EVALUATION OF OIL RECOVERY BY ALKALI/SURFACTANT FLOODING IN MULTI-LAYERED CARBONATE RESERVOIRS WITH DIFFERENT PORE SIZES

Mr. Arnon Larpkachornsanguan

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การประเมินปริมาณน้ำมันที่ผลิตได้จากวิธีการแทนที่ด้วยสารละลายผสมระหว่างสารอัลคาไลน์และสารลดแรงตึงผิวในแหล่งกักเก็บหินปูนหลายชั้นที่มีขนาดรูพรุนต่างกัน

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Thesis Title	EVALUATION OF OIL RECOVERY BY ALKALI/SURFACTANT FLOODING IN MULTI-LAYERED CARBONATE RESERVOIRS WITH DIFFERENT PORE SIZES
By	Mr. Arnon Larpkachornsanguan
Field of Study	Petroleum Engineering
Thesis Advisor	Falan Srisuriyachai, Ph.D.
Thesis Co-advisor	Assistant Professor Suwat Athichanagorn, Ph.D.

Accepted by the Faculty of Engineering, Chulalongkorn University in Partial Fulfillment of the Requirements for the Master's Degree

……………………..................Dean of the Faculty of Engineering
(Associate Professor Boonsom Lerdhirunwong, Dr.Ing.)

THESIS COMMITTEE

…………………….............................. Chairman
(Associate Professor Sarithdej Pathanasethpong)

…………………….............................. Thesis Advisor
(Falan Srisuriyachai, Ph.D.)

……………………................................ Thesis Co-advisor
(Assistant Professor Suwat Athichanagorn, Ph.D.)

…………………….............................. Examiner
(Kreangkrai Maneeintr, Ph.D.)

…………………….............................. External Examiner
(Wisarut Thungsuntornkhun, Ph.D.)

อานนท์ ลาภขจรสงวน : การประเมินปริมาณน้ำมันที่ผลิตได้จากวิธีการแทนที่ด้วยสารละลายผสมระหว่างสารอัลคาไลน์และสารลดแรงตึงผิวในแหล่งกักเก็บหินปูนหลายชั้นที่มีความพรุนต่างกัน. (EVALUATION OF OIL RECOVERY BY ALKALI/SURFACTANT FLOODING IN MULTI-LAYERED CARBONATE RESERVOIRS WITH DIFFERENT PORE SIZES) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: ดร. ฟ้าลั่น ศรีสุริยชัย, อ.ที่ปรึกษาวิทยานิพนธ์ร่วม: ผศ.ดร. สุวัฒน์ อธิชนากร, 104 หน้า.

แหล่งกักเก็บน้ำมันแบบหินปูนมักให้ผลผลิตน้ำมันไม่ดีเท่าที่ควร น้ำมันส่วนใหญ่ตกค้างอยู่ในรูพรุนของหินที่มีขนาดเล็กอันเนื่องมาจากแรงดันคาปิลลารีที่สูง ดังนั้นการฉีดอัดด้วยน้ำจึงสามารถผลิตน้ำมันได้จากรูพรุนที่มีขนาดใหญ่เท่านั้น แหล่งกับเก็บหินปูนหลายชั้นที่มีความพรุนที่ต่างกันเกิดขึ้นจากการตกตะกอนทับถมต่างเวลาและต่างสภาพแวดล้อม สารอัลคาไลน์และสารลดแรงตึงผิวสามารถนำมาฉีดอัดเพื่อเอาชนะแรงดันคาปิลลารีที่สูงระหว่างน้ำมันที่หลงเหลือและพื้นผิวของหินได้

การศึกษานี้มุ่งเน้นที่การทำให้เหมือนจริงบนแบบจำลองแหล่งกักเก็บเพื่อศึกษาผลกระทบของตัวแปรต่าง ๆ ต่อประสิทธิภาพของการฉีดอัดสารละลายผสมระหว่างสารอัลคาไลน์และสารลดแรงตึงผิวในแหล่งกักเก็บหินปูนหลายชั้นที่มีความพรุนต่างกัน การบ่งชี้แบบจำลองขั้นต้นที่เหมาะสมเป็นขั้นแรกของการศึกษานี้

จากผลการศึกษาบนแบบจำลองพบว่าประสิทธิภาพของการผลิตน้ำมันด้วยการฉีดอัดสารละลายผสมอยู่ในช่วง 40 ถึง 50 เปอร์เซ็นต์ ขึ้นอยู่กับการออกแบบตัวแปรต่าง ๆ ในขณะที่การฉีดอัดด้วยน้ำให้ประสิทธิภาพการผลิตน้ำมันเพียงแค่ 25 เปอร์เซ็นต์เท่านั้น การฉีดอัดน้ำก่อนสารละลายผสมไม่มีความจำเป็นในการศึกษานี้เนื่องจากจะทำให้สารเคมีเจือจางลง ขนาดของกลุ่มก้อนสารละลายผสมที่ 0.2 เท่าของขนาดความพรุนทั้งหมดให้ประสิทธิภาพการผลิตน้ำมันที่ดีที่สุดในขณะที่ความเข้มข้นของสารลดแรงตึงผิวควรอยู่ที่ความเข้มข้นที่ทำให้เกิดอนุภาคไมเซลล์ ความแตกต่างของขนาดรูพรุนมาก ๆ และความสามารถในการไหลในแนวตั้งให้ผลดีต่อการผลิตเนื่องจากช่วยยืดอายุของการผลิตได้ ความสามารถในการไหลสัมพัทธ์ของการไหลในรูปแบบเนื้อเดียวส่งผลกระทบต่อประสิทธิภาพการผลิตของสารละลายผสมของสารอัลคาไลน์และสารลดแรงตึงผิวมากกว่าความสามารถในการไหลสัมพัทธ์ของการไหลในรูปแบบเนื้อผสม

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สาขาวิชา วิศวกรรมปิโตรเลียม ลายมือชื่อ อ.ที่ปรึกษาวิทยานิพนธ์หลัก
ปีการศึกษา 2555 ลายมือชื่อ อ.ที่ปรึกษาวิทยานิพนธ์ร่วม

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ARNON LARPKACHORNSANGUAN EVALUATION OF OIL RECOVERY BY ALKALI/SURFACTANT FLOODING IN MULTI-LAYERED CARBONATE RESERVOIRS WITH DIFFERENT PORE SIZES. ADVISOR: FALAN SRISURIYACHAI, Ph.D., CO-ADVISOR: ASST. PROF. SUWAT ATHICHANAGORN, Ph.D., 104 pp.

Carbonate reservoirs can severely yield oil recovery. Major part of residual oil remains in small pores due to high capillary pressure. Waterflooding therefore ca recover oil only large. Carbonate reservoir can be found as layers with different pore sizes. This structure is naturally formed by different sediments in different environments. Surface active agents such as alkaline substances and surfactants, can be injected to overcome high capillary pressure force between residual oil and rock surface.

This study involves with reservoir simulation to study the effects of several parameters on effectiveness of alkali/surfactant flooding in multi-layered carbonate reservoirs with different pore sizes. Optimized chemical flooding base case is first to be identified.

From simulation results, it shows that oil recovery efficiency obtained from alkali/surfactant flooding ranges from 40 to 50%, depending on design parameters, whereas waterflooding only yield 25%. Pre-flushed water is not required since it could reduce concentration of injected chemical. Optimum chemical slug size is 0.20PV, whereas critical micelles concentration is best concentration for. High contrast of pore size and high vertical permeability yield advantage on oil recovery factor due to extension of production life. Relative permeability of immiscible mode is more sensitive to efficiency of alkali/surfactant flooding compared to ones of miscible mode.

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

Page

List of Tables

Page

Page

List of Figures

Page

Page

Page

Page

List of Abbreviations

ASP	Alkali-Surfactant-Polymer
BHP	Bottomhole Pressure
Ca^{2+}	Calcium ion
CMC	Critical Micelle Concentration
cP	Centipoises
EOR	Enhance Oil Recovery
ESP	Electrical Submersible Pump
F or °F	Degree Fahrenheit
Ft	Feet
GOR	Gas Oil Ratio
IFT	Interfacial Tension
lb/ft^3	Pound per cubic feet
LB/LB	Pound per Pound of Reservoir Rock
LB/STB	Pound per Stock Tank Barrel
MMSTB	Million Stock Tank Barrel
mD	Millidarcy
Mg^{2+}	Magnesium ion
psia	Pounds per square inch absolute
PV	Pore Volume
PVT	Pressure-Volume-Temperature
rb/stb	Reservoir barrel per stock tank barrel
SCAL	Special core analysis
SCF/STB	Standard cubic feet per stock-tank barrel
STB/D	Stock tank barrel per day
µm	Micrometer
w/w	Weight by Weight

Nomenclatures

θ_c	Wetting angle of the liquid on the surface
E_D	Displacement efficiency
k	Absolute permeability of the porous media
k_h	Horizontal permeability
k_{rw}	Water relative permeability
k_{ro}	Oil relative permeability
k_v	Vertical permeability
μ_g	Viscosity of gas
μ_o	Viscosity of oil
P_c	Capillary pressure
r_c	Pore radius
ρ_o	Density of oil
ρ_w	Density of water
σ	Surface Tension
S_o	Oil saturation
S_w	Water saturation
S_{wco}	Connate water saturation

CHAPTER I

INTRODUCTION

1.1 Background

After certain period of oil production by means of natural force (so called primary recovery), reservoir pressure declines and oil recovery proportionally decreases. However, there is still large amount of oil remained in reservoir and the secondary recovery or waterflooding is commonly chosen to extend the life of reservoir. Enhanced Oil Recovery (EOR) or tertiary recovery can be alternately applied since it can recover up to 60% of the original oil in place when proper selection is performed [1].

One of the EOR methods, alkali flooding has been widely used to enhance oil recovery for long time. Alkaline substances enhance oil recovery by reacting with organic acids, resulting in generation of in-situ surfactant that is potential in reduction of Inter-Facial Tension (IFT) between oil and aqueous phases. Moreover, this group of chemical is also capable to alternate rock wettability to a more favorable condition for oil recovery mechanism. Together with surfactants, alkali aids a potential flood by reducing the IFT to an ultra-low condition at very low surfactant concentration and moreover, the hydroxide ions also prevents the highly adsorption rate of surfactant onto the rock surface [2].

Generally, carbonate reservoirs yield severely oil recovery according to its heterogeneity, presence of fractures and thief zones, unfavorable wetting condition, and also different types of porosity. Different types of porosity emerged during the geological time frame, resulting in a contrast between porosities: primary and secondary porosities. Due to different emerging pattern, these porosities normally have different in size. The bigger pores can be accessed easier than the smaller pores due to capillary pressure force. Therefore, waterflooding will recover oil mainly from larger pore volumes, leaving large in inaccessible micro pores volumes. Surface active agents such as alkaline substances or surfactants, can be applied in this case to reduce capillary force between residual oil and rock surface. In general, carbonate reservoir is not recommended for alkali flooding due to high adsorption rate. However, limestone with low content of swelling clay demonstrates good results with alkaline substance.

In this study, the black oil simulator **ECLIPSE®100** commercialized by GeoQuest Schlumberger is chosen. The reservoir model is constructed to have varying values of ratio between large and small pores within layers. The reservoir simulation is performed by varying the study parameters which are scenario of flooding, chemical slug size, surfactant concentration, ratio of pore size, ratio of vertical permeability and horizontal permeability, existence of mobile water and different relative permeability. The aim of this study is to evaluate the effects of both reservoir characteristics and operationally adjustable parameter on oil recovery efficiency. Recovery is chosen as major criteria for optimal condition judgment. Cumulative water production, production life, injection rate, oil and water production rate and field water cut are also included in the discussion.

1.2 Objectives

1. To study the effects of various operational parameters which are sequence of injected slugs, concentration of chemical slug and slug size on alkali/surfactant flooding in multi-layered carbonate reservoir with different pore sizes.
2. To evaluate the effect of several reservoir properties consisting of ratio between large and small pores in terms of pore size, reservoir anisotropy through k_v/k_h ratio, mobile connate water and exponential function of relative permeability curves on alkali/surfactant flooding in multi-layered carbonate reservoir with different pore sizes.

1.3 Outline of methodology

1. Construct a reservoir model consisting of three main layers. The middle one contains small pores whereas the top and bottom contain large pores.
2. Simulate the base case waterflooding on the constructed multi-layered carbonate reservoir with different pore sizes as reference case.
3. Optimize operational parameters of alkali/surfactant flooding on the constructed multi-layered carbonate reservoir with different pore sizes. Operation parameters in this study include:
    - Sequence of injection,
    - Slug size of chemical slug,
    - Surfactant concentration.
4. Perform sensitivity analysis of reservoir properties. Reservoir properties in this study are:
    - Ratio of pore sizes between large and small pores,
    - Ratio between vertical permeability and horizontal permeability
    - Existence of mobile connate water,
    - Corey's exponential of relative permeability curves for both immiscible and miscible modes.
5. Discuss all results from simulation for optimization of operational parameters and sensitivity study of reservoir properties.
6. Summarize the most suitable criteria for alkali/surfactant flooding in multi-layered carbonate reservoir with different pore sizes and also new finding from study.

1.4 Thesis outline

In this thesis, it is composed of six chapters as outline below:

Chapter I introduces background, objectives and methodology of the thesis.

Chapter II reviews previous studies on two main topics: alkali/surfactant flooding in carbonate reservoir and oil recovery in reservoirs containing different types of porosity.

Chapter III summarizes the relevant theories including alkali/surfactant flooding and development of porosity.

Chapter IV describes details of reservoir model composing of reservoir dimension and number of grid, number of layer in reservoir, reservoir geometry, PVT data, relative permeability and rock properties.

Chapter V expresses and discusses simulation results of alkali/surfactant flooding in multi-layered carbonate reservoirs with different pore sizes in term of oil recovery factor by comparing with the result obtained from base case waterflooding.

Chapter VI concludes the most suitable criteria for alkali/surfactant flooding in multi-layered carbonate reservoirs with different pore sizes.

1.5 Expected usefulness

This study emphasizes on reservoir simulation of multi-layered carbonate reservoirs with different pore sizes consists of a various ratio of large pores and small pores due to different sediments deposited and different environment in order to study possibility of alkali/surfactant flooding implementation in multi-layered carbonate reservoirs with different pore sizes. Main objectives are to determine optimal operation parameters for alkali/surfactant flooding and to study sensitivities of reservoir properties. Eventually, obtained data will be useful as screening criteria and guideline for alkali/surfactant flooding in multi-layered carbonate reservoirs with different pore sizes.

CHAPTER II

LITERATURE REVIEW

This chapter reviews previous studies on application of alkali/surfactant flooding in carbonate reservoirs and oil recovery in reservoirs containing different porosity. This part shows the benefits of using chemical flooding and general problems of reservoirs containing different porosity.

2.1 Application of alkali/surfactant flooding in carbonate reservoirs

The most common problem of alkali/surfactant flooding in carbonate reservoirs is the high consumption rate of injected alkali/surfactant by several mechanisms. Adsorption by carbonate rock is considered the major part of overall consumption. Moreover, precipitation of in-situ surfactant and divalent ions (Ca^{2+} and Mg^{2+}) and scaled formation can potentially results in damaging of formation by reducing the absolute permeability and therefore, result in loss of injectivity and failure of downhole equipment.

However, attempting to apply alkali/surfactant flooding in carbonate reservoir is still possible. Olsen et al. [3] investigated the oil recovery in an oil-wet cretaceous Upper Edwards reservoir in central Texas which is considered a good candidate for chemical flooding. As a result, an Alkali-Surfactant-Polymer (ASP) flooding was investigated at a lab level in order to evaluate the oil recovery through wettability alteration mechanism. The field was discovered in 1922 and produced by means of a strong natural water drive. At the end of 1980s, high water cut up to 99% was reported. Chemical flooding was considered to be the most promising EOR method to increase oil recovery in Upper Edwards. ASP formulations showed an increment of oil recovery compared to solely polymer flooding or combined alkali-polymer flooding. Although laboratory studies confirmed excellent oil-recovery rates with ASP formulation, ASP was not yet tested at a field level. Sodium carbonate (Na_2CO_3), was chosen as an alkaline substance in this study.

Berger and Lee [4] investigated the ASP flooding in limestone. They attempted to create a new type of surface active agent which was high tolerant to the divalent ions in brine phase. Therefore, normal brine could be used without the divalent ions removal. The alkaline substance was preferentially injected in order to reverse the surface charge and this resulted in reduction of surfactant adsorption.

Hirasaki and Zhang [5] studied the surface chemistry of fractured, oil-wet, carbonate formation. The oil recovery in fractured reservoir was often dependant from spontaneous imbibition. However, spontaneous imbibition in oil-wet carbonate surface was insignificant. Hirasaki and Zhang then attempted to reverse the wettability of carbonate rock to a more favorable condition by the use of sodium carbonate and anionic surfactant. They experimented with wettability reversal on calcite surface and they found that the positively-charged calcite surface could be reversed to negative through the presence of Sodium Hydrogen Carbonate ($NaHCO_3$)/ Sodium carbonate (Na_2CO_3) in brine. However, the wettability reversal of oil-wet calcite surface was a function of aging time, temperature, and surfactant formulation. The degree of wettability alteration observed was in the range of water-wet to intermediate-wet. In the core flood step, they concluded that oil displacement could occur by buoyancy since alkaline and surfactant reduced IFT and altered wettability to a more water-wet condition.

Anderson et al. [6] illustrated the sensitivity simulation results of ASP flooding for mixed-wet dolomite reservoir in the Permian Basin. Several study parameters affecting recovery factor such as surfactant concentration, surfactant slug size, amount of polymer used in polymer drive, salinity, surfactant adsorption and polymer adsorption were investigated. Their study concluded that alkaline substance reduces the surfactant adsorption and high surfactant concentration yields an increase of recovery factor. Moreover, increasing surfactant slug size had an effect on extension of recovery factor and high concentration of injected polymer solution also supported to get higher oil recovery. Besides, this simulation results showed that the salinity of surfactant and polymer slugs had not much effect on recovery factor. Increasing of surfactant adsorption resulted in less oil recovery but increasing of polymer adsorption resulted in higher recovery.

Bortolotti et al. [7] conducted a series of chemical flooding using the combination of alkaline and surfactant substances to enhcance oil recovery from carbonate samples. There were two mechanisms provided by the combination of chemicals that yield an improvement of oil recovery: 1) reduction the IFT between oil and water phases and 2) reversal of wettability from strongly oil-wet to a more favorable condition (neutral-wet or water-wet). When sample was flooded continuously, combination of alkali and surfactant substances yielded better result on enhancing oil production than using of solely alkali or solely surfactant. Moreover, it was also found that the higher the chemical concentration, the higher the oil recovery. On the other hand, when the flow was switched to intermittent to allow the chemical to completely react with rock surface (in order to reverse the wettability), oil recovery was sensitive to alkali concentration. Too high alkali concentration could yield insoluble soap precipitation. This compact soap consecutively obstructed the pore throats and caused the formation damage by reduction of absolute permeability.

Therefore, combination of alkali and surfactant flooding in carbonate reservoir can yield benefit on oil recovery from combination effects between reduction of IFT between oil and water phases and alteration of wettability from strongly oil-wet to a more favorable condition. As concentration and slug size of chemical are raised, oil recovery factor is improved. Main problem of using alkali and surfactant flooding in carbonate reservoir is surfactant adsorption. However, alkali can reduce surfactant adsorption.

2.2 Oil recovery in reservoir containing different types of porosity

The main problem of carbonate reservoir in oil recovery is due to heterogeneity of reservoir. There are several types of heterogeneity in carbonate reservoir such as presence of fracture and consisting of primary and secondary porosity/permeability.

Tabary et al. [8] obtained good results from experiments to improve oil recovery by means of chemical flooding in carbonate cores consisting of different pore sizes with two main classes of pores (0.2 μm and 6 μm). In this study, the screening of a surfactant for a carbonate formation was required. Low chemical adsorption and calcium tolerance are the important criteria for choosing type of surfactant. Typically, anionic sulfonates were not appropriate due to high adsorption rate and also terrible solubility in carbonate formation. Nonionic and mixed anionic-nonionic are more suitable for this case. However, their performances in aspect of IFT reduction are lower than the anionic sulfonates.

Kiani et al. [9] showed that surfactant could mobilize remaining oil in naturally fractured carbonate reservoirs to improve oil recovery. However, the main concern of surfactant flooding in naturally fractured carbonate reservoirs was the shallow penetration of surfactant into the rock matrix. But for the thick matrix blocks, there was often sufficient gravity force to drive surfactant solution into the rock matrix.

CHAPTER III

THEORY AND CONCEPT

This chapter summarizes the main theories about mechanism of alkali and surfactant flooding. Also, this chapter presents the concept of development of porosity of carbonate reservoir. In addition, the content includes effect of slug size and concentration of chemical flooding.

3.1 Alkali/Surfactant flooding

During the primary recovery, parts of oil are trapped in the reservoir formation due to unfavorable conditions for oil recovery mechanism. Secondary recovery by waterflooding is attempted to provide pressure to overcome the capillary force that entraps oil. However, some reservoir rocks can be strongly oil-wet due to the interaction between different charges, resulting in a very strong force between adsorbed compounds and rock surface. Waterflooding is then not adequate to overcome this entrapment force. Alkaline and surfactant substances which have several actions to improve the oil recovery by reducing this entrapment force are then chosen to resolve the problem.

Alkali flooding has been discovered in 1917 by Squires [2]. The alkaline substances were injected to react with the organic acids in oil phase in order to create the in-situ surfactants. Hence, fluid displacement process can be conducted at low IFT condition. Nowadays, it also has been proved that alkaline substances also create the emulsification between oil and water phases, solubilizing the rigid interfacial film which obstructs the in-situ surfactant, and reverse the rock wettability to a more favorable condition. The alkali flooding is relatively simple and inexpensive compared to other chemical flooding. However, the alkali flooding has also some restrictions and therefore, the confirmation from laboratory test is always required before a real implementation.

Sodium hydroxide (NaOH) is the most commonly used alkaline substance. It has shown the highest efficiency among other alkaline substances such as sodium orthosilicate ($2Na_2O \cdot SiO_2$), sodium carbonate (Na_2CO_3), ammonium hydroxide (NH_4OH), polyphosphate and hydroxylamine (NH_2OH).

A minimum acid number is one of the important keys for a successful of alkali flooding. In general, a value of 0.5 or greater is generally considered very favorable. The IFT is normally reduced to the lowest value when alkali concentration is at the optimal point. Lowering IFT is responsible for the emulsification: oil-in-water emulsion is produced and this results in the reduction of water mobility during displacement. Therefore, sweep efficiency is improved. However, after emulsification step, entrainment and entrapment of oil could happen.

Wettability reversal is also primarily considered as a function obtained from the use of alkaline substances. Naturally, heavy components in crude oil are believed to cause the wettability alteration from water-wet to oil-wet (from favorable to unfavorable direction) due to adsorption of these heavy components onto rock surface. In wettability literatures, it is known that wettability is strongly affected by pH of aqueous solution through reaction with the surface-active material adsorbed on the rock surface. This pH sensitively-changeable feature of alkaline solution is an aspect that superiors surfactant substances.

The main detrimental problem of alkali flooding is alkali consumption that causes the ineffectiveness in oil recovery. A presence of several minerals that can consume in reservoir rock therefore, results in a major screening criterion for alkali flooding.

Surfactant flooding shares similarity with alkali flooding, recovering oil from IFT reduction and wettability alteration. For IFT reduction, surfactant molecules are composed of two parts called polar part (water soluble) and non-polar part (oil soluble). From these two parts, surfactant molecules can generate emulsification of oil and water resulting from the IFT reduction between oil and water. When IFT decreases, capillary number is increased affecting increment of oil displacement efficiency. Furthermore, the use of surfactant results in an alteration of wettability by three different mechanisms: 1) remove attached oil, leaving surface less oil-wet. 2) co-adsorb on rock surface and 3) switch surface charge. The removal of attached oil from rock surface results from an ultra-low IFT condition. This mechanism however, does not change a preference of the rock surface. Co-adsorption occurs by surfactant molecules sticking their non-polar parts to attached oil on rock surface, leaving their polar part to stick with aqueous phase. This process alters wettability but does not really improve oil recovery. The switching of surface charge is similar to the effect obtained from alkaline substance. However, only cationic surfactants have this ability. Surfactant can be classified as anionic, cationic, nonionic and amphoteric types. Among these types, anionic surfactants are most widely used in EOR due to their lower adsorption onto reservoir rocks as compared to others. The most typical anionic surfactants are sulfonate compounds (e.g. petroleum sulfonate, ethoxylate sulfonate). The concentration of surfactant that yields the lowest value of IFT and correspondingly the best oil recovery is called a Critical Micelle Concentration (CMC) or a concentration where micelles are initially formed. However, there are also several disadvantages of surfactant flooding. The loss of surfactant when it comes into contact with reservoir rock and brine is quite high especially when rock formation and ionized surfactant have different charges. This could cause high depletion of surfactant within short time and low oil recovery improvement. The presence of divalent ions in connate water may result in precipitation of surfactant and consequently decreases the efficiency of oil displacement. Moreover, most surfactants degrade at high reservoir temperature.

In a combination of alkaline and surfactant substances, the CMC of surfactant can be achieved in lower concentration compared to the use of solely surfactant. This occurs by the charge effect: ionized alkali increases number of charge inside aqueous solution and hence, the ionized surfactant molecules are pushed to the interfacial between oil and brine resulting in IFT reduction and at hence the CMC occurs at very low surfactant concentration. Similar effect also occurs with salinity since salt also provide several ions into solution. Alkaline substance is added into a combination also to prevent an adsorption of surfactant. Since surfactant is more potential in reduction of IFT, alkaline substance which can be absorbed quickly on rock surface is then commonly used as sacrificial material. However, it has been proved that an adsorption of alkaline substance by rock is responsible for the alteration of wettability to a more favorable condition. Therefore, both chemicals help each other to achieve the best condition for oil displacement [2].

3.2 Development of porosity

Porosity can occur in several ways and combine together, resulting in different porosity types as well as pore sizes in the same formation [10]. Porosity can be geologically described into two types. First is so called primary porosity or voids that initially occurred at sand bed deposition. Second type is called secondary porosity or pore spaces that are happened later from various events such as, earth stresses, diagenesis, and solution of water flowing. Generally, primary porosity can be categorized in to four types.

1) Intercrystalline

They are pore spaces between individual crystals, pore spaces in crystal lattices or pore spaces between cleavage planes of crystals. Normally, these pores are smaller than 2 μm in diameter and they are so called micro porosity.

2) Intergranular or interparticle

They are voids between particles. Typically, these voids are greater than 500 μm in diameter.

3) Bedding planes

These voids are created in parallel to bedding planes and they are considered to be large voids in reservoirs. The different grain sizes and arrangement of sediments deposition are part of factors that cause this type of porosity.

4) Miscellaneous sedimentary voids

The examples of these voids are vuggy and cavernous voids. These porosities occurred at time of deposition, caused by living organisms at time of deposition.

After primary porosity is formed, secondary porosity can be induced by several mechanisms. Figure 3.1 displays combination of primary and secondary porosity in same rock structure.

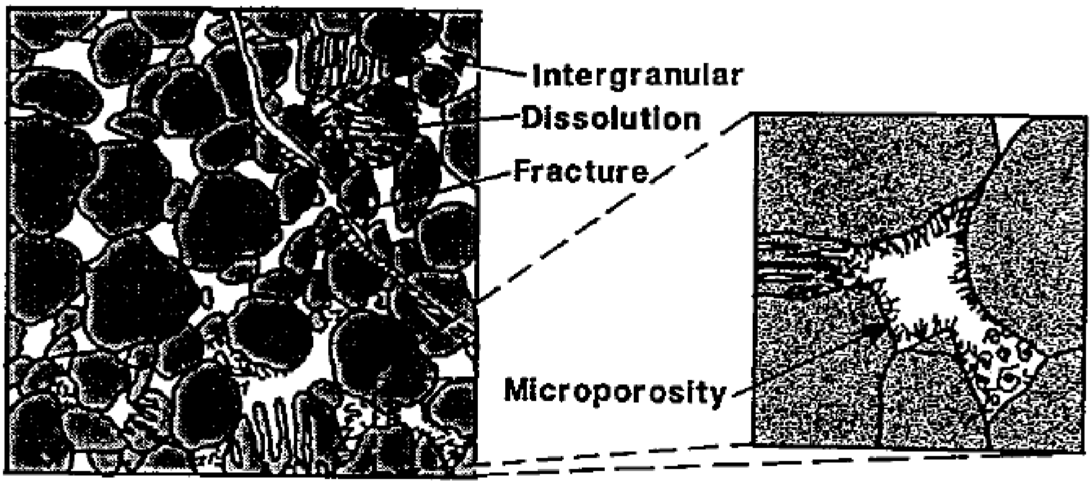


Figure 3.1 Example of porosity containing intergranular porosity and microporosity as primary porosity, dissolution porosity and fracture as secondary porosity [10]

Secondary porosity can be divided to four types.

1) Solution porosity

The example of this porosity is an opening of rock, resulted from flowing of hot or acidic solutions.

2) Dolomitization

This term occurs when limestone transforms to dolomite as following chemical reaction.

$$\underset{\text{Limestone}}{2CaCO_3 + Mg^{2+}} \Rightarrow \underset{\text{Dolomite}}{CaMg(CO_3)_2 + Ca^{2+}}$$

When flowing water in reservoir contains magnesium cation, this ion can replace existing calcium ion in limestone as shown in above chemical reaction. Due to volume of magnesium ion which is significantly smaller than calcium ion, porosity of dolomite increases about 12-13 % from total replacement of calcium by magnesium.

3) Fracture porosity

This channels or paths are caused by structural failure of reservoir rock under tension from tectonic activities such as folding and faulting.

4) Miscellaneous secondary voids

The examples of these voids are pitches and flats that are voids created by slight falling down of some bed planes and voids are caused by gravity movement of seafloor material.

In general, porosity is defined as a fraction of void volume or pore space per total volume. The value is commonly expressed as percentage or fraction. This pore space can include space between grains, fracture openings and caverns. Porosity indicates capacity of reservoir storage for fluids. Typically, porosity can have values ranging from 5% to 40%. However, typical values of porosity are mostly found between 10% and 20%, whereas carbonate porosity can be as high as 30% from primary and secondary porosity. There are four factors that strongly affect magnitude of porosity as following:

1) Uniformity of grain size

Uniformity of grain size means sorting gradation of grain size. Well sorted of grain size results in high quantity of pore space between grains and therefore, reservoir has higher porosity than similarly-sized and poorly-sorted rocks. Smaller grains filling the gaps between larger particles cause the reduction of porosity and hydraulic conductivity.

2) Degree of cementation or consolidation

This is a process that pore space is filled with mineral materials. Cementation directly affects the reduction of porosity. In general, cementing materials can be calcium carbonate, magnesium carbonate, iron carbonate, iron sulfides, limonite, hematite, dolomite, calcium sulphate, clay and the others.

3) Amount of compaction during and after deposition

In general, compaction aids voids to get closer, squeezing the fluid. Compaction is an important lithifying process in most reservoir rocks.

4) Methods of packing

Overburden pressure changes poorly sorted grain from random packing to closer packing.

Two main terms of porosity in engineering point of views are total or absolute porosity and effective porosity. Absolute porosity is a ratio of total void to bulk volume even though isolated void or non-interconnected void, whereas effective porosity is a ratio of only interconnected void to bulk volume. Effective porosity indicated ability of rock to conduct fluids and this type of porosity is used to calculate in all reservoir engineering fields. Effective porosity is affected by many lithological factors such as heterogeneity of grain sizes, any weathering or leaching packing, and cementation of the grains.

In carbonate reservoirs, secondary porosity is greatly important than primary porosity, whereas in sandstone or clastic reservoir, primary porosity is more considerable. Different porosity of carbonate reservoir can be resulted either from the combination of primary and secondary porosities as found in dolomites and limestone reservoir with fracture or combination of two primary porosities as found in vuggy carbonate rocks. Carbonate reservoir can also be characterized as layer from different sediments deposited and different environment. Figures 3.2 and 3.3 illustrate microscopic structures of different porosity carbonate reservoir with fracture and fracture-vuggy system as combination of primary and secondary porosity, respectively.

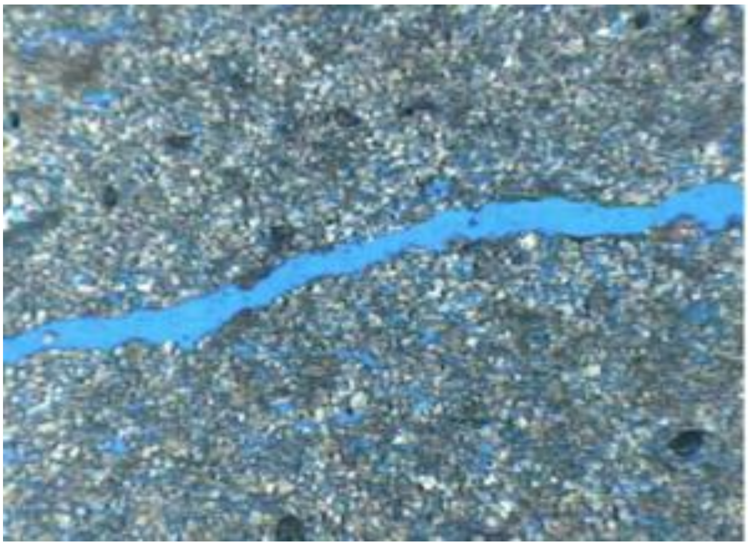


Figure 3.2 Different porosity carbonate rock, showing fractures as secondary porosity [11]

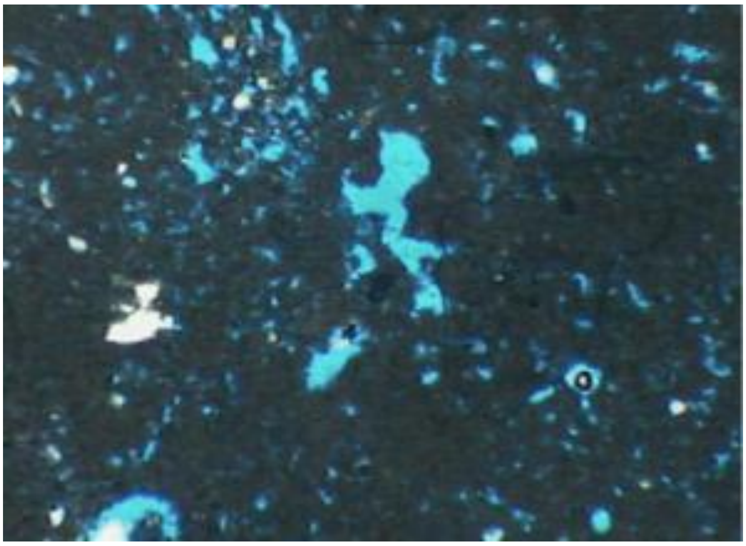


Figure 3.3 Different porosity in carbonate rock, showing fracture-vuggy system as combination of primary and secondary porosity [11]

3.3 Effect of injection rate, alkali concentration and slug size

Together with unfavorable mobility ratio, too high injection rate could result in viscous fingering in which displacing fluid invades into oil zone with finger-like shape intrusions during production of oil particularly in heterogeneous reservoir. As a result, the by-passed oil is often not recovered. On the other hand, too low injection rate could also cause high depletion rate of alkali/surfactant. Rock contains highly reacting materials, resulting in high consumption of alkali/surfactant. Therefore, the optimum injection rate should be determined prior to the field implementation.

For the alkali/surfactant concentration and slug size, chemical concentration strongly affects the oil recovery factor. In general, oil recovery increases as chemical concentration is raised. However, concentration should be at optimum value around its critical micelles concentration because too high concentration could results in several problems such as precipitation of insoluble in-situ soap that could block narrow throats as well as economic problem since surfactant substance is quite expensive. In addition, concentration of alkali/surfactant should be proportionally corresponded with the slug size. Due to the alkaline and surfactant substance that will be adsorbed onto formation rock and react with formation oil, entire mass of chemical should be enough for the whole reservoir. The larger slug size can be used with lower chemical concentration, whereas smaller slug size requires higher chemical concentration. Nevertheless, the use of too high concentration could also cause high depletion rate, formation damage from insoluble in-situ soap and not adequate chemical substance for the entire formation. Hence, moderate slug size should be determined before application on real fields [12].

CHAPTER IV

RESERVOIR SIMULATION AND METHODOLOGY

In this study, the black oil simulator **ECLIPSE®100** commercialized by **GeoQuest Schlumberger** is used for simulating reservoir model with interest study parameters. This chapter describes the detail of reservoir model constructed in ECLIPSE®100 simulator. The ECLIPSE®100 input keywords are provided in the Appendix.

4.1 Reservoir model

The reservoir dimension is 1,000×1,000×75 ft with the number of grids of 50×50×15 in the *x*-, *y*- and *z*-direction, respectively and grid size of 20×20×5 in the *x*-, *y*- and *z*-direction, respectively as illustrated in Figure 4.1. The reservoir grid model is constructed using Cartesian coordinate and reservoir physical properties are listed in Table 4.1. The reservoir model is physically divided to three layers from top and bottom by having big pore size on top and bottom layers, and middle later with small pore size. The pore size of reservoir is controlled by capillary pressure and the detail is described in Section 1.3. The top surface of reservoir is located at the datum depth of 3,200 ft. The reservoir temperature is 108^{o}F at the datum depth and this temperature allows surfactant to function without de-gradation of surfactant concerned.

Several parameters shown in Table 4.1 are in ranges since they are study parameters. Hence, the values are varied in ranges as dictated. Absolute permeability in horizontal direction is set at 20 mD. This low permeability value represents permeability value of carbonate rock where secondary porosity and permeability are not emerged [12]. Effective porosity is 30 percent for every layer. This means that in middle layer where pore size is small the rock contains numerous numbers of pores.

Table 4.1 Reservoir model properties

Parameters	**Values**	**Unit**
Number of grids	50×50×15	Grid
Grid size	20×20×5	ft
Effective porosity	30	%
Horizontal permeability	20	mD
Vertical permeability	2-5	mD
Top of reservoir	3,200	ft
Datum depth	3,200	ft
Initial pressure @ datum depth	1,400	psia
Reservoir temperature	108	^{o}F
Initial oil saturation	0.85-0.70	

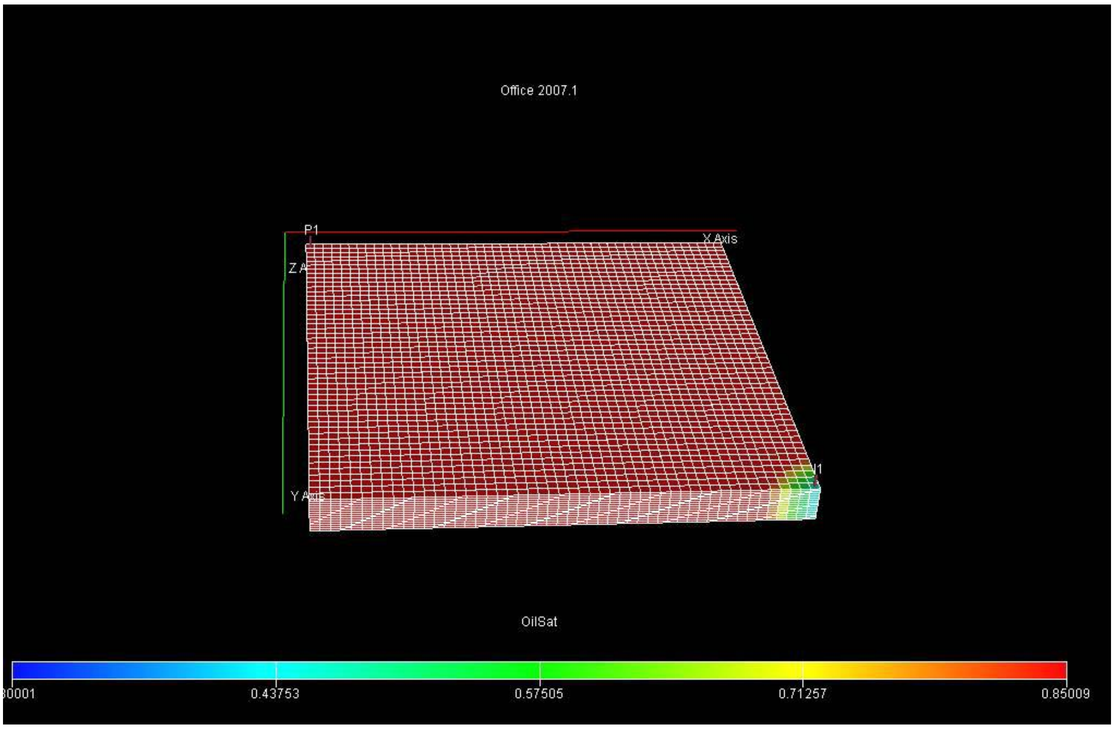


Figure 4.1 Reservoir model at initial condition illustrated by oil saturation

The pattern of fluid displacement is inverse-five-spot pattern. The production well is labeled as P1, whereas the injection well is defined as I1. Both wells are diagonally located at two corners of reservoir model as shown in Figure 4.1.

4.2 Pressure-Volume-Temperature (PVT) properties

This section summarizes Pressure-Volume-Temperature properties of reservoir fluid. The reservoir properties used for this reservoir simulation study are obtained from typical value in text book and several correlations provided by ECLIPSE®100. Oil PVT properties are illustrated in Table 4.2. From the table, oil gravity is 24 °API which is considered as medium gravity oil and compatible with dead oil which have low GOR. This gravity range is still good recommended for waterflooding as well as chemical flooding. Gas oil ratio (GOR) is minimal set as it does not play an important low in chemical flooding study.

Table 4.2 Black oil PVT properties

Parameters	**Values**	**Unit**
Oil gravity	24	°API
GOR	300	SCF/STB
Salinity	0	%
Standard pressure	14.7	psia
Standard temperature	60	°F

Two oil properties affected by pressure are Formation Volume Factor (FVF) and oil viscosity are represented in graph at different pressures as illustrated in Figure 4.2.

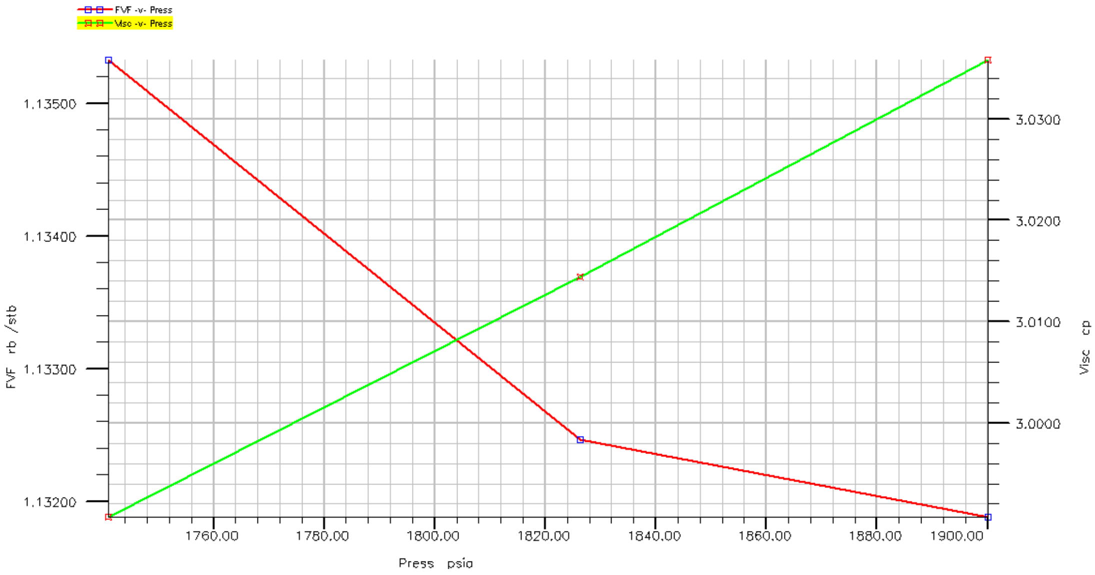


Figure 4.2 Oil PVT properties representing FVF and viscosity at different pressure

The values of formation water PVT and fluid densities at surface condition are summarized in Table 4.3 and Table 4.4, respectively.

Table 4.3 Formation water PVT properties

Property	**Values**	**Unit**
Reference pressure(P_{ref})	1400	psia
Water FVF at P_{ref}	0.9997213	rb/stb
Water compressibility	3.046602×10^{-6}	psi^{-1}
Water viscosity at P_{ref}	0.6277618	cP
Water viscosibility	1.287619×10^{-6}	psi^{-1}

Table 4.4 Fluid densities at surface condition

Property	Value	Unit
Oil density	56.75144	lb/ft^3
Water density	62.42797	lb/ft^3
Gas density	0.04369958	lb/ft^3

4.3 Petrophysical properties

For both large pore and small pore zones, formations share the same set of two-phase relative permeability. Relative permeability is mainly characterized by rock type and both pore sizes are carbonate rock. However, these two zones are different in capillary pressure which indirectly governs pore size. This study chooses two phase system of oil-water since gas phase does not affect much to the effectiveness alkali/surfactant flooding in improving displacement efficiency (E_D). Relative permeability values are generated from Corey's correlation function provided on ECLIPSE®100. Relative permeability curves in this study are based on values of typical oil-wet system of carbonate reservoir [2].

Both large pore and small pore zones require two sets of relative permeability which represent immiscible and miscible modes. The immiscible mode describes situation where physical displacement takes place as found in waterflooding process. Therefore, in immiscible mode, physic-chemical interaction is excluded. On the other hand, miscible mode occurs when interfacial tension (IFT) decreases, resulting in increment of capillary number over 10^{-4} which makes aqueous and oil phases become the same phase or emulsion. This phenomenon emerges through emulsification which is the effect from presence of surface active agent. The water/oil relative permeabilities of immiscible and miscible mode are shown in Table 4.5 and Table 4.6, respectively. The data are plotted as illustrations shown in Figure 4.3 and Figure 4.4, respectively.

From relative permeability curves for both immiscible and miscible mode, it can be seen that the value of relative permeability to oil starts as high as 1.0. This value is obtained from dividing all effective permeability by effective permeability to oil at the irreducible water saturation. This is an assumption made throughout this study that effective permeability to oil at irreducible water saturation is equal to absolute permeability.

The criteria of immiscible/miscible mode are triggered by capillary number. In ECLIPSE®100 the command SURFCAPD is functioned for switching of immiscible/miscible mode. As displayed in Figure 4.5, 0 and 1 are used to represent when immiscible and miscible modes are activated, respectively. CAPN is logarithmic power of capillary number. Therefore, 10^{-4} is the value of capillary number where emulsification occurs.

Table 4.5 Water and oil relative permeability of immiscible flooding

S_w	k_{rw}	k_{ro}	P_c
0.150	0	1	0
0.211	0.00958	0.71907	
0.272	0.03336	0.49476	
0.333	0.06921	0.32132	
0.394	0.11616	0.19286	
0.456	0.17357	0.10325	
0.517	0.24099	0.04614	
0.578	0.31806	0.01483	
0.634	0.40448	0.00213	
0.700	0.50000	0	
1	1	0	-2

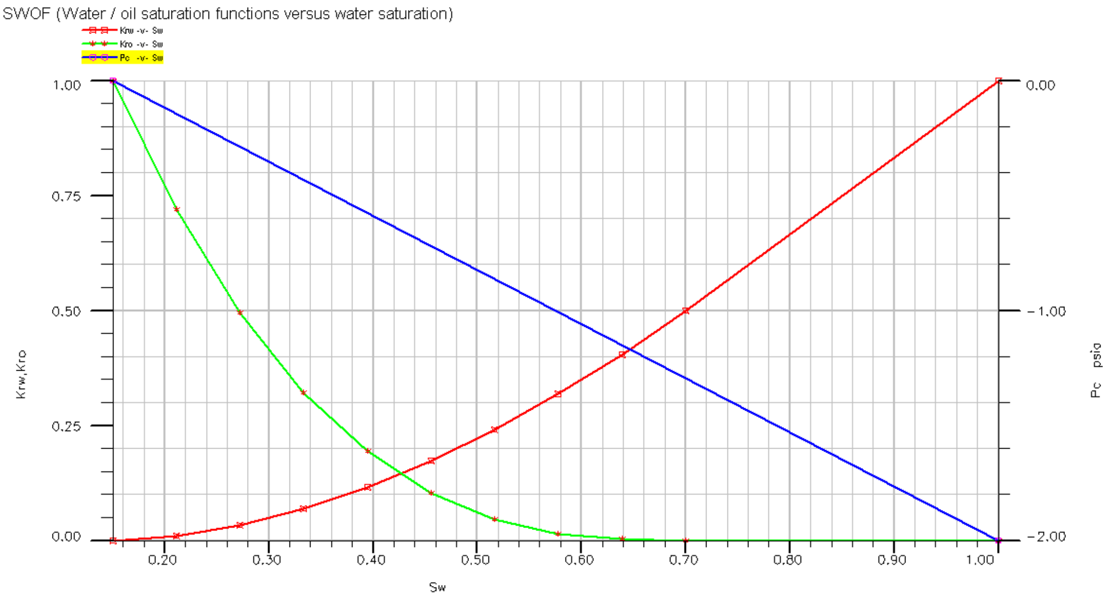


Figure 4.3 Water/oil saturation function of immiscible mode as functions of water saturation

Table 4.6 Water and oil relative permeability of miscible flooding

S_w	**k_{rw}**	**k_{ro}**	**P_c**
0.150	0	1	0
0.233	0.05748	0.85803	
0.317	0.14152	0.72129	
0.400	0.23974	0.59031	
0.483	0.34847	0.46574	
0.567	0.46574	0.34847	
0.650	0.59031	0.23974	
0.733	0.72129	0.14152	
0.817	0.85803	0.05748	
0.900	1	0	
1	1	0	0

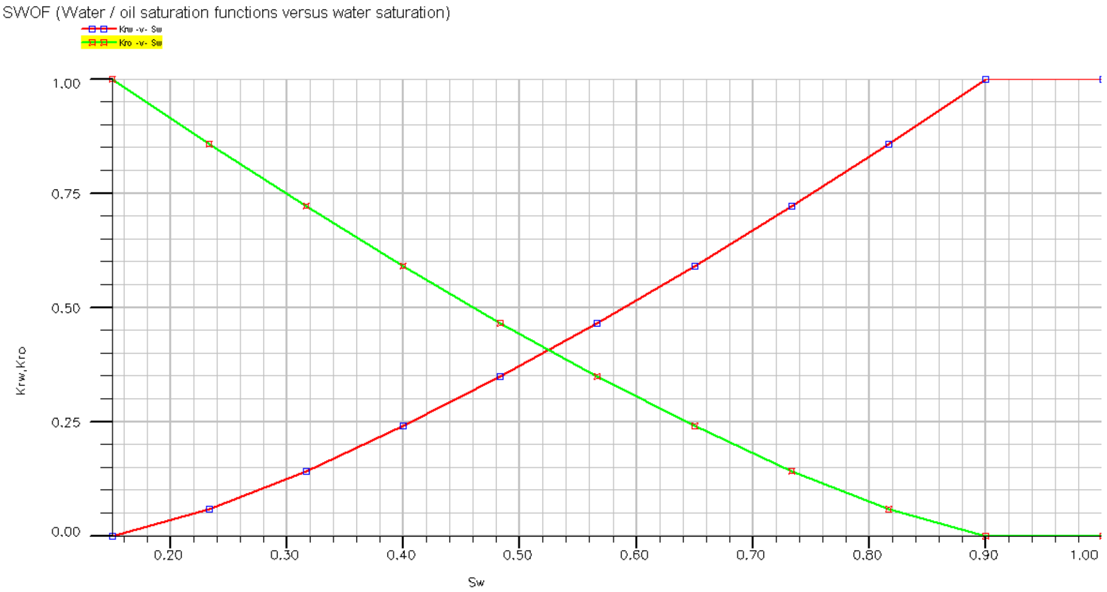
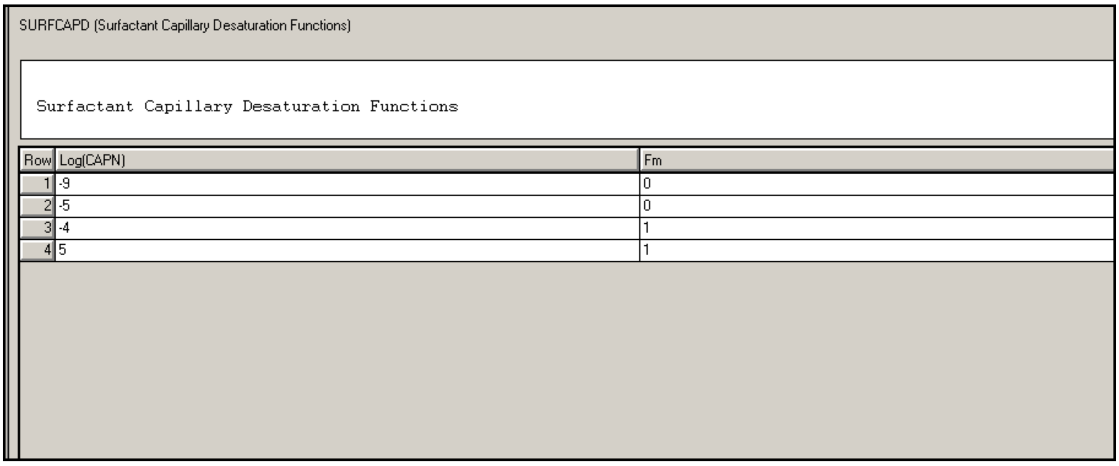


Figure 4.4 Water/oil saturation function of miscible mode as function of water saturation



Surfactant Capillary Desaturation Functions

Row	Log(CAPN)	Fm
1	-9	0
2	-5	0
3	-4	1
4	5	1

Figure 4.5 The criteria of immiscible/miscible mode by using logarithim power of capillary number

It can be noticed from Figure 4.4 that capillary pressure curve is negleted in miscible mode. This can be explained that in miscible mode,rock does not have any preference and hence rock does not have interaction for both oil and water. This also results in straight lines of relative permeability to both water and oil that means flow of water and oil are independent from each phase that is caused by inpreference of rock surface.

4.4 Alkali/Surfactant properties

In this section, important properties related to alkali/surfactant in reservoir simulation are reviewed. In this study, functions of IFT reduction of surfactant used from reference text book [2] as shown in Table 4.7. These values are the range from zero concentration to the critical micelle concentration or lower concentration zone. The reason that this concentration range is picked in this study is to perform low surfactant concentration flooding since concentration is expensive.

Table 4.7 Function of surfactant concentration and IFT reduction

Surfactant concentration (% w/w)	Surfactant concentration (LB/STB)	IFT (Dyne/cm)
0	0	10
0.01	0.035	0.03
0.02	0.070	0.01
0.05	0.175	0.001
0.1	0.350	0.0003

Chemical adsorption is another important thing to concern in chemical flooding. Functions of surfactant adsorption, alkali adsorption and surfactant adsorption reduction of alkali in this study are using from default data of ECLIPSE®100 as seen in Table 4.8, Table 4.9 and Table 4.10, respectively.

Table 4.8 Functions of surfactant adsorption.

Surfactant concentration (LB/STB)	Surfactant adsorption (LB/LB)
0	0
0.10	0.00005
0.20	0.00005
1.00	0.00005

Table 4.9 Functions of alkali adsorption.

Alkali concentration (LB/STB)	**Surfactant adsorption (LB/LB)**
0	0
0.20	0.00002
1.00	0.00005

Table 4.10 Function of surfactant adsorption reduction of alkali

Alkali concentration (LB/STB)	**Surfactant adsorption multiplier**
0	1.00000
0.10	0.99995
0.20	0.99995
1.00	0.50000

4.5 Production strategy

As mentioned in section 1.1, two wells are present in this study. Production well and injection well are diagonally located on the edge of model. Both have the same wellbore diameter of 6-1/8 inches. Another additional assumption made in this study is that there is no presence of skin around the wellbore. For the economic reasons and prevention of reservoir fracture, production constraints for both production well and injection well are specified as listed in Table 4.11 and Table 4.12, respectively.

Table 4.11 Production well constraints

Parameter	Value	Units
Minimum oil production rate	100	STB/D
Maximum water cut of production well	95	%
Bottom hole pressure target of production well	200	psia

Table 4.12 Injection well constraints

Parameter	Value	Units
Liquid injection rate	500	STB/D
Bottom hole pressure target of injection well	1900	psia
Control mode	BHP	

4.6 Thesis methodology

First of all, reservoir model is constructed to have three main layers. The middle layer contains small pore size, whereas top and bottom contain large pore size. In this study, pore size is directly controlled by capillary pressure. Then waterflooding base case is simulated on constructed multi-layered carbonate reservoir with different pore sizes. The result is used as reference to compare with alkali/surfactant flooding.

After that, base case of alkali/surfactant flooding is constructed by setting relevant functions of alkali/surfactant flooding which are; function of surfactant concentration and IFT reduction, function of surfactant adsorption, function of alkali adsorption, function of reduction of surfactant adsorption by alkali, relative permeability to oil and water in miscible mode as mentioned in section 4.4. Next, optimization of operational parameters of alkali/surfactant flooding under production limitations is evaluated. In this part, operational parameters include

1) Sequence of injection slugs that is performed by varying of pre-flush water slug size from zero to 0.3 reservoir pore volume (PV) prior to chemical

slug. In this study, chemical slug and chemical concentration is kept constant,

2) Slug size of chemical slug that is varied from 0.1 to 0.3 PV at fixed chemical concentration, and
3) Chemical concentration that is varied from 0.05% w/w to 0.1 % w/w at fixed chemical slug size.

In order to compare results, oil recovery factor is chosen as major judgment criteria. This simulation outcome is also used to determine the optimal value for each parameter, yielding the highest oil recovery factor. Total production period is also used to assist consideration throughout study. However, other parameters such as chemical consumption and cumulative water produced are occasionally considered because they affect on cost of production as well as proper facilities. The optimized operation parameters are applied for the rest of study. Afterward, sensitivity analysis of reservoir properties is investigated. Interest reservoir properties include:

1) Ratio between size of large pore size and small pore of three layers. The pore size is mainly characterized by capillary pressure in 1:1 proportion. The ratio between large and small pore size is then replaced by the ratio of capillary pressure. In this study, the ratio is varied to 1:5, 1:10, 1:20, and 1:50, respectively. Capillary pressures of top and bottom layers are kept constant, whereas capillary pressure of middle layer is varied according to the ratio.
2) Reservoir anisotropy through k_v/k_h ratio. The chosen ratios are 1:10, 1.5:10, 2:10, and 2.5:10, respectively.
3) Mobile connate water which is additional formation water from irreducible water saturation. The chosen mobile connate water saturations are 0.05, 0.10 and 0.15.
4) Corey's exponential of relative permeability curves, which is varied for both immiscible and miscible modes. For immiscible mode, Corey's exponent is varied first for relative permeability to oil, whereas the exponent of relative permeability to water is kept constant. And when the

exponent of relative permeability to water is studied, the same manner is performed. For miscible mode, Corey's exponent for both oil and water are varied in the same time. Chosen exponents for immiscible mode are 1.8, 2.3, 2.8, 3.3, and 3.8 for relative permeability to oil and 1.1, 1.4, 1.8, 2.3, and 2.8 for relative permeability to water. For miscible mode, chosen exponents are 1.0, 1.3, 1.5, and 2.0 for both relative permeability to oil and water.

CHAPTER V

RESULT AND DISSCUSSION

After the base reservoir model is constructed by ECLIPSE®100, waterflooding process is firstly performed as a reference case. Thereafter, alkali/surfactant flooding base case is simulated by keeping all properties of reservoir and chemical properly constant in order to compare the obtained result with waterflooding base case. After that, sensitivity of interest parameters is evaluated by considering from oil recovery factor and total production life. This chapter is divided to eight parts. To begin with, simulation comparison between waterflooding base case and chemical flooding base case is performed. Then, optimum sequence of injection is determined by comparing results from cases where pre-flushed water is considered before the injection of chemical slug. After that, influence of chemical slug size that is varied from 0.10 PV to 0.30 PV is studied. Afterward, effects of reservoir properties are investigated. Sensitivity analysis is performed on of between size of small pores and large pores, ratio of vertical permeability to horizontal permeability, mobile connate water and exponent number of relative permeability curves for both miscible and immiscible mode.

Bottomhole pressure of production well is constantly kept at 200 psia. This pressure design supports the implementation of Electrical Submersible Pump (ESP). Injection well is controlled by bottomhole pressure at 1,900 psia to prevent undesired fracturing of formation. Thus injection rate is automatically adjusted to keep bottomhole pressure for injection well. Criterion to keep production life is limited by minimum oil production rate of 100 STB/D or 95% of water cut.

5.1 Comparison between waterflooding and chemical flooding base cases

Initially, comparison of oil recovery efficiency between waterflooding and chemical flooding base cases is discussed. In carbonate reservoir composing of both large and small pores, waterflooding displaces oil mainly from large pores due to less capillary pressure. Large amount of oil still remains in small pores due to high capillary pressure. For the base case model of chemical flooding, surfactant concentration of 0.1% w/w and alkali concentration of 0.285% w/w are continuously co-injected. After termination of production, different results between waterflooding and chemical flooding base cases are obtained. Table 5.1 reviews the comparison of cumulative oil production, oil recovery efficiency and production life obtained from waterflooding and chemical flooding base cases. Moreover, Figure 5.1 illustrates evolution of oil recovery efficiencys as functions of production time for both base cases.

Table 5.1 Summary of cumulative oil production, oil recovery efficiency and production life from waterflooding and chemical flooding base cases

Method	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (%)**	**Production life (years, months)**
Waterflooding base case	0.75	25.24	17 y 5 m
Chemical flooding base case	1.15	38.63	18 y 0 m

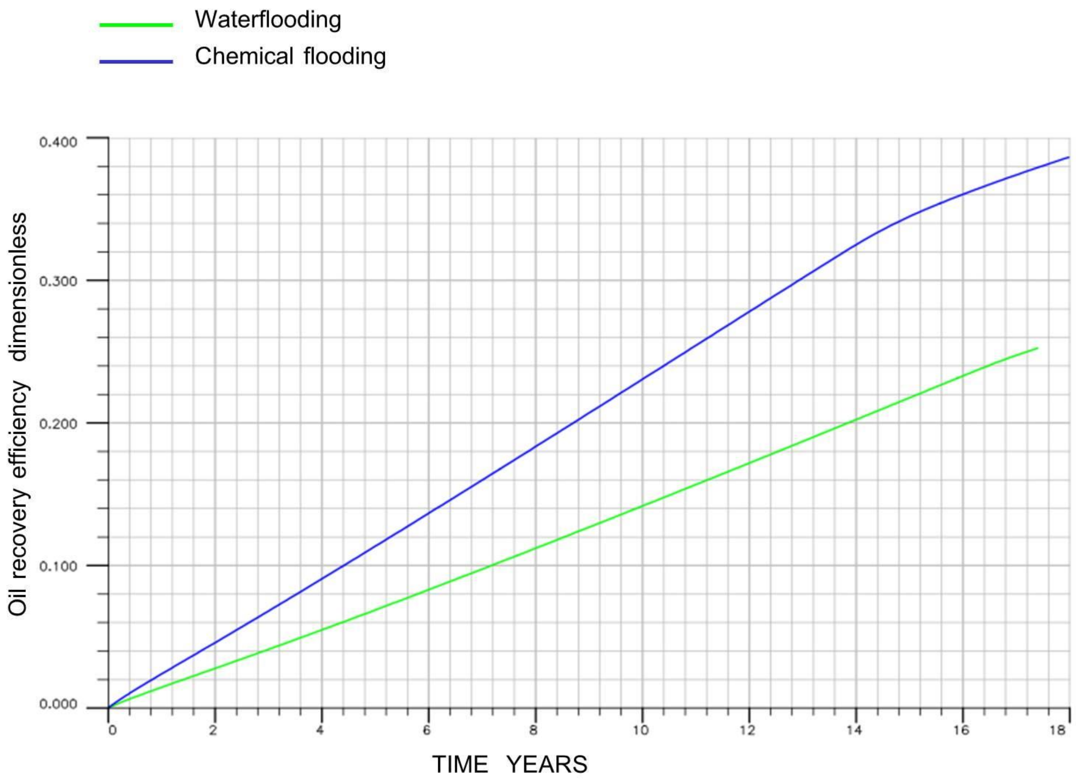


Figure 5.1 Oil recovery efficiencies of waterflooding and chemical flooding base cases as functions of production time

From Table 5.1, result shows considerably improvement of oil recovery efficiency by the use of chemical flooding compared to conventional waterflooding. This is because chemical flooding can better displace oil in all layers due to several effects of injected chemicals. Production life of chemical flooding base case is slightly longer than that of waterflooding base case but difference is displacement efficiency of chemical flooding case that can be obviously seen in Figure 5.1. Separate gap is additional oil recovery as an effect of injected chemical. Ultimate increment of oil recovery is approximately 13.39%. Surfactant decreases IFT between oil and water interface, resulting in substantial increment of capillary number. Hence, oil in small pored can be displaced by injected fluid. Oil recovery improvement can be obviously seen in layer no.2 where small pores exist and hence, capillary pressure is substantially high. Oil recovery efficiency in layer 2 increases from conventional waterflooding base case from 21.50% to 35.20% as can be seen from Table 5.2 in which oil recovery efficiencies in each layer of the reservoir are summarized.

Table 5.2 Oil recovery efficiencies from each layer of the reservoir from waterflooding and chemical flooding base cases

Method	**Layer no.**	**Oil recovery efficiency (%)**
Waterflooding basecase	1	26.00
Waterflooding basecase	2	21.50
Waterflooding basecase	3	29.00
Chemical flooding base case	1	37.70
Chemical flooding base case	2	35.20
Chemical flooding base case	3	43.10

Besides oil recovery efficiencies and total production life, other simulation outcomes are used to compare between of waterflooding and chemical flooding base cases, including water production rate, oil production rate, injection rate, and water cut at producer as illustrated in Figures 5.2 to 5.4.

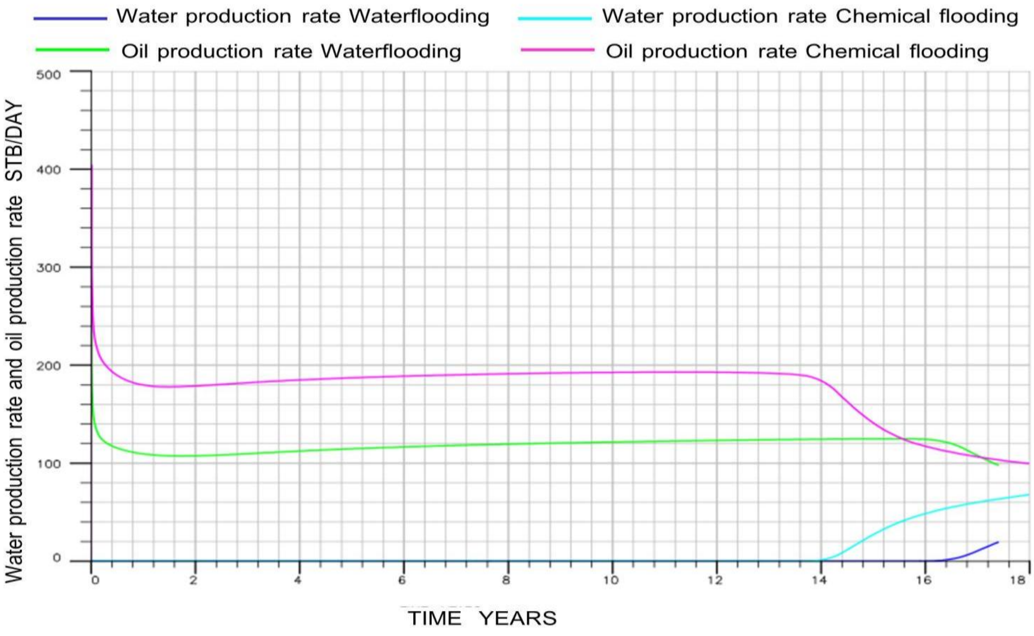


Figure 5.2 Water production rates and oil production rates of waterflooding and chemical flooding base cases

From Figure 5.2, oil production rates begin to decline when water starts to be produced. After breakthrough of water at producer oil production rate gradually decreases until termination of production due to oil production rate reaches preset minimum oil rate of 100 STB/D. Water breakthrough time from chemical flooding is by the way reaches at producer earlier than waterflooding base case. This is due faster movement of flood front when more oil is liberated from pores, resulting in higher rate of increase of water saturation. Flow property of water is therefore improved faster as effective permeability to water is increased as a function of its saturation.

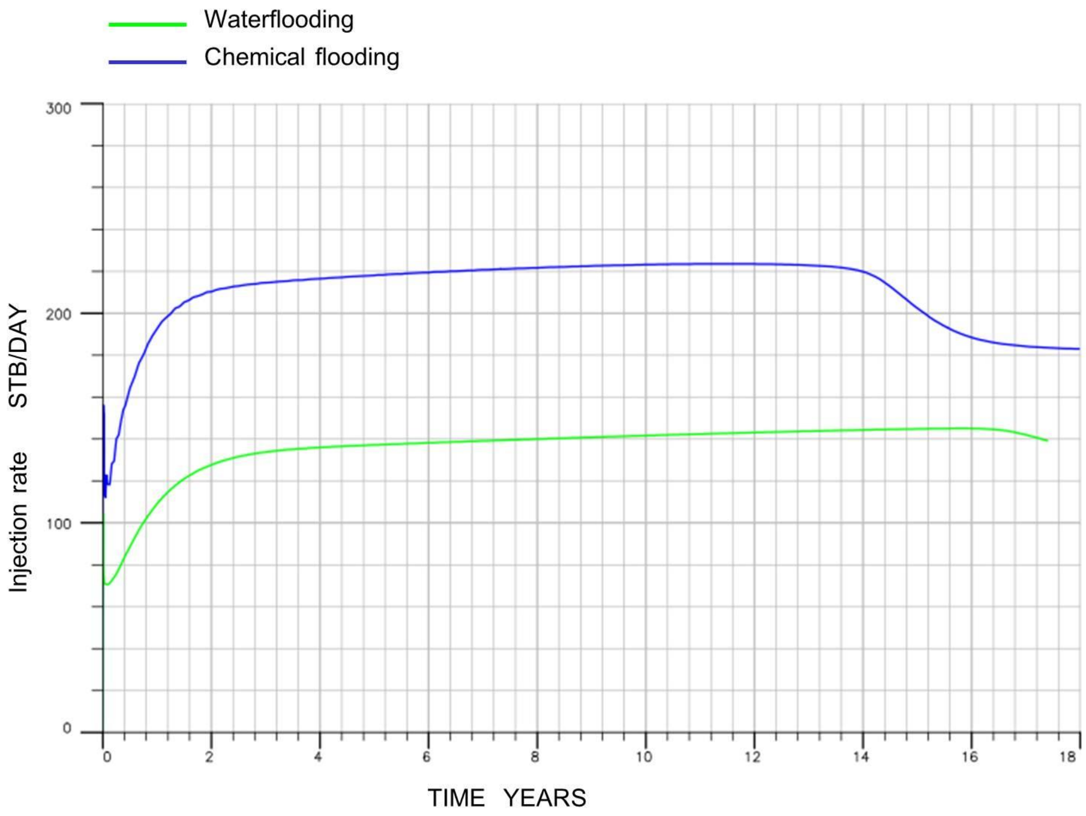


Figure 5.3 Injection rates of waterflooding and chemical flooding base cases

From Figure 5.3, chemical flooding results in higher injection rate than waterflooding base case. This higher injection rate is due to chemical flooding yields higher oil production rate and hence, injectivity increases rapidly as displacing phase saturation increases in quickly around injector. Injection rates are low at the start of production life due to limitation of breakdown pressure at 1900 psia. As displacing phase is kept injected, its injectivity is raised and results in easier of injection and consecutively, higher injection rate.

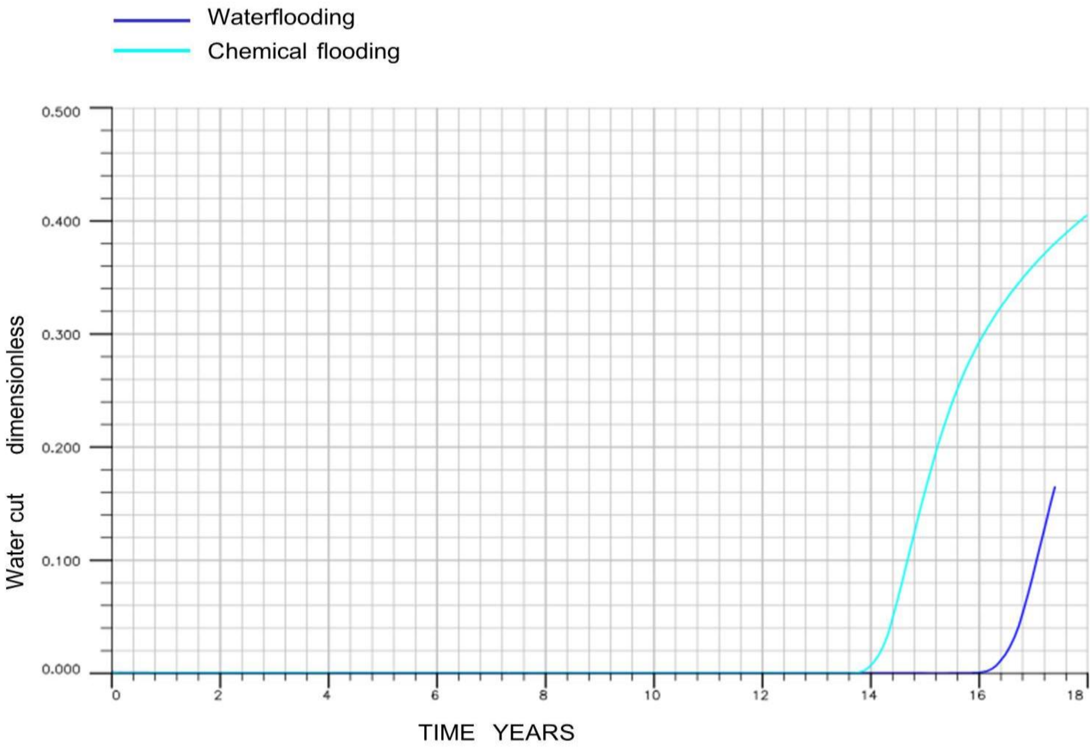


Figure 5.4 Water cut at production well of waterflooding and chemical flooding base cases

As discussed in oil production rate and water production rate section, water cut at production well of chemical flooding is higher than that of water flooding. Figure 5.4 shows higher water cut value of chemical flooding case which is a result from earlier water breakthrough. Termination of production well, however, is not caused from water production constraint.

5.2 Best scenario of chemical flooding

After chemical flooding by the combination of alkaline and surfactant substances proves that it can yield significantly higher oil recovery than waterflooding, study is further aimed on determination of chemical flooding scenario. Before studying effects of design parameters, sequences of displacing phase injection are investigated. Two distinct cases are studied: chemical flooding with pre-flushed slug and without pre-flushed slug. In case that pre-flushed slug is pre-injected, 0.1 to 0.3 PV of water is injected followed by chemical slug size of 0.1 PV. In case that no pre-flushed of water is performed, chemical slug of 0.1 PV is initially injected from first day. Table 5.3a and 5.3b summarize cumulative oil production, oil recovery efficiency, and total production life, cumulative water production, dimensionless cumulative water injected, surfactant consumption and alkali consumption, whereas relationship of simulation outcomes as functions of time are illustrated in Figures 5.5 to 5.7.

Table 5.3a Summary of cumulative oil production, oil recovery efficiency and production life of each chemical flooding scenario

Method	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (%)**	**Production life (years, months)**
No pre-flush	1.151580	38.76	17 y 3 m
Pre-flush 0.10 PV	0.981351	33.03	15 y 0 m
Pre-flush 0.15 PV	0.980225	32.99	15 y 2 m
Pre-flush 0.20 PV	0.980833	33.01	15 y 3 m
Pre-flush 0.25 PV	0.976872	32.88	15 y 4 m
Pre-flush 0.30 PV	0.967678	32.57	15 y 1 m

Table 5.3b Summary of cumulative water production, total water injection, surfactant consumption and alkali consumption of each chemical flooding scenario

Method	**Cumulative water production (STB)**	**Dimensionless cumulative water injected**	**Surfactant consumption (LB)**	**Alkali consumption (LB)**
No pre-flush water	75,852	0.41	106,102	303,148
Pre-flush 0.10 PV	31,929	0.34	106,321	303,774
Pre-flush 0.15 PV	30,478	0.34	111,495	318,558
Pre-flush 0.20 PV	29,845	0.34	109,485	312,815
Pre-flush 0.25 PV	26,096	0.33	89,367	255,334
Pre-flush 0.30 PV	19,873	0.33	63,903	182,581

From Table 5.3a and Table 5.3b, every case where pre-flushed water is implemented shows similar performance by similar value of oil recovery efficiency as well as production period. However, it is obvious that when chemical flooding is performed from the start without pre-flushed of water, oil recovery efficiency is obviously higher and production life is extended. This can be explained that pre-flushing water causes reservoir to be highly saturated with water. Thus concentrations of alkali and surfactant are substantially diluted. As described in Section 4.3, capillary number plays an important role on effectiveness of chemical flooding. At certain concentration, IFT which is a direct function of chemical concentration is high enough to make capillary number exceeding proper range for EOR. This results in flow property switching from miscible to immiscible mode relative permeability curves. And cumulative water production is also increased as more volume of water injection.

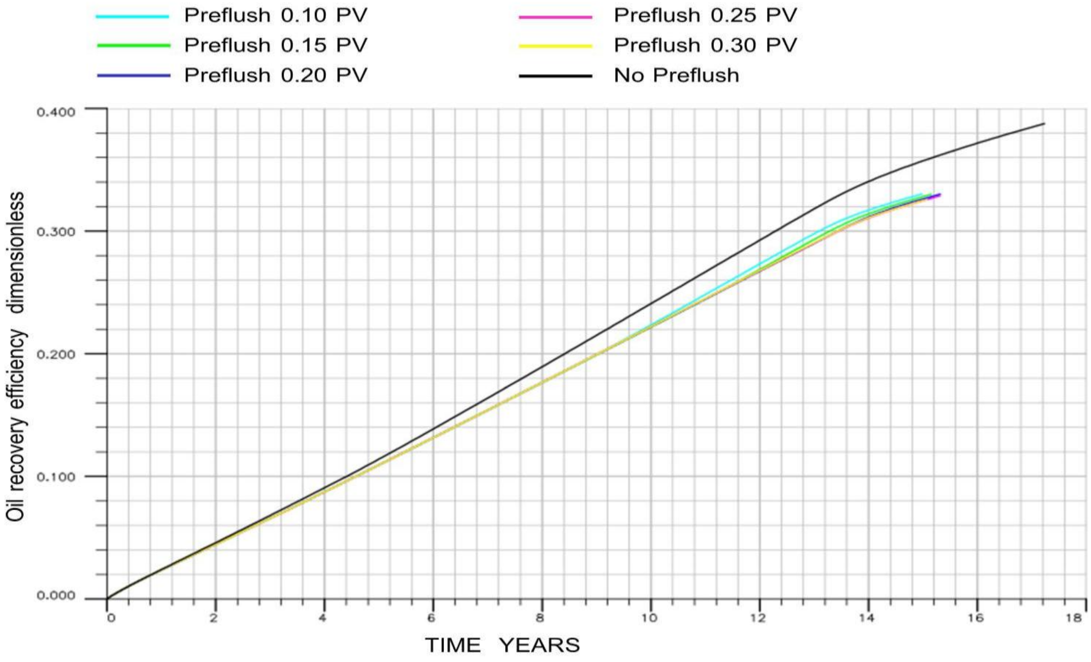


Figure 5.5 Oil recovery efficiencies of each chemical flooding scenario

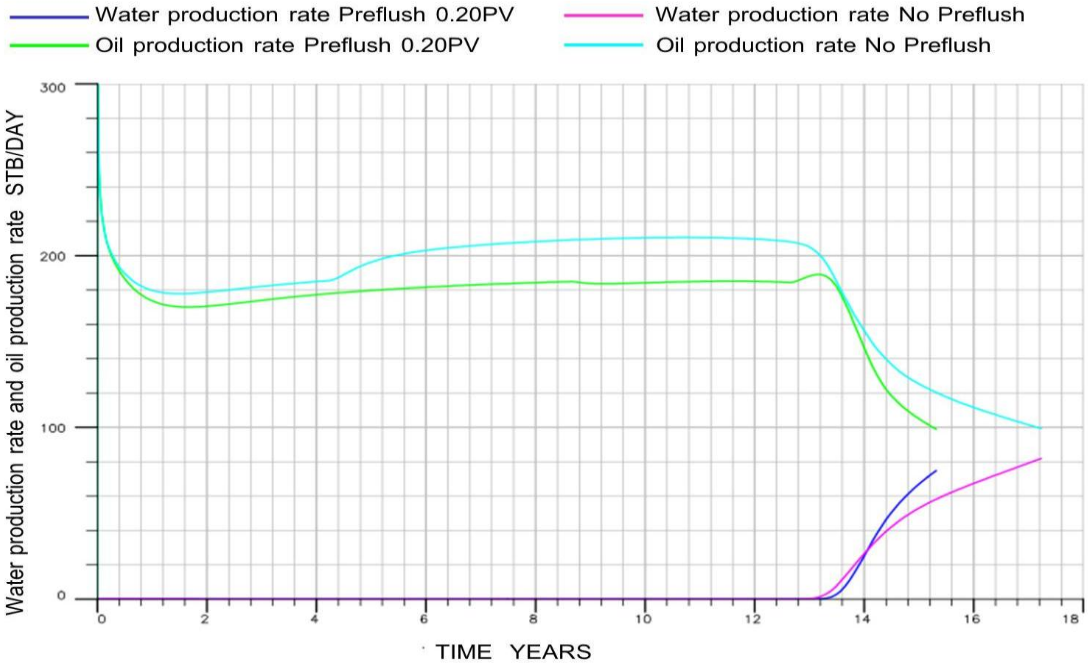


Figure 5.6 Water production rates and oil production rates of each chemical flooding scenario

Figure 5.5 confirms effectiveness of chemical flooding without pre-flushed slug over other cases where pre-flushed slug is performed. From Figure 5.6, oil production rate of a case without pre-flushed is higher than that of another case containing pre-flushing. This phenomenon is described previously, related to higher injectivity by chemical flooding resulting in higher injection rate. As oil can be longer produced, water production rate slightly increases during period after breakthrough until termination of production.

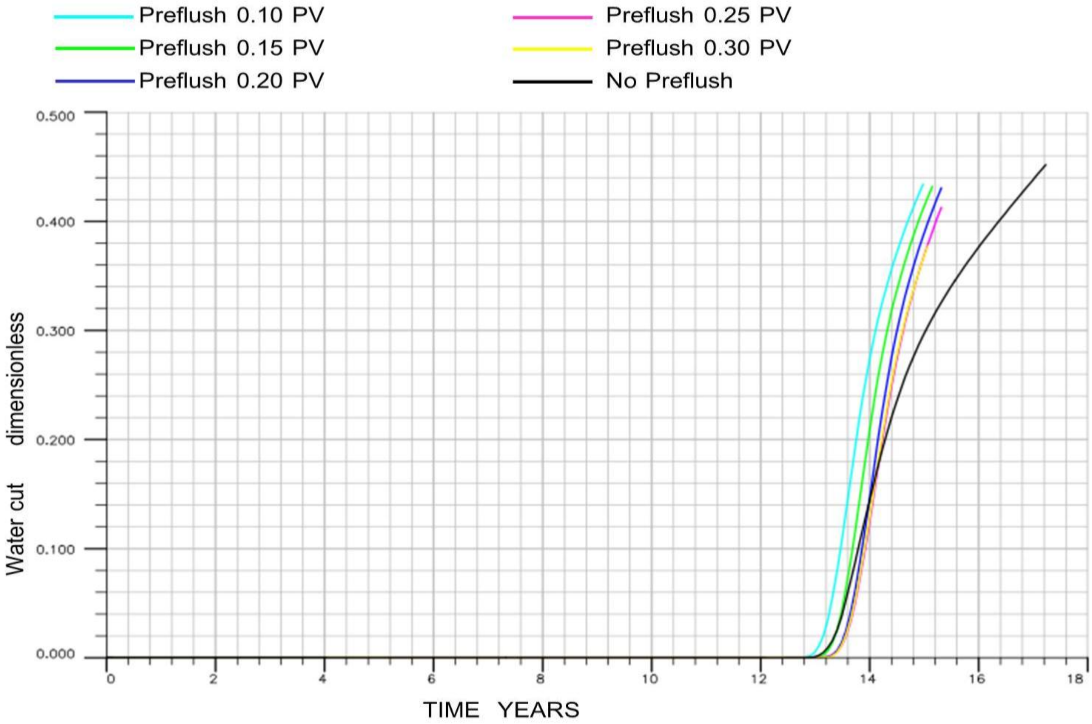


Figure 5.7 Water cut of each chemical flooding scenario

From Figure 5.7, water cut of cases with pre-flushed water are higher than that of case without pre-flushed at any production time. Water cut from case without pre-flushed water rises up with the smallest slope due to higher amount of produced oil, liberated by chemical effect, flowing together with produced water.

5.3 Effect of slug size of chemical flooding

From previous part, it is observed that pre-flushing of water prior to chemical flooding does not yield any benefit. Moreover, it turns out to be a drawback on total oil production. Therefore, the best scenario for chemical flooding is injecting chemical slug without pre-flushing of water. In this section, evaluation of chemical slug size effect on chemical flooding is performed by varying slug size in five different values which are 0.05, 0.10, 0.15, 0.20, 0.25 and 0.30 PV. Concentration of alkaline and surfactant substances are kept constant in order to study only effect of slug size of chemical.

The summary of simulation outcomes including cumulative oil production, oil recovery efficiency and total production life is shown in Table 5.4a and cumulative water production, dimensionless cumulative water injected, surfactant consumption and alkali consumption are summarized in Table 5.4b. Oil recovery factors as functions of time are plotted in Figure 5.8.

Table 5.4a Summary of cumulative oil production, oil recovery efficiency and production life of chemical flooding cases with variation of chemical slug size

Chemical slug size	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (%)**	**Production life (years, months)**
Slug size 0.05 PV	1.08	36.29	15 y 6 m
Slug size 0.10 PV	1.15	38.76	17 y 3 m
Slug size 0.15 PV	1.19	39.98	18 y 4 m
Slug size 0.20 PV	1.19	40.00	18 y 6 m
Slug size 0.25 PV	1.19	39.98	18 y 8 m
Slug size 0.30 PV	1.19	39.95	18 y 9 m

Table 5.4b Summary of total water production, total water injection, surfactant consumption and alkali consumption of chemical flooding cases with variation of chemical slug size

Chemical slug size	**Cumulative water production (STB)**	**Dimensionless cumulative water injected**	**Surfactant consumption (LB)**	**Alkali consumption (LB)**
Slug size 0.05 PV	43,873	0.37	60,292	172,262
Slug size 0.10 PV	75,852	0.41	106,102	303,148
Slug size 0.15 PV	99,194	0.43	173,570	495,913
Slug size 0.20 PV	98,864	0.43	230,086	657,389
Slug size 0.25 PV	96,815	0.43	301,282	860,805
Slug size 0.30 PV	95,047	0.42	344,089	983,111

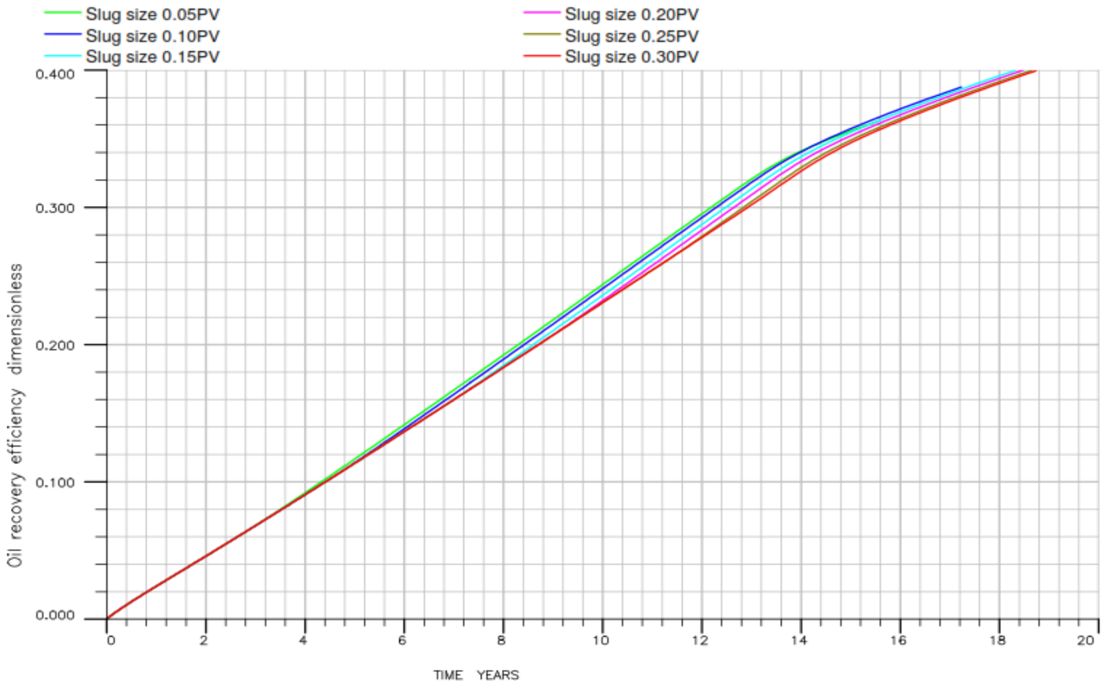


Figure 5.8 Oil recovery efficiencies of chemical flooding cases with variation of chemical slug size

From Table 5.4a and Table 5.4b, oil recovery efficiency increases as chemical slug size is raised from 0.05 PV to 0.20 PV. However, slug size of 0.25 PV and 0.30 PV do not yield better result than 0.20 PV and bring higher cost of chemical consumption. As chemical slug size is increased, more chemical substance is introduced into reservoir and hence, oil is more displaced due to lowering IFT. Recovery factor is therefore increased as well as production life is extended.

However, oversize of chemical slug results in several drawbacks. Injection rate is lower due to higher viscosity of injected solution. As shown in Table 5.5 viscosities of water and surfactant solution are differed as a function of surfactant concentration. In this study surfactant concentration is fixed at 0.1 % w/w or equivalent to 0.35 LB/STB. That means viscosity of solution is a bit higher than 1.20 cP, whereas pure water viscosity is only 0.628 cP. This adverse effect therefore reduces capacity of injected chemical in improving oil recovery.

Table 7.5 Viscosity of pure water and surfactant solution as a function of surfactant concentration

Surfactant concentration (LB/STB)	**Water viscosity (Centipoise)**
0.0	0.628
0.1	1.100
0.2	1.200
0.8	1.300

When injected fluid possesses high viscosity, injection pressure is also increased. But injection pressure cannot exceed fracture pressure, fluid injection is then performed at lower rate. Therefore, injection rate and oil production rate increase when chemical slug is switched to chasing water as shown in Figure 5.9 and Figure 5.10, respectively.

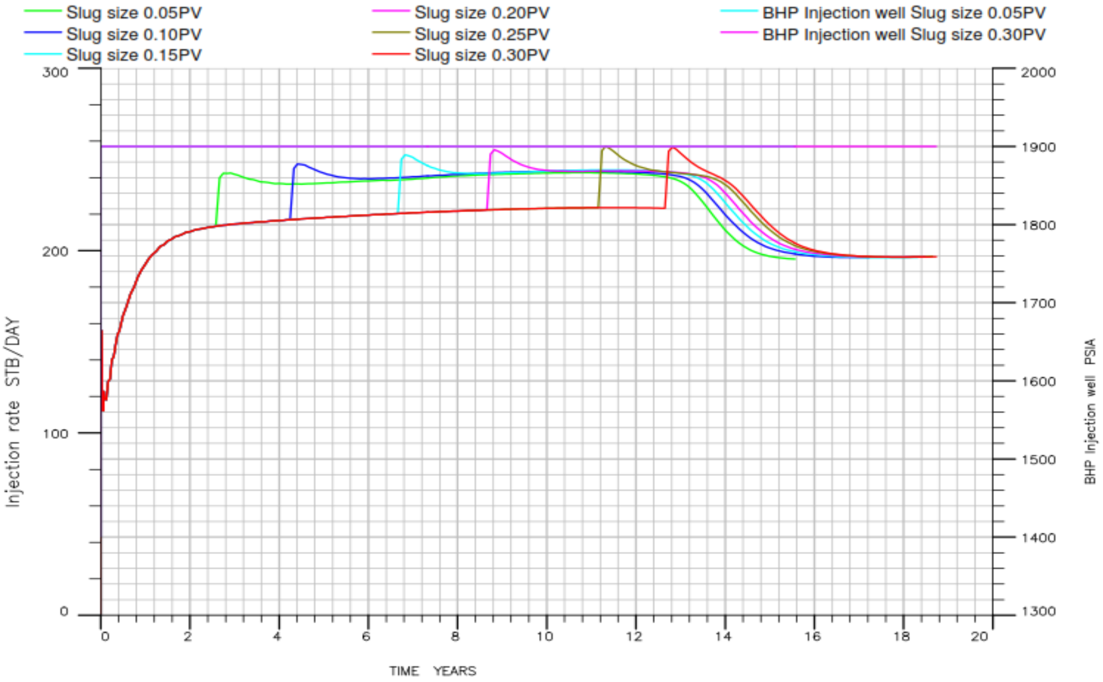


Figure 5.9 Injection rates of chemical flooding with variation of chemical slug size

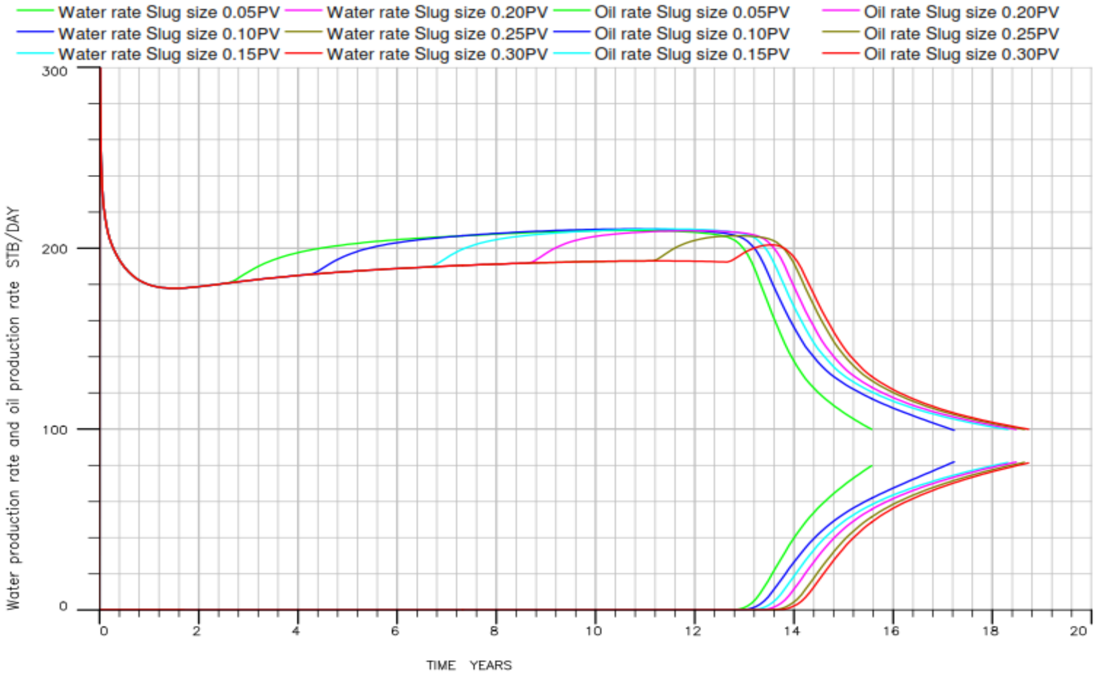


Figure 5.10 Oil production rates and water production rates of chemical flooding with variation of chemical slug size

Figure 5.11 illustrates water cut at production well as functions of time. From the figure, smaller chemical slug size results in higher rate of increment of water cut compared to larger chemical slug size. This can be explained that larger chemical slug size causes injector to perform at lower injection rate, resulting from high viscosity. The lower injection rate therefore results in slow rate of increment of water cut.

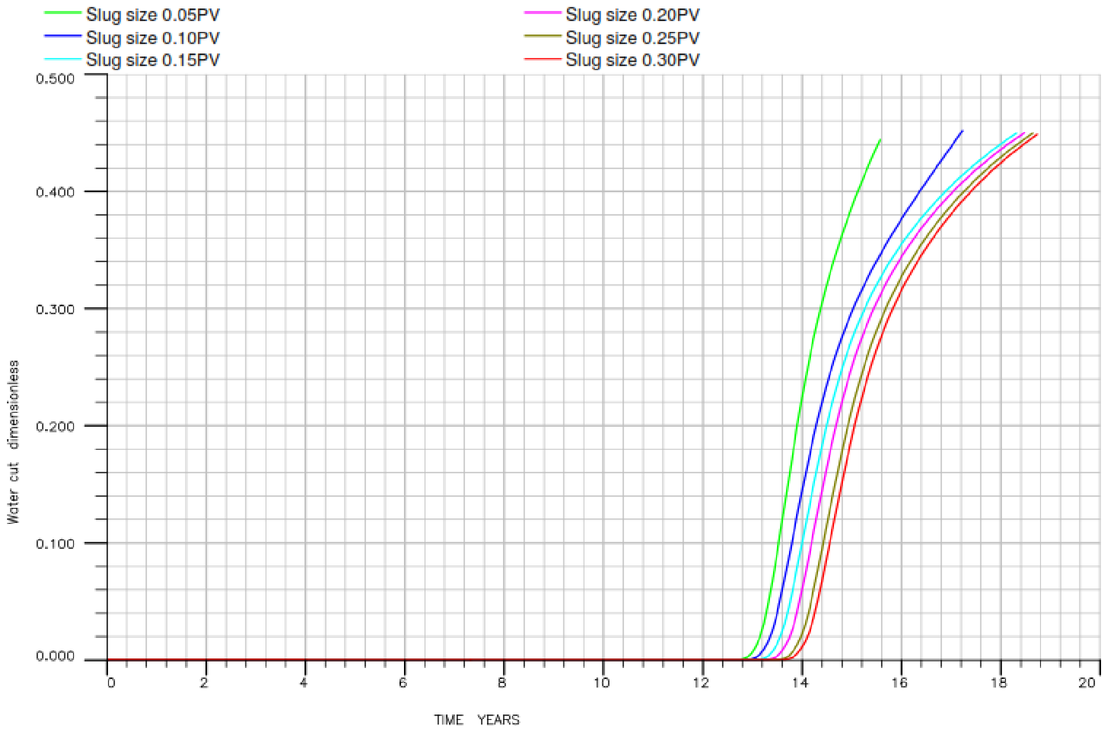


Figure 5.11 Water cut of chemical flooding with variation of slug size

From discussion, it can be concluded that optimized chemical slug size is 0.20PV. This size allows chemical substance to reduce IFT effectively and in the same time, proper viscous force results in moderate rate of increment of water cut. Hence, oil production can be prolonged. Larger slug size than 0.20PV starts to yield drawback from lowering injectivity at injector.

5.4 Effect of surfactant concentration

In this section, effect of surfactant concentration is examined. Concentration of surfactant directly affects reduction of IFT between oil and water phases. Example of

IFT reduction is shown in Figure 5.12 which is obtained from the use of anionic surfactant.

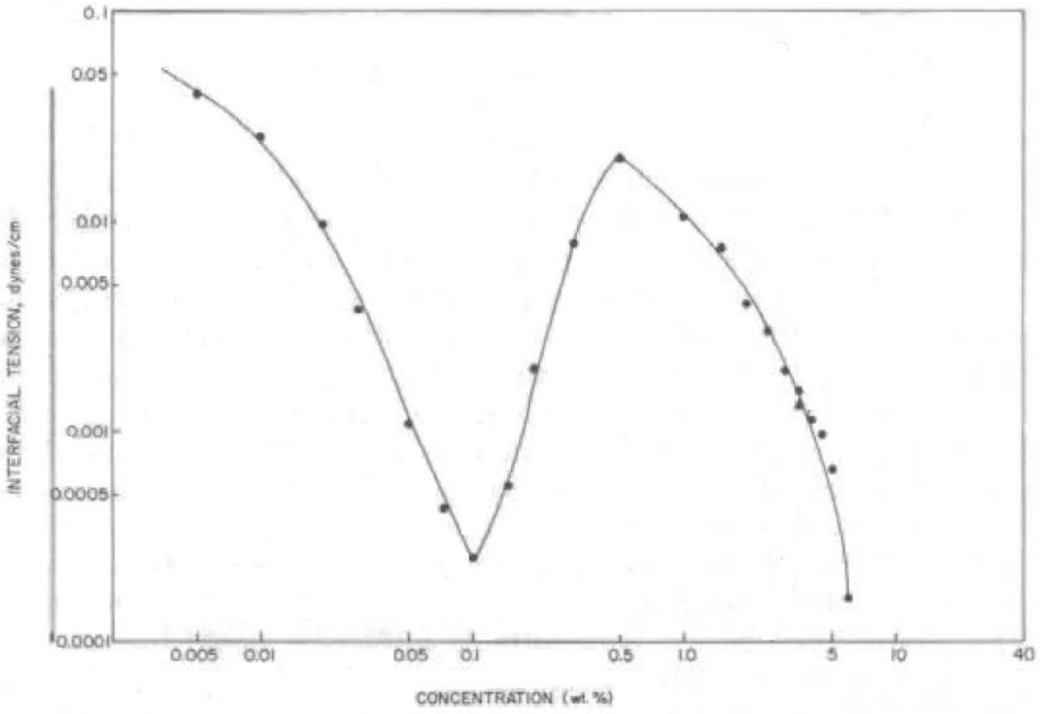


Figure 5.12 Relationship between surfactant concentration and IFT value [2]

For economic reason, maximum surfactant concentration in this study is fixed at 0.1% w/w which is Critical Micelle Concentration (CMC). Relationship between surfactant concentration and IFT values in ECLIPSE®100 is specified as shown in Table 5.6

Table 5.6 Function of surfactant concentration and IFT reduction

Surfactant concentration (% w/w)	**IFT (Dyne/cm)**
0	10
0.01	0.03
0.02	0.01
0.05	0.001
0.10	0.0003

As seen from relationship in Figure 5.12, higher surfactant concentration can better lower IFT value and hence more oil is liberated and displaced. Nonetheless, concentration of surfactant is varied together with chemical slug size in this section. In other words, the higher the chemical concentration, the smaller the slug size. Total surfactant quantity is then important key in this section: surfactant quantity is kept constant for all cases studied. Table 5.7a and 5.7b summarize simulation outcomes from three chosen cases: 1) surfactant concentration 0.1% w/w and slug size 0.15 PV, 2) surfactant concentration 0.075% w/w and slug size 0.20 PV, and 3) surfactant concentration 0.050% w/w and slug size 0.25 PV. Then oil recovery efficiencies, injection rate, oil production rate and water production rates are illustrated as functions of time from Figures 5.13 to 5.15.

Table 5.7a Summary of cumulative oil production, oil recovery efficiency and production life of chemical flooding cases with variation surfactant concentration

Surfactant Concentration	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (%)**	**Production life (years, month)**
0.1% w/w (Slug size 0.15 PV)	1.19	39.98	18 y 4 m
0.075% w/w (Slug size 0.20 PV)	1.14	38.50	17 y 7 m
0.050% w/w (Slug size 0.25 PV)	1.08	36.50	16 y 7 m

Table 5.7b Summary of cumulative water production, dimensionless cumulative water injected, surfactant consumption and alkali consumption of chemical flooding cases with variation surfactant concentration

Surfactant Concentration	**Cumulative water production (STB)**	**Dimensionless cumulative water injected**	**Surfactant consumption (LB)**	**Alkali consumption (LB)**
0.1% w/w (Slug size 0.15 PV)	99,194	0.43	173,570	495,913
0.075% w/w (Slug size 0.20 PV)	83,329	0.41	170,716	656,599
0.050% w/w (Slug size 0.25 PV)	60,343	0.38	150,557	860,323

From Table 5.7a and Table 5.7b, oil recovery efficiency is declined when surfactant concentration is reduced even though chemical slug size is increased. It can be inferred that, surfactant concentration is more sensitive to oil recovery efficienc than chemical slug size in this study. When surfactant concentration is higher, IFT is reduced effectively but cost of surfactant is rising as well. This makes capillary number to be high enough for miscible mode. Oil is then displaced at greater volume and production life is extended longer compared to the lower surfactant concentration. Therefore, initial surfactant concentration also plays a major role. If this value is shifted beyond CMC it could be possible that lowering concentration could yield better oil recovery factor since reduced IFT value could correspond to the highest IFT reduction at CMC. From Figure 5.13, all three cases illustrate oil recovery efficiency curves as functions of time mostly overlaid each other. Slight deviation of values is observed from half period of production life. At the end, longer production life determines the best oil recovery efficiency which is obtained by case where the highest surfactant concentration at CMC is used.

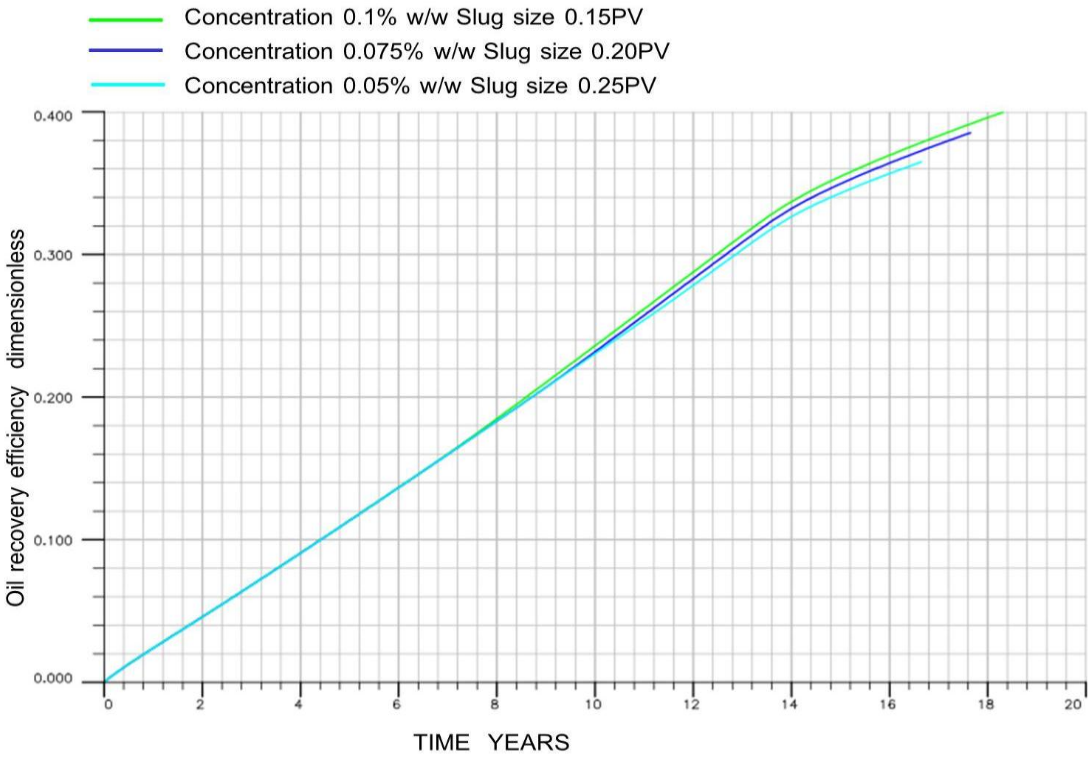


Figure 5.13 Oil recovery efficiencies of chemical flooding cases with variation of surfactant concentration

When chemical injection is switched to chasing water, injection rate of chasing water and oil production rate are rising up as shown in Figure 5.14 and Figure 5.15, respectively. This can be explained by effect of different in fluid viscosity between pure water and surfactant solution as described in previous section. The case where high chemical concentration is used, which corresponds to the smallest chemical slug size, reaches high injection rate earlier than other cases. Therefore, high oil production rate can be maintained for longer time. This eventually, results in the lowest increment rate of water cut at producer as seen in Figure 5.16.

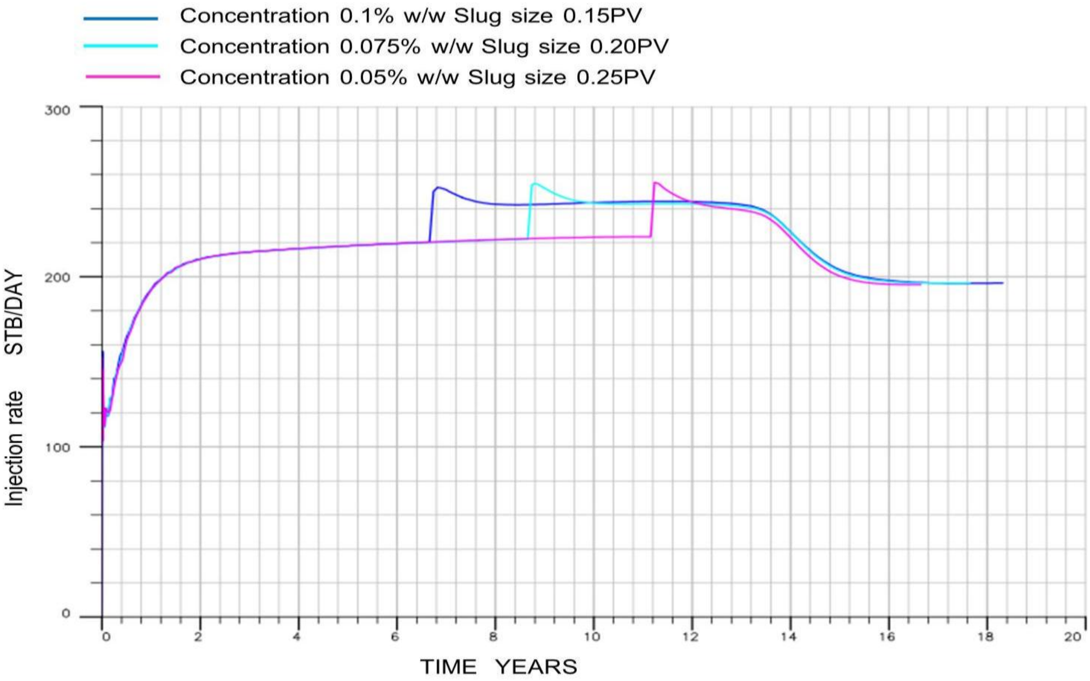


Figure 5.14 Injection rates of chemical flooding cases with variation of surfactant concentration

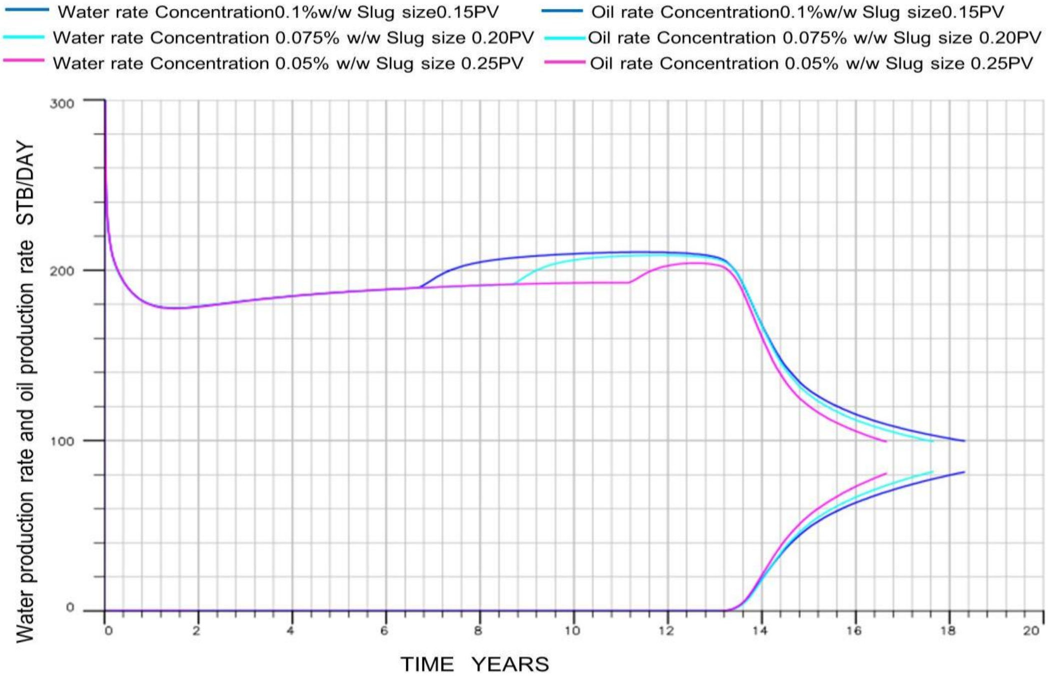


Figure 5.15 Oil production rates and water production rates of chemical flooding cases with variation of surfactant concentration

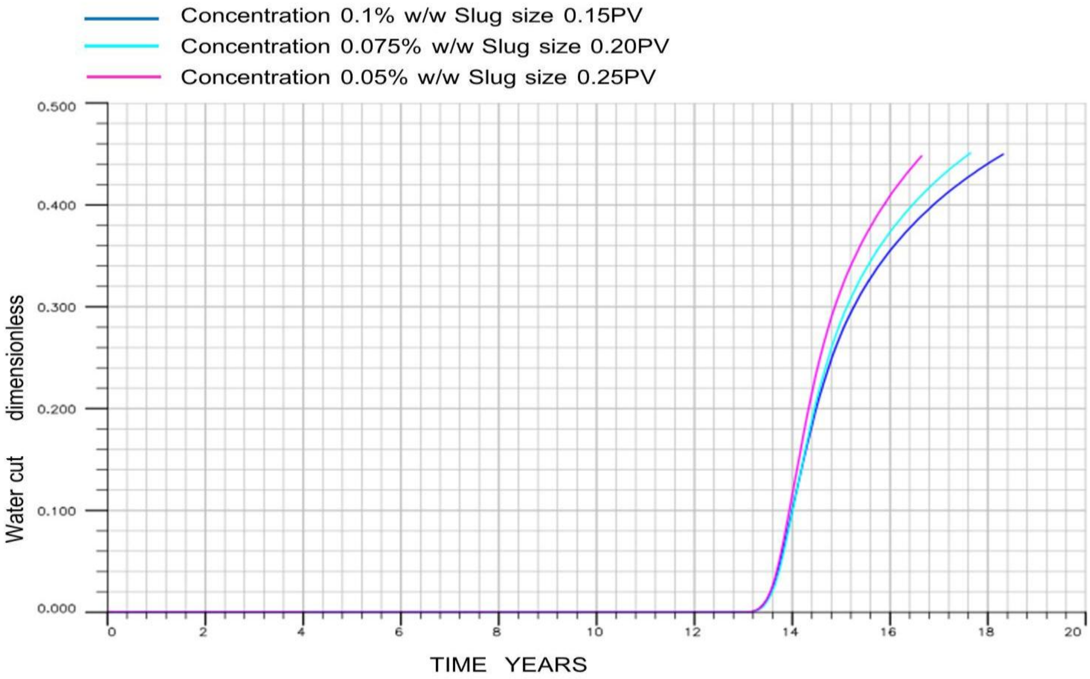


Figure 5.16 Water cut of chemical flooding cases with variation of surfactant concentration

From previous discussion, it can be concluded in this section that surfactant concentration plays more important role on effectiveness of alkali/surfactant flooding than slug size. Proper surfactant concentration that would yield the lowest IFT value should be kept throughout displacement mechanism. If surfactant adsorption by reservoir rock and fluids is severe, sacrificial agent should be added to prevent drastic change of surfactant concentration. A concentration slightly above CMC would be the best for any flooding since CMC could be achieved even part of surfactant is lost due to adsorption.

5.5 Effect of ratio between size of small and large pores

In previous sections, effect of several operational parameters is investigated such as slug size of chemical, concentration of surfactant and scenario of flooding. These are adjustable parameter. From this section, parameters concerning reservoir properties are emphasized. Ratio between size of small pores and large pores is initially considered. Relationship between pore size and capillary pressure is shown in equation 5.1. Due to the term of $2\sigma cos\theta_c$ in equation is a constant in certain condition; ratio of pore size is therefore directly proportional to capillary pressure. In this part, ratio between size of small pores and large pores is varied as 1:5, 1:10, 1:20 and 1:50. The ratio is therefore controlled by capillary pressure to have value between -2 to -100 psi. Value of capillary pressure in large pore is maintained constant on SCAL section in ECLIPSE®100 and the value in small pores is varied due to chosen ratios.

$$P_c = \frac{2\sigma cos\theta_c}{r_c} \tag{5.1}$$

where

P_c = Capillary pressure (psi),

σ = Surface tension between oil and water (dyne/cm),

θ_c = Wetting angle of the liquid on the surface (degree),

r_c = Pore radius (cm).

Table 5.8a and 5.8b summarize simulation outcomes from study of ratio between small and large pores.

Table 5.8a Summary of cumulative oil production, oil recovery efficiency and production life for ratio between size of small pores and large pores

Ratio of pore size small pores : large pores	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (%)**	**Production life (years, month)**
1 : 5	1.19	39.98	18 y 4 m
1 : 10	1.23	41.50	19 y 4 m
1 : 20	1.31	44.00	21 y 1 m
1 : 50	1.36	46.00	22 y 1 m

Table 5.8b Summary of cumulative water production, dimensionless cumulative water injected, surfactant consumption and alkali consumption for ratio between size of small pores and large pores

Ratio of pore size small pores : large pores	Cumulative water production (STB)	Dimensionless cumulative water injected	Surfactant consumption (LB)	Alkali consumption (LB)
1 : 5	99,194	0.43	173,570	495,913
1 : 10	122,350	0.45	173,687	496,248
1 : 20	155,041	0.50	173,806	496,589
1 : 50	186,194	0.54	173,929	496,939

Figures 5.17 to 5.20 illustrate total oil recovery factors, oil recovery factor from layer no.1, oil recovery factor from layer no.2 and oil recovery factor from layer no.3 from different pore size ratios, respectively.

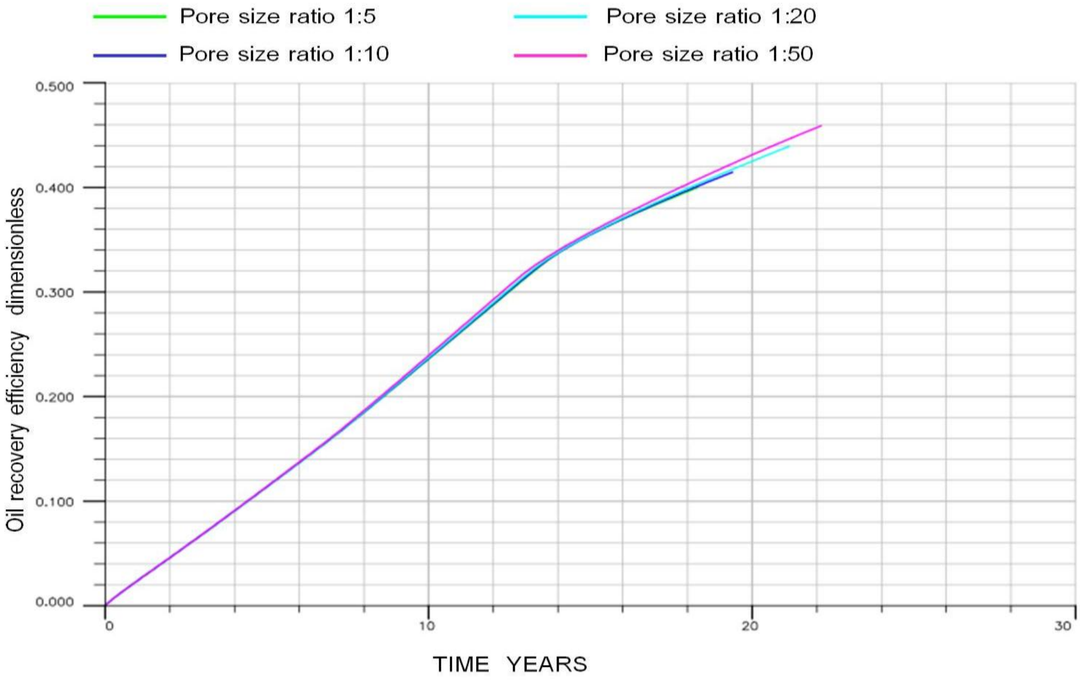


Figure 5.17 Oil recovery efficiencies from reservoir containing different pore size ratio as functions of time

From Table 5.8a, Table 5.8b and Figure 5.17, oil recovery efficiencies increase as ratio between small and large pore size is increased. This incremental trend is a result of production period mainly. However, as production period increases cumulative water production is slightly increased as well as amount of chemical substances consumed.

In order to understand reasons making high pore size contrast extends longer production period, oil recovery efficiencies from each layer in reservoir model are tracked and plotted as functions of time and consecutively shown in Figures 5.18 5.20. In layer no. 1 and no. 3 it can be obviously seen that when contrast of pore size increases, oil recovery factors also increases as shown in Figure 5.18 and 5.20 for layer no.1 and layer no.3, respectively. This can be explained that fluid cannot be easily injected into layer no.2 and hence injected fluid is diverted into other layers. When comparing layer no. 1 and no. 3, distribution of oil recovery efficiencies versus time is layer 3 is higher. This can be explained that in layer no. 3 which is located at the bottommost of reservoir received additional force from gravity effect. Therefore, displacement from high pore size contrast in layer 3 yields the highest oil recovery factor.

In layer no.2 sequence of oil recovery efficiencies is reverse order compared to layer no.1 and no. 3 as shown in Figure 5.19. That is the higher the pore size contrast the lower the oil recovery efficiency. Nevertheless, it is interesting to see that in the highest pore size contrast, production life can be further extended. Since all cases are terminated by minimum oil production limitation, it could be inferred that, in case of high pore size contrast, oil banks in each layer travel with different speed. Oil bank in layer no.2 arrives later in production well, resulting in producer remaining productive until the last oil bank arrives. Oil from layer no.1 and no.3 is therefore continues to be produced even their oil production rates are already low. On the contrary, in case of low pore size contrast, oil bank in all layers arrive relatively in the same period results in termination of production early at the same time.

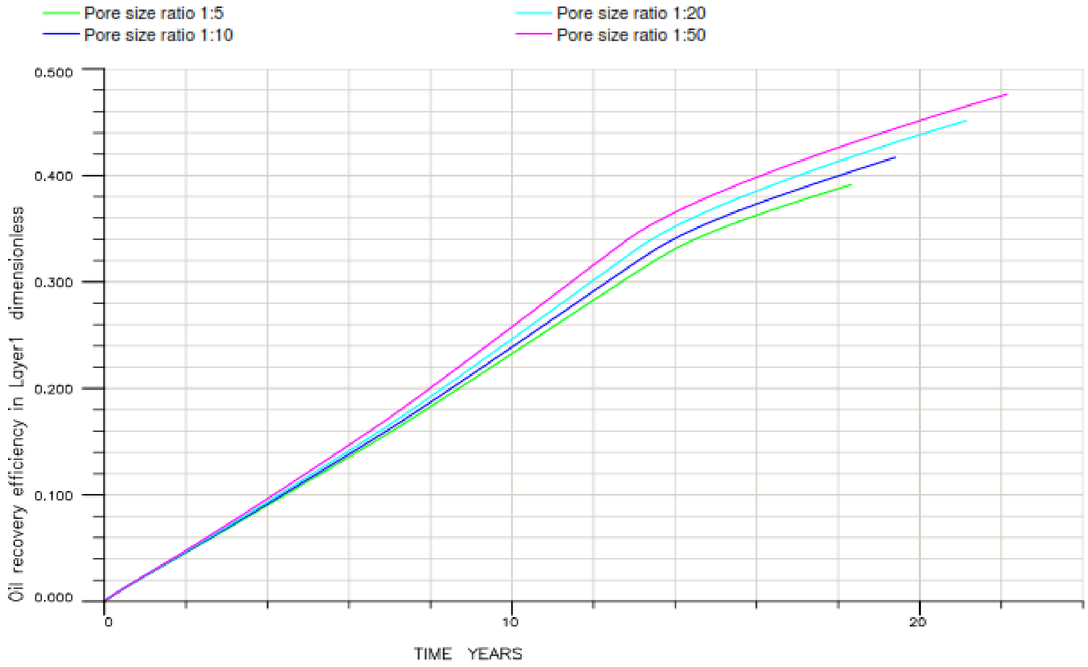


Figure 5.18 Oil recovery efficiencies from first layer of reservoir when reservoir contains different pore size ratio as functions of time

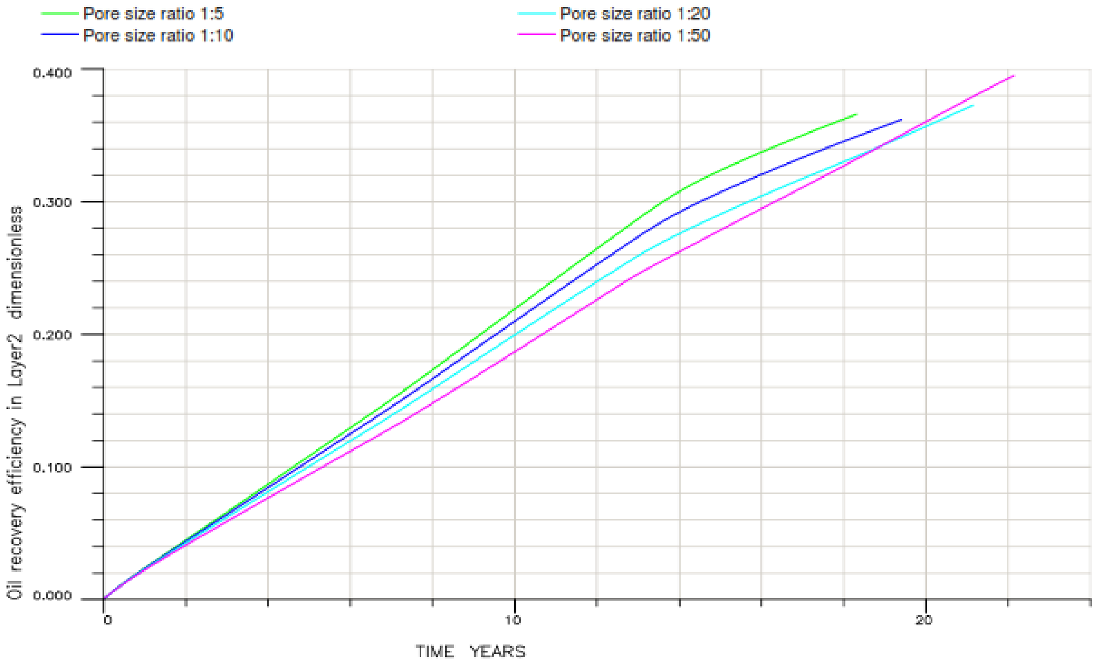


Figure 5.19 Oil recovery efficiencies from second layer of reservoir when reservoir contains different pore size ratio as functions of time

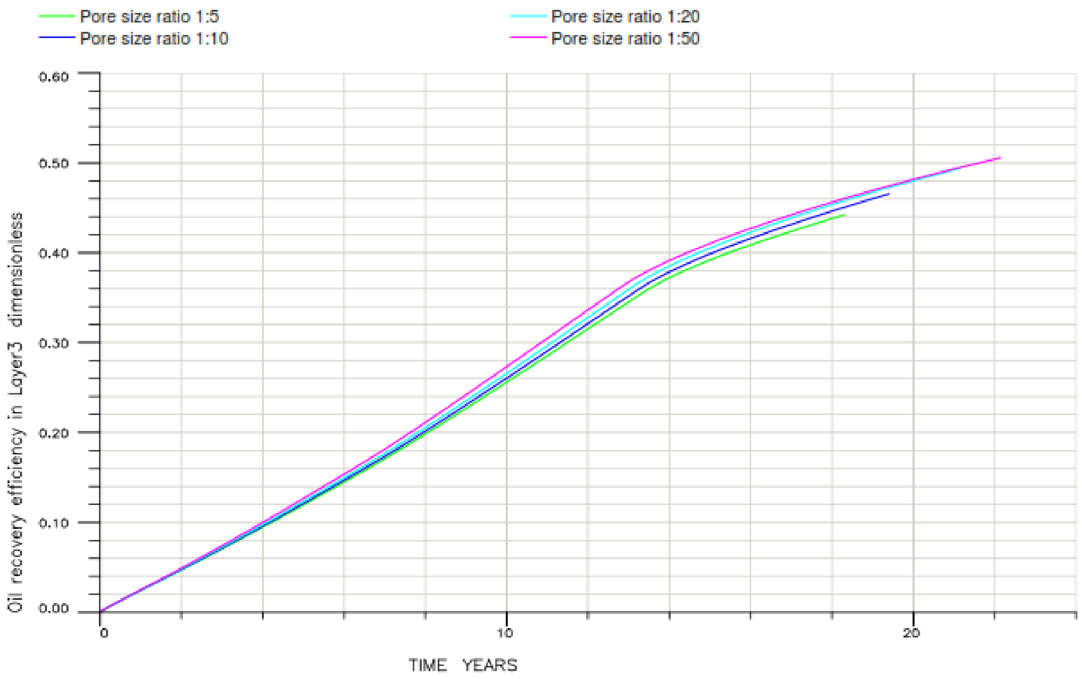


Figure 5.20 Oil recovery efficiencies from third layer of reservoir when reservoir contains different pore size ratio as functions of time

Injection rate at injector and oil production rate at producer in all cases increase when chemical injection is switched into chasing water due to effect of fluid viscosity. Moreover, it can be observed that the higher the contrast of pore size, higher injection rate as well as higher oil production rate as seen in Figure 5.21 and Figure 5.22, respectively.

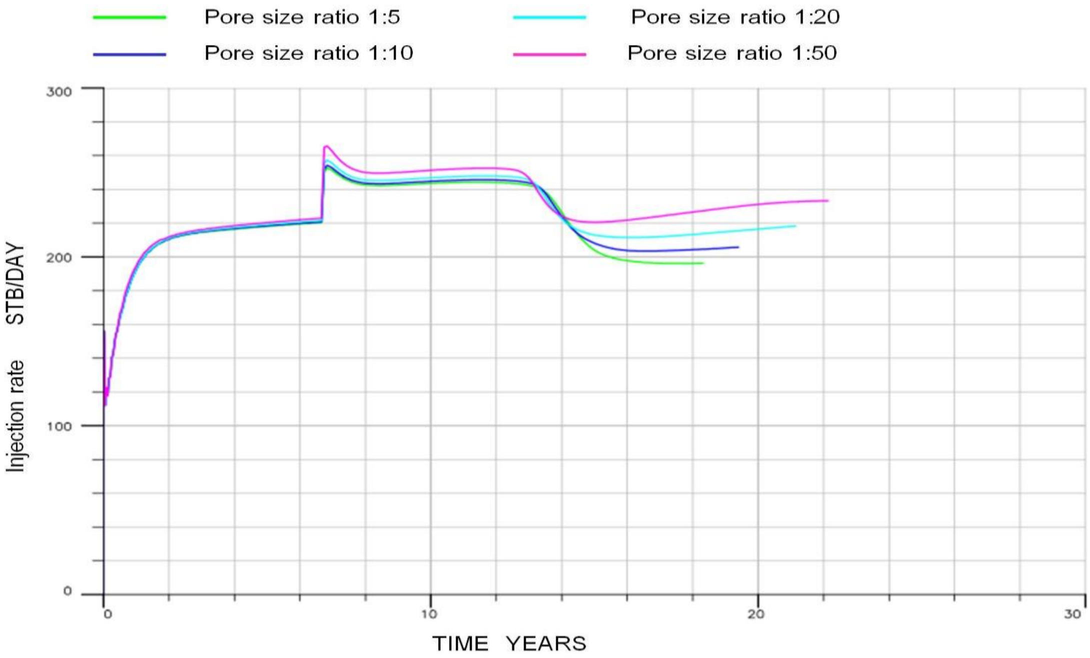


Figure 5.21 Injection rates at producer of reservoir containing different pore size ratio as functions of time

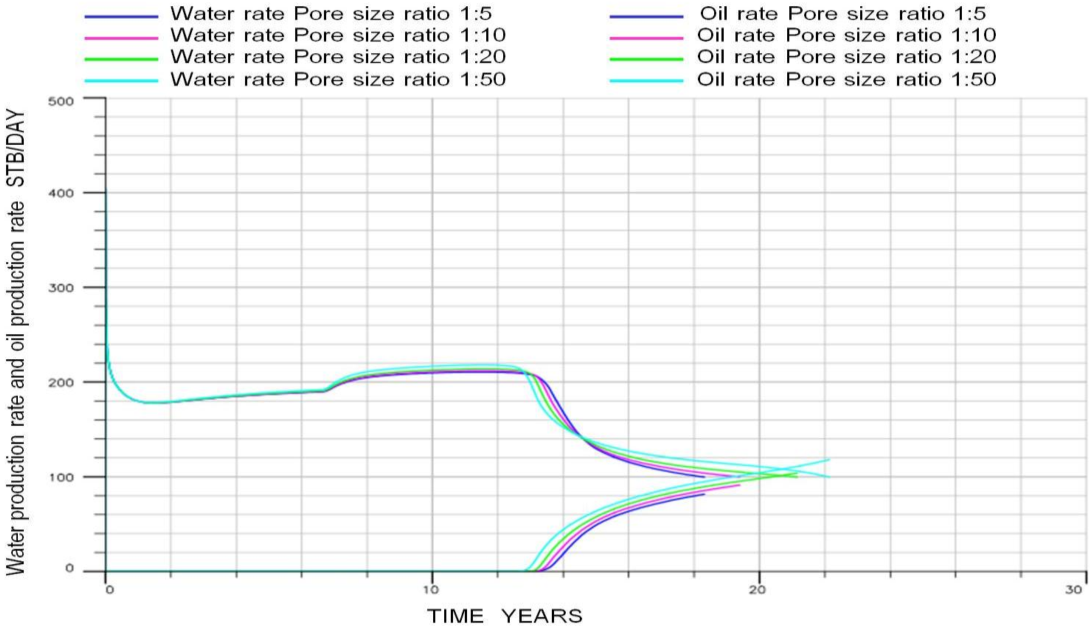


Figure 5.22 Water production rates and oil production rates of reservoir containing different pore size ratio as functions of time

Field water cut of all study cases are illustrated in Figure 5.23. The high pore size contrast reservoir shows the earliest increase of water cut. As explained previously, when pore size contrast is high water tends to flow through later no. 1 and no.3. And eventually, earlier breakthrough of water occurs.

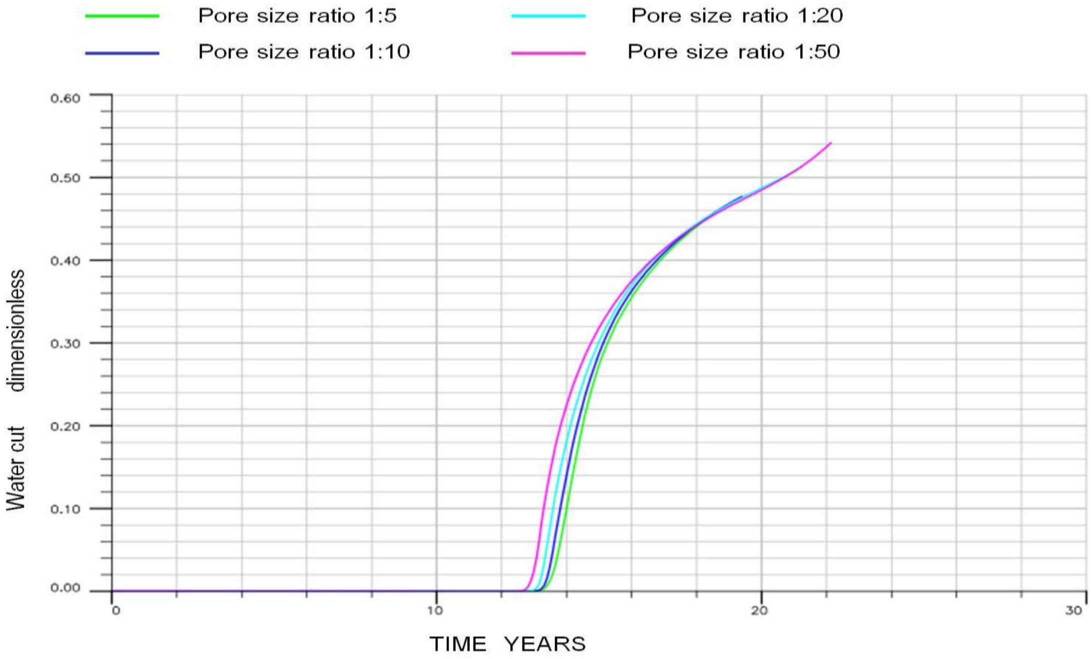


Figure 5.23 Water cut of reservoir containing different pore size ratio as functions of time

From discussion in this section, it can be summarized in high contrast of pore size surprisingly results in benefit on oil recovery efficiency. Existence of high capillary channel forces injected fluid into other zones where capillary pressure is lower. Oil banks that are accumulated from alkali/surfactant effects in each layer therefore travel with different speed. In this study, oil bank in layer no.2 arrives later in production well results in production well productive by producing oil above minimum limit. This event extends production life and increases also oil recovery efficiency.

Nevertheless, benefit obtained in this study might not be valid for every reservoir containing high capillary pressure contrast. Structure of reservoir might be one of the important keys as well as other operational conditions.

5.6 Effect of ratio between vertical permeability (k_v) and horizontal permeability (k_h)

In this section, ratio between vertical permeability (k_v) and horizontal permeability (k_h) is studied. In general, this ratio is approximately 0.1 (1:10). This can be explained that, sand grains which normally are not totally shape are deposited by arranging longitudinal side parallel to bedding plain. Therefore flow in horizontal direction is better than that of vertical one. In this study ratio is varied to 0.15, 0.2 and 0.25 to represent reservoir having better flow ability in vertical directly. Horizontal permeability is kept constant at 20 millidarcy, whereas vertical permeability is varied to obtain mentioned ratios.

Table 5.9a summarizes cumulative oil production, oil recovery efficiency and total production life, whereas Table 5.9b concludes cumulative water production, dimensionless cumulative water injected, surfactant consumption and alkali consumption, of four alkali/surfactant flooding cases having different ratio between vertical permeability to horizontal permeability. And as a consequence, Figures 5.24 to 5.31 illustrate simulation outcomes as functions of time as well as three-dimension illustration of alkali/surfactant model combined with study parameter.

Table 7.9a Summary of cumulative oil production, oil recovery efficiency and production life of chemical flooding cases with variation of ratio between vertical permeability to horizontal permeability

Ratio of k_v : k_h	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (%)**	**Production life (years, month)**
1 : 10	1.19	39.98	18 y 4 m
1.5 : 10	1.21	41.50	19 y 4 m
2 : 10	1.25	44.00	21 y 1 m
2.5 : 10	1.28	46.00	22 y 1 m

Table 5.9b Summary of cumulative water production, dimensionless cumulative water injected, surfactant consumption and alkali consumption chemical flooding cases with variation of ratio between vertical permeability to horizontal permeability

Ratio of $k_v : k_h$	**Total water production (STB)**	**Dimensionless cumulative water injected**	**Surfactant consumption (LB)**	**Alkali consumption (LB)**
1 : 10	99,194	0.43	173,570	495,913
1.5 : 10	142,259	0.44	173,771	496,488
2 : 10	217,156	0.46	174,133	497,522
2.5 : 10	278,558	0.48	175,007	500,021

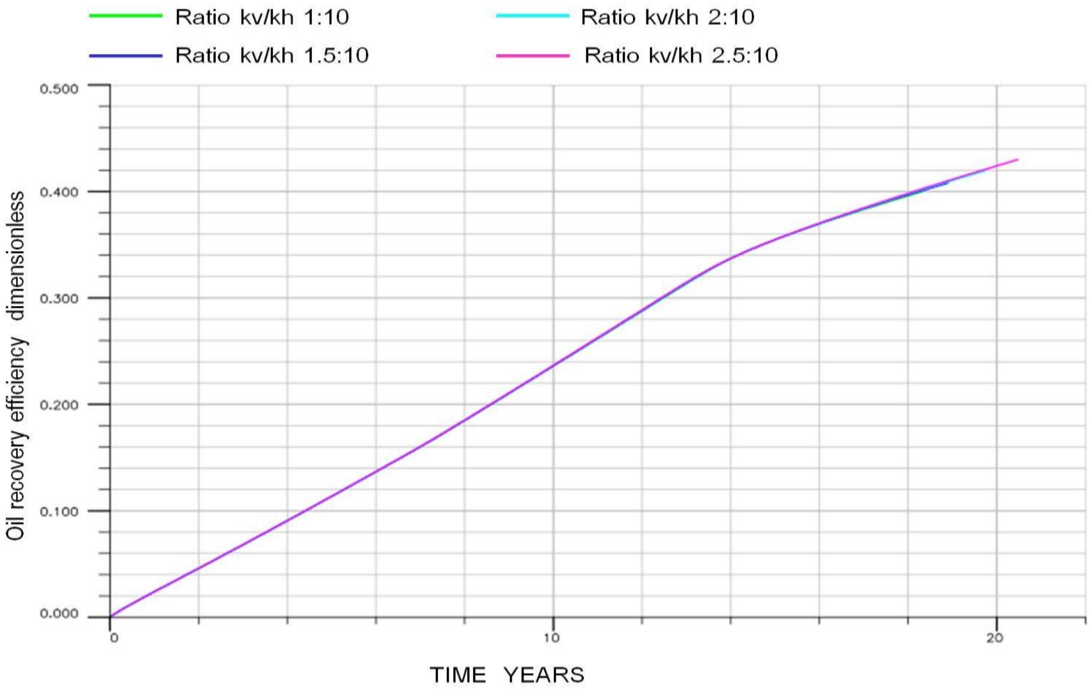


Figure 5.24 Oil recovery efficiencies for ratio between vertical permeability and horizontal permeability

From Table 5.9a, Table 5.9b and Figure 5.24, oil recovery efficiency improved as vertical permeability increases. However, result is similar to previous section: the better result is obtained from longer production life. The total water production is also increased as dimensionless cumulative water injected is increased. Amount of chemical used is slightly increased as well. For better understanding, three-dimensioned model is taken into consideration to assist interpretation from plots.

From Figures 5.25 and 5.26 side view and top view of reservoir containing permeability ratio of 0.1 and 0.24 are illustrated, respectively. These figures are taken at the breakthrough time of injected chemical slug which occurs by flowing through later no.3. From Figure 5.27 it can be seen when vertical permeability is higher, gravity force facilitates injected fluid to flow more in layer no.3. In low vertical permeability, injected fluid flow in layer no. 2 faster than high vertical permeability case since gravity effect cannot segregate fluid down to bottom layer. Hence, breakthrough of injected fluid occurs relatively at the same time. After oil banks in each layer arrive, water is suddenly produced and production terminates due to oil production reaches pre-set minimum value. Flood front of injected fluid in each later obtained in the case of high vertical permeability is higher distributed compared to lower vertical permeability cases. This results in arrival of oil banks in different time and this is similar to explanation made in section 5.5, production life can be extended and consequently oil recovery efficiency is higher.

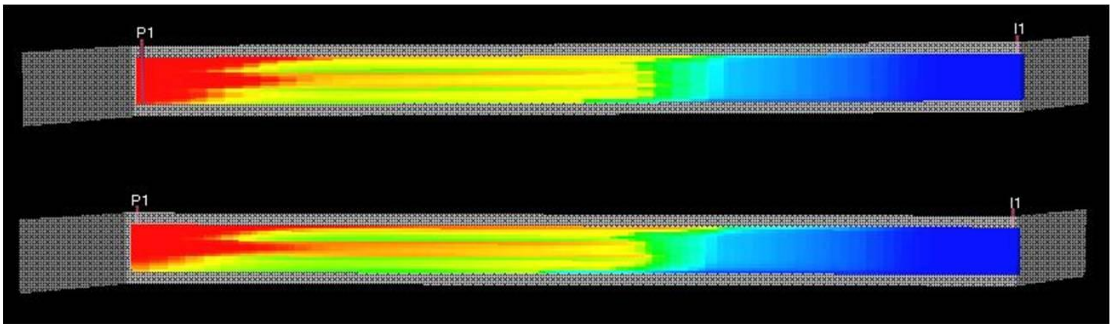


Figure 5.25 Oil saturation profile at water breakthrough (red = oil and blue = water) from side view reservoir containing ratio of vertical permeability to horizontal permeability 1:10 for top figure and 2.5:10 for bottom figure

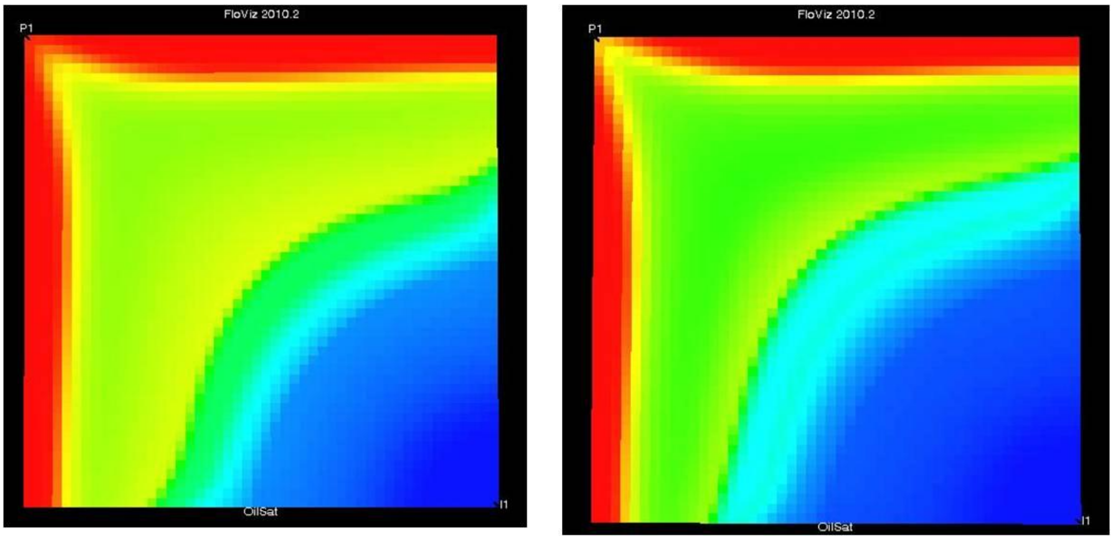


Figure 5.26 Oil saturation profile at water breakthrough (red = oil and blue = water) from top view reservoir containing ratio of vertical permeability to horizontal permeability 1:10 for left figure and 2.5:10 for right figure

The differences in Figures 5.25 and 5.26 may be not very clear for the mentioned explanation. In order to compare these two cases of different ratio, side view and top view figures at termination of production life is captured and considered. Figures 5.27 and 5.28 depict side view and top view of reservoir model containing both low and high vertical permeability, respectively. From both figures, it can be obviously seen that sweep efficiency is much better in the case of high vertical permeability. As described previously, displacing front is more advanced in both vertical and areal views.

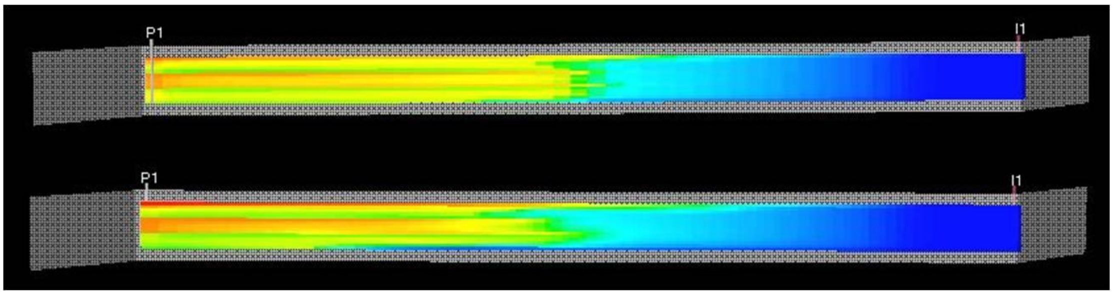


Figure 5.27 Oil saturation profile at termination of production (red = oil and blue = water) from side view reservoir containing ratio of vertical permeability to horizontal permeability 1:10 for top Figure and 2.5:10 for bottom figure

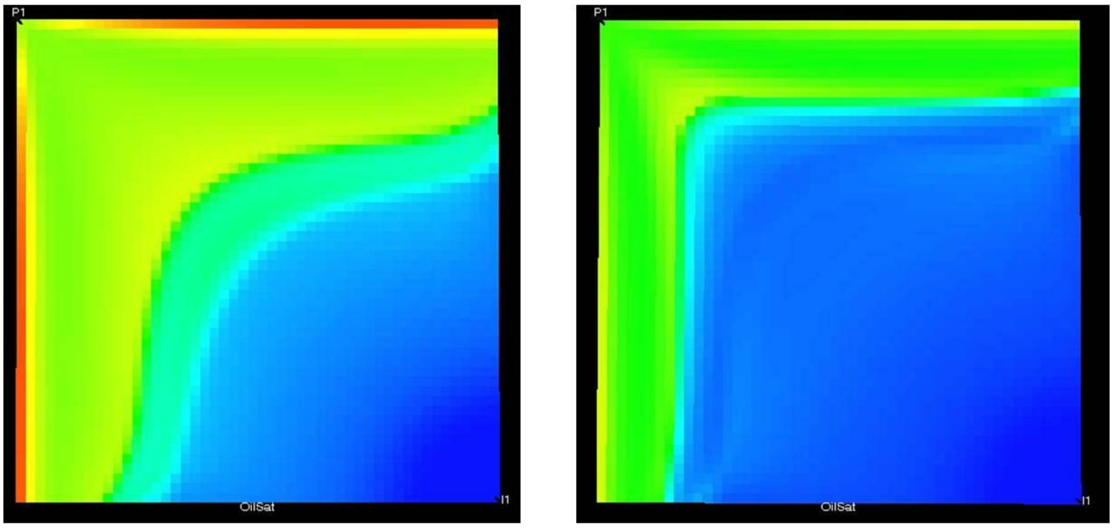


Figure 5.28 Oil saturation profile at termination of production (red = oil and blue = water) from side view reservoir containing ratio of vertical permeability to horizontal permeability 1:10 for left figure and 2.5:10 for right figure

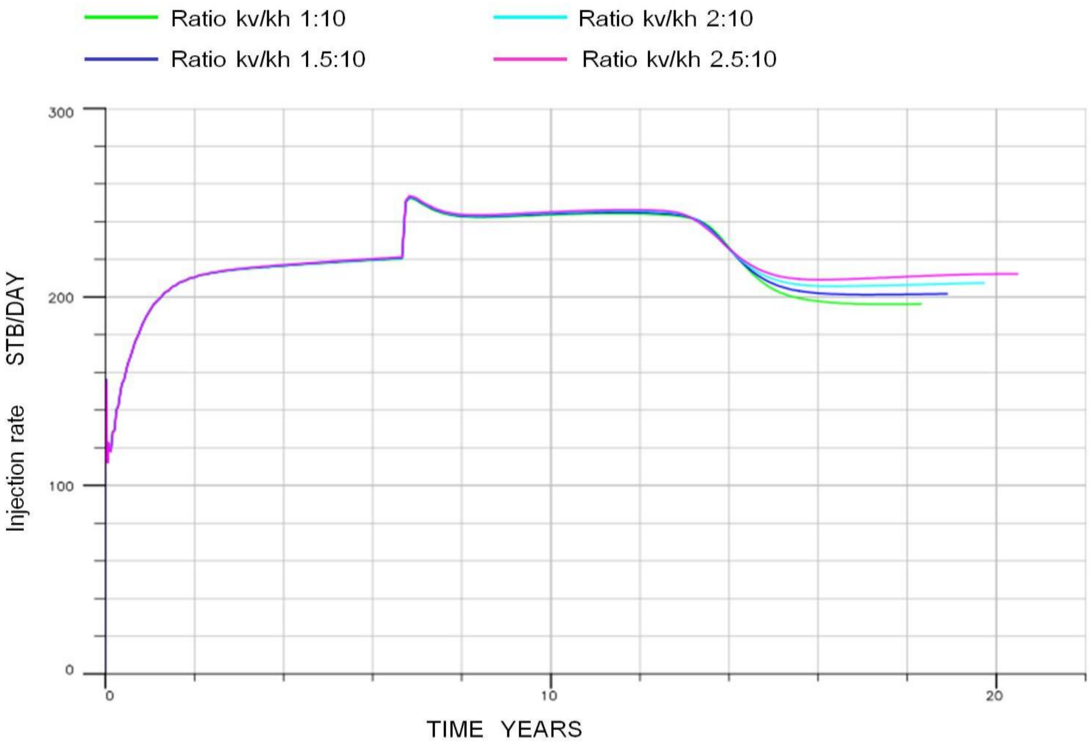


Figure 5.29 Injection rates of chemical flooding cases with variation of ratio between vertical permeability and horizontal permeability

From Figure 5.29 all chemical flooding cases with different values of vertical permeability tend to yield injection rate at the same value throughout production period. However, slight difference can be seen from the year 14th where curves separate from each other. This point is considered as breakthrough time of injected chemical slug. As described before, higher vertical permeability results in earlier breakthrough. After breakthrough of injected aqueous phase, injecting fluid at injection well can be performed easier. Therefore, chasing water can be injected at higher rate. Together with longer life of production, this increment trend also continues and at termination of production, this final injection rate is obviously higher than the case of low vertical permeability.

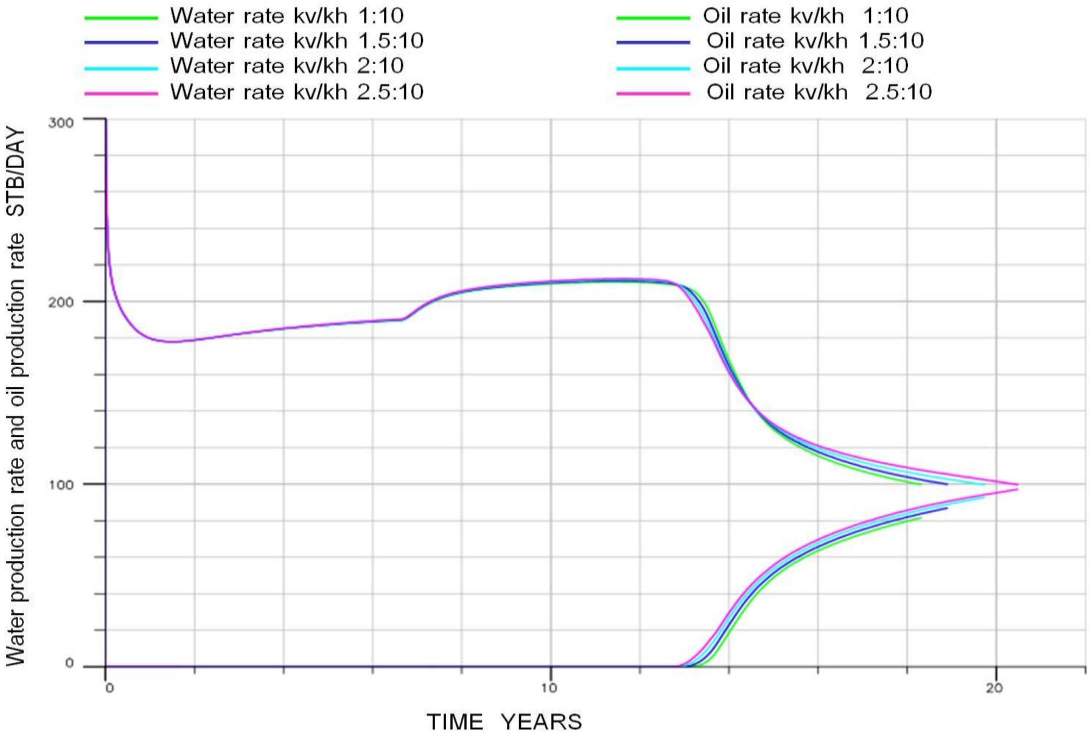


Figure 5.30 Oil production rates and water production rates of chemical flooding cases with variation of ratio between vertical permeability and horizontal permeability

From Figure 5.30, it is noticeable that high vertical permeability results in an earlier breakthrough of injected fluid. As injection rate is raised due to higher injectivity water production rate increases as well. However, order of oil production rates from all cases is slightly different from water production rates. The oil production rate from the highest vertical permeability twists flow the lowest value to the highest value at the year 15th. This is caused by an arrival oil bank in other layers that travel with different speed. This higher oil rate compensates previously lower rate from the year 13th. However, since production is extended, oil production rates from high vertical permeability case continues to decline but this causes in higher total cumulative oil production compared to other cases.

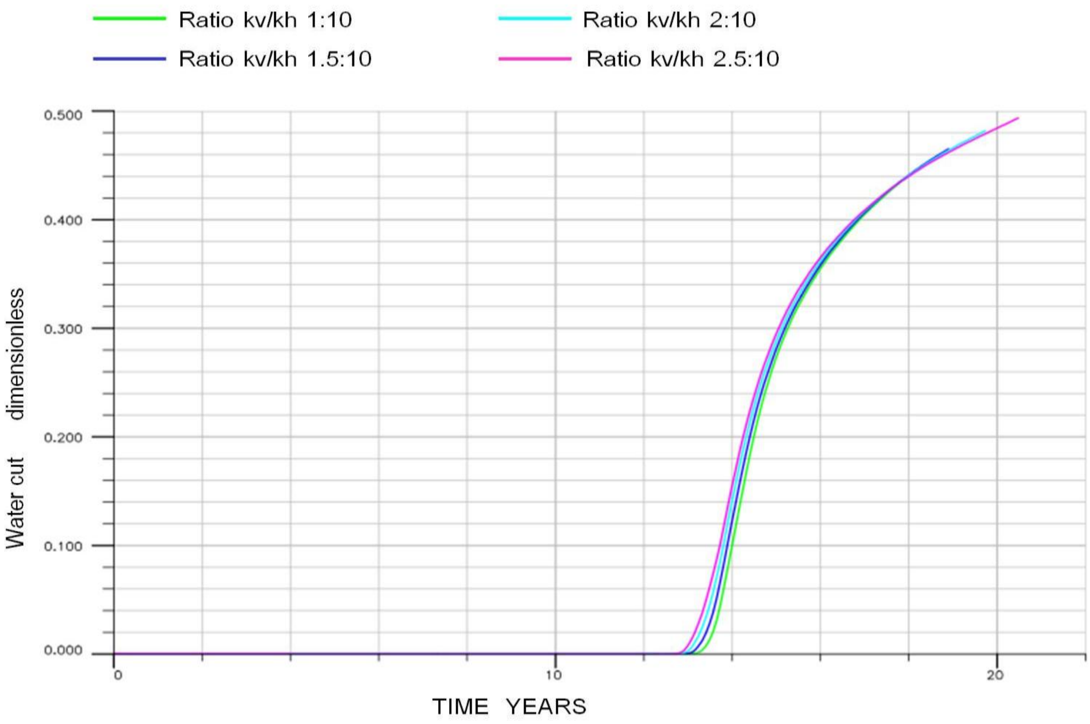


Figure 5.31 Water cut of chemical flooding cases with variation ratio between vertical permeability and horizontal permeability

From Figure 5.31, water cut at producer is higher for high vertical permeability suddenly after breakthrough. However, as described in section of oil and water production rates, water cut obtained from the highest vertical permeability also change to the lowest value at later years when oil bank from other layers arrive.

From discussion, it can be concluded that high vertical permeability yields good result on oil recovery efficiency in this study. Water tends to flow downward to bottom layer, causing different speed of injected chemical flood front. From this reason oil banks from each later are produced in sequence and this extends termination of production time due to minimum oil production rate. Similar to capillary pressure/pore size contrast study, result could be different in different reservoir structure as well as operational conditions.

5.7 Effect of mobile connate water

In this section, investigation is performed on mobile connate water. It refers to condition where reservoir contains connate water saturation higher than irreducible water saturation and this differential water saturation is movable. From previous cases, connate water saturation is fixed at 0.15 thus, initial oil saturation is correspondingly 0.85 that means there is not mobile connate water. In this study, mobile connate water saturations from 0.05 to 0.15 are added to irreducible water saturation of 0.15. However, initial oil saturation is different in each. Hence, cumulative production cannot be used for comparison. Table 5.10a summarizes oil recovery efficiency and total production period of all study cases. As mentioned, cumulative oil production is not considered in this section. Figures 5.32 to 5.35 illustrate simulation outputs which are oil recovery efficiency, injection rate, oil and water production rate and field water cut as functions of time, respectively.

Table 5.10a Summary of oil recovery efficiency and production life for of chemical flooding cases with variation of mobile connate water

Mobile Water	**Oil recovery efficiency (%)**	**Production life (years, month)**
No mobile water	39.98	18 y 4 m
0.05 PV	32.00	16 y 4 m
0.10 PV	24.00	14 y 1 m
0.15 PV	0.14	0 y 1 m

Table 5.10b Summary of total water production, dimensionless cumulative water injected, surfactant consumption and alkali consumption of chemical flooding cases with variation of mobile connate water

Mobile Water	**Total water production (STB)**	**Dimensionless cumulative water injected**	**Surfactant consumption (LB)**	**Alkali consumption (LB)**
No mobile water	99,194	0.43	173,570	495,913
0.05 PV	123,455	0.33	148,444	424,125
0.10 PV	179,258	0.26	132,732	379,234
0.15 PV	1,887	0.001	1,094	3,126

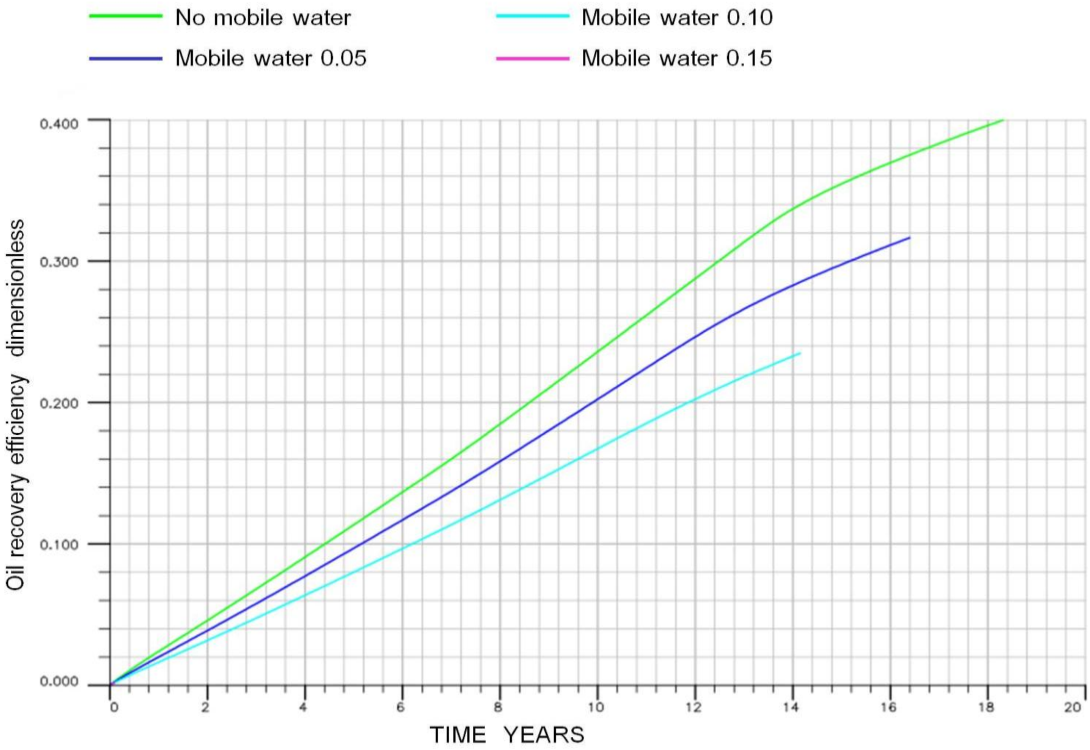


Figure 5.32 Oil recovery efficiencies of chemical flooding cases with variation of mobile connate water

From Table 5.10a, Table 5.10b and Figure 5.32, oil recovery efficiency drastically dropped as mobile connate water. First reason is that when mobile connate water increases, total water saturation increases as well. This results in dilution of injected alkaline and surfactant substances. Therefore, IFT reduction which is a direct function of chemical concentration cannot perform well. The flow is then based on immiscible mode, leaving high residual oil after chemical slug passes. Mobile connate water also reduces concentration of surfactant quickly because this part of water can move in front of chemical front. Therefore, surfactant leaks into this part of water causing concentration of surfactant behind chemical shock front even lower.

In order to clarify previously mentioned paragraph, concentrations of surfactant at any location of reservoir as shown in Figure 5.33 are tracked and reported in Figures 5.34 to 5.36. Location of production well (1:1:8), injection well (50:50:8), block number (25:25:8) and block number (37:37:8) are used for surfactant concentration. Figure 5.34 to 5.36 display comparison of surfactant concentration between cases of no mobile connate water and mobile connate water of 0.10 at injection well (50:50:8), block number (37:37:8) and block number (37:37:8), respectively.

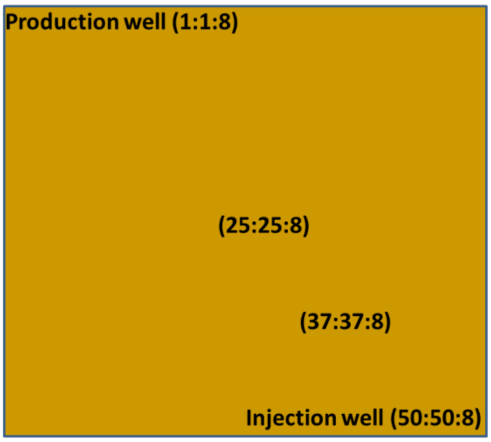


Figure 5.33 Location of production well (1:1:8), injection well (50:50:8), block number (25:25:8) and block number (37:37:8) for tracking surfactant concentration in top view

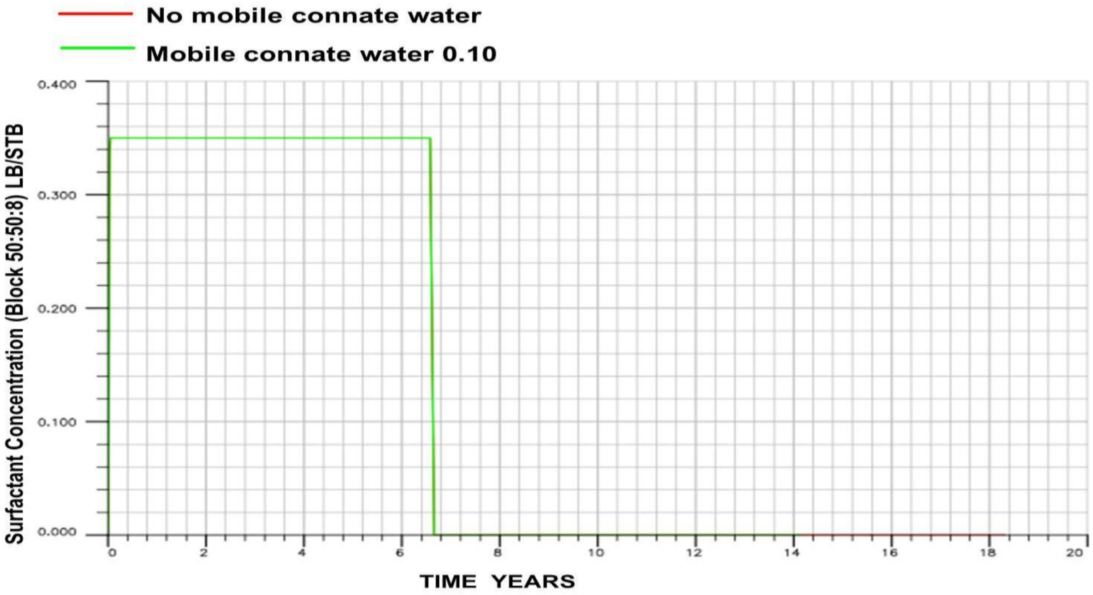


Figure 5.34 Surfactant concentration of injection well (50:50:8) in cases of no mobile connate water and mobile connate water 0.10 as functions of time

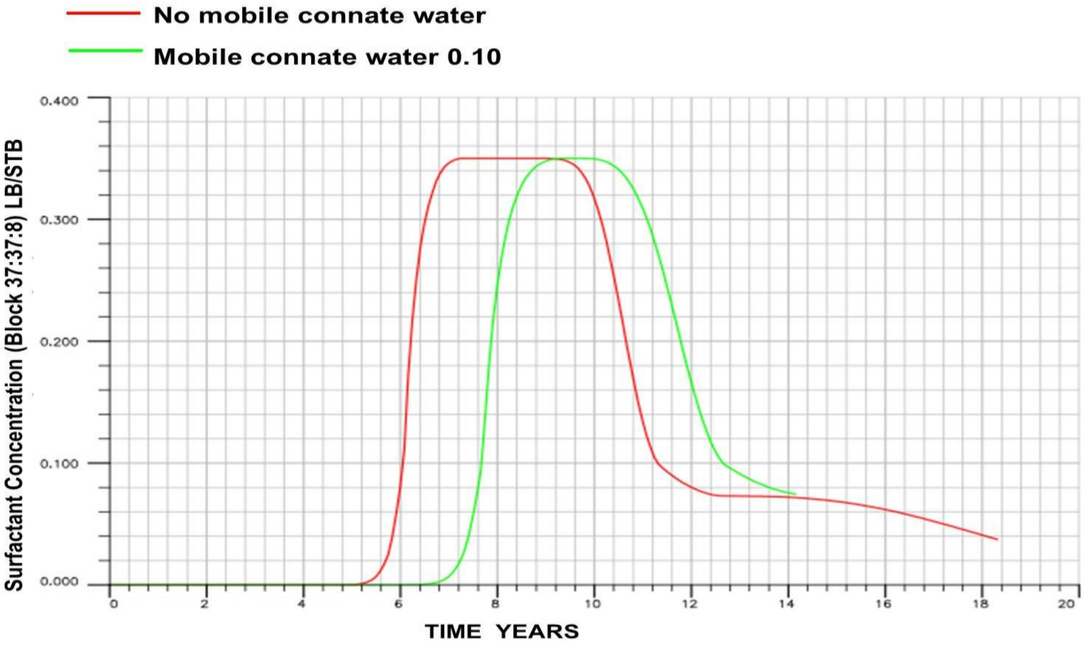


Figure 5.35 Surfactant concentration of block number (37:37:8) in cases of no mobile connate water and mobile connate water 0.10 as functions of time

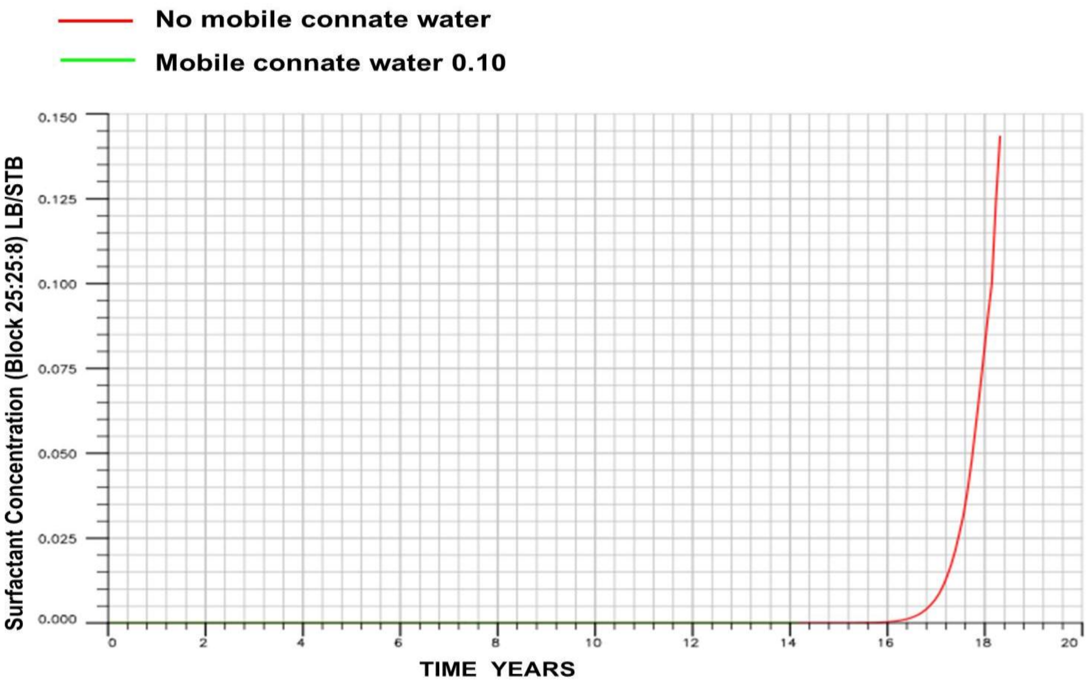


Figure 5.36 Surfactant concentration of block number (25:25:8) in cases of no mobile connate water and mobile connate water 0.10 as functions of time

From Figure 5.34, Figure 5.35 and Figure 5.36, surfactant concentrations of both cases, with and without mobile connate are equal at inject well. By the way, the difference occurs at block number (37:37:8). The plateau of concentration of case without mobile connate water is longer than that of case with mobile connate water. It means that mobile connate diluted concentration of chemical bank. However, when chemical front of both cases moved further at block number (25:25:8), they are adsorbed by the rock until concentration decrease to 0.145 LB/STB. At this location, concentration of both cases is no more different.

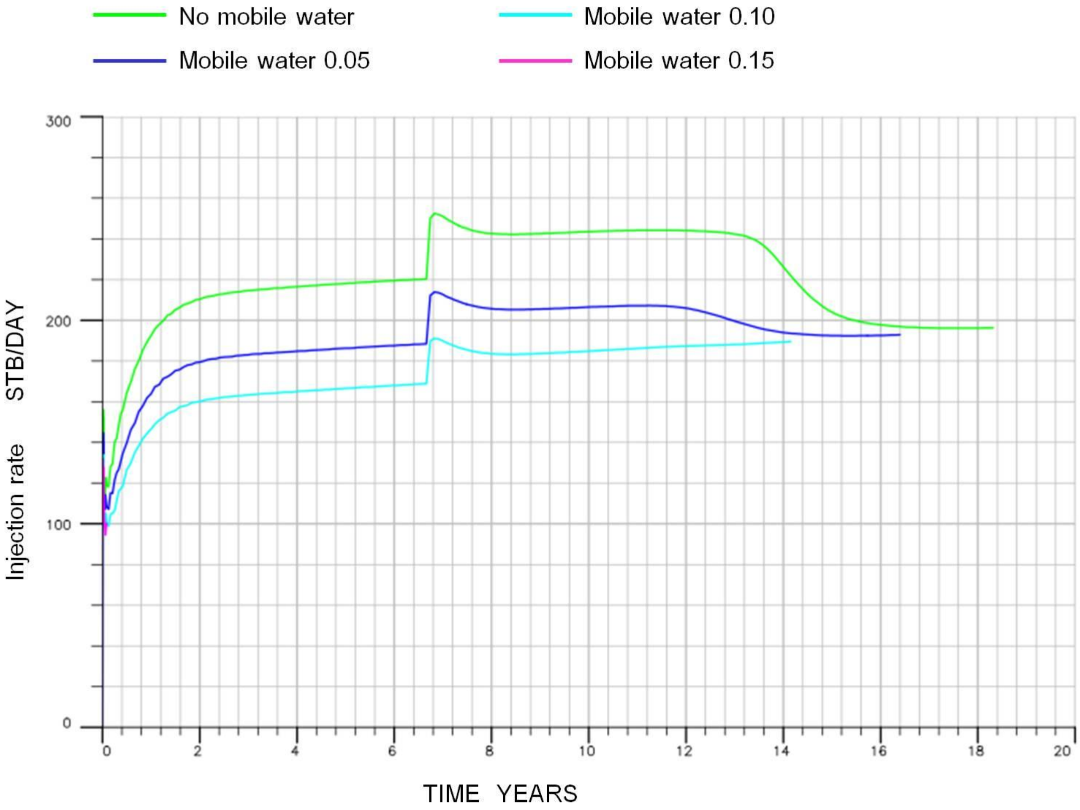


Figure 5.37 Injection rates at injection well of chemical flooding cases with variation of mobile connate water

From Figure 5.37, injection rates at injection well increases for all cases. However, this increment is not equal in all cases. In the case where there is not mobile connate water, miscible mode can be performed and this reduces residual oil around wellbore quickly. Correspondingly, water saturation is high; resulting in rising up of injection rate as injectivity increases and dimensionless cumulative water injected is also high as shown in table 5.10b. For higher amount of mobile connate water, miscible mode is partly switched to immiscible and the flow property is based on conventional waterflooding relative permeability curves. Therefore, residual oil is higher, less water can displace and consecutively injection rate is lower due to low injectivity. In all cases, second increment of injection rates occurs as water is injected after chemical slug. The effect of injected fluid viscosity is taken place and this is already explained in effect of chemical concentration section.

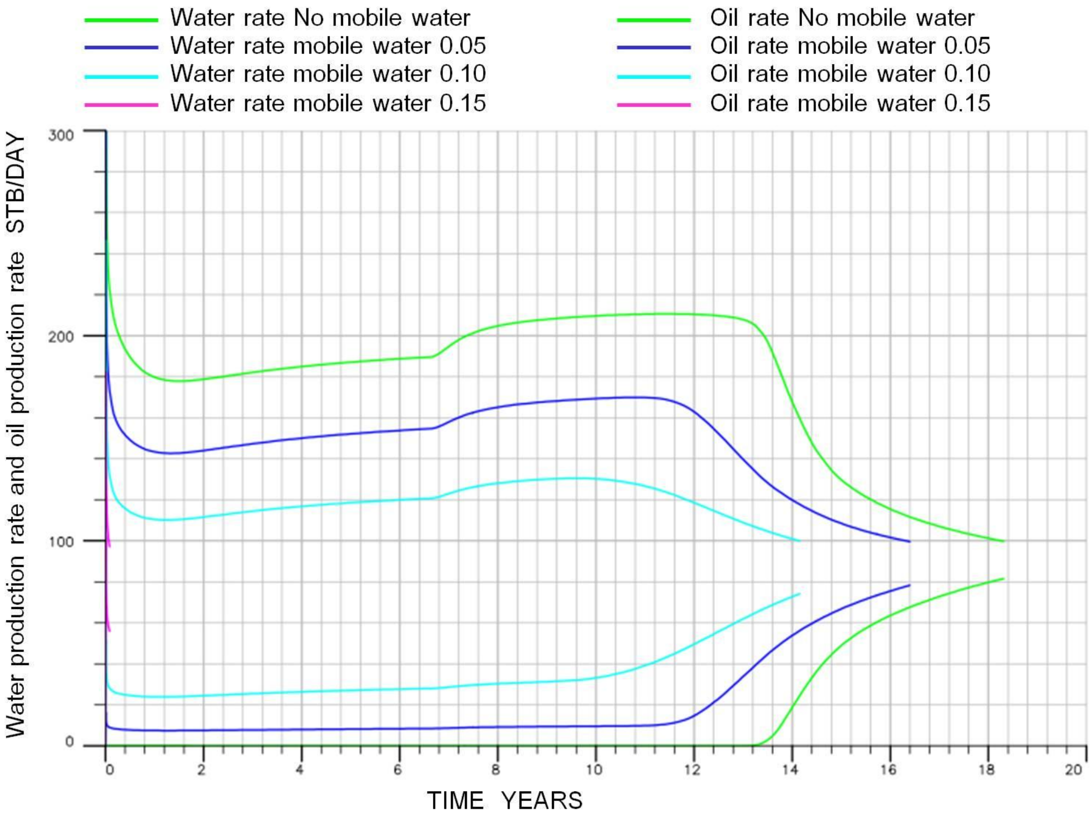


Figure 5.38 Oil production rates and water production rates of chemical flooding cases with variation of mobile water

From Figure 5.38 oil production rate is lower in case of high mobile connate water. This is combination from many reasons. Immiscible mode results in less oil to be produced and injectivity causes lower injection rate that eventually results in low production rate. Mobile connate water which is moveable from the start of production also compete flow ability as seen from water production rate from the start of production period. And moreover, relative permeability of water is substantially high when mobile connate water exists. The combination of these four reasons therefore results in high separation of oil production rates in this section.

Another important point can be seen from Figure 5.38 is that water breakthrough in high mobile connate water is earlier. This can be explained that flood front might travel quicker due to higher water saturation that leads to better flow property of water.

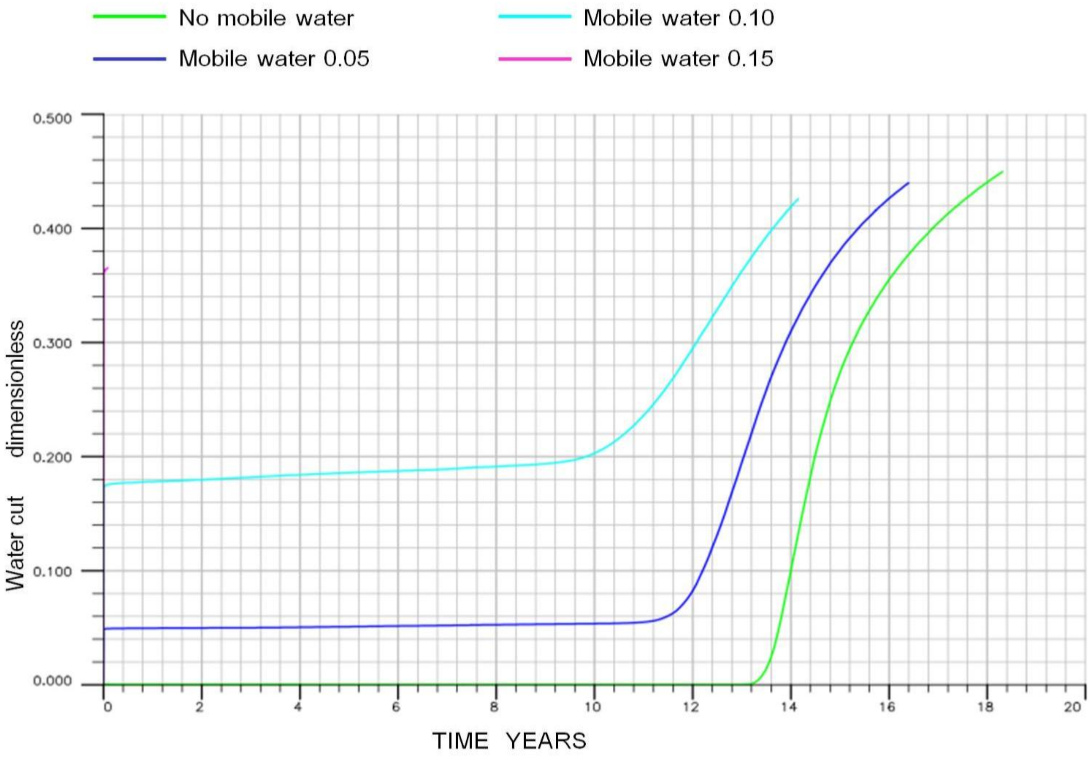


Figure 5.39 Water cut of chemical flooding cases with variation mobile connate water

Similar to oil/water production rates section, water cut is high from the start of production for cases with high mobile connate water saturation. Water breakthrough can be clearly seen for each case from Figure 5.39. It can be obviously seen that the case where mobile connate water is 0.15 well is suddenly terminated due to high water cut due to this part of movable water.

From discussion, it can be concluded that mobile connate water yields substantial drawback to alkali/surfactant flooding. Reason is that this part of water can results in dilution of surfactant behind flood front that could results in fluid flowing in immiscible mode. Moreover, relative permeability is initially high compared to the case with no mobile connate water. Moreover, mobile connate water can be a problem if water cut constraint is adjusted to lower pre-set value. The production is risk to terminate at early time.

5.8 Effect of exponent of relative permeability curve

In this section, shape of relative permeability curve is investigated. Shape of relative permeability is varied by changing exponent value of relative permeability curve equation. In this study, relative permeability curves are constructed from Corey's correlation. Both relative permeabilities to oil and to water are modified in SCAL section of ECLIPSE®100. As described in chapter 4, two sets of relative permeability curves are used which are immiscible and miscible modes. Immiscible mode occurs when capillary number is less than 10^{-4}, whereas miscible mode appears when capillary number is higher than 10^{-4}. Variation of relative permeability curves is performed on both miscible and immiscible mode.

5.8.1 Relative permeability curves of immiscible mode

For relative permeability curves in immiscible mode, normally Corey's exponent of relative permeability to oil is fixed at 2.8, while Corey's exponent of relative permeability to water is 1.8. These values are used in order to match relative permeability curves of oil-wet reservoir based on the reference [2]. Thus Corey's exponent is varied from these initial values, individually. To begin with Corey's exponent of relative permeability to oil, the exponent is varied in the range from 1.8 to 3.8, whereas Corey's number of relative permeability to water is kept constant. Similarly, Corey's exponent of relative permeability to water is varied from 1.1 to 2.8, while Corey's exponent of relative permeability to oil is fixed at constant value. Generated relative permeability curves to oil and to water are illustrated in Figures 5.40 and 5.41, respectively.

Table 5.11a summarizes cumulative oil production, oil recovery efficiency and total production life, whereas cumulative water production, dimensionless cumulative water injected, surfactant consumption and alkali consumption of cases with different Corey's exponent of relative permeability to oil. Then Figures 5.42 to 5.45 illustrate simulation outputs including oil recovery efficiency, injection rate at injector, oil/water production rates and water cut as functions of time of this study, respectively.

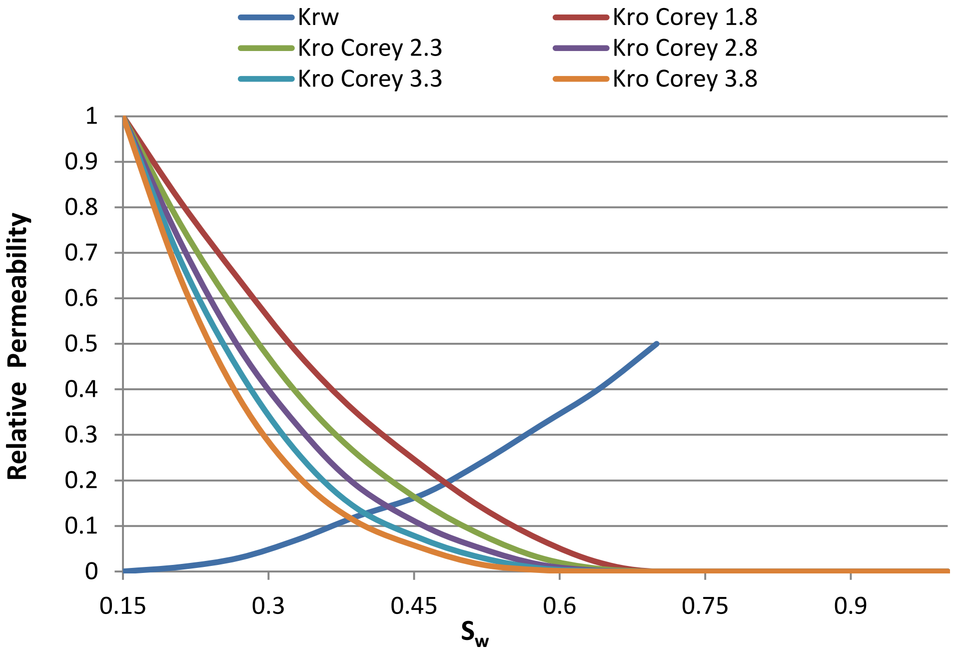


Figure 5.40 Generated relative permeability to oil with variation of Corey's exponent in immiscible mode

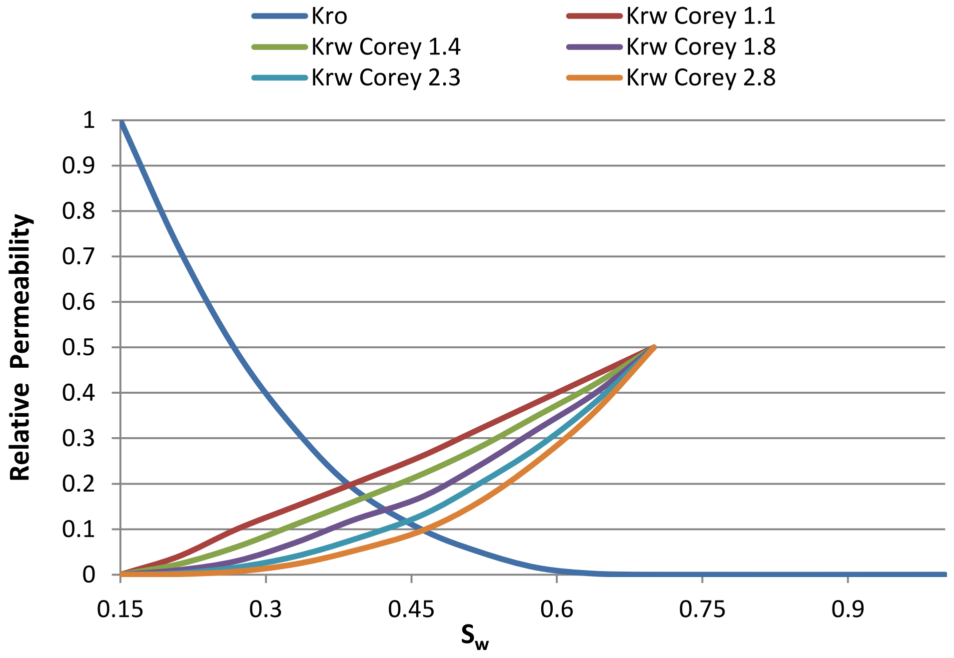


Figure 5.41 Generated relative permeability to water with variation of Corey's exponent in immiscible mode

Table 7.11a Summary of cumulative oil production, oil recovery efficiency and production life of chemical flooding cases with variation of Corey's exponent of relative permeability to oil

Corey exponent of k_{ro}	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (%)**	**Production life (years)**
1.8	1.47	50.00	23 y 2 m
2.3	1.36	44.50	20 y 10 m
2.8	1.19	39.98	18 y 4 m
3.3	1.09	36.50	16 y 7 m
3.8	1.03	32.50	15 y 6 m

Table 5.11b Summary of cumulative water produced, dimensionless cumulative water injected, surfactant consumption and alkali consumption of chemical flooding cases with variation of Corey's exponent of relative permeability to oil

Corey exponent of k_{ro}	**Cumulative water production (STB)**	**Dimensionless cumulative water injected**	**Surfactant consumption (LB)**	**Alkali consumption (LB)**
1.8	313,218	0.58	178537	510106
2.3	193,537	0.50	176100	503143
2.8	99,194	0.43	173570	495913
3.3	51,949	0.38	170934	488382
3.8	27,762	0.35	168451	481289

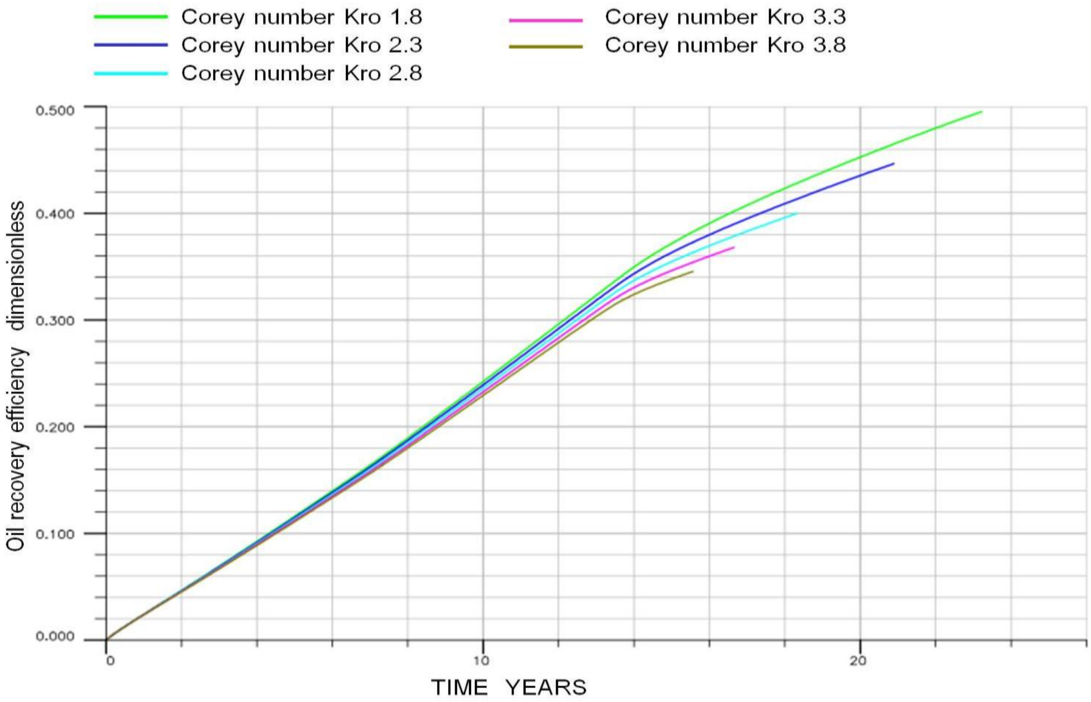


Figure 5.42 Oil recovery efficiencies of chemical flooding cases with variation of Corey’s exponent of relative permeability to oil in immiscible mode

From Table 5.11a, Table 5.11b and Figure 5.42, oil recovery efficiency is significantly improved when Corey’s exponent of relative permeability is low. When Corey’s exponent is low, curvature of k_{ro} curve is straighter as shown in Figure 5.40 and flow ability of oil increases compared to lines generated from higher Corey’s exponent at the same water saturation.

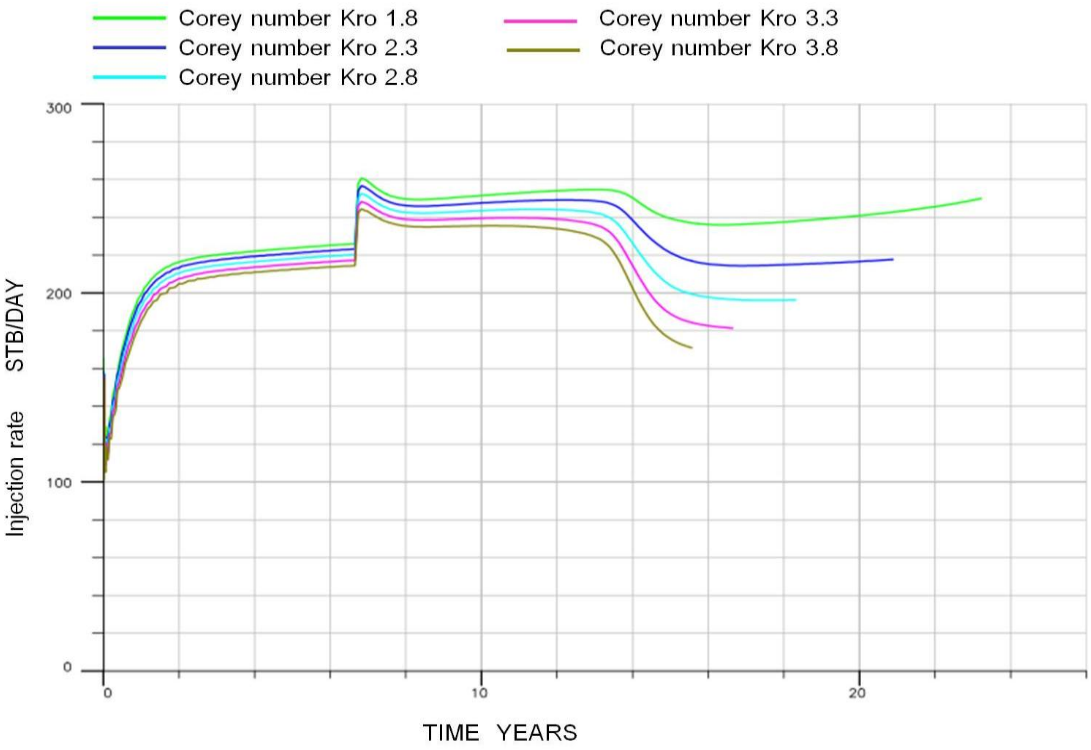


Figure 5.43 Injection rates of chemical flooding cases with variation of Corey's exponent of relative permeability to oil in immiscible mode

From Figure 5.43, injection rates of all cases are similar to results obtained from other sections. However, it can be seen that when relative permeability to oil is improved, injectivity at injector is also increased. That causes a higher injection rate with cases obtained from lower Corey's exponent.

Oil and water production rates are illustrated together in Figure 5.44. It can be obviously seen that, when flow ability is improved, oil production rate is maintained above minimum oil production for longer time than cases of low flow ability of oil. This results in longer production period. Water production rates in contrast, show a reversed trend compared to oil production rates. However, this trend is switch back to opposite after water breakthrough. This is due to high injection rate in case of low Corey's exponent that improves flow ability of oil. Cumulative water production is increased as higher volume of water injection.

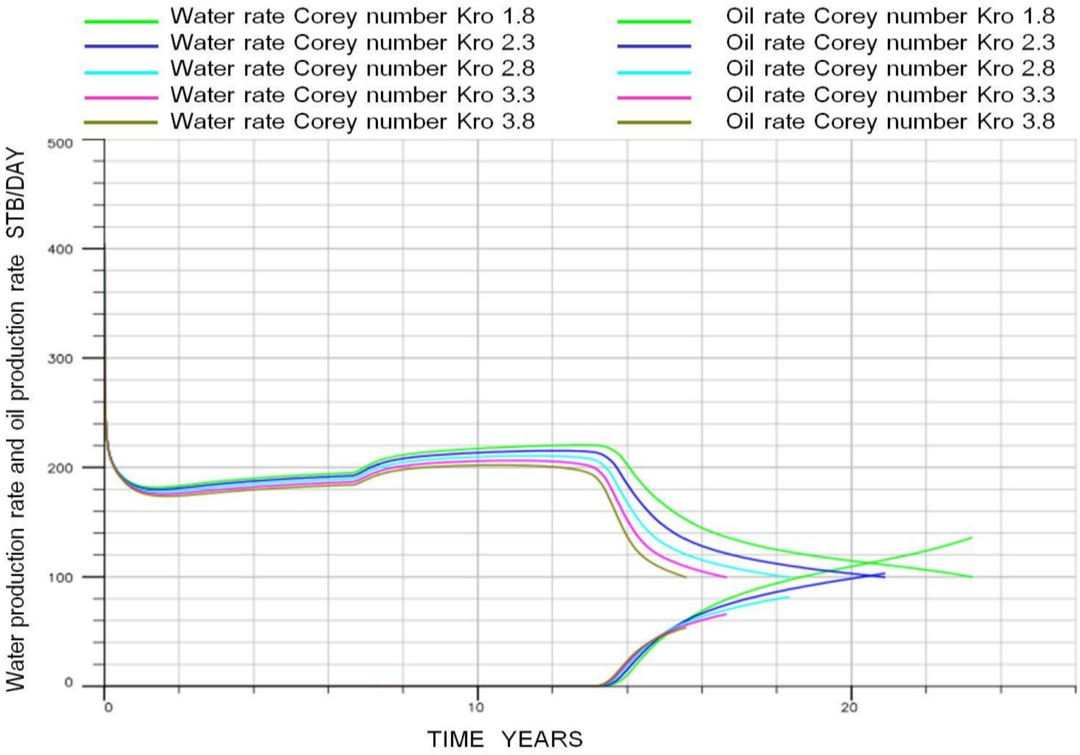


Figure 5.44 Oil production rates and water production rates of chemical flooding cases with variation of Corey's exponent of relative permeability to oil in immiscible mode

From Figure 5.45 water cut of all cases start to rise up from water breakthrough time. It can be seen that, when ability of oil flow is diminished water cut is increased at higher rate because oil is hard to be produced and hence, ratio of water to total fluid produced is higher.

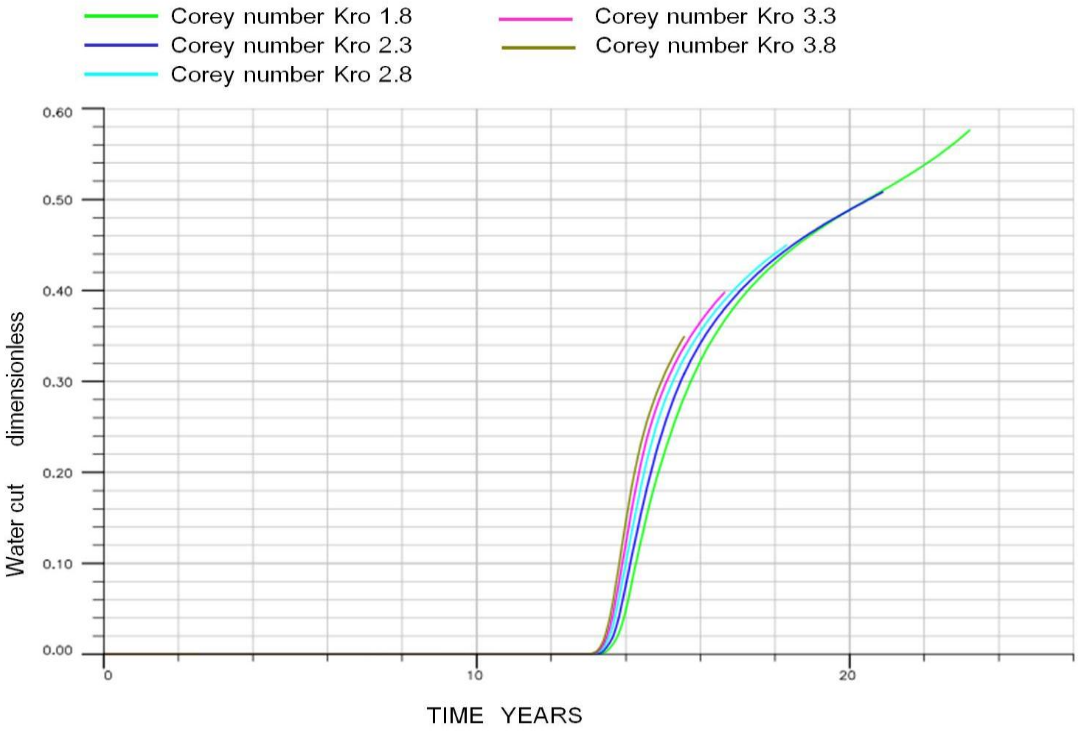


Figure 5.45 Water cut of chemical flooding cases with variation of Corey's exponent of relative permeability to oil in immiscible mode

Similar to the study of Corey's exponent of relative permeability to oil, Table 5.12a summarizes cumulative oil production, oil recovery efficiency and production life, whereas Table 5.12b concludes cumulative water production, dimensionless cumulative water injected, surfactant consumption and alkali consumption, of chemical flooding cases with variation of Corey's exponent of relative permeability to water. Again, Figures 5.46 to 5.49 illustrate simulation output of this parameter study, including oil recovery efficiency, injection rate at injector, oil/water production rates and water cut as functions of time of this study, respectively.

Table 7.12a Summary of cumulative oil production, oil recovery efficiency and production life of chemical flooding cases with variation of Corey exponent of relative permeability to water

Corey exponent of k_{rw}	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (%)**	**Production life (years)**
1.1	1.36	46.00	23 y 9 m
1.4	1.30	44.00	22 y 2 m
1.8	1.19	39.98	18 y 4 m
2.3	1.22	41.00	17 y 10 m
2.8	1.30	44.00	18 y 8 m

Table 5.12b Summary of cumulative water production, dimensionless cumulative water injected, surfactant consumption and alkali consumption of chemical flooding cases with variation of Corey's exponent of relative permeability to water

Corey's exponent of k_{rw}	**Cumulative water production (STB)**	**Dimensionless cumulative water injected**	**Surfactant consumption (LB)**	**Alkali consumption (LB)**
1.1	534,673	0.61	179,352	512,434
1.4	335,732	0.53	176,504	504,298
1.8	99,194	0.43	173,570	495,913
2.3	27,202	0.42	170,565	487,328
2.8	9,344	0.44	168,285	480,815

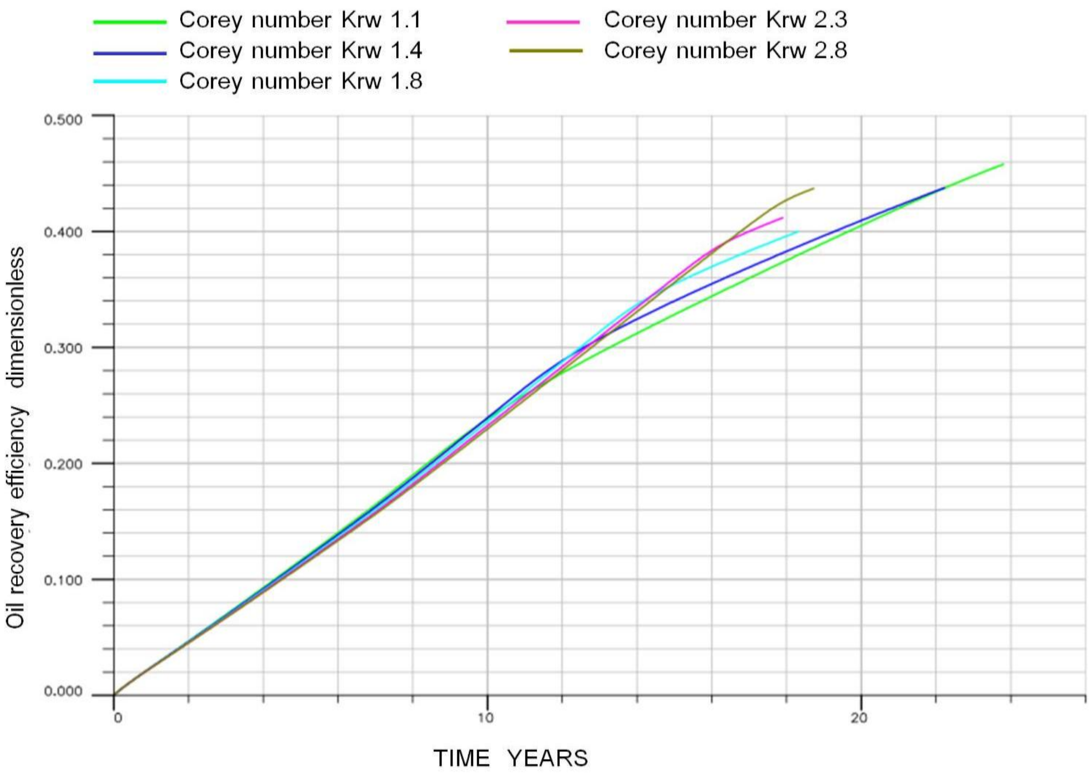


Figure 5.46 Oil recovery efficiencies of chemical flooding cases with variation of Corey's exponent of relative permeability to water in immiscible mode

From Table 5.12a, Table 5.12b and Figure 5.46, oil recovery efficiency is the lowest when Corey's number of relative permeability of water is 1.8. At lower Corey's exponent, relative permeability to water is straightest line. That means flow ability of water is very high. This results in and early breakthrough of water. However, after injected slug of chemical arrives to producer, injectivity is improved and injection rate is increased. Therefore, production can be maintained for long time and oil recovery efficiency is high. On the other hand, when Corey's exponent is high, flow ability of water is very low and water tends to be attached over rock surface. Water breakthrough occurs very late and only oil is produced in front of water bank. Suddenly after water breakthrough oil production declines and production is terminated. These two effects as describe results in reduction of oil recovery efficiency and re-increasing again as Corey's exponent is increased.

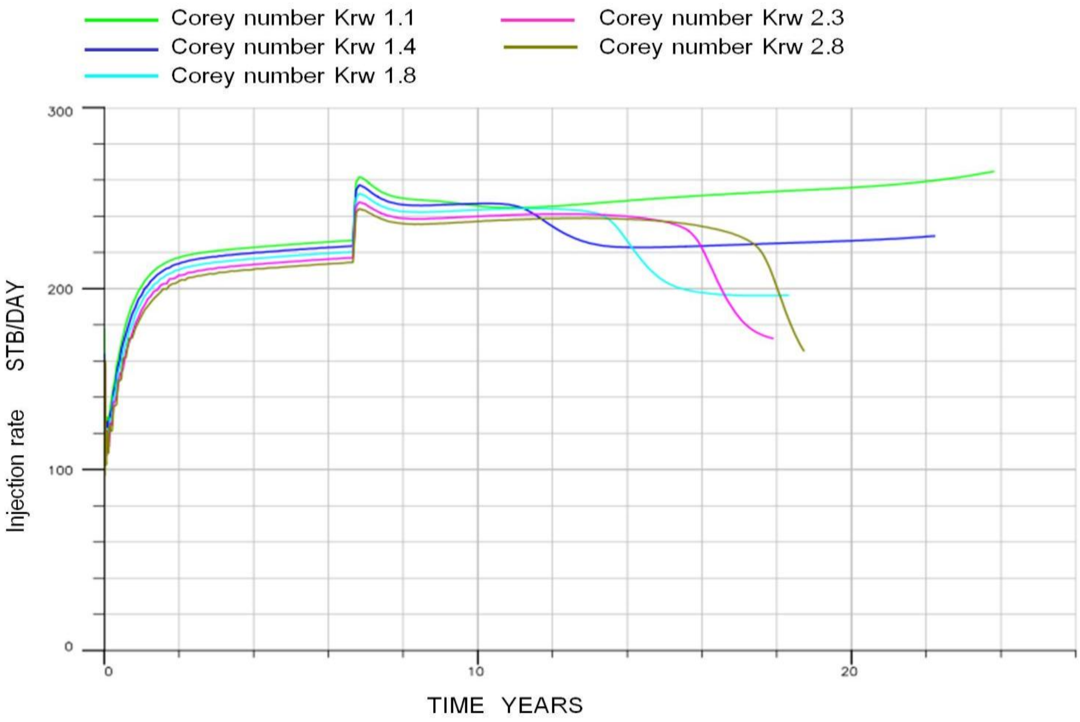


Figure 5.47 Injection rates of chemical flooding cases with variation of Corey's exponent of relative permeability to water in immiscible mode

From Figure 5.47, it can be seen that reduction of injection rate occurs at different period, the higher the flow ability of water, the sooner the reduction of injection rate. High reduction of injection rate occurs when Corey's exponent is high. That means when water breakthrough, oil is produced less and as injected water tends to adhere on rock surface, water is therefore injected difficulty.

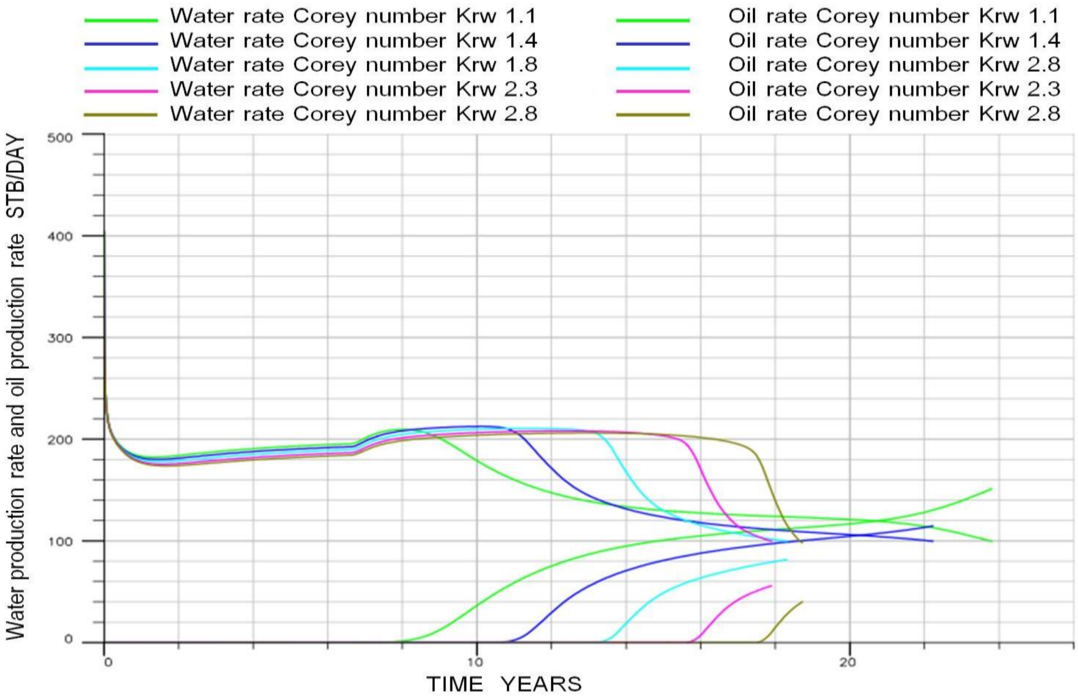


Figure 5.48 Oil production rates and water production rates of chemical flooding cases with variation of Corey's exponent of relative permeability to water in immiscible mode

From Figure 5.48 oil production rates drop when water breakthroughs. Oil production rate from the lowest value of Corey's exponent results in early decline of oil rate. However, oil can be produced for longer period since oil production rate declines slowly. On the contrary, oil production rate declines suddenly for the highest value of Corey's exponent, causing a shut in due to minimum oil production rate. Breakthrough period can be clearly seen in Figure 5.49.

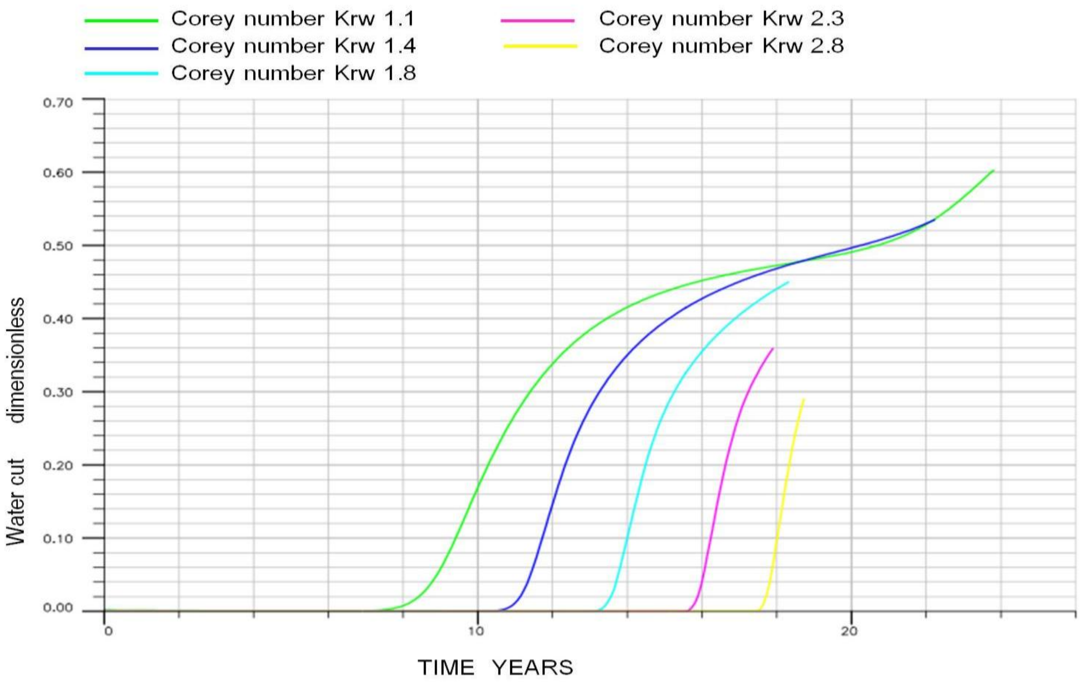


Figure 5.49 Water cut of chemical flooding cases with variation of Corey's exponent of relative permeability to water in immiscible mode

From previous discussion, since relative permeabilities of immiscible mode is modified, oil recovery efficiency of most case are is still high since relative permeabilities of miscible remain the same. Hence, the best strategy mostly depends on relative permeability that can maintain longer production period.

Relative permeability to oil shows an exact trend on oil recovery efficiency. Higher flow ability of oil results in longer production period. However, relative permeability to water shows a different result. When flow ability of water is high, water tends to flow faster. Therefore, water breakthrough occurs early. However, this results in maintaining injectivity and oil production rate. Oil recovery factor is then relatively high in this case. And when flow ability of water is low, only oil is produced, whereas injected water tends to adhere on rock surface. This situation is also good enough for oil production but then injection rate drops suddenly when water breakthroughs. Oil recovery obtained from this case is high as well.

5.8.2 Relative permeability curves of miscible mode

For relative permeability curves of miscible flooding, both Corey's exponent of relative permeability to oil and water are originally fixed at 1.3 to match relative permeability of miscible mode forming when emulsification between oil and water to occurs [2]. Therefore, both Corey's exponents for relative permeabilities to oil and water are changed simultaneously at the same value. In this study, Corey's exponent of both relative permeabilities to oil and water are varied from 1.0 to 2.0. Figure 5.50 illustrates generated relative permeabilities to oil and water in miscible mode.

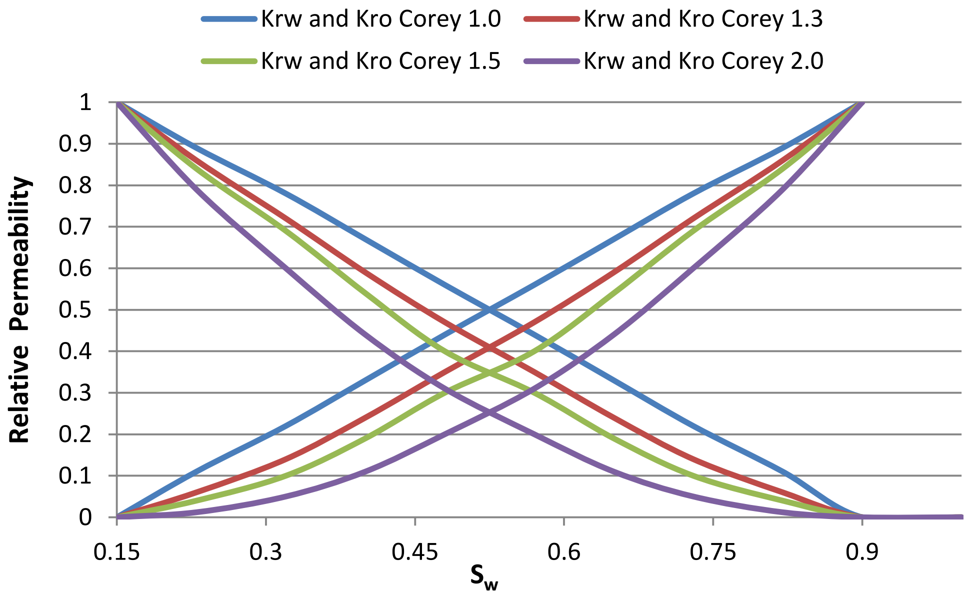


Figure 5.50 Generated relative permeabilities to oil and water with variation of Corey's exponents in miscible mode

Table 5.13a summarizes cumulative oil production, oil recovery efficiency and production life, whereas cumulative water production, dimensionless cumulative water injected, surfactant consumption and alkali consumption of chemical flooding cases with variation of Corey's exponents of both relative permeability to oil and water in miscible mode. Figures 5.51 to 5.54 illustrate simulation outputs of this parameter study, including oil recovery efficiency, injection rate at injector, oil/water production rates and water cut as functions of time of this study, respectively.

Table 7.13a Summary of cumulative oil production, oil recovery efficiency and production life of chemical flooding cases with variation of Corey exponents of relative permeabilities to oil and water in miscible mode

Corey's number of k_{rw} and k_{ro}	**Cumulative oil production (MMSTB)**	**Oil recovery efficiency (%)**	**Production life (years)**
1.0	1.21	40.50	18 y 7 m
1.3	1.19	39.98	18 y 4 m
1.5	1.17	39.50	18 y 0 m
2.0	1.13	38.00	17 y 6 m

Table 5.13b Summary of total water production, total water injection, surfactant consumption and alkali consumption of chemical flooding cases with variation of Corey's exponent of relative permeabilities to oil and water in miscible mode

Corey's number of k_{rw} and k_{ro}	**Cumulative water production (STB)**	**Dimensionless cumulative water injected**	**Surfactant consumption (LB)**	**Alkali consumption (LB)**
1.0	109,433	0.44	175,137	500,391
1.3	99,194	0.43	173,570	495,913
1.5	91,936	0.42	172,181	491,946
2.0	74,512	0.40	167,008	477,167

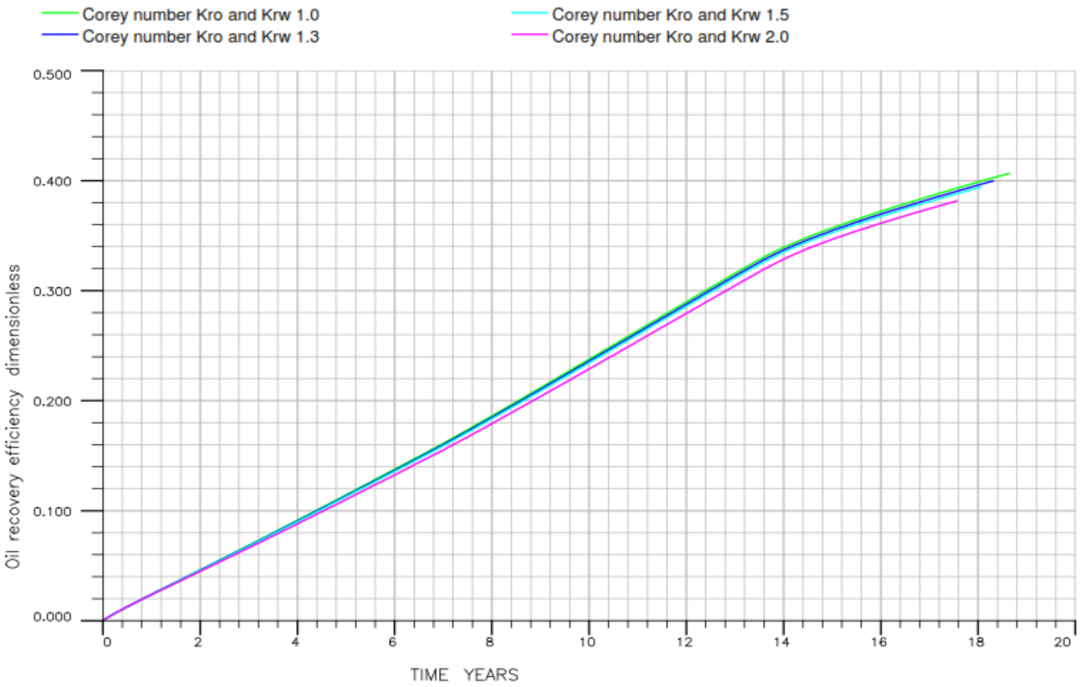


Figure 5.51 Oil recovery efficiencies of chemical flooding cases with variation of Corey’s exponents of relative permeabilities to oil and water in miscible mode

From Table 5.13a, Table 5.13b and Figure 5.51, oil recovery efficiency slightly drops as Corey’s exponents both relative permeability increases. Since increment of Corey’s exponent of relative permeability means curvature of both k_{ro} and k_{rw}, all curves are more concave up as shown in Figure 5.50. Therefore, flow ability of both oil and water drop together. Injectivity plays an important role in this case. As flow ability of both relative permeabilities decrease, oil and water are difficultly produced and injection is then low compared to the case of better flow ability. This results in lower oil recovery efficiency and cumulative water production is increased as higher volume of water injection. Results shown in Figure 5.52, 5.53 and 5.54 do now show significant difference. As described, longer production time results in better oil recovery efficiency.

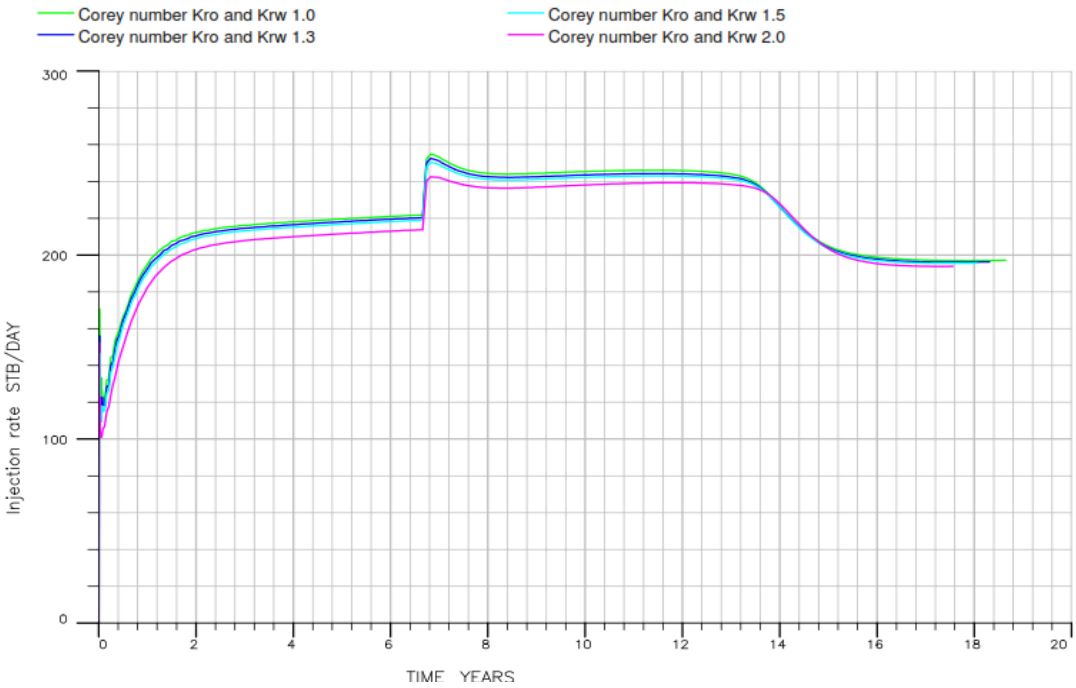


Figure 5.52 Injection rates of chemical flooding cases with variation of Corey's exponents of relative permeabilities to oil and water in miscible mode

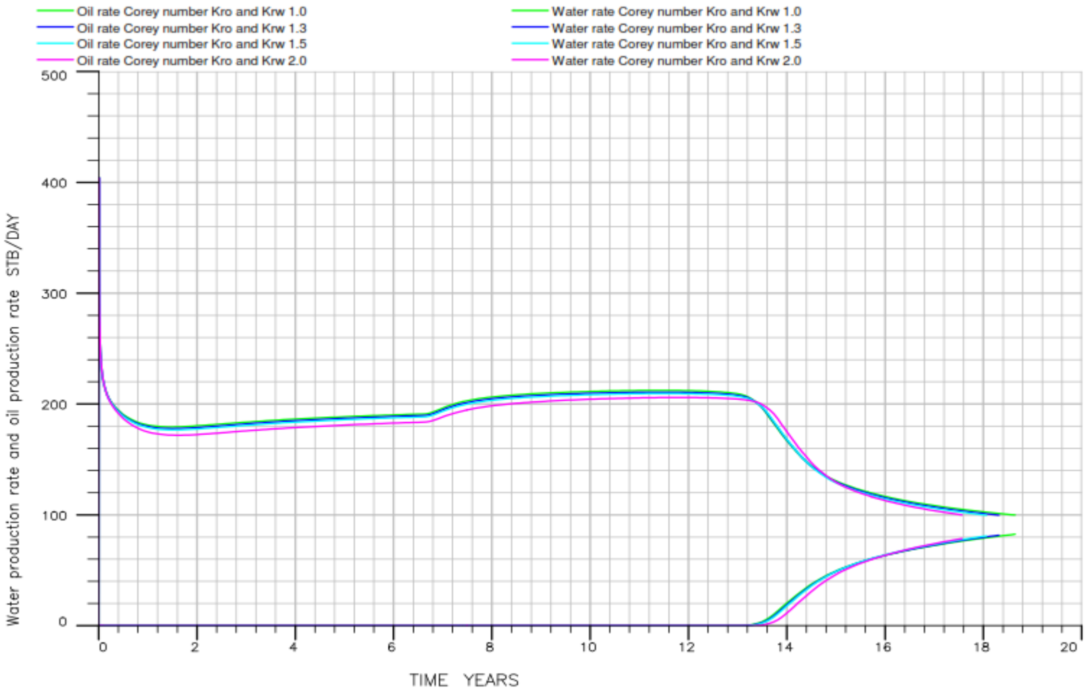


Figure 5.43 Oil production rates and water production rates of chemical flooding cases with variation of Corey's exponents of relative permeabilities to oil and water in miscible mode

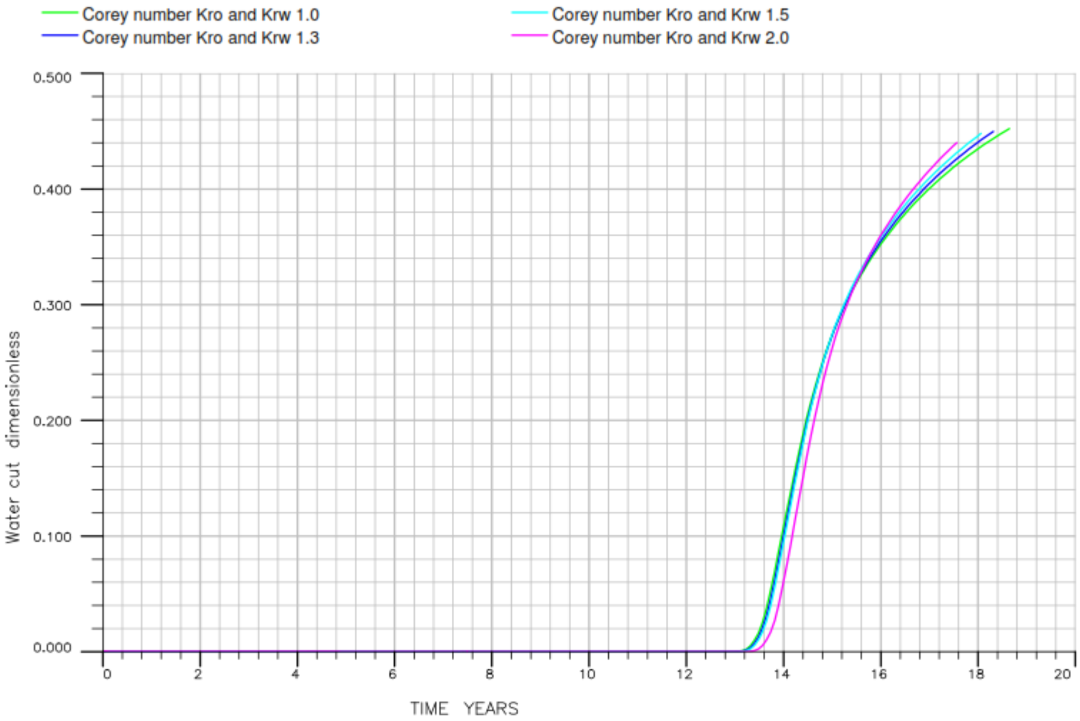


Figure 5.54 Water cut of chemical flooding cases with variation of Corey's exponents of relative permeabilities to oil and water in miscible mode

As flow ability in alkali/surfactant flooding is a combination between immiscible and miscible modes. It can be obviously seen that, when relative permeabilities of immiscible mode are varied, oil recovery efficiency is much more affected compared to variation of permeabilities of miscible mode. This can be concluded that as surfactant is injected close to CMC, maintaining miscible mode throughout flooding process is difficult. At certain point in the reservoir, displacement mechanism returns back to immiscible mode. Hence, relative permeabilities of immiscible mode yield more sensitivity on oil recovery efficiency of alkali/surfactant flooding. In addition, variation of Corey's exponents of relative permeabilities is high highly sensitive to oil recovery efficiency. Thus, precise relative permeabilities from laboratory should be provided for using in simulation to obtain precise result.

CHAPTER VI

CONCLUSIONS AND RECOMMENDATIONS

This chapter summarizes findings from reservoir simulation of alkali/surfactant flooding in multi-layered carbonate reservoirs with different pore sizes. The effect of design parameters on this flooding is concluded. In addition, some recommendations of possible future study are mentioned.

6.1 Conclusion

Results from this study show that oil recovery efficiency obtained from alkali and surfactant flooding ranges from 40 to 50 percent, depending on design parameters. These numbers are outstanding when compared to conventional waterflooding that yields only 25 percent of oil recovery efficiency. An appropriate set of design parameters to yield the best performance of oil production should be cautiously considered. Conclusions of effects from each design parameter on alkali and surfactant flooding process is noted as following.

1. Chemical flooding should be performed without pre-flushed of water in order to avoid dilution of injected chemical. However, this conclusion is not valid for cases where precipitation of chemical with divalent ions is severe.

2. Optimized chemical slug size is 0.20PV. It allows chemical substances to reduce IFT effectively and economically. Slug size larger than 0.20PV does not yield benefit on oil recovery efficiency because it lowers injectivity at injector due to viscosity of chemical solution and also increases cost of chemical substance.

3. Surfactant concentration plays more important role on effectiveness of alkali/surfactant flooding compared to chemical slug size. The best surfactant concentration in this study is 0.1% w/w or at critical micelles concentration.

4. High contrast of pore size results in advantage on oil recovery efficiency. High capillary pressure zone results in diversion of injected fluid to other zones where capillary pressure is lower. This condition causes oil banks from IFT reduction in each layer to travel with different speed. Arrival of oil banks in sequence extends production life as well as increases oil recovery efficiency. However, this could appear differently in different reservoir structure and operational conditions.

5. High vertical permeability yields benefit on oil recovery efficiency. Water tends to flow downward to bottom layer from gravity effect, causing different speed of injected chemical flood front. Likely to effect of high pore size contrast; result could be different in different reservoir structure as well as operational conditions.

6. Mobile connate water saturation results in disadvantage to alkali/surfactant flooding. This present water in formation causes dilution of surfactant behind flood front and consecutively increases interfacial tension. As a result, fluid flows in immiscible mode. Therefore, efficiency is not different from conventional waterflooding. Moreover, mobile connate water also increases relative permeability to water that result is fast movement of water and eventually early water breakthrough.

7. As flow ability in alkali/surfactant flooding is a combination between immiscible and miscible modes and maintaining miscible mode throughout flooding process is difficult. Hence, relative permeabilities of immiscible mode yield more sensitivity on oil recovery efficiency of alkali/surfactant flooding.

6.2 Recommendation

The following issues are recommended for future study.

1. In this study, some properties of chemical substances and reservoir rock such as chemical adsorption, surfactant adsorption reduction by alkali, viscosity of chemical solution are based on the ECLIPSE®100 default data. Real experimented data from laboratory should be used for a more accurate result.

2. IFT reduction is a function of specific type of surfactant. Again, the laboratory result should be involved. Moreover, many commercial surfactants that could yield ultra-low IFT are available. That is, a more reasonable advantage of alkali/surfactant could be obtained.

3. Other patterns of flooding should be performed such as more numbers of injectors as well as producers.

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APPENDIX

Appendix

Reservoir model

A reservoir model is generated by entering required data into **ECLIPSE®100** reservoir simulator. The model used in this study composes of 50 x 50 x 15 cells in the x-, y- and z- direction. 15 blocks in z- direction are divided to 3 layers as thickness of 5 cells in each layer.

1. Case Definition

Simulator	Black oil
Model dimension	Number of cells in the x-direction50
	Number of cells in the y-direction 50
	Number of cells in the z-direction 15
Grid type	Cartesian
Geometry type	Corner Point
Oil-Gas-Water options	Water, oil, no dissolved gas

2. Reservoir properties

Gird

Active Grid Block X(1-50) = 1
Y(1-50) = 1
Z(1-15) = 1

X Permeability	20 md
Y Permeability	20 md
Z Permeability	20 md
Porosity	0.30

Grid block sizes	20 x 20 x 5 feet in the x-, y- and z- direction.

3. PVT

Dead oil PVT properties

Oil gravity	24	API
GOR	300	SCF/STB
Salinity	0	%
Standard pressure	14.7	psia
Standard temperature	60	°F

Formation water PVT properties

Reference pressure(P_{ref})	1400	psia
Water FVF at P_{ref}	0.9997213	rb/stb
Water compressibility	3.046602E-6	psi^{-1}
Water viscosity at P_{ref}	0.6277618	cP
Water viscosibility	1.287619E-6	psi^{-1}

Fluid densities at surface condition

Oil density	56.75144	lb/ft^3
Water density	62.42797	lb/ft^3
Gas density	0.04369958	lb/ft^3

Rock properties

Reference pressure	1400	psia
Rock mass density	1000	LB/RB
Rock compressibility	2.97487 E-06	psi^{-1}

Dead oil PVT properties (No dissolved gas)

Pressure (psia)	FVF (rb /stb)	Visc (cp)
1740.8956	1.1353285	2.9967547
1826.3158	1.1324674	3.0143963
1900.0000	1.1318850	3.0358569

4. SCAL

Water/oil saturation functions of immiscible flooding for big pores

S_w	k_{rw}	k_{ro}	P_c ***(psia)***
0.150	0	1	0
0.211	0.00958	0.71907	
0.272	0.03336	0.49476	
0.333	0.06921	0.32132	
0.394	0.11616	0.19286	
0.456	0.17357	0.10325	
0.517	0.24099	0.04614	
0.578	0.31806	0.01483	
0.634	0.40448	0.00213	
0.700	0.50000	0	
1	1	0	-2

Water/oil saturation functions of immiscible flooding for big pores

S_w	k_{rw}	k_{ro}	P_c ***(psia)***
0.150	0	1	0
0.211	0.00958	0.71907	
0.272	0.03336	0.49476	
0.333	0.06921	0.32132	
0.394	0.11616	0.19286	
0.456	0.17357	0.10325	
0.517	0.24099	0.04614	
0.578	0.31806	0.01483	
0.634	0.40448	0.00213	
0.700	0.50000	0	
1	1	0	-10

Water/oil saturation functions of miscible flooding for both big pores and small pores

S_w	k_{rw}	k_{ro}	P_c (psia)
0.150	0	1	0
0.233	0.05748	0.85803	0
0.317	0.14152	0.72129	0
0.400	0.23974	0.59031	0
0.483	0.34847	0.46574	0
0.567	0.46574	0.34847	0
0.650	0.59031	0.23974	0
0.733	0.72129	0.14152	0
0.817	0.85803	0.05748	0
0.900	1	0	0
1	1	0	0

5. Initialization

Equilibration data specification

Datum depth	3200 ft
Pressure at datum depth	1400 psia
WOC depth	5000 ft

6. Schedule

In reservoir simulation model, well setting is described as follows

Production well specification

Well name	P1
Group	P
I location	1
J location	1

Preferred phase	OIL

Well connection data

Well connection data	P1
K upper	1
K lower	15
Open/shut flag	OPEN
Well bore ID	0.5104167 ft.
Direction	Z

Production well control

Well	P1
Open/shut flag	OPEN
Control	LRAT
Liquid rate	1500 stb/day
BHP target	200 psia

Production well economic limits

Well	P1
Maximum water cut	0.95
Minimum oil production rate	100 stb/day

Injection well specification

Well name	I1
Group	I
I location	50
J location	50
Preferred phase	WATER

Well connection data

Well connection data	I1
K upper	1
K lower	15
Open/shut flag	OPEN

Well bore ID	0.5104167 ft.
Direction	Z

Injection well control

Well	I1
Open/shut flag	OPEN
Control	BHP
Liquid rate	500 stb/day
BHP target	1900 psia

Vitae

Mr. Arnon Larpkachornsanguan was born on July 3rd, 1983 in Bangkok, Thailand. He received his Bachelor degree in Civil Engineering from Faculty of Engineering, Chulalongkorn University in 2005. He has joined SCG Plc. as a Civil Engineer after his graduation. He continues his study in Master’s Degree of Petroleum Engineering at the Department of Mining and Petroleum Engineering, Chulalongkorn University since the academic year 2010.