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IMPROVING OIL RECOVERY USING DOUBLE DISPLACEMENT PROCESS

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A Thesis Submitted in Partial Fulfillment of the Requirements
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ธีศิษฎ์ สุวรรณกูล : การเพิ่มประสิทธิภาพการผลิตน้ำมันโดยวิธีการแทนที่สองครั้ง (IMPROVING OIL RECOVERY USING DOUBLE DISPLACEMENT PROCESS) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร. สุวัฒน์ อธิชนากร, 109 หน้า.

โดยปกติแล้วปริมาณน้ำมันนั้นจะได้ในระดับต่ำถ้าทำการผลิตโดยอาศัยเพียงแค่พลังงานของตัวมันเอง กระบวนการเปลี่ยนหลุมผลิตเป็นหลุมอัดน้ำเพื่อรักษาระดับความดันของแหล่งกักเก็บให้คงที่จึงถูกนำมาใช้ในขั้นตอนการผลิตที่สอง โดยปริมาณน้ำมันที่ผลิตขึ้นมาจากขั้นต้นและขั้นที่สองนั้นรวมกันแล้วได้ประมาณ 40 – 60% ขึ้นอยู่กับ น้ำมันและคุณสมบัติของแหล่งกักเก็บ โดยในตอนท้ายของการผลิตขั้นที่สองนั้นก็ยังมีน้ำมันที่เหลืออยู่ตกค้างในแหล่งกักเก็บเป็นจำนวนมาก ดังนั้นกระบวนการช่วยผลิตน้ำมันในขั้นต่อไป เช่น กระบวนการแทนที่สองครั้งจึงถูกพิจารณา

ในการศึกษานี้ กระบวนการแทนที่สองครั้งถูกนำมาใช้กับแหล่งกักเก็บที่มีความลาดเอียงเพื่อสังเกตผลกระทบของตัวแปรต่างๆ ได้แก่ องศาความลาดเอียง ตำแหน่งของหลุมฉีดของเหลวและอัตราส่วนของน้ำต่อปริมาณของเหลวที่ผลิต พร้อมกับศึกษากระบวนการผลิตน้ำมันที่เหมาะสมที่สุดสำหรับกระบวนการนี้ โดยในส่วนของการวิเคราะห์เชิงละเอียดจะศึกษาถึงผลกระทบจากการใช้ความสัมพันธ์ที่ต่างกันของค่าความซึมผ่านสัมพัทธ์ระหว่างของเหลวสามชนิด และแหล่งกักเก็บที่มีน้ำมันตกค้างอยู่ในปริมาณต่างกันหลังจากทำการอัดฉีดน้ำในส่วนสุดท้ายจะเป็นการเปรียบเทียบผลการศึกษาและอภิปรายเป็นช่วงความแตกต่างของปริมาณน้ำมันที่ผลิตได้และระยะเวลาที่ใช้ในการผลิต

จากผลการศึกษาด้วยแบบจำลองของแหล่งกักเก็บพบว่ากระบวนการแทนที่สองครั้งนั้นช่วยเพิ่มปริมาณน้ำมันที่ผลิตได้มากขึ้นหลังจากทำการไล่น้ำมันด้วยน้ำไปแล้ว อย่างไรก็ตามปริมาณน้ำมันที่ผลิตได้นั้นก็ต่างกันกันเพียงเล็กน้อยถึงแม้ว่าจะใช้กลวิธีการผลิตต่างกัน โดยที่แหล่งกักเก็บที่มีความลาดเอียงน้อยนั้นหากผลิตด้วยหลุมอัดน้ำที่ใกล้ด้านบนแทนที่หลุมที่อยู่ด้านบนสุดของแหล่งกักเก็บจะสามารถผลิตน้ำมันได้เร็วที่สุดในปริมาณเดียวกันเมื่อเทียบกับกลยุทธแบบอื่น สำหรับแหล่งที่มีความลาดเอียงในระดับปานกลาง การผลิตด้วยการแทนที่สองครั้งแบบดั้งเดิมจะใช้เวลาผลิตน้อยที่สุด สำหรับแหล่งกักเก็บที่มีความลาดเอียงมากๆนั้นไม่ว่าจะผลิตด้วยกลยุทธแบบไหนก็ให้ผลไม่ต่างกันทั้งในแง่ของเวลาการผลิตและปริมาณน้ำมันในขณะที่การใช้ความสัมพันธ์ความซึมผ่านสัมพัทธ์สามวัฏภาคและปริมาณน้ำมันตกค้างต่างไปจากค่าเริ่มต้นจะใช้เวลาผลิตต่างกัน

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

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

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Most oil reservoirs have low recovery efficiency when they are produced by natural energy. Iinjection of water to displace oil may be implemented as secondary recovery. The oil recovered by secondary process is around 40-60% depending on oil and reservoir properties. At the end of waterflooding, there is still a lot of water evaded oil left in the reservoir. Then, an stage of oil recovery such as double displacement process should be considered.

In this study, double displacement process (DDP) is applied to dipping reservoir to investigate effect of various parameters such as dip angle, location of injector, water cut ratio in order to optimize oil production with this process. Sensitivity analysis is performed to determine the effect of various three-phase relative permeability correlations and difference in residual oil saturation in presence of water on oil recovery.

The results from reservoir simulation indicate that DDP greatly increases the oil recovery factor on top of waterflooding. However, there is very small difference in oil recovery factor for different injection strategies. Nevertheless, for low degree dipping reservoir, injecting gas at the most updip location gives the shortest production time. For moderate dipping reservoir, conditional DDP gives the shortest production time. For high degree dip angle, the production times are similar for all strategies. For sensitivity cases, difference in three-phase relative permeability correlations and residual oil saturations makes almost no difference in RF but different times of production.

Department: Mining and Petroleum Engineering...Student's Signature:..........................

Field of Study: Petroleum Engineering............... Advisor's Signature: Suwat Athichanagorn

Academic Year: 2010.....................................

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LIST OF ABBREVIATIONS

DDP	double displacement process
ID	inner diameter
lb/cuft	pound per cubic feet
mD	millidarcy
MMscf/d	million standard cubic feet per day
Mscf/d	thousand standard cubic feet per day
OOIP	original oil in place
psi	pounds per square inch
psia	pounds per square inch absolute
PVT	pressure-volume-temperature
RF	recovery factor
SCAL	special core analysis
scf	standard cubic foot
stb	stock-tank barrel
STB/D	stock-tank barrel per day
stb/MMscf	stock-tank barrel per million standard cubic feet
THP	tubing head pressure

NOMENCLATURES

e_o	exponent of relative permeability curve to oil
e_{og}	exponent of relative permeability curve to oil in gas phase
e_{ow}	exponent of relative permeability curve to oil in water phase
k_{rg}	gas relative permeability
k_{ro}	oil relative permeability
k_{ro}^{o}	end point relative permeability to oil
k_{rog}^{o}	end point relative permeability to oil in gas phase
k_{row}^{o}	end point relative permeability to oil in water phase
k_{rog}	oil relative permeability in presence of gas phase
k_{row}	oil relative permeability in presence of water phase
k_{rw}	water relative permeability
k_v	reservoir vertical permeability
p_c	capillary pressure
p_i	initial reservoir pressure
S_g	gas saturation
S_{gc}	critical gas saturation
S_{gr}	residual gas saturation
S_{gro}	residual gas saturation in presence of oil phase
S_o	oil saturation
S_{oc}	critical oil saturation
S_{org}	residual oil saturation in presence of gas phase
S_{orw}	residual oil saturation in presence of water phase
$S'_{o/w}$	final spreading coefficient of oil over water
S_w	water saturation
S_{wr}	residual water saturation
S_{wir}	irreducible water saturation

GREEK LETTERS

σ'_{wg}	water/gas interfacial tension
σ'_{og}	oil/gas interfacial tension
σ'_{ow}	oil/water interfacial tension

CHAPTER I
INTRODUCTION

Important property governing multiphase flow through porous media is "relative permeability" which is defined as the ratio of the effective permeability of the porous medium to the specific (absolute) permeability of the material. The relative permeability is a function of the two or more fluids and the porous material and is used to describe quantitatively the simultaneous flow of multi fluid phases through a porous medium. The relative permeability is dependent upon the fluid saturation levels, because part of the pore space in the porous medium is occupied by one fluid of the multiphase fluid system, so that flow of another fluid is impeded and reduced. Relative permeabilities are major factors that affect the evaluation of reservoir fluid distribution and production performance predictions. It is also important in estimation of reserves in many improved oil recovery projects.

One of tertiary recovery method involving the up-dip injection of gas into steeply dipping after waterflooding is the double displacement process (DDP). Its purpose is to recover more oil by creating a gas cap thereby allowing gravity drainage of the liquids to occur. Injected gas flow to porous media that containing residual oil bulbs, capillary forces cause oil to spread and reconnect. The reconnected oil film flows downward to producer under gravity force.

The purpose of this study is to optimize the oil recovery with double displacement process using a reservoir simulation software as a mean to imitate reservoir response under different conditions.

1.1 Outline of methodology

1. Study the theory from literature review of the double displacement process (DDP).
2. Create base case dipping reservoir using corner grid in ECLIPSE reservoir simulator.
3. Start the reservoir simulation with waterflood process to observe the best criteria and followed by double displacement process for each dipping reservoir.

4. Conduct sensitivity on base case model, 10 degree dip angle of reservoir to observe the effect of relative permeability correlation and residual oil saturation in presence of water phase.
5. Analyze the results and conclude.

1.2 Thesis outline

This thesis consists of six chapters as outlined below:

Chapter I introduces the main idea and concepts of this work.

Chapter II reviews previous studies on multiphase flow and concepts of the double displacement process.

Chapter III describes theory and concepts related to this study.

Chapter IV explains the detail of model construction and reservoir conditions used in the simulation.

Chapter V shows the simulation results and discussion.

Chapter VI concludes the results obtained from the study.

CHAPTER II
LITERATURE REVIEW

In primary production, most of the oil reservoir has low recovery factor when they are produced only by natural reservoir energy which are fluid and rock expansion, solution gas drive, gas cap drive, natural water influx, and combination drive processes.

As petroleum is produced from the reservoir naturally, the pressure in the reservoir decreases, resulting in a decline in production. The decline is caused by both a decrease in the reservoir's ability to supply fluid to the wellbore and, in some cases, an increase in pressure required to lift the fluids to the surface.

Waterflood is a secondary recovery method in which water is injected into the reservoir to displace oil. The water from injection wells physically sweeps the oil to adjacent production wells. It is one common way to improve oil recovery because of its availability, low cost, and high specific gravity which facilitate injection.

In conventional oil reservoirs, a waterflood can only recover 40-60% of the OOIP. However, it has been shown, in the laboratory, that nearly 100% of OOIP can be recovered by tertiary gas injection in the presence of connate water. This tertiary recovery method involving the up-dip gas injection into steeply dipping, strongly water-wet, light-oil reservoirs to recover the residual oil is called the gravity-assisted tertiary gas injection process. It is also known as the double displacement process (DDP). This method involves the use of gas to displace the oil remained after waterflooding. The target for tertiary oil recovery in the DDP is the incremental oil between the 40 to 60% water drive recoveries and the 80 to 90% gravity drainage recoveries.

King and Stiles, Jr. (1970) analyzed past behavior and planned to develop the most efficient operating plan. From study of the Hawkins Woodbine reservoir characteristic, it revealed the need for unitization and pressure maintenance with gas. From observation, recovery efficiency is over 80% by gas cap drive with gravity drainage where as recovery is less than 50% at breakthrough in water-invaded areas.

Re-pressuring by injection of over 100 MMscf/day of gas should increase recovery by more than 150 million barrels of oil.

Carlson (1988) proposed that a test of Double Displacement Process can be economically accomplished in the East Fault Block, Hawkins Field. By monitoring the growth of the oil column, using GR/N and PNC logs.

Kantzas, Chatzis and Dullien (1988) evaluated DDP using glass bed columns. Experiments were carried out with "continuous oil", i.e., oil was the continuous phase in presence of irreducible water, and "discontinuous oil", i.e., residual oil after waterflooding. Oil displacement was performed under "free drainage" and "controlled drainage" conditions. These terms refer to drainage of oil due to its own weight and due to the hindrance of a semipermeable membrane, respectively. Using controlled displacement, the recovery of continuous oil approached 100% of the original oil-in-place while the recovery of continuous oil was 85-95%. Under free drainage conditions, recoveries of continuous oil were lower and ranged from 73-79% of the original oil-in-place.

Kantzas *et al* also examined DDP in consolidated Berea sandstone. The controlled drainage mode was used for Berea sandstone and recovery of continuous oil reached about 76% of original oil-in-place. Although, experiments in Berea sandstone gave lower recovery efficiency but it is still high. Possible ways to optimize the experimental setup for better recoveries are under investigation.

Langenberg and Henry (1995) published expansion plans for the double displacement process in the Hawkins Field, West Fault Block (WFB), after successful implementation in the East Fault Block (EFB). The results and design of EFB are also shown in this paper.

Fassihi and Gillham (1993) from Amoco Production company in partnership with the United States Department of Energy initiated an air injection with DDP project in the West Hackberry Field. They used compressing air instead of nitrogen or CO_2 because it is generally cheaper than others.

Four years later, Gillham, Cerveny and Turek (1997) updated information about air injection project including operation and economic data in West Hackburry field. They concluded that minimizing investment and operating costs through the use of air injection, even a moderate increase in oil production can generate positive economics.

Another important knowledge is multiphase flow in porous media. The principle multiphase flow parameters that appear in fluid transportation are three-phase relative permeabilities. The three-phase relative permeabilities have been the subject of much study over the past 60 years although much still remains to be understood about the behavior of three-phase systems because it is difficult and time-consuming.

The extreme difficulty is measuring three-phase relative permeability isoperms by combining the two phase data in various ways (Stone 1970,1973; Dietrich and Bondor, 1976; Delshad and Pope, 1989; Fayers, 1983; Fayers and Mathews, 1984; Baker, 1988; Blunt, 1999). The early work of Stone (1970, 1973) has been both criticized and extended by later workers in the previous reference list. This approach is based partly on the fact that the three-phase flow parameters must limit appropriately to various combinations of two phases which can occur. For example, in an oil/water/gas system, the three-phase relative permeability should limit correctly to the various two-phase oil/water, gas/oil and gas/water relative permeabilities.

Since 1941, experimental measurements of three-phase relative permeability were reported by Leverett and Lewis (1941) and have continued to trickle into many literature. About 13 different three-phase relative permeability models have been presented.

CHAPTER III
THEORY AND CONCEPTS

This chapter presents the basic principles and theories related to double displacement process and three-phase relative permeabilities. First of all, the basic concepts concerning in the DDP are introduced. Next, three-phase relative permeability is described for fundamental understanding. Then, multiphase relative permeability correlations is explained in details. The most suitable correlation is select for reservoir modeling double displacement process.

3.1 Double displacement process

The double displacement process (DDP) involves updip gas injection into a water-invaded oil column in order to mobilize and produce incremental oil. The incremental oil results from the difference in residual oil saturation in the presence of water as compared to that in the presence of gas. Gravity stable displacement causes the formation of an oil bank which builds up progressively as it migrates downward the reservoir towards the producing wells. A simplified schematic of a dipping reservoir subjected to DDP is shown in Figure 3.1.

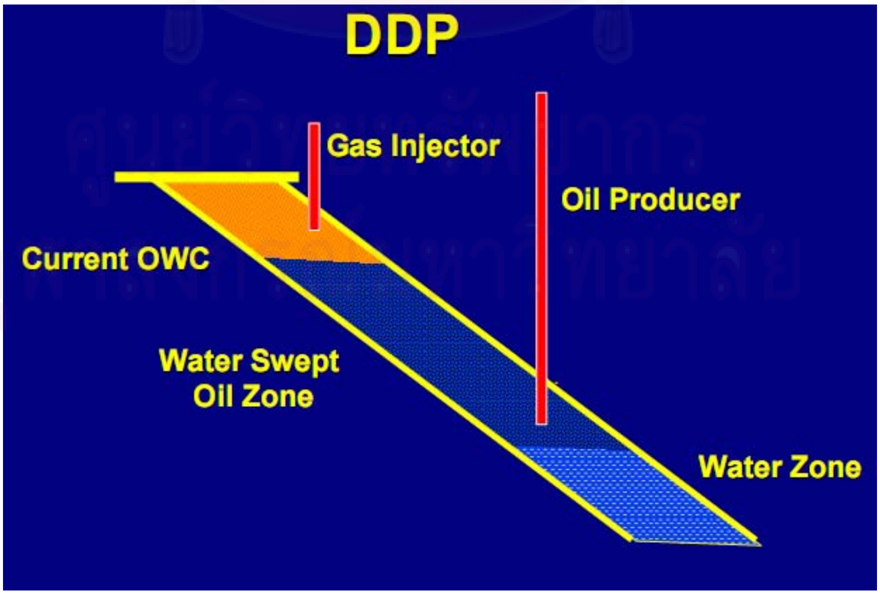


Figure 3.1: Double displacement process

Gas injection will help mobilize oil until the oil-water contact is lowered to its initial position at the beginning of reservoir production. Under favorable conditions, incremental oil recovery on the order of 40% of the original oil-in-place may be recovered using DDP.

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

In order to recover waterflood residual oil, we must restore effective permeability to oil which is essentially zero in the water-swept zone. By injecting gas, some of the excessive water is displaced from pores where oil globules remain trapped. For initially water wet systems with oil trapped in the pores, introduction of a gas phase creates conditions for three phase flow. When gas enters a pore containing residual oil globules, capillary forces cause oil to spread between water coating the pore wall and the gas bubble occupying the center of the pore, as shown in Figure 3.2. This conditions allow the oil phase to reconnect. The reconnected oil film flows downward due to gravity forces and creates an oil bank as shown in Figure 3.3. As more gas is injected, the existing oil bank flows downwards encompassing residual oil blobs as it travels. If gas front progresses slowly, no movable oil is left behind the gas front.

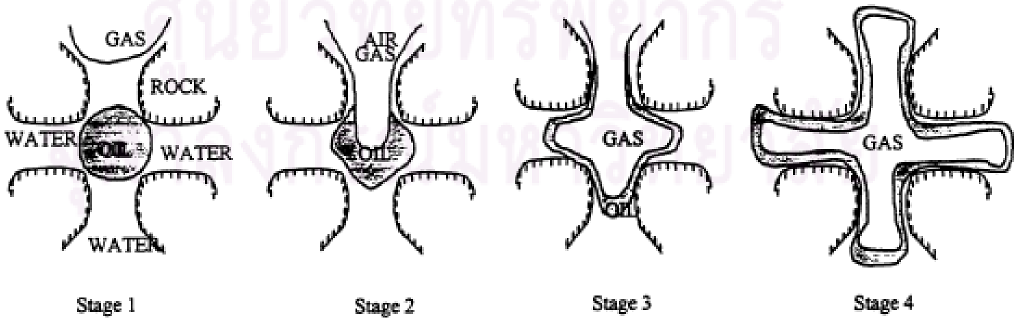


Figure 3.2: Pore scale of gas displacing remaining oil.

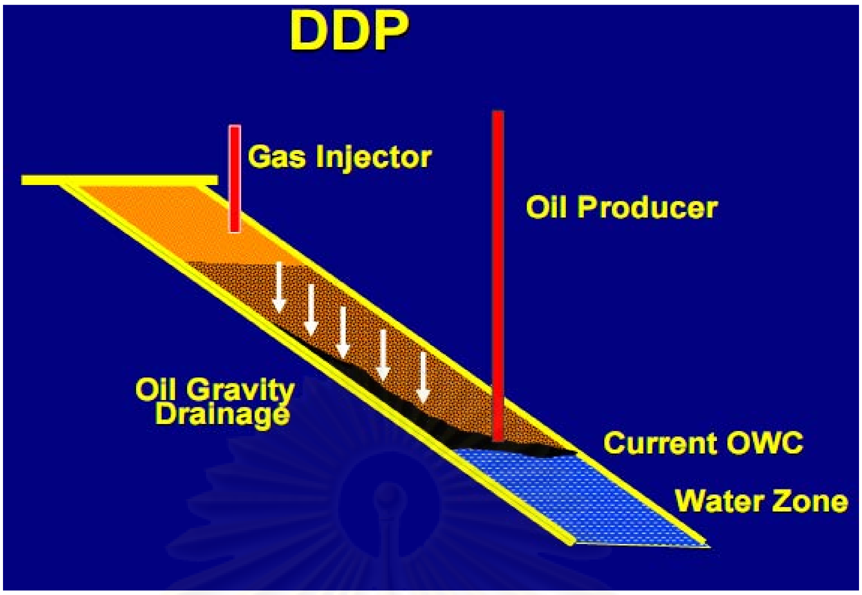


Figure 3.3: Oil gravity drainage after gas injection.

Efficiency of the DDP is governed by several processes, including gravity drainage and the spreading coefficient. Gravity drainage is an oil recovery mechanism in which gravity acts as the main driving force for mobilization of oil with gas replacing the voided volume. A comprehensive description of the process is given by Hagoort (1980).

According to Chatzis, Kantzas and Dullien (1988), process efficiency is dependent on the spreading of oil over water in presence of gas. The spreading coefficient is given by:

$$S'_{o/w} = \sigma'_{wg} - \sigma'_{og} - \sigma'_{ow} \qquad (3.1)$$

where

$S'_{o/w}$ = final spreading coefficient of oil over water

σ'_{wg} = water/gas interfacial tension

σ'_{og} = oil/gas interfacial tension

σ'_{ow} = oil/water interfacial tension

When $S'_{o/w}$ is positive, oil tends to spread on water and form a continuous film. When $S'_{o/w}$ is negative, oil does not spread on water and stays discontinuous. This observations were further investigated by Oren, Billiotte and Pinczewski (1992).

In double displacement process, oil film also plays an important role. After waterflooding, gas is being injected into updip of the reservoir. After a period of gas injection, a gas cap is formed and an oil rim is reconnected at gas front. The gas front moves slowly downward to push the reconnected oil towards to the producing wells. The oil in gas swept zone forms a thin oil film and spreads through porous media and becomes reconnected with all of residual oil to form oil rim. When the oil rim reaches the production wells, oil production begins. The oil production at the early time is a very low rate because thickness of oil rim is still low. Given sufficient time, the flow of oil through the oil films can result in higher thickness. However, the long production time at a low rate is detrimental to the economic success of the process.

3.2 Two-phase relative permeability model

In this section, we describes basic concept of two-phase relative permeability system since three-phase relative permeability is based on two sets of two-phase relative permeability data..

3.2.1 Oil-water system

Both drainage (displacing process in which the saturation of the wetting phase decreases) and imbibitions (displacing process in which the saturation of the wetting phase increases) curves may be required in studies of oil-water system, depending on the process considered. Although most processes of interest involve displacement of oil by water, or imbibitions, the reverse may take in parts of the reservoir due to geometrical effects, or due to changes in injection and production rates resulting in reversals of flow directions.

Therefore, drainage curves may be required. Also, the initial saturations present in the rock will normally be the result of a drainage process at the time of oil accumulation. Thus, for initialization of saturations, the drainage capillary pressure curve is required. Starting with the porous media completely filled with water, and displacing by oil, the drainage relative permeability and capillary pressure curves will be show in Figure 3.4.

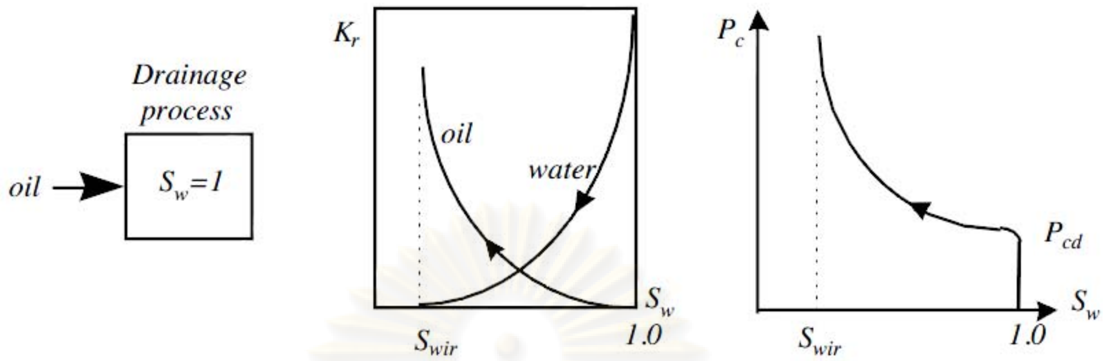


Figure 3.4: Drainage relative permeability and capillary curves in oil-water system.

Reversing the process when all mobile water has been displaed, by injectiong water to displace the oil, imbibitions curves are defined.

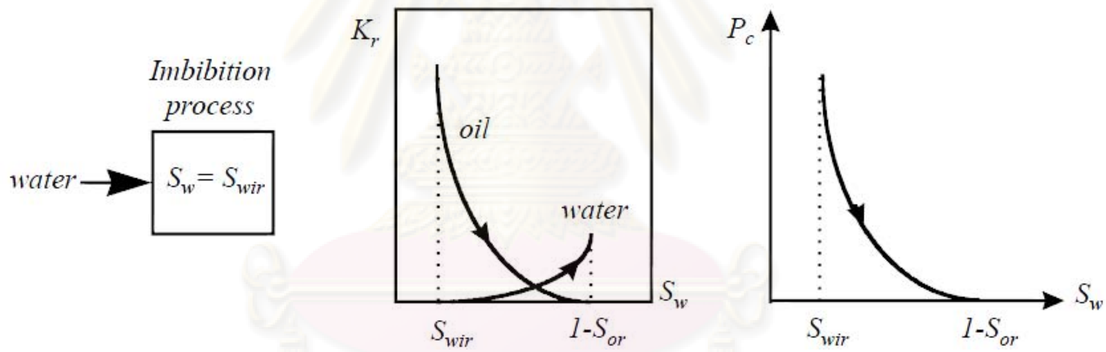


Figure 3.5: Imbibition relative permeability and capillary curves in oil-water system.

3.2.2 Oil-gas system

Normally, only drainage curves are required in gas-oil system, since gas displaces oil. However, sometimes reimbibition of oil into areas previously drained by gas displacement may happen. Reimbibition phenomena may be important in gravity drainage processes in fractured reservoirs. Starting with the porous rock completely filled with oil, and displacing by gas, the drainage relative permeability and capillary pressure curves will be defined.

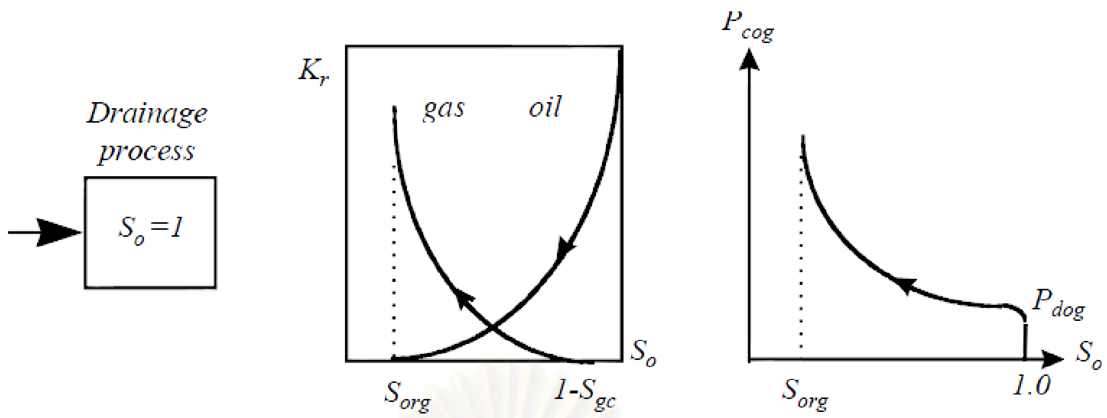


Figure 3.6: Drainage relative permeability and capillary curves in oil-gas system.

If the process is reversed when all mobile oil has been displaced, by injecting oil to displace the gas, imbibitions curves is illustrated in Figure 3.7.

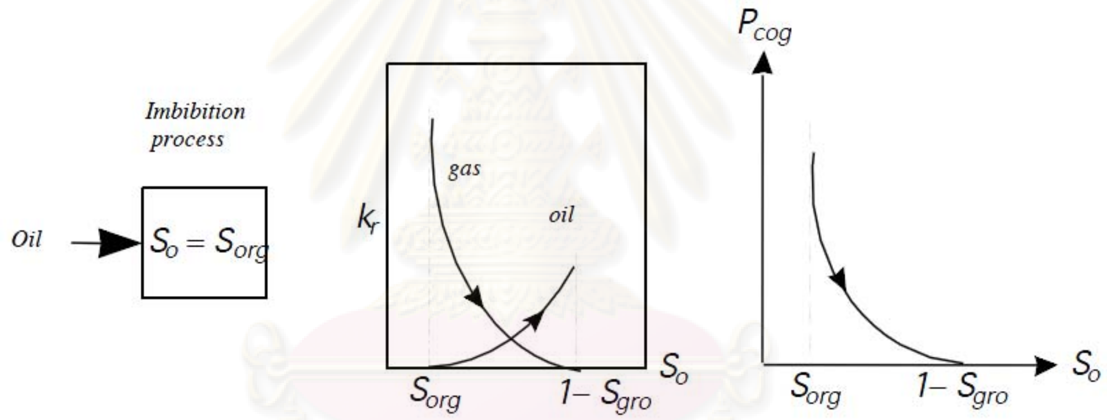


Figure 3.7: Imbibition relative permeability and capillary curves in oil-gas system.

The shape of the gas-oil curves will of course depend on the surface tension properties of the system, as well as on the rock characteristics.

3.3 Three-phase relative permeability model

Since we now have three phases flowing, we need to define the relative permeabilities anew. The following parameters are functions only of the saturations indicated; $k_{rw}(S_w)$, $k_{rg}(S_g)$, $k_{ro}(S_w,S_g)$. Except for the relative permeability to oil, k_{ro} these parameters may be measured in two-phase measurements since they depend on one saturation only. In the discussion of three-phase relative permeability to oil, k_{ro}, we will start with typical two-phase oil-water and oil-gas relationships.

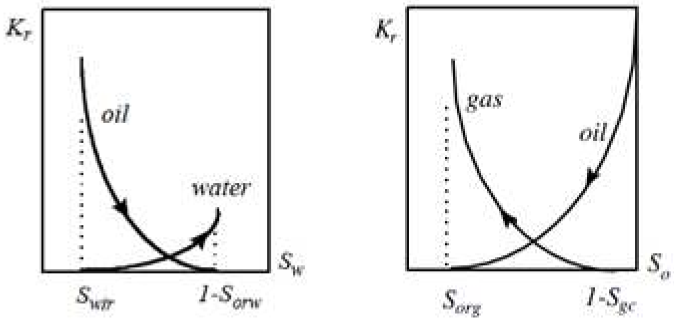


Figure 3.8: Two-phase relative permeability curves.

The two oil relative permeability curves are two phase curves. However, as indicated above, in a three-phase flow situation, the oil relative permeability would be a function of both water and gas saturations. Plotting it in a triangular diagram, so that each saturation is represented by one of the sides, we can define an area of mobile oil limited by the system's maximum and minimum saturations. Inside this area, *iso*-k_{ro} curves may be drawn, as illustrated in Figure 3.9.

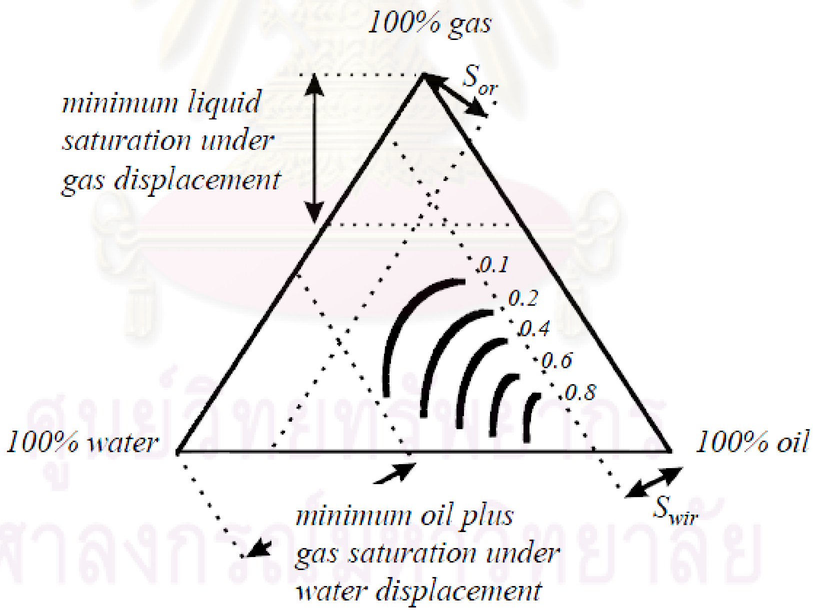


Figure 3.9: Triangular diagram for three phase saturation.

In principle, k_{ro} may be measured in the laboratory. However, due to the experimental complexity of three-phase experiments, we most of the time construct it from two phase oil-water k_{row} and two phase oil-gas k_{rog}. The simplest approach is to just multiply the two.

$$k_{ro} = k_{row} \cdot k_{rog} \tag{3.2}$$

However, since some of the limiting saturations in three phase flow are not necessarily the same as for two phase flow, this model is not representative. For instance, the minimum oil saturation, S_{or}, for three phase flow is process dependent and a very difficult parameter to estimate.

As mentioned before, many correlations to calculate S_{or} have been proposed in the literature. Unfortunately, there are only a few relative permeability functions available in ECLIPSE100. The default model is similar Baker model, known as saturation weighted model. Review of three-phase relative permeability models is as follows:

3.3.1 Corey type

Corey, Rathjens and Henderson (1956) proposed a model for prediction of three-phase relative permeability by assuming that the oil relative permeability depends on two saturations due to the dependence of residual oil saturation on two saturations. The model is given as:

$$k_{ro} = k_{ro}^{o}\left(\frac{S_o - S_{or}}{1 - S_{or} - S_{wr} - S_{gr}}\right)^{e_o} \tag{3.3}$$

where

$$S_{or} = f\left(S_g - S_w\right)$$

k_{ro}^{o} is end point relative permeability to oil

e_o is exponent of relative permeability curve to oil

S_{wr} is residual water saturation

S_{gr} is residual gas saturation

In the absence of experimental data for three-phase oil exponent and end point relative permeability, the following can be used

$$k_{ro}^{o} = bk_{row}^{o} + (1-b)k_{rog}^{o} \tag{3.4}$$

$$e_o = be_{ow} + (1-b)e_{og} \tag{3.5}$$

where

$$b = 1 - \frac{S_g}{1 - S_{wr} - S_{org}} \tag{3.6}$$

k_{row}^{o} is end point relative permeability to oil in water phase

k_{rog}^{o} is end point relative permeability to oil in gas phase

S_{org} is residual oil saturation in gas phase

e_{ow} is exponent of relative permeability curve to oil in water phase

e_{og} is exponent of relative permeability curve to oil in gas phase

3.3.2 Stone I

This model was developed by Stone (1970) based on the channel flow theory that assumes the porous medium as an assemblage of flow channels. This model was originally introduced as an interpolation technique between two-phase flow conditions.

$$k_{ro} = S_o^* \beta_w \beta_g \tag{3.7}$$

where β_w and β_g are factors that account for oil blockage by water and gas, repectively, and can be calculated by the following equations :

$$\beta_w = \frac{k_{row}}{1 - S_o^*} \tag{3.8}$$

$$\beta_g = \frac{k_{rog}}{1 - S_g^*} \tag{3.9}$$

and S_o^*, S_w^* and S_g^* are normalized saturation defined as:

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

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

$$S_g^* = \frac{S_g}{1 - S_{wc} - S_{om}} \tag{3.12}$$

where S_o, S_w and S_g are the saturation of oil, water and gas, respectively; S_{wc} is the connate water saturation; and S_{om} is an adjustable parameter that represents a minimum value of oil saturation in the three-phase system. Stone (1970) suggested that the value of S_{om} should be about $1/2S_{wc}$.

According to Stone I model, at S_o^* = 1.0, the relative permeability to oil approaches 1.0. Reducing to two-phase relative permeability, Stone I model yields the following values:

$$k_{row}\left(S_{wr}\right) = 1 \qquad \text{and} \qquad k_{rog}\left(S_g = 0\right) = 1$$

These conditions are unrealistic because of two reasons: (1) the relative permeability to the oil phase in the presence of connate water should be less than 1.0 because of occupation of some pores by water phase; (2) k_{rog} is usually measured in the presence of connate water to simulate oil reservoir conditions and, therefore, the relative permeability to oil will never equal to 1.0 because the void space is always shared by water.

A few models for three-phase relative permeabilities have been developed from this correlation. For example, Aziz and Settari (1979) introduced a normalized model on the basis of Stone's model. Fayers and Matthews (1984) proposed a method for determination S_{om}.

3.3.3 Stone II

Stone (1973) proposed a new model using an assumption that the total permeability (sum of oil, gas and water permeabilities) is the product of total water/oil permeability $\left(k_{row}+k_{rwo}\right)$ measured at zero gas saturation and the total gas/oil permeability $\left(k_{rog}+k_{rgo}\right)$ measured at irreducible water saturation. Thus,

$$k_{ro}+k_{rw}+k_{rg} \quad = \quad \left(k_{row}+k_{rwo}\right)\left(k_{rog}+k_{rgo}\right) \tag{3.13}$$

k_{rwo} is relative permeability for water

k_{rgo} is relative permeability for gas

Gas and water relative permeabilities are assumed to be the same in two-phase and three-phase flow and can be determined from the two-phase data. Therefore,

$$k_{ro} \quad = \quad \left(k_{row}+k_{rwo}\right)\left(k_{rog}+k_{rgo}\right)-k_{rwo}-k_{rgo} \tag{3.14}$$

The subscripts "*go*" and "*wo*" have been retained for k_{rg} and k_{rw} to indicate the expected source of the data. Stone specified the basis for relative permeability calculations for Method II should be the relative permeability to oil at connate water saturation and zero gas saturation, as for Method I. Inspection of Stone I and Stone II shows that if k_{row} and k_{rog} are not unity at the connate water saturation, the equation will not predict correct two-phase (water/oil and gas/oil) relative permeabilities as the saturation of the third phase approaches zero.

3.3.4 Baker

Baker (1988) proposed a model for prediction of three-phase relative permeability using an interpolation between the two-phase relative permeability data as follows:

$$k_{ro} = \frac{(S_w - S_{wr})k_{row} + (S_g - S_{gr})k_{rog}}{(S_w - S_{wr}) + (S_g - S_{gr})} \tag{3.15}$$

S_{wr} is residual water saturation

S_{gr} is residual gas saturation

where the two-phase relative permeability can be experimental data or they can be estimated using two-phase models such as the following:

$$k_{row} = k_{row}^o \left(\frac{S_o - S_{orw}}{1 - S_{wr} - S_{orw}} \right)^{e_{ow}} \tag{3.16}$$

$$k_{rog} = k_{rog}^o \left(\frac{S_g - S_{Lrg}}{1 - S_{Lrg} - S_{gr}} \right)^{e_{og}} \tag{3.17}$$

k_{row}^o is end point relative permeability to oil in water phase

k_{rog}^o is end point relative permeability to oil in gas phase

e_{ow} is exponent of relative permeability curve to oil in water phase

e_{og} is exponent of relative permeability curve to oil in gas phase

and $S_g = 1 - S_o - \min(S_w - S_{wr})$ and S_{Lrg} is the total residual liquid saturation to gas phase during two-phase flow of gas and oil , $S_{Lrg} = S_{wr} - S_{org}$.

3.3.5 ECLIPSE model

The default model assumed by ECLIPSE is close to Baker's model, known as saturation weighted model. The oil saturation is assumed to be constant and equal to the block average value, S_o, throughout the cell. The gas and water are assumed to be completely segregated, except that the water saturation in the gas zone is equal to the connate saturation, S_{wco}. The full breakdown, as shown in Figure 3.10, assuming the block average saturations are S_o S_w and S_g (with $S_o + S_w + S_g = 1$) is as follows:

The oil relative permeability is then given by

$$k_{ro} = \frac{S_g k_{rog} + \left(S_w - S_{wco}\right) k_{row}}{S_g + \left(S_w - S_{wco}\right)} \tag{3.18}$$

where

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

k_{row} is the oil relative permeability for a system with oil, and water only (also tabulated as a function of S_o)

In a fraction $S_g / \left(S_g + S_w - S_{wco}\right)$ of the cell (the gas zone),

the oil saturation is S_o

the water saturation is S_{wco}

the gas saturation is $S_g + S_w - S_{wco}$

In a fraction $\left(S_w - S_{wco}\right) / \left(S_g + S_w - S_{wco}\right)$ of the cell (the water zone),

the oil saturation is S_o

the water saturation is $S_g + S_w$

the gas saturation is 0

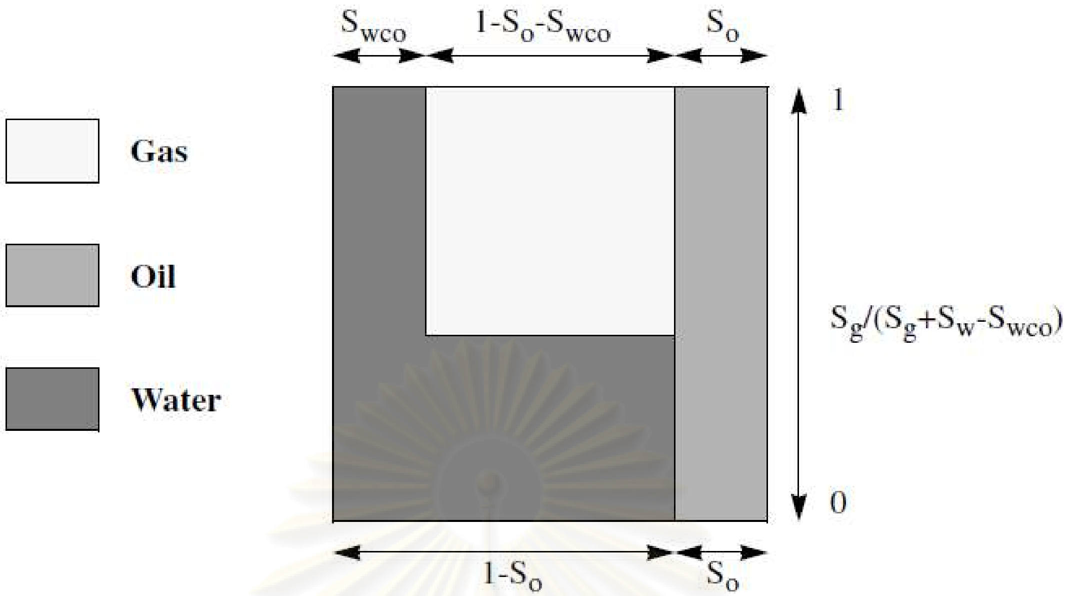


Figure 3.10: The default three-phase oil relative permeability model assumed by ECLIPSE

In fact, not only Stone I and Stone II are functions available in ECLIPSE100 reservoir simulation. Two other methods, IKU method (according to Hustad and Hunsen 1995) and ODD3P method (extension of the IKU method) are available in ECLIPSE 300 compositional reservoir simulation.

CHAPTER IV
MODEL DESCRIPTION

As mentioned before, the objective of this thesis is optimize production performance of the DDP (double displacement process) applied in solution gas drive reservoirs under different operating conditions. In doing so, hypothetical reservoir models with different dip angles are constructed using ECLIPSE 100 reservoir simulator.

This chapter describes the construction of reservoir and well models. The reservoir and well properties were hypothetically constructed for the purpose of result comparison. A dipping reservoir model with 10 degree dip angle was set up as base cases. The hypothetical model is a simple dipping reservoir using corner point grid with four vertical wells in a line drive pattern. The ECLIPSE script for base case is provided in the Appendix.

4.1 Reservoir model

The reservoir model consists of 73x31x21 corner point grid blocks which are 6000x2000x210 ft as shown in Figures 4.1 to 4.3. Four vertical wells are constructed at the mid of reservoir in the y-direction. Out of these four wells, three are producers, located at updip and one is a water injector located downdip. The model is homogeneous reservoir, and the reservoir properties are shown in Table 4.1.

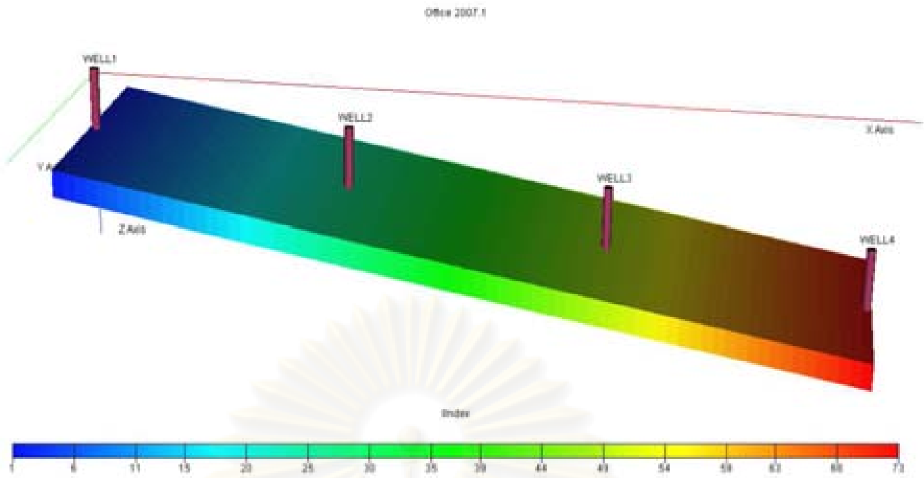


Figure 4.1: Position of cell in the x-direction in the reservoir model.

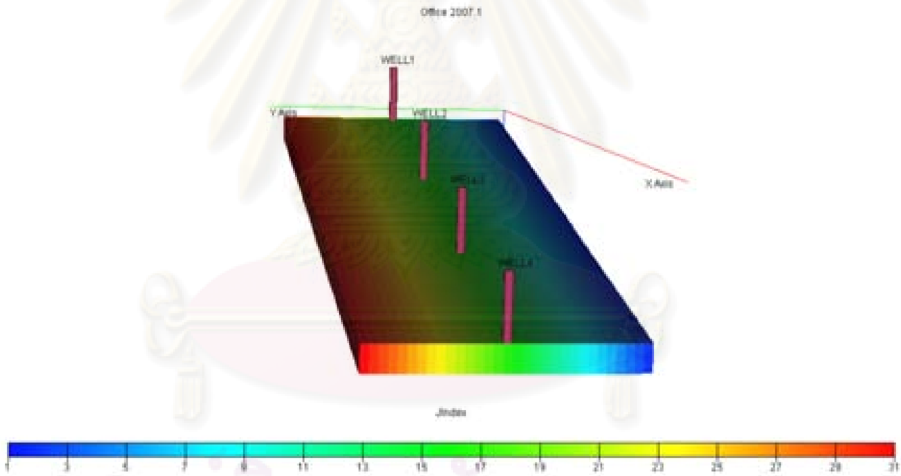


Figure 4.2: Position of cell in the y-direction in the reservoir model.

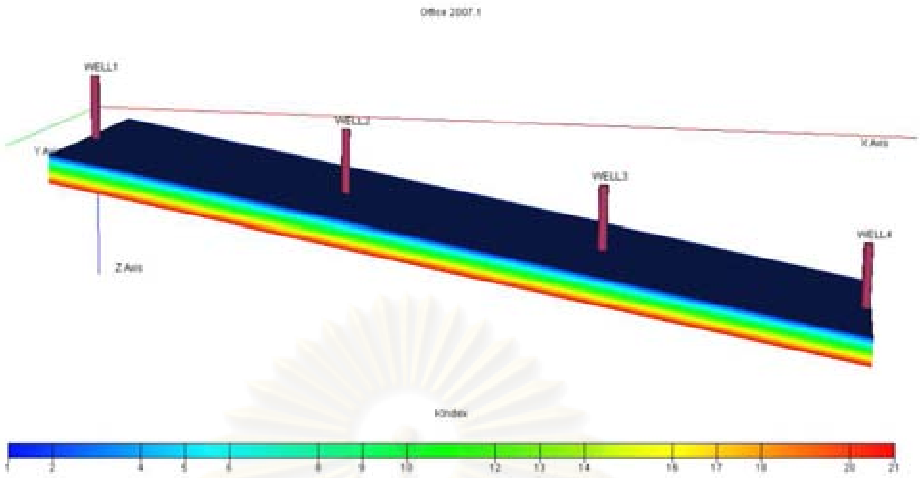


Figure 4.3: Position of cell in the z-direction in the reservoir model.

Table 4.1: Reservoir properties

Parameters	Values	Unit
Number of grids	73×31×21	Grid
Porosity	15.09	%
Horizontal permeability	32.529	mD
Vertical permeability	32.529	mD
Top of reservoir	6000	ft
Datum depth	6000	ft
Initial pressure @ datum depth	2377.1	psia
Dip angle	10	degree

For the base case, an undersarturated oil reservoir with initial oil saturation (S_o) of 39.14% as shown in Figure 4.4 was simulated. At initial conditions, the reservoir has no gas because the initial pressure is equal to the bubble point pressure of 2377.1 psia.

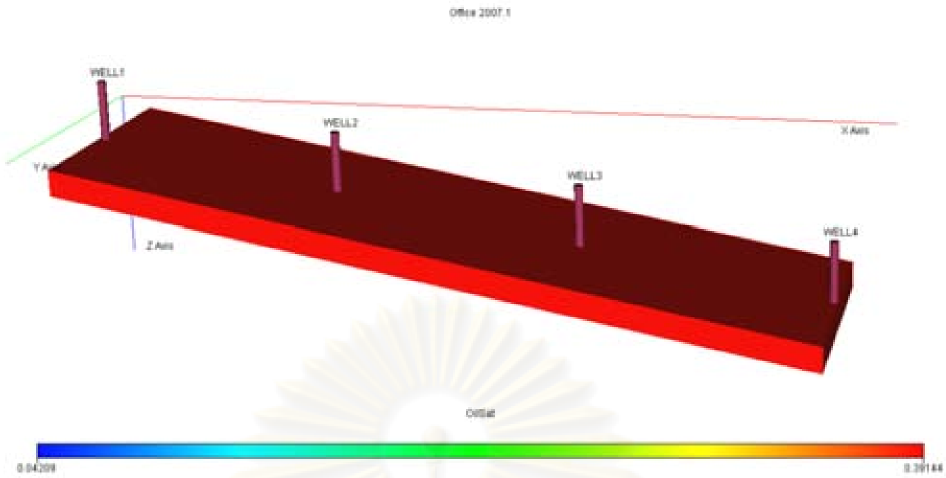


Figure 4.4: Reservoir model with oil saturation.

4.2 General fluid properties

There are several fluid properties which are input to the reservoir simulation. Most of reservoir fluid and rock properties are taken from an onshore field of Thailand. The information is shown in Table 4.2 and Figures 4.5 and 4.6.

Table 4.2: Fluid densities at surface conditions

Property	Value	Unit
Oil density	51.6375	lb/cuft
Gas density	0.04981752	lb/cuft
Water density	62.42841	lb/cuft

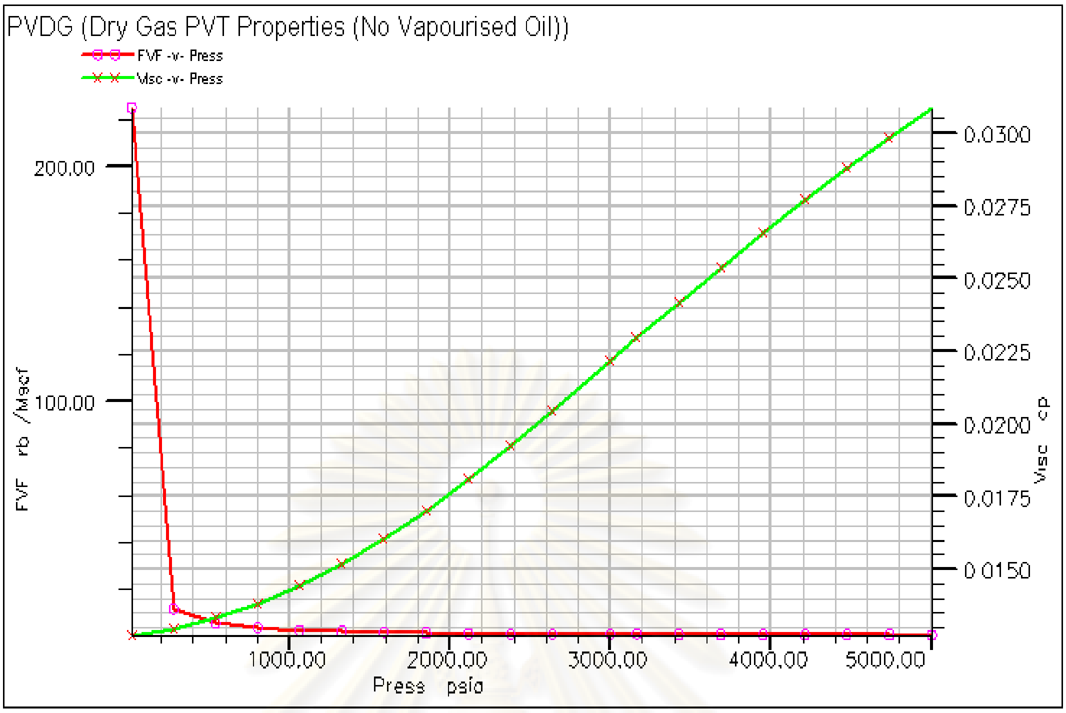


Figure 4.5: Dry gas PVT properties (no vapourised oil)

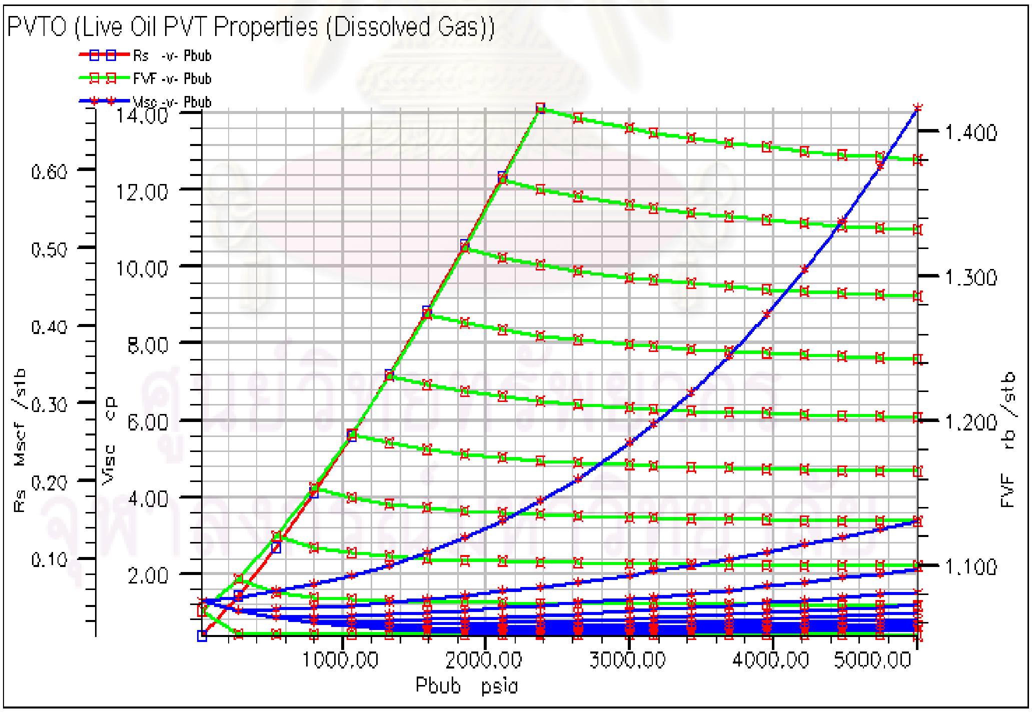


Figure 4.6: Live oil PVT properties (dissolved gas)

4.3 SCAL properties

In this part, SCAL data are generated using Corey's correlation function in ECLIPSE100. The model assumed that water is the most wetting phase and gas is the least wetting phase when residual oil saturation in the water and gas phase is 0.2 and 0.04, respectively. The relative permeabilities are shown in Figures 4.7 and 4.8.

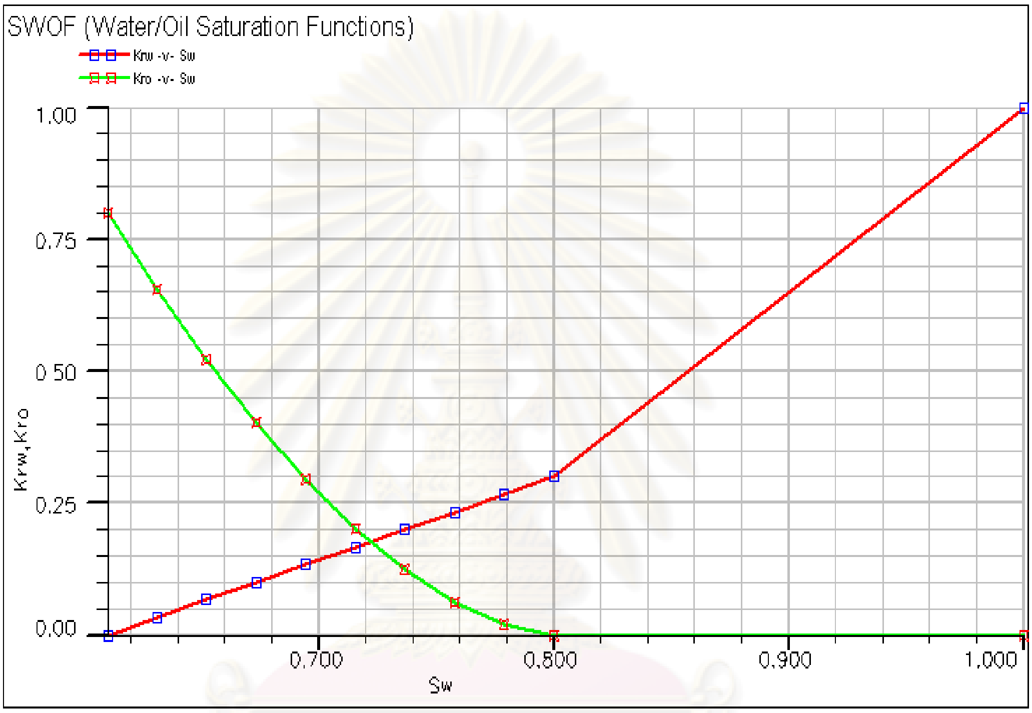


Figure 4.7: Water/oil saturation functions

Figure 4.8: Gas/Oil saturation functions

4.4 Well schedules

According to well information of the onshore field selected for this study, the production constraints are described as shown in Table 4.3.

Table 4.3: Production constraints

Parameters	Values	Unit
Maximum liquid rate of each well	1,000	STB/D
Economic oil production rate of each well	100	STB/D
Maximum field GOR	30	MMSCF/STB
Maximum water cut of each well	98	%
Fracturing reservoir pressure	5000	psia

CHAPTER V
RESULT AND DISCUSSION

In this chapter, we simulated oil reservoir under DDP with waterflood and injection conditions. First of all, we applied waterflooding to the base model to optimize the best condition of production. After that, gas injection is started to evaluate effects of injector location, three-phase relative permeability correlations and dip angle of the reservoir. The base case model is 10 degree dipping reservoir and the various cases are 5 and 20 degree dip angle. The tubing head pressure is set to be 500 psia for all cases. The liquid rate for the producer is controlled at 1000 STB/D. The oil economic rate is assumed to be 100 STB/D. After running the simulation program, results are discussed.

5.1 Criteria to stop waterflooding

In order to determine the most appropriate duration for waterflood, we varied the time that waterflooding is stopped based on the amount of water production (water cut) of the producer. Three water cut are chosen as criteria: 85%, 90% and 95%. As shown in Figure 5.1, there are four wells in the reservoir. The most downdip well (well 4) is chosen as the water injectior while the three updip wells are producer. Each well is individually shut in when the water cut reaches the selected criteria. The water injection constraint is the fracture pressure of 5000 psia. Injected water is controlled to maintain the reservoir pressure to be around the initial pressure as shown in Figure 5.1. Figures 5.2 to 5.4 show oil production profiles for water cut criterion of 85%, 90%, and 95%; respectively while Figure 5.5 compares the oil recovery factors obtained from different constraints on water cut. For the case of 85% water cut criterion, at about 8th year of production, well 3 is shut and water injection rate is decreased to prevent an increase in reservoir pressure. At 16th year, well 2 is shut and water injection rate is decreased again. Finally, all of production wells are shut in the year 2023.

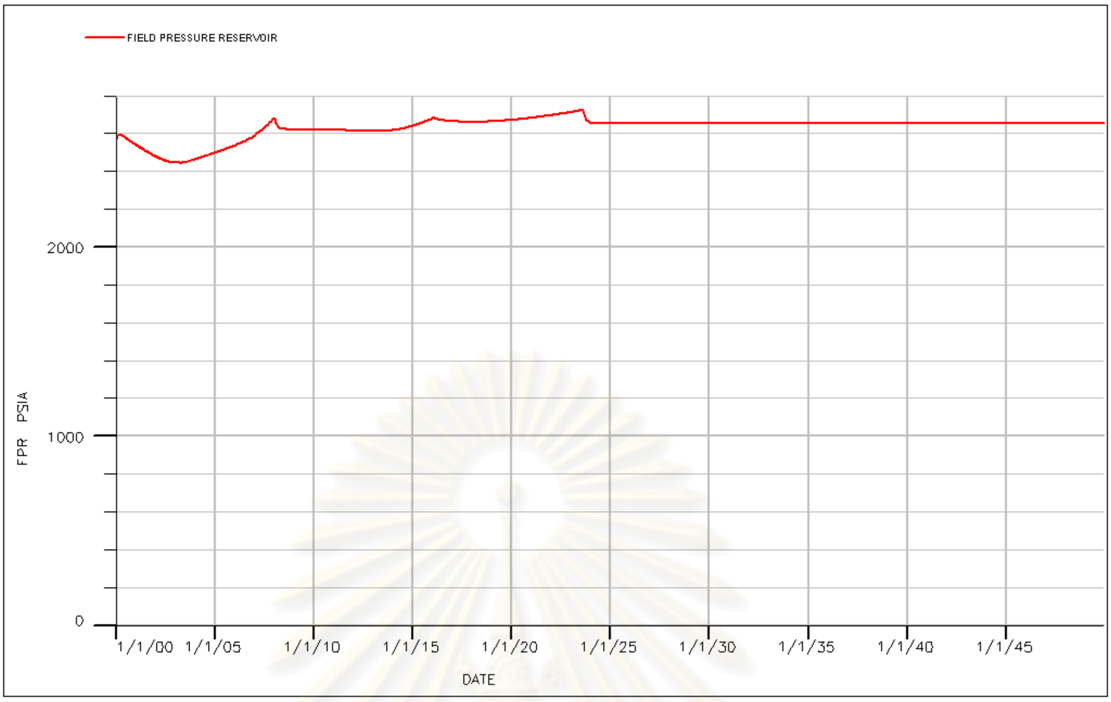


Figure 5.1: Field pressure reservoir for waterflooding.

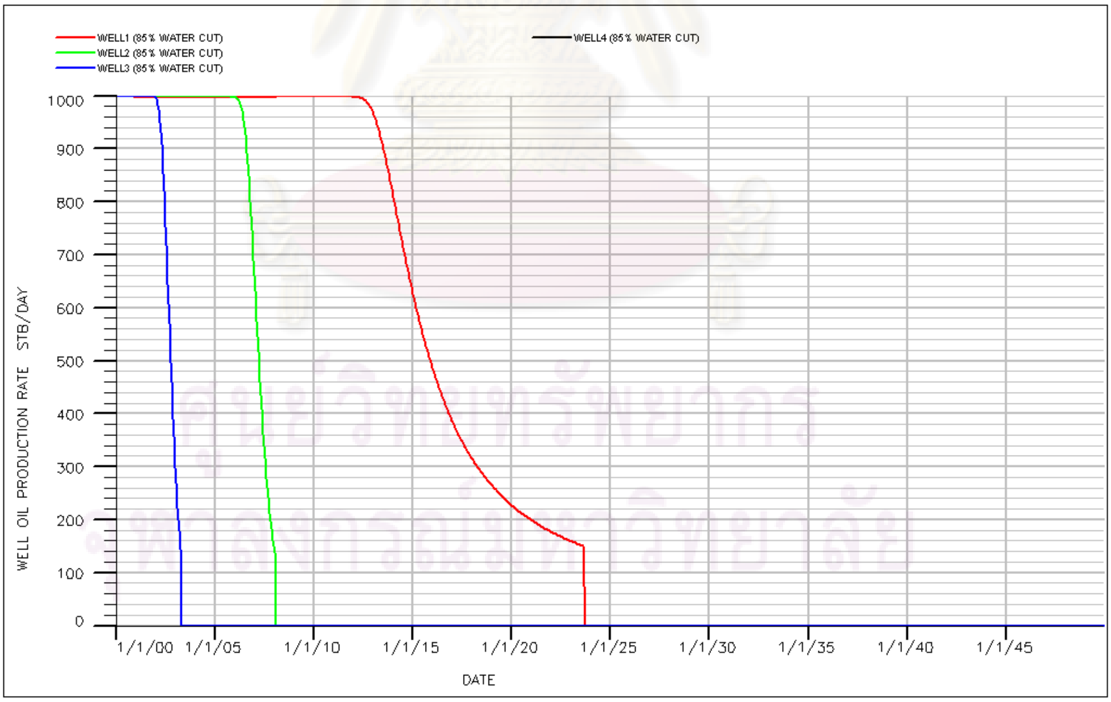


Figure 5.2: Oil production profile for waterflooding being stopped at 85% water cut for 10-degree dipping reservoir.

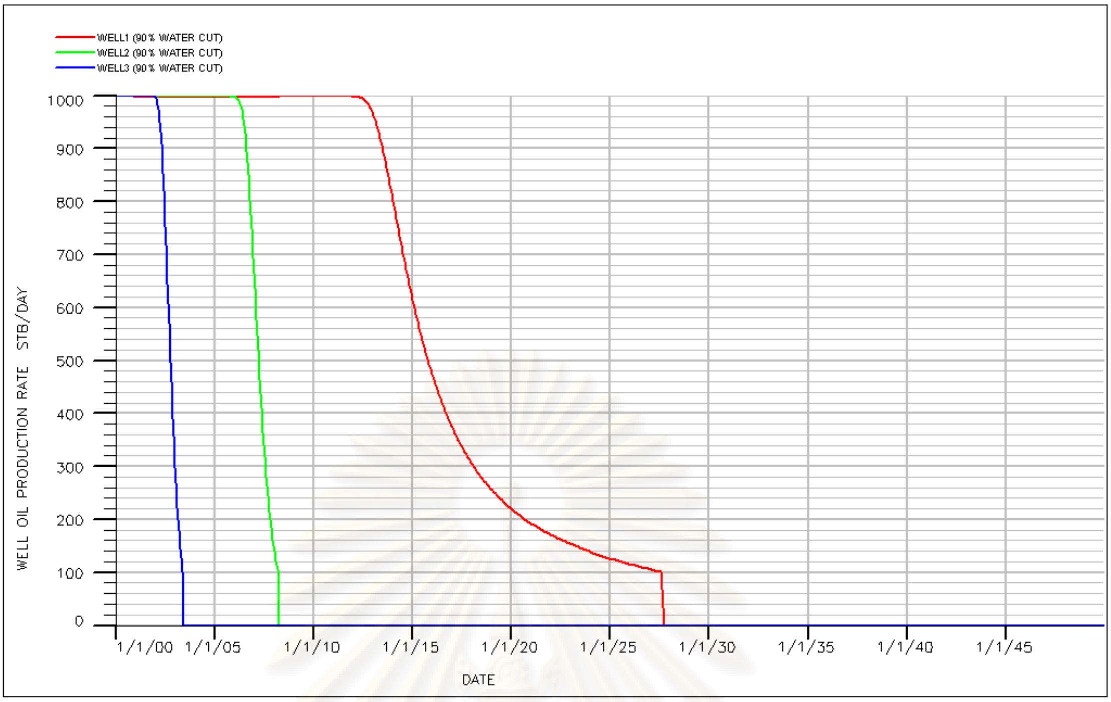


Figure 5.3: Oil production profile for waterflooding being stopped at 90% water cut for 10-degree dipping reservoir.

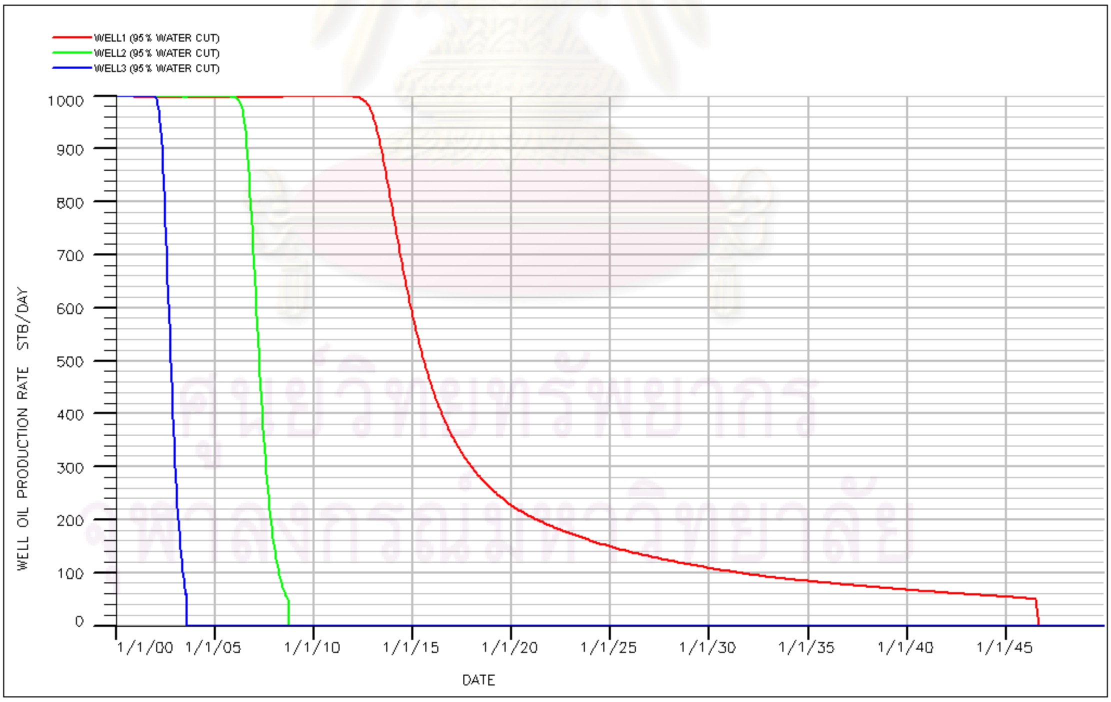


Figure 5.4: Oil production profile for waterflooding being stopped at 95% water cut for 10-degree dipping reservoir.

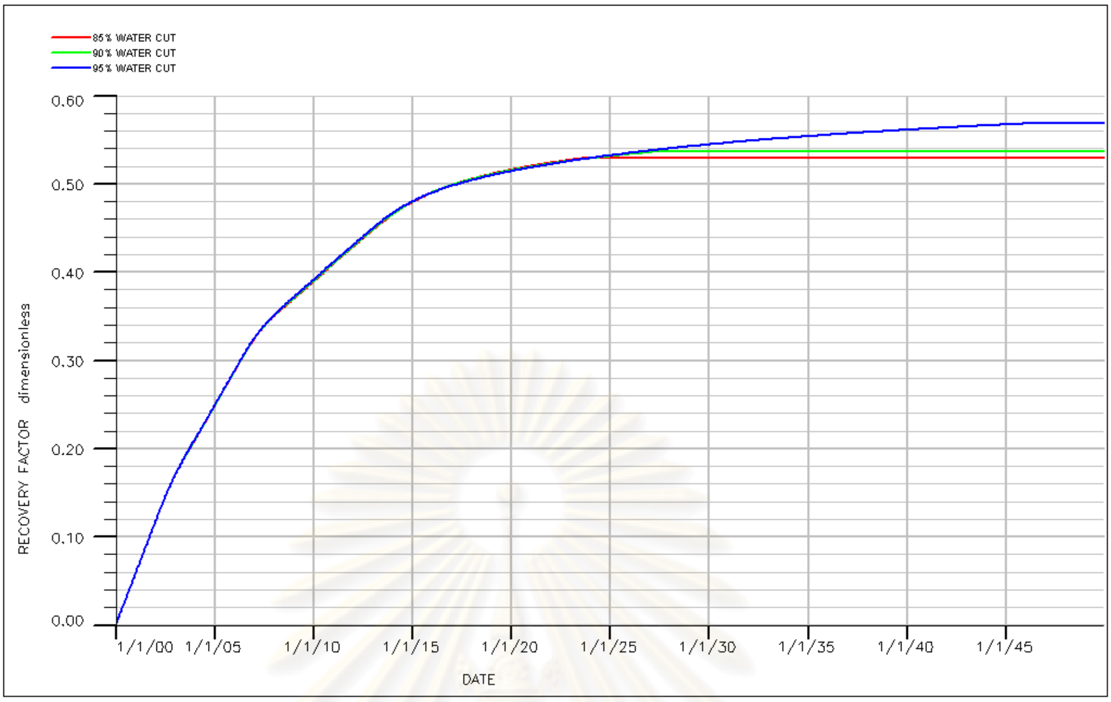


Figure 5.5: Comparison of oil recovery for waterflooding being stopped at different water cuts for 10-degree dipping reservoir.

The same methodology is applied for other reservoirs with 5 and 20 dip angle. The results are shown in Figures 5.6 to 5.13.

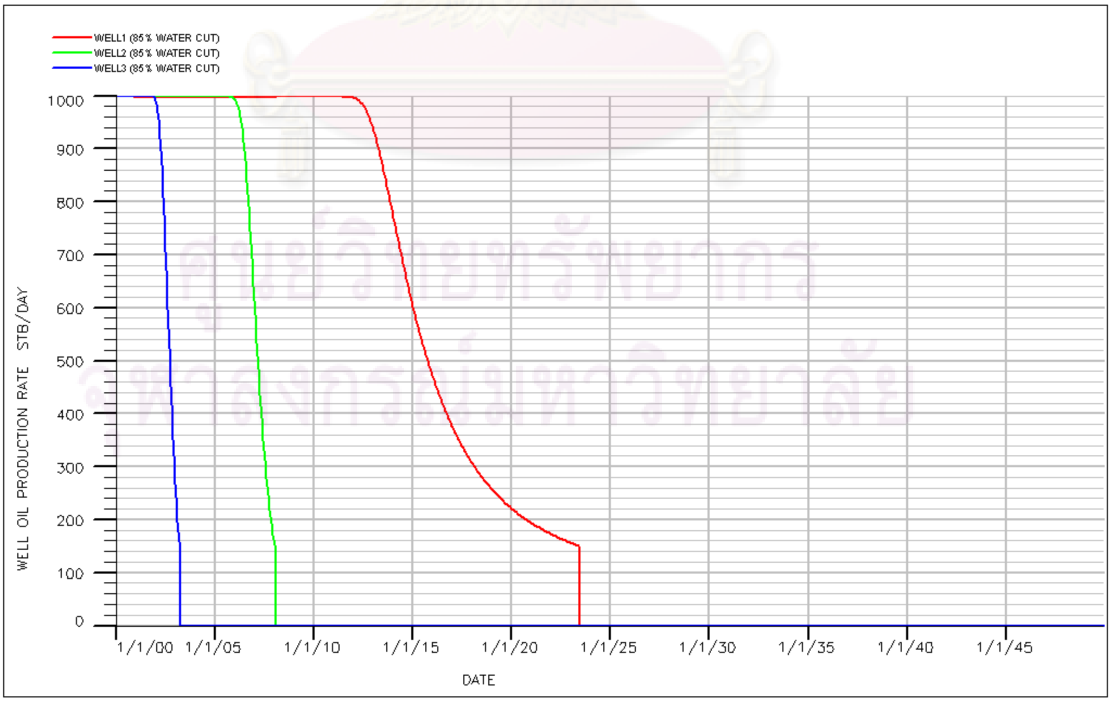


Figure 5.6: Oil production profile for waterflooding being stopped at 85% water cut for 5-degree dipping reservoir.

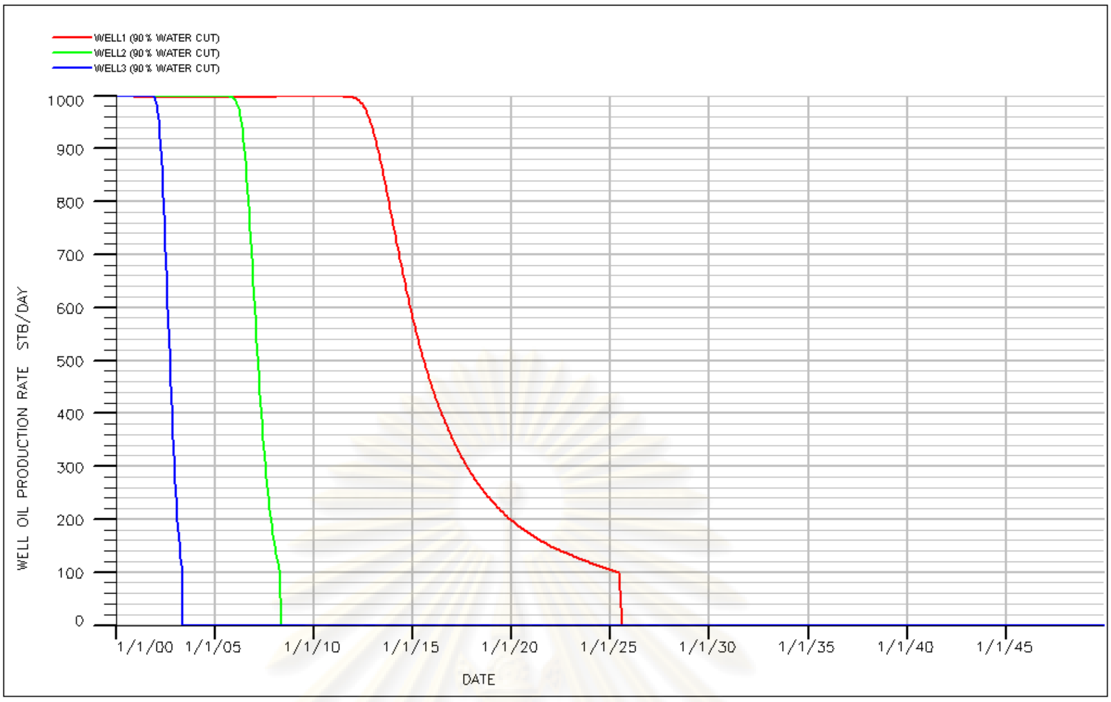


Figure 5.7: Oil production profile for waterflooding being stopped at 90% water cut for 5-degree dipping reservoir.

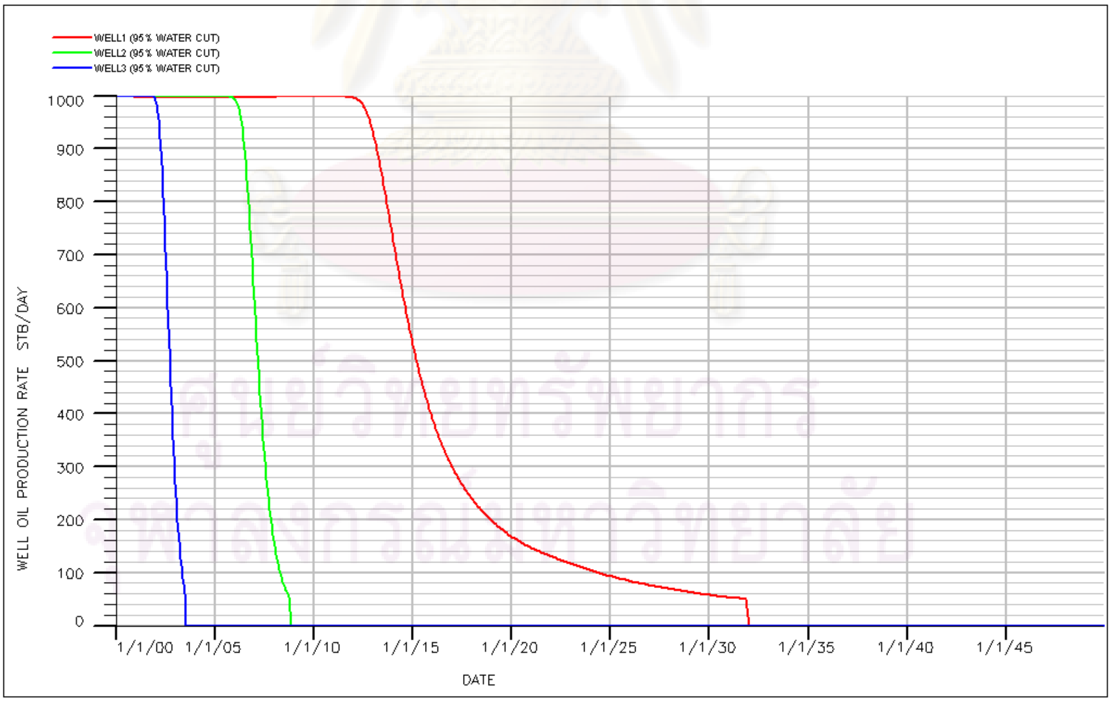


Figure 5.8: Oil production profile for waterflooding being stopped at 95% water cut for 5-degree dipping reservoir.

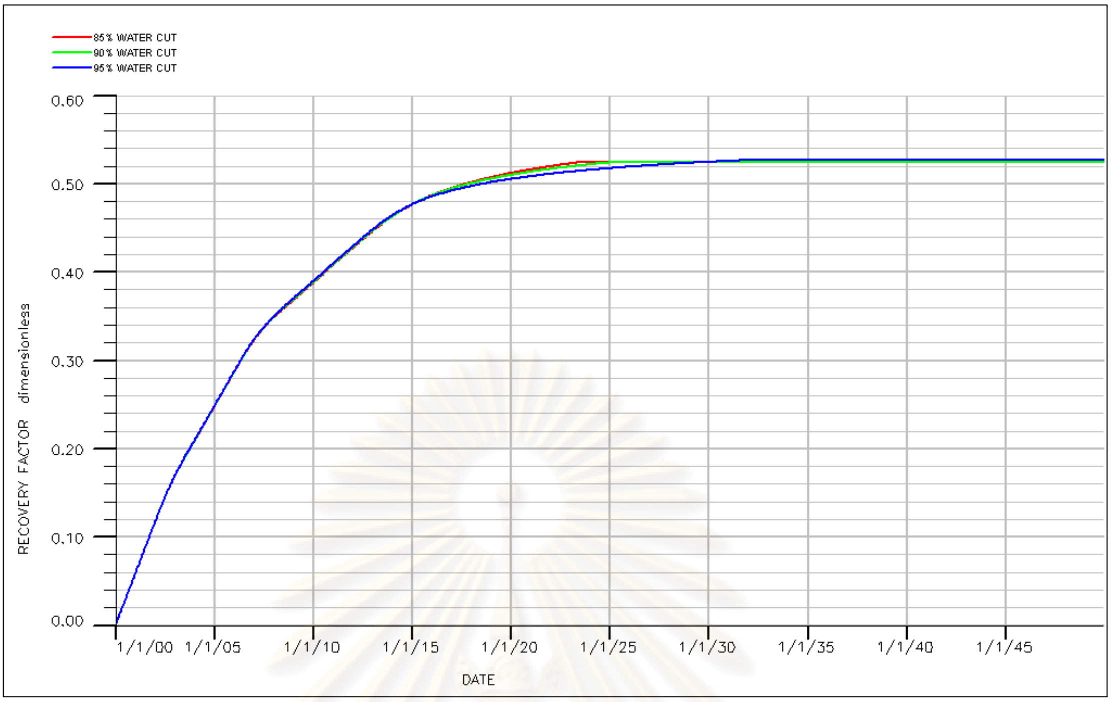


Figure 5.9: Comparison of oil recovery for waterflooding being stopped at different water cuts for 5-degree dipping reservoir.

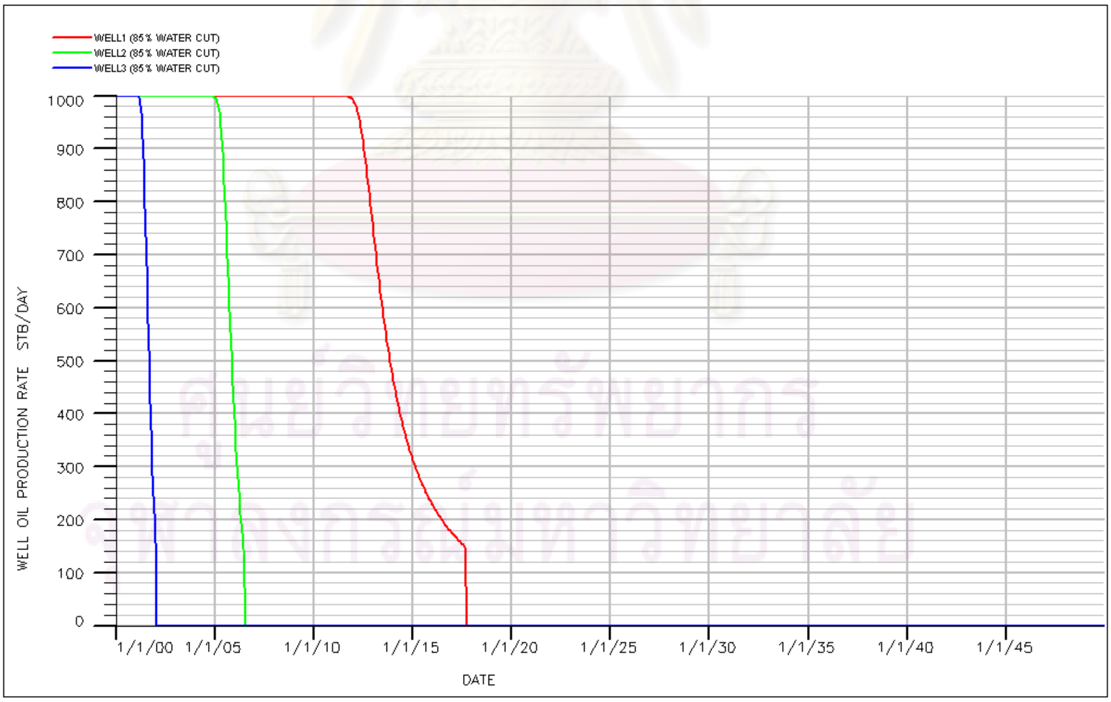


Figure 5.10: Oil production profile for waterflooding being stopped at 85% water cut for 20-degree dipping reservoir.

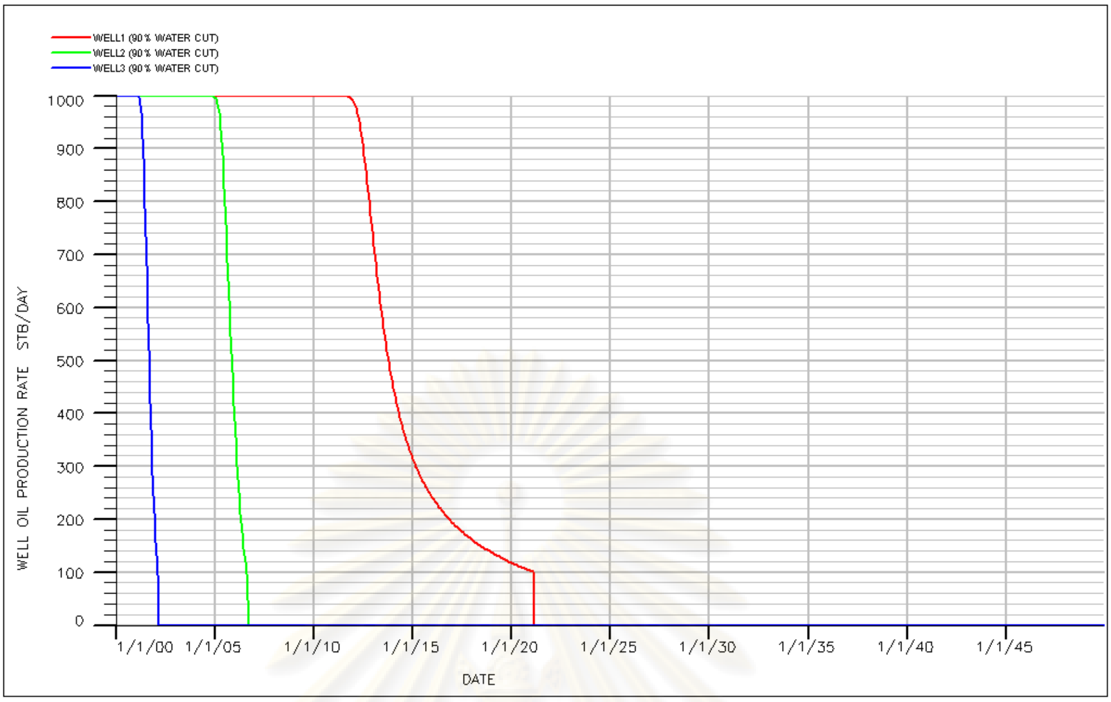


Figure 5.11: Oil production profile for waterflooding being stopped at 90% water cut for 20-degree dipping reservoir.

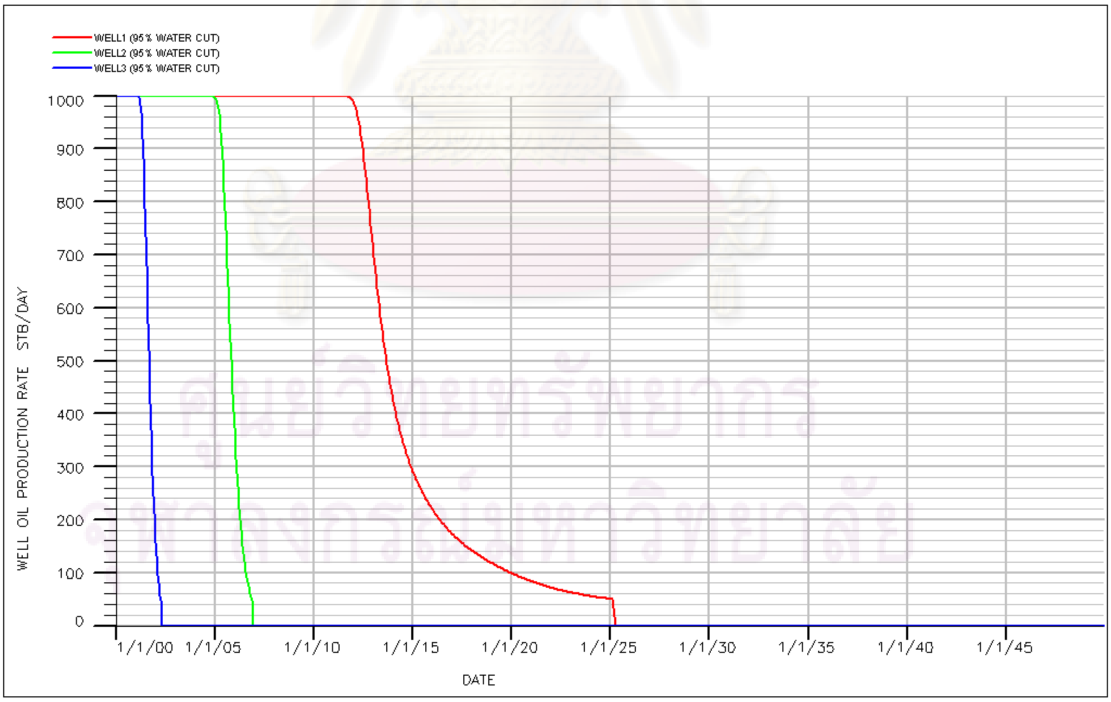


Figure 5.12: Oil production profile for waterflooding being stopped at 95% water cut for 20-degree dipping reservoir.

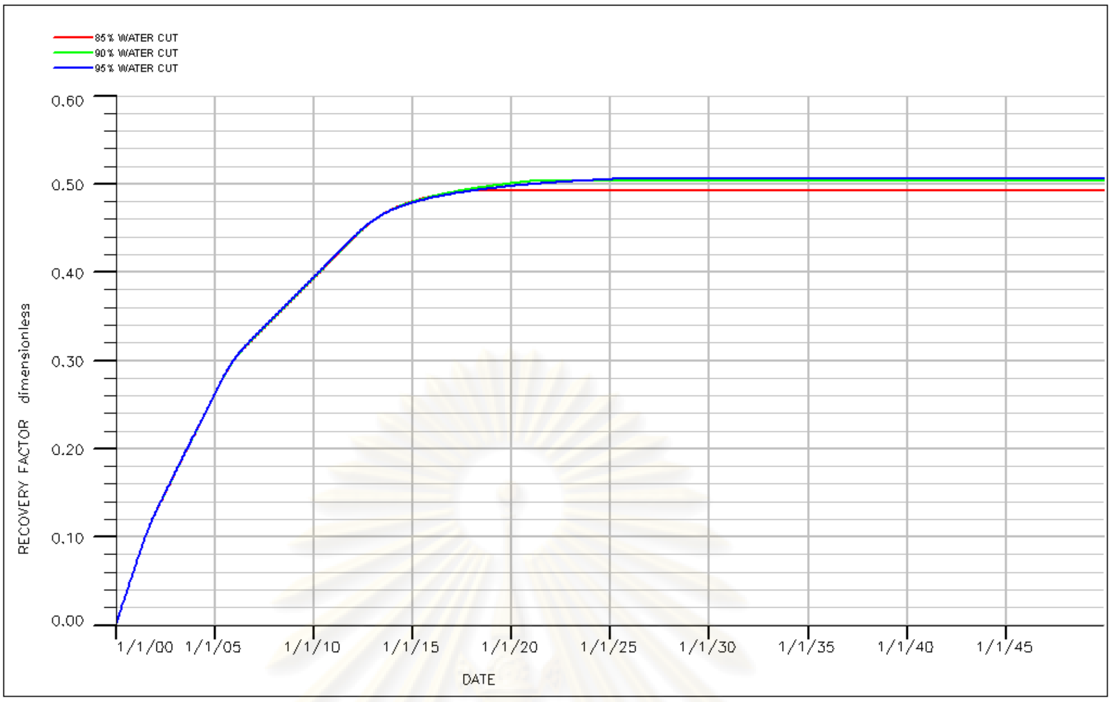


Figure 5.13: Comparison of oil recovery for waterflooding being stopped at different water cuts for 20-degree dipping reservoir.

Table 5.1: Summary of recovery factor for each case under waterflooding process.

Dip angle (degree)	85% water cut		90% water cut		95% water cut	
	RF (%)	Production life (years)	RF (%)	Production life (years)	RF (%)	Production life (years)
5	52.41	23.397	52.50	25.448	52.67	31.853
10	52.90	23.642	53.72	27.587	56.86	46.475
20	49.27	17.645	50.33	21.084	50.54	25.089

Table 5.1 tabulates oil recovery factors for waterflooding being stopped at different water cuts for reservoirs with different dip angles. The oil recovery slightly increases as the waterflood is stopped at a higher water cut as shown in Table 5.1. However, the production time increases a lot if we wait until the water cut reaches 95%. Based on this result, we choose 85% water cut to be the stopping criteria for waterflooding in each case.

5.2 Effect of injection sequence on DDP

After waterflooding is stopped, gas is sequentially injected at the old producers to sweep globules of oil left by waterflood. In conventional DDP, gas injection starts from the updip well. The constraint for gas injection is fracturing pressure of the formation which is 5000 psia.

5.2.1 Conventional DDP

The injection and production sequence of conventional DDP is shown in Table 5.2. The process starts with conventional water flooding until water cut at all producers reach 85%. Then, all wells are shut in for a while to build up reservoir pressure before gas flooding. Then, gas is injected in 3 stages. In the first stage, gas is injected at well 1 (the most updip well) while well 2 is open to produce oil. When gas breaks through the producer (well 2), the well is shut in. In the second stage, the next producer (well 3) is opened. The well is open until gas breaks through the well. In the final stage, the last producer (well 4) is open to produce oil. Note that gas is injected at the same location throughout the process.

Table 5.2: Summary of well schedules for conventional DDP.

Stage	Well 1	Well 2	Well 3	Well 4
Waterflood	Producer	Producer	Producer	Water injector
1st stage of gas injection	Gas injector	Producer	Shut-in	Shut-in
2nd stage of gas injection	Gas injector	Shut-in	Producer	Shut-in
3rd stage of gas injection	Gas injector	Shut-in	Shut-in	Producer

Figure 5.14 shows oil production profile for conventional DDP. In the first stage of gas injection, there are only two wells in operation: well 1 is an injector and well 2 is a producer. As injected gas flows in the reservoir, it helps reconnect globules of oil. The reconnected oil flows downdip due to gravity. Part of it is produced through well 2 as seen by the increase in oil rate at well 2. However, a majority of the oil accumulates further down in the reservoir. In the second stage of injection, more oil is produced from well 3 because the well is located further downdip than well 2.

At this location, there is more oil that has been reconnected. As the injected gas reaches well 3, the well is shut in and well 4 is open for production. From Figure 5.14, we can see that well 4 can produce a lot more oil than well 2 and 3 due to accumulation of oil in the lower part of the reservoir.

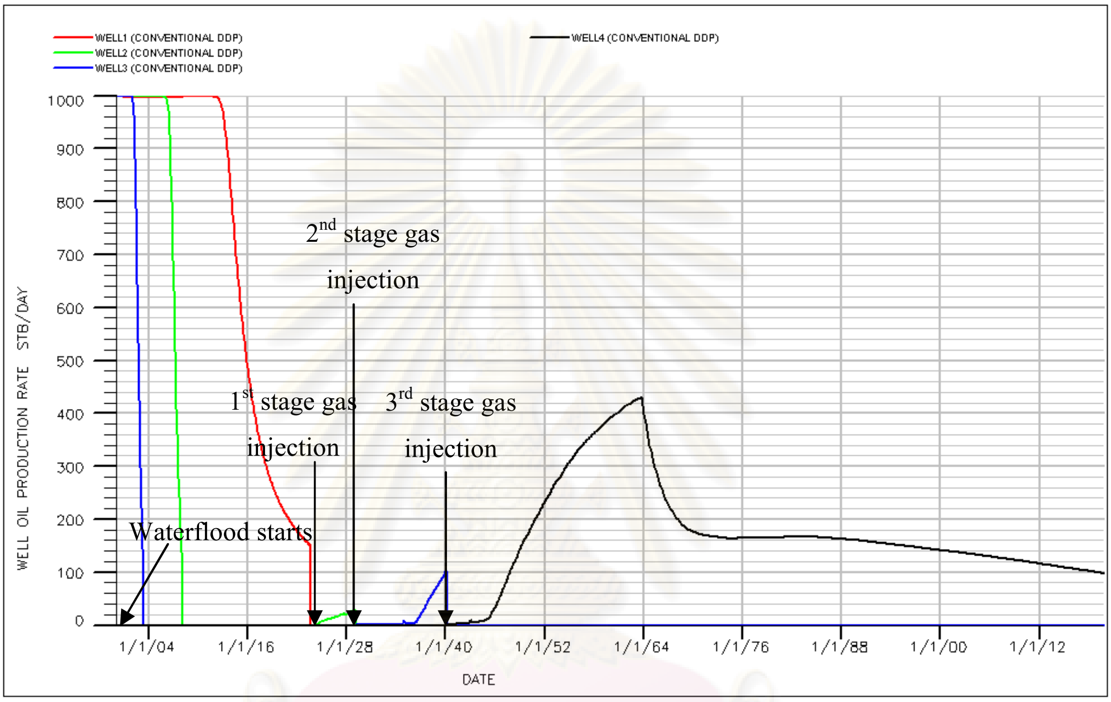


Figure 5.14: Oil production profile in DDP for 10-degree dipping reservoir.

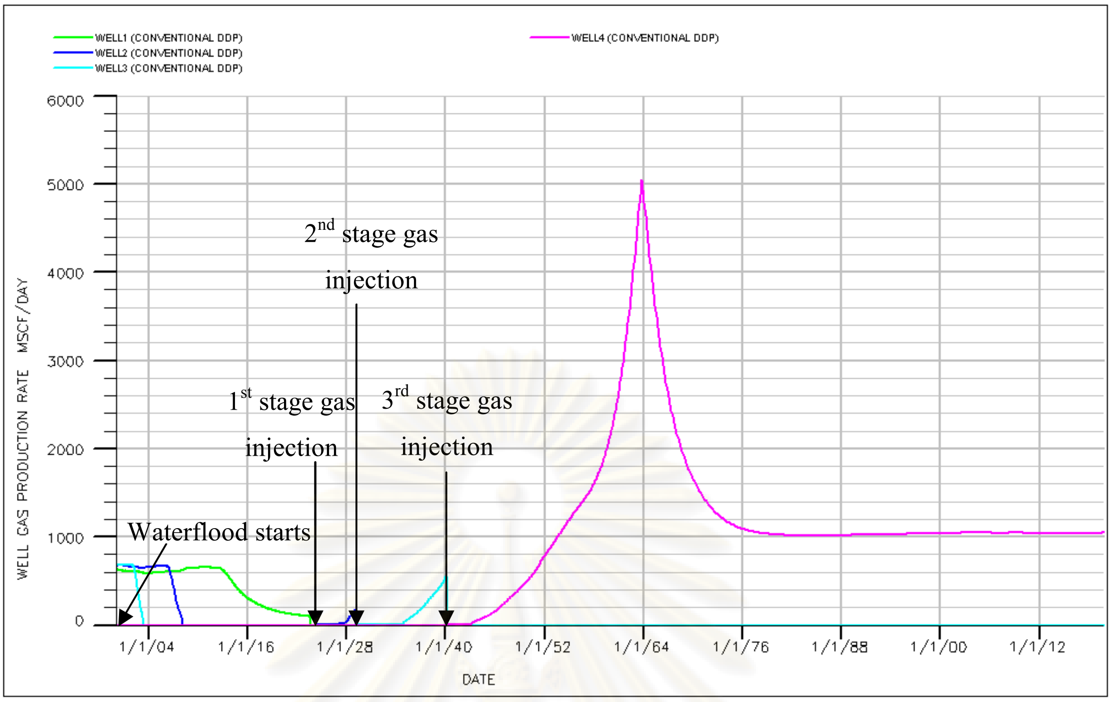


Figure 5.15: Gas production profile for DDP in 10-degree dipping reservoir.

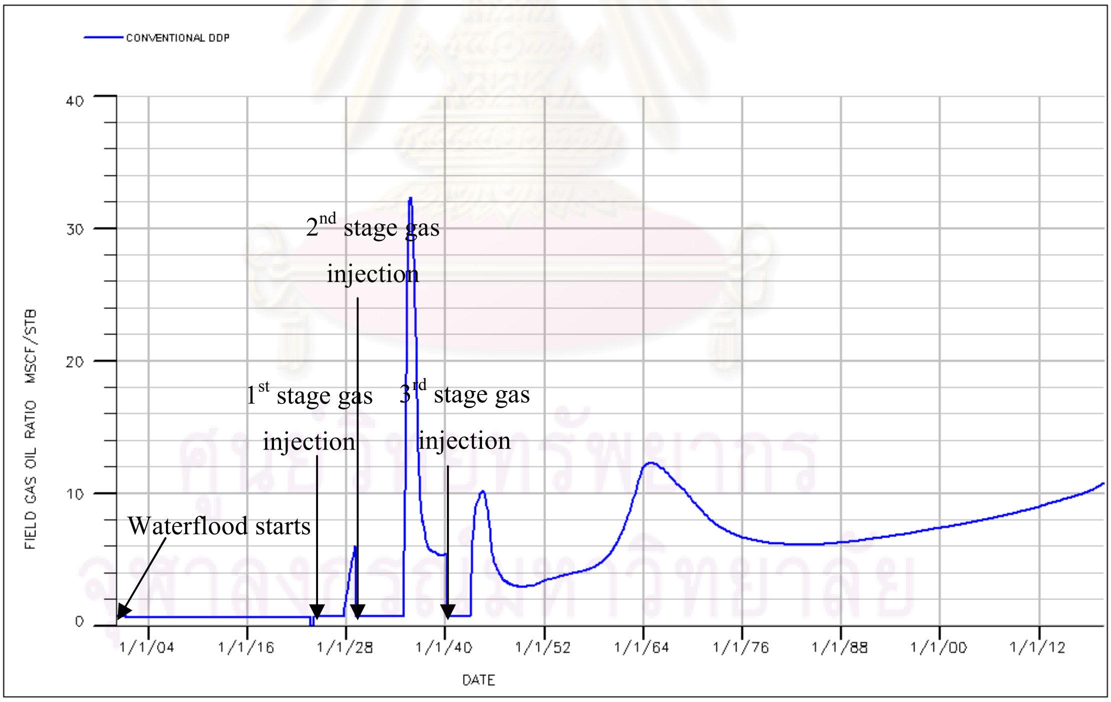


Figure 5.16: Field gas oil ratio for DDP in 10-degree dipping reservoir.

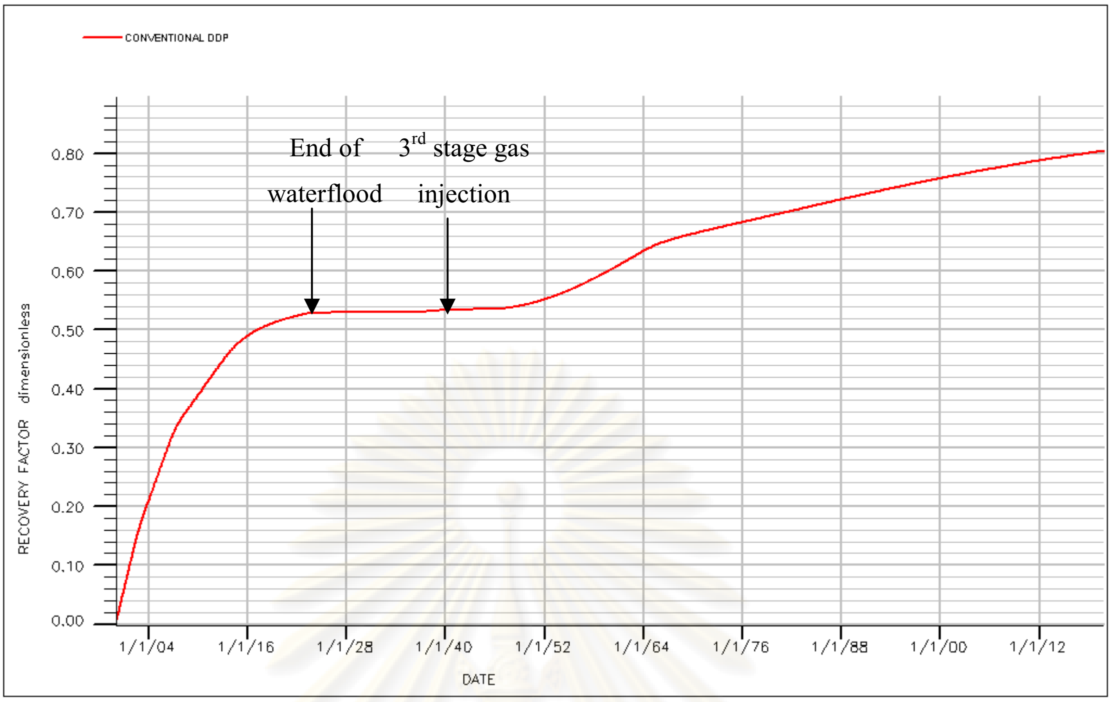


Figure 5.17: Field oil recovery for DDP in 10-degree dipping reservoir.

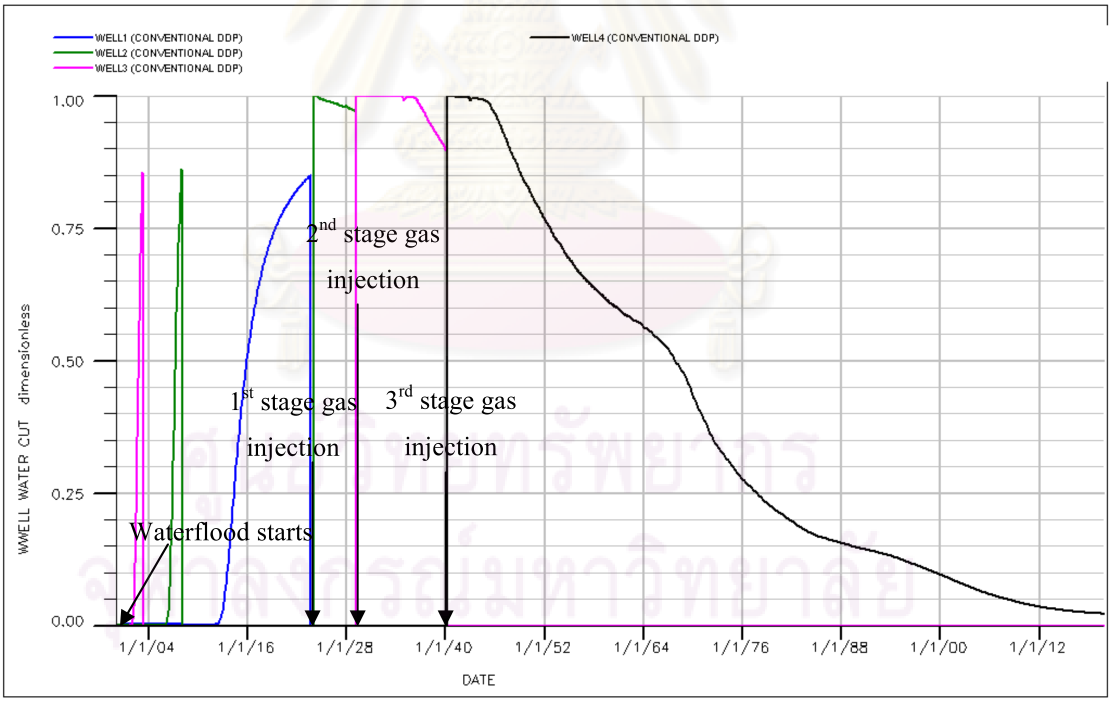


Figure 5.18: Water cut profile for DDP in 10-degree dipping reservoir.

Figures 5.15 to 5.18 show gas production, gas oil ratio, oil recovery, and water cut of base case reservoir model (10 degree dip angle reservoir) with conventional DDP. Figure 5.15 shows that field gas production increases in proportion with oil production. At the final stage of gas injection, a lot of gas is produced due to a large amount of oil production at well 4 and the fact that portion of the injected gas has reached the well. Figure 5.16 illustrates gas oil ratio during production. During the 1st stage of gas injection, gas oil ratio remains constant for a while and then jumps to a high value. This is because the pressure at the producer falls below the bubble point. This kind of trend occurs in all stages of injection. As seen in Figure 5.17, there is a big jump in oil recovery during the last stage of injection because globules of oil that have been reconnected accumulates downdip and is produced by well4. Figure 5.18 shows water cut profile of the base case. At the early time of each stage of gas injection, water cut is equal to one because the reconnected oil formed by gas injection does not reach the producer yet. At this point, there is only water around the producer. After the oil is reconnected and moves downward, oil starts to produce. Then, the water cut decreases. During the last stage of injection, the water cut gradually declines to a small value. This is because the reconnected oil moves and accumulates downdip. As a result, there is a small amount of water surrounding well 4.

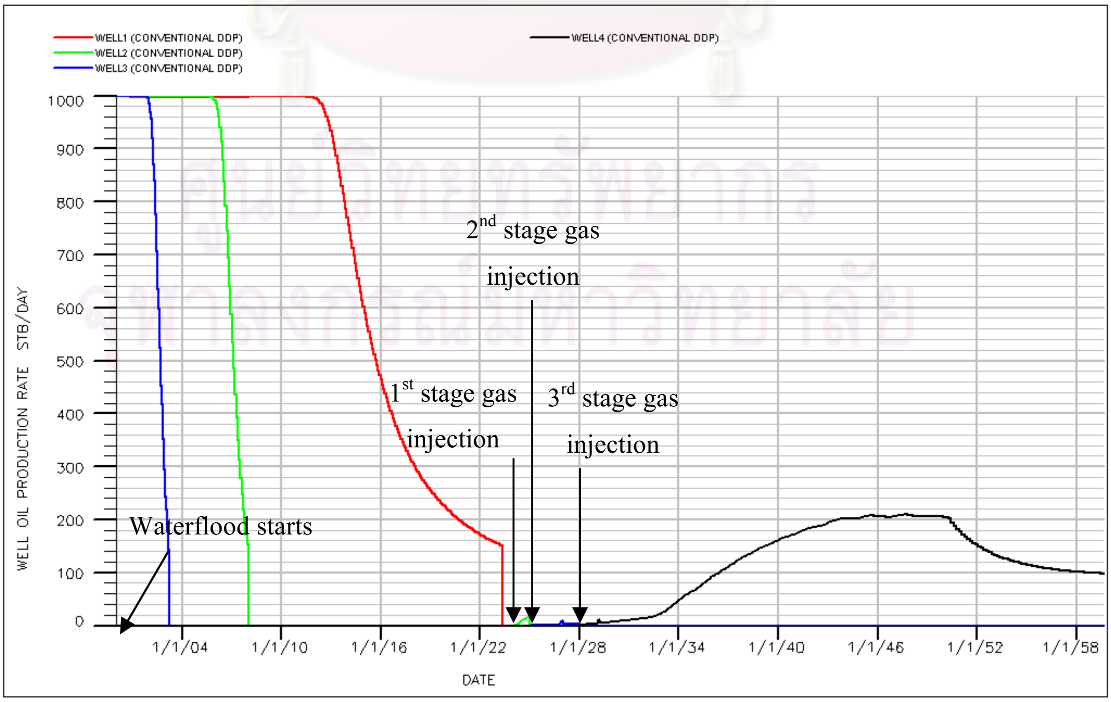


Figure 5.19: Oil production profile for DDP in 5-degree dipping reservoir.

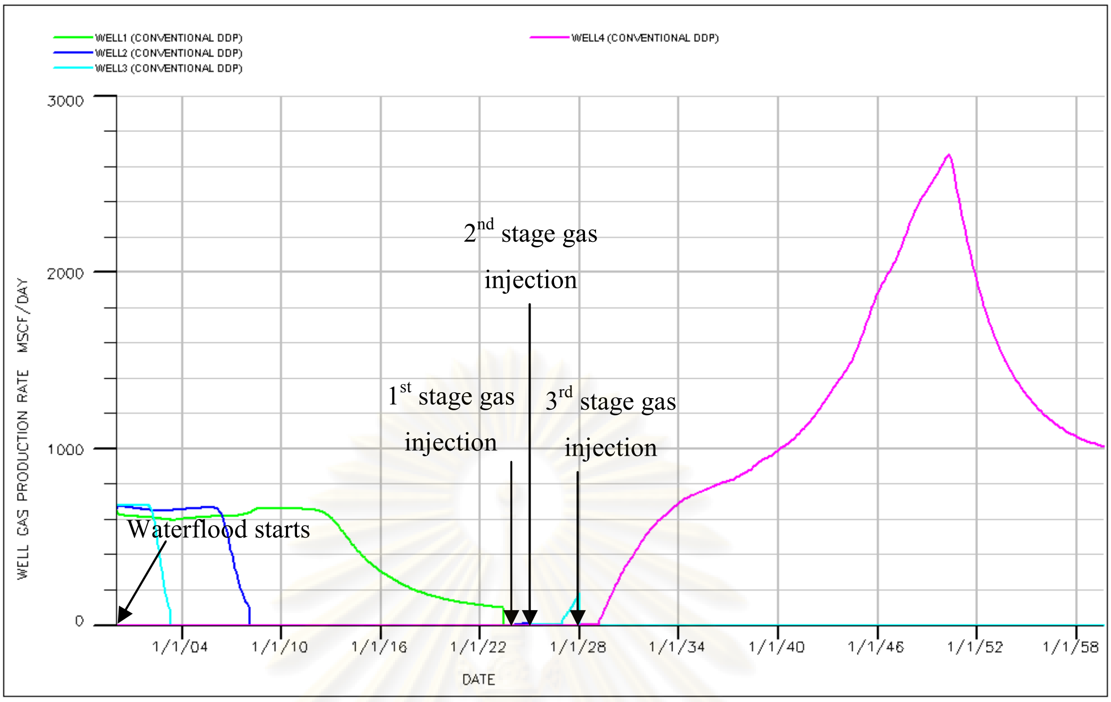


Figure 5.20: Gas production profile for DDP in 5-degree dipping reservoir.

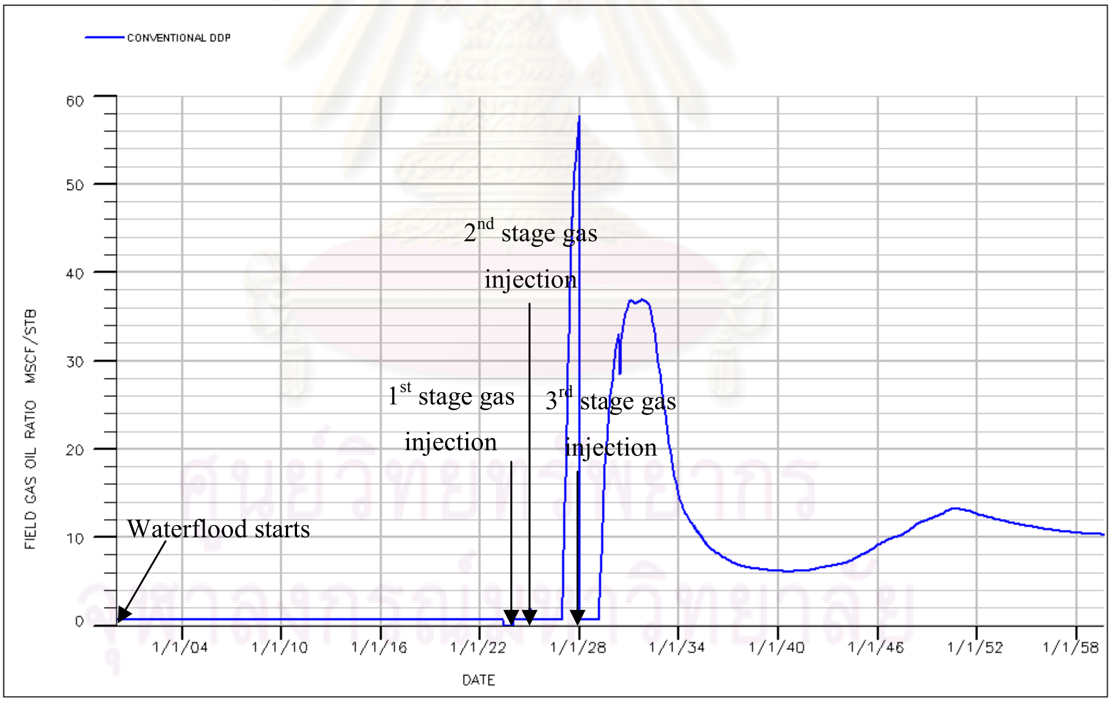


Figure 5.21: Field gas oil ratio for DDP in5-degree dipping reservoir.

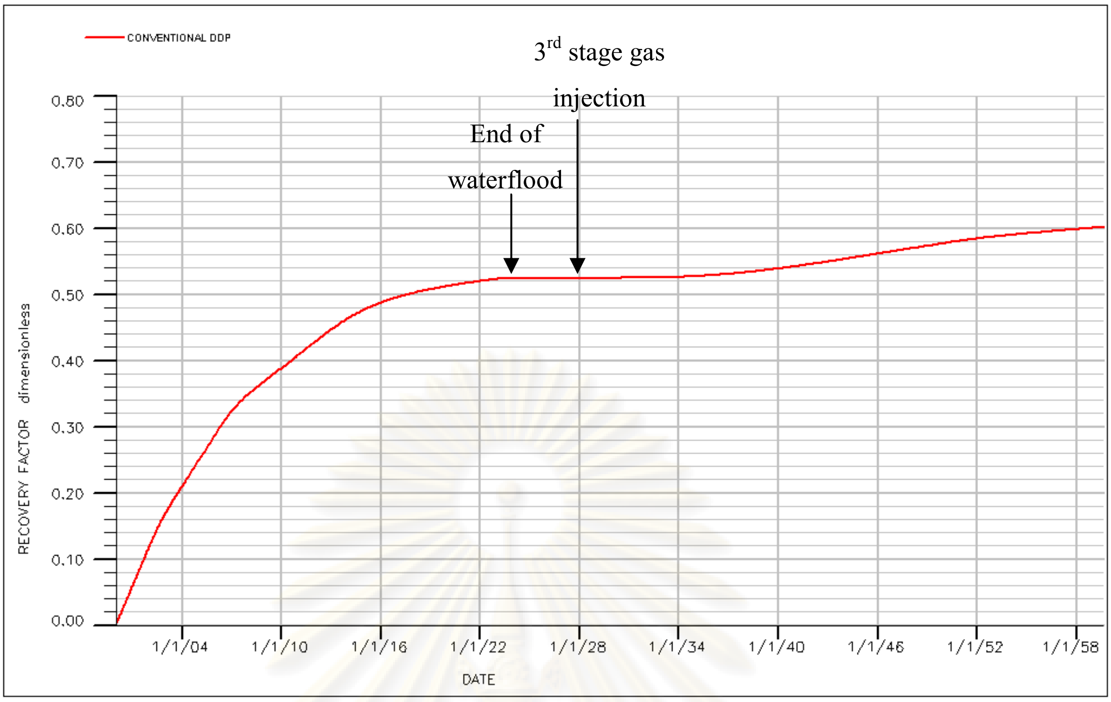


Figure 5.22: Field oil recovery for DDP in 5-degree dipping reservoir.

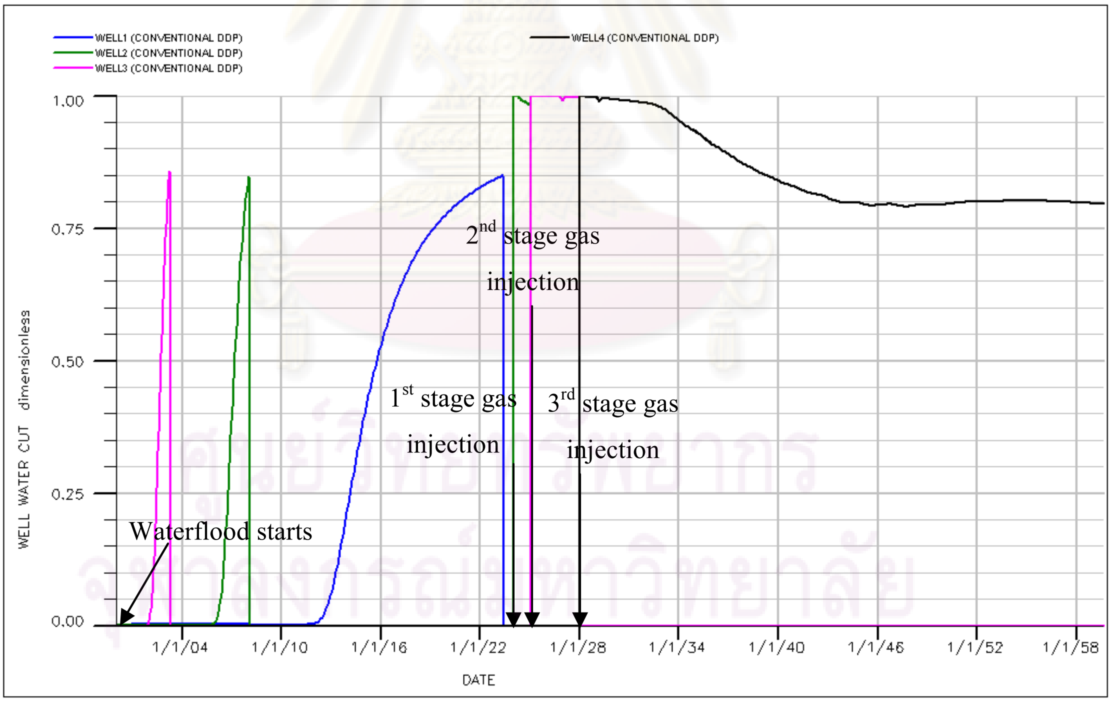


Figure 5.23: Water cut profile for DDP in 5-degree dipping reservoir.

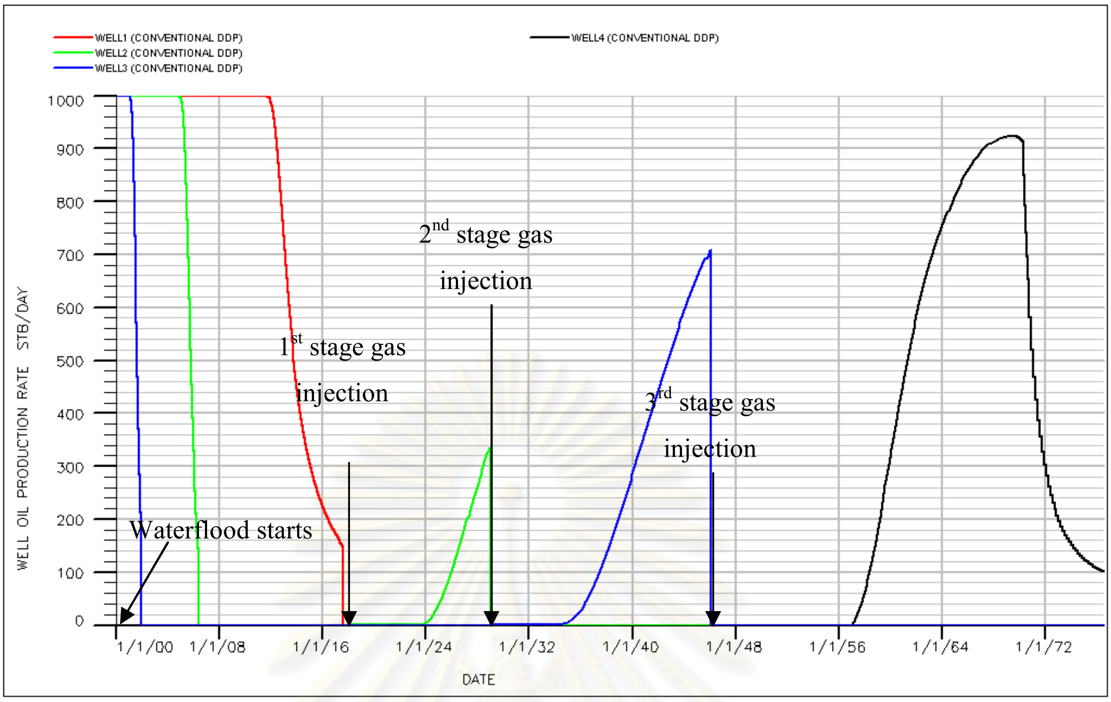


Figure 5.24: Oil production profile for DDP in 20-degree dipping reservoir.

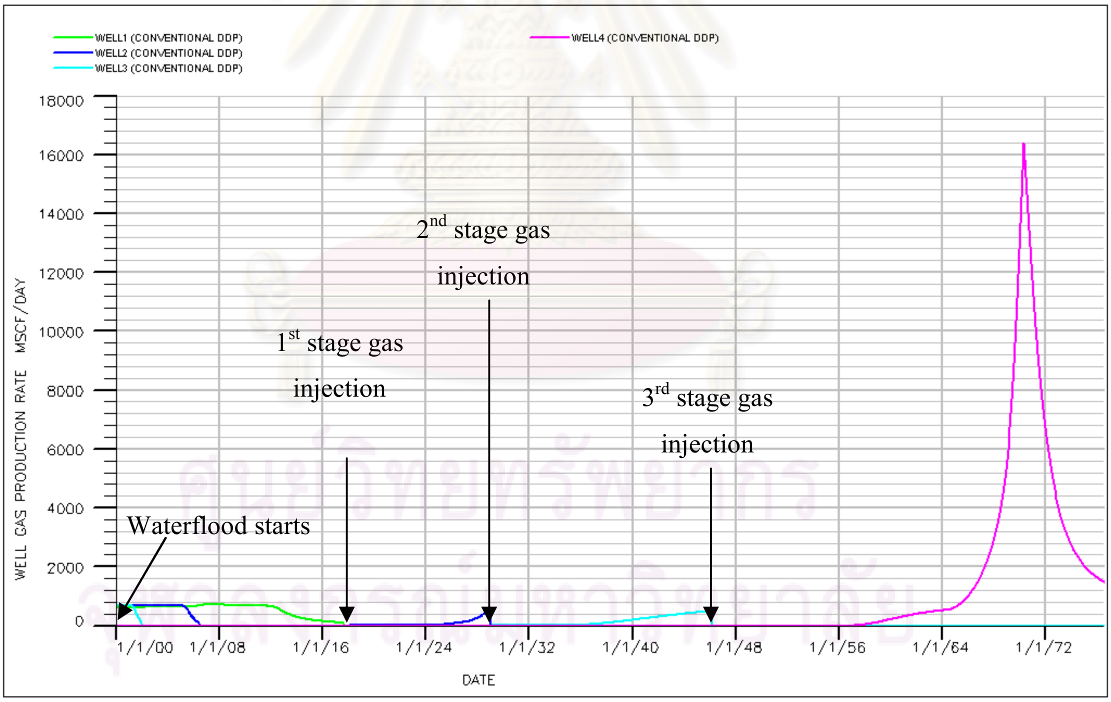


Figure 5.25: Gas production profile for DDP in 20-degree dipping reservoir.

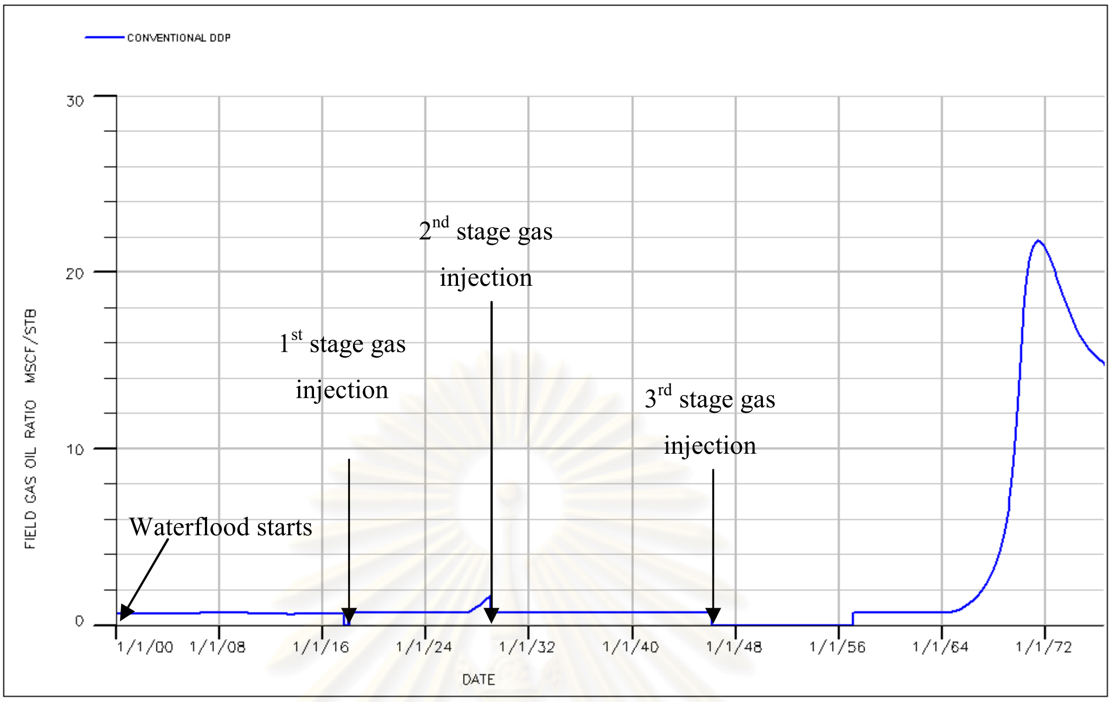


Figure 5.26: Field gas oil ratio for DDP in 20-degree dipping reservoir.

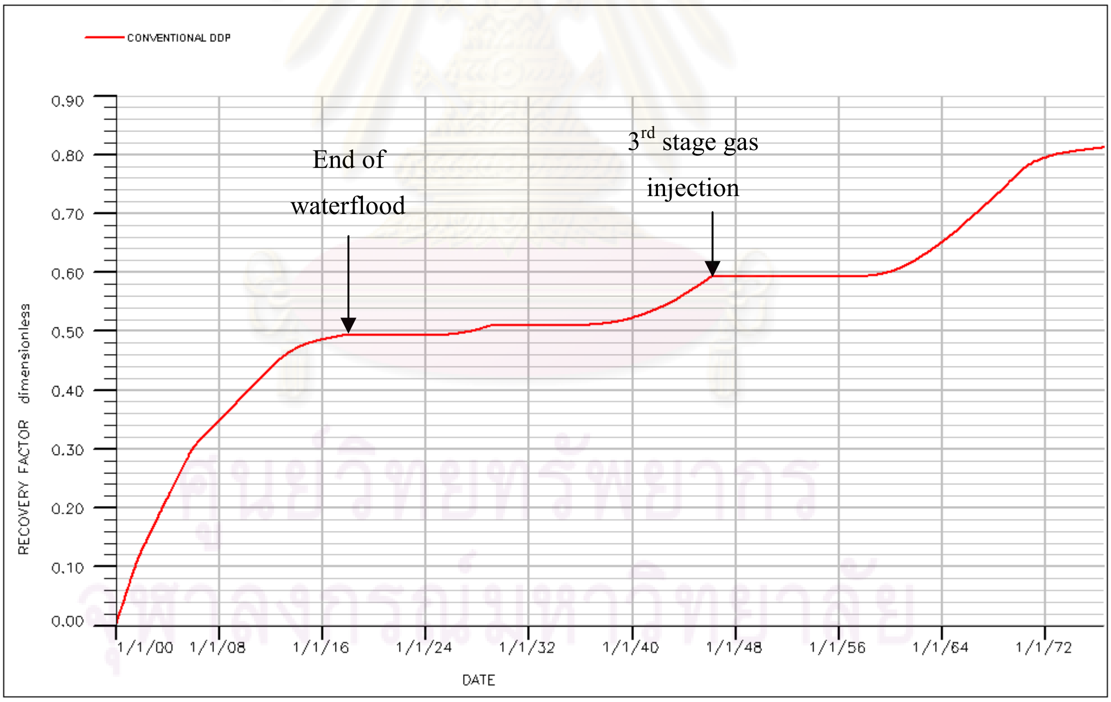


Figure 5.27: Field oil recovery for DDP in 20-degree dipping reservoir.

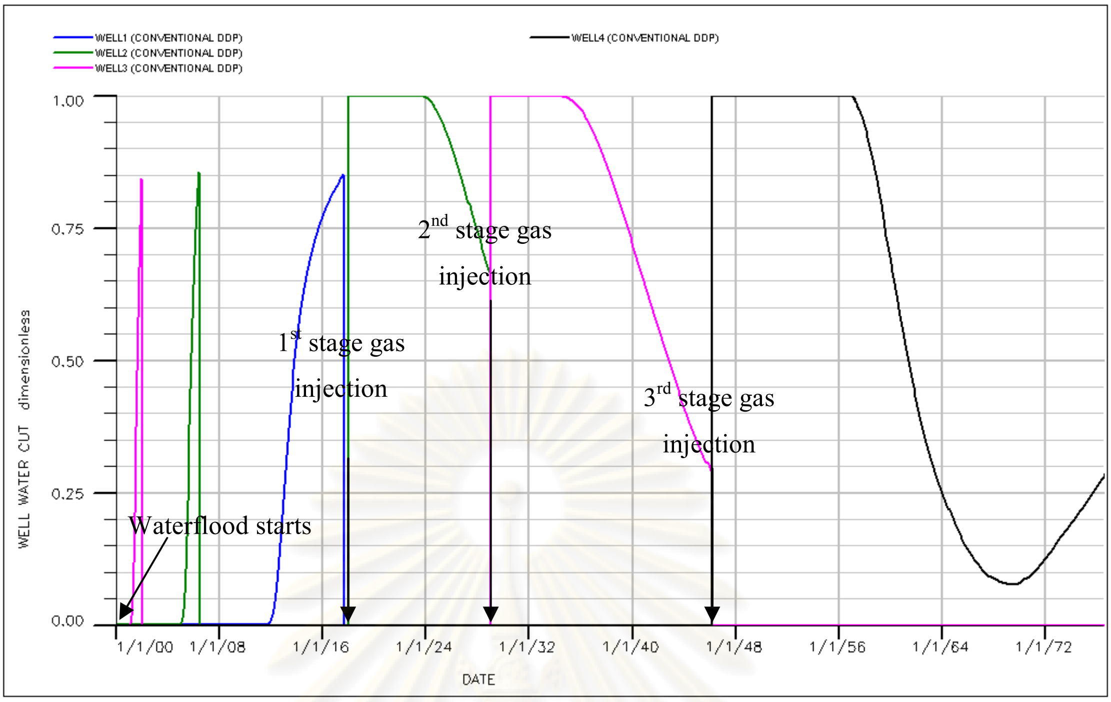


Figure 5.28: Water cut profile for DDP in 20-degree dipping reservoir.

Figure 5.17, 5.22 and 5.27 illustrate the oil recovery factor for reservoir with dip angle of 10, 5 and 20, respectively. Comparison among these figures cleary show that dip angle helps increase oil production in the DDP. The reason that a reservoir with higher dip angle is suitable for DDP is because the reconnected oil can flow downward to the lower part of the reservoir more easily than that in a reservoir with lower dip angle.

Table 5.3 : Comparison between waterflooding and DDP for different dip angles.

Dip angle (degree)	Waterflooding		DDP		Increment	
	RF (%)	Production life (years)	RF (%)	Production life (years)	RF (%)	Production life (years)
5	52.410	23.397	59.943	57.647	5.237	34.250
10	52.900	23.642	80.212	117.764	27.312	94.122
20	49.270	17.645	81.186	75.469	31.916	57.824

5.2.2 DDP with gas injection at well 2

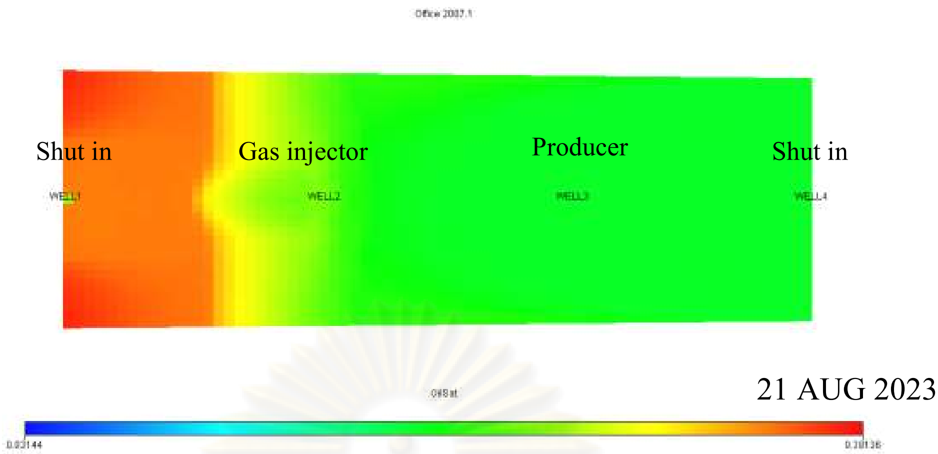
In conventional DDP, we inject gas at well 1 to sweep residual oil from updip to downdip of the reservoir. In this case, we change location of the injector from well 1 to be well 2 to observe effect of the change in location on DDP.

Table 5.4: Summary of well schedules for DDP with gas injection at well 2.

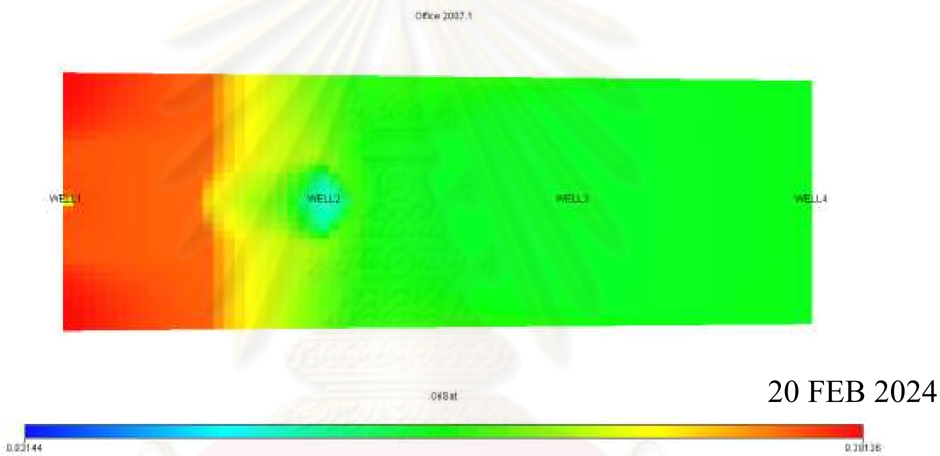
Stage	Well 1	Well 2	Well 3	Well 4
Waterflood	Producer	Producer	Producer	Water injector
1st stage of gas injection	Shut-in	Gas injector	Producer	Shut-in
2nd stage of gas injection	Shut-in	Gas injector	Shut-in	Producer

In this case, we start with waterflooding until the water cut reaches 85% in the same manner as in the previous case. However, gas injection is performed at well 2 and the first producer is well 3. When injected gas breaks through, the first producer (well 3) is shut and the last producer (well 4) at downdip location is open instead.

a)



b)



c)

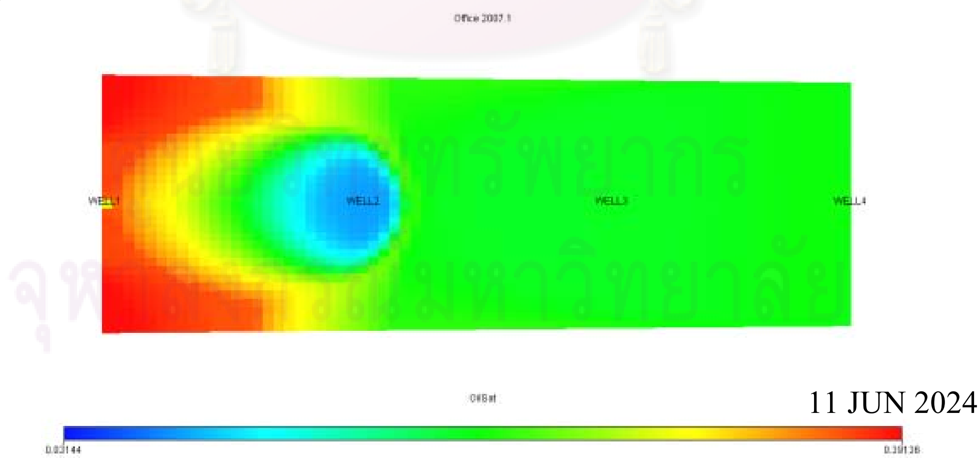


Figure 5.29: Oil saturation distribution for DDP with gas injection at well 2 in top view.

d)

e)

f)

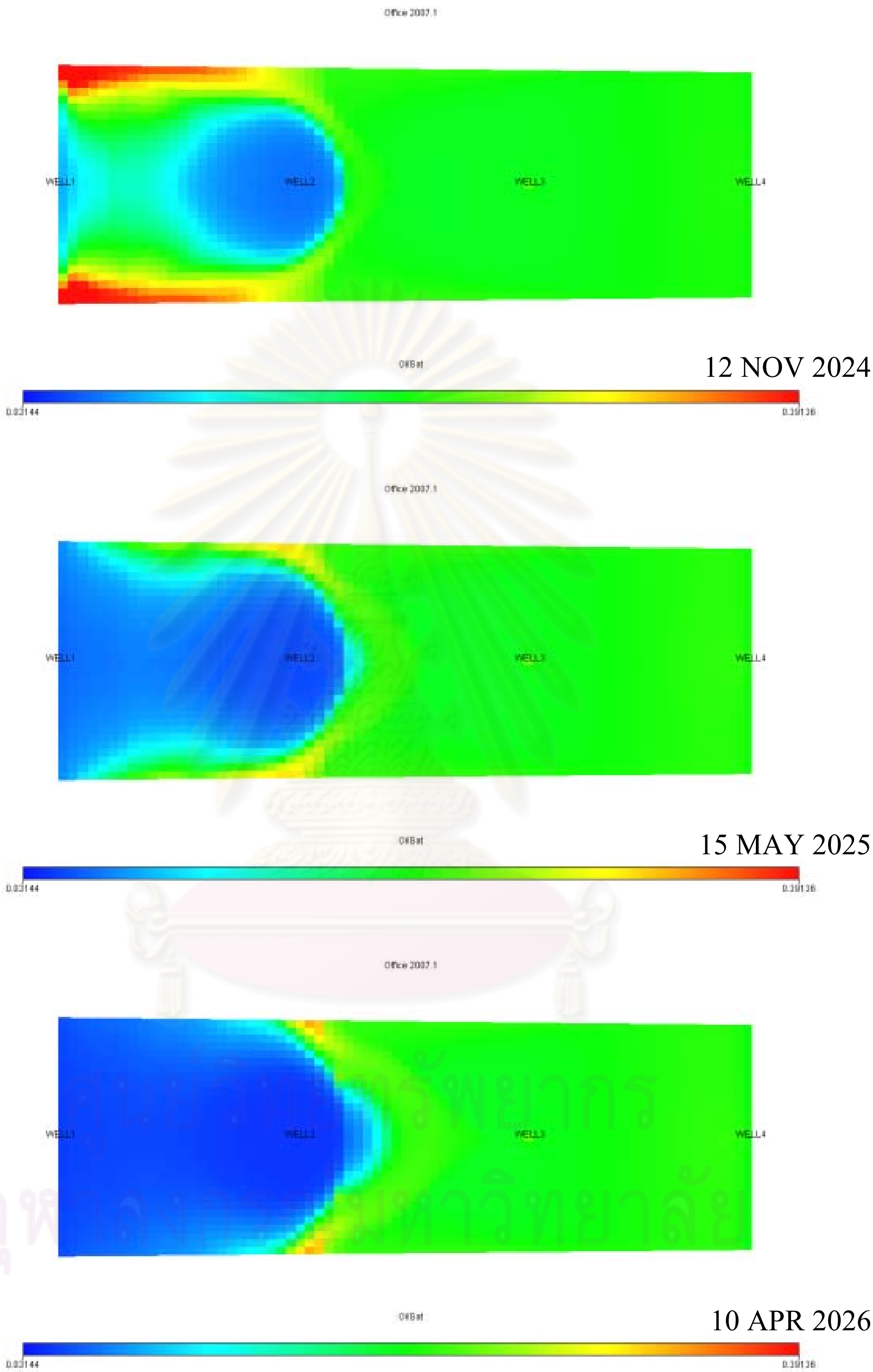
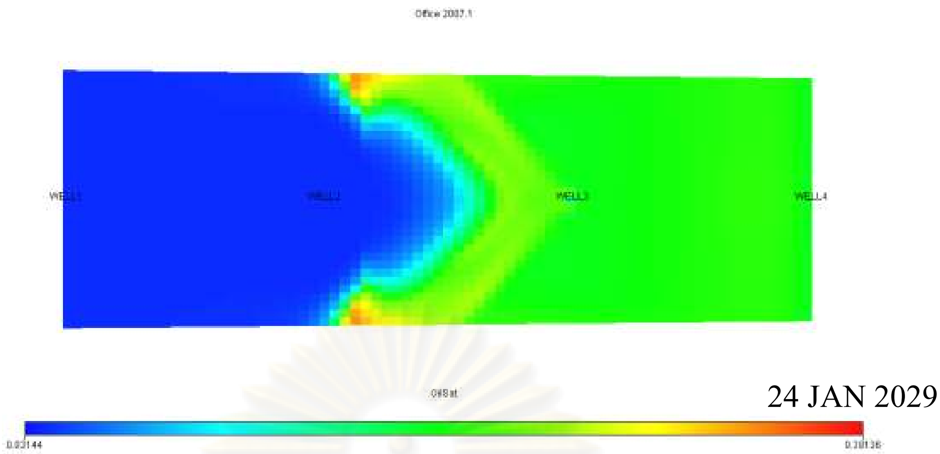


Figure 5.29: Oil saturation distribution for DDP with gas injection at well 2 in top view (continued).

g)



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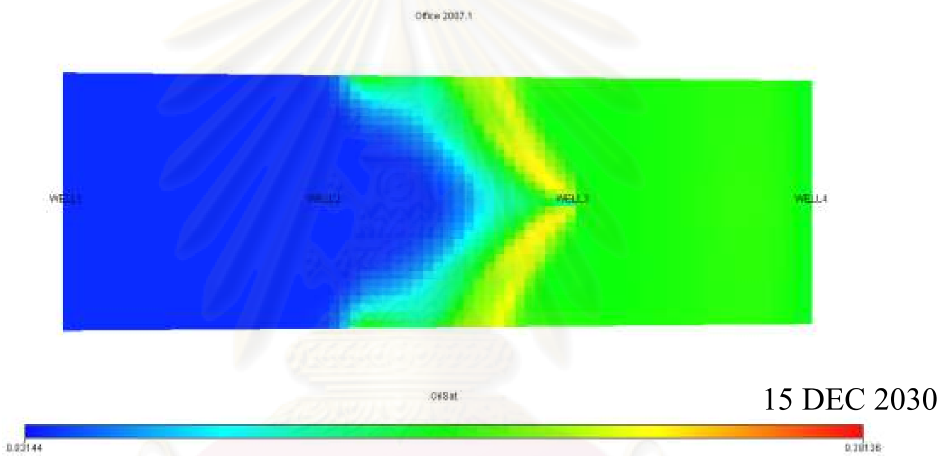

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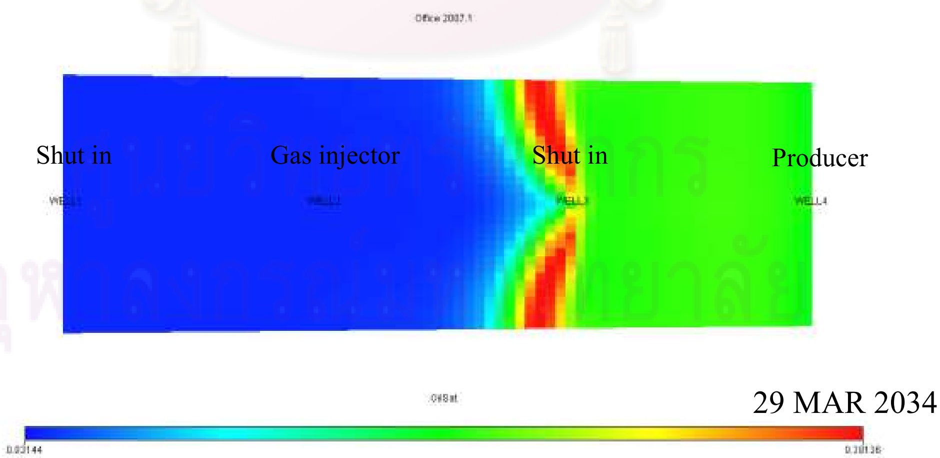
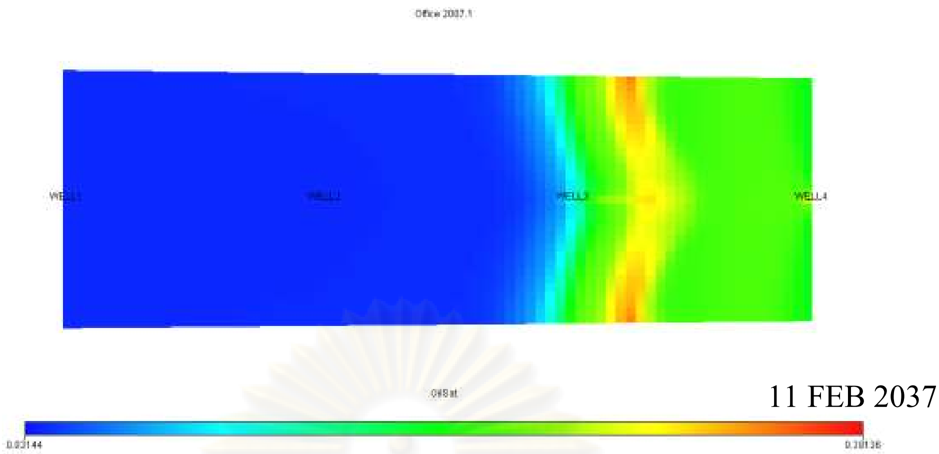
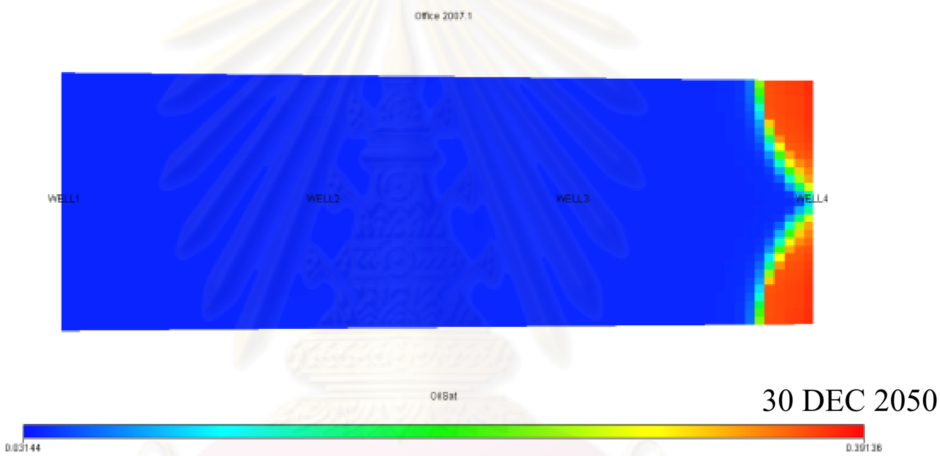


Figure 5.29: Oil saturation distribution for DDP with gas injection at well 2 in top view (continued).

j)



k)



l)

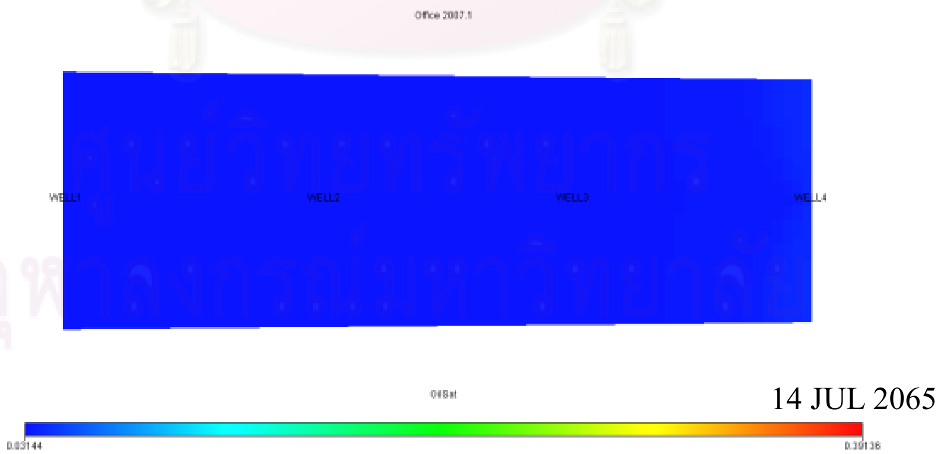


Figure 5.29: Oil saturation distribution for DDP with gas injection at well 2 in top view (continued).

a) 21 AUG 2023

b) 20 FEB 2024

c) 11 JUN 2024

d) 12 NOV 2024

e) 15 MAY 2025

f) 10 APR 2026

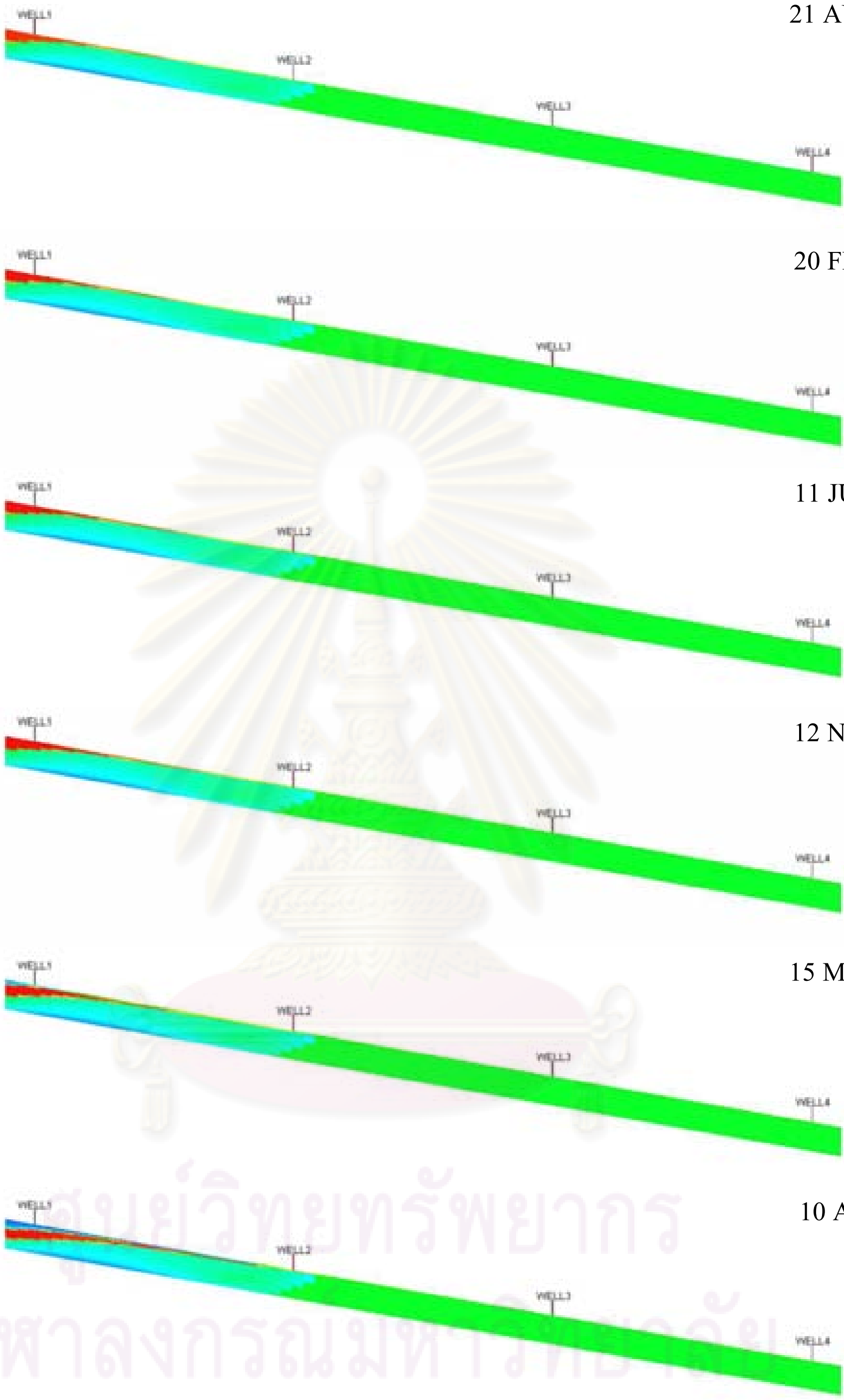


Figure 5.30: Oil saturation distribution for DDP with gas injection at well 2 in side view.

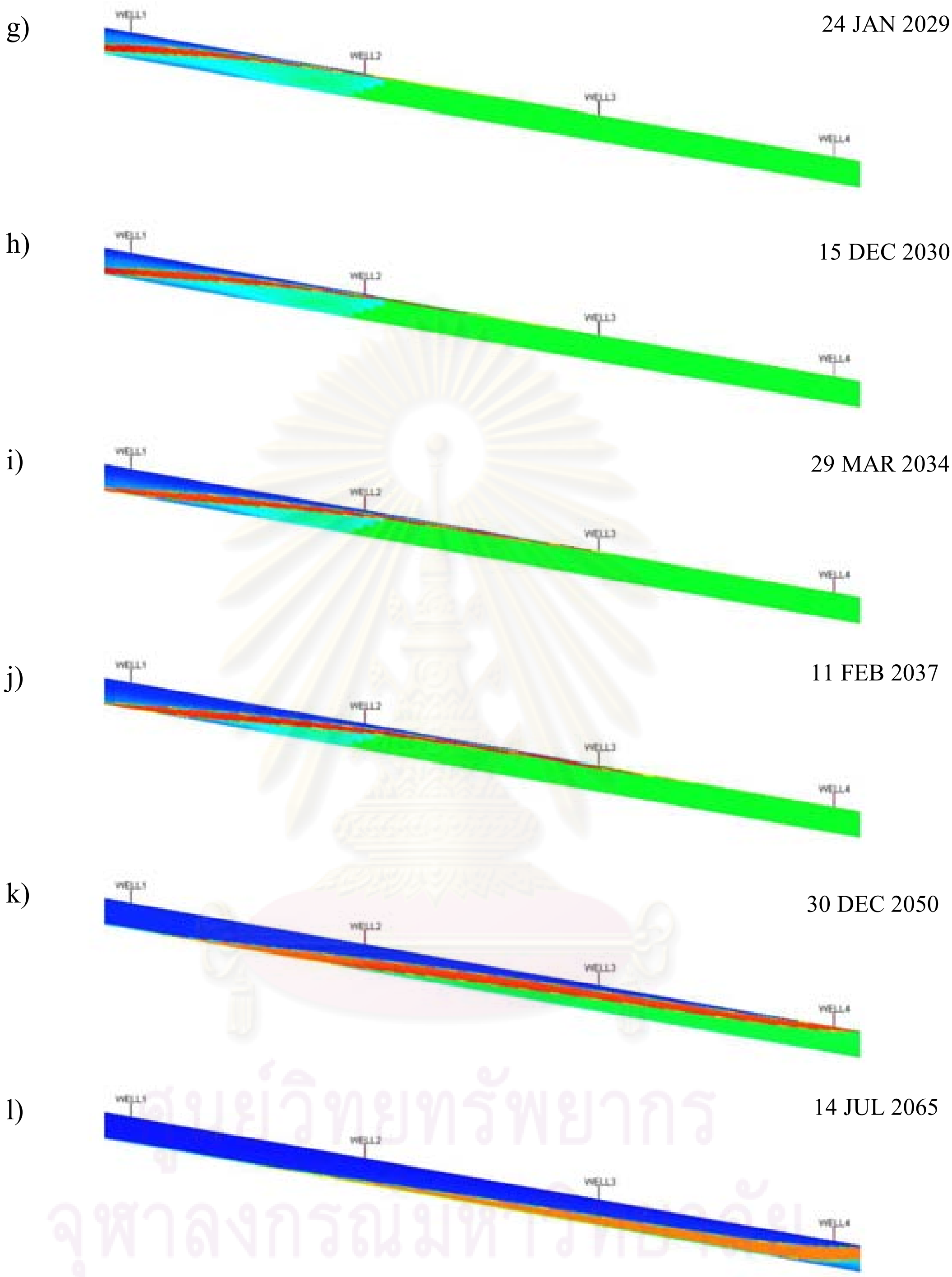


Figure 5.30: Oil saturation distribution for DDP with gas injection at well 2 in side view (continued).

Figures 5.29 to 5.30 show how gas displaces trapped oil in double displacement process. The time step in Figures 5.29 and 5.30 is the same for each step from *a* to *l*. At initial stage (shown in Figure 5.30 a), we start gas injection at well 2 instead of well 1 under expectation to reduce production life time because the reconnected oil should reach well 4 faster than conventional DDP. From this injection point, oil globules between well 1 and well 2 is reconnected by injected gas that flows updip. Then, the oil flows downdip due to gravity force as shown in Figure 5.30 (d). After that, the process is the same as conventional DDP. When injected gas reaches well 3, the well 1 is shut in and the next producer (well4) is opened until the oil rate drops to the economic rate.

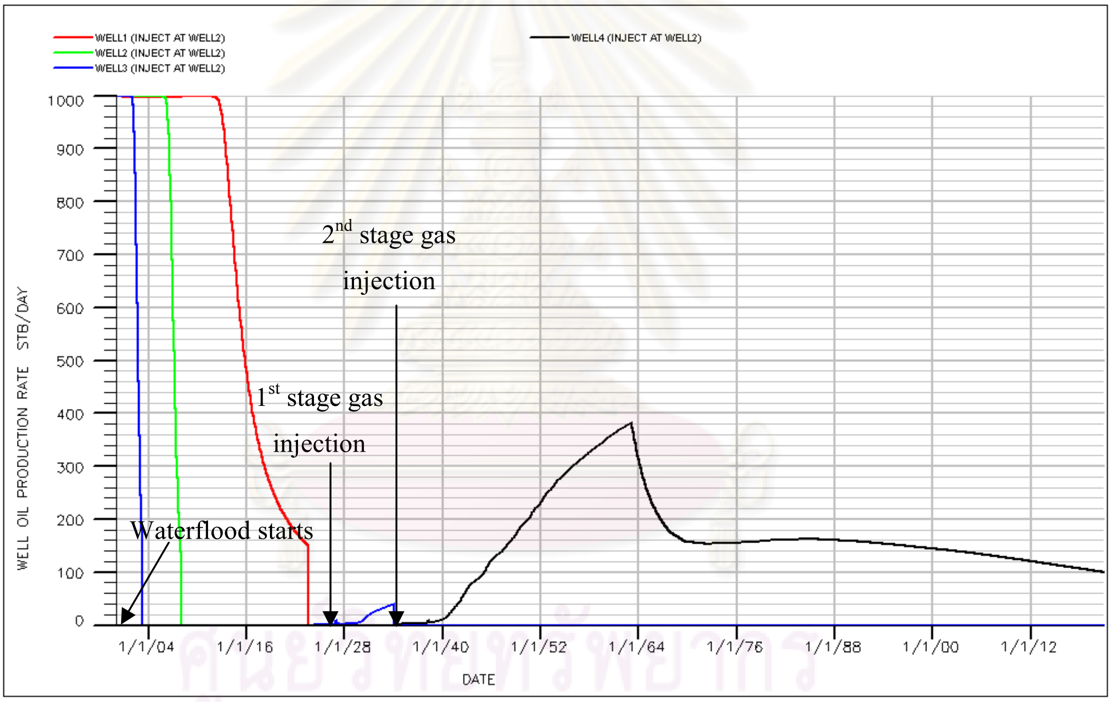


Figure 5.31: Oil production profile for DDP with gas injection at well 2 in 10-degree dipping reservoir.

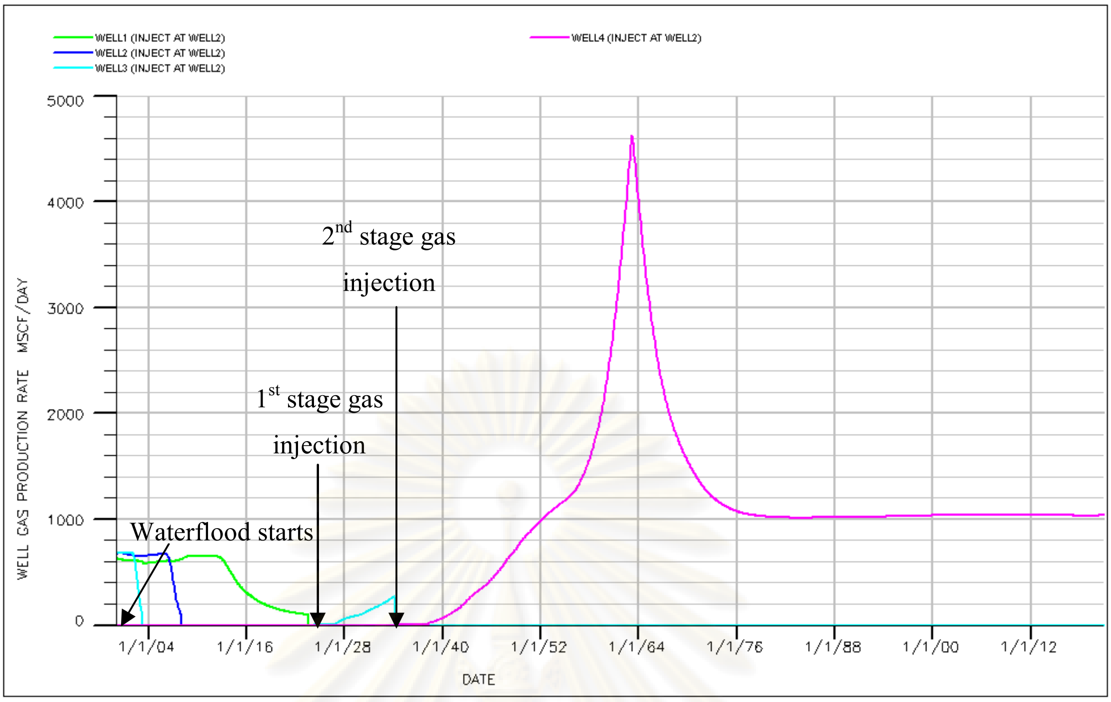


Figure 5.32: Gas production profile for DDP with gas injection at well 2 in 10-degree dipping reservoir.

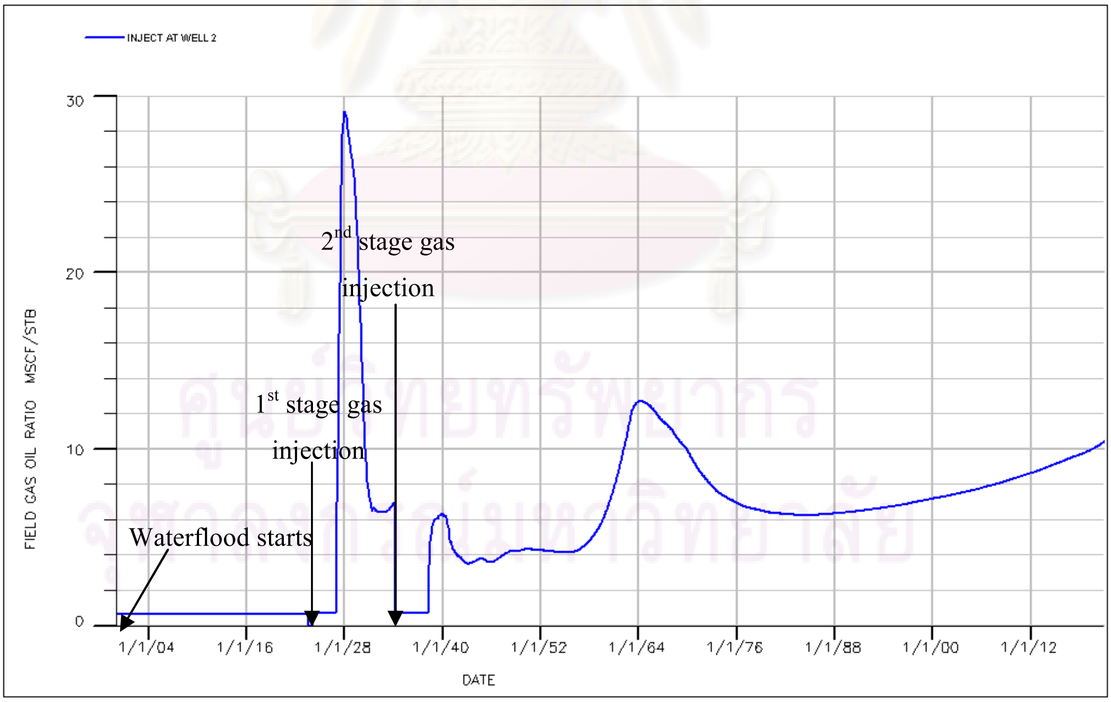


Figure 5.33: Field gas oil ratio for DDP with gas injection at well 2 in 10-degree dipping reservoir.

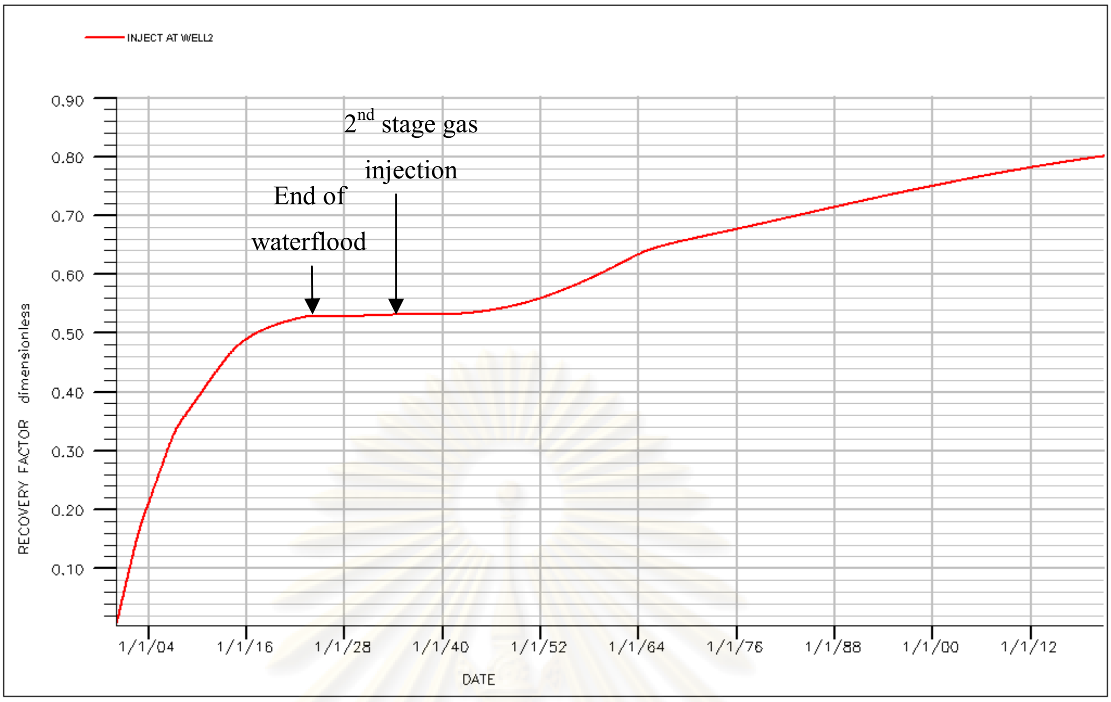


Figure 5.34: Field oil recovery for DDP with gas injection at well 2 in 10-degree dipping reservoir.

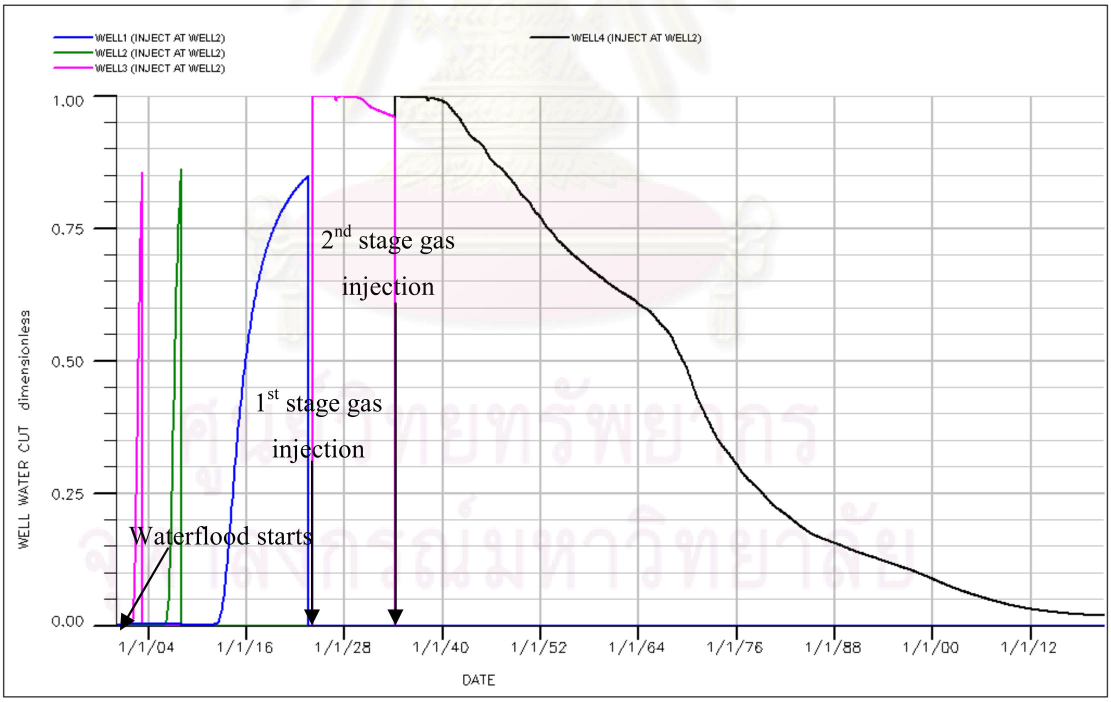


Figure 5.35: Water cut profile for DDP with gas injection at well 2 in 10-degree dipping reservoir.

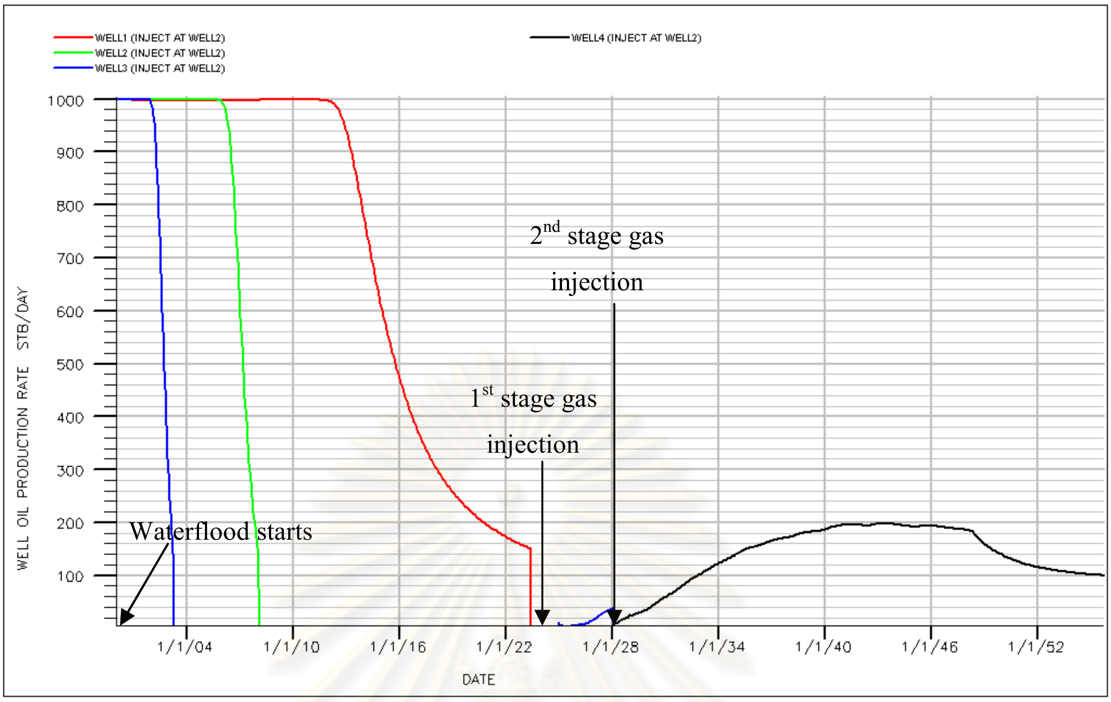


Figure 5.36: Oil production profile for DDP with gas injection at well 2 in 5-degree dipping reservoir.

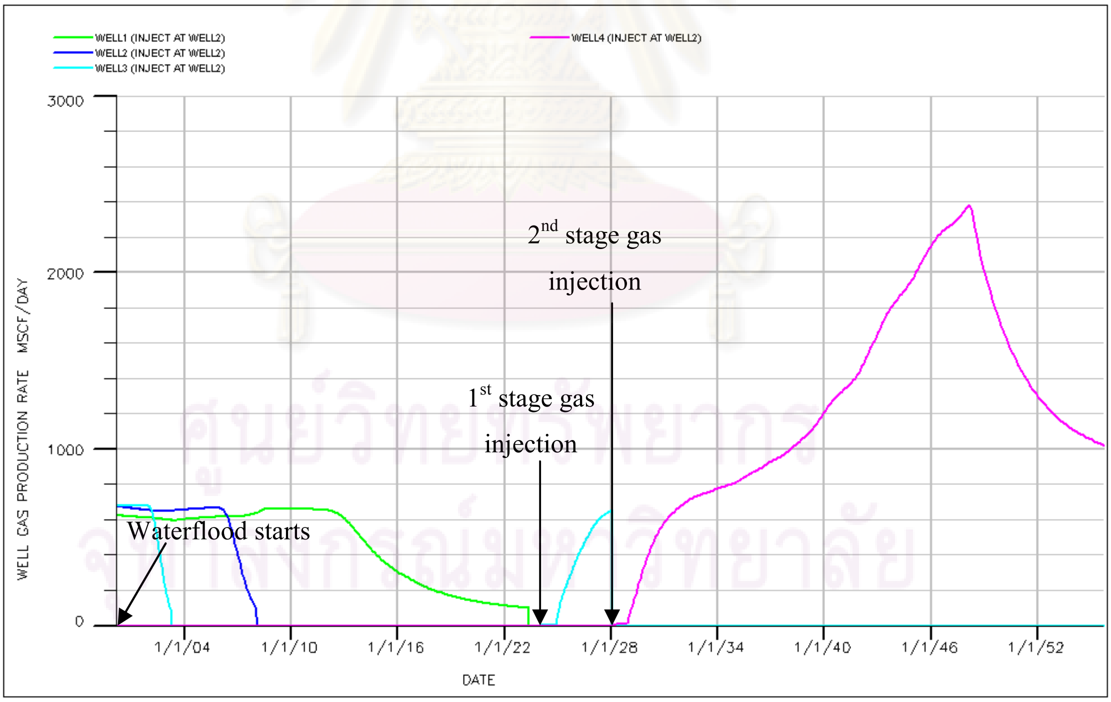


Figure 5.37: Gas production profile for DDP with gas injection at well 2 in 5-degree dipping reservoir.

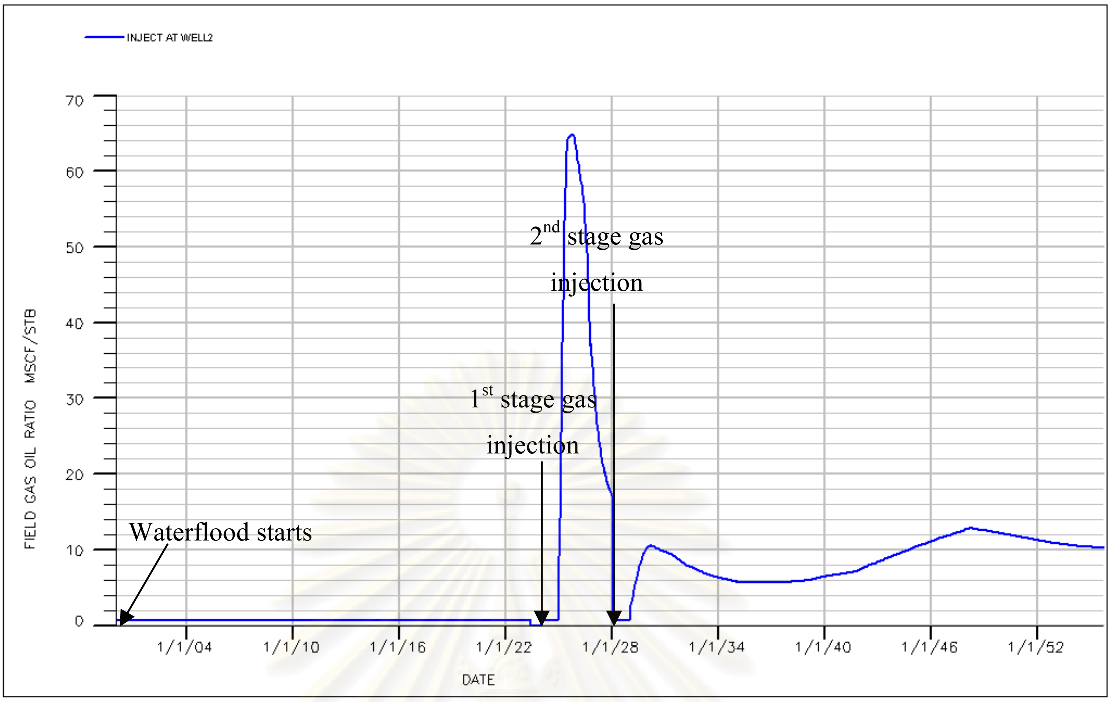


Figure 5.38: Field gas oil ratio for waterflooding followed by DDP injected at updip reservoir in 5-degree dipping reservoir.

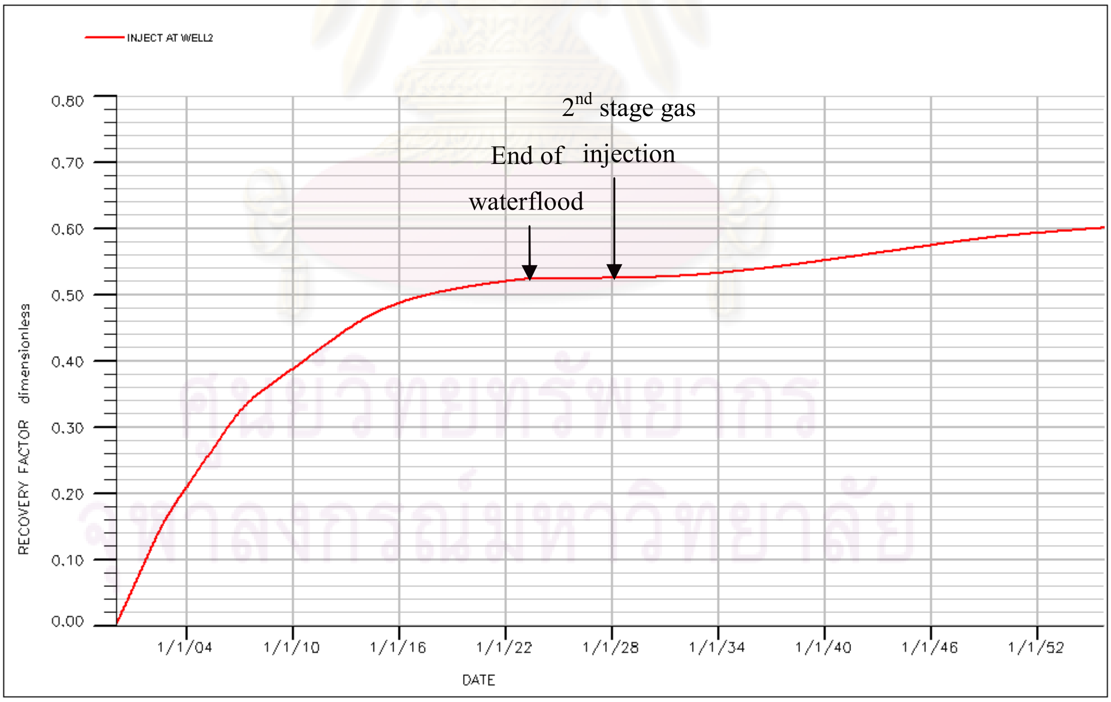


Figure 5.39: Field oil recovery for DDP with gas injection at well 2 in 5-degree dipping reservoir.

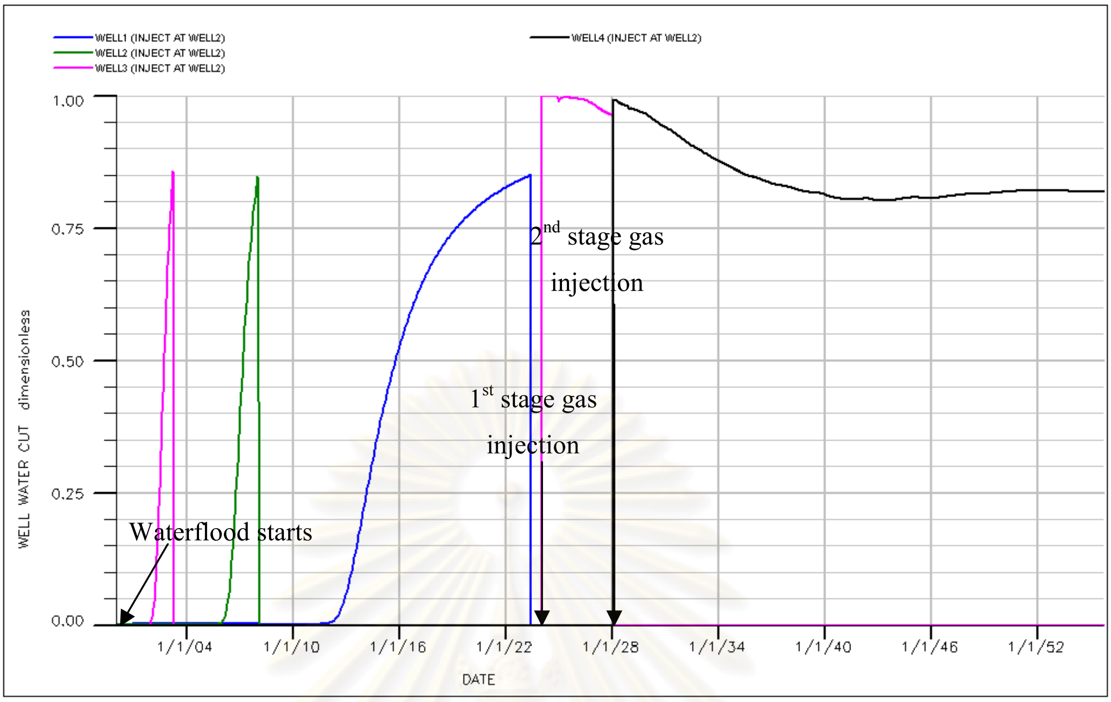


Figure 5.40: Water cut profile for DDP with gas injection at well 2 in 5-degree dipping reservoir.

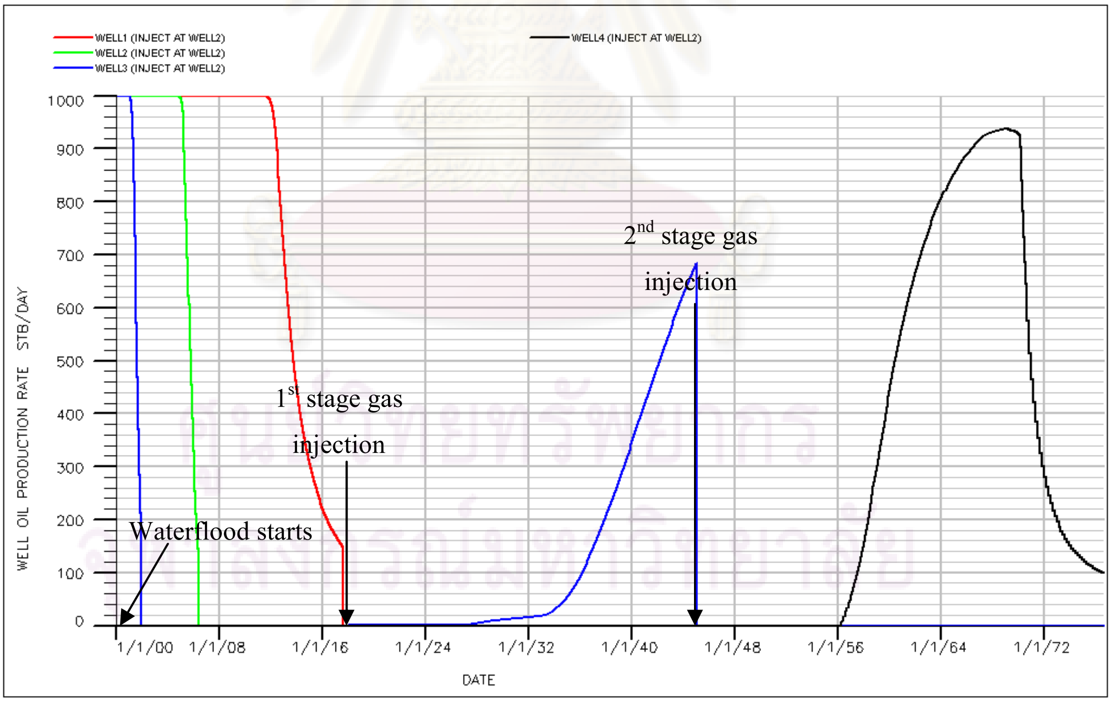


Figure 5.41: Oil production profile for DDP with gas injection at well 2 in 20-degree dipping reservoir.

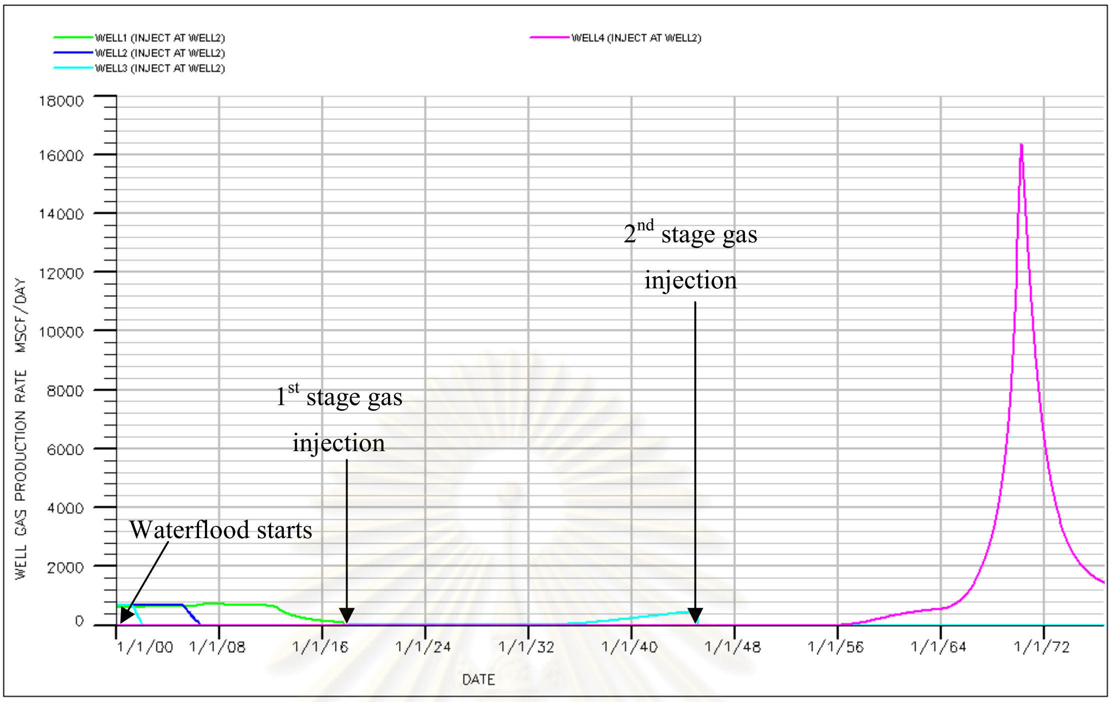


Figure 5.42: Gas production profile for waterflooding followed by DDP injected at updip reservoir in 20-degree dipping reservoir.

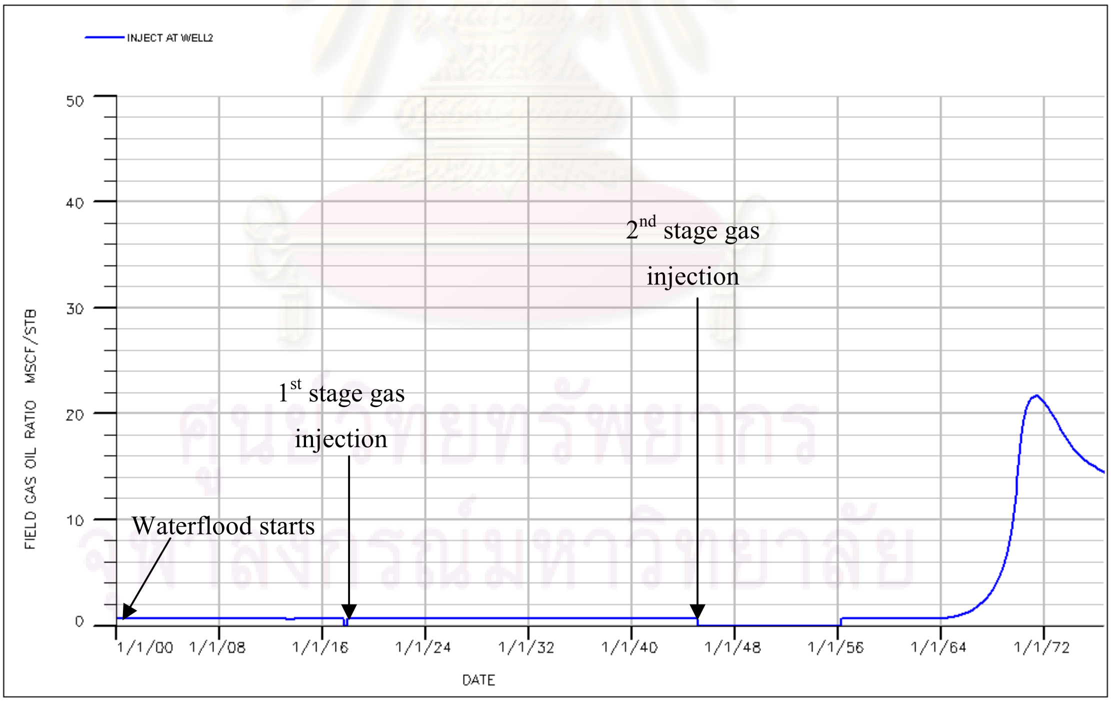


Figure 5.43: Field gas oil ratio for waterflooding followed by DDP injected at updip reservoir in20-degree dipping reservoir.

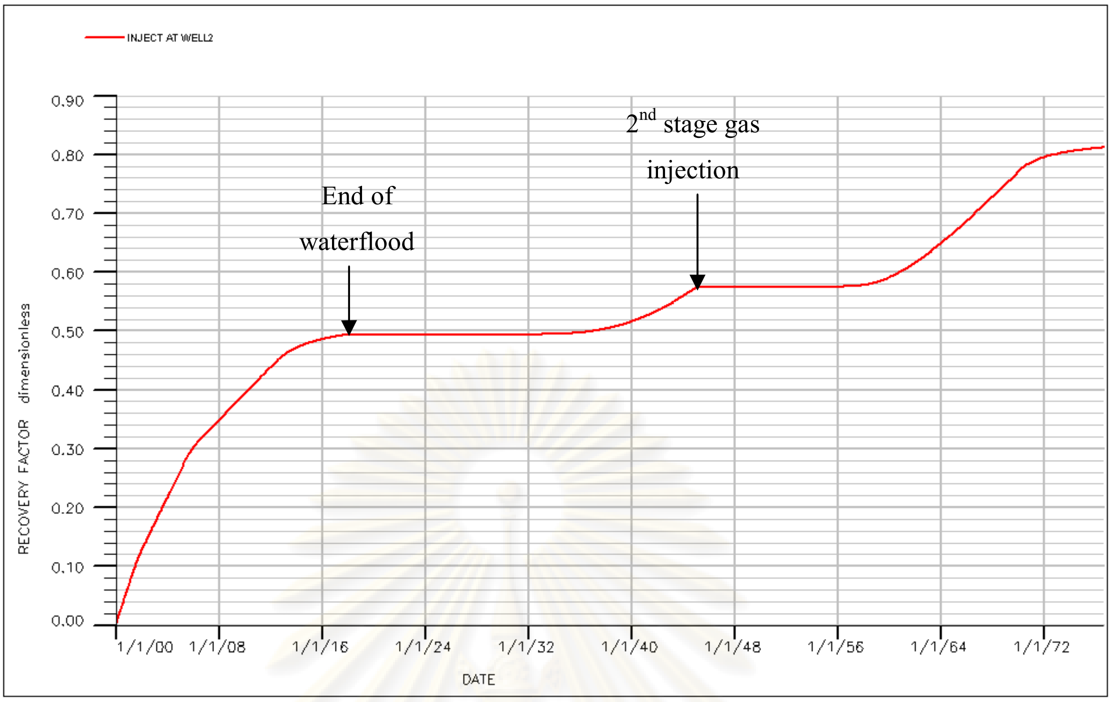


Figure 5.44: Field oil recovery for DDP with gas injection at well 2 in 20-degree dipping reservoir.

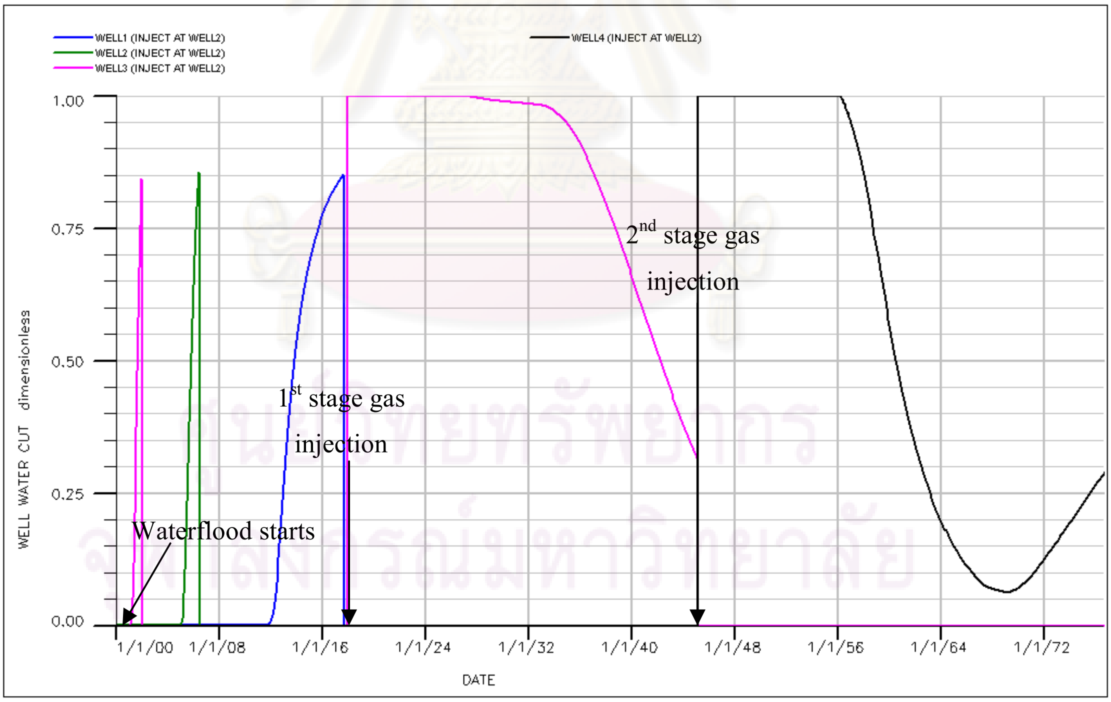


Figure 5.45: Water cut profile for DDP with gas injection at well 2 in 20-degree dipping reservoir.

Figures 5.31 to 5.35 show simulation results for the base case 10-degree dipping reservoir. The results for 5-degree and 20-degree dipping reservoirs are shown in Figures 5.36 to 5.40 and Figures 5.41 to 5.45, respectively. Table 5.5 summarizes the result in term of recovery factor and production life for DDP with gas injection at well 2 in comparison with waterflooding. The most appropriate reservoir for this type of DDP is high degree dip angle reservoir since it has the highest increment in recovery factor. Note that the extended life of the reservoir is quite long in all cases. The delay in recovery of oil may affect the economics of the project.

Table 5.5: Comparison between waterflooding and DDP with gas injection at well 2 for different dip angles.

Dip angle (degree)	Waterflooding		DDP with gas injection at well 2		Increment	
	RF (%)	Production life (years)	RF (%)	Production life (years)	RF (%)	Production life (years)
5	52.410	23.397	60.052	54.689	7.642	31.292
10	52.900	23.642	80.069	119.897	27.169	96.255
20	49.270	17.645	81.170	75.469	31.90	57.824

5.2.3 DDP with gas injection at well 1 and well 2

In this case, gas is first injected into the most updip well. When the injected gas breaks through the oil producer most adjacent to the injector (well 2), the oil producer is converted to gas injector and the original gas injector is shut in. At the same time, well 3 is opened to produce oil. After the injected gas reach well 3, the well is shut in and well 4 is open for production.

Table 5.6: Summary of well schedules for DDP with gas injection at well 2 and well 3.

Stage	Well 1	Well 2	Well 3	Well 4
Waterflood	Producer	Producer	Producer	Injector
1st stage of gas injection	Injector	Producer	Shut-in	Shut-in
2nd stage of gas injection	Shut-in	Injector	Producer	Shut-in
3rd stage of gas injection	Shut-in	Injector	Shut-in	Producer

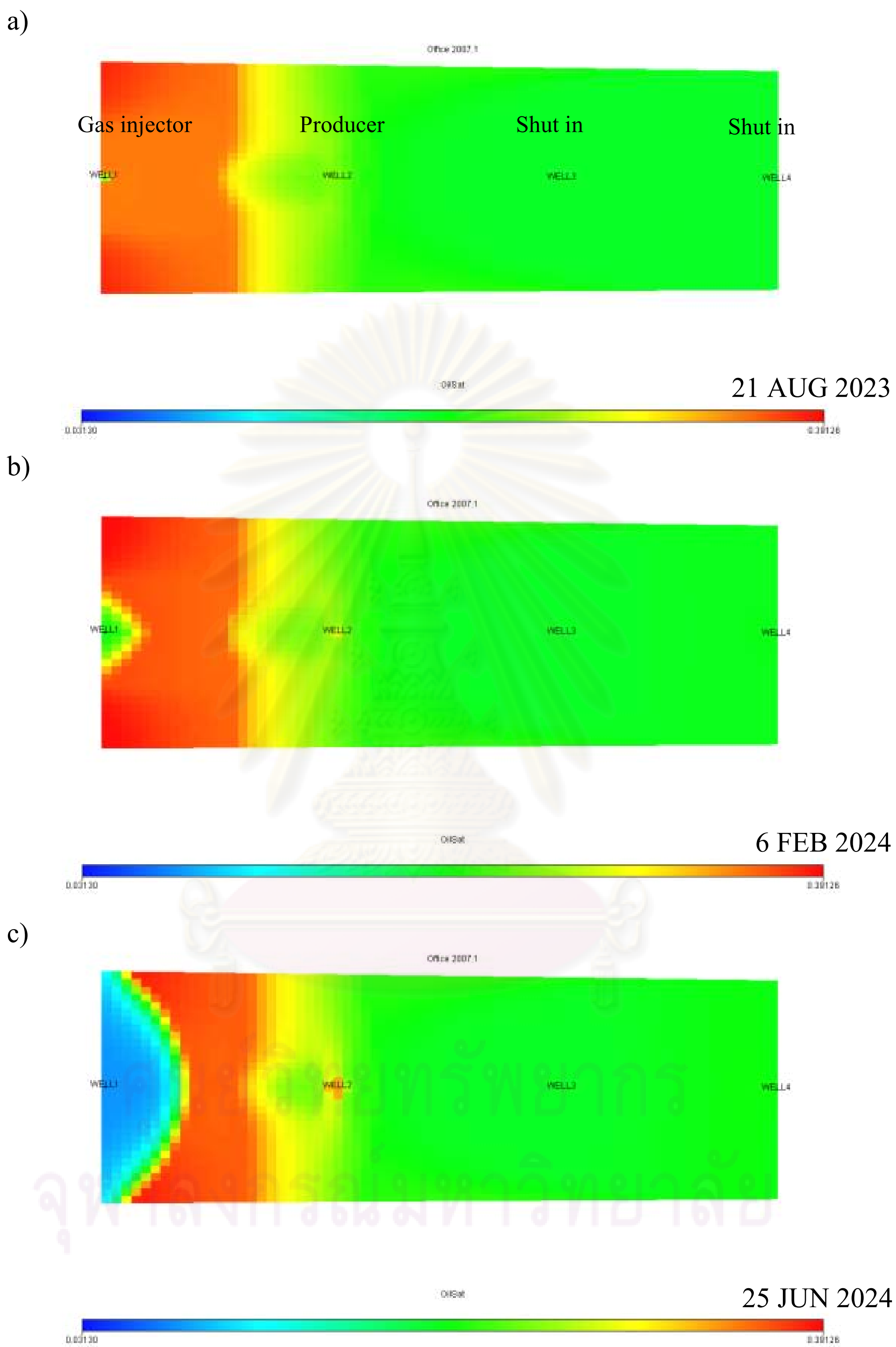
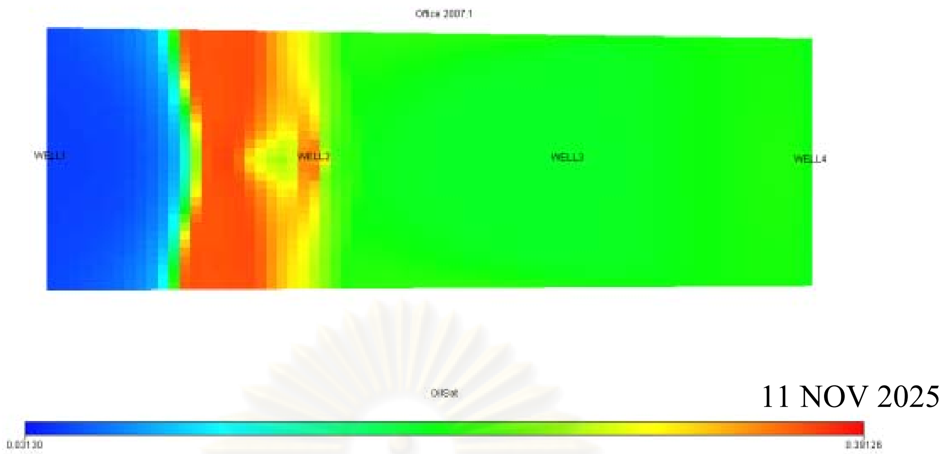
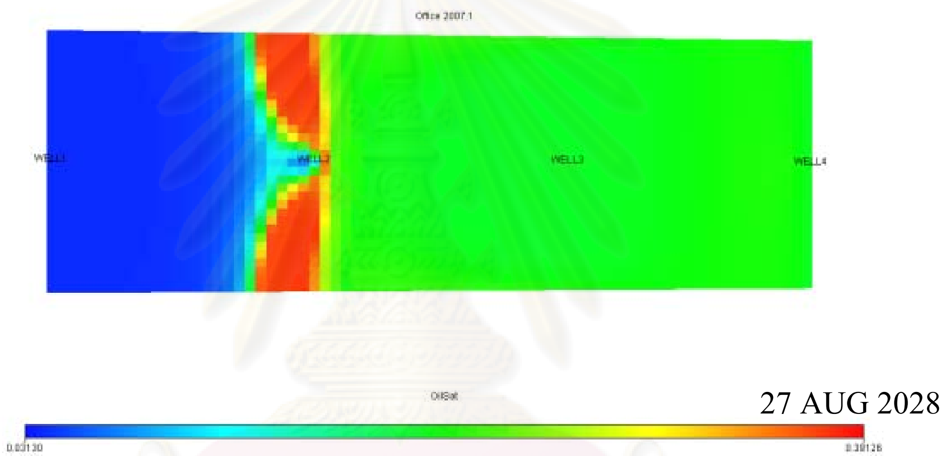


Figure 5.46: Oil saturation distribution for DDP with gas injection at well 1 and well 2 in top view.

d)



e)



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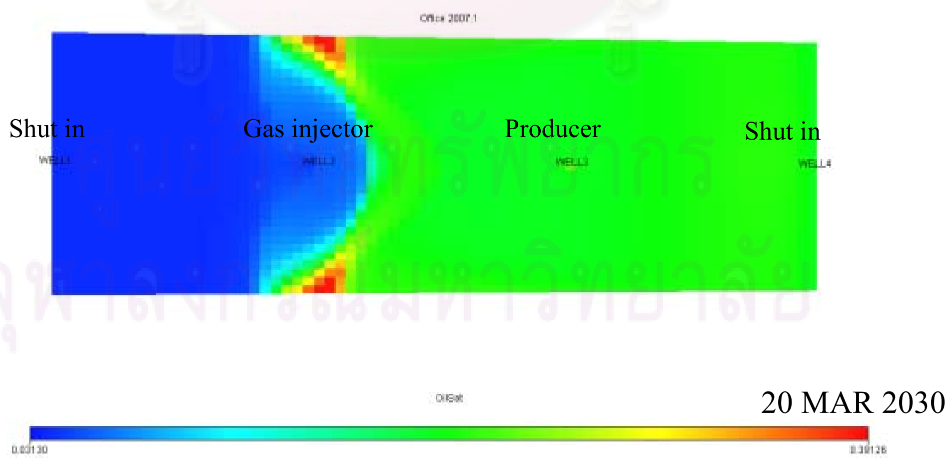
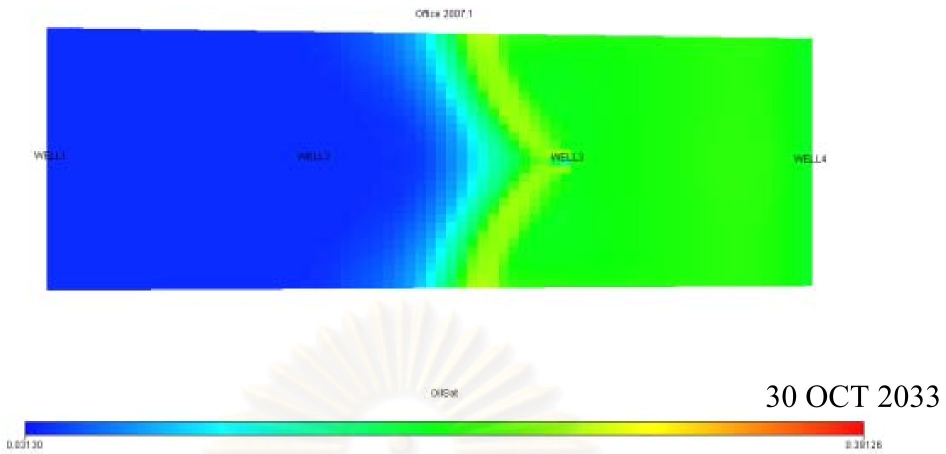


Figure 5.46: Oil saturation distribution for DDP with gas injection at well 1 and well 2 in top view (continued).

g)



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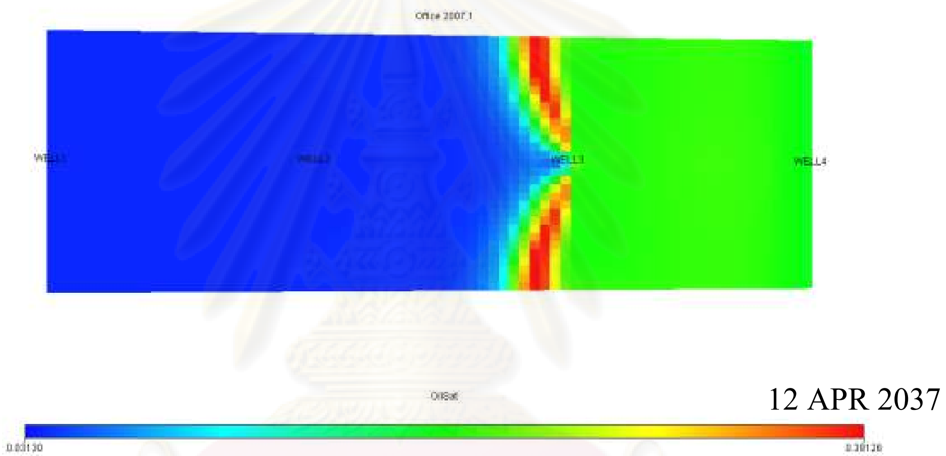


i)

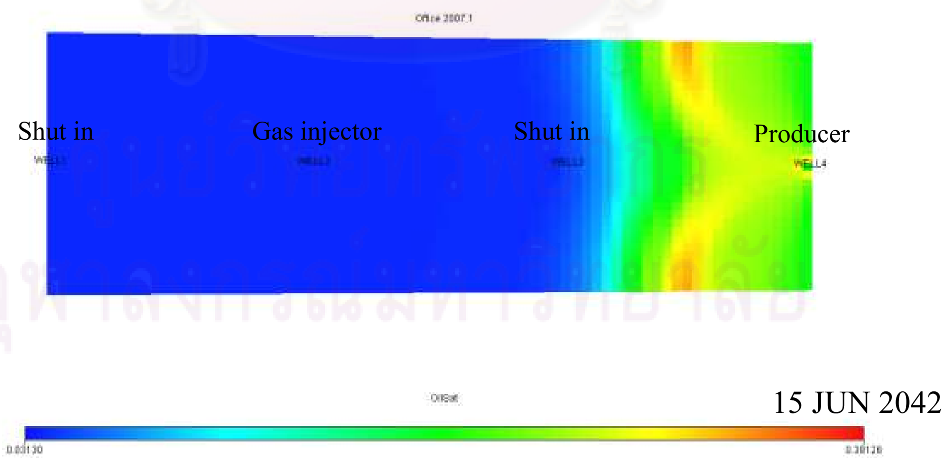
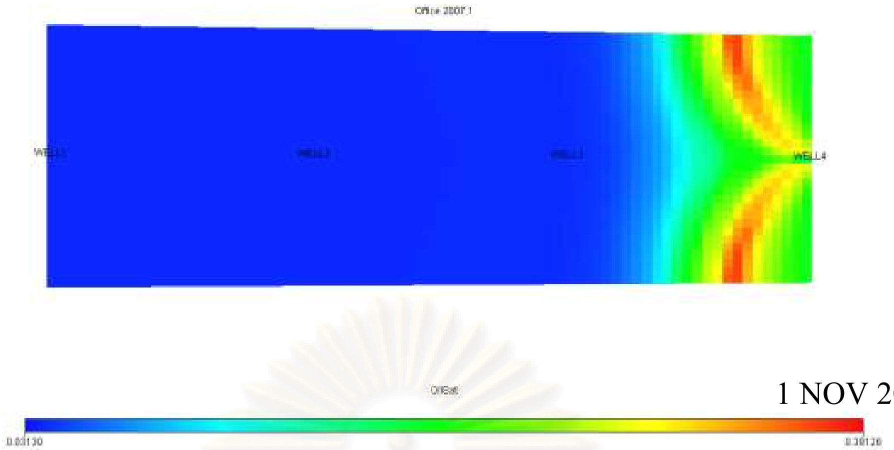


Figure 5.46: Oil saturation distribution for DDP with gas injection at well 1 and well 2 in top view (continued).

j)



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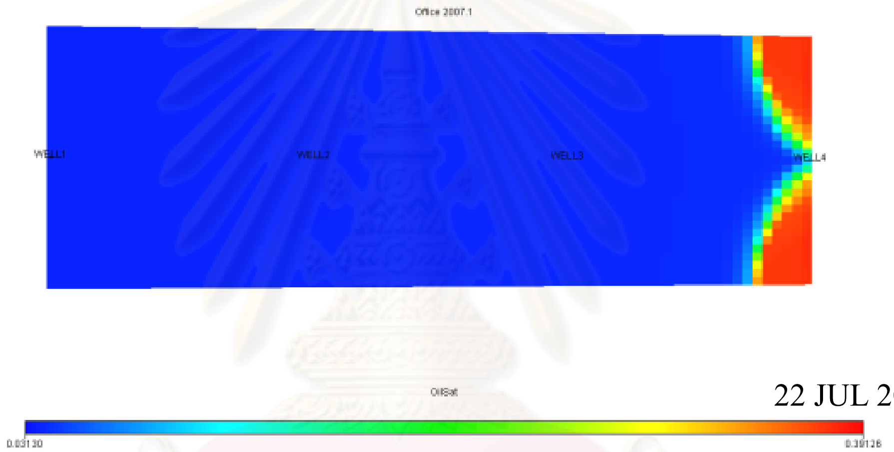
k)



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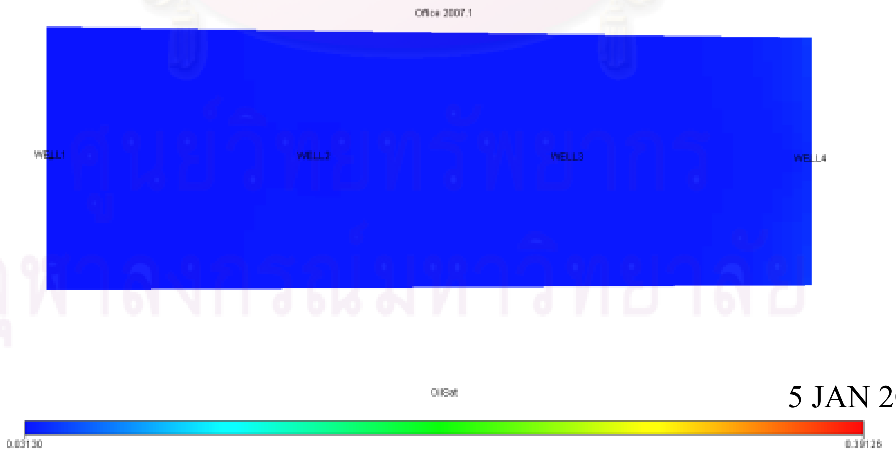
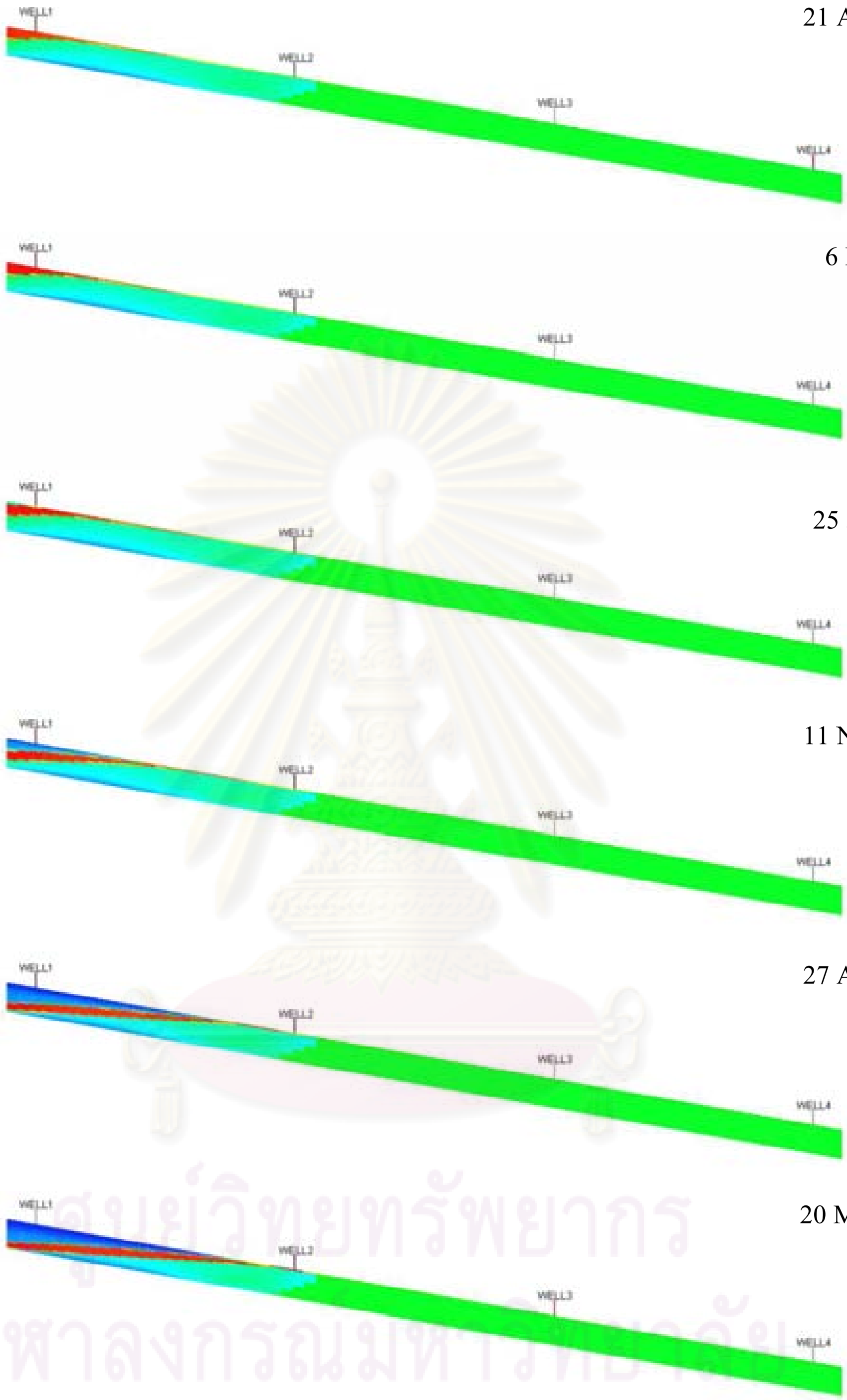


5 JAN 2067

Figure 5.46: Oil saturation distribution for DDP with gas injection at well 1 and well 2 in top view (continued).



a) 21 AUG 2023

b) 6 FEB 2024

c) 25 JUN 2024

d) 11 NOV 2025

e) 27 AUG 2028

f) 20 MAR 2030

Figure 5.47: Oil saturation distribution for DDP with gas injection at well 1 and well 2 in side view.

g) 30 OCT 2033

h) 12 APR 2037

i) 15 JUN 2042

j) 1 NOV 2044

k) 22 JUL 2052

l) 5 JAN 2067

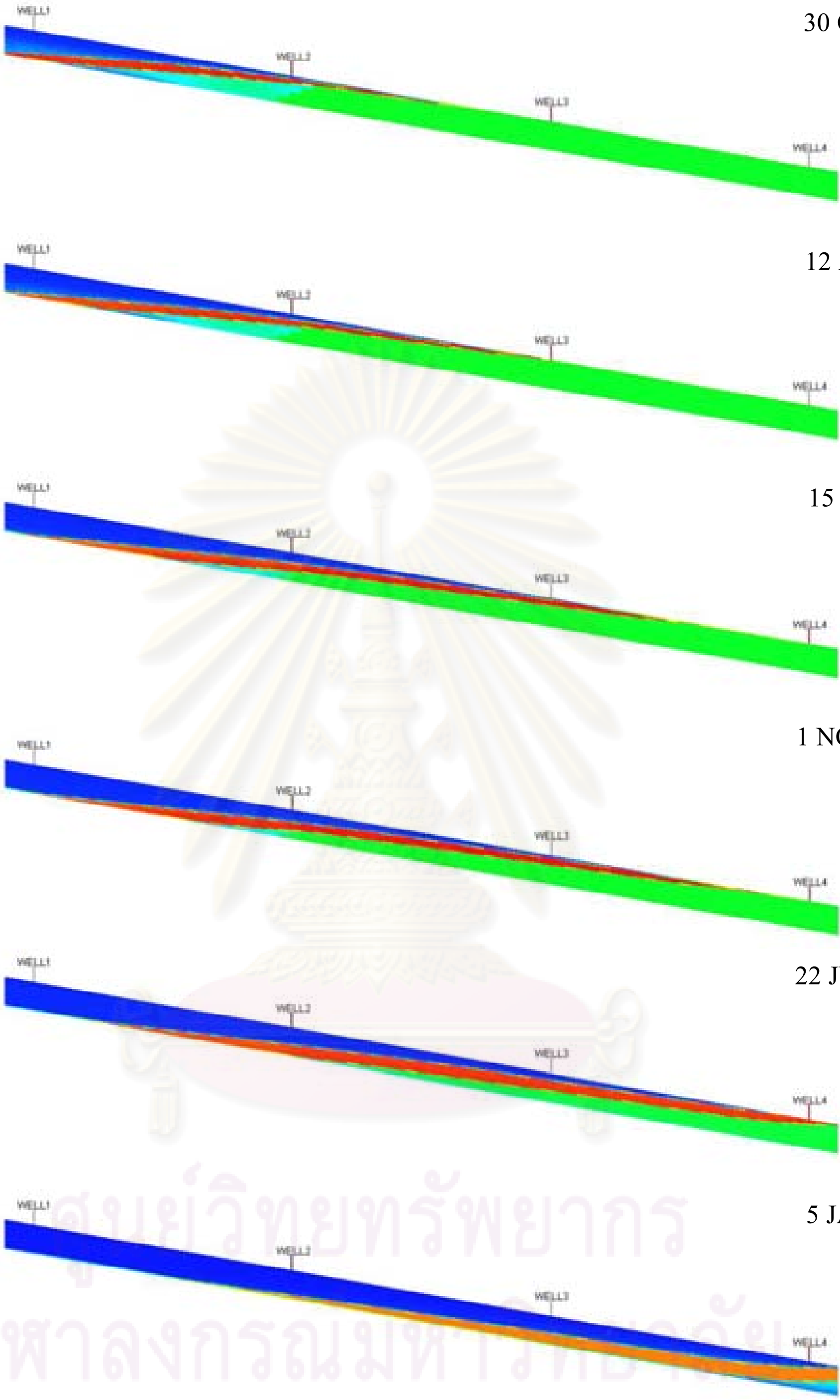


Figure 5.47: Oil saturation distribution for DDP with gas injection at well 1 and well 2 in side view (continued).

Figures 5.46 to 5.47 show how gas displaces trapped oil in double displacement process. The time step in Figures 5.46 and 5.47 is the same for each step from *a* to *l*. At initial stage (shown in Figure 5.47 a), we start gas injection at well 1 in the same manner as in conventional DDP. Then the oil flows downdip due to gravity force as shown in Figure 5.47 (d). When the injected gas reaches well 2, the injector (well 1) is shut in and the producer (well 2) is converted to be injector instead and the next producer (well 3) is opened. The well continues producing with the injected gas reaches well 3. Then, well 3 is shut in and well 4 is open for production until the oil rate drops to the economic rate.

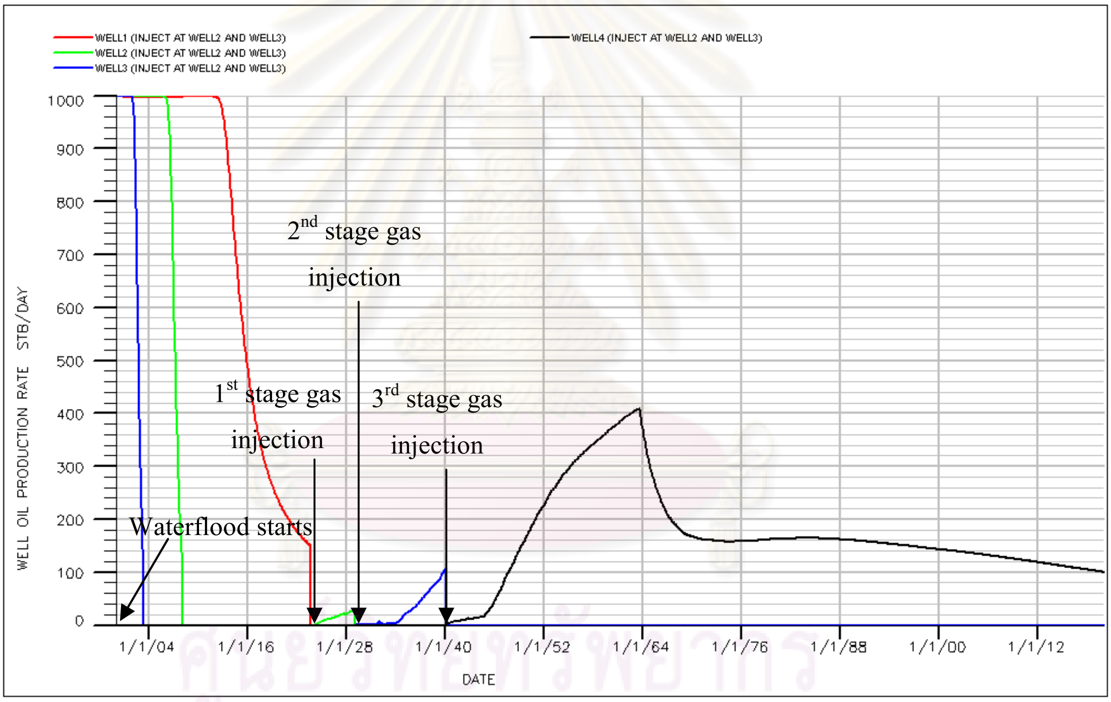


Figure 5.48: Oil production profile for DDP with gas injection at well 1 and well 2 in 10-degree dipping reservoir.

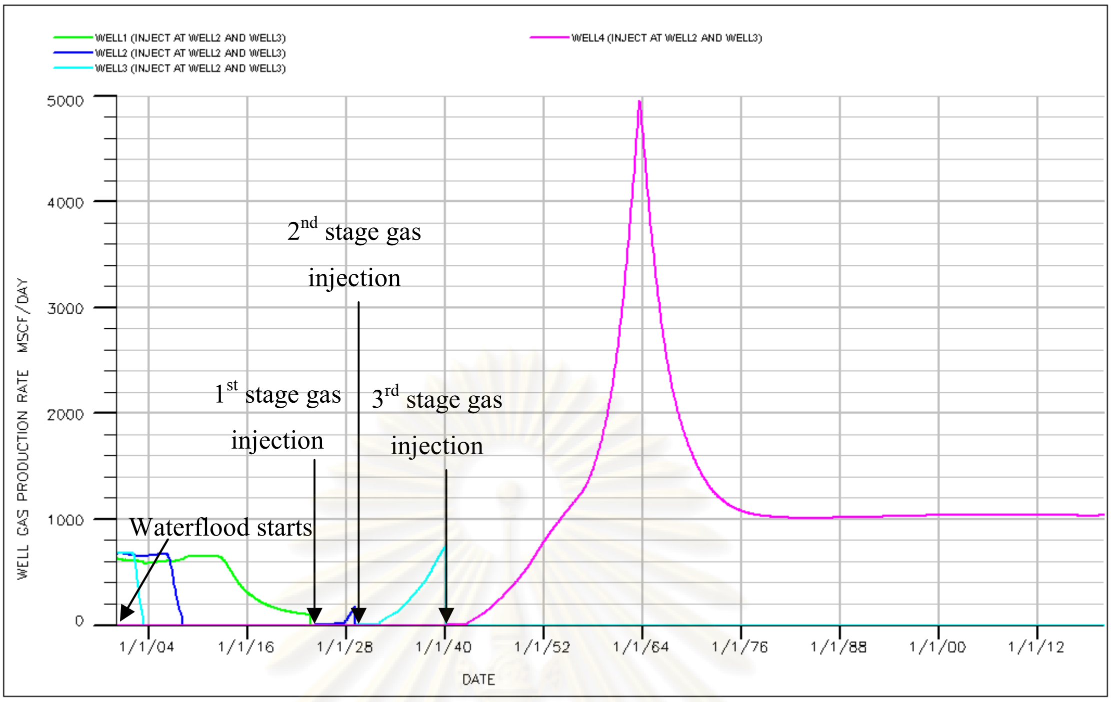


Figure 5.49: Gas production profile for DDP with gas injection at well 1 and well 2 in 10-degree dipping reservoir.

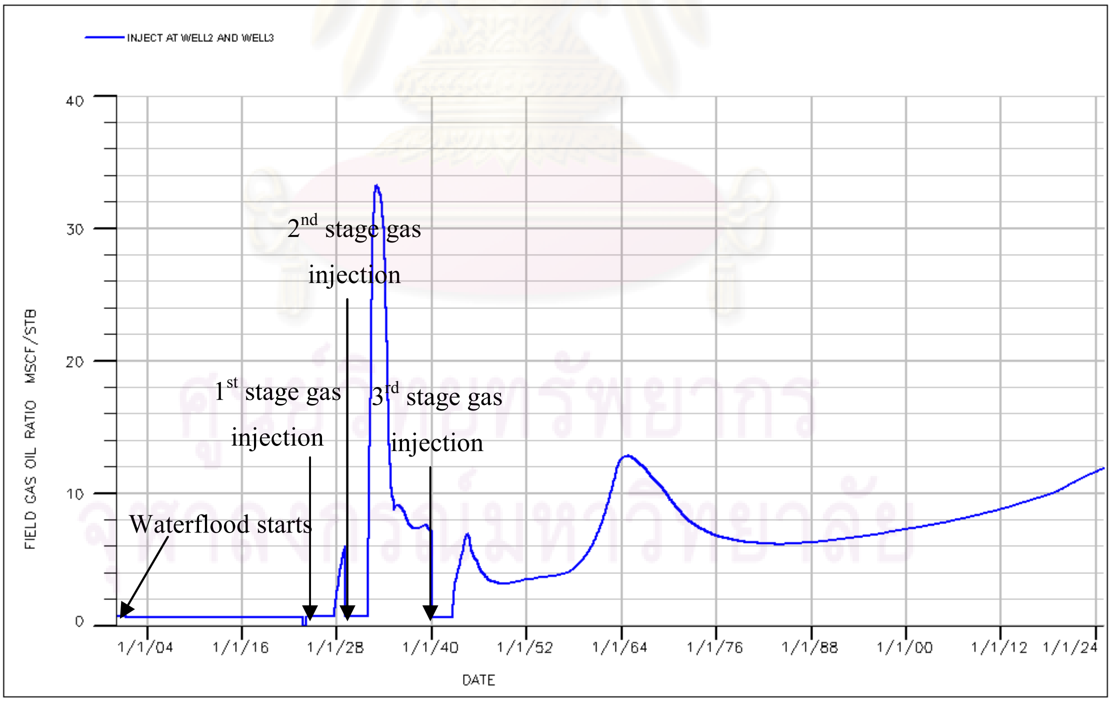


Figure 5.50: Field gas oil ratio for DDP with gas injection at well 1 and well 2 in 10-degree dipping reservoir.

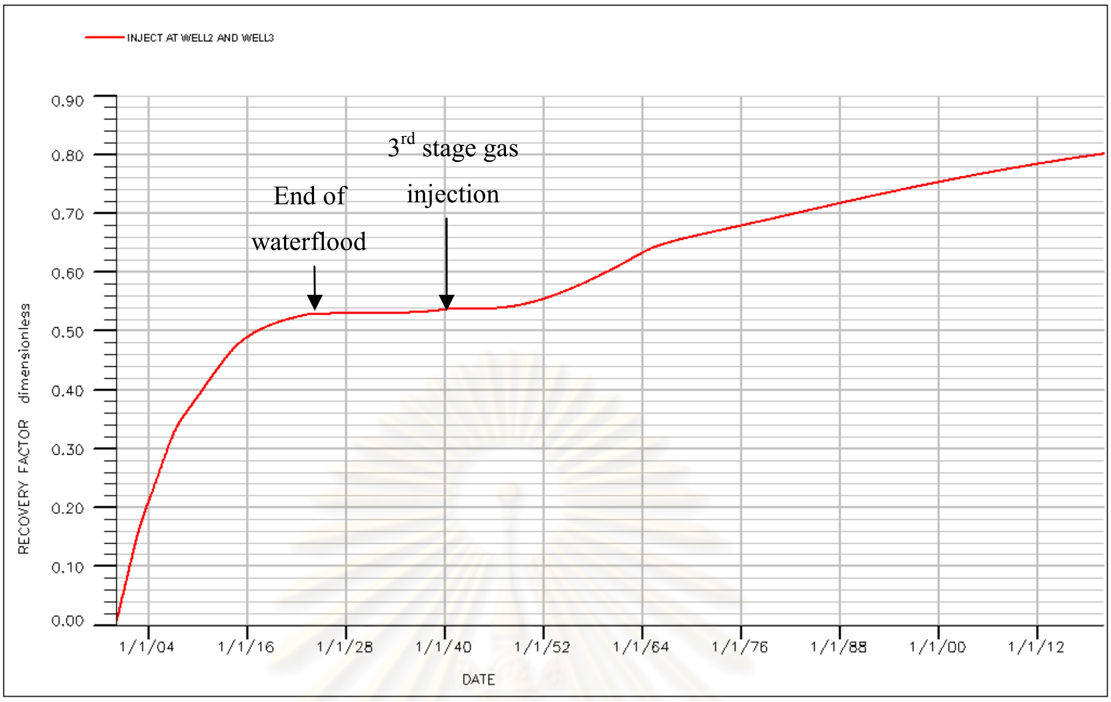


Figure 5.51: Field oil recovery for DDP with gas injection at well 1 and well 2 in 10-degree dipping reservoir.

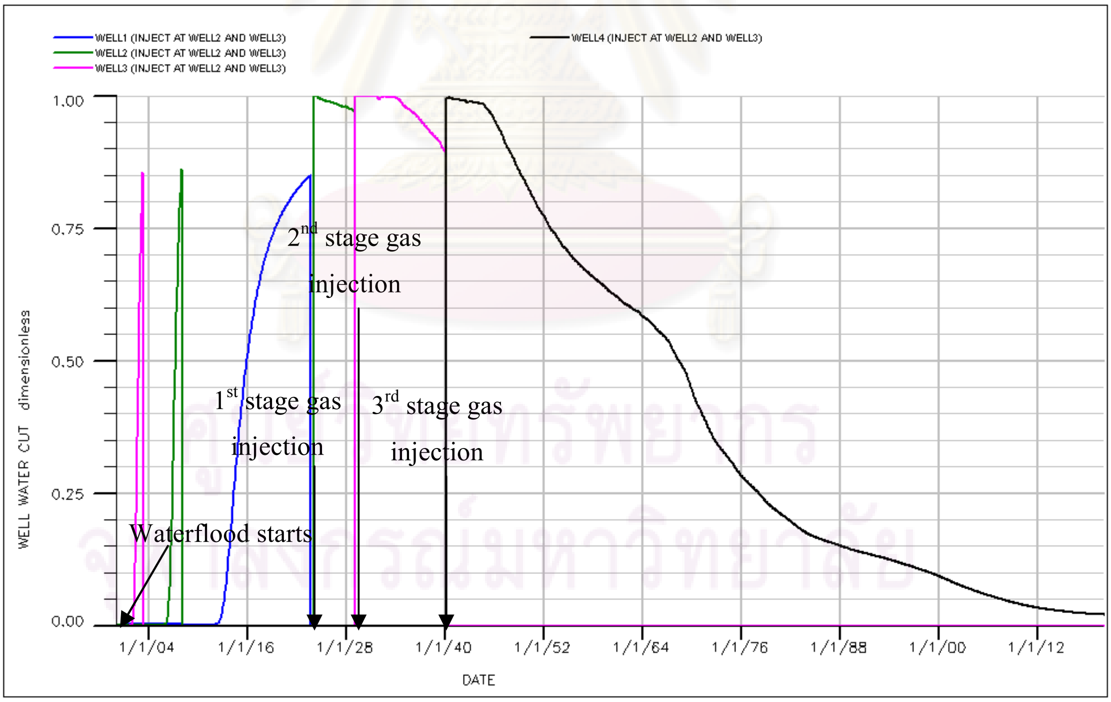


Figure 5.52: Water cut profile for DDP with gas injection at well 1 and well 2 in 10-degree dipping reservoir.

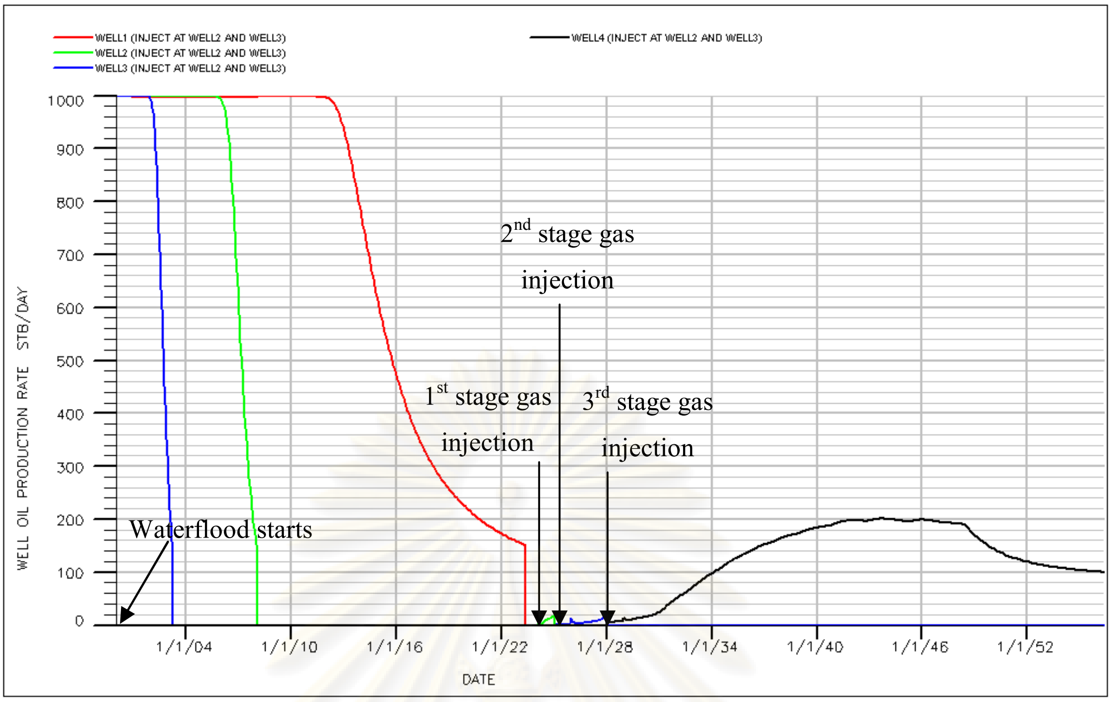


Figure 5.53: Oil production profile for DDP with gas injection at well 1 and well 2 in 5-degree dipping reservoir.

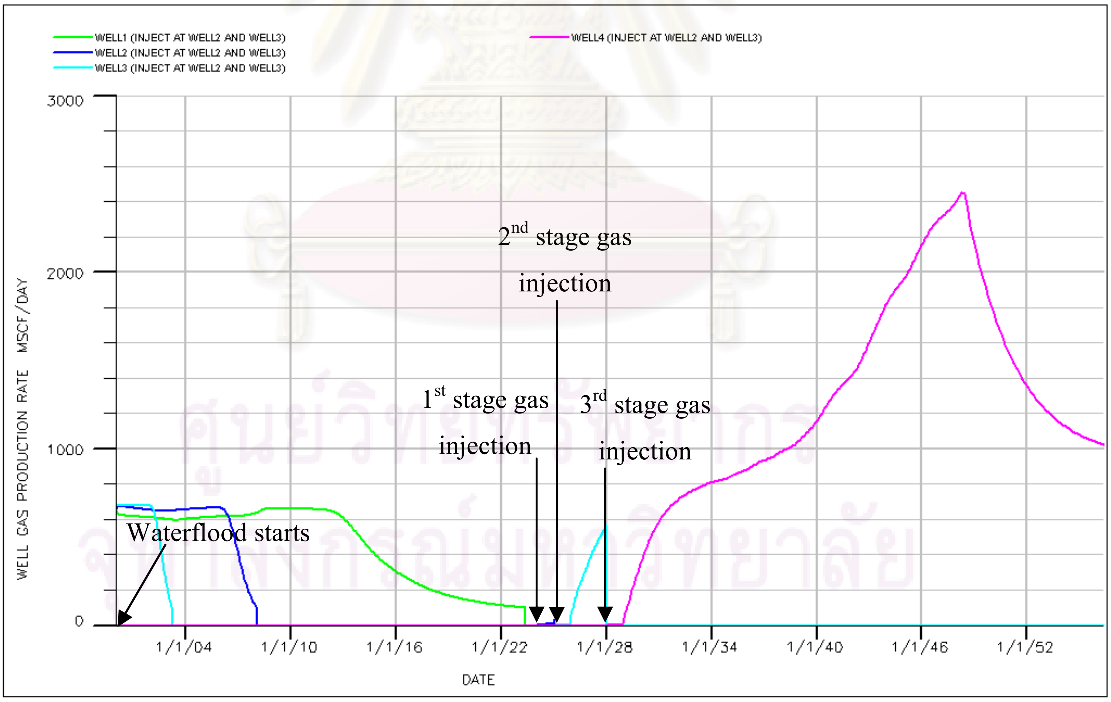


Figure 5.54: Gas production profile for with gas injection at well 1 and well 2 in 5-degree dipping reservoir.

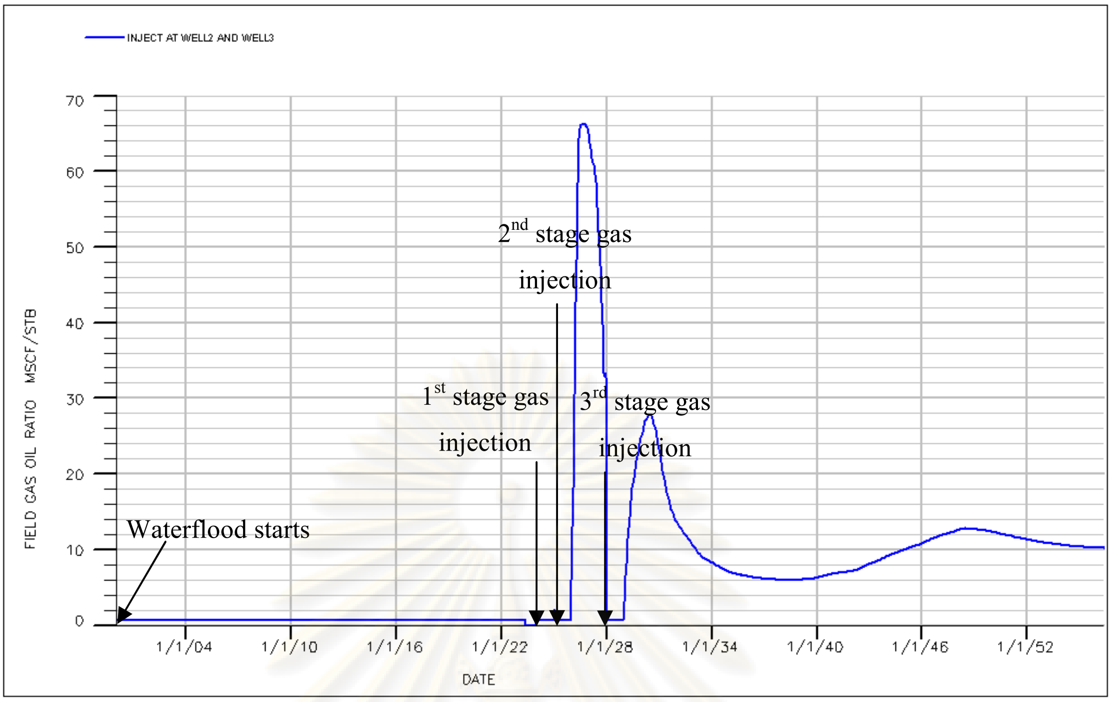


Figure 5.55: Field gas oil ratio for DDP with gas injection at well 1 and well 2 in 5-degree dipping reservoir.

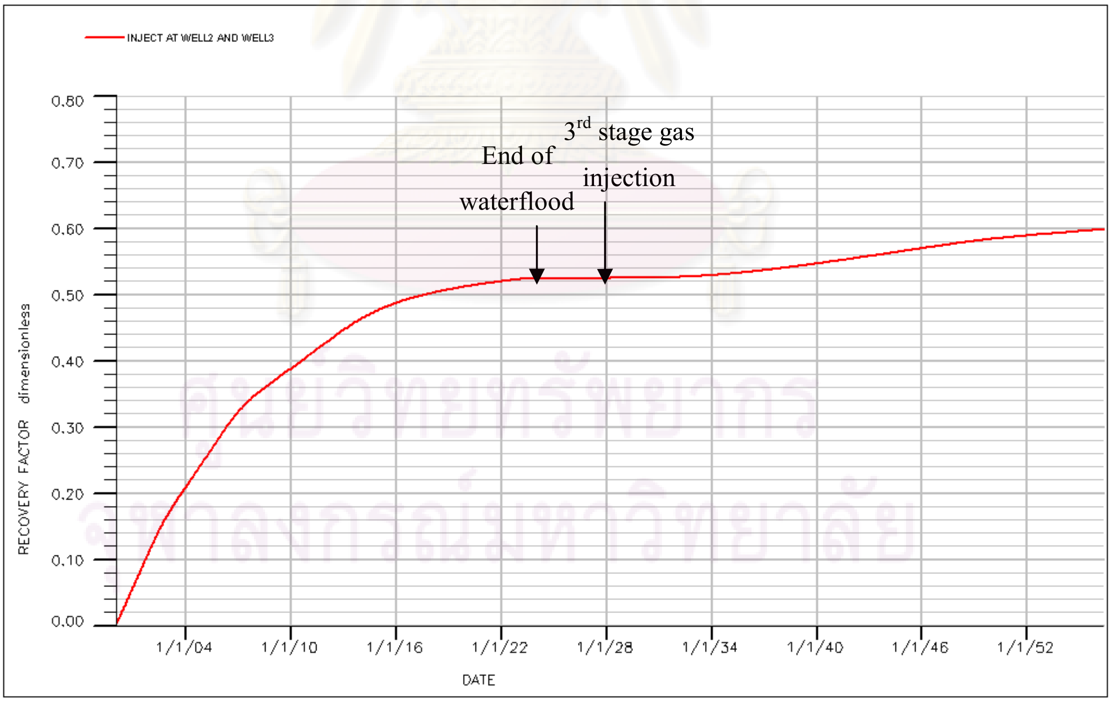


Figure 5.56: Field oil recovery for DDP with gas injection at well 1 and well 2 in 5-degree dipping reservoir.

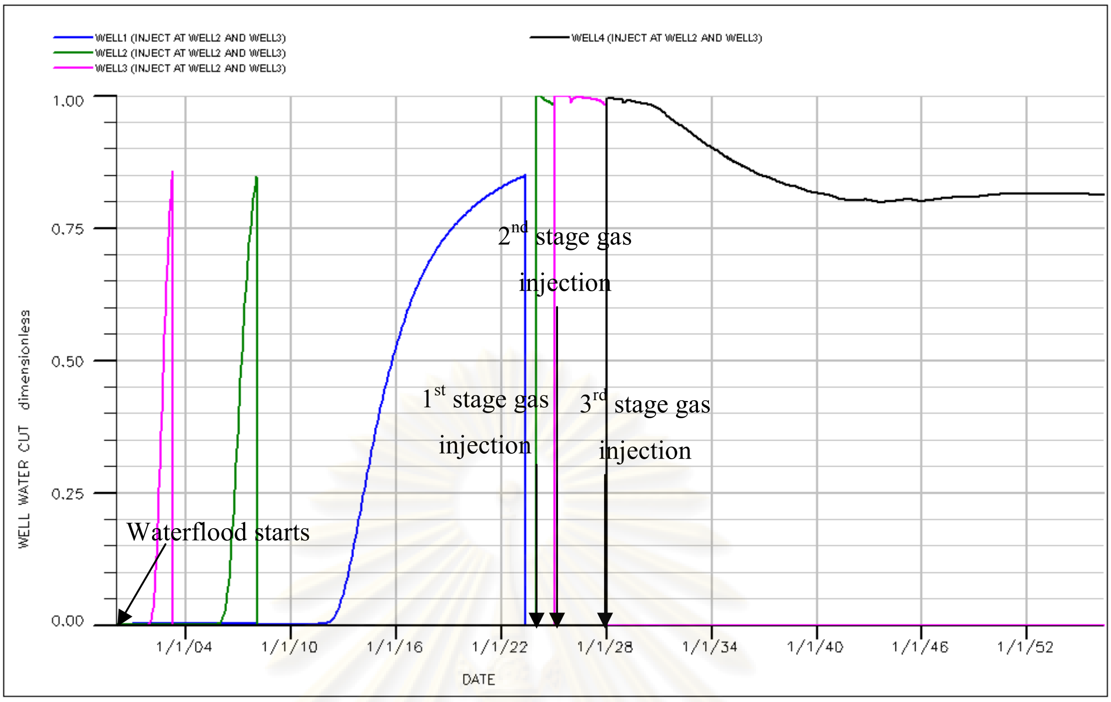


Figure 5.57: Water cut profile for by DDP with gas injection at well 2 and well 3 for 5-degree dipping reservoir.

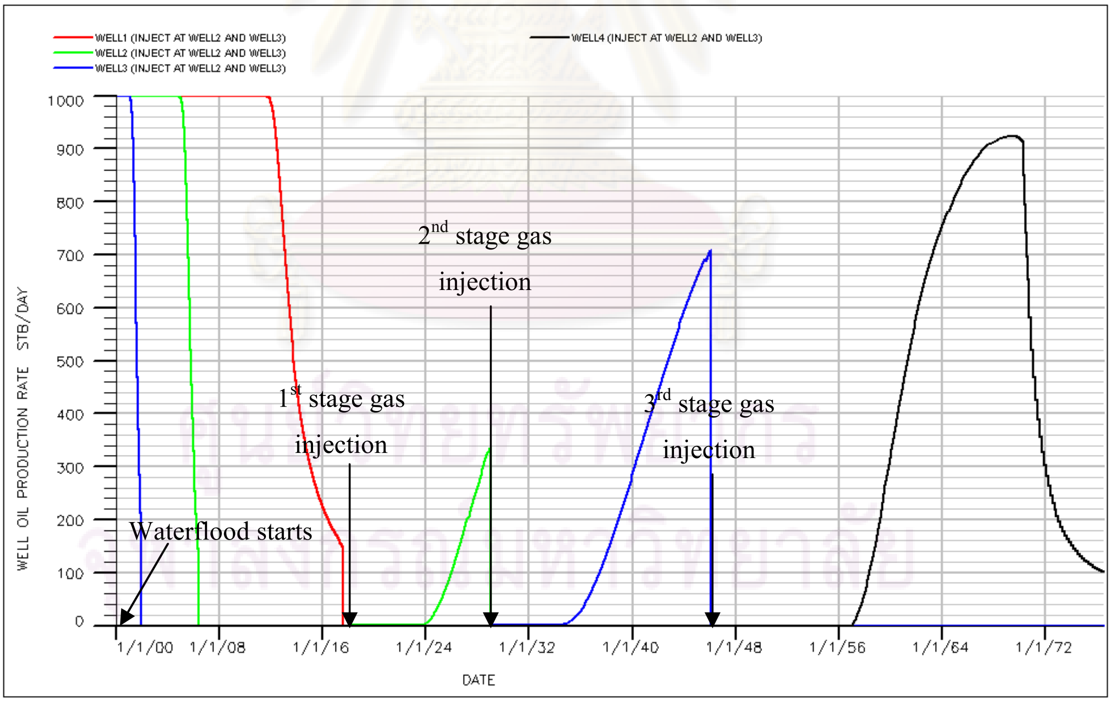


Figure 5.58: Oil production profile for DDP with gas injection at well 1 and well 2 in 20-degree dipping reservoir.

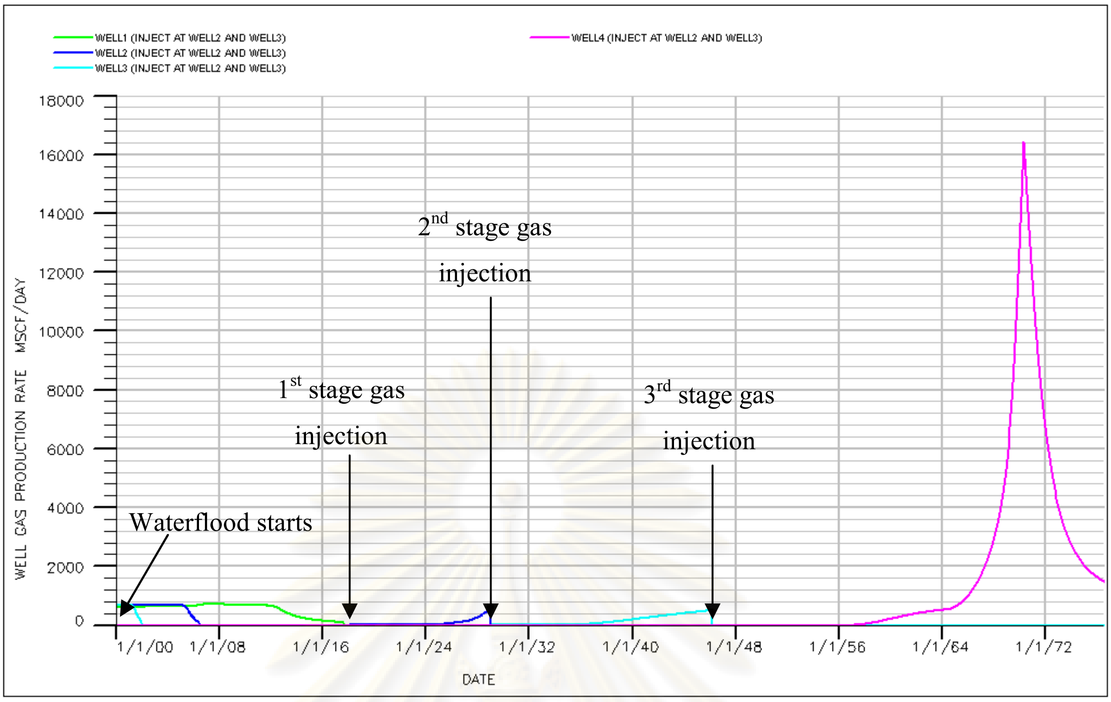


Figure 5.59: Gas production profile for DDP with gas injection at well 1 and well 2 in 20-degree dipping reservoir.

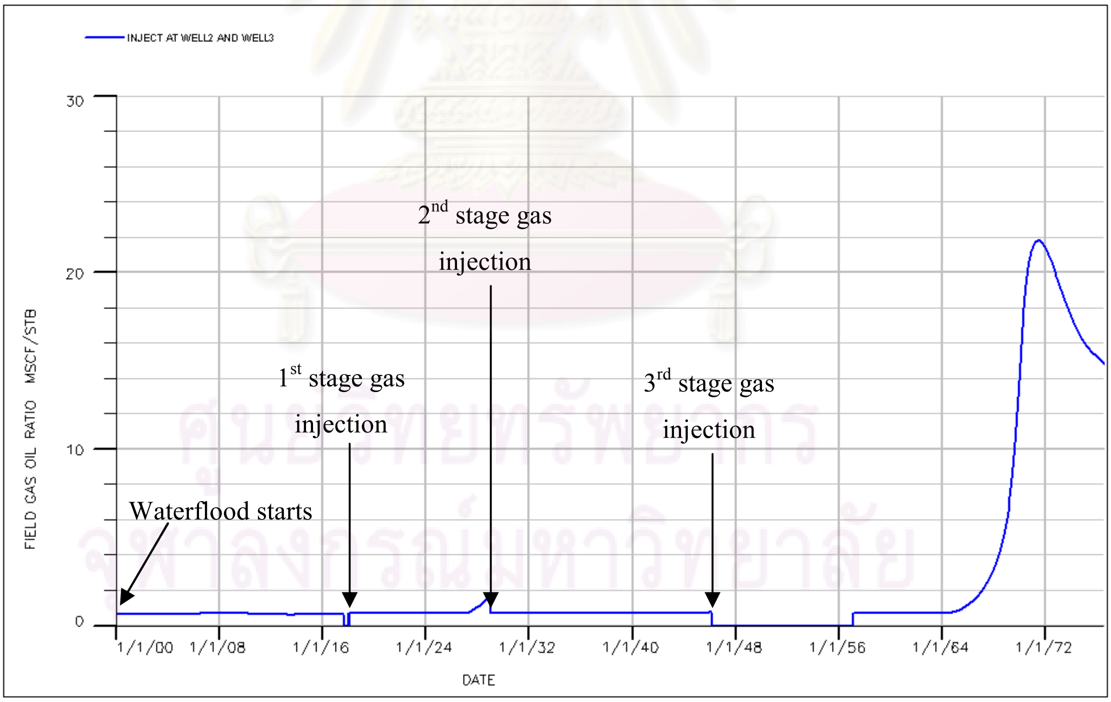


Figure 5.60: Field gas oil ratio for DDP with gas injection at well 1 and well 2 in 20-degree dipping reservoir.

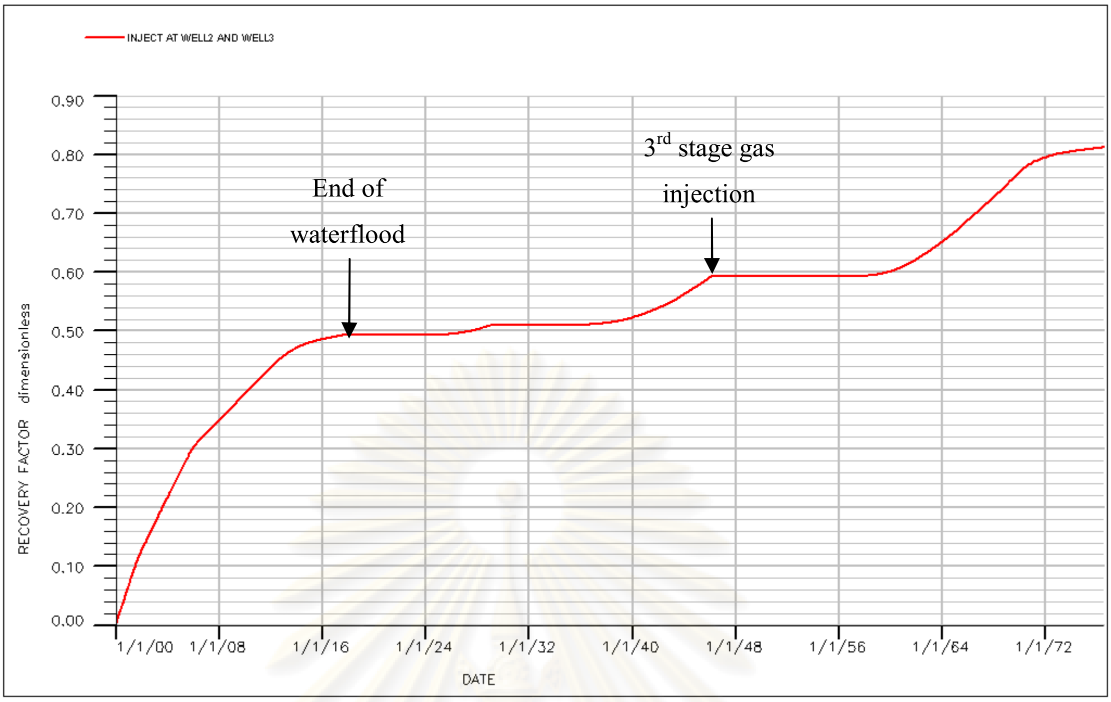


Figure 5.61: Field oil recovery for DDP with gas injection at well 1 and well 2 in 20-degree dipping reservoir.

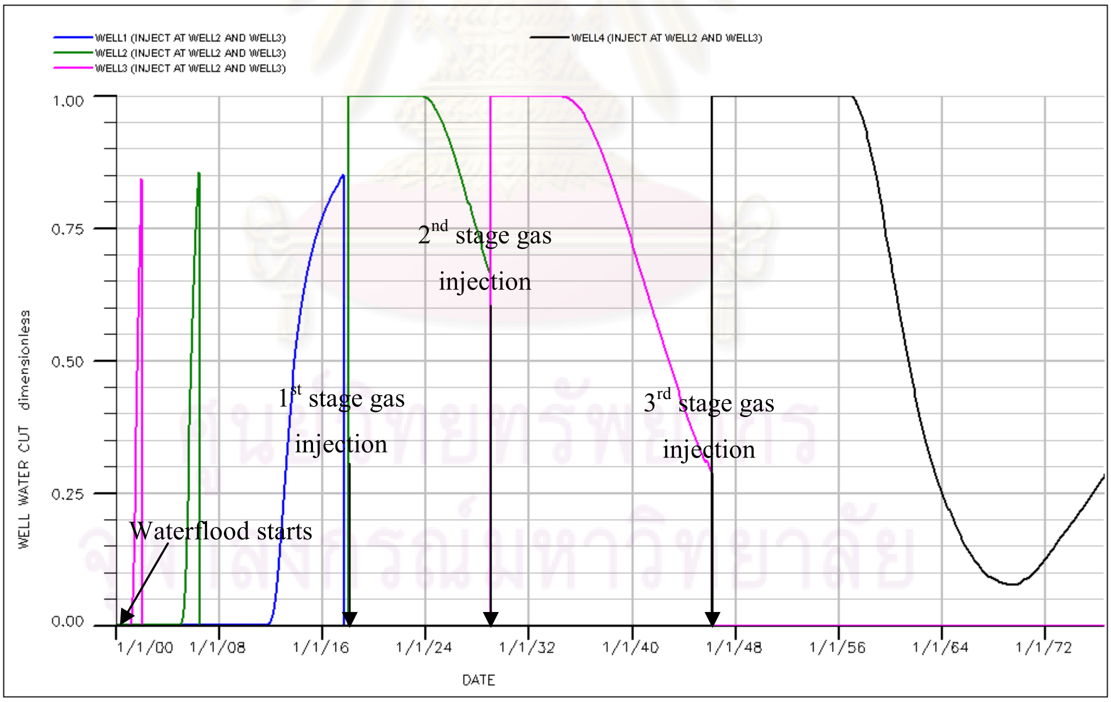


Figure 5.62: Water cut profile for DDP with gas injection at well 1 and well 2 in 20-degree dipping reservoir.

Figures 5.48 to 5.52 show simulation results for the base case 10-degree dipping reservoir. The results for 5-degree and 20-degree dipping reservoirs are shown in Figures 5.53 to 5.57 and Figures 5.58 to 5.62, respectively. Table 5.7 summarizes the result in term of recovery factor and production life for DDP with gas injection at well 1 and well 2 in comparison with waterflooding. The most appropriate reservoir for this type of DDP with gas injection at well 2 is high degree dip angle reservoir since it has the highest increment in recovery factor. Note that the extended life of the reservoir is quite long in all cases. The delay in recovery of oil may affect the economics of the project.

Table 5.7: Comparison between waterflooding and DDP with gas injection at well 1 and well 2in different dip angles.

Dip angle (degree)	Waterflooding		DDP with gas injection at well 1 and well 2		Increment	
	RF (%)	Production life (years)	RF (%)	Production life (years)	RF (%)	Production life (years)
5	52.410	23.397	59.804	55.347	7.394	31.950
10	52.900	23.642	80.093	118.914	27.193	95.272
20	49.270	17.645	81.186	75.469	31.916	57.824

5.2.4 Comparison of results

In this section, we compare and discuss results from different strategies in term of percent oil recovery and production life. Results in Table 5.8 show that there is very small difference in RF for different injection strategies. However, for 5-degree dipping reservoir, injecting gas at well 2 gives the shortest production time. For 10-degree dipping reservoir, conditional DDP (injecting gas at well 1) gives the shortest production time. For 20-degree dip angle, the production times are similar for all strategies.

Table 5.8: Summary table for three injection strategies.

Dip angle (degree)	Conventional DDP		DDP with gas injection at well 2		DDP with gas injection at well 1 and well 2	
	RF (%)	Production life (years)	RF (%)	Production life (years)	RF (%)	Production life (years)
5	59.943	57.647	60.052	54.689	59.804	55.347
10	80.212	117.764	80.069	119.897	80.093	118.914
20	81.186	75.469	81.170	75.469	81.186	75.469

5.3 Sensitivity analysis

In Chapter II, many multiphase flow correlations are presented: Stone I, Stone II and Saturation weighted. Each model uses different assumptions to obtain k_{ro} from two sets of relative permeability data. In order to determine the effect of uncertainty in relative permeability model, different correlations are used in the simulation of waterflooding and DDP. Furthermore, effect of S_{orw} is investigated. All of sensitivity is applied to the base case (dip 10 degree).

5.3.1 Three-phase relative permeability to oil

Based on simulation software, the default correlation is saturation weighted. Other models that are available in ECLIPSE100 are Stone I and Stone II models. In this section, we investigate the effect of relative permeability correlation on oil recovery. In the first set of simulation runs, we focus on waterflood process and the results are illustrated in Figures 5.63 to 5.65.

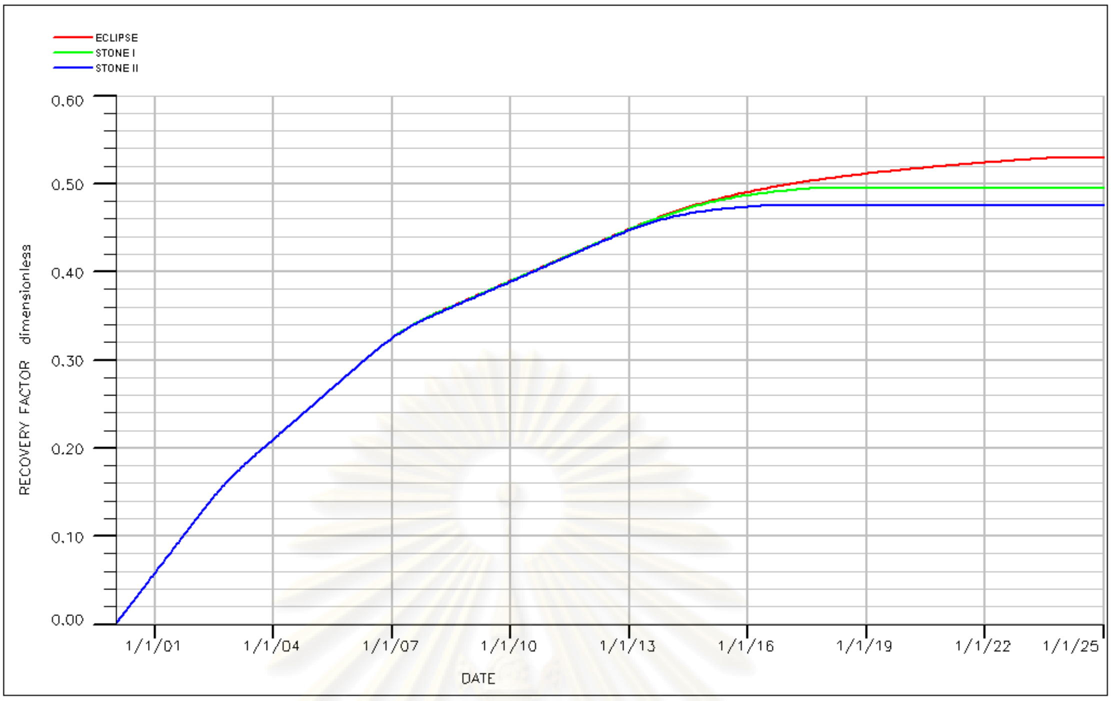


Figure 5.63: Oil recovery factors based on different correlations for waterflooding.

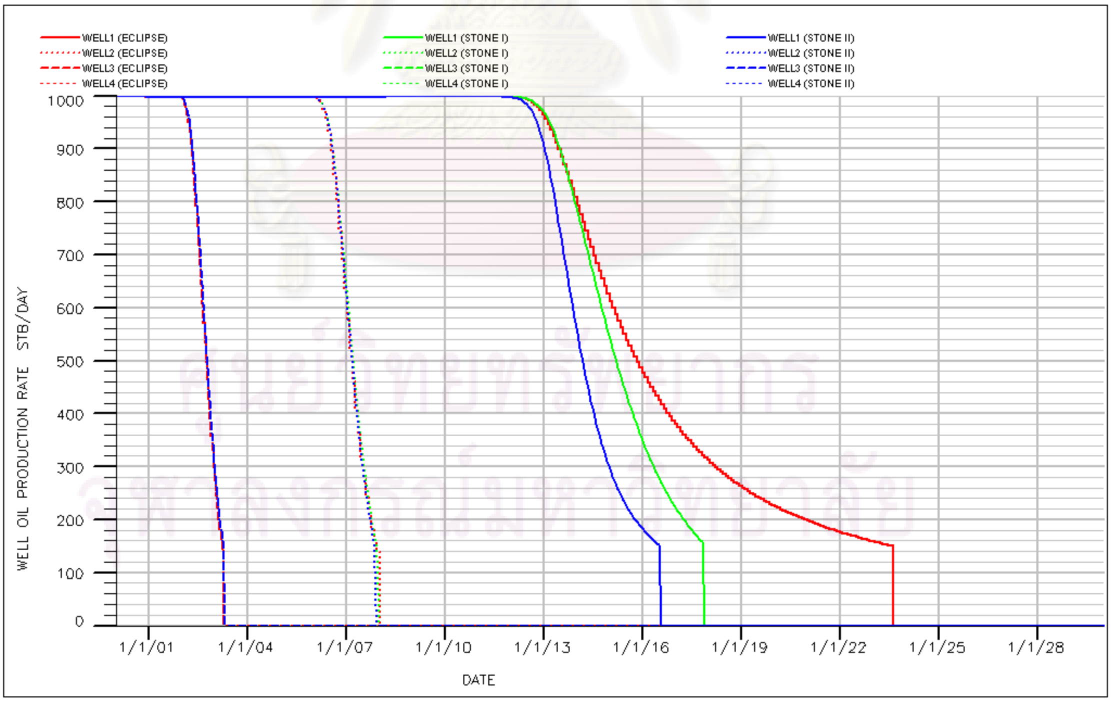


Figure 5.64: Comparison of oil production profiles based on different relative permeability correlations for waterflooding.

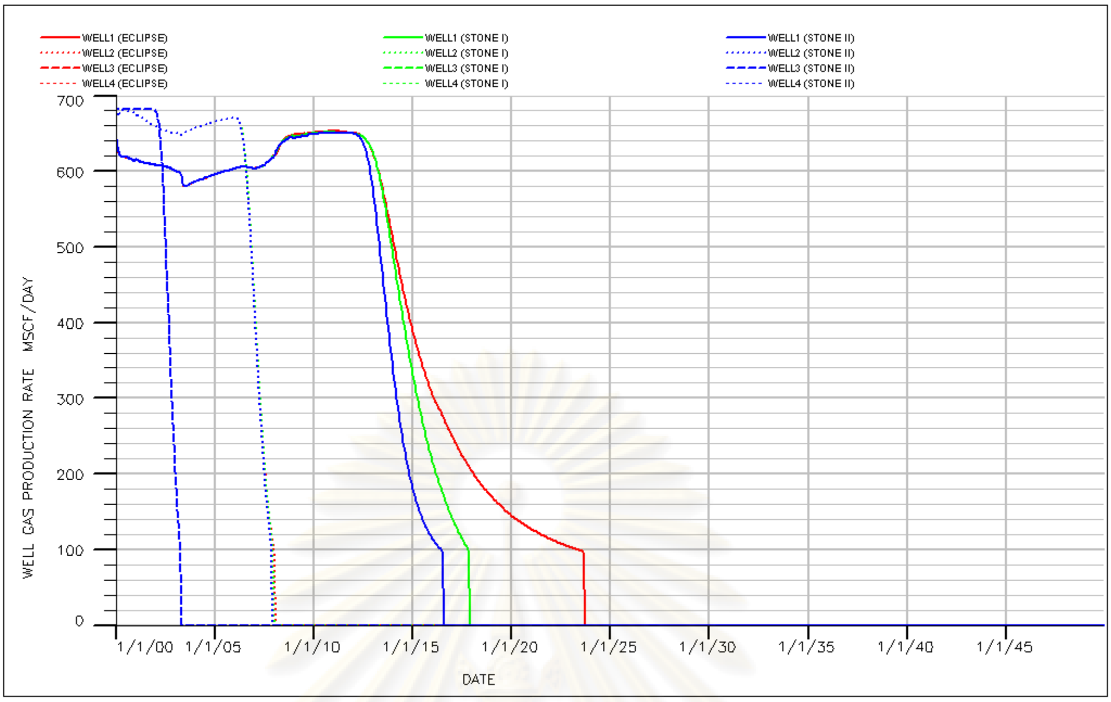


Figure 5.65: Comparison of gas production profiles based on different relative permeability correlations for waterflooding.

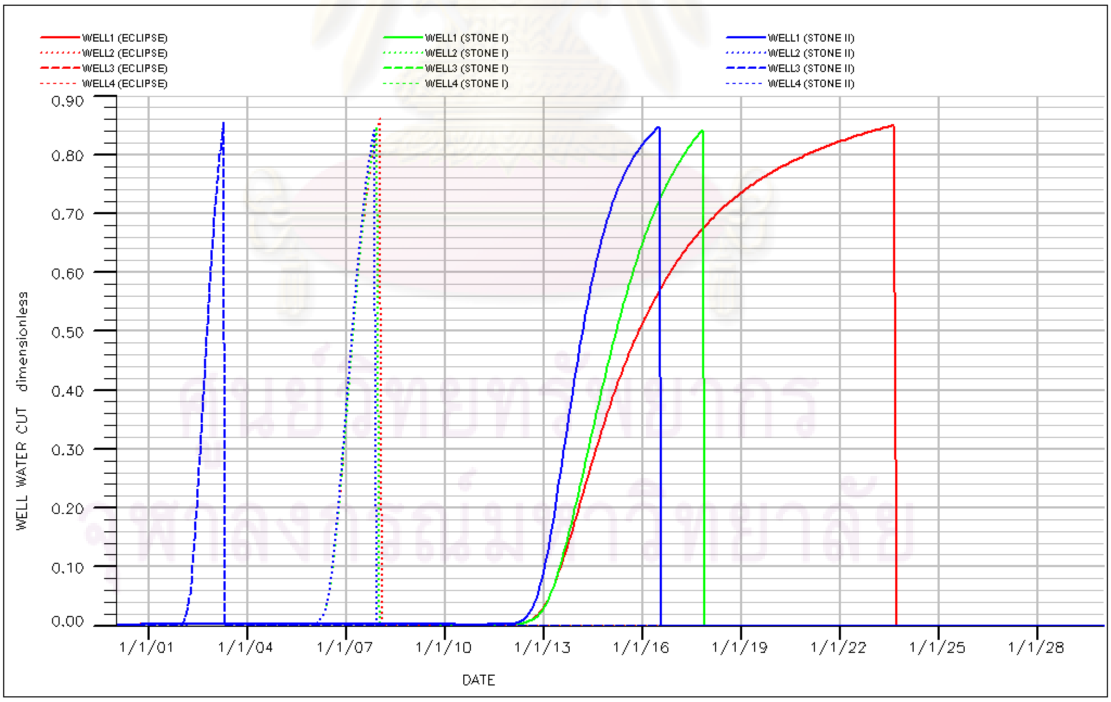


Figure 5.66: Comparison of water production profiles based on different relative permeability correlations for waterflooding

As shown in Figures 5.63 to 5.65, using different three phase relative permeability correlations results in similar production profile for well 2 and well 3. Stone II model is the first correlation to reach the water cut limit while Stone I model and the default function is second and last, respectively. Summary of recovery factors and production life is shown in Table 5.9. The simulation results indicate that ECLIPSE default model delivers the highest RF with the longest production time while Stone II model yields the smallest RF and shortest production time.

Table 5.9: Summary of recovery factors based on different relative permeability correlations for waterflooding.

Correlation	Production performance	
	RF (%)	Production life (years)
ECLIPSE default	52.904	22.647
Stone I	49.513	16.808
Stone II	47.523	15.494

After understanding the effect of relative permeability correlation on performance of waterflooding, now we switch to investigate its effect on DDP by continuing the simulation with gas injection. The results are shown in Figures 5.67 to 5.70. At the final life of the DDP for each correlation, the oil recoveries obtained from difference correlations are slightly different in percentage but there is a moderate different in time of production as shown in Table 5.10. In case of ECLIPSE default model compared with stone I or stone II models which give similar result, lag in time of production is about six to seven years.

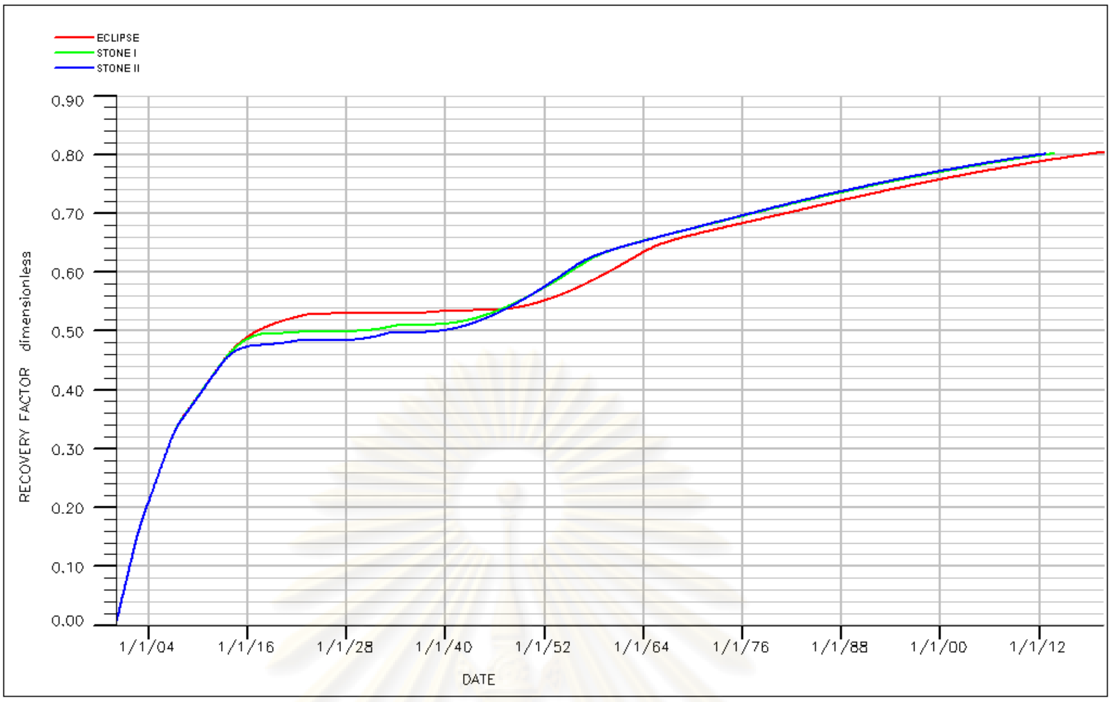


Figure 5.67: Oil recovery factors based on different relative permeability correlations for DDP.

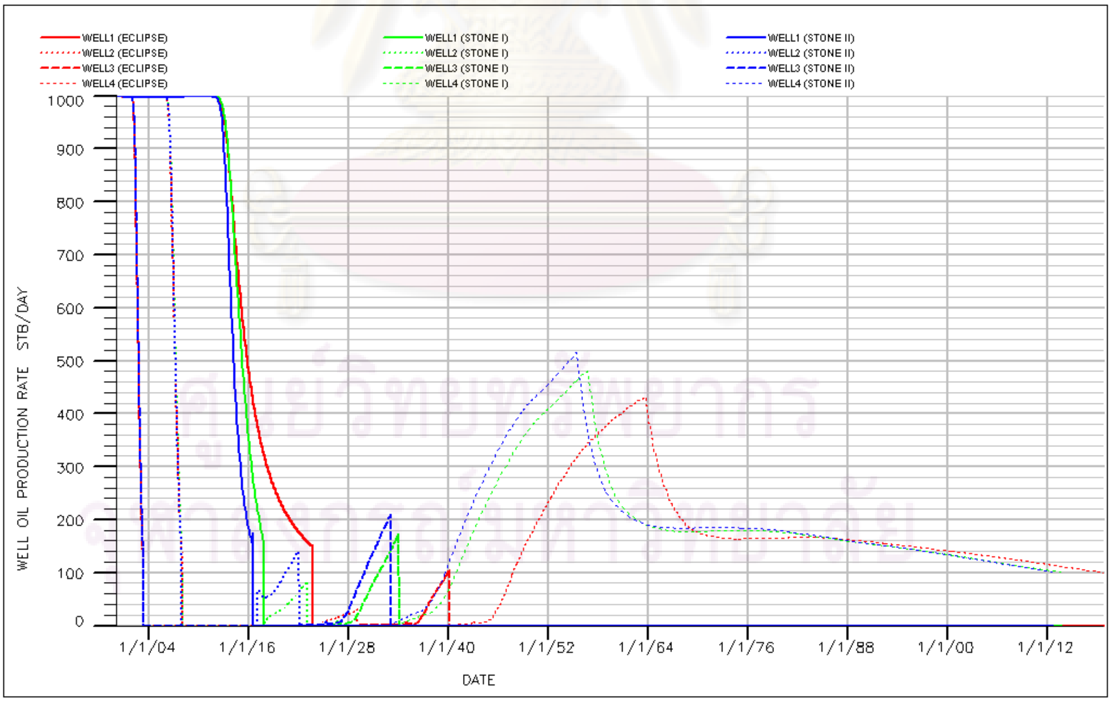


Figure 5.68: Comparison oil production profiles based on different relative permeability correlations for DDP.

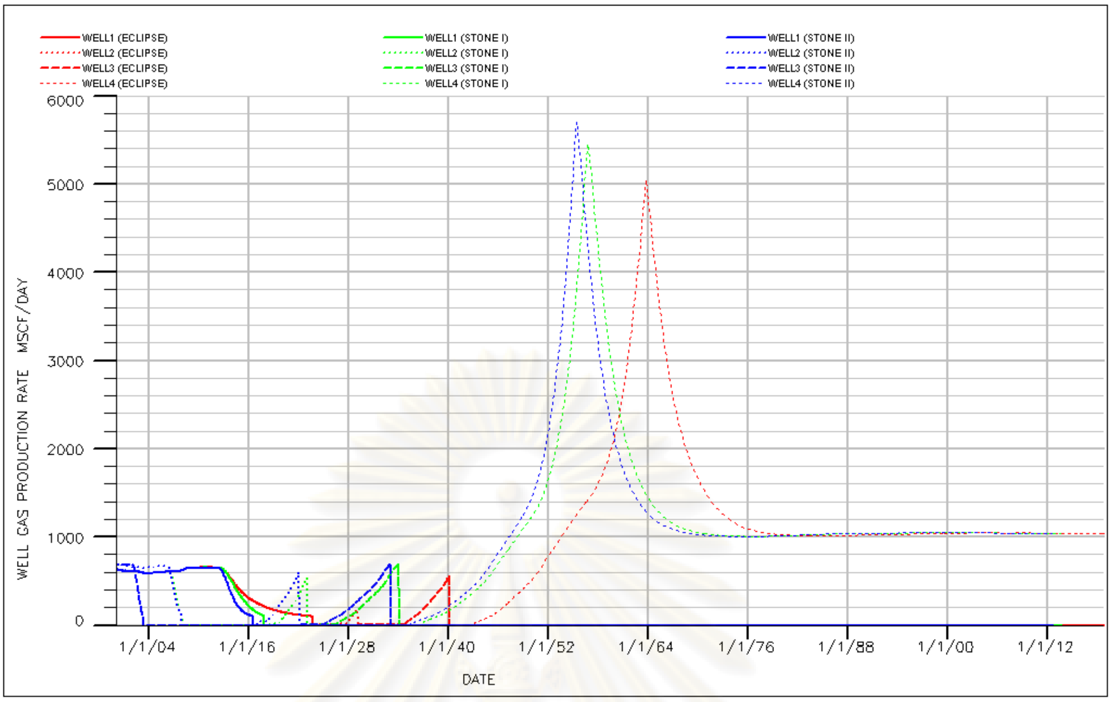


Figure 5.69: Comparison gas production profiles based on different relative permeability correlations for DDP.

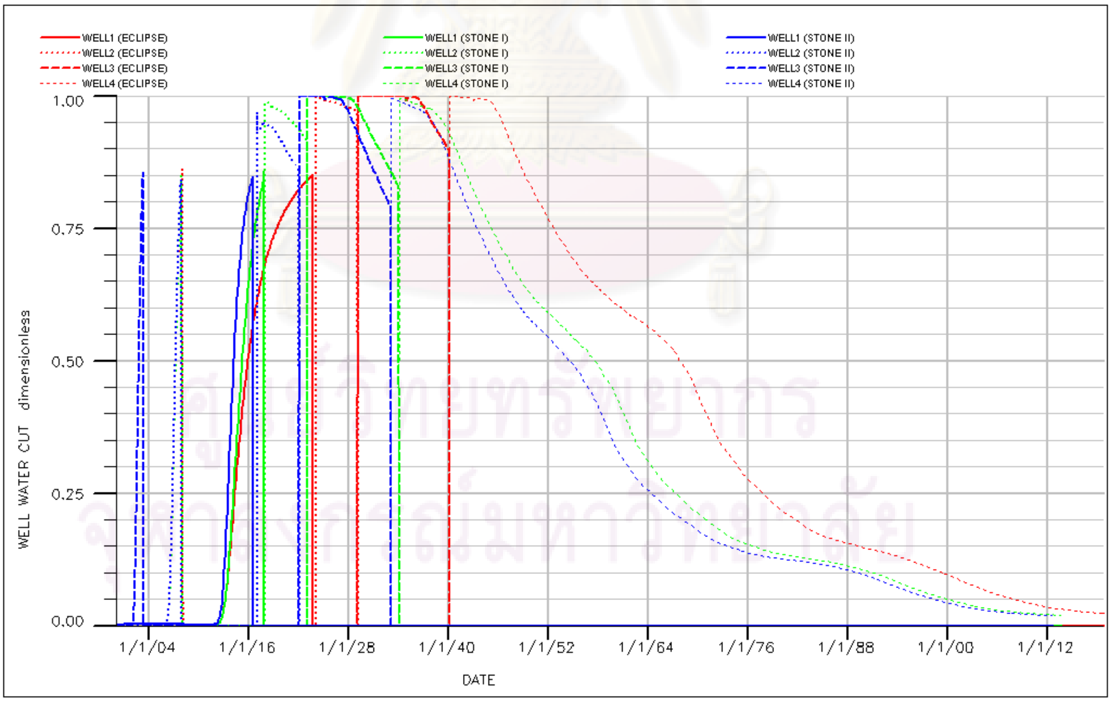


Figure 5.70: Comparison water production profile based on different relative permeability correlations for DDP.

In summary, different three-phase relative permeability models have an effect on production life time but no effect on oil recovery in DDP as seen in Table 5.10.

Table 5.10: Summary of recovery factors based on different relative permeability correlations for DDP.

Correlation	Production performance	
	RF (%)	Production life (years)
ECLIPSE default	80.212	117.764
Stone I	80.155	112.700
Stone II	80.092	111.700

5.3.2 Residual oil saturation in presence of connate water

In this case, the parameter of interest is residual oil in presence of water, S_{orw}. The value is changed from 0.2 to 0.3, which means that the residual oil left in the reservoir after waterflooding is more than the base case. In this section, we investigate the effect of residual oil saturation in presence of connate water on oil recovery. In the first set of simulation runs, we focus on waterflood process and the results are illustrated in Figures 5.71 to 5.74.

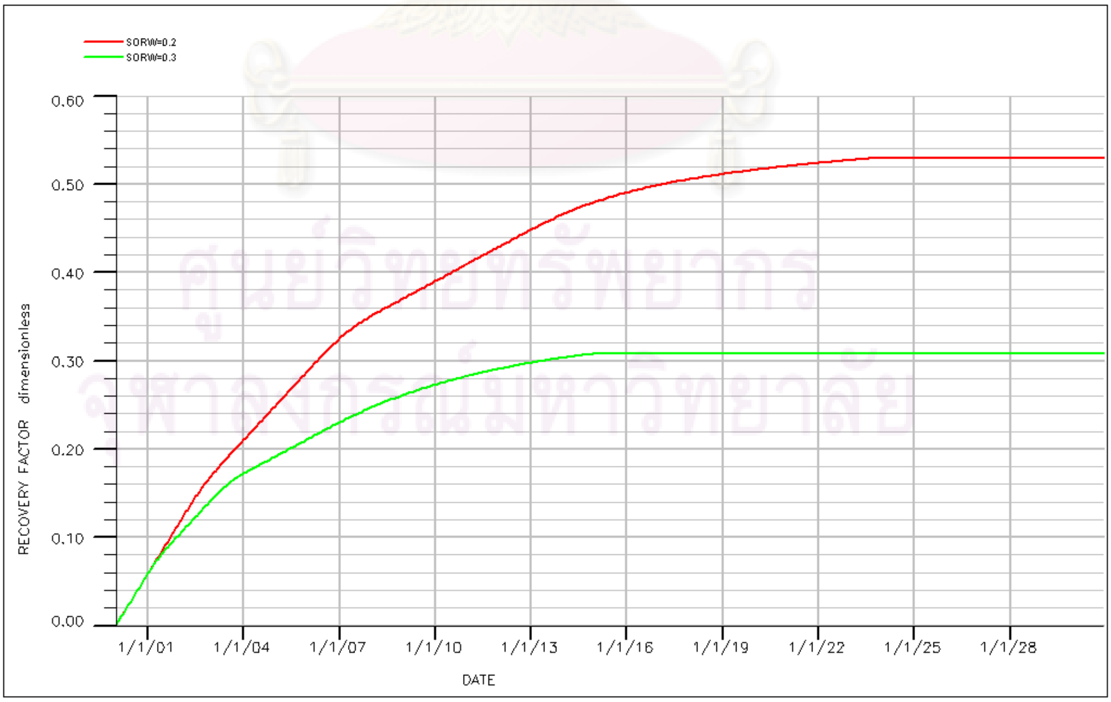


Figure 5.71: Oil recovery factors based on different residual oil saturations for waterflooding.

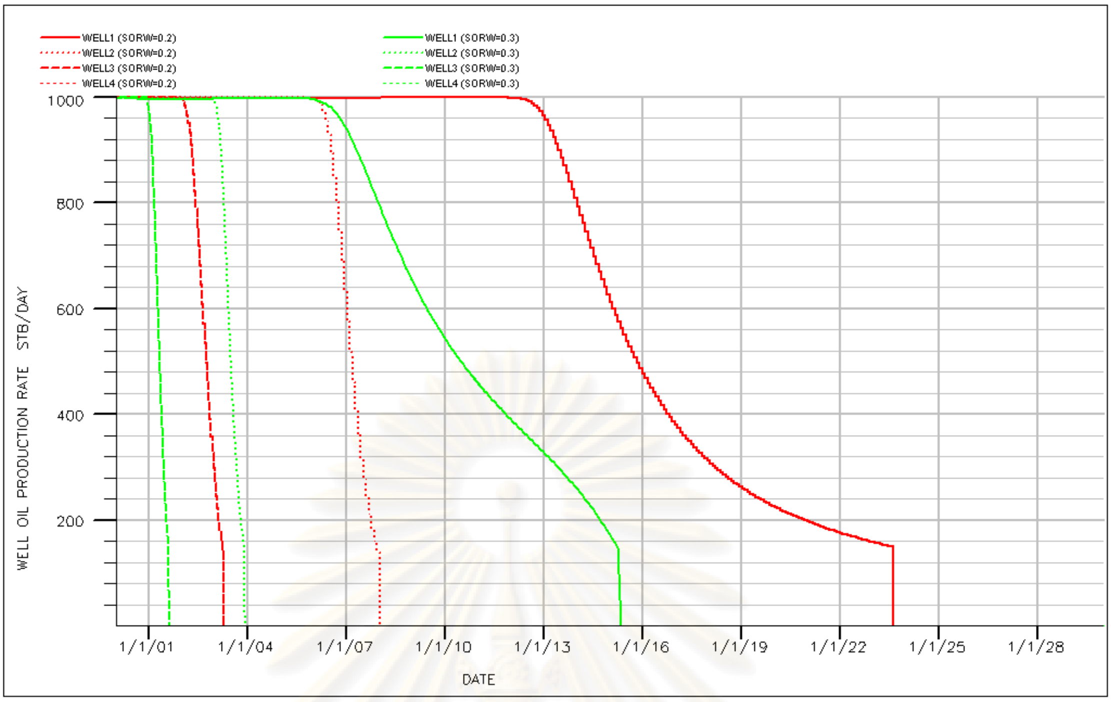


Figure 5.72: Comparison oil production profiles based on different residual oil saturations for waterflooding.

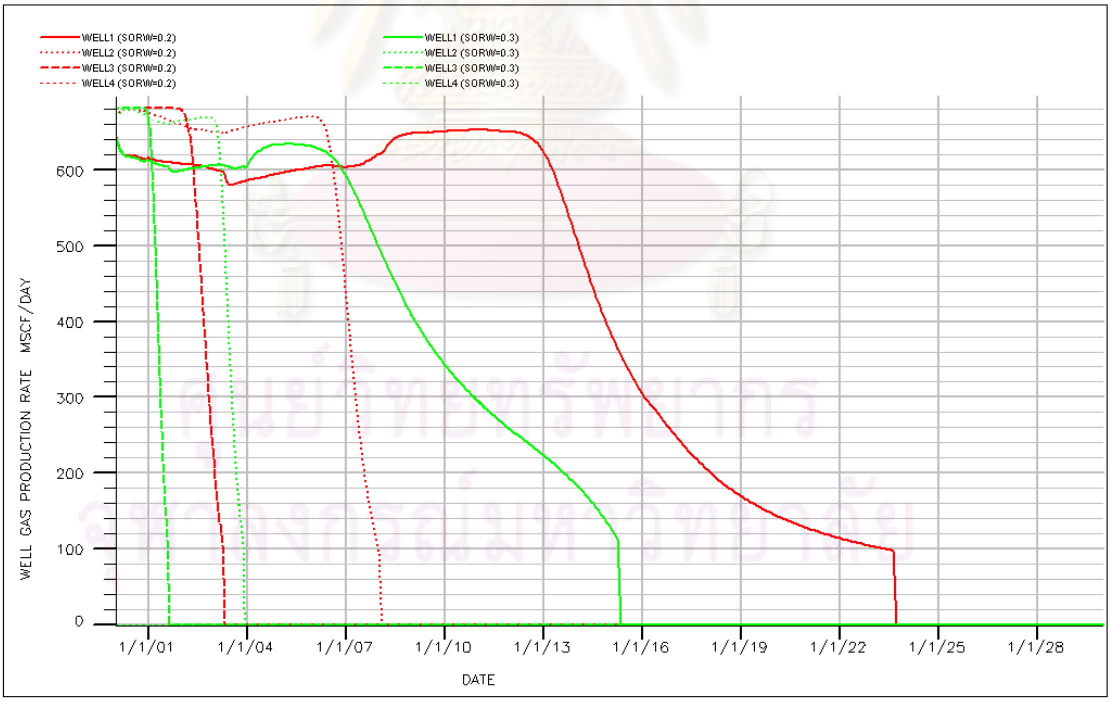


Figure 5.73: Comparison gas production profiles based on different residual oil saturations for waterflooding.

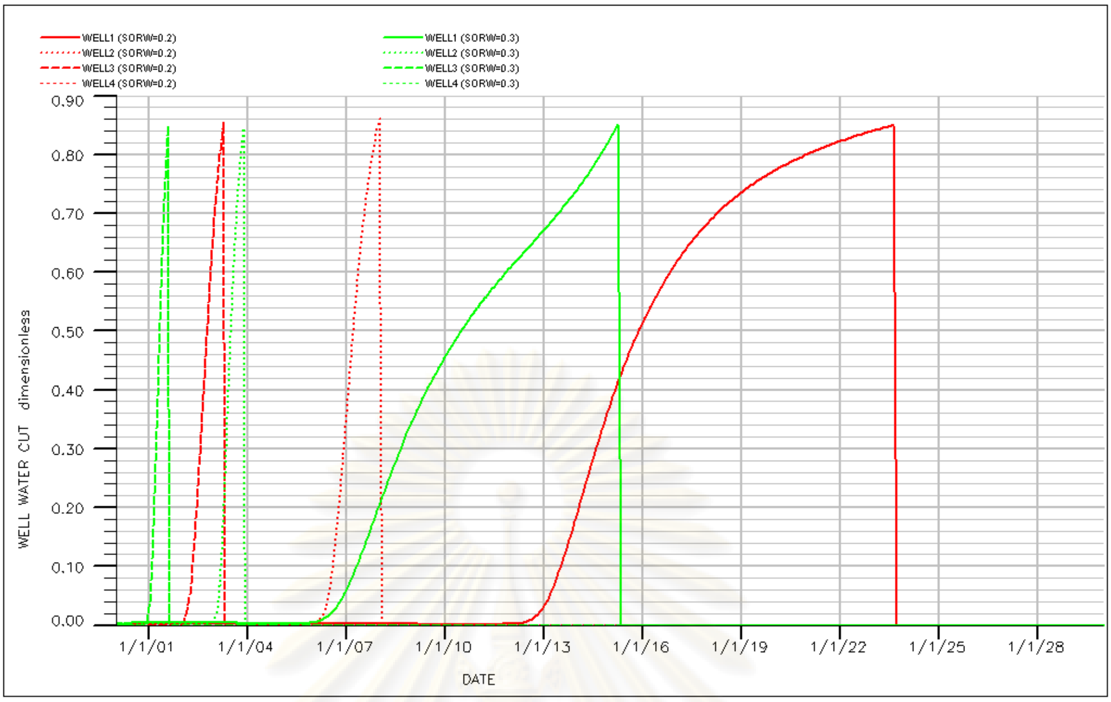


Figure 5.74: Comparison water production profiles based on different residual oil saturations for waterflooding.

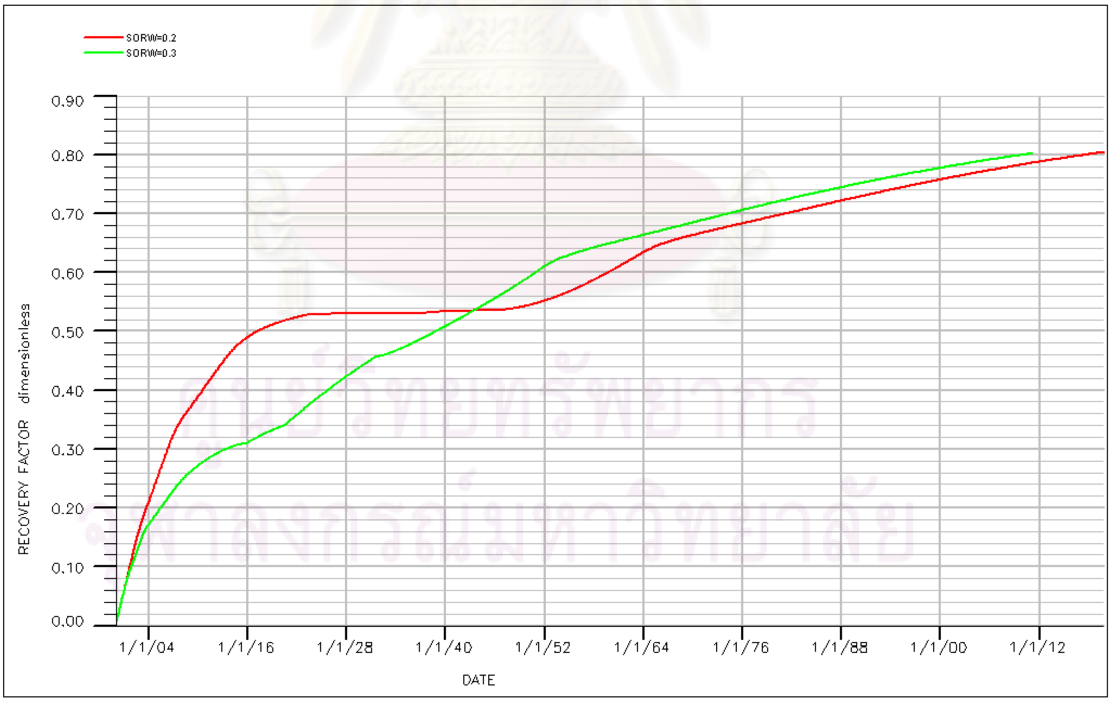


Figure 5.75: Oil recovery factors based on different residual oil saturations for DDP.

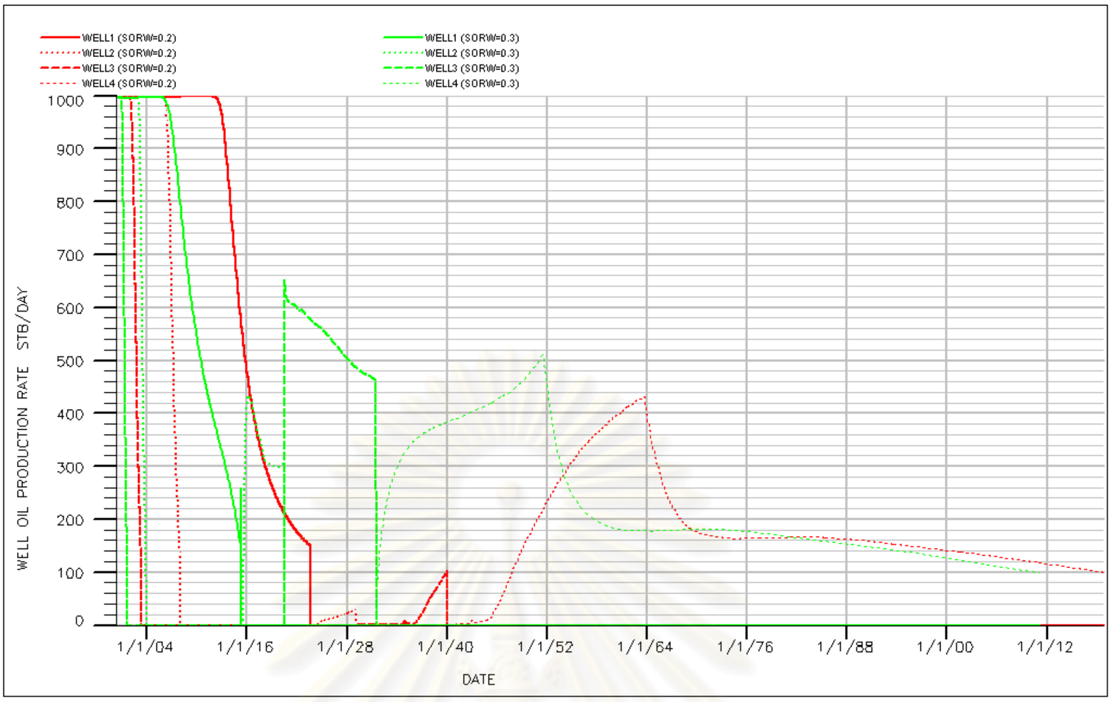


Figure 5.76: Comparison oil production profiles based on different residual oil saturations for DDP.

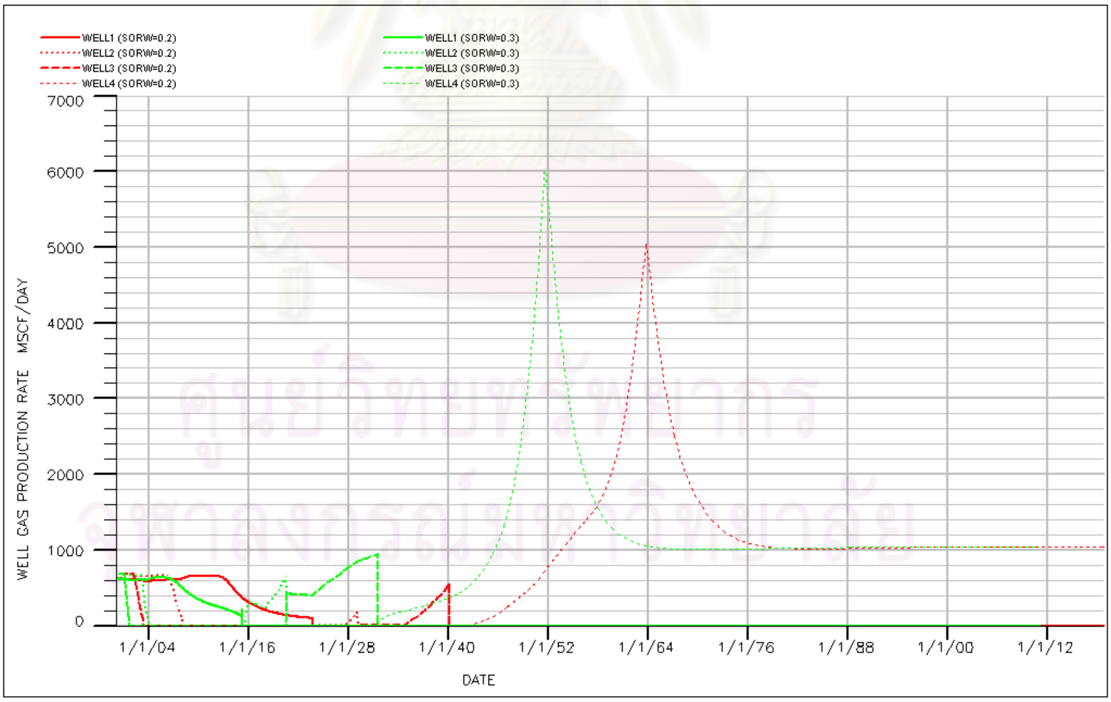


Figure 5.77: Comparison gas production profiles based on different residual oil saturations for DDP.

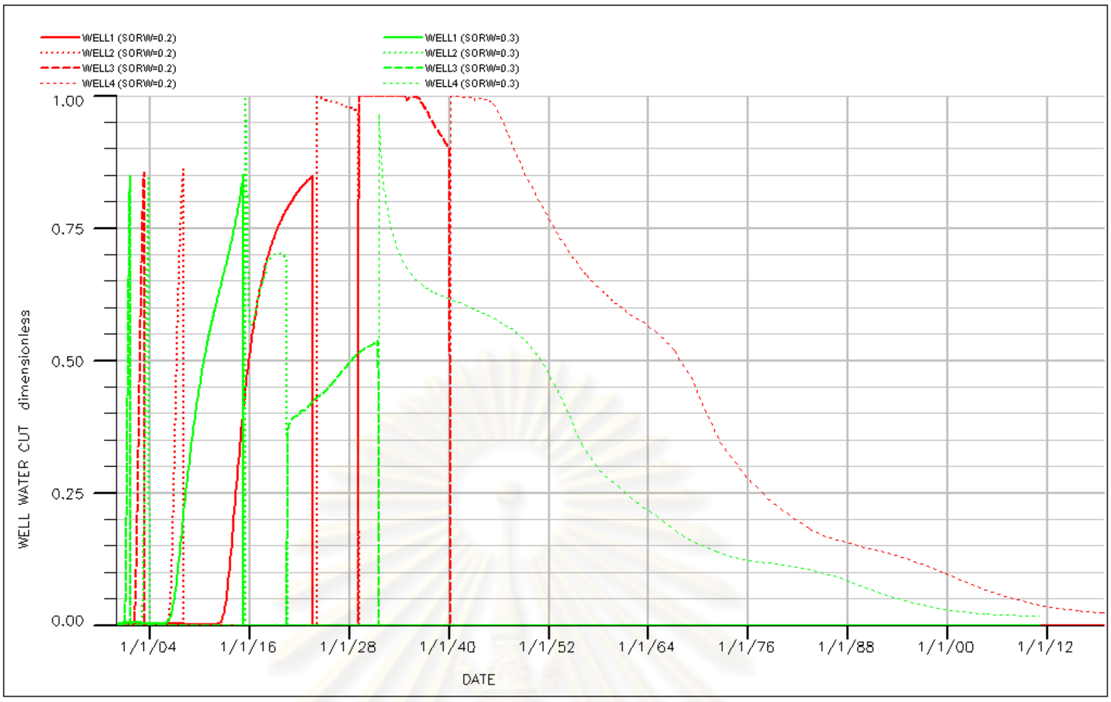


Figure 5.78: Comparison water production profiles based on different residual oil saturations for DDP.

The results are shown Figures 5.75 to 5.78. At the final life of the DDP for each residual oil saturation, the oil recovery obtained from different residual oil saturations are slightly different in percentage but there is a moderate difference in time of production as shown in Table 5.11. When comparing the base case with the case with change in residual oil saturation, recovery factors are similar but lag in time of production is about seven years.

Table 5.11: Summary of recovery factors based on different residual oil saturations for DDP.

Correlation	Production performance	
	RF (%)	Production life (years)
Base case	80.212	117.764
Change residual oil saturation	80.103	110.664

CHAPTER VI
CONCLUSION AND RECOMMENDATION

This chapter concludes the performance of double displacement process concerning with oil recovery factor and production life in term of comparison between conventional DDP and various alternative injections as well as effect of three-phase relative permeability correlation and residual oil saturation. Then some remarks for this thesis are noted.

6.1 Conclusions

Three reservoirs with different degrees of dipping, namely, 5, 10 (base case) and 20, were simulated for waterflooding in order to compare their performances. The result shows that all three cases give the best recovery factor under appropriate production time when the limit on water cut is 85%.

After waterflooding, all wells are shut in for the reservoir pressure to build up for a while. Then, gas injection is started to kick off the double displacement process. In this study, three scenarios for gas injection are investigated: (1) gas is injected at the most updip well (conventional DDP), (2) gas is injected at the second most updip well, and (3) gas is injected at the most updip well first and then at the second most updip well. The results indicate that there is very small difference in RF for different injection strategies. However, for 5-degree dipping reservoir, injecting gas at well 2 gives the shortest production time. For 10-degree dipping reservoir, conditional DDP (injecting gas at well 1) gives the shortest production time. For 20-degree dip angle, the production times are similar for all strategies.

Sensitivity cases are conducted to observe the uncertainty of different three-phase relative permeability models on the double displacement process. Many correlations have been proposed since 1950's but it is unknown which one is the most proper model. This is one uncertainty when simulating three-phase flow in the reservoir. From the evaluation of the double displacement process in reservoir simulator, different three-phase relative permeability models result in difference in oil recovery factor up to 5% for waterflood. However, they make almost no difference in determining the recovery for DDP. Nevertheless, these models result in different time of production for about 6 years.

Another sensitivity case is the study of effect of residual oil saturation. In this case, the residual oil saturation is increased from 0.2 to 0.3. The same process as the base case is repeated. The results are better than the base case because it consumes less production time for the same amount of oil recovery.

All important results can be summarized as follows :

1. Changing injector location to be downdip can effectively improve the oil production in low degree dipping reservoir due to less production time for the same amount of oil recovery but it gives negative effect for intermediate dip angle since it does not allow the oil to flow downdip effectively due to injection rate.
2. High degree of dipping reservoir is governed by gravitational force. Then changing injector location to be downdip has no effect on oil production. This result indicates that we can change location of injection well if a certain injector fails under certain circumstances.
3. For three-phase relative permeability, different correlations have no effect on oil recovery factor but they have moderate effects on production life.
4. High residual oil saturation in presence of water is better than low residual oil saturation case because oil globules can be easily reconnected and flow downdip to the producer.

6.2 Recommendations

Recommendations for further study are as follows:

1. Reservoir simulator in this study is ECLIPSE 100 and there are only three three-phase relative permeability correlations available. ECLIPSE 300 has more options to study three-phase relative permeability correlations such as IKU and ODD3P.
2. In this study, only four operating wells are constructed. Increasing the number of operating wells should provide more details on the results.
3. Other flooding patterns such as five-spot pattern may be applied to the reservoir for further study.
4. Horizontal well may be used instead of vertical well.

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APPENDIX

APPENDIX

ECLIPSE 100 INPUT DATA FOR MODELS

Reservoir model

The reservoir simulation model is constructed by inputting the required data in Eclipse simulator. The geological model comprises of number of cells or blocks in the direction of *X, Y* and *Z*. The number of block in this study is 73 x 31 x 21.

1. Case Definition

Simulator : BlackOil

Model dimensions

Number of grid in x direction : 73

Number of grid in y direction : 31

Number of grid in z direction : 21

Simulation start date : 1 Jan 2000

Grid type : Cartesian

Geometry type : Corner Point

Oil-gas-water properties: Water, oil, gas and dissolved gas

Solution type : Fully Implicit

2. Grid

Properties

Active Grid Block	X(1-73)	= 1
	Y(1-31)	= 1
	Z(1-21)	= 1

X Permeability : 32.529 md

Y Permeability : 32.529 md

Z Permeability : 32.529 md

Porosity : 0.1509

Dip angle : 10 degree in base case

Grid block sizes : based on calculation with dip angle

Geometry

Grid Block Coordinate Lines

Grid Block Corners

Grid data units

Grid Axes wrt Map Coordinatesr

3. PVT

Fluid densities at surface conditions

Oil density : 51.6375 lb/ft^3

Water density : 62.42841 lb/ft^3

Gas density : 0.04981752 lb/ft^3

Water PVT properties

Reference pressure (Pref) : 3000 psia

Water FVF at Pref : 1.021057 rb/stb

Water compressibility : 3.083002 x 10^{-6} psi^{-1}

Water viscosity at Pref : 0.3051548 cp

Water viscosity : 3.350528 x 10^{-6} psi^{-1}

Live oil PVT properties (dissolved gas)

Rs (Mscf /stb)	Pbub (psia)	FVF (rb /stb)	Visc (cp)
0.0014870228	14.7	1.0681108	1.3127257
	277.08421	1.0526951	1.3925997
	539.46842	1.0522782	1.5344885
	801.85263	1.0521342	1.7211519
	1064.2368	1.0520612	1.9514282
	1326.6211	1.052017	2.22775
	1589.0053	1.0519875	2.5541898

	1851.3895	1.0519663	2.9358124
	2113.7737	1.0519504	3.3783753
	2377.1	1.051938	3.8901081
	2638.5421	1.0519281	4.4717768
	3000	1.0519172	5.4094568
	3163.3105	1.0519131	5.8882815
	3425.6947	1.0519074	6.735162
	3688.0789	1.0519025	7.6836247
	3950.4632	1.0518982	8.7401876
	4212.8474	1.0518944	9.9108943
	4475.2316	1.0518911	11.20115
	4737.6158	1.0518882	12.615558
	5000	1.0518856	14.157761
0.051143728	277.08421	1.0906066	1.0422891
	539.46842	1.0811864	1.0728171
	801.85263	1.0779506	1.1200812
	1064.2368	1.076314	1.1805878
	1326.6211	1.075326	1.2528013
	1589.0053	1.0746648	1.335993
	1851.3895	1.0741912	1.4298355
	2113.7737	1.0738354	1.53422
	2377.1	1.0735573	1.6495903

	2638.5421	1.0733362	1.7747267
	3000	1.073094	1.9653042
	3163.3105	1.0730028	2.0581591
	3425.6947	1.0728744	2.2162075
	3688.0789	1.0727643	2.3852196
	3950.4632	1.0726689	2.5651972
	4212.8474	1.0725853	2.7560864
	4475.2316	1.0725115	2.9577697
	4737.6158	1.0724459	3.1700599
	5000	1.0723872	3.3926957
0.11413173	539.46842	1.1200769	0.85185024
	801.85263	1.1124111	0.87503364
	1064.2368	1.1085461	0.90716134
	1326.6211	1.1062164	0.94682385
	1589.0053	1.1046589	0.99323509
	1851.3895	1.1035442	1.0459281
	2113.7737	1.102707	1.1046148
	2377.1	1.102053	1.1693534
	2638.5421	1.1015331	1.2392961
	3000	1.1009639	1.3451364
	3163.3105	1.1007495	1.3963907
	3425.6947	1.1004478	1.4831583

	3688.0789	1.1001891	1.5753064
	3950.4632	1.0999649	1.6727454
	4212.8474	1.0997686	1.7753668
	4475.2316	1.0995953	1.8830397
	4737.6158	1.0994413	1.9956076
	5000	1.0993035	2.1128867
0.18398687	801.85263	1.1538138	0.72366775
	1064.2368	1.1468702	0.74289016
	1326.6211	1.1426948	0.76776202
	1589.0053	1.1399068	0.79755867
	1851.3895	1.1379132	0.83181974
	2113.7737	1.1364169	0.87023804
	2377.1	1.1352486	0.91275774
	2638.5421	1.1343203	0.95874389
	3000	1.1333042	1.0282869
	3163.3105	1.1329215	1.0619139
	3425.6947	1.1323833	1.1187417
	3688.0789	1.1319218	1.1789424
	3950.4632	1.1315218	1.2424221
	4212.8474	1.1311718	1.3090806
	4475.2316	1.1308629	1.3788081
	4737.6158	1.1305882	1.4514836

	5000	1.1303425	1.5269729
0.25876733	1064.2368	1.1909941	0.63258723
	1326.6211	1.1843639	0.64918223
	1589.0053	1.1799457	0.66968305
	1851.3895	1.17679	0.69366217
	2113.7737	1.1744233	0.72082241
	2377.1	1.1725767	0.75106278
	2638.5421	1.17111	0.78388155
	3000	1.1695053	0.8336094
	3163.3105	1.1689012	0.8576684
	3425.6947	1.1680517	0.89832076
	3688.0789	1.1673235	0.94135868
	3950.4632	1.1666924	0.98669539
	4212.8474	1.1661403	1.0342428
	4475.2316	1.1656531	1.0839094
	4737.6158	1.16522	1.1355981
	5000	1.1648325	1.1892055
0.33745756	1326.6211	1.2311619	0.56461085
	1589.0053	1.2246405	0.57928812
	1851.3895	1.219991	0.59682546
	2113.7737	1.2165075	0.6169469
	2377.1	1.2137915	0.63953146

	2638.5421	1.2116356	0.66416732
	3000	1.2092783	0.70163245
	3163.3105	1.2083911	0.71979153
	3425.6947	1.2071439	0.75049948
	3688.0789	1.2060752	0.78302451
	3950.4632	1.2051492	0.81728774
	4212.8474	1.2043391	0.85321166
	4475.2316	1.2036245	0.89071812
	4737.6158	1.2029894	0.92972683
	5000	1.2024213	0.97015431
0.41942037	1589.0053	1.2740113	0.51185961
	1851.3895	1.2674798	0.52505391
	2113.7737	1.2625948	0.54042737
	2377.1	1.2587895	0.55785601
	2638.5421	1.2557711	0.57699221
	3000	1.2524727	0.60623863
	3163.3105	1.251232	0.62045321
	3425.6947	1.2494883	0.64452646
	3688.0789	1.2479947	0.67005552
	3950.4632	1.2467009	0.69696847
	4212.8474	1.2455694	0.72519626
	4475.2316	1.2445714	0.75467084

	4737.6158	1.2436846	0.78532382
	5000	1.2428914	0.81708552
0.50421417	1851.3895	1.3193158	0.46964597
	2113.7737	1.3126977	0.48164739
	2377.1	1.3075514	0.49541011
	2638.5421	1.3034726	0.51064106
	3000	1.2990188	0.53406259
	3163.3105	1.2973444	0.54548646
	3425.6947	1.294992	0.56487279
	3688.0789	1.2929778	0.58546906
	3950.4632	1.2912336	0.60720924
	4212.8474	1.2897087	0.63003098
	4475.2316	1.288364	0.65387395
	4737.6158	1.2871695	0.67867861
	5000	1.2861013	0.7043852
0.59151284	2113.7737	1.3668978	0.43502622
	2377.1	1.3601181	0.44608218
	2638.5421	1.354754	0.45842418
	3000	1.3489019	0.47754232
	3163.3105	1.3467031	0.48690704
	3425.6947	1.3436153	0.50283897
	3688.0789	1.3409726	0.51980481

	3950.4632	1.3386851	0.53774344
	4212.8474	1.3366858	0.55659793
	4475.2316	1.3349234	0.57631399
	4737.6158	1.3333581	0.59683878
	5000	1.3319587	0.61812005
0.68138989	2377.1	1.4167945	0.40596797
	2638.5421	1.4098782	0.41610479
	3000	1.402347	0.43192938
	3163.3105	1.3995193	0.43971958
	3425.6947	1.3955503	0.45301233
	3688.0789	1.392155	0.46720754
	3950.4632	1.3892174	0.4822482
	4212.8474	1.3866508	0.49808183
	4475.2316	1.3843891	0.51465897
	4737.6158	1.382381	0.53193207
	5000	1.3805862	0.54985466

<u>Dry gas PVT properties (no vapourised oil)</u>

Press (psia)	FVF (rb /Mscf)	Visc (cp)
14.7	224.98177	0.012741923
277.08421	11.543356	0.012967158
539.46842	5.7371338	0.01333718
801.85263	3.7395964	0.01382739

1064.2368	2.7357394	0.014438404
1326.6211	2.1378138	0.015173748
1589.0053	1.7463019	0.016033777
1851.3895	1.474605	0.017011783
2113.7737	1.278751	0.018092169
2377.1	1.1332741	0.019255859
2638.5421	1.0240261	0.020462762
3000	0.91256865	0.0221679
3163.3105	0.87309757	0.022938749
3425.6947	0.82007509	0.024164955
3688.0789	0.77698746	0.02536693
3950.4632	0.74140401	0.026538225
4212.8474	0.71157522	0.027675611
4475.2316	0.68622679	0.028778011
4737.6158	0.6644184	0.0298457
5000	0.64544666	0.030879758

Rock properties (For ECLIPSE 100)

Reference pressure : 2500 psia

Rock compressibility : 2.23183 x 10^{-6} psi^{-1}

4. SCAL

Wate/oil saturation functions

Sw	Krw	Kro	Pc (psia)
0.61	0	0.8	0
0.63111111	0.033333333	0.65483321	0
0.65222222	0.066666667	0.52184844	0
0.67333333	0.1	0.40154558	0
0.69444444	0.13333333	0.29452809	0
0.71555556	0.16666667	0.20154856	0
0.73666667	0.2	0.12359015	0
0.75777778	0.23333333	0.062033847	0
0.77888889	0.26666667	0.019093156	0
0.8	0.3	0	0
1	1	0	0

Gas/oil saturation functions

Sg	Krg	Kro	Pc (psia)
0	0	0.8	0
0.04	0	0.56952423	0
0.07875	0.1	0.39186345	0
0.1175	0.2	0.25449763	0
0.15625	0.3	0.15274825	0
0.195	0.4	0.081776443	0

0.23375	0.5	0.036542626	0
0.2725	0.6	0.011742058	0
0.31125	0.7	0.0016860104	0
0.35	0.8	0	0
0.39	1	0	0

5. Initialization

Equilibration data specification

Datum depth : 6000 ft
Pressure at datum depth : 2377.1 psia
WOC depth : 12000 ft
GOC depth : 6000 ft

6. Regions : N/A

7. Schedule

In reservoir simulation model, each production well setting is described as follows:

7.1 Oil production well

Well specification

Well name : WELL1
Group : 1
I location : 1
J location : 16
Preferred phase : OIL
Inflow equation : STD
Automatic shut-in instruction : SHUT
Crossflow : YES
Density calculation : SEG

Well connection data

Well connection data	: WELL1
K upper	: 8
K lower	: 12
Open/shut flag	: OPEN
Well bore ID	: 0.5522083 ft
Direction	: Z

Production well control

Well	: WELL1
Open/shut flag	: OPEN
Control	: LRAT
Liquid rate	: 1000 stb/day
BHP target	: 500 psia

Production well economic limits

Well	: WELL1
Maximum water cut	: 0.98
Workover procedure	: NONE
End run	: YES
Quantity for economic limit	: RATE
Secondary workover procedure	: NONE

There is a few difference in setting between production well and injection well. The first two setting, well specification and well connection data, are the same as previous but we need to change the keyword from production well control to be injection well control. When we start gas injection we change only the preferred phase and injection rate in injection well control.

7.2 Water injection well

<u>Well specification</u>

Well name	: WELL4
Group	: 4
I location	: 73
J location	: 16
Preferred phase	: WATER
Inflow equation	: STD
Automatic shut-in instruction	: SHUT
Crossflow	: YES
Density calculation	: SEG

<u>Well connection data</u>

Well connection data	: WELL4
K upper	: 8
K lower	: 12
Open/shut flag	: OPEN
Well bore ID	: 0.5522083 ft
Direction	: Z

<u>Injection well control</u>

Well	: WELL4
Injector type	: WATER
Open/shut flag	: OPEN
Control mode	: RATE
Liquid surface rate	: 3800 stb/day
BHP target	: 5000 psia

7.3 Gas injection well

Well specification

Well name	: WELL1
Group	: 1
I location	: 1
J location	: 16
Preferred phase	: GAS
Inflow equation	: STD
Automatic shut-in instruction	: SHUT
Crossflow	: YES
Density calculation	: SEG

Well connection data

Well connection data	: WELL1
K upper	: 8
K lower	: 12
Open/shut flag	: OPEN
Well bore ID	: 0.5522083 ft
Direction	: Z

Injection well control

Well	: WELL1
Injector type	: GAS
Open/shut flag	: OPEN
Control mode	: RATE
Liquid surface rate	: 1000 Mscf/day
BHP target	: 5000 psia

VITAE

Theesis Suwannakul was born on April 18, 1984 in Bangkok, Thailand. He graduated from Department of Mining and Petroleum Engineering in Mining Engineer from the Faculty of Engineering, Chulalongkorn University in 2007. After graduating, he worked for his family for one year and then he started his to study in the Master of Petroleum Engineering program at the Department of Mining and Petroleum Engineering Faculty of Engineering in 2008.