic for DWS well.

Similar to the gas zone, water is kept producing at a constant rate until the gas rate drops below economic rate of 0.5 MMscf/d. In this case, water withdrawal rate at the bottom completion is 500 stb/d as shown in Figure 5.11.

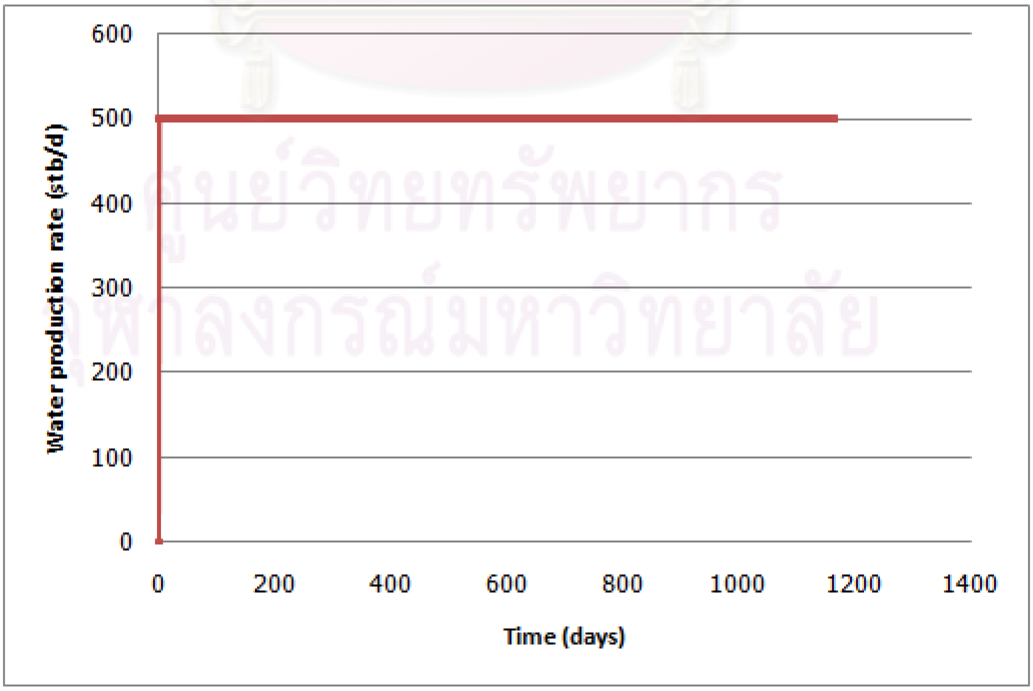

Figure 5.11: Water withdrawal rate from the bottom completion for DWS well.

Figure 5.12 shows gas production rate from top completion. Gas rate from conventional well is also included in the figure for comparison. From the figure, gas rates for conventional and DWS wells are can be kept at constant for almost the same production time. However, after the gas rate declines, DWS well can still be produce gas for a longer period until reaching the economic rate at 1163 days.

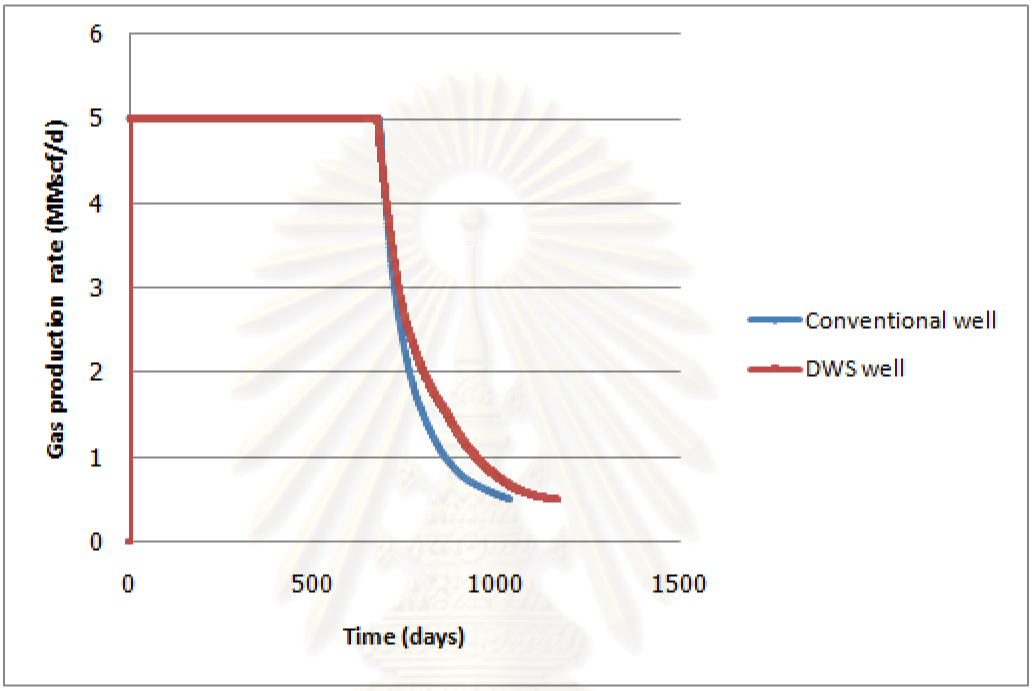

Figure 5.12: Gas production rate from conventional and DWS wells.

From this figure, gas rate of conventional and DWS wells declines almost at the same time although distance of the top completion is closer to gas-water contact comparing to conventional well. The reason is due to water withdrawal from bottom completion. Water withdrawal creates differential pressure at bottom completion against the one from top completion. This prevents gas-water contact to cone into top completion and results in water breakthrough which causes higher hydrostatic pressure drop. Figures 5.13 and 5.14 show the comparison of water coning shape of the conventional and DWS wells at 200 days after production. Although water has already breaks through in DWS well, the gas-water contact is a bit lower than that for the conventional well because of water withdrawal at bottom completion.

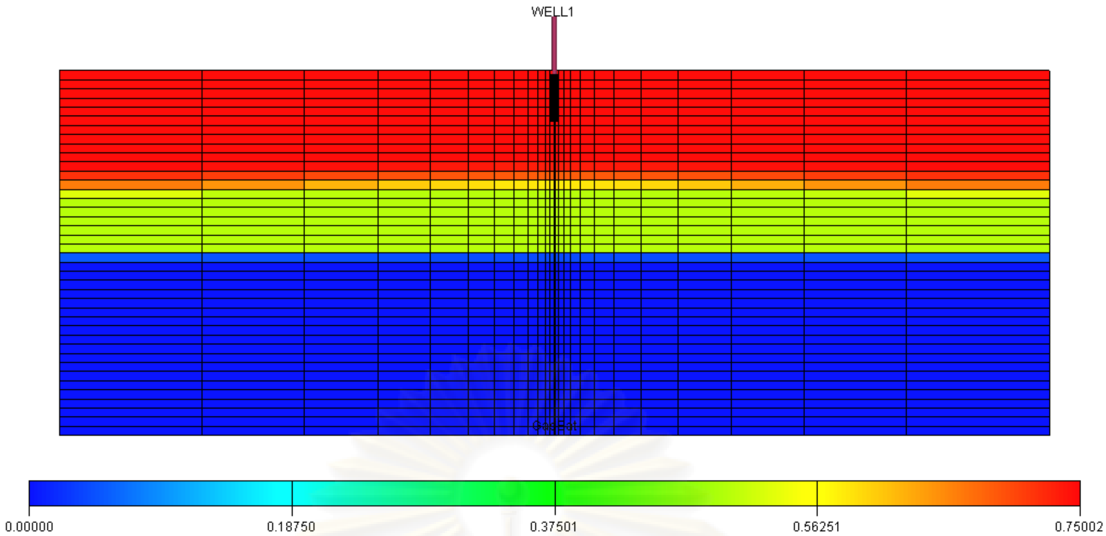

Figure 5.13: Water coning shape after 300 days of production for conventional well.

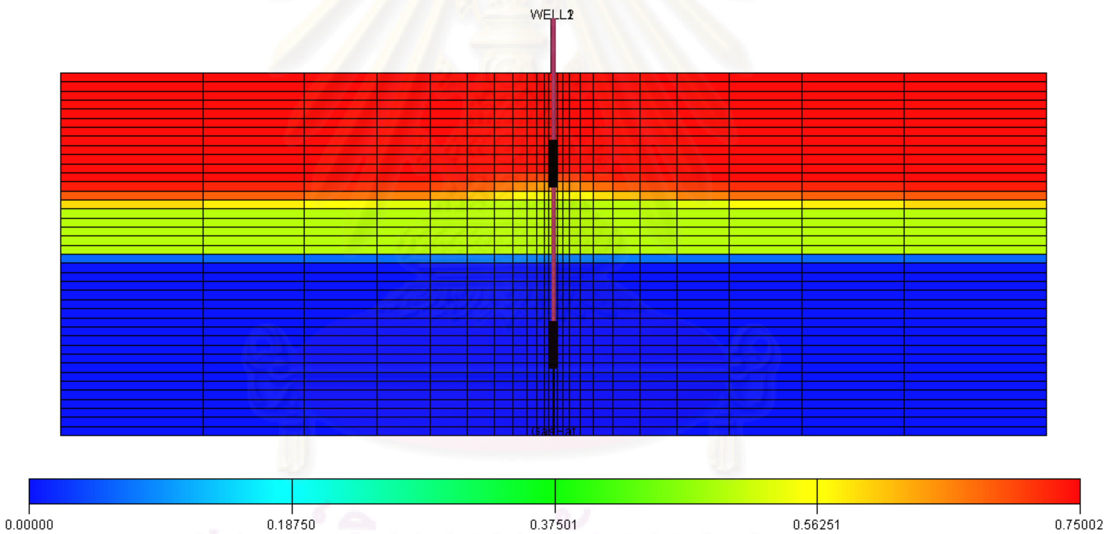

Figure 5.14: Water coning shape after 300 days of production for DWS well.

Figure 5.15 shows water production profiles for conventional and DWS wells. The figure shows that, although water breaks through in DWS well earlier due to shorter distance between the top completion and gas-water contact, water production rate decreases at faster rate after production rate decline due to water withdrawal. However, there is large amount of water withdrawn from the bottom completion in exchange of higher gas recovery.

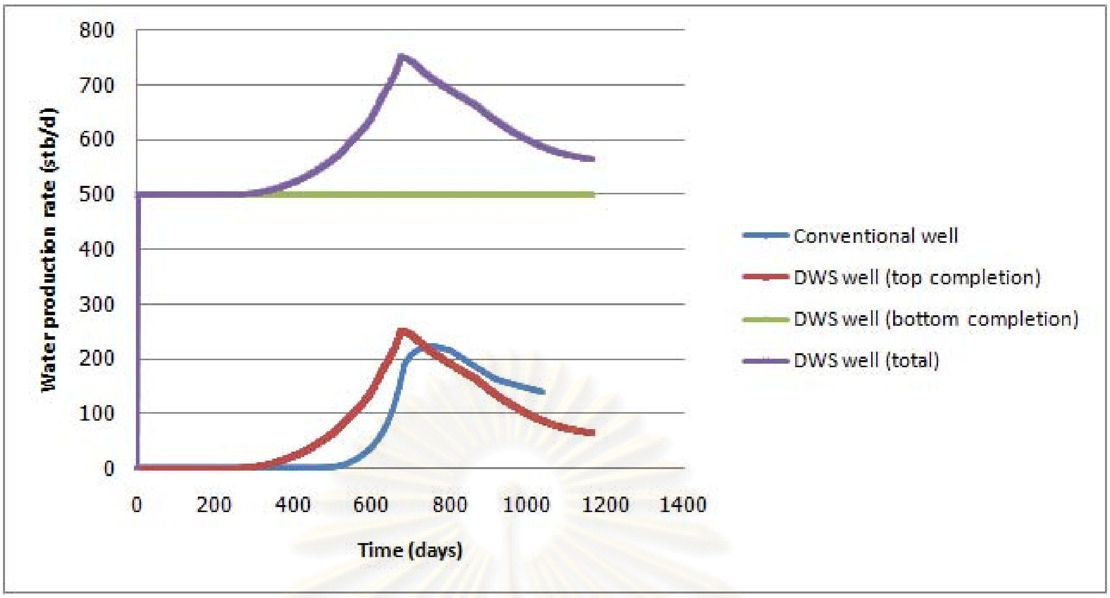

Figure 5.15: Water production profiles for conventional and DWS wells.

Figure 5.16 shows the bottomhole pressure around the wellbore in the gas zone for both cases. As mentioned before, the bottomhole pressure decreases at the beginning as the reservoir pressure decreases in order to maintain constant gas rate. After a certain period, the pressure is too low, and the gas rate begins to drop. At this point, the bottomhole pressure increases in order to accommodate higher hydrostatic pressure drop. For DWS well, Bottomhole pressure decreases lower than that in conventional well due to water production entering into the well.

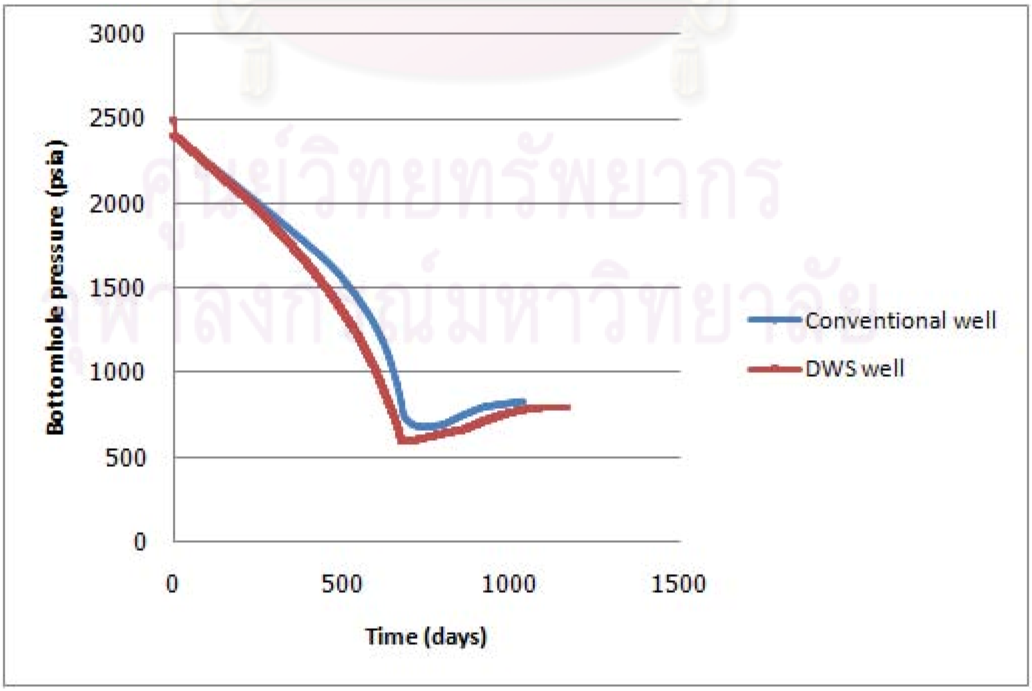

Figure 5.16: Bottomhole pressure for conventional and DWS wells.

Figure 5.17 shows reservoir pressure for conventional and DWS wells. For DWS well, reservoir pressure decreases lower than that in conventional well because of water withdrawal from the bottom completion.

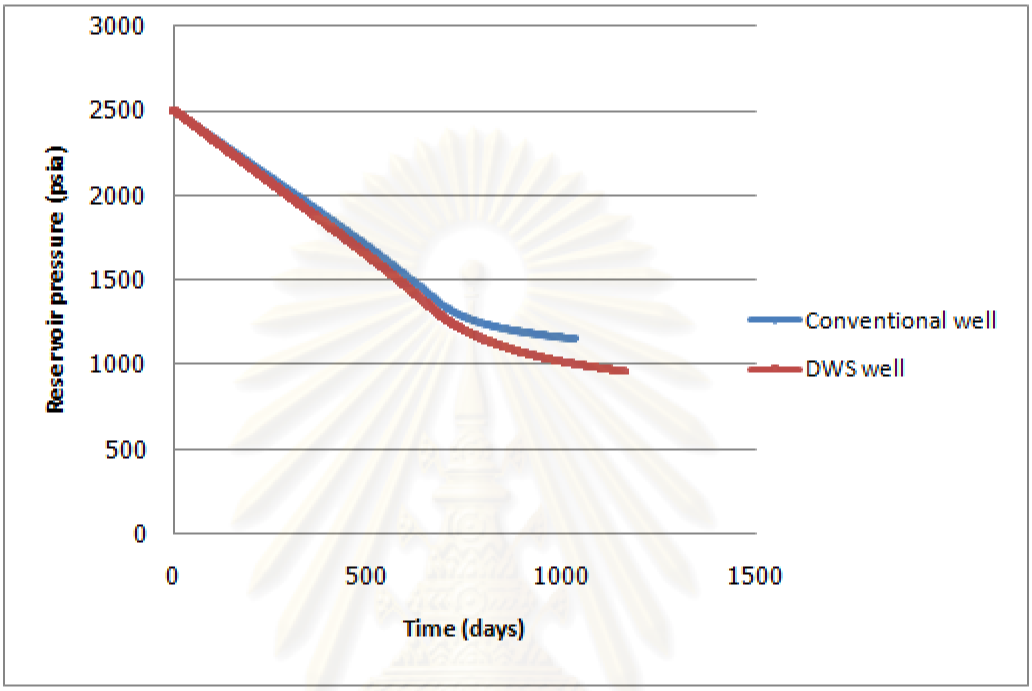

Figure 5.17: Reservoir pressure for conventional and DWS wells.

According to the results, more gas can be recovered if water is produced from bottom completion to prevent water coning effect. Table 5.1 summarizes improvement of production performance. From this table, DWS can produce longer than conventional well for around 2 months and can recover more 375.71 MMscf of gas production. Water production from the top completion also decreases for 55,825 stb. However, water has to be withdrawn for 581,500 stb in exchange of additional gas recovery.

Table 5.1: Production performance of conventional and DWS wells (top completion)

	Conventional well	DWS well	Improvement
Gas production (MMscf)	3922.38	4119.31	+196.93
Gas recovery (percent)	70.76	74.32	+3.56
Water production (stb) (top completion)	74,982	99,001	+24,019
Water production (stb) (bottom completion)	0	581,500	+581,500
Water production (stb) (total)	74,982	680,502	+605520
Production time (days)	1036	1163	+127

5.2 Sensitivity analysis

In this section, gas rate, water rate, perforation position and interval are varied in order to study their effect on gas recovery. The main subject for this analysis focuses on improvement in gas recovery and reduction of water production from coning when downhole water sink technique is applied. Sensitivity analysis is conducted for 2 types of reservoir. The first reservoir type has low vertical permeability which is equal to 8% of horizontal permeability (since horizontal permeability is 126 mD from field data and vertical one is 10 mD from assumption, this results in around 8% of k_v/k_h ratio). The second type has high vertical permeability which is equal to horizontal permeability (126 mD).

5.2.1 Production performance on low vertical permeability reservoir

5.2.1.1 Effect of water withdrawal rate

To study the sensitivity of DWS technique to water withdrawal rate, seven water withdrawal rates of 0, 250, 500, 750, 1000, 1500 and 200 stb/d are considered. Water rate of 0 stb/d indicates conventional completion, and the others indicate DWS technique. Other operating conditions are kept the same.

Figure 5.18 shows gas production obtained from the simulations. The constant rate can be maintained as long as the reservoir pressure is high enough and there is a sufficient amount of gas in the reservoir. At a certain point, the reservoir pressure drops and the gas rate declines.

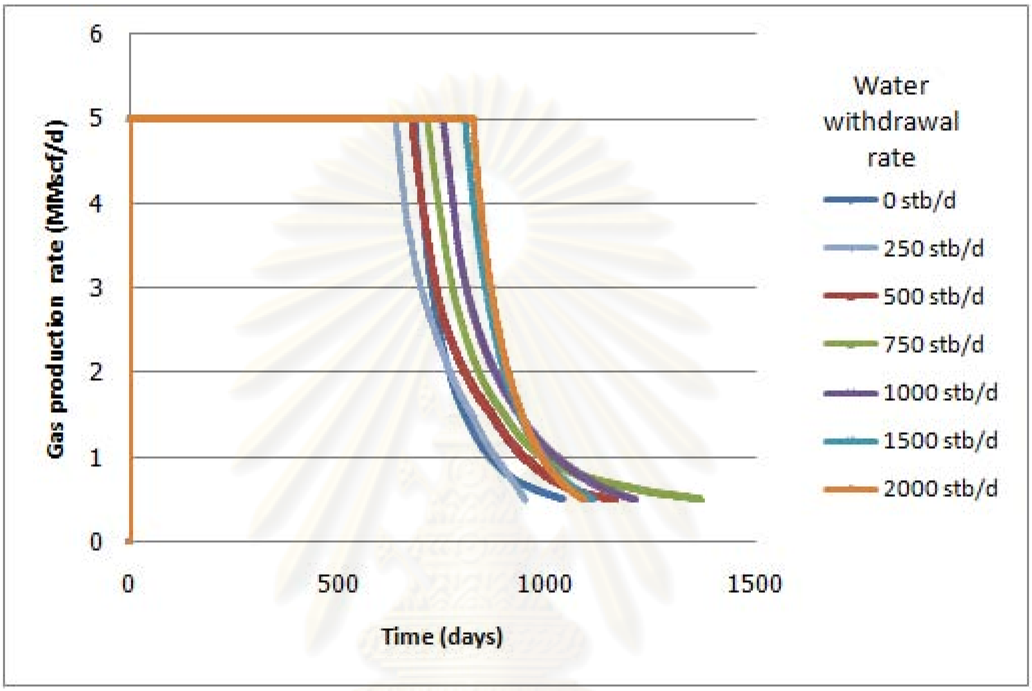

Figure 5.18: Gas production rate for different water withdrawal rates.

For conventional well (0 stb/d), there is a slightly different trend comparing to DWS well. This is because gas is produced through tubing in conventional well while DWS well produces gas through the casing-tubing annulus. For this scenario, conventional well can produce for a longer period than DWS well with water rate of 250 stb/d. The reason is that producing water from the bottom completion causes the reservoir pressure to deplete faster.

For low water withdrawal rates (250 to 750 stb/d), increase in water withdrawal rate causes more differential pressure that counters the one from the top completion, resulting in reduction in water production from water coning effect and a delay of water breakthrough time as shown in Figure 5.19. Thus, gas rate can be kept constant for a longer period when the water withdrawal rate is higher.

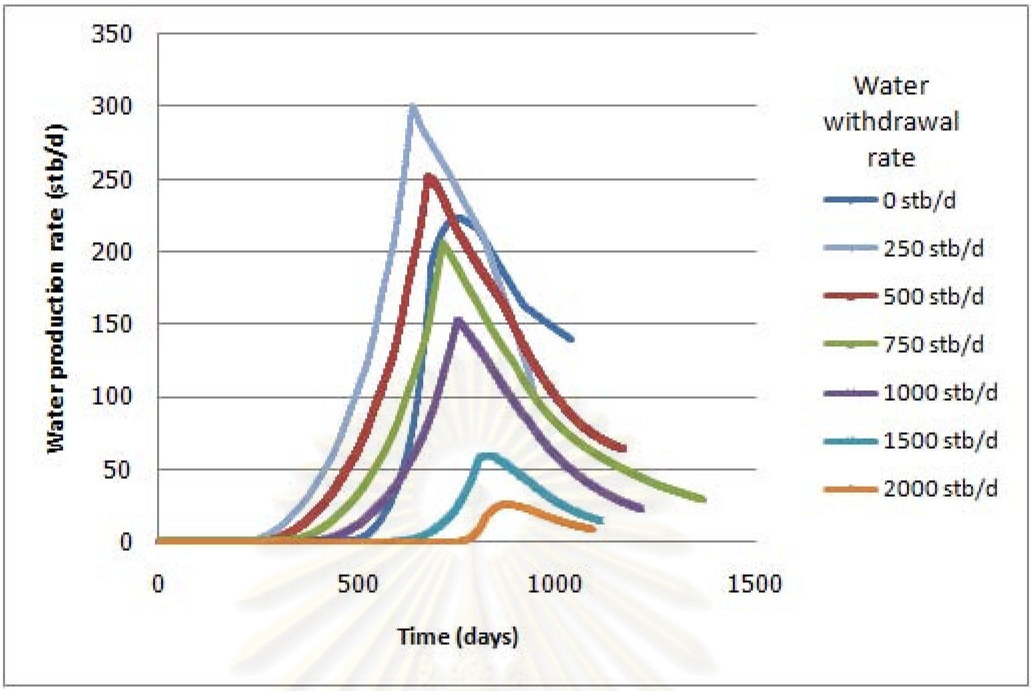

Figure 5.19: Water production rate for different water withdrawal rates.

However, there is a slightly different trend for high water withdrawal rates (1000 to 2000 stb/d). Although constant rate can still be kept for a longer period when increasing the water withdrawal rate, the gas rate drops faster than the one for low water withdrawal rates after this period. The decline rate increases as the water withdrawal rate becomes higher. This is because cumulative amount of gas and water productions in the period with constant gas rate are higher for the cases with high water withdrawal rates. The reservoir pressure depletes fast from a high amount of produced fluid as shown in Figure 5.20 and cannot support production rate for a long time after the rate declines.

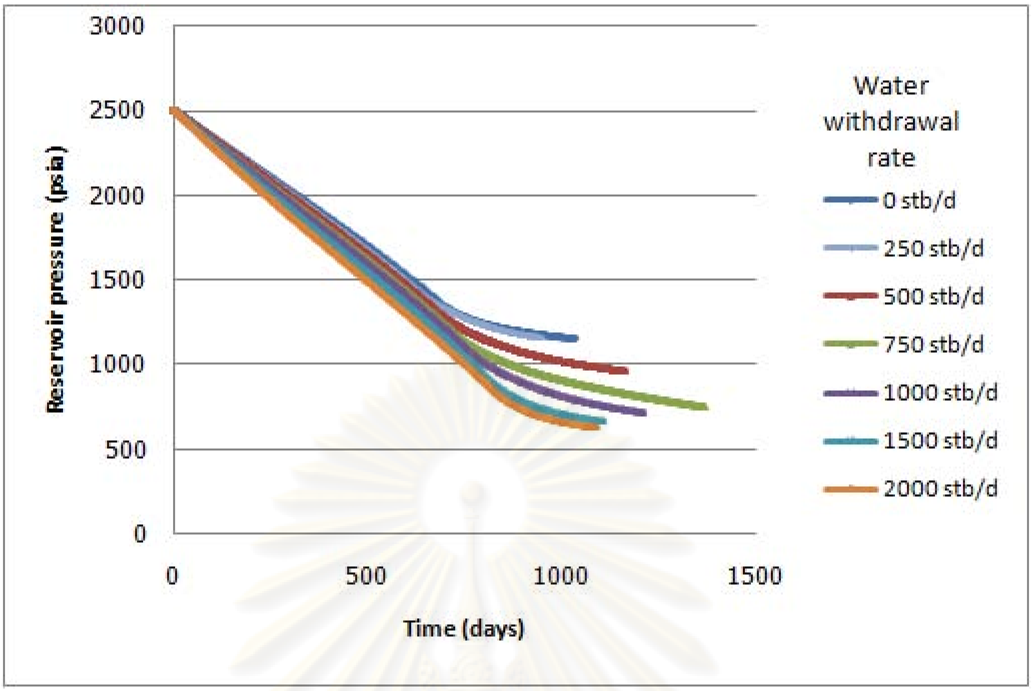

Figure 5.20: Reservoir pressure for different water withdrawal rates.

In contrast to this scenario, there are some cases with high water withdrawal rates that the reservoir pressure drops faster and causes the gas rate to drop earlier than cases with lower water withdrawal rates. One of these cases are, for example, the case with the top completion being perforated at the top of reservoir (other conditions are the same as the main case of DWS well described in Section 4.3). Figure 5.21 shows gas production rate for this case. For the case with 2000 stb/d of water withdrawal rate, the gas rates drop before the one with 1500 stb/d of water withdrawal rate. Figure 5.22 shows reservoir pressures for this scenario. The reservoir pressure in this case is lower than the reservoir pressure shown in Figure 5.19 for all cases.

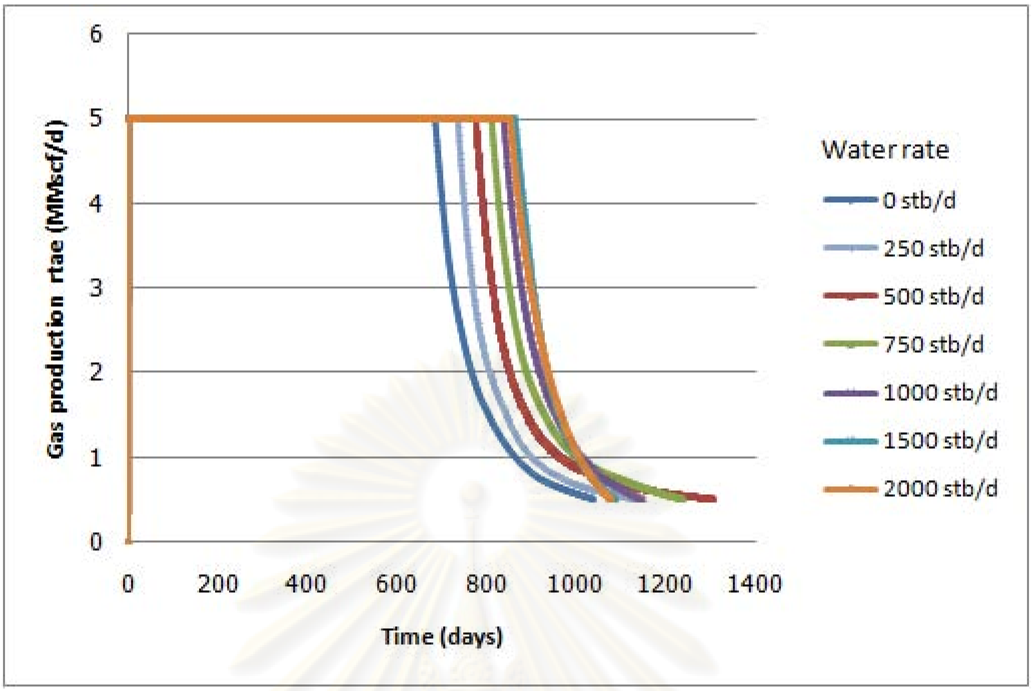

Figure 5.21: Gas production rate for different water withdrawal rates from the cases with the top completion being perforated from top of reservoir.

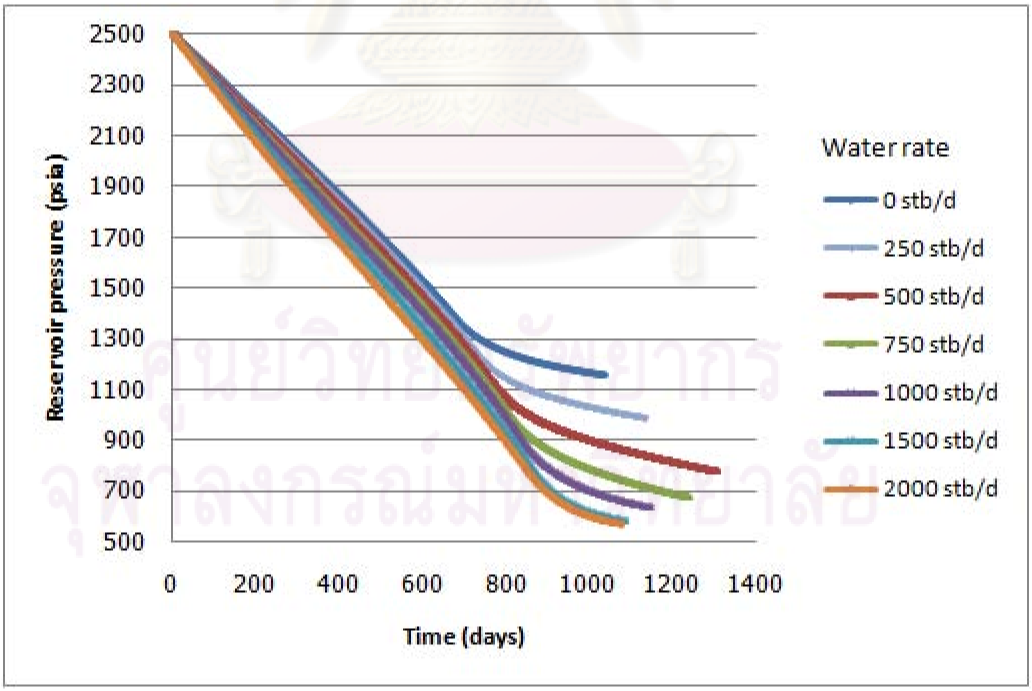

Figure 5.22: Reservoir pressure for different water withdrawal rates from the cases with the top completion being perforated from top of reservoir.

Figure 5.23 shows water withdrawal rate from the bottom completion. In the same manner as gas production, producing water causes the aquifer pressure to drop and eventually results in decrease in water production rate as the aquifer pressure is too low to support the rate. Increasing water withdrawal rate causes more pressure drop in the aquifer and water production rate to drop earlier. There is also more water production when water withdrawal rate is high as shown in Figure 5.24. This can become disadvantage due to higher water disposal cost.

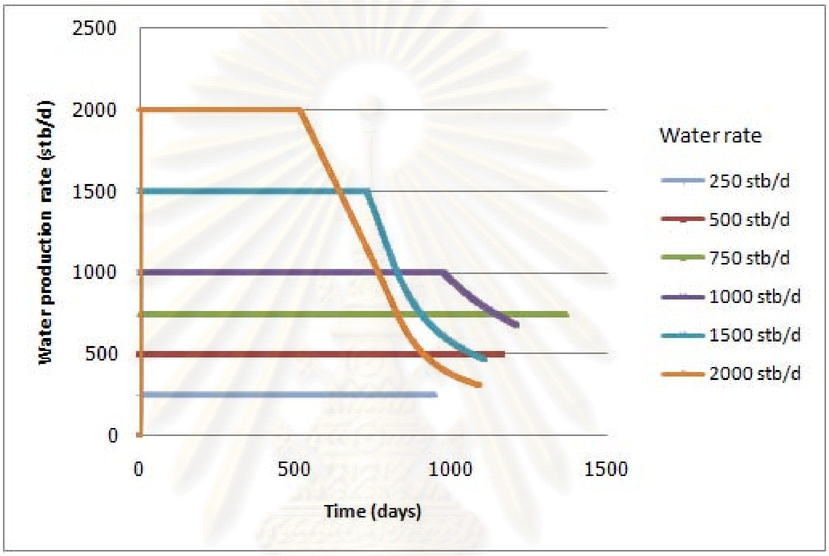

Figure 5.23: Water production rate from the bottom completion for different water withdrawal rates.

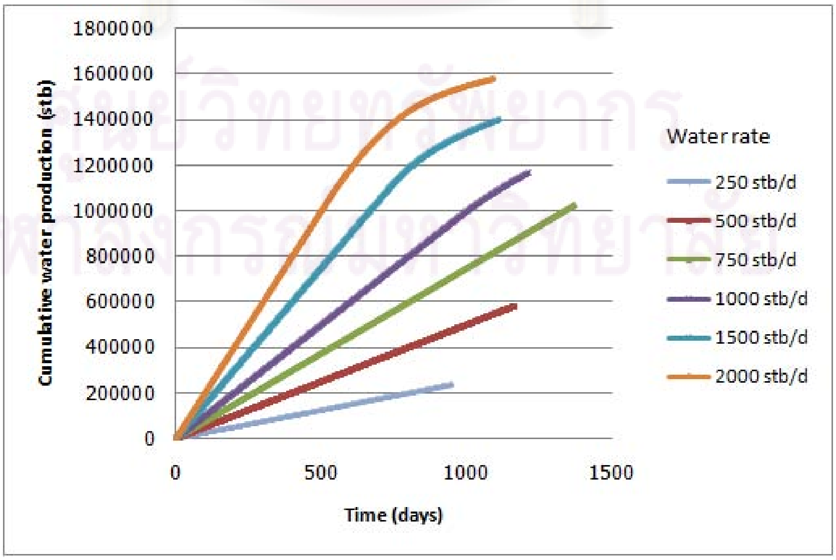

Figure 5.24: Cumulative water production from the bottom completion for different withdrawal water rates.

Although water is produced to prevent water coning effect, producing at too high rate can cause gas coning similar to the one in oil reservoirs and results in gas production as shown in Figure 5.25. The reason is that differential pressure around the bottom completion is too the high. In any case, the amount of gas is quite low. In the figure, only case with 2000 stb/d of water withdrawal rate shows the presence of gas production from the bottom completion while the other cases have gas production close to zero. Figures 5.26 and 5.27 show the difference of coning shape for the case with 750 and 2000 stb/d of water withdrawal rate after 500 days of production, respectively.

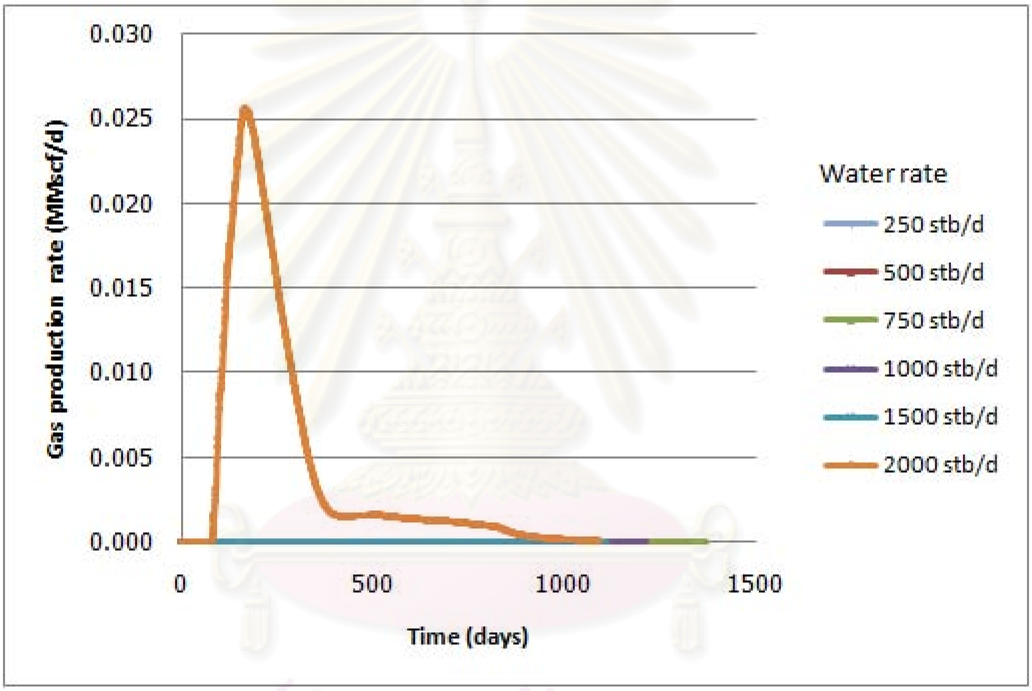

Figure 5.25: Gas production rate from the bottom completion for different water withdrawal rates.

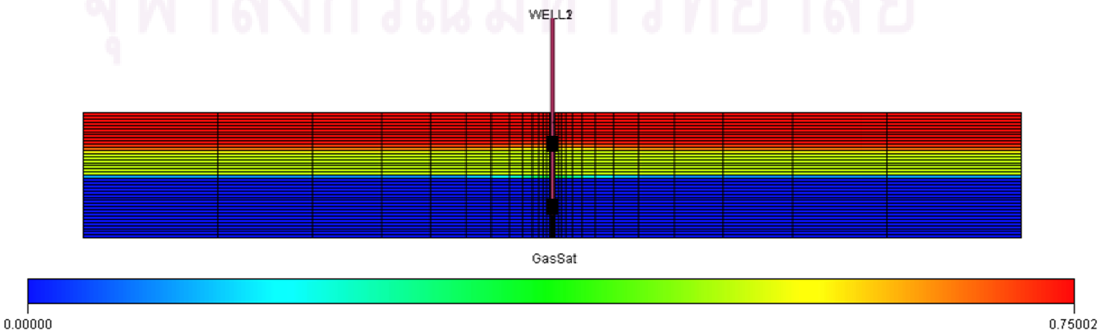

Figure 5.26: Gas coning shape after 500 days of production with 750 stb/d of water withdrawal rate.

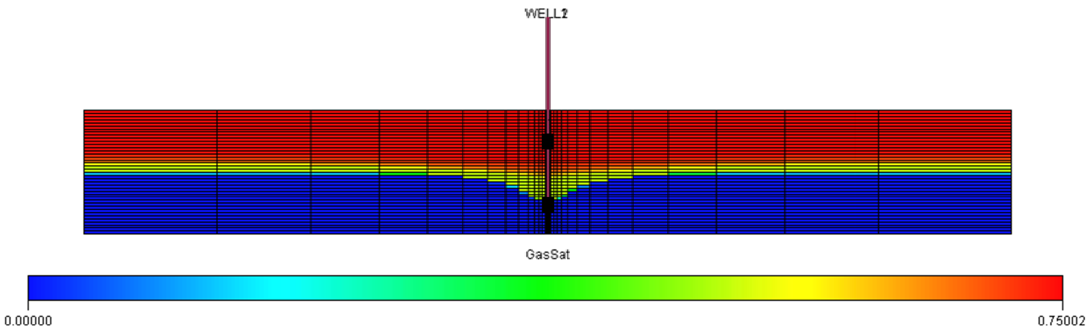

Figure 5.27: Gas coning shape after 500 days of production with 2000 stb/d of water withdrawal rate.

Figure 5.28 shows gas recovery factor for different water withdrawal rates, and Table 5.2 summarizes the production performance for different water withdrawal rates. The recovery factor increases significantly when increasing the water withdrawal rate from 250 to 750 stb/d and slightly increases when increasing the water withdrawal rate even more as the recovery factor is reaching its limit. As the water withdrawal rate increases, water production from the top completion decreases drastically but water production from the bottom completion increases in a linear fashion. In general, it may not be worthwhile to withdraw water at a high rate just to recover slightly more gas.

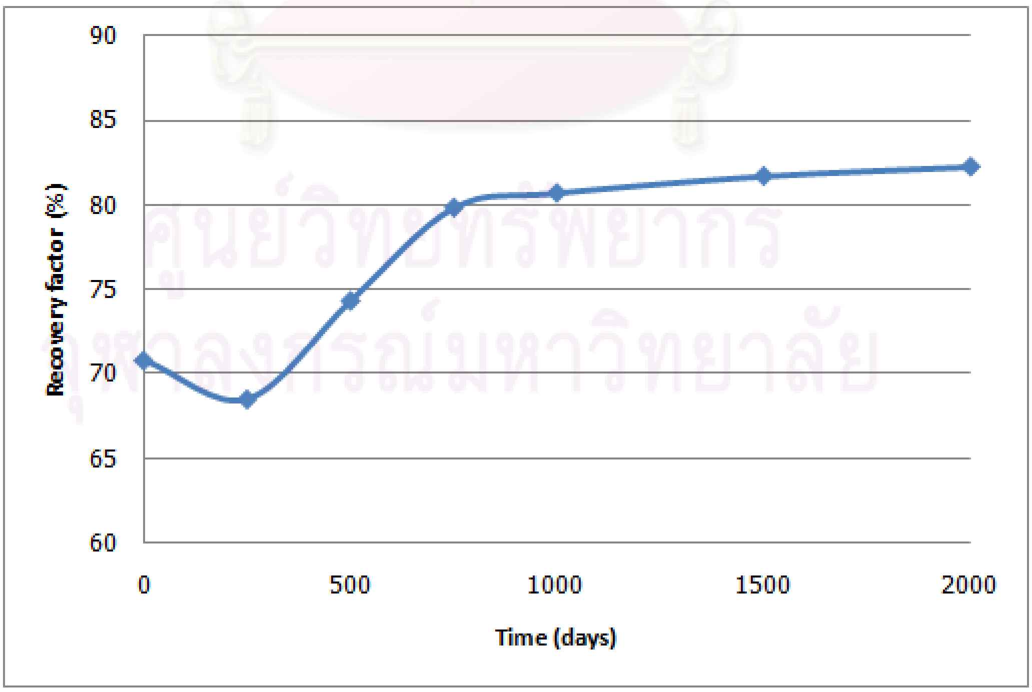

Figure 5.28: A plot of gas recovery factor vs. water withdrawal rate.

Table 5.2 also shows that the well can produce longer when increasing water withdrawal rate. However, total production time becomes less when increasing water withdrawal rate to some specific point due to higher pressure drop. The same reason is applied to comparison between conventional well and DWS well with low water rate (250 stb/d). In any case, total water production always increases as water withdrawal rate increases.

Table 5.2: Production performance for different water withdrawal rates

Water withdrawal rate (stb/d)	Gas production from top zone		Water production (stb)			Production time (days)
	Volume (MMscf)	Recovery factor (%)	Top zone	Bottom zone	Total	
0	3922.38	70.8	74,982	0	74,982	1036
250	3795.18	68.5	100,967	236,500	337,467	946
500	4119.31	74.3	99,001	581,500	680,502	1163
750	4425.13	79.8	81,777	1,024,500	1,106,277	1366
1000	4473.16	80.7	50,114	1,166,584	1,216,698	1210
1500	4528.46	81.7	14,603	1,398,612	1,413,216	1108
2000	4559.14	82.2	5,317	1,577,152	1,582,470	1088

5.2.1.2 Effect of gas rate

To study the sensitivity of DWS technique to gas production rate, three different gas rates of 5, 10 and 15 MMscf/d were simulated. Water is withdrawn at 500 stb/d from the bottom completion. Other operating conditions are kept the same. Figure 5.29 shows gas production profiles obtained from the simulations. High gas rate results in more production at an early period. However, high gas rate causes the reservoir pressure to drop faster as shown in Figure 5.30 and results in early decline in gas rate.

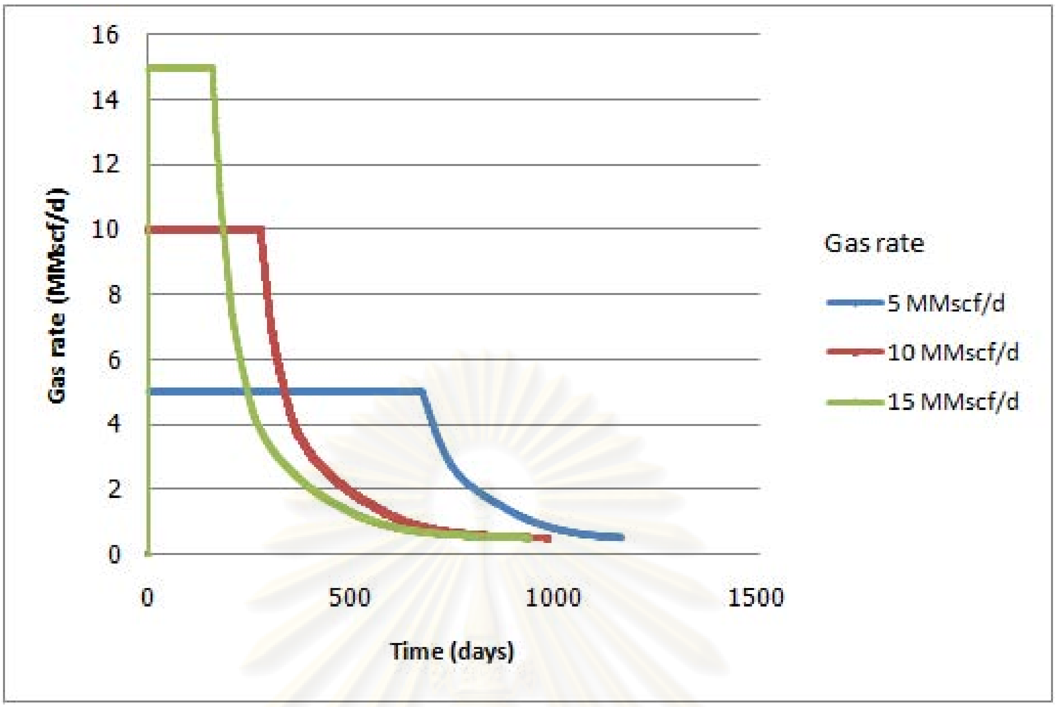

Figure 5.29: Gas production rate from the top completion.

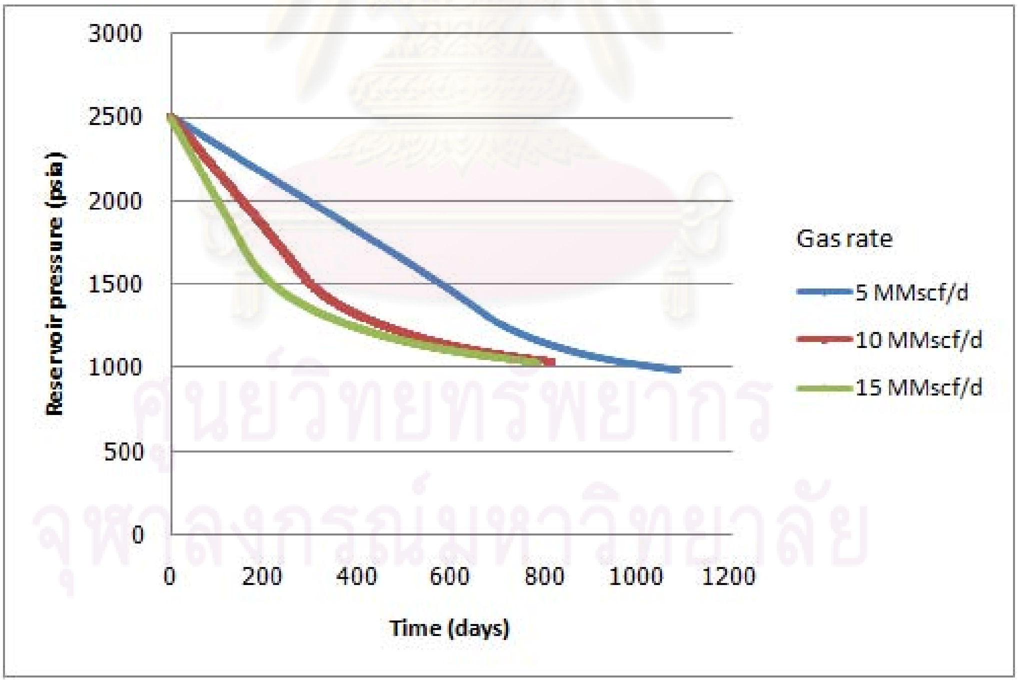

Figure 5.30: Reservoir pressure vs. time for different gas rates.

Although lower gas rate can be kept constant longer, the total production at the end for the three cases are not much different as shown in Figure 5.31. This is because in case of higher gas rate, most of gas production is recovered at early period.

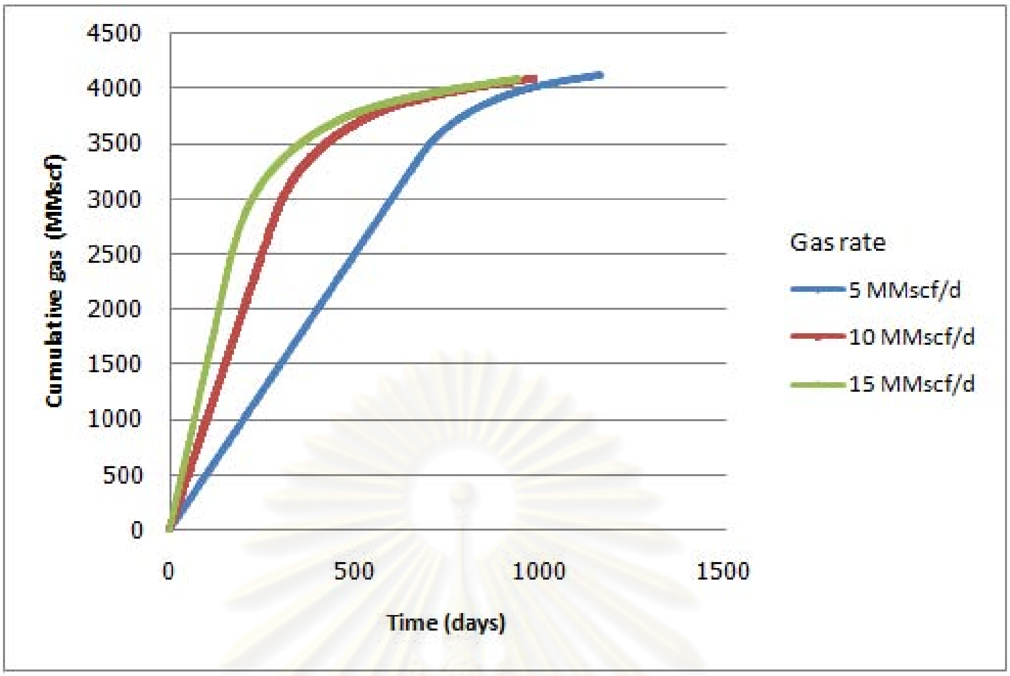

Figure 5.31: Cumulative gas production from the top completion for different gas rates.

Figure 5.32 shows water production from the top completion for different gas production rates. As seen from the figure, a higher gas rate causes more water production. This is because the gas-water contact moves up faster as gas is produced at a high rate as shown in Figures 5.33 and 5.34. In addition, the differential pressure around the top completion is higher for high gas rate, thus, causes more water to cone into the top completion. This also causes the water rate to increase faster after water breakthrough. After producing for a certain period, the water rate for the case of higher gas rate drops sooner than other cases due to sharper decline in reservoir pressure during the early period of gas production.

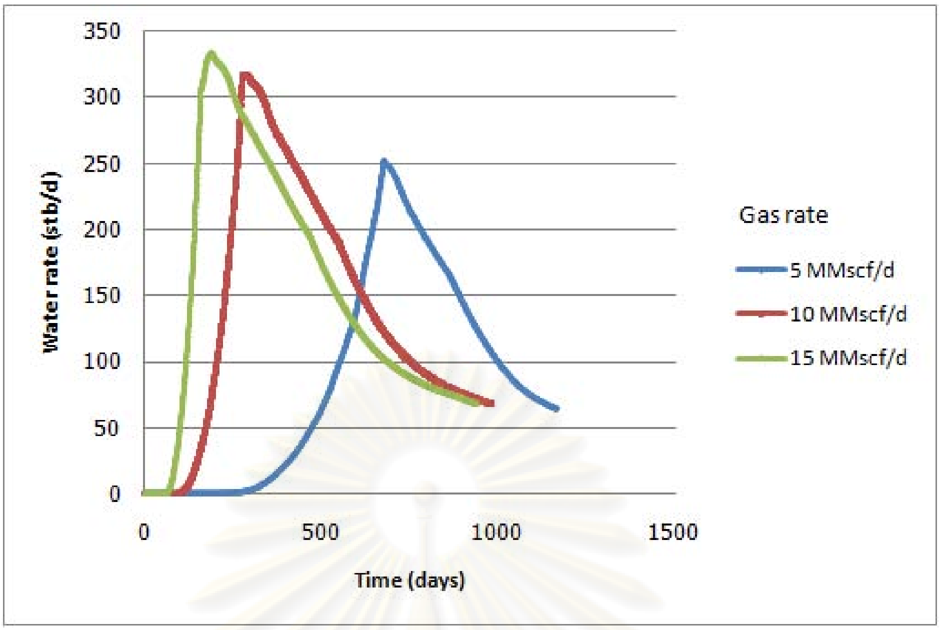

Figure 5.32: Water production rate from the top completion for different gas rates.

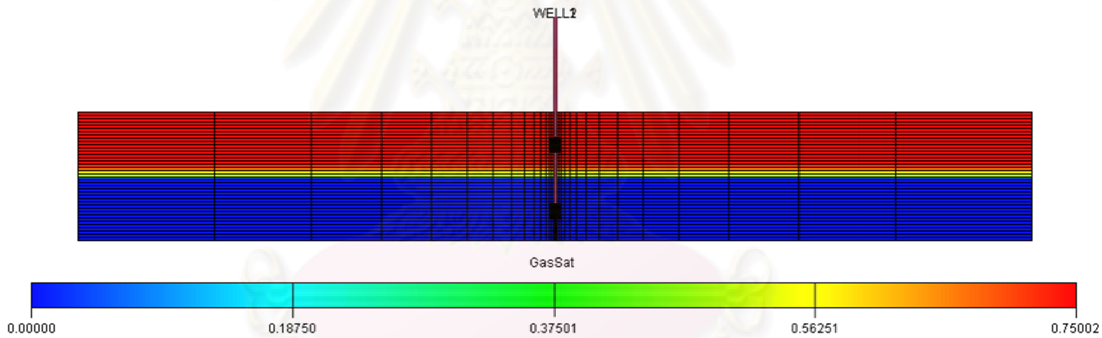

Figure 5.33: Water coning shape at 100 days for 5 MMscf/d of gas rate.

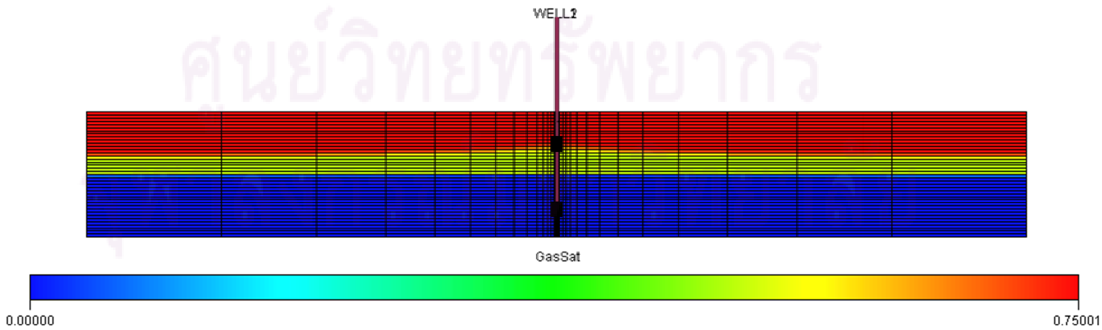

Figure 5.34: Water coning shape at 100 days for 15 MMscf/d of gas rate.

For the bottom completion, water withdrawal rate can be kept constant until the end of production as shown in Figure 5.35. This is because the aquifer pressure is still high enough to support water withdrawal rate. There is also no gas production from the bottom completion due to low differential pressure from low water withdrawal rate.

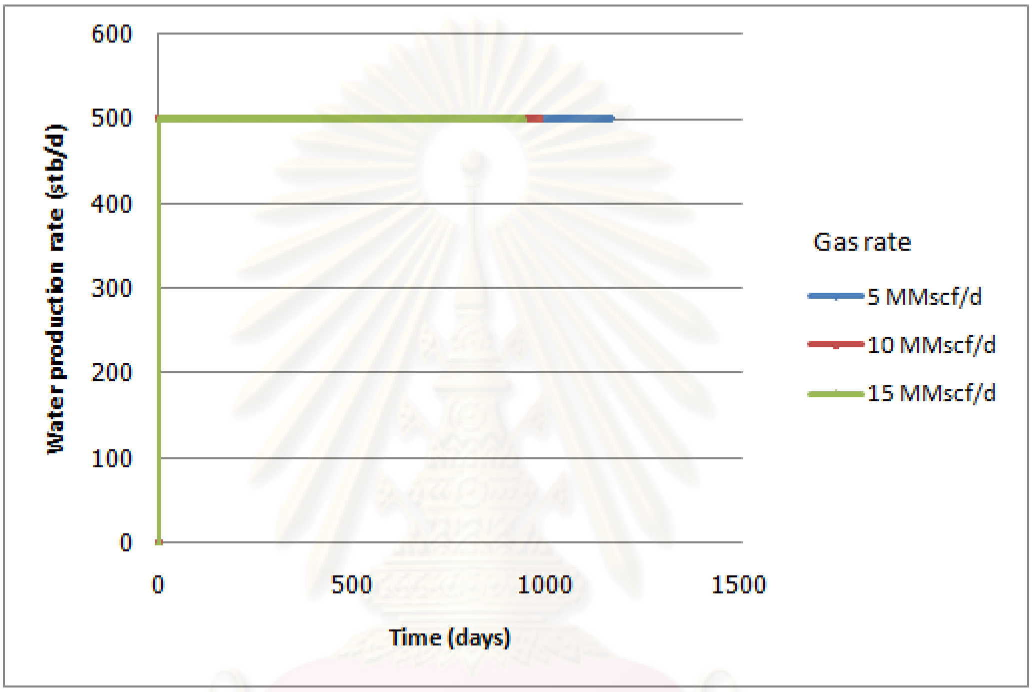

Figure 5.35: Water withdrawal rate from the bottom completion for different gas rates.

However, for some cases in which gas is produced at low rate and water is produced at high rate, there is gas production from the bottom completion. For example, Figure 5.36 shows the results for the cases in which the top completion is perforated for 30 ft from top of reservoir and the bottom completion is perforated for 30 ft at the middle of water zone. Water is produced at 1500 stb/d from the bottom completion, and three gas rates of 5, 10 and 15 MMscf/d are used. In the figure, there is the presence of gas production from the bottom completion for the case with 5 MMscf/d of gas rate. However, the gas production from the bottom completion is very small. The reason for gas breakthrough is that there is more differential pressure at the bottom completion than the top one. This causes gas to cone into the bottom completion. Increasing gas rate can reduce gas production at the bottom completion.

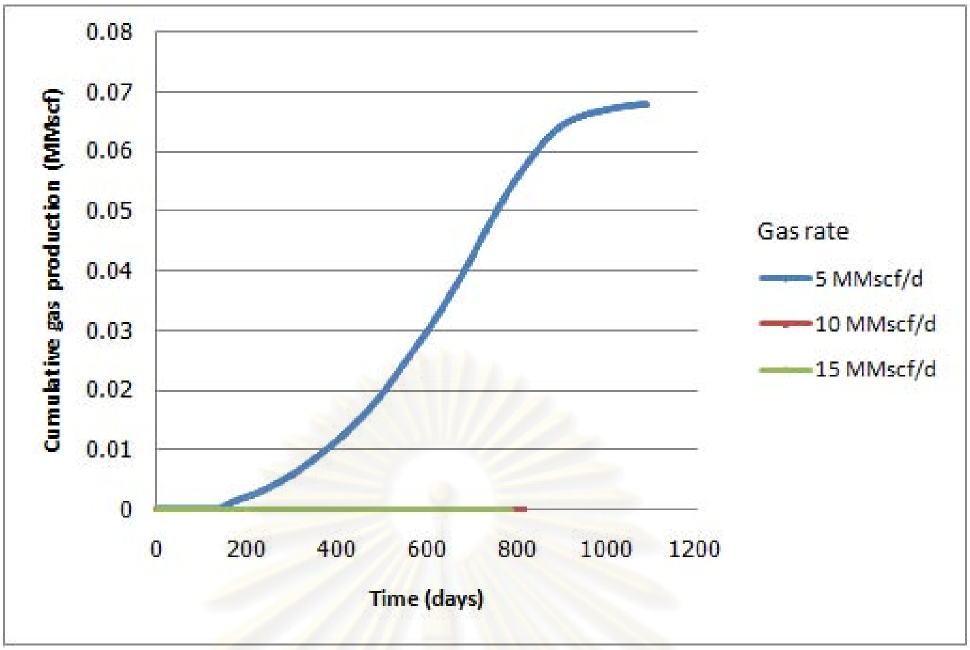

Figure 5.36: Cumulative gas production from the bottom completion which produces 1500 stb/d of water for different gas rates.

Figure 5.37 shows recovery factors for different gas rates. The results show that gas rate does not have much effect on recovery factor. Although low gas rate can reduce water production and slightly improve gas recovery, high gas rate may be better off since more gas can be recovered at an early time. Cumulative water production from the bottom completion is also lower for the case with high gas rate as shown in Table 5.3. The only disadvantage of high gas rate is that there is more water production from the top completion due to high differential pressure at the wellbore.

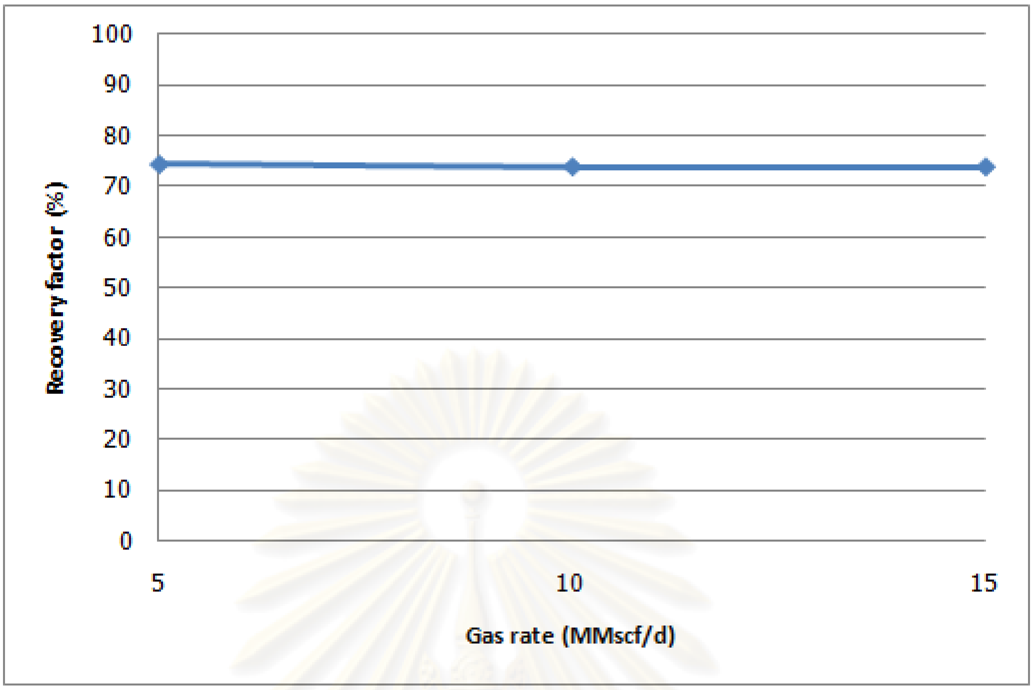

Figure 5.37: Recovery factor vs. gas rate at the top completion.

Table 5.3 also shows that total water production decreases as gas rate increases. This is because more water cones into the top completion instead of withdrawing from the bottom completion. Larger pressure decline from high gas production rate is also another reason for decreasing in total water production. Total production time also decreases due to faster reservoir pressure drop.

Table 5.3: Production performance for different gas rates

Gas rate (MMscf/d)	Gas production from top zone		Water production (stb)			Production time (days)
	Volume (MMscf)	Recovery factor (%)	Top zone	Bottom zone	Total	
5	4119.31	74.3	99,001	581,500	680,502	1163
10	4090.54	73.8	133,235	490,000	623,235	980
15	4090.70	73.8	144,205	469,500	613,705	939

5.2.1.3 Effect of perforation position

As mentioned in Section 4.5, 4 combinations of perforation positions are considered. These combinations are:

a) The top completion is perforated at the top of the gas zone while the bottom completion is perforated in the middle of the water zone
b) The top completion is perforated at the top of the gas zone while the bottom completion is perforated at the bottom of the water zone
c) The top completion is perforated in the middle of the gas zone while the bottom completion is perforated in the middle of the water zone
d) The top completion is perforated at the middle of gas zone while the bottom completion is perforated at the bottom of the water zone
e) The top completion is perforated at the bottom of the gas zone while the bottom completion is perforated at the top of the water zone

The well schematic for these perforation positions are shown in Figure 4.6 in Chapter 4. Gas production rate, water withdrawal rate and perforation intervals for the top completion and bottom completion are kept the same for all cases.

Figure 5.38 shows gas production profiles for different positions of perforation. In all cases, gas flows at a constant rate of 5 MMscf/d at the beginning, and then the flow rate declines after the reservoir pressure becomes too low to sustain such rate. Gas production for 2 pairs of scenarios, (a)-(b) and (c)-(d), are almost the same. The plots imply that position of the bottom completion does not have much effect on gas production. This is due to gas mobility and gas density that makes gas tend to flow upward rather than downward into the bottom completion. The effect of pressure drawdown from the bottom completion is also low due to low water rate (cases with high water rate from the bottom completion are discussed later). However, position of the top completion shows obvious difference in gas production. In the figure, gas rate for scenarios (c) and (d) where the top completion is perforated in the middle of the gas zone drops earlier than that for scenarios (a) and (b) where the top completion is perforated at the top of the gas zone.

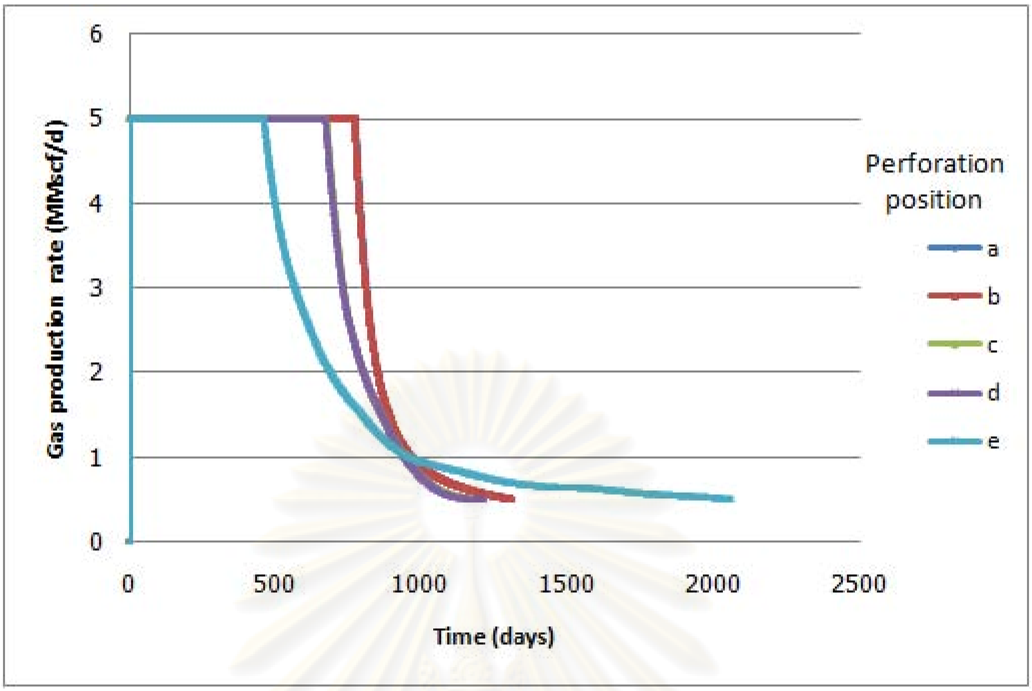

Figure 5.38: Gas production rate from the top completion for different perforation scenarios.

The reason for an early drop in production rate is that there is early water breakthrough in scenarios (c) and (d) as shown in Figure 5.39. This is because the distance between the top completion and the gas-water contact is closer than the one in scenarios (a) and (b), making aquifer water to cone into the top completion more easily. The level of gas-water contact also moves up and reaches the top completion earlier. Figures 5.40 and 5.41 show the difference of water coning shape for scenario (b) and (d) after 300 days of production, respectively.

For scenario (e), gas rate drop earlier than other cases. This is because water breaks through earlier as shown in Figure 5.39 due to the closer distance between the completion and gas-water contact than other cases. Water production reduces production performance by loading the well. However, gas rate can be produced longer because of early rate decline.

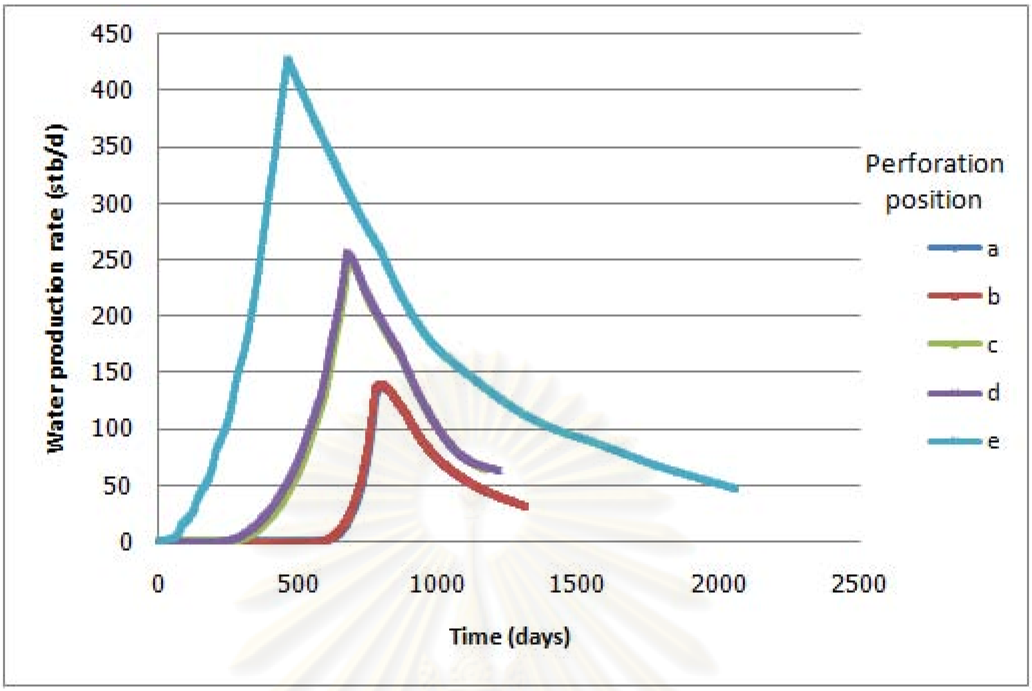

Figure 5.39: Water production rate from the top completion for different perforation scenarios.

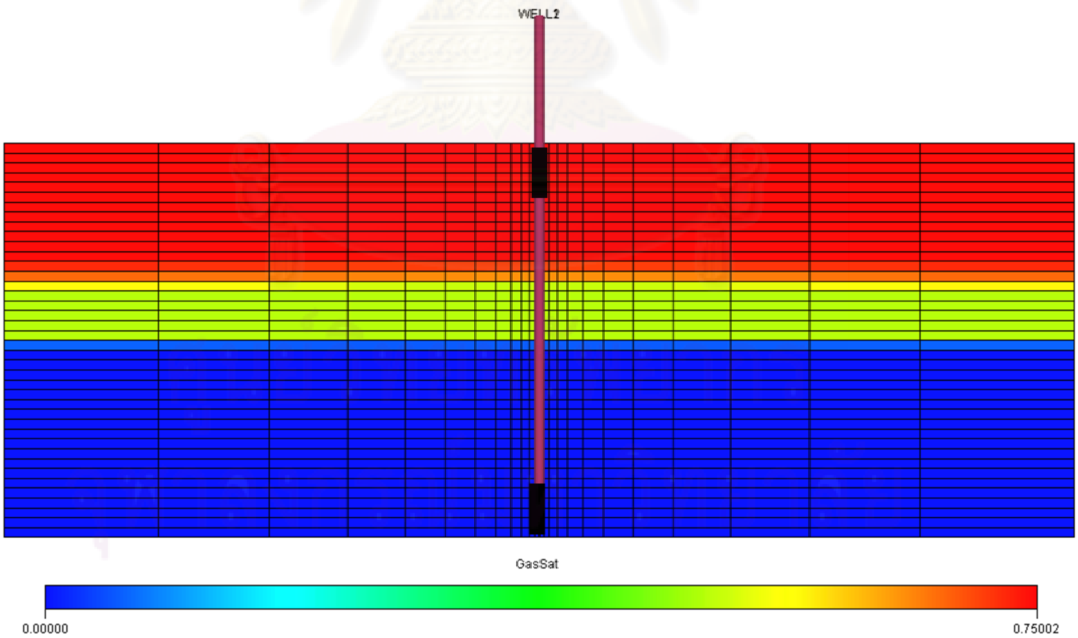

Figure 5.40: Gas coning shape at 300 days for scenario (b).

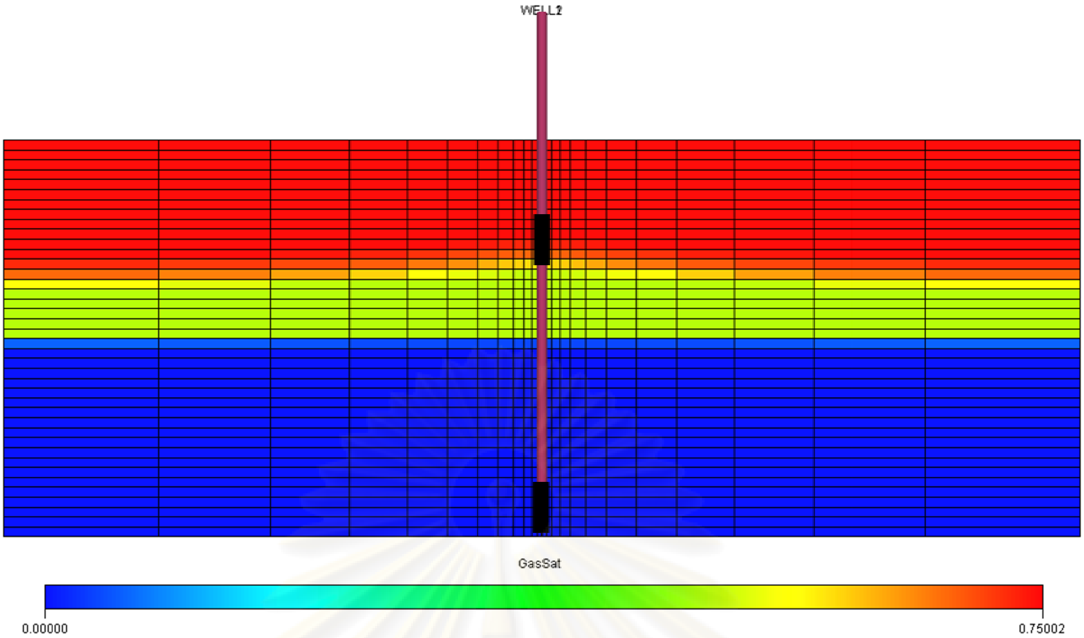

Figure 5.41: Gas coning shape at 300 days for scenario (d).

For the bottom completion, varying perforation positions doesn't have much effect on production. Water withdrawal rate can be kept constant until the end of production as shown in Figure 5.42. There is also no gas production from the bottom completion for these cases.

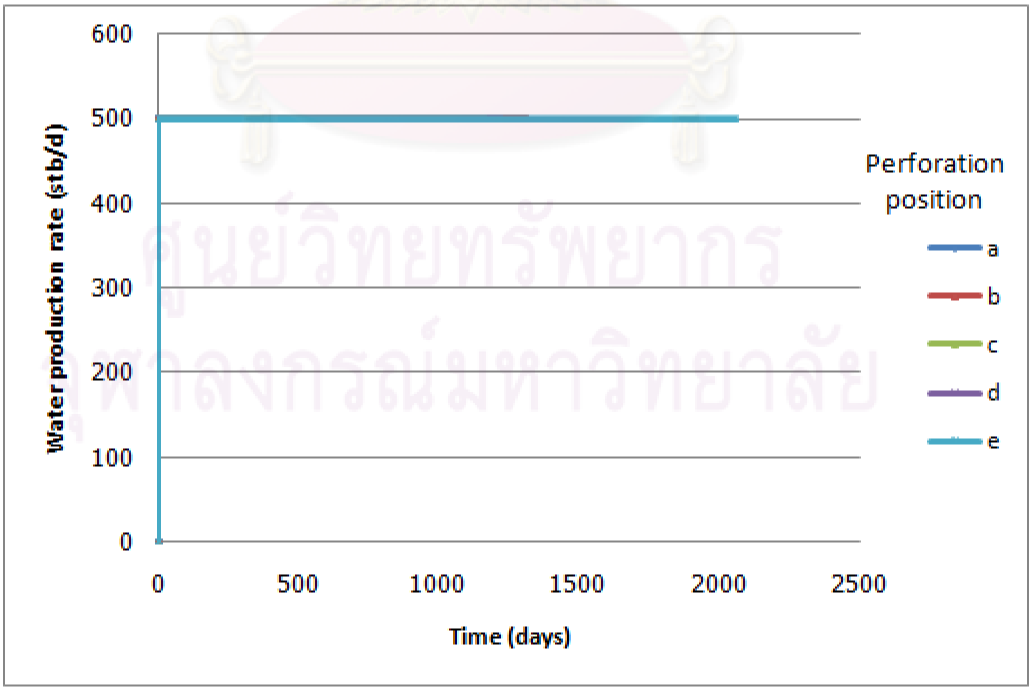

Figure 5.42: Water withdrawal rate from the bottom completion for different perforation positions.

In the figure, gas production for scenario (a) where the top completion is perforated from the top of the gas zone is higher than scenario (c) where the top completion is perforated at the middle of the gas zone. This is because the effect of pressure drawdown from the top completion for scenario (c) is closer to gas-water contact so it can counter the one from the bottom completion more effectively. Figures 5.43 and 5.44 show the difference of gas coning shape between 2 scenarios after 1000 days of production.

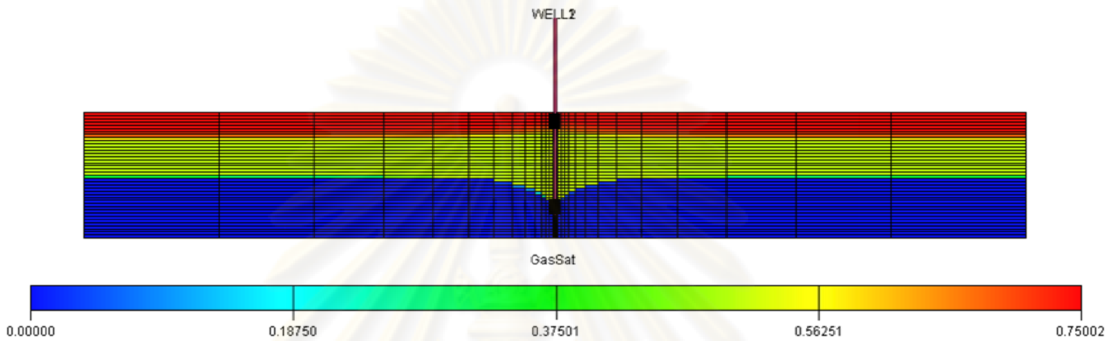

Figure 5.43: Gas coning shape at 1000 days for scenario (a).

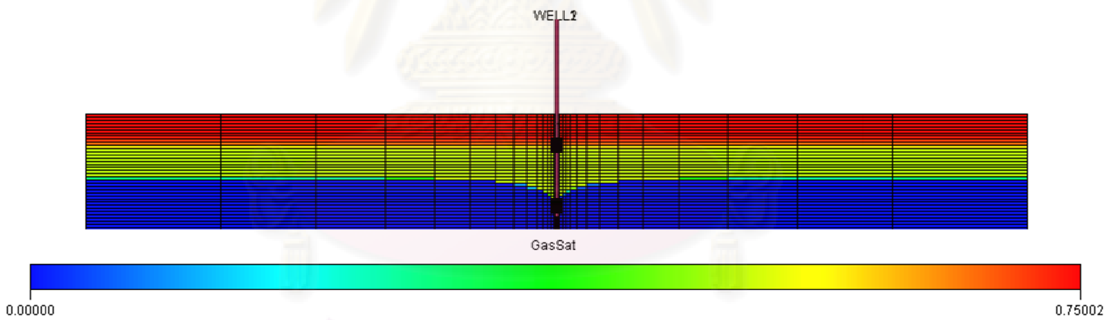

Figure 5.44: Gas coning shape at 1000 days for scenario (c).

Figure 5.45 shows recovery factors for different perforation positions. The position of the bottom completion has only a slight effect on gas production but the position of the top completion can increase the gas recovery significantly if the perforation is far from the gas-water contact because it takes more time for water to reach the completion. The position of the top completion also strongly affects water production from the gas zone as shown in Table 5.4. Perforating the gas zone at the top gives rise to less water production, making it an attractive choice. For the bottom completion, there is no significant difference in water production.

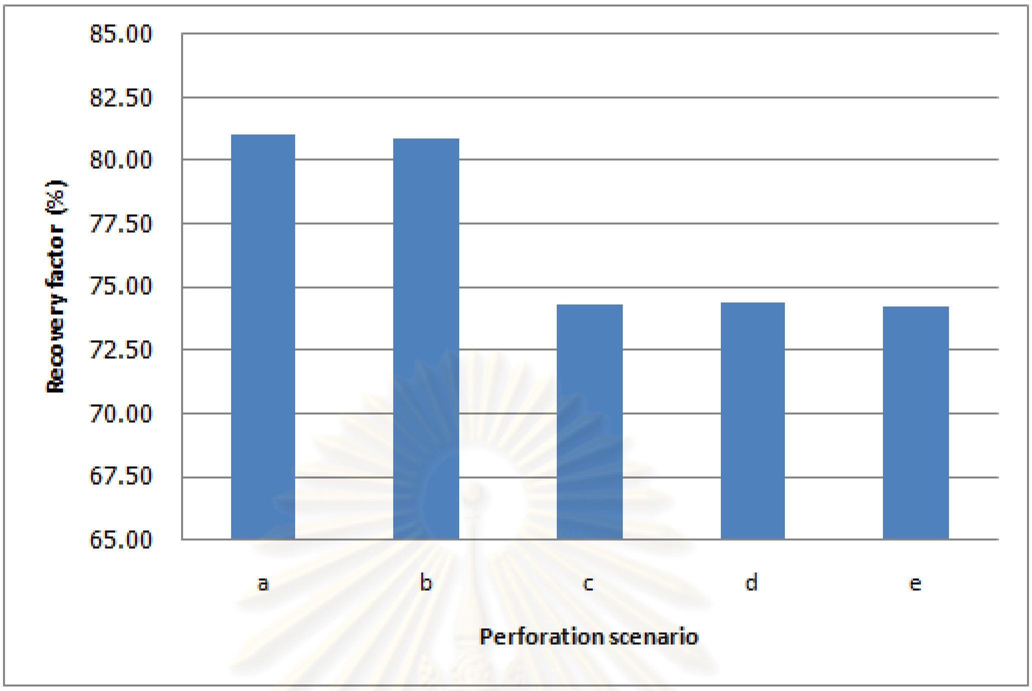

Figure 5.45: Recovery factor for different perforation scenarios.

For total water production, there is no significant difference among all 4 cases. This is due to the fact that water production from the top completion becomes less because the perforation is far from gas-water contact. So, more water is withdrawn from the bottom completion instead. Position of the bottom completion also has no effect on water production from the top and the bottom completion. For total production time, position of the top position has significant effect on it in the same way as gas production. Perforating gas zone at the top of reservoir can delay water breakthrough; so gas can be produced longer. This may be exception for scenario (e) that the well can produce longer due to early gas rate decline and water withdrawal near the top completion.

Table 5.4: Production performance for different perforation scenarios

Perforation scenario	Gas production from top zone		Water production (stb)			Production time (days)
	Volume (MMscf)	Recovery factor (%)	Top zone	Bottom zone	Total	
a	4490.52	81.0	44,665	652,000	696,665	1304
b	4483.14	80.9	46,646	653,000	699,647	1306
c	4119.31	74.3	99,001	581,500	680,502	1163
d	4123.37	74.4	106,166	605,500	711,666	1211
e	4115.53	74.3	317,961	1,028,000	1,345,961	2056

5.2.1.4 Effect of perforation interval

Figure 5.46 shows gas production profiles for different perforation intervals ranging between 10 to 100 feet. The cases with long intervals can maintain constant rate for longer periods than cases with short intervals due to small pressure drawdowns around the vicinity of the well as shown in Figure 5.47.

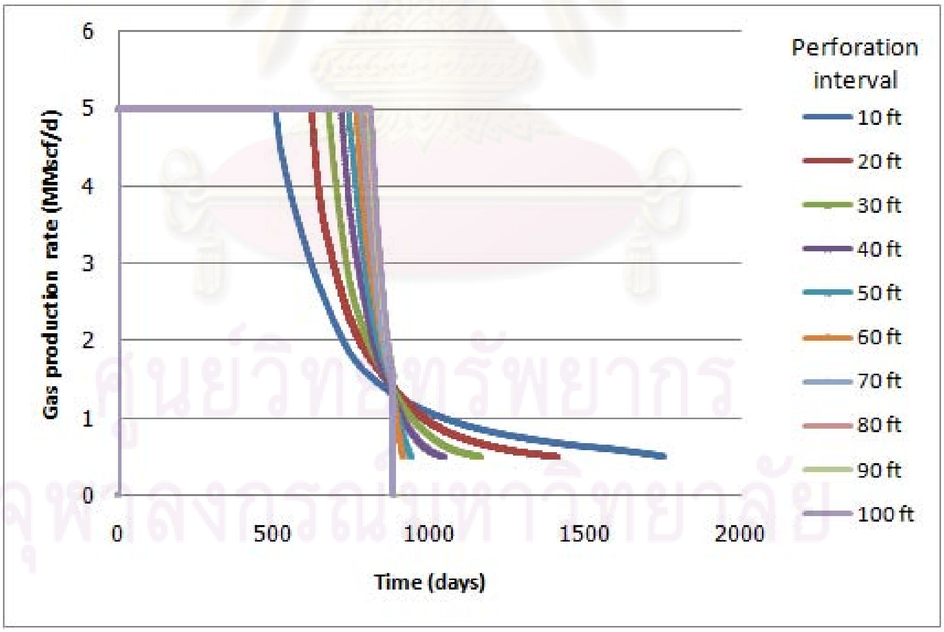

Figure 5.46: Gas production rate from the top completion for different perforation intervals.

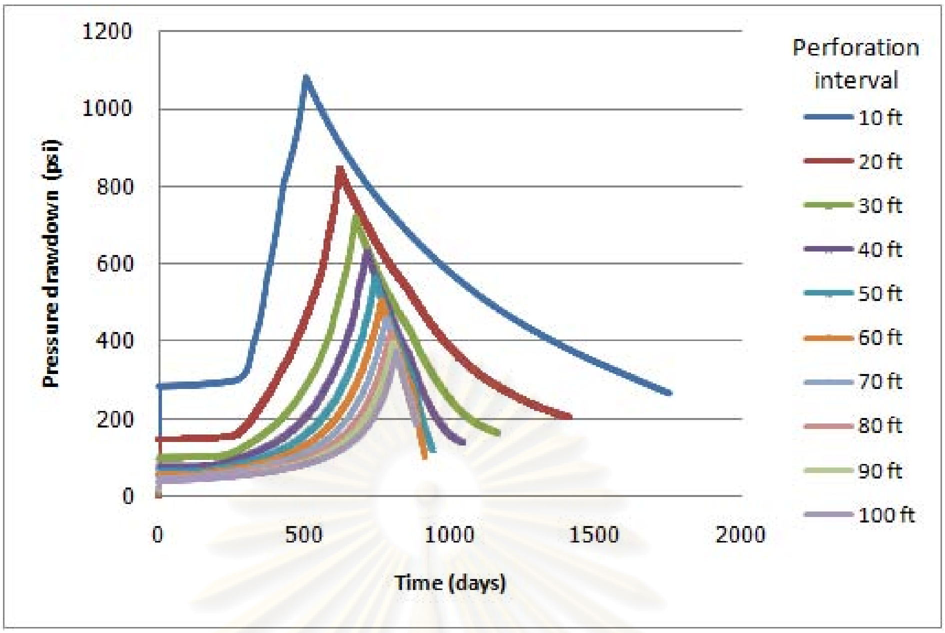

Figure 5.47: Pressure drawdown around the top completion for different perforation intervals.

The shorter intervals have more pressure drop from the skin due to limited entry. The fluid is forced to flow spherically near the wellbore into completion. After a certain period, water begins to break through. At this point, the pressure drop increases because water has low mobility than gas. This effect increases pressure drop pretty much for the cases with short intervals because lower mobility make the fluid harder to flow into the completion.

Figure 5.48 shows water production profiles for different perforation intervals. Water breaks through a bit earlier for long perforation intervals due to closer distances between the bottom of the top completion and the gas-water contact. Long perforation intervals also allow water to enter the completion more easily, giving rise to higher water rates after the breakthrough. However, the water rate in these cases drops faster because of a sharp decline in reservoir pressure caused by a large amount of gas and water production.

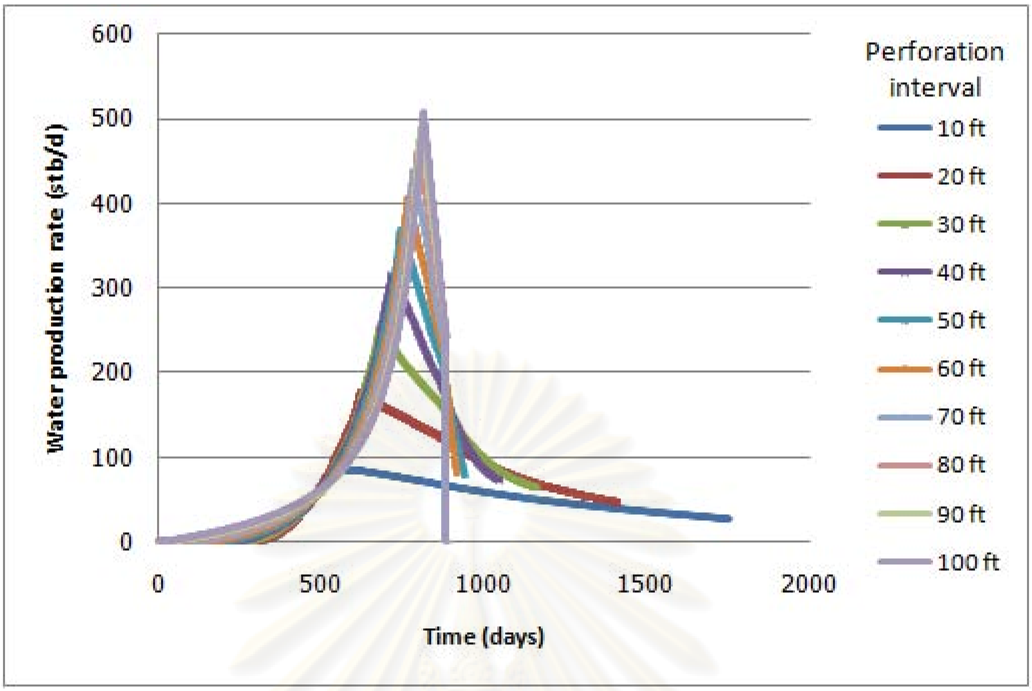

Figure 5.48: Water production rate from the top completion for different perforation intervals.

Similar to sensitivity analysis for gas rate and perforation position of the bottom completion, perforation interval doesn't have much effect on production from the bottom completion. Figure 5.49 shows water withdrawal rate from the bottom completion. Water rate can be kept constant until the end of production except for the case with 10 ft of perforation interval that water rate drops near the end of production due to high pressure drop from skin. There is also no gas production in these cases.

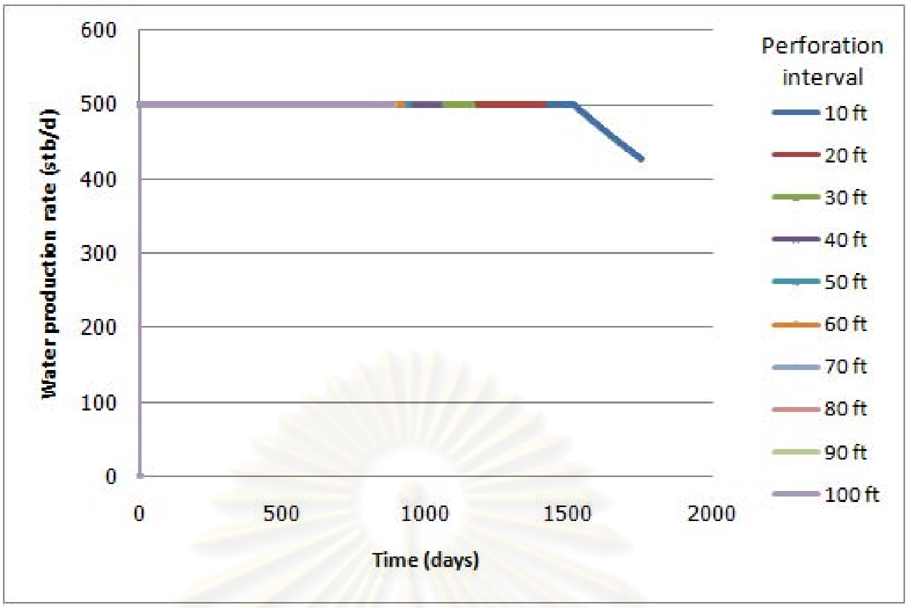

Figure 5.49: Water withdrawal rate from the bottom completion for different perforation intervals.

Figure 5.50 shows recovery factors for different perforation intervals. There is almost no difference in recovery among these cases. This is because long perforation interval has less pressure drop from skin, so gas can be produced at constant rate longer. In contrast, since the production rate drops earlier for shorter perforation interval, the reservoir pressure drops at slower rate than the one from long interval so the well can produce longer. So, it can be concluded that perforation interval doesn't have much effect on gas recovery.

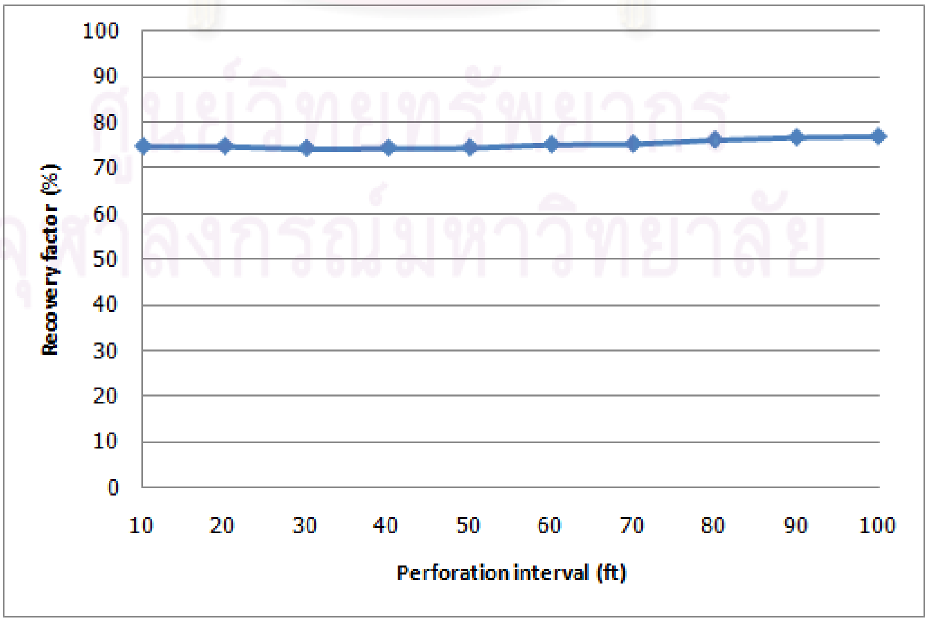

Figure 5.50: Recovery factor for different perforation intervals.

Table 5.5 summarizes production performance for different perforation intervals. As the perforation interval increases, water production from the top completion first increases due to a closer distance to gas-water contact and then slightly decreases due to larger thickness for the gas to flow into the wellbore. A long perforation interval allows more fluid to be produced and causes the reservoir pressure to drop at a high rate. This effect results in production rate decline. The economic limit is reached early, and thus, less water production. For the cases with more than 50 ft of perforation interval, water production has only slightly difference due to water loading in the well.

For the bottom completion, water production decreases as perforation interval increases. This is because a well with a longer perforation interval has a shorter well life resulted from depleted reservoir pressure as a large amount of gas is produced during the early period. Since most of water production comes from the bottom completion, total water production also decreases due to shorter well life as well.

Table 5.5: Production performance for different perforation intervals

Perforation interval (ft)	Gas production from top zone		Water production (stb)			Production time (days)
	Volume (MMscf)	Recovery factor (%)	Top zone	Bottom zone	Total	
10	4142.58	74.7	72,204	865,051	937,255	1748
20	4145.94	74.8	96,232	703,000	799,232	1406
30	4119.31	74.3	99,001	581,500	680,502	1163
40	4123.82	74.4	98,023	522,000	620,023	1044
50	4128.16	74.5	93,455	469,500	562,955	939
60	4165.74	75.2	93,842	456,500	550,342	913
70	4172.36	75.3	90,246	438,000	528,246	875
80	4219.22	76.1	93,103	441,000	534,103	881
90	4248.06	76.6	94,681	442,500	537,181	884
100	4258.70	76.8	95,077	441,000	536,077	881

5.2.2 Production performance on reservoir with high vertical permeability

In this section, the production performance between conventional well and DWS well is evaluated for reservoir with high vertical permeability. For this scenario, vertical permeability is set equal to horizontal permeability; i.e., 126 mD. The sensitivity analysis with the same varied parameters is also performed.

Figure 5.51 shows gas production obtained from the simulations. The results show improvement in gas production similar to that obtained when $k_v/k_h = 0.08$. Water production also decreases as seen in Figure 5.52. Table 5.6 summarizes improvement of production performance for this case.

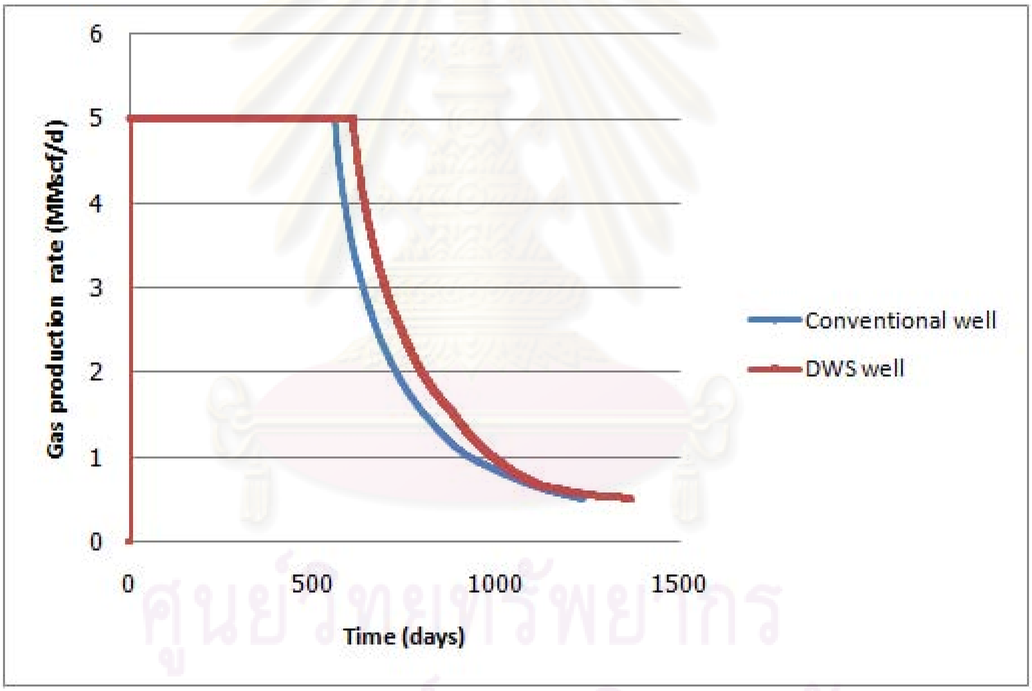

Figure 5.51: Gas production rate for conventional and DWS wells (k_v = 126 mD).

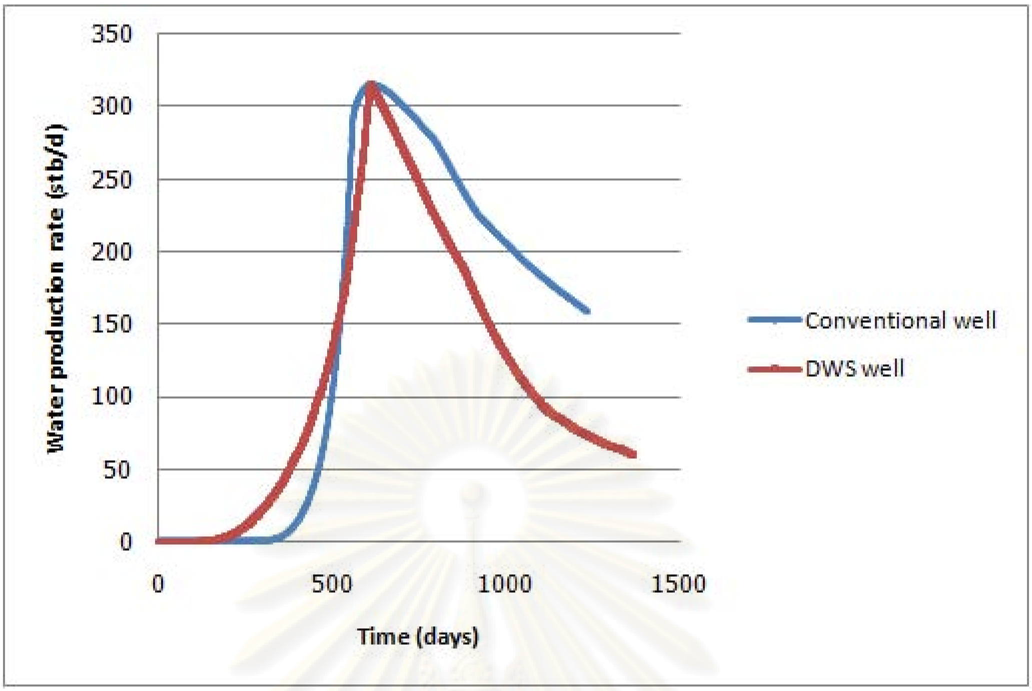

Figure 5.52: Water production rate for conventional and DWS wells (k_v = 126 mD).

For this case, DWS well can produce longer than conventional well for 131 days. Additional 340.46 MMscf of gas can be recovered. However, additional 682,500 stb of water has to be withdrawn in exchange of additional gas production. This amount of water results in higher total water production than conventional well.

Table 5.6: Production performance of base case and DWS well (top completion) for reservoir with $k_v = k_h$

	Conventional well	DWS well	Improvement
Gas production (MMscf)	3806.08	4146.54	+340.46
Gas recovery (percent)	68.66	74.81	+6.15
Water production (stb) (top completion)	178,065	154,908	-23,157
Water production (stb) (bottom completion)	-	682,500	+682,500
Water production (stb) (total)	178,065	837,408	+659,343
Production time (days)	1234	1365	+131

5.2.2.1 Effect of water withdrawal rate

Figure 5.53 shows gas production profile obtained from the simulations. Similar to previous cases, the constant rate can be maintained longer for higher water withdrawal rate. The production profile of conventional well is different from that of DWS well. Similar to the case with k_v/k_h = 0.08, the production rate drops faster for high water withdrawal rate and results in shorter production time than that for low water withdrawal rate. Water production in the gas zone decreases when producing water at high rate as seen in Figure 5.54.

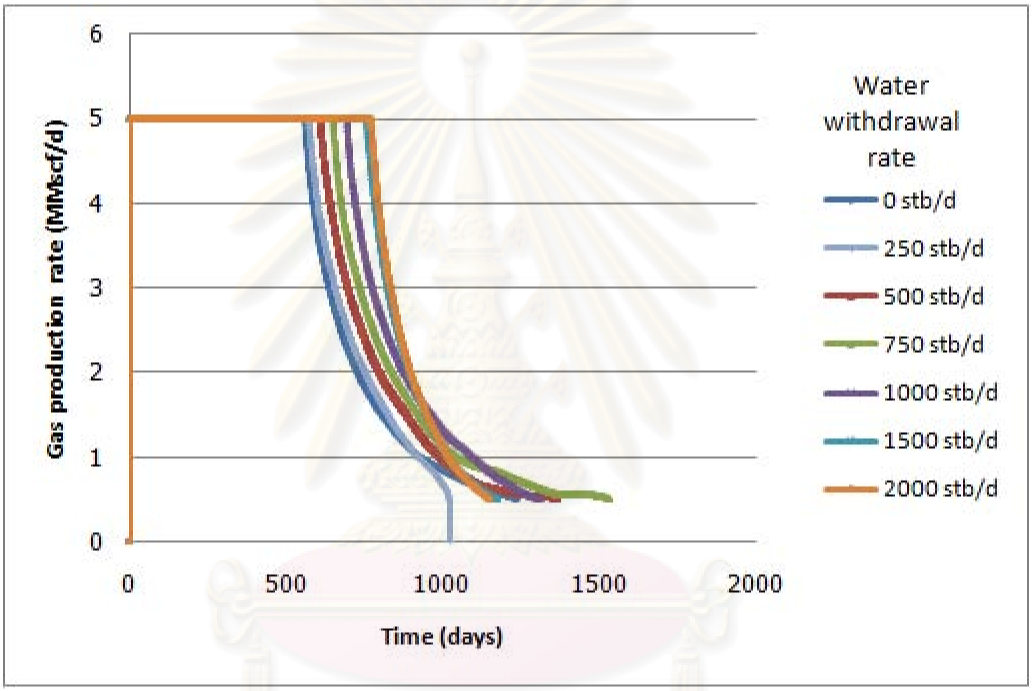

Figure 5.53: Gas production rate from the top completion for different water withdrawal rates (k_v = 126 mD).

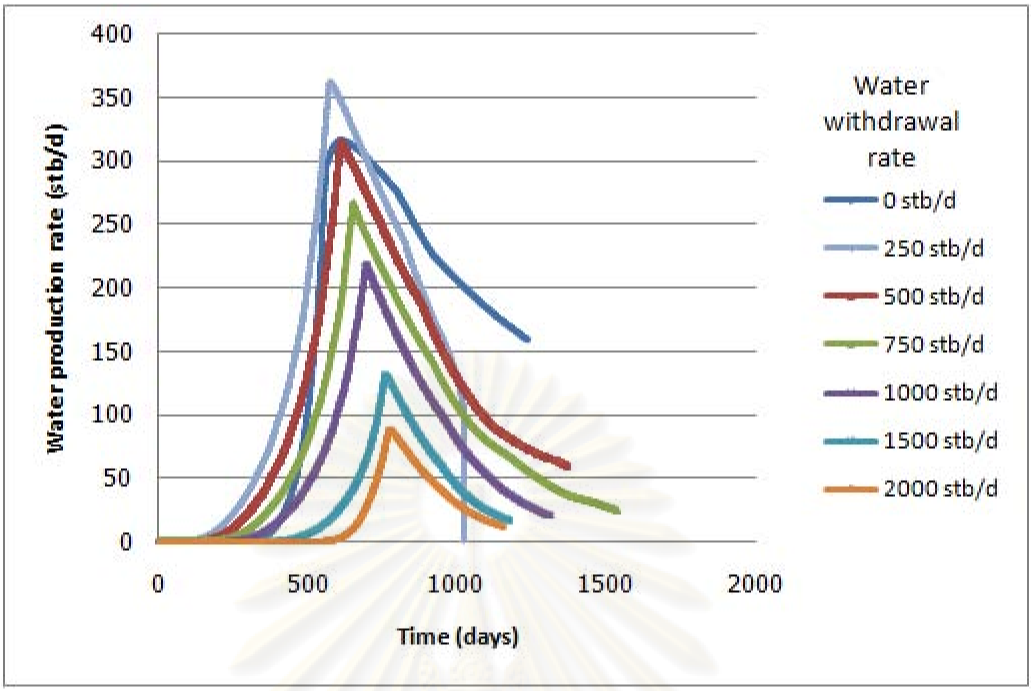

Figure 5.54: Water production rate from the top completion for different water withdrawal rates (k_v = 126 mD).

Recovery factors for different water withdrawal rates are shown in Figure 5.55, and production performances are summarized in Table 5.7. The results show that water withdrawal rate has high effect on a similar fashion as in the cases with $k_v/k_h = 0.08$.

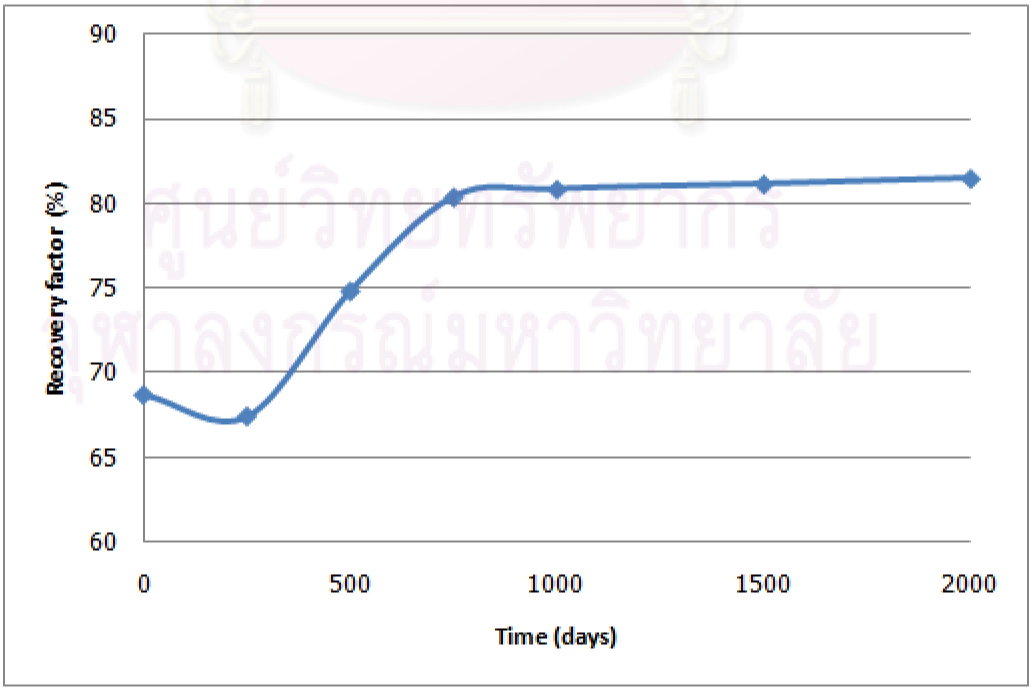

Figure 5.55: Recovery factor for different water withdrawal rates (k_v = 126 mD).

Similar to the case with k_v/k_h = 0.08, the gas production rate increases and water production from the top completion decreases as water withdrawal rate increases. Total water production also increases as most of water production comes from the bottom completion. Production time increases as water withdrawal rate increases and then decreases after water withdrawal becomes high due to high reservoir pressure drop from higher fluid production. For conventional well, the production time is higher than DWS well with low water withdrawal rate due to more reservoir pressure drop from withdrawal of water from the bottom completion.

Table 5.7: Performance for different water withdrawal rates (k_v = 126 mD).

Water withdrawal rate (stb/d)	Gas production from top zone		Water production (stb)			Production time (days)
	Volume (MMscf)	Recovery factor (%)	Top zone	Bottom zone	Total	
0	3806.08	68.7	178,065	0	178,065	1234
250	3735.53	67.4	153,076	255,000	408,076	1020
500	4146.54	74.8	154,908	682,500	837,407	1365
750	4455.22	80.4	124,383	1,148,782	1,273,166	1532
1000	4480.66	80.8	82,650	1,264,822	1,347,472	1311
1500	4497.50	81.1	36,907	1,411,096	1,448,004	1175
2000	4515.98	81.5	21,272	1,542,081	1,563,353	1150

5.2.2.2 Effect of gas rate

Figure 5.56 shows gas production obtained from the simulations. Similar to the cases with k_v/k_h = 0.08, high gas rate causes higher water production rate from the top completion at early times as shown in Figure 5.57. Gas rate also has slightly effect on recovery factor as shown in Figure 5.58. Production performances are summarized in Table 5.8.

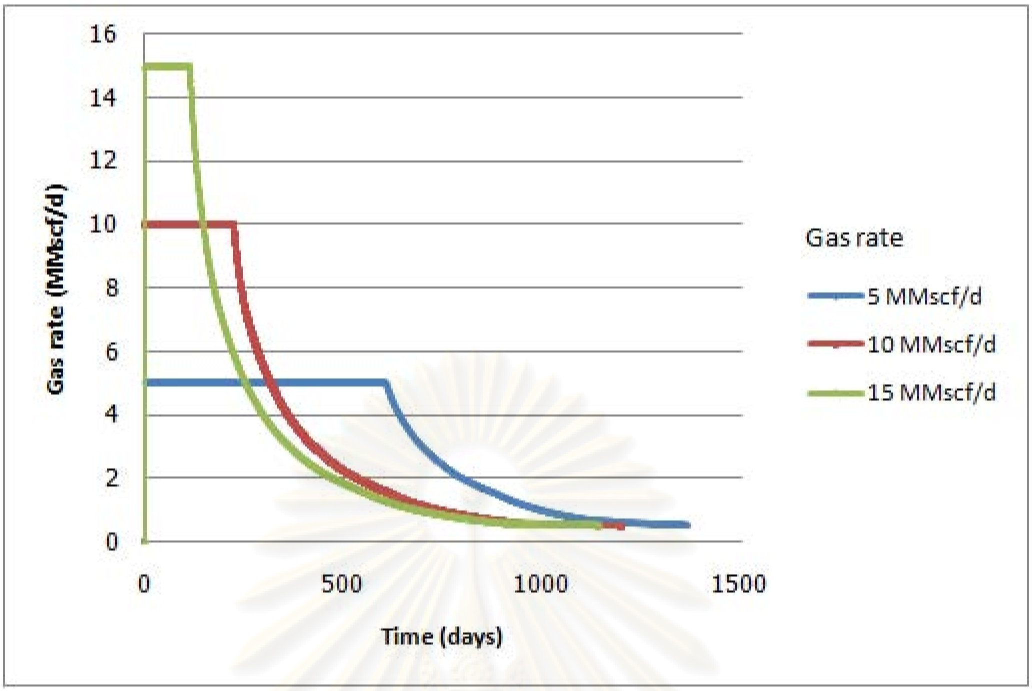

Figure 5.56: Gas production rate from the top completion (k_v = 126 mD).

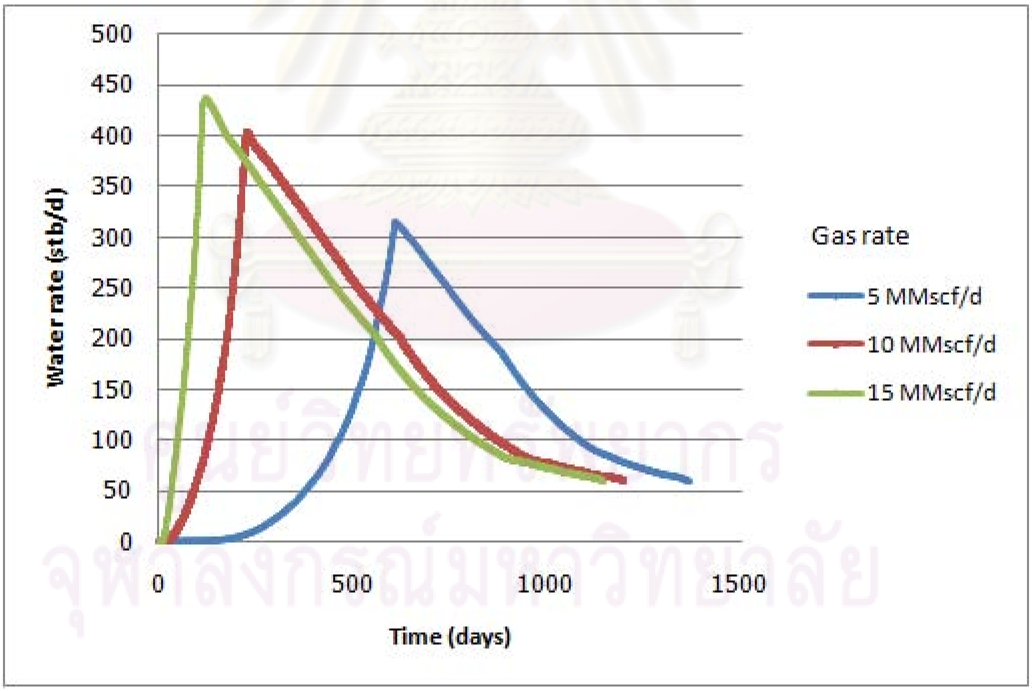

Figure 5.57: Water production rate from the top completion for different gas rates (k_v = 126 mD).

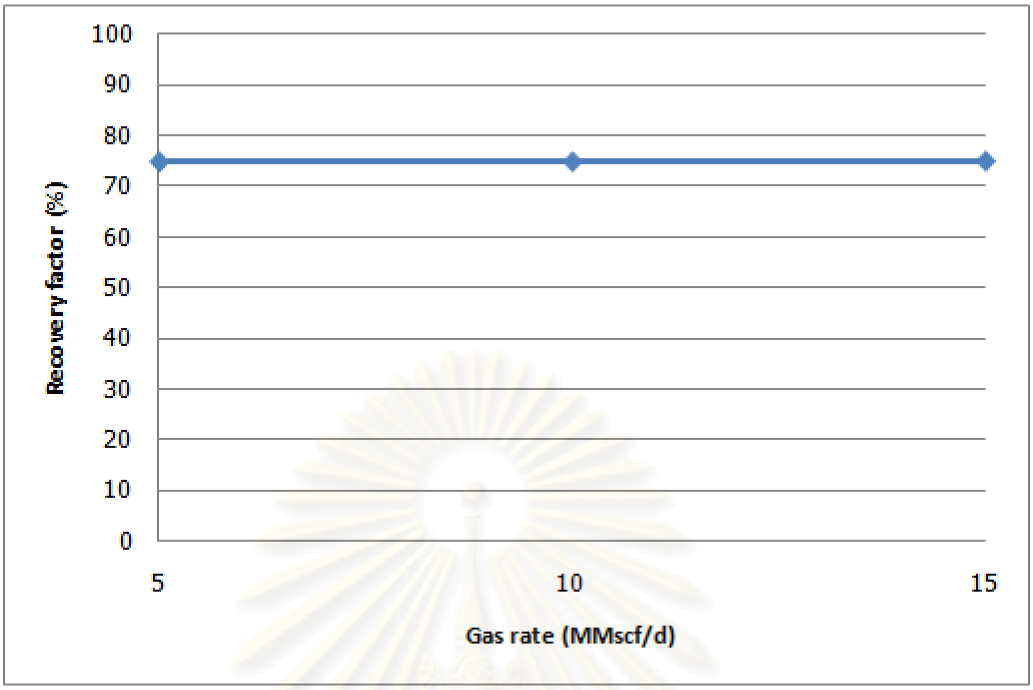

Figure 5.58: Recovery factor for different gas rates (k_v = 126 mD).

Similar to the case with k_v/k_h = 0.08, increasing gas rate results in more water production from the top completion due to higher differential pressure around the wellbore. Water production from the bottom completion becomes less because water tends to cone into the top completion instead. Total water production also decreases because of shorter well life which is a result of higher pressure drop from higher gas rate.

Table 5.8: Production performance for different gas rates (k_v = 126 mD)

Gas rate (MMscf/d)	Gas production from top zone		Water production (stb)			Production time (days)
	Volume (MMscf)	Recovery factor (%)	Top zone	Bottom zone	Total	
5	4146.54	74.8	154,908	682,500	837,407	1365
10	4146.92	74.8	204,326	598,500	802,826	1197
15	4153.28	74.9	219,967	572,000	791,967	1144

5.2.2.3 Effect of perforation position

Figure 5.58 shows gas production obtained from the simulations. Again, the effect of perforation position in high vertical permeability reservoir is similar to the cases with k_v/k_h = 0.08. Position of the bottom completion has slightly effect on water reduction and recovery factor while position of the top completion has major effect on them as shown in Figures 5.59 to 5.61. Production performances are summarized in Table 5.9.

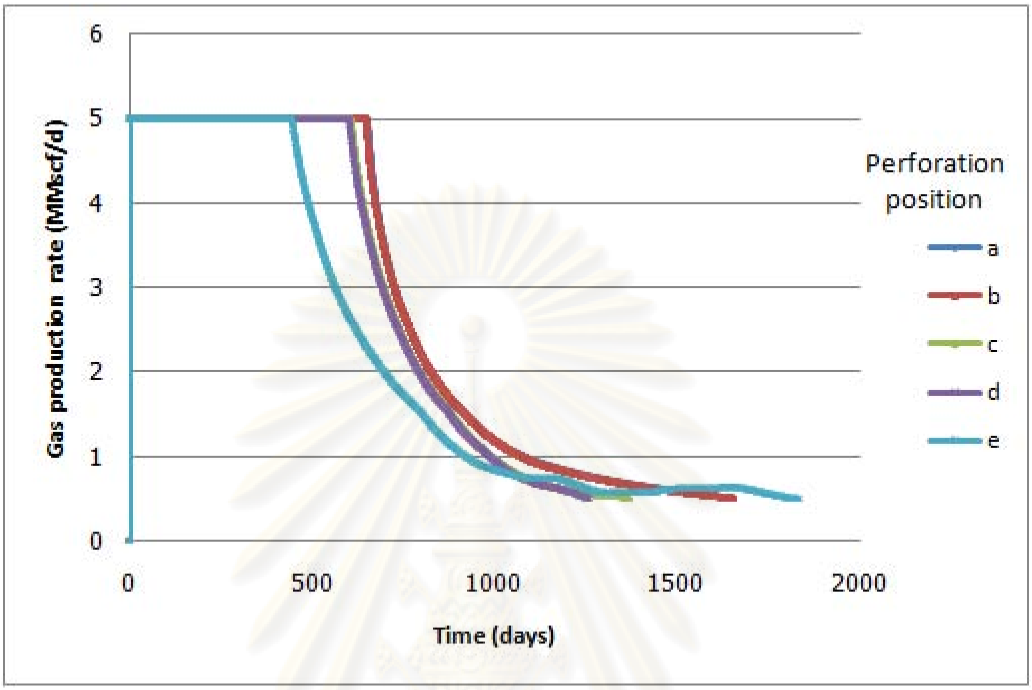

Figure 5.59: Gas production rate from the top completion for different perforation positions (k_v = 126 mD).

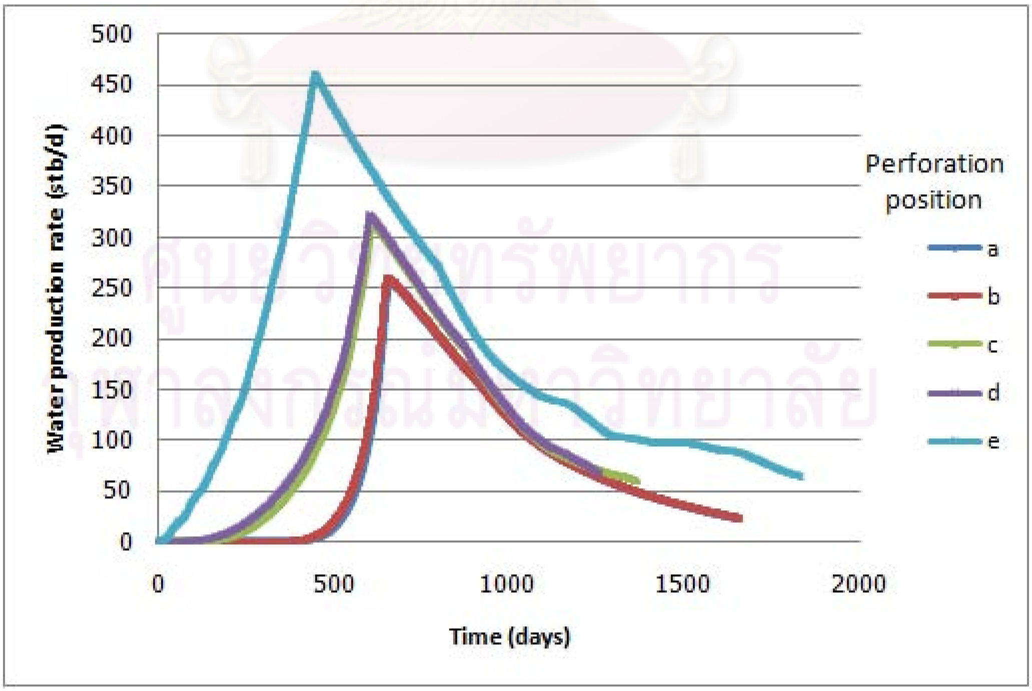

Figure 5.60: Water production rate from the top completion for different perforation positions (k_v = 126 mD).

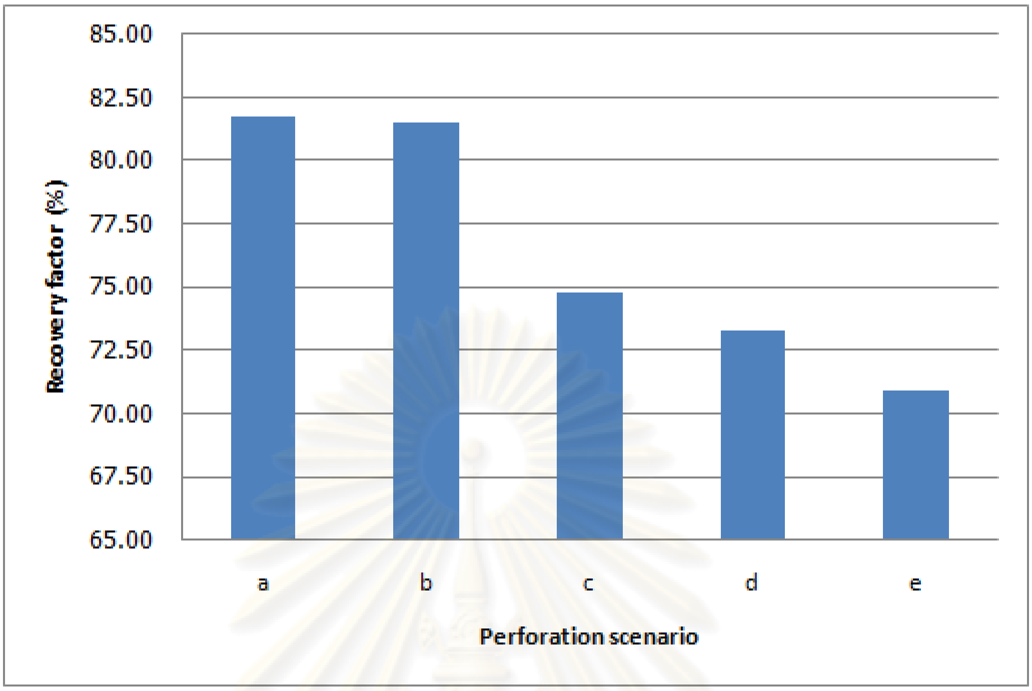

Figure 5.61: Recovery factor for different perforation scenarios (k_v = 126 mD).

Beside the effect on gas production and water production from the top completion, position of the top completion also affects total water production and production time as shown in Table 5.9. This is because perforating gas zone at the top of reservoir can delay water breakthrough so that the well can produce longer. This longer period results in more water withdrawn from aquifer.

Table 5.9: Production performance for different perforation scenarios (k_v = 126 mD)

Perforation scenario	Gas production from top zone		Water production (stb)			Production time (days)
	Volume (MMscf)	Recovery factor (%)	Top zone	Bottom zone	Total	
a	4531.17	81.8	116,318	821,000	937,318	1642
b	4519.20	81.5	121,472	826,500	947,972	1653
c	4146.54	74.8	154,908	682,500	837,407	1365
d	4062.03	73.3	155,398	628,500	783,898	1257
e	3929.94	70.9	329,922	915,000	1,244,922	1830

5.2.2.4 Effect of perforation interval

Figure 5.62 shows gas production, and Figure 5.63 shows water production obtained from the simulations. The effect of perforation interval is similar to that for the cases with k_v/k_h = 0.08. Perforation interval has a slight effect on recovery factor as shown in Figure 5.64. Production performances are summarized in Table 5.10.

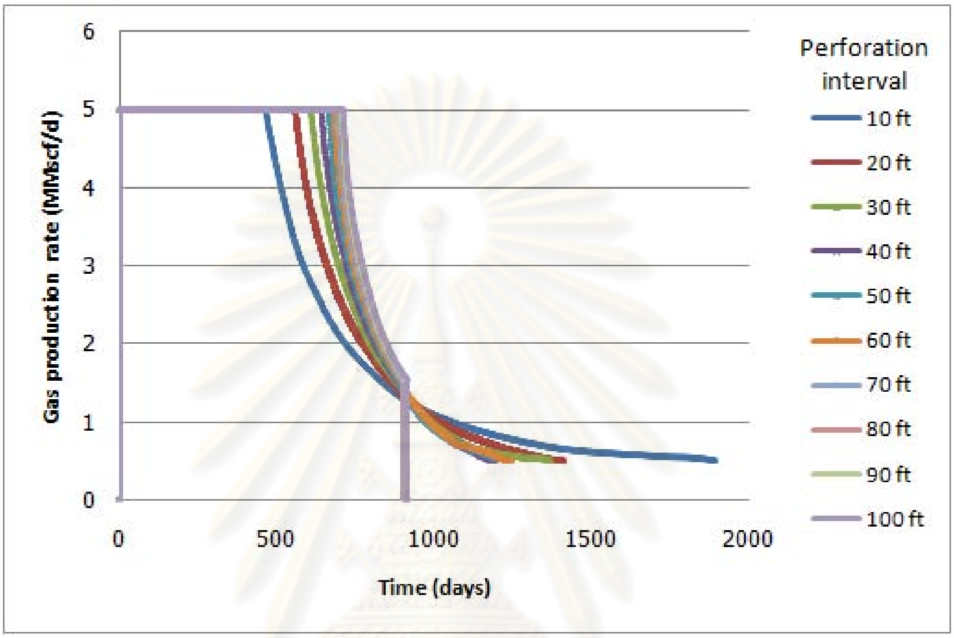

Figure 5.62: Gas production rate from the top completion for different perforation intervals (k_v = 126 mD).

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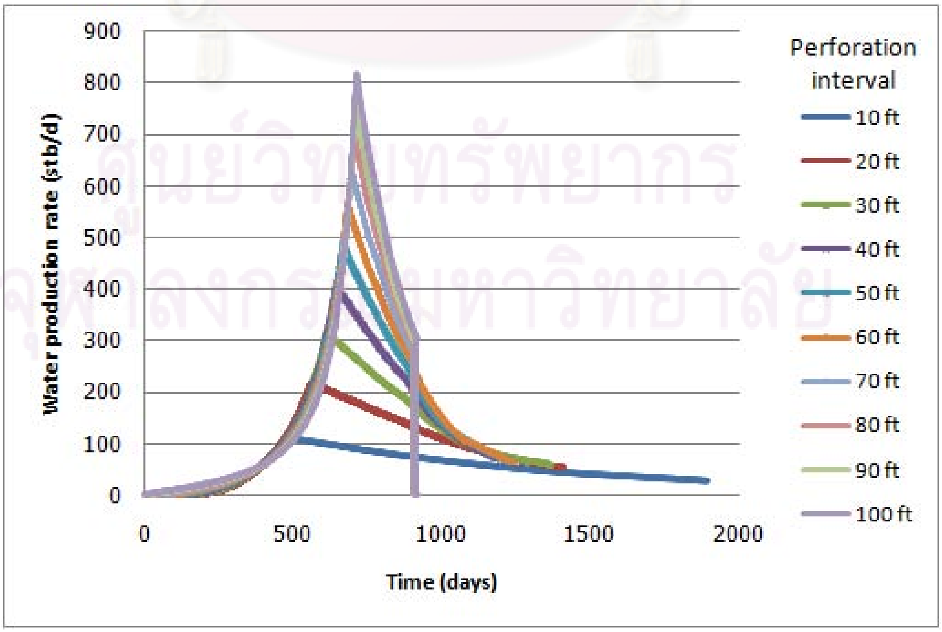

Figure 5.63: Water production rate from the top completion for different perforation intervals (k_v = 126 mD).

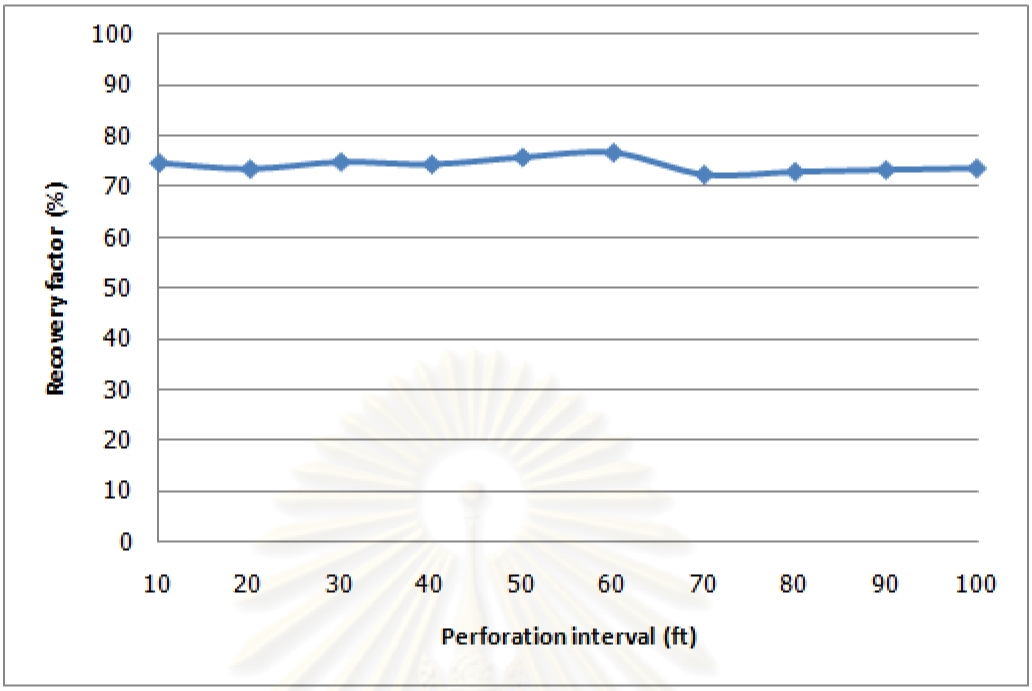

Figure 5.64: Recovery factor for different perforation intervals (k_v = 126 mD).

In Table 5.10, total water production decreases as perforation interval increases. This may result from shorter production time. Although the production time is longer for the case with 50 ft of perforation interval and results in more total water production, gas recovery still has a slightly different from other cases.

Table 5.10: Production performance for different perforation intervals (k_v = 126 mD)

Perforation interval (ft)	Gas production from top zone		Water production (stb)			Production time (days)
	Volume (MMscf)	Recovery factor (%)	Top zone	Bottom zone	Total	
10	4135.53	74.6	97,102	939,694	1,036,796	1889
20	4067.59	73.4	128,286	704,500	832,786	1409
30	4146.54	74.8	154,908	682,500	837,408	1365
40	4120.15	74.3	162,372	597,000	759,372	1194
50	4199.22	75.8	180,649	617,000	797,649	1234
60	4251.64	76.7	194,036	621,500	815,536	1243
70	4003.72	72.2	160,445	451,000	611,445	901
80	4035.75	72.8	170,007	453,500	623,507	906
90	4057.88	73.2	178,608	455,500	634,108	910
100	4075.36	73.5	186,667	457,000	643,667	913

5.2.3 Comparison of production performance in low vertical permeability reservoir and high vertical permeability reservoir

In this section, production performance is compared between two reservoir settings: reservoir with low vertical permeability and reservoir with high vertical permeability. Note that the two reservoirs have the same horizontal permeability (126 mD). Conventional and DWS wells are used to make this comparison. All parameters used in the model are the same as in Section 5.1 for both conventional and DWS wells (gas rate is 5 MMscf/d and water withdrawal rate is 500 stb/d for DWS well).

Figure 5.65 shows gas production from conventional well for reservoir with 10 mD and 126 mD of vertical permeability. The plots show that plateau of gas rate can be maintained longer for low vertical permeability case. This is because it require more time for water to break through the completion due to low vertical permeability. However, the well can produce longer for high vertical permeability case because lower differential pressure is required for fluid to flow due to higher permeability.

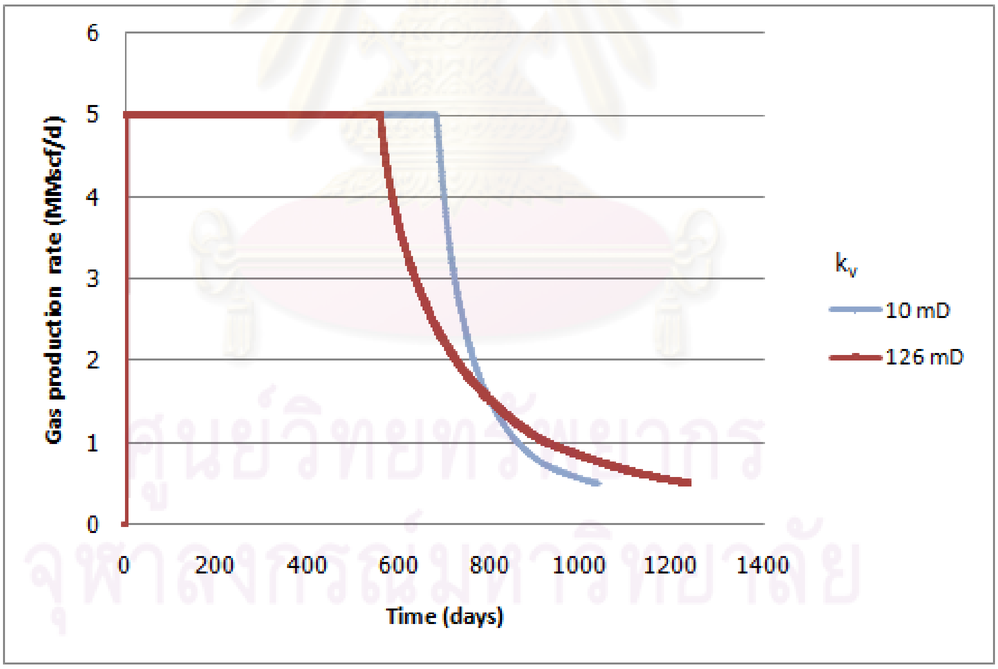

Figure 5.65: Gas rate from conventional well for 10 mD and 126 mD of vertical permeability.

Figure 5.66 shows water production from conventional well for low vertical permeability and high vertical permeability reservoir. As mentioned before, higher vertical permeability causes water to reach the completion earlier. This also results in higher water production rate.

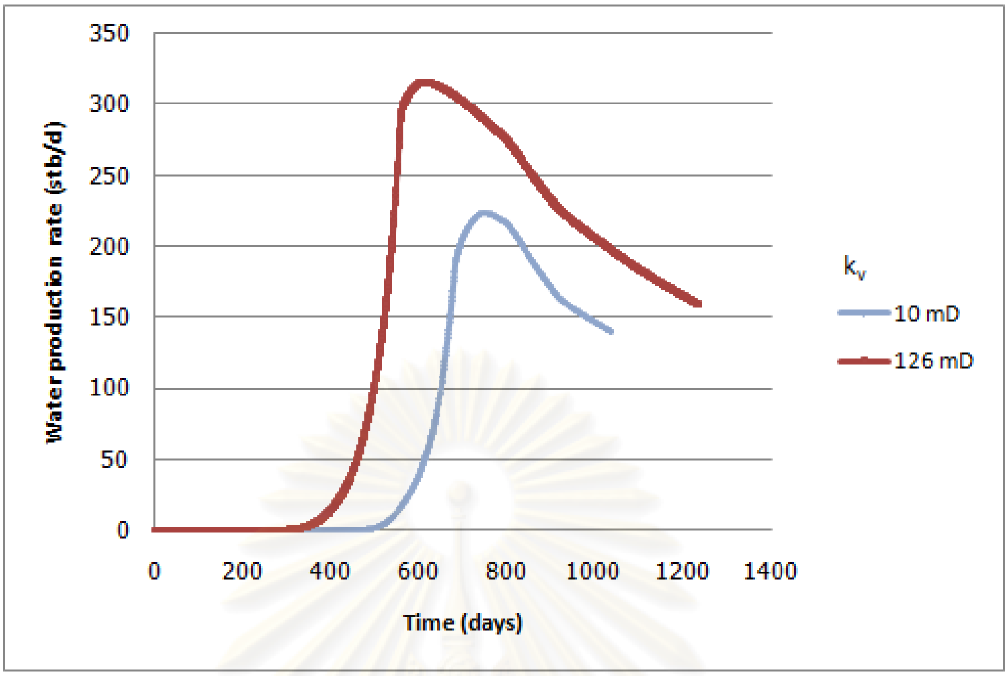

Figure 5.66: Water rate from conventional well for 10 mD and 126 mD of vertical permeability.

Table 5.11 summarizes the production performance between these two cases. Although gas can be produced a bit longer for the case with 126 mD of vertical permeability, gas recovery at the end is still lower since production rate drops sooner. Water production is also significantly larger because higher permeability causes water to cone into the completion more easily.

Table 5.11: Production performance of conventional well for 10 mD and 126 mD of vertical permeability

	10 mD	126 mD	Difference
Gas production (MMscf)	3922.4	3806.1	-116.3
Gas recovery (percent)	70.76	68.66	-2.1
Water production (stb)	74,982	178,065	+103,083
Production time (days)	1036	1234	+198

For DWS well, gas production profiles have the similar trends for reservoir with 10 mD and 126 mD of vertical permeability. Higher vertical permeability causes early water breakthrough but the well can still produce longer due to less pressure drop. Figure 5.67 shows gas production profiles for both cases.

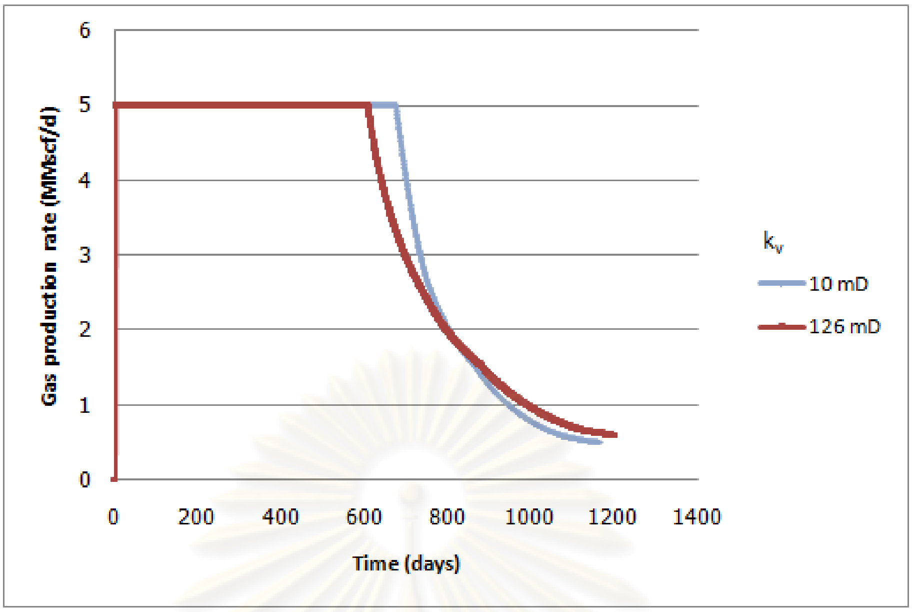

Figure 5.67: Gas rate from the top completion of DWS well for 10 mD and 126 mD of vertical permeability.

Figure 5.68 shows water production from the top completion of DWS well for low vertical permeability and high vertical permeability reservoir. Similar to conventional well, there is early water breakthrough at the top completion for higher vertical permeability. In any case, water production is lower comparing to conventional well (Figure 5.66) because water is withdrawn at the bottom completion to reduce water coning effect.

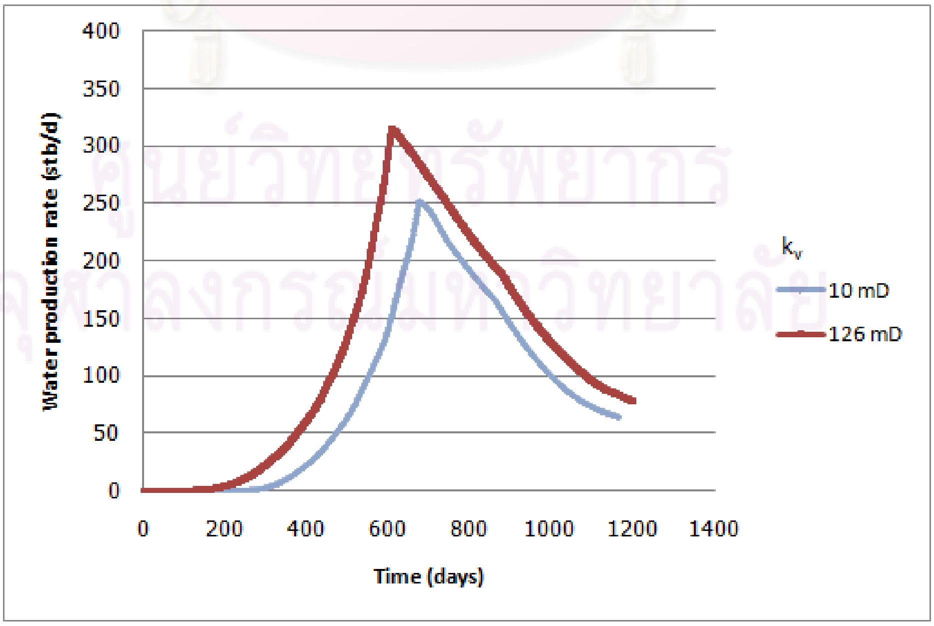

Figure 5.68: Water rate from the top completion of DWS well for 10 mD and 126 mD of vertical permeability.

Although there is more water production for high vertical permeability case, Table 5.12 shows that there is still higher gas production than conventional well (Table 5.11). This value of gas recovery is also slightly higher than DWS well with 10 mD of reservoir vertical permeability. Additional gas recovery may result from longer production time after gas rate declines. Similar to the top completion, the amount of water withdrawn from the bottom completion for 126 mD of vertical permeability is also higher than that for 10 mD of vertical permeability.

Table 5.12: Production performance of DWS well for 10 mD and 126 mD of vertical permeability

	10 mD	126 mD	Difference
Gas production (MMscf)	4119.31	4146.54	+27.23
Gas recovery (percent)	74.32	74.81	+0.49
Water production (stb) (top completion)	99,001	154908	+55,907
Water production (stb) (bottom completion)	581,500	682,500	+101,000
Water production (stb) (total)	680,502	837,408	+156,906
Production time (days)	1163	1365	+202

Table 5.13 shows improvement in production performance when DWS technique is applied comparing to conventional well. From the amount of additional gas recovery, it implies that DWS well can perform better in high vertical permeability reservoir. Additional 2.59 percent of gas recovery can be obtained in this case. There is less water production from the top completion but more water withdrawn from the bottom completion. This is due to longer production time.

Table 5.13: Improvement in production performance comparing to conventional well

	10 mD	126 mD	Difference
Gas production (MMscf)	+196.93	+340.46	+143.53
Gas recovery (percent)	+3.56	+6.15	+2.59
Water production (stb) (top completion)	+24,019	-23,157	-47,176
Water production (stb) (bottom completion)	+581500	+682500	+101,000
Water production (stb) (total)	+605520	+659,343	+53,823
Production time (days)	+127	+131	+4

CHAPTER VI
CONCLUSION AND RECOMMENDATION

6.1 Conclusion

The purpose of this thesis is to evaluate the production performance of Downhole Water Sink in comparison with conventional completion. In this technique, both reservoir fluid and water are produced at the same time by a single well but different flow paths. Reservoir fluid is produced through annulus between casing and tubing while water is produced through tubing. From the evaluation of Downhole Water Sink technique using reservoir simulation, the results show that DWS technique can effectively improve gas production and reduce water production from coning effect.

Sensitivity analysis is also conducted to observe the effect of operating parameters on production performance. The results of sensitivity analysis performed on water withdrawal rate, gas production rate, position of perforation, and perforation interval can be summarized as follows:

1. As water withdrawal rate is increased, gas recovery factor is significantly improved up to a certain point. After that, the increase in water withdrawal rate slightly enhances gas production because production time is shorter due to higher reservoir pressure drop. However, water production from the bottom completion increases linearly as the water withdrawal rate increases and results in larger total water production. Thus, a moderate water withdrawal rate should be implemented in order to balance between the reserve gain and the increase in water production.
2. Gas production rate has a slight impact on gas recovery factor. Although high gas rate enables us to produce the gas faster, it results in a large amount of water production from the top completion. Increasing gas rate also results in less water production from the bottom completion, total water production and production time.
3. Position of the top completion has a significant impact on gas recovery factor and water production. Perforating from the top of reservoir can

improve production by reducing the effect from water coning so that the well can produce longer. On the other hand, position of the bottom completion almost has no effect on gas and water production. However, perforating the bottom completion close to gas-water contact can slightly reduce water coning effect. For total water production, there is no significant difference among the varied cases.

4. Increasing perforation interval only improves production performance by reducing pressure drop from partial penetration skin so that gas can be produced at constant rate longer. The disadvantage is that water can cone into the completion more easily as the distance of the bottom completion to gas-water contact is closer.

Sensitivity analysis is also performed for two different reservoir settings: low and high vertical permeability reservoir. The results show that the effects of operating parameters are very similar between two settings of reservoir. Moreover, DWS well also perform better in high vertical permeability reservoir than low vertical permeability reservoir.

6.2 Recommendation

Although many operating parameters are considered in this study, the effects of some other controllable parameters such as tubing head pressure, size of wellbore, casing and tubing are not investigated. In addition, the effects of each parameter are only observed by varying only one parameter at one time. Thus, there should be more operating parameters to be considered and the relation of the effects among these parameters should be investigated so that optimization method or correlation for DWS well can be developed.

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APPENDICES

APPENDIX A
ECLIPSE 100 AND PROSPER INPUT DATA FOR RESERVOIR MODEL

1. Case Definition

Simulator : BlackOil

Model dimensions

Number of grid in x direction : 17

Number of grid in y direction : 10

Number of grid in z direction : 40

Simulation start date : 1 Jan 2000

Grid type : Radial

Geometry type : BlockCentred

Oil-Gas-Water Properties: Water, Gas

Solution type : FullyImplicit

2. Grid

1) Properties

Active Grid Block	X(1-15)	= 1
	X(16-17)	= 0
	Y(1-10)	= 1
	Z(1-40)	= 1
	Grid (17, 1, 1) = 1	

X Permeability : 126 md

Y Permeability : 126 md

Z Permeability : 10 md

Porosity : 0.215

2) Geometry

Grid block size

X Grid block size		Y Grid block size		Z Grid block size	
No. grid	Grid size (ft)	No. grid	Grid size (degree)	No. grid	Grid size (ft)
1	2	1	36	1	5
2	2.79127	2	36	2	5
3	3.895594	3	36	3	5
4	5.436827	4	36	4	5
5	7.587825	5	36	5	5
6	10.58983	6	36	6	5
7	14.77954	7	36	7	5
8	20.62685	8	36	8	5
9	28.78755	9	36	9	5
10	40.17691	10	36	10	5
11	56.07229	Σ	360	11	5
12	78.25645			12	5
13	109.2174			13	5
14	152.4277			14	5
15	212.7334			15	5
Σ	745.4992			16	5
16	25			17	5
17	25			18	5
				19	5
				20	5
				21	5
				22	5
				23	5
				24	5
				25	5
				26	5
				27	5
				28	5
				29	5

X Grid block size		Y Grid block size		Z Grid block size	
No. grid	Grid size (ft)	No. grid	No. grid	Grid size (ft)	No. grid
				30	5
				31	5
				32	5
				33	5
				34	5
				35	5
				36	5
				37	5
				38	5
				39	5
				40	5
				Σ	200

Coordinate System Information

K1 : 1

K2 : 40

Completion : Comp

Connection : SEPARATE

Depth of top face (top layer) : 4950 ft

inner radius : 0.3646 ft

3) Aquifer

Aquifer Connection

Aq ID : 1

I- : 1

I+ : 15

J- : 1

J+ : 10

K- : 40

K+ : 40

Face : K+

Numerical Aquifer Assignments

I	: 17
J	: 1
K	: 1
XSA	: 1742400 sq ft
Length	: 4900 ft
Porosity	: 0.215
Permeability	: 10 md
Depth	: 5150 ft

3. Fluid and rock properties

PVT Data (For PROSPER)

Variable	Value	Unit
Gas gravity	0.92	-
Separator pressure	100	psia
Condensate to Gas Ratio	0	STB/MMscf
Condensate gravity	45	API
Water to Gas Ratio	0	STB/MMscf
Water Salinity	100000	ppm
Mole percent of H_2S	0	%
Mole percent of CO_2	0	%
Mole percent of N_2	0	%

Rock properties (For ECLIPSE 100)

Reference pressure : 2500 psia

Rock compressibility : 3.46×10^{-6} psi^{-1}

4. SCAL

Water saturation function

Water saturation (S_w)	Water relative permeability (K_{rw})	Capillary pressure (P_c) - psia
0.25	0	10.58
0.3	0.006	4.33
0.35	0.027	2.24
0.4	0.0675	1.36
0.45	0.126	0.91

Water saturation (S_w)	Water relative permeability (K_{rw})	Capillary pressure (P_c) - psia
0.5	0.2055	0.65
0.55	0.3075	0.49
0.6	0.432	0.38
0.65	0.579	0.3
0.7	0.75	0.25
1	1	0.1

<u>Gas saturation function</u>

Gas saturation (S_g)	Gas relative permeability (K_{rg})	Capillary pressure (P_c) - psia
0	0	0
0.3	0	0
0.35	0	0
0.4	0	0
0.45	0	0
0.5	0	0
0.55	0.042	0
0.6	0.105	0
0.65	0.228	0
0.7	0.444	0
0.75	0.8	0

5. Initialization

<u>Initial pressure v Depth</u>

Depth (ft)	Pressure (psia)
0	14.7
5000	2500

<u>Initial water saturation</u> : 0.25

6. Regions : N/A

APPENDIX B
ECLIPSE 100 AND PROSPER INPUT DATA
FOR CONVENTIONAL WELL

1. Schedule

<u>Well specification</u>

Variable	Value	Unit
Well name	WELL1	-
Group	1	-
I location	1	-
J location	1	-
Preferred phase	GAS	-
Inflow equation	STD	-
Automatic Shut-In instruction	SHUT	-
Crossflow	YES	-
Density Calculation	SEG	-

2. PVT (PROSPER INPUT)

<u>Fluid Option</u>

Fluid : Dry and Wet Gas

Method : BlackOil

<u>Separator</u> : Single-Stage Separator

<u>Well</u>

Flow type : Tubing

Well type : Producer

<u>Well completion</u>

Type : Cased Hole

Gravel pack : No

<u>Deviation survey</u>

Measured Depth (ft)	True Vertical Depth (ft)
0	0
5150	5150

Downhole equipment

Type	Measured Depth (ft)	Tubing ID (inch)	Tubing Inside Roughness (inch)
Xmas Tree	0		
Tubing	5150	2.75	0.0006

Geothermal Gradient

Overheat transfer coefficient 2 BTU/h/ft^2/°F

Formation Measured Depth (ft)	Formation Temperature (°F)
0	60
5150	178.45

VLP Input data

Top node pressure : 450 psia

Gas rates (MMscf/d)	First node pressure (psia)	Water gas ratio (stb/MMscf)	Condensate gas ratio (stb/MMscf)
0.5	100	0	0
1.52632	422.222	222.222	
2.55263	744.444	444.444	
3.57895	1066.67	666.667	
4.60526	1388.89	888.889	
5.63158	1711.11	1111.11	
6.65789	2033.33	1333.33	
7.68421	2355.56	1555.56	
8.71053	2677.78	1777.78	
9.73684	3000	2000	
10.7632			
11.7895			
12.8158			
13.8421			
14.8684			
15.8947			
16.9211			

Gas rates (MMscf/d)	First node pressure (psia)	Water gas ratio (stb/MMscf)	Condensate gas ratio (stb/MMscf)
17.9474			
18.9737			
20			

Well connection data

Variable	Value	Unit
Well	WELL1	-
K upper	1	-
K lower	6	-
Open/Shut Flag	OPEN	-
Wellbore ID	0.73	ft
Direction	Z	-

Production well control

Variable	Value	Unit
Well	WELL1	-
Open/Shut Flag	OPEN	-
Control	GRAT	-
Gas rate	5000	Mscf/d
THP target	450	psia

Production well economic limits

Variable	Value	Unit
Well	WELL1	-
Minimum Gas rate	500	Mscf/d
Workover procedure	NONE	-
End Run	YES	-
Quantity for Economic Limit	RATE	-
Secondary Workover Procedure	NONE	-

APPENDIX C
ECLIPSE 100 AND PROSPER INPUT DATA
FOR DWS WELL

1. Schedule

1.1 Gas producer

Well specification

Variable	Value	Unit
Well name	WELL1	-
Group	1	-
I location	1	-
J location	1	-
Preferred phase	GAS	-
Inflow equation	STD	-
Automatic Shut-In instruction	SHUT	-
Crossflow	YES	-
Density Calculation	SEG	-

Well connection data

Variable	Value	Unit
Well	WELL1	-
K upper	1	-
K lower	6	-
Open/Shut Flag	OPEN	-
Wellbore ID	0.73	ft
Direction	Z	-

Production well control

Variable	Value	Unit
Well	WELL1	-
Open/Shut Flag	OPEN	-
Control	GRAT	-
Gas rate	5000	Mscf/d

Variable	Value	Unit
THP target	450	psia

Production well economic limits

Variable	Value	Unit
Well	WELL1	-
Minimum Gas rate	500	Mscf/d
Workover procedure	NONE	-
End Run	YES	-
Quantity for Economic Limit	RATE	-
Secondary Workover Procedure	NONE	-

1.2 Water producer

Well specification

Variable	Value	Unit
Well name	WELL2	-
Group	1	-
I location	1	-
J location	1	-
Preferred phase	WATER	-
Inflow equation	STD	-
Automatic Shut-In instruction	SHUT	-
Crossflow	YES	-
Density Calculation	SEG	-

Well connection data

Variable	Value	Unit
Well	WELL2	-
K upper	28	-
K lower	33	-
Open/Shut Flag	OPEN	-
Wellbore ID	0.73	ft
Direction	Z	-

Production well control

Variable	Value	Unit
Well	WELL2	-
Open/Shut Flag	OPEN	-
Control	WRAT	-
Gas rate	1500	stb/d
BHP target	500	psia

Production well economic limits

Variable	Value	Unit
Well	WELL1	-
Workover procedure	NONE	-
End Run	YES	-
Quantity for Economic Limit	RATE	-
Secondary Workover Procedure	NONE	-
Minimum Liquid Production Rate	10	stb/d

2. PVT (PROSPER INPUT)

Fluid Option

Fluid : Dry and Wet Gas

Method : BlackOil

Separator : Single-Stage Separator

Well

Flow type : Annular Flow (for gas producer)

Well type : Producer

Well completion

Type : Cased Hole

Gravel pack : No

Deviation survey

Measured Depth (ft)	True Vertical Depth (ft)
0	0
5150	5150

Downhole equipment (Gas producer)

Type	Measured Depth (ft)	Tubing ID (inch)	Tubing Inside Roughness (inch)	Tubing OD (inch)	Tubing Outside Roughness (inch)	Casing ID (inch)	Casing Inside Roughness (inch)
Xmas Tree	0						
Tubing	5150	2.75	0.0006	3.5	0.0006	6.276	0.0006

Geothermal Gradient

Overheat transfer coefficient 2 BTU/h/ft^2/°F

Formation Measured Depth (ft)	Formation Temperature (°F)
0	60
5150	178.45

VLP Input data

Top node pressure : 450 psia

Gas rates (MMscf/d)	First node pressure (psia)	Water gas ratio (stb/MMscf)	Condensate gas ratio (stb/MMscf)
0.5	100	0	0
1.52632	422.222	222.222	
2.55263	744.444	444.444	
3.57895	1066.67	666.667	
4.60526	1388.89	888.889	
5.63158	1711.11	1111.11	
6.65789	2033.33	1333.33	
7.68421	2355.56	1555.56	
8.71053	2677.78	1777.78	
9.73684	3000	2000	
10.7632			
11.7895			
12.8158			
13.8421			

Gas rates (MMscf/d)	First node pressure (psia)	Water gas ratio (stb/MMscf)	Condensate gas ratio (stb/MMscf)
14.8684			
15.8947			
16.9211			
17.9474			
18.9737			
20			

VITAE

Pawich Sripongwarakul was born on February 13, 1985 in Bangkok, Thailand. He graduated with Bachelor degree from Department of Computer Engineering, Chulalongkorn University in 2007. After graduating, he continues his studies in the Master of Petroleum Engineering program at Department of Mining and Petroleum Engineering, Faculty of Engineering, Chulalongkorn University.